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Hydrologic Engineering Center

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Potential for Increasing the Output of Existing Hydroelectric Plants

July 1981

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This is Volume IX of the Preliminary Inventory of Hydropower Resources, which is a component of the Corps' National Hydroelectric Power Study. The purpose of this report was to address the question of how much additional power might be generated at existing hydroelectric plants throughout the United States. The potential for increasing power output both through physical improvements in generating equipment and by changes in the manner that existing projects are operated were investigated and estimates of power increase prepared. All existing hydroelectric plants, regardless of ownership, were investigated for improvement in power output.

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POTENTIAL FOR INCREASING THE OUTPUT OF EXISTING HYDROELECTRIC PLANTS *

EXECUTIVE SUMMARY

INTRODUCTION

The investigation reported herein (Hydrologic Engineering Center 1981) was undertaken to address the question of how much additional power might be generated at existing hydroelectric plants throughout the United States. The investigation was one of several special studies performed as part of the Corps of Engineers National Hydroelectric Power Study (NHS) (Institute for Water Resources 1979). The potential for increasing power output both through physical improvements in generating equipment and by changes in the manner that existing projects are operated were investigated and estimates of power increase prepared. The investigation was nationwide in scope, including Hawaii, Alaska, and Puerto Rico. All existing hydroelectric plants, regardless of ownership, were investigated for improvement in power output. The potential is identified by the type of improvement and is reported as aggregate regional values and national summaries.

The amount of power that can be generated at an existing hydroelectric power site is physically limited. The governing factors that determine this limit are: (1) the amount of flow volume that can pass through the powerhouse at a given time, (2) the "head" or elevation difference between the upstream and downstream water bodies acting at the time of power generation, and (3) the generation or "conversion" efficiency, i.e., the mechanical and electrical equipment efficiency in converting potential and kinetic energy of flowing water into electrical energy.

In order for there to be additional potential at an existing project, e.g., some "unused energy," an opportunity must exist for: (1) passing more of the annual volume through the powerhouse (there must be existing spill), (2) increasing the effective operating head (higher pool levels possible), or (3) technical opportunity to generate more efficiently from available head and flow. The option of increasing the storage capacity (raising the dam) was not considered in this study.

Short of this, all other measures that might be undertaken at a site that could effect the opportunities listed above and thereby increase energy output were considered. The primary measures for increasing energy output are: adding new generating units, rehabilitating or replacing existing units, modifying water handling facilities and, altering existing operating policies (reallocation of existing storage and/or change of annual and seasonal operation rule curves).

*Volume IX - National Hydroelectric Power Study

Excess flow or spill is by far the most important opportunity for increasing power output at an existing project. The measures available for capturing and routing additional flow volume through the powerhouse include: increasing the plant's generating capacity by adding additional generating units (expanding the powerhouse) or uprating existing units to higher generating capacity by rehabilitating, modifying or replacing turbines and/or generators; increasing the effective utilization of storage by reallocating additional storage to the power pool; and/or coordinating generation among a system of generating plants. For increasing the operating head, reallocation, or quasi-reallocation through modified rule curves and operating practices is necessary. Increasing the operating head may require that generating units be changed or modified to accommodate sustained operation at heads exceeding the design limits of the existing equipment. The measures available for increasing the conversion efficiency are those that can reduce the fluid energy loss in flow passage and energy loss in converting fluid energy (flow and head) to mechanical energy (turbine output) to electrical energy (generator output). The significant practical opportunity is improvement of the energy conversion efficiency of the hydraulic turbine since the energy conversion efficiency of electrical generators is quite high (about 95%) and modification of the water passage works of tunnels, penstocks, and draft tubes to reduce hydraulic energy loss would likely require significant and costly construction for minor increases. Table 1-1 summarizes the energy increase opportunities and candidate measures considered for capturing the potential.

Table 1-1.
MEASURES FOR INCREASING ENERGY OUTPUT OF EXISTING HYDROPOWER PLANTS

Measure	:	Spill Capture	Head Increase	Efficiency Increase
Add New Units	:	X		
Replace Existing Units	:	X		X
Modify Existing Units	:	X		X
Modify Water Passage	:			X
Reallocate Reservoir Storage	:	X	X	
Improve System Operation	:	X	X	

The main source of information for this study was the data base developed for the National Hydropower Study. The data base, compiled by the District offices of the Corps of Engineers, contains storage space for over 600 data items relevant to each site. There is selected incomplete information stored for more than 15,000 sites with detailed information on 6,000 sites. Those sites with existing hydropower facilities (1,288) were extracted from the file and an additional data item entitled "Equipment Information" (supplied by the Federal Energy Regulatory Commission) was added and a new separate "study" file created. Relevant data items in this computer file are shown in Table 1-2.

Table 1-2. STUDY FILE - PLANT AND REGIONAL DATA

Item	Percentage* of Sites	Percentage of** Total Capacity
Installed capacity in kilowatts	100	100
Average annual energy	99	99
Turbine type	27	66
Age of installation	59	96
Rating of turbine	27	76
Rating of generator	28	76
Design head	28	76
Number of units	28	76
Weighted net power head	100	100
Average annual inflow	93	96
Flow duration data	78	86
Depth of the flood-control space, feet	14***	28
Regional dependable capacity benefit in $/kW-yr	100	100
Regional average annual energy benefit in $/MWh-yr	100	100

* 1,288 sites catalogued in data file.
** Total installed capacity of sites in file is 63,375 MW.
***Represents all existing sites that have flood control storage.

EXISTING HYDROPOWER FACILITIES

The total installed capacity of the existing 1,288 sites that were identified and catalogued into the study file is 63,375 megawatts (MW) and they generate 272,552 gigawatt hours (GWh) of electrical energy per year. Tables 2-2 and 2-1 summarize types and ownership of existing hydropower development. Figures 2-1, 2-2, and 2-3 summarize information on installation date, head, and installed capacity of existing plants. A sampling of the types of turbines representing 80% of the total installed capacity indicates that reaction turbines (Francis) are the predominate type--66%, followed by propeller--25% (Kaplan--17%, fixed blade--8%), then impulse (Pelton)--5%, and other--4%.

Table 2-2. TYPES OF EXISTING HYDROELECTRIC PLANTS

Plant Type	Number of Plants	Capacity kW	Average Annual Energy MWh
1. Run-of-River	431	8,632,900	38,311,800
2. Diversion	160	2,332,900	12,899,300
3. Reservoir	501	44,790,800	190,417,000
4. Reservoir with Diversion	190	7,604,000	30,848,500
5. Other	6	14,800	75,400
Totals	1,288	63,375,400	272,552,000

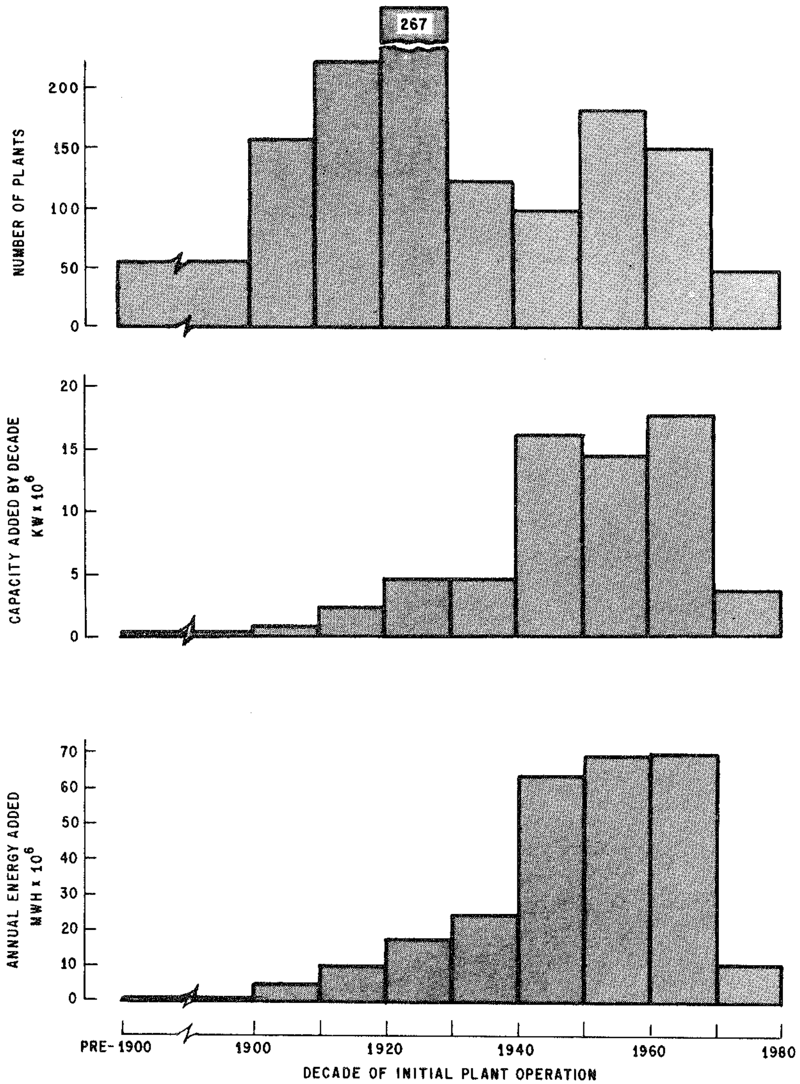


Figure 2-1. PLANT AGE VS. NUMBER OF PLANTS, CAPACITY, AND ENERGY

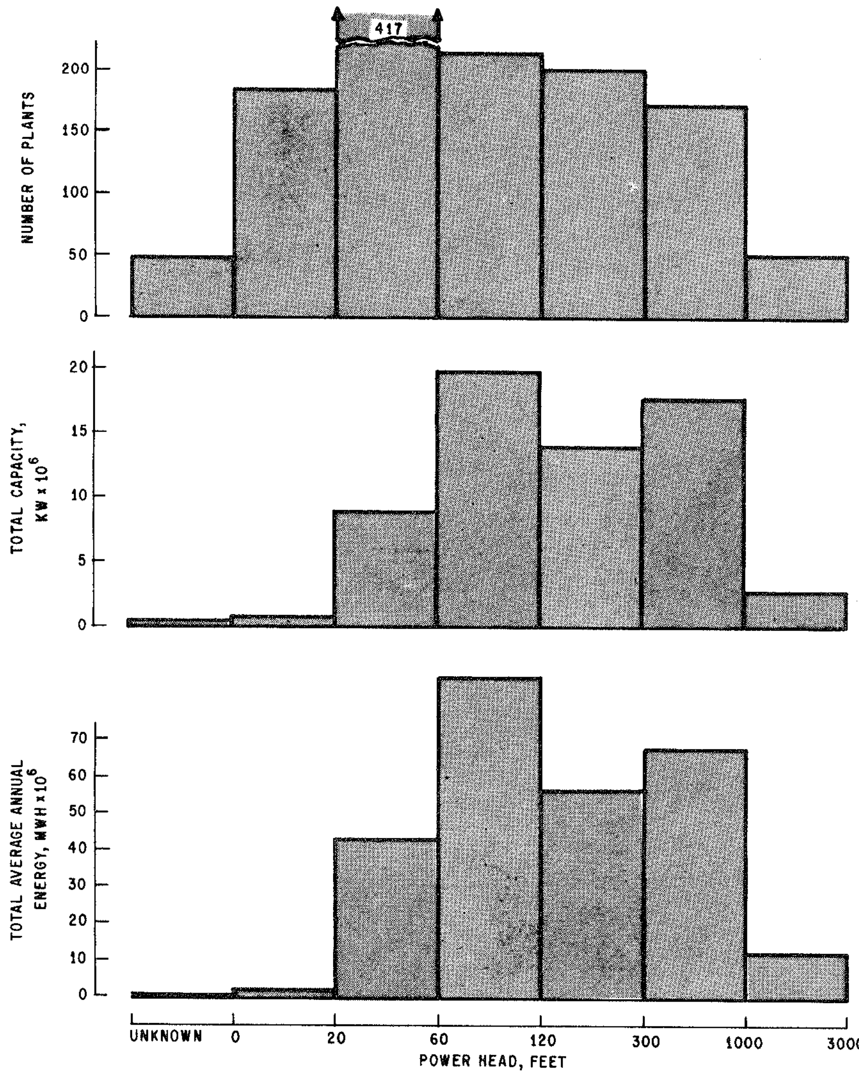


Figure 2-2. POWER HEAD VS. NUMBER OF PLANTS, CAPACITY, AND ENERGY

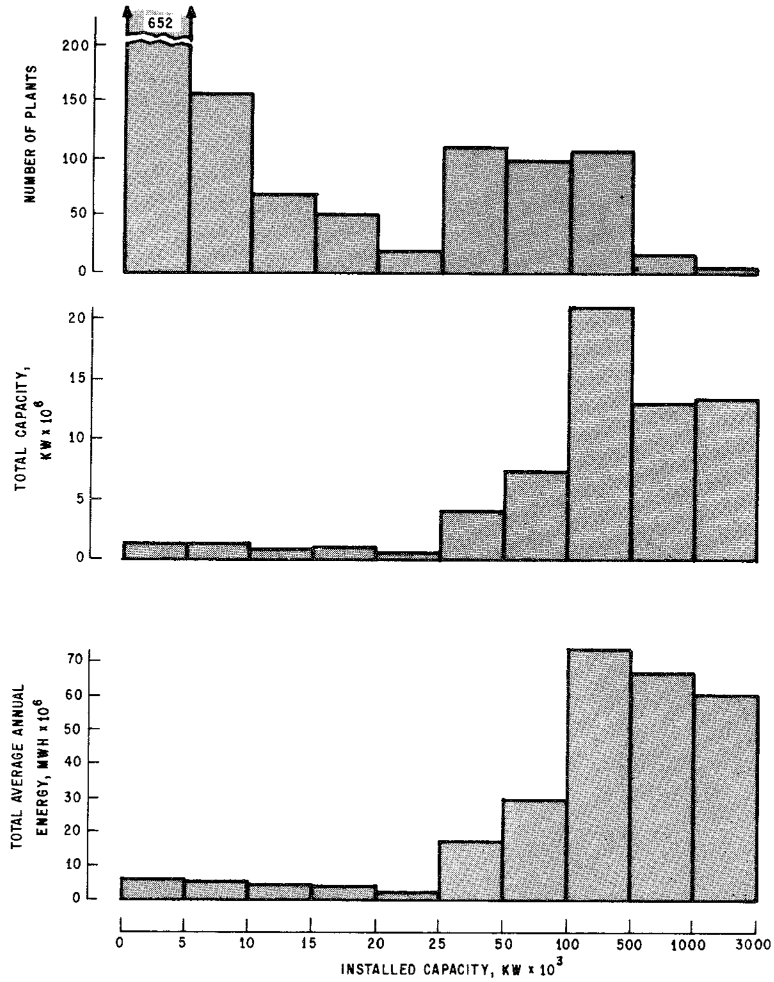


Figure 2-3.

INSTALLED CAPACITY VS. NUMBER OF PLANTS, CAPACITY, AND ENERGY

Table 2-1. OWNERSHIP OF EXISTING HYDROELECTRIC PLANTS *

Ownership Category	Number of Plants	Total Capacity kW	Total Average Annual Energy MWh
1. Corps	92	19,232,900	81,761,400
2. Other Federal	92	14,948,300	63,026,500
3. Non-Federal, Government	151	8,728,000	42,550,700
4. Investor Owned Utility	504	13,977,600	60,342,600
5. Cooperatively Owned Utility	57	2,330,100	8,353,500
6. Other Commercial or Industrial Firm	241	1,745,600	8,359,800
7. Private Citizen or Non-utility Cooperative	41	858,400	4,389,600
8. Unknown	110	1,554,500	3,767,900
Totals	1,288	63,375,400	272,552,000

* All information taken from study computer data file.

EQUIPMENT CHARACTERISTICS

Improvements due to research, materials, and design over the last 80 years have resulted in it being technically feasible to obtain substantial increases in capacity and to a lesser degree increases in efficiency from existing hydroelectrical equipment. When uprating an existing generating unit the amount of actual increase that can be obtained is limited by the specific design and manufacturing characteristics of the installed equipment. The year of manufacture or installation is used herein as an indicator of potential to assist in arriving at the capacity and/or efficiency gain possible.

Indications are that the generator is generally capable of being uprated to obtain a greater percentage capacity gain than can be developed from the turbine for an equivalent year of manufacturer. The turbine has been found in general to be the critical factor in determining the maximum output that can be developed. Figures 3-1, 3-2, 3-3 and 3-4 are examples of technical data compiled and used in this study for analyzing uprating potential. The reader is cautioned that these data were compiled to perform a nationally scoped study and should not therefore be used to make major decisions on a site specific basis. Also it must be emphasized that while these increases shown are within the capability of the machines, additional flow and/or head (beyond existing) must be developed through project changes before increased power output can result.

A major consideration in determining whether to uprate units of an existing hydroelectric powerplant is the question of the outage. Outage is the time the generating unit would be out of service undergoing replacement or modification. Opportunities for uprating appear to lend themselves more to powerplants with multiple units where outages can be scheduled to coincide with seasonal system power demand swings which would provide "windows" where a unit or units could be taken out of service without adversely affecting a system generating capability. This outage period can vary considerably depending on the uprating to be done. If only the turbine runner is replaced with minor structural adjustments, the outage time could be as low as two months. If more major changes are required, this time could be six to twelve months.

INCREASED OUTPUT FROM PHYSICAL MODIFICATIONS

Figure 4-2 is a schematic of the evaluation process that was adopted for this portion of the study. The existing 1,288 plants were separated into one of thirty-two categories based on whether or not the reservoir had flood control storage, whether or not there was spill occurring at the site, the ratio of potential head to existing, and the age of the plant. The following measures were designated as action categories that were studied to enhance the energy output at existing plants.

- Addition of new units for capacity increase
- Replacement of older units for capacity increase
- Uprating of older units for capacity increase
- Replacement of older units for efficiency increase
- Modification of older units for efficiency increase

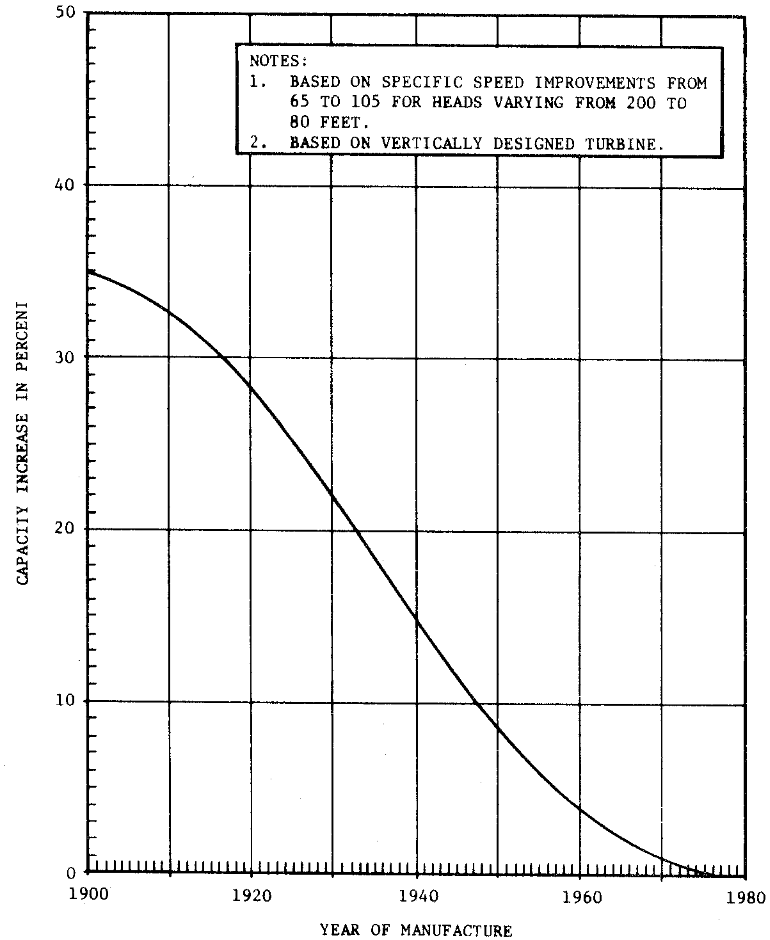


Figure 3-1.

POTENTIAL FOR CAPACITY INCREASE - FRANCIS TURBINE

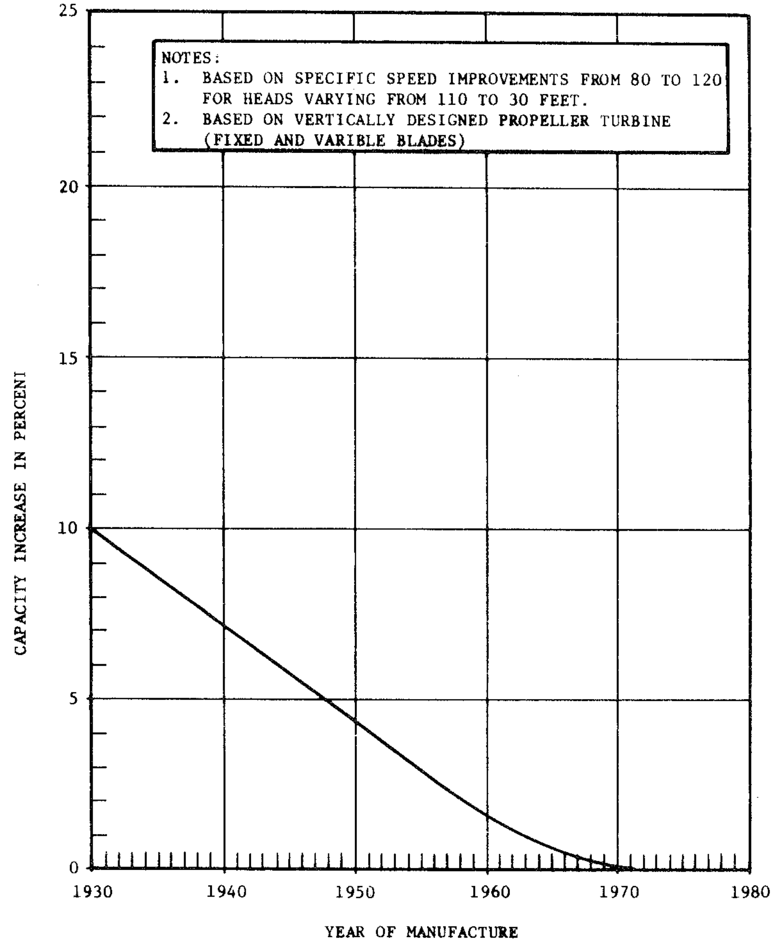


Figure 3-2.

POTENTIAL FOR CAPACITY INCREASE - PROPELLER TURBINE

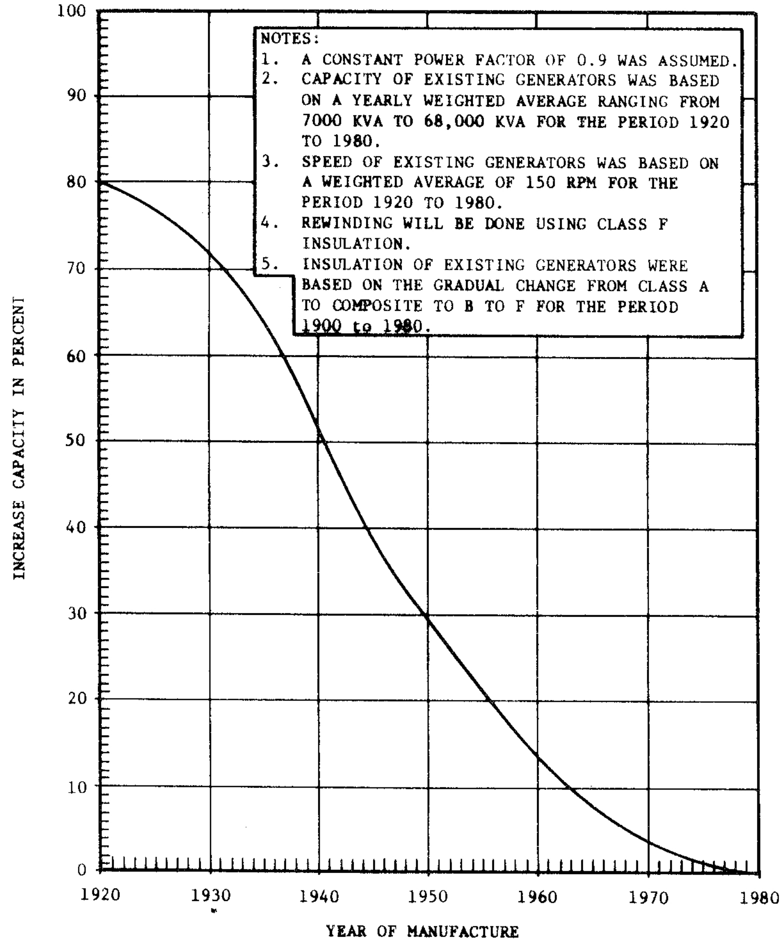


Figure 3-3.

POTENTIAL FOR CAPACITY INCREASE - REWINDING OF STATOR

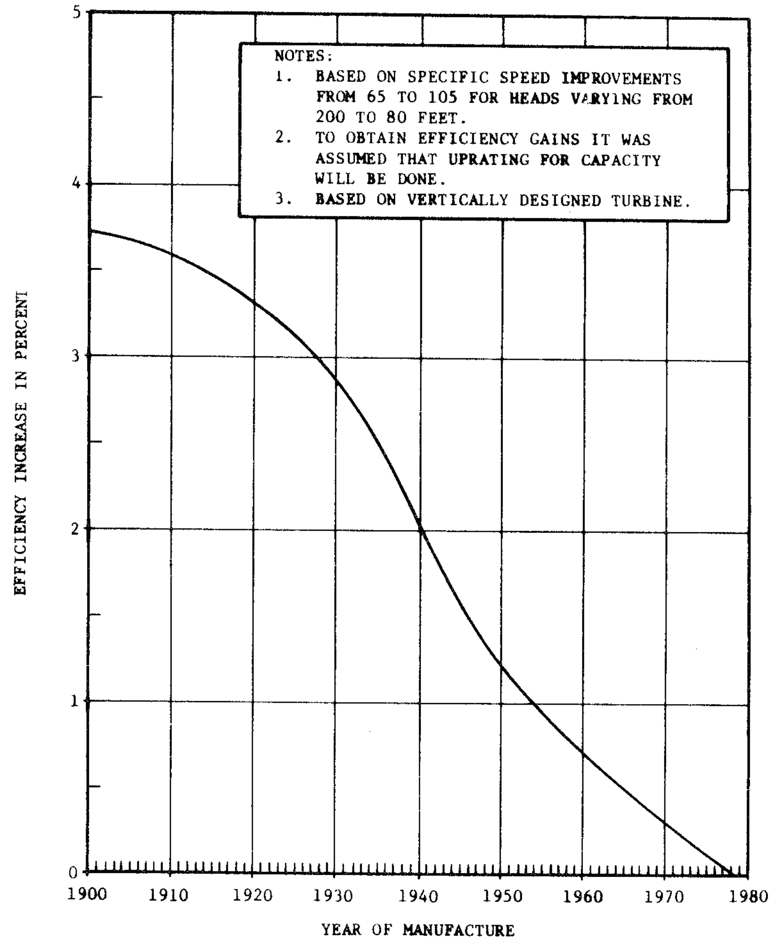


Figure 3-4.

POTENTIAL FOR EFFICIENCY INCREASE - FRANCIS TURBINE

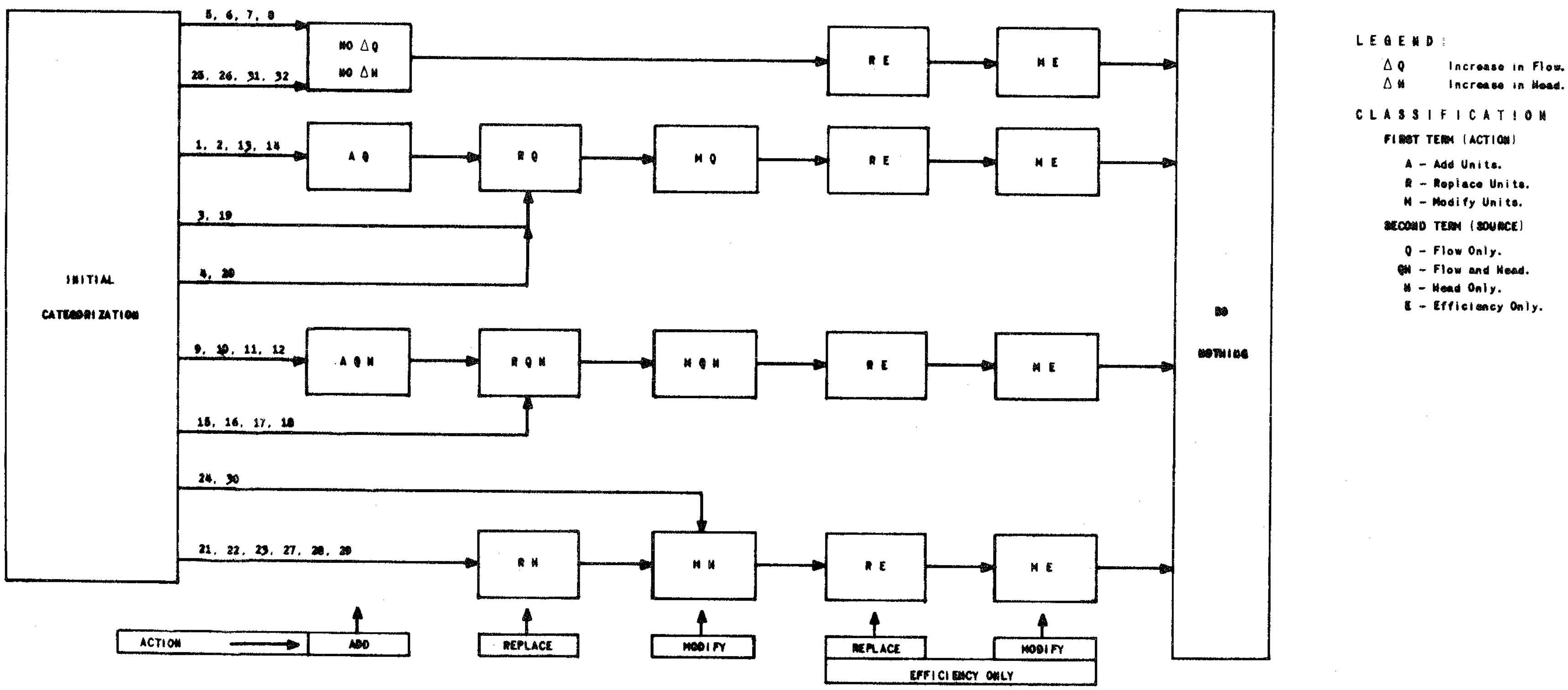


Figure 4-2. SCHEMATIC - EVALUATION PROCESS

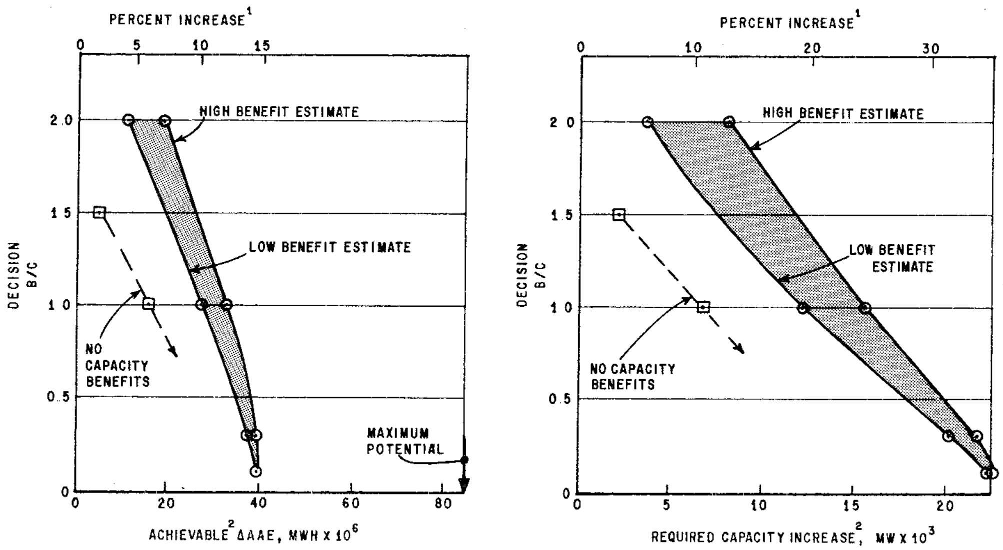
The total gross physical potential increase in energy and corresponding increase in capacity was estimated for each site and appropriate action categories. An indicator of benefit was estimated for the improvement by application of the Federal Energy Regulatory Commission (FERC) regional power values developed for the NHS study. Costs were estimated based on technical data compiled for this study. The test for "achievability" of the energy increase consisted of comparing the calculated benefit to cost (B/C) ratio for each action category to a specified decision B/C ratio. The decision B/C ratio was the decision device used to study the sensitivity of results to a range of acceptable economic criteria. The energy increase of each site that ended up in an action category with a B/C value equal to or greater than the specified decision B/C ratio was considered "achievable".

