

**Electric Energy Supply and Non-Utility Generation:  
A Comparative Analysis of B.C. and Wisconsin**

by

**John A. Logan**

B.A., Simon Fraser University, 1986

THESIS SUBMITTED IN PARTIAL FULFILLMENT OF  
THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF ARTS

in the Department

of

Geography

© John A. Logan

Simon Fraser University

January, 1993

All rights reserved. This work may not be reproduced  
in whole or in part, by photocopy or other means, without  
permission of the author.

## APPROVAL

Name: John Alfred Logan

Degree: Master of Arts

Title of Thesis: Electric Energy Supply and Non-Utility Generation: A Comparative Analysis of B.C. and Wisconsin

Examining Committee:  
Chair: A.M. Gill  
Associate Professor

---

J.T. Pierce, Associate Professor  
Senior Supervisor

---

R. Hayter, Professor

---

Mark Jaccard, Associate Professor  
External Examiner  
Resource and Environmental Management

Date Approved: January 21, 1993



## ABSTRACT

Since the energy shortages of the 1970's, there has been a heightened awareness of environmental issues which has led to the development of new attitudes regarding energy policy making and planning. Electric utility methods for meeting energy demand have subsequently undergone considerable change in response to this development. There is now more emphasis on encouraging the management of energy consumption as well as the development of non-utility generation rather than increasing electric utility production.

In this thesis I examine B.C. Hydro's pricing policies and buy back rates - those policies concerned with the purchase of non-utility generation - and their effectiveness in encouraging the efficient use and development of power. Specifically, the levels of self-generation within B.C.'s pulp mills are examined, as well as, the attitudes of mill managers with respect to increasing energy production. B.C. Hydro's encouragement of self-generation is determined by examining the ratio of the industrial rate for the pulp mills to the utility's long-run marginal cost (LRMC) of power. B.C. Hydro's buy back policies are also examined to determine the level of encouragement they provide for increased self-generation. Wherever possible, comparisons are made with similar data obtained from utilities and pulp mills in Wisconsin because this state has long been regarded as a leader in rate design in the U.S.

The results of the comparison between the B.C. and Wisconsin pulp mills demonstrates similarities with respect to pulp mills' attitudes towards increasing self-generation capacity. There is a significant difference between the two regions, however, in terms of the amount of pulp mill self-generation. The Wisconsin mills generate substantially higher levels of their own energy requirements than do the B.C. mills. The information collected did not provide conclusive results which account for the different levels of self-

generation. The principal benefit demonstrated by these comparisons is that B.C.'s pulp mills have considerable potential to increase their levels of self-generation.

Similarly, the comparison of electric utilities does not reveal a clear leader between regions. The Wisconsin utilities provided greater mark-up through their industrial rates. With respect to buy back policies, it is the Wisconsin utilities again that provide the greatest encouragement for increased self-generation. B.C. Hydro, however, is the only utility which offers a load displacement policy. While the Wisconsin utilities do not lead in all areas of comparison, they do provide a greater level of encouragement for power producers to generate and market surplus power.

In summary, the policies and regulations of both B.C. Hydro and the Wisconsin utilities have the potential to encourage greater industrial energy efficiency and increased levels of self-generated power. The existing levels of encouragement, however, are not determined solely by economic considerations. The level of encouragement tends to reflect utility planning objectives as well as economic criteria.

## **DEDICATION**

**Mom and Dad**

## QUOTATION

Well may the court be dim, with wasting candles here and there: well may the fog hang heavy in it, as if it would never get out; well may the stained glass windows lose their colour, and admit no light of day into the place; well may the uninitiated from the streets, who peep in through the glass panes in the door, be deterred from entrance by its owlish aspect, and by the drawl languidly echoing to the roof from the padded dais where the Lord High Chancellor looks into the lantern that has no light in it....

Charles Dickens, Bleak House

## ACKNOWLEDGEMENTS

Special thanks to:

John Pierce, whose encouragement and patience made my goals attainable,

Timo Makinen, and the many employees of B.C. Hydro and The B.C. Utilities Commission for their assistance in the collection and analysis of data,

Tom, Scott and Lori (hostess with the mostess), Cathy, Tony and Anne, Kevin, Tim and Pat, . . . for the years of friendship which made my time at SFU memorable well beyond the pursuit of academic goals.



## TABLE OF CONTENTS

Approval .....	ii
Abstract .....	iii
Dedication .....	v
Quotation .....	vi
Acknowledgments .....	vii
List of Tables .....	xi
List of Figures .....	xiii
<b>1. INTRODUCTION .....</b>	<b>1</b>
<b>THE CONTEXT .....</b>	<b>2</b>
Resource Management and Geographic Research .....	3
Pulp Mill and Electric Utility Relevant Literature .....	5
<b>PURPOSE .....</b>	<b>7</b>
<b>METHODOLOGY .....</b>	<b>9</b>
Study Regions .....	9
Selection of Wisconsin for Comparison .....	11
The Rationale for Selecting Pulp Mills for Comparison .....	14
Energy Use in the Pulp and Paper Industry .....	16
Factors Influencing Cogeneration .....	17
Electricity Prices and Pulp Mill Self-Generation .....	18
Advantages of Self-Generation vs Megaprojects .....	18
Pulp Mill Production Methods .....	19
Data Sources .....	20
Pulp Mill Questionnaire .....	20

Electric Utility Questionnaire .....	22
Other Data Sources .....	22
Analysis of British Columbia and Wisconsin Data .....	23
Chapter Outline .....	23
<b>2. THEORETICAL AND PRACTICAL CONSIDERATIONS IN THE PRICING OF ELECTRICITY .....</b>	<b>25</b>
MARGINAL COSTS OF ELECTRIC PRODUCTION .....	25
ESTABLISHMENT OF A SPECIFIC RATE (PRICE) STRUCTURE .....	32
ENERGY SUPPLY AND DEMAND PLANNING OPTIONS:DETAILS AND DEFINITIONS .....	34
Deregulation: PURPA and Power Transfers in the U.S. ....	36
Deregulation: A Cautionary Note .....	39
Least-Cost Planning .....	40
The Role of Conservation .....	41
Management of Electricity Demand .....	42
B.C. Hydro's Situation .....	43
<b>3. DATA ANALYSIS .....</b>	<b>47</b>
PULP MILL ANALYSIS .....	47
ANALYSIS OF UTILITIES' PRICING POLICIES AND BUY BACK RATES .....	48
Comparison #1: Industrial Tariff / Utilities LRMC .....	50
Pulp Mills' Cost of Purchased Power .....	50
B.C. Hydro's LRMC .....	52
The Wisconsin Utilities' LRMC .....	53
Comparison #2: Buy Back Rates and Other Incentives .....	53
B.C. Hydro Options .....	54
Wheeling Policy (Proposed) .....	54

Wheeling Energy Charge .....	56
Capacity Credit .....	56
Energy Balancing .....	57
Energy Losses .....	59
Wheeling Demand Charge .....	59
Analysis of B.C. Hydro's Proposed Wheeling Policy .....	59
Wisconsin Utilities and Wheeling .....	60
B.C. Hydro Buy Back Rates and Load Displacement .....	61
B.C. Hydro's Environmental Policy .....	63
Wisconsin Buy Back Policies .....	64
Wisconsin Utilities' Environmental Policies .....	69
Power Exchange Operation (Proposed) and Exports .....	71
<b>4. PULP MILL RESULTS AND INTERPRETATION .....</b>	<b>73</b>
Pulp Mill Results .....	73
B.C. Pulp Mill Responses .....	77
Wisconsin Pulp Mill Responses .....	79
Results of Comparison .....	81
<b>5. ELECTRIC UTILITY COMPARISONS .....</b>	<b>84</b>
LRMC vs Pulp Mill Rate .....	84
Summary of "Mark-up" Comparison .....	89
Comparison of Electric Utilities' Buy Back Options .....	92
B.C. Hydro's Policies .....	92
Wheeling Service Schedule 1841 (Proposed) .....	92
The Wheeling Policy's Positive Effects on Self-Generation .....	96
Negative Effects of B.C. Hydro's Wheeling Policy .....	98

Direct Power Purchases .....	101
Wisconsin Buy Back Rates .....	104
Comparison of B.C. and Wisconsin Buy Back Rates .....	107
Load Displacement .....	110
An Assessment of B.C. Hydro's Load Displacement Policy .....	115
B.C. Hydro's Spot Market Purchases and Export Prices .....	117
<b>6. SUMMARY AND CONCLUSIONS .....</b>	<b>120</b>
Summary .....	120
Pulp Mill Comparison .....	120
Electric Utility Rates .....	122
Electric Utility Buy Back Policies .....	123
Load Displacement .....	126
Conclusion .....	127
Future Research and Recommendations .....	131
<b>APPENDIX A .....</b>	<b>133</b>
<b>APPENDIX B .....</b>	<b>139</b>
<b>APPENDIX C .....</b>	<b>141</b>
<b>REFERENCES .....</b>	<b>145</b>

## LIST OF TABLES

### Chapter 2

Table		Page
2.1	Marginal Generating Costs in an All-Hydro System .....	28
2.2	WEU #2 Types of Baseload Generation .....	30
2.3	WEU #2 Types of Cycling Generation .....	31
2.4	WEU #2 Types of Peaking Generation .....	31

### Chapter 3

3.1	Summary of Analysis of Utilities' Mark-up and Buy Back Policies .....	49
-----	---	----

### Chapter 4

4.1	British Columbia Pulp Mill Data .....	74
4.2	Wisconsin Pulp Mill Data .....	74
4.3	B.C. Pulp Mills - Principal Incentives for Greater Self-Generation .....	76
4.4	Wisconsin Pulp Mills - Principal Incentives for Greater Self-Generation .....	76

### Chapter 5

5.1	Utilities' "Mark-Up" on Pulp Mill Rate .....	85
5.2	Power Factors and Demand Charges .....	86
5.3	Generation Plants Wheeling Credits By Region .....	95
5.4	Levelized Cost / kWh .....	103
5.5	Buy Back Rate and B.C. Hydro System LRMC .....	105

5.6	Wisconsin Utilities' Buy Back Rates Compared to LRMC .....	107
5.7	B.C. Hydro And Wisconsin Utility Comparison of Buy Back Rates .....	108
5.8	Regional Load Displacement Values for Plants (a) and (b) For Contracts Beginning In 1991/92 .....	112
5.9	Total Annual Load Displacement Credit: Plants With Tariff of \$0.0346 for Contracts Beginning in 1991/92 .....	113
5.10	Total Annual Load Displacement Credit: Plants With Tariff of \$0.0316 for Contracts Beginning in 1991/92 .....	114
5.11	B.C. Hydro's Spot Market Power Purchases and U.S. Exports 1990 .....	118

# LIST OF FIGURES

## Chapter 1

Figure		Page
1.1	B.C. Hydro Major Electric System .....	10

## Chapter 2

2.1	Energy Supply and Demand Planning Options .....	37
-----	---	----

## Chapter 3

3.1	B.C. Hydro's Integrated System and Nine Wheeling Regions .....	58
-----	--	----

## CHAPTER 1

### INTRODUCTION

This thesis will analyze B.C. Hydro's pricing policies and buy back rates (those policies concerned with the purchase of non-utility power generation) and in turn its effectiveness in encouraging the efficient use and development of power. More specifically the analysis will examine the effectiveness of these policies in encouraging higher levels of energy production from B.C.'s pulp mills. B.C. Hydro's policies and the pulp mill information will be compared with data collected from electric utilities and pulp mills in Wisconsin to highlight differences in their respective approaches to self-generation.

It is necessary to analyze electric utilities' policies on a regular basis in order to determine their effectiveness in encouraging the development of electricity at the lowest social cost. The significance of examining pulp mill's energy production relates to the industry's large energy requirements and its ability to meet this demand through higher levels of self-generated power. Selected comparisons with Wisconsin's electric utilities and its pulp mills will provide a broader perspective of the many issues surrounding electric utility policies.

During the period 1960-1980, the financial management of publicly owned electric power utilities in Canada was geared toward achieving rapid expansion in both system capacities and geographical coverage. The achievement of these objectives did not create significant problems in the financial management of the utilities. Having employed improved technology, they could cut costs, improve the quality of their services, and break even in "commercial terms" with considerable ease. By the mid-seventies and early eighties, however, electricity markets in Canada and other western countries were extremely volatile.



This was largely the result of rising oil prices and increasing public obligations to nuclear power and larger hydro sites. These factors led to large increases in the costs of producing electricity in most areas of North America (Jaccard et. al.;1991:5). As utilities sought higher tariffs to meet the rising costs of production the consumers, as well as sponsoring departments, began to question pricing policies, as well as demand and investment forecasts (Seth;1984:xiii).

## THE CONTEXT

This study compares several options an electric utility or province (state) might pursue to meet demand for electricity. The thesis addresses how electric energy development can utilize cost-minimizing approaches and the management of energy consumption as opposed to simply meeting demand on the basis of increased utility production. These issues are discussed through an examination of B.C. Hydro's pricing policies and their effect on industrial energy efficiency and self-generation.

While the topic has a geographic dimension, geographers have not explored the issues of utility pricing policies and by back rates in large numbers. These issues, however, impact the utilization of the environment and the development of natural resources. J.R. Whitaker in his article "Geography and Resources" (1954), was one of the first to identify natural resources as an area of study that geography shared with other disciplines (Mitchell;1989:288). Whitaker described how from the beginning of American geography and to the present, geographers have been concerned with the nature and geographic distribution of natural resources, with resource appraisal and the study of the depletion and conservation of natural resources (Whitaker;1954:233-234).

As early as 1923 Barrows described geography as the science of human ecology, in his article "Geography as Human Ecology". Barrows believed the future objective of geographic inquiry should be to make clear the relationships existing between natural environments and the distribution and activities of humans. Barrows suggested geographers view this problem from the perspective of the human adjustment to the environment rather than that of environmental influence (Barrows;1923:3).

Geographic research maintains the tradition of human ecology or ecological analysis to the present day as one of three dominant research traditions (Mitchell;1989:8). Geography is not unique, however, in exploring the questions of the human environment, because all the great questions of the human environment are transdisciplinary (Kates;1987:534). Many other disciplines and professions have a direct interest in an ecological theme.

To date there has been little geographic research on the interrelations among electric utility generation, pricing and the conservation of energy resources. This lack of research is unusual given the time and effort geographers have devoted to public policy and resource management. This thesis will explore the issue of electric utility policies and industrial energy production in the geographic tradition of man and the environment.

## RESOURCE MANAGEMENT AND GEOGRAPHIC RESEARCH

Resource management refers to the controlled use of resources and represents the actual decisions concerning policy or practice regarding how resources are allocated or may be developed (Mitchell;1983:3). At the turn of the century, few limitations were imposed on meeting resource demands, owing to a belief that resources were plentiful and that in the unlikely event of a shortage man's technological ingenuity would prevail (O'Riordon;1971:60). These attitudes have since changed as humans have realized that resources are not

unlimited and that ultimately our survival will depend upon how efficiently we manage natural resources. In the face of these realizations there has been increasing efforts to increase levels of resource management. Paralleling the movement towards resource management has been large increases in environmental legislation at all levels of government. Increased regulation and concerns for the environment have added to the complexity of many resource management and conservation issues (Greenland;1983:3).

Resource management concerns are very complex because the majority of the issues are enmeshed in a rapidly changing political, economic, social and technological milieu. The determination of the various allocation of resources is not determined exclusively by the market place nor by the quasi-political forum, but by a combination of social, cultural, economic, and institutional processes that strive for the best solution, but which inevitably must seek compromise (O'Riordon;1971:19).

The development of energy policies reflects many of these concerns. The many varied objectives of resource policies makes it impossible for pricing alone to meet the required objectives of resource development. The electric utility industry itself attempts to account for many variables in the development of policies. The development of electrical energy must take into consideration the many environmental concerns with regard to protecting environmental quality. There are many political/social objectives as well, such as the requirement of having a uniform tariff, subsidizing rural electrification and the encouragement of industry. At the same time policies must encourage efficient development of new resources while promoting the conservation of present resources.

In addition to these concerns, the management of the electric utility industry has the added complication that it has long been viewed as a "natural monopoly" (Colton;1985:5). Largely due to this consideration, the industry has required regulation as a surrogate for competition. The necessity of government to regulate this resource, for the public benefit,

adds at least to the perception of the complexity of managing the resource.

Understanding these types of policies and how they influence and affect the development of resources is a clearly identifiable line of research in geography. Geographers, for example, have evaluated a wide variety of programs and policies related to the efficiency (defined in a variety of ways) and use of a wide variety of resource management situations (see Mitchell, 1989; 224; Furuseth and Pierce, 1982; Mundie, 1982; Lund, 1983; Johnston and Smit, 1985; Mitchell, 1983; Mitchell and Gardner, 1983; Draper, 1981; As-Sammani, 1984; Mitchell and King, 1984; Val and Nelson, 1983; Brown and Macey, 1985; McTaggart, 1983).

These studies are only a small sample of the numerous analyses of resource policies and programs that seek to determine how adequately resource policies, programs and projects work and what variables account for their (lack of) success (Mitchell, 1989:225). Contemporary concerns over the allocation of scarce resources makes it essential to continue to evaluate the utility of social interventions (Rossi and Freeman, 1989:65). In this tradition this thesis analyzes the electric utility industry and the development of energy sources. In examining these issues the broad context of the problem and the limited geographic publications on the topic necessitated that information be gathered from a variety of disciplines.

#### PULP MILL AND ELECTRIC UTILITY RELEVANT LITERATURE

In evaluating pulp mills and their respective levels of self-generation, a variety of sources were consulted. The most significant of these include publications by economists, notably Helliwell and Cox (1978) and Helliwell and Margolick (1981). These publications identify the potential of B.C.'s pulp and paper mills to produce significantly higher levels of

self-generated power. The authors described how B.C. Hydro's pricing and related policies affect levels of self-generation within the pulp and paper industry. They further suggest how future research must determine the extent to which B.C. Hydro's policies could encourage the development of this resource.

In describing electric utility pricing and the related policies, the majority of the publications utilized were from the field of economics. Works of the greatest significance include Bonbright's "Principles of Public Utility Rates", (1961); Mitchell, Manning and Acton's "Peak Load Pricing", (1978); Seth's "Pricing and Related Policies of Publicly Owned Electric Utilities", (1984); and Munasinghe's "Electric Power Economics: Selected Works", (1990). Through these works the economic principles of electric utility pricing and policies are described in chapters 2 and 3.

Further information was collected from Natural Resource Management (NRM) publications at Simon Fraser University. While several publications from this department were utilized, the most significant was Makinen's NRM research project "The Electricity Self-Generation Potential of the B.C. Pulp and Paper Industry", (1991). This publication provided a detailed assessment of the pulp and paper industry's potential energy production and supplied important definitions and descriptions of self-generation techniques, that are defined and discussed in chapter 1.

Additional information was found in legal journals and publications by lawyers in other disciplines journals. Cudahy and Malko's article "Electric Peak-Load Pricing: Madison Gas and Beyond", (1976) in the Wisconsin Law Review, provided a detailed account of many of the issues of rate design. The article provided a review of the economic theories of rate design and described the direction Wisconsin's electric utility policies have taken since the late 1970's (chapter 1).

An equally important article is Cavanagh's "Least-Cost Planning Imperatives for

Electric Utilities and Their Regulators", (1986) in the Harvard Environmental Law Review. Cavanagh is the Senior Staff Attorney, for the Natural Resources Defense Council, Inc. Cavanagh explores the issues surrounding the costs and benefits associated with increased deregulation of the electric power industry in the United States (chapter 2). The article also provided a useful framework for the discussions on least-cost planning.

This collection of articles provides the foundation for this research. The eclectic nature of these sources indicates that this problem is not the exclusive domain of one discipline or profession and geography itself has much to offer in the discussion.

## PURPOSE

This study examines B.C. Hydro's policies' effectiveness in encouraging the efficient use and development of power. The major research question addressed is as follows: Do B.C. Hydro's current pricing policies and buy back rates encourage the efficient development and utilization of power from the provincial pulp mills? It can be argued that the more efficiently a utility meets power demands the greater potential exists for lessening environmental effects.

Efficiency is interpreted in terms of economic efficiency; this includes both efficient production and rational end use. Efficient production refers to meeting demand at the lowest real costs of capital, fuel, labor and materials. Rational end use implies rates which reflect significant variations in the cost of providing electric service. It must be recognized, however, that this definition does not consider all components of outcome efficiency. Other components include both technical and social efficiency considerations (Bromley, 1971:172). Technical efficiency refers to the relationship between two or more outputs which affect the efficient level of production. Social efficiency refers to a situation in which the output mix of

these resources is "such that relative social values between any two products are equal to the rate at which one must be sacrificed for the other in production, after recognizing possible external effects (such as watershed protection, amenities, and so on)" (Bromley;1991:176). There is no guarantee that the technical or social efficient output will coincide with that of economic efficiency (For a detailed definition of efficiency refer to Bromley [1991]). This thesis therefore focuses primarily on the classic economic definition of efficiency since this provides a solid beginning for analysis of B.C. Hydro's policies. Other components of efficiency are also discussed with respect to energy planning and the production of electricity.

In order to answer the major research question three objectives will be pursued:

1. To analyze the attitudes and efforts of B.C.'s pulp mills, relative to Wisconsin's pulp mills, with respect to the efficiency of energy use and the self-generation of power given prevailing policies and market conditions.
2. To determine the importance B.C. Hydro places on the encouragement of self-generation from pulp mills relative to Wisconsin's electric utilities as measured by electric utility rates.
3. To analyze B.C. Hydro's buy back rates and other incentives that provide a market for self-generated power and to compare the level of incentive they offer to power producers relative to Wisconsin's policies.

## METHODOLOGY

This section will describe the research methodology employed to attain the goals outlined above. There will also be an elaboration upon the reasons for selecting Wisconsin electric utilities for comparison purposes. This is followed by a description of pulp mills and their production processes. An analysis of the comparisons between the pulp mills and B.C. Hydro and the Wisconsin utilities will also be provided. Finally there is a description of the information gathering techniques used.

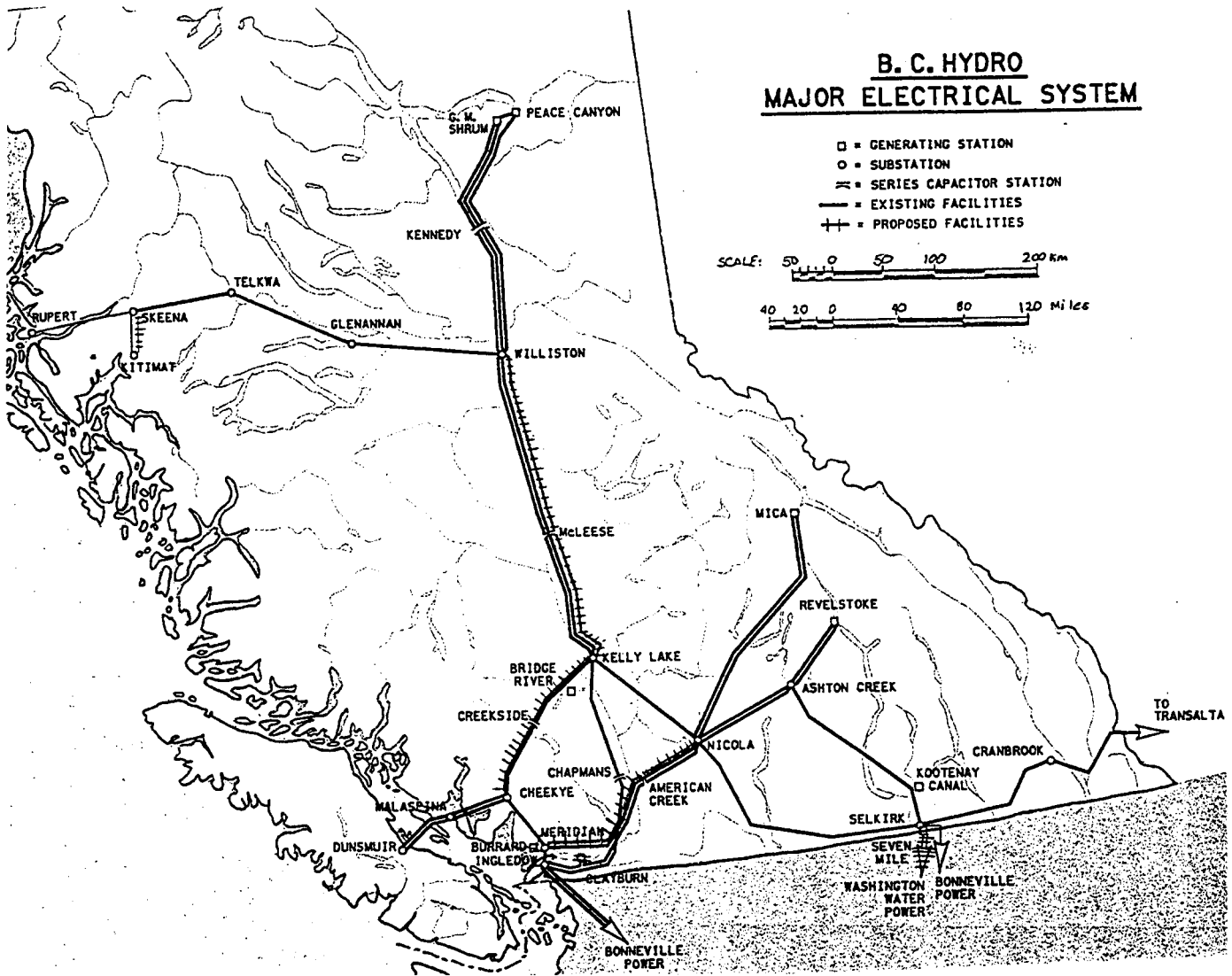
### STUDY REGIONS

To answer the research question, this thesis examines the electric utilities of the Province of British Columbia and the State of Wisconsin. Within British Columbia, B.C. Hydro supplies power and maintains plants and property throughout most of the province. It serves almost 1.3 million customers in an area containing over 92 percent of the province's population (B.C. Hydro;1991). The policies of B.C. Hydro therefore impact upon most of the population of B.C. (Figure 1).

Within Wisconsin, five major electric utilities serve 84 percent of the market (Malko and Stipanuk;1976:33). Two of these electric utilities have been selected for comparison purposes. The utilities selected for comparison service south central and north eastern Wisconsin. They are referred to as WEU #1 and WEU #2 respectively, to protect the confidentiality of the information.



Figure 1.1: B.C. Hydro Major Electric System



(B.C. Hydro; Mar., 1991:28)

## Selection of Wisconsin for Comparison Purposes

Wisconsin has been selected for comparison in this study because it has been a leader among U.S. states in issues relating to rate design (Cudahy and Malko:1976). Wisconsin and New York were the first states to institute formal regulation for utility companies; public service commissioners were given regulatory jurisdiction over Wisconsin's electric utilities in 1907 (Vennard,1979:288).

More recently major increases in fuel and other utility costs in the mid-1970's led to a re-evaluation of electric rate structures and standards of electric service throughout the U.S. Environmentalists and others with strong interest in influencing electric demand, usage and production became concerned about what they termed "promotional" rate structures. The latter included rate designs that recovered less than long-run marginal costs from some categories of users. This thereby induced "wasteful" usage and perpetuated and exacerbated an uneconomic rate of growth in usage. This, in turn, stimulated the construction of allegedly unnecessary and environmentally burdensome power plants and a thicket of transmission lines (Cudahy and Malko;1976:47).

Hundreds of reports were written under the direction of the National Association of Regulatory Utility Commissioners, the Electric Power Research Institute, and many states and regulatory commissions. It was not until 1978, however, that federal legislation was implemented to deal with the changing economic conditions of the electric utility industry. This was done when Congress mandated complete review of energy policy through the National Energy Act, which included the Public Utility Regulatory Policies Act (PURPA) (described in chapter 2)(Cavanagh;1983:584).

Before the National Energy Act was signed into law, Wisconsin's electric utilities were already acting on many of the points PURPA addressed. The Wisconsin utility,

Madison Gas Electric Company (MGEC), filed at the Public Service Commission of Wisconsin (PSCW), for a rate increase in 1973 based upon long-run incremental costs (referred to as the "Madison Gas" case). What began as a routine utility request for an increase in rates was transformed by environmentalist intervention into an adjudication of rate design.

The "Madison Gas" case recognized the importance of electric rate structures and intervenors used this rate case as a forum for the discussion of many of the broad theoretical issues of rate design (Cudahy and Malko;1976:47). The conclusions reached in this case established a new direction in Wisconsin rate policy.

