GENERALIZED OPTIMIZATION IN THE BRITISH COLUMBIA HYDROELECTRIC SYSTEM

by

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B.A.Sc., The University of British Columbia, 2000

A THESIS SUBMITTED IN PARTIAL FULFILMENT OF
THE REQUIREMENTS FOR THE DEGREE OF
MASTERS OF APPLIED SCIENCE IN CIVIL ENGINEERING

in

THE FACULTY OF GRADUATE STUDIES

Department of Civil Engineering

We accept this thesis as conforming
to the required standard

THE UNIVERSITY OF BRITISH COLUMBIA
APRIL 2003

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Date April 23, 2003

ABSTRACT

The purpose of this thesis is to provide a decision analysis tool for BC Hydro medium-term planning engineers to enable them to derive optimal generation schedules to assess the feasibility, advantages and disadvantages of operational alternatives.

The development of a six-component system facilitates the analysis of BC Hydro operations. A graphical user interface, preprocessor and spreadsheet were designed to collect and manipulate the raw model data, which is copied with communication protocols from a client workstation to a dedicated server for the Generalized Optimization Model. AMPL and CPLEX are the programming language and off-the-shelf solver that find the optimization problem solution, whose results are copied to the client workstation to be displayed in results software.

The first stage of the Generalized Optimization Model is operational and producing feasible results for different scenarios on BC Hydro's Columbia River generating system. Stakeholders determined five suitable alternatives for minimum Revelstoke plant discharge. Each of these studies was completed with different historical plant inflows to simulate the uncertainty of the forecasted inflow. The results showed that the value of BC Hydro resources would decrease if the minimum discharge limit were increased. They also showed that the operation of other BC Hydro plants on the Columbia River and Peace River would change to meet the new minimum flow. The model has demonstrated that the operating flexibility is key to the value of BC Hydro resources; the less constraints on the system, the more operational choices, thus creating more value for stored water.

Future development of the Generalized Optimization Model will combine short and long-term studies within the same model. This requires using multiple input data sets to represent the corresponding planning horizons. It will also provide solutions to meet the reliability and capacity requirements of BC Hydro and to sustain the value of the present and future resources for its customers. Modifications will have to be carefully planned to ensure the model's integrity. BC Hydro's residential, commercial and industrial customers will benefit from the results of all of the phases of the Generalized Optimization Model.

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ACKNOWLEDGEMENTS

The guidance and commitment of Dr. Ziad Shawwash as a friend, professor and advisor is gratefully acknowledged. This thesis would have been empty without his extensive knowledge of optimization, BC Hydro and AMPL. His constant support and quiet attitude allowed completion of this research without external pressures or tension. Ziad should be made aware of his outstanding impact on BC Hydro and UBC Civil Engineering. He should be praised for his efforts of growing the partnership with UBC and BC Hydro and continuing his support for UBC students. Special appreciation should be made to Dr. Thomas K. Siu. The past five years at BC Hydro would not have been possible had Tom not seen some potential in this silly, happy character. His commitment to learning while working made this experience invaluable and he should also be recognized for the development and continuing support of such a successful partnership with UBC Civil Engineering. Many thanks to the other UBC students that worked on this project; in particular Amir ala Alavi, Alaa Abdalla, Stacy Langsdale and Chi-ho Yeung. Their work was crucial to the success of this research. Stephen Mason and Daniela Ganea should be acknowledged for their friendship and superior programming skills. Thank you Irene Wong, Mary Reaveley and Christine Pinder for their administrative support and excellent advice.

Wun Kin Cheng, Nan Dai, and Herbert Louie deserve thanks for their role in this research. The studies would not have been possible without their dedication and expertise. Also, they have a great commitment to coffee, which is wonderful to be a part of. The Power Supply shift engineers, M. Hanlon, K. Punch, H. Walk, D. Robinson, C. Ristock, C. Kober should be recognized for their clear explanations and support for my initial research in the next day planning shift office.

The research would never have started without the advice and support of Dr. S.O. Russell. Denis has been a quiet supporter, providing insight and encouragement. He was instrumental in starting the work with BC Hydro and UBC Civil Engineering and continues with suggestions and guidance. As my pseudo supervisor, Dr. Rob Millar deserves thanks for approving my project and for inspiring me through his passion for water resources and excellent teaching. Dr. Barbara Lence was extremely helpful as a teacher, friend and reader. Craig Pond should be thanked for his friendship and excellent coaching to take my mind off of my Master's program. His support through bad days and his dedication to Women's Rowing at UBC are demonstrated in the quality of his program.

This thesis is dedicated to Rocco Fane, our puppy who passed away during my graduate studies. His energy and gratitude served as endless inspiration every day with him and will forever more. His little sister Ruby, who shares Rocco's energy for life and passion for treats, survives him. My husband Jonathan deserves the world for his love, caring, support and excellent cooking skills. Having written a thesis for his undergraduate degree he understood the stress and pressure that one goes through. Thanks go to my parents Michel and Jim for their love and encouragement, my sisters Amy and Lisa for keeping it real and my extended family for keeping me sane. The Fane family and The Russell family provided needed relaxation, entertainment and love.

There are many other unnamed friends who deserve thanks, you all know who you are.

TO MY DOG:

ROCCO

CHAPTER 1
INTRODUCTION

1.1 Background

The need for energy in British Columbia is increasing, as it does so, the need for a firm energy supply also increases. To meet the demand, BC Hydro must study future system constraints and characteristics to ensure that these needs are met. BC Hydro has been using decision analysis tools to support their generation operations in the short-term for the last few years. The use of a Short Term Optimization Model (STOM) in the real time operations at BC Hydro has improved their bottom line and increased value for their customers (Shawwash, 2000). STOM is an optimization model that produces next hour generation and electricity market sales schedules for shift engineers to consider when meeting the hourly demand from the province. The program maximizes the revenue from spot market sales and future reservoir storage to obtain these generation schedules. There is a delicate balance between supplying the system efficiently to meet the demand and trying to take advantage of a complex electricity market. The shift engineers can also use STOM to do post-mortem studies on old generation schedules that will give insight into different strategies to produce economical results. These features of STOM can also be transferred into the medium-term horizons.

The development of the Generalized Optimization Model (GOM) is an enhancement of STOM into a more generalized version for medium-term studies. The program used the main functions of STOM with some additions to increase the functionality for the medium-term user including the ability to model time steps with different lengths and to model system generation under different market price conditions.

The following introduction will examine the purpose of the project, the scope of the problem and the methods of investigation. The final paragraph will discuss the organization of the thesis.

1.2 Purpose, Scope and Method of Investigation

The goal of this thesis is to develop a decision analysis tool to BC Hydro medium-term planning engineers to enable them to derive optimal generation schedules and to assess the feasibility, advantages and disadvantages of different operational alternatives on the BC Hydro system.

There are five main objectives in meeting the goal of this research. The first is to increase one's experience with hydroelectric system operations, this was achieved by learning the characteristics and operational constraints of each individual plant and understanding the impact on other plants in the same river system and on the entire Hydro system. The addition of market requirements and consumer demand adds a crucial dynamic to the scheduling problem.

The second objective is to assess and evaluate the techniques available to model a system with the above characteristics in a medium-term analysis; this was achieved by examining the different available techniques and comparing their usability to that of the Short-Term Optimization Model (STOM). The familiarity of users with the STOM program, and the reduced cost of using a program that BC Hydro already understands, demonstrate the advantages of re-tailoring a current program to meet new user requirements.

The third objective is to investigate the best methods to adapt STOM into a medium-term planning tool. This was achieved by examining both the capabilities of the AMPL modeling language and the new requirements for the medium-term model. Changes were made to the model to accept changing study parameters and to add more medium-term planning requirements that may not apply in short-term studies. As the study length increases, the size of the problem increases, which directly impacts the solution time required; this must also be considered when making modifications to the original program.

The fourth objective is to devise a procedure that can dynamically generate and set user-specified limits over different periods in the study. This was achieved by examining the daily generation schedules prepared by the BC Hydro system operations engineers and by developing a procedure and a set of rules that can be defined to dynamically modify the optimization model to accurately simulate 'real' system scheduling conditions.

The fifth objective is to test and implement the model for use by the medium-term planning engineers. This was achieved by developing a number of tools to simplify both data collection and data manipulation into a format that can be used by the model. A graphical user interface was developed to collect the raw input data and to select the study characteristics. A preprocessor was created to prepare the input data into data that correlated to the user-specified study characteristics. The communication protocols were devised to pass the study data into the model and to run the model. The results display screen was developed to view and evaluate the model outputs.

The report will describe the changes from a short-term generation scheduler to a medium-term generation scheduler, including the addition of a graphical user interface to speed up data retrieval and make it more user-friendly, the creation of a pre-processor to modify the input data, the modification of the short term model constraints and variables, the addition of communication protocols to run the model, the creation of a program to dynamically include additional constraints and characteristics and the development of an output results display.

1.3 Organization of the Thesis

The thesis is organized into six chapters. Chapter 2 reviews the literature on the state of the art on optimization in large-scale generation systems. The chapter will examine the current knowledge and understanding in the area of decision support and the relevance of the techniques to this research. Chapter 3 will explore the BC Hydro system and discuss its current state and the need for medium-term modeling. This chapter will also discuss how this decision support tool was conceptualized. Chapter 4 will detail the methodology adopted for this research. This includes a description of the components of the model including the input data retrieval, the graphical user interface, the pre-processor, the communications protocol, the optimizer and the results display. The mathematical component of the model is then discussed, detailing the major additions to the existing model including the rules procedure formulation. Chapter 5 will detail the results of the model and discuss both their feasibility and their applicability to the current state of the art. This chapter will include specific results for a BC Hydro study on Revelstoke discharge limits. Chapter 6 will conclude the thesis and examine recommendations for further study, which will be followed by the list of references and the appendices.

CHAPTER 2
LITERATURE REVIEW

There are over 45,000 dams that support water supply, irrigation and hydroelectric power in the world today (Veltrop, 2002). Storing water and using it to generate electric power began in 1890. Construction of dams is now on the worldwide platform for social and economic reasons. The construction of dams has many positive and negative impacts. As the population of the world increases, so do the need for electricity and water supply and thus the need for dams, but to meet this need one must mitigate the impacts on the environment, economy and society. The world has become increasingly aware of these impacts, an as such are demanding delays in construction of dams to debate the issues. Those who are pro dam construction see three major benefits in a firm electricity supply, a 'renewable' resource, and a source of water and irrigation for communities (Balser, 2001). Those against the use of dams argue that the capital expenditures are so large that they cause massive debt, they displace people from their communities, they damage the environment, and they don't equitably share the costs and benefits of construction with the communities that they displace. It can be argued that the benefits of dams largely outweigh the costs and vice versa. The World Commission on Dams (WCD) is a forum that was held in 1997 to find out whether this debate could be more productive and found that their report on dam development was focusing people on the issues and improving communication and decision making based on the WCD's core values (Veltrop, 2002).

Hydropower harnesses the energy of moving water. There are three main sources of moving water: falling water, running river water and pumped water. Falling water systems come from constructing a dam to produce an upstream pool to contain the water at elevation, intakes and penstocks tunnels transport the water to a lower elevation, which causes an increase in potential energy of water. The energy is then transformed into mechanical energy by turning the blades of a turbine. This turbine turns and is connected to a generator that induces a transformation into electrical energy. This generated energy is then transmitted to homes and industries to meet the electrical demand of the population. Run-of-river plants use the same conversion of energy, but there is no pool to store the water. This means that the plant has a low change in elevation (head) between the intake and the turbine. The energy of the water comes from its flow down the river, which is usually on a much shallower slope. These types of plants are less likely to have large fluctuations in operation due to their inability to store water. Pumped water is a more inefficient way to generate energy. In this case, water is pumped to a higher elevation to be used for generation at a more opportune time. Again the same principles are used with the turbines and generators as in the falling water example, but there are losses associated with pumping the water to a new elevation.

Reservoirs are the body of water that is prevented from moving downstream by the dam. The water levels of the reservoirs that are dammed for hydroelectric generation are impacted by the following four inflow sources: natural inflow from the surrounding watershed runoff, rainfall on the reservoir, inflow from another upstream plant and any additional inflows to meet regulatory or recreational releases. The additional inflow is met by spilling water from an upstream project. The three sources of outflow from a reservoir are (Renton and Wallace, 1996) plant discharge from generation, spilled water for compensation and evaporation. The level of the reservoir is called the forebay level. The environment, the government or plant operators may control this level and it usually has minimum and maximum limits. The fluctuation of the reservoir level due to natural inflows occurs throughout the year. In British Columbia, the inflows are highest in the spring due to snowmelt runoff. Changes in the operation of a power system would also impact these levels and could be impacted by these levels. As such the operation of a generating plant requires detailed knowledge of the impacts of decision-making and the environment on each system.

The water released is discharged at the plant tailwater level. This water can then be stored in a downstream reservoir for use in another hydro power plant. This type of system, with multiple hydro power plants on one river, is called a cascaded system. The operation of these systems is much more complicated because the outflow from one plant will impact the operation of downstream plants. Therefore the operators must have experience, instinct and ability to understand the dynamics hydraulics of these cascaded systems.

The elevation of the reservoir level, the elevation of the tailwater level and the flow that is released through the turbines determines the amount of generation produced by a reservoir. The higher the elevation between the reservoir and tailwater levels (head) the more energy the same volume of water will produce. This means that there is a relationship between head, discharge and power production. Each turbine unit in a plant has a specific head-discharge-power relationship and these curves can indicate the most efficient level of operation for a unit for different values of head and generation. For multiple units at a plant there is also a relationship between the most efficient level of operation of all the units, the head and the total plant generation.

Transmission lines transport energy to demand centers and connect other energy systems from different regions. The trade of electricity between these systems is a growing trend with the deregulation of electricity markets. For instance, in times of increased demand on one system, the local system may not be able to meet the demand and must buy energy from other systems or reduce the demand. The demand on a system changes hourly, daily, monthly and usually increases from year to year. Most electrical systems experience two peaks in demand, one in the morning and one in the evening when people go home. The late evening and early morning times are the lowest demand times. Usually, the price of energy increases as the demand on a system increases. Most thermal systems don't have the capability to turn on and off (as hydroelectric systems do) and as such they generate steadily throughout these peaks, which means that they may have a surplus of energy at the low demand times and prices will be lower. This surplus and low prices is attractive to a system that has a high percentage of hydroelectric generation, because at these times, operators can reduce the generation, store the water at the reservoir during the low demand times and buy energy from cheaper sources. They can then generate electricity with the stored water during more opportune times.

One can see that the energy markets and decision-making on generation scheduling becomes very complicated. For this reason, generating and energy marketing companies are developing tools to optimize their system operation. This optimization can be performed in hourly market and operating decisions or in the long-term to study the impacts of different schedules and compare different operations and alternatives.

The following techniques have been applied to the hydro generation scheduling problem in both the long and short-term. Linear Programming (Shawwash et. al, 2000, Kuepper et. al, 2001), neural networks (Stokelj et. al, 1999), evolutionary and dynamic programming (Hoang Cau et. al.), genetic algorithms (Huang, 1999, Leite, 2002), mixed integer linear programming and tabu search using non-linear optimization (Mantawy et. al, 2002).

Shawwash (Shawwash et.al, August 2000) discussed the use of linear programming to determine an optimal short-term generation and energy-trading schedule to maximize the value of resources. The analysis included a discussion of the benefits of using linear programming including the ability to perform sensitivity analysis, the ability to produce optimal schedules and the ability to come to a true optimum using the interior point method. The program uses CPLEX, an off-the-shelf solver for linear programs.

The Bonneville Power Authority has been working on consolidating a group of computer models and manual processes into a single cross-functional application as discussed in Kuepper and Borichevsky (Kuepper et al., 2001). The program uses linear programming to obtain operational improvements and to fortify their position in electricity markets. Their solution was to contract out the development of this tool so that BPA could take advantage of rapid advances in off-the-shelf technology and to outsource maintenance and development. This will improve the companies ability to keep a consistent knowledge base in response to the high demand for specialist IT resources. The program will extend from the short-term to the long-term and improve issues of operational efficiency, obsolescence, integration, interfacing, accuracy, speed and cost (Kuepper et al., 2001). All of these issues have stretched the organization's ability to respond to the competitive demands of the deregulated energy market. Dynamic programming was not chosen because of the large problem dimension, the matrix of state variables for each time step, the long processing time and the high numbers of reservoirs and reservoir properties.

Hoang Cau et al. (Hoang Cau et. al, 2001) discussed the use of dynamic programming and evolutionary programming to get the cost of operating a multiple distributed energy storage power system. The multi-stage problem was decomposed into a group of smaller one-stage sub-problems to obtain an optimal schedule of distributed storage resources.

The accuracy of hydro power plant models is discussed in the document by Stokelj, Golob and Gubina (Stokelj et. al, 1999). The authors assessed the accuracy of the models used in Slovenian power projects using neural networks. The disadvantage of considering this model is that it does not involve any market conditions.

Leite, Carneiro and de Carvalho, described the use of genetic algorithms to solve long and mid-term (two years) planning for a hydrothermal generation problem. Genetic algorithms search and optimize an objective function based on genetics and the survival of the 'fittest' approach. This problem was tested on 7 large hydroelectric plants in Brazil. The best results were achieved with a combination of a non-linear network flow algorithm and genetic algorithms. Huang discussed the use of genetic based fuzzy systems to reach an optimal solution. This procedure produced objectives and constraints that were fuzzified through genetic algorithms then defuzzified to produce a near-optimal solution.

Given the complexity of the problem at hand, linear programming was chosen as the best method for optimization. The non-linear problem is transformed into a linear problem using piece-wise linear functions for the head-generation-discharge curves. The problem from Shawwash, 2000 is extended into a long-term version with updated time steps, variables and constraints. This program will be used by different planners and as such has new requirements for data and output. The programming technique was chosen because of its ease of implementation, its ability to view sensitivity information, its quick solutions with near-optimal results and its usability for the users that are already familiar with the Short-Term Optimization Model (STOM).

The following sections will describe the methodology of the model formulation and the results, including the impact that the model has on BC Hydro operations and recommendations for further study.

CHAPTER 3
THE BC HYDRO POWER SYSTEM

BC Hydro is the primary energy producer in the province of British Columbia. The company is a Crown Corporation for the government of British Columbia and meets the majority of the residential, industrial and commercial demand in the province. The system is made up of more than 36 hydroelectric stations, which make up approximately 90% of the electricity supplied by the company. The remaining 10% is supplied by thermal generation and energy purchases from Alberta and the United States. As the need for more generating capability becomes a bigger priority, it becomes necessary to examine the role of the generating facilities in the past, present and future. The lessons learned from these experiences must be captured to produce a sustainable resource for the province.

3.1 The Past

The first BC hydroelectric plant was built at Buntzen Lake in Vancouver in 1903. The history of the remaining plants extends from the early 20th century to the most recent plant built at Stave Falls in Mission in 2000. The decommissioning and building of plants and turbines has become necessary to maintain and improve the efficiency and output of the system to meet the growing electricity demand. BC Hydro was founded in 1962 as the government merged B.C. Electric and the Power Commission to create the BC Hydro Power Authority (Shawwash, 2000). The 1960's were a time of intense expansion for the system; the Peace River and Columbia River Projects are considered mega-projects still today as they supply over 65% of the electricity supplied by BC Hydro.

3.2 The Present

Currently there are 36 hydroelectric plants, one thermal steam station and two combustion turbine stations in public operation in British Columbia. The maximum sustained generating capacity of this system is approximately 11,200 megawatts (MW). The hydroelectric plants use water from 32 reservoirs in 6 major basins and 27 watersheds and constitute 90% of the installed BC Hydro generating capacity. The Williston Reservoir on the Peace River and the Kinbasket Reservoir on the Columbia River provide multi-year storage for BC Hydro operations, which allows planners to schedule operations for several years in the future. The following table lists the regional areas, river systems, BC Hydro plants, and their installed capacity.

Table 1. BC Hydro Plant Characteristics

Region	River System	Plant Name	Reservoir Name	Storage	Plant Type	Generating Capacity	No. of Units	Built
Peace Region	Peace River	G.M. Shrum	Williston	39,462	Hydro	2730	10	1961
		Peace Canyon	Dinosaur	24	Hydro	700	4	1974
Columbia Region	Columbia River	Mica	Kinbasket	14,800	Hydro	1792	4	1977
		Revelstoke	Revelstoke	1,850	Hydro	1980	4	1984
		Keenleyside	Arrow Lakes	8770	Hydro	-	-	1968
	Pend d'Oreille River	Seven Mile	Seven Mile	Daily Pondage	Hydro	594	3	1979
		Waneta	Waneta	5	Hydro	360	4	1954
	Duncan River	Duncan Dam	Duncan Lake	1727	-	-	-	1965
	Kootenay River	Kootenay Canal	Kootenay Canal Headpond	Run-of-River	Hydro	570	4	1976
	Whatshan River	Whatshan	Whatshan Lake	122	Hydro	54	1	1972
	Elk River	Elko	Elk Headpond	Run-of-River	Hydro	12	2	1924
	Cranberry Creek	W.Hardman	Coursier Lake	29	Hydro	8	2	1960
	Bull River	Aberfeldie	Aberfeldie Headpond	Run-of-River	Hydro	5	2	1922
	Spillimacheen River	Spillimacheen	Spillimacheen	Run-of-River	Hydro	4	3	1955
Lower Mainland	-	Burrard	-	-	Natural Gas Thermal	912.5	6	1960
	Alouette River	Alouette	Alouette Lake	155	Hydro	9		1926
	Stave River	Stave Falls	Stave Lake	365	Hydro	90	2	1911
		Ruskin	Hayward Lake	24	Hydro	105	3	1930
	Penstocks	Buntzen	Buntzen/Coquitlam Lakes	202	Hydro	72.8	2	1903
	Cheakamus River	Cheakamus	Daisy Lake	46	Hydro	33	2	1957
	Clowhom River	Clowhom	Clowhom Lake	45	Hydro	33	1	1958
	Wahleach	Wahleach	Jones Lake	66	Hydro	63	1	1952
	Bridge River	La Joie	Downton	722	Hydro	25	1	1956
		Bridge River	Carpenter	928	Hydro	466	8	1948
		Seton	Seton Lake	9	Hydro	48	1	1956
	Shuswap River	Shuswap	Sugar Lake	148	Hydro	6	2	1929
Coastal Region		Prince Rupert	-	-	Natural Gas Thermal	46	2	1977
	Falls River	Falls River	Big Falls Headpond	24	Hydro	7	2	1930
Vancouver Island	Jordan River	Jordan River	Elliott, Diversion and Bear Creek	28	Hydro	170	1	1911
	Campbell River	Strathcona	Upper Campbell Lake and Buttle Lake	823	Hydro	64	2	1955
		Ladore	Lower Campbell Lake	316	Hydro	47	2	1955
		John Hart	John Hart Reservoir	3.3	Hydro	126	6	1945
	Ash River	Ash River	Elsie Lake	77	Hydro	27	1	1957
	Puntledge River	Puntledge	Comox Lake	106	Hydro	24	1	1912
	-	Keogh	-	-	Diesel Thermal	44	2	1975

Source: BC Hydro, 2000

Planning the operation of a hydroelectric system is crucial to account for the variable factors that can impact the next hour up to the next 10 years' supply of energy. There are four main priorities that BC Hydro uses to guide its resource planning. The first priority for meeting the demand on the system is to ensure the safety of lives and property. This can include evaluating the environmental impacts of new acquisitions and examining the sustainability of the present situations. The second priority for the company is to uphold legal obligations. These obligations include maintaining contracts with First Nations, ensuring that the provisions of the Columbia River Treaty are met and dealing with the Department of Fisheries and Oceans. The third priority is to meet present and future power demand and the fourth is to maximize the value of BC Hydro generating resources.

There are five types of operations planning performed at BC Hydro. The divisions are made on the basis of time. The time horizons are displayed in the table below.

Table 2. BC Hydro Planning and Time Horizons

Planning Type	Time Horizon
Long – Term Expansion Planning	4 – 20 years
Long – Term Operations Planning	4 + years
Medium – Term Operations Planning	1 – 4 years
Short – Term Operations Planning	Next day – 12 months
Same Day Operations	Next hour – 24 hours

Source: BC Hydro, 2000

Planning along these time horizons is convenient because it takes advantage of the accuracy of data. As one extends predictions into the future, the uncertainty of those predictions increases, thus there is a need for different types of planning models to address the uncertainties.

Long-term expansion planning ensures that there are enough future resources to meet future demands with sufficient firm energy capability and peak load capacity. This includes developing and analyzing new acquisitions that meet policy requirements and balance supply and demand. It also means developing tools to better facilitate the use of the present supply, including optimization models and forecasting models.

Long and medium-term operations planning provides guidance for marketing decisions with respect to the operation of the electric system. The multi-year reservoirs in the system make the medium-term operations planning necessary. Many studies are performed to evaluate the capability of the existing electricity supply to meet the future demand. In these studies, uncertainties in both inflow and electricity demand, in addition, various operating factors are addressed; thus it becomes necessary to both model these factors and to predict their impacts on system operation. Marginal Cost Studies on the Williston Reservoir are performed to indicate the optimal economic operation of the system and assesses the adequacy of supply under a range of weather conditions.

Short Term Operations Planning is much more predictable. In these studies, the data that is used has less uncertainty. The data includes short-term inflow forecasts and seasonal water supply forecasts. These studies are usually performed for scheduling purposes to determine how to meet the system load. The accuracy of these studies is also improved by the addition of planned maintenance schedules and operating rules that limit the scope of the studies.

Same Day Operations meet the load on the system on an hourly basis. The data is supplied in real time and thus is the most accurate level of operations planning. The same-day planners are also trying to accommodate spot power trades with other power markets and to take advantage of high and low prices. The generation operations centre uses the schedules from the hourly studies to guide implementation and system dispatch.

3.3 The Future

The future of economic development in British Columbia depends on a firm supply of energy. To meet the economic and the sustainability targets of the province it becomes necessary to perform long-term planning activities. The government has put out a set of guidelines for one of these planning processes called Water Use Planning. This planning takes years to finalize, but will form the framework for operating complex systems in the future.

3.3.1 Water Use Planning

Water Use Planning is a process by which special interest groups come together in a consultative process to examine water management at BC Hydro facilities. Planning is done on each river system, as each downstream plant depends on all upstream plants on the same river. The Water Use Plan is focused on the following three tasks (BC Hydro, 2000):

- Defining operation parameters for the water control facility,
- Assessing alternative facility operations, and

- Assessing implications for power and non-power users of the water.

There are many public interest groups that have different values concerning fish, recreation, power, etc. The operating parameters developed for each system must reflect the objectives and the value of the objectives for approval from the BC Water Act.

As a main interest party, the government has the following four main objectives for the water use plans under development in BC (BC Hydro, 2000):

- Protect fish and aquatic habitat,
- Control flood damage,
- Meet the firm energy demand, and
- Understand First Nations' concerns.

Other issues that impact the water use plans are industrial and municipal development, drinking water supply, recreation and tourism, forestry, irrigation, navigation and cultural and heritage values. There are four types of participants in the Water Use Planning process. Government agencies, who are responsible for ensuring compliance with regulatory constraints. First Nations groups, who want to maintain their heritage and may have land claims on the regions. Local citizens, who may have personal and group concerns. In addition, there are often other concerned parties that have direct interest in the uses of water at the concerned projects (e.g. industries, municipalities, etc.).

There are 13 steps to developing a water use plan, as outlined in 'Making a Connection' (BC Hydro, 2000). The steps form the guidelines for interested parties to follow to meet their objectives along with making compromises for others. The steps are summarized as follows: the first step notifies the respective parties about the planning process. Following this, the water use issues are identified and defined as they relate to facility operation. Then the appropriate consultative process for the Water Use Plan development is determined. The next four steps involve consultative committee meetings. At the meetings, the water issues and interests in conflict are brought forward, the value of each issue is formulated, the validity and role of the values of others is established and alternatives are created, evaluated and selected. The evaluation process includes determining the system response to the alternatives and creating performance measures to assess the degree to which each alternative satisfies the Water Use Plan objectives. The alternatives are run through an optimization program, formulated in AMPL, to determine the impact of the changes in operating limits and seasonal operating constraints. The program is run for each of the alternatives and the differences in operation, value, flow and reservoir levels can be used in generating the performance measures that will be used in trade-off discussions and analysis. The selection process uses refined alternatives that can produce a win-win solution for all of the parties. The facilitation process identifies, evaluates and recommends a preferred operating plan that must finally be authorized by the BC Water Act.

CHAPTER 4
THE GENERALIZED OPTIMIZATION MODEL

In this chapter the objectives of developing the deterministic generalized optimization model are outlined. This is followed by a description of the user's requirements, which details the goals of the users in this modeling process. A detailed description of the GOM components is in the next section. This section will outline the basics of the GOM model and the modifications to the STOM model to adopt it into a medium-term planning tool. A description of the hydro systems modeled outlines the reasoning behind the choice of plants selected for modeling. The mathematical modeling section is after this to explain the type of solver and the solver language that were used along with the model description.

4.1 Objectives of the Model

The purpose of the medium-term model is to assist the BC Hydro planners to develop the optimal system operational schedules that meet the forecasted firm load and maximize the value of BC Hydro resources. It will make the optimal trade-off between present benefits, expressed as revenues from market transactions and the potential expected long-term value of resources expressed as the value of water stored in the reservoirs. The main decision is to balance when and how much energy to import and export with when, where and how much to store in or draft from reservoirs while meeting the domestic load and system constraints. The model must produce data on the feasibility of system operation and its interconnectivity. The key to doing this is developing a model that the user can trust and that uses the most accurate data available. The output of the model will be an operationally feasible generation and reservoir forebay schedule and system and plants' incremental costs.

4.2 User Requirements

Similar to STOM, the user requirements are the most important aspect of developing the model. The following goals have guided the model development and set the targets for usability benchmarks.

a. The program must be user-friendly. This means that with little training the user can navigate his/her way through the components of the system and come to a solution that is easy to understand and manipulate. This includes making the input and output interfaces simple to understand and making the principles of the model straightforward so that the user can trust the solution.

b. The program could be used by any authorized user in the BC Hydro computer network. There are a number of advantages of having a client/server system for the user. This will allow multiple users of the program with only one license of the solver and the programming language. The size of the model may become so large that a regular computer could not handle the calculations in a stable manner so a dedicated powerful server was deemed to be the best solution.

c. The program must rely on accurate data. The data from the HYSIM and HENWOOD long-term generation and price scheduling models and the Marginal Cost Model (MCM) will form the main source of data along with several additional user input values or changes.

d. The program must be fully integrated with the HYSIM, HENWOOD and the MCM output. This means that little or no manual data manipulation would be necessary in retrieving the output from these programs. The program should read the files and the data should be applied to the appropriate study characteristics.

e. The program must closely model the possible future status of the system. The results of the study must be as accurate as possible and reflect any possible forecasted changes to system requirements. This will mean the addition of dynamic constraints to the problem depending on small changes in future operation.

f. The program must have the capability to conduct medium-term studies. This includes allowing the user to choose a time step of variable length for the hydraulic balance and simulation and to choose a variable sub-time step length (within each time step) for the load resource balance and trade-off optimization. The program must be able to dynamically set the study characteristics including selecting the plants for optimization, the study length, the time step lengths and the sub-time step lengths.

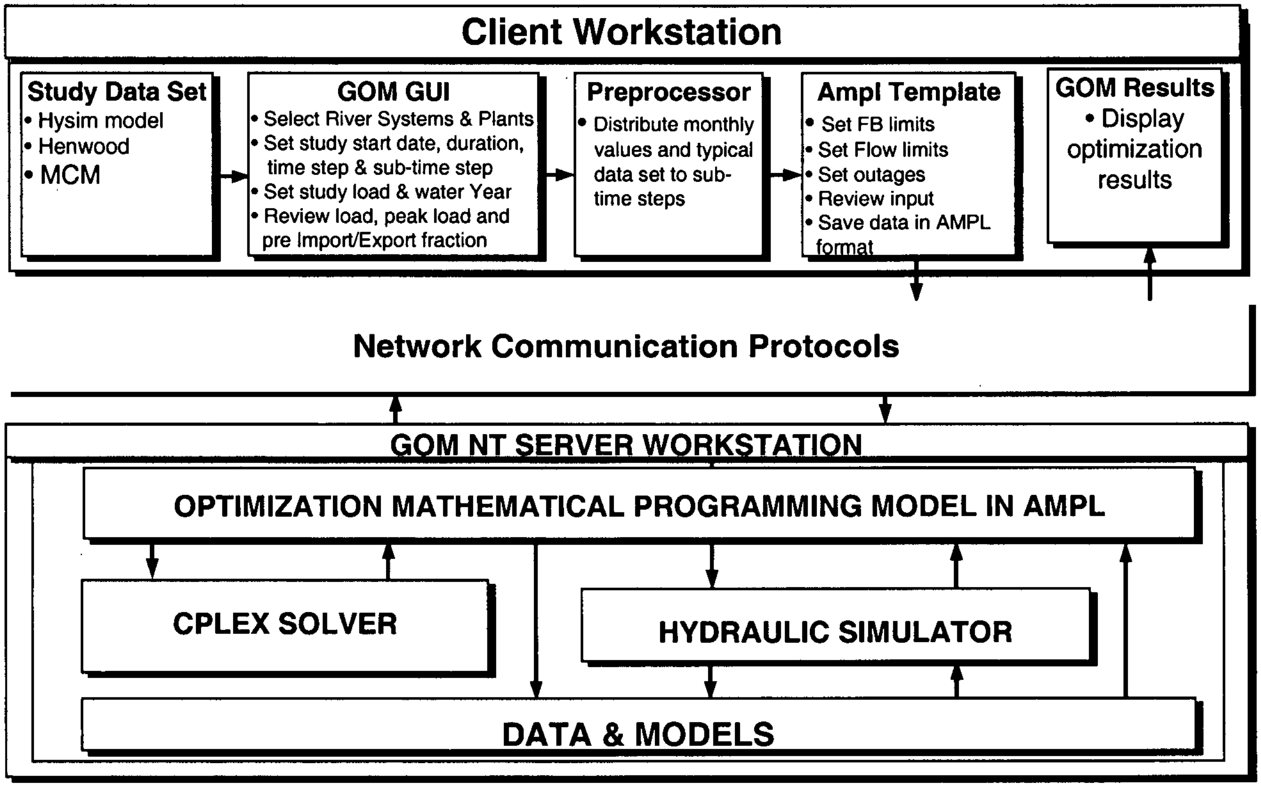
4.3 GOM Components

The Generalized Optimization Model consists of six main components. These components aid the user in completing the optimization study that they wish to carry out. The Generalized Optimization Model consists of the following components:

- Data retrieval from input sources,
- Graphical User Interface (GUI),
- Input Preprocessor,
- AMPL Input Spreadsheet,
- Optimization Model, and
- Results Display Spreadsheet.

The GOM flow chart, shown in Figure 1, represents the processes of the six GOM components and the relationship between the client workstation, the network communication protocols and the GOM server workstation.

Figure 1. GOM Process Diagram



Source: Shawwash, 2002

4.3.1 Data Preparation, Saving and GUI Launch Software

There are three main sources of input for GOM, one is a long-term hydraulic model called HYSIM, the second is a long-term price forecasting model called HENWOOD and the third is a model to calculate the marginal value of water called the Marginal Cost Model (MCM). The models are used in three complementary departments in Resource Management, namely, Planning and Analysis, Business Development, and Resource Coordination respectively.

The HYSIM model is a monthly time step model that determines the most economical dispatch of the generating system under a range of historical inflow sequences. The current practice is to use inflow data for a 45-year record from October 1940 to September 1985 (Newell, 2000). One run of the program for one load forecast year would output a set of monthly generation schedules for each of the historical water years in the range above.

For each time step, the model calculates the firm sources of energy to meet the load, then subtracts these sources from the load to determine the energy requirement from the large hydro and other dispatchable projects (including thermal energy, imports and exports). This energy requirement is then dispatched over different plants according to their incremental cost/value of storage. The plants that have a lower cost of storage will thus store more and those with a higher cost will meet the energy requirements first. A system marginal cost is determined by the incremental cost of the last resource required to meet the load.

The output of HYSIM is in a large text file including the following information:

1. Forecasted monthly loads for the system in GWh,

2. Marginal value of water tables for the entire system and each historical water year in MILS/cubic meter,
3. Forecasted monthly modeled plant generations in GWh for each historical water year,
4. Forecasted monthly independent power producer generation for each historical water year,
5. Forecasted thermal generation for each historical water year in GWh,
6. Pre-scheduled imports and exports for each forecasted water year in GWh,
7. Small hydro generation in monthly GWh for each forecasted water year, and
8. Target end of month forebay levels.

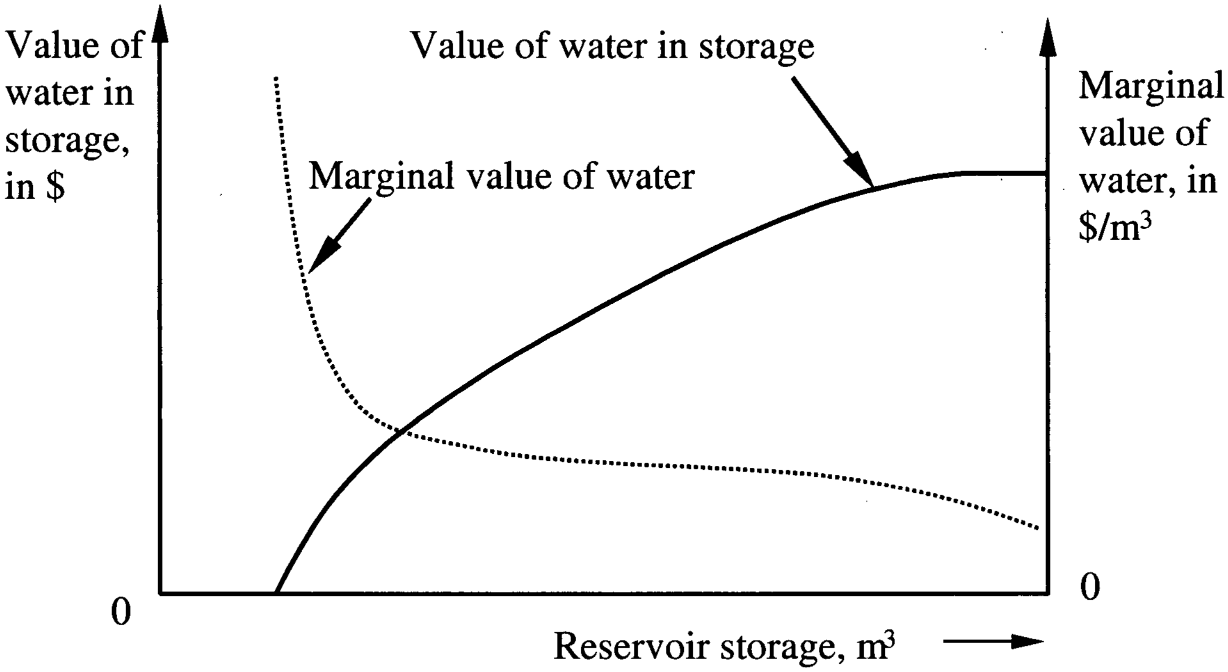
The disadvantage of having the data in the monthly form is that, for the purposes of the GOM model, it is necessary to break them down into hourly data. This process is completed in the preprocessor, as described in the subsequent sections.

Henwood is a program that is used by BC Hydro to forecast mid-term electricity prices and transmission limits for domestic and import/export markets (Newell, 2000). The program calculates market clearing prices and generation production for 29 defined transmission zones that are based on market rules and supply/demand conditions. The objective of the chronological simulation is to meet the hourly loads with minimum economic impact. The simulation is performed on an hourly basis in one-week increments, one year at a time and the market clearing prices generated reflect the cost required to meet the last unit of demand in each transmission area.

The hourly prices and transmission capability information data from Henwood is extremely useful for the purposes of the GOM model because the output data is already in a format that needs little manipulation. The calculated prices are used as the forecasted prices to buy and sell power on the spot market in the model.

The Marginal Cost Model is an optimization model developed by Don Druce (BC Hydro, 2000). This model determines the marginal value of water stored in the Williston Reservoir. Figure 2 below shows the relationship of the value of water and the marginal value of water vs. storage. The value of water increases as storage increases, because as storage increases the ability to generate energy more efficiently also increases. As the reservoir nears it full capacity, the value of water stored increases at a decreasing rate, as more water is stored, the probability of spill will increase. This is demonstrated by the value function that increases at a decreasing rate as storage increases. The marginal value of water is the derivative of the value of water curve and it represents the cost/value of storing an additional unit of water in the reservoir.

