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Attachment B

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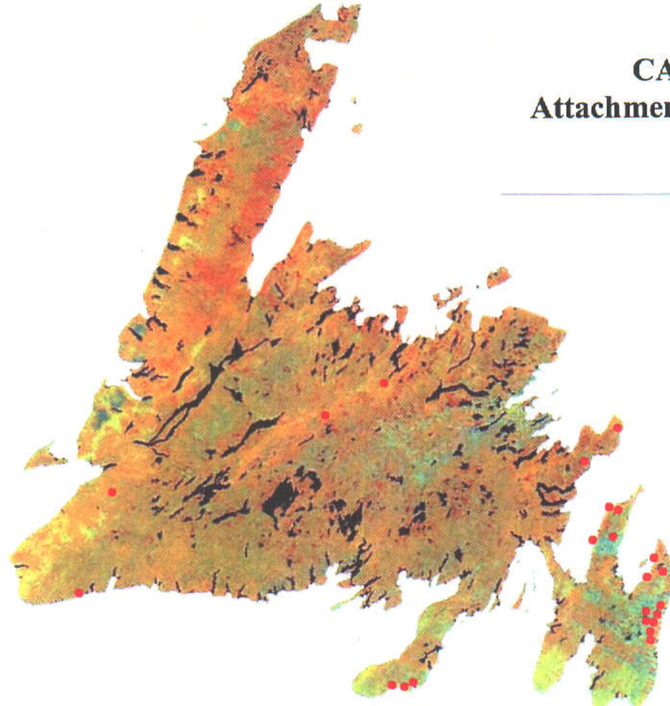
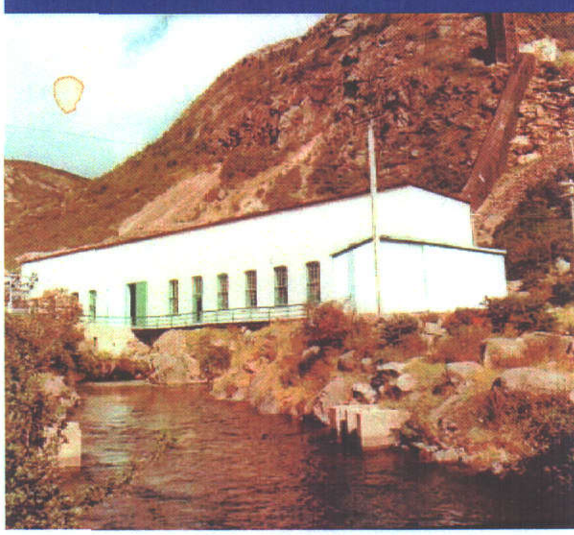


Water Management Study

Volume 1 Main Report



December 2000

Acres International

NEWFOUNDLAND POWER

A FORTIS COMPANY

Water Management Study

Volume 1 Main Report

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Volume 1 - Main Report

Volume 2 - Detailed Model Input and Output for Systems with Installed Capacity Greater than 4 MW

Volume 3 - Detailed Model Input and Output for Systems with Installed Capacity Less than 4 MW

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Executive Summary

Newfoundland Power (NP) generates approximately nine percent of its total energy requirements from its hydroelectric resources; the balance is purchased from Newfoundland and Labrador Hydro. The amount of energy that can be generated from NP's hydroelectric stations in a given year depends largely on weather conditions, particularly the amount of precipitation. In wet years NP can generate higher than average energy and so purchase less than average from Newfoundland and Labrador Hydro in those years. The reverse holds true for dry years. To prevent consumer electricity rates from fluctuating with the varying generation, a Hydro Equalization Reserve is maintained by order of the Board of Commissioners of Public Utilities. Each year's hydroelectric production is compared to the normal production, which is an estimate of the long term average annual generation available for sale to consumers. The reserve is then adjusted accordingly.

Acres International has completed the present *Water Management Study* for NP to provide a revised estimate of the normal production of NP's hydroelectric resources. The study was undertaken by modelling each system using Acres Reservoir Simulation Package (ARSP), a computer model which simulates the operation of reservoirs and hydroelectric stations in order to determine energy production. The models were set up using station data, reservoir and structure characteristics, and operating procedures provided by NP. Reference inflow sequences were developed for each system based on Environment Canada streamflow records on nearby rivers, adjusted as required for differences in drainage area and mean annual runoff.

In order to ensure that the individual models were correctly representing the systems, two selected years were modelled, and the simulated reservoir levels and energy generation were compared to the recorded values for those years. Generally, differences in the two generation values were a result of differences in simulated and actual water management. In months when the simulated energy generation was lower than the recorded generation, water levels at the end of the month were correspondingly higher. This water in storage would then often lead to higher simulated generation in a subsequent month. The models were run with two different inflow sequences and the one that best represented recorded generation and water levels was used for the long term simulations. Even after accounting for changes in storage, the simulated generation was usually greater than the recorded generation. The principal reason for the difference is that the models simulate ideal operation of the system.

The long term average annual production was then determined by simulating operation using the reference inflow sequence at each system. Changes resulting from any upgrades were incorporated in the models. The simulations included a five percent reduction in unit availability to allow for unscheduled outages at the stations, based on recent data from NP's system. The total long term production from all 19 systems, assuming ideal operation, was 457 GWh/yr.

The normal production was estimated by adjusting the total long term average annual production by factors to account for station service and practical operation. These two adjustments lead to a normal production estimate of 423 GWh/yr.

The station service adjustment accounts for energy consumed at the station which is therefore not available for sale. It was based on recent NP station service data. The adjustment for practical operation accounts for the difference between simulated ideal operation of the gates and units and realistic operational limitations. Such limitations include the inaccessibility of control gates and the electrical grid requirements imposed upon generating units. In the case of gate operation, it is not practical at many NP reservoirs to make daily or even weekly adjustments for reasons such as personnel safety, weather, or cost-effectiveness. This limitation can affect spill volumes and unit operating efficiency. Electrical grid requirements such as winter storage reserves and load restrictions during local power outages can have similar impacts on production.

This study recommends use of an annual normal production for the entire NP hydroelectric system of 423 GWh/yr. For comparison, the normal production currently used by NP is 431 GWh/yr. Each year the estimate should be revised to reflect any scheduled outages in the coming year that may affect generation, as well as any physical changes to the facilities over the preceding year. Scheduled outages could lead to spill or to deferral of generation to a later year. Physical changes to the facilities could temporarily or permanently increase cr decrease the expected generation.

In addition to this annual adjustment, NP should undertake a formal review of the normal production estimate in approximately five years. This review would incorporate new data available for each system as well as any revised operating constraints or procedures, and would confirm that annual adjustments for physical changes had been made appropriately. It would also allow for revision of the adjustment factor to account for the practicalities of operation, based on operating data.

1 Introduction

In June, 2000 Newfoundland Power (NP) engaged the services of Acres International (Acres) to estimate the normal production for its hydroelectric resources in Newfoundland. This report documents the analyses required to determine the normal production 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 stations is summarized in Table 1.1. The nameplate capacities provided in this table have been adjusted for unit upgrades since initial commissioning and for known unit limitation. Figure 1.1 shows the locations of the stations.

NP's hydroelectric energy generation makes up about nine percent of its total energy sales to consumers in Newfoundland. The remainder is purchased from Newfoundland and Labrador Hydro (NLH). The amount of energy that can be generated from the hydroelectric resources in a given year depends largely on weather conditions, particularly the amount and pattern of precipitation. In wet years it could be expected that the energy generation would be higher than average and the amount of energy purchased from NLH would be lower, and vice versa in dry years. There would therefore be a savings to NP in energy purchased from NLH during wet years and an extra cost for energy during dry years, as compared to the average.

In order to avoid large fluctuations in the rate to the consumer for electricity, NP compares its hydroelectric production each year to the expected normal production. The normal production represents the long term average annual generation available for sale to consumers from NP hydroelectric systems. The Hydro Equalization Reserve is maintained by Newfoundland Power (by order of the Board of Commissioners of Public Utilities) to normalize the company's purchased power costs with respect to variations in hydroelectric production.

The purpose of the present study was to provide a revised estimate of this expected normal production for NP's total hydroelectric system.

Chapter 2 of this report describes the approach and methodology, Chapters 3 to 21 describe the 19 individual hydroelectric systems and the development of the estimate of the long term production for each, and Chapter 22 provides an overall estimate of the normal production for the total NP hydroelectric system.

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

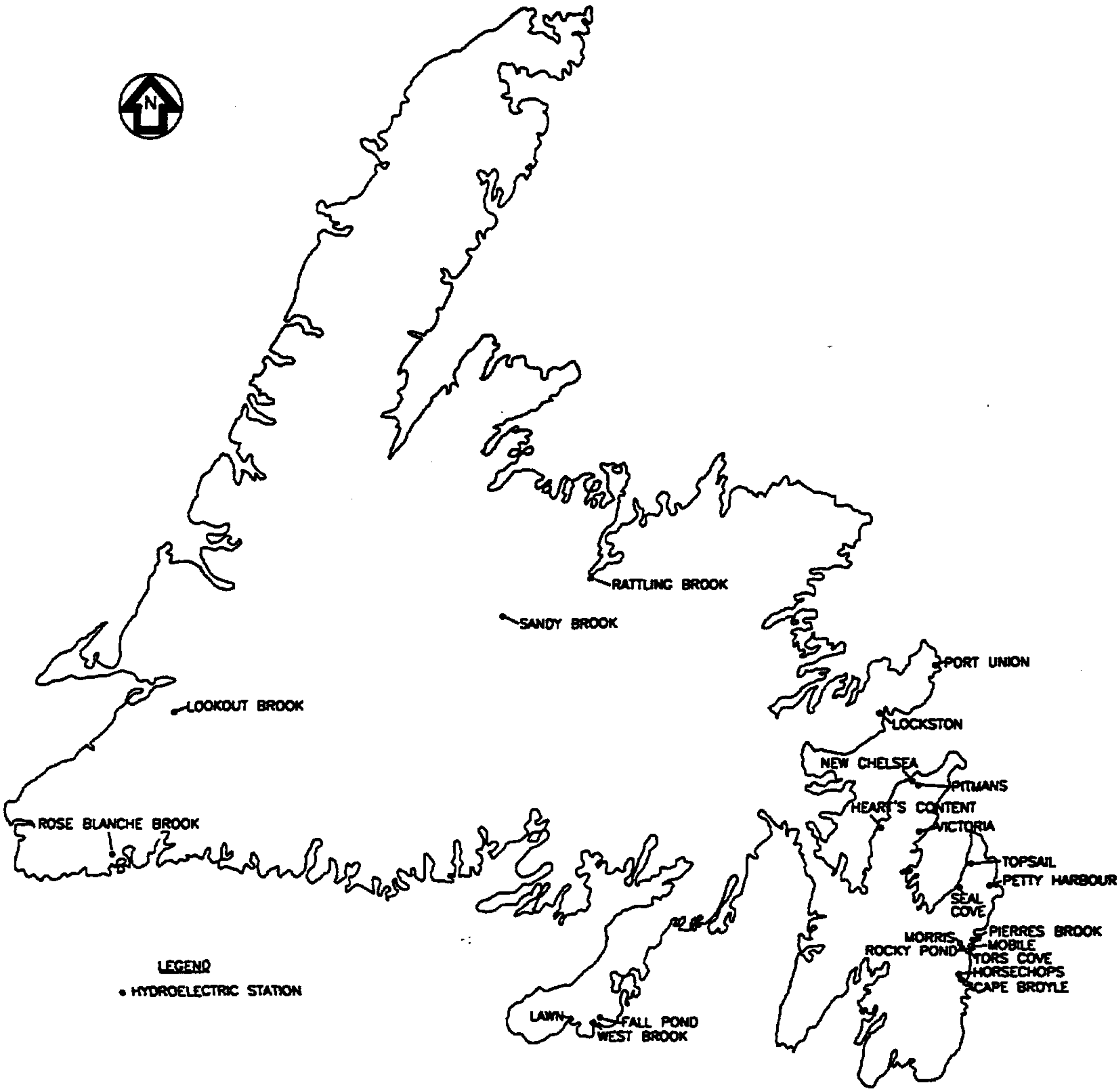


Fig. 1.1

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

LOCATIONS OF HYDROELECTRIC SYSTEMS

2 Methodology

The approach to the study was as follows.

- Set up a computer simulation model of each system using Acres Reservoir Simulation Package (ARSP).
- Develop inflow sequences (hydrology) as input to computer model.
- Compare the results of simulated reservoir levels and generation to recorded data for two selected years.
- Modify input as required to simulate long term operation.
- Estimate long term average annual production for each system.
- Estimate normal production for the entire NP hydroelectric system.

The methodology used for each of these tasks is described below.

2.1 Set Up Computer Model

The model chosen to simulate the long term production of NP's hydroelectric systems was ARSP. ARSP uses a simplified network of channels, reservoirs, nodes (connecting points for channels), structures, and generating stations to represent a water system. This model was first developed in the late 1970's and has been used extensively for estimating power and energy output from hydroelectric systems in Canada and around the world. A detailed description of the ARSP model is provided in Appendix A. The model takes daily inflows and simulates the use of the water to generate energy, based on various physical and operational constraints. The portion of the inflow not used for generation is either stored or spilled.

ARSP model schematics were developed for each of NP's hydroelectric systems. These schematics identified the interconnections between the different channels, reservoirs, and stations and served as the starting point to defining the information required for setting up each ARSP model. They also identified the required breakdown of basins (watersheds) into subbasins. The schematic and a description of each system is provided in the chapter for each system.

The input data required to set up the model include

- inflow sequences (daily flows into each subbasin);
- physical data

    - reservoir characteristics (operating range and storage curves);
    - generating station characteristics (capacities and unit efficiencies);
    - structure characteristics (spillway and gated outlet rating curves);
- operating procedures (e.g., unit dispatch, and operating reservoir levels); and
- other constraints (e.g., consumptive withdrawals and environmental flow requirements).

The first item, development of the inflow sequences, required some analysis as part of the present study and is therefore presented in more detail in Section 2.2. The information on the physical data, as well as other constraints, was provided by NP. The quality of this information varied, and sometimes there were inconsistencies among sources. A careful review of the data was done as part of this study, to ensure that the best available information was used. In some cases, field programs were conducted to fill data gaps.

The operating procedures were provided by NP in the form of plant operating guidelines for each system. The guidelines for each system were issued over the last three to four years to formalize procedures previously in place or to implement new procedures to reflect changed conditions. The guidelines usually specify the order of loading of the different units and the most efficient and maximum loads. They also identify reservoir constraints, such as maximum and minimum levels, as well as particular seasonal levels if necessary. In some cases they also provide some qualitative guidelines on reservoir and gate operation.

ARSP requires specific instructions on how to allocate water among reservoirs and units. This is accomplished using a penalty system on flows and storage zones. Operating on a daily time step, the model notes the inflows available on a given day, the state of storage in the reservoirs, and any constraints, and then simulates the operation of gates and plants according to the specific instructions. The NP guidelines were therefore interpreted according to the perceived intent in order to provide specific instructions to the model. The zones and penalties were adjusted until the intent of NP's guidelines was reflected in the simulated operation.

Each individual system chapter quotes the NP guidelines, and then describes their interpretation in the model of that system.

2.2 Develop Inflow Sequences

Simulation of production from hydroelectric systems requires an inflow sequence for each subbasin. These sequences are used in the model as the inflows to each of the reservoirs or nodes in the system, as shown in the system schematics. The time step for analysis, and therefore for the inflow sequences, varies according to the physical characteristics (particularly storage) of the system; for NP's systems, a sequence of daily inflows is required.

There are three basic approaches that are typically used in developing an inflow sequence. The choice usually depends on the type and quality of data available.

- Approach 1: Use backcalculated inflows from generation and water level data.
- Approach 2: Use precipitation and temperature data, assuming that a relationship has been or can be developed between precipitation and runoff; the sequence is then produced by simulating runoff for the required period from climate data.
- Approach 3: Select a basin with suitable characteristics from the Environment Canada (EC) network of stations and adjust the daily flows from the data base to represent inflows to the basin of interest.

The first approach requires a good long term data base of daily generation and water levels in all reservoirs, so that inflows and outflows at all points of interest in the basin can be calculated. Such a database is not available for NP's systems; in fact it would be unusual for small producers such as NP to have kept such a data base, due to the difficulties of frequent monitoring of water levels in back country storage ponds.

The second approach, using climate data (precipitation and temperature), is described here for completeness, since there is even less information than for the first approach. Developing a precipitation-runoff relationship requires a good network of climate stations with long term records located in or near the basins, with good flow data from the same or adjacent basins. In addition, using precipitation models requires estimating runoff from snowmelt, an important component of flow in Newfoundland, thus adding complexity. The network of climate stations in Newfoundland is sparse, and most of the stations are located in communities along the coast, rather than in the upper parts of the basin where the runoff originates.

There are no climate stations in any of NP's systems, except at some of the coastal communities near the powerhouses themselves.

The third approach, using EC hydrometric data from nearby gauged rivers, is the most appropriate for the present analysis. This section describes the methodology and results for NP's systems based on this data source.

The approach taken was

- to estimate the mean annual runoff (MAR) of each system;
- to select a suitable record from an EC hydrometric station to be used for patterning; and
- to develop the inflow sequences by adjusting the record of daily flows to account for differences in drainage area and relative wetness (represented by MAR).

2.2.1 Estimation of MAR

Mean annual runoff is a measure of the wetness of a basin; it determines the total annual flow volume available from a given drainage area. MAR is the average depth of the effective precipitation (total precipitation minus losses in evapotranspiration) over a basin. For the basins gauged by EC, it can be calculated directly from the average annual flow and the drainage area. For ungauged basins, it can be estimated using MAR's from nearby EC basins.

Since NP's systems are all ungauged, the MAR's from nearby EC basins, together with a knowledge of basin location and orientation, were used to estimate the MAR. Water resource studies for various areas of the island prepared for the provincial Department of Environment and Labour were also consulted.

2.2.2 Selection of EC Record for Patterning

The flows used by a hydroelectric station for generating energy vary not only in the overall volume of water available, but also in inflow patterns from month to month and day to day. Given the same total flow volume and storage capacity, basins that have more variability daily or seasonally will generally have lower energy production than basins that have a more even distribution of flows. It is therefore important when selecting a record from a gauged basin to choose one that is likely to have a pattern similar to the system of interest.

The main concern when developing an inflow sequence to be used for simulating long term production is not whether the flow was exactly as estimated on any particular day, but whether on a daily basis the estimated sequence represents the ups and downs of flows that can be expected over the long term.

A review of the characteristic high and low values for the basins with EC stations on the Avalon Peninsula from previous flow duration curve analysis work by Acres showed that these characteristic values were similar for all stations. The records to be used for patterning were therefore chosen on the basis of proximity and orientation, since it can be expected that basins in the same area with a similar orientation with respect to weather systems would have similar runoff patterns.

The selection of records to be used for patterning for systems on the rest of the island was similarly made considering high and low flow characteristics as well as location and orientation of the basins.

For each system, a record from a nearby EC station was selected for patterning. The sequence developed from this record is referred to as the primary inflow sequence. A second record was usually also identified for sensitivity analysis, and the resulting sequence is referred to as the sensitivity inflow sequence. In cases where an EC station is located near an NP system with no other suitable nearby EC stations, only the primary inflow sequence was used with no sensitivity analysis. In most of those cases the MAR was assumed to be the same as that of the EC basin.

2.2.3 Selection of Length of Sequence

The length of the inflow sequence is limited by the length of the EC record used for patterning. Techniques are available for developing synthetic records by correlation and extension, but they generally maintain the statistics of the same data sets, so there is no particular advantage in applying such techniques in this study.

In general, a long record is preferred over a shorter record for power and energy analysis, to ensure that a full range of wet, average and dry conditions is modelled. In Newfoundland, there are few good stations that have been in place more than 15 to 20 years; however, in the early 1980s EC expanded its network considerably, adding over a dozen stations on the Avalon Peninsula alone. These records provide valuable information for estimating MAR, and offer more choice in the selection of a record for patterning.

After review of the records, a 15 year sequence based on historic years 1984 to 1998 was selected. This period contains representative wet and dry years, and the average of the 15 years is similar to the average for a longer period (at stations where the records are long enough to allow comparison). For each of NP's systems there is at least one station in the region with a suitable record for patterning, having data for most of this 15 year period. In a few cases, the records used for patterning required extension by a year or two to provide the full length for the inflow sequence. In these cases, records from nearby stations were reviewed, and the one with the best correlation with the selected station was used.

As a check, where an EC record used for patterning was available for significantly longer than the 15 year period from 1984 to 1998, one of the simulation models using that gauge was tested using the full period of record. For the Topsail and Seal Cove stations on the Avalon Peninsula, this check confirmed that the 15 year period was representative of the longer-term inflows. The same check when conducted for the Rose Blanche Brook station (using the record for the EC station at Isle Aux Morts River) indicated that the period from 1984 to 1998 was slightly drier than the entire 36 year period of record available at that station. For consistency however, the same 15 year period was used to estimate the long term production for this station.

2.2.4 Information for Sequence Development

Table 2.1 shows the estimated MAR for each of NP's systems, together with the EC station record to be used for patterning. The MAR and drainage area (DA) for the EC stations are provided to allow proration to NP basins (and subbasins) of different sizes. To obtain the required inflow sequence, each daily flow is prorated by MAR and by DA (that is, multiplied by the ratio of the MAR's and by the ratio of the DA's).

The information required for extending an EC record where required is also provided in the notes to the table.

Table 2.1
Hydrological Information

Newfoundland Power System		Primary EC Gauge			Sensitivity EC Gauge		
Name	MAR (mm)	Name	15 yr MAR	DA (km^2)	Name	15 yr MAR	DA (km^2)
HorseChops/ Cape Broyle	1600	ZM09 Sl Cove	1684	53.6	ZN01 NWBrk[1]	1832	53.3
Rattling Brook	900	YO06 Peters R	801	177	YO08 Gt Rattlg	883	773
Morris/ Mobile	1400	ZM09 Sl Cove	1684	53.6	ZM16 South R	1332	17.3
Rocky Pond/ Tors Cove	1500	ZM09 Sl Cove	1684	53.6	ZM16 South R	1332	17.3
Lookout Brook	1250	ZA01 Ltl Bar[2]	1008	343	ZA02 Highlds	1123	72.0
Sandy	875	YO08 Gt Rattlg	883	773	YO06 Peters R	801	177
Pierres Brook	1300	ZM16 South R	1332	17.3	ZM08 Wat Klb	1293	52.7
Rose Blanche	2089	ZB01 IaMorts	2089	205	None	-	-
Petty Harbour	1300	ZM08 Wat Klb	1293	52.7	ZM16 South R	1332	17.3
New Chelsea/ Pitmans	1150	ZL05 Big Brk[3]	1178	11.2	ZL04 Shrs B	949	28.9
Seal Cove	1200	ZM16 South R	1332	17.3	ZM06 NE Pond	1172	3.63
Topsail	1300	ZM16 South R	1332	17.3	ZM06 NE Pond	1172	3.63
Hearts Content	1150	ZL03 Sp Cove[4]	1128	10.8	ZL04 Shrs B	949	28.9
Lockston	1076	ZJ02 Salm Cv	1076	73.6	None	-	-

Newfoundland Power System		Primary EC Gauge			Sensitivity EC Gauge		
Name	MAR (mm)	Name	15 yr MAR	DA (km^2)	Name	15 yr MAR	DA (km^2)
Victoria	1150	ZL03 Sp Cove[4]	1128	10.8	ZL04 Shrs B	949	28.9
West Brook	1268	ZG03 Smnr Rv	1268	115	None	-	-
Port Union	1076	ZJ02 Salm Cv.	1076	73.6	None	-	-
Lawn	1268	ZG03 Smnr Rv	1268	115	None	-	-
Fall Pond	1268	ZG03 Smnr Rv	1268	115	None	-	-

Notes

1. Fill in 1996 - 1998 from Seal Cove Brook using ratio $Q_{NwBrk} = Q_{SlCv}*1.0695$
2. Fill in 1998 from Highlands using ratio $Q_{LdBar} = Q_{Hlds}*3.5799$. For 1997, use Jan-May data as measured, and fill in June - December using ratio $Q_{LdBar} = Q_{hlds}*3.4153$.
3. Fill in 1984 from Spout Cove Brook (ZL03) using ratio $Q_{BigBrk} = Q_{SpCv}*1.0834$
4. Fill in 1997 and 1998 using ratio $Q_{SpCv} = Q_{BigBrook}*0.95714$.

2.3 Compare Simulated and Recorded Results for Selected Years

With the models set up and the inflow sequences developed, the next step was to ensure that the models were operating correctly. NP selected two years for each system for which good data were available. These provided a basis for comparing simulated and recorded generation and water levels. The purpose of the comparisons was to ensure that the models were correctly representing both the physical and operational characteristics of the system.

Because the model operates strictly according to the rules provided, whereas NP can be more flexible in its operation in response to day-to-day practical concerns, exact matches were not expected.

The differences in the estimates of annual generation for the comparison years can arise from three sources,

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

In general, the simulated generation from a model is expected to be greater than was recorded, because the model assumes that the second item listed above (system operation and water usage) is achieved flawlessly. NP has continuously improved its operating practices in an effort to narrow this gap, particularly during 1997/98 with the introduction of formal plant operating guidelines. However, it is difficult, if not impossible, to accomplish perfect operation in practice. Further discussion regarding the practicalities of hydroelectric system operations may be found in Chapter 22. In some cases the other two sources of discrepancies (assumed inflow hydrology and inaccurate assumptions) may also cause the model to underestimate or overestimate generation.

Each of the possible sources of the differences is briefly discussed below.

Hydrology (Inflows)

As described in Section 2.2, the inflow sequences were derived from EC records for nearby basins. Even where two basins are immediately adjacent, the flows into one river will not be identical to the flows into another; local conditions such as topography and soil type can cause one river to have higher or lower flows than anticipated. Even two rivers with the same long term average flow will have differences in the variation of flows from one day to another, and from one year to the next. As long as the reference sequence has a similar pattern of wet and dry periods, and has a similar long term average flow, it can be used to provide a suitable estimate of the long term production. When it is used for direct comparison of a selected year, however, the simulated and recorded generation may show differences due to hydrologic variability.

Differences in Water Use

For most systems, much of the difference between simulated and recorded annual results is attributable to differences in water use. The model assumes perfect operation of units and reservoirs according to the specified operating procedures. The two most important operating assumptions affecting generation comparisons are as follows.

- Ideal operation of the unit(s): In the model, the unit or units always operate exactly at 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.

Assumed Data

Lastly, although the models are set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses, or estimates of efficiency, or differences in such physical characteristics as storage volumes, elevations of spillway sills, and gate discharge capacities. The evaluation of the comparison years also assumes that the water level and generation records are completely accurate.

2.4 Estimate of Normal Production

Once the comparison of recorded and simulated values showed that the models were providing a correct representation of each system, the operation of each system was simulated over the longer term. The models developed for the comparison runs were modified if required to account for any changes made to the system since the comparison years. The inflow sequence providing the better estimate, either primary or sensitivity, was selected to estimate the long term production.

The simulation model runs used to estimate long term production also considered a reduction in plant availability to account for unscheduled unit outages. An availability factor of 0.95 was applied to all NP generating stations when calculating the normal production using the models. This factor was based on comprehensive unit availability data collected by NP since May 1998. The allowance for five percent unscheduled downtime is indicative of the average percentage of total annual hours that NP units were unavailable over this 2-year period for any reason except for scheduled outages. Scheduled outages are therefore not considered in the estimated normal production. It is assumed that such outages can be planned to coincide with periods of low inflow. If a scheduled outage is expected to result in spill or a deferral of generation from one calendar year to the next, the estimated normal hydro production for that year would be adjusted accordingly.

The models were then used to estimate the average production over a 15 year reference period, assuming perfect operation. The final estimate of expected normal production was made by taking the perfect operation estimate, factoring that result to account for the practicalities of operation and then subtracting station service. Further discussion regarding the estimation of station service consumption and the factor to account for the practicalities of operation is provided in Chapter 22.

The estimate of long term production for each system is presented in Chapters 3 to 21. The estimate of normal production for the total NP hydroelectric system is provided in Chapter 22.

3 Horsechops/Cape Broyle Hydroelectric System

The long term production for the Horsechops/Cape Broyle Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequence, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

The estimated long term production of the Horsechops/Cape Broyle system provided in this report is an update of previous preliminary work carried out for NP by Acres in 1999.

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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. The inflow sequence for the Horsechops/Cape Broyle system was generated by prorating the recorded flows at a nearby hydrometric station by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The hydrometric station used to derive the subbasin inflows for the Horsechops/Cape Broyle system was Seal Cove Brook near Cappahayden (02ZM009). The station has a drainage area of 53.6 km^2. As noted in Section 3.4, the record for the sensitivity inflow sequence did not include the comparison years, and was therefore not used.

The mean annual runoff for the Seal Cove Brook record for the reference period was calculated to be 1684 mm/yr. The mean annual runoff of the Horsechops/Cape Broyle basin was estimated during this study to be 1600 mm/yr.

The inflow sequence for the simulation was developed by multiplying the Seal Cove Brook flows by the ratios of Horsechops/Cape Broyle basin mean annual runoff and subbasin drainage area to Seal Cove Brook mean annual runoff and drainage area.

3.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1996 and 1998. The development of the inflow sequence used for the model was described in Section 3.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years, and for the estimate of the long term production, where different. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 2 of this report.

3.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Horsechops/Cape Broyle system

- Blackwoods Ponds;
- Mount Carmel Pond;
- Horsechops Forebay; and
- Cape Broyle Forebay.

Different sources of information on reservoir characteristics were provided by NP but all were generally in agreement.

The storage curve volumes used in the model were converted from the NP energy storage tables for the Horsechops/Cape Broyle system. These tables treat East Blackwoods and Fourth Blackwoods Ponds as a single reservoir, and Northwest Blackwoods Pond as a separate reservoir. However, according to construction drawings and recorded reservoir levels, flows between the three are effectively unregulated, the storage is practically contiguous and the water surface elevation is approximately uniform through all three ponds. Thus for the purpose of this study, the volumes were combined and the three Blackwoods Ponds were modelled as a single reservoir.

Other bodies of water in the system, such as Ragged Hills Pond and the chain of lakes between the Fourth Blackwoods Pond Canal and Mount Carmel Pond, were deemed by NP to have negligible storage and were omitted from the model.

3.3.2 Generating Station Characteristics

Characteristics for the Horsechops Generating Station were based on information provided by NP. In 1997, the turbine runner was replaced and other unit appurtenances were overhauled. This increased the unit efficiency and capacity (from 7.6 MW to the present 8.3 MW). The characteristics of the overhauled unit were obtained from current NP plant operating guidelines and information from the turbine manufacturer. The characteristics of the unit prior to 1997 were estimated from earlier NP efficiency testing. The appropriate characteristics were used in the comparison runs for 1996 and 1998 The tailwater elevation was set to the elevation of Cape Broyle Forebay.

In 2000, the original woodstave penstock at Horsechops was to be replaced by a steel penstock. The head losses for both the woodstave structure and the steel structure were conservatively estimated from standard hydraulic equations, assuming operation between best efficiency and maximum flow. The estimated head loss for the woodstave penstock was used for both comparison runs, and the estimated head loss for the steel penstock was used for the long term production runs.

Characteristics for the Cape Broyle Generating Station were based primarily on data from efficiency testing undertaken by Acres for NP in 1997, supplemented by additional information from NP. The design head entered in the model was 55.6 m, the net head calculated at best efficiency load in the efficiency testing, instead of the rated net head. This was done so that the calculated efficiency values could be used directly in the model. The tailwater elevation is tidal, so an average elevation was assumed.

3.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- Blackwoods Ponds overflow spillways;
- Fourth Blackwoods Pond Canal;
- Mount Carmel Pond overflow spillway;
- Mount Carmel Pond gated outlet;
- Horsechops Forebay overflow spillway; and
- Cape Broyle Forebay overflow spillway.

Stage discharge curves were provided by NP for the Mount Carmel Pond, Horsechops Forebay and Cape Broyle Forebay spillways. In all other cases, curves were estimated from available information using standard hydraulic equations.

The Blackwoods Ponds spillways (Northwest Blackwoods, East Blackwoods and Fourth Blackwoods) were modelled as a single composite structure. The discharge capacities of the three spillways were combined into a single curve, which took into account the slight differences in elevations of the spillway crests. However, there is some uncertainty about the crest lengths and elevations. In general, values were taken from 1985 and 1989 dam safety studies, and the estimated discharge capacities were compared to flood routing calculations in the same studies to ensure consistency.

The West Ragged Hills spillway was omitted, since NP considered Ragged Hills Pond to have negligible storage, and there was insufficient information to model the inflow routing effects of this structure.

The Fourth Blackwoods Pond Canal is approximately 1.5 km long and has a stoplog structure with a concrete sill about 500 m downstream of the inlet. According to NP, current practice is to leave the structure open permanently, although the stoplogs have been in place in the past. Apparently, the concrete sill acts as a submerged weir and controls the outflow from Fourth Blackwoods Pond at low reservoir levels; at higher levels, channel control dominates. The relationship between the reservoir level and outflow was estimated from available information. Flow routing was used to estimate the outflows for two known reservoir levels obtained from NP level records and a field survey, respectively. A third data point was obtained from flood routing calculations in the dam safety studies. The data points were then used to estimate a stage discharge curve for the canal.

For the purpose of maintaining flow in the river reach downstream of Mount Carmel Pond for environmental reasons, the minimum flow through the gated outlet was set to 0.1 m^3/s, if water was available.

3.3.4 System Operation

NP's plant operating guidelines for the Horsechops/Cape Broyle system provide the following procedures.

1.) *Operate Horsechops at best efficiency unless spill will occur. Cape Broyle will have to operate for 20 hours for every 24 that Horsechops operates in order to keep the Cape Broyle reservoir constant with little inflow to Cape Broyle Pond.*
2.) *Need to keep water flowing from Mount Carmel in winter to prevent the canal from freezing up.*
3.) *Prior to spring runoff, Cape Broyle Pond should be lowered to 284.*
4.) *Both plants tend to experience low water trips when the weather turns colder because of frazil ice. Best to shut plants on a cold day to let the forebays ice over.*
5.) *Northwest doesn't have an outlet gate structure.*
6.) *Northwest, Ragged Hills Pond, Blackwoods Pond, and Fly Pond all spill out of the system. In the event of major inflows, it is better to open gates and allow the system to spill at Horsechops so the water can be used at Cape Broyle.*
7.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

These procedures, the information from the operator, and the recorded reservoir levels were used to develop the following operating strategy for the model.

- Leave the Fourth Blackwoods Pond Canal stoplog structure open, so that the Blackwoods Ponds discharge continuously according to the canal's stage discharge characteristics.
- Set the target water level of Horsechops Forebay at its upper operating level.
- Release water through the Mount Carmel Pond gated outlet as necessary to keep the Horsechops unit at best efficiency load.
- For the comparison runs, set the target level of Cape Broyle Forebay midway between its upper and lower operating levels. (This is consistent with NP recorded water levels for both years.) For the run to estimate long term production, set the target level to the upper operating elevation but draw down the level prior to the spring runoff.
- Operate the Cape Broyle unit at best efficiency as long as possible during each day, while maintaining the target level.
- If the combination of local inflow to Cape Broyle Forebay and flow from Horsechops Forebay is greater than the best efficiency flow of the Cape Broyle unit, or if the level of Cape Broyle Forebay is above the target level, bring the Cape Broyle unit to maximum load.
- If spill from Cape Broyle Forebay is predicted, close the Mount Carmel Pond gated outlet to minimum and reduce generation at Horsechops (but only if Mount Carmel Pond is below full supply level). There should be spill at Cape Broyle Forebay only when the unit is operating at maximum load and the forebay is above full supply level.
- If spill from Mount Carmel Pond is predicted (Mount Carmel Pond is at full supply level), open the gated outlet to bring the Horsechops unit to maximum load, and bring the Cape Broyle unit to maximum load as necessary.
- If the level of Horsechops Forebay is above the target level, operate the Horsechops unit at maximum load. There should be spill at Horsechops Forebay only if Mount Carmel Pond is at or above full supply level, the unit is operating at maximum load, and Horsechops Forebay is above full supply level.
- Maintain environmental releases as long as there is water.

Load reductions and shutdowns to avoid frazil ice formation are of short duration and were not modelled.

3.4 Model Comparison

The simulation model was run for the comparison years of 1996 and 1998. Figures 3.2 and 3.3 show the simulated and recorded monthly generation for these two years, for Horsechops and Cape Broyle, respectively. Only the primary inflow sequence was used because the sensitivity inflow record did not include these particular years.

As both figures show, the simulated generation generally follows the same pattern as the recorded generation. There are differences between simulated and recorded values both within each year, and in total annual generation. The within-year (month to month) differences are discussed in Section 3.4.1 below, followed by a discussion of the annual differences in Section 3.4.2.

3.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figures 3.2 and 3.3 are likely due to the combined effect of differences between actual and simulated system operation, and actual and assumed inflows.

Figures 3.4 and 3.5 show comparisons of storage in the main storage reservoirs, the Blackwoods Ponds and Mount Carmel Pond. According to NP, some of the recorded Blackwoods Ponds levels may have been estimated instead of observed on site (for example, when the same level was recorded for extended periods), and therefore may not be reliable. An examination of Figure 3.5 is more useful, since Mount Carmel Pond provides the majority of the total system storage and the recorded levels should be accurate.

When comparing to Figures 3.2 and 3.3, it may be seen that periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that water was being held in storage, rather than used for generation. Examples include July and October to December 1996, and June and July 1998.

June and July 1998 were noteworthy for a major six to seven week scheduled outage at Horsechops. During this time, water was stored in Mount Carmel Pond instead of being released for generation. This built up a large difference in stored water with respect to the simulated values, which persisted to the end of the year.

Reduced generation at Horsechops also resulted in a reduction at Cape Broyle because of the water being held in storage. In general, as may be seen by comparing the plots of in Figures 3.2 and 3.3, Horsechops acts as a constraint on total system generation by controlling the flows available to Cape Broyle.

As shown in Figures 3.6 and 3.7, there was some variation in the recorded level of the two forebays, but the simulated levels remained close to the recorded average.

The Horsechops/Cape Broyle basin is large and encompasses areas of varying hydrology and topography. When using inflows from other basins to approximate the hydrology of this basin, uncertainties will exist on a monthly basis as well as annually.

3.4.2 Differences in Annual Generation

Tables 3.1 and 3.2 summarize the annual energy generation for the two comparison years, for Horsechops and Cape Broyle, respectively. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were different from the recorded values. The adjustment takes account of the energy potential of the water in storage.

Table 3.1
Horsechops Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	39.9	49.1	35.3	41.2	17
1998	42.6	58.8	42.3	49.5	17

Table 3.2
Cape Broyle Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	31.8	39.0	28.8	33.8	17
1998	35.3	43.8	35.2	38.0	8

The difference between simulated and recorded total annual energy generation for the Horsechops/Cape Broyle system is approximately 17 percent in 1996 and 13 percent in 1998.

The kinds of operational differences described in Section 3.4.1, such as holding water back rather than generating, account for the differences in energy from month to month, but should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Horsechops/Cape Broyle system is briefly discussed below.

Hydrology
Overestimating the assumed inflows on an annual basis could lead to higher simulated generation. The hydrology of the Horsechops/Cape Broyle basin

may be more complex than the assumed inflows suggest. Compared to the basin of the Seal Cove Brook hydrometric station, the Horsechops/Cape Broyle basin is close to four times as large in area and more varied in topography, and has a different orientation. Precipitation patterns, mean annual runoff and topography and soil characteristics may vary from one subbasin to the next. The assumed inflows may overestimate runoff or underestimate spill in one or more subbasins. As well, the effective drainage area of the upper basin may be smaller than what has been estimated. With the flat, boggy terrain and flooding caused by the numerous diversion structures, there may be transient or alternative stream channels formed, or some catchment areas may not be adequately contained. Some precipitation falling on the drainage area delineated by NP may not be retained within the system.

The figures suggest some monthly differences between actual and simulated inflows, but there is not enough of a pattern to suggest changing the assumed mean annual runoff; nor is there enough evidence to do so without records of daily inflows or complete records of all spillway discharges.

Differences in Water Use

For the Horsechops/Cape Broyle system, the difference between simulated and recorded annual generation may also be due to differences in water management. The model assumes perfect operation of units and reservoirs according to the input operating strategy in Section 3.3.4. The two most important factors affecting generation are as follows.

- Ideal operation of the units: The units never operate at less than the most efficient load, although they do operate at higher loads if there is a risk of spill.
- Ideal operation of reservoirs and control gates to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels, and opens or closes gates as required to ensure perfect operation of the units and to minimize spill.

Decreased generation would result if the units were run at low efficiencies as a means of maintaining forebay levels or because of infrequent gate control at Mount Carmel Pond. It would also result if the stoplogs in the Fourth Blackwoods Pond Canal were periodically left in place, thereby reducing live storage and outflows from the Blackwoods Ponds, and increasing spill.

Total recorded spill was zero in 1996 and 305 MWh in 1998. No spill was simulated at either generating station in either comparison year. The 1998 recorded spill could be expected at Horsechops due to the length of the scheduled outage.

There may have been spills at the Blackwoods Ponds and West Ragged Hills spillways. Spills at these locations are generally not recorded. Simulated spill at the Blackwoods Ponds spillways amounted to 480 MWh in 1996 and 2320 MWh in 1998. Water levels in the Blackwoods Ponds can change quickly and spill events may often be missed, especially if the levels are not often monitored. As well, NP cautions that any estimates of recorded spill quantity and frequency are often inaccurate.

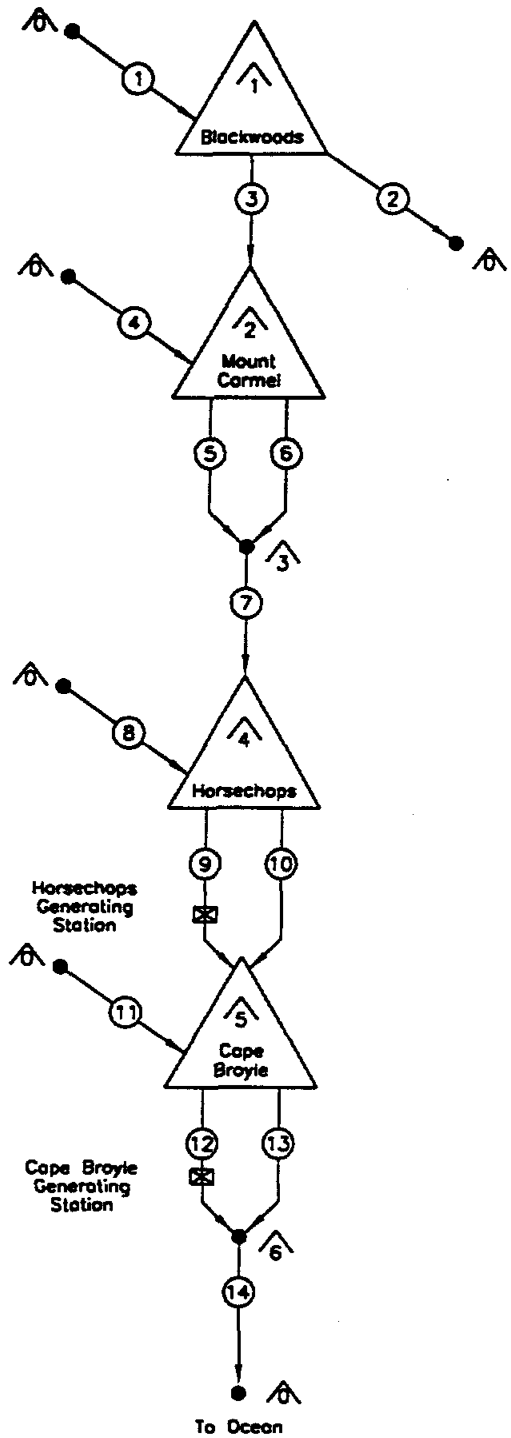
Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves.

In particular, the head losses and efficiency of the overhauled Horsechops unit have not yet been evaluated by efficiency testing. The storage capacity of the Blackwoods Ponds could be overestimated. Finally, some of the structures in the Blackwoods Ponds area may have small leaks, as suggested by previous dam inspections, which could lead to inflow losses.

3.5 Simulated Long Term Production

The system operation was simulated using the inflow sequence for the 15 year reference period to estimate the long term production for the Horsechops/Cape Broyle system. The result of this simulation was an estimate of long term production of 51.0 GWh/yr for the Horsechops station, and 38.1 GWh/yr for the Cape Broyle station, for a total of 89.1 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



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
WATER MANAGEMENT STUDY
HORSECHOPS/CAPE BROYLE ARSP MODEL SCHEMATIC

ACRES

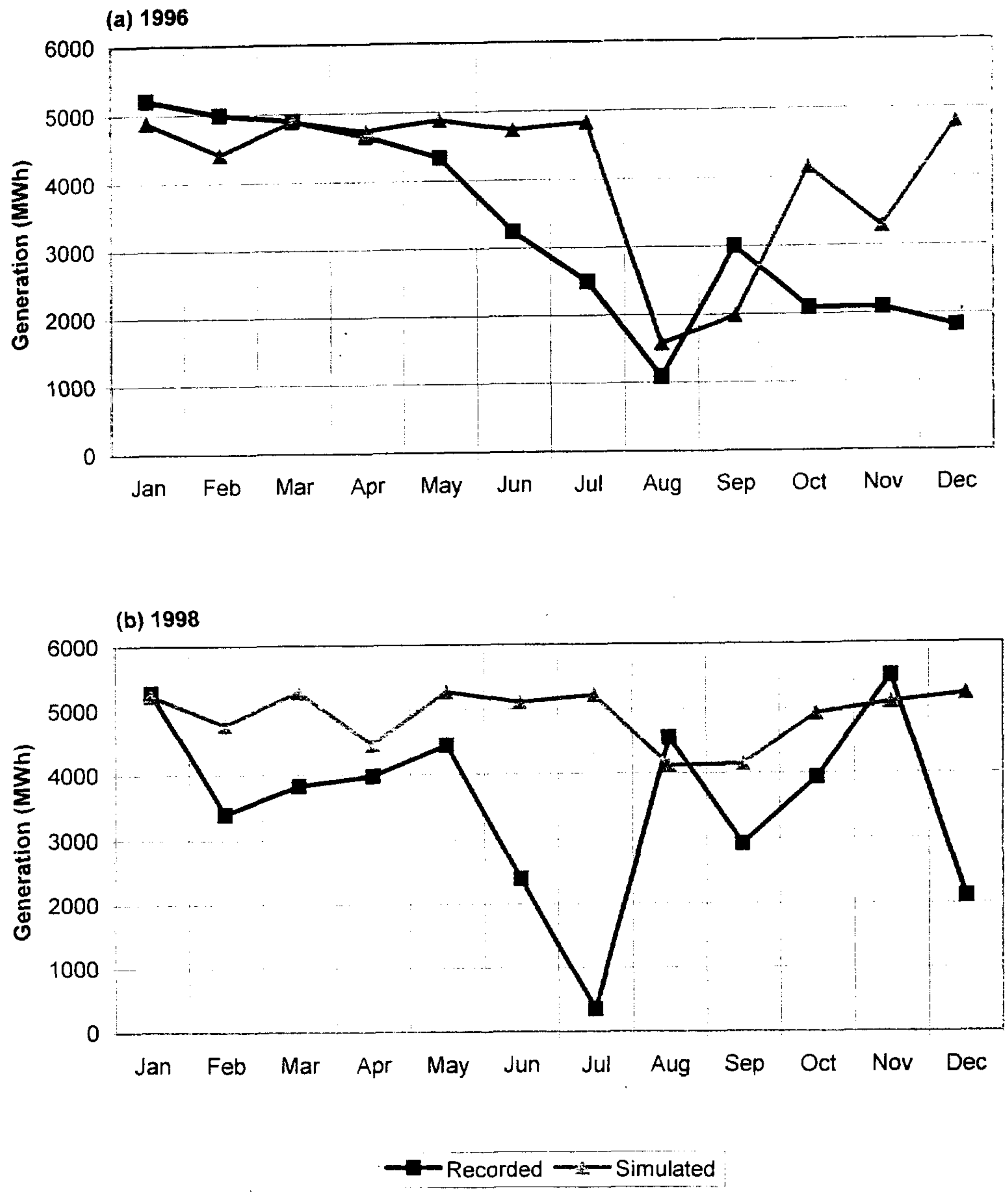


Fig. 3.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

HORSECHOPS GENERATION COMPARISON

ACRES

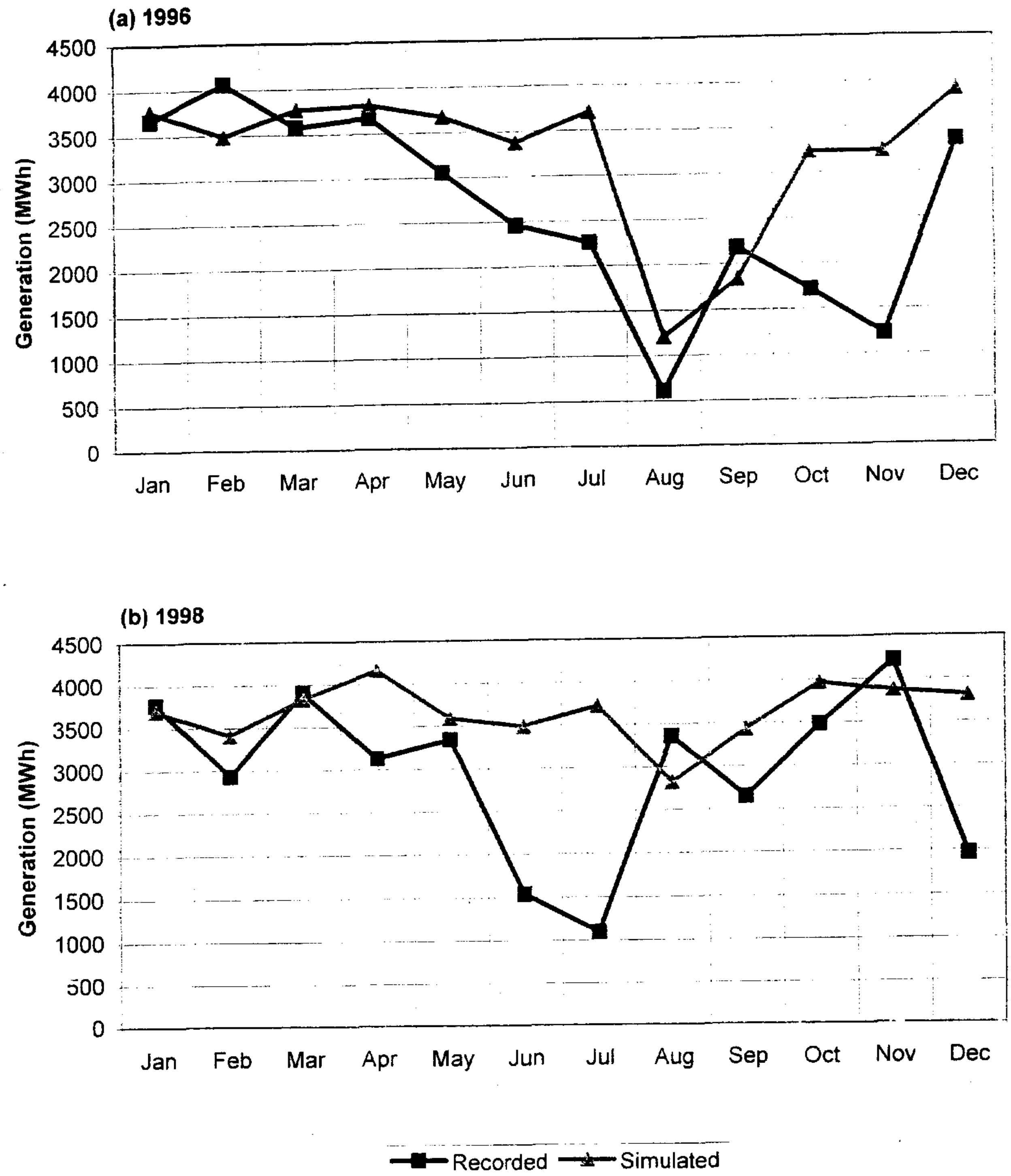


Fig. 3.3

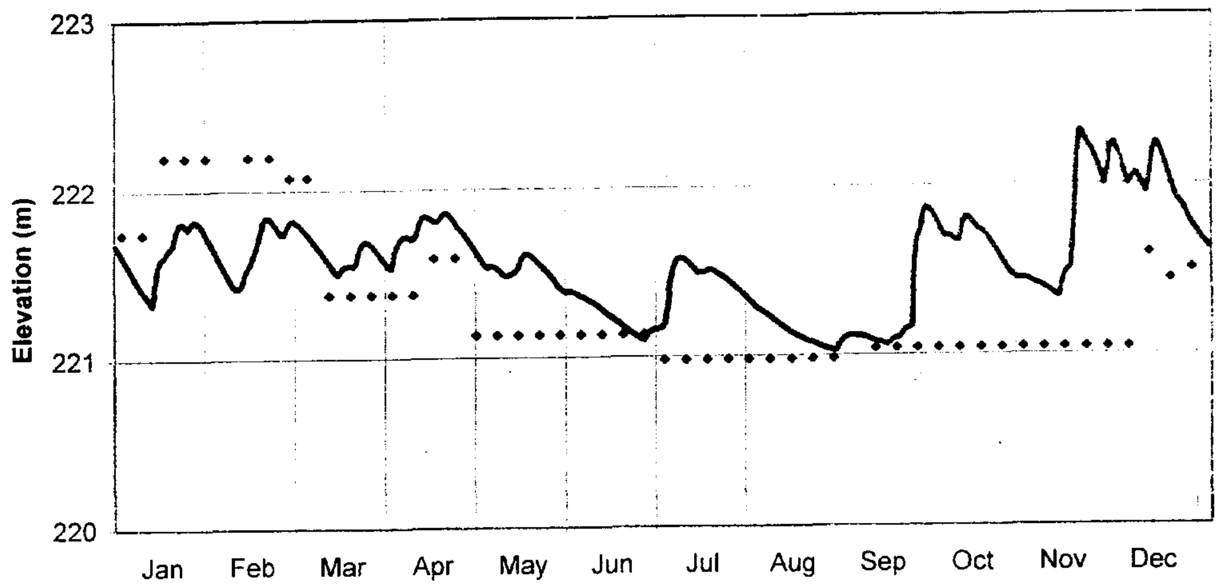
NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

