SCENIC RIVER STUDY

Report No. 6

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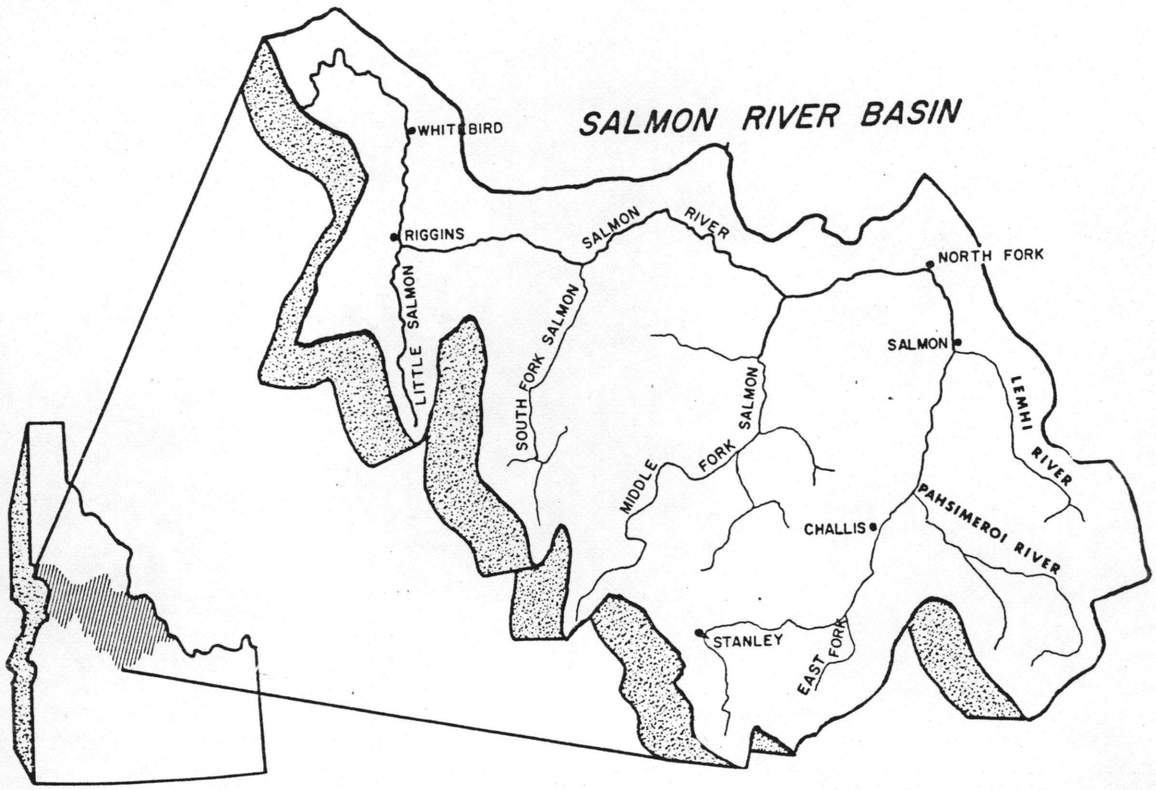

Report of

Hydroelectric Subproject

by

Paul Mann

Water Resources Research Institute
University of Idaho
Moscow, Idaho
June, 1973

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Report No. 6
OWRR Project No. B-014-IDA
Dr. E.L. Michalson, Project Investigator
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REPORT OF
HYDROELECTRIC SUBPROJECT

by

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Submitted to

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Water Resources Research Institute
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Moscow, Idaho

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ABSTRACT

The Salmon River is considered as a single-purpose hydroelectric energy resource from its mouth to North Fork, Idaho, (the "Study River" portion of the river). This stretch is supported by one storage project on the upper river to represent upriver development in general.

Total obtainable storage from the seven project complex is more than adequate to regulate an average year flow to a winter power peaking pattern judged to be compatible with a mature Pacific Northwest hydro-thermal system. The peaking capacity of the ultimate system approaches 8,000,000 kilowatts and average power output is 1,552.000 kw.

The system is considered to be developed in three stages over a 30 year time span. Net cumulative benefits over the first 50 years of operation total 3.7 to 5 billion dollars. Annual benefits exceed $100,000,000 per year from the completed system and are expected to continue for the second 50 years of the project life. Net equilvalent fossil fuel resource saving over the first 50 year term exceeds 300,000,000 tons of coal and over the 100 year term would constitute 1/2500 of the total estimated mineable U.S. coal reserves.

ACKNOWLEDGMENTS

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CHAPTER I

Introduction

General

On October 2, 1968, Public Law 90-542 was passed by the 90th Congress. This public law provides for a National Wild and Scenic Rivers System. It also indicates that the policy of the federal government is to include selected rivers, which with their immediate environment possess outstanding scenic, recreational, geologic, fish and wildlife, historic, cultural or other similar values, and that these rivers shall be preserved in their free flowing condition and shall be protected for the benefit and enjoyment of present and future generations.

The act provides for two categories under which specific rivers will be preserved or studied for possible preservation. Included in the first category are rivers authorized for immediate inclusion in the National Wild and Scenic Rivers System (Instant Rivers). Two such rivers, the Middle Fork of the Salmon River and the Middle Fork of the Clearwater River, are located in Idaho. The second category includes rivers designated to be studied for possible inclusion in the System (Study Rivers). Five rivers in Idaho qualify for study under the second category, namely the main stem of the Salmon River and the Bruneau, St. Joe, Priest and Moyie Rivers.

The act specifies three classes of wild rivers: wild, scenic and recreational. A wild river is one which applies to a river free from impoundments, with shorelines or watersheds still largely primitive and undeveloped, but which is accessible in places by road. A recreational river is one which is readily accessible by roads and railroads and which may have undergone some impoundment or diversion in the past. Public Law 90-542 sets a ten-year time limit on classification studies after which recommendations on the disposition of the study rivers are to be made to the Congress.

It is recognized that little valid methodology has been developed for evaluating rivers for wild or scenic classification. While methodology is a means to an end, it is, nonetheless, the key to developing techniques and criteria for classifying rivers for potential inclusion into a Wild or Scenic Rivers System. In view of this, the Water Resources Research Institute of the University of Idaho through a specially organized Scenic Rivers Study Unit is involved in developing a methodology to evaluate wild rivers. This study has as its goal to establish criteria which can be used to identify and determine the economic, esthetic, scenic and other values of wild rivers. The primary emphasis of this study will be focused for the next few years on the Salmon River in Idaho. This river which originates in central Idaho is about 410 miles long and enters the Snake River 49 miles above Lewiston, Idaho. The average annual runoff of the Salmon River is about 8,000,000 acre-feet.

The portion of the Salmon designated as a study river is from its mouth to the town of North Fork. However, the Institute also will include that portion of the river above North Fork and the major tributaries in the methodology study for two reasons. First, because any economic development--impoundments, dredging, diversion, logging, etc.--would affect the main stem wild river section. Second, because an economic study has to include all of the activity in the river basin to be meaningful in this area. This latter consideration also involves what may happen in the river area if and when the Salmon is selected as a wild river. A wild river status would affect all levels of economic development as well as sociological patterns in the area. Some economic activities such as recreational enterprises would tend to grow, whereas other activities such as logging might tend to be restricted or controlled depending upon whether the river was classified as wild, scenic or recreational.

The purpose of the methodology study is to develop information pertinent to decision-making and planning as it pertains to the selection, use and management of Wild and Scenic River Systems. The methodology study has four broad objectives:

1. Inventory present quantities and qualities of natural resources in the river basin area, and estimate future quantities and qualities of these resources, establishing their values in both situations.
2. Identify, describe and quantify, where possible, benefits from scenic beauty, personal enrichment and other esthetic experiences derived from the river.
3. Develop a series of models to evaluate or determine the resource use pattern consistent with a Wild Rivers System and the resource use pattern which would exist under various levels of development in the river basin area.
4. Present recommendations for alternative uses of resources for the entire river basin area, restrictions if classification is applicable and the economic and social ramifications of each of the alternatives considered.

The plan for the methodology study is to divide the research work into a series of subprojects, each covering an important economic activity related to the river. These subprojects consist of fourteen resource and service functions:

1. Forest and range resources
2. Minerals
3. Outdoor recreation
4. Commercial fisheries
5. Irrigation
6. Water for municipal and industrial use
7. Water quality control
8. Hydroelectric power
9. Flood control
10. Navigation
11. Transportation and access
12. Archeology
13. Hunting
14. Agriculture

Once the above subprojects have been completed, a series of economic models will be developed which will make relatively accurate estimation of costs and benefits for each of the resources included in the subprojects and also permit direct comparisons of costs and benefits of alternative resource uses. This technique will be modified and extended to make economic estimates of future resource use and values. These forecasts of future resource use will be extended to the years 2000 and 2020, consistent with the projection of the Columbia-North Pacific Region Comprehensive Framework Study.

It is at this stage of the analysis that the overall purpose of the methodology study will be realized. This purpose is to make an economic evaluation of the Salmon River in its natural state. The evaluation will be made consistent with the present levels of resource use indicated by the subprojects. This evaluation at the current level of resource use will then be compared with simulated levels of development on the river and within the river basin area. At this stage of the analysis it will be possible to include in the study certain general considerations such as population and economic growth and the demand for recreation, electricity, timber, minerals and other resources in the area in the future.

Two general evaluations of the river resource base can then be made: (1) the current and projected levels of economic activity based on the status quo; (2) a determination of the benefits foregone as a result of maintaining the river in its natural free flowing state. Efforts throughout the study will be to try to identify and quantify the esthetic and personal enhancement values for which the expressed national desire is to protect and conserve.

The Hydroelectric Subproject

The purpose of this hydroelectric subproject report is to collect, develop, and present information relating to the hydroelectric resources of the Salmon River and to estimate the values which the development of this resource would produce. The information which will be presented is that which would be used to model this river system for evaluation of its power resources. This representation and the cost of alternate resources would be necessary in a broad evaluation of the river system for the development of any study methodology or management program. It will represent the resource to the full level of development to measure the benefits derived at maximum utilization.

The development plan as proposed carries neither an advocacy nor non-advocacy position. The development as proposed is an alternative method of using Salmon River resources. As such, it will be used as a basis of information in the generalized methodology study.

The Salmon River hydroelectric potential constitutes about 25 per cent[1] of the total hydroelectric resource in Idaho but has to date by far the least actual developed usage. Major potential projects are largely on the main river from North Fork downstream to its mouth on the Snake River south of Lewiston. Because this particular river reach is in the "study river" category, major power value locations and the study area of the river are essentially the same. One upstream storage project will be included to represent the potential of the system with upstream storage which might develop for flood control, irrigation or water quality needs.

