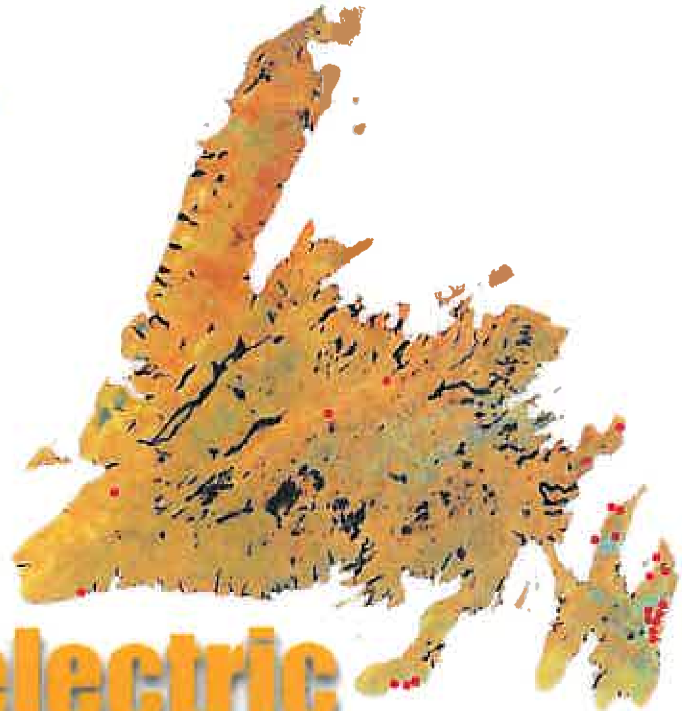
Raise Sandy Lake Spillway, p. 8 of 96, $612,000

Q. Please provide a copy of the 2001 review completed by Hatch (formerly SGE Acres) of NP's larger hydroelectric developments to identify potential opportunities for increasing generation.

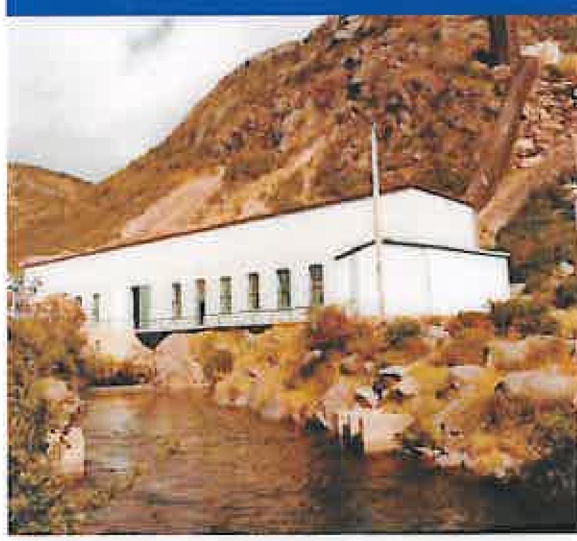
A. Attachment A provides a copy of the 2001 review completed by Hatch.

Attachment A
Hydroelectric Systems Strategic Planning Study
January 2001

NEWFOUNDLAND POWER
A FORTIS COMPANY



Hydroelectric Systems Strategic Planning Study



January 2001

Acres International

NEWFOUNDLAND POWER
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Hydroelectric Systems Strategic Planning Study

January 2001

Acres International

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Executive Summary

Executive Summary

Newfoundland Power (NP) owns and operates 19 hydroelectric generating systems on the Island of Newfoundland. These stations have a total installed capacity of 94 megawatts (MW) with turbine-generator units ranging in size from approximately 250 kW to 12 000 kW. NP's hydroelectric resources make up approximately nine percent of its total requirements for energy; the balance is purchased from Newfoundland and Labrador Hydro.

In December 2000, Acres International completed a Water Management Study for NP to provide an estimate of the normal production of NP's hydroelectric system. As a follow up to that study, Acres completed a review of NP's larger hydroelectric systems to identify potential opportunities for increasing energy generation through operational or physical changes.

The review was undertaken using the computer simulation models set up for the Water Management Study to test various physical and operational changes to the systems. The results of the modelling were compared to the long term production estimated in the Water Management Study to determine if the changes resulted in significant increases in energy. Additional scenarios were modelled to provide NP with information on the cost or value of certain aspects of each system, for instance the value of maintaining storage reservoirs.

This study was intended to identify potential opportunities for increasing energy generation, rather than to design the required operational or physical modifications. The study provides NP with a list of projects at each system which are worth further investigation.

The potential for increasing energy generation by improved application of the existing plant operating guidelines for each system was assessed by a detailed examination of the results of the simulations undertaken to estimate the long term production of the systems. The model operates the system in an ideal manner; comparison of that ideal operation to actual operation indicates where improvements can be made. At most of NP's systems, a review of the application of the plant operating guidelines is recommended.

The potential for increasing energy generation by altering the existing plant operating guidelines or making physical changes to the system was assessed by additional simulations using different operating strategies and revised physical characteristics.

Adjustments to target reservoir water levels and changes to triggers for unit operation at higher than best efficiency loads were considered. The physical improvements considered included dam raising, control gate automation and penstock replacement. At many systems, the results of the review showed that operation using the existing plant operating guidelines leads to near optimum energy generation. For some of NP's systems, a list of physical changes that appear to be cost effective is provided for further study.

Sensitivity simulations were undertaken to estimate the cost of constraints on the systems, for instance water level constraints for recreation, and the value of controlled storage, again using the simulation models.

Introduction

1 Introduction

In June, 2000 Newfoundland Power (NP) engaged the services of Acres International to identify potential opportunities for increasing energy generation at NP's larger hydroelectric systems through operational or physical changes. This report documents the analysis required and presents the results of the study.

NP owns and operates 23 small hydroelectric generating stations in 19 systems throughout Newfoundland. These stations have a total installed capacity of 94 megawatts (MW) with turbine-generator units ranging in size from approximately 250 kW to 12 000 kW. Over 60 percent of the generation is located on the Avalon Peninsula, with the oldest development in the system being Petty Harbour, commissioned in 1900, and the newest being Rose Blanche Brook, commissioned in 1998. Key information for each of the systems is summarized in Table 1.1. The first 12 systems listed in this table were assessed to determine whether there is potential for increasing energy generation through operational or physical changes. The nameplate capacities provided in this table have been adjusted for unit upgrades since initial commissioning and for known unit limitations. Figure 1.1 shows the locations of the stations.

The approach to the analysis was to use the simulation models set up for the Water Management Study - December 2000, conducted by Acres for NP to estimate the long term production for each system. Physical and operational changes to the system were tested using these model setups and the energy results were compared to the long term production as estimated in the Water Management Study. The sensitivity of energy generation to other operating changes and constraints that may not necessarily lead to additional energy generation was also investigated to provide NP with information on the cost or value of certain aspects of its systems.

Chapter 2 of this report describes the methodology, and Chapters 3 to 14 describe the analysis for the 12 individual hydroelectric systems and provide conclusions and recommendations specific to each system. General conclusions and recommendations are provided in Chapter 15.

Table 1.1
Hydroelectric Systems Data

Plant	Nameplate Capacity (MW)	Net Head (m)
Horsechops / Cape Broyle	-	-
- Horsechops	8.3	84.1
- Cape Broyle	6.3	54.8
Rattling Brook	15.1	87.8
Morris / Mobile	-	-
- Morris	1.1	30.0
- Mobile	12.0	114.6
Rocky Pond / Tors Cove	-	-
- Rocky Pond	3.3	32.6
- Tors Cove	6.9	52.7
Lookout Brook	6.2	154.5
Sandy Brook	5.5	33.5
Pierres Brook	4.3	76.0
Rose Blanche Brook	6.0	114.2
Petty Harbour	5.3	57.9
New Chelsea / Pitmans	-	-
- New Chelsea	3.7	83.8
- Pitmans	0.6	21.3
Seal Cove	3.5	55.5
Topsail	2.6	85.5
Hearts Content	2.7	46.9
Lockston	3.0	82.2
Victoria	0.5	64.3
West Brook	0.7	47.0
Port Union	0.5	21.3
Lawn	0.7	24.3
Fall Pond	0.4	15.2

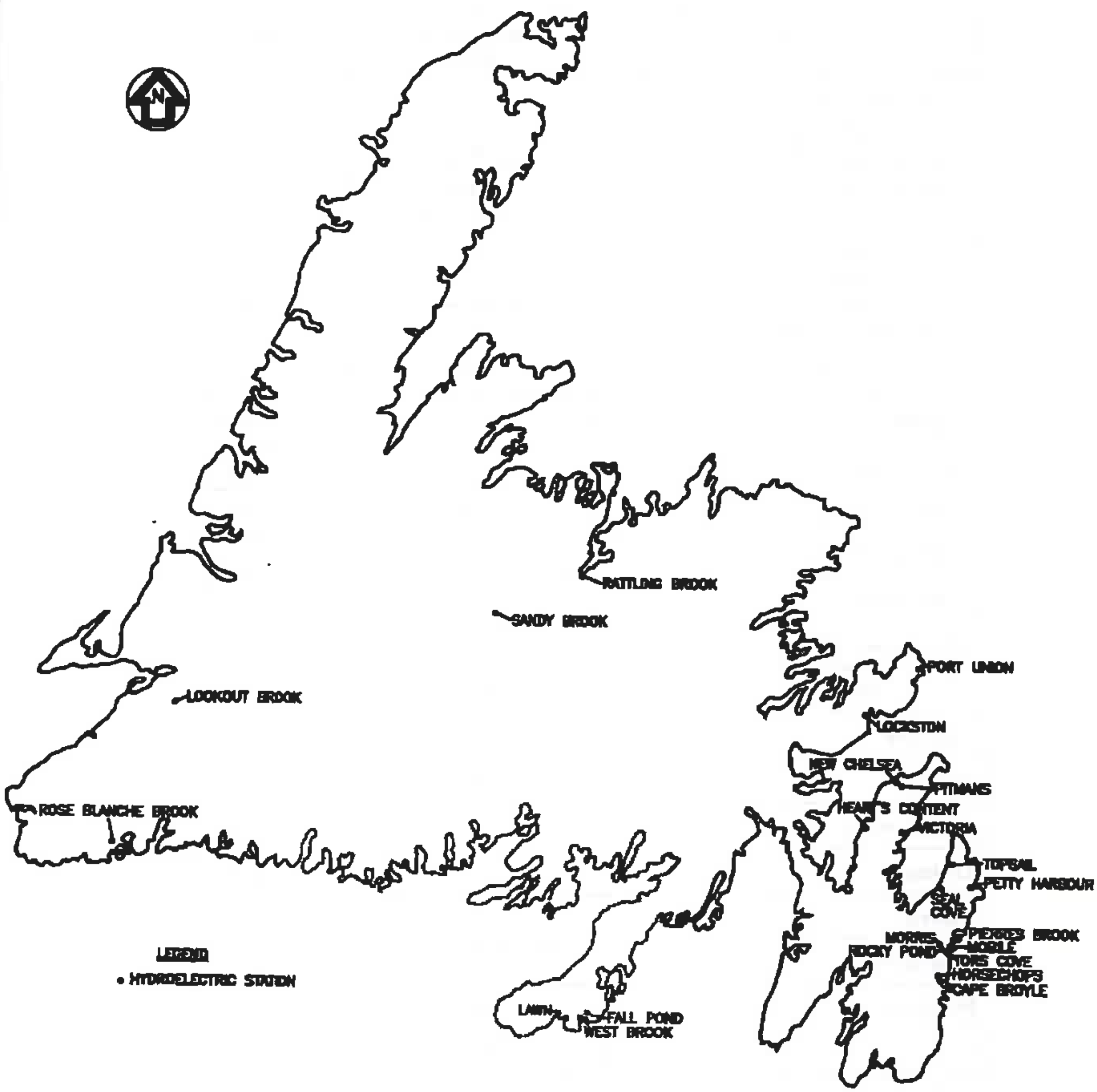


FIG. 1.1

NEWFOUNDLAND POWER
HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY
HYDROELECTRIC SYSTEMS LOCATION

ACRES

Methodology

2 Methodology

Simulation models set up for the Water Management Study to estimate the long term production for each system were used in the current analysis to determine whether there is potential for increasing energy generation by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

The sensitivity of energy generation to operating changes and constraints that may not necessarily lead to additional energy generation was also investigated to provide NP with information on the cost or value of certain aspects of its systems.

The following sections describe the methodology used in assessing the effects operational and physical changes to each system have on energy generation.

2.1 Ideal Operation of System

The operating strategy used for the simulation models was based on current plant operating guidelines for each system. For some systems, the plant operating guidelines provided for a range of operating practices, or did not include all operating practices observed in a particular system, and some interpretation was required to devise an operating strategy for the simulation model. The model assumes perfect operation of units and reservoirs according to the specified operating procedures. The two most important operating assumptions are as follows.

- Ideal operation of the unit(s): In the model, the unit or units always operate exactly at the most efficient load, unless there is excess water, in which case they operate at maximum capacity.
- Ideal operation of reservoirs and control gates to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels in all reservoirs, and opens or closes gates as required to ensure perfect operation of the units and to minimize spill.

In practice, it is difficult, if not impossible, to achieve perfect implementation of the plant operating guidelines. For this reason, and assuming that the model input strategy adequately represents the plant operating guidelines, the simulated generation is generally expected to be greater than recorded generation.

The reasons for deviating from the plant operating guidelines may be beyond the control of plant operations staff. For instance, grid requirements (local power outages, voltage support, etc.) and equipment failure may force a system to operate in a less than ideal manner. However, some component of the difference between simulated and recorded production may be due to controllable difficulties in implementing the guidelines. These difficulties include

- insufficient resources to operate gates and adjust unit loads as frequently as simulated;
- inability to operate gates and controls due to weather, accessibility, or other factors;
- inadequate training or knowledge of operations staff; and
- operator error.

The simulation models do not provide an absolute way of comparing actual and ideal operation. However, certain representative operating measures and plots may be analyzed using system characteristics and simulation results in order to draw conclusions about the sensitivity of system generation to less than ideal operation. These measures and plots are as follows.

1. Flow Utilization Factor
2. Energy Conversion Factor
3. Flow Duration Curve
4. Energy Potential of Spill
5. Reservoir Storage Factor
6. Reservoir Utilization Plot
7. Forebay Storage Factor
8. Gate Operation Plot

These measures and plots are provided for each system where relevant and are used in each system chapter to investigate the opportunities for improving production by operating the system ideally through revised plant operating guidelines, gate/reservoir operation, and unit operation. A brief explanation of each measure and plot is as follows.

1. Flow Utilization Factor

For each station, the flow utilization factors were calculated by dividing the average inflow to the station subbasin by the maximum flow capacity and the most efficient flow of the unit(s). The flow utilization factor provides a practical indication of the design flow capacity within the system. Flow capacity makes the system less reliant on storage to prevent peak inflows from being spilled and enables operators to compensate for operational problems that reduce unit availability.

2. Energy Conversion Factor

For each unit, the energy conversion factor (the ideal average value of water in storage assuming the units are operating alone) was calculated by dividing the maximum and most efficient load converted to energy by the maximum and most efficient flow of the units. For a station with multiple units, the energy conversion factors provide a means of determining the best unit dispatch order. Following the best unit dispatch order ensures that units with higher efficiencies are being operated before those with lower efficiencies and leads to higher energy production.

3. Flow Duration Curve

The flow duration curves presented in this report indicate the percent of time that a given flow is either equalled or exceeded by the power flow of a unit. These curves indicate the percent of time the units are operating at the maximum and most efficient load. These curves provide an indication of the possibility of reducing the amount of time that the units are generating at maximum load. This change in operation would lead to increased energy generation.

4. Energy Potential of Spill

For each system, the energy potential of spill was calculated by multiplying the average energy conversion factors of the units at maximum load by the average simulated spill flow out of the system. This value represents the maximum energy that can be gained from capturing all the spill through operating changes or physical changes to the system.

5. Reservoir Storage Factor

For reservoirs, the storage factor was calculated by dividing the available storage volume by the average inflow to the reservoir subbasin. The result is expressed in days, and represents the average number of days of inflow that the reservoir can store. Storage capacity allows operators to manage inflows so that they better match the flow characteristics of the unit(s), and makes deviations from the operating guidelines less significant in terms of the corresponding impact on production.

Conversely, the less the storage, the more sensitive production is to such deviations; in such systems, inflow forecasting may be especially useful in optimizing actual operation.

6. Reservoir Utilization Plot

For all significant storage reservoirs, summary plots of simulated daily reservoir water levels were prepared to illustrate reservoir utilization. The plots show the general pattern of water level changes and variability in levels from year to year. Reservoir utilization is an important issue to consider for systems with both significant spill flows and substantial storage, to determine whether the spill can be reduced through better use of the storage.

7. Forebay Storage Factor

For each forebay, the forebay storage factor was calculated by dividing the available storage volume by the maximum flow capacity of the station. A forebay that has storage capacity for at least one day at maximum flow should be capable of buffering the station against variations in forebay inflows. A forebay that has less than one day's storage capacity may still be capable of accomplishing this buffering, but this will depend on the range of inflows expected and/or the ability to cycle (start/stop) the unit more than once each day. Forebay water level fluctuations within each day cannot be modelled using a daily time-step, and the accuracy of the model assumption that a unit operates only at best efficiency load or higher depends in part on the type of controls available and the availability of adequate forebay storage.

8. Gate Operation

To keep gate discharge constant while a reservoir level fluctuates, the gate opening must be adjusted; the frequency depends on rate of change of water level in the reservoir. Simulated reservoir gate openings are adjusted daily within the model. However, in actual operation, it may be impractical to make adjustments with such frequency. The degree to which this affects the difference between actual and ideal production depends upon

- frequency of actual gate adjustments;
- appropriateness of actual gate settings;
- available storage downstream of the reservoir/gate in question;
- efficiency of downstream generating unit(s) when operating at inefficient flows, due to inadequate or excessive gate openings; and
- ability to control unit(s) to keep up with gate adjustments (i.e., starting and stopping frequently).

To assess how frequently gates would have to be adjusted to approximate ideal conditions, the simulated daily gate discharges for each reservoir were plotted for selected periods, along with the corresponding reservoir levels and fully open gate capacities. The plot also indicates the flexibility afforded to operations staff in setting appropriate gate positions.

2.2 Changes to Operating Guidelines

The simulation results for each system were examined to identify opportunities to increase production by changing the current plant operating guidelines. The effect on production was estimated by rerunning the simulation model, with changes in the input operating strategy to reflect the new guidelines.

Changes to the current plant operating guidelines may lead to increased production through three principal methods

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

To some extent, the effects of each method can work against each other, so maximizing production depends on achieving a balance among the three. A general description of each method is provided below.

Increasing Head
Maintaining a higher forebay level may increase generation by increasing net head on the unit. The tradeoff is in the increased risk of spill due to reduced storage. As well, if the forebay level affects the tailwater elevation of an upstream generating station, that station may actually experience decreased generation because its net head is decreased.

Spill Avoidance
Spill avoidance is the reduction or elimination of spilled inflows, both in frequency and volume, thereby increasing flow used for generation. Ideally, there would be sufficient storage capacity in a system to store all inflows greater than the most efficient flow of the units, such that no inflows would be spilled. In practice, this is rarely possible. If there is not enough storage capacity, spill may be avoided by generating at maximum flow. This may be necessary, for example, when storage

reservoirs approach their full levels, or at certain times of the year to draw down reservoir levels in anticipation of large inflows. But this means that spill will be avoided at the expense of reduced efficiency. Although more water will be turbined, the energy value per unit of water will be reduced. If there is a large difference between the best efficiency and the efficiency at maximum flow, much of the benefit of spill avoidance may be lost.

The limiting case for spill avoidance is keeping the reservoirs low and operating the units at maximum load. The result of this simulation will provide the maximum possible decrease in spill through spill avoidance, but will probably yield a lower overall energy due to generating at lower efficiencies.

Maximizing Efficient Production

Generating at the most efficient flow maximizes the energy value of the water. The operator can take advantage of any available storage to ensure that the unit is run as often as possible at best efficiency. Reservoir control gates may be operated to supply units with only enough flow to operate at best efficiency, while storing the rest.

The limiting case for maximizing efficient production is keeping the reservoirs high and only operating at maximum load to avoid spill. The result of this simulation will be the maximum possible efficient production limits, but higher spills than in the spill avoidance case because of delay in operating at maximum load until the reservoirs are about to spill. The optimum solution is operating the unit(s) at maximum load at some water level between full supply level and low supply level. The results of these two simulations should provide an indication of the gains in energy production, if any, of fine-tuning this threshold value.

2.3 Physical Changes to System

The simulation results of each system were examined to identify opportunities to increase production through physical improvements in system components. The effect on production was estimated by rerunning the simulation model, with changes in the model setup to include the physical improvements. Only those improvements deemed plausible for each system were investigated. A preliminary assessment of the cost effectiveness of each physical improvement was also made. Possible physical improvements are described below.

Reservoir Storage Capacity

Increasing the storage capacity of reservoirs would be most beneficial in systems with a significant amount of spill. Costs of increasing storage capacity could include modifying existing structures, such as increasing dam heights and spillway elevations, or constructing new ones. By comparing the simulated production of an existing system and the system with expanded storage, the incremental value of the storage may be estimated.

Reservoir Discharge Capacity

In some systems, gate or canal capacity may be inadequate to provide units with the required power flow, especially at low reservoir levels, or to convey water to downstream storage or generating units so as to avoid spilling out of the system. Costs of increasing reservoir discharge capacity could include enlargement of gates or excavation of canal sections.

Unit Efficiency and Head Losses

Generating units, especially in old systems, may undergo rehabilitation (such as turbine replacement) to increase their efficiency. Repairs to or replacement of flow conveyance structures such as intakes, penstocks, and tailraces may improve hydraulic characteristics and reduce head losses.

2.4 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of these systems. These may include

- environmental release requirements;
- total system storage;
- changes to gate operation;
- reservoir water level constraints; and
- consumption demands.

Environmental Release Requirement

Regulatory authorities may impose a minimum flow requirement for fisheries habitat reasons to prevent reaches below gated outlets from running dry in periods of low inflows or when control gates are closed. At present in NP systems, a minimum flow is informally maintained for fish habitat by ensuring that control gates are never closed completely (typically open a minimum of one inch). A commonly used standard that has been imposed in other water resources developments is to maintain a minimum flow equal to 30 percent of the mean annual flow. If this requirement were imposed on NP systems, it could affect the use of storage in reservoirs that could be completely emptied during the year. At such reservoirs, maintaining this flow may require a minimum amount of water to be left in storage, to be released only to satisfy the fisheries requirement and not for generation. This would reduce the amount of live storage available for hydroelectric purposes.

System Storage

Most of NP's systems include storage reservoirs to regulate and store flows for generation at a later time. The value of this storage can be determined by running the simulation models assuming there is no storage in the system. This information could be useful to NP for determining which systems rely heavily on storage for energy generation and those that do not. It could be that the cost of maintaining some of the dams for storage is more than the value of energy that is produced from the storage.

Changes to Gate Operation

The simulation model assumes ideal (automatic) operation of the gates and reservoirs in the system. The value of energy from no operation (leave gate open) to partial (seasonal) operation would be useful in assessing the cost effectiveness of automating the systems.

Reservoir Water Level Constraints

Water level constraints can be imposed by other users of the water resource, for example, recreational users, cabin owners on the reservoir shoreline, or municipal water supply systems. These constraints may affect operational flexibility and have consequences such as reduction of useable live storage, increased spill and reduced power flows.

Consumptive Demands

In some systems, water is withdrawn for purposes such as municipal water supply or fish plant operation. The result is less water available for generation. The cost in energy can be significant and may increase over the long term, as in the case of serving the water supply demands of a growing population centre. In addition, sufficient water must be maintained in storage reservoirs to service these demands even during droughts. This again reduces the live storage available to regulate power flows.

Horsechops/Cape Broyle

3 Horsechops/Cape Broyle Hydroelectric System

The Horsechops/Cape Broyle Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Horsechops/Cape Broyle system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Horsechops/Cape Broyle system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Horsechops/Cape Broyle system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

3.1 System Description

The Horsechops/Cape Broyle system is located on the southern shore of the Avalon Peninsula in eastern Newfoundland. The system has two generating stations, Horsechops and Cape Broyle, both commissioned in 1953. The Horsechops Generating Station contains one generating unit with a nameplate capacity of 8.3 MW and a rated net head of 84.1 m. The drainage area above the intake of the station is approximately 155 km^2. The Cape Broyle Generating Station contains one generating unit with a nameplate capacity of 6.3 MW and a rated net head of 54.8 m. The total drainage area above the intake of the station is approximately 191 km^2. Storage is provided by structures at the Blackwoods Ponds (Northwest Blackwoods Pond, East Blackwoods Pond, and Fourth Blackwoods Pond), Mount Carmel Pond, Horsechops Forebay and Cape Broyle Forebay. A schematic of the system is presented in Figure 3.1.

The upper part of the basin is a plateau with numerous small streams, ponds and bogs. Inflows in this area are diverted by structures located at Ragged Hills Pond, Rock Pond and the Blackwoods Ponds, and are either stored or spilled out of the system. Water stored in the Blackwoods Ponds is conveyed through the Fourth Blackwoods Pond Canal and a series of small lakes to Mount Carmel Pond, the main storage reservoir for the system. Controlled releases and spill from Mount Carmel Pond are both discharged into Horsechops Forebay, and are used for generation or spilled. Power flows and spill from Horsechops Forebay enter Cape Broyle Forebay and are used for generation or spilled out of the system.

The structures in the system are as follows

- West Ragged Hills overflow spillway;
- Northwest Blackwoods Pond overflow spillway;
- East Blackwoods Pond overflow spillway;
- Fourth Blackwoods Pond overflow spillway;
- Fourth Blackwoods Pond Canal;
- Mount Carmel Pond overflow spillway;
- Mount Carmel Pond gated outlet;
- Horsechops Forebay overflow spillway; and
- Cape Broyle Forebay overflow spillway.

All spillways except the Mount Carmel Pond and Horsechops Forebay spillways discharge out of the system.

3.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are described in Chapter 2. The measures as calculated for the Horsechops/Cape Broyle system are provided below. They were developed from the data in the base case simulation. Table 3.1 at the end of this section summarizes the measures for the Horsechops/Cape Broyle system.

1. Flow Utilization Factor

The flow utilization factors (average inflow to forebay divided by flow capacity at most efficient load and maximum load) for the Horsechops station are 0.80 at most efficient load and 0.66 at maximum load. For the Cape Broyle station, the factors are 0.84 at most efficient load and 0.68 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage assuming the units are operating alone) for the Horsechops station are 0.21 kWh/m^3 (6.70 $GWh/yr/m^3/s$) at most efficient load and 0.20 kWh/m^3 (6.26 $GWh/yr/m^3/s$) at maximum load. For the Cape Broyle station, the factors are 0.13 kWh/m^3 (4.03 $GWh/yr/m^3/s$) at most efficient load and 0.13 kWh/m^3 (3.96 $GWh/yr/m^3/s$) at maximum load.

The average energy conversion factors from the base case simulation for the Horsechops and Cape Broyle stations are 0.21 kWh/m^3 (6.68 $GWh/yr/m^3/s$) and 0.13 kWh/m^3 (4.02 $GWh/yr/m^3/s$), respectively. These energy conversion factors take into account the average reduction in availability due to forced outages.

3. Flow Duration Curve

The Horsechops and Cape Broyle flow duration curves for the turbine flow (power flow) in the base case simulation are shown in Figure 3.2. The Horsechops unit is always operated at most efficient load, although sometimes only for part of the day, depending on inflows. The Cape Broyle unit is operated at maximum load about

25 percent of the time, but is otherwise operated at most efficient load for part of each day, depending on outflows from Horsechops, as well as local inflows.

4. Energy Potential of Spill

The monthly distribution of the simulated spill out of the Horsechops/Cape Broyle system over 15 years for the base case simulation is shown in Figure 3.3, for the Blackwoods Ponds and Cape Broyle Forebay.

The simulated annual average spill for the base case was approximately 0.21 m^3/s at the Blackwoods Ponds. Using the simulated energy conversion factors at maximum load presented previously in this section, the spill would produce approximately 2.1 GWh/yr, if entirely saved and used for generation at both stations. At Cape Broyle Forebay, the simulated spill was infrequent, with an annual average of 0.01 m^3/s, equivalent to less than 0.1 GWh/yr at maximum load at Cape Broyle. There was no simulated spill at Horsechops Forebay. There was also no simulated spill at Mount Carmel Pond, although any such spill would remain within the system and be discharged to Horsechops Forebay.

5. Reservoir Storage Factor

The main system storage is provided by Mount Carmel Pond. The reservoir storage factor (the number of days to fill the reservoir without any outflow) was calculated to be approximately 100 days. The Blackwoods Ponds have a reservoir storage factor of about 20 days. Horsechops and Cape Broyle Forebays have reservoir storage ratios of one and five days, respectively.

6. Reservoir Utilization Plot

The plot of simulated Blackwoods Ponds and Mount Carmel Pond reservoir levels for the base case simulation is provided in Figure 3.4. The plot illustrates the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with the unit operating at maximum load) of Horsechops Forebay is estimated to be approximately one day. The forebay storage factor of Cape Broyle Forebay is approximately three days.

8. **Gate Operation**

Provided in Figure 3.5 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1987) for Mount Carmel Pond. This plot illustrates the frequency the gate is being operated in the simulation model to maintain most efficient load at Horsechops while avoiding spill at either station downstream.

Table 3.1
Horsechops/Cape Broyle System Representative Operating Measures

Horsechops/Cape Broyle Representative Operating Measures	
Flow Utilization Factors - Horsechops Most Efficient Load - Horsechops Maximum Load - Cape Broyle Most Efficient Load - Cape Broyle Maximum Load	 0.80 0.66 0.84 0.68
Station Factors - Horsechops Most Efficient Load - Horsechops Maximum Load - Cape Broyle Most Efficient Load - Cape Broyle Maximum Load	 0.21 kWh/m^3 0.20 kWh/m^3 0.13 kWh/m^3 0.13 kWh/m^3
Energy Potential of Spill - Blackwoods Ponds Spill - Cape Broyle Spill	 2.1 GWh/yr <0.1 GWh/yr
Reservoir Storage Factors - Blackwoods Ponds - Mount Carmel Pond - Horsechops Forebay - Cape Broyle Forebay	 20 days 100 days 1 day 5 days
Forebay Storage Factor - Horsechops Forebay - Cape Broyle Forebay	 1 day 3 days

3.3 Ideal Operation of System

The long term energy production for the Horsechops/Cape Broyle system as estimated by the simulation model developed for the Water Management Study is 89.1 GWh/yr (51.0 GWh/yr at Horsechops, 38.1 GWh/yr at Cape Broyle). This compares with recorded energy generation for the same reference period (1984-98) of 75.3 GWh/yr (41.4 GWh/yr at Horsechops, 33.9 GWh/yr at Cape Broyle). While these numbers are not directly comparable due to the upgrade of Horsechops unit in 1997, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately 15 percent for this system. The comparison would therefore suggest that there is substantial opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce the difference between the simulated ideal operation and actual operation at the Horsechops/Cape Broyle system.

3.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Horsechops/Cape Broyle system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plants will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows.

The interpretation used in the simulation model incorporated a rule curve for each forebay in the system, set at the maximum operating levels in the plant operating guidelines. If either forebay level exceeds its rule curve, then the unit is operated at maximum load to bring the level down to the rule curve. If the forebay level is at or below the rule curve, then the unit is operated at best efficiency as necessary to maintain the level at the rule curve.

Obviously, some judgment on the part of the operators in applying the guidelines is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when reservoirs are not full.

The reservoir rule curves, shown in Figure 3.4, are set so that Mount Carmel Pond releases flow only to maintain Horsechops at best efficiency, while the Blackwoods Ponds release continually (i.e., stoplog structure is open).

3.3.2 Gate/Reservoir Operation

The Horsechops/Cape Broyle system has significant storage capacity that can be effectively used to smooth the basin inflows. Mount Carmel Pond provides most of the useable storage capacity. To attain ideal operation as indicated by the simulation model, the Mount Carmel Pond gate must be adjusted as often as necessary to ensure that the Horsechops unit is not loaded above efficient load, and to cut back releases to avoid spilling downstream.

The plant operating guidelines state that Horsechops should run at best efficiency unless spill will occur. The guidelines also state that gates should be opened in major inflows to allow spill at Horsechops, so the water can be used at Cape Broyle, rather than allow spill upstream. With ideal gate control, as shown by the simulation model, spill can be prevented and Horsechops can always run at best efficiency, due to the ample storage capacity of Mount Carmel Pond. By the same token, the model also indicated that opening the Mount Carmel Pond gate to cause spill around Horsechops would not be necessary as long as such capacity was available.

However, the gate that controls this reservoir is not readily accessible. This gate is located approximately 6 km from the Horsechops powerhouse along a rough, unpaved road. Accessing the gate requires approximately 45 minutes of travel (one-way) from this powerhouse, and therefore daily adjustments are not always possible.

Despite the inaccessibility, there are some factors that reduce the effect of infrequent gate adjustment on hydroelectric production. First, the unit at Horsechops is equipped with good controls that may be used to start and stop the unit remotely. Second, Horsechops Forebay has some storage capacity to capture higher local inflows if the gate setting is too high, or to supplement the flow from

Mount Carmel Pond if the gate setting is too low. Finally, the capacity of the Cape Broyle unit and the storage available at Cape Broyle Forebay reduce the effect of infrequent gate adjustments on generation at Cape Broyle.

The stoplog structure at Fourth Blackwoods Pond Canal is located in the distant back country and is not easily accessible at any time of year. However, previous analysis by Acres has indicated that this structure should be left open permanently to minimize spill from the Blackwoods Ponds, as there is ample storage downstream in Mount Carmel Pond. This is the case assumed by the simulation model.

In addition to the accessibility issues, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro (NLH). This winter reserve is not taken into account by the simulation model.

3.3.3 Unit Operation

The simulation model operates the Cape Broyle and Horsechops units at their most efficient loads, except when high inflows dictate that higher loads are necessary to avoid exceeding the forebay rule curves. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate these plants very close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April 1999, and January-February 2000) confirmed that the Horsechops unit is loaded at best efficiency a high percentage of the time and at maximum load for most of the remainder of the time the unit was online. The same was true for the Cape Broyle unit in each of these months with the exception of December 1998, when the unit was operated over a range of loads from 4 to 6.5 MW. Aside from gate control issues, another obstacle to attaining ideal operation is electrical grid requirements that may occasionally require the units to operate at loads other than their most efficient loads. An example of such requirements would be local power outages, which occur infrequently and therefore should not significantly affect annual production.

3.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Feasible alternatives for improving generation by changing the operating guidelines involve changing the forebay operating levels, as described below. As well, shifting generation to most efficient load at Cape Broyle was investigated.

Increased Head at Horsechops Forebay

To simulate a higher forebay level at Horsechops, the level of Horsechops Forebay was set at its spill elevation (176.33 m) instead of its upper operating level, an increase of 0.46 m. Simulated generation at Horsechops was increased slightly, by 0.1 GWh/yr, to 51.2 GWh/yr. The higher forebay elevation led to a small amount of spill at Horsechops, less than 0.1 GWh/yr. Generation at Cape Broyle was not affected.

Increased Head at Cape Broyle Forebay

To simulate a higher forebay level at Cape Broyle, the level of Cape Broyle Forebay was set at its spill elevation (87.78 m) for June to December, instead of its upper operating level of 87.48 m, an increase of 0.30 m. The simulated winter drawdown to 86.56 m (prior to spring runoff) was not changed. The resulting increase in simulated generation at Cape Broyle was 0.1 GWh/yr, but generation at Horsechops was reduced by 0.1 GWh/yr, due to a higher tailwater level. As a result, there was no change in average total system generation.

Spill Avoidance: Lower Level of Cape Broyle Forebay

The potential for savings in spill at Cape Broyle is low. As noted earlier, there was no simulated spill at Horsechops in the base case. The simulated spills at Cape Broyle were small and infrequent, resulting mainly from local inflows. As a possible means of reducing simulated spill at Cape Broyle Forebay, a lower operating level was simulated, by setting the level to 86.56 m year round. However, no reduction in the spill was achieved. The loss of head reduced the average generation at Cape Broyle by 0.3 GWh/yr, although the same amount was gained in generation at Horsechops due to a lower tailwater level. Consequently, there was no change in average total system generation.

Increased Operation at Best Efficiency at Cape Broyle

As shown in Figure 3.2, ideal operation under the existing plant operating guidelines, as indicated by the simulation model, is to maintain the Horsechops unit at efficient load. This is achieved through control of releases from Mount Carmel Pond. About 25 percent of the time, the combination of Horsechops outflow and local inflow to Cape Broyle Forebay require the Cape Broyle unit to be operated at maximum load. An alternative operating strategy would be to control the releases from Mount Carmel Pond so as to shift Cape Broyle generation from maximum load to most efficient load. The simulation model was rerun with this strategy. The strategy was successful in shifting generation to less than five percent at maximum load, as well as reducing spill, for an average gain of 0.1 GWh/yr at that station. However, this resulted in a single year with spill at Mount Carmel Pond, which in turn caused spill at Horsechops, equivalent to about 2.0 GWh. Averaged over the reference period, this equalled a loss in average generation of about 0.1 GWh/yr, resulting in no net gain in average total generation.

Even so, the simulation indicates that such a shift is possible. As well, such a spill event may be avoidable in actual operation, whereas the simulation model imposes the same operating rules on every year. Inflow forecasting could help realize benefits in shifting production.

3.5 Physical Changes to System

Raise Blackwoods Ponds Spillways

According to the simulation model, the main physical limitation of the existing system is the elevation of the spillway crests at the Blackwoods Ponds, where most of the spill out of the system occurs. First of all, the Blackwoods Ponds do not have adequate storage capacity to store inflows without spilling. Second, the spill elevation limits the discharge through the Fourth Blackwoods Pond Canal by preventing full utilization of the canal depth and flow area. The canal itself is deep and fully excavated and is therefore not limited by freeboard on side berms. The discharge could be increased by widening the canal, but at 1.5 km in length, this would be prohibitively expensive. If the spill elevation were raised, more of the canal's physical flow capacity could be utilized.

To determine the effect of increased spill elevation, the model was rerun assuming the crests of all Blackwoods Ponds spillways (Northwest Blackwoods, East Blackwoods, and Fourth Blackwoods) were raised to a minimum tolerable freeboard on the existing diversion dams. The elevation selected was 223.20 m, or 1.00 m higher than the lowest existing spillway elevation (Fourth Blackwoods), and 0.30 m lower than the lowest existing dam crest (Jordan River Dam).

The simulation achieved almost complete recovery of Blackwoods Ponds spill and resulted in average generation of 52.2 GWh/yr at Horsechops and 38.8 GWh/yr at Cape Broyle, for a system total of 91.0 GWh/yr, or 1.9 GWh/yr more than the base case.

Assuming that the cost of energy to NP is $0.04/kWh, this would result in a savings to NP of approximately $76 000/yr. Given an estimated total spillway crest length of 213 m, the savings over perhaps 20 years would justify an expenditure of about $3300/m of crest length. The practicalities of increasing the spill elevation would have to be investigated, including any dam safety issues. NP should also confirm the accuracy of the assumed elevation, storage, length and discharge data for Blackwoods Ponds structures.

3.6 Sensitivities

Environmental Release Requirement

The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reach downstream of the Mount Carmel Pond gated outlet for environmental reasons, the minimum flow of the gate was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoir is empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is approximately 2.1 m^3/s. Using this flow as the minimum flow release from the gates for the base case simulation model, there was no change in system energy. This is the case because 30 percent of mean annual flow is less than the amount required to maintain the Horsechops unit at its most efficient load. This amount is always released in all simulations unless there is no water in storage, in which case the natural inflows are released.

If NP were required to hold a supply of water in the reservoir to ensure that the 30 percent requirement was always met, there would likely be a reduction in energy. The same is true of the winter reserve requirement mentioned in Section 3.3; in fact the winter reserve requirement might lead to more of a reduction since the fish flows held in reserve could be expected to be released in some years, if not in all, leaving room in the reservoir, whereas the winter reserve might not be released and would result in less room to store the spring runoff.

3.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

   Gate Operation: The analysis shows that controlling the release of water from storage is the key to maximizing the output from the Horsechops/Cape Broyle system. The gated outlet at Mount Carmel Pond needs to be adjusted to ensure that the correct flow is being released to keep the units operating at best efficiency, as well as to avoid spill. It may be desirable to examine the cost of automation and monitoring equipment at the Mount Carmel Pond gate compared to the current costs of adjusting the gate manually.

2. **Changes to Operating Guidelines**

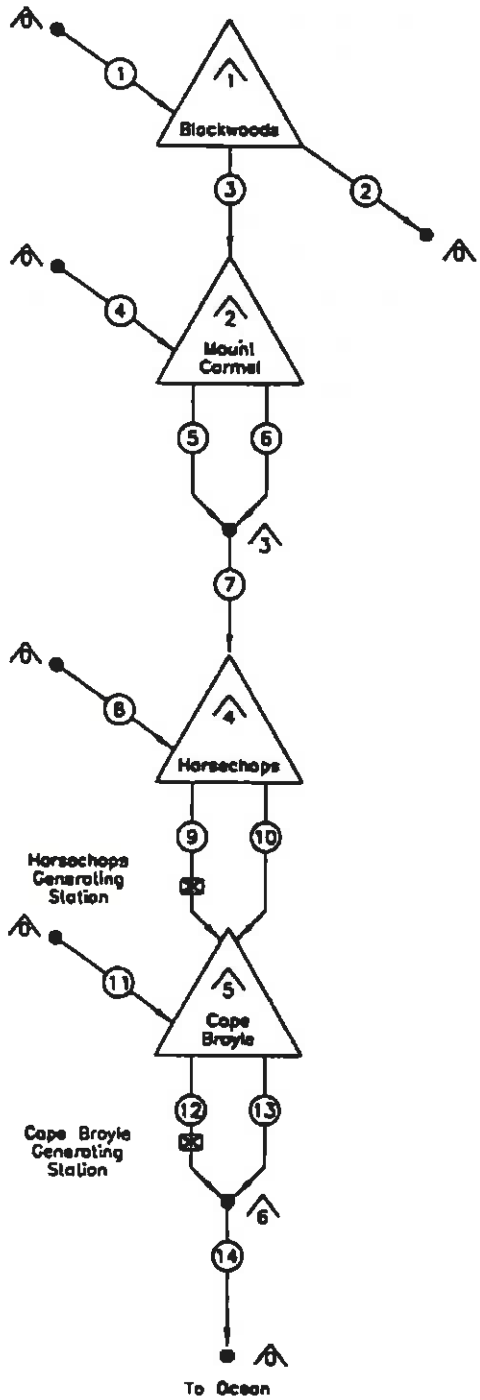
   Clarification of Guidelines: NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum. The guidelines should specifically state that the Fourth Blackwoods Pond Canal stoplog structure should be left open. They should also state that the Mount Carmel Pond gate should be opened to allow spill at Horsechops only if Mount Carmel Pond will spill. It may be desirable to examine the possible benefits of inflow forecasting, which may help devise operating rules to shift as much production as possible to efficient load at both stations.

3. **Physical Changes**

   Blackwoods Ponds Spillways: The analysis showed that raising the elevation of the Blackwoods Ponds spillway crests may increase generation by increasing storage, reducing spill, and utilizing more of the physical discharge capacity of the Fourth Blackwoods Pond Canal. NP should investigate the costs and benefits of raising the spillway crests, while taking into consideration any dam safety concerns. The accuracy of the assumed characteristics (elevation, length, storage, discharge) of Blackwoods Ponds structures should be verified.

4. Sensitivities

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gate at Mount Carmel Pond does not affect energy generation, because this amount is already being released to supply the units. The requirement, however, assumes that when the reservoir is low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.



CHANNELS

1 — Blackwoods Ponds Local Inflow
2 — Blackwoods Ponds Spill
3 — Fourth Blackwoods Pond Canal
4 — Mount Carmel Pond Local Inflow
5 — Mount Carmel Pond Outlet Gate
6 — Mount Carmel Pond Spill
7 — Mount Carmel Pond Total Outflow
8 — Horsechops Forebay Local Inflow
9 — Horsechops Power Flow
10 — Horsechops Spill
11 — Cape Broyle Forebay Local Inflow
12 — Cape Broyle Power Flow
13 — Cape Broyle Spill
14 — Cape Broyle Total Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Blackwoods Ponds
2 — Mount Carmel Pond
3 — Mount Carmel Pond Total Outflow
4 — Horsechops Forebay
5 — Cape Broyle Forebay
6 — Cape Broyle Total Outflow

Fig. 3.1

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

HORSECHOPS / CAPE BROYLE ARSP MODEL SCHEMATIC

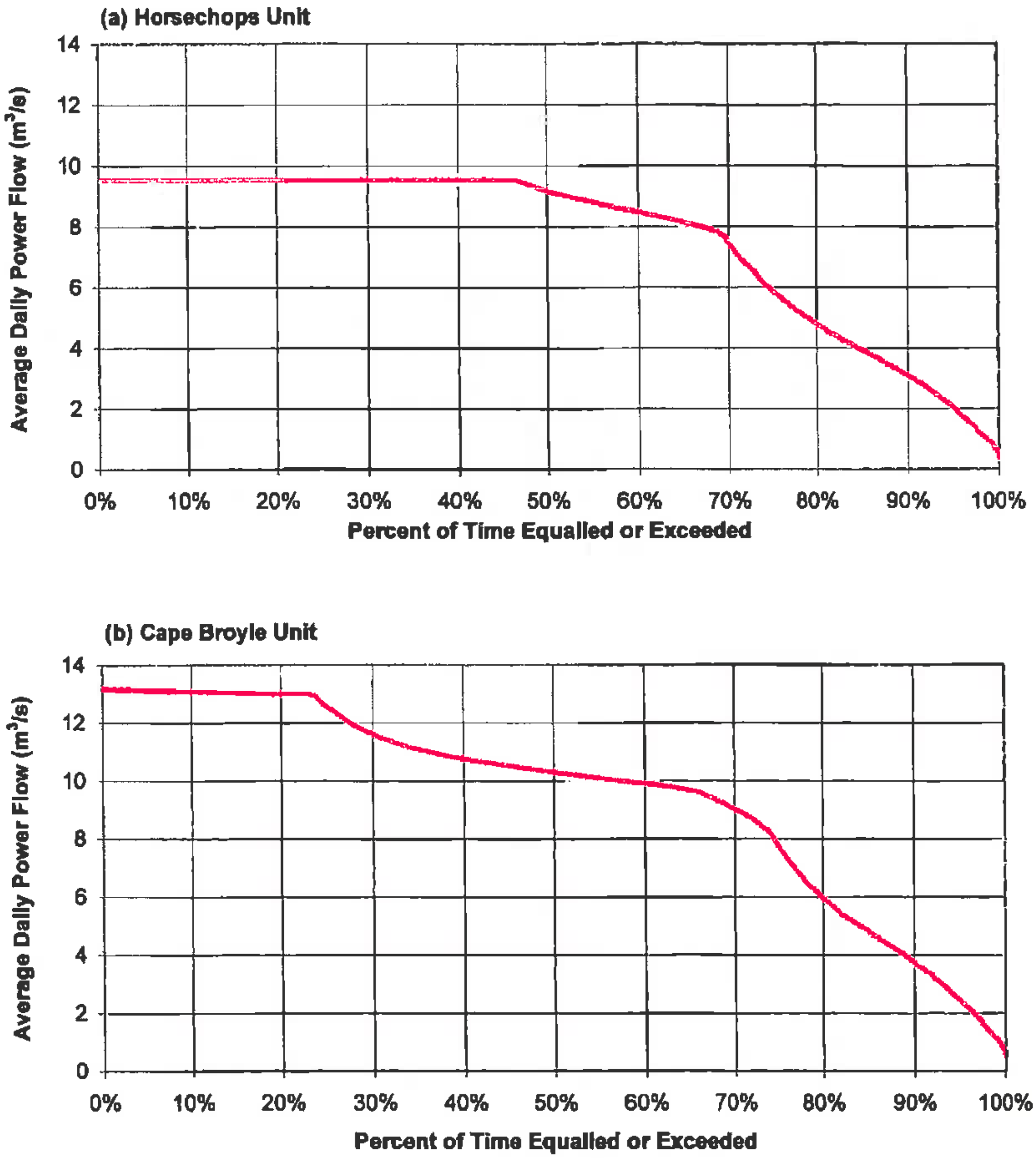
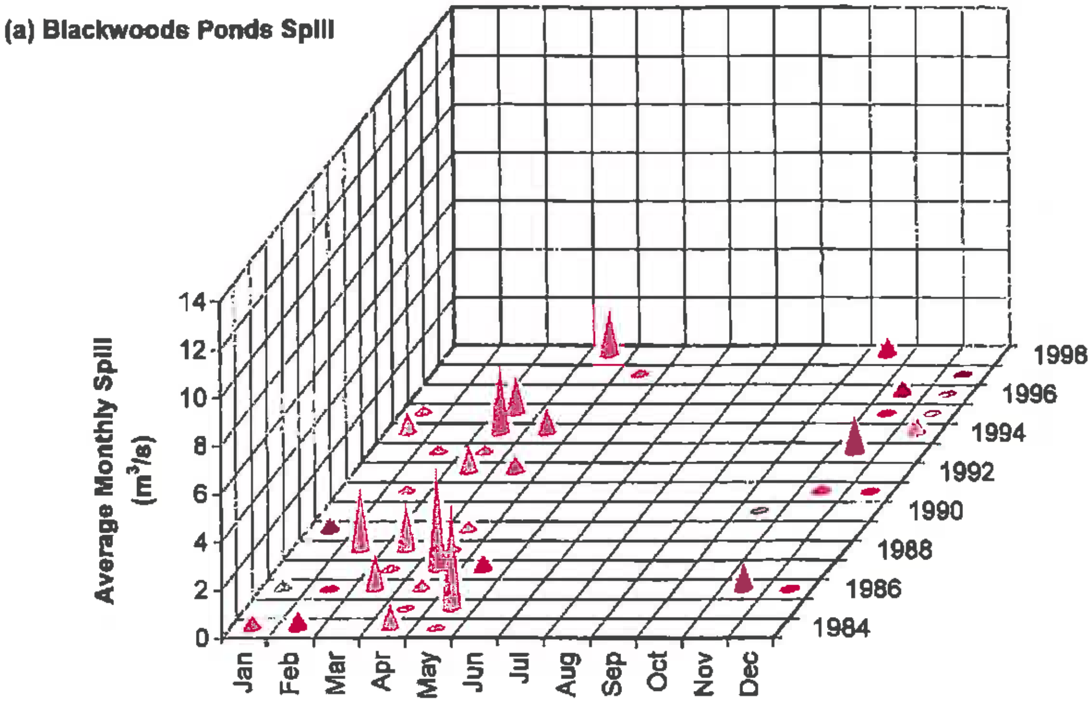


Fig. 3.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

HORSECHOPS AND CAPE BROYLE SIMULATED POWER FLOW DURATION CURVES



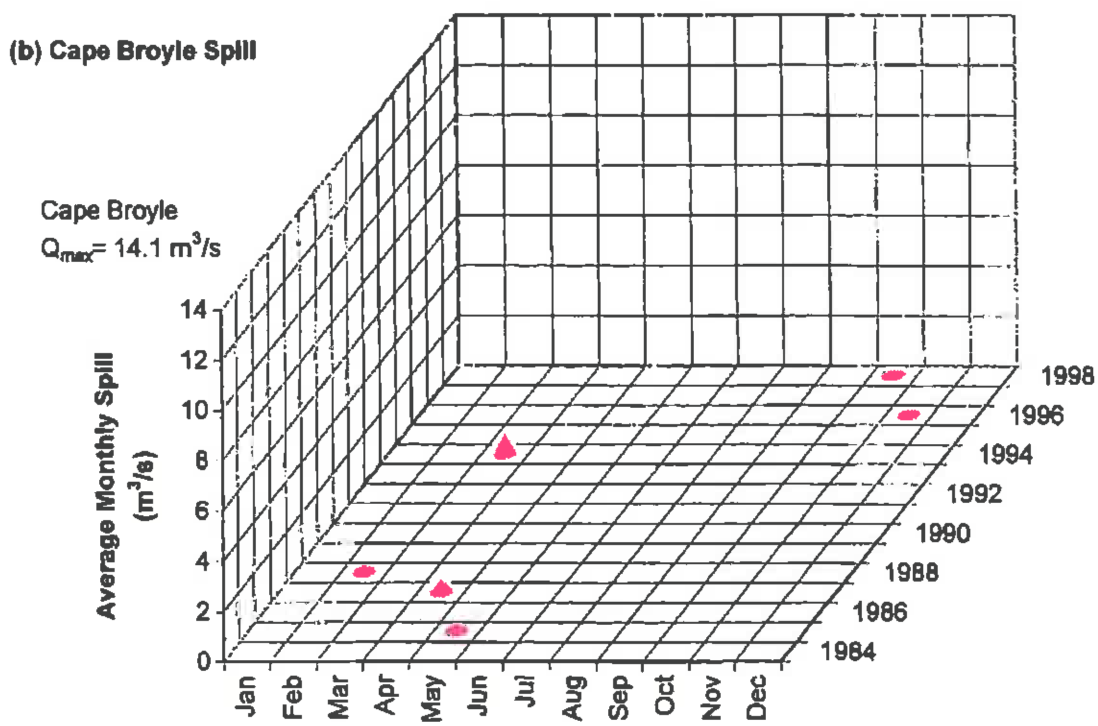


Fig. 3.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

BLACKWOODS PONDS AND CAPE BROYLE SIMULATED SPILLS

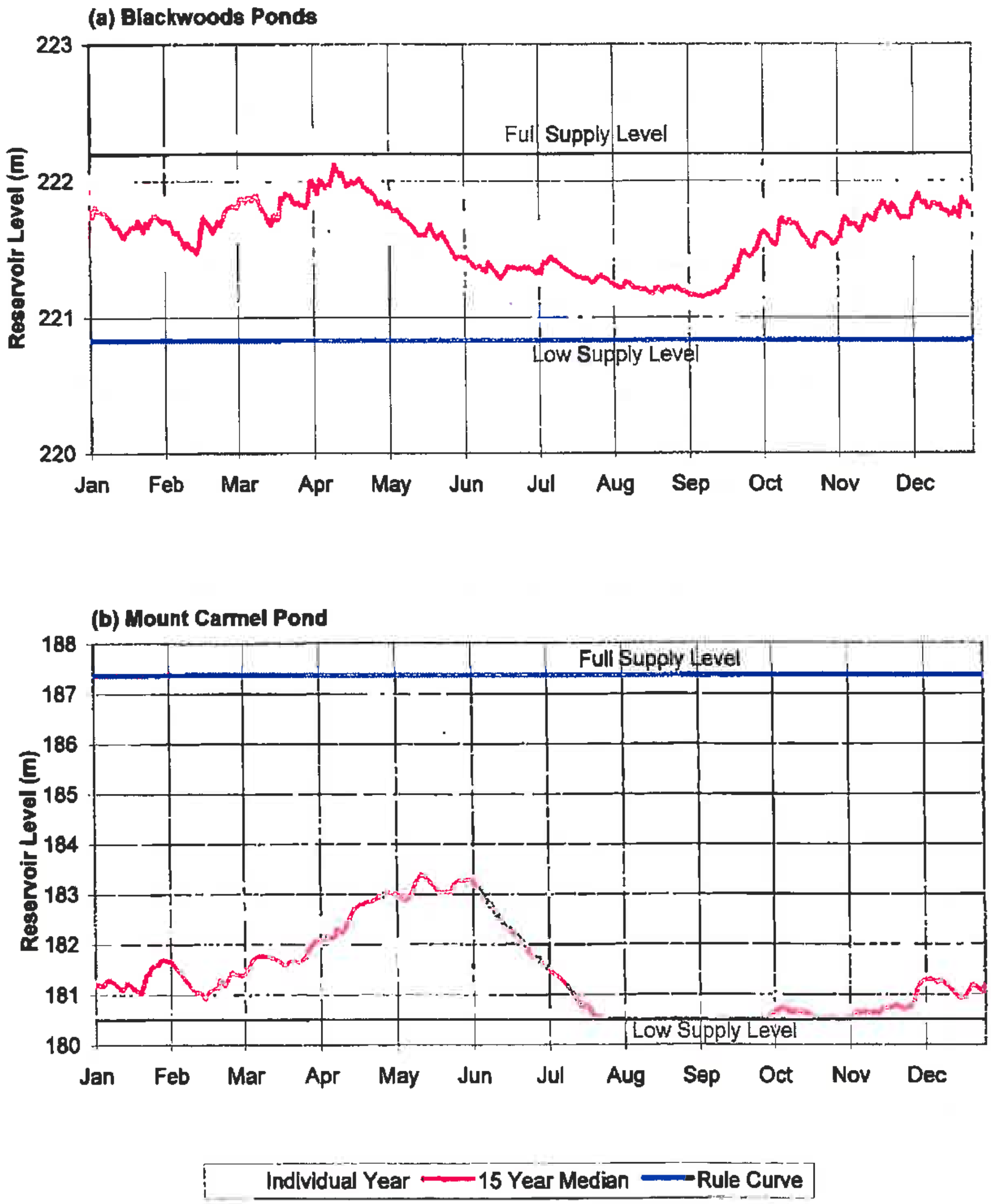


Fig. 3.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

BLACKWOODS PONDS AND MOUNT CARMEL POND
SIMULATED RESERVOIR LEVELS

ACRES

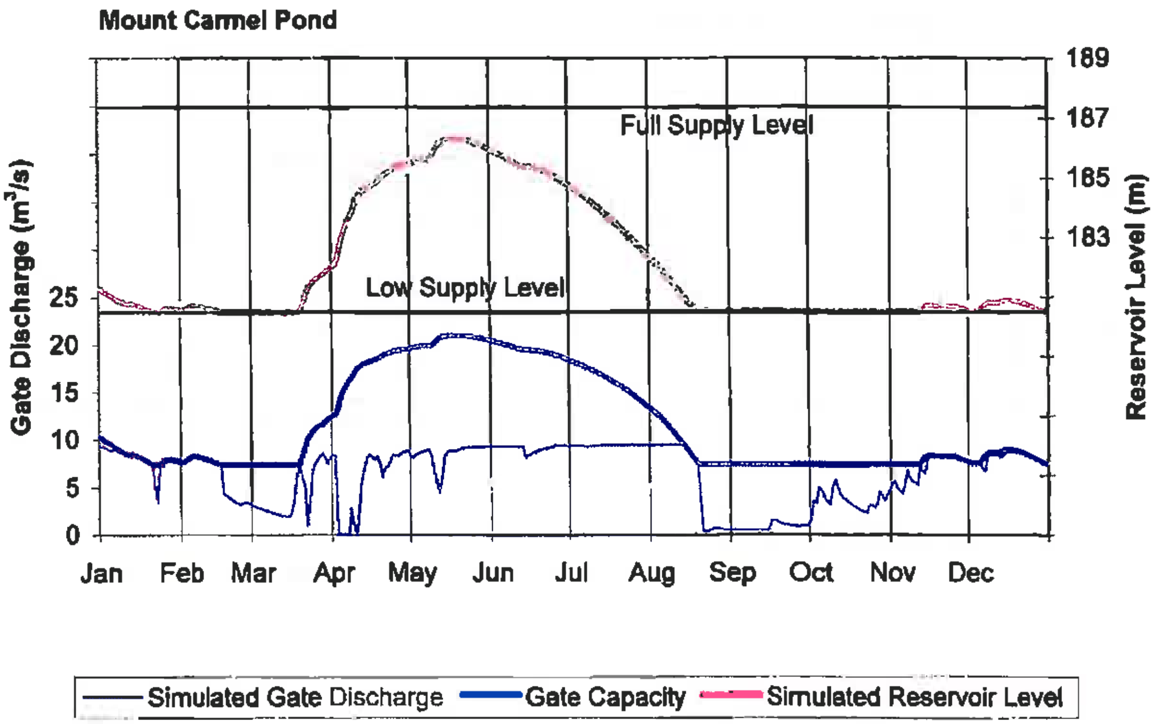


Fig. 3.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

MOUNT CARMEL POND SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

Rattling Brook

4 Rattling Brook Hydroelectric System

Rattling Brook Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Rattling Brook system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Rattling Brook system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Rattling Brook system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

4.1 System Description

The Rattling Brook system is located in central Newfoundland near the community of Norris Arm. The development was commissioned in 1958 with additional storage added in 1961. The plant has a nameplate capacity of 15.1 MW and a rated net head of 87.8 m. The system has two units supplied by a single woodstave penstock. The second unit was originally intended as a stand-by unit, however the two units are now routinely used together.

