A HYBRID SYSTEM TO OPTIMIZE THE VALUE OF IMPORTS FOR HYDRO SYSTEMS

by

Amir Ala Alavi

B.Sc., The University of Tehran, 1993

A THESIS SUBMITTED IN PARTIAL FULFILLMENT

OF THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF APPLIED SCIENCE

in

THE FACULTY OF GRADUATE STUDIES

Department of Civil Engineering

We accept this thesis as confirming to the

required standard

THE UNIVERSITY OF BRITISH COLUMBIA

December 2003

Library Authorization

In presenting this thesis in partial fulfillment of the requirements for an advanced degree at the University of British Columbia, I agree that the Library shall make it freely available for reference and study. I further agree that permission for extensive copying of this thesis for scholarly purposes may be granted by the head of my department or by his or her representatives. It is understood that copying or publication of this thesis for financial gain shall not be allowed without my written permission.

AMIR ALA ALAVI
Name of Author *(please print)*

Dec 19 / 2003
Date (dd/mm/yyyy)

Title of Thesis: A HYBRID SYSTEM TO OPTIMIZE THE VALUE OF I IMPORTS FOR HYDRO SYSTEMS

Degree: MASc

Year: ~~2003~~ 2004

Department of CIVIL ENGINEERING
The University of British Columbia
Vancouver, BC Canada

ABSTRACT

This thesis presents a solution methodology to optimize the value of imports for hydro systems by optimally selecting the unit commitment and loading of plants to provide the required System Rotational Energy or System Inertia. The methodology has been developed for use in short-term hydro system operations in a deregulated market environment to determine the optimal electricity import for a predominantly hydroelectric system consisting of plants with large storage facilities, multiple units and complex hydraulic configurations. The problem is formulated and solved using a hybrid system consisting of two main components. The first component consists of an expert system that is used to screen for potential and feasible system configurations given a set of rules on plant and unit operations. The second component consists of a Mixed-Integer programming algorithm that maximizes the value of import capability of the hydro system during low electricity market-price periods. The proposed solution methodology optimally schedules hydro plants at unit-level for energy and capacity markets in short-term operations while meeting the System Rotational Energy constraints. The application of the technique is demonstrated for four large plants in the B.C. Hydro system for a 24-hour time-step studies for a four-month period in 2002.

TABLE OF CONTENTS

ABSTRACT .... **ii**

TABLE OF CONTENTS .... **iii**

LIST OF FIGURES .... **vii**

LIST OF TABLES .... **x**

ACKNOWLEDGMENTS .... **xi**

CHAPTER 1 – INTRODUCTION **1**

1.1 INTRODUCTION 1

1.2 THE GOAL OF THIS RESEARCH 4

1.3 ORGANIZATION OF THE THESIS 4

CHAPTER 2 – BACKGROUND **6**

2.1 LITERATURE REVIEW 6

2.2 HISTORY OF SYSTEMS AND OPTIMIZATION 8

CHAPTER 3 – THE DECISION-MAKING ENVIRONMENT **10**

3.1 B.C. HYDRO PRODUCTION SYSTEM 10

3.1.1 B.C. Hydro Generation System *11*

3.1.2 The B.C. Hydro Transmission and Distribution Systems *13*

3.2 B.C. HYDRO SYSTEM CHARACTERISTICS 15

3.3 PLANNING LEVELS 18

3.4 POWER GENERATION UNDER DEREGULATED MARKET ENVIRONMENT 21

3.4.1 System Load and Price Forecasting *22*

3.4.2 Electricity Price Volatility *24*

3.5 ELECTRICITY TRADE 24

CHAPTER 4 – THE THE DECISION SUPPORT SYSTEM 26

4.1 INTRODUCTION TO ROTATIONAL ENERGY OPTIMIZATION MODEL (REOM) 26

4.2 OBJECTIVES OF THE DECISION SUPPORT SYSTEM 27

4.3 TRANSFER CAPABILITY 28

4.4 MAIN COMPONENTS AND STRUCTURE OF THE REOM SYSTEM 33

4.4.1 The Graphical User Interface *33*

4.4.2 The Expert System *35*

4.4.3 Optimization Preprocessor *37*

4.4.3.1 Approaches to Formulate the REOM Optimization Problem 38

4.4.3.2 The Elimination Algorithm 42

4.4.4 Mathematical Optimization Model Formulation *43*

4.4.4.1 Hydraulic Modeling of Reservoir Operations (Shawwash 2000) 43

4.4.4.2 Modeling Hydropower Generation (Shawwash 2000) 45

4.4.4.3 Load Resource Balance (Shawwash 2000) 47

4.4.4.4 Import/Export transfer capacity (Shawwash 2000) 47

4.4.5 The REOM Mathematical Formulation *47*

4.4.5.1 The REOM Mathematical Formulation Based on PATH Method 48

4.4.5.2 The REOM Mathematical Formulation of the COMBO Method 49

4.5 OBJECTIVE FUNCTION 51

CHAPTER 5 – RESULTS RESULTS AND DISCUSSION **54**

5.1 CASE STUDIES 54

5.2 RESULTS OF THE PATH AND THE COMBO WITH/WITHOUT EA METHODS 59

5.2.1 Results of the Path and Combo with and without the Elimination Algorithm *59*

5.2.1.1 The REOM Mathematical Formulation of the COMBO Method 59

5.2.1.2 Selecting the Combo with EA Method as preferred Method 61

5.3 STOM AND REOM RESULTS 62

5.3.1 The Optimization Preprocessor *62*

5.3.1.1 Unit Combination 63

5.3.1.2 Total Rotational Energy 65

5.3.1.3 Net B.C. Hydro Transfer Limit 67

5.3.1.4 Elimination Algorithm Preprocessor 68

5.3.2 Optimized Results of STOM and REOM *70*

5.3.2.1 Objective Function 70

5.3.2.2 Forebay Elevation, Generation and Spot U.S. Results 71

5.3.2.3 System Generation Scheduling Summary 78

5.3.2.4 Optimal Solution Configuration 80

CHAPTER 6 – CONCLUSIONS AND RECOMMENDATIONS **81**

6.1 SUMMARY 81

6.2 CONTRIBUTIONS 83

6.3 FUTURE WORKS AND RECOMMENDATIONS 83

REFERENCES **84**

ANNEX A – MATHEMATICAL PROGRAMMING **87**

A.1 LINEAR PROGRAMMING 87
A.2 MIXED INTEGER PROGRAMMING 88
A.3 PIECEWISE LINEAR PROGRAMMING 89

LIST OF FIGURES

FIGURE 3.1 – SOURCES OF ELECTRICITY SUPPLY IN BRITISH COLUMBIA (B.C. HYDRO 1998) 12

FIGURE 3.2 – MAP OF B.C. HYDRO MAJOR ELECTRICAL SYSTEM (SOURCE: B.C. HYDRO 2000) ... 14

FIGURE 3.3 – TYPICAL LOAD SHAPE CURVE FOR 24 HOUR (B.C. HYDRO 2002) 16

FIGURE 3.4 – TYPICAL LOAD SHAPE FOR A WEEK (B.C. HYDRO 2002) 16

FIGURE 3.5 – TYPICAL LOAD SHAPE FOR ONE MONTH (B.C. HYDRO 2002) 17

FIGURE 3.6 – TYPICAL LOAD SHAPE FOR ONE YEAR (B.C. HYDRO 2002) 17

FIGURE 3.7 – VARIATION OF PEAK LOAD DURING A YEAR (B.C. HYDRO 2002) 18

FIGURE 3.8 – SCHEDULING PROBLEM MODELING DECOMPOSITION HIERARCHY (SOURCE: SHAWWASH 2000) 20

FIGURE 3.9 – LOAD AND MARKET PRICE VOLATILITY ORDER (SOURCE: BC HYDRO, 2002) 22

FIGURE 4.1 – VARIATION OF NET TRANSFER LIMIT WITH LOAD AND SRE 31

FIGURE 4.2 – VARIATION OF NET TRANSFER LIMIT WITH. SRE AND LOAD 32

FIGURE 4.3 – SCHEMATIC OF THE REOM SYSTEM 33

FIGURE 4.4 – GRAPHICAL USER INTERFACE 34

FIGURE 4.5 – PATHS FOR CALCULATING TOTAL ROTATIONAL ENERGY 40

FIGURE 4.6 – SCHEMATIC OF TYPICAL RIVER SYSTEMS WITH RESERVOIRS AND HYDROELECTRIC FACILITIES 44

FIGURE 4.7 – VALUE OF WATER IN STORAGE AND MARGINAL VALUE OF WATER FOR TIME STEP T .. 53

FIGURE 5.1 – B.C. HYDRO LOAD SHAPE FOR WINTER AND SUMMER TIMES (B.C. HYDRO 2002) ..56

FIGURE 5.2 – VOLATILITY OF PRICES IN WINTER TIME VS. SUMMER TIME FOR U.S. MARKET (B.C. HYDRO 2002) 57

FIGURE 5.3 – VOLATILITY OF PRICES IN WINTER TIME VS. SUMMER TIME FOR ALBERTA MARKET (B.C. HYDRO 2002) 57

FIGURE 5.4 – WILLISTON INFLOWS (CMS) FOR BEGINNING AND END OF THE STUDY DURATION (B.C. HYDRO 2002) 58

FIGURE 5.5 – KINBASKET INFLOWS (CMS) FOR BEGINNING AND END OF THE STUDY DURATION (B.C. HYDRO 2002) 58

FIGURE 5.6 – PERFORMANCE OF THE EXPERT SYSTEM IN ELIMINATING INFEASIBLE UNIT COMBINATIONS 65

FIGURE 5.7 – GMS FOREBAY ELEVATION RESULTS FOR MARCH 15, 2002 72

FIGURE 5.8 – PCN FOREBAY ELEVATION RESULTS FOR MARCH 15, 2002 73

FIGURE 5.9 – MCA FOREBAY ELEVATION RESULTS FOR MARCH 15, 2002 73

FIGURE 5.10 – REV FOREBAY ELEVATION RESULTS FOR MARCH 15, 2002 74

FIGURE 5.11 – GMS GENERATION FOR MARCH 15, 2002 74

FIGURE 5.12 – PCN GENERATION FOR MARCH 15, 2002 75

FIGURE 5.13 – MCA GENERATION FOR MARCH 15, 2002 75

FIGURE 5.14 – REV GENERATION FOR MARCH 15, 2002 76

FIGURE 5.15 – SPOT U.S. RESULTS FOR MARCH 15, 2002 76

FIGURE 5.16 – SPOT ALBERTA RESULTS FOR MARCH 15, 2002 77

FIGURE 5.17 – US AND ALBERTA PRICE IN CANADIAN DOLLAR IN MARCH 15 , 2002 77

FIGURE 5.18 – TOTAL TIE LIMITS AND NET BC HYDRO TRANSFER CAPABILITY IN MARCH 15, 2002 78
FIGURE 5.19 – GENERATION SCHEDULING RESULTS OF STOM 79
FIGURE 5.20 – GENERATION SCHEDULING RESULTS OF REOM 79

LIST OF TABLES

TABLE 4.1 – NET TRANSFER LIMIT FOR DIFFERENT LOAD AND SYSTEM ROTATIONAL ENERGY 30

TABLE 4.2 – SOME BASIC INFORMATION FOR GMS, PCN, MCA, REV 39

TABLE 5.1 – OPTIMAL SOLUTION CONFIGURATION FOR PATH AND COMBO METHODS 60

TABLE 5.2 – NUMBER OF UNIT COMBINATIONS BEFORE AND AFTER EXPERT SYSTEM SCREENING...64

TABLE 5.3 – TOTAL ROTATIONAL ENERGY CALCULATIONS 66

TABLE 5.4 – VALUES OF SYSTEM LOAD AND MAXIMUM SYSTEM RE AND MINIMUM N.B.C.H.T.L FOR 15TH OF MARCH 2002...68

TABLE 5.5 – ELIMINATION ALGORITHM FACTOR...69

TABLE 5.6 – OBJECTIVE FUNCTION VALUES FOR STOM AND REOM..71

TABLE 5.7 – OPTIMAL SOLUTION CONFIGURATIONS FOR STOM AND REOM 80

ACKNOWLEDGMENTS

I would like to express my sincere appreciation and thanks to my supervisor, Dr. Ziad K. Shawwash, for providing his wise advice and encouragement throughout the course of this research. Undoubtedly without his valuable insight and support, this work would not have been undertaken. I am also very grateful to Dr. B. Lence, whose guidance and support have made this research project a success. Special appreciation is due to the Manager of the Planning and Analysis Section of the Resource Management Department at B.C. Hydro, Dr. Thomas K. Siu. The guidance of Mr. Gordon Bradely and Mr. Douglas Robinson is duly noted. I am also thankful to Wun-Kin Cheng, Iren Wong, Al Mithani and Daniela Ganea for their valuable assistance. I would like to take this opportunity to express my gratitude to Dr. Stephen Allison for his continuous encouragement and support, and give many thanks to my friends Mehrzad Maneshi, Yanling Cong, Alaa Abdallah, Lindsay Fane, Stacy Langsdale, and Niranjan Sanjaya De Zoysa for their help.

Very special thanks and appreciation to my parents, Karim and Sabiheh Alavi, for their great caring and for giving me much motivation to go forward in my life. Without their continuous and constant encouragement, I could not have been able to be successful. I am deeply indebted to my lovely fiancé, Ziba Bozorgzadeh, for her love and valuable help and support and also to my brother Ehsan, his wife Ava and my lovely niece Neeki for their great help and support.

This research and thesis would not have been completed without the will of GOD.

TO MY PARENTS

Karim & Sabiheh Alavi

CHAPTER 1

INTRODUCTION

1.1 Introduction

The electricity industry throughout the world has long been dominated by vertically integrated utilities and is undergoing significant changes. The electricity industry is evolving into a competitive market industry environment in which market forces determine the price of electricity through competition. The new electrical power systems differ noticeably from the traditional systems in their operating environment, size and structural complexity, leading to an overall requirement of developing new techniques and methods of analysis for new system operation.

Over the past five decades, researchers and scientists have made every elaborated effort to develop techniques that can be used at different levels of operational planning of hydroelectric and other energy production facilities. The main goal of introducing and developing such techniques and methodologies was to increase the ability to solve the operation and management problems of energy production that could be applied to both long-term and short-term operations of hydroelectric facilities.

In the traditional, monopolistic, vertically-integrated electric utilities, the main objective of the hydroelectric system operator was to secure a stable supply of electric power to meet the firm domestic load demand and the firm trade transactions while meeting the system's physical and operational constraints. The main constraints in making operating decisions were to ensure the availability of energy as well as having enough capacity to meet the domestic system demand while meeting the non-power requirements. New computer technologies, advanced software and control systems have enabled the market environment to become more competitive. Therefore, the electricity industry in many parts of the world is changing rapidly, and power market environment and competition is evolving, and is affecting the various levels of the traditional strategic and operational decision-making processes.

In hydroelectric systems, storage reservoirs are used to regulate river flows during high inflow periods for use during high demand periods. Moreover, since generation capacity depends on the head of the water column on the turbines, storage reservoirs must be operated to ensure that there is adequate head to meet the capacity reliability criteria. The other major challenge is to balance generation between many river systems under the control of the system operator. Seasonal and annual inflows may be high in one river system and low in the other. The decision to increase generation in a river system propagates throughout the system and affects other generating facilities in other regions.

An electric system can be divided into three subsystems: generation, transmission and distribution. System behavior is affected by the characteristics of every major element within the system. The representation of these elements by means of appropriate mathematical models is critical to the successful analysis of system behavior. For each different problem, the system needs to be modeled in a unique way that is relevant to the problem at hand.

One of the most important strategies in operating a hydro generation system is to manage to increase the import capability when the electricity price is low and in contrast, by increasing the export capability when the price is high. One of the main factors that determine the import capability of an electric system is its available transfer capacity, which depends on many factors and constraints. One of these constraints is what have been recently imposed on the BC Hydro electric system to satisfy reliability criteria, the Total System Rotational Energy (SRE) or System Inertia. Increasing the rotational energy of electric systems can be used as a proxy to ensure that enough generating capacity will be available should a system disturbance occurs when the system import levels are high, relative to the system load. High import levels can potentially be beneficial when the market price for electricity is lower than marginal cost of energy for a utility with significant storage capability. Under such conditions, and provided that the hydro system operator has the flexibility to change the rotational energy of the system, the problem becomes that of finding the optimal tradeoff between increasing system imports and the value of storing additional water in reservoirs while meeting the SRE and other constraints. The additional stored water results from reduced plant generation to absorb more import.

Despite the benefits of hydro units over thermal units, it is well known in industry that the problem of scheduling of hydroelectric systems is one of the most complex problems to solve, particularly for real time and short-term system operations. One of the solution methodologies that have been developed to solve this problem can be found in the work of researches at BC Hydro and the University of British Columbia who developed the Short Term Optimization Model (STOM) (Shawwash, 2000). The STOM model was developed to assist the BC Hydro operation engineers in improving the operational efficiency of the hydro systems and to make optimal operational and trading decisions while meeting the system constraints. This research focused on developing a new approach in modeling the system operation by introducing the system rotational energy constraints in the STOM system. The new methodology, namely the **R**otational **E**nergy **O**ptimization **M**odel (REOM), enables the system operation engineers to make the optimal trade-off between the value of imports and the value of water stored in reservoirs while meeting the SRE and other constraints.

The REOM model is a hybrid system that utilizes mathematical programming and other algorithms, such as mixed integer programming, piecewise linear programming, expert systems and dynamic programming to solve the optimization problem. The REOM optimization model uses two software packages: AMPL, which formulates the optimization problem as a large scale mixed integer problem and CPLEX, which solves the problem. All the model components have been successfully formulated and tested using postmortem studies of actual system operation of a large hydroelectric system.

1.2 The Goal of This Research

The goal of this research was to develop a more efficient operation scheduling of the existing power generating facilities in the B.C. Hydro system by maximizing the value of resources while meeting the operational constraints. This objective was successfully achieved through the application of the System Rotational Energy (SRE) constraint as a new component in the existing models used by BC Hydro to increase the net transfer capability of the system when the electricity price is low.

1.3 Organization of the Thesis

This thesis is organized into six chapters. Chapter 1 provides an introduction and outlines the objectives of the research. Chapter 2 provides a review of the literature. This is followed by Chapter 3, which describes the B.C. Hydro System decision-making environment. In this chapter the history of the B.C. Hydro is briefly explained, and the production system in B.C. Hydro is outlined, giving a brief discussion of the B.C. Hydro System characteristics. An overview of the three components of the production system, i.e., generation, transmission and distribution systems, is provided and the volatility of prices and system load is illustrated and discussed. Moreover, in Chapter 3, the different level of planning and scheduling activities in B.C. Hydro is discussed, and power market characteristics under deregulated market environment are outlined.

Chapter 4 presents the structure of the decision support system and details its main components. The objective of the Rotational Energy Optimization Model (REOM) is first described. This is followed by a description of the new SRE constraint and it's effect on the B.C. Hydro Net Transfer Capability and the main components of REOM are outlined. The mathematical optimization formulation is described. Then the hydraulic modeling of reservoir operations and modeling of plant generation, discharge and load-resource is outlined. The results of testing the ROEM model are presented and discussed in Chapter 5. This chapter begins with a description of case studies for this research, and then it provides the results of different formulations. This thesis concludes with Chapter 6, which includes an evaluation of the proposed model and gives recommendations for future developments of the model. Annex A provides the reference information and theories used in this thesis.

CHAPTER 2

BACKGROUND

2.1 Literature Review

Optimal operation scheduling of hydroelectric systems in real time is a complex and challenging task that has been addressed by many researchers in the past few decades. Well-known traditional techniques such as Integer Programming (IP) (Dillon 1978,Graver 1963), Dynamic Programming (DP) (Lowery 1996, Snyder 1987), Branch and Bound (Cohen and Yashimura 1983), Bender's Decomposition (Baptistella and Geromel 1980), and Lagrangian Relaxation (Bard 1988, Zhuang and Galiana 1988) have been used to solve the power generation optimization problems. More recently, some heuristic approaches have been used such as Simulated Annealing (Zhuang and Galiana 1990), and Genetic algorithm (Kazarlis 1996, Orero and Irving 1998). Some comprehensive models such as Turgeon (1981), Tejada Guibert (1990), and Yeh (1992) that deal with the variety of problems related to the short term operation of hydro power reservoirs can also be found in the literature.

A recent review by Wurbs (1993) provides a description of models developed for hydro power scheduling considering both hourly and daily time intervals. Yeh (1992) developed an optimization model for real time operation of a hydrothermal system. Tajada – Guibert (1990) developed a nonlinear optimization model for real time operation of a hydrothermal system. They have adopted a method to generate alternative operating schedules using different objective functions and constraints in the optimization model. The issue of System Rotational Energy and import capability was not, however, addressed in their study.

Martin (1995) developed a methodology based on optimization as well as simulation to develop hourly generation schedules. Linear programming was used as a technique for the optimization procedure. Turgeon (1981) used the progressive optimality technique to arrive at optimal operating rules for a system of hydropower plants in series on the same river. Hawary and Christensen (1979) presented an elaborate discussion on different types of approaches used for scheduling of hydroelectric power generations. In all the cases they considered, the plant discharges were assumed to be pre-specified over the optimization time interval. This assumption might be helpful in solving the optimization problem but it is not realistic. PRSYM (Power and Reservoir System Model) of the U.S. Tennessee Valley Authority (Shane, 1995) and Hydro-Quebec model (Robitaille, 1995) and B.C. Hydro Short Term Optimization Model (Shawwash 2000) are the three comprehensive operation models now available for solving the real time operation problem of a complex hydroelectric generation systems. Lyra and Ferreira (1995) developed a multi-objective approach for short term scheduling of a complex hydroelectric generation systems. Discrete differential dynamic programming was used to solve the optimization problem. In this model the variation of the forebay level in different time steps was not considered.

2.2 History of Systems and Optimization

System Engineering and Optimization techniques have attracted the attention of the applied scientists and mathematicians from early 20th Century. This area of science has developed relatively rapidly in parallel with the increasing applicability and growth of the computer science and computing machines.

Two major events dominate the history of applied mathematics. The first event was the invention of calculus, which occurred in the seventeenth century. Sir Isaac Newton was one of the two inventors of calculus during 1665 –1666. Almost three centuries later, another event shook and reoriented not only the world of mathematics, but also the field of economics. The invention of linear programming was to influence not only economics but would form the core of an entirely new discipline, Operation Research or System Engineering in 1939. Koopmans in the United Kingdom and Kantorovich in the former U.S.S.R. at about the same time independently found the solution of the problem of least cost distribution. Koopmans came to the United States where he imbued his student Dantzig with the importance of providing a practical method of solution to the problem forms he was proposing. In 1947, in conjunction with a U.S. Air Force research project, Dantzig developed the simplex procedure for solving linear models. His procedure, with some modifications to take advantage of modern computers, is in wide use today.

During the period from 1948 to 1952, Charnes and his co-workers pioneered industrial applications of linear programming and created the simplex tableau, which is a data storage methodology used in the repeated calculation of the simplex procedure. Charnes and co-workers went on to adopt linear programming to deal with convex rather than linear functions, to invent goal programming, and to create new forms of optimization to deal with problems characterized by random parameters. Dantzig went on to make major contribution to the solution of network problems. Koopmans and Kantrovich received the 1975 Nobel Prize in Economics. The magnificent achievements of Dantzig and Charnes are yet to be honored in such a way. Charnes did not stop at industrial application of linear programming. With students and co-workers, he pushed on to the first applications of linear programming in civil engineering.

CHAPTER 3

THE DECISION-MAKING ENVIRONMENT

This chapter discusses the decision-making environment at B.C. Hydro. Historical development of the generating facilities is presented. Then, the energy production system development at B.C. Hydro is described along with a brief description on the characteristics of the generation and distribution systems and the planning levels at the B.C. Hydro System. This is followed by a synopsis of the decision-making framework employed at B.C. Hydro, a description of how deregulation has affected power generation planning activities and the effects of electricity markets on decision-making activities. The last section of this chapter discusses how the Rotational Energy (RE) constraints and the corresponding transfer capability can play a role in scheduling decisions in predominantly hydro systems.

3.1 B.C. Hydro Production System

The B.C. Hydro production system consists of two major components: the generating system and the transmission and distribution systems. In this section, a brief description of each system is given.

3.1.1 B.C. Hydro Generation System

The B.C. Hydro generation system, with 30 hydroelectric power generation facilities and 32 reservoirs in 6 major river basins, 27 watersheds and three thermal generating plants, is used to meet the domestic electricity demand in the province of British Columbia. It also can be used to export and import energy to and from neighboring utilities. B.C Hydro generates power by harnessing the power of moving or falling water to produce mechanical/electrical energy. On average 43,000 Gigawatt-hours of electricity is generated annually by B.C. Hydro to supply electricity for more than 1.5 million residential, commercial and industrial customers.

Over 90% of the generating capacity of British Columbia, amounting to about 11,200 MW of electricity comes from B.C. Hydro's hydroelectric generation systems. The Williston reservoir on the Peace River (40 billion M^3), and the Kinbasket reservoir on the Columbia River (14.8 billion M^3) are the two B.C. Hydro reservoirs that provide multi-year storage. The high capacity of the Williston and the Kinbasket reservoirs enables B.C. Hydro to plan their operations for several years ahead. Thermal generating facilities are used to supplement the hydroelectric system in years of low water flow and during periods when natural gas prices are low.

Figure 3.1 shows the contribution of the main power plants in British Columbia to the total power generation in 1998 (B.C. Hydro 1998).