As an illustration of the evaluation process, consider those sites (Figure 4-2) that were initially classified as "add" categories 9, 10, 11, or 12. All of these sites have potential due to additional flow and head above existing conditions. First the costs and benefits at each site are evaluated for the add (AQH) conditions to see if the calculated B/C ratio is equal to or greater than the specified decision B/C value. If the site does meet this condition the developed information is stored in the AQH category. If the site does not meet the decision B/C ratio at the initially calculated capacity and energy increase, the site is completely re-evaluated at 75 percent of that capacity increase. If required, two more trials are made at 50 percent and 25 percent of the initial value before going on to the next potential action category - RQH. The processing of each site either meets the decision B/C ratio or ends up in the "do nothing" category. Therefore, before sites in categories 9, 10, 11 or 12 are considered "do nothing" sites they could conceivably be tested for achievability for up to twenty different conditions - four conditions for each of the five action categories.

Figures 4-5 and 4-6 present the results of the analysis on an aggregate national scale. Note the maximum physical potential is estimated at slightly over 80 million MWh with a more realistic estimate of physical potential of 40 million MWh. For a decision B/C ratio of 1.0, the achievable energy increase is about 11% (mid range of band) requiring about a 22% capacity increase to accomplish the energy output. Sensitivity results of benefit estimates (HIGH = capacity increase valued as dependable, LOW = capacity increase valued as intermittent), decision B/C ratio (uncertainty in costs and power values), and project life and discount rate (private sector criteria) are shown to provide a complete picture of the potential.

Table 4-4 is a summary computer printout of the computations for the HIGH benefit estimate and decision B/C ratio of 1.0. Note that essentially all the increase is found to be from adding new units (expanding the existing powerhouse). The Northwest accounts for about half of the increase estimated, the Northeast for about 30% of the increase and the Southeast about 10% of the increase.

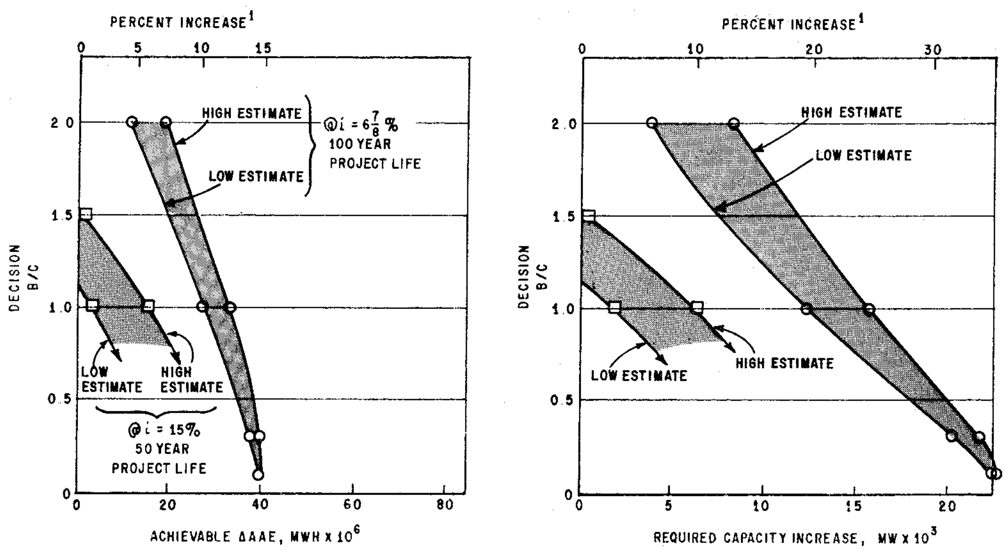
An analysis was performed with the add category removed from the evaluation process to provide some insight into the potential energy increase from the options of only rehabilitating existing plants. The potential increase achievable dropped to 1.4% (from 11%) nationwide.



1 Based on existing installed capacity and average annual energy
2 Costs and benefits are based on 1978 price levels and 6 7/8% interest

Figure 4-5.

ACHIEVABILITY ANALYSES - SENSITIVITY RESULTS



1 Based on existing installed capacity and average annual energy

Figure 4-6.

ACHIEVABILITY ANALYSES - SENSITIVITY RESULTS

- INTEREST RATE AND PROJECT LIFE

Table 4-4. SUMMARY

ACHIEVABILITY EVALUATION OF EXISTING HYDROELECTRIC PLANTS, HIGH BENEFIT ESTIMATE, DECISION B/C= 1.0.

ACTIVITY	NUMBER OF PLANTS	INSTALLED CAPACITY	CAPACITY INCREASE	AVERAGE ANNUAL ENERGY	AVERAGE ANNUAL ENERGY INCREASE	INVESTMENT COSTS	AVERAGE ANNUAL COSTS	AVERAGE ANNUAL BENEFITS
		MW	MW	MILLION MWH	MILLION MWH	MILLION DOLLARS	MILLION DOLLARS	MILLION DOLLARS
ADD UNITS								
AQ	253	9923.0	14491.5	52.284	30.420	12362.7	945.12	1631.41
AQH	15	714.1	961.5	4.045	1.971	766.2	58.52	104.67
ADD SUBTOTAL	268	10637.1	15452.9	56.329	32.391	13128.9	1003.64	1736.07
REPLACE UNITS								
RQ	0	0.	0.	0.	0.	0.	0.	0.
RQH	0	0.	0.	0.	0.	0.	0.	0.
RH	0	0.	0.	0.	0.	0.	0.	0.
RE	4	355.6	10.3	1.930	.019	13.8	1.10	1.79
REPLACE SUBTOTAL	4	355.6	10.3	1.930	.019	13.8	1.10	1.79
MODIFY UNITS								
MQ	10	707.2	70.6	3.549	.092	99.2	7.93	9.28
MQH	1	474.5	111.1	1.719	.138	111.1	8.99	12.53
MH	1	22.5	3.2	.082	.002	.9	.09	.14
ME	15	1605.6	47.1	5.702	.056	67.3	5.40	7.43
MODIFY SUBTOTAL	27	2809.7	232.1	11.052	.288	278.5	22.40	29.39
A,R,M SUBTOTAL	299	13802.3	15695.3	69.312	32.698	13421.1	1027.14	1767.25
DO NOTHING								
DN	989	49573.1	0.	203.240	0.	0.	0.	0.
TOTALS	1288	63375.4	15695.3	272.552	32.698	13421.1	1027.14	1767.25

INCREASED OUTPUT FROM OPERATIONAL CHANGES

Operational changes to existing plants that could potentially increase the energy output are possible. By reallocating a portion of the flood control storage to power storage there is the potential to increase the energy output by capturing and routing additional flow through the powerhouse and by increasing the head available for power generation by keeping the pool level higher. The additional energy increase may be possible without necessarily increasing the plants installed capacity. The loss to the existing project would be reduced flood control protection. It is unlikely that a significant reduction in flood control storage would be found to be acceptable. However, in some cases only a small portion of the flood control space may be needed to capture and control a significant amount of reservoir inflow volume.

Altering the reservoir operation policies is another potential way to increase energy output. Typically, there is a set of operating rules by which a reservoir is operated. The thesis is that there may be opportunities to increase power output such as reducing flood control releases during and following flood events to allow more volume to be passed through the plant; allowing seasonal power pool elevations to remain at higher elevations for longer periods of time; and minimizing all releases that do not go through the plant. In effect this might amount to a quasi-storage reallocation in that some of the goals of reallocation might be achieved without formally modifying the designated storage zones.

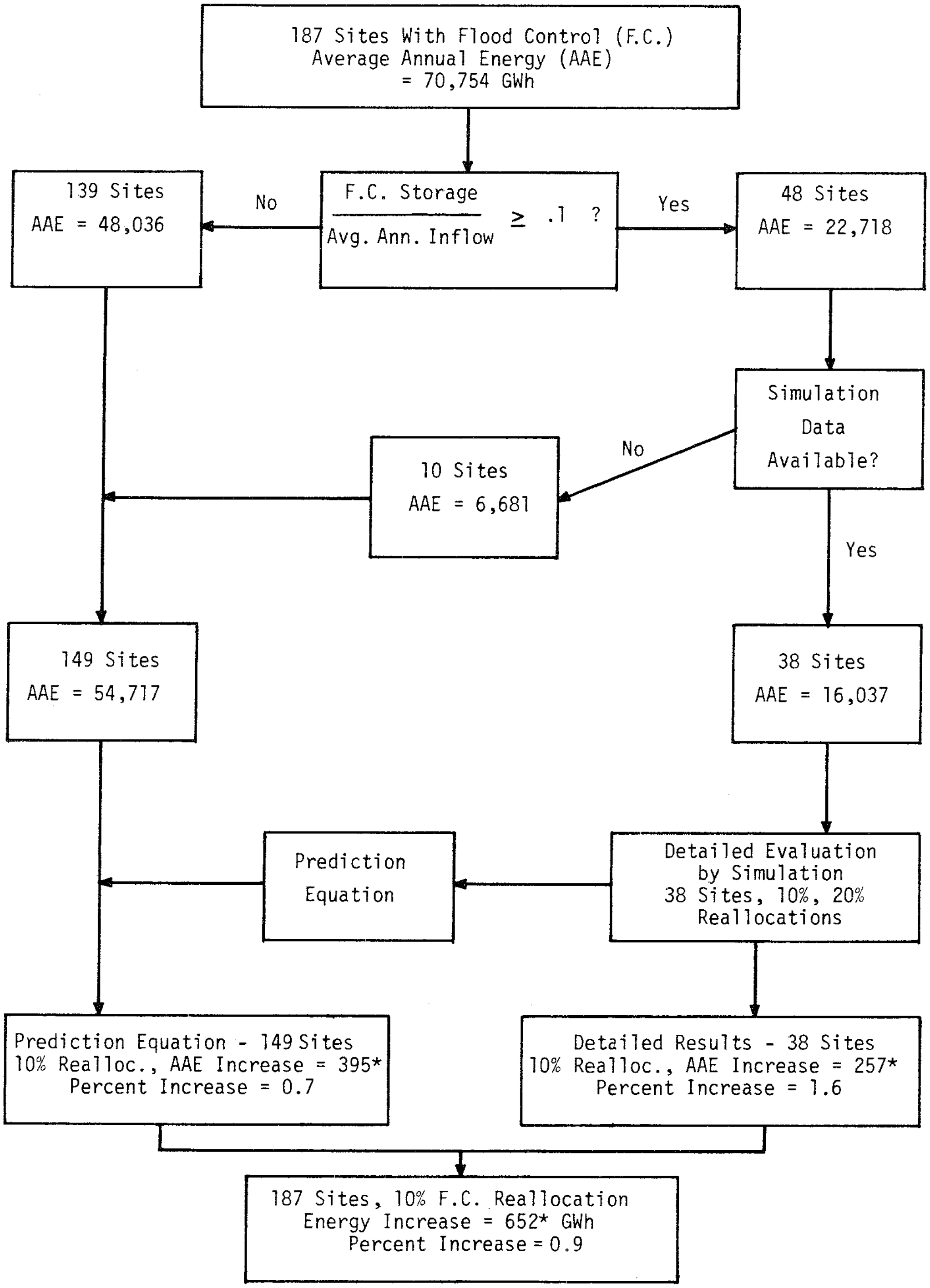
Storage in a multiple-purpose reservoir is usually allocated into flood control space, conservation storage (including hydropower), and inactive or dead storage. Flood control operation requires reservation of storage space in the event a flood might occur thus potentially releasing water that might have been later used for power generation. The hydropower reallocation question for all practical purposes reduces to allocating portions of existing flood control space to hydropower storage. The potential contribution to increased energy output of allocating from one conservation purpose to another is insignificant in comparison. The candidate projects for reallocation of flood control storage are therefore those existing hydropower projects that also have flood control storage. A total of 187 projects were found that met the criteria. Forty-eight (48) of these projects have flood control storage equivalent to 10% of the annual flow volume.

The reallocation analysis was accomplished by performing detailed sequential, hydropower analysis on 38 of the 48 project previously identified, developing a prediction equation from the results obtained, and applying the prediction equation to the remaining sites. Computer simulations were made based on existing storage allocations, then repeated for reallocation of 10% and 20% of flood control storage to power storage. Figure 5-1 is a schematic of the analysis flow and includes the results for the 10% flood control storage reallocation option.

The estimated increase in energy output for reallocation only (installed capacity remains at existing) is 10% reallocation - 652 GWh (.9% increase for all reallocation sites) and 20% reallocation - 1,225 GWh (1.7% increase for all reallocation sites). If the installed capacity is increased commensurate with the increased dependable capacity made possible by the increased power storage and decreased plant factor, an additional 1.7% increase in average annual energy for a 10% reallocation may be possible. The major factor in increased energy output was found to be increased head (pool levels). The contribution due to capturing additional spill was negligible. By adding to the power storage through reallocation, projects are able to meet increased power demands during critical low flow periods. The percentage increase in firm annual energy (conversion of non-firm energy to firm energy) was approximately 3 times the increase in average annual energy.

The likely acceptable reallocation project development would require formulation and implementation of mitigation measures to offset the loss in flood control performance by the reservoir. The benefits from increased power production would have to be greater than the cost of the mitigation measures needed to assure the same (or nearly so) flood control performance for reallocation to be economically justified.

Analysis of the potential for increased output by operational (rule curve) changes indicated that the potential was minor and in fact is included within the estimates made for reallocation analysis. Project operators appear to be diligent in operating their projects to extract the greatest amount of energy that is practical and reasonable.



* Installed capacity maintained at existing values.

Figure 5-1. ESTIMATE OF POTENTIAL ENERGY INCREASE FROM STORAGE REALLOCATION

SUMMARY OF FINDINGS

The hydroelectric power generation system of the United States is comprised of 1,288 individual plants, totaling about 3,000 individual generating units, with installed capacity (exclusive of pumped storage) of 63,375 megawatts (MW), generating 272,552 gigawatt hours of electrical energy per year. The data documenting characteristics of the 1,288 plants have been catalogued into a computer file for use in the evaluation of the potential for increasing output from existing plants. There is modest potential for increasing energy output from these plants (11%) with virtually all the increase due to capturing existing spill through enlargement of the existing powerplant. Equipment uprating and improvements would likely contribute no more than 1.4% increase over existing output. Potential for increased energy output from operational improvements and storage reallocation is possible at sites with existing flood storage and is optimistically estimated to average 2% for the sites with flood control storage (a national increase of about 0.6%). While the total national potential for increasing energy output at existing plants is modest, the opportunities are real and in specific instances could be significant and important on a local scale. The existing hydropower generation system on the whole is making quite efficient use of the energy resources available at the existing sites.

Specifically, the investigation has found:

- The upper physical limit estimate of potential increase in energy output at existing hydropower sites is approximately 86,000 (GWh). A more realistic value for physical potential developed through detailed study in this investigation is a maximum practical limit of about 40,000 GWh (15% increase over existing) indicating that current utilization of potential energy at these sites is 87 percent on a nationwide basis. Based on present day cost and power benefit values as decision criteria, the potential energy increase that is achievable is estimated to be about 30,000 GWh or an 11 percent increase.

- 1,288 sites have been identified and catalogued into the basic data files of the national hydropower study. This data base provides an adequate basis for a national study of potential energy increases at existing sites.

- Existing federal plants (14 percent of total) contain a little over 50 percent of total installed capacity.

- There is flood control storage at about 15 percent of existing sites with a total installed capacity of 17,774 MW (28 percent of the national total).

- There are 431 (33 percent of total) sites with capacity of 8,633 MW (14 percent of national total) that are classified as run-of-the-river locations.

- Approximately 80 percent of the total existing capacity has been added since 1940.

- Two-thirds of existing plants were constructed prior to 1940 and contain only about 20 percent of the existing capacity.

- Approximately 75 percent of existing plants are less than 25 MW installed capacity yet these plants account for only 7 percent of the total installed capacity.

- There can be significant increases of up to 35 percent in turbine output capacity due to modifications to older turbines, if additional head and/or flow are available.

- Improvements in insulating material over the past 50 years allows significant generator capacity increases through uprating.

For summary purposes the values used in the following items are taken from analyses based on costs and benefits in present day values and a decision threshold benefit to cost ratio of 1.0.

- The major source of potential increase in energy at existing plants is the flow that is currently bypassing the existing powerplant and not being captured for power generation. Specific measures of adding additional units, replacing or modifying units to achieve higher output, or storage reallocation would be required to capture portions of the presently passed flows (spill). Utilization of this spillage through addition of units accounts for more than 94 percent of the estimated achievable potential energy output increase at existing sites.

- The increase in energy due to head increases, even using all of the flood control space, accounts for less than 6 percent of the total potential energy increase at existing sites.

- The achievable average annual energy based on the capacity and energy power values used herein and the federal interest rate of 6-7/8% is about 30,000 GWh or an 11 percent increase in energy above existing hydropower output. Development of this additional energy would require adding about 14,000 MW of capacity, an increase of 22 percent over existing capacity.

- If power benefit credit for dependable capacity is omitted from the evaluation (because not all additional capacity could be reasonably expected to be dependable), the achievable annual energy increase drops to about 18,000 GWh or a 6 percent increase over existing output.

- If the interest rate for the implementation decision criteria is raised to 15 percent from the 6-7/8 percent utilized in this study and the project evaluation period is decreased from 100 years to 50 years and the value of power is held constant, the achievable annual energy increase drops to about 10,000 GWh or a 4 percent increase over existing output.

- If adding units were not being considered as an alternative, (e.g., only existing unit uprates and improvements are considered) the potential increase in annual energy due to replacement of and/or modifications to existing units would be about 3,750 GWh or an energy increase of 1.4 percent over existing.

- The loss in energy (and thus revenue) from removing a unit from service to uprate through modification is presently seldom economically justified. Uprates through improvements are more attractive for implementation when the plant must be taken out of service for some other compelling reason.

- The Western Systems Coordinating Council (WSCC), Northeast Power Coordinating Council (NPCC), and Southeastern Electric Reliability Council (SERC) regions contain 88 percent of the estimated achievable annual energy increase.

- The potential energy development due to reallocation of flood control storage in existing power reservoirs - will likely contribute less than a one percent increase in hydroelectric energy output on a national basis. The conversion of non-firm energy to firm energy made possible by increasing power storage through reallocation can be significant - up to 3 times the increase that was estimated for annual energy. Substantial gains in average annual energy can be obtained at those projects where the reservoir power operation can be based on zero firm energy due to the higher heads resulting from the decreased reservoir drawdown.

- It would require about 60 million barrels of fuel oil annually, to produce the equivalent amount of electrical energy (30,000 GWh) that has been found in this investigation to be achievable.

PREFACE

This report documents the findings of an investigation into the potential for increasing power output from the nation's existing hydroelectric powerplants. The study was nationwide in geographic scope, including Alaska, Hawaii and Puerto Rico, and included all existing hydroelectric plants. The investigation is one of the technical overview studies of the National Hydroelectric Power Study, which is under the management of The Institute for Water Resources (IWR), U.S. Army Corps of Engineers.

The preparation of this report was the responsibility of The Hydrologic Engineering Center (HEC), U. S. Army Corps of Engineers, Bill S. Eichert, Director. The report was prepared by the staff of The Hydrologic Engineering Center under the guidance of an advisory staff and with contractural assistance by Parsons, Brinckerhoff, Quade, and Douglas, Inc. Mr. Michael Walsh was the IWR contact for this study. Mr. Darryl W. Davis from HEC was the principal-in-charge and Mr. John J. Buckley was the study manager. Messrs. Bill S. Eichert, Vernon R. Bonner, and Dale R. Burnett performed the reallocation analyses and provided valuable guidance throughout the study period. Mr. Robert C. Luethy performed most of the computer programming required to perform the technical achievability analysis. Mr. Gary M. Franc assisted in developing special computer routines to access the National Hydropower Study data files. Mr. Brian W. Smith assisted in the research on reservoir regulation and coordinated operation of projects and coordinated the final edit, typing, and printing of the report.

The advisory staff was comprised of the senior Corps of Engineers professionals of Messrs. Robert Bruck (recently retired), Office Chief of Engineers; Thomas White, North Pacific Division; James Dalton, Southwestern Division; and Nels Carlson, (recently retired), Missouri River Division.

Parsons, Brinckerhoff, Quade, and Douglas, Inc. (PBQ&D) prepared the information which served as the basis for Chapter 3 and Appendix A of this report and in addition prepared basic cost relationships. Messrs. Clarence E. Korhonen and Richard L. Hearth were the principals in charge for PBQ&D with specialized technical assistance from Messrs. Rolfe Sahle, turbine consultant; Lennart Wuosmaa, generator consultant; Jack Bennett, transformer consultant; and Jerry Bagley, switchyard and transmission consultant.

A special thanks also is extended to the many Federal and private organizations and their staffs for information and comments provided during this investigation.

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Chapter 1

INTRODUCTION AND OVERVIEW

1.1 PURPOSE AND SCOPE OF STUDY

The investigation reported herein was undertaken to address the question of how much additional power might be generated at existing hydroelectric plants throughout the United States. This investigation is the technical overview study "Design and Operation of Existing Hydroelectric Power Resources for More Efficient Use" described in the Plan of Study for the National Hydroelectric Power Study (Institute for Water Resources 1979). The potential for increasing power output through physical improvements in generating equipment and by changes in the manner that existing projects are operated were investigated and estimates prepared.

The investigation was nationwide in scope including Hawaii, Alaska and Puerto Rico. All existing hydroelectric plants, regardless of ownership, were investigated for improvement in power output. The study was site specific and nationwide in scope but the investigation did not include the on-site visits, evaluations, and detailed site specific office investigations that would be necessary to support decisions on a site by site basis. Consequently the potential is identified by the nature of improvement required and is reported as aggregate regional values and national summaries.

The sources and nature of information used, evaluation strategy and proceedures, and basic assumptions are presented and discussed. The results are presented in such a way to allow sensitivity evaluations of the resulting power increase to data and analysis procedures.

1.2 STUDY OVERVIEW

The amount of power that can be generated at an existing site is physically limited. The governing factors are the amount of flow volume that passes through the powerhouse, the "head" or elevation difference between the upstream and downstream water bodies acting at the time of power generation, and the generation or "conversion" efficiency, i.e., the mechanical and electrical equipment efficiency in converting potential and kinetic energy of the flowing water into electrical energy. Existing sites consist of impoundments, diversions and penstocks, turbines and generators; and generate in accordance with adopted operating policies.

In order for there to be additional potential, e.g., some "unused energy", an opportunity must exist for one of the following: a) passing more of the annual volume through the powerhouse (there must be existing spill by-passing the powerhouse), b) increasing the effective operating head (average or seasonal pool levels must be raised), or c) technological opportunity to generate more efficiently from available head and flow. What are the improvements that can be made at existing plants to harness the unused, if any, energy potential? First the conceptual scope of this investigation into existing projects must be defined.

The analytical scope includes any and all measures that might be undertaken at the site without increasing the size of the storage facility (e.g., no dam raising) that could improve power output. The focus is upon <u>increasing energy</u> output, hence "improving power output" is herein synonomous with <u>increasing</u> energy generation. The issue of generating the same energy at lower plant factors (generating at a higher rate (capacity) for less time) is discussed but would not be characterized in this study as "increased output" unless additional energy is generated. The candidate measures for increasing output therefore include: 1) adding new generating units, 2) rehabilitating or replacing existing units, 3) modifying water handling facilities, and 4) altering existing operating policies (reallocation of existing storage and/or change of annual and seasonal operation rule curves).

How do the candidate measures relate to the three governing factors? If spill is occurring, probably by far the most important opportunity for increasing power output, the measures available for capturing and routing additional flow volume through the powerhouse include: increasing the plant's generating capacity by adding additional generating units (expanding the powerhouse); uprating existing units to higher generating capacity by rehabilitating, modifying or replacing turbines and/or generators; increasing the effective utilization of storage by reallocating additional storage to the powerpool and/or coordinating generation among a system of generating plants. The measure available for increasing the operating head is reallocation, or quasi reallocation through modified rule curves and operating practices. Increasing the operating head may require that generating units be changed or modified to accommodate generation at heads exceeding the design limits of the existing equipment. The measures available for increasing the generation efficiency are those that can reduce the fluid energy loss in flow passage and energy loss in converting fluid energy (flow and head) to mechanical energy (turbine output) to electrical energy. The significant practical opportunity is improvement of the energy conversion efficiency of the hydraulic turbine (fluid energy to mechanical energy) since the energy conversion efficiency of electrical generators is quite high (above 95%) and modification of the water passage works of tunnels, penstocks, and draft tubes to reduce hydraulic energy loss would likely require significant and costly construction for minor increases. Table 1-1 summarizes the energy increase opportunities and measures for capturing the potential.

Table 1-1

MEASURES FOR INCREASING ENERGY OUTPUT OF EXISTING HYDROPOWER PLANTS

	Energy Increase Opportunity		
Measure	Spill Capture	Head Increase	Efficiency Increase
Add New Units	X		
Replace Existing Units	X		X
Modify Existing Units	X		X
Modify Water Passage			X
Reallocate Reservoir Storage	X	X	
Improve System Operation	X	X	

The investigation was designed to determine the characteristics and efficiency of the nation's existing hydroelectric generating plants, specifically identify the nature and location of the "unused" energy and systematically appraise the potential contribution of the various improvement measures in increasing energy output.

The report includes (in this chapter) sections on data sources and brief overview of findings. The remainder of the report is divided into five additional chapters. Chapter 2 presents nationwide and regional characteristics of existing hydropower facilities as well as a physical "upper bound" estimate of potential increased energy output at these facilities. Equipment characteristics and limitations regarding potential capacity and efficiency increases are detailed in Chapter 3. The evaluation procedures to estimate "achievable" energy output by physical modifications and operational changes along with a discussion of the results are presented in Chapters 4 and 5.

Chapter 6 discusses those major issues relevant to increasing the energy output of existing plants. While this study is mainly concerned with increased energy output, capacity increases for peaking purposes with little or no increase in energy has been a major reason for power additions at existing plants in the last 5-10 years. For this reason a brief discussion on capacity additions is also included in Chapter 6.

Where information was believed to be too detailed for the main report it was placed in the appendices. Appendix A presents three case studies where modification to existing hydropower plants was carried out. These projects are modifications at Lay Dam and Wilson Dam in Alabama and Hoover Dam in Nevada. Appendix B provides a case study on reservoir regulation schedules at Oroville Dam in California. Case studies on the reallocation of flood control storage for systems within the Arkansas River and White River Basins are located in Appendix C.

1.3 DATA SOURCES

The main source of information used in this study was the data base developed for the National Hydropower Study (NHS). This data base prepared by Corps of Engineers District offices and managed by The Hydrologic Engineering Center includes storage space for over 600 data items relevant to each catalogued hydropower site. There is selected incomplete information stored on over 15,000 locations with detailed information on 6,000 sites. The sites include identified undeveloped sites, existing dams with no existing power generation, and sites with existing hydropower facilities. The major data categories within this data base with reasonably complete information are location and identification; physical characteristics; hydrologic characteristics; and power computation results. A separate computer file was prepared for this study for all existing plants (1,288) that were identified in the NHS file as having "installed capacity". This file is hereafter referred to as the study data file. An additional data category entitled "Equipment Information" was added to the study data file to assist in carrying out study evaluations. The types of data stored in the study data file that were utilized for study analysis are listed on Table 1-2.

Plant equipment information was taken from files of the Federal Energy Regulatory Commission (FERC). FERC also supplied values of regional capacity and energy benefit factors that were used for estimating potential benefits.

Cost data were compiled and documented (Parsons, Brinckerhoff 1980) for study use. The data was assembled from several sources including equipment manufacturers quotes and bids as well as catalog prices. Several additional reports and studies with representative cost information were also used during the study.

Table 1-2
STUDY DATA FILE
PLANT AND REGIONAL DATA

ITEM	PERCENTAGE OF SITES*	PERCENTAGE OF TOTAL CAPACITY **
Installed capacity in Kilowatts	100	100
Average annual energy	99	99
Turbine type	27	66
Age of installation	59	96
Rating of turbine	27	76
Rating of generator	28	76
Design head	28	76
Number of units	28	76
Weighted net power head	100	100
Average annual inflow	93	96
Flow-exceedance frequency data	78	86
Depth of the flood-control space	14***	28
Regional dependable capacity benefit in $/kW-yr.	100	100
Regional average annual energy benefit in $/MWh-yr.	100	100

* 1,288 sites catalogued in study data file.
** Total installed capacity of sites in file is 63,375 MW.
*** Represents all existing sites that have flood control storage. The percentages are representative of energy output as well.

1.4 OVERVIEW OF FINDINGS

The hydroelectric power generation system of the United States is comprised of 1,288 individual plants, totaling about 3,000 individual generating units, with installed capacity (exclusive of pumped storage) of 63,375 megawatts (MW), generating 272,552 gigawatt hours (GWh) of electrical energy per year. The data documenting characteristics of the 1,288 plants have been catalogued into a computer file for use in the evaluation of the potential for increasing energy output from these plants. There is modest potential for increasing energy output from these plants (11%) with virtually all the increase due to capturing existing spill through enlargement of the existing powerplant. Equipment uprating and improvements would likely contribute no more than 1.4% increase over existing output. Potential increased energy output, operational improvements, and storage reallocation is possible at sites with existing flood control storage and is estimated to average 2% (a national increase of about 0.6%). While the total national potential for increasing energy output at existing plants is modest, the opportunities are real and in specific instances could be significant and important on a local scale. The existing hydropower generation system on the whole is making quite efficient use of the energy resources available at the existing sites.

Chapter 2

EXISTING HYDROPOWER FACILITIES

2.1 INTRODUCTION

This chapter describes the existing hydropower facilities in the United States. Nationwide and regional characteristics are presented along with an upper bound estimate of physical hydropower potential at existing facilities. All data and statistics reported herein were extracted from the data file of 1,288 existing plants that was created for this study.

2.2 NATIONWIDE CHARACTERISTICS

Several items of information on existing hydroelectric plants are presented to better understand the activities necessary to develop additional energy at these facilities. Included in this section is information on ownership; type of plants; project purposes; age, head, and capacity of plants; and turbine types.

The current total installed capacity is 63,375 MW. This compares with the published estimate of 59,200 MW as of January 1978 (Federal Energy Regulatory Commission 1979). The total number of plants identified and catalogued into the data file for this study is 1,288. This compares with a published value of 1,426 conventional hydroelectric plants as of January 1976 (Federal Power Commission 1976). The discrepancy is most likely due to omission of a number of very small sites since the total capacity seems quite reasonable considering that several significant plants (5,600 MW at federal sites) were under construction in 1978.

Ownership

Ownership of existing hydroelectric plants has been separated into several categories. The number of plants, total capacity, and total average annual energy are tabulated for each of these categories in Table 2-1. Note that the most prevalent owner category is investor owned utilities and that 184 plants fall under the two Federal categories. A comparison of Table 2-1 classifications with various published sources from the Federal Energy Regulatory Commission, Corps of Engineers, and Water and Power Resources Service indicates different interpretations for such situations as federal reservoirs with private powerhouses, federal reservoirs built by one agency and transferred to another (and with perhaps later additional construction) and federal reservoirs operated by local agencies. All significant sites on readily available published lists have been accounted for.

Table 2-1

OWNERSHIP OF EXISTING HYDROELECTRIC PLANTS*

Ownership Category	Number of Plants	Total Capacity kW	Total Average Annual Energy MWh
1. Corps	92	19,232,900	81,761,400
2. Other Federal	92	14,948,300	63,026,500
3. Non-Federal, Government	151	8,728,000	42,550,700
4. Investor Owned Utility	504	13,977,600	60,342,600
5. Cooperatively Owned Utility	57	2,330,100	8,353,500
6. Other Commerical or Industrial Firm	241	1,745,600	8,359,800
7. Private Citizen or Non-utility Cooperative	41	858,400	4,389,600
8. Unknown	110	1,554,500	3,767,900
Totals	1,288	63,375,400	272,552,000

*All information taken from study computer data file.

Types of Plants

Most of the plants were classified into one of the following four types: run-of-river; diversion; reservoir; and reservoir with diversion. The remaining plants were placed in the "other" category. The number of plants, total capacity, and total average annual energy developed for each of these types are shown on Table 2-2. There are approximately the same number of run-of-river plants as plants with reservoirs. These two types comprise 72 percent of the 1,288 plants.

