On the Economics of Ramping Rate Restrictions at Hydro Power Plants: Balancing Profitability and Environmental Costs*

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December 15, 2010

Abstract

This paper examines the impact of ramping rate restrictions imposed on hydro operations to protect aquatic ecosystems. A dynamic optimization model of the profit maximizing decisions of a hydro operator is solved for various restrictions on water flow, using data for a representative hydro operation in Ontario. Profits are negatively affected, but for a range of restrictions the impact is not large. Ramping restrictions cause a redistribution of hydro production over a given day, which can result in an increase in total hydro power produced. This affects the need for power from other sources with consequent environmental impacts.

Keywords: ramping rate, hydroelectrical power, hydropower plant, hydro-peaking

*Thanks to Ontario Power Generation for data provided. Funding from the Social Sciences and Humanities Research Council is gratefully acknowledged.

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1 Introduction and Motivation

Hydro power is currently favored as a source of clean energy with several desirable features including no carbon emissions, low operating costs, the ability to meet peak demands, significant operational flexibilities and high reliability. In an era of deregulated electricity markets, global warming and volatile prices for fossil fuels, these key features of hydro power become extremely valuable. However, many studies show that hydroelectric production can also have significant negative effects on the environment including impacts on the aquatic ecosystem due to changes in in-stream flow rates, reservoir levels, and water temperatures which cause changes in the chemical and physical composition of the released water. In addition flow fluctuations can impact beaches and cause bank erosion affecting shore areas that provide critical wildlife habitat for native fishes and other aquatic flora and fauna (Edwards et al., 1999). Currently, in Ontario both electricity producers and the Ontario Ministry of Natural Resources are interested in testing whether restricting ramping rates through turbines at hydroelectric facilities can provide ecological benefits without unduly affecting hydro production (Smokorowski et al., 2009).

Hydro power stations are typically operated with the goal of maximizing profits, while meeting operational, physical and legal requirements. With no restrictions, hydroelectric facilities will maximize profits by adjusting water flows so that electricity production is highest when it is most profitable. This implies hydropower stations will tend to increase the rate of water flow (or ramp up) when prices/demands are high and decrease the rate of water flow (or ramp down) when prices/demands are low to let water levels in the dam recover. Any restrictions imposed on water flows reduce efficiency, profitability, and the ability to react to changes in electricity demand and price.

Ramping rate restrictions are believed to provide environmental benefits by protecting downstream fish, fish habitat and the productive capacity of the river. However, to the extent that hydro production is affected, there will also likely be offsetting impacts on other sources of electric power generation such as thermal generation from coal, oil or natural gas. This would have added environmental consequences since thermal power is associated with emissions of green house gases, and pollutants such as SO_2 and NO_2. Hence in evaluating ramping rate restrictions it is important to study the tradeoffs between protecting aquatic ecosystems and the optimal operation of hydropower plants to satisfy electricity demand. In much of the existing research on electric power scheduling, ramping rate restrictions are regarded as physical/technical constraints in optimization models,[1] rather than legal/policy constraints. There are currently only a limited number studies that estimate the extra costs and associated benefits of restricting ramping at hydroelectric generating stations.

In this paper, we examine the effect of ramping rate restrictions imposed by a regulatory authority on a power plant's operations and profit. We model profit maximization of a prototype hydro plant, based on a medium size plant in Ontario. Assuming that the plant must satisfy a minimum contract demand either through producing hydro power or purchasing power on the spot market, we investigate the operator's optimal decisions regarding hydro production and power purchases in on-peak and off-peak periods. We abstract from the issue of electricity price uncertainty by assuming on- and off-peak prices are known and constant.

We also consider the potential impact of ramping restrictions on the need for other sources of power generation. We assume that any change in hydro production implies an equal offsetting change in thermal electric generation - either coal or natural gas. We estimate the environmental cost or benefit of this change in thermal production due to the resulting change in air pollution emissions.

There are currently no suitable monetary measures available in the literature of the environmental benefit for the river ecosystem of ramping restrictions. In the absence of such monetary measures, we determine the net cost of ramping restrictions as the loss in profit from hydro generation net of the value of any implied change in polluting emissions from thermal plants. This net cost for the prototype hydro plant may be viewed as the lower bound needed for the value of aquatic ecosystem benefits of ramping restrictions for these restrictions to be worthwhile.

This paper's contribution to the literature is in furthering our understanding of the trade offs involved when ramping rate restrictions are imposed at hydro facilities. In particular, we examine the sensitivity of hydro station profits to ramping restrictions as well as the potential impact on electricity production from hydro and other sources. Although the impact of ramping restrictions on firm profits will depend on the specifics of the particular hydro plant under consideration, as well as the market structure that the plant operates in, we are able to draw some general conclusions. Ramping restrictions will have a negative effect on profits to the extent that they force a hydro operator to make different choices than when no ramping restrictions are imposed. The most obvious choice variable affected is the allocation of power sales over a given day. Profits are reduced if ramping restrictions force hydro operators to increase the amount of power sold in off-peak periods when prices are lower. In our analysis we observe a significant effect on profits for the most restrictive ramping constraints, but we also observe a range of ramping restrictions over which profits are not substantially affected.

A more surprising result is that ramping restrictions can cause an increase in the total amount of hydro power produced over a 24 hour period. This is a consequence of hydro operators' efforts to maintain profits in the face of constraints. In response to the ramping constraints, operators increase power production in off-peak periods while at the same time attempting to maintain production as much as possible in on-peak periods. If the increased hydro production implies a reduction in power produced by fossil fuel fired plants, this may constitute an added environmental benefit of ramping restrictions, in addition to any benefits to the aquatic ecosystem below the hydro dam.

It is important to note, however, that the analysis in this paper is for a single hydro plant. If ramping rate restrictions were applied to a significant portion of the hydro generation capacity in the a particular province or state, then the impact on the entire grid would need to be considered. In this paper we assume that even though ramping restrictions constrain the system's ability to meet peak demand with hydro, it is possible to meet those peak demands with other electricity sources at little increase in cost. A full analysis of ramping restrictions on a significant portion of hydro generation would need to consider the potential for increased cost in meeting peak demands by operating thermal units less efficiently, or by adding more expensive gas-fired units.

This paper is organized as follows: in the second section, we provide a brief review of the related literature; assumptions and model formulation are presented in section three; then we formally specify the optimization problem; data issues are addressed in section five; next we calibrate the power generation function and the head function[2]; section seven contains the empirical analysis of the hydro plant operations and profit; the environmental impact of changes in thermal generations is considered in section eight; lastly, conclusions and directions of future research are given in section nine.

2 Literature Review

The literature on hydro dam operations and the associated environmental effects is enormous. The existing research in this area can be divided into three broad categories: the power and civil engineering literature; the biology and environmental studies literature; the energy and environmental economics literature. In this section we survey a selection of papers from each of these literatures with an emphasis on ramping related issues.

In the power engineering literature, there has been considerable interest in the application of mathematical programming methods to scheduling the generation of electricity. Most of this work has focused on problems of scheduling the generation of hydro-electricity or thermal electricity, and coordinating thermal electricity generation with hydro-electricity generation. Much of the interest in electricity scheduling models concentrates on the optimal operation of power stations with the objective of producing electric power at the lowest cost, at maximum profit, at the best efficiency, at maximum potential energy and so on. In general, these models include many detailed technical specifications and constraints are quite complex. Their solution is computationally intensive, requiring special solution algorithms.[3] From the power engineering literature, some of the papers studying the optimal production scheduling problem for a hydro-electric power producer include: Hreinsson (1988), Soliman and Christensen (1988), Shawwash et al. (2000), Conejo et al. (2002) and Deng et al. (2006).

In practice, hydro operators face regulatory requirements for minimum and maximum water flows and levels, as well as restrictions on ramping rates which are intended to protect the aquatic environment of the associated rivers and lakes. Some of the studies discussed above include only minimum flow restrictions in their optimization models as physical or environmental constraints. A few of them consider ramping rate restrictions as physical constraints. In the international literature on power engineering, including the papers mentioned above, relatively little attention has been paid to directly address ramping rate restrictions as policy constraints for environmental protection. One exception is Guan et al. (1999), where an optimization-based algorithm is presented for scheduling hydro power systems with restricted operating zones and discharge ramping constraints. In the Guan paper the ramping constraints may be imposed on discharges for generation or spillage through canals or tunnels due to the requirements of navigation, the environment, recreation, etc. They find that, with ramping constraints imposed, the hydro production schedule changes significantly and the costs are generally increased, since the constraints limit the water release so that downstream power plants may generate less power.

The term 'hydropeaking' is used in the literature to refer to the shifting of hydro production to periods in the day when prices are highest. The environmental effects of hydropeaking power generation on fish and fish habitat have attracted much attention from biological and environmental scientists. Most of their studies directly address the effect of the instream flow rate (the minimum flow rate, the variation of flow rate and the ramping rates) of regulated rivers on the downstream biological habitat. In Scruton et al. (2003), hydropeaking or pulse power generation is defined as "reservoir operations, where water is stored to generate electricity during times of peak demand, leading to diurnally and annually variable water pulses in the river below the power station resulting in unnatural flow patterns involving alterations to magnitude, duration, sequence, and frequency of flows." They note that hydropeaking often results in "rapid changes in river discharge and associated habitat conditions over very short time scales (less than a day, or multiple peaks per day) and changes can be moderate or as large as several orders of magnitude." There is a clear consensus that modified flow regimes in regulated rivers mainly for purposes of hydroelectric generation are affecting fish and fish habitat, but the severity and direction of the response varies widely. Murchie et al. (2008) conduct a systematic review of available literature examining the response of fish to fluctuating flow regimes in different systems.

In regulated rivers, the environmental heterogeneity of fish habitat may be aggravated and unpredictable, depending on hydropower demand and price. One consequence experienced in many rivers is peaking flow on a daily basis, with suddenly increasing and high flows in the morning and increasingly higher flows during the day, then decreasing flow in the evening, and extremely low flow at night. Hvidsten (1985), Cross and DosSantos (1988), Bradford et al. (1995) and Saltveit et al. (2001) demonstrate that this variable flow pattern affects the habitat conditions and directly results in stranding of young fish and increased mortality. The negative impacts of hydropeaking are also documented by Flodmark et al. (2002), Berland et al. (2004), Scruton et al. (2003), Scruton et al. (2005), Scruton et al. (2008) and Grand et al. (2006). Freeman et al. (2001) demonstrate that providing periods of stable flow conditions below hydropower facilities during appropriate seasons should facilitate reproduction by native riverine fishes. Marty et al. (2008) find that there is a significant effect of a high ramping rate flow regime on the length of the food web. The operations of waterpower facilities will alter a river's flow in terms of its magnitude, timing, frequency, rate of change, and duration. A publication of the Ontario Ministry of Natural Resources (2003) summarizes some negative effects of this alteration, both from up-ramping and down-ramping. Specifically this report states that excessive up-ramping could affect fish holding instream and result in scouring of substrate and infauna (Cushman (1985)), while slower down-ramping is beneficial for biota by protecting fauna from stranding and ensuring better conditions for vegetation seeding (Petts and Maddock (1994)).

