THE ECONOMIC EFFICIENCY
OF PUBLICLY OWNED HYDRO-ELECTRIC UTILITIES
WITH SPECIFIC REFERENCE TO MANITOBA HYDRO

A Thesis
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Master of Arts

by
Richard Stephen Partridge

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THESIS ABSTRACT

The purpose of this thesis is to discuss methods of evaluating the overall economic performance of publicly owned hydro-electric utilities.

The basic assumption of this study is that there will be a number of key criteria to which a number of variables such as costs of construction, installation costs of capital, interest rates, customer density of service area, customers' growth, increased use per customer, number of employees, payroll costs, productivity of capital and labour, load and utilization factors, etc. might be fitted, which determine both the annual and long run operating results of a public utility such as Manitoba Hydro and determine its rate structure and growth from year to year.

A secondary, but very major objective of this study was to identify, and where possible, quantify those variables subject to the control of Management which might be varied to facilitate the attainment of even greater efficiency in the future.

In approaching this task the author took as his point of departure William Iulo's basic contention that there are various historical, operating, market and in the case of Manitoba geographical factors which affect the unit costs of providing electric energy.

Empirical data related to Manitoba Hydro was studied in an effort to determine the interrelationship of the various factors in order to isolate the influence of each one. An effort was also

made to derive or outline some general principles which are valid as investment, operating and rate determination criteria for Manitoba Hydro, and hopefully, for other hydro-electric utilities with a similar physical and institutional structure.

While it has not been possible to arrive at any precise conclusion as to the relative efficiency of Manitoba Hydro vis-a-vis other publicly owned hydro-electric utilities partly because of the different environment in which each one operates, and it has not been possible to develop any measure of absolute economic efficiency which would state that Utility A is X% efficient it is felt that some definite, if partly subjective conclusions can be stated as to the relative economic and social efficiency of Manitoba Hydro.

The author believes that a unique combination of geographical, historical, operating and market factors have rendered the supply of electric energy to the people of Manitoba a highly efficient operation. For decades, Manitobans have enjoyed the highest per capita consumption of electricity in Canada for domestic and farm purposes and have paid the lowest average unit costs in Canada for this energy.

For the combined industrial-commercial sector, Manitoba's average consumption per customer is less than half that of Ontario and Quebec, the two provinces with the greatest concentration of large industry, yet the average unit costs of industrial and commercial energy is only marginally higher than in these provinces. The author feels that relative to the average industrial and commercial consumption per customer in Manitoba, that Manitobans enjoy the lowest average unit costs in Canada.

While the presence of an abundance of easily developed hydro-electric potential on the Winnipeg River played a prominent role in the success of the electric supply industry of Manitoba this was by no means the sole factor. The advent of public power with the creation of the City of Winnipeg Hydro Utility, the very successful rate structure instituted by the city, and the high utilization per customer encouraged by these rates have also been significant factors as have the various political and technical approaches taken by governments and engineers during each critical stage of the evolution of the Manitoba system.

ACKNOWLEDGEMENTS

The ideas and material contained in this thesis were formulated during the author's undergraduate years at the University of Manitoba. During this period the author had the good fortune to be associated with the Economics Department of Manitoba Hydro and to become deeply involved with the problems, economic and otherwise of running a large publicly owned electric utility.

The inspiration for this thesis comes largely from Dr. K. Kristjanson, an Economist and Assistant General Manager, Administration of Manitoba Hydro. The author's interest in the factors which contribute to the economic efficiency of organizations and particularly electric utilities, was kindled by Dr. Kristjanson's constant urging to find means of determining how well Manitoba Hydro was performing relative to other organizations, relative to its own past performance, and how this performance might be improved.

As the work progressed the author became more aware of how much this thesis owes to the constant discussion with and exposure to the ideas of personnel in all areas of Manitoba Hydro; Engineering, Finance, Administration and Operating. To this extent the work is not so much that of the author, but represents the synthesis of many ideas from many sources.

I should also like to thank Mr. J. Siemens, Mr. H. E. Lyon, Mr. J. Cline and Mr. V. E. Nelson, members of the Manitoba Hydro Economics Department who assisted the author in various steps of the research by suggesting sources of information, by acting as sounding boards for many ideas, and for the provision of the wealth of statistical data which they had prepared and collected over the years. A similar debt is owed to Mr. R. D. Beesley, Mr. G. Lougheed, and Mr. J. Spokes who played major roles in the development of the financial projections which formed an important part of my research.

Miss M. Gardiner, Manitoba Hydro librarian, and her staff, have provided almost daily assistance by locating the most obscure documents and information at the shortest notice, thus easing much of the frustration which often accompanies research of this kind.

My thanks also to Mrs. B. N. Demytrie, Supervisor of the Steographic Pool who arranged to have the manuscript typed, to her staff who did much of the actual work, and to Mrs. Sandra Leveille, Secretary to the Economics Department who patiently set up and typed the many complex tables and other specialized documents which accompanied this work.

My ideas, especially my philosophical approach to public corporations and the concepts of social efficiency owe much to my association with Professor R. F. Harris who kindly consented to act as my faculty advisor. The suggestions he made helped immensely with the organization, assured that I got off to a sound start, and that the work progressed expeditiously to a successful conclusion.

Richard S. Partridge
Winnipeg, Manitoba
March 1969

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CHAPTER I

I N T R O D U C T I O N

The purpose of this theisis is to discuss methods of evaluating the overall performance of publicly owned Hydro-electric utilities. This objective by itself may seem somewhat limited or restricted. This restricted scope was adopted purposely by the writer to allow him to concentrate exclusively on an industry and specific Crown Corporation, in which he has a particular interest. It is hoped however that some of the criteria established here, and approaches employed might later be modified and used to evaluate other public corporations and government departments such as for example a nationally owned airline, railway, public transit system, or even the post office.

THE CROWN CORPORATION

Manitoba Hydro, the public body entrusted with the responsibility of providing electrical energy to the people of the Province of Manitoba is a Crown Corporation. A good working definition of a Crown Corporation is that it is a corporation, ultimately accountable through a Minister to Parliament for the conduct of its affairs. This definition while indicating quite clearly that a Crown Corporation is a quasi governmental body, publicly owned, and in business exclusively to serve the public good, indicates that it is also a corporation and thus should have a degree of administrative flexibility and freedom comparable to that of a private corporation.

Because of the rather hybrid nature of the public corporation form, and the large variety of tasks which have been assigned to them, there has over the years been rather a lot of controversy and confusion regarding their role and their administration.

In Canada a Crown Corporation is the usual form of organization chosen when government wishes to provide a service which is of a business nature such as transportation, or communications. In the past there have been numerous reasons for governments to enter into business enterprises, but in general a public corporation has been formed to provide a vital service in areas where private business is unwilling or unable to enter.

In surveying the many Crown Corporations in Canada we find that the majority are in industries which because of their nature require a monopoly. This is the case with transportation, communications and the provision of electric power. The facilities required are extremely expensive and the duplication which competition would bring about would be highly inefficient and wasteful. In other words a Crown Corporation appears to be the solution when the choice lies between inefficient private competition, efficient private monopoly, or efficient public monopoly.

While the objective of economic efficiency is probably one of the paramount considerations, the objective of providing a vital service to as wide an area as is practicable overrides purely economic considerations. Thus Crown Corporations are expected to extend services to uneconomical rural areas to ensure more equitable regional distribution of social welfare.

In order to achieve the high level of efficiency expected of it, it is desirable that a Crown Corporation enjoy a high degree of autonomy, so that it as far as possible they can be conducted as a commercial concern, and should be self-supporting. Thus in ordinary matters of detail and day to day operations, management should be free to manage. With matters of major policy which might have a very large effect on the entire community, it is generally felt that some sort of consultation or political control is desirable. However the degree of public accountability should not be such as to impair its commercial enterprise and efficiency.

THE STANDARDS BY WHICH THE EFFECTIVENESS OF A CROWN CORPORATION SHOULD BE JUDGED

In assessing the effectiveness of a Crown Corporation it is not realistic or desirable to employ the same standards as one would with a private business. With a private business the ultimate test of its success is its ability to earn profits. This of course is a very imperfect criteria as many economists have pointed out. High profits can result from monopoly, or other fortuitous circumstances and can mask gross inefficiency and high social costs such as pollution which are not charged against the business.

A Crown Corporation too, can earn profits. If circumstances are favorable satisfactory profits resulting from a natural monopoly can again mask inefficiency,while in unfavourable circumstances high efficiency may be achieved despite an absence of profits.

The effectiveness of any organization can partially be measured by subjective means. Manitoba Hydro has generally enjoyed good public relations, and has been able to preserve a favorable image with its customers. For many years there has been a general feeling in Manitoba that electricity rates were reasonable, and it has even been widely believed that Manitobans enjoyed the lowest rates in North America. While no attempt has been made to verify this, it is accurate to say that no rates in Canada are significantly lower than in Manitoba. W. Robson a recognized authority on Public Corporations partially employs this subjective approach. He suggests that the test of efficiency must be whether the service provides facilities which are reasonably adequate to meet the public needs at prices which are reasonable and which will enable the undertaking to pay its way.

Robson quotes the work of Sargant Florence, and Gilbert Walker who contend that breaking even or making a surplus is the best primary test of efficiency in the public sector provided that certain conditions are fulfilled. These are:

1. That surpluses must not be made by exploition. ie. of employees.

2. Money costs should reflect real costs and must not leave social costs out of account.

3. The surplus should result from a small margin on a large output rather than a large margin in a small output.[1]

In short the prime measure of efficiency according to these standards is to break even, or earn a small surplus, at the greatest level of production. Indications of particularly successful management would be the tendency to lower prices, improve the quality of service, or provide an extended range of goods and services.

Florence and Walker urge that public corporations should strenuously avoid meeting increased costs by raising prices and relying upon their monopoly to provide the surplus. Indeed the proper test of the efficiency of a nationalized industry in their view, lies in the degree of success shown by the management in lowering the costs of production.

Robson suggests that while it is desirable that costs should be brought into the picture in assessing efficiency, that if we do not know what the optimum cost should be, we are unable to judge the degree of efficiency reflected by the costs. He adds that even in a free market, it is impossible to determine whether maximum efficiency and minimum cost

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1. Robson, W., Nationalized Industries and Public Ownership, London, University of Toronto Press, 1960, P. 417.

have been attained by the firm.[2]

Elsewhere Robson states, "While it is desirable to seek continually for increased efficiency in nationalized industry, and although it is possible to achieve it in many different ways, the overall effectiveness cannot be reduced to a single quantitative measurement. Nevertheless many particular aspects of a nationalized industry can be measured statistically, and the efficiency of the undertaking can in part be assessed by assembling a large number of these relevant measurements".[3]

In attempting to measure the effectiveness of a Crown Corporation, Manitoba Hydro, the author has arrived at the same general conclusion stated by Mr. Robson. In continuous research spanning more than two years the author has been unable to discover a single measurement which could be regarded as a suitable indicator of corporate performance. However a considerable number of relevant measures have been established, each of which do give a partial indication of effectiveness. The objective of the following chapters is to determine what some of these relevant measurements might be in the case of Manitoba Hydro and similar organizations, to discuss their characteristics, how they might be applied and to point out their shortcomings.

THE HISTORICAL DEVELOPMENT OF THE ELECTRICAL UTILITY INDUSTRY IN MANITOBA

The formation of Manitoba Hydro on April 1, 1961 through the amalgamation of The Manitoba Hydro Electric Board and The Manitoba Power Commission represents the most recent stage of the evolution of the electric utility industry in Manitoba and the consolidation of most of the elements of Manitoba's electrical supply under the central control of one organization.

The history of electrical energy in Manitoba goes back before the turn of the century. Although the actual beginnings of the industry

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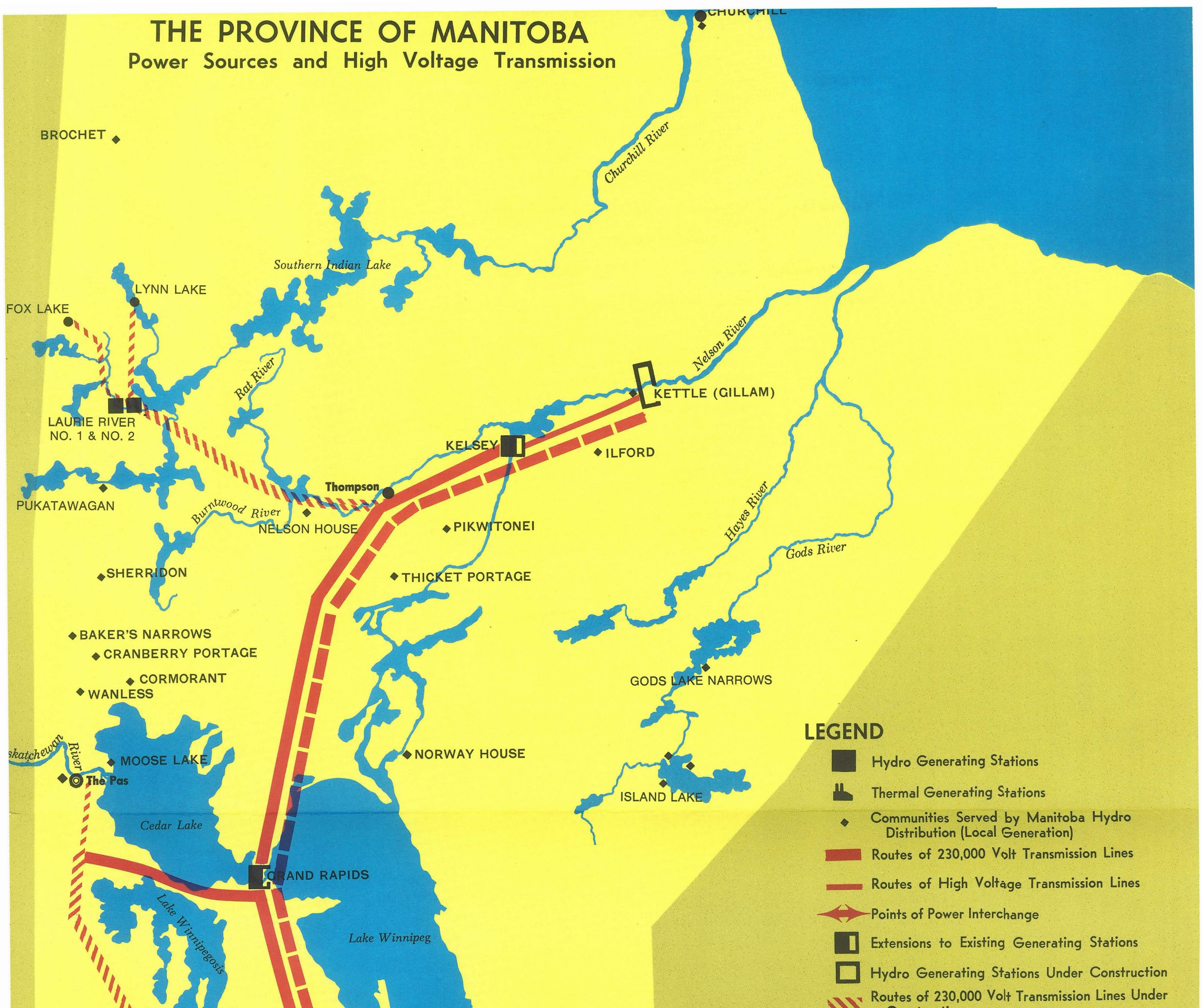
2. Ibid., p. 420

3. Ibid., p. 431


THE PROVINCE OF MANITOBA
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CHURCHILL
Churchill River
BROCHET
Southern Indian Lake
LYNN LAKE
FOX LAKE
Rat River
Nelson River
KETTLE (GILLAM)
LAURIE RIVER NO. 1 & NO. 2
KELSEY
ILFORD
Thompson
PUKATAWAGAN
Burntwood River
NELSON HOUSE
PIKWITONEI
Hayes River
Gods River
SHERRIDON
THICKET PORTAGE
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CRANBERRY PORTAGE
CORMORANT
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Neepawa
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SELKIRK
SLAVE FALLS
SEVEN SISTERS
Portage la Prairie
CITY OF WINNIPEG
Brandon
Red River
Steinbach
Boissevain
Morden
Emerson
PINE FALLS
BRANDON
SELKIRK
GRAND RAPIDS
POINTE DU BOIS
BRANDON
GREAT FALLS
SEVEN SISTERS
AMY
SELKIRK
SLAVE FALLS
GREATER WINNIPEG
MANITOBA HYDRO AND WINNIPEG HYDRO SYSTEM INTERCONNECTIONS

	STATION	LOCATION	No. of Units	Capacity in Kilowatts
HYDRO:	Pine Falls	Winnipeg River	6	82,000
	Great Falls	Winnipeg River	6	132,000
	McArthur	Winnipeg River	8	56,000
	Seven Sisters	Winnipeg River	6	150,000
	Grand Rapids	Saskatchewan R.	3	354,000
	Kelsey	Nelson River	5	160,000
	TOTAL HYDRO			934,000
THERMAL:	Brandon	Brandon East	4	132,000
	Selkirk	Selkirk East	2	132,000
	TOTAL THERMAL			264,000
GAS TURBINE:	Selkirk East	Selkirk East	1	14,000
DIESEL:	Baker's Narrows			230
	Brochet			120
	Cormorant			40
	Cranberry Portage			1,000
	Kettle Rapids (Gillam)			2,700
	God's Lake Narrows			150
	Ilford			60
	Island Lake (3 locations)			600
	Manigotogan			40
	Moose Lake			150
	Matheson Island			40
	Nelson House			150
	Norway House			910
	Pikwitonei			40
	Pine Dock			40
	Pukatawagan			150
	Thicket Portage			40
	The Pas			6,000
	Wanless			40
	TOTAL DIESEL			12,500
	TOTAL GENERATING CAPACITY			1,224,500

LITHOGRAPHED IN CANADA BY
BULMAN BROS. (1966) LIMITED
WINNIPEG

in Manitoba are somewhat hazy it appears that electricity may have appeared on the scene in Winnipeg as early as 1873.[4] Other reports mention that three electric street lights were installed on Main Street in 1882. Energy for these lights being generated from the Hudson's Bay Company grist mill near the junction of the two rivers.[5] From 1882 until 1906 the growth of the industry in Manitoba was continuous if somewhat erratic. Energy requirements in Winnipeg were supplied by a series of rival companies from a number of small oil or steam plants.

By 1900 the Town of Brandon was supplied with electricity generated from a small hydro electric station on the Minnedosa River about ten miles from the Town. The first major hydroelectric development in Manitoba occurred in 1906 with the construction of the Winnipeg Electric Company Plant at Pinawa on the Winnipeg River. In 1911 the City of Winnipeg entered the public utility field with the completion of the Pointe du Bois hydro station, also on the Winnipeg River. The purpose of both these stations was to provide cheap electrical power for the city of Winnipeg.

In 1919 the Manitoba Power Commission was established to extend service to municipalities in rural Manitoba, and in 1920 the first rural line from Winnipeg to Portage la Prairie was completed. Electric energy for rural distribution was purchased from the City of Winnipeg Hydro System. From 1919 to the outbreak of the second world war slow progress in rural electrification continued in spite of a series of setbacks caused by nature, and the economic conditions of the 1930's. By 1939 some 140 communities

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4. D. S. G. Ross, "History Of The Electrical Industry In Manitoba", Reprinted from Papers read before the Historical and Scientific Society of Manitoba. Series III No. 20 1965, p.57.

5. Manitoba Government Public Information Branch - Bulletin dated November 1, 1968.

and a handful of farms had been connected to the system.

In 1942 The Manitoba Electrification Enquiry Commission recommended energetic widespread rural electrification not only of all towns with more than twenty inhabitants but of farms as well. This marked significant forward step as up to 1942 only 500 of the 59,000 farms of the province had electricity. In 1946 an extremely ambitious rural electrification program commenced. Progress was rapid and by 1954 the program was virtually completed with service extended to over 42,000 farms and some 480 communities. By 1954 it could be said that a single integrated distribution system existed for southern rural Manitoba.

The development of an integrated generating system in Manitoba followed a somewhat different path. From 1923 to 1950 three additional hydro generating stations were constructed on the Winnipeg River. Slave Falls constructed by Winnipeg Hydro commenced operation in 1931 while Great Falls and Seven Sisters constructed by The Winnipeg Electric Company became operational in 1923 and 1931 respectively. During this period progress was somewhat irregular as the demand for electrical energy grew at a somewhat uneven rate, a significant decline in demand for electricity occuring during the early thirties. Constant rivalry between the two utilities and the duplication of generation facilities and of distribution facilities within the city of Winnipeg precluded the rational development of Manitoba's electrical supply facilities.

By 1948 it had become apparent that control of the Hydro sites on the Winnipeg River by a number of intersts was inefficient. The Hogg report of 1948 which was commissioned by a provincial government concerned with an impending power shortage stressed the fact that maximum energy output from the Winnipeg River could only be obtained through the closest hydraulic and electrical integration of the various plants.

In 1949 The Manitoba Hydro Electric Board was created to build and control all future power plants in the province. The Board immediately commenced construction of Pine Falls which came into service in 1953 and MacArthur which was completed in 1955. This completed the development of all the potential of the Winnipeg River.

In 1953 the Hydro Board took over all the physical assets of The Winnipeg Electric Company, and in 1955 the facilities of the Hydro Board and Winnipeg Hydro system were integrated to form the Southern Integrated System. At this time distribution networks of the Hydro Board and Winnipeg Hydro in greater Winnipeg were reallocated with Winnipeg Hydro receiving all distribution property in the City of Winnipeg and The Manitoba Power Commission receiving all distribution property in the suburbs. Winnipeg Hydro retained ownership of its two plants on the Winnipeg River, but the Hydro Board assumed the responsibility for co-ordinating the operation of all plants in the province.

In 1956 Manitoba's long issolation from the rest of the electrical world was broken by an interconnection with Ontario. The period of 1957 to 1960 saw the addition of two relatively large thermal plants at Brandon and Selkirk and the Kelsey hydro station on the Nelson River to serve the nickel mining development at Thompson. A second interconnection, this time with Saskatchewan was also established in 1960.

In 1961 the Manitoba Power Commission and The Manitoba Hydro Electric Board were amalgamated under the name of the Manitoba Hydro Electric Board or in an abreviated form Manitoba Hydro. This was an event of some significance both in the evolution of the electric power industry of Manitoba and for this Thesis. With the consolidation of almost all the elements of the electrical utility system of the province in one organization it at last became feasible to conduct a meaningful economic analysis of the entire system.

Since 1961 Manitoba Hydro has expanded extremely rapidly, almost doubling in size in both physical and economic terms. In 1965 the largest single generating station to date, Grand Rapids at the mouth of the Saskatchewan River in northern Manitoba was placed in service. Two years later in 1967 a transmission line from Kelsey to Grand Rapids connected the northern and southern systems to form the Integrated Manitoba System.

At the present time Manitoba Hydro is engaged in the most ambitious hydro development in Manitoba's history, the Phase I development of the Nelson River. This project consists of the Kettle Rapids Generating Station, a series of control dams to divert part of the flows of the Churchill River into the Nelson, and a six hundred mile long direct current transmission line to carry the energy produced to the Winnipeg area. This development due to be placed in service in 1971 will when complete provide almost twice the electrical energy produced in Manitoba in 1960.

Other significant additons planned in the near future are heavier interconnections with Ontario and Saskatchewan and an interconnection with the United States to be in service in 1970.[6]

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6. Information for this brief historical summary was culled from the following sources. William Ivens, "Prismatic Picture of Hydro-Electric Power Development In Manitoba", 1955 Unpublished.

   The Annual Reports of Manitoba Hydro, The Manitoba Power Commission, Winnipeg Hydro and The Winnipeg Electric Company.

CHAPTER II

THE MEANING OF EFFICIENCY AND METHODS OF EVALUATING IT

THE MEANING OF EFFICIENCY

The term efficiency can be defined as the ability to produce the desired effect with a minimum of effort or waste. It has also been defined as the ratio of effective work to the energy expended in producing it.[1] In its simplist terms efficiency is an input - output relationship and can usually be determined fairly easily. In a broader sense however, efficiency is more than just technical efficiency the simple input - output relationship I have just described. In discussing the provision of a vital public service such as that provided by an electric utility privately or publicly owned we should attempt to consider the social efficiency of the operation also. Social efficiency might be defined, if precise definition is possible as the ratio of the use of social resources expended relative to a given social benefit achieved. This is a much less precise concept than simple technical efficiency, but never the less it suggests a criterion that should be applied to any large scale endeavor that has a significant impact on our society. For example we might ask ourselves if the automobile is a socially efficient form of transportation, or if strip mining is a socially efficient way of aquiring minerals, or if manufacturing plants which pollute air and water are socially efficient operations.

Thus seen in its broadest context efficiency is vague and imprecise in its meaning, is not measurable to any degree of precision, and is pregnant with value judgements.

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1. Websters New World Dictionary, p. 239

CRITERIA FOR EVALUATING INVESTMENT PERFORMANCE

This discussion is concerned not only with the criteria and techniques for evaluating expost investment performance, but is concerned with the techniques and criteria employed in arriving at optimal investment decisions. One could say, that the measurement of operating performance is concerned with how effectively the investment is utilized once its in place - the measurement of investment performance is primarily concerned with how correct or how close to the optimum are investment decisions, and how efficiently are these decisions implemented. The objective is to determine how efficiently the capital investment process is carried out.

In approaching the problem of evaluating investment performance it is difficult to escape the feeling that such an evaluation cannot be entirely analytical and objective, and that a large amount of the subjective must enter into it.

In attempting to conceive of an actual measure of investment performance it becomes apparent that operating performance and investment performance are very closely linked. A high level of operating performance is thus probably indicative of a high level of investment performance.

For example productivity measures, total, capital, and labor all reflect the skill with which past investment decisions have been made.

Prices relative to other similar utilities, and price trends over a period of years are all indicative of investment performance. Poor investment decisions, all other factors being equal will show up as upward pressure on costs, while optimal investment decisions will show up as downward pressure.

It could be said that the optimum investment would be that which achieves the minimum unit cost over the longterm. In evaluating performance our objective would appear to be to determine whether or not our actual investment is achieving a minimum cost. (Subject to appropriate constraints of course).

Utilization factors - and measurements of the amount of surplus capacity available at any time provides a partial indication of investment performance, particularly in so far as timing is concerned.

In reviewing the preceeding paragraphs, it can be seen that the efficiency of past investment decisions usually shows up in the present operating performance of a utility. The problem then becomes one of ensuring that the optimal investment decisions are made.

Pierre Massé an economist deeply involved with the investment decisions of Electricite de France has demonstrated a very deep insight into the subtleties and philosophies which must enter into successful investment decisions. In the forward to his book, "Optimal Investment Decisions," he suggests that the essence of the problem is to be able to choose the best investments, the ones that will most wisely answer the people's needs, those that will make it possible to satisfy those needs as cheaply as possible. He points out that, it is necessary to achieve a balance between short term and long term considerations, and that the optimum solution reflects not only quantity, but quality as well.[2]

Massé points out that our basic drive to build things to last can lead us pretty far astray, that the physical life span of things we build is tending to outlast their economic usefulness.[3] This is a phenomena which should concern utility planners, particularly those such

2. Pierre Massé; Optimal Investment Decisions, Englewood Cliffs, N.J. Prentice Hall, 1962, P. IX.

3. Pierre Massé; Ibid, P. IX.

as Manitoba Hydro where the capital intensive nature of hydro generating capacity requires a fifty year amortization period to recover the initial capital.

A really adequate approach to achieving an investment optimum should attempt to achieve a social optimum in Pareto's sense by taking into account all the social benefits and costs involved. Unfortunately for technical reasons as well as intelectual, and institutional reasons present investment decisions rarely approach a social optimum.

Massé suggests that in making investment decisions prices play a leading role, and the most significant price of all is the interest rate. It forms the accounting link between present and future just as the asset invested constitutes their physical link.[4]

Massé quotes George Terborgh's observation that, "In the case of capital goods, aquired and exploited with an eye to profit, all value judgements ultimately lead back to comparisons of returns spread over time," "When the test is expressed in dollars and cents, we all speak the same language." Massé expresses some reservations with this as he believes subjectivity cannot be eliminated, but agrees with its essential validity.[5]

Massé suggests that "In essence investment analysis consists of a comparison between a future return, and an immediate cost which is nothing but a negative return, thus he adds the choice between two investments comes down to a choice in economic terms, between two schedules of returns.[6]

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4. P. Massé; Ibid., P. 9.

5. P. Massé; Ibid., P. 3.

6. P. Massé; Ibid., P. 6.

With Manitoba Hydro the emphasis is not so much on the return, but with the service (in terms of quantity and quality) that must be provided. Once the objective has been established in terms of a Load and Energy Forecast, the investment decision boils down to determining the most economical way of meeting it. The comparison boils down to a comparison of alternative streams of costs (or of alternative streams of net costs where some alternatives enable some offsetting extra revenue to be earned). Massé suggests that where one is called upon to compare two investments providing the same stream of services and hence producing the same sequence of returns, all that is required is to compare the two streams of expenditures. The investment with the lowest discounted cost will then be selected in preference to the other alternatives.[7] Thus Massé says that the best tool (ie. investment) is the one that for a given level of performance, costs least taking into account both immediate and future expenditures.[8]

Massé cautions that the reduction of the two processes to the same duration is a necessary condition for a valid comparison, but it is not a sufficient condition.[9]

The whole process of discounting and calculating the present value is made more difficult by the problem of estimating future interest rates and selecting the discount rate to use in one's computations. As low discount rates favor capital intensive solutions and high discount rates favor labor and material intensive solutions. The choice of an unrealistic discount rate may cause the wrong decision to be taken.

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7. P. Massé; Ibid., P. 12.

8. P. Massé; Ibid., P. 13.

9. P. Massé; Ibid., P. 18.

Depreciation rates are also of crucial importance. The assignment of an unreasonably long or short service life to an asset may likewise cause a poor investment choice to be made.

In evaluating some investments, benefit/cost analysis is most appropriate. This applies particularly where system improvements are contemplated and limited funds are available. Ideally all investment projects would be undertaken when the ratio is greater than one. However with limited resources the technique employed is to rank all proposed projects and select only those which promise the greatest net returns.

In some respects the making of hydro investment decisions with an almost unlimited number of permutations and combinations of possible development sequences is as much an art as a science.

It involves a great deal of specialized experience, and intimate familiarity with all the geographical peculiarities of vast water sheds spread over hundreds of thousands of square miles.

While scientific techniques and computors can render the mass of calculations manageable, they are no substitute for a precise intuitive grasp of the problems involved.

Some appreciation of one aspect of investment performance can be gained from Table 2.1. This represents an attempt to summarize changes in the cost of providing hydro generating capacity for the Manitoba System.

Changes in the cost per kilowatt of hydro capacity result from changes in the costs of construction, and the characteristics of each individual site. Presumably the best sites are developed first, and each successive site bears a cost penalty because it is more difficult to develop.

As each hydro site, and each hydro generating station is unique, it is difficult to compare them to determine their relative costs. In order to partially overcome this problem, the actual cost per installed

TABLE 2.1

MANITOBA

HYDRAULIC GENERATING CAPACITY COST INDICES

Station	Year Major Work Completed	Cost Per Installed Kilowatt	Average Load Factor	Cost Per Kw Divided By Load Factor	Simple Index of Capacity Cost	Capacity MW	Weighted Average Cost/Kw	Weighted Index of Capacity Cost
Point du Bois	1911	$124	84.5	147	100	71.1	147	100
Great Falls	1923	129	74.5	173	117.7	113.4	163	110.9
Slave Falls	1931	150	76.3	197	134.0	72.0	172	117.0
Seven Sisters	1931	164	68.5	239	162.6	165.8	198	134.7
Pine Falls	1951	282	80.9	349	237.4	83.7	223	151.7
McArthur	1954	372	75.9	490	333.3	61.2	252	171.4
Kelsey	1960	272	78.9	344	234.0	160	272	185.0
Grand Rapids	1965	220	37.0	595	404.8	472	399	271.4
Kettle Rapids	1971	283	68.7	411	279.6	1,024	405	275.5

Source: Manitoba Hydro
Economics Department

kilowatt for each station was divided by its average load factor in order to determine what the cost per kilowatt might be if each site had been developed for a 100% load factor. Thus Point du Bois built in 1911 at an adjusted price of $147 per kilowatt represents the cheapest capacity on the system.

Two indexes were constructed: One a simple index to show the relative cost of each station compared to Pointe du Bois, and a second to show the relative increases in average hydraulic capacity cost since 1911. All the costs and indexes presented are in current dollars. Thus we see that in current dollars Grand Rapids cost about four times as much as Point du Bois, and that Kettle Rapids due for completion six years after Grand Rapids is expected to cost only 2.8 times as much as Pointe du Bois (exclusive of transmission lines). However if one were to deflate each station to 1911 prices with a reliable construction index one might find that these more recent stations were cheaper than Pointe du Bois in constant terms.

The weighted index demonstrates that by the middle 1970's when all ten Kettle Rapids units are in service, that the average cost per hydro kilowatt will be approximately 2.75 as much as it was in 1911. As the efficiency of hydro plants has not improved significantly since 1911 this indicates that the unit costs of generation will have increased approximately 2.75 times in current terms since 1911. The fact that total unit costs have only increased slightly since 1911 suggests that significant economies have been achieved elsewhere in the system in both the investment and operating functions. These questions will be discussed in greater depth in subsequent chapters.

CRITERIA FOR EVALUATING OPERATING PERFORMANCE

In an extremely thorough statistical study of the Class A and Class B privately owned electrical utilities of the United States William Iulo[10] investigated the quantitative relationships that exist among the various factors that either by tradition or logic, are believed to affect the unit costs of providing electric energy. One purpose of the study was to explain the variations in unit costs from one utility to another. Armed with this information, Iulo felt, that regulatory commissions could compare actual unit costs of a given utility with what they should be, given average efficiency. Iulo suggests that the efficient utility would have a smaller rate base than the inefficient utility and is thus penalized under present regulatory practices. Using Iulo's criteria the commission could identify the efficient producer and allow a higher rate of return on the rate base. Conversely the inefficient producer could be penalized by being allowed a lower rate of return.[11]

There are several fundamental differences between Iulo's work, and that of the present writer. Iulo was attempting to explain the variations in unit costs of 186 privately owned utilities whose generating capacity was primarily thermal. The present author is attempting to issolate the key determinants of unit costs, and measures of operating effectiveness of a single publicly owned utility whose generating capacity is primarily hydro. For these reasons many of the factors that are significant in determining the unit cost of producing electricity by Manitoba Hydro would not be

10. William Iulo; Electric Utilities - Cost and Performance, Pullman, Washington State University Press, 1961.

11. William Iulo; "The Relative Performance of Individual Electric Utilities", Land Economics, Volume 38, November 1962, p. 325.

significant to Iulo, either because they are significant only with a hydro utility, or because they are not significant factors in explaining variations between utilities.

Iulo divided all the factors that are supposed to affect the unit cost of producing electricity into three categories: Historical factors, Operating factors, and Market factors. A complete listing of these factors follow.

Historical Factors

1. Size of the Utility Enterprise
    (a) Total Assets
    (b) Total Utility Property
    (c) Electric Utility Property
    (d) Kilowatt hour sales
    (e) Kilowatts of generating capacity
    (f) Peak demand
    (g) Size of producing units
        (1) Steam electric
        (2) Hydro electric

2. Cost of construction

3. Level of Technology (an index based upon the experienced changes in the average energy required to produce a kilowatt hour of electricity)

4. Historical cost of debt capital

Operating Factors

1. Capacity utilization
    (a) Load factor
    (b) Utilization factor (peak demand as a percentage of installed capacity of the utility or ratio of total kilowatt hours sold to potential kilowatt hours that could be generated)

2. Type of generation (proportion of thermal to total capacity for any given year.)

3. Nature of electricity distributed (self produced or purchased)

4. Investment relationships
    (a) Production investment per kilowatt of generating capacity
    (b) Distribution investment per kilowatt of generating capacity
    (c) Transmission investment per kilowatt of generating capacity
    (d) All other investment per kilowatt of generating capacity
    (e) Total investment per kilowatt of generating capacity

5. Wage rates

6. Steam electric fuel costs

7. Hydro electric "fuel" costs (total hydro electric production investment per kilowatt of hydro electric generating capacity weighted by the proportion of hydro electric generation to total electric generation).

Market Factors

1. Distribution among consumer classes (residential, commercial and industrial)

2. Density of territory served
   (a) Proximity of customers (number of customers per structure mile of distribution line)
   (b) Proximity of load centers

3. Density of consumption (annual consumption in kilowatt hours per customer by class)
   (a) Consumption per residential customer
   (b) Consumption per rural customer
   (c) Consumption per commercial and industrial customer
   (d) Consumption per all other customer
   (e) Consumption per customer

In order to determine which of these factors were important in explaining inter-utility differences in unit costs of producing electricity Iulo employed multiple regression analysis, a statistical technique. Using this technique he eliminated all the factors whose (1) net regression coefficients were not significantly greater than zero at the one percent confidence level and (2) whose coefficients of partial determination were not significantly greater than zero at the same confidence level. The final criterion was that the direction of the relationship had to conform with what would logically be expected. For example if a relationship of higher fuel costs was found to be associated with lower unit costs this was considered illogical and the factor was discarded.

Employing this technique Iulo selected seven factors which he considered explained some 80% of the total variation in unit costs between the utilities studied. These factors are listed here first by category.

TABLE 2.2

Historical Factors	Proportion of variations in inter-utility costs explained by factor after allowing for relationship of other independent variables [12]
Size of steam-electric generating stations	6%
Operating Factors	
Capacity utilization	12%
Steam-electric fuel costs	8%
Hydro-electric fuel costs	17%
Market Factors	
Distribution among consumer classifications*	23%
Consumption per residential customer	32%
Consumption per industrial and commercial customer	11%

In a further refinement Iulo attempted to rank each factor in order of its relative importance in explaining inter-utility variations. First he ranked them by coefficient of correlation which he explains represents the apparent relationship that is observed when each factor and unit costs are observed in isolation.

* Note: Distribution among consumer classifications is measured by the proportion that total kilowatt hours sold to residential customers were to the total kilowatt hour sales of the utility.

12. William Iulo; op. cit., table prepared by the present author from material on pages 96, 101 and 114 of Iulo's work.

TABLE 2.3

Factors for Which Increased Values[13] Act To Lower Unit Costs	Coefficient of Correlation
1. Consumption per commercial and industrial customer	- .7411
2. Capacity utilization	- .4577
3. Size of steam-electric generating stations	- .4182
4. Consumption per residential customer	- .4088
Factors for Which Increased Values Act To Increase Unit Costs	
1. Distribution among consumer classifications	+ .4864
2. Hydro-electric fuel costs	+ .1846
3. Steam-electric fuel costs	+ .1513

Iulo points out that this measure of the relative importance of these independent factors is not very satisfactory, because it does not take into account the relationships that may exist between the indicated independent factor and other independent factors, whether included in the analysis or not. It merely represents the apparent relation that is observed when only the indicated factor and unit electric costs are considered together.

The second method of ranking employed by Iulo was by net regression coefficient. This he explains represents the apparent inter-relationship when all the independent factors are observed interacting together. The major drawback of this is that the placing of the decimal point of the net regression coefficient is dependent upon the units chosen. Thus the ranking and relative importance can be affected arbitrarily.

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13. William Iulo; op. cit., p. 115

TABLE 2.4

Factors for Which Increased Values[14] Act To Lower Unit Costs	Net Regression Coefficient
1. Capacity utilization	- .07022
2. Consumption per Residental customer	- .002437
3. Consumption per commercial and industrial customer	- .00006959
4. Size of steam-electric generating stations	- .000006989
Factors for Which Increased Values Act To Increase Unit Costs	
1. Distribution among consumer classifications	+ .2044
2. Steam-electric fuel costs	+ .1465
3. Hydro-electric fuel costs	+ .02202

The third method of ranking employed by Iulo is by the coefficient of partial determination , which he explains represents the proportion of variations of unit electric costs explained by the addition of that particular factor to the analysis. This method he feels gives the best indication of the relative importance of each factor. He cautions that a coefficient of 20% does not indicate a significance twice that of 10%, and that the coefficients are not additive. When ranked in this manner Iulo's seven significant independent factors are observed to have the following relative importance.

14. William Iulo; op. cit., p. 117

TABLE 2.5

Factors for Which Increased Values[15] Act To Lower Unit Costs	Coefficient of Partial Determination
1. Consumption per residential customer	.3216
2. Capacity utilization	.1224
3. Consumption per commercial and industrial customer	.1143
4. Size of steam-electric generating stations	.05861
Factors for Which Increased Values Act To Increase Unit Costs	
1. Distribution among customer classifications	.2335
2. Hydro-electric "fuel" costs	.2239
3. Steam-electric fuel costs	.1798

All the calculations and information found in the three preceding tables is based on data for the year 1954, because this was the latest year for which complete data was available when the study was first initiated. Iulo subsequently applied the same analysis to the years 1952 - 1957 in order to check the stability of his findings. The following table indicates that while the ranking changes slightly for some years, the average results support the 1954 findings.

15. William Iulo; op. cit., p. 119

TABLE 2.6

—RANKINGS OF THE RELATIVE IMPORTANCE OF SEVEN FACTORS SIGNIFICANTLY RELATED TO UNIT ELECTRIC COSTS 1952 THROUGH 1957*[16]

FACTORS	1952	1953	1954	1955	1956	1957	Average Rank
Consumption per residential customer	1	1	1	1	1	1	1
Distribution of kilowatt-hour sales among consumer classifications	2	2	2	2	3	2	2
Hydroelectric "fuel" costs	5	3	3	3	4	4	3
Steam-Electric fuel costs	7	4	4	4	2	3	4
Capacity utilization	3	5	5	6	5	6	5
Consumption per commercial and industrial customer	6	6	6	5	6	5	6
Size of steam-electric generating stations	4	7	7	7	7	7	7

* The relative importance of each factor is based upon the coefficient of partial determination for each factor in each year.

Source: Computations by William Iulo

HISTORICAL FACTORS

In reviewing the factors originally proposed by Iulo we see that he considers only one, the size of a utility's steam-electric generating stations as having demonstrable ability to explain inter-utility variation in unit electric costs. He concludes that to a large extent the economies that are usually claimed to result from increasing electric utility size arise from the ensuing ability to utilize larger producing units.[17]

This is a fact of considerable significance to Manitoba Hydro where the majority of the capacity is hydro and where thermal is only used in conditions of low water flows, for peaking, and in years when hydro capacity is in short supply. Immediately following the completion of a new hydro station, thermal facilities may sit idle for two or three years. This suggests that the size of plant of any description is not at the present time a significant factor in determining Manitoba Hydro's unit costs.

16. William Iulo; op. cit., Land Economics p. 318

17. William Iulo; op. cit., p. 92

As we shall see in the latter part of this chapter size of plant only becomes significant as a investment factor, and only when either steam or nuclear is considered as a replacement for hydro to carry the base load of the utility.

Iulo found the results of his statistical study of the costs of construction index, and technology index confusing and contradictory and surmized that a lack of definite results might be attributed to one offsetting the other.