The "Madison Gas" case, in summary, is based upon four basic assumptions:

- (1) the desirability of long-run incremental cost pricing,
- (2) the importance of flattening rates (and decreasing quantity discounts) in circumstances of diseconomies,
- (3) the possibility of reflecting externalities in rate design, but the preferability of addressing the problem through taxation,
- (4) the usefulness of peak-load pricing as the ultimate outcome of cost-based principles and, in particular, pricing based on LRIC (Cudahy and Malko; 1976:78).

The desirability of marginal cost pricing was the most fundamental of the conclusions reached and has been restated by the Wisconsin Commission in subsequent cases. This preference reflects the belief that in the matter of pricing or rate design, marginal costs are more meaningful than traditional average costs. Theoretically marginal-cost pricing promotes efficient resource allocation by providing electric users with adequate price signals of the costs of additional capacity required to meet future increases in electric demand. In practice

enforcement of marginal cost pricing is difficult because of the many imperfections and uncertainties in the world. What is required is to recognize that the principle of fixing rates at marginal cost refers to an optimal economic situation, while at the same time acknowledging the complexity of the problems encountered in actual practice.

The Madison Gas case had a significant impact on the pricing policies of the major electric utilities in Wisconsin. After "Madison Gas", the PSCW directed the major private (investor-owned) electric utilities to perform research studies relating to peak-load pricing. The objectives of these research efforts were to assess the possibility of placing peak-load cost burdens on the appropriate electric customers to measure price elasticity of demand for various electric classes and to provide information on alternative load management approaches (in lieu of pricing) to control peak usage (Malko and Stipanuk;1976:33).

In 1976, MGEC was ordered by the PSCW to implement marginal cost-based, time-of-day rates for its two largest customers. Hearings were to be held to develop such rates for other large commercial and industrial customers. By 1978, the PSCW had ordered all utilities to supply marginal cost information with rate filings (Mahoney;1979:201).

The Madison Gas case and the regulations developed as a result of this case made Wisconsin utilities leaders in research of marginal cost time-of-day pricing relative to many other states and utilities. The PSCW became the first commission to adopt the principles of long-run incremental cost as a basis for designing electric rate structures. This leadership in the development of rate design makes Wisconsin utilities valuable comparison for an evaluation of B.C. Hydro and its policies.

## THE RATIONALE FOR SELECTING PULP MILLS FOR COMPARISON

Besides examining electric utilities and their respective policies, this thesis also examines pulp mills and their energy use. Studying pulp mills is an appropriate choice when examining electric utility pricing policies and buy back rates, because of their unique situation with respect to electrical energy use. Pulp mills have large electrical energy requirements and have the potential to produce even larger amounts of power through self-generation. Pulp mills have, therefore, been selected as a measure to determine the relative importance electric utility policies place on the development of self-generation and to examine the selected pulp mills' technical and operational efficiency of energy use.

Self-generation refers to condensing turbines, cogeneration or other forms of on-site generation of power. Pulp and paper mills' large steam and electricity requirements enhance the attractive possibilities of burning industrial wastes for conventional thermal electricity and the cogeneration of electricity and process steam to help reduce operating costs.

Conventional thermal electricity generation uses condensing steam turbines to generate electricity by burning fuel in boilers to produce high pressure steam. The steam is used to drive a turbine which in turn drives a generator. The exhaust steam is of too low a pressure for use in any further processes, therefore, it is condensed in cooling towers. The condensate is then returned to the boiler feedwater system to be transformed to steam again. The electricity produced in this manner accounts for, on average, 35 percent of the energy in the fuel consumed (Makinen;1991:5).

Cogeneration in a pulp mill consists of burning used chemicals and organic material removed from virgin wood fiber during the cooking process of chemical or kraft pulping (i.e., black liquor) and bark and waste to generate high pressure steam (Makinen;1991:104). Cogeneration systems first use high pressure steam to generate electricity and then use the

resulting low pressure steam for process heat in pulp and paper making processes. The immediate benefit is the increased technical efficiency of energy use. Cogeneration efficiencies can reach as high as 70 to 85 percent or better as compared to 30 to 35 percent for conventional generation (Capehart and Capehart;1991:29). The operating standards will vary depending upon the type of technology used for power production. The net result of the sequential production of electrical energy and thermal energy from a single process (i.e., cogeneration), is the potential to produce more useful energy from a given quantity of fuel.

Within B.C., the large abundance of wood wastes provides the potential for pulp mills to develop large amounts of electricity and process heat. The ability to use forest residuals and wood wastes to create energy may be one of the most profitable avenues for future innovations and investment in the forest industry. Increased levels of cogenerated power would increase the technical and economic efficiency of energy use and development.

Significantly greater amounts of energy would be required to produce electricity and steam separately rather than sequentially through cogeneration. One megawatt of cogeneration capacity operating with a load factor of 75 percent would require approximately 7000 m<sup>3</sup> (44,000 barrels) of oil annually, 930 m<sup>3</sup> (5,800 barrels) less than if the steam and electricity were produced separately (Makinen;1991:7).

Both cogeneration and condensing steam turbine electric generation provide opportunities for pulp mills to reduce their purchased electrical requirements. From the viewpoint of society as a whole, the use of wood wastes to produce steam and electrical energy provides the possibility to reduce the use of valuable natural gas and fuel oil plus lower the overall costs of electricity (Helliwell and Cox;1978). The result of increased self-generation may also delay or remove the need for further megaproject developments, which makes this "type" of development attractive.

## Energy Use in the Pulp and Paper Industry

The increased global awareness of environmental issues has affected the operation of pulp mills. Increased pollution control and declines in the quality/quantity of the forest resource base have increased pulp mill operating costs. This, combined with oil price shocks of the mid-1970's, has greatly affected the finances and operations of the pulp industry. While energy costs have since stabilized and even decreased in real terms, they nonetheless remain an important factor in pulp mill operating costs.

Variable cost is the primary competitive factor in the pulp and paper industry, accounting for 70 to 80 percent of total manufacturing costs. This compares with variable costs below 50 percent for the chemical industry and levels of approximately 40 percent for manufacturing industries (Arpan;1986:3-34). These costs vary between producers depending on the location, degree of integration and type of product.

Purchased energy is one of the principal variable costs in the pulp and paper industry. With electric consumption at about 950 kWh per oven dry tonne (pulp with the majority of moisture removed) of kraft or chemical pulp, energy remains a competitive cost factor in the pulp and paper industry (Tillman;1985:137). The large amount of energy used requires virtually all pulp operations to have some form of cogeneration to help reduce costs of purchased power.

Energy is an important issue in the very competitive pulp and paper industry. Originally, however, in the period between 1950-70 when many pulp mills operating today were built, fuel costs were low and electricity costs were decreasing. Energy consumption was therefore not as strong an influence in the design of a mill as it is today. The growing importance of energy costs increases the incentive for pulp mills to reduce purchased power costs through greater levels of self-generation.

Within B.C.'s pulp and paper industry, it has been estimated that the technical

potential exists to self-generate 10,632 GWh per year (Makinen;1991:91). Of this, 6076 GWh per year is regarded as being economically feasible. This represents 82 percent of the current level of annual utility sales to the pulp industry (Makinen;1991:92). This is a very significant amount when it is understood that, in 1989/90, total sales by B.C. Hydro to the pulp and paper industry were 7,972 GWh; this represented 46 percent of total industrial electricity sales for that year and accounted for 20 percent of B.C. Hydro's total electricity sales (B.C. Hydro;1990:12). Clearly, if B.C. Hydro can encourage the development of any portion of this potential, it could significantly reduce the load demand of this industry.

### Factors Influencing Cogeneration

One recent survey by Reinsch and Battle (1987), examined Canadian corporate attitudes towards cogeneration. The survey was not specific to the forest industry but rather examined the attitudes of all industries that have the potential for substantial benefits from cogeneration, such as those industries with large thermal requirements.

This survey listed the low cost of industrial electricity in most regions of the country as the primary constraint for cogeneration. The low rate resulted in an excessively long pay back period on capital expenditure and thereby reduced the economic advantages of increased cogeneration. Companies tend to demand high rates of return on energy saving investments and typically look for pay back in one to three years. In contrast, investments in new energy supplies only require a return of five to ten percent (Cairncross;1991:13-14).

Another important consideration has been the low buy back rates in Canada. The low rates discourage the construction of facilities large enough to produce surplus power; this eliminates the potential for building larger facilities that have the advantage of providing economies of scale. In brief, the overall conclusion, was that the decision to cogenerate is



primarily economic and related to the rate of return on investment.

### Electricity Prices and Pulp Mill Self-Generation

Electricity rates are a major factor in determining pulp mills' different levels of self-generation. Pulp mills will choose a particular profit maximizing strategy, with respect to energy use, for a given price of electricity. This can range from having no cogeneration capacity to being a net exporter of power. Given low electricity rates, a pulp mill may decide it is less expensive to purchase power as opposed to installing self-generation capacity. The higher the price of electricity, the greater the incentive for pulp mills to increase their cogeneration capacity.

### Advantages of Self-Generation vs Megaprojects

The ideal new energy resource for an electric utility would have short lead times, modest scale and wide dispersal. There would be no single unit responsible for a large proportion of the system's needs (Cavanagh;1983:157). These factors are much more applicable to industrial self-generation projects than large utility megaprojects.

When a megaproject first begins developing power, much of the electricity is surplus because it takes time for demand to equal supply. This, combined with the fact that B.C. Hydro has historically preferred to err on the side of overestimating rather than having shortages has, at times, resulted in very large surpluses. This was the case with the Revelstoke Dam. At its completion in 1984, all of its energy was surplus to domestic needs. Between the years 1984 to 1988 a great deal of this energy was exported on spot markets at an average price of 2.4 cents per kWh while it cost 4.2 cents per kWh to produce (Jaccard et

al;1991:4).

While the Revelstoke Dam was generating surplus power, B.C. Hydro offered incentives to major industrial users to purchase this power. From February 1985 to April 1988 B.C. Hydro offered power at well below normal electricity prices to industrial self-generators to "turn down" their turbines and reduce energy production. During this time, over 1700 GWh of surplus electricity were sold to mills which had the capacity to generate this electricity themselves (Makinen;1991:9).

Industrial self-generation is perceived to have many advantages over utility generation. Self-generation offers the advantages of much shorter lead times and capacity may be increased in much smaller increments avoiding large surpluses. There is also the potential for reduced transmission losses as a result of siting generation near to the industrial customers' loads. These advantages make industrial self-generation a viable alternative for meeting future demands. A determining factor in the development of these generation facilities will be the amount of encouragement offered by the utilities to industry to increase these levels.

### Pulp Mill Production Methods

The pulp and paper industry use a variety of pulp production methods in both Canada and the U.S. The most common of these employs chemicals to separate the fibres in wood by dissolving the lignin or "glue" that holds it together. While there are several types of chemical pulping, it is the sulfate or "kraft" method that is the dominant chemical process. The predominance of kraft pulping technology is largely due to its early success in pulping virtually any wood species and because chemical recovery and reuse is more rapidly accomplished.

Kraft style mills are the most common form of pulp mill in B.C. For comparison purposes it was therefore necessary to select U.S. electric utilities that serve similar types of pulp mills. Because of the presence of several kraft mills in Wisconsin, it proved to be an ideal candidate for comparison with B.C.

## DATA SOURCES

The empirical analysis is based on several sources of information. The data are based in part on questionnaires that were sent to the pulp mills and electric utilities in Wisconsin and British Columbia. A copy of the original questionnaires are included in Appendix A.

### Pulp Mill Questionnaire

The pulp mills selected for the survey were kraft producing pulp mills, because of their ability to cogenerate power. Kraft mills are also the dominant form of pulp production in B.C. Several of B.C.'s pulp mills produce kraft pulp as well as pulp by other methods. For the purposes of this study only those mills that use kraft production exclusively were surveyed.

Using industrial directories (Lockwood's and Post's, 1986) 13 pulp mills served by B.C. Hydro were identified as having exclusively kraft production. Within Wisconsin only 4 pulp mills utilize kraft production and these mills are served by several different electric utilities. The entire population identified was 17 mills and it was decided to survey each mill.

The questionnaire is composed of a total of 14 questions. The first four questions are very general and designed to establish the pulp mill's age, type of production and level of production. Questions five through ten are primarily concerned with the amount of electricity used in the production process and the mill's electricity purchase agreement. These questions also establish the mill's power factor and the percentage of the mill's electricity generated internally or purchased. The final four questions are concerned with the production of self-generated power. They specifically examine the amount of energy produced, the potential for increasing the level of self-generation and the principal incentives that encourage increased self-generation.

In order to obtain complete questionnaires from several pulp mills it was necessary to ensure confidentiality so that the pulp mills would not be identified in connection with any specific data. Even with these assurances not all the mills surveyed completed the questionnaire. In B.C. two pulp mills declined to answer the questionnaire and in Wisconsin one of the four mills surveyed regarded all information requested as confidential and declined to answer. Some of the mills that did complete the questionnaire were unable to answer all the questions because of limitations of mill records, time constraints in the development of the answer, or the information was regarded as confidential.

The information that the B.C. pulp mills did not supply was requested, where applicable, from B.C. Hydro. B.C. Hydro was able to provide satisfactory information on the pulp mills' cost of purchased power and load factors (the latter not included in the original questionnaire). The information supplied by B.C. Hydro will be described in more detail later in this chapter. The response rate represents a satisfactory sample of those surveyed because three out of four Wisconsin mills and eleven out of thirteen B.C. mills completed the questionnaire. The collection of this information took place in the summers of 1989 and 1991. All calculations and references will refer to the 1991 data unless otherwise indicated.

## Electric Utility Questionnaire

Two Wisconsin electric utilities were surveyed in addition to B.C. Hydro. A copy of the questionnaire is included in Appendix B. Of the three Wisconsin pulp mills that responded to the questionnaire two are served by the same Wisconsin electric utility while the third mill is served by a different electric utility. These two Wisconsin utilities were then sent a questionnaire. To ensure the confidentiality of the information the Wisconsin utilities are referred to as WEU #1 and WEU #2.

The electric utilities' questionnaire is composed of seven questions and asks for a variety of information to determine the operating characteristics of the utility. The questions are very general because more specific utility information was available from other sources.

## Other Data Sources

The more detailed utility information, regarding the utilities' long-run marginal cost (LRMC) and buy back rates (i.e., non-utility purchase policies and rates), was collected by means of personal communication with utility employees involved in pricing and costing and forecasting and development. Further information was obtained from utilities' publications.

It was most difficult to obtain information from the Wisconsin utilities. Most of the information regarding these utilities was collected through personal communications with employees of the Public Service Commission of Wisconsin (PSCW). Further information was provided in documents from the PSCW.

Additional information was also collected on pulp mill operations. This was gathered by visiting the Canadian Forest Products pulp mill located in Port Mellon, B.C. Similar information was received from the Wisconsin pulp mills through communication with their

employees.

## ANALYSIS OF BRITISH COLUMBIA AND WISCONSIN DATA

There will be several comparisons made in the analysis of the respective attitudes of pulp mills and electric utilities toward increased self-generation. The pulp mills' various levels of energy production will be examined first. This includes an analysis of pulp mills' attitudes towards increasing their level of self-generated power (objective 1). The second part of the analysis will examine the economic incentives a utility provides for the development of self-generated power. This will be explored in a detailed assessment of two specific issues:

- (1) the utilities' marginal cost of power compared to the rate offered to pulp mills i.e., mark-up (objective 2),
- (2) the buy back options available to self-generators (objective 3).

### Chapter Outline

Chapter 2 summarizes the theoretical and practical considerations in the pricing of electricity that are pertinent to the study. The chapter describes the economics of generating electric power with respect to hydroelectric and thermal generating systems. The chapter also describes the options available for electric utilities to meet demand. Finally there is a brief discussion of B.C. Hydro's electric rates and their effect on the demand for this resource. It is important to have an understanding of B.C. Hydro's early pricing policies, because many of the present day criticisms stem from these early beginnings.

The third chapter provides a detailed description of the specific analysis and comparisons to be performed with the data. The fourth chapter presents the results and interpretations of the analysis of the pulp mills and a discussion of the implications of the

results. Chapter 5, similarly presents and discusses the results of the electric utility comparisons. Finally chapter 6 provides a summary of the results and describes their significance with respect to the objectives of this thesis.

## **CHAPTER 2**

### **THEORETICAL AND PRACTICAL CONSIDERATIONS IN THE PLANNING AND PRICING OF ELECTRICITY**

Current trends in utility pricing reflect a movement towards the marginal cost pricing of electricity. While this is not a new idea in utility pricing, it does represent a change in the direction of pricing in North America and more specifically Canada. This change is indicative of a progressive move towards a least-cost comprehensive style of planning.

In this chapter I will discuss the issues that relate to the economics of generating electric power and provide descriptions and definitions of many of the terms and concepts involved in the planning options available to electric utilities. An understanding of these concerns and pricing strategies is essential to fully appreciate the significance of the policies discussed and the respective analysis presented in the following chapters. Finally there is a discussion of B.C. Hydro's development and its present situation relative to the concerns discussed.

#### **MARGINAL COSTS OF ELECTRIC PRODUCTION**

The economics of generating electric power depends largely on the resources available to a utility. These resources may be roughly divided into either thermal or hydroelectric generating units. Thermal units include coal, oil, or natural gas combustion units as well as nuclear plants that develop high pressure steam to drive turbines, while hydroelectric generating units are driven by fallen water.

Within an electric utility's typical daily load curve, there will be a substantial difference between the minimum and maximum demand. A thermal system will meet this



demand by making greatest use of its generating units with the lowest production cost. As demand rises towards its peak level of the day, the utility will use higher cost plants to meet demand. As a result, operating costs will vary according to the level of the system load curve.

To maintain system reliability, electric utilities will maintain excess capacity to guard against unforeseen outages or unexpected load increases during the peak period. The peak period is usually determined by the shape of the daily load curve during the year's three or four months of extreme temperature.

The marginal cost of generation in a thermal system will therefore vary according to the season and time of day. During the off season, depending on the utility, there will be excess capacity and the more expensive peaking units will seldom be required. During the heavy season, however, the utility's marginal cost of generation is based primarily on the need to meet peak demand.

This system differs considerably from those that are primarily supplied by hydroelectric generators. The primary constraint on a hydroelectric system is the aggregate amount of water that can be stored, however, thermal systems are primarily constrained by the maximum rate at which electricity can be supplied. It is uncommon for hydroelectric systems to be constrained by the daily peak demand, because capacity related costs for turbines and penstocks are a relatively small proportion of its total generating costs (Mitchell et al;1978:32). Hydro dominated systems will therefore build excess capacity to take advantage of peak water flows and as a result tend not to require all of their capacity at once, even during peak periods. This is why hydro systems are called "energy critical" and thermal systems are called "capacity critical" (Jaccard et al;1991:10). More specifically, "energy critical" means that the main expansion costs relate primarily to the provision of extra energy (stored water) rather than to the generators and distribution structures required to meet peak

demands.

In an all-hydro system, the marginal cost of generating capacity incurred during the peak period is based on the cost of increasing the peaking capacity with additional turbines, penstocks, etc. Marginal energy costs, as the result of annual water flows would be the costs of increasing reservoir capacity.

During the wet season, when water inflow from the catchment area exceeds desired outflow, the reservoir fills up and excess water may have to be spilled. During these times, marginal energy costs would be small involving, for the most part, operation and maintenance costs only. Incremental capacity costs may also be ignored during times when demand does not place pressure on capacity.

However, if the system is likely to be energy constrained and all incremental capacity is needed primarily to generate more energy because the energy shortage precedes the capacity constraint for many years in the future, then the distinction between peak and off-peak costs, and between capacity and energy costs, tends to blur (Munasinghe;1990:114).

In the extreme case of a system constrained for energy, because hydro energy consumed at any time (except during spilling) will lead to a draw down on the reservoir, the marginal costs of production could be met by applying a simple kilowatt-hour charge at all times. These results are summarized in Table 2.1 (Munasinghe;1990:135).

If the utility consisted of a mixture of hydroelectric and thermal plants, the estimation of marginal costs would depend on the mix of generating plants used at different times. These systems will typically have some seasonal variation in marginal costs unless the wet periods happen to coincide with seasonal peaks in system load.

A utility's marginal cost of production is also composed of many other variables in addition to the types of generation facilities. These include daily and seasonal demand requirements, as well as a variety of administration and distribution costs.

Table 2.1 : Marginal Generating Costs in an All-Hydro System

Type	Peak Period		Off-Peak Period	
	Wet Season	Dry Season	Wet Season	Dry Season
Capacity Constrained	Capacity	Capacity & Energy	None	Energy
Energy Constrained	Total incremental costs required to supply additional kilowatt-hours			

(Munasinghe;1990:136)

Note - Table 2.1 refers generally to tropical and subtropical climates not to a coast temperate climate. The table is useful, however, in summarizing the large variation possible in an all hydro system.

These differences must also be reflected in the rate a utility must charge in order to receive a fair return on investment. Some of these variables, such as non-retail sales, fuel costs and residential use per customer, explain a significant portion of the differences in electric utilities' costs of service. To determine the difference between utilities' costs of service would require that these variables be normalized.

Utilities with large amounts of non-retail sales can have substantially reduced overhead costs. A utility that sells large amounts of power wholesale does not require the same number of meter readers, telephone service representatives, line crews or miles of distribution wires as would a utility with predominantly residential customers (Zakem;1986:30).

Fuel costs are also a major determining factor in the costing of generating power. Each utility will generally have a variety of generating plants often using various fuels in the generation of power. A utility's mix of generating plants is the result of decisions and actions over many years. While a utility tries to operate its mix as efficiently as possible, it cannot easily or quickly change the mix or the characteristics of the load that the plants were built to serve. The great variations in these costs can be demonstrated through examining WEU #1.

As with all utilities, WEU #1 is concerned with producing electricity at the lowest possible cost. A system with several power plants will run its lowest-cost units all the time, day and night, to carry the maximum load possible. Units loaded in this manner are referred to as baseload units.

WEU #1's baseload capacity is met with a combination of hydro, coal and nuclear-powered generating units (Table 2.2). The fuel for these generating units ranges from zero, for the hydro units, (water rental fees are very low and WEU #1 lists these costs as nil) to as high as \$0.021 per kWh of net generation for two of the coal-fired generating plants (all values in 1988 U.S. dollars). Total variable cost per kWh of net generation for these generating plants varies from \$0.009 for a hydro plant to \$0.027 for two coal fired units. The total variable cost is the sum of fuel expense (including oil and natural gas consumed in coal-fired units) and other operations and maintenance expenses.

The difference in operating costs is even more apparent with the cycling and peaking forms of generation as illustrated in Tables 2.3 and 2.4 (tables provide definitions of the terms cycling and peaking generation). The fuel cost for cycling generation is \$0.019 per kWh of net generation for a coal-fired plant. The total variable cost per kWh of net generation for the plant is \$0.023. WEU #1 lists two costs for the peaking units; for these the fuel cost and total cost per kWh of net generation for the gas/oil units are \$0.06 and \$0.068 respectively. While the hydro units total cost per kWh of net generation is \$0.029.

Tables 2.2 : WEU #2 Types of Baseload Generation

<u>Fuel</u>	<u>Capacity (MW)</u> (nameplate)(a)	<u>In-Service</u> <u>Date</u>	<u>Fuel Cost</u> <u>/Net kWh</u>	<u>Total Cost</u> <u>/Net kWh</u>
Hydro	10	1909	---	\$0.010
Hydro	30	1914	---	\$0.009
Coal	243	1975	\$0.018	\$0.020
Coal	243	1978	\$0.016	\$0.020
Coal	60	1951	\$0.021	\$0.024
Coal	225	1969	\$0.017	\$0.019
Coal	100	1959	\$0.016	\$0.019
Coal	100	1962	\$0.016	\$0.019
Coal	75	1954	\$0.021	\$0.027
Coal	75	1955	\$0.021	\$0.027
Nuclear	217	1974	\$0.005	\$0.019

(WEU #2: 1984, 1988)

(a) In engineering practice several terms are used to designate the rating of a generating unit. Capacity or nameplate rating refers to the manufacturer's rating of the unit. The engineers who design the unit draw up their specifications so that the given generator will produce electricity at a certain rate under specified conditions. This rating will be imprinted on the nameplate attached to the generator; it is given in gross kilowatts, that is, without any deduction for electricity used in the generating process (such as for operation of fuel pumps and other auxiliary purposes) (Vennard;1979).

The difference in fuel cost per kWh of net generation can be substantial, as Tables 2.2, 2.3 and 2.4 demonstrate. The control over these costs often does not rest entirely with the electric utilities. The price for fuel in many cases is subject to geographic considerations as is the availability of hydro sites suitable for large scale power generation. Further restrictions are created by political considerations such as the decision to allow nuclear power generation, large coal generation or large hydroelectric projects. Pressure groups become very active in B.C. whenever the focus of future energy development turns toward hydroelectric megaprojects. Depending on the project, there may be a variety of interest

groups involved. These groups can include members of the commercial fishery, foresters, native people, farmers, etc. The concerted efforts of these groups are capable of exerting sufficient political pressure to influence the final generation mix of a utility.

**Table 2.3 : WEU #2 Types of Cycling Generation (a)**

<u>Fuel</u>	<u>Capacity</u> (nameplate)	<u>In-Service Date</u>	<u>Fuel Cost</u> <u>/Net kWh</u>	<u>Total Cost</u> <u>/Net kWh</u>
coal	294	1985	\$0.019	\$0.023

(WEU #2; 1984, 1988)

(a) Power plants must have reserve and standby capacity so that the company's customers will still have power even if a unit must be taken out of service. Reserve capacity will often consist of older generators. These are kept in good condition, but they stand idle because it costs more to run these older plants than it does to operate newer ones. If the reserve unit is in operation (that is, spinning at full speed), it is called a spinning reserve (cycling reserve). A machine that is running can generate almost instantaneously. The spinning reserve is always running, but often it is not generating any electricity and is only using enough fuel to overcome losses by friction (Vennard; 1979).

**Table 2.4 : WEU #2 Types of Peaking Generation (a)**

<u>Fuel</u>	<u>Capacity</u> (nameplate)	<u>In-Service Date</u>	<u>Fuel Cost</u> <u>/Net kWh</u>	<u>Total Cost</u> <u>/Net kWh</u>
Hydro (4 units)	2	---	---	\$0.029
gas/oil (5 units)	182	---	\$0.060	\$0.068

(WEU #2; 1984, 1988)

(a) For use in meeting peaks and when the load must be picked up quickly companies will often use gas turbines or hydro power to meet peak demands because hydro power and gas turbines can be started very quickly. Peaking generation has the most expensive operating costs and is of smaller capacity.

## **ESTABLISHMENT OF A SPECIFIC RATE (PRICE) STRUCTURE**

There are difficulties in establishing rate structures due, in part, to the mass of technical detail involved in the design of workable rate schedules for different types of utility enterprises. The most difficult decisions are those concerned with taking into account numerous conflicting standards of fairness and functional efficiency in the choice of a rate structure.

In the literature there are many suggestions regarding the desirable attributes to be sought and those that are to be avoided in the development of a sound rate structure. Bonbright listed eight objectives that outline the desirable attributes of a rate structure. Three of these objectives may be designated as primary and are as follows:

- (1) the revenue-requirement or financial-need objective, which takes the form of a fair return standard with respect to private utility companies,
- (2) the fair-cost apportionment objective, which invokes the principal that the burden of meeting total revenue requirements must be distributed "fairly" among the beneficiaries of the service,
- (3) the optimal-use or consumer rationing-objective, under which the rates designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received (Bonbright;1961:292).

Traditionally rate designs have adhered to declining block rates, thus producing what are, in effect, quantity discounts as applied to electric prices. These rate designs were appropriate when conditions of decreasing cost and increasing returns to scale were present and significant. The justification for declining block rates has disappeared and this has led to much of the current discussion of long-run marginal costs (LRMC) and peak load pricing.

LRMC is derived from incremental or discrete additions related to capacity reasonably expected to be added in the near future. The capacity additions used to determine LRMC usually refers to a utility's next major investment or set of investments. Rates based on LRMC represent a usable and practical approach and provide the correct price signal for investment.

In addition to rates based on LRMC electric utilities may promote better utilization of capacity and avoid unnecessary investments to meet peak demands, by structuring prices so that they vary according to the marginal costs of serving demands. These prices may be representative of different consumer categories, i.e., in different seasons, at different hours of the day, by different voltage levels, in different geographical areas, and so on (Munasinghe;1990:100). The implication of this type of planning was first explored for the utilities of France (for example Boiteau and Stasi; 1964) and Great Britain (Turvey; 1968).