Relationships between the quantity of suitable fish habitat and flow have been used to select regulatory minimum flows for numerous rivers (Jager and Smith (2008)). Currently, there is considerable interest in Ontario in using and evaluating instream-flow-needs (IFN) methods for fish. Kilgour et al. (2005) provide a review of IFN methods appropriate to waterpower facilities. Gouraud et al. (2008) estimate the change in brown trout population under different minimum instream flows. Murchie et al. (2008) suggest that more studies are needed to evaluate the behaviour of fish during dynamic periods such as flow increase or decrease (i.e. during the ramping). Jager and Smith (2008) review research on reservoir optimization problems that explicitly includes environmental objectives. They find that nearly half of the studies they reviewed addressed environmental flows by including a constraint on minimum flow releases.

From our survey of the available information it appears that many hydro dams operate with minimum flow requirements, but very few operate under ramping rate constraints. Some examples that do face ramping constraints include the Glen Canyon Dams, located on the Colorado River in Arizona, which are operated under restrictions on maximum flows, minimum flows, ramp rates, and the daily change in flow (Veselka et al. (1995) and Harpman (1999)). Located on the Shuswap River, east of Vernon in the southern interior of British Columbia, the Sugar Lake Dam is operated under ramp rate constraints and the Wilsey Dam needs to meet the minimum discharge requirement (BC Hydro (2005)). The Kerr Dam on the Flathead River about five miles southwest of Polson in Montana faces the following restrictions: minimum flow requirements, maximum between-day flow changes and maximum allowable ramping rates (Flathead Lakers (2005)).

In the economics literature, there are very limited studies regarding the environmental effect of ramping and the associated economic impact on hydro power operations. Some of these studies include Veselka et al. (1995), Edwards et al. (1999), Edwards (2003), Harpman (1999) and Chen and Forsyth (2008), who treat ramping rate restrictions as environmental constraints in their optimization models. These papers (except Chen and Forsyth (2008)) assume that the power stations operate under a particular ramping rate regime, but do not analyze the effect of various levels of ramping rate restrictions on the power station's optimal operation and profit. The trade offs involved in the choice of the optimal ramping rate regime are not addressed. We attempt to fill in this gap in the literature by considering both the associated benefits and costs of ramping restrictions on hydro profits and on total daily hydro production and the potential implications for other sources of power.

There are some related cost and benefit studies similar to this paper. Kotchen et al. (2006) conduct a benefit-cost analysis of changing daily conditions from peaking to run-of-river (ROR) flows for two hydroelectric dams in Michigan. They consider three categories of costs and benefits related to the switch to ROR flow: electricity production costs, air quality benefits, and recreational fishing benefits. Huppert (1999) estimates the costs of protecting the endangered and threatened salmon, including the cost of environmental restrictions on hydropower operations in the Snake River. Jager and Bevelhimer (2007) review hydropower projects with license-mandated changes from peaking to ROR operation, and discuss producer costs and environmental benefits associated with operations: decreased generation efficiency; higher energy cost of fossil fuels needed to replace hydropower during peak versus off-peak hours; the negative costs of environmental externalities.

3 Assumptions and Model Formulation

The goal of the paper is to examine the opportunity cost of ramping rate restrictions on hydro power operations. Our approach is to consider the costs for a representative hydro power plant. We assume that the hydro plant has signed a binding contract to supply a specified amount of power to a certain customer, which implies there is a minimum amount of power that the plant must produce. Any power which is over and above the contracted amount can be sold in the market. This is similar to the assumption in Veselka et al. (1995), but contrasts with Edwards et al. (1999) in which the contract demand must be met exactly with no production allowed over the contracted amount.

This hypothetical contract is a device to permit the estimation of the cost of ramping restrictions. If ramping restrictions imply that the contract cannot be met at certain times during the day, then another source of power must be purchased. The additional cost of this alternative source of power is a measure of the opportunity cost of the ramping restrictions.

The contract specifies the quantity of electricity exchanged for each time t. The price is the spot market rate which is assumed known and non-stochastic. This is clearly unrealistic, since a key feature of electricity prices is their high degree of volatility. In this paper we ignore uncertainty in both electricity demand and price, and focus solely on the opportunity costs of ramping restrictions in a non-stochastic environment. The case of uncertain demand and price is left for future research.

We also ignore the possibility that the hydro power station could provide any ancillary services to the electricity market. For example, besides producing electricity, a hydro unit can also provide spinning reserves, which means that some of its power capacity is put aside to provide electricity in case of a power shortage somewhere over the network.

A typical hydroelectric generation system can consist of more than one independent rivers, with one or several generating facilities and reservoirs in a series or in parallel, and transmission lines to neighboring systems through which electricity may be exchanged. In addition, reservoir management deals not only with power generation, but with recreation, fishery and irrigation as well. In order to focus on the ramping issue of the station's operation, the proposed model will only consider the power generation aspect of one representative station and issues related to system transmission and distribution are ignored in this study. In brief, we will largely follow Edwards et al. (1999) in the theoretical formulation of the model. Specific differences are noted in the model description later in this section.

The time horizon of the model is T periods, with each individual period indexed by $t = 1, ..., T$. In the empirical example to follow we solve the optimization problem for each hour over a five day period. In this case t represents one hour and $T = 5X24 = 120$ hours. We denote the number of days as N where $N = 5$. Each day is further divided into on-peak and off-peak periods. We assume that the prevailing spot price during peak periods will exceed that for off-peak periods. For the prototype hydro power station, there are three alternative choices available to meet the contract demand: generation of hydro power only; purchase of electricity on the spot market at prevailing prices and resale to the consumer; or some combination of these two. The hydro power station operates under various physical constraints and must also meet environmental and other policy constraints set by the regulator. Here, we assume that the hydro operation is subject to the following constraints:

- maximum hourly up-ramping and down-ramping rates;
- maximum daily total water release.[4]
- maximum and minimum hourly
  - water release rates;
  - water spill rates;
  - head requirements;
  - water content;
  - hydro power generation;

In addition, contract demand and the water balance equation must be satisfied at all times.

The total amount of power provided to the market by the owner of the hydro station comprises the portion derived from hydro generation and the portion derived from spot market purchases and resale. For a specific hour, this can be written as follows:

$$q_t = q_t^r + q_t^h(r_t, h_t(w_t)). \tag{1}$$

where q_t is the total electricity supplied by the owner during period t; q_t^r is the electricity purchased from the spot market for resale; and q_t^h is the amount of hydro power generated and sold in period t. Hydro generation is a function of r_t, the water release rate during period t, and h_t, the head of the dam which depends on the amount of water in the reservoir w_t. The hydro power production function will be non-linear and is assumed to be continuous and increasing with respect to both arguments [5], $\frac{\partial q_t^h}{\partial r_t} > 0$ and $\frac{\partial q_t^h}{\partial h_t} > 0$, but the second order derivatives are assumed to be zero, i.e., $\frac{\partial^2 q_t^h}{\partial^2 r_t} = 0$ and $\frac{\partial^2 q_t^h}{\partial^2 h_t} = 0$. We further assume that $q_t^h(0, h_t(w_t)) = 0$ and $q_t^h(r_t, 0) = 0$, meaning that at any level of water head when there is no water release the hydro power generation will be zero, and at any level of water release rate, if the water head is zero there will be no power generated. For the head function $h_t(w_t)$, it is assumed that $\frac{\partial h_t}{\partial w_t} > 0$, $\frac{\partial^2 h_t}{\partial^2 w_t} = 0$ and $h_t(0) = 0$. The specific functional form assumed for the hydro production function is given in Section 6.

Next, we assume that the equation of motion for water is governed by the following formula[6]:

$$w_{t+1} = w_t + \alpha[i_t - r_t - f_t]. \tag{2}$$

This equation states that the total amount of water in the reservoir at time $t + 1$, i.e., w_{t+1}, equals to the total amount of water stored at time t, i.e., w_t, plus the water inflows (coming from snow melting, rain, runoff water and natural river flow) into the reservoir at time t, i.e., i_t, minus the water outflows (turbine and spill flows) at time t, i.e., $\{r_t, f_t\}$. α is the conversion factor to convert water flow units into water volume units. In this paper, water flows are measured in cubic feet per second (CFS) and water volume is in acre feet. Reservoir water losses due to seepage and evaporation are neglected. Here, the dam possesses a mechanism to release water with and without hydro power generation. This general formulation captures the case when it may be necessary to spill a large quantity of water such as during a period of flooding. In practice the spill flow can be controlled quite precisely by adjusting gate openings. However, spilling should be avoided as much as possible, given that no electricity is produced in this case.

In addition, the hydro power station is required to meet contractual obligations for power at any time of the day, so the sum of hydropower production and the purchased power for resale must be sufficient to satisfy the contract demand of the day. This load resource balance can be represented by the following equation:

$$\hat{q}_t \leq q_t^r + q_t^h(r_t, h_t(w_t)). \tag{3}$$

$\hat{q}_t$ represents the contract demand during period t of the day.

We assume that the hydro power station is subject to the up-ramping and down-ramping constraints which will limit its operational ability to increase or decrease the water release rate in any given period. These two constraints can be expressed as:

$$r_{t+1} - r_t \leq r^u. \tag{4}$$

$$r_t - r_{t+1} \leq r^d. \tag{5}$$

r_t refers to water release in period t, which may be an on- or off-peak period. Equation (4) limits the rate at which the water release rate can be increased between periods to r^u.[7] The up-ramping limit will be determined by the physical capabilities of the particular hydro turbine and the ramping rate constraint imposed by regulators to protect the environment. In this paper we concern ourselves only with the latter source of ramping restrictions. Similarly, equation (5) limits the rate of ramping-down, i.e., the rate at which the water release rate can be decreased between periods. Again we assume the ramping constraint is imposed by regulators, although the physical characteristics of a particular hydro unit may also limit down-ramping.

The hydro station also faces minimum and maximum water release rate requirements, which can be represented as:

$$r^{min} \leq r_t \leq r^{max}. \tag{6}$$

Equations (6) limits the range of water release rate by r^{min} and r^{max}. Again we assume the minimum and maximum water release rates are constant over any day and represent regulatory requirements to protect the river ecosystem. The minimum release requirement is loosely defined as the smallest amount of flow that can be left in the river without harming downstream fish populations (Jager and Smith (2008)). By imposing these constraints, the hydro power station's operational flexibility may be significantly affected. Currently, many hydro power stations operate under the minimum and maximum water release constraints.

Similarly, the station faces minimum and maximum water spill rate requirements (Catalão et al. (2006)), denoted f^{min} and f^{max} respectively. These can be represented as:

$$f^{min} \leq f_t \leq f^{max} \tag{7}$$

In practice, especially during flood periods, spillways may release water so that the water does not overtop and damage the dam. Spillways provide added flexibility of operations given variations in water inflow.

