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COST ANALYSIS OF IMPROVED REGULATION
OF THE COLUMBIA RIVER
TO INCREASE MINIMUM FLOW
IN THE HANFORD PLANT VICINITY

R. W. Legan and R. T. Jaske

June 1970

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by

R. W. Legan

Economics and Operation Research Department
Systems and Electronics Division

and

R. T. Jaske

Water and Land Resources Department
Environmental and Life Sciences Division

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ABSTRACT

This report reviews the operational history of the week of October 24-31, 1967 with respect to the actual operations of the Priest Rapids Project and the resulting effects on the flow of the Columbia River. These effects are compared with the degree of management also exerted at the McNary project during the time period. The adverse effects of the uncoordinated regulation of the Columbia River are summarized with respect to Washington State temperature standards. This uncoordinated regulation, much of which could have been reduced by special arrangements, produced a historical record of thermal modifications of continuing interest to researchers studying the effects of peaking operations on the Columbia River.

The linear program code UMPIRE was used to model the actual conditions and, by superposition, minimum flow constraints ranging upwards from 36,000 ft³/sec by 10,000 ft³/sec increments were imposed on the Hanford reach. All scheduled power and energy demands of the Priest Rapids project and the McNary project that existed on that week were met. Where necessary to make each other whole, transmission was used between Big Eddy and the Priest Rapids project to balance requirements. The transmission system existing on February 1970 was used to make the study.

The study showed that the minimum flow of the Hanford reach could be economically raised to 66,000 ft³/sec or higher if special arrangements could be made to eliminate wheeling charges for energy exchange between Grant County and Bonneville

which constituted the primary cost of minimum flow increases under study assumptions. The economics suggest that large reductions in the cost of proposed navigation channel facilities can be made by basing the channel design on $66,000 \text{ ft}^3/\text{sec}$ or higher minimum flows in the Hanford reach. The extra cost for energy losses and management represent a small fraction of the construction cost reduction when capitalized. The study shows the great benefits to multipurpose river use from system coordination on a regional rather than a separate private-federal basis as exists currently. More investigation of other details of the proposed arrangement is recommended.

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INTRODUCTION

Despite the shutdown of most of the reactors at the Hanford Project, the Division of Production of the U.S. Atomic Energy Commission has continued to support an active program of research to determine the effects of the thermal discharges on the regimen of the Columbia River. The research covers a period from the time extensive flow control of the main stem of the Columbia was introduced as a routine operational procedure. Earlier, in 1954, when the licensing of the Priest Rapids project was initiated, the USAEC, following a recommendation by the General Electric Company, requested that minimum flows below that project be included in the operating permit. The AEC requested this action because new production facilities were being put into operation. The originally projected minimums of $12.5 \text{ kft}^3/\text{sec}$ would have created conditions which were detrimental to the environment of the Columbia River.

Since 1966, investigations have focused on the nature and magnitude of the Hanford reactor discharges. In each case the degree of river flow control became a key issue in the judgment of the predicted effects of river modifications for the purpose of power development or navigation. In all of these investigations, the primary assumption was that the plan to extensively manage river flows did not relate to new legislative acts which have culminated in the Federal Water and Environmental Quality Improvement Act of 1970. This act creates broad discretionary power for the multipurpose management of water, air, and land resources.

However, the Clean Water Restoration Act of 1966 created conditions which require intensive re-examination of the decisions to dedicate river flows to peaking type operations. These induced fluctuations raise difficult if not impossible enforcement questions regarding the administration of releases to a river or stream.

To determine the cost associated with the mitigation of the present method of river flow manipulation, the Richland Operations Office authorized a trial study. October 1967 was selected as the period of study. During this time, according to unclassified records, the river below the operating areas showed thermal modifications of from 1 to 3 °C as a result of flow changes. The study is not complete because it was designed to make only a preliminary determination of the potential cost of raising the minimum flow below the Priest Rapids project by increments of 10 kft³/sec to as high as 66 kft³/sec, using power demands for the selected week. Such costs are interesting because they relate to the continued dialogue on similar Federal projects such as the Ben Franklin Dam, the Columbia River Navigation Extension project, and the siting of direct-cooled power reactors on the Hanford reservation.

SUMMARY AND CONCLUSIONS

The preliminary study examined data on independent power operations of the Grant County Public Utility District No. 2 and the Bonneville Power Administration during the 7-day period of October 24 to 30, 1967. The mean Columbia River flow for the week was 68 kft³/sec, while the combined flow of the Snake and Yakima Rivers was 30 kft³/sec. Power and flow data indicate peaking flow variations from the authorized minimum of 36 to a high of 135 kft³/sec below the Priest Rapids project. In contrast, flows below McNary Dam were essentially constant during the study period except for the weekend when

extra generation at McNary was carried out for the Federal system. The linear program UMPIRE was used to simulate operations in such a manner that the actual power demands from each of Wanapum, Priest Rapids, and McNary for the 7-day period starting October 24, 1967 were met as combined loads of a three-dam coordinated system. Data from the Bonneville Power Administration and the Grant County PUD No. 2 were used to derive the operational constraints for the simulation. These included policies normally carried out to enhance the efficiency of the Priest Rapids project which require Priest Rapids Dam to operate with the fullest possible reservoir at all times. Standard time of travel values for both operations were used.

With the use of these operational constraints, the minimum flow rate at Priest Rapids was raised by $10 \text{ kft}^3/\text{sec}$ increments and the energy demand overages and shortages resulting at each project were met by transmission between Midway and Big Eddy. A new set of output hydrographs was generated at each of the three dams for each successive increase in minimum flow rate until spill occurred because of power limitations on the transmission. This occurred at values over $66 \text{ kft}^3/\text{sec}$ below Priest Rapids, at which point increases in the minimum flow rate were terminated because of excessive penalties. These penalties were especially sensitive to the Priest Rapids reservoir filling and emptying rates and administrative charges for power exchange under the 1964 Coordination Agreement. Sufficient information was obtained to reveal that the annualized cost penalties for increases in minimum flow rate were relatively small compared with potential cost reductions in proposed navigation projects and the potential use of direct-cooled power reactors.

The following specific conclusions were reached:

- 1) During the 7-day period commencing October 24, 1967,

the application of a coordinated flow control plan for the Hanford reach would have substantially reduced thermal modification of the Columbia River. Based on the unclassified data collected during the period, the actual temperature increases attributable to Hanford operations would have been less than 1.5 °C had a minimum flow rate of 66 kft³/sec prevailed at Priest Rapids.

- 2) Costs attributable to raising minimum flows are uncertain because the present coordination agreement does not provide for flow management and energy exchange of the type simulated in the study. For this reason, the study predicts costs which are believed high because no basis exists for reducing the 0.25 mill/kW-hr service charge levied by the terms of the present Coordination Agreement against transmission by Grant County PUD No. 2 which was carried out in the simulation to support the raising minimum flow rates. The government, in its own interest, could waive or reduce this charge in view of the substantial savings in related water resources development costs for alternative project designs and management policies. An estimated annual cost associated with raising the minimum flow rate at Priest Rapids from the present 36 kft³/sec to 60 kft³/sec is very small. These projected annual costs for raising the flow rate to 46, 50, 55, and 60 kft³/sec are estimated to be zero, \$43,000, \$78,000, and \$125,000 respectively. At a flow rate above 60 kft³/sec, spillage occurs and thus, under the study ground rules, the cost of raising the minimum flow rate above 60 kft³/sec increases very rapidly. At 66 kft³/sec the estimated annual cost is \$268,000 where \$70,000 is associated with spillage.

As a further example of how rapidly the cost rises when the minimum plan rate is increased above $60 \text{ kft}^3/\text{sec}$, the estimated annual cost with a minimum flow rate at $70 \text{ kft}^3/\text{sec}$ is \$464,000; and again almost half, \$203,000, is associated with spillage. This cost is 3.7 times the cost at $60 \text{ kft}^3/\text{sec}$, but as the loads increase, the spillage will decrease or be eliminated; thus, in the future when the power demands are higher, a higher minimum flow rate than $60 \text{ kft}^3/\text{sec}$ may become warranted. However, in the event other dams beyond the three under consideration are added, such spillage would not take place. The point is only stressed in determining the level of coordination among users in arriving at a new coordination agreement.