Within a capacity critical system the main expansion costs relate primarily to the provision of generators and distribution structures to meet peak demands. Establishing the appropriate peak periods for a capacity critical system, therefore, leads to the conclusion that peak consumers should pay both capacity and energy costs whereas off-peak consumers should pay only the energy costs. A marginal increase or decrease in usage by off-peak users does not affect the capacity costs, whereas, a change in usage by peak-users alters the need for this level of capacity cost. Consequently, capacity costs are properly attributable to peak users. Under this method of cost allocation, electric services provided during the off-peak periods are not assigned capacity costs because the demand for electricity at the time of system peak is thought to cause the peak, together with its capacity costs (Howe and Rassmussen;1982:193). This differs from an energy critical system (i.e., a hydro system with excess capacity) where the distinction between capacity costs and energy costs is not so clear. In these systems the marginal costs of production can be met by applying a simple



kilowatt-hour charge at all times.

Similarly, rates can be differentiated by voltage level or geographical areas to determine the cost consumers impose on the system. Ideally a utility's resources should be allocated as far as possible among the customers according to the incremental costs they impose on the power system. Data constraints, however, and the objective of simplifying metering and billing procedures usually requires that there be a practical limit to differentiation of tariffs. Also, other constraints may be incorporated into LRMC tariffs, such as the political requirement of having a uniform tariff, subsidizing rural electrification, accounting for environmental costs, etc. It must be realized that each derivation from LRMC imposes an efficiency cost on the economy (Munasinghe;1990:102).

#### **ENERGY SUPPLY AND DEMAND PLANNING OPTIONS: DETAILS AND DEFINITIONS**

Since the energy shortages of the 1970's, there has been much debate concerning the rationality of those energy policies that utilize projections of unlimited growth. In addition to this, a more developed awareness of the environment has led to the formulation of new attitudes regarding energy policy making and planning (Kuropatwa;1987). The emphasis has now shifted from energy development to a cost minimizing approach which involves the management of energy consumption. The first step in this "management" approach to energy planning, has been the recognition and acknowledgment that improvements in existing efficiencies, when achieved on a large scale within a predictable schedule, may constitute an energy resource (Tremain;1990:6).

Electric utilities recognized the need to undertake systematic supply and demand analyses as dramatic departures from past trends in growth of demand occurred. During the period 1973 to 1986 electricity markets were very volatile due to erratic international oil

prices, which led to sharp increases in the cost of producing electricity from fossil fuels. This coincided with other factors such as a growing distrust of nuclear power plants, a reduction in the availability of large hydro sites and increased intervention by environmentalists and other special interest groups (Jaccard et al;1991:5). These factors served to dramatically increase the price of electricity at a time when most areas of North America were experiencing an economic downturn. The higher price of electricity, combined with the economic downturn, to slow dramatically electricity demand. This had extreme financial consequences for many utilities that had constructed, or were constructing, generating facilities that were now surplus to demand (Jaccard et al;1991:5). As a result of these changes energy supply and demand planning are subject to far more risk and diversity today than they were 20 years ago (Berry;1988:9).

Presently there are two principal options available to help regulators in dealing with this greater uncertainty and diversity. Figure 2.1 contrasts the two options that both strive to match energy demand with energy production. The first option is to promote the deregulation of power generation and to use the competitive marketplace to inform economic decision making (Berry;1988:9). This option has been most actively pursued in the U.S. The argument is as follows:

the classic rationales for sustaining regulated monopolies may apply to the transmission and distribution of electricity, but the generation side of the business is perfectly amenable to competitive arrangements; thus, we should allow entrepreneurs to bid for the opportunity to provide power to individual distribution systems over common-carrier transmission lines, in an environment free of both guaranteed returns and regulated prices (Cavanagh;1986:306).

The competitive market would determine what kinds of power plants are built and how many. This description bears little resemblance to how business is now conducted. Vertically-integrated utilities provide the most generating capacity. The deregulation of power

generation, however, has become a popular theme in the academic literature, and within the U.S., steps have been taken which appear to favor deregulation.

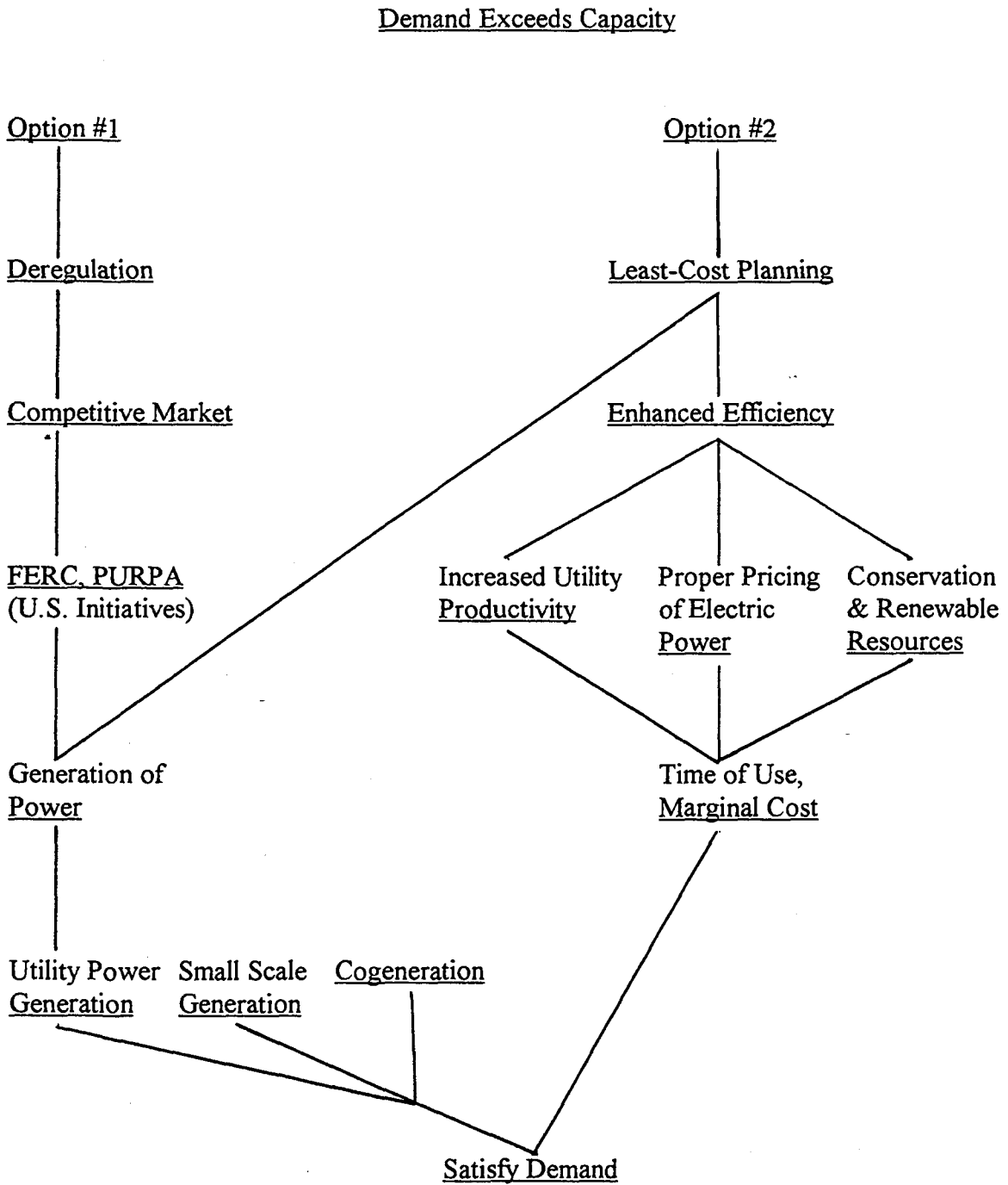
#### DEREGULATION: PURPA AND POWER TRANSFERS IN THE U.S.

A crucial step to the development of a deregulated power system in the U.S. was the signing of the National Energy Act into law November 9, 1978. The Act comprises five major statutes as follows:

- (1) the National Energy Conservation Policy Act of 1978,
- (2) the Power Plant and Industrial Fuel Use Act of 1978,
- (3) the Public Utility Regulatory Policies Act of 1978,
- (4) the Energy Taxation Act of 1978,
- (5) the Natural Gas Policy Act of 1978.

The Public Utility Regulatory Policies Act (PURPA) is a major concern for electric utilities. PURPA is divided into six separate sub-sections; Title I -- Retail Regulatory Policies for Electric Utilities, is particularly relevant. Title I represented a major incursion on the part of the federal government into the traditionally state-governed process of rate making. While Title I did not shift the primary responsibility for regulation of retail electric rates to the federal government, it substantially expanded federal involvement in rate making by creating new federal procedures for rate setting (Partridge;1979:16).

Figure 2.1 : Energy Supply and Demand Planning Options



(Based on Cavanagh's article, [1986])

One of the primary intents of PURPA is to remove the major obstacles to cogeneration and small scale renewable resource production that resulted from the combination of an unfavorable legal climate and the unaccommodating attitude of the utilities. The courts and state commissions were active in protecting the utilities from competition by industrial generators. For example disputes over the utilities' duty to provide back-up service were often decided in favor of the utilities (Wooster;1983:712). The most significant of the obstacles preventing non-utility generation have been identified as follows:

- (1) the unwillingness of utilities to purchase the electric output of cogenerators and small power producers,
- (2) the likelihood of utilities charging discriminatingly high rates for the back-up power required by these producers,
- (3) the risk that cogenerators and small producers which provide electricity to a utility's grid would be subjected to regulation as an electric utility (Charo et al;1986:453).

PURPA, therefore, set out to develop rules that would require utilities to sell electric energy to qualifying facilities and purchase electric energy from such facilities at just and nondiscriminatory rates (Charo;1986:456).

The intent of Congress with respect to PURPA was to provide access for private investors to sell electricity to their local utilities, at whatever rate those utilities would have had to pay to generate the equivalent amount of electricity themselves. The concepts as outlined in PURPA were not particularly revolutionary concepts for U.S. utilities or state regulatory commissions; they had been considering some or all of the concepts for years. It was hoped, however, that the Act would give greater emphasis to efforts that already had been initiated in many states to redesign their rate structures.

In some parts of the United States, the response to this legislation was remarkable. In California, for example,

as of April 1985, California utilities had received or were anticipating power sales offers from sponsors of some 1500 independently-financed generating units with a cumulative capacity equivalent to 22,000 Megawatts (MW)- this is in a state whose total peak demand in 1982 was about 35,000 Megawatts, and whose anticipated needs for all sources through the year 1996 total less than what these entrepreneurs are already claiming the ability to develop (Cavanagh;1986:307).

On the transmission side, the Federal Energy Regulatory Commission (FERC) exhibited a strong interest in promoting freer and more varied inter-utility transactions. "While it is doubtful that FERC currently has authority to force anything approaching common-carrier status on the transmission systems, some observers see that status as an inevitable outgrowth of current trends" (Cavanagh;1986:307).

#### Deregulation: A Cautionary Note

The contemporary movement toward a competitive electricity marketplace in the U.S., through PURPA's legislation and FERC does, however, provide ample cause for concern. This movement has done little to promote the development of efficient energy use or conservation (Cavanagh;1986). PURPA speaks exclusively to the generation of electricity without providing any incentive to conserve the product. "Such attitudes reflect widespread but irrational preferences for generation over conservation when additional power supply is required" (Cavanagh;1986:310).

## LEAST-COST PLANNING

The second option (Fig. 2.1) is least-cost planning. This involves the careful considerations of different supply and demand side scenarios. Least-cost planning is characterized by the Wisconsin Public Service as:

a process in which all renewable options for both supply and demand are assessed against an array of cost and benefit considerations which are defined as broadly as possible.... This approach...does not segregate supply side options...from demand side options.... Instead, it seeks to evaluate all options on an integrated equivalent basis (Wisconsin Public Service Commission, Order 05-EPH, August 5, 1986, p.3) (Berry:1986:9-10).

The fundamental characteristic of least-cost planning, as demonstrated in figure 2.1, is therefore, the systematic exploitation of all available resources, including the option of conservation, with the lowest cost resources being exploited first. The focus of utilities must shift from that of being a supplier of electricity to being a supplier of electricity services (Tremain;1990:5).

Least-cost planning explores a variety of supply and demand side issues to determine the most economically efficient manner to adequately meet future demand. Within the context of a least-cost planning framework, the goal of both regulators and utilities must be the provision of a sustainable reliable electricity service at the lowest possible cost. Energy supply can be expanded either by producing more or wasting less. The goal of energy planners should then be to develop utility investment according to whatever methods best reduce costs, uncertainty and risk while at the same time meeting demand requirements.

An effective least-cost plan would improve commission review of utility plans and proposed projects. It would also create greater utility acceptance of demand management and alternative sources of supply. This requires improved knowledge of energy supply and

demand issues which, in turn, will reduce the chance of excess capacity while at the same time providing for lower costs and rates. The result would be greater public involvement in planning issues (Berry,1988:14).

### The Role of Conservation

Within a least-cost planning scenario, conservation would assume greater importance in energy planning than it has up to this point. Utilities would be required to stop viewing electricity demand as something they are limited to only predicting. Demand should be viewed instead as the sum of millions of "end uses" of generally low efficiency when compared with the best technologies that are available (Cavanagh,1986:314). By influencing the efficiency of the many end uses, utilities can actually influence future demand rather than merely predicting levels of future demand. In this way utilities can effectively begin to manage electricity demand.

The commitment to conservation within least-cost strategic planning has the advantage of both scale and flexibility; which is not possible with megaproject developments. Energy conservation programs may be implemented at varying scales ranging from a very small local program to much larger system wide conservation efforts. This is very different from the scale and commitment required to add new generation capacity. The technology used in energy conservation programs is often relatively simple (as simple as insulating houses) and may be installed in days or weeks as opposed to years. "No tiresome planning permission is needed, no furious residents demonstrate, and the technology is, generally speaking safe" (Cairncross,1991:13). This process also avoids the high costs of uncertainty about future demand, which is always present with megaproject developments (Cavanagh,1986:159).



## Management of Electricity Demand

The first step toward a "management" approach to energy planning is to recognize that a kilowatt-hour saved is indistinguishable from a kilowatt-hour produced from a new power plant. This approach to energy planning was first proposed by the Environmental Defense Fund (EDF) in California in the late 1970's. The EDF argued that promoting conservation was cheaper than building new power stations, yet had the same effect of matching energy supply with demand (Cairncross;1991:19). End-use efficiencies should, therefore, be evaluated as potential sources of supply with a claim on utility investment dollars superior to that of more costly resources.

The actual management of electricity consumption patterns is referred to as "demand side management" (DSM). This refers to utility activities designed to change the pattern and amount of electricity used by its customers. DSM relates specifically to utility intervention within the market to alter usage patterns. The purpose of this is to control load growth, alter the shape of the load curve or increase non-utility sources of supply. Utility intervention may take the form of incentives that encourage the purchase of efficient appliances, advertising and education regarding the advantages of conservation, rate design (peak load pricing), etc., (MacRae;1989:60). Energy management programs provide utilities with essentially low risk alternatives for meeting demand relative to the risks associated with megaproject styles of energy development.

"Many analysts now believe that the electric utility industry should not engage in further pursuit of large central station electricity production" (Colton;1986:176). It is felt that utilities should promote energy conservation, load management and small power production. All of these components, as advocated in a least-cost planning strategy, prevent many of the risks associated with the megaproject style of energy development.

It is consideration of the risks involved in energy planning that makes least-cost planning a desirable alternative to the old style of megaproject development. These considerations are of particular significance to B.C. Hydro's future plans. This is because on the present course, B.C. Hydro will have to add new generation facilities to meet the expected future demand increases. It is, therefore, imperative to pursue a better understanding of the issues and options available with respect to meeting future demand and to consider how others have responded in similar situations.

### **B.C. HYDRO'S SITUATION**

Historically, the British Columbia government has provided domestic markets with low cost electricity to help promote resource development. The predominance of hydroelectric generation in B.C. has largely contributed to the development of low prices. In addition to the low cost hydroelectric facilities the low prices were perhaps due to economies of scale and to public subsidy (Jaccard et al;1991:3).

The Bennett government of 1962 pursued the "two rivers policy", which was the development of hydropower on the Peace and Columbia river systems. "Power from the Columbia projects was exported to the U.S. in the form of down stream benefits. Power from the Peace was sold domestically, contributing through plentiful supply and low industrial prices to the dramatic development of the pulp and paper industry in the interior of the province in the 1960's" (Jaccard et al;1991:4).

While large hydroelectric projects provided low cost electricity in the 1960's, controversy surrounding these policies increased. During this time economists criticized B.C. Hydro's use of a declining block rate structure. It was argued that this rate structure was uneconomical in that it encouraged demand for electricity; the marginal price decreased as the

quantity of electricity increased (Helliwell;1978:120-121). B.C. Hydro, on its part, had serious doubts as to the possibility of implementing any form of marginal cost pricing. The concerns of B.C. Hydro were as follows:

- (1) they found in general the definition of the concept to be too confusing to be operational,
- (2) they questioned its objectivity when it came to putting the principle into practice,
- (3) they contended that the application of the principle does not promote other objectives of public ownership such as ensuring fairness in the allocation of joint costs to various classes of customers,
- (4) they felt that if the utility were to apply the marginal cost pricing principle its rates might have to be pitched so high that the utility would lose competitiveness in the energy market (Seth;1984:187).

More recently, controversy developed over the Revelstoke Dam's large surpluses and its environmental impact. In light of these criticisms several changes have been made at B.C. Hydro.

Instead of having a predominantly development-oriented philosophy, B.C. Hydro has become more receptive to innovations in utility management originating elsewhere. This change in focus is illustrated by B.C. Hydro's initiation of the Power Smart Program in 1989. Under this program, B.C. Hydro initially offered 14 conservation programs and has since developed another nine. The initial goal was to save 2400 GWh per year by the year 2000, however, this objective has been raised to 6460 GWh per year and a 1200 MW reduction in peak demand (B.C. Hydro;Mar.1991:7).

The Resource Smart Program was also implemented in 1989; this is intended to enhance the contribution of existing generation and transmission facilities. It is expected that this program will increase supply to the system by about 23 MW and 690 GWh per year by

2000. After 2000, potential gains of 1000 MW and 3000 GWh per year are considered economically feasible (B.C. Hydro;Mar.1991:10).

In addition to these programs significant changes have occurred in the pricing of electricity since the mid-1980's. In October of 1989, the Lieutenant Governor in Council issued a Special Direction to the British Columbia Utilities Commission Act. This special direction, designated as No. 3, replaced the previous Special Direction No. 1 that had been in place since 1984.

The new Special Direction requires the Commission to ensure that B.C. Hydro meets minimum financial requirements for the future, and also gives the Commission guidance with respect to long-term rate setting to ensure the rates not only meet the fair, just and reasonable requirements of the Act, but are also smooth, stable and predictable for the future, to reflect the cost of new generation facilities that will be required (BCUC;1989:ii).

In response to the Special Direction B.C. Hydro filed a Rate Application on November 30, 1989, for an across-the-board increase in revenue requirements over three years. The B.C. Utilities Commission (BCUC) did not accept the rate increases as an appropriate or effective signal to promote conservation and efficient use of electricity (BCUC;1992:5). The Commission approved increases in rates sufficient to allow B.C. Hydro to attain the financial requirements of the special direction, however, it specified that rate design was the preferable method for promoting conservation and efficient energy use (BCUC;1992:5).

B.C. Hydro subsequently filed Application for Rate Design of its Electric Tariffs with the BCUC.

B.C. Hydro stated that its Rate Design Application began a process of establishing rates which will promote efficient use of electricity by ensuring that electricity will be sold at a price which reflects the cost of new supply (BCUC;1992:7).

B.C. Hydro's proposal for attaining these objectives was presented to the BCUC in the spring of 1992. B.C. Hydro's Application has subsequently had approval of several of its initiatives that are designed to promote the efficient use of electricity. Some of B.C. Hydro's proposals have been rejected, however, with instructions to perform further research on these issues.

B.C. Hydro has therefore taken a step forward by beginning to generate some of its own information to ascertain how the application of marginal-cost pricing effects its particular situation. With these new policy directions, B.C. Hydro is moving from being a utility that meets demand solely through increased energy production to one that encourages independent power producers and demand side management. Industrial self-generation offers a significant source of non-utility electricity production and according to the principles of least-cost planning, should be pursued if it costs less than alternative generation sources. It is therefore important to determine the level of encouragement B.C. Hydro provides for the development of this valuable resource.

## **CHAPTER 3**

### **DATA ANALYSIS**

In this chapter I will provide a detailed description of the data analysis used to meet the research objectives described in chapter 1. The pulp mill analysis will be described followed by a discussion of the utilities' pricing policies and buy back rates. In addition, the problems of data comparability and the specific time intervals and methods of measurement will also be presented

### **PULP MILL ANALYSIS**

The pulp and paper industry is the largest user of purchased electricity in B.C.'s industrial sector. The pulp and paper mills' large requirements for both steam and electricity make the industry well suited for cogeneration. The attitude of the pulp and paper mills toward increasing their levels of cogeneration is, therefore, important with respect to the large energy potential available.

The first objective is to determine the attitudes and efforts of B.C.'s pulp mills regarding the improvement of energy efficiency and the self-generation of power. These results are compared with similar information collected from Wisconsin's pulp mills. To determine these attitudes the B.C. and Wisconsin pulp mills were questioned with respect to their present and future levels of energy production. The responses to these questions will be analyzed to evaluate any potential differences between the regions.

Pulp mills were also surveyed regarding their attitudes toward self-generation. Utilities often vary in their attitudes towards electricity generation by their customers. This

may also be applied to individual industries such as the pulp and paper industry. It is not uncommon for pulp mills to have very different attitudes with respect to generating power. Some mill managers may choose not to invest in large self-generating facilities, but rather develop other equally cost effective investments. Mills may choose to replace older less efficient equipment with the latest technologies rather than invest in self-generation facilities. The responses to these questions will help to clarify some of the reasons for the various levels of self-generation in pulp mills. The results are presented and discussed in the chapter 4.

### **ANALYSIS OF UTILITIES' PRICING POLICIES AND BUY BACK RATES**

Electric utilities directly influence the level of non-utility generation through their pricing policies and buy back rates. Pulp mills are less likely to develop their own power when electric utility rates are very low or surplus electricity from self-generation cannot be sold at a reasonable rate.

These issues are analyzed to determine B.C. Hydro's level of encouragement for self-generation and compared, whenever possible, with Wisconsin data. Specifically, this will be accomplished by addressing five separate points related to the electric utilities' pricing policies and buy back rates. Table 3.1 summarizes the items to be examined. Comparison #1 addresses the thesis's second objective of determining the importance B.C. Hydro places on the encouragement of self-generation from pulp mills relative to Wisconsin's electric utilities, as measured by electric utility rates. Comparison #2 involves four separate comparisons, that address the third and final objective of the thesis. These comparisons examine B.C. Hydro's buy back rates and other incentives that provide a market for self-generated power and compare the level of incentive they offer to power producers relative to Wisconsin's policies.

**Table 3.1 : Summary of Analysis of Utilities' Mark-up and Buy Back Policies**

**Comparison #1 : Industrial Power / Utilities LRMC**

---

B.C. Pulp Mill Rate	compared	Wisc. Pulp Mill Rate
-----	with	-----
B.C. Hydro LRMC		Wisc. Utility LRMC

**Comparison #2 : Buy Back Rates and Other Utility Incentives**

---

- (i) B.C. Hydro's Wheeling Policy : no comparable Wisc. data (Proposed)
- (ii) B.C. Hydro's Direct Purchase Agreement compared with Wisconsin Utilities' Buy Back Rates
- (iii) B.C. Hydro's Load Displacement Policy : no comparable Wisc. data
- (iv) B.C. Hydro's Spot Market Purchases : no comparable Wisc. data

---

In examining the economic incentives a utility provides for the self-generation of power, the rate charged is the most direct and obvious indicator. This study will not directly compare the electric utility rates, however, because this does not take into account the different production costs that utilities encounter in the development of power (many of these are described in chapter 2). What is emphasized, in this study, is how much incentive the utilities offer relative to their LRMC of production. This will provide a reflection of the utilities' attitude toward encouraging self-generation and not just determine which utility has the highest cost of production.



## COMPARISON #1 : INDUSTRIAL RATE / UTILITIES' LRMC

The first comparison is the ratio of the industrial rate for pulp mills to the utilities' LRMC. Using the LRMC as the denominator, the actual "mark-up" each utility applies to the electricity sold to the pulp mills may be expressed by converting the ratio to a percentage value. The mark-up refers to the amount a utility prices its power relative to the LRMC of production. This percentage value is used as a measure of the incentive provided for cogeneration based on each utility's LRMC of production.

### Pulp Mills' Cost of Purchased Power

B.C. pulp mills' cost of purchased power was regarded as being confidential and as a result was not made available. It was necessary, therefore, to make an approximation based on available data.

While B.C. Hydro's rate schedule for pulp mills and the mills' total usage requirements are available, it is not possible to calculate a specific mill's cost per kilowatt. To calculate an accurate cost per kilowatt would require the cooperation of each individual mill.

The large electrical requirements of industrial users require that their rates reflect the nature of their use and the cost of service. The industrial rate takes into consideration both the number of kilowatt-hours used (the energy charge) and the kilowatts of demand they impose on the system (the demand charge). The energy charge is generally a flat rate that is charged for each kilowatt hour the pulp mill uses during a billing period. The demand charge has a sliding scale which is based on the customer's rate of energy use (load factor) and reflects the kilowatts of generating capacity the utility company must reserve for a customer (Vennard;1970:237). The sliding nature of a demand charge frequently results in two B.C.

pulp mills paying different rates for power.

The B.C. pulp mills' cost of purchased power was therefore supplied by B.C. Hydro (Robinson;1991). Since it was necessary for B.C. Hydro to respect the mills' confidentiality, an average rate that is not specific to any particular pulp mill was used. The rate is an average of 1989, 1990 and 1991 rates for the mills surveyed. The mills are separated into two separate categories to provide a more accurate reflection of the actual rates paid for power. The two categories are:

- (1) BCPM(a), which represents the eight pulp mills that have self-generation capacity,
- (2) BCPM(b), representing the three pulp mills without generation capacity.

These categories provide a more accurate representation of the pulp mills' varying demand levels.

In addition to the levels of demand, the efficiency of a pulp mill's equipment also influences the price per kilowatt. This level of efficiency is represented by the mill's power factor. Certain electrical devices function in such a way that there is a demand for more kilowatts than are actually put to any useful purpose. The induction motor, which is common in pulp and paper production, has this characteristic when it is run at less than full capacity.

The actual work being done by the motor results in a certain kilowatt demand that can be measured by an ordinary demand meter. However, when partially loaded, the motor makes a different and useless kind of demand on the electric system. This demand is greater than the partial load on the meter and cannot be measured by the ordinary meter (Vennard;1979:15)

In other words, the operation of such an electric device results in the generation of a measurable amount of useful electric current and an amount of useless current. The useless current requires capacity in the system; reducing this level lowers the cost of providing

electric service. The power factor expresses the relationship between the useful current and the total current required. When there is no useless current in evidence, the power factor is said to be 100 percent. The customer has the ability to achieve this level by adding condensers to the system (Vennard;1979:15). The varying levels of the power factors between the mills will therefore be examined as part of the comparison on utility mark-up.

### B.C. Hydro's LRMC

The LRMC of the electric utilities is considered to be their next planned major generation facility. B.C. Hydro, in its 1990 Electricity Plan, identified the Peace Site C plus several projects on the Lower Columbia as the most economic resource options available. These projects are considered to be representative of B.C. Hydro's future developments and have been used to estimate the cost of new electricity supply for the long term.

In planning to meet future demand B.C. Hydro must compare many electric supply options and their relative merits. Electric supply proposals are difficult to compare because of different levels of energy cost, operating cost, location, start date and terms. To allow comparison of the various supply options, B.C. Hydro uses a standardized cost called levelizing. A levelized cost represents the sum of an investment's capital costs and operating costs (the former having been converted into an equal stream of annual payments), divided by the number of kWh's produced or saved by the investment. The levelized cost for these projects, in 1990 dollars, is estimated to be \$0.064 / kWh (B.C. Hydro;Dec.1990:9).

The location of demand will have an impact on the cost of electricity supply. The cost of transmission to many areas of B.C. contributes significantly to the cost of servicing new demands. In an effort to reflect these differences, B.C. Hydro has divided its service area into nine transmission regions and generates a cost of new electricity for each region.

The Lower Mainland is the reference point since it is B.C. Hydro's largest load center (B.C. Hydro;Dec.,1990:4). This study uses the average price of servicing the Lower Mainland and Vancouver Island regions, which represent roughly 70 percent of the demand on B.C. Hydro's system (B.C. Hydro;1990:1).