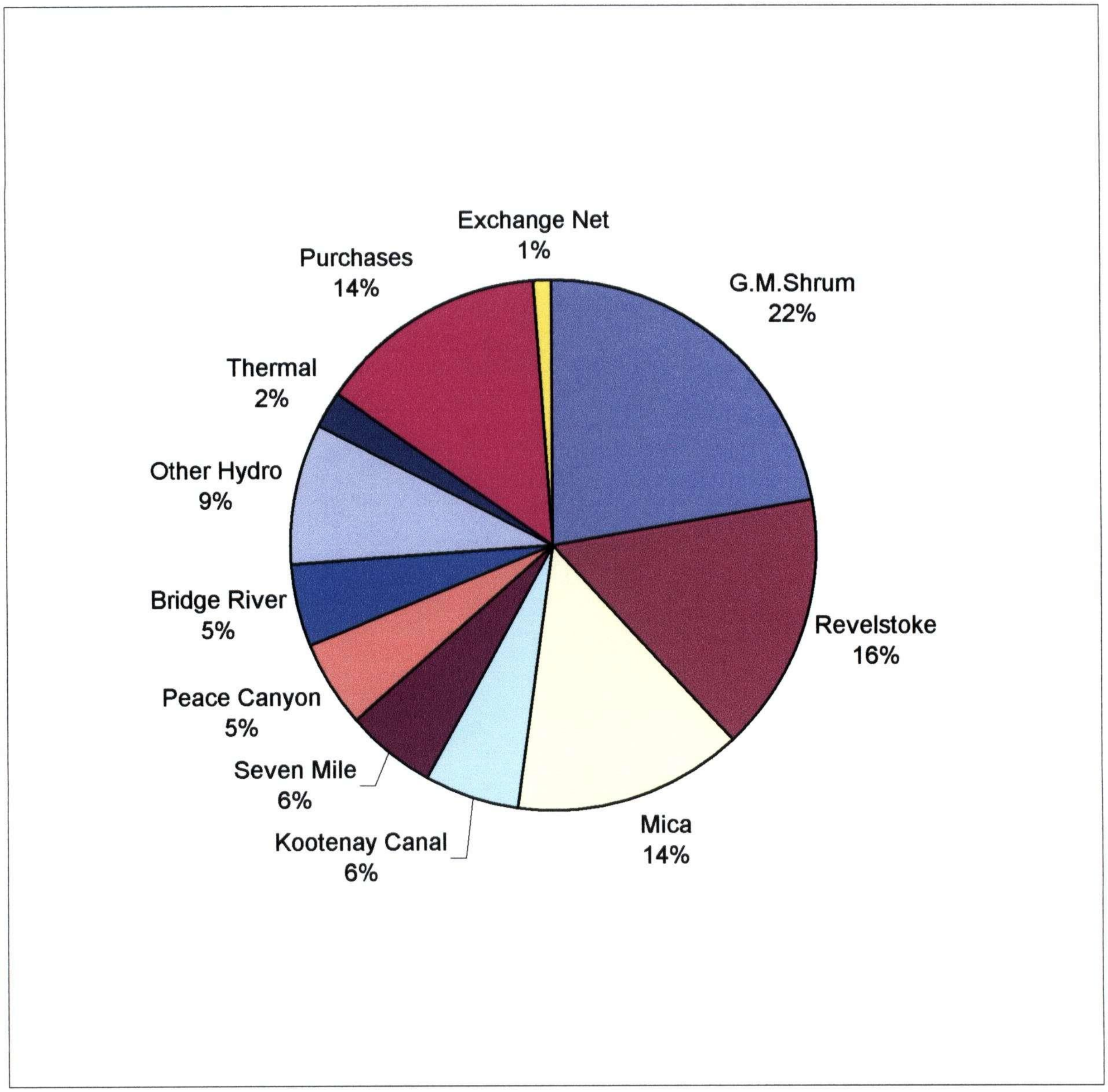


Figure 3.1 – Sources of Electricity Supply in British Columbia (B.C. Hydro 1998)

3.1.2 The B.C. Hydro Transmission and Distribution Systems

The B.C. Hydro transmission system moves electricity from the generating stations to the distribution substations where it is transformed to lower voltages for distribution to customers. The B.C. Hydro high voltage transmission system consists of 17,800 kilometers of transmission lines, operating at voltages from 60kV to 500kV.

The 500 kV bulk transmission network connects the major generators in the Northern and South Interior regions of the Province with the major load centers in heavily populated southwest B.C. Electricity is supplied to the Lower Mainland and Vancouver Island from the Peace River hydroelectric system through Kelly Lake Substation and from the Columbia River system through Nicola Substation. The relationship between installed generation capacity and electrical demand throughout the Province drives the development and operation of B.C. Hydro bulk transmission system. The B.C. Hydro 500 kV bulk transmission system is planned and operated to ensure high level of reliability, and the bulk of the transmission system is compliant with industry planning and operating standards to ensure a high level of reliability.

The transmission network connects all generating facilities to the demand centers. The power generation systems with high production capacity, but which are located in low demand centers are connected to the high demand centers through the transmission network. The imbalance between generating resources and demand centers has shaped the developments of the B.C. Hydro transmission network. Figure 3.2 shows the transmission network and the Alberta and U.S. transmission networks. The tie line capacity to Alberta is rated at 1100 MW and the U.S. tie line capacity is 3250 MW.

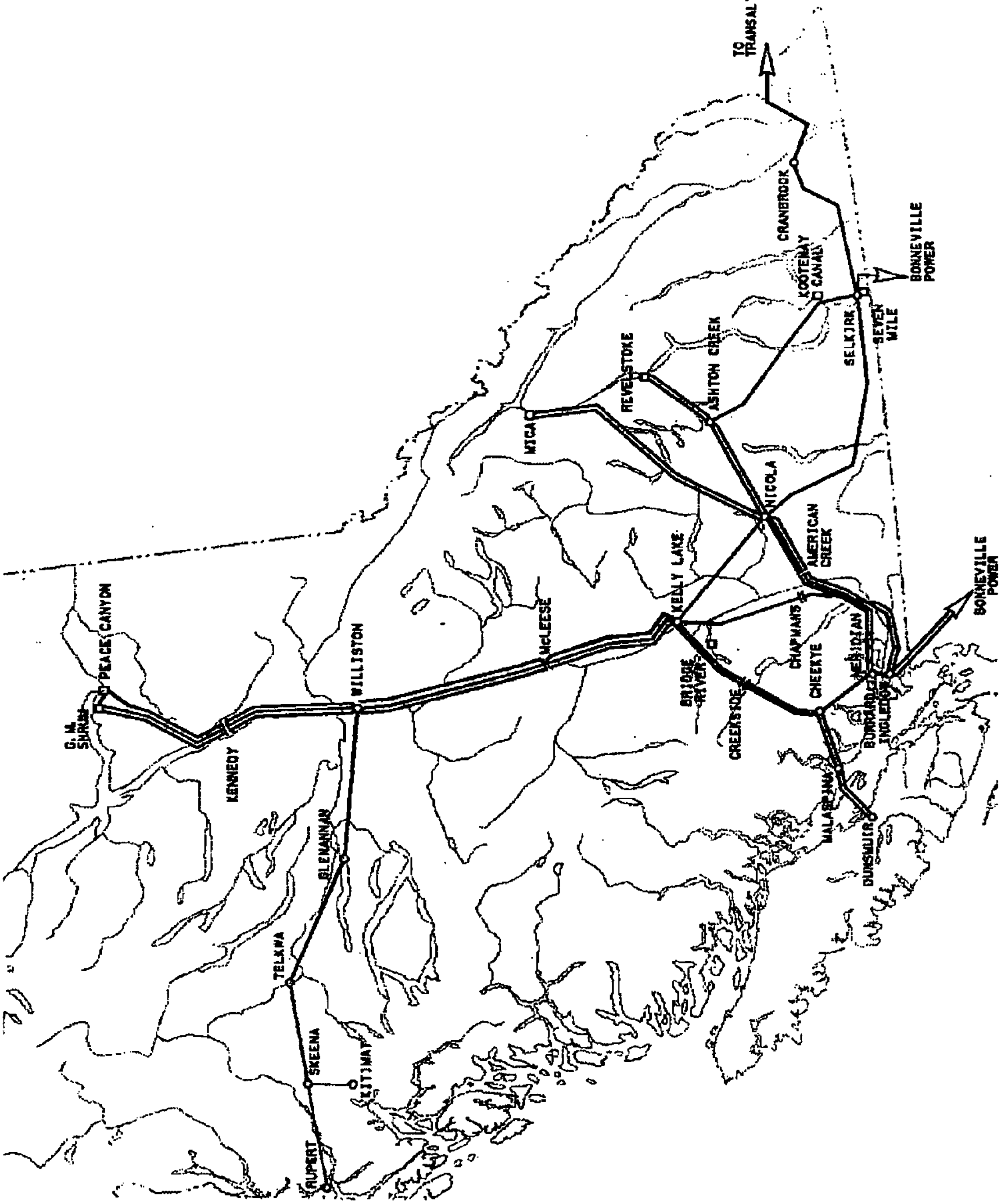


Figure 3.2 – Map of B.C. Hydro Major Electrical System (source: B.C. Hydro 2000)

3.2 B.C. Hydro System characteristics

Generation scheduling is one of the main activities practiced in every power generation systems. The main concern of the B.C. Hydro system operator involves implementing operations plans that will ensure load-resources balance. On the other hand, as the electricity market has deregulated or restructured in the past few years, the B.C. Hydro generation system also needs to plan the generation scheduling to determine the short-term and real time electricity trade capability and requirements. Other functions of the system operator include management of non-power needs, such as balancing power generation requirements with the needs of fish, wildlife, recreation and flood control.

The main parameters considered in hydroelectric system operations, however, are electricity demand and water inflow. As the demand for electricity and water inflows are the two exogenous parameters in a hydroelectric power generation system and since they are beyond the control of the system operator, the B.C. Hydro generation system is operated to satisfy the firm domestic load, to minimize operating costs and to ensure that the consumers have enough electricity to protect from shortages when the water inflow is low during the dry-year periods. On the other hand, when water is in abundance, system operations are focused on making the best use of available resources to maximize value of resources.

To operate the generating system reliably two conditions must be met: sufficient energy capability and sufficient peak capacity. A complicating factor in meeting these goals is the fact that the demands for electricity and water inflows are both uncertain, as both primarily depend on weather conditions. More recently, and due to deregulation, system operation must make a balanced tradeoff between system operations reliability and opportunities in the market place in the long-term as well as in the short term.

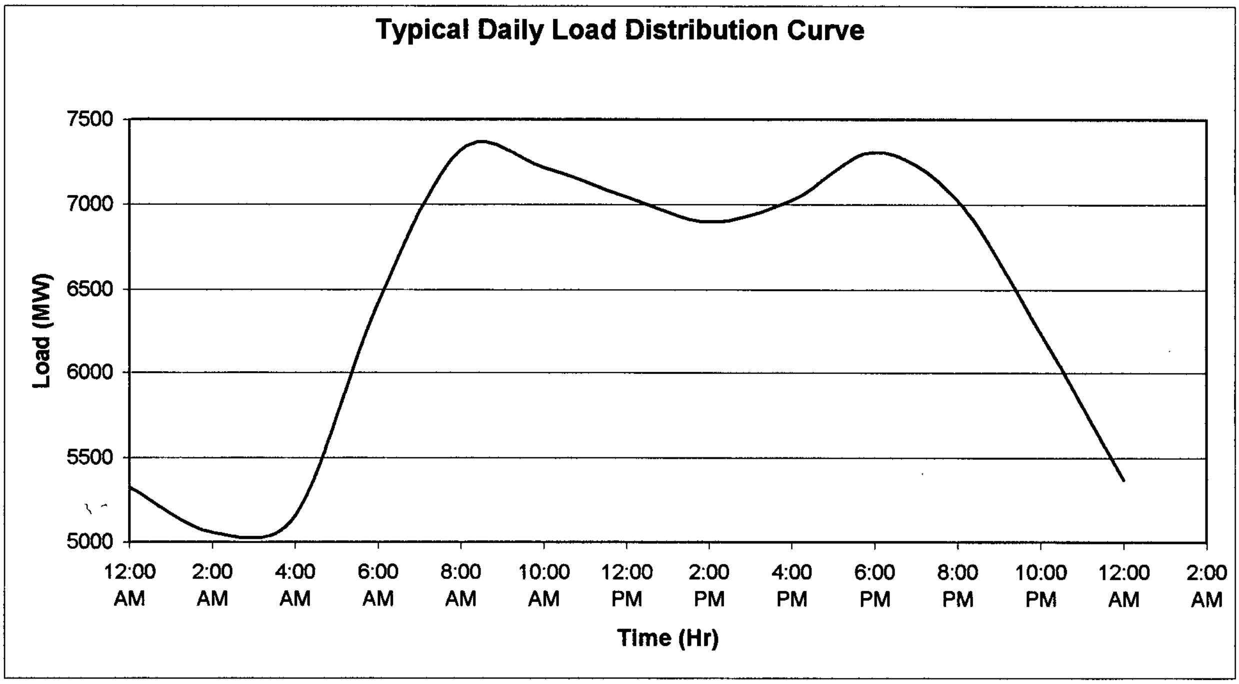


Figure 3.3 – Typical Load shape curve for 24 hour (B.C. Hydro 2002)

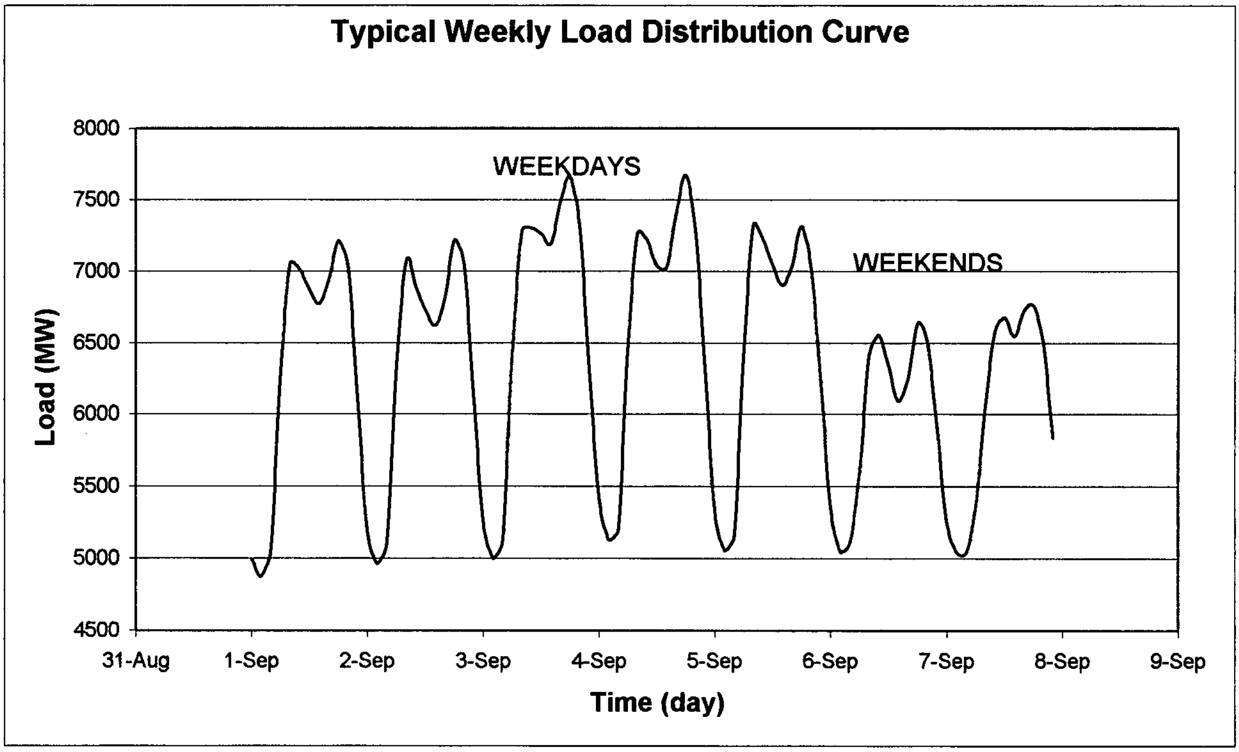


Figure 3.4 – Typical load shape for a week (B.C. Hydro 2002)

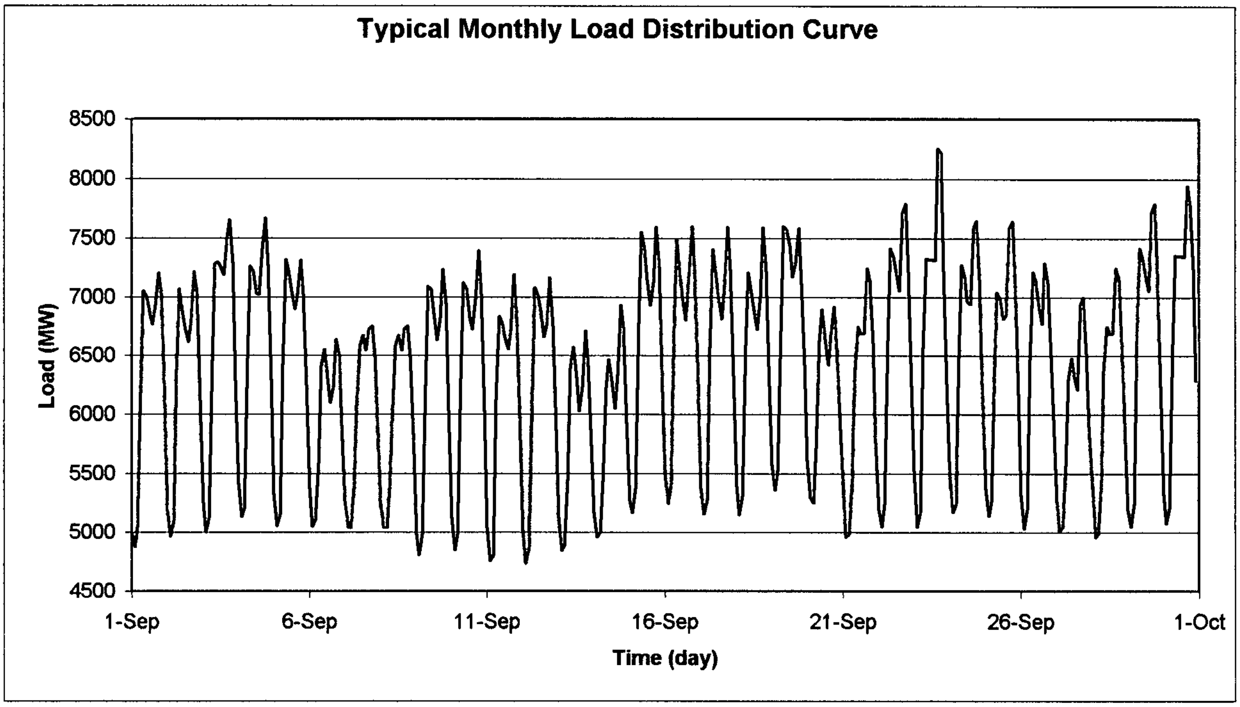


Figure 3.5 – Typical load shape for one month (B.C. Hydro 2002)

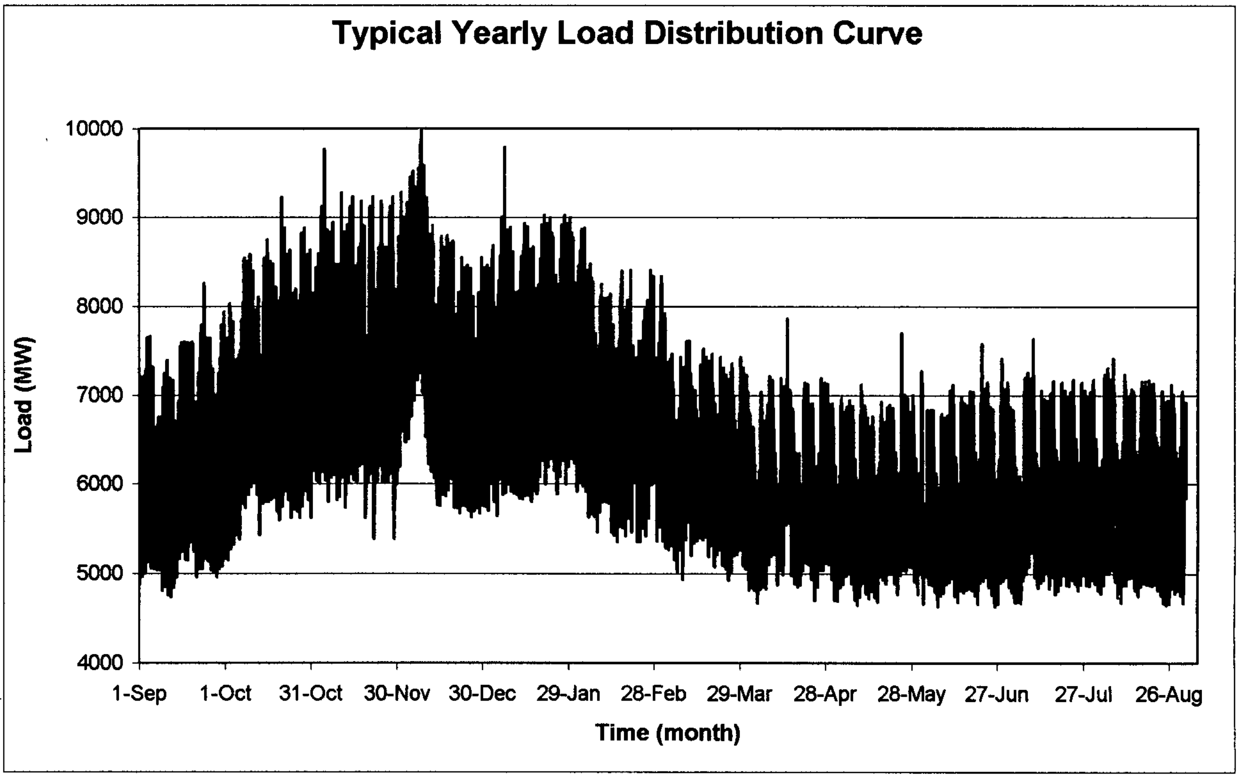


Figure 3.6 – Typical load shape for one year (B.C. Hydro 2002)

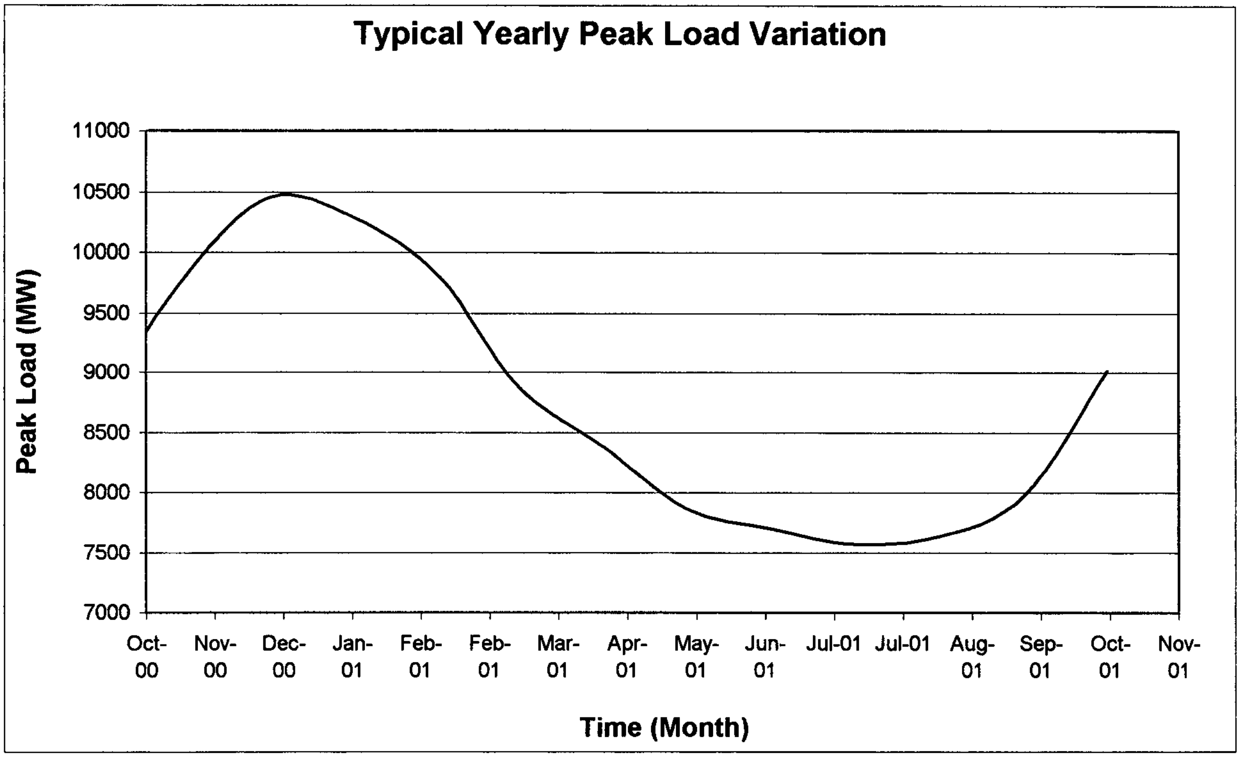


Figure 3.7 – Variation of peak load during a year (B.C. Hydro 2002)

3.3 Planning Levels

The B.C. Hydro power generation system, with its high energy production capacity, is a large-scale system. The decision making process for this system is very complex. Both forecasted and historical data is used, and different models are developed to optimize the system at different planning levels. These decision support systems help the system operator to make informed and near optimal decisions. The following is a brief description of the various operational planning levels currently employed by B.C. Hydro. Figure 3.8 shows the major information flows between models within the Power Supply Business Unit and between other business units at B.C. Hydro.

As illustrated in Figure 3.8, the optimal operation of hydroelectric generating systems can be divided into several computationally manageable levels with each level providing answers to a different aspect of the total problem. The different levels that can be distinguished are as follows:

1) Long term-hydroelectric operations planning, where hydro and thermal resources utilization policy and trade decisions are determined over monthly time steps for 1-4 years.
2) Medium-term hydroelectric operations planning, where hydro and thermal resource utilization and trade decisions are optimized over weekly time steps for 1 year.
3) Short-term operations scheduling, where hydro and thermal resource utilization and spot trade opportunities are optimized over daily or hourly time steps for one week.
4) Real-time hydroelectric operations scheduling, where hydro resource and thermal utilization and spot trade opportunities are optimized over hourly time steps for several hours.
5) Real-time economic dispatch, where commitment and loading of hydro and thermal resource are optimized within the hour. This is essentially a static optimization procedure requiring re-optimization at 10 minutes or shorter time intervals.