Basically Idaho, as the location of the Salmon River, cannot be separated from the Pacific Northwest region in terms of the general energy supply system.

[1] R.R. Goranson, "A Study of Hydro Peaking Capacity in Idaho", unpublished thesis, University of Idaho, 1964.

40 per cent of total Columbia River flow either rises in or passes through the state. Sometimes Idaho has been an exporter of energy and sometimes a net importer. Any export of energy contributes to the growth of regional population centers which are important markets for the State's extractive and partial-processing industries and agriculture.

In part, because of a favored position with respect to hydroelectric energy, industries which are high consumers of electrical energy relative to employee numbers and product have developed. Those based on local materials are electrochemical and eclectrometallurgical (lead, zinc, phosphates), pulp and papaer and irrigation (pumped and sprinkler). The large basic aluminum industry generates on imported materials.

With the construction of Canadian storage projects and completion of the last main stem Columbia plants, Pacific Northwest hydroelectric resources are approaching full development. Those remaining are largely concentrated in Idaho and Montana. The Middle Snake, Salmon and Clearwater basins contain many of the remaining major possible storage and energy projects.

Important and unique to the area's process of development has been the compatibility of flood control storage, power and river regulation. Major floods are predictable, spring snow-melt floods. This controlled water can safely be held in reservoirs for use in the late fall and winter when flows are low and power loads are high. The projects concerned have high power values and this results in an actual cash return from power operations. Continuing income from power sales are expected to be available after the power installation has been paid for to repay the costs of other phases of development.

Because the rate of energy development necessary to support current economic and population growth cannot be sustained exclusively on the hydroelectric system, other sources are now being evaluated and planning groups have particular plants identified and scheduled through the 1970 decade. Coal reserves other than those on which the recently constructed Chehalis plant will operate are small with respect to needs. Large quantities of coal are available in Montana and Wyoming which could be used as energy in south Idaho. The Jim Bridger coal burning plant is currently under construction near Rock Springs, Wyoming, and is a joint venture of Idaho Power Company and Pacific Power and Light Company. Beyond this, fossil fuels are scarce; and thus, nuclear plants are likely to represent the largest fraction of the area's new base energy supply system.

Regional loads are forecast[2] to double their present value by 1984-85 and to triple present values by 1992-93. Even though there are questions raised about how long present rates of growth will be sustained, no major changes have yet occurred. Should rates of growth slow somewhat (and they will at some uncertain time in the future), a few years delay in reaching the predicted levels is unlikely to change any of the major premises of planning.

Because the main energy base will change from hydroelectric power to thermal power, we should not assume either 1) that there will be no more water related problems for those responsible for the energy supply to the economy or 2) that no more construction will be done in the area of hydroelectric plants.

Either fossil fuel fired or nuclear plants require large quantities of cooling. Nuclear plants are presently in the order of 30 per cent efficient on a thermal basis and, thus, release somewhat more than twice as much heat energy as electrical energy. Because they operate at higher temperatures and pressures, fuel fired plants are more efficient (around 40 per cent) and, thus, produce

[2] Review of Power Planning in the Pacific Northwest, Calendar Year 1971. Power Planning Committee, Pacific Northwest River Basins Commission.

less surplus heat than nuclear plants. In either case, water is an effective and economical coolant.

As a measure of the quantities involved, a 1,000,000 kw (1,000 mw) nuclear plant might raise the temperature of a 3,000 cfs flow by 10° F or more. This is through flow and is not a consumptive use. An alternative is to use cooling towers and evaporative cooling. With this choice, investment cost goes up by 5 to 8 million dollars and the evaporated water (perhaps 30,000 acre feet/year) becomes a consumptive use.[3]

The large, high-efficiency thermal plants should be operated as continuously as possible. In order for this to be achieved, the hydro system (which is much more adaptable to rapid load changes) will be used more and more for carrying peak loads. When the future hydro system is operated for peaking, more machine capacity will be required for most hydroelectric plants even though total energy output has only a modest increase. New plants will be designed for more capacity than now anticipated. Added capacity may be secured for incremental costs as low as $70 to $100 per kw[4] while new thermal plants may cost in the range of $180 to $300 per kw based on current estimated plant costs.[5] For this reason we may well expect to see in the next two decades a rapid increase in both thermal and hydro capacity.

There are some impacts which this transition may have on the energy economy in Idaho separately and in the Pacific Northwest in general.

1. Because new thermal plants will be about as expensive here as anywhere else in the country, the region will have lost some of

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[3]Nuclear Power Plant Siting in the Pacific Northwest, Battelle-Northwest report for the Bonneville Power Administration, 1967.

[4]Hydroelectric Power Evaluation, Federal Power Commission, p. 35, 1968.

[5]"Plant Capital Costs Spiral Upward", Electrical World, July 1, 1971.

unique present advantage in power costs.

2. If Idaho is to have a part of the industry represented by construction and operation of new thermal power plants, its water supply must support either the impact of the heat discharged or the consumptive use of cooling tower water.
3. The resources of the Clearwater and the Salmon Rivers are at present (and until resolution of policy) unavailable as far as a further energy resource is concerned and these represent an important part of the remaining resource.
4. Further irrigation expansion is largely based on pumping. If we look toward major water transfers, pumping energy needs will be large.
5. Nuclear energy is not likely to be "free". Even if fuel costs were reduced to a negligible figure the cost of these complex plants plus transmission and distribution costs make it highly unlikely that there will be any substantial change (especially downward) in energy costs. The problem is to maintain some of the advantage the area now has.

Proposals for development as they are made in detail will be based upon these expectations and conditions.

CHAPTER II

A Salmon River Power System

Plants and Operating Guidelines

That portion of the Salmon River from its mouth on the Snake River to North Fork (about 20 miles below the town of Salmon) is directly involved in the Wild Rivers study area. Elevation at the mouth, which would also be the tail water of the Lower Canyon Dam, is about 910 feet and the elevation at North Fork is about 3,750 feet. A tentative hydroelectric generating system design based upon already identified and assumed practical dam sites can be developed to utilize this reach of the Salmon River. Detailed cost and benefit studies[6] have been made and updated covering the lower reach of this river. The projects of Lower Canyon (or the alternative of Nez Perce to control both Snake and Salmon Rivers), Freedom and Crevice develop about 1,500 feet of the total head in three projects. Upstream projects are smaller and control less of the total river flow. Also included with consideration of the Wild Rivers study area will be the Pashimeroi project because its large upstream storage would have an important effect on downstream operations.

Table I summarizes the principal features of the plants involved. Figure 1 is a profile of the river stretch, and Figure 2 is a map of the area.

Operation of this system for power production would in practice be coordinated with operations of the Northwest Power Pool. Spring operations would

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[6] Columbia River and Tributaries, H.D. #403, 87th Congress, 2nd Session.

Table I

PROJECT DATA
SALMON RIVER HYDROELECTRIC SYSTEM

Project	Gross Head (Feet)	Usable Storage (1000 Acre Feet)	Ave Flow [7] (cfs) (1928-1958)	KW at Ave Flow and Full Pool	K_p (KW/CFS)
Pashimeroi	297	1,042	1,912	40,920	21.4
Indianola	248	265	2,415	43,200	17.9
Pinnacle Peak	376	445	5,888	159,425	27.1
Black Canyon	332	425	6,616	157,825	23.9
Crevice	725	2,300	9,537	500,565	52.2
Freedom	205	180	10,473	156,965	14.9
Lower Canyon	635	2,500	10,694	492,440	45,7

[7] Extension of Historical Flows Through 1958, Water Management Subcommittee of Columbia Basin Interagency, 1961, (Basic Data). Adjusted by Columbia River Water Management Groups and Corps of Engineers for Specific Sites.

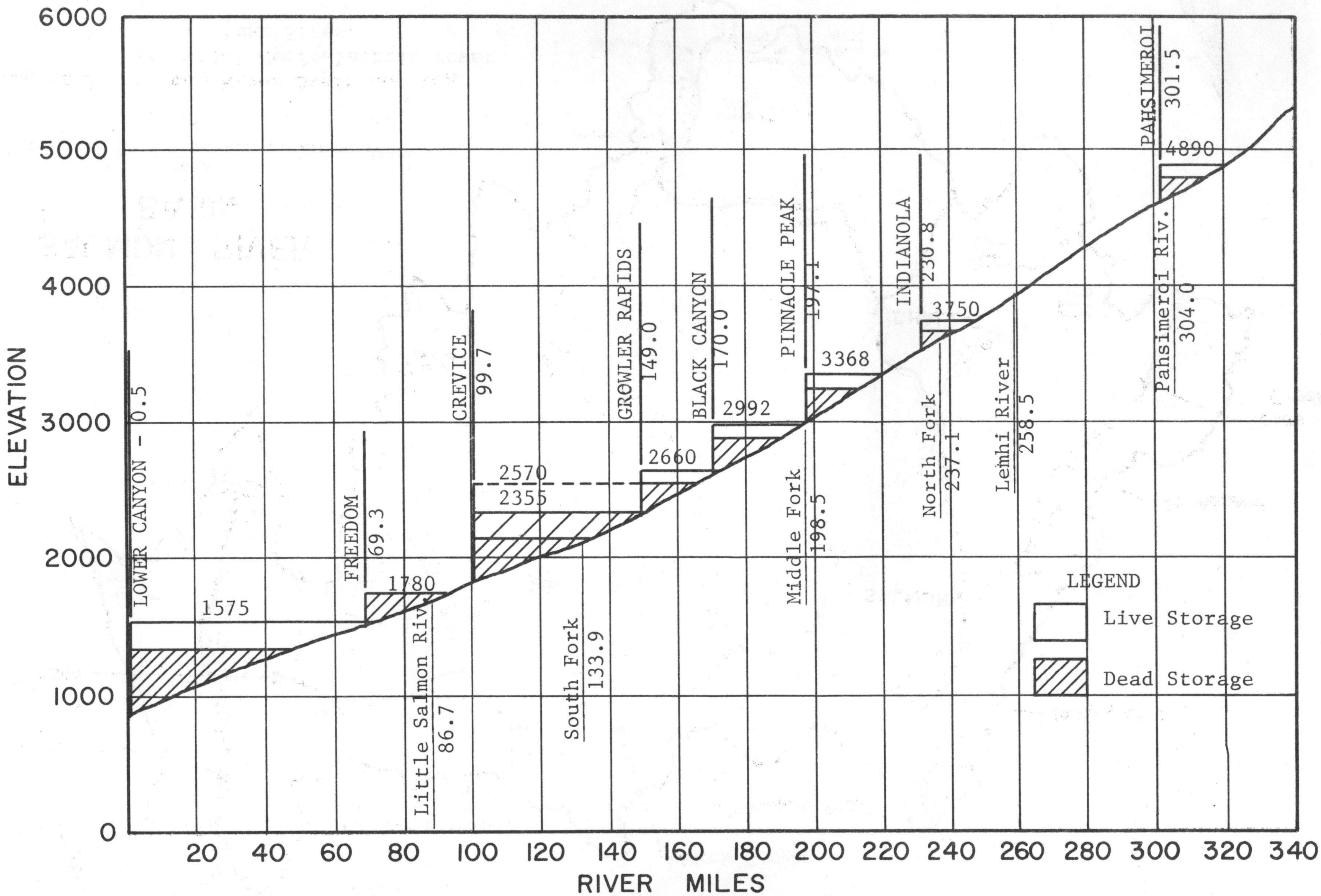

Figure 1: Condensed profile of Salmon River showing potential power projects.