The Rattling Brook system has a drainage area of approximately 383 km^2. On the west side of the basin, a series of small lakes along Rattling Brook, including Frozen Ocean Lake, Gull Lake and Beaton's Lake, flow into Rattling Lake. To the east, a second series of ponds including Dowd Pond, Lewis Pond, and Upper and Lower Christmas Ponds also flow into Rattling Lake. The impoundment for the system joined Rattling Lake and Amy's Lake. Rattling/Amy's Lake flows into Rattling Brook Forebay. A schematic of the system is presented in Figure 4.1.

Only Frozen Ocean Lake, Rattling/Amy's Lake and Rattling Brook Forebay are controlled. The structures in the system are as follows

- Frozen Ocean Lake gated outlet;
- Frozen Ocean Lake overflow spillway;
- Rattling/Amy's Lake gated outlet;
- Rattling/Amy's Lake overflow spillway; and
- Rattling Brook Forebay overflow spillway.

The Frozen Ocean Lake spillway discharges within the system; both the Rattling/Amy's Lake spillway and the Rattling Brook Forebay spillway discharge out of the system.

4.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are presented in Chapter 2. The measures as calculated for the Rattling Brook system are provided below. They were developed from the data in the base case simulation. Table 4.1 at the end of this section summarizes the measures for the Rattling Brook system.

1. Flow Utilization Factor

The Rattling Brook station houses two generating units, but for the purpose of this study they were modelled as one. The most efficient flow for the combined unit was set as the most efficient flow for one unit, and the maximum flow for the combined unit was set as the combined maximum flow of both units. The flow utilization factors for the Rattling Brook station (average inflow to forebay divided by capacity at most efficient load and maximum load) are 1.24 at most efficient load (one unit operating) and 0.60 at maximum load (both units operating).

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage) for most efficient load and maximum load for the units are 0.21 kWh/m^3 (6.75 GWh/yr/m^3/s) and 0.17 kWh/m^3 (5.44 GWh/yr/m^3/s), respectively.

The average energy conversion factor from the base case simulation is 0.20 kWh/m^3 (6.33 GWh/yr/m^3/s). These energy conversion factors take into account the average reduction in availability due to forced outages, and reflect the fact that the units are frequently operated simultaneously, which leads to higher head losses.

3. Flow Duration Curve

A flow duration curve for the turbine flow (power flow) in the base case simulation is shown in Figure 4.2. The plot indicates that the operation is with one unit only for approximately 70 percent of the time, and that operation is at maximum flow approximately 20 percent of the time.

4. Energy Potential of Spill

The simulated spill for the base case was approximately 0.63 m^3/s on average at the Rattling/Amy's Lake spillway and 0.24 m^3/s on average at the Rattling Brook Forebay spillway. Using the simulated energy conversion factor at maximum load the spill would produce approximately 5.5 GWh/yr, if entirely saved and used for generation.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figure 4.3 for the Rattling Brook spillways. Most of the spill occurs at the Rattling/Amy's Lake spillway in March and April.

5. Reservoir Storage Factor

Storage is provided by structures located at the outlets of Frozen Ocean Lake, Rattling/Amy's Lake and Rattling Brook Forebay. The reservoir storage factors were calculated to be approximately 30 days for Frozen Ocean Lake, 74 days for Rattling/Amy's Lake, and one day for Rattling Brook Forebay. These factors represent the number of days required to fill the reservoirs at average inflow and with no outflows.

6. Reservoir Utilization Plot

Plots of simulated Frozen Ocean Lake and Rattling/Amy's Lake reservoir levels for the base case simulation are provided in Figure 4.4. The forebay level varies little so was not plotted.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with units operating at maximum load) is less than one day (19 hours).

8. Gate Operation

There are control gates located at the outlets of Frozen Ocean Lake and Rattling/Amy's Lake. Provided in Figure 4.5 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1994) for Frozen Ocean Lake and Rattling/Amy's Lake. These plots illustrate the frequency the gates are being operated in the simulation model to maintain most efficient load and to avoid spill.

Table 4.1
Rattling Brook System Representative Operating Measures

Rattling Brook Representative Operating Measures	
Flow Utilization Factors	
- Most Efficient Load (one unit)	1.24
- Maximum Load (two units)	0.60
Station Factors	
- Most Efficient Load (one unit)	0.21 kWh/m^3
- Maximum Load (two units)	0.17 kWh/m^3
Energy Potential of Spill	5.5 GWh/yr

Rattling Brook Representative Operating Measures	
Reservoir Storage Factors - Frozen Ocean Lake - Rattling/Amy's Lake - Rattling Brook Forebay	 30 days 74 days 1 day
Forebay Storage Factor	<1 day (19 hours)

4.3 Ideal Operation of System

The long term energy production at Rattling Brook as estimated by the simulation model developed for the Water Management Study is 63.6 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 66.7 GWh/yr. While it would normally be expected that the simulated production would exceed the actual average for any given period, this difference does provide some indication that there is little potential for improving actual generation at this system under the current plant operating guidelines. As discussed in the Water Management Study, the inflow hydrology used for the Rattling Brook simulation is the most likely cause of this unusual result. However, insufficient hydrometric data are available for the region to confirm this conclusion.

Further indicators that this system's actual operation approaches the ideal are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately -10 percent for this system. Again, a negative result for the comparison is unusual, but this result also points to the conclusion that the Rattling Brook system is being operated in a manner close to the simulated ideal and that there is little opportunity for improvement under the current operating guidelines.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual operation at the Rattling Brook System.

4.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Rattling Brook system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plant will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated target levels for each reservoir in the system. The reservoirs were operated to keep the forebay at its target level and to maintain operation at best efficiency. If the forebay level exceeds the target level at any particular time of the year, then the units are operated at maximum load to bring the water level down.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the target levels.

4.3.2 Gate/Reservoir Operation

The Rattling Brook system has significant storage capacity. The gate that controls the main storage reservoir at Rattling/Amy's Lake is remotely operated from the powerhouse. In addition, remote water level indication is available for this storage reservoir. Therefore, the outlet gate can be adjusted frequently (several times daily, if necessary) by operations staff.

This is not true of Frozen Ocean Lake, the other storage reservoir in this system. However, this reservoir provides much less storage and its discharges can be stored downstream at Rattling/Amy's Lake. Therefore, infrequent gate adjustments at this reservoir do not have a significant impact on plant production.

In addition to the accessibility issues, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro. This winter reserve is not taken into account by the simulation model.

4.3.3 Unit Operation

The simulation model operates the Rattling Brook units exclusively at most efficient load, except when high inflows dictate that higher loads are necessary to avoid spill. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate this plant close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April 1999, and January-February 2000) indicated that, with the exception of the April data, the Rattling Brook units are loaded over a range of loads from 4 to 7.8 MW. This plant would therefore not appear to be making efficient use of the available water, although a more detailed study would also include an examination of unit availability and system conditions during these months. The main obstacles to attaining ideal operation are electrical grid requirements which may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences.

4.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Each of these is discussed below for the Rattling Brook system. Increasing the head through a change in the use of the flashboards or installation of inflatable crest gates was considered as a potential physical change (Section 4.5).

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The case described for the base case is an intermediate case, since it uses rule curves varying between the low supply and full supply levels of the reservoirs, as described in Section 4.3.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low
The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water level in the storage reservoirs as low as possible.

At Rattling Brook, the potential for savings in spill compared to the base case is low. The maximum possible reduction in spill would be the equivalent of 5.5 GWh/yr, as shown in Table 4.1. However, the spill distribution plot (Figures 4.2) shows that this would be difficult to capture since the spills occur infrequently and in large amounts.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The average annual spill from the system was reduced by 0.38 m^3/s, from an average of 0.87 m^3/s to 0.49 m^3/s. This represents an increase of approximately 2.4 GWh/yr, but does not compensate for the approximately 4.2 GWh/yr decrease in energy production due to operating the units at a lower efficiency.

Best Efficiency Operation, Limiting Case: Reservoirs High
The limiting case for maximizing the amount of time the units are operating at best efficiency is to run the units at best efficiency, until the storage reservoirs are just about to spill. This may require frequent gate operation because the gates must be adjusted to release the exact amount of water to match the best efficiency flows.

The result of a simulation using this rule was an average annual production of 60.3 GWh/yr, with a spill of 1.63 m^3/s. This production is lower than the base case production.

These simulations suggests that the rule curve used for the base case simulation is near optimum for the Rattling Brook system. There could be minor adjustments made to the rule curve that could increase production monthly, but the increase would be expected to be marginal.

Revised Unit Dispatch
The current Rattling Brook plant operating guidelines state the following.

1.) When flows are minimal operate Unit #1 at best efficiency instead of #2 as the efficiency of this unit is better. Operate #2 at best efficiency if #1 cannot handle the flow. For higher flows, use #2 at full load and #1 at best efficiency. Operate *both units at full load only when necessary to avoid spill. This is the most inefficient setting of the units as the pressure loss in the penstock is very high at full load.*

Efficiency testing undertaken in August 2000, however, showed that Unit #2 has a higher efficiency and therefore higher energy conversion factor than Unit #1. The simulation modelling for the Water Management Study used a unit dispatch based on the efficiency testing rather than the operating guidelines. This lead to an increase in generation of approximately 0.5 GWh/yr.

4.5 Physical Changes to System

The two principal options for physical changes to the existing system to improve energy generation are to increase head and to increase storage. To give an indication of the value of these changes, the following options were investigated.

- Increase dam height at Rattling/Amy's Lake to increase storage.
- Reduce headlosses by enlarging the penstock at Rattling Forebay.

Each of these physical changes to the system is discussed below. Table 4.2 summarizes the results.

Increase Storage at Rattling/Amy's Lake
To determine the effect of an increase in storage on energy production, the dams and structures at Rattling/Amy's Lake were assumed to be raised to allow increases in full supply level of one and two meters. The effect is to reduce system spill. The resulting increases in energy generation were 1.3 GWh/yr for the one meter rise, and 2.2 GWh/yr for the two meter rise.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $52 000/yr for the one meter increase in dam height and $88 000/yr for the two meter increase in dam height. Given a dam length of approximately 960 m, the savings over perhaps 20 years would justify an expenditure of about $500/m of dam length based on a one meter increase. The practicalities of adding additional flashboards to the existing structures at Rattling/Amy's Lake dam, or of raising the dam in some other manner would have to be investigated.

Reduce Headlosses
One method of increasing head is to reduce headlosses. The penstock at Rattling Brook was designed for operation of one unit only, therefore operating the two units together results in high headlosses For the purposes of examining the value of a reduction in headlosses, a new headloss curve based on larger penstock (approximately 50 percent larger diameter) was calculated and used in the simulation model. The resulting energy generation was 70.9 GWh/yr or a net increase in average annual energy of 7.3 GWh/yr. Recovery of some or all of these losses could have a net present value in excess of $2 million over a 20 year project life.

Table 4.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	63.6	-
Increase Storage in Rattling/Amy's Lake by 1 m	64.9	+1.3
Increase Storage Rattling/Amy's Lake by 2 m	65.8	+2.2
Reduce headlosses	70.9	+7.3

4.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of their systems. Results for the sensitivity cases are provided in Table 4.3. Along with the average energy generation, average annual spill for each case is presented in Table 4.3.

The sensitivity cases were as follows.

- Environmental release requirement of 30 percent of mean annual flow.
- No storage in system (to obtain value of storage); remove dams and gates.
- Changes to gate operation at Frozen Ocean Lake.

Environmental Release Requirement

The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 0.5 m^3/s at Frozen Ocean Lake and 3.25 m^3/s at Rattling Amy's Lake. Using these flows as the minimum release from the gates leads to an annual average energy of 63.5 GWh/yr, only 0.1 GWh less than the base case. This is the case because 30 percent of mean annual flow is less than the best efficiency flow of the unit. This amount is released in all simulations unless there is no water in storage, in which case the natural inflows are released.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement were always met, there would likely be an additional reduction in energy.

No Storage in System

To provide NP with an indication of the value of the storage in the system, a simulation was done with all storage removed. The resulting average annual energy generation from this sensitivity was 47.2 GWh/yr, a net decrease of 16.4 GWh/yr. This represents the value of maintaining the structures at Frozen Ocean Lake and Rattling/Amy's Lake.

Changes to Frozen Ocean Lake Gate Operation

The remote location and difficult access of the Frozen Ocean Lake outlet structure make it a candidate for automation. The simulation for the base case assumed that the gate could be operated daily, however the gate operation plot in Figure 4.5 shows that the gate is usually open to full capacity. The base case could be considered the full automation case.

To investigate the value of automation, or of some alternative procedure, a simulation was run assuming that the gate was left fully open year round. The structure itself will provide some natural regulation.

The difference in the estimate of energy generation in this case and the base case indicates the value of having a gate that can be operated daily. The resulting energy generation from this sensitivity was 63.1 GWh/yr, or a net decrease in energy of 0.5 GWh/yr. This decrease is due to extra spill at the forebay and additional operation at maximum load. This finding suggests that automation would save sufficient energy to justify an expenditure of approximately $200 000 and therefore should be investigated further.

Table 4.3
Energy Results for Sensitivity Simulations for Rattling Brook System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)	Average Spill (m^3/s)
Base Case	63.6	-	0.87
Environmental Releases	63.5	- 0.1	0.87
Value of Storage	47.2	- 16.4	3.36
Frozen Ocean Lake Gate Operation - Leave Gate Full Open	63.1	- 0.5	0.96

4.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Changes to Operating Guidelines**

   Clarification of Guidelines: The present guidelines as interpreted for the Water Management Study come close to maximizing system output.

   Unit Dispatch Order: The current operating guidelines suggest a unit dispatch order that is inconsistent with the station factors as calculated from recent efficiency testing. NP should consider revising the guidelines.

2. Physical Changes

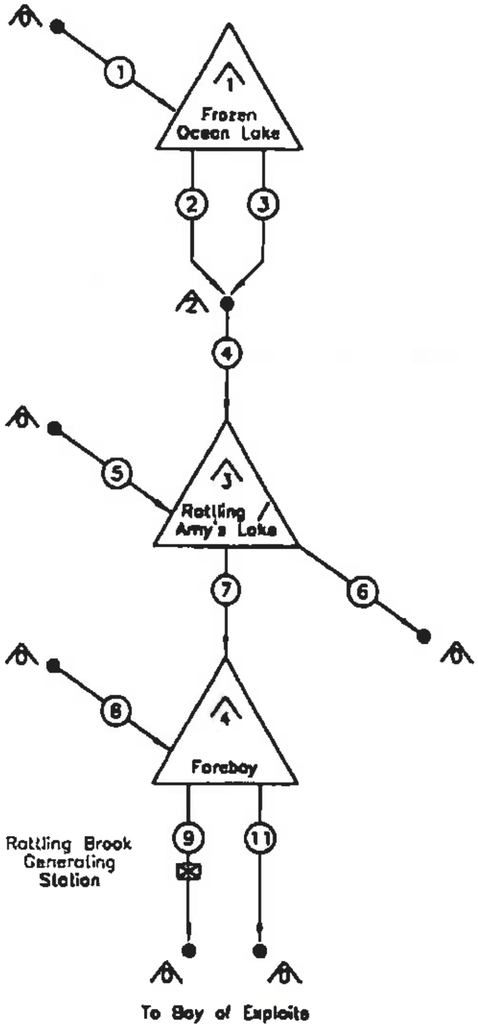
Headlosses: The analysis showed that there may be some gains in energy by reducing headlosses. The costs and benefits of replacing the penstock should be examined.

3. Sensitivities

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gates at Frozen Ocean Lake and Rattling/Amy's Lake does not significantly affect energy generation, because the flow is already being released to supply the units. The requirement, however, assumes that when the reservoirs are low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.

Value of Storage: The value of the storage at Frozen Ocean Lake and Rattling/Amy's Lake is 16.4 GWh/yr. NP can use this value in considering the costs of maintaining the structures.

Changes to Frozen Ocean Lake Outlet Gate Control/Operation: The value of operating the gate at Frozen Ocean Lake on a daily basis, if required, is 0.5 GWh/yr. Automation of the gate should be considered.



CHANNELS

(1) — Frozen Ocean Lake Inflow
(2) — Frozen Ocean Lake Outlet
(3) — Frozen Ocean Lake Spill
(4) — Frozen Ocean Lake Total Outflow
(5) — Rattling / Amy's Lake Inflow
(6) — Rattling / Amy's Lake Spill
(7) — Rattling / Amy's Lake Outlet
(8) — Rattling Brook Forebay Inflow
(9) — Rattling Brook Power Channel
(11) — Rattling Brook Forebay Spill

RESERVOIRS / NODES

0 — Source / Sink
1 — Frozen Ocean Lake
2 — Frozen Ocean Lake Total Outflow
3 — Rattling / Amy's Lake
4 — Rattling Brook Forebay

Fig. 4.1

NEWFOUNDLAND POWER
HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY
RATTLING BROOK ARSP MODEL SCHEMATIC

AGRES

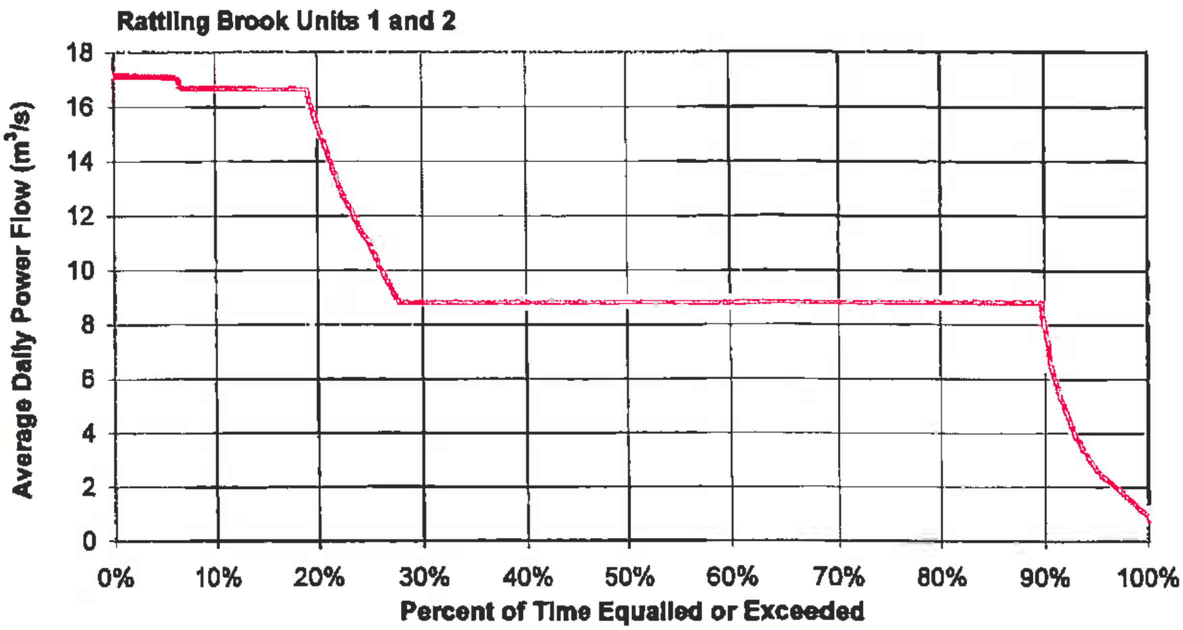
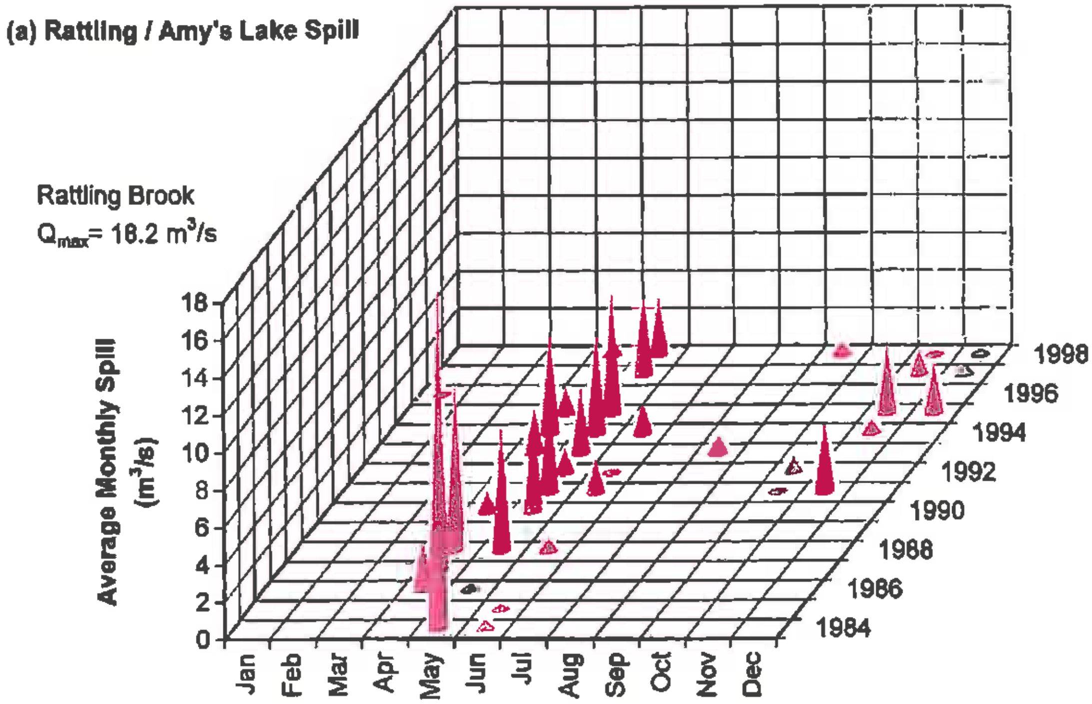


Fig. 4.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

RATTLING BROOK SIMULATED POWER FLOW DURATION CURVES



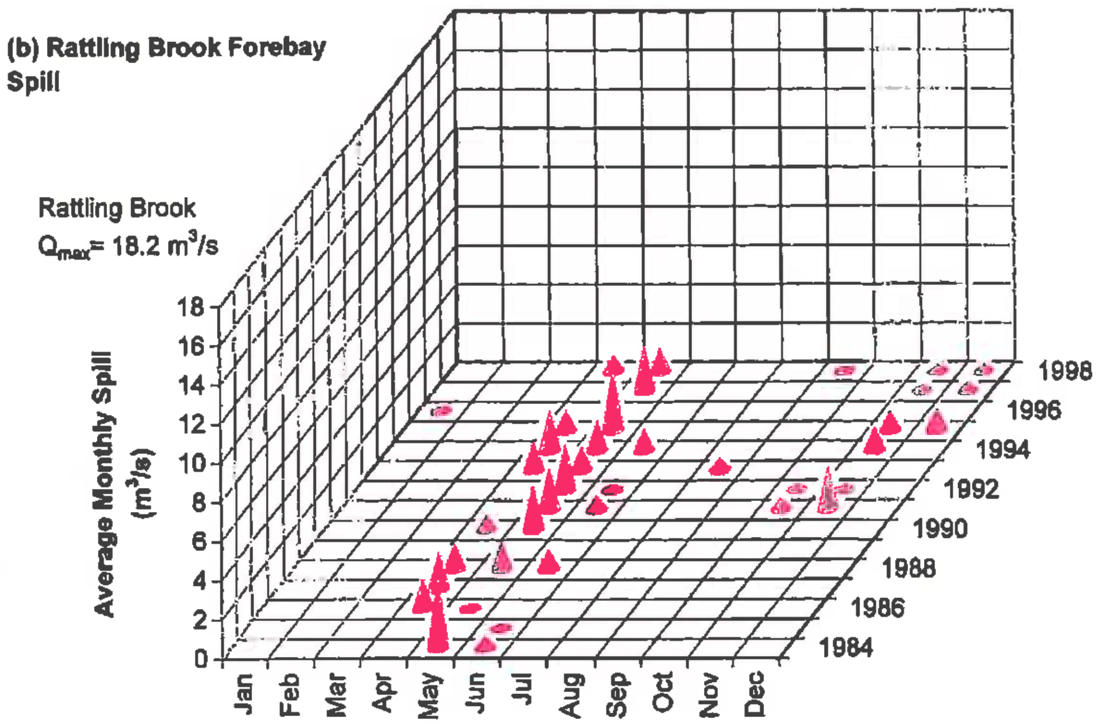


Fig. 4.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

RATTLING / AMY'S LAKE AND RATTLING BROOK FOREBAY SIMULATED SPILLS

ACRES

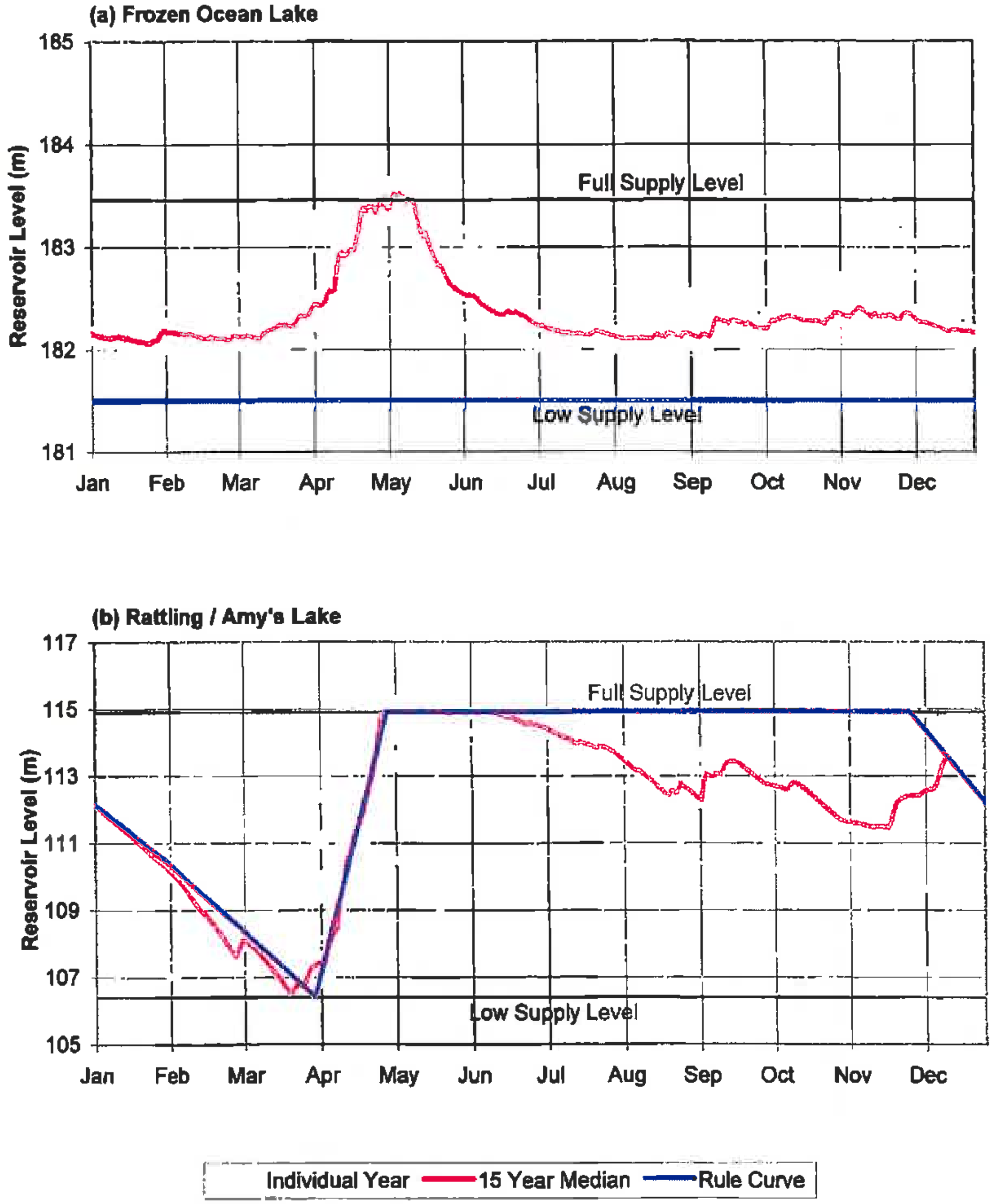


Fig. 4.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

FROZEN OCEAN LAKE AND RATTLING / AMY'S LAKE
SIMULATED RESERVOIR LEVELS

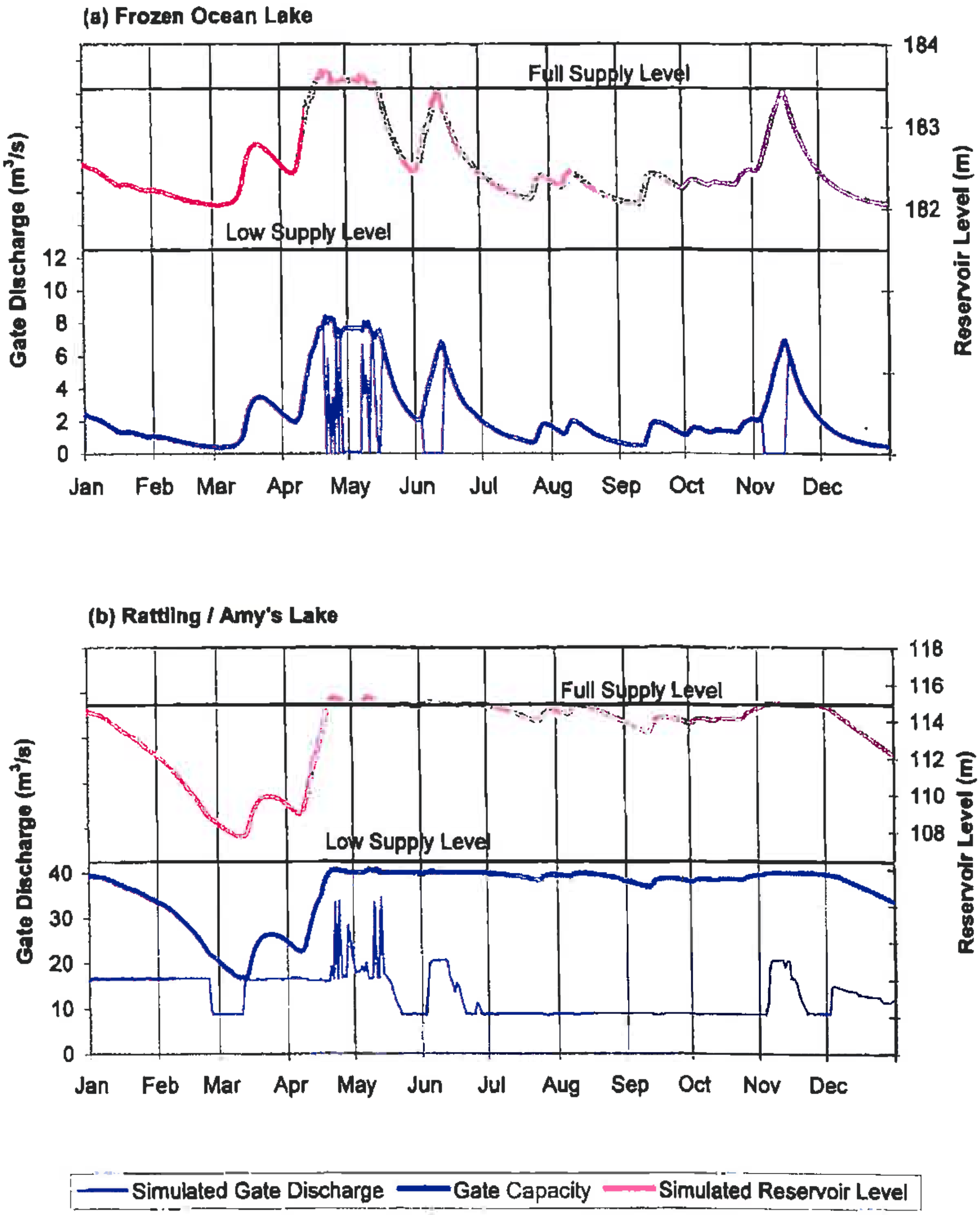


Fig. 4.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

FROZEN OCEAN LAKE AND RATTLING / AMY'S LAKE SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

ACRES

Morris/Mobile

5 Morris/Mobile Hydroelectric System

The Morris/Mobile Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Morris/Mobile system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Morris/Mobile system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Morris/Mobile system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

5.1 System Description

The Morris/Mobile system is located on the southern shore of the Avalon Peninsula in eastern Newfoundland, and has two generating stations. The Morris Generating Station was commissioned in 1983 and has a nameplate capacity of 1.1 MW and a rated net head of 30.0 m. The drainage area above the intake of the Morris station is approximately 96 km^2. The Mobile Generating Station was commissioned in 1951 and has a nameplate capacity of 12.0 MW and a rated net head of 114.6 m. The total drainage area above the intake of the Mobile station is approximately 113 km^2. Storage is provided by structures at Mobile Big Pond and Mobile First Pond. A schematic of the system is presented in Figure 5.1.

The upper part of the basin drains into Mobile Big Pond, which is the main storage reservoir for the system. Morris Canal extends 2.5 km from Mobile Big Pond to Morris Forebay. Both the canal and Mobile Big Pond are equipped with overflow spillways, which discharge around the Morris station into Mobile First Pond. Power flows from the Morris station are discharged through a fish spawning canal, about 100 m in length, into Mobile First Pond. Mobile Canal extends 2.1 km from Mobile First Pond to Mobile Forebay. Spill from Mobile First Pond is discharged out of the system.

The structures in the system are as follows

- Mobile Big Pond overflow spillway;
- Mobile Big Pond gated outlet;
- Morris Canal;
- Morris Canal overflow spillway;
- Mobile First Pond overflow spillway; and
- Mobile Canal.

The Mobile First Pond spillway discharges out of the system; the Mobile Big Pond and Morris Canal spillways discharge within the system.

5.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.

7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are described in Chapter 2. The measures as calculated for the Morris/Mobile system are provided below. They were developed from the data in the base case simulation. Table 5.1 at the end of this section summarizes the measures for the Lookout Brook system.

1. Flow Utilization Factor

The flow utilization factors (average inflow to forebay divided by flow capacity at most efficient load and maximum load) for the Morris station are 0.91 at most efficient load and 0.82 at maximum load. For the Mobile station, the factors are 0.50 at most efficient load and 0.42 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage) for the Morris station are 0.07 kWh/m^3 (2.05 GWh/yr/m^3/s) at most efficient load and 0.06 kWh/m^3 (1.94 GWh/yr/m^3/s) at maximum load. For the Mobile station, the factors are 0.29 kWh/m^3 (8.99 GWh/yr/m^3/s) at most efficient load and 0.28 kWh/m^3 (8.83 GWh/yr/m^3/s) at maximum load.

The average energy conversion factors from the base case simulation for the Morris and Mobile stations are 0.06 kWh/m^3 (1.88 GWh/yr/m^3/s) and 0.28 kWh/m^3 (8.70 GWh/yr/m^3/s), respectively. These energy conversion factors take into account the average reduction in availability due to forced outages.

3. Flow Duration Curve

The Morris and Mobile flow duration curves for the turbine flow (power flow) in the base case simulation are shown in Figure 5.2. The average daily flow through the Morris unit is usually at or above most efficient load. The plot of average daily flow though the Mobile unit illustrates that the unit is usually operated for only part of each day (at efficient load), and is rarely operated at maximum load.

4. Energy Potential of Spill

The monthly distribution of the simulated spill over 15 years for the base case simulation is shown in Figure 5.3 for the Morris station (Mobile Big Pond overflow spillway) and Mobile station (Mobile First Pond overflow spillway).

The simulated annual average spill for the base case was approximately 0.12 m^3/s at Morris. Using the simulated energy conversion factor at maximum load presented previously in this section, the spill would produce approximately 0.2 GWh/yr, if entirely saved and used for generation. At Mobile, the simulated spill occurred in only two years, with annual amounts of 0.03 m^3/s (0.2 GWh) and 0.05 m^3/s (0.4 GWh) for the two years respectively (15 year average less than 0.1 GWh/yr).

5. Reservoir Storage Factor

The main system storage is provided by Mobile Big Pond. The reservoir storage factor (the number of days to fill the reservoir without any outflow) was calculated to be approximately 70 days (without flashboards). Mobile First Pond, used only to provide head and short term storage for the Mobile station, has a reservoir storage factor of five days.

6. Reservoir Utilization Plot

The plot of simulated Mobile Big Pond reservoir levels for the base case simulation is provided in Figure 5.4. The plot illustrates the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range.

7. Forebay Storage Factor

The Morris Forebay comprises only the canal below the gate at Mobile Big Pond. The forebay storage factor (time required to draw forebay down assuming no inflow with the unit operating at maximum load) is estimated to be only a few hours. The Mobile Forebay is essentially an extension of Mobile First Pond, which has a forebay storage factor of more than two days.

8. Gate Operation

The only reservoir with a control gate is Mobile Big Pond. Provided in Figure 5.5 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1987) for Mobile Big Pond. These plots illustrate the frequency the gate is being operated in the simulation model to maintain most efficient load and to avoid spill by operating at maximum load.

Table 5.1
Morris/Mobile System Representative Operating Measures

Morris/Mobile Representative Operating Measures	
Flow Utilization Factors	
- Morris Most Efficient Load	0.91
- Morris Maximum Load	0.82
- Mobile Most Efficient Load	0.50
- Mobile Maximum Load	0.42
Station Factors	
- Morris Most Efficient Load	0.07 kWh/m³
- Morris Maximum Load	0.06 kWh/m³
- Mobile Most Efficient Load	0.29 kWh/m³
- Mobile Maximum Load	0.28 kWh/m³
Energy Potential of Spill	
- Morris Spill	0.2 GWh/yr
- Mobile Spill	<0.1 GWh/yr
Reservoir Storage Factors	
- Mobile Big Pond	70 days
- Mobile First Pond	5 days
Forebay Storage Factor	
- Morris Forebay	<½ day
- Mobile Forebay	2 days

5.3 Ideal Operation of System

The long term energy production of the Morris/Mobile system as estimated by the simulation model developed for the Water Management Study is 51.6 GWh/yr (7.8 GWh/yr at Morris, 43.8 GWh/yr at Mobile). This compares with recorded energy generation for the same reference period (1984-98) of 47.7 GWh/yr (7.2 GWh/yr at Morris, 40.5 GWh/yr at Mobile). While these numbers are not directly comparable due to upgrades of the Mobile unit in 1990, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately four percent for this system. The comparison would therefore suggest that there is little opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual operation at the Morris/Mobile system.

5.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Morris/Mobile system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines state that Morris should be operated at best efficiency 24 hours per day, which should then allow Mobile to be operated about 12 to 14 hours per day depending on inflows.

Obviously, some judgment on the part of the operators in applying the guidelines is required. It is noted that the existing plant operating guidelines provide no guidance on when to increase load to maximum for spill avoidance. Historically, spill has been exceptionally rare. However, with the flashboards removed from Mobile Big Pond, spill may be more frequent in future. For this reason, the simulation model incorporated a rule curve for each reservoir in the system. The rule curves determine how to operate the system, based on the observed reservoir levels. If the reservoir levels are above the rule curve level at any particular time of year, then the units are operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the units are operated at best efficiency. The rule curve used in the simulation model for Mobile Big Pond is illustrated in Figure 5.4. The rule curve for Mobile First Pond was set at the maximum operating level of Mobile Forebay, 150.48 m.

As another example requiring operator judgment, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff.

5.3.2 Gate/Reservoir Operation

The Morris/Mobile system has significant storage capacity that can be effectively used to smooth the basin inflows. Mobile Big Pond provided most of the useable storage capacity. It is also the only reservoir with a control gate. Typically, a constant gate discharge has to be maintained, corresponding to the best efficiency flow of Morris. This requires regular adjustment of the gate position to account for the fluctuation in reservoir level. The full capacity of the gate is much greater than the required discharge, and therefore it is not a limiting factor in selecting appropriate gate settings. However, the gate is not readily accessible. This gate is located approximately 10 km from the nearest major highway along an unpaved road. Accessing the gate requires approximately 45 minutes of travel (one-way) from the Mobile powerhouse. Daily adjustments to this gate are not always possible.

Despite its inaccessibility, several factors ensure that infrequent adjustment of the Mobile Big Pond gate will not greatly affect hydroelectric production. First, the unit at Morris is equipped with good controls which may be used to start and stop the unit remotely. The unit may be shut down for brief periods before the canal begins to spill, without having to adjust the Mobile Big Pond gate. Second, the efficiency curve at Morris is flat enough that operating the unit at loads slightly different than the most efficient load will have minimal impact on generation. Finally, the capacity of the Mobile unit and the storage available at Mobile First Pond ensure that generation at the much larger Mobile plant is not affected by infrequent adjustments to the releases from Mobile Big Pond.

With respect to reservoir operation, prolonged shutdowns at Morris would be the most significant constraint on reservoir utilization. As indicated by the flow utilization factor, the station would have to be operated at most efficient load over 90 percent of the time in an average year to keep up with inflows. Prolonged or frequent outages lead to an accumulation of water in storage which cannot be rapidly reversed, resulting in an increased risk of spill over the long term. In addition, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro (NLH). This winter reserve is not taken into account by the simulation model.

5.3.3 Unit Operation

The simulation model operates the Morris and Mobile units at their most efficient loads, except when higher loads are necessary to avoid exceeding the reservoir rule curves. Both units are equipped with modern control equipment which permits flexible automated remote control. With the available control equipment, minimal constraints on turbine flows, and the available forebay storage in the case of Mobile, it should be possible to operate both stations very close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April 1999, and January-February 2000) confirmed that the Mobile unit is loaded at best efficiency a high percentage of the time. Based on these same daily log sheets, the load on the Morris unit appeared to more variable, possibly as a result of frequent debris blockages at the intake which reduce the unit load for a given turbine flow.

Another obstacle to attaining ideal operation is electrical grid requirements which may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences. In addition, providing a minimum flow in the Morris tailrace spawning channel and infrequent gate adjustments may force the Morris unit to operate at less efficient loads.

5.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

For this system, forebay operation was examined only for Mobile. It was not examined for Morris because its forebay level is only a function of the flow in Morris Canal.

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The base case is an intermediate case, since it uses a rule curve in Mobile Big Pond between full supply level and low supply level, as described in Section 5.3.

Increased Head at Mobile Forebay

To simulate a higher forebay level at Mobile, the level of Mobile First Pond was set to its maximum operating level (150.48 m), instead of the lower part of its operating range, an average increase of about 0.3 m. There was no increase in simulated generation at Mobile. The increase in net head was only about 0.3 percent. Generation at Morris decreased slightly, from 7.8 GWh/yr to 7.7 GWh/yr, due to the higher tailwater elevation resulting from the level of Mobile First Pond.

Spill Avoidance, Limiting Case: Low Rule Curve

The limiting case for spill avoidance is to maximize the amount of storage available in Mobile Big Pond to contain inflows. To do this, the Morris unit would be operated at maximum flow to keep the level of Mobile Big Pond as low as possible.

The potential for savings in spill compared to the base case is low. At Morris, the simulated spills tend to be small; the maximum possible reduction in spill would be the equivalent of 0.2 GWh/yr, as shown in Table 5.1. As well, the high flow utilization factor of Morris suggests that the unit does not have enough unused capacity to achieve a reduction in spill. At Mobile, the simulated spill is both small and infrequent.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the Morris unit was always operated at maximum load when water was available. The average annual spill from Mobile Big Pond was reduced from an average of 0.12 m^3/s to 0.11 m^3/s, but there was a net decrease in average generation at Morris, from 7.8 GWh/yr to 7.7 GWh/yr, due to operating the unit at a lower efficiency. There was no change in average generation at Mobile.

Best Efficiency Operation, Limiting Case: High Rule Curve

The limiting case for maximizing the amount of time operating at best efficiency is to run Morris at best efficiency until Mobile Big Pond is just about to spill.

A simulation using this rule resulted in no change in average annual generation, compared to the base case. This suggests that the rule curve used for the base case simulation is near optimal.

5.5 Physical Changes to System

The principal option for physical changes to the existing system to improve energy generation is to increase storage.

Increase Storage at Mobile Big Pond

For dam safety reasons, the flashboards were recently removed from the Mobile Big Pond overflow spillway. With the flashboards, the full supply level of Mobile Big Pond was 0.97 m higher than existing, and the reservoir had 37 percent more live storage capacity.

To determine the effect of an increase in storage on energy production, the spill elevation was assumed to be restored to its former level. This reduced the average annual spill at Morris from 0.12 m^3/s to 0.01 m^3/s, with a resulting increase in energy generation of 0.1 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh, this would result in a savings to NP of approximately $4000/yr. Given a spillway length of approximately 54 m, the savings over perhaps 20 years would justify an expenditure of about $680/m of spillway length. The practicalities of increasing the spill elevation at Mobile Big Pond would have to be investigated. The spillway flashboards could be reinstalled, but dam safety concerns would still exist as before. One option would be to remove flashboards in years of anticipated high runoff, but in other years to leave them in all year round. If the flashboards cannot be used, then inflatable crest gates (rubber dam) on the spillway section may be considered.

5.6 Sensitivities

No aspects of operation for this system were identified as requiring sensitivity analysis.

5.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

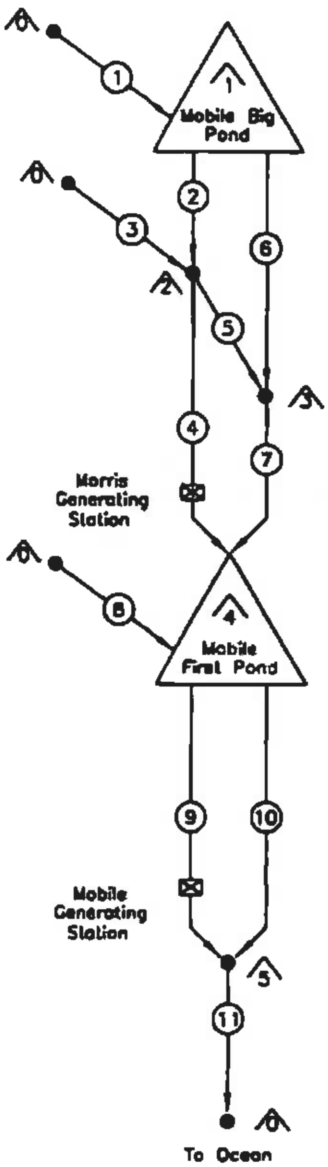
    Gate Operation: The system is presently operated in a manner approaching the ideal indicated by the system model, but it may be desirable to examine the cost of automation and monitoring equipment at the Mobile Big Pond gate compared to the current costs of adjusting the gate manually.

2. **Changes to Operating Guidelines**

    Clarification of Guidelines: NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum to avoid spill. The present guidelines as interpreted for the Water Management Study come close to maximizing system output, if NP can operate in this manner.

3. **Physical Changes**

    Increased Storage: Increasing the storage capacity of Mobile Big Pond to its former value increases energy output by reducing spill. If flashboards cannot be used for dam safety reasons, then an inflatable crest gate (rubber dam) on the spillway section may be considered. NP should investigate the costs and benefits of alternative flashboard/crest gate arrangements, taking into account dam safety requirements.