CAPE BROYLE GENERATION COMPARISON

ACRES

(a) 1996



(b) 1998

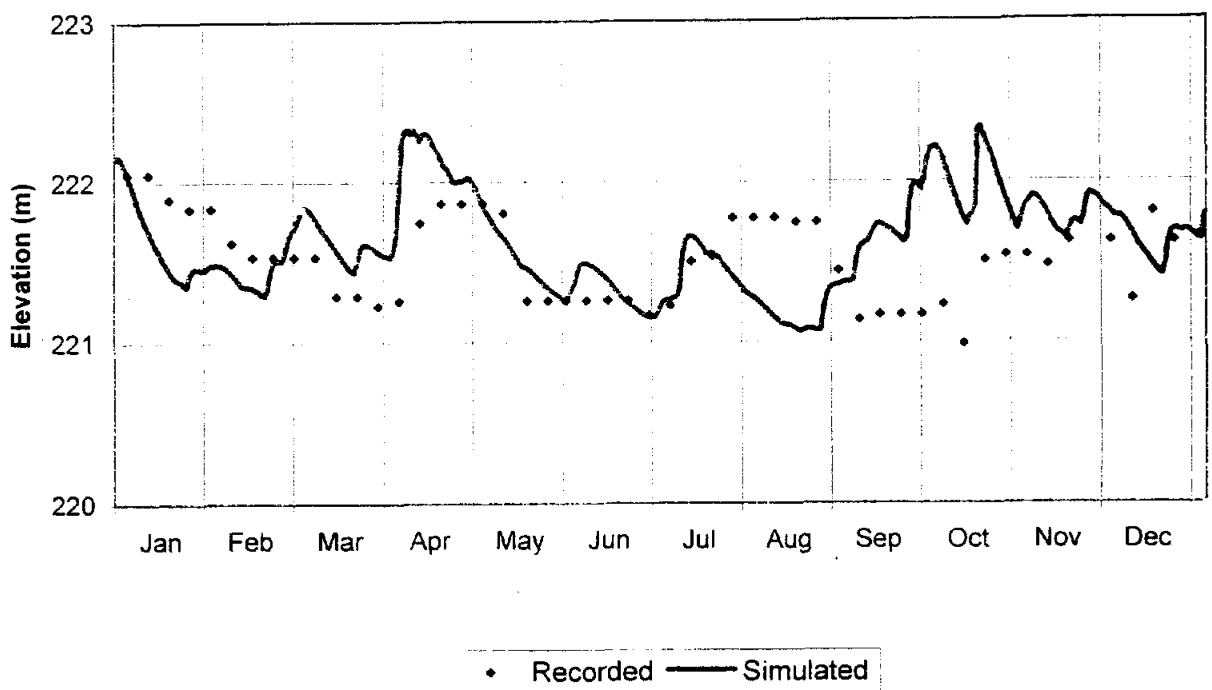


Fig. 3.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

BLACKWOODS PONDS STORAGE COMPARISON

ACRES

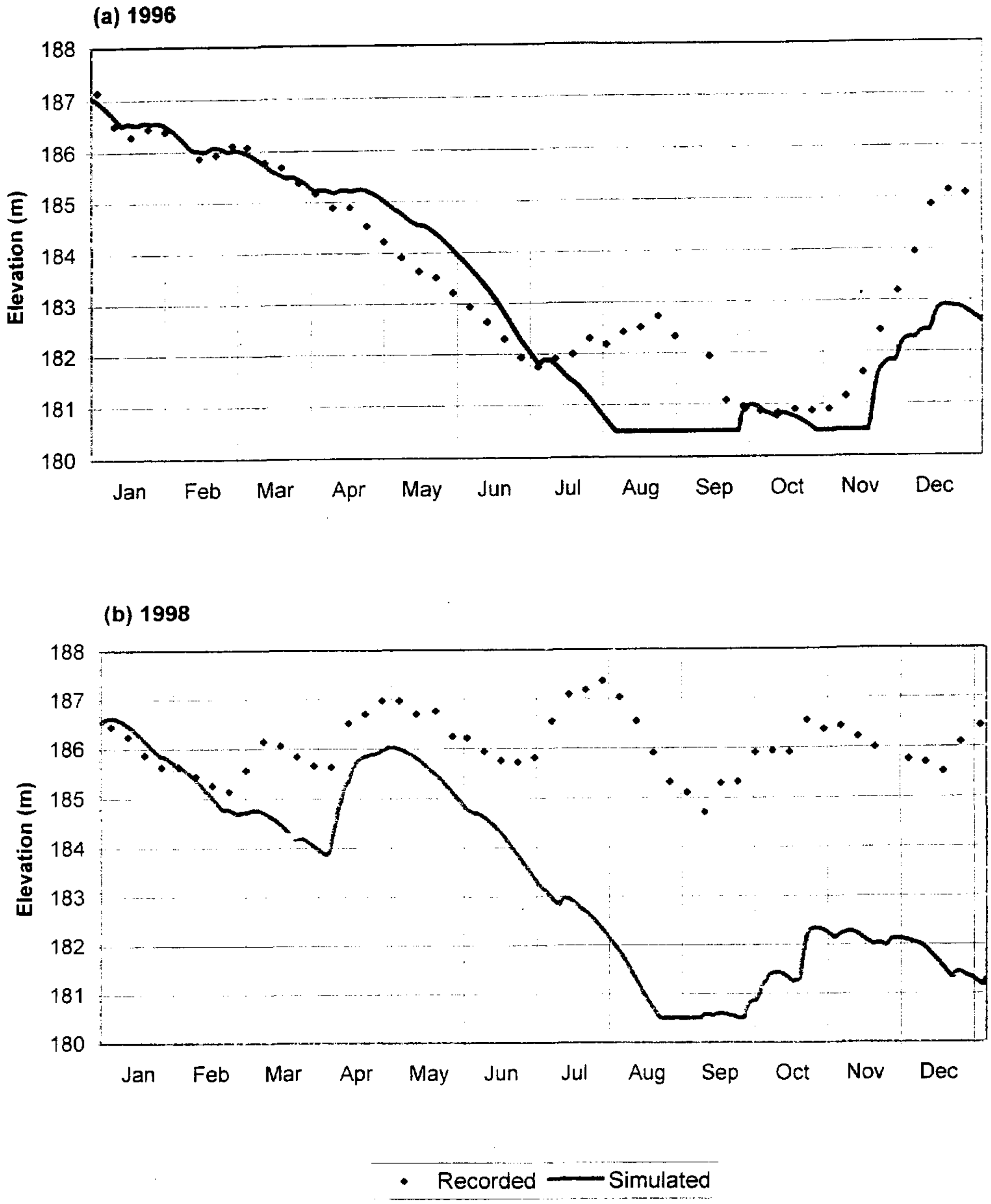


Fig. 3.5

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

MOUNT CARMEL POND STORAGE COMPARISON

ACRES

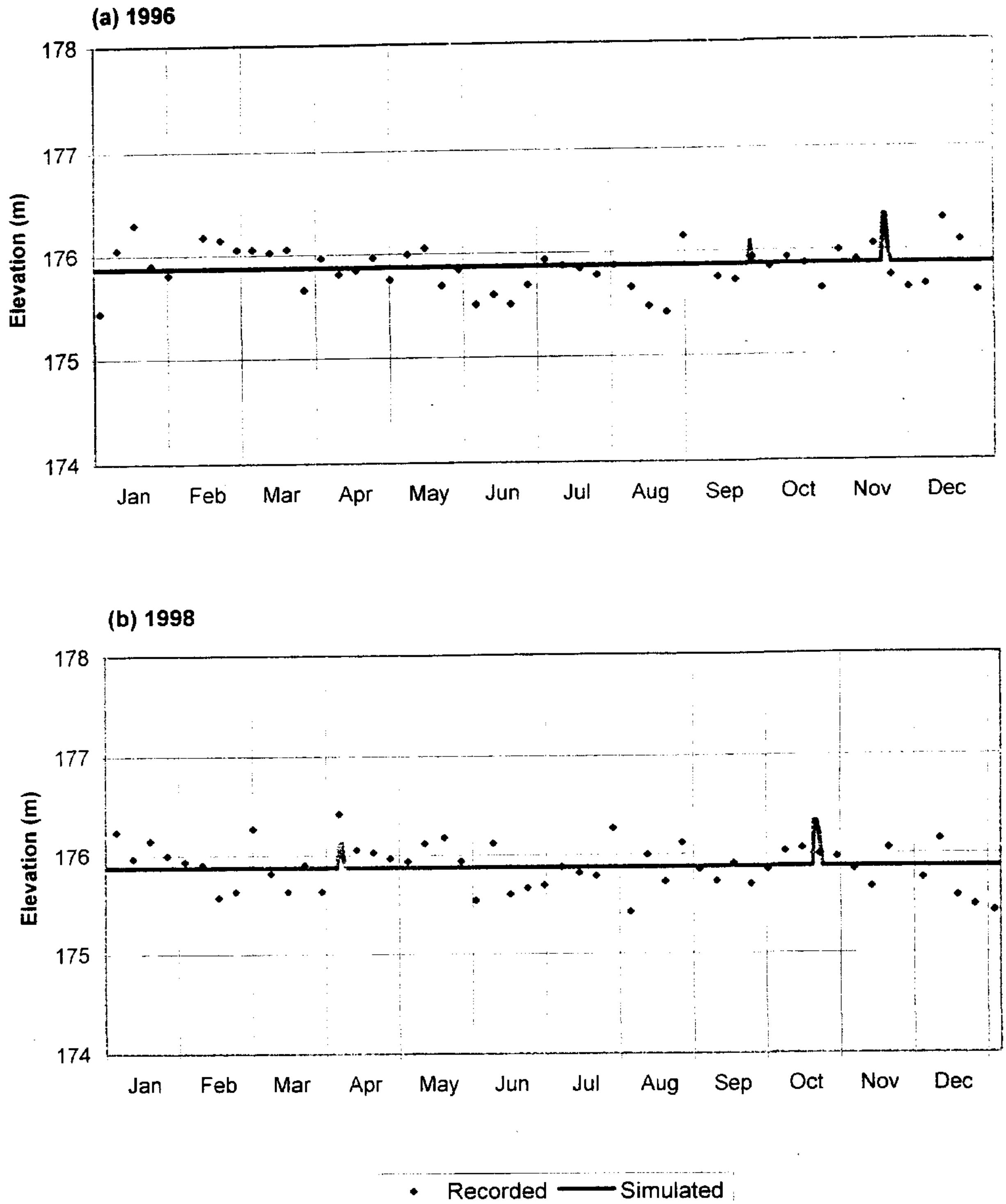


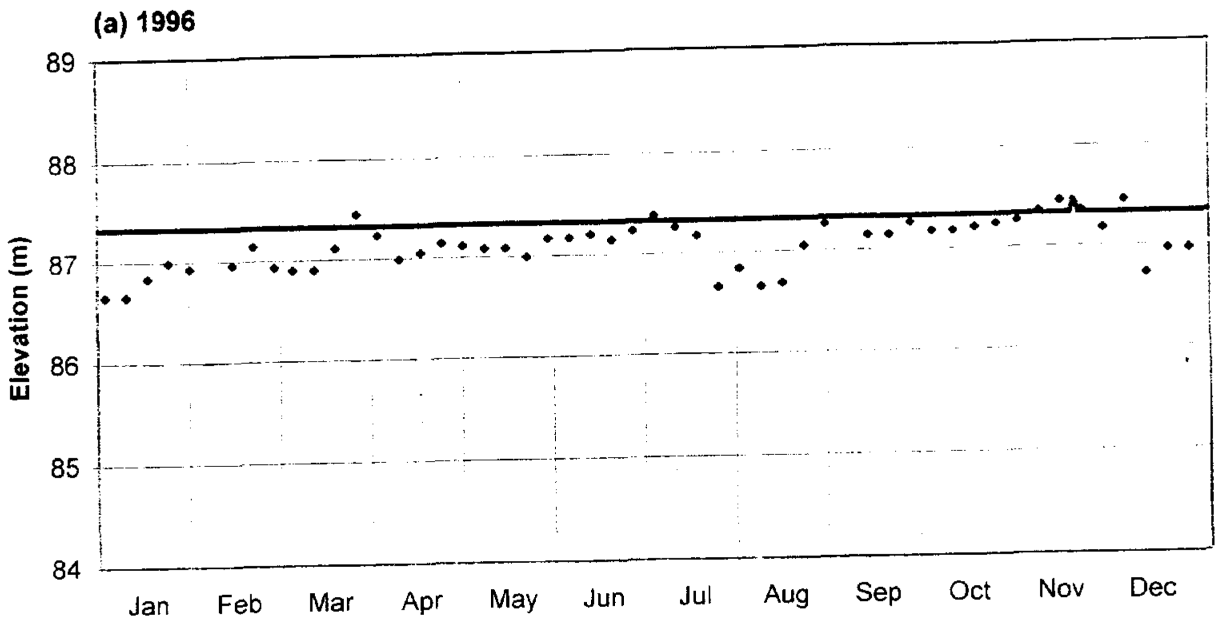
Fig. 3.6

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

HORSECHOPS FOREBAY STORAGE COMPARISON

ACRES



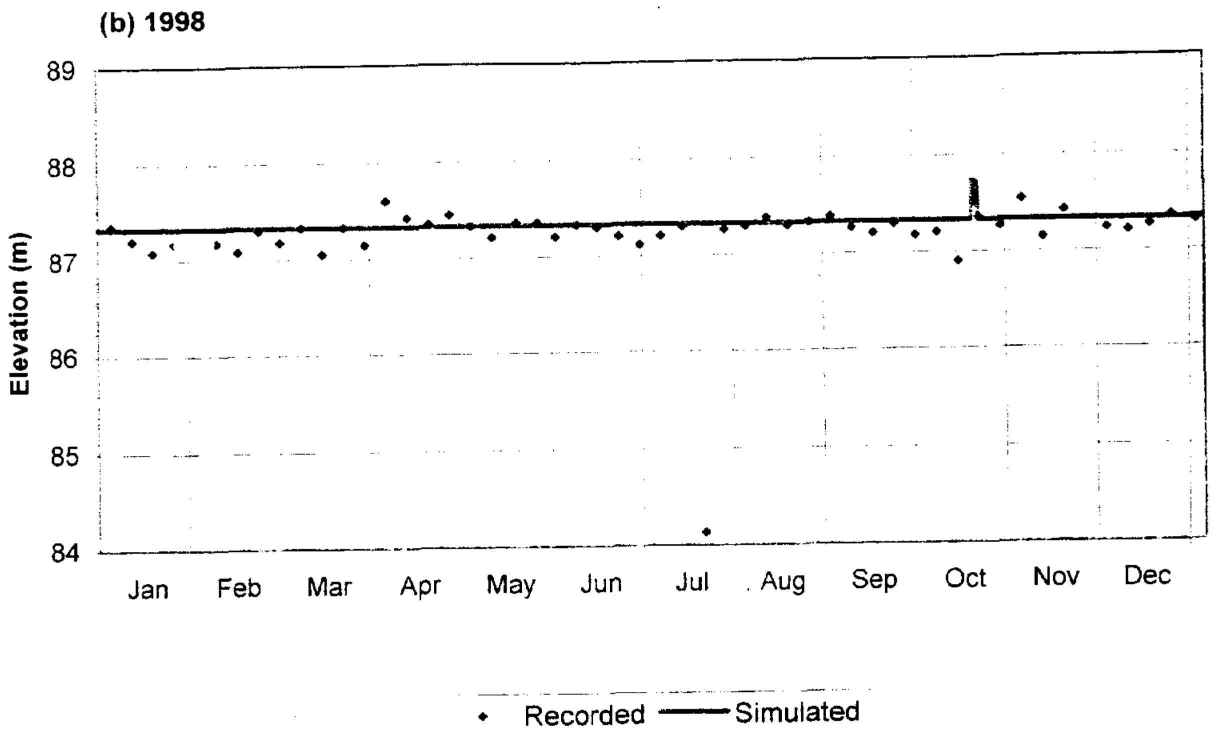


Fig. 3.7

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

CAPE BROYLE FOREBAY STORAGE COMPARISON

ACRES

4 Rattling Brook Hydroelectric System

The long term production for the Rattling Brook Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two to three selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. For each subbasin in the Rattling Brook system, an inflow sequence was derived by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The mean annual runoff was assumed to be the same for all subbasins, so the subbasin sequences differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Rattling Brook system were Peters River near Botwood (02YO006), and Great Rattling Brook above Tote River Confluence (02YO008). Peters River near Botwood was chosen as the primary gauge for deriving the Rattling Brook flows. The drainage area of Peters River is 177 km^2. Great Rattling Brook was used to prepare a second inflow sequence for sensitivity analysis. The drainage area of Great Rattling Brook is 773 km^2.

The mean annual runoff for the Peters River basin is estimated to be 801 mm/yr for the reference period, and the mean annual runoff of the Great Rattling Brook basin is estimated to be 883 mm/yr for the same period. The mean annual runoff of the Rattling Brook basin was initially estimated during this study to be 825 mm/yr. Following preliminary runs showing an underestimate of energy, the hydrology was reviewed and the estimate of mean annual runoff was increased to 900 mm/yr. This was based on some meteorological and hydrometric evidence that suggested that the Rattling Brook basin could be a local area of higher annual precipitation.

4.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1996 and 1997. The development of inflow sequences used for the model were described in Section 4.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and for the estimate of long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 2 of this report.

4.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Rattling Brook system

- Frozen Ocean Lake;
- Rattling/Amy's Lake; and
- Rattling Brook Forebay.

Storage curves for the reservoirs were provided by NP. Two sets of storage curves were provided for each of two upstream reservoirs in the Rattling Brook system. As a means of resolving the discrepancy, the lake areas were planimetered from the 1:50 000 scale mapping, and the curve which best represented the area at full supply level was used in the model.

4.3.2 Generating Station Characteristics

Generating station characteristics for the Rattling Brook station were based on data from efficiency testing undertaken by Acres for NP in 2000.

The two units have very similar characteristics when operating independently. When both units are operating, the head losses are significant. The two units were modelled as one, with best efficiency input as for one unit. Flow efficiency and flow head loss curves were used to model the characteristics of the combined operation at high flows. The modelled capacity was 11.3 MW, the maximum generation measured during the efficiency testing.

To account for the variation in penstock head losses as a function of the power flow, the fixed head loss value in the model input was set to zero, and the head losses were added to the values in the tailwater curve. Therefore, the tailwater curve does not represent physical water levels at the plant, but synthetic water levels used to account for the drop in net head due to head losses, in addition to the actual variation in tailwater level with flow.

4.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- 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.

In some cases multiple curves were provided for the same structure, perhaps reflecting outlets before and after replacement. In these cases curves were taken from previous modelling by NP, or were estimated using standard hydraulic equations.

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 was available.

4.3.4 System Operation

NP's plant operating guidelines for the Rattling Brook system provide the following procedures.

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.*
2.) *Rattling - Amy's must be kept at 368' or lower during winter months to keep ice from rafting up on the flashboards.*
3.) *Prior to spring runoff (March) Amy's & Frozen Ocean should be brought to minimum levels.*
4.) *Maintain constant head at Rattling Forebay by adjusting the gate at Amy's.*
5.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

These procedures, and the recorded reservoir levels, were used to develop the following operating strategy for the modelling.

- Set the target level at Frozen Ocean Lake at the lower bound of the operating range.
- Set the target level at Rattling/Amy's Lake at full supply level for most of the year, but with a gradual lowering to the lower bound of the operating range during spring, and at the level indicated in the guidelines for the winter.
- Set the forebay target level near the upper bound of the operating range given in the plant operating guidelines.
- If the forebay water level is below full supply level, operate the unit at best efficiency.
- Release water from Frozen Ocean Lake and Rattling/Amy's Lake to keep the unit operating at best efficiency, and to keep the forebay at its target level. (At times the use of storage is limited by the capacity of the outlet facilities.)
- If the water levels in Frozen Ocean Lake and Rattling/Amy's Lake approach their target levels, release water and increase generation above best efficiency if required.
- If the forebay level continues to rise, initiate spill.
- Maintain a minimum environmental release of 0.1 m^3/s (even if this leads to generation above best efficiency or spill downstream).

The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

4.4 Model Comparison

The years first selected by NP for the comparison runs were 1996 and 1997. When large discrepancies in production were noted, an additional year, 1994 was added. The simulation model was run for 1994, 1996 and 1997 using both the primary inflow sequence and the sensitivity inflow sequence. Figure 4.2 shows the simulated and recorded monthly generation for 1994 and 1996. The pattern was similar in 1997, so only the first two years are presented here.

As Figure 4.2 shows, the simulated generation is less than the recorded generation. In some months the pattern is similar but while the simulation models shows many months operating at best efficiency with one unit, the recorded values show that two units were operating for some time in most months.

There are differences between the recorded values both within each year, and also on an annual basis. The within-year variation is discussed in Section 4.4.1 below, followed by a discussion of the annual differences in Section 4.4.2.

4.4.1 Differences in Monthly Generation

Some of the differences in generation, as shown in Figure 4.2, can be explained by differences in operation. In late 1994, for instance the recorded generation is higher than the simulated. Figure 4.3 shows however, that the simulated water levels in Rattling/Amy's Lake are correspondingly higher, because water is being stored rather than used for generation. However, while the recorded generation in 1996 shows the same trend, the simulated water levels (as shown in Figure 4.4) are lower than recorded. The discussion of the discrepancies between the recorded and simulated generation and storage continues in Section 4.4.2.

Differences in the storage plots can be due to recorded data problems; this may be the case for Frozen Ocean Lake. Figure 4.4 shows that the simulations do not reproduce the recorded low water levels in Frozen Ocean Lake in 1994. The other two years have similar patterns. Since the site is remote, and operators are not required to frequently adjust the gate settings, it may be that the recorded levels are estimates rather than measured values.

4.4.2 Differences in Annual Generation

Table 4.1 summarizes the annual energy generation for the three comparison years. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 4.3 and 4.4). The adjustment takes account of the energy potential of the water in storage.

Table 4.1
Rattling Brook Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1994	83.3	72.1	76.9	71.7	-7
1996	70.0	64.9	75.4	66.9	-11
1997	75.8	68.4	72.1	66.2	-8
Sensitivity Inflow Sequence					
1994	83.3	68.7	77.1	68.0	-12
1996	70.0	65.3	75.2	67.4	-10
1997	75.8	67.8	72.1	62.5	-13

The kinds of operational differences described in Section 4.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy generation after adjusting for storage.

Simulated generation significantly lower than recorded is an unexpected result in simulation modelling. Since the model generally simulates ideal operation of units and reservoir control structures, it normally results in overestimated generation when compared with recorded values. Since Rattling Brook is one of NP's largest stations, it is expected to be operated efficiently but even so, the model would be expected to generate more energy with the same inflow volume.

Differences between simulated and recorded values generally arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates);
- inaccurate assumptions regarding characteristics of the system.

Each of these is briefly discussed below.

Hydrology

Since NP does not maintain a data base which would allow calculation of daily inflows, the flow sequences were derived from records in adjacent basins. Although the inflow sequence will serve to provide a good estimate of long term normal production, direct comparison of a selected year will undoubtedly show differences.

In the case of the Rattling Brook system, further increasing the mean annual runoff, and therefore the inflows, would bring the simulated generation closer to the recorded generation. Though there is some indication that the runoff could be a few percent higher, the review of the hydrology already described increased the mean annual runoff as much as can be considered reasonable without long term, site specific precipitation data.

A second possibility related to hydrology that could partially explain the underestimated energy generation is that the actual drainage area may be larger than currently indicated by available topographic mapping. Field investigations of the watershed boundaries would be required to determine if any additional area is contributing to the basin.

Differences in Water Use

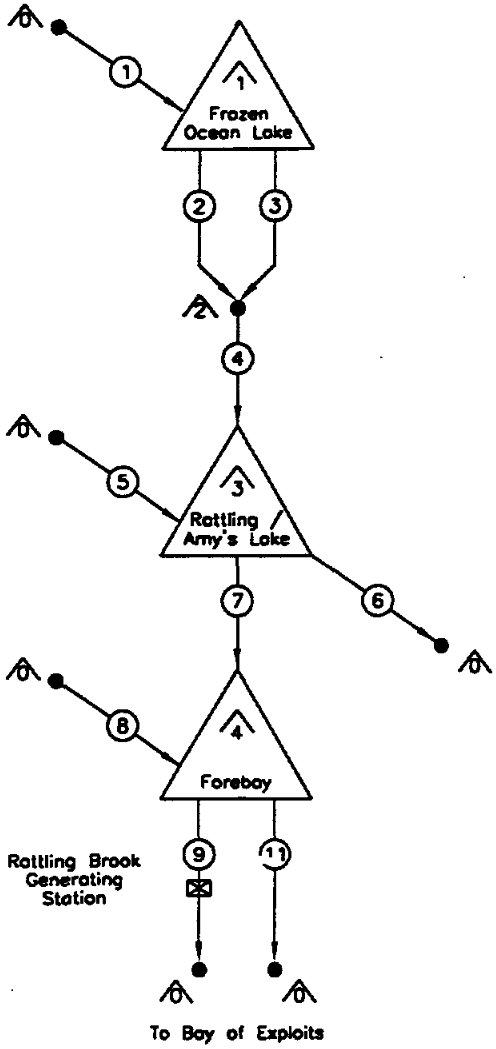
The simulation model simulates generation for most of the year using one unit at best efficiency. Due to the high head losses when both units are operating the model goes to full load only when the reservoirs go above their target levels and spill is a possibility. Recorded generation, however, indicates that the second unit is operated almost 50 percent of the time, again suggesting that more water is available than modelled. In addition, NP may be operating the units more efficiently than the model because operators can respond to varying conditions from year to year, whereas the model uses a fixed rule curve for each year. This could have an effect on Rattling Brook where the energy is sensitive to small changes in loading due to head losses and varying efficiency.

Though NP cautions that recorded spill data is often not reliable, recorded spills were compared to simulated. No spill was recorded or simulated in 1996; the model overestimates spill when compared to that recorded in both 1994 and 1997. Adjusting the energy values by spill decreases the discrepancy, especially in 1994.

Assumed Characteristics
Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves. There are two possible contributors to the discrepancy relating to the assumed characteristics. One is the storage relationships, which could explain the differences in spill as well as energy. The other is the characteristics of the two units operating together. Spot measurements by Environment Canada in 1990 suggest that there may be more power per unit of flow than is assumed in the model.

4.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate a long term production for the Rattling Brook system of 63.6 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production, provided in Chapter 22.



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
WATER MANAGEMENT STUDY
RATTLING BROOK ARSP MODEL SCHEMATIC

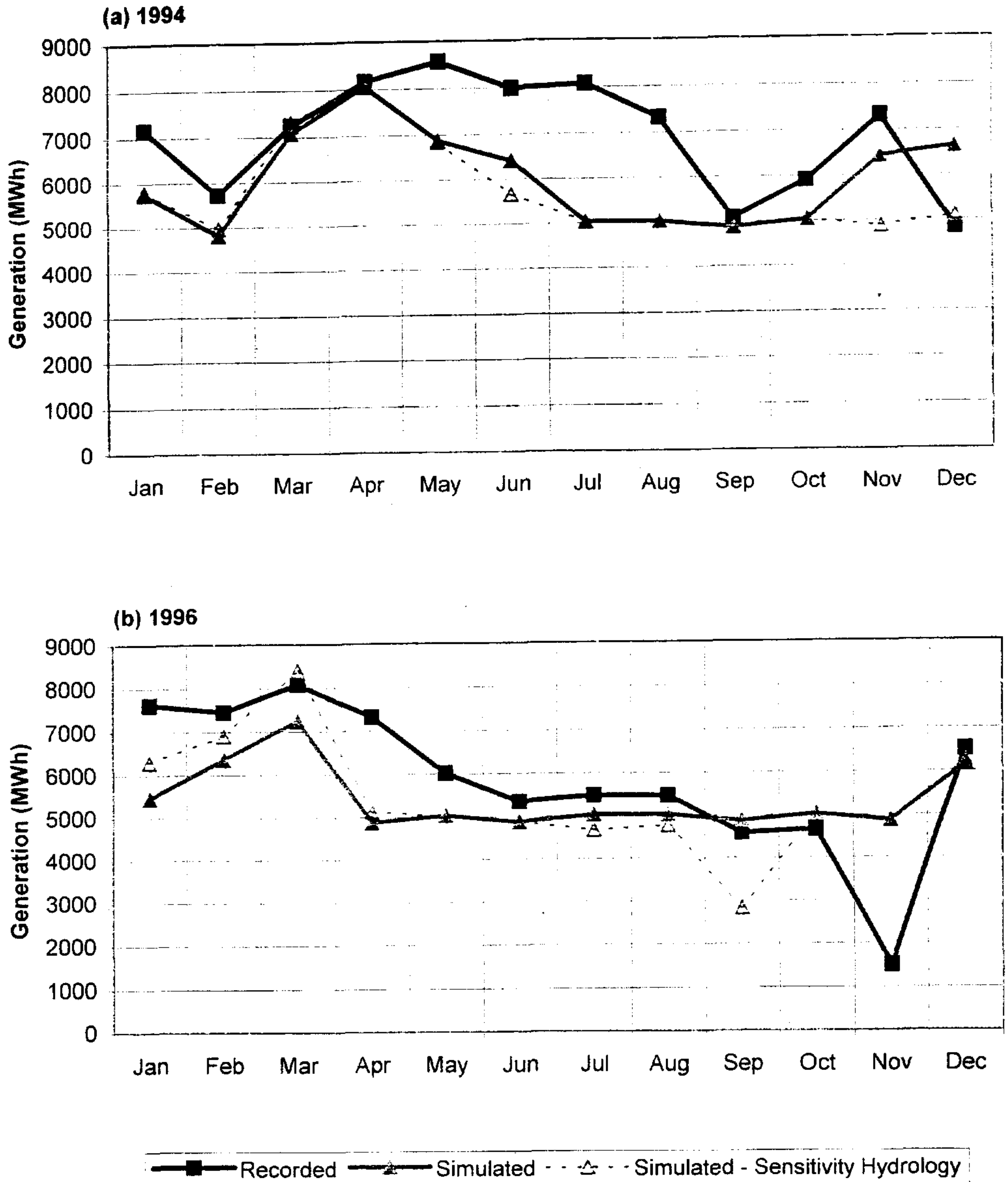


Fig. 4.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

RATTLING BROOK GENERATION COMPARISON

ACRES

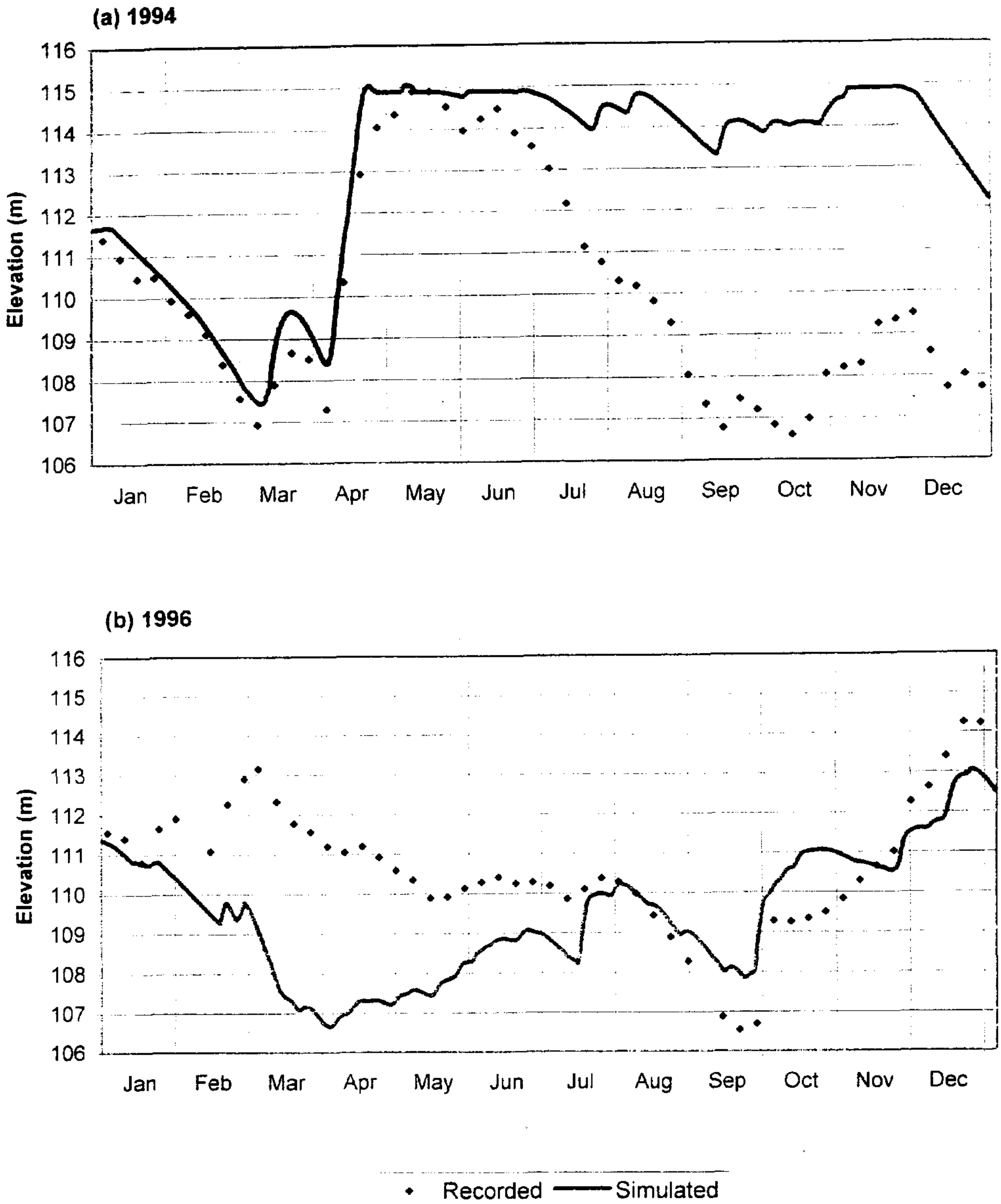


Fig. 4.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

RATTLING BROOK STORAGE COMPARISON

ACRES

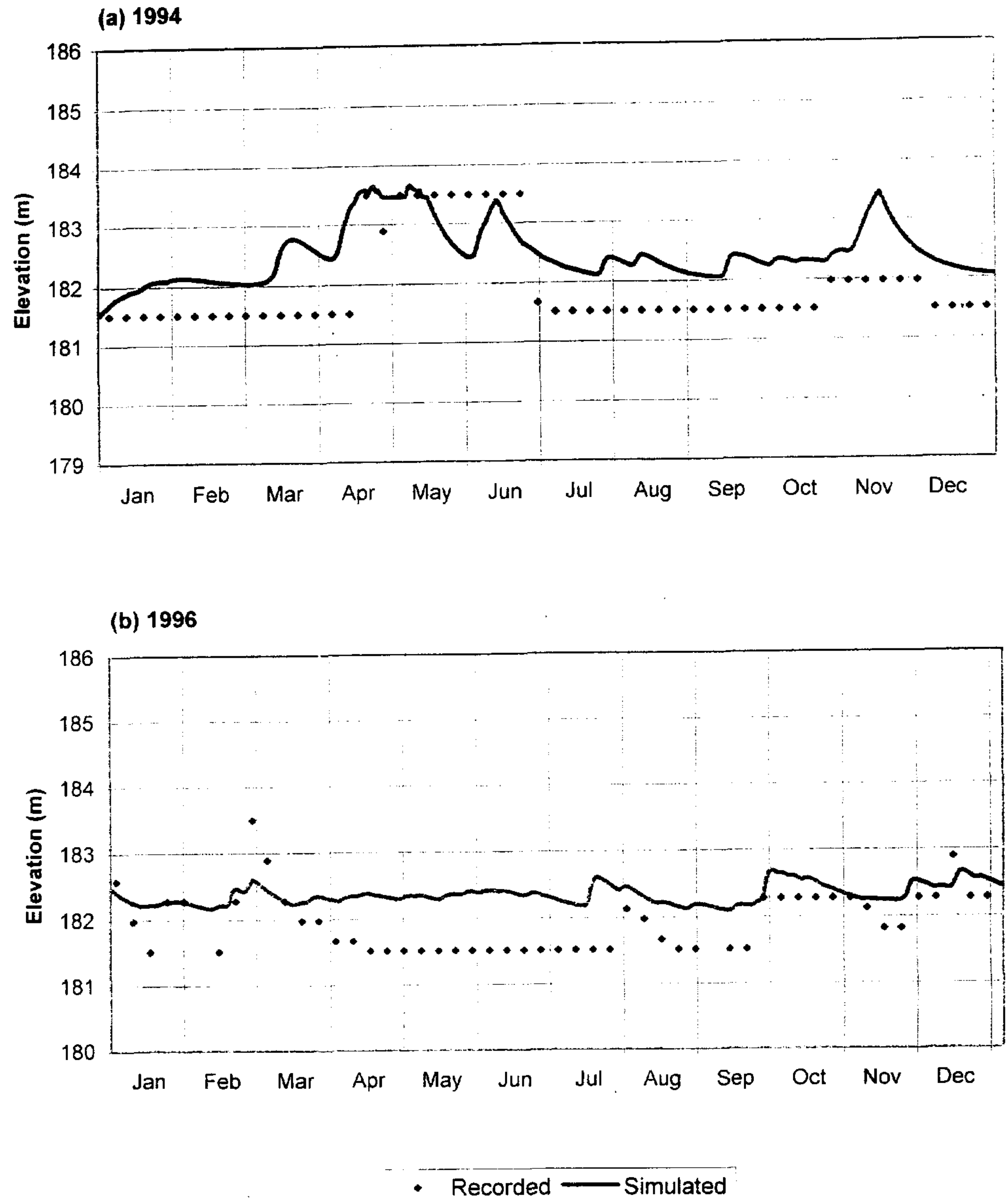


Fig. 4.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

FROZEN OCEAN LAKE STORAGE COMPARISON

ACRES

5 Morris/Mobile Hydroelectric System

The long term production for the Morris/Mobile Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Morris/Mobile system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Morris/Mobile system were Seal Cove Brook near Cappahayden (02ZM009) and South River near Holyrood (02ZM016). The Seal Cove Brook station has a drainage area of 53.6 km^2. The record from the Seal Cove Brook station was chosen as the primary gauge for deriving the Morris/Mobile system subbasin flows. The South River record was used to prepare a sequence for sensitivity analysis. The drainage area of the South River station is 17.3 km^2.

Mean annual runoffs for the reference period were calculated to be 1684 mm/yr for the Seal Cove Brook record and 1332 mm/yr for the South River record. The mean annual runoff of the Morris/Mobile basin was estimated during this study to be 1400 mm/yr.

The primary inflow sequence for the simulation was developed by multiplying the Seal Cove Brook flows by the ratios of Morris/Mobile basin mean annual runoff and subbasin drainage area to Seal Cove Brook mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using South River.

5.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequences used for the model was described in Section 5.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years, and for the estimate of long term production, where different. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 2 of this report.

5.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Morris/Mobile system

- Mobile Big Pond; and
- Mobile First Pond.

Sources of information on reservoir characteristics provided by NP were generally in agreement. The storage curve volumes used in the model were converted from the NP energy storage tables for the Morris/Mobile system.

The spillway flashboards at Mobile Big Pond are scheduled to be removed in 2001 for dam safety reasons. This will have the effect of decreasing full supply level from 186.14 m to 185.17 m. The higher level was used in the two comparison runs, while the lower level was used in the run to estimate long term production.

5.3.2 Generating Station Characteristics

Characteristics for the Morris Generating Station were based on information provided by NP. The design head used in the model was 29 m (95 ft), the net head given in the NP index testing of the Morris unit, instead of the rated net head. This was done so that the efficiencies calculated in the testing could be used in the model directly.

The flow in Morris Canal is controlled by the Mobile Big Pond gated outlet, and the water level in Morris Forebay is dependent on the flow in the canal. Since the unit is normally operated in a narrow range between best efficiency flow and maximum load, the forebay water level and canal head loss were approximated by average values. The average forebay level was estimated from recorded data. The average head loss was estimated from NP index testing of the Morris unit.

The tailwater level in the Morris spawning canal is variable. When Mobile First Pond is low, the tailwater level is dependent on the power flow from the generating station. When Mobile First Pond is high, the tailwater level is equal to the elevation of the reservoir water surface, which extends upstream through the canal. A tailwater curve was estimated using hydraulic computer modelling of the spawning canal, assuming unit operation at or near maximum load through a range of reservoir levels.

Characteristics for the Mobile Generating Station were based primarily on data from efficiency testing undertaken by Acres for NP in August 2000, supplemented by additional information from NP. Although the maximum capacity of the Mobile station is 12.0 MW, operation is currently limited to the best efficiency load of 10.1 MW because the wicket gates impinge on the turbine runners at gate openings above this setting. This limitation was modelled in the comparison runs. However, a planned overhaul will allow the unit to be run at its maximum load, so the model to estimate long term production was run with the 12.0 MW capacity enabled. The design head entered in the model was 117.9 m, the net head calculated at best efficiency load in the efficiency testing, instead of the rated net head. This was done so that the calculated efficiency values could be used directly in the model.

Unlike the flow in Morris Canal, reservoir flow into Mobile Canal is uncontrolled. The water level in Mobile Forebay is the same as in Mobile First Pond when the unit is not operating; otherwise, when the unit is drawing flow, the level is slightly lower, due to the head loss along the length of the canal. This head loss was estimated from the change in recorded forebay level as the unit was loaded from zero to maximum. The head loss was incorporated into the tailwater curve by adding it to the estimated tailwater levels from the efficiency tests.

5.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

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

Curves were not available for the Mobile Big Pond spillway and gated outlet, and therefore they were estimated from available information using standard hydraulic equations. The Mobile Big Pond spillway was modelled as having the flashboards in place for the comparison runs, and with the flashboards removed for the run to estimate long term production.

For the purpose of maintaining flow in the canal downstream of the Mobile Big Pond gated outlet for environmental reasons, the minimum flow through the gate was set to 0.1 m^3/s, if water was available.

5.3.4 System Operation

The plant operating guidelines for the Morris/Mobile system provide the following guidelines.

1.) *Morris plant should be operated at best efficiency 24 hours per day. This will allow about 12 to 14 hours operation at Mobile depending upon inflows. If Mobile plant is out of service, Morris plant should be shut down as well.*
2.) *Morris Canal is prone to a lot of trash during the summer and fall (leaves, grass, etc.). Frazil ice can become a problem when it gets colder. May have to reduce loading to about 900 kW if it becomes common. Will need to shut plant if a cold days is forecasted so the canal can ice over. This will prevent the frazil problem.*

3.) All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.

4.) Wet season is generally October through December and March through April. Use operating elevations as required to maintain approximately 10 to 12 hours of operation per day.

5.) Operate unit every four (4) hours to prevent water lines from freezing when temperature falls below -8 degrees Celsius.

6.) The penstock at the Mobile plant supplies water pressure to a fire hose connection inside a red box on the exterior of the Mobile powerhouse. The Witless Bay Fire Department and the Town Council of Mobile shall be notified each time the penstock will be dewatered. Sufficient warning shall be given in order that alternate provisions for water may be made.

These procedures, the information from the operator, and the recorded reservoir levels were used to develop the following operating strategy for the modelling.

- A target level at Mobile Big Pond is set at approximately 1 m below full supply level to indicate high inflows and risk of spills. If the reservoir level is below this level, operate the Morris unit at best efficiency, as long as water is available.
- If the level of Mobile Big Pond is above the target level (indicating high inflows), operate the Morris unit at maximum load.
- Open the Mobile Big Pond outlet gate to provide the Morris unit with the required power flow.
- Operate the Mobile unit at best efficiency load as long as possible during each day, while maintaining the water level in Mobile First Pond between its upper and lower operating elevations.
- If the Mobile First Pond is above its upper operating elevation, bring the Mobile unit to maximum load (or maintain best efficiency load, in the comparison runs).
- If Mobile Big Pond is spilling, continue to operate the Morris unit at maximum load, and bring the Mobile unit to maximum load as necessary to avoid spill at Mobile First Pond. Spill should not occur at Mobile First Pond unless Mobile Big Pond is also spilling, the Morris and Mobile units are both at maximum load, and Mobile First Pond is above full supply level.
- Maintain environmental releases as long as there is water available.

Load reductions and shutdowns to avoid frazil ice formation are of short duration and were not modelled.

5.4 Model Comparison

The simulation model was run for the comparison years of 1997 and 1998 for both the primary and sensitivity inflow sequences. Figures 5.2 and 5.3 show the simulated and recorded monthly generation for these two years, for Morris and Mobile respectively.

As both figures show, the simulated generation using both the primary and sensitivity inflow sequences generally follows the same pattern as the recorded generation, with the primary inflow sequence providing the better estimate. There are differences between simulated and recorded values within each year, and also on an annual basis. The within-year (month to month) variation is discussed in Section 5.4.1 below, followed by a discussion of the annual differences in Section 5.4.2.

5.4.1 Differences in Monthly Generation

The variation in generation through the year shown in Figures 5.2 and 5.3 are principally due to differences between the actual and simulated operation of the system. Figure 5.4 shows the comparison of storage in Mobile Big Pond. The periods when the simulated energy is greater than the recorded energy clearly coincide with periods when NP records show that the water was held in storage, rather than used for generation. Recorded generation was affected by major scheduled and unscheduled outages; examples include June to August 1998 at the Morris station, and July 1998 at the Mobile station. Also, any reductions in generation at Morris will result in a reduction at Mobile because of the water being held in storage. Conversely, if Mobile is out of service, Morris must be shut down as well to avoid spilling.

In 1998 there were several months in which water was held in storage instead of being generated, resulting in a large difference in recorded and simulated storage by the end of the year. The effect of this storage difference on annual generation is described in the next section.

As shown in Figure 5.5, there was some variation in the recorded level of Mobile First Pond, but the simulated level remained within the NP operating range and was close to the recorded average.

5.4.2 Differences in Annual Generation

Tables 5.1 and 5.2 summarize the annual energy generation for the two comparison years, for Morris and Mobile stations respectively. Simulated annual energy generation is shown using both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were different from the recorded values (as shown in Figure 5.4). The adjustment takes account of the energy potential of the water in storage.

Table 5.1
Morris Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1997	7.9	8.8	6.8	7.5	10
1998	6.8	8.4	7.8	8.0	3
Sensitivity Inflow Sequence					
1997	7.9	8.8	6.8	8.2	21
1998	6.8	8.7	7.8	8.3	6

Table 5.2
Mobile Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1997	45.5	50.1	40.5	44.0	9
1998	39.4	45.8	44.0	43.6	-1
Sensitivity Inflow Sequence					
1997	45.5	49.1	40.5	46.1	14
1998	39.4	47.3	44.0	45.6	4

The difference between simulated and recorded total annual energy generation for the Morris/Mobile system using the primary inflows is approximately nine percent in 1997 and zero percent in 1998.

The kinds of operational differences described in Section 5.4.1, such as holding water back rather than generating, account for the differences in energy from month to month, but should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Morris/Mobile system is briefly discussed below.

Hydrology

In the case of the Morris/Mobile system, the simulation using the primary inflow sequence gave reasonable results for both years and was used to estimate the long term production as presented in Section 5.5.

Differences in Water Use

For the Morris/Mobile system, the difference between the simulated and recorded annual results may be partly due to differences in water management. The model assumes perfect operation of units and reservoirs according to the input operating strategy in Section 5.3.4. The two most important factors affecting generation are as follows.

- Ideal operation of the unit: The unit never operates at a flow less than the most efficient load, although it does operate at higher loads if the reservoir levels are high or if there is a risk of spill.
- Ideal operation of reservoirs and control gates to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels, and opens or closes gates as required to ensure perfect operation of the units and minimize spill.

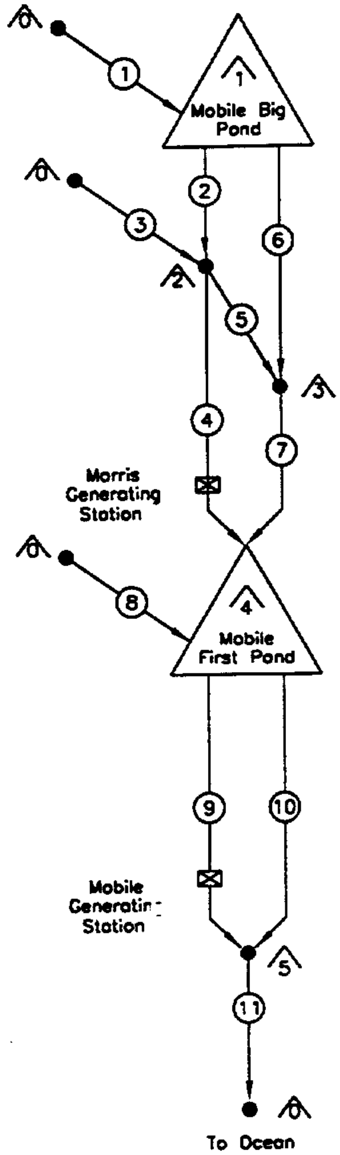
A small amount of spill at Mobile Big Pond was observed by the operator in May 1997, when the water level was high. No estimate of quantity was available. The simulated spill in this month was equivalent to 347 MWh. No other spills were recorded or simulated in either of the two comparison years. NP cautions that estimates of recorded spill quantity and frequency are often inaccurate. Spills in this system have been rare, due to the large storage capacity of Mobile Big Pond, although the removal of the flashboards may lead to more frequent spills than in the past.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves.

5.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate the long term production. The resulting estimate of long term production is 7.8 GWh/yr from the Morris station and 43.8 GWh/yr for the Mobile station, for a system total of 51.6 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



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
WATER MANAGEMENT STUDY
MORRIS/MOBILE ARSP MODEL SCHEMATIC

ACRES

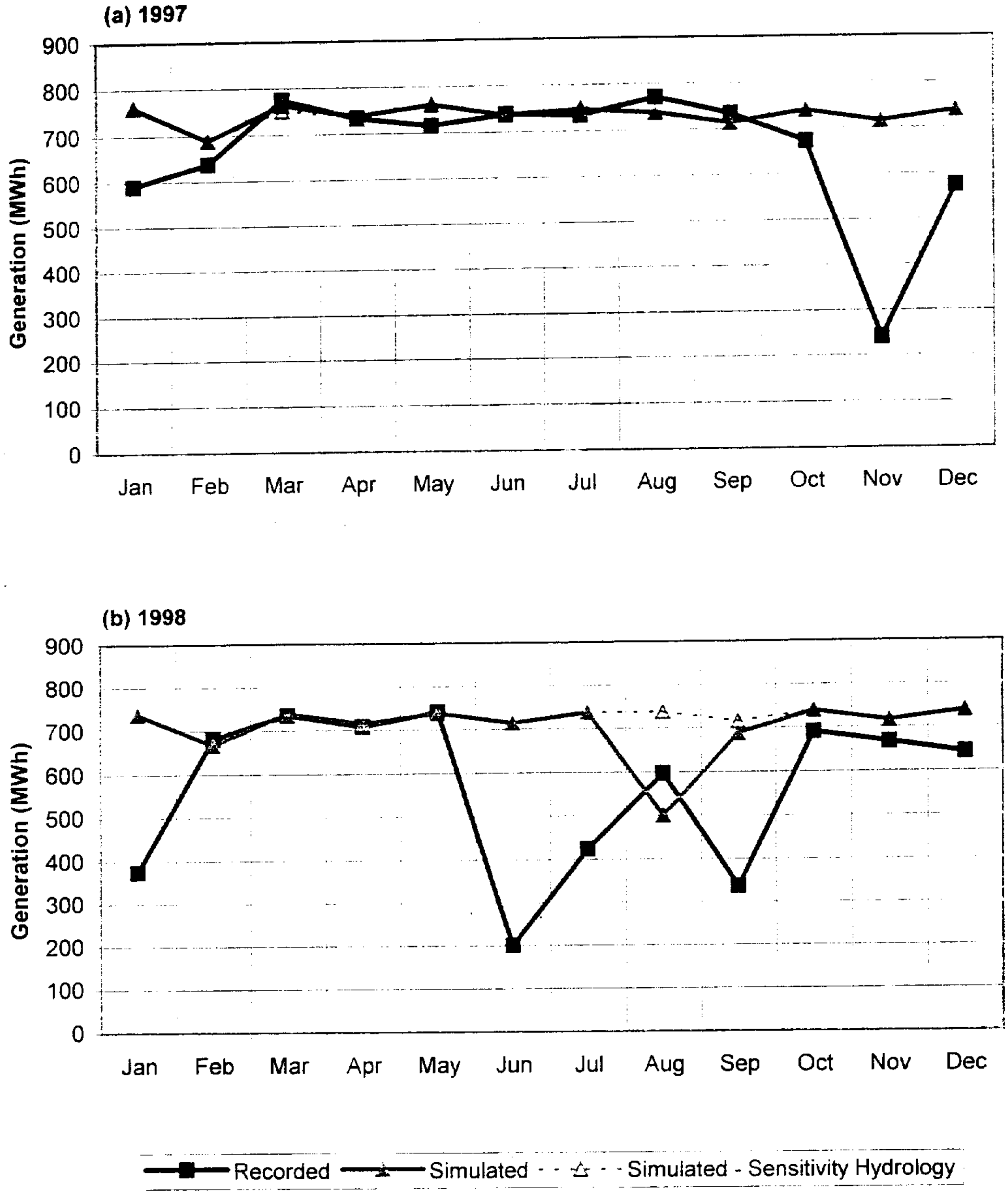


Fig. 5.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

MORRIS GENERATION COMPARISON

ACRES

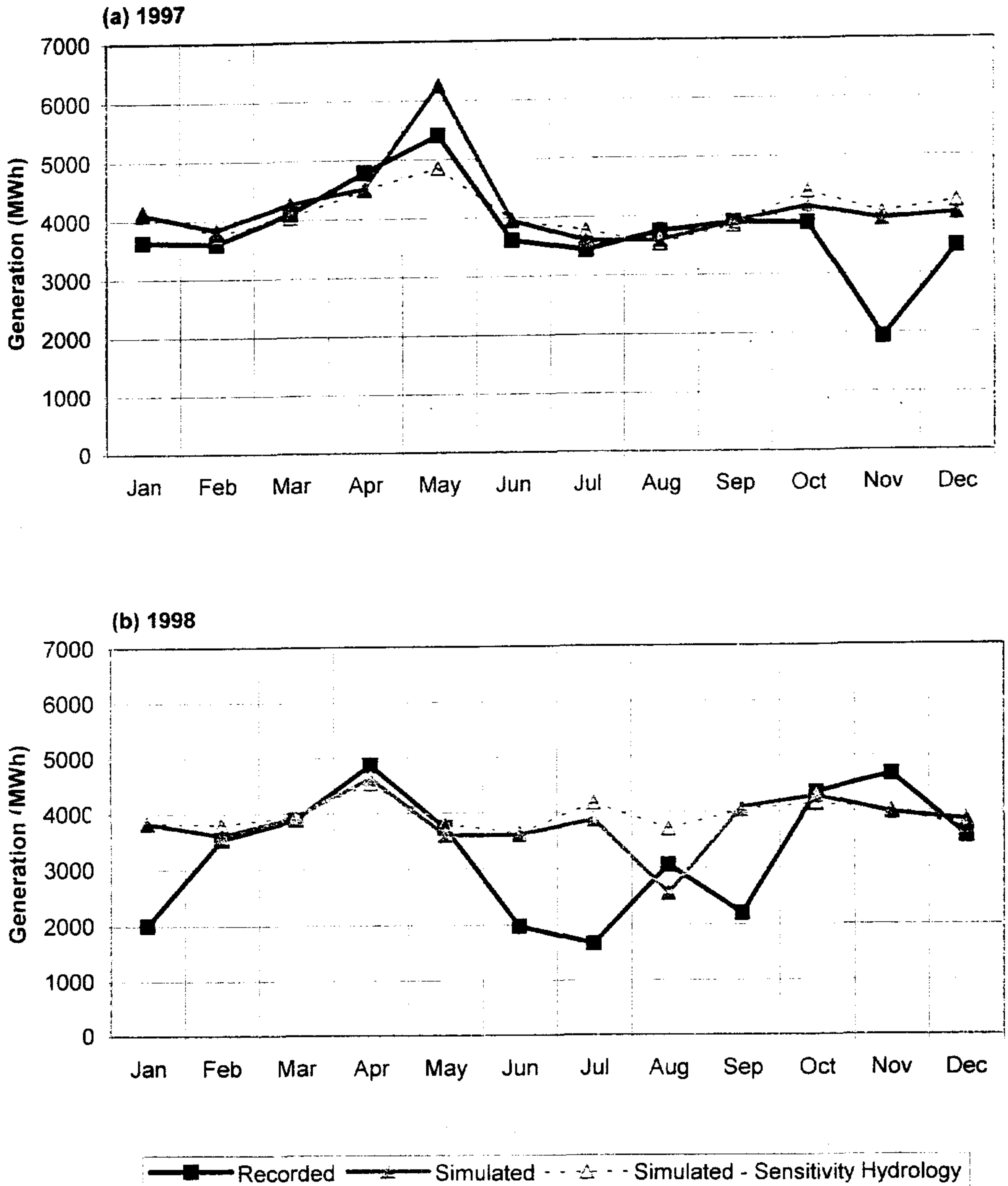


Fig. 5.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

MOBILE GENERATION COMPARISON

ACRES

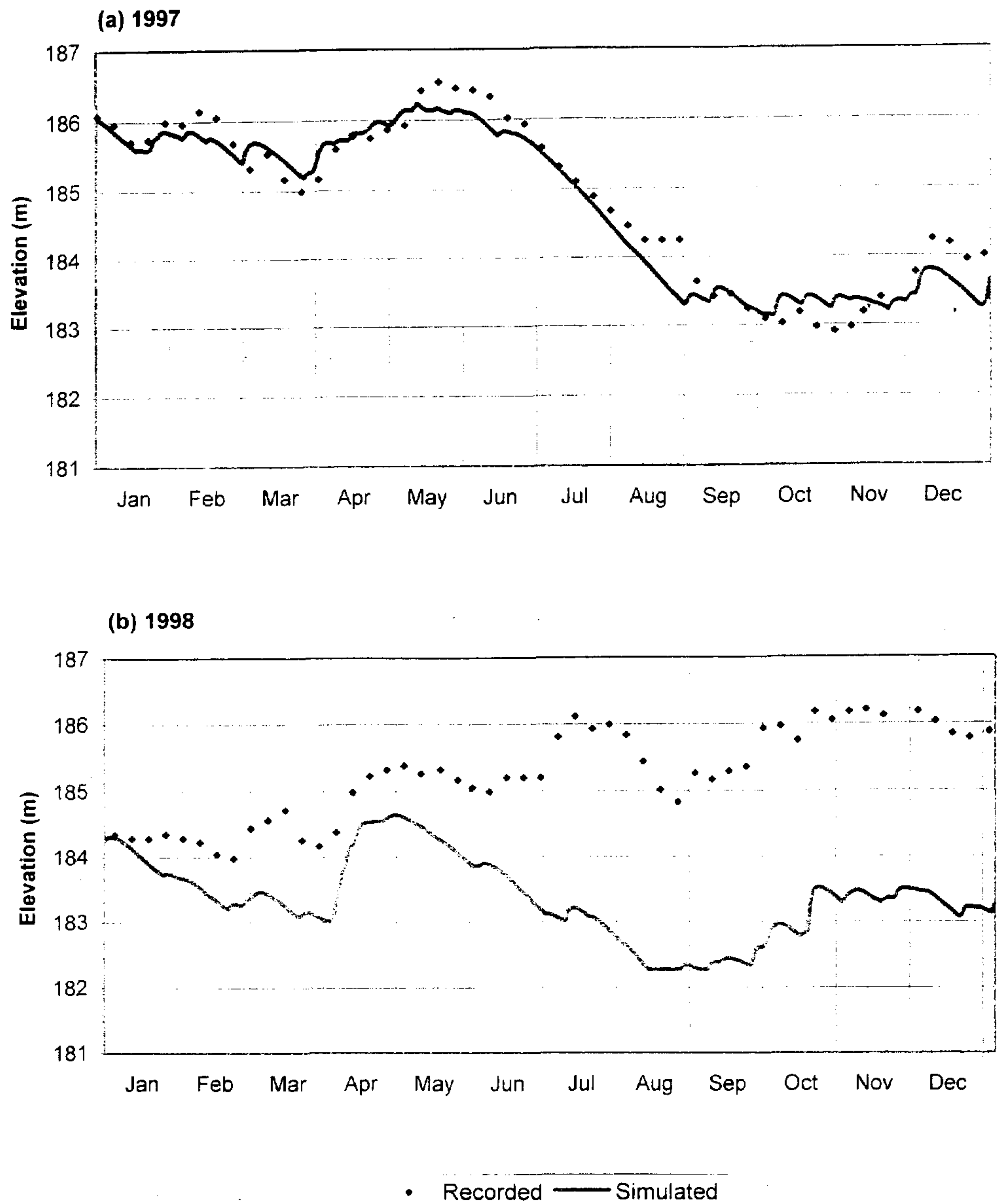


Fig. 5.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

MOBILE BIG POND STORAGE COMPARISON

ACRES

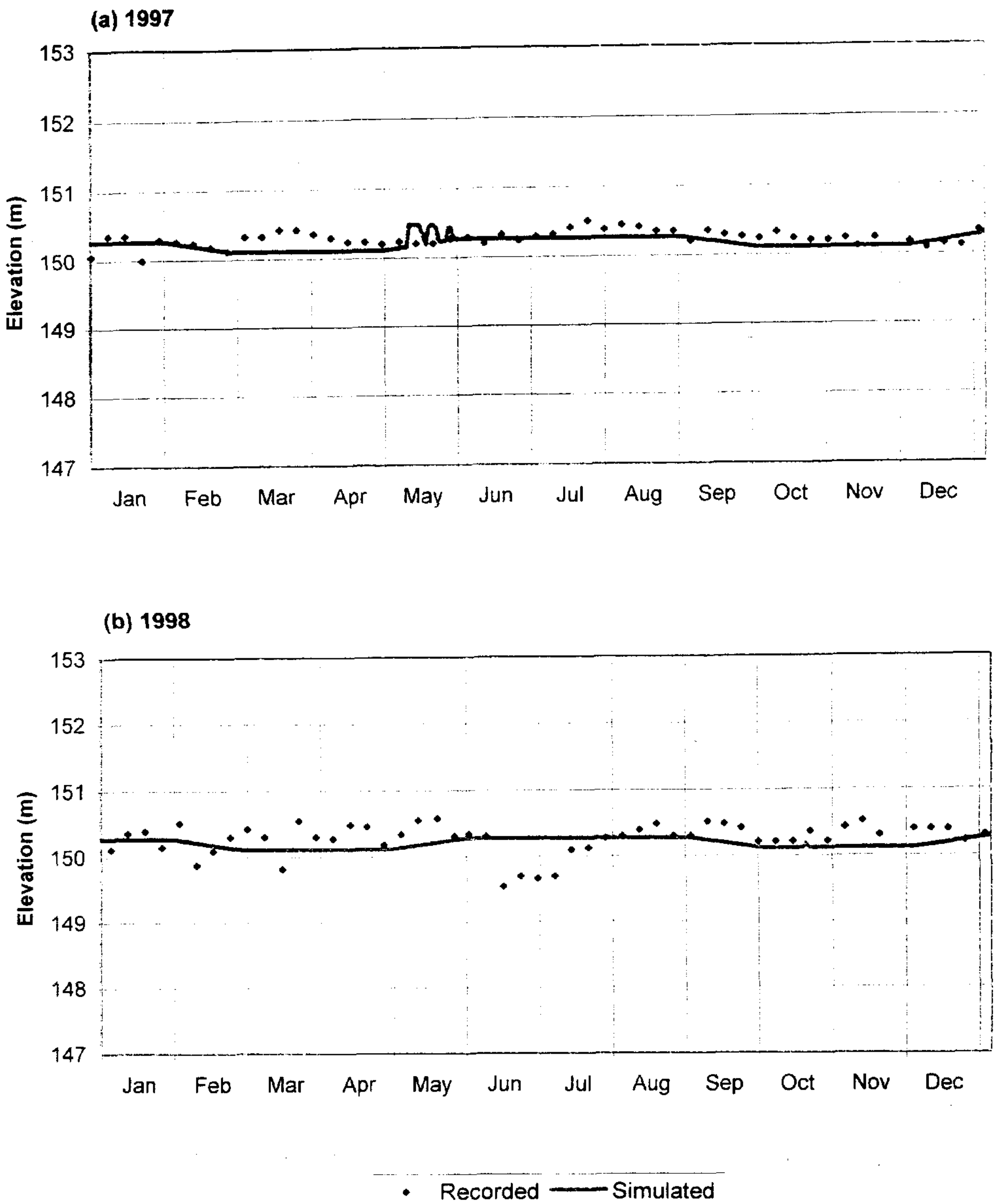


Fig. 5.5

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

MOBILE FIRST POND STORAGE COMPARISON

ACRES

6 Rocky Pond/Tors Cove Hydroelectric System

The long term production for the Rocky Pond/Tors Cove Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Rocky Pond/Tors Cove system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Rocky Pond/Tors Cove system were Seal Cove Brook near Cappahayden (02ZM009) and South River near Holyrood (02ZM016). The record from the Seal Cove Brook station, with a drainage area of 53.6 km^2, was chosen as the primary source for deriving the Rocky

Pond/Tors Cove system subbasin flows. South River record was used to prepare a sequence for sensitivity analysis. The drainage area of the South River basin is 17.3 km^2.