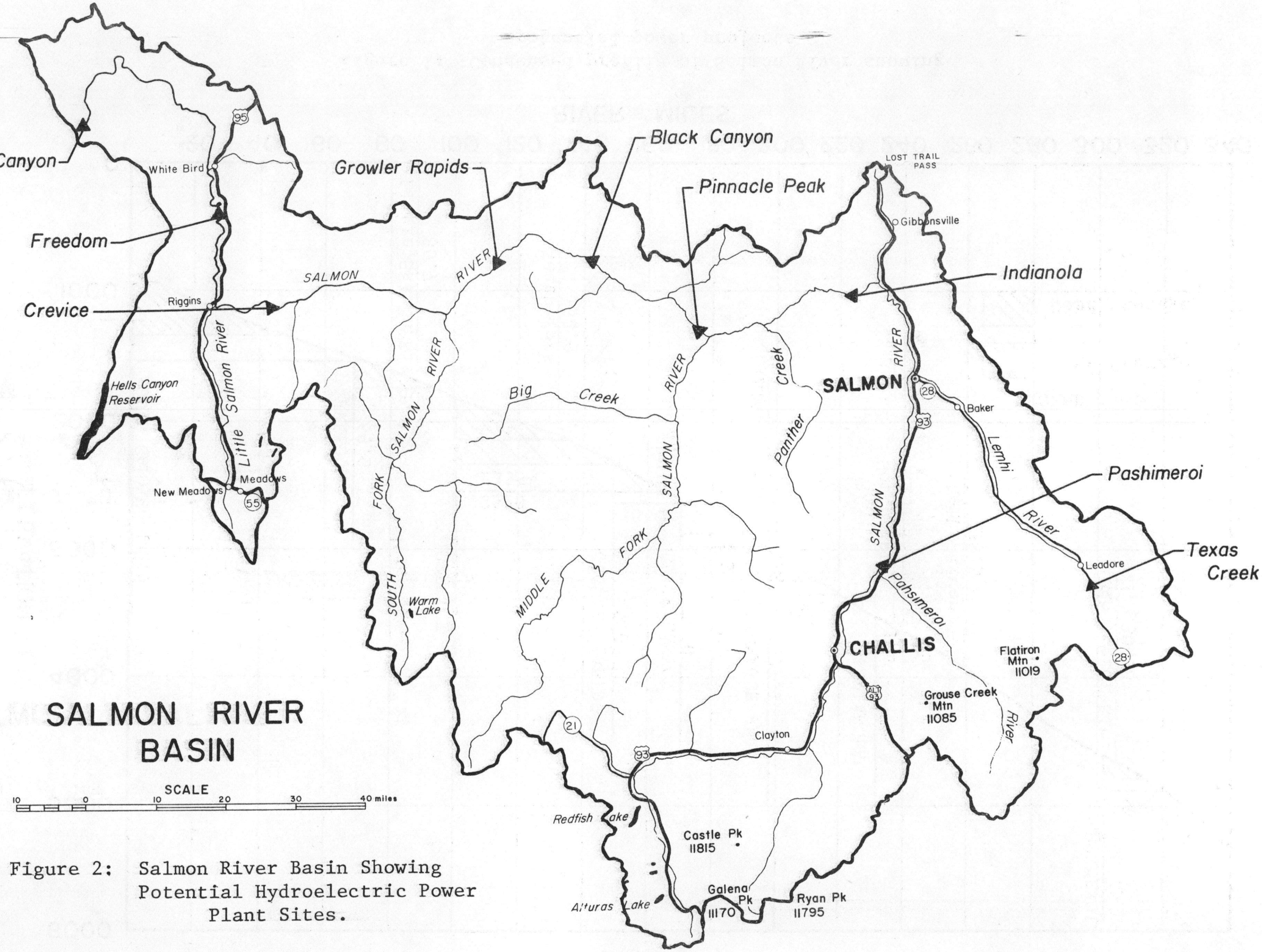

Figure 2: Salmon River Basin Showing Potential Hydroelectric Power Plant Sites.

be controlled for reservoir drawdown for flood control as indicated by forecasts of runoff.

For the purposes of this study the Salmon River System will be operated as an entity to produce its maximum output during the winter peak load period. The most current information for timing of storage release and power generation is the Pacific Northwest River Basins Commission's Electric Power Report.[8] Storage release in the Salmon System is programmed to produce generation from storage that is similar to that in the 1980 program as developed for the total power system. Generation from storage for the two low-flow years of 1929-30 and 1936-37 are averaged to obtain the storage release pattern which is used.

The operating life of this tentative power system if built would be largely within the period 1990 and later when hydroelectric plants will be used to produce peak load capacity rather than critical year energy. For this reason average flows rather than critical water years are used as a base for water quantities. In critical water years capacities would be comparable, but the time of operation would be restricted and total energy output would be lower.

The storage capacity which can be developed by this system is more than ample for average year flows. Storage drafts are limited to the refill capability at the site for an average year. Principal effects of this constraint are at Pahsimeroi where only about 65 per cent of total storage will refill in the typical year, at Freedom where no draft is proposed as head loss is considerable for a small storage quantity and at Lower Canyon where only 840,000 of 2,500,000 acre feet of usable

[8] Columbia-North Pacific Region Comprehensive Framework Study: Appendix XV, Electric Power, Pacific Northwest River Basins Commission, 1970.

storage would be used in the average year. With these limited drafts, heads at the downstream plants (where flow quantities are high) are maintained for most of the drawdown season. For this reason the head at all plants is considered as constant at full pool head. This overstates the capacity and energy to some degree. Because upstream releases flow through many downstream plants while they are still at practically full pool and refill operation is at minimum release flows, the error is relatively small. For a final study reservoir head-storage curves would be applied and adjustments made for the variable head.

Production figures are developed on a monthly average basis except for April. April is divided into two periods (1-15 and 16-30) because spring flows increase rapidly and transition from storage to refill operation occurs normally between these half-month periods.

Annual Operations Cycle

A basic annual operating cycle will be carried through. This cycle is based on the 1928-1958 average-year flow and is designed to meet the storage release cycle from the previously mentioned (1980) anticipated power demand.

Table II shows the seasonal variation in the power demands for the Pacific Northwest load area into which the Salmon River System would feed. Energy is stated as per cent of average annual energy and capacity as per cent of peak capacity. This indicates clearly the regional seasonal variation. Regulation of the Salmon River System would be more severe than this system average curve because it would be regulated primarily to supply winter peak energy and capacity demands with much of the generation based on storage release.

Tables III and IV contain further data on individual projects in respect to storage and storage operation. Storage is represented in the conventional unit of acre-feet and also inflow units of second-foot-days (one cfs for 24 hours) which is also equal to approximately 2 acre-feet and in energy units of thousands of kilowatt-days. This last unit is derived as the product of the storage in cfs days and the system kilowatts per cfs. System kilowatts per cfs are the kilowatts that will be generated by the release of a flow of one cfs from the project's storage falling through the remainder of the Salmon River projects. It does not include any capacity downstream from Lower Canyon.

Table V is the basic data from which storage releases are planned. It was derived from the average monthly storage release for the Pacific Northwest system operation in 1980. The column for gross storage represents the release schedule if all reservoirs were to be drafted to minimum power pool. The column for refillable energy is that storage release capable of refill from flows of the average year.

Table VI is a monthly schedule of storage release from each project. The development of this schedule is based upon refillable storage. Upstream storage is released first so that this flow passes through downstream plants while they are still at maximum head. This particular schedule is based on estimates of reasonable schedules to maintain monthly power requirements. Transitions in actual practice would be adjusted to current flow patterns and the sharp steps shown in the schedule would be smoothed in practice. Routing of flows in conjunction with other Pacific Northwest projects would likely optimize regional output at some schedule other than precisely shown in this report. Changes would not be expected to be large.

Table II

MONTHLY VARIATIONS IN PEAK AND ENERGY REQUIREMENTS[9]

Month	Monthly Energy (kwh) as Per Cent of Annual Monthly Average	Monthly Peak (kw) as Per Cent of Annual Peak
January	111.2	96.2
February	96.3	90.7
March	102.5	87.5
April	95.7	84.6
May	95.0	82.3
June	91.3	79.7
July	96.3	79.7
August	96.9	80.8
September	94.4	83.1
October	101.2	87.5
November	104.3	95.6
December	114.9	100.0

[9] _Ibid._, p. 44.