With respect to Manitoba Hydro increasing costs of construction are extremely significant in determining changes in unit costs. While the effects of improved technology are not as apparent on the generation side for a hydro system as with a thermal system, improved technology has been an important offset to rising costs particulaly in transmission[18] and distribution, and in the automation of station and system operation and so on. As Manitoba Hydro's capacity is primarily hydro, and the efficiency of hydro generating stations has been greater than 90% for several decades, major economies from technological advances in this area does not seem possible. Because of this Iulo's technology index (based upon the experienced changes in the average energy required to produce a kilowatt hour of electricity in thermal stations) is not appropriate. No attempt was made by the present writer to measure the impact of technology.

Iulo dismissed the cost of debt capital (the rate of interest) as not significant to his study. This he explained as caused by the fact that virtually all utilities studied by him enjoyed a historical cost of debt

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18. Transmission technology and efficiencies have improved at a faster rate than thermal generating efficiency.

capital within the relatively narrow range of 2.8 to 3.8 percent. Since all utilities enjoyed about the same rate, it was not a significant factor to explain inter-utility differences. Other reasons why the rate of interest might not be as significant to a utility in Iulo's study is that a thermal utility is much less capital intensive than a hydro utility, and a privately owned utility is financed partially with equity capital, while Manitoba Hydro is financed entirely with debt capital. These two factors; the capital intensive nature of hydro capacity, and the large total requirement of debt capital, plus the higher interest rates prevalent in Canada make interest rates an extremely important determinant of unit costs.

OPERATING FACTORS

Iulo's study considers only three operating factors significant; capacity utilization, steam electric fuel costs, and hydro-electric fuel costs. The first, capacity utilization is considered extremely significant in the present study and will be discussed in depth in a later chapter. The second steam-electric fuel costs is not significant where thermal is used only occasionally as explained previously. The third hydro-electric fuel costs will not be considered in Iulo's sense for a number of reasons.

First Iulo's definition of hydro-electric "fuel" costs (total hydro-electric production investment per kilowatt of hydro-electric generating capacity weighted by the proportion of hydro-electric generation to total electric generation) is considered a very poor one conceptually. If one takes the total cost of a hydro station, some of the costs as with a thermal station are related strictly to the capacity component of its output. Others such as part of the main dam, and dykes, and other facilities associated with the storage of water could be considered as energy costs or fuel costs. The proportion of total costs which would be considered "fuel" costs would vary from station to station. Because of the extreme complexity associated with determining hydro "fuel" costs the present writer will consider them only as consisting of the water rental payment of .25 mills per kilowatt hour which is paid to the provincial government. All the fixed costs associated with a hydro plant will be considered in the same manner as the fixed costs of a thermal station.

While Iulo did not find the nature of electricity distributed (self produced or purchased), investment relationships, and wage rates significant in explaining inter-utility differences in unit costs, they are significant factors in the determination of unit costs for a specific utility. Accordingly they along with a number of other related factors will be discussed in various contexts in the pages that follow.

MARKET FACTORS

Iulo concludes that the two factors that are the most important to the combined explanation of the inter-utility variation in unit electric costs in his study are both market factors: distribution among customer classifications which explains 23% of the remaining variation, and consumption per residential customer which explains 32%. He feels that these results provide substantial evidence that indicates that unit electric costs are largely a function of the market that a given electric-utility serves.

It is considered that these two factors are extremely relevant in the determination of unit costs with Manitoba Hydro. Accordingly these measures as well as some measure of customer density will be employed in the following analysis of Manitoba Hydro.

In summing up the combined effects of all his important factors, Iulo suggests that over the period his analysis included (1952-57) the substantial increases in steam-electric generating station size, in consumption per residential customer, and in consumption per commercial & industrial customer all tended to produce lower unit electric costs, as did the more moderate changes in capacity utilization and in hydro-electric "fuel" costs. On the other hand, increases in steam-electric fuel costs acted to increase unit electric costs as did the increasing concentration of sales to residential customers. These counter acting forces did not quite balance each other, but, rather produced a slight tendency for unit electric costs to decline during the period analyzed.[19]

In the analysis which follows we shall see that with Manitoba Hydro another combination of factors interacted to produce similar results over the period of 1961 - 1968, the period with which this study is primarily concerned.

19. William Iulo; op. cit., p. 136

CHAPTER III

ALTERNATIVE LINES OF DEVELOPMENT

Unlike Alberta and Saskatchewan, Manitoba is not richly endowed with fossil fuels. Fortunately however, Manitoba does possess an abundance of water power principally on the Winnipeg, Saskatchewan, Churchill and Nelson Rivers. Throughout the development of the electricity supply system of Manitoba this abundance of water power has been the dominant energy fact of the province.

From the time Pinawa hydro station was constructed on the Winnipeg River (1906) until the first major thermal station was constructed at Brandon (1957) the overwhelming superiority of the Winnipeg River as a source of cheap energy dictated the development of a hydro system. During this period the relative inefficiency of thermal generation and the distance from sources of coal, oil, or gas precluded this form of generation.

By 1955 however the Winnipeg River was completely developed. From 1900 to 1955 the thermal efficiency of thermal generating stations improved seven times.[1] The larger size of the Manitoba system no longer ruled out the economies of scale associated with larger thermal units. Although neither Brandon or Selkirk which were installed to firm up hydro developments and for peaking purposes could produce energy cheaply enough to compete with hydro on base load, the possibility that future thermal stations would be able to do so became a real possibility.

Since about 1958 or 59 on the Manitoba system has been faced with three basic alternatives. The first is power from conventional thermal stations, the second is nuclear generating stations, and the third alternative is the

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1. E. W. Morehouse, and T. Baumeister; How Will Atomic Power Affect The Electric Power Industry, Land Economics, Vol. XXXI Number 2, May 1955, p. 105

mighty though remote Nelson River. The existence of three alternatives of course does not preclude an optimum combination of any two or three of them.

In discussing these alternative lines of development it is useful to review some of the characteristics and constraints associated with the long term planning of an electrical supply system.

The electrical supply industry in Manitoba as elsewhere is in a constant state of development and evolution. The planning horizon is very long. It takes from 5 to 7 years to plan and build a new capacity addition, but the actual long run planning should span a greater period than this, particularly where the development of complex river systems is involved. While it is impossible to anticipate specific developments more than about 10 years in the future, planners should try to consider the broad range of possible alternatives twenty or twenty-five years in the future in order to avoid making decisions which will commit the utility too deeply to a single course of development. All planning should be sufficiently flexible so that as many options as possible are kept open in the future, and the system is able to take advantage of any new technology as it arises. This is absolutely imperative in the electric utility industry where the useful life of a hydro station maybe as great as one hundred years, and where the economic development of a river system is dependent upon a sequence of heavy capital investments over a period of forty years or so.

Above all planners should not be too firmly wedded to one source of power, or to the limitations psychological and otherwise imposed by political boundaries. Provincialism may preclude pursuing the alternative which promises the greatest long term benefits for the region or the nation as a whole thus in the long run making everyone a little poorer than they might have been.

In evaluating alternative forms of generating capacity, some of the principal considerations are:

1. Capital investment requirements per kilowatt of the alternative units.
2. Operating and fuel costs of alternative units.
3. The useful life or period over which the initial investment must be amortized.
4. How will each alternative operate within the constraints and conditions of the system? What are the plant capacity factors, single unit size limitations and so on?
5. Total cost of the electricity produced by the alternative units.
6. Geographical and locational limitations of the alternatives.
7. What is the overall effect on the system economically and from the point of view of system reliability?

In evaluating alternative lines of development it must be ensured that secondary benefits and costs are not forgotten. The economic benefits which might accompany hydro development in the north, air or water pollution which might accompany thermal or nuclear development, or resource values which might be sacrificed in the extensive flooding associated with a hydro development are all important considerations which present machinery does not always adequately take into account. An important point here is that it must be realized that the optimum solution to the problem of providing electric power might not be optimum from the overall point of view of society.

In planning the future development of an electric utility system, planners are always faced with certain facts or constraints. Perhaps the first constraint is the nature of the product. The service must be available at the flick of a switch. Sufficient capacity must be available to meet the demand of the coldest day and on the darkest night. Electrical energy is not commercially storable. A second constraint is the long lead time that is required to bring new plant into service. A third consideration is the capital intensive nature of the industry. A Fourth consideration is the fact that economies of scale are present in some phases of electricity supply, but not all. It is necessary to balance the economies of scale that can be captured against the diseconomies and risks created by the other constraints. A fifth consideration is the amount of reserve capacity which must be provided, and the size of the largest single unit which can be accomadated on the system. This is a sort of triple barrelled constraint. First it has been determined that reserve capacity equivalent to about 12% of the annual system peak is desirable. Secondly as a general rule of thumb it is considered that no more than 10% of the system load should be carried by a single unit, and thirdly spinning reserve equivalent to the largest single unit on line must be available in case that unit breaks down. These interlocking constraints have precluded the capture of economies which might accompany the adoption of a smaller reserve ratio, and the economies of scale which might accompany a really large (500 - 1,000 M W) thermal or nuclear unit. A sixth consideration in utility planning is that most of the capital assets involved have very long service lines. A hydro-electric station may provide reliable service for over one hundred years. Some of the first hydro-electric stations constructed are still in service and show no signs of wearing out. In order to be on the safe side, to hedge against redundance caused by yet unanticipated technological break throughs in the production of energy, a maximum period of fifty years is used for planning purposes. Thus in the planning phase a hydro station which might last 100 years carries a burden in that it must appear economically viable over a 50 year period.

Now that we have reviewed the planning environment in which Manitoba Hydro operates I shall discuss present system developments and the implications of technological advance, inflation and other relevant factors upon the future evolution of the system.

Manitoba Hydro is presently undertaking the Phase I Development of the Nelson River. I shall discuss this project both from the perspective of the situation which existed during its planning phase (about 1960 - 1966) and from the perspective of present (1969) interest rates and cost estimates.

The crucial elements of the Phase I Development of the Nelson River are:

1. Kettle Generating Station (1020 - 1224 MW)
2. Churchill River Diversion
3. D.C. Transmission to Winnipeg

This scheme is consistant with either the full development of the 6,000 MW potential of the Nelson - Churchill complex, or is economically viable if no further stations are constructed after Kettle.

The decision to undertake Phase I was reached by comparing a fifty year thermal - nuclear reference sequence of development with alternative Nelson River sequences.

Economic comparisons between alternative sequences were arrived at by computing the total costs which would be imposed upon the utility in each year, through the adoption of either of the alternative sequences. The present value of each sequence was computed and compared.

In the short term because of the load building period of the station and transmission lines and some forward investment associated with indivisable facilities the Nelson River sequence was more expensive than the thermal - nuclear sequence. In time however the costs of the Nelson sequence start to decline relative to the thermal - nuclear sequence, and continue to decline until they reach a cross over point at about 1990. From this point onwards hydro costs fall significantly below those applicable to the thermal - nuclear sequence. It was computed that the present value of the savings in the years after 1990 were about five times greater than the present values of the extra costs incurred before 1990.

The major problem associated with long range planning of this nature is an inability to forsee the future. At the time the Phase I decision was being made (early 1966) Manitoba Hydro was paying less than 5.5% to borrow money. Accordingly 5.5% was considered a prudent interest rate to employ in computations. Unfortunately with about half the Kettle Rapids Station completed the average interest rate so far applicable is close to 6.75% with the prospect that the money required to complete the station will bear interest rates in excess of 7.0%.

To assess the impact of these higher interest rates and increases in cost estimates which have been made since 1966 the author computed the long run unit costs for both Phase I and a hypothetical representitive thermal (200 MW) unit at Brandon employing 7.0% interest and 1968 construction cost estimates.

The following conclusions were reached. First if development of the Nelson River were to stop with the completion of the Kettle Generating Station, including the Churchill River Diversion, the total long run cost of electricity delivered to Winnipeg would be about 6.11 mills per kwh. This unit cost would be sufficient to amortize the entire cost of the D. C. transmission line over 50 years from the first power year. Secondly it was concluded that the cost of thermal energy at Brandon (at an 80% load factor) would be about 6.34 mills per kwh. This assumes 4.0 mills for fuel (the present fuel cost of Brandon). Thus on the basis of present estimates Nelson River power is still marginally cheaper than thermal.

There are, however, several important assumptions which bias the decision either in favour of Hydro or Thermal-Nuclear.

The thermal costs are based on present thermal efficiences and fuel costs at Brandon. Subsequent thermal stations could be expected to reduce unit fuel costs even at present prices. Any reduction in fuel prices would further reduce fuel costs.

Some assumptions are biased against Hydro however. The 6.11 mill figure assumes amortization of all capital costs over a fifty year period when the useful life might be twice that figure. This 6.11 mill figure also includes transmission costs including losses of energy delivered at Winnipeg while the thermal costs do not include a transmission charge. Also included in the 6.11 mills is about .25 mills water rental charge. This .25 mills is not an economic cost, and accrues to the Government of Manitoba in the form of extra revenue. In effect it is a form of tax on the use of water to generate hydro-electricity. Based upon this static analysis, it appears that in the short run at least Phase I Nelson Power remains viable in spite of unprecedentedly high interest rates.

In assessing this 6.11 mill unit cost for Phase I Nelson Power an important factor must be borne in mind. This is that a large proportion of this unit cost is associated with forward investments. This forward investment is in three areas; a central townsite at Gillam designed to form a base for construction of and remote control of subsequent hydro stations, the Churchill River Diversion which will increase the water flow for all hydro stations downstream of its confluence with the Nelson, and transmission facilities with an ultimate capacity of from two to three times the initial capacity of the Kettle Site.

Recent estimates suggest that Kettle Rapids will cost about $285. per installed kilowatt when completed. (At 1020 MW with a capacity factor of about 80%). The value of the diversion and transmission facilities some of which is forward investment is some $222 million or almost $200 per kilowatt of a 1020 MW installation at Kettle.

Kettle Rapids is expected to take care of anticipated system load growth from 1971 to 1976 or 1977. It is probable that more large capacity additions will have to be brought in service around 1980. Lead time requirements will necessitate a decision not later than 1973 or 1974. At this time a choice will have to be made between additional capacity on the Nelson, or thermal or nuclear capacity in the Southern part of the province.

Several large attractive sites exist on the Nelson. Of these, Limestone (1840 MW) and Long Spruce (806 MW) appear the most attractive. Since the Churchill River Diversion and the basic D.C. Transmission will already be in place the only costs to consider are those required to increase the capacity of the D.C. terminal stations at either end of the transmission line and the costs of the generating stations themselves.

Because of inflation the costs per kilowatt of a hydro station scheduled to come into service in 1980 will probably be considerably greater than if it were completed in 1970. Thus the estimate of future unit energy costs on the Nelson River must be based on estimates of 1980 capacity costs. The following table shows unit costs at the station for various costs per kilowatt at an 80% capacity factor.

TABLE 3.1

Installed Cost per kilowatt	Unit Cost Per kilowatt Hour
$300	3.5 mills
$400	4.5 mills
$500	5.7 mills

In essence, if the major hydro generating capacity which might follow Kettle Rapids is estimated to cost less than $400 per kilowatt when completed, a competing thermal or nuclear plant of a size appropriate to the Manitoba System will have to be capable of producing energy at something less than 4.5 mills per kilowatt hour (plus or minus appropriate adjustments for transmission, costs of nuclear and transmission losses from the Nelson).

NUCLEAR ENERGY AS A FUTURE ENERGY SOURCE

The development of nuclear generating station technology has been extremely rapid since the first nuclear generating stations went into service in Britian in the early 1950's. Although initial installations were expensive relative to thermal stations and were justified partially as research projects, significant improvements have been made which suggest that nuclear energy will shortly be cheaper than conventional thermal in all but the cheapest fuel areas.

In the United States there was little active interest in nuclear generating stations until after 1960. However since that date there has been a dramatic shift from conventional thermal generation which has far surpassed earlier predictions. In 1966, 53% of new generation committed by United States Utilities was nuclear,[2] however because of the long lead time it will not be until about 1972 that more than half the new capacity actually placed in service will be nuclear. Because of the rapidity of this shift to nuclear power there is very little actual operating data available, and most decisions and projections of future costs are made from estimates.

This shift to nuclear energy is much more rapid than the projections of a decade ago predicted.[3] If these stations live up to or surpass expectations the shift may be even more dramatic in the future.

E. O. Smith reports that the average large scale nuclear plant contracted for in 1967 was estimated to cost $150 per kilowatt ($162 can.). He expressed the hope that this would be a stable price level. In order to realize these prices a plant of about 700 MW must be constructed. Plants less

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2. Morehouse and Baumeister suggest that the most optimistic estimates of 1955 expected 50% of new capacity being installed by 1975 to be nuclear. Ibid. p. 107

3. "Twelfth Annual Report on Nuclear Power", Electrical World, June 12, 1967 McGraw Hill, New York, p. 92 - 111

than 400 MW cost about $200[4] per kilowatt ($218 can).

These figures represent a dramtic reduction from those quoted in 1955. Morehouse and Baumeister mention that at that time most estimates for nuclear power plants were running in excess of $250 per kw.[5]

In comparing the capital cost figures for hydro and nuclear installations two important points must be considered. First a hydro installation has no fuel and little maintenance expense while nuclear installations do consume fuel and require considerable maintenance. The second factor is that these installations have quite different service lives. In all likelihood nuclear reactors will have a shorter life. Write off periods should be no more than 25 - 35 years until some actual operating experience justifies a longer period. Thus capital costs per kilowatt will in all likelihood have to be considerably less than hydro in order to be a viable alternative. An off setting factor is the very high capacity factors expected with nuclear installations. The best operating performance occurrs with continuous operation, thus ensuring high utilization which makes nuclear generation very attractive on base load.

Perhaps the best comparison is total cost per kilowatt hour at each plants average expected output. While with hydro the total cost per kilowatt hour is expected to continue to rise with construction costs, it is predicted that technological improvements in the nuclear field will reduce total costs per kilowatt hour. These savings are expected to occur for several reasons. The stabilization or reduction of capital costs per kilowatt through technological advance and economies of scale associated with larger plants. The reduction of fuel costs per kilowatt hour generated for the same reasons stated above.

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4. E. O. Smith; "Nuclear Decisions Hinge On More Than Economics", Electric Light and Power, September 1968, p. 118

5. E. W. Morehouse and T. Baumeister; Op. cit., p. 104

Fuel costs particularly are expected to decline. Current estimates of fuel costs for a large water reactor due to go on line in 1970 are about 1.8 mills per kilowatt hour, but through advances in fabrication and processing fuel, it is believed that this can be reduced by 25% by 1980.[6] The advent of the breeder reactor is expected to reduce fuel costs even further.

While the following total cost per kilowatt hour figures are based on estimates and have yet to be proved they do indicate the possible competition which further hydro development is up against. In Sweden a 400 MW plant at Simpwarp which is under construction is expected to cost $175 per kilowatt ($190 can.) and produce power at 5.5 mills per kilowatt hour.[7] In the United States Oyster Creek contracted in 1964 at $129 ($139 can.) for 515 MW is expected to produce power at 4.25 mills per kilowatt hour.[8]

While a wide variety of costs are quoted in different publications for various types of nuclear plants, capital costs of $140 - $150 U.S. for plants in the 800 - 1100 MW range are common with total power costs of about 4.5 mills per kilowatt hour.

It has been suggested that by the year 2020 total costs may be as low as 1 - 1.4 mills per kilowatt hour. Moreover nuclear power costs will be essentially the same in any location.[9] It appears however that the real economies are possible only with large plants 800 - 1,000 MW or more.

This last fact poses a real dilema for the Manitoba System. The System presently has about 1500 MW of capacity. This is expected to grow to 3,000 MW by 1980 and 6,000 MW by 1990. Employing the 10% in one unit rule, this would preclude adding a nuclear unit larger than 600 MW before 1990.

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6. G. F. Hoveke; "Additional Fuel Resources Vital To Nuclear Expansion", Electrical World, June 12, 1967, p. 93

7. L. M. Olmstead: "Today's Power Reactors Tuned for Greater Economy", Electrical World, June 12, 1967, P. 103

8. H. C. Short; "Nuclear Power Build up Goes Critical", Chemical Week, May 25, 1968, p. 47

9. Ibid., p. 45

This suggests that a province with electrical energy demands equivalent to Manitoba's may be smaller than that required for the operation of a really efficient electric utility, and that only by very close co-operation on regional basis will optimum operating conditions be achieved. The solution may lie in building and sharing nuclear capacity with Saskatchewan or with Western Ontario. In this case the combined interconnected capacity could safely be accomodated.

However Saskatchewan has plentiful cheap coal at Estevan which may preclude interest in nuclear capacity unless a shortage of cooling water in that area or significant price decreases in nuclear vis a vis thermal tip the scale in favor of shared nuclear facilities.

At the present time it is very difficult to determine when nuclear energy will be competitive in Manitoba. A slow down in nuclear progress could well delay the date beyond 1990. However the apparent acceleration in nuclear technology which has occured in the past decade could, if sustained, well render nuclear energy Manitoba's next major source of generation capacity and could well be a contender for service not long after 1980.

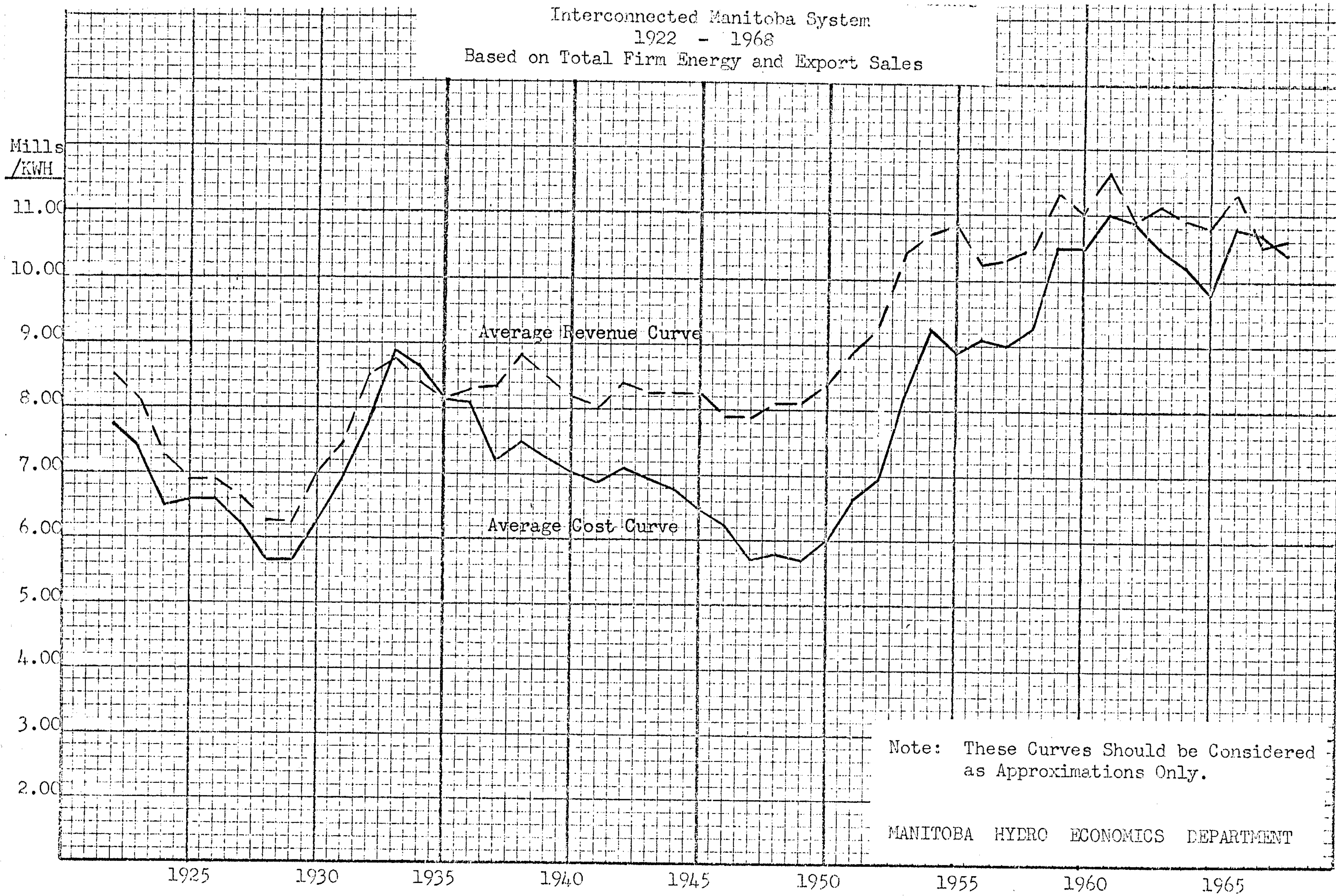
CHAPTER IV

THE ANALYSIS OF OPERATING RESULTS 1961 - 1968

This chapter deals with one of the most important aspects of the operation of a public utility. This is the cost of providing service. The importance of cost in measuring the operating performance of a public utility, or any other enterprise for that matter arises because cost properly analysed and understood provides the best indication of economic efficiency available. In the operation of a public enterprise such as Manitoba Hydro the minimization of cost subject to the constraints of quality and reliability of service becomes a primary objective. Although this analysis is primarily concerned with operating performance since the amalgamation in 1961 due to a lack of accurate and comparable data prior to that year, historical cost and revenue data from 1922 to the present will be presented in order to indicate the long term movements of these factors.

Historical Unit Costs and Unit Revenues

A study of the historical movement of unit costs and unit revenues provides a fairly clear though somewhat intuitive insight into the factors both arbitrary and economic which have influenced costs. The long run average cost and average revenue curves shown in Figure 4.1 were derived by adding the total accounting costs and revenues associated with the production of electric power of the various utilities in Manitoba. These total costs and revenue figures were converted to unit costs by dividing by total firm energy sales to ultimate customers. Double counting was eliminated by subtracting all inter-utility transfers of energy or revenue.



Interconnected Manitoba System
1922 - 1968
Based on Total Firm Energy and Export Sales
Mills /KWH
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
Average Revenue Curve
Average Cost Curve
1925
1930
1935
1940
1945
1950
1955
1960
1965
Note: These Curves Should be Considered as Approximations Only.
MANITOBA HYDRO ECONOMICS DEPARTMENT

FIGURE 4.1

In undertaking an economic analysis of power production in Manitoba it rapidly became apparent that cost as reported or computed for any given year or period would be a somewhat arbitrary figure. This situation arises because the accounting values that are recorded and reported in the annual reports of the various utilities represent arbitrary decisions regarding such things as depreciation methods (straight line vs sinking fund or modifications of the two), service lives of capital assets, the manner in which new capital assets are brought into the operating accounts and so on. As these policies are subject to change over the years, and have been, the unit costs and revenues computed for any one year are not strictly comparable, but do provide a fairly good approximation of long term trends.

Reviewing the entire period from 1922 to 1968 we see that unit costs have varied from a low of 5.6 mills per kilowatt hour in 1929 to a high of 11.0 mills per kilowatt hour in 1961, the year of the amalgamation. While the prevailing trend has been upward, the actual costs have risen and fallen in a series of long cycles. The explanation of these cycles is extremely significant in any analysis of the factors which determine unit costs of an electric utility particularly in Manitoba.

The signifcant changes in unit costs which have occured since 1922 appear to have been caused by the following factors.

1. Straight line depreciation policies.
2. From 1922 - 1929 an extremely high rate of growth of energy sales was experienced which resulted in all capacity being fully loaded by 1929 (Pinawa, Pointe du Bois, and Great Falls).
3. The period 1930 to 1933 saw a 12% decline in electricity sales and the unfortunate additon of two new stations (Slave Falls and Seven Sisters)

in 1931. This caused a rise in unit costs to almost 9.0 mills per kilowatt hour in 1933.

4. From 1933 to 1951 no new stations were added. Additional generators were added to Slave Falls and Seven Sisters to meet demand which increased from 729 million kilowatt hours in 1934 to 1,827 million kilowatt hours in 1950. By 1950 existing capacity was stretched to its limit. The combined effects of straight line depreciation, steadily increasing volume, and almost full utilization of installed capacity resulted in unit costs declining to 5.7 mills in 1949.

5. From 1946 to 1951 downward pressure on unit costs was partially offset by the rural electrification program. In 1951 the addition of Pine Falls, the intensification of the rural electrification program, and the continuation of a pronounced shift from industrial to residential consumption combined to push unit costs up to about 9.2 mills in 1954, the year in which the rural electrification program was completed.

6. In spite of the addition of MacArthur a high cost hydro station in 1954 unit costs remained stable until 1958 when Brandon, and Selkirk thermal stations and Kelsey hydro station were all added in rapid succession. The addition of these three stations appear largely responsible for pushing unit costs up to a historical high of eleven mills in 1961, the year of the amalgamation.

7. From 1961 to 1965 unit costs declined to 9.8 mills largely because a years delay in the completion of Grand Rapids hydro station caused all available capacity to be totally utilized in that year.

8. The completion of Grand Rapids in 1966 again caused unit costs to rise to 10.8 mills, but these appear to be declining again as this station becomes more fully loaded.

9. Another factor which appears to have been placing downward pressure on unit costs during most of this period has been a greatly increased use of electrical energy by all established customers, thus reducing distribution costs.

While it is impossible to isolate the precise quantitative effect of each factor discussed upon unit costs, it can be seen very clearly from the abrupt changes in the direction of unit cost trends what the effects of economic depression, the addition of new capacity, the under utilization of capacity, the rural electrification program and so on have been. It can also be appreciated that the unit of production has changed qualitatively during the period. Unfortunately this is a factor that the author has been unable to take into account in this analysis, beyond a subjective appreciation that the product has been changing qualitatively to a very substantial extent.

The kilowatt hour of electrical energy produced for 9.0 mills in 1933 was distributed almost entirely within the city of Winnipeg. Interruptions of service were much more frequent than today, and a large proportion was distributed to industrial customers. (An increasing proportion being distributed to industrial customers during the war may have contributed to downward pressure on unit costs).

Since 1946 a large proportion of electrical energy has been distributed to rural customers who are much more expensive to serve than urban residential customers. A steady shift from industrial sales to residential sales from 1946 to 1958 [1] represents a pronounced qualitative change in the product. Although this question of qualitative changes will not be pursued in depth it can be appreciated that for these reasons and others which shall be discussed in detail later that it is a mistake to think of the kilowatt hour of electricity as a homogeneous unit. Taking these qualitative improvements into account it would appear that actual unit costs for a hypothetical standard product have not risen by as much as Figure 4.1 would suggest.

Because of the indivisable nature of a hydro electric station, the addition of anew station to a predominantely hydro system may have a much greater impact than the addition of a new thermal station. This occurs first because a hydro station is much more capital intensive than a thermal station. Idle hydro capacity is much more expensive. The second reason for the extreme impact of a hydro station results from the fact that the entire river must be damed in order to install one of perhaps ten generating units. As 75% or more of the total cost is represented by the dam and power house, almost all of the fixed costs are normally incurred from the first day of operation. A small saving can be realized by delaying the installation of additional generators until required. Thus Seven Sisters which first began operation in 1931 was not fully completed until 1952. The high cost in terms of fixed costs during the load building period results in a trade off between small relatively expensive sites, and large cheaper sites when the addition of new capacity is contemplated. In the Manitoba case it can be seen that as the system has grown it has been able to absorb larger hydro stations with a shorter load building period, thus smoothing out fluctuations in unit costs, and improving the overall economic efficiency of the system.

From Figure 4.1 it can be seen that with the exception of the years 1933 - 1935 the electric utilities of Manitoba have enjoyed a considerable surplus of revenue over expenses until the very recent past. This was accomplished with a rate structure which has remained largely unchanged since 1911 except for the addition of new rates when required (for rural customers) and numerous downward revisions that have occured in various rates over the years. The first upward revision of course occured in 1963 when rates to Manitoba Hydro's general consumers were increased by about 10%. The manner in which unit revenues followed unit costs upward during the 1946 to 1954 rural electrification program suggests that these rates must have borne a fairly close relationship to the actual cost of providing this service.

DETAILED BREAKDOWN OF UNIT COSTS OF PRODUCTION AND DISTRIBUTION 1961 - 1968

With the amalgamation of the Manitoba Hydro Electric Board and the Manitoba Power Commission in 1961 it has become possible to undertake a much more detailed analysis of the electricity supply industry in Manitoba than previously. Since that date Manitoba Hydro's production has grown from about 75% to 85% of total electricity produced and distributed in the province and thus provides most of the economic factors of significance.

A detailed breakdown of unit costs is provided in Figure 4.2. The cost per kilowatt hour for the period 1961/62 to 1967/68 has shown a slight downward trend from 11.5 mills in 1961/62.[2] This result was partially accomplished by exporting a large volume of energy in 1966/67 and 1967/68. Without these export sales, the cost per kilowatt hour would have been at least 11.6 mills in 1967/68. This demonstrates superficially at least the economic advantages of interconnections, which enable the fuller utilization of excess capacity which would otherwise remain idle. The following is a detailed breakdown of the various major cost components:

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2. Note 1961/62 refers to Manitoba Hydro's 1961/62 fiscal year which runs from April 1 to March 31.

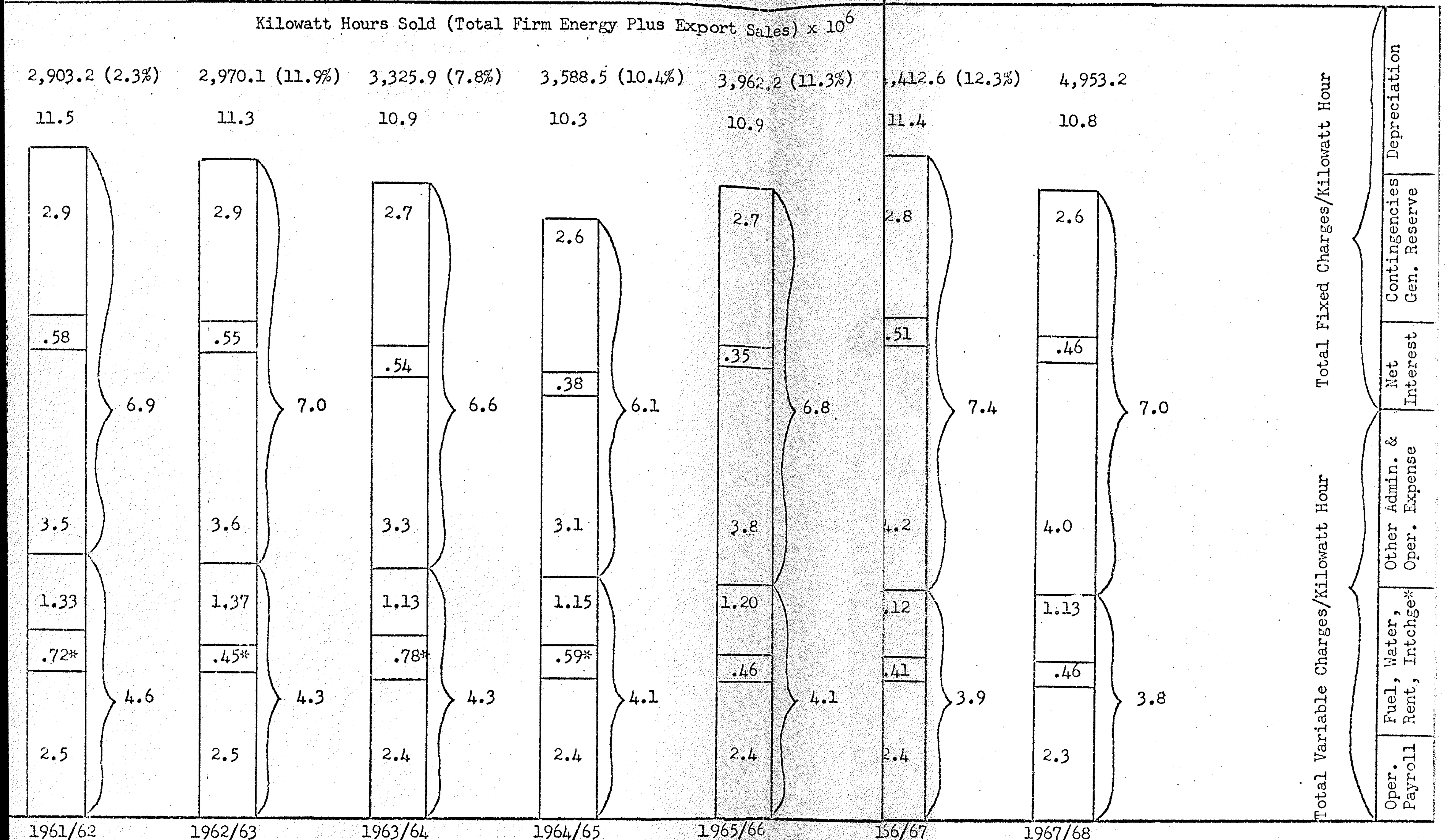
For The Years 1961/62 - 1967/68

TABLE 4.1

ELECTRIC UTILITY PLANT AT COST	338.6 M	352.0 M	363.6 M	373.8 M	498.8 M	513.1 M	537.1 M
Revenue	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68
General Consumers	24,739	26,565	29,003	31,643	33,946	36,824	39,521
Winnipeg Hydro	4,113	3,418	3,604	3,043	3,873	4,945	4,712
International Nickel	2,957	3,037	2,950	3,042	3,594	3,503	4,369
Direct Customers	940	1,070	1,077	1,149	1,112	1,144	1,102
Interchange Capacity	-	-	-	-	-	-	600
Interchange Energy	-	-	-	-	115	349	804
Joint Use and Other	340	414	393	421	392	421	490
TOTAL	33,089	34,504	37,027	39,298	43,032	47,185	51,598
Operating Expenses							
Wages & Salaries Operating	7,324	7,427	7,991	8,668	9,565	10,680	11,153
Other (Office Supplies, Travelling Expenses, Materials, Repairs, Parts)	3,848	4,075	3,745	4,126	4,753	4,943	5,579
Water Rentals	527	764	846	831	1,083	1,180	1,260
Interchange Capacity	-	-	1,050	-	-	-	-
Interchange Energy	444	165	230	262	-	-	-
Fuel	1,035	294	372	934	614	503	874
TOTAL	13,261	12,725	14,234	14,821	16,015	17,306	18,863
Fixed Charges							
Interest Net	10,146	10,681	11,027	11,263	14,889	18,371	19,605
Depreciation	8,318	8,627	9,036	9,410	10,746	12,172	12,757
Contingency	1,675	1,640	1,793	1,374	1,379	2,248	2,260
TOTAL	20,139	20,948	21,856	22,047	27,014	32,791	34,622
Total Annual Expenses	33,400	33,673	36,090	36,868	43,029	50,098	53,485
Surplus or (Deficit)	(311)	831	937	2,430	3	(2,912)	(1,888)
Cummulative Surplus or (Deficit) from 1961/62	(311)	520	1,457	3,887	3,890	978	(910)
Rate Stabilization Reserve	15,031	15,862	16,800	19,229	19,233	16,320	14,432
Rate Stab. & Cont. Reserve	25,597	28,068	30,963	34,622	35,920	35,192	35,453

ANNUAL EXPENDITURE PER KILOWATT HOUR SOLD

FIGURE 4.2



* Includes charges for interchange imports.

A. Fixed Charges

1. Fixed charges: decreased from 6.90 mills in 1961/62 to 6.10 mills in 1964/65 as all existing capacity became totally loaded. The completion of Grand Rapids hydro station in the fall of 1965 pushed fixed charges to 7.4 and 7.0 mills in 1966/67 and 1967/68. Large export sales in 1967/68 utilized much of this new capacity and were responsible for reducing fixed charges from a potential 7.7 mills to the 7.0 mills actually experienced.

2. Net Interest: decreased from 3.5 mills in 1961/62 to 3.1 mills in 1964/65, and then increased to 4.2 and 4.0 mills in 1966/67 and 1967/68. The increase in interest charges per kilowatt hour is partially the result of a rise of almost 20% in the weighted average annual interest rate from about 4.40% in 1961/62 to 5.24% in 1967/68. Had the 4.40% rate prevailed in 1967/68, unit interest charges would have been in the order of 3.4 mills per kilowatt hour. Another factor contributing to the increased interest charges is that the first three units of Grand Rapids and its associated transmission facilities cost some $320 per installed kilowatt and represent the most expensive capacity installed to date.

3. Depreciation: Unit depreciation charges declined over the period from 2.9 mills in 1961/62 to 2.6 mills in 1967/68.

4. Contingencies and General Reserve: This item is in the nature of self insurance and is computed as 1% of all undepreciated generation assets. Over the entire period there was a net decrease from .58 mills in 1961/62 to .46 in 1967/68. This item is not a real economic cost of producing electric energy in the year in which it is charged. If used to pay for acts of nature such as ice storm damage, or unexpected damage to other equipment it would offset expenses in the year of the contingency. If not required for its insurance role, interest earned on it would reduce net interest charges and in the long term slightly lower costs of producing electrical energy.

B. Operating Expense Charges

1. Operating Charges: have decreased continuously from 4.6 mills in 1961/62 to 3.8 mills in 1967/68.

2. Operating Payroll: has declined from 2.5 mills in 1961/62 to 2.3 mills in 1967/68.

3. Other Adminsitrative and Operating Expenses: (Vehicles, communications, stationary, office expenses, computer charges etc.) have declined from about 1.33 mills in 1961/62 to 1.13 mills in 1967/68.

3. Fuel, Water Rentals[3], and Interchange: will vary with available hydraulic capacity, export sales via interconnections, etc. These charges reached .72 and .78 mills in 1961/62 and 1963/64 due to large fuel expenses plus imports in 1961/62 (an extremely dry year) and a capacity purchase and energy imports in 1963/64. In the past three years, moderate fuel expenses, and net exports of energy have kept these charges at about .45 mills.