CHANNELS

1 — Mobile Big Pond Local Inflow
2 — Mobile Big Pond Outlet Gate
3 — Morris Canal Local Inflow
4 — Morris Power Flow
5 — Morris Canal Spill
6 — Mobile Big Pond Spill
7 — Morris Total Spill
8 — Mobile First Pond Local Inflow
9 — Mobile Power Flow
10 — Mobile Spill
11 — Mobile Total Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Mobile Big Pond
2 — Morris Forebay
3 — Morris Total Spill
4 — Mobile First Pond
5 — Mobile Total Outflow

Fig. 5.1

NEWFOUNDLAND POWER
HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY
MORRIS / MOBILE ARSP MODEL SCHEMATIC

ACRES

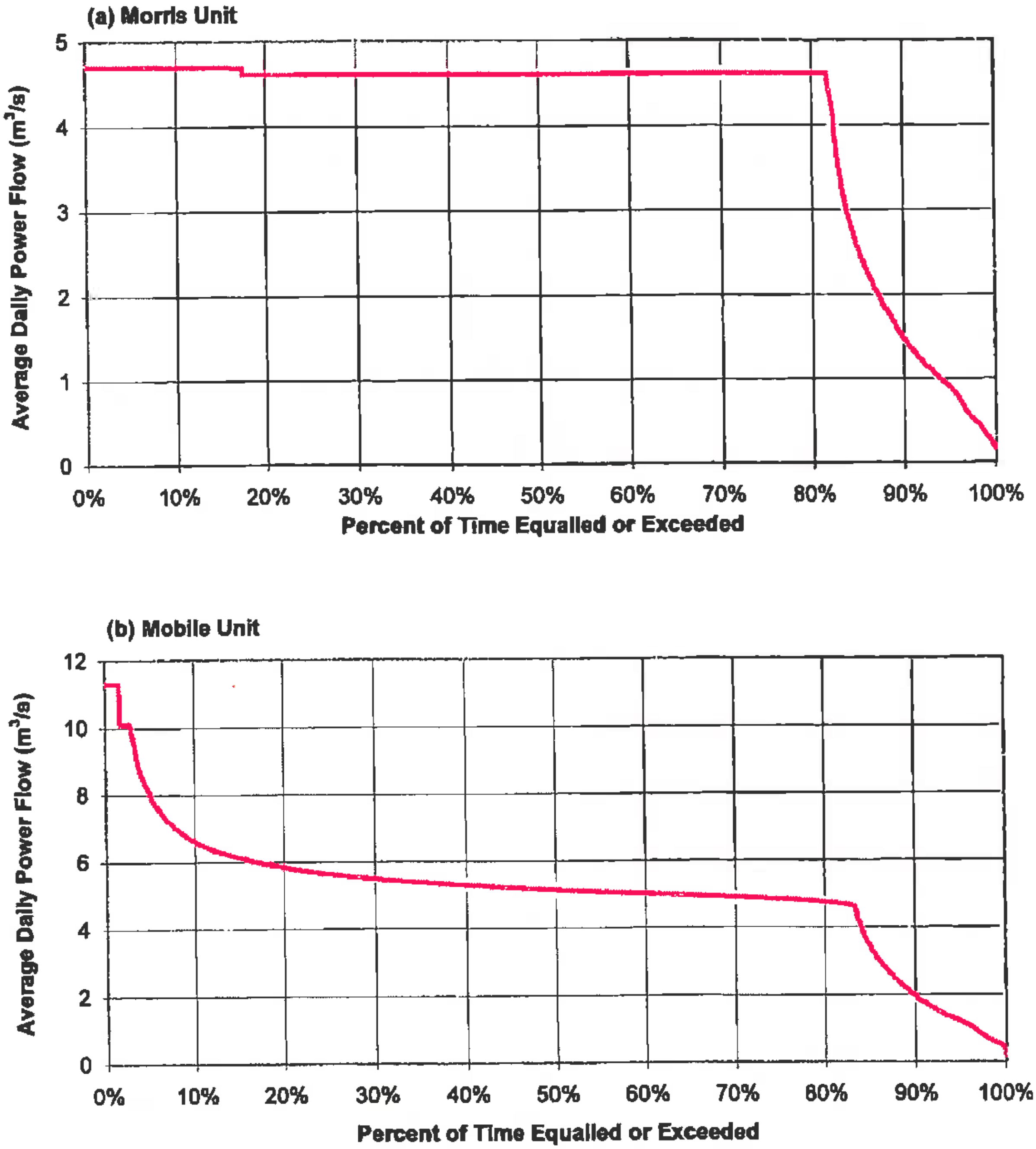


Fig. 5.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

MORRIS AND MOBILE SIMULATED POWER FLOW DURATION CURVES

ACRES

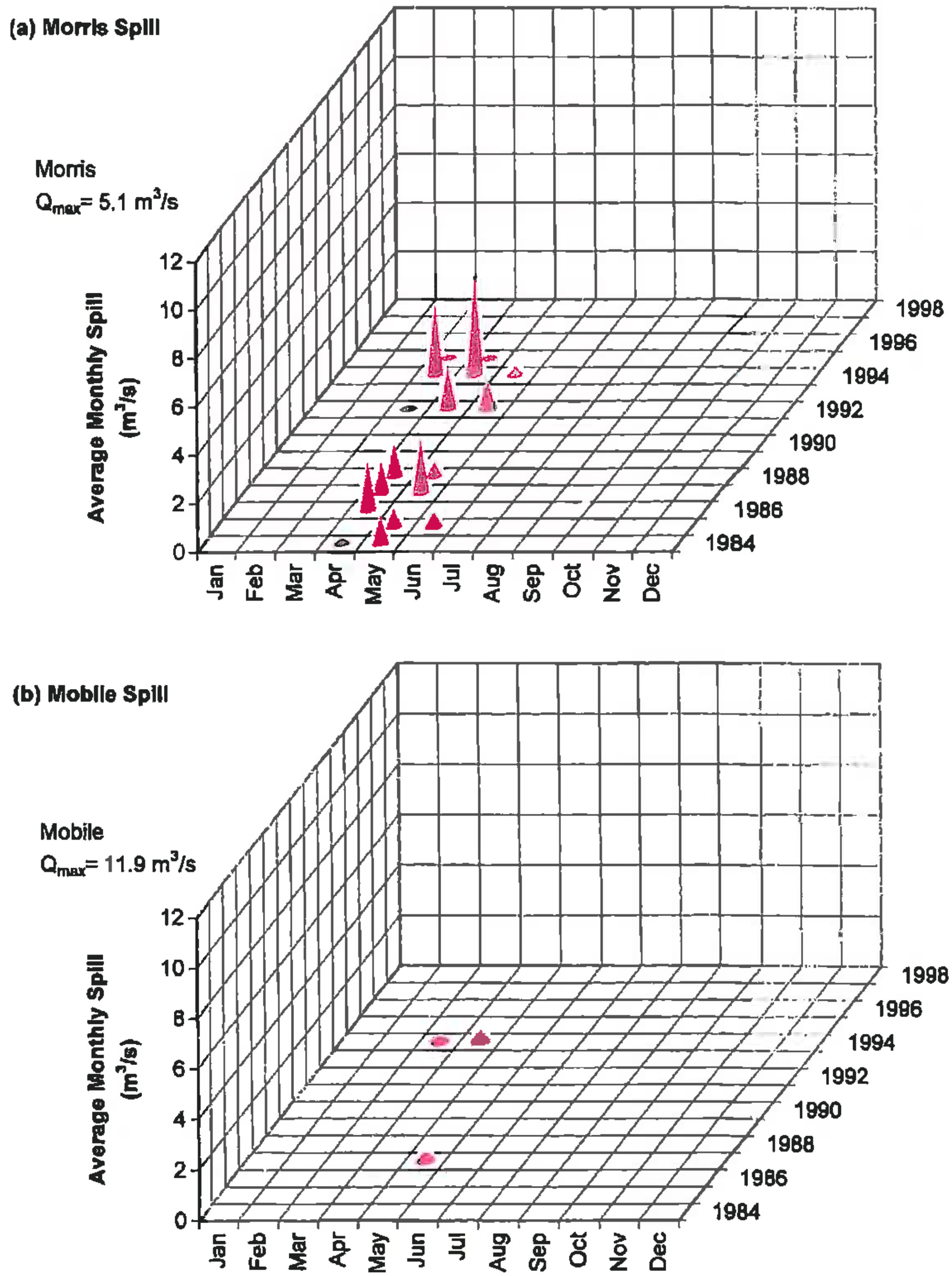


Fig.5.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

MORRIS AND MOBILE SIMULATED SPILLS

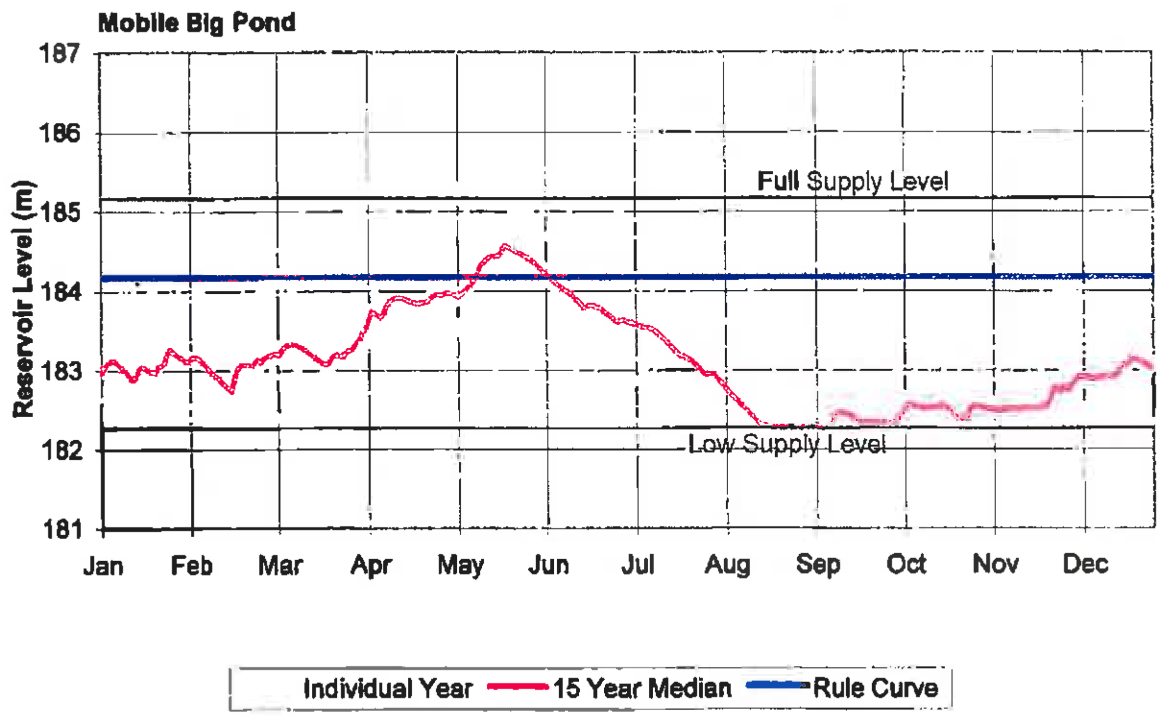


Fig. 5.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

MOBILE BIG POND SIMULATED RESERVOIR LEVELS

ACRES

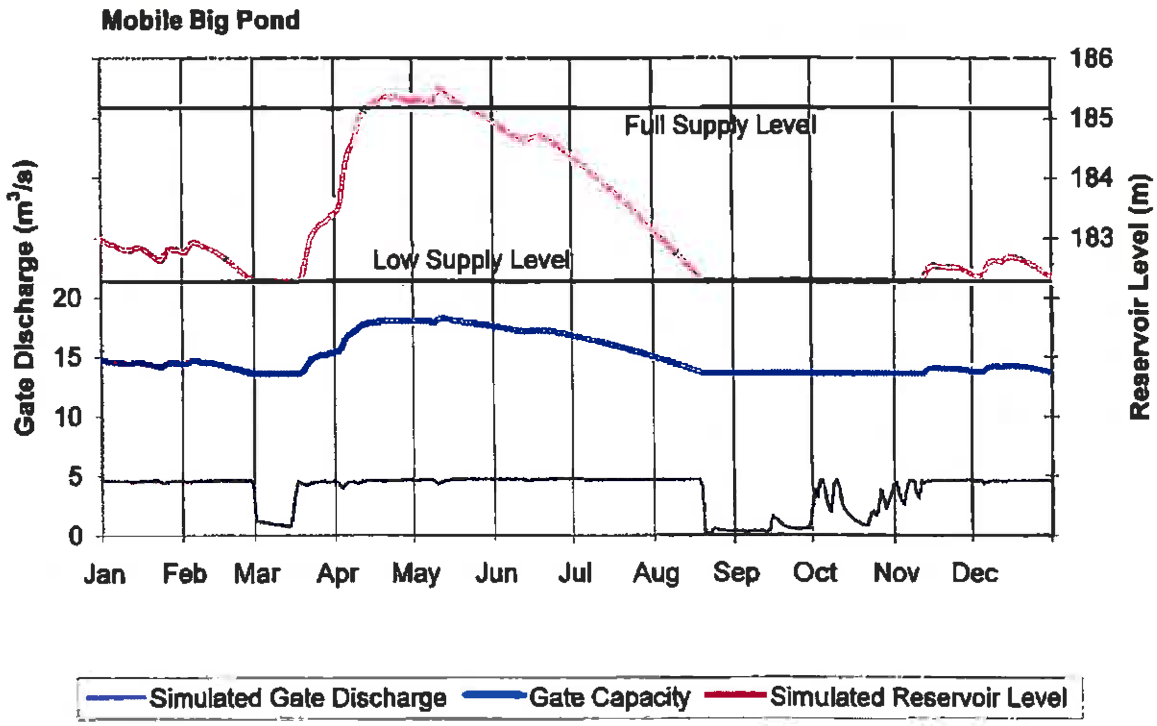


Fig. 5.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

MOBILE BIG POND SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

Rocky Pond/Tors Cove

6 Rocky Pond/Tors Cove Hydroelectric System

Rocky Pond/Tors Cove Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Rocky Pond/Tors Cove system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Rocky Pond/Tors Cove system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Rocky Pond/Tors Cove system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

6.1 System Description

The Rocky Pond/Tors Cove system is located on the southern shore of the Avalon Peninsula in eastern Newfoundland and has two generating stations, Rocky Pond and Tors Cove, located within the system.

The Rocky Pond Generating Station contains one generating unit with a nameplate capacity of 3.25 MW and has a rated net head of 32.6 m. The drainage area above the intake to the Rocky Pond station is approximately 152 km^2. The station was commissioned in 1943. The Tors Cove Generating Station contains three generating units with nameplate capacities of 2.25 MW, 2.25 MW, and 2.4 MW with a rated net head of 52.7 m. The drainage area above the intake to the Tors Cove station is approximately 183 km^2. The station was commissioned in 1940. The total nameplate capacity of the system is 10.25 MW. Storage is provided by structures at Franks Pond, Cape Pond, Rocky Pond Forebay and Tors Cove Pond Forebay. A schematic of the system is presented in Figure 6.1.

All major storage reservoirs are in series, with Franks Pond being the most upstream reservoir in the system. There are two dams with overflow spillways located on Franks Pond, which when overtopped, would lead to spill out of the system. Water is conveyed from Franks Pond through a canal to Cape Pond which has a control structure located at its outlet. Water is conveyed from Cape Pond to Rocky Pond Forebay through the Cluneys and La Manche canals. Spillways are located along both canals, which when overtopped, would lead to spill out of the system. Water from upstream reservoirs entering Rocky Pond Forebay via La Manche Canal is either stored, spilled, or used for generation. Power flow and spill from Rocky Pond Forebay enters Tors Cove Pond Forebay where the water is either stored, spilled out of the system, or used for generation. There is a fish plant located in the community of Tors Cove which draws water from the Tors Cove station penstock for its water supply.

The structures in the system are as follows

- Franks Pond gated outlet;
- Franks Pond overflow spillways;
- Franks Pond Canal overflow spillway;
- Cape Pond gated outlet;
- Cape Pond overflow spillway;
- Cluneys Canal overflow spillways;
- La Manche Canal overflow spillways;
- Rocky Pond Forebay overflow spillway; and
- Tors Cove Pond Forebay overflow spillway.

The Franks Pond, Franks Pond Canal, Cluneys Canal, La Manche Canal and Tors Cove Pond Forebay overflow spillways discharge out of the system; the other spillways discharge within the system.

6.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are presented in Chapter 2. The measures as calculated for the Rocky Pond/Tors Cove system are provided below. They were developed from the data in the base case simulation. Table 6.1 at the end of this section summarizes the measures for the Rocky Pond/Tors Cove system.

1. Flow Utilization Factor

The Rocky Pond station houses one generating unit. The flow utilization factors for the Rocky Pond station (average inflow to forebay divided by combined flow capacity for both units at most efficient load and maximum load) are 0.62 at most efficient load and 0.58 at maximum load.

The Tors Cove station houses three generating units. The flow utilization factors for the Tors Cove station (average inflow to forebay divided by combined flow capacity for both units at most efficient load and maximum load) are 0.59 at most efficient load and 0.47 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage assuming the units are operating alone) for most efficient load and maximum load for ROP-G1 are 0.081 kWh/m^3 (2.57 GWh/yr/m^3/s) and 0.079 kWh/m^3 (2.50 GWh/yr/m^3/s), respectively. For TCV-G1 and TCV-G2 the most efficient load and maximum load conversion factors are 0.114 kWh/m^3 (3.59 GWh/yr/m^3/s) and 0.110 kWh/m^3 (3.48 GWh/yr/m^3/s), respectively. For TCV-G3 the most efficient load and maximum load conversion factors are 0.120 kWh/m^3 (3.78 GWh/yr/m^3/s) and 0.116 kWh/m^3 (3.66 GWh/yr/m^3/s), respectively.

The average energy conversion factors from the base case simulation for ROP-G1, TCV-G1, TCV-G2 and TCV-G3 are 0.080 kWh/m^3 (2.53 GWh/yr/m^3/s), 0.107 kWh/m^3 (3.37 GWh/yr/m^3/s), 0.110 kWh/m^3 (3.47 GWh/yr/m^3/s), and 0.116 kWh/m^3 (3.65 GWh/yr/m^3/s), respectively. These energy conversion factors take into account the average reduction in availability due to forced outages and higher headlosses when the units at Tors Cove are operating at the same time.

Based on the energy conversion factors for the Rocky Pond and Tors Cove units, the recommended dispatch would be as follows.

Rocky Pond

- Operate ROP-G1 at most efficient load first.
- Operate ROP-G1 at maximum load last.

Tors Cove

- Operate TCV-G3 at most efficient load first.
- Operate TCV-G3 at maximum load second.
- Operate TCV-G2 at most efficient load third.
- Operate TCV-G1 at most efficient load fourth.
- Operate TCV-G2 at maximum load fifth.
- Operate TCV-G1 at maximum load last.

The interpretation of the order recommended in NP's plant operating guidelines is the same as the unit dispatch listed above.

3. Flow Duration Curve

The ROP-G1 and TCV-G3 flow duration curves for the turbine flow (power flow) in the base case simulation are shown in Figure 6.2. The curves for TCV-G1 and TCV-G2 are shown Figure 6.3.

4. Energy Potential of Spill

The simulated spill out of the system (Franks, Cluneys Canal, and Tors Cove overflow spillways) for the base case was approximately 0.63 m^3/s on average. Using the average simulated energy conversion factors for both Rocky Pond and Tors Cove presented previously in this section, the spill would produce approximately 3.8 GWh/yr, if entirely saved and used for generation. The Rocky Pond and Tors

Cove stations are in parallel, so total spill out of the system upstream of each station was assumed in the calculation of energy potential of spill.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figure 6.4 for the Franks Pond and Cluneys Canal overflow spillways. Tors Cove Pond Forebay simulated spill is presented in Figure 6.5.

5. Reservoir Storage Factor

Storage is provided by structures located at the outlets of Franks Pond and Cape Pond. Rocky Pond and Tors Cove Pond act as the headponds for the Rocky Pond and Tors Cove stations, respectively. The reservoir storage factors were calculated to be approximately 160 days for Franks Pond, 45 days for Cape Pond, one day for Rocky Pond, and 15 days for Tors Cove Pond. These factors represent the number of days to fill the reservoirs at average inflows without any outflow.

6. Reservoir Utilization Plot

The plot of simulated Franks Pond and Cape Pond reservoir levels for the base case simulation is provided in Figure 6.6. The plot illustrates the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range. For the Rocky Pond/Tors Cove system the use of reservoir storage is not limited by other physical or operational constraints.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with units operating at maximum load) is less than one day (17 hours) for Rocky pond and eight days for Tors Cove Pond.

8. Gate Operation Plot

There are control gates located at the outlet of Franks Pond and Cape Pond. Provided in Figure 6.7 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1987) for Franks Pond and Cape Pond. These plots illustrate the frequency with which the gates are being operated in the simulation model to maintain most efficient load and to avoid spill by operating at maximum load.

Table 6.1
Rocky Pond/Tors Cove System Representative Operating Measures

Rocky Pond/Tors Cove Representative Operating Measures	
Rocky Pond Flow Utilization Factors	
- Most Efficient Load	0.62
- Maximum Load	0.58
Tors Cove Flow Utilization Factors	
- Most Efficient Load	0.59
- Maximum Load	0.47
Station Factors	
- ROP-G1 - Most Efficient Load	0.081 kWh/m^3
- ROP-G1 - Maximum Load	0.079 kWh/m^3
- TCV-G1 - Most Efficient Load	0.114 kWh/m^3
- TCV-G1 - Maximum Load	0.110 kWh/m^3
- TCV-G2 - Most Efficient Load	0.114 kWh/m^3
- TCV-G2 - Maximum Load	0.110 kWh/m^3
- TCV-G3 - Most Efficient Load	0.120 kWh/m^3
- TCV-G3 - Maximum Load	0.116 kWh/m^3
Energy Potential of Spill	3.8 GWh/yr
Reservoir Storage Factors	
- Franks Pond	160 days
- Cape Pond	45 days
- Rocky Pond	1 day
- Tors Cove Pond	15 days
Forebay Storage Factor	
- Rocky Pond	<1 day (17 hours)
- Tors Cove Pond	8 days

6.3 Ideal Operation of System

The long term energy production at Rocky Pond/Tors Cove as estimated by the simulation model developed for the Water Management Study is 45.6 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 39.0 GWh/yr. While these numbers are not directly comparable due to the upgrade of ROP-G1 in 1996 and several prolonged outages affecting generation during this period, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately 11 percent for this system. The comparison would therefore suggest that there is substantial opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce the difference between the simulated ideal operation and actual operation at the Rocky Pond/Tors Cove system.

6.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Rocky Pond/Tors Cove system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plants will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated a rule curve for each reservoir in the system. If the reservoir levels exceed the rule curve at any particular time of the year, then the units are operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the units are operated at best efficiency.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff. The rule curves used in the simulation model are illustrated in

Figure 6.6 and are provided in the echo of the detailed simulation model input in Volume 2 of the Water Management Study.

6.3.2 Gate/Reservoir Operation

The Rocky Pond/Tors Cove system has significant storage capacity that can be effectively used to smooth the basin inflows (storage ratio of 160 days for Franks Pond and 45 days for Cape Pond). Franks Pond and Cape Pond reservoirs provide most of the usable storage capacity. However, the gates that control these reservoirs are not readily accessible. The Franks Pond control structure is located approximately 25 km from the Horsechops powerhouse along a rough, unpaved road. Accessing the gate requires over 2 hours of travel (one-way) from this powerhouse, and therefore daily adjustments are not possible. The Cape Pond gate is located approximately 12 km along an unpaved road from the Rocky Pond powerhouse and requires approximately 1 hour of travel (one-way) from this location. This gate is therefore more easily accessible than Franks Pond and controls a greater fraction of the Rocky Pond/Tors Cove drainage area. However, daily access is still difficult at the best of times and impossible under some circumstances.

As a result of this inaccessibility, infrequent adjustment of the Franks Pond and Cape Pond gates are thought to have a significant affect on hydroelectric production. The problem is compounded by the fact that discharges from both of these reservoirs are conveyed downstream by canals with limited capacities. Flows exceeding the canal capacities are lost to generation due to spills from numerous canal spillways. While little spill is recorded at these spillways, the simulation model suggests that either significant quantities of spill go unnoticed at these locations or the canals are operated at less than full capacity the majority of the time. This latter possibility would also affect generation as the reservoirs would not be fully utilized and spills would likely occur from these reservoirs as a result.

In addition to the accessibility issues, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro. This winter reserve is not taken into account by the simulation model.

For the Rocky Pond/Tors Cove system, the gate and reservoir operational difficulties discussed above are likely the largest component of the difference between the simulated and actual generation.

6.3.3 Unit Operation

The simulation model operates the Rocky Pond and Tors Cove units exclusively at their most efficient loads, except when high inflows dictate that higher loads are necessary to avoid exceeding the reservoir rule curves. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate these plants very close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April and August 1999, and January-February 2000) confirmed that the Rocky Pond and Tors Cove units are loaded at best efficiency a high percentage of the time. The main obstacles to attaining ideal operation are electrical grid requirements that may occasionally require the units to operate at loads other than their most efficient loads. An example of such requirements would be local power outages, which occur infrequently and therefore should not significantly affect annual production.

6.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Each of these is discussed below for the Rocky Pond/Tors Cove system. Increasing the head through a change in the use of flashboards or installation of inflatable crest gates was not considered for Tors Cove Pond due to the effect an increase in level would have on the tailwater for the Rocky Pond station. It was, however, considered as a sensitivity discussed in Section 6.6.

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The case described for the base case simulation is the high rule curve case and represents the maximum time operating at best efficiency; therefore, only the spill avoidance case was considered.

Increasing Head: Operating Forebay Higher to get More Head
As interpreted from NP plant operating guidelines for the Rocky Pond Forebay, the operating level is approximately 0.2 m below the full supply level. The simulation model was run assuming that the Rocky Pond Forebay level was kept at the full supply level. The resulting increase in energy generation from this change was 0.10 GWh/yr, from 45.61 GWh/yr to 45.71 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $4000/yr for no cost. It is possible that this type of operating change could have dam safety implications. If NP were to implement this operating change in the plant operating guidelines, the implications to dam safety should be further investigated.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low
The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At Rocky Pond/Tors Cove, the potential for savings in spill is high. The maximum possible reduction in spill would be the equivalent of 3.8 GWh/yr, as shown in Table 6.1. However, the spill distribution plot (Figure 6.4) shows that most of the spill is at Cluneys Canal. To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The result was a decrease in spill at Tors Cove Pond Forebay, but a decrease in energy generation of 0.02 GWh/yr due to operating the units at maximum efficiency more of the time. The spill at Cluneys Canal is the greatest in the system and remained unchanged compared to the base case simulation.

6.5 Physical Changes to System

The two principal options for physical changes to the existing system to improve energy generation are to increase storage and canal capacity. To give an indication of the value of these changes, the following options were investigated.

- Increase sill elevation of Franks Pond overflow spillway.
- Increase dam height at Franks Pond.
- Increase dam height at Cape Pond.
- Increase La Manche Canal capacity.
- Increase dam height at Cape Pond and La Manche Canal capacity.
- Reduce headloss.

Each of these physical changes to the system is discussed below. Table 6.2 summarizes the results.

Increase Sill Elevation of Franks Pond Overflow Spillway

To determine the effect increasing the sill elevation of Franks Pond overflow spillway would have on energy production, the sill elevation was raised half a metre and one metre. The effect is to reduce spill out of the system at Franks Pond. The resulting increases in energy generation were 0.08 GWh/yr for the half meter rise, and 0.16 GWh/yr for the one meter rise.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $3 200/yr for the half meter increase in sill elevation and $6 400/yr for the one meter increase in sill elevation. Given a spillway length of approximately 120 m, the savings over perhaps 20 years would justify an expenditure of about $485/m of dam length based on a one meter increase. The practicalities of increasing the sill elevation at Franks Pond overflow spillway would have to be investigated. By increasing the sill elevation while leaving the top of the dam at the same elevation effectively reduces the spill capacity. If this change were made to the system, NP would have to address the dam safety concern of reduced spillway capacity. A detailed analysis into the benefits and cost would have to be conducted to determine the economical feasibility.

Increase Dam Height at Franks Pond

To determine the effect of an increase in storage on energy production, the dams and structures at Franks Pond were assumed to be raised to allow an increase in full supply level of one and a half meters. The effect is to reduce system spill. The resulting increase in energy generation was 0.19 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $7 600/yr. Given a dam length of approximately 580 m, the savings over perhaps 20 years would justify an expenditure of about $120/m of dam length based on a one and a half meter increase. The practicalities of increasing the dam at Franks Pond would have to be investigated. A detailed analysis into the benefits and cost would have to be conducted.

Increase Dam Height at Cape Pond

To determine the effect increasing the dam height at Cape Pond would have on energy production, all structures at Cape Pond were assumed to be raised by one meter and two meters. The effect is to reduce spill at Cape Pond which leads to spill out of the system at Cluneys Canal. The resulting increases in energy generation were 0.55 GWh/yr for the one meter rise, and 0.80 GWh/yr for the two meter rise.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $22 000/yr for the one meter increase in dam height and $32 000/yr for the two meter increase in dam height. Given a dam length of approximately 160 m, the savings over perhaps 20 years would justify an expenditure of about $1824/m of dam length based on a two meter increase. The practicalities of increasing the dam height at Cape Pond would have to be investigated. A detailed analysis into the benefits and cost would have to be conducted to determine the economical feasibility. For the two meter rise in dam height there is spill at Cape Pond in the simulation. As a further analysis, the dam height could be optimized to further reduce spill by increasing dam height and preparing detailed costs for the increment of dam height.

Increase La Manche Canal Capacity

To determine the effect of an increase in canal capacity has on energy production, the capacity at La Manche Canal was assumed to be increased from 6.0 m^3/s in the base case simulation model to 7.0 m^3/s, 8.0 m^3/s, and 9.0 m^3/s. The effect is to reduce spill at Cluneys Canal. The resulting increase in energy generation was 1.54 GWh/yr for 7 m^3/s capacity, 2.21 GWh/yr for 8.0 m^3/s capacity, and 2.47 GWh/yr for 9.0 m^3/s capacity.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $61 600/yr for 7 m^3/s capacity, $88 400 for 8.0 m^3/s capacity, and \$98 800 for 9.0 m^3/s capacity. The savings over perhaps 20 years would justify a capital cost expenditure of about \$900 000 on canal improvements to upgrade the canal to pass a maximum of 9.0 m^3/s. The practicalities of increasing the capacity of the canal would have to be investigated. A detailed analysis into the benefits and cost would have to be conducted.

Increase Dam Height at Cape Pond and La Manche Canal Capacity

To determine the combination effect increasing the dam height at Cape Pond and increasing the La Manche canal capacity would have on energy production, all structures at Cape Pond were assumed to be raised by two meters and the canal capacity was assumed to be increased from 6.0 m^3/s to 9.0 m^3/s. The effect is to reduce spill out of the system at Cluneys Canal by reducing spill at Cape Pond and increasing canal capacity. The resulting increase in energy generation was 2.88 GWh/yr.

Assuming that the cost of energy to NP is \$0.04/kWh this would result in a savings to NP of approximately \$115 200/yr or a net present value of about \$1 051 000 assuming an interest of nine percent over 20 years. The practicalities of increasing the dam height at Cape Pond and La Manche canal capacity would have to be investigated. A detailed analysis into the benefits and cost would have to be conducted to determine the economical feasibility. As a further analysis, the dam height and canal capacity could be optimized to further reduce spill by increasing dam height and canal capacity, and preparing detailed costs for each increment of dam height and canal capacity.

Reduce Headloss

To determine the effect decreasing the headlosses at Tors Cove station would have on energy production, the units were assumed to be able to operate at maximum load when all units were operating together. The resulting increase in energy generation was 0.34 GWh/yr.

Assuming that the cost of energy to NP is \$0.04/kWh this would result in a savings to NP of approximately \$13 600/yr. The practicalities of decreasing the headlosses would have to be investigated. A detailed analysis into the benefits and cost would have to be conducted.

Table 6.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	45.61	-
Increase Franks Pond Spill 0.5 m	45.69	0.08
Increase Franks Pond Spill 1.0 m	45.77	0.16
Increase Franks Pond Dam 1.5 m	45.80	0.19
Increase Cape Pond Dam 1.0 m	46.16	0.55
Increase Cape Pond Dam 2.0 m	46.41	0.80
Increase La Manche Canal 1 m^3/s	47.15	1.54
Increase La Manche Canal 2 m^3/s	47.82	2.21
Increase La Manche Canal 3 m^3/s	48.08	2.47
Increase Cape Pond Dam 2.0 m Increase La Manche Canal 3 m^3/s	48.49	2.88
Reduce Headlosses	45.95	0.34

6.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of their systems. The gates that control the reservoirs are difficult to access and canals downstream of the two main reservoirs have maximum discharge capacities limiting the amount of flow that can be passed to the stations downstream. In addition to some standard sensitivities, the cases chosen for Rocky Pond/Tors Cove were selected with a view to providing NP with some values related to its specific situation. Results for all sensitivity cases are provided in Table 6.3. Along with the average energy generation, average annual spill out of the system for each case is presented in Table 6.3.

The sensitivity cases were as follows.

- Environmental release requirement of 30 percent of mean annual flow.
- No storage in system (to obtain value of storage); remove dams and gates.

- Changes to Tors Cove Fish Plant Water Supply Demand.
- Changes to Franks Pond gate operation.
- Changes to Maximum Capacity of Franks Pond Canal.
- Changes to Tors Cove Operating Levels.

Environmental Release Requirement
The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 0.54 m^3/s at Franks Pond and 1.48 m^3/s at Cape Pond. This amount is always released in all simulations unless there is no water in storage, in which case the natural inflows are released. Using these flows as the minimum flow release from the gates for the base case simulation model, there was a decrease in average energy of 0.24 GWh/yr, from 45.61 GWh/yr to 45.37 GWh/yr. Assuming that the cost of energy to NP is $0.04/kWh this would result in a loss in revenue to NP of approximately $9 600/yr, if NP where required to release 30 percent of the mean annual flow.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement were always met, there would likely be a larger reduction in energy.

No Storage in System
To provide NP with an indication of the value of the storage in the system, all storage in the system was assumed to be removed. The resulting average annual energy generation from this sensitivity was 40.90 GWh/yr, a net decrease of 4.71 GWh/yr. Assuming that the cost of energy to NP is $0.04/kWh this would result in a loss in revenue to NP of approximately $188 400/yr, if NP where to remove all storage from the system. This represents the value of maintaining the structures at Franks Pond and Cape Pond. For this simulation it was assumed that all the basin inflow would enter Rocky Pond Forebay. This may not be the case because by removing the upstream structures, including the canals, would cause water to divert away from the forebay and into another basin. Therefore, this result may not represent the actual

value of storage, but does provide an indication as to the magnitude no storage in the system would have on energy generation

Changes to Tors Cove Fish Plant Water Supply Demand
For the base case simulation model the assumed water supply demand to Tors Cove fish plant was 0.023 m^3/s. The effect a plus or minus 50 percent change in water supply demand would have on energy generation was determined by simulating the model for this change in water supply. The resulting average annual energy generation from this sensitivity was 45.57 GWh/yr, a net decrease of 0.04 GWh/yr for a 50 percent increase, and 45.64 GWh/yr, a net increase of 0.03 GWh/yr for a 50 percent decrease. Assuming that the cost of energy to NP is $0.04/kWh this would result in a loss in revenue to NP of approximately $1 600/yr for a 50 percent increase in water supply demand. The resulting savings to NP for a reduction in water supply demand by 50 percent would be $1 200/yr.

Changes to Franks Pond Gate Operation
The difficult access to the Franks Pond outlet structure makes it an obvious candidate for automation, if it were cost effective. The simulation for the base case assumed that the gate could be operated daily, and the gate operation plot in Figure 6.7 showed that the gate is rarely open to full capacity and are closed in April; possibly to avoid spill at Cluneys Canal. The base case could be considered the full automation case. The analysis was carried out for Franks Pond, but the results would be similar for Cape Pond.

To investigate the value of automation, or of some alternative procedure, three cases were considered. A variety of other cases are possible, but these three give an indication of the range of savings that can be achieved. The three cases are

- Leave gate full open: leave the gate open all the time, using whatever natural regulation remains;
- Seasonal operation: adjusting the gate a couple of times a year; and
- Leave gate partially open: restrict the opening to improve the natural regulation, leaving the gate in a partly open position all year round.

The effects of these three procedures are described below.

Leave Gate Full Open: Because of the difficulty of adjusting Franks Pond outlet gate, one option is to simply leave the gate open. The structure itself will provide some natural regulation. The difference in the estimate of energy generation in this case and the base case indicates the value of having a gate that can be operated daily. The resulting energy generation from this sensitivity was 42.50 GWh/yr, or a net decrease in energy of 3.11 GWh/yr. This decrease is due to extra spill out of the system at Cluneys Canal, and additional operation at maximum load. Assuming that the cost of energy to NP is $0.04/kWh this would result in a loss in revenue to NP of approximately $124 400/yr or a net present value of $1 135 000 (assuming 20 years at nine percent interest). The gate should be able to be automated for a cost less than the net present value of loss in revenue.

However, it may be possible to obtain some or all of the energy gains more cost-effectively, as considered in the two other options.

Seasonal Operation: In this case, the gate was assumed to be operated twice a year, closed in April and opened fully in May. The resulting energy generation from this sensitivity was 42.80 GWh/yr or a net decrease in energy of 2.81 GWh/yr.

Leave Gate Partially Open: The Franks Pond outlet gate was assumed to be opened to release 2 m^3/s at an elevation half way between full supply and low supply level. The resulting energy generation from this sensitivity was 44.80 GWh/yr or a net decrease in energy of 0.81 GWh/yr. As the table below shows this would be the best of the three alternatives considered here for gate operation at Franks Pond. With the exception of possibly fabricating stoplogs there should be no cost to this option. Other gate settings could be investigated to optimize the size of the gate opening that provides the smallest decrease in energy generation from the base case.

Changes to Maximum Capacity of Franks Pond Canal

In this case, the maximum canal capacity of Franks Pond Canal was assumed to 1.5 m^3/s and 3.5 m^3/s. The canal capacity in the base case simulation is 2.5 m^3/s. The resulting energy generation from this sensitivity was 43.91 GWh/yr for the 1.5 m^3/s canal capacity (net decrease in energy of 1.7 GWh/yr) and 45.51 GWh/yr for the 3.5 m^3/s canal capacity (net decrease in energy of 0.1 GWh/yr).

Changes to Tors Cove Operating Levels

Due to the negative effect on Rocky Pond station energy generation an increase in Tors Cove Pond Forebay operating level would have, increasing the operating level was investigated as a sensitivity. As interpreted from NP's plant operating guidelines the operating level for Tors Cove Pond Forebay is below the full supply level. For this sensitivity it was assumed that the operating level would be the full supply level.

The resulting average annual energy generation from this sensitivity was 45.53 GWh/yr, a net decrease of 0.08 GWh/yr.

Table 6.3
Energy Results for Sensitivity Simulations at Rocky Pond/Tors Cove System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)	Spill Out of System (m^3/s)
Base Case	45.61	-	0.63
Environmental Releases	45.37	-0.24	0.67
Value of Storage	40.90	-4.71	1.14
Water Supply Demand - 50% + 50%	45.57 45.64	-0.04 +0.03	0.63 0.63
Franks Pond Gate Operation - Leave Gate Full Open - Seasonal Operation - Leave Gate Partially Open	 42.50 42.80 44.80	 -3.11 -2.81 -0.81	 1.13 1.08 0.80
Maximum Capacity Franks Pond 1.5 m^3/s	43.91	-1.70	0.87
Maximum Capacity Franks Pond 3.5 m^3/s	45.51	-0.10	0.65
Tors Cove Operating Level	45.53	-0.08	0.66

6.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

   Gate/Unit operation: The analysis shows that controlling the release of water from storage and operation of the units does effect the energy output of the Rocky Pond/Tors Cove system. Automation of the gates would provide the best control, but simpler approaches would be more cost effective and provide close to the energy produced due to ideal operation by reducing the full capacity of the gates.

2. **Changes to Operating Guidelines**

   Clarification of Guidelines: The present guidelines as interpreted for the Water Management Study come close to maximizing system output if NP can operate in this manner. NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum.

3. **Physical Changes**

   Increased Storage: Because of the fact that the canal capacities reduce the amount of water that can be passed down the system to the generating stations, storage is important in the system to reduce spill out of the system. The maximum gain in energy for increased storage was 0.80 GWh/yr for a two meter increase in structures and dam height at Cape Pond.

   Increased Canal Capacity: An increase canal capacity at Cluneys Canal would reduce spill out of the system and increase energy generation by 2.47 GWh/yr for a 3 m^3/s increase in canal capacity. The cost for increasing capacity should be further investigated to do a detailed optimization analysis.

   Reduce Headlosses: To determine the effect decreasing the headlosses at Tors Cove station would have on energy production, the units were assumed to be able to operate at maximum load when all units were operating together. The resulting increase in energy generation was 0.34 GWh/yr.

4. Sensitivities

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gates at Franks Pond and Cape Pond reduces the energy generation by 0.24 GWh/yr. The requirement, however, assumes that when the reservoirs are low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.

Value of Storage: The value of the storage at Franks Pond and Cape Pond is approximately 4.71 GWh/yr. This may not be the case because removing the upstream structures, including canals, would cause water to divert away from the forebay and into another basin, therefore, this result may not represent the actual value of storage, but does provide an indication as to the magnitude no storage in the system would have on energy generation. NP may use this value in considering the costs of maintaining these structures.

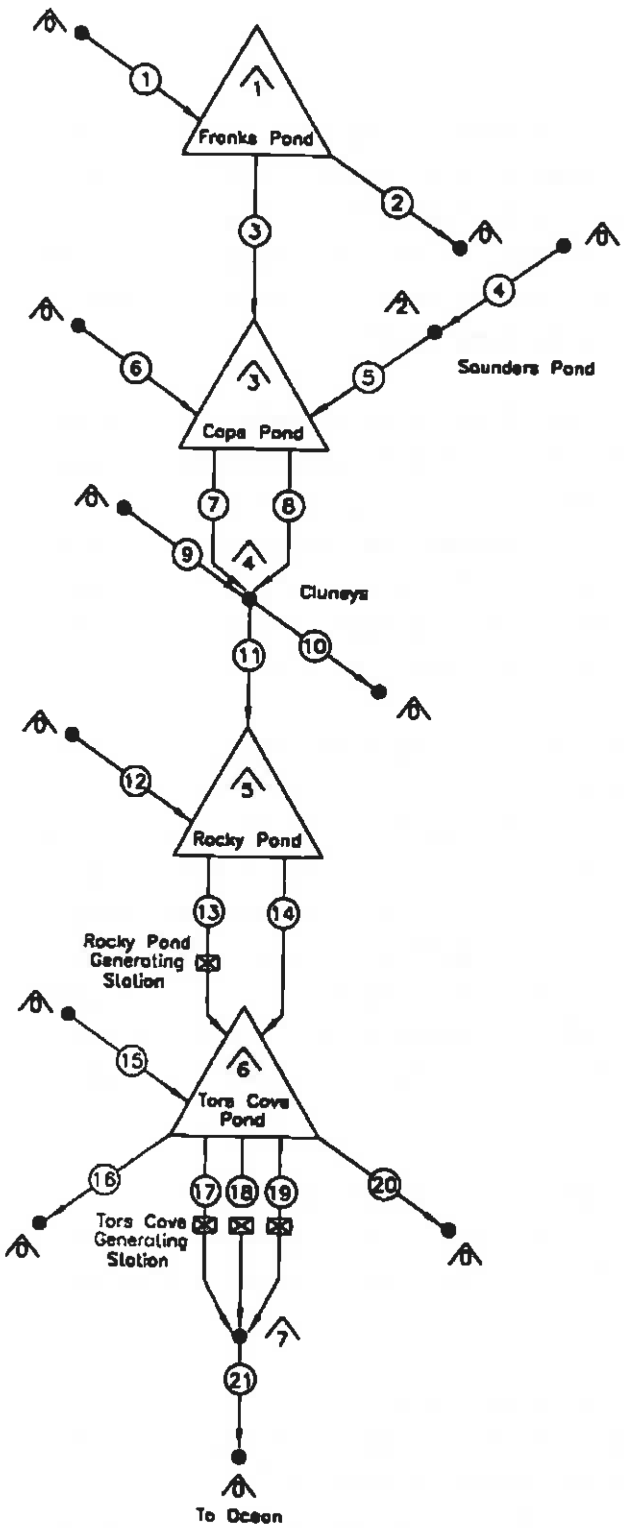
Changes to Franks Pond Outlet Gate Control/Operation: The value of operating the gate at Franks Pond on a daily basis is 3.11 GWh/yr. However, it may be possible to obtain some or all of the energy gains more cost-effectively, considering changing the gate setting a couple of times a year or restricting the gate opening. In the simulation to consider alternatives for Franks Pond, the outlet gate was assumed to be operated daily if required. NP should determine the costs of automation or more frequent personnel access to the gates at both Franks Pond and Cape Pond, and compare it with the costs and benefits of the simpler approaches at both locations. The most cost-effective overall solution can then be selected.

Changes to Maximum Capacity of Franks Pond Canal

A plus or minus 1 m^3/s in canal capacity of 2.5 m^3/s results in a decrease in energy generation. Therefore, the canal capacity has modelled in the base case is close to optimal.

Changes to Tors Cove Operating Levels

Changing Tors Cove station operating level to full supply level reduces the system energy generation. The gain in generation in Tors Cove due to increased head is not enough to offset the loss in generation at Rocky Pond due to the increase in tailwater.



CHANNELS

① — Franks Pond Local Inflow
② — Franks Pond Spill
③ — Franks Pond Canal
④ — Saunders Pond Local Inflow
⑤ — Saunders Pond to Cape Pond General Flow
⑥ — Cape Pond Local Inflow
⑦ — Cape Pond Spill
⑧ — Cape Pond Outlet Gate
⑨ — Cluneys Canal Local Inflow
⑩ — Cluneys Canal Spill
⑪ — La Manche Canal
⑫ — Rocky Pond Local Inflow
⑬ — Rocky Pond Power Flow (ROP-G1)
⑭ — Rocky Pond Spill
⑮ — Tors Cove Pond Local Inflow
⑯ — Tors Cove Pond Spill
⑰ — Power Flow (TCV-G1)
⑱ — Power Flow (TCV-G2)
⑲ — Power Flow (TCV-G3)
⑳ — Fish Plant Demand
㉑ — Tors Cove Total Power Flow

RESERVOIRS / NODES

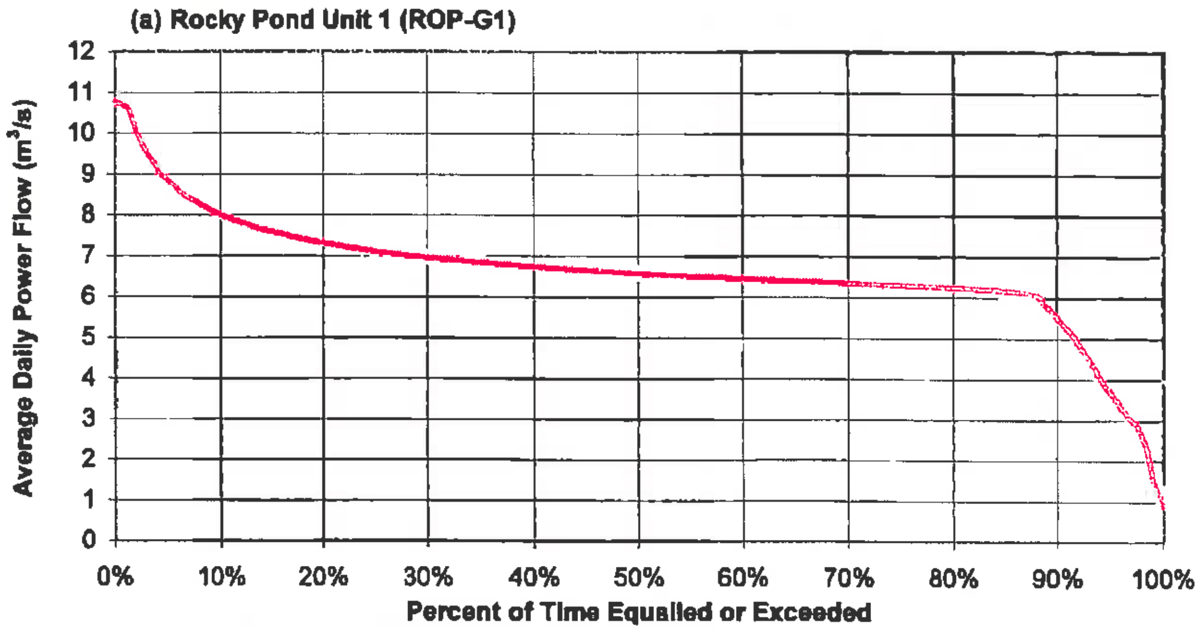
0 — Source / Sink
1 — Franks Pond
2 — Saunders Pond
3 — Cape Pond
4 — Cluneys
5 — Rocky Pond
6 — Tors Cove Pond
7 — Tors Cove Total Power Flow

Fig. 6.1

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

ROCKY POND/TORS COVE ARSP MODEL SCHEMATIC



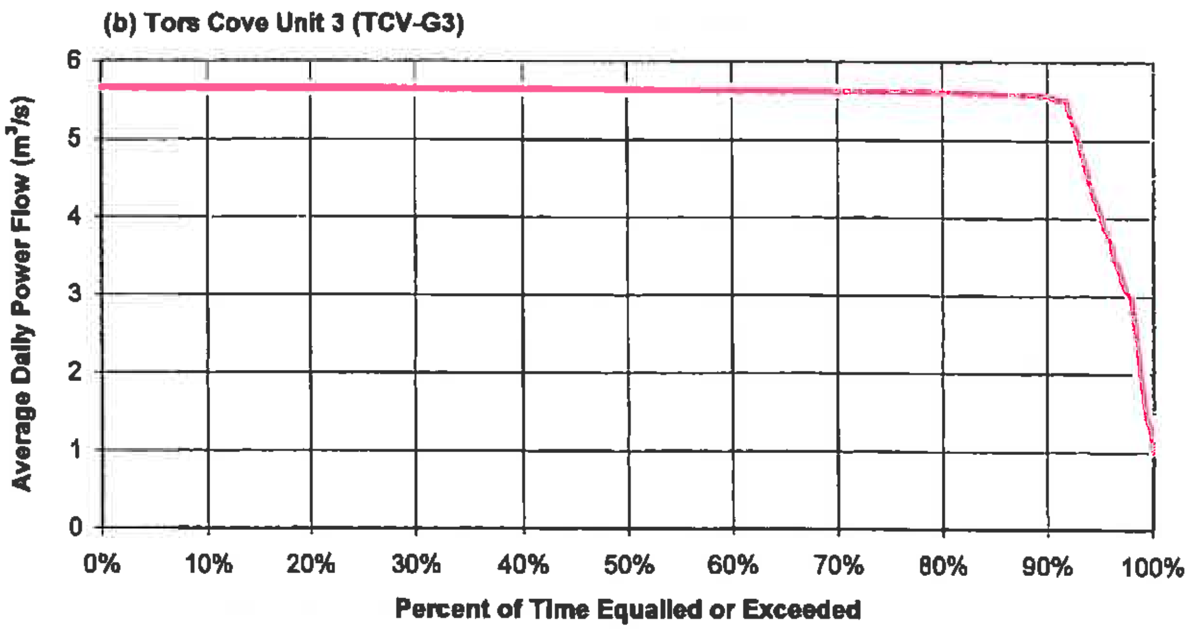


Fig. 6.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

ROCKY POND/TORS COVE (UNIT 3) SIMULATED POWER FLOW DURATION CURVES

ACRES

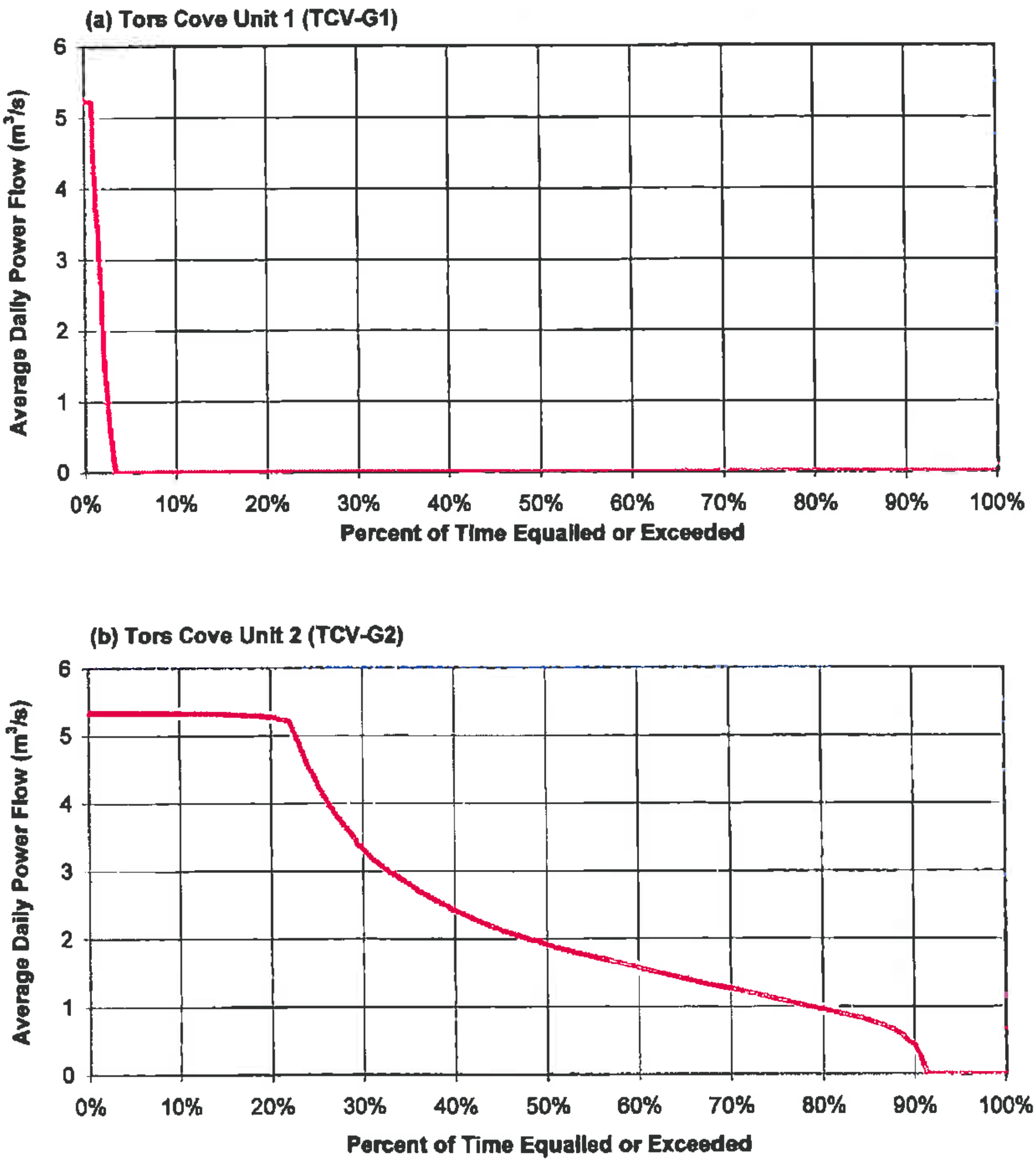


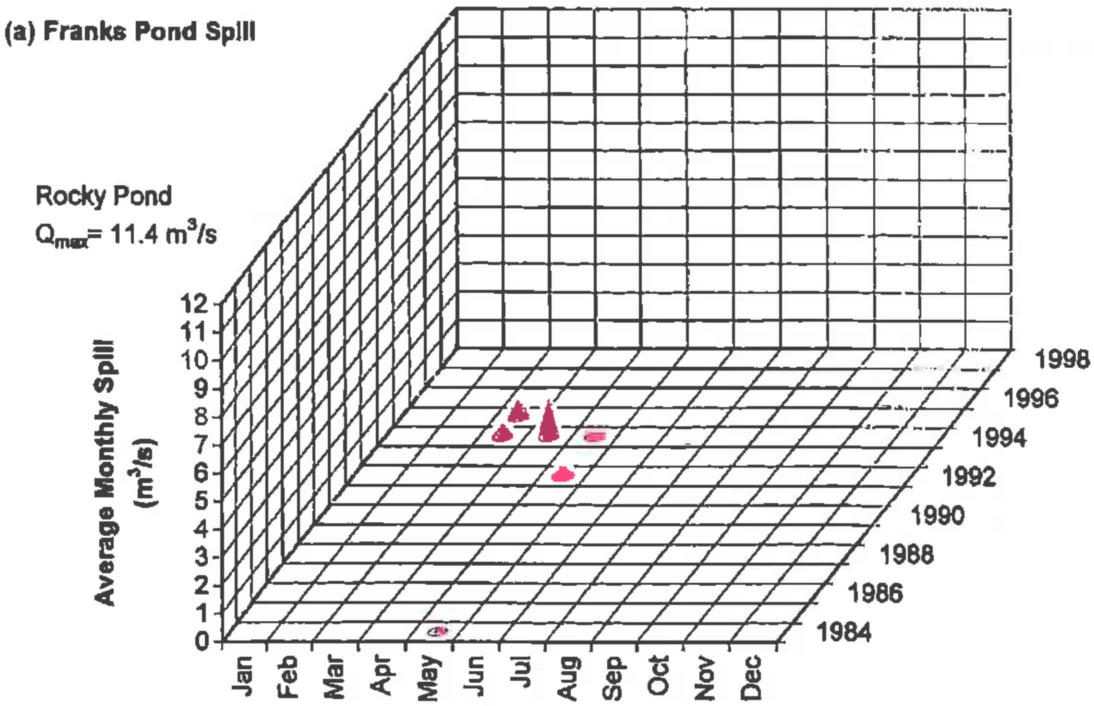
Fig. 6.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

TORS COVE (UNITS 1 AND 2) SIMULATED POWER FLOW DURATION CURVES

ACRES



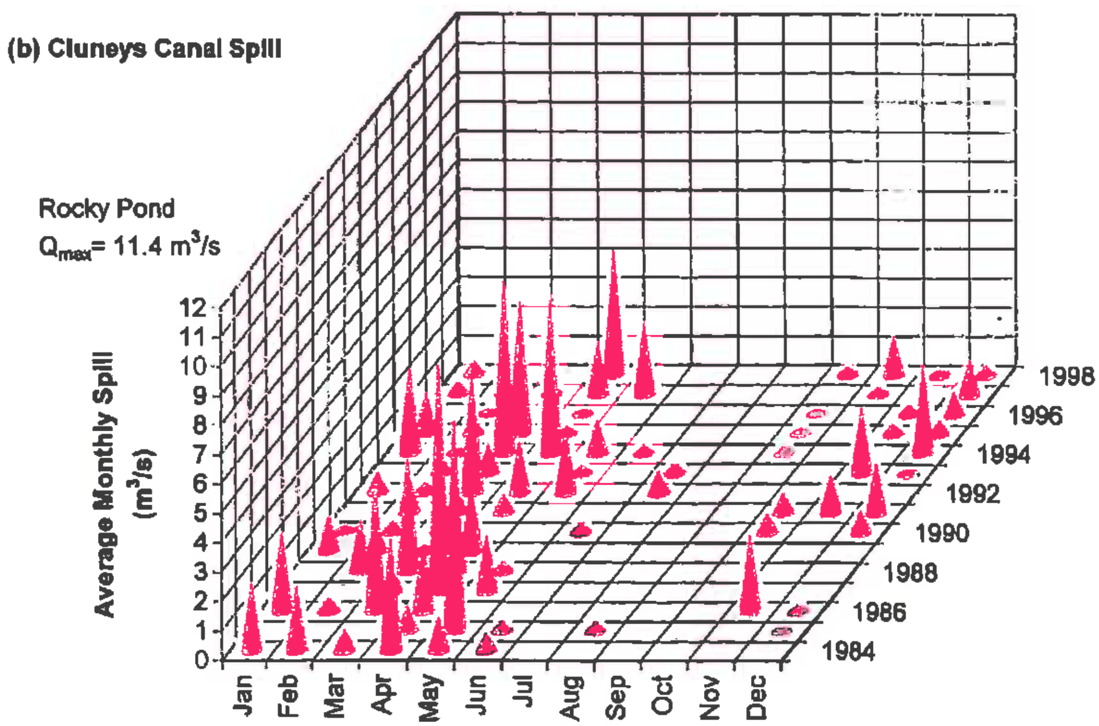


Fig. 6.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

FRANKS POND AND CLUNEYS CANAL SIMULATED SPILLS

ACRES

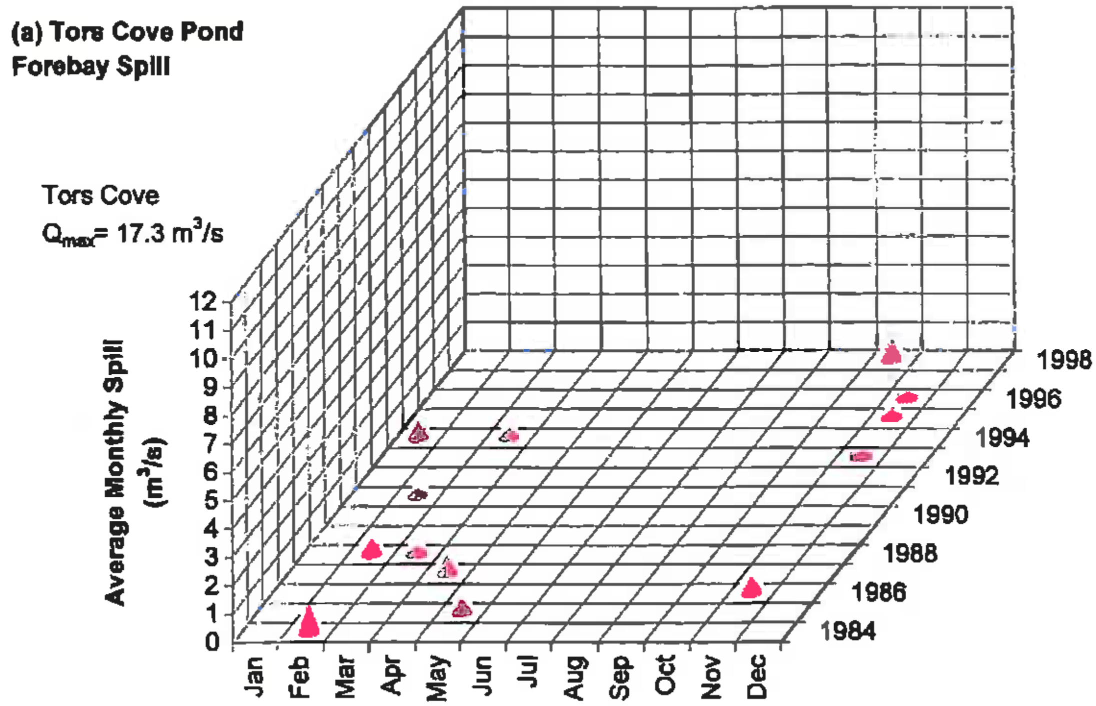


Fig. 6.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

TORS COVE POND FOREBAY

SIMULATED SPILLS

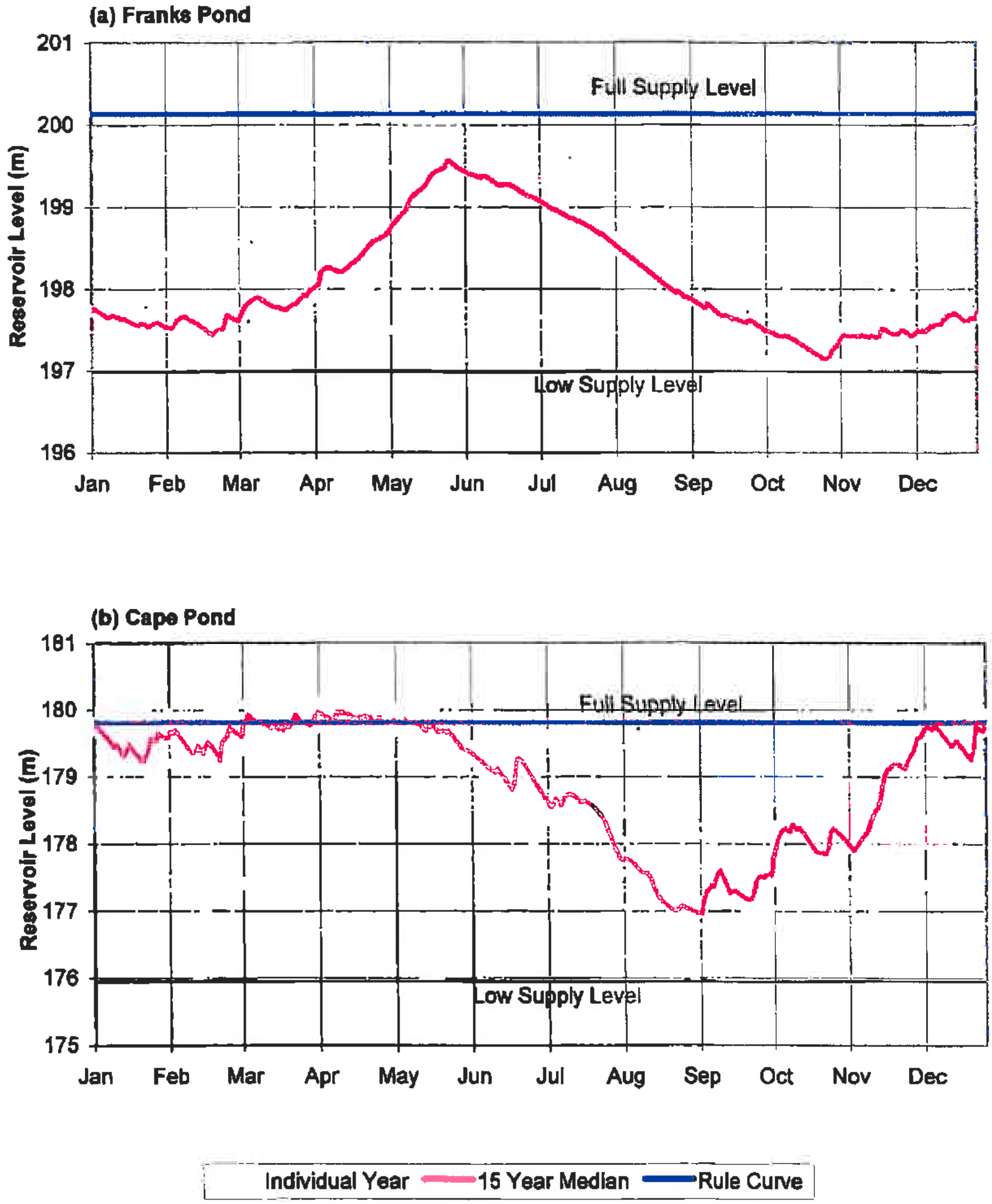


Fig. 6.6

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

FRANKS POND AND CAPE POND
SIMULATED RESERVOIR LEVELS

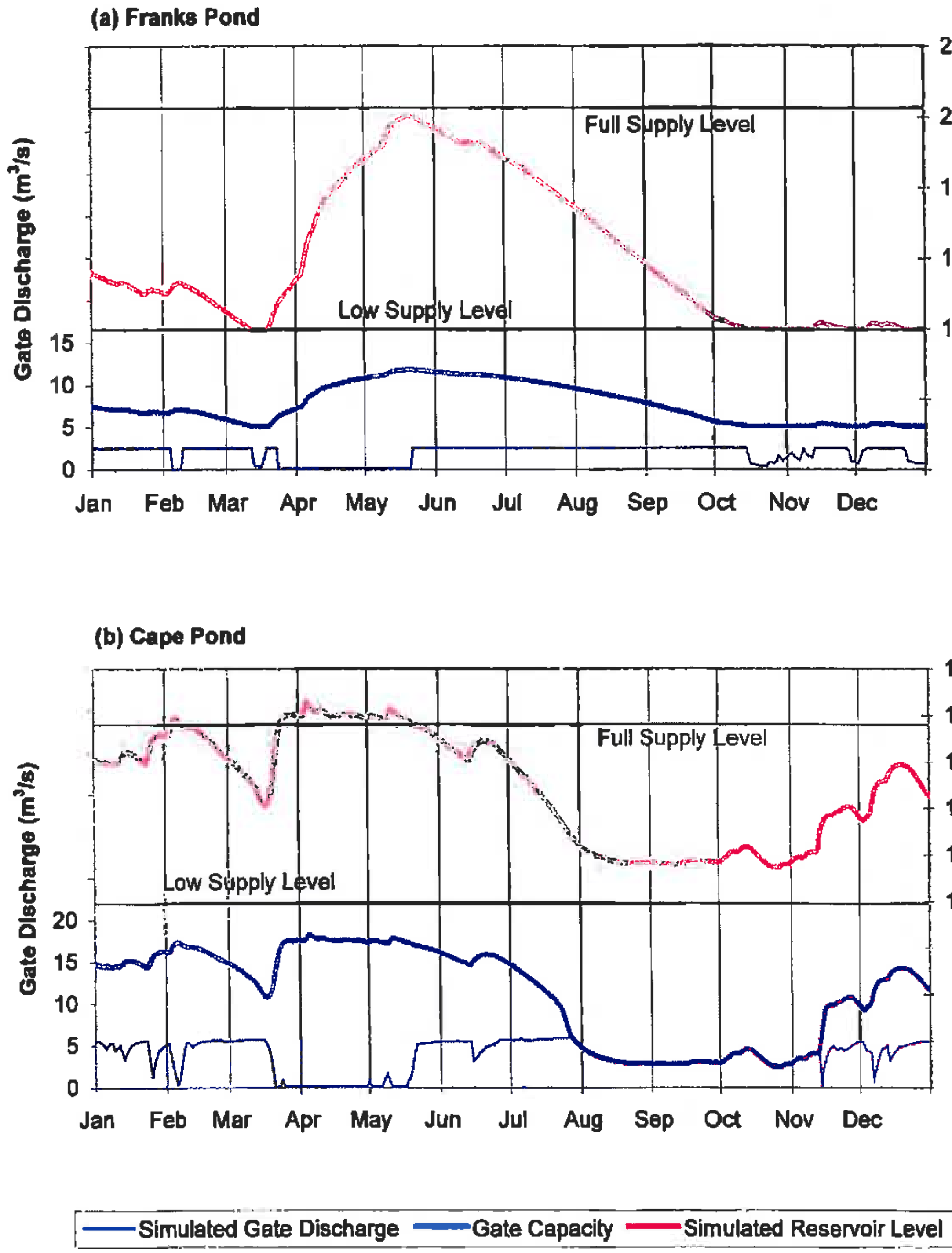


Fig. 6.7

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

FRANKS POND AND CAPE POND SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

ACRES

Lookout Brook

7 Lookout Brook Hydroelectric System

Lookout Brook Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Lookout Brook system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Lookout Brook system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Lookout Brook system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

7.1 System Description

The Lookout Brook system is located on the West Coast of Newfoundland near the community of St. George's and has one generating station located within the system.