Additional operational constraints include that the water level must remain between specified minimum and maximum values. This implies the station faces minimum and maximum water head requirements (equation (8)), and upper and lower reservoir storage constraints (equation (9)), which may vary over the year (Catalão et al. (2006)). These constraints can be stated as:

$$h^{min} \leq h_t \leq h^{max} \tag{8}$$

$$w^{min} \leq w_t \leq w^{max}. \tag{9}$$

where, the water head lower bound is h^{min} and the water head upper bound is h^{max}. The reservoir storage lower bound is w^{min} and the reservoir storage upper bound is w^{max}.

We further assume that the hydro station is facing minimum and maximum power production constraints, which can be written as:

$$q^{min} \leq q_t^h \leq q^{max}. \tag{10}$$

These limits may be technical limits of hydro turbines or may reflect a constraint on the amount of power that can be transmitted through power lines, perhaps due to congestion.

According to Edwards et al. (1999) and Harpman (1999) hydro dams typically are required to release a specified quantity of water each month. For example, in the United States Power Marketing Administrations (PMAs) are required to release specific amounts of water for each dam during each month of the year (Edwards et al. (1999)). In this paper the optimization occurs over 5 days and it is assumed that there is a maximum that can be released in each 24 hour period. The constraint is given by:

$$\sum_{t=1}^{24} \alpha r_{tj} \leq R, \; j = 1, ..., N. \tag{11}$$

where α is the conversion factor to convert a water flow into a water volume and j indexes each day. Additional optional constraints in the model can be easily imposed if required, such as system reliability and ancillary service requirements; more detailed market conditions; transmission losses and other operational details.

4 The Optimization Problem

In this section we formulate the optimization problem for the representative hydro power station. The owner of the station is assumed to maximize profits subject to various constraints described in the previous section. Profit maximization involves determining the amount of power production which depends in a non-linear fashion on water released through the turbine and on dam head, as given in equation (1). Dam head is a reflection of water content in the reservoir. A hydro operator knows that water released today reduces dam head and therefore the amount of power that can be produced in the next period. Profit maximization over time involves choosing the level of water releases so that the benefit in terms of electricity production today just offsets the opportunity cost in terms of foregone future production and profits.

In order to keep our optimization problem of manageable size, our empirical analysis considers a 5 day period of operations. The optimal choices in any single day depend on initial conditions, and in particular on the initial water content and dam head. To avoid dependence on arbitrary initial conditions, we look for a steady state solution where the optimal choice of water release and water level in the dam is unchanging from the previous day. In our empirical example, we choose initial conditions for water level and the water release rate that allow us to reach a steady state within the five day period. We then report the results for a steady state day in all cases.

Our focus in this paper is on ramping rate constraints, equations (4) and (5), and we measure their cost as the lost profit from having to meet these constraints, net of the cost of any change in pollutant emissions caused by a change in the economy's reliance on thermal power. As noted earlier, we do not attempt to specify the benefits of environmental restrictions in terms of reduced damages to the aquatic environment. This is beyond the scope of the current paper.

The representative hydro station's power generation is assumed to be small in the electricity market and hence is a price-taker during each period. The station charges the spot market price for its power, whether generated by the station, purchased from the spot market for resale, or some combination of the two. The power purchased for resale is purchased and sold at the same spot price, so no net revenue is generated. However it is assumed that an administrative cost is incurred, c_t^r per kWh, so the hydro station incurs a net loss on this transaction. A similar assumption is made in Edwards et al. (1999). This administrative cost can be an arbitrarily small number, but is required to achieve a reasonable solution to the optimization problem in that spot market purchases are only made when needed to meet contract demand. The hydro generation and transmission (G&T) costs are given by c^h per unit of power and are assumed to be the same during both off-peak and on-peak periods. The spot electricity price is denoted by p_t per kWh during time t.

The minimum amount of power produced or purchased by the hydro plant owner is specified in the contract. Therefore, whatever the realized market conditions and water inflows, contract demand must always be satisfied, and purchase for resale may become necessary at some points in time. The option to purchase power in the spot market is valuable to the hydro operator, since it means the contract demand can always be met. In the empirical examples that follow we assume water inflow is deterministic, but in practice the uncertainty and variability of water inflow due to weather conditions may impact the amount of electricity that a hydro station can generate in any given period. The stochastic nature of water flows would give added value to the ability to satisfy contract demand with spot market purchases. In addition, this option also creates value by giving the operator the flexibility of hydro-shifting. Hydro-shifting refers to the practice of shifting production to on-peak periods when prices are highest. In off-peak periods, contract demand can be satisfied through spot market purchases.

The total profit of providing power over the T periods is given by the following equation:

$$\sum_{t=1}^{T} \left\{ (p_t - c^h) q_t^h (r_t, h_t(w_t)) - c_t^r q_t^r \right\}. \tag{12}$$

The first term inside the brace accounts for the total profit from generating hydroelectric power, given the hourly spot prices. The second term inside the brace represents the net cost of purchasing power for resale from the spot market. It is the per unit administrative cost c_t^r multiplied by the quantity of spot market purchases.

The optimization problem is to maximize equation (12) subject to a suite of constraints. The set of control variables includes the water release rate for power generation, the water spill rate and the amount of power to purchase for resale for each period t, i.e., $\{r_t, f_t, q_t^r\}$. The state variables is the water content, w_t. Exogenous variables including the water inflow rate, electricity demand, and electricity price for each period t, i.e., $\{i_t, \hat{q}_t, p_t\}$ are assumed to be known and deterministic. This is a deterministic dynamic non-linear optimization problem. The objective function and constraints are given below in equations (13)-(24). The constraints are as detailed in Section 3, with the addition of the non-negativity constraint, equation (23).

$$\max_{r_t, f_t, q_t^r} \sum_{t=1}^{T} \left\{ (p_t - c^h) q_t^h(r_t, h_t(w_t)) - c_t^r q_t^r \right\}. \tag{13}$$

Subject to

$$w_t = w_{t-1} - \alpha(r_{t-1} + f_{t-1}) + \alpha i_{t-1}, t = 2, ..., T. \tag{14}$$

$$\hat{q}_t \leq q_t^r + q_t^h(r_t, h_t(w_t)), t = 1, 2, ..., T. \tag{15}$$

$$r_t - r_{t-1} \leq r^u, t = 2, ..., T. \tag{16}$$

$$r_{t-1} - r_t \leq r^d, t = 2, ..., T. \tag{17}$$

$$r^{min} \leq r_t \leq r^{max}, t = 1, 2, ..., T. \tag{18}$$

$$f^{min} \leq f_t \leq f^{max}, t = 1, 2, ..., T. \tag{19}$$

$$h^{min} \leq h_t \leq h^{max}, t = 1, 2, ..., T. \tag{20}$$

$$w^{min} \leq w_t \leq w^{max}, t = 1, 2, ..., T. \tag{21}$$

$$q^{min} \leq q_t^h \leq q^{max}, t = 1, 2, ..., T. \tag{22}$$

$$0 \leq q_t^r, t = 1, 2, ..., T. \tag{23}$$

$$\sum_{t=1}^{24} \alpha r_{tj} \leq R,\ j = 1, ..., N. \tag{24}$$

The Karush-Kuhn-Tucker conditions for this mathematical programming problem can be easily derived. This type of analysis admits two possible solution forms. The first is an interior solution characterized by all endogenous variables having positive values at the optimum (i.e., the dispatcher relies on both thermal power resales and hydro generation in both periods). The second is a corner solution, in which at least one of the endogenous variables will take on a zero value at the optimum (e.g., no thermal power is sold or no hydro power is generated in one of the periods). For the empirical studies in the following sections, we will specify the optimization problem, and obtain solutions using Matlab.[8]

5 Data Description

The prototype hydro plant used in our empirical example is based on a medium sized plant in Ontario. We construct our example using some specifications of an Ontario Power Generation (OPG) generating station, as well as our own assumptions based on input from a variety of sources. An example of a medium sized hydro plant is OPG's Abitibi Canyon generating station located on the Abitibi River in northeastern Ontario. Details of the generating station can be found on the OPG web site,[9] and in Statistics Canada (2000) and Hendry and Chang (2001).[10]

OPG owns 65 hydro generating stations with a total capacity of 6,963 megawatts (MW). The Abitibi Canyon station consists of five generating units and has a total generation capacity of about 336 MW. In terms of water inflow, the combined physical capacity of the generators is assumed to be about 19 thousand Cubic-feet-per-second (CFS) of water. The storage capacity of the reservoir is assumed to be about 17 thousand acre-feet of water.

We model the optimal operation of the hydro station over a 24 hour period assuming it faces a contract demand requirement that ranges from 112 MW during the off-peak period to 336 MW during the on-peak period (Table 1). This contract is hypothetical and mimics the daily pattern of Ontario electricity demand. The contract demand can be met either by generating hydroelectricity, or purchasing power from the spot market for resale, or some combination of both.

Consistent with the empirical observations, peak hours are specified as being from 6:00 AM to 11:00 PM Mondays through Fridays, and off-peak hours are from 11 PM to 6:00 AM. Each 24 hour period begins at 11 PM, with 11 PM - 12 PM labeled as the first hour. This can be seen in Table 1.

Data for the Hourly Ontario Electricity Price (HOEP) from 01 May 2002 to 30 Nov 2006 is used to determine reasonable assumptions for electricity prices. Based on the definitions of off-peak and on-peak periods, we calculate the average prices for both periods using these data. The average spot electricity price is 36.33 $/MWh during the off-peak period and 62.13 $/MWh during the on-peak period, which will be used in our empirical analysis (Table 1). We also assume that purchase for resale incurs an administrative cost of 2 $/MWh, which will be paid by the hydro operator. This is the amount assumed in Edwards et al. (1999). In addition, the cost of generating hydroelectric power is assumed constant at 20 $/MWh in both off-peak and on-peak periods for the hydro station.

Actual water inflows are stochastic in nature, but are handled here in a deterministic manner in this analysis. Based on data for the historical water inflow for the Abitibi Canyon from 01 January 2001 to 30 November 2006, we calculate an average daily amount of 6671 CFS.[11] We abstract from fluctuations in water inflow over a typical day, and assume that inflow is a constant 6671 CFS for each hour.