### The Wisconsin Utilities' LRMC

Unlike B.C. Hydro the Wisconsin utilities do not have access to a river system that provides the opportunity for large scale, relatively low cost, hydroelectric power. The Wisconsin utilities' preferred method to meet demand is through the use of coal gasification plants. At present the technological development for these plants has not reached an operational stage. If these coal technologies do not mature as expected the utilities will be forced to use their alternative plans that involve the construction of conventional pulverized coal plants. WEU #1 and WEU #2 both have alternative plans that forecast the need for a 300 MW pulverized plant for each of the utilities in the year 2003.

For the purpose of determining the Wisconsin utilities' next major generation project it is assumed that the pulverized coal plants represent the best estimate. The levelized cost of electricity from WEU # 1's coal plant is \$0.0781 / kWh in 1991 U.S. dollars. The levelized cost for WEU # 2's plant is \$0.070 / kWh in 1990 U.S. dollars (Cost estimates supplied by WEU # 1 and WEU # 2;July:1992).

### COMPARISON #2 : BUY BACK RATES AND OTHER INCENTIVES

The development of self-generated power provides a valuable source of energy. Important factors influencing the development of this resource are the options available for

self-generators to market their power. Within the U.S. the development of PURPA was largely due to a recognition of the need for policies that would encourage the development of this energy source. This section will compare those policies of the Wisconsin utilities that encourage self-generation with those of B.C. Hydro. An analysis of the electric utility policies that provide power producers with the ability to market their power (i.e., buy back policies) will reflect the utilities' effectiveness in the development of this valuable resource.

The buy back options available to self-generators varies considerably between electric utilities. B.C. Hydro does not have a specific "buy back" rate as the Wisconsin utilities do, however, it does provide several options for self-generators, such as pulp mills, to market surplus power. These include a proposed Wheeling Policy, the Direct Purchase of Electricity, Load Displacement, the Power Exchange Operation and the Spot Market. The Wisconsin utilities' options are Net Energy Billing, posted Buy Back rates or a negotiated Buy Back rate. B.C. Hydro and Wisconsin policies will be discussed separately and comparisons will be made where applicable.

#### B.C. Hydro's Options:

##### Wheeling Policy (Proposed)

One of B.C. Hydro's future incentives for independent power producers to self-generate power is the proposed wheeling policy. The prices available through the proposed wheeling policy will have the ability to influence the development of self-generation projects. This type of policy does not have as direct an influence on power development as buy back policies, however, it does provide self-generators access to markets.

It is necessary to examine the costs of this service in order to determine the potential benefits it may provide for the encouragement of self-generated power. The policy and its respective costs are described below.

B.C. Hydro established a "Wheeling Committee" in late 1988 to develop a wheeling tariff and a generic service agreement. Wheeling power refers to:

the transmission of electric energy generated by one party to another using the transmission system of a third party, referred to as the wheeler. The wheeler accepts electric power at one point on its transmission system and delivers it to another point on the system. The wheeler does not own, generate or purchase the electricity being transported from one point to another. It only "wheels" it by allowing the use of its electric system (B.C. Hydro; Mar., 1990: 1).

The proposed wheeling policy will be available for plants that wheel electricity for a period of one year or longer and are located in B.C.

The power producer's return on wheeled power is determined, in large part, by the negotiated price with the load. B.C. Hydro will influence the return through its service rate schedule (charges associated with wheeling power). B.C. Hydro's general wheeling service rate schedule will have five components:

- (1) wheeling energy charge,
- (2) capacity credit,
- (3) energy balancing,
- (4) energy losses,
- (5) wheeling demand charge.

## Wheeling Energy Charge

The Wheeling Energy Charge will consist of a commission charge of \$0.001 per kWh applied to all wheeled energy. This is designed to recover the cost of administration, operation and maintenance. There is also a minimum cost for all wheeling transactions regardless of the amount of energy wheeled. In order to recover this cost, the minimum wheeling energy charge per billing period is \$300.00 (B.C. Hydro;Mar:1990:4).

## Capacity Credit

The capacity credit will be available for wheeling arrangements that involve a term of six years or longer. The load receives a capacity credit at the point where wheeling energy enters the B.C. Hydro system and the load is charged a demand charge at the delivery point. The capacity credit is differentiated by time of day, season, year and region. The total capacity credit is the sum of estimated cost savings of additional capacity in generation, area transmission, and system transmission. The capacity credit is designed to give B.C. Hydro's full avoided cost as a credit (Lail;Dec.:1991). The credit applies only to the capacity supplied during heavy load hours on a weekday and is adjusted by monthly weighting factors. The generation credit recognizes the value of system generation capacity as derived from the B.C. Hydro Generation Resource Plan.

The area transmission credit recognizes that wheeling energy may reduce the area transmission demands placed on the system by having wheeling energy sources closer to the load and at different points on the system. To qualify for area transmission credits, the wheeling supply must be at voltages less than 500 KV. The system transmission credit varies according to the region of the interconnection point of the source. This credit reflects the

cost saving a wheeling supply source will have on a particular region's area/local transmission. The average area transmission credit is \$0.080/kW/month.

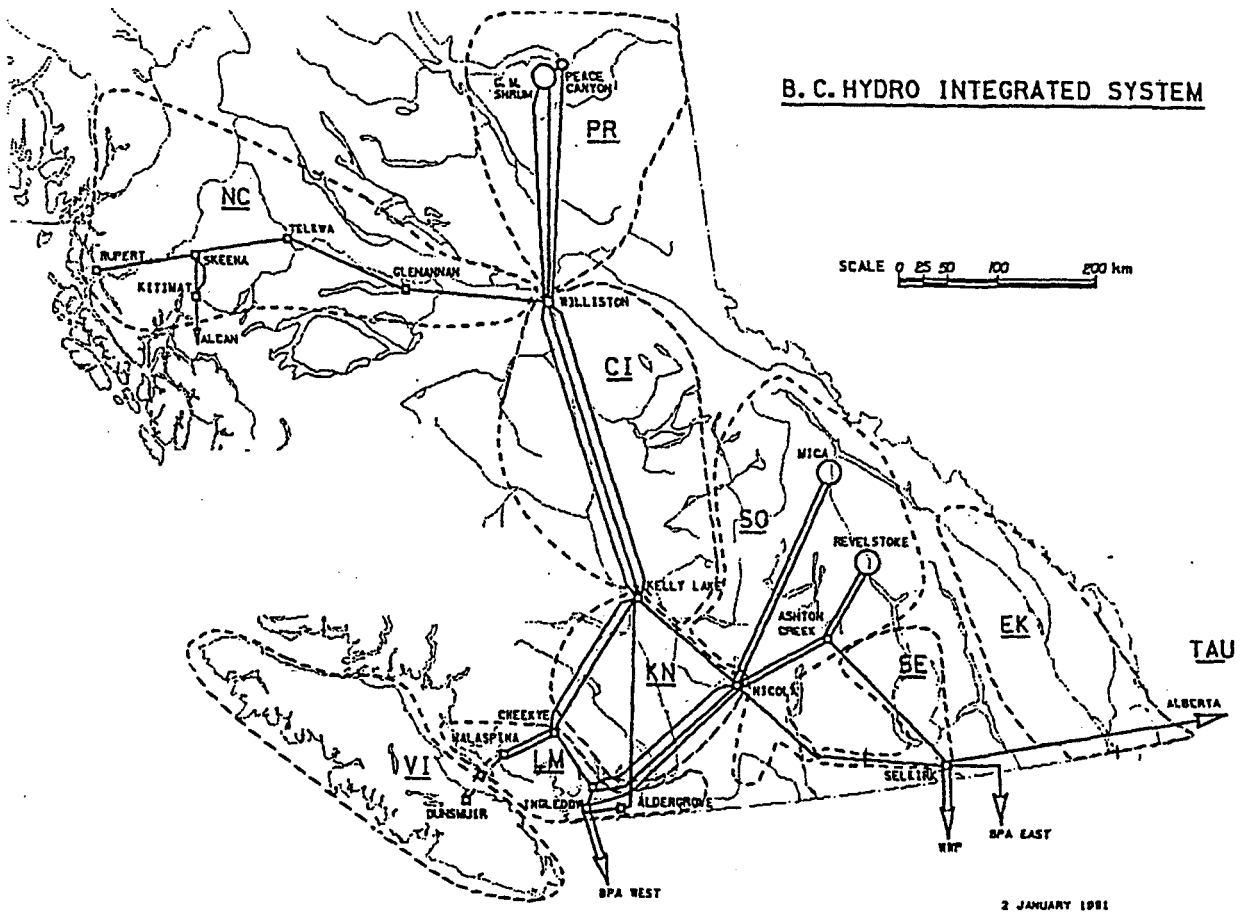
Most of B.C. Hydro's future generation sources will be located in the south eastern or northern part of the province while most load growth will be in the Lower Mainland and Vancouver Island regions (B.C. Hydro;Mar. 1990:6). The wheeling supply sources located in the south west part of the province will therefore result in larger savings in system transmission costs than sources located in the northern or eastern parts. To recognize the regional transmission cost saving differences, the transmission system is divided into nine regions and a separate credit is assigned for each region. Figure 3.1 lists the nine regions and the credits are listed in the Wheeling Service schedule in Appendix C.

### Energy Balancing

B.C. Hydro will provide system capacity for the quantity of energy wheeled as stipulated in the agreement. B.C. Hydro will balance the load either by selling or buying the necessary amount of energy depending on whether production is higher or lower than consumption. The wheeler's responsibility is to deliver the stipulated energy by the end of the billing period. Any difference (within 3 percent) between the amount stipulated and the supply will be carried over to the next billing period. Otherwise, the energy balance is sold to or bought from the Power Exchange Operation (PEO) at its posted monthly prices for the billing period. The rate structure therefore includes provisions for the shaping, storage, increased reliability and back-up of wheeled energy (B.C. Hydro;Mar.,1990:4-5).



Figure 3.1: B.C. Hydro's Integrated System and Nine Wheeling Regions



(B.C. Hydro, Schedule 1841; Aug. 16, 1991)

## Energy Losses

In electric transmissions there are losses associated with wheeling energy over the system. These losses are a function of the system voltages at the supply and load interconnection points. The rate schedule will be designed to recover losses on wheeled energy based on system voltage at the point of delivery (B.C. Hydro;Mar.,1990:4).

## Wheeling Demand Charge

The final charge is the wheeling demand charge that will be designed so that the load consuming wheeled energy receives a demand charge that is compatible with the demand charge in accordance with the Electricity Supply Agreement for the customer's plant. The charge, in principle, will recover the cost of shaping, storage and standby costs (B.C. Hydro;Mar.,1990:4).

The prices available through B.C. Hydro's wheeling policy will influence the development of self-generation. The benefits to the power producer are dependent on the rate charged per kWh negotiated between the supplier and the customer. The net return to the producer is the negotiated rate "less" the wheeling service charges and credits. The actual rate negotiated is not accessible public information; the only data available are the charges and credits in the wheeling schedule.

## Analysis of B.C. Hydro's Proposed Wheeling Policy

To illustrate how the wheeling policy would affect the rate of wheeled power, a theoretically constructed plant with actual production values is used to demonstrate several

possible scenarios. The calculations will be based on a power plant with a maximum continuous rating of 25 MW and a wheeling agreement that is six years long. From this information the policy will be evaluated with respect to the level of encouragement it will offer potential power producers.

B.C. Hydro's proposed wheeling policy must be examined without comparing it to those of Wisconsin utilities as they are not required to wheel power. The analysis will focus on the amount of encouragement the policy will offer to power producers.

### Wisconsin Utilities and Wheeling

Within Wisconsin, wheeling is voluntary and cannot be forced on a utility. No state laws exist which specifically promote the wheeling of customer-produced power. The PSCW believes a voluntary wheeling policy is adequate since any wheeling that occurs will be minimal because of the buy back policy. Wisconsin utilities are required to buy back power from all power producers at the utilities' full avoided costs. The Wisconsin utilities' buy back rates and avoided costs are discussed later in this chapter.

If utilities in Wisconsin were required to wheel power an independent power producer could arrange to sell power to distant utilities that may have higher avoided costs than the local utility. Wheeling power in these situations could have adverse effects on the quality of service provided by the utility. The only obligation for the utility, therefore, is to notify the commission when it does not want to wheel in response to a specific request.

## B.C. HYDRO BUY BACK RATES AND LOAD DISPLACEMENT

B.C. Hydro purchases surplus electricity directly from self-generators provided the quality is acceptable and the cost is lower than other alternatives available. B.C. Hydro will also consider purchase arrangements for electricity released by load displacement through initiatives such as cogeneration and energy efficiency measures. The latter enables the same amount of "work" to be performed with fewer units of electricity. Electricity made available through load displacement attenuates the need for B.C. Hydro to build new generating facilities. It is in B.C. Hydro's interest to purchase load displacement if the energy is produced at a cost lower than the avoided cost. This load displacement policy is aimed primarily at B.C. Hydro's large industrial customers.

For projects of 5 MW or more, B.C. Hydro issues Requests For Proposals (RFP's) for blocks of firm electricity in accordance with its energy requirements. It evaluates the proposals on the basis of financial viability, reliability, technical merit, the candidate's qualifications, the quantity of electricity being offered or load displaced, as well as price. B.C. Hydro will then negotiate with those presenting the best proposals to determine which arrangements will optimize benefits to both B.C. Hydro and its rate payers. The purchase price takes into account increases in B.C. Hydro transmission and transformer losses caused by the power producer. Other factors affecting the price include reliability and proximity to the major market areas (B.C. Hydro;Dec.,1988, and B.C. Hydro;Feb.,1990).

To qualify for a purchase agreement, the power producers must be able to design, finance, construct and operate the proposed project. The power producer must also supply the load requirements at the generating site before selling electricity to B.C. Hydro. To qualify for a load displacement agreement the power producer must demonstrate essentially the same capabilities as required for the power purchase agreement.

Each proposed load displacement or power purchase agreement will have a specific schedule for commencement of energy deliveries, i.e., when a customer begins generating for its own internal use or for direct sales to B.C. Hydro, and a specific contract period. The length of the contract is arbitrary but B.C. Hydro generally tries to negotiate twenty year agreements (Wells;Sept.,28:1991).

B.C. Hydro also requests proposals for the purchase of electricity less than 5MW and for load displacement less than 5 MW. In this thesis, however, I will only examine the load displacement and purchase agreements for projects greater than 5 MW. These policies represent B.C. Hydro's most generous buy back rates and are the best possible choices for comparison.

B.C. Hydro's direct purchase of power policy will be examined by developing theoretical power plants to calculate actual production values to demonstrate the benefits to the power producer. Direct purchase of power agreements value electricity similar to the "Wheeling Policy" by taking into account the level of energy produced, capacity supplied, proximity to markets, time of year, and days of the week. These values are calculated by region as were those described for the "Wheeling Policy".

A buy back rate will be calculated for each of these regions based on several different production scenarios that will be described in chapter 5. Each of the regions will have a buy back rate converted to a ratio with B.C. Hydro's LRMC (for each particular region) as the denominator. Percentages will be calculated from these ratios and compared with the relevant data for the Wisconsin buy back policies.

The load displacement policy will be examined without comparison because the Wisconsin utilities presently do not have any load displacement policies in place. B.C. Hydro's policy is therefore evaluated by calculating load displacement credits for the different regions based on data developed from the operating figures of the theoretically constructed

plants. The description of these plants and their different production levels are provided in chapter 5.

### B.C. Hydro's Environmental Policy

In some cases, B.C. Hydro has paid an additional premium for environmentally beneficial private power projects. B.C. Hydro was instructed by the provincial government to offer the proposed Williams Lake 55 MW wood waste generating facility a direct purchase rate 15 percent greater than the standard purchase price (Fairburn; May: 1992). This premium is to be paid by the provincial government (i.e., tax payers) beginning in 1993 for a term of 25 years.

This premium was the result of the provincial government's "Policy for Environmentally Beneficial Private Power Projects," which was approved on September 15, 1989. The objective of this policy was to assist private power projects that provide a significant improvement in the local environment in specific areas of British Columbia. This policy was not designed to promote all kinds of environmentally friendly power generation.

Certain kinds of power projects may be environmentally "friendly", but not environmentally "beneficial." For example, small hydro, solar, wind, tidal, geothermal or conventional thermal projects will not qualify for assistance under this policy (Ministry of Energy Mines and Resources; Oct. 1990:2)

This policy was originally written in a manner to cover future power production facilities, however, it can be argued that it was only intended for the Williams Lake project (Thiessen; 1992). In the fall of 1991 this policy was repealed after having only been applied to the Williams Lake project. While replacement policies have been discussed there are presently no new policies in place.

B.C. Hydro currently recognizes a 15 percent premium for in house projects that are environmentally benign. B.C. Hydro, however, will not pay a premium to non-utility generators unless directed by the provincial government. At present there are not any government policies that direct B.C. Hydro to pay environmental premiums. All calculations of direct purchase agreements will, therefore, not account for any environmental premiums.

### WISCONSIN BUY BACK POLICIES

The principal aim of FERC with PURPA was to remove the major obstacles to cogeneration and small scale renewable electricity production. In order to achieve this, FERC required utilities to purchase surplus electricity from cogenerators and other qualified generating facilities at the utilities' full avoided costs. The avoided cost of each utility, therefore, represents the standard buy back rate of the electric utilities.

The avoided cost refers to FERC's regulations requiring electric utilities to purchase energy from a qualifying facility at a rate equal to the purchasing utilities' full avoided costs (Whitaker;1986:139). A qualifying facility is an electricity generator that meets PURPA's regulatory standards of energy efficiency and ownership (Makinen;1991:104).

PURPA has determined that the avoided cost must take into account three major components:

- (1) the energy component of the utility's cost,
- (2) the capacity component of the utility's cost,
- (3) the component reflecting the utility's environmental and societal costs (Charo;1986:464).

The energy component is a reflection of the costs that a utility would incur on a day to day basis to produce energy. The capacity component reflects the fixed capital costs of

generation and transmission facilities that would be incurred by a utility to produce and transmit the electricity being purchased. The environmental impacts and social costs would be those costs related to mitigation programs and pollution control equipment, etc. The environmental component of the Wisconsin buy back rates is discussed later in this chapter.

Many states have adopted, to a greater or lesser degree, specific methodologies which utilities must employ in making their calculations of avoided cost. The various state interpretations have led to a proliferation of methodologies in calculating avoided costs. The preferred means of calculating avoided cost is therefore a subject of continuing and extensive debate (Charo;1986:464).

The concepts of marginal cost and avoided costs are fairly simple and straight forward. In practice, however, the calculations involved are generally complex and controversial. "The complexity and controversy principally arise because of the availability of a number of methods which can be used to calculate avoided cost and because of the large amount of judgment involved in executing each of these methods" (PSCW;1983:24).

Much of the confusion surrounding the calculation of an avoided cost is that, while FERC rules require utilities to calculate avoided costs, they do not specify how these costs should be determined. A widely debated issue in determining a utility's avoided cost is whether to use long-run or short-run costs or a combination of the two.

The PSCW concluded that it was appropriate to use a combination of short-run and long-run costs in computing avoided costs.

Avoided energy costs should be computed based on the short-run marginal energy cost averaged over the applicable rating period. Avoided capacity costs should be computed based on the annual carrying charge on the generation and transmission facilities which would otherwise be built in the long-run, less any applicable fuel savings (PSCW;1983:18).



It is the PSCW's belief that this combination of short-run and long-run costs reflected in both the avoided cost calculation and the buy back rate levels will provide proper price signals to customer owned generating facilities of the applicable on-peak and off-peak avoided costs.

"The PSCW believes it is not desirable to adopt a particular method of computing avoided costs. Rather, the commission deems it appropriate to allow for flexibility in computing avoided capacity costs" (PSCW;1983:24). Utilities that are building a plant within a ten-year planning period will use the avoided capacity cost of that plant with corresponding adjustments for energy savings to calculate their full avoided costs.

The PSCW determined that utilities which are not planning to construct plants within a ten-year planning horizon will still be avoiding capacity costs at some point in the future and felt that a price signal should be given which recognized this. The type of production plant and associated energy cost or energy savings these utilities will be avoiding is difficult to determine because the plants may be avoided over ten years in the future. For these utilities, avoided capacity costs are based on the present value of a natural gas combustion turbine expressed in current dollars.

Utilities using these methods will calculate capacity and energy components in the following manner. The on-peak per kilowatt-hour rate shall include full avoided capacity costs based on 75 percent of the utility's generation-related marginal capacity cost (PSCW;1983:13). This will be averaged over all on-peak hours and reflect the uncertainties in the customer-owned generating system supply. The energy component should reflect the utility's short-run marginal energy cost that will be averaged over the on-peak period.

The utilities within Wisconsin are separated into two regions: (1) the western Wisconsin utilities (2) the eastern Wisconsin utilities. The PSCW has authorized the western Wisconsin utilities to calculate avoided costs on proposed generating units while the eastern Wisconsin utilities are to base their avoided costs on a peaking plant.

The Wisconsin utilities WEU #1 and WEU #2 are both in the eastern utilities area and therefore calculate their avoided costs by using a peaking plant to estimate the avoided capacity costs. The energy cost is computed on the short-run marginal energy cost averaged over the applicable rating period (5 years). This avoided cost represents a utility's standard buy back rate.

The PSCW determined that all customer-owned electric generation facilities that are rated above 20 kW of capacity are eligible for the standard buy back rate, regardless of whether they meet FERC's requirement for qualifying status or not. The Commission feels that all facilities that can generate electricity at a lower cost than a utility should be encouraged to do so through the extension of avoided cost benefits because electricity is equally valuable to the utility regardless of the source (PSCW;1984:4).

For customer owned generators rated at 20 kW or less, the utilities provide net energy billing as a method for marketing power. Net energy billing refers to the practice of allowing the retail meters of a customer owned generator to run backwards when they are producing energy in excess of their own needs. Public demand for this practice began when the buy back rates were initially authorized. Nearly all of the buy back rates require the customer-owned generators to have parallel metering installed to measure the surplus power output of the power producer and a separate customer charge to cover the additional metering costs. In some cases, the separate customer charge assessment exceeded the monthly payment to the power producer for its surplus power supplied to the utility. Owners of small generators objected to this and requested that net energy billing be offered to eliminate the requirement for a separate meter and to simplify their transactions with the utility. In response to these concerns, the commission approved net energy billing for power producers with less than 20 kW in 1982 (PSCW;1983:7).

Net energy billing provides an incentive for small power producers to market their surplus power. This policy, however, will not be analyzed or compared with B.C. Hydro's policies. There would be too much difficulty in determining the actual benefits to the generator, as this depends on the particular rate schedule the customer uses. The rates may vary considerably and in addition to this, the policy is designed for very small power generators. An accurate comparison with B.C. Hydro's policies is not possible since the latter are designed to accommodate much larger power producers.

The net energy billing policy is concerned with small power producers and does not affect industrial levels of self-generation. The principal comparison here will therefore be the Wisconsin utilities' buy back rates compared with B.C. Hydro's direct purchase of electricity.

The Wisconsin utilities' standard buy back rates, however, are not comparable with B.C. Hydro's buy back rate. B.C. Hydro's buy back rates have been calculated for a 20 year term. The Wisconsin standard buy back rate on the other hand is calculated every year and designed for short term power producers. It is the long term buy back rates that should be compared, because these rates provide the correct price signal for investment. Long term rates reflect each utility's policies most accurately since they are not influenced by short term fluctuations in supply and demand.

The Wisconsin utilities have long term buy back rates in addition to the standard buy back rates. These rates offer greater incentive to the power producers than do the standard buy back rates. The level of these rates depends on several factors. Wisconsin's long term buy back rates are determined through private negotiations between the electric utilities and prospective power producers. The actual rate is influenced by the operating characteristics of the generating facility, the term of the contract and the skill of the negotiator. These rates are regarded as strictly confidential and were not available for comparison purposes.

To calculate the Wisconsin utilities' long term buy back rates it was necessary to make estimates from the utilities' standard buy back rates. The standard buy back rates are based on the utilities' average marginal energy costs for five years and 75 percent of a gas turbine's capacity costs.

On the basis of the marginal energy costs percentage increase from one year to the next, over the five year period, the energy cost could be projected into the future. The underlying assumption being that energy costs would continue to increase by the same amount each year over a five year cycle. The capacity costs, however, were held constant at the utilities' standard buy back rates until the year 2003. The capacity costs were then changed to represent the utilities' 300 MW pulverized coal plants' capacity costs, which are forecast to be required in the year 2003. Based on this method buy back rates were calculated for 20 year terms for both WEU # 1 and WEU # 2.

The weakness in these calculations is that they are based on the utilities' standard buy back rates. In fact, the power producers would be negotiating for a rate in excess of the standard buy back rates. This difference could result in a lower long term buy back rate than the power producers could negotiate for themselves.

#### Wisconsin Utilities' Environmental Policies

As with the B.C. Hydro buy back rate the Wisconsin buy back rates will not reflect any externalities even though the utilities are required to account for externalities for their own in house energy planning. Originally the Wisconsin utilities accounted for externalities by applying a 15 percent credit to reduce the cost of noncombustion options in advance planning (The Wheeler:May, 1992:2). This credit was the first attempt to establish a value for the environmental costs of producing power. This credit has now been set aside because

it was argued it did not account for the varying levels of environmental costs associated with different supply side and demand side alternatives.

In place of the 15 percent environmental credit the Wisconsin utilities must now monetize the environmental costs associated with air toxins, in order to consider economic and environmental factors of the various alternatives in utility advance plans. The externalities must now be accounted for, in the purpose of planning, on the following: CO<sub>2</sub> - \$15/ton; CH<sub>4</sub> - \$150/ton; and N<sub>2</sub>O - 2,700/ton (The Wheeler;May, 1992:6). In addition to these values the federal government had already regulated SO<sub>2</sub> and NO<sub>x</sub> in planning and demand side management (The Wheeler;May, 1992:4). Monetization is not a means of imposing emissions standards on utilities, but rather a way of quantifying the total cost of different supply side and demand side alternatives.

With respect to buy back rates there was concern about accounting for externalities because it was an area that could have the most significant and immediate impact on rates. The PSCW recognized the importance in balancing environmental and economic impacts, however, it was believed that experience was needed in using externalities in buy back rates before implementing them fully. It was feared that if externalities were fully accounted for it could change rates and cogenerators might not take the risk required to develop new power sources.

Presently the Wisconsin utilities are using renewables as a test, because renewables generally come in small increments, so the risk is less. The information from this pilot will help understand how externalities work when it comes to buy back rates. The State of Wisconsin is proposing to offer electric utilities a credit for having renewables in their system. With the pilot project electric utilities will share this credit with renewable, independent power producers (Ailift;1992). It is hoped this initiative will provide the incentive required to increase renewable energy production in Wisconsin.

The Wisconsin utilities' buy back rates therefore attempt to account for externalities with respect to the development of renewable resources. Since renewables account for only a small percentage of Wisconsin's non-utility generation and this policy is a test project it was decided not to include these variables in the long term buy back rates. The comparison of B.C. Hydro's and the Wisconsin utilities' buy back rates will therefore not account for any externalities in the development of the rates.

The Wisconsin utilities buy back rates will be converted to a ratio comparable to those for the B.C. Hydro data. The information is then compared to highlight similarities or differences in the respective levels of encouragement for self-generation.

### POWER EXCHANGE OPERATION (PROPOSED) AND EXPORTS

In 1988, the British Columbia Provincial Government endorsed the establishment of the British Columbia Power Exchange Corporation (POWEREX)(B.C. Hydro;May, 1991:1). POWEREX is a wholly owned subsidiary of B.C. Hydro. POWEREX's objective is to promote the development of new generating resources for the purpose of long term sales to the U.S. utilities. One of POWEREX's initiatives is the Power Exchange Operation (PEO), which has been proposed to promote and develop efficient short term electricity trade among utilities, independent power producers, and industrial customers. The PEO is a proposed marketing operation designed to serve short term (less than one year) bulk electricity markets within and outside British Columbia.

POWEREX has requested proposals for between 400 and 600 MW of privately built generating capacity. It is hoped that these projects will be producing power for export by 1996 (MacRae;1989:32). Possible choices include coal fired generating stations at Balmer or Fording River, in south east B.C., a hydro site on the Columbia River and wood waste based

generating plants.

The PEO is proposed to buy and sell either interruptable or firm energy. Firm energy refers to a category of energy or capacity that is not subject to interruption by the supplier. While interruptable energy may be curtailed at any time at the discretion of the supplier or receiver, typically with 10 minutes notice (B.C. Hydro; May, 1991:61). Firm energy requires the additional purchase of capacity, which the PEO will buy and sell on an hourly, monthly or longer term basis. These prices will be based on the differences in the regional system, market, and time value. The PEO will post prices for eight regions within British Columbia and at three interconnection points at the border.