The foregoing represents, but one method of breaking down unit costs. Another equally useful method is by the functional categories of Generation, Distribution, Transmission, and Administration of Figure 4.3. These values were computed by calculating the fixed charges for the physical assests devoted to each function. To these were added payroll, fuel charges, material, power purchses, and miscellaneous expenses attributable to each category. The totals were divided by the total number of kilowatt hours, generated, distributed, transmitted and administered respectively. Because the denominators in each were not the same the unit costs derived are not additive strictly speaking. The totals found if added are up to .5 mills less than the totals shown in Figure 4.2. This is because total energy generated was used for the generation and

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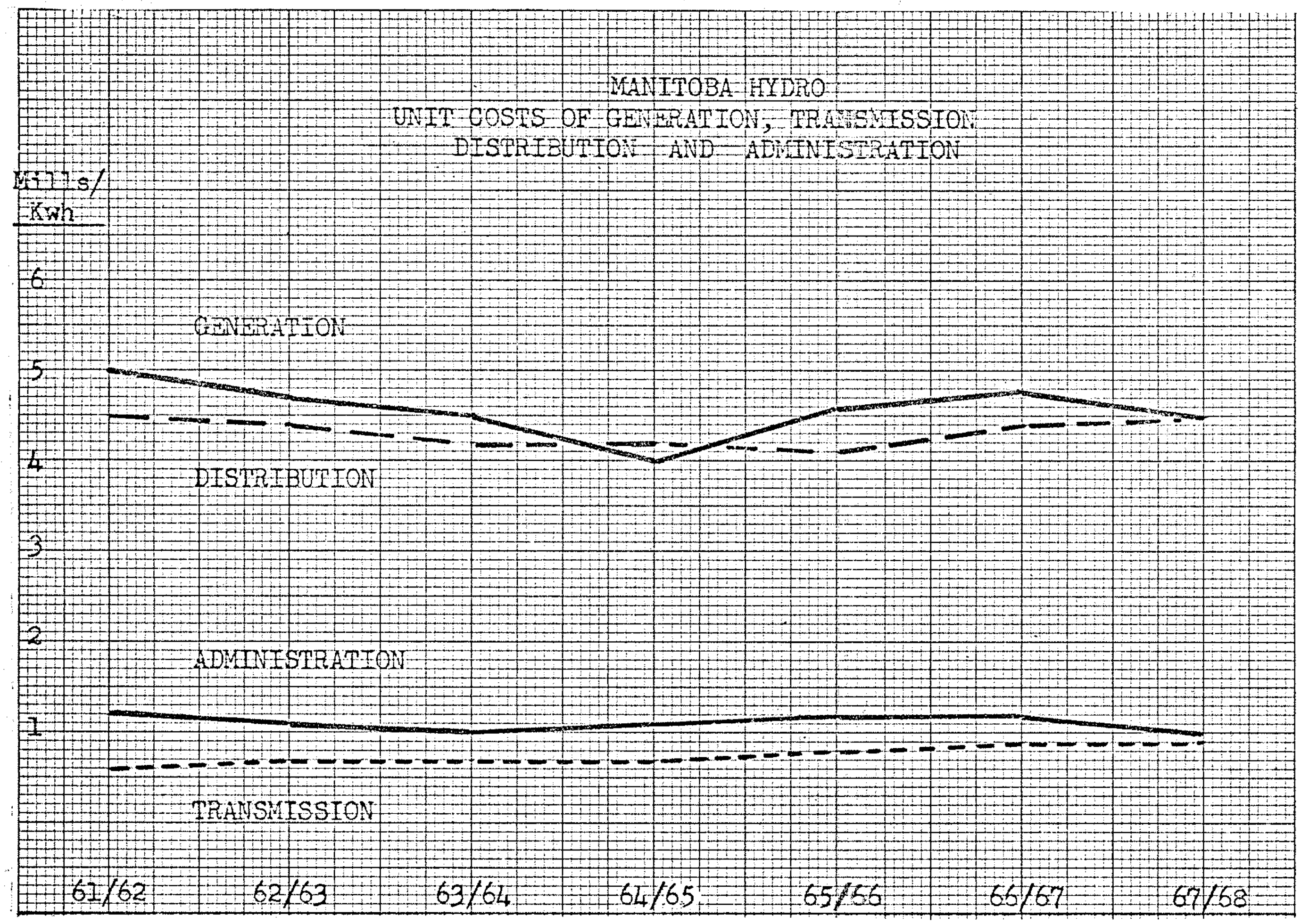
3. A water rental fee of about .25 mills per kilowatt hour generated is transferred to the provincial government.

transmission category, thus making the unit costs for these two categories somewhat less than if losses were excluded as they are for the calculations of Figure 4.2.

FIGURE 4.3



The unit costs derived in this fashion show a remarkable stability, with the exception of generation costs which declined until 1964/65 as generation capacity became fully loaded. (The system peak for that year came within 7MW of total installed capacity). This illustrates the cost penalty incurred by carrying more than a minimum amount of idle generating capacity.

It is interesting to note that distribution charges remained almost constant during the period inspite of a 60% increase in the number of kilowatt hours distributed.

One item that deserves mention is the rather high administrative expenses - about 1.0 mills. This results in the main from administrative and transportation expenses associated with capital projects and strictly speaking should be capitalized (added to the cost of capital projects). A recent "Overhead Study" has recommended that this be done. This will result in a slight reduction in unit costs in the short run, but in the long run these expenses will show up as fixed charges. The information contained in this breakdown is of particular significance when determining the cost of providing service to various types of customer. It can easily be seen that industrial customers who often receive energy directly from the transmission system can be served much more cheaply than domestic customers or farm customers.

MARGINAL COSTS OF PRODUCTION AND DISTRIBUTION

Marginal cost can be defined as the extra cost incurred in the production of one extra unit of output in the cheapest way possible.[4] In attempting to determine the marginal cost of producing an additonal kilowatt hour on the Manitoba Hydro system it rapidly becomes apparant that there is no single unique marginal cost. The marginal cost is dependent upon many circumstances, the time of day, the season of the year, the facilities employed to generate it, the customer to which it is distributed and so on. Also of crucial importance is the time period under consideration. Is short term marginal cost most significant, or is it long term marginal cost that is required to formulate an adequate economic analysis of the cost relationships of an electric utility? Short run marginal cost concepts

4. P. A. Sameulson: Economics - An Introductory Analysis, New York, McGraw Hill Book Co. Inc., 1961 p. 464

assume plant fixed and are concerned only with the variable costs associated with producing and distributing an extra kilowatt hour of electricity, while the longrun marginal cost concept assumes that in the longrun additional capacity will have to be added to the system and that both fixed and variable costs will have to enter into longrun marginal cost. Eli Clemens appears to agree with this reasoning. He says, "If the project is yet to be built, all costs, including the expected fixed costs are marginal costs."[5]

When a utility has surplus capacity and desires to utilize it until normal load growth requires it, the utility often enters into a short term contract with a large industrial customer or with a neighbouring utility to supply energy for a limited period. If the load is not permanent, and the capacity is truly surplus, variable costs alone must be recovered, and shortrun marginal cost applies in the pricing of this energy.

On the other hand if the utility is selling energy to a permanent customer, longrun marginal costs must be covered even if surplus capacity is available in the shortrun. This is because new capacity will soon have to be added to serve normal load growth and a permanent customer whose price is based on shortrun marginal costs will not produce enough revenue to cover the longrun costs of serving him.

SHORT RUN MARGINAL COSTS

In the short run, marginal cost depends almost entirely on fuel costs alone. Thus if the extra kilowatt hour is produced from a hydro station the marginal cost is about .25 mills, the cost of the water rental only. A kilowatt hour produced at Brandon thermal station costs 4.0 mills and at Selkirk thermal station 4.5 mills, because of higher transportation costs. These costs are often described as incremental costs in the electric utility

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5. E. W. Clemens: Economics and Public Utilities, New York, Century - Crofts inc., 1950 P. 261

business, and have over the years formed the basis for many fallacious arguments regarding the proper pricing policy to apply to energy sales.

In summer when thermal stations are normally shutdown the short run marginal cost becomes .25 mills, and this becomes the appropriate guide for the pricing of seasonal loads (irrigation, air conditioning) or short term sales to neighbouring utilities. In the winter, especially in the peak hours thermal capacity is required to provide the marginal kilowatt hour, thus 4.0 or 4.5 mills is the appropriate marginal cost. In off peak hours, if surplus water is available .25 may be appropriate for determining the cost of serving an off peak load even during winter months.

LONG RUN MARGINAL COSTS

In determining the marginal cost of serving a permanent customer who contributes to the annual system peak long run marginal cost must apply. The actual long run marginal cost which should apply is dependent upon the actual load characteristics of the customer, his annual load factor, type of customer, and where he is located on the system. In actual fact the long run marginal cost of serving each individual customer is different. To overcome this problem I should like to introduce the concept of an average long run marginal cost.

From Figure 4.2 it can be seen that the average cost per kilowatt hour has varied between 11.4 mills and 10.3 mills since 1961/62. In spite of a slight downward trend, it might be said that in the seven year period the average cost has remained almost constant at about 11.0 mills. This is not unreasonable when one remembers that the lower unit costs of the last three years has been the result of short term export sales. Projections (Figure 5.1 in Chapter V) suggest that the average unit cost for the next ten years may vary between 11.0 mills and 9.6 mills. Again the low cost of 9.6 mills is the result of export sales and may not reflect a downward trend in the production of energy for the provincial market. The average cost for 1968/69 to 1977/78 is 10.3 mills.

This may be somewhat optimistic due to the large proportion of export sales in this period, and the present high rate of interest which may not adequately be reflected in the projection. For these reasons it is felt that it is not unreasonable to expect an average cost of 11.0 mills per kilowatt hour for the next ten years especially for energy sales in the province. Given this assumption it is not unreasonable to expect long run marginal cost to approximately equal long run average cost during these years. Due to fluctuations from year to year marginal cost may be greater, equal to or less than average cost in any given year, but would not appear to deviate greatly from average cost over the long term.

AVERAGE RETURN PER KILOWATT HOUR

TABLE 4.2

	Annual Average 1961/62-1967/68	Annual Average Past 5 years	1967/68
Average rate of growth of energy sales.			
a) Manitoba			
i) Energy	7.5%	8.6%	7.9%
ii) Revenue	7.2%	7.7%	7.2%
b) Manitoba Plus Export			
i) Energy	9.3%	10.7%	12.3%
ii) Revenue	7.7%	8.5%	9.5%
c) General Consumers			
i) Energy	9.3%	9.3%	9.2%
ii) Revenue	8.3%	8.4%	7.3%

From Table 4.2, it can be seen that while total energy sales increased by an average of 9.3% per year for the seven year period, total revenue increased by only 7.7%. Observation will indicate that a similar gap existed between rate of increase of energy sales, and rate of increase of revenue for the other major categories listed.

This situation results partially from the operation of the "Wright"[6] type rate structure which Manitoba Hydro and most public utilities employ for residential billing.

During the seven year period being studied the average return per kilowatt hour (total firm energy sold in Manitoba) declined slightly from 11.3 mills in 1961/62 to 11.1 mills in 1967/68. This appears to have resulted fromthe following three reasons.

1. The Wright rate structure
2. A slow rate of increase of customers (average of 2.7% per year)
3. A slight shift from residential to industrial consumption

If one takes the average return per kilowatt hour for total firm energy plus export sales we see the decline has been substantial - from 11.3 mills to 10.3 mills. This results for the three reasons mentioned above, plus the fact that export energy commands a much lower rate than firm domestic energy (about 3.0 mills per kilowatt hour in 1967/68).

This decline in unit return results from the rate structure and reflects the theoretical belief found in so much of the literature that an electric utility is a decreasing cost industry. As we have seen Manitoba Hydro - largely because it is primarily a "hydro" utility has not on the average experienced decreasing costs as increased demand has necessitated the development of less favorable sites. Static technology in the

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6. Wright's original rate proposal was a two block schedule with the length of the first block in kilowatt hours dependent upon the size of the customer's maximum rate of consumption. Supposedly included in the rate for the first block are capacity and energy costs as well as customer costs, while the rate for the second block is essentially only an energy charge. (The run-off rate).
R. F. Davidson: Price Discrimination In Selling Gas and Electricity, Baltimore, The Johns Hopkins Press, 1955 p. 39

generation end, steadily increasing costs, and in the past few years rapidly rising interest rates have all contributed to an upward trend in long term unit costs.[7] This as can be seen from Table 4.3 results in a dilema. Although in the period under review total unit costs have actually declined slightly, the return per kilowatt h our has declined even faster resulting in deficits for four separate years.

By refering to Table 4.1 it can be seen that a net deficit of $910,000 dollars was incurred for the entire seven year period. This represents about .35% of total expenses for the period and indicates a very close match between average cost and average return. It is anticipated that it should be possible to maintain unit costs at approximately their present level until at least 1980. However, a continued decline in unit returns is expected to result in a short fall in revenues.

Figure 4.4 represents a pictorial summary of the financial projection discussed in detail in the next chapter. This projection represents the best current information and some assumptions regarding planned capital spending, anticipated interest rates, negotiated contracts for energy sales, anticipated rate of increase of consumer revenue, rates of increase of payrolls, administrative expenses etc. In short it is an educated guess or 'guesstimate' about the future.

Figure 4.4 represents an attempt to give an approximate indication of anticipated trends in revenue, and expense per kilowatt hour sold.

The figures shown for the first three years are for energy sold in Manitoba only, while the slightly lower returns per kilowatt hour from

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7. The downward cost trend shown in Figure 4.2 and Figure 5.2 in the following chapter have been achieved because of export sales. The revenues earned through export sales help offset rising costs of producing electricity for the provincial market.

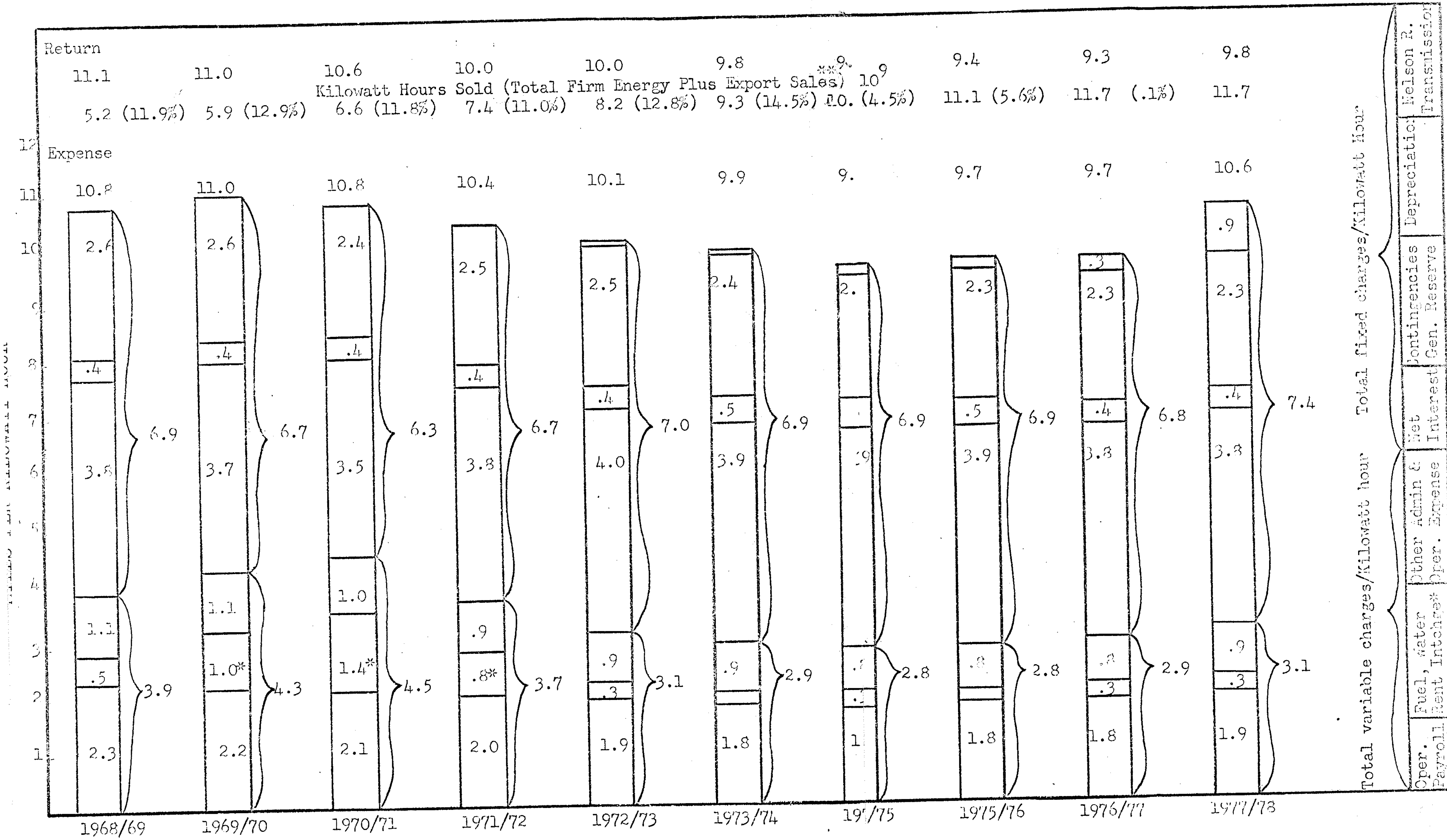
TABLE 4.3

MANITOBA HYDRO

TRENDS IN UNIT COSTS AND UNIT REVENUES

	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68
Annual Expenditure per KWH Sold (T.F.E. Sold in Manitoba & Export)	11.5 mills	11.3 mills	10.9 mills	10.3 mills	10.9 mills	11.4 mills	10.8 mills
Annual Return Per KWH (T.F.E. Sold in Manitoba)	11.3 mills	11.5 mills	11.0 mills	10.8 mills	11.0 mills	11.2 mills	11.1 mills
Annual Return Per KWH (T.F.E. Sold in Manitoba & Export)	11.3 mills	11.5 mills	11.0 mills	10.8 mills	10.8 mills	10.6 mills	10.3 mills
Ratio of Total Rtn/Total Expenditure Per KWH	.98	102	101	105	.99	.93	.95

PROJECTED ANNUAL EXPENDITURE AND REVENUE PER KILOWATT HOUR SOLD



* Includes charge for interchange imports.

** Not included in the above energy figures are possible export sales of economy energy if water conditions etc. permit.

1971/72 to 1976/77 reflect the effect of negotiated export sales. The large jump in both revenue and expense per kilowatt hour in 1977/78 is partially caused by a large decrease in export sales for that year. The energy so released is used to supply the normal load growth of the Manitoba system at the normal prices charged to customers within the province.

The return per kilowatt hour figures represent the effect of the present rate structure. It can be seen that this rate structure implies a steadily declining average return per kilowatt hour from 11.1 mills in 1968/69 to 9.3 mills in 1976/77. The 9.8 figure represents the partial effect of halving the volume of export sales in the final year.

MARGINAL RETURN PER KILOWATT HOUR

As with marginal cost, there is not a unique marginal return which can be expected for the sale of an additonal kilowatt hour of electricity. The revenue earned by selling a marginal unit depends upon whom it is sold to.

In the sale of day to day economy energy to neighboring utilities price is usually negotiated for each sale at the time of sale using guide lines and established practice as price criteria. Marginal revenue from interutility sales may run from about 1 to 5 mills depending upon the circumstances and source of the energy.

The marginal revenue earned from the sale of an additional kilowatt hour to a Manitoba customer depends upon what class he is in, what rate structure he is on, whether he is a new customer or an established one, and what his present consumption is. The most useful marginal revenue data can be derived from an analysis of Manitoba Hydro's General Consumers. This group accounts for about 75% of total revenue and includes all customers in Manitoba with the exception of Winnipeg Hydro, and three or four large industrial customers.

There are four principal classes in this group: residential, farm, commercial, and industrial. All are characterized by a block type rate structure (for example - 75 kwhs per month @ 4¢, + 100 kwhs @ 2¢ + balance at 1¢, with a 10% discount) which reduces the average cost per kilowatt hour to the customer as his monthly consumption increases. Thus in the example above, virtually all established residential consumers who consume more than 175 kwhs per month pay a marginal rate of 9 mills for each additional kilowatt hour consumed. The average return per kilowatt hour for a given customer would thus decline, approaching a limit of 9 mills.

TABLE 4.4[8]

AVERAGE REVENUE PER KILOWATT HOUR (Mills)

Year	Average	Residential	Farm	Commercial	Industrial
1961/62	15.3	15.4	17.3	21.3	12.0
62/63	15.2	15.4	16.7	21.3	12.1
63/64	14.8	15.3	16.4	21.1	11.7
64/65	14.4	14.5	15.7	20.5	11.7
65/66	14.0	14.2	15.3	19.9	11.3
66/67	13.5	14.0	14.8	19.3	10.8
67/68	13.1	13.7	14.4	18.4	10.5

Table 4.4 shows the major customer classes affected by the block type rate structure. Manitoba Hydro in additon has several large customers, and municipal street lighting customers, but generally these customers do not have the same block rate structure, and thus have a more constant average return per kilowatt hour. For the purpose of trend observation it is considered that the four customer classifications given in Table 4.4 are

8. Source: Manitoba Hydro Monthly Reports Year Ending March 31st.
   Note: Residential and commercial customers exclude flat rate water heater; industrial customers exclude direct customers.

adequate.

Although a variety of rates apply to residential and farm consumers a common run-off rate of 9 mills and thus limit applys in both cases. The Commercial run-off rate is 15 mills with a flat 10 mill rate for cooking and heating. This gives an average commercial run-off rate of about 13.5 mills. The industrial rate schedule is complex employing combination demand and energy charges so no single run-off rate is in effect. It appears, however, that the effective industrial run-off rate would be about 6 mills per kilowatt hour.

In order to determine a composite run-off rate for all four classes of consumers, the run-off rate for each class of consumer was weighted by the proportion of additonal energy sales to established customers in each class to the total additional energy sales to established customers. Data from the 1967/68 fiscal year was employed. A composite General Consumers run-off rate of 8.7 mills per kilowatt hour was calculated. For the sake of simplicity 9.0 mills will be employed in future calculations.

The marginal return per kilowatt hour for each class would be a function of new customers added and energy sold at the run-off rate. Thus if all additional energy was sold to established customers marginal revenue would be about 9.0 mills per kilowatt hour. If all additional sales were to new customers at the average number of kilowatt hours of current customers the average marginal revenue in 1967/68 would be about 13.1 mills.

With reference to Table 4.4 it can be seen that the average revenue per kilowatt hour has declined rapidly since 1961/62. This has occured because with all classses the run-off rate is less than the average return, about 70% of additonal energy sales each year has been to existing consumers at the run-off rate, and with each passing year a larger proportion of energy sold to each new consumer has been at the run-off rate. In other words marginal revenue is less than average revenue. Assuming that the rate structure remains unchanged as it has in general since 1911, a larger and larger proportion of all additional energy will be sold at the run-off rate with each passing year, and thus the marginal revenue will approach the run-off rate.

TABLE 4.5

General Consumers - Average and Marginal Revenue Per Kilowatt Hour Sold (mills)

Year	Average Revenue	Marginal Revenue
1961/62	13.6	13.2
62/63	13.6	13.2
63/64	13.6	13.2
64/65	13.4	11.7
65/66	13.2	11.2
66/67	13.0	10.5
67/68	12.7	10.3

Unlike Table 4.4 the above table reflects all General Consumer revenue, and energy including street lighting and flat rate water heating. As can be seen both average and marginal revenue per kilowatt hour sold is declining. For the reasons mentioned earlier it is expected that marginal revenue will decline to a level slightly above 9.0 mills and then become constant. Assuming the present run-off rates are retained, both average and marginal revenue could be expected to approach a limit of about 9.0 mills.

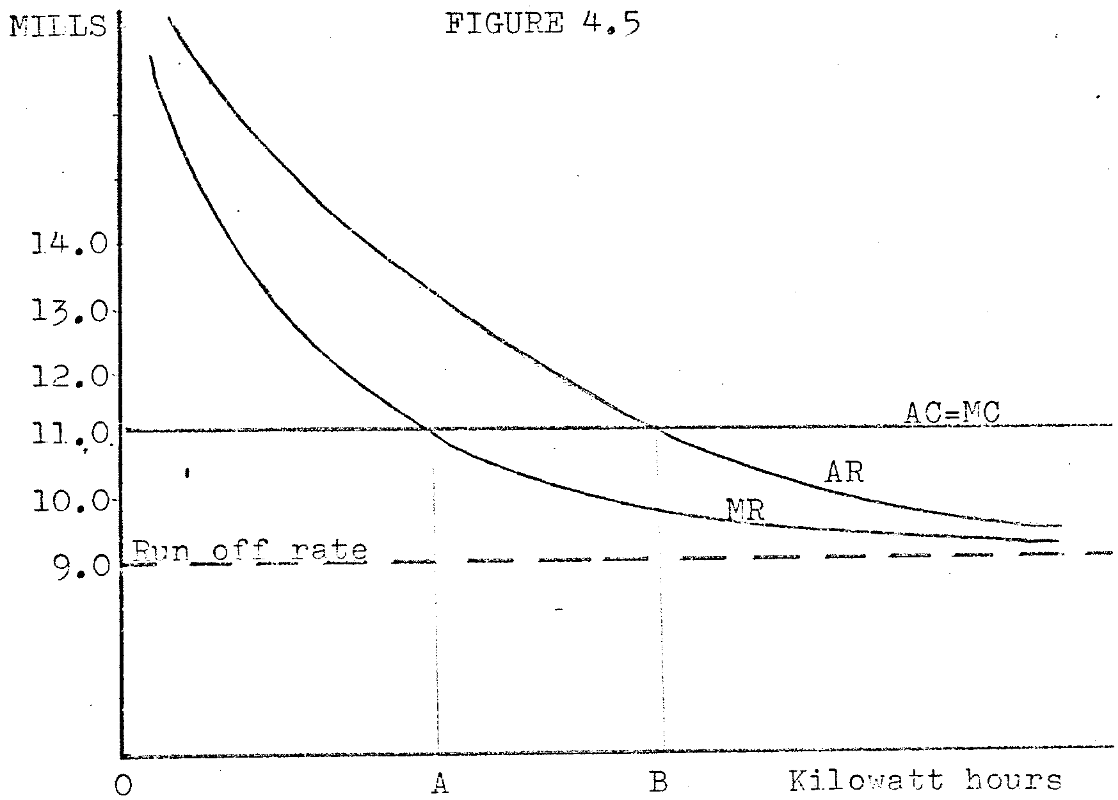


Figure 4.5 demonstrates the approximate relationships between the major long run cost and revenue components affecting Manitoba Hydro. Long run average cost and marginal cost are assumed to be constant at 11.0 mills. The run-off rate is constant at 9.0 mills. In the range OA marginal revenue is greater than marginal cost, at A they are equal and beyond A marginal revenue is less than long run marginal cost. Beyond A each additional kilowatt hour is sold at a price less than its long run cost of production. In the range OB average revenue is greater than long run average cost, but is declining. At point B average revenue is equal to average cost and to the right of B average revenue is less than long run

average cost. This occurs because beyond B the proportion of total energy sold at less than long run marginal cost is sufficient to outweigh the proportion sold at more than long run marginal cost. In studying Figure 4.5 it must be appreciated that it represents a dynamic situation. The X axis represents a time scale, and an annual increase of energy sales of about 8% per year. The marginal revenue curve represents the combined effects of increased sales to existing customers at a composite run-off rate, and the addition of new customers to the system.

It can be appreciated that Figure 4.5 represents an untenable situation in the long run. The basic philosophy of Manitoba Hydro is to provide service at cost and to break even over the long run. This objective does not seem possible given the present level of costs and present rate structure.

It will be recalled that prior to 1957 this situation did not exist. The long run average cost was less than 9.0 mills and thus marginal revenue was always greater than average cost if not marginal cost which obviously was rising. Since 1957 however average cost has been considerably above 9.0 mills. In three separate years 1961/62, 1966/67, and 1967/68 average cost has been greater than average revenue, and for the period 1961/62 - 1967/68 average cost was just slightly in excess of average revenue.

This situation was temporarily solved by a rate increase which increased the size of the first blocks, but left the run-off rates unchanged, thus leaving long run marginal revenue slightly below long run marginal cost. This situation ensures that average revenue will again fall short of average cost in the long run, and has implications regarding the efficient or optimum allocation of resources as we shall discuss in chapter XII.

In order to realize the basic objective of providing service at cost, it is necessary to bring long run marginal cost and long run marginal revenue into approximate equality. This might be accomplished in a number of ways. First my assumption that long run average and marginal cost are approximately equal and constant may be in error. If marginal cost is less than average cost and declining slightly, both will decline, thus eventually closing the gap.

If however marginal cost is either constant or rising there appear to be two basic solutions. These are either an increase in the marginal revenue through raising the run-off rate to about 10.0 mills or so, or accomplishing a downward shift in the AC - MC curve through technological advance, or by realizing an improvement in utilizaton of capital. There are several ways in which a shift in the average cost curve might be achieved which shall be discussed in more detail in subsequent chapters.

TRENDS IN FIXED CHARGES AND OPERATING EXPENSE COMPONENTS

Fixed Charges

The trend to increasing fixed charges per kilowatt hour relative to operating charges is expected to continue with average fixed charges declining slightly to 6.3 mills immediately before the introduction of Kettle Rapids in 1971/72. Fixed charges are expected to increase abruptly to 7.0 mills per kilowatt hour with the first full year of Kettle Rapids' fixed charges in 1972/73 and remain approximately at that level until 1976/77. In 1977/78 unit fixed charges are expected to rise abruptly again to 7.4 mills as the full impact of the Nelson River Transmission charges become effective.

It should be noted that unit fixed charges are at approximately the same level as the 1961/62 - 1967/68 period in spite of the much higher interest rates expected. This occurs for the following reasons: unit depreciation charges are declining slightly thus offsetting slightly higher unit interest charges, high utilization of generating capacity is anticipated thus partially offsetting higher interest rates, and the extremely favorable interest rate and repayment conditions (based on actual use) for the Federally financed Nelson River Transmission reduce the impact of this facility on unit fixed charges in the early load building period.

Should the average interest rates for the period exceed the 6.5% employed in the projection, or should the actual increase in kilowatt hour sales be less than anticipated, unit fixed charges will be somewhat higher than the level experienced from 1961/62 to 1967/68.

Operating Charges

The downward trend in operating expenses per kilowatt hour established in the past seven years is expected to continue, but with a short term increase to 4.3 and 4.5 mills in 1969/70 and 1970/71 due to high fuel and interchange expenses in those years. Unit operating expenses are expected to drop as low as 2.8 mills during the period with slight rise the final years as export sales dropoff.

Unit operating charges are expected to decline because little fuel is expected to be burned after 1971/72 and the favorable payroll costs per kilowatt hour trend established from 1961/62 to 1967/68 is expected to continue.

CHAPTER V

PROJECTED INCOME STATEMENTS

THE USE OF FINANCIAL PROJECTIONS OR CORPORATE MODELS AS DECISION MAKING AND RESEARCH TOOLS

The twentieth century has witnessed a continuing increase in the size and complexity of industrial enterprises. In the earliest stages of our industrial society most enterprises were relatively small by todays standards, manufactured a relatively restricted range of products, faced fewer alternatives and options and could generally be effectively managed by one or two men who were capable of comprehending most of the factors affecting the business.

As industrialization progressed, the complexity of industrial organization rapidly grew beyond the ability of one man to grasp. In order to optimize the effectiveness of a corporation it has been necessary to develop techniques which can comprehend and take into account all the multitude of factors which affect the success of the enterprise. The effective size of an industrial enterprise has and will continue to be limited by the ability of men to develop and utilize management techniques and analytical information gathering, and decision making tools which can effectively control the organization.

One technique which has been developed over the past few years is the simulation of either part or all of the organization's activities with the assistance of a so called corporate model. Although a crude corporate model can be constructed and utilized employing manual techniques a really effective model requires the use of a computor. A computor enables the consideration of many more factors, reduces computation time from days to minutes, and enables decision makers to ask the model questions, to play the "What if" game.

Because of the nature of an electric utility, a corporate model promises to be a particularly effective management tool. An electric utility is a particularly stable enterprise which generates certain trends and growth patterns which can be analysed quantitatively employing econometric methods or simpler techniques. An electric utility grows in an evolutionary fashion which does not seem to be affected by dramatic shifts in demand or supply parameters either by technological change, taste, obsolescence of products and so on. Electric utilities are subject to extremely long planning horizons. Decisions made today will continue to affect the performance of the utility many years in the future. The overall operating performance is a function of thousands of individual variables and factors all of which contribute in either a positive or negative way to the long run operating results of the utility.

Because of these characteristics of an electric utility, a tool which can integrate all of the thousands of variables and factors which affect its operation into a single easily understood document, and can demonstrate quantitatively the effect of a given change in any one variable promises to be an extremely useful aid to effective management.

It is with these thoughts in mind that Manitoba Hydro personnel have been actively engaged in the development of a corporate model during the past five or six years.

This corporate model which is, and will continue to be in a state of evolution, still falls far short of a true corporate model which is capable of taking all the factors influencing the performance of the utility into account. At the present time the Manitoba Hydro model takes the form of a projected income statement. It shows the financial impact only, of changes in a limited number of variables and is presently incapable of showing the true economic impact of decisions.

These projections which began as a simple five year manual projection of three or four revenue and expense components, plus total revenue and total expenses for each year have evolved steadily in detail and accuracy. The present projections show all the major revenue and expense components for eleven years and are prepared with the use of an IBM 360/F 30 computor. In essence the projection is a simulation of Manitoba Hydro's accounting system. All relevant information regarding anticipated sales of energy, payrolls, capital budgets, fuel expenses, interest rates, bond maturity dates and so on are fed into the computor on punch cards and the computor prepares an accounting summary or income statement showing the financial impact by year of the combined effect of all these factors. In its present form the projection automatically considers all the financial factors affecting the corporation. In the future it is planned to expand the present program and to increase the number of inputs to include more operating or physical factors in order to increase the economic content of the projections. In addition to the projected income statements presently produced it is planned to project balance sheets, source and application of funds statements, and an output which shows installed generating capacity, anticipated system peaks, energy requirements, surplus capacity, surplus energy, load factors, utilization factors and so on for each year of the projection. The projections would thus integrate information from the operating statement, operating budget, load and energy forecast, and the capital budget and ideally would provide an extremely clear and accurate picture of every major facet of the total system operation over the medium term.

The Manitoba Hydro projections have proved an extremely valuable tool even in their formative stages. Their development demanded a disciplined and exhaustive examination of the current practices of planning, accounting, information processing, and capital budgeting. It became apparent that the five year projection dictated by a five year capital budget was not sufficient. Accordingly the detailed planning horizon was extended to ten years and a detailed ten year capital budget was prepared. It was found that the detailed work required to prepare and analyse a projection enabled the early identification of potential surpluses or shortages or capacity and energy well in advance and enabled early remedial action. It also enabled the determination of the sensitivity of the total operation to changes in various factors, enabled identification of the important variables, and helped develop a clearer picture of how all the various factors interacted in the operation of the utility.

Once developed even partially, the projection becomes an extremely valuable management tool. The existence of a carefully prepared projection enables the identification of inconsistencies in planning. These inconsistencies can be dealt with early while there is still time to adjust capital schedules or seek markets for surplus capacity or energy. Thus management can seek the optimum utility performance by a sort of iterative process.

The salient feature of a projection of this nature is that it provides a tool that can be used to great advantage in decision making. It provides more complete data on which to base decisions. It provides the analysis of numerous alternatives at greater depth, and provides a clear picture of the financial results of one course of action compared with another. Ideally management should be furnished with all the necessary information required to weigh and measure all possible advantages and disadvantages associated with each decision to be made. While it is not claimed that Manitoba Hydro's projection or indeed any corporate model will ever accomplish this to perfection, it is felt that the projection which has been developed at Manitoba Hydro is at least a small step in this direction.

THE TECHNIQUES EMPLOYED IN THE MANITOBA HYDRO PROJECTION

Figure 5.1 is the final print out form of the the Manitoba Hydro projection. It shows the approximate impact in financial terms of the current capital budget (which is subject to constant revision) and a large number of assumptions as to possible levels of interest rates, rates of growth of energy sales and total wage bill, water flows, fuel expenses, depreciation policies and so on. Figure 5.3 represents the integration of this projection with the current Manitoba Hydro load and energy forecast. It shows a breakdown of unit costs of producing electricity to the year 1977/78 in almost precisely the same form as past unit costs have been presented. Figure 5.2 is the capital additions schedule employed by the computor program in computing the figures shown in this projection. The capital additions schedule is derived from the capital budget and shows the in service dates of each item in the capital budget. This schedule also shows the approximate amount or value of each capital project which will be introduced into the operating accounts in any one year. Thus with a large project such as Kettle Rapids the total cost of the project when completed is computed, then one tenth of this computed cost is introduced into the operating accounts in the year each of the ten generating units comes into service. This is an arbitrary practice which enables the lumpy nature of investment to be moderated so that total expenses are increased in a more or less continuous fashion as does revenue. All items greater than one million dollars are listed specifically, while smaller items are lumped together under the heading Other Additions. A variety of techniques are employed to compute various segments of the projection. Some items are a straight projection of past trends with or without modification, into the future, while other items are calculated manually and inserted in the appropriate years and still other items are computed automatically from coefficients, manual inputs, and other information contained

FIGURE 5.2-A

ASSUMED CAPITAL ADDITIONS X $1000

YEAR	SPECIFIC ADDITIONS OVER ONE MILLION	AMOUNT	OTHER ADDITIONS	FISCAL YEAR TOTALS
1968/69	SELKIRK GAS TURBINE	$1400		
	GRAND RAPIDS UNIT =4	$10658		
	GRAND RAPIDS-VERMILION LINE	$9074		
	OVERFLOWING RIVER-THE PAS LINE	$1720		
	OVERFLOWING RIVER STATION	$1290		
		$24142	$14800	$38942
				$38942
1969/70	BRANDON G.S.-UNIT =5	$16700		
	KELSEY G.S.-UNIT =6	$8684		
	GRAND RAPIDS SCOUR HOLE	$1600		
	VERMILION-RAVEN LINE	$1630		
	WAVERLEY SERVICE CENTRE	$1150		
		$29764	$15900	$45664
				$84606
1970/71	DORSEY-LAVERENDRYE LINE	$1060		
	LAVERENDRYE-U.S. LINE	$1755		
	THOMPSON-LAURIE RIVER LINE	$4450		
	SHERRITT-GORDON PROPERTIES	$1098		
		$8363	$16250	$24613
				$109219
1971/72	KETTLE G.S.-UNIT 1,2,3,4	$119424		
	DORSEY STATION	$1964		
	SEVEN SISTERS-ONTARIO LINE	$3900		
	ONTARIO INTERCONNECTION STATION	$2050		
		$127338	$15700	$143038
				$252257
1972/73	KETTLE G.S.-UNIT 5	$29856		
	LAVERENDRYE STATION	$2375		
	KELSEY-THOMPSON LINE	$3200		
	GREAT FALLS HEADGATES	$1500		
		$36931	$11780	$43711
				$300968
1973/74	KETTLE G.S.-UNIT 6,7	$59712		
	CHURCHILL RIVER DIVERSION	$29000		
	SOUTHERN INDIAN LAKE	$1000		
	VERMILION-ROBLIN LINE	$1774		
	CORNWALLIS-LETELLIER LINE	$5446		
	CORNWALLIS-U.S. BORDER LINE	$2000		
	ROSSER-TELLON LINE	$1050		
	GILLAM-CHURCHILL LINE	$4800		
		$104782	$10330	$115112
				$416080
1974/75	KETTLE G.S.-UNIT 8,9	$59712		

FIGURE 5.2-B

ASSUMED CAPITAL ADDITIONS X $1000

YEAR	SPECIFIC ADDITIONS OVER ONE MILLION	AMOUNT	OTHER ADDITIONS	FISCAL YEAR TOTALS
	RAVEN LAKE-CORNWALLIS LINE	$1690		
	RAVEN LAKE STATION	$1055		
		$62457	$11100	$73557 $489637
1975/76	ASHERN-VERMILLION LINE	$2600		
	KETTLE-KELSEY LINE	$4500		
		$7100	$10700	$17800 $507437
1976/77	BRANDON G.S. UNIT 6,7	$32100		
	WAVERLEY SERVICE CENTRE	$2000		
	DORSEY-BRANDON LINE	$7740		
	BRANDON STATION	$1280		
	DORSEY STATION	$1710		
	ST. VITAL STATION	$1070		
	HEAD OFFICE BUILDING	$3750		
		$49650	$10760	$60410 $567847
1977/78			$10415	$10415 $578262
1978/79	DORSEY-BRANDON LINE	$8200		
	BRANDON-SASKATCHEWAN LINE	$4675		
	LAVERENDRYE-ST. VITAL LINE	$2230		
	BRANDON STATION	$2200		
	DORSEY STATION	$1900		
	THE PAS-FLIN FLON LINE	$2100		
		$21305	$9590	$30895 $609157

FIGURE 5.1

PROJECTED INCOME STATEMNT
IN MILLIONS OF DOLLAR
FOR THE YEARS 1968/69 TO 978/79

PROJECTION 69-07-00-0
DECEMBER 10 1968

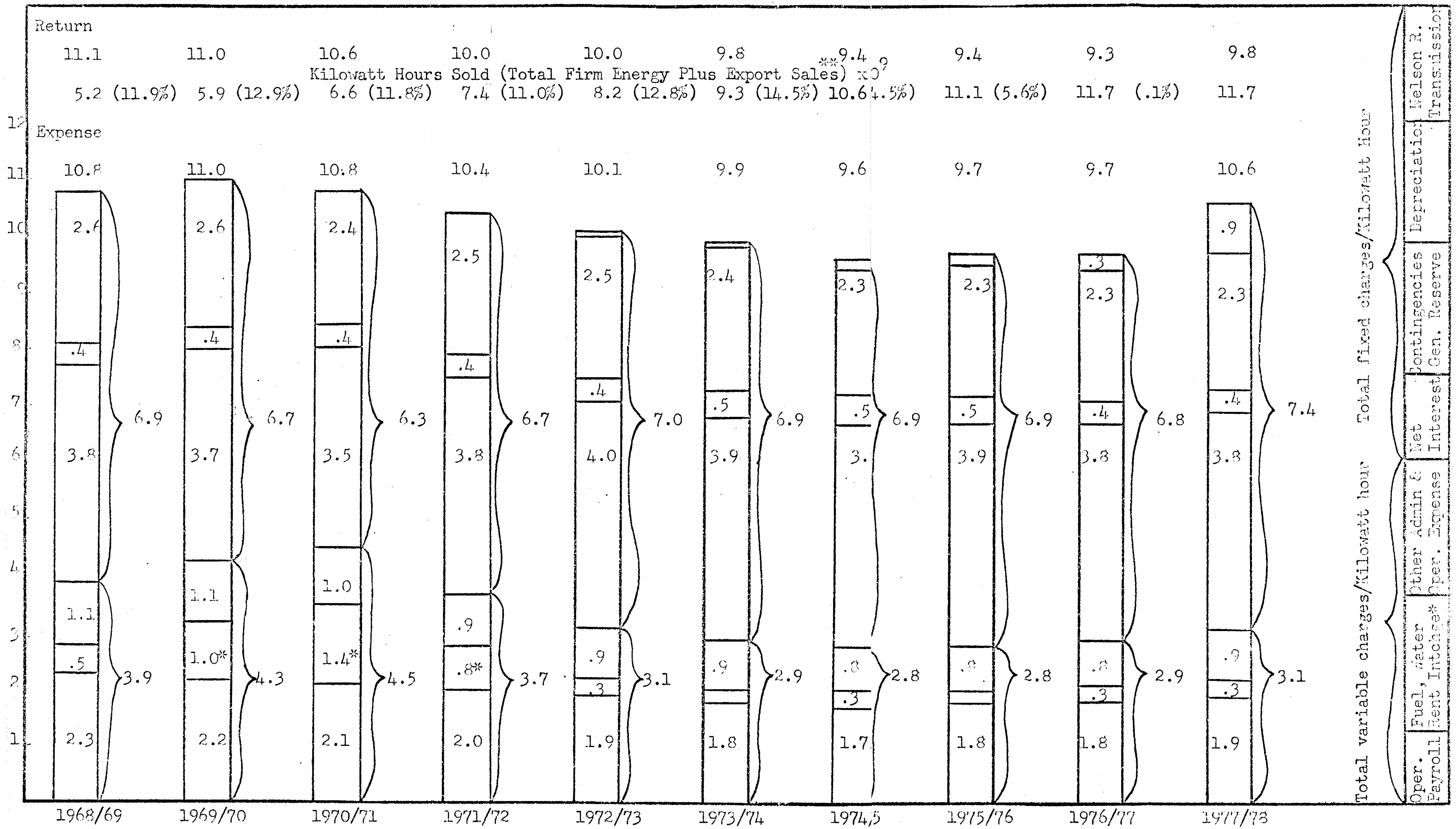
	1968 1969	1969 1970	1970 1971	1971 1972	1972 1973	973 974	1974 1975	1975 1976	1976 1977	1977 1978	1978 1979
REVENUE											
GENERAL CONSUMERS	45.3	49.6	53.5	57.7	62.3	7.2	72.6	78.3	84.6	91.3	98.6
WINNIPEG HYDRO	4.7	5.5	6.1	6.1	5.8	6.0	6.5	7.1	7.6	9.1	8.3
INCO.	5.8	7.3	8.0	8.0	8.0	7.9	7.9	7.9	7.9	7.9	7.9
DIRECT CUSTOMERS	1.0	1.0	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
INTERCHANGE CAPACITY	-	-	-	-	2.2	5.0	8.4	7.3	6.0	3.0	-
INTERCHANGE ENERGY	.7	.2	.2	.2	1.4	2.3	2.4	1.8	.8	.8	.8
OTHER	.5	.8	.8	.8	.9	.9	.9	.9	.9	.9	.9
TOTAL REVENUE	58.0	64.4	70.0	74.3	82.1	0.8	100.2	104.8	109.3	114.5	118.0
EXPENSES											
WAGES AND SALARIES	12.0	12.9	13.8	14.8	15.9	7.0	18.3	19.6	21.0	22.6	24.2
OTHER ADMIN. AND OPER. EXP.	5.8	6.2	6.6	7.0	7.5	3.0	8.5	9.1	9.7	10.3	11.0
WATER RENTALS	1.4	1.3	1.3	1.5	2.1	2.3	2.7	2.7	2.7	2.7	2.7
INTERCHANGE CAPACITY	-	.8	2.1	-	-	-	-	-	-	-	-
INTERCHANGE ENERGY	-	.7	2.4	1.6	-	-	-	-	-	-	-
FUEL	1.2	3.0	3.2	2.9	.1	-	-	-	.8	.9	1.3
INTEREST-NET	20.0	21.9	23.3	27.8	33.0	5.6	41.5	43.0	44.2	44.8	45.3
DEPRECIATION	13.8	15.1	16.2	18.2	20.4	2.2	24.2	25.3	26.4	27.4	28.1
NELSON RIVER TRANSMISSION	-	-	-	-	.5	1.1	2.0	2.7	3.4	10.3	10.5
TOTAL EXPENSES	54.2	61.9	68.9	73.8	79.5	7.2	97.2	102.4	108.2	119.0	123.1
NET OPERATING INCOME	3.8	2.5	1.1	.5	2.6	3.6	3.0	2.4	1.1	4.5DB	5.1DB
CONTINGENCY RESERVE	2.3	2.4	2.5	3.0	3.7	4.2	4.8	5.0	5.0	5.0	4.9
SURPLUS OR DEFICIT	1.5	.1	1.4DB	2.5DB	1.1DB	.6DB	1.8DB	2.6DB	3.9DB	9.5DB	10.0DB
ACCUMULATED SURPLUS OR DEFICIT	1.5	1.6	.2	2.3DB	3.4DB	4.0DB	5.8DB	8.4DB	12.3DB	21.8DB	31.8DB
RATE STAB. RESERVE BALANCE	15.9	16.0	14.6	12.1	11.0	0.4	8.6	6.0	2.1	-	-

PROJECTION COMMENTS

GENERAL CONSUMERS REVENUE 8.25 PERCENT.
PLUS 3,000,000 A YEAR COMMENCING JULY1,1968 AT 2.0 PERCENT.
WAGES AND SALARIES 7.3 PERCENT.
OTHER ADMIN. 6.6 PERCENT.
INTEREST 6.50 PERCENT.
BASE CASE WITH SASKATCHEWAN SALE
KETTLE G.S. SCHEDULE 4-1-2-2

PROJECTED ANNUAL EXPENDITURE AND REVENUE PER KILOWATT HOUR SOLD

FIGURE 5.3



* Includes charge for interchange imports.