Table III

PROJECT AND SYSTEM STORAGE DATA

Project	Usable Storage (1000 AF)	Cumulative Storage (1000 AF)	Storage Refill Capability (1000 AF)	Minimum Release (CFS)	Refillable Storage (Project) (1000 AF)	Refillable Storage (Cumulative) (1000 AF)
Pashimeroi	1042	1042	743	350	743	743
Indianola	265	1307	863	700	120	863
Pinnacle Peak	445	1752	2626	1100	445	1308
Black Canyon	425	2177	3021	1100	425	1733
Crevice	2300	4477	4394	2000	2300	4033
Freedom	180	4657	Pondage	2500	Pondage	--
Lower Canyon	2500	7157	4871	2500	838	4871

Table IV

PROJECT DATA - GENERATION FROM STORAGE

Project	Project "K" KW/cfs	System "K" KW/cfs	Storage Gross (1000 cfs days)	Storage Gross (1000 KW days)	Storage Refillable (1000 KW days)
Pashimeroi	21.4	203.1	521	105,815	75,452
Indianola	17.9	181.7	132	23,984	10,811
Pinnacle Peak	27.1	163.8	222	36,364	36,445
Black Canyon	23.9	136.7	212	28,980	29,049
Crevice	52.2	112.8	1150	129,720	129,720
Freedom	14.9	60.6	90	5,454	0
Lower Canyon	45.7	45.7	1250	57,125	19,171
TOTAL			3577	387,442	300,648

Table V

MONTHLY GENERATION FROM STORAGE

Average of 1929-30 and 1936-37 years

Source: Pacific Northwest River Basins Commission
Comprehensive Framework Study (Appendix XV)
Electric Power Report, 1970
Figure 17

Month	Per Cent of Years Generation From Storage	Gross KW Days (x1000)	Refillable KW Days (1000)
August	2.11	8,175	6,348
September	5.94	23,014	17,858
October	9.94	38,512	29,884
November	14.29	55,365	42,963
December	18.58	71,987	55,860
January	19.49	75,512	58,596
February	16.52	64,005	49,667
March	9.65	37,388	29,013
April (1-15)	3.48	13,483	10,459
TOTAL	100.00	387,442	300,648

Table VI

STORAGE DRAFT SCHEDULE - SALMON RIVER SYSTEM
(1000 KW Days

Month	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr. (1-15)
Month's Draft	6,348	17,858	29,884	42,963	55,860	58,596	49,667	29,013	10,459
Project									
Pashimeroi									
Start of Month	75,452	69,104	51,246	31,246	11,246	0	0	0	0
Month's Draft	6,348	17,858	20,000	20,000	11,246	0	0	0	0
Indianola									
Start of Month	10,811	10,811	10,811	4,811	811	0	0	0	0
Month's Draft	0	0	6,000	4,000	811	0	0	0	0
Pinnacle Peak									
Start of Month	36,445	36,445	36,445	32,561	16,561	4,561	0	0	0
Month's Draft	0	0	3,884	16,000	12,000	4,561	0	0	0
Black Canyon									
Start of Month	29,049	29,049	29,049	29,049	26,086	6,086	0	0	0
Month's Draft	0	0	0	2,963	20,000	6,086	0	0	0
Crevice									
Start of Month	129,720	129,720	129,720	129,720	129,720	117,917	77,917	32,917	5,917
Month's Draft	0	0	0	0	11,803	40,000	45,000	27,000	5,917
Freedom									
Start of Month	0	0	0	0	0	0	0	0	0
Month's Draft	0	0	0	0	0	0	0	0	0
Lower Canyon									
Start of Month	19,171	19,171	19,171	19,171	19,171	19,171	11,222	6,555	4,542
Month's Draft	0	0	0	0	0	7,949	4,667	2,013	4,542

Tables VII through XIII give month by month operation of each of the seven plants involved. Information starts with the storage release in thousands of kilowatt days which then is reduced to storage release flow in cfs. This is then added to natural flow and any storage release flows from upstream projects to find net flows. Storage content is shown for first-of-month conditions and corrected for monthly withdrawals (or gains in refill season).

Table XIV summarizes yearly generation for all the Salmon River System. The numbers stated in this table are average monthly kilowatts. They do not indicate actual plant capacity that would be needed under the proposed operations.

Table VII

PROJECT OPERATING DETAIL
PASHIMEROI

Month	Storage Draft 1000 KW Days	Storage Draft or (Gain) CFS	Storage Draft or (Gain) AF	Storage Content Start of Month AF	Natural Flow CFS	Storage Release Upstream Projects (CFS)	Net Flow (CFS)	Generation at Site (Ave KW)
August	6,348	1,008	62,496	1,042,000	1,185	0	2,193	46,930
September	17,858	2,930	171,660	979,504	1,024	0	3,954	84,620
October	20,000	3,176	196,912	803,704	1,194	0	4,370	93,520
November	20,000	3,282	196,920	606,792	1,245	0	4,527	96,880
December	11,246	1,786	110,732	409,872	1,124	0	2,910	62,270
January	0	0	0	299,140	1,036	0	1,036	22,170
February	0	0	0	299,140	1,042	0	1,042	22,300
March	0	0	0	299,140	1,076	0	1,076	23,030
Apr. (1-15)	0	0	0	299,140	1,227	0	1,227	26,260
Apr. (16-30)	0	(1,931)	(57,930)	299,140	2,281	0	350	7,490
May	0	(3,873)	(240,126)	357,070	4,223	0	350	7,490
June	0	(5,077)	(304,620)	597,196	5,427	0	350	7,490
July	0	(2,259)	(140,058)	901,816	2,609	0	350	7,490
				1,041,974			Annual Ave.	40,922

System K = 203.1 KW/cfs   Project K = 21.4

Table VIII

PROJECT OPERATING DETAIL
INDIANOLA

Month	Storage Draft 1000 KW Days	Storage Draft or (Gain) CFS	Storage Draft or (Gain) AF	Storage Content Start of Month AF	Natural Flow CFS	Storage Release Upstream Projects (CFS)	Net Flow (CFS)	Generation at Site (Ave KW)
August	0	0	0	265,000	1,390	1,008	2,398	42,920
September	0	0	0	265,000	1,265	2,930	4,195	75,090
October	6,000	1,065	66,030	265,000	1,561	3,176	5,802	103,860
November	4,000	734	44,040	198,970	1,642	3,282	5,658	101,280
December	811	144	8,928	154,930	1,473	1,786	3,403	60,910
January	0	0	0	146,002	1,390	0	1,390	24,880
February	0	0	0	146,002	1,386	0	1,386	24,810
March	0	0	0	146,002	1,479	0	1,479	26,470
Apr. (1-15)	0	0	0	146,002	1,600	0	1,600	28,640
Apr. (16-30)	0	(335)	(10,050)	146,002	2,966	(1,931)	700	12,530
May	0	(724)	(44,888)	156,052	5,297	(3,873)	700	12,530
June	0	(904)	(54,240)	200,940	6,681	(5,077)	700	12,530
July	0	(173)	(10,726)	255,180	3,132	(2,259)	700	12,530
				265,906			Annual Ave.	43,200

System K = 181.7 KW/cfs   Project K = 17.9 KW/cfs

Table IX

PROJECT OPERATING DETAIL
PINNACLE PEAK

Month	Storage Draft 1000 KW Days	Storage Draft or (Gain) CFS	Storage Draft or (Gain) AF	Storage Content Start of Month AF	Natural Flow CFS	Storage Release Upstream Projects (CFS)	Net Flow (CFS)	Generation at Site (Ave. KW)
August	0	0	0	445,000	2,935	1,008	3,943	106,860
September	0	0	0	445,000	2,456	2,930	5,386	145,960
October	3,884	765	47,430	445,000	2,816	4,241	7,822	211,980
November	16,000	3,256	195,360	397,570	2,889	4,016	10,161	275,360
December	12,000	2,363	146,506	202,210	2,649	1,930	6,942	188,130
January	4,561	898	55,676	55,704	2,418	0	3,316	89,860
February	0	0	0	28	2,472	0	2,472	66,990
March	0	0	0	28	2,860	0	2,860	77,510
Apr. (1-15)	0	0	0	28	4,550	0	4,550	123,300
Apr. (16-30)	0	(2,804)	(84,120)	28	8,070	(2,266)	3,000	81,300
May	0	(2,850)	(176,700)	84,148	17,097	(4,597)	9,650	261,520
June	0	(3,070)	(184,200)	260,848	18,715	(5,981)	9,664	261,890
July	0	0	0	445,048	7,035	(2,432)	4,603	124,740

Annual Ave. 159,425

System K = 163.8 KW/cfs   Project K = 27.1 KW/cfs

Table X

PROJECT OPERATING DETAIL
BLACK CANYON

Month	Storage Draft 1000 KW Days	Storage Draft or (Gain) CFS	Storage Draft or (Gain) AF	Storage Content Start of Month AF	Natural Flow CFS	Storage Release Upstream Projects (CFS)	Net Flow (CFS)	Generation at site (Ave. KW)
August	0	0	0	425,000	3,253	1,008	4,261	101,840
September	0	0	0	425,000	2,698	2,930	5,628	134,510
October	0	0	0	425,000	3,070	5,006	8,076	193,020
November	2,963	722	43,020	425,000	3,141	7,272	11,135	266,130
December	20,000	4,720	292,640	381,680	2,889	4,293	11,902	284,460
January	6,086	1,436	89,032	89,040	2,625	898	4,959	118,520
February	0	0	0	8	2,692	0	2,692	64,340
March	0	0	0	8	3,146	0	3,146	75,190
Apr. (1-15)	0	0	0	8	5,018	0	5,018	119,930
Apr. (16-30)	0	(2,000)	(60,000)	8	9,318	(5,070)	2,248	53,730
May	0	(3,559)	(220,658)	60,008	19,606	(7,447)	8,600	205,540
June	0	(2,406)	(144,360)	280,666	21,250	(9,051)	9,793	234,050
July	0	0	0	425,026	7,849	(2,432)	5,417	129,470

Annual Ave. 157,825

System K = 136.7 KW/cfs Project K = 23.9 KW/cfs

Table XI

PROJECT OPERATING DETAIL
CREVICE

Month	Storage Draft 1000 KW Days	Storage Draft or (Gain) CFS	Storage Draft or (Gain) AF	Storage Content Start of Month AF	Natural Flow CFS	Storage Release Upstream Projects (CFS)	Net Flow (CFS)	Generation At Site (Ave. KW)
August	0	0	0	2,300,000	4,547	1,008	5,555	289,970
September	0	0	0	0	3,637	2,930	6,567	342,800
October	0	0	0	0	4,059	5,006	9,065	473,190
November	0	0	0	2,300,000	4,173	7,994	12,167	635,120
December	11,803	3,375	209,250	2,300,000	3,898	9,013	16,286	850,130
January	40,000	11,439	709,218	2,090,750	3,470	2,334	17,243	900,080
February	45,000	14,248	797,888	1,381,532	3,598	0	17,846	931,560
March	27,000	7,721	478,702	583,644	4,338	0	12,059	629,480
Apr. (1-15)	5,917	3,497	104,910	104,942	7,518	0	11,015	574,980
Apr. (16-30)	0	(3,892)	(116,760)	32	13,962	(7,070)	3,000	156,600
May		(15,469)	(959,078)	116,792	29,575	(11,006)	3,000	156,600
June	0	(16,914)	(1,014,840)	1,075,832	31,371	(11,457)	3,000	156,600
July	0	(3,376)	(209,312)	2,090,710	11,085	(2,432)	5,277	275,460
				2,300,022			Annual Ave.	500,565