- 3) To the extent that the scope of the study permitted, additional examination of raising minimum flow rate in the Hanford reach by coordinated dam operation appears essential. An estimated annual cost of \$125,000 (under what are believed highly conservative assumptions described above) for raising the minimum flow through the Hanford reach to $60 \text{ kft}^3/\text{sec}$ would justify only \$2,500,000 in increased capital investment for related projects over 20 years. This amount, on the basis of currently accepted estimates in the power industry, would be less than a fifth of the price of a single off-stream cooling installation for a 1000 MW_e power reactor. The present worth of such a cost at a 10% interest rate is 1.06 million dollars. Further, the reduction of dredging and migration of wildlife losses would cut the cost of the proposed navigation channel and would appear highly justified in a financial sense and popular in the public eye because of environmental effects.

- 4) No effort was made to investigate the potential coordination of additional power plants beyond the three specified having access to the Bonneville transmission system. Preliminary study by the non-Federal dam operators⁽¹⁾ indicates that more investigation might reveal added benefits from real time load coordination carried out for purposes of multipurpose resources management. Our study suggests that the construction of the California intertie and the resulting commitments to provide peaking energy over the regional intertie system have dedicated the Columbia River to increasingly severe flow and level fluctuations characteristic of this type single purpose development. These fluctuations may seriously limit the development of a number of potential diversified uses of the land area of the Hanford reservation and upstream locations.

In view of the above detailed conclusions, the data and information contained in Figure 1 are regarded as the primary conclusion of the study. These data are viewed as preliminary estimates of the high side range of costs. Detailed study of optimum methods of increasing the degree and scope of coordination promises markedly reduced costs ranging downward to as little as 10% of the values in Figure 1. Attainment of these objectives would require negotiation of a new coordination agreement with specific provisions for the management of water flows to enhance local planning options. The beginning of negotiations leading to such an improved arrangement is strongly recommended.

FIGURE 1. Summary of Cost of Increasing Minimum Flows at Priest Rapids Dam by Coordination of Dam Operation in Vicinity of Hanford Plant

DISCUSSION

The mathematical model covered a period of 1 week, or 168 hr. To obtain an annual cost, every week of a year could have been modeled in a continuous manner. However, this would have been prohibitively expensive--about \$500 per data week just for computer time. Because this work was intended to be only a preliminary study, the following procedure was adopted to project the 1 week analysis into an annual cost. After choosing 1967 as a normal year, each day of the year was examined to obtain the number of hours that the flow rate at Priest Rapids was below 46, 56, 66, and 76 kft³/sec. Between September 1967 and February 1968 there was an average of 41 hr per week where the Priest Rapids flow rate was below 46 kft³/sec. From October 27 to 30, 1967, the period selected for study, the time periods and flow rates were as follows:

Flow Rate, <u>kft³/sec</u>	<u>Hours</u>
<46	67
<56	82
<66	91
<76	103

Two other weeks, the first week in January and the third week in February 1968, also had exceptionally many hours of low flow. The week in February had 124 hr where the flow at Priest Rapids was less than 76 kft³/sec. A continuation of this work should include an investigation of these 2 weeks.

Table 1 shows the estimated costs for minimum flow rates of 46, 56, and 66 kft³/sec at Priest Rapids. In this table the electrical rates at Wanapum, Priest Rapids, and McNary Dams were taken at 2.26 mills/kW-hr.

By ratioing the number of hours in the week to the number of hours in the year that the flow rate was below a value, an estimate was made of the annual cost projections associated

with raising the flow rate at Priest Rapids. For example, during 1967 there were 1124 hr when the flow rate at Priest Rapids was less than $46 \text{ kft}^3/\text{sec}$, while for the week of October 24 there were 67 hr. Thus, the weekly cost was transformed into an annual cost (see Table 1), as seen below.

$$\text{Annual cost} = \left(\frac{1124}{67} \right) (\text{weekly cost})$$

When the weekly cost is \$1150, the annual cost estimate becomes \$19,300.

Table 1 shows the weekly and projected annual costs associated with raising the flow rate at Priest Rapids. Also presented in this table are two cases of study, one in which the Priest Rapids reservoir was limited from falling at a rate of 0.25 ft/hr and the other in which the rate of drop was limited to 0.5 ft/hr. With a $56 \text{ kft}^3/\text{sec}$ minimum flow rate minimum flow rate at Priest Rapids and a 0.25 ft/hr rate of drop for the reservoir, the estimated total cost to the system is \$16,000 per year.

Shown in Tables 1 and 2 and Figure 1, the cost is very closely associated with the size of the Priest Rapids reservoir. If, for example, on the assumption that there is an abundance of water, it is clear that as the Priest Rapids reservoir approaches an infinite size, the cost associated with raising the minimum flow rate at Priest Rapids approaches zero. This suggests that a complete benefit-to-cost analysis on raising the minimum flow rate at Priest Rapids must include an economic evaluation of enlarging the pool's storage capacity. This is one of the greatest advantages of a mathematical model, because the costs in Tables 1 and 2 could be reported at varying sizes of the Priest Rapids reservoir, instead of just the working nominal 44,000 acre-ft. When compared with the 185,000 acre-ft for McNary and 161,000 acre-ft for Wanapum, the importance of Priest Rapids reservoir on the cost can be readily seen.

TABLE 1. Weekly and Projected Annual Cost Associated with the Minimum Flow Rate at Priest Rapids

	Week of 10-24-67				Projected Annual Cost			
	Minimum Flow at Priest Rapids	Water Management	Energy Loss	Service Charge	Total Cost	Water Management	Energy Loss	Service Charge
Case 1:	46	0	0	0	0	0	0	0
	56	0	1,365 (31%)	3,020 (69%)	4,385	0	26,900	59,400
	66	3,181 (26%)	2,815 (23%)	6,220 (51%)	12,216	69,900	61,800	136,600
Case 2:	46	0	358 (31%)	792 (69%)	1,150	0	6,000	13,300
	56	0	1,611 (31%)	3,569 (69%)	5,175	0	31,700	70,200
	66	3,942 (22%)	3,364 (23%)	7,439 (50%)	14,745	86,600	73,900	163,400
								237,300
								19,300
								102,000
								324,000

Basis: Equal electrical rates at all three plants, 2.26 mills/12H-hr.

Case 1: When the Priest Rapids Reservoir is permitted to drop at a maximum rate of 0.5 ft/hr.

Case 2: When the Priest Rapids Reservoir is permitted to drop at a maximum rate of 0.25 ft/hr.

TABLE 2. Cost Associated with Raising Minimum Flow from 36 kft³/sec

Minimum Flow, kft ³ /sec	Wanapum Rapids	Priest Rapids	McNary	Total	Service Charge Transmission, one way (MW-hr)	Total Cost, \$	Project annual cost of raising minimum flow
46	275	0	83	356	792 (1,584)	1,150 (69% of cost is service charge)	19,300
56	749	653	209	1,611	3,564 (7,128)	5,175 (69% of cost is service charge)	102,000
66 (Priest Rapids Pool drop 0.25 ft/hr)	1,024	10,208	(+3,926)	7,306	7,439 (14,878)	14,745 (50% of cost is service charge)	324,000
66 (Priest Rapids Pool drop 0.5 ft/hr)	(+1,475)	11,430	(+3,959)	5,996	6,220 (12,456) (238.95 ft ³ /sec-hr was spilled at Priest Rapids)	12,216 (51% of cost is service charge)	268,000

Higher Electrical Rates at Grant (3.2 mills vs. 2.26 mills)						
46	(+808)	1,468	(+228)	432	1,224 (1,600)	1,656 (74% of cost is transmission cost)
56	284	1,633	29	1,946	5,510 (7,144)	7,456 (74% of cost is transmission cost)
66	(+1,122)	13,735	(+3,868)	8,745	11,651 (15,083) (245.63 ft ³ /sec-hr was spilled at Priest Rapids)	20,396 (57% of cost is transmission cost)

FIGURE 2. Basic Transmission System

The annual costs owing to the energy loss and service charge in Table 1 were converted into a mathematical equation for easy interpolation.