Mean annual runoffs of 1684 mm/yr and 1332 mm/yr for the reference period were calculated from the hydrometric station records for Seal Cove Brook and South River, respectively. The mean annual runoff of the Rocky Pond/Tors Cove basin was estimated during this study to be 1500 mm/yr.

The primary inflow sequence for the simulation was developed by multiplying the Seal Cove Brook flows by the ratios of Rocky Pond/Tors Cove basin mean annual runoff and drainage area for each subbasin to Seal Cove Brook mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using South River.

6.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequences used for the model was described in Section 6.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 2 of this report.

6.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Rocky Pond/Tors Cove system

- Franks Pond;
- Cape Pond;
- Rocky Pond Forebay; and
- Tors Cove Pond Forebay.

Different sources of information on storage were available from NP's records. These sources were in agreement for Cape Pond and Rocky Pond Forebay, but differed for Franks Pond and Tors Cove Pond Forebay. The information was reviewed with NP and appropriate values were selected for use in this study. The difference in storage between the sources of information for Franks Pond could lead to small inaccuracies in the results, but for Tors Cove Pond Forebay it was not an issue for the current study because Tors Cove Pond Forebay storage is not used extensively.

6.3.2 Generating Station Characteristics

The generating station at Rocky Pond houses one generating unit (ROP-G1) while the generating station at Tors Cove houses three generating units (TCV-G1, TCV-G2, TCV-G3). Since each unit was modelled separately for Tors Cove station, generating station characteristics were required for each unit. Characteristics for Rocky Pond and Tors Cove stations were based primarily on data from NP's plant operating guidelines. The installed capacities used to estimate the long term production were 3.3 MW for ROP-G1, 2.3 MW for TCV-G1, 2.3 MW for TCV-G2 and 2.5 MW for TCV-G3 for a total capacity of 10.4 MW.

To account for the loss in energy due to the variation in penstock head losses as a function of the power flow at Tors Cove station, the fixed head loss with one unit generating was input in the model as a constant loss and additional head losses were included in the tailwater curve. Therefore, the tailwater curve does not represent physical water levels at the plant, but synthetic water levels used to account for the drop in net head due to head losses, in addition to the actual variation in tailwater level with flow. Due to these losses the maximum output of the Tors Cove station with all units operating is 6.5 MW.

6.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- Franks Pond gated outlet;
- Franks Pond overflow spillway;
- Cape Pond gated outlet;
- Cape Pond overflow spillway;
- Rocky Pond Forebay overflow spillway; and
- Tors Cove Pond Forebay overflow spillway.

Structure curves were estimated based on information provided by NP and standard hydraulic equations. La Manche Canal spillways and Franks Pond Canal spillway were not modelled as individual structures. For La Manche Canal spillways all flow above the maximum flow capacity was assumed to be spilled. At Franks Pond, it was assumed that when the flow capacity of the canal was reached the water would be stored in Franks Pond and eventually spilled at Franks Pond overflow spillway if inflows remained high. The maximum flow capacities were 2.5 m^3/s for Franks Pond Canal and 6 m^3/s for La Manche Canal, as provided by NP.

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 was available. The fish plant water supply was provided by NP as a constant demand of 2000 m^3/day.

6.3.4 System Operation

NP's plant operating guidelines for the Rocky Pond/Tors Cove system provide the following procedures.

1.) *Operate Rocky Pond at best efficiency and Tors Cove #3 at best efficiency when inflows are minimal. As flows increase, operate Rocky Pond at maximum load, Tors Cove #3 at maximum and Tors Cove #2 at best efficiency or maximum load as required. Unit #1 is not automated and should be operated in times of very high inflows only.*

2.) *Maintain forebay elevation limits at Tors Cove by either cycling Unit #3 between best efficiency and maximum load or having Unit #3 at maximum load and cycling Unit #2 on and off at best efficiency.*
3.) *There is a restriction in La Manche Canal which only permits enough water to reach Rocky Pond to allow about 18 hours of operation per day. This should all be at best efficiency unless inflows from Butlers Pond are high (rainstorm).*
4.) *In the event of a predicted heavy inflow, the gate at Cape Pond feeding the canal should be closed to minimum as the flow from Butlers is not controlled and inflow from here could overtop the canal. Rocky Pond Forebay can be drawn down to as low as 396 feet should an extended rainstorm be forecast by operating at full load with the canal gate closed. Franks Pond may have to be closed in this event as well.*
5.) *Prior to spring runoff, keep Rocky Pond at 398 feet and Tors Cove Pond at 282 feet.* (Note that these elevations are approximately 1.1 m below full supply level at Rocky Pond Forebay and approximately 1.4 m below full supply level at Tors Cove Pond Forebay)
6.) *The canal between Cape Pond and Rocky Pond has 7 spillways and they all spill out of the system. A gate opening of 20" at the Cape Pond gate will typically keep the canal full without spill. The uncontrolled flow from Butlers Pond causes most of the canal spills.*
7.) *Franks Pond spills out of the system.*
8.) *A fish plant is fed from the Tors Cove penstock.*
9.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

These procedures were used to develop the following operating strategy for the modelling.

- Set the target water levels to the upper operating elevations for Rocky Pond Forebay and Tors Cove Pond Forebay.
- Draw forebay water levels down prior to the spring runoff.
- Release water from Franks Pond and Cape Pond to keep ROP-G1 at most efficient load and TCV-G3 at most efficient load.
- If the combination of flow from Rocky Pond Forebay and the local inflow to Tors Cove Pond Forebay is greater than the best efficiency flow of TCV-G3, then bring the unit up to maximum load.

- If Tors Cove Pond Forebay is above the target level, operate TCV-G2 at maximum load.
- If the combination of local inflow to Tors Cove Pond Forebay and flow from Rocky Pond Forebay is greater than the combined maximum flow of TCV-G2 and TCV-G3, then store the excess flow in Tors Cove Pond Forebay.
- To avoid spill at Tors Cove Pond Forebay, bring TCV-G1 on to maintain the Tors Cove Pond Forebay at full supply level. There should only be spill at Tors Cove Pond Forebay when all units at Tors Cove are generating at maximum load and the forebay is above full supply level.

The same operating procedures were used for both the comparison runs and the run to estimate long term production.

6.4 Model Comparison

The years selected by NP for the comparison runs were 1997 and 1998. The simulation model was run for these years for both the primary and sensitivity inflow sequences. Figures 6.2 and 6.3 show the Rocky Pond and Tors Cove simulated and recorded monthly generation for these two years, respectively.

As Figures 6.2 and 6.3 show, the simulated generation using both the primary and sensitivity inflow sequences generally follows the same pattern as the recorded generation, with the primary inflow sequence providing the better estimate. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 6.4.1 below, followed by a discussion of the annual differences in Section 6.4.2.

6.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figures 6.2 and 6.3 are most likely due in combination to the differences between the actual and simulated operation of the system and the actual and assumed inflows.

Figures 6.4 and 6.5 show comparisons of storage in the main storage reservoirs, Franks Pond and Cape Pond, respectively. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation, and vice versa. For the months January and February 1998, for example, Figure 6.2 shows that the model generates more energy than was recorded. Figure 6.4 shows that at the end of this period, the model has less water in storage in Franks Pond, because it was used for generation. The opposite effect for the same months can be seen in Figure 6.5 for 1997.

The largest differences in monthly generation occur for the months September to November 1997. Although there are large differences in monthly generation for April to August 1997, the total recorded and simulated energy for these months closely match because the recorded generation is greater than the simulated in April and May and vice versa for July and August. The recorded and simulated energy for June closely match. The differences during the fall are partly due to differences in operation, but more likely, the result of the estimate of inflows for this period. Since both the primary and sensitivity inflow sequences showed the same pattern, an additional sensitivity to the hydrology was conducted using the hydrometric station Waterford River at Kilbride (02ZM008) to develop an inflow sequence for 1997. The simulated generation for this period is closer to the recorded using the Waterford River inflow sequence, but is still higher. It is expected that the combination of the differences in operation and hydrology for this period are the reasons for the difference.

6.4.2 Differences in Annual Generation

Table 6.1 and 6.2 summarize the annual energy generation for the two comparison years for Rocky Pond and Tors Cove stations, respectively. Simulated annual energy generation is shown using both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values at the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 6.4 and 6.5). The adjustment takes account of the energy potential of the water in storage.

Table 6.1
Rocky Pond Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1997	15.2	17.3	14.0	16.7	19
1998	15.3	16.9	15.5	17.1	10
Sensitivity Inflow Sequence					
1997	15.2	17.4	14.0	17.5	25
1998	15.3	17.5	15.5	17.6	14

Table 6.2
Tors Cove Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1997	26.7	29.0	25.3	28.6	13
1998	27.8	29.0	28.1	29.3	4
Sensitivity Inflow Sequence					
1997	26.7	29.6	25.3	30.2	19
1998	27.8	30.0	28.1	30.2	7

The difference in total annual energy generation for the Rocky Pond/Tors Cove system using the primary inflow sequence is approximately 16 percent in 1997 and 7 percent in 1998.

The kinds of operational differences described in Section 6.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage. The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Rocky Pond/Tors Cove system is briefly discussed below.

Hydrology

In the case of the Rocky Pond/Tors Cove system, the simulation using the primary inflow sequence gave reasonable results for 1998 and was used to estimate the long term production as presented in Section 6.5. Although there seems to be some differences in the estimated and actual inflows for the fall of 1997, there isn't enough evidence to suggest changing the mean annual runoff estimate for the Rocky Pond/Tors Cove basin. The possible difference in these months should not effect the estimate of long term production as it is an average over a 15 year period.

Differences in Water Use

For the Rocky Pond/Tors Cove system, the difference between the simulated and recorded annual results is possibly due to differences in water management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described in Section 6.3.4. The two most important factors in the model affecting generation are as follows.

- Ideal operation of the units: The units never operate at less than the most efficient load, although they do operate at higher loads if there is a risk of spill.

- 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.

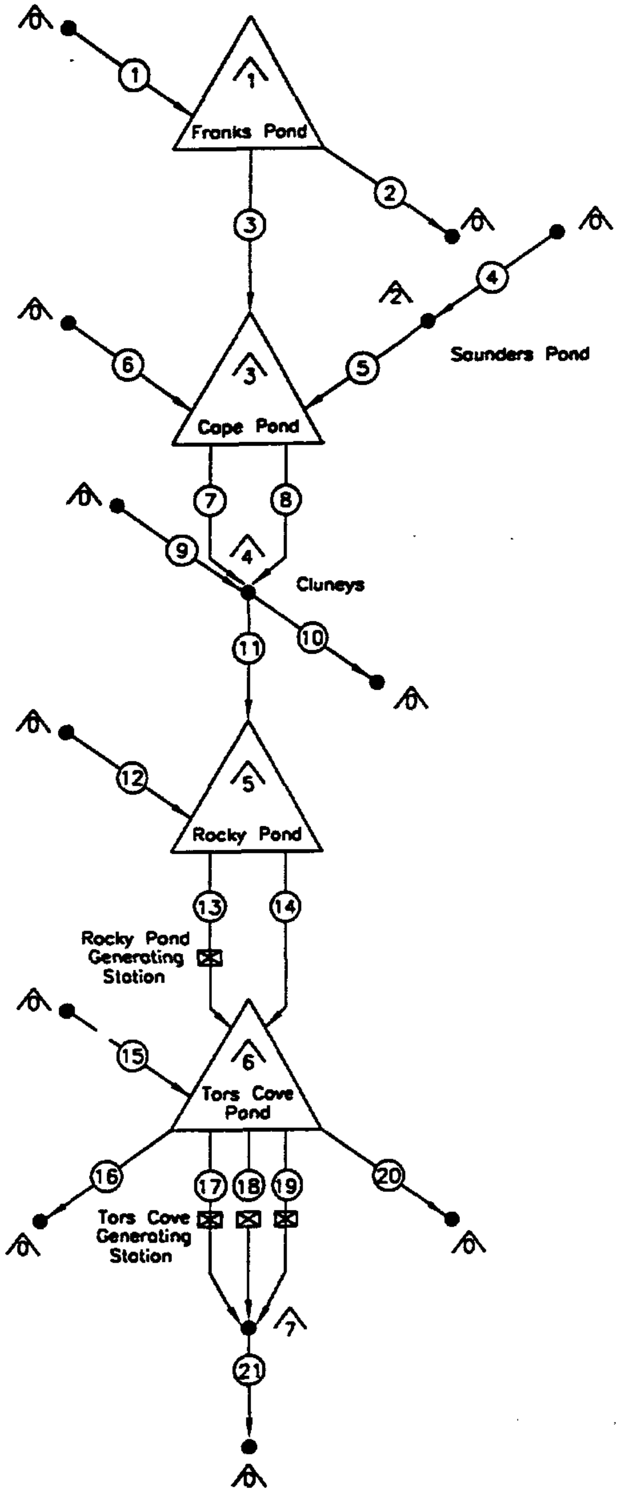
A comparison of recorded and simulated spill at Tors Cove Pond Forebay shows that there was no spill in either in 1997. In 1998 the recorded spill was 565 MWh and the simulated spill was 0 MWh. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded. The additional actual spill could be partially responsible for the lower recorded energy generation when compared with the simulated. Adjusting the results tabulated above by the difference in recorded and simulated spill for 1998 would reduce the discrepancy between simulated and recorded energy generation in 1998, but provide no change in 1997 unless there was unrecorded spill from the canals.

A comparison of the recorded and simulated forebay levels in Figures 6.6 and 6.7 shows that the simulated forebay levels are usually higher than the recorded. These higher levels would lead to higher net heads and higher simulated generation than the recorded.

Assumed Characteristics
Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, gate discharge curves, or estimate of Tors Cove fish plant water supply.

6.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate the long term production for the Rocky Pond/Tors Cove system. The result of this simulation was an estimate of long term production of 16.7 GWh/yr for the Rocky Pond station and 28.9 GWh/yr for the Tors Cove station for a total of 45.6 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



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
WATER MANAGEMENT STUDY
ROCKY POND/TORS COVE ARSP MODEL SCHEMATIC

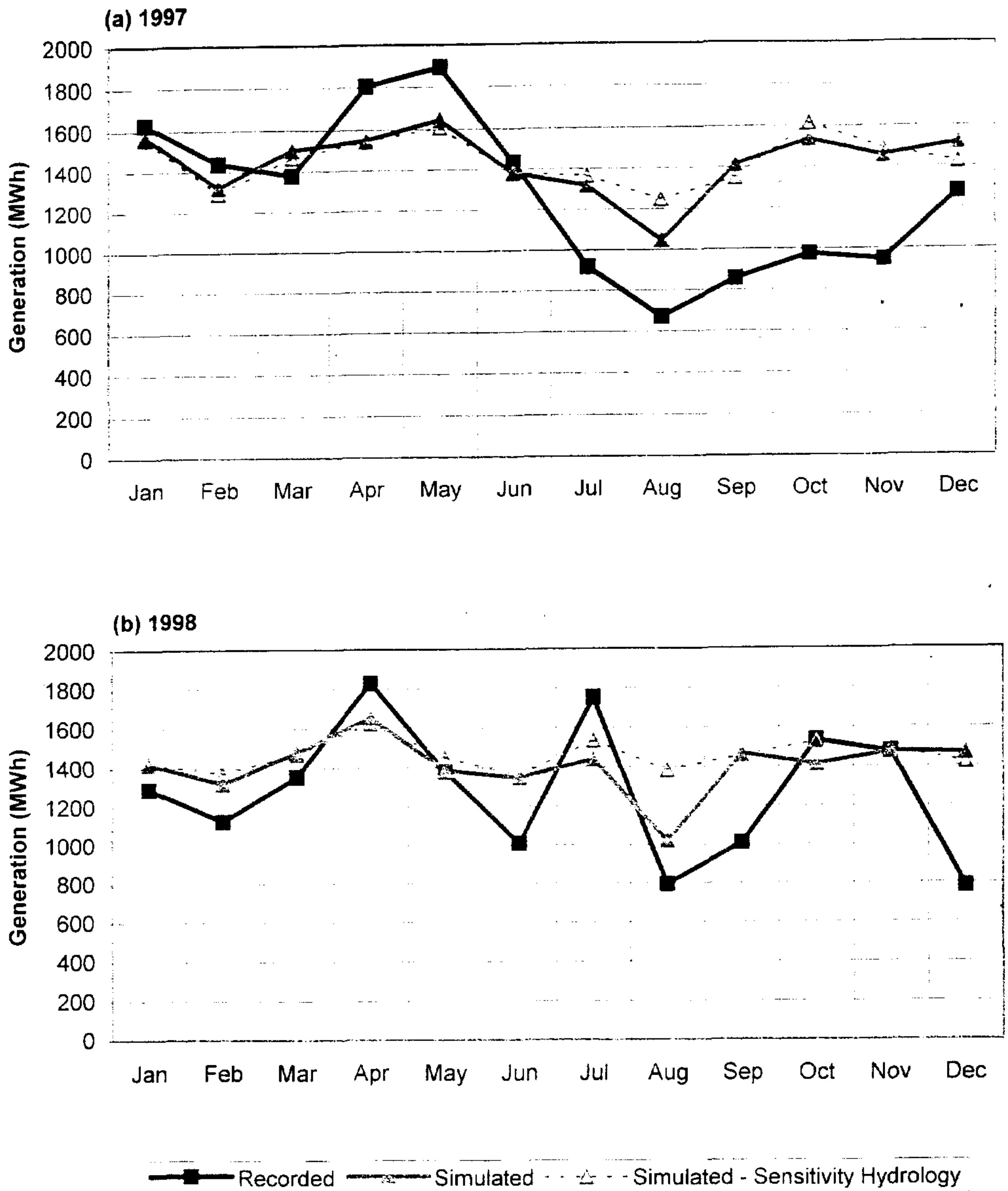


Fig. 6.2

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
ROCKY POND GENERATION COMPARISON

ACRES

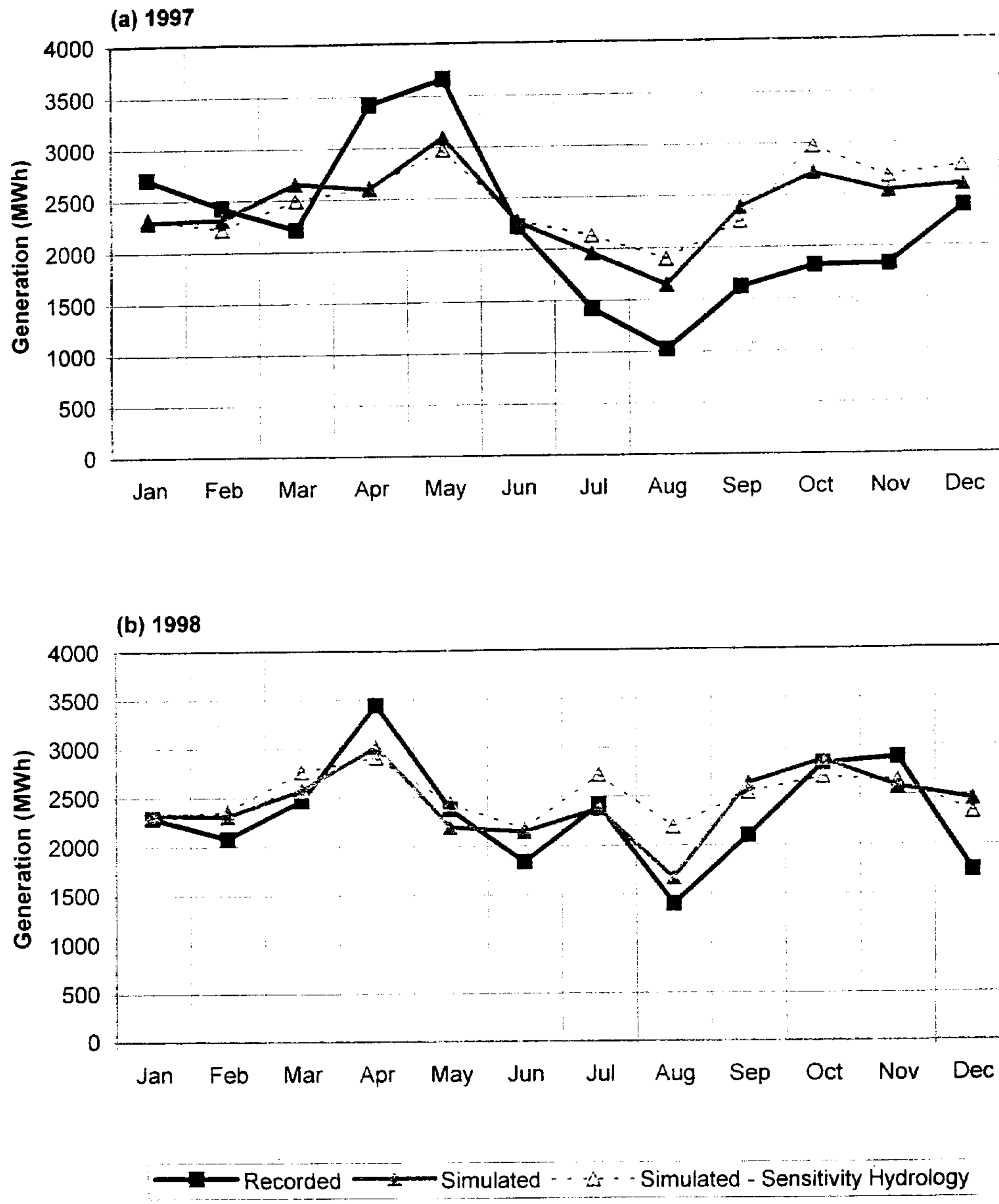


Fig. 6.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

TORS COVE GENERATION COMPARISON

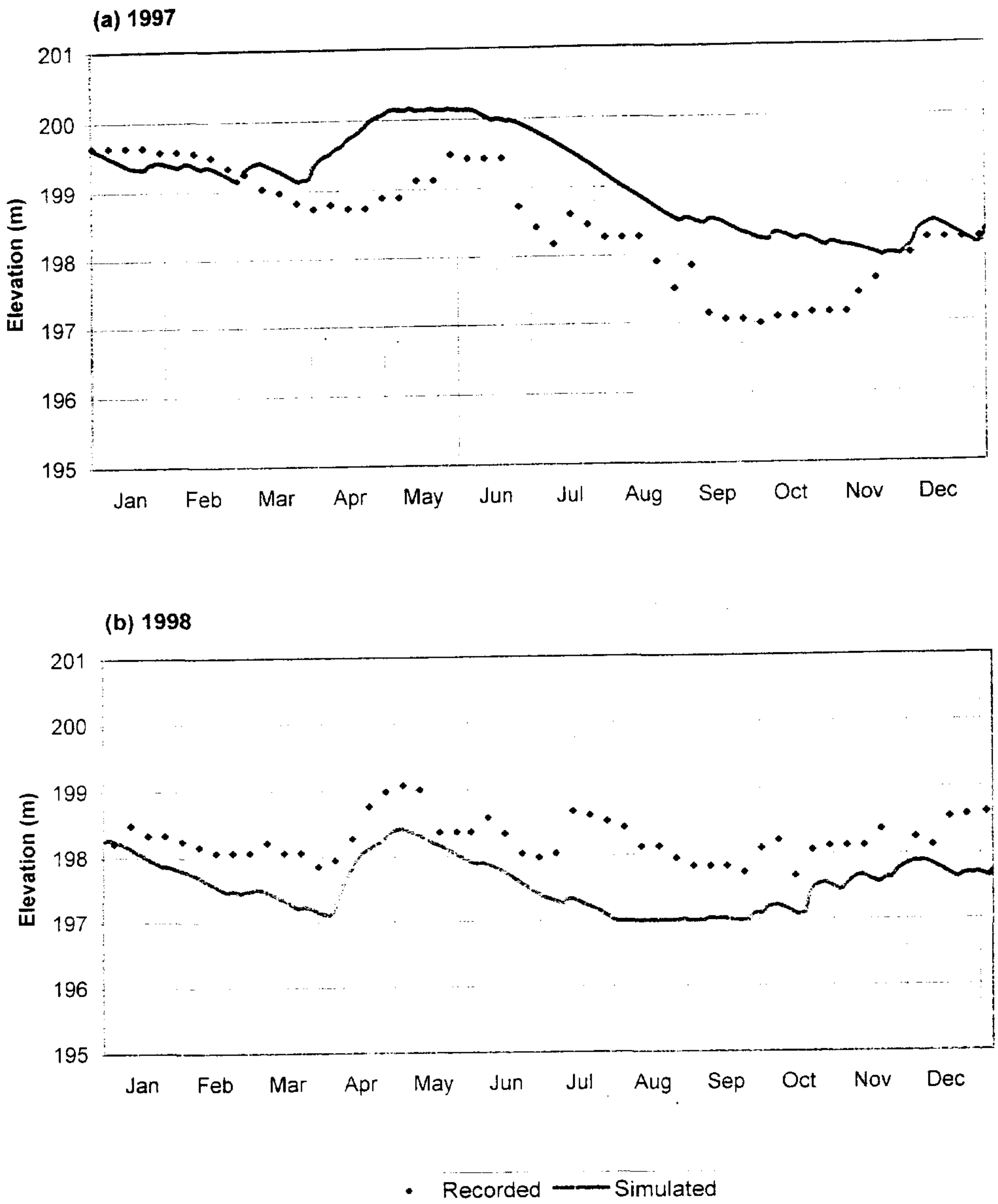


Fig. 6.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

FRANKS POND STORAGE COMPARISON

ACRES

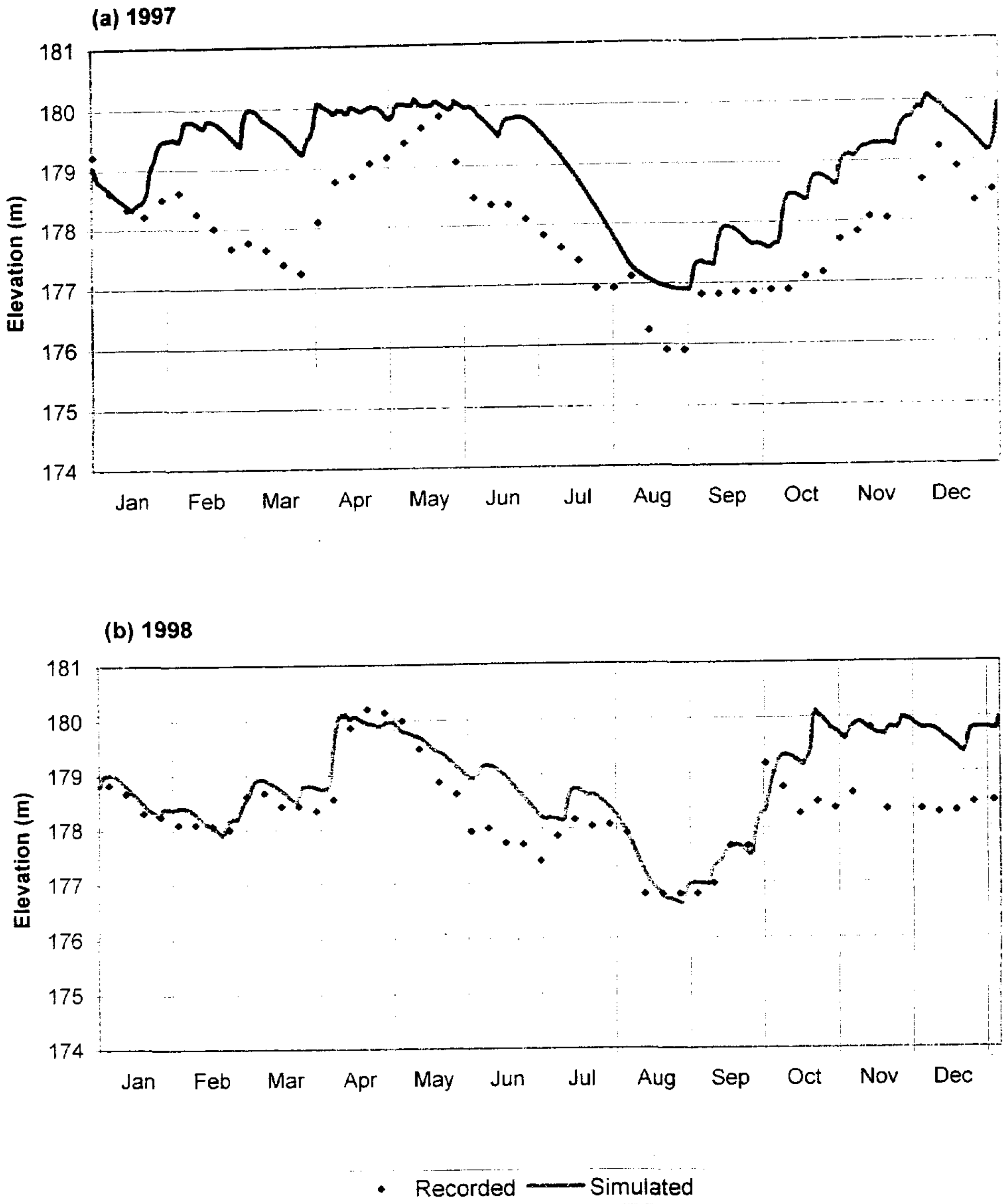


Fig. 6.5

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

CAPE POND STORAGE COMPARISON

ACRES

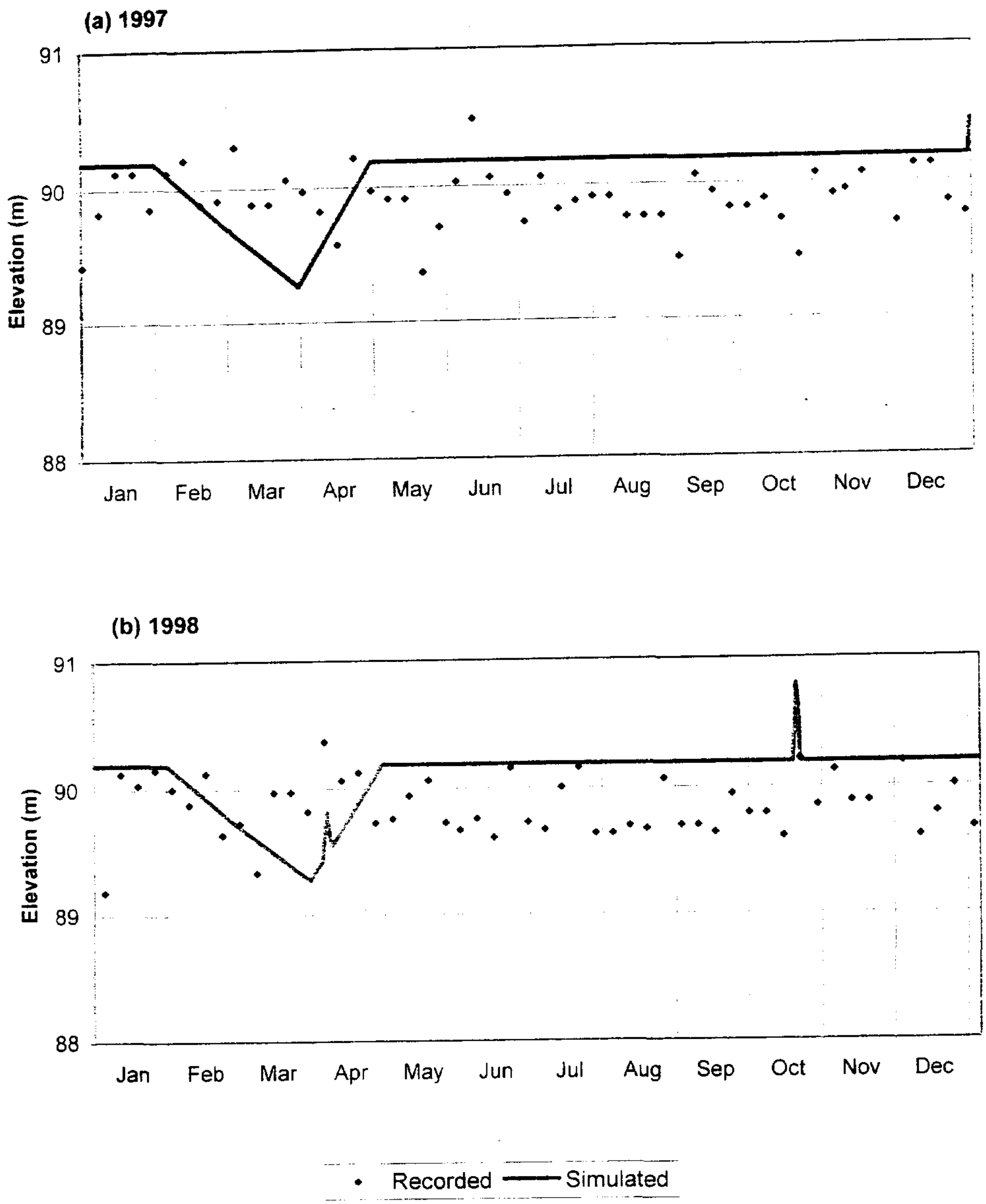


Fig. 6.6

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

ROCKY POND STORAGE COMPARISON

ACRES

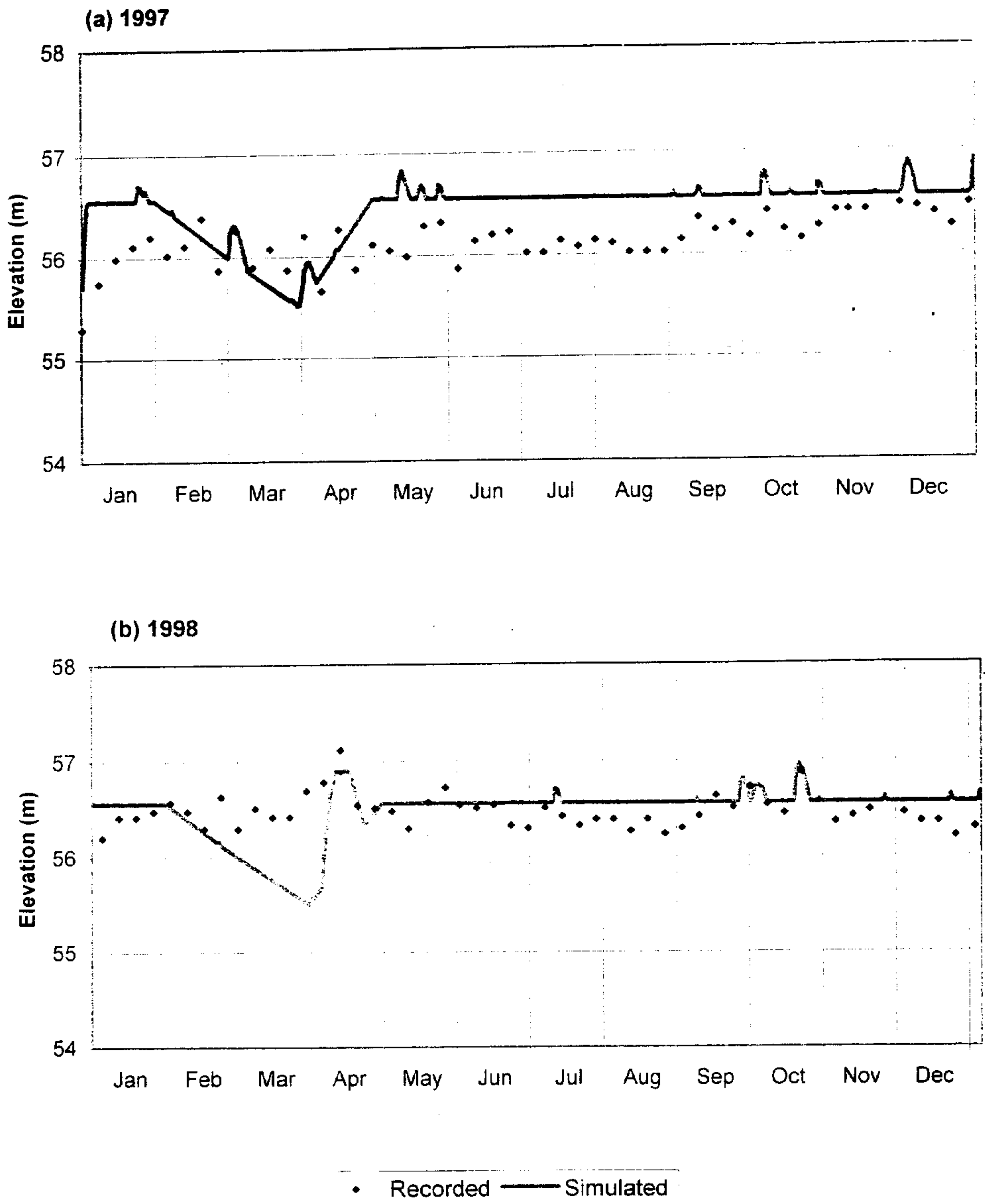


Fig. 6.7

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

TORS COVE POND STORAGE COMPARISON

ACRES

7 Lookout Brook Hydroelectric System

The long term production for the Lookout Brook Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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 6.2 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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Lookout Brook system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Lookout Brook system were Little Barachois Brook near St. George's (02ZA001) and Highlands River at Trans-Canada Highway (02ZA002). The record from the Little Barachois Brook station, with a drainage area of 343 km^2, was chosen as the primary source for deriving the Lookout Brook system subbasin flows based on its proximity to Lookout Brook. Flows have been recorded from November 1978 to May 1997. Highlands River record was used to prepare a sequence for sensitivity analysis. The drainage area of the Highlands River basin is 72.0 km^2. The missing 1997 and 1998 flows for Little Barachois Brook were filled in using Highlands River flows, adjusted for the difference in drainage area and mean annual runoff.

Mean annual runoffs of 1008 mm/yr and 1123 mm/yr for the reference period were calculated from the hydrometric station records for Little Barachois Brook and Highlands River, respectively. The mean annual runoff of the Lookout Brook basin was estimated during this study to be 1250 mm/yr, greater than Little Barachois Brook and Highlands River due to its higher elevation.

The primary inflow sequence for the simulation was developed by multiplying the Little Barachois Brook flows by the ratios of Lookout Brook basin mean annual runoff and drainage area for each subbasin to Little Barachois Brook mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using Highlands River.

7.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1996 and 1997. The development of the inflow sequences used for the model was described in Section 7.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 2 of this report.

7.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Lookout Brook system

- Cross Pond;
- Joe Dennis Pond; and
- Lookout Brook Forebay.

Different sources of information on storage were available from NP's records. These sources were in agreement. As a further check, the area of the reservoirs were planimetered and compared with the areas provided by NP. The areas were also in agreement.

7.3.2 Generating Station Characteristics

The generating station at Lookout Brook houses two generating units (LBK-G3 and LBK-G4). Since each unit was modelled separately, generating station characteristics were required for each unit.

The units underwent runner replacements in 1998 and 1999, therefore the generating station characteristics were different in the comparison year simulations from those used to estimate the long term production.

Information was sparse for LBK-G3 for the comparison runs, so the plant factor provided by NP was used to develop the generating station characteristics. Index test results were available for LBK-G4 and were used to determine the generating station characteristics. For the run used to estimate long term production, generating station characteristics were based on NP's plant operating guidelines and manufacturers guaranteed curves for both units based on the unit runner replacements. The installed capacities used to estimate the long term production were 2.9 MW for LBK-G3 and 3.1 MW for LBK-G4 for a total capacity of 6.0 MW. This total differs slightly from the nameplate capacity shown in Table 1.1 of 6.2 MW due to the adjustment in installed capacity to account for generator efficiency.

To account for the loss in energy due to the variation in penstock head losses as a function of the power flow at Lookout Brook station, the fixed head loss with one unit generating was input in the model as a constant loss and additional head losses were included in the tailwater curve. Therefore, the tailwater curve does not represent physical water levels at the plant, but synthetic water levels used to account for the drop in net head due to head losses, in addition to the actual variation in tailwater level with flow. Due to these losses the maximum output of Lookout Brook station with both units operating is 5.6 MW.

7.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- Cross Pond gated outlet;
- Cross Pond overflow spillway;
- Joe Dennis Pond gated outlet;

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

Structure curves were estimated based on information provided by NP and standard hydraulic equations.

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 was available.

7.3.4 System Operation

NP's plant operating guidelines for the Lookout Brook system provide the following procedures.

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.*
3.) *Spring runoff may begin in June and continue through July 15 so the watersheds should be near minimums by this time. The runoff can be quite heavy. Inflows in the fall may be heavy as well so the storage levels should be maintained on the lower range going into late September/early October.*
4.) *Cross Pond spills out of the system.*
5.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

Copies of reservoir rule curves in the information provided by NP were used in conjunction with NP's plant operating guidelines to develop the following operating strategy for the modelling.

- If the reservoir levels are below the rule curve, operate LBK-G3 and LBK-G4 at most efficient load.
- If reservoirs are low, only operate LBK-G4 at most efficient load when water is available.
- To avoid going over the rule curve, LBK-G3 is brought up to maximum load.

- If bringing unit LBK-G3 up to maximum load is not enough to keep water level on rule curve, then bring unit LBK-G4 up to maximum load.

The same operating procedures were used for both the comparison runs and the run to estimate long term production.

7.4 Model Comparison

The years selected by NP for the comparison runs were 1996 and 1997. The simulation model was run for these years for both the primary and sensitivity inflow sequences. Figure 7.2 shows the Lookout Brook simulated and recorded monthly generation for these two years.

As Figure 7.2 shows, the simulated generation using both the primary and sensitivity inflow sequences generally follows the same pattern as the recorded generation, except for the last half of 1997, with the primary inflow sequence providing the better estimate. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 7.4.1 below, followed by a discussion of the annual differences in Section 7.4.2.

7.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 7.2 are most likely due to differences between the actual and simulated operation of the system.

Figures 7.3 and 7.4 show comparisons of storage in the main storage reservoirs, Cross Pond and Joe Dennis Pond, respectively. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation, and vice versa. For the months February and March 1996, for example, Figure 7.2 shows that the model generates more energy than was recorded. Figure 7.3 shows that at the end of this period, the model has less water in storage in Cross Pond, because it was used for generation. The opposite effect for April 1996 can be seen in the same figures.

The largest differences in monthly generation occur for the months July to September 1997. These differences can be attributed to the actual operation of the system compared to the assumed operation of the system. Review of NP's records for 1996 and 1997 indicated that there were mechanical problems (cracks in runner blades) with unit LBK-G4. This could explain why the modelled generation differs significantly from the recorded generation in this period and others.

7.4.2 Differences in Annual Generation

Table 7.1 summarizes the annual energy generation for the two comparison years for Lookout Brook station. Simulated annual energy generation is shown using both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values at the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 7.3 and 7.4). The adjustment takes account of the energy potential of the water in storage.

Table 7.1
Lookout Brook Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	27.5	32.5	29.7	33.5	13
1997	28.1	34.9	28.8	32.6	13
Sensitivity Inflow Sequence					
1996	27.5	39.5	29.7	41.1	38
1997	28.1	41.3	28.8	39.0	35

The kinds of operational differences described in Section 7.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage. The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Lookout Brook system is briefly discussed below.

Hydrology

In the case of the Lookout Brook system, the simulation using the primary inflow sequence gave reasonable results for 1996 and 1997 and was used to estimate the long term production as presented in Section 7.5. Although the adjusted results for simulated generation are over 10 percent higher than the actual generation for 1996 and 1997, it is believed that most of the difference is due to forced outages during these years due to the cracks in the runner blades for unit LBK-G4. It is believed that based on the difficulty of estimating the mean annual runoff in this area the best possible estimate for Lookout Brook mean annual runoff has been made and there is no strong evidence that would suggest changing the hydrological estimates.

Differences in Water Use

For the Lookout Brook system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described in Section 7.3.4 and does not account for forced outages which occurred during 1996 and 1997. The two most important factors in the model affecting generation are as follows.

- Ideal operation of the units: The units never operate at less than the most efficient load, although they do operate at higher loads to avoid going over the specified rule curve.

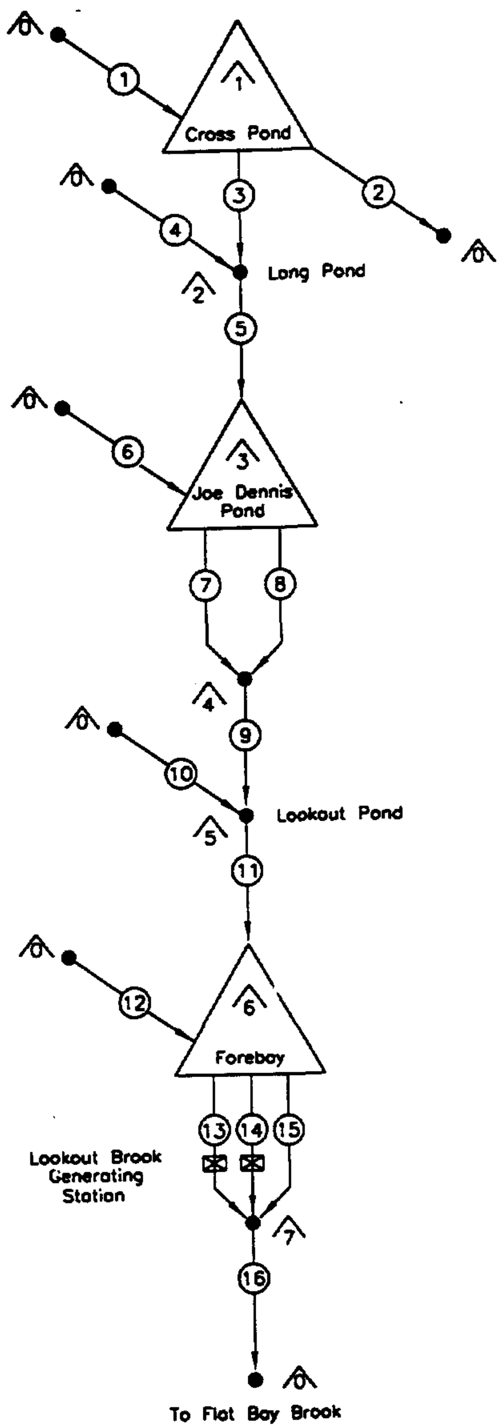
- Ideal operation of reservoirs and control gates to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels in all reservoirs, and opens or closes gates as required to ensure perfect operation of the units and to minimize spill.

A comparison of recorded and simulated spill shows that the values for 1996 were 594 MWh and 400 MWh, respectively and for 1997 were 3408 MWh and 3100 MWh, respectively. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded. The additional actual spill could be partially responsible for the lower recorded energy generation when compared with the simulated. Adjusting the results tabulated above by the difference in recorded and simulated spill for 1996 and 1997 would reduce the discrepancy between simulated and recorded energy generation in both years.

Assumed Characteristics
Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, especially for unit LBK-G3 that had little information available on station characteristics for the comparison runs.