The Lookout Brook Generating Station contains two generating units with nameplate capacities of 2.95 MW and 3.25 MW with a rated net head of 154.5 m. The drainage area above the intake to the Lookout Brook station is approximately 82 km^2. The station was commissioned in 1945 and has a total nameplate capacity of 6.20 MW. Storage is provided by structures at Cross Pond and Joe Dennis Pond with Lookout Brook Forebay acting as the headpond for the Lookout Brook station. A schematic of the system is presented in Figure 7.1.

All major storage reservoirs are in series, with Cross Pond being the most upstream reservoir in the system. There is an overflow spillway located on Cross Pond, which when overtopped, would lead to spill out of the system. Water is released from Cross Pond to Joe Dennis Pond using the control structure located at its outlet. Water entering Joe Dennis Pond is either stored, spilled within the system or released downstream to Lookout Brook Forebay using the control structure located at its outlet. Water from upstream reservoirs entering Lookout Brook Forebay is either spilled out of the system or used for generation.

The structures in the system are as follows

- Cross Pond gated outlet;
- Cross Pond overflow spillway;
- Joe Dennis Pond gated outlet;
- Joe Dennis Pond overflow spillway; and
- Lookout Brook Forebay overflow spillway.

The Cross Pond and Lookout Brook Forebay overflow spillways discharge out of the system; the other spillway discharges within the system.

7.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.

7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are presented in Chapter 2. The measures as calculated for the Lookout Brook system are provided below. They were developed from the data in the base case simulation. Table 7.1 at the end of this section summarizes the measures for the Lookout Brook system.

1. Flow Utilization Factor

The Lookout Brook station houses two generating units. The flow utilization factors for the Lookout Brook station (average inflow to forebay divided by combined flow capacity for both units at most efficient load and maximum load) are 0.98 at most efficient load and 0.70 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage assuming the units are operating alone) for most efficient load and maximum load for LBK-G3 are 0.37 kWh/m^3 (11.80 GWh/yr/m^3/s) and 0.35 kWh/m^3 (11.14 GWh/yr/m^3/s), respectively. For LBK-G4 the most efficient load and maximum load station factors are 0.38 kWh/m^3 (11.89 GWh/yr/m^3/s) and 0.37 kWh/m^3 (11.51 GWh/yr/m^3/s), respectively.

The average energy conversion factors from the base case simulation for LBK-G3 and LBK-G4 are 0.35 kWh/m^3 (11.14 GWh/yr/m^3/s) and 0.36 kWh/m^3 (11.49 GWh/yr/m^3/s), respectively. These energy conversion factors take into account the average reduction in availability due to forced outages and the fact that over 70 percent of the time they are operating together resulting in higher headlosses.

Based on the energy conversion factors for the Lookout Brook units, the unit dispatch to maximize efficiency would be as follows.

- Operate LBK-G4 at most efficient load first.
- Operate LBK-G3 at most efficient load second.
- Operate LBK-G4 at maximum load third.
- Operate LBK-G3 at maximum load last.

The order recommended in NP's plant operating guidelines is different from this and the effect of the change is discussed in Section 7.4.

3. Flow Duration Curve

The LBK-G3 and LBK-G4 flow duration curves for the turbine flow (power flow) in the base case simulation are shown in Figure 7.2. The units operate at maximum flow around 22 percent of the time.

4. Energy Potential of Spill

The simulated spill for the base case was approximately 0.24 m^3/s on average at the Lookout Brook Forebay overflow spillway. Using the simulated energy conversion factors for LBK-G3 and LBK-G4 at maximum load presented previously in this section, the spill would produce approximately 2.7 GWh/yr, if entirely saved and used for generation.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figure 7.3 for the Cross Pond and Lookout Brook Forebay overflow spillways. As can be seen in this figure there was no spill at Cross Pond in the base case simulation.

5. Reservoir Storage Factor

Storage is provided by structures located at the outlets of Cross Pond and Joe Dennis Pond. The Lookout Brook Forebay acts as the headpond for the Lookout Brook station. The reservoir storage factors were calculated to be approximately 60 days for Cross Pond, 40 days for Joe Dennis Pond, and less than half a day (7 hours) for Lookout Brook Forebay. These factors represent the number of days to fill the reservoirs at average inflows without any outflow.

6. Reservoir Utilization Plot

The plot of simulated Cross Pond and Joe Dennis Pond reservoir levels for the base case simulation is provided in Figure 7.4. The plot illustrates the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range. For the Lookout Brook system the use of reservoir storage is not limited by other physical or operational constraints.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with units operating at maximum load) is less than half a day (5 hours).

8. Gate Operation

There are control gates located at the outlet of Cross Pond and Joe Dennis Pond. Provided in Figure 7.5 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1993) for Cross Pond and Joe Dennis Pond. These plots illustrate the frequency with which the gates are being operated in the simulation model to maintain most efficient load and to avoid spill by operating at maximum load.

Table 7.1
Lookout Brook System Representative Operating Measures

Lookout Brook Representative Operating Measures	
Flow Utilization Factors - Most Efficient Load - Maximum Load	 0.98 0.70
Station Factors - LBK-G3 Most Efficient Load - LBK-G3 Maximum Load - LBK-G4 - Most Efficient Load - LBK-G4 - Maximum Load	 0.37 kWh/m³ 0.35 kWh/m³ 0.38 kWh/m³ 0.37 kWh/m³
Energy Potential of Spill	2.7 GWh/yr
Reservoir Storage Factors - Cross Pond - Joe Dennis Pond - Lookout Brook Forebay	 60 days 40 days <½ day (7 hours)
Forebay Storage Factor	<½ day (5 hours)

7.3 Ideal Operation of System

The long term energy production at Lookout Brook as estimated by the simulation model developed for the Water Management Study is 34.0 GWh/yr. This compares with recorded energy generation for the same reference period (1984 to 1998) of 28.1 GWh/yr. While these numbers are not directly comparable due to upgrades of both units in 1998/99 and a number of unusual events affecting the recorded generation, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately 13 percent for this system. The comparison would therefore suggest that there is substantial opportunity to improve the operation of this system by more closely following the ideal.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce the difference between the simulated ideal operation and actual operation at the Lookout Brook system.

7.3.1 Plant Operating Guidelines

The simulation model used to estimate generation at the Lookout Brook system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the units will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high or low inflows. The interpretation used in the simulation model incorporated a rule curve for each reservoir in the system. If the reservoir levels are above the rule curve level at any particular time of the year, then the units are operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the units are operated at best efficiency.

Obviously, some judgement on the part of the operators in applying this guideline is required. For instance, a knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to operating staff. The rule curves used in the simulation model are illustrated in Figure 7.4 and are provided in the echo of the detailed simulation model input in Volume 2 of the Water Management Study.

7.3.2 Gate/Reservoir Operation

The Lookout Brook system has substantial storage capacity that can be effectively used to smooth the highly seasonal basin inflows. (Reservoir storage factor of 60 days for Cross Pond and 40 days for Joe Dennis Pond). However, the gates which control the two main storage reservoirs at Cross Pond and Joe Dennis Pond are not easily accessible. The Cross Pond gate is located 17 km from the end of the nearest road over very rugged terrain. This gate requires a full day of travel for a return trip at most times of year, unless a helicopter or floatplane is available. It is not unusual for this gate to be completely inaccessible by any means for several weeks each year.

Although the Joe Dennis Pond gate is much closer to a road link (approximately 7 km) it still requires 1 to 2 hours of all terrain vehicle (ATV) travel using overland routes or the use of aircraft. Again, there are times of the year when travel to this structure by almost any means is not possible.

Based on the difficulties inherent in operating these control gates on a frequent basis, substantial differences exist between the simulated and actual operation of these storage reservoirs. These differences have the effect of reducing the actual production below simulated values.

In addition to the accessibility issues, NP does maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro. This winter reserve is not taken account of in the simulation model.

For the Lookout Brook system, the gate and reservoir operational difficulties discussed above are likely the largest component of the difference between the simulated and actual generation. The effects of differences in gate operation were investigated and the results are presented in Section 7.6.

7.3.3 Unit Operation

The simulation model operates the Lookout Brook units exclusively at their most efficient loads, except when high inflows dictate that higher loads are necessary to avoid exceeding the reservoir rule curves. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate this plant very close to this ideal. The only obstacles to attaining this ideal would be electrical grid requirements, such as local power outages, which may occasionally require that the units operate at loads other than their most efficient loads.

7.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Each of these is discussed below for the Lookout Brook system. Increasing the head through a change in the use of the flashboards or installation of inflatable crest gates was considered as a potential physical change (Section 7.5).

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The case described for the base case is an intermediate case, since it uses a NP rule curve varying between the low supply and full supply levels of the reservoirs, as described in Section 7.3. A change in unit dispatch order to improve efficiency was also investigated.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low
The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At Lookout Brook, the potential for savings in spill compared to the base case is low. The maximum possible reduction in spill would be the equivalent of 2.7 GWh/yr, as shown in Table 7.1. However, the spill distribution plot (Figure 7.2) shows that this would be difficult to capture since the spills occur infrequently and in large amounts.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The average annual spill from Lookout Brook Forebay was reduced by only 0.01 m^3/s, from an average of 0.24 m^3/s to 0.23 m^3/s. This represents an increase of approximately 0.1 GWh/yr. This small amount does not compensate for the decrease in energy production due to operating the units at a lower efficiency.

Best Efficiency Operation, Limiting Case: Reservoirs High
The limiting case for maximizing the amount of time the units are operating at best efficiency is to run the units at best efficiency, until the storage reservoirs are just about to spill. This may require frequent gate operation because the gates must be adjusted to release the exact amount of water to match the best efficiency flows.

The result of a simulation using this rule was an average annual production of 33.7 GWh/yr, with a spill of 0.29 m^3/s. This production is lower than the base case production. This suggests that the rule curve used for the base case simulation is near optimum for the Lookout Brook system. There could be minor adjustments made to the rule curve that could increase production monthly, but the increase would be expected to be marginal.

Revised Unit Dispatch
At Lookout Brook, another option for improving operation is to change the unit dispatch. The unit dispatch based on the energy conversion factors provided in Section 7.2 is different from the unit dispatch in NP's plant operating guidelines. This difference probably results from guidelines being written prior to the upgrade of Unit #3 in 1999.

1.) *For minimal inflow operate Unit #4 at best efficiency. For higher inflows, bring #3 on at best efficiency and cycle on and off to maintain forebay limits.*
2.) *For higher inflows, keep #4 at best efficiency and bring #3 to full load. If required to keep ahead of inflow, operate both units at full load. Total output with both machines on will be about 5800 kW due to the additional head loss in the penstock.*

The recommendation in Section 7.2 is for higher inflows to bring LBK-G4 to full load before LBK-G3. LBK-G3 should be brought to full load last.

Changing the unit dispatch in the base case simulation improves the energy generation by an estimated 0.1 GWh/yr, at no cost to NP.

This result assumes that the energy conversion factors calculated from available data are correct; efficiency testing on the units operating separately and together would provide confirmation.

7.5 Physical Changes to System

The two principal options for physical changes to the existing system to improve energy generation are to increase head and to increase storage. To give an indication of the value of these changes, the following options were investigated.

- Change pattern of flashboards installation/removal at Lookout Brook Forebay to increase head.
- Increase dam height at Joe Dennis Pond to increase storage.
- Reduce headlosses.

Each of these physical changes to the system is discussed below. Table 7.2 summarizes the results.

Change Pattern of Flashboards at Lookout Brook Forebay
It was interpreted from the existing plant operating guidelines that the flashboards at the Lookout Brook Forebay are removed in the spring to allow for additional spillway capacity. This results in the forebay level drawing down from 262.13 m to 261.72 m in the spring. To determine whether any additional energy could be obtained through extra head, the flashboards were assumed to be in place year round, but still drawing the forebay down in the spring. This would allow for some storage of inflows at the forebay during the spring runoff. The resulting increase in energy generation from this change was 0.2 GWh/yr, from 34.0 GWh/yr to 34.2 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $8 000/yr with no additional cost for this change, but leaving the flashboards in year round may lead to dam safety concerns. A separate analysis into spill capacity was conducted by NP in 1996 which had shown that flashboards 0.4 m in height could be maintained all year round and still allow for adequate spill capacity during the design flood. If it did become a dam safety concern that the flashboards must be removed, then inflatable crest gates (a rubber dam) on the spillway section may be considered. The comparison analysis conducted in the

Water Management Study noted that the recorded levels in the spring are higher than those modelled. This would suggest that some of the flashboards are being kept in during the spring. Although the plant operating guidelines suggest that the flashboards are removed actual operation are to keep them in up to approximately 0.36 m.

Increase Storage at Joe Dennis Pond

To determine the effect of an increase in storage on energy production, the dams and structures at Joe Dennis Pond were assumed to be raised to allow increases in full supply level of one and two meters. The effect is to reduce system spill. The resulting increases in energy generation were 0.8 GWh/yr for the one meter rise, and 1.6 GWh/yr for the two meter rise.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $32 000/yr for the one meter increase in dam height and $64 000/yr for the two meter increase in dam height. Given a dam length of approximately 470 m, the savings over perhaps 20 years would justify an expenditure of about $625/m of dam length based on a one meter increase. The practicalities of increasing the dam at Joe Dennis Pond would have to be investigated. NP has previously considered reinstating old control structures or constructing new ones. Previous work on the costs show that it would be economically feasible to increase the storage at Joe Dennis Pond. A detailed analysis into the benefits and cost would have to be conducted.

Reduce Headlosses

Another method of increasing head is to reduce headlosses. NP recently replaced the penstocks at Lookout Brook and would likely not replace these again for many years. For the purposes of examining the value of a reduction in headlosses, however, it was assumed that the units could operate at the maximum load at the same time (no additional headlosses with both units operating). The resulting energy generation was 35.2 GWh/yr or a net increase in average annual energy of 1.2 GWh/yr. Over the life of the project a recovery of some or all of these losses could have a net present value of several hundred thousand dollars; the efficiency testing to determine the preferred unit loading should include a determination of the sources of the headlosses. Measures to reduce these cost-effectively could then be investigated.

Table 7.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	34.0	-
Flashboard at Forebay	34.2	+0.2
Increase Storage Joe Dennis by 1 m	34.8	+0.8
Increase Storage Joe Dennis by 2 m	35.6	+1.6
Reduce headlosses	35.2	+1.2

7.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of their systems. Lookout Brook's location on a remote high plateau has two effects; first, the pattern of runoff is dominated by snowmelt, so storage to capture the runoff is important, and second, the rugged undeveloped terrain makes access for gate operation difficult. In addition to some standard sensitivities, the cases chosen for Lookout Brook were selected with a view to providing NP with some values related to its specific situation. Results for all sensitivity cases are provided in Table 7.3. Average energy generation, average annual forebay spill for each case is presented in Table 7.3.

The sensitivity cases were as follows.

- Environmental release requirement of 30 percent of mean annual flow.
- No storage in system (to obtain value of storage); remove dams and gates.
- Changes to Cross Pond gate operation.

Environmental Release Requirement

The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 0.4 m^3/s at Cross Pond and 0.8 m^3/s at Joe Dennis Pond. Using these flows as the minimum flow release from the gates for the base case simulation model, there was no change in system energy. This is the case because 30 percent of mean annual flow is less than the best efficiency flow of the unit. This amount is always released in all simulations unless there is no water in storage, in which case the natural inflows are released.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement were always met, there would likely be a reduction in energy.

No Storage in System
To provide NP with an indication of the value of the storage in the system, all storage in the system was assumed to be removed. The resulting average annual energy generation from this sensitivity was 25.0 GWh/yr, a net decrease of 9.0 GWh/yr. This represents the value of maintaining the structures at Joe Dennis Pond and Cross Pond.

Changes to Cross Pond Gate Operation
The remote location and difficult access of the Cross Pond outlet structure make it an obvious candidate for automation. The simulation for the base case assumed that the gate could be operated daily, and the gate operation plot in Figure 7.5 showed that it was usually open to less than full capacity. The base case could be considered the full automation case. The analysis was carried out for Cross Pond, but the results would be similar for Joe Dennis Pond.

To investigate the value of automation, or of some alternative procedure, three cases were considered. A variety of other cases are possible, but these three give an indication of the range of savings that can be achieved. The three cases are

- Leave gate full open: leave the gate open all the time, using whatever natural regulation remains;
- Seasonal operation: adjusting the gate a couple of times a year; and
- Leave gate partially open: restrict the opening to improve the natural regulation, leaving the gate in a partly open position all year round.

The effects of these three procedures are described below.

Leave Gate Full Open: Because of the difficulty of adjusting Cross Pond gate, one option is to simply leave the gate open. The structure itself will provide some natural regulation. The difference in the estimate of energy generation in this case and the base case indicates the value of having a gate that can be operated daily. The resulting energy generation from this sensitivity was 31.5 GWh/yr, or a net decrease in energy of 2.5 GWh/yr. This decrease is due to extra spill at the forebay and additional operation at maximum load.

If the gate can be automated for perhaps $50,000 to $70,000, automation would be justified by the energy savings.

However, it may be possible to obtain some or all of the energy gains more cost-effectively, as considered in the two other options.

Seasonal Operation: In this case, the gate at the outlet of Cross Pond was assumed to be operated twice a year, closed to 0.3 m in April and opened fully in July. The resulting energy generation from this sensitivity was 32.5 GWh/yr or a net decrease in energy of 1.5 GWh/yr. Adjusting the opening and closing dates to take account of conditions in a particular year would likely improve this result.

Leave Gate Partially Open: The gate curve from Section 7.2 indicated that the gate is usually opened in the base case to release about 3-4 m^3/s. As a sensitivity, the gate was assumed to be open 0.3 m all year round to release those flows when Cross Pond is half full. The resulting energy generation from this sensitivity was reduced by 0.7 GWh/yr from the base case. As the table below shows this would be the best of the three alternatives considered here for gate operation at Cross Pond. With the exception of possibly fabricating stoplogs there should be no cost to this option.

Table 7.3
Energy Results for Sensitivity Simulations at Lookout Brook System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)	Forebay Spill (m^3/s)
Base Case	34.0	-	0.24
Environmental Releases	34.0	0.0	0.24
Value of Storage	25.0	- 9.0	1.04
Cross Pond Gate Operation			
- Leave Gate Full Open	31.5	- 2.5	0.34
- Seasonal Operation	32.5	- 1.5	0.37
- Leave Gate Partially Open	33.3	- 0.7	0.29

7.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

   Gate operation: The analysis shows that controlling the release of water from storage is the key to maximizing the output from the Lookout Brook system. The outlet gates at Cross Pond and Joe Dennis Pond need to be adjusted frequently to ensure that the correct flow is being released to keep the units operating at best efficiency, as well as to avoid spill. Automation of the gates would provide the best control, but simpler approaches may be more cost effective.

2. **Changes to Operating Guidelines**

   Clarification of Guidelines: The present guidelines as interpreted for the Water Management Study come close to maximizing system output if NP can operate in this manner. NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum.

   Unit Dispatch Order: The present guidelines suggest a unit dispatch order that is inconsistent with the station factors as calculated from the available information. NP should carry out efficiency testing on both units, operating separately and together, to determine the preferred dispatch order.

It may be possible to make modest gains through fine-tuning, first of the timing of the flashboard installation/removal dates in the forebay, and second, of the reservoir rule curves that determine when to switch from best efficiency load to maximum load. NP should review the present practice and update as required.

3. **Physical Changes**

Forebay Flashboards: Keeping the flashboards in all year and drawing the forebay down in the spring increases energy output by increasing head and reducing spill. If flashboards must be removed in the spring for dam safety reasons, then an inflatable crest gate (rubber dam) on the spillway section may be considered. The spillway section is short, and it may be possible not only to keep the head up during periods of high runoff risk, but also to raise the full supply level in lower risk periods. NP should investigate the costs and benefits of alternative flashboard/crest gate arrangements, taking into account dam safety requirements.

Increased Storage: Because of the fact that runoff is dominated by large events, especially spring runoff, storage is important in the system. The effect of reducing spill at Joe Dennis Pond by increasing the storage results in an increase in energy generation of 0.8 GWh/yr for a one metre rise, and 1.6 GWh/yr for a two metre rise. Based on previous cost estimates conducted by NP for increased storage at Joe Dennis Pond, it would be worth investigating in more detail the economical feasibility of increased storage at Joe Dennis Pond.

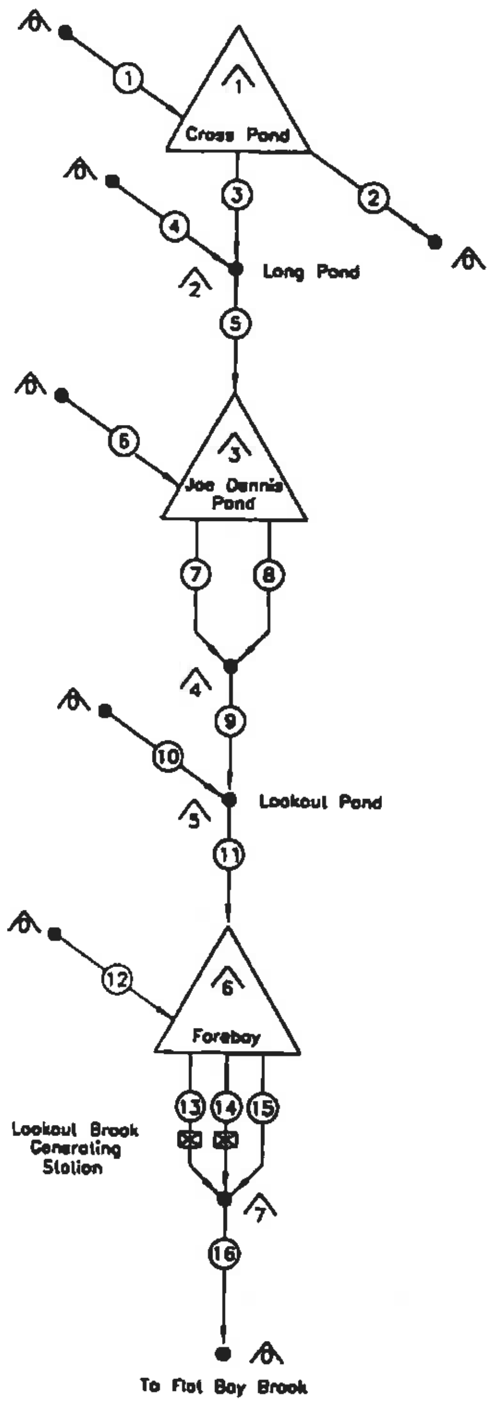
Headlosses: The analysis showed that there may be some gains in energy by reducing headlosses. When NP is conducting the efficiency testing to determine unit loading, it should give particular attention to finding the sources of the headlosses. The costs and benefits of improvements can then be determined.

4. **Sensitivities**

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gates at Cross Pond and Joe Dennis Pond does not affect energy generation, because this amount is already being released to supply the units. The requirement, however, assumes that when the reservoirs are low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.

Value of Storage: The value of the storage at Joe Dennis Pond and Cross Pond is 9.0 GWh/yr. NP may use this value in considering the costs of maintaining these structures.

Changes to Cross Pond Outlet Gate Control/Operation: The value of operating the gate at Cross Pond on a daily basis is 2.5 GWh/yr. If the gate can be automated for perhaps $50 000 to $70 000, automation would be justified by the energy savings. However, it may be possible to obtain some or all of the energy gains more cost-effectively, considering changing the gate setting a couple of times a year or restricting the gate opening. In the simulation to consider alternatives for Cross Pond, Joe Dennis Pond outlet gate was assumed to be operated daily if required. NP should determine the costs of automation or more frequent personnel access to the gates at both Joe Dennis Pond and Cross Pond, and compare it with the costs and benefits of the simpler approaches at both locations. The most cost-effective overall solution can then be selected.



CHANNELS

1 — Cross Pond Local Inflow
2 — Cross Pond Spill
3 — Cross Pond Canal
4 — Long Pond Local Inflow
5 — Long Pond to Joe Dennis Pond General Flow
6 — Joe Dennis Pond Local Inflow
7 — Joe Dennis Pond Spill
8 — Joe Dennis Pond Outlet Gate
9 — Joe Dennis Pond To Lookout Pond General Flow
10 — Lookout Pond Local Inflow
11 — Lookout Pond To Forebay General Flow
12 — Lookout Brook Forebay Local Inflow
13 — Power Flow (LBK-G3)
14 — Power Flow (LBK-G4)
15 — Lookout Brook Spill
16 — Lookout Brook General Outflow

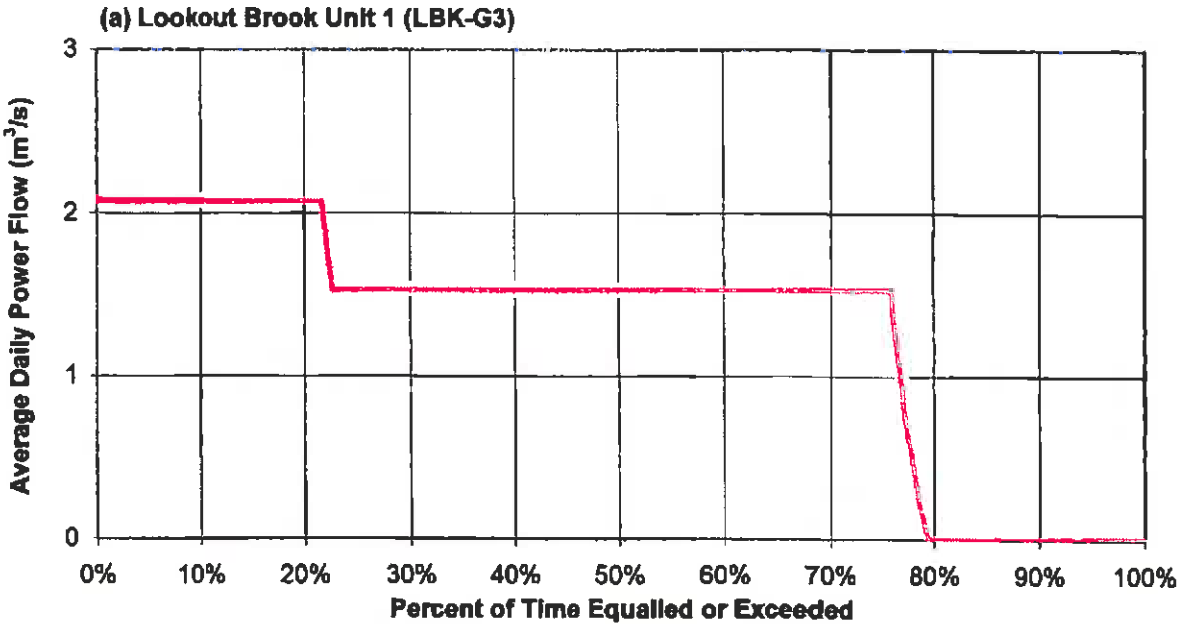
RESERVOIRS / NODES

0 — Source / Sink
1 — Cross Pond
2 — Long Pond
3 — Joe Dennis Pond
4 — Joe Dennis Pond Total Outflow
5 — Lookout Pond
6 — Lookout Brook Forebay
7 — Lookout Brook Total Outflow

Fig. 7.1

NEWFOUNDLAND POWER
HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY
LOOKOUT BROOK ARSP MODEL SCHEMATIC

ACRES



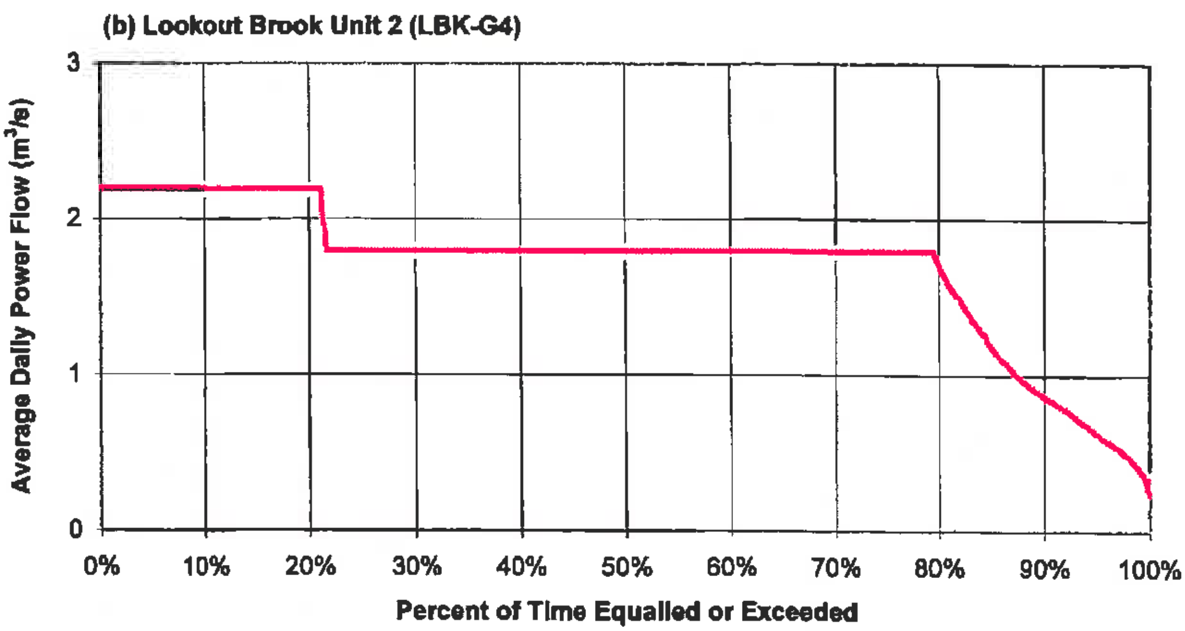


Fig. 7.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

LOOKOUT BROOK SIMULATED POWER FLOW DURATION CURVES

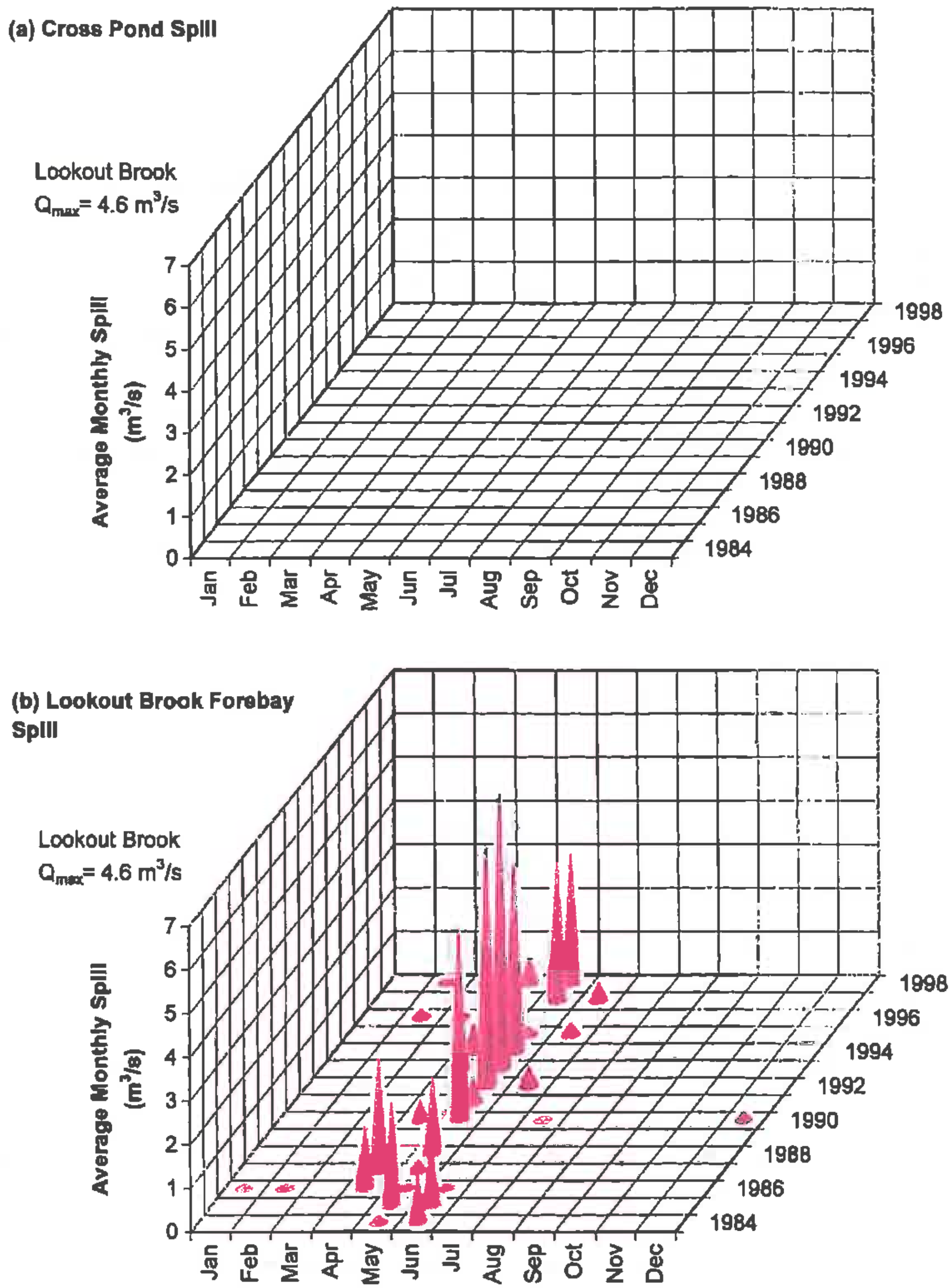


Fig. 7.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

CROSS POND AND LOOKOUT BROOK FOREBAY SIMULATED SPILLS

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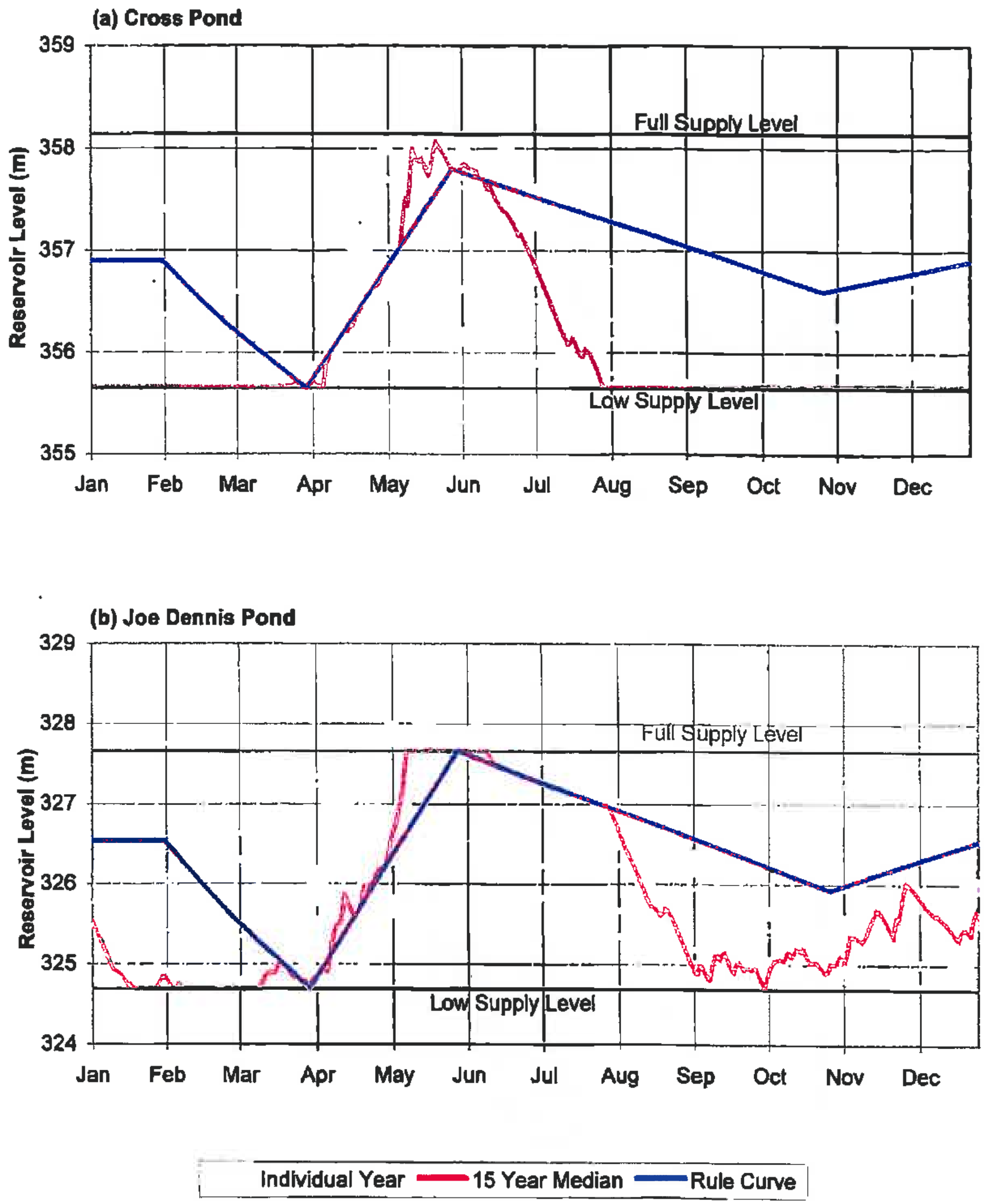

Fig. 7.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

CROSS POND AND JOE DENNIS POND
SIMULATED RESERVOIR LEVELS

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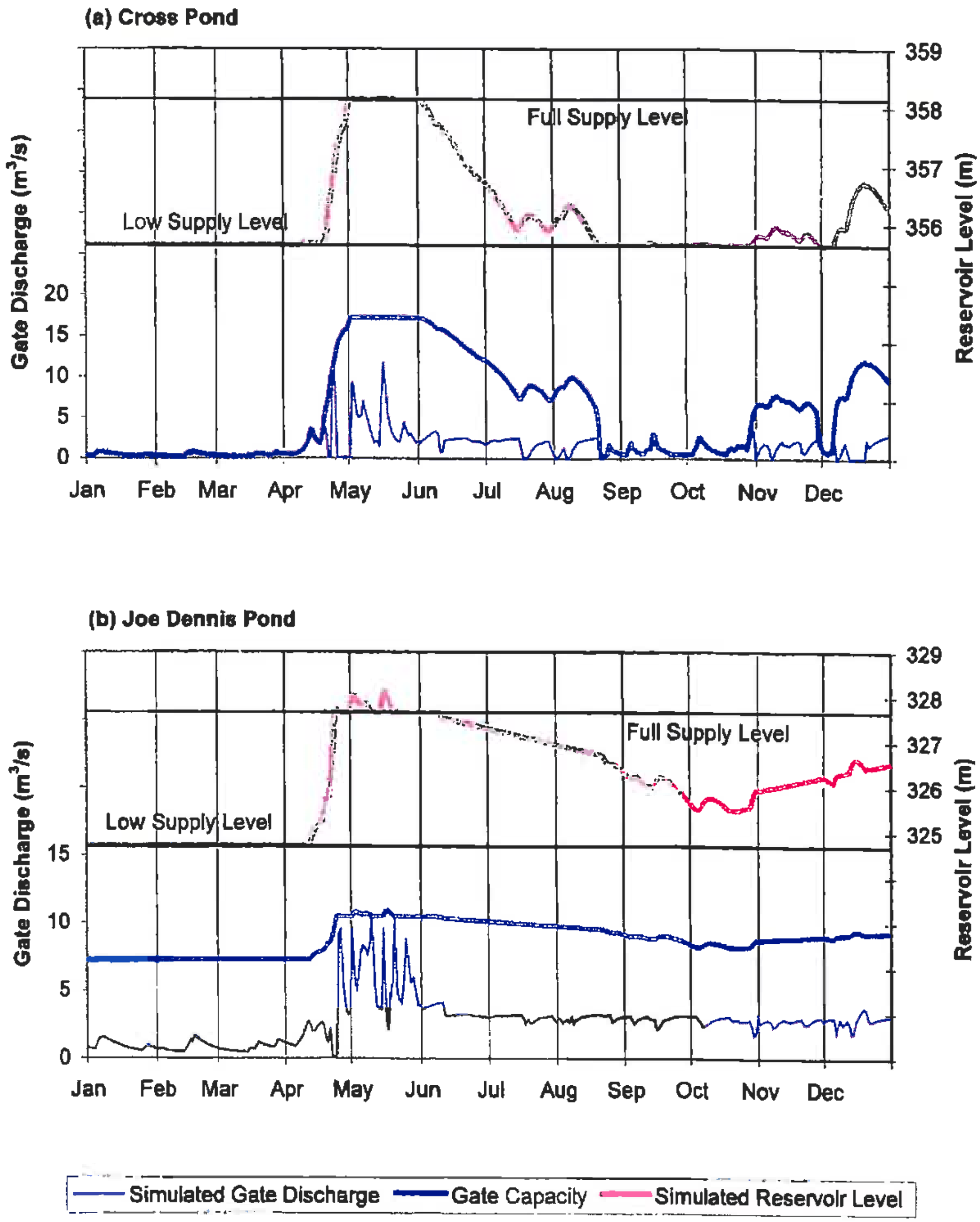


Fig. 7.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

CROSS POND AND JOE DENNIS POND SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

Sandy Brook

8 Sandy Brook Hydroelectric System

Sandy Brook Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Sandy Brook system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model set up for the Sandy Brook system in the Water Management Study conducted by Acres for all NP hydroelectric systems was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Sandy Brook system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

8.1 System Description

The Sandy Brook system is located in central Newfoundland near the Town of Grand Falls-Windsor. The system was commissioned in 1963 and has a nameplate capacity of 5.5 MW and a rated net head of 33.5 m. Storage is provided by structures at Island Pond, West Lake, Sandy Lake and Sandy Brook Forebay. The total drainage area above the intake to the Sandy Brook Generating Station is approximately 529 km^2. A schematic of the Sandy Brook system is presented in Figure 8.1.

On the west side of the drainage basin, Island Pond drains into a series of small lakes along West Brook, and into West Lake. On the east side of the basin, Sandy Lake plus other small lakes drain into Sandy Brook. West Lake flows into Sandy Brook in the forebay of the generating station. West Lake and Sandy Lake are the main storages for the system. Island Pond provides some storage but is essentially uncontrolled.

The structures in the system are as follows

- Island Pond outlet (uncontrolled);
- West Lake gated outlet;
- West Lake overflow spillway;
- Sandy Pond gated outlet;
- Sandy Pond overflow spillway;
- Sandy Brook Forebay gated spillway; and
- Sandy Brook Forebay overflow spillway.

The Sandy Brook Forebay spillways discharge out of the system; the other spillways discharge within the system.

NP plans to replace the runner at Sandy Brook Generating Station in the summer of 2001. The unit efficiency will increase as a result.

8.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are presented in Chapter 2. The measures as calculated for the Sandy Brook system are provided below. They were developed from the data in the base case simulation. Table 8.1 at the end of this section summarizes the measures for thc Sandy Brook system.

1. Flow Utilization Factor

The flow utilization factors for the Sandy Brook station (average inflow to forebay divided by the flow capacities of the unit at most efficient load and maximum load) are 0.81 at most efficient load and 0.66 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage) for most efficient load and maximum load at Sandy Brook station are 0.078 kWh/m^3 (2.45 GWh/yr/m^3/s) and 0.069 kWh/m^3 (2.16 GWh/yr/m^3/s), respectively.

The average energy conversion factor from the base case simulation is 0.077 kWh/m^3 (2.42 GWh/yr/m^3/s). The energy conversion factor takes into account the average reduction in availability due to forced outages and the operation at greater flows than most efficient load.

3. Flow Duration Curve

The Sandy Brook power flow duration curve from the base case simulation is shown in Figure 8.2. The units operate at above most efficient flow approximately 18 percent of the time.

4. Energy Potential of Spill

The average annual simulated spill for the base case was approximately 3.11 m^3/s. Using the simulated energy conversion factor at maximum load, the spill would produce approximately 7.5 GWh/yr, if entirely saved and used for generation.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figure 8.3. The figure demonstrates that there is significant spill in April and May in almost every year of the base case simulation.

5. Reservoir Storage Factor

Storage is provided by structures located at the outlets of West Lake, Sandy Lake and Sandy Brook Forebay. The reservoir storage factors were calculated to be approximately 23 days for West Lake, 48 days for Sandy Lake, and between one and two days (39 hours) for Sandy Brook Forebay. These factors represent the number of days to fill the reservoirs with average inflows and without any outflows.

6. Reservoir Utilization Plot

The plots of simulated West Lake and Sandy Lake reservoir levels for the base case simulation are provided in Figure 8.4. The plot illustrates that Sandy Lake never draws down to the dead supply level. This is because the shape of the approach channel to the outlet prevents releases at low reservoir levels.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow and with units operating at maximum load) is approximately one day (26 hours).

8. Gate Operation

There are control gates located at the outlets of West Lake and Sandy Lake. Provided in Figure 8.5 are the simulated gate discharges, gate capacities and simulated reservoir levels for an example year (1994) for both lakes. These plots illustrate the frequency with which the gates are being operated in the simulation model to maintain most efficient load and to avoid spill.

Figure 8.5 shows an inconsistency in the rating curve for the outlet at West Lake. A capacity of approximately 5 m^3/s is shown when West Lake is at low supply level. NP should investigate this inconsistency.

Table 8.1
Sandy Brook System Representative Operating Measures

Sandy Brook Representative Operating Measures	
Flow Utilization Factors - Most Efficient Load - Maximum Load	 0.81 0.66
Station Factors - Most Efficient Load - Maximum Load	 0.078 kWh/m^3 0.069 kWh/m^3
Energy Potential of Spill	7.5 GWh/yr

Sandy Brook Representative Operating Measures	
Reservoir Storage Factors - West Lake - Sandy Lake - Sandy Brook Forebay	 23 days 48 days 1.6 (39 hours)
Forebay Storage Factor	1.1 days (26 hours)

8.3 Ideal Operation of System

The long term energy production at Sandy Brook as estimated by the simulation model developed for the Water Management Study is 28.1 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 25.3 GWh/yr. These figures provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately eight percent for this system. The comparison would therefore indicate that there is some opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual generation at the Sandy Brook System.

8.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Sandy Brook system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plant will be operated at maximum load (and less than maximum efficiency) to avoid spills.

This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated target levels for each reservoir in the system. The reservoirs were operated to keep the forebay at its target level to maintain operation at best efficiency. If the forebay levels exceed target level at any particular time of the year, then the units are operated at maximum load to bring the water level down. If the reservoir levels are below the rule curve, then the units are operated at best efficiency.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve.

8.3.2 Gate/Reservoir Operation

The Sandy Brook system has relatively little storage capacity particularly in light of the seasonal runoff variations experienced in Central Newfoundland. Sandy Lake and West Lake are the two primary storage reservoirs. The gates that control these reservoirs are difficult to access. Travel to Sandy Lake requires about 2.5 hours (one-way) from the powerhouse, while West Lake can be reached in about one hour. Therefore, operations staff cannot adjust these outlet gates frequently.

Despite the difficulty posed by operating these gates, the impact of this practicality on system generation is probably not significant. This is due to the fact that these reservoirs control only a small fraction of the overall watershed, and that they would therefore not be effective in regulating runoff even if the gates could be adjusted daily.

In addition to the accessibility issues, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro. This winter reserve is not taken into account by the simulation model. As with the gate accessibility issue however, the system production is not overly sensitive to other reservoir operating constraints.

8.3.3 Unit Operation

The simulation model operates the Sandy Brook unit exclusively at its most efficient load, except when high inflows dictate that higher loads are necessary to avoid spill. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate the plant very close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April and August 1999, and January-February 2000) indicated that the Sandy Brook unit is loaded at various loads between 4.4 MW and 5.9 MW for most of these periods. This plant would therefore not appear to be making efficient use of the available water, although a more detailed study would also include an examination of unit availability and system conditions during these months. The main obstacles to attaining ideal operation are electrical grid requirements that may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences.

8.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

The operating changes were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The base case is an intermediate case, since it uses rule curves varying between the low supply and full supply levels of the reservoirs, as described in Section 8.3.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low

The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At Sandy Brook, the potential for savings in spill compared to the base case is high. The maximum possible reduction in spill would be the equivalent of 7.5 GWh/yr, as shown in Table 8.1. However, the spill distribution plot (Figure 8.3) shows that this potential would be difficult to capture since the spills occur primarily within a relatively short period in the spring.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The average annual spill from Sandy Brook Forebay was reduced by only 0.07 m^3/s, from an average of 3.11 m^3/s to 3.04 m^3/s. This represents an increase of approximately 0.2 GWh/yr. This small amount does not compensate for the approximately 0.7 GWh/yr decrease in energy production due to operating the units at a lower efficiency.

Best Efficiency Operation, Limiting Case: Reservoirs High

The limiting case for maximizing the amount of time the units are operating at best efficiency is to run the units at best efficiency, until the storage reservoirs are just about to spill. This may require frequent gate operation to match releases to best efficiency flow.

The result of a simulation using this rule was an average annual production of 27.9 GWh/yr, with a spill of 3.4 m^3/s. This production is lower than the base case production and the spill is greater.

These simulations suggests that the rule curve used for the base case simulation is near optimum for the Sandy Brook system. There could be minor adjustments made to the rule curve that could increase production, but the increase would be marginal.

8.5 Physical Changes to System

To give an indication of the value of physical changes to the existing system, the following options were investigated.

- Increase the capacity of the control gates at the outlet structures.
- Increasing the efficiency of the units was not examined because NP is already planning to replace the runner at Sandy Brook.
- Increase available storage.

These physical changes to the system is discussed below. Table 8.2 summarizes the results.

Increase Capacity of Control Structures
The value of increasing the capacity of the control structures at both West Lake and Sandy Lake was assessed by simulating operation with arbitrarily doubled capacities. The resulting energy was 28.3 GWh/yr, 0.2 GWh/yr greater than the base case.

A second simulation was run to investigate the effect of removing the channel obstruction at the Sandy outlet to create capacity at lower reservoir levels. The result was marginally less spill but no increase in energy.