At present, the PEO is not functioning and therefore the only option for power producers with surplus power and without a purchase agreement, is the rate B.C. Hydro offers to purchase power on the spot market. B.C. Hydro purchases power on the spot market to meet provincial energy requirements and for export. These purchases will eventually be part of the PEO's power but at present remain with B.C. Hydro and the spot market.

The sale of power to B.C. Hydro on the spot market represents the final option for a self-generator with surplus capacity. An analysis of the purchase price available on the spot market will provide an indication of the level of encouragement it provides for increased self-generation. This is accomplished by examining the average spot market purchase price for 1990. The export values are also listed for comparison. From this data the relative incentive these purchases provide for increased self-generation is then discussed.

## CHAPTER 4

### PULP MILL RESULTS AND INTERPRETATION

#### PULP MILL RESULTS

The B.C. and Wisconsin pulp mills in the study are all kraft mills, which are suitable for cogeneration. While the production processes are similar there are many characteristics unique to each region, as illustrated in Tables 4.1 and 4.2.

A noticeable difference between the two regions is the median age of the mills. The B.C. mills were constructed more recently, with a median construction date of 1967, compared with 1910 for the Wisconsin mills. The B.C. mills are also much larger, with a median production of 775 tonnes of pulp per day; the Wisconsin mills' median is 627 tonnes of pulp per day. With larger production totals, B.C. mills also use more electricity, having a median energy requirement per day of 721 MWh. The Wisconsin mills' median is 585 MWh per day. This translates into a median of 802 kWh per tonne of pulp for B.C. pulp mills and 788 kWh per tonne for the Wisconsin mills.

The Wisconsin median production total is somewhat misleading because WPM #2's production totals include 300 tonnes of paper production. The pulp mill and paper mill's electric consumption totals are calculated as one. The energy consumption totals for the pulp mill may therefore be different from those reported in Table 4.2.

It is unlikely that these inconsistency would seriously affect the accuracy of the results. The Wisconsin mills' median electricity per tonne of pulp is only 14 kWh less than the B.C. mills and their individual usage totals are well within the range of the B.C. totals.



Table 4.1 : British Columbia Pulp Mill Data

<u>Pulp Mill</u>	<u>Const. Date</u>	<u>Daily Prod. (dry tonnes)</u>	<u>Daily Elec. Req.(kWh)</u>	<u>Elec./Tonne(kWh)</u>	<u>Self-Generated Power(%) (a)</u>
BCPM #1	1972	775	612,000	790	100.0
BCPM #2	1965	1,450	937,285	646	83.0
BCPM #3	1968	522	408,000	782	74.0
BCPM #4	1967	1,193	975,000	871	70.0
BCPM #5	1965	1,226	1,032,000	842	65.0
BCPM #6	1950	1,100	993,055	903	50.0
BCPM #7	1985	624	390,000	625	32.5
BCPM #8	1908	650	400,000	615	17.0
BCPM #9	1970	960	958,000	998	nil
BCPM #10	1968	669	536,560	802	nil
BCPM #11	1966	790	720,571	912	nil
Median	1967	775	720,571	802	50.0

(Data collected in 1989)

- (a) The percentage of the pulp mills electrical energy needs met through self-generated power.

Table 4.2 : Wisconsin Pulp Mill Data

<u>Pulp Mill</u>	<u>Const. Date</u>	<u>Daily Prod. (dry tonnes)</u>	<u>Daily Elec. Req.(kWh)</u>	<u>Elec./Tonne(kWh)</u>	<u>Self-Generated Power(%)</u>
WPM #1	1968	850(a)	660,000	788	100.0
WPM #2	1910	548	432,000(b)	933	90.0
WPM #3	1900	627	585,000	776	74.0
Median	1910	627	585,000	788	90.0

(Data collected in 1991)

- (a) WPM #1 records its production totals as a wet tonne.  
 (b) This value includes the amount of energy to produce 248 tonnes of pulp, as well as, 300 tonnes of paper. WPM #2 does not keep separate totals for energy use.

From these totals there appears to be little difference in the level of energy efficiency in the production of pulp in the two regions.

An area where there is a substantial difference is the amount of self-generated power. The B.C. mills median level of self-generation is 50 percent of their electrical needs, compared to 90 percent for the Wisconsin mills. A further difference is the inter-regional variation in the levels of self-generated power. The B.C. mills levels of generation range from 100 percent for one mill to several mills with no self-generation capacity. This compares to the Wisconsin mills where self-generation levels range from 74 to 100 percent.

One possible explanation for the wide range in B.C. are the pulp mills' attitudes towards the generation of power. Industrial firms will often "vary in their willingness to invest funds and management effort in a utility-type operation that is, or seems to be, peripheral to their main line of business" (Helliwell and Cox,1979:258). Pulp mills could effectively assume the lowest possible value when evaluating cogeneration if management was negatively inclined toward the project. Another reason is that the level of self-generation represents each mill's attempt to gain an advantage in a very competitive market. The cost of electricity will also play a major factor in determining the economic advantage of self-generation facilities. Low electric prices may have influenced the three mills with zero generation capacity, because these mills were built when B.C. Hydro was trying to absorb the massive generation capacity of the Peace project (Jaccard;May, 1992). Tables 4.3 and 4.4 summarize the pulp mills' attitudes and perceptions with respect to their levels of self-generation.

**Table 4.3 : B.C. Pulp Mills - Principal Incentives for Greater Self - Generation**

<u>Pulp Mill</u>	<u>Self-Generated Power</u>	<u>Potential For &gt; Self-Generation</u>	<u>Principal Incentives</u>
BCPM #1	100%	little	no plans to increase
BCPM #2	83%	large	government incentives: govt. must agree to purchase excess power from hog fuel
BCPM #3	74%	large	no plans to increase (transportation for hog fuel is prohibitive)
BCPM #4	70%	large	government incentives would encourage this
BCPM #5	65%	little	rising energy costs
BCPM #6	50%	large	rising energy costs
BCPM #7	32.5%	very little	(1) security of supply (2) rising energy costs (3) additional government incentives
BCPM #8	17%	very large	100 MW coming on line (1) security of supply (2) government incentives
BCPM #9,#10,#11	nil	very large	rising energy costs

(Data collected in 1989)

**Table 4.4 : Wisconsin Pulp Mills - Principal Incentives for Greater Self - Generation**

<u>Pulp Mill</u>	<u>Self-Generated Power</u>	<u>Potential For &gt; Self-Generation</u>	<u>Principal Incentives</u>
WPM #1	100%	little	40 MW coming on line security of supply
WPM #2	90%	very little	(1) rising energy costs
WPM #3	74%	large	(1) environmental issues (2) security of supply

(Data collected in 1991)

## B.C. Pulp Mill Responses

The pulp mills were asked if they felt there was any additional self-generation capacity available and what the principal incentives would be to increase these levels. Generally, the responses corresponded with the amount of power currently produced. The mills with the least amount of self-generation felt there was the greatest potential for increasing their level, while the mills with higher levels expressed less interest.

Four of the eleven B.C. mills feel there is a very large potential for increased self-generation. BCPM #1 produces 100 percent of its electrical energy requirements and has no plans to increase this level. BCPM #5 and BCPM #7, generate 65 percent and 32.5 percent of their power respectively and feel there is little potential to increase these levels. BCPM #5 feels, at present, there is only the potential for an additional 3 MW of power through an improved energy management system, and the principal incentive for increasing the level of self-generation is the threat of future rising energy costs and the associated costs.

BCPM #7 feels the principal incentives for increased power production are for reasons of security of supply, followed by rising energy costs and then government incentives. The mill requires a new larger power boiler which would improve self-generation capacity. There are presently no plans to increase current levels of self-generation.

The ability of pulp mills to produce large amounts of power is well illustrated by BCPM #2, BCPM #3 and BCPM #4. These mills produce 83, 74 and 70 percent of their power respectively. While these mills produce the majority of their power requirements they still feel there is the potential for large increases in the generation of power. BCPM #3 feels that large increases in energy production are possible if the mill invests in a hog fired boiler. There are, however, no immediate plans to increase power production because of prohibitive transportation and handling costs.

BCPM #2 and BCPM #4 both feel additional government incentives could lead to increased self-generation. BCPM #2 has an excess capacity of hog fuel that the mill must dispose of in an environmentally acceptable manner. If a purchasing agreement could be reached with B.C. Hydro the costs associated with disposing of the hog fuel would be greatly alleviated. It is expected, however, that premiums for wood waste projects, such as the Williams Lake project, will be reduced or eliminated when a provincial beehive burner phase-out policy fully implements the "polluter pays" principle (Ministry of Energy Mines and Resources; Oct. 1990:3). This would compel the mills to find environmentally acceptable ways to dispose of wood waste, thereby reducing the need of the provincial government to offer a premium for wood waste thermal projects. Regardless of these considerations BCPM #4 is investigating the installation of a condensing turbine to increase the mill's energy self-sufficiency and reduce its susceptibility to power surges and interruptions. Neither mill feels that rising energy prices or security of supply present sufficient incentive to increase power production.

The final four pulp mills, BCPM #8, BCPM #9, BCPM #10 and BCPM #11, have little or no self-generation capacity and believe there is a very large potential to increase energy production. BCPM #8 is developing approximately 100 MW of additional self-generation. The principal incentives for increased production are for reasons of security of supply and government incentives. The increased production will provide for the mill's needs and excess power will be sold to B.C. Hydro.

BCPM #9 feels there is a potential for 25 MW of power generation during peak periods and an average level of 19 MW overall. These levels represent 62 and 48 percent, respectively of the mill's electrical energy requirements. BCPM #9 recognizes that self-generation has the potential for reasonable return on investment, however, the mill has other potential investments of similar magnitude with a higher return. The mill does not foresee

any immediate change to this situation unless the economics change through lower costs of installation, lower costs of capital, or higher power costs.

BCPM #10 and BCPM #11 see the potential for very large increases in self-generation, yet at present neither mill has any turbogenerators. Both mills are currently examining the return on investment of such installations. The major incentive encouraging this development is the possible money savings associated with the lower energy costs of self-generation.

### Wisconsin Pulp Mill Responses

The Wisconsin mills all produce the majority of their power requirements. WPM #1 produces 100 percent of its energy requirements while WPM #2 and WPM #3 produce 90, and 74 percent respectively. Even though the mills produce the majority of their power requirements they feel there is a need to increase the amount of self-generated power.

WPM #1 was constructed in 1968 and at that time produced 100 percent of its power requirements. The mill is currently installing 40 MW of additional self-generation capacity and is considering a condensing turbine for summer peak load to satisfy steam requirements. The pulp mill is directly connected to a paper mill and the additional power will serve these energy demands. Any additional increases in generation would be for increased security of supply. Rising energy prices and government incentives are not important considerations because of the large level of self-generation currently produced and planned.

WPM #2 was constructed in 1910 and began generating power as early as 1914. The first self-generation began with two water wheels that combine to produce 33,600 kWh per day and in 1923 another water wheel was installed, producing 48,000 kWh per day. Further power generation was added in 1951 and 1976 with the addition of steam turbines. These

produce 96,000 and 240,000 kWh per day respectively and represent the mill's latest investment in self-generation facilities.

WPM #2 feels there is very little potential to increase the mill's level of self-generation. One possible option is to increase the amount of hydropower developed. The river flow would allow for 1500 kWh of additional hydropower that represents roughly 50 percent more hydro power than is currently developed. At present the return on investment does not justify the capital required for this expansion. The mill is also speaking to a vendor who claims to have more efficient water wheels and runners that could increase present levels of hydro production. The principal incentive for WPM #2 to increase self-generation is the threat of rising energy prices. Security of supply and government incentives are not significant factors in the mill's energy planning.

WPM #3 was constructed in 1900 and is the oldest mill in the survey. The mill began producing power in 1965 and currently produces 66 percent of its power through cogeneration and a further 8 percent through a hydro facility. WPM #3 believes there is a large potential for increased power generation which could reduce the \$10,000,000 per year worth of electricity the mill purchases.

WPM #3 does not have any schedules plans to increase its current level of self-generation. The mill will increase its level of generation capacity by replacing old inefficient boilers as they wear out with more efficient, higher pressure systems. The mill has many boilers ranging in pressure from 150 psi to 1500 psi, with some of these being 50 years old. Many of the boilers remain functioning under a grandfather clause and must eventually be upgraded to meet environmental standards governing levels of effluent discharge into the river. In addition to increasing power generation through replacing boilers, the mill is also considering adding gas-powered generators because of possible access to new gas resources.

The mill's immediate plans are to continue to replace old boilers as required, but any

further investment required for additional generation capacity is not economic at present. The environmental issue, requiring the old boilers to be upgraded, is the principal incentive to increase energy production. The threat of rising energy prices is not an immediate concern, because the utility rates in Wisconsin are regarded by WPM #3 as relatively affordable in comparison to other areas of the U.S. Security of supply is a consideration to the mill because of the large amounts of purchased power. Overall though, it is the age of the equipment and steam demands that will determine the most immediate change.

### Results of Comparison

The results from the comparison of the B.C. and Wisconsin pulp mills indicate more similarities than differences. The mills with the least amount of self-generation expressed the greatest potential for increasing their energy production. Those mills with larger amounts of self-generation generally expressed less interest in increasing their level of power production.

An exception to this is the Wisconsin mill WPM #1, which produces 100 percent of its energy needs and is increasing this level by an additional 40 MW and may also add a condensing turbine. A factor influencing much of the mill's energy production is the energy requirements of the paper mill connected to the pulp mill.

The most striking differences highlighted between the two regions, in Tables 4.1 and 4.2, are the age of the pulp mills and their respective levels of self-generation. The B.C. mills' median age is 57 years newer than the Wisconsin mills. While the B.C. mills' median level of self-generated power represents 40 percent less of their electrical energy requirements than the Wisconsin mills. The year many of the B.C. mills were constructed may account for their low levels of self-generated power. Nine of the eleven B.C. mills were constructed after 1962. It is noteworthy that British Columbia Hydro and Power Authority was created March



30, 1962. B.C. Hydro was able to produce low cost electricity due to large generating facilities and low-cost hydro sites. This availability of low-cost electricity in the 1960's, more than any other reason, probably accounts for many of the B.C. pulp mills having limited amounts of self-generation.

Another consideration is the attitudes of management towards power generation. Mills may choose to invest in other areas with as high or higher return on investment. It may be more profitable for older mills to replace old motors and equipment before increasing levels of self-generation.

From these data, it is not possible to determine conclusively the reasons for the difference in the levels of self-generation. The difficulty in making this determination is due to several reasons. One principal reason is the number of respondents in the Wisconsin sample. With a sample of only three mills it is difficult to make conclusive statements with respect to the data collected. The addition of one or more mills to the Wisconsin sample could significantly shift the median in some of the categories. A larger sample size would therefore make the results more significant.

A further consideration is the extent to which many of the decisions of the pulp mills are based on individual costs, and on considerations that may be mill specific. For example many Wisconsin mills located on the Wisconsin river which gave them access to their own hydroelectric facilities (Waltz,1989). This is evident with WPM #2 which installed hydroelectric facilities in 1914 and 1923. WPM #1 is also in a unique position because the mill owns one electric company and is one third owner of another. WPM #1 is therefore operating under very different circumstances than most pulp mills.

With respect to the B.C. mills, the low cost of electricity has been identified as a contributing factor in the lower levels of self-generation. There are also many other factors that, in part, could account for these lower values. These include a mill's competitive cost

advantages in labor, chemicals, forest resources and proximity to markets. Any advantage or disadvantage with respect to these factors could influence a mill's decision to increase self-generation facilities. Within B.C. locational considerations may influence a pulp mill's decision to self-generate. The large distance between many pulp mills and the principal electricity markets reduces the value of surplus self-generated power because of increased transmission costs. The locational value of electricity within B.C. will be discussed in chapter 5.

These considerations must all be taken into account in order to understand the differences in self-generated power between the B.C. and Wisconsin pulp mills. Based on the survey data the most significant conclusion is that the mills have the potential to substantially improve their levels of self-generated power given sufficient encouragement.

## CHAPTER 5

### ELECTRIC UTILITY COMPARISONS

Electric utilities' energy policies, in large part, influence the level of self-generated power through the prices charged for power and the policies that affect the buy back of power. The next analyses will examine the difference between the electric utilities' LRMC and the rate paid by pulp mills for utility power.

#### LRMC VS PULP MILL RATE

A comparison of the "mark-up" a utility applies to energy reflects, in part, the utility's effort to encourage industry to generate power. The respective levels of mark-up are compared in Table 5.1.

Table 5.1 shows that the three B.C. pulp mills, without any generating capacity, have an average rate of \$0.0316 per kWh compared with \$0.0346 per kWh for the eight pulp mills with self-generation. The lower rate per kilowatt, for the mills without any self-generation capacity, reflects the mills' higher average power factors combined with higher load factors.

Utilities incorporate power factors and load factors into their rate schedule to encourage high levels of technical and operational efficiency. B.C. Hydro's transmission rate schedule encourages high power and load factors through its demand charges. The minimum monthly demand charge is \$4.158 per kV.A of Billing Demand (B.C. Hydro; April 1, 1991). This charge may increase depending on each mills specific power and load factors.

**Table 5.1 : Utilities' "Mark-Up" on Pulp Mill Rate**

	<u>BCPM(a)</u>	<u>BCPM(b)</u>	<u>WPM #1</u>	<u>WPM #2</u>	<u>WPM #3</u>
Utility	B.C. Hydro	B.C. Hydro	WEU #1	WEU #1	WEU #2
Pulp Mill Rate (\$/kWh) (c)	0.0346	0.0316	0.030	0.039	0.035
LRMC (\$/kWh)	0.064	0.064	0.0781	0.0781	0.070
Mark - Up(%)	54	49	38	50	50

(a) Represents the 8 B.C. pulp mills with generation capacity.

(b) Represents the 3 B.C. pulp mills without self-generation capacity.

(c) The rate used for the B.C. pulp mills is an average of rates from 1989, 90 and 91. The Wisconsin rates are the actual 1990 average cost for each pulp mill.

The Wisconsin utilities' rate schedules are also designed to encourage higher power and load factors. These utilities reward higher load factors with lower demand charges. This is similar to B.C. Hydro's rate schedule; however, the Wisconsin utilities encourage high power factors differently than B.C. Hydro. WEU #1 and WEU #2 have separate charges based on the specific power factor. WEU #1 provides a credit to its industrial customers if their power factor is greater than 84 percent. If the power factor is less than 84 percent additional charges will accrue. The amount of this charge depends on how far the mill's power factor is below 84 percent. WEU #2 similarly offers a credit for power factors greater than 90 percent and a charge for those less than 90 percent. Table 5.2 lists the power factors and load factors of the pulp mills and breaks down the mills' rates to show the demand charges. Any charges or credits associated with a mill's power factor or load factor will be

Table 5.2 : Power Factors and Demand Charges

	<u>Power</u> <u>Factor (%)</u>	<u>Load</u> <u>Factor(%)<sup>1</sup></u>	<u>Mill Rate</u> <u>(\$/kWh)</u>	<u>Demand</u> <u>Charge<sup>2</sup></u> <u>(\$/kWh)</u>	<u>Demand Charge</u> <u>Percentage of</u> <u>Mill Rate</u>
<u>BCPM (a)</u>					
BCPM #1	94				
BCPM #2	97				
BCPM #3	96				
BCPM #4	97				
BCPM #5	99	66			
BCPM #6	90				
BCPM #7	95				
BCPM #8	93				
MEDIAN	95.5				
MEAN	95.125	66	0.0346	0.01141	33
<u>BCPM(b)</u>					
BCPM #9	95				
BCPM #10	99	86			
BCPM #11	98				
MEDIAN	98				
MEAN	97.33	86	0.0316	0.00841	26
<u>Wisc. Pulp Mills</u>					
WPM #1	95	76	0.030	0.0051	17
WPM #2	80	80	0.039	0.0141	36
WPM #3	90	65	0.035	0.013	37
MEDIAN	90				

<sup>1</sup> The B.C. pulp mills' load factors are an average of 1989, 90 and 91 values.

<sup>2</sup> Equivalent unit charge; this equals the average pulp mill rate less the energy charge.

accounted for in the demand charge column.

The B.C. pulp mills with self-generation pay higher electricity rates than the mills without self-generation capacity. This is because the mills with self-generation capacity have a median load factor of 66 percent compared to 86 percent for the mills without self-generation capacity. This accounts for much of the difference in the electric rates between BCPM (a) and BCPM (b). In addition to the load factor the pulp mills' different power factors affect the rate paid for electricity. Within the B.C. example, the power factors are very similar; therefore, they do not account for significant difference in the rates paid by the various B.C. pulp mills. The different load factors account for most of the difference in electric rates among the B.C. pulp mills.

The difference in load factors among the mills is due to the mills' different amounts of cogeneration. A pulp mill with cogeneration facilities utilizes the maximum amount of steam in the production process while additional steam is used in the production of electricity. When large amounts of steam are present for the production of electricity this reduces the need for purchased power. This variation in demand is what accounts for those mills with cogeneration having lower load factors. The lower load factor results in an increased cost per kilowatt of purchased power; however, the benefits from the cogenerated power outweigh the increased costs due to higher electricity rates (Kehl; Dec. 1991).

The Wisconsin pulp mills' electricity rates are also affected by power factors and load factors. Pulp mills WPM #1 and WPM #2 are both served by WEU #1 and pay very different electricity rates. WPM #1 pays \$0.030 per kWh compared to \$0.039 for WPM #2.

The power factors of the pulp mills account for some of the differences in the electricity rates. WPM #1 receives a credit because its power factor of 95 percent is greater than 84 percent. WPM #2's power factor is only 80 percent and must pay a charge. These charges and credits partially account for the differences between the pulp mills' electricity

rates. A further factor influencing the rates are the mills' load factors.

WPM #1 has the lowest load factor of the three Wisconsin mills, however, this does not necessarily indicate lower operational efficiency than the other mills. The Wisconsin utilities sell power at on-peak and off-peak rates. Pulp mills will purchase large amounts of power during off-peak periods and reduce power purchases during the on-peak period. This is a common practice among the Wisconsin pulp mills to help reduce purchase power costs.

WPM #2 purchases as much power as possible during the off-peak period by reducing fuel purchases and turning down its condenser. In addition, the mill diverts more steam for process (reducing cogeneration) during this period to increase power purchases. This results in variable levels of power purchases and lowers the mill's load factor. WPM #2's load factor for the off-peak period is only 70 percent compared to 92 percent during the on-peak period where the emphasis is on reducing power purchases and maintaining a high load factor. This results in WPM #2 having an average load factor of 80 percent (WPM #2; Dec. 1991).

WPM #1 has the ability to generate 100 percent of its power requirements. The mill's self-generation facilities include hydroelectric capacity, with the ability to store water (i.e., energy). The combination of a high level of power production and the ability to store "energy" allows the mill to limit power purchases to off-peak periods. Purchasing power in this manner lowers the mill's load factor while reducing the average rate paid per kilowatt of purchased power. The lower rate paid by WPM #1 relative to WPM #2 is accounted for largely by the amount of off-peak power purchased and partly by the higher power factor of WPM #1.

WPM #3 is also served by an electric utility with peak-load pricing and has the same opportunities as WPM #1 and WPM #2 to reduce its purchased power costs. The mill's load factor is, therefore, not an accurate indication of its operational efficiency with respect to electrical energy use.

The level of mark-up a utility places on its power provides an indication of the utility's encouragement of self-generation. The greater the mark-up a utility places on its energy the greater the incentive for industry to provide its own power. B.C. Hydro in the past has been criticized for not charging high enough rates to its large industrial customers. Presently there does not appear to be a significant difference in the mark-up of power between B.C. Hydro and the other utilities in this study. The mark-up on the power sold to the B.C. pulp mills BCPM(a) and BCPM(b) are 54 percent and 49 percent respectively, while the mark-ups to the Wisconsin pulp mills are 38, 50 and 50 percent.

While these values are similar, with the exception of WPM #1's (38%), the real level of mark-up may not be revealed by these figures. The Wisconsin utilities' efforts to increase purchases during the off-peak period, while reducing on-peak purchases will affect these comparisons. A disproportionate amount of energy purchased during the off-peak period reduces the mark-up on the pulp mill rates. The Wisconsin pulp mills' efforts to purchase power in off-peak periods places less demand on the electrical system's capacity than usage during peak periods. The mills, theoretically, should be rewarded with lower mark-ups on purchased power. The similarity in the mark-up between the two regions, therefore, suggests that given similar usage patterns the Wisconsin utilities would be providing higher levels of mark-up.

#### Summary of "Mark-up" Comparison

Utilities' pricing structures are designed to encourage high load factors and efficient energy use. Customers that most effectively meet these requirements are rewarded with lower rates. The success a utility has in encouraging technical efficiency of energy use is reflected by the mills' power factors. High power factors indicate electrical equipment



operating at a high level of technical efficiency. Mills with high load factors, indicate high operating efficiency, which also reduces a utility's cost of service.

Table 5.2 lists the B.C. pulp mills' median power factor as 95.5 and 98 percent for BCPM(a) and BCPM(b) respectively. This compares to 90 percent for the Wisconsin mills. The Wisconsin mills' power factors are lower than either WPM #2 and WPM #3 would like. WPM #2's power factor fell from 84 percent in 1987, to 80 percent in 1991 because of the addition of production facilities. The mill went from a position of receiving a credit in 1987 to paying a penalty in 1991. WPM #3 also added more production facilities that lowered its power factor from 99 percent in 1987 to 90 percent in 1991. The mill currently pays a penalty, but with the assistance of the electric utility plans to add capacitors to increase its power factor.

The higher power factors of the B.C. pulp mills are an indication that B.C. Hydro's utility rate schedule may be encouraging a higher level of technical efficiency than the Wisconsin utilities. An explanation for the Wisconsin mills' lower power factors, in part, could be the mills' higher level of self-generation. This reduces the mills' purchased power costs and could reduce the impact of charges related to lower power factors. While many factors may account for the Wisconsin pulp mills' lower power factors it is ultimately the objective of the rate schedule to encourage high levels of technical efficiency.

Many electric utilities encourage their industrial customers to maintain high load factors, however, this may not be the case for utilities with peak load pricing. Electric utilities encourage increased electrical usage during off-peak periods to increase system load factors. The encouragement of off-peak sales, for the Wisconsin pulp mills has resulted in the lower load factors. Table 5.2 shows that even with off-peak purchases the Wisconsin pulp mills' load factors are equal to or greater than the majority of the load factors of the B.C. mills. If the load factors are assumed to be an indication of a mill's efforts to maintain high

levels of operational electrical efficiency it appears that the Wisconsin mills' efforts are equal to or greater than the B.C. mills' efforts.

The comparison of the utilities' mark-up on power sold to the pulp mills is also influenced by the Wisconsin mills' efforts to purchase greater amounts of power in the off-peak period. Off-peak purchases place less of a burden on a utility's capacity and therefore have a lower mark-up. As a result even though the level of mark-up appears similar between the two regions given equivalent energy use patterns the Wisconsin utilities pulp mill rates may have a higher mark-up than B.C. Hydro pulp mill rates.

These comparisons demonstrate the ability of pulp mills to alter their pattern of electric use given sufficient incentive. The availability of peak-load pricing has encouraged the Wisconsin mills to purchase more power in the off-peak period. This has the advantages of higher load factors for utilities and lower purchased power costs for the pulp mills.

The benefits of a peak-load pricing system, however, are not necessarily applicable to all electric utilities. WEU #1 and WEU #2 are capacity critical systems. This means their main expansion costs relate primarily to the addition of extra capacity (chapter 2). This is very different from B.C. Hydro which is an energy critical system. In this type of system a kilowatt hour produced at the systems peak has no more value than a kilowatt hour produced at any other time. As a result energy critical systems do not have any justification for peak-load pricing.

By the mid 1990's B.C. Hydro will become both capacity and energy critical (Stafford;June, 1992). However, 80 to 90 percent of the cost of new electricity production will be on the energy component because of the availability of low cost capacity. B.C. Hydro has the ability to add two generating units at both Mica and Revelstoke dams for a total of 1800 MW of capacity at a fairly low cost (Stafford;June, 1992). There is also a provision for additional generating units at the Seven Mile project. This availability of cheap capacity

means that peak-load pricing is not an immediate consideration for B.C. Hydro. When B.C. Hydro eventually requires more expensive capacity, however, the benefits of a peak-load pricing system should then be considered as an alternative to the construction of another large dam.

## COMPARISON OF ELECTRIC UTILITIES' BUY BACK OPTIONS

A significant factor in the development of self-generation facilities are the electric utilities' willingness to purchase or market this energy. Electric utilities often vary in their efforts and methods to buy back power from power producers. This section will compare B.C. Hydro's policies affecting the marketing of self-generated power with those of the Wisconsin utilities.

### B.C. HYDRO'S POLICIES

B.C. Hydro has a Wheeling Policy (proposed), Direct Purchases of Electricity, Load Displacement and Spot Market purchases for self-generators to market their power. Each option is unique and designed for a specific function.

