Non-Treaty Storage Agreement

Technical Report: Appendices A - L

Bonneville
POWER ADMINISTRATION

March 1990

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LIST OF PRIOR AGREEMENTS FOR ADDITIONAL
USE OF CANADIAN TREATY AND NON-TREATY SPACE
1977-1983

Year	Arrangement
1977	Emergency release of Arrow Lakes storage. (Prepared by BC Hydro, therefore no BPA contract number. Signed 2/14/77 and 2/18/77.)
1977	Storage of excess generation due to fishery releases in non-Treaty Canadian reservoirs. (BPA Contract No. 14-03-79140.)
1977	Delivery of BC Hydro energy to BPA to raise the summer level of Arrow Lakes. (BPA Contract No. 14-03-79156.)
1978	Storage of energy in Mica to enhance its refill and delivery to Canada of energy from the release of 500,000 acre-feet from Mica. (BPA Contract No. EW-78-Y-83-0069.)
1979	Storage of excess generation due to fishery releases in non-Treaty Canadian reservoirs. (BPA Contract No. DE-MS79-79BP90076 and 5-10-79 teletype.)
1980	Storage of energy in Mica to enhance its refill. (BPA Contract No. DE-MS79-80BP90138.)
1980	Storage of excess generation due to fishery releases in non-Treaty Canadian reservoirs. (BPA Contract No. DE-MS79-79BP90076 and 4-10-80 letter.)
1980	Storage of an additional 2 feet of water in Arrow Lakes (BPA Contract No. 14-03-9017.9)
1981	Storage of excess generation due to fishery releases in non-Treaty Canadian reservoirs. (BPA Contract No. DE-MS79-79BP90076 and 4-16-81 letter.)
1981	Storage of an additional 2 feet of water in Arrow Lakes. (BPA Contract No. DE-MS79-81BP90329)
1982	Storage of excess generation due to fishery releases in non-Treaty Canadian reservoirs. (This was under the existing system-to-system storage agreement.)
1983	Two short-term agreements providing the use of 2 feet of non-Tretay storage of Arrow and up to 4 feet of non-Treaty storage at Mica. These short-term agreements enabled storage of surplus water to help fill Revelstoke reservoir prior to the long-term non-Treaty storage agreement.

The above arrangements are in addition to general system-to-system storage and load-factoring agreements which enable BPA and BC Hydro to accept energy from the other for storage in non-Treaty reservoir space.

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APPENDIX B

ANALYTICAL METHODS AND ASSUMPTIONS

APPENDIX B

Part 1

Description of Models and Their Use

APPENDIX B

Part 1

Description of Models and Their Use

System Analysis Model

The System Analysis Model (SAM) was used to generate data for the non-Treaty Storage Agreement EA. SAM simulates, monthly for 20 years, the operation of the Pacific Northwest hydro/thermal system. It provides information regarding the reliability of the system, the expected operation of individual thermal resources, and the expected operation of the hydro system, including reservoir elevations, flows, and spill. SAM input includes information from the Least Cost Mix Model (LCMM) regarding future resource development.

The SAM simulates the Pacific Northwest's power system. It models the operation of existing and planned resources to meet load, season by-season and month-by-month over a 20-year planning period. The model simulates both planning policies and operational policies, on a monthly basis.

The following major components of the region's power system are accounted for in SAM:

- -- policies of regional planning and operation.
- -- uncertainties of loads and resources.
- -- physics of hydro and thermal resources.
- -- nonpower constraints on the hydro system.
- -- transactions outside the region.
- -- net regional revenue requirements.

The model makes assumptions about the region and the load to be served, so that the region defined for this model conforms to that mandated in the Pacific Northwest Power Act. The defined region, however, is assumed to be a single-owner system.

SAM models the region's energy resources: hydro, thermal (including nuclear plants, combustion turbines, and coal projects), and miscellaneous (such as renewables, cogeneration units, existing steam plants and small diesel generators). Conservation is also considered a resource.

SAM models uncertainty in the following

- -- Regional load. The energy load reflects the variations in weather conditions and economic trends. SAM does not, however, consider load growth uncertainty.

- -- Major hydro. Hydro conditions are selected from a detailed 40-year historical record of individual project inflows.

- -- Thermal plants. The two sources of uncertainty modeled are the availability of a thermal plant and the arrival date for a new plant.

SAM simulates these uncertainties using a Monte Carlo process, randomly selecting values for each of these variables for each month of the study period (in this case, 20 years). SAM runs each study many times, selecting a new set of variables each time. For this EA, each study was run 200 times. Each alternative used the same 200 sets of variables for each month of the 20 years. In most cases, output values for the 200 simulations were averaged (monthly or annually). However, for certain analyses (for example. fish impacts) individual simulations were examined.

Given the loads, resources, and the established policies for the region, SAM operates the hydro system in conjunction with the non-hydro resources to meet loads in the most economic manner possible. Included in these policies are the following economic considerations.

- All available regional resources are used to meet firm regional load.

- A portion of the direct service industrial customer load is not firm and can be restricted and interrupted, but is met, provided that reasonably priced resources are available.

- If the power outlook and streamflow forecast permit, the region sells energy to California.

SAM models three major decision points in operating a hydro system:

- the annual planning process, which determines how to shift and shape water over a 2-year critical period;

- the period planning process, which looks at such items as firm surplus, the runoff forecasts and refill, to determine the use of hydro over the following 4 months; and

- the period operating process, which dispatches Pacific Northwest resources to meet loads in the most economic manner possible. If there is sufficient energy, economy energy sales are made to California, taking into account the Intertie Access Policy, available secondary energy from Canada, and the California market.

Included in SAM is a model of BC Hydro's resources and loads. BC Hydro's resources are run to meet its own loads; any additional energy is available for sale to the U S. BC Hydro may use this energy to directly serve any unserved PNW load (firm or nonfirm), to displace higher cost PNW resources, or to sell to California markets.