System K = 112.8 KW/cfs   Project K = 52.2 KW/cfs

Table XII

PROJECT OPERATING DETAIL
FREEDOM

Month	Storage Draft 1000 KW Days	Storage Draft or (Gain) CFS	Storage Draft or (Gain) AF	Storage Content Start of Month AF	Natural Flow CFS	Storage Release Upstream Projects (CFS)	Net Flow (CFS)	Generation At Site (Ave. KW)
August	0	0	0	0	4,888	1,008	5,896	87,850
September	0	0	0	0	3,953	2,930	6,883	102,560
October	0	0	0	0	4,385	5,006	9,391	139,930
November	0	0	0	0	4,498	7,994	12,492	186,130
December	0	0	0	0	4,288	12,388	16,676	248,470
January	0	0	0	0	3,781	13,773	17,554	261,550
February	0	0	0	0	3,959	14,248	18,207	271,280
March	0	0	0	0	4,934	7,721	12,655	188,560
Apr. 1-15	0	0	0	0	8,515	3,497	12,012	178,980
Apr. 16-30	0	0	0	0	15,821	(10,962)	4,859	72,400
May	0	0	0	0	32,723	(26,475)	6,248	93,100
June	0	0	0	0	34,229	(28,371)	5,858	87,280
July	0	0	0	0	11,928	(5,808)	6,120	91,190
							Annual Ave.	156,965

Project K = 14.9 KW/cfs

Table XIII

PROJECT OPERATING DETAIL
LOWER CANYON

Month	Storage Draft 1000 KW Days	Storage Draft or (Gain) CFS	Storage Draft or (Gain) AF	Storage Content Start of Month AF	Natural Flow CFS	Storage Release Upstream Projects (CFS)	Net Flow (CFS)	Generation At Site (Ave. KW)
August	0	0	0	0	4,970	1,008	5,978	273,190
September	0	0	0	0	4,019	2,930	6,949	317,570
October	0	0	0	0	4,454	5,006	9,460	432,320
November	0	0	0	0	4,582	7,994	12,576	574,720
December	0	0	0	2,500,000	4,385	12,388	16,733	766,530
January	7,949	5,611	347,822	2,500,000	3,854	13,733	23,238	1,061,980
February	4,667	3,647	204,232	2,152,118	4,043	14,248	21,938	1,002,570
March	2,013	1,421	88,102	1,947,886	5,072	7,721	14,214	649,580
Apr. 1-15	4,542	6,625	198,750	1,859,784	8,738	3,497	18,860	861,900
Apr. 16-30	0	(2,767)	(83,010)	1,661,034	16,229	(10,962)	2,500	114,250
May	0	(4,464)	(276,768)	1,744,044	33,439	(26,475)	2,500	114,250
June	0	(4,030)	(241,800)	2,020,812	34,901	(28,371)	2,500	114,250
July	0	(3,818)	(236,716)	2,262,612	12,126	(5,808)	2,500	114,250
				2,499,328			Annual Ave.	492,440

Project K = System K = 45.7 KW/cfs

Table XIV

SUMMARY SHEET OF AVERAGE GENERATION
KILOWATTS

Month	Pashimeroi	Indianola	Pinnacle Peak	Black Canyon	Crevice	Freedom	Lower Canyon	Total
August	46,930	49,290	106,860	101,840	289,970	87,850	273,190	955,930
September	84,620	75,090	145,960	134,510	342,800	102,560	317,570	1,203,110
October	93,520	103,860	211,980	193,020	473,190	139,930	432,320	1,647,820
November	96,880	101,280	275,360	266,130	635,120	186,130	574,720	2,135,620
December	62,270	60,910	188,130	284,460	850,130	248,470	766,530	2,460,900
January	22,170	24,880	89,860	118,520	900,080	261,550	1,061,980	2,479,040
February	22,300	24,810	66,990	64,340	931,560	271,280	1,002,570	2,383,850
March	23,030	26,470	77,510	75,190	629,480	188,560	649,580	1,669,820
April 1-15	26,260	28,640	123,300	119,930	574,980	178,980	861,900	1,913,990
April 15-30	7,490	12,530	81,300	53,730	156,600	72,400	114,250	498,300
May	7,490	12,530	261,520	205,540	156,600	93,100	114,250	851,030
June	7,490	12,530	261,890	234,050	156,600	87,280	114,250	874,090
July	7,490	12,530	124,740	129,470	275,460	91,190	114,250	755,130
ANNUAL AVE.	40,920	43,730	159,425	157,825	500,565	156,965	492,440	1,551,870

CHAPTER III

Power Values

Introduction

Evaluation of electric power is normally made in terms of two components - energy and capacity. Energy costs are those costs which are variable with output (such as fuel) and are usually stated in mills (1/10 cent) per kilowatt hour. Capacity costs are stated in dollars per year per kw of capacity and represent the fixed costs of owning the plant.

A wide choice of design factors is available to the builder of either hydro or thermal plants. His choices will be governed by the anticipated use of the plant. Depending upon the anticipated hours of use per year costs may vary widely in both capital and fuel. As was stated earlier, the system design for the Pacific northwest is based upon an energy deficiency which will be supplied by the high-efficiency thermal plants. Hydro system developments to coordinate with the thermal plants will be designed to supply peak loads and reserve capacity. The hydro system will then operate at low plant factors where captial costs are relatively low because of large capacity machine installations at each plant.

The benefit obtained from the hydro installation is measured by the cost to produce its equivalent capacity and energy with the lowest cost alternative supply. This benefit is then compared with the actual cost of the hydro system, and the ratio of the benefit (alternative costs) to actual cost is the conventional and well known benefit-cost ratio used to measure the relative performance of projects.

The larger downstream projects were designed in some detail in early planning studies and benefit-cost ratios were developed on the basis of earlier construction and alternative costs (benefits). For plants upstream from Crevice much less detail is available. Costs developed will be preliminary and will be refined upon availability of detailed site data and designs.

A relatively current study was developed in 1968 by the Corps of Engineers by updating 1958 detailed estimates to then-current cost indices and power values. This was for guidelines only and could not be considered specific, but they would be a guide to relative performance of projects or groups of projects. These data are summarized in Table XV and include some Snake River projects which have impact on the Salmon River system. Some of these projects are mutually exclusive.

Nez Perce Dam on the Snake River below the confluence of the Salmon and Snake performs the same function as Lower Canyon Dam (Salmon) and High Mountain Sheep Dam (Snake) together. Freedom and Crevice may function with either Nez Perce or Lower Canyon. There are several alternatives to the specific High Mountain Sheep structure.[10]

These values indicate the advantage of large projects. The purely economic advantage of Nez Perce is especially demonstrated in the fact that both streams (the Snake and the Salmon) could be developed with one structure if power development and water control were the only objectives of the system (see map, Fig. 2).

Benefit-cost ratios for Crevice and Freedom here appear marginally low. It is probable that at the time of calculating these benefits the power costs from alternative sources were at about the minimum level. The long cycle of decreasing

[10] Columbia River and Tributaries, 87th Congress, 2nd Session, H.D. No. 403, U.S. Corps of Engineers, Vol. I, pp. 364-9.

Table XV

DATA FROM PREVIOUS STUDIES

	Power Ave. Annual Installed (Killowatts)	Flood Control Active Acre - Feet	Cost Ave. Annual $	Benefits Ave. Annual $	Net Benefits (Pwr Only)	Benefit-to-cost ratio
Nez Perce Pool El 1510 (With China Gardens Pool El 925)	1,250,000 (Incl. 150,000 @ China Gardens) 5,220,000 (Incl. 440,000 KW @ China Gardens)	4,500,000	$26,370,000	$79,960,000	53,590,000	3.0
Lower Canyon Pool El 1575 (With China Gardens Pool El 940)	528,000 (Incl. 181,000 @ China Gardens) 2,280,000 (Incl. 530,000 @ China Gardens)	2,500,000	$22,500,000	$35,100,000	12,600,000	1.56
High Mountain Sheep Pool El 1510 (With China Gardens Pool El 940)	842,000 (Incl. 181,000 @ China Gardens) 3,430,000 (Incl. 530,000 @ China Gardens)	2,700,000	$24,270,000	$52,230,000	27,960,000	2.2
Freedom Pool El 1780	147,400 640,000	24,000 (for Crevice regulation)	$ 8,234,000	$ 9,760,000	1,526,000	1.19
Crevice Pool El 2570	418,300 1,820,000	2,300,000	$23,956,000	$27,760,000	3,804,000	1.16

costs due to technological improvements, savings due to economy of scale with larger machines and the increasing use per customer was bottoming out in the latter part of the 1960's. Future trends in costs from alternative sources will follow general economic directions and have already shown sharply increasing trends. No attempts will be made in this report to specifically evaluate further hydro system benefits due to cost inflation in alternative sources due either to direct increase in costs or to added complexity of plants to meet a variety of environmental constraints.

Calculation of Benefits
(Alternative Costs)

The benefits (alternative costs) for the Salmon River System will be determined from 1971 power values for the Pacific northwest region as developed by the Federal Power Commission for the Corps of Engineers.

Three categories of alternative plants are available depending upon the annual capacity factor of the hydro system being considered. For very low capacity factor plants, oil fired gas turbine units are most economical. Fuel cost is high but capital savings offset fuel costs because of the low total operating time. At about 10 per cent capacity factor (800-900 hours per year of operation) oil fired steam turbine plants become more economical because of more efficient fuel use and less expensive fuel. At around 35 per cent capacity factor (3,000 hours per year) conventional coal fired or nuclear steam plants become most economical. The actual capacity factor at which types change is also a function of the interest rate considered.

Table XVI summarizes the basic plant and fuel data on which power values are based and Table XVII gives specific costs for the plants under different financing methods and for the range of operation possible.

Table XVI

BASE QUANTITIES FOR POWER COST DATA[11]

Type	Capacity	Capital Cost	Fuel Cost	Heat Rate
	MW	$/kw	¢/million/ btu	btu/kwh
Nuclear	2,000	278	13.0	10,450
Oil-fired base-load	2,000	152	79.5	8,890
Oil-fired peaking	800	120	79.5	11,400
Gas turbine peaking	660	108	135.0	15,200

An example of calculations from Table XVI to derive Table XVII for alternative costs for a 45 per cent annual capacity factor is carried out below. Financing is assumed at the combined 75 per cent public and 25 per cent private level.