Table 2-2

TYPES OF EXISTING HYDROELECTRIC PLANTS

Plant Type	Number of Plants	Capacity kW	Average Annual Energy MWh
1. Run of River	431	8,632,900	38,311,800
2. Diversion	160	2,332,900	12,899,300
3. Reservoir	501	44,790,800	190,417,000
4. Reservoir with Diversion	190	7,604,000	30,848,500
5. Other	6	14,800	75,400
Totals	1,288	63,375,400	272,552,000

Project Purposes

An examination of existing hydroelectric plants shows that most of these plants are single purpose projects. However, a significant number of plants are multi-purpose. Impacts on each of the project purposes must be considered very carefully when evaluating the possibility of increasing energy output at a specific site. Tables 2-3 and 2-4 indicate the number of projects by type of purpose for the various owner and plant type categories.

Table 2-3

PROJECT PURPOSE AND OWNERSHIP

	Project Purpose*							
	H	I	F	N	W	R	D	O
Owner Category								
1. Corps	92	13	50	43	10	49	1	13
2. Other Federal	92	38	14	23	20	63	2	24
3. Non-Federal, Government	151	23	27	6	28	47	3	2
4. Investor Owned Utility Utility	504	14	27	8	19	90	0	4
5. Cooperatively Owned Utility	57	3	11	1	6	18	5	0
6. Other Commerical or Industrial Firm	241	9	50	0	7	27	0	11
7. Private Citizen or Non-utility Cooperative	41	12	5	0	7	7	0	2
8. Unknown	110	4	3	1	4	9	0	11
Totals	1,288	116	187	82	101	310	11	67

*Number of plants at projects with the following purposes:

H = Hydroelectric
I = Irrigation
F = Flood Control
N = Navigation
W = Water Supply
R = Recreation
D = Debris Control
O = Other

Table 2-4

PROJECT PURPOSE AND TYPE OF PLANT

Plant Type	H	I	F	N	W	R	D	O
	Project Purpose*							
1. Run of River	431	6	22	27	10	36	1	11
2. Diversion	160	14	7	2	3	3	0	2
3. Reservoir	501	68	149	50	53	236	4	38
4. Reservoir with Diversion	190	30	8	3	32	37	6	9
5. Other	6	0	1	0	1	3	0	1
Totals	1,288	118	187	82	99	315	11	61

*Number of plants at projects with the following purposes:

H = Hydroelectric
I = Irrigation
F = Flood Control
N = Navigation
W = Water Supply
R = Recreation
D = Debris Control
O = Other

Plant Age, Head, and Capacity

Information on the age, power head, and installed capacity of existing plants is presented on Figures 2-1, 2-2, and 2-3.

Note that two thirds of the existing hydroelectric plants (Figure 2-1) were constructed prior to 1940. However, approximately 80 percent of the total U.S. capacity was added after 1940. This suggests that there might develop in the near future a significant effort to replace older units for maintenance reasons potentially providing an opportunity to increase the capacity at these plants.

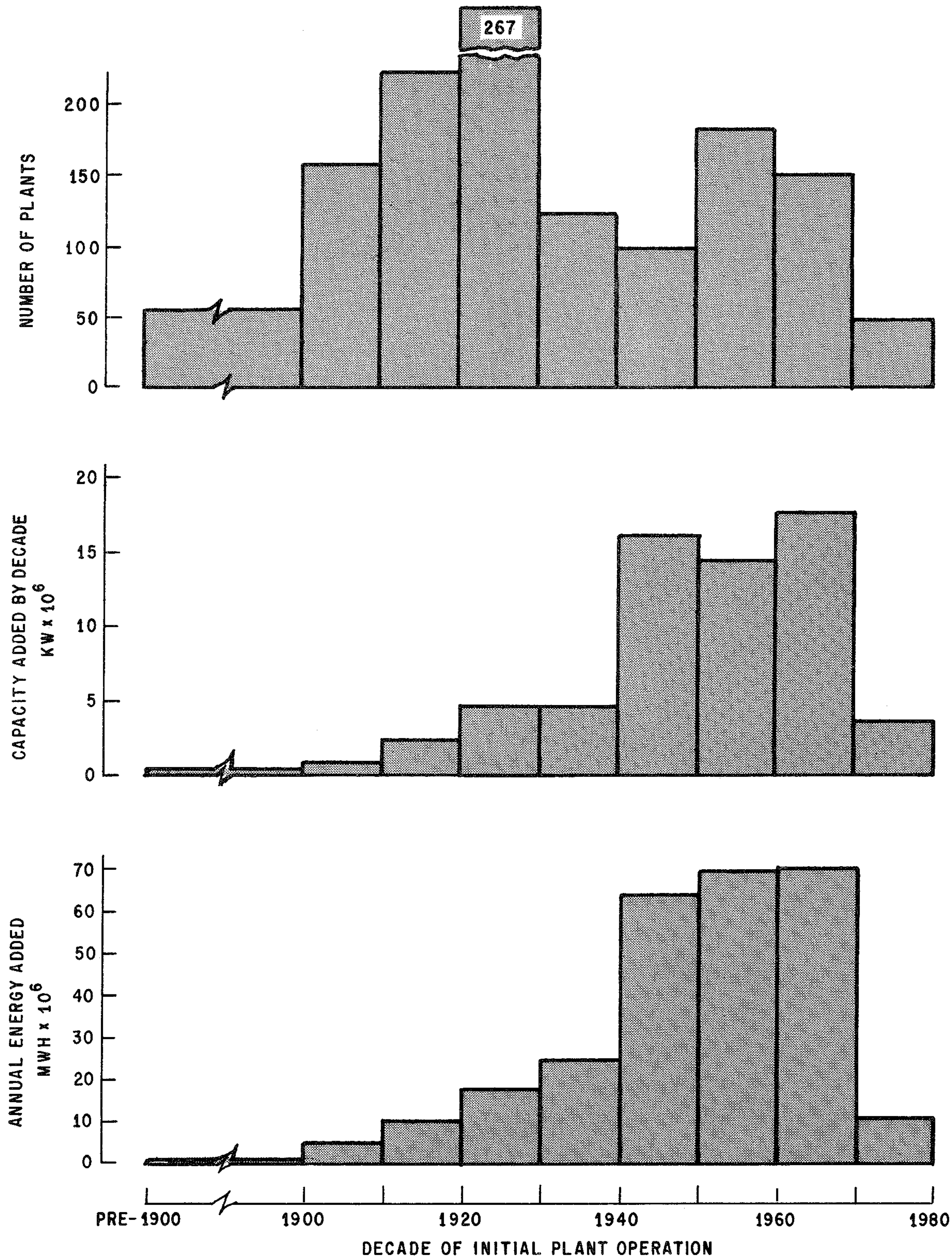


Figure 2-1

PLANT AGE VS. NUMBER OF PLANTS, CAPACITY, AND ENERGY

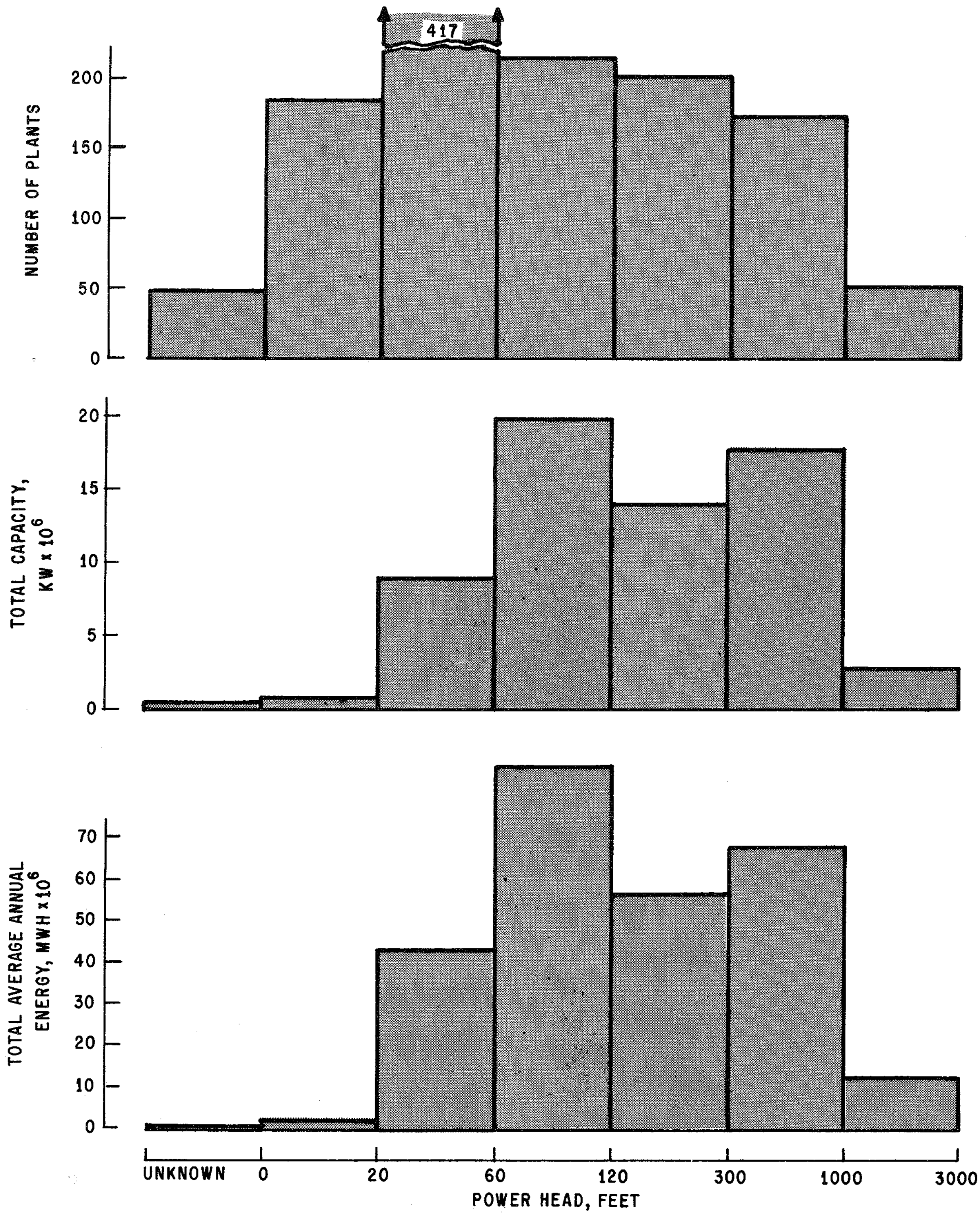


Figure 2-2

POWER HEAD VS. NUMBER OF PLANTS, CAPACITY, AND ENERGY

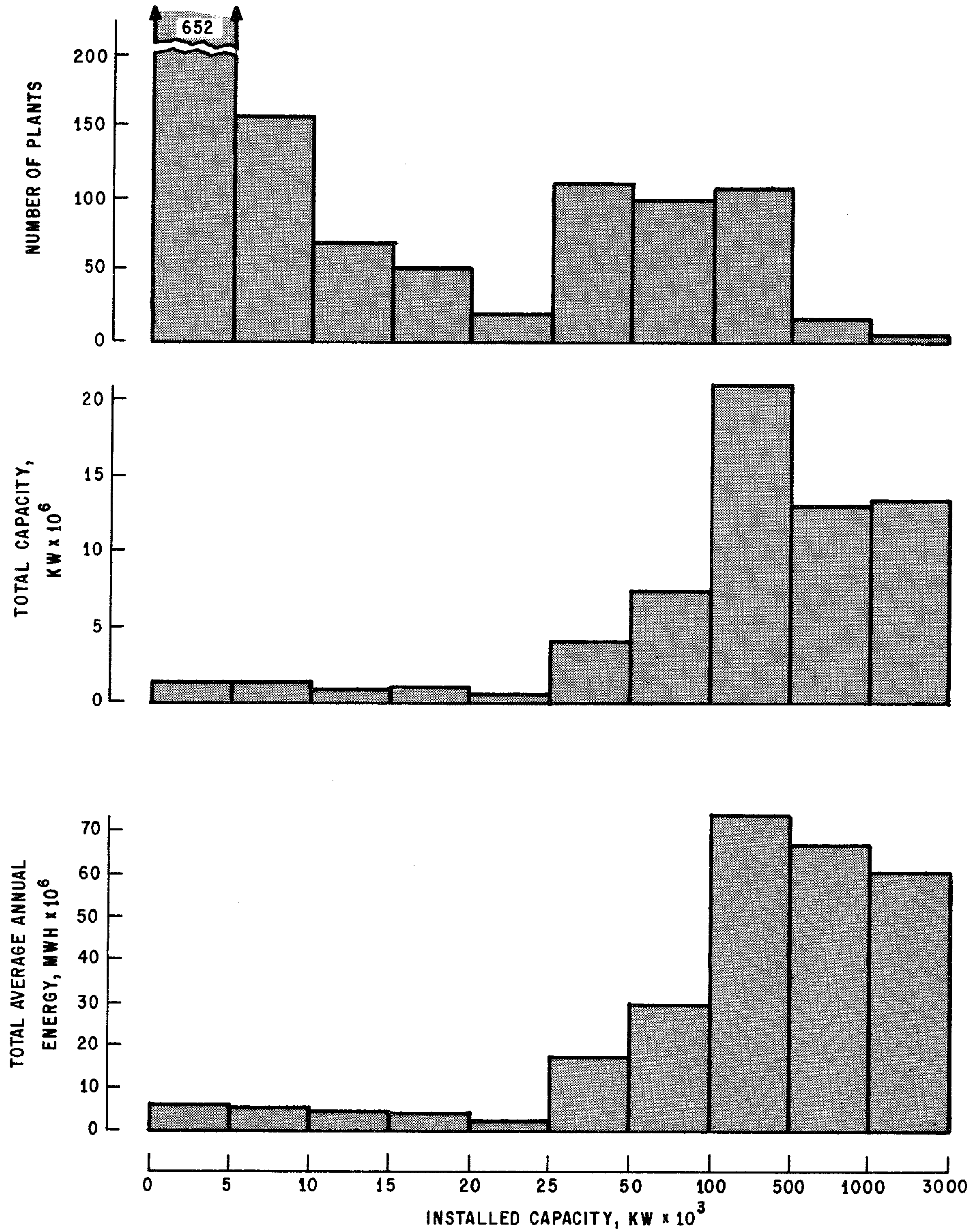


Figure 2-3

INSTALLED CAPACITY VS. NUMBER OF PLANTS, CAPACITY, AND ENERGY

Figure 2-2 shows that 50 percent of the plants have power head values of less than 60 feet. However, these plants contribute only 15 percent of the existing installed capacity and produce only 18 percent of the existing energy. The 60-300 feet head range contains only 32 percent of the plants, but these plants contribute 53 percent of the total capacity and produce 53 percent of the total energy.

Figure 2-3 presents the most graphic display of "big" versus "small" plants. Approximately 74 percent of the plants have installed capacities of less than 25 MW, yet these plants contribute less than 7 percent of the total installed capacity. A majority of the plants (51 percent) have installed capacities of less than five MW, and these plants have a combined capacity of less than 2 percent of the nationwide total hydropower capacity. On the other end of the scale, 22 plants (2 percent) with installed capacities of more than 500 MW contribute about 42 percent of the total existing capacity and produce about 47 percent of the total average annual energy.

Turbine Types

The information presented on turbine types (Table 2-5) is limited since data was available on only the 415 (28 percent) plants having capacities equal to or greater than 10 MW. However, this sample does represent approximately 80 percent of the total installed capacity. Therefore, any significant change in total installed capacity and average annual energy due to adding, replacing, or modifying units would probably occur at the larger sized plants.

2.3 REGIONAL CHARACTERISTICS

In order to provide an indication of regional differences, Table 2-6 was prepared to separate the number of plants, total installed capacity, and total average annual energy developed by State within the electric reliability council regions. Figure 2-4 delineates the area covered by each of these regions.

Table 2-5

TURBINE TYPE AT PLANTS 10 MW AND LARGER

Type	Normal Head Range, Ft.	Total Number of Units*	Percent of Total Sample
1. Impulse (Pelton)	60-2000	81	5
2. Reaction (Francis)	60-1000	1021	66
3. Propeller			
a. Adjustable (Kaplan)	10-120	272	17
b. Fixed	10-120	122	8
4. Other	----	58	4
Total Sample		1554	100

*Sample of 1554 units was taken from 415 plants with capacities equal to or greater than 10 MW.

2.4 PHYSICAL HYDROPOWER POTENTIAL

An upper bound estimate of total physical hydropower potential for existing sites in each region was prepared. This estimate provides insight as to where the physical potential is located and the order of magnitude limit of the potential for increase in energy output at existing sites.

The estimated maximum available energy at each plant is computed by routing the total runoff volume through the existing plant utilizing maximum available head. The weighted net power head was used except for those sites with flood control storage. At the flood control sites, the head used in the calculations was set equal to the existing weighted net power head plus the depth of the flood control space.

Table 2-6

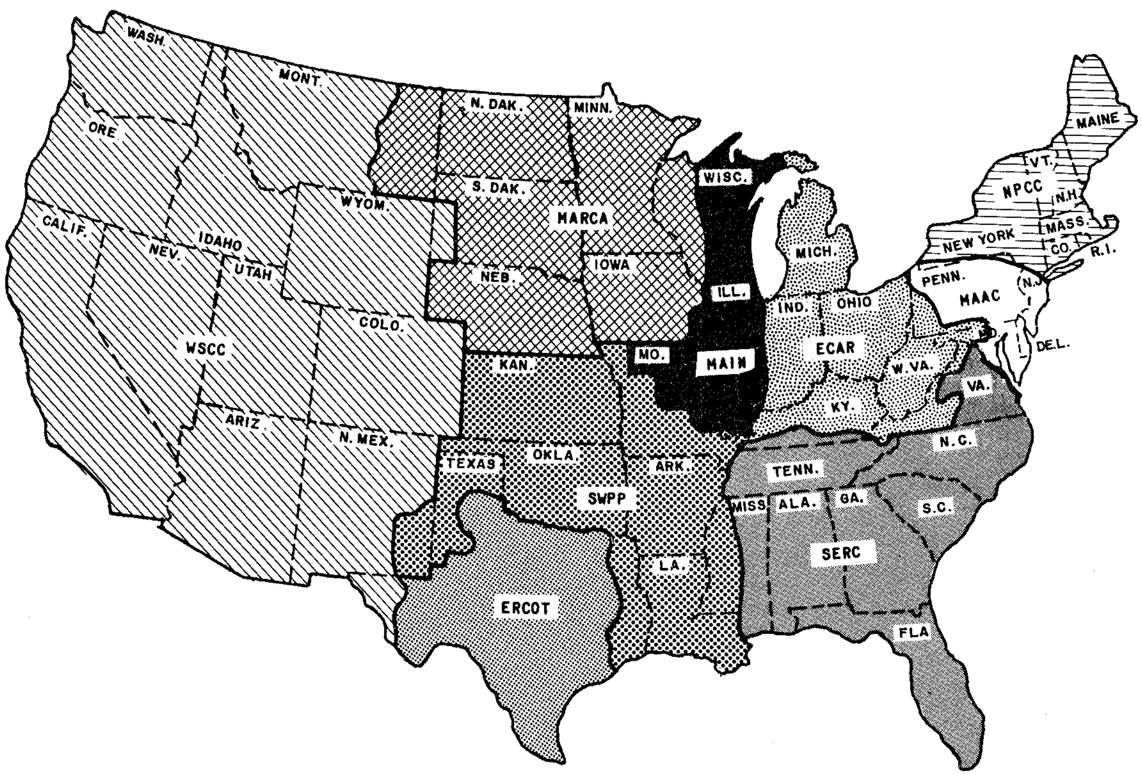
REGIONAL CHARACTERISTICS

Electric Reliability Council Region	State	Number of Plants	Installed Capacity MW	Average Annual Energy GWh
ECAR	Indiana	2	10.7	38.0
	Kentucky	1	61.0	67.0
	Maryland	3	3.0	21.2
	Michigan	40	238.3	1,035.9
	Virginia	10	95.9	195.2
	W. Virginia	4	124.7	674.0
Total ECAR		60	533.6	2,031.3
ERCOT	Texas	15	314.7	716.3
Total ERCOT		15	314.7	716.3
MAAC	Maryland	1	474.5	1,719.0
	New Jersey	2	5.8	17.5
	Pennyslvania	5	426.1	1,796.6
Total MAAC		8	906.4	3,533.1
MAIN	Iowa	2	130.8	825.0
	Illinois	10	48.9	237.8
	Michigan	29	143.6	705.0
	Missouri	2	472.0	440.0
	Wisconsin	63	230.5	1,133.5
Total MAIN		106	1,025.8	3,341.3
MARCA	Iowa	3	4.7	16.0
	Minnesota	27	171.4	897.6
	Montana	2	415.0	2,019.0
	Nebraska	18	368.5	824.2
	N. Dakota	1	400.0	2,270.0
	S. Dakota	10	1,492.2	6,093.2
	Wisconsin	28	223.1	901.6
Total MARCA		89	3,074.9	13,021.6
NPCC	Connecticut	15	103.3	360.2
	Maine	71	540.0	2,743.8
	Massachusetts	30	154.4	522.0
	New Hampshire	31	385.7	1,092.1
	New York	138	1,796.4	10,712.7
	Rhode Island	2	2.0	6.0
	Vermont	51	216.5	894.4
Total NPCC		338	3,198.3	16,286.2

Table 2-6 (Cont'd)

REGIONAL CHARACTERISTICS

Electric Reliability Council Region	State	Number of Plants	Installed Capacity MW	Average Annual Energy GWh
SERC	Alabama	21	2,706.6	10,898.4
	Florida	2	30.2	232.9
	Georgia	32	2,069.7	4,410.7
	Kentucky	3	575.0	2,192.0
	N. Carolina	56	1,923.4	6,568.9
	S. Carolina	34	1,138.2	3,072.0
	Tennessee	27	2,096.0	11,208.2
	Virginia	10	279.8	702.7
Total SERC		185	10,818.9	39,285.8
SWPP	Arkansas	11	1,079.5	2,791.8
	Kansas	2	2.4	10.0
	Louisiana	1	81.0	215.0
	Missouri	5	424.2	936.4
	Oklahoma	11	1,029.0	2,349.8
	Texas	1	52.0	127.6
Total SWPP		31	2,668.1	6,430.6
WSCC	Arizona	9	1,406.2	6,064.1
	California	125	7,947.0	31,121.2
	Colorado	21	530.5	2,118.0
	Idaho	41	2,549.6	12,436.8
	Montana	21	1,649.0	8,068.7
	N. Mexico	1	24.3	96.0
	Nevada	6	676.6	4,011.0
	Oregon	59	6,858.8	36,854.3
	S. Dakota	2	8.0	32.0
	Utah	43	192.0	939.2
	Washington	56	18,413.1	84,127.3
	Wyoming	17	284.9	1,280.0
Total WSCC		401	40,540.0	187,148.5
Other	Alaska	26	132.4	520.6
	Hawaii	14	17.5	106.2
	Puerto Rico	15	144.8	130.4
Total Other		55	294.7	757.2
GRAND TOTALS		1,288	63,375.4	272,552.0



Source: Inventory of Power Plants in the United States - April 1979, U.S. Dept. of Energy, Energy Information Administration

1. ECAR - East Central Area Reliability Coordination Agreement
2. MAIN - Mid-America Interpool Network
3. MAAC - Mid Atlantic Area Council
4. MARCA - Mid-Continent Area Reliability Coordination Agreement
5. NPCC - Northeast Power Coordinating Council
6. SERC - Southeastern Electric Reliability Council
7. SWPP - Southwest Power Pool
8. ERCOT - Electric Reliability Council of Texas
9. WSCC - Western System Coordinating Council

Figure 2-4

REGIONAL ELECTRIC RELIABILITY COUNCIL AREAS

The upper limit estimate of energy increase is the maximum available energy at each plant minus the existing energy presently being produced at that plant. The summation of these energy increases by region is shown on Table 2-7. An indication of present use of available energy potential can be obtained through computation of the utilization ratio, defined as existing average annual energy divided by maximum available average annual energy. Nationwide it is estimated to be 0.76. The upper limit estimate of energy increase above existing energy output is about 86,000,000 MWh or a maximum increase of approximately 31 percent.

A review of Table 2-7 shows that the WSCC region has the most potential for increasing energy at existing sites. However, the region also has a relatively high utilization ratio of 0.82. This indicates that the hydroelectric potential of existing sites in this region is already highly developed.

NPCC and SERC are two other regions that indicate significant potential. A utilization ratio of 0.50 within the NPCC region indicates there is a relatively large portion of the potential passing by the existing sites. The SERC region, by comparison, has a relatively high utilization ratio - similar to the WSCC region - and the remaining unused energy will likely be difficult to develop.

It must be emphasized that this maximum potential increase at existing plants cannot realistically ever be realized because:

- All of the current spillage cannot reasonably be captured and passed through a powerhouse.
- All of the flood control storage space certainly cannot realistically be reallocated to power storage.
- The project feature additions necessary to develop these increases in output will certainly not all be economically feasible.

Table 2-7

REGIONAL UPPER BOUND ESTIMATE OF POTENTIAL ENERGY INCREASE

Electric Reliability Council Region	Existing			Potential			
	Number of Plants	(1) Total Capacity (kW)	(2) Total Avg. Ann. Energy (AAE) (MWh)	(3) Maximum Possible Energy (AAE) (MWh)	(2)/(3) Utilization Ratio (U.R.)	(3)-(2) Maximum Energy Increase (MWh)	(3)/(2)-1 Increase Above Exist. AAE (%)
ECAR	60	533,600	2,031,300	3,549,000	0.57	1,518,000	75
ERCOT	15	314,700	716,300	1,190,000	0.60	474,000	66
MAAC	8	906,400	3,533,100	5,866,000	0.60	2,333,000	66
MAIN	106	1,025,800	3,341,300	6,683,000	0.50	3,342,000	100
MARCA	89	3,074,900	13,021,600	17,107,000	0.76	4,085,000	31
NPCC	338	3,198,300	16,286,200	32,384,000	0.50	16,098,000	99
SERC	185	10,818,900	39,285,800	51,343,000	0.77	12,057,000	31
SWPP	31	2,668,100	6,430,600	9,729,000	0.66	3,298,000	51
WSCC	401	40,540,000	187,149,600	229,039,000	0.82	41,890,000	22
OTHER	55	294,700	757,200	1,319,000	0.57	562,000	74
Total	1,288	63,375,400	272,552,000	358,209,000	(Avg.) 0.76	85,657,000	(Avg.) 31

These upper bound estimates do, however, provide an anchor point from which to refine estimates of potential. They do indicate plants that should be further studied for alternative approaches such as adding, replacing, or modifying units to utilize, at least, a portion of the unused available energy.

Table 2-8 was prepared to provide the following information pertinent to hydropower potential:

- Number of plants with potential for increased output, i.e., utilization ratio less than 1.0.
- Number of plants with essentially no potential for increased output, i.e., utilization ratio equal to 1.0.
- Number of plants with inadequate information to evaluate potential increased output. Also, the relative magnitude of installed capacity and average annual energy at these plants in comparison with nationwide totals.
- Relative magnitude of potential increased output at plants that have existing flood control storage compared to those that do not.

There are approximately 993 plants with some potential for increasing their energy output up to a maximum of 85,657,000 MWh. Only 17 percent of these plants (166) have flood control storage, but they do have the potential to provide 27 percent of the increased energy output. Approximately 16 percent of the plants indicate that they are fully developing the available energy at their locations. Currently, 7 percent of the plants (91) representing 4 percent of the total installed capacity have insufficient data catalogued into the study data files used for the analysis to evaluate their potential.

Table 2-8

MAXIMUM ENERGY INCREASE AT SITES WITH AND WITHOUT FLOOD CONTROL

Condition	Number of Plants	Existing (1) Total Capacity (kW)	Existing (2) Total Avg. Ann. Energy (AAE) (MWh)	Potential (3) Maximum Possible Energy (AAE) (MWh)	Potential (2)/(3) Utilization Ratio (U.R.)	Potential (3)-(2) Maximum Energy Increase (MWh)	Potential (3)/(2)-1 Increase Above Exist. AAE (%)
No Flood Control							
U.R.< 1.0	827	22,785,000	104,036,000	166,360,000	0.63	62,324,000	60
U.R.= 1.0	183	20,424,000	91,823,000	91,823,000	1.00	-	-
Subtotal	1,010	43,209,000	195,859,000	258,183,000	(Avg.) 0.76	62,324,000	(Avg.) 32
With Flood Control							
U.R.< 1.0	166	16,310,000	64,964,000	88,297,000	0.74	23,333,000	36
U.R.= 1.0	21	1,464,000	5,790,000	5,790,000	1.00	-	-
Subtotal	187	17,774,000	70,754,000	94,087,000	(Avg.) 0.75	23,333,000	(Avg.) 36
No Head & Inflow Data	91	2,392,000	5,939,000	5,939,000	(Assumed) 1.00	-	-
Total	1,288	63,375,400	272,552,000	358,209,000	(Avg.) 0.76	85,657,000	(Avg.) 31

Chapter 3

EQUIPMENT CHARACTERISTICS AT EXISTING PLANTS

3.1 OVERVIEW

The capabilities of each component of a hydroelectric plant are chosen by the plant designer either to agree with the plant size or the requirements of the equipment associated with it. Some components are custom made to agree with the capacity of the plant such as the turbines, generators, and transformers and some are made in standard ratings such as the switchgear and switchgear equipment. The ratings of equipment which are of standard manufacture will most likely be greater than the capacity ratings of the plant. This equipment will generally have additional capacity which may be utilized without modification. The additional amount of capacity is not the same for each standardized component.

Redesign is generally required to increase the efficiency of a turbine, generator, or transformer. Equipment design does not provide margin from which additional efficiency can be obtained. In the case of a turbine, operation at a greater percentage of the time at a head and/or flow different than originally contemplated, will result in a lower overall efficiency, since machines are generally designed to be most efficient for the planned operation regime. The overall operation will therefore be at a lower efficiency.

Obtaining additional output from existing hydroelectric plants by replacement or modification of the mechanical and/or electrical equipment for capacity and efficiency improvements is technically feasible. For purposes of this report, the term "uprating" will be used when referring to modification or replacement of the turbine and/or generator of an existing hydroelectric powerplant to increase plant output. This chapter discusses characteristics of mechanical/electrical equipment consisting of the turbine, generator, transformer, switchgear, transmission and switchyard relevant to uprating decisions. The reader is cautioned that additional flow and/or head must be available to drive the machines to higher output for capacity uprating to result in any increase in power output. Improvements in energy conversion efficiency can directly increase output for the same flow and/or head regime.

Uprating of existing hydroelectric powerplants in the United States has generally involved many more generator rewinds than replacement or modification of the turbine. This stems from age impacting generators more severely than turbines and the fact that turbines generally have additional capacity above the generator nameplate rating.

Improvements due to research, materials and design over the last 80 years have resulted in it being technically feasible to obtain substantial increases in capacity and to a lesser degree increases in efficiency from existing hydroelectrical equipment. When uprating an existing generating unit through modification or runner replacement, the amount of actual increase that can be obtained is limited by the specific design and manufacturing characteristics of the installed equipment. The year of manufacture or installation is used herein as an indicator of potential to assist in arriving at the potential capacity and/or efficiency gain.

Indications are that the generator is generally capable of being uprated to obtain a greater percentage capacity gain than can be developed from the turbine for an equivalent year of manufacturer. The turbine has been found in general to be the critical factor in determining the maximum output that can be developed.

A major consideration in determining whether to uprate an existing hydroelectric powerplant is the question of outage. Outage is the time the generating unit would be out of service undergoing replacement or modification. Opportunities for uprating appear to lend themselves more to powerplants with multiple units where outages can be scheduled to coincide with seasonal system power demand swings which would provide "windows" where a unit or units could be taken out of service without adversely affecting a systems generating capability. This outage period can vary considerably depending on the uprating to be done. If only the turbine runner is replaced with minor structural adjustments, the outage time could be as low as two months. If more major changes are required, this time could be six to twelve months.

Economics play a key role in the decision process of whether to uprate. With energy values increasing rapidly and alternative energy sources becoming more expensive, more attention is being given to obtaining additional output from existing hydroelectric plants.

3.2 TYPES OF POTENTIAL MODIFICATIONS

This study considered the following types of modifications that could be made to an existing powerplant to obtain additional capacity and/or improve the energy conversion efficiency. The potential adjustments considered were the following:

- Modifications to existing turbines and generators.
- Replacement of existing turbines and generators.
- Addition of new turbines and generators to existing plants.
- Addition of a new hydroplant near existing plant.

The information available for making the assessment of the potential additional output at 1,288 existing hydroelectric plants is limited to the data noted on Table 1-2. The information required to make an accurate assessment of the amount of additional output that can be developed at a specific hydroelectric plant should be obtained by site survey and investigation and would be considerably more detailed than that available for this assessment.

3.3 IMPACT OF AGE ON EXISTING TURBINES, GENERATORS AND OTHER EQUIPMENT

For purposes of this study, age is the single most important indicator when assessing an existing turbine or generator in determining the potential for an increase in efficiency or capacity. Age is the common factor for the evaluation of the condition of all components of hydroelectric plants. Age is an indicator of both deterioration and obsolescence. Deterioration has the effect of lowering the plant's capacity through a small loss in efficiency. Obsolete equipment has less capacity than new equipment given the same physical space for the unit. Age as used in this study is a screen by which equipment is evaluated for loss of efficiency resulting from deterioration; and a screen by which to evaluate the potential increase in capacity that could result from uprating and rehabilitating if additional flow and/or head might be available.