Model Assumptions

Model assumptions used in the base case studies comprise the most likely set of conditions expected to prevail during the study period regardless of the alternative being analyzed. These assumptions are:

Loads

- The Pacific Northwest regional loads for 1989 through 2008 are based on BPA's 1988 long-term medium load forecast.

- The California loads are based on the medium Common Forecasting Methodology (CFM-7) forecast.

- The BC Hydro loads are based on their March 1988 Twenty-Year Resource plan.

Resources

- The Pacific Northwest resources include existing hydro and thermal plants, and currently planned resources in BPA's 1988 Pacific Northwest Loads and Resources Study. Additional resources are included as chosen by the Least Cost Mix Model to achieve load/resource balance.

- BC Hydro resources are based on their March 1988 Twenty-Year Resource Plan. The non-Treaty Storage Agreement was assumed to expire in 1993.

- BPA's April 1988 long-term medium gas forecast was assumed.

Interties

- The Third AC Intertie to the Pacific Southwest is assumed to be operational as of October 1992.

- The Pacific Northwest/BC Hydro Intertie is assumed to be 2300 MW.

Least Cost Mix Model (LCMM)

The Least Cost Mix ModeL formulates projected loads, existing resources, potential new resources and their costs, and the potential for sale or resale of resources as a linear program. The objective is to minimize overall cost while meeting load requirements. The LCMM considers the costs and benefits of adding or delaying construction of each available resource. The optimal mix and timing of potential new resources is selected. Construction schedules are provided for conservation, renewables, coal plants, combustion turbines, and nuclear plants. The model selects a mix of resources in order to meet load (accounting for existing and committed capacity of resources), within the limits of project availability, reserve margins, hydro availability on a critical water basis, and maintenance requirements.

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APPENDIX B

Part 2

Model Assumptions Regarding DSI Service

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Model Assumptions Regarding DSI Service

System Analysis Model (SAM)

The SAM was used to generate data for the NTSA environmental studies. SAM simulates, monthly for 20 years, operation of the Pacific Northwest hydro/thermal system. It provides information regarding the reliability of the system, the expected operation of individual thermal resources, and the expected operation of the hydro system, including reservoir elevations, flows, and spill. SAM input includes information from the Least Cost Mix Model (LCMM) regarding future resource development.

The SAM simulates the PNW's power system. It models the operation of existing and planned resources to meet load, season by season and month by month over a 20-year planning period. The model simulates both planning policies and operational policies, on a monthly basis.

The following gives an overview of DSI restriction rights as modeled in SAM. All assumptions for the alternatives are effective for the entire study horizon, 1989 through 2008. For more details regarding DSI load service as modeled in SAM see the Pacific Northwest Utilities Conference Committee's Methods and Theory Manual, November 1983.

First Quartile

The first quartile is interruptible. Resources are not planned to meet this load on a firm basis. However the first quartile may be served with surplus firm, nonfirm, or outside purchases. In addition, if the coordinated system has refilled at the end of July, shifted FELCC, provisional energy, and flexibility may be used to serve the first quartile in the fall (September through December). These are limited respectively to 1,000,000 MWh, 800,000 MWh, and 750,000 MWh. This is currently sufficient to serve the entire fall first quartile load. If shift, provisional, or flexibility have been committed to serve the first quartile in the fall, the system is operated to meet this load as if it were firm. In exchange for service to the first quartile with these borrowing techniques, future restriction rights to third quartile load are granted.

Second Quartile

The second quartile is considered to be firm with one exception. If a planned resource is delayed or does not perform as expected, restriction rights may be granted. These rights are the amount of the delay (or underperformance), limited by the projected deficit for the current year and the amount of the second quartile.

Third Quartile

The third quartile is also considered to be firm; however, it may be restricted as a result of using borrowing techniques to serve the first quartile. Depending on which technique was used, the restriction rights are granted either in the current year or in the upcoming operating year. If the hydrosystem refills at the end of the year, any restriction rights for the upcoming year are canceled.

Additional Notes

The remaining quartile is modeled as entirely firm. SAM is an energy model and so does not consider restriction rights on a capacity basis. Also, restriction rights are not automatically exercised even though they are available. A reasonable attempt is made to serve the load prior to making any restrictions.

APPENDIX B

Part 3

SAM Modeling Changes Since the IDU Final EIS

APPENDIX B

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SAM Modeling Changes Since the IDU Final EIS

In order to sucessfully model the use of the proposed non-Treaty storage agreement, several improvements were made in the System Analysis Model (SAM) to more accurately reflect non-Treaty storage activity and the Canadian system's operation. In addition many assumptions were revised to reflect more recent operating strategies, and the inputs were updated to reflect the most probable values. These changes are listed with an explanation of each.

Non-Treaty Modeling Improved

Opportunity storage non-Treaty logic designed to produce a realistic operation of non-Treaty storage space was developed for both the U.S. and BC Hydro. The Canadian half of non-Treaty storage was modeled for the first time. Previously the effects of Canadian non-Treaty storage were assumed to cancel out from one case to another. However since non-Treaty storage itself was being studied in this case, it was necessary to model the Canadian half of non-Treaty. In SAM each party's half of the non-Treaty storage space is divided into two parts: the upper portion which may be sold at relatively low prices, and the lower portion which is considered to be more valuable and thus sold only when higher prices can be obtained. The amount of storage space designated as being in the upper and lower portions varies by month with the lower portion being very large in September, decreasing in size through the winter and becoming larger again throughout the late spring and summer. This shape resembles the Energy Content Curves of other reservoirs.