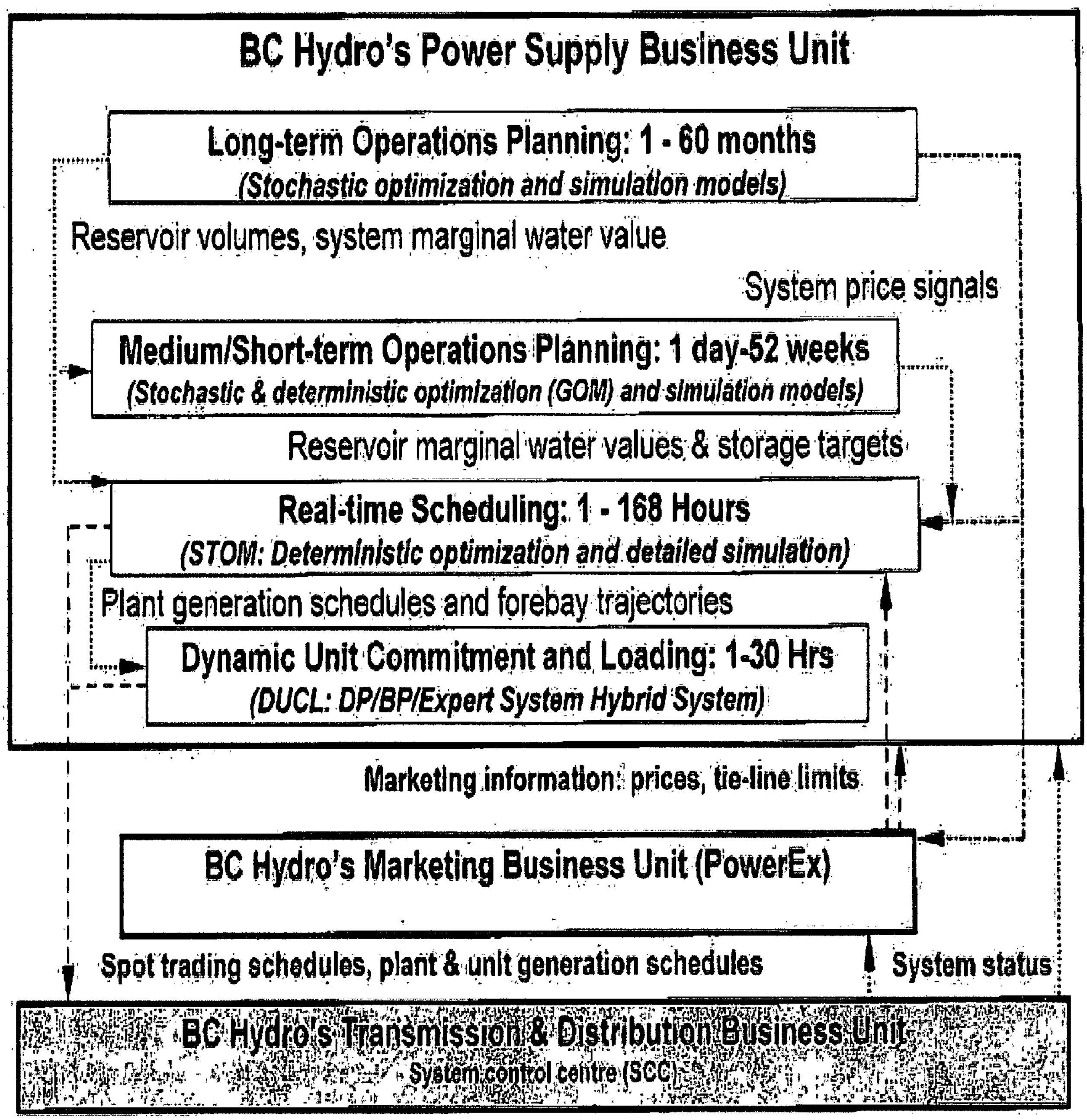


Figure 3.8 – Scheduling Problem modeling decomposition hierarchy (source: Shawwash 2000)

Short term operation scheduling is the subject of this research. For the B.C. Hydro system, the prime objective of the short-term optimization model is to first meet the domestic firm load demand and firm export contracts and then to make the optimal trade-off between present benefits, expressed as revenues from real-time spot energy transactions and the potential expected long-term value of resources, expressed as the marginal value of water stored in reservoirs. In other words, the decision to be made is when and how much to import and/or export and how much thermal energy to generate as well as when, where and how much water to store in or draft from reservoirs while meeting the domestic load and the firm export/import contracts.

3.4 Power Generation Under Deregulated Market Environment

In a regulated market, a power generating utility solves the Short Term Optimization Model and Unit Commitment problems to obtain an optimal schedule that meets the domestic load demand. The optimal schedule is found by minimizing the production cost over a time interval while satisfying the demand as well as a set of operating constraints. The minimization of the production costs assures maximum profit because the power generating utility has no option but to reliably supply the prevailing load. The price of the electricity over this period is predetermined and unchanging; therefore, the decision on how the units are operated has no effect on the utility's revenue.

As deregulation is being implemented in various regions of the world, specifically in North America, the traditional power generation schedule problems continues to remain applicable to the scheduling decisions made by a utility. In a deregulated market, the generation scheduling for a large electric power producer will require a new formulation that includes the electricity market in the model. The main difficulty here is that the spot price of electricity is no longer predetermined but set by open competitive market, and the decision making for the scheduling of the generation system becomes much harder. Under such conditions, forecasting spot prices and system load becomes very important in this new operating environment. Figure 3.9 shows the high volatility of the hourly spot price of electricity.

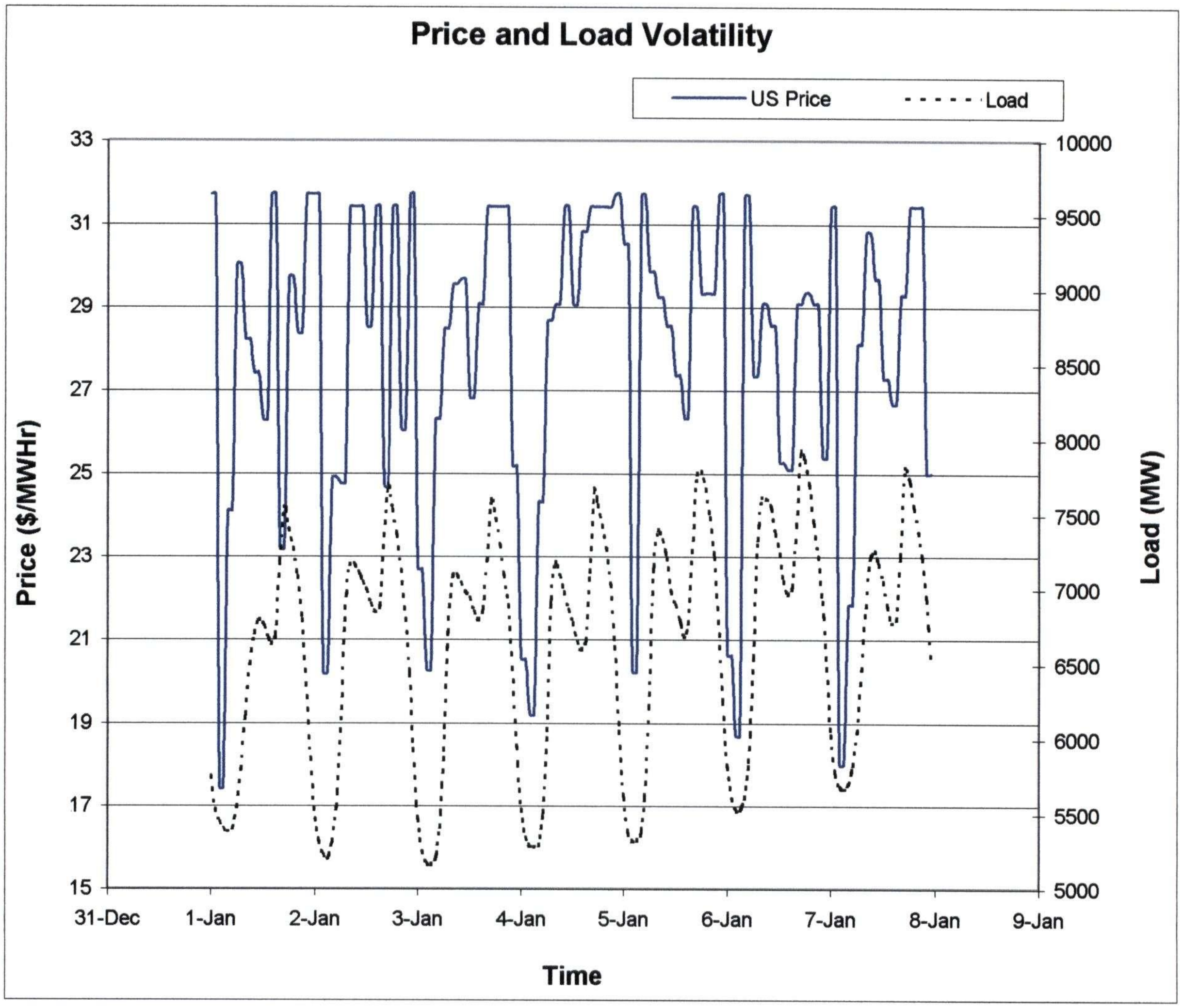


Figure 3.9 – Load and Market Price volatility order (source: BC Hydro, 2002)

3.4.1 System Load and Price Forecasting

In a deregulated power system, a generating company must forecast the system demand and the corresponding price in order to make an informed decision. Different forecasting models have been employed in power systems operations to forecast the system load and price accurately.

For hydro generation systems, and using system load and price forecasts, the effect of scheduled operation on power system security can be predicted and preventive and corrective actions can be prescribed before the occurrence of a contingency. There could be abrupt changes in power generation or demand caused by, for instance, sudden load increases. The appropriate amount of reserve can be determined based on load forecasts. Moreover, load forecasts can be very useful for the dispatcher to operate the system economically. System load also affects the net transfer capability of the system. As it will be discussed in detail in the next chapter, the amount of imported energy is constrained by the Net Transfer Capability of the system and the forecasted power price. This transfer capability also depends on the forecasted system load. Applying an appropriate technique to forecast the system load and price could help the system operator in making a well-informed decision, and accordingly, running the system optimally.

The first step to make an accurate load forecast is to identify the factors that would affect load patterns. One of those is the economical condition in a region, and they could also depend on other factors such as the type of customers served, demographic conditions, industrial activities and population.

The second factor that could affect the load shape and market price is "Time". Time factors include seasonal, weekly and holiday effects. The third factor is weather and the prevailing temperature. Weather fluctuation could impact the amount of energy needed for heating in the winter months or cooling in summer. The level of humidity in a region affects the load forecasting similar to temperature variation.

3.4.2 Electricity Price Volatility

The most distinct property of electricity is its price volatility in deregulated environment. Volatility is the measure of change in the price of electricity over a given period of time. Compared to load, the price of electricity in a restructured power market is much more volatile. Figure 3.9 shows system load and price curves. From these curves, it can be observed that:

- The load curve is relatively homogeneous and its variations are cyclic.
- The price curve is non-homogeneous and its variations show a little cyclic property.

The main reasons for electricity price volatility are:

- Matching of supply and demand
- Load uncertainty
- Generation uncertainty
- Transmission congestion
- Behavior of market participant, and
- Non-storability of electricity

3.5 Electricity Trade

Since 1998, Powerex Corporation Ltd. (Powerex), B.C. Hydro's power marketing subsidiary, has made a name for itself as a buyer and seller of wholesale energy products and services in Western Canada and the Western United States (U.S.). Electricity trade and power marketing are possible because B.C. Hydro's bulk transmission network is interconnected to

Alberta to the east and to the U.S. to the south. This transmission network links B.C. Hydro with a large market for the purchase and sale of wholesale electricity outside B.C.

The wholesale electricity marketplace is characterized by increased competition among a growing number of energy suppliers, price volatility resulting from fluctuations in energy supply and demand. Despite this, B.C. Hydro, through Powerex, has become a key participant in this marketplace, earning significant revenues for B.C. Hydro and the Province of British Columbia.

The flexibility of the B.C. Hydro's predominantly hydroelectric generating system enables Powerex to purchase electricity from the market when prices are low and sell electricity to the market when prices are high. This flexibility also enables Powerex to take advantage of differences in demand between the winter-peaking north and summer-peaking south and between heavy load and light load hours.

General trends exist both seasonally and daily, corresponding to fluctuations in supply and demand. Seasonally, the price of electricity in the marketplace will be higher during the cold winter months with an increase in electricity use for heating and again during the warmer summer months with the increase in use of air conditioners. Daily price fluctuation also exists. Prices increase during working hours and drops overnight when people activity is low. The term 'peak hours' or 'heavy load hour' refers to the time period where demand (load), and thus prices, are higher. Alternatively, the term 'low load hours' refers to the period where demand (load), and thus prices, are generally lower.

CHAPTER 4

THE DECISION SUPPORT SYSTEM

In this chapter, the decision support system is described. First, the objective of the mathematical model, which is employed to modify the short-term scheduling optimization problem, is described in detail. In this model, the effect of the new system rotational energy constraints on the Net B.C. Hydro Transfer Capability, which is the subject of the present research, is considered. Then, a detailed description of the new methods that were used to formulate the mathematical programming problem and the algorithm used to efficiently solve the problem is provided.

4.1 Introduction to Rotational Energy Optimization Model (REOM)

The Rotational Energy Optimization Model (REOM) decision support system was designed as a solution technique to optimize the value of imports for hydro systems by optimally selecting the unit commitment and loading of plants that provide the required system rotational energy (SRE) or system inertia. The methodology has been developed for use in short-term hydro system operations in a deregulated market environment in order to determine the optimal electricity import for a predominantly hydroelectric system consisting of plants with large storage facilities, multiple units and complex hydraulic configurations.

The problem was formulated and solved using a hybrid system consisting of two main components. The first component comprises of an expert system that given a set of rules on plant, unit operations and markets states screens for potential and feasible system configurations. The second component is a Mixed-Integer programming algorithm that is used to maximize the value of import capability of the hydro system during low electricity market price periods. The proposed technique optimally schedules hydro plants for the energy and the capacity markets for short-term operations while meeting the SRE constraint.

4.2 Objectives of the Decision Support System

Hydroelectric generating plants with significant storage and generating capacity provide the hydro system operators with a relatively high level of operational flexibility, and they enable the system operator to compete favorably in both the energy and capacity markets. From this perspective, both the B.C. Hydro Short Term Optimization Model (STOM) and the Dynamic Unit Commitment and Loading system (DUCL) were developed to assist the B.C. Hydro scheduling engineers in managing the resources and in making good operational and trading decisions while meeting the constraints.

Due to the power blackout in the West Coast during the late 90s, the need for sufficient SRE for system reliability started to attract attention. STOM was originally designed to maximize the value accrued from trade activities given a static transmission capability without considering SRE. From this perspective, the objective of the proposed algorithm described in this research is to extend STOM to incorporate the new SRE requirements. The Rotational Energy Optimization Model (REOM) is particularly useful during periods when the marginal cost of energy resources is significantly higher than the market price. As described below, the proposed REOM system treats the unit commitment and the transfer capability as variables in the optimization process, and it provides the system operations engineers with a tool that can be used to optimize the value of import of the hydro system.

4.3 Transfer Capability

Transfer capability is a term that describes the amount of electric power that can be transferred from one area to another through a transmission network. It is a useful and important concept for a power system. Transfer capability computations play a role in both planning and operation of the power system with regard to system security.

Power system transfer capability indicates how much inter-area power transfers can be increased without compromising system security, and it provides information for the system planners on identifying the system bottlenecks. An interconnected power system has its benefits as well. One of these benefits is the potential for increased reliability. This is due to the fact that in an interconnected system a sudden loss of generation in one area can be replaced by generation from another area. This makes it more reliable than that of an isolated system. Transfer capability plays its part by helping in evaluating the ability of the interconnected system to remain secure following generation and transmission outages.

Determining the adequacy of the transmission system in allowing external generation to replace internal generation is a typical application for transfer capability computations. A transfer is specified by changes in power injections at buses in the network. For example, a point-to-point transfer from bus A to bus B is specified by increasing power at bus A and reducing power at bus B. In particular, if 100 MW are to be transferred from A to B, the power at bus B is reduced by 100 MW and power at bus A is increased by 100 MW plus an amount to cover transmission losses.

Transfer capability, or in other words the Net Transfer Limit, is a function of the load and the system rotational energy. In this research, Net Transfer Limit was obtained from a table prepared by the system operator (Table 4.1) as a function of system load (B.C. Hydro Load) and system rotational energy. Figures 4.1 and 4.2 illustrate the relationship between the Net Transfer Limit and both B.C. Hydro Load and system rotational energy.

It can be seen from the charts that the transfer limit decreases for a certain rotational energy as the load increases, and it also decreases for a certain load while the system rotational energy increases. Given the system load, linear interpolation and extrapolation can thus be used to calculate the net transfer limit from these tables.

Table 4.1 – Net transfer limit for different load and system rotational energy

(Source, B.C. Hydro System Operating Order - January 2002)

B.C. Hydro Load (MW)	Limit for "net B.C. Hydro Transfer" (MW) as a function of B.C. Hydro Load and Rotational Energy						
	20,000 Mega-joules	25,000 Mega-joules	30,000 Mega-joules	35,000 Mega-joules	40,000 Mega-joules	45,000 Mega-joules	50,000 Mega-joules
3800	-1689	-1838	-1987	-2136	.	.	.
3900	-1726	-1867	-2008	-2149	.	.	.
4000	-1761	-1896	-2031	-2165	.	.	.
4100	-1797	-1925	-2054	-2183	.	.	.
4200	-1831	-1955	-2078	-2201	.	.	.
4300	-1866	-1984	-2103	-2222	-2340	.	.
4400	-1900	-2014	-2129	-2243	-2357	.	.
4500	-1934	-2044	-2155	-2265	-2375	.	.
4600	-1968	-2074	-2181	-2288	-2394	.	.
4700	-2001	-2105	-2208	-2311	-2415	-2518	.
4800	-2035	-2135	-2235	-2336	-2436	-2536	.
4900	-2068	-2165	-2263	-2360	-2458	-2555	.
5000	-2101	-2196	-2291	-2386	-2480	-2575	.
5100	-2134	-2227	-2319	-2411	-2504	-2596	-2688
5200	-2167	-2257	-2347	-2437	-2527	-2617	-2708
5300	-2209	-2297	-2386	-2475	-2563	-2652	-2741
5400	-2264	-2352	-2440	-2529	-2617	-2705	-2793
5500	-2319	-2407	-2495	-2583	-2670	-2758	-2846
5600	-2375	-2462	-2549	-2637	-2724	-2811	-2899
5700	-2430	-2517	-2604	-2691	-2778	-2864	-2951
5800	-2486	-2572	-2658	-2745	-2831	-2918	-3004
5900	-2541	-2627	-2713	-2799	-2885	-2971	-3057
6000	-2597	-2682	-2768	-2853	-2939	-3024	-3110
6100	-2652	-2737	-2822	-2907	-2992	-3077	-3162
6200	-2708	-2793	-2877	-2962	-3046	-3131	-3215
6300	-2764	-2848	-2932	-3016	-3100	-3184	-3268
6400	-2820	-2903	-2987	-3070	-3154	-3238	-3321
6500	-2876	-2959	-3042	-3125	-3208	-3291	-3374
6600	-2932	-3014	-3097	-3179	-3262	-3345	-3427
6700	-2988	-3070	-3152	-3234	-3316	-3398	-3480
6800	-3044	-3125	-3207	-3289	-3370	-3452	-3534
6900	-3100	-3181	-3262	-3343	-3424	-3506	-3587
7000	-3156	-3237	-3317	-3398	-3479	-3559	-3640

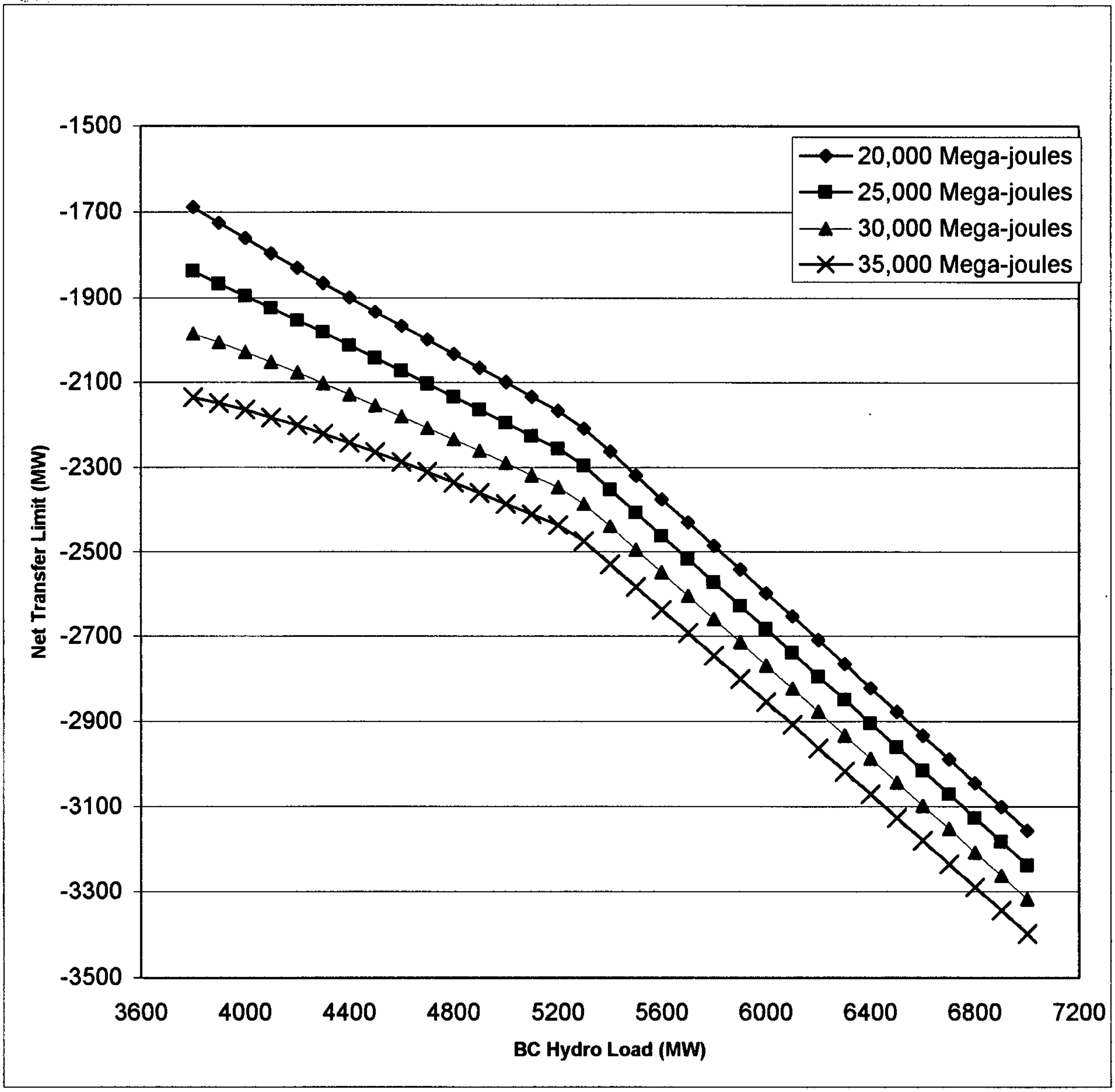


Figure 4.1 – Variation of Net Transfer Limit with Load and SRE

(Source, B.C. Hydro System Operating Order - January 2002)

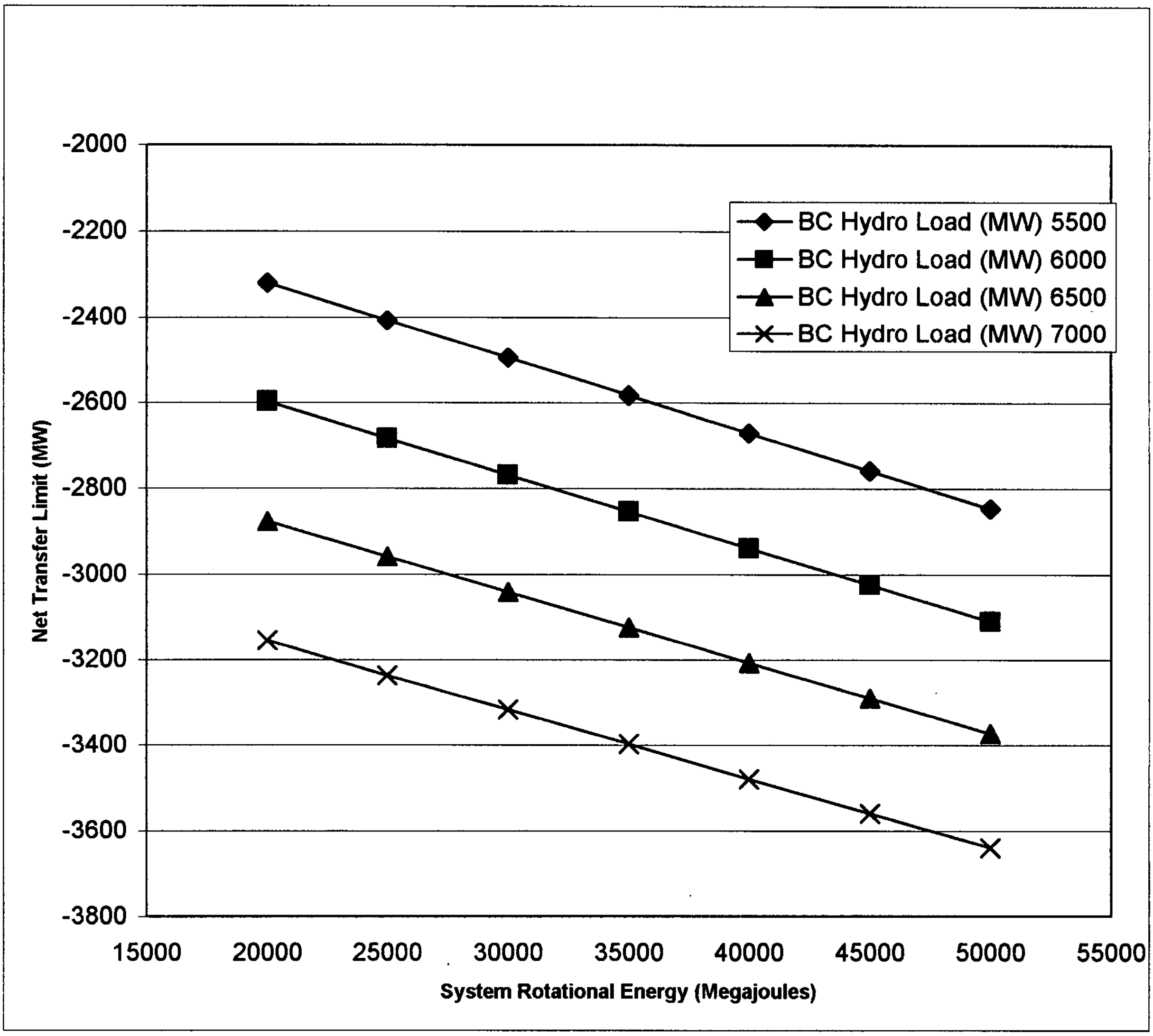


Figure 4.2 – Variation of Net Transfer Limit with. SRE and Load

(Source, B.C. Hydro System Operating Order - January 2002)

4.4 Main Components and Structure of the REOM System

REOM consists of five main components as shown in Figure 4.3: the Graphical User interface (GUI), the Expert System, the optimization preprocessor, the mixed-integer optimization model and the results display software. The function of each component is detailed in this section.

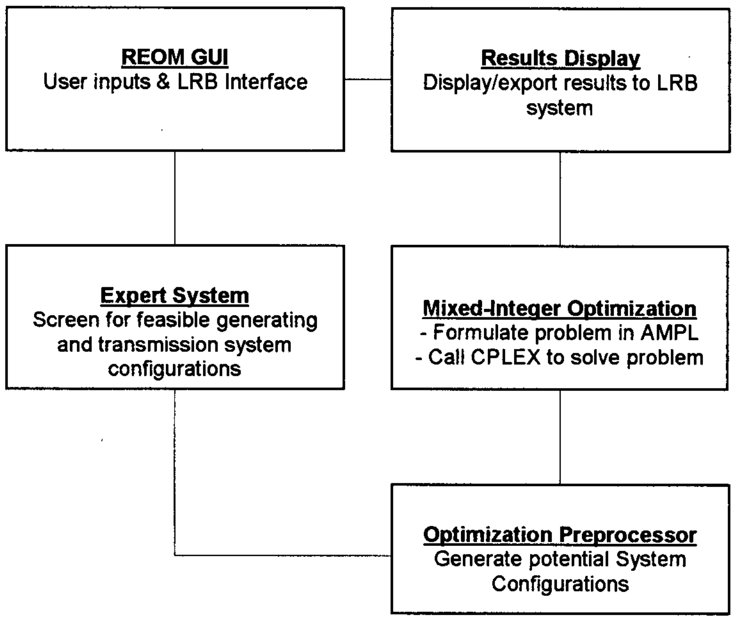


Figure 4.3 – Schematic of the REOM System

4.4.1 The Graphical User Interface

The graphical user interface (Figure 4.4) component provides an intuitive and convenient method for the operations engineer to specify input parameters and set conditions for a study. It provides the user with a friendly input forms to set some of the parameters used by the optimization model as well as the facility for the REOM system to access the latest operational input data available.