#### Wheeling Service Schedule 1841 (Proposed)

The Wheeling Policy rate structure is designed to recover the full cost of making the service available and to provide price signals for capacity that encourage supply locations in the desired areas of the province. B.C. Hydro states that "the policy facilitates competition in the generation and supply of electricity in British Columbia which is expected to result in

lower cost to consumers. The additional generation will allow B.C. Hydro to postpone building future generation plants and reduce future costs to British Columbians at large" (B.C. Hydro;Mar. 1990:8).

As described in Chapter 3, B.C. Hydro does not buy the energy but rather allows its transmission system to be used by one party to transport electricity to another. It is the responsibility of the supplier to find a market for his power and to negotiate a rate for the sale of the power. B.C. Hydro is a factor in determining this price through the system of charges and credits applied to the wheeled power.

To better understand the wheeling policy and the various charges and credits a theoretical construct, with assigned production values, will be created to demonstrate several possible scenarios. While the plant does not actually exist, it does represent realistic operating values. The theoretical construct will be a power plant with a maximum continuous rating of 25 MW and a wheeling agreement that is six years long.

A 25 MW plant could theoretically deliver 18,300 MWh of energy per month. This does not take into account the customer's load factor and the maximum demand required. This plant will have values based on two possible load factors (plants [a] and [b]). It will be assumed that plant (a) has a load factor of 65 percent (B.C. Hydro's system load factor) and the maximum demand is 22 MW. The actual energy required to equal demand for plant (a) would be 10,467.6 MWh of energy per month (billing period) (B.C. Hydro;Dec. 1990:4). Plant (b) will have a maximum demand of 22 MW and a customer with a 90 percent load factor. The energy delivered per month would rise from 10,467.6 MWh to 14,493.6 MWh.

B.C. Hydro calculates the capacity supplied as the lesser of either:

- (a) the average capacity supplied during the billing period to B.C. Hydro from 0700 to 2000 on weekdays excluding statutory holidays,

(b) the average capacity scheduled during the billing period for these same hours.

The plants' average production values are 22 MW per hour during the hours from 0700 to 2000 (on average 270.5 hours per month), for both plants (a) and (b). The scheduled level of capacity in the wheeling agreement is also 22 MW. The energy supplied during the heavy load hours is calculated by multiplying 270.5 hours by 22 MW, which equals 5951 MWh supplied during the billing period. The two plants are assumed to supply the same capacity because of the very high levels assumed in the first example.

From this information and the Wheeling Service Schedule in Appendix C, it is possible to calculate the various credits that will apply to the wheeled energy. Table 5.3 lists the credits for each region based on the figures from plants (a) and (b). Depending on the region, the plant will receive credit for wheeled energy between \$17,600 to \$92,400 per billing period. It has been assumed that the area transmission credit is \$0.80/kW/month and the generation and transmission credits are as listed in the Wheeling Service schedule. These different credits are designed to reflect B.C. Hydro's cost of developing new electricity resources in these regions.

Table 5.3 lists the average credit per kilowatt for each of the regions. These values range from \$0.0012/kW to \$0.0088/kW, depending upon the plant and the region. The lower credit per kilowatt for plant (b) is because the plants higher load factor results in greater amounts of energy produced relative to the amount of capacity supplied.

Other scenarios are possible that would result in very different credits for wheeling energy. Both examples in Table 5.3 assumed a large amount of capacity supplied to B.C. Hydro. If the amount of capacity was reduced the capacity credit would be reduced proportionately.

**Table 5.3 : Generation Plants Wheeling Credits By Region**

<u>Regions</u>	<u>Plant</u>	<u>Capacity Credit \$</u>	<u>MWh of Prod/ Billing Period</u>	<u>Ave Credit/ kWh of Prod\$</u>
North Coast (NC)	(a)	17,600.00	10,467.60	0.0017
	(b)	17,600.00	14,493.60	0.0012
Peace River (PR)	(a)	17,600.00	10,467.60	0.0017
	(b)	17,600.00	14,493.60	0.0012
Central Interior (CI)	(a)	26,400.00	10,467.60	0.0025
	(b)	26,400.00	14,493.60	0.0018
East Kootenay (EK)	(a)	19,800.00	10,467.60	0.0019
	(b)	19,800.00	14,493.60	0.0014
Shuswap Okanagan (SO)	(a)	33,000.00	10,467.60	0.0032
	(b)	33,000.00	14,493.60	0.0023
Selkirk (SE)	(a)	26,400.00	10,467.60	0.0025
	(b)	26,400.00	14,493.60	0.0018
Kelly Lake /Nicola (KN)	(a)	39,600.00	10,467.60	0.0038
	(b)	39,600.00	14,493.60	0.0027
Lower Mainland (LM)	(a)	92,400.00	10,467.60	0.0088
	(b)	92,400.00	14,493.60	0.0064
Vancouver Island (VI)	(a)	92,400.00	10,467.60	0.0088
	(b)	92,400.00	14,493.60	0.0064

(a) Plant supplying load with 65 percent load factor.

(b) Plant supplying load with 90 percent load factor.

(Results based on theoretical plants' production values and B.C. Hydro's proposed wheeling policy)

In addition to the credits there are several charges that would accrue for plants (a) and (b). A charge of \$0.001 per kWh is applied to all wheeled energy. This equals charges of \$10,467.60 for plant (a) and \$14,493.60 for plant (b) per billing period. The load is also responsible for a wheeling demand charge. The amount of this charge will depend on the load's particular pattern of energy use.

The situations discussed assume the generation plants have wheeling agreements with a term of six years or longer. If the contract was less than six years the capacity credit would not apply. This would result in the supplier paying a flat rate of \$0.001 per kWh of wheeled energy. As mentioned earlier, this would result in plants (a) and (b) paying charges of \$10,467.60 and \$14,493.60 respectively, per billing period.

These examples represent only a few of the many possible combinations of credits and charges. The combinations of various capacity credits and load factors creates too many combinations to explore all possibilities; however, the two hypothetical examples will serve to highlight the wheeling policy's characteristics. Utilizing these results, the positive and negative effects of the wheeling policy on increased self-generation are discussed in the following pages.

### The Wheeling Policy's Potential Positive Effects on Self-Generation

The wheeling policy's principal incentive for increased self-generation is that it enables a power producer to market electricity, and to negotiate a price for this power. This is constrained by the fact that the customer has the option to purchase power from B.C. Hydro. This policy also enables a power producer to wheel electricity between two or more of its plants.

The return to the power producer is influenced because the load must pay a demand charge the same as the customer would pay if he purchased power directly from B.C. Hydro. With the customer's ability to purchase power from B.C. Hydro, the principal reason to purchase wheeled energy would be the possibility of reducing energy costs.

In addition to the revenue from the sale of wheeled energy the Wheeling Service Agreement has the incentive of capacity credits. These credits are available in all nine regions in the examples listed for plants (a) and (b), however, it is possible for some regions not to receive credits under different conditions. The level of the credits available act as an incentive for power producers to consider wheeling power.

A further incentive or assistance to the generation and marketing of power is the energy balancing feature of the wheeling policy. B.C. Hydro's generation system predominately consists of hydro plants and has the ability to store energy. B.C. Hydro uses this ability to enhance the value of power generated by non-utility generators by providing, shaping, storage, increased reliability and back-up. This allows a great deal of flexibility for the plant wheeling the power and provides a more reliable source of power to the load. This benefit is paid for by the load through the wheeling demand charge.

The wheeling policy also has several negative aspects with respect to encouragement of self-generation. Any charge for wheeling power or failure to pay fair value for benefits derived by the utility would constitute a negative influence towards self-generation. At the same time, however, it must be recognized that there are utility costs involved in wheeling a customer's power. A wheeling policy that offers the most encouragement is therefore one that most accurately recovers costs and pays credits in full.



## Negative Effects of B.C. Hydro's Wheeling Policy

B.C. Hydro's charge for wheeled power includes the wheeling commission charge. This is designed to recover costs of administration, operation and maintenance. It is essentially a customer charge and as such should recover the costs a customer places on the system. B.C. Hydro chooses to use a commission charge of \$0.001 per kWh on all wheeled energy to collect the required amount. At the same time, B.C. Hydro has determined that the minimum wheeling charge of \$3600.00 must be met regardless of the amount of energy wheeled; however, there is not a limit to the maximum amount that may be charged.

For the maximum encouragement of self-generation this charge should not include a share of existing costs and overheads that are not directly related to the wheeling of power, such as administrative and general costs. Nor should the charges include costs that are already recovered in normal retail schedules. It is not possible to determine what costs are included in the wheeling commission charge because B.C. Hydro does not itemize each cost. It is difficult to imagine, however, that an open ended charge can accurately reflect the concerns mentioned above. The production values for power plants (a) and (b) (Table 5.3) can be used to demonstrate the limitations of this charge.

If power plants (a) and (b) operated in the North Coast region and wheeled power at their respective levels for one year, producer (a) would pay \$125,611.20 in commission charges while producer (b) would pay \$173,923.20 in commission charges for a difference of \$48,312.00. This represents a substantial difference in charges for what should be similar costs to the utility. This becomes more obvious when these levels are compared with a plant that only pays the \$3,600.00 minimum wheeling commission charge. Plant (a) and (b) would pay \$122,011.20 and \$170,323.20, respectively, more than a plant that paid the minimum wheeling charge.

B.C. Hydro has stated that the wheeling commission charge would not be a significant factor relative to the operating costs of a 25 MW generating facility. Most plants assessing the viability of wheeling power, should the policy become operational, would not consider the wheeling commission charge a determining factor (Lail;Dec:1991). Regardless of this, B.C. Hydro should ensure that the wheeling commission charge reflects the actual costs incurred through the wheeling of power.

A second criticism of the wheeling policy is the allocation of capacity credits. B.C. Hydro only provides capacity credits for wheeling agreements with terms of six years or longer. B.C. Hydro states that short term wheeling transactions, that is, agreements with terms greater than one year but less than six years, do not attract a capacity credit, because there is little or no impact on the system's long term plans (Lail;Dec:1991).

This policy does not take into consideration the aggregate capacity of the short term facilities. The combined supply of short term producers can significantly increase a utility's capacity. The possibility of all short term energy supplies ceasing to operate at one occasion is extremely low, especially if the power producer provides the correct price signals. B.C. Hydro therefore has the potential for increased capacity and this should be reflected in the capacity credits available to the power producers. There will always be some element of risk involved in using short term contracts for investment planning. This uncertainty should be reflected in the value of the capacity credits for short term contracts.

In the U.S. FERC has regulated utilities to consider the "individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system" (Charo;1986:467). The value of aggregate capacity, however, is subject to a great deal of debate. Not all states have followed FERC's direction to make aggregate capacity payments to all small power producers (Charo;1986:468).

The Wheeling Policy could also offer greater encouragement in the method it uses to determine the amount of capacity supplied. The capacity supplied is calculated as the lesser of either the average capacity during heavy load hours or the average capacity scheduled in the agreement. This could create a situation where the wheeler will supply energy during B.C. Hydro's heavy load hours and not receive a credit. This energy contributes to B.C. Hydro's aggregate capacity and should receive a capacity credit that reflects the value of this capacity. There may, however, be technical difficulties that inhibit B.C. Hydro from accepting more than the scheduled amount of power and in these cases this criticism would not be applicable.

The availability of capacity credits recognizing the value of aggregate capacity does not represent a major consideration in the development of non-utility generation. Investment decisions for these facilities are based primarily on the return available from long term contracts. The availability of capacity credits that recognize aggregate capacity, however, could influence these investment decisions. A pulp mill for example, can vary in the amount of power produced over the course of a year and from hour to hour depending on the amount of steam required (Cox and Helliwell, 1978:15). At certain times during the year pulp mills could be in a position to supply capacity in excess of the scheduled amount. In these circumstances the availability of capacity credits recognizing aggregate capacity could have an effect on long term power producers.

The Wheeling Policy, therefore, does not offer the maximum level of incentive for self-generation for several reasons. It does not recognize the aggregate capacity supplied by short term contracts or have a customer charge based on the lowest possible service charges. The policy also does not recognize the aggregate capacity delivered in excess of the scheduled amount of capacity in the Wheeling Agreement. Again there may be technical limitations that inhibit B.C. Hydro from dealing with these points in a different manner, however, from a purely economic standpoint these points reduce the level of incentive for

self-generation.

### Direct Power Purchases

To determine the return to a power producer, three theoretical power plants will be used to calculate several buy back rates. Plants (a) and (b) will be the same as the two plants described earlier, with a maximum continuous rating of 25 MW and a maximum demand of 22 MW. These plants operate at 65 and 90 percent load factors and deliver 10,467.6 MWh and 14,493.6 MWh of energy respectively, per month. The plants deliver 5951 MWh of energy during peak hours per billing period.

• Plant (c) will deliver power evenly throughout the year. The actual level of power production for this plant does not matter since it is assumed to remain constant 24 hours a day (i.e., 100% load factor).

B.C. Hydro's basic objective in determining a buy back rate is to calculate the rate as 85 percent of avoided cost, although realistically, these purchases will average 90 percent (Wells;Sept. 1, 1991). To calculate a buy back rate it is necessary to calculate a levelized cost of electricity for each of the nine regions as defined by B.C. Hydro's Resource Planning departments. This cost may be calculated by inserting the appropriate values in the following equations:

$$\begin{aligned} \text{Levelized Total Cost of Electricity} = \\ & (\text{Annual Energy Output} \times \text{Levelized Unit Cost of Energy}) \\ & + (\text{Effective Capacity} \times \text{Levelized Unit Cost of Capacity}) \end{aligned}$$

$$\begin{aligned} \text{Levelized Cost / kWh} = & (\text{Levelized Total Cost of Electricity}) / \\ & (\text{Annual Energy Output}) \end{aligned}$$

(B.C. Hydro;June,1991:7)

The annual energy output is calculated by multiplying the monthly energy output, listed above, by 12. The effective capacity is calculated by the following formula:

$$\text{Effective Capacity} = \text{Capacity (Heavy Load Hours)} =$$

$$\frac{\text{Energy Delivered During Heavy Load Hours}}{\text{Number of Heavy Load Hours}}$$

(B.C. Hydro; June, 1991:26)

The levelized unit cost of energy and capacity are supplied by B.C. Hydro's Resource Planning documents (i.e., B.C. Hydro; April, 1991, and B.C. Hydro; June, 1991).

With the production figures described for plants (a), (b) and (c) and the above formulas, buy back rates have been calculated for each region for 20 years beginning in 1991. These results are presented in Table 5.4. B.C. Hydro normally purchases power at the levelized cost for a 20 year contract. This results in the power producer receiving a greater return on investment during the early years of the contract. This additional revenue is an important consideration for power plants with high start-up costs. These benefits cannot be directly compared with the Wisconsin results other than to mention their significance.

In Table 5.4, column 4 represents the actual price based on B.C. Hydro's marginal cost, that the utility is willing to pay for power from each of the regions. Table 5.4 shows that with this method of calculating B.C. Hydro's production costs, the plants with the higher load factors, in the Lower Mainland and Vancouver Island Regions, receive a lower credit per kilowatt of energy. The plants actually receive the same credit; however, the plants with higher load factors have their credit averaged over a greater number of kilowatts produced. Table 5.4 shows three different plants to demonstrate several different scenarios. In the real world these plants would attempt to maximize their return by maintaining high load factors and high levels of effective capacity. Plants (b) and (c) therefore most accurately represent

Table 5.4 : Levelized Cost/kWh

<u>Region</u>	<u>1</u> <u>Term</u>	<u>2</u> <u>Plant</u>	<u>3</u> <u>Lev. Cost/kWh</u>	<u>4</u> <u>Lev. Cost/kWh</u> <u>x 0.9</u>
North Coast	20 years beginning in 1991	(a)	\$0.03	\$0.027
		(b)	\$0.03	\$0.027
		(c)	\$0.03	\$0.027
Peace River	"	(a)	\$0.0305	\$0.028
		(b)	\$0.0304	\$0.027
		(c)	\$0.03	\$0.027
Central Interior	"	(a)	\$0.0331	\$0.03
		(b)	\$0.0325	\$0.029
		(c)	\$0.029	\$0.026
East Koot�enay	"	(a)	\$0.031	\$0.029
		(b)	\$0.0306	\$0.028
		(c)	\$0.0306	\$0.028
Selkirk	"	(a)	\$0.0331	\$0.03
		(b)	\$0.0325	\$0.029
		(c)	\$0.0324	\$0.029
Shuswap Okanagan	"	(a)	\$0.034	\$0.031
		(b)	\$0.0332	\$0.03
		(c)	\$0.0329	\$0.03
Kelly Lake / Nicola	"	(a)	\$0.0349	\$0.031
		(b)	\$0.0338	\$0.03
		(c)	\$0.0335	\$0.03
Lower Mainland	"	(a)	\$0.0404	\$0.036
		(b)	\$0.0381	\$0.034
		(c)	\$0.0375	\$0.034
Vancouver Island	"	(a)	\$0.0415	\$0.037
		(b)	\$0.0388	\$0.035
		(c)	\$0.0381	\$0.034

(Figures based on respective value of energy and capacity supplied by the theoretical plants, as determined by B.C. Hydro's Resource Planning Documents [i.e., B.C. Hydro; April, 1991 and B.C. Hydro; June, 1991])

an independent power producer's production values.

B.C. Hydro calculates the buy back rate based on the specific plant's operating costs, taking into account the amount of energy produced, the effective capacity and the location. While the rates in Table 5.4 represent 90 percent of B.C. Hydro's cost of production, these rates are not necessarily 90 percent of the system's marginal cost of production in these regions. B.C. Hydro's marginal cost of production for each region may be higher than the examples. B.C. Hydro's cost of production must take into account the dispatchability of the energy being purchased. In a Direct Purchase Agreement B.C. Hydro agrees to purchase the specified amount of power for the entire length of the contract. B.C. Hydro's own power production, however, must be dispatchable. This refers to production facilities that increase or decrease their output so that production equals demand. The cost related to the dispatchable nature of B.C. Hydro's production facilities is calculated into its marginal cost and results in B.C. Hydro's own power being valued higher than an equivalent amount of purchased power (Peterson;1991).

Table 5.5 lists the actual percentage the buy back rate represents of B.C. Hydro's marginal cost for each of the regions. These values will be compared with similar values for the two Wisconsin utilities.

### WISCONSIN BUY BACK RATES

The Wisconsin utilities' long run marginal costs were listed in chapter 4. These values will be compared with the Wisconsin utilities' buy back rates.

The results are based on the same plants as used in the B.C. example. Plants (a) and (b) are assumed to produce the same amount of power during the on-peak and off-peak periods. Plant (c) represents a plant producing power at a constant output 24 hours a day.

Table 5.5 : Buy Back Rate and B.C. Hydro System LRM

<u>Region</u>	<u>Term</u>	<u>Plant</u>	<u>LRMC/kWh</u>	<u>Buy Back Rate</u>	<u>Percent</u>
North Coast	20 years beginning in 1991	(a)	\$0.05	\$0.027	54.0
		(b)	\$0.05	\$0.027	54.0
		(c)	\$0.05	\$0.027	54.0
Peace River	"	(a)	\$0.051	\$0.028	54.9
		(b)	\$0.051	\$0.027	52.9
		(c)	\$0.051	\$0.027	52.9
Central Interior	"	(a)	\$0.055	\$0.03	54.5
		(b)	\$0.055	\$0.029	52.7
		(c)	\$0.055	\$0.029	52.7
East Kootenay	"	(a)	\$0.053	\$0.029	54.7
		(b)	\$0.053	\$0.028	52.8
		(c)	\$0.053	\$0.028	52.8
Selkirk	"	(a)	\$0.055	\$0.03	54.5
		(b)	\$0.055	\$0.029	52.7
		(c)	\$0.055	\$0.029	52.7
Shuswap Okanagan	"	(a)	\$0.057	\$0.031	54.4
		(b)	\$0.057	\$0.03	52.6
		(c)	\$0.057	\$0.03	52.6
Kelly Lake / Nicola	"	(a)	\$0.059	\$0.031	52.5
		(b)	\$0.059	\$0.03	50.8
		(c)	\$0.059	\$0.03	50.8
Lower Mainland	"	(a)	\$0.064	\$0.036	56.3
		(b)	\$0.064	\$0.034	53.1
		(c)	\$0.064	\$0.034	53.1
Vancouver Island	"	(a)	\$0.071	\$0.037	52.1
		(b)	\$0.071	\$0.035	49.3
		(c)	\$0.071	\$0.034	47.9



Plants (b) and (c) again represent the most realistic production values, because a power producer would attempt to maintain the highest possible load factor. Plants (b) and (c) have load factors of 90 and 100 percent respectively.

WEU #1 and WEU #2 list their peak period hours as 322 and 298.6 hours per billing period, respectively. By comparison B.C. Hydro's peak period is 270.5 hours per billing period. Because of the longer peak periods equivalent plants in Wisconsin could produce more energy during the peak period. For the example, however, both plants (a) and (b) are assumed to produce 5951 MWh during their peak periods. Plant (c) will reflect the longer peak periods and therefore will produce more energy during the peak periods relative to the off-peak period in the Wisconsin example than in the B.C. Hydro example.

Longer peak periods would allow a power producer to increase their average buy back rates per kilowatt by producing large amounts of power during the on-peak period and little or no power during the off-peak period. Under normal operating conditions, however, plants would not operate in this manner. Power producers receive the greatest return on investment by operating at maximum capacity and by maintaining a high load factor. For this reason plants (b) and (c) are the best possible choices for comparing the buy back rates.

Table 5.6 lists the percentage of the Wisconsin utilities' buy back rates relative to LRMC. These values range from as low as 65.7 percent to as high as 102.4 percent of LRMC. Both WEU #1 and WEU #2's plants (b) and (c) have considerably lower buy back rates than for plant (a). This difference reflects plant (a)'s large amount of energy produced during peak periods relative to off-peak energy production. WEU #1's plants (b) and (c) have buy back rates representing 87.1 and 90.9 percent of LRMC, respectively. WEU #2's plants (b) and (c) both have buy back rates that are 65.7 percent of LRMC. The percentage values for buy back rates relative to LRMC will be compared with B.C. Hydro's data in Table 5.7.

**Table 5.6 : Wisconsin Utilities' Buy Back Rates Compared to LRMC**

<u>Utility</u>	<u>Year</u>	<u>Plant*</u>	<u>Average Buy Back Rate/kWh</u>	<u>LRMC/kWh</u>	<u>Percentage</u>
WEU #1	1991	(a)	\$0.08	\$0.0781	102.4
	"	(b)	\$0.068	\$0.0781	87.1
	"	(c)	\$0.071	\$0.0781	90.9
WEU #2	1990	(a)	\$0.055	\$0.07	78.6
	"	(b)	\$0.046	\$0.07	65.7
	"	(c)	\$0.046	\$0.07	65.7

\* Plant (a) represents a plant delivering 5951 MWh during peak periods, and a total of 10,467.6 MWh per month.

Plant (b) represents a plant delivering 5951 MWh during peak periods, and a total of 14,493.6 MWh per month.

Plant (c) represents a plant with a constant output 24 hours a day.

#### Comparison of B.C. and Wisconsin Buy Back Rates

A comparison of the B.C. Hydro and Wisconsin utilities' data (Table 5.7) demonstrates that both Wisconsin utilities purchase power at considerably higher levels, relative to their LRMC, than B.C. Hydro. B.C. Hydro's highest buy back rates for plants (b) and (c) represent 54 percent of LRMC. WEU #1's equivalent plants have buy back rates of 87.1 and 90.9 percent of LRMC while WEU #2's plants (b) and (c) have buy back rates 65.7 percent of LRMC. None of the plants in the Wisconsin example have a buy back rate representing a lower percentage of LRMC than any of B.C. Hydro's plants.

While the percentage difference between the B.C. Hydro and Wisconsin data is large this may not be an accurate indication of the differences. The method used to calculate the

Table 5.7 : B.C. Hydro and Wisconsin Utility Comparison of Buy Back Rates

<u>Utility</u>	<u>Plant</u>	<u>Percentage</u>
<u>B.C. Hydro</u>		
North Coast	(a)	54.0
	(b)	54.0
	(c)	54.0
Peace River	(a)	54.9
	(b)	52.9
	(c)	52.9
Central Interior	(a)	54.5
	(b)	52.7
	(c)	52.7
East Kootenay	(a)	54.7
	(b)	52.8
	(c)	52.8
Selkirk	(a)	54.5
	(b)	52.7
	(c)	52.7
Shuswap Okanagan	(a)	54.4
	(b)	52.6
	(c)	52.6
Kelly Lake / Nicola	(a)	52.5
	(b)	50.8
	(c)	50.8
Lower Mainland	(a)	56.3
	(b)	53.1
	(c)	53.1
Vancouver Island	(a)	52.1
	(b)	49.3
	(c)	47.9
<u>WEU #1</u>	(a)	102.4
	(b)	87.1
	(c)	90.9
<u>WEU #2</u>	(a)	78.6
	(b)	65.7
	(c)	65.7

Wisconsin utilities' buy back rates could account for some of the difference. The large difference between WEU #1 and WEU #2's data could indicate that the method used to calculate the long term buy back rates has a significant margin of error.

The difference between the Wisconsin and B.C. buy back rates, however, are likely too large to be accounted for entirely by an error in the method of calculation. The standard buy back rates, which Wisconsin's long term buy back rates were based on, represent a significant percentage of the Wisconsin utilities' LRMC. If plant (c) were to sell power at the standard buy back rates of each utility WEU #1's rate would be \$0.0301 per kilowatt (\$1991) and WEU #2's would be \$0.0252 per kilowatt (\$1990) (Data supplied by WEU #1 and WEU #2: July, 1992). These rates represent 38.5 and 36 percent of the utilities' LRMC. B.C. Hydro's long term buy back rate for plant (c) in the Vancouver Island region is only 47.9 percent of LRMC. This represents only 10 percent more than the Wisconsin utilities' standard buy back rates which are short term purchase rates.

It is also possible that the method used to calculate the Wisconsin long term buy back rates could have underestimated their value. The standard buy back rate, which the calculations are based on, is calculated on 75 percent of the electric utilities' avoided costs. The long term rate would be a negotiated rate in excess of the standard buy back rate. The actual level of the rate would depend on many factors including the ability of the negotiator. It is therefore conceivable that the Wisconsin long term buy back rates could be higher than those used in these comparisons.

While B.C. Hydro's buy back rates represent a lower percentage of LRMC than the Wisconsin utilities' rates, the B.C. power producers have the advantage of a levelized payment schedule. This may act as a significant incentive to power producers through off-setting start-up costs, however, all direct purchase agreements will not receive payment on a levelized payment schedule. This is decided during the negotiations between B.C. Hydro and

the power producer. This option is not available to the Wisconsin power producers.

### Load Displacement

With load displacement, B.C. Hydro is purchasing the ability to redistribute its existing electricity to defer the requirement to expand the electric system. The net unit price paid by B.C. Hydro for the load displacement is the power producer's negotiated price for electricity (as per a direct buy back), less the tariff for electricity that would otherwise be purchased from B.C. Hydro.

To examine this policy, production costs for each of the nine regions were calculated as in the analysis of direct purchases. Load displacement contracts are long term investments with contract terms negotiated for approximately 20 years. The same two power plants ([a] and [b]) will have their levelized production costs calculated for contracts beginning in 1991/92 for terms of 15 and 20 years. The levelized production cost represents B.C. Hydro's marginal cost for the terms of these contracts. The net return to the power producer is the negotiated price for electricity (as per IPP contract) less the tariff for electricity purchased from B.C. Hydro. The pulp mill rates of \$0.0346 and \$0.0316 will be used as the industrial rates. These rates are an average of 1989, 90 and 91 and therefore could be slightly lower than the actual 1991/92 rate. This lower rate will make load displacement credits appear higher than they are. The example also uses 100 percent of the levelized cost of power for each region. In actual practice this value would have to be negotiated and could be reduced by as much as 15 percent. Using 100 percent of the levelized cost of power provides the highest possible credits. In addition to this the industrial rate paid for power could also change over the term of the contract. If the rate were to go down the credit would then be higher. More likely the rate will go up which will reduce the amount of credit. It is difficult

to predict how the rates will change over the term of the contract, therefore, for this example it has been assumed that the rates will remain constant. The results for the nine regions are summarized in Table 5.8.

The Levelized Cost column, in Table 5.8, represents the value B.C. Hydro places on power generated in each specific region taking into account, annual output, and effective capacity. The Less Tariff column is the Levelized Cost minus the rates of either \$0.0346 or \$0.0316. If the value is negative B.C. Hydro will not make any contribution for load displacement. If the value is positive the load displacement contribution from B.C. Hydro per year is represented in the Revenue columns. The total Annual Revenue for the B.C. Hydro contribution equals the difference between the Levelized cost and the pulp mills' electricity rate (if the value is positive) multiplied by the total kilowatts produced per year.