Capacity Cost

$278 per kw x annual fixed cost factor (0.139) = $38.60 kw/yr.

Annual fixed costs cover:
- Interest and Amortization
- Interim replacements
- Operation and maintenance
- Insurance and taxes

[11] Federal Power Commission, 1971, Power Values and Alternative Costs, Pacific Northwest Region.

Energy Cost

Fuel:

$\frac{13¢/\text{million btu} \times 10{,}450 \text{ btu kwh}}{1{,}000{,}000 \text{ btu}}$	=	1.36 mills/kwh
Cost variable with operations	=	0.12 mills/kwh
Total energy cost	=	1.48 mills/kwh
$\frac{1.48 \times 24 \text{ hrs} \times 365 \text{ days} \times 0.45}{1{,}000}$	=	$5.84 yr/kw
TOTAL COST[12]		$44.44 kw/yr

The development of a system such as that of the Salmon River would probably be realized in three stages. Stage 1 is the early system operating at near 40 per cent capacity factor for years 1 - 15. In years 16 - 30 capacity is assumed to be expanded and the system then operates around 30 per cent annual capacity factor. For years 31 - 50 the capacity would be further expanded and the system would operate at a 20 per cent capacity factor. Capacity benefits are taken as the alternative capacity costs at the total system capacity factor. Individual plants then are assigned capacity benefits at this cost on the basis of their capacity. In some cases the actual operating capacity factor of individual plants may differ considerably from the general system capacity factor.

Annual benefits (alternative costs) per kilowatt for the timed stages (from Table XVII) vary with the assumed interest rates which are considered to vary from about 7 per cent (for combined public and private financing) down to 3 1/4 per cent for minimum rate federal financing.

[12] These costs are corrected to include some additional transmission costs to load centers for hydro plants.

Table XVII

POWER VALUES (ALTERNATIVE COSTS)
PACIFIC NORTHWEST REGION
1971

Financing		Capacity $/KW - Yr	Energy Mills/KWH
I 75% Public and 25% Private - (Approx. 7% effective interest rate)			
Capacity Factor	0-9%	11.12	21.76 (Gas turbine)
	10-36%	23.41	6.37 (Oil fired base load)
	over 36%	38.60	1.48 (Nuclear)
II Federal Financing 3 1/4% Interest			
Capacity Factor	0-7%	4.93	21.76 (Gas turbine)
	7-13%	14.26	6.37 (Oil fired base load)
	over 13%	19.97	1.48 (Nuclear)
III Federal Financing 5 3/8% Interest			
Capacity Factor	0-8%	6.95	21.76 (Gas turbine)
	8-20%	17.25	6.37 (Oil fired base load)
	over 20%	25.64	1.48 (Nuclear)

*Source: Federal Power Commission for Corps of Engineers

Calculation of Costs

Actual costs involved in development of a system such as that proposed depends on reasonably accurate data on design requirements. There can, however, be good guidelines developed that indicate cost probabilities in those cases where only general feasibility data are available. These probable costs can then be used to project benefit/cost ratios with accuracies adequate for general planning studies.

For this system it would be necessary to consider four groups of plants:

(1) The Lower Canyon, Freedom, Crevice group contains the major part of the total system capacity, operates on the major flow of the river and would be most economical to construct on a cost/kw basis. Using recent preliminary cost estimates and similar plants (Table XVIII)[12] as a guide, a cost of $250/kw for the initial stage of these projects would appear satisfactory. Incremental capacity for stages 2 and 3 is assumed at $75/kw.

Table XVIII

COSTS OF RECORD, MODERATE SIZE HYDROELECTRIC PLANTS

Year	Plant	Stream	Capacity	Head	Pond or Storage	Cost $/kw
1960	Brownlee	Snake	360,000	235	ST	225
1963	Oxbow	Snake	190,000	115	Pond	269
1954	Yale	Lewis	108,000	250	ST	329
1960	Noxon	Clark Fork	336,000	152	ST	240
1957	Moore	Connecticut	140,000	160	ST	217
1956	Indian Pond	Kennebec	75,000	150	ST	220

[12] Hydroelectric Power Evaluation, Federal Power Commission, FPC P-35, 1968.

(2) A second group would consist of those plants above Crevice, but still utilizing Middle Fork water. These plants (Black Canyon and Pinnacle Peak) have lesser flows than the first group but still are sizable plants and contribute substantial quantities of capacity and energy to the system. Because of lesser flows but no other substantial changes in the system, costs here will be higher. Costs for this group may well be in the $400/kw range for the initial plant with the incremental capacity at $75/kw.

(3) Above the Middle Fork flows reduce considerably and unit costs would be expected to increase again. In the specific plan considered only Indianola would be involved. There are other alternatives, however, which would avoid backing water up the Middle Fork as does the Pinnacle Peak project. If these alternatives were used, there would be two additional plants in this river segment (Long Tom and Sheepeater sites). Cost for this segment is more difficult to estimate. There is more development and road cost in this upstream reach. A figure of $750/kw will be assigned to the basic plant and again $75/kw used for incremental costs. Even though this cost might seem excessive, the use of a value in this range also has the advantage of costs being available over a three-to-one range of plant costs. The final result then will be a spectrum of costs and benefit/cost ratios as well as a specific estimate for a particular system.

(4) The large upstream storage at Pashimeroi site is a special case. Much of its benefit is indirectly generated in the downstream sections. Because this is the farthest upstream plant, its storage is the first released. It is effective through the entire head of the rest of the

system, and it enables the highest head plants (Crevice and Lower Canyon) to operate at near maximum heads during the December-January critical load period. No direct downstream benefit has been separated for Pashimeroi storage.

The plant will be evaluated on the basis of $1,000/kw, and a less-than-one direct benefit/cost raito will be expected. It would be sufficient for this analysis that the system achieve a net benefit.

The example calculation below shows the components that go into the cost actually incurred in the ownership and operation of a particular facility. The cost figures given are based on a 3 1/4 per cent federal interest rate.

Example Calculation[13]

Costs for $250 per kilowatt hydroelectric plant. Power plant facilities @ 75.00/kw and other and joint use facilities at $175.00/kw. A 100 year economic analysis is used.

	Power Plant	Other Facilities
Interest	3.25	3.25
Amortization	0.14	0.14
Interim Replacements	1.25	0.05
Insurance (in lieu of)	0.20	0.02
TOTAL FIXED CHARGES	4.84%	3.46%

Operation and Maintenance $1.25/yr/kw

[13] Ibid., p. 35.

Administration and General (0.39 x O and M)	0.50/yr/kw
TOTAL OPERATIONS COSTS	1.75/yr/kw

	Base Plant $/kw/yr	Incremental Plant $/kw/yr
P. Plant 4.84% x $75.00	3.63	3.63
Other Facility 3.46% x 175.00	6.06	
Operation and Maintenance	1.25	1.25
Administration and General	0.50	0.50
TOTAL ANNUAL COST	$11.44/kw	$5.38/kw

Table XIX is a summary of costs for: 1) 3 1/4 per cent federal, 2) 5 3/8 per cent federal, and 3) combined 75 per cent public non-federal and 25 per cent private where a combined rate of 7 per cent was used (the combined rate for alternative costs for thermal power in Table XVII is about 7.25 per cent).

Table XIX

ANNUAL COSTS FOR HYDROELECTRIC DEVELOPMENTS
(Dollars per year per kw capacity)

Interest Rate	3 1/4% Federal	5 3/8% Federal	Combined (7%) 75:25 public-private
Project Costs			
250.00/kw			
Base	11.44	16.47	20.90
Incremental	5.38	6.89	8.19
400.00/kw			
Base	16.63	24.68	31.88
Incremental	5.38	6.89	8.19

Table XIX (cont.)

Interest	3 1/4% Federal	5 3/8% Federal	Combined (7%) 75:25 public-private
750.00/kw			
Base	28.73	43.85	57.50
Incremental	5.38	6.89	8.19
1,000.00/kw			
Base	37.38	57.53	75.80
Incremental	5.38	6.89	8.19

Table XX

TENTATIVE INSTALLED PLANT CAPACITIES

Project	Maximum Month Average Killowatts	Stage I			Stage II			Stage III		
		Installed Capacity KW	Capacity Factor Annual	Capacity Factor January	Installed Capacity KW	Capacity Factor Annual	Capacity Factor January	Installed Capacity KW	Capacity Factor Annual	Capacity Factor January
Pashimeroi	96,880	100,000	41	22	100,000	41	22	120,000	34	19
Indianola	103,860	110,000	39	23	110,000	39	23	140,000	31	18
Pinnacle Peak	275,360	300,000	53	30	300,000	53	30	375,000	42	24
Black Canyon	284,460	300,000	53	39	300,000	53	39	500,000	32	24
Crevice	931,560	1,250,000	40	72	1,750,000	29	51	3,000,000	17	30
Freedom	271,280	300,000	53	88	500,000	31	52	800,000	20	33
Lower Danyon	1,061,980	1,250,000	39	80	1,750,000	28	61	3,000,000	16	35
	TOTAL	3,610,000	43	69	4,710,000	33	53	7,935,000	20	31

Table XXI

ANNUAL COSTS AND BENEFITS - SALMON RIVER HYDROELECTRIC SYSTEM

Case 1: Federal Financing at 3 1/4%

Project		Stage I 1-15 yrs ($1000)	Stage II 15-30 yrs ($1000)	Stage III 30-50 yrs ($1000)
Pashimeroi				
Benefits:	Energy	530	530	530
	Capacity	1,997	1,997	2,397
	TOTAL	2,527	2,527	2,927
Costs		3,738	3,738	3,846
B/C Ratio		0.68	0.68	0.76
Indianola				
Benefits:	Energy	560	560	560
	Capacity	2,197	2,197	2,796
	TOTAL	2,757	2,757	3,356
Costs		3,160	3,160	3,322
B/C Ratio		0.87	0.87	1.01
Pinnacle Peak				
Benefits:	Energy	2,066	2,066	2,066
	Capacity	5,991	5,991	7,489
	TOTAL	8,057	8,057	9,555
Costs		4,989	4,989	5,392
B/C Ratio		1.61	1.61	1.77
Black Canyon				
Benefits:	Energy	2,045	2,045	2,045
	Capacity	5,991	5,991	9,985
	TOTAL	8,036	8,036	12,030
Costs		4,989	4,989	6,065
B/C Ratio		1.61	1.61	1.98

Table XXI (Cont.)