Figure 2. Value of Water and Marginal Value of Water vs. Storage



Source: Shawwash, 2002

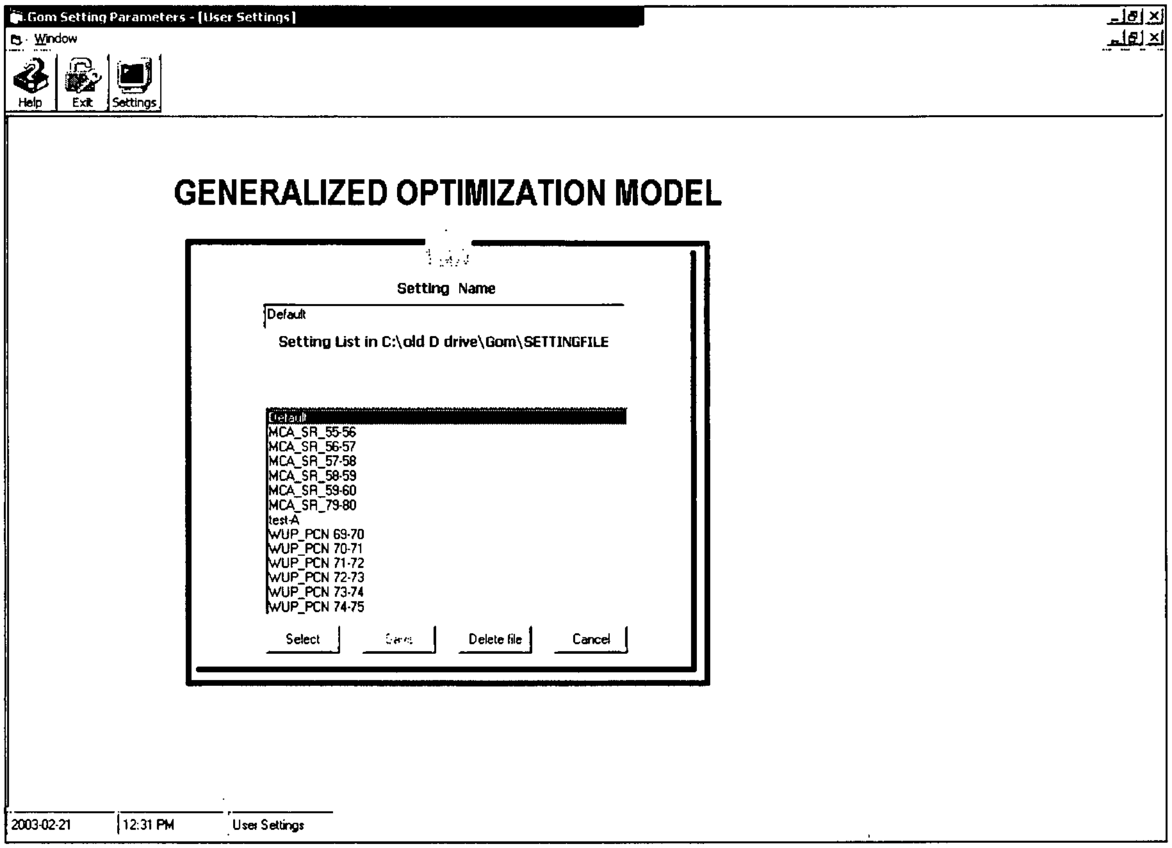
4.3.2 The Graphical User Interface

The graphical user interface (GUI) for GOM is a tool that allows the user to set some of the input parameters for the GOM studies. Computer programmers, Mr. Stephen Mason and Mrs. Daniela Ganea of BC Hydro programmed the GUI. To make the interface user-friendly, it was necessary to automate some data collection processes. The interface is made up of four dialog boxes that are interactive with each other:

- Settings,
- Plants,
- Time Steps, and
- Loads.

The dialog boxes must be completed in consecutive order. The functions of these dialog boxes are as follows.

Figure 3. GUI Start Up Menu – Settings Dialog Box



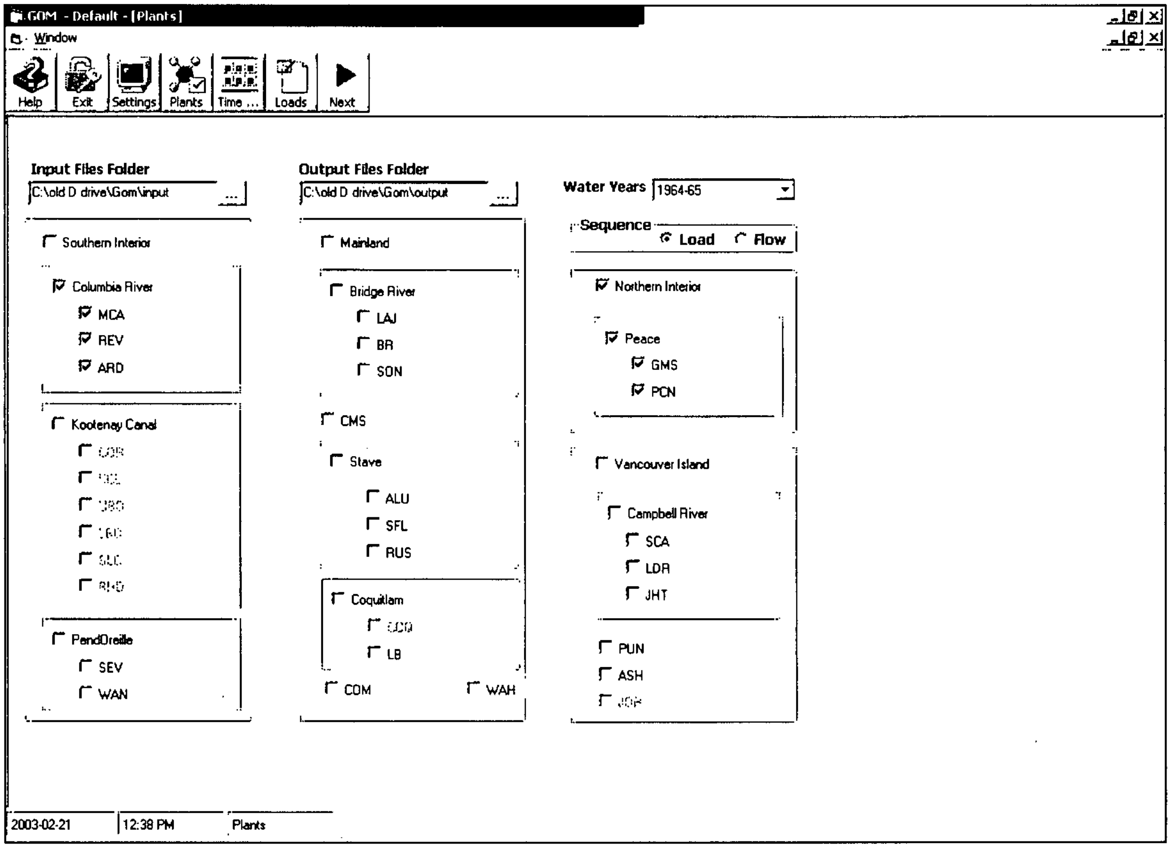
4.3.2.1 Settings

The 'Settings' dialog box, shown in Figure 3, allows the user to start and name a new study or to select a previously saved study. Once the user has finished selecting the study parameters for, they can save their study settings for future use. The settings are saved in a file in a designated directory for later retrieval. This is a useful feature because the user may not want to go through the entire data collection process again if they only would like to make a small change to a previous study. The user may also delete old study settings in this section.

4.3.2.2 Plants

The 'Plants' dialog box, shown in Figure 4, is where the user would choose the directory location of the input/output files and the river systems, plants and historical water year for the study. In addition, the user may specify if the study is a multi-load year study or a single load year study. There are a total of 22 input files in the input directory. The 43 output files from the GUI are saved in a different directory for use by the spreadsheet viewer.

Figure 4. Plants Dialog Box



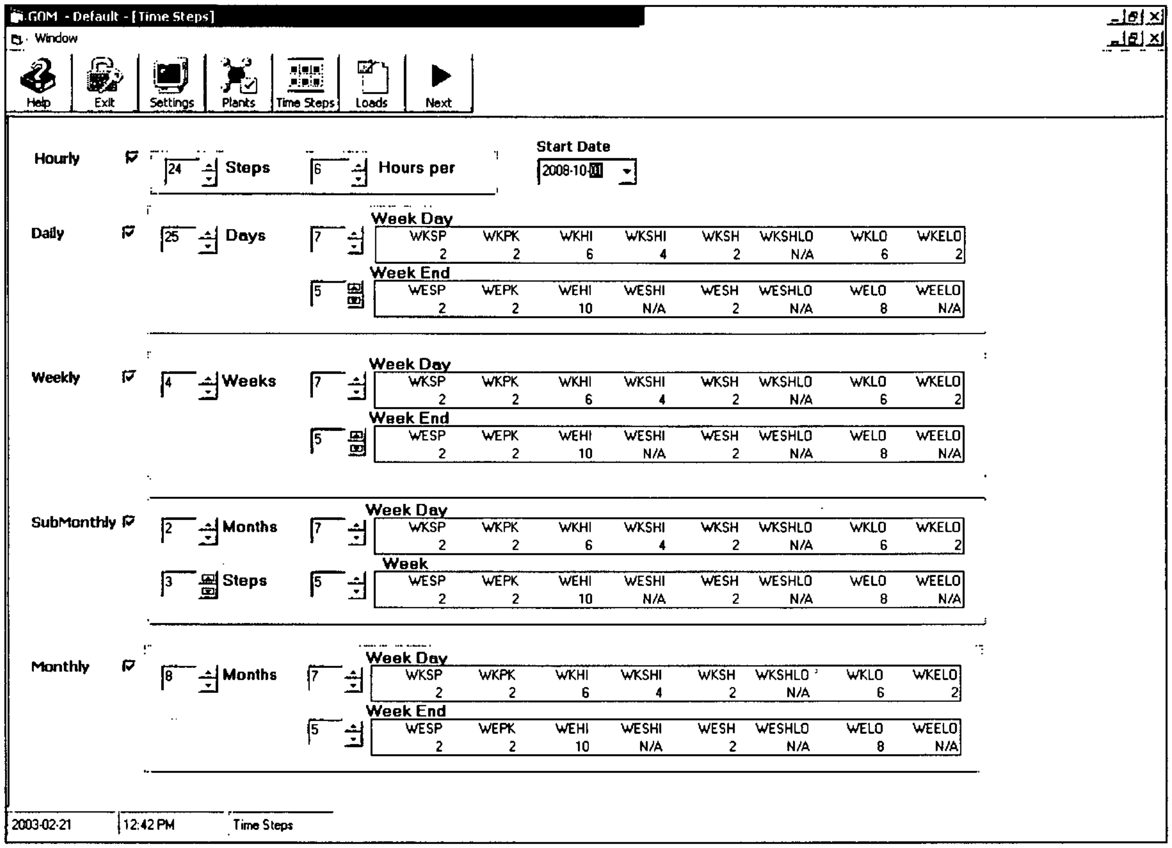
The GUI is designed so the user can select a number of river systems to be included in the study. Some river systems have more than one reservoir and generating plant and as such, the downstream plants in a multi-plant, single river system receive discharge from upstream plants. This characteristic makes the operation of the downstream plants more complicated, so for the purposes of this tool, it is assumed that once the user selects a river system all of the plants in the river system will be optimized. It is possible to model any plant as long as all of the inflows, including upstream plant discharges, are accounted for. A feature is also included in this dialog box to hide the plants that cannot be modeled in the optimization due to unavailability of input data.

The historical water year indicates the data sequence from HYSIM that will be used for the study. A toggle key is included to allow the user to choose between a load sequence and a water sequence study, which is a simplified description of the choice between a single load-year study and a multi-load-year study.

<u>4.3.2.3 Time Steps</u>

The 'Time Steps' dialog box, shown in Figure 5, facilitates input of the chronology of the study. There are three main inputs; the study start date, the time step values and the sub-time step values.

Figure 5. Time Steps Dialog Box



The study start date is the date that the study will commence. This date will determine the load water year data sequence from the HYSIM and HENWOOD output. For example, if the 1964/65 water year was chosen with a single load year in the 'Plants' dialog box, the start date of the study was October 1, 2008 and the study duration was for two years, then the load data for the study would begin in 2008/09. This is because the data from HYSIM is output from Oct yyyy/Sept (yyyy+1). The following example shows which HYSIM data that is selected. For more information see the Graphical User Interface User Guide (Mason, Ganea and Fane, 2002)

Load Year:	2007/08	2008/09	2009/10	…
Sequence 25:	1963/64	1964/65	1965/66	…
Sequence 26:	1964/65	1965/66	1966/67	…
Sequence 27:	1965/66	1966/67	1967/68	…
Sequence 28:	1966/67	1967/68	1968/69	…
etc.				
Sequence 24:	1962/63	1963/64	1964/65	…

Each study is divided into time steps; the length of each time step is not fixed. The ability to change the length of each time step will give the user the flexibility to specify the structure of the study. In addition, the user has the choice of either using a time step of the same length or a combination of different lengths. The options in the graphical user interface allow the user to choose from the following time step lengths or any combination of any of them:

- Hourly
- Daily
- Weekly
- Sub-Monthly
- Monthly

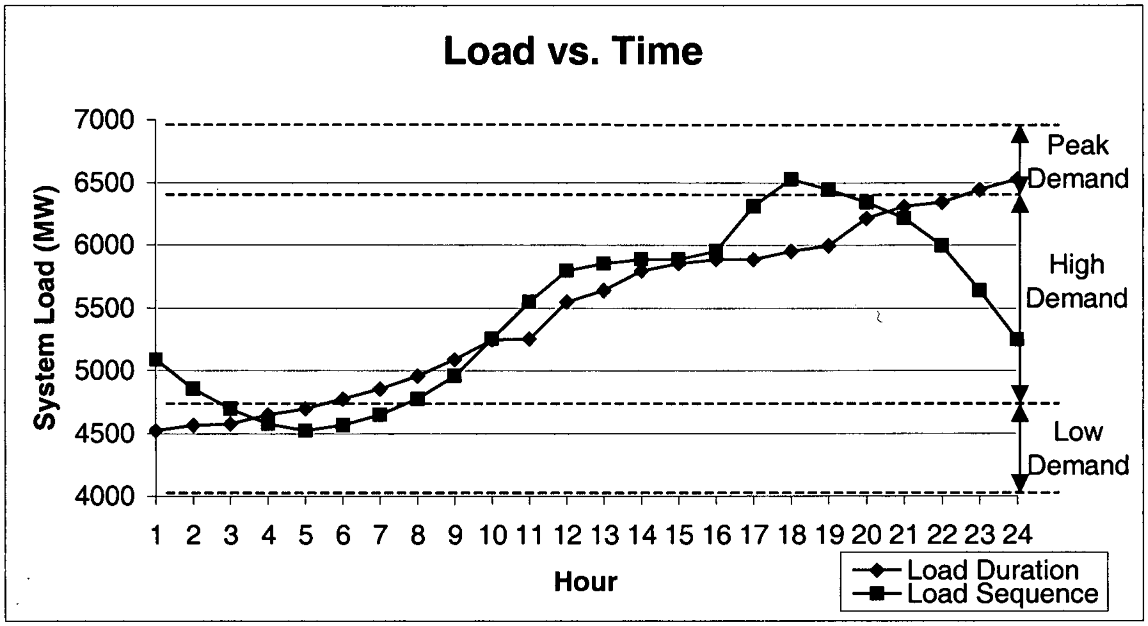
In choosing a combination of time step lengths, the time step lengths must go from shortest to longest to simulate the accuracy of going from present to future conditions. In the mathematical model there is no limit on the length of the time steps or the number of time steps that the user chooses; however the graphical user interface restricts the lengths of the time steps to hourly, daily, weekly, sub-monthly or monthly.

The hourly time steps must have a length less than 24 hours. The number of hourly time steps is also chosen in this section. One of the rules for the hourly time steps is that the sum of these time steps adds to a whole number of days so that the next time step (i.e. daily) would start at the beginning of a day.

All of the other time step length choices are made up of whole days. The daily time steps are 24 hours long. The weekly time steps are always 168 hours long. The sub-monthly time steps vary in length depending on the number of sub-monthly divisions that are chosen and on the number of days in the months. The monthly time step length depends on the number of days in the month.

When choosing time steps that are larger than hourly time step lengths, the program would lose the detail that it could return on an hourly basis. For this reason, it was necessary to have a feature to capture the intricacies of system operations on a daily, weekly and monthly basis. The model performs a load-resource balance and trade-off optimization for each variable sub-time step within each time step. This division will make it possible to perform the optimization process on a more accurate level of details. For each time step in the study, the user can define a set of sub-time steps; these sub-time steps do not fall chronologically within each time step, they are determined by a load-duration curve and their effective demand state (e.g. peak, hi, low) within that time step as shown in Figure 6.

Figure 6. Typical 24-Hour Load Sequence and Load-Duration Curves



The sub-time steps use hourly load-duration curves to represent the load shape within a 24-hour period. For example, for each time step that is greater than an hourly time step, load duration curves are used to represent both weekend and weekday load shapes. Typically, the load duration curve is lower on weekends due to the decrease in demand. The sub-time step thus provides a more detailed view of the load/resource balance and the market trade-offs under different system demand conditions. The sub-time step divisions are based on a user-specified number of sub-time steps and number of hours in each sub-time step. The user can select up to 8 sub-time steps as follows:

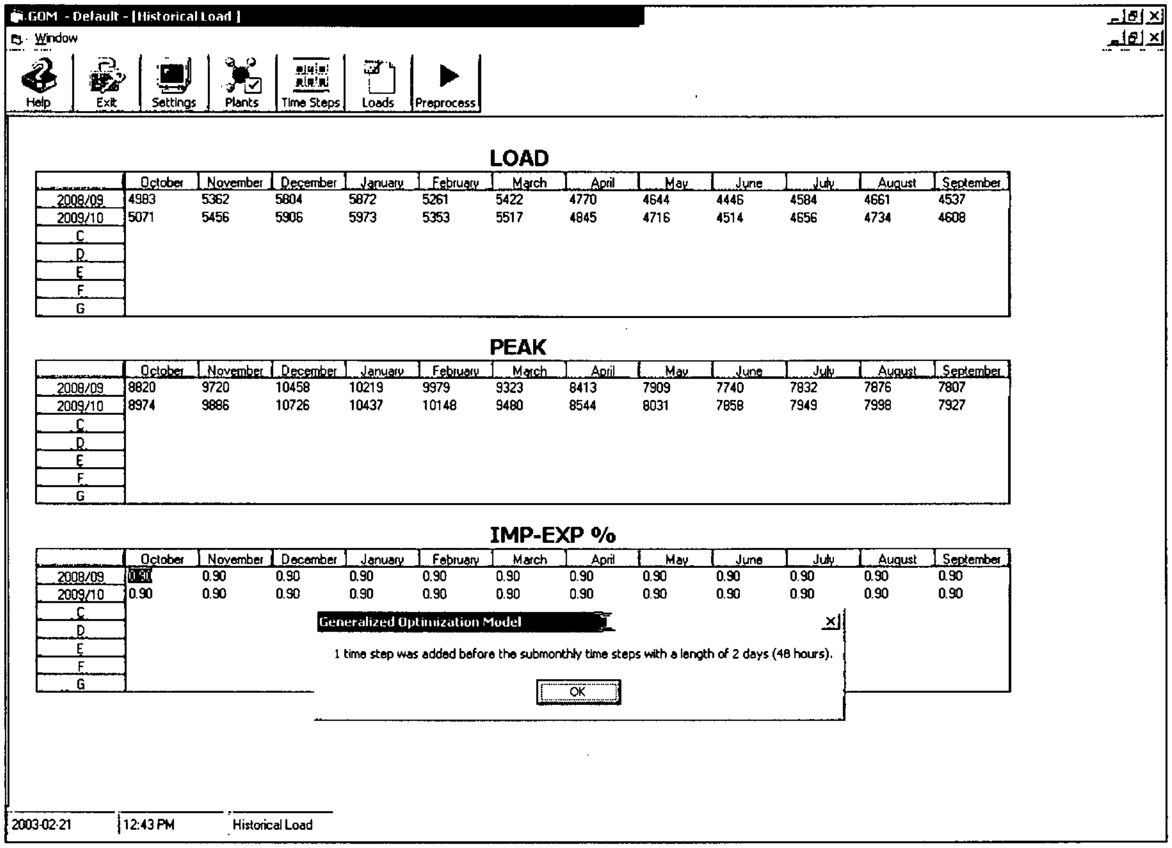
- Super Peak Load
- Peak Load
- Heavy Load
- Shoulder Heavy Load
- Shoulder Load
- Shoulder Light Load
- Light Load
- Extreme Light Load

The sum of the hours in the sub-time steps must equal 24. If some of the input is inconsistent, then the user will be notified and prompted to correct it. Validation of the user input is performed once the user moves to the Loads dialog box.

4.3.2.4 Loads

The 'Loads' dialog box, shown in Figure 7, allows the user to check the study duration, the forecasted total monthly BC Hydro system load, the forecasted monthly peak load, and the prescheduled import and export fractions.

Figure 7. Loads Dialog Box



A simple procedure is run when entering this dialog box to gather some of the input from HYSIM to make sure that the study parameters are correct. There are three tables on this display to show the load data, the peak load data and the import/export fraction data. Each table contains highlighted data that confirms the sequence of the study length. These tables allow the user to check that all of the HYSIM data is available and to modify the load, peak and fraction values.

The prescheduled import and export default fractions can also be modified in this window. These fractions indicate the percentage of imports and exports that will be pre-scheduled and thus not available for optimization.

This final dialog box includes a 'Pre-processor' button that will run the Pre-processor as described below.

4.3.3 The Preprocessor

The pre-processor is a program that was written by Mr. Amir ala Alavi. His work produced an invaluable tool to convert monthly HYSIM and HENWOOD data into time step and sub-time step data format, which can be used in the optimization model.

To calculate the load, the preprocessor uses a historical load shape and applies it to the study dates. Historical load data is stored on the client station that has typical hourly data for four weeks in each month of one historical year. The study year may not be the exact same configuration as the historical year so the data must be recalculated in the appropriate format. The pre-processor rearranges the typical historical load data into the corresponding study period, which will give a historical load shape for the present study period. The relative hourly historical demand is then calculated to give an hourly percentage of the historical monthly demand that can be multiplied by the forecasted monthly demand to calculate the forecasted hourly demand on the system. These values are then checked with the forecasted system peak load to make sure that the forecasted and calculated peak loads are the same. If there is a difference, then an adjustment is calculated with the difference shifted to other time steps. A similar procedure is used to calculate the forecasted plant generations for each time step as these values also follow a specified shape.

The forecasted imports and exports are output from HYSIM. The values include both the prescheduled transactions and forecasted spot market sales. For the purpose of this model, the two need to be separated. The prescheduled transactions are calculated as a percentage of the total monthly forecasted imports and exports set out by the fractions in the 'Loads' dialog box. The remaining transactions are left as a variable for optimization. The prescheduled imports and exports for each time step are then calculated using typical transaction shapes for weekdays and weekends. The typical shapes are based on the fact that the heavy load hours occur during the day and the light load hours occur during the night and early morning hours. This shape is applied to the study time steps by calculating the number of light load and heavy load hours in each study month and then factoring the prescheduled imports and exports for the light load and heavy load hour time steps.

The Burrard Thermal Plant, independent power producer (IPP's) and non-treaty storage (NTS) generation values are calculated in a similar manner, although in these cases it is assumed that the generation is the same level in heavy and light load hours.

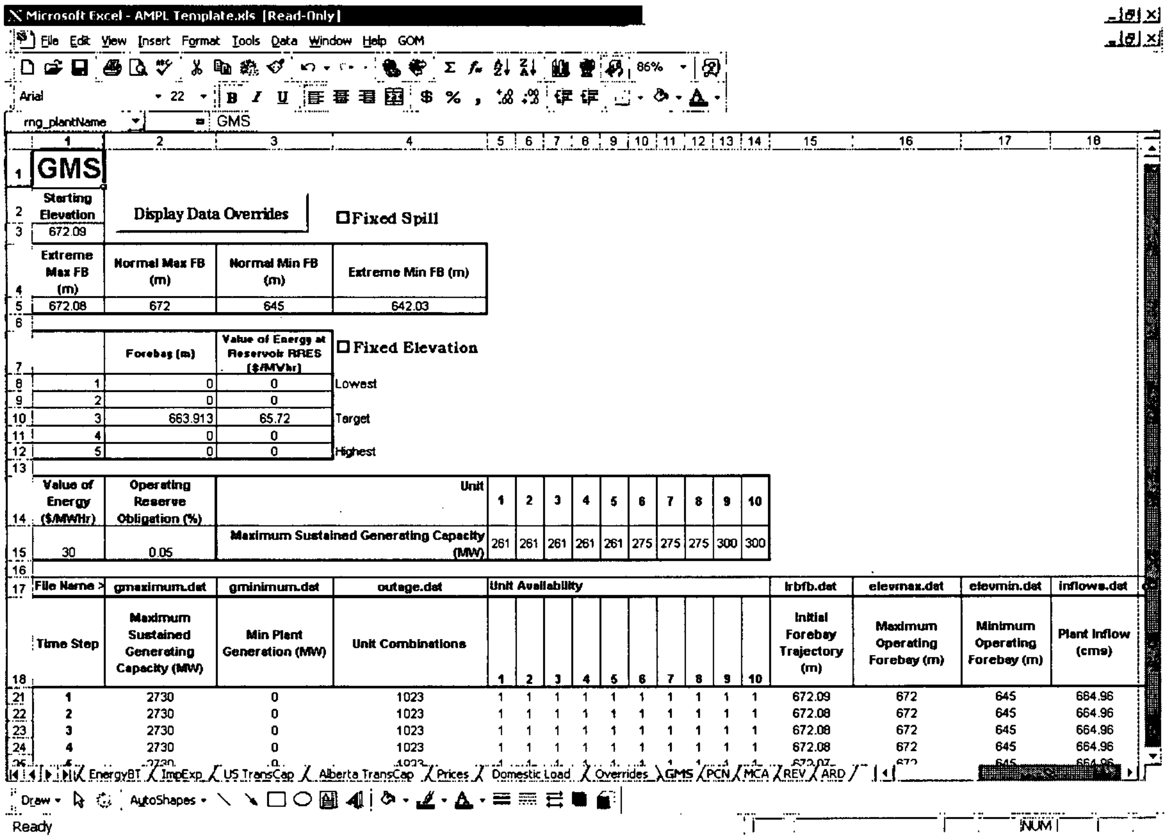
The forecasted prices are applied to the time steps in a similar manner. The prices are organized into hourly data for four typical weeks of each forecasted month of the study year and averaged over the time steps to calculate the prices used for the spot market sales to Alberta and the US.

4.3.4 The Input Display Software

An Excel workbook, shown in Figure 8, is used to display the output of the graphical user interface and pre-processor. In this workbook, the user can view and modify the output from the pre-processor. There are 6 fixed worksheets in the workbook that contain system parameters. The first worksheet contains the main 'Study Parameters' including start date, number of plants, number of time steps and operating reserve information. The other five worksheets contain the forecasted system load for each time step, the fixed residual generation for the system, the Alberta and US market prices, the Alberta and the US transmission limits and the prescheduled imports and exports.

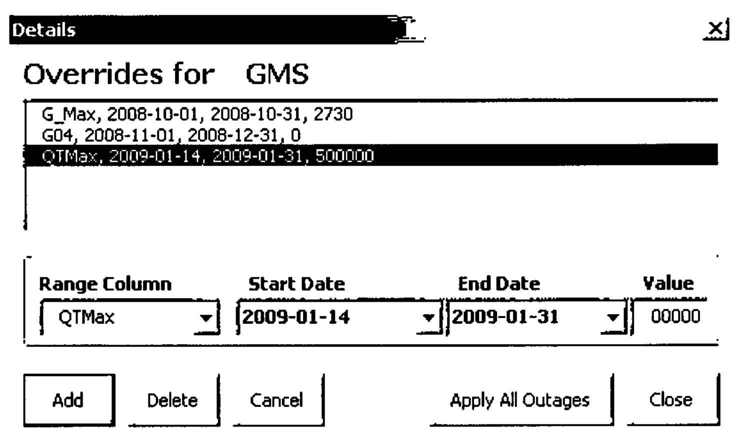
Each optimized plant in the study has its own worksheet, which details the plant limits and inputs. For each time step, there are forebay limits, unit availability, discharge limits, forebay values, generation limits, forebay change limits, fixed forecasted spill, inflows, generation ramp rates and turbine discharge ramp rates. In addition, there are tables for the marginal value of water and the end of study target forebay.

Figure 8. Excel Input Display Plant Worksheet



On each plant worksheet there is a tool to dynamically update the default values for a number of limits, as shown in Figure 9. This tool allows the user to override specific limit values by entering specific rule attributes including, plant name, unit number (if applicable), limit value and a start and end date. These rules are saved to a worksheet called 'Overrides', which is passed on as an input file so the user can modify it as necessary. This tool was designed to automate the process of updating the input parameters in Excel, but since the time to make changes in Excel took too long to process, it was decided to develop a program to process the rules in AMPL.

Figure 9. Rules Dialog Box for Plants

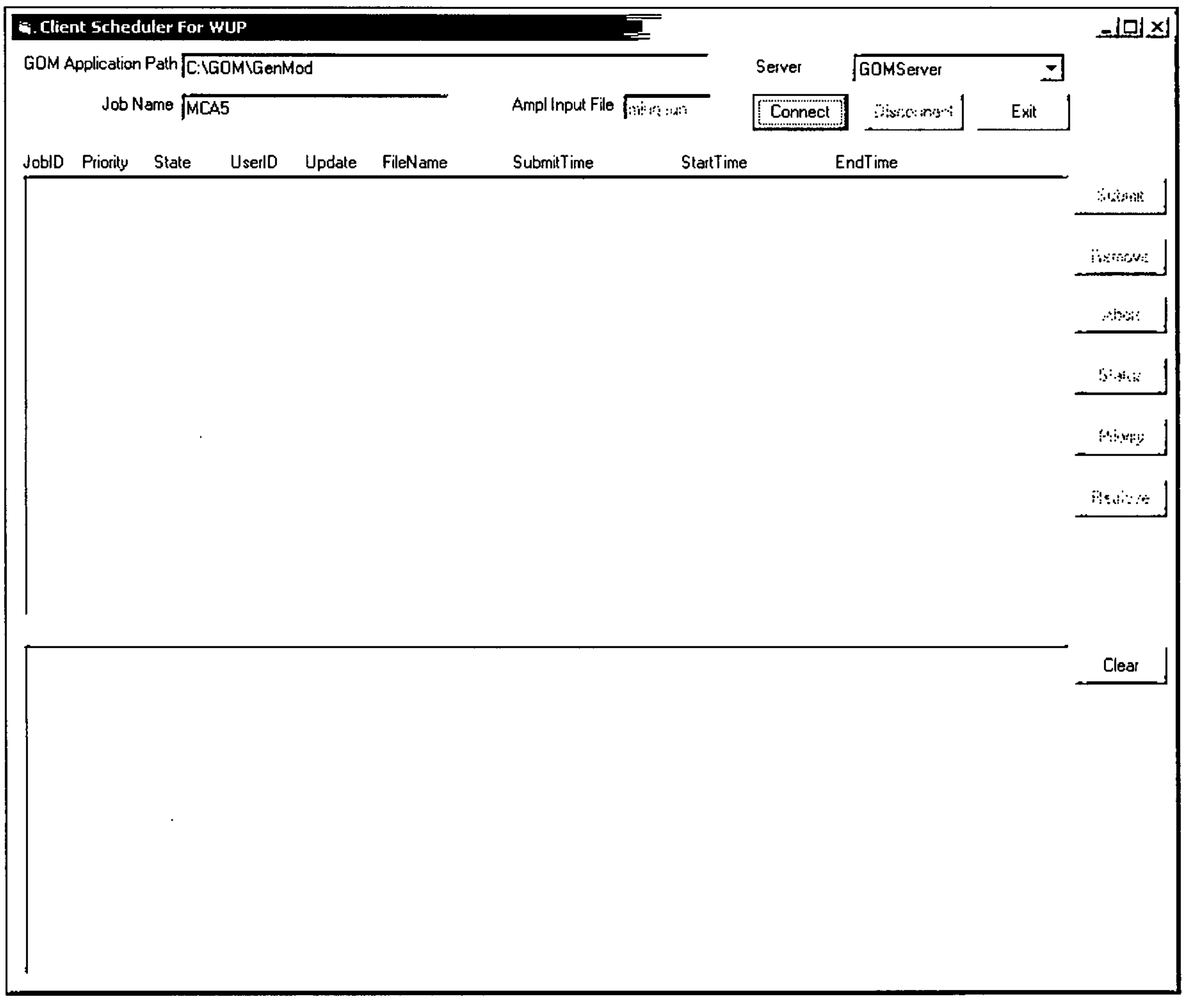


The Excel Input display collects the system and plant information and writes out several files in the AMPL and simulator format, which are then transferred onto a dedicated server to perform the optimization process.

4.3.5 The Communication Protocols

The communication protocols pass the input information from the client workstation to a dedicated AMPL server (where the optimization occurs) and return the optimization results. A client scheduler, shown in Figure 10 and written by Mr. Johnny Gan, allows users to select input and output paths for each run and co-ordinates the use of the server for multiple users according to a priority order. This allows the users to bump low priority for higher priority runs if there is some urgency to obtain results.

Figure 10. GOM Client Scheduler



4.3.6 The Optimization Model

This component is the hub of the entire process. The optimization model is a decision analysis tool that is made up of a number of files written in the AMPL modeling language: data files, run files and one model file. The model file is a declaration of the optimization problem, it contains the basic elements of the optimization problem: the objective, the variables, the constraints and the parameters. The data files contain the parameter values for the problem instance and the run files contain the algorithm for setting up the problem and then call the solver to solve it. These files may also include procedures to calculate additional parameters and rules. The solver is a CPLEX program that reads the problem instance generated by AMPL and finds the optimum variable values to maximize the objective function. The solver outputs files are then communicated back to AMPL, which writes out the results for display in the Results Display Software.

4.3.7 The Results Display Software

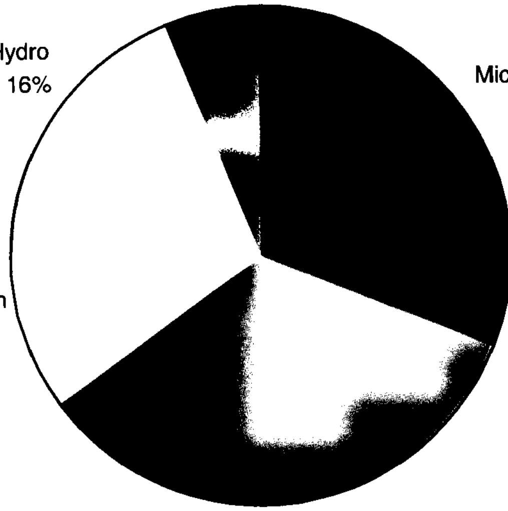
The Results Display Software, developed by Mr. Chi-ho Yeung, is used to display the output of the optimization process. There are a total of 29 output text files that are imported by the display software. Microsoft Excel is used as a base for the viewing software because of its ease of programming and use of charts. The software allows the user to view the output in a variety of ways, including examining alternative studies and comparing specific parameters for different demand sub-time steps. The output files for the results display software are listed in Appendix IV.

To make it easier for the user to view and assess the results of multiple runs, up to six workbooks can be linked. The results are displayed in graphs of plant generation, discharge, forebay, the US and Alberta market summaries and the system summaries for the load resource balance. One main base case workbook is linked to up to five alternative workbooks. Procedures within the workbooks allow the user to compare output data of the alternative studies on one chart or to compare output data from the sub-time steps within these alternatives. A sample of the graphical representation of the output can be found in Appendix VI.

4.4 Hydroelectric Systems Modeled

For the purpose of this study, only the plants in the Columbia River System and the Peace River System are modeled. The GOM system can easily be adapted to model other plants in the BC Hydro System. The Peace River includes the G.M. Shrum and Peace Canyon projects while the Columbia River projects include the Mica, Revelstoke and Keenlyside (Arrow) plants. As shown in Figure 11, these five plants were chosen because together they produce approximately 65% of BC Hydro's energy requirements.

Figure 11. Generation from BC Hydro Sources



Source: BC Hydro, 2000

4.5 AMPL Software

AMPL is an acronym for A Mathematical Programming Language. The GOM program is written as a mathematical representation of the optimization problem in files that are read by the AMPL program. The CPLEX solver reads the AMPL problem declaration and solves the optimization problem.

4.6 Mathematical Modeling

STOM can easily be transferred into a medium-term model by letting the user choose the number of time steps and sub time steps and changing the input data sources. There were additional changes to the model to make this transition more representative for medium-term studies. The model description and the changes are described in the following paragraphs and the main model declaration is listed in Appendix I.

4.6.1 STOM Modeling

The GOM model follows the same modeling methodology adopted in STOM. The Short Term Optimization Model (STOM) is a program that was written in AMPL by Dr. Ziad Shawwash. The program is operational and is used by the shift engineers at BC Hydro to plan the generation schedule for short-term studies. The user can select one of four objectives for the analysis. The default objective function is to maximize the value of spot market sales and future reservoir storage. Each study is done for up to a seven-day period with an hourly time step. For more details see Dr. Shawwash's thesis (Shawwash, 2000).

4.6.2 *GOM Modeling Basics*

The model file is the declaration of the problem and is written in AMPL. There are five main declarations that can be used in each optimization model:

SET
PARAMETER
VARIABLE
CONSTRAINT
OBJECTIVE FUNCTION

A 'SET' command is a declaration used for indexing the problem. The indexing can be used for parameters, variables, constraints, and for the objective function. The name of the set is followed by a list of strings or numbers for which to index the array of values over. There are ten sets used in GOM, as listed below:

- RIVER –the river systems that the optimized plants are based on
- PLANT – the set of user specified plants to be optimized
- FCCPLANT* – the set of user specified plants that have flood control curves
- HPL* – the set of divisions of the time steps into sub-time steps based on market conditions
- HPLWK* – the set of divisions of the weekday time steps into sub-time steps
- HPLWE* – the set of divisions of the weekend time steps into sub-time steps
- WKSTEPS* – the set of time steps that fall on weekdays (for output)
- WESTEPS* – the set of time steps that fall on weekends (for output)
- MONTHS* – the set of months in the study duration
- TT* – the set of time step hours in each day
- 1..T – the pseudo set of time steps in the study.

The asterisk (*) indicates sets that were added to the STOM model to convert it into the generalized optimization model.

The set HPL constitutes the main change from the short-term optimization model. This set allows the user to represent the generation schedules for different demand times in each time step (sub-time steps).

Almost all of the parameter values, constraint and variables in the model are indexed over one or a combination of these sets. The parameter values in the problem are assigned constant values unless they are recalculated in the run script files. This is usually done before or after the solver completes the solution. The majority of the parameter values in the problem represent the values of limits for the constraints. The following are the main constraints in the optimization model:

- STORAGE – the simulated plant storage or the reservoir mass-balance equation,
- STORAGE_BOUNDS – the storage must be between the minimum and maximum storage levels,
- STORAGE_INCREMENT* – the positive change in storage from time step to time step must not exceed a user-specified storage increase rate,
- STORAGE_DECREMENT* – the negative change in storage from time step to time step must not exceed a user-specified storage decrease rate,

- TURBINE_BOUNDS – the turbine flow must be between than the minimum and maximum turbine discharge limits,
- GEN_INCREMENT* – the positive change in generation from time step to time step must not exceed a user-specified generation increase rate,
- GEN_DECREMENT* – the negative change in generation from time step to time step must not exceed a user-specified generation decrease rate,
- PLANT_DISCHARGE – the plant discharge is equal to the sum of the turbine discharge and the plant spill,
- PLANT_DISCHARGE_BOUNDS – the plant discharge is limited between a minimum and maximum parameter value,
- SPILL_DECINCR* – the spill at the Arrow (ARD) plant must be the same throughout the day for hourly time steps,
- LOAD_BALANCE_SPOT – sum of the optimized plant generations, residual loads, imports, exports (negative), the spot market transactions must be greater than or equal to the load on the system,
- SPOT_US_TRANS* – the spot market sales to the US must be between the US tie line transmission limits,
- SPOT_AB_TRANS* – the spot market sales to Alberta must be between the Alberta tie line transmission limits,
- RM_BUFFER – the sum of the plant regulating margins for each sub-time step must be greater than the minimum system regulating margin buffer,
- GENERATION_LIMITS – the plant generation at any sub-time step must be within its' operating limits, and
- POWER_GENERATION – the converted value of plant generation and an additional power requirement must be greater than the optimized plant generation.

The constraints with an asterisk (*) are the new constraints added to the generalized model to enhance representation of medium-term studies.

Variables, also called decision variables in optimization, are the elements in the optimization model that can change to produce optimal results. A trade-off must be made between variables through the constraints to find the best course of action. In this case the course of action is how to schedule the optimized plants and spot market sales to maximize the value of resources. The following variables are used in the study.

- Spot_USH* – the spot market sales to the US for each sub-time step,
- Spot_ABH* – the spot market sales to Alberta for each sub-time step,
- G_RM_BUFFER* – the regulating margin requirement for each plant for each sub-time step,
- QT* – the plant turbine discharge for each sub-time step,
- UT* – substituted variable indicating the turbine discharge into a plant from another plant in matrix form,
- RQTR* – substituted variable indicating the turbine discharge from a plant to another plant in matrix form,
- QP* – the total plant discharge for each sub-time step,
- QS* – the total plant spill for each time step,
- US* – substituted variable indicating the plant spill as inflow into another plant,
- RQSR* – substituted variable indicating the plant spill as discharge from one plant into another in matrix form,

- VTEMP – a temporary storage variable,
- VDIFFQT – a volume change associated with the turbine discharge,
- DQT – a change in turbine discharge variable,
- V – a storage variable indicating the volume of water in a reservoir at a sub-time step,
- P_all – the total generation at a plant including regulating margin, and
- QTTEMPdQT – a temporary change in discharge variable.