The decision of whether storing or releasing is desirable is determined by the revenue available for water released or stored each period compared with the best revenue that could be realized for the same release. For the U.S. half of the storage space this is determined by comparing the Grand Coulee through Bonneville water/energy conversion factor (H/K) times the expected California market price, with a optimum H/K times the best annual California market price. Thus when revenues are poor, storing is considered desirable and when markets are good or energy is needed to meet firm regional energy requirements, releasing is considered desirable. In the SAM modeling logic, water is available for release from the upper portion of non-Treaty storage space when the revenue that can be obtained for the energy produced is 85 percent of the best available revenue expected for the year. Water is available for release from both portions of non-Treaty storage space when the revenue which can be obtained is about 98 percent of the best revenue for the year. If the revenue is between 70 and 85 percent of the best revenue available only the lower portion can be stored into and if the revenue is less than 70 percent of the best revenue then both portions can be stored into. Once the desirablility of storing or releasing is determined the blocks of energy are assigned prices and a normal SAM economic dispatch of loads and resources is done. Thus it may occur that storing is desirable based on revenue, but if there are no economic resources available to supply the energy foregone in storing, no storing will occur.

BC Hydro's half of non-Treaty storage is modeled in the same manner. However BC Hydro examines the Mica through Bonneville water/energy conversion factor. They stated this was the way they actually operate. BPA normally only examines the Grand Coulee through Bonneville H/K in making decisions for the U.S. portion, assuming the Mica/Revelstoke H/K to be nearly constant. In addition, for the U.S. half only, a factor was added which delays refill in high runoff conditions, so that space is more likely to be available to catch high flows in the May through August period in very wet years.

The maximum release rate for non-Treaty storage was assumed to be 15 kcfs, or turbine capacity minus the Treaty flow at Mica, whichever was less. Similarly the maximum rate of storing is 15 kcfs, or the Treaty outflow minus the minimum outflow, whichever is less. The 15 kcfs value was used to allow greater month average rates of storing or releasing than has been observed historically, while preventing the model from storing or releasing unrealistically large amounts in any one month.

Logic was added to the program which would allow initial contents to be specified for the non-Treaty space, and allow the non-Treaty space to expand to a different volume later. This was so that the studies could show only 2.0 MAF available for the first year. The 2.0 MAF of non-Treaty space was initialized empty in the studies to reflect actual conditions in late 1988.

Use of Non-Treaty as a Firm Resource

Logic was added to allow SAM to study the use of non-Treaty storage as a firm resource. The Canadian half of the storage was operated as under the opportunity storage case, but was priced so that non-Treaty storage energy could not be sold to California or be used to serve U.S. Direct Service Industry (DSI) top quartile load. The Canadians also showed two hydro resources as being deferred in the last three years of the study period. The U.S. half of non-Treaty storage space was modeled as a firm hydro resource under the Coordination Agreement. This required the creation of ECCs, and Critical Rule Curves for the U.S. half of non-Treaty storage. ECCs were assumed to be full at all times since there is no inflow to the non-Treaty space. The Critical Rule Curves drafted the storage volume in equal monthly increments throughout the Critcal Period. Thus non-Treaty space remained full unless the U.S. system was proportionally drafting, and the space had a refill requirement just like any other reservoir.

Use of the U.S. half of the non-Treaty space as a firm resource results in approximately 165 MW of additional Firm Energy Load Carrying Capability (FELCC). To maintain comparability with the opportunity storage case, load/resource balance was kept constant between cases by adding a firm sale of 165 mW to the firm use case.

The modeling of the Canadian System was expanded and improved

Canadian energy produced by a draft from flood control to ECC was divided into two parts since BC Hydro stated that some of this water would be drafted before non-Treaty storage and some after it. The pricing scheme for the Canadian hydro blocks was revised to accomodate the non-Treaty storage energy in the BC Hydro resource stacks.

The minimum outflows for Mica, Revelstoke, and Arrow were revised downward from the Treaty values to the physical limits at the projects for non-Treaty transactions. This allowed non-Treaty transactions to reduce the flows at these projects below the Treaty minimums, even though Treaty operations were still limited by the Treaty minimums.

Burrard, BC Hydro's combustion turbine, was modeled for the first time. A file was added to allow Canadian thermal plants and purchases to be modeled as needed and logic was added to BC Hydro's resource stack to allow the energy to be dispatched.

The modeling of G.M. Shrum project was updated to reflect additional information supplied by BC Hydro. The Energy Content Curves were revised so the plant would normally operate down about five feet from full in the summer. Outflows were limited to turbine capacity unless higher flows were needed to meet flood control or to pass inflow if the project was full. In addition the turbine capacity was reduced to show one unit out of service for maintenance.

Water Budget Operation Updated and Revised

Water budget flows revised from 60 kcfs in the first half of April, 115 kcfs in the second half of April and 115 kcfs in May to 70, 76, and 134 kcfs, to more accurately reflect the way the water budget has been used in recent years. The logic was also revised to draft only Grand Coulee and Arrow below ECC to meet the Columbia River water budget. This was done because BC Hydro does not participate in water budget, and the other upstream storage projects are not normally used. The Corps of Engineers 1987 Spill plan was used as being the most up to date information available at the time to model fisheries spill.

ECC Determination and Calculation Revised

The calculation of the Energy Content Curves (ECCs) was revised so that if the system was full on July 31, new ECCs are calculated that produce the shifted and shaped FELCC during Sept thru Dec period. The determination of fall ECCs was revised to use full contents instead of August actuals as the base from which to determine the new ECC elevations. When the U.S. is calculating proportional draft due to FELCC shifting/shaping, BC Hydro projects and Brownlee are exempted. FELCC IS determined using Treaty contents, not actual contents. This correction became important as a result of non-Treaty storage being used frequently and the larger amount of space modeled. Logic was also added that limits the downward adjustment of a plant's ECCs to assure they do not go below the assured refill curves. This reduced unrealistic drafting during the fall.

If the system draft is more than 10,000 MW months in September hydro block 4 (draft from ECC to FELCC) will be priced to not sell to the S.W. It was felt that if the system significantly failed to refill, this energy would probably be saved for PNW load.