Case 1 - Priest Rapids reservoir rate of fall: 0.5 ft/hr

$$\text{Annual cost, \$1000} = 55 \left(\frac{\text{Flow Rate}}{46} \right)^4 - 34$$

(Energy loss and
service charge)

Case 2 - Priest Rapids reservoir rate of fall: 0.25 ft/hr

$$\text{Annual cost, \$1000} = 26 \left(\frac{\text{Flow Rate}}{36} \right)^4 - 50$$

(Energy loss and
service charge)

The costs are a function of the flow rate to be established to the fourth power. This shows the high correlation and the rate at which the cost raises. For example, in Case 2 the annual cost will double when the minimum flow rate is increased from 46 kft³/sec to 49 kft³/sec. At high flow rates the gap is wider, and a raise from 56 to 64 kft³/sec will double the cost.

When the minimum flow rate at Priest Rapids is above approximately 60 kft³/sec, water management is another factor that increases the cost. In this model, water management turned out to be spillage. Wasting power revenue that could have been generated but had to be spilled is obviously very expensive. The water had to be spilled to maintain the set minimum flow rate. With a flow rate of 60 kft³/sec at Priest Rapids, the minimum flow rate at Wanapum is calculated to be (see Constraint 4, page 20)

$$60 - (82.7)(0.25) = 39.375 \text{ kft}^3/\text{sec}.$$

This combined flow at Wanapum and Priest Rapids ($60 + 39 = 99 \text{ kft}^3/\text{sec}$) will produce 581 MW of power. On the assumption that this quantity of energy is above the demand (which it is for many of the time periods), the excess energy will be transmitted to Big Eddy (Figure 2). For example, the power demand at Grant Public Utility District No. 2 for the 147 time periods under investigation was only 284 MW.

This excess energy means that McNary can reduce its production by 95% of the transmitted energy (less energy transmission loss of 5%). However, because there is a minimum flow rate at McNary of $43 \text{ kft}^3/\text{sec}$ (equivalent to 268 MW), the combined minimum energy which the system wants to generate to maintain the established high flow rate at Priest Rapids is about 850 MW-hr. If the system can not handle this load, it will not generate it, and thus spillage will result. In the week under investigation, the minimum combined power demand for the three hydroelectric plants was 875 MW, therefore, any rise of the minimum flow rate at Priest Rapids above $62 \text{ kft}^3/\text{sec}$ with the rate of drop of the Priest Rapids pool being limited to 0.25 ft/hr would cause water to be spilled. If the minimum power demands can be expected to increase in the future, this expensive fact will be eliminated.

To emphasize the magnitude of the spillage costs, the total cost for Case 2 has again been estimated in Table 1, represented by a mathematical equation (the additional term is the cost associated with water spillage):

$$\text{Annual cost, \$1000} = 26 \left(\frac{X}{36} \right)^4 - 50 + 10.2(X-62)^{1.54}$$

where this equation applies at flow rates above $62 \text{ kft}^3/\text{sec}$.

The projected annual cost at $62 \text{ kft}^3/\text{sec}$ is \$179,000 whereas at $72 \text{ kft}^3/\text{sec}$ the annual cost for the energy loss

and service charge is \$366,000 and another \$354,000 for the water spillage, resulting in a total cost of \$720,000, which is a factor of four times what it was at 62 kft³/sec. However, if either the Priest Rapids pool was larger or it was allowed to oscillate at a higher rate than 0.5 ft/hr, much of the spillage above, say, 75 kft³/sec could be eliminated. However, based on the available water and costs presented in this report, the minimum flow rate at Priest Rapids should not be raised above 70 kft³/sec.

Table 2 shows an additional case to determine what effects the electrical rates at Grant Public Utility District, assumed to be 3.2 mill/kW-hr, would have on the associated cost of raising the minimum flow rate at Priest Rapids. This higher electrical rate would raise the cost in Case 1 by approximately 40%. Table 2 also shows that the costs originate from the service charge. Where the electrical rates are higher for the Grant County PUD No. 2 and where the Priest Rapids minimum flow rates are 46 and 56 kft³/sec, it can be seen that 75% of the cost is associated with the 0.25 mill/kW-hr service charge while the other 26% is associated with the energy loss. Obviously, if the 0.25 mill/kW-hr service charge was reduced by a new coordination agreement, the costs herein reported would be substantially lower.

The figures in Appendix C show the simulated hourly production and transmission at the three dams.

GENERAL FORMULATION OF PROBLEM

At one time the Hanford reach of the Columbia River (Figure 3) supplied the cooling water for nine nuclear reactors; however, even though there are only two still operating, KE and NPR, the thermal effects from these two reactors continue to require evaluation. This, along with the fact that this area has a relatively large potential for many nuclear power

plants and associated industry in the future, inspires investigation of the present coordination between the hydroelectric plants, particularly to determine if the presently authorized minimum flow rate criterion of $36 \text{ ft}^3/\text{sec}$ is a viable planning basis. Therefore, a simulation model of the three hydroelectric plants (Wanapum, Priest Rapids, and McNary) was developed for the Hanford reach on the Columbia River.

(Appendix D contains a detailed problem formulation.)

FIGURE 3. Schematic Diagram of Hanford Reach

The simulation model was solved by linear programming techniques (UMPIRE code) and (as will be shown later in Figure C-6 in Appendix C) produced excellent agreement with the actual energy production.

In general, the process of problem formulation is crucial since it greatly affects the relevancy of the study. It is difficult to extract the "right" answer from the "wrong" problem. Therefore, considering the preliminary status of this effort, this phase, formulating the problem, was executed with considerable care. The initial formulation was continuously re-examined in the light of new insights obtained during the late phases as trial runs were made.

An operations research study, such as this one, seeks solutions that are optimal for the overall organization, in this case the Wanapum-Priest Rapids, McNary complex, rather than suboptimal solutions that are best for only one component. Therefore, the objectives that were formulated were those that treated these three hydroelectric plants and the Hanford reach as one entire organization or system.

Mathematical Model

Models are idealized representations. Mathematical models are expressed in terms of mathematical symbols and expressions. This does not mean however, that they do not predict accurately the laws of nature. A couple of familiar expressions are: $F = Ma$, and $E = mc^2$. One obvious advantage of a mathematical model is that it describes a problem much more concisely, making the overall structure of the problem more comprehensible, helping to reveal important cause-and-effect relationships. Also, mathematical model forms a bridge to the use of high-powered mathematical techniques, such as, linear programming, and the electronic computers.

Because a model is necessarily an abstract idealization of the problem, and approximations and simplifying assumptions are required, care must always be taken to insure that the model remains a valid representation of the problem. Thus, the proper criterion for judging the validity of any mathematical model is whether or not it predicts the relative effects of the courses of action with sufficient accuracy to permit a sound decision. Figure C-6 in Appendix C shows that the model developed here does predict the operation of the hydroelectric dams and should yield excellent results for the systems operations at different criteria.

Mathematical Formulation

Objective Function

The crucial step in formulating the mathematical model is constructing the objective function. Since a weekly estimate of the hourly production of each hydroelectric plant is commonly made,⁽³⁾ it becomes clear that the logical objective function is to maximize the total power reserves in pondage at the conclusion of each week. However, because of energy imbalances, the total service charge as specified in the 1964 Coordination Agreement (0.25 mills/kW-hr) must be accounted in the objective function as a charge.

Constraints

What is the value of water?*

To a man dying of thirst, water is worth a great deal, but to a drowning man it has no value at all. The answer often depends on how much water is available, how much is needed, and what it is to be used for. The availability of a commodity is expressed mathematically by an inequality constraint.

* *When the well's dry, they know the worth of water.*
Benjamin Franklin, Poor Richard's Almanack (1758).