6 Modeling Hydropower Generation

In this section, we specify the hydro power production function and the gross head function. The production function we adopt is standard in the power engineering literature, and is identical to that used in Philpott et al. (2000). Water flowing through a turbine generates electricity by changing its potential energy into electrical energy. The amount of power available from a hydro power station is proportional to the product of its water flow rate, its water head and its generation efficiency. The hydro electricity generation function is determined empirically and is, in general, a non-linear function of the turbine discharge and the gross head. The amount of electricity produced by each unit (turbine) can be calculated using the following relation:

$$q_t^h(r_t, w_t) \propto r_t h_t(r_t, w_t) e(r_t, h_t). \tag{25}$$

Where, q_t^h is the power output, r_t is the flow rate, h_t is the gross head, e is the efficiency factor and $\propto$ means proportion. Gross head refers to the vertical distance between the top of the penstock that conveys water under pressure and the point where the water discharges from the turbine. Here, the gross head is a function of the flow rate and the water content, and can be represented as $h_t(r_t, w_t)$. The generation efficiency in converting water flow to electrical power is a non-linear function of the flow rate and the gross head of the water flowing through the turbine, and can be written as $e(r_t, h_t)$. Due to the complexity of this nonseparable hydro production function, we have chosen to make a number of simplifying assumptions about its functional form for our model. Following Harpman (1999), equation (25) becomes:

$$q_t^h(r_t, h_t(w_t)) = 0.001\, g\, r_t\, h_t(w_t)\, e. \tag{26}$$

where, g is the gravitational constant (32.15 feet-per-square-second) and the factor 0.001 converts q_t^h to MW from KW, r_t is in CFS and h_t is in feet. According to Equation (26) gross head is only a function of the water content and does not vary with the flow rate, and the generation efficiency is kept as constant over the course of our (short-term) planning horizon (Hreinsson (1988)). Energy is always lost when converted from one form to another, and all the equipment used to convert power available in the flowing water to electrical power is less than 100 percent efficient. We use an efficiency factor of 0.87. Therefore, the right hand side of equation (26) can be rewritten as $0.001 \times 32.15 \times 0.87 \times r_t h_t(w_t) = 0.028 r_t h_t(w_t)$ where r_t is in CFS and h_t is in feet. This simple formulation of the hydroelectric generating plant's production function has the characteristics of convexity, continuity and smoothness, which implies that standard optimization techniques can be usefully applied.

The level of head can be expressed as function of the water content in the reservoir. Due to the unavailability of some key data, following Edwards et al. (1999) we make the simplifying assumption of a linear functional form which can be written as:

$$h_t(w_t) = \beta w_t \tag{27}$$

where, w_t is the water content in acre-feet. Then the parameter value of beta can be approximated using the available data. Under the normal operating range, the calibrated beta value is 0.0089. The advantage of using linear functional form is that only one parameter needs to be calibrated and it provides a good approximation when converting from gross head to reservoir storage, particularly for reservoirs with high inflows but small storage capacities.

7 Empirical Analysis

In this section, we examine three optimization cases under various operational and environmental constraints. The baseline case optimizes equation (13) subject to equations (14), (15), and equations (19) through (24). The second case adds both the minimum and maximum water release requirements given by equation (18). The third case adds extra up-ramping and down-ramping constraints, which are equations (16)-(17).

Hourly contract demand, given in Table 1, is based on the contract used in Edwards et al. (1999) but is scaled up to match the production capacity of our medium sized prototype hydro station. For the baseline case the constraints are specified as follows:

- up-ramping and down-ramping constraints are 1,000 Cubic-feet-per-second per hour (CFS-hr);
- the minimum water release requirement is 2,000 CFS and the maximum release constraint is 15,000 CFS;
- the minimum spill rate is 0 CFS and the maximum spill rate is 10,000 CFS;

- the minimum water content requirement is 7,000 Acre-feet and the maximum value is 17,497 Acre-feet;
- hydro generation capacity is from 0 MW to 336 MW.
- a maximum of 13,100 acre-feet of water may be released during a 24 hour period for power generation.

This latter constraint may be thought of as an environmental constraint ensuring that the dam will not be drained in any period or it may be a technical constraint of the turbines. Note that this constraint on total release does not include spillage. Spillage will always be kept to a minimum as it does not contribute to profits. In the following examples the maximum release constraint is set slightly below the total quantity of water inflow during the day implying that once the desired water level is obtained in the dam, it will be necessary to spill a certain amount each day to avoid overtopping.[12] In practice the option to spill allows a hydro operator flexibility in cases where water inflow is higher than normal. This is not an issue in our empirical example in which water inflow does not vary from one hour to the next.

We begin the optimization by choosing an initial water release rate and water content. The optimization proceeds over the 5 day period. Through the choice of optimal hourly water releases, the water level in the dam changes over time until a steady state is reached so that subsequent days are identical to the previous day. The initial conditions are specified so that a steady state is reached (or nearly reached) within the five day optimization scenario.[13] We report results for the fourth day for all cases. The first 7 hours of any day represent the off-peak period and the next 17 hours represent the on-peak period.

The results of the optimization are reported in the following sections. We begin with the baseline which uses the basic operational constraints, but no restrictions on minimum and maximum releases and ramping. The operational constraints are equations (14)(water balance), (15)(contract demand) and (19)-(24), which are constraints on water spillage, head level, water content, minimum and maximum hydro production, and total water release. Although our focus is on ramping constraints, we first consider the impact of minimum and maximum flow constraints alone and then add on ramping constraints.

7.1 Baseline Optimization

The base case results for a steady state day are reported in Table 2 and Figure 1. In Table 2, water release is seen to be zero during the off-peak hours. The spillage shown during off-peak periods is the amount needed to equalize flow into and out of the dam, so that the water level remains unchanged. During on-peak hours, water releases rise fairly steadily, peaking at 11,343 CFS at the 24th hour. The largest ramp-up in the water release rate occurs from the 7th to the 8th hour which is the cross over point from off-peak to on-peak. Similarly, the largest ramping-down occurs between the 10pm-11pm and 11pm-12pm periods of the day, which is at the cross point from the on-peak period to the off-peak period. During the off-peak period contract demand is satisfied only by purchasing power from the market for resale. During on-peak hours contract demand is met by hydro power only and for a significant number of hours more hydro electricity is produced than the contract requires. No thermal power is purchased for resale in this period. Clearly, in this case the absence of minimum and maximum release constraints and ramping constraints allows for rather dramatic changes in water release rates. Figure 1 plots the total power (hydro production and resale power), contract demand, hydroelectric production and power purchase for resale under this baseline case. It shows a clear pattern of hydro-shifting.

These results make sense intuitively and are consistent with Edwards et al. (1999). Because of the upper limit on the total water flow through the turbine in any one day, it is in the interests of the hydro operator to release the permitted water flow when the electricity price is highest, which is during on-peak hours. In addition, the requirement that sufficient power must be sold during the base period in order to satisfy the demand requirement, induces the decision maker to purchase and resell thermal power during the off-peak period to satisfy this contract demand. To maximize the value of hydro resources, the power station stores water during the off-peak period for release during the on-peak period, and sells thermal power during the base period to satisfy the demand requirement of its customers.

7.2 Optimization with Release Rate Constraints

In this second optimization, we impose a minimum release requirement of 2,000 CFS and a maximum release requirement of 15,000 CFS. Together with the operational constraints in the first scenario, these constraints cause several major changes in the water release profile during the representative day (Table 3 and Figure 2). First, off-peak period releases increase to satisfy the new minimum release rate constraint and are maintained at the lower bound of 2,000 CFS from the 1st hour up to the 7th hour of the representative day. As a result, from the 8th hour to the 24th hour water releases are either slightly lower than or the same as the baseline case. This indicates that, during the off-peak period, it is optimal to maintain the minimum release rate and to purchase from the spot market the remaining power needed to meet the demand requirement. During the on-peak period, since the electricity prices are much higher, it is desirable to keep the water release rate similar to the baseline case.

During the off-peak period, at a release rate of 2,000 CFS the produced hydro power is lower than the contract demand, however during the on-peak period the hydro power production is either higher than or same as the contract demand. Correspondingly, power resales are lower during the off-peak hours than under the baseline case. As in the baseline case, there are no power resales in the on-peak period.

Also consistent with the baseline case, up-ramping is highest from the 7th to the 8th hour and down-ramping is highest from 10pm-11pm to 11pm-12pm. However, these ramping rate peaks have lower magnitudes than in the baseline case. As shown in Table 3, the maximum release constraint is never binding during the on-peak period. Maximum water release occurs from 10pm -11pm, and at 10,463 CFS is less that in the baseline case. After imposing the minimum and maximum release constraints, hydro-shifting is still apparent, but less significant compared with the baseline case, as is illustrated in Figure 2. This indicates that these extra environmental constraints limit the station's ability to make full use of the benefit of hydro-shifting, and therefore reduce its value.

7.3 Optimization with Ramping Rate Constraints

In this scenario we add up-ramping and down-ramping restrictions, both of which are set initially at 1,000 CFS-hr. As Table 4 and Figure 3 illustrate, with ramping restrictions the highest on-peak water release rate during the representative day reaches the maximum of 9656 CFS in the 20th hour, which is lower than the previous two cases. The ramping constraints reduce the extent of hydro-shifting that is possible. In the off-peak period, the hydro power station gradually ramps down the water release rate, and then in the on-peak period gradually ramps up again. However while still in the on-peak period, after the 20th hour, ramping down has commenced in preparation for the approaching off-peak period.

The change in the pattern of hydro production over the day compared to the previous scenarios is most easily seen in Figure 3 compared to Figure 2. With the maximum allowable release during a day, the increase in hydro production during off-peak periods implies there will be a reduction during the on-peak period. During the 21st and 22nd hours a small portion of demand is met by purchases of thermal power. The inability to fully satisfy peak demand with hydro production will have a negative effect on profits.

7.4 Comparing the Three Optimization Scenarios

Figure 4 compares water release rates for these three optimization scenarios. From this graph the shifting of hydro production from the on-peak to the off-peak period is very evident for the case with minimum and maximum flow constraints compared to the baseline. This shift is even larger for the case with ramping constraints.

The impact of these constraints on profits for a range of ramping constraints is detailed in Table 5 and Figure 5. In general, the more restrictive the constraint the greater is the limitation on the station's operational flexibility and the larger the impact on profits. Under the baseline case, the total profit from providing power is \$226 thousand. For Case I with the minimum and maximum release constraints, the total daily profit drops to \$223 thousand, representing a 1.1% reduction over the baseline scenario. When ramping constraints of 5000 cfs-hr are added in Case II profit drops marginally to \$222 thousand which is 1.7% less than the baseline. As ramping rate restrictions are increased profits continue to drop, until at a restriction of 250 CSF-hr, i.e., the water release rate can increase or decrease by at most 250 CFS between any two consecutive hours, then the total profit drops to as low as \$208 thousand, which is an 8% decrease relative to the baseline. From Figure 5 we also observe profits fall proportionately more as ramping restrictions are increased when ramping rates are already quite restrictive - i.e. for rates of less than 2000 CFS-hr.

In Table 5 and Figure 6, we report total power sales, hydro power generation, and spot purchases for resale. Interestingly we observe that total power sales are affected, implying that the impact of the restrictions is not simply a redistribution from on-peak to off-peak periods. We observe the largest power production level in the most restrictive case (ramping rate constraints of 250 CFS-hr). Figure 7 gives a clue as to why this is so. In this figure water content by hour is shown for the baseline case, the case of min/max release constraints and the cases of 250 and 1000 CFS-hr up and down ramping restrictions. The flat portions on the graph are periods when water content is at the upper limit. Starting at a given initial water content, as optimization proceeds over the 5 day period the optimal choice of water release and spillage affects the water content of the dam. By the time a steady state is achieved, the water level profile by hour over a 24 hour period remains the same from one day to the next and the amount of spillage in one day is chosen so that the water level in the dam is maintained.