BC Hydro Marketing Logic

Previously many high priced U.S. coal plants were not displaceable by BC Hydro's nonfirm energy. Logic has been revised so more U.S. thermal plants are displaceable by BC Hydro energy if it was an economic transaction. Logic was added so that if limited by line capacity BC Hydro will use non-Treaty to gain additional SW sales.

Libby Minimum Flows

Libby minimum flow logic has been revised to allow the outflow to be reduced to 3 kcfs if the project cannot refill with the outflow at 4 kcfs, the preferred minimum flow.

SW Marketing Logic

Fewer U.S. high cost thermal plants are included in determining the Intertie Access Policy (IAP) condition and the amount of Southern Intertie transmission capacity available to BCH. The PNW utilities must now pay wheeling charges on Intertie capacity reserved and thus are unlikely to declare any more resources than they expect to sell. In determining the probable California market price the U.S. non-Treaty storage is not included in the U.S. resources. It is assumed that BC Hydro would not return non-Treaty storage to the U.S. if the U.S. used the energy to displace a sale by BC Hydro to the S.W. The model logic was also changed so that BC Hydro would serve California market before displacing thermals serving the same priced market.

Centralia Operation

The contract with the mine requires that the Centralia coal plant must accept a minimum amount of coal each month. If their coal storage area is full, then the plant must run to use up this coal, and normally both units run to reduce the size of the coal pile. The Centralia operation in SAM was revised to show both units running if the plant is in a must run configuration.

Combustion Turbine Operation

The thermal operation was revised so that combustion turbines may be used to meet load whether or not they were reserved in the annual planning process. However, only the amount reserved is used in firm planning.

The PNW/BCH Intertie Size

The PNW/BCH tie size was expanded from its previous value of 2000 MW to 2300 MW. It is only rated at 2300 MW for non-firm power and depending on line loading may not be available at that level all the time. In an effort to determine the maximum likely enviromental effects the full 2300 MW value was modeled as if it were always available.

California Market

The new model Accelerated California Market Estimator (ACME) was used to provide a California market for the SAM model. California loads were taken from the California Utility forecasts (the CFM7 submittals).

All Inputs Updated

All inputs were updated to the 1988-1989 year. The Hanford Generating Project was also removed from the resource stack.

APPENDIX B

Part 4

Summary of SAM Modeling Constraints

APPENDIX B

Part 4

Summary of SAM Modeling Constraints

Assumptions Related to Non-Treaty Storage Usage. The modeling assumptions used to store or release non-Treaty storage in SAM are designed to make the system operate as realistically as possible. The assumptions outlined here refer to the Non-Treaty Storage Agreement (NTSA) Base Case analyses. In some cases sensitivity analyses varying these assumptions have also been run.

- Opportunity Storage

  a. Size/Duration. The No-Action Alternative uses 2.0 MAF of equally-shared non-Treaty storage. Releasing terminates in 1993. Storage continues until the space is full. The Proposed Alternative uses 5.0 MAF of equally-shared space utilized through the end of the study (2008). One of the sensitivity studies terminates releases in 2003 rather than 2008, allowing only storage to occur after that time until the space is full.

  b. Setup of NTS Space. Both BPA's and BC Hydro's NTS are divided into an upper and a lower part. The size of each part varies by month and the upper part is assumed to have a lower value and thus can be used to serve lower-priced loads. Figure 1 depicts this division of non-Treaty space.

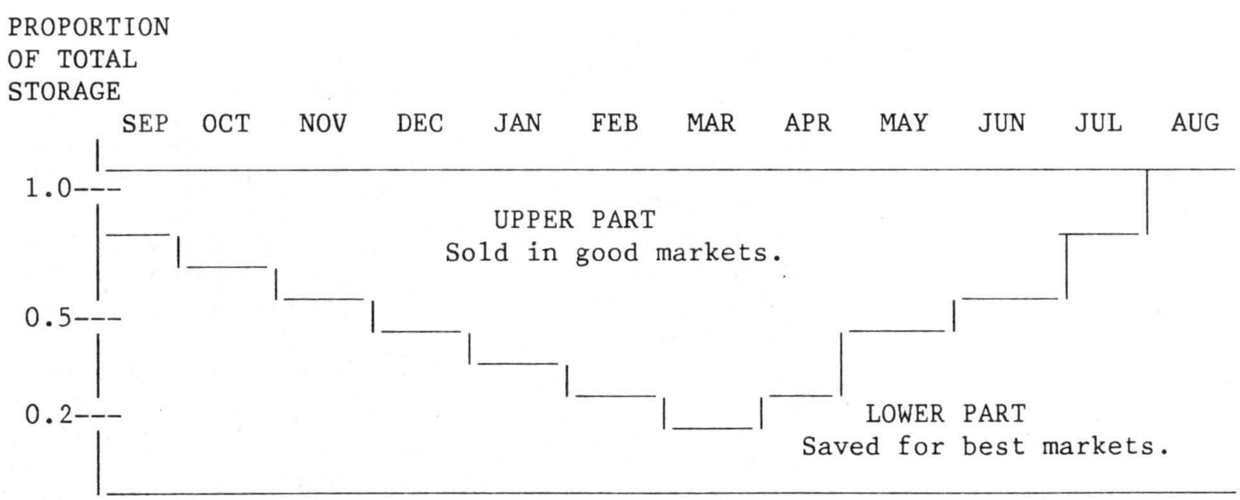

FIGURE 1

  c. Store/Release Decision. A "willingness-to-release" factor is calculated which is the ratio between the expected revenue/kcfs released and the maximum revenue/kcfs released. The expected revenue is the estimated Southwest (SW) market price multiplied by the water/energy conversion factor (H/K) when the system is drafted to flood control. The maximum revenue is the September highest SW market price multiplied by the maximum system H/K. A decision is then made to either store into NTS or release from NTS according to the following guidelines:

Ratio < 0.70	Store in both parts
Ratio 0.70 - 0.85	Store in lower part
Ratio 0.85 - 0.98	Release upper part
Ratio > 0.98	Release both parts

The <u>Alternative Dispatch Criteria</u> sensitivity study examines the effects of changing the criteria to allow for release of NTS at somewhat lower ratios than in the Base Cases.

d. <u>Dispatch of NTS</u>. If the decision is to store in NTS then a load block is set up and a price is assigned to that load. If the decision is to release then a resource is set up and a price is assigned to that resource. In the Base Case studies, NTS is priced as a resource such that it is used after the U.S. system has produced its full hydro FELCC to meet firm loads (including surplus firm sales). The dispatch of resources to meet loads in SAM is based on an economic dispatch in which all resources are assigned costs and the loads are assigned values. These two groups are then matched, lowest cost resource vs highest value load until transactions are no longer economic. NTS will be used if it is economic to do so.

e. <u>Release Limits</u>.