Increase Storage at Sandy Lake
To determine the effect of an increase in storage on energy production, the dams and structures at Sandy Lake were assumed to be raised to allow increases in full supply level of two meters. The effect is to reduce system spill. The resulting increase in energy generation was 1.7 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $68 000/yr for a two meter increase in dam height. Given a dam length of approximately 215 m, the savings over perhaps 20 years would justify an expenditure of about $2900/m of dam length. The practicalities of increasing the dam crest would have to be investigated along with the costs and benefits of such a project.

Table 8.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	28.1	-
Increase Capacity of Control Structures	28.3	+0.2
Remove Obstruction in Sandy Lake Outlet Channel	28.1	0.0
Increase Storage in Sandy Lake	29.8	+1.7

8.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of their systems. Results for all sensitivity cases are provided in Table 8.3. Along with the average energy generation, average annual forebay spill for each case is presented in Table 8.3.

The sensitivity cases were as follows.

- Environmental release requirement of 30 percent of mean annual flow.
- No storage in system (to obtain value of storage); remove dams and gates.
- Changes to gate operation.

Environmental Release Requirement
The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 1.0 m^3/s at West Lake and 1.8 m^3/s at Sandy Lake. Using these flows as the minimum releases from the gates did not change the simulated energy generation because 30 percent of mean annual flow is still less than the flow released to meet the generation objectives.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement were always met, there would likely be a reduction in energy.

No Storage in System
To provide NP with an indication of the value of the storage in the system, all upstream storage in the system was assumed to be removed. The resulting average annual energy generation from this sensitivity was 24.4 GWh/yr, a net decrease of 3.7 GWh/yr. This represents the value of maintaining the structures at Island Pond, West Lake and Sandy Lake.

Changes to Gate Operation
The remote location and difficult access of the Sandy Brook system outlet structures make them candidates for automation. Though the simulation for the base case assumed that the gates could be operated daily, the plots in Figure 8.5 showed that they are open at full capacity for most of the year.

In order to assess the value of the automation, a simulation was run with the gates fully open all year. The difference in the estimate of energy generation in this case and the base case indicates the value of having a gate that can be operated daily. The resulting energy generation from this sensitivity was 27.3 GWh/yr, or a net decrease in energy of 0.8 GWh/yr. This decrease is due to extra spill at the forebay and additional operation at maximum load.

If the gates could be automated for less than the value of the additional energy, the project would be worthwhile.

Table 8.3
Energy Results for Sensitivity Simulations at Sandy Brook System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)	Forebay Spill (m^3/s)
Base Case	28.1	-	3.11
Environmental Releases	28.1	0.0	3.11
Value of Storage	24.4	- 3.7	4.57
Gate Operation - Leave Gates Full Open	27.3	- 0.8	3.45

8.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

   NP should review the operating procedures in light of new runner and controls to be installed at Sandy Brook in 2001.

2. **Changes to Operating Guidelines**

   The present guidelines as interpreted for the Water Management Study come close to maximizing system output. No changes are recommended.

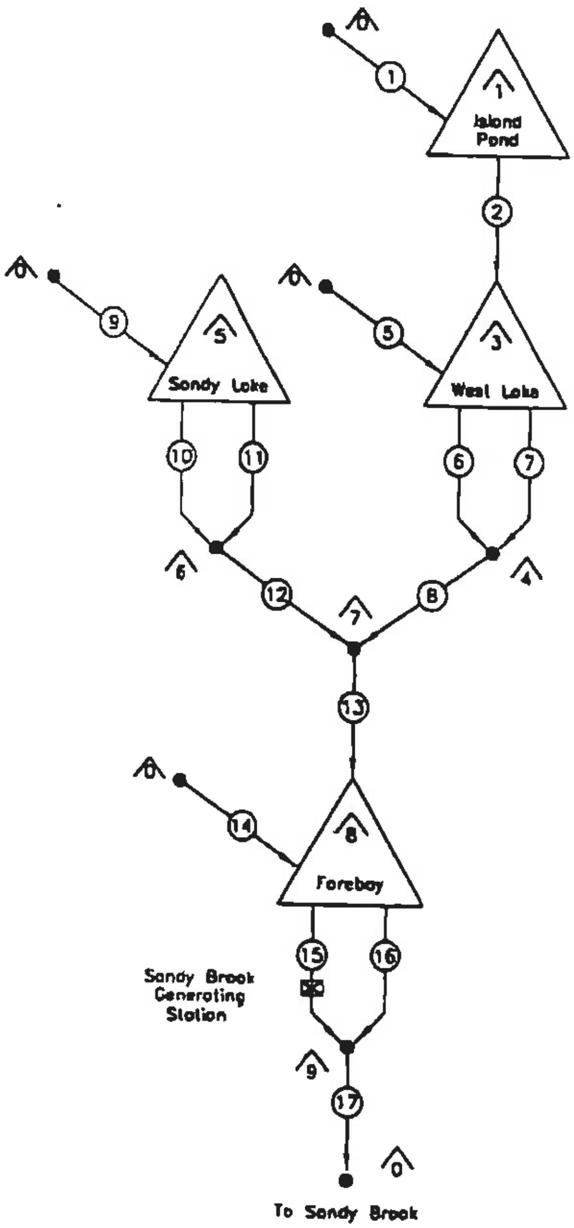
3. **Physical Changes**

   Because runoff is dominated by spring snowmelt, storage is important in the system. Increasing storage would increase generation; raising the dams should be investigated. Neither automating the gates, nor increasing their capacities contributes significant additional energy.

4. **Sensitivities**

   Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gates at West Lake and Sandy Lake does not affect energy generation, because this amount is already being released to supply the units. The requirement, however, assumes that when the reservoirs are low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.

   Value of Storage: The value of the storage at West Lake and Sandy Lake is 3.7 GWh/yr. NP may use this value in considering the costs of maintaining the structures.



CHANNELS

- (1) — Island Pond Inflow
- (2) — Island Pond Outlet
- (5) — West Lake Inflow
- (6) — West Lake Outlet
- (7) — West Lake Spill
- (8) — West Lake Total Outflow
- (9) — Sandy Lake Inflow
- (10) — Sandy Lake Outlet
- (11) — Sandy Lake Spill
- (12) — Sandy Lake Total Outflow
- (13) — Sandy Lake and West Lake Outflow
- (14) — Sandy Brook Forebay Inflow
- (15) — Sandy Brook Power Flow
- (16) — Sandy Brook Forebay Spill
- (17) — Sandy Brook Forebay Total Outflow

RESERVOIRS / NODES

- 0 — Source / Sink
- 1 — Island Pond
- 3 — West Lake
- 4 — West Lake Total Outflow
- 5 — Sandy Lake
- 6 — Sandy Lake Total Outflow
- 7 — Sandy Lake and West Lake Outflow
- 8 — Sandy Brook Forebay
- 9 — Sandy Brook Forebay Total Outflow

Fig. 8.1

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

SANDY BROOK ARSP MODEL SCHEMATIC

ACRES

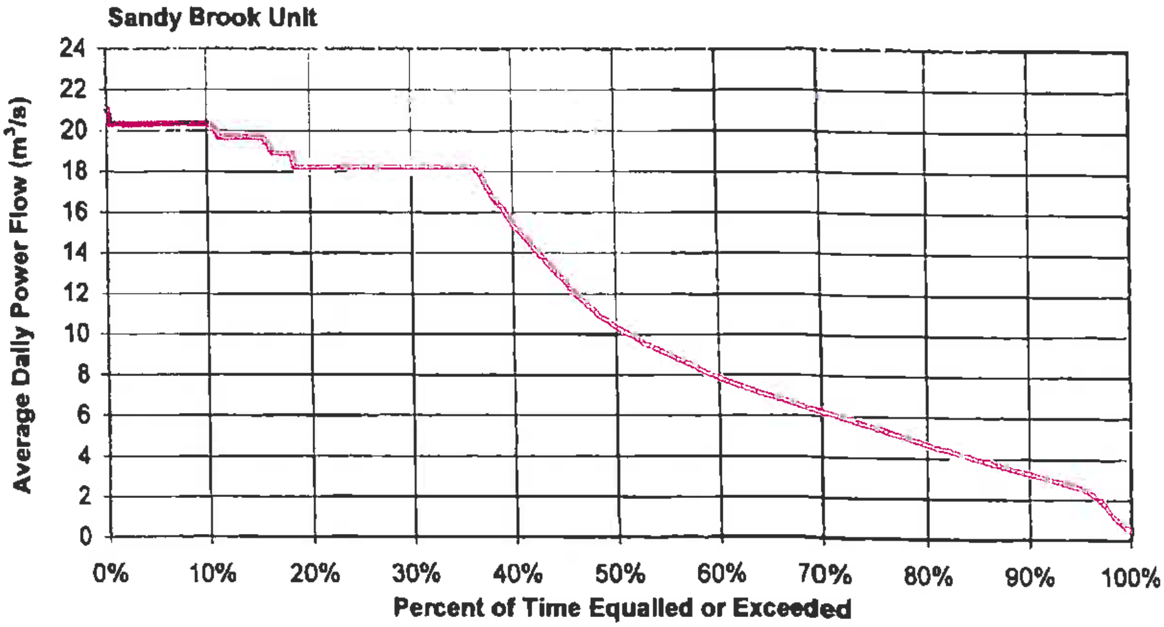


Fig.8.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

SANDY BROOK SIMULATED POWER FLOW DURATION CURVE

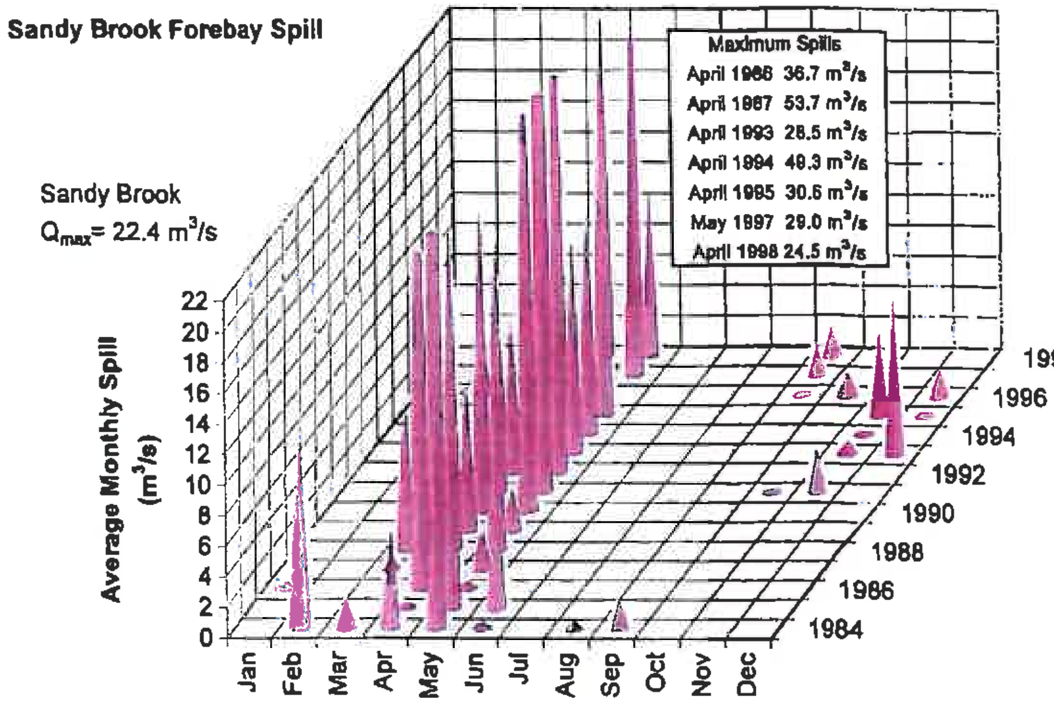


Fig. 8.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

SANDY BROOK FOREBAY SIMULATED SPILLS

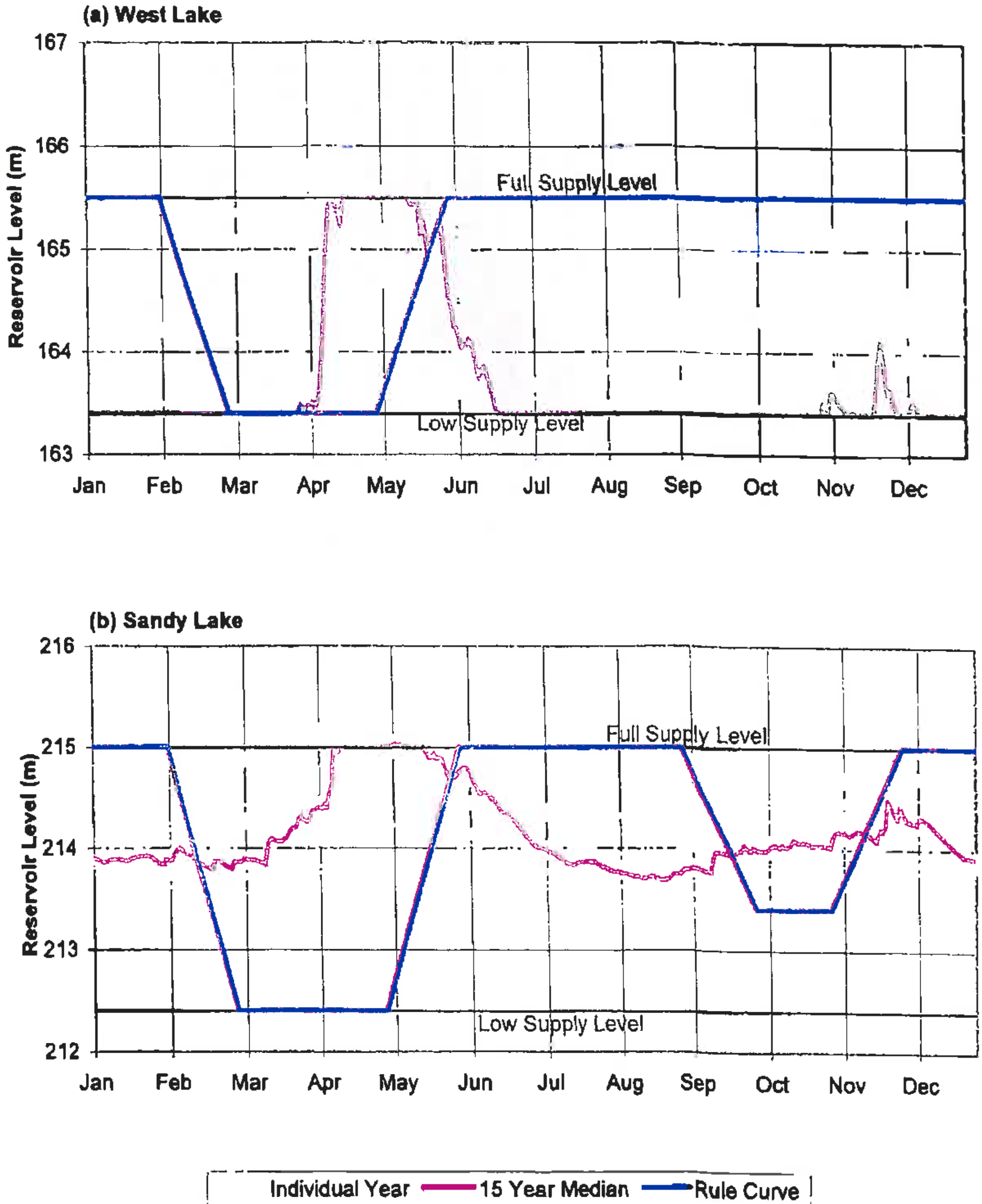


Fig. 8.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

WEST LAKE AND SANDY LAKE

SIMULATED RESERVOIR LEVELS

AGRES

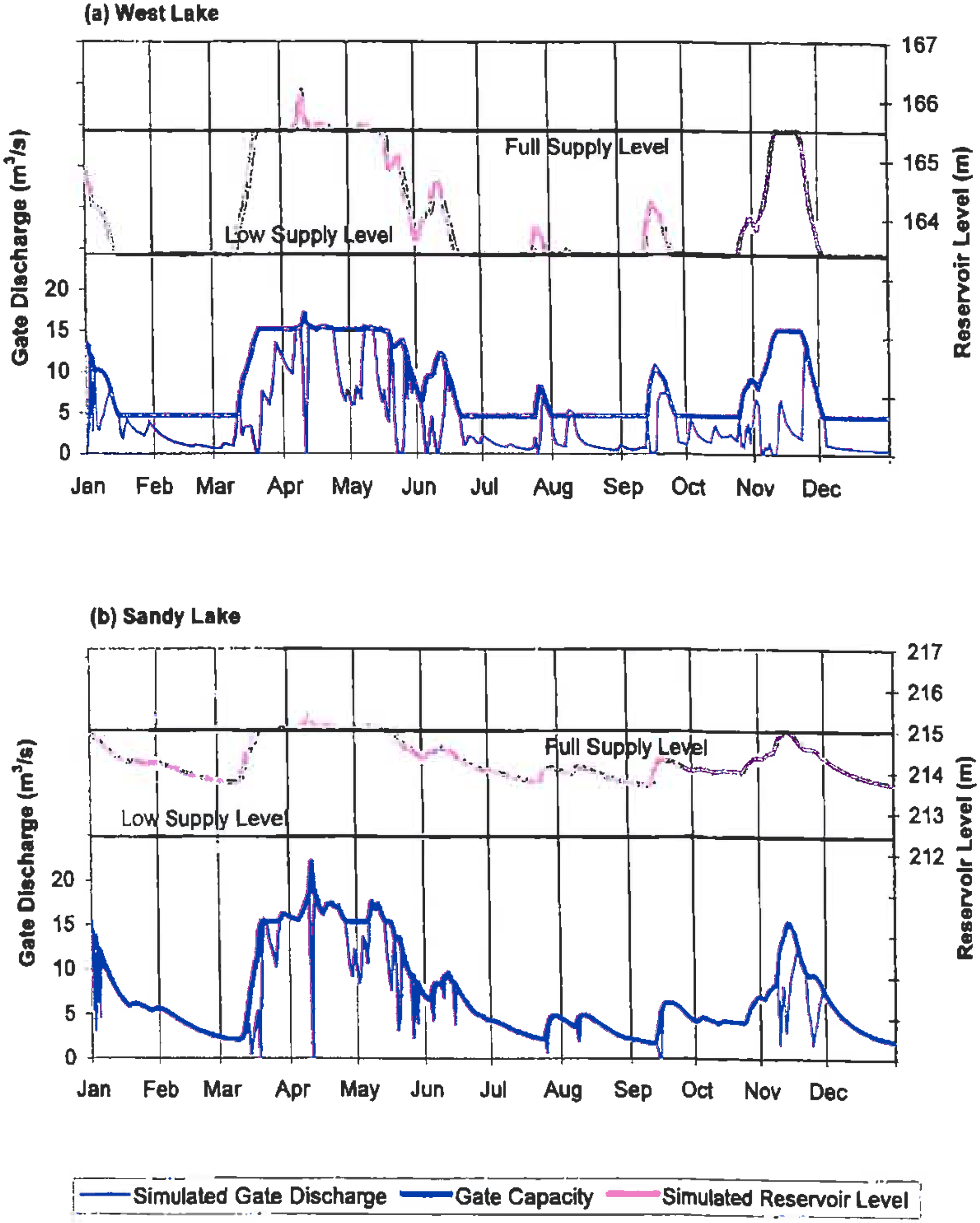


Fig.8.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

WEST POND AND SANDY POND SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

Pierres Brook

9 Pierres Brook Hydroelectric System

Pierres Brook Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Pierres Brook system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Pierres Brook system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Pierres Brook system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

9.1 System Description

The Pierres Brook system is located on the southern shore of the Avalon Peninsula in eastern Newfoundland. The Pierres Brook Generating Station was commissioned in 1931 and has a nameplate capacity of 4.3 MW and a rated net head of 76.0 m. Storage is provided by structures at Gull Pond, Big Country Pond and Witless Bay Country Pond.

The total drainage area above the intake of the Pierres Brook station is approximately 116 km^2. A schematic of the Pierres Brook system is presented in Figure 9.1.

Controlled releases and spill from Big Country Pond, and controlled releases from Witless Bay Country Pond, are discharged into Gull Pond. Spill from Witless Bay Country Pond is discharged out of the system. Gull Pond is the forebay for the generating station. Spill from Gull Pond is discharged out of the system.

The structures in the system are as follows

- Witless Bay Country Pond gated outlet;
- Witless Bay Country Pond overflow spillway;
- Big Country Pond gated outlet;
- Big Country Pond overflow spillway; and
- Gull Pond overflow spillway.

The Witless Bay Country Pond and Gull Pond spillways discharge out of the system; the Big Country Pond spillway discharges within the system.

A fish processing plant withdraws water intermittently from the penstock. This demand is not metered; information from other fish plants suggests a maximum of 2000 m^3/day (about 0.023 m^3/s). Over a single year, this amount would be less than one-half percent of the estimated mean annual flow through the generating station.

9.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are presented in Chapter 2. The measures as calculated for the Pierres Brook system are provided below. They were developed from the data in the base case simulation. Table 9.1 at the end of this section summarizes the measures for the Pierres Brook system.

1. Flow Utilization Factor

The flow utilization factors for the Pierres Brook station (average inflow to forebay divided by flow capacity at most efficient load and maximum load) are 0.96 at most efficient load and 0.73 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage) for most efficient load and maximum load are 0.19 kWh/m^3 (5.96 GWh/yr/m^3/s) and 0.18 kWh/m^3 (5.75 GWh/yr/m^3/s), respectively.

The average energy conversion factor from the base case simulation is 0.19 kWh/m^3 (5.83 GWh/yr/m^3/s). This energy conversion factor takes into account the average reduction in availability due to forced outages.

3. Flow Duration Curve

The flow duration curve for the turbine flow (power flow) in the base case simulation is shown in Figure 9.2. The unit operates at maximum flow around 30 percent of the time.

4. Energy Potential of Spill

The simulated spill for the base case was approximately 0.18 m^3/s on average at the Gull Pond overflow spillway. Using the simulated energy conversion factor for maximum load presented previously in this section, the spill would produce approximately 1.0 GWh/yr, if entirely saved and used for generation.

The simulated spill at the Witless Bay Country Pond for the base case was approximately 0.01 m^3/s on average. Using the simulated energy conversion factor for maximum load presented previously in this section, the spill would produce less than 0.1 GWh/yr, if entirely saved and used for generation. The average simulated spill at Big Country Pond was 0.20 m^3/s but the spill was discharged to Gull Pond and remained within the system.

The monthly distribution of spill over 15 years for the base case simulation is shown in Figure 9.3 for Witless Bay Country Pond and the Pierres Brook station (Gull Pond overflow spillway).

5. Reservoir Storage Factor

Storage is provided by structures located at Witless Bay Country Pond, Big Country Pond and Gull Pond. Gull Pond also acts as the headpond for the Pierres Brook station. The reservoir storage factors were calculated to be approximately 48 days for Witless Bay Country Pond, 53 days for Big Country Pond, and 60 days for Gull Pond. These factors represent the number of days to fill the reservoirs at average inflows without any outflow.

6. Reservoir Utilization Plot

The plots of simulated reservoir levels for the base case simulation are provided in Figures 9.4 and 9.5. The plots illustrate the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range. For the Pierres Brook system the use of reservoir storage is not limited by other physical or operational constraints.

7. Forebay Storage Factor

The forebay storage factor of Gull Pond (time required to draw forebay down assuming no inflow with unit operating at maximum load) is 37 days.

8. Gate Operation

There are control gates located at the outlets of Witless Bay Country Pond and Big Country Pond. Provided in Figure 9.6 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1987) for Witless Bay Country Pond and Big Country Pond. These plots illustrate the frequency with which the gates are being operated in the simulation model to maintain most efficient load and to avoid spill by operating at maximum load.

Table 9.1
Pierres Brook System Representative Operating Measures

Pierres Brook Representative Operating Measures	
Flow Utilization Factors - Most Efficient Load - Maximum Load	 0.96 0.73
Station Factors - Most Efficient Load - Maximum Load	 0.19 kWh/m³ 0.18 kWh/m³
Energy Potential of Spill - Witless Bay Country Pond Spill - Pierres Brook Spill	 <0.1 GWh/yr 1.0 GWh/yr
Reservoir Storage Factors - Witless Bay Country Pond - Big Country Pond - Gull Pond	 48 days 53 days 60 days
Forebay Storage Factor	37 days

9.3 Ideal Operation of System

The long term energy production at Pierres Brook as estimated by the simulation model developed for the Water Management Study is 26.7 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 23.8 GWh/yr. While these numbers are not directly comparable due to the runner replacement in 1994 and several other prolonged outages over this period, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately nine percent for this system. The comparison would therefore indicate that there is some opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual generation at the Pierres Brook system.

9.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Pierres Brook system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the unit will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated a rule curve for each reservoir in the system. If the reservoir levels exceed the rule curve at any particular time of the year, then the unit is operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the unit is operated at best efficiency.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the unit at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff. The rule curves used in the simulation model are illustrated in Figures 9.4 and 9.5 and are provided in the echo of the detailed simulation model input in Volume 2 of the Water Management Study.

9.3.2 Gate/Reservoir Operation

The Pierres Brook system has significant storage capacity that can be effectively used to smooth the basin inflows. Big Country Pond provides most of the usable storage capacity, apart from Gull Pond which also serves as the forebay. The gate that controls Big Country Pond is not readily accessible as it is located about 3 km from the nearest road (access is by boat in summer or snowmobile in winter). However, water levels at Big Country Pond can be monitored daily as the reservoir shoreline is accessible by road. In addition, the control gate at

Witless Bay Country Pond is readily accessible. Therefore, the impact of these practicalities on system generation should not be significant.

In addition to the accessibility issues, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro (NLH). This winter reserve is not taken into account by the simulation model and may have a more important impact on actual generation.

9.3.3 Unit Operation

The simulation model operates the Pierres Brook unit exclusively at its most efficient load, except when high inflows dictate that higher loads are necessary to avoid exceeding the reservoir rule curves. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate this plant very close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April and August 1999, and January-February 2000) confirmed that the Pierres Brook unit is loaded at best efficiency a high percentage of the time. The main obstacles to attaining ideal operation are electrical grid requirements which may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences.

9.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the unit at best efficiency more of the time.

Increasing the head as a consequence of increasing storage at Gull Pond was considered as a potential physical change (Section 9.5).

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The case described for the base case is an intermediate case, since it uses a NP rule curve varying between the low supply and full supply levels of the reservoirs, as described in Section 9.3. Operation at a lower forebay level to avoid spill was also investigated.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low

The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the unit would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At Pierres Brook, the potential for savings in spill compared to the base case is low. The maximum possible reduction in spill would be the equivalent of about 1.0 GWh/yr, as shown in Table 9.1. However, the spill distribution plots (Figure 9.3) shows that this would be difficult to capture since the spills occur infrequently and in large amounts.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the unit was always operated at maximum load when water was available. The average annual spill from Gull Pond was reduced by only 0.01 m^3/s, from an average of 0.18 m^3/s to 0.17 m^3/s. This represents an increase of less than 0.1 GWh/yr. This small amount does not compensate for the decrease in energy production due to operating the unit at a lower efficiency.

Best Efficiency Operation, Limiting Case: Reservoirs High

The limiting case for maximizing the amount of time the unit is operating at best efficiency is to run the unit at best efficiency, until the storage reservoirs are just about to spill. This may require frequent gate operation because the gates must be adjusted to release the exact amount of water to match the best efficiency flow.

The result of a simulation using this rule was an average annual production of 26.4 GWh/yr, with a spill of 0.25 m^3/s. This production is lower than the base case production. This suggests that the rule curve used for the base case simulation is near optimum for the Pierres Brook system. There could be minor adjustments made to the rule curve that could increase production monthly, but the increase would be expected to be marginal.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low
An alternative method of avoiding spill would be to operate the forebay at a lower level, although this would also reduce head. This was simulated by setting the forebay target elevation at 116.43 m, its lower operating level in the plant operating guidelines.

The result was an average annual production of 26.6 GWh/yr, or 0.1 GWh/yr less than that of the base case. Although the average spill was reduced to 0.15 m^3/s from 0.18 m^3/s, the savings did not compensate for the decrease in energy production due to reduced head on the unit.

9.5 Physical Changes to System

The principal options for physical changes to the existing system to improve energy generation are to increase storage capacity and increase head. To give an indication of the value of these changes, the following options were investigated.

- Increase dam height at Big Country Pond to increase storage.
- Increase dam height at Gull Pond to increase storage and head.
- Reduce headlosses.

Each of these physical changes to the system is discussed below. Table 9.2 summarizes the results.

Increase Storage at Big Country Pond
To determine the effect of an increase in storage on energy production, the dams and structures at Big Country Pond were assumed to be raised to allow an increase in full supply level of 1 m. The effect is to reduce system spill. The resulting increase in energy generation was 0.3 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $12 000/yr. Given a dam length of approximately 97 m, the savings over perhaps 20 years would justify an expenditure of about $1100/m of dam length based on a 1 m increase. The practicalities of increasing the dam height at Big Country Pond would have to be investigated. A detailed analysis into the benefits and cost would have to be conducted.

Increase Storage at Gull Pond

The dams and structures at Gull Pond were assumed to be raised to allow an increase in full supply level of one metre. This would also have the effect of increasing head on the unit. The resulting increase in energy generation was 0.5 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $20 000/yr. Given a dam length of approximately 172 m, the savings over perhaps 20 years would justify an expenditure of about $1100/m of dam length based on a 1 m increase.

Reduce Headlosses

Another method of increasing head is to reduce headlosses. For the purposes of examining the value of a reduction in headlosses, the simulation model was run with the assumed headlosses reduced by 50 percent. The resulting energy generation was 28.1 GWh/yr, or a net increase in average annual energy of 1.4 GWh/yr. Over the life of the project a recovery of some or all of these losses could have a net present value of several hundred thousand dollars; the actual total headloss is uncertain and would have to be determined by efficiency testing. Measures to reduce the losses cost-effectively could then be investigated.

Table 9.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	26.7	-
Increase Storage Big Country by 1 m	27.0	+0.3
Increase Storage Gull Pond by 1 m	27.2	+0.5
Reduce Headlosses	28.1	+1.4

9.6 Sensitivities

Environmental Release Requirement

The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 0.23 m^3/s at Witless Bay Country Pond and 0.80 m^3/s at Big Country Pond. Using these flows as the minimum flow release from the gates for the base case simulation model, there was no change in system energy. This is the case because 30 percent of mean annual flow is less than the flow released to maintain the best efficiency flow of the unit. This amount is always released in all simulations unless there is no water in storage, in which case the natural inflows are released.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement were always met, there would likely be a reduction in energy.

9.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

   Gate operation: Ideally, the gated outlets at Big Country Pond and Witless Bay Country Pond should be adjusted frequently to ensure that the correct flow is being released to keep the units operating at best efficiency, as well as to avoid spill. Automation of the gates would provide the best control, but simpler approaches may be more cost effective.

2. **Changes to Operating Guidelines**

   Clarification of Guidelines: The present guidelines as interpreted for the Water Management Study come close to maximizing system output if NP can operate in this manner. NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum.

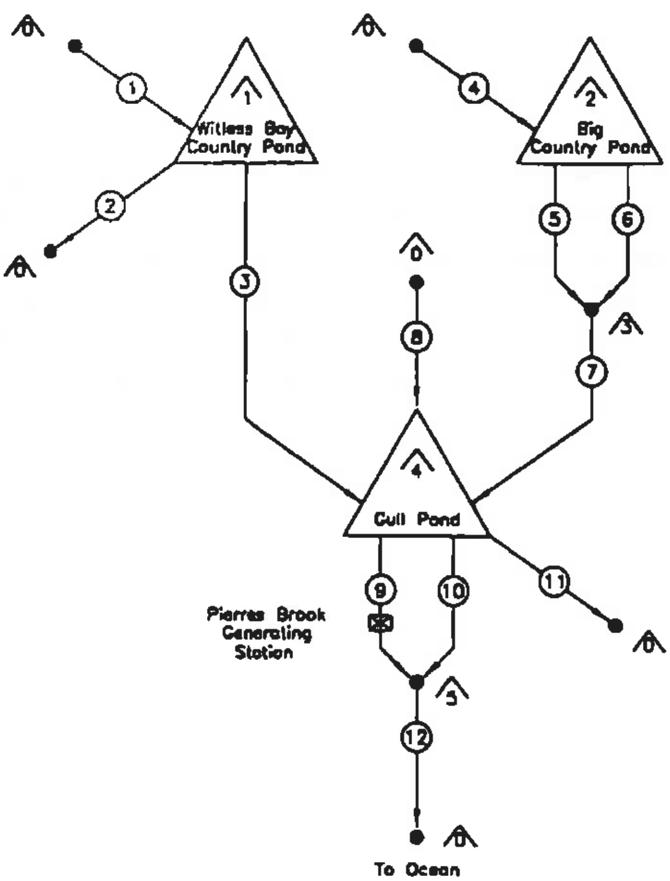
3. **Physical Changes**

   Increased Storage: Because of the fact that runoff is dominated by large events, especially spring runoff, storage is important in the system. Reducing spill at Big Country Pond by increasing the storage by 1 m results in an increase in energy generation of 0.3 GWh/yr. The result of a 1 m increase at Gull Pond is an increase of 0.5 GWh/yr, due to the combined effect of reduced spill and increased head.

Headlosses: The analysis showed that there may be some gains in energy by reducing headlosses. NP should conduct efficiency testing, which should provide an accurate estimate of headlosses and give particular attention to finding the sources of the losses. The costs and benefits of improvements can then be determined.

4. Sensitivities

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the gated outlets at Witless Bay Country Pond and Big Country Pond does not affect energy generation, because this amount is already being released to supply the units. The requirement, however, assumes that when the reservoirs are low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.



<u>CHANNELS</u>

(1) — Witless Bay Country Pond Local Inflow
(2) — Witless Bay Country Pond Spill
(3) — Witless Bay Country Pond Outlet Gate
(4) — Big Country Pond Local Inflow
(5) — Big Country Pond Outlet Gate
(6) — Big Country Pond Spill
(7) — Big Country Pond Total Outflow
(8) — Gull Pond Local Inflow
(9) — Pierres Brook Power Flow
(10) — Pierres Brook Spill
(11) — Fish Plant Demand
(12) — Pierres Brook Total Outflow

<u>RESERVOIRS / NODES</u>

0 — Source / Sink
1 — Witless Bay Country Pond
2 — Big Country Pond
3 — Big Country Pond Total Outflow
4 — Gull Pond (Forebay)
5 — Pierres Brook Total Outflow

Fig. 9.1

NEWFOUNDLAND POWER
HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY
PIERRES BROOK ARSP MODEL SCHEMATIC

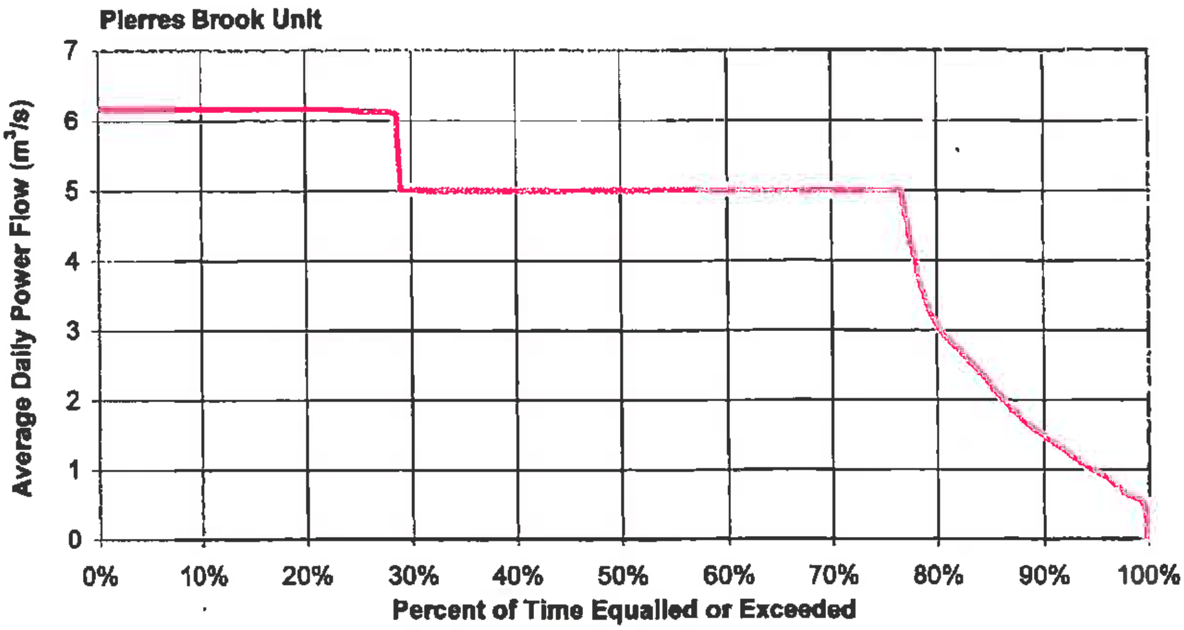


Fig. 9.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

PIERRES BROOK SIMULATED POWER FLOW DURATION CURVE

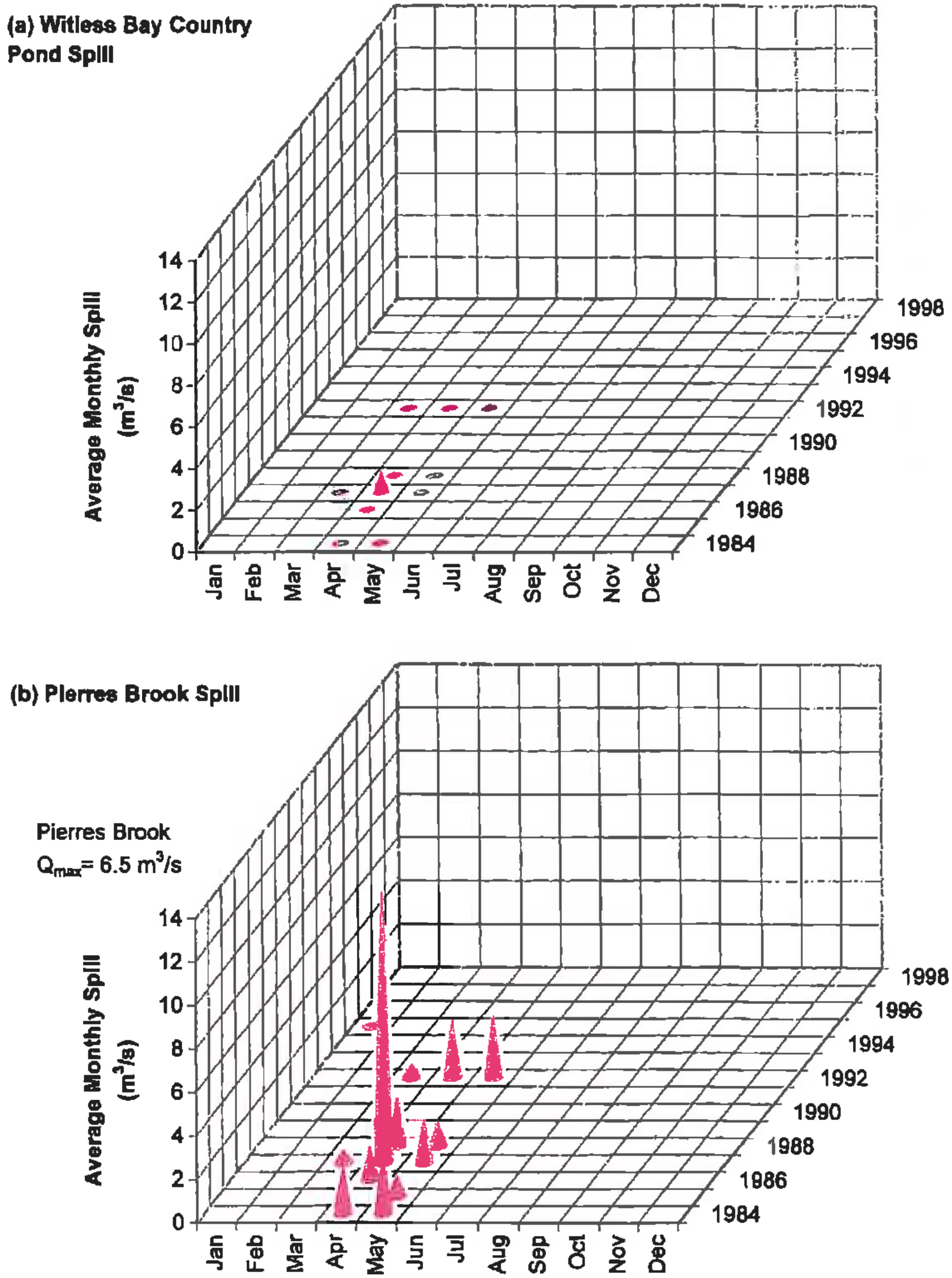


Fig. 9.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

WITLESS BAY COUNTRY POND AND PIERRES BROOK SIMULATED SPILLS

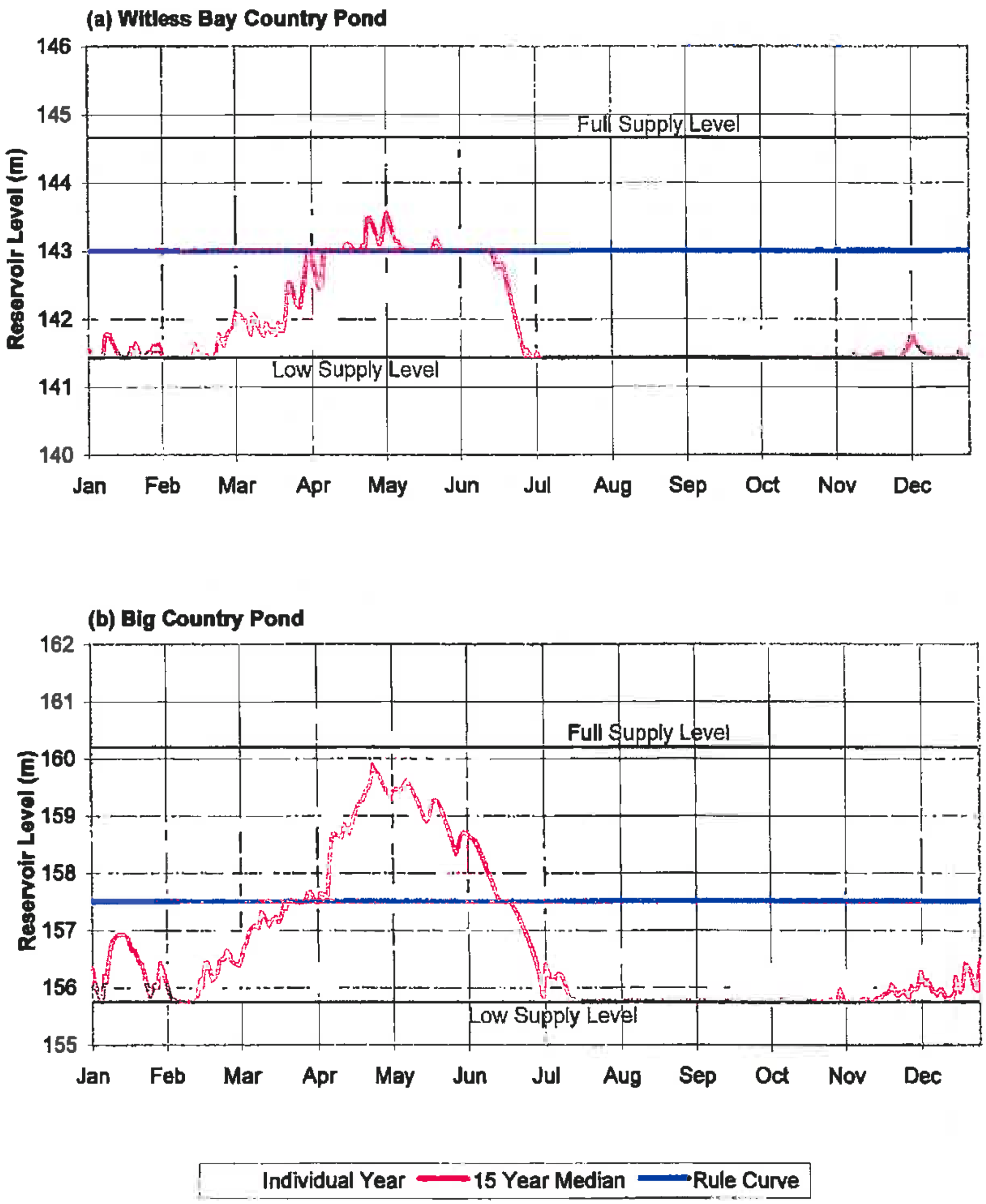


Fig. 9.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

WITLESS BAY COUNTRY POND AND BIG COUNTRY POND
SIMULATED RESERVOIR LEVELS

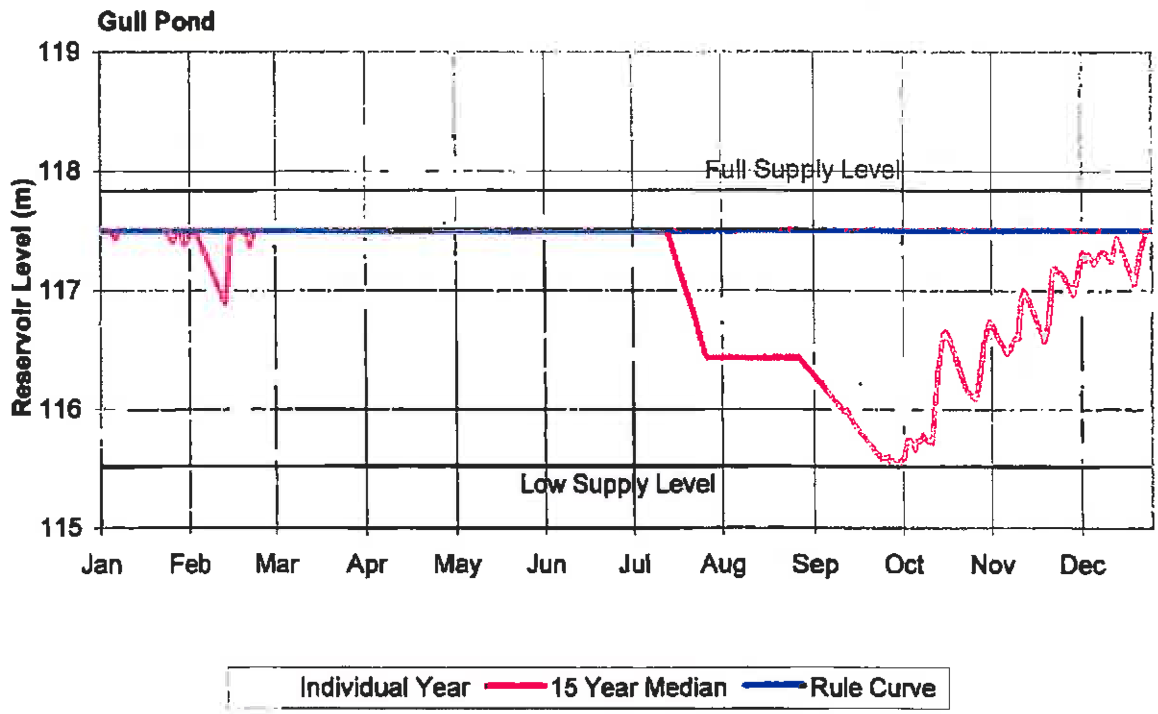
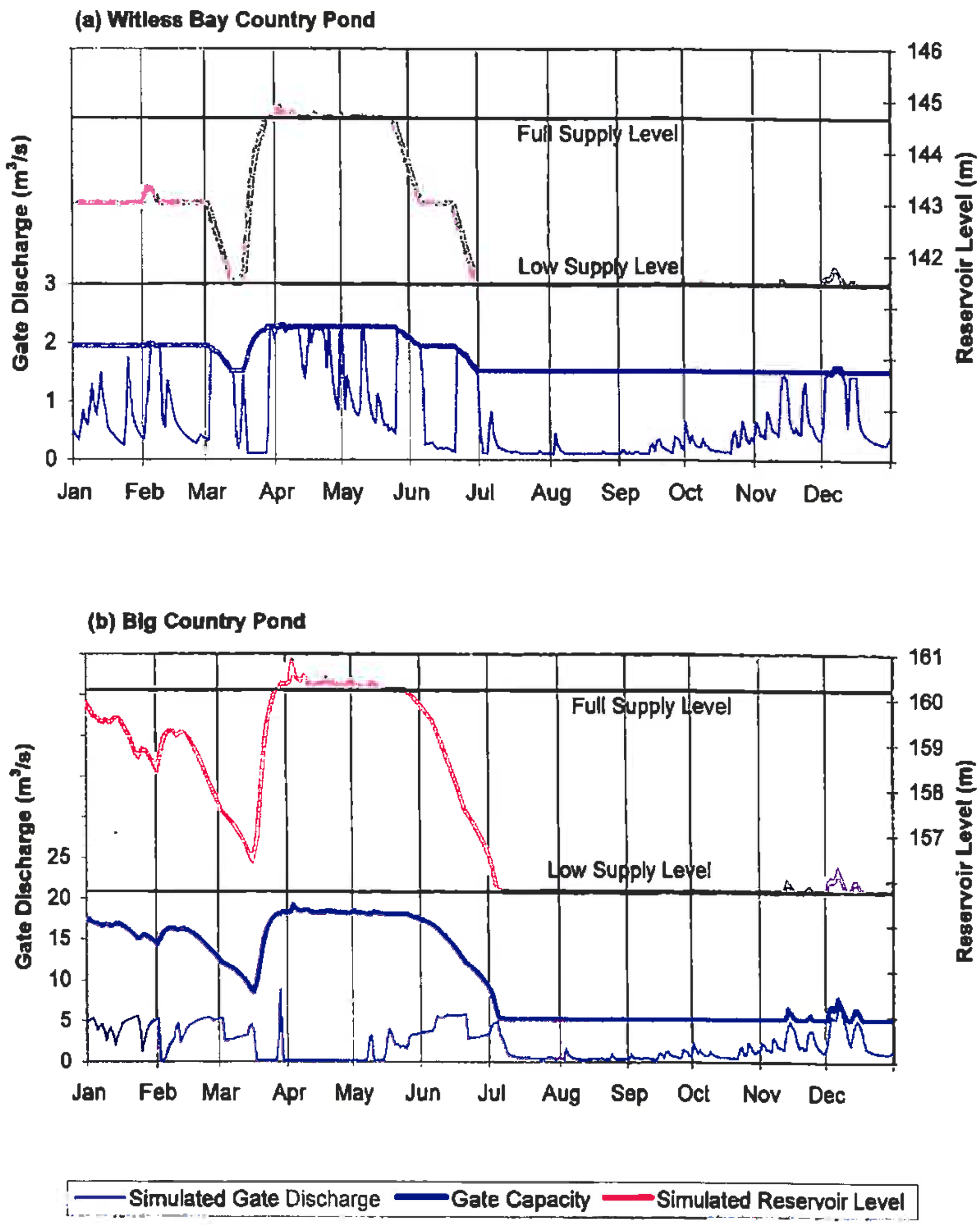


Fig. 9.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

GULL POND SIMULATED RESERVOIR LEVELS



NEWFOUNDLAND POWER

Fig. 9.6

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

WITLESS BAY COUNTRY POND AND BIG COUNTRY POND
SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL
FOR EXAMPLE YEAR

Rose Blanche Brook

10 Rose Blanche Brook Hydroelectric System

Rose Blanche Brook Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

Because Rose Blanche Brook is a new system and is essentially run-of-river, it was considered likely that the existing operating strategy is near optimal, and that there would be little potential for increasing energy. The system was included in the review for completeness.

The following sections describe the Rose Blanche Brook system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Rose Blanche Brook system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Rose Blanche Brook system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

10.1 System Description

The Rose Blanche Brook system is located on the south coast of Newfoundland near the community of Rose Blanche. Rose Blanche Brook station is NP's newest generating station, commissioned in 1998. Rose Blanche Brook station has two units with nameplate capacities of 3.0 MW each for a total nameplate capacity of 6.0 MW. The two units share a single generator. The Rose Blanche Brook station has a rated net head of 114.2 m. The total drainage area above the intake to the penstock to Rose Blanche Brook station is 53 km^2. The only controlled storage in the Rose Blanche Brook system is the forebay, which is relatively small. Rose Blanche is essentially a run-of-river station. A schematic of the Rose Blanche Brook system is presented in Figure 10.1.

There is one overflow spillway on Rose Blanche Brook Forebay. The spill reenters Rose Blanche Brook downstream of the station.

10.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are presented in Chapter 2. The measures as calculated for the Rose Blanche Brook system are provided below. They were developed from the data in the base case simulation. Table 10.1 at the end of this section summarizes the measures for the Rose Blanche Brook system.

1. Flow Utilization Factor

The Rose Blanche Brook station houses one generating unit with two turbines. The flow utilization factors for the Rose Blanche Brook station (average inflow to forebay divided by combined flow capacity for both units at most efficient load and maximum load) are 0.64 at most efficient load and 0.57 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage) for most efficient load and maximum load for each unit are 0.28 kWh/m^3 (8.87 GWh/yr/m^3/s) and 0.26 kWh/m^3 (8.31 GWh/yr/m^3/s), respectively.

The average energy conversion factor from the base case simulation for the two units is 0.25 kWh/m^3 (7.93 GWh/yr/m^3/s). The energy conversion factor take into account the average reduction in availability due to forced outages.

3. Flow Duration Curve

The flow duration curves for the turbine flow (power flow) in the base case simulation is shown in Figure 10.2. The two units operate at, or above, the combined most efficient flow more than 35 percent of the time, and a maximum flow approximately 10 percent of the time.

4. Energy Potential of Spill

The average simulated spill at the Rose Blanche Brook Forebay overflow spillway for the base case was approximately 0.63 m^3/s. Using the simulated energy conversion factor at maximum load, the spill would produce approximately 5.0 GWh/yr, if entirely saved and used for generation.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figure 10.3. Most of the spill occurs during the freshet in April and May, but spill can occur in any month.

5. Reservoir Storage Factor

The only storage in the Rose Blanche Brook system is the forebay. The reservoir storage factor for the forebay is approximately 11 days. This represents the number of days to fill the live storage of the reservoir, assuming average inflows and no outflows.

6. Reservoir Utilization Plot

The plot of simulated forebay levels for the base case simulation is provided in Figure 10.4. The plot illustrates the reservoir operation assumed for the base case, which generally keeps the reservoir in the top half of the operating range, except during spring.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with units operating at maximum load) is approximately 6 days.

8. Gate Operation

There are no control gates in the Rose Blanche Brook system.

Table 10.1
Rose Blanche Brook System Representative Operating Measures

Rose Blanche Brook Representative Operating Measures	
Flow Utilization Factors - Most Efficient Load - Maximum Load	 0.64 0.57
Station Factors - Both Units, Most Efficient Load - Both Units, Maximum Load	 0.28 kWh/m³ 0.26 kWh/m³
Energy Potential of Spill	5.0 GWh/yr
Reservoir Storage Factors - Rose Blanche Brook Forebay	 11 days
Forebay Storage Factor	6 days

10.3 Ideal Operation of System

The long term energy production at Rose Blanche Brook as estimated by the simulation model developed for the Water Management Study is 22.4 GWh/yr. Recorded energy generation for the same reference period is unavailable as the plant only commenced operation in December 1998. However, an indication of the difference between simulated and actual generation is provided by the comparisons conducted for the Water Management Study. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately 2 percent for this system. The comparison would therefore indicate that there is little opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was 7 percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual generation at the Rose Blanche Brook System.

10.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Rose Blanche Brook system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plant will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated a rule curve for each reservoir in the system. If the reservoir levels exceed the rule curve at any particular time of the year, then the units are operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the units are operated at best efficiency.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff. The rule curves used in the simulation model are illustrated in Figure 10.4 and are provided in the echo of the detailed simulation model input in Volume 2 of the Water Management Study. The control systems installed at this plant also incorporate a rule curve as the basis for making the transition from efficient to maximum load. This existing rule curve should be compared with the simulation curve and the curve which produces the best results (if significant differences exist) should be programmed into the control systems.

10.3.2 Gate/Reservoir Operation

The Rose Blanche Brook system has very limited storage capacity (storage ratio of 11 days), with all of the available storage contained by the forebay reservoir. NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro. This winter reserve is not taken into account by the simulation model. At Rose Blanche Brook however, the practicalities of gate and reservoir operation should not have a significant impact on actual generation.

10.3.3 Unit Operation

The simulation model operates the Rose Blanche Brook units exclusively at their most efficient loads, except when high inflows dictate that higher loads are necessary to avoid exceeding the reservoir rule curves. With the available control equipment and the storage available at the forebay which permit frequent starting and stopping of the units, it should be possible to operate the plant close to this ideal. An examination of daily Control Centre Logs for January-February 2000 confirms that the Rose Blanche units are loaded at best efficiency a high percentage of the time, with the exception of prolonged periods at 0.5-0.7 MW for environmental releases as described below

One obstacle to attaining ideal operation is electrical grid requirements that may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages which can be expected to occur more frequently at Rose Blanche Brook than at most other plants due to its location at the end of a long radial transmission line. Another operational practicality at Rose Blanche is the maintenance of a minimum flow (for environmental reasons) downstream of the powerhouse. Although the units have been designed so that they can use this flow for generation, their efficiency is substantially reduced at such a relatively low flow. These two factors probably account for most of the difference between the simulated and actual production of this system.