** Not included in the above energy figures are possible export sales of enony energy if water conditions etc. permit.

in or inserted into the program. The actual production of a projection requires a computor with a large amount of storage so that a vast amount of information can be processed and sorted during the computational phases. The final stage occurs with the printing of the actual projection (Figure 5.1) and the capital additions schedule (Figure 5.2) and a number of other schedules showing detailed depreciation calculations, the refinancing of current debt and bond investments, and other working papers which are employed to verify or control results.

The following paragraphs will be a very brief summary of the basic techniques employed in each major sector of the current Manitoba Hydro projection.

Revenue .

1. General Consumers Revenue

Since 1961/62 general consumers revenue has increased at about 8.3% per year. Accordingly the current years budget figure for general consumers revenue is projected into the future at 8.25%. A rate increase effective July 1968 is anticipated to bring in $3,000,000 in the first full year that it is in force. This figure is expected to increase by 2% per year with the addition of new customers. This information was super imposed upon the basic general consumers revenue calculation by the computor to get the final estimate in this area.

2. Winnipeg Hydro Revenue

Winnipeg Hydro Revenue is computed by simulating the operation of the ten year Winnipeg Hydro power agreement under which Manitoba Hydro wholesales power to that utility. Although the present agreement expires in 1974 it was assumed to be in force for the entire projection. The agreement provides for the sharing of common generation and transmission costs. The actual amount paid in any given year is a function of the ratio of system peaks, Manitoba Hydro's capital investment for generation and transmission, the effective interest rate, capacity or energy sales and purchases made by Manitoba Hydro, Manitoba Hydro fuel cost and a number of other minor factors. Winnipeg Hydro revenue is presently being calculated manually and is inserted into the master program as a manual input employing a separate IBM punch card for each year. In the near future Winnipeg Hydro revenue will be calculated by a separate subprogram which will become a module of the master program.

3. International Nickel Company Revenue

Manitoba Hydro has a long term contract with the International Nickel Company which provides for minimum revenue under all conditions, plus additional charges for all extra capacity and energy. Inco. revenue is calculated manually on the basis of this contract and inserted manually into the master program.

4. Direct Customers

This revenue category represents a number of large industrial customers whose individual requirements can be estimated separately. These figures are calculated manually and inserted into the master program.

5. Interchange Capacity and Energy Revenue

These figures are calculated manually and are inserted into the master program. They represent minimum revenue from already negotiated contracts, which may be negotiated for many years in the future. As such they represent surpluses of capacity and energy which occur over the long term during load building periods. Many interchange sales occur in the day to day operation of the system and are not included in the projected figures.

6. Other Revenue

This category of revenue comes from a number of miscellaneous sources other than the sale of energy. It represents revenue from Manitoba Telephones for use of Manitoba Hydro's poles and other facilities including the micro-wave system installed for communication with the Northern Manitoba System. These figures are calculated manually and inserted in the master program.

Expenses

1. Wages and Salaries

Since 1961/62 wages and salaries have increased at about 7.3% per year. Accordingly the current or base year's wages and salaries estimate is projected into the future at 7.3%. This operation is executed automatically by the computor.

2. Other Administrative and Operating Expenses

This expense category has increased at about 6.6% per year. This figure of 6.6% is employed to project other administrative and operating expenses into the future. As with wages and salaries, the figures are computed automatically by the computor.

3. Water Rentals

This expense item is computed manually assuming average water flows and employing the system load and energy forecast. The results are inserted into the master program on IBM punch cards.

4. Interchange Capacity and Energy Purchases

As with interchange revenue, this category represents negotiated purchases. The amounts are inserted into the master program manually.

5. Fuel Expenses

Fuel expenses are calculated manually taking into account hydraulic capacity additions and average water flow conditions. These figures are inserted into the master program.

6. Interest Net

This expense category represents the largest single exepnse item and is one of the most complex computations in the projection as it presently stands. Because a change in any other figure in the projection with the exception of depreciation or contingency reserve (non cash expenses) will alter the net interest charges, this is the final computation made by the computor before making the final sort and print out. Using the current year budget estimate of net interest expense as a base the program integrates an assumed interest rate, with total revenue and expense information, plus assumed capital additions and the previous years deficit or surplus to arrive at a net interest figure for the next year. This operation is repeated for each successive year. The following list provides a simplified summary of the various steps and the basic logic which enters into this calculation.

INTEREST

Determine Net Interest Cost in base year.

Add
- X% x $\frac{1}{2}$ x Current year capital additions.
- X% x $\frac{1}{2}$ x Previous year capital additions.
- X% - effective rate of issue x $\frac{1}{2}$ x Bond maturities in previous year.
- X% - effective rate of issue x $\frac{1}{2}$ x Bond maturities in current year.
- X% x Previous year Deficit.

Deduct
- X% x previous year depreciation and contingency provision.
- X% x previous year surplus.

(x = 6.50%)

7. Depreciation

Depreciation is a non cash expense. It therefore has no effect upon the net interest calculation and can vary without affecting that figure.

It is computed automatically by the program employing the following basic procedure and logic. As different types of physical assets have different service lives, a different composite depreciation rate is employed for each class of asset. The composite rates presently in use are shown below. The program presently simulates the actual Manitoba Hydro depreciation policy with a straight line method. However, the modular construction of the program enables alternative depreciation methods and rates to be substituted easily, thus facilitating the determination of the long term effects of hypothetical changes in depreciation policy.

Depreciation

Determine depreciation provision in base year.

Add - Composite rate x $\frac{1}{2}$ x current year major capital additions.
- Composite rate x $\frac{1}{2}$ x previous year major capital additions.
- Composite rate x 1 x previous year other capital additions.

Deduct - Reductions at Generating Stations due to components at stations becoming fully depreciated.

Composite Rates

Specific Additions

Generation -	Hydraulic	1.75%
	Hydraulic Additions	2.5 %
	Steam	2.3 %
	Gas Turbine	10.0 %
Transmission		2.5 %
Stations		2.75%
Communications		8.0 %
Buildings		1.5 %
Other Additions		4.3 %

8. Contingency Reserve

The contingency reserve is a sort of self insurance scheme and like depreciation is a non cash item. It is computed automatically by the computer using the following logic.

Contingency Reserve

Determine contingency reserve provision in base year.

Add - 1% x generation additions (hydraulic and steam) in previous year.

Deduct - 1% x previous year generation depreciation provision (hydraulic and steam).

9. Nelson River Transmission Expense

This expense item is of a special nature which is not normally encountered in the accounts of a utility system. Because the transmission lines associated with the Phase I development are being built and will be owned by the Government of Canada, Manitoba Hydro will have to pay a rental charge for their use. The rental charge is based on actual use and is designed to amortize the full cost of the line over fifty years. The actual payments are in reality interest and depreciation charges but are included as a special item because they represent financial obligations not directly related to the interest and depreciation charges incurred in any given year. The payments are calculated manually and inserted in the program.

ASSUMED CAPITAL ADDITIONS

Because of the capital intensive nature of Manitoba Hydro's operation, one of the most important inputs in the projection is that of assumed capital additions. As will be demonstrated shortly the projection is extremely sensitive to changes in capital investment. In order to introduce the capital investment assumptions into the program each specific addition over one million dollars is punched onto a separate IBM card with depreciation coding and other relevant information. The total of other additions for each year is punched onto another card. These cards are sorted and placed in the appropriate order in an input deck. The effect of any change in capital spending may be simulated by changing the appropriate cards.

THE SENSITIVITY OF THE MANITOBA HYDRO PROJECTION TO CHANGES IN THE INPUT VARIABLE

Table 5.1 shows the approximate effect of changes in a number of assumptions and input variables. The results are calculated primarily by changing one assumption at a time and comparing the results with a so called base case. The accumulated surplus or deficit in any year shows the net effect of a change in any assumption up to that point in time. Bracketed figures indicate an improvement in the utilities financial position while non bracketed figures indicate a deterioration. The first figure shows the direct effect of the change upon the item changed, while the figures below show indirect effects such as changes in net interest expenses associated with the change. In cases where the program does not automatically calculate all the secondary effects (as with manual input items), the items affected are indicated but no qualititative measurement is given. The list of variations is by no means exhaustive but does serve to indicate the approximate sensitivity of the projection and of the Manitoba Hydro system to changes in some of the variables affecting its operations.

TABLE 5.1

The Effects of Selected Variations in the
Basic Assumptions of the Manitoba Hydro Projections

The following schedule indicates the approximate effects on the five-year and ten-year deficits of variations in the assumptions used in the Manitoba Hydro Projection.

The variations are grouped according to the degree of control which may be exercised over them.

	Approximate Effect on Accumulative Deficit Thousands of Dollars 5 Years	 10 Years	Other Items Affected
A. Variations which might result directly from policy decisions			
1. Elimination of Prompt Payment Discount	(22,800)	(56,800)	R1
	(2,800)	(16,000)	E7
	(25,600)	(72,800)	
2. Adoption of proposed "Modified Sinking Fund" method of depreciation applicable to major projects	(15,000)	(39,000)	E8
	1,900	4,700	R2
	200	1,100	E7
	(13,400)	(33,200)	
3. Elimination of contingency reserve provisions	(13,400)	(34,400)	E10
	2,400	5,500	R2
	300	800	E7
	(10,700)	(28,100)	
B. Variations which might result from policy decisions but are not directly controllable			
1. Increase of 1% in rate of growth of General Consumer Revenue	(7,700)	(37,400)	R1
	(600)	(6,700)	E7
			C1, E3, E5
			E6, E7, E9
Assuming this resulted in a 1% increase in Manitoba Hydro rate of load growth	1,300	5,100	R2
	100	1,100	E7

	Approximate Effect on Accumulative Deficit — Thousands of Dollars		Other Items Affected
	5 Years	10 Years	
2. Decrease of 1% in rate of escalation of wages and salaries	(2,600) (200)	(11,800) (2,200)	E1 E7 R2
3. Decrease of $1 million per year in capital additions	(1,000) (400)	(4,100) (1,400)	E7 E8
C. Variations caused by events which are virtually uncontrollable			
1. Increase in INCo. revenue resulting from loads 10% higher than minimum	(3,700) (500)	(7,700) (2,500)	R3 E7 R2, C1, E3 E5, E6, E7
2. Increase of 1% in effective rate of interest on new borrowings	7,000	32,800	E7 R2 R3

	Approximate Effect on Accumulative Deficit — Thousands of Dollars				
	1968/69	1969/70	1970/71	1971/72	1972/73
3. Effect on energy - oriented costs* of water flow conditions other than average					
(a) Optimum Flows	(1,700)	(3,300)	(4,300)	(2,200)	-
(b) Minimum Flows	5,200	5,800	5,800	5,500	3,800

* E3, E5, E6, E9

Key to Symbols

R1	General Consumers Revenue	E1	Wages and Salaries
R2	Winnipeg Hydro Revenue	E2	Other Admin. & Oper. Expenses
R3	International Nickel Revenue	E3	Water Rentals
R4	Direct Customers Revenue	E4	Interchange Capacity Net
R5	Other Revenue	E5	Interchange Energy Net
		E6	Fuel
		E7	Interest Net
C1	Capital Additions (Affecting E7, E8, E10)	E8	Depreciation
		E9	Nelson River Transmission
		E10	Contingency Reserve

THE LIMITATIONS OF PROJECTIONS IN GENERAL AND SPECIFIC LIMITATIONS OF THE MANITOBA HYDRO PROJECTIONS

In constructing porjections, in working with and analysing them, and in employing them in making decisions it extremely important to understand their nature and particularly to understand their limitations. It must be always realized that they are an attempt to gain some understanding about events which may or may not occur in the future. Just because these events are printed in the form of numbers on a piece of paper gives them no substance or validity. Future events and circumstances can only be evaluated with varying degrees of uncertainty. Future events may prove a theoretically perfect projection dead wrong, while a quirk of fate may render a logically invalid projection dead right. There is a tendency among some model makers to call their results forecasts as if they were actually forecasting future events. With the Manitoba Hydro model the term projection seems more appropriate because it is in essence a projection of past and present information into the future and not really a forecast in the sense of being a prophecy of things to come.

A major short coming of these projections is their extreme sensitivity to changes in any of the variables, particularly in an early year. If for example the fixed coefficient used to project wages and salaries is in error by 1% from the first year this error will be compounded throughout the entire ten year period of the projection. While the error may not be very great in the early years, it will be extremely large by year ten, thus the degree of confidence decreases rapidly as one attempts to project further into the future. If the fixed coefficient deviates from the actual trend only after year five, the cummulative error by year ten will, of course, not be nearly as great. In general the first five years are considered to be fairly reliable, while the years beyond this are at present considered to be little better than a guesstimate. At present insufficient experience has been accumulated with these projections to determine just how much confidence can be placed in them.

The use of average coefficients to represent variables such as interest rates, rate of growth of payrolls, and revenue which change from day to day and year to year also poses some problems. This almost ensures that most of the annual expense and revenue figures will be incorrect. Although the projection may prove to be correct on the average, that is be generally correct over a number of years, it would not be correct in each and every year. This does not detract from the projections value as a decision making tool but may cause personnel who are less familiar with it to lack confidence when none of the annual figures turn out to be correct.

Ideally a projection should never turn out to be true or accurate, because a central assumption implicit in the projection is that no action will be taken to change the other assumptions of the projection. However, if the projection is employed properly, any problems or inconsistencies which are identified should be resolved thus changing the final outcome.

Another factor which might influence actual results particularly in the short term is weather conditions. An extremely cold winter would significantly increase energy sales and revenue while an extremely dry year might unexpectedly add one or two million dollars to fuel expenses.

One particular point that should be stressed is that it is extremely difficult to compare two projections which on the surface might appear quite similar. Two projections might indicate exactly the same surplus or deficit at the end of a ten year period, yet closer examination of the balance sheet might reveal total debt less with one than the other, or more physical assets in place with one than the other. If two projections indicate the same cummulative surplus or deficit we must consider which years individual surpluses or deficits occur. Because of discounting, a deficit of one million dollars in 1980 is not nearly as serious as a similar deficit in 1970.

Perhaps the most important short coming or limitation of this type of projection is that it demonstrates the short term financial effects of various decisions and not the economic. For this reason each individual decision as to the timing or desirability of specific capital additions or of making an export sale must be analysed independently and justified on economic grounds before being introduced into the projections. In the short term the most viable alternative on economic grounds may appear the most expensive, so that it must always be stressed that the projection shows only the short term financial impact of the addition or sale and not the economic.

Another problem arises with attempting to forecast the long term movement or trend in unit costs as shown in Figure 5.3. These unit costs and revenues to the year 1977/78 were computed by combining the projection shown in Figure 5.1 with the figures from Manitoba Hydro's current load and energy forecast. Both of these projections are quite sensitive, thus a 5% overestimate of energy sales combined with a 5% underestimate of expenses could produce a 10% error in the estimate of unit costs. For this reason these projections of the trend in unit costs should be considered as rough indications of future trends only.

Beyond this brief discussion of some of the theoretical limitations of these projections little more can be said. A more definitive analysis of their strengths and weaknesses will require more experience and the test of several years to determine how accurate and useful they actually are.

The results whatever they are, are in the last analysis dependent upon the assumptions chosen . It thus appears that the most important challange is to gain a better insight into the economic relationships governing the operation of an electric utility, so that the most reasonable assumptions can be employed in future porjections.

CHAPTER VI

EMPLOYMENT, PAYROLLS AND LABOUR PRODUCTIVITY

Labour costs represent approximately 22% of the total operating expenses of Manitoba Hydro. While this is a much smaller proportion than is the case in most other industries, due to the capital intensive nature of a hydro-electric utility, it is never the less an important factor in determining the long run cost of electrical energy. In order to realize the objective of maintaining the long run cost of electricity at its present level or even decreasing it if possible, it becomes imperative to keep the payroll component from rising. With inflationary pressure dictating an annual wage increase per employee in the order of 5 or 6% or more, the payroll, Component of unit costs can only be maintained by achieving a high rate of increase of labour productivity each year. The purpose of this chapter is to explore some of the relationships between level of employment, payrolls, and productivity at Manitoba Hydro.

It is extremely difficult to arrive at an accurate measure of operating employment, and operating payroll in the case of Manitoba Hydro. In fact it must be admitted that it has been impossible to calculate precise figures for these two items. This problem arises because of the large amount of capital construction undertaken by Manitoba Hydro. This is generally known as force account construction. Because of this a large part of Manitoba Hydro's total payroll is capitalized in any given year (charged into the costs of a given capital project). This is particularly so with respect to Manitoba Hydro's Engineering and Construction Divisions where most of the activity is directly related to capital formation. In the most simple case, payroll is capitalized directly with the use of a capital work order because a given employee would be devoting all his efforts to a single capital project. The operation becomes more complex when an employee shares his time among several capital projects and even more complex when an employee's time is divided between capital and operating tasks. To arrive at a perfect allocation of total payroll between the capital and operating functions would require a great deal of unproductive paper work which would reduce rather than increase economic efficiency. While it has been found quite simple to capture the major portion of capital payroll through capital work orders, it is more difficult to determine how much of the time of departments primarily concerned with administration and operations is devoted to capital formation. This problem has been resolved through the capitalization of a portion of total operating expenses as "Overhead Capitalized." This overhead which is arrived at by a mathematical approach includes, payroll, fringe benefits, sick leave, vacations, office space, transportation and supplies. The payroll component of overhead capitalized is approximately 60.0% but varies from year to year. Capitalized payroll is then calculated by adding labour charges to capital work orders plus the payroll component of overhead capitalized. Operating payroll is then determined by employing the following equation.

Operating Payroll = Total Payroll - Capitalized Payroll

While this method is not precise in an accounting sense it is felt that it is sufficiently accurate for the measurement of productivity and other economic analysis.

Similar round about methods have had to be employed in the determination of the allocation of employees between operating and capital formation. Prior to 1965/66 Manitoba Hydro's "Employment and Payrolls" reports provided a somewhat less than adequate record of employment. It was prepared on a monthly basis and showed the maximum number of employees in each division for the month. While this provided an accurate indication of the number of salaried employees, it did not provide an accurate indication of the number of hours worked by hourly paid employees. In extreme cases where a large number of hourly employees were hired for one or two days in a month to repair damage caused by an ice storm, or during periods of heavy overtime, the maximum number of hourly employees deviated considerably from the average number of employees for the month. Because of this lack of statistics on the number of hours worked prior to 1965/66 all analysis involving employment has been based on a measure of man years. This measure was calculated by taking the average maximum monthly employment for each year. Since 1965/66 a detailed breakdown of man-hours worked by hourly employees has been available. In order to maintain continuity these figures have been converted into man years by dividing by 2080, the standard number of hours worked by an hourly paid employee in a year. Total employment figures were calculated for 1965/66 using both methods. Using the maximum number of employees approach a figure of 2603 man years was obtained and by converting man-hours to man years a figure of 2594 man years was obtained. This suggested that the error built into the old system was not too great. In calculating the rate of growth of total employment this slight discrepancy from the old system to the new was compensated for by an adjustment to the percentage increase from 1965/66 to 1966/67. During the seven year period from 1961 to 1968 the standard number of hours of work, the duration of vacations and so on remained constant, thus making this man years approach acceptable as an actual record of man-hours. In 1968/69 a reduction in hours for salaried employees and changes in the duration of vacations invalidated the man years approach. Future employment and productivity measures will thus have to be based on man-hours worked. This will necessitate converting the 1961/62 - 1964/65 figures to man-hours a process that will introduce errors. The errors will, of course, diminish in importance as time passes. Because of the problems introduced by this conversion it was considered desirable to retain man years for the present analysis.

THE DIVISION OF EMPLOYMENT BETWEEN OPERATING AND CAPITAL FORMATION

In order to estimate the proportion of total employment devoted to operating, it was assumed that the average salary of an operating employee was the same as that of a capital employee. The ratio of operating payroll to total payroll was then multiplied by total man years of employment. This simple expedient was necessitated by the lack of detailed knowledge available as to what average salaries in each category are. Other ratios such as 45/55 were tried and made very little difference to the results. As the author was unable to decide whether the average salary of capital employees might be greater than operating employees or vice versa, it was decided to retain the 50/50 ratio.

TRENDS IN EMPLOYMENT AND PAYROLLS

Since 1961/62 total employment has increased at an average rate of 4.8% per year with a large increase of 14.3% in 1967/68. It would appear that the largest part of this increase in employees has been caused by the requirements of the capital construction program which has increased from an annual rate of about $50 million in 1961/62 to about $90 million in 1967/68. The number of employees allocated to capital has increased from about 765 in 1961/62 to about 1370 in 1967/68.

Examination of Table 6.1 indicates that the number of employees allocated to operating have not increased at a constant rate, but have fluctuated up and down. This has occurred because of the cyclical nature

TABLE 6.1

MANITOBA HYDRO

EMPLOYMENT AND PAYROLLS

EMPLOYMENT

	1961/62		1962/63		1963/64		1964/65		1965/66		1966/67		1967/68
TOTAL	2316	7.9*	2500	6.1*	2653	(.9)*	2628	(1.0)*	2594	1.5*	2632	14.3*	3009
CAPITAL	764	32.1	1010	7.2	1083	(6.8)	1009	(15.2)	856	3.4	885	54.7	1369
OPERATING	1552	(4.0)	1490	4.7	1560	(4.4)	1629	7.1	1738	.5	1747	(6.1)	1640

PAYROLL (Dollars x 10^6)

	1961/62		1962/63		1963/64		1964/65		1965/66		1966/67		1967/68
TOTAL	10.93	14.0*	12.46	9.0*	13.58	2.9*	13.97	2.2*	14.28	12.6*	16.09	27.3*	20.47
CAPITAL	3.61	39.6	5.03	11.0	5.59	(5.0)	5.31	(11.1)	4.72	14.6	5.41	72.3	9.32
OPERATING	7.32	1.4	7.43	7.6	8.00	8.5	8.67	10.3	9.57	11.6	10.7	4.4	11.15

* Percentage Change

Source: Manitoba Hydro
Employment and Payroll Reports
Economics Department

of the capital program which in the past seven years reached a peak in 1963/64 during the construction of Grand Rapids, then subsided before rising toward a similar peak with the present construction of Kettle Rapids.

Because of the desirability of maintaining a stable work force at Manitoba Hydro the cyclical nature of the capital program results in a cyclical change in operating payroll and employment. Total employment has fluctuated with the capital program cycle, but not by as much as the cycle. The slack has been taken up by changes in the allocation of employment between operating and capital formation.

During periods of heavy capital formation a large proportion of total engineering and administrative expenses are justifiably charged against specific capital projects. During low periods of construction activity the engineering and administrative staffs remain about the same as in peak periods. Most of their activities are directed toward research, system planning and related work which is concerned not with current operations, but with the long term evolution of the system. They are in fact preparing for future capital formation. As no specific capital work orders exist against which this time can be charged, it is charged to current operations. The result is a rapid increase in operating employment and payrolls during the down turn in capital formation and a relative decline in operating employment and payrolls during periods of increasing capital formation.

During the seven year period, operating and capital employment, particularly the latter fluctuated quite widely thus the figures recorded in any given year are not indicative of the long term trend. The average increase in operating employment for the entire period was about 1.1% per year, quite a modest increase. The average increase in capital employment was 12.6% which resulted in a doubling of the capital work force during the period. As capital formation also just about doubled during the period this is not unreasonable, but it does suggest that all the productivity gains which have occurred have been realized in the operating function of the utility.

Total payroll has increased by an average of 11.3% since 1961/62. The largest annual increase 27.3% occurred in 1967/68 and was due almost entirely to a 72.3% increase in the capital payroll associated with Kettle Rapids.

Operating payroll has increased by an average of 7.3% per year since 1961/62. A modest increase of 4.4% in operating payroll in 1967/68 was caused by the large proportion of total payroll charged to capital projects through labour charges to capital work orders and general overhead capitalized.

TABLE 6.2

TRENDS IN EMPLOYMENT AND PAYROLLS 1961/62 - 1967/68

	Average 1961/62-1967/68	Average Past 5 Years	1967/68
Average annual increase in employees.			
a) Total Employment	4.8%	4.2%	14.3%
b) Operating Employment	1.1%	2.1%	-6.1%
c) Capital Employment	12.6%	8.7%	54.7%
Average annual increase in payroll.			
a) Total Payroll	11.3%	10.8%	27.3%
b) Operating Payroll	7.3%	8.4%	4.4%
c) Capital Payroll	20.2%	16.3%	72.3%

PRODUCTIVITY OF LABOUR

(a) The Concept of Productivity

Of all the means of assessing operating performance, productivity measurement is one of the most significant. Productivity has been described as a measure of the efficiency with which resources are converted into the commodities and services that men want. [1] Essentially productivity is an input-output concept in which we attempt to measure an increase in efficiency by calculating the ratio of an index of physical output to an index of physical input. There are a wide variety of productivity measures, and a wide variety of techniques for attaining them. All measures of productivity are subject to conceptual inconsistencies and errors, thus productivity measures should be considered as a general tool of economic analysis rather than a precise tool. Productivity measures are generally broad generalizations, frequently tentative, based on a series of estimates which may contain off setting errors and which at their most accurate give a picture of trends in output for a nation, industry or company.

There are two essential ways of looking at productivity. One is static, the other dynamic. Both are important. The first could be described as absolute productivity which could be expressed by output per worker. The second is the rate of change of productivity which can be expressed as a percentage increase per unit of time. There are numerous measures of productivity - per capita , per member of the labour force, per employee, per payroll dollar, per man-hour, or per unit of capital input

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1. Fabricant Solomon: Basic facts on productivity change, occasional Paper 63, National Bureau of Economic Research New York University, 1959. p. 1

and so on which can be employed for various purposes. All these are only partial measures of productivity and unless properly understood can lead to incorrect conclusions.

As Solomon Fabricant explains, an adequate index of productivity for a single resource requires not only eliminating the effect of changes in other resources, but also somehow taking into account the relative importance of the resource.

When other resources are used in significant volume, and change occurs in the volume of such resources used (which is almost always the case), a measure of productivity based on a single resource might tell us little or nothing of change in the efficiency with which this resource was being utilized. For example, output per unit of plant and equipment might have fallen because plant or equipment was being substituted for labour or other resources (as is the case with Manitoba Hydro). Yet the efficiency with which plant and equipment was being used might have risen.

Fabricant stresses quite correctly that an index of any single resource would not provide reliable information on the efficiency with which all resources were being used. He suggests that as a general rule it is better not to limit productivity indexes that purport to measure change in efficiency to a comparison of output with a single resource. The best measure he feels is one that compares output with the combined use of all resources. [2]

Conceptual problems also occur in the measurement of physical output. Most firms do not produce a homogeneous product that can be measured in physical terms. Multi-product firms, or firms with products

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2. S. Fabricant; <u>I bid</u>., p. 6

which change in composition and quality must measure product in value terms. A central assumption here is that under competitive conditions changes in price will represent changes in quality and perhaps inflation and that no component of price change will result from monopolistic advantage.

In arriving at productivity measures for Manitoba Hydro, a quasi-physical unit (the kilowatt-hour) has been employed as a unit of output. Although some inaccuracies result due a lack of homogeneity among kilowatt-hours, and due to a declining return per kilowatt-hour associated with the rate structure, the kilowatt-hour was employed for the following reason.

In the monopolistic setting in which Manitoba Hydro operates, price is set not by competition, but by cost. Although an upward revision of rates had not occurred for many years, a 10% increase in general consumer's rates in 1968/69 would show up as an increase of productivity if value terms were used. This factor plus the ease with which kilowatt-hours could be manipulated determined their use as a measure of physical productivity. It was felt that any inconsistencies that might show up in the short term would cancel out over a longer period.

It must be stressed that the measures of productivity employed in this chapter are partial productivity measures only and as such are subject to all the short comings previously discussed. They are employed to illustrate some of the more important aspects of the utilizations of labour, and the significance of labour costs in the unit costs of producing electricity which would not be apparent in the more comprehensive "total productivity" measures which we shall discuss in the next chapter.

(b) Absolute Productivity

Three separate measures were employed in order to obtain an indication of the absolute productivity of labour on the Manitoba Hydro system. These were installed capacity per operating employee, energy generated per operating employee and customers per operating employee. These measures were also calculated for Canada and for the six major provinces to provide some comparative data. The figures calculated suggest that the absolute productivity of labour for Manitoba is below the Canadian average, and below all the other provinces with the exception of Saskatchewan.

The statistical information employed in the calculation of the absolute productivity figures was obtained from Electric Power Statistics, DBS Cat. No. 57-202 1961 to 1966. Installed capacity, electric energy generated and number of customers were divided by the number of operating employees reported for each province and Canada. As the same denominator, operating employees was used in all three measures the low absolute productivity in Manitoba indicated by all three might reasonably be considered to result from having too many operating employees for the size of Manitoba's electrical requirements. However, Manitoba is among the lowest cost producers of electricity in Canada. This suggested that perhaps the number of operating employees reported for Manitoba by DBS might be too great. Further investigation suggests that this is the case. The monthly statistical returns required by DBS shows total employees, full time construction employees, operating employees and office employees. It is suspected that a large number of employees actually working on capital projects are recorded by DBS as operating employees.

As the mode of operation of each utility is different, some do all their own construction, while others employ contractors extensively it is felt that the figures obtainable on operating employees are not too accurate. Accordingly the absolute productivity of labour measures which are shown here should be regarded as rough indications of interprovincial differences only, but probably are reasonably accurate in showing the trends between provinces. The figures for Manitoba Hydro were calculated employing the operating employee figures of Table 6.1.

TABLE 6.3

Installed Capacity/Employee Ratio - Kilowatts per Employee

	Can.	M.H.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
1961	495	548	650	450	422	308	496	721
1962	510	571	658	480	409	348	582	631
1963	513	546	616	485	406	368	585	739
1964	507	522	575	490	409	393	616	700
1965	552	671	641	525	470	398	683	742
1966	601	676	694	546	506	369	734	732
Average Annual Percentage Increase	4.0	4.3	1.3	4.0	3.7	3.8	8.1	.3

TABLE 6.4

Energy Generated/Employees Ratio - Millions of kilowatt-hours per Employee

	Can.	M.H.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
1961	2.3	1.9	3.5	2.0	1.5	1.0	2.0	2.8
1962	2.3	2.3	3.3	2.1	1.7	1.2	2.2	2.7
1963	2.3	2.4	3.2	2.2	1.8	1.3	2.2	2.8
1964	2.4	2.5	3.1	2.2	1.9	1.4	2.4	3.0
1965	2.5	2.7	3.0	2.5	1.8	1.5	2.7	3.3
1966	2.9	2.9	3.6	2.7	2.2	1.4	3.0	3.7
Average Annual Percentage Increase	4.7	8.7	.6	6.3	7.9	7.0	8.5	5.7

TABLE 6.5

Customer/Employee Ratio

	Can.	M.H.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
1961	136	125	140	124	119	108	212	218
1962	138	134	138	129	117	126	221	198
1963	137	133	137	130	117	122	213	203
1964	135	130	128	130	120	122	214	206
1965	137	125	130	134	107	126	217	209
1966	143	127	138	135	117	115	221	212

It can be seen that while the ranking between the absolute numbers recorded for each province remains about the same for all three measures, the rate of change recorded for each province varies widely with each measure. The fact that kilowatt-hours per employee increased at a faster rate than installed capacity per employee for Canada, Manitoba Hydro, Ontario, Manitoba, Saskatchewan, Alberta and British Columbia suggests that there was more surplus capacity available in 1961 than 1966 in each case.

Customers per employee as shown in Table 6.5 remain reasonably constant over the six year period in each province. While there is some fluctuation from year to year in all provinces, there is only a slight trend to more customers per employee in 1966 as compared to 1961. The Canadian average is increasing slightly.

There is, however, considerable difference in customers per employee between the provinces. Both Alberta and British Columbia have almost twice as many customers per employee as either Manitoba or Saskatchewan. This suggests that either the statistics are grossly in error or the number of customers per employee has little bearing on the unit costs of electricity. Manitoba has consistently charged less per kilowatt-hour than the other three provinces as can be seen from Table 6.6.

TABLE 6.6

Average Revenue per Kilowatt-hour Sold (Cents per kwh)

	Can.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
1961	1.08	.78	1.00	.98	2.59	1.89	1.63
1966	1.04	.82	.97	1.09	1.97	1.64	1.18

(c) Average Annual Rate of Productivity Increase per Employee

In order to maintain the unit cost of producing electricity as low as possible, while maintaining wage and salary scales which are adequate to attract and hold well qualified employees, a high annual rate of productivity increase per employee must be attained. As we saw in Chapter IV, the average rate of productivity increase per operating employee has been adequate to maintain the operating payroll cost per kilowatt-hour sold consistently below the 2.5 mills per kilowatt-hour recorded in 1961/62. While this has partially been achieved by exporting a large volume of energy via the interconnections during the past three years, there are several other important factors such as larger plants, greater use per customer and technological improvements in communications, transmission, vehicles, automatic controls and computors which permit the operation of all phases of the system with relatively fewer men. This factor of technological improvement is very closely tied with the substitution of capital for manpower. During the past few years dozens of billing clerks have been replaced with a computor and a few programers, nearly all sub and terminal stations have been fully automated, as have several generating stations. The increased

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Source DBS Cat. No. 57-202

use of two way radios and increasing numbers of vehicles have improved the efficiency of field staff.

In substituting capital for labour extreme caution must be employed to avoid substituting beyond the point (assuming the marginal productivity of capital is greater) at which the marginal productivity of capital equals that of labour. In practice this involves the examination of each specific proposal for capital substitution to ensure the benefits more than justify the expense. If the annual cost of capital required to replace a single employee is just equal to the annual cost of the employee (salary plus fringe benefits, office space and other employee overhead) the substitution is justified as the rapid increase in cost per employee will tip the balance more in favour of the capital with each passing year.

The social implications of replacing labour with capital have not posed a problem. A long standing policy of continuous progression and training coupled with rotation programs have kept Manitoba Hydro's employees quite mobile. As the number of employees have been steadily increasing the only effect of capital substitution has been to reduce the rate of new employment.

Table 6.7 presents a summary of the productivity of labour figures obtained. Because of fluctuations in the rate of increase of energy sales, and of employees due to the requirements of the capital program, productivity figures for any one year are meaningless. The large increase in employees in 1967/68 is not directly related to energy sales for that year, but is required to meet demand in the far off future. The average figures for the entire period since 1961/62 are more meaning full as are the averages for the past five years. This approach was taken to determine how the experience of the recent past compared with the long term.

TABLE 6.7

Average Annual Rate of Productivity Increase per Employee

	Average 1961/62-1967/68	Average Past 5 Years	1967/68
a) Total Employees	4.7%	6.9%	-1.8%
b) Operating Employees	8.5%	8.8%	19.6%
c) Capital Employees	-.8%	4.6%	-27.4%

Refering to Table 6.7 it can be seen that productivity increases for operating employees seem rather high while those for capital employees seem rather low. This can partially be explained by the methodological difficulties mentioned previously. First the productivity of operating employees is not pure labour productivity, but includes a component attributable to capital substitution and secondly operating employment must be determined by subtracting capital employement from total employment. A third and perhaps most significant reason is that capital employment bears no direct relationship to current production.

It may not, however, be unreasonable to expect a low rate of productivity increase for capital employees under the conditions in which Manitoba Hydro operates. At the present time more than half of all capital formation is taking place in the northern part of the province under severe geo graphical and climatic conditions. The logistics problems are immence compared to similar projects in the south. A higher proportion of man-hours are devoted to travel and administrative tasks than would be the case in the south. Isolation contributes to a high labour turnover, a factor which would be expected to adversely effect productivity.

CHAPTER VII

THE STRUCTURE AND PRODUCTIVITY OF CAPITAL INPUTS

While labour costs represent some 22% of total operating expenses and appear to be decreasing relatively, capital costs; interest and depreciation amount to 60% of total costs and are expected to increase to about 70% or more by about 1978. For this reason capital costs or fixed costs are an even more significant factor in determining the long run unit costs of electrical energy than are labour costs. This is particularly true in the case of a hydro based electric utility.

THE DISTRIBUTION OF CAPITAL ASSETS BETWEEN GENERATION, TRANSMISSION AND DISTRIBUTION

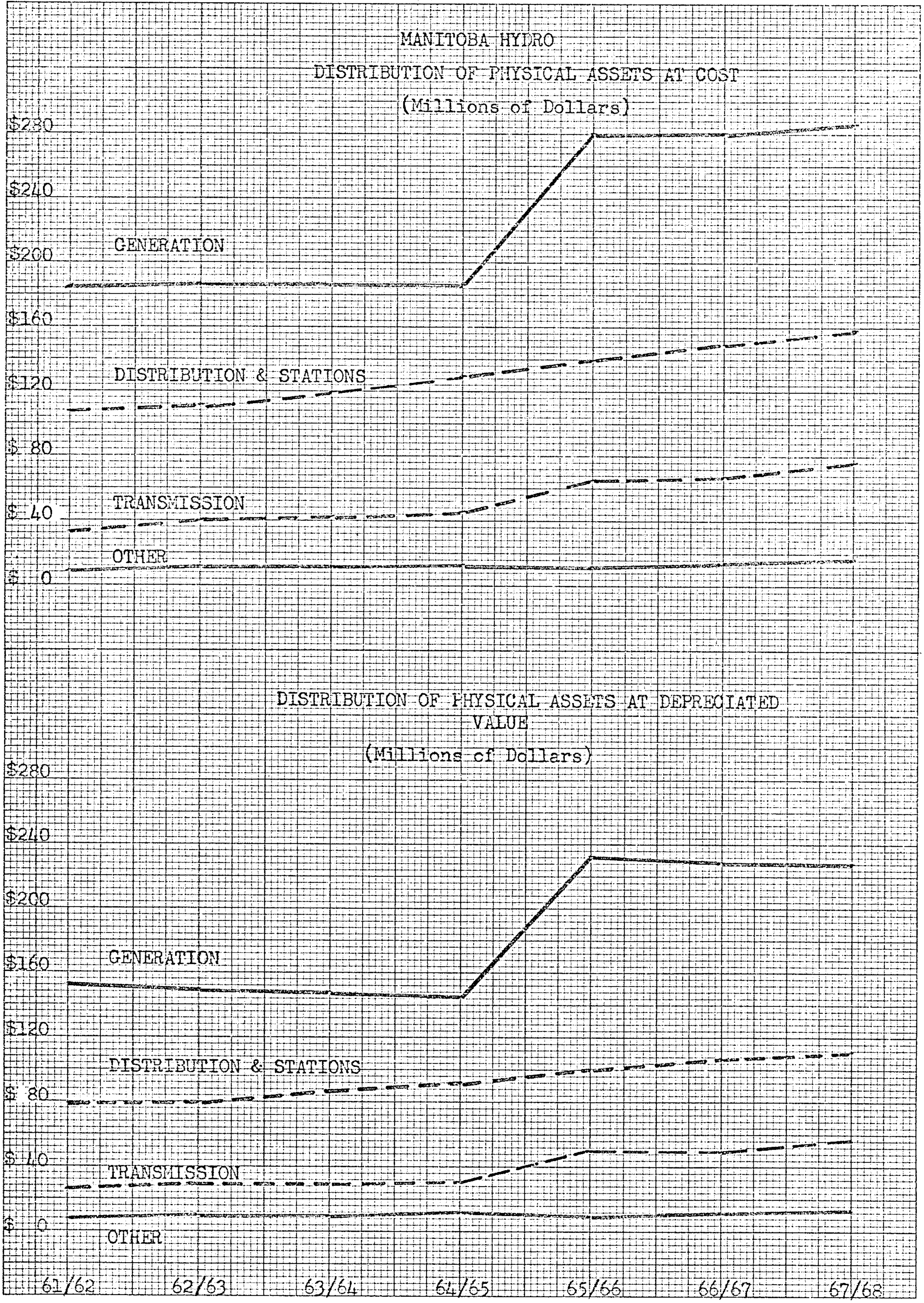
Figure 7.1 presents the distribution of the physical assets of Manitoba Hydro both at cost and at their depreciated value. The fact that both measures present an identical picture suggests that either could be employed to demonstrate the basic relationships involved and any trends that may be developing.