- No at-site spill at Mica or Revelstoke
- No spill caused at McNary
- Limited to amount of non-Treaty water in storage
- Limited to 15 kcfs total (BC Hydro and BPA combined). This limit is to prevent SAM from releasing or storing unrealistically large amounts of NTS. The assumptions in SAM necessarily do not include the daily and hourly operating limits which are encountered on a real-time basis and which limit the actual amount of NTS which can be utilized. (Such as turbine capacity limits at Mica or Revelstoke, short-term project constraints at Canadian projects, short-term transmission limitations, etc.) Historically, up to 25 kcfs of NTS has been stored or released in 1 day. Releases of 20 ksfd/day or more have occurred on nine days: March 28 and 29, 1985 (25 ksfd/day); May 16 and 17, 1985 (20 ksfd/day); July 25, 26, 28, and 29, 1989 (20 ksfd/day); and July 27, 1989(22 ksfd/day). Storage of 20 ksfd/day or more has occurred on five days: February 5 and 6, 1987 (20 ksfd/day); November 15 and 16, 1987 (23 ksfd/day); and October 21, 1988 (22 ksfd/day). However, in the 5 years of operation since 1983, monthly average non-Treaty storage has never exceeded 10 kcfs and the maximum monthly release was 13.6 kcfs. Therefore, a modeling limit of 15 kcfs is reasonable.

f. Storage Limits

- Limited by Treaty discharge and minimum discharge requirements at Mica, Revelstoke, and Arrow
- Limited by non-Treaty space available
- No violation of U.S. minimum flow requirements (Water Budget)
- Limited to 15 kcfs total (BC Hydro and BPA combined). (See discussion under Release Limits.)

- Firm Resource Use

a. Both the U.S. and Canadian portions of NTS are modeled as firm resources throughout the study period.

b. The U.S. portion is assumed to be declared as a firm resource for Coordination Agreement planning and is operated as any other reservoir

- Critical Rules Curves assume a uniform draft over the 42-month critical period
- Energy Content Curve and Upper Rule Curve are full at all times. (This is because NTS has no identified inflow. All inflow into Mica is dedicated to Treaty operation.)
- Other limits on storage/release are similar to use as Opportunity Storage.

c. The Canadian portion is operated as in the Opportunity Storage Alternative with restrictions on what load can be served

- NTS may only serve BC Hydro load and U.S. PNW firm load
- NTS may not serve the DSI top quartile

Assumptions Related to Treaty Operations

a. The Assured Operating Plan (AOP) or Detailed Operating Plan (DOP) operation is assumed for each year in the SAM studies. Each year BPA and BCH must agree on an AOP for the sixth year in the future and a DOP for the next Operating Year. This is required by the Columbia River Treaty and governs the operation of the Treaty Projects, including Mica. These plans must be agreed upon by both the U.S. and BC Hydro. The DOP is what the Treaty projects will be operated to and is a mutually agreed-upon update to the AOP. If no mutual agreement can be reached, then the AOP operation is used for the DOP. It is expected that AOP flows will remain at or near minimum in the spring as there is little advantage to BPA or BC Hydro to plan for higher flows at a time when they usually have surplus energy. BPA and BC Hydro are both committed to meeting these flows as required by the Columbia River Treaty. BC Hydro has the capability to move some water internally between Mica and Arrow reservoirs, but these activities do not change flows into the U.S.

b. For years in which the AOP has not yet been prepared, the last AOP available is assumed to remain in effect for the remainder of the study.

Assumptions Related to Fisheries Requirements

a. Spill Plan. The 1987 spill plan is used. This is the most recent spill plan for which data was ready to use at the time the studies were started. The recently signed Spill Agreement is modeled as one of the sensitivity studies.

b. April 1-15 minimum flow. For the first half of April a minimum flow of 70 kcfs is used for Priest Rapids dam. This is done to simulate operations under the Vernita Bar Agreement. Without some constraint SAM does not maintain flows in the spring unless there is load to be met. We feel that using 70 kcfs may overstate the Vernita Bar requirements in some cases but provides a more realistic operation of the hydro system than using either no constraint or some lesser value for minimum flow. This also allows us to assess the potential for increased difficulty in meeting the Vernita Bar requirements as a result of the proposed NTSA.

c. April 16-30 minimum flow. A minimum flow of 76 kcfs at Priest Rapids is used in the second half of April because this is the base power flow used in planning and the Water Budget is considered to be in addition to this amount. Thus, it is possible for Water Budget to be requested in a very small amount during the second half of April to obtain a flow at Priest Rapids of 76 kcfs and still maintain essentially the full Water Budget amount for the month of May. Again, we feel that this represents a more realistic operation than could be obtained by using either no constraint in SAM or some other assumption to represent this constraint.

d. Water Budget - Priest Rapids. A minimum flow of 134 kcfs at Priest Rapids in May is used to represent the Water Budget. This is the full volume of the Water Budget added to the base power flow of 76 kcfs. The Water Budget is shown all in May because this more closely represents the way that the Water Budget has been used recently, especially in dry years. Also having the Water Budget all occurring in 1 month more accurately portrays the excess energy which is produced on the hydro system.