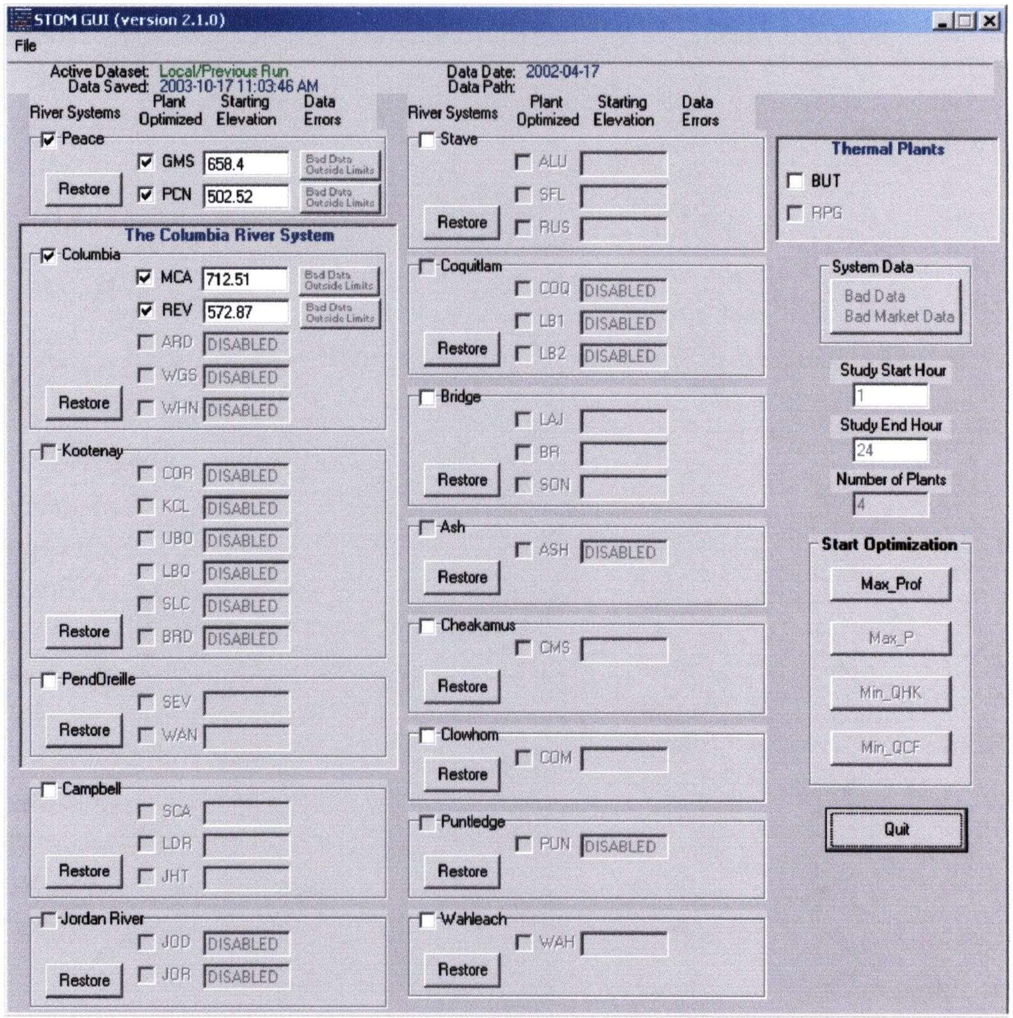


Figure 4.4 – Graphical User Interface

(Source; B.C. Hydro Short Term Optimization Model)

The GUI allows the user to perform the following functions:

- Select the plants to be included in the study,
- Set the study starting time step and the number of time steps in the study,
- Verify the plant loading and reservoir level schedules prepared by the Load Resource Balance (LRB) system,

- Allow the user to review the plant constraint limits and restrictions on unit operations, and
- Provide a platform to input the set of rules, guidelines and the heuristics used.

4.4.2 The Expert System

The expert system component in REOM achieves two main objectives. First, it ensures that the optimal unit loading schedules implicitly incorporate the set of rules and guidelines that must be followed by the scheduling engineers. Second, it ensures that only feasible and desirable unit commitment and system configurations are included in the optimization process, and it, therefore, considerably reduces the size and complexity of the optimization problem.

The expert system contains the knowledge base that represents the set of rules, guidelines, heuristics and constraints that the system operator takes into consideration, and it uses them to eliminate infeasible and undesirable solutions. The knowledge base that contains the set of rules, guidelines, heuristics and constraints was developed through several interview sessions with the scheduling engineers.

A prototype of the expert system has been developed using the Aion Expert System shell. The use of rule-based systems such as Aion allows the knowledge of unit commitment selection to be coded conveniently, as opposed to lengthy and cumbersome conventional computer programs. Individual rules can be coded independently of each other and can be appended to the inference engine that determines the applicable rules to be fired as well as the order in which they should be fired.

Several rules were used in the REOM system as described below:

a. Specified states for individual units, such as Synchronous Condense (SC) state for voltage support, fixed generation level, “OFF” mode as in the case of unit maintenance, or must run state.

b. Requirement for a generating system to provide enough capacity, spinning and operating reserve to meet system contingencies. Examples for calculating the generating capacity of the generating system with units committed at different modes in the Aion syntax are shown as below:

```
If G1 = “SC” then correctionFactor = pPlant.M1+GetSyncCondGen (1)
Elseif (G1 <> “MR” and G1 <> “OFF AND G1 <> “AV and G1 <> Null) then
Decode (ival, G1)
CorrectionFactor = (pPlant.M1 – ival)
END
```

Here ival represents a fixed generation value of a unit (e.g., 200 MW).

c. Minimum number of units on-line for providing voltage and frequency support and other system contingencies. This type of rule can link the states of units in multiple plants at the same time particularly when one transmission line serves multiple plants.

d. Other optional rule to ensure that the candidate unit combination meets a given or possible plant loading levels.

e. Rules that screen for unit availability to derive the feasible unit combinations.

f. Rules to screen for allowable unit combination as specified by the user.

These and other rules are coded in the expert system shell, and then appended to generate a C++ code, which can be compiled as a library. The library can then be called whenever the REOM system is used.

The results of the screening instance, which consists of the set of feasible and desirable unit commitment combinations, are fed into the optimization preprocessor to generate the potential system configurations. The current implementation of the expert system is in the 'prototype' stage, and further rules will be added to the knowledge base in the future to reflect other heuristics and guidelines that the scheduling engineers use in their daily operations.

4.4.3 Optimization Preprocessor

Running a power generation scheduling model requires careful consideration of the length of run-time that an optimization algorithm would take. Generation scheduling models depend on the level of planning and should solve the problem in the shortest time possible. Solving these types of models can take a very long time since they deal with many parameters and variables as well as various formulation methods. The best mathematical model is the one that solves the problem with the same sets of data but in the shortest time possible. In this research, this important issue was taken into consideration. This section discusses different ways to formulate and solve the REOM optimization problem, and then, it presents the elimination algorithm that is used to automatically determine at which time steps in the study, rotational energy constraint will be active.

4.4.3.1 Approaches to Formulate the REOM Optimization Problem

In this section, two different approaches for preprocessing the data and indexing of some variables and constraints are discussed in detail. These two methods are referred to as the PATH Method and the COMBO Method.

A) The PATH Method.

One of the approaches to formulate the REOM optimization problem is called the "PATH" method. A typical REOM problem consists of a number of generating plants. Each plant consists of a number of units. Based on the design characteristics and the type of the turbine and the generators capacity, each unit has a given rotational energy. This rotational energy is fixed and does not usually change under typical operational conditions or during different time steps. The rotational energy for a power plant is calculated as the sum of the rotational energy of each generating unit at any specific time. Consequently, the total System Rotational Energy (SRE) is calculated as the by sum of the rotational energy of all generating plants in an electric network. Table 4.2 shows some basic information on the rotational energy for the four main plants in the B.C. Hydro System.

At each time step, the Expert System module in the preprocessor calculates all feasible combinations of available units. For instance, the Expert System and the Preprocessor consider the number of units available and it recognizes all the similar units that have exactly the same characteristics and it eliminates similar unit combinations with similar characteristics. The grouping of all feasible combinations is used to create a set of combination, which indicates the possible generating system configurations that can be used to formulate a mixed integer programming. In the present research, these new sets of configurations are called PATH, and the total number of combinations at each time step is called TOTAL PATH. Figure 4.5 illustrates typical layout of the path method for a single time step.

Table 4.2 – Some basic information for GMS, PCN, MCA, REV

River System	Plant	Max Capacity	Unit No.	min Gen (MW)	max Gen (MW)	R.E. Mega-J
Peace	GMS	2745	U1	-6	261	1195
			U2	-6	261	1195
			U3	70	261	1195
			U4	70	261	1195
			U5	70	261	1195
			U6	70	280	1264
			U7	70	280	1264
			U8	70	280	1264
			U9	190	300	1356
			U10	190	300	1356
	PCN	700	U1	50	175	1108
			U2	50	175	1108
			U3	50	175	1108
			U4	50	175	1108
Columbia	MCA	1780	U1	-8	430	2865
			U2	-8	430	2865
			U3	275	460	2865
			U4	100	460	2865
	REV	2000	U1	-6	500	2444
			U2	-6	500	2444
			U3	70	500	2444
			U4	70	500	2444

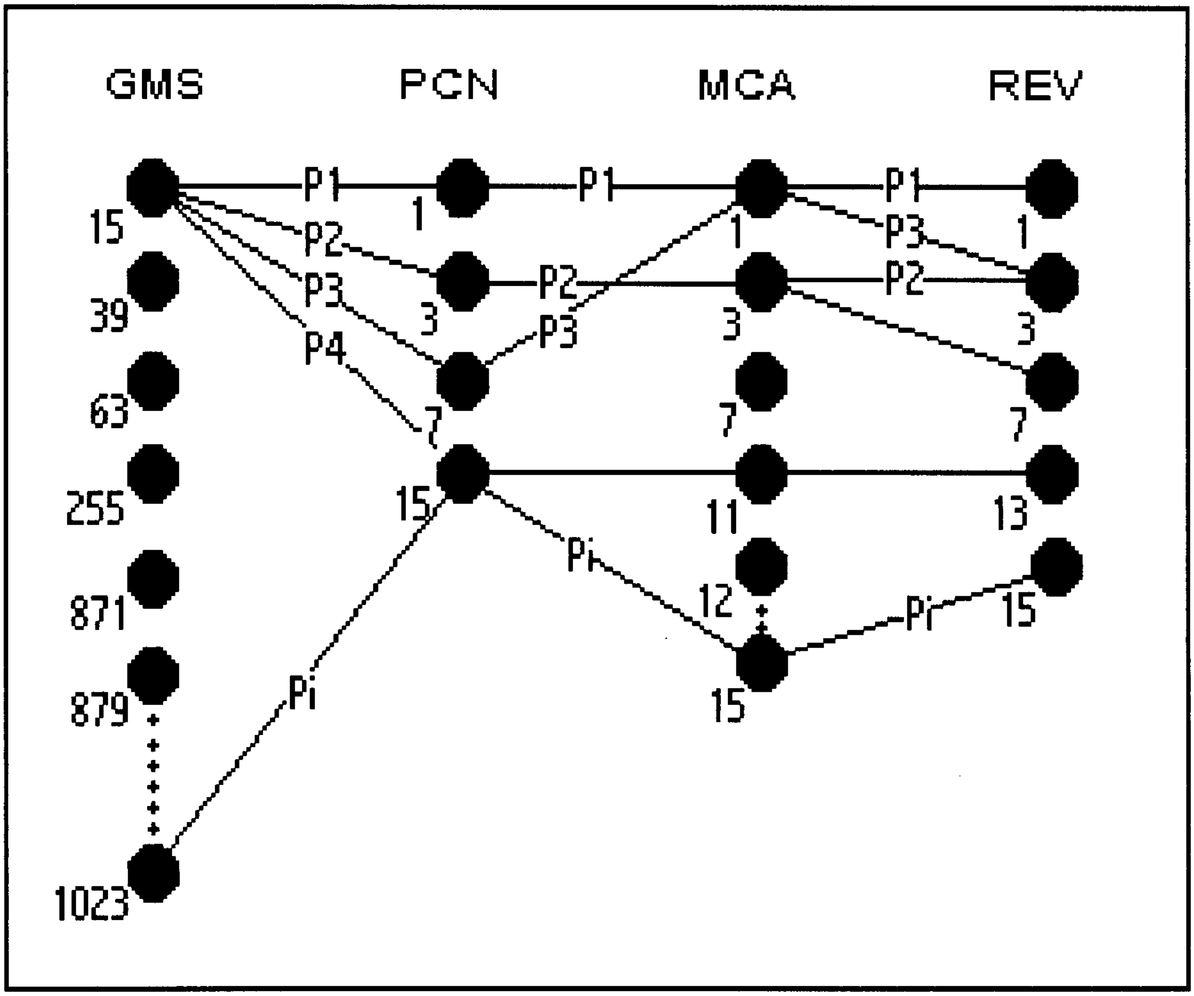


Figure 4.5 – Paths for calculating total rotational energy

In the present model, some parameters and variables are indexed over the total path set and the total path set is indexed over time steps. The Net B.C. Hydro Transfer is one of the variables that are indexed over the total path and is calculated by using the corresponding system rotational energy and system load at each time step. The linear interpolation for calculating the Net B.C. Transfer limit is implemented in AMPL in the preprocessor.

The other parameters and variables indexed over the total path are: generating capacity, minimum generation limit given the rough load zones for each unit, and the set of generation production function coefficients for each plant, time step and path. The formulation of the path method is described in detail in the mathematical formulation section, Section 4.4.4.

B) The COMBO Method

The next potential method to solve the problem is called the COMBO method. The hydro generation system includes a number of plants with a number of different units available. At each time step, based on the system load, there are a set of feasible combinations of the units online for each plant. In this method, variables and constraints are indexed over the sets of unit combination of each plant at each time step. At each iteration, only one of the unit combinations for each plant is used in the optimization process. Therefore, the difference between this method and path method is the number of alternatives. In the path method, the number of paths is determined by multiplying the number of unit combinations for each plant, while in the combo method, the number of the alternatives is simply the sum of the number of unit combinations for each plant.

In this method, similar to the path method, the Net B.C. Hydro Transfer Capability can be calculated using an AMPL piecewise linear functions for a certain system rotational energy and system load, for each time step. The other parameters and variables indexed over the combinations are: generating capacity, minimum generation limit given the rough load zones for each unit, and the set of generation production function coefficients for each time step, plant and combos. The detailed formulation of the combo method is described in the mathematical formulation section, in Section 4.4.4.

4.4.3.2 The Elimination Algorithm

In the two previous sections, two indexing methods of some variables and constraints over the path or over feasible combination of units online were described. The procedure within the algorithm to solve the optimization problem is to take all paths or combinations in all time steps into account and to calculate an optimal solution. In such a large-scale optimization problem, like the present research, and because of the large number of alternatives that the model must consider, the solving time of the problem drastically increases. Therefore in this research, the Elimination Algorithm was developed to reduce the size of the problem and consequently to reduce the runtime needed to solve the problem.

This algorithm calculates the value of the minimum possible Net B.C. Hydro Transfer Capability from Table 4.1, for a given system load at a certain time step and given the maximum rotational energy of all the plants included in this study. For example, in this research only the minimum rotational energy values for the "GMS", "PCN", "MCA", "REV" power plants were added to the rotational energy of all other plants in the BC Hydro system and were used to calculate the minimum Net B.C. Hydro Transfer. This was considered as the achievable transfer capability and it is compared with the sum of the minimum U.S. and Alberta transmission limits. If the value of the minimum U.S. and Alberta transmission limit is greater than the value of the calculated minimum net transfer limit for the corresponding time step, then the model automatically drops the rotational energy constraints from the optimization problem.

The preprocessor module extracts all the required parameters for the elimination procedure and generates a data set that contains binary numbers for each time step. If the value of the binary number at the corresponding time step is 1, then the constraints and the variables do not enter the optimization problem. If the value of the binary number is 0, it implies that for those time steps, the net transfer capability limit is active, and the constraint need to enter the optimization problem.

4.4.4 Mathematical Optimization Model Formulation

The REOM optimization model component is formulated as a mixed-integer programming problem, and it uses two software packages: AMPL, which formulates the optimization problem as a large-scale mixed-integer problem and CPLEX, which solves the problem.

REOM is a modified version of an existing model, STOM. All the equations and constraints in REOM are the same as in STOM, but with different indexing over sets. Moreover, ROEM contains a set of new constraints to address the SRE issues. In the mathematical formulation, all issues such as natural factors, complexity of the hydroelectric systems, user expectation and functionality were taken into the consideration.

Following is a general description of the STOM formulation, and then the new formulations for REOM are described.

4.4.4.1 Hydraulic Modeling of Reservoir Operations (Shawwash 2000)

A typical hydroelectric generation system consists of sets of rivers, tributaries, powerhouses and additional hydraulic facilities such as intake structures, spillway gates and weirs. A river system may contain one or more generating facilities that could be connected serially or in parallel, Figure 4.4. Inflows to reservoirs may be natural or modified by the operation of an upstream plant. Several matrices were used to describe the turbine and spill discharges and inflows from or to reservoirs as follows. The QTR_{jk} and QSR_{jk} matrices describes the turbine and spill flows from reservoir j to reservoir k. other matrices were used to describe the turbine UQT $_{jk}$ and spill UQS $_{jk}$ reservoirs inflows from reservoir j to reservoir k. an entry of "1" in the matrix indicates that a physical flow occurs from or between reservoirs, while "0" indicates no flows.

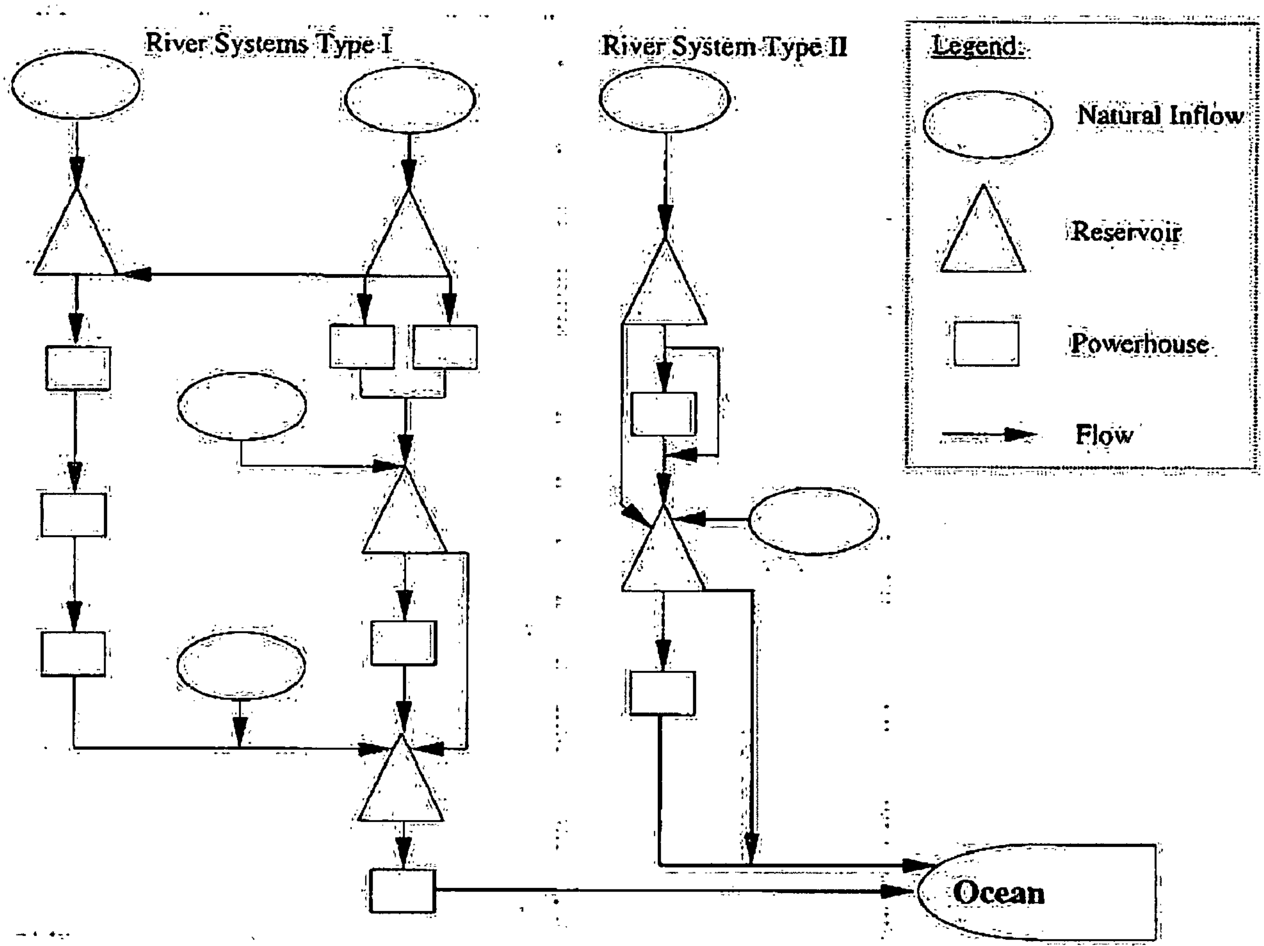


Figure 4.6 – Schematic of typical river systems with reservoirs and hydroelectric facilities

(Source; Shawwash, 2000)

Total spills from the reservoir at time step t, (t in T) consist of fixed (QSF $_{jt}$) spills and variable spills (QS $_{jt}$). Fixed spills are required to satisfy regulatory and non-power requirements, while variable spills depend on the reservoir's storage level, and are expressed as a piecewise linear penalty function of the reservoirs storage (S_{kt}) as follows,

$$QS_{kt} = f(S_{kt}). \qquad [1]$$

The hydraulic continuity equation for typical reservoir storage in m^3/s-day, and natural river inflows (NRI_{kt}) and turbine and spill flows in m^3/s, can be written,

$$S_{k(t+1)} = S_{kt} + (-\Sigma^{J}_{j=1}RT_{jkt} - \Sigma^{J}_{j=1}RS_{jkt} + \Sigma^{J}_{j=1}UT_{jkt} + \Sigma^{J}_{j=1}US_{jkt} + NRI_{kt})/24. \qquad [2]$$

where RT_{jkt} and RS_{jkt} are the downstream or outflow of turbine and spill discharge from each unit for plant k at time step t and UT_{jkt} and US_{jkt} are the inflows of upstream turbine discharge and spill discharge.

The upper and lower reservoir storage constraint is described as,

$$S^{min}_{kt} <= S_{kt} <= S^{max}_{kt}. \qquad [3]$$

Storage of a reservoir can be expressed as a function of the plant forebay (FB_{kt}), $S_{kt} = f(FB_{kt})$ [4], or alternatively a plant forebay can be expressed as a function of reservoir storage, $FB_{kt}=f(S_{kt})$ [5], which are expressed in the model as piecewise linear function.

4.4.4.2 Modeling Hydropower Generation (Shawwash 2000)

Power generation of unit i in power house n in plant j (G_{inj}), in a function of the gross head (H_{nj}) of power house n, and the turbine discharge (Q_{inj}) of unit I, $G_{inj} = f(H_{nj}, Q_{inj})$. [6] The gross head of a power house is a function of the plants forebay (FB) and its tail water level

TWL_{nj}, $H_{nj}=FB_j-TWL_{nj}$ [7]. The tail water level depends on the plant's total discharge and downstream water level $DSWL_j$,

$$TWL_{nj} = f(f(DSWL_j), \Sigma^{I}_{i=1} \Sigma^{N}_{n=1} QT_{inj}, QS_j, QSF_j). \qquad [8]$$

Where QT, QS and QSF are turbine discharge and spill discharge and fixed spill discharge respectively.

The other complicating factor is that all of the above relationships are a function of the unit availability (C_j) for a given plant load. For this reason an optimal unit commitment assumption had to be made when operating a plant for a given number of available units, forebay level, and plant loading. To derive an optimal unit commitment, a static plant unit commitment program (SPUC) using a dynamic programming algorithm tabulated the optimal plant discharge for each increment in plant loading, forebay, and for each unit availability combination. The objective function of the SPUC is to minimize the plant's total turbine discharge.

The assumption of optimal unit commitment has allowed the use of the SPUC tabulated data to generate a family of piecewise linear curves that accurately describe the plant generation at time step t (G_{jt}) as a function of its forebay level, turbine discharge and unit availability, $G_{jt}=f(FB_{jt}, QT_{jt}, C_{jt})$ [9]. Generation in a plant at time step t is constrained by the minimum (G^{min}_{jt}) and the maximum (G^{max}_{jt}) physical and operational limits,

$$G^{min}_{jt} <= G_{jt} <= G^{max}_{jt}. \qquad [10]$$

Similarly the maximum and minimum total turbine and spill discharge from a reservoir represent the operational and the physical constraints or non-power and legal requirements. Thus for each time step the limits are expressed as

$$Q^{min}_{jt} <= (QT_{jt} + QS_{jt} + QSF_{jt}) <= Q^{max}_{jt}. \qquad [11]$$

Where (Q^{min}_{jt}) and (Q^{max}_{jt}) are minimum and maximum turbine discharge for each unit at each time step.

4.4.4.3 Load Resource Balance (Shawwash 2000)

The generation facilities are usually operated to meet the system firm demand (D_t), pre-scheduled net transactions (PNS_{mt}), net spot sales ($SpotUS_t$ and $SpotAB_t$). In addition, generating facilities are operated to meet real time operational contingencies such as the operating and spinning reserve obligations. An additional set of equations is included to model the ancillary service requirements.

$$\Sigma^{T}_{j=1} G_{jt} + GSim_{st} + GTher_t + \Sigma^{M}_{m=1} PNS_{mt} + SpotUS_t + SpotAB_t = D_t \qquad [12]$$

4.4.4.4 Import/Export transfer capacity (Shawwash 2000)

The import/export transfer capability reflects the tie line maximum and minimum available transfer capability for imports/exports to the US market ($USTie^{Max}_t$, $USTie^{Min}_t$) and to the Alberta market ($ABTie^{Max}_t$, $ABTie^{Min}_t$) for each time step as follows,

$$USTie^{Min}_t <= SpotUS_t <= USTie^{Max}_t \qquad [13]$$

$$ABTie^{Min}_t <= SpotAB_t <= ABTie^{Max}_t . \qquad [14]$$

4.4.5 The REOM Mathematical Formulation

As discussed in the previous section, the mathematical formulation of the ROEM model is identical to the STOM formulation, except for the following equations of the PATH and the COMBO methods.