7.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate the long term production for the Lookout Brook system. The result of this simulation was an estimate of long term production of 34.0 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



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
WATER MANAGEMENT STUDY
LOOKOUT BROOK ARSP MODEL SCHEMATIC

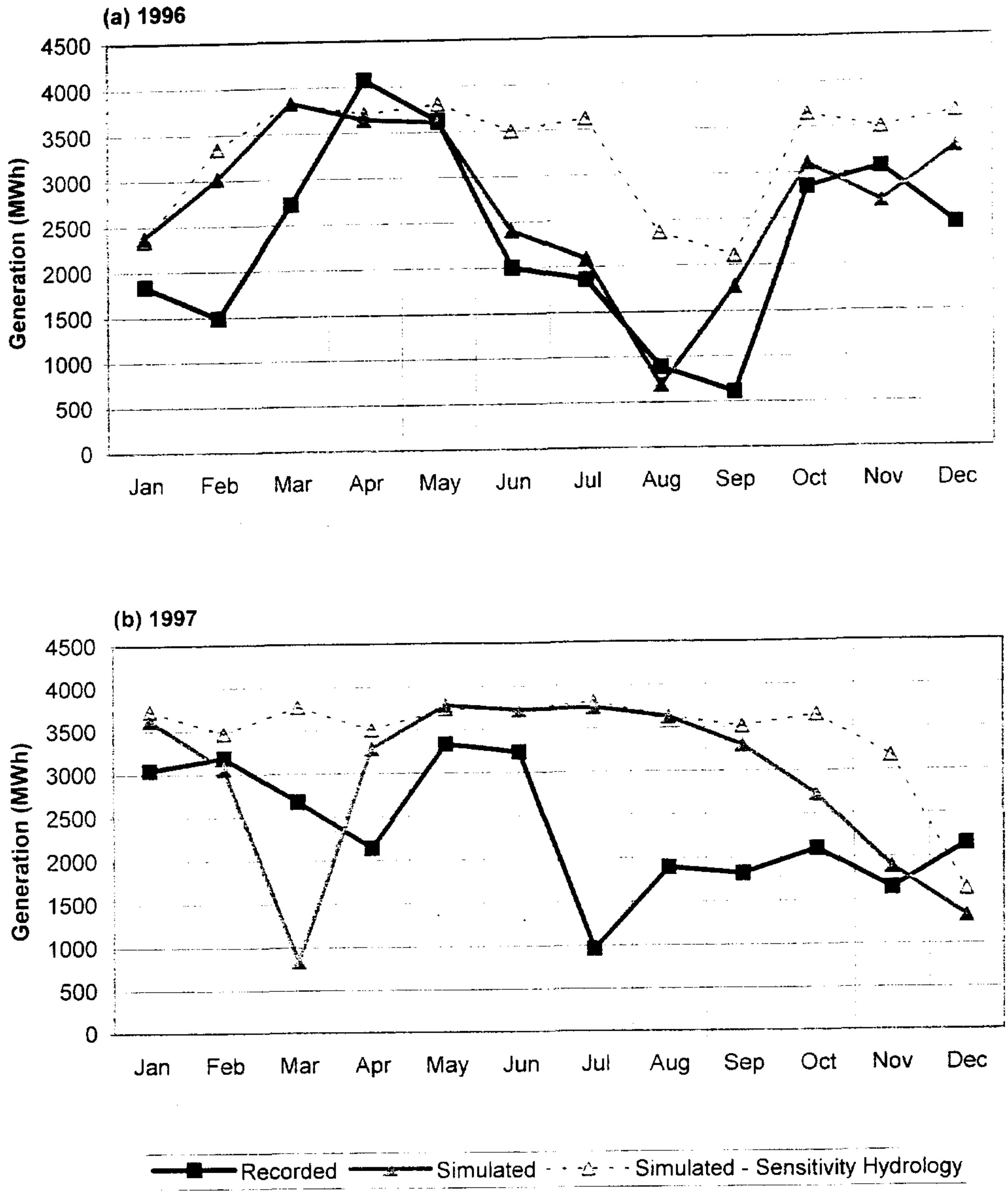


Fig. 7.2

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
LOOKOUT BROOK GENERATION COMPARISON

ACRES

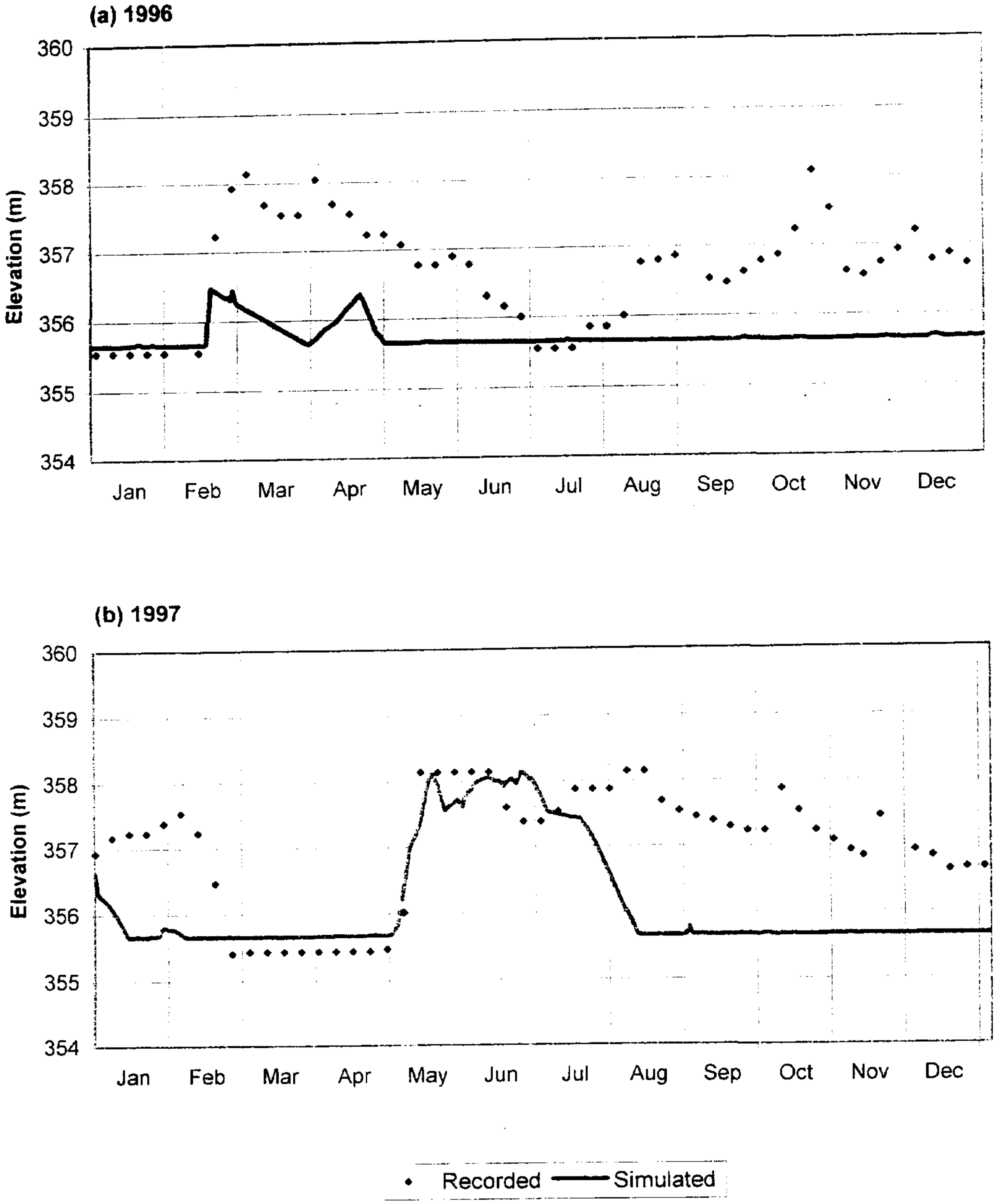


Fig. 7.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

CROSS POND STORAGE COMPARISON

ACRES

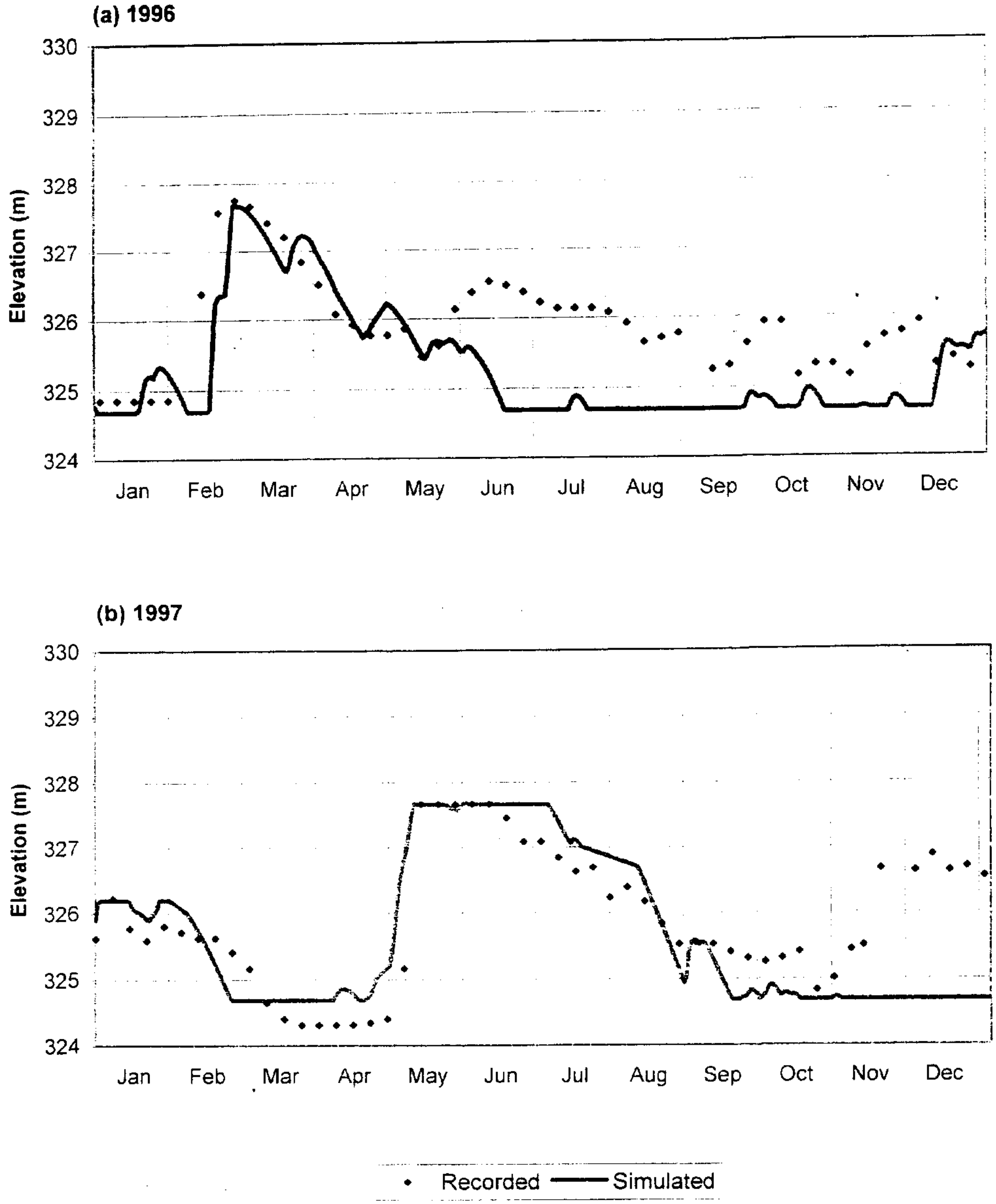


Fig. 7.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

JOE DENNIS POND STORAGE COMPARISON

8 Sandy Brook Hydroelectric System

The long term production for the Sandy Brook Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate normal production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used to calculate the normal production for the entire NP hydroelectric system in Chapter 22.

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.

8.2 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Sandy Brook system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the individual sequences differ only by drainage area.

The two hydrometric stations used to derive the inflow sequences for the Sandy Brook system were Great Rattling Brook above Tote River Confluence (02YO008) and Peters River near Botwood (02YO006). Great Rattling Brook, with a drainage area of 773 km^2, was chosen as the primary station for deriving the Sandy Brook flows. Peters River near Botwood, with a drainage area is 177 km^2, was used to prepare a sequence for sensitivity analysis.

Mean annual runoffs of 883 mm/yr and 801 mm/yr for the reference period were calculated from the hydrometric station records for Great Rattling Brook and Peters River, respectively. The mean annual runoff of the Sandy Brook basin was estimated during this study to be 875 mm/yr.

The primary inflow sequence for the simulation were developed by multiplying the Great Rattling Brook flows by the ratios of Sandy Brook mean annual runoff and local drainage area for each subbasin to Great Rattling Brook mean annual runoff and drainage area. A similar procedure was used to prepare the inflow sequence for the sensitivity analysis using Peters River.

8.3. Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1996 and 1997. The development of the inflow sequences used for the model was described in Section 8.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and for the estimate of long term production. Values used for the final normal production runs are provided in the echo of the input file in Volume 2 of this report.

8.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Sandy Brook system

- Island Pond;
- West Lake;
- Sandy Lake; and
- Sandy Brook Forebay.

Two sets of storage curves were found for each of the reservoirs in the Sandy Brook system. As a means of resolving the discrepancy, the lake areas were planimetered from 1:50 000 scale mapping, and the curve which best represented the area at full supply level was used in the model.

8.3.2 Generating Station Characteristics

Generating station characteristics for the Sandy Brook station were based primarily on data from efficiency testing undertaken by Acres for NP in 1997, supplemented by additional information from NP. The modelled installed capacity was 5.53 MW as indicated in the plant operating guidelines. This capacity is lower than the nameplate capacity because of losses.

To account for the variation in penstock head losses as a function of the power flow, the fixed head loss value in the simulation model input was set to zero, and the head losses were added to the values in the tailwater curve. Therefore, the tailwater curve does not represent physical water levels at the plant, but synthetic water levels used to account for the drop in net head due to head losses, in addition to the actual variation in tailwater level with flow.

8.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- 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.

Many of the structure curves provided by NP reflected the outlets prior to replacement, in which cases curves were taken from previous modelling by NP, or were estimated using standard hydraulic equations.

During spring, there may be flow over the top of the closed gates of the Sandy Brook Forebay gated spillway. This was modelled by adding that flow capacity to the Sandy Brook Forebay overflow spillway capacity during the appropriate months.

For the purpose of maintaining flow in the river reaches downstream of the low level gated outlets for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water was available.

8.3.4 System Operation

NP's plant operating guidelines for the Sandy Brook system provide the following procedures.

1.) *Operate at best efficiency unless heavy inflow expected or happening. The unit efficiency drops dramatically above 5100 kW.*
2.) *The plant has a large drainage area and is prone to spilling during heavy inflows. Reservoirs should be brought to their minimum level prior to spring runoff (March). At that time the plant should be cycled on and off at best efficiency to keep the forebay within limits. In advance of rainstorms, bring forebay down as low as possible by operating at best efficiency or full load as necessary.*
3.) *Typically Sandy Lake should be kept at a maximum of 3' from mid September to the end of October to enable the proper capture of fall precipitation.*
4.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

The operator at Sandy Brook indicated that during spring the forebay is usually operated slightly below full supply level, to allow for high inflows without spill. Following spring runoff, flashboards are added to the top of the spillway gates to allow the forebay to be kept higher.

The operating procedures, the information from the operator, and the recorded reservoir levels were used to develop the following operation strategy for use in the modelling.

- Set the forebay target level half way between the upper and lower bounds of the operating range given in the plant operating guidelines. (This average was lower than the levels indicated by the operator, but more closely matched recorded levels.)
- If the forebay water level is below full supply level, operate the unit at best efficiency.
- Release water from Sandy Lake and West Lake to keep the unit operating at best efficiency, and to keep the forebay at its target level. (At times the use of storage is limited by the capacity of the outlet facilities.)

- If the forebay water level is above the full supply level, operate the unit at maximum flow and close West Lake and Sandy Lake gates, unless this would lead to spill from the upstream reservoirs.
- If the forebay level continues to rise, initiate spill.
- If the water levels in Sandy Lake and West Lake approach full supply level (or targeted drawdown levels in spring), release water and increase generation above best efficiency if required.
- Maintain a minimum environmental release of 0.1 m^3/s (even if this leads to generation above best efficiency or spill downstream).

The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

8.4 Model Comparison

The years selected by NP for the comparison runs for the Sandy Brook Hydroelectric System were 1996 and 1997. The simulation model was run for these two years using both the primary and sensitivity inflow sequences. Figure 8.2 shows the simulated and recorded monthly generation.

As Figure 8.2 shows, the simulated generation using the primary inflow sequence generally follows the same pattern as the recorded generation, though there is some variation month to month. The annual simulated energy is greater than the recorded energy in both years.

There are differences between the recorded values both within each year, and also on an annual basis. The within-year variation is discussed in Section 8.4.1 below, followed by a discussion of the annual differences in Section 8.4.2.

8.4.1 Differences in Monthly Generation

The differences in generation through the year, as shown in Figure 8.2, can be due to differences in operation and in hydrology. In the case of the Sandy Brook system the differences are principally due to differences between the actual and simulated operation of the system. Figures 8.3 and 8.4 show comparisons of storage in the main reservoirs, Sandy Lake and West Lake. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation. Figure 8.2 shows that in January 1996, for example, the model generates more energy than was recorded. Figure 8.3, however, shows that at the end of the month, the model has less water in storage in West Lake, because the water was used for generation.

Differences between simulated and recorded storage can be due to recorded data problems; this appears to be the case for Sandy Lake. Figure 8.4 shows that the simulations do not reproduce the recorded low water levels in Sandy Lake in the March to September periods of both years. The fact that the generation during these periods is relatively well reproduced by the model suggests that the error is in the data rather than in the simulation. The low levels reported at Sandy Lake do not seem reasonable; in fact a comparison of the volume of drawdown during February 1997 with the estimated inflows shows that capacity in excess of that at the outlet would be required to reproduce the recorded levels. The most likely explanation is that the recorded levels are often estimated rather than measured. Since access is difficult, and no gate changes are needed in summer, operators are rarely required to visit Sandy Lake Dam. If recorded levels have been estimated rather than measured, this would explain the apparent discrepancy in both years.

8.4.2 Differences in Annual Generation

Table 8.1 summarizes the annual energy generation for the two comparison years, for both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 8.3 and 8.4). The adjustment takes account of the energy potential of the water in storage.

Table 8.1
Sandy Brook Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	30.0	33.7	30.4	34.2	13
1997	29.8	30.2	27.9	28.8	3
Sensitivity Inflow Sequence					
1996	30.0	34.0	30.4	34.0	12
1997	29.8	30.7	27.9	30.0	8

The kinds of operational differences described in Section 8.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates);
- inaccurate assumptions regarding characteristics of the system.

Each of these is briefly discussed below.

Hydrology
In the case of the Sandy Brook system, the simulation using the primary gauge gave reasonable results and was used to estimate the long term production as presented in Section 8.5.

Differences in Water Use
For the Sandy Brook system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs

according to the specified operating procedures described above. The two most important factors affecting generation are as follows.

- Ideal operation of the unit: In the model, the unit never operates at a flow less than the most efficient load, although it does operate at higher flows if the reservoir is above the target water level.
- Ideal operation of reservoirs and control gates to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels, and opens gates as required to pass water downstream if there is room in a downstream reservoir, or if the unit can handle the flow.

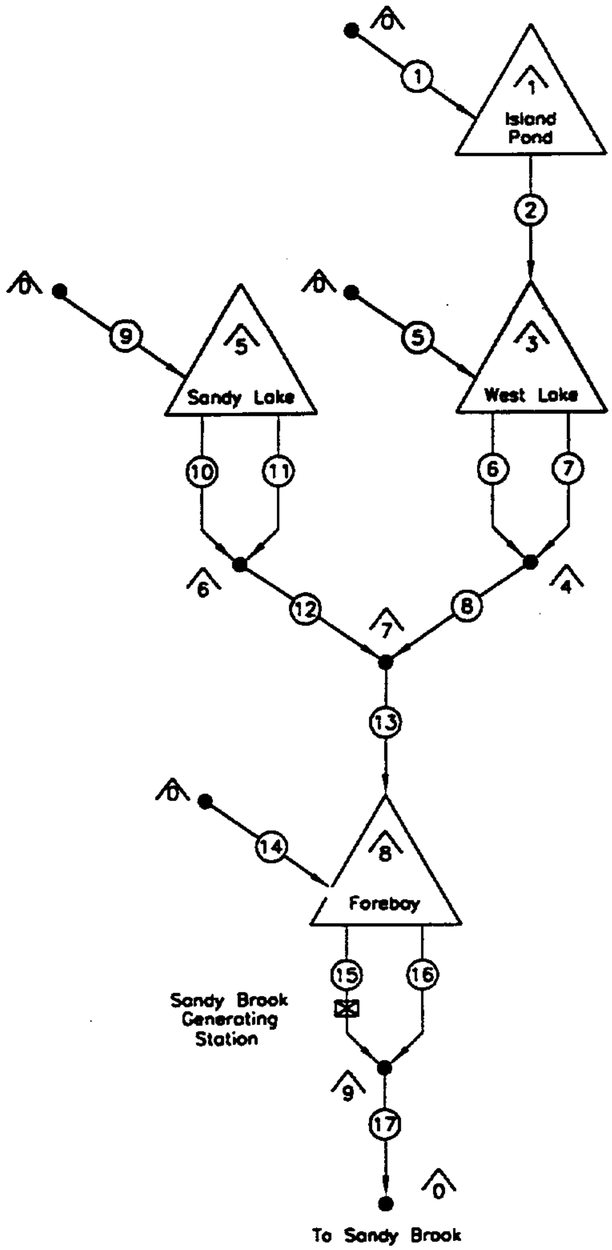
A comparison of recorded and simulated spills shows that the values for 1996 were 0.16 MWh and 0.77 MWh, respectively. For 1997 the recorded and simulated spills were 6.07 MWh and 5.97 MWh, respectively. NP cautions that recorded spill data is often not reliable, and this would seem to be the case for 1996. It is unlikely that the simulation model would overestimate spill; some unreported spill seems likely. Adjusting the results tabulated above by the difference in recorded and simulated spill would reduce the discrepancy between simulated and recorded energy generation in 1996, but increase the discrepancy in 1997.

An additional small source of the discrepancy in the annual energy values may be the modelled storage in Island Pond, upstream of West Lake. Though the pond is modelled, there are no recorded values for comparison; so the energy values were not adjusted for change in storage at Island Pond.

Assumed Characteristics
Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves.

8.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate a long term production for the Sandy Brook system of 28.1 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production, provided in Chapter 22.



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
WATER MANAGEMENT STUDY
SANDY BROOK ARSP MODEL SCHEMATIC

ACRES

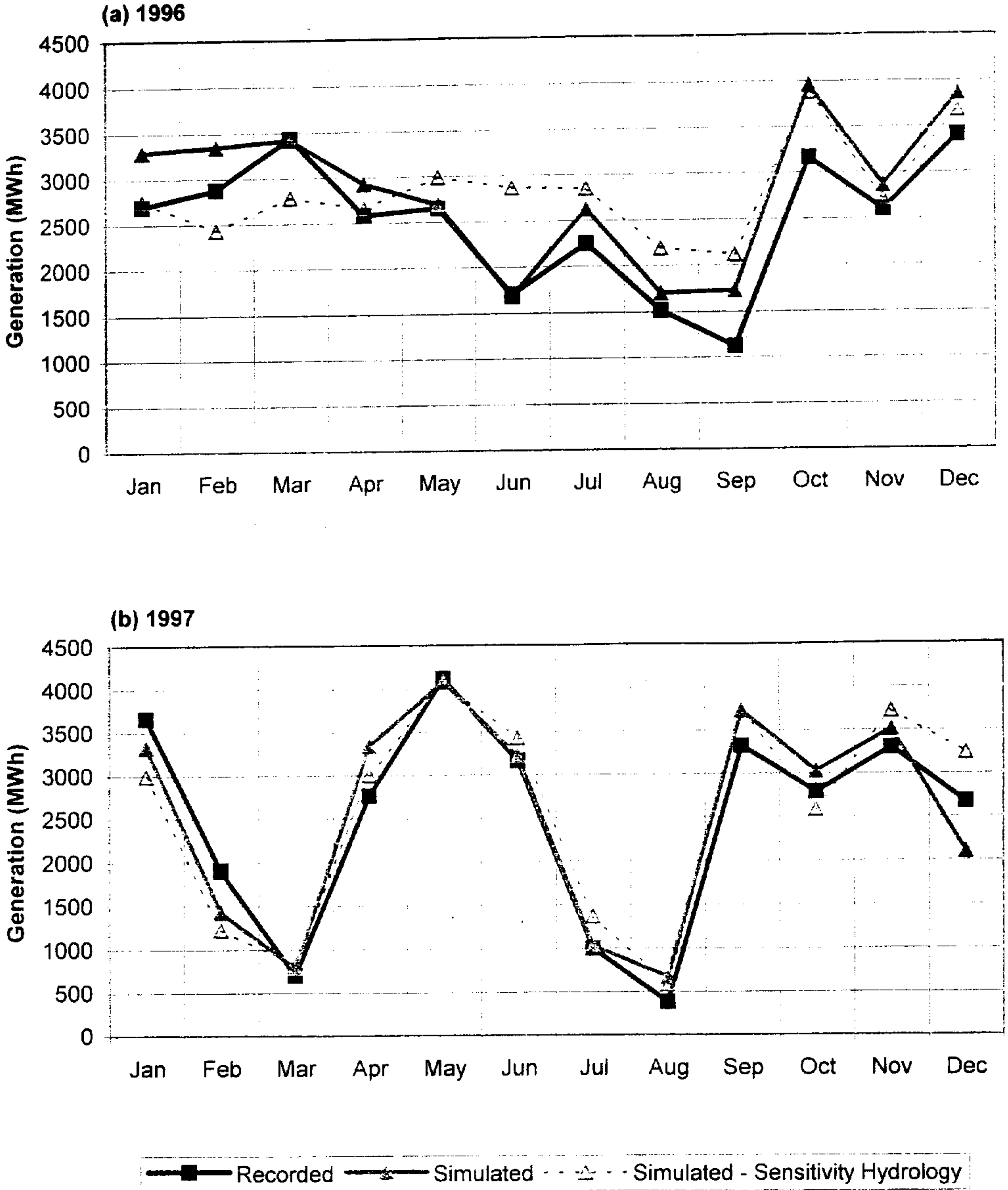


Fig. 8.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

SANDY BROOK GENERATION COMPARISON

ACRES

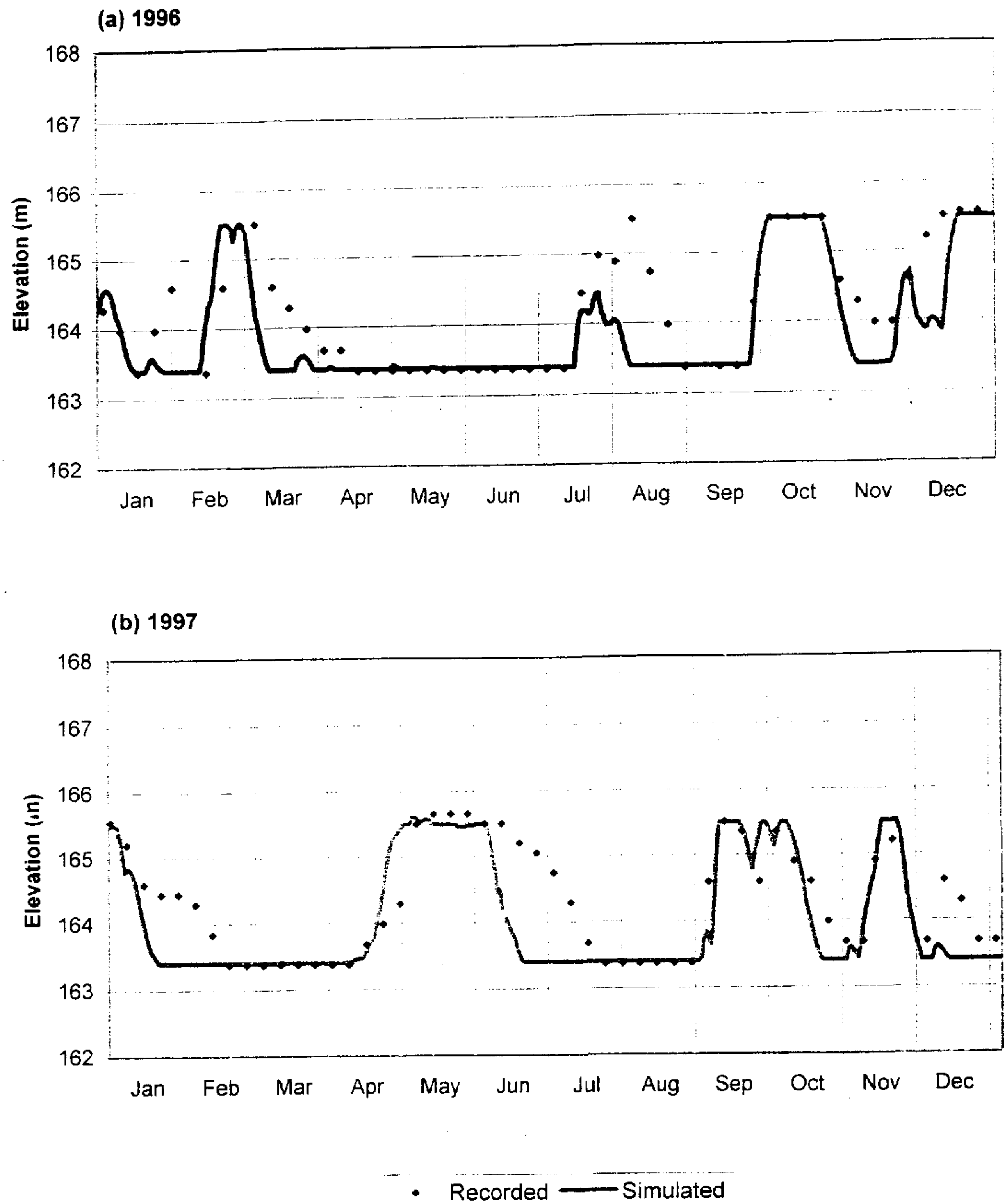


Fig.8.3

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
WEST LAKE STORAGE COMPARISON

ACRES

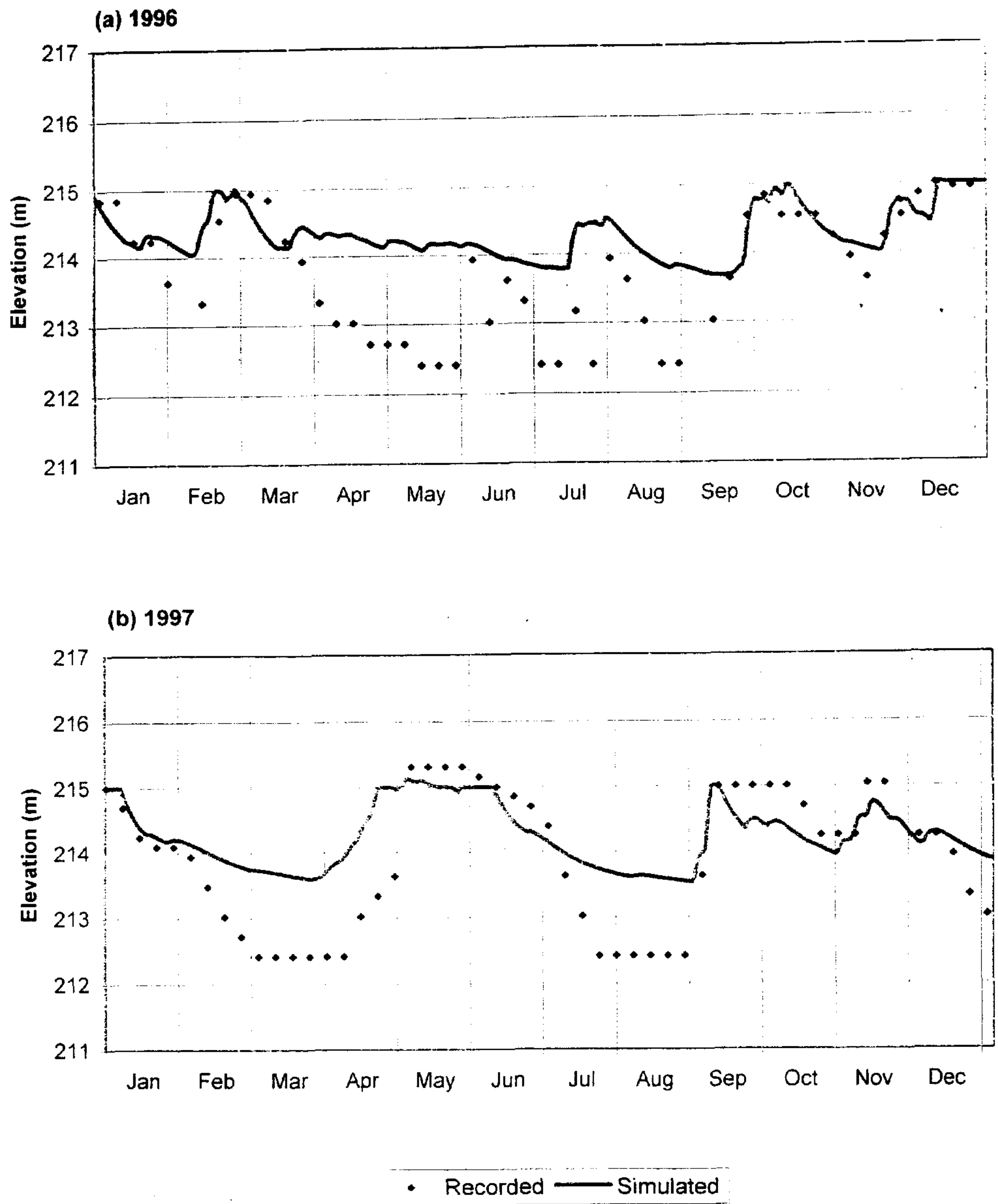


Fig.8.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

SANDY LAKE STORAGE COMPARISON

ACRES

9 Pierres Brook Hydroelectric System

The long term production for the Pierres Brook Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate normal production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system is Chapter 22.

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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Pierres Brook system subbasins were derived by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The mean annual runoff was assumed to be the same for all subbasins, so the subbasin sequences differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Pierres Brook system were South River near Holyrood (02ZM016) and Waterford River at Kilbride (02ZM008). The record for the South River station was chosen as the primary source for deriving the Pierres Brook flows. The drainage area of the South River station is 17.3 km^2. The record for the Waterford River station was used to prepare a sequence for sensitivity analysis. The drainage area of the Waterford River station is 52.7 km^2.

Mean annual runoffs of 1332 mm/yr and 1293 mm/yr were calculated from the hydrometric station records for the reference period for the South River and Waterford River basins, respectively. The mean annual runoff of the Pierres Brook basin was estimated during this study to be 1300 mm/yr.

The primary inflow sequence was developed by multiplying the South River flows by the ratios of Pierres Brook mean annual runoff and subbasin drainage area to South River mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using Waterford River.

9.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequences used for the model was described in Section 9.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and the estimate of long term production. Values used for the long term production runs are provided in the echo of the input file in Volume 2 of this report.

9.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Pierres Brook system

- Witless Bay Country Pond;
- Big Country Pond; and
- Gull Pond.

There were various sources of information provided by NP on reservoir storage volumes and operating levels, some of which contained conflicting data. Discrepancies were resolved in consultation with NP personnel. Operating levels were taken from the NP plant operating guidelines, and storage volumes were based on NP energy storage tables.

9.3.2 Generating Station Characteristics

Generating station characteristics were based on information provided by NP. Since it was assumed that the unit is always operated in the narrow range between best efficiency flow and maximum load, it was assumed that head loss is more or less constant whenever the unit is in operation. A value of 8.8 m was assumed, the same value used by NP in a previous model of the Pierres Brook system.

An average tailwater elevation was estimated, based on the estimated gross head.

9.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

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

For most of these structures, previously established curves were not available, and therefore the curves were estimated from available information using standard hydraulic equations.

For the purpose of maintaining flow in the river reaches downstream of the low level outlet gates for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water was available.

9.3.4 System Operation

The plant operating procedures for the Pierres Brook Hydroelectric System provide the following guidelines.

1.) Plant inflows are such that this plant is in operation 75 to 80% of the time.
2.) Operate unit at best efficiency unless heavy inflows are predicted to occur.

3.) *Prior to spring runoff, Gull Pond elevation should be lowered to the minimum.*
4.) *Big Country Pond gate usually kept at 3" to 5" in summer and West Country Pond gate kept at 3" in summer.*
5.) *Flow has to be maintained to the Lower Pond for at least 2 hours per day for fisheries. If the plant has to be off for more than 24 hours an alternate method of providing flow must be established.*
6.) *West Country Pond spill out of the system.*
7.) *Fish plant is fed from the penstock.*
8.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*
9.) *During cold weather, shut down the plant and let the forebay freeze over to prevent frazil ice formation on the trashracks.*

The operating procedures, the information from the operator, and the recorded reservoir levels were used to develop the following operating strategy for use in the modelling.

- If the reservoir levels are low, provide enough water from Witless Bay Country Pond and Big Country Pond to keep the unit operating at best efficiency and to keep Gull Pond at its target level.
- If the levels are high (indicating high inflows), increase unit load to maximum. At these times, draw water from Witless Bay Country Pond before Big Country Pond, since Witless Bay Country Pond spills out of the system.
- Maintain environmental releases as long as there is water.
- When there is a flow demand imposed by the fish processing plant, satisfy this demand before using any water for generation.

The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

Shutdowns to prevent frazil ice formation are of short duration and were not modelled.

9.4 Model Comparison

The simulation model was run for these the comparison years of 1997 and 1998 for both the primary and sensitivity inflow sequences. Figure 9.2 shows the simulated and recorded monthly generation.

As Figure 9.2 shows, the simulated generation using the primary inflow sequence generally follows the same pattern as the recorded generation. There are some monthly differences between simulated and recorded generation, notably in the summers. The annual simulated energy is greater than the recorded energy in both years. The within-year (month to month) variation is discussed in Section 9.4.1 below, followed by a discussion of the annual differences in Section 9.4.2.

9.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 9.2 can be due to differences in operation or in hydrology. In the case of the Pierres Brook system it is principally due to differences between the actual and simulated operation of the system. Figures 9.3 and 9.4 show comparisons of storage in Big Country Pond and Witless Bay Country Pond. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation.

The dam at Big Country Pond was reconstructed during the period from the end of July to mid-October 1997, which may have affected the storage levels at that time. Some outages and system downtime in August and September of 1998 (about 400 hours total) likely contributed to the lower recorded production in those months. The higher generation by NP in the following months of October and November results from the use of the previously stored water.

The sensitivity inflow sequence provided better tracking of water levels, and more consistent results in the two years.

9.4.2 Differences in Annual Generation

Table 9.1 summarizes the annual energy generation for the two comparison years, with results for the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 9.3 and 9.4). The adjustment takes account of the energy potential of the water in storage.

Table 9.1
Pierres Brook Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1997	26.3	30.2	24.8	29.1	17
1998	28.2	30.1	29.1	29.3	1
Sensitivity Inflow Sequence					
1997	26.3	29.0	24.8	26.9	8
1998	28.2	31.9	29.1	31.7	9

The kinds of operational differences described in Section 9.4.1, such as holding water back rather than generating, account for the differences in energy from month to month, but should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

Each of these is briefly discussed below.

Hydrology

In the case of the Pierres Brook system, the sensitivity inflow sequence gave more reasonable results than the primary sequence and so the sensitivity inflow sequence was used to estimate the long term production in Section 9.5.

Differences in Water Use

For the Pierres Brook system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the input operating strategy in Section 9.3.4. The two most important factors affecting generation are as follows.

- Ideal operation of the unit: In the model, the unit never operates at a flow less than the most efficient load, although it does operate at higher flows if the reservoir levels are high.
- Ideal operation of reservoirs and control gates to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels, and opens gates as required to pass water downstream if there is room in a downstream reservoir, or if the unit can handle the flow.

No spill was recorded or simulated in either of the two comparison years.

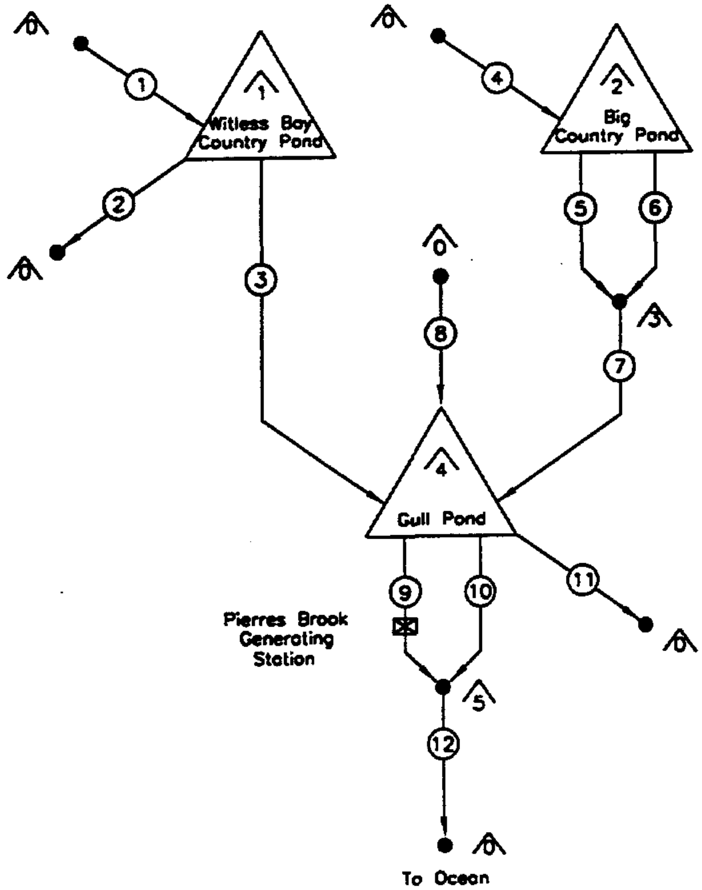
The above results assume no fish plant demand. The flow demand estimated for fish plant use was 0.023 m^3/s, as explained in Section 9.1. If the fish plant had been drawing water continuously at this rate in either of those years, the average annual energy would have been reduced by just over 0.1 GWh, or less than one-half percent.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves.

9.5 Simulated Long Term Production

The system operation was simulated using the sensitivity inflow sequence for the 15 year reference period to estimate the long term production for the Pierres Brook system of 26.7 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

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

RESERVOIRS / NODES

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

WATER MANAGEMENT STUDY

PIERRES BROOK ARSP MODEL SCHEMATIC

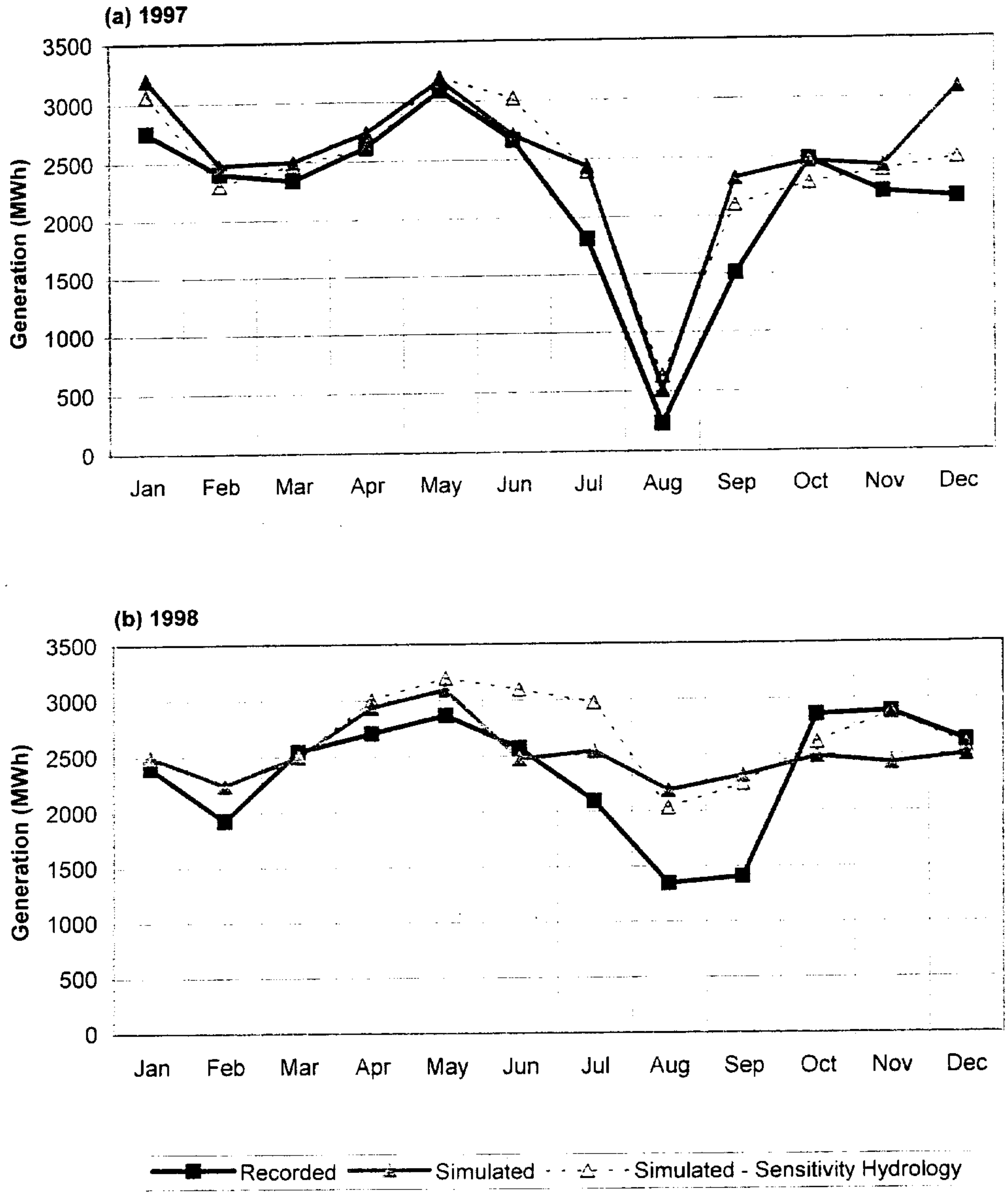


Fig. 9.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

PIERRES BROOK GENERATION COMPARISON

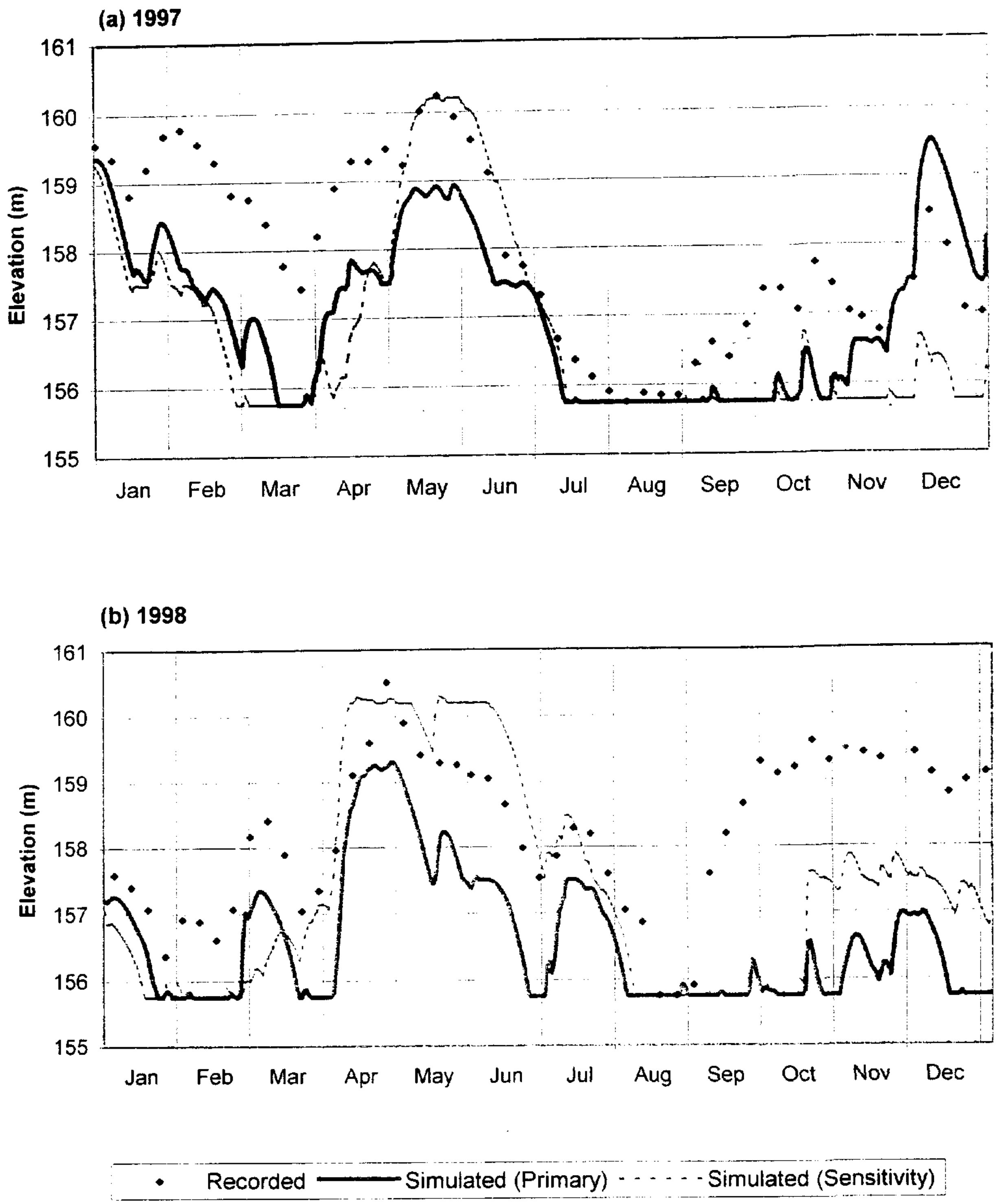


Fig. 9.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

BIG COUNTRY POND STORAGE COMPARISON

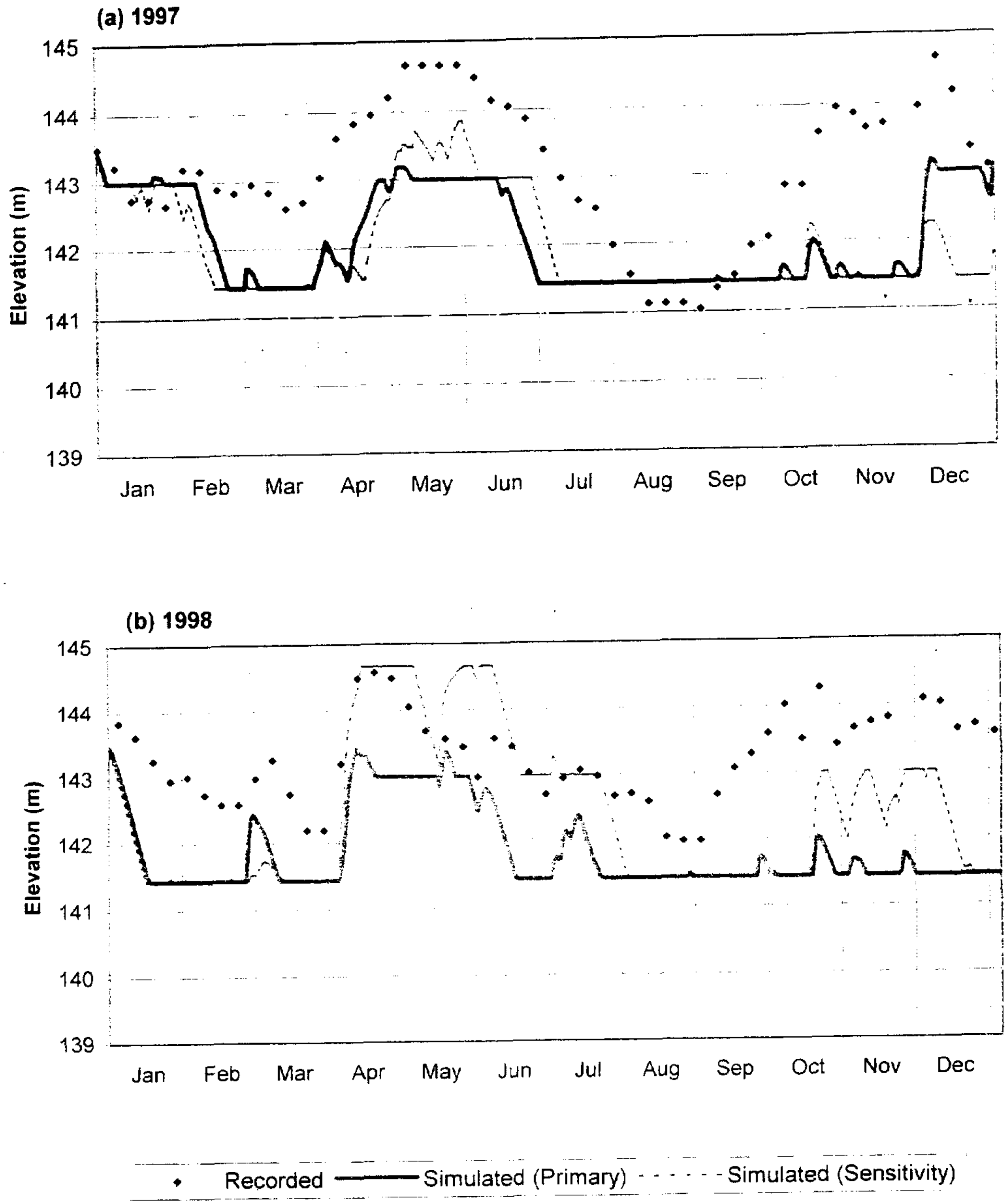


Fig. 9.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

WITLESS BAY COUNTRY POND STORAGE COMPARISON

10 Rose Blanche Brook Hydroelectric System

The long term production for the Rose Blanche Brook Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for a selected comparison period;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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 Inflow Sequences

The daily inflow sequence required for the simulations was generated using the methodology presented in Chapter 2 of this report.

Only one hydrometric station was suitable for use in deriving the hydrology for the Rose Blanche Brook system, Isle Aux Morts River below Highway Bridge (02ZB001) with a drainage area of 205 km^2. The hydrology from Isle aux Morts was used in the design studies for Rose Blanche and has been found to be reliable. Due to the proximity of the two basins, they likely have the same mean annual runoff and therefore the proration factor was based on drainage area alone.

10.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The development of inflow sequence used for the model was described in Section 10.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison runs and for the estimate of long term production. Values used for the model runs to estimate long term production are provided in the echo of the input file in Volume 2 of this report.

10.3.1 Reservoir Characteristics

Characteristics for Rose Blanche Brook Forebay were provided by NP in the form of an elevation-volume-area chart.

10.3.2 Generating Station Characteristics

Generating station characteristics for the Rose Blanche Brook station were based primarily on data from performance and index testing undertaken by the manufacturer (Sulzer) in February 2000. The characteristics of the two units were combined in the model. The modelled capacity for the combined units was 5.8 MW, lower than the nameplate capacity of 6.0 MW because of the losses associated with the operation of the two units together.

There is a fisheries valve at the powerhouse which is opened to release a flow of up to 1 m^3/s, depending on water availability, at times when the units are shut down. The units can operate down to flows of 0.5 m^3/s. The flow efficiency curve was entered with an efficiency of 0 percent at flows below 0.5 m^3/s to model the release of fisheries flow without generation.

To account for the variation in penstock head losses as a function of the power flow, the fixed head loss value in the model input was set to zero, and the head losses were added to the values in the tailwater curve. Therefore, the tailwater curve does not represent physical water levels at the station, but synthetic water levels used to account for the drop in net head due to head losses, in addition to the actual variation in tailwater level with flow.

10.3.3 Structure Characteristics

A stage discharge curve for the Rose Blanche Brook forebay overflow spillway was provided by NP.

10.3.4 System Operation

NP's plant operating guidelines for the Rose Blanche Brook system provide the following procedures.

1.) *When flows are minimal operate either Unit #1 or Unit #2 at best efficiency point. Water management scheme calls for the operation of both units simultaneously when water level reaches 160.0.*
2.) *Prior to spring runoff Rose Blanche Forebay should be brought to minimum levels.*
3.) *Open 20" fisheries valve at the main dam a minimum of four hours prior to dewatering penstock.*
4.) *DFO Agreement requires that a minimum flow of 1.0 cms is maintained in the Rose Blanche River at all times. Once the turbines shut-down in the powerhouse, the 16" fisheries valve is required to open to provide 1.0 cms.*
5.) *The Rose Blanche River downstream of the powerhouse supplies a holding pond for the Town of Rose Blanche and Town of Harbour LeCou water supply.*

These procedures were used to develop the following operating strategy for use in the modelling.

- For most of the year, operate the forebay with a target level half way between the upper and lower bounds of the operating range given in the operating guidelines.
- In spring, operate with a target level at the lower bound of the operating range given in the operating guidelines.
- If the forebay water level is below full supply level, operate one or both units at best efficiency, if possible.
- If the forebay water level is low, and inflows are low, operate one unit to pass inflow, down to the minimum unit flow.
- At flows below minimum for the units, release the water with no generation, for fisheries purposes.
- If the forebay water level is above the full supply level, operate the units at maximum flow.

The same operating procedures were used for both the comparison run and the runs to estimate long term production.

10.4 Model Comparison

Because the station is new, only limited data are available for comparison. The simulation model was run for the last eight months of 1999 and the first six months of 2000. Figure 10.2 shows the simulated and recorded monthly generation for comparison.

As Figure 10.2 shows, the simulated generation generally follows the same pattern as the recorded generation, though there is some variation month to month. The energy for the whole 13-month period is overestimated, as discussed below.

10.4.1 Differences in Monthly Generation

The differences in generation through the period shown in Figure 10.2 can be due to differences in operation and in hydrology. In the case of the Rose Blanche Brook system it is principally due to differences between the actual and simulated operation of the system.

Figure 10.3 shows comparisons of the storage in the forebay. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation. In February 2000, for example, Figure 10.2 shows that the model generates more energy than was recorded. Figure 10.3, however, shows that the end of the month, the model has less water in storage, because it was used for generation. In this case, ARSP was drawing down the reservoir in accordance with the operating guidelines.

At Rose Blanche, the start-up activities ongoing in 1999 lead to differences between the recorded and simulated energy and water levels. No energy generation was recorded in July of 1999, but as Figure 10.3 shows, the water level was drawn down, likely through use of the fisheries valve. This water was lost from the system and therefore there was no generation later in the period to balance the simulated overestimate.

10.4.2 Differences in Annual Generation

Table 10.1 summarizes the energy generation for the two comparison periods. The results are adjusted for the difference in energy in storage from the beginning to the end of the period. Although the water levels in the simulation started at the recorded values, by the end of the simulated period the water levels in the simulation were usually different from the recorded values (as shown in Figure 10.3). The adjustment takes account of the energy potential of the water in storage.

Table 10.1
Rose Blanche Brook Generating Station Recorded and Simulated Annual Energy Generation

Year	Energy Generation (GWh) *				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
May -Dec 1999	15.9	17.2	15.3	16.7	9
Jan - Jun 2000	16.2	17.1	16.1	17.3	7

* Note that because only May to December,1999 and January to June, 2000 were considered, the energy values tabulated are for 7 and 6 months respectively, they are not annual values

The kinds of operational differences described in Section 10.5.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the total energy after adjusting for storage. The differences in total energy arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of storage; and
- inaccurate assumptions regarding characteristics of the system.

Each of these is briefly discussed below.

Hydrology

In the case of the Rose Blanche Brook system, the simulation using the primary gauge gave reasonable results and was used to estimate the long term production as presented in Section 10.5.

Differences in Water Use

For the Rose Blanche Brook system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described above. The two most important factors affecting generation are as follows.

- Ideal operation of the unit: In the model the units always operate at the most efficient load except where flow is constrained by the fisheries requirement. The units operate at higher flows if the reservoir is above the target level.
- Ideal operation of storage to maximize flow for energy generation and minimize spill.

Spill has only recently started to be recorded at Rose Blanche Brook. A comparison of recorded and simulated spills shows that the values for 2000 were 3.8 GWh and 3.0 GWh, respectively. Adjusting the results tabulated above by the difference in recorded and simulated spill would reduce the discrepancy. Accounting for the water discharged through the fisheries valve in July 1999 would also reduce the discrepancy.

Discussions with NP indicate that ongoing start-up activities may have affected generation through to January 2000. A comparison of the generation in February through June 2000 indicates an overestimate of only two percent. As Rose Blanche Brook is a run-of-river system with modern control equipment, it is expected that actual production at this plant should more closely approach the model's perfect operation.

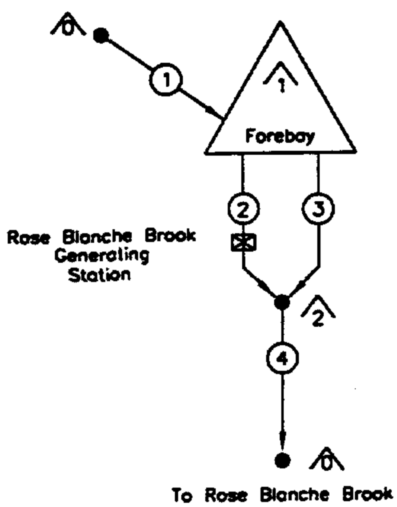
Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves.