e. Water Budget - Lower Granite. SAM models the Water Budget on the Snake River by having Dworshak reservoir release up to 10 kcfs in the month of May to increase Lower Granite Dam flows up to 85 kcfs. If a 10 kcfs release from Dworshak results in a flow of less than 85 kcfs at Lower Granite, Brownlee is drafted to an elevation dependant on the runoff forecast. This modeling method follows the specifications of the Water Budget that Dworshak does not have to be spilled (turbine capability 10 kcfs) and a Lower Granite target flow of 85 kcfs is used. In actual operation the Water Budget provides for a more flexible operation to meet fisheries need, however.

e. Vernita Bar Fall Flows. SAM does not use any restrictions on fall flows to reduce the level of flow required to protect redds during the December through April period. This is consistent with the Vernita Bar Agreement which does not limit fall flows. However, there is no direct link in SAM between the fall spawning flows and the spring protection flows at Vernita Bar.

APPENDIX B

Part 5

FISHPASS Model Assumptions and Input Parameters

APPENDIX B

Part 5

FISHPASS Model Assumptions and Input Parameters

The FISHPASS model was used to simulate downstream fish passage survival for anadromous fish passing the Lower Snake, Mid-Columbia, and mainsteam Columbia River hydroprojects during the April through August period of downstream migration. Simulated flows and spills from the SAM were used as input to the FISHPASS model to calculate the downstream survival, to below Bonneville. This Appendix provides information for the key FISHPASS model assumptions and input parameters.

The period average values of planned, overgeneration, and forced spill from the SAM were shaped into separate values of spill within a 24-hour period: (a) spill during planned fish-spill hours; and (b) spill during nonfish-spill hours. On a real-time operational basis, overgeneration spill can be shaped into the hours with the greatest benefit to fish (planned fish-spill hours), while forced spill is not controllable. Therefore, for the FISHPASS analyses, the planned and overgeneration spill are shaped into the fish-spill hours for the specific project, while the forced spill is maintained as a flat daily average rate occurring during both fish-spill and nonfish-spill hours. Table B.5-1 shows the fish-spill hours used in the analysis and the percent of fish in a given day which pass the dam during those spill hours.

The period average flows simulated by the SAM were modulated to daily values within each period before entry into FISHPASS using the 1986 historical (within period) flow shapes. the 1986 daily flows at Priest Rapids, Ice Harbor, and The Dalles were used to modulate (shape) the period average SAM data for the Mid-Columbia, Lower Snake, and Lower Columbia hydroprojects, repectively. The modulated flows for the SAM-FISHPASS runs were daily average values and were the same for both fish-spill and nonfish-spill hours. Spill rates were not affected by the daily modulation of period average flows.

Both hatchery and natural fish numbers for fish above Lower Granite Dam are based on dam counts as used in the 1987 development of the Corps of Engineers' Juvenile Fish Passage Plan. For other projects, hatchery fish release numbers and timing are based on 1986 hatchery release data reported in the Smolt Monitoring Program Annual Report by the Fish Passage Center. Natural fish numbers and migration timing are based on (a) the 1984 final report on Stock Assessment of Columbia River Anadromous Salmonids; (b) the 1985 report on Downstream Migrant Estimates for Rocky Reach and Rock Island; and (c) consultation with the National Marine Fisheries Service.

Except in the Spill Agreement Signed sensitivity studies, which used the values outlined in the negotiated Spill Agreement, the planned fish spill at Federal projects is based on the Corps of Engineers 1987 Juvenile Fish Passage Plan with sliding scale spill at The Dalles, John Day, and Lower Monumental. Planned fish spill at Mid-Columbia PUD projects is based on the current Federal Energy Regulatory Commission stipulation agreement.

Planned spill is only an interim protection that is assumed to be eliminated at each project when bypass improvements are completed.

Values and relationships used for spill efficiencies, dam passage parameters, and reservoir survival are provided in Tables B.5-2 and B.5-3 for the Mid-Columbia and Federal hydro projects. These values for the Mid-Columbia projects were based on consultation with the project managers. For the Federal projects, the values are those specified by the Council's Mainstem Fish Passage Advisory Committee (1986). The reservoir mortality rate for the Mid-Columbia projects was recently increased based on comments from the National Marine Fisheries Service and review of the testimony in the court proceedings for the Mid-Columbia Stipulation Agreement. The fish guidance efficiency values projected for future bypass improvements at Federal projects are best available estimates from the COE based on research and experience regarding current systems. For the Mid-Columbia projects, the values for future fish guidance efficiencies are the bypass system minimum design standards. Table B.5-4 gives future projected values of fish guidance efficiencies used the analyses and the dates when passage improvements are expected to occur.

Fish transportation at Lower Granite, Little Goose, and McNary are based on the current guidelines developed by the Fish Transportation Oversight Team (FTOT) comprised of fishery agencies, Tribes, and the Corps. Transportation survival is assumed to be 95 percent at Lower Granite and Little Goose, and 99 percent at McNary.

Overgeneration spill was allocated to different hydro projects based on the spill priority lists given in Table B.5-5 which were developed from a review of Fish Passage Center spill requests.

(VS5-RPSC-2229j)

Table B.5-1

HOURLY FISH PASSAGE DISTRIBUTIONS

Project	Stocks	Spill Hours	Percent Fish *
Wells	Spring Chinook	20:00 - 6:00	71
	Summer Chinook	20:00 - 6:00	58
	Steelhead	20:00 - 6:00	58
	Sockeye	20:00 - 6:00	43
Rock Reach	All	20:00 - 6:00	43
Rock Island	All	20:00 - 6:00	71
Wanapum	All	20:00 - 6:00	58
Priest Rapids	All	20:00 - 6:00	58
Lower Granite	All	18:00 - 6:00	82
Little Goose	All	18:00 - 6:00	82
Lower Monumental	All	18:00 - 6:00	82
Ice Harbor	All	18:00 - 6:00	66
McNary	All	18:00 - 6:00	82
John Day	All	18:00 - 6:00	82
The Dalles	All	18:00 - 6:00	66
Bonneville	All	20:00 - 6:00	71

* Percent of the daily total of fish arriving at the project which pass during the given hours of spill.