4.4.5.1 The REOM Mathematical Formulation Based on PATH Method

The following subsections outline the modified equations in REOM compared to the STOM model for the path method:

a. The piecewise linear generation production function, equation [9], for a hydro plant j was modified to include the unit commitments (C_{ktp}) for paths p at time-step t:

$$G_{kt}=\Sigma_{p}^{P} f(FB_{jt}, QT_{jt}, C_{jtp}), \qquad [15]$$

where the optimal plant generation at time-step t (G_{jt}) depends on the plants forebay level (FB_{jt}), turbine discharge (QT_{jt}) and unit commitments for the optimal path. The summation over the paths for each time step selects the optimal path. Equations [16] and [17] set the plant generation and the turbine discharge to zero for all other paths, respectively and therefore the only optimal path is selected as the optimal solution.

b. The upper and lower bounds on plant generation at time-step t represent the minimum generation limit ($G^{Min}{}_{jtp}$) and the maximum plant generation limit ($G^{Max}{}_{jtp}$) for potential paths p such that

$$\Sigma_{p}^{P} PS_{tp} *G^{Min}{}_{jtp} \leq G_{jt} \leq \Sigma_{p}^{P} G^{Max}{}_{jtp} *PS_{tp}, \qquad [16]$$

where PS_{tp} is a binary variable that selects the optimal path p for each time-step t.

c. The upper and lower bounds on turbine discharge at time-step t represent the minimum turbine discharge limit ($QT^{Min}{}_{jtp}$) and the maximum turbine discharge limit ($QT^{Max}{}_{jtp}$) for potential paths p such that

$$\Sigma_{p}^{P} PS_{tp} *QT^{Min}{}_{jtp} \leq QT_{jt} \leq \Sigma_{p}^{P} QT^{Max}{}_{jtp} *PS_{tp}, \qquad [17]$$

d. A new constraint that restricts the sum of the binary variables, PS_{tp}, in each time-step to 1 is also added to the model:

$$\Sigma_p^{P} PS_{tp} = 1. \quad [18]$$

This constraint ensures that only one path is selected in the optimization process as the optimal path.

e. A new constraint representing the net transfer capability equation is added in the path method to calculate the transfer potential of the B.C. Hydro network at each time step and for all potential path p. The constraint incorporate the prescheduled import/export to U.S. and Alberta and spot value of U.S. and Alberta sales, plus the import and export from other generators such as ALCAN, West Kootney, etc.

$$BCUS\text{-}Net_t + SpotUS_t + BCAB\text{-}Net_t + SpotAB_t - (0.1*0.75*D_t) + ALCAN_t +$$
$$WANITA_t >= \Sigma_p^{P} (NetBCHT_{t,pl} * PS_{tp}) \quad [19]$$

where NetBCHT is Net Transfer Capability of the BC Hydro system, which is calculated from table (4.1) as a function of the system Load and System Rotational Energy. BCUS_Net is the prescheduled import and export for each time step. $(0.1*0.75*D_t)$ is the value of the West Kooteney power plant and ALCAN and WANITA are the valu of the prescheduled generation for the two power plants.

4.4.5.2 The REOM Mathematical Formulation of the COMBO Method

The following subsections outline the modified equations in REOM compared to the STOM model for the combo method:

a. The upper and lower bounds on plant j generation at time-step *t* represent the minimum plant generation limit (G^{Min}_{jtc}) and the maximum plant generation limit (G^{Max}_{jtc}) for each feasible unit combination (combo) *c* such that

$$\Sigma^{T}_{j}(\Sigma_c PS_{tjc} * G^{min}_{tjc}) \leq G_{tj} \leq \Sigma^{T}_{j}(\Sigma_c PS_{tjc} * G^{min}_{tjc}), \quad [20]$$

where PS_{tjc} is a binary variable that selects the optimal combo c for each plant and time-step t.

b. The upper and lower bounds on plant j turbine discharge at time-step t represent the minimum turbine discharge limit (QT^{Min}_{jtc}) and the maximum turbine discharge limit (QT^{Max}_{jtc}) for each combo c such that

$$\Sigma^{T}_{j}(\Sigma_{c} PS_{tjc} * QT^{min}_{tjc}) \leq QT_{tj} \leq \Sigma^{T}_{j}(\Sigma_{c} PS_{tkc} * QT^{min}_{tjc}), \qquad [21]$$

where PS_{tjc} is a binary variable that selects the optimal combos c for each time-step t.

c. A constraint that restricts the sum of the binary variables for each plant, PS_{tjc}, in each time-step to 1 is also added to the model:

$$\Sigma_{c}^{C} PS_{tjc} = 1, \qquad [22]$$

d. A new constraint representing the net transfer capability equation is added in the combo method to calculate the transfer potentials of the whole network at each time step. The following equation contains the fixed import/export to the US and the Alberta and the spot US and Alberta sales, plus import and export from other generators such as the ALCAN, West Kootney, etc.

$$BCUS\text{-}Net_{t} + SpotUS_{t} + BCAB\text{-}Net_{t} + SpotAB_{t} - (0.1*0.75*D_{t}) + ALCAN_{t} + WANITA_{t} >= (NetBCHT_{t}) \qquad [23]$$

where NetBCHT is Net Transfer Capability of the BC Hydro system, which is calculated from table (4.1) as a function of the system Load and System Rotational Energy.

4.5 Objective Function

For hydroelectric systems with significant multi-year storage, the REOM objective function represents the optimal trade-off between present benefits, expressed as revenues from spot energy transactions, and the potential expected long-term value of resources, expressed as the marginal value of water stored in reservoirs. The objective function of REOM is identical to STOM objective function:

Max:

$$\Sigma_t^T SpotUS_t * USPrice_t + \Sigma_t^T SpotAB_t * ABPrice_t + \Sigma_k^K (S_{jT} - Starget_{jT}) * MVW_j, \quad [24]$$

The first and second terms represent the sum of revenues/costs accrued from spot energy exports and imports for each time step, given forecast hourly export spot prices in the U.S. and Alberta markets (US Price, AB Price) in \$/MWHr. The third term represents the sum of storage cost (or added storage value) of deviating from the terminal target storage level for reservoir j (STargetj_T) at target hour (T). For each optimized reservoir, multiplying the difference between the optimized storage at target hour (S_{jT}) and the target storage ($Starget_{jT}$) by the marginal value of water (MVW_j), in \$/m3, yields its storage cost (or added storage value). The marginal value of water and the target storage for each reservoir are derived from other long and medium term optimization models, as shown in Figure 4.7.

In STOM, there are four kinds of objective functions for the optimization study: maximizing efficiency, minimizing the cost of the water use, maximizing the value power production for a given storage at a given target level, and maximizing the value of resources. The objective function in REOM is the same as the last objective function in STOM, which maximizes the value of resources. The rotational energy of the system directly influences the amount of the net transfer capability of the transmission system, and therefore, it will impact the value of the spot sales to the U.S. and Alberta and the value of additional water stored in reservoirs in the objective function.

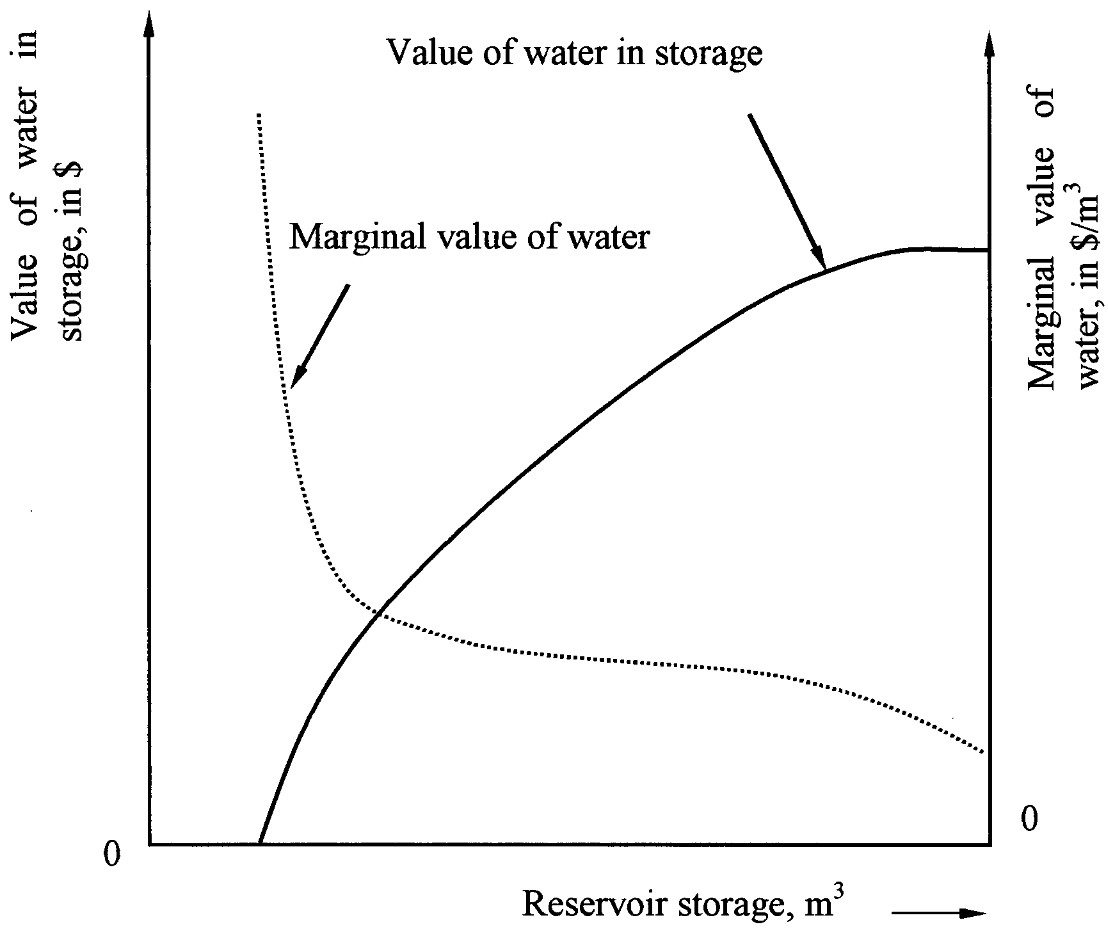


Figure 4.7 – Value of water in storage and marginal value of water for time step t

(Source; Shawwash 2000)

CHAPTER 5

RESULTS AND DISCUSSION

In this chapter, the results of running the Rotational Energy Optimization Model (REOM) for the PATH and COMBO methods are numerically and graphically illustrated. Then, results of the PATH and the COMBO methods with/without Elimination Algorithm (EA) are compared, and the rational for selecting the combo method with EA as the more efficient solution method are discussed. Then the results of the Short Term Optimization Model (STOM) and the REOM systems including the effect of the SRE constraint on the optimized forebay and generation scheduling and spot energy to U.S. and Alberta schedules are compared. The preprocessor modules are outlined in detail, and the implementation of the preprocessor output in the model is explained.

5.1 Case Studies

To illustrate the results of running REOM, a number of 24-hour postmortem studies for four months in 2002 were prepared. The Hydro plants used in these studies have: G. M. Shrum (GMS), a 2,730 MW Hydro power plant with ten units of three different types; Peace Canyon (PCN), a 700 MW Hydro power plant with four similar units; Mica (MCA), a 1,780 MW plant with four similar units and the Revelstoke (REV), a 2,000 MW hydro power plant with four similar units.

The data sets were prepared for a 24-hour study for the months of March, April, May, and June 2002. The operational input data were retrieved from the B.C. Hydro postmortem data sets. Additional data sets on market prices and the actual available transfer capabilities for the U.S. and the Alberta ties were retrieved from Bonnievile Power Administration (BPA) and from the Alberta Power pool web pages and from PowerEX Ltd.

The months of March, April, May and June were selected to show the performance of REOM during periods when the B.C. Hydro system is usually in import mode. These months represent the end of the winter and they extend over spring until the beginning of summer. In winter, the energy demand in B.C. is usually high, and in contrast, demand in the western US is rather low. On the other hand, during summer the demand of energy in B.C. is low and in the Southern U.S. is high. The discrepancy in demand directly influences the energy prices in the Pacific North West. Figure 5.1 compares a typical 24-hour B.C. Hydro load during the winter and summer times, and Figures 5.2 and 5.3 compares the hourly spot electricity prices in the U.S. and the Alberta markets.

Another factor that may differentiate this period from the rest of the year is the inflows to the reservoirs. In winter , and because of the very cold weather conditions in the Northern part of B.C., all precipitations fall as snow and rivers are usually frozen. During spring and early summer most of the accumulated snow in winter starts to melt and flow in rivers. Figures 5.4 and 5.5 illustrate the inflows to the Williston and the Kinbasket reservoirs, the two largest reservoirs in the B.C. Hydro system.

Prices are also different in winter and summer times. Figure 5.2 and 5.3 illustrate the volatility of the spot prices in winter and summer in the US and Alberta.

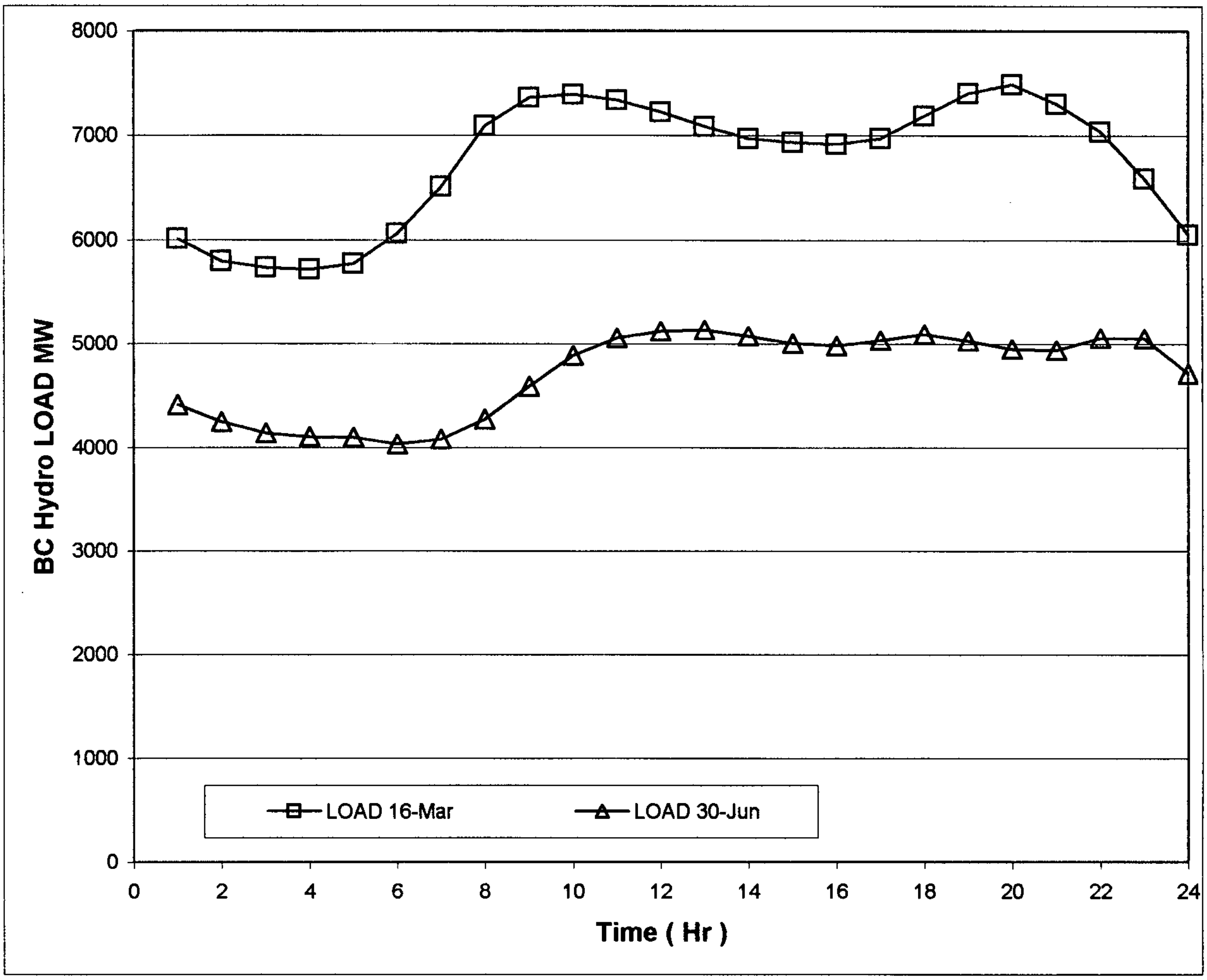


Figure 5.1 – B.C. Hydro LOAD shape for winter and summer times (B.C. Hydro 2002)

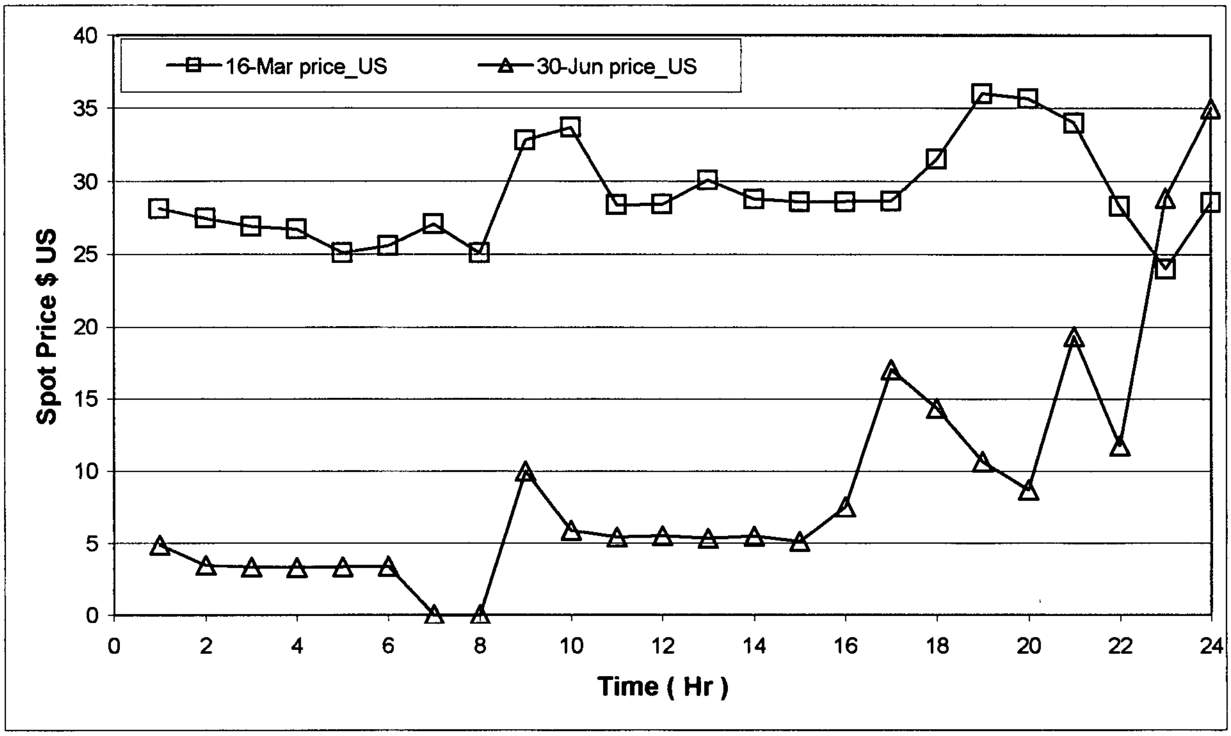


Figure 5.2 – Volatility of Prices in Winter time vs. Summer time for U.S. Market (B.C. Hydro 2002)

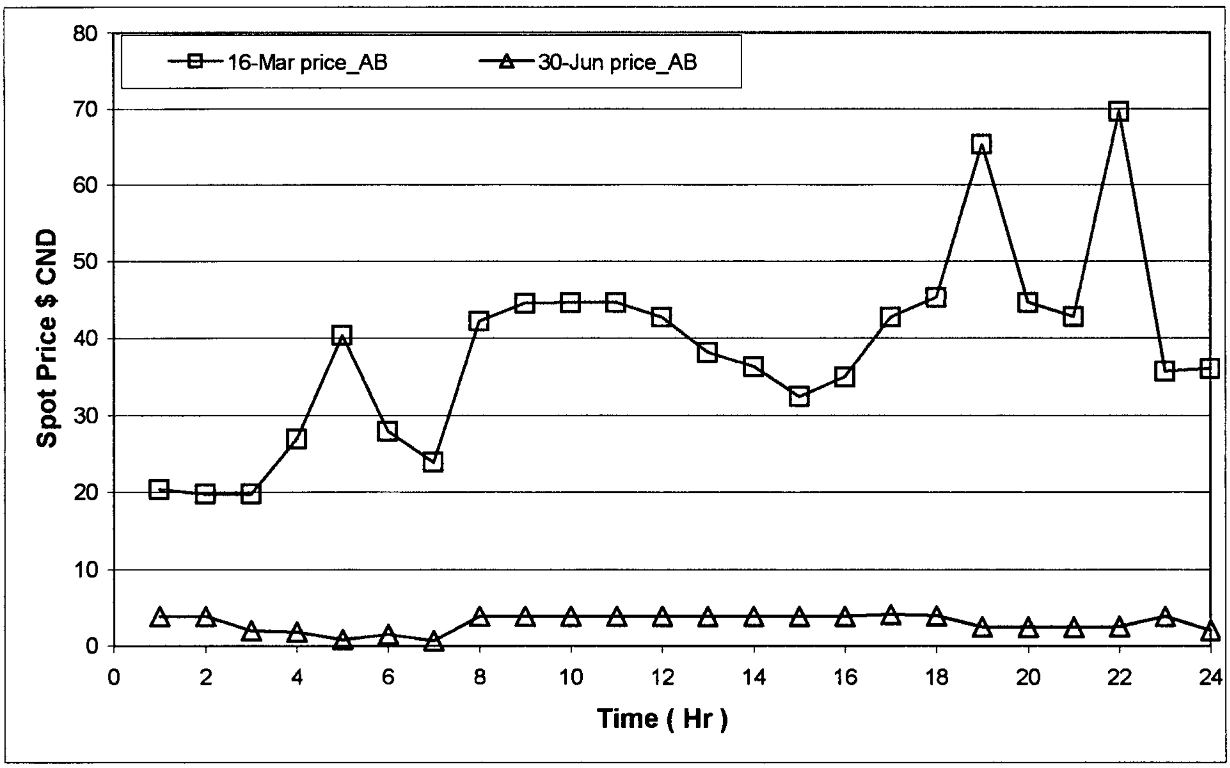


Figure 5.3 – Volatility of Prices in Winter time vs. Summer time for Alberta Market (B.C. Hydro 2002)

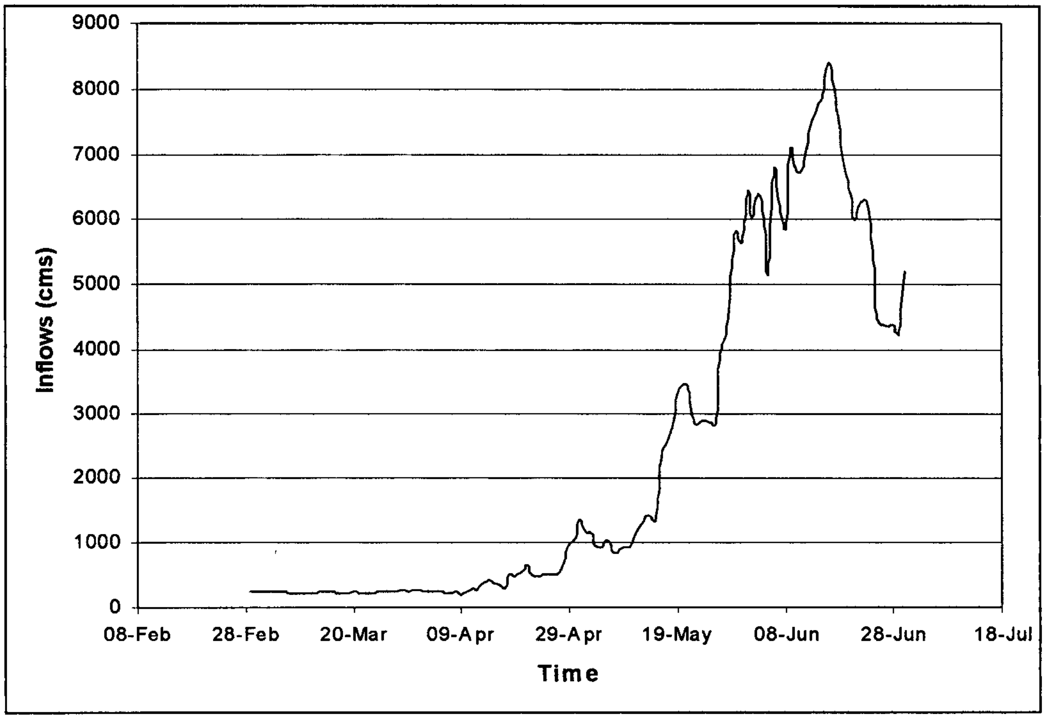


Figure 5.4 – Williston Inflows (cms) for beginning and end of the study duration (B.C. Hydro 2002)

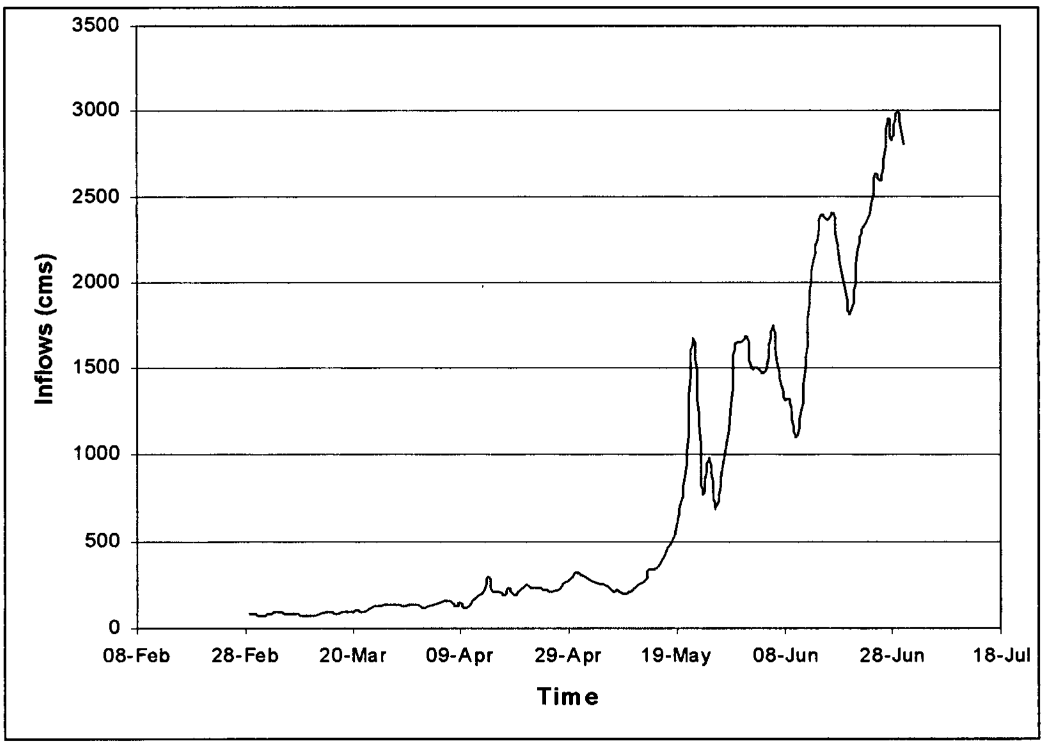


Figure 5.5 – Kinbasket Inflows (cms) for beginning and end of the study duration (B.C. Hydro 2002)

5.2 Results of the Path and the Combo with/without EA Methods

In this section, the results of the PATH and the COMBO with and without Elimination Algorithm (EA) methods are discussed. This is followed by a discussion on why the COMBO with EA method was selected as the more efficient method to solve the optimization problem. Then, the results of applying the Elimination Algorithm (EA) in the COMBO method is illustrated and compared with the case without EA and PATH methods.