We observe from Figure 7 that the optimal water levels for the restricted cases (min/max release constraints and ramping rate constraints) are greater than or equal to the water level for the baseline case. Further, the ramping rate case shows a higher water level than the min/max release constraint case for many hours of the day. The larger water content is a result of optimal choices necessitated by the restrictions and allows the operator to generate more power with a given water release rate (recall Equation 26). This is needed in order to produce as much as possible during on-peak periods despite the ramping constraints.

In Figure 6 different levels of restrictions can also be seen to have an impact on the level of power purchased for resale. The largest amount of resale power occurs in the base case without restrictions. Resale power is reduced as ramping restrictions are made more restrictive moving from 5000 CFS-hr to 1000 CFS-hr. However for restrictions of 500 and 250 CFS-hr an increase in the purchase of resale power is observed. This purchase happens in peak period hours, and without it the hydro operator would be unable to meet contract demand. In summary, we observe that the ramping restrictions have caused an increased reliance on hydro-power and a decreased reliance on purchases for resale compared to the baseline case. This is a somewhat counter intuitive result.

The results we have shown so far for our prototype Ontario dam are consistent with Edwards et al. (1999). Edwards showed that ramping restrictions increase the amount of hydro sold in the off-peak period and reduce it in the on-peak period and thereby reduce overall profitability of the hydro operations. Our results differ from Edwards in the finding that total hydro production may increase as ramping restrictions are imposed. This follows from our assumption that total hydro sales can exceed contract demand, and that as the hydro operator optimizes water releases over several days the water level in the dam adjusts until a steady state is reached. The ability to increase hydro production is a means for the operator to reduce the impact of ramping restrictions on profits. However, profitability is still affected with the most significant effects coming when ramping is restricted to 1000 CFS-hr and less.

8 Including the Environmental Impact of Changes in Thermal Generation

In the previous sections, we detailed the impact of ramping restrictions on the profitability of the firm. However in setting a ramping rate policy a regulator should consider other potential impacts that will affect the public good. Ideally the determination of an optimal level of range of ramping constraints would begin with a comprehensive environmental assessment of the positive effect of various levels of ramping restrictions on the river ecosystem. Evidence on the benefits for the aquatic ecosystem would be weighed against the negative effects on hydro station profits as well as the environmental impact of the change in reliance on other sources of power generation such as fossil fuels. If one were able to put a dollar value on each of these effects, the optimal ramping rate restrictions could be chosen. However, practically it is very difficult to measure the environmental effect of ramping on the river ecosystem based on biological studies and it is even more challenging to calculate this effect quantitatively in terms of monetary value. Currently, there is very limited research on this environmental effect and no studies available to provide some appropriate monetary measure of the environmental benefit of ramping restrictions. In contrast, there are estimates available of the environmental costs of thermal power generation. In this section we estimate the difference in environmental damages due to the change in reliance on thermal generation as a result of ramping rate restrictions and add this to the loss in hydro profits to get an estimate of the total cost of ramping restrictions.

In this section we investigate the impact of imposing up-ramping and down-ramping restrictions when minimum and maximum flow restrictions are already in place. We will measure the unit environmental cost (\$/MWh) of the replacement power by using an estimate of the marginal external cost of emissions of a thermal generation plant. These emissions include SO_2, NO_x and CO_2. We consider two cases for thermal (replacement) power: (i) replacement power is generated with coal during both the off-peak and on-peak periods; or (ii) it is generated with coal during the off-peak period and natural gas during the on-peak period [14].

In the empirical results presented in Section 7, we found that in the steady state, when ramping constraints were imposed, hydro production decreased during on-peak periods and increased during off-peak periods. Overall total hydro power production increased in the 24 hour period as ramping restrictions became increasingly tight. We assume that total market demand and production for electricity are not affected by the hydro power plant's operation. It follows that every unit change in hydro power production will be exactly offset by a change in thermal power generation. As a consequence, these flow restrictions will result in a decrease in polluting emissions from thermal power during off-peak hours and an increase in on-peak hours. Overall on a daily basis we will observe a reduction in pollutant emissions from thermal power.

For the first case, this environmental benefit is calculated as the total net increase in hydro production over the 24 hour period after imposing the ramping restrictions (which also equals the change in the amount of thermal power) multiplied by the marginal external costs of emissions for coal. For the second case, the associated total environmental benefit is calculated as the increase in the amount of hydro power generation during the off-peak period after imposing the ramping restrictions multiplied the marginal external costs of emissions for coal, minus the reduced amount of hydro power generation during the on-peak period after imposing the ramping restrictions multiplied by the marginal external costs of emissions for natural gas. The benefit of emissions reduction from thermal generation is subtracted from the lost profit caused by ramping restrictions which gives the net cost of the ramping restrictions, ignoring any benefits that accrue to the aquatic ecosystem. This cost estimate provides a lower bound on the level of benefits to the aquatic ecosystem which would make ramping constraints worthwhile.

We consider the benefits of reduced emissions from thermal plants for the scenarios examined in the previous section of equal levels of up-ramping and down-ramping constraints. For the marginal external costs of emissions, we choose both the high and low cost estimates.[15] For coal, these are 67.18$/MWh and 45.20$/MWh. For natural gas, these are 9.96$/MWh and 7.44$/MWh.

The results for the scenario with coal as replacement power under various equal levels of up-ramping and down-ramping constraints are reported in Figure 8. As we can observe, at any given level of ramping restrictions, higher marginal external costs of emissions always result in higher associated environmental benefits. However the cost in terms of lost profits nearly always exceeds the benefit from any reduction in pollution from thermal fired generation. Only for the most restrictive ramping rate (250 CFS-hr) and with the higher estimate for marginal external costs of pollution do we observe that the benefit from reduced thermal emissions exceeds the cost from lost profit. If we could measure the associated environmental benefits for the river ecosystem, these could be directly included in a cost benefit analysis. The net cost lines show how large this benefit would have to be to justify ramping restrictions. Using the high marginal external cost estimate (blue lines) we see that the necessary ecosystem benefit actually declines as ramping constraints are made more restrictive, getting smaller from 1000 CFS-hr.

The results for the scenario with coal as replacement power during the off-peak period and natural gas as replacement power during the on-peak period under various equal levels of up-ramping and down-ramping constraints are reported in Figure 9. With more and more restrictive ramping constraints, both the cost curve and the environmental benefit curves move up steadily, but the environmental benefit curves increase at a slightly faster rate and is always located above the cost curve. The net cost curves are always below zero and move down steadily with increasing ramping restrictions. This follows because with increasing ramping restrictions the environmental benefit gained through the reduction of thermal power generated using coal in the off-peak period exceeds by an increasing amount the associated loss of profit and the environmental cost of increased thermal power generated using natural gas in the on-peak period. In this example, the greater the ramping restrictions, the greater the net social benefit. Optimal ramping restrictions are shown to be 250 CFS-hr even without any consideration of the potential benefits to the river ecosystem.

Our assumption of a one-for-one replacement of thermal power by hydro power, with no effects on price, is clearly overly simplistic, but illustrates the importance of looking at the impact of hydro ramping rates on other sources of electricity generation. In Ontario, coal is generation is being phased out as part of government policy to reduce air pollution. As the province moves to “greener” sources of power the potential for an associated positive impact of ramping restrictions on air quality will be reduced.

9 Conclusions

The ability of hydro facilities to respond quickly through ramping to changing demand conditions is one of the benefits of hydro power. However the possibility of negative consequences of ramping on aquatic ecosystems needs to be considered by regulators. These negative impacts are case specific, dependent on the ecological conditions of particular rivers and streams. In cases where ramping rate restrictions are being considered, there should be a recognition of the costs imposed on hydro operators in terms of lost profits as well as potential environmental impacts that result from the need to utilize alternative sources of electricity. Ideally ramping rate regulations would be determined through a careful analysis of all the potential impacts. This paper contributes to our understanding of these impacts and the trade offs involved.

For a prototype hydro dam we modelled the lost profits for a range of ramping restrictions over a five day period. We present results for a typical day once a steady state has been obtained. We find that profits are significantly affected (by about 8%) in the case of the most severe ramping constraints. However we also find a range of less severe ramping constraints for which profits are impacted by less than 2%. We examine the change in total hydro production, as well as the purchase of replacement power that results from the restrictions. One counter intuitive result is that total hydro production increases as a result of the ramping constraints. This result follows from the desire of the hydro operator to mitigate the effect of the ramping constraints by producing more power in off-peak periods and in our example resulted in an increase in the average water level in the dam over a 24 hour period. Our assumption is that the increase in hydro production will result in reduced thermal generation in the economy, which causes an environmental benefit from reduced air pollution emissions. We calculate a net cost of the ramping restrictions as the lost profits net of any environmental benefit of reduced air pollution. This net cost can be compared to expected environmental benefits from an improved aquatic ecosystem.

An important conclusion of the paper is that ramping restrictions should not be determined in isolation, but rather using a cost-benefit approach that evaluates the trade offs involved. This paper has identified some of the important trade offs that should be examined more carefully in future research. These include the impact on hydro operator profits as well as the environmental impact of a change in the intensity of use of other types of power.

There are several directions for further research. First, we could account for uncertainty in demand, water inflow and electricity prices through a stochastic dynamic optimization model assuming these uncertain variables can be modelled as known stochastic processes. Second, more realistic, but sophisticated hydro power production functions could be used and the provision of ancillary services such as spinning reserve to the electricity market could be considered. Finally further efforts are needed to construct a measure of the environmental benefits for the river ecosystem gained by imposing these ramping restrictions.