One week of operation for three hydroelectric plants plus the following twelve constraints creates a very large problem. There is a matrix with 2184 columns and 2691 rows, reaching the limit of the computer. However, the solution times shown in Appendix B range between 5 and 17 min, depending on the minimum flow rate at Priest Rapids. The constraints to the objective function are described below.

Constraint 1: Total Power Demand. Obviously the total power demand that the three plants originally generated for the week must be met on an hourly basis. Thus, for the 168 time periods,

Total simulated production at the three plants	-	Energy loss due to transmission = to meet demands	Total actual pro- duction at the three plants
--	---	---	---

Constraint 2: Partial Power Demand. Because they are only 18 miles apart and are both operated by the Grant Public Utility District No. 2, only the combined production of Wanapum and Priest Rapids was regulated. Their individual production was determined by what was optimum for the system. Thus, the power demand for Priest Rapids and Wanapum is expressed for the 168 hr periods by:

Simulated production at Wanapum and Priest Rapids	-	Production transmitted to Big Eddy
+ Production received from Big Eddy	=	Actual production demand at Wanapum and Priest Rapids

Constraint 3: Rate of Change of Priest Rapids Pool.
Grant County usually maintains the reservoir as full as they can, in addition to observing the net rate of change of its height. Physical limitations of equipment and safety reasons limited the net rate of change of the Priest Rapids Reservoir.

The net hourly rise or drop were both input parameter to obtain the computer solution. In one case the Priest Rapids Reservoir was allowed to drop by 0.25 ft/hr and rise by 0.5 ft/hr. Since the costs associated with this constraint are significant, the case where both the fall and rise could be 0.5 ft/hr was also performed. This constraint can be written as

$$\begin{array}{l} \text{Net hourly change} \\ \text{in the} \\ \text{Priest Rapids Reservoir} \end{array} - \text{Hourly rise} + \text{hourly drop} = 0$$

For all 168 time periods

Constraint 4: Minimum Flow Rates. The total outlet from Priest Rapids and McNary were required to be above an input minimum. The total flow is the sum of the water through the turbines (generating electricity) and water over the spillways. Obviously, with an objective to maximize the power revenue, no water should be spilled. Water was spilled only when the minimum flow rate at Priest Rapids was increased above 62 kft³/sec. The minimum flow rate at Priest Rapids was set at 36, 46, 56, and 66 kft³/sec. This was the parameter that was changed to evaluate the associated cost.

At McNary the minimum flow rate was set at 43 kft³/sec, a minimum flow rate established* below Bonneville by the Corps of Engineers. This flow rate was historically associated with river transportation. McNary's flow rate is usually above 80 kft³/sec, and the minimum flow of 43 kft³/sec only constrained when the minimum flow at Priest Rapids was above 56 kft³/sec. At this flow, the amount of energy to be transmitted to Big Eddy was increasing and this, of course, reduces the production level at McNary.

* *The relationship of this flow to the impounded river is arbitrary and is subject to further review.*

No minimum flow rate at Wanapum was needed because of the combination of Constraints 3 and 4. For example, if the minimum flow rate at Priest Rapids is $36 \text{ kft}^3/\text{sec}$ and the Priest Rapids Reservoir can not drop faster than 0.25 ft/hr , the minimum flow at Wanapum can be calculated

$$\text{Flow at Wanapum} = 36 \text{ kft}^3/\text{sec} - \left(82.7 \frac{\text{kft}^3/\text{sec}}{\text{ft}}\right) \left(0.25 \frac{\text{ft}}{\text{hr}}\right)$$

where $82.7 \text{ kft}^3/\text{sec}$ per ft of pool height is a conversion factor taking into account the size of the reservoir.

Constraints 5, 6, and 7: Water Balance on Reservoirs.

In the next three constraints, there is a water balance on each of the reservoirs.

$$\begin{aligned} &\text{Net hourly change} \\ &\text{in reservoir height} + \text{output} = \text{input} \end{aligned}$$

Constraint 5 is the water balance on the Wanapum reservoir. Here, the input to the Wanapum pool was back calculated from the actual data.

Constraint 6 is the water balance on the Priest Rapids pool. The input into the Priest Rapids pool is the output from the Wanapum Dam. The user has the option to put an hour time lag between Wanapum and the Priest Rapids Reservoir. Placing an hour time lag between these two dams causes the model to operate these two hydroelectric plants in an unstable manner.

Constraint 7 is the water balance on the McNary pool. Likewise, the input to the McNary pool from Priest Rapids has a time lag feature. Although 8 hr were used, the program gives the user the option to input any value he desires. Besides input from Priest Rapids, the McNary pool also receives water from two rivers, the Snake and the Yakima. It was necessary to take the actual flow rates from the Columbia River at different points and calculate an hourly combined

Snake and Yakima flow rate. This value had an average of 30 kft³/sec and appears very reasonable.

Constraint 8: Interchange Energy Imbalances. This constraint states that the interchange energy imbalances incurred during the week must be balanced out by the end of the week. In other words, a net receiver of energy during any time period within the week must return the full amount of this energy to the supplier before the end of the time period. Because there is an energy loss of approximately 5% in transmitting energy for every megawatt hour of energy that the receiver needed for his demand, the supplier had to generate 1.05 MW-hr. As will be seen later, this is one of the three originating sources of the cost of raising the minimum flow rate. (See Figure 1 on page 7.)

Constraint 9: Generating Capacity. Obviously, the maximum generating capacity of each site has a limit. The function of this constraint was to keep the production of the hydroelectric plants below their respective ratings. These computer input limits were 850, 830, and 980 MW at Wanapum, Priest Rapids, and McNary, respectively.

Constraint 10: Pool Heights. The height of each reservoir must be bounded on the low as well as the high side. This constraint will maintain the water level behind each dam within the appropriate range, which is again specified by the user. The following ranges were used for the height of their pools:

Wanapum	560-571.5 ft
Priest Rapids	484-488.5 ft
McNary	335-340.5 ft

The minimum height at Priest Rapids is 481.5 ft; however, as noted above, a little higher minimum - 484 ft - was used. This was done to maintain the Priest Rapids Reservoir at a higher level and reduce the oscillation from 7 ft. There

is, however, a cost associated with this policy. This is also in line with the normal operating policy of the plant.

Constraint 11: Rate of Rise. In accordance with Constraint 3, the maximum permissible rate or rise of the Priest Rapids Reservoir was set by an input parameter, 0.5 ft/hr in this case. Constraint 11 checked all time periods and prevented the rate of rise from being higher than 0.5 ft/hr.

Constraint 12: Rate of Fall. Again as in Constraint 3, the maximum permissible rate of fall of the Priest Rapids Reservoir was also set by the user as an input parameter. Two cases were done, one with the maximum fall of 0.25 ft/hr and another at 0.5 ft/hr.

ACKNOWLEDGMENT

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APPENDIX A

PROGRAM COMPUTATIONS AND FORMULATIONS

APPENDIX A

PROGRAM COMPUTATIONS AND FORMULATIONSLINEAR PROGRAMMING

Linear Programming (LP) deals with the problem of allocating limited resources in an optimal manner. The problem of allocation in this case involves water: at what power level should each hydroelectric plant be operating to meet the total demand with the minimum amount of water. In this application, LP was used to coordinate hydroelectric plants and maximize the resources of the Columbia River.

Linear programming uses a linear mathematical model to describe the problem. "Linear" means that all the mathematical functions in this model are required to be linear functions (to the first degree). "Programming" is essentially a synonym for planning. Thus, LP involves the planning of activities in order to obtain an "optimal" result, that is, a result which reaches the specified goal best (according to the mathematical model) among all feasible alternatives.