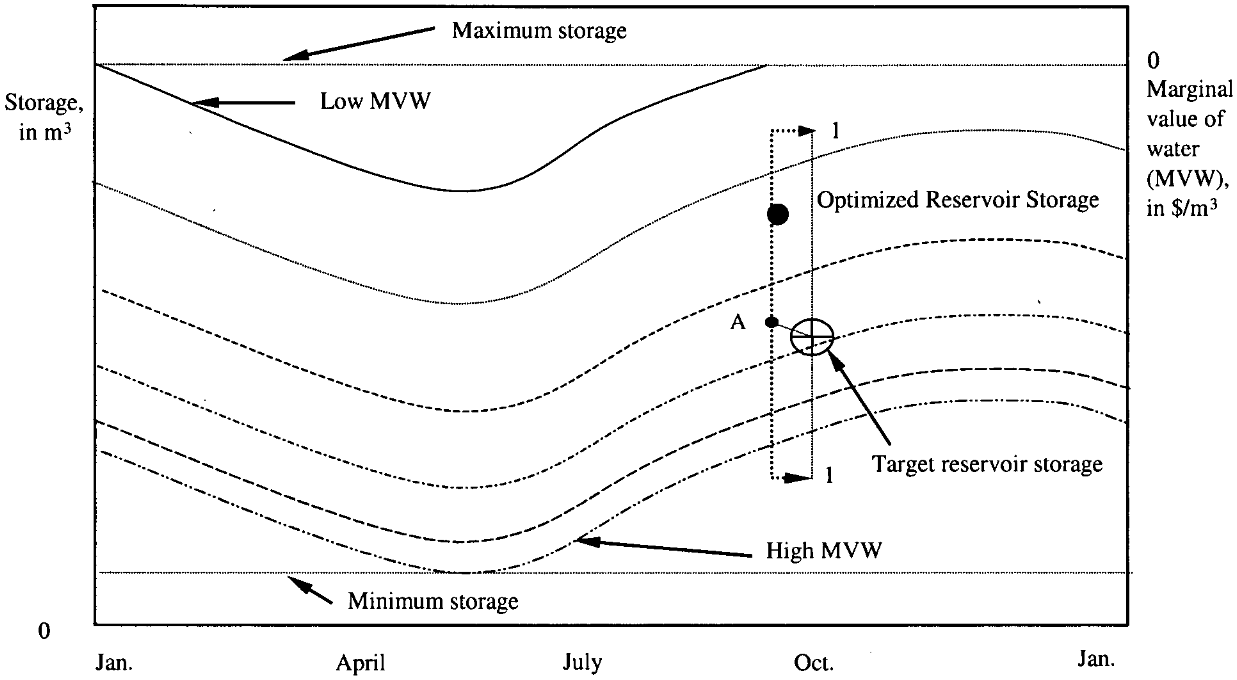
Variables with an asterisk (*) indicate new or changed variables in the model. Most of the variables are only modified to include sub-time steps whereas the QS variable has been changed from a constant parameter value to a variable.

Lastly, the objective function is made up of three terms, namely the total value of the US and Alberta spot market sales, summed over time step and sub-time step and converted to US$, and the value of deviation from a target storage as described below:

```
maximize EXTRA_POWER_AB_US :
    sum {t in initial..T, h in HPL} Spot_USH[t, h] * price_USH[t, h]
  + sum {t in initial..T, h in HPL} Spot_ABH[t, h] * price_ABH[t, h] * USExchRate
  + sum {j in plant} (24 * 3.6 * (<<{n in 2..tvnpce[j]-1}dVbkpt[j,n];{n in 1..tvnpce[j]-
    1}dPslope[j,n]>>(VDiff[j])));
```

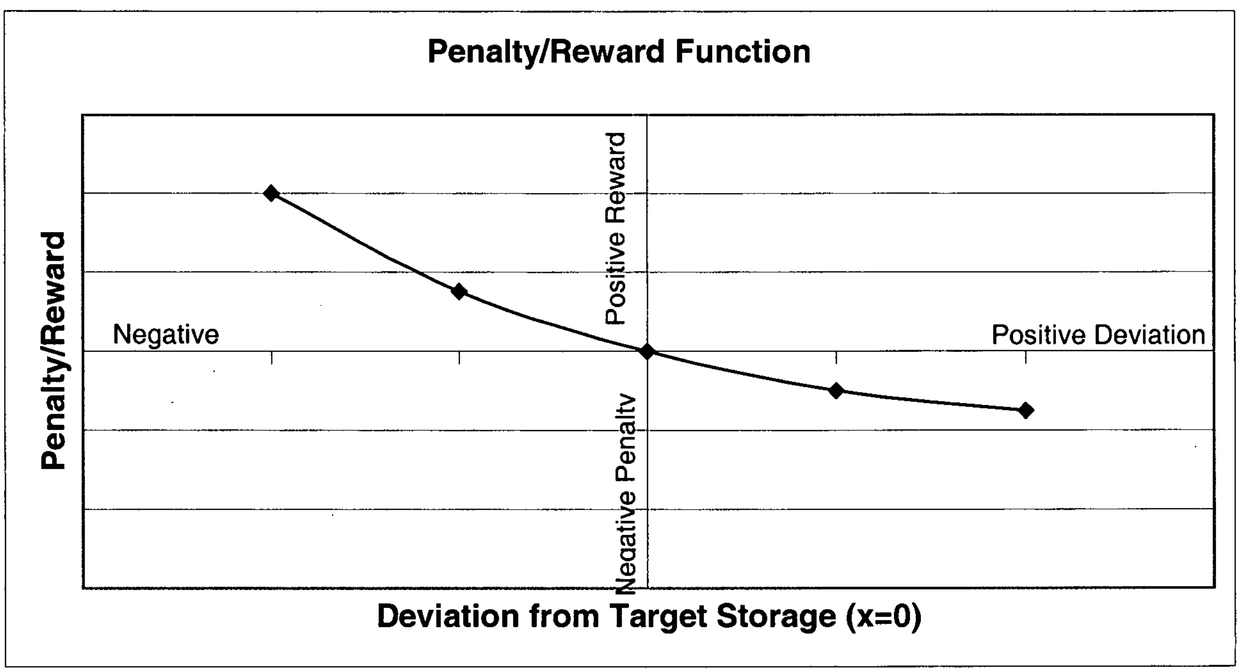
The last term in the objective function represents a penalty/reward function depending on the deviation from the target reservoir storage at the end of the study. The penalty function is a piece-wise linear term that shows the change in marginal value of water with the change in storage. Figure 12 below shows the relationship between the Marginal Value of Water, Storage and Time. Cross-section A indicates that at any time in the year the relationship between the Marginal Value of Water and Storage can be represented as a penalty reward function as indicated in Figure 13. The user inputs a target end of study storage for the optimization process. If the optimization finds a more valuable return that does not meet this target, there is a penalty applied to the objective function by taking the deviation in storage and finding the corresponding deviation of the marginal value of water to be taken from or added to the objective function.

Figure 12. Graph of the Relationship between the Marginal Value of Water as a function of Storage and Time



Source: Shawwash, 2002

Figure 13. Marginal Value of Water Penalty/Reward Function



The GOM algorithm reads in all of the input parameters controlling the constraints, sets the objective function co-efficients, calculates some additional input parameters, sends the problem to the solver to optimize it and print out the results. The following section describes a rule-based component used to calculate and manipulate the input data.

4.7 Rule Based Optimization

In real life, simple limits are not always realistic. Many of the operational limit values are usually defaulted to operating values that are the same for every time step and sub-time step. There may be small changes to parameter values for different time steps and sub-time steps, so it would be advantageous to have an easy-to-use process to model these changes. To do this, an algorithm was developed to read in these changes and apply them to the data sets used in the optimization process. This process is described in the following sections.

4.7.1 Goal and Objectives

The goal of this rule-based optimization was to produce a simple, automated procedure for updating a GOM input data set with operating rules from a generation schedule. This procedure is the first step in automating the generation schedules, and applying them to different optimization models (STOM, GOM). The initial stage of this development produced an automated tool that was used in the Excel Input Display; this tool was easy to set up, but due to large data sets, the procedures took too long to process in Excel. For this reason, it was decided to try the same method in AMPL with the following objectives:

- The first objective was to produce a tool that would enhance the current model by allowing the user to automatically update an input data set. This was achieved by the development of a series of programs to read in user-specified rules and to update the base input data.

- The second objective was to use the rules from a daily generation schedule that sets the operational limits for the BC Hydro plants. This was achieved by the collection of daily schedules for the entire year and finding patterns for the types of rules and the plants that use them.

- The third objective was to make the program quick and easy to use. This was achieved by the utilization of text files for the generation schedules, which can be easily formed in an Excel spreadsheet or by a future process to automate the generation schedules themselves.

- The fourth objective was to correctly apply the dates from the generation schedules to the time steps in the study. This was done by converting the generation schedule dates into time steps and shifting them according to their respective weight in each start and end time step.

4.7.2 Generation Schedules

Many of the rules that are used in real life situations are seasonal. For example, annual maintenance on turbine units is usually done at the same time every year and flow limits change seasonally on different river systems at different plants. At BC Hydro, these changes are depicted in a Generation Schedule Order in narrative form.

A generation schedule is a document produced by the system planners to reflect the desired operating modes of the system. The majority of the rules give specific operating constraints on each plant. Each rule has a set of attributes associated with it, such as the type of rule, the plant at which it occurs, the value of the rule and the starting and ending date for the rule. This research examined the rules that were used over a one-year period. It was found that one could formulate patterns and generate a list of the most common rules that were used. Fifteen common rules were chosen for this study because of their high frequency and their ease of implementation. The following paragraphs detail the plants that were chosen and the most common operational rules that were used at those plants.

4.7.2.1 Plants

Upon review of the Generations Schedules for one year, it was decided to examine, in detail, the rules that were used for operating the following 15 plants for two main reasons. First, these plants share the majority of the domestic load, and second, these plants are also the plants listed in the graphical user interface.

Stave Falls	Bridge River	Campbell River	Jordan River	Peace River	Columbia River
Alouette	LaJoie	Ladore	Jordan	G.M. Shrum	Mica
Stave Falls	Bridge	Strathcona		Peace Canyon	Revelstoke
Ruskin	Seton	John Hart			Keenlyside

4.7.2.2 Rules

A total of fifteen rules were chosen to be included in the model, fourteen of which were derived from the generation schedules. The rules were chosen because they could be easily modeled in GOM. The following paragraphs describe the set of rules used in this study

FLATC –Full Load Around the Clock – This rule is used when the plant is required to generate at its maximum generation capacity of the available units for all of the specified hours. If a unit is unavailable for generation, it will not be included in the maximum generation calculation and the maximum generation of the plant will be reduced accordingly.

SD –Shut Down – The plant will not generate for all of the specified hours.

OOS – this is an acronym for Out of Service. This could apply to a unit or a plant. For the purposes of our study, the program treats OOS as a plant shutdown, thus similar to SD above. A unit outage will be treated as an 'OUTAGE' below.

ATCGEN (MW) –Around the Clock Generation – This rule sets the plant generation to a specific value (MW) for the duration of the specified hours.

MAXGEN (MW)– Maximum Generation – This rule fixes the plant maximum generation to a specific value (MW) for the duration of the specified hours. The change in this value may or may not affect the model depending on whether or not the plant generation limits constraint is binding.

FIXGEN (MW) –Fixed Generation – This rule fixes the scheduled plant generation to a specific value (MW) for the duration of the specified hours. This command fixes a variable and as such reduces the complexity of the problem.

MINGEN (MW) –Minimum Generation – This rule sets the minimum plant generation parameter to a specific value (MW) for the duration of the rule. This rule is similar to the MAXGEN rule in that the rule may not affect the model outcome if the plant generation limits constraint is not binding.

MINCMS (cms) – Minimum Discharge – This rule sets the minimum plant discharge to a specific value (cms) for the duration of the rule. This rule may not affect the objective function if the plant discharge constraint is not binding.

MAXCMS (cms) – Maximum Discharge – This rule sets the maximum plant discharge to a specific value (cms) for the duration of the rule. This rule may not affect the objective function if the plant discharge constraint is not binding.

OUTAGE (Unit #, e.g. G01) – Outage Request – This rule removes a specific unit at a plant for the duration of the rule. This means that the number of possible combinations of units will be decreased for the range. This request will also reduce the calculated maximum plant generation by the unit's maximum generation.

SPILL (cms) – Fixed Spill – This rule changes the plant spill from a variable to a fixed parameter value (cms) specified in the generation schedule. The conversion to a parameter will reduce the scope of the problem for the solver by reducing the number of variables.

TARGET FB (m) – Target Forebay – This rule changes the forebay variable value at the end of the range to the user specified value (m) in the generation schedule. The procedure for this is to set the forebay and corresponding volume constraints to the value for the last time step in the range.

MINFB (m) – This rule sets the minimum limit of the forebay constraint to the user specified value (m) for the specified hours. The minimum forebay rule is often used in combination with the maximum forebay rule to limit the forebay between these two values.

MAXFB (m) – This rule sets the maximum value of the forebay constraint to the user specified value (m) for the specified hours. The rule is often used in combination with the MINFB rule to limit the forebay between two values. The rule also updates the maximum volume limit using the forebay storage curves.

MINTWEL (m) – This rule limits the minimum tailwater elevation value (m) for the specified hours. The code to include this rule is quite simple so it was included in the set of rules.

ADDUNIT – This rule is the only rule that adds capacity to the system. Instead of decreasing the number of possible combinations of online units, the extra unit doubles the number. This extra unit also increases the maximum generating capacity of the plant.

4.7.3 Seasonal Changes

Some of the rules occur seasonally throughout the year. For example, during the winter there is the possibility of ice forming on the Peace River. It is necessary to prevent this ice from collapsing, so the plant generation fluctuation must be kept to vary within a specific range. Also, it is necessary to take units out at plants at specific times in the year for annual maintenance. This is usually done at the same time every year to take advantage of low seasonal demand. For example, units at Mica and Revelstoke are usually taken out of service one at a time in late March and April when the demand is low. Other seasonal rules include maintaining water levels within a given elevation range for fish and recreational purposes, or maintaining minimum discharge levels for fish to spawn in the early fall or maximum generation ramping level for lake recreation in the summer.

4.7.4 Formulation of Rules in AMPL

A text file contains an identification symbol for each rule followed by its attributes can be produced manually or it can be generated automatically in the future. Overriding the system parameters means either changing an input data value or adding/removing limitations from the problem. Each override changes one value for a user-specified duration defined by two different dates. The overrides represent plant and system constraints, or restrictions on unit availability. The program can apply each rule to all time steps and thus can reduce or increase the problem size, as shown in Figure 14.

Each rule is defined by six attributes: the rule name, the plant name, the value of the rule, the value of the unit (if a unit outage) and the start and end date of the rules. The first step in the program is to read in the rules and their attributes.

For each rule, their start and end dates are converted into serial numbers to compare with the time step serial numbers created in the input spreadsheet display. This process takes some time to do for a lot of rules because of the logic of determining a serial number for a date. If the rule's start date falls within a time step, then it is considered the start time step for the rule. If the rule end date falls within a time step, the time step is considered the end time step for the rule. On some occasions, the rule does not fall within the study period. In this case the rules are discarded.

In some cases, the rules will not begin and end at the start and finish of a time step so it becomes necessary to shift, shorten, remove or lengthen a rule duration to coincide with the time step parameters in the study, as shown in Figure 15. After determining a preliminary start and end time step, the weight of each rule in the start and end time steps are calculated. The following cases are applied to correct for these weights.

CASE 1: If a rule's hours take up a majority, greater than 1/2 of the rule's start/end time step length, then the rule's start/end time step remains the same.

CASE 2: If the rule does not take a majority of the time in both the start and end time steps, there is a possibility that the sum of the hours in those time steps could be shifted to either the start time step or the end time step depending on the weight of the sums in each time step. A shift of the weight to the start or end time step is performed and the other is discarded.

CASE 3: If no shifting/extending can take place, the start and end time steps are increased and decreased by one respectively. The purpose of this shifting is to use the rule to its best potential in terms of impacting the model. If the rule is still not long enough it will be discarded.

After converting the start and end dates of the rules into valid start time steps and end time steps, the rules can simply be applied to those time steps accordingly. Each rule is applied in order of entry in the text file as seen in Appendix V.

Figure 14. Rules Algorithm

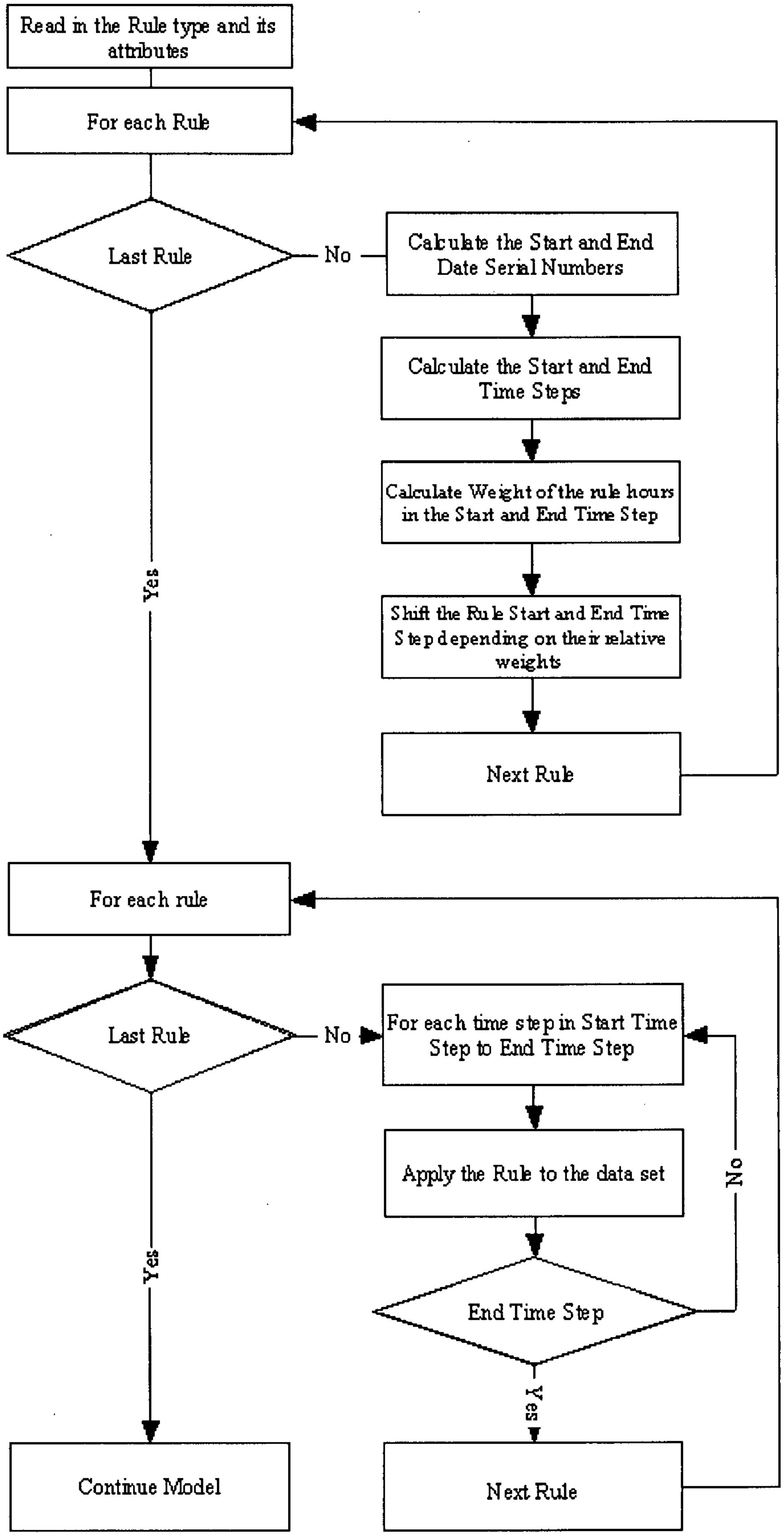
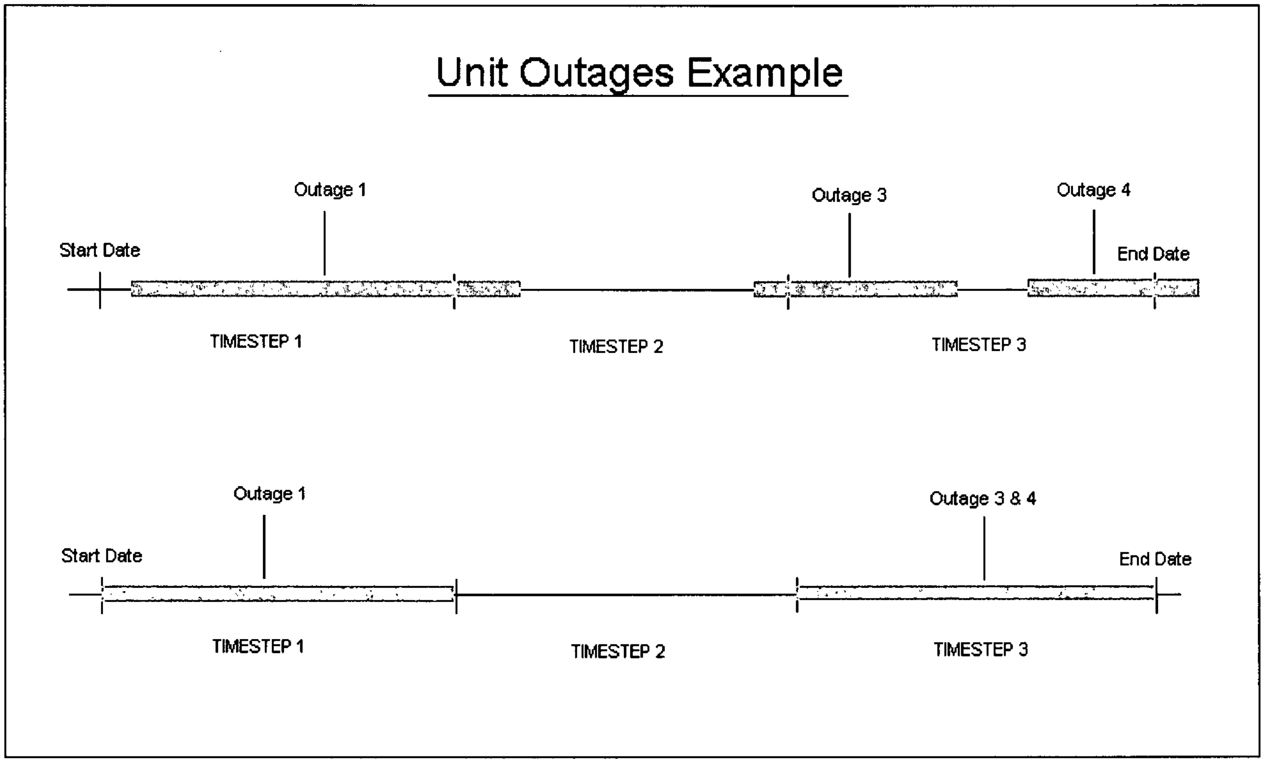


Figure 15. Example of the Shifting Logic for 3 Unit Outage Rules



4.7.5 Implementation in the Generalized Model

The rules algorithm was added to GOM using AMPL in three different places. The first set is processed at the beginning of the main run file. This is the location where all of the rules' start and end dates are converted into start and end time steps. Following this, the unit outages rules are applied first, then system shut downs and then unit additions. This procedure is completed before the model is loaded. These rules update the number of units available at each plant, which, in turn, updates the generating capacity for each plant. If the plant is shut down then the maximum and minimum generating capacities are held to zero. This process then prints out new data files that will update the model parameters, and the optimization model file is loaded.

The second set of rules are processed after the program has read the applicable data files in. The following rules are applied in this location:

FLATC
MAXGEN
MINGEN
MAXCMS
SPILL
TARGET FB
MINFB
MAXFB
MINTWEL

The final sets of rules (FIXGEN, ATCGEN and MINCMS) are processed prior to sending the optimization problem to the solver. This is done because this is the location where the parameter values cannot be changed any further before the problem is sent to the solver.

The final sets of rules are applied again before the solver is called again. This will ensure that the correct values, derived by rules are applied to the second run of the optimization process. The final output reflects these changes in the text file values of generation, forebay levels, constraint limits, discharge and objective function values.

CHAPTER 5
RESULTS AND DISCUSSION

The GOM program is intended to derive a plan of generation schedules at BC Hydro. The program can also be used to examine the impact of imposing new operational limits on BC Hydro bottom lines. The following sections will examine the results from the Water Use Planning studies for the Columbia River and discuss the impacts of changing a limit at one of the plants on the system operation.

5.1 Results Interface

The results interface is an Excel based workbook that allows the user to view the output of the optimization run. The output files are imported into Excel and the output is displayed in graphs and tables. The advantage of using Excel is that the graphs are standardized and can be easily modified and compared. The user can "zoom-in" at desired time steps and sub-time steps to see the impacts of the market or the limits on system operation. In addition, the workbook can be used to compare results of up to five studies.

5.2 Study Parameters

A total of 80 studies were performed to test the adequacy of the model for medium-term planning purposes. The studies were based on evaluating different system alternatives and their impact on the objective function value compared to a base case. A total of 78 of these studies were broken down to nine separate study sets consisting of 10 separate, but consecutive water years from Oct 1964 – Sept 1974, with the exception of sets 4 and 9, which have only 4 historical water years. The nine study sets were performed for the Columbia River Water Use Plan to examine the impacts of changing the minimum discharge limit at the Revelstoke Generating Station on the Columbia River operation. Four alternatives for minimum turbine discharge limits at the plant varying from 0 ft^3/s (Base Case) to 20,000 ft^3/s in 5000 ft^3/s (5 kcfs) increments. The data sets for studies 2-5 and 6-9 were identical, the only difference between the two sets is that in the first set of studies (2-5), the rules program was not included, while it was included in the second set (6-9). For the first set of studies the data files had to be manually changed and in the second set of studies, the rules were written as one line with 6 parameters in a text file for the rules program to read.

The studies were performed for the Columbia Water Use Plan to examine different alternatives that the interest groups (stakeholders) have agreed on possible new limits on operation. The studies examined the impact of these alternatives on the operation and on the value of the objective function for the year starting October 2008 to September 2009.

The following parameters were used for the base case:

- Start Date: October 1, 2008
- Rivers: Peace River, Columbia River
- Plants: GMS PCN MCA REV ARD
- Time steps: 4380 2-hourly time steps (1 year)
- Sub-Time Steps: For each time step there was one sub-time step that indicated if the time step was in a weekday or a weekend
- Regular maintenance outage schedules

- Existing plant limits

The yearly data sets for the studies are listed in Table 3:

Table 3. Study Data Sets

Study Set	Study No.	Limit Type	Limit Value	Water Years
1	1-10	REV QT_Min	0 kcfs	1964-65 to 1973-74
2	11-20	REV QT_Min	5 kcfs	1964-65 to 1973-74
3	21-30	REV QT_Min	10 kcfs	1964-65 to 1973-74
4	31-40	REV QT_Min	15 kcfs	1964-65 to 1973-74
5	41-44	REV QT_Min	20 kcfs	1964-65 to 1973-74
6	45-54	REV QT_Min	5 kcfs	1964-65 to 1973-74
7	55-64	REV QT_Min	10 kcfs	1964-65 to 1973-74
8	65-74	REV QT_Min	15 kcfs	1964-65 to 1973-74
9	75-78	REV QT_Min	20 kcfs	1964-65 to 1973-74
10	79	Generation Schedule Rules	408 values	1964-65
11	80	No Rules, Multiple Time Steps	0	1964-65

Study number 79 used the same base case for the 64-65 water year. The rules were taken from the generation schedules for 2001-2002 and were listed in a text file for the plants in the study. A total of 408 of rules were applied in that study as seen in Appendix V.

The same HYSIM data and Henwood input data was used for the 80th study; however, the time step values and sub-time step values were changed. This study was performed to evaluate the programs' ability to solve multiple sub-time steps. The study parameters chosen in the graphical user interface are shown below.

- Start Date: October 1, 2008
- Rivers: Peace River, Columbia River
- Plants: GMS PCN MCA REV ARD
- Time steps: 68 variable time steps (1 year)
  - 24 6-hourly time steps (4 days)
  - 25 daily time steps
  - 4 weekly time steps
  - 1 added time step of 2 days to get to a beginning of a month
  - 6 sub-monthly time steps that make up two months
  - 8 monthly time steps
- Sub-Time Steps: The hourly time steps had one sub-time step to indicate whether they fall on a weekday or weekend, all other time steps had 7 weekday sub-time steps and 5 weekend sub-time steps. The number of hours for a typical day in the time step in each sub-time step is as follows:
  - Weekday Super Peak Demand – 2 hours
  - Weekday Peak Demand – 2 hours
  - Weekday High Demand – 6 hours
  - Weekday Shoulder High Demand – 4 hours
  - Weekday Shoulder Demand – 2 hours
  - Weekday Low Demand – 6 hours

- Weekday Extreme Low Demand – 2 hours
- Weekend Super Peak Demand – 2 hours
- Weekend Peak Demand – 2 hours
- Weekend High Demand – 10 hours
- Weekend Shoulder Demand – 2 hours
- Weekend Low Demand – 8 hours

- Regular maintenance outages
- Typical plant limits

Feasible results were obtained for 78 out of the 80 studies. The values of the objective functions for these 78 studies are listed in Appendix III. The final two studies have not yet produced feasible results. Study 79 had 408 rules to apply to 4380 time steps. The program had to be shut down after five days of trying to process the rules to the study, due to some problems applying if..then..else logic in AMPL. The AMPL program is not designed to handle such complex logic statements. It was found that calculating a serial number for each start and end date and then a start and end time step for each serial number and trying to shift these start and end time steps to apply to the model takes an excessive amount of time for a large study. The addition of more plants and more rules will also compound this problem so it is necessary to speed up this process in the future, perhaps by the use of an expert system. The rules algorithm completed processing all of the input data for Study 80, but the solver has come to an internal error that does not have a clear solution. The time constraints of this research did not allow for further research on the causes of these problems.

5.3 Results of Studies 1-78

It is well known that when decision variables in an optimization problem are constrained, the value the objective function would decrease. This can clearly be seen in the results of the nine sets of studies carried out. In each study, the objective function value decreased as the minimum limit on discharge increased. Some infeasibilities were encountered when the 20kcfs minimum flow limit was used and a forebay goal program was used to produce feasible runs for four of the water years in the study. The following sections will examine the effects of the different alternatives on the Columbia and Peace operation for a typical study: the 1964-65 water year. The alternatives investigated have a minimum flow limit of 5000cfs, 10,000cfs and 15,000cfs, and these will be referred to as 5kcfs, 10kcfs and 15kcfs respectively on the graphs.

5.3.1 Impact on Revelstoke Operation

When the minimum discharge limit at a plant is increased, this usually causes an increase in the minimum generation level. Generation is a function of the discharge and head at a plant; this relationship is evident in the two graphs shown below. Figure 16 shows the Revelstoke plant discharge levels for the base case, while Figure 17 shows the discharge levels for alternative 3 (15,000cfs). When the minimum discharge level is increased it will affect the timing and the magnitude of plant releases to maintain its' monthly target levels. This is easiest to see in the months of February to June. In the base case the operation of the units fluctuates from 0 to approximately 1300 cms consistently throughout the period. As the minimum discharge at Revelstoke increases, this fluctuation decreases.

Figure 16. Revelstoke Discharge vs. Time for Base Case

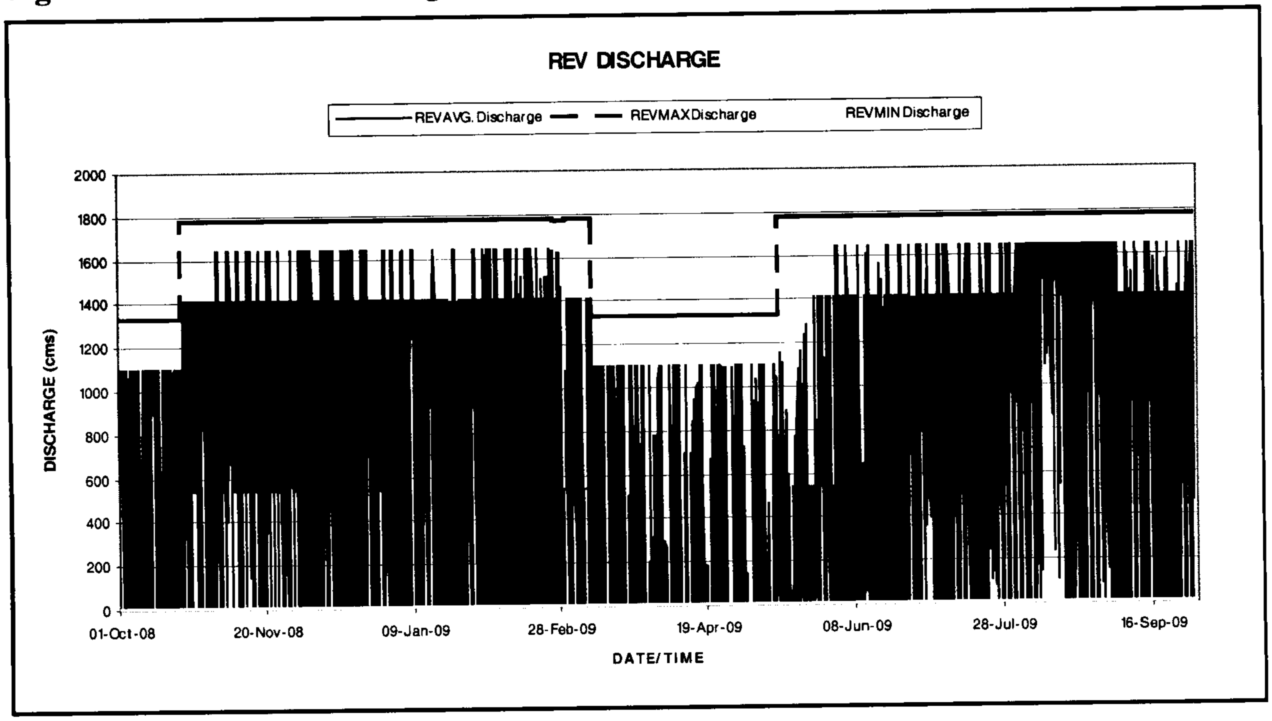
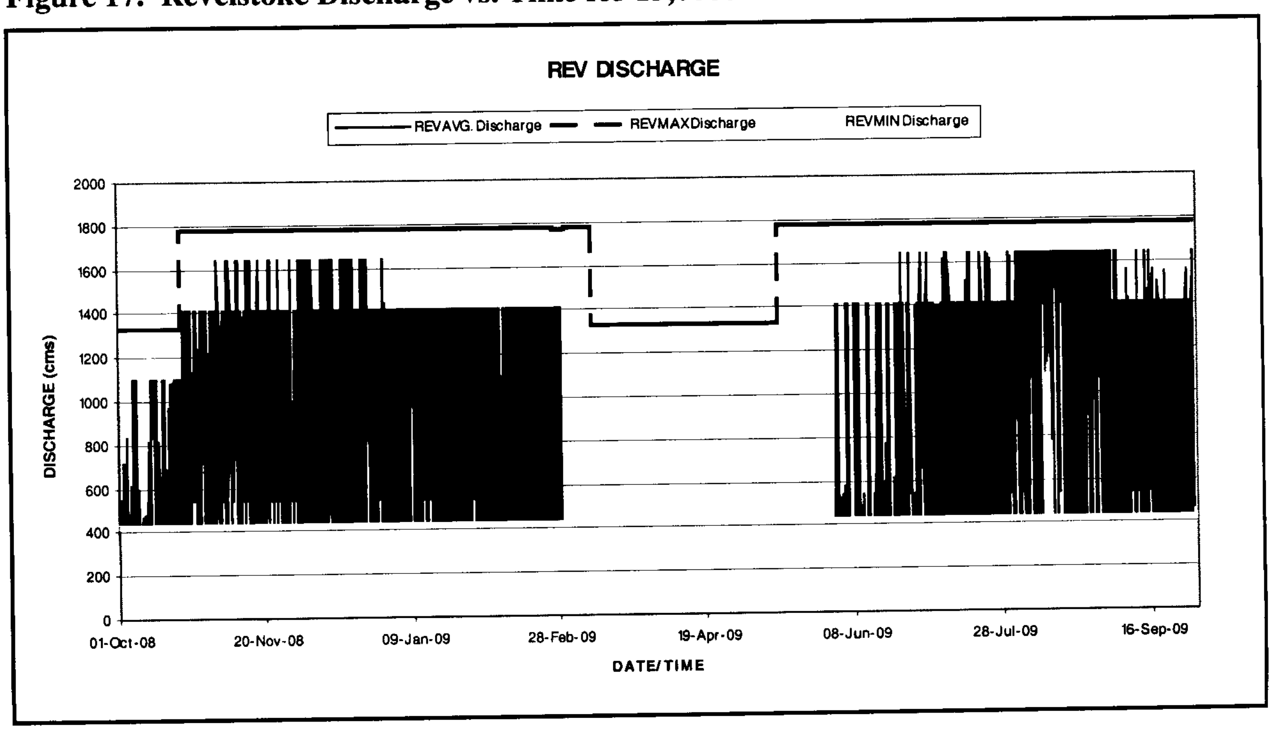


Figure 17. Revelstoke Discharge vs. Time for 15,000cfs Alternative



It can also be noted that as the minimum flow limits increase, the plant generation fluctuations decrease. Figure 17 clearly illustrates this effect. The plant fluctuation is reduced to a minimum through the period to maintain the minimum flow requirements.

The same holds true for Revelstoke generation. The shapes of the graphs are identical to the shapes of the corresponding discharge graphs. The main observation on these graphs is that the minimum generation constraint is not affecting the generation at Revelstoke; this means that this constraint is not binding and has no affect on the objective function. The minimum generation is simply responding to the binding minimum flow constraint at Revelstoke.

5.3.2 Impact on Mica and Keenlyside Operation

The Mica Generating Station is located upstream of the Revelstoke Generating Station, therefore it can be seen that the inflow at Revelstoke is dependent on the outflow of Mica. So if the minimum flow limit at Revelstoke is increased the Mica plant may have to discharge more water to meet this requirement. The following figures show the relationship between the discharge at Mica and time. Comparing the same time period from February to June, the base case (Figure 18) shows the operation without the alternative constraints. For the same period, the 15,000cfs alternative (Figure 19) show an increase in discharge to meet the downstream target flows. This effect is known as hydraulic coupling, such that the operation of the downstream plant affects the operation of an upstream plant.

The Arrow reservoir and Keenlyside generating station are located downstream of the Revelstoke plant on the Columbia River and this means that they receives all of the discharge from Revelstoke. The Arrow reservoirs must therefore be able to capture this inflow and still meet its monthly forebay targets. This means that for the months of February to June there may be more generation at the plant to mitigate the inflows. In addition to meeting the forebay requirements at the plant, there is an additional constraint that impacts the operation. The Columbia River Treaty is an agreement developed by Canada and the US to regulate the operation of the Columbia River. This agreement allows different regions in the Columbia River to benefit from the large storage capacity of the system. The Keenlyside plant discharges water into US generating systems. The Treaty requires that a minimum discharge requirement be met from Keenlyside. Any increase/decrease in discharge from Keenlyside will give the downstream plants additional water for generation; the Treaty describes who should benefit from this additional water in terms of revenue or compensation. The downstream plants must therefore compensate the upstream plant for any change in water releases below or above the treaty requirements.

A system with a set of cascaded reservoirs requires extremely complex modeling, especially with the addition of the Columbia Treaty requirements. The optimization of these systems in the long term is impossible without computer optimization tools such as GOM. Appendix II has all of the results for the discharge and forebay elevations at each plant included in the optimization study for the base case and the alternatives for the 1964-65 historical inflow water year. The water use planners have used the output from these studies to evaluate the impacts of these alternatives on the future operation of the Columbia River.

Figure 18. Mica Discharge vs. Time for the Base Case

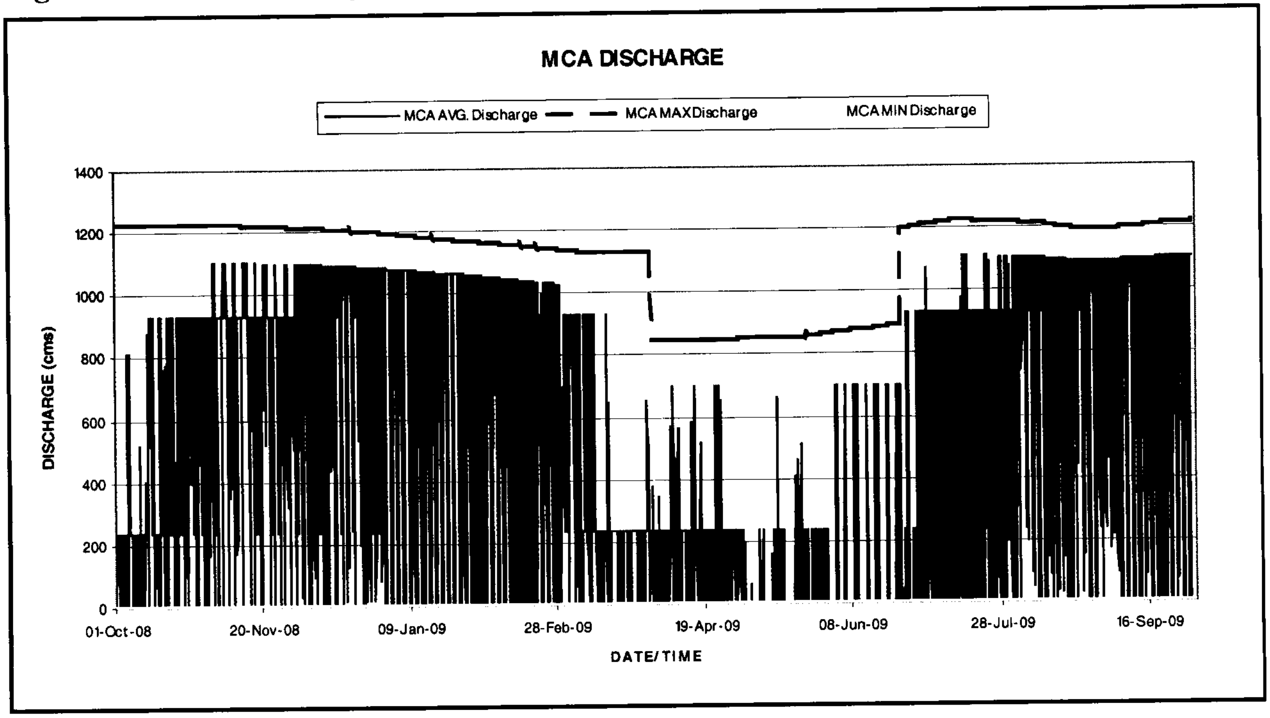
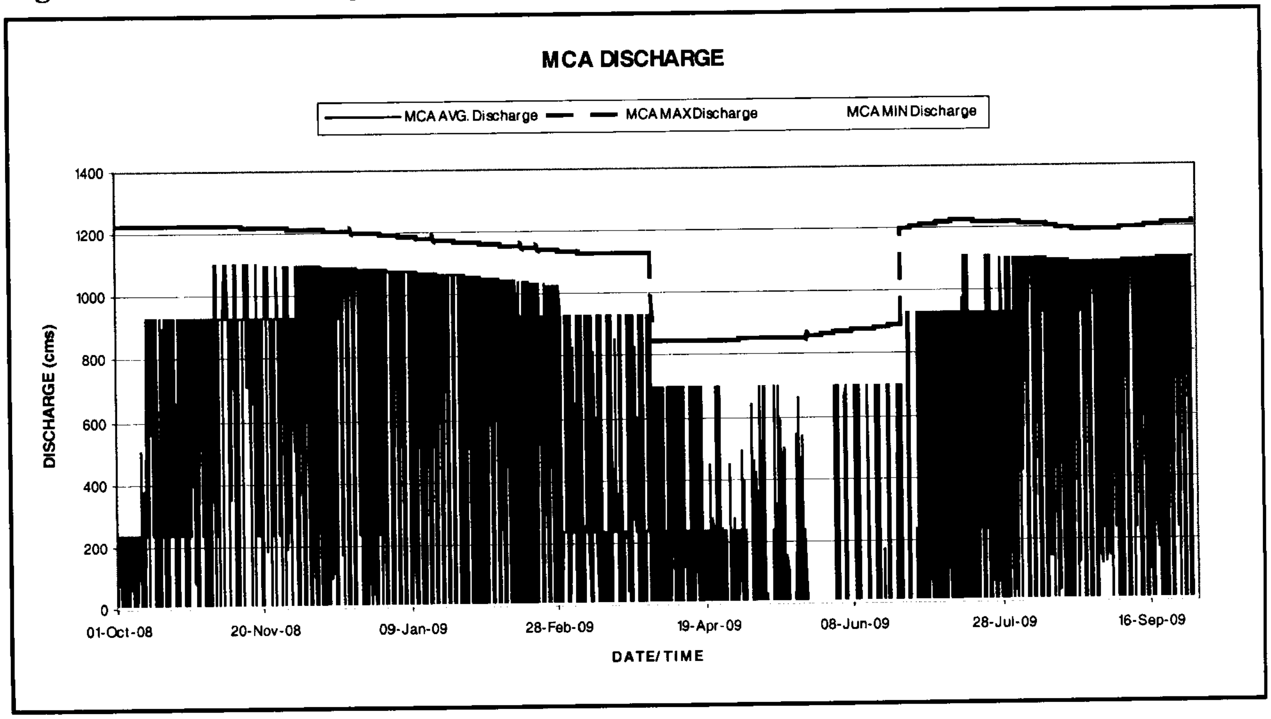


Figure 19. Mica Discharge vs. Time for 15,000cfs Alternative



5.3.3 Impact on Peace River Operation

The results of these studies indicate that the Revelstoke minimum discharge limit impacts the Peace River operations as well. During the months of February to June, the Revelstoke, Mica and Keenlyside plant generations increase, this means that to meet the demand, the Peace River must generate less. This translates into an increase in Peace River generation in the months prior to and following February to June to prevent spillage at these plants and to meet their monthly and end of study reservoir targets as derived by the HYSIM model. The full impact of these alternative minimum discharge limits can be seen in Appendix II.