One important factor to take into consideration is the lumpiness of generation investment. Because of this, the proportion of total assets devoted to generation may change abruptly from one year to the next. Over fifteen or twenty years a significant trend might be established but over the seven year period of this study conclusions must be reached with some caution.

Taking the depreciated value of capital assets, it was determined that generation declined from 58% of the total in 1961/62 to 55.5% in 1967/68, transmission increased from 9.5% to 13.5%, distribution declined from 30% to 27.5 and other assets increased from 2.5% to 3.5%.

A number of quite interesting factors stand out, some of which if

FIGURE 7.1



MANITOBA HYDRO
DISTRIBUTION OF PHYSICAL ASSETS AT COST
(Millions of Dollars)
$280
$240
$200
$160
$120
$ 80
$ 40
$ 0
GENERATION
DISTRIBUTION & STATIONS
TRANSMISSION
OTHER
DISTRIBUTION OF PHYSICAL ASSETS AT DEPRECIATED VALUE
(Millions of Dollars)
$280
$240
$200
$160
$120
$ 80
$ 40
$ 0
GENERATION
DISTRIBUTION & STATIONS
TRANSMISSION
OTHER
61/62
62/63
63/64
64/65
65/66
66/67
67/68

substantiated over a longer period of time would tend to cast doubt on some of the principles which were believed to apply to an electric utility. In spite of rising construction costs and the impossibility of significant improvements in the efficiency of hydro generating stations, generation has declined as a proportion of total assets. This situation may not prevail beyond 1971/72 when Kettle Rapids (an extremely large block of generating capacity is added to the system). Transmission not surprisingly has increased due to the long transmission lines required by more remote generation sites, such as Grand Rapids. A point of particular interest concerns the proportion of distribution assets. In spite of the large economies of scale which are believed to accompany the distribution of electricity once the distribution system is in place, the proportion of total assets devoted to this function declined only slightly from 30% to 27.5%. This fact, coupled with the rising interest rates of the period partially explain why distribution costs per kilowatt hour have remained at 4.5 mills per kilowatt hour throughout the 1961/62 - 1967/68 period.

THE PRINCIPLES OF PRODUCTIVITY MEASUREMENT

The basic principles and problems associated with productivity measurement which were discussed in chapter VI apply equally here. The basic objective is to determine what increases of production have resulted from improved technology, greater utilization of capacity, economies of scale and so on. In order to accomplish this it is necessary to compensate for the effects of price rises, changes in interest rates, increase in wage rates and so on. In constructing a productivity of capital index, which is a partial productivity measure, and the more comprehensive total productivity measure which follows it, the basic approach developed by John W. Kendrick[1] was employed. Kendrick and his co-author Daniel Creamer have developed an approach which is directed specifically at the measurement of productivity in a single company. Although their techniques required some modification in order to apply them to Manitoba Hydro the basic approach employed was theirs.

Kendrick and Creamer stress that productivity is the ratio of output to all associated inputs in physical volume terms.[2] They feel that although productivity changes in the short run reflect changes in rates of utilization of capacity (and other temporary factors, such as the flow of supplies), over the longer run increases in output in relation to inputs chiefly reflect improvements in productive efficiency stemming from technological advances.[3]

Kendrick and Creamer suggest that productivity measures provide a much better indication of productive efficiency than the "ultimate" measure, profit. This they explain is because other forces such as favorable shifts in demand may obscure the effects of below average productivity in the short run.[4] Productivity measures do not suffer from this defect. With a publicly owned hydro utility this is particularly true. Such factors as a captive market, favorable water flows and so on could result in large surpluses in spite of relatively low efficiency, while under other circumstances losses could be incurred in spite of quite high efficiency. Productivity measures largely overcome this problem, "and thus furnish

1. John W. Kendrick and D. Creamer; Measuring Company Productivity, New York, The National Industrial Conference Board, Inc., 1961.
2. Ibid, P. 6
3. Ibid, P. 6
4. Ibid, P. 7

another reference point for viewing profits."[5]

In the authors discussion of their methodological approach they explain that since we are interested in a technical relationship, it is necessary to deal with the "physical volumes" of output and inputs.[6] Further they state that only by relating output to all associated inputs can it be determined whether there has been a net saving of inputs per unit of output, and if so, how much of a saving. The ratio of output to all associated inputs has been called "total productivity", in contrast to the "partial productivity" measures it reveals advances in over-all productive efficiency - the same output with lowered total input.[7]

However, Kendrick and Creamer do feel that ratios between output and individual types or classes of inputs are useful in showing economies that have been achieved overtime in the consumption of these inputs per unit of output.[8]

In discussing the actual techniques to employ in measuring productivity the authors recommend that because of the non homogeniety of outputs and inputs, that the usual way to measure productivity is to employ the values of inputs and outputs deflated to base year prices and quantities. This is because changes in values result from price changes as well as in numbers of units of outputs and inputs. It is fundamental in productivity measurement to disentangle the price and quantity components of values.[9] In the manner in which this basic approach has been applied to Manitoba Hydro it could be described as a Deflated Income Statement Approach.

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5. Ibid, P. 7
6. Ibid, P. 10
7. Ibid, P. 10
8. Ibid, P. 10
9. Ibid, P. 10

Kendrick and Creamer point out that because of diversity between industries and companies that the basic techniques of productivity measurement must be modified to the specific case. They suggest that ingenuity must be used to adapt general principles and methods to specific situations.[10]

They stress that in dealing with individual types of output or input, we could work with the quantity data alone for the periods being compared. But as soon as we aggregate two or more types of output or input, we must weigh each of the physical volume series by their relative unit values in a base period. This transforms the physical unit measures into constant price measures.[11] The authors mention that one way of doing this is to deflate values of inputs or outputs by indexes of representative prices.[12] This is approximately the approach taken in the study of Manitoba Hydro.

To obtain the productivity ratio's for the company, the real value of output is divided by the total real cost of inputs. Alternatively output and input can be converted to index numbers,[13] and the ratios of output index to input index determined.

Having presented the basic principles advocated by Kendrick and Creamer it is now appropriate to demonstrate how these basic principles may be applied to a public utility such as Manitoba Hydro. First an index of physical output was constructed as described in chapter VI.[14] Because of the single product produced the output calculations were extremely straight forward and simple.

The measurement of physical input was a different story and

10. Ibid, P. 15
11. Ibid, P. 16
12. Ibid, P. 16
13. Ibid, P. 21
14. See page 100 of Chapter VI.

because of the variety of different inputs involved was a relatively time consuming and complex operation. The basic approach was to take each of the entries in the annual income statements of Manitoba Hydro, deflate them back to the amount they would have been at 1961/62 prices and interest rates, sum the results to get total deflated expenses, and then construct an index of physical input. The income statements are divided into two main sections: Operating Expenses (the variable input portion) and Fixed Charges (the capital input portion). The specific entries in the income statement are: Wages and salaries, Other operating and administration expenses, Water rentals, Interchange energy and capacity, Fuel expenses, Net interest charges, Depreciation, and Contingency reserve charges. The last three items are considered fixed charges.

WAGES AND SALARIES

The average annual salary per employee was calculated for 1961/62 the base year. This figure was multiplied by the number of man years charged to operating in each subsequent year to get wages and salaries deflated to base year prices.

OTHER OPERATING AND ADMINISTRATION EXPENSES

As no specific index was available, it was assumed that prices in this area have increased at 2% per year. Thus actual operating and administration expenses were deflated to base year values based on this assumption.

WATER RENTALS, INTERCHANGE, AND FUEL

These expense items were not deflated because no significant price changes have occurred in these areas since 1961/62. There have been some slight increases in transportation costs for coal since 1961/62, but since Manitoba Hydro uses a combination of coal, natural gas and bunker oil at thermal stations (the gas usually at dump prices) in varying amounts each year it has not been possible to construct a reliable fuel price index.

INTEREST AND DEPRECIATION CHARGES

The calculation of deflated interest and depreciation charges was the most complex operation encountered. First gross capital assets were broken down into the categories of generation, transmission, stations, distribution, and buildings as were the annual depreciation charge allocations. Then transmission, stations and distribution assets were deflated to 1961 prices employing price indexes for these categories of assets recently developed by DBS.[15] Annual depreciation charges for each category of assets were deflated to 1961 prices employing the same indexes. In deflating these assets particular care was taken to deflate only the assets placed in service since the base year to 1961 prices. Thus if $81. million of distribution assets were in place in 1961, and $2 million were added in 1962, the $2 million figure was deflated to 1961 prices and added to $81. million to arrive at 1962 distribution assets deflated to 1961 prices. Similarly if a further $2. million were added in 1963, this figure was deflated for two years, then added to the 1962 deflated assets to arrive at 1963 distribution assets deflated to 1961 prices.

D.B.S. does not at present publish a specific price index which can be used to deflate generation assets or buildings. Accordingly the

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15. Dominion Bureau of Statistics catelogue 62-526, occasional.

general construction price index published by the Southam Building Guide[16] was employed to deflate these assets, and their associated depreciation expenses.

Once each individual category had been deflated to base year prices the five individual depreciation charges were summed to arrive at total depreciation charges at base year prices for each year. Deflated assets at cost for each category were summed to determine total deflated assets at cost for each year.

Annual interest charges at base year prices and interest rates were determined by taking the ratio of net interest charges to gross capital assets in 1961, and multiplying this ratio by total deflated assets in each subsequent year.

CONTINGENCY RESERVE CHARGES

As these charges are based on generation assets in place, the actual contingency charge in each year was deflated to base year prices employing the same index that was used to deflate generation assets.

THE PRODUCTIVITY OF CAPITAL

In order to determine the productivity of capital a productivity of capital index was constructed. This was accomplished by summing the deflated values of the three fixed costs or capital input components; net interest charges, depreciation charges, and contingency charges. A physical capital input index was constructed using 1961 as the base year. The Productivity of Capital index, Table 7.1 was calculated by taking the ratio

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16. "Southam National Construction Index", Southam Building Guide Don Mills, Canada, Volume 49, Number 1, January, 1968, P. 12.

Table 7.1

MANITOBA HYDRO

PRODUCTIVITY OF CAPITAL INDEX

	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68
Physical output index	100	102.3	114.7	123.6	136.5	152.0	170.6
Physical Capital Input Index	100	103.5	107.1	107.7	119.7	139.7	145.2
Productivity of Capital Index	100	.988	107.1	114.8	114.0	108.8	117.4
Average Percentage Change		-1.2%	8.4%	7.2%	-.7%	-4.6%	7.9%
Average Annual Increase							2.83%

Total Productivity Index

	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68
Physical Output Index	100	102.3	114.7	123.6	136.5	152.0	170.6
Total Physical Input Index	100	.996	105.9	107.0	116.7	129.4	134.0
Total Productivity Index	100	102.8	108.3	115.5	117.0	117.5	127.3
Average Percentage Change		2.8%	5.4%	6.6%	1.3%	.4%	8.3%
Average Annual Increase							4.13%

of the Physical Output Index to the Physical Capital Input Index. Using this information it was determined that the average annual increase in the productivity of capital over the seven year period since 1961/62 has been 2.83%. The annual productivity change has fluctuated violently from a high of 8.4% in 1963/64 to a low of -4.6% in 1966/67. These fluctuations result from variations in the utilization of capital plant and reflect the discontinuous manner in which new capital is brought into service. In 1966/67 the full impact of Grand Rapids was reflected in the income statements, thus causing a reduction in the productivity of capital for that one year.

TOTAL PRODUCTIVITY

A total productivity index was constructed to determine the relationship of output to all associated inputs using a Total Physical Input Index employing the sums of the deflated values of all inputs, fixed and variable. The Total Productivity Index in Table 7.1 was constructed by taking the ratio of the Physical Output Index to the Total Physical Input Index. The average annual increase in Total Productivity was found to be 4.13%. As can be seen from Table 7.1 the year to year changes in total productivity increase have been less severe than with the productivity of capital.

OTHER PRODUCTIVITY MEASURES

In order to form a clearer picture of Manitoba Hydro's operating performance other quasi partial productivity measures were constructed. The term quasi is employed here because the measures constructed are not really productivity measures in that they employ current year values to determine the relationships between output and various inputs.

PRODUCTIVITY OF FIXED AND VARIABLE EXPENSES

This measure is one of output in kilowatt hours per dollar of expense. The basic objective of this measure is to determine whether productivity increases which have occurred have been adequate to reduce the cost in each expense category in current dollars.

TABLE 7.2

Productivity of Fixed and Variable Expenses (output in kwh's per dollar o expense)

	Kilowatt-hours of energy sold per doll expense		
	Annual Average 1961/62-1967/68	Annual Average Past 5 years	[illegible]
1. Productivity increase per dollar of Fixed Charges	0%	.5%	5.
2. Productivity increase per dollar of Variable Operating Expense.	3.1%	2.4%	3.
3. Productivity increase per dollar of Total Annual Expense.	1.1%	1.1%	5.

Productivity of fixed charges (interest, depreciation, and conti reserve) has remained more or less constant over the entire seven year pe since 1961/62 in spite of rising construction costs and rising interest r In other words the effects of inflation and higher interest rates have ju been balanced by increases in the productivity of capital. It does appea however, that the productivity of capital is improving relative to these two other forces. It appears that this favorable trend has been accompli by achieving relatively higher utilization of installed generating capaci during the past five years.

Table 7.2 indicates that productivity of operating expense has been increasing at about 3.1% per year, resulting in a reduced operating expense per kilowatt hour sold.

Productivity of total annual expenditure has been rising slightly at about 1.1% per year since 1961/62. This has resulted in slightly lower unit costs than in 1961/62 and has partially been achieved by making large export sales of energy in the past two years.

It can be appreciated that it is desirable, to maintain the present high rate of productivity increase for operating expenses, and a positive rate of productivity increase for fixed charges, and total annual expenses in order to maintain costs per kilowatt hour at or below their present level.

TABLE 7.3

Productivity of Capital Assets (as measured by kwh's distributed per dollar of capital assets)

	Average Changes in Productivity of Capital Assets 1961/62-1967/68	Average for Past 5 Years	1967/68
1. Annual rate of productivity increase per dollar of capital assets at cost (Electric Utility Plant)	1.7%	2.3%	7.2%
2. Annual rate of productivity increase per dollar of depreciated capital assets (Electric Utility Plant)	1.7%	2.0%	8.6%
3. Annual rate of productivity increase per dollar of depreciated capital assets including work in progress (Utility Plant Net)	-1.4%	.2%	-4.0%

During the period 1961/62 to 1967/68, there has been a positive increase in the productivity of capital assets in current dollars. It appears moreover that this desirable trend has been improving in more recent years, thus partially offsetting the effects of high interest rates. In 1967/68, Manitoba Hydro was able to produce and sell 9.2 kwh per dollar of Electric Utility Plant (at cost) or 12.0 kwh per dollar of Electric Utility Plant (depreciated), while in 1961/62 only 8.6 and 10.9 kwh were sold in these two categories.

CHAPTER VIII

THE INFLUENCE OF INCREASING CONSTRUCTION COSTS, AND THE LEVEL OF INTEREST RATES ON THE UNIT COSTS OF PRODUCTION

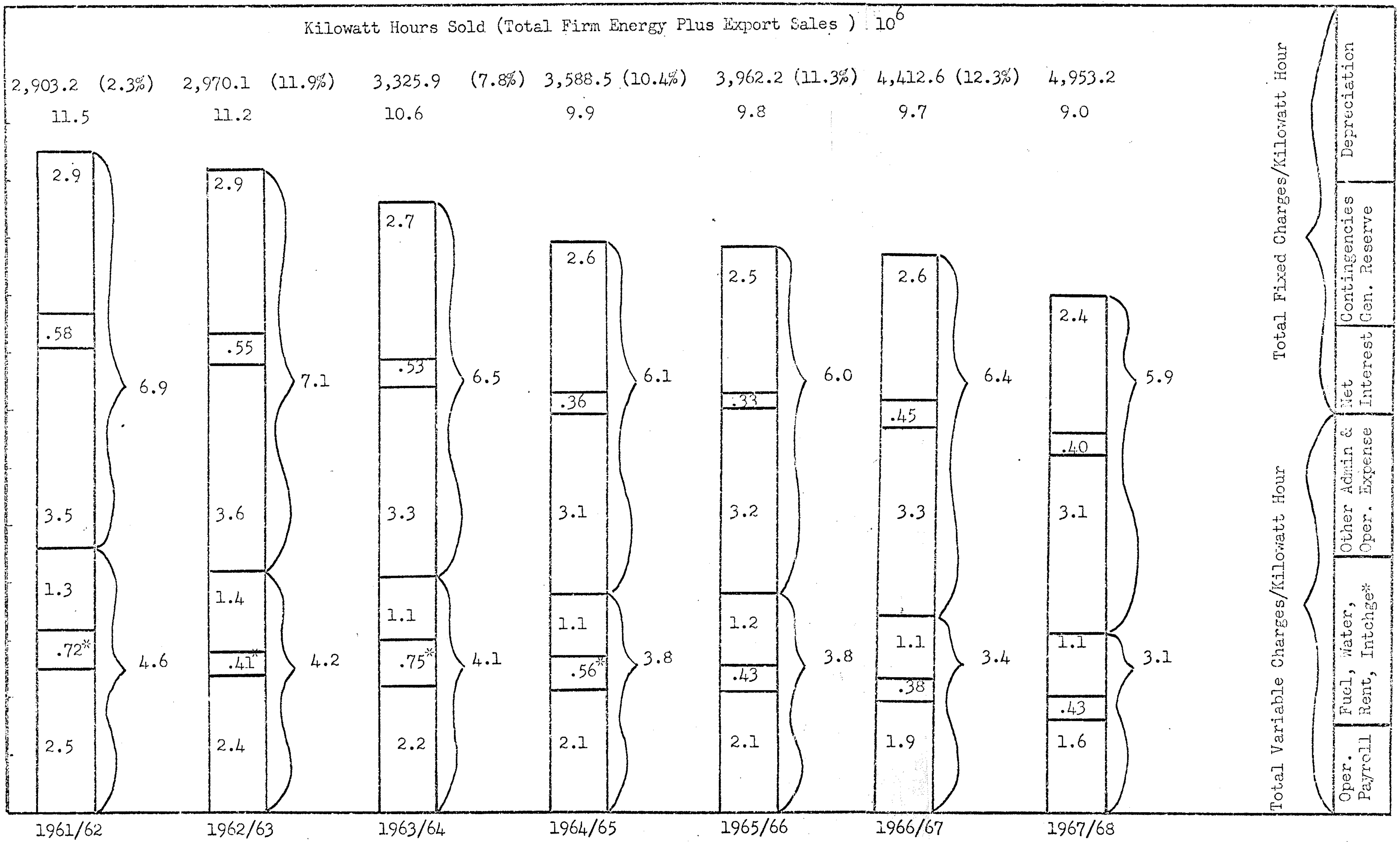
The purpose of this chapter is to examine the effect of price changes and changes in the level of interest rates upon the unit costs of producing electricity by Manitoba Hydro.

Figure 8.1 indicates what unit costs might have been if prices and interest rates had remained at 1961/62 levels. The unit cost figures were computed from the deflated expense figures which were employed in the determination of total productivity.

Comparison with Figure 8.2 indicates that had prices and interest rates remained at 1961/62 levels, the unit costs would have declined substantially from the 11.5 mills per kilowatt hour recorded in 1961/62. Because of the discontinuous manner in which new capital is added to the system the full effect of price increases and changes in the interest rate does not show up until 1966/67 when all the fixed charges for Grand Rapids were added to the income statement. By comparing the actual 1966/67 and 1967/68 unit costs with their deflated counter parts it can be seen that price increases and the substantial increase in interest rates that have occurred since 1961 are responsible for adding approximately 1.8 mills to the unit costs. This represents an increase in unit costs of about 20%. As can be seen the largest part of this increase in unit costs, .9 mills has occurred in interest charges. This increase can be attributed to both increased construction costs, and the rise in interest rates. The second largest increase in unit costs occurred with operating payrolls where an increase .7 mills was recorded in 1967/68.

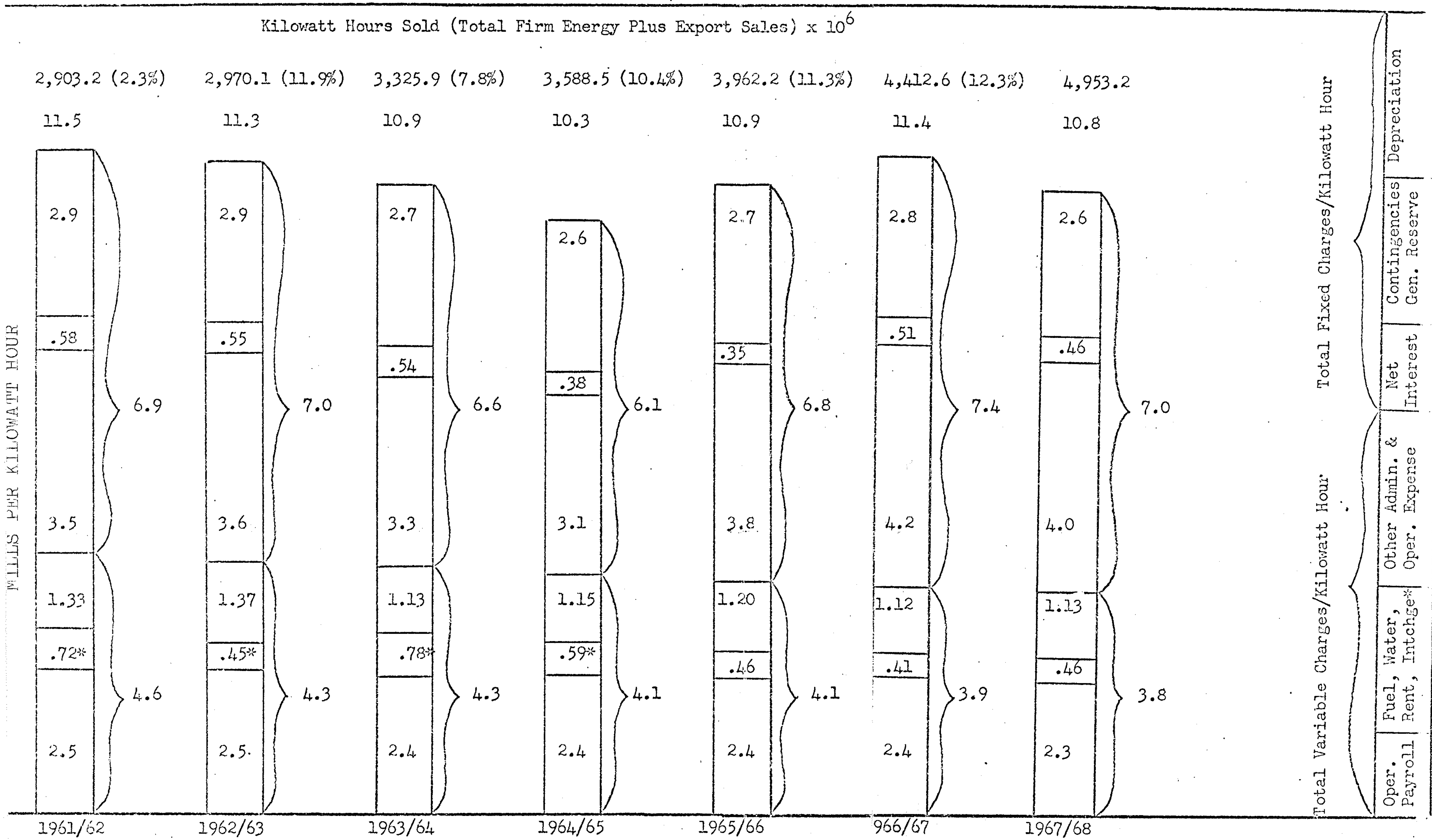
It is important to note that inspite of the increases in prices and interest rates that did occur, that the increase in total

ANNUAL EXPENDITURES PER KILOWATT HOUR SOLD (Deflated to 1961/62 Prices and Interest Rates) FIGURE 8.1



* Includes charges for interchange imports.

ANNUAL EXPENDITURE PER KILOWATT HOUR SOLD FIGURE 8.2



* Includes charges for interchange imports.

productivity (an average of 4.13%per year) that was achieved was sufficient to reduce actual unit costs from 11.5 mills per kilowatt hour in 1961/62 to 10.8 mills per kilowatt hour in 1967/68.

THE EFFECT OF INCREASED INTEREST RATES ON UNIT COSTS

Since 1961/62 there has been a substantial increase in the effective interest rate to which Manitoba Hydro is subject. Table 8.1 shows the extent of this increase.

TABLE 8.1

	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68
Effective Interest Rates Paid on Outstanding Long Term Debt[1]	4.43%	4.77%	4.83%	5.02%	5.03%	5.24%	5.45%
Weighted Average Annual Interest Rate[2]	4.33%*	4.67%*	4.73%*	4.87%	4.95%	5.02%	5.26%

In order to determine the effect of this increase in interest rates on unit costs the productivity of capital indexes were recomputed once with prices deflated to 1961 levels, but with actual interest rates, and once with actual prices, but with interest rates adjusted to the

1. Determined by taking the sum of coupon interest payment plus amortized discount on the outstanding long term debt as of March 31st. This interest payment is divided by the sum of the realized amounts of the outstanding issues to determine the effective rate of interest. To this is added the 1/8 of 1% charge made by the Provincial Government for guaranteeing the bonds. Systematic errors involved in this system would cause the interest rate determined to be slightly high. The large difference in 1966/67 was the result of a large bond issue in the latter part of the fiscal year.

2. This figure has been calculated since 1964/65 for the purposes of the Winnipeg Hydro power agreement. It reflects actual interest paid and received or accrued on all Manitoba Hydro long and short term debt and investments over the entire fiscal year. Because of the precision with which it is calculated it is an extremely accurate calculation of Manitoba Hydro average net interest rate for a given fiscal year.

* Estimated

1961 level. These calculations enabled the examination of construction price increases, and interest rate increases in isolation. It was found that the productivity of capital index compensated for interest rate increases only (By employing the 1961/62 interest rate) indicated an average annual productivity of capital increase of 1.75% while the index compensated for price increases only yielded an average annual productivity of capital increase of 1.05%. In Chapter VII we determined the actual average increase in the productivity of capital to be 2.83%. This indicates that the rise in construction costs from 1961 to 1968 had less of an impact (1.05%) on the productivity of capital than the rise in interest rates (1.75%) over the same period.

This point can be demonstrated more clearly by converting the adjusted capital input figures to unit costs. Table 8.2 shows the effect of increases in construction costs only, and increases in interest rates only on fixed charges. Fixed charges are employed here because a change in interest rate affects interest charges only, while a change in price affects interest charges, depreciation charges, and contingency charges. From Table 8.2 it can be seen that neither increased costs nor higher interest rates had a noticable effect on unit costs prior to 1965/66. This is because of the very small capital additions which were made prior to 1965/66. In that year capital assets were increased about 25% with the additon of about $100 million associated with Grand Rapids.

With reference to 1967/68 it can be seen that fixed charges have been increased about 1.1 mills by the combined effect of higher construction costs, and higher interest rates. Of this amount .70 mills is attributable to the increase in interest rates that has taken place and .40 mills to the increase in construction costs.

MANITOBA HYDRO

THE EFFECT OF INCREASES IN CONSTRUCTION COSTS
AND INCREASES IN INTEREST RATES UPON UNIT FIXED CHARGES

	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68
Fixed charges deflated for Price and Interest Increases*	6.98	7.05	6.53	6.06	6.03	6.35	5.90
Fixed charges deflated for Interest Increases only	6.98	7.01	6.53	6.13	6.37	6.78	6.30
Fixed charges deflated for Price Increases only	6.98	7.05	6.55	6.09	6.55	7.06	6.59
Actual fixed charges per kilowatt hour sold	6.98	7.00	6.60	6.10	6.80	7.40	7.00
Fixed charges deflated for Price and Interest increases	6.98	7.05	6.53	6.06	6.03	6.35	5.90
Effect of increased Interest Rates	0	0	.02	.03	.52	.71	.69
Effect of Price Increases	0	-.04	0	.07	.34	.43	.40
Actual fixed charges per kilowatt hour sold	6.98	7.00	6.60	6.10	6.80	7.40	7.00

* Mills per kilowatt hour.

Because of the effect of increased productivity and various degrees of capacity utilization, there is no direct relationship between the level of interest rates and the unit interest charges. However it is quite obvious that everything else equal, higher interest rates will mean higher unit interest charges. It has been determined that an increase of nearly 1% in interest rates from 1961/62 to 1967/68 caused an increase in unit costs of about .7 mills. It was also determined that the average unit interest charge per 1% of interest rate in each year from 1961/62 to 1967/68 was approximately .75 mills per kilowatt hour. While these relationships are not as precise as they might be, they do permit us to make a rough estimate as to what unit interest charges might be in the future at varous levels of interest rates.

TABLE 8.3

MANITOBA HYDRO

UNIT INTEREST CHARGES AT VARIOUS LEVELS OF INTEREST RATES

Weighted Average Annual Interest Rate	Approximate Unit Interest Charge
5.0%	3.80 mills
5.5%	4.15 mills
6.0%	4.50 mills
6.5%	4.90 mills
7.0%	5.25 mills

Weighted average annual interest rates increased from about 4.3% in 1961/62 to 5.26% in 1967/68. It is estimated that they will be not less than 6.0% by 1971/72 when Kettle Rapids comes into service. Thus it can be seen that in this ten year period unit costs will have been increased by about 1.25 mills per kilowatt hour because of increases in interest rates alone. This suggests that the level of interest rates is the most crucial variable in determining the unit costs of producing electricity in Manitoba.

Because of the long lead time involved in the planning and construction of new generation assets, there is little that can be done about changes in interest rates. Once committed, new plant has to be completed on schedule to meet future energy requirements. Even if future energy requirements were not a factor it would make little sense to interrupt construction to await more favorable interest rates. Once a sizeable investment has been made it is desirable to finish the project as quickly as possible to reduce interest capitalized during construction, and to render it capable of earning revenue as quickly as possible. Thus changes in the level of interest rates play only a small role as a regulator of investment activity in a hydro electric utility.

Only in the initial planning process do interest rates play a role in the choice of generating capcity selected. Once a course of action is decided upon the utility becomes locked-in and the actual interest rates encountered can influence the investment tempo only slightly.

THE EFFECT OF INCREASING CONSTRUCTION COSTS ON UNIT COSTS

As was demonstrated in the analysis of interest rates, only .40 mills of the unit cost of producing electricity in 1967/68 can be attributed to increases in construction costs from 1961/62 to 1967/68. During this entire period prices were subject to what might be described as moderate inflation. Construction costs of distribution assets increased by about 11.5%,[3] transmission lines by 12.5%,[3] stations by 38.5%[3] and generating stations by about 25%.[4] Productivity of capital increases that were achieved were just about adequate to offset both the effect of these increases in construction costs and the rise in interest rates that did

3. Dominion Bureau of Statistics catelogue 62-526 occasional. Indexes up to 1965 were given only, 1966 and 1967 were estimated by projecting the trend for the previous five years.

4. Southam Building Guide.

occur. Should the level of interest rates stabilize at or below 6.0% there is every reason to believe that unit costs can be maintained below the 11.5 mills recorded in 1961/62 for the next ten years and possibly longer. Assuming stable interest rates, a rate of productivity of capital increase of 2.83% as recorded since 1961/62 should be more than adequate to offset continued construction cost increases of the magnitude experienced since 1961. This would tend to suggest that while moderate inflation as represented by increasing construction costs does place upward pressure on unit costs, that the effect is minor and more than offset by technological change and other factors. Under these circumstances it would appear that given an extended period of stable interest rates, that the long term trend in unit costs of production would be downward.

In suggesting that moderate inflation by itself will probably be more than compensated for, if the past rate of productivity increase continues. The author is not arguing that Manitoba Hydro would be immune to all price increases. Price increases resulting from the development of geographically remote hydro sites might well be much greater than that caused by inflation alone and ultimately would result in a long term upward trend in unit costs. However, if the optimum source of generation capacity is selected, advancing thermal or nuclear technology will probably rule out the development of many more remote hydro sites, and this geographical component of price need not be a factor in the long term.

CHAPTER IX

Load Factors and the Utilization of Capital Investment

The System Load Factor

One of the most commonly employed indicators of efficiency which has been applied to electric utilities is the system load factor. This represents an attempt by utility engineers and economists to cope with the implications of a branch of economics sometimes described as Utilization Economics. Economies of utilization generally have been held to arise from the distribution of overhead costs associated with a fixed plant, over varying amounts of output.

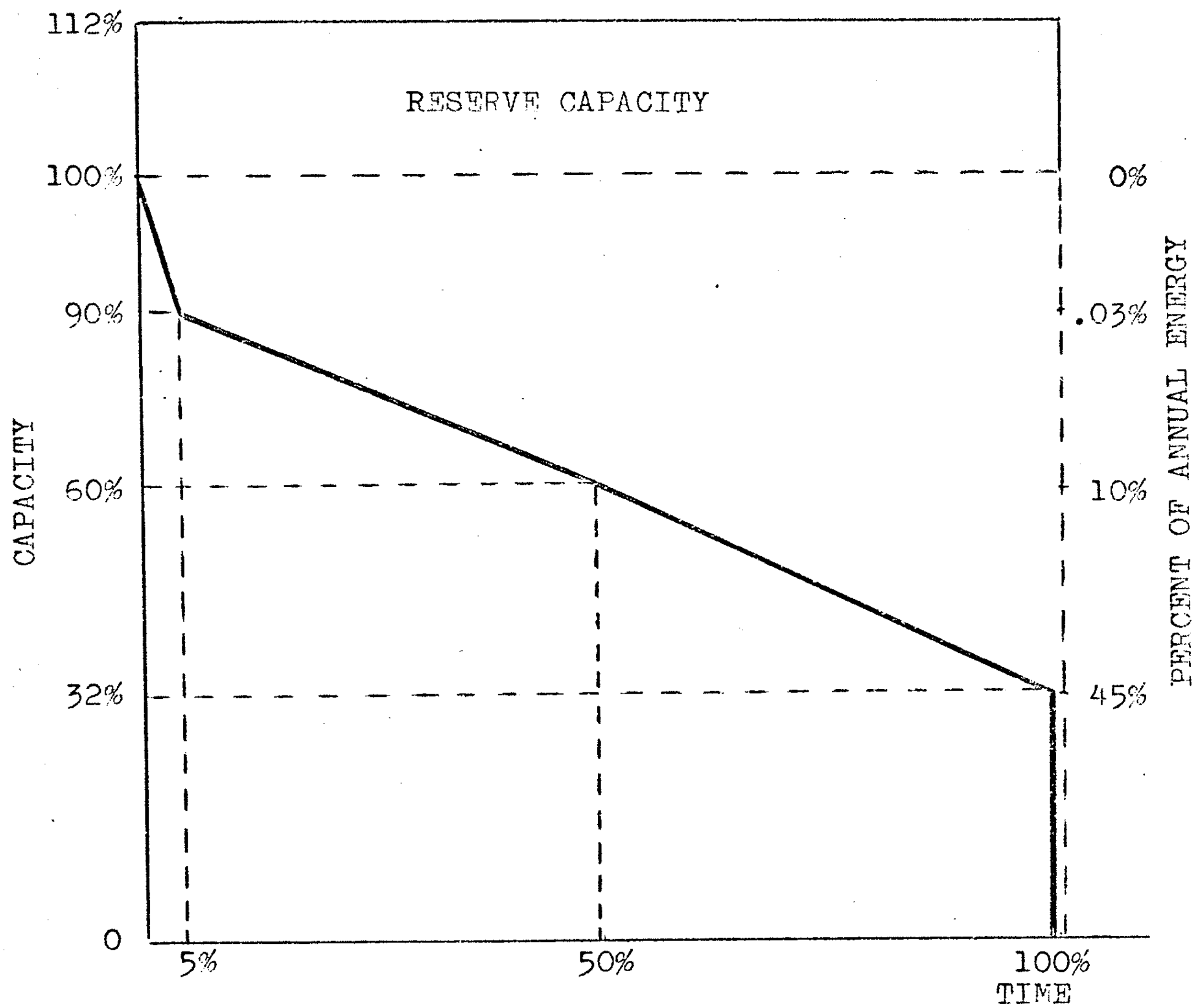
The significance of utilization of fixed plant increases as the capital intensity of the industry or system increases. An industry with high variable costs relative to fixed costs is relatively unconcerned about the utilization of its plant. A thermal based utility whose fuel costs represent a large proportion of total costs is less affected by the degree of utilization of its plant, than a hydro based utility whose fixed costs are high and whose truly variable costs are negligible.

The problem of utilization of fixed plant , or in the case of a utility, capacity arises because the demand for electricity is not constant. Over a twenty four hour period demand is low during the night and early morning, begins to rise around breakfast time, peaks around noon, then declines before rising to a daily peak about 5:30 in the evening. After supper demand again drops off and is low until the next morning. On an annual basis a similar pattern is repeated. In Manitoba and other northern latitudes demand for electricity is high during the dark cold months of winter. An annual system peak usually occurs in December or January, then demand drops off to a low in the summer months. In a detailed study of the load characteristics of load curve of a system, we find that there is an annual load curve with daily, weekly and monthly load curves superimposed upon it. This presents a many dimensional problem to anyone trying to gain a clear understanding of the cost relationships involved in this load pattern.

The basic problem faced by an electric utility is this. A utility must build capacity sufficient to meet the greatest demand expected plus a suitable reserve. However, the average demand is much less than the maximum. The utility must buy kilowatts of capacity, and sells kilowatt hours of energy. Each kilowatt of capacity has a potential of 8760 kilowatt hours (the number of hours in a normal year). If the load were constant and all those hours were sold the fixed costs per kilowatt hour would be minimized. If only half the potential 8760 hours are sold, unit fixed costs are doubled. Figure 9.1 presents a schematic view of a typical load duration curve. Capacity is shown left-hand vertical axis and percent of annual energy on the right-hand vertical axis, and time on the horizontal. One Hundred percent represents the peak capacity on an annual basis.

FIGURE 9.1

REPRESENTITIVE LOAD DURATION CURVE



The load duration curve shown represents approximately the characteristics of the Manitoba Southern Integrated System in 1966/67 which contains all of the generating capacity of Manitoba Hydro and Winnipeg Hydro with the exception of Kelsey which was not physically connected at that time. This load duration curve demonstrates graphically that some 10% of the capacity required to meet the peak is used less than 5% of the time and produces less than.03% of total annual energy requirements. This roughly can be imagined to represent the capacity required during the peak hours of the peak day of the year. Measuring from the peak down it can be seen that about 40% of peak capacity is used less than 50% of the time and produces about 10% of total annual energy requirements. Sixty-eight percent of peak capacity is in use less than 100% of the time and produces only about 45% of total annual energy requirements. The remainder, only 32% is employed on what is called base load and is utilized 100% of the time.

At the top of the diagram is a band representing 12% of the annual peak. As the Manitoba peak is increasing at an annual rate of about 7.0% it is necessary to forecast peak demands several years in advance because of the long (5 - 7 year) planning horizon required to bring new capacity into service. This 12% represents a minimum reserve requirement which is carried as insurance against variations between forecast and actual peaks, delays in building programs and emergencies caused by breakdowns of generating equipment. This reserve represents a dead weight cost which is required to ensure reliability of service at all times. It can be seen that the actual utilization of installed capacity is even less than the figures which were given in the preceding paragraph.

The System Load Factor, the numerical equivalent of the load duration curve is a ratio of the number of kilowatt hours produced over the potential number of kilowatt hours that could have been produced. The following formula is employed.

$$\frac{\text{Energy Generated in kwh}}{\text{Peak capacity in kw x the number of hours in the period}^{1.}}$$

This formula can be used to determine the load factor on a daily,

1. Day 24, Week 168, Month about 720, Year 8760 or in leap years 8784

weekly, monthly or annual basis. Using this formula the annual load factor for the Southern Integrated System was found to be 56.3% in 1967/68.

By referring to the load duration curve it can be seen that any action which would shift the load duration curve to the right (increased demand for off-peak energy) would improve the load factor, improve capacity utilization and reduce unit fixed costs. Any reduction of reserve capacity either deliberate or accidental would not affect the load factor, but would improve utilization and reduce unit fixed costs.

Although in theory a 100% load factor is possible, in practice it is not. With a thermal based utility maintenance requirements limit the theoretical maximum to perhaps 85%, while with a hydro based utility, the theoretical maximum is even less.

While thermal stations are more or less standard products each hydro station is a unique creation custom fitted to the requirements and limitations of a particular site and a particular system. Given a particular flow of water a hydro station can be designed for energy or for capacity. A run of the river station can be designed for the maximum capacity at which it will produce continuous energy. Its load factor or capacity factor will be very high. A site with a large reservoir can be developed to produce continuous energy with low installed capacity and a high load factor or to produce peaking energy with perhaps twice the installed capacity and a much lower load factor. Thus we have a trade-off between capacity and energy. The compromise chosen depends upon the projected characteristics of the system into which the new station must be integrated. Doubling the capacity of a station would not double the cost, thus the cost per installed kilowatt of a peaking station is lower than for a station required for base load. The cost per kilowatt hour for a peaking station however, will be greater.

Because of the above factors the maximum practical load factor for the Manitoba system is probably between 75% and 80%. A precise figure is not available. The highest load factor attained by the Integrated Manitoba System (including Kelsey) in the past seven years was 62.4% registered in 1963/64.

Table 9.1 presents the annual load factors for both the Integrated Southern System and the Integrated Manitoba System. The Integrated Manitoba System has a higher load factor because Kelsey hydro station serving Thompson has a high load factor and is operated at a constant load.

The System Utilization Factor

While the System Load Factor has often been employed as an indication of efficiency, it is not for obvious reasons directly related to the economic efficiency with which the fixed plant is being utilized. This is because the load factor does not take into account reserve and other idle capacity which can vary from 12% up to 20 or 30% or greater when a new generating station is added. What is required is a true measure of utilization or a Utilization Factor.