Project		Stage I 1-15 yrs ($1000)	Stage II 15-30 yrs ($1000)	Stage III 30-50 yrs ($1000)
Crevice				
Benefits:	Energy	6,487	6,487	6,487
	Capacity	24,963	34,948	59,910
	TOTAL	31,450	41,435	66,397
Costs		14,300	16,990	23,715
B/C Ratio		2.2	2.44	2.80
Freedom				
Benefits:	Energy	2,034	2,034	2,034
	Capacity	5,991	9,985	15,976
	TOTAL	8,025	12,019	18,010
Costs		3,432	4,508	6,122
B/C Ratio		2.34	2.67	2.94
Lower Canyon				
Benefits:	Energy	6,382	6,382	6,382
	Capacity	24,963	34,948	59,910
	TOTAL	31,345	41,330	66,292
Costs		14,300	16,990	23,715
B/C Ratio		2.19	2.43	2.80
System Annual				
Benefits		92,197	116,161	178,567
Costs		48,908	55,364	72,177
B/C Ratio		1.89	2.10	2.47
Net Benefits (Annual)		43,289	60,797	106,390
Net Benefits (Stage)		649,335	911,955	2,127,800
Net Benefits (50 yr total)		3,689,090		

All stages used alternative costs of $38.60 KW-yr capacity cost and 1.48 mills/KWH energy cost as derived for over 13% capacity factor nuclear plant at this interest rate.

Table XXII

ANNUAL COSTS AND BENEFITS - SALMON RIVER HYDROELECTRIC SYSTEM

Case 2: Federal Financing at 5 3/8%

Project		Stage I 1-15 yrs ($1000)	Stage II 15-30 yrs ($1000)	Stage III 30-50 yrs ($1000)
Pashimeroi				
Benefits:	Energy	530	530	530
	Capacity	2,564	2,564	3,077
	TOTAL	3,094	3,094	3,607
Costs		5,753	5,753	5,891
B/C Ratio		0.54	0.54	0.61
Indianola				
Benefits:	Energy	560	560	566
	Capacity	2,820	2,820	3,590
	TOTAL	3,380	3,380	4,150
Costs		4,824	4,824	5,030
B/C Ratio		0.70	0.70	0.83
Pinnacle Peak				
Benefits:	Energy	2,066	2,066	2,066
	Capacity	7,692	7,692	9,615
	TOTAL	9,758	9,758	11,681
Costs		7,404	7,404	7,921
B/C Ratio		1.32	1.32	1.47
Black Canyon				
Benefits:	Energy	2,045	2,045	2,045
	Capacity	7,692	7,692	12,820
	TOTAL	9,737	9,737	14,865
Costs		7,404	7,404	8,782
B/C Ratio		1.32	1.32	1.69

Table XXII (Cont.)

Project		Stage I 1-15 yrs ($1000)	Stage II 15-30 yrs ($1000)	Stage III 30-50 yrs ($1000)
Crevice				
Benefits:	Energy	6,487	6,487	6,487
	Capacity	32,050	44,870	76,920
	TOTAL	38,537	51,357	83,407
Costs		20,587	24,032	32,645
B/C Ratio		1.87	2.14	2.55
Freedom				
Benefits:	Energy	2,034	2,034	2,034
	Capacity	7,692	12,820	20,512
	TOTAL	9,726	14,854	22,546
Costs		4,941	6,319	8,386
B/C Ratio		1.97	2.35	2.69
Lower Canyon				
Benefits:	Energy	6,382	6,382	6,382
	Capacity	32,050	44,870	76,920
	TOTAL	38,432	51,252	83,302
Costs		20,587	24,032	32,645
B/C Ratio		1.87	2.13	2.55
System Annual				
Benefits		112,664	143,432	223,558
Costs		71,500	79,768	101,300
B/C Ratio		1.58	1.80	2.21
Net Benefits (Annual)		41,164	63,664	122,258
Net Benefits (Stage)		617,460	954,959	2,445,160
Net Benefits (50 yr total)		4,017,579		

All stages used $38.60 KW-yr capacity cost and 1.48 mills/KWH energy cost as derived from over 20% capacity factor nuclear plant at this interest rate.

Table XXIII

COST AND BENEFIT DATA - SALMON RIVER HYDROELECTRIC SYSTEM

Case 3: 75% Public, 25% Private Financing (7% appoximate rate)

Project		Stage I 1-15 yrs ($1000)	Stage II 15-30 yrs ($1000)	Stage III 30-50 yrs ($1000)
Pashimeroi				
Benefits:	Energy	530	2,163	2,163
	Capacity	3,860	2,341	2,809
	TOTAL	4,390	4,504	4,972
Costs		7,580	7,580	7,743
B/C Ratio		0.58	0.59	0.64
Indianola				
Benefits:	Energy	560	2,284	2,284
	Capacity	4,246	2,575	3,277
	TOTAL	4,806	4,859	5,561
Costs		6,325	6,325	6,571
B/C Ratio		0.76	0.77	0.85
Pinnacle Peak				
Benefits:	Energy	2,066	8,427	8,427
	Capacity	11,580	7,023	8,779
	TOTAL	13,646	15,450	17,206
Costs		9,564	9,564	10,178
B/C Ratio		1.43	1.62	1.69
Black Canyon				
Benefits:	Energy	2,045	8,343	8,343
	Capacity	11,580	7,023	11,705
	TOTAL	13,625	15,366	20,048
Costs		9,564	9,564	11,202
B/C Ratio		1.42	1.61	1.79

Table XXIII (Cont.)

Projects		Stage I 1-15 yrs ($1000)	Stage II 15-30 yrs ($1000)	Stage III 30-50 yrs ($1000)
Crevice				
Benefits:	Energy	6,487	26,460	26,460
	Capacity	48,250	40,966	70,230
	TOTAL	54,737	67,426	96,690
Costs		26,125	30,220	40,457
B/C Ratio		2.10	2.23	2.39
Freedom				
Benefits:	Energy	2,034	8,295	8,295
	Capacity	11,580	11,705	18,728
	TOTAL	13,614	20,000	27,023
Costs		6,270	7,908	10,365
B/C Ratio		2.17	2.53	2.61
Lower Canyon				
Benefits:	Energy	6,382	26,030	26,030
	Capacity	48,250	40,996	70,230
	TOTAL	54,632	66,996	96,260
Costs		26,125	30,220	40,457
B/C Ratio		2.09	2.22	2.38
System Annual				
Benefits		159,450	194,601	267,760
Costs		91,533	101,381	126,973
B/C Ratio		1.74	1.92	2.11
Net Benefits (Annual)		67,917	93,220	140,787
Net Benefits (Stage)		1,018,755	1,398,300	2,815,740
Net Benefits (50 yr total)		5,232,795		

Stage I used alternative costs for nuclear plant ($38.60 KW-yr and 1.48 mills/KWH) while Stages II and III used oil-fired base load plant costs of $23.41 KW-yr and 6.37 mills/KWH as most economical plant for 10-36% capacity factor range for this interest rate.

CHAPTER IV

Alternatives to Conventional Development

In addition to considering only conventional development for power purposes or of total loss of this resource, alternative special or limited uses were also reviewed. Those special or limited uses would be expected to have limited impact on the river system, but hopefully would also salvage some of the resource.

Pumped Storage

This special type of plant will become usable in the Pacific Northwest in the future as the quantity of thermal plants become appreciable. The pumped storage plant is quite simply a high-head hydro plant where the water is obtained from pumping from a lower pool rather than from a natural flow. Pumping energy comes from surplus energy during light load periods (nights and week ends). The plant then returns this water for generation to carry peak loads. Because these plants can be built for relatively low capital costs, they become attractive for carrying peak loads and presently are being rapidly developed on systems that have largely thermal capacity.

In the Pacific Northwest region where large amounts of hydro capacity are available by additions to existing plants the pumped storage plant will not be too attractive for the near future. Preliminary surveys indicate that suitable daily cycle sites are plentiful near the coastal load centers (13). However, if

14. Pumped-storage Potential of the Pacific Northwest, Summary Report, Part I and II, Corps of Engineers, January, 1972.

seasonal plants were physically feasible the value of both the peak season power and the water delayed from flood flows to storage release seasons would be considerable.

Seasonal plants of course require large storage reservoirs, and so far only one has been specifically identified in the area under study. The Warren Creek Complex (14) has storage capability up to nearly 1,000,000 acre feet, develops nearly 4000 feet of head, and could be extended to about 5000 megawatts on a peak season cycle of 100 days of 6 hours each. It could also serve as a conventional pumped storage system to extend operation times or to operate with no net water release.

Present development of fossil fuel plants in Wyoming and Utah will accelerate the desirability of conventional daily or weekly pumped storage. Probably these could be located closer to loads in Bear or Snake River Basins or on the Salmon above the Wild River sections.

Diversion to Other Basins

The total flow of the Salmon River has surplus water above that necessary for conventional stream and recreation needs. Diversion of flood flows and surplus flows and surplus flows to other basins and uses would contribute values with little impact on the basic river system. The unique configuration of the Salmon River makes this most difficult. Small diversions to the Boise and Wood River basins from headwaters are physically feasible, but the small amounts of water involved have limited the attractiveness of these plans. In the area of Salmon more water

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15. Warren Creek Complex, Gary M. Ihle, Unpublished Master's Thesis, University of Idaho, 1966.

is available (about 25 percent of Whitebird flow) but necessary lift in elevation to make this available in the Upper Snake River Basin is about 3300 feet. Power recovery on the outfall side would be less than pumping needs, because destination elevation is somewhat higher than the source elevation in the Salmon River. Basin diversions thus do not look promising in the upper reaches of the basin (above Wild River designated stretch).

A major opportunity for diversion occurs below Riggins near Freedom damsite, where a tunnel to the Snake River (which here parallels the Salmon a few miles to the west) would result in delivery to a proposed power pool on the Snake and development would serve as an alternate to Lower Canyon high dam and result in recovery of some power resource. The project would require a low dam at or near the Freedom site. High estimated costs plus the possibility that most of this fall might eventually be developed by Nez Perce site has held up any firm proposals until resolution of the Middle Snake - Lower Canyon - Nez Perce alternatives determines a specific design for this stretch.

CHAPTER V

Summary and Conclusions

System Benefits

Overall system annual and cumulative benefits are restated from Tables XXI, XXII and XXIII.