There are other factors unique to each component that would refine the estimates, but this information is not available without detailed site specific and equipment data; therefore, this study is restricted to available information from which to determine potential increases in capacity and efficiency.

Turbines

This study confines itself to reaction turbines (Francis, Fixed Bladed Propeller and Variable Bladed Propeller). Approximately 90 percent of the existing sites under consideration consist of installations with reaction turbines. The impulse turbines are assumed to account for the balance. Even though the older impulse turbine installations may have opportunities for uprating, they were not considered separately.

The Francis turbine is the oldest of the reaction types and dates back to the early 1900's. It wasn't until the 1920's that the propeller turbine was developed and not until 1930 that it began to be extensively manufactured.

Since the early 1900's when hydraulic turbines were first used to generate electrical energy, improvements in design and materials have resulted in turbines being able to develop greater capacity. Improved runner design along with higher specific speeds results in more compact machines, improved hydraulic flow conditions and increases in turbine efficiencies.

During the early days, turbine design and manufacture was restricted to the Francis turbine. Most of the early smaller Francis Turbines manufactured between 1900 and 1920 were furnished with vertical draft tubes and installed in an open flume setting. The flumes were large and the velocities into the turbine low. Some of the early Francis turbines were also furnished with an elbow type of draft tube. The elbow design followed results of tests at the Holyoke Laboratories which was the final word in turbine design at that time.

From the period 1925 to 1950 extensive testing and research was conducted and many modifications in design of the turbine casing, runner, and draft tube were made. During this period, turbine efficiencies reached into the range of 89 to 90 percent. Turbine capacities during the same period increased.

During the period 1955 to 1973, research and development continued, but in a limited amount due to decreased demand for hydraulic turbines. Newer designed turbines have higher specific speeds and through improvements in fabrication techniques and quality of materials it is feasible to manufacture larger sized parts with a resulting reduction in fabrication time and cost. Higher specific speeds also mean the turbine size has been reduced for an equivalent horsepower output. Efficiencies have improved slightly due to more improved hydraulic flow patterns through the water passages (from turbine intake through draft tube) which was due to improved and extensive model testing and results obtained through field tests of operating turbines.

Hydraulic turbines are very reliable pieces of machinery and are capable of being operated for periods of 50 years or more without major repairs. As with any piece of machinery, improvements in design take place which normally result in better performance. In the case of the hydraulic turbines this has been the situation. The improvements in materials and design have generally affected the runner, specific speed, water passages (draft tube), and wicket gate.

Factors which enter into the rate and severity of deterioration varies depending on a number of factors such as operating conditions, quality of workmanship, degree of maintenance, type of materials used, design, and quality of flow through water (corrosiveness and presence of injurious foreign elements). Table 3.1 summarizes the impacts of deterioration and obsolesence on capacity and/or efficiency for the components of the turbine. The most significant advance in turbine design has been improvements in runner design.

Table 3-1

IMPACTS OF AGE ON EXISTING TURBINES

Component	Impacts Caused By	
FRANCIS TURBINE	Deterioration	Replacement of Obsolescent Equipment
Runner Design and Material	Some loss of efficiency due to pitting from cavitation.	Moderate increase in efficiency due to runner shape and improved hydraulic flow patterns - 3 to 4 percent maximum.
	No decrease in capacity.	Large increase in capacity due to runner design - 25 to 30 percent maximum.
		Improvement in cavitation due to use of stainless steel.
*Water Passages (Draft Tube)	Essentially no decrease in efficiency or capacity.	Moderate increase in efficiency due to improved hydraulics - 1.5 to 2 percent maximum.
		Moderate increase in capacity due to improved hydraulics - 3 to 4 percent maximum.
*Wicket Gates	Essentially no decrease in efficiency or capacity.	Small increase in efficiency due to more streamlined gates - 1/2 to 1 percent maximum.
		No change in capacity.

*Only normally done in combination with runner replacement or modification

Table 3-1 (Continued)

IMPACTS OF AGE ON EXISTING TURBINES

Component	Impacts Caused By: Deterioration	Impacts Caused By: Replacement of Obsolescent Equipment
PROPELLER TURBINE (Fixed Blade & Kaplan)		
Runner Design and Material	Some loss of efficiency due to pitting from cavitation.	Moderate increase in efficiency due to runner design and blade angle and improved hydraulic flow patterns - 2 to 3 percent maximum.
	No decrease in capacity.	Moderate increase in capacity due to rummer design and blade angle and improved hydraulic flow patterns - 10 percent maximum.
		Improvement in cavitation due to large number of blades and use of stainless steel.
*Water Passages (Draft Tube)	Essentially no decrease in efficiency or capacity.	Moderate increase in efficiency due to improved hydraulic flow patterns - 1.5 to 2 percent maximum.
		Moderate increase in capacity due to improved hydraulic flow patterns - 3 to 4 percent maximum.
*Wicket Gates	Essentially no decrease in efficiency or capacity.	Small increase in efficiency due to more streamlined gates - 1/2 to 1 percent maximum.
		No change in capacity.

*Only normally done in combination with runner replacement or modification

Generators

In order for electrical equipment to conduct electricity, the conductors must be isolated from each other and from ground (the potential of earth). This isolation is commonly provided by air, oil, gas, vacuum, and by many non-conducting types of solid materials. These materials are called insulators and their effectiveness is measured by their lack of conductance for electricity.

Early in the development of electrical equipment air and organic materials were used to provide this isolation of the "live" conductors from each other and ground. In equipment where physical space is a major consideration, the use of an insulating material is necessary. This is particularly true for generators and transformers. Improvements in insulating materials over the past 50 years is the single most influential factor in being able to obtain additional capacity from an existing generator. Generator insulation deteriorates with time due to the heat generated by thermal, mechanical or electrical stresses. Even though the insulating material is deteriorating with time, the effect of this on the efficiency and capacity of the equipment is normally small. This is because the major loss is caused in the conductors and the magnetic core materials. The normal order of events for deteriorating insulation is a catastrophic failure.

The three basic insulation systems are Class A, Class B, and Class F. All of the basic insulation systems and hybrid variations of them are still in use today although the trend has clearly been away from the cellulosic materials used in Class A systems to the mica tapes of Class B and the high temperature resins of Class F.

Class A insulation has been pretty much limited to small, low voltage machines due mainly to its low dielectric strength, limited temperature range and very poor resistance to corona (ionization of surrounding atmosphere) damage. This limits the size and voltage rating of Class A insulated machines. Manufacturers tended to design Class A machines with an extra temperature margin to improve the useful life. This resulted in machines which were oversized for the rating. The first improvement in Class A insulation was the introduction of mica type to improve dielectric strength. Even though such insulation systems were still thermally limited to Class A temperatures, more economical design resulted in reduced size and cost of higher voltage machines.

The elimination of Class A materials gave a full Class B system with improved dielectric and thermal performance, but it was not until vacuum-pressure impregnation with asphalt was used that the full capabilities of a Class B system were realized. The higher dielectric strength and improved thermal conductivity of Class B and Class F systems are necessary for the development of larger, higher rated voltage machines. Class B and Class F systems when applied to Class A machines can lead to significant upratings. Class F insulation resulted from the replacement of the asphalt with one or more of a number of synthetic resins.

The development of insulating materials and systems has been gradual; consequently, it is not possible to state with precision when one system of insulation displaced an earlier one. For the purpose of this investigation, the development of the three basic insulation classes are best represented by the following listing:

Class of Insulation	Year of Use
A	1900 - 1930
B	1930 - 1970
F	1950 - Present

While age is a measure of deterioration of insulation, it is not a major factor in loss of efficiency or capacity. Time has seen the production of better insulating materials which allow equipment to operate more efficiently and have more capacity for the same physical size. Thus age is a measure of obsolescence which is in itself a major factor in determining efficiency and capacity.

The impacts of age on generators through use can be attributed to deterioration of components or systems and obsolescence due to materials improvement and design methods. The components of the generator that this study considers to be impacted by age are insulation, stator winding, stator core, bearings, and ventilation. Table 3-2 summarizes the impacts of deterioration and obsolescence on capacity and/or efficiency for the components of the generator. By far, the most significant impact of age on generators is through the improvements that have resulted in insulating materials and methods.

Transformers

A transformer is a relatively old product. As such, improvements have been introduced and continue to grow through evolutionary processes rather than revolutionary changes. Nevertheless, progress has been such that in 40 years the size of transformers shippable within the same clearance profile has grown from 100,000 kVA to 1,300,000 kVA and commercial operating voltages have increased from 220 kV to 750 kV.

In general, it is found to be both more economical as well as necessary to purchase new transformers, rather than endeavor to uprate the old units. When large number of stations are involved in uprating, it may be possible and practical to move transformers to different sites and only make purchases for the larger stations. However, mismatch of voltages and impedances as well as transportation and physical limitations may place restrictions on this approach.

Other Electrical Equipment

Other electrical equipment such as circuit breakers, bus bars, and switches which conduct the electrical current of the generator output have insulation and that insulation is exposed to the same processes with age as to generators and transformers. The equipment's insulation is not a distinguishable factor in the overall plant efficiency and is not a constraint on increasing the capacity of the plant.

Table 3-2

IMPACTS OF AGE ON EXISTING GENERATORS**

Component	Impacts Caused By: Deterioration	Impacts Caused By: Replacement of Obsolescent Equipment
*Insulation for Stator Coil	Essentially no decrease in efficiency or capacity.	Moderate increase in efficiency and large increase in capacity due to improved materials, increased amount of copper, and better manufacturing techniques. Capacity increase due to increased copper - 50%. Capacity increase due to insulation - 30% Total combined capacity increase - 80%
*Winding Copper for Stator Coil		Maximum efficiency increase - 0.6 percent. (Combination of insulation and winding copper.)
Core Steel (Replacement)	Small decrease in efficiency and little or no decrease in capacity.	Moderate increase in efficiency, little or no increase in capacity. Maximum efficiency increase - 0.7 percent.
Bearings	Essentially no decrease in efficiency or capacity.	Small increase in efficiency from better bearing materials and design. No increase in capacity. (Not considered to impact on results of report.)
Ventilating System	Small decrease in efficiency and little or no decrease in capacity.	Small increase in efficiency and moderate increases in capacity due to the addition of forced ventilation and then later to computer aided design. (Considered to be dependent on rebuilding of machine -- not an alternative.)

**The reader is cautioned that while these capacity increases are within the capability of the machines, the capacity of the turbine that is coupled to the generator must also be increased and additional flow and/or head (beyond existing) must be developed before increased power output can result.

*Reinsulating and recoiling is never done separately.

3.4 MAGNITUDE OF POTENTIAL INCREASES IN CAPACITY AND EFFICIENCY THROUGH UPRATING

The technical data presented in this section indicating potential capacity and efficiency increases were used for the investigation reported herein. They were not intended to be applied to an isolated site and, thus, should not be applied without careful study for site specific analyses.

Future improvements in capacity and efficiency appear feasible due to continued research resulting in technological and material developments. For purposes of this study, no credit will be given to future improvements but only to associate increase in capacity and efficiency that is achievable under today's technology and materials.

Turbine Capacity

Improvements in design of turbines since 1900 make it possible to uprate to obtain capacity increases as much as 35 percent through improved runner design and appropriate changes to other parts such as the draft tube for a Francis turbine and up to 10 percent for a propeller turbine (fixed bladed and variable bladed).

Turbines designed in the early years did not generally have the benefit of accurate flow measurements and therefore caution was exercised in selecting a turbine that would be in operation continuously. This resulted in the turbines in many cases being too small to take full advantage of the hydraulic or hydrologic conditions available. Advancements in design and materials used in the runners promoted by research and testing has resulted in turbine specific speeds increasing over the years without sacrifice to performance. These advancements have led to more compact turbines for similar operating conditions of head and flow. These improvements afford the opportunity to replace an old turbine with a higher capacity new turbine in the physical plant space.

Age is used herein as the indicator in establishing the amount of additional capacity which can be realized by uprating an existing turbine. In order to put into representative terms the amount of capacity increase that can be realized by uprating based on the year of manufacture, it is necessary to understand those factors which significantly impact the possibility of uprating.

Francis Turbines -- The factors that need to be considered in any capacity uprate of a Francis Turbine are many in number. The significant ones are as follows:

- Type of runner and wheel case design.
- Type of draft tube design (vertical or elbow).
- Setting of runner in relation to tailwater.
- Type of installation (open flume, concrete pressure flume, steel pressure case, semi-concrete spiral casing or complete spiral casing)
- Specific speed.
- Range of head and flow (site characteristics).

The design of a turbine runner is different for various specific speeds. Specific speed provides a means of comparing the speed of hydraulic turbines on the same basis of head and horsepower capacity. A single runner having a higher specific speed than another will run at a higher number of revolutions per minute to deliver the same horsepower under the same head.

The runner design establishes the type of runner used and this can then be compared with design improvements that have been made over the years to establish the turbine uprating potential for additional capacity.

Modifications or replacement of the runner or wheel case of the turbine provides the greatest portion of any capacity increase that can be realized by uprating. Modifications to the water passages such as the draft tube have less influence in obtaining increased capacity but can be very important in the turbines operational characteristics. Modification of an existing turbine can be by: a) cutting the buckets at the discharge edge and near the runner band; b) increasing the vented area (opening between buckets); c) use of a lesser number of buckets on the runner, and d) improved discharge angle. Replacing an old runner with a new one of greater capacity depends upon the setting of the turbine runner in relation to the tailwater, as well as the type of pressure case (or spiral case) in which the units are installed. Consideration must be given to the velocity at the intake to the spiral case or pressure case so that these velocities would not result in a improper velocity distribution entering the turbine. The significance of the type of installation is that each setting impacts the uprate potential differently due to the velocities encountered and it becomes necessary to make a very careful study to determine whether uprating is possible and whether it would provide the desired results.

Figure 3-1 graphically illustrates the improvements that have been made in capacity gains for a Francis turbine for the period 1900 to 1980 based on specific speeds that vary from 65 to 105 and heads in the range of 80 to 200 feet. Figure 3-1 is a composite curve of the significant factors that are considered representative of capacity increases that can be applied to other ranges of specific speed and head.

Francis turbines designed and installed up to 1950 have the potential for the greatest improvement. Increases in capacity of up to 35 percent are possible.

<u>Propeller Turbines (Fixed and Adjustable Blade)</u>--Propeller turbines did not come into use until about 1920 with early versions being fixed bladed. By 1925 the variable bladed propeller (Kaplan) was being manufactured and installed. Starting about 1930 extensive research and testing of the Kaplan turbine was carried out and continued until 1955. The significant factors effecting the uprating potential of a propeller turbine in order to obtain additional capacity are:

- Type of runner design.
- Number of blades.

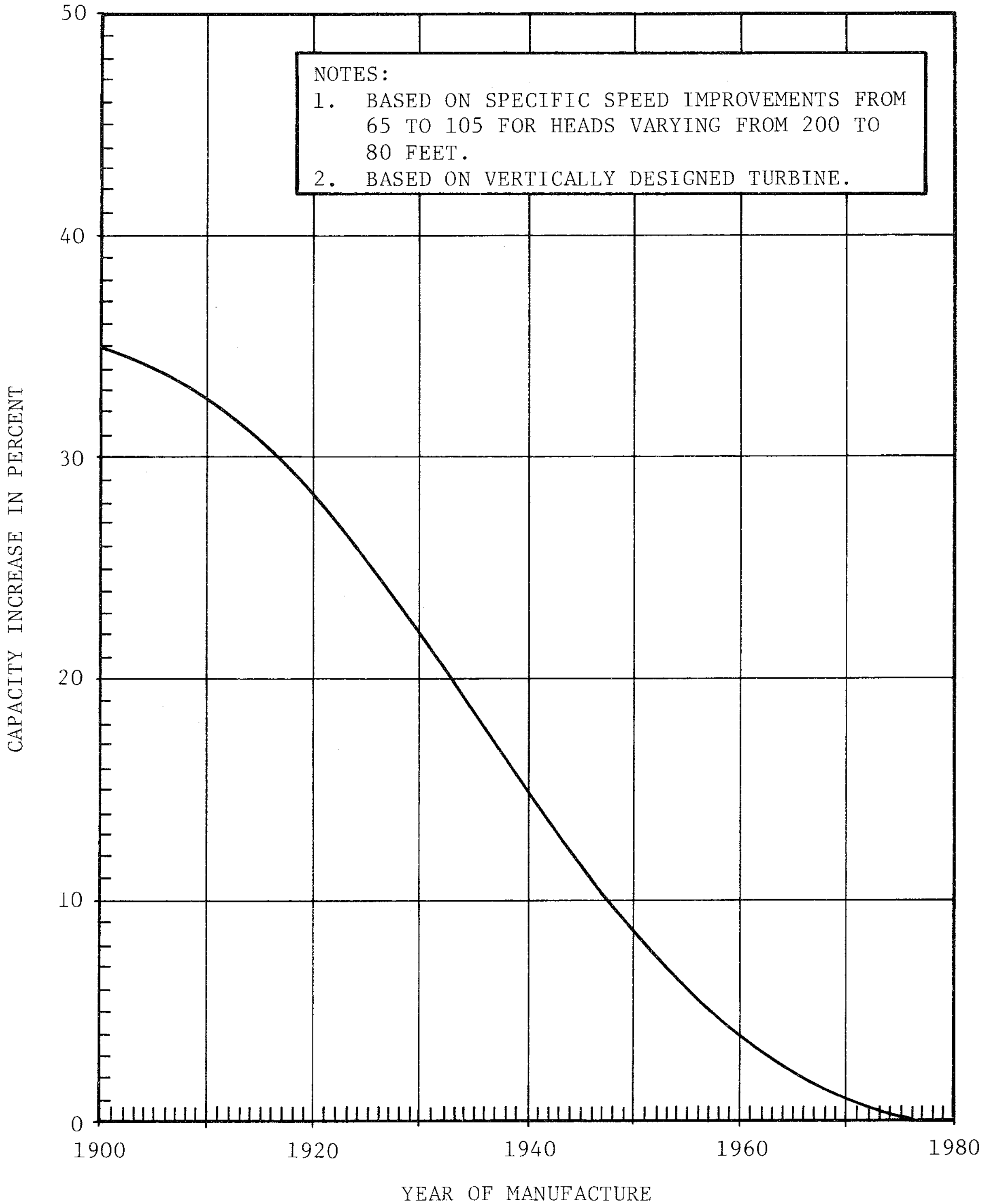


Figure 3-1

POTENTIAL FOR

CAPACITY INCREASE - FRANCIS TURBINE

- Angle of blades
- Setting of runner in relation to tailwater
- Type of draft tube design (vertical or elbow)
- Type of material in runner (cast steel or stainless steel)
- Type of discharge ring and hub (straight or spherical)
- Specific speed
- Head and flow (site characteristics)

The runner design establishes the type and number of blades used and whether the runner will be fixed or variable bladed (Kaplan). This information can then be compared with design improvements that have resulted over the years to establish the turbines uprating potential for additional capacity.

Increasing the blade angle of the turbine provides the greater portion of any capacity increase that can be realized. Improvements in capacity can only come about through replacement of the runner for a fixed bladed installation. This requires that the replacement runner have its blade angle increased which results in being able to obtain a capacity increase of 10 percent or more. The early Kaplan turbines were designed and built to have the blade move from a fairly low blade angle of around 6 degrees to a maximum blade angle of 26 or 28 degrees. This type of installation can be uprated to obtain approximately 8 to 10 percent additional capacity by increasing the maximum blade angle to around 32 degrees. This can only be done if the runner setting would be within reasonable limits.

In cases where cavitation is a problem the number of blades could be increased to 5 or 6 without requiring any changes in runner setting or the blades could be constructed of stainless steel.

The significance of the type of discharge ring and hub is that the earlier straight discharge ring and hub resulted in excessive clearance between the discharge ring and the blade as well as excessive clearance at the runner hub at certain blade angles causing leakage cavitation on the back of the runner blades. This was corrected by making the discharge ring and hub spherical.

Figure 3-2 graphically illustrates the improvements that have been made in capacity gains as a percentage increase for the propeller turbine for the period 1930 to 1980 based on specific speeds from 80 to 170 and heads in the range of 30 to 110 feet. The improvements have been gradual varying from around a maximum of 10 percent for installation dating back to the early 1930's to no improvement for installations after 1970. Figure 3-2 is considered representative of capacity increases that can be expected of other ranges of specific speed and head.

Generator Capacity

Generators manufactured in 1920 and earlier have the potential of being increased in capacity over 80 percent of the original rating. Generators manufactured after 1920 have a decreasing potential for uprating. Generators can be uprated through modifications of the following:

- Rewinding of the stator
- Improving the ventilation
- Adding core

Rewinding of the stator has the greatest potential for increased capacity because:

- New insulation has higher dielectric strength allowing for thinner insulation and increased copper
- New insulation has higher thermal capability allowing for operation at higher temperature

Increases in the amount of stator copper permits an increase in output which is proportional to the ratio of the square root of the additional amount of copper divided by the existing amount of copper (without additional loss or temperature change). The higher thermal capability permits a percentage increase in output equal to the square root of the new allowable temperature divided by the existing temperature. Thus, changing from Class A to B insulation permits a 15 percent increase and changing from Class B to F

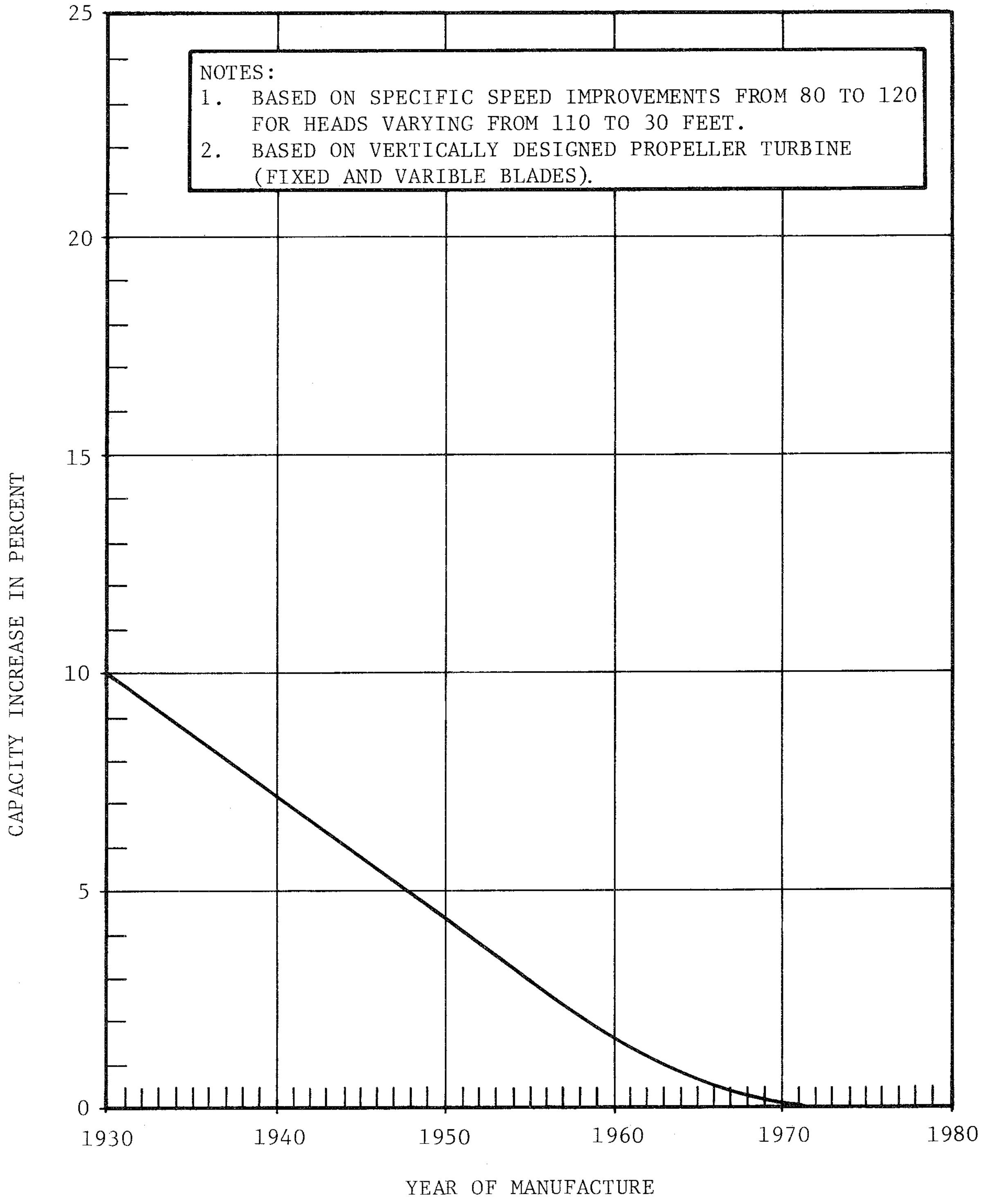


Figure 3-2

POTENTIAL FOR

CAPACITY INCREASE - PROPELLER TURBINE

insulation permits a 12 percent increase. Since the amount of copper that can be added depends on slot size as well as the type and volume of insulation to be used, the overall gain will be a function of terminal voltage and machine size.

Figure 3-3 illustrates the increase in capacity if new Class F insulated coils were installed in machines for the period 1920 to 1980.

The increases are based on better utilization of slot space due to increased dielectric strength and taking into account the 80 degree Celsius temperature rise capability of Class B and the 100 degree Celsius temperature rise capability of Class F.

While it is possible to obtain the increase in capacity shown in Figure 3-3 each generator is different and when any significant increase in capacity is contemplated it becomes more than a rewind of the stator. It becomes a major rebuilding of the machine electrically, mechanically, and structurally.

Design changes involving the ventilating circuit can often be very effective in increasing capacity. A better design of fan, improved baffling to direct the air flow more effectively or the addition of motor driven blowers can sometimes result in significant capacity improvement. Also, if the output of an open ventilated machine is limited by high seasonal ambient temperature, the capacity may be increased by adding surface air coolers and recirculating the cooling air.

Very little increase in capacity can be obtained from restacking the stator core with improved core materials unless the core is enlarged. Recognized that the capacity obtained from rewinding is sufficient for any increases in capacity obtainable from the turbine, restacking is usually only done to replace damaged core. Restacking the core will reduce the fixed losses.

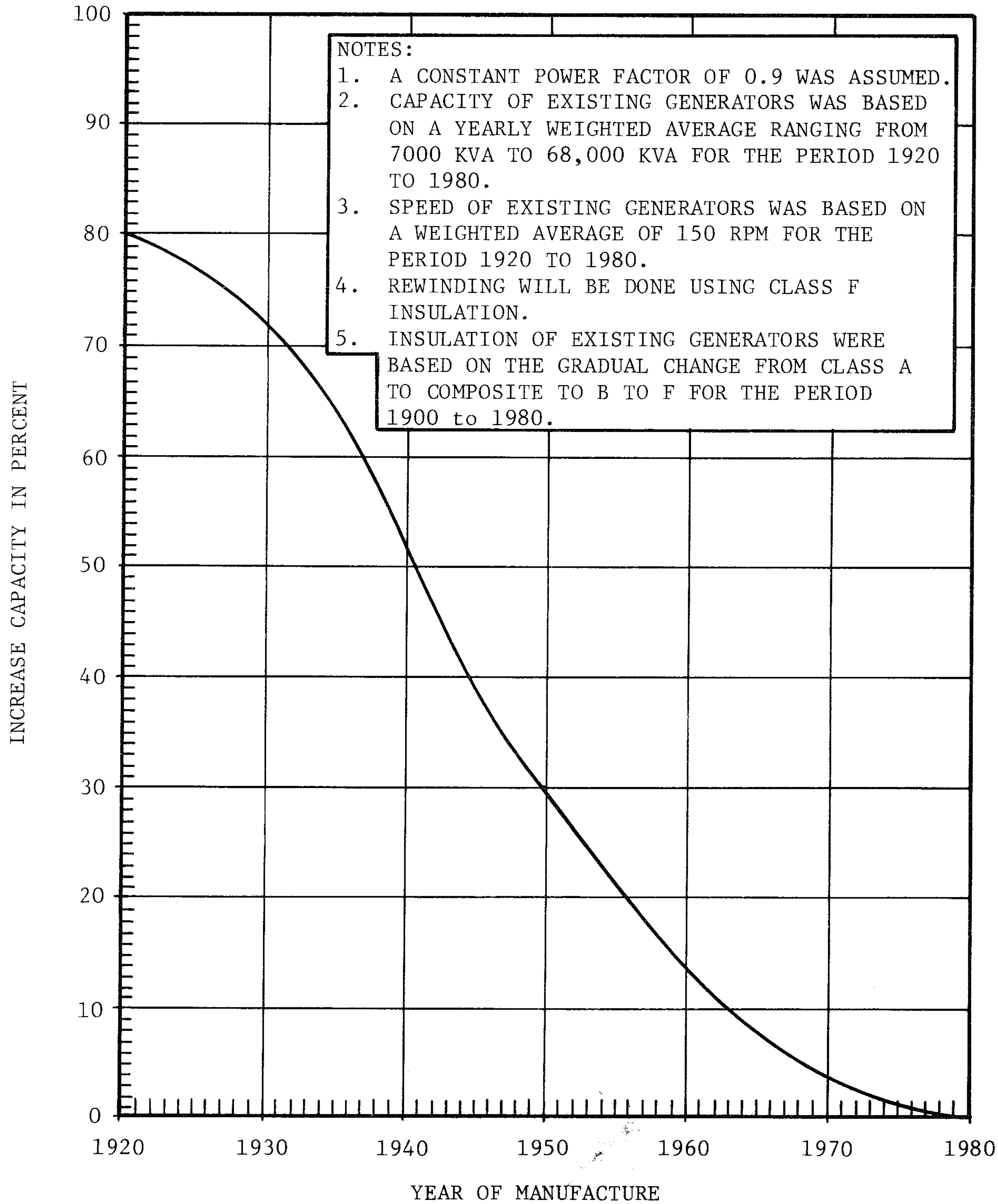


Figure 3-3

POTENTIAL FOR

CAPACITY INCREASE - REWINDING OF STATOR

Power Transformer Capacity

Power transformers manufactured prior to 1940 essentially have no uprate capability. Power transformers manufactured after 1940 have some uprate capability and the amount depends upon the type of cooling they have. This is because the transformer's rating is based upon the temperature rise and temperature rise can be altered by cooling. The capacity of oil insulated transformers depends upon the method of cooling the oil. Different methods of cooling the oil are available such as:

- Natural cooling
- Forced air cooling
- Forced oil cooling
- Heat exchanger using water as the exchange medium
- Combination of the above

The standard temperature rating is 55 degrees Celsius rise (at rated load) over a 40 degrees Celsius maximum ambient temperature. Modern transformers are built with insulation material that allows operation at the 65 degree Celsius temperature rise. Operation at the 65 degree Celsius temperature corresponds to 112 percent of the 55 degree Celsius capabilities and is reserved for temporary overload conditions. The addition of auxiliary cooling equipment allows increased capabity over the self-cooled ratings discussed above.

The age of the apparatus is very important. The useful life of a transformer is normally considered to be forty to fifty years. Some transformers manufactured before the late 1930's used soldered connections in windings and tap changers which have little ability to withstand overloads. The manufacturing records and drawings are normally preserve documents for 25 years. It is extremely doubtful whether the original manufacturers have sufficient data on units built prior to 1940 to be able to make a sound engineering evaluation as to the possibility of increasing the output KVA.

It may be possible to overload transformers manufactured after 1940 through the use of supplementary cooling. If the overloads are of short duration, then the American Standards Association (ASA) guides can be used as a base and the overloads will, in effect, shorten the life of the transformer.

Water cooled transformers, when tested at the factory, normally have a low temperature rise, that is, they test 10 degrees or more under guarantee. This is due to the fact that water coolers must be designed with a "fouling factor." If the cooling water has been generally free of corroding agents, the coolers may still be fairly efficient due to the built-in fouling overload capacity that has not been utilized. This may be in the 5-10 percent range. In a few instances, perhaps, new and larger external water coolers can be used.

The ratings of some self-cooled (OA) and self-cooled-fan-cooled (OA/FA) units can be increased by the addition of fans. The increase of radiating surface by the addition of radiators is generally not considered practical due to mechanical problems.

Transformers constructed in the last two decades generally have a dual 55/65 degree rating and can carry 12 percent extra MVA above the 55 degree base rating without loss of life. There is the possibility that a few older transformers could be built with new insulation. However, such a step would be evaluated against the advantages of buying a new unit.

For this study it was assumed that transformers installed prior to 1940 could not be uprated and those installed after 1940 could handle up to a 20 percent increase in capacity. Beyond a 20 percent increase in capacity the transformer was replaced.