5.3.4 Impact on the Objective Function

The main advantage of using a modeling system like GOM is that by only changing the value of one parameter, the user can easily see the impact on the entire system operation and on the objective function. It may also be possible to get a relationship between the changes in the objective function with the change in minimum flow, as can be seen in Figure 20. The objective function values are listed in Appendix III. There seems to be a relationship between these alternatives and the objective function up until the third alternative (15,00cfs). The fourth alternative is not shown on the curves because there is not a complete data set for all of the 10 years in the study. The forebay limit data that is used for the 20kcfs case was modified from the other alternatives using a goal programming approach, and therefore cannot be compared with the others using the same basis.

Figure 20 shows that the objective function shape is almost identical for the different water years. This means that the water inflow has a larger effect than the minimum flow requirement on the objective function value, but this does not diminish the impact of the minimum flow requirement.

The graph below also shows the range in objective function values for different water years. The range extends from a net loss of $37 million to a net gain of $162 million. This demonstrates the large relationship between the value of optimal operation and the inflow into the system. It would follow that years of high inflow would produce more revenue, as there is more capability for exports of electricity in times of high demand. In years of low inflow, the objective function shows that on the balance, there is little possibility for electricity market export because the operators must meet the demand by importing electricity from the market.

Figure 21 shows the average cost of the alternative minimum flow requirements. It shows that as the minimum flow requirement at Revelstoke increases, the average cost of the alternative also increases. This follows from the above argument that if one limits a decision variable; the value of the objective function will decrease. The shape of this curve is representative of the shapes of all of the curves for each of the 10 years.

Figure 20. Change in Objective Function vs. Change in Revelstoke Minimum Plant Discharge

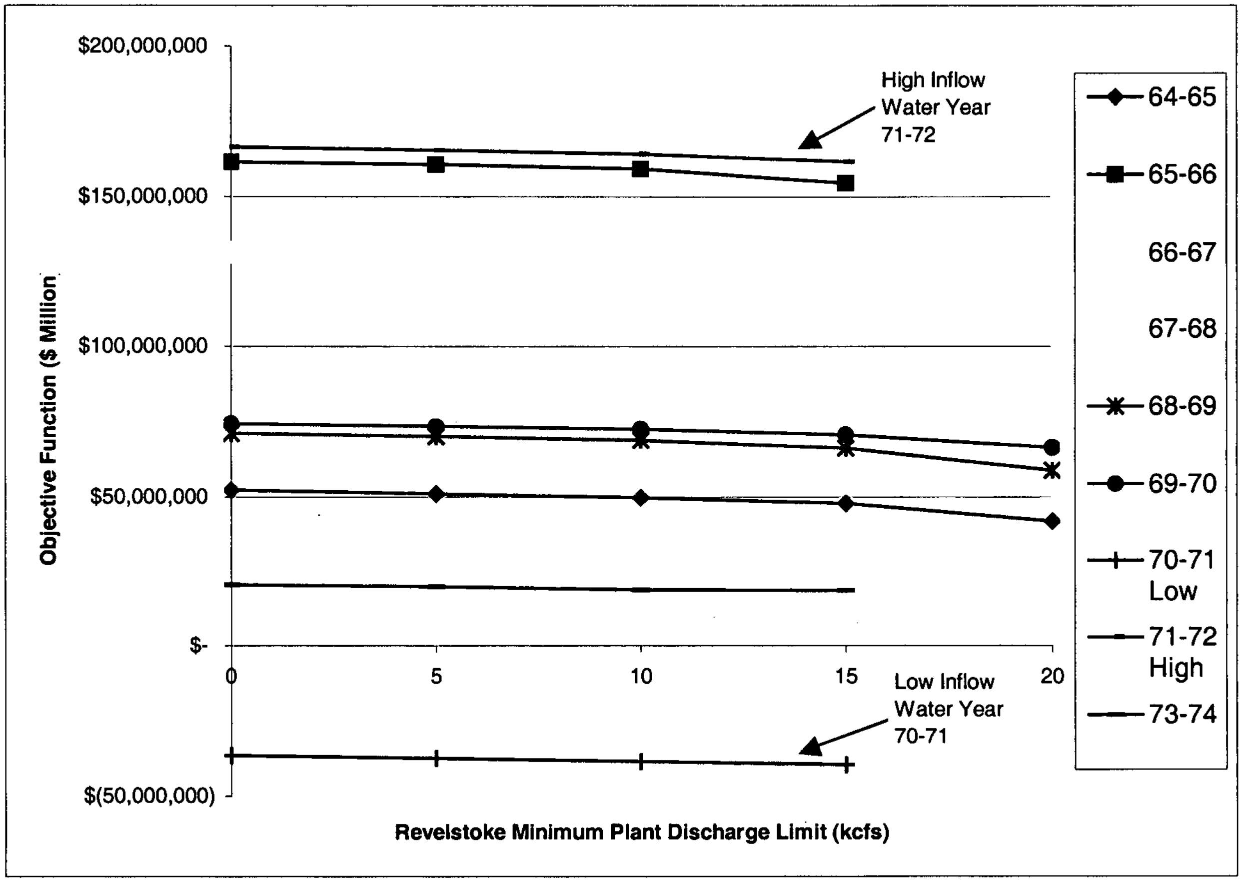
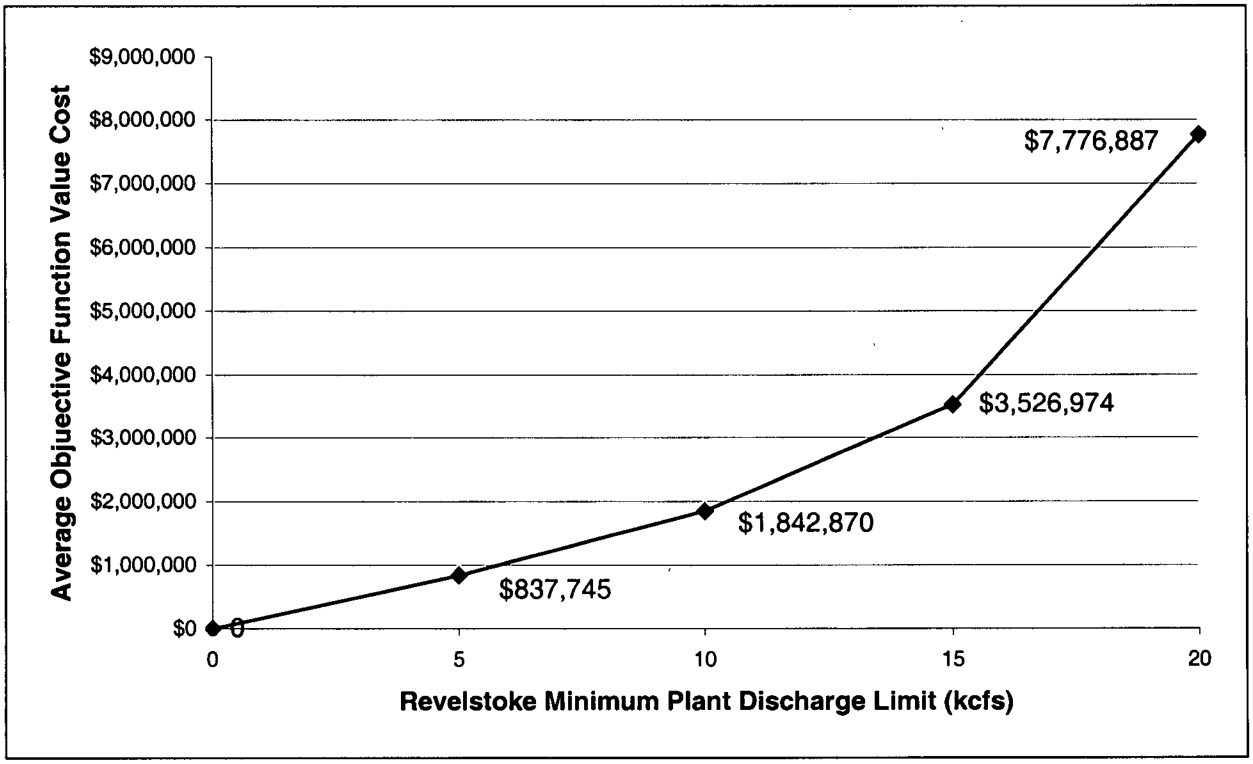


Figure 21. Average Cost of Alternative Minimum Discharge Limits



5.4 GOM Performance

The Base Case studies took the longest to prepare of the Revelstoke Minimum Flow requirement studies. This involved using the GOM graphical user interface to collect the HYSIM data for each of the historical water years. Each run of the user interface would take approximately 5 minutes; making sure that the appropriate HYSIM and Henwood input data is available. The Excel spreadsheet took approximately 10 minutes to check the values, change any of the default plant limits, and set the end of study targets.

The changes to these base case studies used two different methods of gathering input data for the alternatives. The first method was to change the minimum flow limits manually and the second was to enter the rules and their attributes into a text file. The manual changes took approximately 5 minutes per case, because the changes were so minimal, and the rules text file took approximately 30 seconds to set up. This makes a total of 20 minutes to prepare one study using the manual rule entry and 15.5 minutes for the automated rule entry.

In Studies 79 and 80, using the generation schedule rules, the preparation time was longer. The 408 rules were entered into a text file manually, taking approximately 2 hours; in the future, this process will be automated from the generation schedule. It is expected that this process will take approximately 5 seconds. The graphical user interface took the same amount of time to run, approximately 5 minutes, along with the Excel spreadsheet at 10 minutes. The total time to prepare these studies took approximately 2.1 hours and the projected time to prepare the studies using the automated generation schedule rules is approximately 15 minutes.

The GOM program can handle large amounts of data, constraints and variables; in each of the Revelstoke discharge limit studies there were a total of 1,600,000 constraints and 960,000 variables. For each run, the AMPL program reduces the problem by substitution of variables and dropping inapplicable constraints. Each GOM run takes approximately 12 minutes to run; this time increases with the addition of the rules program. With each additional rule, the program takes longer to run, for example with 2 rules it took about 15 minutes to run and with four rules it took approximately 20 minutes to run. As discussed in the rules section, the study with 408 rules had to be shut down after five days of trying to process the rules.

The results of comparing these times indicate that the graphical user interface and Excel spreadsheet take approximately 15 minutes to run; after this, the time to prepare a study can be shortened by automating the generation schedules. In addition, the optimization model run time can be shortened dramatically by shortening the rules process. This can be achieved by the addition of an expert system to perform these functions.

CHAPTER 6
CONCLUSION AND RECOMMENDATIONS

The BC Hydro system is a complex network of hydroelectric and thermal plants. The main components of the BC Hydro system consist of storage reservoirs, hydroelectric generating and transmission facilities that convert the power of falling water to hydroelectric power and then transmit it to BC Hydro's residential, commercial and industrial consumers. The system has a high degree of flexibility as it enables BC Hydro to either buy or sell power in an open electricity market or to store energy for future use. This high degree of flexibility, however, increases the complexity of the decision making process. The Generalized Optimization Model is a decision support tool that assists the system operators in making sound and informed decisions.

6.1 Conclusions

The purpose of this research was to develop a medium-term decision analysis tool for BC Hydro planning and operations engineers. The tool could be used in many ways. First, it could be used to develop medium-term system plans. Second, it could be used to evaluate the feasibility, advantages and disadvantages and the projected costs resulting from imposing new limits on system operations. Third, it could be used to assess the impacts of enhancing the system operating efficiency, or the impacts of capacity expansion on system operations. Finally, it could be used as the main optimization engine for future development of a comprehensive planning tool for the BC Hydro system. The goal that was set for this research has been achieved with the development of a decision support tool that consists of six components as described in this thesis.

Development and implementation of the decision support tools in real-life situations require an in-depth knowledge of the characteristics, constraints and on how these complex systems are operated. The decision support tool developed by this research met the majority of its users' requirements. It was also found that the users of such decision support tools must first develop the confidence that the system is performing as required and as expected, and this has been achieved by working closely with the end-users of the system to address their needs and expectations.

Several studies were carried out using the GOM system. A typical process that is followed to complete a study using this tool consists of the following steps. First, the user determines the purpose of the study and the sources of information. Second the user sets the study characteristics, converts the input to match the study requirements and perform several checks for correctness and consistency. Third, the inputs for the study are transferred to server workstation where the simulation and optimization process are activated to solve the problem. Finally, the results are transferred back to the client workstation and the output data set is displayed and summarized at the client workstation. The entire process was made quick and easy through the development of automated procedures and components such as the Graphical User Interface, the Preprocessor and the Excel Input and Output display tools.

The Generalized Optimization Model has been adapted from the short-term optimization model that has already been tested and implemented at BC Hydro, and therefore many of the lessons learned were used to make the model more robust and a usable tool that meets the user requirements. It was found that in modifying a program that BC Hydro already uses, the integrity of the mathematical modeling methodology adopted has been enhanced.

The rules program was successfully added to dynamically generate seasonal and operational limits in the optimization model. There are still some additional technicalities to be worked out, but the initial stages of the algorithm have been completed.

Several studies were carried out using the GOM system and the results of these studies are being used for Water Use Planning process for two of the largest and most important hydroelectric facilities in British Columbia: the Columbia River and the Peace River hydroelectric systems. Experienced planning and operations engineers at BC Hydro assessed the adequacy of the GOM system. Their extensive knowledge of the system and their understanding of the results have demonstrated time and again the role of experienced system operators in evaluating such decision support systems.

6.2 Recommendations

There are a number of recommendations for further improvements and study. To remain a state-of-the-art, the program must continue to be further developed to include more rules, to address uncertainty and to model other hydroelectric plants in the system.

The addition of the rules algorithm can be thought of as an initial step in automating the Generation Schedules. Studies carried out by this research indicated that there is a need to accelerate the rules algorithm, and this will be crucial for the automation process. This research identified a total of 25 main rules that are used often in real-life system operations. A total of 14 rules were implemented in this research without major difficulty. The logic embodied in the remaining 11 rules is much more difficult to implement in the AMPL software system. Several rules may be in conflict with one another and a conflict resolution process, or an inference engine, will need to be developed. Therefore, it is recommended that the potential use of an expert system for this purpose be explored.

Uncertainty in market prices, inflows and in the system load could have a major impact on how hydroelectric systems are operated. It is recommended that the GOM system be extended to automatically address uncertainty in these variables. In addition, the Burrard thermal generating station produces about 6% of the total energy produced by the BC hydro system. This resource should be modeled in the GOM system. Modeling of this thermal resource will allow the user of the GOM system to model the impacts of uncertainty inherent in the prices of natural gas on the operation of the predominantly hydroelectric system.

Marketing potential of this model to other hydro companies could also be investigated. This strategy may appear to be lucrative at first stance, but the decision support system was specifically designed and developed for the BC Hydro system and it would require some further development effort and resources to generalize the system for any hydroelectric systems. The program, however, is very easy to adapt, but it is very difficult to find two systems in the world that share the same characteristics and planning processes used.

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APPENDIX I:
MODEL FORMULATION

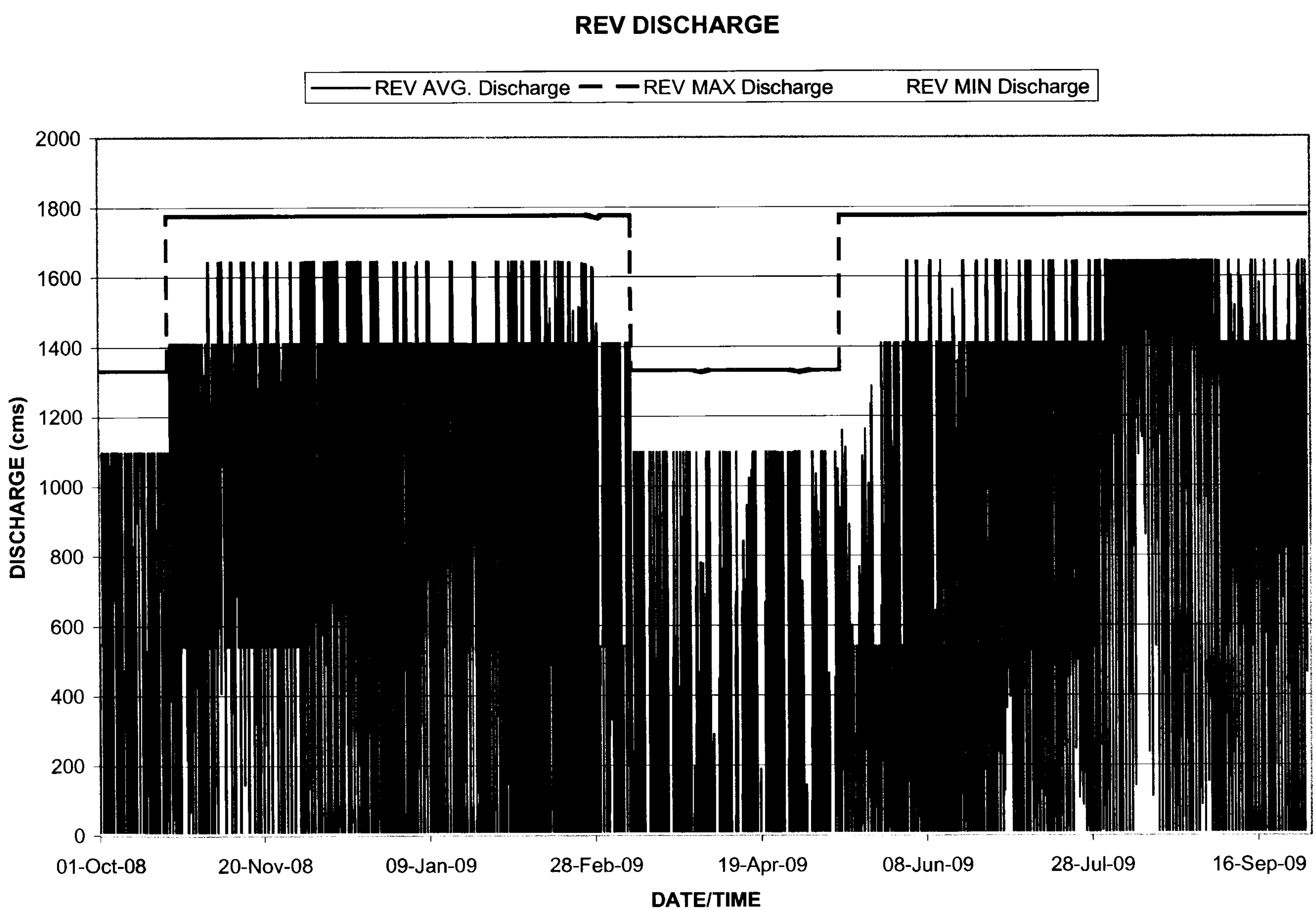
```
# ---------------------------------------------
# BC HYDRO GENERALIZED OPTIMIZATION MODEL
# MATHEMATICAL MODEL FORMULATION
# COPYRIGHT 2003 BC Hydro
# Matrix VERSION
# ---------------------------------------------

param T > 0;                                            # Number of production periods in hours
param initial;                                          # Initial time step in the analysis

### SETS ###
set river ordered;                                      # Set of river basins
set plant ordered;                                      # Power generating plant in a river basin, ordered by
                                                        # location along the river
set FCCPLANT ordered;
set HPL ordered;                                        # Set of subtime steps(e.g.WKHI WKPK WKL WEHI WEPK)
set HPLWK ordered;                                      # Set of weekday sub-time steps
set HPLWE ordered;                                      # Set of weekend sub-time steps
set WKSTEPS ordered;                                    # Set of weekday sub-time steps
set WESTEPS ordered;                                    # Set of weekend sub-time steps
set MONTHS ordered;                                     # Set of months in the study
set TT{1..(6)} ordered;                                 # Set of days that have hourly time steps

# Spot exports variables and limits
var Spot_USH  {t in initial..T, HPL} ;                 # Spot US exports as a function of time step, sub-time step
var Spot_ABH  {t in initial..T, HPL} ;                 # Spot AB exports as a function of time step, sub-time step
var G_RM_BUFFER {plant, t in initial..T, HPL} >= 0;    # Regulating margin minimum buffer requirement, in MW for
                                                       # each plant, time step, sub-time step
## FLOW VARIABLES ##
var QT {plant, t in initial..T, HPL} >= 0;             # Total water outflow from a plant at time step t, in m3/s

# SUBSTITUTED TURBINE FLOWS FOR THE MATRIX FORMULATION
var UT{j in plant, k in plant, t in initial..T, h in HPL} = QT[j,t, h] * UQT[j,k] ;
                                                       # Turbine Inflow Variables in m3/s for time t, sub time
var RQTR{j in plant, k in plant, t in initial..T, h in HPL} = QT[j,t, h] * QTR[j,k] ;
                                                       # Turbine Discharge Variables in m3/s for time t, sub-time
var QP {plant, initial..T} >= 0;                       # Plant outflows = Turbine  + spills, in m^3/ s (Dependant
                                                       # variable)
# SPILL VARIABLE
var QS {plant,initial..T} >= 0;                        # Total water spills from reservoir at
                                                       # time step t, in m3/s
var US{j in plant, k in plant, t in initial..T} = QS[j,t] * UQS[j,k] ;  # Total inflow spills into a reservoir at
                                                                        # time step t, in m3/s
var RQSR{j in plant, k in plant, t in initial..T} = QS[j,t] * QSR[j,k] ;# Total outflow spills from a reservoir
                                                                        # at time step t, in m3/s
## POWER VARIABLES ##
```

```
var P {plant, t in initial..T, HPL} >= 0;             # Power generated at plants at time step t

## RESERVOIR VARIABLES ##
var VTEMP {plant, initial..T} >= 0;                   # Reservoir storage at time step t, in cubic meters
                                                      # (Dependant variable)
var VDiffQT {j in plant, t in initial..T} = - (sum {h in HPL}
((VTEMP[j,t]*dQTmCoeff[j]+dQTcCoeff[j])*P_LRBdQT[j,t,h]/dQTPCoeff[j])* HPLHR[t,h]/24) + (sum {h in HPL}
((VdQT[j,t]*dQTmCoeff[j]+dQTcCoeff[j])*P_LRBdQT[j,t,h]/dQTPCoeff[j])* HPLHR[t,h]/24) ;

var dQT {j in plant, t in initial..T, h in HPL} = -
((VTEMP[j,t]*dQTmCoeff[j]+dQTcCoeff[j])*P_LRBdQT[j,t,h]/dQTPCoeff[j]) +
((VdQT[j,t]*dQTmCoeff[j]+dQTcCoeff[j])*P_LRBdQT[j,t,h]/dQTPCoeff[j]) ;

var V {j in plant, t in initial..T} = VTEMP[j,t] + VDiffQT[j,t];
var QP_ARD{initial..T, HPL};
var P_all {j in plant, t in initial..T, h in HPL} = P[j,t, h] + G_RM_BUFFER [j,t, h] + (P[j,t, h] * G_ORO[j]) ;
var QTTEMPdQT {j in plant, t in initial..T, h in HPL} = QT[j,t,h]+dQT[j,t,h];
var V_Average {j in plant} = (V[j,T] + V_Target[j])/2;
var RRES1{j in plant} = <<{n in 2..tvnpce[j]}tvbkpt[j, n];{n in 1..tvnpce[j]}(tvslope[j, n])>>(V_Average[j])+
yintercept[j];
var MVW1 {j in plant} = RRES1[j]*VALHK[j,T]/3.6 + sum {k in plant}UMVW[j,k] * RRES1[k] * VALHK[k,T] / 3.6;
var VDiff {j in plant} = V[j,T] - V_Target[j];  # Volume Deviation Variable for the penalty piecewise linear term

## Check the convexity of the piecewise linear P vs. Q curves
check {j in plant, n in 1..npce[j]-1, t in initial..T }: slope[j,n,t] >= slope[j,n+1,t];
                                                      # Check if the  slopes are decreasing for convexity
### MODEL CONSTRAINTS ###
## RESERVOIR VOLUME CONSTRAINTS ##
subj to LRB_STORAGE {k in plant}:
      tvbkpt[k,3] = V[k,T];

subj to STORAGE{k in plant, t in initial..T}: (if t = initial then V00[k] else VTEMP[k, t-1] )
      + (- sum {j in plant, h in HPL} RQTR[j,k,t, h] * HPLHR[t,h]
      - sum {j in plant} RQSR[j,k,t]* hours[t]
      + sum {j in plant, h in HPL} UT[j,k,t, h] * HPLHR[t, h]
      + sum {j in plant} US[j,k,t]* hours[t]
      + QIR[k,t]* hours[t]) / 24 =  VTEMP[k,t];

subj to STORAGE_BOUNDS{k in plant,t in initial..T}:   # Upper and Lower reservoir storage constraint
      VMin[k,t] <= V[k,t] <= VMax[k,t];

subj to STORAGE_INCREMENT{j in plant, t in initial..T: t >initial}:
        (V[j,t] - V[j,t-1]) <= VIncr[j,t];
                                                      # Ramping rates (increment) on turbine discharge

subj to STORAGE_DECREMENT{j in plant, t in initial..T: t >initial}:
```

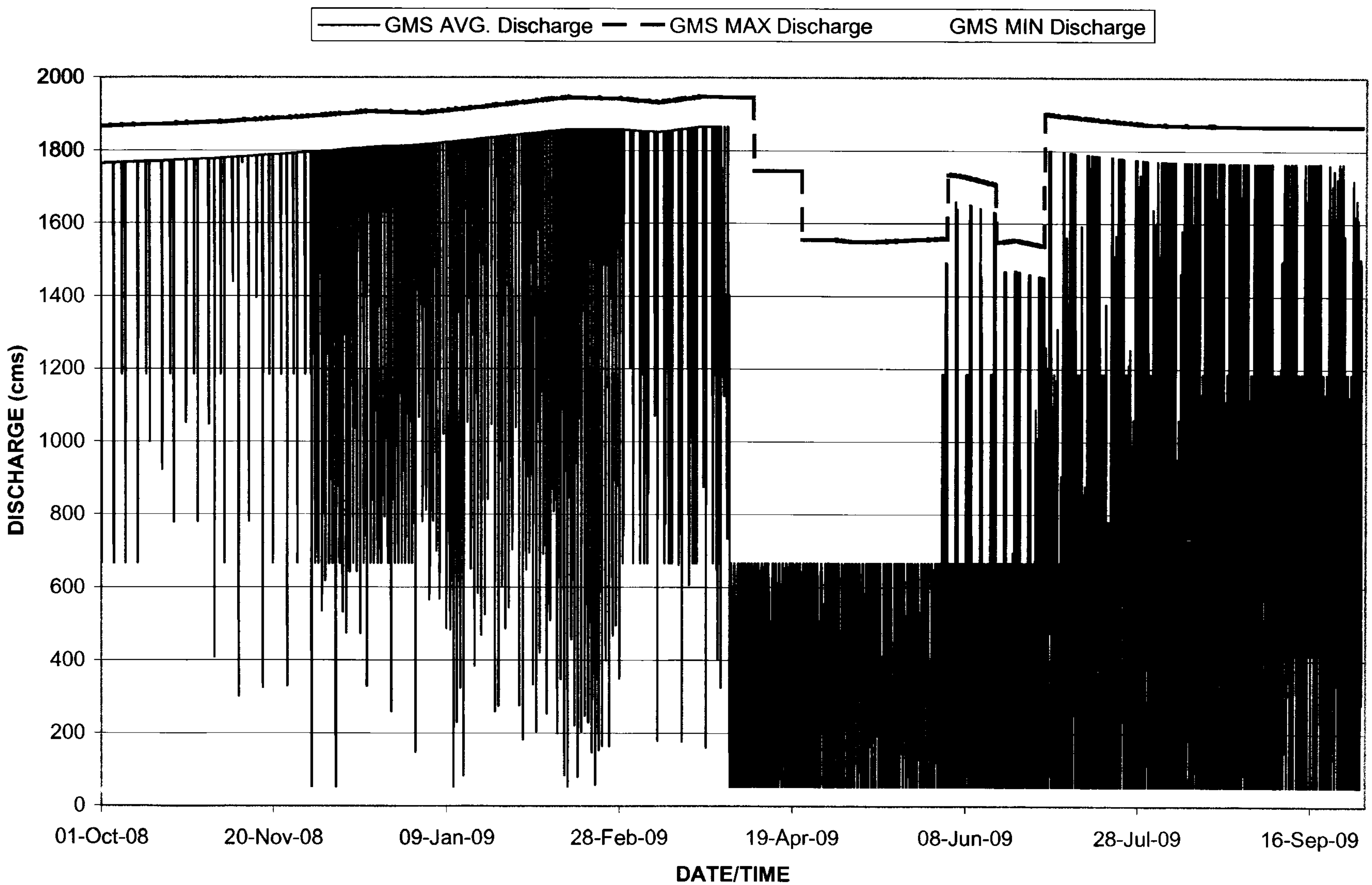
```
        (V[j,t] - V[j,t-1]) >= VDecr[j,t];
                                                          # Ramping rates (decrement) on turbine discharge
## FLOW CONSTRAINTS ##
subj to TURBINE_BOUNDS {j in plant, t in initial..T, h in HPL}:
      QTMin[j,t] <= (QT[j,t, h]+dQT[j,t,h]) <= QTMax[j,t];
                                                          # Upper and Lower turbine flows constraint

subj to PLANT_DISCHARGE{j in plant, t in initial..T}: # Plant total outflow
       (sum{h in HPL} QT[j,t, h]*HPLHR[t,h])/hours[t] + QS[j,t] = QP[j,t];

subj to PLANT_DISCHARGE_BOUNDS{j in plant, t in initial..T}:
       QP_Min[j,t] <= QP[j,t] <= QP_Max[j,t];          # Upper and Lower plant total flow constraint

subj to SPILL_DECINCR{r in 1..365, q in TT[r]}:
       QP["ARD",q] = QP["ARD",first(TT[r])] ;
## POWER GENERATION CONSTRAINTS ##

subj to LOAD_BALANCE_SPOT {t in initial..T, h in HPL}:
      sum {j in plant} P[j,t, h] + POTHH[t, h] + P_Imports[t,h] - P_Exports[t,h] - Spot_USH[t, h] - Spot_ABH[t, h]
+ ((QP["ARD",t] - ARDFLOW[t]) /0.3048^3/1000* HKARD[t]) >= LOADH[t, h] ;
                                                          # Sum of the plant generations, prescheduled
                                                          # imports/exports minus the spot sales in US and AB
                                                          # must be greater than or equal to the demand
subj to SPOT_US_TRANS {t in initial..T, h in HPL}:
       US_tran_maxH[t,h] >= Spot_USH[t, h] >= US_tran_minH[t,h]   ;

subj to SPOT_AB_TRANS {t in initial..T, h in HPL}:
      AB_tran_maxH[t,h] >= Spot_ABH[t, h] >= AB_tran_minH[t,h];

subj to RM_BUFFER {t in initial..T, h in HPL}:
      sum {j in plant} G_RM_BUFFER [j,t, h] >= G_Min_BUFFER ;
                                                          # The sum of the plant regulating margins must be >= the
                                                          # system minimum regulating margin buffer

subj to GEN_INCREMENT{j in plant, t in initial..T, h in HPL: t >initial}:
        (P[j,t,h] - P[j,t-1,h]) <= PIncr[j,t];         # Ramping rates (decrement) on Plant Generation

subj to GEN_DECREMENT{j in plant, t in initial..T, h in HPL: t >initial}:
        (P[j,t,h] - P[j,t-1,h]) >= PDecr[j,t];         # Ramping rates (increment) on Plant generation

subj to GENERATION_LIMITS {j in plant, t in initial..T, h in HPL}:
      P_Min[j,t] <= P_all[j,t, h] <= P_Max[j,t] ;
                                                          # The sum of the plant gen + operating reserve + regulating
                                                          # margin buffer must be between the minimum and maximum
                                                          # generation limits for each time, subtime and plant
```

```
subj to POWER_GENERATION {j in plant, t in initial..T, h in HPL}:       # Piecewise linear terms for the P =
<<{n in 2..npce[j]} Qbkp [j,n,t]; {n in 1..npce[j]} slope[j,n,t]>> (QTTEMPdQT[j,t,h], Qintrcpt[j,t]) >= P[j,t, h];
                                                                        # f(QT, GH) equation


maximize EXTRA_POWER_AB_US :
        sum {t in initial..T, h in HPL} Spot_USH[t, h] * price_USH[t, h]
      + sum {t in initial..T, h in HPL} Spot_ABH[t, h] * price_ABH[t, h] * USExchRate
      + sum {j in plant} (24 * 3.6 * (<<{n in 2..tvnpce[j]-1}dVbkpt[j,n];{n in 1..tvnpce[j]-
1}dPslope[j,n]>>(VDiff[j])));

#END OF MODEL
```

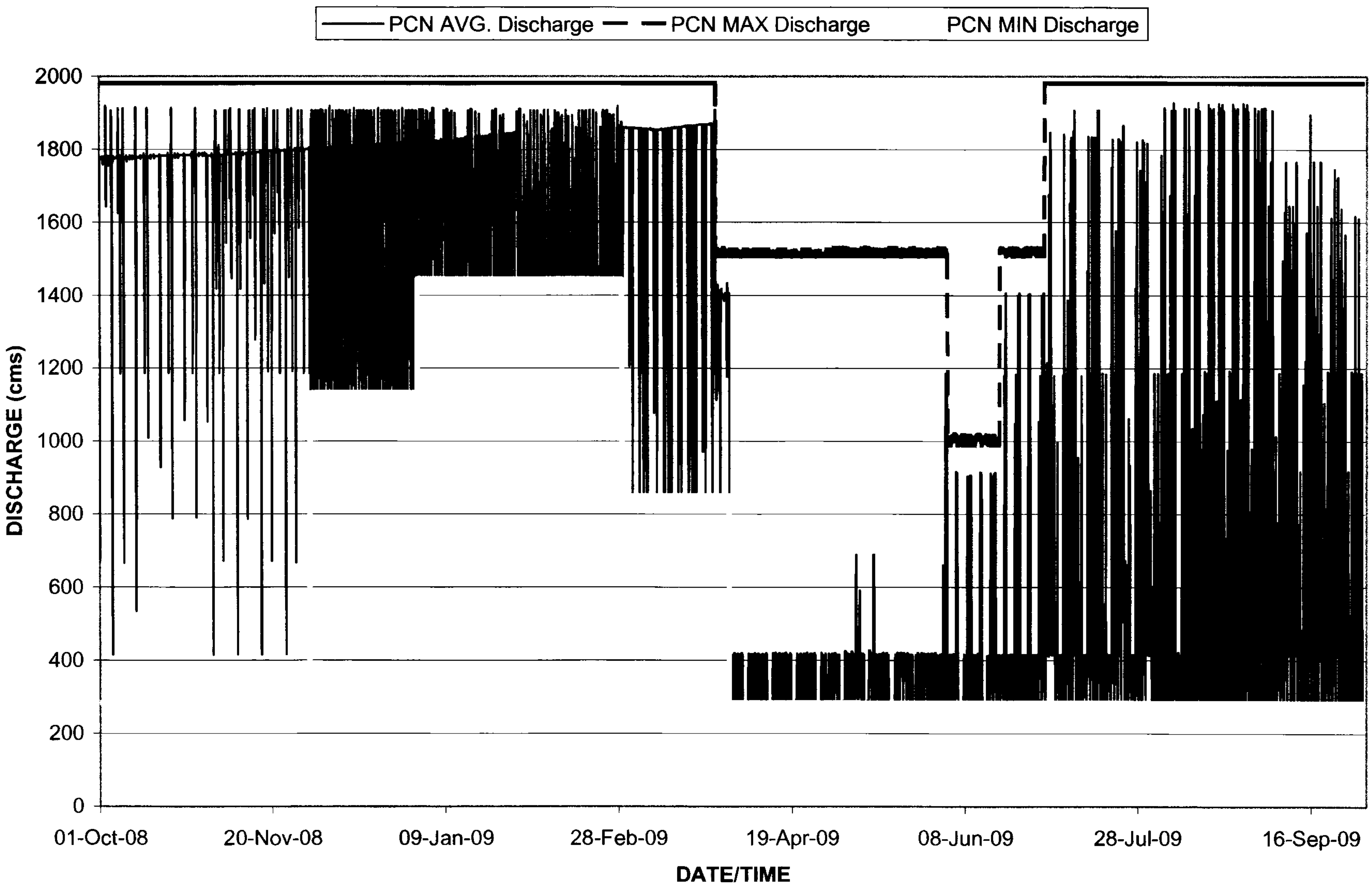
APPENDIX II:
64-65 BASE CASE AND ALTERNATIVE FOREBAY AND DISCHARGE RESULTS

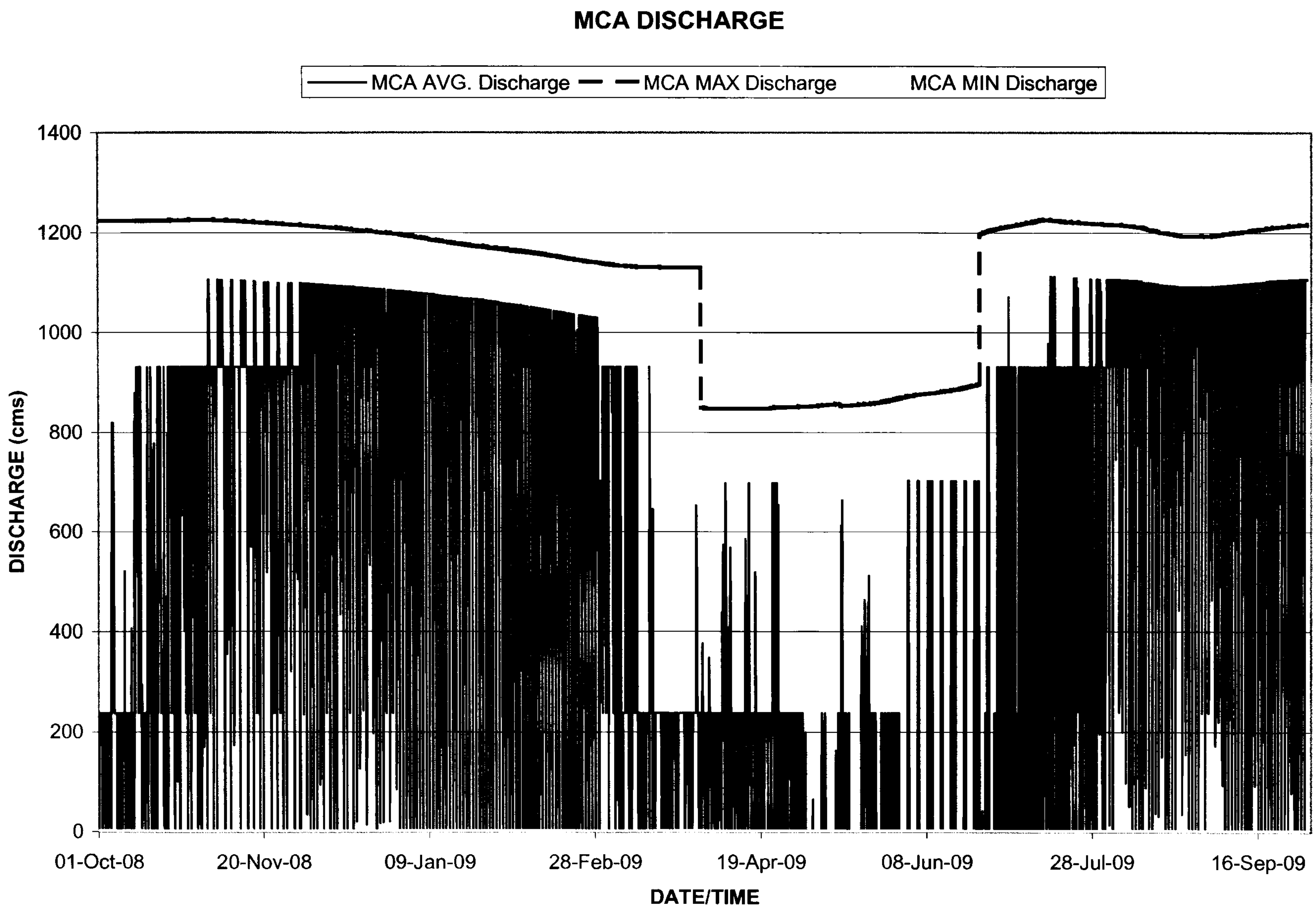

REV DISCHARGE
REV AVG. Discharge
REV MAX Discharge
REV MIN Discharge
2000
1800
1600
1400
1200
1000
800
600
400
200
0
DISCHARGE (cms)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