For plants (a) and (b) there are several regions where credits are not available for load displacement. While several other regions receive very little credit for load displacement. The principal saving for load displacement is the savings resulting from a reduction in purchased power. Tables 5.9 and 5.10 list the combined totals of the revenue saved from the displaced power and the load displacement credit. This total represents the total annual positive revenue and is an important consideration in the calculation of the benefits of self-generation.

There is not a load displacement credit for either plant (a) or (b) in the North Coast, Peace River and East Kootenay regions. The Central Interior, Selkirk and Shuswap Okanagan regions only receive a credit for the 20 year contract where the plants' rates are \$0.0346. Kelly Lake/Nicola receives credits in three of the eight scenarios while the Lower Mainland and Vancouver Island regions receive credits for all scenarios.

As with the direct purchase of power, B.C. Hydro bases its avoided costs on the specific operating characteristics of the individual plant and its location. Depending on the

**Table 5.8 : Regional Load Displacement Values for Plants (a) and (b) For Contracts Beginning in 1991/92**

<u>Region</u>	<u>Plant</u>	<u>Levelized Cost</u>	<u>Less Tariff<sup>1</sup></u>	<u>Less Tariff<sup>2</sup></u>	<u>Annual Revenue<sup>1</sup></u>	<u>Annual Revenue<sup>2</sup></u>
<u>North Coast</u>						
15 year term	(a)	\$0.027	(0.0076)	(0.0046)	nil	nil
	(b)	\$0.027	(0.0076)	(0.0046)	"	"
20 year term	(a)	\$0.030	(0.0046)	(0.0016)	"	"
	(b)	\$0.030	(0.0046)	(0.0016)	"	"
<u>Peace River</u>						
15 year term	(a)	\$0.028	(0.0071)	(0.0041)	"	"
	(b)	\$0.027	(0.0072)	(0.0042)	"	"
20 year term	(a)	\$0.031	(0.0041)	(0.0011)	"	"
	(b)	\$0.030	(0.0042)	(0.0012)	"	"
<u>East Koot.</u>						
15 year term	(a)	\$0.028	(0.0069)	(0.0039)	"	"
	(b)	\$0.028	(0.0071)	(0.0041)	"	"
20 year term	(a)	\$0.031	(0.0037)	(0.0007)	"	"
	(b)	\$0.031	(0.0040)	(0.0010)	"	"
<u>Central Int.</u>						
15 year term	(a)	\$0.030	(0.0048)	(0.0018)	"	"
	(b)	\$0.029	(0.0053)	(0.0023)	"	"
20 year term	(a)	\$0.033	(0.0015)	0.0015	"	\$188,416
	(b)	\$0.033	(0.0021)	0.0009	"	\$156,530
<u>Selkirk</u>						
15 year term	(a)	\$0.030	(0.0047)	(0.0017)	"	nil
	(b)	\$0.030	(0.0052)	(0.0022)	"	"
20 year term	(a)	\$0.033	(0.0015)	0.0015	"	\$188,416
	(b)	\$0.033	(0.0021)	0.0009	"	\$156,530
<u>Shuswap/Ok.</u>						
15 year term	(a)	\$0.031	(0.0038)	(0.0008)	"	nil
	(b)	\$0.030	(0.0046)	(0.0016)	"	"
20 year term	(a)	\$0.034	(0.0006)	0.0024	"	\$301,466
	(b)	\$0.033	(0.0014)	0.0016	"	\$278,277
<u>Kelly Lake/Nic.</u>						
15 year term	(a)	\$0.032	(0.0031)	(0.0001)	"	nil
	(b)	\$0.031	(0.0041)	(0.0011)	"	"
20 year term	(a)	\$0.035	0.0003	0.0033	\$37,683	\$414,517
	(b)	\$0.034	(0.0008)	0.0016	nil	\$382,631
<u>Lower Main.</u>						
15 year term	(a)	\$0.037	0.0025	0.0055	\$314,028	\$690,862
	(b)	\$0.035	0.0002	0.0032	\$34,784	\$556,554
20 year term	(a)	\$0.040	0.0058	0.0088	\$728,545	\$1,105,378
	(b)	\$0.038	0.0035	0.0065	\$608,731	\$1,130,501
<u>Vancouver Isl.</u>						
15 year term	(a)	\$0.038	0.0030	0.0060	\$376,834	\$753,667
	(b)	\$0.034	0.0006	0.0036	\$104,354	\$626,124
20 year term	(a)	\$0.042	0.0069	0.0099	\$866,717	\$1,243,551
	(b)	\$0.039	0.0042	0.0072	\$730,447	\$1,252,247

<sup>1</sup> Represents tariff of \$0.0346, and corresponding Annual Revenue.

<sup>2</sup> Represents tariff of \$0.0316, and corresponding Annual Revenue.

**Table 5.9 : Total Annual Load Displacement Credit: Plants With Tariff of \$0.0346 For Contracts Beginning In 1991/92**

<u>Region</u>	<u>Plant</u>	<u>Tariff x Annual kWh</u>	<u>Load Disp. Annual Credit</u>	<u>Total Savings</u>	<u>L.D. % of Total Sav.</u>
<u>North Coast</u>					
<u>Peace River</u>					
<u>East Koot.</u>					
<u>Central Int.</u>					
<u>Selkirk</u>					
<u>Shuswap Ok.</u>					
15 year	(a)	\$4,346,148	nil	\$4,346,148	nil
term	(b)	\$6,017,743	"	\$6,017,743	"
20 year	(a)	\$4,346,148	"	\$4,346,148	"
term	(b)	\$6,017,743	"	\$6,017,743	"
<u>Kelly Lake/Nic.</u>					
15 year	(a)	\$4,346,148	"	\$4,346,148	"
term	(b)	\$6,017,743	"	\$6,017,743	"
20 year	(a)	\$4,346,148	\$37,683	\$4,383,831	0.85%
term	(b)	\$6,017,743	nil	\$6,017,743	nil
<u>Lower Main.</u>					
15 year	(a)	\$4,346,148	\$314,028	\$4,660,176	6.73%
term	(b)	\$6,017,743	\$34,784	\$6,052,527	0.57%
20 year	(a)	\$4,346,148	\$728,545	\$5,074,693	14.36%
term	(b)	\$6,017,743	\$608,731	\$6,626,474	9.17%
<u>Vancouver Isl.</u>					
15 year	(a)	\$4,346,148	\$376,834	\$4,722,982	7.99%
term	(b)	\$6,017,743	\$104,354	\$6,122,097	1.70%
20 year	(a)	\$4,346,148	\$866,717	\$5,212,865	16.63%
term	(b)	\$6,017,743	\$730,477	\$6,748,220	10.82%



**Table 5.10 : Total Annual Load Displacement Credit: Plants With Tariff of \$0.0316  
For Contracts Beginning In 1991/92**

<u>Region</u>	<u>Plant</u>	<u>Tariff x Annual kWh</u>	<u>Load Disp. Total Credits</u>	<u>Total Savings</u>	<u>L.D % of Total Sav.</u>
<u>North Coast</u>					
<u>Peace River</u>					
<u>East Koot.</u>					
15 year	(a)	\$3,969,314	nil	\$3,969,314	nil
term	(b)	\$5,495,973	"	\$5,495,973	"
20 year	(a)	\$3,969,314	"	\$3,969,314	"
term	(b)	\$5,495,973	"	\$5,495,973	"
<u>Central Int.</u>					
<u>Selkirk</u>					
15 year	(a)	\$3,969,314	"	\$3,969,314	"
term	(b)	\$5,495,973	"	\$5,495,973	"
20 year	(a)	\$3,969,314	\$188,416	\$4,157,730	4.53%
term	(b)	\$5,495,973	\$156,530	\$5,652,503	2.77%
<u>Shuswap/Ok</u>					
15 year	(a)	\$3,969,314	nil	\$3,969,314	nil
term	(b)	\$5,495,973	"	\$5,495,973	"
20 year	(a)	\$3,969,314	\$301,466	\$4,270,780	7.06%
term	(b)	\$5,495,973	\$278,277	\$5,774,250	4.82%
<u>Kelly Lake/Nicola</u>					
15 year	(a)	\$3,969,314	nil	\$3,969,314	nil
term	(b)	\$5,495,973	"	\$5,495,973	"
20 year	(a)	\$3,969,314	\$414,517	\$4,383,831	9.46%
term	(b)	\$5,495,973	\$382,631	\$5,878,604	6.51%
<u>Lower Main.</u>					
15 year	(a)	\$3,969,314	\$690,862	\$4,660,176	14.82%
term	(b)	\$5,495,973	\$556,554	\$6,052,527	9.20%
20 year	(a)	\$3,969,314	\$1,105,378	\$5,074,692	21.78%
term	(b)	\$5,495,973	\$1,130,501	\$6,626,474	17.06%
<u>Vancouver Isl.</u>					
15 year	(a)	\$3,969,314	\$753,667	\$4,722,981	15.95%
term	(b)	\$5,495,973	\$626,124	\$6,122,097	10.23%
20 year	(a)	\$3,969,314	\$1,243,551	\$5,212,865	23.86%
term	(b)	\$5,495,973	\$1,252,247	\$6,748,220	18.56%

shape of the output, location and contract duration many different load displacement credits are available. This is demonstrated in the Kelly Lake/Nicola region where plant (a) with a 20 year contract and a rate of \$0.0346 would receive a credit of \$37,683 annually, while plant (b) under the same conditions does not receive any credit. The total savings for plant (b), however, would be greater than the total savings for plant (a) because of the greater level of displaced energy. Plant (a)'s total saving, including the load displacement credit, is \$4,383,831 while plant (b)'s is \$6,017,743.

In addition to the reduced cost of purchased energy and load displacement credits the power producer receives credit for any reduced area transmission costs it saves B.C. Hydro. If the load displacement project defers any capacity costs of transmission facilities, through a reduction of transmission requirements, B.C. Hydro will use the expenses deferred to put toward the development of the power plant (Wells;Sept.28:1991). B.C. Hydro will also look at avoided line losses achieved through off-loading existing transmission circuits (Peterson;1991).

### An Assessment of B.C. Hydro's Load Displacement Policy

The Wisconsin utilities' lack of a load displacement policy makes it necessary to analyze B.C. Hydro's policy independently. The fact that other utilities in this study do not have load displacement policies suggests that B.C. Hydro is progressive in this area of encouraging self-generation. While B.C. Hydro leads the Wisconsin utilities it must be remembered that B.C. Hydro's policy is very limited. B.C. Hydro's load displacement policy provides the greatest benefits to the Lower Mainland and Vancouver Island regions. In these regions the benefits account for as much as 23.86 percent of the total savings of revenue from the reduced power purchases and load displacement credits.

Along with the regional considerations the level of the industrial rate has a significant impact on the amount of load displacement credits. If all variables are constant, the industry with the higher rate will receive a lower credit than industry with a lower rate. The actual differences are listed in Table 5.8 by dollar value and repeated in Tables 5.9 and 5.10. Calculating the load displacement credit in this manner balances the plants' total savings. For example in the Vancouver Island region (Table 5.9) plant (b) with a 20 year contract and a \$0.0346 rate has a \$4,730,743 load displacement credit and a Total Savings of \$6,748,220. The same plant with a \$0.0316 rate (Table 5.10) would have a load displacement credit of \$1,252,247 and a Total Savings of \$6,748,220.

The load displacement credits generally are very low in many regions. In several cases there is either no payment or it is too low to be significant in the planning of most power projects. Part of the reason the credit is low could be the method used to calculate the avoided cost of the project. B.C. Hydro has stated that the cash payment made for load displacement is less than the amount paid in the direct purchase of power because different products are being purchased (B.C. Hydro; June 1991:8). In the case of a direct power purchase, B.C. Hydro is purchasing additional electricity that it can sell, and in the case of load displacement it is purchasing the ability to redistribute its existing electricity to defer expanding the electric system.

A further difference not mentioned is that once a load displacement contract has expired B.C. Hydro is not obligated to pay for further power generation. This is very different from direct power purchases where at the end of a contract, if demand has continued to rise, B.C. Hydro will require additional power and have to purchase this power at much higher rates.

The load displacement credit has only recently been implemented (only 2 contracts signed), and this makes it difficult to predict the value of load displacement projects beyond

the terms of their contracts. Power producers have as one of their objectives to negotiate contracts with terms as long as the generating facilities' life expectancy. B.C. Hydro would only receive additional benefits if these generating facilities continued to produce power beyond the terms of their contracts. B.C. Hydro will not have any first hand experience with these potential benefits until several contracts have been signed and run the length of their contract.

Establishing a "fair" load displacement policy will benefit both B.C. Hydro's customers and industry through the encouragement of self-generation. Determining a fair load displacement credit, however, is not the most efficient method of encouraging power production from industry. If B.C. Hydro provided the correct price signal to industry, by charging a rate based on the LRMC of power, load displacement credits would not exist. B.C. Hydro would be providing the same incentive for industry to generate power without offering load displacement credits.

#### B.C. Hydro's Spot Market Purchases and Export Prices

The final option available for self-generators with surplus capacity is to sell their power to B.C. Hydro on the spot market. Table 5.11 lists B.C. Hydro's mean purchase and export prices for 1990. Column (1) lists the amount of power purchased from independent power sources while column (2) lists the total expenditures for these power purchases. Column (3) represents the actual purchase price in dollars per kilowatt (all values are listed in 1990 Canadian dollars). Columns (4), (5), and (6) represent the total exports, export revenue, and dollars per kilowatt.

Table 5.11 lists the mean purchase price for 1990 as \$0.0126/kWh while the mean export price was \$0.0246/kWh. The purchase price of \$0.0126/kWh represents the lowest of

Table 5.11 : B.C. Hydro's Spot Market Power Purchases and U.S. Exports 1990

<u>Date</u>	<u>1</u> <u>Purchases</u> <u>(GWh)</u>	<u>2</u> <u>Expenditures</u> <u>(CDN\$)</u>	<u>3</u> <u>\$/kWh</u> <u>(\$CDN)</u>	<u>4</u> <u>Exports</u> <u>(GWh)</u>	<u>5</u> <u>Exports</u> <u>\$CDN)</u>	<u>6</u> <u>\$/kWh</u> <u>(\$CDN)</u>
Jan-90	83	1,009,635.20	0.0122	465	14,971,927	0.0322
Feb-90	75	937,017.70	0.0125	132	3,961,485	0.0300
Mar-90	82	1,020,003.50	0.0124	---	8,187	---
Apr-90	79	992,368.90	0.0126	56	1,099,099	0.0196
May-90	87	1,055,454.60	0.0121	100	2,207,441	0.0221
Jun-90	111	1,249,568.10	0.0113	22	398,806	0.0181
Jul-90	83	1,039,410.30	0.0125	556	12,041,024	0.0217
Aug-90	83	1,084,301.90	0.0131	674	15,009,761	0.0223
Sep-90	81	1,182,931.60	0.0146	490	12,397,933	0.0253
Oct-90	163	1,979,904.72	0.0121	737	18,489,281	0.0251
Nov-90	164	2,100,034.43	0.0128	308	7,438,671	0.0241
Dec-90	93	1,259,345.67	0.0135	355	7,851,750	0.0221
Totals	1,184	14,909,976.62	---	3,894	95,875,364	---
Mean	--	----	0.0126	---	---	0.0246

(Lum; Oct. 1991)

all possible buy back options reviewed in this study. B.C. Hydro's lowest direct purchase buy back rate listed in Table 5.4 is \$0.027/kWh. The price offered for spot market purchases, in actual practice, would be lower than those listed in Table 5.11, because the majority of the purchases listed are from Alcan (5 year agreement) (Mark;Sept:1991). Alcan's purchase agreement is higher than the spot market price and serves to drive up the

average price for purchases listed in Table 5.11. Further purchases are also made from Trans Alta's large coal fired generators when they have surplus power.

The lower purchase price is not surprising since most of these power producers do not have a contract and the power supplied is non-firm energy. The spot market purchase price represents a power producers final option to market excess power. This market provides very little incentive for self-generators to produce excess power. The rates paid vary according to market conditions based on the supply and demand of electricity. Large power producers such as Trans Alta and Alcan are much better suited to use this market, because of their availability of low cost surplus power during certain times of the year. In most cases the low prices available will be of little encouragement to the smaller power producer.

## CHAPTER 6

### SUMMARY AND CONCLUSION

#### SUMMARY

In this study I have assessed the importance B.C. Hydro places on the encouragement of self-generation by examining both its proposed and existing pricing policies and buy back rates. In analyzing the level of incentives B.C. Hydro provides for increased self-generation, several pulp mills have been examined. These pulp mills were chosen because of the self-generation potential. Where possible, this information has been compared with similar data collected from Wisconsin.

#### Pulp Mill Comparison

This comparison of B.C. and Wisconsin pulp mills has revealed more similarities than differences. The most notable difference in the pulp mill data is indicated in the levels of self-generation. The B.C. mills' median self-generated power accounted for 50 percent of their total electrical energy requirements as compared to 90 percent for the Wisconsin mills. One factor that may account for this difference is the cost of energy available when the various pulp mills were constructed.

Many of the B.C. mills were constructed when electricity prices were low and this, in part, may account for the mills' lower levels of energy production. Electricity costs, however, are only one variable in pulp production and it would be inaccurate to suggest that they are solely responsible for these lower levels of self-generation.

On the basis of the data collected, the higher levels of self-generation evident in the Wisconsin mills cannot be attributed solely to higher energy costs or greater utility incentives. This is because the Wisconsin utilities' pricing policies and buy back rates examined were developed after the Wisconsin mills had installed their generation capacity. The utilities' pricing policies reviewed were developed in the late 1970's and early 1980's, however, the Wisconsin mills installed most of their generation capacity before 1968. This does not preclude the possibility that earlier Wisconsin electric utility pricing policies and buy back rates were responsible for the higher levels of self-generation of the Wisconsin pulp mills surveyed.

The apparent differences between the B.C. and Wisconsin mills' self-generation levels are probably the result of many different factors. These include the availability of low cost electricity when many of the B.C. mills were constructed. Many other factors which influence pulp mills' decisions to generate power are based on considerations that may be mill specific. For example, many Wisconsin mills were developed on the Wisconsin river and have access to low cost hydroelectric power. Other considerations are the large distances between some of B.C.'s pulp mills and the principal markets for electricity. This reduces the value of self-generated power because of the increased transmission costs.

Another factor that may contribute to different levels of generation may be the attitude of mill managers. Management's attitude may vary considerably from mill to mill regarding the attractiveness of self-generation. In some instances, management may consider the production of electricity to be peripheral to the production of pulp and paper. When this occurs, a mill may opt for a number of alternatives before choosing to increase the levels of self-generation.

These examples represent only a few of the many factors that influence a pulp mill's decision to generate power. The many factors involved in a mill's decision to generate power



make it impossible to account for the differences between the B.C. and Wisconsin pulp mills' generation levels based on the information collected.

### Electricity Utility Rates

Electric utilities' policies can influence industrial decisions regarding the development of self-generation facilities. The most obvious means of encouraging self-generation is to modify the rate charged to industry. By increasing the cost of purchased power electric utilities can increase the attractiveness of self-generation facilities.

The comparison of the "mark-up" applied to power sold in Wisconsin versus B.C. revealed few differences. On average, B.C. Hydro's power had a slightly higher mark-up than the Wisconsin utilities. The encouragement provided by such utility mark-ups suggests that B.C. Hydro is providing more encouragement for industry to self-generate than the Wisconsin electric utilities.

This, however, does not take into consideration the pulp mills' load factors. The Wisconsin mills purchase large amounts of power during off-peak hours. This lowers the mills' load factors but, unlike B.C. Hydro's rate schedule, this does not increase the pulp mills' purchase rates. Off-peak purchases reduce the electric utilities cost of service and therefore the pulp mills' rates are correspondingly reduced. This makes it difficult to accurately compare the B.C. and Wisconsin pulp mill rates or load factors; given equivalent energy usage patterns, the Wisconsin rate structure would provide more encouragement for self-generation. While the levels of mark-up between the regions are very similar, the Wisconsin pulp mills are not purchasing an equivalent amount of power during peak periods. This serves to reduce the mark-up on the utility power. A pulp mill without self-generation capacity that was served by either WEU #1 or WEU #2 would pay a higher mark-up than an

equivalent mill served by B.C. Hydro.

A utility's rate schedule may also encourage industry to maintain a high power factor. B.C. Hydro appears to offer greater incentive for pulp mills to maintain a higher power factor. The B.C. mills have noticeably higher power factors than those in Wisconsin. The Wisconsin mills' lower levels can be explained, in part, by their higher levels of self-generation. This results in lower purchased power cost and may reduce the incentive to maintain a higher power factor. Using the power factor as an indicator of a mill's technical efficiency of energy use, demonstrates that B.C.'s pulp mills are using electricity more efficiently.

#### Electric Utility Buy Back Policies

An important consideration for an industry installing self-generation capacity is the availability of buy back policies and the respective purchase prices. The Wisconsin utilities provide a standard buy back rate that is available to all utility customers. These customers may also negotiate an agreement with the electric utilities if the standard buy back rates are not acceptable. This differs from B.C. Hydro's policies that do not guarantee power producers the ability to sell power. In order for self-generators to market power, B.C. Hydro provides the options of a negotiated Direct Purchase Agreement and Spot market purchases. B.C. Hydro is also developing a Wheeling policy and the Power Exchange Operation as two other options that allow self-generators to market their power.

The Wisconsin buy back policy establishes both an on-peak and off-peak rate that is available to its customers. The average cost per kilowatt each customer receives depends on the amount of power produced during the on-peak and off-peak hours. The plants described in chapter 5 list the average buy back rates as being 65.7 percent to 102.4 percent of the

utilities' LRMC.

B.C. Hydro's direct purchase agreement attempts to negotiate a buy back rate at 85 percent of the avoided cost of production. B.C. Hydro's rate is not as large a percentage of its LRMC as are those of the Wisconsin utilities. B.C. Hydro's buy back policy also differs from Wisconsin's in that it establishes rates that account for the regional transmission cost savings associated with energy production. B.C. Hydro accomplishes this by calculating separate avoided costs for nine regions. Those regions located nearest the Lower Mainland and Vancouver Island have the highest avoided cost because this is where it is predicted future load requirements will be the greatest.

On the basis of the plants in this study, B.C. Hydro's buy back rates range from 48 to 56 percent of a region's LRMC. While the buy back rates are near 50 percent, the actual return to the power producer varies substantially. This is because of the difference in the value of electricity produced in separate regions. The Lower Mainland and Vancouver Island regions have buy back rates that are significantly higher than the other regions, because of their higher avoided cost projections.

The comparison of the Wisconsin utilities' buy back rates with B.C. Hydro's direct purchase agreements clearly shows that Wisconsin's rates represent a higher percentage of LRMC than do B.C. Hydro's. Plant (c), which produced power at a constant rate, had buy back rates of 66 and 91 percent of the Wisconsin utilities' LRMC. The equivalent plant in the B.C. Hydro example had buy back rates that ranged from 48 to 54 percent of LRMC, depending on the region. Plant (c)'s constant output is the best comparison because it provides an average rate, with equivalent energy production during peak and off-peak periods, which is comparable to a utility's average LRMC. In addition, the Wisconsin rates are available to all utility customers while B.C. Hydro's purchase agreements are based on a competitive bidding process. In B.C., when a power producer cannot secure a Direct

Purchase Agreement, the alternatives are to sell the power to B.C. Hydro on the Spot Market, or in the near future, to market excess power through the proposed Wheeling Policy or PEO.

The Spot Market provides a final option for self-generators to market surplus power. The prices offered are generally low and accordingly provide little incentive for self-generators to produce surplus power. The self-generator must compete with B.C. Hydro and other large power producers on the Spot Market. At times of electricity surplus, the price of power available will be very low. These low rates therefore offer little encouragement for self-generators to produce surplus power. The Spot Market, however, does provide an option for large power producers to sell short term, low cost energy.

B.C. Hydro has also proposed the Power Exchange Operation (PEO) and a Wheeling Policy. The PEO is presently not operating and therefore could not be evaluated as to the level of encouragement it would provide self-generators. The PEO will fill a similar role as the Spot Market. Purchase prices will be established in a competitive market place. The competitive nature of determining purchase prices for the PEO will result in low purchase prices, relative to Direct Purchase rates. These rates will provide little support to increase levels of self-generation. The objective of the PEO, however, is to market short term energy surpluses rather than the encouragement of long term investments.

B.C. Hydro is also formulating a Wheeling Policy. With this option power producers will be able to wheel surplus power. The principal incentive for the power producer to wheel power will be the price negotiated with the load. Besides the negotiated rate, B.C. Hydro will provide capacity credits for most wheeling contracts. These credits vary in amount depending upon the benefits a given wheeling contract provides to the system. These credits will reflect B.C. Hydro's estimate of the cost savings of additional capacity in generation, area transmission and system transmission.

The Wheeling Policy also has several components that may inhibit wheeling transactions. In particular, the Wheeling Policy does not recognize the value of aggregate capacity from short term wheeling contracts and does not recognize all the capacity delivered when it exceeds the wheeling agreement. The policy also establishes a customer charge that may be discriminatory for larger customers.

The Wheeling Policy will, however, provide the opportunity for a power producer to earn a substantial return on wheeled energy. This is constrained by the ability of the producer to sign a contract with a load. The ability to secure a load will be the primary limiting factor when wheeling is considered as a means of marketing power. Any degree of uncertainty in marketing surplus power is another major consideration for power producers planning to expand their generating systems.

The comparison of Wisconsin's buy back policy with B.C. Hydro's shows that Wisconsin utilities offer more incentive for self-generators to generate surplus power. This is primarily due to the availability of the Wisconsin buy back rate and the higher rate relative to LRMC.

### Load Displacement

Neither of the Wisconsin utilities have a load displacement policy to compare with B.C. Hydro's. B.C. Hydro, therefore, offers greater incentive with this type of policy. While this is a positive step in the promotion of self-generation, the limited application of this policy must be acknowledged.

The method B.C. Hydro uses to calculate load displacement credits results in significant credits being available only in the Lower Mainland and Vancouver Island regions. The calculation of these credits may also fail to reward the power producer with a fair return

on the cost savings to B.C. Hydro.

B.C. Hydro does not seem to recognize the possible advantages of load displacement power sources. For example, once the load displacement contract has expired, B.C. Hydro is not obligated to renew the contract. As long as this producer continues to produce power, B.C. Hydro will continue to benefit from the load displacement at no charge. This is very different from a Direct Purchase Agreement that expires; these agreements, in most circumstances, must be replaced or renewed at much higher rates. The actual benefit provided beyond the term of the contract is difficult to determine. This is because the policy is relatively new and there is little information to determine how long a particular project might continue to generate power beyond the term of its contract.

B.C. Hydro could also avoid the use of load displacement credits by providing the correct price signals. If industry was charged a rate based on B.C. Hydro's LRMC of power, load displacement credits would not be required. With B.C. Hydro's postage stamp rate this would require all regions be charged the LRMC of the most expensive region's cost of service. If the Vancouver Island region's LRMC was the highest, this region would be able to receive a load displacement credit unless all regions were charged a rate based on the LRMC to serve this region. The alternative to this would be to alter the current postage stamp rate. Both options may be politically unsuitable to the present government. In this case the justification for the load displacement credit will remain.

## CONCLUSION

The primary purpose of this thesis was to analyze B.C. Hydro's pricing policies and buy back rates in terms of their effectiveness for developing and utilizing power more efficiently. This effectiveness has been assessed according to the encouragement these

policies provide for pulp mills to increase self-generation. A variety of comparisons and examinations have been explored to support the conclusions as follows:

In the direct comparison of pulp mill self-generation levels, the Wisconsin mills produced significantly higher levels than the B.C. mills. Since the generation capacity of the Wisconsin mills was installed before the establishment of the policies examined, it is beyond the scope of this study to suggest that these higher levels of self-generation are solely the result of electric utility policies. The principal benefit demonstrated by these comparisons was that B.C.'s pulp and paper industry has a considerable potential for increasing self-generation levels.

The comparisons of the pulp mill rates and buy back policies of the Wisconsin utilities and B.C. Hydro did not reveal a clear leader in all categories. Wisconsin provided greater incentives with its industrial rate schedule than did B.C. Hydro. Given equivalent energy use patterns the Wisconsin rate structure would provide higher levels of mark-up on purchased power, relative to each utilities' LRMC. B.C. Hydro did, however, provide greater incentive with its rate structure for the pulp mills to maintain high power factors. Concerning buy back policies, it was the Wisconsin utilities that provided the greatest encouragement for industry to produce surplus levels of self-generation capacity. Finally, B.C. Hydro's load displacement policy clearly provided the opportunity for industry to increase self-generation levels, that was not available with the Wisconsin utilities.