ANNUAL AND CUMULATIVE NET BENEFITS

Interest Rate	Stage 1 0-15 yrs (Annual)	Stage 2 16-30 yrs (Annual)	Stage 3 31-50 yrs (Annual)	Cumulative Benefits (Over first 50 Operating Years)
3-1/4%	$43,000,000	$61,000,000	$106,000,000	$3,680,000,000
5-3/8%	41,000,000	64,000,000	122,000,000	4,015,000,000
7%	68,000,000	93,000,000	141,000,000	5,235,000,000

The 50 year operating period used for illustration is not the total system payout period. The general payout period is 100 years for the hydroelectric system. Assuming a continuing economy in which energy values have at least the same utility as in the next few decades the benefit values would continue through the 50 year period beyond 2020.

The total life of this hydro system would compare to three successive thermal plants whose individual lives would be about 30-35 years. A logical question would consider why the comparison was not made on a present-worth (discounted to present time) basis for the investment costs and benefits of each system. The principal reason for not using this system (which is a common method of comparing choices extending over a period of time) was the desire to state the benefits in terms of actual dollars rather than in present-value dollars which can greatly understate the actual benefits. The calculations below show the present-worth system applied to the net benefits of the 5-3/8% interest series. Three values of discount rates will be used. These are 5, 7 and 10 percent. The 10 percent value is used to illustrate the tendency of this system to reduce benefits beyond a modest time period to nearly zero. Again the arbitrary 50 year period is used. In an actual system analysis where both investment costs and returns were discounted to present worth the limitation of time to 50 years understates the benefits because costs occur early in the time period and appear in present worth at high fractions of actual dollars while the larger benefits appear in the latter part of the time period - and in this case well beyond the 50 year period - and are greatly understated by present-worth dollars.

PRESENT WORTH COMPARISON TO CURRENT BENEFITS (AMORTIZATION)

	Stage 1 1-15 yrs.	Stage 2 16-30 yrs.	Stage 3 31-50 yrs.
Annual Benefits	41,000,000	64,000,000	122,000,000
Total Stage Benefits	615,000,000	960,000,000	2,440,000,000
Present Worth (Total of Stage Benefits)			
5%	426,000,000	320,000,000	352,000,000
7%	373,000,000	211,000,000	170,000,000
10%	312,000,000	117,000,000	60,000,000

Average Annual Value of First 50 Years Benefits

Direct Benefits	80.3 million
Present Value Benefits	
5% rate of discount	22.0 million
7% rate of discount	15.1 million
10% rate of discount	9.8 million

While present worth is a valid method of comparing series of costs and benefits it states the results in magnitudes of numbers that are meaningful principally to place plans in relative order. As shown above, this system, by use of a 10 percent discount rate, can cause a benefit that averages 80 million dollars per year to appear as less than 10 million. Because the basic purpose of the study was to measure the resource value, it was thought that results should be expressed generally in the form of conventional dollars and then in present-worth dollars for comparison to other present worth systems if needed.

To measure the relative magnitude of this energy source, it will be compared to the present electrical power supply to the south Idaho economy. The average annual production of 1,500,000 kilowatts if used at a normal system load factor of 65 percent would be adequate to supply a system with a peak load of 2,300,000 kilowatts. This value exceeds the present combined peak load of Idaho Power Company and Utah Power and Light Company for south Idaho. As a resource then it can be said to be equivalent to a source capable of supporting a doubling of the south Idaho economy.

Resource Conservation

Hydroelectric energy represents the only large scale present method of utilizing (even if indirectly) the continuing solar energy source. In addition it is the only major energy source which does not add a net heat input to the earth's atmospheric system.

The alternative non-replacable energy resource that would be consumed to replace this system over only the first 50 year period will be expressed in terms of coal. The heat rate of the equivalent thermal station is about 9,000 BTU per kilowatt hour which is also approximately the heat value of a pound of coal. The equivalent coal consumption works out to an average of 765 tons per hour which becomes 6,700,000 tons per year and 335,000,000 tons in 50 years. This coal has a value today of about $4,00 per ton at the mine-mouth. It represents about 1/5000 of the total estimated mineable (1486 x 10^9 metric tons) United States coal (15).

Even though this 1,500,000 average kilowatts looks small in relation to the total energy needs of the future, it represents quite easily measured impacts on total reserves of conventional alternative sources of energy - none of which exist in significant quantities within the State of Idaho.

Partial System Development

Although the entire system is included in the benefit-cost summary to represent the complete development, some portions of the system can be omitted while retaining the principal benefits.

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16 M. K. Hubbert, The Energy Resources of the Earth, Scientific American, September, 1971.

The Indianola project has a benefit-cost ratio of less than one. Its location is also in a much-used recreational stretch of the upper stream. Omission would result in increased net benefits as well as retention of open stream above the Middle Fork.

Although the Pinnacle Peak project shows a positive net benefit, its location just below the mouth of the Middle Fork would not be permissible currently as the storage pool would back into the already-designated Wild River reach of the Middle Fork. The loss of stoage at Pinnacle Peak and at Indianola would reduce the flexibility of operation downstream, but ample total storage exists to achieve regulation. As indicated earlier (Table III) only about one-third of Lower Canyon storage is refillable in the average year when Indianola and Pinnacle Peak are used. If these two projects are omitted somewhat over one-half of the total Lower Canyon storage would be used and refilled.

Moving downstream, the Black Canyon project, while also showing positive net benefits, is above the South Fork and its omission results in reduction of net benefits of only around 5% of the total project. Thus, if the projects above Crevice are not considered, a great portion of the least-developed stretch of the river is left open. The losses to the resource system are minimal. Basically, Lower Canyon, Freedom and Crevice produce the greatest portion of the system value.

Plant Cost Change Impacts

As was stated earlier, there was no direct effort made in the original report text to anticipate future changes in price levels of plants or fuels. In the passage of time since the initiation of the report work, rapid changes have occurred in both areas. Generally these changes were anticipated by those involved in the energy supply technology. The current timing and rapid changes in magnitudes, however, have been such as to make discussion of directions and magnitudes worthwhile as part of this evaluation.

Plant costs have escalated at a rate to make the capital costs of 1971 significantly too low in 1973, and predictions for the future should not be too optimistic. Those portions of plant costs which are due to general increases in construction cost levels will affect both the hydro plant and any thermal alternative. The cost ratios are not likely to change greatly and benefits are likely to change only in the order of general price level changes. However, much of the price increase in alternative thermal plants has been due to actual change in plant design. Environmental factors have required extensive plant modification both in the heat rejection system of fuel and nuclear plants and in the combustion system of fuel burning plants.

Both higher air standards and the use of low sulphur coals have required great changes in precipitator design. Precipitator equipment for the Jim Bridger plant in Wyoming is costing $12,000,000 per 500,000 kw unit (16). This capital cost of $40 per kilowatt for precipitators alone compares to perhaps one-third as much with higher sulphur coals and lower earlier emission standards. (Western coals are generally low-sulphur coals. Design of precipitators thus is principally a function of emission standards for western plants. Older midwestern plants that changed to low-sulphur coals to meet SO_2 standards had trouble with emission standards because of poor performance of precipitators with lower sulphur content in stack gases.)

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[17] Annual report, Idaho Power Company, 1972.

Inadequate water supplies for direct cooling (Bridger, Centralia) or temperature restrictions on receiving waters (Trojan) have forced designers to cooling tower design which adds several dollars per kilowatt to plant costs. Because of added cooling apparatus costs, the overall economic plant design results also in a net reduction in plant efficiency of three to five percent for typical plants (17). This reduction in energy efficiency is due to higher exhaust temperatures and pressures to minimize capital investment in cooling systems.

As a measure of the rate of increase in nuclear plants costs, data from four announced plants in the spring of 1973 (18), averaged $372.50/kw for a total of 3484 megawatts and an announced cost of $1,298 million. This represents an increase of 34 percent (from $278 per kw) from the 1971 cost data used in the report text.

The same source (18) carried a story on a potentially feasible method of removing sulphur from coal. Cost estimates were from 5 to 15 cents per million BTU equivalent of fuel. This would add from 20 to 60 percent to the current base price of coal fuel of 25 cents per million BTU.

Fuel Availability and Costs

Fuel availability and cost factors predictably will have serious impacts on alternative costs. Any increases in cost will accrue to the benefit side of the hydro system (in the climate of the "Energy Crisis", the assumption is that changes will be upward).

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18 R.T. Jaske, Battelle Northwest Laboratories, SA-4126, "Is There a Future for Once-Through Cooling in the Utility Industry?".

19 Electrical World, May 1, 1973.

Any current attempt to assess the extent of changes in either price or availability would be premature. It is sufficient to say that most predictions tend toward the direction of scarcity for liquid fuels, the conversion of coal for the longer term source of liquid fuels and gases, and the necessary reliance on nuclear energy and coal for bulk base energy supplies. Currently many users are forced to premium fuels to meet SO_2 restrictions on existing plants. Access to world oil and gas supplied implies problems in foreign exchange and therefore national policy considerations.

A measure of the sensitivity of gross national costs to electrical energy costs is well illustrated in a recent national energy study (19). A 5 mill increase in costs from the 1970 mean consumer cost of 15 mills/kwh would result in a 600 billion doallar cumulative added cost for electrical energy to the year 2000. This figure gives some perspective to the caluculated cumulative net benefit of four to five billion dollars for the Salmon River system over the first 50 year operating span.

Conclusions

1. The Wild Rivers Study Area of the Salmon River is capable of sustaining a hydroelectric peaking system with an installed capacity approaching 8,000,000 kilowatts operating into the expected hydrothermal system of the Pacific Northwest. The average energy output of this system is 1,552,000 kw.

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[20] G.C. Szego, The U.S. Energy Problem, Volume 1, p. 11. NTIS No. PB207 517.

2. The cumulative net benefits of this system over the first 50 years of operation are from \$3.7 billion to \$5.2 billion depending upon assumed interest rate. Annual net benefits exceed \$100,000,000 in the third stage of development.
3. The upper three projects in the Study Area (Indianola, Pinnacle Peak and Black Canyon) may be omitted from the system with a reduction of approximately 7 percent in net benefits.
4. The omission of the projects in item 3 result in retaining 70 miles of main Salmon River between the upper end of Crevice Pool and North Fork as open river as well as eliminating Pinnacle Peak reservoir intrusion into the Middle Fork. (The Corps of Engineers' Plan avoids intrusion into the Middle Fork area by substitution of Sheepeater and Long Tom for the Pinnacle Peak - Indianola project). Finally, the benefit-cost ratios above the Middle Fork are less than 1 which also justifies the omission of these dams.
5. Plant cost escalations and expected fuel cost escalations make any changes in system values since the 1971 cost base favor the hydro-electric system.