GMS DISCHARGE

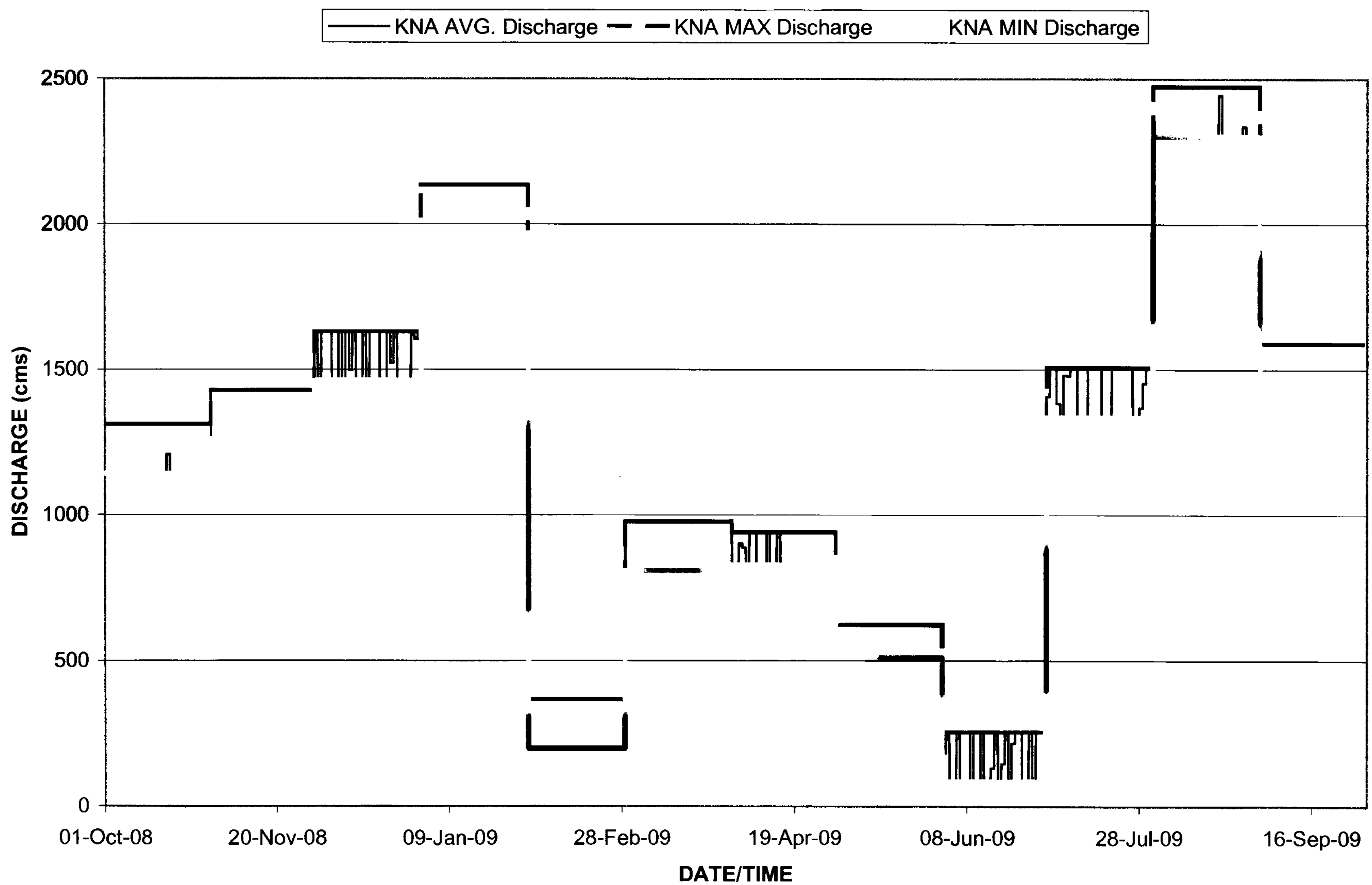


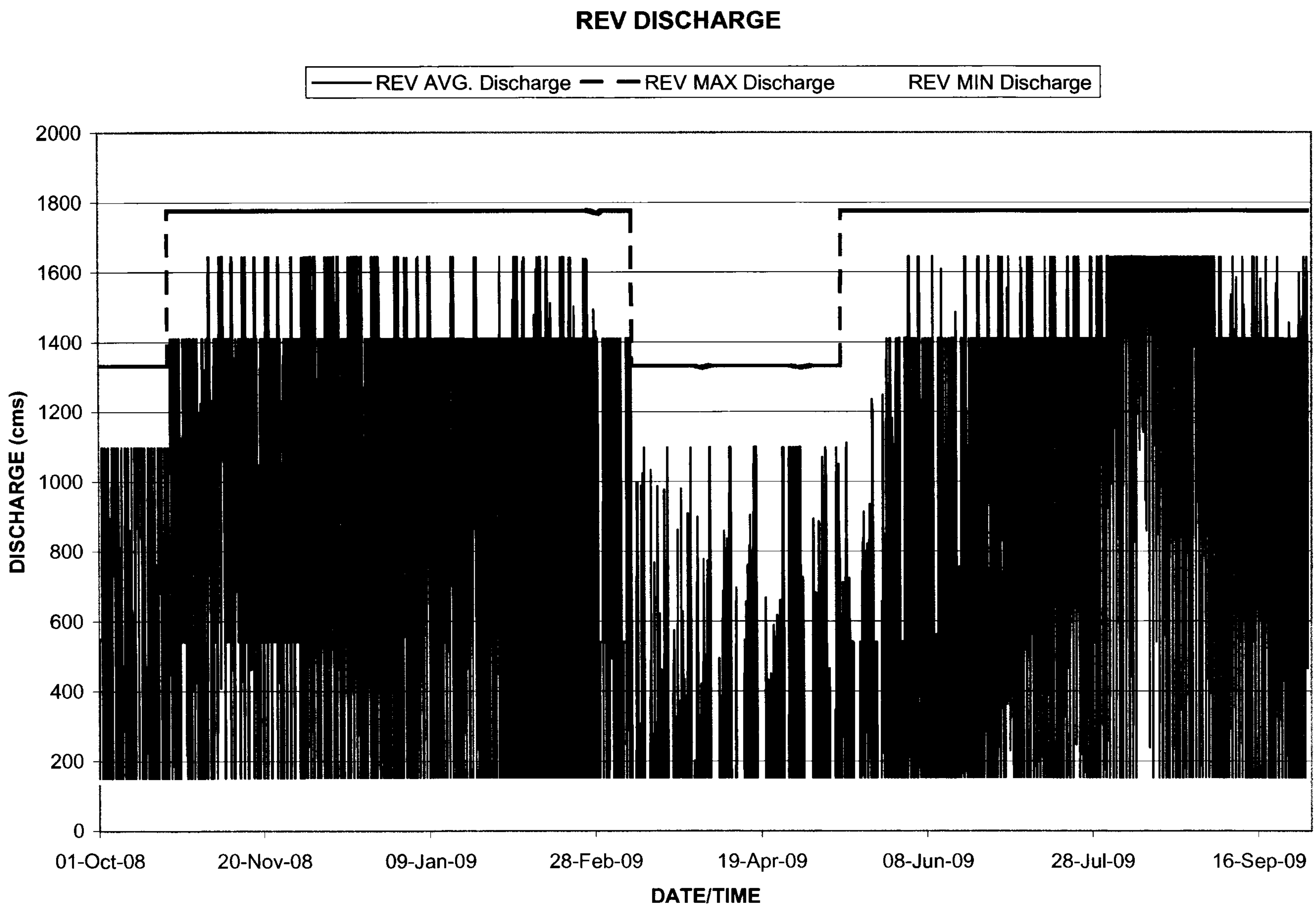
PCN DISCHARGE




MCA DISCHARGE
MCA AVG. Discharge
MCA MAX Discharge
MCA MIN Discharge
1400
1200
1000
800
600
400
200
0
DISCHARGE (cms)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

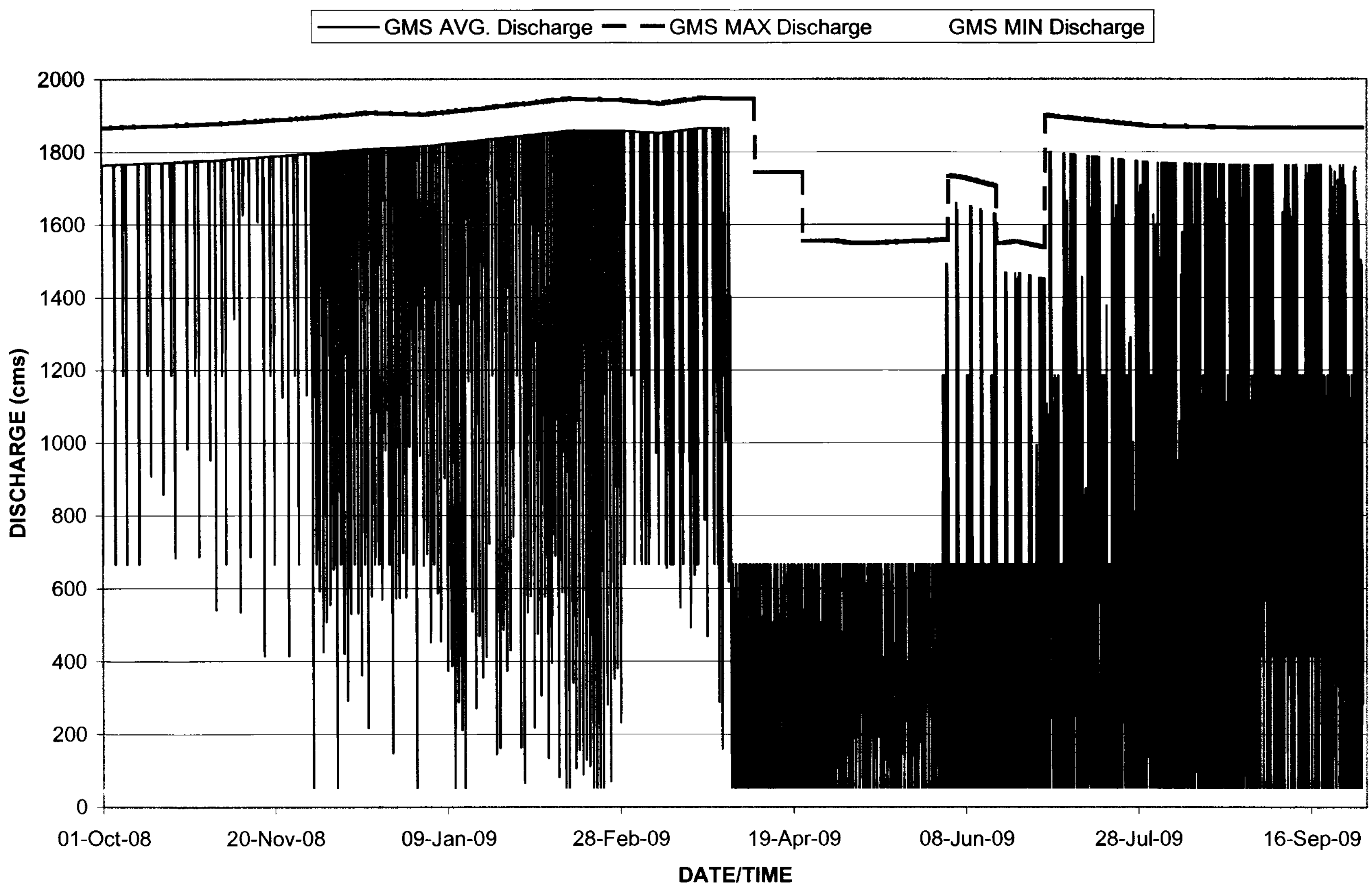
KNA DISCHARGE

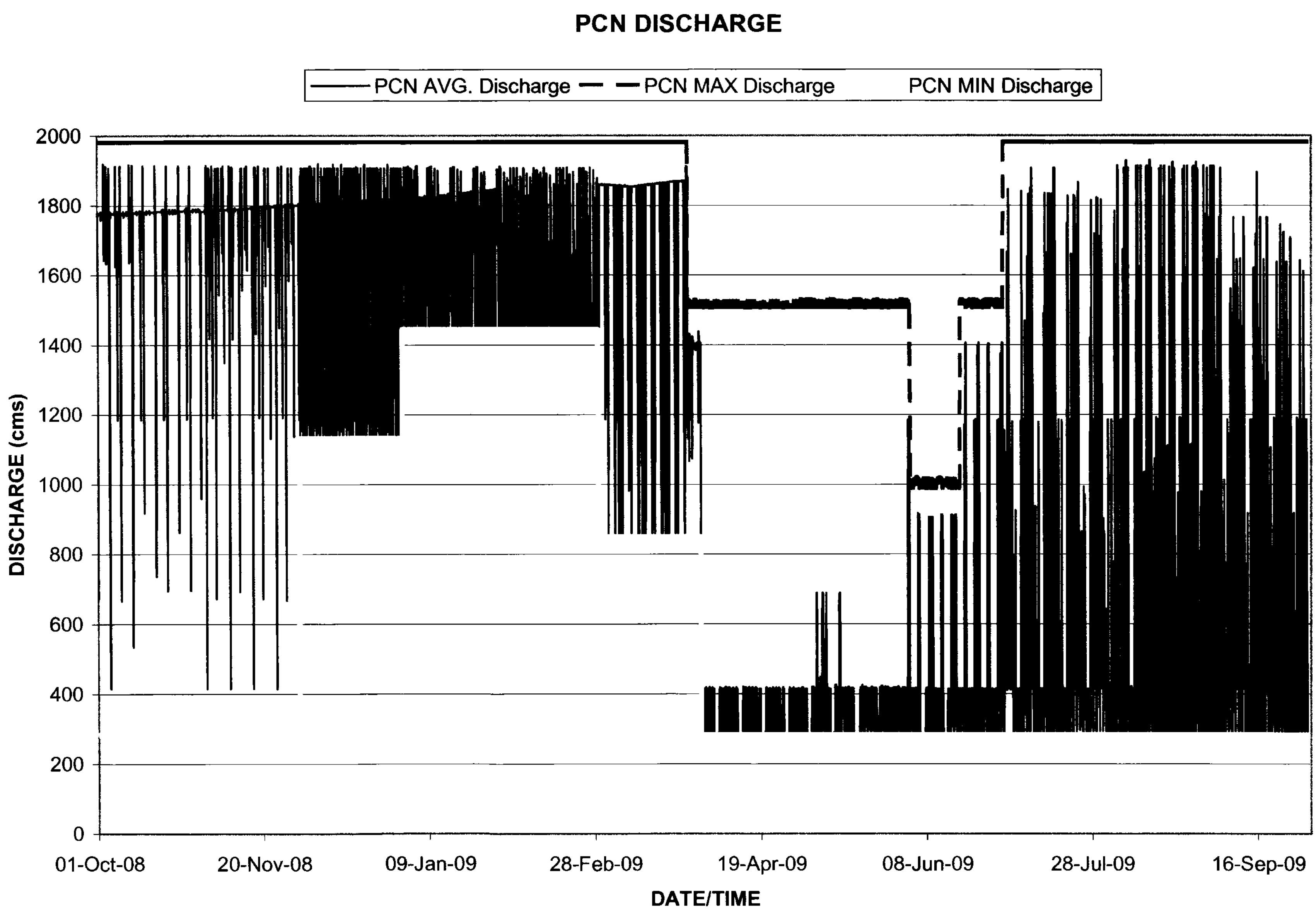




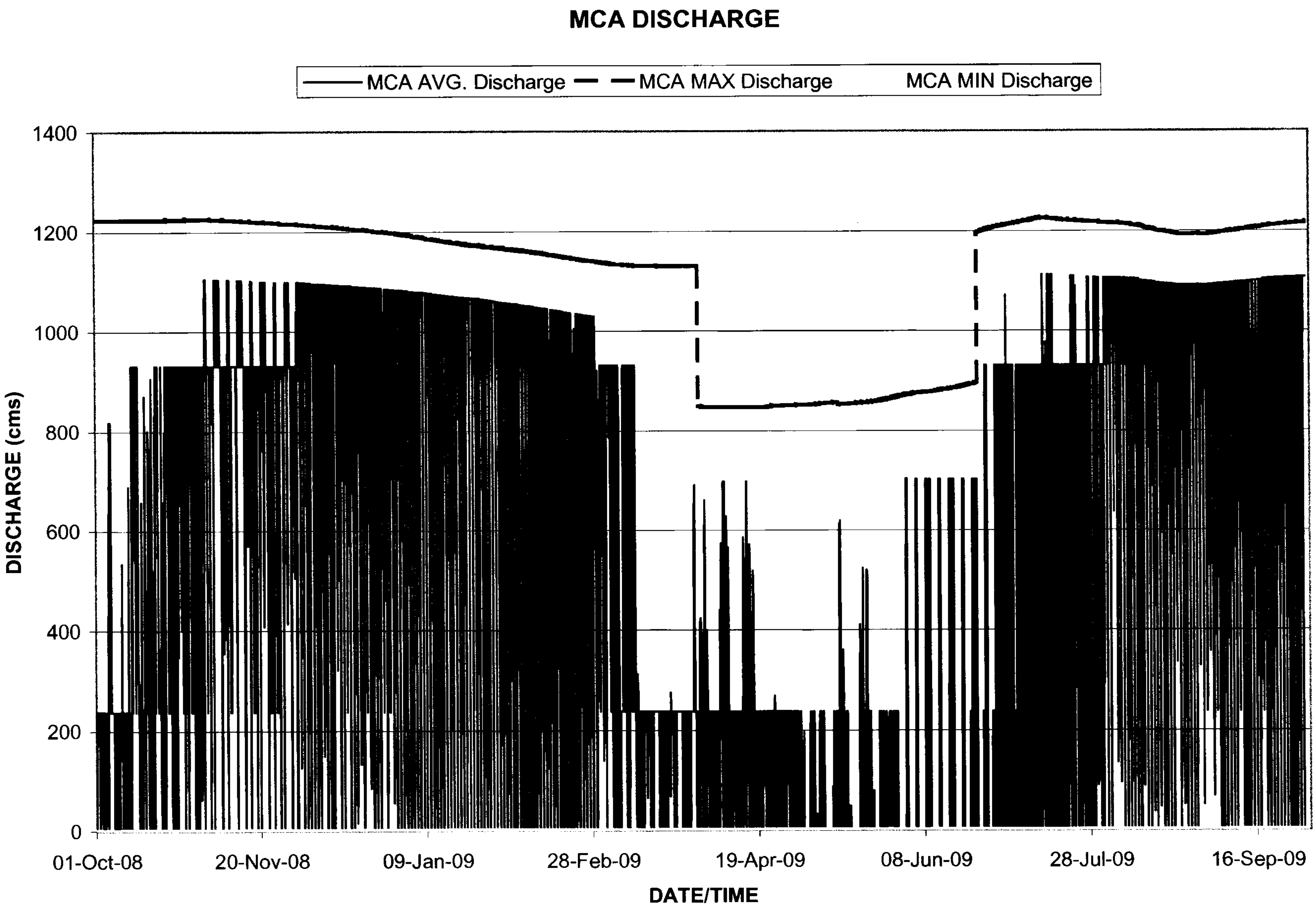
REV DISCHARGE
REV AVG. Discharge
REV MAX Discharge
REV MIN Discharge
DISCHARGE (cms)
2000
1800
1600
1400
1200
1000
800
600
400
200
0
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

GMS DISCHARGE





PCN DISCHARGE
PCN AVG. Discharge
PCN MAX Discharge
PCN MIN Discharge
DISCHARGE (cms)
2000
1800
1600
1400
1200
1000
800
600
400
200
0
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME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MCA AVG. Discharge
MCA MAX Discharge
MCA MIN Discharge
1400
1200
1000
800
600
400
200
0
DISCHARGE (cms)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
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08-Jun-09
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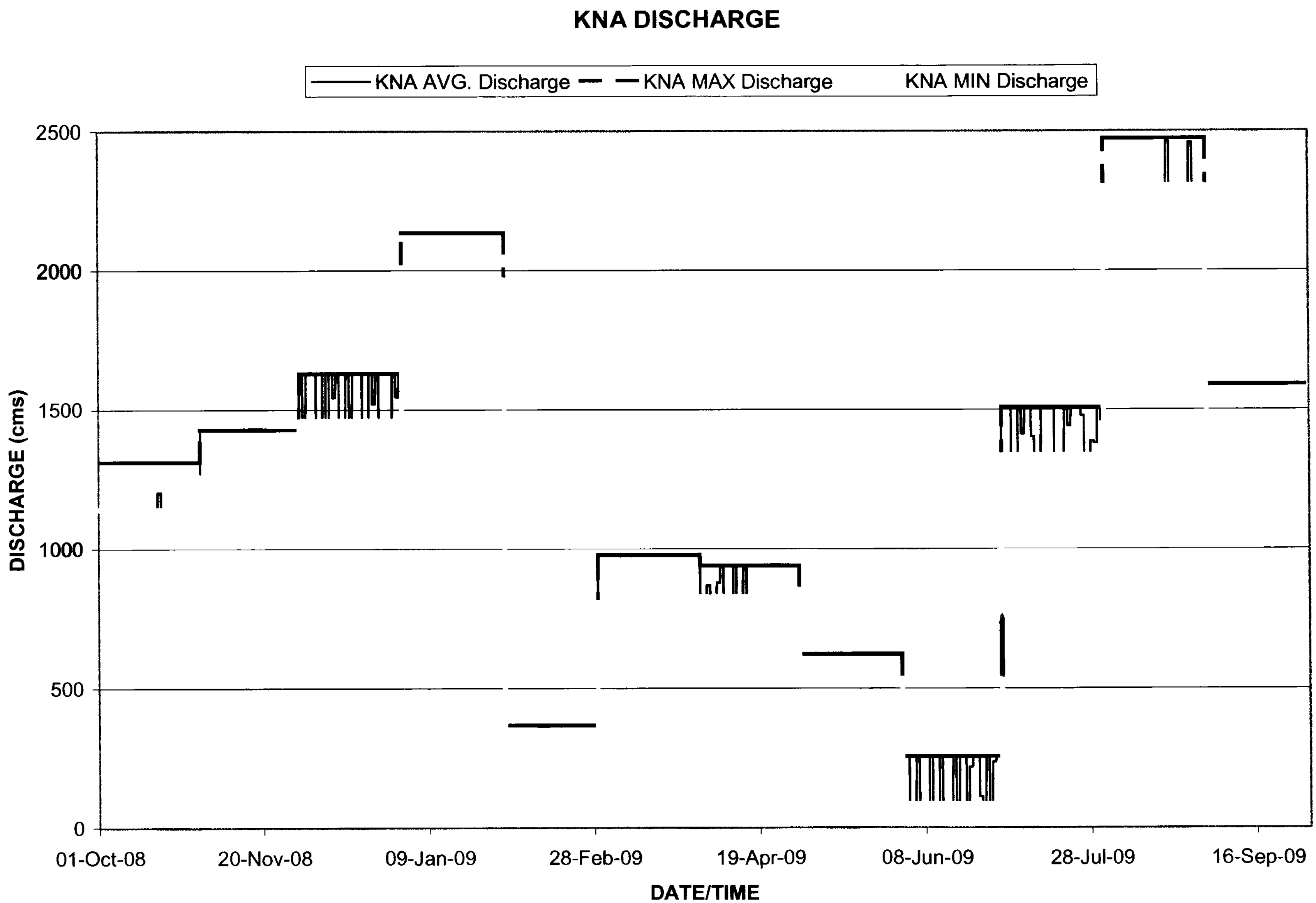
DATE/TIME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1500
1000
500
0
DISCHARGE (cms)
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20-Nov-08
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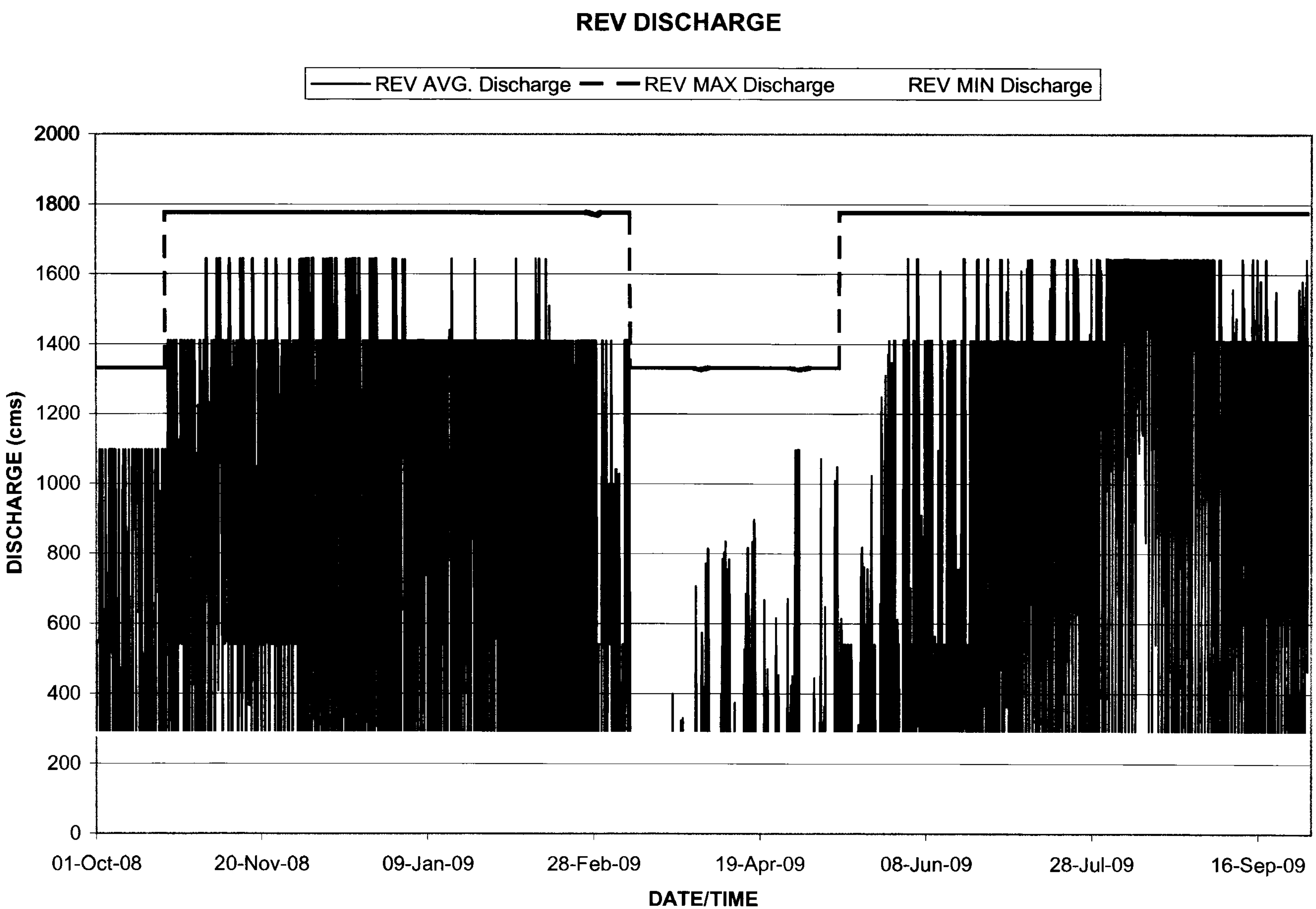
16-Sep-09
DATE/TIME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REV AVG. Discharge
REV MAX Discharge
REV MIN Discharge
DISCHARGE (cms)
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1600
1400
1200
1000
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600
400
200
0
01-Oct-08
20-Nov-08
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28-Feb-09
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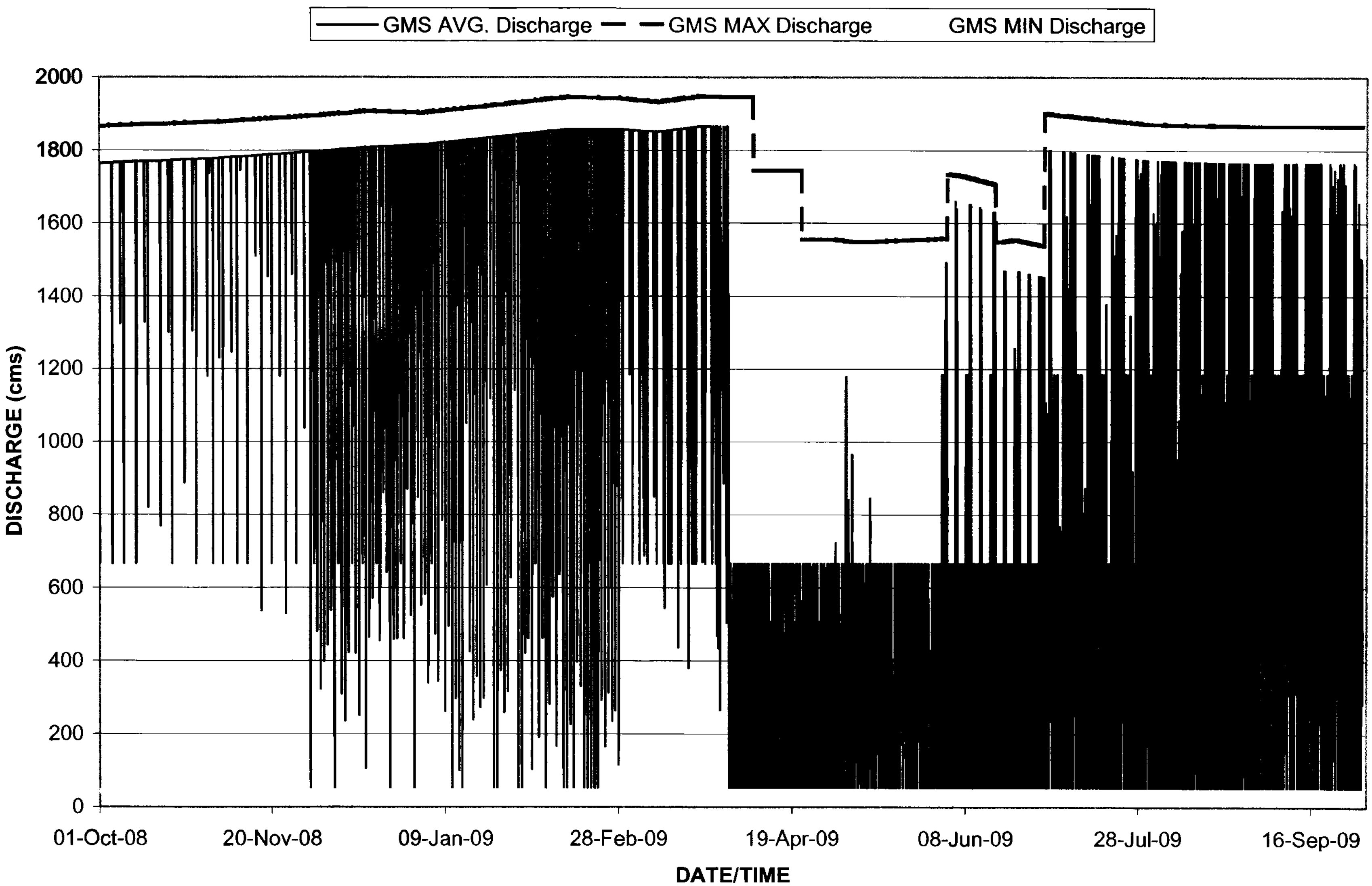
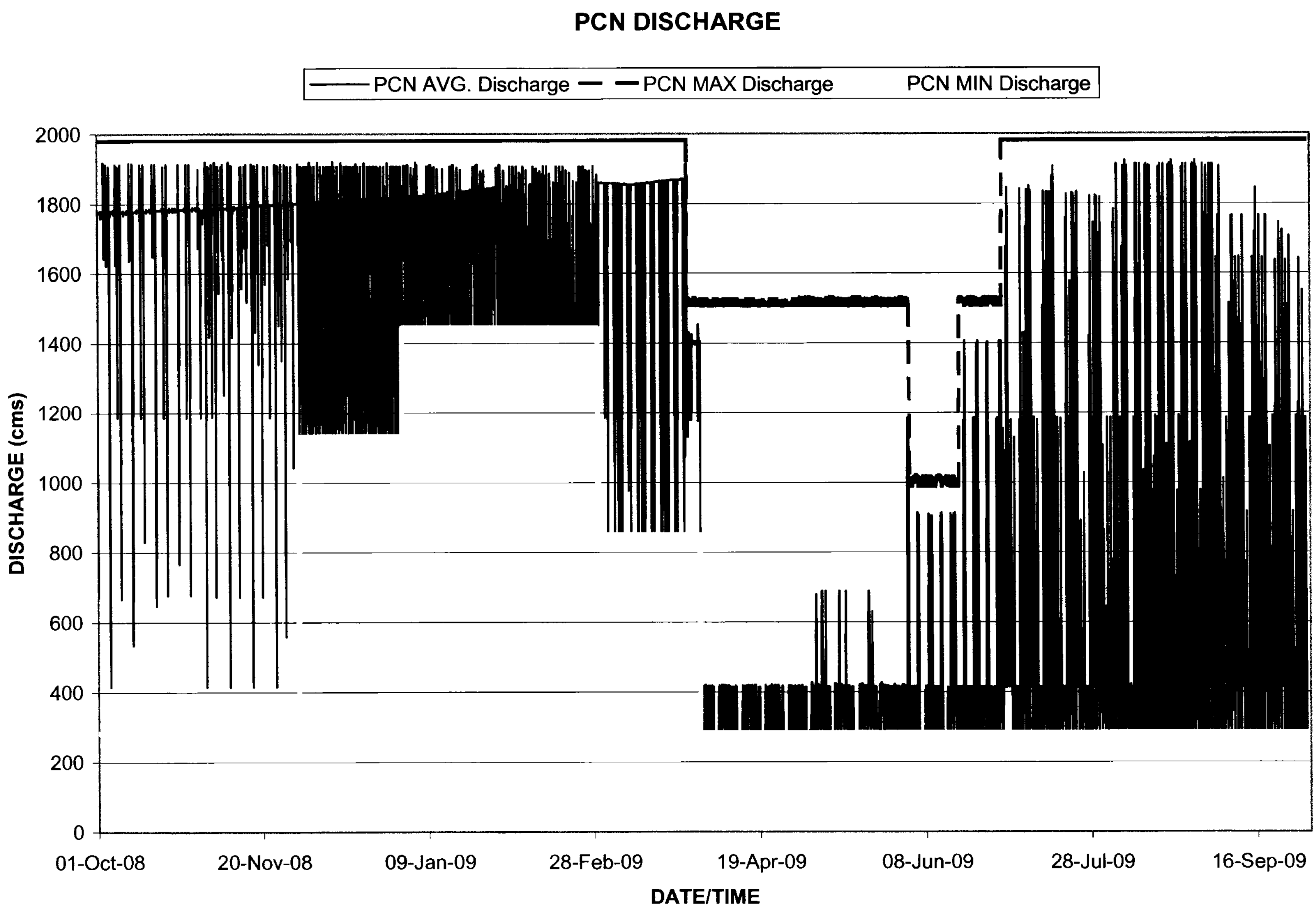
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

GMS DISCHARGE





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PCN AVG. Discharge
PCN MAX Discharge
PCN MIN Discharge
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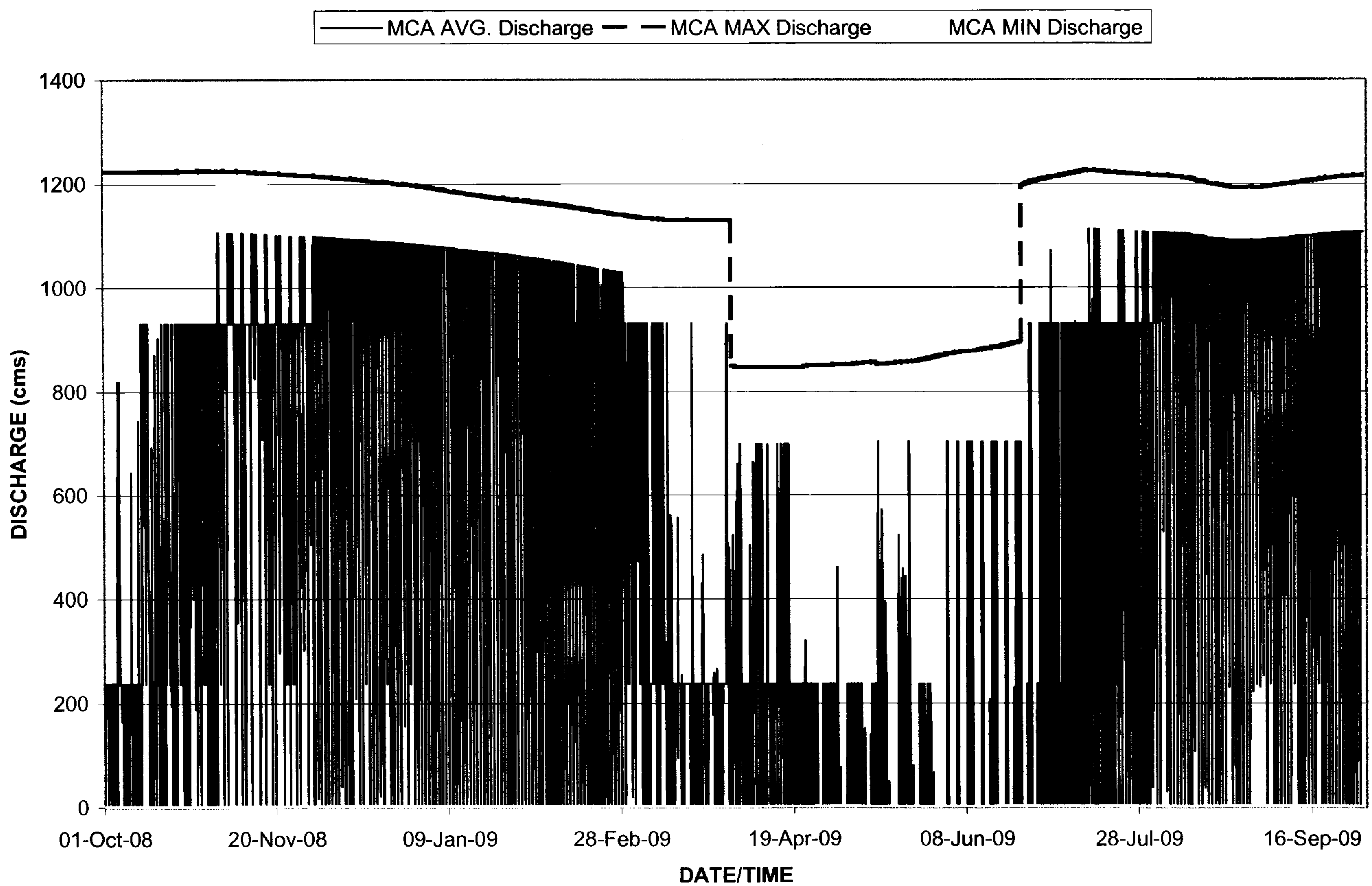
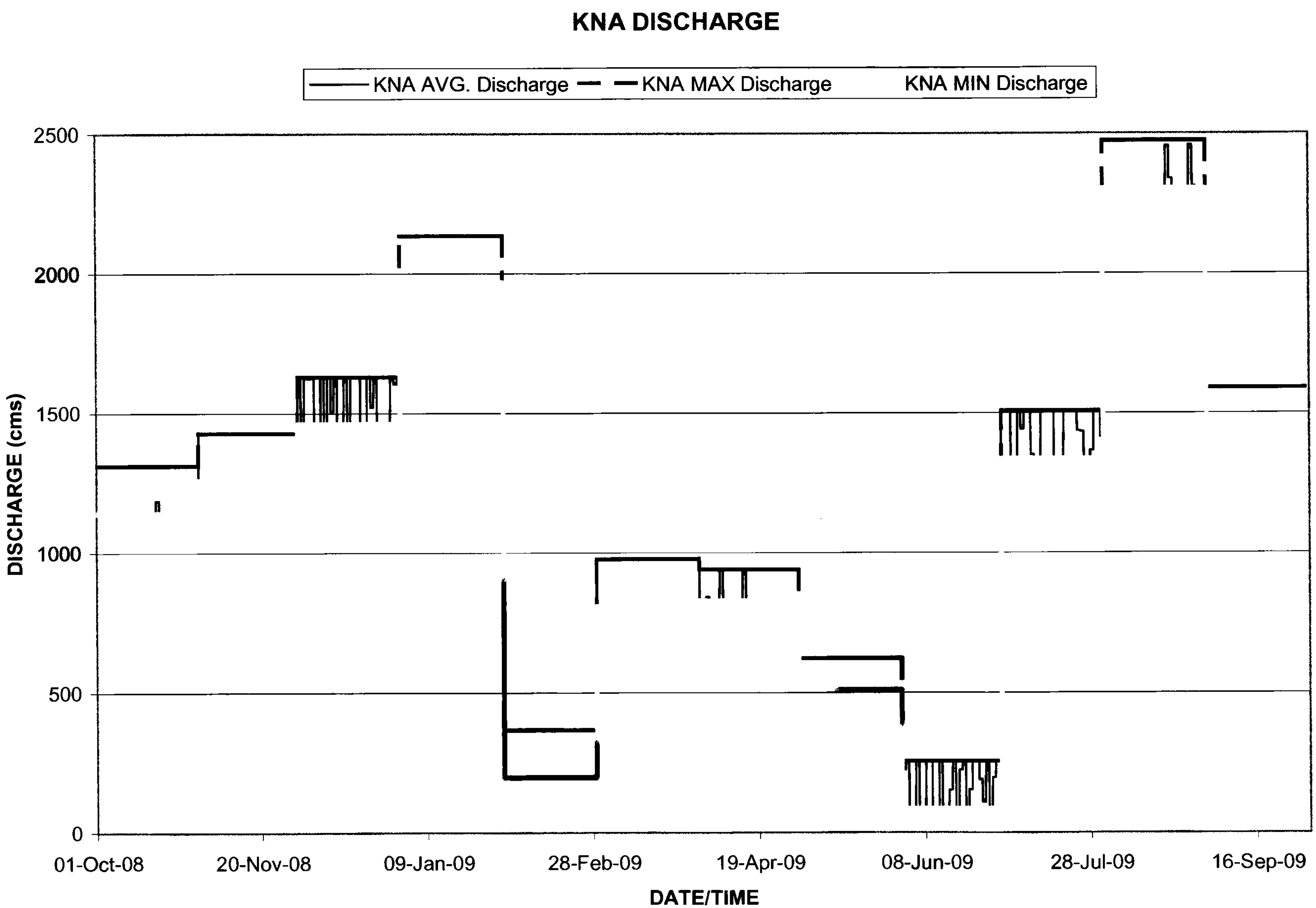
1800
1600
1400
1200
1000
800
600
400
200
0
DISCHARGE (cms)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