Table B.5-2

DAM PASSAGE PARAMETERS

Project	Spill Efficiency 1/	Spill Mortality (%)	Turbine Mortality (%)	Collection Mortality (%)	Bypass Mortality (%)
Wells	80% Fish/21% Spill 94% Fish/30% Spill	0	15	1	1
Rocky Reach	y = 0.663x (range 20-80%)	0	15	1	1
Rock Island	y = exp (0.054x) (range 15-80%)	0	6.5	1	1
Wanapum	y = 15.42 ln(x) (range 20-85%)	0	11	1	1
Priest Rapids	ln (y) = 0.819 ln(x) (range 20-85%)	0	11	1	1
Federal Projects 2/	y = x	2	15	1	1

1/ Spill Efficiency - y = % fish spilled
x = % river spilled (instantaneous)
Spill outside ranges given for data are interpolated toward end points of 0% fish/0% spill and 100% fish/100% spill

2/ For The Dalles the following spill efficiency relationship is used for x/y: 0/0, 20/52, 41/80, 100/95

Table B.5-3

RESERVOIR FLOW/SURVIVAL RELATIONSHIPS (KCFS/%)

For Mid-Columbia Projects*

Rocky Reach Flow/Survival	Rock Island Flow/Survival	Wanapum Flow/Survival	Priest Flow/Survival
0/21.3	0/76.6	0/0	0/61.5
10/24.8	10/80.1	10/0	10/65.0
50/85.	50/96.0	50/79.4	50/93.0
100/92.5	100/98.0	100/89.7	100/96.5
250/97	250/99.2	250/95.9	250/98.6
750/97	750/99.2	750/95.9	750/98.6

For Snake River Projects*

Little Goose Flow/Survival	Lower Monumental Flow/Survival	Ice Harbor Flow/Survival
0/53.0	0/61	0/58
12/54	12/62	12/59
50/67	50/73	50/71
75/79	75/83	75/81
100/87	100/90	100/89
125/92	125/94	125/93
150/92	150/94	150/93
175/88	175/91	175/90
1000/88	1000/91	1000/90

For Mainstem Columbia Projects

McNary Flow/Survival	John Day Flow/Survival	The Dalles Flow/Survival	Bonneville Flow/Survival
0/55	0/30	0/68	0/49
50/56	50/31	50/69	50/50
150/72	150/52	150/81	150/68
175/79	175/62	175/86	175/76
200/85	200/72	200/90	200/82
225/89	225/80	225/93	225/87
250/92	250/85	250/95	250/91
275/93	275/86	275/95	275/92
300/92	300/84	300/95	300/90
350/84	350/71	350/90	350/81
1000/84	1000/71	1000/90	1000/81

* Wells and Lower Granite use fish input data given as fish counts at the dam and there is no reservoir mortality applied to these fish numbers.

Table B.5-4

FISH GUIDANCE EFFICIENCIES
(Percent)

Project	Yearling C	Yearling F	S/Yearling C	S/Yearling F	Steelhead C	Steelhead F	Sockeye C	Sockeye F	Year
Wells	80	80	70	70	80	80	70	70	n/a
R. Reach	0	70	0	50	0	70	0	50	1992
R. Island	0	70	0	50	0	70	0	50	1992
Wanapum	0	70	0	50	0	70	0	50	1995
Priest R.	0	72	0	50	0	72	0	50	1995
L. Granite	77	88	48	60	79	88	48	60	1995
L. Goose	77	88	48	60	79	88	48	60	1995
L. Monumental	2	73	2	35	4	74	2	35	1992
I. Harbor	0	78	0	35	0	92	0	35	1993
Sluiceway	51	0	51	0	51	0	51	0	n/a
McNary	75	90	40	60	75	90	40	60	1996
John Day	72	90	30	60	86	90	30	60	1997
The Dalles	0	80	0	63	0	83	0	63	1997
Sluiceway	40	0	40	0	40	0	40	0	n/a
Bonneville 1	76	76	30	30	78	78	30	30	n/a
Bonneville 2	19	65	24	24	35	50	24	24	1996

C = Current bypass FGE.
F = Future Bypass FGE
Year = Estimated date of bypass installation or upgrade.

Table B.5-5

PRIORITY LISTS FOR ALLOCATION OF
OVERGENERATION SPILL WITHIN SAM 1/

APRIL

Project	Spill up to (kcfs)
Lower Monumental	5
Ice Harbor	5
Lower Monumental	12.5
Ice Harbor	12.5
The Dalles	15
Lower Monumental	20
Ice Harbor	20
The Dalles	30
John Day	30
Bonneville	30
Rock Island	10.4
Rocky Reach	10.4
Wells	10.4
Wanapum	16.7
Priest Rapids	16.7
Lower Monumental	25
Ice Harbor	25
The Dalles	40
John Day	40
Bonneville	40
Lower Monumental	40
Ice Harbor	40
The Dalles	60
John Day	60
Bonneville	60
Rock Island	20.8
Rocky Reach	20.8
Wells	20.8
Wanapum	33.3
Priest Rapids	33.3
Lower Monumental	25 percent of daily flow
Ice Harbor	30 percent of daily flow
The Dalles	40 percent of daily flow
Rock Island	41.7
Rocky Reach	33.3
Wanapum	41.7
Priest Rapids	50
Lower Monumental	40 percent of daily flow
Ice Harbor	40 percent of daily flow
John Day	40 percent of daily flow
Bonneville	40 percent of daily flow

Table B.5-5 (Continued)