10.5 Simulated Long Term Production

The system operation was simulated using the derived inflow sequence for the 15 year reference period to estimate a long term production for the Rose Blanche system of 22.4 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production, provided in Chapter 22.

Due to the shorter period of streamflow records used in this study, the energy estimate is somewhat lower than the long term production estimate for Rose Blanche used in design.



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
WATER MANAGEMENT STUDY
ROSE BLANCHE BROOK ARSP MODEL SCHEMATIC

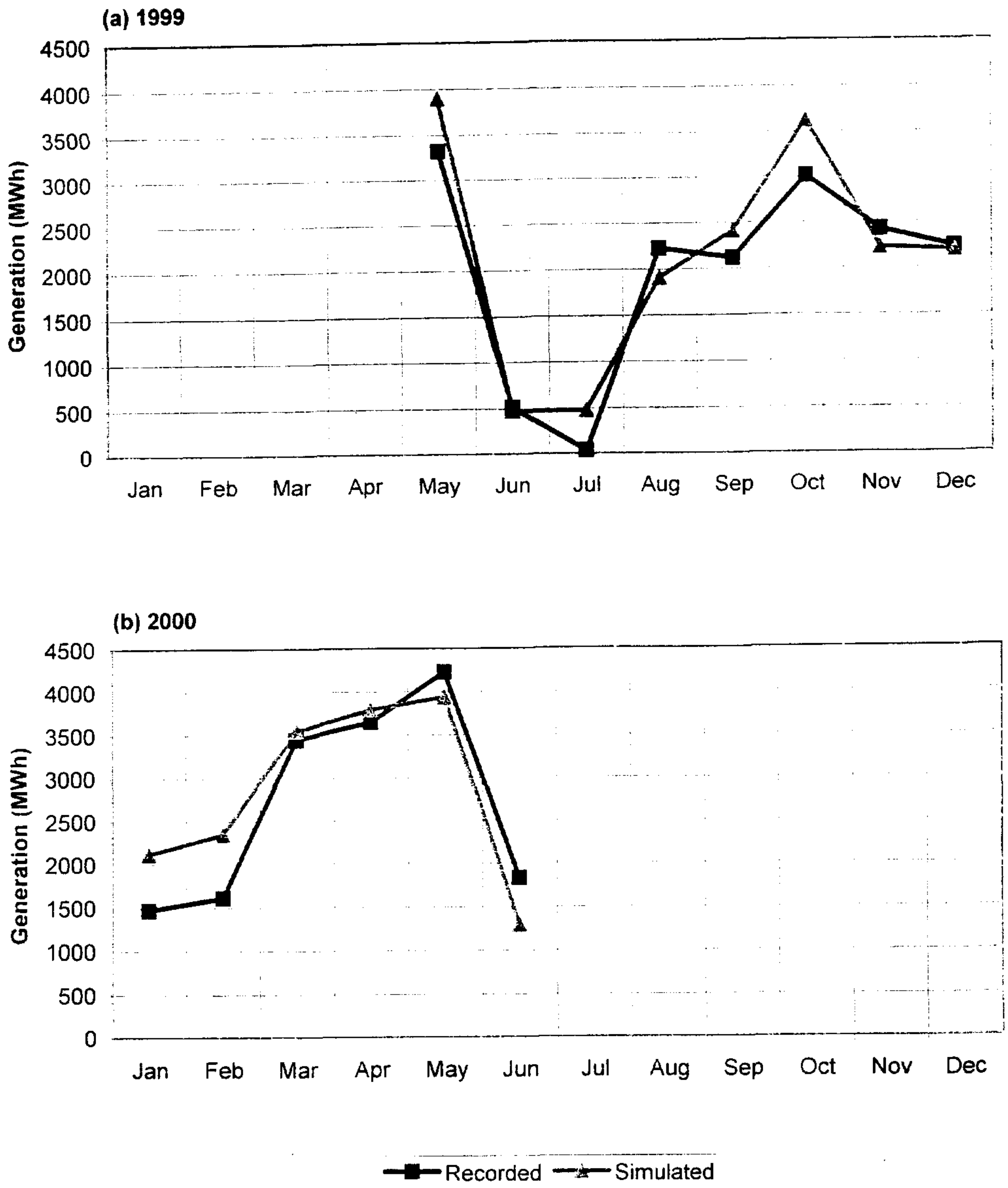


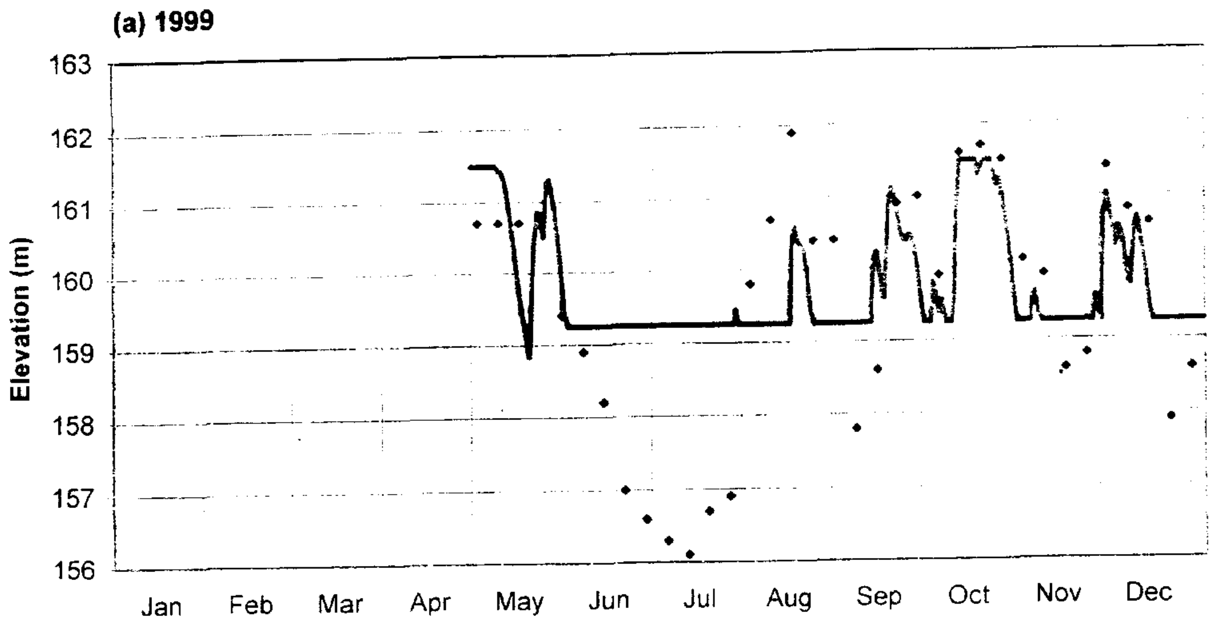
Fig. 10.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

ROSE BLANCHE BROOK GENERATION COMPARISON

ACRES



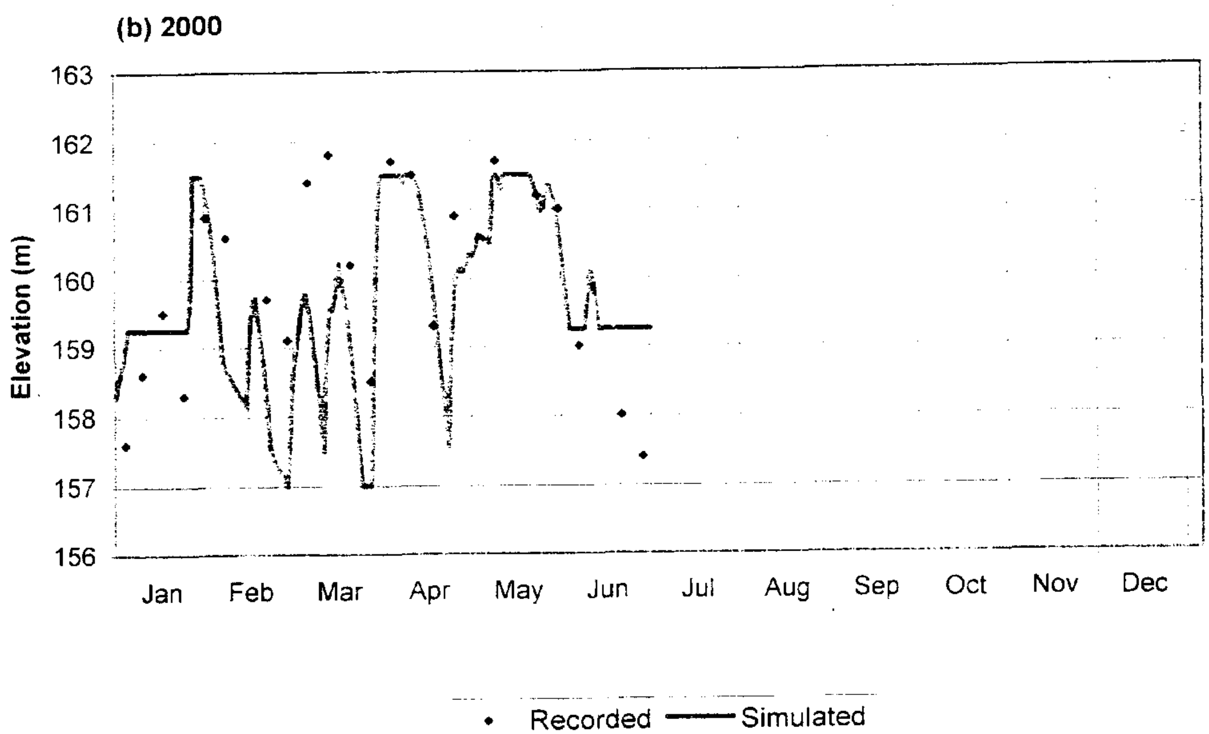


Fig. 10.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

ROSE BLANCHE BROOK STORAGE COMPARISON

ACRES

11 Petty Harbour Hydroelectric System

The long term production for the Petty Harbour Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. The estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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
- 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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. For each subbasin in the Petty Harbour system, an inflow sequence was derived by prorating the recorded flows at nearby hydrometric stations, according to drainage area and mean annual runoff. The mean annual runoff was assumed to be the same for all subbasins, so the subbasin sequences differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Petty Harbour system were Waterford River at Kilbride (02ZM008) and South River near Holyrood (02ZM016). The Waterford River station has a drainage area of 52.7 km^2. The record from the Waterford River station was chosen as the primary source for deriving the Petty Harbour system subbasin flows. The South River record was used to prepare a sequence for sensitivity analysis. The drainage area of the South River station is 17.3 km^2.

Mean annual runoffs of 1293 mm/yr and 1332 mm/yr were calculated for the reference period from the hydrometric station records for Waterford River and South River, respectively. The mean annual runoff of the Petty Harbour basin was estimated during this study to be 1300 mm/yr.

The primary inflow sequence for the simulation was developed by multiplying the Waterford River flows by the ratios of Petty Harbour mean annual runoff and subbasin drainage area to Waterford River mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using South River.

11.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1996 and 1997. The development of the inflow sequences used for the model was described in Section 11.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of long term production. Values used for the long term production are provided in the echo of the input file in Volume 2 of this report.

11.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Petty Harbour system

- Bay Bulls Big Pond;
- Cochrane Pond; and
- Forebay.

Various sources of information on the reservoir characteristics were provided by NP. All information on reservoir operating levels was generally in agreement, but there was some disagreement in storage volumes. Model input storage volumes were finalized in consultation with NP. For Bay Bulls Big Pond and Cochrane Pond, volumes were obtained from an as-built storage curve and a previous flood study by NP, respectively. For the forebay, volumes were estimated from 1:25,000 scale topographic mapping.

11.3.2 Generating Station Characteristics

Generating station characteristics were based on information provided by NP. The station at Petty Harbour has three generating units (PHR-G1, PHR-G2 and PHR-G3), supplied by a single penstock. Since the units were modelled separately, characteristics were required for each unit.

To account for the variation in penstock head loss as a function of the power flow, a synthetic tailwater curve including both tailwater and head losses was estimated. However, the model was not able to converge on a solution for multiple units on a single penstock using this curve. As an alternative, using flow duration analysis and knowing the order of unit dispatch (Section 11.3.4), it was possible to estimate the average penstock flows occurring during the times each unit was in use. An average head loss for each unit was then calculated, and entered as a fixed value.

The original woodstave penstock was replaced by a steel penstock in 1999, and the head losses are expected to be reduced as a result. The estimated head losses in the new steel penstock were applied to the model for estimating long term production. However, the estimated head losses in the old woodstave structure were used in the comparison runs, since both of the selected comparison years were prior to penstock replacement.

An average tailwater elevation was estimated by matching the average power flow to levels recorded during index testing of the Petty Harbour units.

11.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

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

For the purpose of maintaining flow in the river reaches downstream of the gated outlet for environmental reasons, the minimum flow of all gates was set to 0.1 m^3/s, if water was available.

11.3.4 System Operation

The plant operating guidelines for the Petty Harbour Hydroelectric System provide the following procedures.

1.) *Depending on inflow, use Unit #3 or #2 at best efficiency. For higher flows use #3 at best efficiency and #2 at maximum load. For still higher flows use #3 & #2 at maximum load and bring on #1 at best efficiency or maximum load as required. Unit #1 is not automated.*
2.) *Set unit operation to maintain constant forebay elevation under normal circumstances.*
3.) *In case of a predicted heavy inflow, drain the forebay as much as possible prior to the start of the rainstorm. Bay Bulls - Big Pond should be closed to minimum gate as should Cochrane Pond.*
4.) *The opening of Bay Bulls-Big Pond gate should be gradual to prevent downstream flooding (Maximum 32"). In winter, gate should be open at least 2" to prevent flooding in the spring.*
5.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*
6.) *Cochrane Pond spills into Topsail system (Paddy's Pond).*
7.) *Bay Bulls - Big Pond is a municipal water supply used by the St. John's Region.*
8.) *Large drainage area, forebay rises extremely quickly.*

At present, there is a verbal agreement between the Regional Water System and NP to regulate the water level of the reservoir in a manner which ensures a reliable water supply to the region while addressing the needs of NP. A formal operating regime was suggested in a technical note by the provincial Department of Environment and Labour. Under this regime, NP gate releases from Bay Bulls Big Pond would be managed so as to maintain a minimum allowable level of 121.0 m (149.8 m NP operating datum) and maximum allowable gate releases would be dependent on water level.

The above water management regime, the NP operating guidelines, information from the operator, and the recorded reservoir levels were used to develop the following operating strategy for use in the modelling.

- Set the forebay target level equal to the upper bound of the operating range given in the plant operating guidelines. (According to NP, the forebay level is normally maintained in the upper part of the range.)
- If the forebay water level is at or below the target level, operate the units at best efficiency as necessary to maintain the target level.
- Release water from Bay Bulls Big Pond as needed to keep the unit operating at best efficiency, and to keep the forebay at its target level, provided that releases do not exceed the maximum allowable gate discharge.
- Release water from Cochrane Pond continually up to the capacity of the gate, unless this would cause the forebay to exceed its target level.
- If the water level in Cochrane Pond exceeds full supply level, release water and increase generation above best efficiency if required.
- If the forebay water level is above the target level, operate the units at maximum flow as needed to return to the target level, and close the Bay Bulls Big Pond and Cochrane Pond gates to minimum.
- Maintain the water level in Bay Bulls Big Pond above the minimum allowable level unless required by water supply demand or environmental releases.
- Maintain a minimum environmental release of 0.1 m^3/s (even if this leads to generation above best efficiency or spill downstream).

The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

All simulations included water supply system demands on Bay Bulls Big Pond. For the comparison runs, the recorded monthly demands for 1996 and 1997 were simulated. The equivalent average flow rate for each month varied from 0.59 m^3/s to 0.83 m^3/s with an average of 0.70 m^3/s.

For the simulation of long term production, the average water supply demand was taken as 60 000 m^3/d assuming present day (2000) municipal consumption, as provided in the technical note. The total annual demand was distributed by a monthly pattern, expressed as ratios of monthly demand to the monthly average. The ratios varied between 0.90 and 1.15. The equivalent average monthly demand varied between 0.65 m^3/s and 0.78 m^3/s with an average of 0.69 m^3/s.

11.4 Model Comparison

The years selected by NP for the comparison runs for the Petty Harbour system were 1996 and 1997. The simulation model was run for these two years using both the primary and sensitivity inflow sequences. Figure 11.2 shows the simulated and recorded monthly generation for these two years.

As Figure 11.2 shows, the simulated generation using the primary inflow sequence generally follows the same pattern as the recorded generation. There are some monthly differences between simulated and recorded generation, notably in the summers. The simulated annual energy is greater than the recorded energy in both years. The within-year variation is discussed in Section 11.4.1 below, followed by a discussion of the annual differences in Section 11.4.2.

11.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 11.2 can be due to differences in operation or in hydrology. In the case of the Petty Harbour system it is principally due to differences between the actual and simulated operation of the system. The good agreement in recorded and simulated reservoir levels, as shown in Figures 11.3, 11.4 and 11.5, shows that the model is closely following the NP operating procedures. One notable exception is the level of Bay Bulls Big Pond in November and December 1997. The discrepancy between recorded and simulated levels is due to a drawdown that was carried out in November 1997 as a safety precaution, when maintenance was required at the Bay Bulls Big Pona dam. As seen in Figure 11.2(b), the resulting discharge caused an increase in the recorded generation for that month, followed by a decrease in December due to a lack of water in storage.

Possible reasons for the differences in simulated and recorded generation during the summer months include the following.

- In actual practice, the units may have been operating at low loads during the summer to maintain constant elevation in the forebay.
- Unaccounted for consumptive demands in the system, e.g., irrigation of agricultural land or more evapotranspiration, with a corresponding decrease in runoff to brooks.

- Increased flows in the primary inflow sequence (Waterford River) due to urbanization in the Waterford River basin. Discharges from the municipal water supply system (e.g., lawn sprinklers, car washes) into the Waterford River basin could result in slight overestimation of the simulated inflows in the Petty Harbour system.

11.4.2 Differences in Annual Generation

Table 11.1 summarizes the annual energy generation for the two comparison years. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 11.3, 11.4 and 11.5). The adjustment takes account of the energy potential of the water in storage.

Table 11.1
Petty Harbour Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorde_	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	16.4	18.6	15.8	18.9	20
1997	17.6	19.2	16.6	19.8	19
Sensitivity Inflow Sequence					
1996	16.4	16.9	15.8	16.7	6
1997	17.6	21.1	16.6	22.0	33

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;

- differences in water use, both in operation of units and of reservoirs (through control gates);
- inaccurate assumptions regarding characteristics of the system.

Each of these is briefly discussed below.

Hydrology

The presence of unaccounted for consumptive demands or urbanization effects, as described in Section 11.4.1, could contribute to the annual difference between simulated and recorded energy.

For this system, the simulation using the primary gauge gave reasonable results and was used to estimate the long term production as presented in Section 11.5.

Differences in Water Use

For the Petty Harbour system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the input operating strategy in Section 11.3.4. The two most important factors affecting generation are as follows.

- Ideal operation of the unit: In the simulation model the unit never operates at a flow less than the most efficient load, although it does operate at higher flows if the forebay is above its target level. Operation at inefficient loads, as referred to in Section 11.4.1, would decrease the annual generation.
- Ideal operation of reservoirs and control gates to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels, and opens gates as required to pass water downstream if there is room in a downstream reservoir, or if the unit can handle the flow.

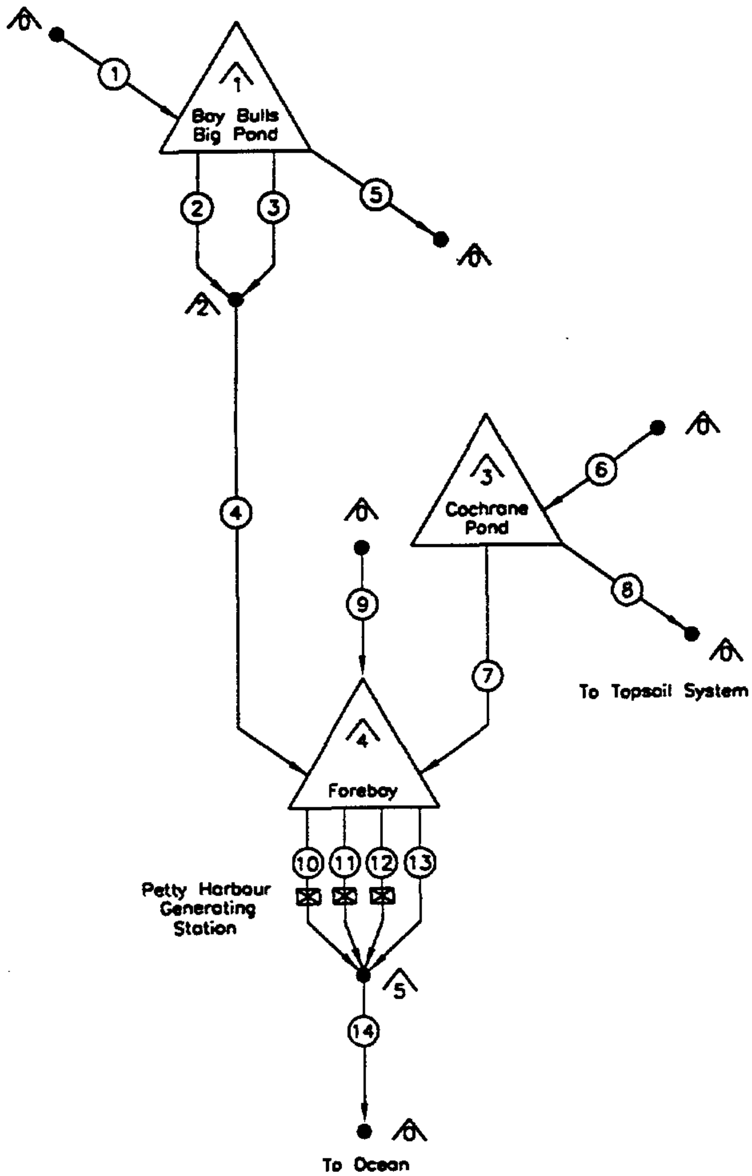
A comparison of recorded and simulated spills shows that the values for 1996 were 770 MWh and 950 MWh, respectively. For 1997 the recorded and simulated spills were 40 MWh and 510 MWh, respectively. NP cautions that recorded spill data are often unreliable; some unreported spill is possible, which could lessen the discrepancy between simulated and recorded generation.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves.

11.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate a long term production for the Petty Harbour system of 19.9 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating the normal production presented in Chapter 22.



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
WATER MANAGEMENT STUDY
PETTY HARBOUR ARSP MODEL SCHEMATIC

ACRES

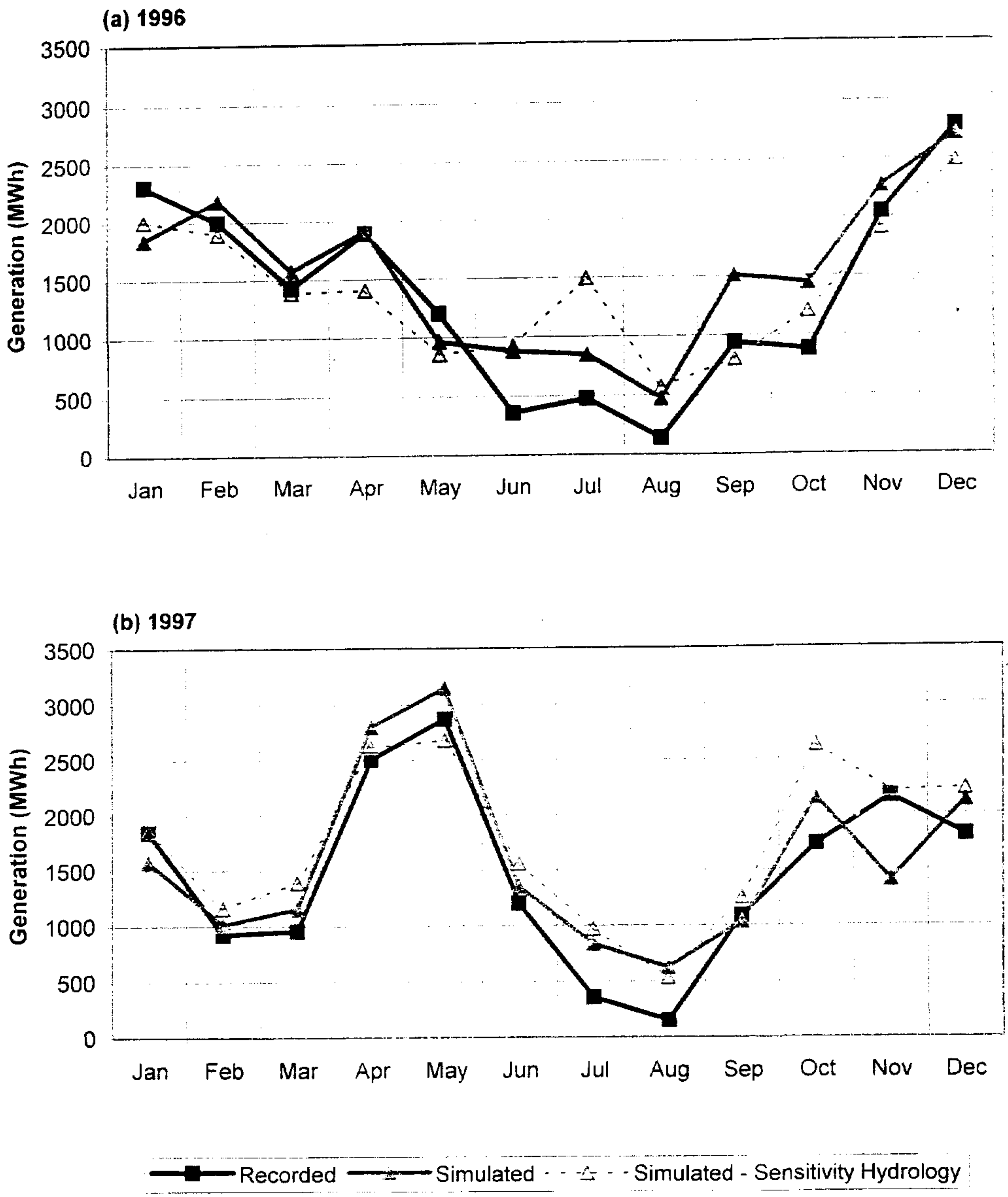


Fig. 11.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

PETTY HARBOUR GENERATION COMPARISON

ACRES

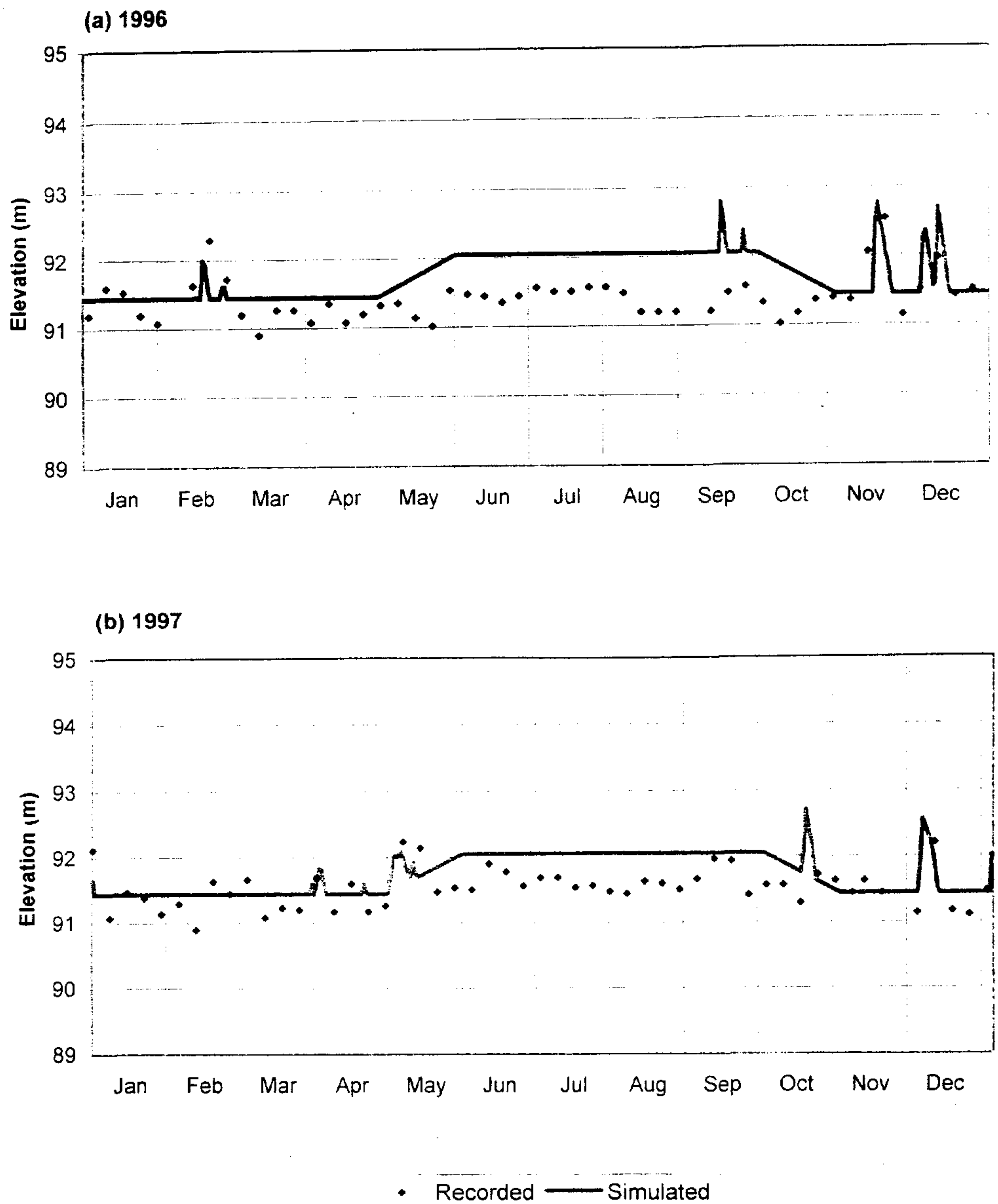


Fig. 11.3

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
PETTY HARBOUR FOREBAY STORAGE COMPARISON

ACRES

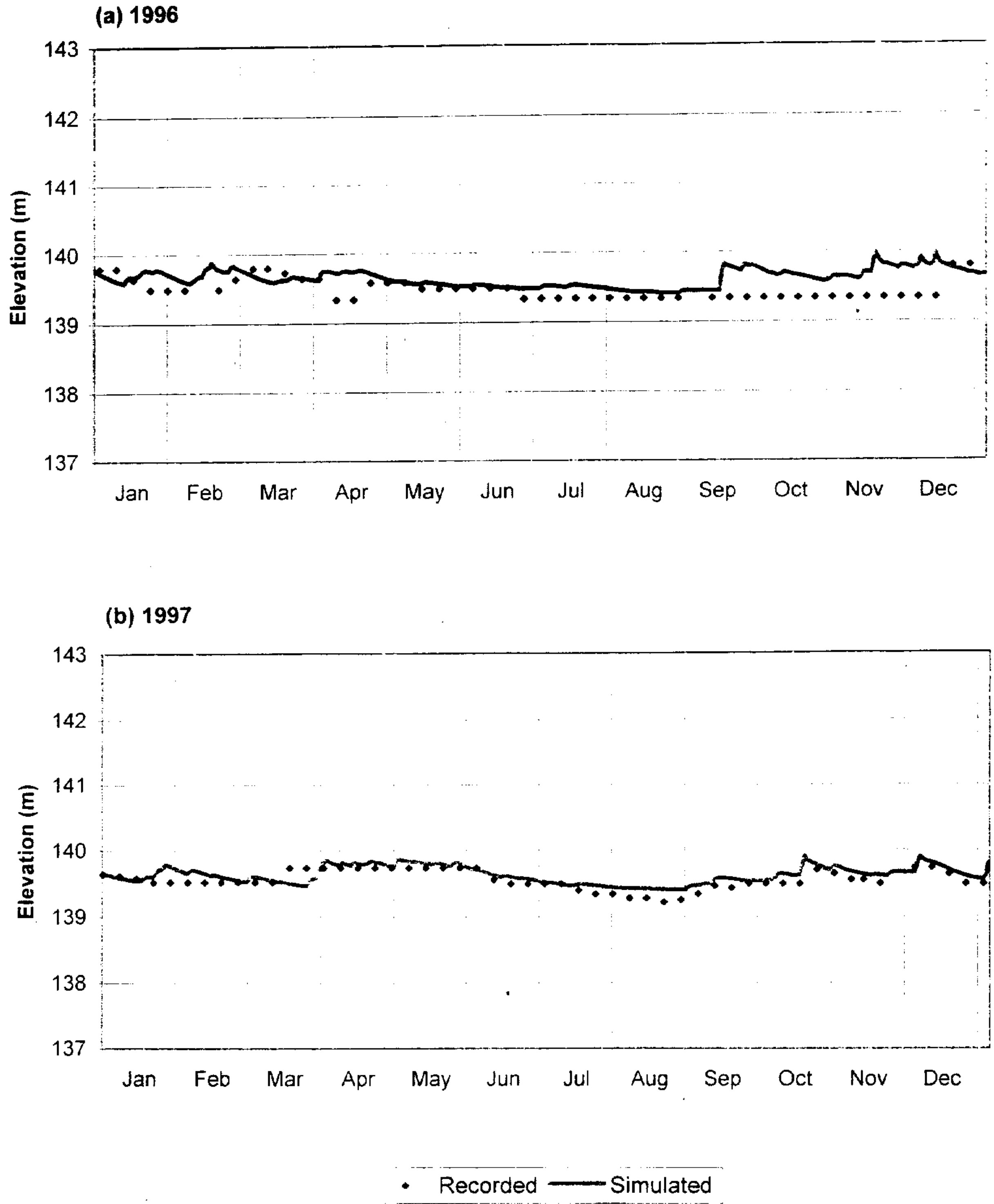


Fig. 11.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

COCHRANE POND STORAGE COMPARISON

ACRES

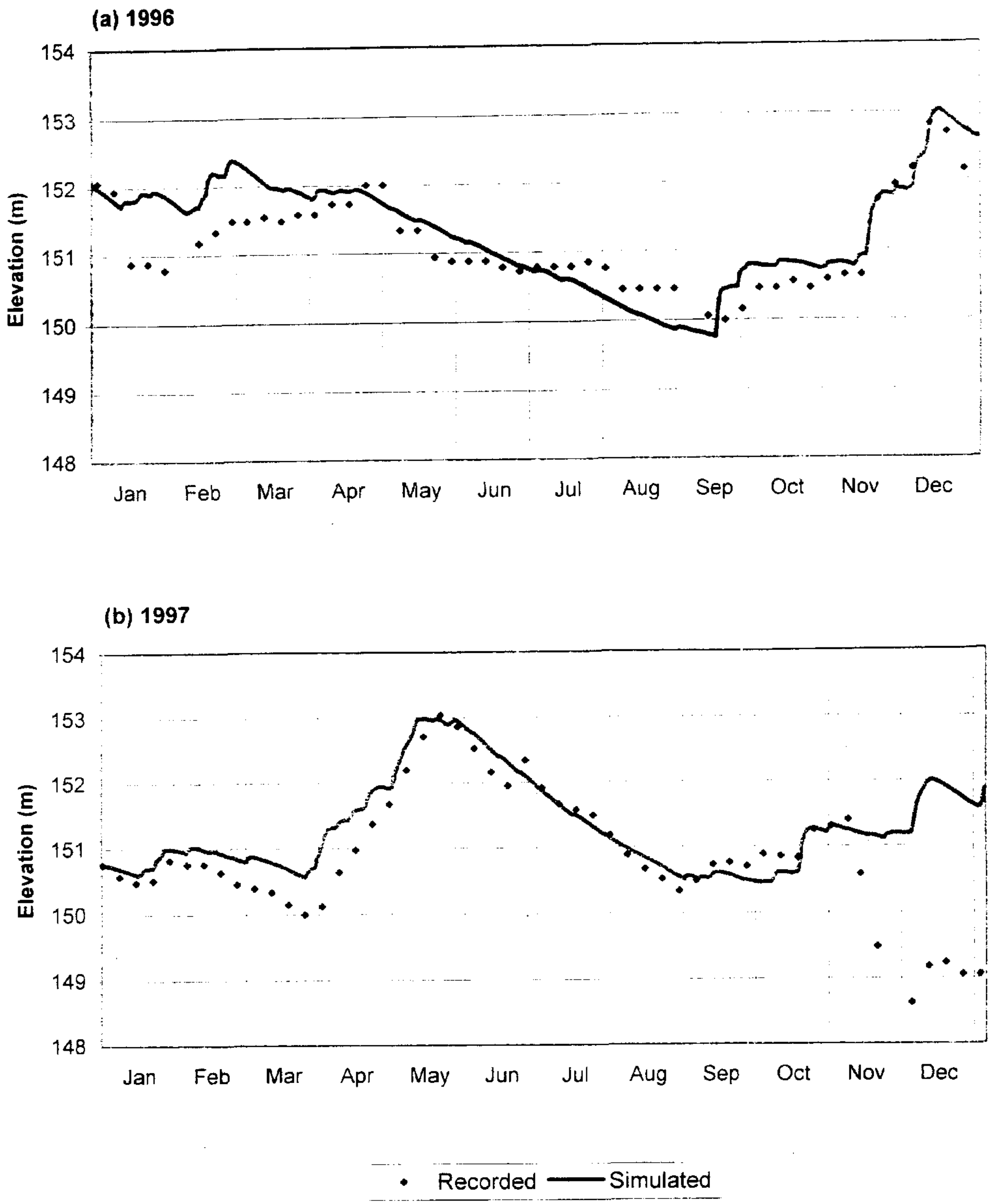


Fig. 11.5

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

BAY BULLS BIG POND STORAGE COMPARISON

ACRES

12 New Chelsea/Pitmans Hydroelectric System

The long term production for the New Chelsea/Pitmans Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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 Inflow Sequences

The daily inflow sequences required for the simulation model were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the New Chelsea/Pitmans system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the individual sequences differ only by drainage area.

The three hydrometric stations used to derive the inflow sequences for the New Chelsea/Pitmans system were Spout Cove Brook near Spout Cove (02ZL003), Shearstown Brook at Shearstown (02ZL004) and Big Brook at Lead Cove (02ZL005). Big Brook at Lead Cove was chosen as the primary station for deriving the New Chelsea/Pitmans flows. The Big Brook hydrometric record starts in 1985; data from Spout Cove Brook was used to fill in 1984. The drainage area of Big Brook is 11.2 km^2. Shearstown Brook at Shearstown and was used to prepare an inflow sequence for sensitivity analysis. The drainage area of the Shearstown Brook gauge is 28.9 km^2.

Mean annual runoffs of 1178 mm/yr and 949 mm/yr for the reference period were calculated from the hydrometric station records for Big Brook and Shearstown, respectively. The mean annual runoff of the New Chelsea/Pitmans basin was estimated during this study to be 1150 mm/yr.

The primary inflow sequence for the simulation was developed by multiplying the Big Brook flows by the ratios of the New Chelsea/Pitmans mean annual runoff and local drainage area for each subbasin to the Big Brook mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using Shearstown data.

12.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1996 and 1998. The development of inflow sequences used for the model was described in Section 12.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and for the estimate of long term production. Values used for the final normal production runs are provided in the echo of the input file in Volume 2 of this report.

12.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the New Chelsea/Pitmans system.

- Pitmans Pond; and
- Seal Cove Pond.

Only Pitmans Pond has significant controlled storage in the New Chelsea/Pitmans system. Seal Cove Pond stores only about one day's generation at New Chelsea within the normal operating range.

Two different sets of storage curves were provided by NP for each of the reservoirs in the New Chelsea/Pitmans system. As a means of resolving the discrepancy, the pond areas were planimetered from available 1:50 000 scale mapping, and the curve which best represented the area at full supply level for each reservoir was used in the modelling.

12.3.2 Generating Station Characteristics

Generating station characteristics were required for the following stations in the New Chelsea/Pitmans system

- New Chelsea; and
- Pitmans.

Pitmans station has a single unit, modelled with a capacity of 0.64 MW. The tailwater of Pitmans station is influenced by the water level in Seal Cove Pond. New Chelsea generating station has a single unit, modelled with a capacity of approximately 4.2 MW. Records show that the maximum generation is above the nameplate capacities of 0.6 MW and 3.7 MW listed in Section 12.1.

Acres undertook efficiency testing for NP at New Chelsea in 1997. Data from those tests were used as the primary source of information for the New Chelsea station characteristics. Additional information provided by NP was used to supplement these data.

The New Chelsea data were used in combination with water level and plant load data from NP's SCADA system to estimate the characteristics for Pitmans station. Hourly plant load data at New Chelsea and the corresponding hourly water levels at Seal Cove Pond, together with the plant efficiency data, were used to estimate turbine flows at New Chelsea. The turbine flows were then used to back calculate the turbine flow at Pitmans considering changes in water level at Seal Cove Pond and estimated local inflows between the two generating stations. Finally, the turbine flows together with unit output at Pitmans were used to derive the overall unit efficiency for Pitmans station.

12.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

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

Curves were derived using structure geometries provided by NP and standard hydraulic equations and then verified by comparison with curves provided by NP.

12.3.4 System Operation

NP's plant operating guidelines for the New Chelsea/Pitmans system provide the following procedures.

1.) *Operate Pittman's at best efficiency or full load and cycle New Chelsea on & off to maintain operation at best efficiency within the forebay operating range.*
2.) *During heavy inflows, keep Pittman's at best efficiency or shut off. Operate New Chelsea at full load only as long as forebay elevation is increasing, then back off to best efficiency.*
3.) *The elevation of Pittman's Pond should be maintained below 362' during the period of September to December to prevent damage to the dam due to wave erosion.*
4.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

NP staff have indicated that the constraint listed in item 3 is a temporary measure until riprap repairs are completed at Pitmans Pond dam. An operations directive issued in 1995 suggests that Pitmans Pond is to be maintained within 0.5 m of full supply level in order to maximize the head on the unit and this constraint was used in modeling reservoir operations.

Aside from the operating procedures described above, the model was set up to maximize average energy production using the defined power plant characteristics, while minimizing spill. The following operating strategy was used in the modelling.

- Generate at best efficiency at both stations when water is available from inflows or storage.
- When water levels approach the target level, generate at maximum to avoid spill.

Due to significant storage available at Pitmans Pond, the system experiences only minor spills which are usually the result of high local inflows to Seal Cove Pond. The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

12.4 Model Comparison

The years selected by NP for the comparison runs for the New Chelsea/Pitmans Hydroelectric System were 1996 and 1998. The simulation model was run for these comparison years using both the primary and sensitivity inflow sequences. Figure 12.2 shows the simulated and recorded monthly generation for these two years for the New Chelsea generating station and Figure 12.3 shows the corresponding results for the Pitmans generating station.

As Figures 12.2 and 12.3 show, the simulated generation generally follows the same pattern as the recorded generation, though there is some variation month to month. The annual simulated generation is greater than the recorded energy generation in 1996 and less than the recorded generation in 1998.

There are differences between the recorded values both within each year, and also on an annual basis. The within-year variation is discussed in Section 12.4.1 below, followed by a discussion of the annual differences in Section 12.4.2.

12.4.1 Differences in Monthly Generation

The differences between simulated and recorded generation through the year can be due to differences in operation or in hydrology. In the case of the New Chelsea/Pitmans system it is principally due to differences between the actual and simulated operation of the system. The most notable differences may be explained by operations which deviated from the procedures described in the operating guidelines and Section 12.3.4. For much of the months of February and October 1998, the New Chelsea station was unavailable due mainly to system problems. As a result, recorded generation was well below the model's estimate during these months and above the model's estimate in the subsequent months. During the fall of 1996, the operation of the Pitmans station was reduced to one day per week in an effort to raise the operating level of Pitmans Pond. This mode of operation was not incorporated into the model and therefore discrepancies in the recorded and modelled results are observed.

Figure 12.4 shows comparisons of recorded and simulated storages in the main reservoir, Pitmans Pond. The effects of the operation changes and problems described above can be readily seen in the water levels. When NP generated less than the model, the recorded water levels are higher than simulated and vice versa.

The patterns displayed were similar when the sensitivity gauge was used to develop the inflow sequence, although the sensitivity gauge gives inferior results.

12.4.2 Differences in Annual Generation

Tables 12.1 and 12.2 summarize the annual energy generation for the two comparison years at the New Chelsea and Pitmans generating stations, respectively. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figure 12.4). The adjustment takes account of the energy potential of the water in storage.

Table 12.1
New Chelsea Generating Station
Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	12.9	14.3	14.4	14.7	2
1998	16.2	16.3	16.8	16.5	-2
Sensitivity Inflow Sequence					
1996	12.9	14.4	14.4	14.4	0
1998	16.2	14.2	16.8	14.3	-15

Table 12.2
Pitmans Generating Station
Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	2.3	2.6	2.6	2.6	0
1998	3.2	3.1	3.2	3.1	-3
Sensitivity Inflow Sequence					
1996	2.3	2.6	2.6	2.6	0
1998	3.2	2.6	3.2	2.6	-19

The kinds of operational differences described in Section 12.4.1 that account for the differences in energy from month to month, such as short term plant outages, should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs; and
- inaccurate assumptions regarding characteristics of the system.

Each of these is briefly discussed below.

Hydrology
In the case of the New Chelsea/Pitmans system, the simulation using the primary gauge gave reasonable results and was used to estimate the long term production as presented in Section 12.5.

Differences in Water Use
For the New Chelsea/Pitmans system, the difference between the simulated and recorded annual results are largely attributable to differences in water

management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described above. The two most important factors affecting generation are as follows.

- Ideal operation of the unit: In the model, the units never operates at a flow less than the most efficient load, although they do operate at higher flows if the reservoir is above the target level.

- Ideal operation of reservoirs to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels, and opens gates as required to pass water downstream if there is room in a downstream reservoir, or if the unit can handle the flow.

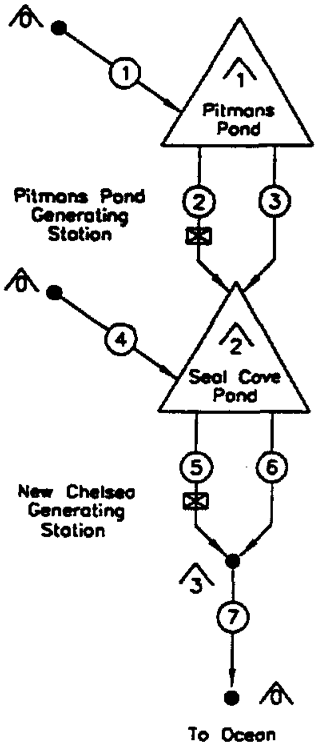
A comparison of recorded and simulated spills shows that the values for 1996 were 0.02 GWh and 0.03 GWh, respectively. For 1998 the recorded and simulated spills were 0.16 GWh and 0.08 GWh, respectively. NP cautions that recorded spill data is often not reliable, however, these data indicate that the recorded and simulated spills are of the same order of magnitude. The simulation did not show any spill at Pitmans Pond during the comparison years, nor were any spills recorded.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or differences in physical characteristics such as storage volumes, spillway sill elevations, and gate discharge curves. The efficiency testing conducted in 1997 provided good plant characteristics for the New Chelsea generating station. However, the methods used to back calculate efficiencies at Pitmans using SCADA data were very approximate and this could be one of the sources of error in the model.

12.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate the long term production for the New Chelsea/Pitmans system. The result of this simulation was an estimate of long term production of 15.6 GWh/yr for the New Chelsea station and 2.9 GWh/yr for the Pitmans station for a total of 18.5 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production, provided in Chapter 22.



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

0 — Source / Sink
1 — Pitmans Pond
2 — Seal Cove Pond
3 — Seal Cove Pond Total Outflow

Fig. 12.1

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
NEW CHELSEA / PITMANS ARSP MODEL SCHEMATIC

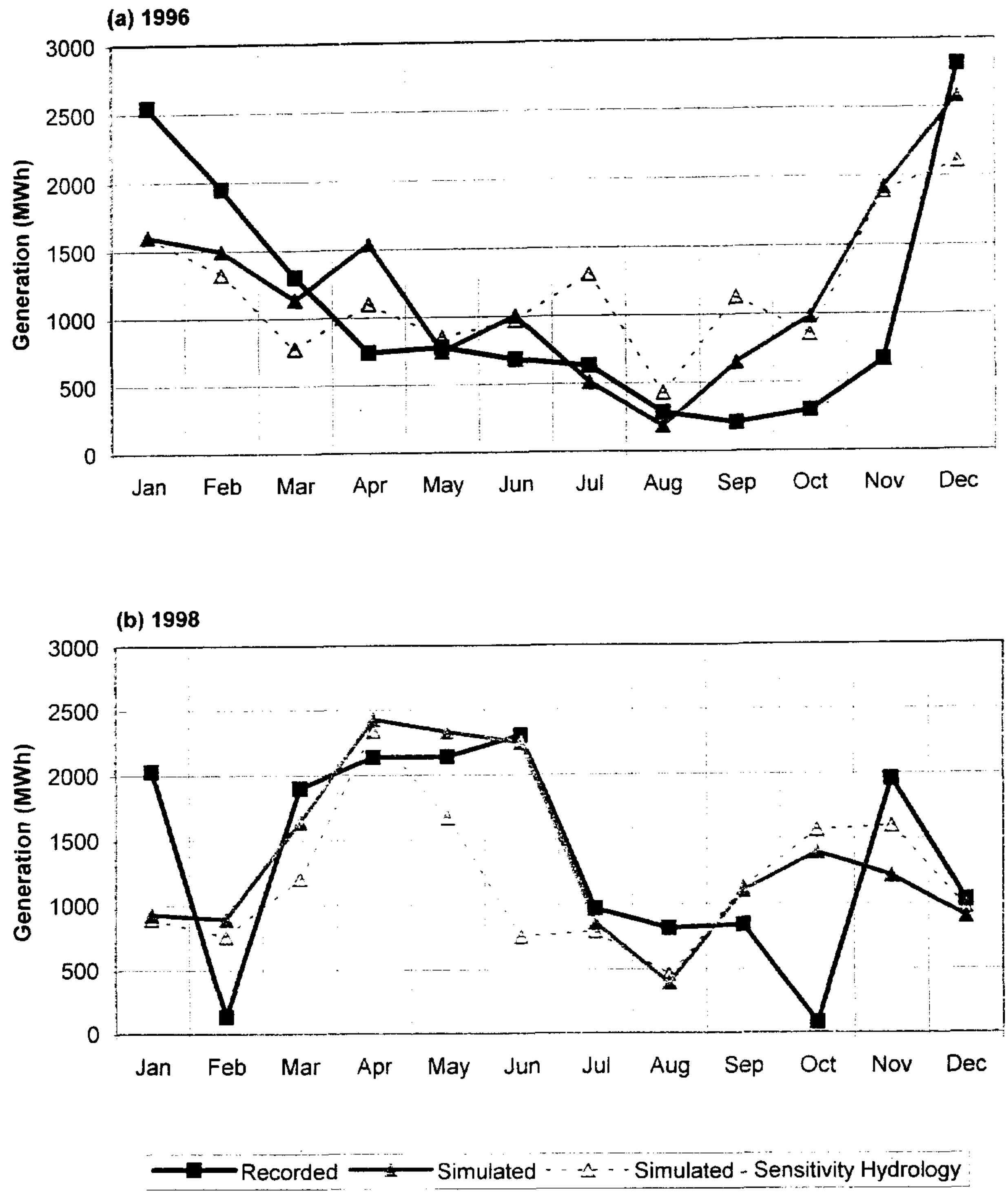


Fig. 12.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

NEW CHELSEA GENERATION COMPARISON

ACRES

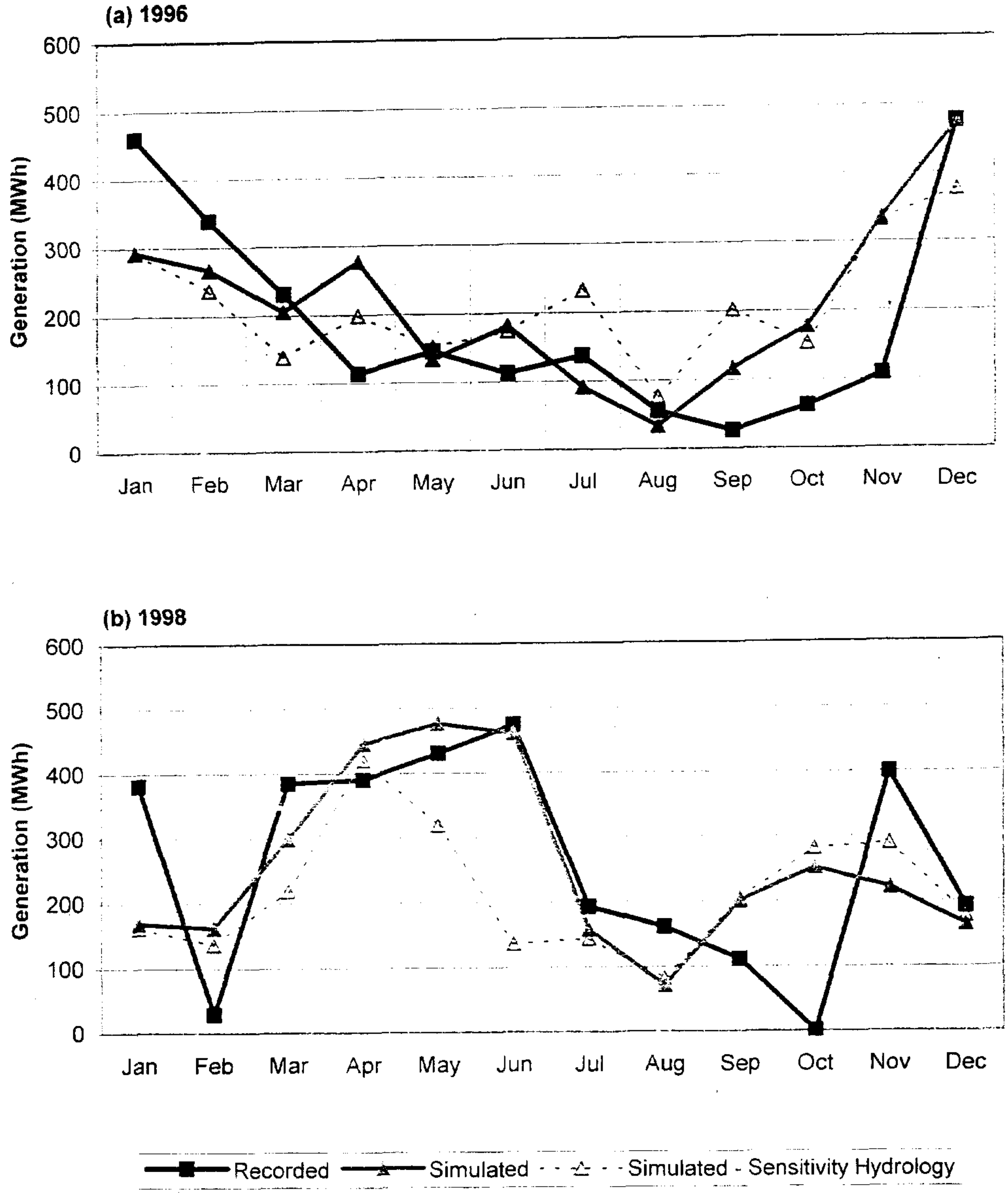


Fig. 12.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

PITMANS POND GENERATION COMPARISON

ACRES

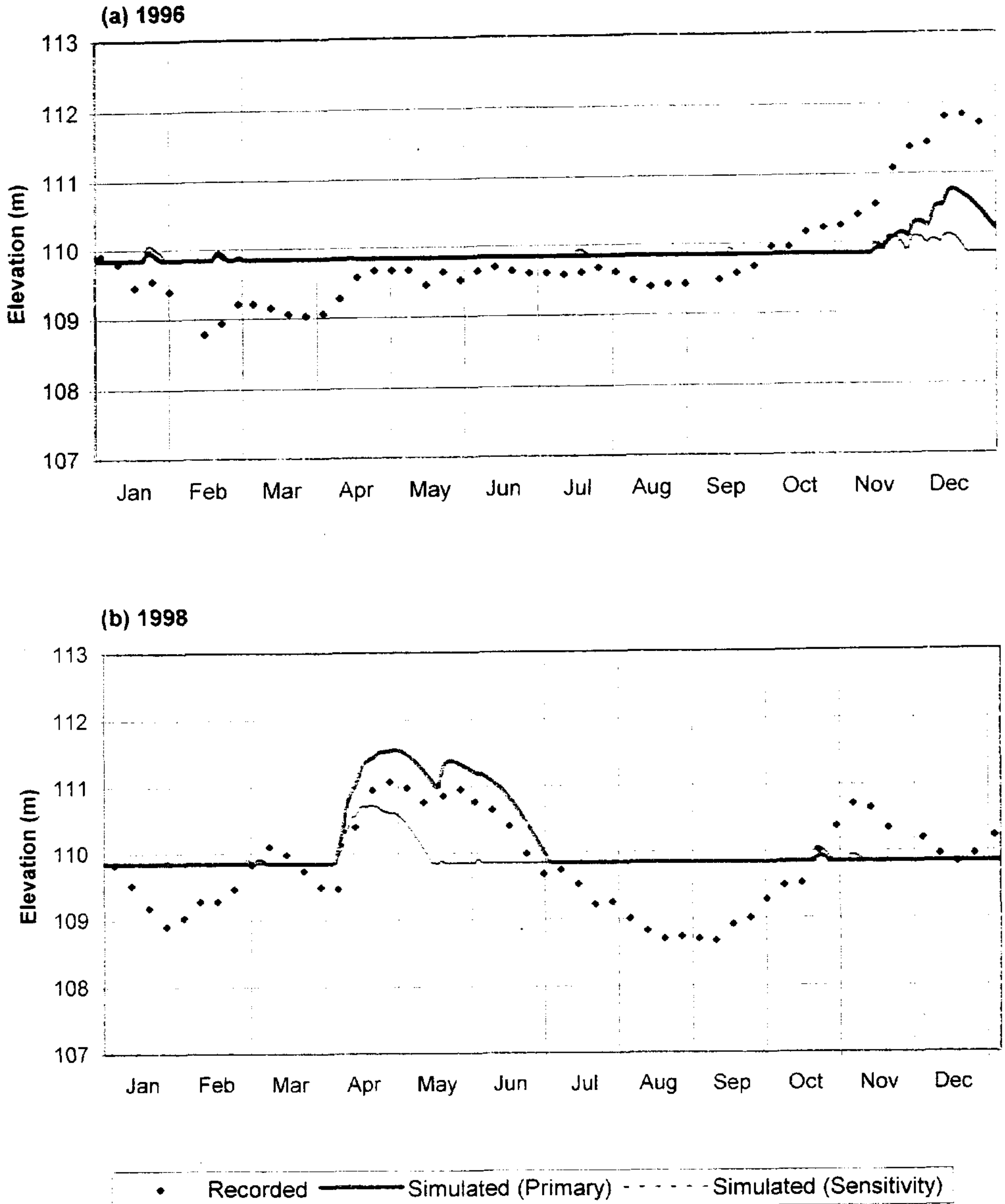


Fig. 12.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

PITMANS POND STORAGE COMPARISON

ACRES

13 Seal Cove Hydroelectric System

The long term production for the Seal Cove Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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, Soidiers 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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Seal Cove system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Seal Cove system were South River near Holyrood (02ZM016) and Northeast Pond River at Northeast Pond (02ZM006). The record from the South River station, with a drainage area of 17.3 km^2, was chosen as the primary source for deriving the Seal Cove system subbasin flows. Northeast Pond River record was used to prepare a sequence for sensitivity analysis. The drainage area of the Northeast Pond River basin is 3.63 km^2.