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Figure 1: *Hydro and Thermal Power Production: Baseline Experiment*

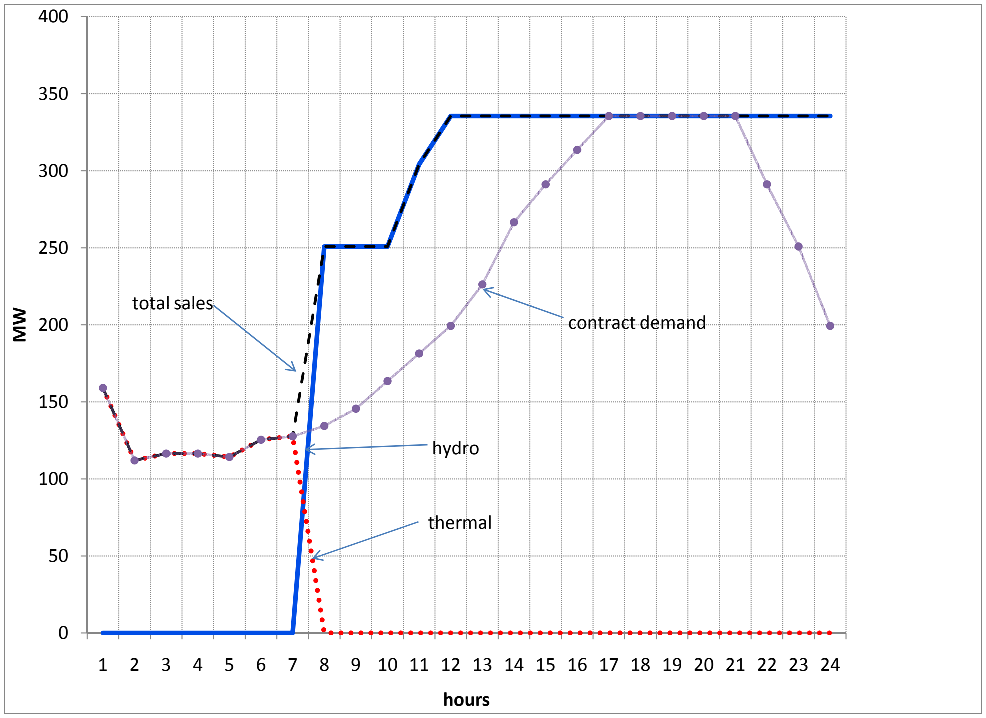

FIGURE 2: *Hydro and Thermal Power Production: Experiment with Minimum and Maximum Release Constraints*

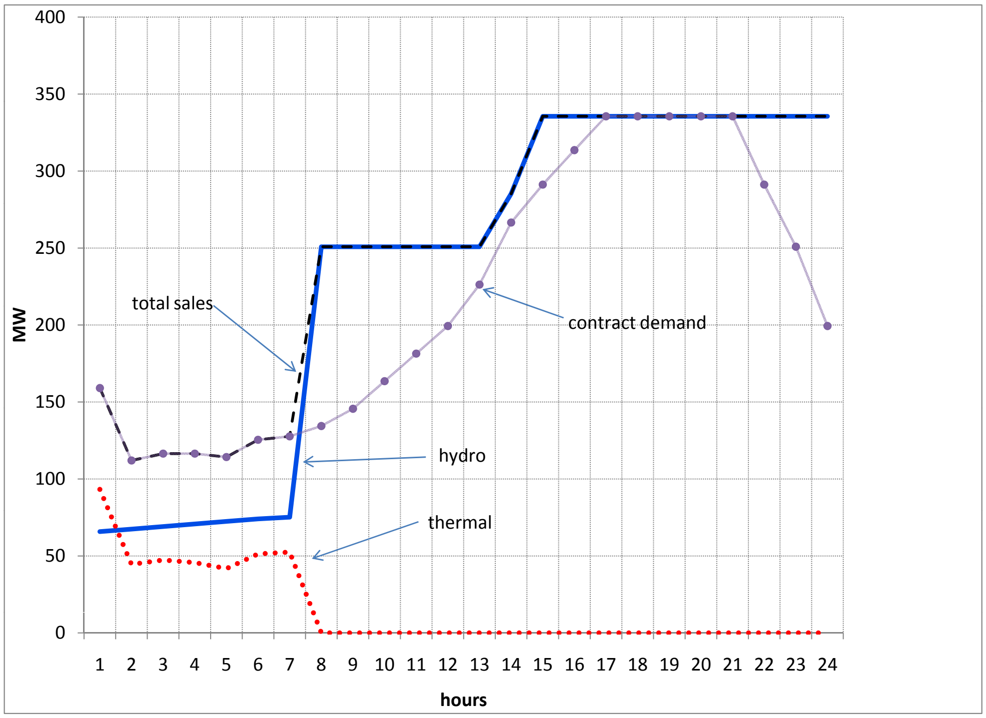

FIGURE 3: *Hydro and Thermal Power Production: Experiment with Up-ramping and Down-ramping Constraints*

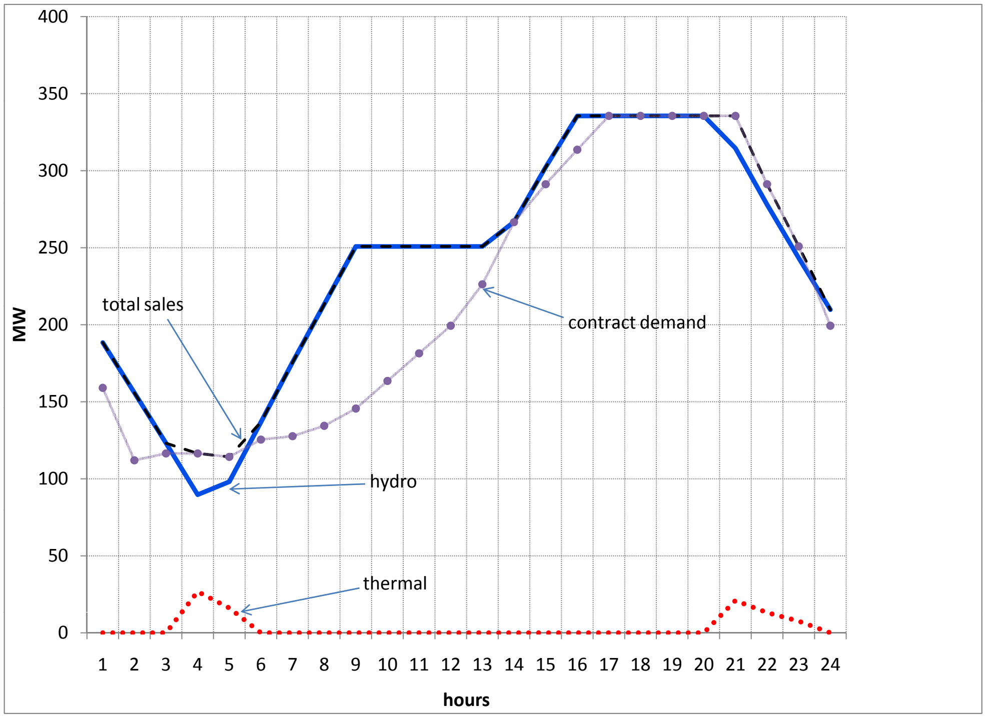

Figure 4: *Comparing Water Release Rates for Hydro Production*

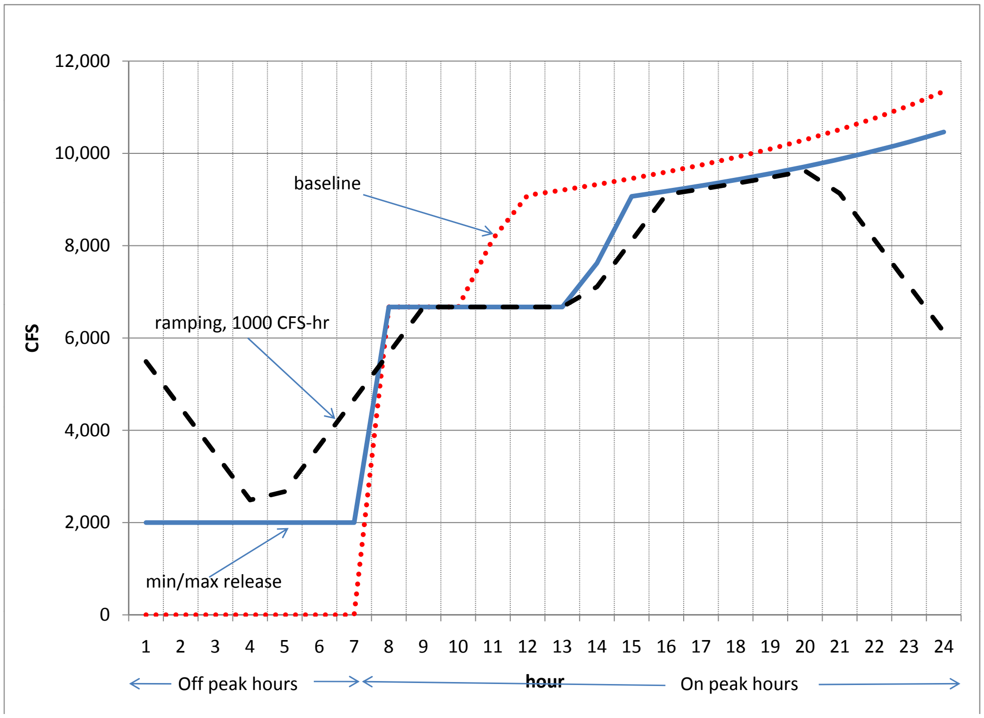

FIGURE 5: *Comparing Profit Levels; Case I is min/max release constraints only; Cases II through VIII include min/max release constraints as well as equal up and down ramping constraints respectively in CFS-hr of 5000, 4000, 3000, 2000, 1000, 500, and 250.*

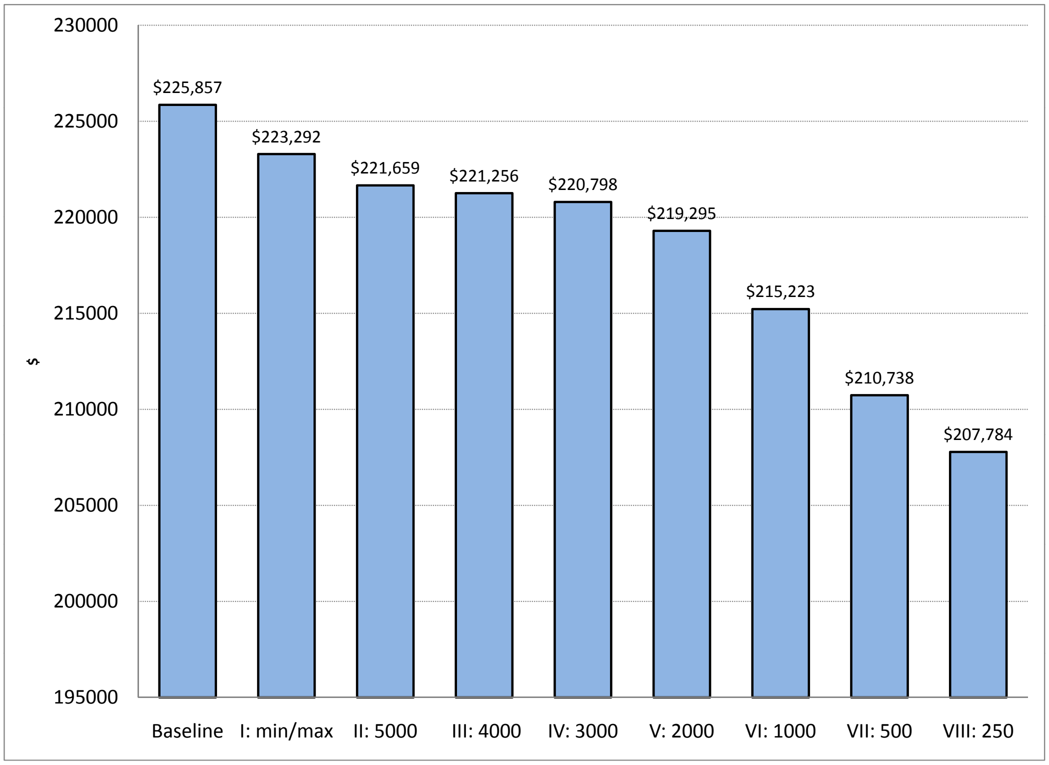

Figure 6: *Comparing Power Production Levels; Case I is min/max release constraints only; Cases II through VIII include min/max release constraints as well as equal up and down ramping constraints respectively in CFS-hr of 5000, 4000, 3000, 2000, 1000, 500, and 250.*