5.2.1 Results of the Path and Combo with and without the Elimination Algorithm

To illustrate the results of the path and the combo methods, the optimal solution configurations consisting of the number of variables and constraints for the three methods are compared. Then, the outputs of the optimization problem for the three methods are tabulated, and then the process of selecting one of the three methods as the preferred methode is elaborated. Five dates were randomly selected in order to illustrate the difference between the PATH and the COMBO with/without EA methods.

5.2.1.1 The REOM Mathematical Formulation of the COMBO Method

Running the REOM with three different methods of formulating and indexing the variables and constraints in the path method and the COMBO with/without EA methods resulted in three different solution configurations. Table 5.1 lists the type of the compared. One of the main parameters is the value of the Objective Function, and it can be observed that, the value of the Objective Functions for both PATH and COMBO without EA methods are practically the same for each study. This indicates that formulating the problem by either method has no influence on the final result of the optimization problem. In optimization problems, the number of variables and constraints indicate that the size of the problem. It can be seen in Table 5.1 that the time it takes to solve the problem using the COMBO method with Elimination Algorithm is much less than that using the path method and COMBO without EA, and the main reason for this is the fact that there are fewer binary variables and constraints in the COMBO with EA formulation.

Table 5.1 – Optimal solution configuration for path and combo methods

Study Date	Method	Objective Functions	Timing (seconds)			Total #of Variable	Variable type		Total # of Constraints
			Input	Solve	Output		Binary	Linear	
15-Mar	PATH	45480.6	0.01	2	0.02	1440	612	828	783
	COMBO	45487.0	0.02	15.5	0.02	1370	336	1034	1017
	COMBO_EA	46303.9	0.01	0.13	0.01	976	210	764	578
17-Apr	PATH	112963.7	0.05	124.50	0.3	58288	57408	880	782
	COMBO	112960.3	0.02	12.3	0.02	2063	921	1142	1188
	COMBO_EA	112964.2	0.01	0.04	0.01	1503	695	808	631
12-May	PATH	116509.1	0.17	601.2	0.12	18254	17361	893	808
	COMBO	114651.3	0.02	360.0	0.03	1947	801	1146	1193
	COMBO_EA	139542.6	0.01	80.3	0.02	1639	692	947	846
17-May	PATH	504188.2	0.24	9.28	0.14	25746	24840	906	807
	COMBO	504236.3	0.01	105.80	0.02	2041	872	1169	1214
	COMBO_EA	505910.1	0.01	6.589	0.02	1647	729	918	770
5-June	PATH	55577.4	0.11	600.96	0.08	11474	10670	804	782
	COMBO	56482.0	0.02	180.24	0.02	1836	775	1061	1158
	COMBO_EA	57740.3	0.01	3	0.01	1322	590	732	593

As discussed in Chapter 4, the Elimination Algorithm (EA) recognizes the time steps in which the sum of the minimum U.S. and Alberta transmission limits is greater than the Net B.C. Hydro Transfer Capability at each time step and then automatically removes the indexing of variables and constraints over the available unit combinations for the corresponding time step. Table 5.2 indicates that the size of the optimization problem is considerably smaller when EA is used. EA reduces the number of binary variables and the number of constraints considerably and accordingly accelerates the solution process of the optimization problem. It can be thus concluded that using the combo with EA method will yield a smaller problem size and will require less time to solve the optimization problem.

The objective function and the other problem elements are very similar in both PATH and COMBO without EA. The reason for the difference of objective function in PATH and COMBO without EA with COMBO with EA is that, the model uses different sets of transfer capability limits and plant minimum and maximum generation limits. The calculated net transfer capability limit is used as a constraint for transfer capability of the network in both the PATH and the COMBO without EA method. In COMBO with EA, the model calculates the net transfer capability and compares it with the minimum tie limits for the US and Alberta and select the higher limits for the constraint and use them in the optimization model. Therefore, the model can solve the optimization problem more quickly because the number of variables and constraints are less.

5.2.1.2 Selecting the Combo with EA Method as preferred Method

Table 5.1 was used as reference in determining which method is more efficient to solve the optimization problem. The number of variables in REOM depends on the unit combinations derived by the expert system. If more unit combinations are available at each time step for each plant, the number of variables will increase, and will directly influence the time it will take to solve the problem.

It was observed that, for a small number of variables, the time it takes to solve the problem using the path method is less than the combo method (e.g., March in Table 5.1). In contrast, if the number of unit combinations at each time step for each plant is high, then the number of binary variables for the PATH method increases rapidly. Since the number of binary variables for the PATH method increases much more than the COMBO without EA method, the time it will take to solve the problem will increase accordingly as can be clearly seen in Table 5.1.

The COMBO with EA method is selected as a better method compared to the PATH method and COMBO without EA, the COMBO with EA method takes much less time when solving problems that have large number of variables and constraints.

5.3 STOM and REOM Results

In this section, the output of the preprocessor is discussed. Then, the values of the Objective Function for the STOM and the REOM are provided, and the results of the optimal solution derived from each model are compared. The System Generation scheduling summary is included in this section as well, and the optimization solution configurations for the STOM and the REOM are listed.

5.3.1 The Optimization Preprocessor

As in other large-scale optimization models, the REOM System has large data sets. The data required for the REOM model are extracted from several sources. For the case studies used in this research, the raw data sets were obtained from the archived postmortem data sets for the year 2002. The raw data were passed to the hydraulic simulation model to prepare the optimization model inputs. The simulation model provides the required data on spills, inflows, turbine discharge limits, generation limits, forebay limits and all other required data sets needed for the optimization process in appropriate formats. The preprocessor is then invoked to provide other inputs needed for the REOM System. In this section, preparation of the unit combinations by the optimization preprocessor and calculation of the total rotational energy for each time step are discussed. Then, the procedure used to calculate the Net B.C. Hydro Transfer Capability is described. Finally, the Elimination Algorithm (EA) preprocessor component is outlined.

5.3.1.1 Unit Combination

In most large hydro power plants, the physical and operational characteristics of the units are not the same. Usually two or more unit types are installed. This variation in unit types usually helps the operator to run the plant more efficiently. For instance, the GMS plant is the largest hydro power plant in B.C. with 10 units of three different unit types. The variation in unit types produces a large number of possible unit combinations of units online at each time step. It should, however, be noticed that since some or all units in a power plant are of the same type, then there will be some unit combinations that contain the exact properties of the combinations and these similar combos can therefore be eliminated.

To accelerate the solution process, the optimization preprocessor uses an expert system to eliminate all in-feasible, undesirable and similar unit combinations. The Expert System screens for all feasible combinations based on unit capacity, efficiency margins, must-run requirements, spinning reserve requirements and Synchronous Condense (S/C) requirements. Figure 5.6 illustrates the efficiency of the Expert System in eliminating infeasible unit combinations based on the above criteria. Table 5.2 illustrates the results of the number of unit combination before and after running the preprocessor.

Table 5.2 – Number of unit combinations before and after expert system screening

Date	Time Step	GMS		PCN		MCA		REV	
		Before	After	Before	After	Before	After	Before	After
15-MARCH-02	1	1023	64	15	4	15	9	15	5
	2	1023	64	15	4	15	9	15	5
	3	1023	64	15	4	15	9	15	5
	4	1023	64	15	4	15	9	15	5
	5	1023	64	15	4	15	9	15	5
	6	1023	64	15	4	15	9	15	5
	7	1023	64	15	4	15	9	15	5
	8	1023	64	15	4	15	9	15	5
	9	1023	40	15	4	15	9	15	5
	10	1023	40	15	4	15	9	15	5
	11	1023	40	15	4	15	9	15	5
	12	1023	40	15	4	15	9	15	5
	13	1023	40	15	4	15	9	15	5
	14	1023	40	15	4	15	9	15	5
	15	1023	40	15	4	15	9	15	5
	16	1023	40	15	4	15	9	15	5
	17	1023	64	15	4	15	9	15	5
	18	1023	64	15	4	15	9	15	5
	19	1023	64	15	4	15	9	15	5
	20	1023	64	15	4	15	9	15	5
	21	1023	64	15	4	15	9	15	5
	22	1023	64	15	4	15	9	15	5
	23	1023	64	15	4	15	9	15	5
	24	1023	64	15	4	15	9	15	5

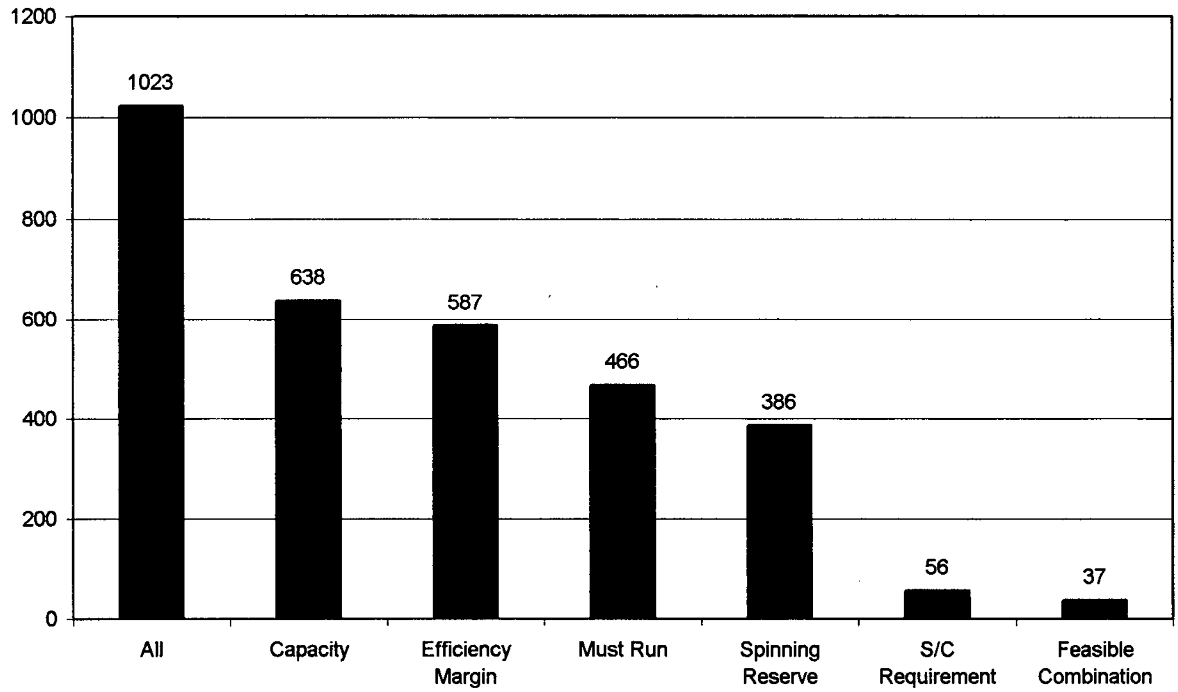


Figure 5.6 – Performance of the Expert System in Eliminating Infeasible Unit Combinations

5.3.1.2 Total Rotational Energy

The total maximum rotational energy is the summation of the rotational energy for each unit online for each plant that is included in the optimization study, plus the rotational energy for all other generating units in the B.C. Hydro system. The preprocessor reads all the feasible unit combinations derived by the Expert System module and calculates the values of the rotational energy for each unit and for each plant, and then it calculates the total rotational energy for each plant in the study for each feasible unit combination at each time step. The calculated rotational energy values for each plant in the study and the rotational energy for all other plants in the B.C. Hydro network (REOTH) at corresponding time steps are then added to calculate the maximum System Rotational Energy. Table 5.3 illustrates the maximum System Rotational Energy calculation procedure for March 15th for available units.

Table 5.3 – Total Rotational Energy calculations

Date	Time Step	Power Plant	Unit Combo	Spec.	Units Available										RE Other	Total RE
					U1	U2	U3	U4	U5	U6	U7	U8	U9	U10		
15-MARCH-02	3	GMS	1007	R. E.	1195	1195	1195	1195	1195	1264	1264	1264	1356	1356	17754	48289
				Status	ON	ON	ON	ON	OFF	ON	ON	ON	ON	ON		
		PCN	14	R. E.	1108	1108	1108	1108	-	-	-	-	-	-		
				Status	OFF	ON	ON	ON	-	-	-	-	-	-		
		MCA	14	R. E.	2865	2865	2865	2865	-	-	-	-	-	-		
				Status	OFF	ON	ON	ON	-	-	-	-	-	-		
		REV	7	R. E.	2444	2444	2444	2444	-	-	-	-	-	-		
				Status	ON	ON	ON	OFF	-	-	-	-	-	-		

5.3.1.3 Net B.C. Hydro Transfer Limit

The next step in the preprocessor algorithm is to calculate the Net B.C. Hydro Transfer Limit. As indicated in Chapter 4, the Net Transfer Limit can be calculated from Table 4.1, prepared by B.C. Hydro, and it depends on the values of the System Rotational Energy and the B.C. Hydro System Load. The preprocessor calculates the transfer limit using piece-wise linear functions in two steps. In the first step, it calculates a set of values for the transfer limit based on the system load and for a range of rotational energy values. In the second step, it calculates the minimum Net Transfer Limit for each time step based on the given maximum System Rotational Energy. Table 5.4 shows the values of the Net B.C. Hydro Transfer Limit (N.B.C.H.T.L) for the 24 hours time step on 15th of March 2002.

Table 5.4 – Values of System Load and maximum System RE and minimum N.B.C.H.T.L for15th of March 2002

Time step	LOAD	TOTAL_RE	REOTH	N.B.C.H.T.L
1	5635	38461	10142	-3039.6
2	5459	36282	12851	-3104.4
3	5390	39990	16559	-3175.2
4	5405	48289	17754	-2765.5
5	5444	37995	14564	-3180.3
6	5708	42883	14564	-3120.1
7	6310	44064	15745	-3014.2
8	7082	42030	13711	-2973.1
9	7321	39597	11278	-2937.0
10	7340	39597	11278	-2940.5
11	7280	37331	9012	-2936.0
12	7151	40196	11877	-2927.3
13	7143	40196	11877	-2927.7
14	7101	43061	14742	-2923.5
15	7025	42792	14473	-2917.8
16	7014	38886	15455	-2918.0
17	7098	40489	17058	-2922.3
18	7330	38955	15524	-2939.7
19	7579	40799	12480	-2958.4
20	7576	43485	15166	-2956.2
21	7407	43307	14988	-2941.5
22	7075	45993	17674	-2970.6
23	6780	40937	17506	-3003.5
24	6334	39872	16441	-3092.0

5.3.1.4 Elimination Algorithm Preprocessor

The Elimination Algorithm recognizes the time steps in which the minimum Net Transfer Limit at each time step is less than the sum of the minimum U.S. and Albert transmission limits. In this study, the values of the minimum transmission capacity were retrieved from the existing Data Base at BC Hydro. The minimum Net Transfer Limit is then calculated by applying piecewise linear functions based on the system load at the corresponding time step and also the maximum value of the system rotational energy. The maximum system rotational energy is the total plant rotational energy when it is in the must-run mode of operation for the plants in the study plus the rotational energy of all other plants in the B.C. Hydro generation system. Table 5.5 shows the summary results of the preprocessor module using the Elimination Algorithm. The final output of the preprocessor in this step is a data file that contains the Elimination Factors. The Elimination Factor is a binary variable for each time step and it signals if the max Net Transfer Limit will prevail as the import limit for that time step or if the min transmission capacity for U.S. and Alberta will be the dominant constraint at the corresponding time step.

Table 5.5 – Elimination Algorithm Factor

Time Step	LOAD	TOTAL RE	U.S._tran_min	AB_tran_min	N.B.C.H.T.L	EA Factor
1	5635	38461	-2000	-225	-3039.63	1
2	5459	36282	-2000	-300	-3104.43	1
3	5390	39990	-2000	-375	-3175.25	1
4	5405	48289	-2000	-375	-2765.53	0
5	5444	37995	-2000	-375	-3180.3	1
6	5708	42883	-2000	-300	-3120.1	1
7	6310	44064	-2000	-150	-3014.25	1
8	7082	42030	-2000	-50	-2973.15	1
9	7321	39597	-2000	0	-2937.08	1
10	7340	39597	-2000	0	-2940.5	1
11	7280	37331	-2000	0	-2936	1
12	7151	40196	-2000	0	-2927.33	1
13	7143	40196	-2000	0	-2927.73	1
14	7101	43061	-2000	0	-2923.58	1
15	7025	42792	-2000	0	-2917.88	1
16	7014	38886	-2000	0	-2918.05	1
17	7098	40489	-2000	0	-2922.35	1
18	7330	38955	-2000	0	-2939.75	1
19	7579	40799	-2000	0	-2958.43	1
20	7576	43485	-2000	0	-2956.2	1
21	7407	43307	-2000	0	-2941.53	1
22	7075	45993	-2000	-50	-2970.63	1
23	6780	40937	-2000	-100	-3003.5	1
24	6334	39872	-2000	-225	-3092.05	1

In Table 5.5, the results for 17^{th} of May 2002 are selected to demonstrate the performance of the Elimination Algorithm. In this table, the EA factors for hour 4 is 0, which means that in this time step the Net Transfer Limit will prevail. These factors are also used to determine if the generation and discharge constraints in the model will be indexed over the feasible combinations. In addition, the Net B.C. Hydro Transfer limit is activated when the EA Factor is equal to 0.

5.3.2 Optimized Results of STOM and REOM

In this section, the optimized results of STOM and REOM are presented and discussed. It starts with a description of the Objective Function values obtained from running the STOM and the REOM models. Then, the forebay elevations in four major plants in B.C. Hydro System are compared. This is followed by a comparison of the STOM and REOM system for generation schedules spot energy U.S. and spot energy Alberta. Then, unit commitment results are demonstrated and compared for these two different models. Finally, the System Generation Schedule Summary is illustrated, and the optimal solution statistics, such as the problem solving time length and the size of the optimization problem, are tabulated across the studies used in this research.

5.3.2.1 Objective Function

The Objective Function output is the most important parameter for evaluating the model performance. The Objective Function for REOM is used to maximize the value of the B.C. Hydro resources by finding the trade-off between the value of imports from U.S. and Alberta and the additional water stored in the reservoirs. The REOM objective function maximizes the sum of Import and Export energies as Spot energy to U.S. and Alberta and the additional value of the stored water in the reservoirs. In Table 5.6, the Objective Function values for the STOM and the REOM are compared. The difference between the Objective Function values determines the trade-off between the value of the imported energy and the value of additional water stored in reservoirs. In some case studies, the values of the Objective Function for the STOM and the REOM are the same or are very close. This happens when the values of the minimum U.S. and Alberta transmission limits are low. In these cases, the summation of the minimum values of the transmission limits for U.S. and Alberta are lower than the Net B.C. Hydro Transfer Limit. As it can be noted from this table, in some cases the value of the Objective Function in REOM is less than the value of the Objective Function in STOM. This happens when the Spot energy to US and Alberta limits are constrained with the Net BC Hydro Transfer capability limit instead of the Tie limits in STOM. In these cases, Net Transfer Capability is less than the tie limits and therefore the importing and exporting to or from the US and Alberta market place are less than STOM, so, the value of the gain is lower. In the other words, the REOM model will yield the cost of applying the Rotational energy constraints.

Table 5.6 – Objective Function values for STOM and REOM

Date	Objective Function		Gain or Cost	Description
	STOM	REOM		
15-Mar-02	61422.3	46304.0	-15118.3	cost
17-Apr-02	109395.5	112964.5	3569	gain
12-May-02	156308.0	139542.6	-16765.4	cost
17-May-02	505154.5	505910	755.5	gain
5-Jun-02	57973.6	57740.3	-233.3	cost

5.3.2.2 Forebay Elevation, Generation and Spot U.S. Results

In this section, the variation of the forebay level and generation scheduled for the two major hydro power plants in the B.C. Hydro System are discussed. This is followed by an illustration of the optimized import and export to the U.S. and the Alberta, results derived by STOM and REOM. Figures 5.7 to 5.18 illustrate the variation in water level and generation in GMS and MCA power plants and spot U.S. and spot Alberta for one case study for the STOM and the REOM.

For the case study of March 15, 2002, the REOM system recommends generation at some time steps a reduction in GMS, resulting in more water storage in the GMS reservoir. In MCA, however, generation is increased in peak hours and in the next time steps generation is the same as STOM. Therefore, water level in MCA reservoir is dropped down. Spot US, however, did not change as compared to STOM results, while Spot Alberta in REOM imported more than STOM model, due to low spot price levels.