Mean annual runoffs of 1332 mm/yr and 1172 mm/yr for the reference period were calculated from the hydroelectric station records for South River and Northeast Pond River, respectively. The mean annual runoff of the Seal Cove basin was estimated during this study to be 1200 mm/yr.

The primary inflow sequence for the simulation was developed by multiplying the South River flows by the ratios of Seal Cove basin mean annual runoff and drainage area for each subbasin to South River mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using Northeast Pond River.

13.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequences used for the model was described in Section 13.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

13.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Seal Cove system

- Fenelons Pond;
- Soldiers Pond; and
- White Hill Pond Forebay.

Different sources of information on storage were available from NP's records and were cross referenced for confirmation. All references were in agreement for White Hill Pond Forebay, but were inconsistent for Soldiers Pond and Fenelons Pond. The inconsistency was in total reservoir volume available for generation (live storage). To select an appropriate value, the surface areas of the reservoirs at different levels were estimated to calculate a total volume. This volume was compared to the volumes from various NP sources to select an appropriate value for modelling.

13.3.2 Generating Station Characteristics

The generating station at Seal Cove houses two generating units (SCV-G1 and SCV-G2). Since each unit was modelled separately, generating station characteristics were required for each unit.

During the course of this study Acres conducted efficiency testing for NP at the Seal Cove station. At the time of the testing SCV-G1 was unavailable for testing due to an unscheduled outage; therefore, efficiency testing could only be performed on SCV-G2. The results of the efficiency testing for SCV-G2 were used to develop generating station characteristics for both units. It was assumed for this study that SCV-G1 would have the same efficiencies as SCV-G2 at most efficient load and maximum load. NP's plant operating guidelines were used to determine the most efficient load and maximum load for SCV-G1. The installed capacities used to estimate the long term production were 1.1 MW for SCV-G1 and 2.3 MW for SCV-G2 for a total capacity of 3.4 MW. This total differs slightly from the nameplate capacity shown in Table 1.1 of 3.5 MW because the installed capacities used to estimate the long term production were based on recent efficiency testing at Seal Cove station. The rated net head of the station was also adjusted based on the results of the efficiency testing to 51.8 m compared with 55.5 m noted in Table 1.1.

To account for the loss in energy due to the variation in penstock head losses as a function of the power flow at Seal Cove station, the fixed head loss with one unit generating was input in the model as a constant loss and additional head losses were included in the tailwater curve. Therefore, the tailwater curve does not represent physical water levels at the plant, but synthetic water levels used to account for the drop in net head due to head losses, in addition to the actual variation in tailwater level with flow.

13.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

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

Structure curves were estimated based on information provided by NP and standard hydraulic equations.

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 was available.

13.3.4 System Operation

NP's plant operating guidelines for the Seal Cove system provide the following procedures.

1.) *Units are not remote control but are equipped with automatic water level control. This type of control drops the unit load in proportion to the forebay water level.*
2.) *During October through February, Unit #2 should be used if water inflows dictate. As inflow increase in the spring, Unit #1 should be brought on in conjunction with #2. Summer flows can usually be handled by #1 alone.*
3.) *In the event of a predicted rainstorm, the gates at Fenlons and Soldiers Pond should be closed as quickly as possible as there is only 3 to 4 hours lead time to do something. The water level control system should be blocked and the units run at full load to lower the forebay elevation as much as possible prior to the storm.*
4.) *Soldiers Pond spills out of the system.*
5.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*
6.) *Inform staff at Butterpot Park of any significant change to Fenlon's Pond gate openings, both summer and winter, as it affects the swimming area in summer and cross country skiing in winter.*

These procedures were used to develop the following operating strategy for the modelling.

- Operate SCV-G1 and SCV-G2 at most efficient load using all inflows plus stored water if available.
- If there is not enough water as indicated by low reservoir levels and low inflows, operate SCV-G2 at most efficient load.
- To avoid going over the full supply level and spilling, operate SCV-G2 at maximum load.
- If operating SCV-G2 at maximum load is not enough to avoid spill then operate SCV-G1 at maximum load.
- If inflows are greater than the combined maximum flow of the units and the forebay is at full supply level there will be spill.

The same operating procedures were used for both the comparison runs and the run to estimate long term production.

13.4 Model Comparison

The years selected by NP for the comparison runs were 1997 and 1998. The simulation model was run for these years for both the primary and sensitivity inflow sequences. Figure 13.2 shows the Seal Cove simulated and recorded monthly generation for these two years.

As Figure 13.2 shows, the simulated generation using both the primary and sensitivity inflow sequences generally follows the same pattern as the recorded generation, with both inflow sequences providing a good estimate. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 13.4.1 below, followed by a discussion of the annual differences in Section 13.4.2.

13.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 13.2 are most likely due to differences between the actual and simulated operation of the system.

Figures 13.3 and 13.4 show comparisons of storage in the main storage reservoirs, Fenelons Pond and Soldiers Pond, respectively. Simulated water levels for both the primary and sensitivity inflow sequences have been shown because both inflow sequences provide a good estimate of generation. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation, and vice versa. For January 1997, for example, Figure 13.2 shows that the model generates more energy than was recorded. Figure 13.3 shows that at the end of this month, the model has less water in storage in Fenelons Pond, because it was used for generation. The opposite can be seen for February 1997 where the model generates less energy than was recorded.

13.4.2 Differences in Annual Generation

Table 13.1 summarizes the annual energy generation for the two comparison years for Seal Cove station. Simulated annual energy generation is shown using both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values at the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 13.3 and 13.4). The adjustment takes account of the energy potential of the water in storage.

Table 13.1
Seal Cove Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1997	9.4	11.4	8.9	10.6	19
1998	10.4	10.7	10.3	10.7	4
Sensitivity Inflow Sequence					
1997	9.4	10.0	8.9	9.1	2
1998	10.4	10.1	10.3	10.0	-3

The kinds of operational differences described in Section 13.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage. The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Seal Cove system is briefly discussed below.

Hydrology

In the case of the Seal Cove system, the simulation using the sensitivity inflow sequence gave reasonable results for 1997 and 1998 and a closer match to recorded water levels than the primary inflow sequence. The sensitivity inflow sequence was used to estimate the long term production as presented in Section 13.5.

Differences in Water Use

For the Seal Cove system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described in Section 13.3.4. The two most important factors affecting generation are as follows.

- Ideal operation of the units: The units never operate at less than the most efficient load, although they do operate at higher loads if there is a risk of spill.
- 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.

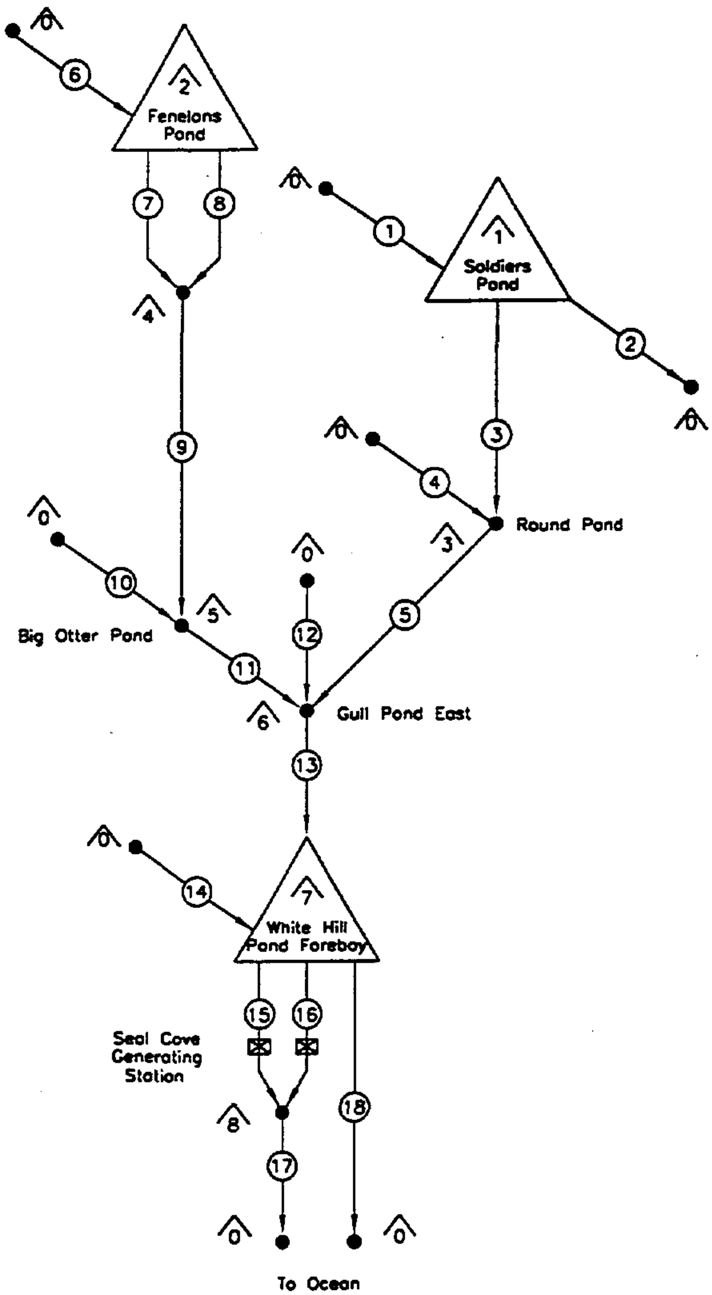
A comparison of recorded and simulated spill shows that the values for 1997 were 10 MWh and 200 MWh, respectively and were 214 MWh and 700 MWh in 1998, respectively. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded. Adjusting the results tabulated above by the difference in recorded and simulated spill for 1997 and 1998 would increase the discrepancy between simulated and recorded energy generation for 1997, and would produce a positive discrepancy (simulated greater than recorded) for 1998.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses, inconsistency between various NP sources of information for reservoir characteristics and the possible over estimate of efficiencies for SCV-G1 for the comparison runs.

13.5 Simulated Long Term Production

The system operation was simulated using the sensitivity inflow sequence for the 15 year reference period to estimate the long term production for the Seal Cove system. The result of this simulation was an estimate of long term production of 9.9 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



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
WATER MANAGEMENT STUDY
SEAL COVE ARSP MODEL SCHEMATIC

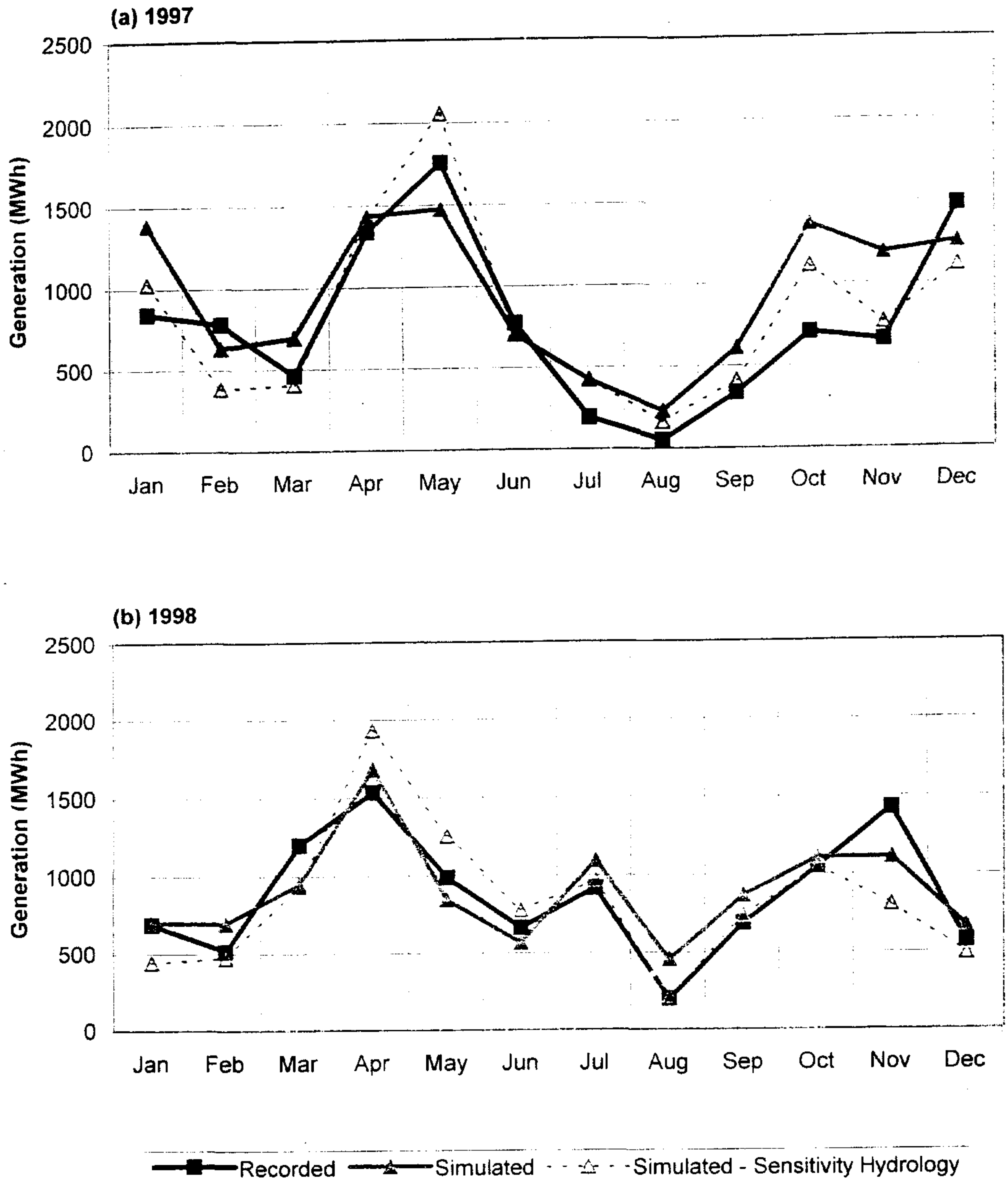


Fig. 13.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

SEAL COVE GENERATION COMPARISON

AGRES

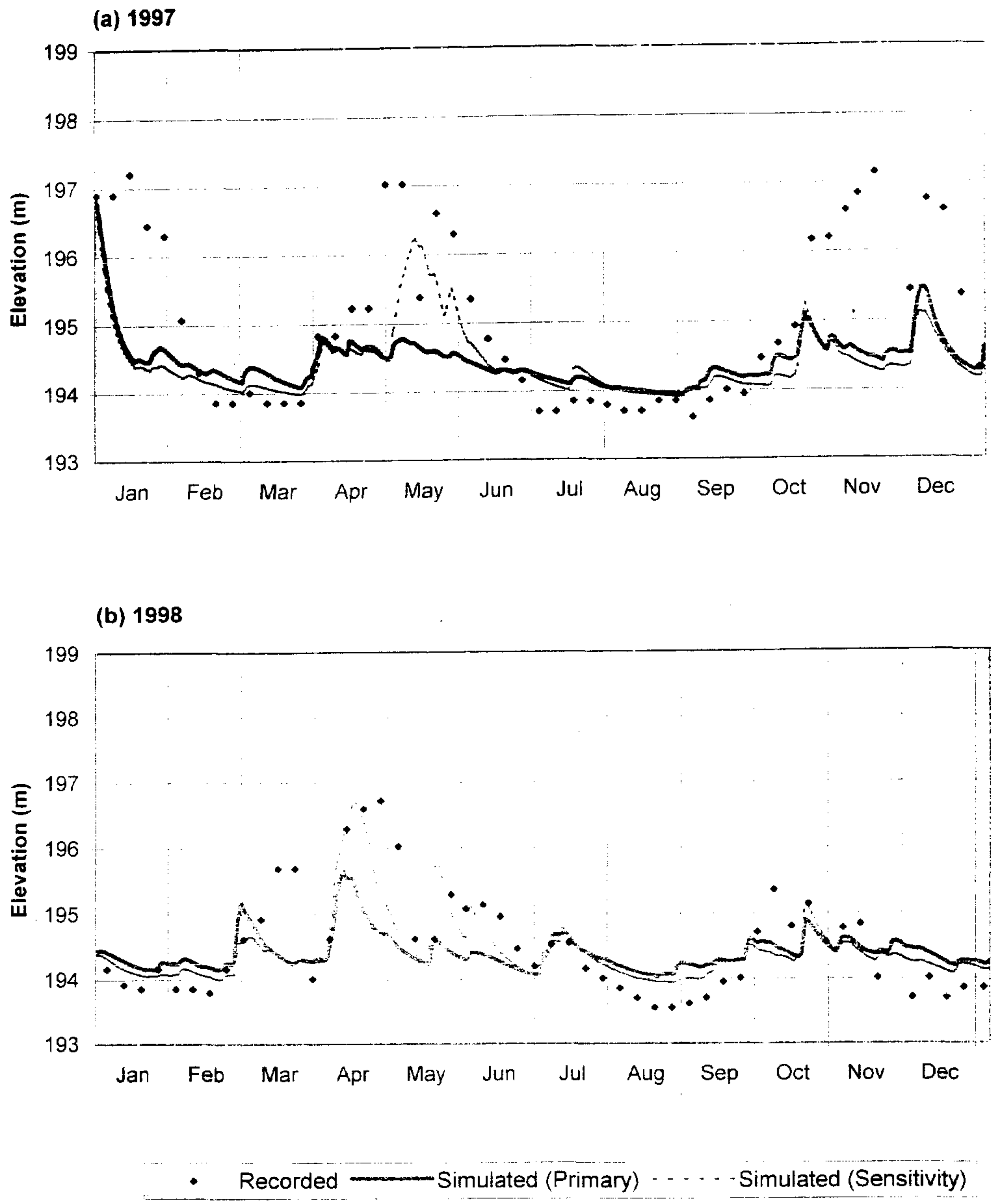


Fig. 13.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

FENELONS POND STORAGE COMPARISON

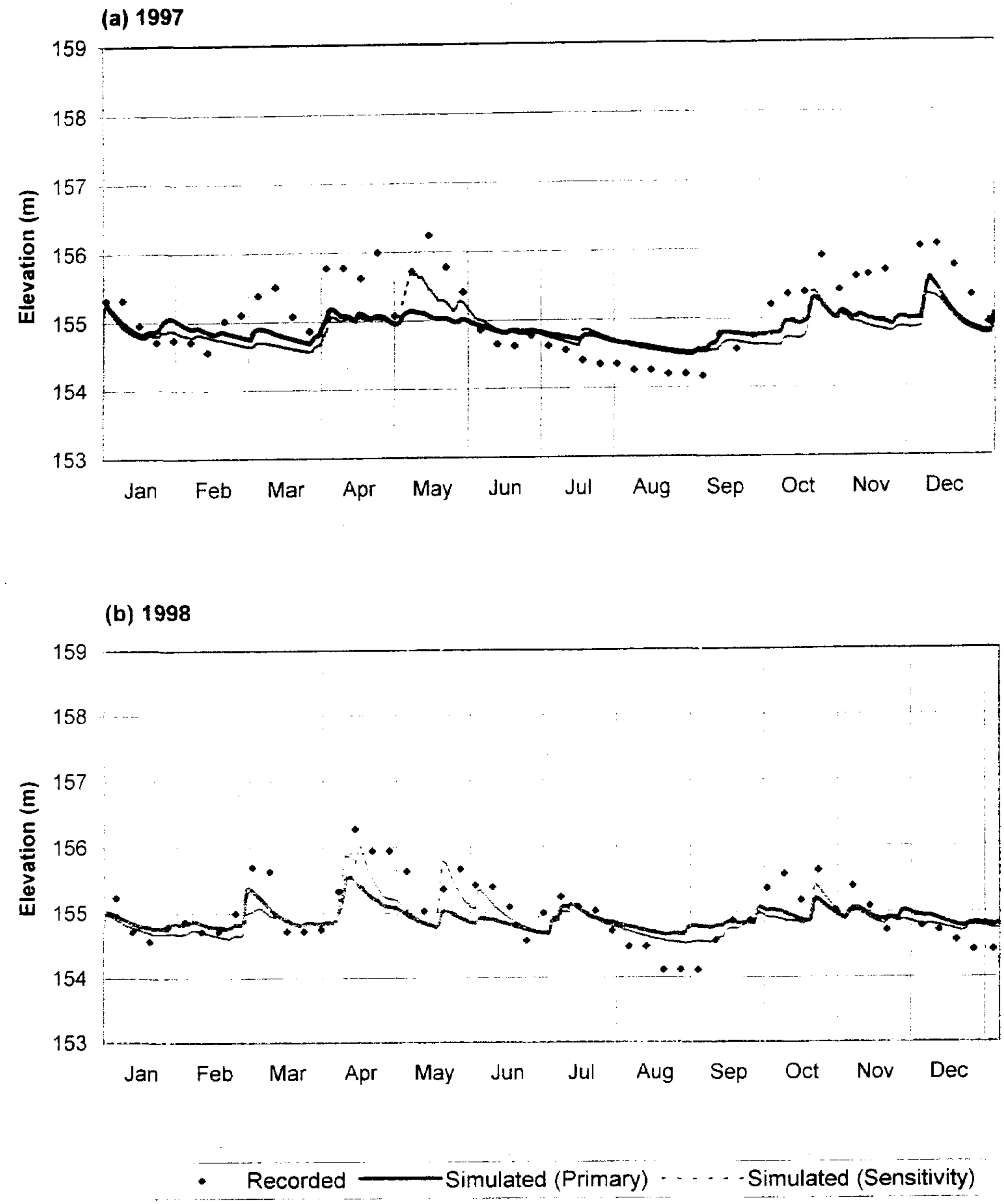


Fig. 13.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

SOLDIERS POND STORAGE COMPARISON

ACRES

14 Topsail Hydroelectric System

The long term production for the Topsail Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

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 has 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 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Topsail system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Topsail system were South River near Holyrood (02ZM016) and Northeast Pond River at Northeast Pond (02ZM006). The record from the South River station, with a drainage area of 17.3 km^2, was chosen as the primary source for deriving the Topsail system subbasin flows. Northeast Pond River record was used to prepare a sequence for sensitivity analysis. The drainage area of the Northeast Pond River basin is 3.63 km^2.

Mean annual runoffs of 1332 mm/yr and 1172 mm/yr for the reference period were calculated from the hydrometric station records for South River and Northeast Pond

River, respectively. The mean annual runoff of the Topsail basin was estimated during this study to be 1300 mm/yr.

The primary inflow sequence for the simulation was developed by multiplying the South River flows by the ratios of Topsail basin mean annual runoff and drainage area for each subbasin to South River mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using South River.

A small amount of additional inflow into the Topsail system occurs when Cochrane Pond (in the Petty Harbour system) spills into Paddys Pond. Since this usually occurs when Paddys Pond is already spilling, the extra water has little effect on generation (less than one percent). The Cochrane Pond spills were included in the Topsail simulation model to ensure that the estimate of long term production accounted for this small amount of extra inflow.

14.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were initially 1994 and 1995, but both of these are prior to runner upgrades at the Topsail station in 1997. To ensure the model was adequately representing the Topsail system after runner upgrades, an additional comparison year (1998) was selected. The results presented, herein, are for comparison years 1995 and 1998, before and after runner upgrades. The development of the inflow sequences used for the model was described in Section 14.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

14.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Topsail system

- Thomas Pond;
- Paddys Pond;
- Three Arm Pond;
- Three Island Pond; and
- Topsail Pond.

Different sources of information on storage were available from NP's records and were cross referenced for confirmation. All references were in general agreement. The short canal between Topsail Pond and the intake to the Topsail station which physically acts as the forebay has negligible storage and was not explicitly modelled. For the purpose of modelling, simulated Topsail Pond elevations were used as forebay elevations with the drop in head in the canal taken account for in the tailwater level. This is further explained in the next section.

14.3.2 Generating Station Characteristics

The generating station at Topsail houses one generating unit (TOP-G1) that underwent a runner replacement in 1997, therefore the generating station characteristics were different in the comparison year simulations for 1995 from those used to estimate the long term production and the comparison year 1998.

Generating station characteristics before the runner replacement in 1997 were based on previous simulation models set up by NP and index testing conducted by NP at the Topsail station in 1985. For the long term production runs and comparison years after the runner replacement, generating station characteristics were based on manufacturers guaranteed curves for the runner replacement. The installed capacity used to estimate the long term normal production was 2.6 MW.

To account for the drop in head between Topsail Pond elevations and the canal (Forebay) water levels at the intake to the Topsail station, the head loss was added to the tailwater levels. Therefore, the tailwater curve does not represent physical water levels at the plant, but synthetic water levels used to account for the drop in head in the canal, as well as tailwater.

14.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- 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.

Structure curves were estimated based on information provided by NP and standard hydraulic equations.

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 was available.

14.3.4 System Operation

NP's plant operating guidelines for the Topsail system provide the following procedures.

1.) *Operate unit at best efficiency unless danger of spilling.*
2.) *Elevation shown on SCADA is of Topsail Pond not the forebay so care has to be taken during operation that the canal doesn't draw down too much leading to a low water trip. The forebay elevation is to be added to the SCADA.*
3.) *Usual operation is to fill Three Arm Pond and allow to spill into Three Island Pond. When Island Pond fills, run the unit for a day or two until the Island Pond elevation reaches 3 feet.* (Note that this elevation is 116.1 m). *The plant is then shut until the Pond fills up again.*
4.) *In the event of a predicted rainstorm, the gate at Thomas Pond and Paddys Pond should be closed to the minimum. Three Island Pond gate should be*

opened and the plant operated to get as much water out of the system as possible before the storm.

5.) *Thomas Pond and Paddys Pond spill out of the system. Cochrane Pond from the Petty Harbour System spills into Paddys Pond.*

6.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

These procedures were used to develop the following operating strategy for the modelling.

- If the reservoir levels are between the upper and lower water level, operate unit at most efficient load.
- If the levels are at the upper limit (indicating high inflows), operate unit at maximum load.
- When water is required from storage, use water from Thomas Pond first to keep unit operating at most efficient load and to keep downstream ponds at their desired levels.
- To avoid spill, store excess water in the upper ponds (especially Thomas Pond), but do not risk spill out of the system; if spill out of the system is imminent, open gates at Thomas Pond and Paddys Pond to pass water downstream.

The same operating procedures were used for both the comparison runs and the run to estimate long term production.

14.4 Model Comparison

As discussed in Section 4.3, the years selected by NP for the comparison years were 1995 and 1998. The simulation model was run for these years for both the primary and sensitivity inflow sequences. Figure 14.2 shows the Topsail simulated and recorded monthly generation for these two years.

As Figure 14.2 shows, the simulated generation using both the primary and sensitivity inflow sequences generally follows the same pattern as the recorded generation, with the primary inflow sequence providing a slightly better estimate. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 14.4.1 below, followed by a discussion of the annual differences in Section 14.4.2.

14.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 14.2 are most likely due to the differences between the actual and simulated operation of the system.

Figure 14.3 shows comparisons of storage in the main storage reservoir, Thomas Pond. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation, and vice versa. For January 1998, for example, Figure 14.2 shows that the model generates more energy than was recorded. Figure 14.3 shows that at the end of this month, the model has less water in storage at Thomas Pond, because it was used for generation.

14.4.2 Differences in Annual Generation

Table 14.1 summarizes the annual energy generation for the two comparison years for Topsail station. Simulated annual energy generation is shown using both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values for the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figure 14.3). The adjustment takes account of the energy potential of the water in storage.

Table 14.1
Topsail Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1995	14.1	14.9	13.8	15.2	10
1998	16.3	18.6	16.4	17.8	9
Sensitivity Inflow Sequence					
1995	14.1	16.3	13.8	16.9	22
1998	16.3	16.7	16.4	15.8	-4

The kinds of operational differences described in Section 14.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage. The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of unit and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Topsail system is briefly discussed below.

Hydrology

In the case of the Topsail system, the simulation using the primary inflow sequence gave reasonable results for 1995 and 1998 and there is no reason to change the hydrological estimates.

Differences in Water Use

For the Topsail system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of the unit and reservoirs according to the specified operating procedures described in Section 14.3.4. The two most important factors in the model affecting generation are as follows.

- Ideal operation of the unit: The unit never operates at less than the most efficient load, although it does operate at higher loads if there is a risk of spill.
- 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.

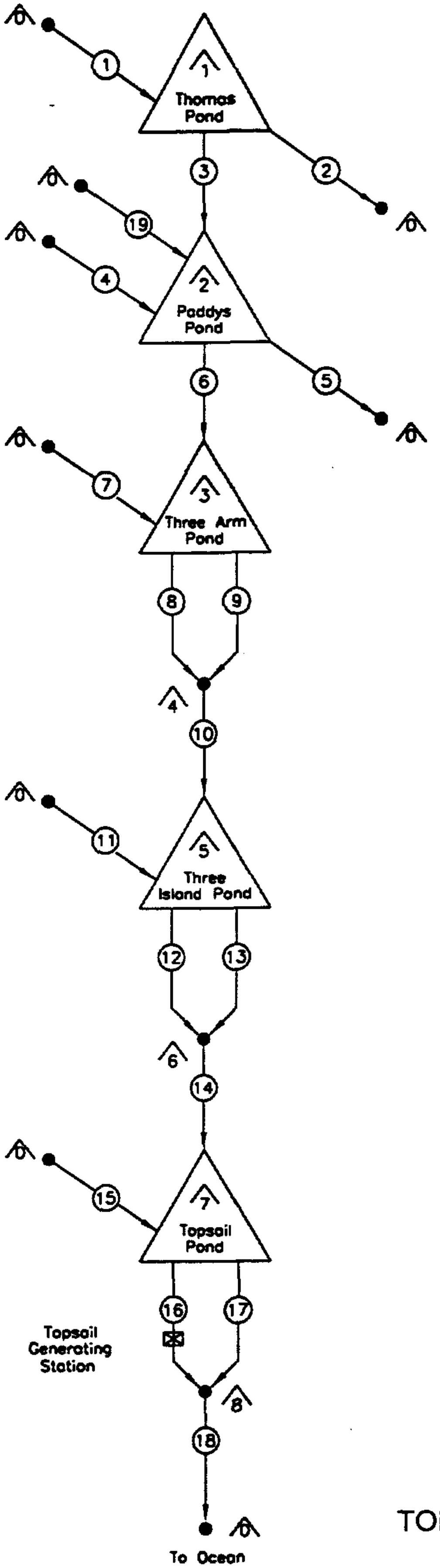
A comparison of recorded and simulated spill shows that the values for 1995 were 2920 MWh and 2700 MWh, respectively and were 220 MWh and 50 MWh in 1998, respectively. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded. The additional actual spill could be partially responsible for the lower recorded energy generation when compared with the simulated. Adjusting the results tabulated above by the difference in recorded and simulated spill for 1995 and 1998 would reduce the discrepancy between simulated and recorded energy generation.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, or not accounting for Cochrane Pond spill in the comparison runs.

14.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate the long term production for the Topsail system. The result of this simulation was an estimate of long term production of 15.9 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



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

WATER MANAGEMENT STUDY

TOPSAIL ARSP MODEL SCHEMATIC

ACRES

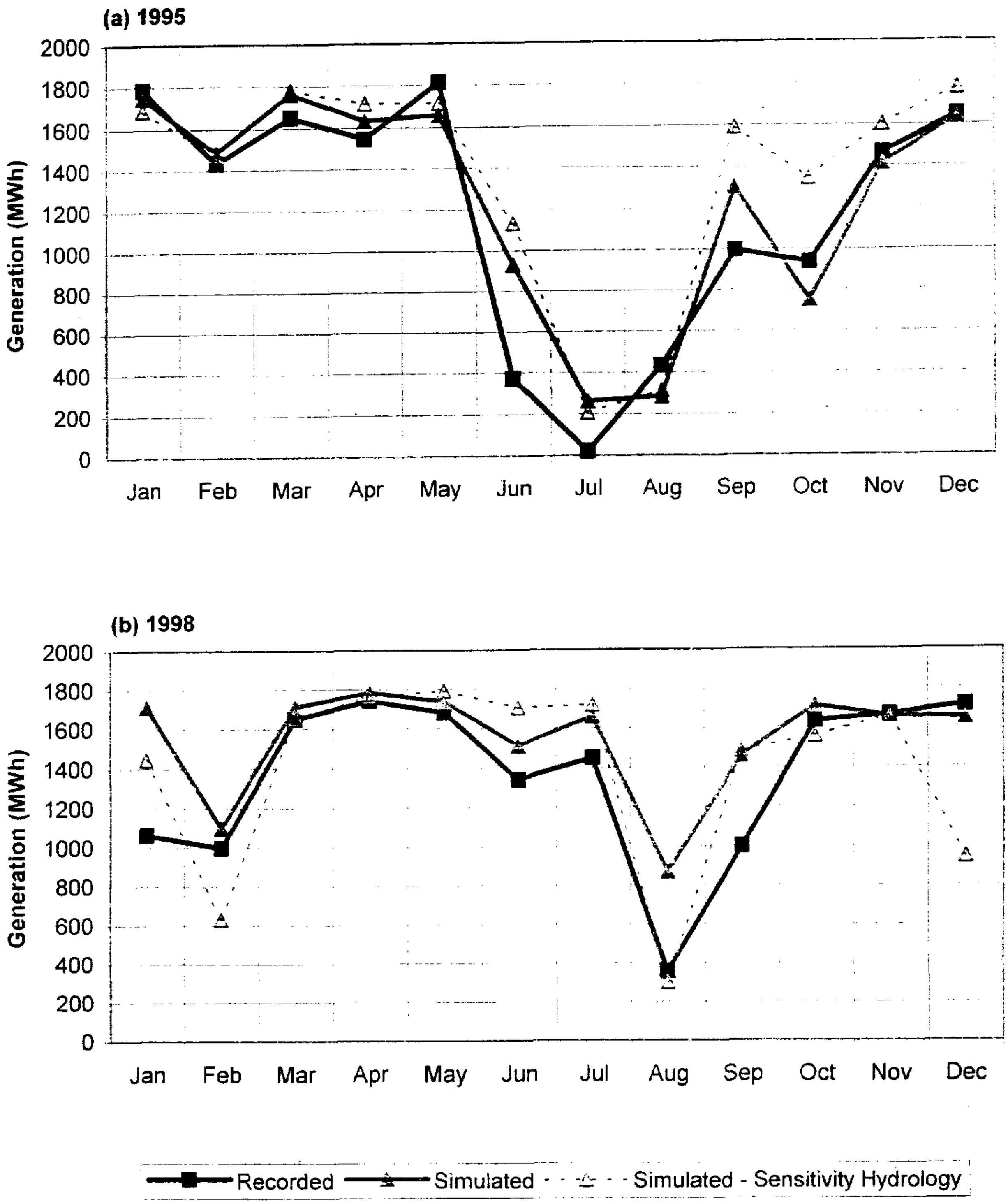


Fig. 14.2

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
TOPSAIL GENERATION COMPARISON

ACRES

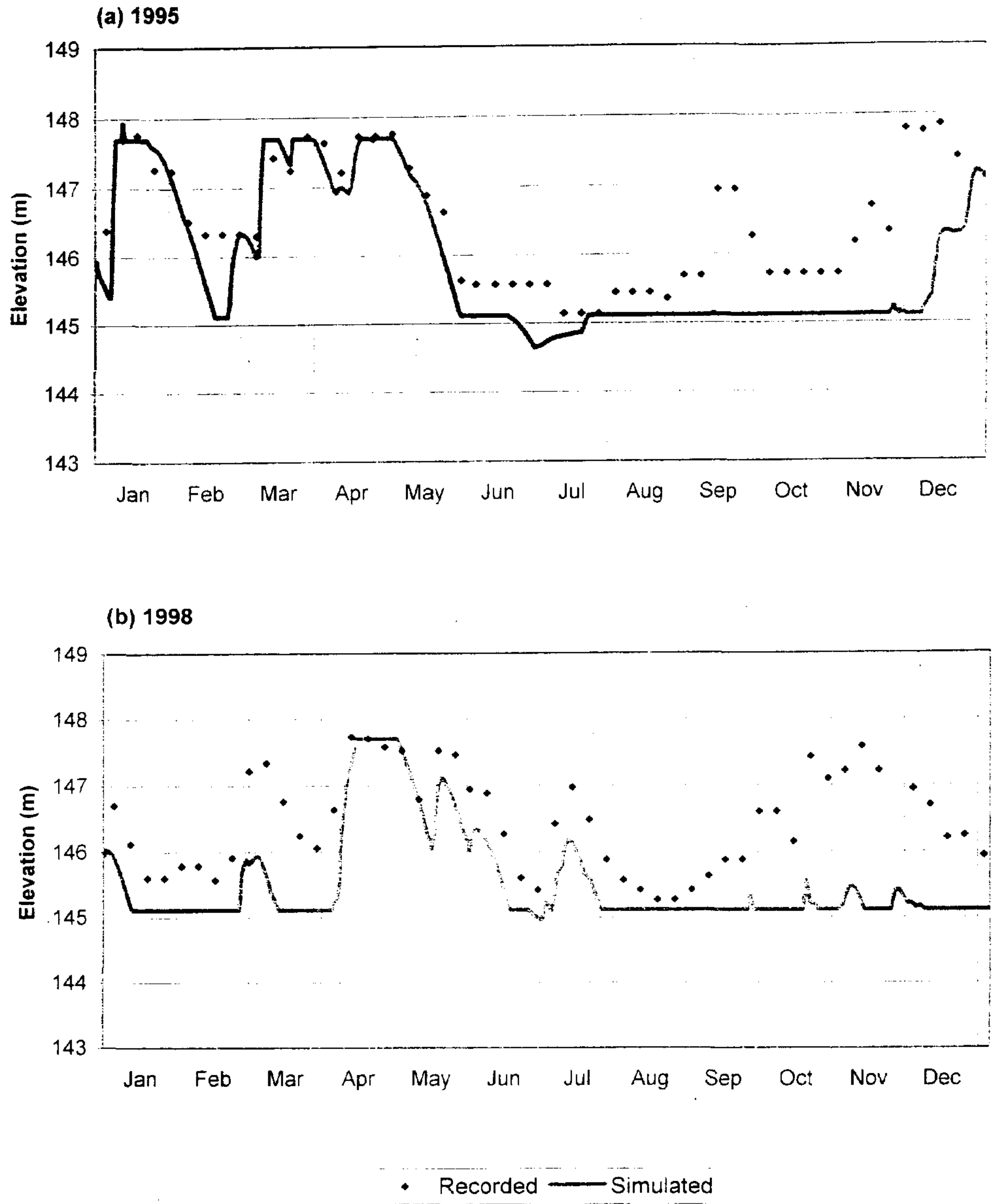


Fig. 14.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

THOMAS POND STORAGE COMPARISON

ACRES

15 Hearts Content Hydroelectric System

The long term production for the Hearts Content Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

15.1 System Description

The Hearts Content system is located on the Avalon Peninsula of Newfoundland near the community of Hearts Content. The Hearts Content Generating Station was commissioned in 1918 and contains one generating unit with a nameplate capacity of 2.7 MW and a rated net head of 46.9 m. The drainage area above the intake to the Hearts Content station is approximately 89 km^2. Storage is provided by structures at Packs Pond, Long Pond and Southern Cove Pond. Southern Cove Pond is the forebay for the Hearts Content station.

The storage reservoirs are in series, with Packs Pond being the most upstream reservoir in the system. Water is released from Packs Pond to Long Pond through the diversion canal located at its outlet. Water entering Long Pond is either stored, spilled out of the system or released downstream to Hearts Content Forebay using the control structure located at the outlet. Water from upstream reservoirs entering Hearts Content Forebay is used to satisfy the water supply demand from the community of Hearts Content, stored, spilled out of the system or used for generation.

The structures in the system are as follows

- Long Pond gated outlet;
- Long Pond overflow spillway; and
- Forebay (Southern Cove Pond) overflow spillway.

15.2 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Hearts Content system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Hearts Content system were Spout Cove Brook near Spout Cove (02ZL003) and Shearstown Brook at Shearstown (02ZL004). The record from the Spout Cove Brook station, with a drainage area of 10.8 km^2, was chosen as the primary source for deriving the Hearts Content system subbasin flows. Flows at this station have been recorded from January 1, 1979 to June 26, 1997. Shearstown Brook record was used to prepare a sequence for sensitivity analysis. The drainage area of the Shearstown Brook basin is 28.9 km^2. The missing 1997 and 1998 flows for Spout Cove Brook were filled in using Shearstown Brook flows, adjusted for the difference in drainage area and mean annual runoff.

Mean annual runoffs of 1128 mm/yr and 949 mm/yr for the reference period were calculated from the hydrometric station records for Spout Cove Brook and Shearstown Brook, respectively. The mean annual runoff of the Hearts Content basin was estimated during this study to be 1150 mm/yr, greater than Spout Cove Brook and Shearstown Brook due to its higher elevation.

The primary inflow sequence for the simulation was developed by multiplying the Spout Cove Brook flows by the ratios of Hearts Content mean annual runoff and drainage area for each subbasin to Spout Cove Brook mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using Shearstown Brook.

15.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1995 and 1996. The development of the inflow sequences used for the model was described in Section 15.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

15.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Hearts Content system

- Packs Pond;
- Long Pond; and
- Forebay (Southern Cove Pond).

Different sources of information on storage were available from NP's records. These sources were in agreement. As a further check, the area of the reservoirs were planimetered and compared with the areas provided by NP. The areas were also in agreement.

15.3.2 Generating Station Characteristics

The generating station at Hearts Content houses one generating unit. Information regarding the generating unit was based on NP's plant operating guidelines. The installed capacity used in the modeling was 2.4 MW. This differs slightly from the nameplate capacity shown in Table 1.1 of 2.7 MW because the model value is taken from the plant operating guidelines which is NP's estimate of the true maximum load of the plant and the nameplate capacity is the value obtained from the manufacturer.

Constant values were used for the head loss and tailwater respectively.

15.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- Long Pond gated outlet;
- Long Pond overflow spillway; and
- Forebay (Southern Cove Pond) overflow spillway.

Structure curves were estimated based on information provided by NP.

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 was available.

15.3.4 System Operation

NP's plant operating guidelines for the Hearts Content system provide the following procedures.

1.) *Operate at best efficiency unless is danger of spill.*
2.) *Plant is essentially a run of river with very little storage. Plant typically has to be cycled on and off to allow the forebay to refill.*
3.) *If a heavy rainfall is predicted, the gate at Long Pond should be closed and the plant operated at full load to lower the forebay. Keep at full load during rainfall.*
4.) *Gate at Long Pond is usually open.*
5.) *Seal Cove Pond and Forebay spill out of system.*
6.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

NP's plant operating guidelines were used to develop the following operating strategy for the modelling.

- If the reservoir levels are below the rule curve, operate unit at most efficient load.
- If reservoirs are low, only operate unit at most efficient load when water is available.
- To avoid going over the rule curve, the unit is brought up to maximum load.

The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

15.4 Model Comparison

The years selected by NP for the comparison runs were 1995 and 1996. The simulation model was run for these years for both the primary and sensitivity inflow sequences. Figure 15.2 shows the Hearts Content simulated and recorded monthly generation for these two years.

As Figure 15.2 shows, the simulated generation using both the primary and sensitivity inflow sequences generally follows the same pattern as the recorded generation, except for the last half of 1996. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 15.4.1 below, followed by a discussion of the annual differences in Section 15.4.2.

15.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 15.2 are most likely due to differences between the actual and simulated operation of the system.

Figures 15.3 and 15.4 show comparisons of storage in the main storage reservoirs, Long Pond and Hearts Content Forebay, respectively. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation, and vice versa. For September 1995, for example, Figure 15.2 shows that the model generates more energy than was recorded.

Figure 15.3 shows that at the end of this period, the model has less water in storage in Long Pond because of the higher generation.

The largest differences in monthly generation occur for the months October to December 1996. It is believed that most of the difference is due to a six week period in November and December when the station was shut down to replace the pivot valve. Inflows were quite high during this period so the model simulated high generation whereas actually there was no generation and some of the inflow was spilled.

15.4.2 Differences in Annual Generation

Table 15.1 summarizes the annual energy generation for the two comparison years for Hearts Content station. Simulated annual energy generation is shown using both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values at the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 15.3 and 15.4). The adjustment takes account of the energy potential of the water in storage.

Table 15.1
Hearts Content Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1995	10.1	10.2	10.2	10.2	0
1996	7.7	9.7	7.7	9.5	23
Sensitivity Inflow Sequence					
1995	10.1	9.2	10.2	9.2	-10
1996	7.7	10.4	7.7	10.2	32

The kinds of operational differences described in Section 15.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Hearts Content system is briefly discussed below.

Hydrology
In the case of the Hearts Content system, the simulation using the primary inflow sequence gave reasonable results for 1995 and most of 1996 and was therefore used to estimate the long term production as presented in Section 15.5.

Differences in Water Use
For the Hearts Content system, some differences between the simulated and recorded annual results are attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described in Section 15.3.4. The two most important factors in the model affecting generation are as follows.

- Ideal operation of the unit: The unit never operates at less than the most efficient load, although it does operate at higher loads if there is a risk of spill.
- 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.

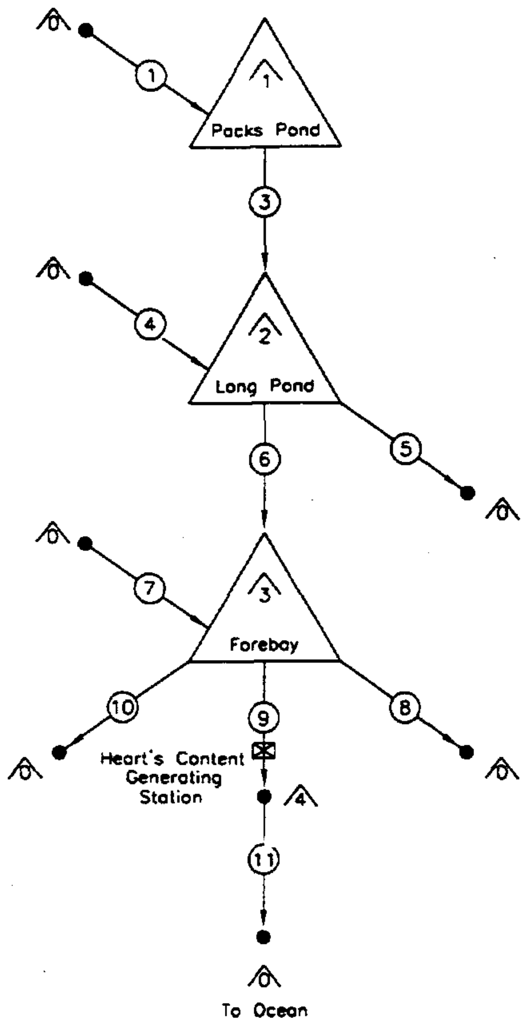
A comparison of recorded and simulated spill shows that the values for 1995 were 210.9 MWh and 585.9 MWh, respectively and for 1996 were 1175.0 MWh and 306.7 MWh, respectively. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded. This is likely the case in 1995 as it is unusual for the simulation model to have more spill than recorded. The higher recorded spill in 1996 explains the remaining discrepancy between recorded and simulated generation. Adjusting the results tabulated above by the difference in recorded and simulated spill would reduce the discrepancy between simulated and recorded energy generation.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency.

15.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequences for the 15 year reference period to estimate the long term production for the Hearts Content system. The result of this simulation was an estimate of long term production of 9.4 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

1 — Packs Pond Local Inflow
3 — Packs Pond Outlet Canal
4 — Long Pond Local Inflow
5 — Seal Cove Pond Spill
6 — Long Pond Outlet Gate
7 — Southern Cove Pond Local Inflow
8 — Rocky Pond Spill
9 — Heart's Content Power Flow
10 — Heart's Content Water Supply Demand
11 — Station Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Packs Pond
2 — Seal Cove Pond/Long Pond
3 — Forebay (Southern Cove Pond)
4 — Station Outflow

Fig. 15.1

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
HEART'S CONTENT ARSP MODEL SCHEMATIC

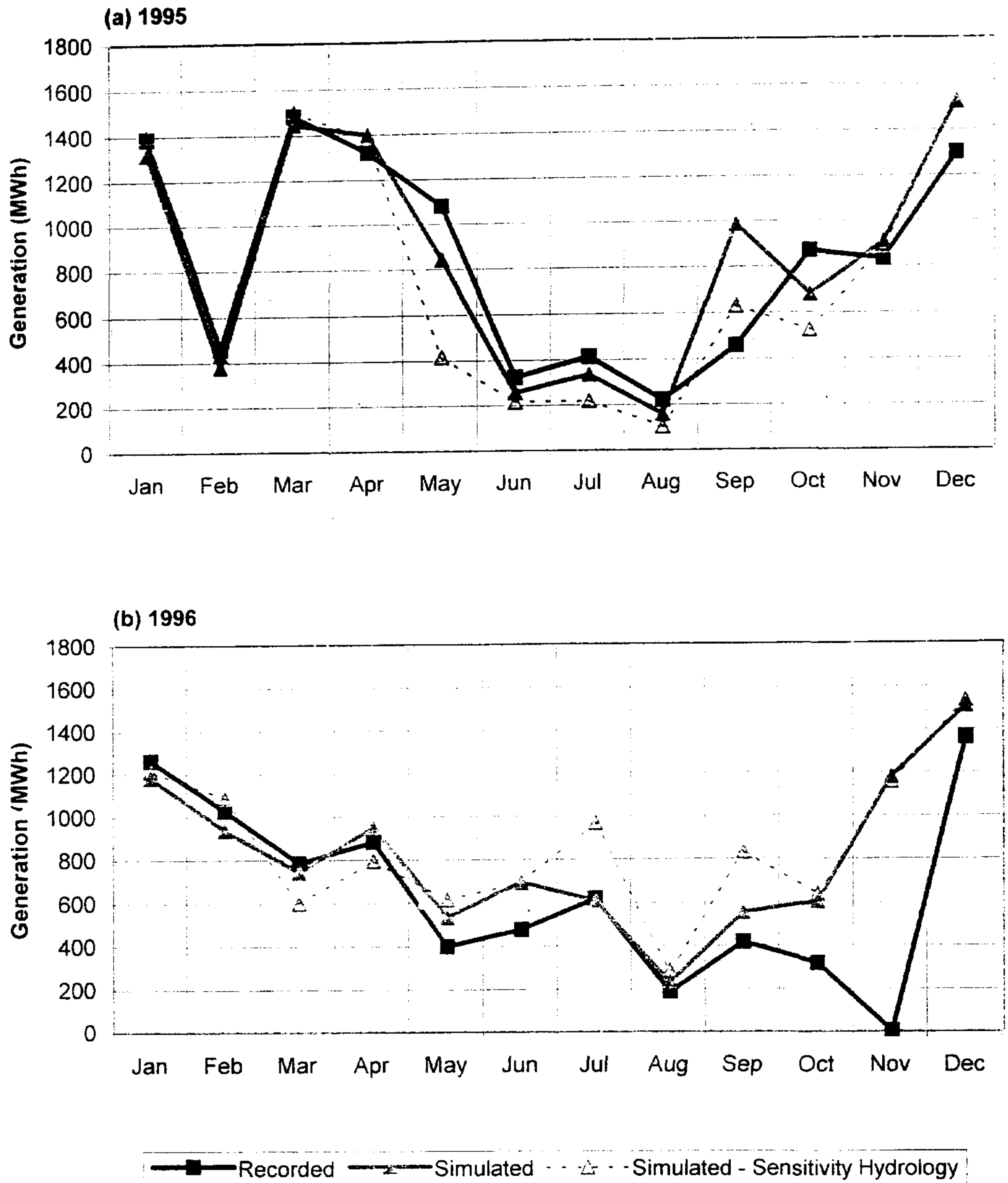


Fig. 15.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

HEART S CONTENT GENERATION COMPARISON

ACRES

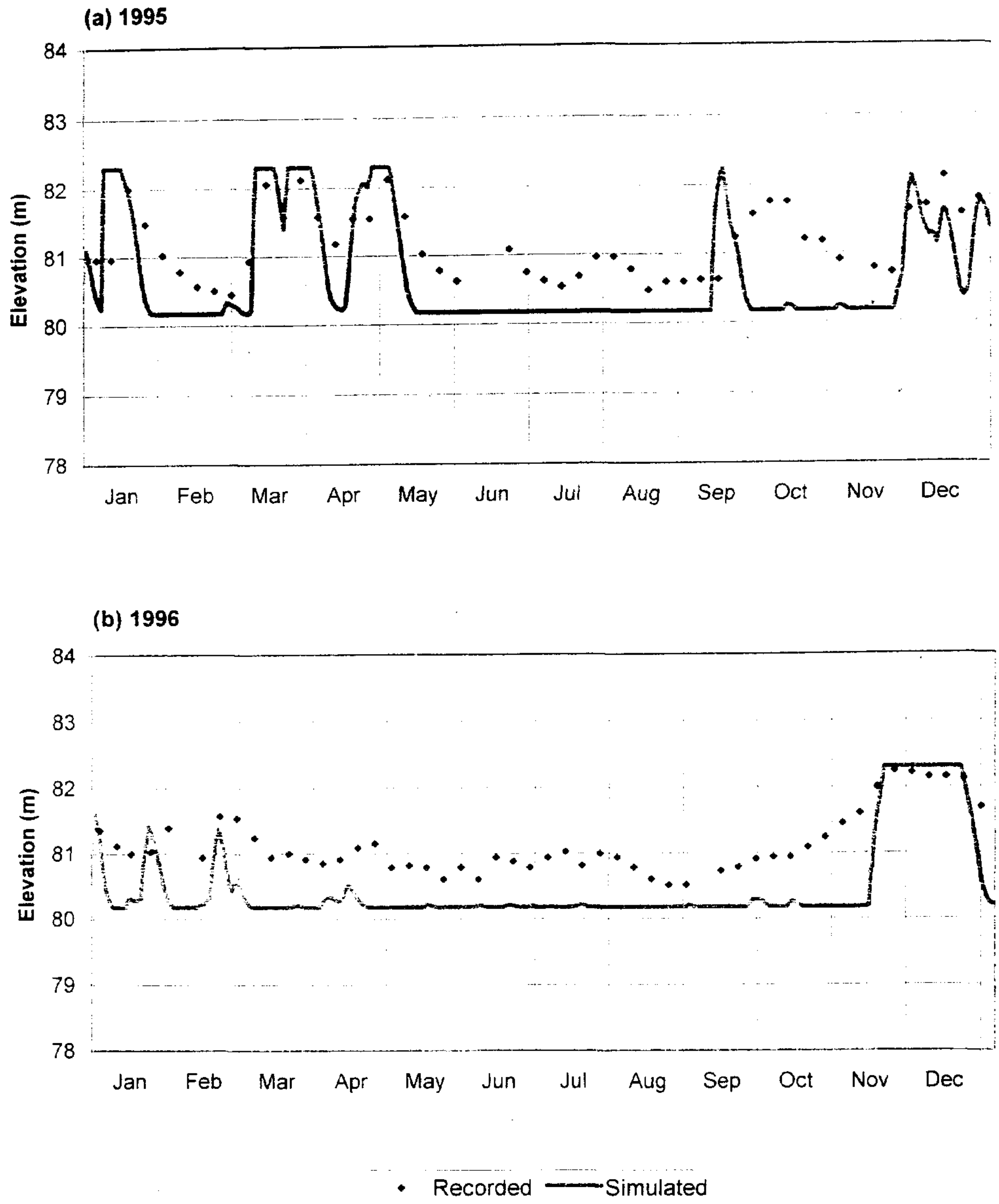
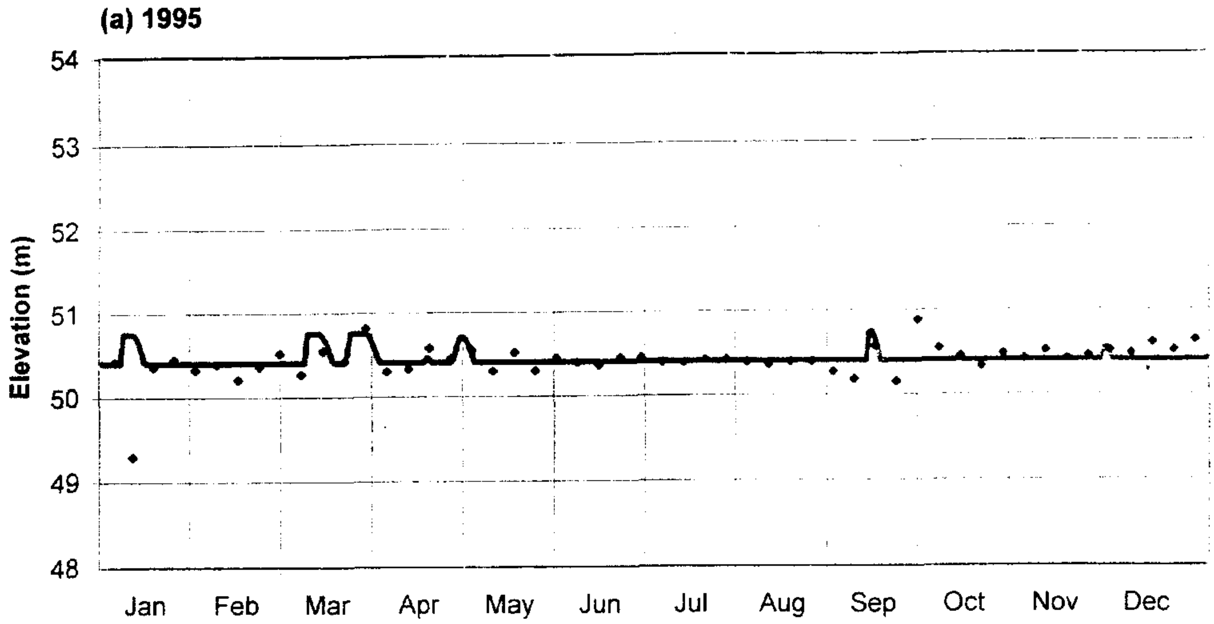


Fig. 15.3

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
LONG POND STORAGE COMPARISON



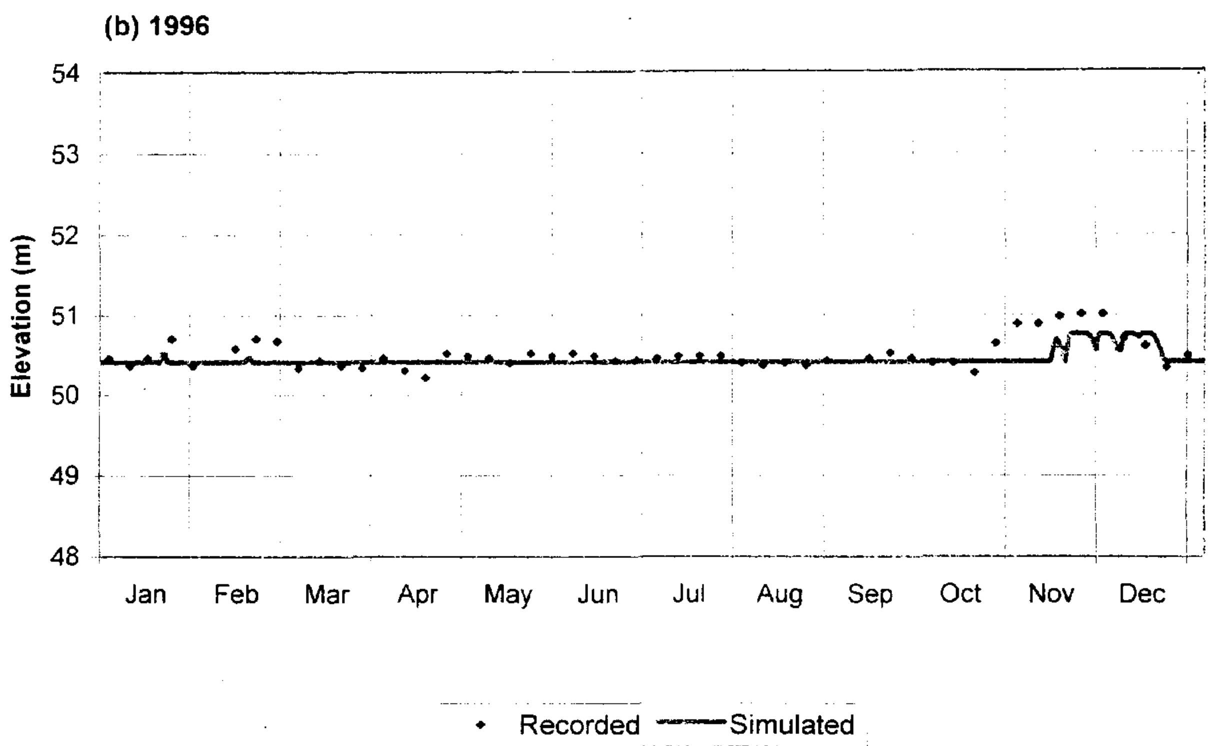


Fig. 15.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

FOREBAY STORAGE COMPARISON

AGRES

16 Lockston Hydroelectric System

The long term production for the Lockston Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequence, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

16.1 System Description

The Lockston system is located on the Bonavista Peninsula of Newfoundland near the community of Lockston and has one generating station located within the system. The Lockston Generating Station contains two generating units each with nameplate capacities of 1.5 MW, and with a rated net head of 82.2 m. The station was commissioned in 1956. The drainage area above the intake to the station is approximately 46 km^2. Storage is provided by a structure at Trinity Pond with Rattling Pond Forebay acting as the headpond for the Lockston station. A schematic of the system is presented in Figure 16.1.