Switchgear

Switchgear (for this study includes the generator leads, the generator breaker, potential transformers, surge capacitors and low side transformer leads) is manufactured in preselected sizes in accordance with manufacturer association standards. The designer must select from these standard sizes. Switchgear is initially classified by voltage and comes in basically three voltage levels in the U.S. They are 600V, 5000V and 15,000V.

The switchgear voltage rating is selected to agree with the generator voltage. The generator voltage is usually selected on the basis of generator cost; however, there are situations where other considerations may dictate a higher generator voltage. This usually is due to operation and maintenance considerations.

As generator kW approaches the maximum power rating of 15,000 volt switchgear, the practice of using a generator breaker is limited and a line (high voltage) breaker is used for tripping, starting and stopping. This requires each generator to have its own bus, transformer and line circuit breaker. This is called a unit scheme. This is an area where designers' and owners' discretion is used. It is not unusual to see unit schemes at much lower generator capacities. Where reliability is a major consideration use of unit schemes is warranted.

Unit bus and switchgear will normally have the same nominal ratings. These ratings depend upon the generator voltage, full load current, or short circuit capability, as well as short circuit capacity of power system to which the generator is connected. The available capacities are standard, and generally next greater sizes are selected providing a "built-in" uprate capability.

The "built-in" uprate capability in the bus and switchgear is assessed by analysis of available data on existing generator units. Since the voltage of existing generators is not available, a typical voltage has been assumed on the basis of manufacturing standards. Based on this evaluation the average uprate capability for switchgear was taken as 25 percent.

Transmission Line and Switchyard Capacity

Based on the identified hydroelectric unit capacities, and significant sampling for typical transmission outlets (i.e., 9.4 percent of total number of plants in U.S. and 26 percent of total plant capacity), an analysis was made to determine if sufficient line and switchyard capacity existed for increasing plant capacity by 100 percent. An overall screening of the sampling indicated possible transmission problems in the 10 to 50 MW plant size range and in the 100 to 150 MW plant size range. All other ranges surveyed appeared to have suitable capacity for up to 100 percent increase in capacity for hydroplants. To analyze these restricted outlet cases, typical transmission line and switchyard designs were assumed and their capacity compared to the average plant capacity, with the resulting available capacity margin derived.

Although a significant sample of outlets for plants less than 10 MW were not available, experience has shown that these plants have been historically located near or within local distribution service areas that utilize the generation directly. As a result, outlet capability should be adequate without major capital expenditure, and if any modifications or reconstruction is necessary on a site specific basis, the capital costs should be minimal compared to overall plant improvement costs.

In general, all identified hydroelectric plant capacities could be improved 100 percent without modification of existing transmission lines and switchyards. With the exception of a few specific cases, transmission outlets for plants in the 10 to 500 MW ranges were found to be of multiple line configuration, with the interconnected system utilizing the plants as convenient junction points.

Turbine Efficiency

The efficiency developed by a hydraulic turbine is dependent on the design and hydraulic characteristics of the water passage from the turbine inlet through the draft tube including wicket gate and runner. Improvements in efficiency of hydraulic reaction turbines has been very gradual over the past 80 years. The magnitude of these increases has been such that the maximum increase achievable is 3 to 4 percent for the Francis Turbine and 2 to 3 percent for the Propeller turbine (fixed bladed and variable bladed). It is reimphasized here that uprates to increase capacity must also include measures to develop additional flow and/or head in order to increase power output. On the otherhand, energy conversion efficiency (or simply efficiency) improvements would of themselves increase power output with the flow head regime unchanged.

Manufacturers of hydraulic turbines will generally not guarantee efficiency increases for modifications to existing turbines. Modifications of a turbine runner to obtain additional efficiency by itself is not normally done. The primary reason for uprating an existing turbine is to obtain additional capacity. There may not be any corresponding gain in efficiency. The output rating is generally guaranteed, therefore the opportunity for increased turbine performance is weighted much in favor of capacity improvements.

Being that the efficiency developed by a hydraulic turbine is dependent not only on the design of the runner, but also on the design of the associated water passages, any modifications to an existing turbine runner may require that model studies be performed in order to evaluate what adjustment may be necessary in the water passages to avoid losses in the turbine's performance and to insure its operational stability.

Francis Turbines---The factors that need to be considered in any improvements for efficiency of a Francis turbine closely parallel those for capacity with the significant ones as follows:

- Type of runner and wheel case design
- Type of draft tube (vertical or elbow)
- Setting of runner in relation to tailwater
- Type of installation (open flume, concrete pressure flume, steel pressure case, semi-concrete sprial casing and complete spiral casing)
- Specific speed
- Wicket gates
- Head and flow (site characteristics)

Modification of the draft tube can account for an increase in efficiency in the range of 1-1/2 to 2 percent. This applies to installations up to the early 1920's for a draft tube with an elbow where the horizontal dimension was short and its opening area patterned after the vertical conical draft tube. This type of draft tube can be replaced with one whose horizontal dimension is large by comparison and whose area does not follow that of a vertical conical draft tube but instead is based on design determined by extensive hydraulic laboratory research and testing supplemented by field results.

Improvements in runner and casing design during the period from 1925 to 1955 enabled turbine efficiencies to reach 89 to 90 percent at best gate opening. Since that time any modifications in turbine design have resulted in only small incremental changes in efficiency when model tested.

As stated, improvements by modification for efficiency alone is not normally done. If additional efficiency can be obtained through uprating for capacity (e.g., turbine capacity is increased and the energy conversion is also more efficient) it becomes an added benefit to the overall turbine performance but cannot be counted on in all cases. Figure 3-4 graphically illustrates the improvements that have been made in efficiency gains as a percentage increase for Francis turbines for the period 1900 to 1980 based on specific speeds varying from 65 to 105 and corresponding head range of 200 to 80 feet. Figure 3-4 is a composite of the significant factors to yield a curve that is considered representative of efficiency increases that can be applied to other ranges of specific speed and head.

<u>Propeller Turbines (Fixed and Adjustable Bladed)</u>---The factors that need to be considered in any uprate for efficiency of a propeller turbine closely parallel those for capacity with the significant ones as follows:

- Type of runner design
- Number of blades
- Angle of blades
- Setting of runner in relation to tailwater
- Type of draft tube design (Vertical or Elbow)
- Type of material in runner (cast steel, stainless steel)
- Type of discharge ring and hub (straight or spherical)
- Wicket gates
- Specific speed
- Head and flow (site characteristics)

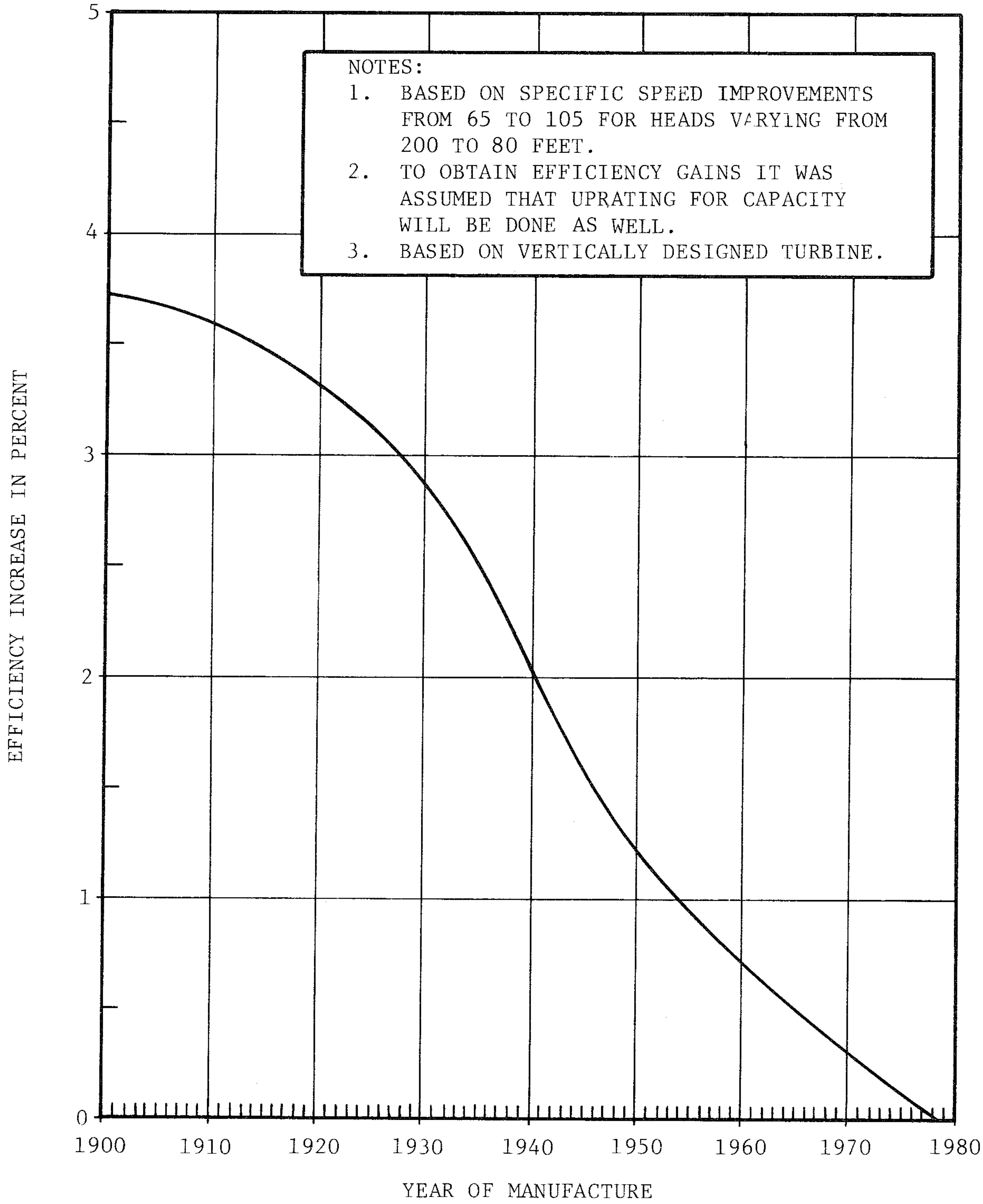


Figure 3-4

POTENTIAL FOR EFFICIENCY INCREASE - FRANCIS TURBINE

In the case of the adjustable bladed turbine (Kaplan) where the earlier designs used a straight discharge ring and straight hub the result was excessive clearance between the discharge ring and the blades at certain blade angles including excessive clearance at the runner hub. By replacement of the straight ring with one that is spherical the excessive clearance problem is minimized and results in being able to increase the efficiency 1 to 1.5 percent. It wasn't until the late 1930's that the spherical discharge ring and hub design replaced the straight version.

Design of the earlier turbine wicket gates for both the fixed and variable bladed propeller turbine were rather heavy and through improvements in design the gates were made thinner and more stream-lined, which resulted in obtaining an increase in efficiency of 1/2 to 1 percent. Modifications to the draft tube can also account for improvements in the efficiency. Improvements in design over the years has resulted in the elbow draft tube for the larger Kaplan and fixed bladed propeller turbines being designed with a vertical pier in the draft tube. Increases in efficiency to improved draft tube designs ranged from 1-1/2 to 2 percent. To overcome pitting problems caused by cavitation the material in the blades can be made of stainless steel and the number of blades can be increased. Older style propeller turbines were designed with 4 blades and by use of a 5 or 6 blade design, problems of cavitation can be minimized.

Figure 3-5 graphically illustrates the improvements that have been made in efficiency gains as a percentage increase for the propeller turbine from 1930 to 1980 based on specific speeds varying from 80 to 170 and heads ranging from 30 to 100 feet. Figure 3-5 is a composite of the significant factors to yield a single curve that is considered representative of efficiency increases that can be expected from other ranges of specific speed and head.

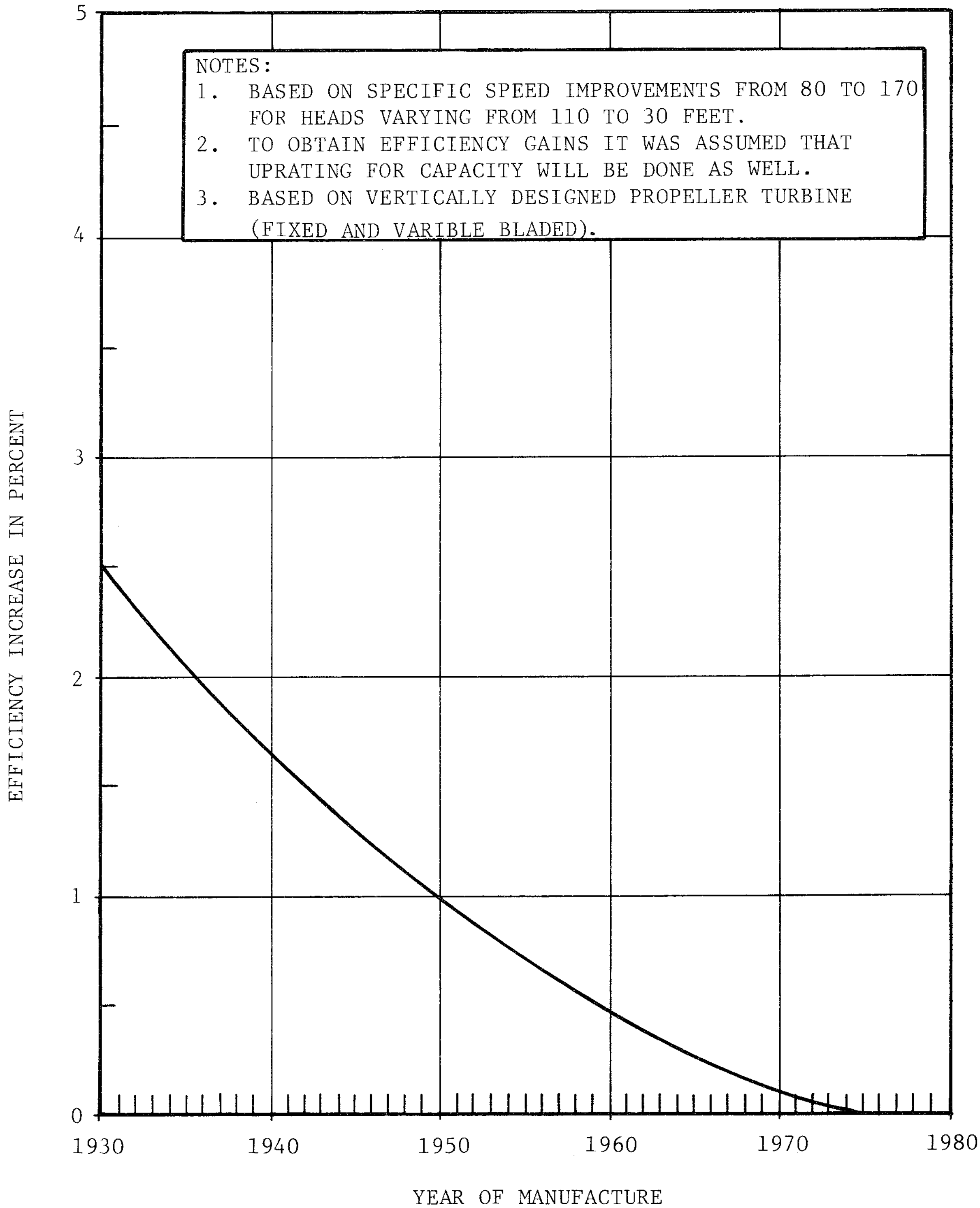


Figure 3-5

POTENTIAL FOR
EFFICIENCY INCREASE - PROPELLER TURBINE

Generator Efficiency

An increase in the efficiency of a generator can be obtained through:

- Improved insulation
- Improved coil design
- Improved core materials

For example a machine rewound with improved insulation (no change in capacity) will operate at a reduced stator temperature which results in an increase in efficiency. This is because the variable losses are reduced in direct proportion to the increase in copper weight while all other losses remain constant.

When a stator winding is replaced it is usually possible to increase its efficiency by reducing the losses in winding. This can be accomplished by substituting insulation having a higher dielectric strength and a higher temperature capability. Some additional improvement in efficiency may be possible by improving the stranding of the conductors or by somehow improving the transportation of the coil or winding; however, the increase from these sources will be small. That is not to say that coil design is not important but that it will not affect the results of this study. The volume of copper that can be placed in a slot depends on the thickness of insulation and the number of turns in the coil.

For a maximum increase in efficiency an uprating may take advantage of the higher temperature capability of the new insulation as well as the increase of stator copper.

Potential efficiency increases due to stator rewinding or stator recoring of the generator are relatively minor. Figure 3-6 shows the potential improvement in efficiency if Class F insulated coils were installed in machines of the year of manufacture. Figure 3-7 shows the possible improvement in efficiency if a machine of the year of manufacture were to be restacked with modern low loss steel.

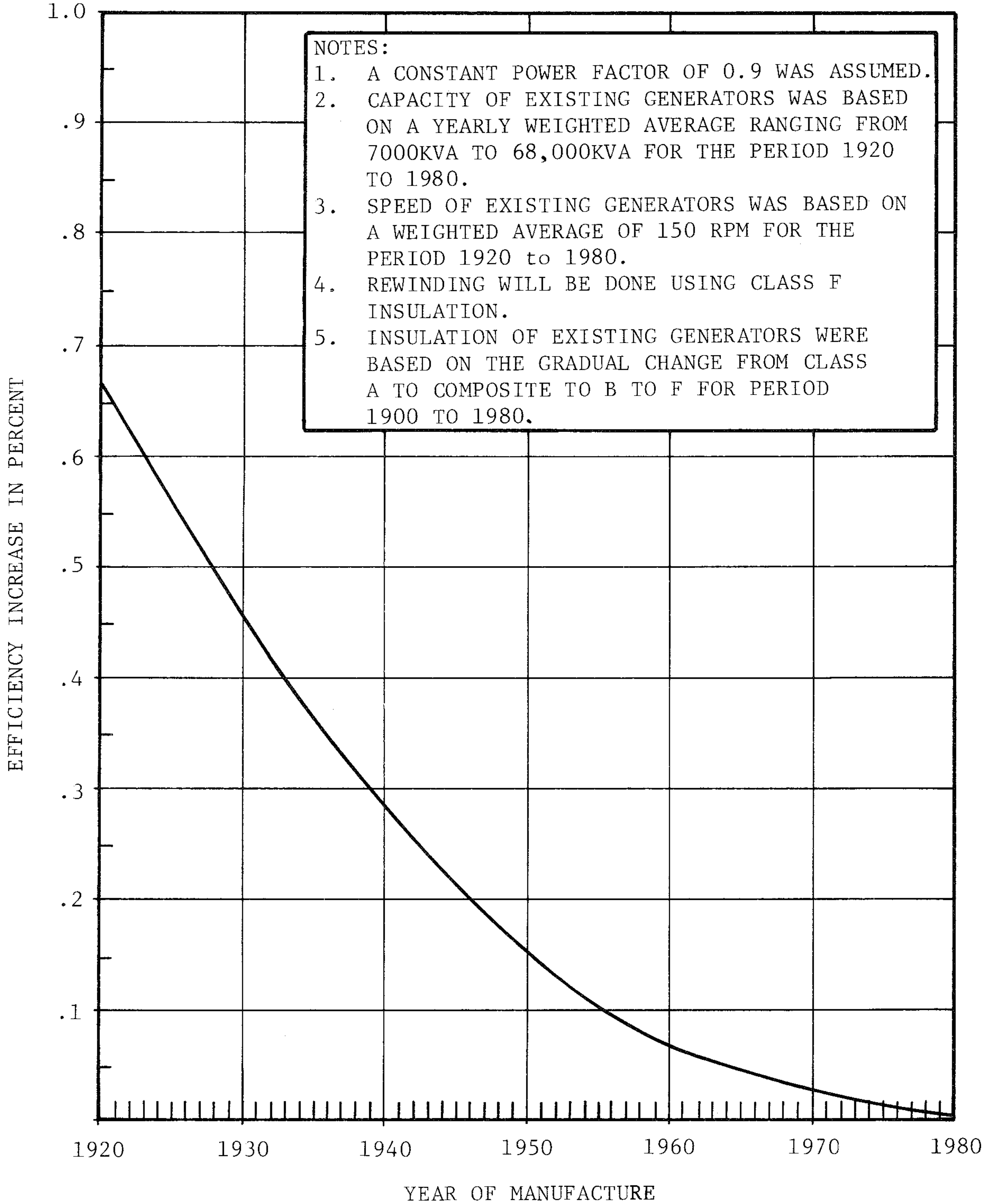


Figure 3-6

POTENTIAL FOR

EFFICIENCY INCREASE - REWINDING OF STATOR

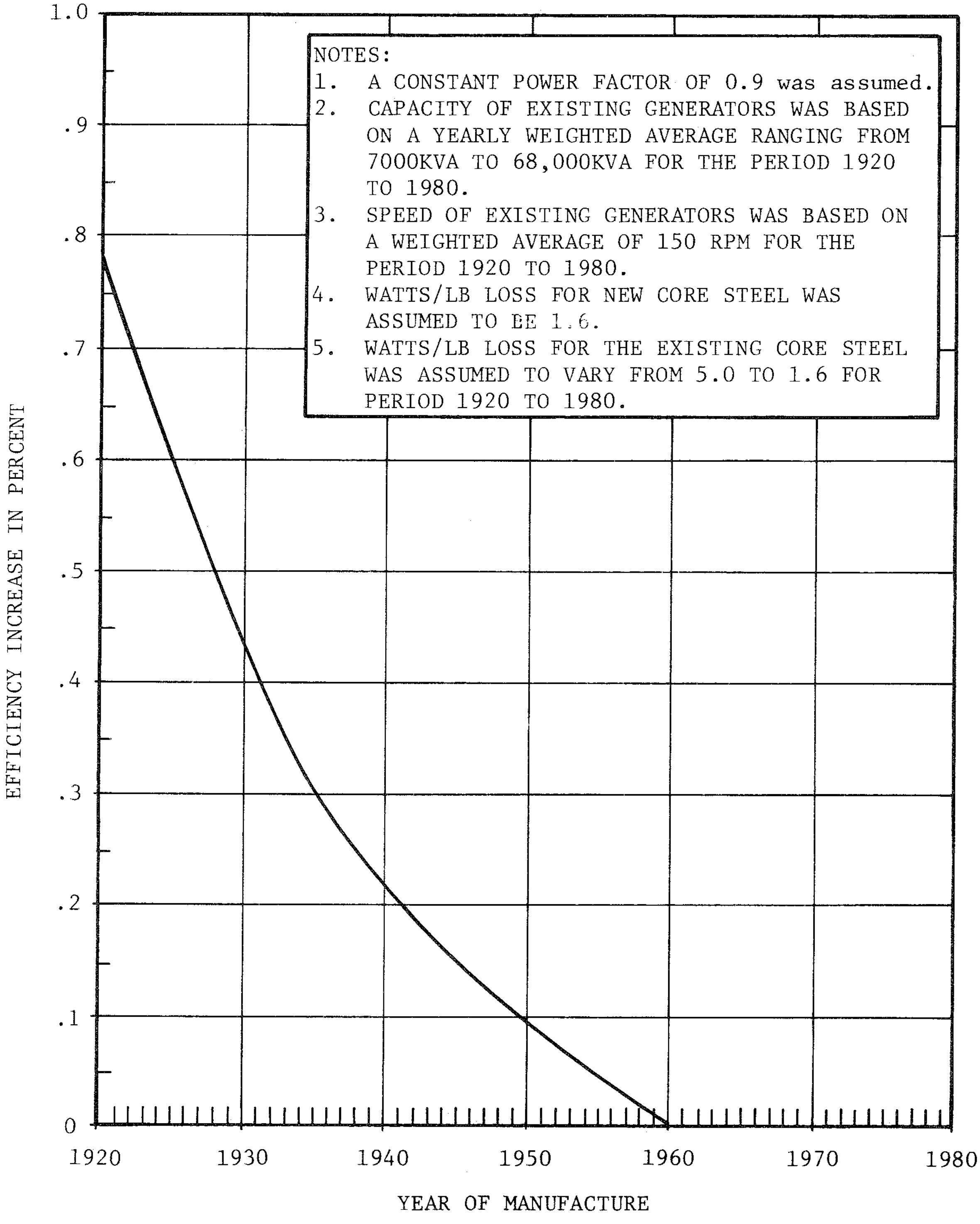


Figure 3-7
POTENTIAL FOR
EFFICIENCY INCREASE - STATOR RECORING

Transformer Efficiency

Power transformers do not have the same constraint on physical design as a generator, consequently its efficiency has always been high. A transformer is a very efficient apparatus. Yet, small changes in efficiency will result in a substantial savings through reduction of power losses. A transformer manufactured in 1925 may have an efficiency of 99.3 percent whereas a modern unit will have efficiency of 99.7 percent. Due to the small amount of potential increase in transformer efficiencies since 1925 this efficiency increase was neglected for this study.

Other Equipment Efficiencies

There are three categories of equipment in the plant other than the turbine, generator, and power transformer. These equipment all have the common characteristic of being of standard manufacture. The three categories are:

- Equipment in the main power flow
- Equipment which provides support for the plant (structure)
- Equipment which provides support for the turbine and generator

Equipment in the main power flow other than the turbine, generator, and transformer consists of the switchgear, main conductors, switches, and circuit breakers. This equipment almost always has additional capacity from 20 to 100 percent. Consequently, its efficiency is greater than what is would be if it was not of standard manufacture. Any attempt in increasing the efficiency would not be effective.

Equipment supporting the environment of the plant is small in rating compared with the main power equipment and even though increases in efficiency are to be expected, it is not considered to be either significant or pertinent to the purpose of this study.

Equipment providing support for the main power equipment is part of the consideration of the main power equipment. In an uprate situation the main power equipment auxiliaries must be considered for modification or replacement.

3.5 SUMMARY

Existing powerplants which have been uprated have not generally had new head and flow values which exceed 25 percent of the original design head and flow values. This is based on a very limited number of actual uprates (turbine and generator) that have been completed in the United States and elsewhere in the world. This past trend probably stems from the economics associated with uprating and availability of alternative energy generation sources. Therefore, uprates that have taken place were mainly confined to generator rewinds and a handful of turbine runner modifications. With energy values increasing rapidly and alternative sources of generation expensive, more attention is being given to uprating existing hydroelectric plants to obtain increased output through capacity and efficiency improvements.

An existing powerplant is generally capable of having the mechanical and/or electrical machinery modified or replaced to obtain increased output without requiring an expansion of the powerplant. This can be attributed to the fact that improvements in turbine and generation design have produced more compact machinery capable of increased output. This study assumes that if a new generating unit is to be added and the potential increase in capacity above existing capacity is less than 25 percent then the existing powerplant can be modified to accommodate it. All capacity increases above 25 percent will be accomplished by constructing a totally new powerplant separate from the original.

Limitations of Design and Manufacture

Each component of a hydroelectric plant has different design limits and consequently has different built-in capabilities and different potentials for being uprated. It is necessary to evaluate each component of the plant and determine the constraints and limiting factors for uprating the plant. In general, the turbine is the limiting component. Whatever amount the turbine can be uprated, all other components can also be uprated.

Design practices utilized in older installations normally resulted in the turbines and generators being designed with rather large margins of safety as compared to today. Designers would refer to past designs, scale sizes up or down, add additional material if needed to increase safety factors and possibly dispense with certain calculations. With the advent of the computer, continued research and testing, materials improvements, and improved fabrication techniques, close margins of safety can be adhered to.

Turbines are designed to operate within prescribed limitations. These limitations vary according to the type of turbine (Francis, Fixed Blade Propeller and Adjustable Blade Propeller). The normal practice is to provide the following margins for operation of the turbine (Corps of Engineers 1979).

Type of Turbine	Percent of Design Head Max.	Percent of Design Head Min.	Percent of Flow Max.	Percent of Flow Min.
Francis	125	65	105	40
Fixed Blade Propeller	110	90	105	40
Adjustable Blade Propeller	125	65	105	30

To deviate from these values can cause serious cavitation and vibration problems. In addition, if the turbine is operated above its rated head or flow a larger percentage of time than originally contemplated, the overall plant efficiency will be less due to a greater percentage of the operation being at a point of less efficiency than originally planned.

There is capacity in the components of the hydroelectric plant above the nameplate rating. In general, this capacity as a percent of the nameplate rating is as follows:

Component	Capacity Reserve Above Nameplate Rating
Tubine	15%
Generator	15%
Power Transformer	12%
Switchgear	30%
Switchyard	100%
Transmission Line	100%

Uprating Limitations

Improvements in capacity and efficiency that can be realized for the turbine, generator, and transformer by uprating are dependent on a number of factors as discussed earlier. For purposes of this study, it was necessary to generalize the factors so that relationships could be developed to yield representative values showing the relationship of potential increase in capacity and efficiency by the year of manufacture.

Results of this study show that each component of a hydroelectric powerplant has different uprate potential in terms of percent increase or change that can be obtained through modification or replacement. The critical components and potential improvements were previously identified in this chapter and are restated below:

Turbine---

- Up to 35 percent in capacity by replacement of the runner for a Francis turbine and up to 10 percent increase in capacity by replacement of the runner for a propeller turbine
- Up to 4 percent increase in efficiency by replacement of the runner for a Francis turbine and up to 2.5 percent in efficiency by replacement of the runner for a propeller turbine
- Up to 1.5 percent in efficiency for replacement of the Wicket Gates
- Capacity and efficiency increases are not necessarily additive

Generator---

- Up to 60 percent increase in capacity by rewinding the stator coils with new insulation (Class F) and new copper
- Up to 0.6 percent in efficiency by rewinding the stator with Class F insulation
- Up to 0.6 percent increase in efficiency by recoring the stator with modern low loss silicon steel
- Capacity and efficiency increases are not necessarily additive

Bus and Switchgear---

- Up to an average of 25 percent additional capacity without modification

Transformer---

- 12 Percent overload capacity with no loss of life
- Up to 20 percent increase in capacity by modification of cooling

Switchyard---

- Up to 100 percent increase in generation without modification

In using all of the figures in this chapter it is cautioned that the curves are not a substitute for a complete field evaluation by highly qualified personnel to obtain data and to examine the physical condition of the equipment to be uprated. This should be done in consultation with qualified manufacturers and the site owner. Only through a detailed study of the powerplant's physical configuration, history of the equipment and adequate site data can the uprating potential be established and whether it will be necessary to undertake model studies.

It is not the practice of the manufacturer to guarantee efficiency increases as a result of equipment modification because it is not the primary objective of an uprate. To add to this, there are accuracy limitations in measurement methods which make it inappropriate to guarantee efficiency increases through rebuilding of the equipment.

Chapter 4

INCREASED OUTPUT FROM PHYSICAL MODIFICATIONS

4.1 GENERAL OVERVIEW

This chapter presents the procedures used to calculate potential energy output and to determine that portion of the potential that is practically achievable due to physical changes to existing facilities. Applicable benefits and costs as well as the evaluation process are discussed. The last section presents and discusses the results of this work.

What determines the potential to develop additional energy at a particular location? The following general equation provides the components to explain the basis for increasing energy output:

$$\text{Energy Output, MWh} = (Q \bullet t \bullet H \bullet E_t \bullet E_g) / 11{,}800$$

WHERE Q = Flow through the plant, cfs

t = Time that plant is operating, hours

H = Net power head on turbine, ft.

E_t = Turbine efficiency

E_g = Generator efficiency

A review of this general equation indicates several ways of increasing energy output at existing plants.

- Increase flow (volume) through the plant
- Increase net power head
- Increase turbine and generator efficiencies

An increase in flow or volume through the plant can be accomplished by capturing and diverting some or all of the existing spillage, if any occurs, through the plant. These increased flows could be handled by replacing or modifying existing units and/or by adding new units to increase plant capacity. An increase in head can be accomplished by minimizing conveyance headlosses through the plant or by increasing power storage capacity to allow higher operating reservoir levels. Replacement or modification of existing units may be necessary at those sites where the change in head is significant. Turbine and generator efficiencies can be improved by replacing or modifying older units; however, note that the improvement in efficiency will likely be relatively minor (less than 3 to 4 percent).

The following physical changes were designated as "action" categories or measures that were studied to enhance the energy output at existing plants.

- Addition of new units for capacity increase
- Replacement of older units for capacity increase
- Uprating of older units for capacity increase
- Replacement of older units for efficiency increase
- Modification of older units for efficiency increase

Initially, all sites were categorized by region according to potential changes in flow and/or head as well as age to allow a systematic evaluation of these plants. The total gross physical potential increase in average annual energy and the corresponding increase in capacity were estimated at each site. Then the applicable benefits and costs of implementing one of the "action" items at each site were estimated and compared with a specified decision benefit/cost (B/C) ratio. The decision benefit/cost ratio was the decision device used to study the sensitivity of results to a range of acceptable economic criteria. If the B/C ratio for a specific "action" at a particular plant was greater than the decision B/C ratio, then, the increased energy was considered "achievable." A range of decision B/C ratio values were evaluated to provide sensitivity information.