William Iulo employs the following formula for a Utilization Factor.

$$\frac{\text{Energy Generated kwh}}{\text{Installed Capacity mw x hours in period}}$$

This defination assumes that all capacity is in place for the entire year. As Manitoba Hydro generally plans construction schedules in order to bring generating capacity into service in the autumn to serve winter peaks it was considered desirable to modify Iulo's formua to reflect this fact. Accordingly a weighted installed capacity figure was employed with all new capacity added during a fiscal year prorated to reflect the actual number of months of availability. Separate utilization factors were prepared for total

TABLE 9.1

MANITOBA HYDRO

UNIT COSTS, LOAD FACTORS, AND UTILIZATION FACTORS

	1961/62	1962/63	1963/64	1964/65	1965/66	1966/67	1967/68
nnual Expenditure per KWH Sold T.F.E. Sold in Manitoba & Export)	11.5 mills	11.3 mills	10.9 mills	10.3 mills	10.9 mills	11.4 mills	10.8 mills
nnual Return Per KWH T.F.E. Sold in Manitoba)	11.3 mills	11.5 mills	11.0 mills	10.8 mills	11.0 mills	11.2 mills	11.1 mills
nnual Return Per KWH T.F.E. Sold in Manitoba & Export)	11.3 mills	11.5 mills	11.0 mills	10.8 mills	10.8 mills	10.6 mills	10.3 mills
atio of Total Rtn/Total Expenditure Per KWH	.98	102	101	105	.99	.93	.95
nnual Load Factor							
(Integrated Southern System)	60.7	58.2	59.2	58.7	58.4	58.1	56.3
(Integrated Manitoba System)	60.7	60.3	62.4	60.7	61.3	60.2	59.5
nnual Utilization Factor All M.H. Installed Capacity)	40.0	42.7	48.7	52.3	49.5	46.3	51.6
nnual Hydraulic Utilization Factor Hydraulic Capacity Only)	52.4	64.2	72.5	73.9	68.5	61.2	66.0
nnual Thermal Utilization Factor Thermal Capacity Only)	14.5	3.4	3.8	10.4	6.1	3.9	9.7

generating capacity, hydro generating capacity and theraml generating capacity for Manitoba Hydro plant alone. The utilization factors calculated are found in Table 9.1.

The Utilization of Capital Investment

As mentioned previously the major portion of Manitoba Hydro's annual expenses are fixed charges associated with capital investment. In order to keep the unit fixed costs at a minimum, it is desirable to ensure a high degree of utilization of installed capital facilities.

In practice, the maximum practical utilization factor for the Manitoba Hydro system is probably between 70% and 75% due to the limitations of water supply, requirements for maintenance, and reserve requirements. The Optimum utilization factor may be somewhat less than this, perhaps between 55% and 60%.

This optimum range for utilization exists because of the high cost of thermal energy. Fuel costs at Brandon are about 4.0 mills per kilowatt hour, at Selkirk about 4.5 (due to higher transportation costs). The best operating results are achieved if thermal capacity is only operated when lower cost hydro energy is not available as in dry years, during system peak and in years immediately prior to the completion of a new hydro station.

From Table 9.1 it appears that a rather strong relationship exists between the total utilization factor and unit costs. In 1961/62 an extremely dry year the lowest recorded total utilization factor 40.0% coincided with the highest unit cost 11.4 mills. In 1964/65 the year of the highest utilization factor 52.3% (due to a one year delay in the completion of Grand Rapids) the lowest unit cost 10.3 mills was achieved. The second highest utilization factor 51.6% occurred in 1967/68, the year of the second lowest unit cost 10.8 mills.

Given a fairly high utilization factor of say 50% or greater, the most desirable situation would appear to be a high hydro utilization factor (70% or greater) and a low thermal utilization factor (10% or less). While relatively low unit costs were achieved in 1964/65 and 1967/68 inspite of about 10% thermal utilization, it is quite obvious that particularly in 1967/68 a higher hydro utilization factor and a lower thermal utilization factor would have resulted in even lower unit costs.

Utilization Factors and Unit Costs

It is estimated that in the 50% range, a 1 % improvement in the total Utilization Factor would result in a net reduction in the unit cost of about .2 mills. In order to realize this reduction, it is necessary (water conditions permitting) to obtain the improvement in Total Utilization Factor through increased generation from hydraulic capacity. It is estimated that a 1.3% increase in the Hydro utilization factor is required to realize a 1% improvement in the Total Utilization Factor.

Iulo determined that on the average a one percent change in utilization factor is associated with a change in overall unit electric costs of about .07 mills,[2] and that the lower the utilization factor, the greater the effect of a 1% change. Iulo's figure is about one third that found for Manitoba Hydro. Iulo's study was based on predominantly thermal utilities where variable costs are significant. With a hydro utlity variable costs are insignificant (perhaps .25 mills) hence the difference. In his study Iulo ranked capacity utilization as the fifth most important determinant of differences in inter utility unit costs. It is suspected that with a hydro based utility capacity utlization should be ranked perhaps second after interest rates.

2. W. Iulo: Electric Utilities Costs and Performance, Pullman, Washington State University Press, 1961, pp. 108, 141

Methods of Improving Utilization Factors

Theoretically there are a number of ways in which utilization factors can be improved. Some of these are:

1. By improving the system load factor by selling off-peak energy.
2. By reducing reserve capacity requirements.
3. By ensuring so surplus capacity exists above reserve requirements.
4. By co-operating and planning on a regional basis, so that surplus capacity can be sold to neighbouring utilities until required.
5. By entering into swap agreements with southern utilities so that the capacity required to serve winter heating loads in Manitoba can serve summer air conditioning loads in the United States.

The first method, that of increasing utilization through improving the system load factor by selling off-peak energy will be discussed briefly in the following paragraphs. The following four topics will be discussed in the next chapter, The Economic advantages of interconnections.

The system load factor which in simple terms is the ratio of average load to peak load is a very significant determinant of system utilization, and unit costs. A high load factor contributes to a high utilization factor. The annual system load factor is approximately the upper limit to which utilization can rise[3]. Under these circumstances system peak would equal installed capacity, and reserve capacity would be zero.

The annual load factor can be improved by increasing the volume of energy sold in off-peak periods. As the Manitoba system establishes a significant peak in the winter months because of a heavy heating and lighting load, any additional load which can be established which does not add to this peak would increase the volume of off-peak energy sold.

3. The use of a weighted capacity figure by the author when calculating Utilization Factors would cause a small discrepancy during years in which new capacity is placed in service.

In this respect seasonal loads such as air conditioning, the pumping of water for irrigation, patio lighting and so on are particularly favourable loads as they utilize normally excess capacity and the utility is assured that they will not add to the winter peak.

On a daily basis the daily winter peak usually occurs about 5:30 p.m. on a weekday in December or January. The annual load factor can thus be improved by attracting loads during off-peak hours on weekdays, or on weekends. In this respect such loads as automatically controlled water heating (shut off over the peak), controlled space heating, and off-peak industrial loads are aften encouraged by electric utilities.

In general the annual load factor may be improved by imaginative marketing and rate policies. In some cases appliances and applications of electricity with particularly desirable load characteristics may be promoted employing existing rates, while in other cases the development of special rates might be necessary and economically justifiable.

CHAPTER X

THE ECONOMIC ADVANTAGES OF INTERCONNECTIONS

The two basic contributions which interconnections make to the efficient operation of an electric utility are the means of improving capacity utilization, and the means of realizing the economies of scale associated with larger more efficient generating units. The presence of an interconnection usually also contributes to an improvement of system reliability.

The interconnection of neighbouring electric utilities, a practice which has only come into widespread use in North America since World War II is rapidly bringing all the individual systems of the continent into one unified power grid.

During the earlier development of the utility, industry experience indicated that marked economies were effected when transmission lines were built to tie all the individual generating stations and consumers of a reasonably wide area into one system. This enabled the integration of the total supply of one area under a single system. Economies resulted from a reduction of reserve requirements as risks were shared among more generating units, from the ability to add and use larger more efficient units, and from increased diversification of use.

Initially the high transmission costs, especially in losses, precluded the economic transmission of electricity more than a few miles. Systems were at first small, then in case of Canada gradually grew to embrace the whole area of a province. Ontario, a province with two separate pockets of population separated by a vast wilderness, developed two separate systems which are only in the process of being interconnected at the present time.

In short, technological developments in generating, in high voltage transmission, and in electronics have been continually enlarging the efficient area of system operation. These developments have enabled Manitoba Hydro to effectively break the isolation which geography has so long dictated, with the construction of the interconnections to Ontario and Saskatchewan. These interconnections ultimately will form part of a national power grid which will in turn form part of a continent wide grid.

While the establishment of interconnections duplicates many of the principles which accompany the integration of generating stations, a new dimension is added because of the vast geographical area encompassed by an interconnected system. Climatic and time zone variations add new possibilities for economies that were not present previously.

A primary advantage of interconnections is that they enable a utility to dispose of surplus capacity and energy. In the discussion that follows, of the specific economic advantages that theoretically can be gained from a well managed system of interconnections this principle of disposal of surpluses will be a paramount consideration.

THE CO-ORDINATION OF CAPITAL PROGRAMS

Economic gains in this area are primarily of a long term nature and can be realized only by the long term co-ordination of generation and transmission additions by neighbouring utilities. It is doubtful that interconnections can effect economies in the distribution of electricity.

The gains from co-ordination apply to hydro, thermal and nuclear programs, but in different fashions. These gains accrue from the economies of scale associated with large scale plants or from the economies associated with large scale hydro sites. These economies are not precisely the same. With a hydro plant there are no economies of scale per se, but a particular large site might have a lower development cost per kilowatt than alternate small sites. Economies of scale may arise however with the transmission required to bring energy from a hydro site into the market area. Here a large volume of energy from a large hydro site may be required to justify the construction of the line.

With Thermal or Nuclear stations, the larger the turbines the lower the unit costs of construction and the more efficient is their operation. The maximum size of turbine which can be constructed is continually growing. Thus real economies of scale exist here.

Most utility systems are by themselves unable to take advantage of these economies of scale for two reasons. First; it is inprudent to have more than 10% of the capacity of a system in single unit due to the risk of breakdown, maintenance requirements etc. Secondly; the adding of a single large unit to a small system would involve a long costly load building period until the capacity was entirely required. This expense of carrying unused capacity would more than offset the economies of scale.

Co-ordinated planning between two or more interconnected utilities enables the realization of these economies associated with large generation additions. Utility A is able to construct a large plant, and load it up quickly by selling capacity and energy to Utilities B and C. Then B's building program is timed to bring in another large station when A's initial station is fully loaded up. The larger size of the combined interconnected system minimizes the risk involved with the installation of large units. The risk can be shared between all the interconnected utilities.

Economies can also be realized with transmission lines. The construction of a new transmission line within a system could be delayed by supplying a portion of the load in a particular area from a neighbouring system with surplus transmission capability.

THE REDUCTION OF RESERVE CAPACITY REQUIREMENTS

It is a generally accepted principle that as a system grows in size (in terms of the number of interconnected generating units in the system) that the amount of reserve capacity which must be kept idle is reduced. The optimum amount of reserve required by a utility depends upon the characteristics of the system (which change as new units and transmission lines are added) and upon the degree of reliability which is felt to be necessary. With an electric utility system 99.5% reliability can be achieved reasonably economically, but from that point on diminishing returns sharply increase the cost of each additional increment of reliability. Manitoba Hydro has retained a 12% generation reserve requirement for many years. Extremely complicated calculations which include the use of probability have determined that the introduction of heavy interconnections, and the improvement of communications and automated switching gear and so on improve the reliability of the system and theoretically reduce the amount of reserve capacity that is required. Thus the introduction of interconnections can reduce the amount of reserve capacity that is required by increasing the effective size of the system.

Assuming that a system was able to constantly maintain a 12% reserve and no more, the reduction of this requirement to 11% would represent a significant improvement in the utilization of capacity. It is estimated that this would improve the utilization factor by about .5 at the 50% range, and would reduce average unit costs by about .1 mills per kilowatt hour.

EXPORT SALES DURING LOAD BUILDING PERIODS

A system without interconnection is rarely able to get its' surplus capacity down to 12%, and thus usually incurs an efficiency penalty for carrying excess capacity. This occurs because of the lumpy nature of capacity additions. Kettle Rapids the next major addition to the Manitoba System provides a good example of this.

The planned capacity of Kettle Rapids is 1024 megawatts in ten units. While all these units would not be installed simultaneously to be ready for service in the first year of operation, the optimum installation schedule would have them all installed before the Manitoba System is capable of absorbing them. Thus Manitoba might have excess capacity of up to 30% in some years and only attain 12% in about one year out of five, immediately prior to the addition of another large station. This situation has prevailed in Manitoba particularly with Seven Sisters which took some twenty years to fully complete. The presence of interconnections overcomes this problem of over capacity. Accordingly Manitoba Hydro has contracted to sell large blocks of capacity to Ontario and Saskatchewan during the Kettle Rapids load building period. This arrangement is mutually advantageous and enables Manitoba Hydro to keep excess capacity at a minimum.

HORIZONTAL OR E-W DISPLACEMENT OF LOAD ON A DAILY BASIS

In the co-ordinated operation of interconnected utilities, interchange transactions may be either long run (take the form of formal contractual arrangements spanning months or years as with load building etc.) or may involve short run optimization by neighbouring utilities with the day to day co-ordination of load dispatching, spinning reserves, and scheduled maintenance.

This short run optimization process resembles arbitrage operations in a foreign exchange market with exchanges arranged at short notice on the telephone according to informal practices enforced primarily by custom.

The following outlines the optimization principles that apply both within a system and which govern interconnection transactions.

"In its day-to-day operations, an electric power system is chiefly concerned with meeting an autonomous demand on its facilities in least cost fashion. At any given time the problem reduces to determining the optimal allocation of the system's total output (load) among its interconnected plants. Demand fluctuates continually and sharply in ever varying, daily, weekly, and seasonal patterns. Since electricity is not commercially storable, the supply response is instantaneous and the least cost allocation of the load among system plants is subject to constant adjustment.

The minimum cost solution to the problem requires that total delivered output be at the demanded level and that marginal delivered costs be equal for all plants in operation. Idle plants must have marginal delivered costs at least as high as those in operation. For each plant marginal delivered cost is equal to the sum of marginal generating costs and the value of the electricity lost in transmission as a result of the plants increased output."[1]

Inter utility pricing arrangements are usually based on the formula $\frac{X + Y}{2}$ where X is the incremental costs to the seller of producing and delivering the energy sold, and Y is the incremental cost the buyer would incur if he had to produce the energy himself. Using this formula the savings from the transactions (Y - X) are shared equally.[2]

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1. William R. Huges, Short Run Efficiency and the Organization of the Electric Power Industry, Quarterly Journal of Economics, Volume 76, November, 1962, Page 597.

2. Ibid., Page 601

Horizontal displacement deviates somewhat from the transactions described above because the objective is not so much minimization of energy costs but conservation of capacity. Because of the wide band of longitude across which Canada stretches, the country spans some seven time zones. (A time zone is approximately 15° of longitude.) Assuming that the daily peak in each zone occurs at 5:00 p.m. local time, the daily peak would occur first in the east, then travel westward following the sun. Within a given system, the peak would not occur everywhere at the same time thus contributing to the diversity of the system.

Interconnections such as exist between Saskatchewan, Manitoba and Western Ontario would enable each utility to benefit from the diversity over a wider band of longitude. Although the principle could apply any time during the year, it is most applicable during the winter months when the annual peaks occur. As the peak would occur in Western Ontario an hour earlier than in Manitoba, Manitoba could supply say 50 mw of capacity to Ontario and thus reduce their capacity requirements by that amount. Any shortage in Manitoba could be supplied from Saskatchewan, still two hours from their own peak. Initially, then capacity would be shifted eastwards. As the peak begins to subside in Ontario, Manitoba's capacity could be slowly released keeping Ontario's capacity in full use until the net displacement of capacity is zero. As the peak begins to build in Manitoba, capacity there can be supplemented by an inflow of capacity from both Ontario and Saskatchewan. The third step of the process takes place with Manitoba and Ontario supplementing the capacity of Saskatchewan during the peak there. In theory, each utility might then be able to operate with at least 50 mw less capacity than without interconnections. The kilowatts of capacity which serve the annual peak and normally are only utilized a few hours per year would also receive greater use. Thus significant improvements in utilization factors could be realized.

VERTICAL OR N-S DISPLACEMENT OF LOAD ON A SEASONAL BASIS

The possibility of Vertical Displacement or Seasonal swaps of capacity and energy occur because of the variations in temperature which take place with latitude in North America. Manitoba Hydro in common with most Canadian utilities is subject to a rather severe winter peak because of the short hours of daylight and heavy space heating load. Most American utilities not in the extreme northern part of the country are subject to a summer peak (due to air conditioning loads) equal to or greater than their winter peaks. The utilities serving the Minneapolis area fall in this category. Thus the systems of Manitoba Hydro, and the utilities of the Minneapolis area complement each other on a seasonal basis and the swaping of summer capacity and energy for winter capacity and energy becomes a practical possibility.

The following hypothetical example roughly approximates what could be accomplished with the Manitoba Hydro System. Assume that without a swap Manitoba Hydro's system peak is 1160 mw, total energy is 5.6 Billion kilowatt hours. The annual load factor would be:

$$\frac{5.6 \text{ B}}{1160 \text{ mw} \times 8760} = 56\%$$

Assume Manitoba Hydro agrees to place 100 mw at the disposal of the United States for the six summer months in return for 100 mw during the six winter months. As energy would only be required during the heat of the day, an energy conponent of about 2000 hours per kilowatt would be reasonable. Thus Manitoba Hydro would have to generate some 200 million extra kilowatt hours during the summertime and would receive them back during the winter. The cost to Manitoba Hydro of generating this energy in summer would be small as water is most plentiful in these months, (water rentals, plus miscellaneous operating expenses about .25 mills per kilowatt hour) while its value to Manitoba Hydro when received back in the winter months would be the long run average cost of generating energy in those months.

In effect, this represents the accomplishment of the age old dream of being able to store electricity in commercial quantities. The only costs of storage would be the fixed and operating costs of the interconnection, and the line losses.

With this swap the physical capacity required by Manitoba Hydro would be reduced to 1060 mw, total energy would remain at 5.6 billion kilowatt hours, and the load factor based upon the physical capacity required by Manitoba Hydro would be:

$$\frac{5.6B}{1060 \text{ mw} \times 8760} = 60\%$$

Thus the load factor of Manitoba Hydro capacity would be improved about 4.0%. In anyone year, this sort of swap would not result in an improvement of capacity utilization unless the swap was part of long term planning. Once capacity addition programs were adjusted so that surplus capacity was minimized under the swap arrangements utilization factors could be improved by approximately 4.0% with a resulting improvement in long run unit costs of almost .8 mills per kilowatt hour.

As the sizes of the systems involved increased, the amount of the swap could also be increased from 100 mw if that were to the advantage of both parties. In all probability, these transactions would not involve the transfer of money as approximately the same benefits would accrue to both parties.

THE PRINCIPLES OF PRICING SHORT TERM EXPORT COMMITMENTS vs
PRICING OF PERMANENT EXPORT COMMITMENTS OR PERMANENT DOMESTIC COMMITMENTS

The discussion involved in this section touches on one of the most controversial issues of public utility economics. This is the question of the definition of incremental or marginal costs.

In pricing short term (two or three years) export power the only costs which must be recovered are the incremental costs actually incurred in providing the energy (and capacity) to the customer (plus a small surplus to make the sale worthwhile to the seller). If the energy is provided from true excess capacity, if the schedule of planned capacity additions is unaltered by the sale then the only costs are incremental fuel, water rental and miscellaneous operating expenses. The essential point is that if the excess is not sold as an export at what ever price it will bring, it will be sold to no one and will be wasted.

If, however, additional generating capacity is installed or additional transmission (interconnections etc.) must be constructed, the price at which export energy is sold must reflect these expenses and in general, the long run costs of producing energy will apply.

The primary principle which must be observed is that in order for short run incremental costs to become the basis on which price can be based, the sale must not alter normal capital additions schedules in anyway. It has been this principle, the existence of a true surplus which has governed most of Manitoba Hydro's energy exports over the past few years. Actual prices negotiated usually reflect the custom of sharing the savings equally. Because of this "true surplus" principle, it is possible to sell energy to neighbouring utilities at from 1 to 3 mills, a price less than that at which energy could be sold to a permanent customer within the province.

In selling electricity to a customer, within the province, it must be assumed that service is being provided to a permanent customer, and that the sale constitutes normal load growth for which existing capacity has been constructed. Under this circumstance, the principle that must apply is that the price charged must reflect the average long run cost of providing this particular service.

These essential relationships appear to have been poorly understood by policy makers in many utilities, and by a large number of economists. This appears to have been so because of the large number of utility personnel and economists who have believed an electric utility to be a declining cost industry. In actual fact an electric utility might be subject to decreasing costs, constant costs, or increasing costs depending upon a whole host of factors which affect its costs.

R.K. Davidson demonstrates a very clear understanding of this problem. He suggests that, "the writers who call electric utilities decreasing cost industries usually do not explain what they mean by decreasing costs. It is clear that some of them have in mind the movement of average costs in the short run, with plant capacity treated as fixed."[3]

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3. R.K. Davidson, Price Discrimination in Selling Gas and Electricity, Baltimore, The Johns Hopkins Press 1955, Page 101

Davidson feels that this basic misconception results in price discrimination in the pricing of electricity.[4] In the past, he claims many pricing theories for public utilities have been based either on a theory of decreasing costs or excess capacity.

Davidson writes, "Some writers in the excess capacity and decreasing costs camp, characterize electric utilities as having excess capacity or unutilized capacity only part of the time, while others believe that the utilities always operate with excess capacity; but all believe that unit costs fall with increasing output. Consequently, they argue that price discrimination, which may not be desirable in industries that do not have unutilized or excess capacity, is desirable where idle capacity exists because the use of price discrimination results in a larger output at a lower unit cost.[5] The essence of this argument is that many people, economists and others justify prices at less than long run average cost in order to load up excess capacity quickly.

Note: Incremental costs - fuel and other variable costs.

The term incremental costs is widely used to refer to marginal cost when the additional output is from a given plant.

Total incremental costs has been used to refer to long run marginal cost. Ibid., Page 72

4. Davidson uses price discrimination in the economic sense and defines it as an action by a seller whereby the relative prices he charges for the units of his product or products are disproportionate to the relative costs of production of the units sold. Ibid., Page 25

5. Ibid., Page 101

Davidson continues, "Whether discussing short run or long run decreasing average costs, excess capacity theorists reach the same conclusion: Price discrimination as it is found in the public utility industry, is desirable in decreasing cost industries in order to utilize existing capacity more fully and to produce a larger output at a lower unit cost!"[6]

The foregoing argument clears the air somewhat for a discussion of marginal costs. First it appears evident that there is no single marginal cost. It is generally concluded that in the short run, marginal costs are low and less than average costs. It should, however, be clear that the marginal cost is dependent upon the particular service contemplated. (ie. industrial or domestic, peak or off peak)

In the long run, the relationship between marginal and average costs is less clear. If one accepts that there are economies of scale in transmission and distribution, the analysis hinges on generation costs. If the capital costs per kilowatt of new larger plants is less than old, and if fuel costs (in BTU's per kwh) are declining as with thermal plants, it appears that long run marginal costs will be less than average costs and average costs will be declining. If economies associated with scale and technology are insufficient to offset inflation, higher interest rates, fuel costs and so on, long run marginal costs may be equal to long run average costs or higher. Long run average costs will be either constant or perhaps rising slightly.

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6. Ibid., Page 102

H.S. Houthakker seems to feel that in the long run marginal and average costs will be approximately equal. He says, "Our analysis is based on long term cost, and it is a well known theorem that in the long run, both decreasing marginal cost and discrepancies between marginal cost and average cost are merely signs of market imperfections or bad planning.[7] It would appear that this reasoning is correct and that the approximate equivalence of marginal cost and average cost in the long run would make long run average cost an appropriate pricing guide."

Davidson's general argument would appear to support this contention. He says:

"Marginal costs are below average costs in the long run only when decreased costs due to economies of scale outweigh the increased costs due to changing proportions of factors employed. When economies of scale are present, the long run cost curve may be rising, horizontal or falling, depending upon the weight of the increased costs due to changing proportions of factors, relative to the decreased costs due to economies of scale. Beyond the point where the decreasing costs just balance, the increasing costs of expanded output, the long run cost curve will rise and marginal cost will exceed average cost.

When the individual establishments in the gas and electricity industry were small and not interconnected, significant indivisibilities leading to decreasing costs were undoubtedly present. In view of the multiplicity of establishments today and their wide spread interconnections, indivisibilities do not appear significant in the long run. Therefore, if rates are set equal to long run marginal or incremental costs, when increased capital is necessary and indivisibilities are unimportant in the long run, the additional and total costs will be covered."[8]

Thus Davidson suggests that sales proceeds must cover long run marginal cost including a return on investment.

In the past, pricing policies in Manitoba and elsewhere have often reflected this short term decreasing cost philosophy. Prices were set at less

7. H.S. Houthakker, Economic Journal (1951) Pages 10 & 11

8. R.K. Davidson, <u>op. cit.</u>, Page 74.

than long run average costs in order to increase volume and reduce unit costs. This may have been justifiable in order to load up large blocks of excess capacity which resulted from bad planning or depression, but does not appear defensible in a well planned optimizing utility where capacity additions are carefully tailored to a reliable load forecast.[9]

Under normal operating conditions load building programs should be based upon long run average costs for that particular type of service. If load growth is accelerated beyond what normal load growth would be, by charging artificially low rates the time at which new, more expensive capacity is required will be hastened. Average costs will rise with the addition of the new capacity and average returns will be inadequate to cover them. The utility will then be faced with the problem of raising the promotional rates to cover the new average costs. This might antagonize the customer who would feel he had become a customer under false pretenses, or might merely result in the loss of a load, a load that could only be attained in the first place by charging less than full costs. At any rate, the utility having just added new capacity would be faced all over again with the problem of load building.

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9. The late D. M. Stephens, former Chairman of Manitoba Hydro, in discussing the fact that both the Winnipeg Electric Company and the City Hydro simultaneously embarked on construction of new generating plants in 1928 suggested, "One wonders at the economic outlook for either of the competing utilities as they each embarked on a very large new plant in 1928. While the terms "capacity sharing" and "capital conservation" were not then in common use, arithmetic was well developed long before that time.

   D. M. Stephens - Talk presented to Saskatchewan Power Corporation, Senior Management Conference, Regina, Saskatchewan, March 20, 1968.

The alternative which this writer feels superior is to rely upon non-price promotions. This policy involves an attempt to determine what the optimum rate of growth is.[10] It is suggested that a utility should adjust its capital program (ie. the overall rate of growth of the system) to the normal rate of load growth that would occur with a rate structure based upon average cost. This would involve extremely keen pricing calculations in an order to develop differential prices for various classes of service such as industrial, commercial, rural, urban, domestic, on peak, off peak and so on. The objective being to determine the optimum long run average costs of each class of service at the highest possible utilization factor. Increased volume would be encouraged by advertising the non-price advantages of electricity over competitive energy sources. Price competition would not be entered into except in the case where average off peak costs permitted this type of competition.

Following this philosophy, the system load would grow at a normal rate (not artificially accelerated by prices below cost). Capacity additions, when they were required would come into service at their normal time (not a year or two early to serve an artificially created load). Any "true excess" capacity may be sold to neighbouring utilities as such. As capacity becomes fully loaded due to normal load growth, new capacity additions can be delayed by purchasing the "true excess" capacity of another utility. This sort of policy would enable a number of interconnected utilities to maximize their utilization collectively. If price increases are necessary from time to time, they would reflect normal load growth and not be inflated by the requirement to offset the effects of early capacity installations and prices which are less than full cost.

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10. The author has found this task beyond his capability at the present time.

CHAPTER XI

CUSTOMER AND CONSUMPTION DATA

The two most important determinants of inter-utility variations in units costs in William Inlo's analysis were consumption per Residential customer, and the distribution of the market among consumer classifications. The sixth most important factor was consumption per commercial and industrial customer. While it has not been possible to demonstrate the effects of these three relationships on Manitoba Hydro's unit costs in precise quantitative terms it is felt all these factors have had a profound and favourable influence on the present level of unit costs.

Throughout almost its entire history, the electric power industry of Manitoba has been renowned for its high volume of electricity usage per customer and its extremely low rates. According to W.L. Morton, the cost of electricity in Winnipeg from 1912 through the early 1920's was the lowest in North America.[1] In Canada, Manitoba was from 1948 to 1964 consistently in second place behind Quebec in average cost per kilowatt hour sold, (see Appendices). The average cost per kilowatt hour sold was less than one cent. Quebec's lowest cost position has largely been the result of the tremendous volume of energy consumed by the aluminum industry at very low prices as Manitoba's average costs per kilowatt hour for domestic and farm and commercial customers have consistently been below those of that province. In 1965, Manitoba slipped to fourth place in average cost per kilowatt hour sold, but by 1966 the last year for which figure are available, had regained third place.

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1. W.L. Morton: Manitoba - A. History, Toronto, The University of Toronto Press 1957, Page 308

With respect to average cost per kilowatt hour for domestic and farm energy, as well as consumption, Manitoba has from 1948 to 1966 consistently had the highest per capita consumption and the lowest average cost per kilowatt hour. This is an extremely significant achievement and of very great interest from an analytical point of view. In 1966, Manitobans consumed 2,021 kilowatt hours per capita for domestic and farm purposes at a price of 1.18 cents per kilowatt hours. This represents a per capita consumption of 25% greater than the Canadian average at a price 16% less than the Canadian average. This would tend to confirm Inlo's conclusion that consumption per residential customer is an extremely significant determinant of the unit cost of providing electric energy.

THE RATE OF INCREASE OF TOTAL CUSTOMERS

Total energy sales are a function of the number of customers and consumption per customer. Similarily, the rate of increase in energy sales is also a function of the rate of increase of customers and the rate of increase of energy consumption per customer.

Thus, in 1967/68, 226,861 customers consumed an average of 19,775 kilowatt hours each. This represented an increase over the previous year of 2.3% in total customers, and 5.5% in energy consumption per customer. Total energy sales on the Manitoba Hydro System increased by about 7.9% in 1967/68. During the period from 1961/62 to 1967/68, total customers have increased at an average rate of 2.7% per year, energy sales per customer at an average of 4.8% per year and total energy sales on the Manitoba Hydro System at an average of 7.5% per year.

It can be seen from the previous paragraph that some 35% of the annual increase in energy sales on the Manitoba Hydro System in the past seven years has been accounted for by the addition of new customers. This is an extremely significant factor in determining the effect of increasing energy sales upon unit costs. It can be demonstrated intuitively at least that the higher the proportion of increased energy sales attained through the acquisition of new customers, the less will be the downward pressure upon unit costs. This is particularly so in the case of a hydro based electric utility.

With a thermal based electric utility a fairly high rate of energy sales increase is desirable because it enables the utility to capture economies of scale in all three phases of electricity supply: generation, transmission, and distribution. In the generation phase, it enables the utility to install new larger, more efficient thermal stations and load them up relatively quickly. These factors account for the thermal based electric utility industry being considered a decreasing cost industry.

With a hydro based utility, a more complex situation exists. Economies of scale and efficiencies related to improved technology are almost non-existent with hydro generating stations. Transmission economies do exist, but these may be more than offset by the expense of constructing longer lines to reach more remote hydro sites. Thus from 1961/62 to 1967/68 transmission costs increased from .6 to .9 mills per kilowatt hour exclusive of transmission losses. It thus appears that increases in energy sales force a hydro based utility into more expensive generation and transmission costs. If these costs can be more than offset by economies in distribution, a high rate of increase of energy sales will in the long term result in lower unit costs.

An increase in energy sales achieved through the aquisition of a new customer costs the utility much more than an increase of energy sales to an established customer. This occurs because of the so called "Customer Component" of the cost of providing service. While the customer component is negligeable in the case of an industrial or large commercial customer it forms a large proportion of the total cost of serving a residential or farm customer. The customer component consists of the material and labour costs of connecting a new customer to the system and the cost of metering, meter reading, and billing the new customer. This cost is approximately fixed and is the same for a large or small consumer. It is considerably higher in a rural area than an urban one. Thus, it can be seen that if a high rate of energy sales increase can be achieved with established customers only, unit distribution costs may be decreased, while if the entire increase in energy sales is achieved by adding new customers, unit costs of distribution may increase.

This can be appreciated by examining Manitoba's farm electrification program. From 1946 to 1954, total energy sales in Manitoba increased by an average of 6.2% per year while new customers, including over 40,000 farms, were added at a rate of 7.6% per year. Consumption per customer actually declined by about 1% per year. During this period average unit costs for the province rose from about 6.0 mills per kilowatt hour in 1946 to over 9.0 mills in 1954. This increase occurred not only because of the customer component (which is high in rural areas) but because of the necessity of building a distribution system in many areas.

Once a distribution system is established, the level of unit costs of distribution appear much more sensitive to the volume of kilowatt hours sold per customer, than the density of customers within the system.[2] In spite of an

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2. This conclusion was arrived at by William Inlo and appears to be confirmed by the Manitoba Experience.

overall density in 1967/68 of only 6.3 customers per mile of line, and a farm density of only about .8 customers per mile of line, the unit costs of distribution were 4.5 mills per kilowatt hour. This is an extremely low figure which has remained consistently at this level since 1961/62.

POPULATION GROWTH AND THE RATE OF INCREASE OF TOTAL CUSTOMERS

Only since 1954 has the rate of population growth been a significant factor in determining the rate of customer increase, and the level of unit costs in Manitoba. This is because prior to 1954, a large segment of the population had no electric service, and thus the rate of customer increase was more dependent upon the level of intensity of expansion programs than population growth.

TABLE 11.1

Population of Manitoba 1950 - 1967 [3]
(in thousands)

		Percentage Increase
1950	768	
1951	776	1.04
1952	798	2.84
1953	809	1.38
1954	823	1.73
1955	839	1.94
1956	850	1.31
1957	862	1.40
1958	875	1.51
1959	891	1.83
1960	906	1.68
1961	922	1.77
1962	936	1.52
1963	949	1.39
1964	959	1.05
1965	965	.63
1966	963	- .21
1967	963	0

3. Source: Dominion Bureau of Statistics, Cat. No. 91-201

From Table 11.1, it can be seen that the average rate of population growth in Manitoba since 1950 has been quite reasonable, about 1.35% per year. From 1961 to 1968 it has been some what lower at .73%. During the latter period, total customer growth has been 2.7% per year, a figure considerably higher than population growth. This is because a single individual can be more than one customer. A farm may have several services, or an individual may own a home, a business, and a cottage. It can thus be concluded that a zero rate of population growth in itself may not mean an undesirably low rate of customer growth, and that a zero rate of customer growth may lead to a reduction in unit costs of distribution assuming a high rate of increase in energy use per customer, but this is beyond the scope of this study.

THE RATE OF INCREASE OF CUSTOMERS BY CLASS

There are four broad classes of customer served by Manitoba Hydro. These are domestic or residential, farm, commercial, and industrial. A summary of some of the relevant statistical information concerning these classes may be found in Tables 11.2, 11.3 and 11.4. During the period 1960/61 to 1967/68, the number of domestic customers increased at an average of 3.5% per year, farm by .1%, commercial by 2.2% and industrial by 3.5% per year. During this same period, consumption per domestic customer increased at an average of 2.6%, farm by 9.6% commercial 7.8% and industrial by 12.5% per year. The trends indicated by these factors all have significant implications for the future unit costs of distributing electricity.

The highest rate of increase in energy consumption is occurring in three main sectors of the Manitoba economy - the farm sector, the commercial

TABLE 11.2

MANITOBA HYDRO

KILOWATT HOURS CONSUMED BY CONSUMER CLASSIFICATION ($x\ 10^6$)

Year	Total	Domestic and Farm	Farm		Domestic		Commercial		Industrial		Commercial & Industrial
1960/61	1,957	940	224	-	716	-	207	-	811	-	1,018
1961/62	2,538	1,028	247	10.0*	781	9.2*	231	11.7*	1,280	57.7*	1,510
1962/63	2,738	1,092	268	8.6	824	5.4	251	8.9	1,396	9.1	1,647
1963/64	3,064	1,153	293	9.3	860	4.4	272	8.4	1,638	17.4	1,911
1964/65	3,271	1,293	353	20.6	940	9.3	306	12.4	1,672	2.1	1,979
1965/66	3,522	1,353	360	1.8	993	5.7	330	7.8	1,839	10.0	2,169
1966/67	3,764	1,434	395	9.9	1,039	4.6	360	9.0	1,971	7.2	2,330
1967/68	4,061	1,519	425	7.5	1,094	5.4	402	11.7	2,140	8.6	2,541

* Percentage Change

Source: Manitoba Hydro
Monthly Reports

TABLE 11.3

MANITOBA HYDRO

NUMBER OF CONSUMERS BY CONSUMER CLASSIFICATION (x 10^3)

Year	Total Consumers		Domestic and Farm		Farm	Domestic		Commercial		Industrial		Commercial and Industrial	
1960/61	187	-	159	-	39.0	120	-	21.4	-	6.7	-	28.1	-
1961/62	194	3.6*	164	3.4*	39.0	125	4.5*	22.3	4.2*	7.0	5.0*	29.3	4.4*
1962/63	199	2.7	169	2.7	39.2	130	3.4	22.7	2.0	7.3	4.1	30.1	2.5
1963/64	207	3.7	175	3.7	39.4	136	4.6	23.9	4.9	7.3	(.3)	31.1	3.6
1964/65	211	2.3	179	2.3	39.3	140	3.1	24.3	1.9	7.6	3.7	31.9	2.3
1965/66	217	2.5	183	2.4	39.2	144	3.1	25.0	2.7	7.8	3.4	32.8	2.8
1966/67	222	2.3	188	2.8	39.4	149	3.4	24.6	(1.5)	8.2	4.3	32.7	(.1
1967/68	227	2.3	193	2.2	39.2	153	2.9	25.0	1.8	8.5	4.7	33.6	2.5

* Percentage Change

Source: Manitoba Hydro
Monthly Reports

TABLE 11.4

MANITOBA HYDRO

MISCELLANEOUS CONSUMER AND CONSUMPTION DATA (KWH x 10^3)

Year	Total Consumers Per Circuit Mile of Line	T.F.E.** Plus Export Kwh Per Mile of Line		T.F.E.** Plus Export Kwh Per Customer		T.F.E.** Only Kwh Per Mile of Line		T.F.E.** Only Kwh Per Customer		Kwh Per Farm Customer		Kwh Per Domestic Customer	
1960/61	5.6	68.4	-	12.3	-	68.4	-	12.3	-	5.8	-	6.0	-
1961/62	5.7	85.6	25.2*	15.0	21.8*	85.6	25.2*	15.0	21.8*	6.3	10.2*	6.2	4.5*
1962/63	5.8	86.4	1.0	14.9	(.4)	86.4	1.0	14.9	(.4)	6.8	7.8	6.4	1.9
1963/64	6.0	96.7	11.9	16.1	8.0	96.7	11.9	16.1	8.0	7.4	8.5	6.3	-
1964/65	6.0	102.3	5.7	17.0	5.4	102.3	5.7	17.0	5.4	9.0	21.1	6.7	6.1
1965/66	6.1	112.1	9.6	18.3	8.4	109.3	6.9	17.8	5.1	9.2	1.9	6.9	2.5
1966/67	6.2	123.8	10.5	20.0	8.8	116.6	6.7	18.7	5.1	10.0	9.6	7.0	1.1
1967/68	6.3	137.6	11.2	21.8	9.7	124.6	6.9	19.8	5.5	10.8	7.9	7.1	2.4

* Percentage Change
** Total Firm Energy

Source: Manitoba Hydro Monthly Reports

Facts & Figures Book

sector and the industrial sector. While increased energy sales are occurring in the domestic or residential sector, they are increasing at a slower rate than in the other three sectors just mentioned.

Table 11.5 indicates the average rate of increase of customers, of energy consumption per customer, and the rate of increase of energy sales in each sector for the period 1960/61 - 1967/68.

TABLE 11.5

BREAKDOWN OF INCREASES IN ENERGY SALES
1960/61 to 1967/68

Classification	Rate of Consumer Increase	Increased Energy Consumption per Consumer	Rate of Increase of Class
Domestic	3.5%	2.6%	6.3%
Farm	.1%	9.6%	9.7%
Commercial	2.2%	7.8%	10.0%
Industrial	3.5%	12.0%	16.0%
Total Customers	2.8%	7.2%	11.2%

DOMESTIC CUSTOMERS

The rate of increase in kilowatt hours consumed by domestic customers 2.6% is less than the 3.5% rate of increase of domestic customers. This suggests that increased energy sales to domestic customers have had little downward effect on unit distribution costs. As domestic customers account for 67% of all customers, the pattern of energy sales increase within this class may dominate the movement of distribution costs.

FARM CUSTOMERS

The number of actual farms in Manitoba have been declining for several years while the number of farm services have remained about static. The number of kilowatt hours consumed per farm customer has increased rapidly at 9.6% per year, and is expected to continue to rise at a rapid rate in the future. These increases can be distributed without incurring additional customer costs, and should realize the full economies of scale inherent in the distribution of electricity. It can be concluded that the pattern that is developing on the rural sector of the distribution system should enable considerable downward pressure on the unit costs of distribution in the rural areas. This is because, while the number of farm customers per mile of rural line has remained about constant at .8 per mile, the number of kilowatt hours distributed per mile of rural line has about doubled from just over 6,000 kwhrs per mile to over 12,000 kwhrs per mile annually.

During the past two decades, energy sales to Manitoba farm consumers have increased from 1% of domestic energy sales in 1947 to 13% in 1957 and 20% in 1967.

COMMERCIAL CUSTOMERS

While distribution costs per kilowatt hour for commercial customers are about the same as for residential customers due to their close proximity in urban areas and joint use of the same facilities, customer costs are somewhat less per kilowatt hour due to a higher use per customer (about 16,000 kwh per customer in 1967/68). During the period 1960/61 to 1967/68, the rate of increase of energy sales per commercial customer at 7.8% was high and significantly greater than the 2.2% average increase in customers in this class. While it seems reasonable to expect the high rate of increase in energy consumption by established commercial customers to place the greatest downward pressure on unit distribution costs, the addition of new commercial customers may also place some slight downward pressure on unit distribution costs because of the high average initial consumption per customer.

INDUSTRIAL CUSTOMERS

Because of the much higher average consumption of industrial customers (about 255,000 kilowatt hours in 1967/68 on the Manitoba Hydro system) the customer cost component is negligeable. This accounts in part for the much lower average cost per kilowatt hour for industrial energy. During the 1961/62 to 1967/68 period, the rate of increase of industrial energy sales was high, about 16.0% per year. This figure is somewhat high because it includes a 58% increase in 1962 associated with the nickel development at Thompson. During this period, the number of industrial customers increased by 3.5% per year, and the average use per customer increased by about 12.5% per year. This rapid increase in industrial energy consumption could be expected to place considerable downward pressure on unit costs of distribution.

As the rate of increase of industrial consumption has been greater than the combined rate of increase of all other categories, the proportion of total energy sold for industrial use has increased almost continuously since 1958.