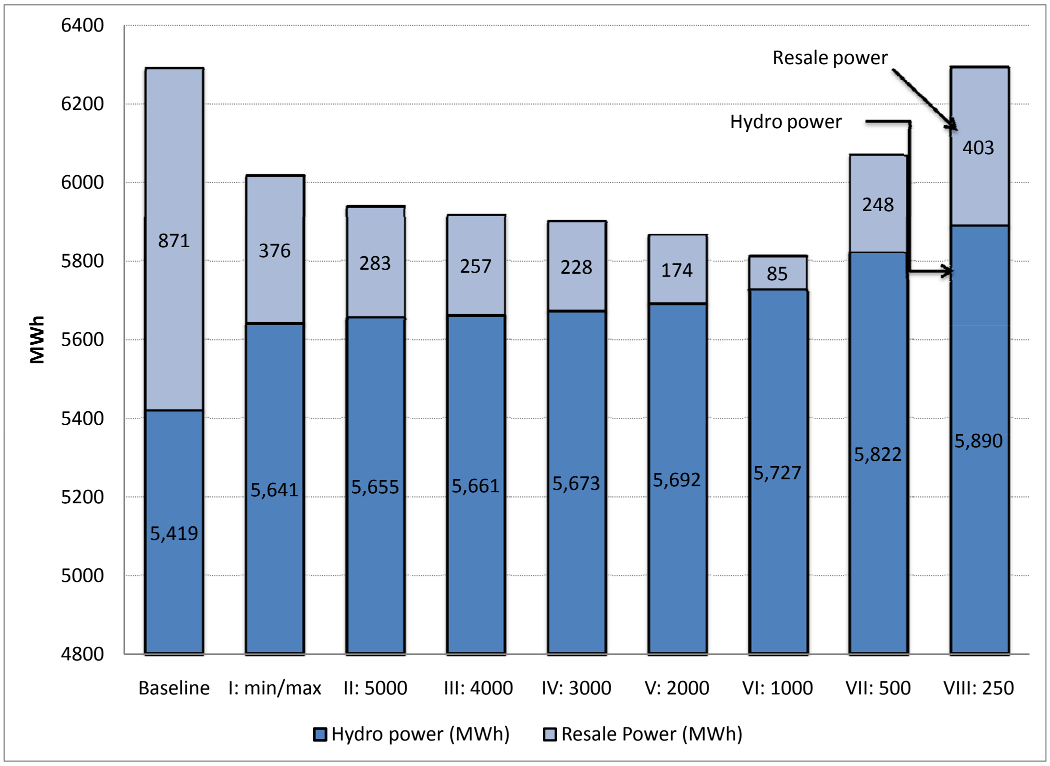

Figure 7: *Comparing Water Content across Cases*

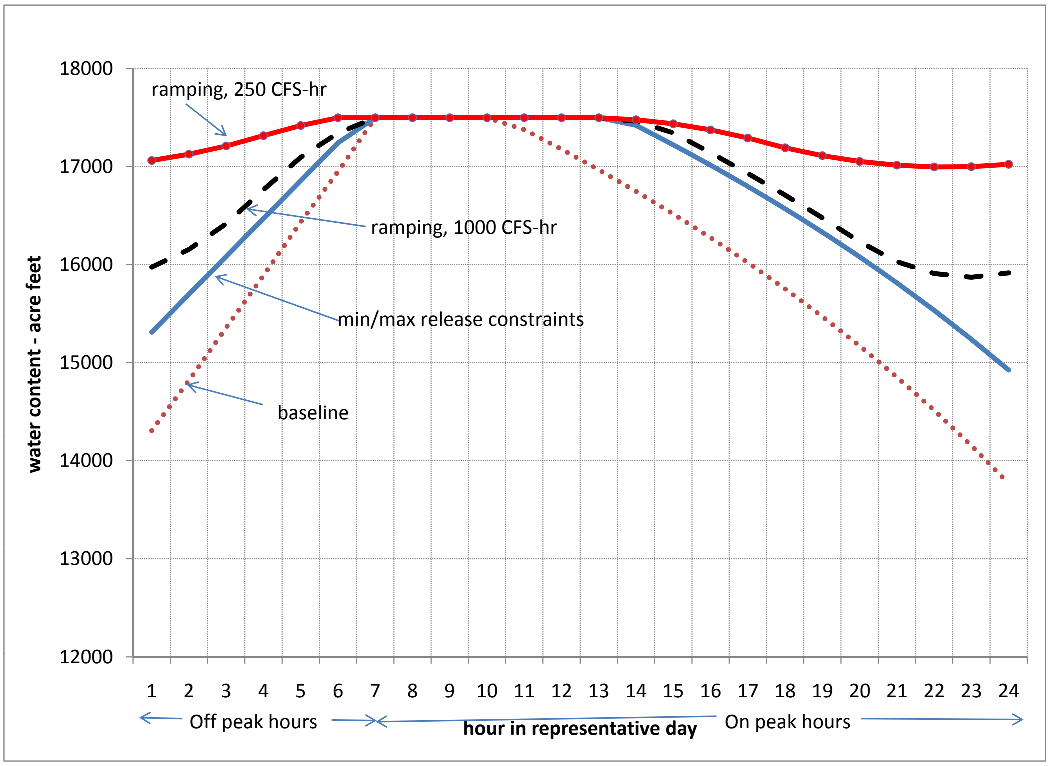

Figure 8: *Net Cost Analysis under Various Equal Levels of Up-ramping and Down-ramping Constraints. 'Benefit' curves show the extra environmental benefit under various levels of ramping rate restrictions using either \$67.18/MWh or \$45.20 as a proxy for the marginal environmental cost of thermal power. 'Cost' refers to the generator's cost (reduction of profit) under various levels of ramping rate restrictions). The 'net cost' curves show the 'cost' minus 'benefit' for the two different estimate of the marginal environmental cost of thermal power.*

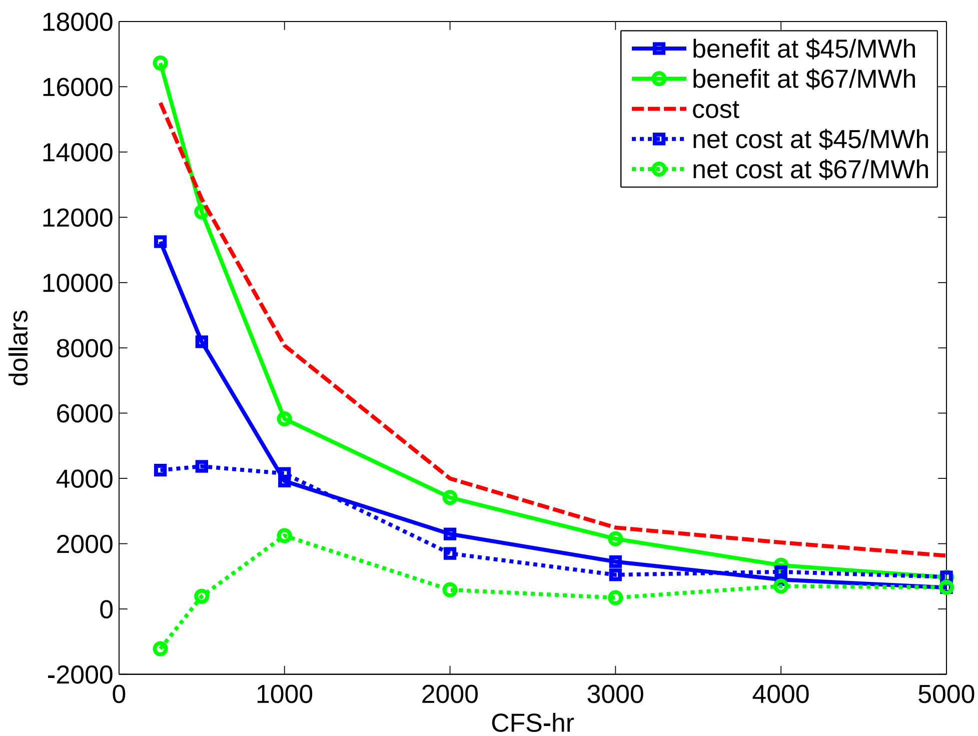

Figure 9: *Net Cost Analysis under Various Equal Levels of Up-ramping and Down-ramping Constraints. 'Benefit' curves show the extra environmental benefit under various levels of ramping rate restrictions using either $67.18/MWh or $45.20 as a proxy for the marginal environmental cost of coal fired power and $9.96/MWh or $7.44/MWh as the marginal environmental cost of natural gas fired power. 'Cost' refers to the generator's cost (reduction of profit) under various levels of ramping rate restrictions). The 'net cost' curves show the 'cost' minus 'benefit' for the two different estimate of the marginal environmental cost of thermal power.*

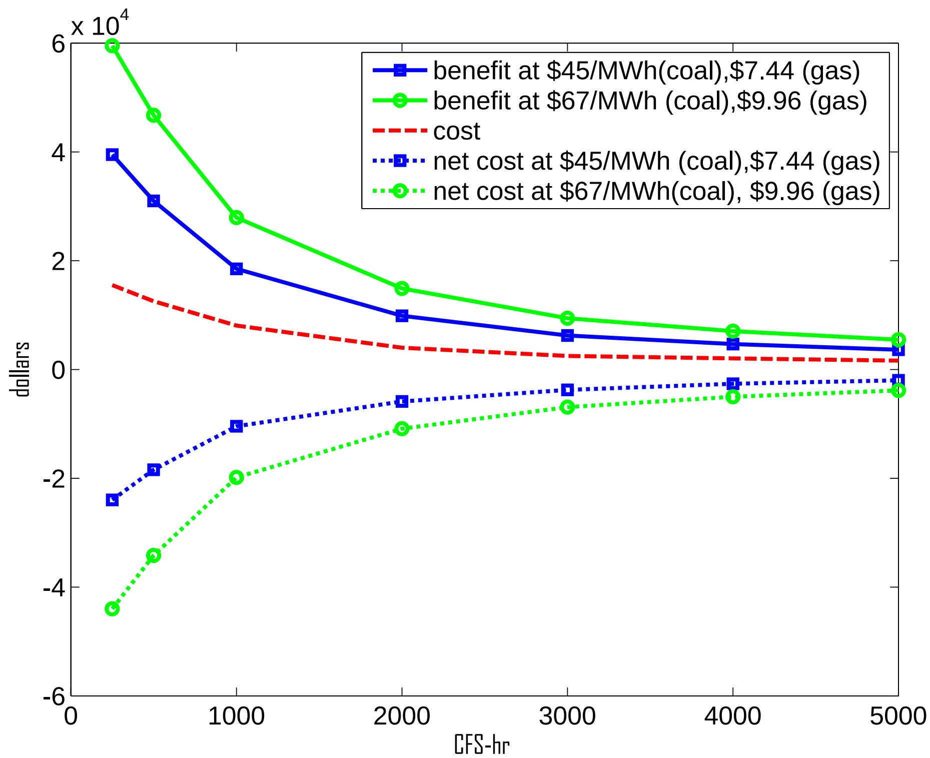

Table 1: *Parameter Values Used in the Empirical Examples*

Hour	Time	Demand (MW)	Water Inflow (CFS)	Price ($/MWh)
0	10pm-11pm	199	6671	62
1st	11pm-12pm	159	6671	36
2nd	12pm-1am	112	6671	36
3rd	1am-2am	116	6671	36
4th	2am-3am	116	6671	36
5th	3am-4am	114	6671	36
6th	4am-5am	125	6671	36
7th	5am-6am	128	6671	36
8th	6am-7am	134	6671	62
9th	7am-8am	146	6671	62
10th	8am-9am	164	6671	62
11th	9am-10am	181	6671	62
12th	10am-11am	199	6671	62
13th	11am-12am	226	6671	62
14th	12am-1pm	267	6671	62
15th	1pm-2pm	291	6671	62
16th	2pm-3pm	314	6671	62
17th	3pm-4pm	336	6671	62
18th	4pm-5pm	336	6671	62
19th	5pm-6pm	336	6671	62
20th	6pm-7pm	336	6671	62
21st	7pm-8pm	336	6671	62
22nd	8pm-9pm	291	6671	62
23rd	9pm-10pm	251	6671	62
24th	10pm-11pm	199	6671	62