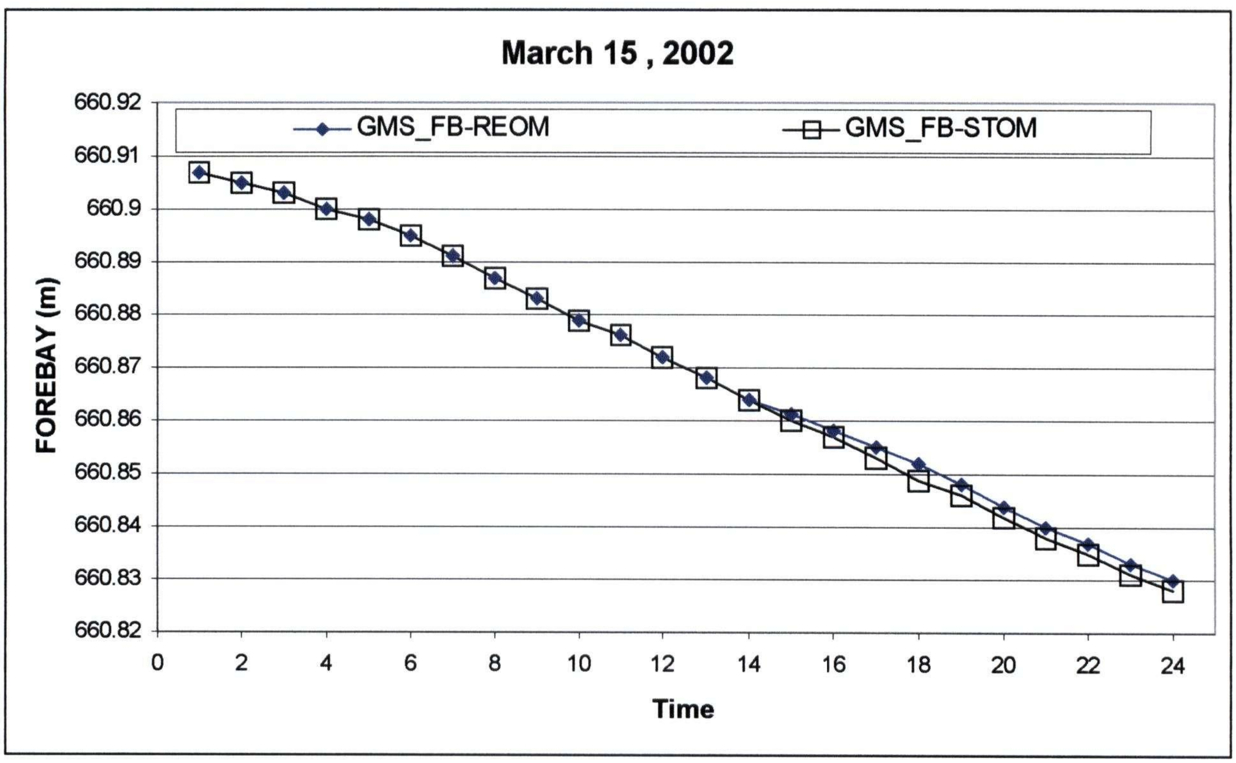


Figure 5.7 – GMS Forebay Elevation results for March 15, 2002

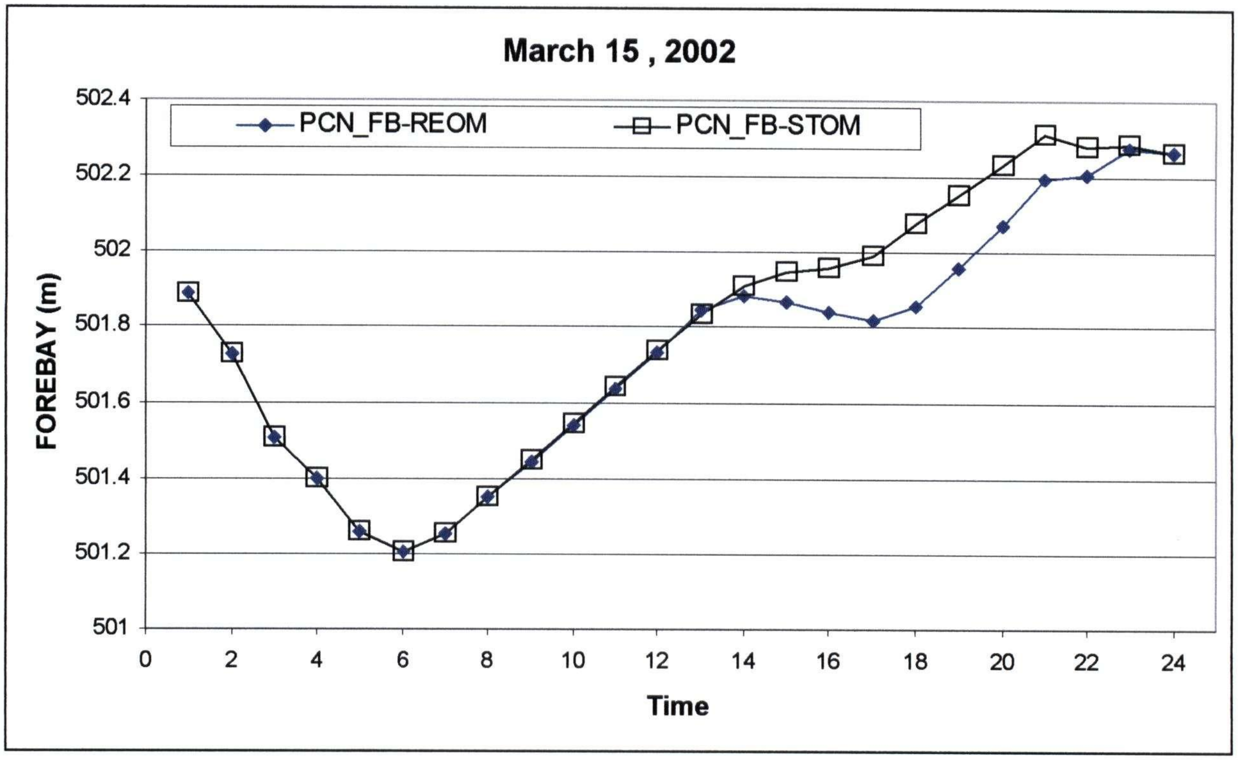


Figure 5.8 – PCN Forebay Elevation results for March 15, 2002

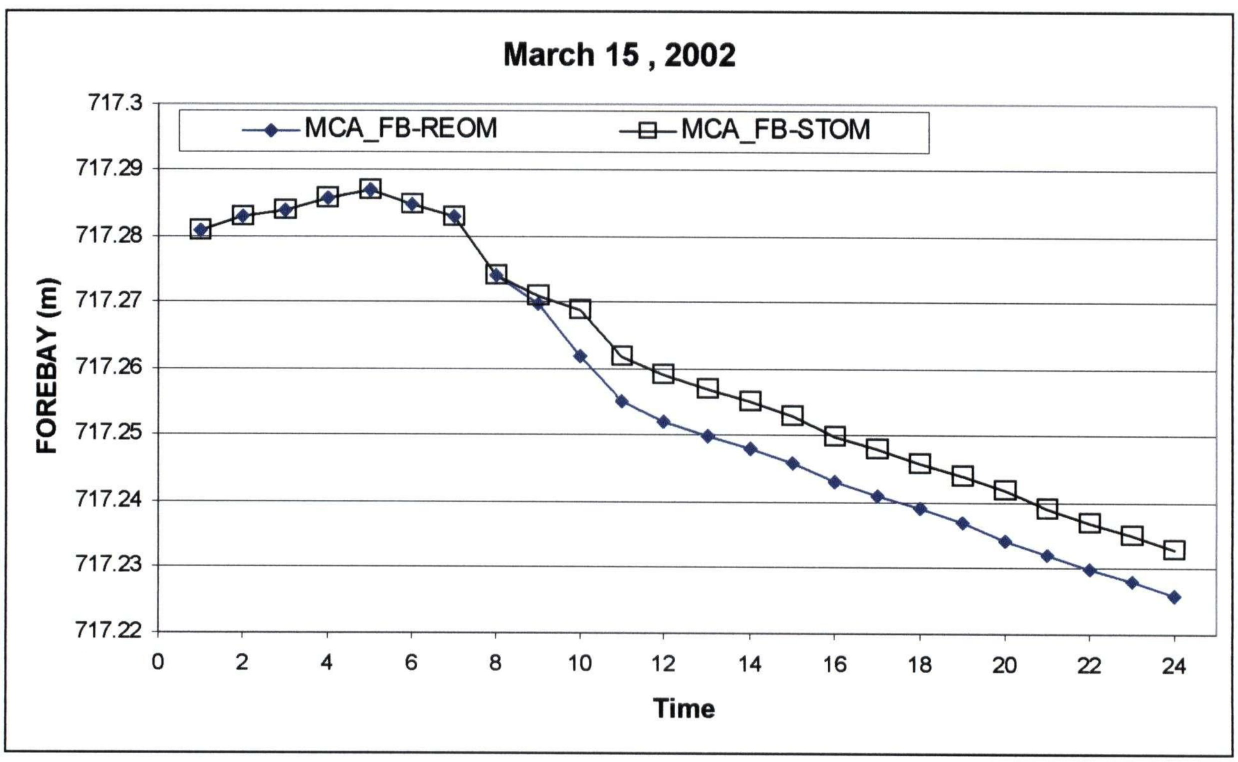


Figure 5.9 – MCA Forebay Elevation results for March 15, 2002

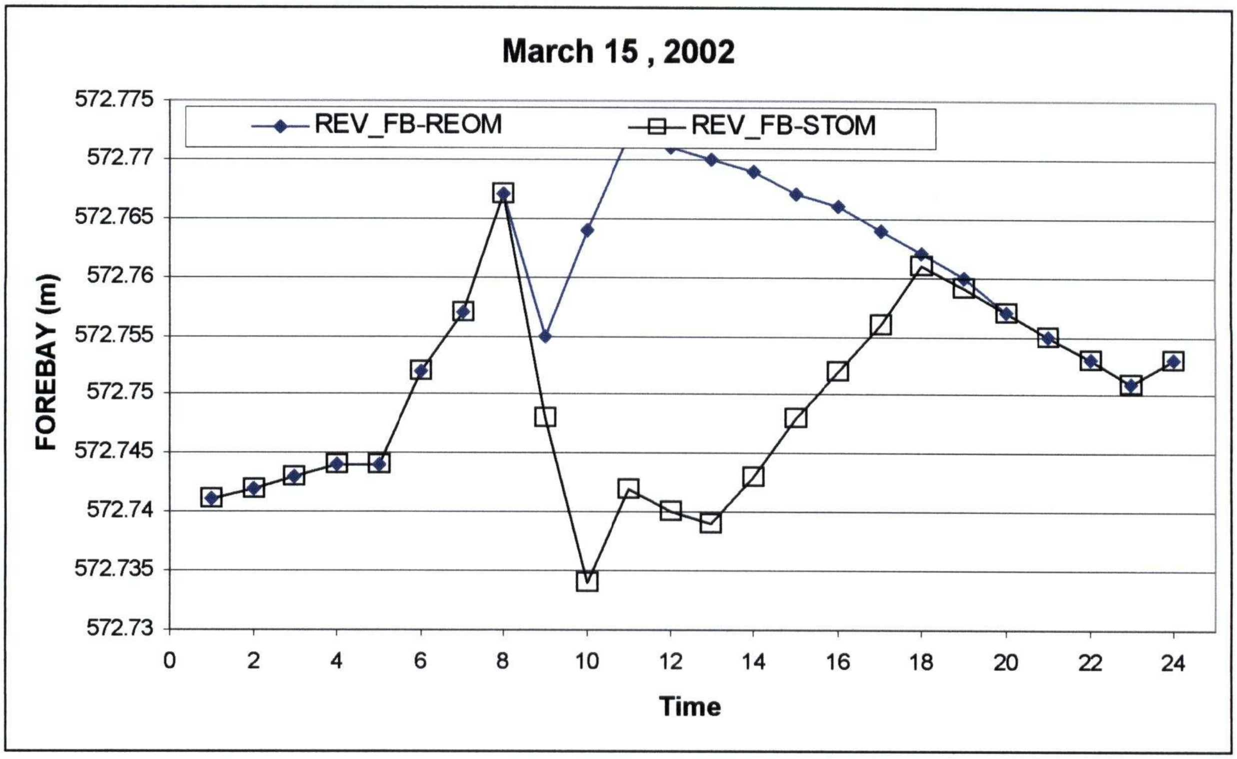


Figure 5.10 – REV Forebay Elevation results for March 15, 2002

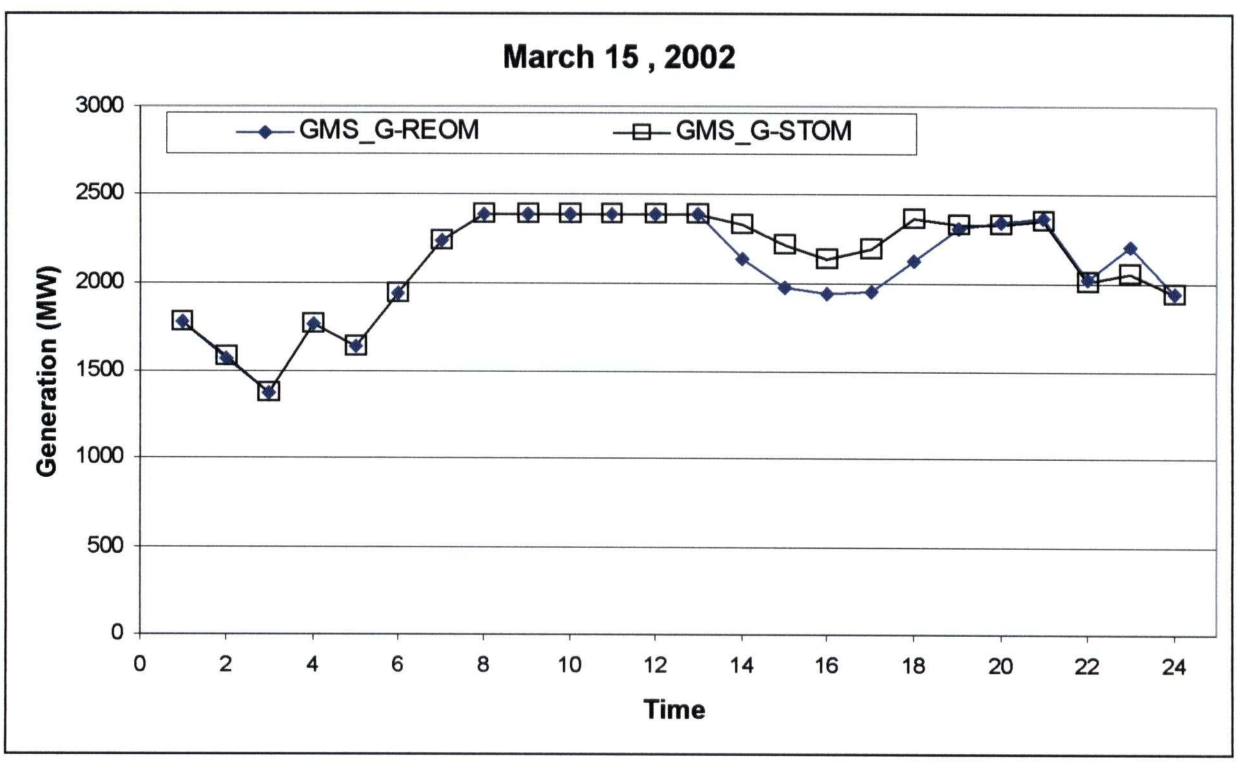


Figure 5.11 – GMS Generation for March 15, 2002

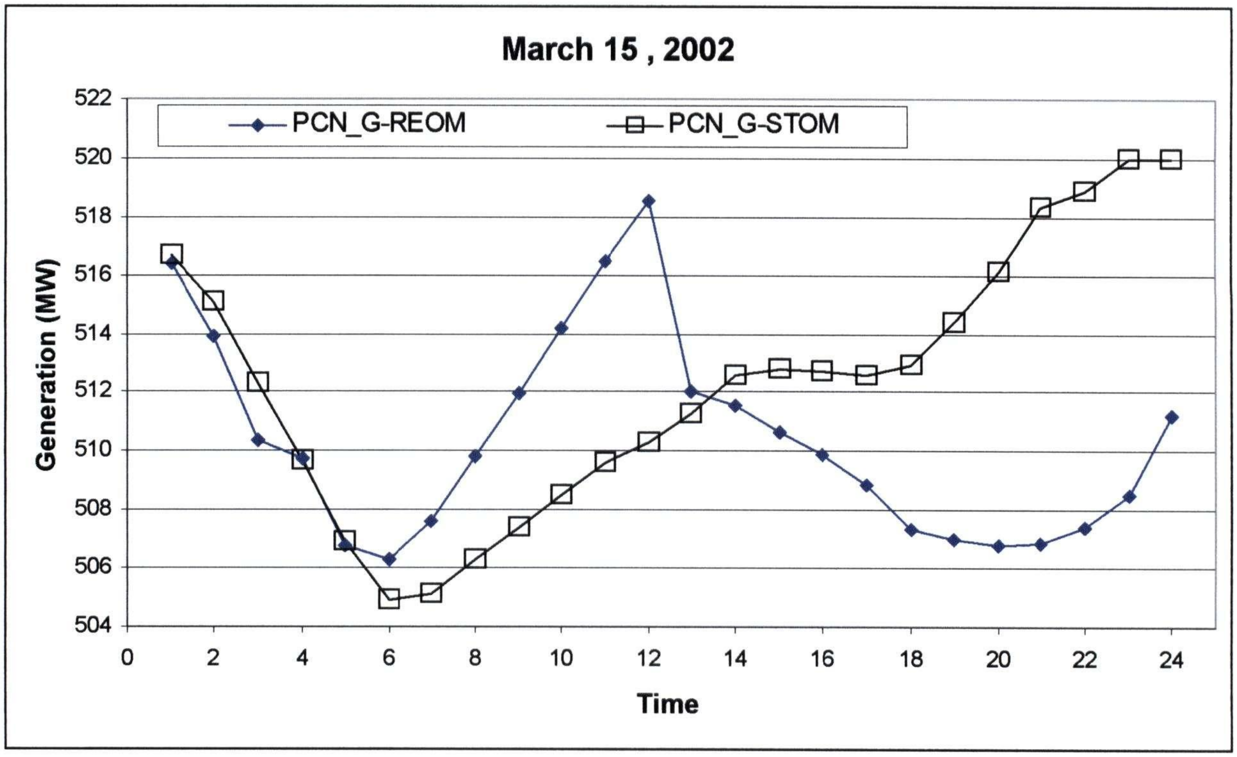


Figure 5.12 – PCN Generation for March 15, 2002

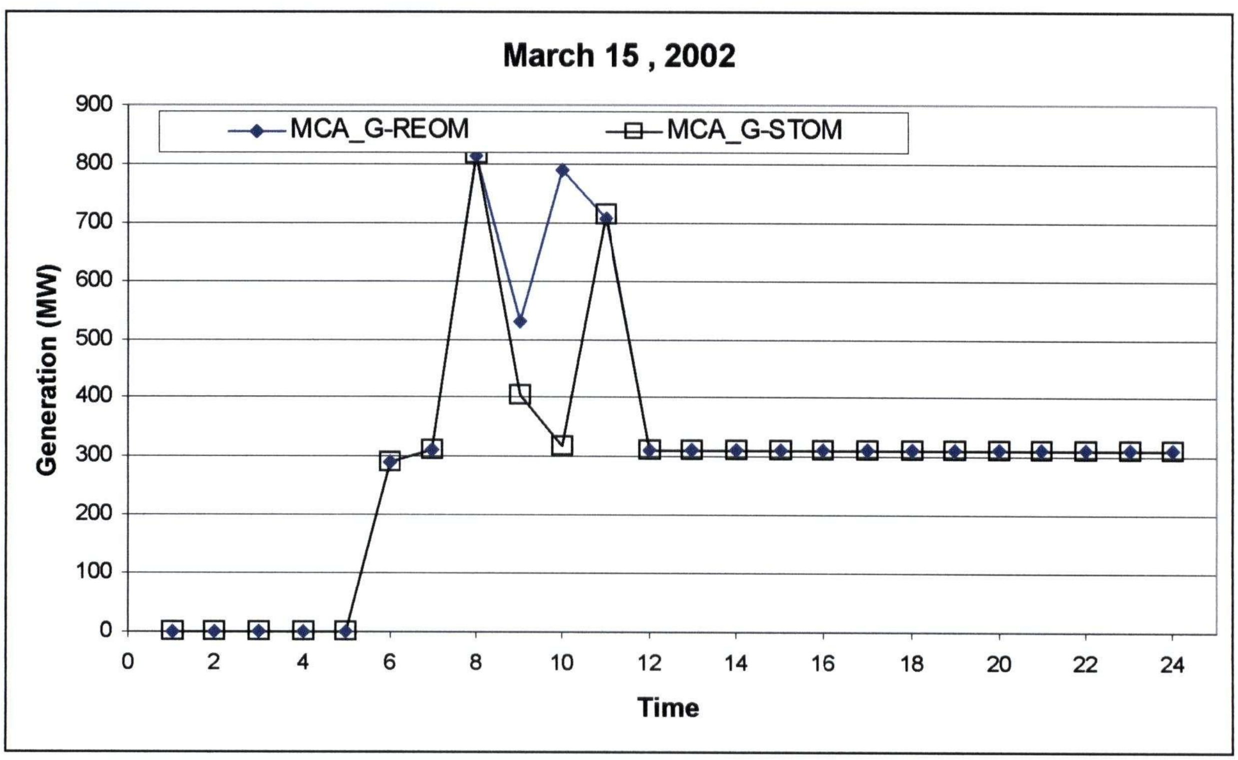


Figure 5.13 – MCA Generation for March 15, 2002

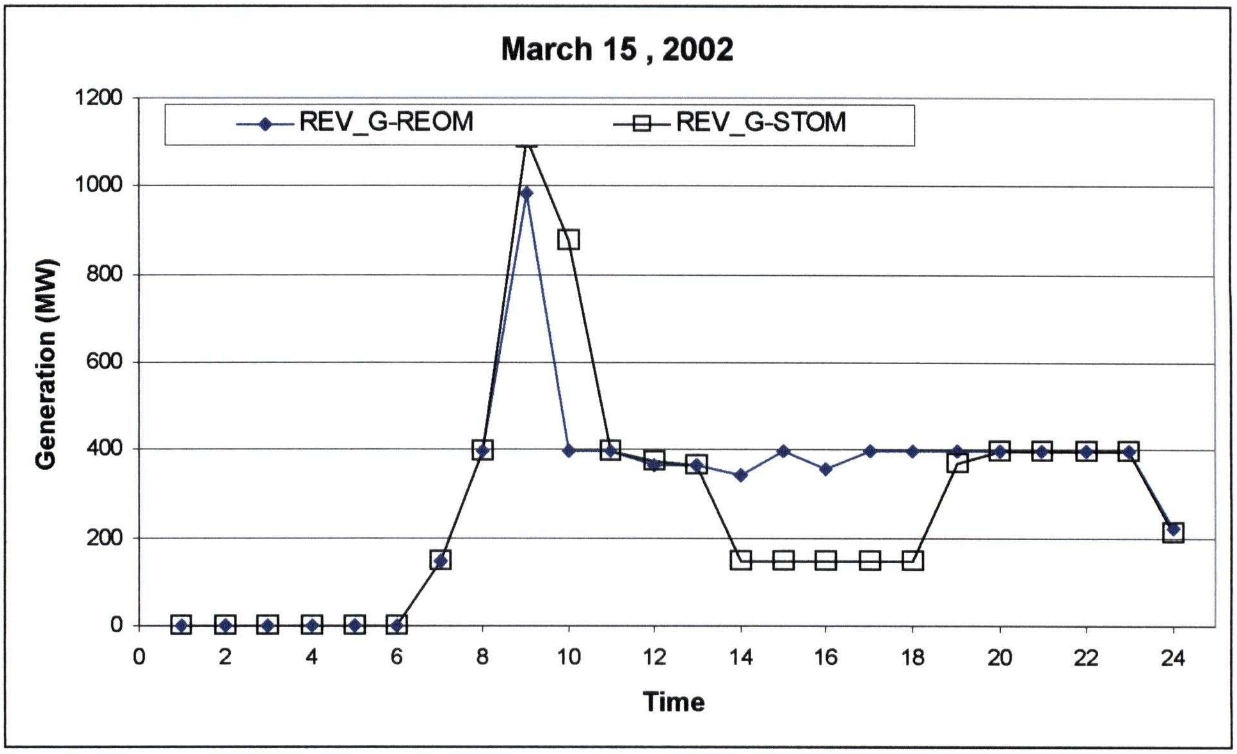


Figure 5.14 – REV Generation for March 15, 2002

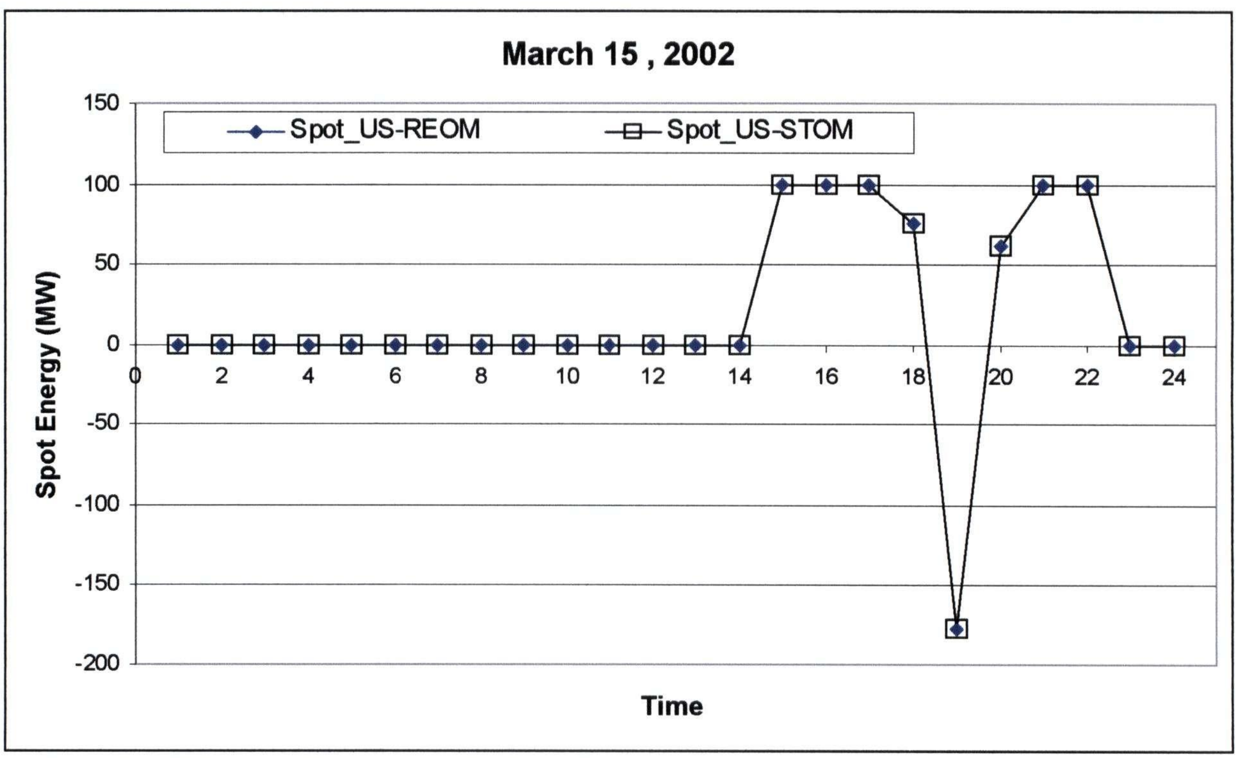


Figure 5.15 – Spot U.S. results for March 15, 2002

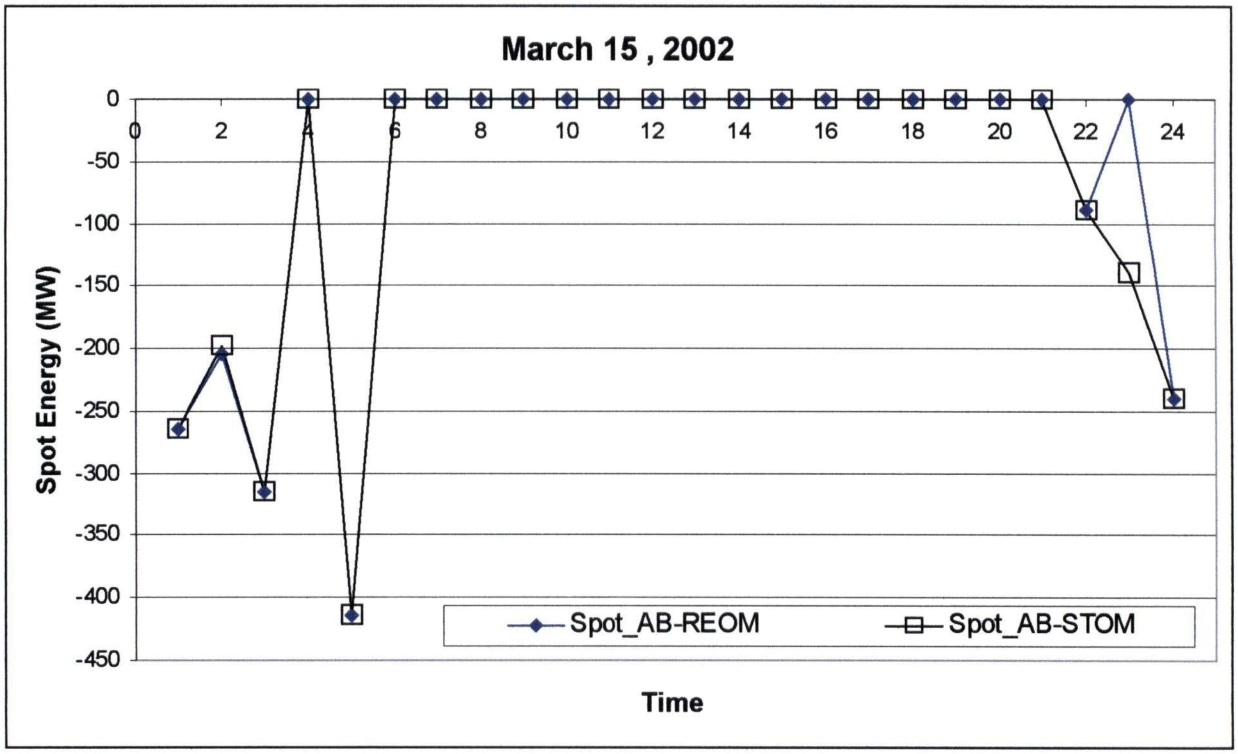


Figure 5.16 – Spot Alberta results for March 15, 2002

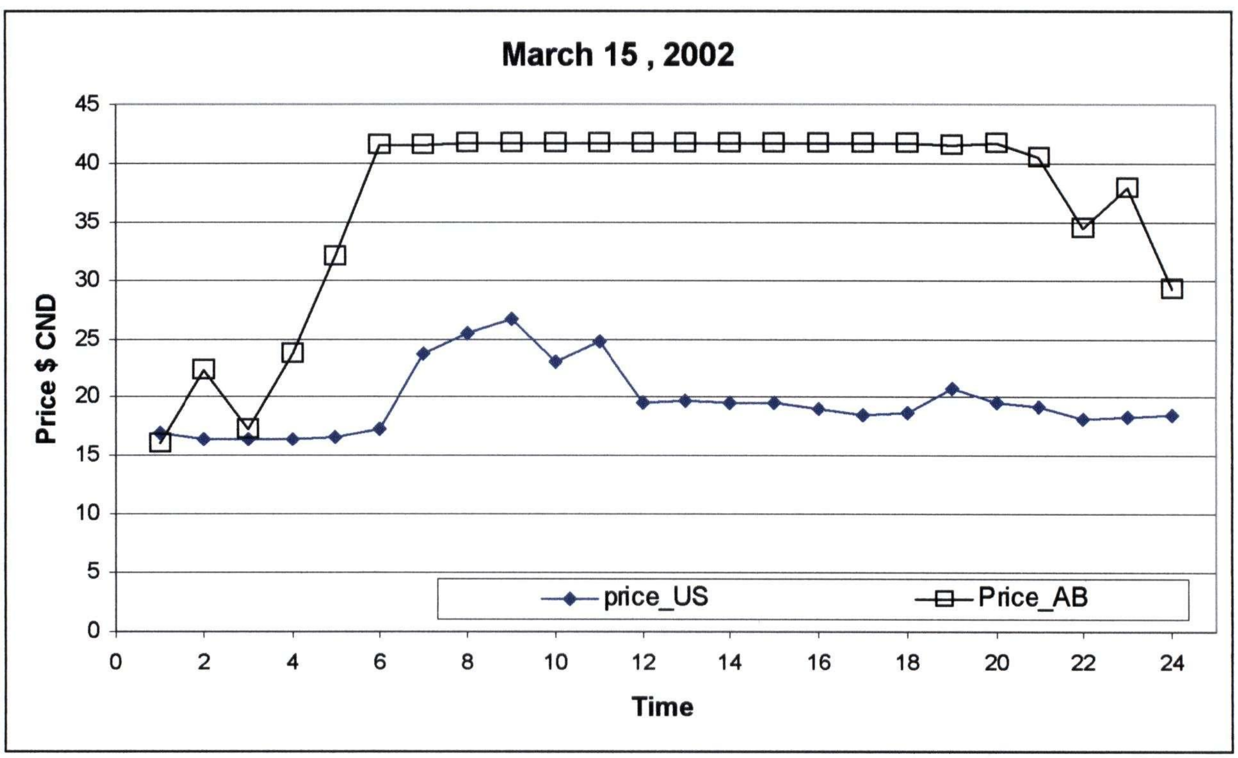


Figure 5.17 – US and Alberta price in Canadian Dollar in March 15 , 2002

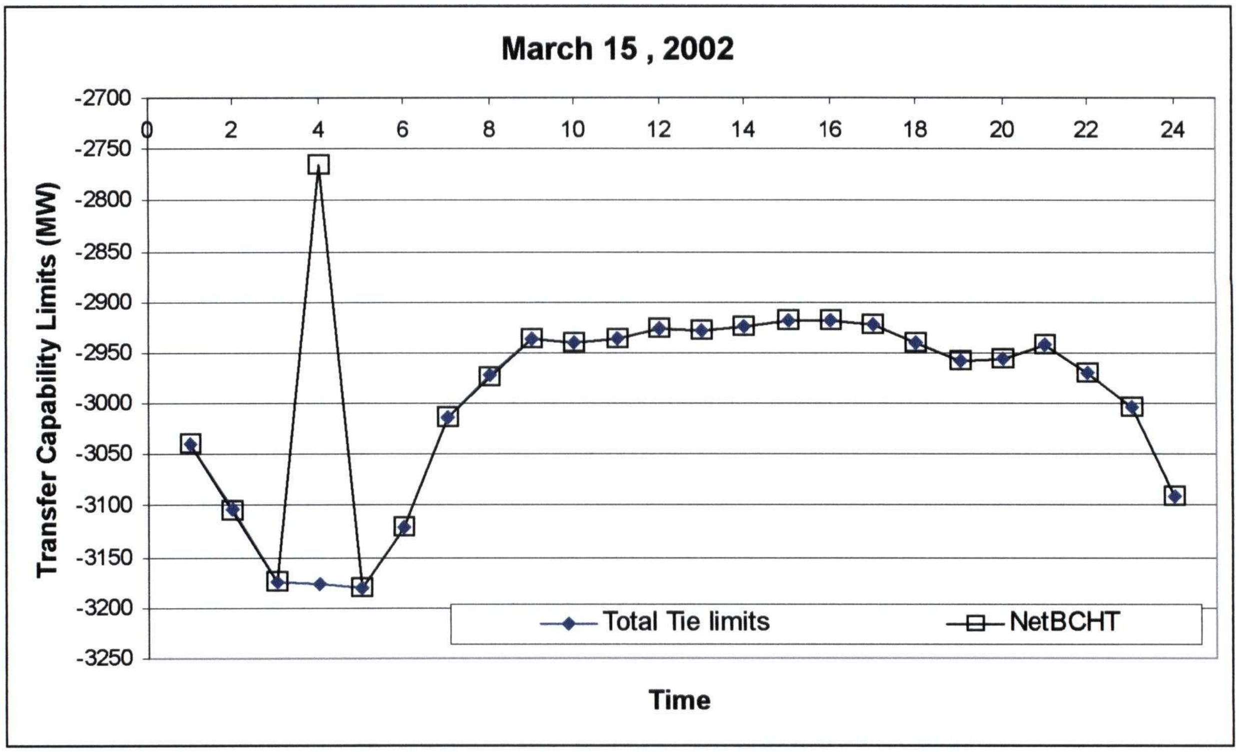


Figure 5.18 – Total Tie limits and Net BC Hydro Transfer Capability in March 15, 2002

5.3.2.3 System Generation Scheduling Summary

In this section, System Generation Scheduling Summary is illustrated. Figures 5.19 and 5.20 illustrate the generation summary of the STOM and REOM. It can be noted that by applying the REOM, there are some differences in generation scheduling.

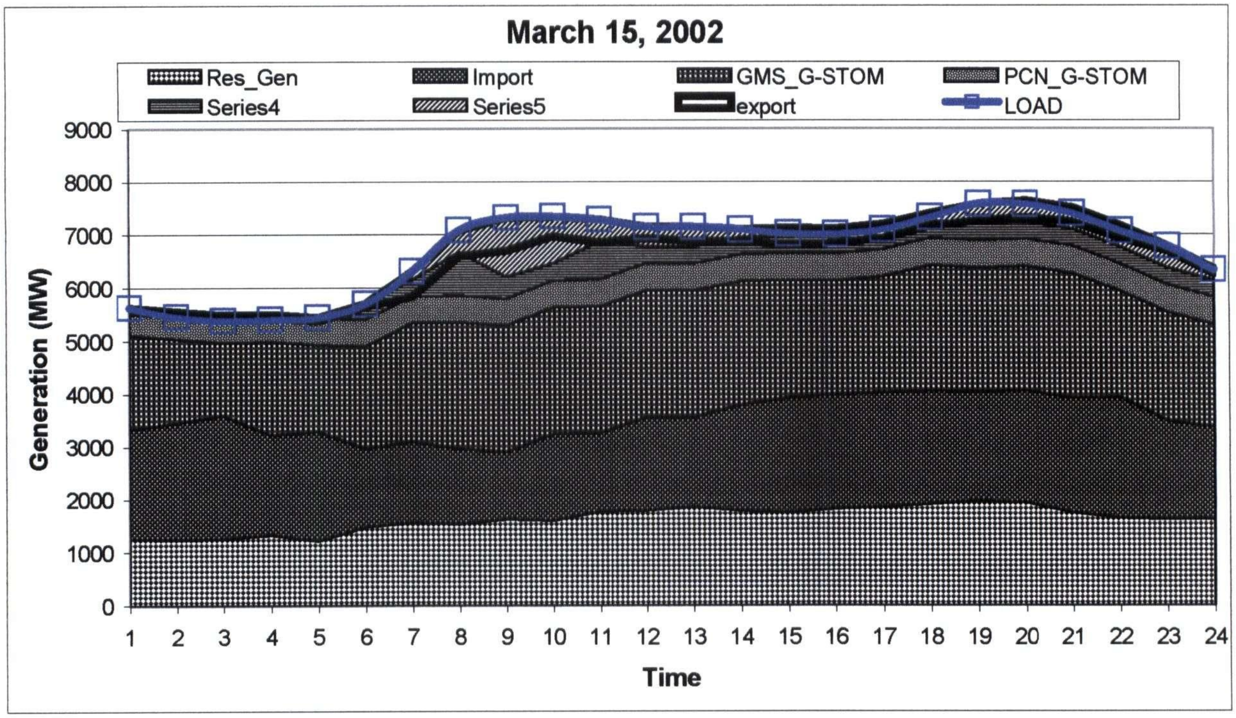


Figure 5.19 – Generation Scheduling results of STOM

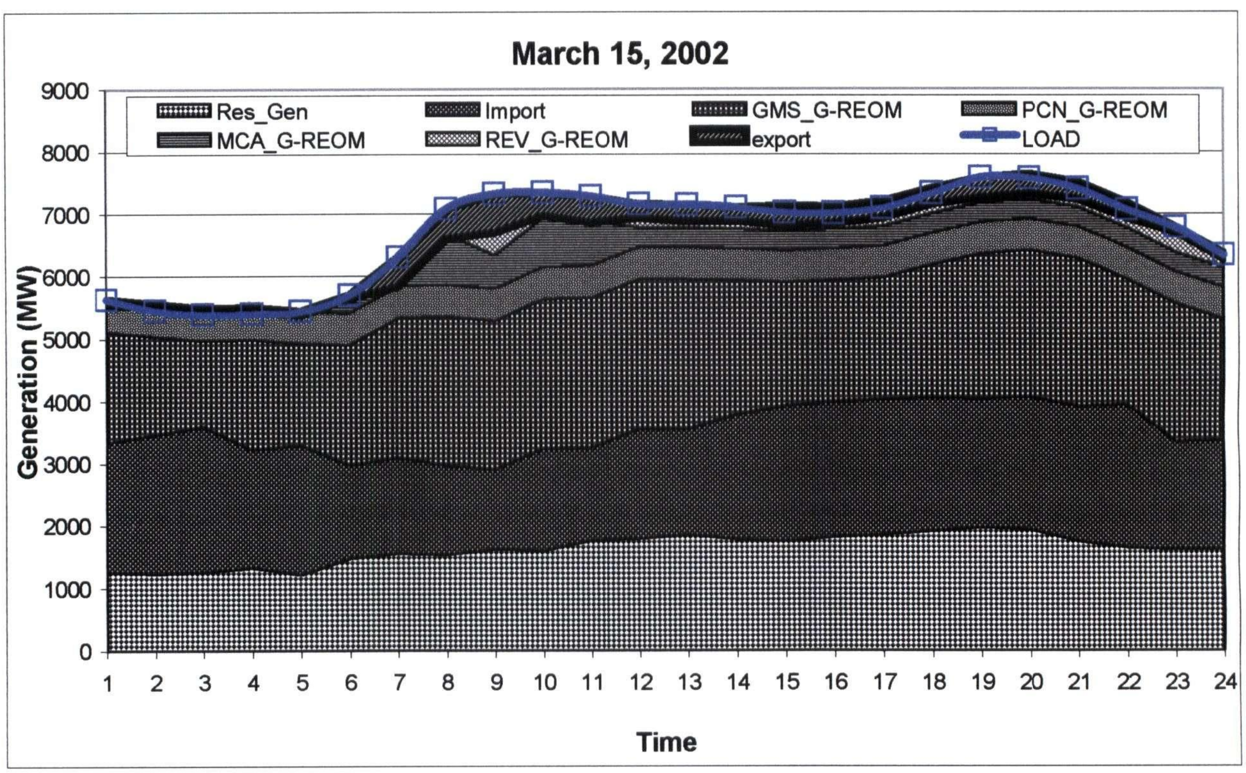


Figure 5.20 – Generation Scheduling results of REOM

5.3.2.4 Optimal Solution Configuration

In this section the optimal solution configurations for STOM and REOM are discussed. Table 5.7 numerically indicates the difference in the objective functions and the size of the problem for the two different models. As it can be noted from the table, the size of the problem in REOM is larger than STOM. The difference is due to the number of alternatives that REOM considers. REOM calculates all possible the optimal solution for all feasible unit commitments for the time steps. The large size of the optimization problem results in longer time requirement to run the model. Table 5.7 indicates, however that the time needed to run the model is still acceptable.

In this section the optimal solution configurations for STOM and REOM are compared for five case studies. There are two reasons for the longer time for REOM: first, the size of the optimization problem in REOM is larger than that in STOM. Second, additional time is needed to run the preprocessor modules to generate data for the optimization algorithm.

Table 5.7 – Optimal Solution Configurations for STOM and REOM

Study Date	Method	Objective Functions	Timing (seconds)			Total #of Variable	Variable type		Total # of Constraints
			Input	Solve	Output		Binary	Linear	
15-Mar	STOM	61422.3	0.01	0.11	0.01	816	0	816	870
	COMBO_EA	46303.9	0.01	0.13	0.01	976	210	764	578
17-Apr	STOM	109395.6	0.03	0.11	0.01	816	0	816	870
	COMBO_EA	112964.2	0.01	0.04	0.01	1503	695	808	631
12-May	STOM	156308.0	0.03	0.063	0.015	816	0	816	870
	COMBO_EA	139542.6	0.01	80.3	0.02	1639	692	947	846
17-May	STOM	505154.5	0.03	0.094	0.015	816	0	816	870
	COMBO_EA	505910.1	0.01	6.589	0.02	1647	729	918	770
5-June	STOM	57973.6	0.03	0.08	0.01	816	0	816	870
	COMBO_EA	57740.3	0.01	3	0.01	1322	590	732	593

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Summary

In recent years, deregulation of power markets has directly influenced the way power production facilities are managed. In a competitive electricity market environment, energy producers need to develop new methods and techniques to aid them in optimizing the performance of their systems and in maximizing their profits by buying and selling energy in the most opportune time. In a competitive energy market, there is always a price at which energy can be either purchased or sold. Prices then become the major driving force in making key operational decisions. Under these circumstances, any physical and operational constraints limit the ability of the system operator to exploit the full flexibility of the system and to maximize the value of the resources. B.C. Hydro, as one of the largest hydroelectric producers in North America, have developed and implemented a set of large-scale optimization and simulation models to manage and operate their energy production system in an optimal way. These models are used to aid them in operations planning activities in the long-term, short-term, and in real-time system operations. From this perspective, the aim of developing the REOM model was to assist the B.C. Hydro system operation engineers in improving the operational efficiency of the B.C. Hydro system and to maximize the value of their resources.

This thesis proposes a practical decision support system that could be used by hydropower producers who control large scale storage facilities to develop hydro generation schedules and maximizes the value of resources when the system is in import mode. The objective function in the REOM system maximizes the value of B.C. Hydro resources by finding the optimal trade-off between the value of imports from the U.S. and Alberta markets and the value of the additional water that could be stored in reservoirs. The REOM system provides the operators with a tool to assist them in making the operational decisions on when and how much energy to import/export, as well as when, where and how much water to store or draft while meeting the firm domestic load and other system constraints. In addition to satisfying the system load constraint, the REOM system deals with other constraints that reflect operational limits on plants and reservoirs, established non-power requirements, and transmission and system transfer capability as well as restrictions on unit operations.

The REOM system relies on several sources of data and limits and its user has to ensure the accuracy and the integrity of the data used by the model, as inaccurate input data can result in wrong results.

This thesis investigated two approaches to solve the problem: The PATH method and the COMBO method. The two methods were successfully implemented and tested on different ways of formulating and indexing the variables and constraints in the optimization model. An Elimination Algorithm was also developed and implemented to accelerate the solution process in both solution methods. The purpose of the Elimination Algorithm is to eliminate the optimization model equations that depend on the system Rotational Energy in time steps when import limits are not dependent on the System Net Transfer Capability. Implementing the Elimination Algorithm in solution process of the REOM system has significantly reduced the size of the optimization problem, and therefore a significant reduction in the time needed to solve the problem.

6.2 Contributions

Several contributions were made in this research effort. First, the System Rotational Energy constraint was incorporated in the formulation of the scheduling optimization problem for the B.C. Hydro System. Second, three different approaches were investigated to solve this complex optimization problem, namely the PATH method, the COMBO with EA method and the COMBO without EA method. Third, the Elimination Algorithm was developed and implemented, and it has significantly reduced the time needed to solve the optimization problem. Fourth, an expert system was employed to reduce the size of the optimization problem. Fifth, a mixed integer optimization algorithm was developed to derive the optimal generation schedules for a large-scale hydroelectric system, and the optimal tradeoff between the value of imports and the value of water stored for hydro systems with multiyear storage. And, finally, the challenging problem of incorporating the System Rotational Energy constraint in the Short Term Optimization Model (STOM) was successfully formulated and solved.

6.3 Future Works and Recommendations

Future work will need to be carried out to expand and enhance the ROEM components. First, the preprocessor of input data should be improved. Second, more restrictions on unit operations and more rules must be incorporated in the expert system component. And finally, other modeling and optimization techniques that could accelerate the solution process should be explored.

REFERENCES

[1] Shawwash, Z. K., Siu, T.K. and Russell, S. O., "The B.C. Hydro Short Term Scheduling Optimization Model," *IEEE Transactions on Power Systems*, August 2000.

[2] Siu, T. K., Nash, G. and Shawwash, Z. K., 2001, "A Practical Hydro Dynamic Unit Commitment and Loading Model," *IEEE Transactions on Power Systems*, April 2001.

[3] Shawwash, Z. K., Siu. T. K., Nash, G., Gosselin, R. and Dai, N., "Dynamic Unit Commitment and Loading of Hydro Systems," *IEEE ISAP2001 Conference*, Budapest, Hungary, June 18-21, 2001.

[4] Kothari, D. P. and Ahmad, A., "An Expert System Approach to the Unit Commitment Problem," *Energy Convers. Mgmt.*, vol. 36, no. 4, pp. 257-261, 1995.

[5] "Aion Reference Manual", Computer Associates, 2001.

[6] Fourer, R., D. M. Gay, and Kernighan, B. W., "AMPL: A Modeling Language for Mathematical Programming," The Scientific Press, Mass., USA, 1993.

[7] ILOG, Inc, "CPLEX Optimization Subroutine Library Guide and Reference, Version 6.0.1," CPLEX Division, Incline Village, NV, USA, 1998.