Water is released from Trinity Pond to Rattling Pond using the control structure located at the outlet of Trinity Pond. Controlled releases and spill from Trinity Pond enter Rattling Pond Forebay, and are either stored, spilled out of the system or used for generation.

The structures in the system are as follows

- Trinity Pond gated outlet;
- Rattling Pond Forebay gated outlet; and
- Rattling Pond Forebay overflow spillway.

The Trinity Pond overflow spillway discharges within the system, and the Rattling Pond Forebay overflow spillway discharges out of the system.

16.2 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. The inflow sequence for the Lockston system was generated by prorating the recorded flows at a nearby hydrometric station by drainage area. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The hydrometric station used to derive the hydrology for the Lockston system was Salmon Cove River near Champney's (02ZJ002). The Salmon Cove River station has a drainage area of 73.6 km^2.

A mean annual runoff of 1076 mm/yr for the reference period was calculated from the hydrometric station record for Salmon Cove River. The mean annual runoff of the Lockston basin was assumed to be the same.

The inflow sequence for the simulation was developed by multiplying the Salmon Cove River flows by the ratio of drainage area for each subbasin to Salmon Cove drainage area. No suitable alternative stations were identified for sensitivity analysis.

16.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequence used for the model was described in Section 16.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

16.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Lockston system

- Trinity Pond; and
- Rattling Pond Forebay.

Different sources of information on storage were available from NP's records. These sources were in agreement. As a further check, the areas of the reservoirs were planimetered and compared with the areas provided by NP. The areas were also in agreement.

16.3.2 Generating Station Characteristics

The two generating units in the Lockston station were modelled as one combined unit. Generating station characteristics were based on NP's plant operating guidelines.

To account for the loss in energy due to the variation in penstock head losses as a function of the power flow, the head loss with one unit generating was input in the model as a constant loss and additional head losses were included in the tailwater curve. Therefore, the tailwater curve consists of synthetic water levels used to account for the drop in net head due to head losses, in addition to the actual variation in tailwater level with flow.

16.3.3 Structure Characteristics

The stage discharge curve for the Trinity Pond gated structure was based on information provided by NP.

For the purpose of maintaining flow in the river reaches downstream of the gated outlet for environmental reasons, the minimum flow in this gate was set to 0.1 m^3/s, if water was available. The Trinity Pond and Rattling Pond Forebay spillways were not modelled as individual structures. Instead, all water stored above full supply level was assumed to be spilled. The Rattling Pond Forebay gated outlet was also not modelled since it was assumed to have adequate capacity and to be always open.

16.3.4 System Operation

NP's plant operating guidelines for the Lookout Brook system provide the following procedures.

1.) *Units should be cycled on and off at best efficiency to maximize water use.*
2.) *Full load should be used only in event of predicted spill. Main control should be via operating gates.*
3.) *Plant has a large storage reservoir and seldom spills. The control gate at Rattling Pond which feeds the canal is usually full open. The water flows to the plant is controlled using the outlet gate at Trinity Pond.*
4.) *The gate at Trinity Pond is typically kept open 8 - 10" in the winter.*
5.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

These guidelines were used to develop the following operating strategy for the modelling.

- Release water through the Trinity Pond gated outlet as necessary to keep Lockston at best efficiency load and maintain the target level.
- Set the target level of Rattling Pond Forebay midway between its upper and lower operating levels.
- Operate Lockston at best efficiency as long as possible during each day, while maintaining the target level.
- If the level of Rattling Pond Forebay exceeds full supply level, operate Lockston at maximum load.

The same operating procedures were used for both the comparison runs and the run to estimate long term production.

16.4 Model Comparison

The years selected by NP for the comparison runs were 1997 and 1998. Figure 16.2 shows the Lockston simulated and recorded monthly generation for these two years.

As Figure 16.2 shows, the simulated generation using the primary inflow sequences generally follows the same pattern as the recorded generation. There are differences between the recorded and simulated values within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 16.4.1 below, followed by a discussion of the annual differences in Section 16.4.2.

16.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 16.2 are most likely due to differences between the actual and simulated operation of the system.

Figure 16.3 shows a comparison of storage in the main storage reservoir, Trinity Pond. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation, and vice versa. In both years, the model drew down Trinity Pond to keep the station running at best efficiency, and ran out of stored water by the end of March.

16.4.2 Differences in Annual Generation

Table 16.1 summarizes the annual energy generation for the two comparison years for the Lockston station. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values at the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figure 16.3). The adjustment takes account of the energy potential of the water in storage.

Table 16.1
Lockston Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1997	8.9	12.5	8.4	8.1	-4
1998	8.8	13.5	8.7	9.6	10

The kinds of operational differences described in Section 16.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Lockston system is briefly discussed below.

Hydrology
In the case of the Lockston system, the simulation gave reasonable results for 1998 and was used to estimate the long term production as presented in Section 16.5.

Differences in Water Use
The model assumes perfect operation of units and reservoirs according to the input operating strategy described in Section 16.3.4. The two most important factors in the model affecting generation are as follows.

- Ideal operation of the units: The units never operate at less than the most efficient load, although they do operate at higher loads if there is a risk of spill.
- 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.

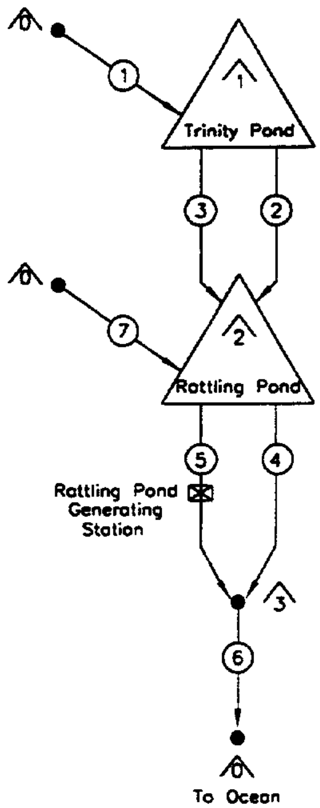
There was no spill recorded or simulated in either of the comparison years. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency in the power plant characteristics.

16.5 Simulated Long Term Production

The system operation was simulated for the 15 year reference period to estimate the long term production for the Lockston system. The results of this simulation was an estimate of long term production of 8.8 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

① — Trinity Pond Local Inflow
② — Trinity Pond Overflow Spillway
③ — Trinity Pond Outlet Spillway
④ — Rattling Pond Overflow Spillway
⑤ — Rattling Pond Power Flow
⑥ — Rattling Pond Total Outflow
⑦ — Rattling Pond Inflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Trinity Pond
2 — Rattling Pond
3 — Rattling Pond Total Outflow

Fig. 16.1

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
LOCKSTON ARSP MODEL SCHEMATIC

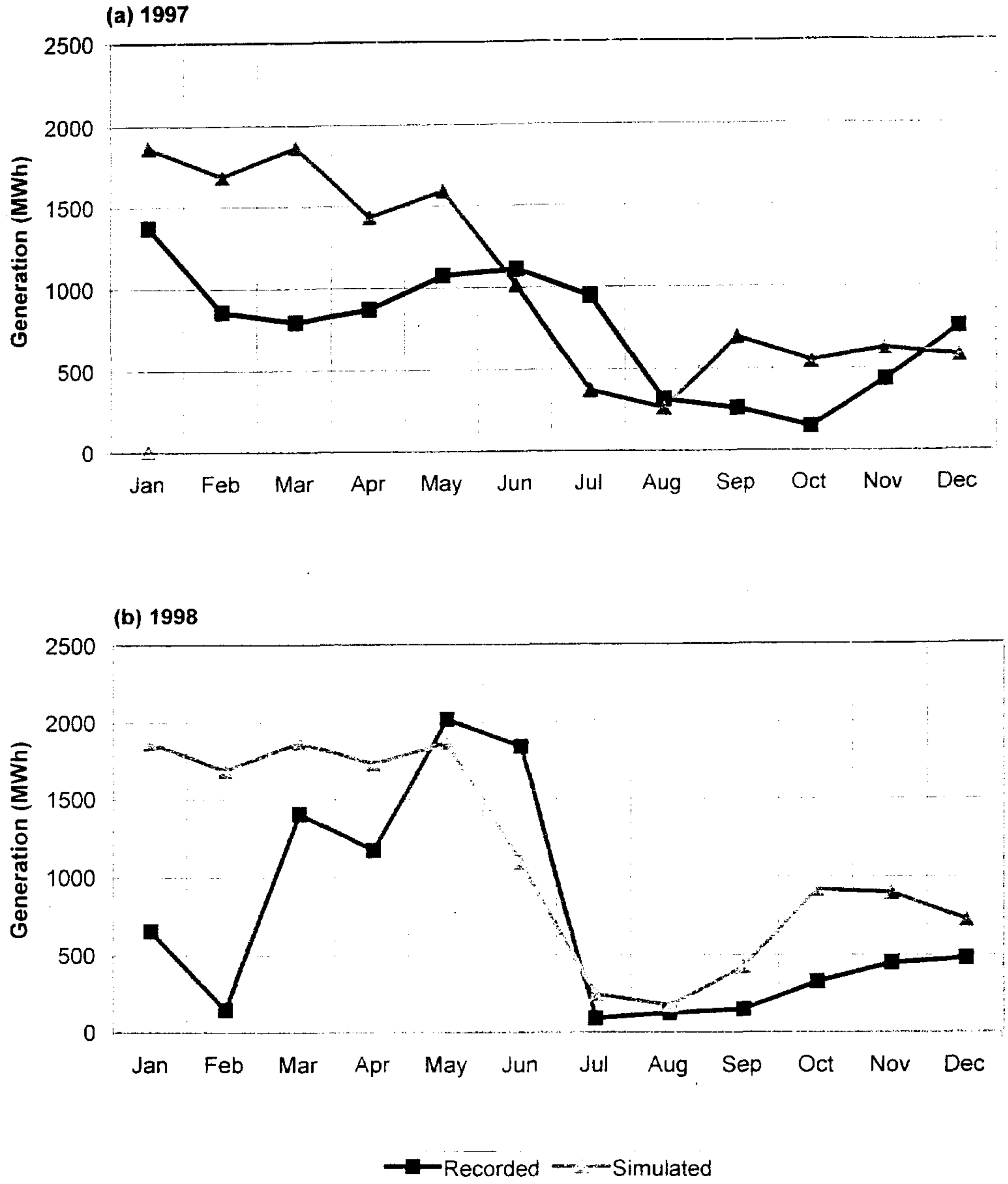
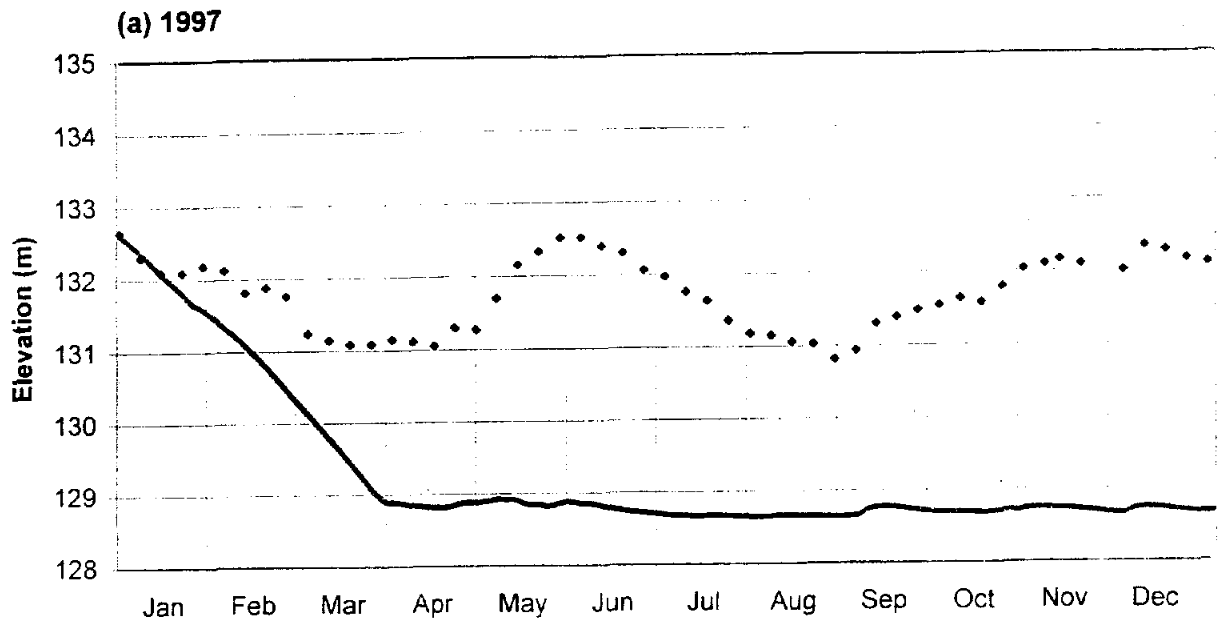


Fig. 16.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

LOCKSTON GENERATION COMPARISON



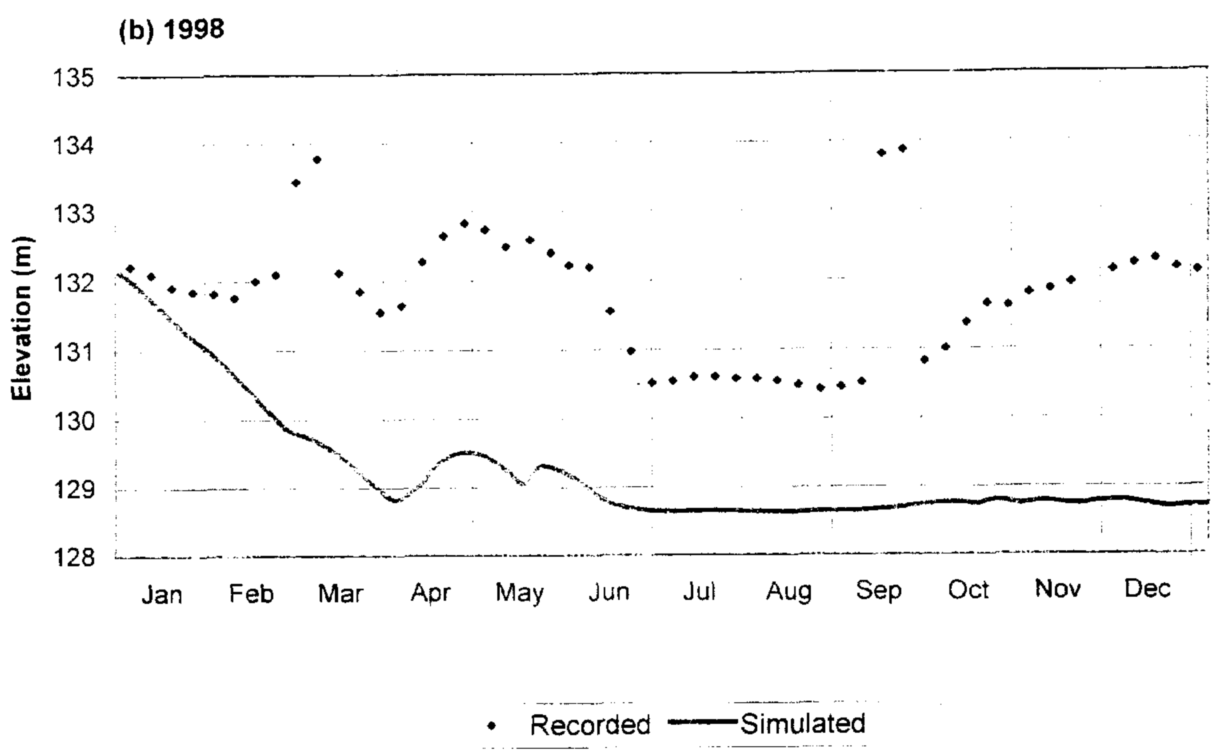


Fig. 16.3

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
TRINITY POND STORAGE COMPARISON

ACRES

17 Victoria Hydroelectric System

The long term production for the Victoria Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

17.1 System Description

The Victoria system is located on the Avalon Peninsula of Newfoundland near the town of Victoria. The Victoria Generating Station was commissioned in 1904 and contains one generating unit with a nameplate capacity of 0.5 MW and a rated net head of 64.3 m. The drainage area above the intake to the Victoria station is approximately 19.4 km^2. Storage is provided by a structure at Rocky Pond, and Blue Hill Pond is the forebay for the Victoria station. A schematic of the system is presented in Figure 17.1.

Water entering Rocky Pond is either stored, spilled within the system or released downstream to the forebay using the control structure located at its outlet. Water entering the forebay is either spilled out of the system or used for generation.

The Victoria system also serves as the water supply for the town of Victoria. The intake is in the canal between Rocky Pond and the forebay.

The structures in the system are as follows

- Rocky Pond dam;
- Rocky Pond outlet gate;
- Rocky Pond overflow spillway;
- Blue Hill Pond (Forebay) dam; and
- Blue Hill Pond (Forebay) overflow spillway.

17.2 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. Inflow sequences for the Victoria system subbasins were generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The two hydrometric stations used to derive the hydrology for the Victoria system were Spout Cove Brook near Spout Cove (02ZL003) and Shearstown Brook at Shearstown (02ZL004). The record from the Little Spout Cove Brook station, with a drainage area of 10.8 km^2, was chosen as the primary source for deriving the Victoria system subbasin flows based on its proximity to Victoria. Flows at this station have been recorded from January 1, 1979 to June 26, 1997. Shearstown Brook record was used to prepare a sequence for sensitivity analysis. The drainage area of the Shearstown Brook basin is 28.9 km^2. The missing 1997 and 1998 flows for Spout Cove Brook were filled in using Shearstown Brook flows, adjusted for the difference in drainage area and mean annual runoff.

Mean annual runoffs of 1128 mm/yr and 949 mm/yr for the reference period were calculated from the hydrometric station records for Spout Cove Brook and Shearstown Brook, respectively. The mean annual runoff of the Victoria basin was estimated during this study to be 1150 mm/yr, greater than Spout Cove Brook and Shearstown Brook due to its higher elevation.

The primary inflow sequence for the simulation was developed by multiplying the Spout Cove Brook flows by the ratios of Victoria basin mean annual runoff and drainage area for each subbasin to Spout Cove Brook mean annual runoff and drainage area. The same approach was used to develop the sensitivity inflow sequence using Shearstown Brook.

17.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1994 and 1995. The development of the inflow sequences used for the model was described in Section 17.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

17.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Victoria system

- Rocky Pond; and
- Victoria Forebay.

Different sources of information on storage were available from NP's records. These sources were in agreement. As a further check, the area of the reservoirs were planimetered and compared with the areas provided by NP. The areas were also in agreement.

17.3.2 Generating Station Characteristics

The generating station at Victoria houses one generating unit. Information was sparse for the generating unit, so the generating station characteristics were based on NP's plant operating guidelines. The installed capacity used to estimate the long term production was 0.55 MW. This total differs slightly from the nameplate capacity shown in Table 1.1 of 0.5 MW due to the maximum load recordings in the plant operating guidelines.

Constant values were used for the head loss and tailwater.

17.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- Rocky Pond Outlet Gate;
- Rocky Pond Spillway; and
- Blue Hill Pond (Forebay) Spillway.

Structure curves were estimated based on information provided by NP.

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 was available.

17.3.4 System Operation

NP's plant operating guidelines for the Victoria system provide the following procedures.

1.) Plant is equipped with water control which cycles the unit between just below best efficiency and full load depending upon the Forebay elevation.
2.) Rocky Pond is the only storage in the system. The outlet gate is adjusted to maintain flow to the forebay.
3.) The canal from Rocky Pond to the forebay is used by the Town of Victoria as the municipal water supply so a minimum water flow must always be maintained to the forebay.

4.) All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.

5.) Municipality uses 2.5 million gallons of water weekly.

NP's plant operating guidelines were used to develop the following operating strategy for the modelling.

- If the reservoir levels are below the rule curve, operate unit at most efficient load.
- If reservoirs are low, operate unit at most efficient load when water is available.
- To avoid going over the rule curve, the unit is brought up to maximum load.

The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

17.4 Model Comparison

The years selected by NP for the comparison runs were 1994 and 1995. The simulation model was run for these years for both the primary and sensitivity inflow sequences. Figure 17.2 shows the Victoria simulated and recorded monthly generation for these two years.

As Figure 17.2 shows, the simulated generation using both the primary and sensitivity inflow sequences generally follows the same pattern as the recorded generation, except for the last half of 1995, with the sensitivity inflow sequence providing the better estimate. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 17.4.1 below, followed by a discussion of the annual differences in Section 17.4.2.

17.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 17.2 are most likely due to differences between the actual and simulated operation of the system.

Figure 17.3 shows comparison of storage in the main storage reservoir, Rocky Pond. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation, and vice versa. For the months August through December 1995, for example, Figure 17.2 shows that the model generates more energy than was recorded. Figure 17.3 shows that at the end of this period, the model has less water in storage in Rocky Pond, because it was used for generation. The opposite effect for October and November 1994 can be seen in the same figures.

17.4.2 Differences in Annual Generation

Table 17.1 summarizes the annual energy generation for the two comparison years for Victoria station. Simulated annual energy generation is shown using both the primary and sensitivity inflow sequences. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values at the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figure 17.3). The adjustment takes account of the energy potential of the water in storage.

Table 17.1
Victoria Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference Using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1994	3.7	3.9	3.0	3.4	13
1995	3.2	3.7	3.6	3.8	6
Sensitivity Inflow Sequence					
1994	3.7	3.9	3.0	3.5	17
1995	3.2	3.4	3.6	3.4	-6

The kinds of operational differences described in Section 17.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage.

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Victoria system is briefly discussed below.

Hydrology
In the case of the Victoria system, the simulation using the primary inflow sequence gave reasonable results for 1994 and 1995 and was used to estimate the long term production as presented in Section 17.5.

Differences in Water Use
For the Victoria system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described in Section 17.3.4. The two most important factors in the model affecting generation are as follows.

- Ideal operation of the unit: The unit never operates at less than the most efficient load, although it does operate at higher loads if there is a risk of spill.

- Ideal operation of the reservoir and control gate to maximize flow for energy generation and minimize spill: The model avoids spill by tracking water levels in the reservoir, and opens or closes the gate as required to ensure perfect operation of the units and to minimize spill.

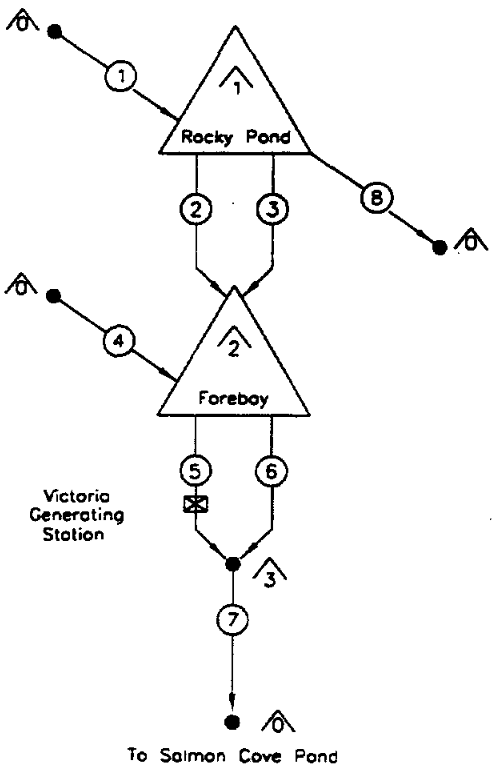
A comparison of recorded and simulated spill shows that the values for 1994 were 123.5 MWh and 47.4 MWh, respectively and for 1995 there was no spill recorded or simulated. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded. The additional actual spill could be partially responsible for the lower recorded energy generation when compared with the simulated. Adjusting the results tabulated above by the difference in recorded and simulated spill for 1994 would reduce the discrepancy between simulated and recorded energy generation.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency.

17.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequences for the 15 year reference period to estimate the long term production for the Victoria system. The result of this simulation was an estimate of long term production of 3.3 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

(1) — Rocky Pond Local Inflow
(2) — Rocky Pond Outlet Gate
(3) — Rocky Pond Spill
(4) — Forebay Local Inflow
(5) — Victoria Power Flow
(6) — Blue Hill Pond Spill
(7) — Victoria Total Outflow
(8) — Town of Victoria Water Supply Demand

RESERVOIRS / NODES

0 — Source / Sink
1 — Rocky Pond
2 — Blue Hill Pond (Forebay)
3 — Blue Hill Pond Total Outflow

Fig. 17.1

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
VICTORIA ARSP MODEL SCHEMATIC

ACRES

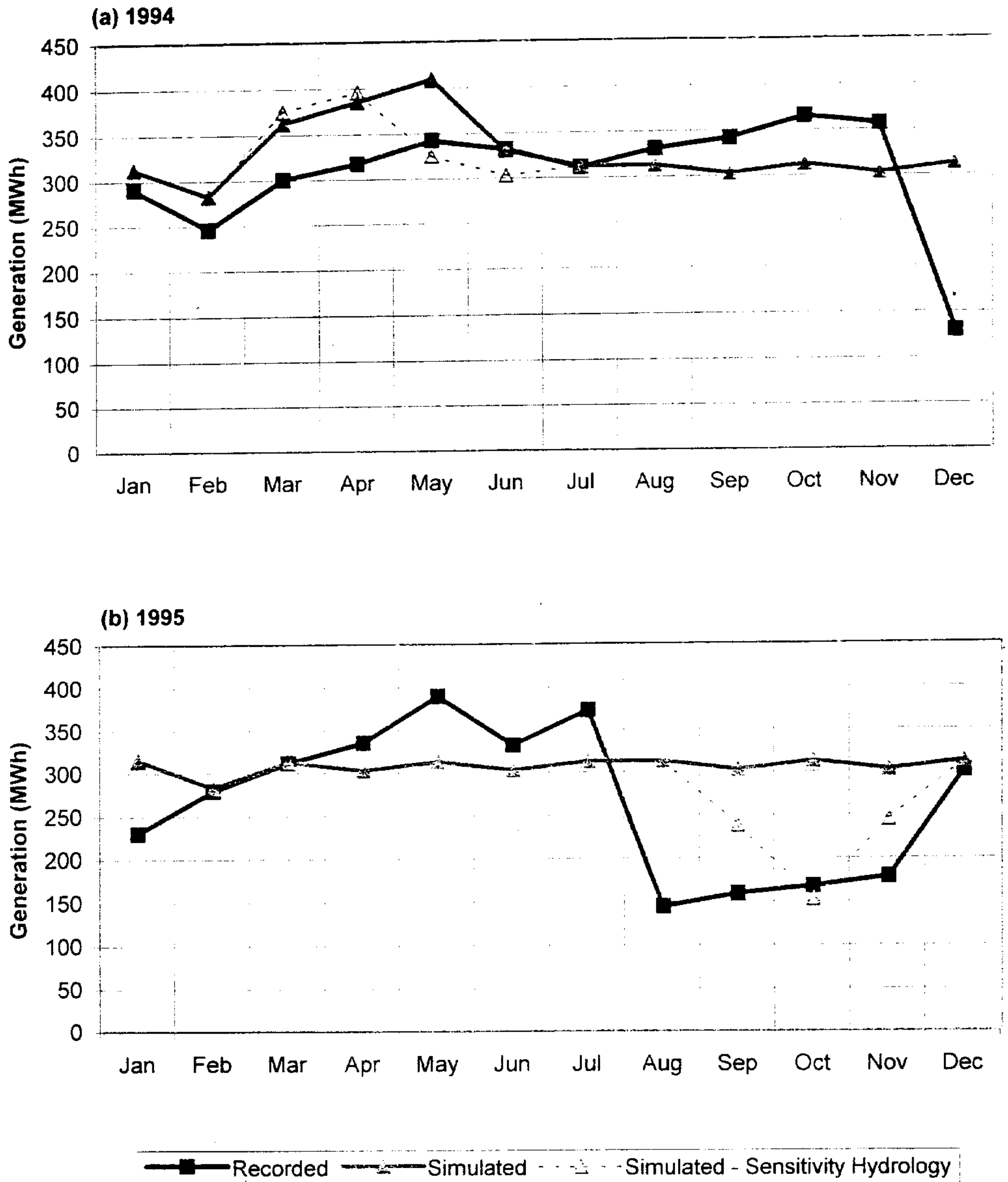


Fig. 17.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

VICTORIA GENERATION COMPARISON

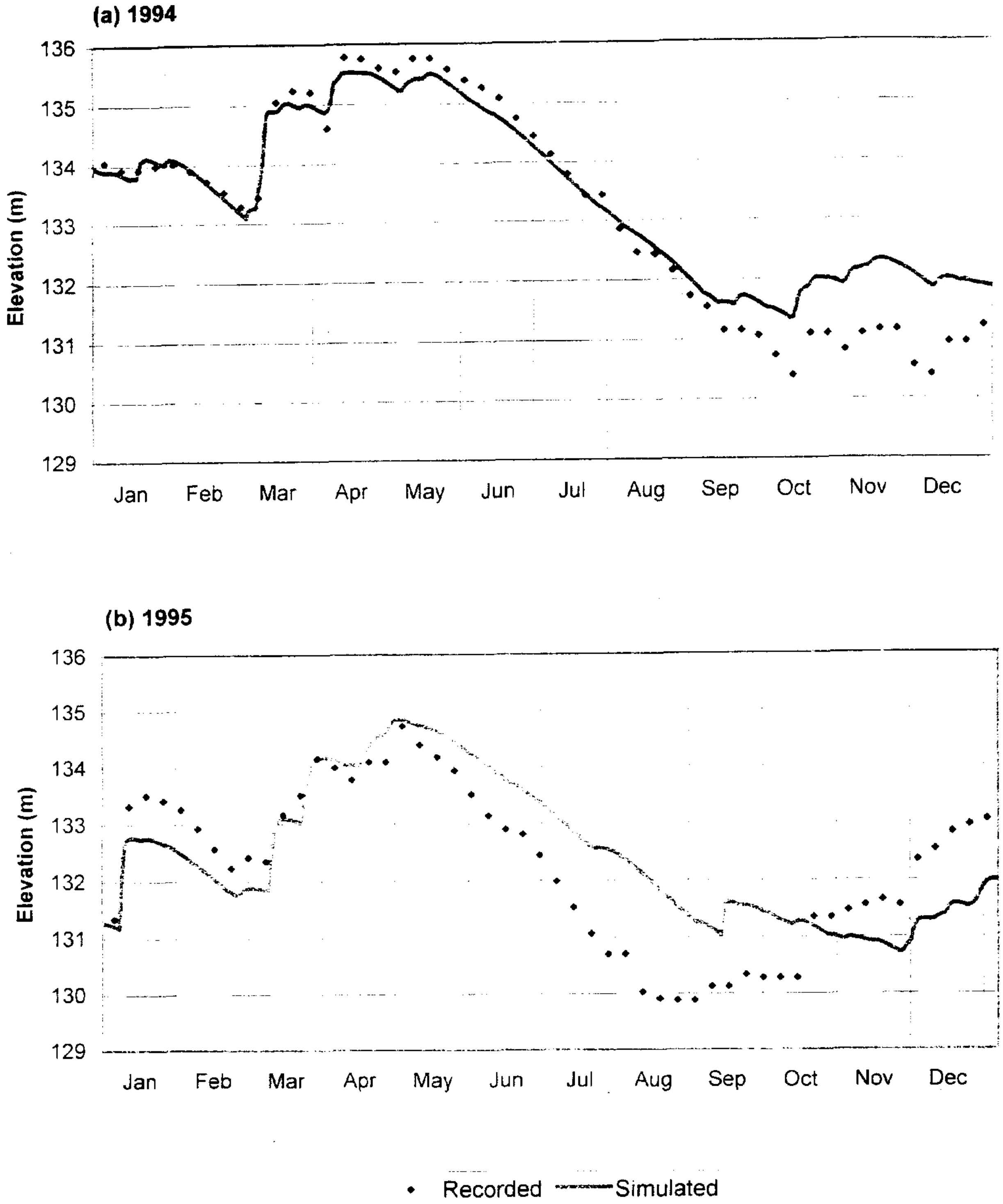


Fig. 17.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

ROCKY POND STORAGE COMPARISON

AGRES

18 West Brook Hydroelectric System

The long term production for the West Brook Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

18.1 System Description

The West Brook system is located on the southern part of the Burin Peninsula near the town of St. Lawrence and has one generating station located within the system.

The West Brook Generating Station contains one generating unit with a nameplate capacity of 0.7 MW and a rated net head of 47.0 m. The drainage area above the intake to the West Brook station is approximately 48 km^2. The station was commissioned in 1942 and there are no storage reservoirs in the system. A schematic of the system is presented in Figure 18.1.

The West Brook station is run of river and there is an overflow spillway located on the forebay, which when overtopped, would lead to spill out of the system. The West Brook system serves as a water supply for the town of St. Lawrence with the intake located in the canal exiting West Brook Forebay.

18.2 Inflow Sequences

The daily inflow sequence required for the simulations was generated using the methodology presented in Chapter 2 of this report. The inflow sequence for the West Brook system basin was generated by prorating the recorded flows at a nearby hydrometric station by the drainage area.

The hydrometric station used to derive the hydrology for the West Brook system was Salmonier River near Lamaline (02ZG003). The record from the Salmonier River station, with a drainage area of 115 km^2, was chosen as the primary source for deriving the West Brook system basin flows. Due to the proximity it was assumed that the West Brook system has the same mean annual runoff of the Salmonier River station; therefore, the flows were prorated only by drainage area. There were no other suitable hydrometric stations nearby the West Brook system, so only a primary inflow sequence was used with no sensitivity analysis.

The primary inflow sequence for the simulation was developed by multiplying the Salmonier River flows by the ratio of West Brook drainage area to the Salmonier River drainage area.

18.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequence used for the model was described in Section 18.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

18.3.1 Reservoir Characteristics

Characteristics required for West Brook Forebay were available from NP's records.

18.3.2 Generating Station Characteristics

The generating station at West Brook houses one generating unit (WBK-G1). The unit underwent an overhaul during the Spring of 2000, therefore the generating station characteristics were different in the comparison year simulations from those used to estimate the long term production.

NP's plant operating guidelines were used to develop generating station characteristics for WBK-G1 before and after the unit overhaul in 2000. The installed capacity used for the model comparison was 0.62 MW and was 0.72 MW for the estimate of long term production. These differ from the nameplate capacity presented in Table 1.1 due to NP's operating experience.

18.3.3 Structure Characteristics

The stage discharge curve required for West Brook Forebay overflow spillway was estimated based on information provided by NP and standard hydraulic equations.

The town water supply requirement was provided by NP to be 4500 m^3/day. The water supply was reduced by 50 percent from October to March assuming that the fish plant was not operating.

18.3.4 System Operation

NP's plant operating guidelines for the West Brook system provide the following procedures.

1.) Plant is a run of river and operates under water level load control.

2.) Water supply for the town of St. Lawrence is taken off the canal feeding the powerhouse.

3.) All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.

NP's plant operating guidelines were used to develop the following operating strategy for the modelling.

- If the reservoir level is below the rule curve, operate the station at most efficient load.
- If reservoirs are low, only operate the station at most efficient load when water is available.
- To avoid going over the rule curve, the station is brought up to maximum load.

The same operating procedures were used for the comparison runs and the run to estimate long term production.

18.4 Model Comparison

The years selected by NP for the comparison runs were 1997 and 1998. Figure 18.2 shows the West Brook simulated and recorded monthly generation for these two years.

As Figure 18.2 shows, the simulated generation generally follows the same pattern as the recorded generation. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 18.4.1 below, followed by a discussion of the annual differences in Section 18.4.2.

18.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 18.2 are most likely due to differences between the actual and simulated operation of the system. NP does not record water levels at the West Brook system, so it was not possible to compare simulated and recorded water levels.

18.4.2 Differences in Annual Generation

Table 18.1 summarizes the annual energy generation for the two comparison years for the West Brook station unadjusted for the difference in energy in storage from the beginning to the end of the year. NP does not record water levels for West Brook Forebay, so it was not possible to do an energy adjustment for the actual generation.

Table 18.1
West Brook Generating Station Recorded and Simulated Annual Energy Generation

Year	Unadjusted Annual Energy Generation (GWh/yr)		Difference (%)
	Recorded	Simulated	
Primary Inflow Sequence			
1997	2.7	3.4	26
1998	2.9	3.4	17

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use (operation of the unit); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the West Brook system is briefly discussed below.

Hydrology
In the case of the West Brook system, the simulation using the primary inflow sequence gave reasonable results for 1997 and 1998 and was used to estimate the long term production as presented in Section 18.5. Although the unadjusted results for simulated generation are higher than the actual generation for 1997 and 1998, it is believed that most of the difference is due to the differences between the actual and simulated operation of the system.

Differences in Water Use

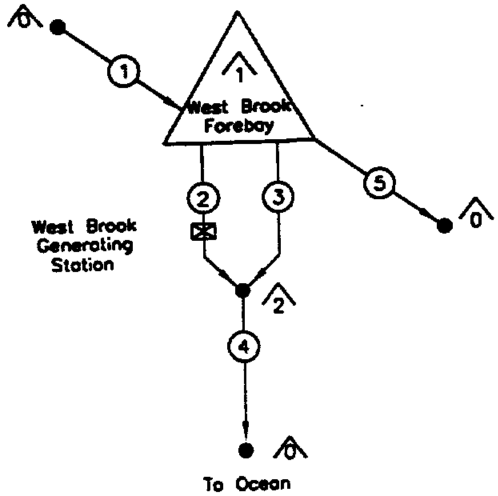
For the West Brook system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of the unit according to the specified operating procedures described in Section 18.3.4. The unit never operates at less than the most efficient load, although it does operate at higher loads if there is a risk of spill.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses, unit efficiency, or the estimate of water supply for the Town of St. Lawrence. There was sparse information available for the town supply and it was indicated by NP that there is a lot of leakage in the system. It could be possible that the town supply is higher than what is being modelled.

18.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequences for the 15 year reference period to estimate the long term production for the West Brook system. The result of this simulation was an estimate of long term production of 3.7 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

1 — West Brook Forebay Local Inflow
2 — West Brook Power Flow
3 — West Brook Spill
4 — West Brook Total Outflow
5 — Town of St.Lawrence Water Supply Demand

RESERVOIRS / NODES

0 — Source / Sink
1 — West Brook Forebay
2 — West Brook Total Outflow

Fig. 18.1

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
WEST BROOK ARSP MODEL SCHEMATIC

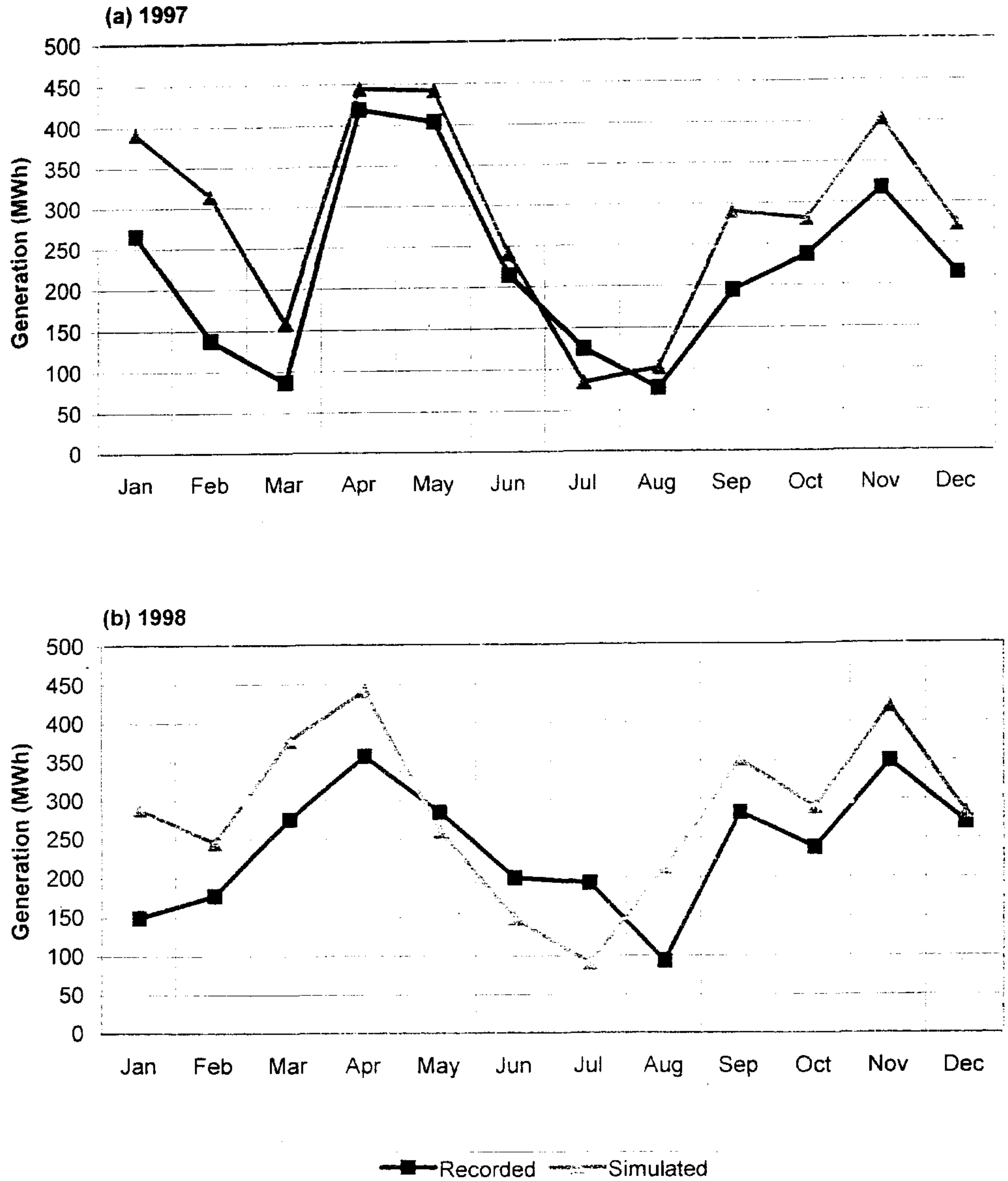


Fig. 18.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

WEST BROOK GENERATION COMPARISON

19 Port Union Hydroelectric System

The long term production for the Port Union Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequence, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

19.1 System Description

The Port Union system is located on the Bonavista peninsula of Newfoundland and has one generating station.

The Port Union Generating Station was commissioned in 1917 and contains two generating units with a total nameplate capacity of 0.5 MW and a rated net head of 21.3 m. The drainage area above the intake of the Port Union station is approximately 77 km^2. Storage is provided by structures at Halfway Pond, Wells Pond, Long Pond, and Whirl Pond with Port Union Forebay acting as the headpond for the Port Union station. A schematic of the system is presented in Figure 19.1.

Spill and controlled releases from Halfway Pond and Wells Pond flow into Long Pond. From Long Pond, spill and controlled releases enter Whirl Pond. Water entering Whirl Pond is either spilled out of the system or released downstream to Port Union Forebay using the control structure located at its outlet. Whirl Pond also serves as a municipal water supply for the Town of Port Union. Water from upstream reservoirs entering Port Union Forebay is either spilled out of the system or used for generation.

The structures in the system are as follows

- Halfway Pond gated outlet;
- Halfway Pond overflow spillway;
- Wells Pond gated outlet;
- Wells Pond overflow spillway;
- Long Pond gated outlet;
- Long Pond overflow spillway;
- Whirl Pond gated outlet;
- Whirl Pond overflow spillway; and
- Port Union Forebay overflow spillway.

19.2 Inflow Sequences

The daily inflow sequences required for the simulations were generated using the methodology presented in Chapter 2 of this report. The inflow sequence for the Port Union system was generated by prorating the recorded flows at nearby hydrometric stations by drainage area and mean annual runoff. The subbasins were assumed to have the same mean annual runoff, so the sequences for the subbasins differ only by drainage area.

The hydrometric station used to derive the hydrology for the Port Union system was Salmon Cove River near Champney's (02ZJ002). The record from the Salmon Cove River station, with a drainage area of 73.6 km^2, was chosen as the source for deriving the Port Union system subbasin flows. There were no other suitable EC stations near the Port Union system, so no sequence for sensitivity analysis was prepared.

A mean annual runoff of 1076 mm/yr for the reference period was calculated from the hydrometric station record for Salmon Cove River. The mean annual runoff of the Port Union basin was assumed to be the same.

The inflow sequence for the simulation was developed by multiplying the Salmon Cove River flows by the ratios of Port Union drainage area to the Salmon Cove River drainage area.

19.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequence used for the model was described in Section 19.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

19.3.1 Reservoir Characteristics

Characteristics were required for the following reservoirs in the Port Union system

- Halfway Pond;
- Wells Pond;
- Long Pond;
- Whirl Pond; and
- Port Union Forebay.

Different sources of information on storage were available from NP's records. These sources were in agreement. As a further check, the area of the reservoirs were planimetered and compared with the areas provided by NP. The areas were also in agreement.

19.3.2 Generating Station Characteristics

The generating station at Port Union houses two generating units. For simplicity, the two units were modelled as one unit.

Information on the units was sparse. The installed capacity used in the model was 0.6 MW, based on data from NP's plant operating guidelines, instead of the total nameplate capacity of 0.5 MW. Unit efficiency was estimated from the NP plant factor for the system, since other sources suggested unrealistically high values. Constant values were assumed for head loss and tailwater elevation.

19.3.3 Structure Characteristics

Stage discharge curves for the following water control structures were based on information provided by NP

- Whirl Pond gated outlet;
- Long Pond gated outlet;
- Halfway Pond gated outlet; and
- Wells Pond gated outlet.

Structure curves were estimated based on information provided by NP and standard hydraulic equations. Due to lack of information, the overflow spillways were not modelled as individual structures. Instead, it was assumed that any water stored above full supply level was spilled.

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 was available.

19.3.4 System Operation

NP's plant operating guidelines for the Port Union system provide the following procedures.

1.) Operate Unit #1 and/or #2 at maximum load to avoid spill. Cycle unit on and off to maintain forebay limits.

2.) System is essentially run of river and water has to be used as it becomes available.

4.) Storage at Wells and Halfway should be kept towards the lower limit so that inflows from rainstorms may be captured. In the event of a predicted spill, gates at Halfway and Wells should be closed to the minimum and the forebay run down to minimum in anticipation of the inflow.

5.) Whirl Pond is a water supply for the town of Port Union and a minimum coverage of 3' is required at their intake.

6.) All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.

7.) Fish screens must be installed at Whirl Pond commencing immediately on ice out and must not be removed until August 31.

NP's plant operating guidelines were used to develop the following operating strategy for the modelling.

- Release water from Halfway Pond and Wells Pond as necessary to keep Port Union operating at best efficiency.
- Maintain the target levels in Long Pond and Whirl Pond and store only to avoid spill at Port Union.
- If the forebay water level is above the rule curve, operate at maximum load; otherwise, operate at best efficiency while maintaining the level at the rule curve.
- Release water from Whirl Pond to satisfy the Port Union water supply demand.

The same operating procedures were used for both the comparison runs and the runs to estimate long term production.

19.4 Model Comparison

The years selected by NP for the comparison runs were 1997 and 1998. Figure 19.2 shows the Port Union simulated and recorded monthly generation for these two years.

As Figure 19.2 shows, the simulated generation generally follows the same pattern as the recorded generation. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 19.4.1 below, followed by a discussion of the annual differences in Section 19.4.2.

19.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 19.2 are most likely due to differences between the actual and simulated operation of the system.

Figures 19.3, 19.4, 19.5, and 19.6 show comparisons of storage in the main storage reservoirs, Whirl Pond, Long Pond, Wells Pond and Halfway Pond, respectively. Periods when the simulated energy is greater than the recorded energy usually coincide with periods when NP records show that the water was held in storage, rather than used for generation. Examples include March 1997 and August 1998. Figure 19.5 shows that during these months, the model simulated the release of water for generation, while NP records show water being held in storage.

19.4.2 Differences in Annual Generation

Table 19.1 summarizes the annual energy generation for the two comparison years for Port Union station. The results are adjusted for the difference in energy in storage from the beginning to the end of the year. Although the water levels in the simulation started at the recorded values at the beginning of the year, by the end of the year the water levels in the simulation were usually different from the recorded values (as shown in Figures 19.3, 19.4, 19.5, and 19.6). The adjustment takes account of the energy potential of the water in storage.

Table 19.1
Port Union Generating Station Recorded and Simulated Annual Energy Generation

Year	Annual Energy Generation (GWh/yr)				Difference using Adjusted Values (%)
	Unadjusted		Adjusted for Storage		
	Recorded	Simulated	Recorded	Simulated	
Primary Inflow Sequence					
1996	2.3	2.7	2.3	2.7	17
1997	2.5	2.9	2.5	2.9	16

The kinds of operational differences described in Section 19.4.1 that account for the differences in energy from month to month, such as holding water back rather than generating, should not affect the annual energy after adjusting for storage. The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use, both in operation of units and of reservoirs (through control gates); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Port Union system is briefly discussed below.

Hydrology
In the case of the Port Union system, the simulation using the selected inflow sequence gave reasonable results for 1997 and 1998 and was used to estimate the long term production as presented in Section 19.5.

Differences in Water Use
For the Port Union system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of units and reservoirs according to the specified operating procedures described in Section 19.3.4. The two most important factors in the model affecting generation are as follows.

- Ideal operation of the units: The units never operate at less than the most efficient load, although they do operate at higher loads if there is a risk of spill.
- 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.