LINEAR PROGRAMMING MODEL

The mathematical statement of a general form of the LP problem is the following. Find x_1, x_2, x_n which maximizes the linear function.

$$Z = c_1 x_1 + c_2 x_2 + \dots + c_n x_n$$

subject to the restrictions, often called the constraints,

$$a_{11}x_1 + a_{12}x_2 + \dots + a_{1n}x_n \leq b_1$$

$$a_{21}x_1 + a_{22}x_2 + \dots + a_{2n}x_n \leq b_2$$

$$a_{m1}x_1 + a_{m2}x_2 + \dots + a_{mn}x_n \leq b_m$$

and

$$x_1 \geq 0, x_2 \geq 0, x_n \geq 0$$

where the a_{ij} , b_i , and c_j are given constants. The function

being maximized is called the objective function. In the above formulation for example, if each activity is the production of a certain product, then x_j would be the number of units of the j th product to be produced during a given period of time. Z is the chosen overall measure of effectiveness, for example, profit over the given time period. c_j is the increase in the overall measure of effectiveness that would result from each unit increase in x_j . The number of relevant scarce resources is m , so that each of the first m linear inequalities correspond to a restriction on the availability of one of these resources. b_i is the amount of resource i available to the n activities. a_{ij} is the amount of resource consumed by each unit of activity j . Therefore, the left side of these inequalities is the total usage of the respective resources. The nonnegative restrictions ($x_j \geq 0$) rule out the possibility of negative activity levels.

LINEAR PROGRAMMING PROBLEM

A consideration of two hydroelectric plants furnishes a typical example of an LP problem. The first plant can sell its electricity for 3 mills/kW-hr but has a maximum capacity of 4 MW. Likewise, the second plant can sell its electricity for 5 mills/kW-hr and has a maximum capacity of 6 MW. Also, because of interties and available water, there is an additional constraint. This problem can be formulated as:

$$Z = 3x_1 + 5x_2 \text{ (in dollars)}$$

subject to the constraints,

- 1) $x \leq 4$
- 2) $x_2 \leq 6$
- 3) $x_1 \geq 0$
- 4) $x_2 \geq 0$
- 5) $3x_1 + 2x_2 \leq 18$ (intertie constraint)

For this very simple case, where there are only two variables and therefore only two "dimensions" involved, a simple graphical method can be used. This method will also help illustrate the mathematical solution, the simplex methods. (For the mathematical solution, see Reference 1, pages 139-148.)

The first step is to depict graphically the values of (x_1, x_2) , which are permitted by the restrictions. This is done by drawing the lines which must border the region of permissible values. To begin with, note that the constraint, $x_1 < 4$, means that (x_1) cannot lie to the right of the line $x_1 = 4$ (Figure A.1). Adding the line $x_2 = 6$, $3x_1 + 2x_2 = 18$, $x_1 = 0$, and $x_2 = 0$, the feasible region of permissible values of (x_1, x_2) is obtained (shaded area of Figure A.1).

FIGURE A-1. Permissible Values of (x_1, x_2)

The second and final step is to pick out the point in the region which maximizes the value of Z . But there is an infinite number of points within this feasible region, and, it would be desirable to be able to reduce the size of this search. Without much detail (see Reference 2, page 25), it was proven that the objective function will assume its maximum (or minimum) at an extreme point, in this case only five points (A,B,C,D,E).

Also, since it is logical that the optimal solution will have the coordinates the greatest distance from the origin, points D, C, and E need to be considered. And as shown in Figure 1, the objective function is maximum at point E, where the first plant is operating at 2 MW and the second plant at 6 MW.

This sample problem is very small and compares with the coordination of the Columbia River plants which produced a matrix of 2691 rows (the number of dimensions) by 2184 columns.

LIMITATIONS OF LINEAR PROGRAMMING

The underlying assumptions that limit the applicability of LP are given below.

Proportionality

A primary requirement of LP is that the objective function and every constraint function must be linear. This requires, in turn, that the measure of effectiveness and resource usage must be proportional to the level of each activity conducted individually.

Addition

The measure of effectiveness and each resource usage being directly proportional to the level of each activity conducted individually is not sufficient to guarantee linearity. A special form of nonlinearity will arise if there are joint

interactions between some of the activities regarding the total measure of effectiveness or the total usage of some resource. Therefore, it is required that the activities be "additive" with respect to the measure of effectiveness and each resource usage. In other words, the total measure of effectiveness and each total resource usage resulting from the joint performance of the activities must equal the respective sums of these quantities resulting from each activity being conducted individually.

Determinism

All of the coefficients in the LP model (a_{ij} , b_i , and c_j) are assumed to be known constants. In reality, they are frequently neither known nor constants. LP models are usually formulated in order to select some future course of action. Therefore, the coefficients used would be related to the prediction of future conditions. The assumption of continuity of the value of coefficients constitutes one of the weak links in the use of mathematical analysis to predict events for out of the range of acceptable extrapolations. To test validity of coefficients, a parametric study (an extension of sensitivity analysis) is usually done. For example, in the LP model the dollar value associated with restricting the Priest Rapids Reservoir from having a maximum allowable drop rate was determined, as well as the effect of the Grant Public Utility District receiving a higher electrical rate. But more important than these is the cost associated with raising the minimum flow rate at Priest Rapids to certain levels; this is a parametric study.

One point to remember is that a practical problem which completely satisfies all the assumptions of LP is very rare indeed. However, the LP model is often the most accurate representation available, which will yield a reasonable recommendation for action before implementation is required.

APPENDIX B
RIVER MODEL NOMENCLATURE

APPENDIX B

RIVER MODEL NOMENCLATURESUFFICES

D	Dams	DMAX	3
	1. Wanapum		
	2. Priest Rapids		
	3. McNary		
I	Time Period	IMAX	200
	1 wk - 168 hr		

VARIABLES

H(D,I)	= reservoir head, ft
S(D,I)	= reservoir outflow over spillways, kft^3/sec
T(D,I)	= reservoir outflow through turbines, kft^3/sec
B(I)	= electrical transmission from Grant Co. PUD to McNary from Midway to Big Eddy, MW-hr
C(I)	= electrical transmission from McNary (Big Eddy) to Grant Co. PUD (Midway), MW-hr
D(I)	= hourly rise in the Priest Rapids Reservoir, ft
E(I)	= hourly drop in the Priest Rapids Reservoir, ft

Define

TS(D,I)	= T(D,I) + S(D,I)
---------	-------------------

EXTERNAL VALUES

CONV(D)	= power to flow ratio, $\text{MW-hr}/\text{kft}^3/\text{sec-hr}$
TLOSS	= fraction of energy lost in transmission
PW(I)	= energy demand at Wanapum, MW-hr
PP(I)	= energy demand at Priest Rapids, MW-hr
PM(I)	= energy demand at McNary, MW-hr
VPH(D)	= reservoir capacity-to-area factor, $\text{kft}^3/\text{sec-hr}/\text{ft}$
HO(D)	= initial reservoir head, ft

FLOWIN(I) = flow into Wanapum Reservoir during period of
 investigation, $\text{kft}^3/\text{sec-hr}$
 POWMAX(D) = maximum permissible power level, MW
 HMAX(D) = maximum permissible reservoir level, ft
 FLMIN(D) = max flow rate released at dam, D, kft^3/sec
 HEAD(I) = head at McNary, ft
 FLOM(I) = actual flow rate out of McNary, ft^3/sec
 NETH = Priest Rapids Reservoir, maximum hourly head
 rise, ft/hr
 HV = Priest Rapids Reservoir, maximum hourly head
 drop, ft/hr
 FPP(I) = Actual flow rate out of Priest Rapids Reservoir,
 advanced (I + LAG), kft^3/sec
 LAG = water lag time between Priest Rapids and
 McNary, hr
 LAGP = water lag time between Wanapum and Priest
 Rapids, hr
 FLOWINW = initial flow out of Wanapum, kft^3/sec
 C13 = thousand dollars per foot of the Wanapum Pool
 C14 = thousand dollars per foot of the Priest Rapids
 Pool
 C16 = thousand dollars per foot of the McNary Pool
 C20 = transmission service charge, 1000\$/MW-hr