10.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2, there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Because it has only recently been commissioned, physical changes were not considered for the Rose Blanche Brook system.

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The base case is an intermediate case, since it uses a rule curve between the low supply and full supply levels of the forebay, as described in Section 10.3.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low

The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At Rose Blanche Brook, the potential for savings in spill compared to the base case is high. The maximum possible reduction in spill would be the equivalent of 5.0 GWh/yr, as shown in Table 10.1. However, the spill distribution plot (Figure 10.2) shows that this may be difficult to capture since the spills generally occur over a short period of time, i.e. during the spring freshet.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The average annual spill from Rose Blanche Brook Forebay was reduced by 0.1 m^3/s, from 0.63 m^3/s to 0.53 m^3/s, and the energy increased by 0.4 GWh/yr to 22.8 GWh/yr.

Best Efficiency Operation, Limiting Case: Reservoirs High
The limiting case for maximizing the amount of time the units are operating at best efficiency is to run the units at best efficiency, until the storage reservoirs are just about to spill.

The result of a simulation using this rule was an average annual production of 22.7 GWh/yr, with a spill of 0.56 m^3/s. This production is 0.3 GWh/yr higher than the base case production, but 0.1 GWH/yr lower than the Spill Avoidance, Limiting Case.

The small gains in energy confirm that the current operating guidelines lead to near optimum generation. The intermediate rule curve chosen for the Water Management Study appears to give lower annual energy than operation at either extreme.

10.5 Physical Changes to System

Given that the Rose Blanche Brook system was only commissioned in 1998, an examination of physical changes is not required. There is no information available now that would result in different conclusions than were drawn during the optimization studies undertaken as part of the design.

10.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of their systems. Results for all sensitivity cases are provided in Table 10.3. Along with the average energy generation, average annual forebay spill for each case is presented in Table 10.3.

The sensitivity cases were as follows.

- No environmental release requirement (compared to minimum flows established during design).
- No storage in system (to obtain value of storage); remove dam.

Environmental Release Requirement
An agreement with the Federal Department of Fisheries and Oceans requires that a minimum flow of 1 m^3/s be maintained in the Rose Blanche River downstream of the

powerhouse at all times. This is approximately 30 percent of the mean annual inflow to the basin. If the turbines are shut down, a fisheries valve is opened to provide the minimum flow. NP is required to hold a supply of water in the reservoirs to ensure that the low flow requirement is met even during periods of low inflow. The fisheries value can draw the reservoir down to below low supply level of the reservoir.

The cost of the fisheries release was estimated by removing the 1 m^3/s limitation and allowing the unit to operate only at best efficiency flows or above. This simulation provided an additional 0.8 GWh/yr. Since at times the fishery release will draw the reservoir down below low supply level which would further reduce generation, the total cost of maintaining the fisheries release is in excess of 0.8 GWh/yr.

No Storage in System

To provide NP with an indication of the value of the storage in the system, the forebay storage in the system was assumed to be removed. The resulting average annual energy generation from this sensitivity was 17.9 GWh/yr, a net decrease of 4.5 GWh/yr. This represents the value of storage at the forebay dam.

Table 10.2
Energy Results for Sensitivity Simulations at Rose Blanche Brook System

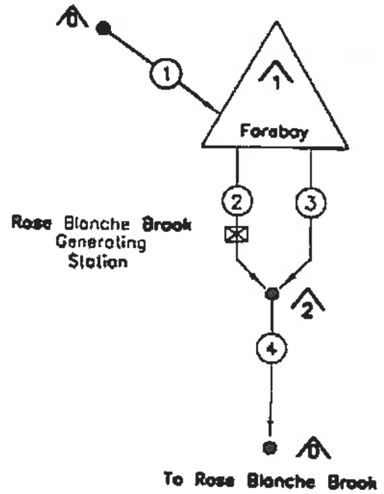
Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)	Average Spill (m^3/s)
Base Case	22.4	-	0.63
Environmental Releases - minimum removed	23.2	0.8	0.63
Value of Storage	17.9	- 4.5	1.16

10.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

Environmental Releases: Providing a minimum flow release of approximately 30 percent of mean annual flow downstream of the plant costs in excess of 0.8 GWh/yr.

Value of Storage: The value of the storage at Rose Blanche Brook Forebay is 4.5 GWh/yr.



CHANNELS

① — Rose Blanche Brook Inflow
② — Rose Blanche Brook Power Flow Units #1 and #2
③ — Rose Blanche Brook Spill
④ — Rose Blanche Brook Total Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Rose Blanche Brook Forebay
2 — Rose Blanche Brook Total Outflow

Fig. 10.1

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

ROSE BLANCHE BROOK ARSP MODEL SCHEMATIC

ACRES

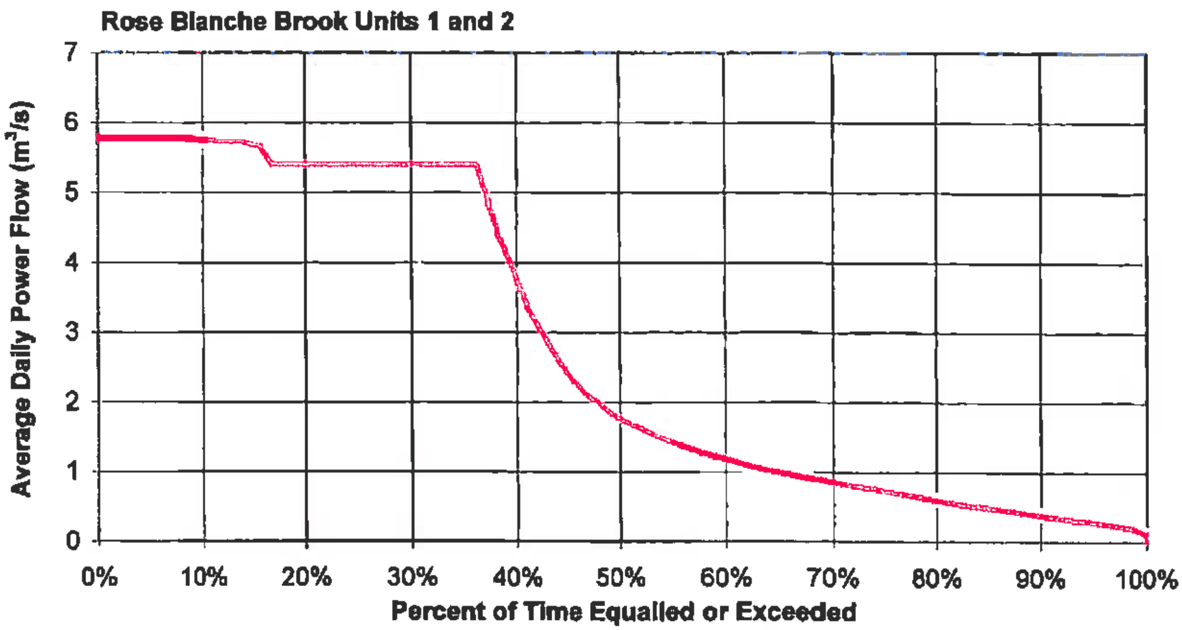


Fig. 10.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

ROSE BLANCHE BROOK SIMULATED POWER FLOW DURATION CURVE

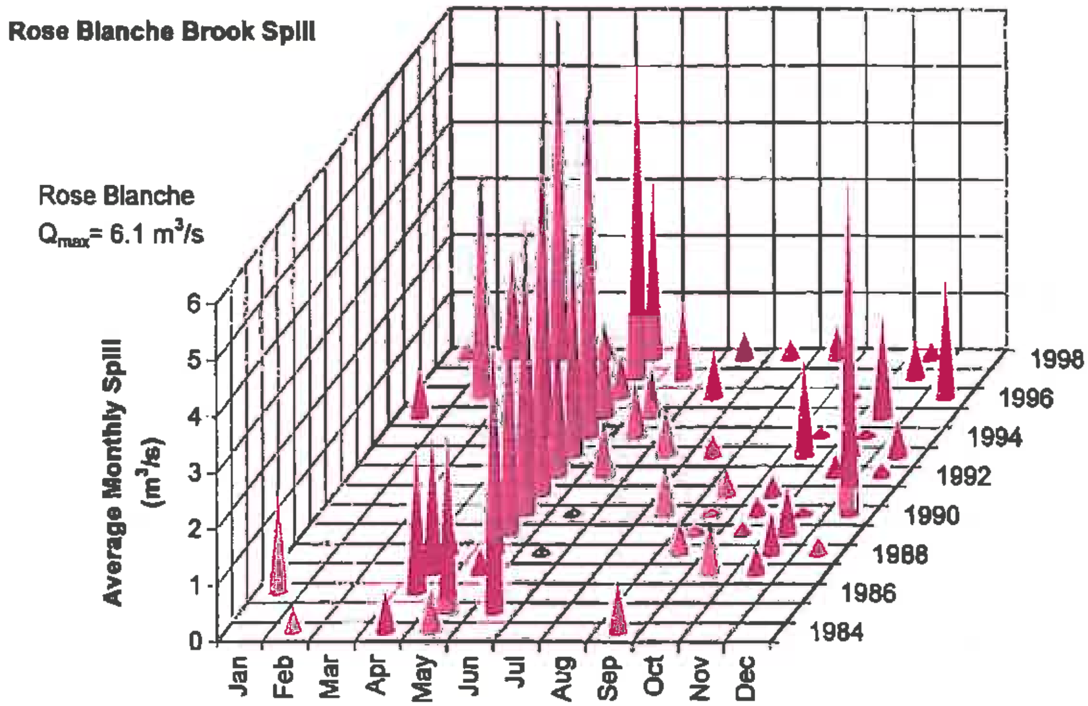


Fig. 10.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

ROSE BLANCHE BROOK SIMULATED SPILLS

ACRES

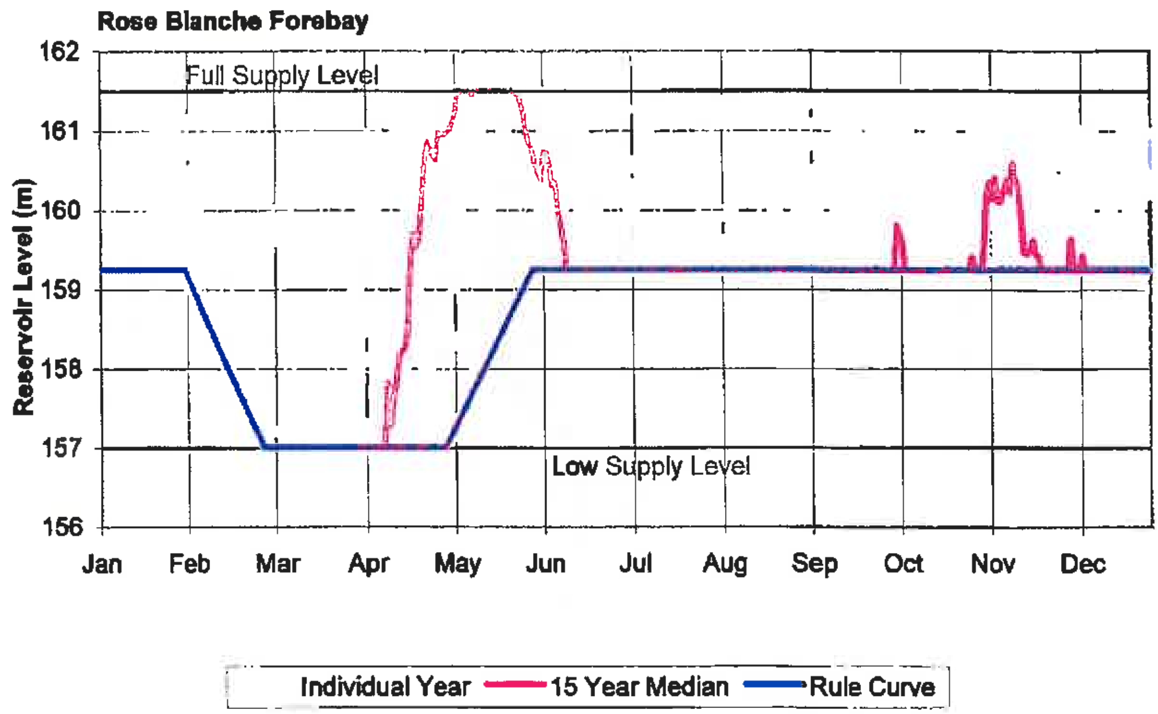


Fig. 10.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

ROSE BLANCHE FOREBAY SIMULATED RESERVOIR LEVELS

ACRES

Petty Harbour

11 Petty Harbour Hydroelectric System

Petty Harbour Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Petty Harbour system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Petty Harbour system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Petty Harbour system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

11.1 System Description

The Petty Harbour system is located on the east coast of the Avalon Peninsula of Newfoundland. The system was commissioned in 1900 and has a nameplate capacity of 5.3 MW and a rated net head of 57.9 m. Storage is provided by structures at Bay Bulls Big Pond, Cochrane Pond, and Petty Harbour Forebay.

The total drainage area above the intake of the Petty Harbour Generating Station is approximately 136 km^2. A schematic of the Petty Harbour system is presented in Figure 11.1.

The drainage area falls largely within the municipal boundary of the City of St. John's. Bay Bulls Big Pond is the largest storage reservoir and is also used as a municipal water supply for the Regional Water System, serving the City of St. John's, the City of Mount Pearl, the Town of Conception Bay South, and the Town of Paradise. Spill and controlled releases from Bay Bulls Big Pond are discharged into Raymond Brook, which in turn flows into the forebay. Controlled releases from Cochrane Pond are discharged into Cochrane Pond Brook, which also flows into the forebay. Spill at Cochrane Pond is discharged into Paddy's Pond, part of the adjacent Topsail Hydroelectric System. The forebay, comprising First Pond and Second Pond, is located near the community of Goulds. The generating station is located in the community of Petty Harbour and draws flow from the forebay through a single penstock. Spill from the forebay is discharged around the station and out of the system.

The structures in the system are as follows

- Bay Bulls Big Pond overflow spillway;
- Bay Bulls Big Pond gated outlet;
- Cochrane Pond overflow spillway;
- Cochrane Pond gated outlet; and
- Petty Harbour Forebay overflow spillway.

The forebay and Cochrane Pond spillways discharge out of the system; the Bay Bulls Big Pond spillway discharges within the system.

11.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.

4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are described in Chapter 2. The measures as calculated for the Petty Harbour system are provided below. They were developed from the data in the base case simulation. Table 11.1 at the end of this section summarizes the measures for the Petty Harbour system.

1. Flow Utilization Factor

The flow utilization factors for the Petty Harbour station (average inflow to forebay divided by combined flow capacity for all three units at most efficient load and maximum load) are 0.52 at most efficient load and 0.41 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage at rated net head) for most efficient load and maximum load for PHR-G1 are 0.11 kWh/m^3 (3.57 GWh/yr/m^3/s) and 0.11 kWh/m^3 (3.45 GWh/yr/m^3/s), respectively. For PHR-G2 the most efficient load and maximum load energy conversion factors are 0.14 kWh/m^3 (4.40 GWh/yr/m^3/s) and 0.13 kWh/m^3 (4.04 GWh/yr/m^3/s), respectively. For PHR-G3 the most efficient load and maximum load energy conversion factors are 0.14 kWh/m^3 (4.39 GWh/yr/m^3/s) and 0.14 kWh/m^3 (4.29 GWh/yr/m^3/s), respectively.

The average energy conversion factors from the base case simulation for PHR-G1, PHR-G2 and PHR-G3 are 0.13 kWh/m^3 (3.57 GWh/yr/m^3/s), 0.14 kWh/m^3 (4.46 GWh/yr/m^3/s), and 0.14 kWh/m^3 (4.47 GWh/yr/m^3/s) respectively. These energy conversion factors take into account the average reduction in availability due to forced outages, and the lower headlosses during the 80 percent of the time that only one or two units are operating.

Based on the energy conversion factors for the Petty Harbour units, the unit dispatch to maximize efficiency would be as follows.

- Operate PHR-G2 at most efficient load first.
- Operate PHR-G3 at most efficient load second.
- Operate PHR-G3 at maximum load third.

- Operate PHR-G2 at maximum load fourth.
- Operate PHR-G1 at most efficient load fifth.
- Operate PHR-G1 at maximum load last.

NP's plant operating guidelines recommend that PHR-G2 be loaded to maximum before PHR-G3. The simulated flow duration curves, discussed below, show that the units are loaded to maximum almost the same amount of time in ideal operation, so a change in dispatch order may not have any practical effect. However, in the absence of up-to-date efficiency test results, the available estimates of headlosses and unit efficiencies are subject to considerable uncertainty.

4. Flow Duration Curve

The flow duration curves for the turbine flow (power flow) in the base case simulation are shown in Figures 11.2 and 11.3. PHR-G2 is loaded first. Both PHR-G2 and PHR-G3 are operated at maximum load no more than 25 percent of the time. PHR-G1 is used less than 20 percent of the time.

5. Energy Potential of Spill

The monthly distribution of the simulated spill out of the Petty Harbour system over 15 years for the base case simulation is shown in Figure 11.4, for Cochrane Pond and Petty Harbour Forebay.

The simulated spills for the base case were approximately 0.08 m^3/s and 0.27 m^3/s on average at the Cochrane Pond and Petty Harbour Forebay overflow spillways, respectively. Using the simulated energy conversion factors at maximum load presented previously in this section, the Cochrane Pond spill would produce approximately 0.3 GWh/yr and the Petty Harbour Forebay spill would produce approximately 1.1 GWh/yr, on average, if entirely saved and used for generation.

6. Reservoir Storage Factor

Storage is provided by structures located at Bay Bulls Big Pond and Cochrane Pond. The Petty Harbour Forebay acts as the headpond for the generating station. The reservoir storage factors were calculated to be approximately 250 days for Bay Bulls Big Pond, 20 days for Cochrane Pond, and nine days for Petty Harbour Forebay. These factors represent the number of days to fill the reservoirs at average inflows without any outflow.

7. Reservoir Utilization Plot

The plot of simulated Bay Bulls Big Pond and Cochrane Pond reservoir levels for the base case simulation is provided in Figure 11.5. The plot illustrates the reservoir utilization corresponding to ideal operation. As may be seen in the figure, the storage range of Bay Bulls Big Pond is limited by the minimum allowable level of 149.80 m. This level was agreed upon by NP and the Regional Water System. Below this level, there are no releases of water for generation, so that the municipal water supply is not interrupted.

At Cochrane Pond, the available storage range is not fully utilized. As discussed in item number 9 below, this could be the result of the gated outlet being undersized.

8. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with the units operating at maximum load) is estimated to be approximately four days.

9. Gate Operation

There are control gates located at the outlet of Bay Bulls Big Pond and Cochrane Pond. Provided in Figure 11.6 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1987) for both reservoirs. These plots illustrate the frequency the gates are being operated in the simulation model to maintain most efficient load and to avoid spill.

For Bay Bulls Big Pond, the simulation model incorporates a maximum allowable discharge as a function of reservoir level, according to an operating regime suggested for sharing water between NP and the Regional Water System. In contrast, the releases from Cochrane Pond are limited by the physical capacity of the gate. As mentioned in item number 7 above, this may prevent utilization of the full storage range.

Table 11.1
Petty Harbour System Representative Operating Measures

Petty Harbour Representative Operating Measures	
Flow Utilization Factors - Most Efficient Load - Maximum Load	 0.52 0.41
Station Factors - PHR-G1 Most Efficient Load - PHR-G1 Maximum Load - PHR-G2 Most Efficient Load - PHR-G2 Maximum Load - PHR-G3 Most Efficient Load - PHR-G3 Maximum Load	 0.11 kWh/m³ 0.11 kWh/m³ 0.14 kWh/m³ 0.13 kWh/m³ 0.14 kWh/m³ 0.14 kWh/m³
Energy Potential of Spill - Cochrane Pond Spill - Petty Harbour Spill	 0.3 GWh/yr 1.1 GWh/yr
Reservoir Storage Factors - Bay Bulls Big Pond - Cochrane Pond - Petty Harbour Forebay	 250 days 20 days 9 days
Forebay Storage Factor	4 days

11.3 Ideal Operation of System

The long term energy production at Petty Harbour as estimated by the simulation model developed for the Water Management is 19.9 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 16.3 GWh/yr. While these numbers are not directly comparable due to the two runner replacements in 1985/86, several prolonged outages over this period, and the steady increase in consumptive withdrawals from Bay Bulls Big Pond by the Regional Water System, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately 20 percent for this system. The comparison would therefore indicate that there is substantial opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual generation at the Petty Harbour system.

11.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Petty Harbour system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the units will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated a rule curve (target level) for the forebay. The rule curve was set equal to the maximum summer and winter operating elevations listed in the plant operating guidelines (92.05 m and 91.44 m respectively). If the forebay level exceeds the rule curve at any particular time of the year, then the units are operated at maximum load according to the specified dispatch order to bring the level down to the rule curve. If the forebay level is at or below the rule curve, then the units are operated at best efficiency according to the dispatch order to maintain the level at the rule curve.

Obviously, some judgment on the part of the operators in applying the guidelines is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding when to operate the units at maximum load even when the water level is not above the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff.

The reservoir rule curves, shown in Figure 11.5, are set so that Bay Bulls Big Pond releases flow only to maintain the units at best efficiency, while Cochrane Pond releases continually (i.e., gate is open) unless the forebay is spilling and Cochrane Pond has available storage.

11.3.2 Gate/Reservoir Operation

The Petty Harbour system has relatively little storage capacity. Bay Bulls Big Pond is the primary storage reservoir. Some additional storage is available at Cochrane Pond and the forebay. Bay Bulls Big Pond and Cochrane Pond are equipped with control gates. The gates are relatively easy to access and therefore the impact of this operating practicality on system generation should not be significant.

Of potentially greater impact to station generation however, is the maintenance of minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro (NLH). This winter reserve is not taken into account by the simulation model.

11.3.3 Unit Operation

The simulation model operates the Petty Harbour units exclusively at their most efficient loads, except when high inflows dictate that higher loads are necessary to avoid exceeding the forebay rule curve. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate the plant very close to this ideal. An examination of daily Control Centre Logs for January and February 2000 indicated that the Petty Harbour units were loaded at various loads between 1.0 and 1.5 MW for PHR-G2 and between 1.9 and 2.6 MW for PHR-G3 during this period. This plant would therefore not appear to be making efficient use of the available water, although a more detailed study would also include an examination of unit availability and system conditions during these months.

The plant operating guidelines state that unit operation should be set to "maintain constant forebay elevation under normal circumstances". Cycling units to efficient load would require some tolerance of within-day fluctuations about an average forebay level. This would not appear in the simulation results because the model uses a daily time step. Depending on the interpretation of this guideline, it is possible that units could be set at inefficient loads in order to rigidly adhere to a constant forebay level.

Another obstacle to attaining ideal operation is electrical grid requirements that may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences.

11.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

The only feasible change to the present operating guidelines that could improve generation is to change the forebay operating elevations. Operating the forebay at a lower elevation is possible, and could increase generation by reducing spill, even though it would also reduce head. It is not feasible to increase the operating elevations without changing the elevation of the forebay spillway. Such a physical modification is examined in Section 11.5.

Spill Avoidance: Lower Forebay Operating Elevation
Due to the lack of reservoir storage coupled with the large inflow area of the forebay, the forebay level tends to rise quickly during heavy inflows, resulting in spill and forcing the units to be loaded above their most efficient settings. Targeting a lower forebay operating elevation could reduce the amount of spill, although the reduction in head could be a drawback.

As one alternative, the rule curve was set at 90.89 m year round. This is currently the minimum winter elevation in the plant operating guidelines (298.2 ft). The average simulated generation was 20.1 GWh/yr, or 0.2 GWh/yr more than the base case. The average forebay spill was reduced from 0.27 m^3/s to 0.20 m^3/s.

As a second alternative, the rule curve was further lowered to 90.30 m, which is estimated to be the bed elevation of the channel joining First and Second Pond. The average simulated generation was 20.0 GWh/yr. The average forebay spill was reduced to 0.15 m^3/s, but the saving in spill was not enough to offset the reduced head. As a variation on this alternative, the units were set to operate at most efficient load until just before spilling, thereby generating more efficiently with the available forebay storage. This also reduced the use of the inefficient PHR-G1 unit. The average simulated generation was 20.2 GWh/yr, or 0.3 GWh/yr more than the base case. The average forebay spill was 0.17 m^3/s.

11.5 Physical Changes to System

The principal options for physical changes to the existing system to improve generation are to increase head, increase storage, increase gate capacity and increase unit efficiency. To give an indication of the value of these changes, the following options were investigated.

- Raise the spill elevation of Petty Harbour Forebay to increase head and storage.
- Increase the discharge capacity of the Cochrane Pond gated outlet.
- Rehabilitate PHR-G1.

Each of these physical changes is discussed below. Table 11.2 summarizes the results.

Raise Spill Elevation of Forebay

The elevation of the existing spillway crest at Petty Harbour Forebay is 92.35 m and the dam crest elevation is 93.82 m. To determine whether any additional energy could be obtained through extra head, the spill elevation was assumed to be raised by 1 m, while maintaining the present summer and winter operating elevations. This would allow for some additional storage at the forebay during heavy inflows.

The resulting increase in energy generation from this change was 0.5 GWh/yr, from 19.9 GWh/yr to 20.4 GWh/yr. The average forebay spill was reduced from 0.27 m^3/s to 0.18 m^3/s.

Assuming that the cost of energy to NP is $0.04/kWh, this would result in a savings to NP of approximately $20 000/yr. Given an estimated spillway crest length of 40 m, the savings over perhaps 20 years would justify an expenditure of about $4600/m of crest length. Raising the spill elevation could be achieved by installing flashboards or an inflatable crest gate. The practicalities of increasing the spill elevation would have to be investigated, including any dam safety issues and restrictions on the levels of First Pond and Second Pond.

Increase Discharge Capacity of Cochrane Pond Gated Outlet

The average annual inflow to Cochrane Pond is estimated to be 0.44 m^3/s, but the average simulated gate discharge in the base case is only 0.36 m^3/s, with the remaining 0.08 m^3/s being spilled out of the system. The spills are frequent and the storage is not fully utilized, as shown in Figures 11.4 and 11.5 respectively, even with the gate normally fully open. To examine the option of increasing the discharge capacity, it was assumed that the discharge capacity of the gate was doubled.

The resulting average generation was 20.2 GWh/yr, or 0.3 GWh/yr more than the base case. Cochrane Pond average spill was decreased to 0.02 m^3/s, while spill at the forebay was increased slightly from 0.27 m^3/s to 0.30 m^3/s.

Assuming that the cost of energy to NP is $0.04/kWh, this would result in a savings to NP of approximately $12 000/yr. The savings over perhaps 20 years would justify an expenditure of about $110 000. The existing outlet is about 1.3 m wide. The practicalities of increasing the gate capacity would have to be examined, including whether or not there are any other hydraulic restrictions on the outlet.

Rehabilitate PHR-G1

The PHR-G2 and PHR-G3 units are relatively efficient and equipped with modern control equipment. Headlosses have been improved by the recent rehabilitation of a large section of the Petty Harbour penstock. One of the station's main remaining deficiencies is PHR-G1, the oldest and least efficient of the three units. To investigate the option of rehabilitating the unit, it was assumed that the estimated unit efficiency was increased by a factor of 20 percent, which would make it comparable to the estimated efficiencies of PHR-G2 and PHR-G3. The unit dispatch order was also revised so that all units would be loaded to best efficiency before any were loaded to maximum.

The resulting average generation was 20.3 GWh/yr, or 0.4 GWh/yr more than the base case. Assuming that the cost of energy to NP is $0.04/kWh, this would result in a savings to NP of approximately $16 000/yr. The savings over perhaps 20 years would justify a total expenditure of about $150 000.

Unlike the other two units, PHR-G1 is not automated. When considering options for rehabilitation, it may be desirable to examine the costs and benefits of installing modern control equipment for this unit. This should be preceded by efficiency testing to obtain accurate estimates of unit performance.

Table 11.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	19.9	–
Raise Spill Elevation of Forebay	20.4	+0.5
Increase Discharge Capacity of Cochrane Pond Gated Outlet	20.2	+0.3
Rehabilitate PHR-G1	20.3	+0.4

11.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain operating constraints on their systems. Results for the sensitivity cases are summarized in Table 11.3.

The sensitivity cases were as follows.

- Environmental release requirement of 30 percent of mean annual flow.
- Increased Regional Water System demand.
- No Regional Water System demand (to obtain cost of demand).

Environmental Release Requirement

The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 0.46 m^3/s at Bay Bulls Big Pond and 0.13 m^3/s at Cochrane Pond. Using these flows as the minimum flow release from the gates for the base case simulation model, there was no change in system energy.

The flow through the Bay Bulls Big Pond gate satisfied the minimum flow requirement, but it was necessary to exceed the maximum allowable gate discharge, as well as go below the 149.80 m minimum allowable level in six of the fifteen years. For the base case, in which the maximum allowable gate discharge and the minimum allowable level were enforced, the 30 percent mean annual flow requirement was not met for 36 percent of the time. However there was little change in the average discharge between the two runs.

There was no change in the Cochrane Pond gate discharge because the gate was already releasing as much as physically possible. The 30 percent mean annual flow requirement was not satisfied for 10 percent of the time.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement was always met, without violating the minimum allowable water level of Bay Bulls Big Pond, there would likely be a reduction in energy.

Increased Regional Water System Demand

The sensitivity to an increase in municipal water supply demand was investigated. For the base case, the average present day (2000) municipal consumption was taken as 60 000 m^3/d. The sensitivity run assumed an ultimate future (2059) demand of 86 000 m^3/d. The resulting average annual energy was 18.6 GWh/yr, or 1.3 GWh/yr less than the base case.

No Regional Water System Demand

To provide NP with an indication of the energy cost of sharing Bay Bulls Big Pond with the Regional Water System, a sensitivity run was carried out assuming there were no water supply withdrawals and no associated restrictions on the level or discharge of Bay Bulls Big Pond. The resulting average annual energy was 23.2 GWh/yr, or 3.3 GWh/yr more than the base case.

Table 11.3
Energy Results for Sensitivity Simulations at Petty Harbour System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)	Forebay Spill (m^3/s)
Base Case	19.9	-	0.27
Environmental Releases	19.9	0.0	0.29
Increased Regional Water System Demand	18.6	- 1.3	0.27
No Regional Water System Demand	23.2	+ 3.3	0.26

11.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

   Unit Operation: NP should investigate the reasons for past inefficient operation of the units, and ensure that the units are operated at efficient load settings as much as possible.

2. **Changes to Operating Guidelines**

   Clarification of Guidelines: NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum. The guidelines should also be clarified to provide for allowable forebay level fluctuations when cycling units at efficient load.

   Unit Dispatch Order: The present guidelines suggest a unit dispatch order that is inconsistent with the energy conversion factors as calculated from the available information. NP should carry out efficiency testing on all three units, operating separately and together, to determine the accuracy of the estimated energy conversion factors and to determine if the dispatch order should be changed.

Forebay Operating Level: The analysis suggests that operating at a lower forebay level could increase generation by reducing spill, despite the reduction in head. This alternative should be investigated further to determine an optimal forebay target level, contingent on obtaining accurate estimates of available net head and unit efficiency.

3. **Physical Changes**

Forebay Spill Elevation: The analysis showed that raising the spill elevation of the Petty Harbour Forebay may increase generation by increasing head and reducing spill. NP should investigate the costs and benefits of alternative flashboard/crest gate arrangements, taking into account dam safety requirements and any other constraints on the forebay elevation.

Cochrane Pond Gated Outlet: The analysis shows that the Cochrane Pond gated outlet may be undersized, resulting in spill out of the system and less than ideal storage utilization. NP should investigate possible modifications to the outlet to increase its discharge capacity.

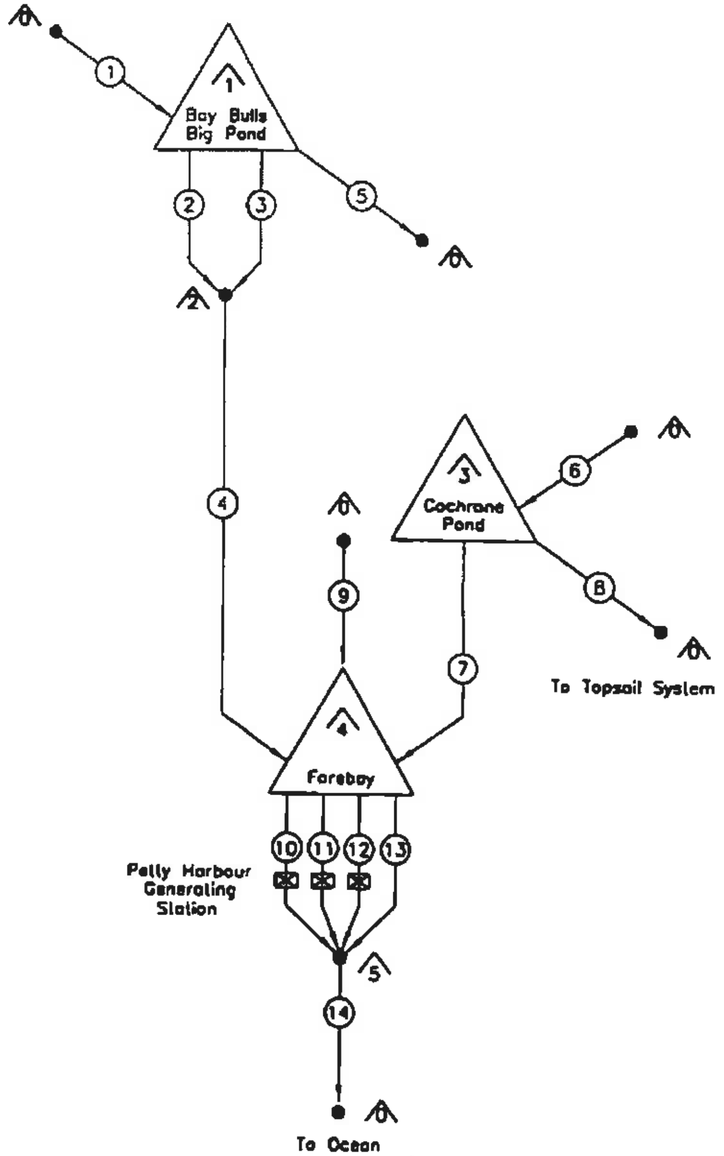
PHR-G1 Unit: This unit is the oldest and least efficient of the three units, and the only one not equipped with automated control equipment. NP should investigate the costs and benefits of rehabilitating PHR-G1 to modern standards.

4. **Sensitivities**

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gates at Bay Bulls Big Pond and Cochrane Pond does not affect energy generation, as there is little change in the average flow already being released to supply the units. The requirement, however, assumes that Cochrane Pond releases only the natural inflow when the water level is low, and that Bay Bulls Big Pond satisfies the requirement without regard to the minimum allowable water level and maximum allowable gate discharge restrictions. If the requirement were to guarantee 30 percent at Cochrane Pond and not violate the operating restrictions at Bay Bulls Big Pond, a reserve would have to be maintained similar to the winter reserve.

Increased Regional Water System Demand: Assuming a future ultimate average demand of 86 000 m^3/d, up from the present 60 000 m^3/d, the decrease in average generation at Petty Harbour would be 1.3 GWh/yr.

Cost of Regional Water System Demand: The estimated energy cost of sharing the water resource of Bay Bulls Big Pond with the Regional Water System is 3.3 GWh/yr.



CHANNELS

① — Bay Bulls Big Pond Local Inflow
② — Bay Bulls Big Pond Outlet Gate
③ — Bay Bulls Big Pond Spill
④ — Bay Bulls Big Pond Total Outflow
⑤ — Regional Water Supply Demand
⑥ — Cochrane Pond Local Inflow
⑦ — Cochrane Pond Outlet Gate
⑧ — Cochrane Pond Spill
⑨ — Forebay Local Inflow
⑩ — Petty Harbour Unit 1
⑪ — Petty Harbour Unit 2
⑫ — Petty Harbour Unit 3
⑬ — Petty Harbour Spill
⑭ — Petty Harbour Total Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Bay Bulls Big Pond
2 — Bay Bulls Big Pond Total Outflow
3 — Cochrane Pond
4 — Forebay (First Pond and Second Pond)
5 — Petty Harbour Total Outflow

Fig. 11.1

NEWFOUNDLAND POWER
HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY
PETTY HARBOUR ARSP MODEL SCHEMATIC

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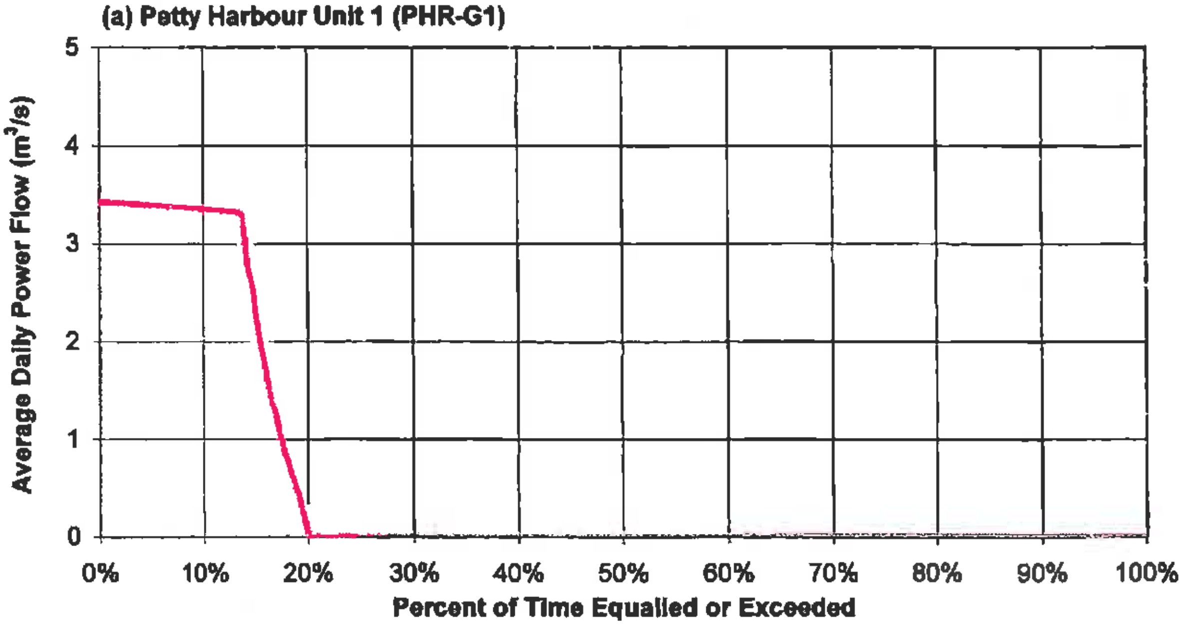

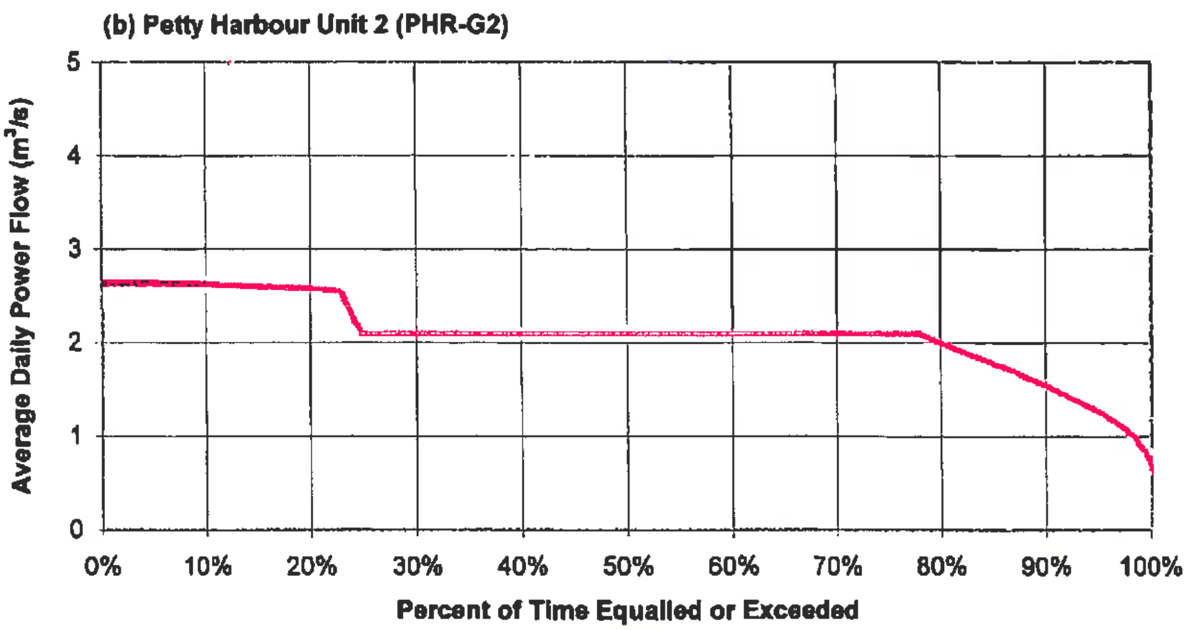

Fig. 11.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

PETTY HARBOUR UNITS 1 AND 2 SIMULATED POWER FLOW DURATION CURVES

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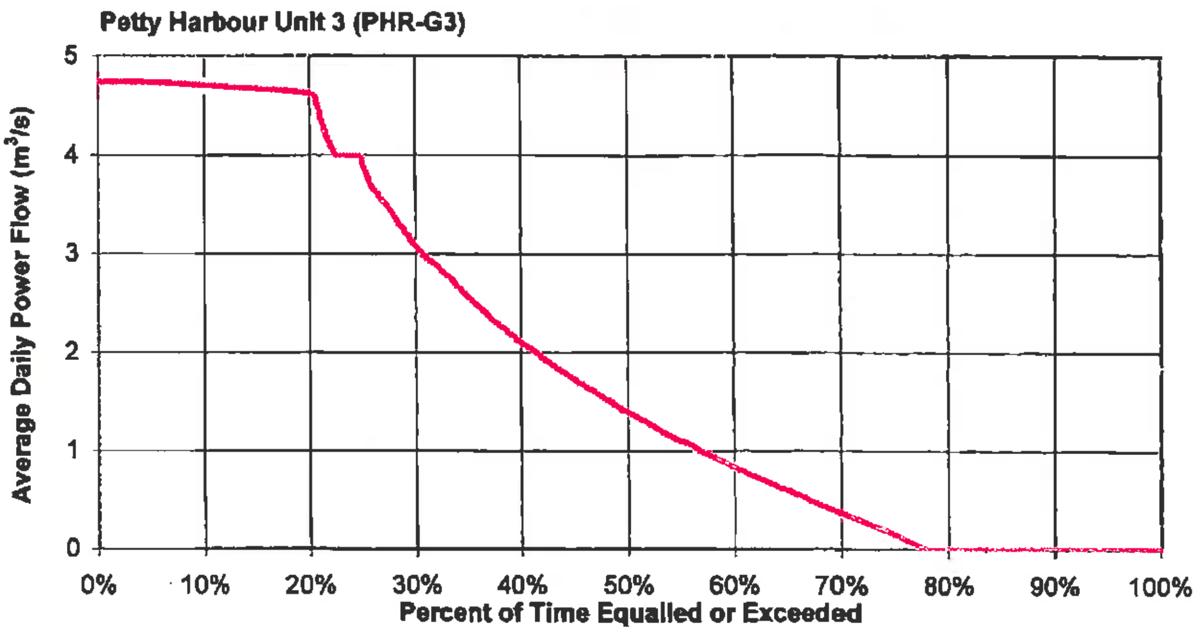

Fig. 11.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

PETTY HARBOUR UNIT 3 SIMULATED POWER FLOW DURATION CURVE

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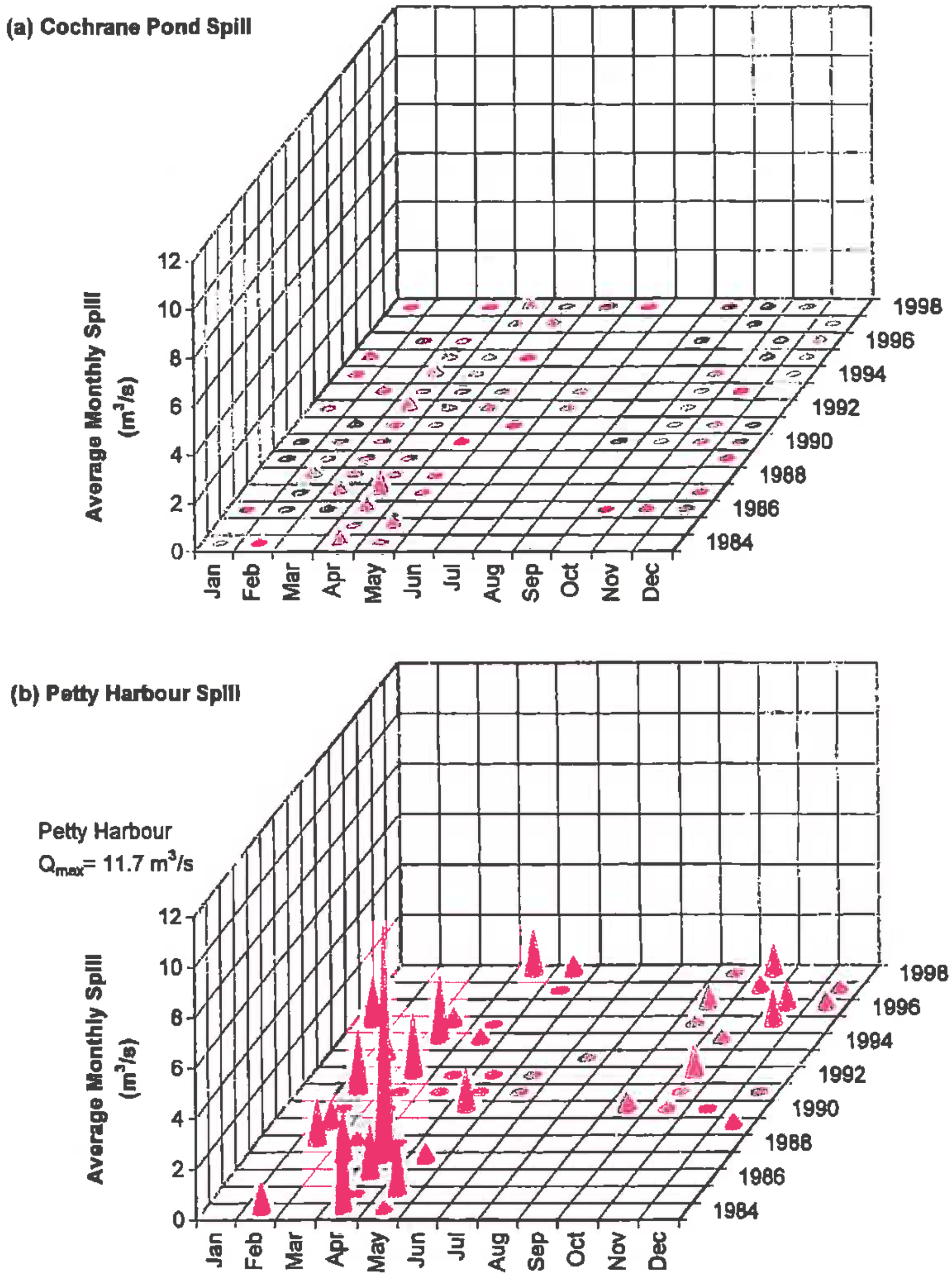

Fig. 11.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

COCHRANE POND AND PETTY HARBOUR SIMULATED SPILLS

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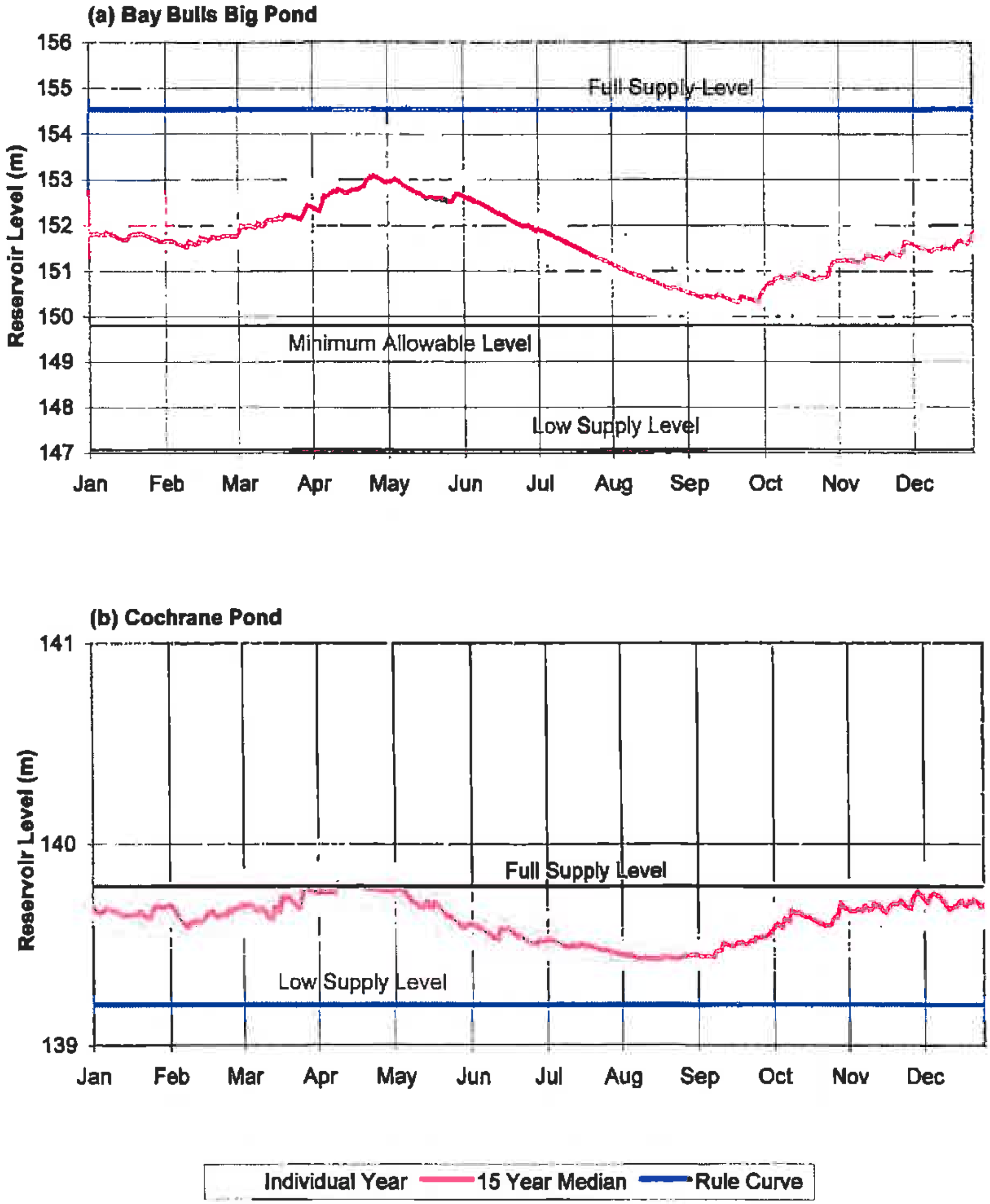

Fig. 11.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

BAY BULLS BIG POND AND COCHRANE POND
SIMULATED RESERVOIR LEVELS

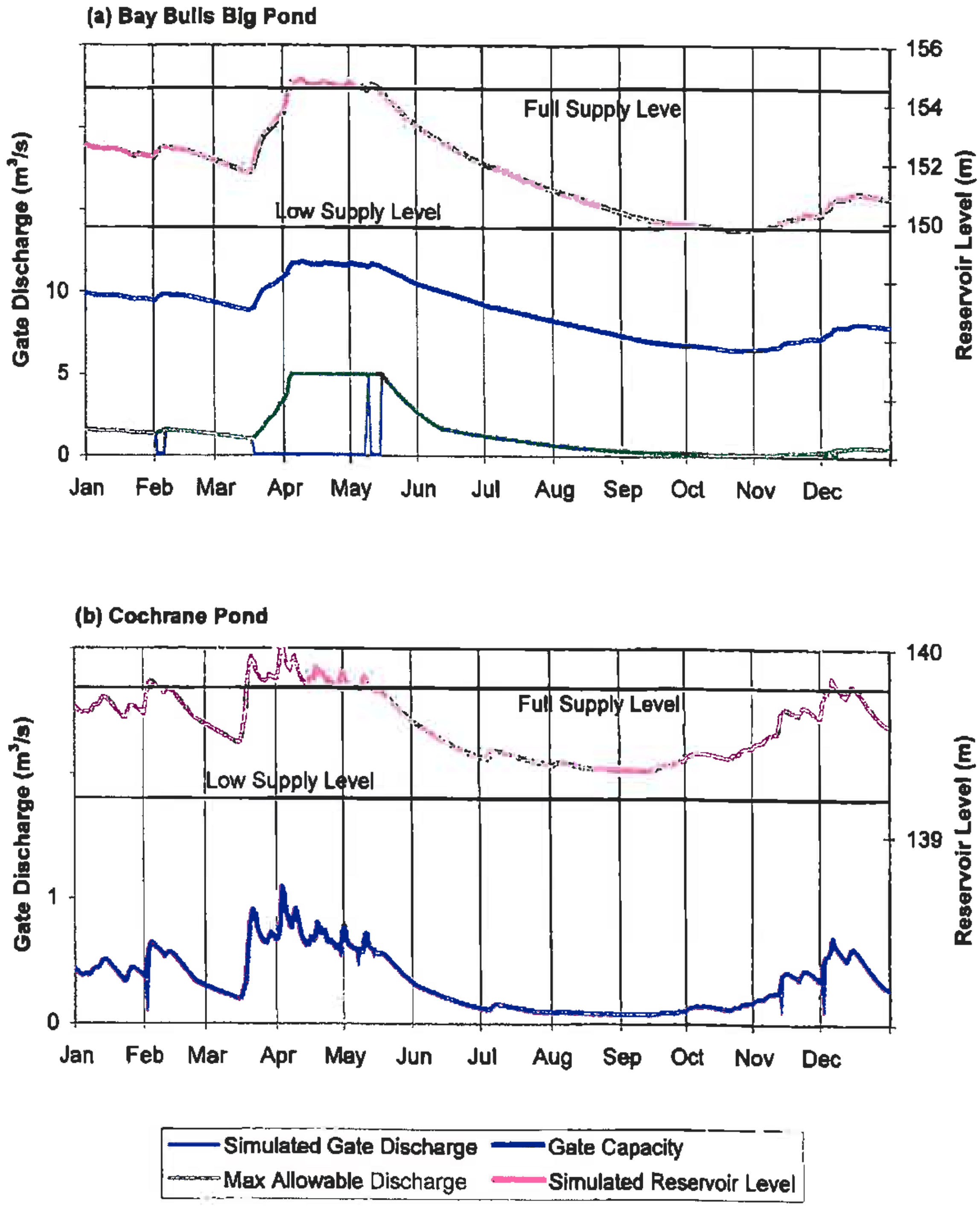

Fig. 11.6

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

BAY BULLS BIG POND AND COCHRANE POND SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

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New Chelsea/Pitmans

12 New Chelsea/Pitmans Hydroelectric System

New Chelsea/Pitmans Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the New Chelsea/Pitmans system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the New Chelsea/Pitmans system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the New Chelsea/Pitmans system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

12.1 System Description

The New Chelsea/Pitmans system is located on the east side of Trinity Bay, near the community of New Chelsea. Pitmans and New Chelsea powerhouses are in series and have nameplate installed capacities of 0.6 MW and 3.7 MW, respectively. The rated net heads are 21.3 m and 83.8 m, respectively. New Chelsea Generating Station was commissioned in 1956. The powerhouse is located near sea level and has one generating unit supplied by a penstock from Seal Cove Pond. Pitmans

Generating Station was commissioned in 1959 and is located upstream from New Chelsea. The plant has one unit supplied by a penstock from Pitmans Pond.

The New Chelsea/Pitmans system encompasses the drainage basins of Pitmans Pond and Seal Cove Pond. The drainage area of Pitmans Pond is 66 km^2. The drainage area of Seal Cove Pond downstream of Pitmans Pond is 8 km^2. Prior to the fall of 1997, a second outlet from Pitmans Pond was diverting flow from the equivalent of approximately 6 km^2 drainage area. A small dam was constructed in 1997 to prevent this leakage. A schematic of the New Chelsea/Pitmans system is presented in Figure 12.1.

The structures in the system are as follows

- Pitmans Pond overflow spillway; and
- Seal Cove Pond overflow spillway.

Pitmans Pond is the headpond of the Pitmans station and Seal Cove Pond is the headpond for the New Chelsea station. Each reservoir has a spillway. The spill from Pitmans Pond flows into Seal Cove Pond. The spill from Seal Cove Pond flows out of the system.

12.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are described in Chapter 2. The measures as calculated for the New Chelsea/Pitmans system are provided below.

They were developed from the data in the base case simulation. Table 12.1 at the end of this section summarizes the measures for the New Chelsea/Pitmans system.