4.2 INITIAL CATEGORIZATION OF PLANTS

All of the existing plants within each of the Electric Reliability Council Regions were separated into one of thirty-two categories based on whether or not the upstream reservoir had flood control storage, whether or not there is spill occurring at the site, the ratio of potential head to the existing average head at each flood control site, and the age of the plant.

The determination of whether spill is occurring at a site is based on comparing the average annual flow at the site with the average annual flow through the plant. Spill occurs if the average annual flow at the site is greater than the flow through the plant.

The approximate average annual flow through the plant was calculated based on the following:

$$AAE = (Q_p \bullet H_p \bullet E \bullet t) \;/\; 11{,}800$$

Where AAE = Average Annual Energy, MWh

Q_p = Average Annual Flow through the Plant, cfs

H_p = Existing Average Net Power Head, ft.

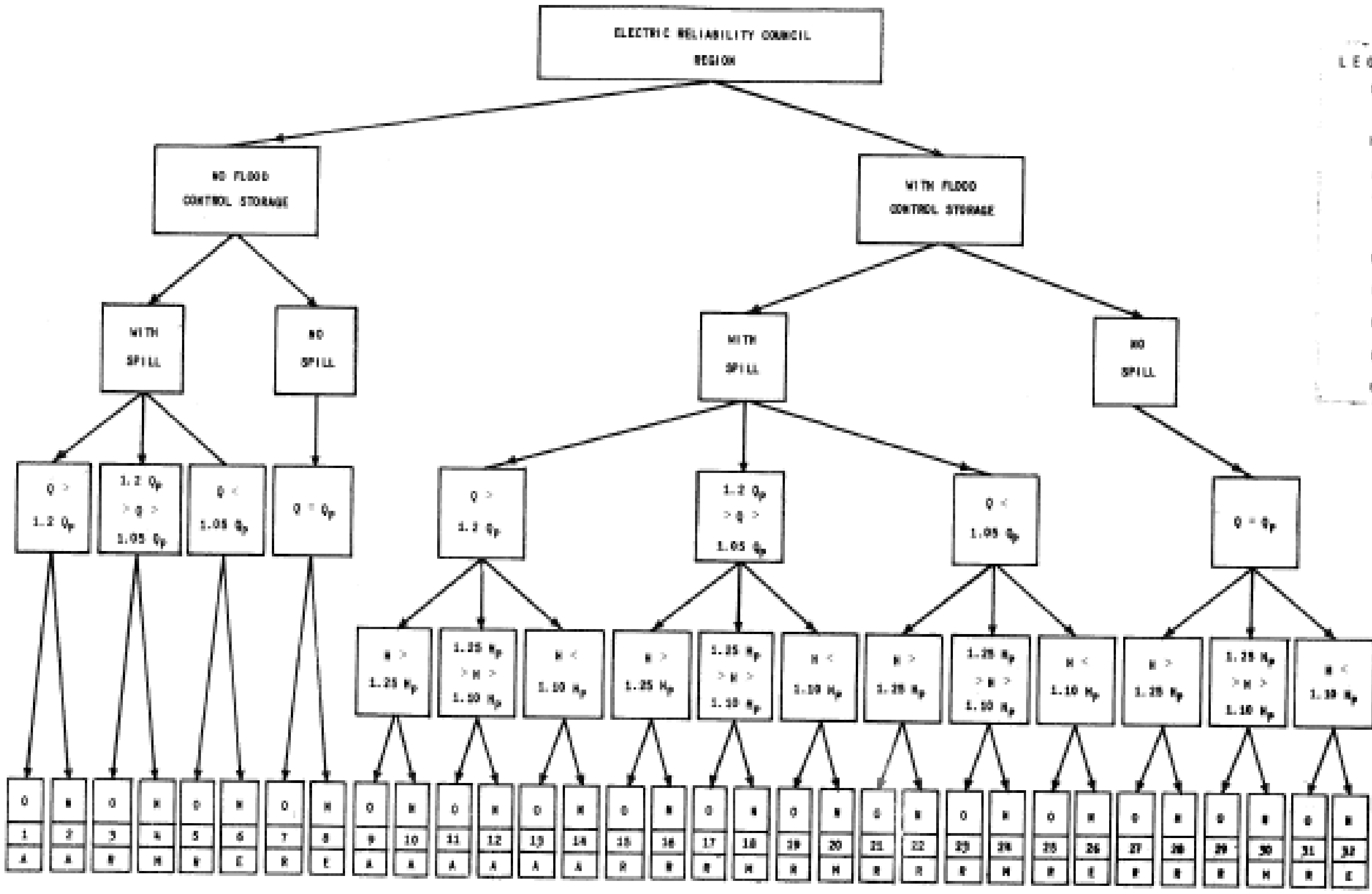
E = Plant Efficiency (assumed as .86)

t = 8,760 Hours Per Year

Therefore $Q_p = 1.57 \bullet AAE \;/\; H_p$

The flows calculated using this equation compared reasonably well with flows through the plant that were calculated with a reservoir simulation model (Hydrologic Engineering Center 1979) for 33 sample reservoirs.

Figure 4-1 is a schematic showing the plant categorization process. This initial categorization was used to provide an indication of the location and number of plants with various types of potential, and to simplify final evaluations. For example, old plants that do not have any flood control



LEGEND:

Q_p	Average Annual Flow through the Plant.
Q	Average Annual Flow.
H_p	Current Average Head at the Plant.
H	Maximum Available Head.
A	Plants are Candidates for Additional Units.
R	Plants are Candidates for Replacement of Units.
M	Plants are Candidates for Modification of Units.
E	Plants are Candidates for Efficiency Increase Only.
O	Turbines Installed Prior to 1950.
N	Turbines Installed After 1950.
8	Category Number.

Figure 4-1

INITIAL CATEGORIZATION OF HYDROELECTRIC PLANT storage or spill are candidates only for additional energy development due to improved efficiency resulting from replacement or modification of the existing units. On the other hand, a plant that is categorized with potential for adding units is also a candidate for replacement or modification of units.

Table 4-1 summarizes this initial categorization by indicating the number of plants within each category for each of the Electric Reliability Council Regions. This table also reveals the number of plants with or without flood control storage in combination with plants with or without spill. Note that only 187 plants (15 percent) have flood control storage and that 960 (74 percent) indicate at least some spill.

4.3 ACHIEVABLE ENERGY OUTPUT

How much of the upper bound estimate of potential energy development at existing plants presented in Table 2-7 is reasonable or practically "achievable" within the foreseeable future? This section presents the procedures used to provide an improved estimate of potential energy development that is achievable by adding, replacing, or modifying generating units at existing plants. Information is provided on development of associated benefits and costs followed by a discussion of the results of this section.

Potential Energy Output

As noted earlier there are several methods to increase output at a particular site that can be implemented by making physical changes:

- Increasing head on the plant
- Increasing flow through the plant
- Increasing head and flow
- Increasing plant generation efficiency

Table 4-1

INITIAL CATEGORIZATION BY REGION *

Region / Category	1	2	3	4	5	6	7	8	9	10	Total		
1	21	62	2	47	233	101	5	1	171	25	668		
2	1	2	0	3	6	5	4	1	23	8	53	With Spill (818)	No F.C. (1101)
3	1	5	0	3	19	9	1	0	22	5	65		
4	2	0	0	0	4	0	0	0	6	1	13		
5	0	1	0	0	2	4	0	0	8	0	15		
6	0	0	0	0	2	1	0	0	1	0	4		
7	1	4	2	16	70	42	0	3	99	12	249	No Spill (283)	
8	0	0	0	1	1	9	0	0	20	3	34		
9	6	11	0	1	1	0	0	2	4	0	25		
10	0	1	0	0	0	1	3	1	0	0	6		
11	8	4	0	5	0	2	2	1	0	0	22		
12	0	0	0	0	0		0	2	1	0	3		
13	9	5	2	4	0	1	2	2	17	1	43		
14	1	0	0	0	0	1	1	0	3	0	6		
15	1	1	1	0	0	0	0	1	1	0	5		
16	0	1	0	0	0	0	0	1	1	0	2	With Spill (142)	
17	3	0	0	0	0	1	1	0	1	0	6		
18	0	0	0	2	0	0	4	0	0	0	6		
19	2	1	1	1	0	0	0	0	3	0	8		
20	0	0	0	0	0	2	1	0	3	0	6		With F.C. (187)
21	0	0	0	0	0	0	0	0	0	0	0		
22	0	0	0	0	0	0	0	0	0	0	0		
23	0	0	0	0	0	0	0	0	0	0	0		
24	0	0	0	0	0	0	0	0	0	0	0		
25	1	0	0	1	0	0	0	0	0	0	2		
26	0	0	0	0	0	1	0	0	1	0	2		
27	3	1	0	2	0	0	1	1	4	0	12		
28	0	0	0	0	0	0	0	0	0	0	0		
29	0	4	0	1	0	0	0	1	2	0	8	No Spill (45)	
30	0	1	0	0	0	3	1	0	0	0	5		
31	0	2	0	2	0	1	0	0	9	0	14		
32	0	0	0	0	0	1	3	0	2	0	6		
	60	106	8	89	338	185	31	15	401	55	1288		

*See figure 2-4 for Electric Reliability Council regions and location (Region 10 includes Alaska, Hawaii, and Puerto Rico).

The reduction in inlet and outlet conveyance headlosses is another method that was considered. Typically inlet and outlet conveyance facilities at hydroelectric plants are designed to be reasonably efficient. A normal range of total headlosses for both inlets and outlets is 1 to 4 percent of the total head available at a site. Therefore, only minor decreases in headloss could be expected, probably at a relatively high construction cost. It would not be expected to be justified to shut a plant down for the sole purpose of implementing inlet/outlet headloss improvements. At those sites with long unlined penstocks there would be a possibility to significantly decrease headlosses by lining the conduit with a smoother, more efficient surface. Two utilities noted that this possibility has been given serious consideration; however, the benefits derived from the increase in energy generation were outweighted by the downtime costs during construction. For these reasons no attempt was made to evaluate the potential energy increase due to reducing inlet and outlet conveyance losses.

In order to evaluate the appropriate potential increase in energy at each site the increases were calculated for three possible conditions: maximum potential, resource limit, and equipment limit. The replace and modify cases considered all three conditions. The equipment limit was not applicable for "add" cases. The calculated energy increases for each case were compared and the limiting or minimum increase was selected. The relationship between increases in energy and capacity were generally based on flow-capacity to energy-duration information (hereafter referred to as flow-duration information) taken from the from the NHS data base. This information is available for 78 percent of the plants and 86 percent of the total installed capacity. For those sites without flow-duration information a relationship between the change in energy and the change in capacity was developed. A brief discussion on the calculation of the potential energy increase for the three conditions follows. Figure 4-2 is an example flow-duration curve that has been annotated to illustrate the calculations discussed herein.

<u>Maximum Potential</u>-- The maximum potential condition evaluates the increase in energy and corresponding capacity increase obtainable by capturing a reasonable upper limit of the available flow. For this condition a judgement was made that flows higher than those that would be exceeded less

LEGEND

CAP = Capacity, KW

AAE = Average Annual Energy, MWH

APF = Annual Plant Factor

ΔCAP = Capacity Increase, KW

ΔCAP_M = Maximum Capacity Increase, KW

ΔAAE = Energy Increase, MWH

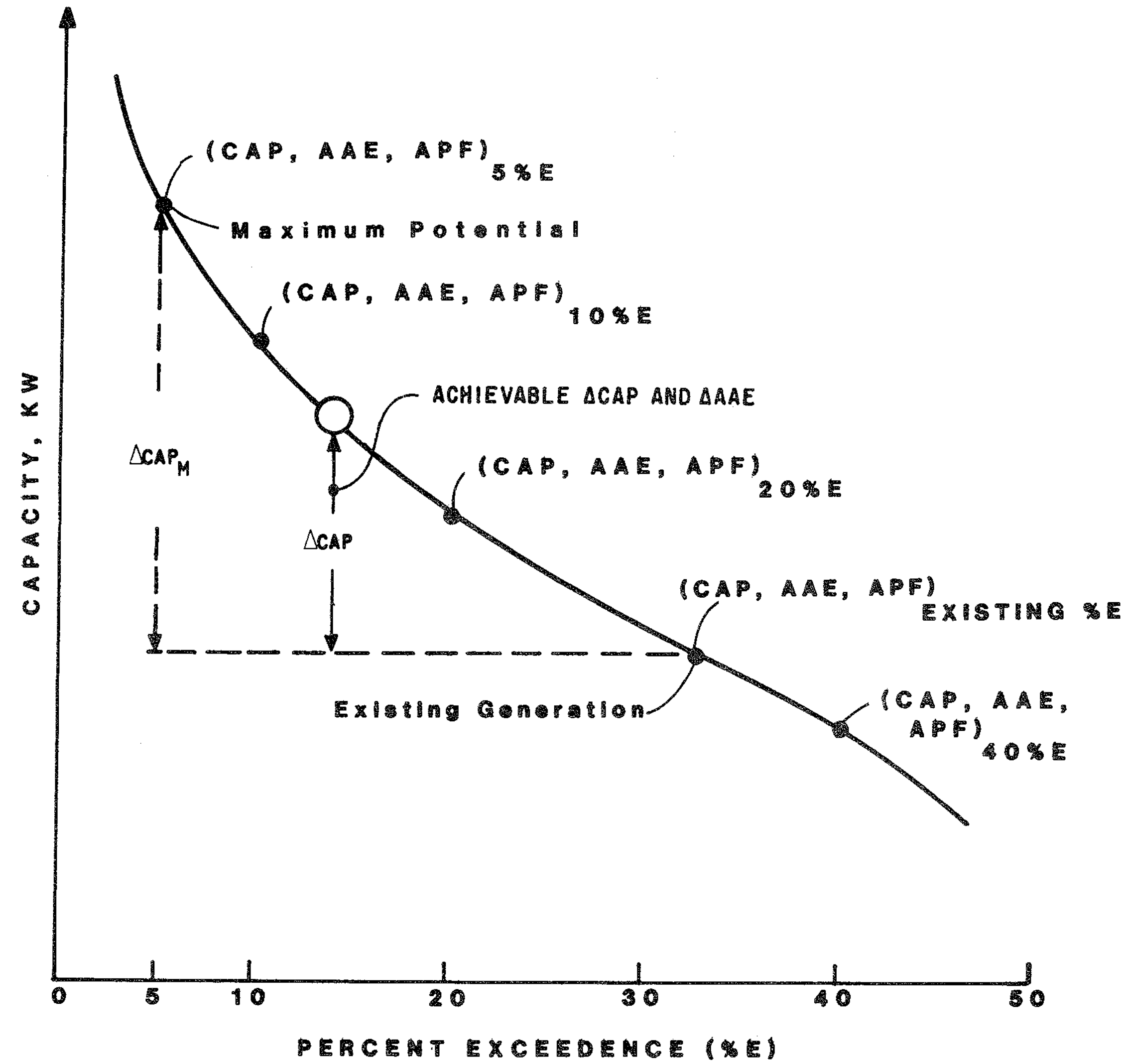


Figure 4-2

SCHEMATIC—CAPACITY AND ENERGY INCREASE EVALUATIONS

than a 5 percent of the time would not likely be capturable. Therefore, for this condition the maximum increase in energy and capacity would be the difference between the values at the 5 percent exceedance frequency and the existing values. From Figure 4-2 it is seen that

$$\Delta AAE = AAE_{5\%} - AAE_{Existing}$$

Resource Limit-- This condition was included mainly to cover those sites that did not have flow-duration information available. The increase in energy for the resource limit condition is equal to the difference between the calculated maximum average annual energy (based on utilizing all the available flow and maximum head) and the existing average annual energy.

Where flood control storage is available the maximum head includes the depth of the flood control space. The equation used for this condition was developed based on the general equation as follows:

$$AAE = (Q \bullet t \bullet H \bullet E) \ / \ 11{,}800$$

Where

AAE = Average annual energy, MWH

Q = Average annual inflow, cfs

t = 8,760 hours/yr

H = Appropriate net power head, ft.

E = Plant efficiency (assumed = .86)

$$\text{Max. } AAE = (Q \bullet 8760 \bullet H \bullet 0.86) \ / \ 11{,}800 = 0.64 \bullet Q \bullet H$$

and

$$\text{Max. Potential } \Delta AAE = (0.64 \bullet Q \bullet H) - AAE_{Existing}$$

An analysis of over 1,000 sites with flow-duration information was performed comparing the calculated maximum average annual energy with the average annual energy at the 5 percent exceedance frequency. The results indicated that the latter value was approximately 90 percent of the maximum value. Based on these results the general equation to calculate the energy increase for this condition was adjusted to reflect this difference and is:

$$\text{Max. Potential} \quad \Delta AAE = (0.58 \bullet Q \bullet H) - AAE_{Existing}$$

Equipment Limit -- This condition is applicable only to sites where replacement or modification of existing units is being considered. The increase in capacity for these cases may be limited by the existing equipment as noted in Chapter 3. The increase in energy value calculated for the equipment limit condition is compared to those values calculated for the maximum potential and resource limit conditions and the minimum increase is selected.

Value of Power Increase

The evaluation strategy previously described assures that each existing plant is evaluated for those action items that are available for increasing power output. Criteria are therefore necessary to choose from among the action items the one appropriate for each site that is consistent with the intent of the investigation. The strategy selected was that each site would be subjected to evaluation beginning with the action item that would result in the greatest increase in energy output and proceeding progressively to the items that would result in the least potential increase. The evaluation process for each site would stop whenever the action item evaluated meets the specific economic decision criteria. In effect, the item resulting in the greatest energy gain and was "economically justified", as defined below, was selected for that site.

Economic justification was determined based on an indicator decision benefit to cost ratio. The decision benefit to cost ratio is allowed to vary such that a range of results for achievable energy increase is determined. Benefits and costs, in a very general sense, are developed for each action item for each site. The method of developing the benefits used in the analysis are discussed below.

Power output from hydropower plants is often valued by crediting value for "capacity" and value for "energy" separately. See Water Resources Council documentation (Water Resources Council 1979) for a complete description of current Federal policy regarding valuing power output. The capacity benefit conceptually values the ability of a power facility to meet a particular load (demand) under a stated set of conditions. The capacity value is determined by comparing the proposed plant (or addition) to a likely plant alternative, and assigning what might be thought of as the fixed cost of the alternative plant as the capacity value. The hydropower plant capacity associated with the capacity value is almost always referred to as dependable capacity. The capacity benefit is therefore the product of the dependable capacity of the hydropower plant and the derived capacity value.

The energy benefit conceptually values the ability of a power facility to generate continuously over a period of time to meet a particular energy load. The energy value is determined by comparing the proposed plant or addition to a likely plant alternative, and assigning the continuous operating cost (fuel plus operation and maintenance) as the energy value. The hydropower plant energy output most often (although present concepts are rapidly changing) associated with the energy value is referred to as firm energy. The energy benefit is therefore the product of the hydropower plant firm energy and the derived energy value. The total power benefit used in these evaluations is the sum of the capacity benefit and the energy benefit.

Two major difficulties surfaced when considering power benefit estimates for this investigation. It became obvious that it would be impossible within this study scope to determine the amount of capacity that might be added at a specific site that would be classed as "dependable" (and the amount of energy that would be defined as "firm" as well). It was also obvious that developing the power values on a site specific case would likewise not be possible. The approach taken for this latter difficulty was to make use of the nation-wide in scope, regionally developed power values developed by the Federal Energy Regulatory Commission (FERC) (Federal Energy Regulatory Commission 1978). These values represent an attempt to integrate the nature of the likely alternative to the regional characteristics of the existing generating systems.

The uncertain nature of the power output was accommodated in this investigation, at least for the capacity issue, by carrying through the analysis for two sets of capacity values--full value and one-half of full value to represent "intermittent" capacity - high and low estimates. Energy values were used as documented in this chapter by determining the value of energy as if it were all firm.

There are difficulties in using any general data on a wide spread basis. To assure that inconsistencies and quirks that might be in the power value tables were not permitted to greatly bias results, several sensitivity studies were performed and are later discussed.

The high and low estimates are based on the following equations:

High

$$TAB = (\Delta Cap \bullet CB) + (\Delta AAE \bullet EB)$$

Low

$$TAB = (\Delta Cap \bullet CB/2) + (\Delta AAE \bullet EB)$$

Where TAB = Total annual benefits, \$/yr.

ΔCap = Additional capacity added to plant, kW

CB = Regional dependable capacity benefit factor, \$/kW

CB/2 = Regional intermittent capacity benefit factor, \$/kW

ΔAAE = Additional average annual energy developed at plant, MWh

EB = Regional energy benefit factor \$/MWh

Tables 4-2 and 4-3 contain the regional energy benefit (EB) and regional capacity benefit (CB) values for 32 regions (See Figure 4-3) developed by the Federal Energy Regulating Commission (FERC) in 1978. These regional values are a function of annual plant factor that conceptually represents the nature of the alternative power generation source.

Table 4-2

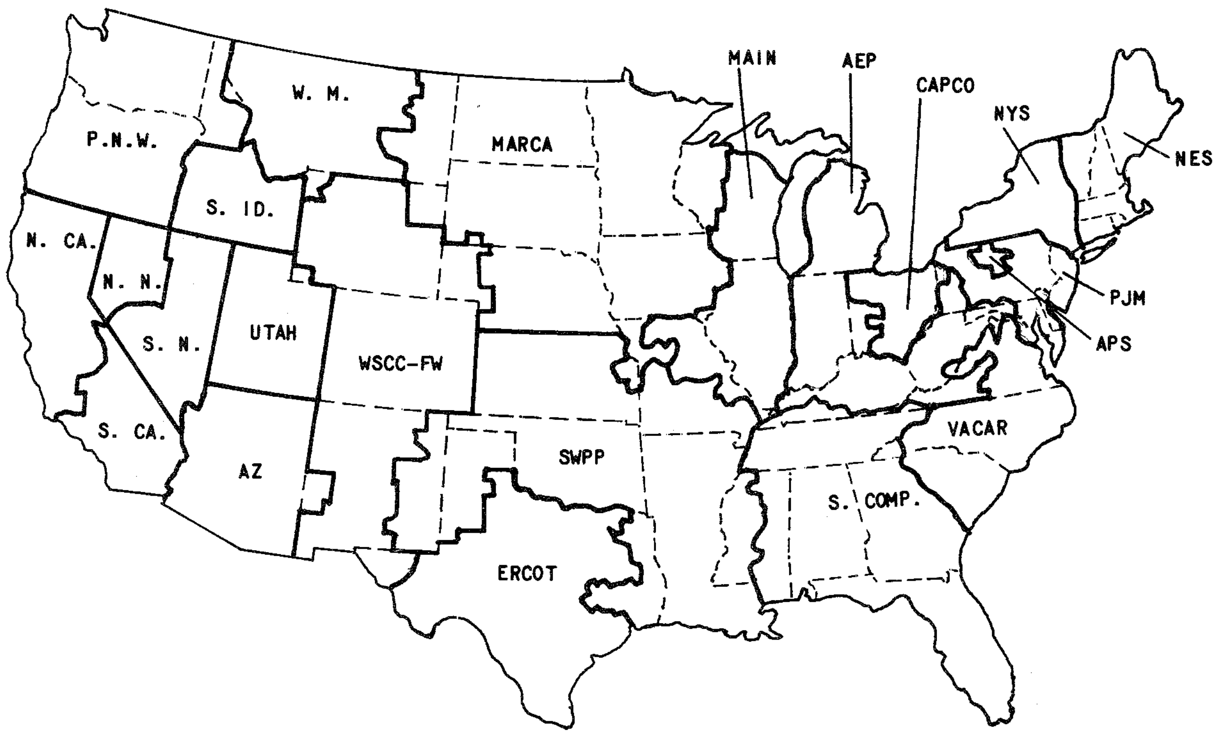
REGIONAL ENERGY BENEFIT VALUES (FERC 1978)

Region	APF: 0	0.10	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90	1.00
	Energy Benefit as Function of APF ($/MWH)										
VACAR	45.3	45.3	45.3	35.7	35.7	11.0	11.0	4.8	4.8	4.8	4.8
Southern Companies (S. COMP)	45.0	45.0	45.0	35.7	35.7	9.1	9.1	4.8	4.8	4.8	4.8
ECAR	38.2	38.2	38.8	23.5	23.1	12.7	12.6	12.5	12.4	12.4	12.3
MAIN	43.9	43.9	41.6	25.4	23.5	12.9	12.4	12.0	11.8	11.6	11.4
MARCA	40.3	40.3	37.2	24.1	22.6	10.1	10.0	9.9	9.8	9.7	9.7
WSCC-FW	33.5	33.5	27.4	24.1	23.6	5.8	6.7	7.3	7.8	8.2	8.5
SWPP	35.2	35.2	34.9	23.3	22.1	12.0	11.9	11.9	11.9	11.8	11.8
ERCOT	29.8	29.8	23.8	22.6	21.1	9.4	9.6	9.7	9.8	9.9	9.9
New England (NES)	35.5	35.5	30.5	28.9	27.1	1.0	4.0	6.0	7.6	8.8	9.8
New York (NYS)	39.2	39.2	39.1	29.2	26.9	10.5	11.8	12.8	13.5	14.1	14.5
PJM	38.6	38.6	36.2	29.8	28.1	11.3	11.5	11.6	11.7	11.8	11.9
CAPCO	37.6	37.6	33.8	29.8	26.7	2.8	4.5	5.6	6.5	7.2	7.8
AFP	33.2	33.2	22.9	29.8	25.1	9.4	9.5	9.6	9.7	9.7	9.7
APS	45.0	45.0	49.1	31.1	23.7	9.4	9.8	10.1	10.3	10.4	10.5
Northern California (N.CA.)	34.4	34.4	35.3	21.2	21.6	11.8	13.0	13.8	14.4	14.9	15.3
Southern California (S.CA.)	33.8	33.8	33.6	21.0	21.4	10.0	11.0	11.6	12.1	12.5	12.8
Pacific Northwest (P.N.W.)	31.9	31.9	28.7	21.1	21.2	14.1	13.5	13.1	12.7	12.5	12.3
Arizona (AZ.)	34.6	34.6	34.6	21.8	22.4	15.2	14.7	14.4	14.2	14.0	13.9
Southern Idaho (S.ID.)	39.0	39.0	43.3	22.4	22.4	9.7	10.0	10.2	10.4	10.5	10.6
Western Montana (W.M.)	39.4	39.4	45.2	22.0	22.1	3.4	3.4	3.4	3.4	3.4	3.4
Northern Nevada (N.N.)	38.5	38.5	44.8	21.4	21.6	10.7	11.8	12.6	13.1	13.6	13.9
Southern Nevada (S.N.)	36.1	36.1	39.5	21.3	21.9	9.3	9.1	9.0	8.8	8.7	8.7
Utah	34.3	34.3	34.0	20.0	18.5	7.7	7.8	7.8	7.8	7.9	7.9
Island of Oahu, Hawaii	35.5	35.3	32.9	24.2	25.7	20.1	21.2	22.0	22.7	23.1	23.5
Island of Hawaii, Hawaii	7.9	7.9	21.4	25.9	28.2	25.7	26.7	27.5	28.0	28.5	28.8
Island of Kauai, Hawaii	7.6	7.6	21.3	25.9	28.1	25.7	26.7	27.5	28.1	28.5	28.8
Island of Maui, Hawaii	4.4	4.4	20.1	25.4	28.0	25.6	26.8	27.6	28.2	28.7	29.1
Island of Molakai, Hawaii	22.8	22.8	32.0	35.1	36.6	37.5	38.1	38.6	38.9	39.1	39.3
Anchorage, Alaska	20.6	20.6	20.3	8.7	11.4	10.1	10.9	11.5	12.0	12.4	12.6
Fairbanks, Alaska	27.0	27.0	29.1	29.8	30.2	8.7	8.9	9.0	9.1	9.2	9.3
Valdez, Alaska	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Ketchikan, Alaska	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6

Table 4-3

REGIONAL CAPACITY BENEFIT VALUES (FERC 1978)

Region		Capacity Benefit as Function of APF ($/KW)									
	APF: 0	0.10	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90	1.00
VACAR	25.1	25.5	25.9	40.9	31.0	120.1	121.8	179.0	184.3	189.6	194.6
Southern Companies (S. COMP)	30.1	21.2	12.3	45.0	43.1	109.5	111.8	170.7	175.5	180.4	185.3
ECAR	31.9	32.8	32.8	66.1	66.1	135.2	135.2	135.2	135.2	135.2	135.2
MAIN	37.2	33.2	33.2	67.1	67.1	134.9	134.9	134.9	134.9	134.9	134.9
MARCA	36.9	31.5	31.5	63.5	63.5	135.5	135.5	135.5	135.5	135.5	135.5
WSCC-FW	40.8	30.1	30.1	68.1	68.1	130.8	130.8	130.8	130.8	130.8	130.8
SWPP	30.8	30.4	30.4	68.9	68.9	125.1	125.1	125.1	125.1	125.1	125.1
ERCOT	39.8	29.3	29.3	65.9	65.9	119.0	119.0	119.0	119.0	119.0	119.0
New England (NES)	39.3	30.5	30.5	70.0	70.0	188.1	188.1	188.1	188.1	188.1	188.1
New York (NYS)	33.3	33.0	33.0	75.5	75.5	183.7	183.7	183.7	183.7	183.7	183.7
PJM	32.5	28.2	28.2	64.9	64.9	136.0	136.0	136.0	136.0	136.0	136.0
CAPCO	36.0	29.3	29.3	67.5	67.5	180.1	180.1	180.1	180.1	180.1	180.1
AEP	45.4	27.3	27.3	62.5	62.5	110.0	110.0	110.0	110.0	110.0	110.0
APS	20.4	27.5	27.5	62.5	62.5	139.4	139.4	139.4	139.4	139.4	139.4
Northern California (N.CA.)	36.1	37.6	37.6	69.7	69.7	156.5	156.5	156.5	156.5	156.5	156.5
Southern California (S.CA.)	50.0	49.6	49.6	80.4	80.4	164.8	164.8	164.8	164.8	164.8	164.8
Pacific Northwest (P.N.W.)	30.3	24.7	24.7	53.6	53.6	121.0	121.0	121.0	121.0	121.0	121.0
Arizona (AZ.)	44.2	44.3	44.3	86.8	86.8	224.0	224.0	224.0	224.0	224.0	224.0
Southern Idaho (S.ID.)	21.6	35.4	35.4	71.0	71.0	160.1	160.1	160.0	160.1	160.0	160.1
Western Montana (W.M.)	27.1	37.2	37.2	74.3	74.3	161.5	161.5	161.5	161.5	161.5	161.5
Northern Nevada (N.N.)	24.1	35.0	35.0	70.1	70.1	197.4	197.4	197.4	197.4	197.4	197.4
Southern Nevada (S.N.)	30.5	36.5	36.5	72.6	72.6	164.4	164.4	164.4	164.4	164.4	164.4
Utah	36.8	36.2	36.2	72.3	72.3	162.2	162.2	162.2	162.2	162.2	162.2
Island of Oahu, Hawaii	49.5	45.0	45.0	75.4	75.4	120.6	120.6	120.6	120.6	120.6	120.6
Island of Hawaii, Hawaii	78.7	102.3	102.3	102.3	102.3	169.4	169.4	169.4	169.4	169.4	169.4
Island of Kauai, Hawaii	78.4	102.3	102.3	102.3	102.3	169.4	169.4	169.4	169.4	169.4	169.4
Island of Maui, Hawaii	55.1	82.7	82.7	82.7	82.7	171.1	171.1	171.1	171.1	171.1	171.1
Island of Molakai, Hawaii	103.6	119.7	119.7	119.7	119.7	119.7	119.7	119.7	119.7	119.7	119.7
Anchorage, Alaska	30.5	30.4	30.4	48.4	48.4	124.5	124.5	124.5	124.5	124.5	124.5
Fairbanks, Alaska	35.7	37.1	37.1	37.1	37.1	149.5	149.5	149.5	149.5	149.5	149.5
Valdez, Alaska	109.0	109.0	109.0	109.0	109.0	109.0	109.0	109.0	109.0	109.0	109.0
Ketchikan, Alaska	49.5	49.5	49.5	49.5	49.5	49.5	49.5	49.5	49.5	49.5	49.5



Source: Hydroelectric Power Evaluations. Federal Power Commission, Washington, D.C., March 1968.

Figure 4-3

FERC REGIONS FOR CAPACITY AND BENEFIT FACTORS

For all increases in capacity and average annual energy at existing plants, the annual plant factor was calculated based on the new total capacity and average annual energy. Where a new powerplant was required, the benefits were determined by using an annual plant factor based on the incremental capacity being installed and the average annual energy being developed at the new plant.