[8] Druce D. J., "Incorporating Daily Flood Control Objectives into a Monthly Stochastic Dynamic Programming Model for a Hydroelectric Complex," *Water Resources Research*, 26 (1), pp 5-11. 1990.

[9] Barritt-Flat, "A comprehensive optimization model for hydro-electric reservoir operations." ASCE, New York, 463-477, 1988.

[10] Bertzekas, Lower, Posbergh, "Optimal Short Term Scheduling of Large-Scale Power Systems," *IEEE Trans on Automatic Control*, AC-28(1), pp. 1-11, 1983.

[11] Turgeon, A, "Optimal Short Term Hydro Scheduling from the Principle of Progressive Optimality," *Water Resource Research,* 17(3), pp. 481-486, 1981.

[12] Tejada-Guibert, "Optimization of Value of CVP's Hydropower Production," *Water Resources Planning and Management,* ASCE, 116(1), pp. 52-70, 1990.

[13] Yeh, Becker, "Optimization of Real Time Hydrothermal System Operation," *Water Resources Planning and Management,* ASCE, 118(6), pp. 636-653, 1992.

[14] Martin, Q.W., "Optimal Reservoir Control for Hydro Power on Colorado River," *Water Resources Planning and Management,* ASCE, 121(6), pp. 438-446, 1995.

[15] Hawary, Christensen, "Optimal Economic Operation of Electric Power Systems" Academic New York, 1979.

[16] Robitaille, "Development of a Real Time River Management System for Hydro-Quebec's Short Term Operation," Water Power, 95, vol. 1, ASCE, New York, pp. 1848-1857, 1979.

[17] Shane, "Modeling Framework for Optimizing Basin Hydropower," Water Power, 95, vol. 1, ASCE, New York, pp. 1869-1873, 1995.

[18] Lyra and Ferreira, " A Multi-Objective Approach to the Short Term Scheduling of a Hydro Power System," *IEEE Trans on Power System,* 10(4), pp. 1750-1755, 1995.

[19] Shawwash, Z. K. and Siu, T.K., "The Short Term Optimization Model User's Guide", BC Hydro Resource Management, 2001.

[20] Shawwash, Z. K. (2001)," The Short Term Optimization Model – A Primer", BC Hydro Resource Management.

[21] Mohamed Shaaban, and Yixin Ni, "Transfer Capability Computations in Deregulated Power Systems", 33rd Hawaii International Conference on System Science, 2000.

[22] Jorge Valenzuela, Mainiak Mazumdar, "Probabilistic Unit Commitment Under a Deregulation Market," University of Pittsburgh.

[23] Castillo, E., and Conejo A.J., "Building and Solving Mathematical Programming Models in Engineering and Science", John Wiley and Sons, New York, 2002.

[24] "BC Hydro Transfer Limits", BC Hydro, System Operating Order, 2002.

[25] "Making the Connection," BC Hydro, April 2000.

[26] James A. Momoh," Electric Power System Applications of Optimization," Marcel Dekker Inc., 2001.

ANNEX A

MATHEMATICAL PROGRAMMING

In this section, the main mathematical programming techniques that have been applied for solving the optimization problem in this thesis study are introduced and very briefly described.

A.1 Linear Programming

The most general description of the linear programming (LP) problem is given as the problem of allocating a number m of resources among 1, 2, ..., n activities in such a way to maximize the worth of all the activities. The term "linear" refers to the fact that all the mathematical relationships among the decisions (variables) that allocate resources to activities and the various restrictions applicable therein (constraints) as well as the criterion (objective function) are devoid of any non-linearity. The objective function is some measure of the overall performance of the activities such as cost, profit, efficiency, etc.

Various approaches have been made over the years to solve linear programming problems. The commonly encountered techniques that have gained wide attention from engineers, mathematicians, and economist are the graphical approach, the simplex method, the revised simplex method, and the tableau approach.

A.2 Mixed Integer Programming

One of the methods applied in this research was solving the given complex problem with mixed integer or binary programming. Integer and mixed integer programming problems are special classes of linear programming where all or some of the decision variables are restricted to integer values. There are many practical cases in linear programming in which some of the variables can be dropped and/or some of the variables can take up only discrete values. Sometimes the discrete values are restricted to zero and one only; that is, ***yes*** or ***no*** decisions or binary decision variables. The occurrence of binary variables may be due to a variety of decision requirements, the most common among which is *ON/OFF decisions*. The most common type of binary decision falls into this category for engineering optimization problems. This decision variable can also have an alternative representation of SELECTED/NOT SELECTED or SCHEDULE/NOT SCHEDULE, etc., depending on the specific application.

The other variation to the binary/integer programming function that is usually used in mixed integer optimization problems is a *function with N possible values*. In many real life problems, the function does not have smooth continuous properties, but can take up only a few discrete values. For example:

$$f(x_1,\ldots,x_n) = d_1 \text{ or } d_2,\ldots,d_N.$$

The equivalent integer programming formulation would be :

$$f(x_1,\ldots,x_n) = \Sigma^N_{i=1} d_i y_i$$

$$\Sigma^N_{i=1} y_i = 1$$

where y_i = binary (0 or 1) for $.i = 1,\ldots,N.$

Pure integer or mixed integer programming problems pose a great computational challenge. While there exist highly efficient linear programming techniques that enumerate the basic LP problem for each possible combination of the discrete variables (nodes), the problem lies in the astronomically large number of combinations to be enumerated. If there are N discrete variables, the total number of combinations becomes $2^N!$. The simplest procedure one can think of for solving an integer or mixed integer programming problem is to solve the linear programming relaxation of the problem and then rounding the non-integer values to the closest integer solution. This, however, could result in an integer solution that may not be feasible in the first place or, even if the rounding leads to a feasible solution, it may be far from the optimal solution.

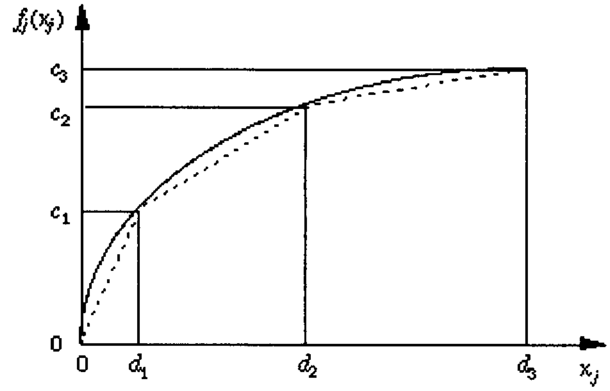
Algorithmic development for handling large-scale integer or mixed integer programming problems continues to be an area of active research. There have been exciting algorithmic advances during the middle and late 1980s. The method applied for solving the mixed integer programming in this research was the branch-and-bound technique. The basic philosophy in the branch-and-bound procedure is to divide the overall problem into smaller and smaller sub-problems and enumerate them in a logical sequence. The division procedure is called *branching* and the subsequent enumeration is done by *bounding* to check how good the best solution in the subset can be and then discarding the subset if its bound indicates that it can not possibly contain an optimal solution for the original problem.

A.3 Piecewise Linear Programming

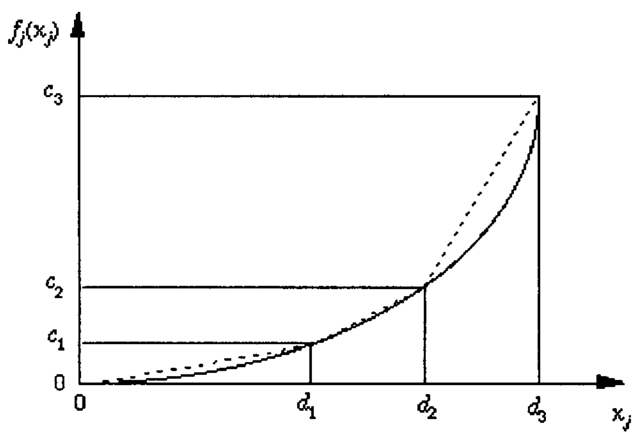
Some optimization problems may deal with more than one variable at the same time or may deal with discrete values. The optimization problem subject of this research involved dealing with nonlinear functions for the discharge and generation relationship and discrete values for system transfer limit based on the domestic load and total system rotational energy. Since the functions of the problem were nonlinear, the typical method for solving these kinds of problems would have been nonlinear programming. However, piecewise linearity is often employed to give a more realistic description of these kinds of problems that can be achieved by linear terms alone. In this kind of application, piecewise linear terms serve much the same purpose as nonlinear terms, but without some of the difficulties that is inherent in nonlinear programming, which is basically why analysts prefer to convert non-linear problems to their linear equivalent. One of the most effective methods to do this conversion is *Piecewise Linear Programming*.

In Piecewise Linear Programming several kinds of linear programming problems can be solved while the functions that are applied to the problem are not really linear, but are pieced together from connecting linear segments. There are two kinds of approaches to the piecewise linear functions:

1) *A function of a single variable with a decreasing derivative*. The figure below shows a concave function of a decision variable. A piecewise linear approximation is shown by the dotted lines. A concave function in the objective function of a maximization problem can be represented by the sum of several linear expressions with a piecewise linear approximation (3 in this figure).



2) *A function of a single variable with an increasing derivative*. The figure below shows a convex function of a decision variable. A piecewise linear approximation is shown by the dotted lines. A convex function in the objective function of a minimization problem can be represented by the sum of several linear expressions with a piecewise linear approximation (3 in this figure).



An AMPL piecewise linear term has the general form:

<< *breakpoint-list ; slope-list* >> *PL-argument.*

In the present research, Piecewise Linear Programming was successfully applied for those constraints that needed to be calculated from a nonlinear function or needed to be interpolated between discrete numbers.