1. Flow Utilization Factor

The New Chelsea and Pitmans stations each house a single generating unit (NCH-G1 and PIT-G1, respectively). The flow utilization factors for the New Chelsea station (average inflow to forebay divided by combined flow capacity at most efficient load and maximum load) are 0.52 at most efficient load and 0.46 at maximum load. The flow utilization factors for the Pitmans station are 0.53 at most efficient load and 0.47 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage assuming the units are operating alone) for most efficient load and maximum load for NCH-G1 are 0.183 kWh/m^3 (5.76 GWh/yr/m^3/s) and 0.177 kWh/m^3 (5.58 GWh/yr/m^3/s), respectively. The energy conversion factors for most efficient load and maximum load for PIT-G1 are 0.038 kWh/m^3 (1.19 GWh/yr/m^3/s) and 0.034 kWh/m^3 (1.07 GWh/yr/m^3/s), respectively.

The average energy conversion factor from the base case simulation for NCH-G1 is 0.184 kWh/m^3 (5.80 GWh/yr/m^3/s). The average energy conversion factor from the base case simulation for PIT-G1 is 0.039 kWh/m^3 (1.22 GWh/yr/m^3/s). This energy conversion factor takes into account the average reduction in availability due to forced outages.

3. Flow Duration Curve

The NCH-G1 and PIT-G1 flow duration curves for the turbine flow (power flow) in the base case simulation are shown in Figure 12.2. The New Chelsea unit operates at maximum flow around 7 percent of the time, while the Pitmans unit operates at maximum flow about 11 percent of the time.

4. Energy Potential of Spill

The simulated spill for the base case was approximately 0.008 m^3/s on average at the Seal Cove Pond Forebay overflow spillway. Using the simulated energy conversion factor for NCH-G1 at maximum load presented previously in this section, the spill would produce approximately 0.045 GWh/yr, if entirely saved and used for generation. The simulated spill for the base case was approximately 0.005 m^3/s on average at Pitmans Pond overflow spillway. Using the energy conversion factor for

PIT-G1 at maximum load, this spill would produce approximately 0.005 GWh/yr, if entirely used for generation.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figure 12.3 for the Pitmans Pond and Seal Cove Pond Forebay overflow spillways.

5. Reservoir Storage Factor

Storage is provided by structures located at the outlets of Pitmans Pond and Seal Cove Pond Forebay which act as the headponds for the Pitmans and New Chelsea stations, respectively. The reservoir storage factors were calculated to be approximately 184 days for Pitmans Pond and 2.75 days for Seal Cove Pond Forebay. These factors represent the average number of days to fill the reservoirs with average inflow and without any outflow.

6. Reservoir Utilization Plot

The plot of simulated Pitmans Pond and Seal Cove Pond Forebay reservoir levels for the base case simulation is provided in Figure 12.4. The plot illustrates the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range. For the New Chelsea/Pitmans system the use of reservoir storage is not limited by other physical or operational constraints, although both reservoirs also serve as forebays and therefore the maintenance of higher water levels increases the head on the generating units.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with units operating at maximum load) is 87 days at Pitmans and 1.3 days at New Chelsea.

8. Gate Operation

There are no control gates located in the New Chelsea/Pitmans system as discharges from both storage reservoirs are determined by turbine flows at the generating stations.

Table 12.1
New Chelsea/Pitmans System Representative Operating Measures

New Chelsea/Pitmans System Representative Operating Measures	
Flow Utilization Factors	
- Pitmans Most Efficient Load	0.53
- Pitmans Maximum Load	0.47
- New Chelsea Most Efficient Load	0.52
- New Chelsea Maximum Load	0.46
Station Factors	
- PIT-G1 Most Efficient Load	0.038 kWh/m^3
- PIT-G1 Maximum Load	0.034 kWh/m^3
- NCH-G1 Most Efficient Load	0.183 kWh/m^3
- NCH-G1 Maximum Load	0.177 kWh/m^3
Energy Potential of Spill	0.05 GWh/yr
Reservoir Storage Factors	
- Pitmans Pond	184 days
- Seal Cove Pond Forebay	2.8 days
Pitmans Forebay Storage Factor	87 days
New Chelsea Forebay Storage Factor	1.3 days

12.3 Ideal Operation of System

The long term energy production at New Chelsea/Pitmans as estimated by the simulation model developed for the Water Management Study is 18.5 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 17.1 GWh/yr. While these numbers are not directly comparable due to the construction of a diversion in the watershed in 1997, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated a negligible difference between recorded and simulated generation (after adjustments for storage). The comparison would therefore suggest that there is very little opportunity to improve the operation of this system by more closely following the ideal demonstrated by the simulation model.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was 7 percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce any difference between the simulated ideal operation and actual operation at the New Chelsea/Pitmans System.

12.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the New Chelsea/Pitmans system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plants will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated a rule curve for each reservoir in the system. If the reservoir levels exceed the rule curve at any particular time of the year, then the units are operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the units are operated at best efficiency.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff. The rule curves used in the simulation model are illustrated in Figure 12.4 and are provided in the echo of the detailed simulation model input in Volume 2 of the Water Management Study.

12.3.2 Gate/Reservoir Operation

The New Chelsea/Pitmans system has significant storage capacity (storage ratio of 127 days). Discharges from the system's main storage reservoir at Pitmans Pond are determined by the turbine flow at Pitmans station, which can be remotely adjusted. However, remote water level indication is not available for this storage reservoir and several days may elapse between water level measurements by operating staff. Despite this operating practicality, the size of Pitmans Pond relative to its watershed ensures that water levels in this reservoir do not change rapidly and it is unlikely that this would cause actual generation at this system to differ from the simulated estimate.

NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro. This winter reserve is not taken into account by the simulation model. Again, due to the storage capacity available at Pitmans Pond, the actual system production is not overly sensitive to this type of reservoir operating constraints unless they severely restrictive.

12.3.3 Unit Operation

The simulation model operates the New Chelsea and Pitmans units exclusively at their most efficient loads, except when high inflows dictate that higher loads are necessary to avoid exceeding the reservoir rule curves. With the available control equipment, minimal constraints on plant flows, and the available forebay storage, it should be possible to operate these plants very close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April and August 1999, and January-February 2000) confirmed that the New Chelsea and Pitmans units are loaded at best efficiency a high percentage of the time. The main obstacles to attaining ideal operation are electrical grid requirements which may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences.

12.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Each of these is discussed below for the New Chelsea/Pitmans system. Increasing the head at Pitmans Pond by raising the dam was considered as a potential physical change (Section 12.5).

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The case described for the base case is an intermediate case, since it uses a NP rule curve varying between the low supply and full supply levels of the reservoirs.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low
The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At New Chelsea, the potential for savings in spill compared to the base case is low. The maximum possible reduction in spill would be the equivalent of 0.05 GWh/yr, as shown in Table 12.1. Spill is rare at Seal Cove Pond Forebay due to the substantial storage available in the system at Pitmans Pond. Therefore, there is little generation benefit possible by reductions in spill flows.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The average annual spill from Seal Cove Pond Forebay was reduced by only 0.008 m^3/s, from an average of 0.008 m^3/s to zero. The spill at Pitmans Pond Forebay was also reduced to zero from 0.005 m^3/s in the base case. This represents a total increase of approximately 0.05 GWh/yr. This small amount does not compensate for the average annual decrease of 0.8 GWh in energy production due to operating the PIT and NCH units at lower efficiencies.

Best Efficiency Operation, Limiting Case: Reservoirs High
The limiting case for maximizing the amount of time the units are operating at best efficiency is to run the units at best efficiency, until the storage reservoirs are just about to spill.

The result of a simulation using this rule was an average annual production of 18.4 GWh/yr, with a spill of 0.26 m^3/s at Seal Cove Pond and 0.021 m^3/s at Pitmans Pond. This production is slightly lower than the base case production (by 0.1 GWh/yr). This suggests that the rule curve used for the base case simulation is near optimum for the New Chelsea/Pitmans system. There could be minor adjustments made to the rule curve that could increase production monthly, but the increase would be expected to be marginal.

12.5 Physical Changes to System

Two principal options for physical changes to the existing system to improve energy generation were considered: increasing head and storage, and increasing unit efficiency. To give an indication of the value of these changes, the following options were investigated.

- Increase dam height at Pitmans Pond to increase storage and head.
- Replace runners at Pitmans or New Chelsea plants with more modern designs.

Each of these physical changes to the system is discussed below. Table 12.2 summarizes the results.

Increase Storage and head at Pitmans Pond

To determine the effect of an increase in storage and head on energy production, the dams and structures at Pitmans Pond were assumed to be raised to allow increases in full supply level of one and two meters. The effect is to reduce system spill and increase head on the Pitmans unit. The resulting increases in energy generation were 0.2 GWh/yr for the one meter rise, and 0.3 GWh/yr for the two meter rise.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $12 000/yr for the one meter increase in dam height and $18 000/yr for the two meter increase in dam height. Given a dam length of approximately 344 m, the savings over perhaps 20 years would justify an expenditure of about $320/m of dam length based on a one meter increase. It is unlikely that this work could be completed for less than this cost, unless it is found that excess freeboard is present at this structure which would permit raising only the spillway crest to achieve these energy gains. Alternatively, a seasonal flashboard arrangement could also be considered which would increase the head on Pitmans unit and allow a portion of this generation gain to be realized.

Increase Unit Efficiency

Another method of increasing generation is to improve unit efficiency through runner or major turbine component replacement. Both of these units were commissioned in the early 1950s and most of the major components have not been replaced. Efficiency testing conducted on the New Chelsea unit in 1997 indicated that the turbine efficiency was acceptable considering the age of the unit. Best efficiency was estimated to be just over 83 percent and efficiency at maximum load was over 82 percent. A new runner design might be expected to increase these values to about 89 percent and 85 percent, respectively. The resulting increase in simulated generation from the system due to this change is 1.0 GWh/yr.

The Pitmans unit is of a similar vintage, and a similar unit overhaul could be considered at this station. Unfortunately, efficiency testing has not been conducted on this unit, but based on an analysis of SCADA data, the efficiency of this unit was thought to be substantially lower than that of New Chelsea. The simulation model used a best efficiency of 71 percent and an efficiency at maximum load of 66 percent. If this unit were upgraded to 88 percent and 84 percent efficiency, respectively, the simulation model indicated that an increase in generation of 0.7 GWh/yr would be realized. NP may want to further pursue the costs of major unit overhauls at New Chelsea and Pitmans to better assess the economic feasibility of such projects

Table 12.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	18.5	-
Raise Pitmans Pond by 1 m	18.7	+0.2
Raise Pitmans Pond by 2 m	18.8	+0.3
New Chelsea turbine overhaul	19.5	+1.0
Pitmans turbine overhaul	19.2	+0.7

12.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done at most systems to provide NP with information on the cost or value of certain aspects of their systems. The sensitivities considered for this study are not applicable to the New Chelsea/Pitmans system. Environmental releases from storage dams are not necessary due to the fact that the only reservoirs in this system are also forebays for generating units. For this same reason, it is not necessary to estimate the value of removing storage or various modes of storage gate operation.

12.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. Improvements to Better Match Simulated Ideal Operation

As indicated by the model comparisons, the New Chelsea/Pitmans system appears to be operated in a manner which closely resembles the ideal indicated by the simulation. The major operating practicalities which reduce generation when compared with that of the simulation are beyond the control of the system operators.

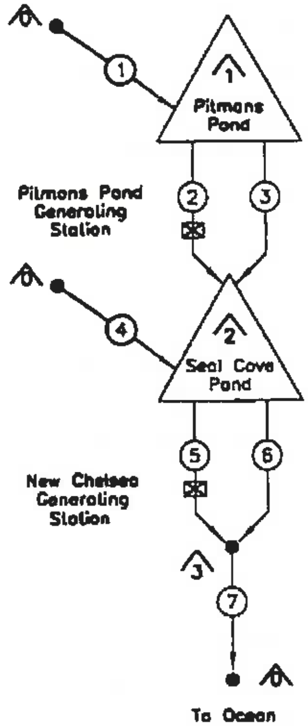
2. Changes to Operating Guidelines

Clarification of Guidelines: The present guidelines as interpreted for the Water Management Study come close to maximizing system output if NP can continue to operate in this manner. NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum.

3. Physical Changes

Increased Storage: Because of the amount of storage available at Pitmans Pond in relation to the drainage basin, additional storage does not have substantial value in this system. Increasing the full supply level of Pitmans Pond may be economical means of increasing the head on Pitmans unit provided excess freeboard is available at the dam at least for significant portions of the year

Unit Overhauls/Runner Replacements: The analysis showed that there may be considerable gains in energy by replacing one or both runners in this system and overhauling the turbines. These units are relatively old and have not been upgraded since first commissioned.



CHANNELS

① — Pitmans Pond Inflow
② — Pitmans Pond Power Flow
③ — Pitmans Pond Spill
④ — Seal Cove Pond Inflow
⑤ — New Chelsea Power Flow
⑥ — Seal Cove Pond Spill
⑦ — Seal Cove Pond Total Outflow

RESERVOIRS / NODES

— Source / Sink
— Pitmans Pond
— Seal Cove Pond
— Seal Cove Pond Total Outflow

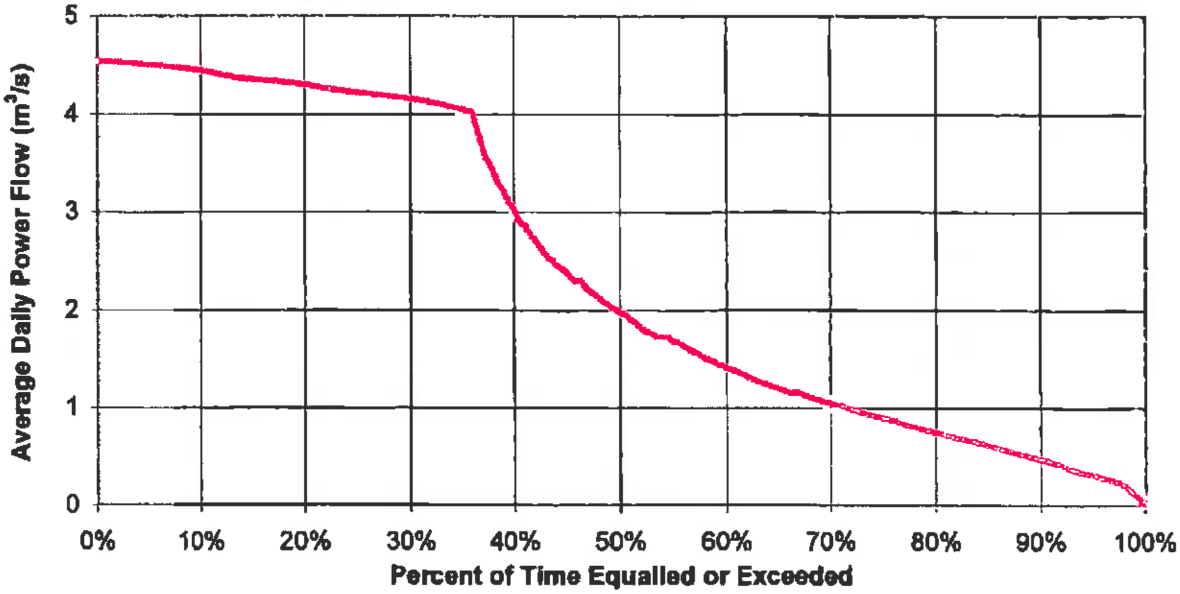
Fig. 12.1

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

NEW CHELSEA / PITMANS ARSP MODEL SCHEMATIC

(a) Pitmans Unit (PIT-G1)



(b) New Chelsea Unit (NCH-G1)

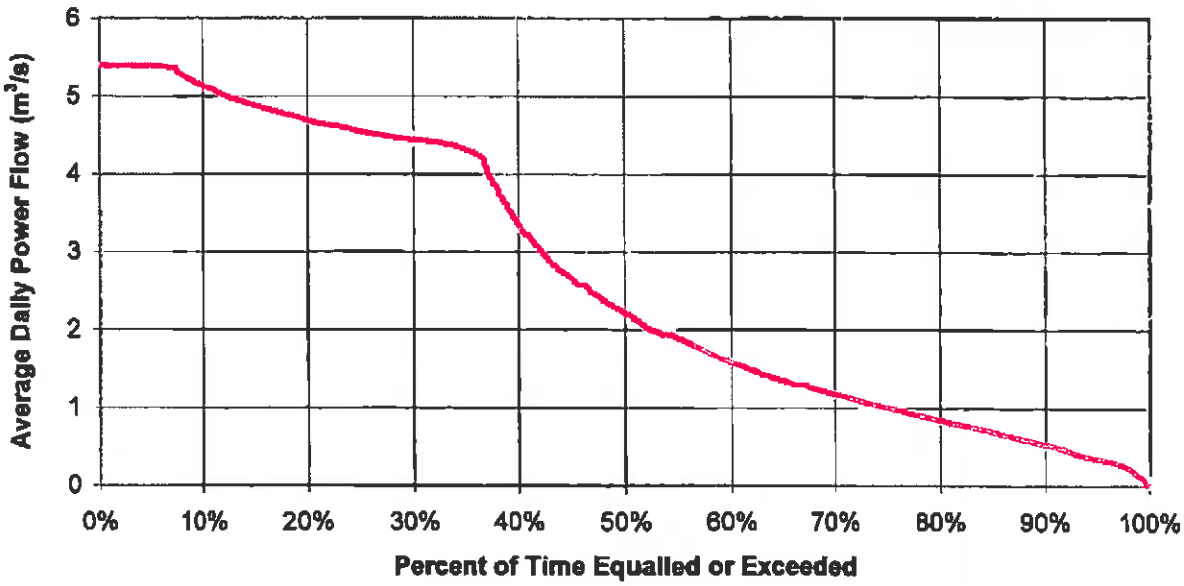


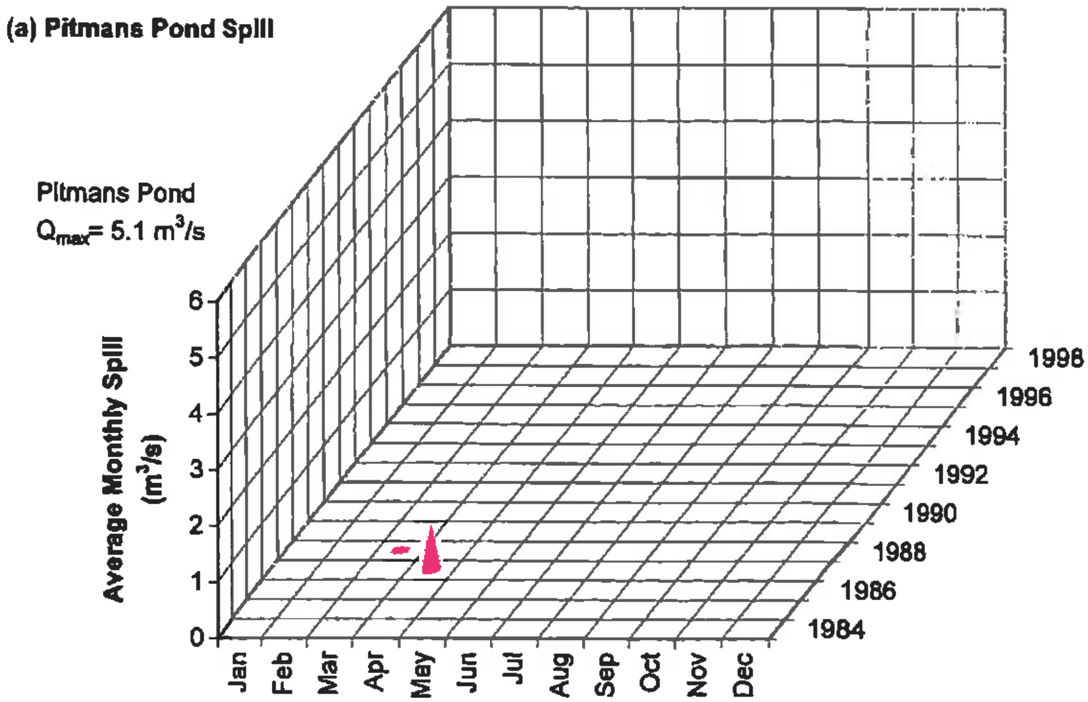
Fig. 12.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

NEW CHELSEA / PITMANS SIMULATED POWER FLOW DURATION CURVES

ACRES



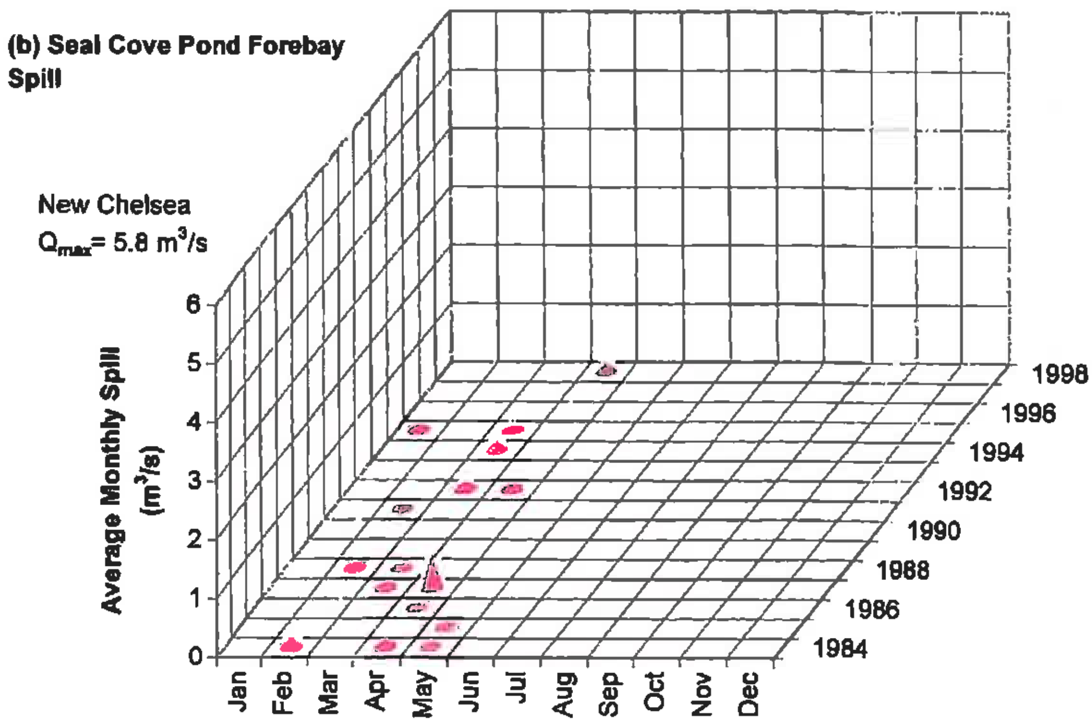


Fig. 12.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

PITMANS POND AND SEAL COVE POND FOREBAY SIMULATED SPILLS

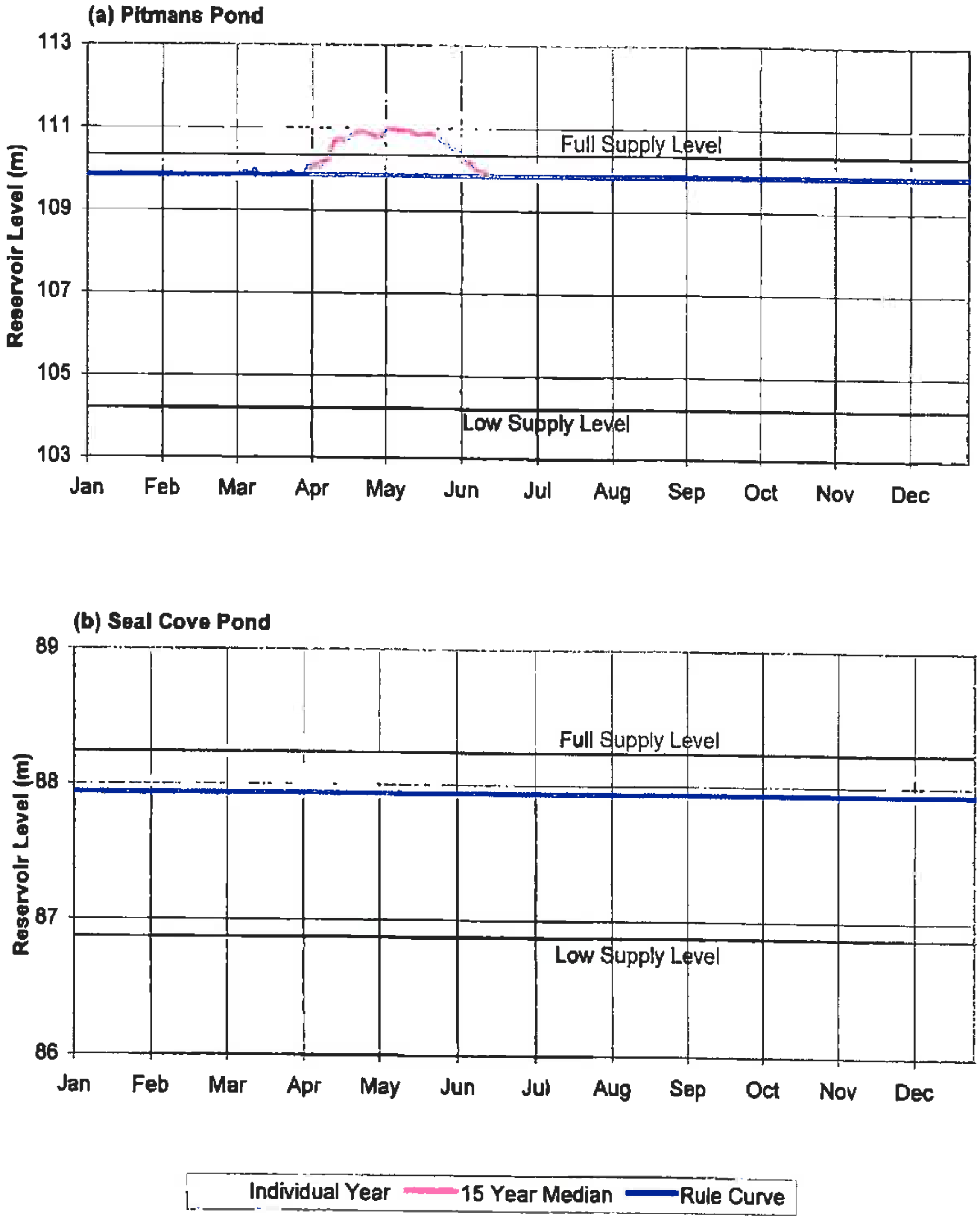


Fig. 12.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

PITMANS POND AND SEAL COVE POND
SIMULATED RESERVOIR LEVELS

ACRES

Seal Cove

13 Seal Cove Hydroelectric System

Seal Cove Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Seal Cove system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Seal Cove system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Seal Cove system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

13.1 System Description

The Seal Cove system is located on the southern coast of Conception Bay near the community of Seal Cove and has one generating station located within the system.

The Seal Cove Generating Station contains two generating units with nameplate capacities of 1.1 MW and 2.4 MW with a rated net head of 55.5 m. The drainage area above the intake to the Seal Cove station is approximately 78 km^2. The system was commissioned in 1924 and has a total nameplate capacity of 3.5 MW. Storage is provided by structures at Fenelons Pond and Soldiers Pond with White Hill Pond Forebay acting as the headpond for the Seal Cove station. A schematic of the system is presented in Figure 13.1.

The two main storage reservoirs in the Seal Cove system, Fenelons Pond and Soldiers Pond, are in parallel. Spill flow and flow released through the gated outlet at Fenelons Pond travels to Big Otter Pond and then to Gull Pond East. At Soldiers Pond, spill flow is out of the system and flow released through the gated outlet travels to Round Pond and then to Gull Pond East. The flows at Big Otter Pond, Round Pond and Gull Pond East are not controlled. The combination of flows from Fenelons Pond, Soldiers Pond and the local inflows to Big Otter Pond, Round Pond and Gull Pond East discharge into White Hill Pond Forebay. Flow into White Hill Pond Forebay is either stored, spilled out of the system or used for generation.

The structures in the system are as follows

- Fenelons Pond gated outlet;
- Fenelons Pond overflow spillway;
- Soldiers Pond gated outlet;
- Soldiers Pond overflow spillway; and
- White Hill Pond Forebay overflow spillway.

The Soldiers Pond and White Hill Pond Forebay overflow spillways discharge out of the system; the other spillway discharges within the system.

13.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.

7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are presented in Chapter 2. The measures as calculated for the Seal Cove system are provided below. They were developed from the data in the base case simulation. Table 13.1 at the end of this section summarizes the measures for the Seal Cove system.

1. Flow Utilization Factor

The Seal Cove station houses two generating units. The flow utilization factors for the Seal Cove station (average inflow to forebay divided by combined flow capacity for both units at most efficient load and maximum load) are 0.39 at most efficient load and 0.35 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage assuming the units are operating alone) for most efficient load and maximum load for SCV-G1 are 0.11 kWh/m^3 (3.61 $GWh/yr/m^3/s$) and 0.11 kWh/m^3 (3.56 $GWh/yr/m^3/s$), respectively. For SCV-G2 the most efficient load and maximum load station factors are 0.11 kWh/m^3 (3.61 $GWh/yr/m^3/s$) and 0.11 kWh/m^3 (3.56 $GWh/yr/m^3/s$), respectively.

The average energy conversion factors from the base case simulation for SCV-G1 and SCV-G2 are 0.11 kWh/m^3 (3.36 $GWh/yr/m^3/s$) and 0.11 kWh/m^3 (3.54 $GWh/yr/m^3/s$), respectively. These energy conversion factors take into account the average reduction in availability due to forced outages and the fact that less than five percent of the time they are operating together resulting in higher headlosses.

Based on the energy conversion factors for the Seal Cove units, the unit dispatch would not matter as the energy conversion factors are the same for both units at maximum and most efficient loads. To maximize efficiency the units should be loaded at most efficient load first and then maximum load second. A recommended dispatch would be as follows.

- Operate SCV-G2 at most efficient load first.
- Operate SCV-G1 at most efficient load second.
- Operate SCV-G2 at maximum load third.
- Operate SCV-G1 at maximum load last.

The interpretation of the order recommended in NP's plant operating guidelines is the same as the unit dispatch listed above.

3. Flow Duration Curve

The SCV-G1 and SCV-G2 flow duration curves for the turbine flow (power flow) in the base case simulation are shown in Figure 13.2. The units operate at maximum flow less than five percent of the time.

4. Energy Potential of Spill

The simulated spill for the base case was approximately 0.15 m^3/s on average at the White Hill Pond Forebay overflow spillway. Using the average simulated energy conversion factors for SCV-G1 and SCV-G2 presented previously in this section, the spill would produce approximately 0.5 GWh/yr, if entirely saved and used for generation.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figure 13.3 for the Soldiers Pond and White Hill Pond Forebay overflow spillways. As can be seen in this figure there was no spill at Soldiers Pond in the base case simulation.

5. Reservoir Storage Factor

Storage is provided by structures located at the outlets of Soldiers Pond and Fenelons Pond. The White Hill Pond Forebay acts as the headpond for the Seal Cove station. The reservoir storage factors were calculated to be approximately 80 days for Soldiers Pond, 95 days for Fenelons Pond and half a day (12 hours) for White Hill Pond Forebay. These factors represent the number of days to fill the reservoirs at average inflows without any outflow.

6. Reservoir Utilization Plot

The plot of simulated Soldiers Pond and Fenelons Pond reservoir levels for the base case simulation is provided in Figure 13.4. The plot illustrates the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range. For the Seal Cove system the use of reservoir storage is not limited by other physical or operational constraints.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with units operating at maximum load) is less than half a day (5 hours).

8. Gate Operation

There are control gates located at the outlet of Soldiers Pond and Fenelons Pond. Provided in Figure 13.5 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1987) for Soldiers Pond and Fenelons Pond. These plots illustrate the frequency with which the gates are being operated in the simulation model to maintain most efficient load and to avoid spill by operating at maximum load.

Table 13.1
Seal Cove System Representative Operating Measures

Seal Cove Representative Operating Measures	
Flow Utilization Factors - Most Efficient Load - Maximum Load	 0.39 0.35
Station Factors - SCV-G1 Most Efficient Load - SCV-G1 Maximum Load - SCV-G2 Most Efficient Load - SCV-G2 Maximum Load	 0.11 kWh/m^3 0.11 kWh/m^3 0.11 kWh/m^3 0.11 kWh/m^3
Energy Potential of Spill	0.5 GWh/yr
Reservoir Storage Factors - Soldiers Pond - Fenelons Pond - White Hill Pond Forebay	 80 days 95 days ½ day (15 hours)
Forebay Storage Factor	<½ day (5 hours)

13.3 Ideal Operation of System

The long term energy production at Seal Cove as estimated by the simulation model developed for the Water Management Study is 9.93 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 9.44 GWh/yr. Further indication of the difference between recorded and simulated generation is provided by the comparisons conducted for the Water Management Study for two sample years. These comparisons indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately -0.5 percent for this system. A negative result for the comparison is unusual, but this result suggests one of two things; that the Seal Cove system is being operated in a manner close to the simulated ideal or that there is flexibility in the operation of the system such that energy generation is not sensitive to operation. In either case, there would be little opportunity for improvement under the current operating guidelines. For the Seal Cove System it is more probable that there is flexibility in operating the system rather than the system being operated near the ideal as explained further in the following sections.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual generation at the Seal Cove System.

13.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Seal Cove system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plant will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated a rule curve for each reservoir in the system. If the reservoir levels exceed the rule curve at any particular time of the year, then the units are operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the units are operated at best efficiency.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff. The rule curves used in the simulation model are illustrated in Figure 13.4 and are provided in the echo of the detailed simulation model input in Volume 3 of the Water Management Study.

13.3.2 Gate/Reservoir Operation

The Seal Cove system has substantial storage capacity that can be effectively used to smooth any highly seasonal basin inflows. (Reservoir storage ratio of 80 days for Soldiers Pond and 95 days for Fenelons Pond). The gates that control the reservoirs are difficult to access. The Fenelons Pond gate is accessible only by way of a rough 2 km long gravel road which is not passable at some times during the year. The Soldiers Pond outlet is only about 1 km from a major highway, but the access road to the structure is also impassable at times. Therefore, operations staff do not adjust these outlet gates frequently or ideally.

Despite the difficulty posed by operating these gates, the impact of this practicality on system generation is probably not significant. This is due to the fact that these reservoirs control only a small fraction of the overall watershed, and that they would therefore not be effective in regulating runoff even if the gates could be adjusted daily. This provides the operator flexibility in operating the gates at these reservoirs.

In addition to the accessibility issues, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro. This winter reserve is not taken into account by the simulation model. As with the gate accessibility issue however, the system production is not overly sensitive to other reservoir operating constraints.

13.3.3 Unit Operation

The simulation model operates the Seal Cove units exclusively at their most efficient loads, except when high inflows dictate that higher loads are necessary to avoid exceeding the reservoir rule curves. With minimal constraints on plant flows and the available forebay storage, it should be possible to operate the plant close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April 1999, and January-February 2000) however, seems to indicate that the units are not loaded at best efficiency very often. Plant loads at Seal Cove during these months ranged from 0.2 MW to 3.5 MW. This is most likely due to the fact that the controls at this plant are outdated and the limited extent to which the plant can be remotely operated. In addition, there may be electrical grid requirements that occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences. Although there are operating difficulties due to the outdated controls, the efficiency curve for SCV-G2 based on the efficiency testing conducted by Acres in August 2000 show that there is only a difference of approximately six percent in efficiency for wicket gate openings between 60 and 100 percent. This illustrates that although the units are operating at lower loads there isn't much of a difference in efficiency, explaining why the simulated and record energy are close although the operation and loading of the units are not ideal.

13.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Each of these is discussed below for the Seal Cove system. Increasing the head through a change in the use of flashboards or installation of inflatable crest gates was considered as a potential physical change (Section 13.5).

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The case described for the base case simulation is the high rule curve case and represents the maximum time operating at best efficiency; therefore, only the spill avoidance case was considered.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low
The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At Seal Cove, the potential for savings in spill compared to the base case is low. The maximum possible reduction in spill would be the equivalent of 0.5 GWh/yr, as shown in Table 13.1. However, the spill distribution plot (Figure 13.3) shows that this would be relatively easy to capture since the spills occur frequently and in small amounts.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The average annual spill and energy generation from Seal Cove remained the same. This indicates that there is no difference to energy generation through the operation of the units or the rule curve for the reservoirs.

13.5 Physical Changes to System

The two principal options for physical changes to the existing system to improve energy generation are to increase head and to increase storage. Increasing storage at the two main storage reservoirs was not considered as there is relatively no spill from these reservoirs representing no potential for increased energy generation through capturing spill. Increasing the dam height to increase storage and capture spill was investigated for the White Hill Pond Forebay only. To give an indication of the value of these changes, the following options were investigated.

- Change pattern of flashboards installation/removal at White Hill Pond Forebay to increase head.
- Increase dam height at White Hill Pond Forebay to increase storage.
- Reduce headlosses.
- Increase net head.
- Combination of reducing headlosses and increasing net head.
- New reservoir and control gate at Gull Pond East.

Each of these physical changes to the system is discussed below. Table 13.2 summarizes the results.

Change Pattern of Flashboards at White Hill Pond Forebay
It was interpreted from the existing plant operating guidelines that the forebay level is drawn down in the spring to allow for storage of spring runoff. To determine whether any additional energy could be obtained through extra head, it was assumed that flashboards were in place year round, but still drawing the forebay down in the spring. This would allow for some storage of inflows at the forebay during the spring runoff. The resulting increase in energy generation from this change was 0.14 GWh/yr, from 9.93 GWh/yr to 10.07 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $5 600/yr with a relatively small cost for fabrication of flashboards, but leaving the flashboards in year round may lead to dam safety concerns. If it did become a dam safety concern that the flashboards must be removed, then inflatable crest gates (a rubber dam) on the spillway section may be considered.

Increase Storage at White Hill Pond Forebay

To determine the effect of an increase in storage on energy production, the dams and structures at White Hill Pond Forebay were assumed to be raised to allow increases in full supply level of half a meter and one meter. The effect is to reduce system spill. The resulting increases in energy generation were 0.08 GWh/yr for the half meter rise and 0.16 GWh/yr for the one meter rise.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $3 200/yr for the half meter increase in dam height and $6 400/yr for the one meter increase in dam height. Given a dam length of approximately 420 m, the savings over perhaps 20 years would justify an expenditure of about $140/m of dam length based on a one meter increase. The practicalities of increasing the dam at White Hill Pond Forebay would have to be investigated. A detailed analysis into the cost would have to be conducted, but based on the above expenditure it may not be cost effective.

Reduce Headlosses

Another method of increasing head is to reduce headlosses. The existing woodstave penstock is reaching the end of its useful life and NP is currently investigating replacing this penstock. For the purposes of examining the value of a reduction in headlosses through penstock replacement it was assumed that the woodstave penstock would be replaced with a steel penstock of equal diameter (seven feet) and one with a larger diameter (eight feet). The effect on headlosses a steel penstock would have as apposed to a woodstave penstock would be in reducing the headloss due to lower friction losses. A large diameter penstock would reduce the headlosses further at higher flows (both units operating at the same time). The resulting energy generation was 10.24 GWh/yr or a net increase in average annual energy of 0.31 GWh/yr for the seven foot diameter penstock and 10.35 GWh/yr or a net increase in average annual energy of 0.42 GWh/yr for the eight foot diameter penstock.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $12 400/yr for the seven foot steel penstock and $16 800/yr for the eight foot diameter penstock. This represents the gain in energy production and savings to NP by replacing a woodstave penstock at Seal Cove with steel. At the point it becomes apparent to NP that the penstock has to be replaced detailed cost estimates for both woodstave and steel penstocks should be compared along with the savings to determine the cost effectiveness of going to steel and possibly a larger diameter penstock. Detailed efficiency testing on SCV-G1 operating alone and with SCV-G2 would allow for accurate measures of current headloss to allow for a more accurate estimation of increased energy production.

Increase Net Head

Currently there are no draft tubes at the exit of the units in the Seal Cove station. At some point in time these were either removed or have fallen off. By installing new ones it will effectively increase the net head of the station, therefore, increasing energy production. The resulting energy generation assuming draft tubes in the station was 10.44 GWh/yr or a net increase in average annual energy of 0.51 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $20 400/yr. NP should look into the cost effectiveness of fabrication and installation of new draft tubes based on these approximate savings.

Combination of Reducing Headlosses and Increasing Net Head

The combination effect of installing flashboards at White Hill Pond Forebay and draft tubes at Seal Cove Station, and replacing the seven foot diameter woodstave penstock with an eight foot diameter steel penstock to increase net head on the energy production was investigated. The resulting energy generation was 10.73 GWh/yr or a net increase in average annual energy of 0.80 GWh/yr.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $32 000/yr.

New Reservoir and Control Gate at Gull Pond East

To determine the effect additional storage in the system would have to energy generation by regulating more of the basin runoff, a reservoir and control gate at Gull Pond East were added to the system. Reservoir and discharge characteristics were based on the previous structure that was located at Gull Pond East. The resulting energy generation was 10.33 GWh/yr or a net increase in average annual energy of 0.40 GWh/yr.

Assuming that the cost of energy to NP is 0.04 kWh this would result in a savings to NP of approximately $16 000/yr or a net present value of $146 000 for 20 years at nine percent. NP should look into the cost effectiveness of building a new dam at Gull Pond East based on this approximate savings. It may be the case that when Fenelons Pond is due for rehabilitation it may be worth investing the capital cost into building a new dam at Gull Pond East and decommissioning the Fenelons dam. This could allow for more regulation of the basin inflows and easier access to the control structure for operation.

Table 13.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	9.93	-
Flashboard at Forebay	10.07	+0.14
Increase Storage at Forebay by 0.5 m	10.01	+0.08
Increase Storage at Forebay by 1.0 m	10.09	+0.16
Seven Foot Diameter Steel Penstock	10.24	+0.31
Eight Foot Diameter Steel Penstock	10.35	+0.42
Install Draft Tubes	10.44	+0.51
Steel Penstock/Draft Tube/Flashboards	10.73	+0.80
Reservoir Gull Pond East	10.33	+0.40

13.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of their systems. In addition to some standard sensitivities, the cases chosen for Seal Cove were selected with a view to providing NP with some values related to its specific situation. Results for all sensitivity cases are provided in

Table 13.3. Along with the average energy generation, average annual forebay spill for each case is presented.

The sensitivity cases were as follows.

- Environmental release requirement of 30 percent of mean annual flow.
- No storage in system (to obtain value of storage); remove dams and gates.
- Changes to Soldiers Pond and Fenelons pond gate operation.

Environmental Release Requirement

The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 0.15 m^3/s at Soldiers Pond and 0.23 m^3/s at Fenelons Pond. This amount is always released in all simulations unless there is no water in storage, in which case the natural inflows are released. Using these flows as the minimum flow release from the gates for the base case simulation model, there was a decrease in average energy of 0.02 GWh/yr, from 9.93 GWh/yr to 9.91 GWh/yr. Assuming that the cost of energy to NP is $0.04/kWh this would result in a loss in revenue to NP of approximately $800/yr, if NP where required to release 30 percent of the mean annual flow.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement were always met, there would likely be a larger reduction in energy.

No Storage in System

To provide NP with an indication of the value of the storage in the system, all storage in the system was assumed to be removed. The resulting average annual energy generation from this sensitivity was 8.57 GWh/yr, a net decrease of 1.36 GWh/yr. Assuming that the cost of energy to NP is $0.04/kWh this would result in a loss in revenue to NP of approximately $54 400/yr, if NP where to remove all storage from the system. This represents the value of maintaining the structures at Soldiers Pond and Fenelons Pond.

Changes to Soldiers Pond and Fenelons Pond Gate Operation

The difficult access to the Soldiers Pond and Fenelons Pond outlet structures make it obvious candidates for automation, if it were cost effective. The simulation for the base case assumed that the gates could be operated daily, and the gate operation plot in Figure 13.5 showed that it was usually open to full capacity, except for in the spring. This means that there may not be a large benefit in automation of the gates, but it may be best to look into other means of operation. The base case could be considered the full automation case. To investigate the value of automation, or of some alternative procedure, three cases were considered. A variety of other cases are possible, but these three give an indication of the range of savings that can be achieved. The three cases are

- Leave gate full open: leave the gate open all the time, using whatever natural regulation remains;
- Seasonal operation: adjusting the gate a couple of times a year; and
- Leave gate partially open: restrict the opening to improve the natural regulation, leaving the gate in a partly open position all year round.

The effects of these three procedures are described below.

Leave Gate Full Open: Because of the difficulty of adjusting Soldiers Pond and Fenelons Pond outlet gates, one option is to simply leave the gate open. The structure itself will provide some natural regulation. The difference in the estimate of energy generation in this case and the base case indicates the value of having a gate that can be operated daily. The resulting energy generation from this sensitivity was 9.38 GWh/yr, or a net decrease in energy of 0.55 GWh/yr. This decrease is due to extra spill at the forebay and additional operation at maximum load. Assuming that the cost of energy to NP is $0.04/kWh this would result in a loss in revenue to NP of approximately $22 000/yr.

If the gates could be automated for perhaps $100,000 to $150,000, automation would be justified by the energy savings.

However, it may be possible to obtain some or all of the energy gains more cost-effectively, as considered in the two other options.

Seasonal Operation: In this case, the gates were assumed to be operated twice a year, closed to one quarter full open in April and opened fully in June. The resulting energy generation from this sensitivity was 9.64 GWh/yr or a net decrease in energy of 0.29 GWh/yr. Adjusting the opening and closing dates to take account of conditions in a particular year would likely improve this result.

Leave Gate Partially Open: The gate curve from Section 13.2 indicated that the gate is usually full open for all the year, except for during the spring. During the spring the gates are usually opened to release about 2-3 m^3/s. As a sensitivity, the gates were assumed to be open one quarter full capacity all year round to release approximately those flows. The resulting energy generation from this sensitivity was 9.68 GWh/yr or a net decrease in energy of 0.25 GWh/yr. As the table below shows this would be the best of the three alternatives considered here for gate operation at Soldiers Pond and Fenelons Pond. With the exception of possibly fabricating stoplogs there should be no cost to this option. Other gates settings could be investigated to optimize the size of the gate opening that provides the smallest decrease in energy generation from the base case.

Table 13.3
Energy Results for Sensitivity Simulations at Seal Cove System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)	Forebay Spill (m^3/s)
Base Case	9.93	–	0.15
Environmental Releases	9.91	- 0.02	0.16
Value of Storage	8.57	- 1.36	3.19
Soldiers and Fenelons Pond Gate Operation			
- Leave Gate Full Open	9.38	- 0.55	0.32
- Seasonal Operation	9.64	- 0.29	0.25
- Leave Gate Partially Open	9.68	- 0.25	0.24

13.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. **Improvements to Better Match Simulated Ideal Operation**

   Gate/Unit operation: The analysis shows that controlling the release of water from storage and operation of the units does not effect the energy output of the Seal Cove system substantially. The storage reservoirs regulate only a small portion of the total basin inflow, therefore, allowing for flexibility in operation of the control gates. The efficiency curve for SCV-G2 prepared by Acres during efficiency testing conducted in August 2000 illustrates that the curve is flat between 60 percent and 100 percent wicket gate opening with a difference in efficiency of approximately six percent. This small difference in efficiency allows for flexibility in unit loadings due to problems with outdated controls. Automation of the gates would provide the best control, but simpler approaches would be more cost effective and provide close to the energy produced using ideal operation.

2. **Changes to Operating Guidelines**

   Clarification of Guidelines: The present guidelines as interpreted for the Water Management Study come close to maximizing system output if NP can operate in this manner. NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum.

   Unit Dispatch Order: NP should carry out efficiency testing on SCV-G1, operating separately and together with SCV-G2, to determine the preferred dispatch order.

3. **Physical Changes**

   Forebay Flashboards: Installing flashboards and keeping in all year round while drawing the forebay down in the spring increases energy output by increasing head and reducing spill. If flashboards must be removed in the spring for dam safety reasons, then an inflatable crest gate (rubber dam) on the spillway section may be considered. The spillway section is short, and it may be possible not only to keep the head up during periods of high runoff risk, but also to raise the full supply level in lower risk periods. NP should investigate the costs and benefits of alternative flashboard/crest gate arrangements, taking into account dam safety requirements.

Increased Storage: Because of the fact that a small amount of runoff is controlled from the two main storage reservoirs and there is relatively no spill for the simulation period, the dam height was increased at the forebay by half a meter and one meter. The effect of increasing storage at White Hill Pond Forebay results in an increase in energy generation of 0.08 GWh/yr for a half meter rise, and 0.16 GWh/yr for a one meter rise. NP should look into the costs for this increase in dam height to determine the economical feasibility.

Reduce Headlosses: Another method of increasing head is to reduce headlosses through replacing the existing woodstave penstock with a steel penstock of equal diameter or one with a larger diameter (eight feet). The resulting energy generation was 10.24 GWh/yr or a net increase in average annual energy of 0.31 GWh/yr for the seven foot diameter penstock and 10.35 GWh/yr or a net increase in average annual energy of 0.42 GWh/yr for the eight foot diameter penstock. Headlosses would have to confirmed by detailed efficiency testing of SCV-G1 operating separately and with SCV-G2.

Increase Net Head: Currently there are no draft tubes at the exit of the units for Seal Cove. At some point in time these were either removed or have fallen off. By installing new ones it will effectively increase the net head of the station, therefore, increasing energy production. The resulting energy generation was 10.44 GWh/yr or a net increase in average annual energy of 0.51 GWh/yr.

Combination of Reducing Headlosses and Increasing Net Head: The combination effect of installing flashboards at White Hill Pond Forebay and draft tubes at Seal Cove Station, and replacing the seven foot diameter woodstave penstock with an eight foot diameter steel penstock to increase net head on the station on the energy production was investigated. The resulting energy generation was 10.73 GWh/yr or a net increase in average annual energy of 0.80 GWh/yr.

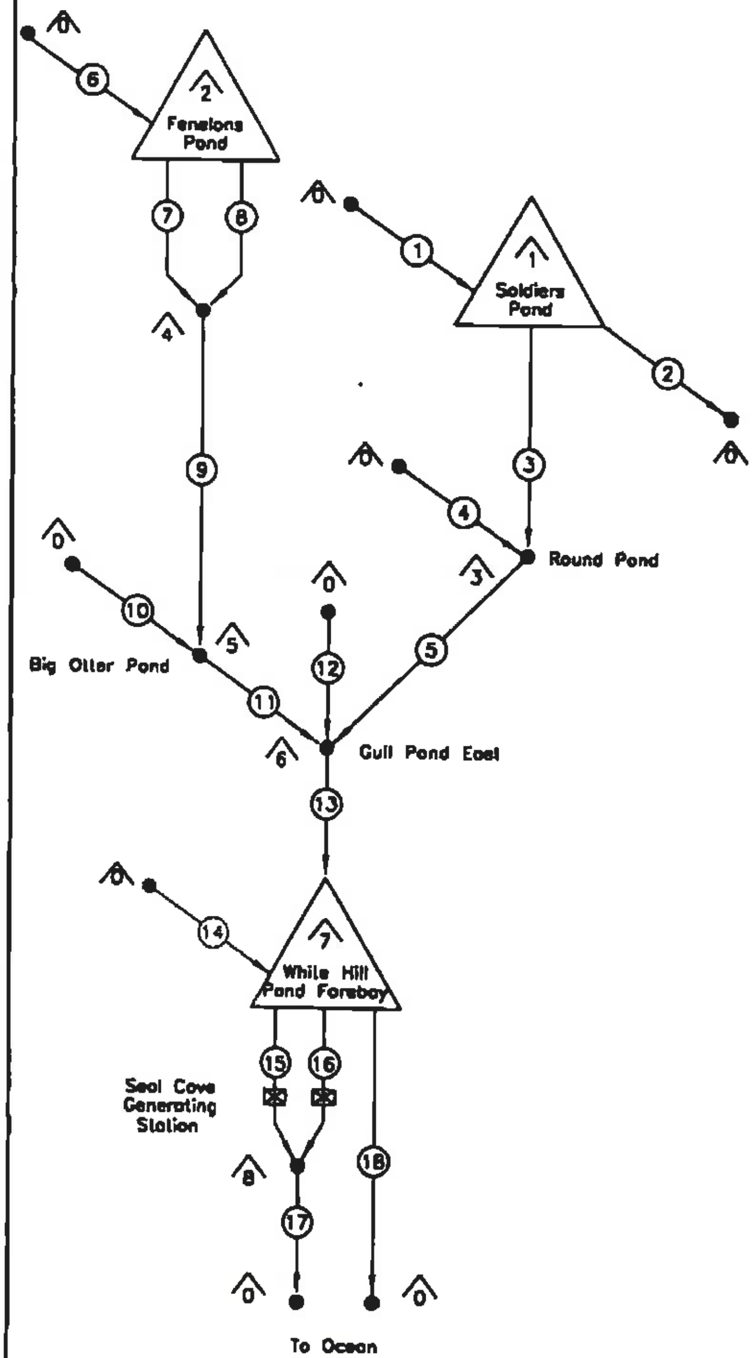
New Reservoir and Control Gate at Gull Pond East: Constructing a new reservoir and control gate at Gull Pond East would result in an increase in energy production of 0.40 GWh/yr.

4. Sensitivities

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gates at Soldiers Pond and Fenelons Pond does not affect energy generation, because this amount is already being released to supply the units. The requirement, however, assumes that when the reservoirs are low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.

Value of Storage: The value of the storage at Soldiers Pond and Fenelons Pond is 1.36 GWh/yr. NP may use this value in considering the costs of maintaining these structures.

Changes to Soldiers Pond and Fenelons Pond Outlet Gate Control/Operation: The value of operating the gates at Soldiers Pond and Fenelons Pond on a daily basis is 0.55 GWh/yr. If the gate can be automated for perhaps $100 000 to $150 000, automation would be justified by the energy savings. However, it may be possible to obtain some or all of the energy gains more cost-effectively, considering changing the gate setting a couple of times a year or restricting the gate opening.