Costs

General cost relationships were developed to evaluate the large number of existing plants. These cost curves were not intended to be used for site specific planning, but only as they apply to the National Hydropower Study. Manufacturer's costs are normally solicited when more detailed analysis is undertaken. The data used to prepare the cost curves utilized in this study were obtained from a number of sources. They represent manufacturer's quotes and bids, catalog prices, as-constructed costs, and special reports or studies having representative cost information. All costs have been brought to July 1978 price levels to be consistent with the benefit values being used for this study. Cost curves were prepared for the following changes at existing hydroelectric plant locations:

- Adding a new powerplant
- Adding a new turbine, generator and pertinent equipment to an existing plant
- Replacing an existing turbine
- Replacing an existing generator
- Replacing an existing transformer
- Replacing existing switchgear
- Modifying an existing generator-coil replacement
- Modifying an existing generator-core replacement
- Modifying an existing transformer

The cost curves developed have a common set of parameters. The parameters are: size of generating unit in megawatts, effective head in feet, and cost. Effective head has a large influence on cost. In general, the lower the head the higher the cost per installed kilowatt. This is due to most of the major equipment (turbine and generator) having to be custom designed requiring nearly equivalent engineering whether large or small. Other factors include the economies of scale of larger equipment from a fabrication view point, and the fact that lower head installations require larger turbines and generators for an equivalent output. Adjustments were made to the first costs derived from the generalized cost curves by using geographic cost factors to simulate representative costs of various projects located in different states.

Total investment costs included 25 percent contingencies; engineering and overhead costs ranging from 17.5 percent to about 10 percent depending upon total construction costs; and interest during construction costs based on a rate of interest of 6.875 percent and total construction time. The amortization costs were based on an interest rate of 6.875 per cent and a 100 year project service life.

Whenever possible, the cost curves were keyed to turbine type. Information on turbine type was available on about 27 percent of the existing plants. However, all of these sites have capacities above 10 MW and contain approximately 66 percent of total installed capacity. For those sites where turbine type information was not available, the net power head was used to indicate a probable type. All sites with heads above 100 feet were assumed to be Francis turbine installations and those with heads below 100 feet were assumed to be fixed blade propeller turbines.

A key assumption made for the "add capacity" condition was that the existing plant could be expanded to handle up to 25 percent additional capacity without requiring a new intake and outlet works. For all sites with more than a 25 percent increase in potential capacity, two alternatives were compared. The first alternative was a totally new powerplant with intake and outlet works to handle all of the new capacity. The second alternative included adding the first 25 percent of additional capacity to the existing plant and a new powerplant with intake and outlet works to handle the remaining portion of the additional capacity. All increases in capacity due to replacement or modification of existing units assumed that no new intake and outlet works would be required.

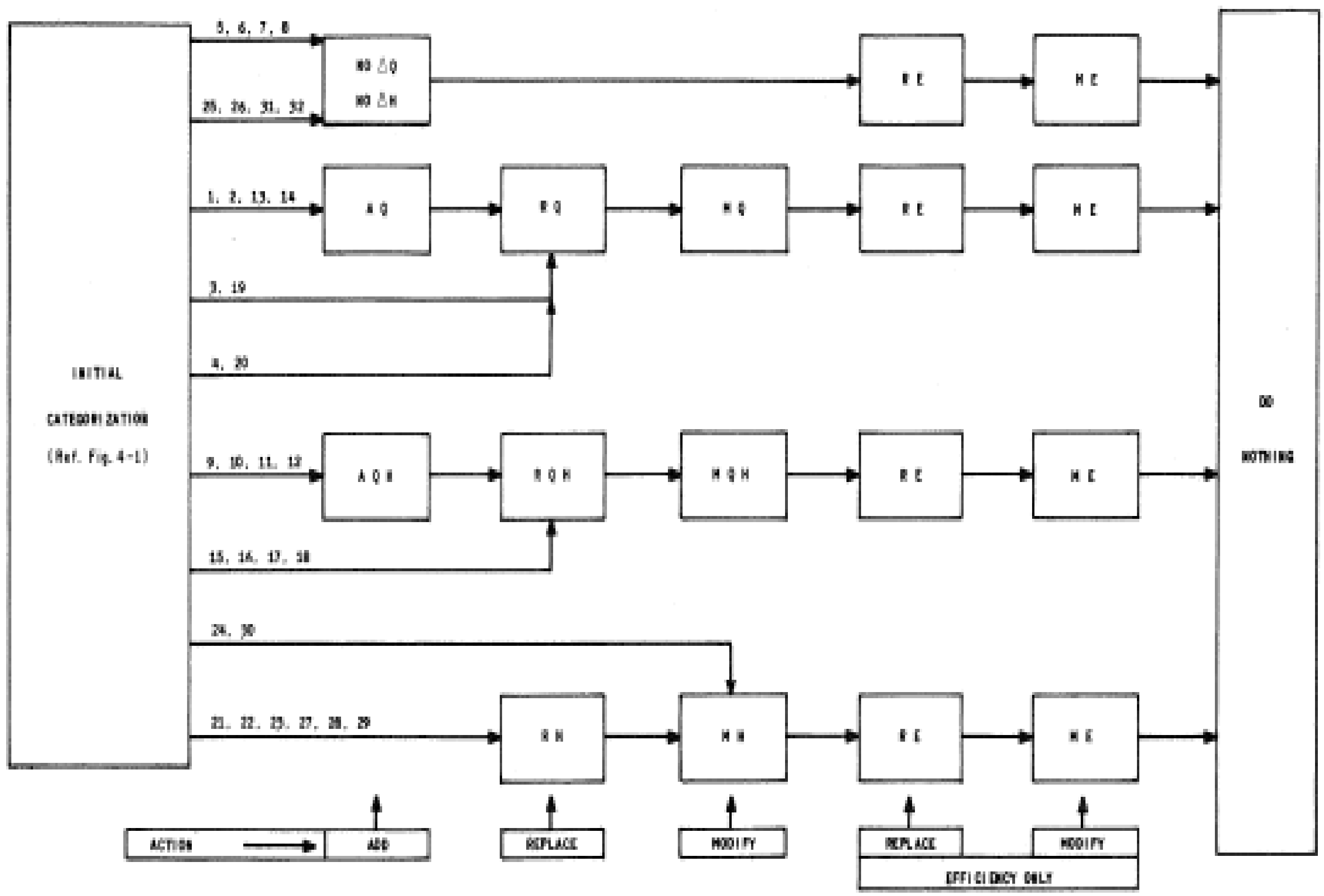
Site Evaluation Process

The evaluation process included determination of the appropriate annual benefits and costs based on the action category, the calculated potential increase in average annual energy and the associated capacity.

Figure 4-4 is a schematic of the evaluation process that was developed. For each action category there is a set of calculations being carried out. There is a descriptive classification code for each set with two terms. The first term indicates whether we are evaluating an add, replace, or modify possibility. The second term indicates whether the potential increase in energy is due to increased flow only, increased flow and head, increased head only, or increased efficiency only.

The test for achievability consists of comparing the calculated B/C ratio for each action category to a specified decision B/C ratio. The energy increase at each site that ended up in an action category with a B/C value equal to or greater than the specified decision B/C ratio was considered "achievable."

As an illustration of the evaluation process, consider those sites that were initially classified as "add" categories 9, 10, 11, or 12. All of these sites have potential due to additional flow and head above existing conditions. First the costs and benefits at each site are evaluated for the add (AQH) conditions to see if the calculated B/C is equal to or greater than the specified decision B/C value. If the site does meet this condition the developed information is stored in the AQH category. If the site does not meet the decision B/C at the initially calculated capacity and energy increase, the site is completely re-evaluated at 75 percent of that initial capacity increase. If required, two more trials are made at 50 percent and 25 percent of the initial value before going on the next potential action category - RQH. The processing of each site is repeated and will continue on to the next action category until the site either meets the decision B/C ratio or ends up in the "do nothing" category. Therefore, before sites in categories 9, 10, 11 or 12 are considered "do nothing" sites they could conceivably be tested for achievability for up to twenty different conditions - four conditions for each of the five action categories.



LEGEND:

ΔQ Increase in Flow.
ΔH Increase in Head.

CLASSIFICATION

FIRST TERM (ACTION)

A - Add Units.
R - Replace Units.
M - Modify Units.

SECOND TERM (SOURCE)

Q - Flow Only.
QH - Flow and Head.
H - Head Only.
E - Efficiency Only.

Figure 4-4

SCHEMATIC - EVALUATION PROCESS

Estimate of Achievable Energy Output

This section presents the results from the analyses of increased energy output due to physical modifications at existing plants. National results will be presented first along with some sensitivity analyses. Results for each of the regional Electric Reliability Council Areas are also summarized.

National Results---The results from the analysis of all the existing plants in the U. S. are based on three separate evaluations at decision B/C ratios of .3, 1.0, and 2.0. Tables 4-4 and 4-5 show the results for the high and low benefit estimates at a decision B/C ratio of 1.0 The high estimate benefits are based on treating all of the increased capacity is treated as dependable capacity. The low estimate benefits are based on treating all of the increased capacity as intermittent capacity. These tables indicate the amount of average annual energy increase that is considered achievable at a decision B/C ratio of 1.0. They also show the required amount of increased capacity to develop the energy increase at the number of plants shown as well as estimates of the investment costs, average annual costs, and average annual benefits. Note that the results for the add, replace, and modify categories are separated into sub-categories to indicate whether the source of the increased energy is from additional flow only, additional flow and head, addition head only, or efficiency increases.

Figure 4-5 summarizes the results for the three decision B/C ratios evaluated. The amount of achievable increase in average annual energy and the corresponding increase in capacity are plotted. The percent increases in energy and capacity above existing conditions nationally are also indicated. For example, at a B/C ratio of 1.0 the achievable energy increase is about 30 million MWh or a nationwide percent increase of 11 percent (reading the curves at the mid point between the high and low estimate). The corresponding capacity increase is about 14,000 MW or an increase of 22 percent.

Table 4-4

SUMMARY - ACHIEVABILITY EVALUATION OF EXISTING HYDROELECTRIC PLANTS

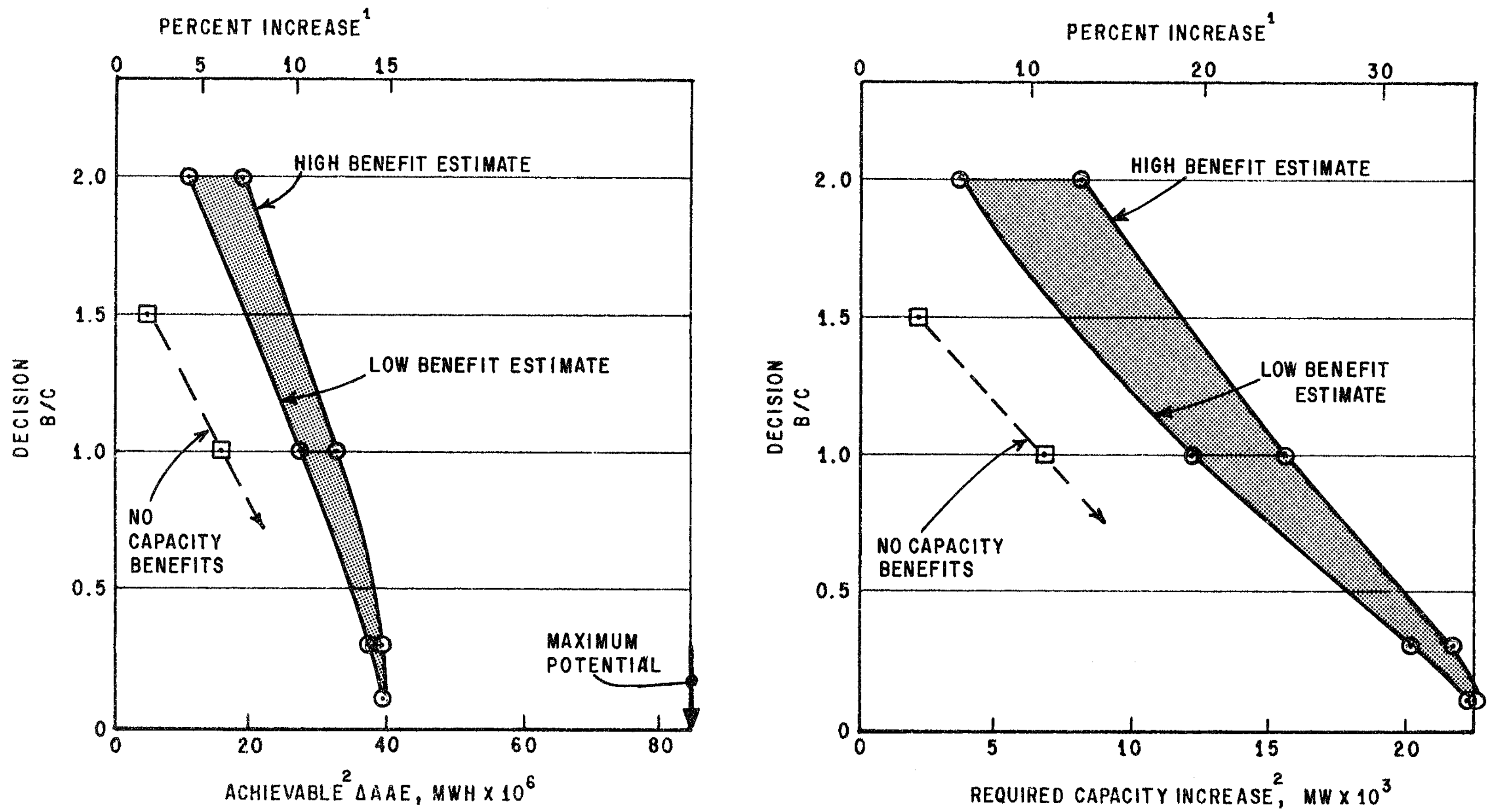
HIGH BENEFIT ESTIMATE, B/C= 1.0

ACTIVITY	NUMBER OF PLANTS	INSTALLED CAPACITY	CAPACITY INCREASE	AVERAGE ANNUAL ENERGY	AVERAGE ANNUAL ENERGY INCREASE	INVESTMENT COSTS	AVERAGE ANNUAL COSTS	AVERAGE ANNUAL BENEFITS
		MW		MILLION MWH		MILLION DOLLARS		
ADD UNITS								
AQ	253	9923.0	14491.5	52.284	30.420	12362.7	945.12	1631.41
AQH	15	714.1	961.5	4.045	1.971	766.2	58.52	104.67
ADD SUBTOTAL	268	10637.1	15452.9	56.329	32.391	13128.9	1003.64	1736.07
REPLACE UNITS								
RQ	0	0.	0.	0.	0.	0.	0.	0.
RQH	0	0.	0.	0.	0.	0.	0.	0.
RH	0	0.	0.	0.	0.	0.	0.	0.
RE	4	355.6	10.3	1.930	.019	13.8	1.10	1.79
REPLACE SUBTOTAL	4	355.6	10.3	1.930	.019	13.8	1.10	1.79
MODIFY UNITS								
MQ	10	707.2	70.6	3.549	.092	99.2	7.93	9.28
MQH	1	474.5	111.1	1.719	.138	111.1	8.99	12.53
MH	1	22.5	3.2	.082	.002	.9	.09	.14
ME	15	1605.6	47.1	5.702	.056	67.3	5.40	7.43
MODIFY SUBTOTAL	27	2809.7	232.1	11.052	.288	278.5	22.40	29.39
A,R,M SUBTOTAL	299	13802.3	15695.3	69.312	32.698	13421.1	1027.14	1767.25
DO NOTHING								
DN	989	49573.1	0.	203.240	0.	0.	0.	0.
TOTALS	1288	63375.4	15695.3	272.552	32.698	13421.1	1027.14	1767.25

Table 4-5

SUMMARY - ACHIEVABILITY EVALUATION OF EXISTING HYDROELECTRIC PLANTS LOW BENEFIT ESTIMATE, B/C = 1.0

ACTIVITY	NUMBER OF PLANTS	INSTALLED CAPACITY	CAPACITY INCREASE	AVERAGE ANNUAL ENERGY	AVERAGE ANNUAL ENERGY INCREASE	INVESTMENT COSTS	AVERAGE ANNUAL COSTS	AVERAGE ANNUAL BENEFITS
		MW	MW	MILLION MWH	MILLION MWH	MILLION DOLLARS	MILLION DOLLARS	MILLION DOLLARS
ADD UNITS								
AQ	138	8054.6	11201.2	43.317	24.538	8180.1	625.22	951.00
AQH	11	699.9	885.0	3.982	1.808	665.0	50.79	74.81
ADD SUBTOTAL	149	8754.5	12086.2	47.299	26.345	8845.2	676.01	1025.81
REPLACE UNITS								
RQ	0	0.	0.	0.	0.	0.	0.	0.
RQH	0	0.	0.	0.	0.	0.	0.	0.
RH	0	0.	0.	0.	0.	0.	0.	0.
RE	2	147.0	4.3	.908	.009	5.4	.43	.45
REPLACE SUBTOTAL	2	147.0	4.3	.908	.009	5.4	.43	.45
MODIFY UNITS								
MQ	2	47.3	2.8	.193	.003	1.6	.13	.22
MQH	0	0.	0.	0.	0.	0.	0.	0.
MH	1	22.5	3.2	.082	.002	.9	.09	.09
ME	9	768.5	22.8	2.320	.023	8.3	.71	1.40
MODIFY SUBTOTAL	12	838.3	28.8	2.595	.028	10.9	.93	1.71
A,R,M SUBTOTAL	163	9739.8	12119.2	50.802	26.382	8861.4	677.37	1027.97
DO NOTHING								
DN	1125	53635.6	0.	221.750	0.	0.	0.	0.
TOTALS	1288	63375.4	12119.2	272.552	26.382	8861.4	677.37	1027.97



1 Based on existing installed capacity and average annual energy.

2 Costs and benefits are based on 1978 price levels and 6 7/8% interest

Figure 4-5

ACHIEVABILITY ANALYSES - SENSITIVITY RESULTS

The add units category accounts for essentially all of the increased average annual energy. For the B/C ratio of 1.0 and the benefit based on dependable capacity (Table 4-4), 15,453 MW were added to 268 plants with a total investment cost averaging about $850 per kw. The annual cost per MWh averaged out to be $31 for these same sites.

Note that those flood control sites with additional head (AQH, RQH, RH, MQH, and MH) account for only 2.1 million MWh or about 6.5 percent of the total energy increase shown. Since the head used in the calculations for these categories reflects the existing normal power head plus the depth of the flood control storage space it is likely that even this relatively minor amount of estimated energy increase is too high. Two reasons for this would be that 1) it is unlikely that more than a small portion of the flood control storage could be reallocated to power storage and 2) it would be improbable that the higher head could be maintained over the long term.

The appropriateness of including all or a portion of the capacity benefits in the calculations of total benefits (e.g., all capacity increase taken as dependable) can been questioned. In order to provide some sensitivity analysis regarding this question a separate evaluation was carried out with no benefits attributed to the capacity component. The results from this analysis are shown on Table 4-6 and are also superimposed on Figure 4-5. There are only 68 plants that meet a decision B/C ratio of 1.0 and contribute additional average annual energy in the amount of 15.7 million MWh based on an increased capacity of 6850 MW. Note that the reduction in achievable average annual energy is not a linear relationship when decreasing the capacity benefit from: 1) utilizing the total capacity benefit factor for adding dependable capacity, to 2) half the capacity benefit for adding intermittent capacity, to 3) no benefit for adding capacity. On a nationwide basis, the percent increase in achievable average annual energy and capacity for the no capacity benefit condition would drop to 5.7 and 10.8 percent respectively.

Table 4-6

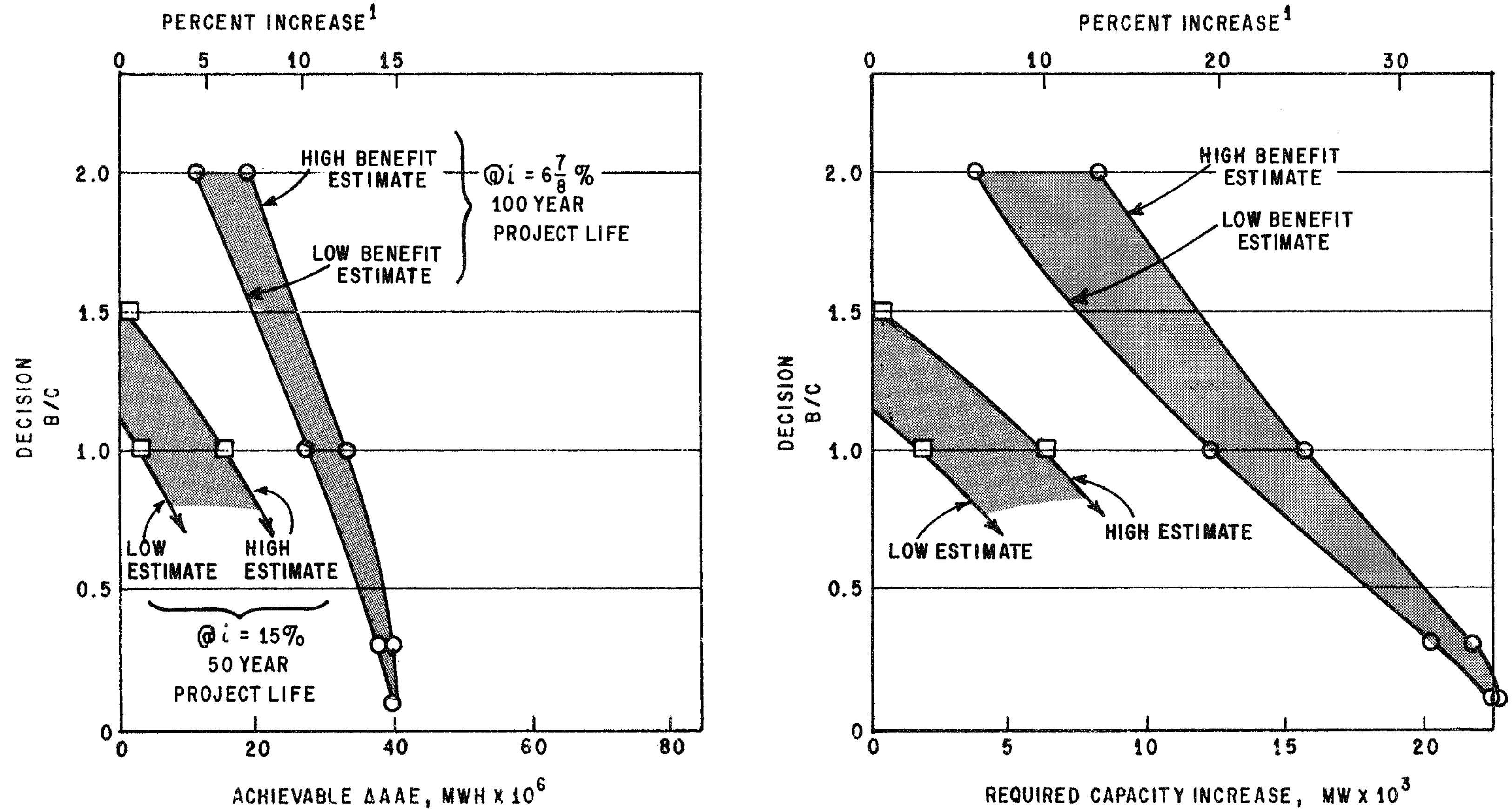
SUMMARY - ACHIEVABILITY EVALUATION OF EXISTING HYDROELECTRIC PLANTS

NO CAPACITY BENEFITS, B/C = 1.0

ACTIVITY	NUMBER OF PLANTS	INSTALLED CAPACITY	CAPACITY INCREASE	AVERAGE ANNUAL ENERGY	AVERAGE ANNUAL ENERGY INCREASE	INVESTMENT COSTS	AVERAGE ANNUAL COSTS	AVERAGE ANNUAL BENEFITS
		MW	MW	MILLION MWH	MILLION MWH	MILLION DOLLARS	MILLION DOLLARS	MILLION DOLLARS
ADD UNITS								
AQ	56	4285.9	6231.4	23.007	14.518	3954.3	302.00	383.37
AQH	3	387.0	479.8	2.175	.904	253.0	19.38	30.75
ADD SUBTOTAL	59	4672.9	6711.2	25.182	15.423	4207.3	321.37	414.12
REPLACE UNITS								
RQ	1	135.0	29.7	.518	.038	8.4	.72	.82
RQH	0	0.	0.	0.	0.	0.	0.	0.
RH	0	0.	0.	0.	0.	0.	0.	0.
RE	0	0.	0.	0.	0.	0.	0.	0.
REPLACE SUBTOTAL	1	135.0	29.7	.518	.038	8.4	.72	.82
MODIFY UNITS								
MQ	7	416.6	108.5	2.012	.197	33.5	2.86	3.43
MQH	0	0.	0.	0.	0.	0.	0.	0.
MH	0	0.	0.	0.	0.	0.	0.	0.
ME	1	66.0	2.0	.241	.002	.5	.05	.05
MODIFY SUBTOTAL	8	482.6	110.5	2.253	.200	34.0	2.91	3.48
A,R,M SUBTOTAL	68	5290.5	6851.4	27.952	15.660	4249.7	325.00	418.41
DO NOTHING								
DN	1220	58084.9	0.	244.600	0.	0.	0.	0.
TOTALS	1288	63375.4	6851.4	272.552	15.660	4249.7	325.00	418.41

Because projects developed by private and utility owned organizations are normally evaluated by them at a higher (than the Federal) discount rate another evaluation was carried out to determine the sensitivity of the amount of achievable energy increase to interest rates. In addition to increasing the interest rate from 6-7/8 percent to 15 percent the project economic life was shortened from 100 years to 50 years. The results are plotted on Figure 4-6 and are compared with the high and low estimates from the original achievability analyses shown on Figure 4-5. The achievable average annual energy dropped to 15.3 and 2.1 million MWh for the high and low estimates respectively at a decision B/C ratio of 1.0. The corresponding capacity increases dropped off to 6190 and 1120 MW. If this interest rate and project life were used, the nationwide percent increase in achievable average annual energy would decrease to 5.6 and 0.8 percent for the high and low estimates respectively. It can be argued that private developers would likely receive higher revenues than the benefit values in the FERC tables and thus the above estimate could be considered to be conservative.

Since the analyses developed for this study normally evaluated the add category first, those sites that satisfied the decision B/C ratio were not evaluated for the replace or modify categories. In order to provide some insight into the potential energy increase from rehabilitating existing plants, analyses were performed with the add category removed from the evaluation process. The results from this analysis are shown on Tables 4-7 and 4-8. Using the high benefit case for comparative purposes, it is seen that most of the sites that were in the add category ended up in the replace and modify categories. However, the potential energy increase dropped from 32.7 to 3.75 million MWh thus resulting in only a 1.4 percent increase nationwide. It is also noted that 61 sites ended up in the replace and modify categories for efficiency increase. The contribution to average annual energy increases from these two sub-categories were relatively minor as most of the energy increase was due to the RQ and MQ sub-categories. The average investment costs for the replace and modify categories were about $1000 and $940 per kW, respectively.



1 Based on existing installed capacity and average annual energy.

Figure 4-6

ACHIEVABILITY ANALYSES-SENSITIVITY RESULTS-INTEREST RATE AND PROJECT LIFE

Table 4-7

SUMMARY - ACHIEVABILITY EVALUATION OF EXISTING HYDROELECTRIC PLANTS

NO ADD UNITS, HIGH BENEFIT ESTIMATE, B/C = 1.0

ACTIVITY	NUMBER OF PLANTS	INSTALLED CAPACITY	CAPACITY INCREASE	AVERAGE ANNUAL ENERGY	AVERAGE ANNUAL ENERGY INCREASE	INVESTMENT COSTS	AVERAGE ANNUAL COSTS	AVERAGE ANNUAL BENEFITS
		MW		MILLION MWH		MILLION DOLLARS		
ADD UNITS								
AQ	0	0.	0.	0.	0.	0.	0.	0.
AQH	0	0.	0.	0.	0.	0.	0.	0.
ADD SUBTOTAL	0	0.	0.	0.	0.	0.	0.	0.
REPLACE UNITS								
RQ	72	5509.1	1051.1	26.785	2.018	1040.7	83.89	154.68
RQH	3	541.5	127.7	2.214	.229	151.5	12.20	15.66
RH	1	454.3	58.6	2.022	.033	57.0	4.59	7.92
RE	4	355.6	10.3	1.930	.019	19.4	1.55	1.79
REPLACE SUBTOTAL	80	6860.5	1247.7	32.951	2.299	1268.6	102.23	180.05
MODIFY UNITS								
MQ	100	3752.6	423.4	17.964	.969	475.8	38.63	62.58
MQH	9	779.0	61.7	3.475	.147	59.3	4.79	8.01
MH	5	806.0	71.6	3.457	.065	50.0	4.06	5.97
ME	57	12039.6	248.1	55.319	.273	172.8	13.93	25.04
MODIFY SUBTOTAL	171	17377.2	804.9	80.214	1.454	757.9	61.40	101.60
A,R,M SUBTOTAL	251	24237.6	2052.6	113.166	3.753	2026.5	163.63	281.64
DO NOTHING								
DN	1037	39137.8	0.	159.387	0.	0.	0.	0.
TOTALS	1288	63375.4	2052.6	272.552	3.753	2026.5	163.63	281.64

Table 4-8

SUMMARY - ACHIEVABILITY EVALUATION OF EXISTING HYDROELECTRIC PLANTS

NO ADD UNITS, LOW BENEFIT ESTIMATE, B/C = 1.0

ACTIVITY	NUMBER OF PLANTS	INSTALLED CAPACITY	CAPACITY INCREASE	AVERAGE ANNUAL ENERGY	AVERAGE ANNUAL ENERGY INCREASE	INVESTMENT COSTS	AVERAGE ANNUAL COSTS	AVERAGE ANNUAL BENEFITS
		MW	MW	MILLION MWH	MILLION MWH	MILLION DOLLARS	MILLION DOLLARS	MILLION DOLLARS
ADD UNITS								
AQ	0	0.	0.	0.	0.	0.	0.	0.
AQH	0	0.	0.	0.	0.	0.	0.	0.
ADD SUBTOTAL	0	0.	0.	0.	0.	0.	0.	0.
REPLACE UNITS								
RQ	35	3326.8	692.2	16.037	1.284	528.9	42.96	60.08
RQH	0	0.	0.	0.	0.	0.	0.	0.
RH	0	0.	0.	0.	0.	0.	0.	0.
RE	0	0.	0.	0.	0.	0.	0.	0.
REPLACE SUBTOTAL	35	3326.8	692.2	16.037	1.284	528.9	42.96	60.08
MODIFY UNITS								
MQ	77	3920.7	563.4	19.009	1.238	412.4	33.82	49.86
MQH	8	1050.0	172.2	4.509	.349	119.4	9.75	13.66
MH	3	725.3	98.4	3.073	.060	47.5	3.91	5.94
ME	30	10022.2	198.2	46.320	.218	110.1	8.88	11.92
MODIFY SUBTOTAL	118	15718.1	1032.2	72.911	1.865	689.3	56.37	81.37
A,R,M SUBTOTAL	153	19045.0	1724.3	88.948	3.149	1218.3	99.32	141.45
DO NOTHING								
DN	1135	44330.4	0.	183.604	0.	0.	0.	0.
TOTALS	1288	63375.4	1724.3	272.552	3.149	1218.3	99.32	141.45

Regional Results---The national results were separated into the nine Electric Reliability Council regions along with results from sites in Alaska, Hawaii, and Puerto Rico being placed in the "other" category as shown in Table 4-9. Note that only a little more than a third of the maximum potential energy increase is considered achievable at a decision B/C ratio of 1.0. Those regions that indicated the most potential based on the maximum potential analyses, were also the same regions that were found to have the most achievable energy and in about the same order. Three regions stand out above the other regions in terms of achievable energy increase - WSCC, NPCC, and SERC. These three regions contain 88 percent of the estimated achievable energy increase.

The WSCC region located in the West and Northwest indicates the most achievable potential energy increase with about 16 million MWh. Essentially all of this potential increase is due to adding units. This increase in average annual energy is only about an 8.5 percent increase to this region because this region presently generates almost 70 percent of the conventional hydropower in the U.S.

The NPCC region located in Northeast had the next largest amount of achievable energy increase - 10.3 million MWh. In this region almost two-thirds of the potential is considered achievable which is a significantly higher percentage than any of the other regions. This indicates a significant portion of the flow by existing sites is not currently being utilized. One reason for this might be that approximately two-thirds of the plants in this region operate as run of river facilities as compared to less than 25 percent for the remainder of the nation. The achievability analyses assumed that all flows up to the 5 percent exceedence flow can be captured and passed through the plant if sufficient capacity has been added. Because most of the plants in this region are run-of-river it is possible that a portion of the estimated achievable energy increase will not be realized due to the additional costs required to physically transport the high flows to and through the plants.