DISTRIBUTION OF KILOWATT HOUR SALES AMONG CONSUMER CLASSIFICATIONS

The measure chosen by Iulo to represent the distribution of the market of an electric utility among the several classes of consumers was the proportion that total kilowatt hour sales to residential customers were to the total kilowatt hour sales of the individual utility. This is approximately the approach used here where the ratio of domestic and farm sales to the total of domestic and farm, commercial and industrial is employed. Figure 11.1 shows the proportionate distribution of these three classifications from 1947 to 1966. From 1947 to 1958, domestic and farm increased from 23% to 40% of the total. This resulted from the boom in appliance sales that followed the war and the farm electrification program. During this period as mentioned previously,

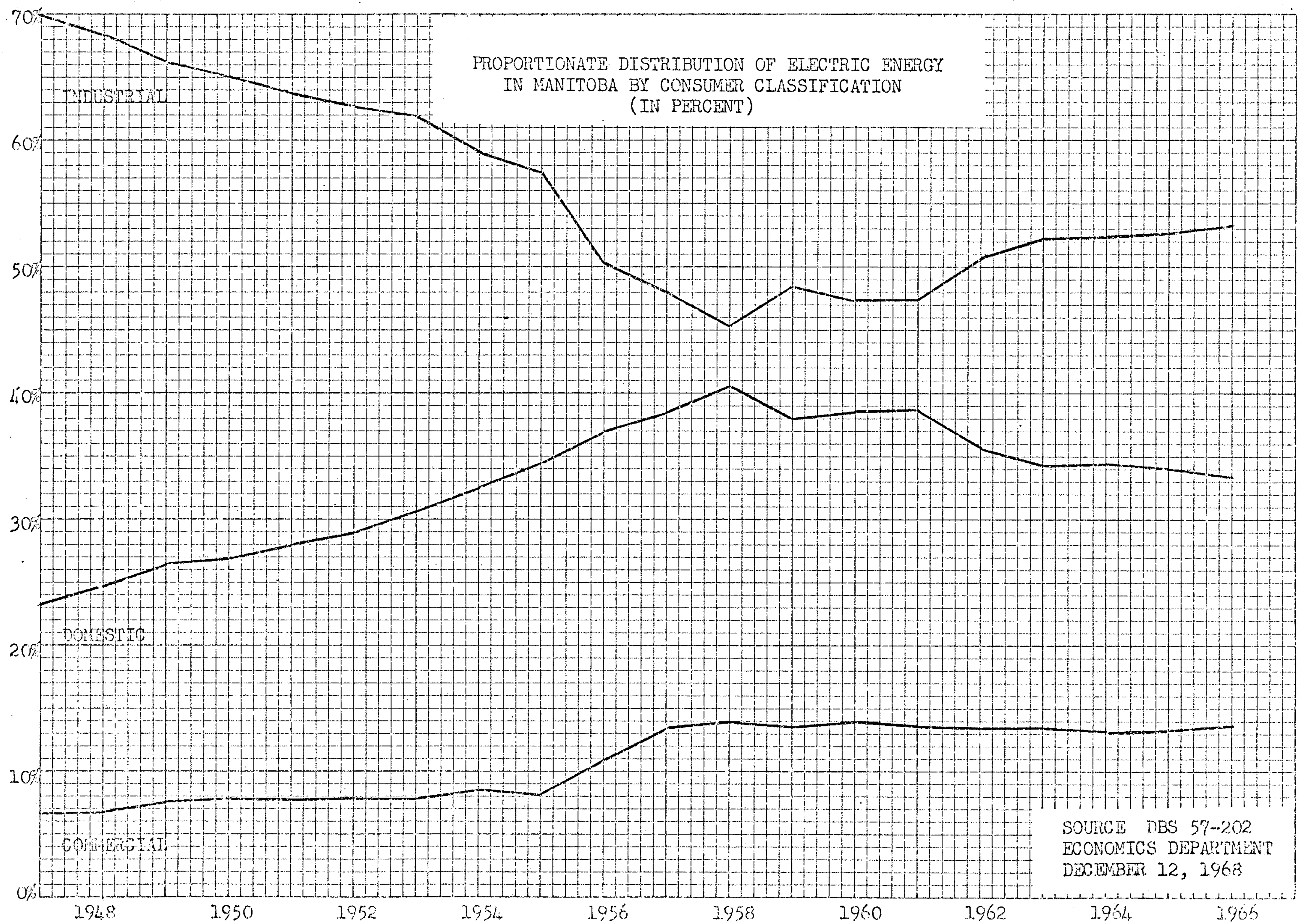

PROPORTIONATE DISTRIBUTION OF ELECTRIC ENERGY
IN MANITOBA BY CONSUMER CLASSIFICATION
(IN PERCENT)
INDUSTRIAL
DOMESTIC
COMMERCIAL
70%
60%
50%
40%
30%
20%
10%
0%
1948
1950
1952
1954
1956
1958
1960
1962
1964
1966
SOURCE DBS 57-202
ECONOMICS DEPARTMENT
DECEMBER 12, 1968

FIGURE 11.1

unit costs increased from about 6.0 mills per kilowatt hour to 10.5 mills. While the farm electrification program no doubt was the major factor for this rise, the shift from industrial to domestic sales by itself no doubt was a factor. Since 1958, the proportion of domestic and farm has declined from 40% to 33% of the total in 1966. This was partially caused by a significant increase in industrial sales, and an upward shift in the proportion of commercial sales from 8% of the total in 1956 to 13% in 1958. This may possibly have resulted from a change in definition of commercial energy by DBS. It is significant that the relative decline in domestic sales following 1958 has been accompanied by a decline in average unit costs from about 11.0 mills in 1961 to 10.4 mills in 1968.

It should be stressed that changes in the structure of the market which result in cost declines do not represent changes in efficiency per se, but merely represent the cost of providing a different service. However, recognition of these factors can lead to greater efficiency in the overall operation of the system. Incentive rates designed to encourage the highest possible use per customer, by using more off-season and off-peak power may improve the overall efficiency of the system in two ways, by improving utilization and by increasing the consumption per residential customer.

CONSUMPTION PER COMMERCIAL AND INDUSTRIAL CUSTOMER

The sixth most important determinant of unit costs in Inlo's study was consumption per commercial and industrial customer. This measure which was employed in the present study was also found to be an extremely significant determinant of unit costs in the case of Manitoba.

The most effective way of determining the effect of consumption per commercial and industrial customer was found to be that of comparing the figures for the ten provinces with those of Manitoba Hydro.

TABLE 11.6

AVERAGE CONSUMPTION AND AVERAGE REVENUE PER KILOWATT HOUR
FOR INDUSTRIAL AND COMMERCIAL CONSUMERS IN CANADA

	INDUSTRIAL		COMMERCIAL		TOTAL			
	Kwh/Consumer (x 1,000)	Average Revenue Per Kwh (cents)	Kwh/Consumer	Avge. Revenue Per Kwh (cents)	Kwh/Consumer	**	Avge. Revenue Per Kwh (cents)	**
CANADA	535	.69	23.5	1.74	93.0	4	.92	3
NEWFOUNDLAND	1,318	.75	11.4	3.04	101.0	3	.99	5
PRINCE EDWARD ISLAND	1,071	1.51	13.9	3.11	17.4	12	2.77	12
NOVA SCOTIA	240	1.13	20.3	2.54	34.0	11	1.92	11
NEW BRUNSWICK	472	.95	20.3	2.55	74.7	5	1.33	8
QUEBEC	798	.55	17.3	1.86	121.6	2	.71	1
ONTARIO	731	.69	35.6	1.32	130.0	1	.83	2
MANITOBA	161	.83	18.8	1.50	52.6	8	1.01	6
MANITOBA HYDRO	241	.78	14.6	1.70	71.2	6	.93	4
SASKATCHEWAN	121	1.50	9.5	2.58	37.1	10	1.71	10
ALBERTA	165	1.13	17.5	2.35	44.5	9	1.52	9
BRITISH COLUMBIA	148	.67	25.3	2.00	61.3	7	1.20	7

** Totals ranked from high to low for Consumption per Consumer, and low to high for Revenue per Kilowatt Hour.

Source: Electric Power Statistics
DBS Cat. No. 57-202

In Iulo's study, the aggregated commercial and industrial consumption was employed because his source The Federal Power Commission does not publish a breakdown of these figures into the two individual categories. In the present study, the same aggregated figures were employed because variations in the definition of commercial and industrial consumers from utility to utility rendered the individual classes unreliable for comparison purposes. Table 11.6 shows the average consumption per consumer and average revenue per kilowatt hour for industrial and commercial consumers and for the combined class. The combined class was ranked from one to twelve for consumption per consumer, with the highest consumption per consumer Ontario being ranked one. Revenue per kilowatt hour was ranked with the lowest revenue per kilowatt hour being ranked one. Thus it can be seen that Ontario with the highest average consumption per customer has the second highest revenue per kilowatt hour. Five of the rankings matched up perfectly while four deviated by one, two deviated by two, and only one deviated by as much as three. Manitoba with the eighth highest consumption per customer has the sixth highest return per kilowatt hour, while Manitoba Hydro with the sixth highest consumption per kilowatt hour has the fourth highest return per kilowatt hour. This suggests that the cost of industrial and commercial energy in Manitoba is relatively less than consumption per customer might warrant.

Excluding Canada and Manitoba Hydro, the average number of kilowatt hours per customer and average return per kilowatt hour were computed for the five lowest consumption provinces and for the five highest consumption provinces. Table 11.7 presents the results.

TABLE 11.7

THE RELATIONSHIP BETWEEN CONSUMPTION PER INDUSTRIAL AND COMMERCIAL CUSTOMER AND THE COST PER KILOWATT HOUR

AVERAGE OF THE FIVE LOWEST CONSUMPTION PROVINCES

Consumption per Customer	Average Return Per Kilowatt Hour
37,000 kwh	1.78 cents

AVERAGE OF THE FIVE HIGHEST CONSUMPTION PROVINCES

Consumption per Customer	Average Return Per Kilowatt Hour
98,000	1.01 cents
Manitoba	
52,600	1.01 cents

Two conclusions can be drawn from this analysis: first, it appears that by increasing consumption per industrial and commercial consumer from about 37,000 to about 98,000 kilowatt hours, the cost per kilowatt hour can be reduced significantly by almost 40%, and secondly that Manitoba a province with relatively low consumption per industrial and commercial customer (52,600 kilowatt hours), never the less produces and distributes this energy at the average cost (1.01 cents per kilowatt hour) of the high consumption provinces. This suggests that Manitoba achieves significant economies in the generation of industrial energy as well as in its distribution.

CONSUMPTION PER DOMESTIC AND FARM CUSTOMER

An analysis similar to that of the previous section was carried out for domestic and farm customers. Tables 11.8 and 11.9 show the results, employing per capita consumption rather than consumption per customer.

TABLE 11.8

PER CAPITA CONSUMPTION AND AVERAGE RETURN PER KILOWATT HOUR FOR DOMESTIC AND FARM CONSUMERS IN CANADA: 1966

	Per Capita Consumption	Rank	Return/Kwh	Rank
Canada	1,605 kwhs		1.41 cents	
Nfld.	553	10	2.44	8
P.E.I.	571	9	3.49	10
N.S.	986	7	2.28	7
N.B.	852	8	2.74	9
Que.	1,546	4	1.23	2
Ont.	1,972	2	1.29	3
Man.	2,021	1	1.18	1
Sask.	1,241	5	2.27	6
Alta.	1,085	6	1.87	5
B.C.	1,762	3	1.45	4

TABLE 11.9

THE RELATIONSHIP BETWEEN PER CAPITA DOMESTIC AND FARM CONSUMPTION & COST PER KILOWATT HOUR

AVERAGE OF THE FIVE LOWEST PER CAPITA CONSUMPTION PROVINCES

Per Capita Consumption	Average Return Per Kilowatt Hour
810	2.65 cents

AVERAGE OF THE FIVE HIGHEST PER CAPITA CONSUMPTION PROVINCES

Per Capita Consumption	Average Return Per Kilowatt Hour
1,710	1.48 cents
Manitoba 2,021	1.18 cents

Table 11.8 indicates an extremely close relationship between per capita consumption and cost per kilowatt hour. Only two provinces showed a difference as great as two in the rankings of the two measures.

Thus it appears that by approximately doubling domestic and farm consumption per capita, unit costs are approximately halved from about 2.65 cents to about 1.48 cents in this case or by about 11.5 mills per kilowatt hour. These figures of course must be used with caution. From the information presented, it cannot be determined if low consumption per capita has resulted because of high costs, or if low costs as in Manitoba and the other high consumption provinces has resulted from the high utilization. There is strong reason to suspect that the latter is the case.

Another cautionary remark is related to the phenomena of diminishing returns. It is doubtful that unit costs in Manitoba could be significantly reduced by suddenly doubling per capita consumption again or for that matter could significantly be reduced no matter how high consumption per capita increased. This can easily be appreciated by observing industrial consumption and cost. It is desirable however to continually increase domestic and farm consumption in order to offset upward pressure on costs caused by inflation.

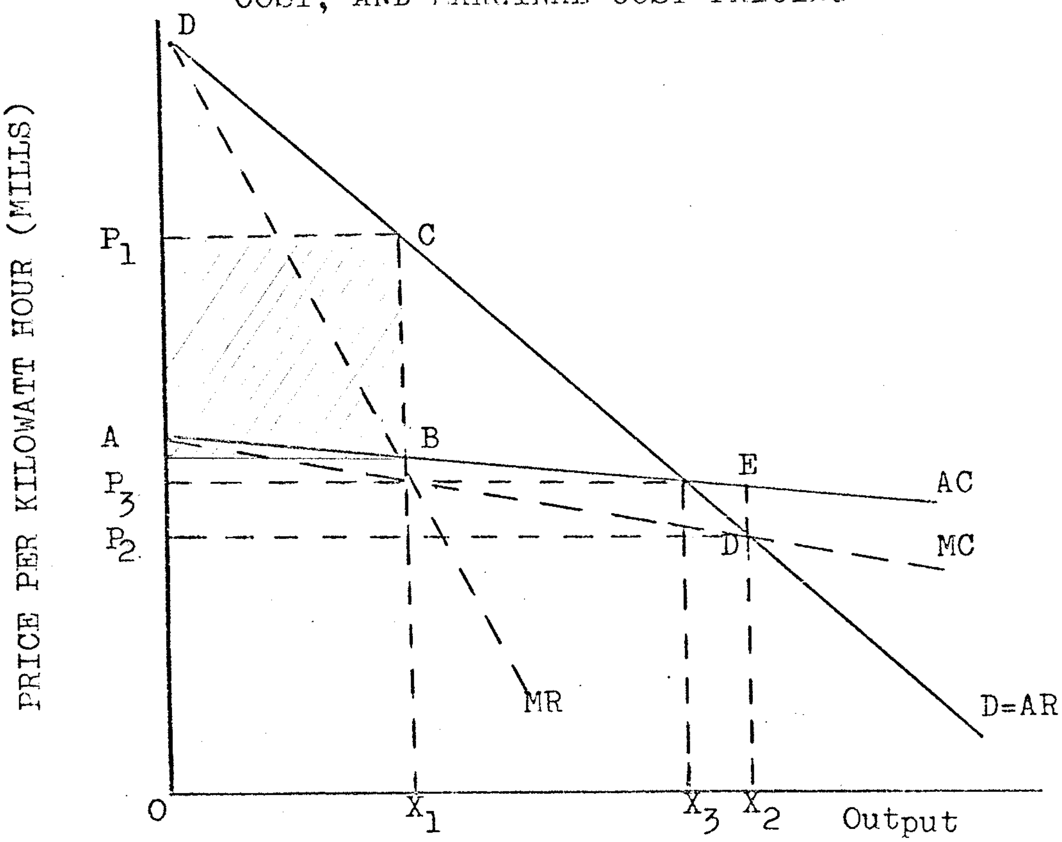
CHAPTER XII

THE ROLE OF THE RATE STRUCTURE IN ATTAINING GREATER ECONOMIC EFFICIENCY

It has long been recognized by economists that the social economic efficiency of an enterprise is closely related to the pricing policy of that enterprise. Under conditions of monopoly or other degrees of imperfect competition a business enterprise is faced by a downward sloping demand or average revenue curve which indicates the volume of sales it can expect at various price levels. The profit maximizing enterprise will restrict its' output to the volume dictated by the intersection of the marginal cost and marginal revenue curves and charge the price dictated by that level of output.

FIGURE 12.1

OUTPUT AND PRICE, UNDER MONOPOLY, AVERAGE COST, AND MARGINAL COST PRICING



In the diagram a profit maximizer sets output equal to OX_1, price equal to OP_1 and realizes a monopoly profit of $ABCP_1$.

On the contrary the enterprise, in this case a publicly owned utility, conerned with maximizing social welfare will set its price at long run marginal cost. In so doing output will have to be increased to OX_2 to satisfy demand at this low price. In the above illustration it was assumed that average costs will decline with the increased volume of sales per customer. Under this assumption marginal cost will be less than average cost and a slight loss will be incurred equivalent to DE times OX_2 units. This can be offset either by a small subsidy from the public purse or by resorting to average cost pricing.

Under average cost pricing, price would be raised to OP_3, output would decline to OX_3 and the public utility would be self-supporting with average cost equal to average revenue. Social efficiency would be slightly less than the optimun dictated by marginal cost pricing, but unless marginal cost deviate significantly from average cost, the loss of efficiency associated with average cost pricing would not be important. If the long run average cost is constant over an extended period of time, marginal cost will equal average cost, and either method will give the same results, but if long run average cost is increasing slightly over time, marginal cost will be greater than average cost and marginal cost pricing will result in a slight profit, and a smaller output than will the average cost solution.

HISTORICAL ESTABLISHMENT OF THE MANITOBA HYDRO RATE STRUCTURE

From the advent of the electric utility industry until 1911 pricing policy approximated the first case discussed above. Prior to 1911 the industry was characterized by private monopoly, high prices, and limited output. This resulted in a movement in Winnipeg for public ownership and operation of a hydro electric system in the hope that competition would effect a substantial reduction in rates. These expectations were fulfilled when the City Hydro commenced operation in 1911. During the utilities' first year of operation, rates for commercial and domestic service were established in which the basic charge of 3 1/3¢ per kilowatt hour was adopted. A 10% prompt payment discount made the effective rate 3¢. A 1¢ per kwh rate was established for cooking and domestic heating. These rates which the Winnipeg Electric Company quickly met formed the basis for electric utility rates in Manitoba until 1968, a period of almost fifty years. Table 12.1 shows the movement of electric utility rates in Winnipeg from 1906 to 1912.

TABLE 12.1

Winnipeg Electricity Rates 1906 - 1912

1906 -	20 cents per kwh
1907 -	10 cents per kwh
1911 -	$7\frac{1}{2}$ cents per kwh
1912 -	3 1/3 cents per kwh [1]

During the period 1911 - 1968 new rates were devised for new types of services as they became available, and a number of special rates particularly in the industrial area came into being. The special rates largely took the form of wholesale discounts.

As the Manitoba Power Commission extended service into rural areas new rates were devised to reflect the extra cost of rural distribution. These rates were based on Winnipeg rates, but reflected additional transmission costs associated with the greater distance from the Winnipeg River.

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1. H. C. Goldenberg: Royal Commission on the Municipal Finances And Adminstration of the City of Winnipeg, Hydro Electric System Sections, 1939

As a result, rates in Portage la Prairie were higher than Winnipeg, Brandon higher still, and Dauphin rates were even greater. The extension of service to farms required higher rates still, however the cost of power in Winnipeg was always retained as a basis in determining these rates.

During the rural expansion program the Manitoba Power Commission displaced a number of local utilities serving individual towns. In these cases the policy was to either retain existing rates, or institute Power Commission rates depending upon which was lower. In this fashion a number of anomalies became part of the rate structure of the system.

During the period following 1911 the original 3 1/3¢ per kwh flat rate evolved into a block type rate with a one cent run-off. The discount of 10% was retained as an incentive for prompt payment. This one cent run-off rate and 10% discount also prevailed in rural rates, farm rates and some industrial rates. Other industrial rates were characterized by an 8 mill run-off rate plus a series of discounts which increased with the size of the bill. The commercial run-off rate was 1 1/3¢ less 10% in Metropolitan Winnipeg and 2¢ less 10% outside of Winnipeg.

The rate adjustment which became necessary in 1968 was the result of two basic situations. The first was the unprecedented rise in long term interest rates, which has significantly raised the cost of producing electricity during the 1960's, and the second is the declining average return per kilowatt hour caused by selling a larger and larger proportion of total energy at the respective run-off rates of each consumer class. The combined effect of these two factors has caused average revenue per kilowatt hour to decline at a faster rate than average cost per kilowatt hour (which has also declined slightly) to bring about a short fall in total revenue.

Given the lower interest rates of the 1950's, there is little doubt that the old rate structure would have been adequate for many more years.

The rate revision not only enabled Manitoba Hydro to increase some rates in order to offset the short fall in revenue, but enabled a general streamlining and rationalization of a rate structure which had many inconsistancies and anomalies, some dating back nearly fifty years. A number of rates were eliminated entirely, and a uniform industrial rate was adopted for the entire area of the province served by network power. Table 12.2 presents a few representative rates under both the old and new rate structures.

TABLE 12.2

Old Rates

Suburban Residential	First 60 kwhs per month at 3 1/3 cents.		
	Balance of Monthly consumption at 1 cent.		
	Monthly minimum	.50 cents	
	Discount	10%	
Farm 10 h.p.	First 75 kwhs per month		@ 8 cents
	Next 100 kwhs per month		@ 2 cents
	Balance of monthly consumption		@ 1 cent
	Monthly minimum	$ 5.40	
	Discount	10%	
Commercial	Suburban Winnipeg		
	First 450 kwhs per month		@ 3 1/3 cents
	Next 14,550 kwhs per month		@ 2 cents
	Balance		@ 1 1/3 cents
	Minimum $1.00 net per meter		
	Discount	10%	
	Southern Rural Manitoba		
	First 100 kwhs used per month		@ 6 cents
	Next 200 kwhs used per month		@ 3 cents
	Balance		@ 2 cents
	Minimum $1.00 net per month		
	Discount	10%	
Industrial 1 or 3 h.p. all purposes	Metropolitan Winnipeg		
	First 50 kwh per kva of connected load per month		@ 3 1/3 cents
	Next 50 kwh per kva of connected load per month		@ 2 1/2 cents
	Next 50 kwh per kva of connected load per month		@ 1.9 cents
	Next 50 kwh per kva of connected load per month		@ 1.4 cents
	Next 50 kwh per kva of connected load per month		@ 1.1 cents
	Balance of monthly consumption		@ .8 cents

Wholesale discounts apply on gross bills exceeding $1 00 per month.

$100 - $ 200 gross	10%
200 - 300 gross	20%
300 - 400 gross	30%
400 - 500 gross	40%
500 - 1,000 gross	50%
Over - 1,000 gross	60%

Discount:	1 year contract	10%
	2 year contract	15%
	3 year contract	20%

Minimum: $0.75/h.p. of connected load
Minimum $1.00 net per meter.

New Rates

Residential Suburban Winnipeg

Standard

First 75 kwhs per month @ 4 cents
Next 100 kwhs @ 2 cents
Balance of monthly consumption @ 1 cent
Monthly minimum $1.50
Discount 10%

Farm
10 h.p.

First 100 kwhs per month @ 8 cents
Next 100 kwhs @ 2 cents
Balance of monthly consumption @ 1 cent
Monthly minimum $5.40
Discount 10%

Commercial Suburban Winnipeg and Southern Rural Areas

First 150 kwhs per month @ 5 cents
Next 200 kwhs @ 3 cents
Next 15,000 kwhs @ 2 cents
Balance of monthly consumption @ 1.5 cents
Monthly minimum $3.00 plus $1.20 per
kva of inductive load connected
Discount 10%

Industrial All Southern Manitoba

First 40 kilowatt hours per kva of connected load or metered demand per month @ 4¢
Next 80 kilowatt hours per kva of connected load or metered demand per month @ 2¢
Next 80 kilowatt hours per kva of connected load or metered demand per month @ 1¢
Balance of monthly consumption @ .8¢

Wholesale discount

First \$200.00 of monthly gross bill	Nil
Next \$100.00 of monthly gross bill	10%
Next \$100.00 of monthly gross bill	20%
Next \$100.00 of monthly gross bill	30%
Excess of \$500.00 monthly gross bill	40%

Prompt Payment Discount - 10% after wholesale discount

Monthly Minimum Charges - \$1.20 per kva of connected load
but in no event less than 5 kva - \$6.00

Or

\$1.20 per kva of established demand which in no case shall be less than 25% of the highest established demand in the previous twelve months or 100 kva.

<u>Shortcommings</u> - <u>of the present rate philosophy and structure</u>

In reviewing the philosophy which has prevailed in Manitoba with respect to rate policies and structures it must be emphasized that the rates which were instituted in 1911 and remained largely unchanged from that time suited the requirements of the system admirably well. The 3 1/3 cent rate adopted in 1911 was uncommonly low for that time, but subsequent events have tended to confirm the essential correctness of this rate for the Manitoba electrical environment. This particular rate seems to have been remarkably successful in balancing the value of the service to the consumer against the long term revenue requirements of the Manitoba System.

It seems reasonable to conclude that the rate structure has been primarily responsible for attaining the highest domestic and farm consumption in Canada at the lowest cost per kilowatt hour in Canada. In other words the low price was responsible for the high volume which in turn enabled a surplus to be earned at the low price because of the effect of volume on costs. It would appear that the price set must have been reasonably close to that which would be dictated by the intersection of the long run marginal cost and marginal revenue curves.

In retrospect it can be seen that even the 3 1/3 cent rate while reasonable in 1911 was marginally high during most of the subsequent period. The original rate was based on estimated costs of construction for Pointe du Bois, an estimate that later proved conservative. As average costs declined as further development of the Winnipeg River occurred there was a tendency for considerable surpluses to be generated. Rather than reduce rates further to conform to actual costs the City of Winnipeg transferred these surpluses to general revenue thus permitting the Winnipeg Electric Company to earn substantial profits. Had rates been adjusted downward to reflect actual costs the usage per consumer might have been even higher than the actual usage that occurred.

The fact that unit revenue followed unit costs reasonably closely particularly in the years from 1922 to 1936 and again from the commencement of the rural electrification program in 1946 to the present time suggests that while the rates may have been slightly high, the distribution of costs among the various classes being served must have been reasonably accurate. (Figure 4.1) It can be seen that with the addition of the large number of farm consumers after 1946 both unit costs and unit revenues increased at approximately the same rate.

The most serious shortcoming of the rate structure inherited by Manitoba Hydro stems largely from its very success. The basic rate structure in effect since 1911 developed a certain rigidity which manifested itself in a reluctance to adjust rates frequently to reflect changes in the markets served by the utilities involved. Rate adjustments which did occur appear to have been prompted more by commercial and promotional reasons than economic ones. Most of these adjustments occurred in the industrial area, and took the form of a somewhat arbitrary discounting system that could not be justified on pure economic grounds.

The more or less rigid rate structure which has been in force since 1911, is contrary to the belief expressed by many rate engineers and utility economists that a rate structure should be flexible and constantly adapted to the ever changing environment in which the utility operates. The market served by electric utilities in 1968 does not even remotely resemble the market of 1911, and it is highly unlikely that a rate structure if perfectly suited to the market of 1911 would be suitable in 1968 or many of the intervening years.

For example with the block rate structure, the initial blocks are designed to reflect the capacity costs while the final block (the run off rate) usually reflects the energy costs. If a given rate remains unchanged for many years it implies that additional customer demands take the form of additional energy only, that the capacity demand remains the same, and that the individual customer's load factor is constantly increasing. Common sense and observation suggests that this is clearly not the case.

Another problem associated with the present rate structure; a problem common to most electric utilities, is the tendency to receive a declining return per kilowatt hour sold because all additional energy sold to established customers is sold at the run off rate.

This presented no problem when the one cent run off rate characteristic of the majority of Manitoba Hydro's domestic, farm and commercial rates was greater than the average unit cost of electricity. (prior to about 1957). However with the block rate structure, a larger proportion of total sales each year is sold at the run off rate, causing the average return per kilowatt hour sold (excluding industrial) to approach a limit of less than 10 mills per kilowatt hour.

With the long run average cost expected to hover between 10 and 11 mills per kilowatt hour for the forseeable future, this suggests that average revenue will have a tendency to decline below average cost unless the discount is removed, the one cent run off rate is raised slightly or some means can be found to shift the average cost curve slightly downward.

In summarizing, it might be said that the present Manitoba Hydro rate philosophy and rate structure has a number of shortcomings which although not of a fundamental nature, do inhibit the full utilization of the rate structure as an instrument to help maximize economic efficiency.

The Ideal Rate Structure

Theoretically the ideal rate structure would assign to each and every customer, charges that were precisely equivalent to the cost of providing him with service. The advantages of such an achievement would be to improve economic efficiency in the use of electricity, and would ensure perfect equity in the distribution of costs. Because of the practical impossibility of achieving such a perfect allocation of costs the theoretical implications will be discussed no further here.

In practice it has been found that for all practical purposes that it is impossible not only to determine the exact costs of serving a particular customer, but also impossible to determine the exact costs of serving a particular class of customer, or members of that class in a particular geographical area. Although numerous attempts have been made to construct a truly scientific rate system it is generally recognized that there is no such thing as absolute truth in utility rate making. Because of this, public utility rate making as with most aspects of economics remains more of an art than a science, and a certain amount of intuition and pragmatism must enter into successful rate design. This philosophy is reflected in the work of most economists in the utilities field. James Bonbright suggests, "The art of rate making is an art of wise compromise."[2] Eli Clemens goes a step further and suggests that, "In many instances rate making is nothing more than a system of bit by bit pragmatic adjustment."[3] The present author feels that a combination of analysis, bit by bit pragmatic adjustment, and trial and error appear to be the best approach to achieving the most effective rate structure.

In the paragraphs which follow no attempt will be made to undertake an exhaustive examination of the problem of rate making. The primary purpose is to discuss some aspects of public utility rates which the author feels are related to the problem of improving the economic efficiency of an electric utility

In general the basic objectives of electric rates are:

1. To provide adequate revenues.
2. To distribute the total costs of the utility as equitably as possible among the various classes of customer.
3. To encourage maximum use of electric service in such a manner as to increase the overall efficiency of the utility.

Virtually all-electric utilities in North America use some form of block rate structure particularly for domestic, farm, and commercial customers. Under this block rate the customer pays a certain price per kilowatt hour for his first block of energy and pays progressively lower rates for successive blocks. The block rate promotes greater use because the customer secures the added use at successively lower rates. This rate structure is felt to be consistent with the declining cost principle generally operative in the electric utility industry.

For industrial rates a two part block type rate reflecting both demand (in kilowatts) and energy are in general use. A minimum charge is often

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[2] James C. Bonbright - Principles of Public Utility Rates, New York, Columbia University Press, 1961, p. 38

[3] E. W. Clemens - Economics and Public Utilities, New York, Appleton, Century-Crofts inc., 1950, p. 261

specified which will vary with the class of customer.

The following discussion of rates will be a general one and will apply to both types of rates and all classes of customer unless specific mention is made of a particular class or rate.

In theory the blocks are so designed that customer costs will be covered by the minimum charge, demand and energy costs will be covered by the first two blocks, while the last or incremental block (the run off rate) is largely a marginal cost rate that covers little more than the additional energy costs. In practice the run off rate usually covers some capacity costs as well.

In introducing his approach to electric utility rate making C. W. Bary sumarizes the essential factors involved in the following terms. He says, "There are many considerations which underlie the formation of the rate function of such operational economics; but not withstanding anything to the contrary, the major ones are: the cost (used in its broadest sense) to the utility enterprise of rendering service, and the load characteristics of the service supplied."[4]

This basic idea is reflected in most works on electric utility rate making, although the analytic approaches employed, and the basic principles and approaches employed by different authors are widely disparate.

Bary mentions that there are two basic types of electric rates in use in the United States (presumably this applies also to Canada) for general classes of service; one employs energy use as the sole parameter for pricing of the service rendered; the other employs energy use and maximum demands as dual parameters of the service rendered.[5]

He adds that "Rates which employ the energy as the controlling

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4 Constantine W. Bary: Operational Economics of Public Utilities, New York, Columbia University Press, 1963, p. 3

5 Ibid., p. 104

characteristic in effect reflect the averaging of the operational economics of service supply to individual customers of a class along energy intervals over a wide range of customers' uses. Rates which employ load factors as the controlling characteristic in effect reflect such averaging by demands along load factor intervals over the complete range of customers' requirements."

"Since the parametric component of cost-to-serve related to the "Class Peak" or Diversified Demand," is by far the largest item in the cost-to-serve relationships, it should be noted that energy type rates basically reflect the operational economics of a fixed load factor, that is they can be made to satisfy the cost-to-serve for a given diversified load factor, but they will become inadequate for lower load factors, and more than adequate for higher ones."[6]

Bary's explanation suggests a converse that an energy type rate structure that is adequate for a utility with a given system load factor will become inadequate if that system suffers a decline in load factor, and will be more than adequate if the system experiences an increase in its load factor.

Bary claims that the production system is the most significant functional element of a modern electrical utility and represents over one-half of the overall total cost-to-serve.[7] With Manitoba Hydro it was determined that total production costs represented slightly over 40% of total costs. (Chapter IV). However, if one includes the cost of transmission from remote hydro sites this figure climbs to over 50%.

Bary further suggests that with a hydro station only about 5% of the total of its fixed and operating charges can be classified as energy charges, while the remainder falls into the category of constant and capacity charges.[8]

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[6] Ibid., p. 105

[7] Ibid., p. 20

[8] Ibid., p. 24

According to Bary, experience has shown that for a modern electric utility system the simple combination into one total of all individual elements of the entire load for averaging does not provide the necessary means to predict reliably the physical or economic impacts on the system of the behaviour of loads over a wide range of service requirements.

On the other hand he also feels that a highly refined Subdivision of the load structure for averaging, unrelated to the operational economics of electric service supply is also undesirable.[9]

Accordingly he suggests that for cost and rate analysis the electric system should be broken up into half a dozen or so large blocks or classes having fairly homogeneus load characteristics. With Manitoba Hydro the following basic classes are utilized: Residential, farm, commercial, and industrial. These classes are further subdivided to reflect geographical and urban, rural variations in distribution costs.

Bary bases his analysis on class peaks and measures of customers' diversified maximum demand, claiming that adequate knowledge of these factors must be had before any reliable information can be obtained on the cost to serve.[10] The present writer feels that essentially the same objective can be attained by taking the average of the coincident load factor of the class and using this figure to calculate cost-to-serve relationships. It is felt that this figure can be determined directly using strip demand recorders on a small sample of the customers in a class during the peak months of each power year.

On the question of actual rates Bary states, "Rates also should provide as much as possible self-acting economic inducements to consumers for the use of service at improved characteristics upon the utility's supply system, and should create desirable psychological attitudes as to their durability and

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9 Ibid., p. 43
10 Ibid., p. 88

stability."[11]

Although Bary's rate making philosophy and his intuitive understanding and explanation of the basic factors contributing to cost seems quite reasonable, his actual rate structure based as it is on class peaks and measures of customers diversified maximum demand is extremely complex and requires much more detailed information than would appear readily available to most utilities. For this reason and because of its complexity Bary's approach does not seem practical.

R. K. Davidson in his book "Price Discrimination In Selling Gas and Electricity"[12] attempts a new approach to utility rate making which appears a significant advance over traditional rate making theory. In addition to his contribution to rate determination, an approach which is closely related to marginal cost pricing techniques, Davidson provides a first class discussion of public utility economics which appears a vast improvement over much of the traditional work in this field.

Vitally important for rate evaluation Davidson stresses is the conclusion that the costs of service are not constant over the day or year, but vary widely between peak and off-peak hours. The costs of energy consumed during peak hours include both capacity and energy costs, while there are no capacity costs of output consumed during off-peak hours.[13] He suggests that in view of this fact, that the block rate structure so widely employed in North America is a poor instrument with which to reflect differences in capacity costs.[14]

Davidson quite correctly states that, "The block rate itself does not take account of the variation of costs between peak and off-peak hours.

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11 Ibid., p. 104

12 R. K. Davidson: Price Discrimination In Selling Gas and Electricity, Baltimore, Johns Hopkins Press, 1955

13 Ibid., p. 76

14 Ibid., p. 81

Attempts have been made to justify the block rate as a type of rate that is based on costs, but they rest on a fallacious cost analysis that regards capacity cost as fixed and spreads the capacity costs over the total output in kilowatt hours, thus showing decreasing average unit costs with increasing output."[15] Davidson feels that the cost analysis underlying the acceptance of the block rate as based on costs is seriously incorrect. He stresses that capacity costs of a utilities total output are a function of maximum demand, and not of total consumption in kilowatt hours per month. Further he states, "The capacity costs attributable to any individual customer are a function of the customer's maximum rate of consumption during the system's peak, not necessarily of his maximum rate of consumption during the year."[16]

What is of importance he feels is the customer's rate of consumption at the time of the system peak load. It is the customer's contribution to the system peak load which adds to the capacity costs. Accordingly he stresses that the price should be higher in peak periods than in off-peak periods, for it really costs more to provide the service in peak hours than in off-peak hours.[17]

Davidson points out that according to the proponents of promotional pricing, the last block should cover only energy costs; but the use of the energy which is purchased at the low rate is not limited to off-peak hours. It is just as probable that some of the increased consumption will take place during system peak hours, thus increasing the maximum rate of demand on the system and necessitating an increase in capacity.[18] However the increased capacity costs brought about by the increase in the maximum amount of demand

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[15] Ibid., p. 81
[16] Ibid., p. 82
[17] Ibid., p. 86, 87
[18] Ibid., p. 94, 95

on the system will not be covered by the rate charged in the low block and a loss will be made on these sales. The loss can only be covered by changing more than cost in the early blocks.[19]

The net result of all this, is that the utility charges less than cost during peak hours and more than cost during off-peak hours. Some of the increased consumption induced by the promotional rate is consumption of electricity that is sold at less than long run marginal cost. Davidson concludes that if the full cost were to be charged, less electricity would be demanded during peak hours, which of course means less investment would be required for capacity. Therefore the practice of using promotional rates results in over investment in the utility, over investment in the sense that some of the investment would not be required if the output from the increased investment were offered at a price that fully covered the costs of investment. He feels that this same conclusion holds for all rate forms under which some of the output may be sold at less than long run incremental or marginal cost.[20]

Pursuing this line of reasoning further Davidson suggests that the utility load curve, the ratio of peak to off peak electricity is partially a function of the rate structure, and that it can be altered by a suitable change of rates.[21]

Davidson's approach represents a fundamental departure from the conventional wisdom supported by most traditional public utility economists. The following passage from Eli Clemens work is typical of the traditional explanation.

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[19] Davidson suggests that one utility increases the size of the second and third blocks of a four block residential schedule if a customer uses electricity for space heating or air conditioning and the connected load is in excess of 7.5 kilowatts. In Manitoba, with the large winter peak, such a provision if adopted, need only apply to space heating.

[20] Ibid., p. 95

[21] Ibid., p. 100

Clemens states that, "The belief that low rates or a reduction of rates will increase consumption and revenues is based on the assumption that demand is so elastic that total revenues and profits will be increased." He adds, "that regardless of how precisely we can draw a demand curve in a text-book, the fact remains that one and only one point is known with certainty, the point representing existing price and demand. However he continues, "experience has shown that consumption is not static, that it increases faster at low rates than at high. A decrease in rates might bring such an increase in consumption that the decline in unit costs would again bring costs and rates into equilibrium."[22]

This statement illustrates the fundamental difference between the traditional approach to public utility economics and that of Davidson. The traditionalists generally argue that a low run off rate, or promotional rate will increase consumption, reduce unit costs and increase profits. Davidson argues that there is a tendency for these promotional rates to be set at less than long run marginal cost, thus increasing total costs more than total revenue, and ultimately leading to rate increases (usually in the initial blocks) in order to ensure an adequate rate of return.

Davidson's approach is based essentially on long run marginal costs. In explaining this approach he claims that the problems associated with the allocation of fixed, common, and joint costs do not prevent a determinate and unambiguous idea of incremental or marginal cost.[23] Thus the object of an

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[22] E. W. Clemens: op. cit., p. 666

[23] R. K. Davidson: op. cit., p. 101

economic allocation of capacity cost is to allocate to each unit of output the long run marginal or incremental cost of producing that unit of output. The long run marginal cost of electricity at any particular time of year depends on the shape of the annual load curve.[24]

In order to explain his approach Davidson initially assumes that the expected daily load curve of a utility is known, and is exactly the same every day of the year. He divides the day into peak and off-peak hours, and calculates the marginal cost per kilowatt hour in both periods. The marginal cost of peak hours bear the marginal cost of energy only. Davidson's method is thus a peak responsibility method of allocating costs.[25]

Davidson admits that a variation of the peak responsibility method of allocating capacity costs was widely used in the early days of electric utilities, but was later rejected in favor of other methods. The principal reasons given for this rejection were: (1) that the stability of the cost allocation was poor, (2) that the annual peak shifted from one hour to another from year to year, (3) that off peak sales expanded and created a new peak or equalled the old peak, and (4) that not all the customers consuming energy at the time of the system peak contributed to the peak.[26] This fourth reason is an obvious fallacy and will not be discussed further here.

Caywood offers a similar but slightly different criticism. He suggests that, "With the peak responsibility method, system capacity costs are divided among classes in proportion to class loads at the time of the system peak. Critics feel that this method is not entirely satisfactory because a class load at the time of the system peak might be zero while at some time it

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[24] R. K. Davidson: <u>op. cit.</u>, p. 112

[25] R. K. Davidson: <u>op. cit.</u>, pp. 112 - 118

[26] R. K. Davidson: <u>op. cit.</u>, p. 119

might be of considerable size; yet no expense would be allocated to it. Further more, an allocation made on the basis of today's load conditions might be widely different in the future as a result of a shift in the system peak or a shift in the peak of the load of the class itself.[27]

Davidson accepts the argument that an economic allocation of capacity cost based on peak responsibility is unstable is correct, if unstable is taken to mean an allocation that changes from year to year as the load curve changes. He adds however, that this is not a good reason for rejecting it. He stresses that capacity costs are a function of the load curve, and if the load curve changes, the change should be reflected in a changed allocation of capital costs.[28]

In response to the third criticism Davidson suggests that if the rate of consumption in some off peak hour becomes equal to and threatens to become greater than the rate of consumption during peak hours, when this hither-to off peak consumption is charged for at a price which does not include any capacity cost, the correct economic solution is to increase gradually the rate for electrical energy applicable to that hour, in order to restrict the rate of consumption to that which can be supplied from existing capacity. At the same time the rate for peak energy should be reduced gradually.[29]

The process of increasing the allocation of capacity cost to the former off peak hour and reducing the allocation of capacity cost to peak hours continues until the allocation of capacity cost to output in both periods is equal per unit of output, and the rate of consumption in both periods is kept equal.

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27 R. E. Caywood: Electric Utility Rate Economics, New York, McGraw Hill Book Company Inc., 1956, p. 156

28 R. K. Davidson: op. cit., p. 119

29 R. K. Davidson: op. cit., p. 121

Thus Davidson implies that significant peaks and valleys during a daily period or on an annual basis are the result of charging too little for service at peak hours, and too much for service during off peak hours or periods.

Davidson believes that a time of day rate schedule appears to be the type of schedule that fits this cost variation, utilizing a combination watt hour meter and time switch such as those used at present here special off peak rates are given for water heating. Energy used during peak hours would register on one set of dials, while off peak consumption would be recorded on another set of dials.[30]

Davidson employs a privately owned electric utility in Baltimore as an example. He defines a peak period of 735 hours out of a possible 8760 hours. He estimates the annual cost of the cental stations and transmission at $24 per kilowatt. This capacity allocated to the peak hours would amount to 3.3 cents per kilowatt hour. He takes .5 cents per kilowatt hour as roughly equal to the off peak marginal production costs. Thus the rates he would charge are 3.8 cents per kilowatt hour during 735 peak hours and .5 cents during the remaining 8,025 hours, a ratio of more than seven to one. He recommends an annual adjustment of rates whenever required.[31]

Under Davidson's rate schedule the monthly bill would be made up of the following components:

1. Customer charge
2. X kilowatt hours @ 3.8 cents (peak rate)
3. Y kilowatt hours @ .5 cents (off peak rate)

It is felt that the essence of the argument presented by Davidson does have applicability in the case of Manitoba Hydro. Manitoba has a

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30 R. K. Davidson: op. cit., p. 182

31 R. K. Davidson: op. cit., p. 194

pronounced load curve variation on both a daily and a seasonal basis. In 1967/68 the daily load curve of the integrated Manitoba System, on the peak day in January varied about 320 MW from 840 MW in the early morning hours to 1162.4 MW at the system peak. This daily variation in load of about 320 MW was fairly consistent throughout the year.