APPENDIX C

SIMULATED HOURLY PRODUCTION
AND TRANSMISSION AT WANAPUM,
PRIEST RAPIDS, AND MCNARY

FIGURE C-1. Actual Hourly Flow Rate at Wanapum Dam

FIGURE C-2. Actual Hourly Flow Rate at Priest Rapids Dam

FIGURE C-3. Actual Hourly Flow Rate at McNary Dam

FIGURE C-4. Actual and Simulated Hourly Flow Rate at Priest Rapids Dam

FIGURE C-5. Simulated Hourly Flow Rate at Wanapum Dam with Minimum Flow Rate Criterion of 36 kft³/sec at Priest Rapids Dam

FIGURE C-6. Simulated Hourly Flow Rate at Priest Rapids Dam with Minimum Flow Rate Criterion of 36 kft³/sec

FIGURE C-7. Simulated Hourly Flow Rate at McNary Dam with Minimum Flow Rate Criterion of 36 kft³/sec at Priest Rapids Dam

FIGURE C-8. Simulated Hourly Flow Rate at Wanapum Dam with Minimum Flow Rate Criterion of 46 kft³/sec at Priest Rapids Dam

FIGURE C-9. Simulated Hourly Flow Rate at Priest Rapids Dam
with Minimum Flow Rate of 46 kft³/sec

FIGURE C-10. Simulated Hourly Flow Rate at McNary Dam with Minimum Flow Rate Criterion of 46 kft^3/sec at Priest Rapids Dam

FIGURE C-11. Simulated Hourly Flow Rate at Wanapum Dam with Minimum Flow Rate Criterion of 56 kft³/sec at Priest Rapids Dam

FIGURE C-12. Simulated Hourly Flow Rate at Priest Rapids Dam with Minimum Flow Rate Criterion of 56 kft³/sec

FIGURE C-13. Simulated Hourly Flow Rate at McNary Dam with Minimum Flow Rate Criterion of 56 kft^3/sec at Priest Rapids Dam

FIGURE C-14. Simulated Hourly Flow Rate at Wanapum Dam With Minimum Flow Rate Criterion of 66 kft³/sec at Priest Rapids Dam

FIGURE C-15. Simulated Hourly Flow Rate at Priest Rapids Dam with Minimum Flow Rate Critierion of 66 kft³/sec

FIGURE C-16. Simulated Hourly Flow Rate at McNary Dam with Minimum Flow Rate Criterion of 66 kft³/sec at Priest Rapids Dam

FIGURE C-17. Summary of Energy Transfer, 46 kft³/sec

FIGURE C-18. Summary of Energy Transfer, 56 kft³/sec

FIGURE C-19. Summary of Energy Transfer, 66 kft³/sec

FIGURE C-20. River Surface Elevation at Various Flows

FIGURE C-21. River Temperatures at Richland

APPENDIX D
DETAILS OF PROBLEM FORMULATION

APPENDIX D

DETAILS OF PROBLEM FORMULATIONOBJECTIVE FUNCTION

It was decided that the objective of this effective coordination between the three dams should be to maximize the power revenue in storage at the end of the time period after meeting the required power demands. Thus, the objective function consists of the power reserve of each dam,

$$\text{Power Reserve} = C13 * (H1, \text{IMAX}) + C14 * (H2, \text{IMAX}) \\ + C16 * (H3, \text{IMAX})$$

where C13, C14, C16 are associated dollars per foot of water in the respective pool.

However, additional terms must also be included, namely, the service charge associated within energy imbalances, and water in the system unaccounted for because of the lag time between dams, which were input variables, must be taken and adjusted to the height of the respective pools.

For instance, if there is a 1 hr time lag from the Wanapum to the Priest Rapids Pool or even an 8 hr time lag (assumed between Priest Rapids and the McNary Pools), the discharges during these periods must be treated as if they are already in their subsequent pool. That is,

$$\text{Final head at McNary} = H(3,168) + \frac{1}{\text{VPH}(3)} \sum_{I=161}^{168} \text{TS}(2,I)$$

when an 8 hr lag between Priest Rapids and McNary exists.

Where the value VPH(D) converts units of $\text{kft}^3/\text{sec-hr}$ into the pool height, ft.

According to the Pacific Northwest Coordination Agreement [September 1964, Section 14.(a)(2)] for Interchange Energy

Imbalances, a service charge of \$0.25 per MW-hr is charged. Thus, the total system revenue is reduced one dollar for every 4 MW-hr of electricity transmitted to a site so they can meet their commitments. This is mathematically expressed as,

$$\text{Service charge} = 0.25 \sum_{I=1}^{\text{IMAX}} B(I) + 0.25 \sum_{I=1}^{\text{IMAX}} C(I)$$

where $B(I)$ is the transmission from Midway to Big Eddy and $C(I)$ is from Big Eddy to Midway.

Since the energy imbalances, $B(I)$ and $C(I)$, are to be balanced at the end of the time period,

$$\sum_{I=1}^{\text{IMAX}} B(I) = \sum_{I=1}^{\text{IMAX}} C(I)$$

the

$$\text{service charge} = 0.50 \sum_{I=1}^{\text{IMAX}} B(I)$$

the objective function, the total power revenue, can be expressed as

$$\text{Total power revenue} = \text{power reserves} - \text{service charges} \\ \text{(pool height} \\ \text{adjusted for} \\ \text{lag time water)}$$

CONSTRAINTS

The constraints on the objective function are as follows
(ALL constraints cost something):

I. Total System Power Demand

Total generation at three dams - line loss for any transmission = total system power demand

$$\sum_{D=1}^3 \text{CONV}(D) * T(D,I) - \text{TLOSS} [B(I) + C(I)] = \text{PW}(I) + \text{PP}(I) + \text{PM}(I)$$

For all I.

II. Power Demand at Priest Rapids and Wanapum

Generation - transmission + receive via transmission = demand

$$\sum_{D=1}^2 \text{CONV}(D) * T(D,I) - B(I) + (1.0 - \text{TLOSS}) * C(I) = \text{PW}(I) + \text{PP}(I)$$

For all I.

III. Maximum Permissible Hourly Variation in Priest Rapids Pool

Net hourly change - hourly rise + hourly drop = 0

$$H(2,I) - H(2,I-1) - D(I) + E(I) = 0$$

For all I.

IV. Minimum Reservoir Outlet Flow Rate

Hourly water release $\geq$ minimum set

$$S(D,I) + T(D,I) \geq \text{FLMIN}(D)$$

For D = 1, I = IMAX

D = 2, 3,

For all I.

A combination of a minimum flow at Priest Rapids and a maximum hourly variation of the Priest Rapids Pool, Constraint III, places a minimum flow criterion on the Wanapum Dam, for all time periods except the last.

V. Water Balance on the Wanapum Pool

Accumulation + output = input

$$H(1,I) - H(1,I-1) + \text{TS}(1,I)/\text{VPH}(1) = \text{FLOWIN}(I)/\text{VPH}(1)$$

The input into the pool was back calculated from the actual data. This was believed to be the best approach since the volume-capacity curve for the pools, the VPH(D) values, has to be constant in any linear programming problem.

For all I.

VI. Water Balance on the Priest Rapids Pool

Accumulation + output - input = 0

$$H(2,I) - H(2,I-1) + TS(2,I)/VPH(2) - TS(1,I-LAGP)/VPH(2) = 0$$

For all I.

Where LAGP is the lag time between Wanapum and Priest Rapids, usually zero or one.

VII. Water Balance on the McNary Pool

Accumulation + output - input from Priest Rapids
= input from the Snake and Yakima Rivers

$$H(3,I) - H(3,I-1) + TS(3,I)/VPH(3) - TS(2,I-LAG) = C15(I)$$

For all I.

Where C15 is the amount of water entering the McNary Pool from the Snake and Yakima Rivers. Again this value was back calculated from,

$$C15(I) = HEAD(I) - HEAD(I-1) - FPP(I)/VPH(3) + FLOM(I)/VPH(3)$$

VIII. Interchange Energy Imbalances

$$\sum_{I=1}^{IMAX} B(I) = \sum_{I=1}^{IMAX} C(I)$$

This statement says that if any energy is transmitted at any time during the time period, that the receiver of this energy must return the full amount of this energy before the end of the time period, in this case 1 week.