CHANNELS

1 — Soldiers Pond Local Inflow
2 — Soldiers Pond Spill
3 — Soldiers Pond Outlet Gate
4 — Round Pond Local Inflow
5 — Round Pond to Gull Pond East General Flow
6 — Fenelons Pond Local Inflow
7 — Fenelons Pond Spill
8 — Fenelons Pond Outlet Gate
9 — Fenelons Pond to Big Otter Pond General Flow
10 — Big Otter Pond Local Inflow
11 — Big Otter Pond to Gull Pond East General Flow
12 — Gull Pond East Local Inflow
13 — Gull Pond East to White Hill Pond (Forebay) General Flow
14 — White Hill Pond (Forebay) Local Inflow
15 — Power Flow (SCV-G1)
16 — Power Flow (SCV-G2)
17 — Seal Cove Total Power Flow
18 — Seal Cove Spill

RESERVOIRS / NODES

0 — Source / Sink
1 — Soldiers Pond
2 — Fenelons Pond
3 — Round Pond
4 — Fenelons Pond Total Outflow
5 — Big Otter Pond
6 — Gull Pond East
7 — White Hill Pond (Forebay)
8 — Total Power Flow

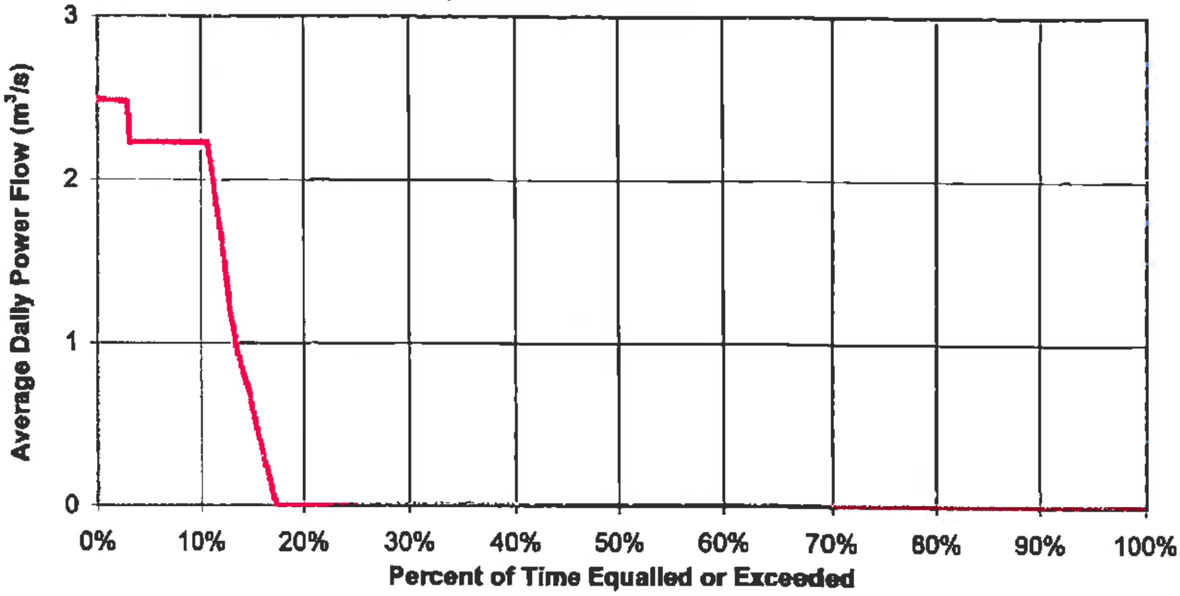
Fig. 13.1

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

SEAL COVE ARSP MODEL SCHEMATIC

(a) Seal Cove Unit 1 (SCV-G1)



(b) Seal Cove Unit 2 (SCV-G2)

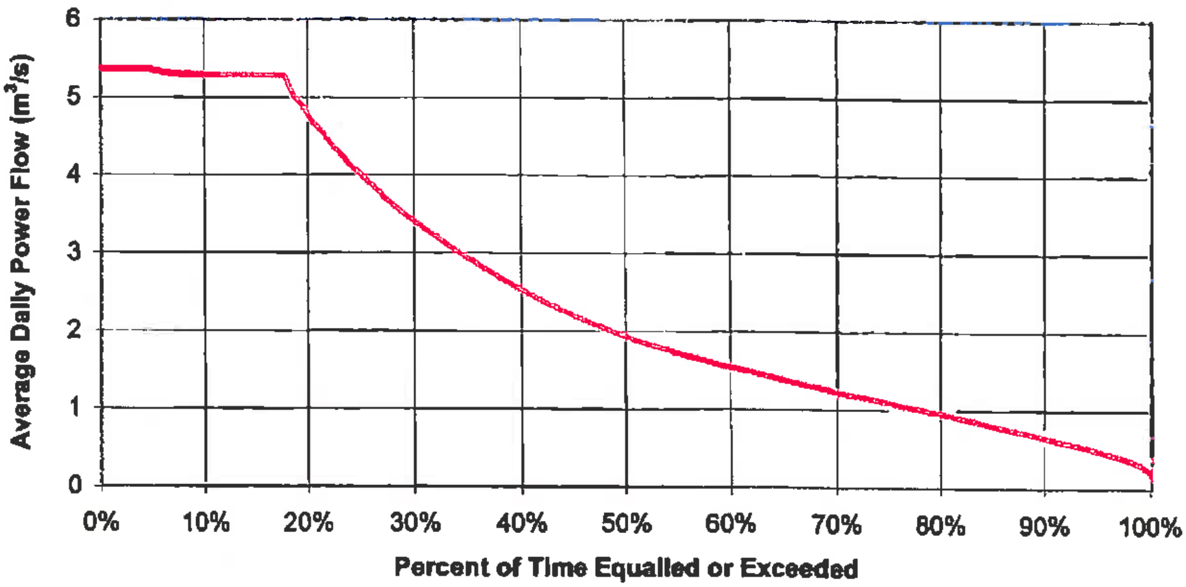


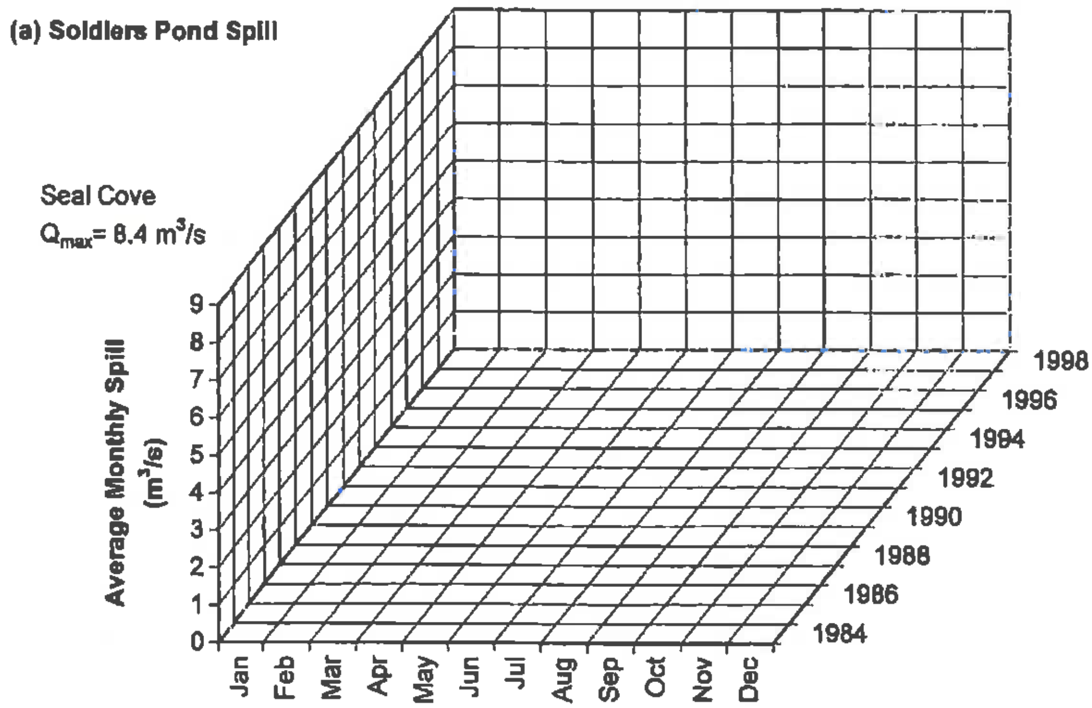
Fig. 13.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

SEAL COVE SIMULATED POWER FLOW DURATION CURVES

ACRES



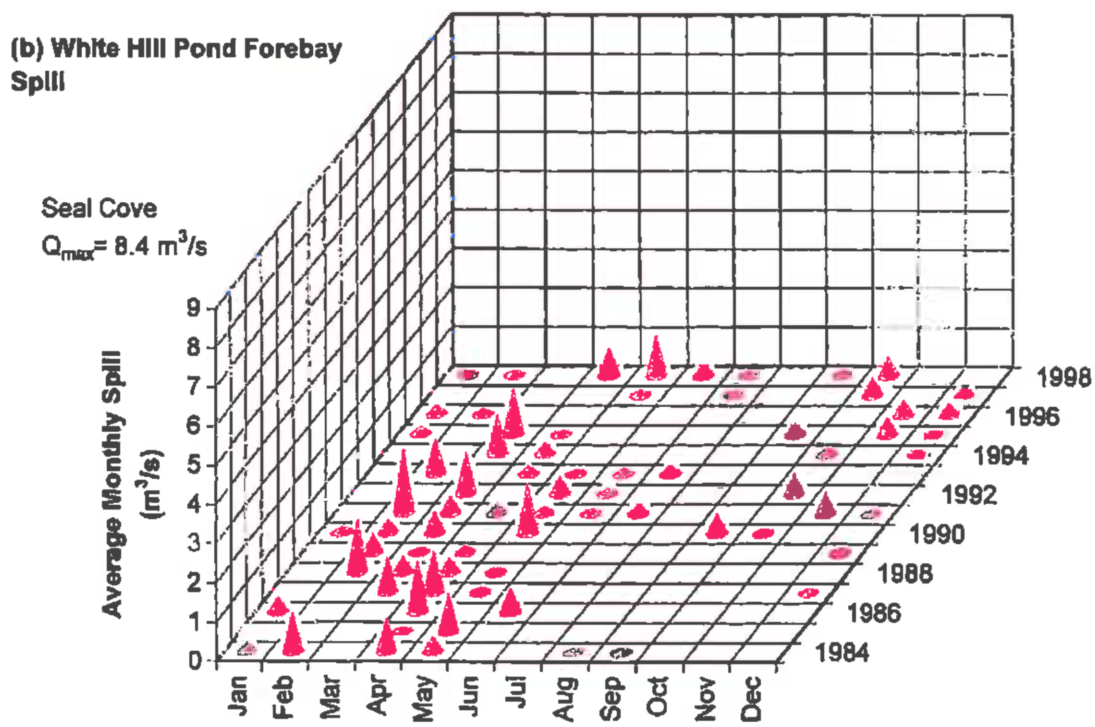
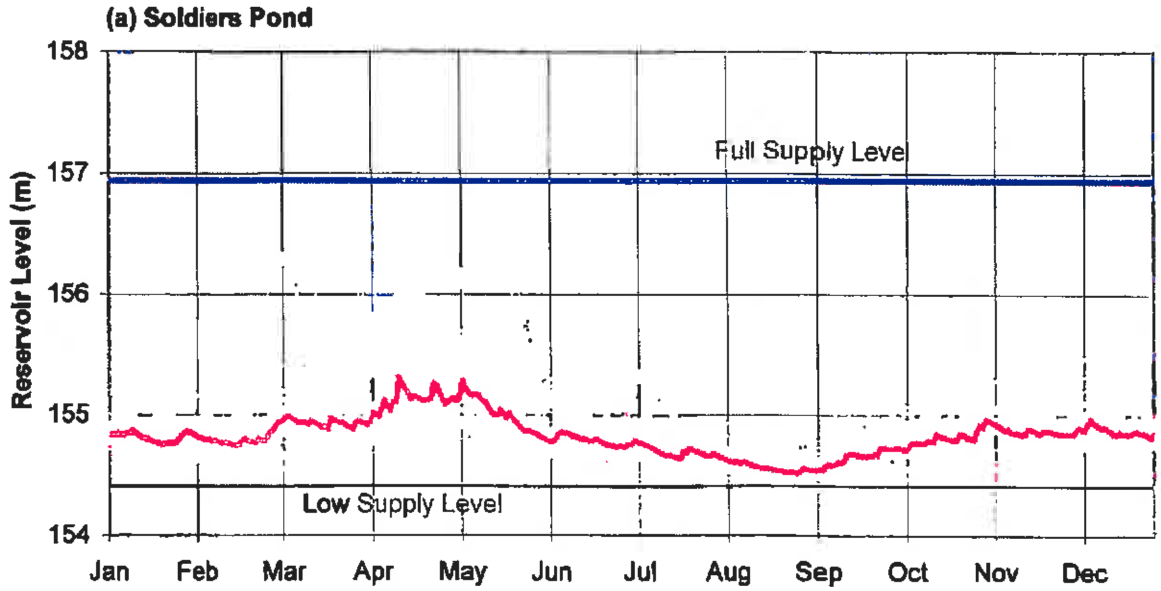


Fig. 13.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

SOLDIERS POND AND WHITE HILL POND FOREBAY SIMULATED SPILLS



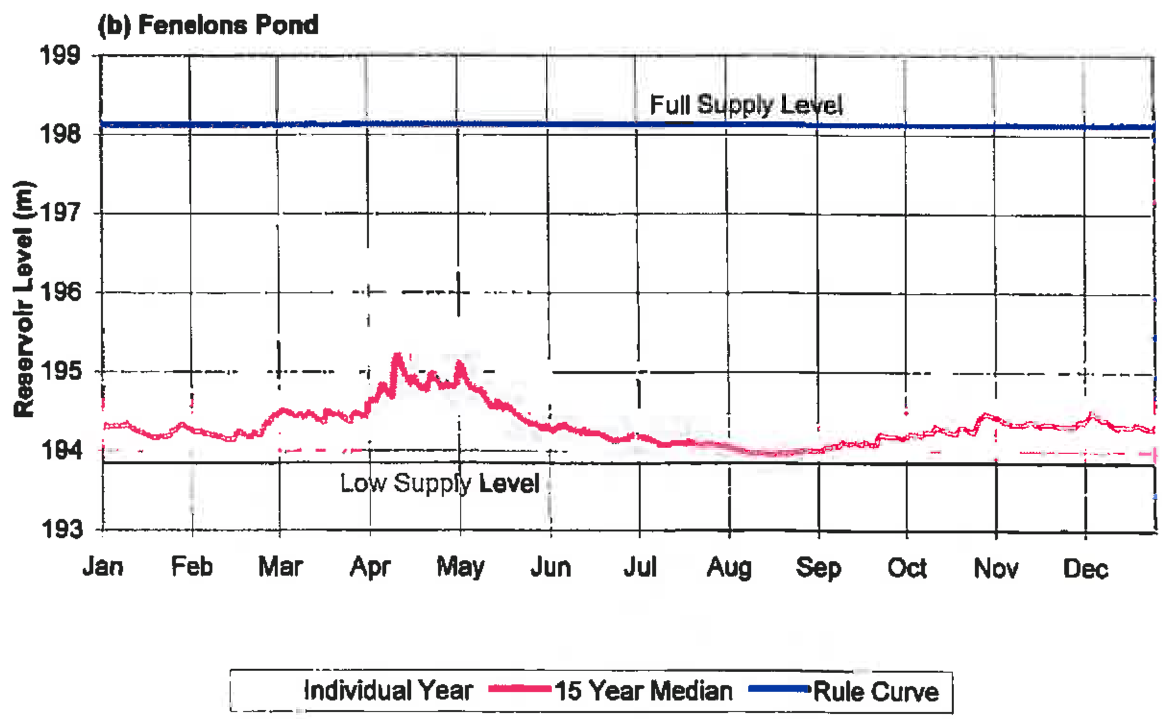


Fig. 13.4

NEWFOUNDLAND POWER
HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY
SOLDIERS POND AND FENELONS POND
SIMULATED RESERVOIR LEVELS

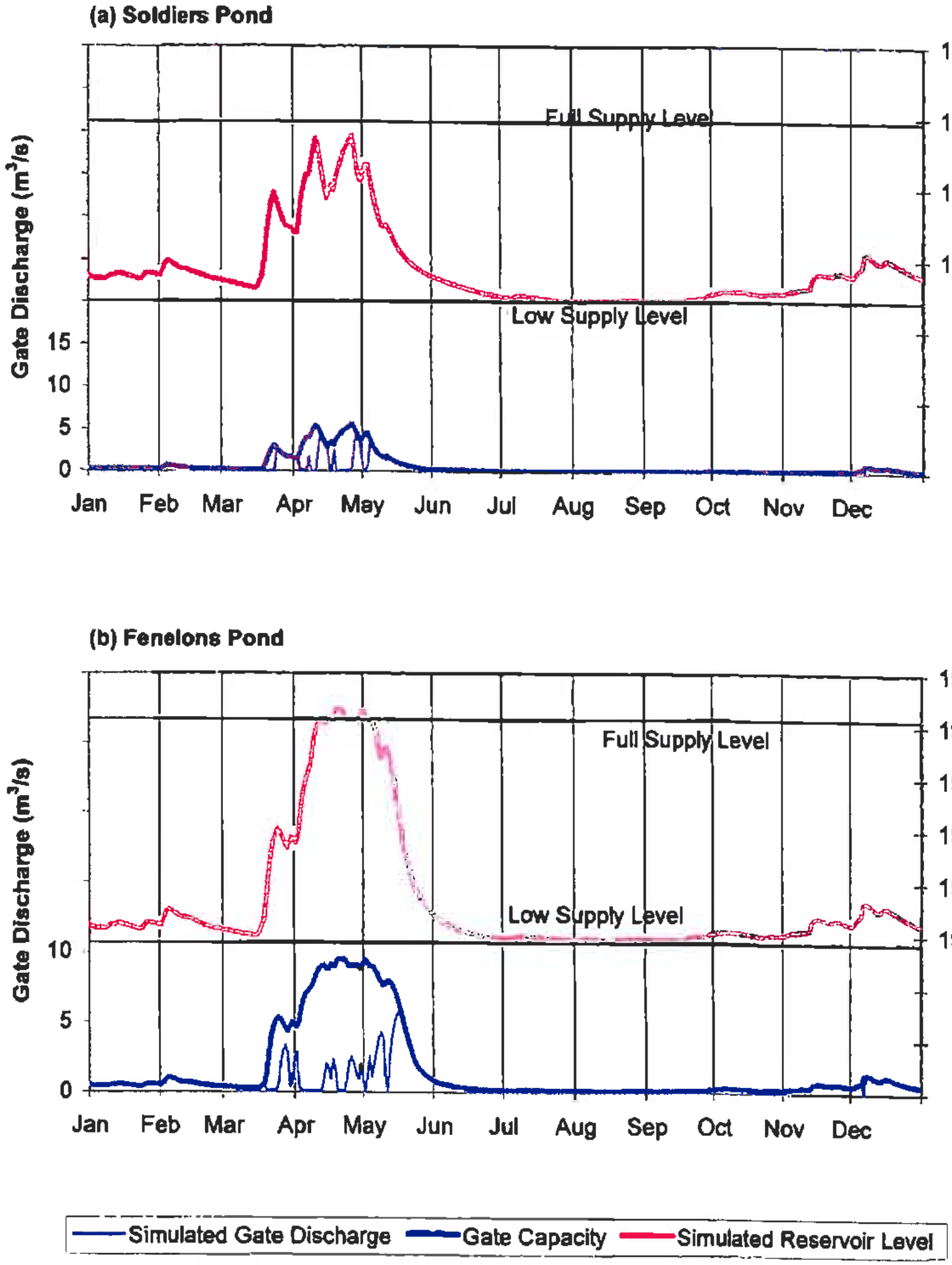


Fig. 13.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

SOLDIERS POND AND FENELONS POND SIMULATED GATE DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

ACRES

Topsail

14 Topsail Hydroelectric System

Topsail Hydroelectric System was assessed to determine whether there is potential for increasing energy generation, following the methodology in Chapter 2, by

- improving current practice to better follow existing plant operating guidelines;
- revising existing plant operating guidelines; and
- making physical changes to the system.

In addition, the sensitivity of energy generation to operating changes and constraints was investigated.

The following sections describe the Topsail system, present representative operating measures (e.g., flow utilization factor and energy potential of spill) and provide the results of the analysis used to assess the effect of operational and physical changes on energy generation. The last section provides conclusions and recommendations.

The simulation model which was set up for the Topsail system in the Water Management Study, conducted by Acres for all NP hydroelectric systems, was used to assess the effect of operational and physical changes on energy generation. The long term production estimated in the Water Management Study assumed ideal operating practices using current NP plant operating guidelines, as interpreted for the study. The result of this simulation for the Topsail system is referred to in this section as the base case system generation. Other estimates of energy generation resulting from operational or physical changes to the system are compared to this value.

14.1 System Description

The Topsail system is located on the south east coast of Conception Bay near the community of Topsail and has one generating station located within the system.

The Topsail Generating Station contains one generating unit with a nameplate capacity of 2.6 MW and a rated net head of 85.5 m. The drainage area above the intake to the Topsail station is approximately 61 km^2. The station was commissioned in 1932. Storage is provided by structures at Thomas Pond, Paddys Pond, Three Arm Pond and Three Island Pond. There is a short canal between the uncontrolled outlet of Topsail Pond and the intake to the Topsail station. A schematic of the system is presented in Figure 14.1.

All major storage reservoirs are in series, with Thomas Pond being the most upstream reservoir in the system. There is an overflow spillway located on Thomas Pond, which when overtopped, would lead to spill out of the system. Water is released from Thomas Pond to Paddys Pond using the control structure located at its outlet. Water entering Paddys Pond is either stored, spilled out of the system or released downstream to Three Arm Pond. Additional inflow occurs at Paddys Pond due to spill from Cochrane Pond located in the Petty Harbour Hydroelectric System.

Water from upstream reservoirs entering Three Arm Pond is either stored, spilled within the system or released downstream to Three Island Pond using the structure located at its outlet; this is similar for Three Island Pond. Water entering Topsail Pond is either spilled out of the system or used for generation.

The structures in the system are as follows

- Thomas Pond gated outlet;
- Thomas Pond overflow spillway;
- Paddys Pond gated outlet;
- Paddys Pond overflow spillway;
- Three Arm Pond gated outlet;
- Three Arm Pond overflow spillway;
- Three Island Pond gated outlet;
- Three Island Pond overflow spillway; and
- Topsail Pond overflow spillway.

The Thomas Pond, Paddys Pond and Topsail Pond overflow spillways discharge out of the system; the other spillways discharge within the system.

14.2 Representative Operating Measures

In assessing the potential for increased energy generation at a particular system, certain representative operating measures and plots can be used to draw conclusions about the impact of operational or physical changes to the system. These measures and plots are as follows.

1. Flow Utilization Factor.
2. Energy Conversion Factor.
3. Flow Duration Curve.
4. Energy Potential of Spill.
5. Reservoir Storage Factor.
6. Reservoir Utilization Plot.
7. Forebay Storage Factor.
8. Gate Operation Plot.

The definition and use of these measures and plots are described in Chapter 2. The measures as calculated for the Topsail system are provided below. They were developed from the data in the base case simulation. Table 14.1 at the end of this section summarizes the measures for the Topsail system.

1. Flow Utilization Factor

The Topsail station houses a single generating unit (TOP-G1). The flow utilization factors for the Topsail station (average inflow to forebay divided by combined flow capacity at most efficient load and maximum load) are 0.85 at most efficient load and 0.72 at maximum load.

2. Energy Conversion Factor

The energy conversion factors (the ideal average value of water in storage assuming the units are operating alone) for most efficient load and maximum load for TOP-G1 are 0.212 kWh/m^3 (6.68 GWh/yr/m^3/s) and 0.202 kWh/m^3 (6.36 GWh/yr/m^3/s), respectively.

The average energy conversion factor from the base case simulation for TOP-G1 is 0.22 kWh/m^3 (6.82 GWh/yr/m^3/s). This energy conversion factor takes into account the average reduction in availability due to forced outages.

3. Flow Duration Curve

The TOP-G1 flow duration curve for the turbine flow (power flow) in the base case simulation is shown in Figure 14.2. The unit operates at maximum flow approximately 10 percent of the time.

4. Energy Potential of Spill

The simulated spill for the base case was approximately 0.143 m^3/s on average at the Topsail Pond Forebay overflow spillway, 0.115 m^3/s at Paddys Pond overflow spillway and 0.003 m^3/s at Thomas Pond overflow spillway. Using the simulated energy conversion factor for TOP-G1 at maximum load presented previously in this section, the combined spill flows would produce approximately 1.8 GWh/yr, if entirely saved and used for generation.

The monthly distribution of this spill over 15 years for the base case simulation is shown in Figures 14.3 and 14.4 for the Thomas Pond, Paddys Pond and Topsail Pond Forebay overflow spillways. As can be seen in this figure there was little spill at Thomas Pond for the base case simulation.

5. Reservoir Storage Factor

Storage is provided by structures located at the outlets of Thomas Pond, Paddys Pond, Three Arm Pond and Three Island Pond. The Topsail Pond Forebay acts as the headpond for the Topsail station. The reservoir storage factors were calculated to be approximately 46 days for Thomas Pond, 22 days for Paddys Pond, 3 days for Three Arm Pond, 6 days for Three Island Pond and less than one day (18 hours) for Topsail Pond Forebay. These factors represent the average number of days to fill the reservoirs without any outflow.

6. Reservoir Utilization Plot

The plot of simulated Thomas Pond reservoir levels for the base case simulation is provided in Figure 14.5. The plot illustrates the reservoir utilization corresponding to ideal operation, which generally makes full use of the available storage range. For the Topsail system the use of reservoir storage is severely limited by other physical or operational constraints, particularly the reservoirs at Paddys Pond, Three Island Pond and Topsail Pond Forebay where constraints imposed by recreational users restrict the extent to which these reservoirs can be used to store water for generation.

7. Forebay Storage Factor

The forebay storage factor (time required to draw forebay down assuming no inflow with units operating at maximum load) is 0.53 days (13 hours).

8. Gate Operation

There are control gates located at the outlets of Thomas Pond, Paddys Pond, Three Arm Pond and Three Island Pond. Provided in Figure 14.6 is the simulated gate discharge, gate capacity and simulated reservoir level for an example year (1996) for Thomas Pond. This plot illustrates the frequency the gate is being operated in the simulation model to maintain most efficient load and to avoid spill by operating at maximum load.

Table 14.1
Topsail System Representative Operating Measures

Topsail Representative Operating Measures	
Flow Utilization Factors - Most Efficient Load - Maximum Load	 0.85 0.72
Station Factors - TOP-G1 Most Efficient Load - TOP-G1 Maximum Load	 0.212 kWh/m^3 0.202 kWh/m^3
Energy Potential of Spill	1.8 GWh/yr
Reservoir Storage Factors - Thomas Pond - Paddys Pond - Three Arm Pond - Three Island Pond - Topsail Pond Forebay	 46 days 22 days 3 days 6 days 0.74 days (18 hours)
Forebay Storage Factor	0.53 days (13 hours)

14.3 Ideal Operation of System

The long term energy production at Topsail as estimated by the simulation model developed for the Water Management Study is 15.9 GWh/yr. This compares with recorded energy generation for the same reference period (1984-98) of 12.4 GWh/yr. While these numbers are not directly comparable due to runner replacement in 1997 and a number of prolonged outages affecting the recorded generation over this period, the difference does provide some indication of the potential for improving actual generation at this system under the current plant operating guidelines. Further indicators of this difference are provided by the comparisons conducted for the Water Management Study for two sample years. This comparison indicated an average difference between recorded and simulated generation (after adjustments for storage) of approximately 10 percent for this system.

For the entire NP hydroelectric system, the value used for the adjustment for practical operations was seven percent. This factor is intended to reflect an average difference between the simulated results and the generation that can actually be expected based on realistic operational constraints and recent operating experience. Further details on the calculation of this factor and its application may be found in Section 22.3 of the Water Management Study. The remainder of this section will consider opportunities to reduce this difference between the simulated ideal operation and actual generation at the Topsail System.

14.3.1 Plant Operating Guidelines

The simulation model used to estimate the energy generation of the Topsail system assumes that the operations staff has interpreted the existing operating guidelines as described in the Water Management Study. Plant operating guidelines provide operators with procedures regarding how to operate the system based on current inflows. During periods of high inflows, the plant will be operated at maximum load (and less than maximum efficiency) to avoid spills. This requires some interpretation by the operators regarding what constitutes high inflows. The interpretation used in the simulation model incorporated a rule curve for each reservoir in the system. If the reservoir levels exceed the rule curve at any particular time of the year, then the units are operated at maximum load to bring the level down to the rule curve. If the reservoir levels are below the rule curve, then the units are operated at best efficiency.

Obviously, some judgment on the part of the operators in applying this guideline is required. For instance, knowledge of above normal snow accumulations in the watershed prior to spring runoff may be employed in deciding to operate the units at maximum load even when water levels have not reached the rule curve. However, the rule curve will ordinarily provide useful guidance to system operating staff. The rule curves used in the simulation model are illustrated in Figure 14.5 and are provided in the echo of the detailed simulation model input in Volume 3 of the Water Management Study.

14.3.2 Gate/Reservoir Operation

The Topsail system has significant storage capacity that can be effectively used to smooth the basin inflows (storage ratio of 58 days). Thomas Pond and Paddys Pond reservoirs provide most of the usable storage capacity. The gates that control these reservoirs are readily accessible. Many other constraints are imposed on reservoir operations in this system due to the many recreational users of the four downstream reservoirs. However, these constraints have been considered (to the extent possible) in the simulation model and therefore these factors should not be the source of differences between the modeled and actual results. Therefore, the impact of the practicalities of gate and reservoir operation on system generation should not be significant.

In addition to the above issues, NP must maintain certain minimum storage levels, particularly during the winter months, to ensure plant availability in the event of local power outages or when called upon by Newfoundland and Labrador Hydro (NLH). This winter reserve is not taken into account by the simulation model.

14.3.3 Unit Operation

The simulation model operates the Topsail unit exclusively at its most efficient load, except when high inflows dictate that higher loads are necessary to avoid exceeding the reservoir rule curves. With the available control equipment, minimal constraints on plant discharges, and the available forebay storage, it should be possible to operate this plant very close to this ideal. An examination of daily Control Centre Logs for several months (December 1998, April and August 1999, and January-February 2000) confirmed that the Topsail unit is loaded at best efficiency a high percentage of the time. The main obstacles to attaining ideal operation are electrical grid requirements which may occasionally require that the units operate at loads other than their most efficient loads. Such requirements would include local power outages or other infrequent occurrences.

14.4 Changes to Operating Guidelines

The purpose of the analysis described in this section is to determine whether there is any energy to be gained by changing NP's current plant operating guidelines. As discussed in Chapter 2 there are three ways improvements could occur through changes to the guidelines. These are

- increasing head, by operating the forebay to get more head or reducing headlosses;
- by avoiding spill; and
- by operating the units at best efficiency more of the time.

Each of these is discussed below for the Topsail system. Increasing the head through a change in the use of the flashboards or installation of inflatable crest gates at

Topsail Pond Forebay was not considered as the number of recreational users and home owners on this reservoir preclude such an alternative.

The other two possibilities were examined using the limiting cases of high and low reservoir rule curves, discussed in Chapter 2. The case described for the base case is an intermediate case, since it uses a NP rule curve varying between the low supply and full supply levels of the reservoirs although it very nearly approximates the high rule curve case, as discussed below.

Spill Avoidance, Limiting Case: Maximum Load, Reservoirs Low
The limiting case for spill avoidance is to maximize the amount of storage available to contain inflows. To do this, the units would be operated at maximum flow to keep the water in the storage reservoirs as low as possible.

At Topsail, the potential for savings in spill compared to the base case is considerable. The maximum possible reduction in spill would be the equivalent of 1.8 GWh/yr, as shown in Table 14.1. However, the spill distribution plot (Figures 14.3 and 14.4) shows that this would be difficult to capture since the spills occur in large amounts.

To assess the potential for additional energy generation in the system using spill avoidance, the simulation model was run assuming the units were always operated at maximum load when water was available. The average annual combined spill from Topsail Pond Forebay, Paddys Pond and Thomas Pond was reduced by 0.068 m^3/s, from an average of 0.26 m^3/s to 0.19 m^3/s. This represents an increase of approximately 0.46 GWh/yr. This amount more than compensates for the average annual decrease of 0.06 GWh in energy production due to operating the units at a lower efficiency.

Best Efficiency Operation, Limiting Case: Reservoirs High
The limiting case for maximizing the amount of time the units are operating at best efficiency is to run the units at best efficiency, until the storage reservoirs are just about to spill.

The result of a simulation using this rule was an average annual production of 13.5 GWh/yr, with a spill of 0.61 m^3/s. This production is substantially lower than the base case production. This suggests that the rule curve used for the base case simulation is near optimum for the Topsail system. With the number of reservoirs and constraints in the Topsail system, gains of up to 0.5 GWh/yr may be achieved by making adjustments to the rule curve, particularly at Thomas Pond which has few constraints due to other water users. NP should refine its rule curves and clarify these operating targets in the plant operating guidelines

14.5 Physical Changes to System

The principal options for physical changes to the existing system to improve energy generation are to increase watershed inflow and to increase storage. To give an indication of the value of these changes, the following options were investigated.

- Increase dam height at Thomas Pond to increase storage.
- Change gate dimensions at Paddys Pond to permit better storage utilization.
- Consider diverting Cochrane Pond drainage area to Topsail system to increase average inflow.

Each of these physical changes to the system is discussed below. Table 14.2 summarizes the results.

Increase Storage at Thomas Pond

To determine the effect of an increase in storage on energy production, the dams and structures at Thomas Pond were assumed to be raised to allow increases in full supply level of one and two meters. This reservoir is the only one in the Topsail system where such a change could be considered as the remaining reservoirs have considerable recreational usage. The effect of increasing storage is to reduce system spill. The resulting increases in energy generation were 0.3 GWh/yr for the one meter rise, and 0.6 GWh/yr for the two meter rise.

Assuming that the cost of energy to NP is $0.04/kWh this would result in a savings to NP of approximately $12 000/yr for the one meter increase in dam height and $24 000/yr for the two meter increase in dam height. Given a dam length of approximately 400 m, the savings over perhaps 20 years would justify an expenditure of about $275/m of dam length based on a one meter increase. It is unlikely that the work could be completed for less than this unit cost and therefore increasing the available storage in this system is probably not economical at this time.

Change Gate Capacity at Paddys Pond

Due to the fact that over 80 percent of the Topsail watershed area lies upstream of Paddys Pond dam as does the majority of the system storage, sizing of the gates which convey these flows to the forebay is critical for system generation. The gate having the most limited capacity on examination appears to be the one located at Paddys Pond outlet structure. To assess whether or not the capacity of this gate is restricting flows to the powerhouse, the model was tested assuming that this gate had double its present capacity. The resulting energy generation was 16.0 GWh/yr or a net increase in average annual energy of only 0.1 GWh/yr. Based on this information, it may be concluded that the gates in the Topsail system appear to have adequate capacity.

Divert Cochrane Pond Watershed

The Cochrane Pond watershed was diverted from Manuels River (now the Topsail system) as part of the Petty Harbour hydroelectric development in 1917. Subsequent to this diversion, the Topsail hydroelectric development was constructed. As Topsail unit operates under a greater net head than the Petty Harbour units, a simulation considering the rerouting of Cochrane Pond flows to Topsail was modeled for both systems. The resulting annual production at Topsail was 17.3 GWh/yr, an increase of 1.4 GWh/yr when compared with the base case. The reduction in annual generation at Petty Harbour due to the loss of Cochrane Pond storage and inflows was also 1.4 GWh/yr.

While this would seem to indicate that such a change would not be worth pursuing, it was noted that the spill at Topsail with the addition of Cochrane Pond inflows increased by the equivalent of approximately 1.6 GWh/yr (from 0.261 m^3/s to 0.501 m^3/s). As the simulation did not consider the additional storage provided at Cochrane Pond, it is possible that most of this spill would not occur provided the storage at this reservoir were maintained.

Table 14.2
Results of Physical Changes to System

Case	Average Annual Energy (GWh/yr)	Change in Energy (GWh/yr)
Base Case	15.9	-
Double Paddys Pond Gate Capacity	16.0	+0.1
Increase Storage Thomas Pond by 1 m	16.2	+0.3
Increase Storage Thomas Pond by 2 m	16.5	+0.6
Divert Cochrane Pond	17.3	+1.4-1.4 (+1.6)

14.6 Sensitivities

In addition to the investigation of specific operational and physical changes, sensitivity runs were done to provide NP with information on the cost or value of certain aspects of their systems. Results for all sensitivity cases are provided in Table 14.3.

The sensitivity cases were as follows.

- Environmental release requirement of 30 percent of mean annual flow.
- No storage in system (to obtain value of storage); remove dams and gates.

Environmental Release Requirement
The sensitivity of energy generation to changes in environmental releases downstream of gated outlet structures was investigated. In the current model setup, for the purpose of maintaining flow in the river reaches downstream of the gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water is available. As a sensitivity, this minimum flow was set to 30 percent of the mean annual flow into the reservoir, as long as there is water in the reservoir. When the reservoirs are empty, the natural inflow would be released.

The 30 percent mean annual flow requirement is equivalent to approximately 0.51 m^3/s at Thomas Pond, 0.63 m^3/s at Paddys Pond, 0.68 m^3/s at Three Arm Pond and 0.73 m^3/s at Three Island Pond. Using these flows as the minimum flow release from the gates for the base case simulation model, there was no change in system energy. This is the case because 30 percent of mean annual flow is less than the best efficiency flow of the unit. This amount is always released in all simulations unless there is no water in storage, in which case the natural inflows are released.

If NP were required to hold a supply of water in the reservoirs to ensure that the 30 percent requirement were always met, there would likely be a reduction in energy.

No Storage in System
To provide NP with an indication of the value of the storage in the system, all storage in the system was assumed to be removed. The resulting average annual energy generation from this sensitivity was 12.5 GWh/yr, a net decrease of 3.4 GWh/yr. This represents the value of maintaining the structures at Thomas Pond, Paddys Pond, Three Arm Pond and Three Island Pond.

Table 14.3
Energy Results for Physical Changes to Topsail System

Case	Average Annual Energy (GWh/yr)	Change In Energy (GWh/yr)
Base Case	15.9	-
Environmental Releases	15.9	0.0
Value of Storage	12.5	-3.4

14.7 Conclusions and Recommendations

The conclusions and recommendations arising from the analysis are as follows.

1. Improvements to Better Match Simulated Ideal Operation

The Topsail system appears to be operated in a manner which closely resembles the ideal indicated by the simulation. The major operating practicalities which reduce generation when compared with that of the simulation are beyond the control of the system operators.

2. Changes to Operating Guidelines

Clarification of Guidelines: The present guidelines as interpreted for the Water Management Study come close to maximizing system output if NP can operate in this manner. NP should clarify the guidelines for the operators, in particular providing guidance on when to increase load from best efficiency to maximum. It may be possible to make modest gains through fine-tuning of the reservoir rule curves that determine when to switch from best efficiency load to maximum load. NP should review the present practice and update as required.

3. Physical Changes

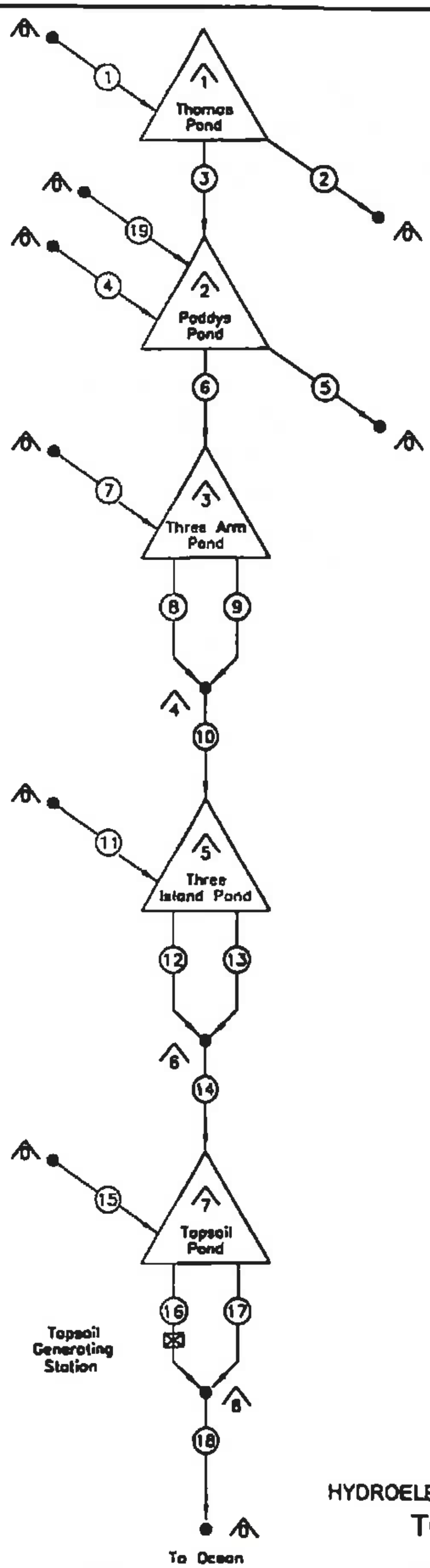
Increased Storage: Options for increasing storage at Topsail are limited to changes at Thomas Pond. These alternatives do not appear to be economically feasible based upon the analysis conducted.

Cochrane Pond Diversion: The diversion of Cochrane Pond flows from the Petty Harbour system to the Topsail system is not economically feasible unless the storage capability of Cochrane Pond is retained. Further analysis is required to assess the potential of this change if the Cochrane Pond storage capability was added to the Topsail system in addition to the inflows to this reservoir.

4. Sensitivities

Environmental Releases: Providing a minimum flow release of 30 percent of mean annual flow downstream of the outlet gates of all four storage reservoirs does not affect energy generation, because this amount is already being released to supply the unit. The requirement, however, assumes that when the reservoirs are low, the release is equal to the natural inflow. If the requirement were to guarantee 30 percent, a reserve would have to be maintained similar to the winter reserve.

Value of Storage: The value of the storage at Thomas Pond, Paddys Pond, Three Arm Pond and Three Island Pond is 3.4 GWh/yr. NP may use this value in considering the costs of maintaining the structure.



CHANNELS

1. — Thomas Pond Local Inflow
2. — Thomas Pond Spill
3. — Thomas Pond Outlet Gate
4. — Paddys Pond Local Inflow
5. — Paddys Pond Spill
6. — Paddys Pond Outlet Gate
7. — Three Arm Pond Local Inflow
8. — Three Arm Pond Spill
9. — Three Arm Pond Outlet Gate
10. — Three Arm Pond to Three Island Pond General Flow
11. — Three Island Pond Local Inflow
12. — Three Island Pond Spill
13. — Three Island Pond Outlet Gate
14. — Three Island Pond to Topsail Pond General Flow
15. — Topsail Pond Local Inflow
16. — Topsail Power Flow
17. — Topsail Spill
18. — Topsail General Outflow
19. — Cochrane Pond Spill

RESERVOIRS / NODES

0 — Source / Sink
1 — Thomas Pond
2 — Paddys Pond
3 — Three Arm Pond
4 — Three Arm Pond Total Outflow
5 — Three Island Pond
6 — Three Island Pond Total Outflow
7 — Topsail Pond
8 — Topsail Total Outflow

Fig. 14.1

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

TOPSAIL ARSP MODEL SCHEMATIC

AGRES

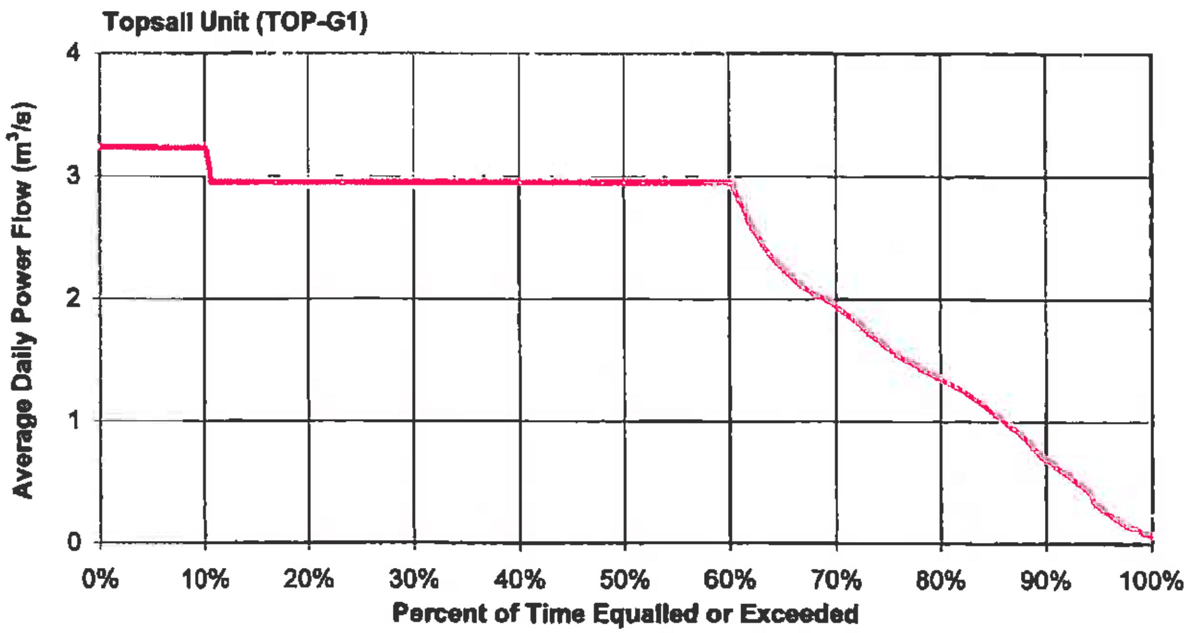


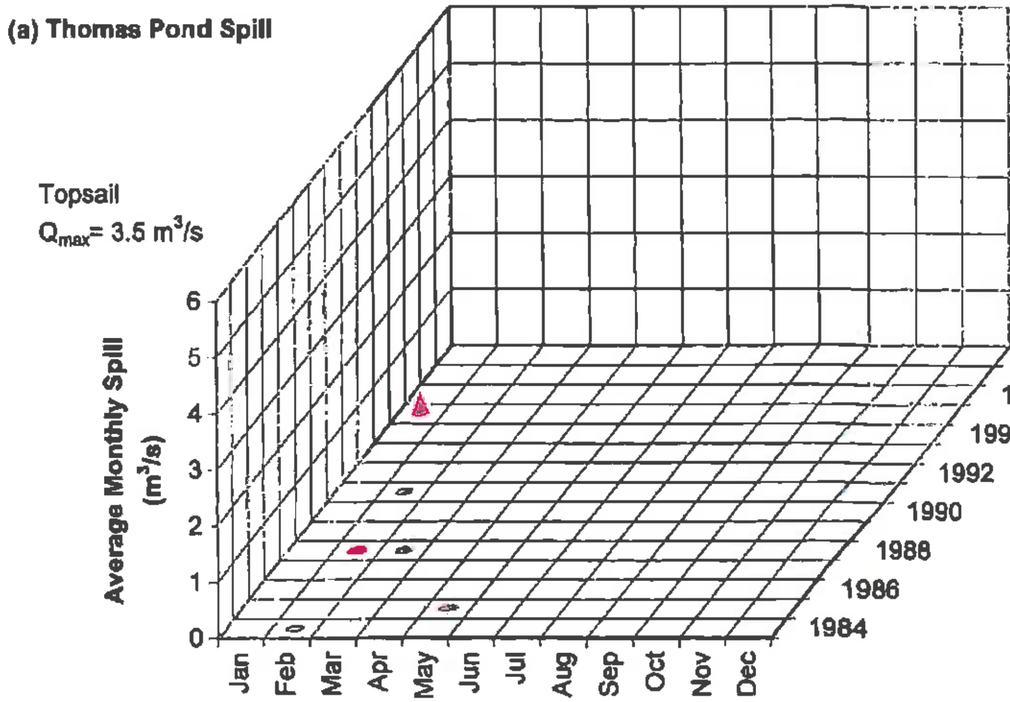
Fig. 14.2

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

TOPSAIL SIMULATED POWER FLOW DURATION CURVE

ACRES



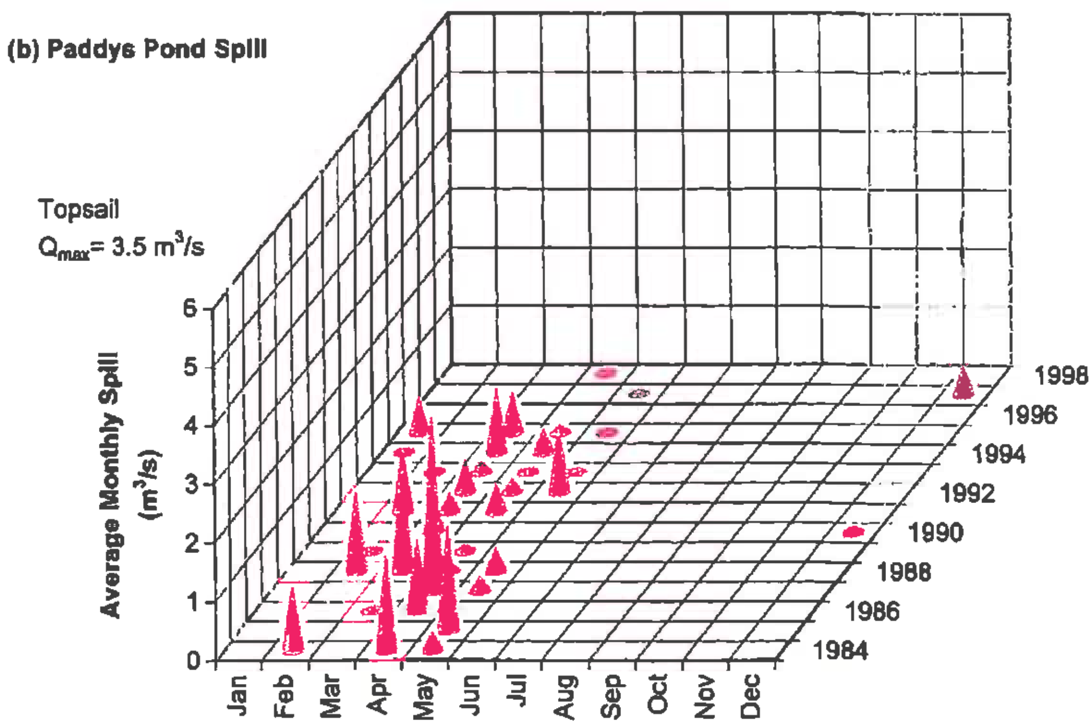


Fig. 14.3

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

THOMAS POND AND PADDYS POND
SIMULATED SPILLS

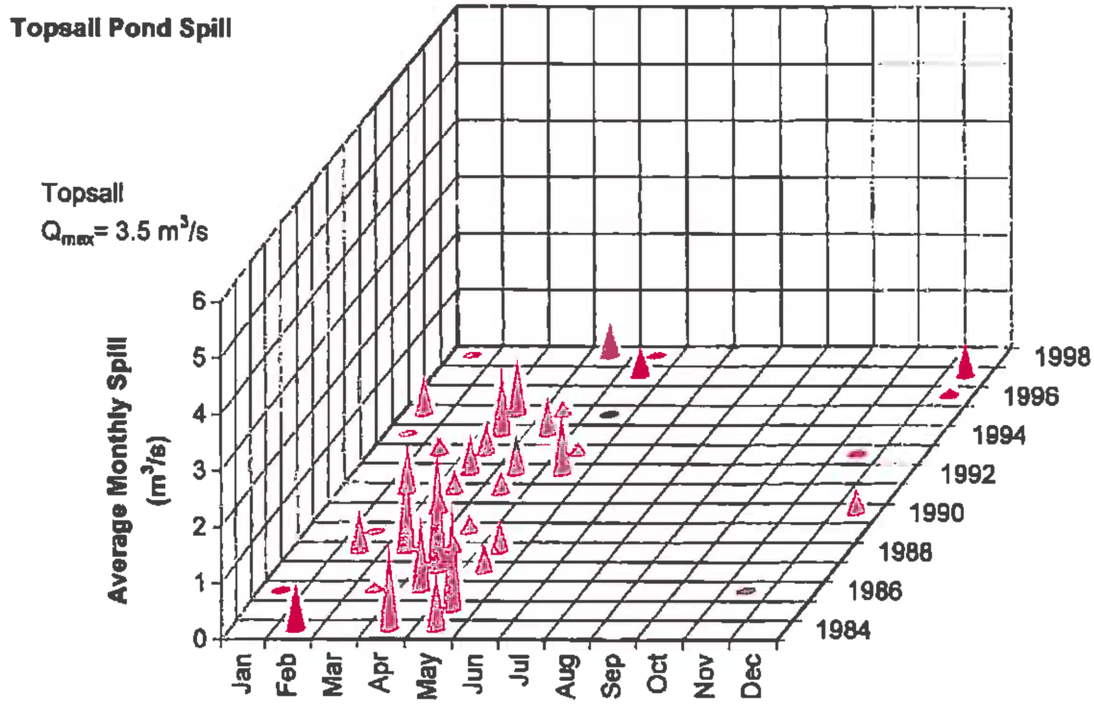


Fig. 14.4

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

TOPSAIL POND SIMULATED SPILLS

ACRES

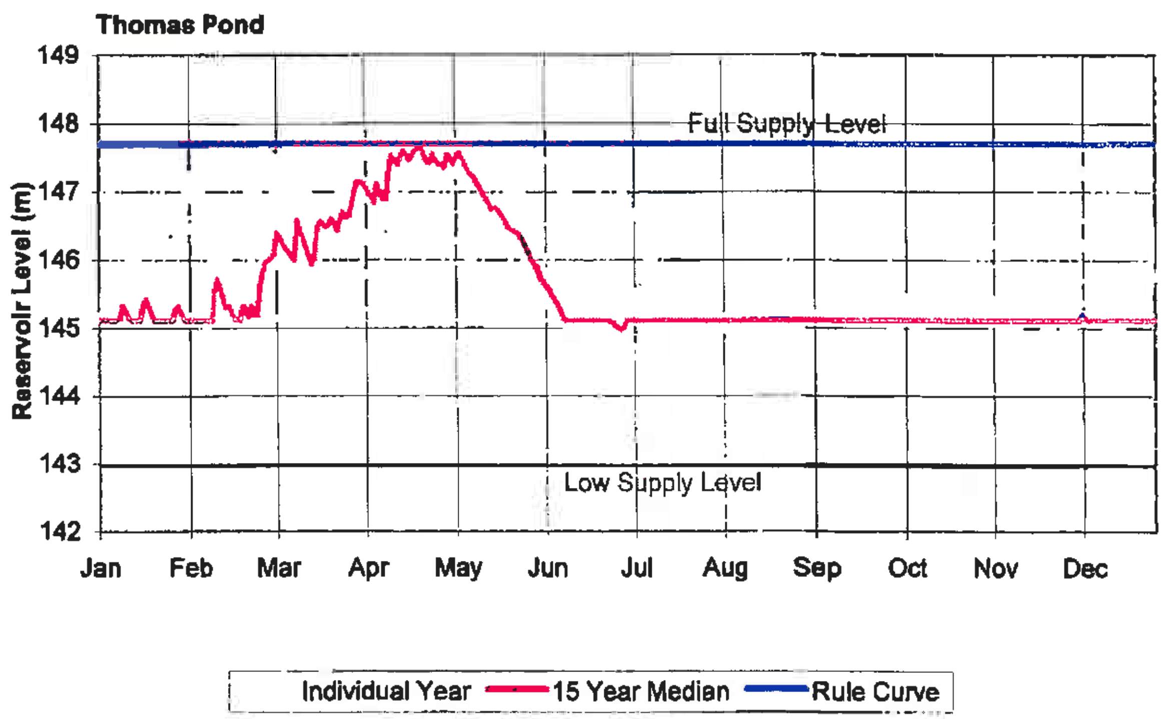


Fig. 14.5

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

THOMAS POND SIMULATED RESERVOIR LEVELS

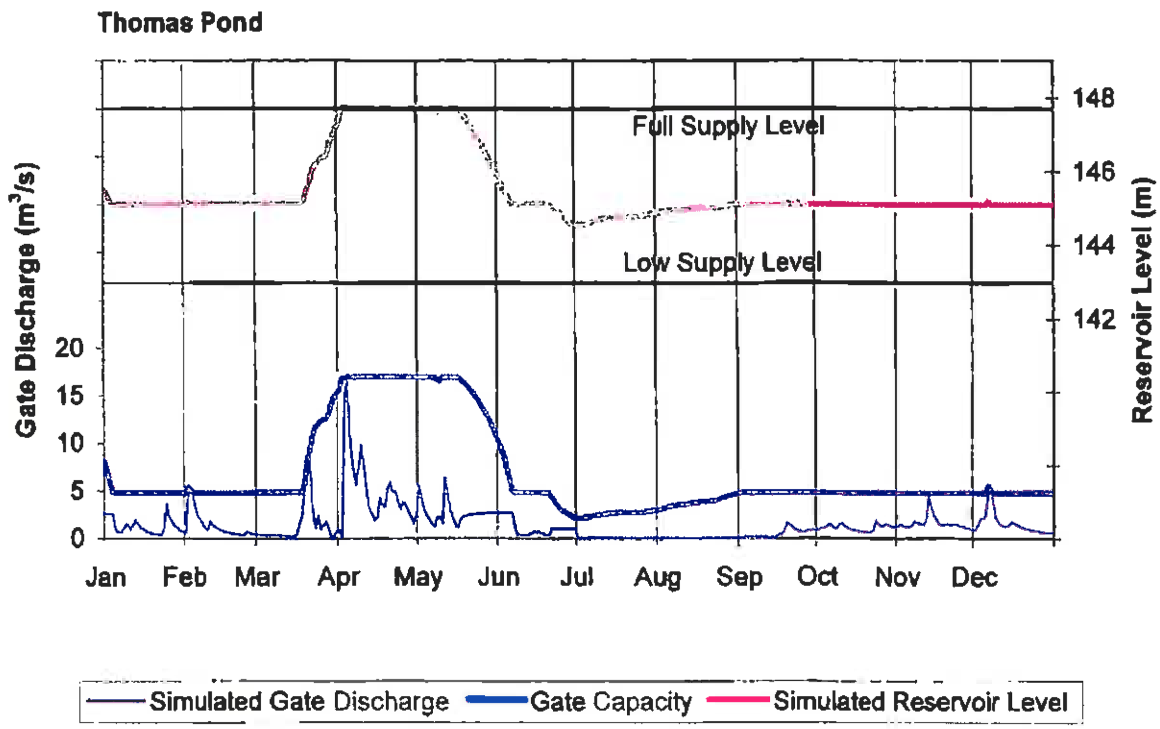


Fig. 14.6

NEWFOUNDLAND POWER

HYDROELECTRIC SYSTEMS STRATEGIC PLANNING STUDY

THOMAS POND DISCHARGE AND RESERVOIR LEVEL FOR EXAMPLE YEAR

Conclusions and Recommendations

15 Conclusions and Recommendations

Acres has completed a review of NP's hydroelectric system to identify potential opportunities for increasing energy generation through operational and physical changes. Specific conclusions and recommendations for each of the systems reviewed are included in the individual system chapters. General conclusions regarding the whole system are as follows.

1. In some instances, a review of the Control Centre logs showed that the units are not always being operated to obtain maximum generation. In some cases inefficiencies are unavoidable due to system demands, in other instances, improvements may be possible. Additional review of the logs, in combination with discussions with the operators, may identify opportunities for improved operation and increased generation.

2. NP should undertake a review of each plant's operating guidelines. In many instances, the guidelines require revision to remove ambiguity regarding interpretation.

   As noted in the individual chapters, corrections are required in some operating procedures, for instance in unit dispatch order.

   The unit loadings in some of the plant operating guidelines should be revised to reflect results of efficiency testing undertaken by Acres for NP in the past.

3. As noted in the individual system chapters, the review has identified potential sources of additional energy through physical modifications of existing structures. Modifications considered included raising dams, automating control gates, and replacing penstocks.

   The modelling undertaken in this study gives a preliminary indication of additional energy that may be obtainable through physical changes, but additional work needs to be done to quantify both the benefits and the costs of such modifications.

4. Sensitivity simulations were undertaken to estimate the cost of constraints on the systems, for instance water level constraints for recreation, and the value of controlled storage, again using the simulation models.