On a seasonal basis the daily peak varied from a low of about 760 MW in the summer months to 1162 on the peak day in the winter. Thus it can be seen that there is a seasonal variation of daily peaks of about 400 MW on the Integrated Manitoba System. On an annual basis the load at any one time varied from a minimum of about 450 MW during the early morning hours in the summer to 1162 MW at the time of the system annual peak. The total variation in annual capacity required is about 700 MW. From this brief description it can be seen that there are two ways in which the Manitoba System load curve can be improved: (1) on a seasonal basis by smoothing out the variation between summer and winter peaks, and (2) on a daily basis by increasing the amount of energy sold during off peak hours. Although approximately the same principles, a modified form of Davidson's approach could apply to either it appears that each problem could be tackled independently.

Because of the extreme variation between summer and winter peaks it does not seem to make much sense to employ Davidson's rate design criteria at the present time. All hours with the exception of a few peak hours in December, January, and February are off peak hours. For this reason seasonal variations in rates may be required as well as daily variations in rates to improve the load characteristics of the Manitoba System. It is felt that experience might be gained by introducing differential run off rates on a seasonal basis before tackling the more complex problem of differential pricing on a daily basis.

DIFFERENTIAL PRICING ON A SEASONAL BASIS

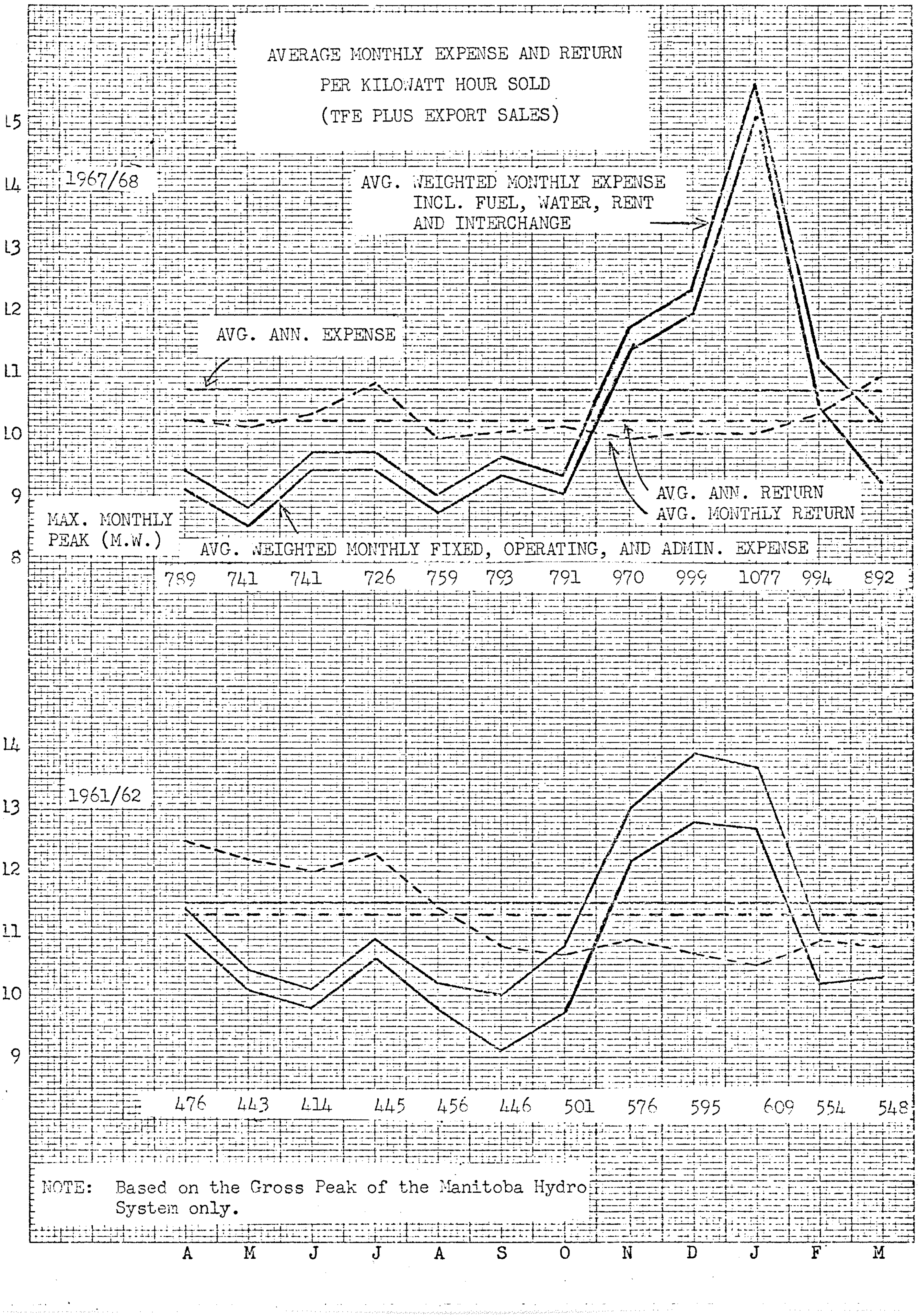
Figure 12.2 represents an attempt to determine the average expense and return per kilowatt hour in each month of the year for the Manitoba Hydro System alone. The chart was prepared by distributing annual fixed expenses by months using the maximum peak in each month to determine the fixed expenses attributable to each month. In 1967/68, 78 MW of capacity were used exclusively in January. Thus fixed expenses equivalent to 78 MW were charged exclusively against January. Actual variable expenses (fuel, water rentals, and interchange expenses) for each month were superimposed upon the fixed expenses derived for each month. This proceedure was carried out for both 1961/62 and 1967/68 in order to determine what changes have taken place over the seven year period of this study.

Studies have indicated that the monthly system peaks and energy sales in the coldest month of the year (usually January) are growing relatively more rapidly than the monthly summer peaks and energy sales. This appears to be confirmed by the 1961/62 - 1967/68 comparison of Figure 12.2. Because of this situation a larger proportion of Manitoba Hydro's generating capacity is used only in the peak month and is redundant the remaining eleven months of the year. In distributing the fixed expenses of the utility to reflect the usage of generating capacity, we find the average expense per kilowatt hour sold in the peak month has risen from 13.9 mills in 1961/62 to 15.7 mills in 1967/68.

During this six year period, the average monthly expense per kilowatt hour dropped somewhat in most other months as did the average annual expense (from 11.5 to 10.8 mills per kilowatt hour).

This experience appears to confirm Davidson's theory that most utilities charge too little during peak periods, and too much during off peak periods thus tending to make the system peak grow more rapidly than it might

FIGURE 12.2



AVERAGE MONTHLY EXPENSE AND RETURN
PER KILOWATT HOUR SOLD
(TFE PLUS EXPORT SALES)
1967/68
AVG. WEIGHTED MONTHLY EXPENSE INCL. FUEL, WATER, RENT AND INTERCHANGE
AVG. ANN. EXPENSE
AVG. ANN. RETURN
AVG. MONTHLY RETURN
MAX. MONTHLY PEAK (M.W.)
AVG. WEIGHTED MONTHLY FIXED, OPERATING, AND ADMIN. EXPENSE
789 741 741 726 759 793 791 970 999 1077 994 892
15 14 13 12 11 10 9 8
1961/62
14 13 12 11 10 9
476 443 414 445 456 446 501 576 595 609 554 548
NOTE: Based on the Gross Peak of the Manitoba Hydro System only.
A M J J A S O N D J F M

under a more rational rate structure.

FIGURE 12.3

AVERAGE WINTER AND SUMMER UNIT COSTS

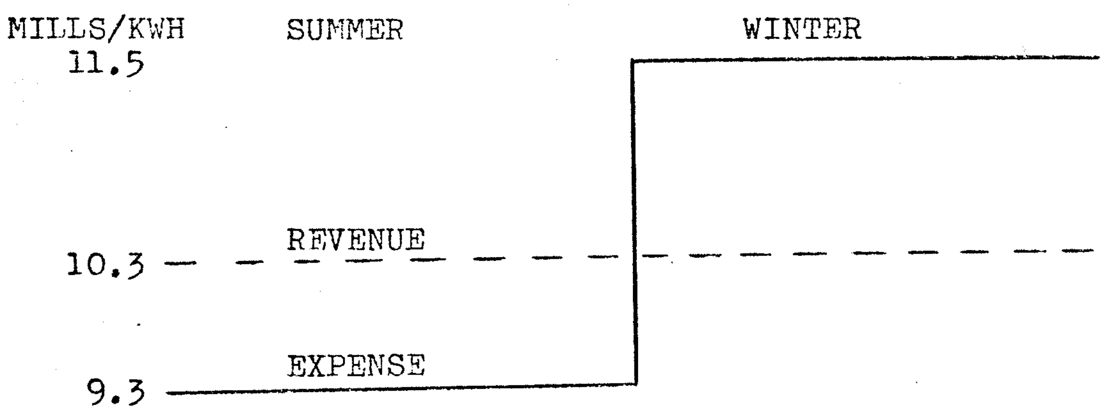


Figure 12.3 shows the average expense and return per kilowatt hour sold in the summer period from April to September inclusive, and for the winter period from October to March inclusive, based on the previously discussed allocation of expenses. This analysis suggests that a differential run off rate might more accurately reflect the cost of providing service in these two periods, and if the demand for electricity is at all responsive to price might encourage relatively more consumption in the summer months, thus improving the annual load factor, annual utilization, and placing downward pressure on the long run cost of producing electricity.

It is suggested that a seasonal differential in run off rates could be employed quite easily within the present rate structure. The effectiveness of such differentials could be assessed by modifying one rate at a time, and observing the effect of this change upon the annual load curve over a period of three or four years. The impossibility of making precise calculations necessitates a pragmatic trial and error approach with a careful monitoring of the results.

As an example the run off rate for domestic and farm consumers might be reduced from the present 9.0 mills to 8.0 mills in the summer period. It could be raised very slightly to 9.5 mills in the winter period. This step could be carried out easily and cheaply merely by modifying the computor program which calculates the monthly bills. No modification to meters would be required.

As a much larger number of kilowatt hours are sold at the run off rate in winter than in summer, total revenue would probably not be changed much initially in spite of the 1.0 mill reduction in summer run off vs. the .5 mill increase in the winter months. The annual cost to the customer would decrease, remain constant or increase depending upon the proportion of his annual electricity consumption occurred in the winter months. The tendency would be for the annual costs of the very large winter consumers (electric space heating customers) to increase somewhat. However, a consumer with both air conditioning and space heating might find his annual cost unchanged.

The objective is to modify rates in such a fashion that consumers will be encouraged to increase consumption in such a way as to improve the annual load factor, and thus improve the utilization of capacity. In Chapter IX it was demonstrated that a 1% improvement in utilization factor will reduce average unit costs about .2 mills in the long run. Thus if a seasonal differential in run off rates is successful in improving utilization, it might be possible to reduce both summer and winter run off rates over the long term, but maintaining a differential between them which might be modified as the load curve changed over time. If successful such a rate system might result in somewhat greater consumption per consumer at a lower average cost per kilowatt hour over the long term.

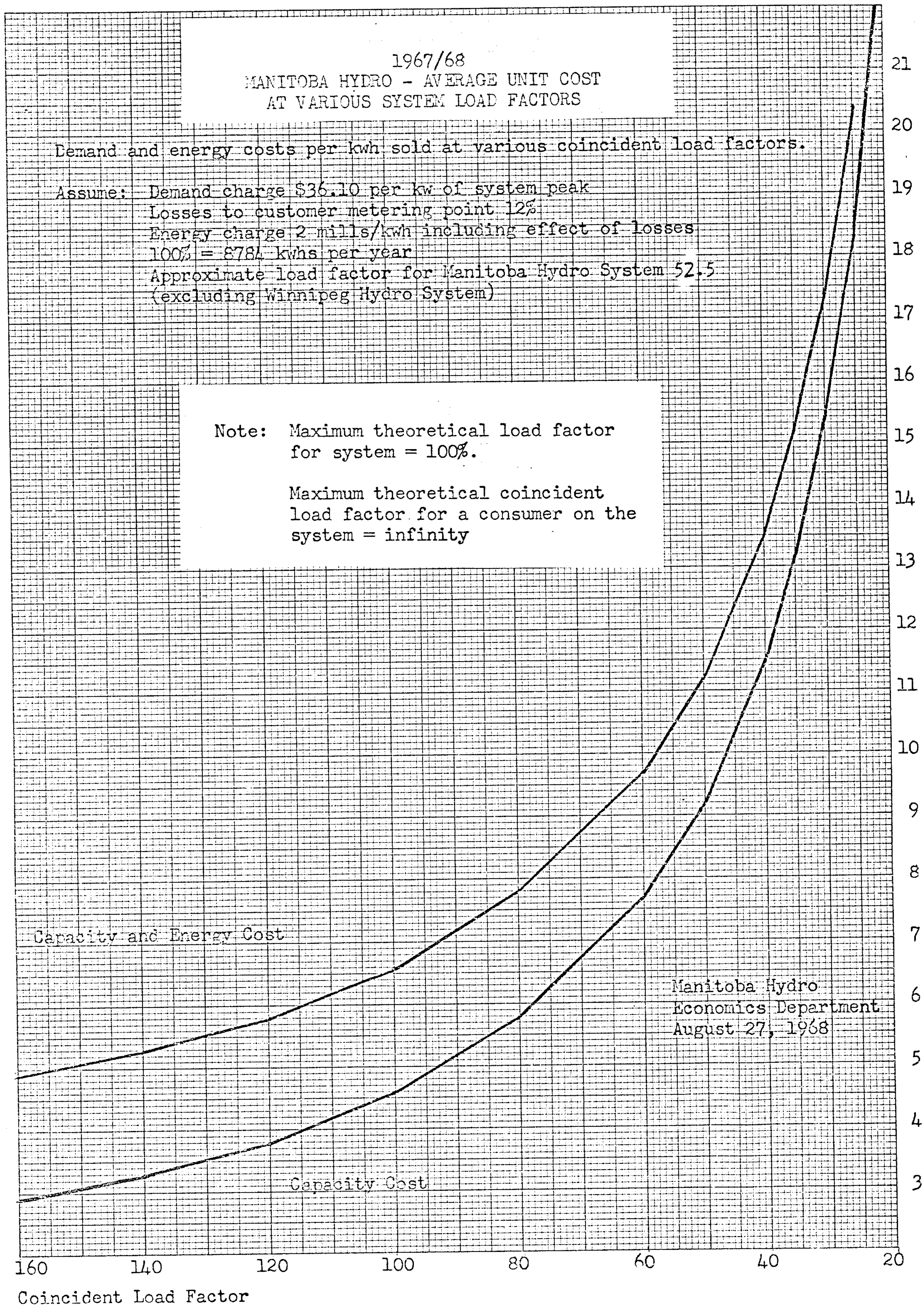
CRITERIA FOR ESTABLISHING THE COST OF PROVIDING SERVICE TO A CUSTOMER CLASS OR FOR A SPECIFIC USE OF ELECTRICITY

The foregoing argument for establishing rate differentials in order to improve the system annual load factor to improve utilization and reduce average unit costs appears consistent with the philosophy that the cost to the consumer should be related to the load characteristics of the service supplied.

Figure 12.4 represents the approximate average cost to Manitoba Hydro of supplying a kilowatt hour of energy at various coincident load factors. It may also be regarded as representing the average load characteristics and the average cost per kilowatt hour of serving the average customer on the system in 1967/68. The consumer's coincident load factor is based upon the amount of demand he places upon the system at the time of annual system peak. For example if he contributed 1 kilowatt of demand to the system peak and consumed 8784 kilowatt hours during 1967/68 his coincident load factor would be 100% and he would cost approximately 6.5 mills per kilowatt hour to serve. If he consumed only 4600 kilowatt hours, his coincident load factor would be about 52.5% and he would cost approximately 10.8 mills per kilowatt hour to serve. Thus the coincident load factor is an excellent criteria for establishing the cost of providing service.

It can be appreciated then that a seasonal rate differential if successful in encouraging a shift toward greater summer, and hence off peak consumption will have a tendency to increase the coincident load factor of the consumer, and reduce the unit cost of providing service over the long term.

FIGURE 12.4


Mills/kwh
1967/68
MANITOBA HYDRO - AVERAGE UNIT COST
AT VARIOUS SYSTEM LOAD FACTORS
Demand and energy costs per kwh sold at various coincident load factors.
Assume: Demand charge $36.10 per kw of system peak
Losses to customer metering point 12%
Energy charge 2 mills/kwh including effect of losses
100% = 8784 kwhs per year
Approximate load factor for Manitoba Hydro System 52.5
(excluding Winnipeg Hydro System)
Note: Maximum theoretical load factor for system = 100%.
Maximum theoretical coincident load factor for a consumer on the system = infinity
Capacity and Energy Cost
Capacity Cost
Manitoba Hydro
Economics Department
August 27, 1968
21
20
19
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
160
140
120
100
80
60
40
20
Coincident Load Factor

Ideally the separate rate for each individual customer might be established by determining the characteristics of the load; the coincident demand and number of kilowatt hours consumed each year. These figures could be converted into the coincident load factor to determine how much the consumer should pay for each kilowatt hour consumed. Once a rate was established however there would be no incentive for individual consumers to improve the characteristics of their load unless an annual study was taken to redetermine the characteristics of each load. This would be impractical. A similar approach can be used to set the rate for a class load (ie. Residential consumers) using sampling methods. If an average annual rate is adopted however, there exist no incentives.

The coincident load factor provides an excellent criteria or analytical tool not only for determining the approximate cost of providing service to an individual customer or class of customers, but can also be applied to determine the cost of providing a particular specialized type of service or application of electricity.

For example, air conditioners require no capacity on the Manitoba Hydro system peak, their coincident load factor would be infinity, and thus a special low rate could conceivably be offered to encourage their use. This is consistent with the rationale which lies behind the differential rate concept.

CONCLUSION

In reviewing the role of the rate structure it has been suggested that it can play an important part in achieving a high degree of economic efficiency in the operation of an electric utility. In the case of Manitoba it would appear that the extremely low rates which were established in 1911 and which have evolved with little modification since then, have played a primary role in achieving high utilization per customer and low unit costs.

The main criticism which could be directed at these rates is that they have tended to become somewhat rigid. Their success has encouraged a reluctance to change them or employ them in an effort to improve the overall efficiency of the utility. While it is desirable that a rate structure should be reasonably stable in order to retain the confidence of public, it should be flexible enough to reflect the changing characteristics and production costs of the system, and the ever changing characteristics of the market environment in which the utility exists.

The primary argument for a flexible rate structure is that the load characteristics, and efficiency of the utility can be improved by suitable modifications of the rates. By designing the rate structure to encourage greater use of off peak energy, the utilization of capacity will be improved, the long run unit costs will be reduced, and the overall efficiency of the utility will be improved.

It is suggested that individual rates could be adjusted in a piece meal fashion one at a time. In the foregoing paragraphs the possibility of seasonal rate differentials were discussed as a means of improving the annual load curve of a utility with a significant winter peak. Similar principles would apply to differentials which might apply over the daily cycle, however since special metering equipment would be involved such differentials might be less practical on a daily basis as on a seasonal basis.

CHAPTER XIII

THE OPTIMUM RATE OF GROWTH

Throughout this study one question that has concerned the author is whether or not there is an optimum rate of growth for an electric utility. It is a question that the author has been unable to resolve with any degree of certainty. It appears however that the optimum rate of growth for a given utility depends upon the special circumstances of that utility. The following general principles might apply.

1. If an isolated utility had all its generation and distribution plant fully loaded, a zero rate of growth might be optimum.

2. If an isolated utility was growing, a fairly high rate of growth would be desirable so that the largest most efficient plants could be fully loaded rapidly. In this case a large utility would have an advantage over a small utility.

3. If a utility were interconnected and could sell suplus capacity, or buy all its capacity from a neighbouring utility, a slow rate of growth might not be disadvantagous. Winnipeg Hydro fits into this category. It is an extremely profitable utility and does not seem to suffer from a low rate of growth.

4. While a slow rate of growth migh not be a disadvantage to an interconnected utility, a low level of consumption per customer might be. However, if absolute consumption per consumer was high so that additional consumption per consumer would be subject to considerable diminishing returns, a very low rate of growth might not be undesirable

with respect to either generation or distribution expenses.

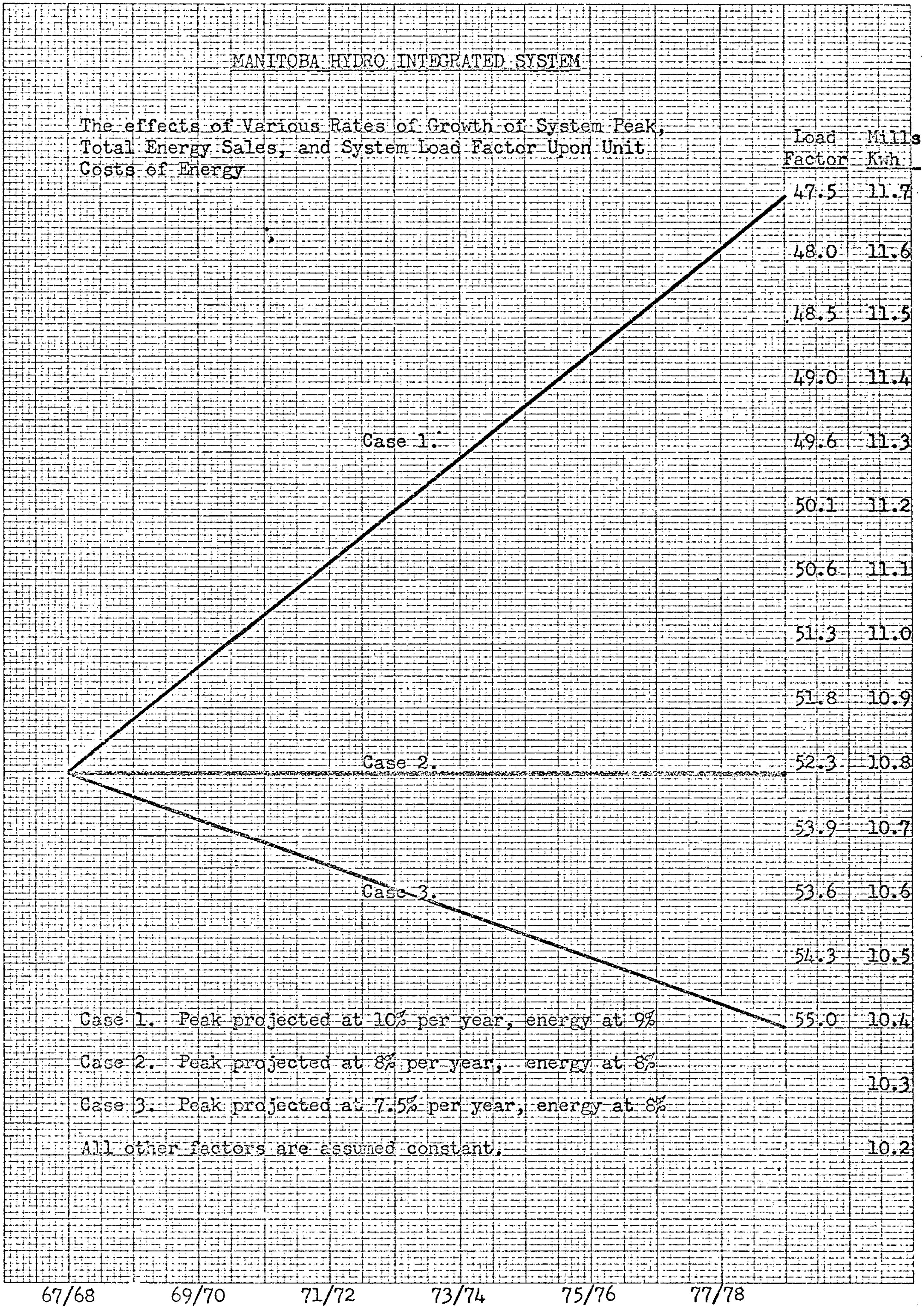
Figure 13.1 was prepared to demonstrate the long term effects of various rates of growth upon unit costs. While it has not been possible to determine the optimum rate of growth, the following general conclusions seem valid.

1. In the long run, a high rate of growth of energy sales at a declining load factor will be detrimental to the system. This will result in accelerated building programs to meet a rapidly increasing peak, thus placing upward pressure on unit costs. (Case I.)

2. A more moderate increase in energy sales accompanied by an increasing load factor should in the long run be beneficial to the overall operation of the system. Capital construction programs can be adjusted to a more slowly growing peak. The deferral of new capital additions would result in a downward trend in unit costs. (Case 3.)

It can be seen that these two conclusions are closely related to the question of utilization as discussed in Chapter IX.

FIGURE 13.1



MANITOBA HYDRO INTEGRATED SYSTEM
The effects of Various Rates of Growth of System Peak, Total Energy Sales, and System Load Factor Upon Unit Costs of Energy
Load Factor
Mills Kwh
47.5 11.7
48.0 11.6
48.5 11.5
49.0 11.4
49.6 11.3
50.1 11.2
50.6 11.1
51.3 11.0
51.8 10.9
52.3 10.8
53.9 10.7
53.6 10.6
54.3 10.5
55.0 10.4
10.3
10.2
Case 1.
Case 2.
Case 3.
Case 1. Peak projected at 10% per year, energy at 9%
Case 2. Peak projected at 8% per year, energy at 8%
Case 3. Peak projected at 7.5% per year, energy at 8%
All other factors are assumed constant.
67/68
69/70
71/72
73/74
75/76
77/78

CHAPTER XIV

CONCLUSIONS

In the pre-amble of the Manitoba Hydro Act, it states that, "The intent purpose and object of this Act is to provide for the continuance of a supply of power adequate for the needs of the province, and to promote economy and efficiency in the generation, distribution, supply and use of power." A central objective of this thesis has been to arrive at some evaluation as to how effectively the electrical supply industry in Manitoba has fulfilled the intent of this Act.

In studying the provision of electricity in Manitoba, the author has come to the conclusion that a unique combination of geographical, historical, institutional, operating and market factors have combined to render the supply of electric energy to the people of Manitoba a highly efficient operation. For decades, Manitobans have enjoyed the highest per capita consumption of electricity in Canada for domestic and farm purposes and have paid the lowest average unit costs in Canada for this energy.

Although Manitoba's average consumption per customer for industrial and commercial purposes is less than half that of Ontario and Quebec, the two provinces with the greatest concentration of large industry, the average unit costs of industrial and commercial energy in Manitoba is only marginally higher than in those provinces. It appears that relative to the average industrial and commercial consumption per customer, that Manitobans enjoy the lowest average unit costs in Canada.

Geographical Factors

The primary factor in the initial success of the electric utility industry in Manitoba and which continues to contribute to its very favourable cost position today is a geographical or perhaps topographic one. The abundance of easily developed hydro-electric potential on the Winnipeg River close to the main population centre of the province played a very important role, as did the absence of any fossil fuel. These factors dictated the early development of hydro power. While the financing and technology required to develop a hydro site sixty miles from the load centre was more complex than for thermal, and required more courage the end result was much cheaper power than could be produced at that time from Thermal, and much greater abundance. Both these factors contributed to the low rates and high per capita consumption which have contributed to the industries' success subsequently.

Historical Factors

In this category one might include the establishment of the City of Winnipeg Hydro Utility, the subsequent competition the Winnipeg Electric Company which brought rates to the lowest level in North America and the establishment of hydro energy as the primary source of power. With respect to this third factor the important point is the previous price levels experienced when building hydro stations. There is little doubt that one of the reasons Manitobans enjoy low cost electricity today is the longevity of previously built hydro stations and the low initial cost by today's standards at which they were built. Because of this factor, it has been suggested that while hydro stations are usually marginal at the time they are built, that they are excellent insurance against inflation and thus become more viable economically with the passage of time.

Institutional Factors

The primary institutional factor presently at work to promote economic efficiency in the electric power industry of Manitoba is the Crown Corporation form selected for Manitoba Hydro. As a publicly owned body, Manitoba Hydro is in business to provide service at cost. A paramount objective of Manitoba Hydro is the minimization of cost rather than the maximization of profit as with a private firm. One way in which Manitoba Hydro can minimize cost is to minimize investment. As Iulo points out, there is not the same incentive for a privately owned utility to minimize the unit cost of electricity. The typical regulated utility is allowed a rate of return on a rate base. If the utility makes non optimal investments, it will merely raise prices to ensure its authorized rate of return.[1]

Operating Factors

Only one of the three operating factors which Iulo found contributed to inter-utility differences in unit costs was found to be a factor in determining the unit cost of producing electricity in Manitoba.

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1. William Iulo "The Relative Performance of Individual Electric Utilities" Land Economics, Volume 38, November 1962, P. 325.

This factor was capacity utilization. In addition to capacity utilization, the level of interest rates was found to be a highly signifigant factor in determining unit costs. It was also determined that given stable interest rates, moderate inflationary forces appear to be more than offset by the gains in the productivity of capital that have taken place, at least since 1961.

Market Factors

All three market factors selected by Iulo; the proportion of total energy distributed to residential consumers, consumption per residential customer, and consumption per industrial and commercial customer are highly relevant in the Manitoba environment. A fourth market factor, the rate structure has also had a profound influence on the present cost of producing electricity in Manitoba. The contribution the rate structure has made in achieving the present level of economic efficiency in the provision of electric energy in the province is considerable.

All three of Iulo's market factors are contributing to the further reduction of unit costs or have made a signifigant contribution in the past. Since 1957 the proportion of total energy sold to residential consumers has declined thus placing downward pressure on unit costs. Consumption per domestic and farm customer has always been very high and has contributed signifigantly to the low unit costs enjoyed today. High consumption per customer in itself contributes to a higher level of efficiency because the facilities required to serve the individual customer are more fully utilized. The present high level of consumption per domestic and farm customer does, however, pose a dilemma as far as realizing still lower unit costs in the future by promoting even greater consumption. Domestic and farm consumption in Manitoba is now at the level where serious diminishing returns set in and it is doubtful if further signifigant reductions in unit costs can be attained no matter how much consumption increases.

It is difficult to define the role of industrial and commercial consumption in determining the unit cost of producing electricity in Manitoba. The average price per unit to the consumer appears somewhat lower than the average consumption per customer might warrant. This suggests that while the level of consumption attained in the past may have contributed to the low unit costs enjoyed today, that if price does approximately equal cost the low prices presently in effect may preclude signifigant reductions of unit costs on the system in the future even through large increases in average consumption occur.

Productivity

An important determinant of the movement of unit costs, and the operating performance of a utility is the rate of productivity increase that can be attained.

(a) Productivity of Labour:

Three comparative labour productivity measurements were utilized: Installed capacity per employee, energy generated per employee and customers per employee. In the first two, Manitoba Hydro demonstrated absolute productivity higher than the Canadian average, and a higher rate of productivity increase than the Canadian average. For the third measure, Manitoba Hydro's absolute productivity and rate of increase of productivity was somewhat less than the national average.

For Manitoba Hydro alone, the productivity of labour as measured by the number of kilowatt hours sold per employee has increased sufficiently to more than offset increases in the cost of labour. During the seven year period from 1961/62 to 1967/68 the average rate of increase of productivity for operating employees appears to have been about 8.5% per year.

(b) Productivity of Capital:

In spite of almost static technology in hydro generation the productivity of capital has increased by an average of 2.83% over the period from 1961/62. As mentioned previously, this increase has been adequate to more than offset the inflation that has taken place during the period, but has not been adequate to offset the combined effect of inflation and the signifigant rise in interest rates which has also occured.

(c) Total Productivity:

Total productivity has increased by an average of 4.13% per year since 1961/62. This productivity increase has been more than adequate to offset all increases in prices and the rise in interest rates which was experienced. Unit costs were reduced from 11.5 mills per kilowatt hour to 10.8 mills per kilowatt hour during the period. Had prices and interest rates remained at their 1961/62 levels unit costs would have been reduced to 9.0 mills per kilowatt hour.

The Rate Structure

In reviewing the role of the rate structure in electric utility economics, it appears that it can play a very important part in achieving a high degree of economic efficiency. In the case of Manitoba, it would appear that the extremely low rates which were established in 1911 and which have evolved with little modification since then have been instrumental in achieving high utilization per customer and low unit costs.

If properly employed in the future, rate adjustments carefully tailored to the differential costs of producing electricity under different conditions might further decrease unit costs by improving the utilization of capacity.

A secondary objective of this study has been to identify and where possible, quantify those variables subject to the control of Management which might be varied to facilitate the attainment of even greater efficiency in the future. In order to clearly establish these relatiohships, I shall list first those factors which contribute signifigantly to the unit costs of producing electricity, but which are not subject to managerial control, and secondly, those factors which are subject to managerial control to some degree.

Factors Not Subject to Managerial Control

1. Geographical factors
2. The level of prices

3. Inflation

4. Level of Interest Rates:

   1% change in average interest rate = .7 mills change in the unit cost of electricity.

<u>Factors Subject to Managerial Control to Some Degree</u>

1. The Rate Structure
2. Distribution among customer classes
3. Consumption per residential customer
4. Consumption per industrial and commercial customer
5. Capacity utilization:

   1% change in capacity utilization = .2 mills change in the unit cost of electricity.

6. Technology

In concluding, it must be stressed that the author has been unable to evaluate the operating performance or economic efficiency of the Manitoba Hydro-Electric System in a definitive manner. It cannot be said that Manitoba Hydro or any other utility is sixty or seventy or eighty percent efficient because of the problem of determining what one hundred percent might be.

There is, however, enough evidence available to conclude that the supply of electrical energy in Manitoba is a highly efficient operation. Natural advantages have been successfully exploited to provide Manitobans with an abundance of electrical energy at the lowest average prices in

Canada, and there is considerable evidence that in spite of the diminishing importance of these natural advantages that electricity will continue to be produced at very favourable prices in the forseeable future.

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APPENDICES

APPENDIX

1. Revenue per Kilowatt Hour - 1948 to 1960 (By Province).

2. Revenue per Kilowatt Hour Sold - 1960 to 1966
   (By Class and by Province).

3. Domestic and Farm per Capita Consumption of Electricity
   by Province.

Revenue per Kilowatt Hour in Cents by Provinces

Year	Can.	Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.	N.W.T.
1948	0.71		4.27	1.71	1.27	0.55	0.76	0.75	1.41	1.93	1.53	2.49
1949	0.74	1.04	4.25	1.80	1.33	0.56	0.78	0.68	3.48	1.95	1.55	1.68
1950	0.67	1.51	3.60	1.60	1.21	0.42	0.67	0.62	1.37	1.75	1.26	1.60
1951	0.80	1.76	4.24	1.90	1.57	0.59	0.86	0.71	3.34	2.02	1.69	1.55
1952	0.81	1.66	4.56	1.92	1.67	0.57	0.89	0.73	3.35	2.02	1.75	1.48
1953	0.86	1.84	4.61	1.95	1.80	0.57	1.00	0.79	3.34	2.04	1.76	1.78
1954	0.89	1.89	4.59	1.94	1.74	0.59	1.01	0.81	3.21	2.05	1.74	2.24
1955	0.89	1.07	4.49	1.98	1.79	0.56	0.98	0.81	2.65	2.01	1.70	2.20
1956	1.04	0.92	4.12	1.94	1.93	0.78	0.97	0.84	2.77	1.94	1.73	2.71
1957	1.06	1.00	4.30	1.97	1.91	0.80	0.99	0.86	2.77	1.93	1.71	2.64
1958	1.06	1.03	4.12	2.01	1.82	0.77	1.01	0.94	2.75	1.95	1.61	2.22
1959	1.05	1.04	3.93	1.94	1.81	0.77	0.98	0.93	2.66	1.96	1.65	2.51
1960	1.05	1.09	3.85	2.09	1.97	0.75	0.99	0.95	2.61	1.92	1.65	2.72

Source: Electric Power Statistics - Dominion Bureau of Statistics.
Revenue per kilowatt hour from ultimate customers within province.

MANITOBA HYDRO FACTS AND FIGURES BOOK

Revenue per Kilowatt-Hour Sold to Various Classes of Consumer - by Province

(Cents per Kilowatt-Hour)

	Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.	Can.
1960											
Domestic & Farm	2.30	4.49	2.76	3.23	1.45	1.34	1.15	2.91	2.22	2.11	1.60
Commercial	3.16	3.69	3.59	2.70	1.26	1.47	1.53	2.72	3.26	2.82	1.71
Industrial	0.70	2.64	1.37	1.15	0.57	0.71	0.70	1.94	1.35	0.95	0.73
Street Lighting	2.92	5.13	4.42	3.73	2.32	2.36	1.96	3.91	2.67	2.11	2.46
Average	1.09	3.85	2.09	1.97	0.75	0.99	0.95	2.61	1.92	1.65	1.05
1961											
Domestic & Farm	2.35	4.28	2.59	3.13	1.43	1.32	1.15	2.93	2.17	2.10	1.58
Commercial	2.98	3.16	3.53	2.68	1.91	1.45	1.54	3.10	2.94	2.53	1.92
Industrial	0.74	2.22	1.53	1.07	0.57	0.73	0.66	1.84	1.30	0.84	0.72
Street Lighting	3.35	5.12	4.20	3.52	2.30	2.40	1.99	4.09	2.63	2.06	2.47
Average	1.20	3.72	2.16	1.86	0.78	1.00	0.98	2.59	1.89	1.63	1.08
1962											
Domestic & Farm	2.37	4.20	2.54	3.03	1.40	1.32	1.14	2.83	2.15	1.86	1.54
Commercial	3.10	3.41	3.49	2.79	1.87	1.42	1.55	2.77	2.81	2.38	1.88
Industrial	0.80	2.21	1.50	1.06	0.55	0.72	0.68	1.94	1.28	0.76	0.71
Street Lighting	3.12	5.52	4.22	3.68	2.18	2.46	2.02	4.00	2.61	2.05	2.46
Average	1.10	3.65	2.13	1.83	0.80	1.00	0.96	2.53	1.87	1.53	1.08

Source: Dominion Bureau of Statistics

REVENUE PER KILOWATT HOUR SOLD
BY PROVINCE
(Cents per Kilowatt Hour)

		Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.	Can.
1962	Domestic & Farm	2.37	4.20	2.54	3.03	1.40	1.32	1.14	2.83	2.15	1.86	1.54
	Commercial	3.10	3.41	3.49	2.79	1.87	1.42	1.55	2.77	2.81	2.38	1.88
	Industrial	0.80	2.21	1.50	1.06	0.55	0.72	0.68	1.94	1.28	0.76	0.71
	Street Lighting	3.12	5.52	4.22	3.68	2.18	2.46	2.02	4.00	2.61	2.05	2.46
	Average	1.10	3.65	2.13	1.83	0.80	1.00	0.96	2.53	1.87	1.53	1.08
1963	Domestic & Farm	2.41	4.03	2.44	2.98	1.35	1.32	1.16	2.76	2.05	1.80	1.52
	Commercial	2.76	3.42	2.83	2.61	1.92	1.40	1.53	2.70	2.69	2.12	1.85
	Industrial	0.73	1.96	1.17	1.03	0.66	0.72	0.66	1.77	1.30	0.76	0.72
	Street Lighting	3.32	6.12	4.24	3.83	2.19	2.49	2.09	4.01	2.60	2.10	2.49
	Average	1.07	3.51	2.09	1.85	0.84	1.00	0.95	2.38	1.82	1.46	1.08
1964	Domestic & Farm	2.42	4.00	2.34	2.89	1.26	1.31	1.17	2.59	1.99	1.72	1.47
	Commercial	3.24	3.35	2.71	2.54	1.88	1.37	1.55	2.73	2.61	2.09	1.83
	Industrial	0.70	1.97	1.06	1.00	0.59	0.70	0.67	1.40	1.19	0.73	0.70
	Street Lighting	3.91	5.97	4.45	4.33	2.21	2.49	2.19	4.11	2.64	2.02	2.52
	Average	1.03	3.46	1.96	1.75	0.82	0.99	0.97	2.26	1.75	1.38	1.06
1965	Domestic & Farm	2.42	3.63	2.32	2.82	1.25	1.30	1.15	2.35	1.92	1.50	1.42
	Commercial	3.34	2.79	2.64	2.52	1.84	1.36	1.54	2.60	2.43	1.97	1.76
	Industrial	0.72	3.41	1.18	1.05	0.59	0.70	0.79	1.52	1.17	0.71	0.71
	Street Lighting	4.54	5.63	4.49	4.71	2.22	2.55	2.28	4.31	2.62	2.07	2.57
	Average	1.05	3.25	2.01	1.69	0.86	0.98	1.06	2.03	1.69	1.25	1.07
1966	Domestic & Farm	2.44	3.49	2.28	2.74	1.23	1.29	1.18	2.27	1.87	1.45	1.41
	Commercial	3.04	3.11	2.54	2.55	1.86	1.32	1.50	2.58	2.35	2.00	1.74
	Industrial	0.75	1.51	1.13	0.95	0.55	0.69	0.83	1.50	1.13	0.67	0.69
	Street Lighting	4.92	5.67	4.83	4.81	2.33	2.56	2.38	4.41	2.59	2.14	2.63
	Average	1.09	3.52	1.94	1.57	0.82	0.97	1.09	1.97	1.64	1.18	1.04

Source: Dominion Bureau of Statistics

Domestic & Farm per Capita Consumption of Electricity by Provinces

(Kwh Annually)

Source: Electric Power Statistics - Dominion Bureau of Statistics

Year	Can.	Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
1948	389		90	178	136	219	655	742	107	126	383
1949	422	92	100	203	173	257	703	814	127	147	442
1950	492	114	110	231	191	302	819	898	154	180	534
1951	552	134	117	262	215	354	902	979	183	212	593
1952	605	165	120	291	234	403	969	1,034	219	240	654
1953	665	188	129	335	256	458	1,046	1,111	263	279	723
1954	738	220	139	369	284	534	1,119	1,219	324	336	821
1955	813	255	158	412	312	595	1,208	1,286	426	384	936
1956	892	293	191	459	353	671	1,304	1,379	454	446	1,033
1957	956	311	208	507	399	753	1,351	1,451	535	486	1,115
1958	1,012	317	213	543	439	823	1,411	1,538	579	538	1,150
1959	1,087	365	268	604	517	906	1,471	1,558	662	631	1,253
1960	1,141	378	293	635	557	972	1,525	1,606	706	672	1,312
1961	1,205	392	403	695	605	1,046	1,586	1,748	754	729	1,350
1962	1,276	416	369	753	674	1,140	1,654	1,736	840	788	1,431
1963	1,340	432	395	798	691	1,221	1,730	1,775	917	839	1,456
1964	1,418	462	439	862	732	1,320	1,787	1,857	994	893	1,525
1965	1,519	503	508	914	768	1,445	1,881	1,963	1,139	1,024	1,651
1966	1,605	553	571	986	852	1,546	1,972	2,021	1,241	1,085	1,762

APPENDIX 3.