MAY

Project	Spill up to (kcfs)
Lower Monumental	5
Ice Harbor	5
The Dalles	7.5
Lower Monumental	7.5
Ice Harbor	7.5
The Dalles	12.5
Lower Monumental	12.5
Ice Harbor	12.5
The Dalles	17.5
Lower Monumental	17.5
Ice Harbor	17.5
The Dalles	22.5
John Day	10
Bonneville	10
Rock Island	20.8
Rocky Reach	10.4
Wells	10.4
Wanapum	12.5
Priest Rapids	12.5
John Day	15
Bonneville	15
Lower Monumental	25
Ice Harbor	25
The Dalles	30
Lower Monumental	40
Rock Island	33.3
Rocky Reach	20.8
Wells	20.8
Wanapum	25
Priest Rapids	25
John Day	30
Bonneville	30
The Dalles	60
Lower Monumental	40
Ice Harbor	40
John Day	60
Bonneville	60
Lower Monumental	25 percent of daily flow
Ice Harbor	30 percent of daily flow
The Dalles	40 percent of daily flow
Rock Island	41.6
Rocky Reach	33.3
Wells	33.3
Wanapum	41.6
Priest Rapids	50
Lower Monumental	40 percent of daily flow
Ice Harbor	40 percent of daily flow
John Day	40 percent of daily flow
Bonneville	40 percent of daily flow

Table B.5-5 (Continued)

JUNE, JULY, AUGUST

Project	Spill up to (kcfs)
Rock Island	10.4
Wanapum	8.3
Priest Rapids	8.3
Wells	4.2
Rocky Reach	4.2
Lower Monumental	10
Ice Harbor	10
The Dalles	15
John Day	15
Bonneville	15
Rock Island	20.8
Wanapum	16.7
Priest Rapids	16.7
Wells	8.3
Rocky Reach	8.3
Lower Monumental	20
Ice Harbor	20
The Dalles	30
John Day	30
Bonneville	30
Rock Island	31.3
Wanapum	25
Priest Rapdis	25
Wells	12.5
Rocky Reach	12.5
Lower Monumental	30
Ice Harbor	30
The Dalles	45
John Day	45
Bonneville	45
Rock Island	41.7
Wanapum	33.3
Priest Rapids	33.3
Wells	20.8
Rocky Reach	20.8
Lower Monumental	40
Ice Harbor	40
The Dalles	60
John Day	60
Bonneville	60
Wanapum	41.7
Priest Rapids	50
Wells	33.3
Rocky Reach	33.3
Lower Monumental	25 percent of daily flow
Ice Harbor	30 percent of daily flow
The Dalles	40 percent of daily flow
Lower Monumental	40 percent of daily flow
Ice Harbor	40 percent of daily flow
John Day	40 percent of daily flow
Bonneville	40 percent of daily flow

1/ Spill rates are in addition to planned spill, but include forced spill and are applied to monthly average flows in SAM. Total spill at Bonneville is limited to 60 percent of the monthly average flow.

AUGUST 1985

Mica Active Storage, BPA/BCH 1 MAF each
Daily Transaction Records: store -
(1 MAF = 504.17 KSFD) release +

Date	BPA Daily Stored KSFD	BCH Daily Stored KSFD	Total Daily Stored KSFD	BPA Content KSFD	BCH Content KSFD	PRD Outflow kcfs	TDA Outflow kcfs
08/01/85	0.00	0.00	0.00	317.17	147.17	60.00	97.90
08/02/85	0.00	0.00	0.00	317.17	147.17	55.70	106.70
08/03/85	0.00	0.00	0.00	317.17	147.17	41.10	103.10
08/04/85	0.00	0.00	0.00	317.17	147.17	38.90	84.60
08/05/85	0.00	0.00	0.00	317.17	147.17	61.60	112.30
08/06/85	0.00	0.00	0.00	317.17	147.17	72.90	105.50
08/07/85	0.00	0.00	0.00	317.17	147.17	88.70	97.70
08/08/85	0.00	0.00	0.00	317.17	147.17	79.90	112.20
08/09/85	4.00	0.00	4.00	313.17	147.17	72.50	87.20
08/10/85	5.00	0.00	5.00	308.17	147.17	62.80	84.50
08/11/85	5.00	0.00	5.00	303.17	147.17	51.10	71.80
08/12/85	5.00	0.00	5.00	298.17	147.17	64.20	100.60
08/13/85	8.00	7.00	15.00	290.17	140.17	82.60	85.90
08/14/85	8.00	6.00	14.00	282.17	134.17	89.70	104.90
08/15/85	10.00	6.00	16.00	272.17	128.17	88.40	111.70
08/16/85	10.00	6.00	16.00	262.17	122.17	67.30	105.70
08/17/85	10.00	6.00	16.00	252.17	116.17	69.60	91.20
08/18/85	10.00	7.00	17.00	242.17	109.17	64.70	76.00
08/19/85	6.00	4.00	10.00	236.17	105.17	74.90	104.30
08/20/85	4.00	2.00	6.00	232.17	103.17	56.20	82.50
08/21/85	5.00	1.00	6.00	227.17	102.17	67.00	100.00
08/22/85	0.00	0.00	0.00	227.17	102.17	58.70	100.00
08/23/85	0.00	0.00	0.00	227.17	102.17	56.40	89.20
08/24/85	0.00	0.00	0.00	227.17	102.17	52.30	70.30
08/25/85	4.00	0.00	4.00	223.17	102.17	56.90	85.20
08/26/85	3.00	0.00	3.00	220.17	102.17	80.80	89.50
08/27/85	3.00	0.00	3.00	217.17	102.17	88.40	94.90
08/28/85	3.00	0.00	3.00	214.17	102.17	61.10	107.10
08/29/85	3.00	2.00	5.00	211.17	100.17	63.60	84.20
08/30/85	2.00	0.00	2.00	209.17	100.17	65.00	80.20
08/31/85	5.00	0.00	5.00	204.17	100.17	43.50	84.50