MCA DISCHARGE

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KNA MIN Discharge
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2000
1500
1000
500
0
DISCHARGE (cms)
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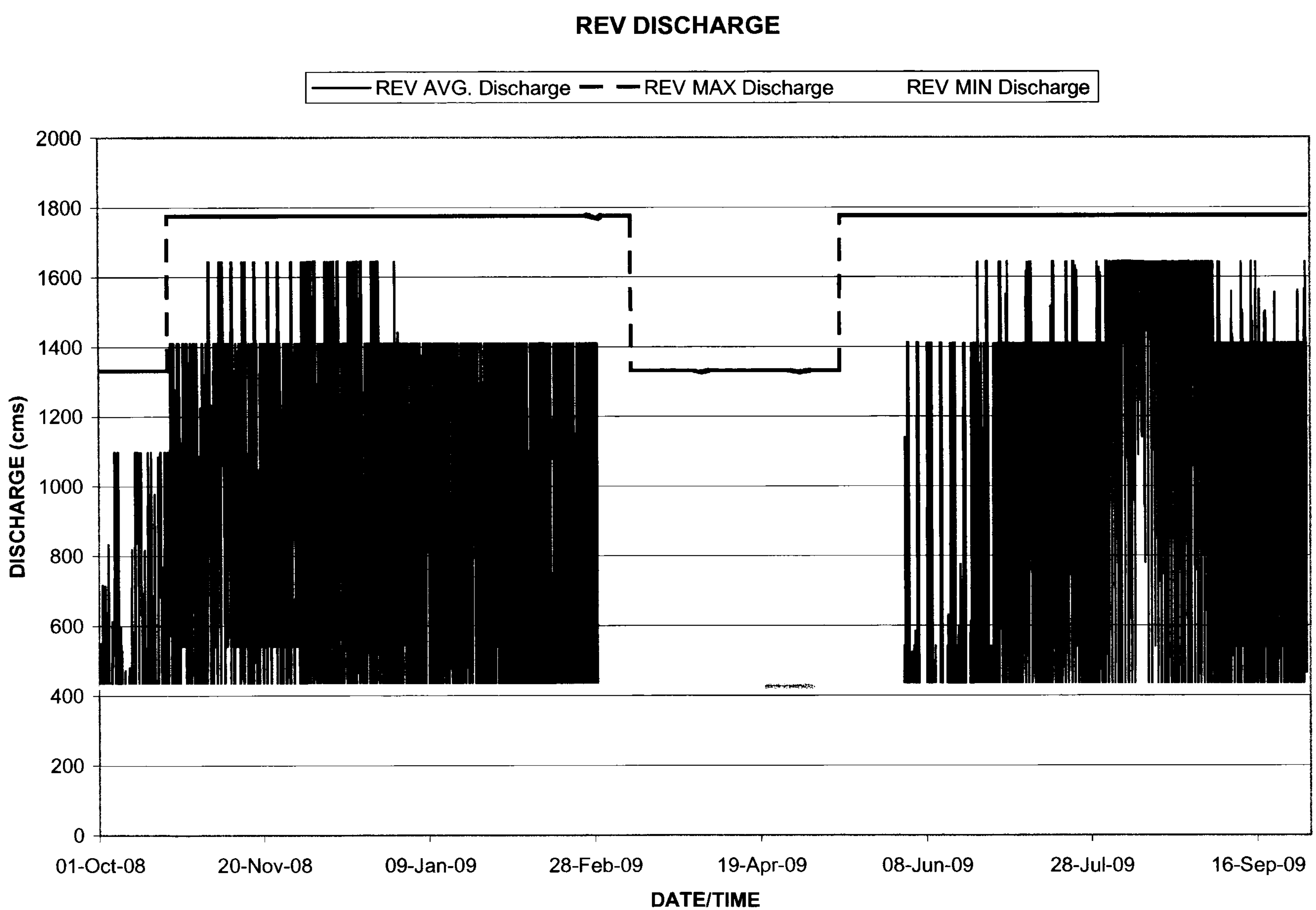
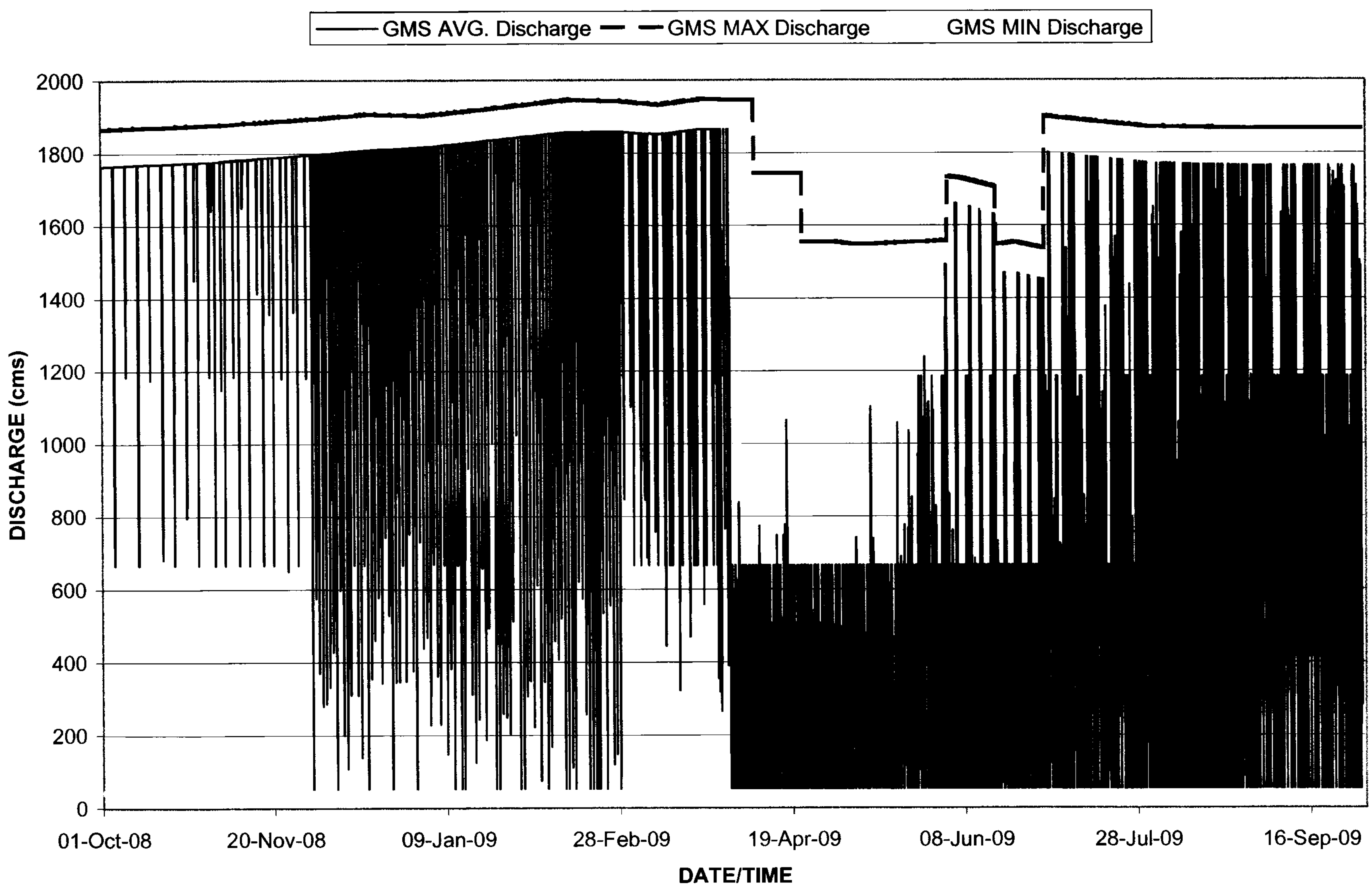
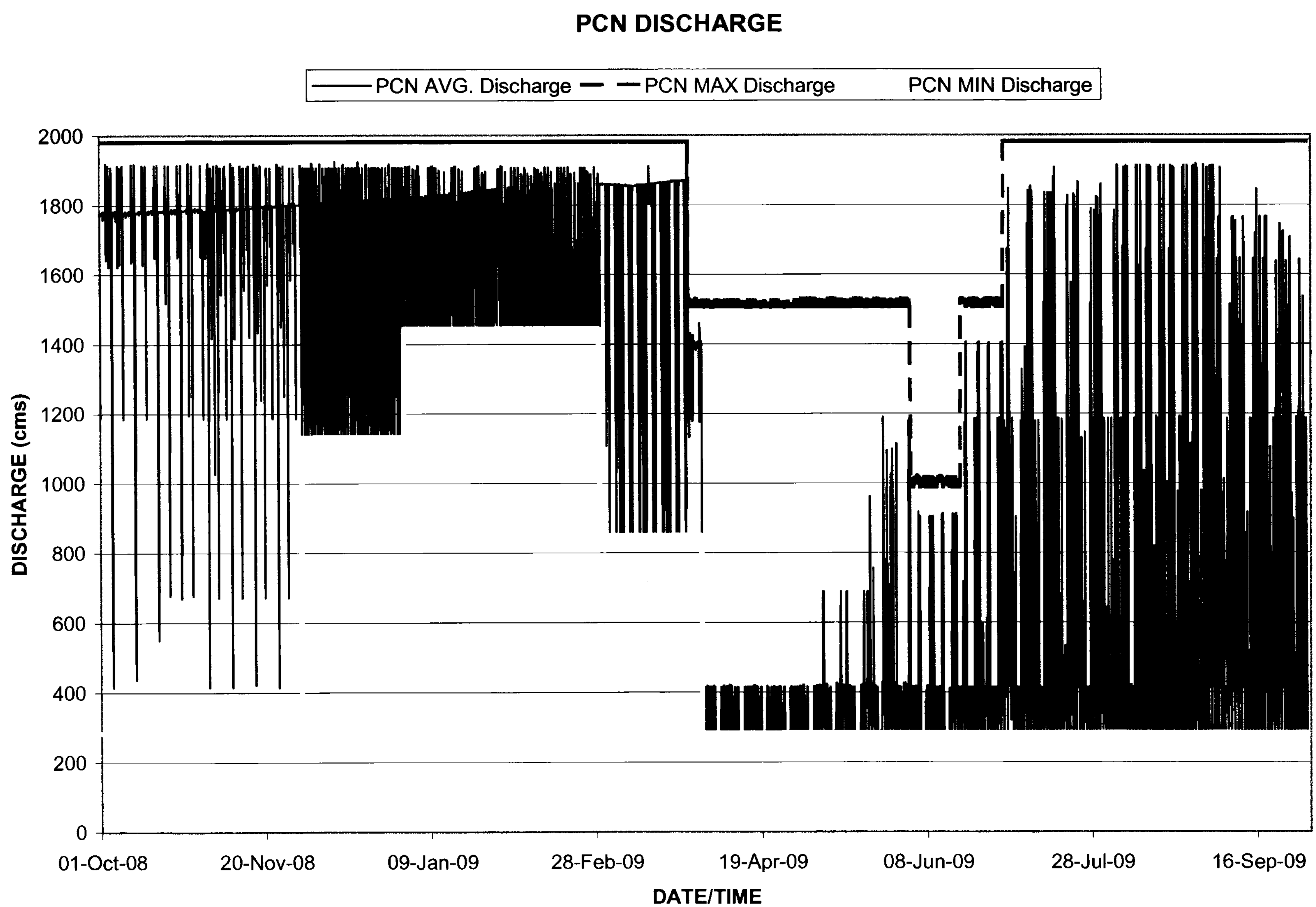
28-Jul-09
16-Sep-09
DATE/TIME



REV DISCHARGE
REV AVG. Discharge
REV MAX Discharge
REV MIN Discharge
DISCHARGE (cms)
2000
1800
1600
1400
1200
1000
800
600
400
200
0
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

GMS DISCHARGE

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PCN AVG. Discharge
PCN MAX Discharge
PCN MIN Discharge
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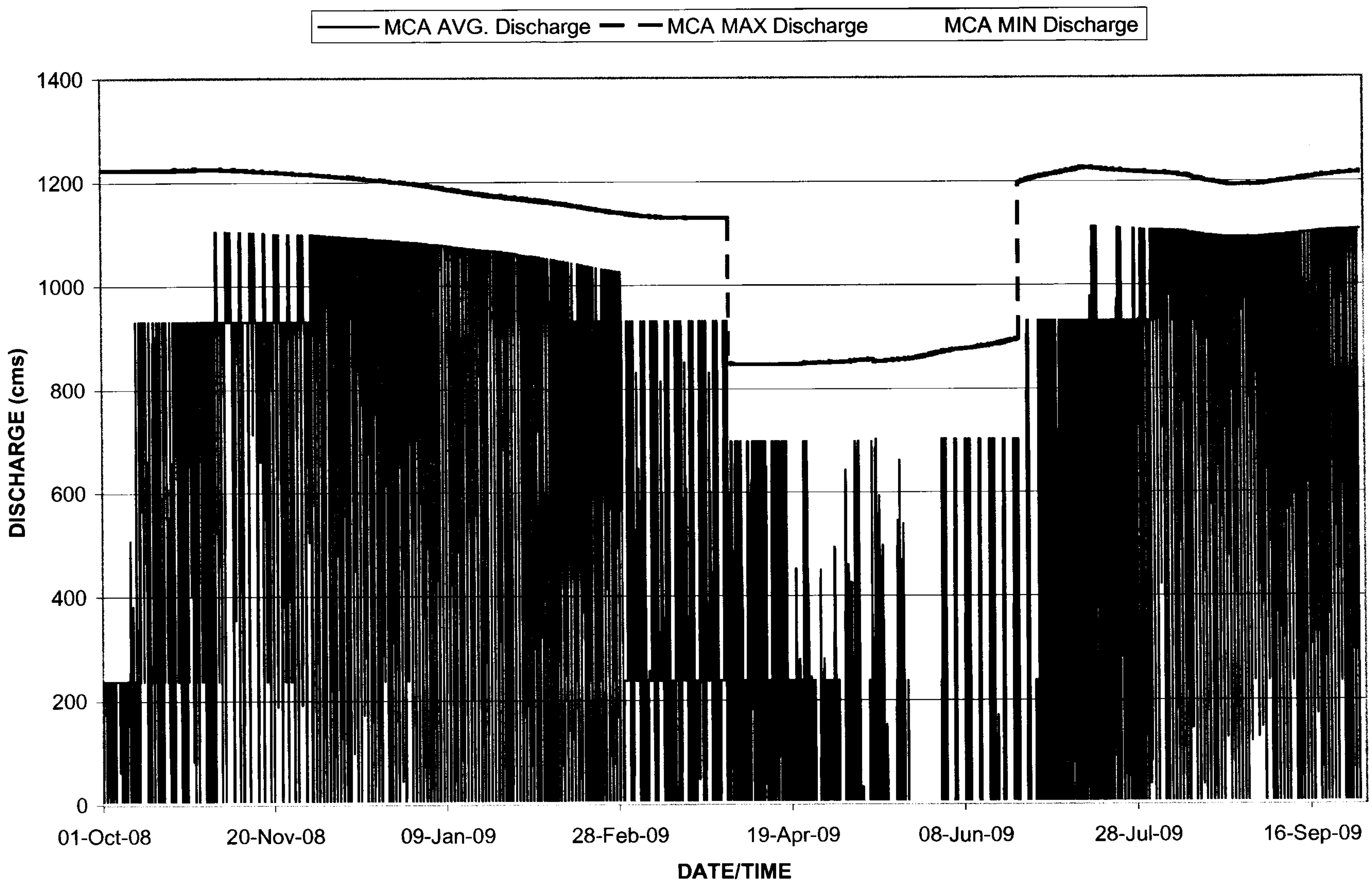
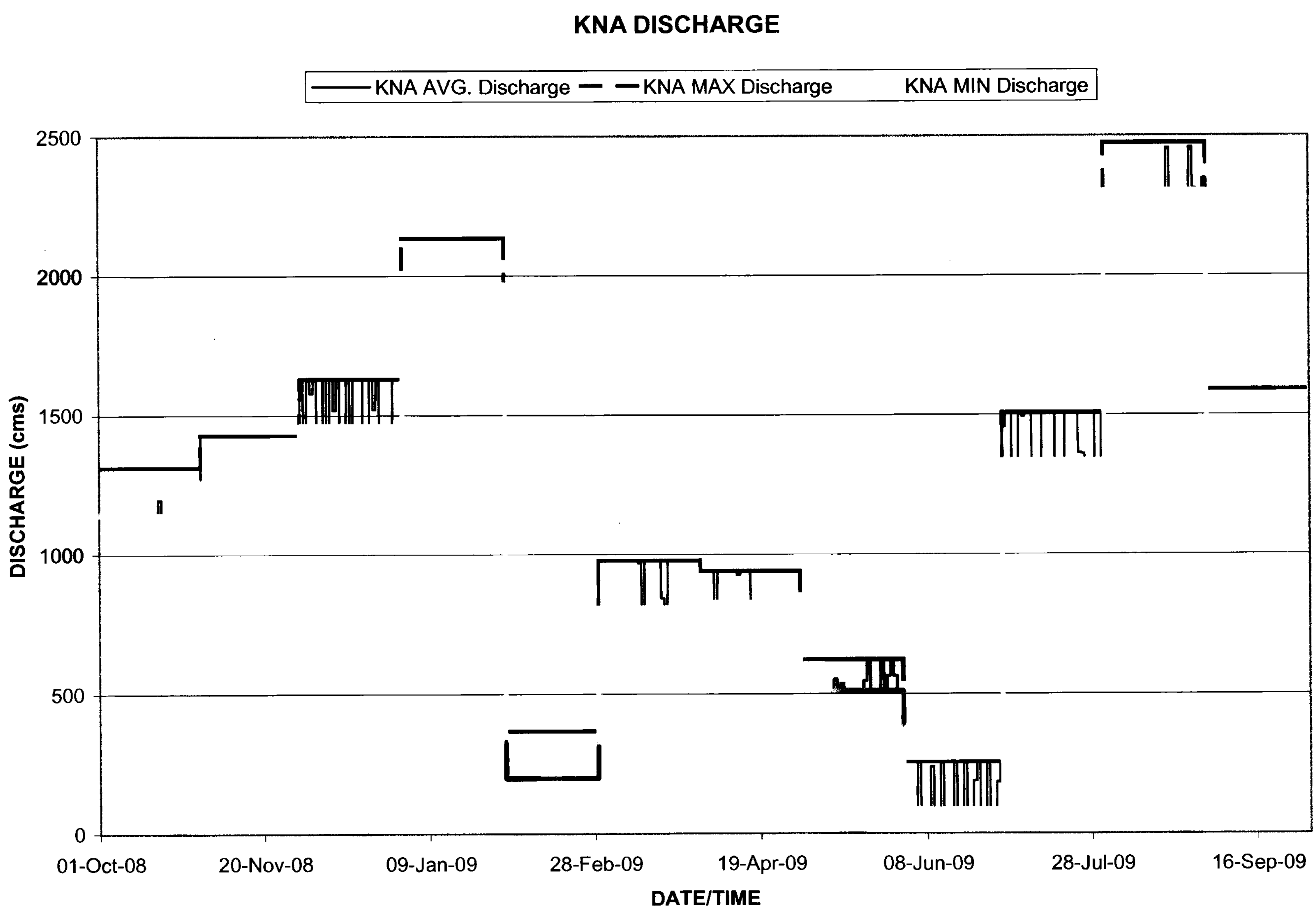
1800
1600
1400
1200
1000
800
600
400
200
0
DISCHARGE (cms)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

MCA DISCHARGE

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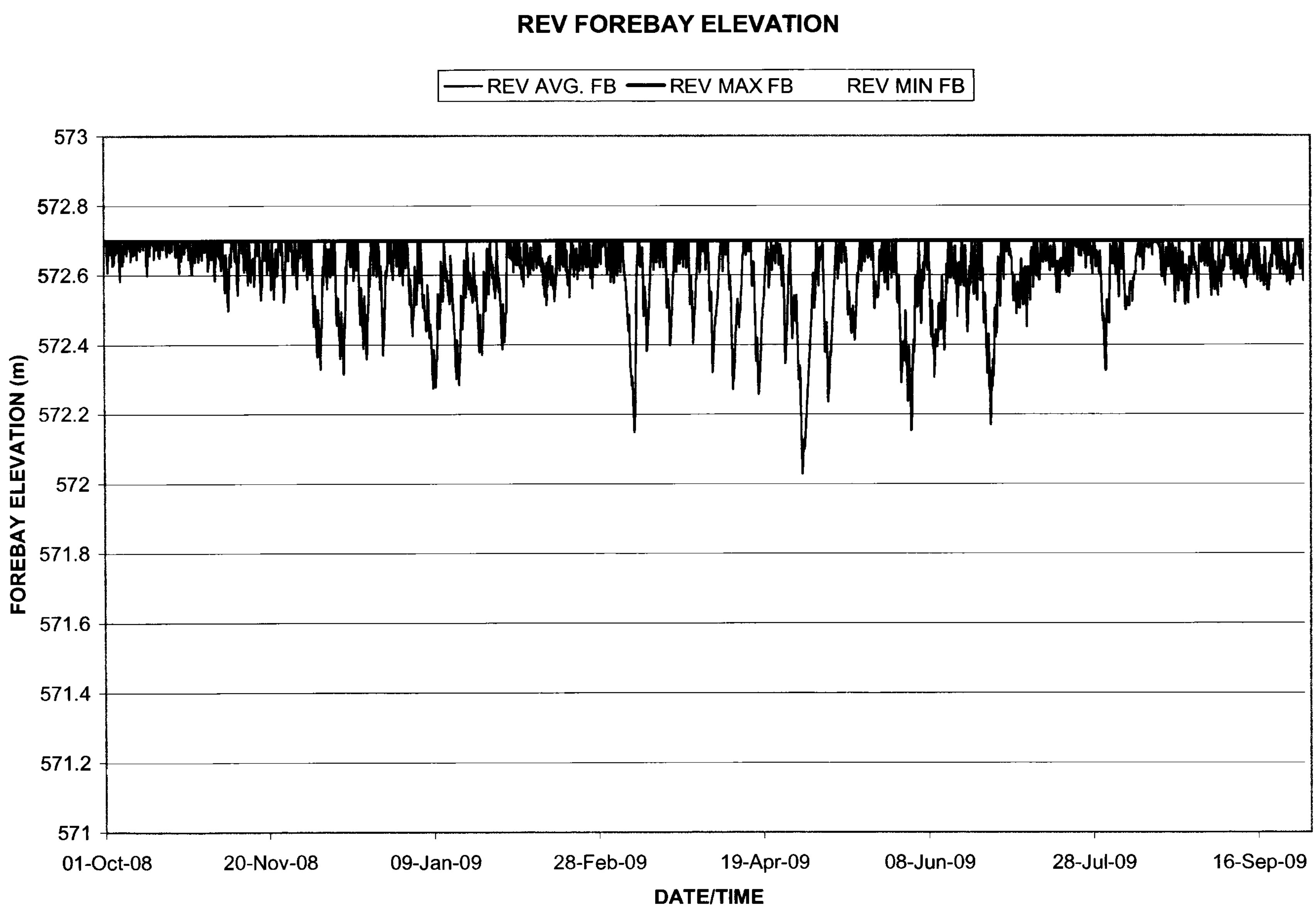
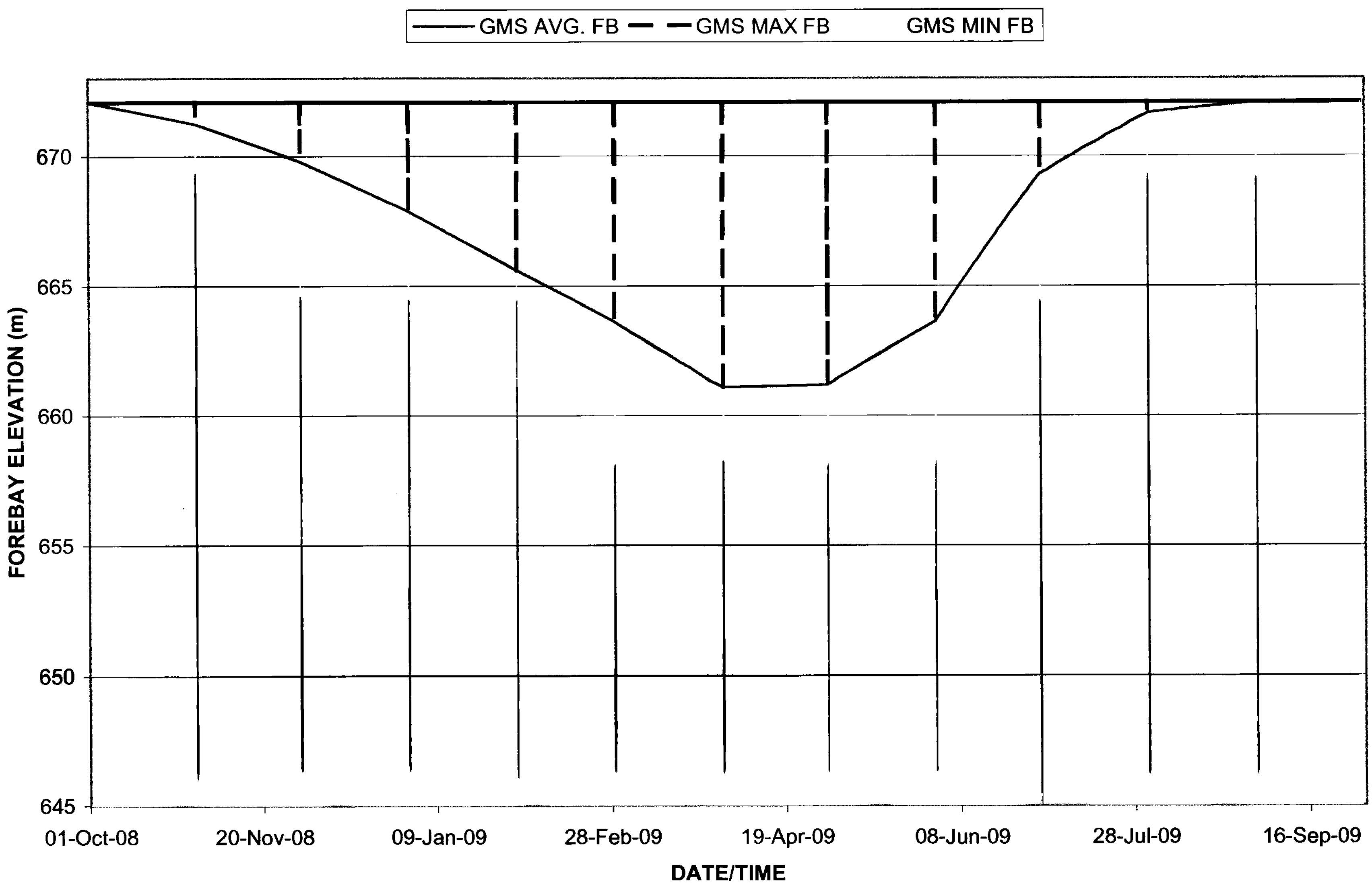
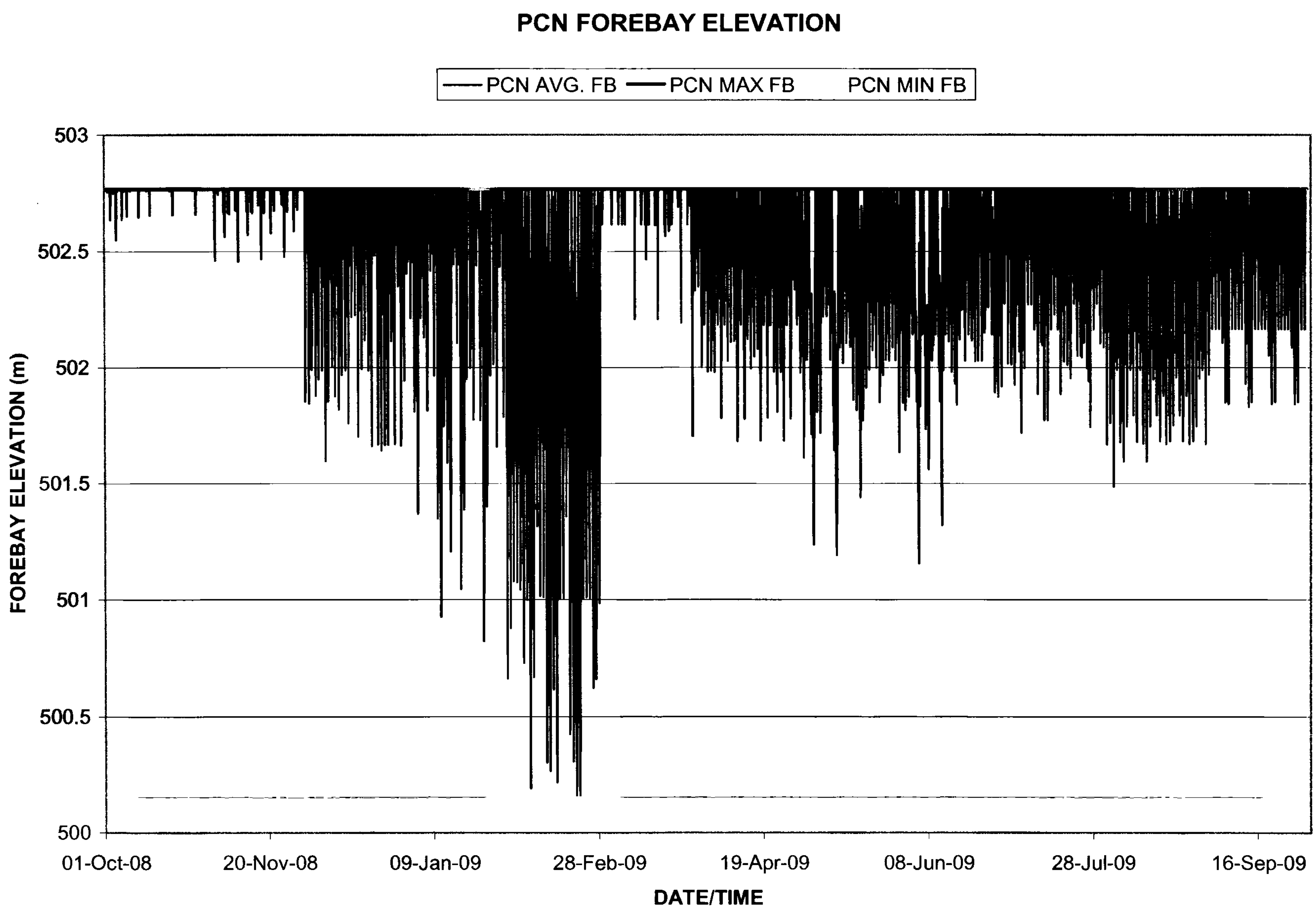
KNA AVG. Discharge
KNA MAX Discharge
KNA MIN Discharge
2500
2000
1500
1000
500
0
DISCHARGE (cms)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME


REV FOREBAY ELEVATION
REV AVG. FB
REV MAX FB
REV MIN FB
FOREBAY ELEVATION (m)
573
572.8
572.6
572.4
572.2
572
571.8
571.6
571.4
571.2
571
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

GMS FOREBAY ELEVATION




PCN FOREBAY ELEVATION
PCN AVG. FB
PCN MAX FB
PCN MIN FB
503
502.5
502
501.5
501
500.5
500
FOREBAY ELEVATION (m)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
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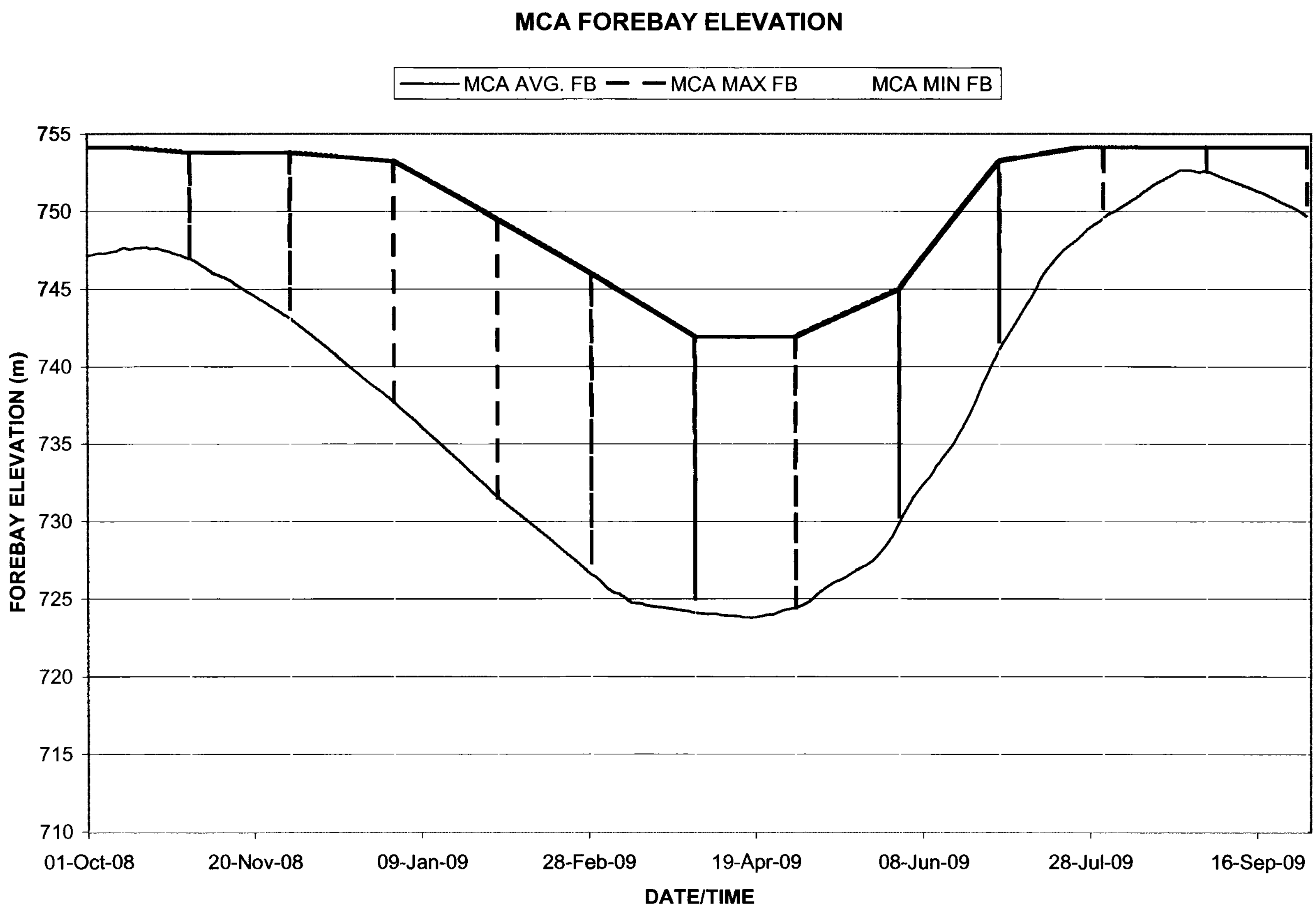
16-Sep-09
DATE/TIME


MCA FOREBAY ELEVATION
MCA AVG. FB
MCA MAX FB
MCA MIN FB
755
750
745
740
735
730
725
720
715
710
FOREBAY ELEVATION (m)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
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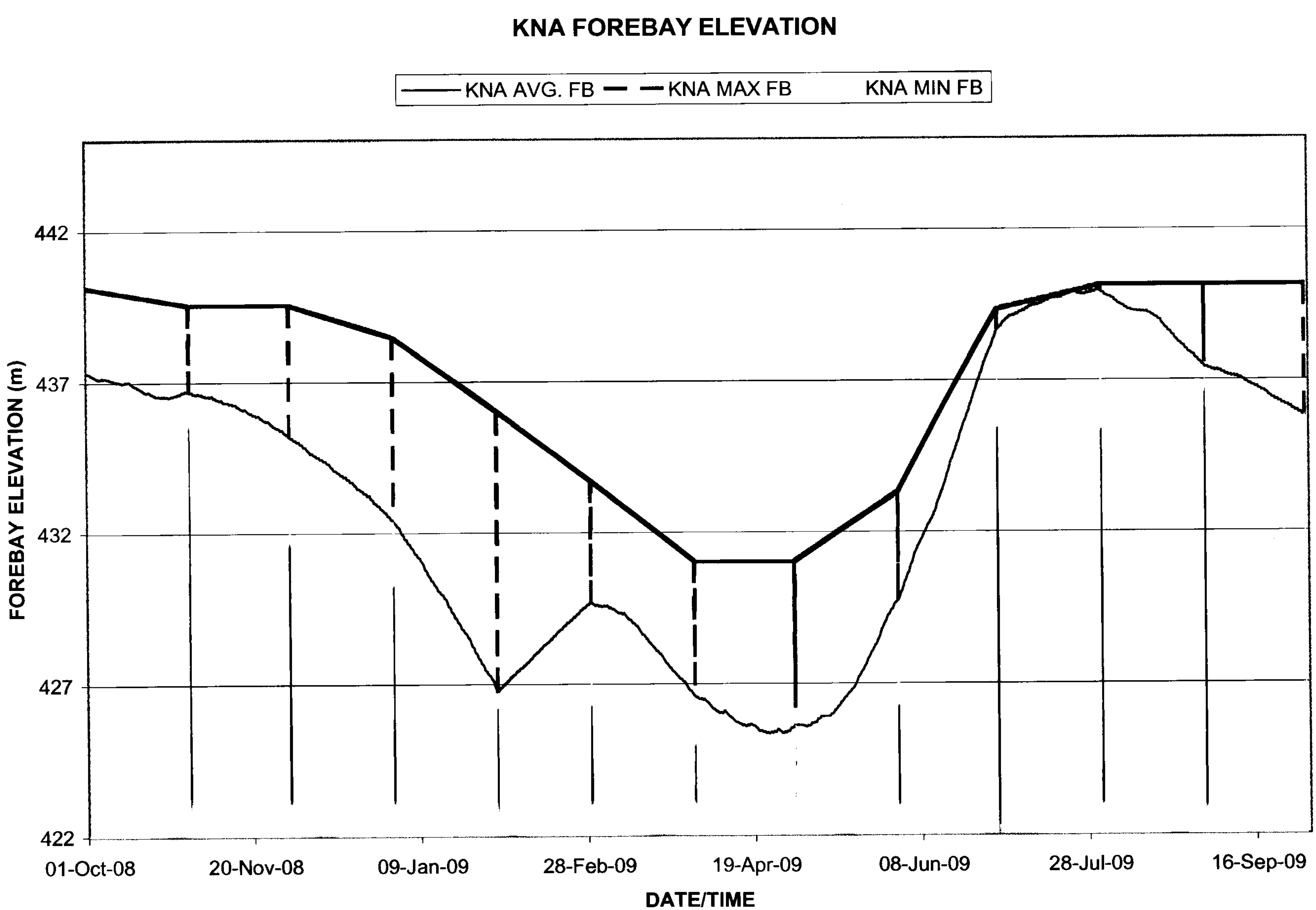
16-Sep-09
DATE/TIME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KNA AVG. FB
KNA MAX FB
KNA MIN FB
442
437
432
427
422
FOREBAY ELEVATION (m)
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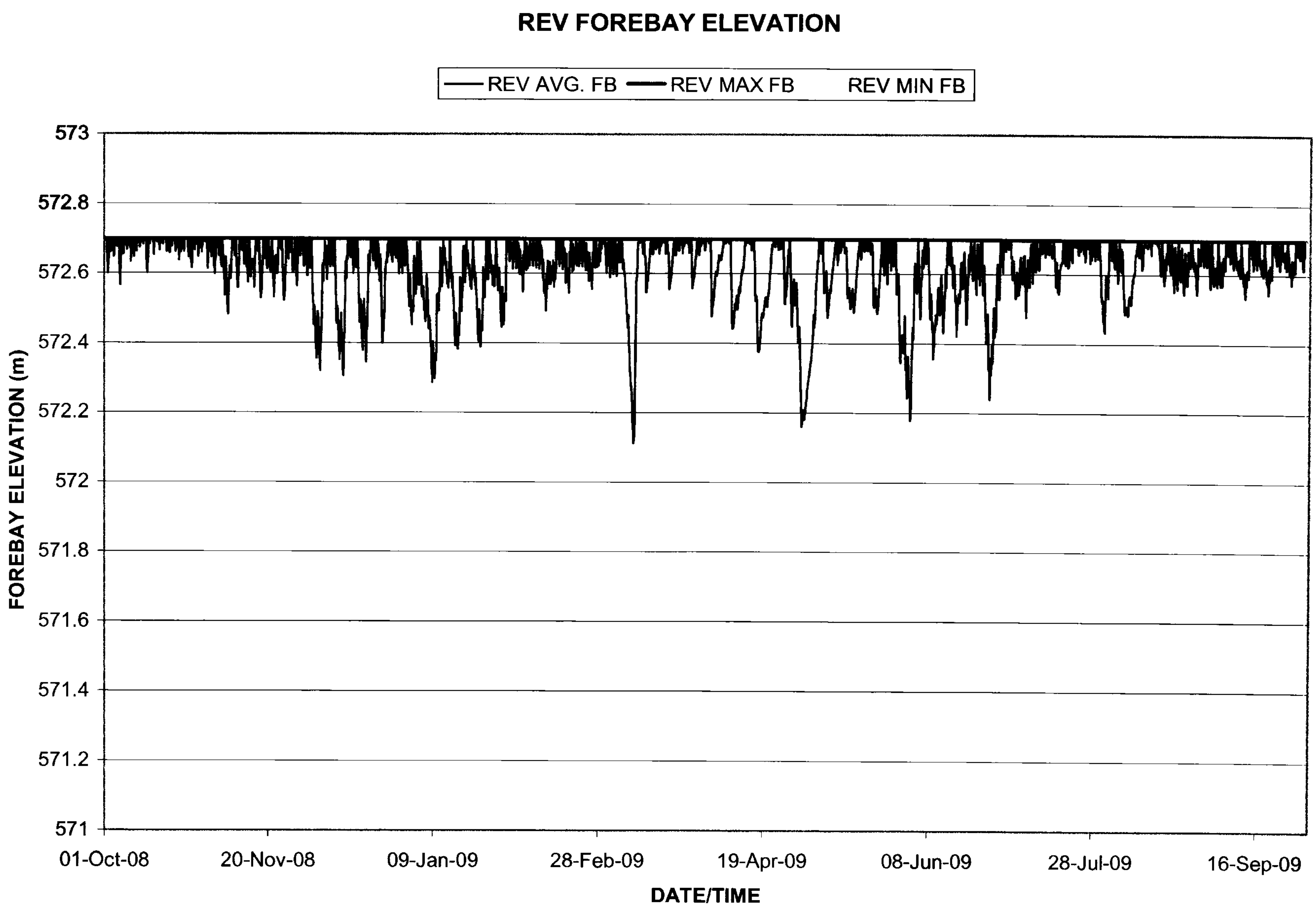
16-Sep-09
DATE/TIME