While the Wisconsin utilities did not offer greater incentives to increase self-generation levels in each of the areas compared overall they did provide significantly greater incentive for industry to produce surplus power. A higher buy back rate was available to all power producers, while B.C. Hydro's purchase agreements did not guarantee a price to all power producers but rather were allotted on a competitive basis. In the future the Wisconsin utilities may be in a position where they cannot continue to guarantee all power producers the

standard buy back rate. At present the rate is available and provides a greater level of incentive to self-generators.

The Wisconsin utilities provided a greater level of encouragement for power producers to generate and market surplus electricity. The greater availability and reliability of the Wisconsin buy back rates provided a more effective incentive than did B.C. Hydro's policies for the development of self-generation.

In this thesis, I have analyzed the level of incentive electric utilities provided to power producers to generate power. It must be recognized that a utility which offers the greatest incentives to these producers does not necessarily have a better or more progressive energy policy. Each utility must plan to meet future demand requirements as they arise. This may be achieved in a variety of ways and is often dependent on several factors, including the availability of resources and political agendas. There are several methods for meeting future demands that, although they are very different, in the long term may be equally effective.

This thesis, therefore, is not a criticism of B.C. Hydro's planning policies per se, but rather a critical appraisal of these policies and their potential for encouraging self-generation. Many of the criticisms levied were relative to other jurisdictions and described how B.C. Hydro's policies may be improved to provide greater incentive for self-generation.

In 1992, B.C. Hydro had sufficient resources to meet demand in the near future. It expresses little concern for increasing the amount of incentive to self-generators. In the future, B.C. Hydro will require additional generation facilities and, then, may be faced with the option of either increasing the level of encouragement for non-utility power producers or face the possible need for additional megaprojects.

In order for B.C. Hydro's policies to encourage the full potential of self-generation resources, they must be consistent in their focus and fair in their assessment of the value of non-utility generation. B.C. Hydro's policies presently are inconsistent for several reasons.



B.C. Hydro's direct purchase agreement determines the value of power by taking into account the cost of transmission, the amount of power produced and the effective capacity supplied. When this power is sold, however, B.C. Hydro uses a postage stamp rate that offers power at the same cost irrespective of the region, season, or time of day. This inconsistency creates a situation where a pulp mill (or any industry) located in the south west portion of B.C. purchases power at rates below the marginal costs of production. A mill in the Lower Mainland also has the advantage of the highest possible return from load displacement, direct purchase agreements, and the proposed wheeling policy, relative to B.C. Hydro's LRMC cost of serving this region. Pulp mills in other regions continue to pay electricity costs higher than marginal costs and continue to receive the lowest levels of incentive for load displacement and direct purchases. In the future these regions would also receive a lower incentive to wheel power, should B.C. Hydro's current wheeling policy be implemented.

These policies do not provide accurate price signals to the consumers with respect to the actual value of the resource. An accurate price signal in itself would encourage more conservation in the Lower Mainland and Vancouver Island regions and greater levels of self-generation. Much of the postage stamp pricing is due to political considerations and is therefore beyond the control of B.C. Hydro. This situation limits the impact of B.C. Hydro's policies and objectives thereby inhibiting the more economically efficient development of resources. Economic efficiency, however, is not the only measure used to determine a fair rate schedule. Electric utility pricing must also reflect issues related to social efficiency that may not be reflected by the respective market prices. Accounting for both economic and social efficiencies in electric rates increases the difficulty in determining rates and will often require rates not merely reflect market signals.

Besides accurate pricing, B.C. Hydro's policies should provide for the payment of the

actual value for purchased energy. This requires that all purchase agreements, including wheeling and load displacements, recognize the value of their suppliers and reward them accordingly. This will encourage the development of the appropriate resources.

B.C. Hydro appears to be caught midway in an attempt to develop policies that provide effective price signals to its producers and consumers. In certain policies, B.C. Hydro recognizes the time, value and locational advantages of power production yet with others ignores these values altogether. This provides inaccurate price signals to both producers and consumers. An efficient system must consistently provide the correct signals to effectively allocate and develop its resources. Any deviations from the actual costs of resources will impose an efficiency cost on the provincial economy.

#### FUTURE RESEARCH AND RECOMMENDATIONS

Several of the B.C. Hydro policies examined in this thesis are in the proposal stage of development. These policies should, therefore, be re-examined once they become operational. B.C. Hydro's Power Exchange Operation should be evaluated to determine its actual impact with respect to the encouragement of self-generation. The proposed Wheeling policy should also be re-examined, if it becomes operational, because of the influence this policy will have on the development of self-generated power.

Along with these analyses, future research should examine the practicality of establishing a separate planning committee, perhaps through the B.C. Utilities Commission, to develop an appropriate energy strategy for B.C.'s electric industry. The committee would be responsible for the determination of B.C. Hydro's "avoided cost" for future power purchases and advise B.C. Hydro on the development of an appropriate energy strategy. B.C. Hydro cannot be expected to "fairly" predict or value future energy requirements

because of the biases inherent within the utility. Organization and program staff tend to resist change, especially where such change challenges either the continued existence of the organization and staffing, or the basic assumptions underlying their objectives or procedures (Day et.al.;1977, Suchman; 1967). These factors make it difficult for B.C. Hydro's employees to make objective decisions regarding energy planning and forecasts.

Future research must continue to focus on improving the management of our resources. This begins by developing pricing policies that provide the correct price signals for future investment and encourage the efficient use of these resources. The efficient development of resources must also include procedures that account for the full environmental costs associated with energy production. Geographers' skills of analysis and interpretation can play a valuable role in these research efforts.

## APPENDIX A

Simon Fraser University  
Department of Geography  
Burnaby, B.C.  
V5A 1S6

Phone 604-291-3321

Dear Sir,

You have been chosen to take part in a survey of energy use in pulp mills, which is being carried out in the Department of Geography, Simon Fraser University.

We hope you will spare a little of your time to answer some questions about your plant. It is important that everyone who is chosen does take part so that an accurate representation is achieved.

The answers you supply to this questionnaire will be treated as **STRICTLY CONFIDENTIAL**. Please return completed questionnaire by July 15, 1989.

Thank you very much for your cooperation. If you have any questions or would like further information please contact Dr. John Pierce or Mr. John Logan at the above address.

Yours truly,

Dr. John Pierce  
Mr. John Logan

1. What method or methods of pulp production are utilized at this plant?
  - a) Kraft
  - b) Semi Bleached Kraft
  - c) Bleached Kraft
  - d) Sulfitte
  - e) Other...
  
2. What year was the mill constructed?
  
3. What is the principal type of wood used?
  - a) Hardwood
  - b) Softwood
  
4. What were the mill's average daily and yearly capacities for 1988?
  - a) \_\_\_\_\_ tonnes of pulp per day
  - b) \_\_\_\_\_ tonnes of pulp per year
  
5. From which utility company or companies does the mill purchase its electricity?
  - a) \_\_\_\_\_
  - b) \_\_\_\_\_
  - c) \_\_\_\_\_

6. Describe what type of pricing arrangement the utility company or companies have with the mill. (i.e., is the mill charged; a flat rate, a negotiable contract rate, time of use rate, an interruptable rate, etc.)

7. What was the mill's daily electric consumption in 1988?

\_\_\_\_\_ kWh/day

• \* Indicate the beginning and finished products.

- Ex.    a) chips to dry pulp  
      b) chips to wet pulp  
      c) logs to dry pulp  
      d) logs to wet pulp  
      e) other...

8. On average, what percentage of the mill's electricity is generated internally or purchased?

\_\_\_\_\_ % of the mill's power needs are generated internally.

\_\_\_\_\_ % of the mill's power needs are purchased from a electric utility.

\_\_\_\_\_ % of the mill's power needs are purchased from an external source. (i.e., this is a generating facility owned by the mill)

9. What were the mill's electric utility rates for the years 1978 to 1988?

Year	Rate
1978	\$ _____ /kWh (on-peak or flat)* \$ _____ /kWh (off-peak)

\*Circle either peak or flat depending on the rate structure of the utility.  
If it is a flat rate ignore the off-peak line below.

1979	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---

1980	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---

1981	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---

1982	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---

1983	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---

1984	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---

1985	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---

1986	\$ _____ /kWh (on-peak or flat) \$ _____ /kWh (off-peak)
------	---





14. If there are plans to improve the mill's power generation, what were the principal incentives to change?

Number in order of importance 1 to 4

- rising energy prices
- security of supply
- government incentives
- other

Explain...

## **APPENDIX B**

### Electric Utility Questionnaire

1. What is the utility's total electric generation capacity?  
(nameplate)
  
2. How much of the generation capacity can be met by:
  - a) Baseload Generation?
  - b) Cycling Generation?
  - c) Peaking Generation?
  
3. What types of base load generation are utilized?  
(i.e., hydro, coal, fossil fuel, etc.)
  
4. What types of cycling generation are utilized?
  
5. What types of peaking generation are utilized?
  
6. What percentages of customers are:
  - a) Residential?
  - b) Commercial?
  - c) Industrial?

7. What percentage of total electricity generated is purchased by:
  - a) Residential?
  - b) Commercial?
  - c) Industrial?
  
8. What were the utility's yearly load factors for the years 1978-1988?

## APPENDIX C

British Columbia Hydro and Power Authority  
Electric Tariff  
Original Page 1841-1  
August 16, 1991

### SCHEDULE 1841

#### WHEELING SCHEDULE

Availability: For Customer's Plant which requires B.C. Hydro to wheel Electricity in conjunction with Schedules 1822 or 1824 for a period of one year or longer and is located in British Columbia.

Applicable in: Rate Zone 1 excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Wheeling Energy Charge:

\$0.001 per kWh of Wheeled Energy per Billing Period.

The Minimum wheeling Energy Charge per Billing Period is \$300.00.

Wheeling Demand Charge:

Demand associated with Wheeled Energy is billed under Schedule 1822 or 1824 in accordance with the Electricity Supply Agreement for the Customer's Plant.

Capacity Credit

For longer Wheeling Agreements with a term of six years or longer credit is given for Capacity Supplied to B.C. Hydro as follows:

The Capacity Credit is \$ per kW of Capacity Supplied per Billing Period is  $(Cgs + Ca) \times W$  per kW where:

1. Cgs is the generation and major transmission credit that varies by the wheeling energy source interconnection region as outlined in the REGIONAL MAP (ie., in text):

(a) Prior to April 1998:

<u>\$ per kW per Billing Period by Region</u>								
<u>NC</u>	<u>PR</u>	<u>CI</u>	<u>EK</u>	<u>SO</u>	<u>SE</u>	<u>KN</u>	<u>LM</u>	<u>VI</u>
0.0	0.0	0.4	0.1	0.7	0.4	1.0	3.4	3.4

(b) On or after 1 April 1998:

<u>\$ per kW per Billing Period by Region</u>							
<u>NC</u>	<u>PR</u>	<u>CI</u>	<u>EK</u>	<u>SO</u>	<u>SE</u>	<u>KN</u>	<u>LM</u>
0.1	0.6	1.7	0.8	2.3	1.8	2.8	4.7

<u>VI (Yr. &lt; 2002)</u>	<u>VI (Yr. &gt; or = 2002)</u>
4.9	7.6

2. Ca is the area transmission credit equal to
  - a) zero if
    - i) the wheeling energy source interconnection point is at 500 kV or greater; or
    - ii) to a utility intertie; or
    - iii) from outside B.C. Hydro's service area; and otherwise
  - b) The \$ per kW Billing Period credit evaluated and determined on a case specific basis for each source location as specified in the Wheeling Agreement.
3. W is the Monthly Weighting Factor as shown below:

<u>Monthly Weighting Factor by Month:</u>					
<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>
1.5	1.5	1.0	1.0	0.5	0.5
<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>
0.5	0.5	1.0	1.0	1.5	1.5

Capacity  
Supplied:

The Capacity Supplied is the lesser of:

1. the average capacity supplied during the Billing Period to B.C. Hydro from 0700 to 2000 on weekdays excluding Statutory holidays; or
2. the average capacity scheduled in the Wheeling Agreement during the billing Period from 0700 to 2000 on weekdays excluding Statutory holidays.

Failure to  
Deliver  
Capacity:

The Capacity Credit will be reduced by 2% for each 1% that the Capacity Supplied is less than the capacity scheduled for the Billing Period in the Wheeling Agreement, except when the supplier was wholly or partly unable to supply capacity because of a Force Majeure as defined in the Wheeling Agreement or the Electricity Supply Agreement for the Customer's Plant.

Energy  
Balancing:

Energy Balance for the Billing Period will be computed as follows:

Energy Balance = (Credit Energy) - (Wheeled Energy) + (Energy Balance from previous Billing Period)

If Energy Balance is within 3% of Nominated Energy it will be carried forward to the next month; otherwise the Energy Balance is sold to or bought from the Power Exchange Operation at its posted monthly prices for the Billing Period by B.C. Hydro. At the end of the Wheeling Agreement any remaining Energy Balance will be sold to or bought from the Power Exchange Operation by B.C. Hydro.

Wheeled  
Energy:

Wheeled Energy is the lesser of:

1. the Nominated Energy; or
2. the energy deemed to have been taken by the Customer's Plant during the Billing Period in accordance with the Wheeling Agreement and the Electricity Supply Agreement for the Customer's Plant.

Credit  
Energy:

Credit Energy is the lesser of:

1. the Nominated Energy; or
2. the actual energy delivered to B.C. Hydro's system at the source during the Billing Period, less Energy Losses.

Nominated Energy: Is as specified in the Wheeling Agreement for the Billing Period.

Energy Losses: Energy Losses will be calculated based on B.C. Hydro's system voltage for the source and the load interconnections and regions, as shown in the B.C. Hydro Integrated System Losses Map (in text).

$$\text{Energy Losses} = \text{Wheeled Energy} \times \text{Percent Losses}$$

$$\text{Percent Losses} =$$

$$\begin{aligned} & (\text{Load region Losses \%} + \text{Load region Area Transmission Losses \%}) \\ & - (\text{Source Region Losses \%} + \text{Source region Area Transmission Losses \%}) \end{aligned}$$

The minimum Percent Losses is 0 %

a) Regional Losses are shown below:

Losses % by Region

<u>NC</u>	<u>PR</u>	<u>CI</u>	<u>EK</u>	<u>SO</u>	<u>SE</u>	<u>KN</u>	<u>LM</u>	<u>VI</u>
5%	6%	4%	4.5%	3%	4%	2%	0%	0%

b) Area Transmission Losses vary by the interconnection voltage and are shown below:

Area Transmission Losses %

<u>500 kV or Greater</u>	<u>130 - 360 kV</u>
0 %	2 %
<u>69 kV</u>	<u>Less than 69 kV</u>
3 %	5.5 %

Taxes: The Rates and Monthly Minimum Charge contained herein are exclusive of the Goods and Services Tax and Social Services Tax.

Special Conditions: B.C. Hydro will only wheel Customer-generated Electricity in excess of requirements for the Customer's Plant.

## REFERENCES

- Ailift, David. Employee, Public Service Commission of Wisconsin, personal communication, September 1992.
- Albrecht, Gerry. Employee, Public Service Commission of Wisconsin, 1991.
- Arpan, J.S., Bauerschmidt, A.D., Clamp, J.C., Dess, G., Gillespie, K., Sullivan, D., Truitt, J.F. and Ecro Artto. The United States Pulp and Paper Industry: Global Challenges and Strategies. University of South Carolina Press, 1986.
- As-Sammani, M.D. "Private Sector and Government Commercial Fishing in the Sudd Area, Southern Sudan", Economic Geography. vol. 60, pp. 210-16, 1984.
- Barrows, H.H. "Geography as Human Ecology", Annals of the Association of American Geographers. vol. 13, pp. 1-14, 1923.
- B.C. Hydro. Information on the: Purchase of Electricity and Load Displacement for Non - Integrated Areas. December, 1988.
- B.C. Hydro. Short Term Electric Load Forecast, 1990/91-1995/96. 1990.
- B.C. Hydro. Information on the: Purchase of Electricity and Load Displacement for the Integrated System From Projects Greater Than 5MW, February, 1990.
- B.C. Hydro. B.C. Hydro Wheeling Policy. Policy Development, March, 1990.
- B.C. Hydro. The Cost of New Electricity Supply in British Columbia, Resource Planning Corporate and Environmental Affairs, December, 1990.
- B.C. Hydro. Pocket Facts. 1991.
- B.C. Hydro. Electricity Plan 1991 Update. March, 1991.
- B.C. Hydro. British Columbia Hydro and Power Authority Electric Tariff. April 1, 1991.
- B.C. Hydro. The Cost of New Electricity Supply in British Columbia, 1991 Update. Resource Planning, April, 1991.
- B.C. Hydro. Opportunities in the Short Term Electricity Market: A Symposium on the Power Exchange Operation. British Columbia Power Exchange Corporation, May 17, 1991.



- B.C. Hydro. Financial Evaluation Guide for Private Power Projects. Resource Planning, June, 1991.
- B.C. Utilities Commission Annual Report. 1989.
- B.C. Utilities Commission. A Rate Design Application by British Columbia Hydro and Power Authority. Decision, April 24, 1992.
- Berry, D. "Least-Cost Planning and Regulation." Public Utilities Fortnightly. March 17, pp. 9-15, 1988.
- Boiteux, M. and Stasi, P. "The Determination of Costs of Expansion in an Interconnected System of Production and Distribution of Electricity." in J. Nelson (ed) Marginal Pricing in Practice. Prentice-Hall, 1964.
- Bonbright, James, C. Principles of Public Utility Rates. Columbia University Press, 1961.
- Bromley, Daniel, W. Environmental and Economy, Property Rights and Public Policy. Cambridge, MA: Basil Blackwell, Inc. 1991
- Brown, M.A. and Macey, S.M. "Evaluating the Impact of Two Energy Conservation Programmes in a Midwestern City", Applied Geography. vol. 5, pp. 39-53, 1985.
- Cairncross, Frances. "Energy and the Environment." The Economist. Aug. 31, 1991, pp. 3-30.
- Capehart, Lynn, C., and Capehart, Barney, L. "Efficiency Trends for Industrial Cogeneration", Public Utilities Fortnightly. pp. 28-31, April 1, 1991.
- Cavanagh, Ralph. "Electrical Energy Futures." Environmental Law. vol. 14, pp. 133-175 1983.
- Cavanagh, Ralph. "Least-cost Planning Imperatives for Electric Utilities and Their Regulators." Harvard Environmental Law Review. vol. 10, pp. 299-244, 1986.
- Charo, R.A., Stearns, L.R., and Mallory, K.L. "Alternative Energy Power Production: The Impact of the Public Utility Regulatory Policy Act," Columbia Journal of Environmental Law. pp. 447-493, no. 11, 1986.
- Colton, Roger, D. "Utility Involvement in Energy Management: The Role of a State Power Plant Certification Statute." Environmental Law. vol. 16, no. 1-2, pp. 175-206, 1986.

- Cox, Alan, J. and Helliwell, John, F. Economic Modeling of Energy Supply From Burning Wood Wastes at British Columbia Pulp and Paper Mills. Resource Paper No. 21, August 1978.
- Cudahy, Richard, D. and Malko, Robert J. "Electric Peak-Load Pricing: Madison Gas and Beyond." Wisconsin Law Review. pp. 47-78, 1976.
- Day, J.C., Brady, R.F.; Bridger, K.C., Friesen, B.F., Peet, S.E., "A Strategy For Hindsight Evaluation of Environmental Impacts," in Plewes, M., Whitney, J.B.R., eds., Environmental Impact Assessment in Canada: Processes and Approaches. University of Toronto, 1977.
- Draper, D. "Oceans Exploitation: Efficiency and Equity Questions in Fisheries Management", in Mitchell, B. and Sewell, W.R.D. (eds.), Canadian Resource Policies: Problems and Prospects. Methuen, Toronto, 1981.
- Fairburn, Don. Employee, North West Energy, personal communication, May 26, 1992.
- Furuseth, O.J. and Pierce, J.T. "A Comparative analysis of Farmland Preservation Programmes in North America", Canadian Geographer. vol. 26, pp. 191-206, 1982.
- Greenland, David. Guidelines For Modern Resource Management: Soil, Land, Water, Air. Columbus: CE Merrill Pub. Co., 1983.
- Helliwell, John, F. and Cox, Alan, J. Electricity Pricing and Electricity Supply: The Influence of Utility Pricing on Electricity Production by Pulp and Paper Mills. Department of Economics, University of British Columbia, August, 1978.
- Helliwell, John, F. "Some Emerging Economic Issues in Utility Regulation and Rate-Making," in W.T. Stanbury (ed) Studies On Regulation in Canada. Butterworth and Company Ltd. 1978.
- Helliwell, John, F. and Margolick, M. "Electricity Generation From Wood Wastes in British Columbia." Journal of Business Administration. pp. 15-27, 1981.
- Howe, Keith, M. and Eugene, F. Rasmussen. Public Utility Economics and Finance. Englewood Cliffs, N.J.: Prentice-Hall, Inc. 1982.
- Jaccard, M., Nyboer, J., and Makinen, T. "Managing Instead of Building: B.C. Hydro's Role in the 1990's," Working paper. Burnaby, B.C.: Natural Resources Management Program, Simon Fraser University, 1991.

- Jaccard, Mark. Associate Professor, School of Resource and Environment Management, Simon Fraser University, personal communication, May 1992.
- Johnston, T., and Smit, B. "An Evaluation of the Rationale for Farmland Preservation Policy in Ontario", Land Use Policy. vol. 2, pp. 225-37, 1985.
- Kates, Robert. "The Human Environment: The Road not Taken, The Road Still Beckoning", Association of American Geographers Annals. vol. 77, pp. 525-535, 1987.
- Kehl, Gerhardt. B.C. Hydro Manager, Vancouver. Personal Communication, Dec. 1991.
- Kuropatwa, R. "Legislating Comprehensive Energy Planning For Manitoba Hydro", April 7, 1987, unpublished MRM paper.
- Lail, Kelly, S. Manager, Power Services Pricing and Costing, B.C. Hydro, Vancouver. Personal Communication, 1991.
- Lockwood's Directory of the Paper and Allied Trades, 1986. Vance Publishing, 1986.
- Lum, King. B.C. Hydro Engineer, Vancouver. Personal Communication, Oct., 1991.
- Lum, King. B.C. Hydro Engineer, Vancouver. Personal Communication, Sept. 18, 1991.
- Lund, R. "The Need for Monitoring and Result Evaluation in a Development Project- Experiences From the Mahaweli Project", Norsk Geografisk Tidsskrift. vol. 37, pp. 171-86, 1983.
- MacRae, Morgan, K. Critical Issues in Electric Power Planning in the 1990s, Volume 1. Canadian Energy Research Institute, Study No. 33, November, 1989.
- Mahoney Jr., Leo, T. "Time-of-Use Rates: Marginal Costing and the System Planner", Issues in Public Utility Regulation. pp. 197-205. Edited by Harry M. Trebing. MSU Public Utilities Papers, 1979.
- Makinen, Timo, A. The Electricity Self-Generation Potential of the B.C. Pulp and Paper Industry. SFU, March 1991.
- Malko, J. Robert and Stipanuk, David. "Electric Peak-Load Pricing: A Wisconsin Framework", Public Utilities Fortnightly. pp. 33-36, July 15, 1976.
- Mark, Henry, B.C. Hydro Engineer, Vancouver, personal communication. Sept. 28, 1991.

McTaggart, W.D. "Forestry Policy in Bali, Indonesia", Singapore Journal of Tropical Geography. vol. 4, pp. 147-61, 1983.

Ministry of Energy, Mines and Petroleum Resources. "Policy for Environmentally Beneficial Private Power Projects" October 1990.

Mitchell, B.M., Manning W.G., Acton, J.P. Peak Load Pricing. Rand Corporation, 1978.

Mitchell, B. Geography and Resource Analysis. John Wiley and Sons, 1989.

Mitchell, B. "Comprehensive River Basin Planning in Canada: Problems and Opportunities", Water International. Vol. 8, pp. 146-153.

Mitchell, B. and Gardner, J.S., eds. River Basin Management: Canadian Experiences. Publication Series No. 20, Department of Geography, University of Waterloo, Waterloo, Ontario, 1983.

Mitchell, B. and King, P. "Resource Conflict Policy Change and Practice in Canadian Fisheries Management", Geoforum. vol. 15, pp. 419-32, 1984.

Munasinghe, Mohan. Electric Power Economics: Selected Works. Butterworth and Co., 1990.

Mundie, R.M. "Evaluating the Effectiveness of Local Government Farmland Protection Programmes," Geojournal. Vol. 6, pp.573-7, 1982.

O'Riordon, T. Perspectives on Resource Management. Pion, London, 1971.

Partridge, Waring. "A Road Map to Title I of the Public Utility Regulatory Policies Act of 1978." Public Utilities Fortnightly. pp. 16-22, January 18, 1979.

Peterson, Bill. B.C. Hydro, Financial Evaluation Engineer, Vancouver. Personal communication, Dec. 1991.

Post's Pulp and Paper Directory, 1986. Miller Freeman Publications, Inc. 1985.

Public Service Commission of Wisconsin. "Docket 05-ER-11, 05-ER-12, and 05-ER-13", June 21, 1983.

Public Service Commission of Wisconsin. "Docket 05-ER-11, August, 1984.

Reinsch, Anthony, E. and Battle, Ellen, F. Industrial Cogeneration in Canada: Prospects and Perspectives. Canadian Energy Research Institute, Study No. 24, March 1987.

- Robinson, Doug. Manager, Costing Department, B.C. Hydro, Vancouver. Personal Communication, Sept., 1991.
- Rossi, Peter, H. and Freeman, Howard E. Evaluation a Systematic Approach. Sage Publications, 1989.
- Seth, Ram Parkash. Pricing and Related Policies of Publicly Owned Electrical Utilities. Institute of Public affairs Dalhousie University Halifax, Canada, 1984.
- Stafford, Ken. Manager, B.C. Hydro, Vancouver. Personal Communication, June 1, 1992.
- Suchman, E.A. Evaluation Research. Russell Sage Foundation, 1967.
- The Wheeler PSC Report. 23 North Pickney St. Madison Wisconsin, May 14, 1992.
- Thiessen, Lee. Senior Project Analyst Energy Policy Branch, Ministry of Energy Mines and Resources, Energy Resource Division. Personal communication, May 26, 1992.
- Tillman, David, A. Forest Products: Advanced Technologies and Economic Analysis. Academic Press, Inc. 1985.
- Tremain, D.L. Electricity Conservation Investment Within Least-Cost Planning. Natural Resource Management Program, Report No. 75, April, 1990.
- Turvey, R. Optimal Pricing and Investment in Electricity Supply. MIT Press, 1968.
- Val, E. and Nelson, J.G. "Offshore Petroleum and Commercial Fishery Interactions: The Case of Long Point, Port Dover, Lake Erie," Geo Journal. vol. 7, pp. 247-260, 1983.
- Vennard, Edwin. The Electric Power Business. McGraw-Hill, Inc., 1970.
- Vennard, Edwin. Management of the Electric Energy Business. McGraw-Hill Book Company, 1979.
- Waltz, Bob. Employee, WPM #3, Personal Communication, 1989.
- Wells, Lorne, G. Manager, Power Contracts, B.C. Hydro, Vancouver. Personal Communication, Aug. 27, 1991.
- Wells, Lorne, G. Manager, Power Contracts, B.C. Hydro, Vancouver. Personal Communication, Sept. 1, 1991.

Wells, Lorne, G. Manager, Power Contracts, B.C. Hydro, Vancouver. Personal Communication, Sept. 28, 1991.

WEU #2. "Statistical Supplement and Forecast for Utility Analysis," 1984.

WEU #2. "Statistical Supplement," 1988.

WEU #1 and WEU #2. LRMC estimates are based on each utilities' Advance Plan 6, July 1992.

Whitaker, J.R. "The Geography of Resources," in James, P.E. and Jones, C.F. (eds.), pp. 226-239, American Geography: Inventory and Prospect. Syracuse University Press, Syracuse, 1954.

Whitaker, Curtis, M. "The Federal Power Act and Hydro Power Development: Rediscovering State Regulatory Powers and Responsibilities," Harvard Environmental Law Review. vol. 10, no. 2, pp. 135-187, 1986.

Wooster, Claire, A. "Cogeneration: Revival Through Legislation?," Dickinson Law Review. vol. 87, pp. 705-777, 1983.

WPM #2. Senior Electrical Project Engineer. Personal Communication, Dec. 1991.

Zakem, Alexander, J. "Comparing Utility Rates," Public Utilities Fortnightly. pp. 30-32, November 13, 1986.