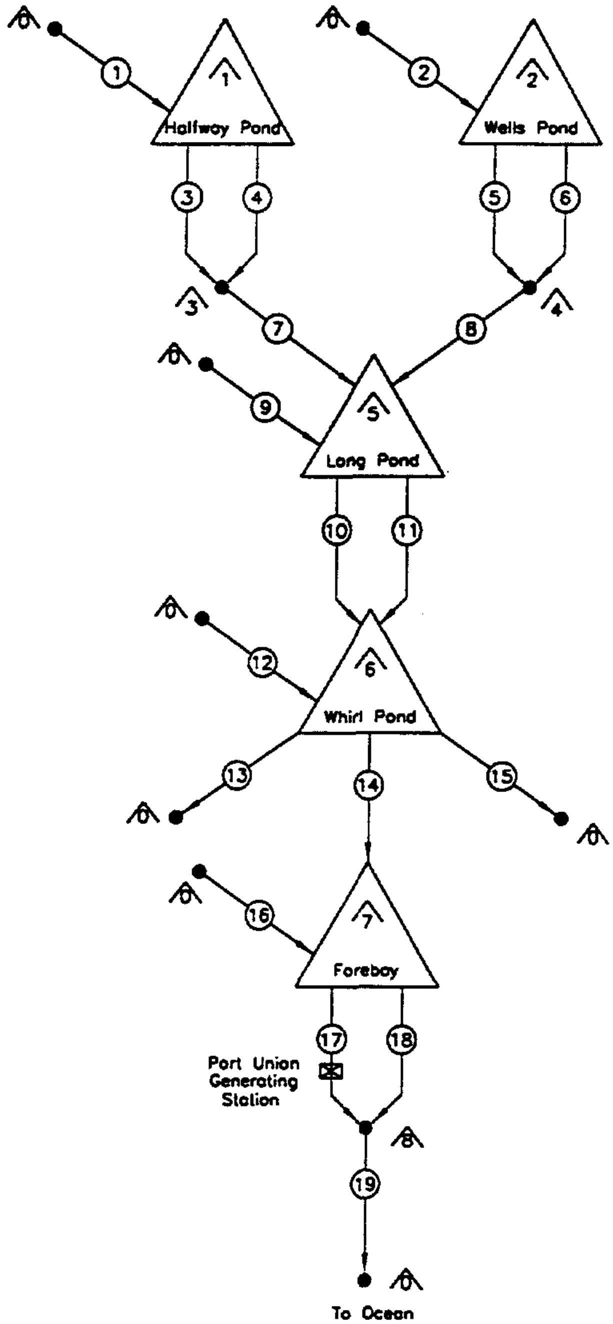
A comparison of recorded and simulated spill shows that the simulated values are lower. NP cautions that recorded spill data is often not reliable and it is possible that there could be spill out of the system that is not being recorded. The additional actual spill could be partially responsible for the lower recorded energy generation when compared with the simulated generation. Adjusting the results tabulated above by the difference in recorded and simulated spill for 1997 and 1998 would reduce the discrepancy between simulated and recorded energy generation in both years.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to such factors as estimates of head losses or unit efficiency, especially since little information was available for station characteristics.

19.5 Simulated Long Term Production

The system operation was simulated for the 15 year reference period to estimate the long term production for the Port Union svstem. The result of this simulation was an estimate of long term production of 2.8 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

① — Halfway Pond Local Inflow
② — Wells Pond Local Inflow
③ — Halfway Pond Outlet Gate
④ — Halfway Pond Spill
⑤ — Wells Pond Outlet Gate
⑥ — Wells Pond Spill
⑦ — Halfway Pond Total Outflow
⑧ — Wells Pond Total Outflow
⑨ — Long Pond Local Inflow
⑩ — Long Pond Outlet Gate
⑪ — Long Pond Spill
⑫ — Whirl Pond Local Inflow
⑬ — Town of Port Union Water Supply Demand
⑭ — Whirl Pond Outlet Gate
⑮ — Whirl Pond Spill
⑯ — Forebay Local Inflow
⑰ — Port Union Power Flow
⑱ — Port Union Spill
⑲ — Port Union Total Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Halfway Pond
2 — Wells Pond
3 — Halfway Pond Total Outflow
4 — Wells Pond Total Outflow
5 — Long Pond
6 — Whirl Pond
7 — Forebay
8 — Port Union Total Outflow

Fig. 19.1

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

PORT UNION ARSP MODEL SCHEMATIC

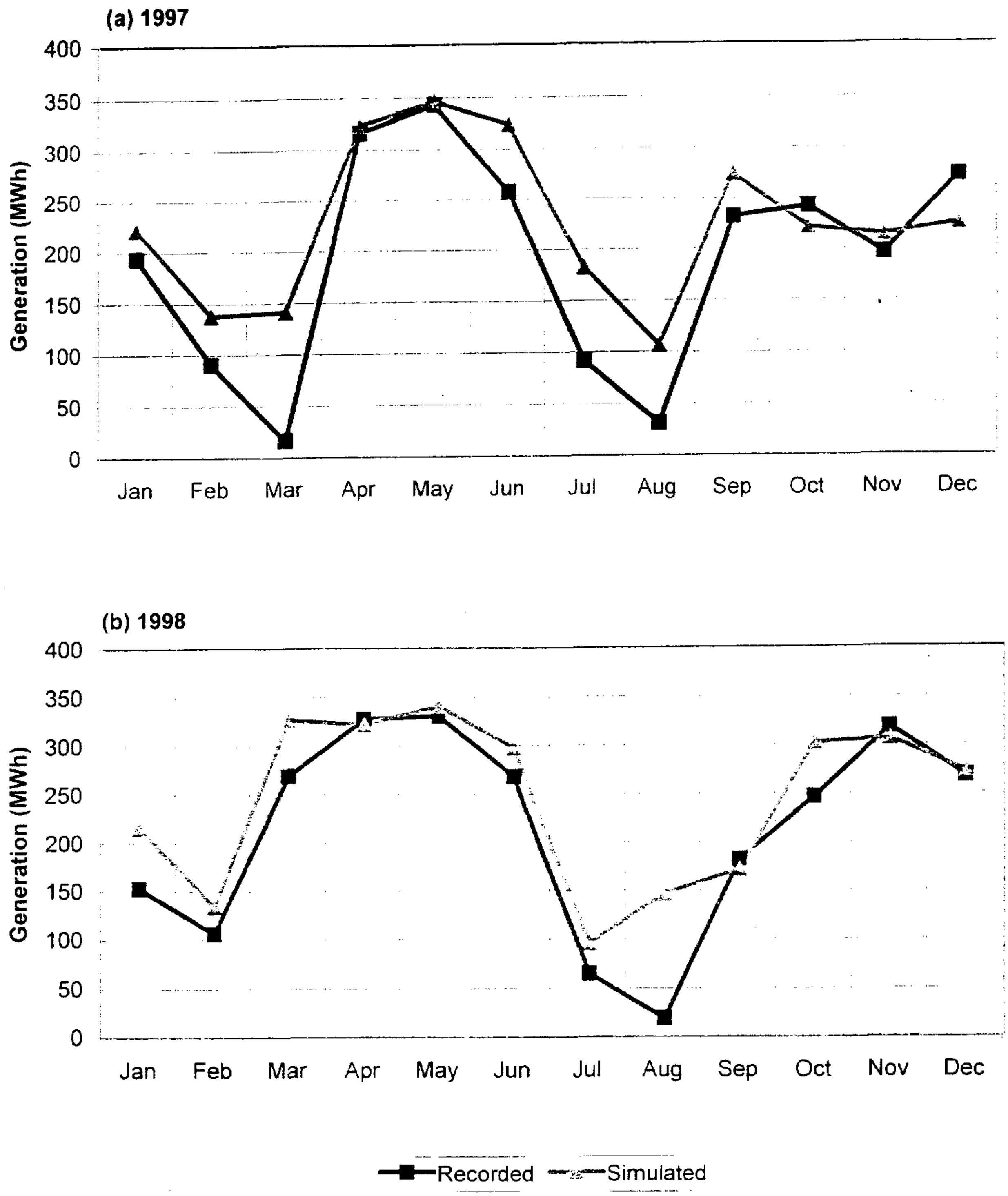


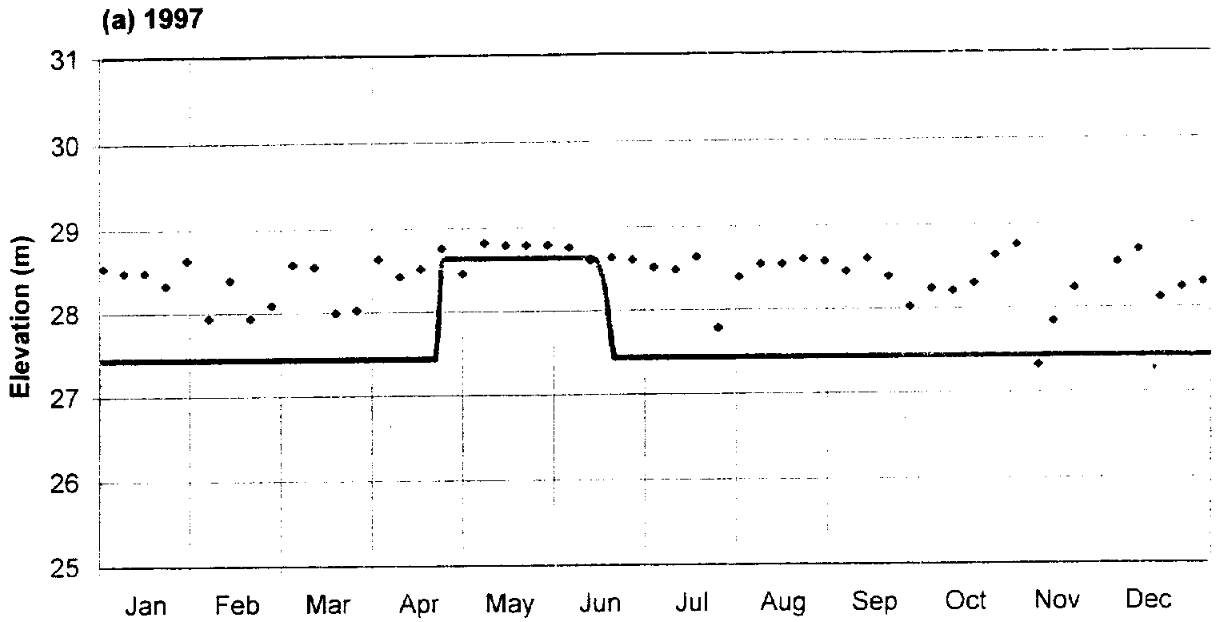
Fig. 19.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

PORT UNION GENERATION COMPARISON

ACRES



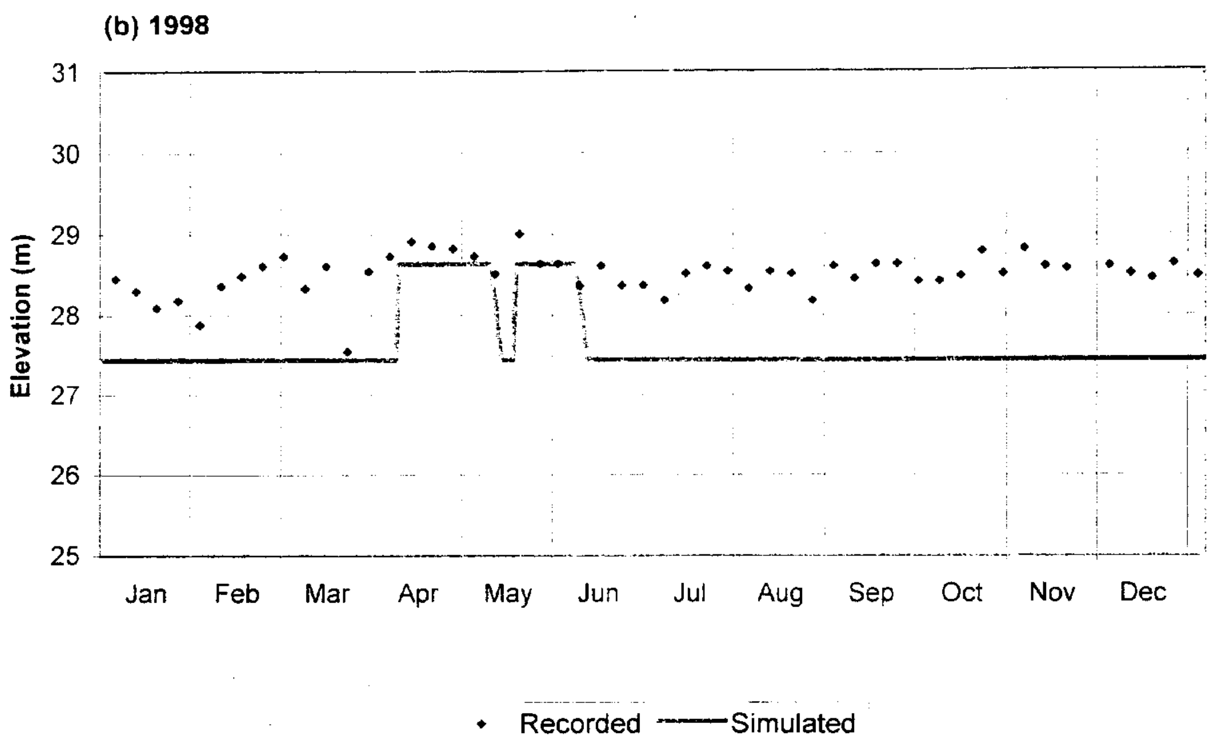


Fig. 19.3

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

WHIRL POND STORAGE COMPARISON

ACRES

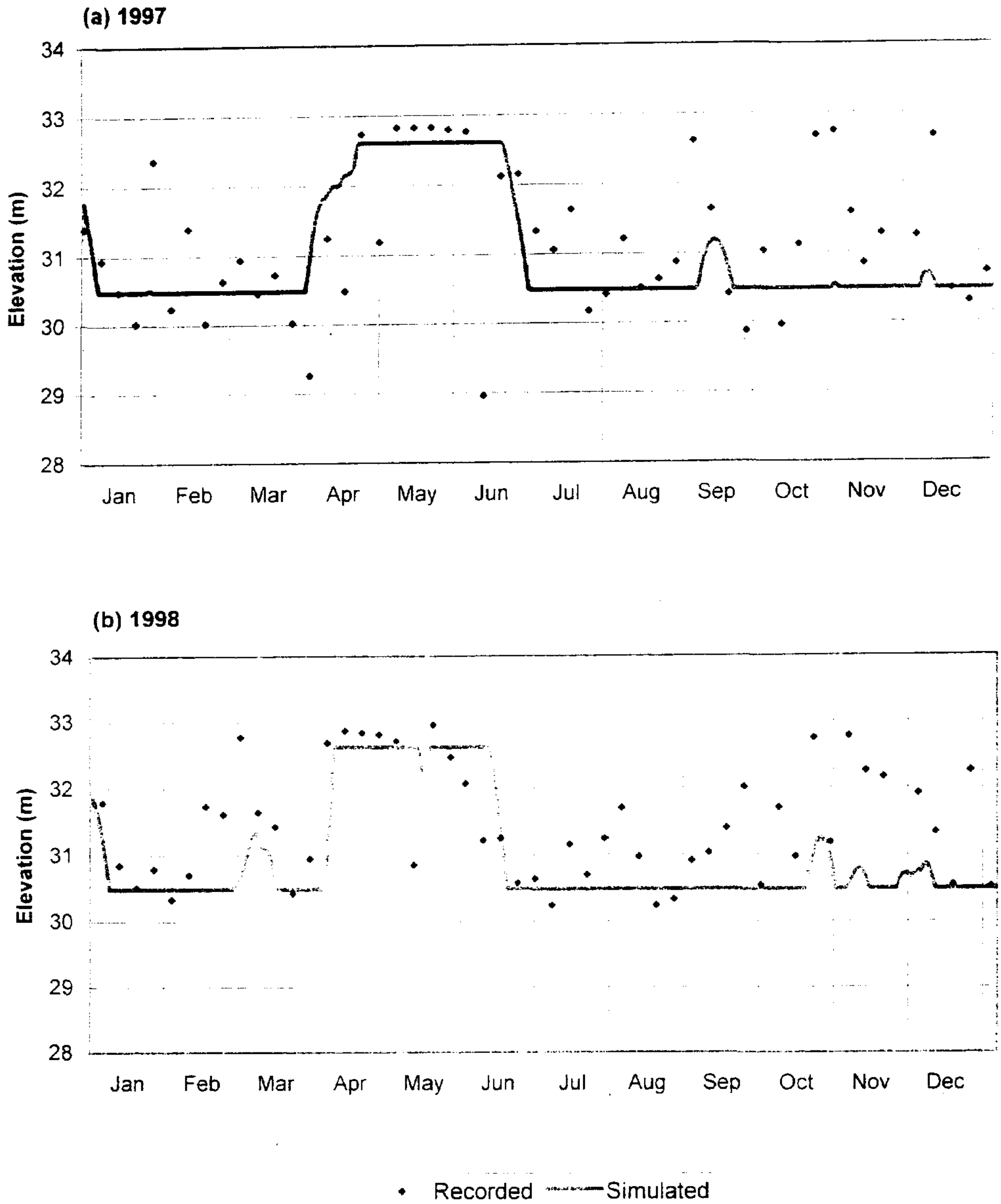


Fig. 19.4

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

LONG POND STORAGE COMPARISON

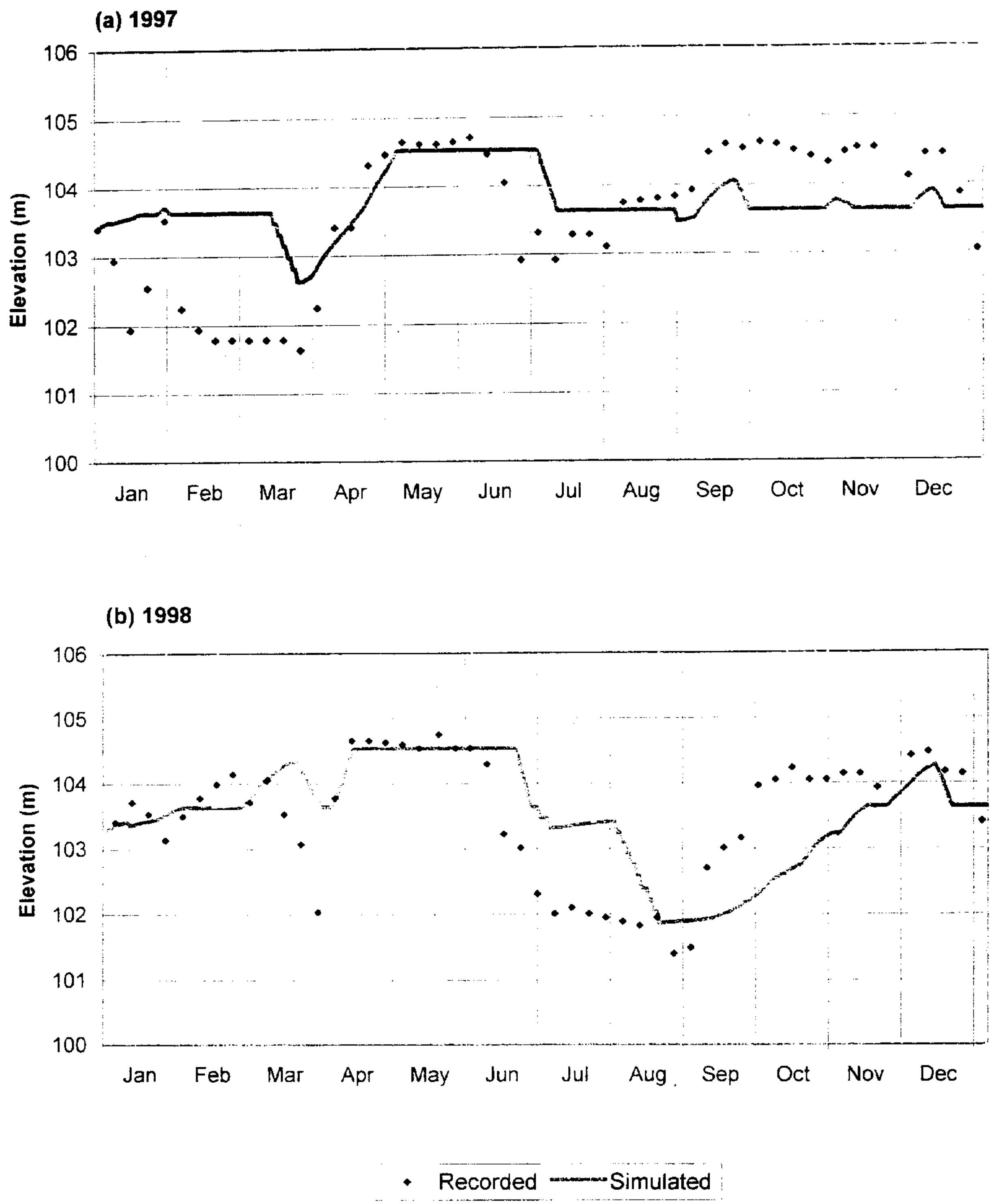


Fig. 19.5

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

HALFWAY POND STORAGE COMPARISON

ACRES

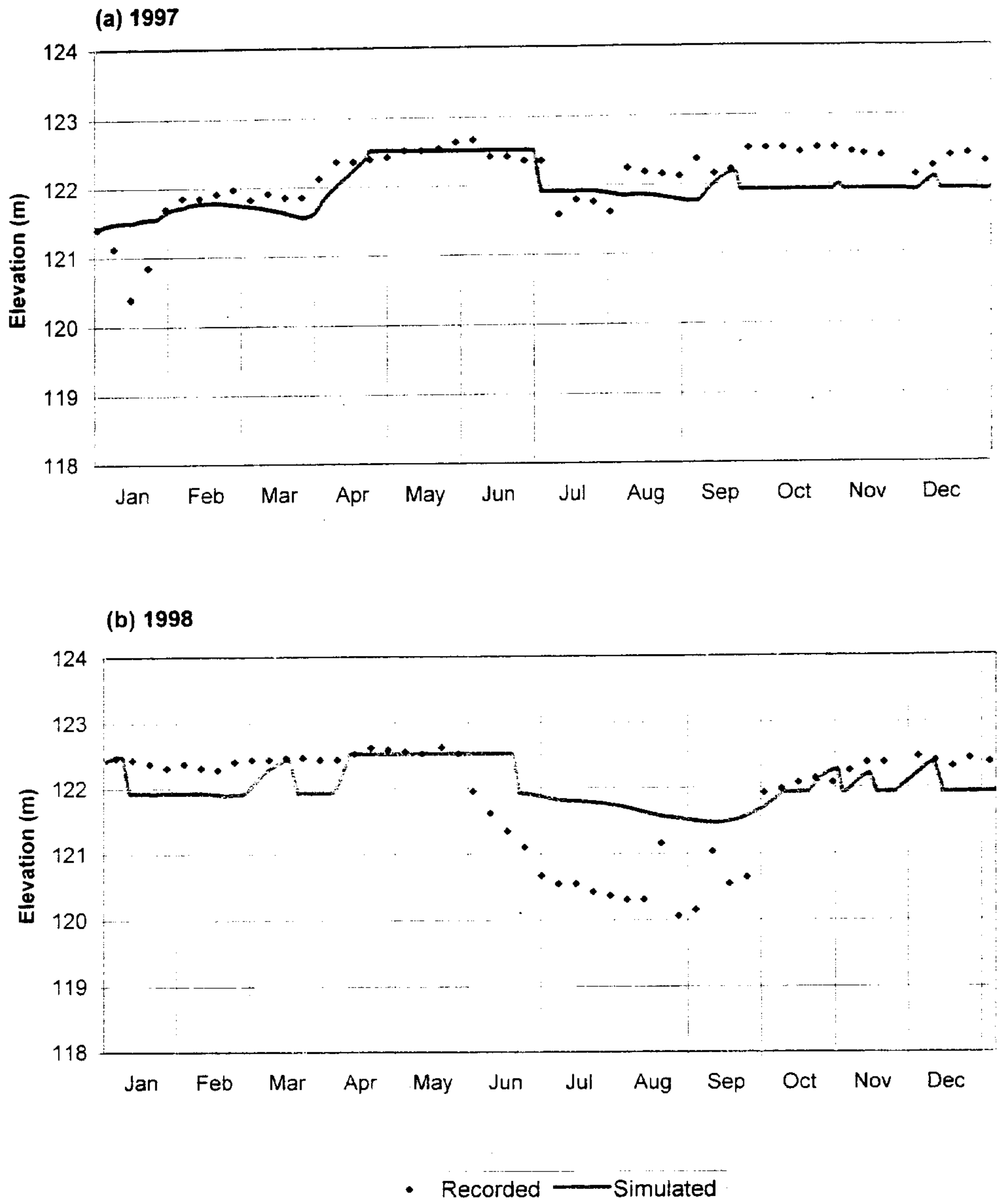


Fig. 19.6

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

WELLS POND STORAGE COMPARISON

ACRES

20 Lawn Hydroelectric System

The long term production for the Lawn Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

20.1 System Description

The Lawn system is located on the southern part of the Burin Peninsula near the community of Lawn and has one generating station located within the system.

The Lawn Generating Station contains one generating unit with a nameplate capacity of 0.69 MW and a rated net head of 24.3 m. The drainage area above the intake to the Lawn station is approximately 81 km^2. The station was commissioned in 1930 and there are no storage reservoirs in the system. A schematic of the system is presented in Figure 20.1.

The Lawn station is run of river and there is an overflow spillway located on the forebay, which when overtopped, would lead to spill out of the system.

20.2 Inflow Sequences

The daily inflow sequence required for the simulations was generated using the methodology presented in Chapter 2 of this report. The inflow sequence for the Lawn system basin was generated by prorating the recorded flows at a nearby hydrometric station by the drainage area.

The hydrometric station used to derive the hydrology for the Lawn system was Salmonier River near Lamaline (02ZG003). The record from the Salmonier River station, with a drainage area of 115 km^2, was chosen as the primary source for deriving the Lawn system basin flows. Due to the proximity it was assumed that the Lawn system has the same mean annual runoff of the Salmonier River station; therefore, the flows were prorated only by drainage area. There were no other suitable hydrometric stations nearby the Lawn system, so only a primary inflow sequence was used with no sensitivity analysis.

The primary inflow sequence for the simulation was developed by multiplying the Salmonier River flows by the ratio of Lawn drainage area to the Salmonier River drainage area.

20.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequence used for the model was described in Section 20.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

20.3.1 Reservoir Characteristics

Characteristics required for Lawn Forebay were available from NP's records.

20.3.2 Generating Station Characteristics

The generating station at Lawn houses one generating unit (LWN-G1). Index test results were available for LWN-G1 and were used to determine the generating station characteristics. The installed capacity used to estimate the long term production was 0.60 MW. This differs from the nameplate capacity presented in Table 1.1 due to NP's plant operating guidelines stating that the maximum load of the unit is 0.60 MW. The rated net head used for the comparison runs and run to estimate long term production was 18.7 m. This differs from the rated net head in Table 1.1 of 24.3 m. The revised net head was based on index test results for LWN-G1.

20.3.3 Structure Characteristics

No structures were modelled in the Lawn system.

20.3.4 System Operation

NP's plant operating guidelines for the Lawn system provide the following procedures.

1.) *Plant is a run of river and operates under water level load control.*
2.) *Forebay is relatively small and there are no control structures on this system.*
3.) *All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.*

NP's plant operating guidelines were used to develop the following operating strategy for the modelling.

- If the reservoir level is below the rule curve, operate the station at most efficient load.
- If reservoir is low, only operate the station at most efficient load when water is available.
- To avoid going over the rule curve, the station is brought up to maximum load.

The same operating procedures were used for both the comparison runs and the run to estimate long term production.

20.4 Model Comparison

The years selected by NP for the comparison runs were 1997 and 1998. Figure 20.2 shows the Lawn simulated and recorded monthly generation for these two years.

As Figure 20.2 shows, the simulated generation generally follows the same pattern as the recorded generation. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 20.4.1 below, followed by a discussion of the annual differences in Section 20.4.2.

20.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 20.2 are most likely due to differences between the actual and simulated operation of the system. NP does not record water levels at the Lawn system, so it was not possible to compare simulated and recorded water levels.

20.4.2 Differences in Annual Generation

Table 20.1 summarizes the annual energy generation for the two comparison years for the Lawn station unadjusted for the difference in energy in storage from the beginning to the end of the year. NP does not record water levels for the Lawn Forebay, so it was not possible to do an energy adjustment for the actual generation.

Table 20.1
Lawn Generating Station Recorded and Simulated Annual Energy Generation

Year	Unadjusted Annual Energy Generation (GWh/yr)		Difference (%)
	Recorded	Simulated	
Primary Inflow Sequence			
1997	2.7	2.9	7
1998	2.7	2.8	4

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use (operation of the unit); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Lawn system is briefly discussed below.

Hydrology

In the case of the Lawn system, the simulation using the primary inflow sequence gave reasonable results for 1997 and 1998 and was used to estimate the long term production as presented in Section 20.5.

Differences in Water Use

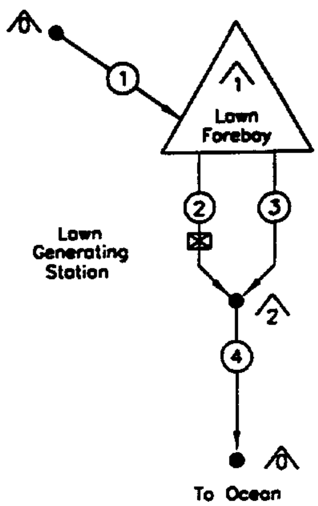
For the Lawn system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of the unit according to the specified operating procedures described in Section 20.3.4. The unit never operates at less than the most efficient load, although it does operate at higher loads if there is a risk of spill.

Assumed Characteristics

Lastly, though the model was set up using the best data available, some of the difference between recorded and simulated energy generation may be due to estimates of unit efficiency.

20.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate the long term production for the Lawn system. The result of this simulation was an estimate of long term production of 2.8 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

① — Lawn Foreboy Local Inflow
② — Lawn Power Flow
③ — Lawn Foreboy Spill
④ — Lawn Total Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Lawn Foreboy
2 — Lawn Total Outflow

Fig. 20.1

NEWFOUNDLAND POWER
WATER MANAGEMENT STUDY
LAWN ARSP MODEL SCHEMATIC

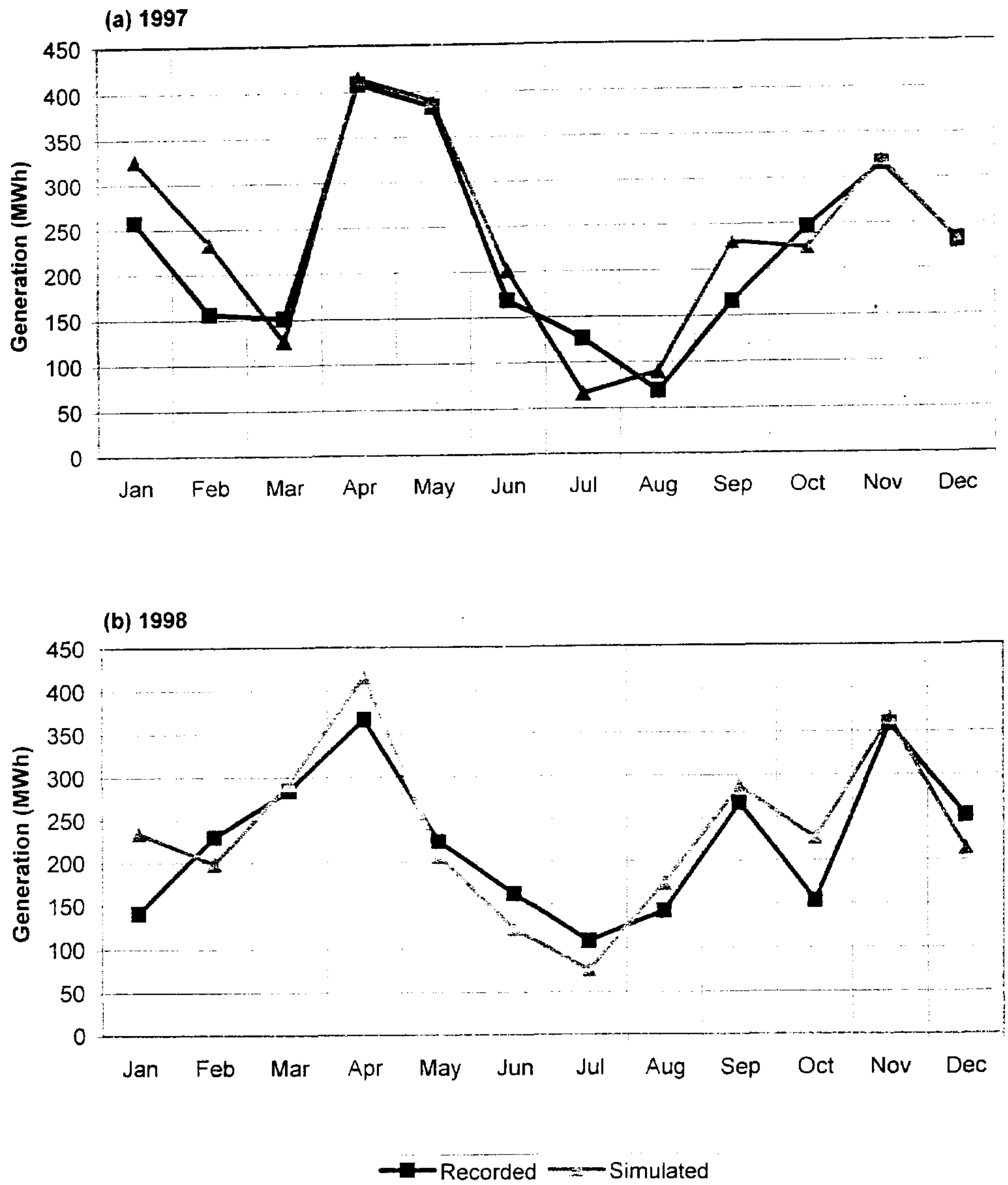


Fig. 20.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

LAWN GENERATION COMPARISON

ACRES

21 Fall Pond Hydroelectric System

The long term production for the Fall Pond Hydroelectric System was estimated following the methodology described in Chapter 2, that is,

- set up a computer simulation model of the system using ARSP;
- develop inflow sequences for the model;
- simulate reservoir levels and generation for two selected years;
- compare simulated and recorded results;
- modify input as required to simulate long term operation; and
- estimate long term production.

The following sections describe the system, the inflow sequences, the model setup, and the results of the comparison runs. The last section provides an estimate of long term production. This estimate is then used in the calculation of the normal production for the entire NP hydroelectric system in Chapter 22.

21.1 System Description

The Fall Pond system is located on the southern part of the Burin Peninsula near the community of Little St. Lawrence and has one generating station located within the system.

The Fall Pond Generating Station contains one generating unit with a nameplate capacity of 0.37 MW and a rated net head of 15.2 m. The drainage area above the intake to the Fall Pond station is approximately 39 km^2. The station was commissioned in 1939 and there are no storage reservoirs in the system aside from Fall Pond itself. A schematic of the system is presented in Figure 21.1.

The Fall Pond station is run of river and there is an overflow spillway located on the forebay, which when overtopped, would lead to spill out of the system.

21.2 Inflow Sequences

The daily inflow sequence required for the simulations was generated using the methodology presented in Chapter 2 of this report. The inflow sequence for the Fall Pond system basin was generated by prorating the recorded flows at a nearby hydrometric station by the drainage area.

The hydrometric station used to derive the hydrology for the Fall Pond system was Salmonier River near Lamaline (02ZG003). The record from the Salmonier River station, with a drainage area of 115 km^2, was chosen as the primary source for deriving the Fall Pond system basin flows. Due to the proximity it was assumed that the Fall Pond system has the same mean annual runoff of the Salmonier River station; therefore, the flows were prorated only by drainage area. There were no other suitable hydrometric stations nearby the Fall Pond system, so only a primary inflow sequence was used with no sensitivity analysis.

The primary inflow sequence for the simulation was developed by multiplying the Salmonier River flows by the ratio of Fall Pond drainage area to the Salmonier River drainage area.

21.3 Model Setup

The information required to set up the simulation model for the comparison years includes

- inflow sequences;
- reservoir characteristics;
- generating station characteristics;
- structure characteristics; and
- operating procedures.

The years selected by NP for the comparison runs were 1997 and 1998. The development of the inflow sequence used for the model was described in Section 21.2. The remaining information was collected from various NP sources and reviewed to select the appropriate values to use for the current study. The following sections describe the required input for the comparison years and any changes required for the estimate of the long term production. Values used for the runs to estimate long term production are provided in the echo of the input file in Volume 3 of this report.

21.3.1 Reservoir Characteristics

Characteristics required for Fall Pond Forebay were available from NP's records.

21.3.2 Generating Station Characteristics

The generating station at Fall Pond houses one generating unit. Plant operating guidelines were used to determine the generating station characteristics. The installed capacity used to estimate the long term production was 0.35 MW. This differs from the nameplate capacity presented in Table 1.1 due to NP's plant operating guidelines stating that the maximum load of the unit is 0.35 MW.

21.3.3 Structure Characteristics

No structures were modelled in the Fall Pond system.

21.3.4 System Operation

NP's plant operating guidelines for the Fall Pond system provide the following procedures.

1.) Plant is a run of river and operates under water level load control.
2.) Forebay has the capacity to hold a lot of water and should be brought to it's minimum level prior to spring runoff. There are no control structures on this system.
3.) All gates to be left open a minimum of 1" to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.

NP's plant operating guidelines were used to develop the following operating strategy for the modelling.

- If the reservoir level is below the rule curve, operate the station at most efficient load.
- If reservoirs are low, only operate the station at most efficient load when water is available.
- To avoid going over the rule curve, the station is brought up to maximum load.

The same operating procedures were used for both the comparison runs and the run to estimate long term production.

21.4 Model Comparison

The years selected by NP for the comparison runs were 1997 and 1998. Figure 21.2 shows the Fall Pond simulated and recorded monthly generation for these two years.

As Figure 21.2 shows, the simulated generation generally follows the same pattern as the recorded generation. There are differences between the recorded and simulated values both within each year, and also on an annual basis. The within-year (month to month) differences are discussed in Section 21.4.1 below, followed by a discussion of the annual differences in Section 21.4.2.

21.4.1 Differences in Monthly Generation

The differences in generation through the year shown in Figure 21.2 are most likely due to differences between the actual and simulated operation of the system. NP does not record water levels at the Fall Pond system, so it was not possible to compare simulated and recorded water levels.

21.4.2 Differences in Annual Generation

Table 21.1 summarizes the annual energy generation for the two comparison years for the Fall Pond station unadjusted for the difference in energy in storage from the beginning to the end of the year. NP does not record water levels for the Fall Pond Forebay, so it was not possible to do an energy adjustment for the actual generation.

Table 21.1
Fall Pond Generating Station Recorded and Simulated Annual Energy Generation

Year	Unadjusted Annual Energy Generation (GWh/yr)		Difference (%)
	Recorded	Simulated	
Primary Inflow Sequence			
1997	1.1	1.2	9
1998	1.0	1.3	30

The annual differences arise from

- inflow hydrology different from assumed, particularly in total volume but also in pattern;
- differences in water use (operation of the unit); and
- inaccurate assumptions regarding characteristics of the system.

The effect of each of these on the Fall Pond system is briefly discussed below.

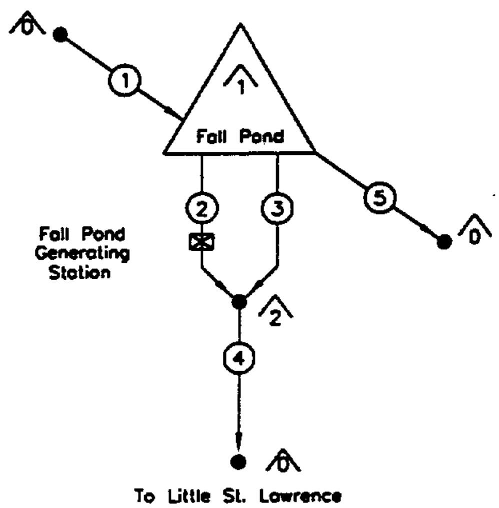
Hydrology
In the case of the Fall Pond system, the simulation using the primary inflow sequence gave reasonable results for 1997 and 1998 and was used to estimate the long term production as presented in Section 21.5.

Differences in Water Use
For the Fall Pond system, the difference between the simulated and recorded annual results is largely attributable to differences in water management. The model assumes perfect operation of the unit according to the specified operating procedures described in Section 21.3.4. The unit never operates at less than the most efficient load, although it does operate at higher loads if there is a risk of spill.

Assumed Characteristics
Lastly, though the model was set up using the best data available, most of the difference between recorded and simulated energy generation may be due to estimates of unit efficiency.

21.5 Simulated Long Term Production

The system operation was simulated using the primary inflow sequence for the 15 year reference period to estimate the long term production for the Fall Pond system. The result of this simulation was an estimate of long term production of 1.3 GWh/yr. This estimate is referenced to the output of the generator and does not take into account the adjustments for station service and practical operation which are necessary for estimating normal production provided in Chapter 22.



CHANNELS

1 — Fall Pond Local Inflow
2 — Fall Pond Power Flow
3 — Fall Pond Spill
4 — Fall Pond Total Outflow
5 — Town of Little St.Lawrence Emergency Water Supply Demand

RESERVOIRS / NODES

0 — Source / Sink
1 — Fall Pond (Forebay)
2 — Fall Pond Total Outflow

Fig. 21.1

NEWFOUNDLAND POWER
WATEP MANAGEMENT STUDY
FALL POND ARSP MODEL SCHEMATIC

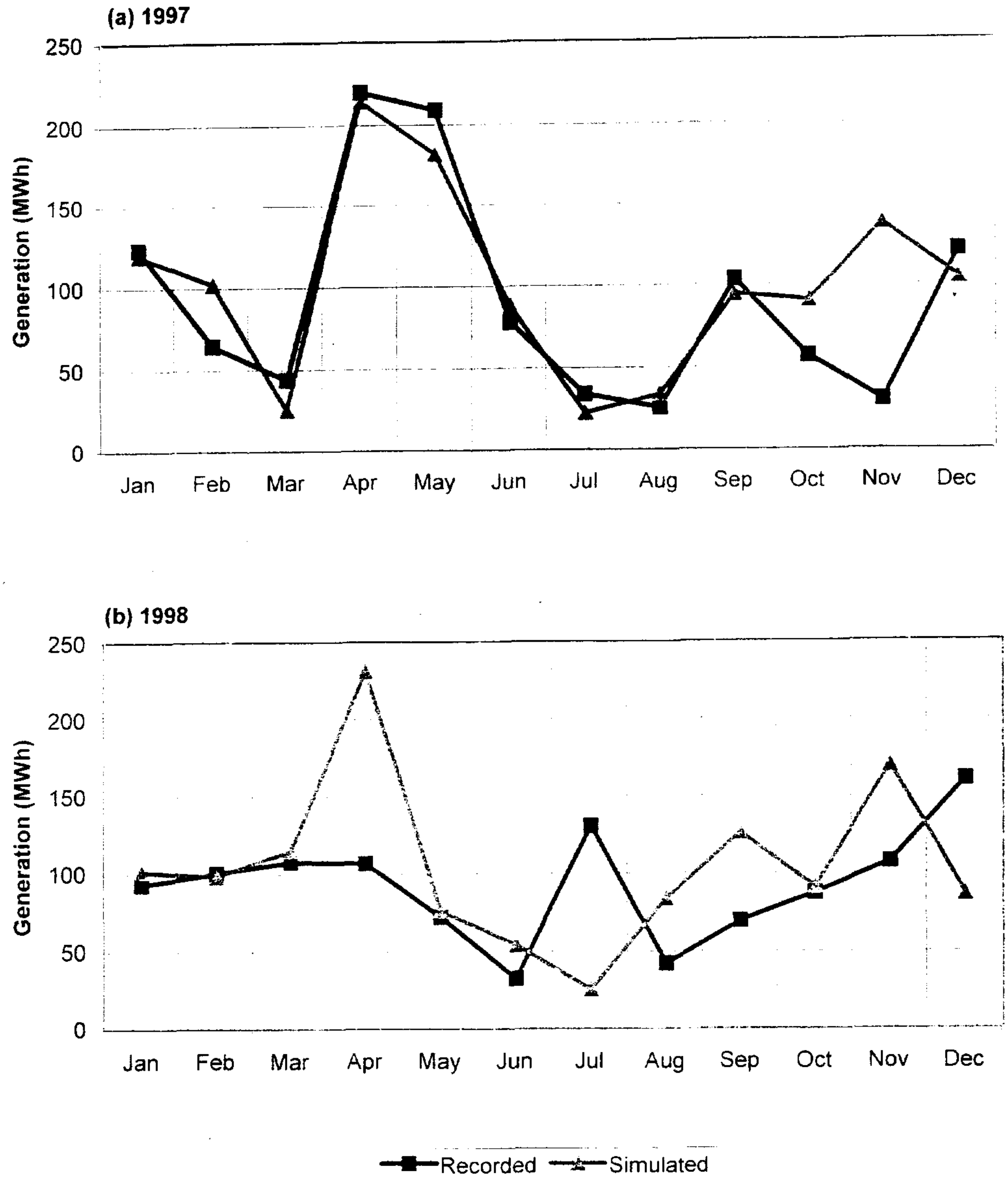


Fig. 21.2

NEWFOUNDLAND POWER

WATER MANAGEMENT STUDY

FALL POND GENERATION COMPARISON

AGRES

22 Estimate of Normal Production

The estimates of long term production from each of NP's stations presented in Chapters 3 to 21 were used to calculate the normal production for the entire NP hydroelectric system. The total estimate takes into account station service and an adjustment for practicalities of operation.

22.1 Simulated Long Term Production

As described in the previous chapters, the simulation model output provides an estimate of the average annual long term hydroelectric production as measured at the generator output terminals of each station. This estimate therefore takes into account all water passage, turbine and generator losses. The final model runs used to determine the long term average production also considered a five percent reduction in plant availability to account for unscheduled unit outages. Scheduled outages can usually be planned for times when no generation will be lost and were therefore not included in the model. Losses due to longer outages can be accounted for in the year in which they are planned (see Sections 2.4 and 22.4).

By definition, NP's normal production estimate represents the hydroelectric energy available for sale in an average water year. As such, two further adjustments were made to the long term production estimates from the simulations to account for station service and for practicalities of operation.

22.2 Station Service

Station service at a hydroelectric generating station is the energy produced by the station but consumed at the associated facilities. This quantity therefore includes such energy uses as powerhouse heating and lighting, trashrack heating, and powering motors to drive gates and cranes. Since the station service represents energy used in the plant operations, it is not available for sale. An estimate of station service must therefore be subtracted from the simulated long term production estimate.

The station service estimate for each plant was calculated using recorded monthly data over the eight year period from 1992 to 1999. The station service estimated in all cases is small (ranging from 0.3 to 3.2 percent of production), with the smaller percentage values being recorded at the larger plants. The values used for each plant are provided in Table 22.1.

Table 22.1
Station Service Estimates

Plant	Station Service (GWh/yr)	Plant	Station Service (GWh/yr)
Cape Broyle	0.1	New Chelsea	0.1
Horsechops	0.1	Pitmans	0.0
Rattling Brook	0.2	Seal Cove	0.1
Mobile	0.2	Topsail	0.1
Morris	0.1	Hearts Content	0.1
Tors Cove	0.2	Lockston	0.1
Rocky Pond	0.1	Victoria	0.0
Lookout Brook	0.2	West Brook	0.0
Sandy Brook	0.1	Port Union	0.0
Pierres Brook	0.1	Lawn	0.1
Rose Blanche Brook	0.1	Fall Pond	0.0
Petty Harbour	0.2	**Total**	**2.3**

22.3 Adjustment for Practical Operation

The practical difficulties encountered in operating small hydroelectric systems cannot fully be accounted for in computer simulation models such as ARSP. The model operates each generating station in an ideal manner which usually overestimates the production available from these stations over the long term.

This fact is demonstrated by the percentage differences observed in each of the comparison years. With very few exceptions, the modeled production in the years chosen for comparison exceeds the recorded generation. As explained in Chapter 2, and in the individual system chapters, the differences can result from three sources, hydrology, operations, and data assumptions.

Differences due to hydrology and data assumptions could be expected to be random or non-systematic. Of the 19 systems, the inflows may be overestimated in some and underestimated in others. Similarly, any data discrepancies could work either way; in some systems they could lead to overestimates of energy, and in other systems to underestimates. So although on a system specific basis the difference is attributable to all three sources, when the overall average is taken, the differences due to hydrology and data should cancel out, and the remaining difference can be assumed to be principally due to the difference between ideal and practical operation.

The practical difficulties encountered in the operation of hydro stations may be illustrated using the example of outlet gate adjustments at remote storage reservoirs. The simulation model determines in each day precisely what flow from a controlled reservoir will optimize generation and adjusts the reservoir control gate accordingly. For many NP reservoirs, it may be difficult to predict exactly the flow required. It is also not practical to make daily or even weekly adjustments to some control gates, for reasons such as personnel safety, weather, cost-effectiveness or informal constraints imposed by other water users.

In addition to reservoir operation, unit loading can lead to significant differences between actual and simulated operations. The simulation model operates units only at their most efficient loads, except when a unit is operated at its maximum load to avoid spill. NP operators can face many impediments to such ideal operation. These include electrical grid requirements (such as local power outages, winter storage reserves or voltage support) and age and condition of control equipment. Also, since the model operates on a daily time step, it does not take account of within-day variations in loads or inflows.

The end result of these practical operational limitations is that actual generation is slightly less than what would be predicted by a model. Therefore, an adjustment factor based upon an average of the differences calculated for the 12 larger systems during the comparison process was applied to the simulated long term production values to account for the practicalities of hydro station operations. This value was found to be seven percent.

The results of the model comparisons for these 12 systems were included in the calculation as the models were thought to provide a good representation of the physical system. The inclusion of the comparison results for the other seven systems could exaggerate the impact of these smaller producers on the entire NP hydroelectric system.

Table 22.2 summarizes the unadjusted estimates of long term production for each of NP's hydroelectric systems, based on the results of the simulations. The adjustments for station service and practical operation are also shown, and are used to calculate the total normal production of 423 GWh/yr. For comparison, the current estimate of total normal production used by NP is 431 GWh/yr (revised in 2000).

22.4 Future Changes to Estimates of Normal Production

In any given year, the estimated normal production for NP's hydroelectric system may require minor adjustments due to scheduled outages and physical system changes which may have occurred in the preceding year. In addition, NP should carry out periodic formal reviews of the normal hydroelectric production (as estimated by this report). These issues are discussed below.

22.4.1 Annual Adjustment

The normal production calculated in Section 22.3 does not account for scheduled unit or plant outages. If a prolonged outage is scheduled in a given year which will result in spill, then an adjustment to the normal hydroelectric production should be made. A negative adjustment would apply to the year in which the outage is scheduled to account for generation lost due to spill.

Any physical changes to NP facilities which are expected to impact hydroelectric production should also be addressed in the annual revision to the normal production estimate. The impact that physical improvements have on normal production should be based on the engineering estimates used to justify the projects. Changes that have a negative impact on production should also be reflected in the estimated normal production. This latter category of changes includes removal of storage structures, removal of flashboards and the imposition of new operating constraints. The engineering estimates used in adjusting the normal production should be re-evaluated during periodic formal reviews.

Table 22.2
Calculation of Normal Production

System	Simulated Long Term Production (GWh/yr)
Horsechops/Cape Broyle	89.1
Rattling Brook	63.6
Morris/Mobile	51.6
Rocky Pond/Tors Cove	45.6
Lookout Brook	34.0
Sandy Brook	28.1
Pierres Brook	26.7
Rose Blanche Brook	22.4
Petty Harbour	19.9
New Chelsea/Pitmans	18.5
Seal Cove	9.9
Topsail	15.9
Hearts Content	9.4
Lockston	8.8
Victoria	3.3
West Brook	3.7
Port Union	2.8
Lawn	2.8
Fall Pond	1.3
Simulated Long Term NP Production	457.4
Less 7% for practical operation	(32.0)
Less Station Service	(2.3)
Calculated Normal Production	**423.1**

22.4.2 Periodic Review

In addition to these minor annual refinements to the normal production estimate, a complete review of NP's normal hydroelectric production is suggested in approximately five years. As NP's own data collection programs evolve through improvements to the SCADA system and the availability of more cost-effective data collection technology, improved model comparisons will be possible. New streamflow data from the Environment Canada stations would also be available. The review should include a comparison of actual and modelled production in a recent year, similar to the ones carried out for this study. The five year review would also ensure that any operational and physical changes to the hydroelectric system had been incorporated into the normal production estimate in a consistent manner. The timing of future reviews should be determined as part of the five year review.

It is interesting to note that the comparisons at nearly all stations showed an improvement from the earlier year to the later year (that is, the difference in 1998, for example, was less than the difference in 1997, if those were the years chosen). This result is not unexpected, since NP is improving operating procedures at its hydroelectric plants on a continuous basis. The periodic review of the normal production will provide an opportunity to update the normal production to reflect the operational improvements.

23 Conclusion

Based on simulation modelling of NP's hydroelectric system, this study estimates that the normal production for the entire NP hydroelectric system is 423 GWh/yr. For comparison, the current total normal production used by NP is 431 GWh/yr (revised in 2000).

Each year the estimate of normal production should be revised to reflect any scheduled outages, and any changes to the facilities over the preceding year. Scheduled outages could lead to spill or to deferral of generation to a later year. Physical changes to the facilities could temporarily or permanently increase or decrease the expected generation.

In addition to the annual adjustments to the estimated normal production, NP should undertake a formal review of the normal production estimate in approximately five years. This review would incorporate new data available for each system, as well as any revised operating constraints or procedures, and would confirm that annual adjustments for physical changes had been made appropriately. It would also allow for revision of the adjustment factor to account for the practicalities of operation, based on operating data from the preceding five-year review period.

ACRES RESERVOIR SIMULATION PROGRAM (ARSP) COMPUTER MODELING PROGRAM

ARSP is a general reservoir simulation program that is capable of simulating a wide range of operating policies in multipurpose, multi reservoir systems. Water resource allocation problems involving energy production, flood control, water supply, irrigation, low-flow augmentation, diversion, navigation, environmental, and many other requirements can be modeled. The model takes natural inflows, precipitation, evaporation and evapotranspiration data as input.

A major advantage of ARSP is its flexibility in allowing the user to make structural or operating policy changes by modifying the input data rather than by changing the computer program itself. Furthermore, the operating policies are modeled separately from the physical system. In this way, a unique and powerful division in representation of a water resource network is realized and is responsible, in large part, for the flexibility and general applicability of the model. This approach allows alternative water resource policies to be investigated by superimposing new penalty structures on the existing network. The penalty structure defines the relative priorities of conflicting water uses under various hydrologic conditions, and at various times of the year. The priorities are specified by the user, and are not dependent on the system configuration.

Operational features that can be represented include storage and release of water by reservoirs, physical discharge controls at reservoir outlets, water flow in channels (e.g., streams, power channels, diversion or irrigation canals), consumptive demands (e.g., agricultural, industrial or municipal), hydropower releases, head losses in channels, water losses in channels, hydraulic routing through channels and reservoirs, and inflow forecasts. Flow and water level constraints may be absolute, or they may be relative to the flow or level in a previous time step.

ARSP is based on the premise that a water resource system can be represented by a flow network and that an optimal operating decision for the upcoming time period can be made given the initial state of the system and estimates of net inflows during the period. It is a steady-state model since the system configuration and the penalty structure do not change with time. It is not an "optimization model", but it does use a solution algorithm that is based on optimization principles. It is known as the "out of kilter" algorithm.

In the model, a physical water resource system is described as a network consisting of discrete components, each of which is defined separately. Junctions and control points, such as reservoirs, are represented as nodes, while natural or man-made flow paths that connect junctions are referred to as channels. The network solution technique allocates water in such a way that the total penalties for demand and reservoir storage are minimized for a given time step, e.g., the model might determine if it is preferable to draw a reservoir down to maintain a minimum flow in a channel or to keep the water in storage and allow the channel flow to fall below the desired value.

ARSP Reservoir Data

Reservoir Name : ______________________
Reservoir Number : ____________

Upstream Channels : ______________________
____
____
____

Downstream Channels : ______________________
____
____
____

Surcharge Level =	
Full Supply Level =	1) Spill Zone (Penalty =)
Rule Curve =	2) Flood Control Zone (Penalty =)
Dead Storage Level =	3) Conservation Zone (Penalty =)
Reservoir Bottom =	4) Dead Storage Zone (Penalty =)

Elevation	Area	Volume

Rule Curve

Elev

Month

Notes: ____
____
____
____
____

ARSP Channel Characteristics

Channel Name : ______________________

Channel Number : ________

Upstream Node : ________

Downstream Node : ________

Channel Type : ______________________

No. of Arcs/Concerns : ________

List of Concerns	Penalty
1. ________	________

Period							
Value							

List of Concerns	Penalty
2. ________	________

Period							
Value							

List of Concerns	Penalty
3. ________	________

Period							
Value							

Notes:

ARSP Power Plant Characteristics

General :

Plant Name : ______________________
Plant Number : ______________

Power Channel Number : ______________
Spill Channel Number: ______________

Generator Capacity : ______________
Nominal Headpond W/L : ______________

Design Net Head : ______________
Maximum Net Head : ______________
Minmum Net Head : ______________
Head Losses : ______________

Tailwater Parameters :

Tailwater Type : (1) Dicharge/Elev Curve or (2) Depends on d/s Reservoir
No. of Points in Curve : ________

Discharge	T/W

D/S Res	T/W

Efficiency Parameters :

Maximum Q : ______________
Best Efficiency Q : ______________

Efficiency : ______________
Best Efficiency : ______________

Eff	Head

Notes: ____