REV FOREBAY ELEVATION
REV AVG. FB
REV MAX FB
REV MIN FB
FOREBAY ELEVATION (m)
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572.6
572.4
572.2
572
571.8
571.6
571.4
571.2
571
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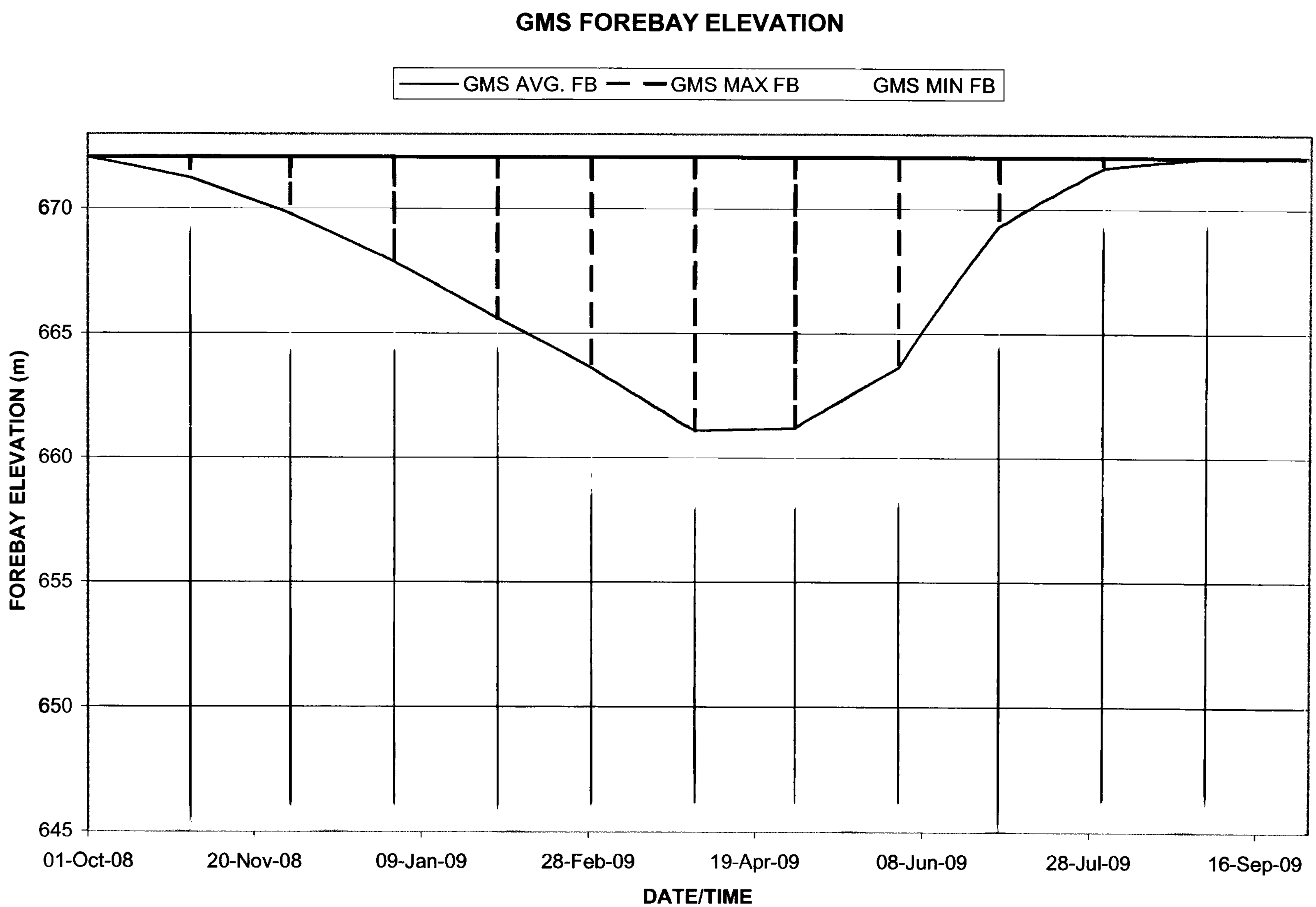
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME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GMS AVG. FB
GMS MAX FB
GMS MIN FB
FOREBAY ELEVATION (m)
670
665
660
655
650
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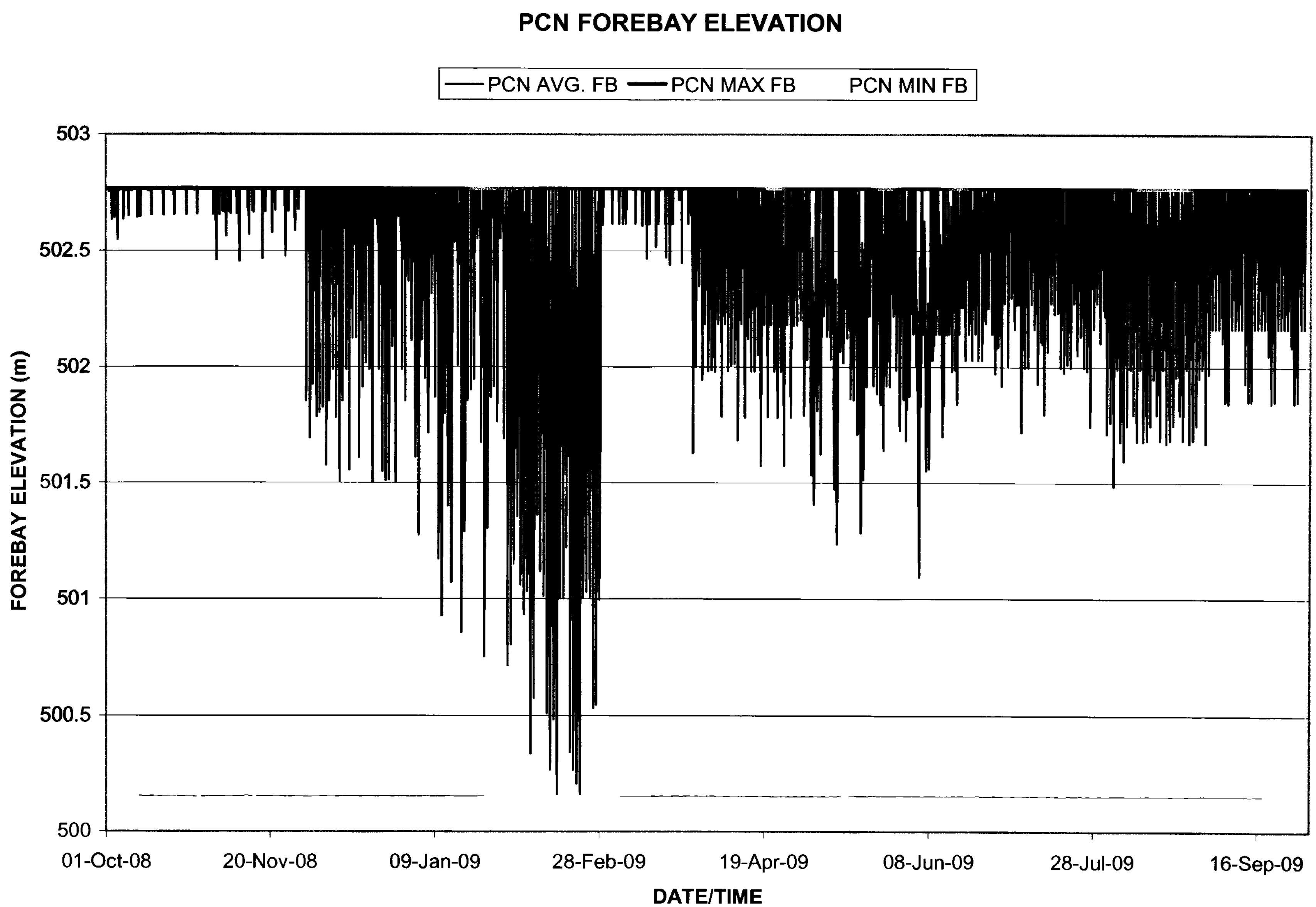
16-Sep-09
DATE/TIME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PCN MAX FB
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502.5
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501
500.5
500
FOREBAY ELEVATION (m)
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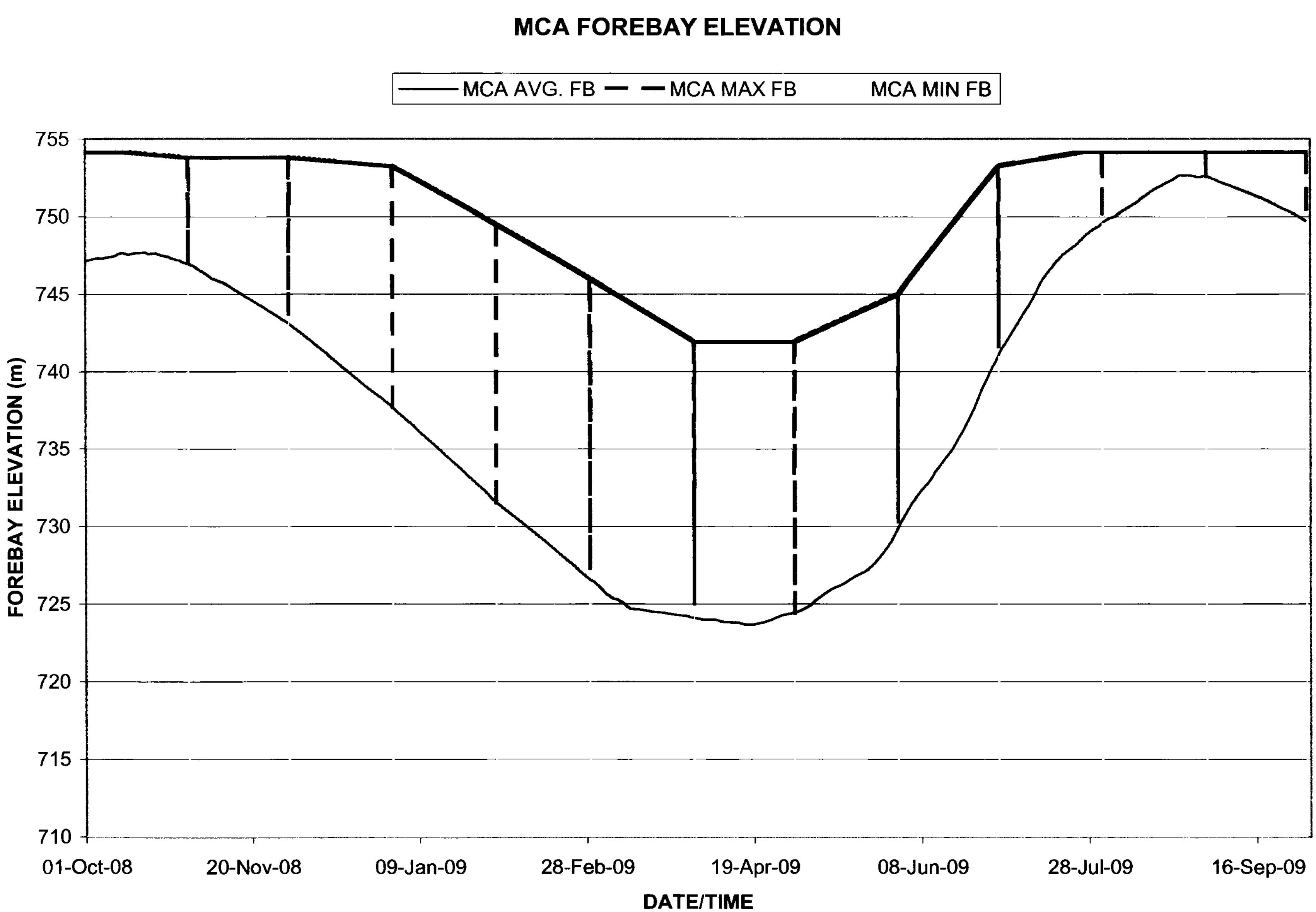
DATE/TIME


MCA FOREBAY ELEVATION
MCA AVG. FB
MCA MAX FB
MCA MIN FB
FOREBAY ELEVATION (m)
755
750
745
740
735
730
725
720
715
710
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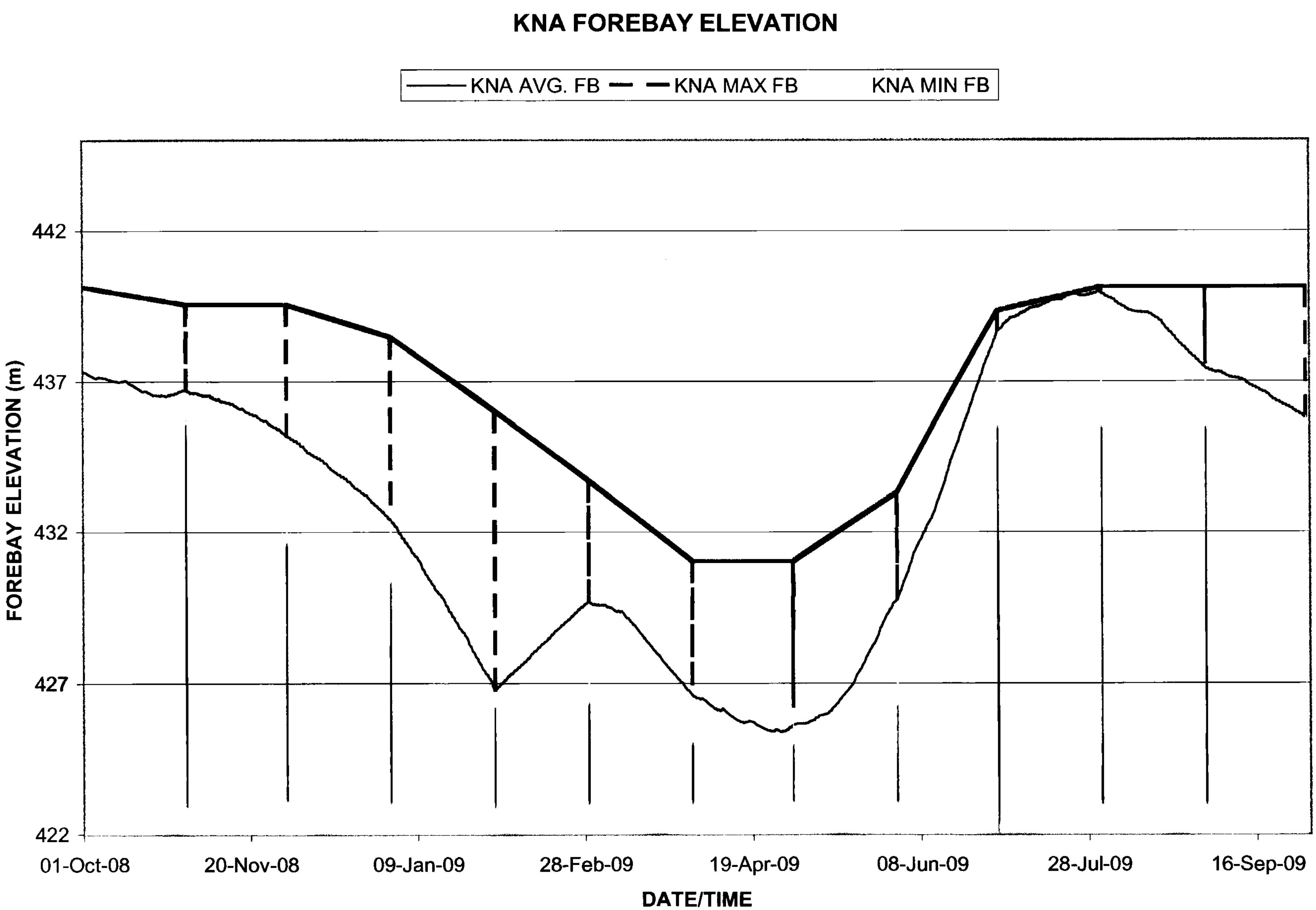
16-Sep-09
DATE/TIME


KNA FOREBAY ELEVATION
KNA AVG. FB
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432
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FOREBAY ELEVATION (m)
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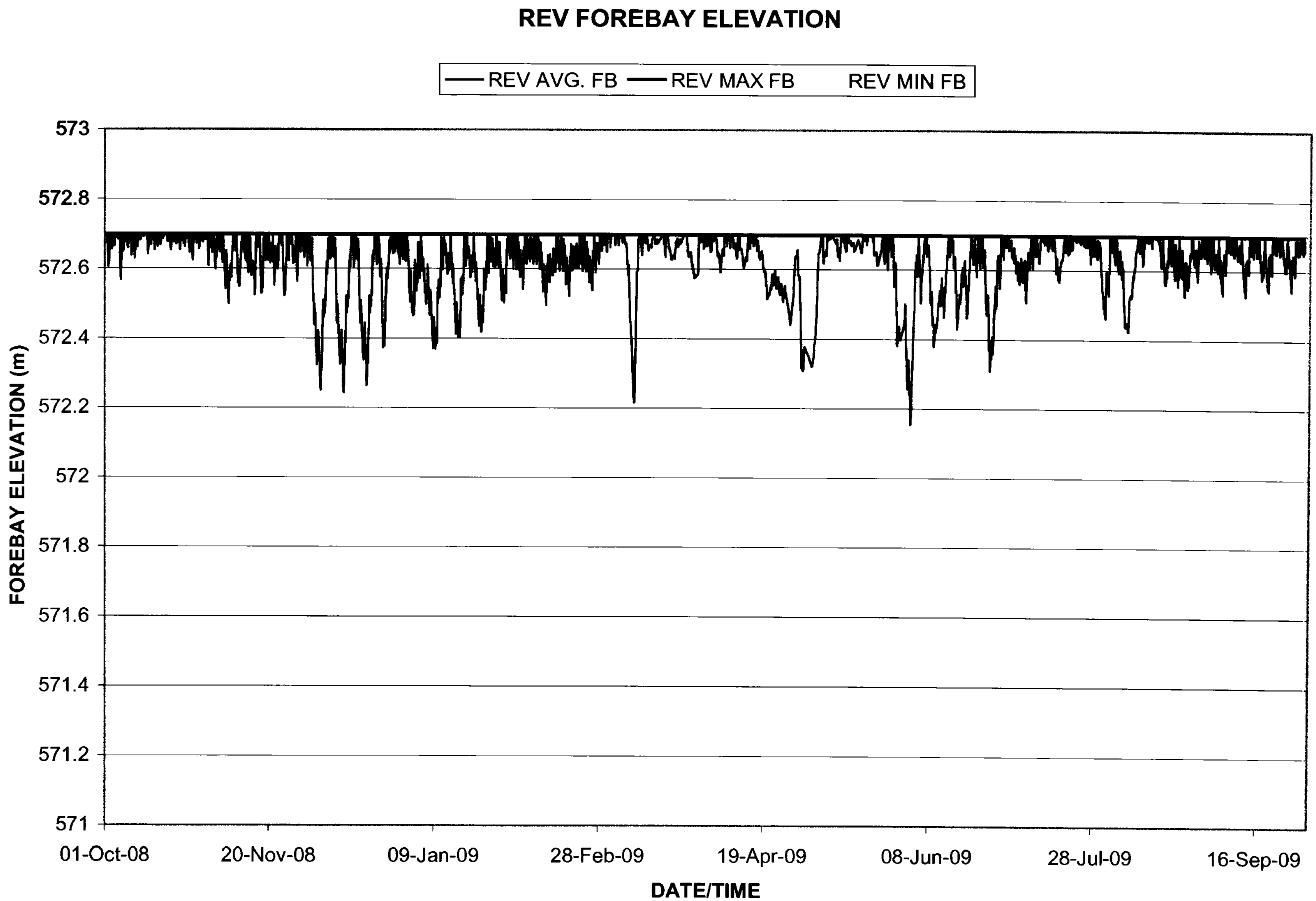
DATE/TIME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571.4
571.2
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FOREBAY ELEVATION (m)
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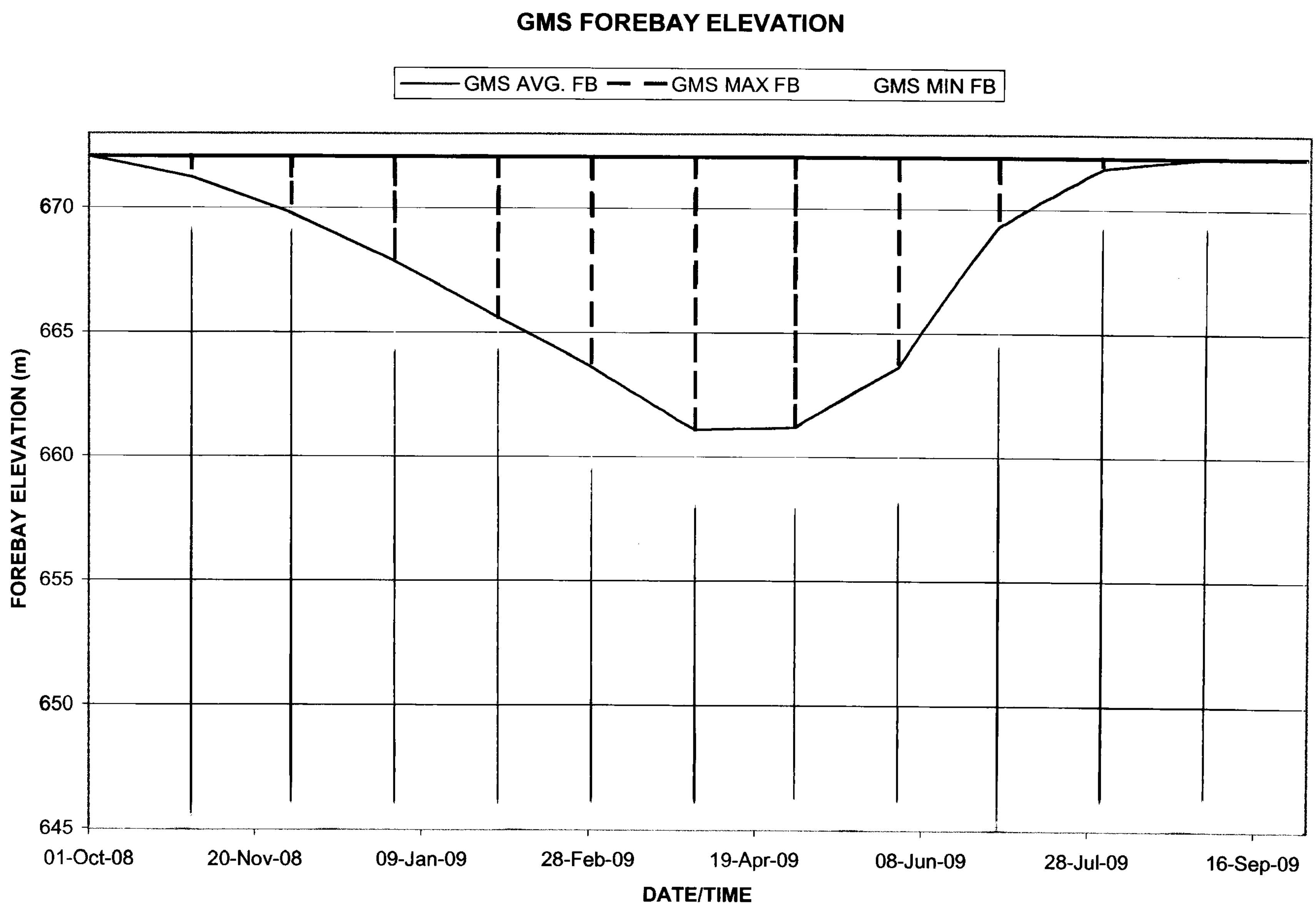
16-Sep-09
DATE/TIME


GMS FOREBAY ELEVATION
GMS AVG. FB
GMS MAX FB
GMS MIN FB
FOREBAY ELEVATION (m)
670
665
660
655
650
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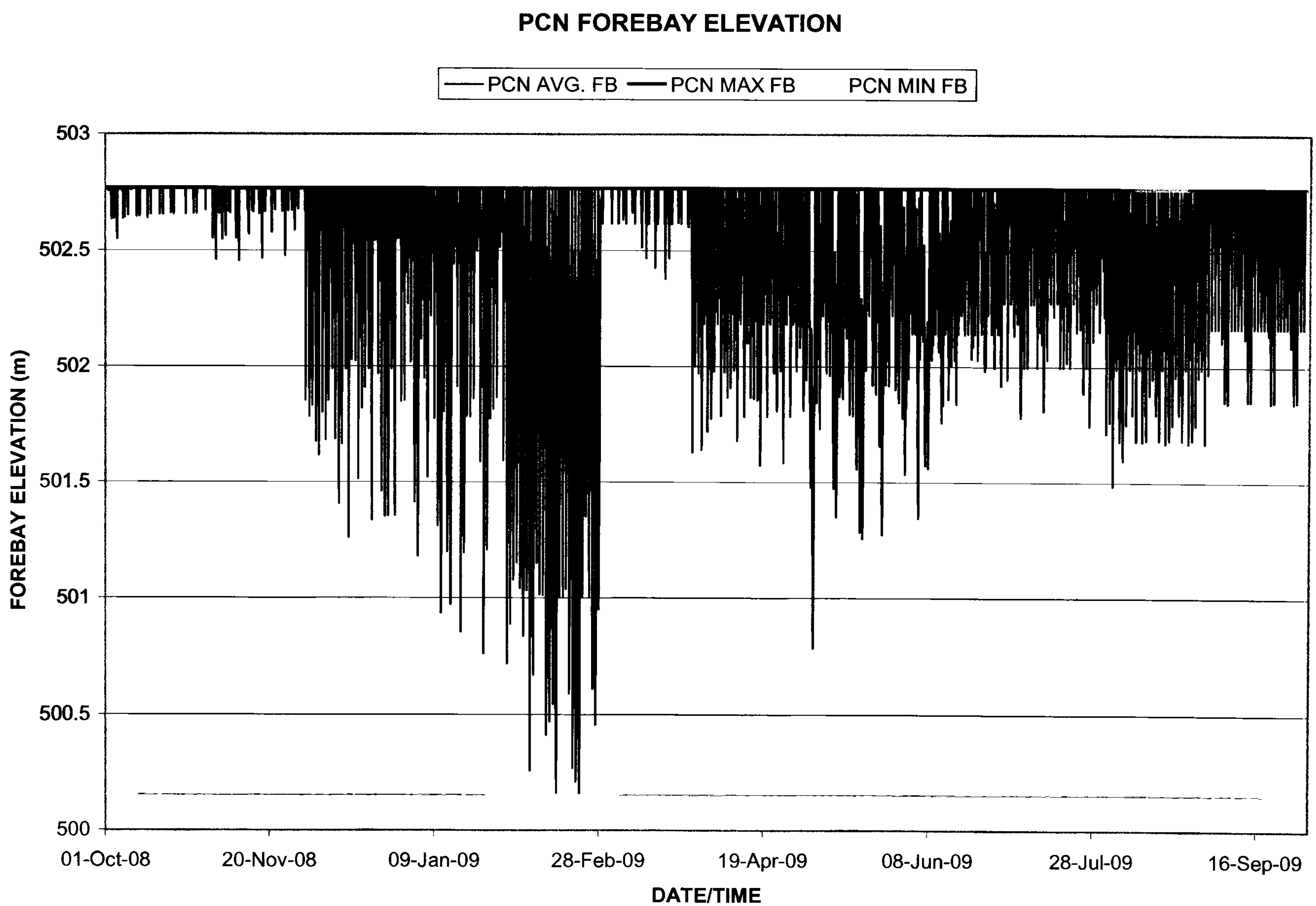
16-Sep-09
DATE/TIME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PCN AVG. FB
PCN MAX FB
PCN MIN FB
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502
501.5
501
500.5
500
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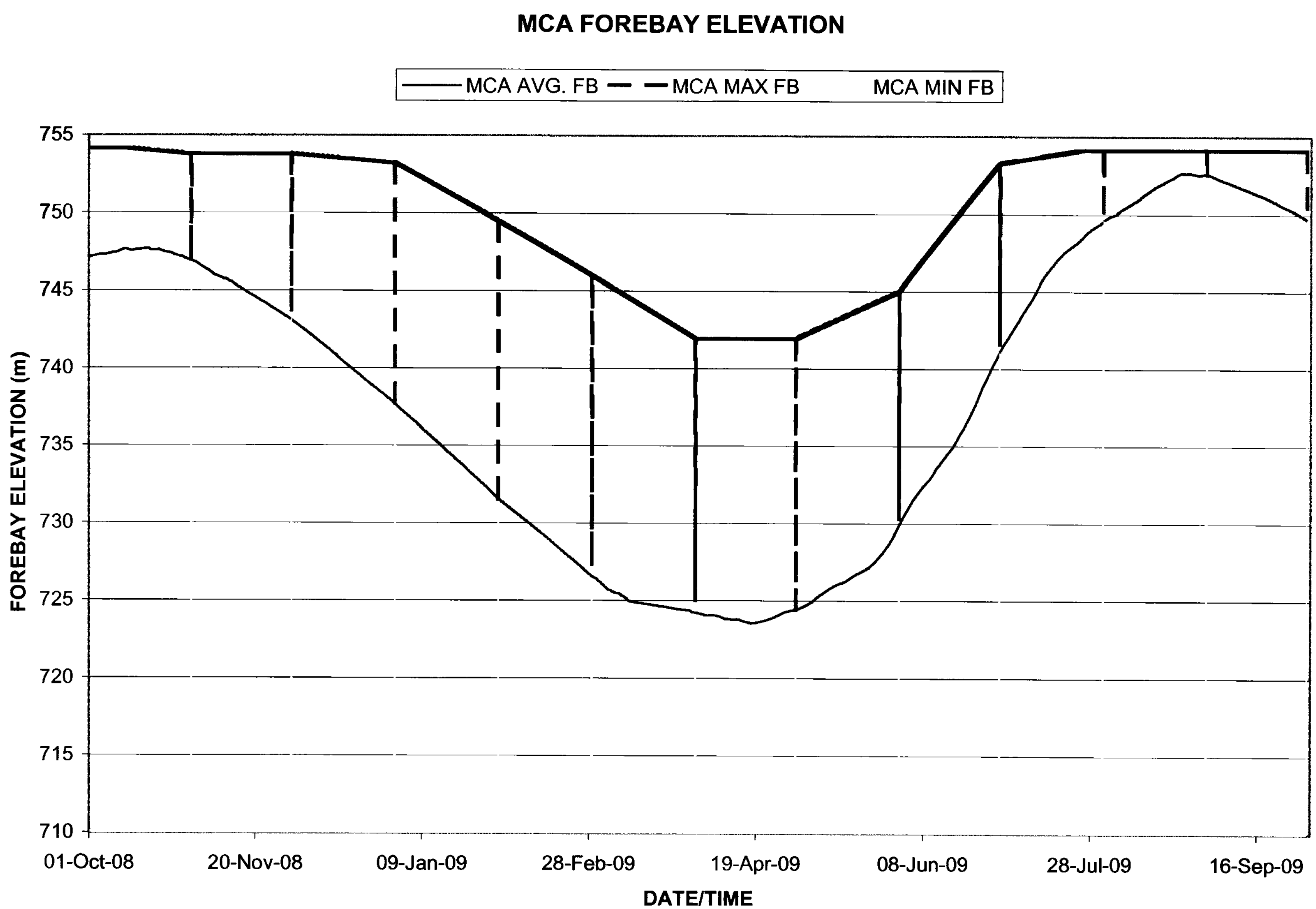
DATE/TIME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MCA AVG. FB
MCA MAX FB
MCA MIN FB
FOREBAY ELEVATION (m)
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750
745
740
735
730
725
720
715
710
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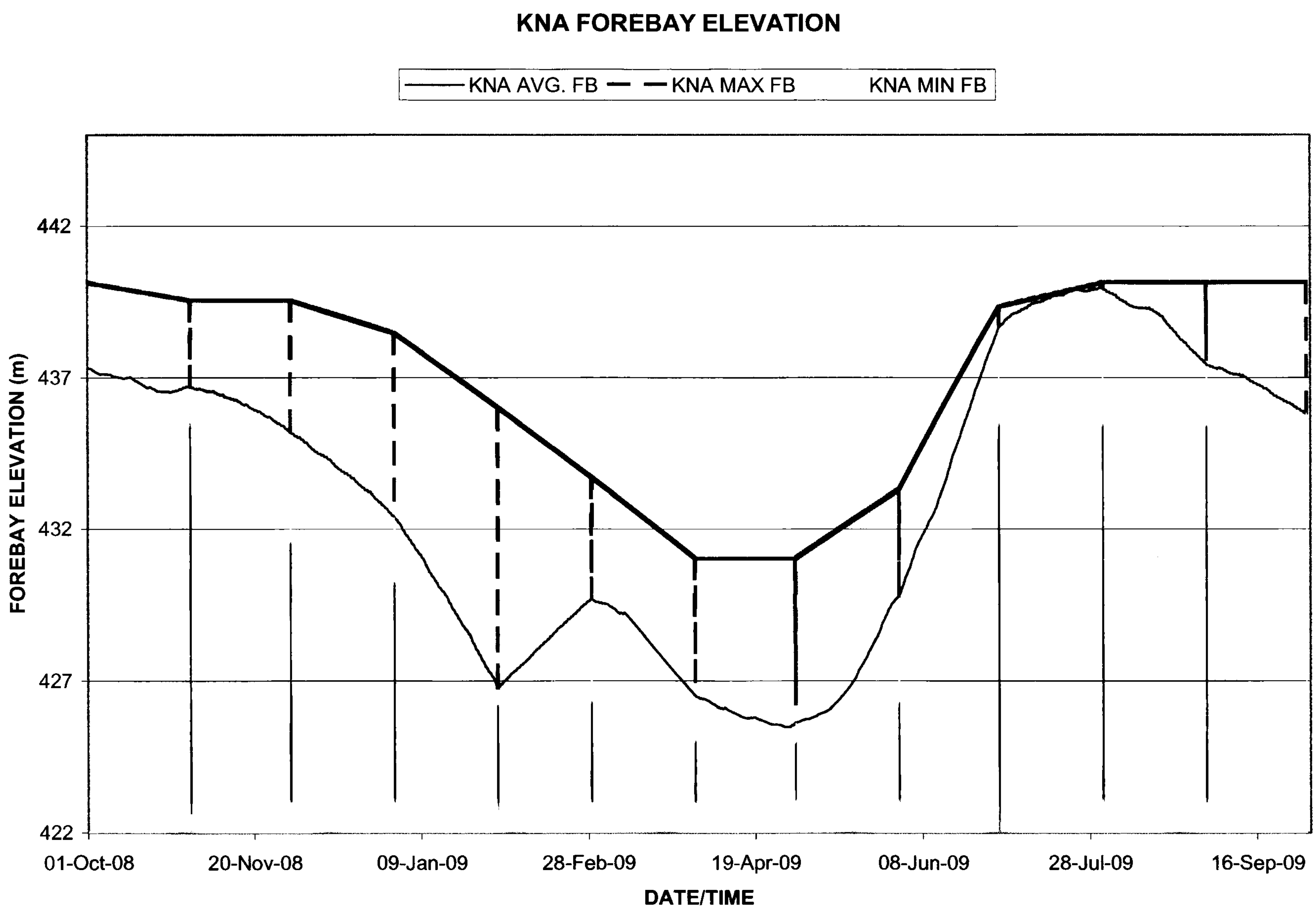
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME


KNA FOREBAY ELEVATION
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FOREBAY ELEVATION (m)
442
437
432
427
422
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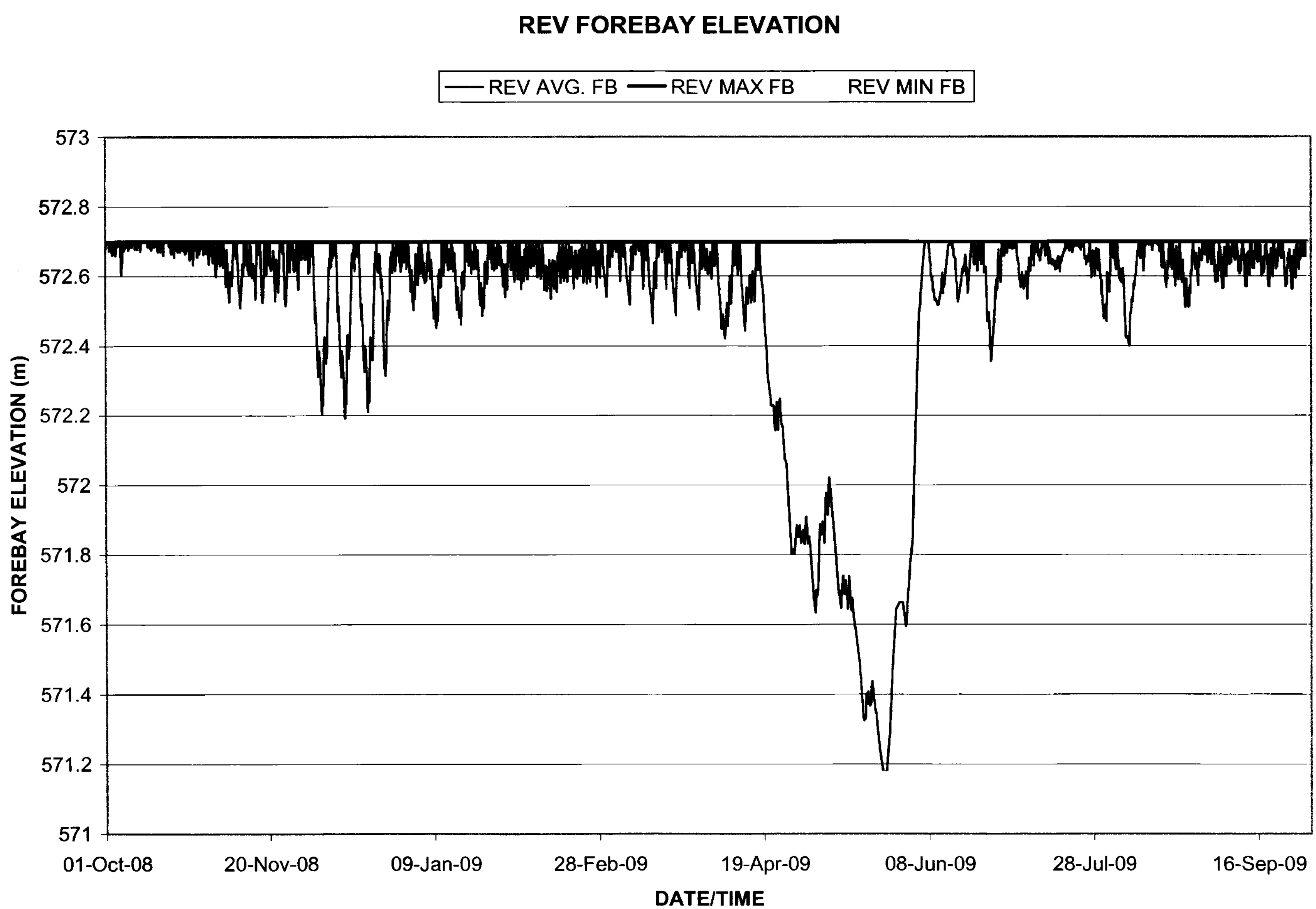
DATE/TIME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REV AVG. FB
REV MAX FB
REV MIN FB
FOREBAY ELEVATION (m)
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572.6
572.4
572.2
572
571.8
571.6
571.4
571.2
571
01-Oct-08
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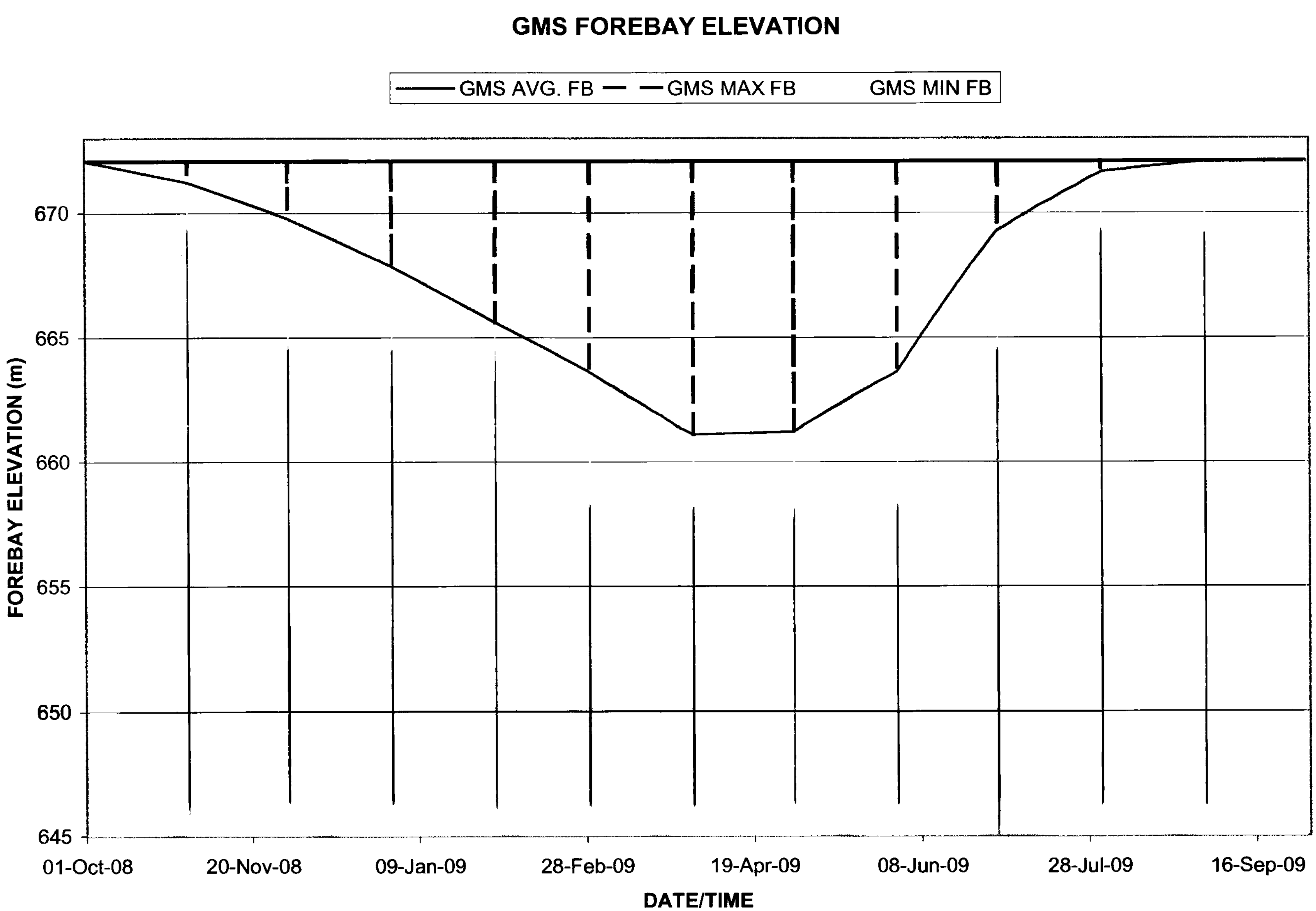
16-Sep-09
DATE/TIME


GMS FOREBAY ELEVATION
GMS AVG. FB
GMS MAX FB
GMS MIN FB
FOREBAY ELEVATION (m)
670
665
660
655
650
645
01-Oct-08
20-Nov-08
09-Jan-09
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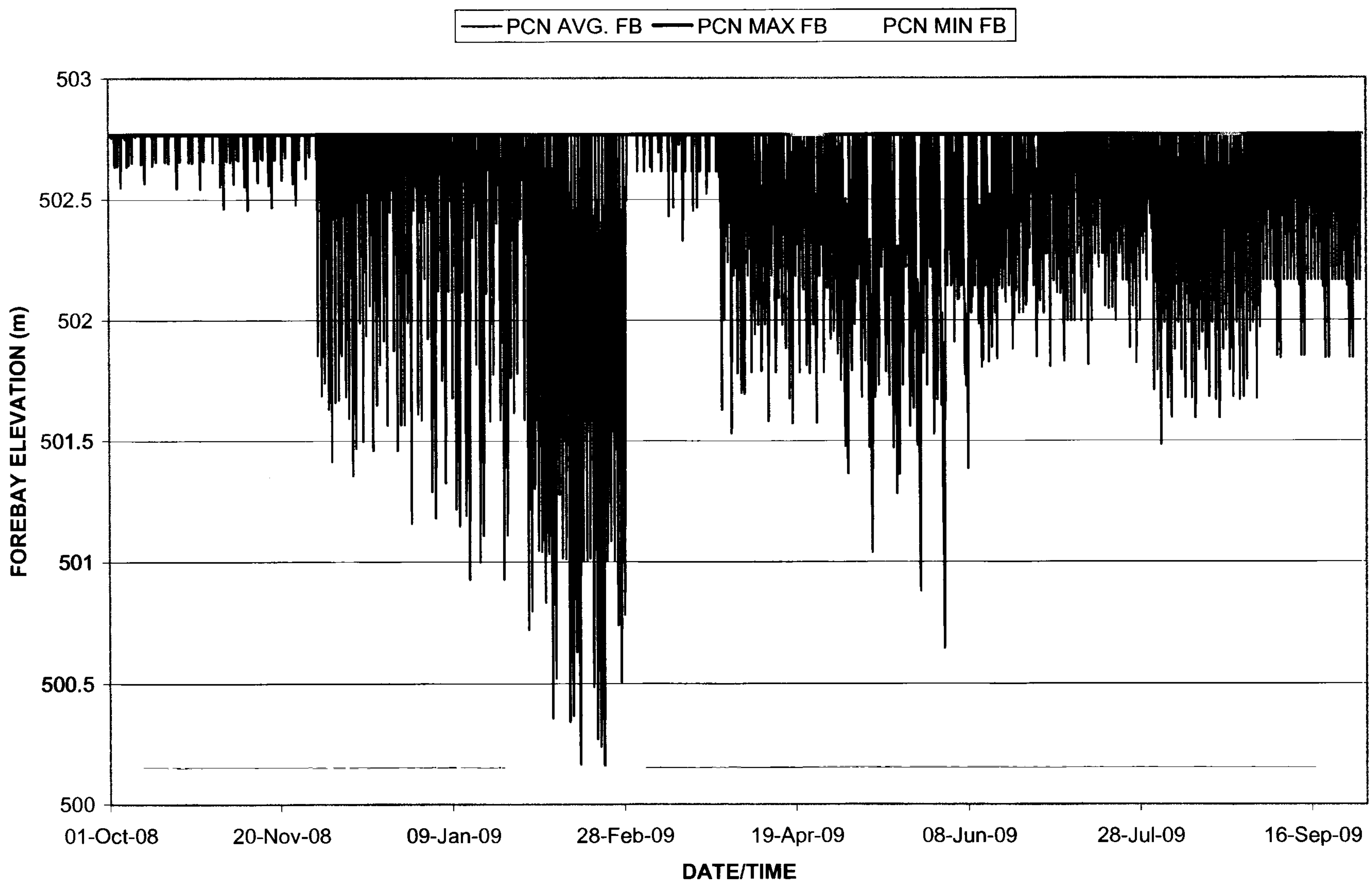
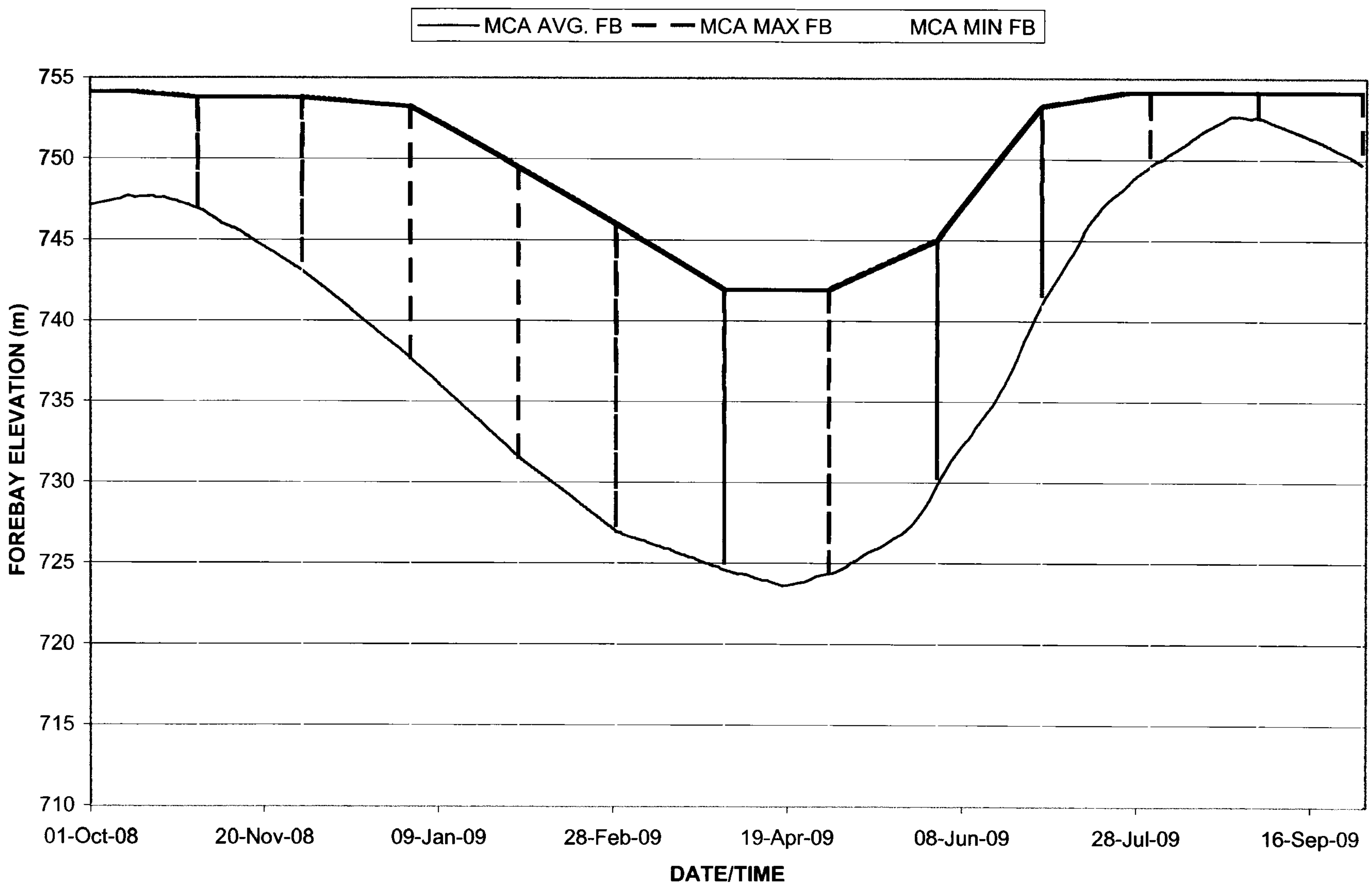
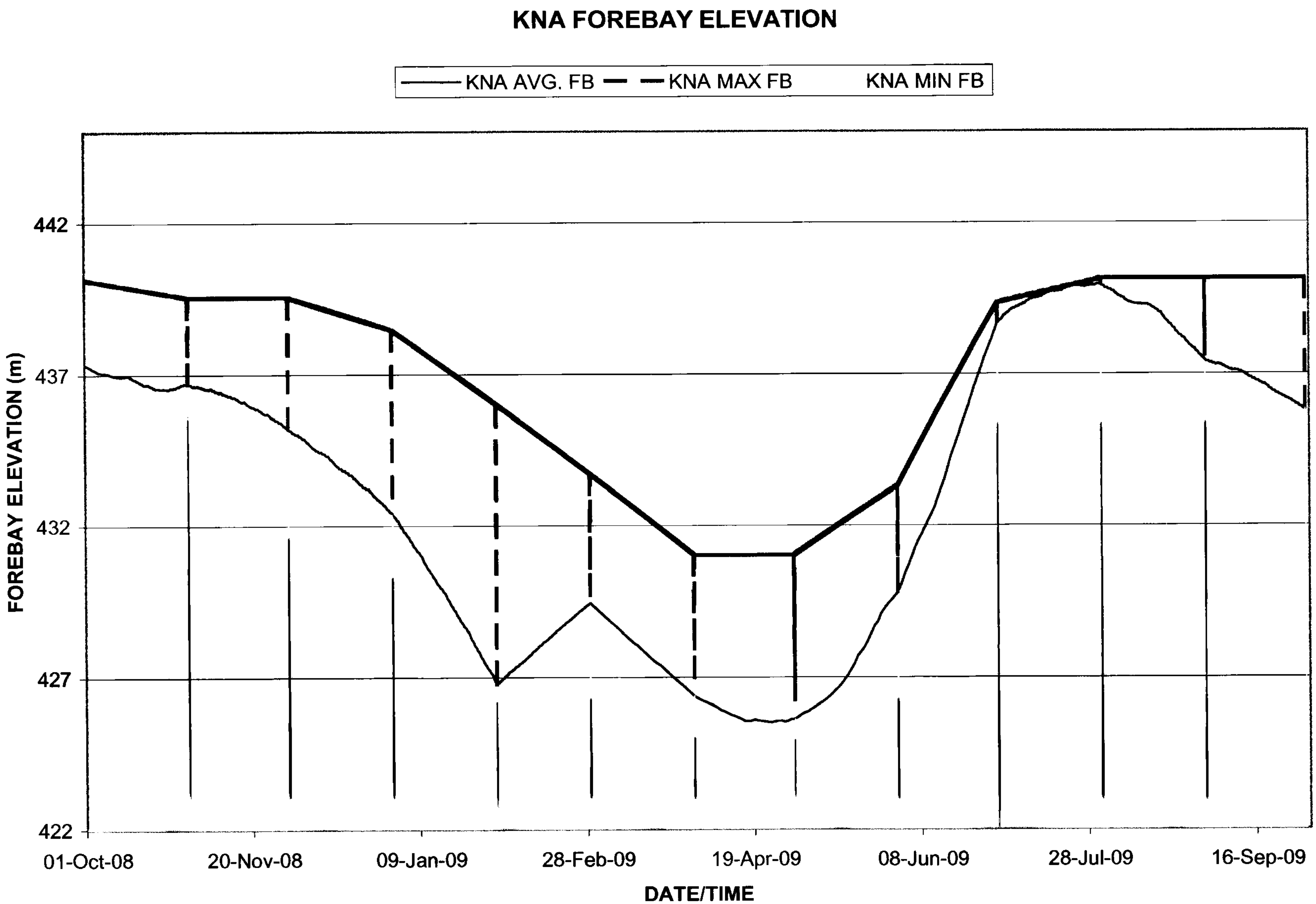
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

PCN FOREBAY ELEVATION



MCA FOREBAY ELEVATION




KNA FOREBAY ELEVATION
KNA AVG. FB
KNA MAX FB
KNA MIN FB
442
437
432
427
422
FOREBAY ELEVATION (m)
01-Oct-08
20-Nov-08
09-Jan-09
28-Feb-09
19-Apr-09
08-Jun-09
28-Jul-09
16-Sep-09
DATE/TIME

APPENDIX III:
OBJECTIVE FUNCTION VALUES: ORIGINAL GOM VS. RULES GOM

Original Generalized Optimization Model Objective Function

	CASE	64-65	65-66	66-67	67-68	68-69	69-70	70-71	71-72	72-73
BASE	BASE	$ 52,217,036	$ 161,563,880	$ 130,556,077	$ 134,676,029	$ 71,119,346	$ 74,341,305	$ (36,610,239)	$ 166,547,201	$ - 159,666,501
	5kcfs	$ 51,026,136	$ 160,633,971	$ 129,859,521	$ 133,980,407	$ 70,062,381	$ 73,507,924	$ (37,431,896)	$ 165,474,000	$ 158,602,009
COLUMBIA	10kcfs	$ 49,688,255	$ 159,213,797	$ 129,016,621	$ 133,196,939	$ 68,834,273	$ 72,525,726	$ (38,408,428)	164228587	$ 157,401,699
WUP	15kcfs	$ 47,770,234	$ 154,719,430	$ 127,550,108	$ 132,226,189	$ 66,250,361	$ 70,734,587	$ (39,572,922)	$ 161,729,471	$ 155,974,444
	20kcfs	$ 41,698,491		$ 122,498,340		$ 58,763,156	$ 66,389,323			

Original Generalized Optimization Model Objective Function Results Compared to the Base

	CASE	64-65	65-66	66-67	67-68	68-69	69-70	70-71	71-72	72-73
	5kcfs	$ (1,190,900)	$ (929,909)	$ (696,556)	$ (695,622)	$ (1,056,965)	$ (833,381)	$ (821,657)	$ (1,073,201)	$ (1,064,492)
COLUMBIA	10kcfs	$ (2,528,781)	$ (2,350,083)	$ (1,539,456)	$ (1,479,090)	$ (2,285,073)	$ (1,815,579)	$ (1,798,189)	$ (2,318,614)	$ (2,264,802)
WUP	15kcfs	$ (4,446,802)	$ (6,844,450)	$ (3,005,969)	$ (2,449,840)	$ (4,868,985)	$ (3,606,718)	$ (2,962,683)	$ (4,817,730)	$ (3,692,057)
	20kcfs	$ (10,518,545)		$ (8,057,737)		$ (12,356,190)	$ (7,951,982)			

Rules Generalized Optimization Model Objective Function

	CASE	64-65	65-66	66-67	67-68	68-69	69-70	70-71	71-72	72-73
BASE	BASE	$ 52,217,036	$ 161,563,880	$ 130,556,077	$ 134,676,029	$ 71,119,346	$ 74,341,305	$ (36,610,239)	$ 166,547,201	$ 159,666,501
	5kcfs	$ 51,026,136	$ 160,633,971	$ 129,859,521	$ 133,980,407	$ 70,062,381	$ 73,507,924	$ (37,431,896)	$ 165,474,000	$ 158,602,009
COLUMBIA	10kcfs	$ 49,688,255	$ 159,213,797	$ 129,016,621	$ 133,196,939	$ 68,834,273	$ 72,525,726	$ (38,408,428)	$ 164,228,587	$ 157,401,699
WUP	15kcfs	$ 47,770,234		$ 127,550,108	$ 132,226,189	$ 66,250,361	$ 70,734,587		$ 161,729,471	$ 155,974,444
	20kcfs									

Rules Generalized Optimization Model Objective Function Results Compared to the Base

	CASE	64-65	65-66	66-67	67-68	68-69	69-70	70-71	71-72	72-73
	5kcfs	$ (1,190,900)	$ (929,909)	$ (696,556)	$ (695,622)	$ (1,056,965)	$ (833,381)	$ (821,657)	$ (1,073,201)	$ (1,064,492)
COLUMBIA	10kcfs	$ (2,528,781)	$ (2,350,083)	$ (1,539,456)	$ (1,479,090)	$ (2,285,073)	$ (1,815,579)	$ (1,798,189)	$ (2,318,614)	$ (2,264,802)
WUP	15kcfs	$ (4,446,802)		$ (3,005,969)	$ (2,449,840)	$ (4,868,985)	$ (3,606,718)		$ (4,817,730)	$ (3,692,057)
	20kcfs									

Rules Generalized Optimization Model Compared to the Original Generalized Optimization

	CASE	64-65	65-66	66-67	67-68	68-69	69-70	70-71	71-72	72-73
BASE	BASE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5kcfs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COLUMBIA	10kcfs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WUP	15kcfs	$ -		$ -	$ -	$ -	$ -		$ -	$ -
	20kcfs									

APPENDIX IV:
OUTPUT FILES DESCRIPTION

- ABWDMRKT.OUT – This file contains the Alberta weekday and average market information including spot market transactions, prices and tie limits.
- ABWEMRKT.OUT – This file contains the Alberta weekend and average market information including spot market transactions, prices and tie limits.
- ALABMRKT.OUT – This file contains the Alberta weekday, weekend and average spot market transactions, prices and tie limits.
- ALLGEN.OUT – This file contains the plant generation information including sub-time step generation, average generation and minimum and maximum generations.
- ALLQS.OUT – This file contains the plant discharge information including plant spill, plant turbine discharge, and minimum and maximum plant and turbine discharges.
- ALLQT.OUT – This file contains the plant turbine discharge information including turbine discharge for each sub-time step, an average turbine discharge and minimum and maximum turbine discharge.
- ALUSMRKT.OUT – This file contains the US spot market sales information including the sub-time step spot market energy sales, prices and tie limits and the average spot market energy sales, prices and tie limits
- CALCFB.DAT – This file contains the calculated forebays for each time step
- FB.OUT – This file contains the calculated forebays for each plant and time step and the forebay minimum and maximum.
- FLASH.OUT – This file contains the minimum and maximum plant and turbine discharges, the plant spill and the flash flows
- LENGTH.OUT – This file contains the length in hours of each time step
- PARA.OUT – This file contains the initial study parameters including the number of plants, plant names, start date, and total number of time steps, sub-time steps and their corresponding names
- PIECE1.DAT – This file contains the number of line segments for the Marginal Value of Water vs. Forebay piecewise linear curve
- RRES2.DAT – This file contains the breakpoints for the Marginal Value of Water vs. Forebay piecewise linear curve
- RRES3.DAT – This file contains the breakpoints for the Marginal Value of Water vs. Forebay piecewise linear curve
- SCREEN.OUT – This file contains the screen output from the AMPL display.
- SENSY.OUT – This file contains the sensitivity analysis including incremental costs for the generation, transmission requirements, storage, and ramp rates
- SUMMARY.OUT – This file contains the time step summary of plant generation, small hydro generation, imports, exports and system load
- SUMWD.OUT – This file contains the sub-time step weekday summary of the small hydro generation, imports and exports, plant generation, prices, system load, plant turbine discharge, incremental costs of various constraints, and the plant forebay values
- SUMWE.OUT – This file contains the sub-time step weekend summary of the small hydro generation, imports and exports, plant generation, prices, system load, plant turbine discharge, incremental costs of various constraints, and the plant forebay values
- TOTALS.OUT – This file contains the monthly totals for the study of plant generation, discharge, forebay, HK, and imports and exports
- USWDMRKT.OUT – This file contains the US weekday and average market information including spot market transactions, prices and tie limits
- USWEMRKT.OUT – This file contains the US weekend and average market information including spot market transactions, prices and tie limits
- VOO.DAT – This file contains the initial plant reservoir volumes

- VMAXMIN.DAT – This file contains the minimum and maximum plant reservoir volumes
- WDGEN.OUT – This file contains the weekday sub-time step plant generation, average generation and minimum and maximum limits on generation
- WDQT.OUT – This file contains the weekday sub-time step plant discharge, average discharge and minimum and maximum limits on turbine discharge
- WEGEN.OUT – This file contains the weekend sub-time step generation, average generation and minimum and maximum limits on generation
- WEQT.OUT – This file contains the weekend sub-time step plant discharge, average discharge and minimum and maximum limits on turbine discharge

APPENDIX V:
GENERATION SCHEDULE RULES

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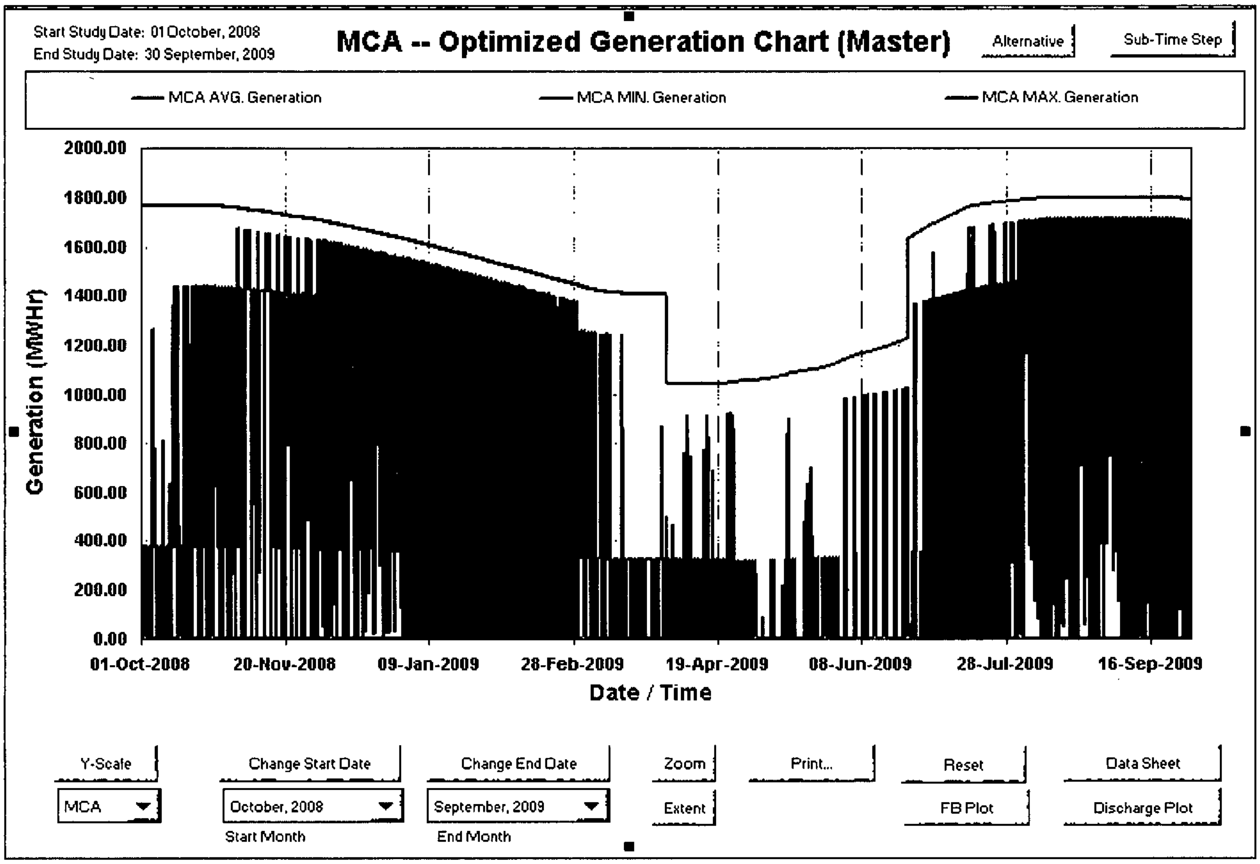
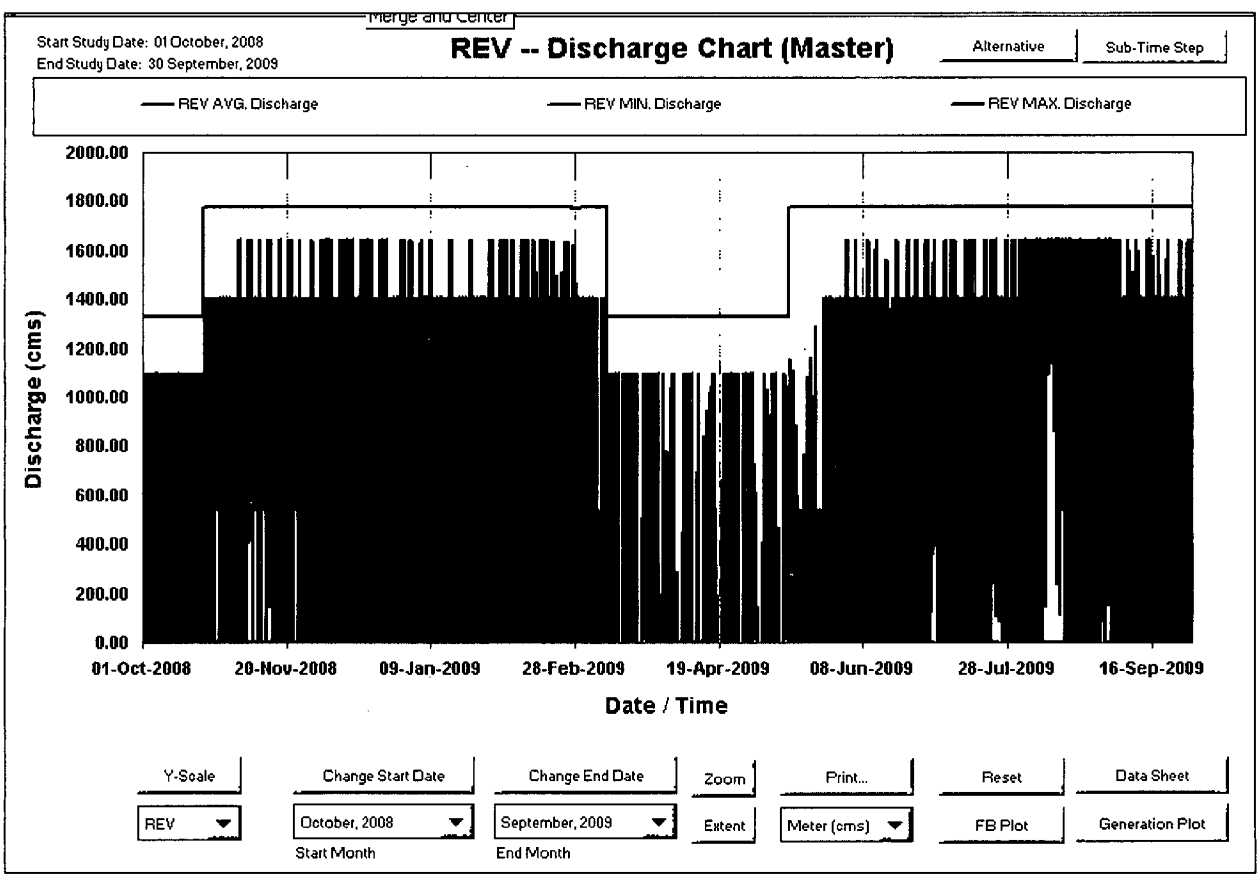
GMS	OUTAGE	0	G1	2008100100	2008110700
GMS	OUTAGE	0	G6	2008100100	2008100300
GMS	OUTAGE	0	G5	2008100307	2008100312
GMS	OUTAGE	0	G5	2008100300	2008100400
GMS	OUTAGE	0	G7	2008100100	2008101922
GMS	OUTAGE	0	G8	2008100100	2008100116
GMS	OUTAGE	0	G10	2008100512	2008100515
GMS	OUTAGE	0	G3	2008101215	2008101403
GMS	OUTAGE	0	G3	2008101908	2008102122
GMS	OUTAGE	0	G2	2008102308	2008102316
GMS	OUTAGE	0	G5	2008102408	2008102416
GMS	OUTAGE	0	G6	2008102509	2008102513
GMS	OUTAGE	0	G3	2008102707	2008102723
GMS	OUTAGE	0	G7	2008110608	2008110618
GMS	OUTAGE	0	G7	2008110708	2008110718
GMS	OUTAGE	0	G7	2008110808	2008110818
GMS	OUTAGE	0	G8	2008110906	2008110916
GMS	OUTAGE	0	G9	2008112107	2008112115
GMS	OUTAGE	0	G3	2008121112	2008121114
GMS	OUTAGE	0	G5	2008121107	2008121111
GMS	OUTAGE	0	G6	2008121319	2008121323
GMS	OUTAGE	0	G3	2008122023	2008122105
GMS	OUTAGE	0	G4	2008122707	2008122715
GMS	OUTAGE	0	G2	2009030607	2009030715
GMS	OUTAGE	0	G4	2009030100	2009031400
GMS	OUTAGE	0	G9	2009030113	2009030114
GMS	OUTAGE	0	G8	2009030507	2009030515
GMS	OUTAGE	0	G7	2009030711	2009030715
GMS	OUTAGE	0	G9	2009030708	2009030710
GMS	OUTAGE	0	G7	2009030810	2009030814
GMS	OUTAGE	0	G4	2009031400	2009040100
GMS	OUTAGE	0	G9	2009032609	2009032612
GMS	MAXGEN	2200	.	2009080208	2009080223
GMS	OUTAGE	0	G3	2009080100	2009082000
GMS	OUTAGE	0	G1	2009081708	2009081716
GMS	OUTAGE	0	G7	2009081908	2009081722
GMS	OUTAGE	0	G9	2009082108	2009082121
GMS	OUTAGE	0	G10	2009082100	2009082723
GMS	OUTAGE	0	G8	2009082908	2009082916
GMS	OUTAGE	0	G8	2009090215	2009090219
GMS	OUTAGE	0	G9	2009090916	2009090920
GMS	MAXGEN	2470	.	2009091114	2009091117
GMS	OUTAGE	0	G7	2009091000	2009091700
GMS	OUTAGE	0	G1	2009091309	2009091316
GMS	OUTAGE	0	G4	2009091600	2009100700
GMS	OUTAGE	0	G5	2009091908	2009091916
GMS	OUTAGE	0	G5	2009092008	2009092016
GMS	OUTAGE	0	G9	2009091516	2009091518
GMS	OUTAGE	0	G6	2009091800	2009091820
GMS	OUTAGE	0	G8	2009092208	2009092220
GMS	OUTAGE	0	G9	2009092208	2009092220
GMS	OUTAGE	0	G7	2009091700	2009100500
GMS	OUTAGE	0	G7	2008091700	2008100500
GMS	OUTAGE	0	G1	2009092908	2009110400
GMS	OUTAGE	0	G1	2008092908	2008110400
GMS	OUTAGE	0	G8	2009092800	2009100100
GMS	OUTAGE	0	G9	2009092800	2009092900
PCN	MINGEN	2100	.	2008102307	2008102318

PCN	MINGEN	2100	.	2008102407	2008102418
PCN	MAXGEN	2400	.	2008102307	2008102318
PCN	MAXGEN	2400	.	2008102407	2008102418
PCN	ATCGEN	630	.	2008120500	2008120600
PCN	SPILL	1755	.	2008120600	2008121700
PCN	FLATC	0	.	2008121700	2008122700
PCN	MINGEN	600	.	2008122700	2008123100
PCN	FLATC	0	.	2009020100	2009020700
PCN	ATCGEN	500	.	2009020700	2009020800
PCN	ATCGEN	550	.	2009020800	2009021000
PCN	ATCGEN	600	.	2009021000	2009021100
PCN	ATCGEN	625	.	2009021100	2009021800
PCN	ATCGEN	600	.	2009021800	2009021822
PCN	ATCGEN	575	.	2009021822	2009022200
PCN	ATCGEN	550	.	2009022200	2009031100
PCN	FLATC	0	.	2009031100	2009040100
PCN	FIXGEN	350	.	2009080208	2009080221
PCN	FIXGEN	160	.	2009080314	2009080318
PCN	FIXGEN	170	.	2009092108	2009092218
PCN	FIXGEN	130	.	2009092606	2009092610
PCN	MINCMS	283	.	2009030100	2009040200
PCN	OUTAGE	0	G1	2009030800	2009031800
PCN	OUTAGE	0	G3	2009031707	2009032200
PCN	OUTAGE	0	G2	2009032207	2009032823
PCN	MINCMS	283	.	2009050100	2009100100
PCN	MINCMS	283	.	2008100100	2009010100
PCN	MINGEN	100	.	2008102009	2008102011
PCN	OUTAGE	0	G3	2009080100	2008080500
PCN	OUTAGE	0	G1	2009082208	2008082216
PCN	OUTAGE	0	G2	2009082200	2008082400
PCN	OUTAGE	0	G3	2009091114	2009091116
PCN	OUTAGE	0	G1	2009092800	2009100100
PCN	OUTAGE	0	G1	2008100100	2008101000
PCN	OUTAGE	0	G2	2008101200	2008102400
PCN	MINFB	502.2	.	2009091200	2009091300
PCN	MINFB	502.2	.	2009082708	2009082716
PCN	MINFB	502.2	.	2009082808	2009082816
PCN	MINFB	502.2	.	2009082908	2009082916
PCN	MAXFB	502.0	.	2009091708	2009091716
PCN	MAXFB	502.0	.	2009091808	2009091816
PCN	MAXFB	502.0	.	2009091908	2009091916
MCA	OUTAGE	0	G3	2008100302	2008100320
MCA	OUTAGE	0	G2	2008100908	2008101000
MCA	OUTAGE	0	G2	2008110500	2008110916
MCA	OUTAGE	0	G4	2008110807	2008110914
MCA	OUTAGE	0	G3	2008111408	2008111415
MCA	OUTAGE	0	G4	2008111509	2008111615
MCA	OUTAGE	0	G4	2008112108	2008112112
MCA	OUTAGE	0	G3	2008121507	2008121612
MCA	OUTAGE	0	G3	2009022819	2009030322
MCA	OUTAGE	0	G4	2009030116	2009030322
MCA	OUTAGE	0	G1	2009030400	2009030716
MCA	OUTAGE	0	G2	2009031123	2009031416
MCA	OUTAGE	0	G3	2009031015	2009031123
MCA	FIXGEN	220	.	2009042000	2009042300
MCA	ATCGEN	235	.	2009042300	2009043000
REV	ATCGEN	385	.	2009042300	2009043000
MCA	ATCGEN	235	.	2009050100	2009051100
REV	ATCGEN	385	.	2009050100	2009051100

REV	FBMIN	572.0	.	2009042300	2009043000
REV	FBMAX	573.0	.	2009042300	2009043000
REV	FBMIN	572.0	.	2009050100	2009051100
REV	FBMAX	573.0	.	2009050100	2009051100
REV	FBMIN	571.5	.	2009051100	2009101200
REV	FBMAX	573.0	.	2009051100	2009101200
MCA	SD	0	.	2009061420	2009061420
MCA	OUTAGE	0	G3	2009080100	2009082316
MCA	OUTAGE	0	G1	2009091908	2009091917
MCA	OUTAGE	0	G4	2009092308	2009092816
REV	MINGEN	150	.	2009030108	2009030118
REV	MINGEN	150	.	2009030208	2009030218
REV	MINGEN	150	.	2009030308	2009030318
REV	MINGEN	150	.	2009030408	2009030418
REV	MINGEN	150	.	2009030508	2009030518
REV	MINGEN	150	.	2009030608	2009030618
REV	MINGEN	150	.	2009030708	2009030718
REV	OUTAGE	0	G1	2009030408	2009030412
REV	OUTAGE	0	G3	2009030412	2009030416
REV	OUTAGE	0	G2	2009030508	2009031316
REV	OUTAGE	0	G3	2009031403	2009031921
REV	FBMAX	572.95	.	2009052108	2009052110
REV	FBMIN	572.6	.	2009052108	2009052110
REV	MINGEN	150	.	2009051108	2009051118
REV	MINGEN	150	.	2009051208	2009051218
REV	MINGEN	150	.	2009051308	2009051318
REV	MINGEN	150	.	2009051408	2009051418
REV	MINGEN	150	.	2009051508	2009051518
REV	MINGEN	150	.	2009051608	2009051618
REV	MINGEN	150	.	2009051708	2009051718
REV	MINGEN	150	.	2009051808	2009051818
REV	MINGEN	150	.	2009051908	2009051918
REV	MINGEN	150	.	2009052008	2009052018
REV	MINGEN	150	.	2009052108	2009052118
REV	MINGEN	150	.	2009052208	2009052218
REV	OUTAGE	0	G4	2008101200	2008101216
REV	OUTAGE	0	G4	2008101302	2008102223
REV	OUTAGE	0	G3	2008101700	2008101900
REV	OUTAGE	0	G3	2008102608	2008102617
REV	OUTAGE	0	G3	2008110308	2008110315
REV	OUTAGE	0	G1	2008120308	2008120312
REV	OUTAGE	0	G2	2008120312	2008120316
REV	OUTAGE	0	G1	2008120906	2008120916
REV	OUTAGE	0	G3	2008120700	2008120716

APPENDIX VI:
RESULTS DISPLAY GRAPHICAL OUTPUT


Start Study Date: 01 October, 2008
End Study Date: 30 September, 2009
MCA -- Optimized Generation Chart (Master)
Alternative
Sub-Time Step
MCA AVG. Generation
MCA MIN. Generation
MCA MAX. Generation
Generation (MWHr)
2000.00
1800.00
1600.00
1400.00
1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
01-Oct-2008
20-Nov-2008
09-Jan-2009
28-Feb-2009
19-Apr-2009
08-Jun-2009
28-Jul-2009
16-Sep-2009
Date / Time
Y-Scale
Change Start Date
Change End Date
Zoom
Print...
Reset
Data Sheet
MCA
October, 2008
September, 2009
Extent
FB Plot
Discharge Plot
Start Month
End Month


Merge and Center
Start Study Date: 01 October, 2008
End Study Date: 30 September, 2009
REV -- Discharge Chart (Master)
Alternative
Sub-Time Step
REV AVG. Discharge
REV MIN. Discharge
REV MAX. Discharge
Discharge (cms)
2000.00
1800.00
1600.00
1400.00
1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
01-Oct-2008
20-Nov-2008
09-Jan-2009
28-Feb-2009
19-Apr-2009
08-Jun-2009
28-Jul-2009
16-Sep-2009
Date / Time
Y-Scale
Change Start Date
Change End Date
Zoom
Print...
Reset
Data Sheet
REV
October, 2008
September, 2009
Extent
Meter (cms)
FB Plot
Generation Plot
Start Month
End Month