The remaining constraints are called Single Upper Bounds and do not significantly increase the solution time of the problem.

IX. Maximum Power Generation

Obviously, the amount of energy each dam can generate is limited, usually its capacity.

$$\text{CONV}(D) * T(D, I) \leq \text{POWMAX}(D)$$

For all D, I.

X. Maximum and Minimum Reservoir Elevation

$$H(D, I) \leq \text{HMAX}(D)$$

For all D, I.

By subtracting out a base, a minimum pool height is also maintained. For example, if the desired range of the Wanapum Pool is 560 to 571.5 ft, by subtracting out 560 ft the range becomes 0 to 11.5 ft. By setting HMAX(1) to 11.5 and because variables are always positive, the effective range is maintained between 560 to 571.5 ft of elevation.

XI. Priest Rapids Reservoir Maximum Permissible Hourly Rise

$$D(I) \leq \text{NETH}$$

where NETH was taken as 0.5 ft/hr.

XII. Priest Rapids Reservoir Maximum Permissible Hourly Drop

$$E(I) \leq \text{HV}$$

where HV was taken as 0.25 ft/hr except for one case when the minimum flow at Priest Rapids was 66 kft³/sec when it was set at 0.5 ft/hr.

LIMITS: UPPER BOUNDSMAXIMUM POWER

	<u>Rating</u>	<u>Actual for week</u>	<u>90% Rating</u>	<u>Nameplate Rating</u>
Wanapum	983	799	885	790
Priest Rapids	912	815	821	830
McNary	1127	803	1014	980

For the LP Model we will pick the following values for the maximum power capabilities:

Wanapum	850
Priest Rapids	830
McNary	980

Maximum and Minimum Pool Heads

	<u>Rating</u>	<u>Actual for week</u>	<u>Range from Previous Runs</u>
Wanapum	560 - 571.5	564.9 - 570.9	567 - 571.5
Priest Rapids	481.5 - 488.0	484.0 - 488.3	481.5 - 488.5
McNary	355 - 340.5	336.7 - 339.5	336.8 - 340

For LP Model.

	<u>Range</u>	<u>Max. Head</u>	<u>Base</u>
Wanapum	560 - 571.5	11.5	560
Priest Rapids	484 - 488.5	4.5	484
McNary	335 - 340.5	5.5	335

Minimum Flow Rate, FLMIN(D)

	<u>kft³/sec</u>
Wanapum	13
Priest Rapids	36, 46, 56, 66
McNary	43

Maximum Reservoir Elevation Change at Priest Rapids

down	-0.25 ft
up	+0.50 ft

APPENDIX E

PROBLEM SIZE AND SOLUTION TIME

APPENDIX EPROBLEM SIZE AND SOLUTION TIME

For the three dams, and a week time period to optimize over, there were

2184 columns
1347 rows
6049 elements
1344 simple upper bounds

Thus the matrix was (2691×2184) , which is about the limit of UMPIRE, the linear programming used.

The solution time at the various minimum flow rates are shown below:

<u>Minimum Flow Rate at Priest Rapids, kft³/sec</u>	<u>UMPIRE Solution Time, min</u>
36	5.3
46	6.2
56	10.2
66	16.7

APPENDIX F
CALCULATION OF COEFFICIENTS

APPENDIX F

CALCULATION OF COEFFICIENTSTRANSMISSION COSTS

The cost associated with transmitting energy between plants can be divided into the following four items:

- 1) Water location
- 2) Energy loss
- 3) Difference associated with the different electrical rates
- 4) Service charge and incremental cost.

Water Location

Since it is the objective to maximize the total power revenue, if by transmitting energy, and by the return of this energy, the final power revenue is less if transmission took place for that time period. Obviously, the objective function will minimize the amount of energy transmitted in minimizing the power revenue.

Energy Loss

Energy losses (sometimes referred to as line losses) for the BPA customers have averaged about 5%* between 1963 and 1968; therefore, this value, 5%, was used in this program. The energy losses and costs are accounted for in Constraints I and II, the power demand constraints. For example, assuming that McNary needs another 100 MW, Grant PUD would have to generate and send 105 MW. The 5 MW are lost to the system and represent the cost associated with transmission, the value of 5 MW of power.

* *Study of Energy Losses on BPA System, BPA, Draft December 12, 1968. Unpublished.*

Electrical Difference and Service Charge

- 1) If Grant PUD transmits because BPA needs power,
 - a) Grant gets \$3.2 power revenue
 - b) BPA gets 0.95 MW-hr at 2.26 - service charge -3.2
- 2) If McNary transmits because Grant needs power,
 - a) McNary gets \$2.26
 - b) Grant gets [(0.95) 3.2 - service charge -2.26]

Net effect:

$$\begin{array}{rcl}
 \text{Grant:} & 3.2 + (0.95) 3.2 - 0.25 - 2.26 & = 3.73 \\
 \text{BPA:} & (0.95)(2.26) - 0.25 - 3.2 + 2.26 & = \underline{0.957} \\
 & & 4.687
 \end{array}$$

If no transmission but all generated at each plant,
total revenue

$$3.2 + 2.26 = 5.46$$

Net loss = 0.773 \$/MW-hr transmitted (two ways)

Summary (Assumed incremental cost was zero)

- 1) Assume equal electrical rate (2.26 mill/kW-hr)
Net Cost = Service charge both ways = \$0.50/MW-hr
- 2) If Grant power is valued at 3.2 mills
Net Cost = \$0.773/MW-hr

CALCULATION OF RESERVOIR CAPACITY-TO-AREA VALUE: VPH

VOL(D) = volume-area relationship

$$\begin{aligned}
 \text{VOL(1)} &= 81.2 \text{ KSF-D}/11.5 \text{ ft draft} \\
 &= 7.0609 \text{ kft}^3/\text{sec-day/ft} \\
 &= 169.46 \text{ kft}^3/\text{sec-hr/ft}
 \end{aligned}$$

$$\begin{aligned}
 \text{VOL(2)} &= 22.4/6.5 \text{ ft draft} \\
 &= 3.446 \text{ kft}^3/\text{sec-day/ft} \quad 3.529 \text{ (top ft)} \\
 &= 82.7 \text{ kft}^3/\text{sec-hr/ft} \quad 84.696 \text{ (top ft)}
 \end{aligned}$$

$$\begin{aligned}
 \text{VOL}(3) &= 93.3/5 \text{ ft draft} \\
 &= 18.66 \text{ kft}^3/\text{sec-day/ft} \quad 19.2 \text{ (top ft)} \\
 &= 447.84 \text{ kft}^3/\text{sec-hr/ft} \quad 460.8 \text{ (top ft)}
 \end{aligned}$$

CALCULATION OF RESERVOIR VALUE PER FOOT OF POOL HEIGHT

Case I:

Grant power worth 3.2 \$/MW-hr
 BPA power worth 2.26 \$/MW-hr

One acre-ft:

$$\begin{aligned}
 &\equiv 43,560 \text{ ft}^3 \equiv \frac{43,560 \text{ ft}^3}{3,600 \text{ sec/hr}} = 12.1 \frac{\text{ft}^3/\text{sec-hr}}{\text{acre-ft}} \\
 &\qquad\qquad\qquad \equiv 1.98347 \frac{\text{acre-ft}}{\text{ft}^3/\text{sec-day}}
 \end{aligned}$$

<u>Dam</u>	<u>CONV(D)</u>
Wanapum	$5.785 * 0.012.1 \text{ kft}^3/\text{sec-hr} * 3.2 \text{ $/MW-hr} = 0.2240$
Priest Rapids	$5.892 * 0.012.1 \text{ kft}^3/\text{sec-hr} * 3.2 \text{ $/MW-hr} = 0.2281$
McNary	$6.243 * 0.012.1 \text{ kft}^3/\text{sec-hr} * 2.26 \text{ $/MW-hr} = 0.1707$

or for Wanapum and Priest Rapids

$$\begin{aligned}
 &\text{\$/acre-ft} = 0.03872 * \text{CONV(D)} \\
 \text{McNary} \quad &\text{\$/acre-ft} = 0.027346 * \text{CONV(3)}
 \end{aligned}$$