Table 2: *Baseline Experiment*

Hour	Time (Hour)	Water Content (Acre-feet)	Spillway (CFS)	Water Release (CFS)	Hydro Generation (MW)	Power Purchase (MW)	Total Power (MW)
0	10pm-11pm	13768	N/A	N/A	N/A	N/A	N/A
1st	11pm-12pm	14307	157	0	0	159	159
2nd	12pm-1am	14817	490	0	0	112	112
3rd	1am-2am	15357	146	0	0	116	116
4th	2am-3am	15888	236	0	0	116	116
5th	3am-4am	16433	85	0	0	114	114
6th	4am-5am	16947	451	0	0	125	125
7th	5am-6am	17497	10	0	0	128	128
8th	6am-7am	17497	0	6671	251	0	251
9th	7am-8am	17497	0	6671	251	0	251
10th	8am-9am	17497	0	6671	251	0	251
11th	9am-10am	17375	0	8147	304	0	304
12th	10am-11am	17175	0	9093	336	0	336
13th	11am-12am	16966	0	9205	336	0	336
14th	12am-1pm	16746	0	9326	336	0	336
15th	1pm-2pm	16516	0	9456	336	0	336
16th	2pm-3pm	16275	0	9596	336	0	336
17th	3pm-4pm	16020	0	9748	336	0	336
18th	4pm-5pm	15752	0	9914	336	0	336
19th	5pm-6pm	15469	0	10095	336	0	336
20th	6pm-7pm	15170	0	10295	336	0	336
21st	7pm-8pm	14853	0	10515	336	0	336
22nd	8pm-9pm	14515	0	10759	336	0	336
23rd	9pm-10pm	14154	0	11033	336	0	336
24th	10pm-11pm	13768	0	11343	336	0	336

Table 3: *Case Including Minimum and Maximum Release Constraints*

Hour	Time (Hour)	Water Content (Acre-feet)	Spillway (CFS)	Water Release (CFS)	Hydro Generation (MW)	Power Purchase (MW)	Total Power (MW)
0	10pm-11pm	14925	N/A	N/A	N/A	N/A	N/A
1st	11pm-12pm	15311	0	2000	66	93	159
2nd	12pm-1am	15697	0	2000	67	45	112
3rd	1am-2am	16083	0	2000	69	47	116
4th	2am-3am	16469	0	2000	71	46	117
5th	3am-4am	16855	0	2000	72	42	114
6th	4am-5am	17241	0	2000	74	51	125
7th	5am-6am	17497	1574	2000	75	52	127
8th	6am-7am	17497	0	6671	251	0	251
9th	7am-8am	17497	0	6671	251	0	251
10th	8am-9am	17497	0	6671	251	0	251
11th	9am-10am	17497	0	6671	251	0	251
12th	10am-11am	17497	0	6671	251	0	251
13th	11am-12am	17497	0	6671	251	0	251
14th	12am-1pm	17419	0	7621	285	0	285
15th	1pm-2pm	17220	0	9069	336	0	336
16th	2pm-3pm	17013	0	9179	336	0	336
17th	3pm-4pm	16796	0	9298	336	0	336
18th	4pm-5pm	16569	0	9426	336	0	336
19th	5pm-6pm	16330	0	9564	336	0	336
20th	6pm-7pm	16078	0	9713	336	0	336
21st	7pm-8pm	15813	0	9876	336	0	336
22nd	8pm-9pm	15534	0	10053	336	0	336
23rd	9pm-10pm	15238	0	10248	336	0	336
24th	10pm-11pm	14925	0	10463	336	0	336

Table 4: *Case Including Up-ramping and Down-ramping Constraints*

Hour	Time (Hour)	Water Content (Acre-feet)	Spillway (CFS)	Water Release (CFS)	Hydro Generation (MW)	Power Purchase (MW)	Total Power (MW)
0	10pm-11pm	15876	N/A	6490	N/A	N/A	N/A
1st	11pm-12pm	15974	0	5490	188	0	188
2nd	12pm-1am	16154	0	4490	156	0	156
3rd	1am-2am	16417	0	3490	123	0	123
4th	2am-3am	16762	0	2490	90	27	117
5th	3am-4am	17093	0	2671	98	16	114
6th	4am-5am	17341	0	3671	137	0	137
7th	5am-6am	17497	108	4671	176	0	176
8th	6am-7am	17497	1000	5671	213	0	213
9th	7am-8am	17497	0	6671	251	0	251
10th	8am-9am	17497	0	6671	251	0	251
11th	9am-10am	17497	0	6671	251	0	251
12th	10am-11am	17497	0	6671	251	0	251
13th	11am-12am	17497	0	6671	251	0	251
14th	12am-1pm	17461	0	7110	267	0	267
15th	1pm-2pm	17342	0	8110	302	0	302
16th	2pm-3pm	17140	0	9110	336	0	336
17th	3pm-4pm	16929	0	9225	336	0	336
18th	4pm-5pm	16708	0	9347	336	0	336
19th	5pm-6pm	16476	0	9478	336	0	336
20th	6pm-7pm	16233	0	9621	336	0	336
21st	7pm-8pm	16029	0	9134	315	21	336
22nd	8pm-9pm	15908	0	8134	278	13	291
23rd	9pm-10pm	15870	0	7134	243	8	251
24th	10pm-11pm	15915	0	6134	210	0	210

Table 5: *Comparing Profits under Various Equal Levels of Up-ramping and Down-ramping Constraints*

Case	Baseline	Max & Min Release Constraints (I)	5000 5000 (CFS-hr) (II)	4000 4000 (CFS-hr) (III)	3000 3000(CFS-hr) (IV)	2000 2000 (CFS-hr) (V)	1000 1000 (CFS-hr) (VI)	500 500 (CFS-hr)(VII)	250 250 (CFS-hr) (VII)
Total Profit ($)	225857	223292	221659	221256	220798	219295	215223	210738	207784
Total Power (MWh)	6290	6017	5938	5918	5901	5866	5812	6070	6293
Hydro Power (MWh)	5419	5641	5655	5661	5673	5692	5727	5822	5890
Resale Power (MWh)	871	376	283	257	228	174	85	248	403
Change of Total Profit (%)	N/A	-1.1	-0.7	-0.2	-0.2	-0.7	-1.9	-2.1	-1.4
Change of Total Profit Compared with (I) (%)	N/A	N/A	-0.7	-0.9	-1.1	-1.8	-3.6	-5.6	-6.9
Change of Total Power Compared with (I) (%)	N/A	N/A	-1.3	-1.7	-1.9	-2.5	-3.4	0.9	4.6
Change of Hydro Power Compared with (I) (%)	N/A	N/A	0.3	0.4	0.6	0.9	1.5	3.2	4.4
Change of Resale Power Compared with (I) (%)	N/A	N/A	-24.8	-31.8	-39.5	-53.7	-77.5	-34.1	7.1

Notes

[1]Thermal units, especially large and efficient units, frequently have the most significant ramp limits in the system (Svoboda et al. (1997)). In this paper, we only consider the ramping issue for hydro units.

[2]The head refers to the difference in height between a dam's water source and water outflow.

[3]See Bensalem et al. (2007) for example.

[4]In this model we do not explicitly include a constraint on the maximum daily change in water flow. Normally, up-ramping and down-ramping are believed to have more a severe effect on the environment compared with fluctuations in daily flow. Since our main focus is on the ramping rate, we assume the allowable fluctuations in daily flow are large enough that our optimization results are not affected.

[5]The more realistic hydro power production function is not continuous, but our simplified assumptions still allow a good approximation of the actual function (see Harpman (1999)). It should be pointed out that for any specific dam, to apply this production function, both the water release rate and water head should be within certain limits as described in equations (6) and (8)-(9). Normally, the upper and lower limit will be different for various dams.

[6]This water balance equation differs from the one in Edwards et al. (1999) by the inclusion of spill flows.

[7]In general the desired ramping restrictions my vary over the hours in a day, and over months and seasons as well. In this paper we assume fixed ramping constraints.

[8]Using Matlab's optimization tool fmincon.

[9]For example, see *http://www.opg.com/power/* and *http://www.opg.com/power/hydro/northeast_plant_group/abitibi.asp*.

[10]Hendry and Chang (2001) investigated the composition and structure of fish communities, and habitat features in the Abitibi Canyon generating station tailwater. Further information about the Abitibi Station is available in their study.

[11]This daily average excludes the months of April and May which are atypical with water inflows significantly higher than the rest of the year.

[12]One CFS for 1 hour converts to approximated 0.082646 acre-feet. Converting the water inflow in each hour in Table 1 and adding over the 24 hour period gives 13,232 acre-feet as the total inflow.

[13]An initial water release rate of 7000 CFS is used in all cases. An initial water content of 14,000 acre-feet is used for the cases without ramping rate restrictions, while 17,000 acre-feet is used for the cases with ramping rate restriction.

[14]In Kotchen et al. (2006), they assume that the thermal (replacement) power during peak periods is generated with fuel oil and natural gas, while thermal power during off-peak periods is generated with coal only.

[15]These estimates are first calculated based on the coal generation plant's marginal external costs (MEC) in the US in 2004 (Dewees (2008)). We use the Michigan MEC at 34.77 $US/MWh (low MEC scenario), and the Ohio MEC at 51.68 $US/MWh (high MEC scenario). Then these values are converted to Canadian dollars at the 2004 exchange rate of 1.3 $CAD/$US. Natural gas emissions and external costs for gas-fired power plants are much lower than those of coal. The gas-fired power plant's marginal external cost is 5.72 $US/MWh for Michigan (low MEC scenario) and 7.66 $US/MWh for Indiana (high MEC scenario).