Water Value

$$\begin{aligned}
 &\text{At McNary, } \text{\$/acre-ft} = 0.027346 * \text{CONV(3)} = 0.1707 \\
 &\text{at Priest Rapids, } \text{\$/acre-ft} = 0.027346 * \text{CONV(3)} + \\
 &\qquad\qquad\qquad 0.03872 * \text{CONV(2)} \\
 &\qquad\qquad\qquad = 0.1707 \quad 0.2281 = 0.3988 \\
 &\text{at Wanapum, } \text{\$/acre-ft} = 0.027346 * \text{CONV(3)} + \\
 &\qquad\qquad\qquad 0.03872 * [\text{CONV(1)} + \text{CONV(2)}] \\
 &\qquad\qquad\qquad 0.3988 + 2240 \quad 0.6228 \\
 &\text{worth (d) } \text{\$/acre-ft} = 0.0121 * \text{CONV(D)} * \text{RATE(D)}
 \end{aligned}$$

APPENDIX G
COMPUTER OUTPUT
OF THE INPUT DATA

OMAX EQUALS 3 IMAX EQUALS 168

TIME LAG BETWEEN PRIEST AND MCNARY IS 8

TIME LAG BETWEEN WANAPUM AND PRIEST IS 0 HOURS

VALUE 1 TO 5 6.8638900 2.2685500 6.3178699 .2500000 .0005000

TITLE ONE WEEK RIVER MODEL MAX HEAD

START
=====

CONV POWER TO FLOW RATIO

=====

CONV	1	5.785	5.892	6.243
=====				

TLOSS POWER LOSSED IN TRANSMISSION

=====

TLOSS	1	.050
=====		

PW POWER DEMAND AT WANAPUM

=====

PW	1	307.	269.	252.	233.	257.	321.	476.	693.	799.	772.	733.	671.	607.
=====														

H0 1 9.6 4.2 1.8

=====

FLOWIN FLOW INTO WANAPUM

=====	1	86.3	80.3	77.1	39.1	60.0	53.1	44.9	67.0	70.5	82.5	75.3	81.1	69.4
=====		55.3	93.5	70.3	69.3	85.3	97.7	96.7	78.9	82.1	78.8	76.2	77.0	72.9
=====		30.6	51.6	71.3	36.8	66.9	91.0	77.5	57.0	65.1	79.7	85.3	65.6	59.7
=====		58.1	86.0	64.9	77.5	103.8	87.5	67.4	88.4	89.4	68.4	83.0	26.1	45.2
=====		63.0	18.5	69.4	56.5	81.4	53.0	94.2	88.8	75.8	72.4	66.9	72.6	65.8
=====		80.0	89.1	101.4	80.9	85.1	68.8	94.8	82.5	42.7	72.8	34.0	37.3	59.6
=====		70.0	45.5	79.1	79.0	76.0	70.1	66.7	99.6	89.0	75.8	90.2	82.9	88.3
=====		78.8	59.9	76.0	84.0	81.8	65.9	44.3	34.9	31.6	53.7	42.2	36.6	31.0
=====		59.2	51.8	94.0	95.2	72.3	72.7	97.9	76.8	62.1	74.2	71.1	85.3	76.2
=====		67.7	71.8	65.8	58.7	67.5	35.4	18.8	69.1	34.0	27.2	68.0	52.5	63.1
=====		94.7	68.6	93.0	75.6	62.9	27.2	66.4	104.6	65.9	67.2	62.9	87.3	75.3
=====		15.5	51.2	71.2	30.2	19.4	58.4	23.5	30.5	65.0	75.6	90.5	70.5	80.6
=====		75.2	69.6	84.2	69.7	53.6	71.4	106.6	89.2	56.8	71.1	40.7	48.6	

=====

POWMAX MAX POWER AT DAMS

=====	1	850.	830.	980.
-------	---	------	------	------

=====

POWMAX

=====

HMAX MAX HEAD

=====	1	11.5	4.5	5.5
-------	---	------	-----	-----

=====

HMAX

=====

FLMIN MINIMUM FLOW OUT OF DAMS

=====	1	13.	66.	43.
-------	---	-----	-----	-----

=====

FLMIN

=====

FLOWIN TOTAL FLOW OUT OF WANAPUM AT (I-1)

=====	1	56.1
-------	---	------

=====

FLOWIN

=====

[illegible]

1	98.8	95.1	99.3	98.4	98.4	95.9	96.5	97.4	95.9	94.9	96.5	96.5	97.4
	97.4	95.7	98.2	97.4	96.5	97.9	98.6	96.0	99.2	96.7	95.8	96.5	97.4
	97.0	95.5	97.2	95.5	97.2	95.3	95.3	95.3	95.3	96.0	95.1	96.1	98.6
	98.7	98.8	97.6	95.3	96.1	97.4	95.9	95.0	95.9	95.6	95.6	97.1	97.7
	95.4	96.2	97.7	95.2	96.0	94.1	97.3	95.2	99.2	99.2	105.1	105.1	102.7
	107.0	113.2	109.7	114.7	113.4	102.7	99.0	97.2	99.0	98.2	99.5	98.2	100.2
	102.6	106.4	118.2	124.4	132.6	130.8	122.6	104.2	98.5	100.9	97.4	97.4	104.6
	96.5	96.2	99.6	99.9	98.7	100.5	107.2	107.5	109.7	107.2	108.7	107.2	115.8
	131.3	109.2	103.7	101.9	96.9	96.3	99.3	98.1	96.5	95.6	97.4	97.4	96.5
	97.4	98.5	97.6	98.7	96.2	97.7	94.8	95.0	96.5	95.0	96.5	96.5	96.5
	96.5	96.7	99.0	97.0	97.0	97.0	96.1	97.6	96.4	96.4	97.0	95.8	95.8
	101.0	100.2	97.7	97.1	96.3	96.3	96.1	98.2	97.1	97.9	97.4	97.4	97.4
	98.0	97.4	98.2	98.0	96.8	98.4	98.4	95.9	97.4	96.5	96.5	96.5	96.5

NETH 1 .50

FPP TOTAL FLOW OUT OF PRIEST, ADVANCED I+8

=====
FPP

1	65.5	61.8	84.4	99.3	98.2	90.2	67.5	49.3	48.7	42.7	40.0	37.3	40.0
	48.9	78.0	124.2	144.4	139.8	134.0	124.6	113.8	108.4	96.6	87.5	85.5	101.7
	117.1	116.4	96.9	80.6	59.8	40.0	39.5	37.5	36.8	37.1	37.3	37.8	62.9
	100.0	115.3	117.1	106.4	99.1	96.4	95.5	86.9	83.0	75.1	85.3	111.1	121.7
	106.9	85.1	71.3	51.8	48.0	45.3	41.8	39.8	41.5	56.5	96.4	118.9	127.8
	128.0	126.4	127.1	107.3	85.5	70.4	74.2	76.6	91.1	117.1	118.9	100.0	74.6
	56.0	46.7	38.4	37.5	37.8	37.8	38.0	40.7	73.3	111.5	115.8	122.4	121.5
	114.9	112.2	111.2	107.8	98.6	93.1	96.9	97.3	87.3	66.4	46.9	39.5	39.1
	39.1	39.1	39.3	38.4	38.0	38.0	38.2	38.2	42.9	48.2	57.5	58.2	53.1
	52.2	43.1	39.3	37.3	48.4	61.1	60.6	51.1	40.7	37.8	37.8	38.2	38.4
	38.7	38.9	37.3	37.1	37.3	38.9	38.4	42.7	38.4	38.0	38.7	38.0	38.2
	38.4	39.0	37.8	41.0	53.8	49.5	41.1	37.8	37.8	37.8	38.0	36.7	36.2
	38.2	38.2	39.8	68.4	86.9	86.2	81.8	76.4	71.3	69.8	65.5	73.1	

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