Table 4-9
REGIONAL POTENTIAL

Region	Existing		Potential							
				Energy Increase 1/				Capacity Increase 1/		
	Installed Capacity	Average Annual Energy	Maximum Potential	Achievable Potential	Add	Replace	Modify	Add	Replace	Modify
	--MW---	MWH x 10^6						MW		
ECAR	533.6	2.031	1.518	0.248	0.248	—	—	118.2	—	—
ERCOT	314.7	.716	0.474	0.002	—	—	0.002	—	—	3.2
MAAC	906.4	3.533	2.333	0.883	0.744	—	0.139	443.5	—	112.5
MAIN	1.025.8	3.341	3.342	1.064	1.063	—	.001	462.8	—	0.2
MARCA	3,074.9	13.021	4.085	1.319	1.315	—	0.004	700.4	—	1.5
NPCC	3,198.3	16.286	16.098	10.288	10.261	—	0.027	3270.2	—	20.9
SERC	10,818.9	39.286	12.057	2.500	2.451	—	0.049	1533.6	—	45.7
SWPP	2,668.1	6.431	3.298	0.308	0.308	—	—	307.1	—	—
WBCC	40,540.0	187.150	41.890	16.086	16.001	0.019	0.066	8617.1	10.3	48.1
OTHER	294.7	.757	0.562	0.000	—	—	—	—	—	—
TOTALS	63,375.4	272.552	85.657	32.698	32.391	0.019	0.288	15452.9	10.3	232.1

1/ Evaluations based on high benefit estimate and decision B/C = 1.0

The estimated potential energy increase within the SERC region is 2.5 million MWh or a little over 6 percent above the existing energy output. Essentially all the potential increase is due to adding units. It appears that this region, much like the Northwest region of the U.S., has already developed a large portion of the available energy at its existing sites.

Chapter 5

INCREASED OUTPUT FROM REALLOCATION AND OPERATIONAL CHANGES

5.1 GENERAL OVERVIEW

Operational changes to existing plants that could potentially increase the energy output are possible. This chapter describes basic concepts, discusses the technical studies performed for storage reallocation and operational policy changes, and presents estimates of the energy increase that might be derived therefrom.

By reallocating a portion of the flood control storage to power storage there is the potential to increase the energy output by capturing and routing additional flow through the powerhouse and increasing the head by keeping the pool level higher. The additional energy increases may be possible without necessarily increasing the plants installed capacity. Of course, the trade off would be reduced flood control protection. It is unlikely that a large reduction in flood control storage would be found to be acceptable. However, in some cases only a small portion of the flood control space many may be needed to capture and control a significant amount of additional reservoir inflow volume.

Altering the reservoir operation policies is another potential way to increase energy output. Typically, there is a set of operating rules by which the reservoir is operated. When the project is a multi-purpose facility the operation becomes more complex because each purpose has specific constraints that could have a significant impact on the manner in which the facility is operated, i.e., maintain specified minimum flow releases for downstream water quality; minimize fluctuations in the reservoir levels for recreation; minimize spills to pass more flow through the hydroelectric plant; maintain storage space for flood control purposes.

The thesis is that there may be opportunities to increase power output such as reducing flood control releases to allow more volume to be passed through the plant, allowing seasonal power pool elevations to remain at higher elevations for longer periods of time, and minimizing all releases that do not go through the plant. In effect this might amount to a quasi storage reallocation in that some of the goals of reallocation might be achieved without formally modifying the designated storage zones.

5.2 REALLOCATION OF FLOOD CONTROL STORAGE

Storage in a multiple-purpose reservoir is usually allocated into flood control space, conservation space (including hydropower), and inactive or dead storage. Also, an additional surcharge storage is often provided above the flood control space to provide for temporary storage of exceptional flood flows which the spillway is unable to pass. Typically, detailed sequential routings of historical flows are made to define storage allocation and operation rules that will provide for all authorized purposes to the maximum extent possible.

Flood control operation in a multi-purpose project is generally in conflict with conservation operation in two ways. Flood control operation requires reservation of storage space in the event a flood might occur thus potentially releasing water that might have been stored for conservation purposes. Also operation during flood events may require curtailing hydropower releases. Developing flood control operation plans usually requires routing historic and design floods through the reservoir to evaluate reservoir performance and impact on downstream damage centers.

The conservation storage in a reservoir may provide some incidental flood control benefits; however, its primary purpose is to meet firm water demands and to provide head for generation of hydroelectric energy. The upper and lower limits of conservation storage may vary seasonally, thus resulting in seasonal variations in storage allocations. The upper boundary can in some geographical regions be increased when less flood space is required in the non-flood season. The minimum pool level may vary to provide a higher storage level during the recreation season and then allow the pool to be lowered to supply other purposes. If several conservation purposes exist, then priorities will be required to ensure the highest priority demands are met. The conservation storage can be subdivided by allocating a portion of the total storage to a buffer zone. When water in storage gets down to the buffer zone, only the highest priorities would be supplied or supplies for all purposes will be reduced.

As with flood control, the storage allocated to conservation governs a portion of the operation. Within the conservation storage zone, water will be stored for future use and releases are only made to provide for project demands. Given the total storage, the operation plan is generally designed to meet specified purposes. If a safe yield approach was used to size storage, then all demands can be met during the historical critical period. The operation study would be performed using the historical flow sequence, expected demands, and evaporation data. During the most critical period, all demands are met while storage is drawn down to the minimum.

The hydropower reallocation question for all practical purposes reduces to allocating portions of existing flood control space to hydropower storage. The potential contribution to increased energy output of allocating from one conservation purpose to another is insignificant in comparison. Reallocating a portion of the flood control storage of a project to the power pool provides more storage to meet critical period demands and higher operating heads for power generation. The additional conservation storage can be used to store additional surplus water and thus reduce spills if significant amounts occur. The water is then available to meet higher demands which means the yield (firm energy) of the project is increased. Because the added storage is at the top of the power pool, conservation operation within the new storage adds directly to the power head and thus increases total annual energy output as well as contributes to firming up existing energy generation. The question of whether the existing generation equipment might require modification in order to operate in an acceptable manner for the changed head/flow regime must be considered.

The loss of flood control space, from reallocating storage, reduces the ability of the project to store flood water and thus reduces the degree of downstream flow regulation. The amount of loss in flood control benefits depends on the amount of flood storage lost, and the degree of protection provided by the existing flood control storage. The loss in flood control benefits would be only for floods exceeding the magnitude of the reduced flood control storage. The flood damage increase due to reduced flood control storage can only be determined by detailed analysis of the project's operation and resulting damage at downstream damage centers. The expected annual damage would of necessity increase with the loss of flood control storage, but would likely be small for the initial increments of loss in flood control storage.

To estimate the potential gain in energy from the reallocation of flood control storage to the power pool, it is necessary to first identify the projects that are the most likely candidates. With the potential projects identified, analysis of the energy production under current storage allocations provides a basis for comparison. Then, by analyzing the energy production with modified allocations, the potential gain in energy can be determined and relationships of energy gained as a function of increased power storage can be derived.

Screening

To locate the candidate projects for reallocation of flood control storage, the study data file was searched to identify all hydropower projects that have flood control storage. A total of 187 projects were found that met the criterion. Many of the projects, however, have little flood control storage in relation to the mean annual flow. The potentially attractive candidate projects were therefore further screened by performing an additional search with the added constraint that the flood control storage in these projects be at least equivalent to 10 percent of the mean annual flow. This constraint reduced the candidate set to those projects that have flood control storage equivalent to at least 1.2 months of the mean annual flow. Only 48 of the 187 projects met the added criterion.

Reallocation Evaluations

Because only 48 projects met the screening criteria, an attempt was made to analyze each site. The selected approach was to automatically generate input files for a reservoir system simulation program (Hydrologic Engineering Center 1979) from the data files created for the NHS study. The maximum energy capability given a specified storage allocation was then computed by detailed monthly sequential analysis. Data input files for sequential analysis were sucessfully generated for 38 of the 48 projects. The remaining 10 projects had data errors or other deficiencies that could not be easily remedied.

The sequential analysis performed for each of the 38 projects was a single purpose hydropower operation using average monthly flows. The physical features of the project consisting of powerplant characteristics, reservoir storage, reservoir area, and reservoir elevation relationships were extracted from the NHS data file. The monthly flow data were based on gaged data near the project location retrieved from the U.S.G.S. streamflow data files (Geological Survey 1975). Other project purposes were not considered in the simulation.

The sequential analysis determined the maximum firm energy based on the concept of firm yield. The critical period within the flow record is first determined, then the firm energy computed for the critical period, and then a period of record simulation is performed that yields an estimate of average annual energy.

Existing Conditions. --- The computed firm energy and corresponding average annual energy computed for the existing project power storage is used as the basis for comparison with potential increase from reallocation. To verify the acceptability of this procedure, average annual energy values catalogued into the study data file were compared to these estimates. The computed total for the 38 projects analyzed was 12 percent below the sum contained in the study data file. The computed energy was judged sufficiently accurate for use as the base condition for estimating changes in energy generation from storage reallocation.

Modified Conditions. --- The estimates of potential gain in energy from reallocating storage were made by repeating the analysis described above by first reallocating 10 percent and then reallocating 20 percent of the flood control storage to the power storage of each project. The gains in energy thus computed were then compared to the existing condition estimate of energy production to compute the percent gain in energy.

Results. --- The existing average annual energy for the 38 projects analyzed is 16,037 GWh or about 6 percent of the total output from the existing 1,288 sites. With an increase in power storage from reallocating 10 percent of the flood control storage, the average annual energy increase 257 GWh to a total of 16,294 GWh (a 1.6 percent increase in energy). By reallocating 20 percent of the flood control storage, the average annual energy increases 483 GWh above existing to a total of 16,520 GWh (a 2.9 percent increase in energy). Note particularly that these results are for reallocation of storage only; no additional generating capability was considered to be operating. Several projects were analyzed with higher percentages of flood control storage reallocated, even though it is quite doubtful that it would be practical to reallocate that much storage. In general, the rate of return in increased energy output related to storage reallocation decreased slightly with increased reallocation of storage; however, the response was nearly linear.

An analysis of the major physical factors involved in reallocation was undertaken to better understand the contributing source of potential energy increase. The finding was that a relationship including increased head as the prediction factor explained most of the variability, and further the relationship was linear. For the reallocation situation studied, the major significant contributor to increased energy output is from increased head on the plant and further that increased energy from additional volume capture by reducing spill is relatively minor.

Another result of the analysis was the determination of firm energy for the 38 projects studied. By adding to the power storage, the projects are able to meet increased power demands during critical low flow periods. The percentage increase in firm annual energy (conversion of non-firm energy to firm energy) was approximately 3 times the increase in average annual energy. The increase in firm annual energy for the 10 percent and 20 percent reallocation are shown below:

% Reallocation of Flood Control	% Increase in Power Storage	% Increase Average Annual Energy	% Increase Firm Annual Energy
10	5.5	1.6	5.3
20	11.1	2.9	9.8

If the existing project is sized (installed capacity) at the computed dependable capacity, then it is likely that the installed capacity might be increased commensurate with the increase in dependable capacity that is made possible by increasing power storage and decreasing plant factor. Analysis of this concept indicates that for 10% storage reallocation, this likely increase in installed capacity would result in an annual energy increase of 4.0% (compared to 1.6% previously cited) and an increase in annual firm energy of 6.0% (compared to 5.3% previously cited). The number of existing projects actually sized at the computed dependable capacity is unknown but the general belief is that a significant proportion of the major storage projects are so sized.

Reliability of Results. --- The computational results are considered representative since most of the major candidate projects were included in the analysis. Several issues, that are affected by the computational procedure and therefore bear on the results, are discussed in the following paragraphs.

Several operational procedures, not considered in the sequential simulation analysis as performed may account for the simulation results for existing conditions being generally lower than the values that were placed in the study data files by NHS study participants. For example, flood control operation could, in some cases, give higher energy values than estimated because the data file ommitted flood release constraints. For projects that remain in the flood control pool for long periods, the added head, if usable, could provide more energy. If this were the case, and there is evidence that it is in many projects, then the estimated base energy for existing storage allocation would be too low and the computed gain from reallocation may be too high. Also seasonally varying storage allocation not considered in this analysis, is common in many multipurpose projects and can provide additional power storage as the flood season passes. Seasonal storage allocation is, in effect, reallocation on a continuous basis. The seasonally adjusted storage in practice already provides a portion of the computed gain from storage reallocation. Some of the projects may also have unique diversions for power supply or pump back operation that would provide more energy than was estimated.

Multiple reservoir operation may also provide system flexibility which would increase the present energy production over that estimated by single site simulation. A comparison was made on the White River System to evaluate the credibility of the results derived from the single site evaluations performed. The Southwestern Division (SWD) of the Corps of Engineers provided an independent analysis of the potential gain from the reallocation of storage at five projects in the White River system. Using a different simulation analysis (Hula 1979) that simulates the White River system operation plan and modeling the entire system with daily flow data, an estimate was prepared of the average annual energy values for the existing and several other flood control storage allocations. When the total average annual energy computed by the two simulation approaches is compared for the five storage projects, results for existing conditions from the approach used herein are 11 percent below those from the alternative approach. Subsequent analysis has isolated the primary source of the difference.

When the projects analyzed are in flood operation, the water stored in the flood storage space is normally released at rates within the capacity of the generating plants and this method of operation is captured by the alternative simulation analysis. The single project analysis using monthly flows, spills the flow in excess of conservation storage (channel capacity is unknown) during the month they occur. This will result in less computed energy generation because the spill is not routed through the plant and additionally the maximum head that can be reached is the top of conservation (power) pool. For every day the White River System operation is in flood control storage, the projects are operating at a higher head than estimated herein and, therefore, have a greater energy output than was reflected in the analysis performed herein.

As expected, the SWD simulation also shows less gain in energy from reallocating flood control storage to conservation storage. The current operation is already gaining most of the added energy by generating power within the flood control pool whenever possible, thus in effect accomplishing what would be the goal of formal storage reallocation. The SWD estimation is that reallocating 30 percent of the flood control storage to power would only provide an additional 0.5 percent in average annual energy. The sum of the single site results for the five projects shows a potential 4.3 percent gain from reallocating 20 percent of the flood control storage.

The degree to which the White River system operation is representative of hydropower projects with flood control purpose throughout the United States is not known. It is believed however that this operating procedure is reflective of operating procedures that should be practiced elsewhere, and is in itself a form of informal quasi reallocation. The increase in energy gain from reallocation, while modest for the nation as a whole should be considered for those specific projects which could provide significant increased power output through reallocation without serious impact on flood control performance. These opportunities should be vigorously pursued since on a local scale, they could be quite important.

The SWD system evaluation also provided an opportunity to compare a system evaluation to the single project evaluation concept used herein. The three projects, Beaver, Table Rock, and Bull Shoals, are in series with

Beaver the upper project. The existing annual energy estimates for each project is as follows:

Project	Average Annual Energy SWD (GWh)	Single Site Analysis (GWh)	Diff.
Beaver	171.35	171.63	0.2%
Table Rock	520.8	456.30	12.3%
Bull Shoals	762.42	598.78	21.5%
Norfork	196.26	201.7	2.8%
Greers Ferry	210.90	236.29	12.0%

With the exception of Bull Shoals (the most downstream project), the estimates are very close. Considering the differences in basic operation mentioned previously, the single project analysis using monthly flows were judged to be sufficiently accurate for this analysis.

5.3 RESERVOIR OPERATION POLICIES

Alterations to existing reservoir operation policies may result in a potential for energy increase. As in the case of reallocation of storage space the potential energy increase due to improvements in reservoir operation is likely limited to those sites with some flood control space. Typically those hydropower plants with no flood control space are presently operated to meet hydropower objectives, although there may be instances where constraints due to other purposes could be released to enhance power generation, i.e., allow more fluctuations in pool levels to reduce spillage or increase generation during low flow periods. In this section the trade off between flood control and hydropower production will be stressed relative to the potential of increasing energy output at existing plants. When alterations to existing reservoir regulations are being considered it must be recognized that the development of reservoir regulation plans are highly technical undertakings, particularily for multi-purpose reservoirs.

There is an obvious conflict at existing plants between flood control and hydropower production for use of available storage space. Maximum reservation of empty storage space would be most beneficial for flood control purposes. However, hydropower production would be best served by maintaining high pool levels and being able to minimize or eliminate spillage allowing all flow releases to go through the plant. This conflict is most obvious immediately before, during, and after flooding periods. Flood control operations attempt to evacuate the flood control space as rapidly as possible by releasing flows at the maximum rate keyed to allowable downstream channel capabilities. During major floods these flood control releases could be well above the maximum outflow capacity of the existing hydropower plant, thus, losing some potential energy generation. The most beneficial overall use of the storage space often requires an operating policy which is a compromise between the various purposes being used at a specific site, including water supply, recreation, water quality, and navigation as well as flood control and hydropower.

Two major items were reviewed as possible areas to improve the operation of a reservoir to enhance power generation - operational rule curves and coordinated operation of reservoir projects.

Operational Rule Curves

Operational rule curves are the operating guides that have been derived to satisfy the adopted operational policies for a project. They generally are in the form of graphs and charts of reservoir pool levels and release rates but may also be descriptive directions providing instructions to project operators for unique inflow and storage conditions. These rule curves generally represent a summary of experience and are initially developed based on many engineering analyses including simulations considering the several project purposes using historical stream flow conditions.

Some of the major items considered during preparation of the rule curves (or regulation schedules as they are sometimes called) are upstream and downstream runoff and flooding characteristics, flood damage, flood control space requirements, minimum release requirements, multiple use of reservoir storage, upstream regulation, downstream channel capacities, conservation operations, flood forecasts, limitations on storage and releases, and emergency operations.

Rule curves may be viewed as the detailed operating criteria that are required to achieve the authorized purposes of the project with the authorized storage allocations. To a degree, operation criteria and the concept of formal storage reallocation are interrelated. For illustration purposes the following example is presented. A particular project might have a total storage capacity of 500,000 acre-feet of which 300,000 acre-feet are designated as flood control space and 200,000 as power storage space. The rule curve that has abeen adopted might specify that from 15 November through 15 April (the flood period) the flood control reservation must be at the maximum of 300,000 acre-feet, with possible adjustments made downward within the flood period to 200,000 acre-feet based on a watershed wetness index (indicator of runoff potential). The "other" storage during this November-April period would be available for power storage and would be a minimum of 200,000 acre-feet. For the remainder of the year, 16 April through 14 November, the flood control reservation is zero and the power storage space available is the full 500,000 acre-feet. Further the rules might specify that whenever water is stored in the flood control space that it be evacuated as quickly as downstream conditions permit, regardless of generating capacity.

The transition from maximum flood control space reservation to no space reservation required is normally specified to occur such that the goal of a full conservation space reservoir is likely to occur at the end of each flood season...in effect filling the full 500,000 acre-feet as power storage.

The question is -- What would constitute a formal storage reallocation and what would constitute a change in operating policy and how are they different? Specifically, what would they accomplish?

Formal storage reallocation would be accomplished by altering (reducing) the maximum flood control space reservation. For example, a reallocation of 20 percent would result in the maximum space reservation for flood control to be 240,000 (20% reduction) rather than 300,000 and power storage minimum to be 260,000 (a 30% increase) rather than 200,000 acre-feet. The potential energy gain could occur in two ways. If there is spill, and it's likely there is always at least a very small amount of spill because of flood operations, then the added 60,000 acre-feet of power storage might capture a portion. Probably more importantly, the minimum pool level could be allowed to achieve a higher level. The trade-off?..higher risk regarding adequate flood control.

Another operating rule change might be to lower the rate at which the storage in the flood pool is evacuated so that more of the flood volume could be passed through the powerhouse at a higher head than would be the existing case. The effect on flood control operation would be to reduce the effective available flood storage space reservation and thus increase the risk regarding adequate flood regulation.

Another operating rule change might be to alter the wetness adjustment criteria such that the space reservation is less than the present rules allow, thus permitting more storage use for power during low runoff potential periods during the flood season than presently exists. The gain? Perhaps (but not very likely) a slight gain in volume captured for the powerplant and (more likely) a small increase, for only those low runoff potential periods, of the pool level if additional flow is available at those times to cause the pool level to rise. The trade-off?..if done simply to increase the available power storage, higher risk regarding adequate flood regulation. If done as a result of technical analysis to refine the ability to predict runoff potential, perhaps no significant loss in flood control performance.

Note that the results of changing operating rules are very similar to formal storage reallocation, e.g., altering the effectively available storage for flood control and power generation and increasing the risk regarding adequate flood regulation. The potential gain from operational changes are therefore intertwined with formal storage reallocation. The previous reallocation analysis (subsection Reallocation Evaluations) most likely includes within the estimate the increased energy that could be obtained by altering rule curves. This suggests that the potential overall gain from altering existing operational procedures would be very modest.

It proved to be impossible in this study to exhaustively catalogue the operating procedures and rule curves for all projects having flood control and power storage. It does seem to be the prevailing practice, however, to adjust rule curves depending on the flood season, e.g., in the winter in the West, snow melt season in the Northwest, and to some degree hurricane season in the East and Southeast. It is common in the West to adjust maximum space reservation for the runoff potential status of the watershed; no definite indication of practices elsewhere were found. Modifying releases to capture additional flow through the powerhouse seems to be done "informally" thus maximizing the power generation. Some systems have specifically sized the plants (a physical measure option) such that flood releases can to a great extent be routed through the powerhouse.

In summary, it appears that on a national scale, the potential is less than a one percent increase in energy output through reallocation of flood control storage in existing reservoirs. Part of this modest increase can be obtained either through formal reallocation of reservoir storage or by adopting operating rules such as the seasonal rule curve concepts prevalent at least in the West, and/or through adjusting flood releases on an event by event basis to allow additional power generation. If the current policy of operating power storage reservoir projects primarily for firm energy requirements were eliminated, substantial gain in average annual energy could be obtained. While this long standing policy has been wise where firm energy values were high in comparison with dump energy values, it appears that the policy to use large power drawdowns, which reduces average annual energy, in order to provide firm energy should be re-evaluated in all power systems.

The case study in appendix B documents the development and application of seasonal rule curves and runoff potential with adjusted rule curves. Appendix C documents a system that has plants sized and operating rules adjusted to capture virtually all available energy potential at the existing powerplants.

Operational rule curves are commonly re-evaluated on a periodic schedule and alterations made, if necessary, to satisfy changing conditions and to ensure that the objectives of the existing project are being served as intended. Corps of Engineers policy (Corps of Engineers 1970) indicates that on all Corps projects: "Necessary actions will be taken to keep approved reservoir regulation plans up-to-date. For this purpose, plans will be subject to continuing and progressive study by personnel in field offices of the Corps of Engineers who are professionally qualified in technical areas involved and who are familar with comprehensive project objectives and considerations affecting reservoir operations."

Coordinated Operation of River Projects

Another aspect of reservoir regulation that could provide an opportunity for increasing energy output is the coordination of the operations of reservoir projects. Projects that are located such that their operation is impacted by the operation of one or more upstream reservoirs are candidates for enhancing their energy output. Most projects have informal coordination with upstream projects; however, if different owners are involved there may be different constraints governing the operation of each reservoir that are not compatible for maximizing energy output.

The coordination of reservoir projects with several different owners and purchasers of storage space is a significant task. One must keep track of inflows and outflows, best loading pattern to minimize spill, interchange of energy from one owner to another, and credits for allocation of storage space by purchasers of the space for power. One major system of hydroelectric projects with automated coordinated operations was examined to focus on the issues and opportunities. This system, the Mid-Columbia River hydro projects, is described below.

The Mid-Columbia River System is located in central Washington State and consists of seven plants with a total installed capacity of 12,579 MW as noted on Table 5-1 (Dunstan 1979). This capacity amounts to about 20 percent of the total installed capacity in the United States. The owners of these seven projects include the Federal Government and three separate public utility districts.

Table 5-1

MID-COLUMBIA RIVER HYDRO PROJECTS

General Data

Site	Owner	Head Feet	Flow cfs	Capacity Mw
Grand Coulee	U.S. Government	337	273,000	6,280
Chief Joe	U.S. Government	168	----	2,069
Wells	Dougalas CPUD*	70	220,000	775
Rocky Reach	Chelan CPUD	85	213,000	1,213
Rocky Island	Chelan CPUD	37	265,000	622
Wanapun	Grant CPUD	76	179,000	831
Priest Rapids	Grant GPUD	74	178,000	789
	Total System Capacity			12,579

*CPUD = County Public Utility District

The region controlled by these seven projects is particularly suited to a coordinated operation. The heavy runoff in the spring and summer from accumulated winter snow cover is relatively predictable since it results from measurable winter snow cover. Mohler and Lewis in 1962 indicated the following relative to this region:

The ability to predict runoff volumes at projects on the snow-fed streams east of the Cascades provides a unique compatibility in the use of storage for power, flood control, navigation and even recreation. The objective of the power operation on these streams is to use enough storage for power generation in advance of the flood so that the space will be available to retain the flood water for later use in power generation. This same objective, with little modification, meets the flood control and navigation requirements and normally provides full reservoirs during the summer recreation season. Because the summer volumes are predictable, coordinated operation can make effective use of storage to develop maximum use of the water with a minimum loss of head, and flood control operations interfere very little with optimum regulation for power.

Another major reason favoring the coordinated system at this location is that all of the dams below the lowest dam in the system are Federally owned, therefore, no additional contractual agreements were necessary. (Dunstan 1979.)

There were a number of attempts in the 1950-1960 decade to establish coordination agreements between individuals utilities. A big step toward establishing coordination was the Columbia River Treaty with Canada signed in 1961. That treaty indicated "that downstream power will be shared with Canada, and that all downstream generating entities are to participate in this responsibility." The utilities which were formulating amendments to the Federal Power Act then entered negotiations with the Federal agencies involved in the treaty, with the objective of fully coordinated operation over the period covered by the treaty. (Mohler and Lewis 1962)

Then in 1972 a one-year agreement for the Hourly Coordination of Projects on the Mid-Columbia River was signed by twelve parties representing the United States, three public utility districts, and eight power purchasers. One year agreements were signed until 1977 when a ten-year contract was signed. "The general objectives of the coordination were to: obtain increased amounts of electrical power and energy from the total system of projects; enhance the non-power uses of the river by reducing the extent and rate of fluctuations of river levels insofar as practicable; provide flexibility and ease of scheduling generation for the projects by a method of centralized control and through the use of composite scheduling and accounting procedures." (Dunstan 1979.)

Increased energy development and system flexibility are two of the benefits resulting from hourly coordination. Since the hourly coordination was set up the system has periodically operated at full capacity which had never occurred prior to implementing the system. The following examples cited by Dunstan (1979) certainly indicate the flexibility of the coordinated system:

> It is significant to note that during the course of hourly coordination on the Mid-Columbia, important physical changes to the system have occurred which have tested the adaptability of the control to the utmost. Three of four units at Priest Rapids have been rewound during the period. All ten units at Wells have been rewound during hourly coordination. Five of eight new units have been added at Rock Island Dam and the forebay has been raised by six feet. Ten of eleven new units have been added at Chief Joseph. Five of six new units at Grand Coulee have been added. The system had to operate around various constraints from capacity reductions, cofferdam constraints for elevation and discharge, deep drafts for construction purposes, and limitations to protect divers.

5.4 ESTIMATE OF ACHIEVABLE ENERGY OUTPUT

This chapter reviewed possible operational changes that might provide opportunities for potential energy increases in output. Reallocation of flood control storage, alternations to operational rule curves, and implementation of coordinated operation of river projects were evaluated.

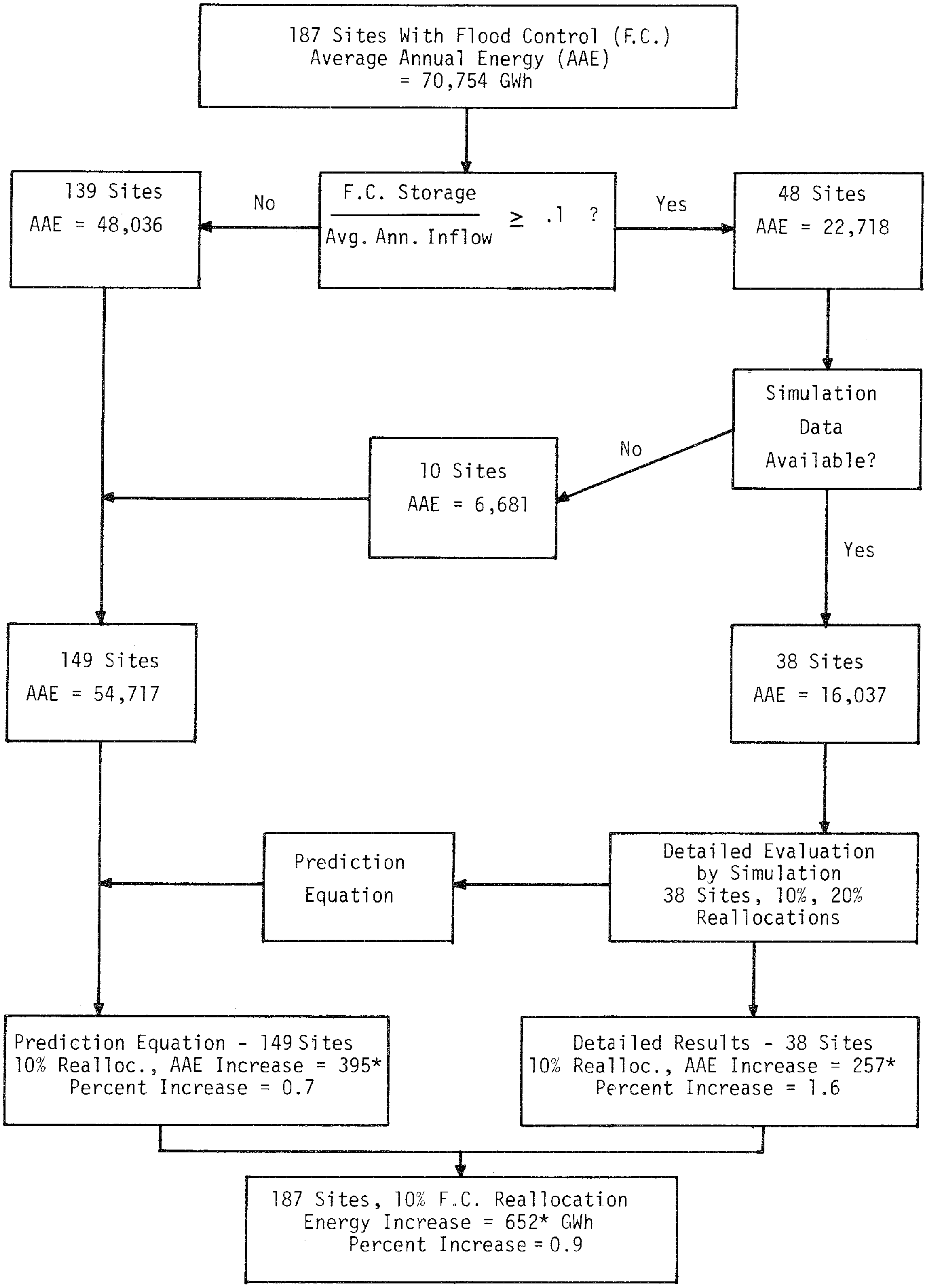
Reallocation of Flood Control Storage

Reallocation studies were made (assuming no increase in installed capacity) for 10 and 20 percent reductions in flood control storage. These reductions in flood control storage were converted to power storage at all of the 187 sites that have flood control storage. The evaluation procedure to estimate the potential energy increase at these sites is shown in Figure 5-1. A selected sample of 38 sites was evaluated by sequential period of record analysis to determine the potential increase at those sites and to develop a prediction relationship to estimate the potential increases at the remaining 149 sites.

As noted on Figure 5-1 the energy increase for a 10 percent reduction in flood control was about 257 GWh or an increase of 1.6 percent at the sample sites. The opportunities at the remaining sites, based on the developed prediction relationship, were smaller in proportion to the sample resulting in a potential increase of 395 GWh or only a 0.7 percent increase for these remaining sites. These comparative results seem reasonable because almost all of the sites evaluated with the prediction relationship had relatively smaller flood control storages available that could be converted to power storage. The estimated increase for potential reallocation opportunities are shown below:

Case	Energy Increase GWh	Percent Increase at All Reallocation Sites
10% F.C. Reduction	652	0.9
20% F.C. Reduction	1,225	1.7

When these flood control sites were evaluated during the achievability analysis discussed in Chapter 4, the amount of increased energy ranged from 750 to 2,700 GWh for the range of B/C ratios considered. The estimated amount of energy increase determined from the reallocation analysis was 652 to 1,225 GWh for the 10 and 20 percent reduction in flood control storage respectively as noted above. Even though these two evaluations were based on different assumptions, both reveal that the increase in energy due to moving up into the flood control storage space would be relatively minor. An increase of 1,000 to 3,000 GWh would be an overall increase of 1.4 to 4.2 percent above the existing average annual energy at these flood control sites. Nationally this amount would be an increase of 0.4 to 1.1 percent. It is accepted that even these estimates of energy increases will be high due to many sites not having sufficient benefits to overcome subsequent increases in flood control damage and, probably a stronger deterrent, the difficulty of communities with flood plain residents to accept less flood protection.



* Installed capacity maintained at existing values.

Figure 5-1. ESTIMATE OF POTENTIAL ENERGY INCREASE FROM STORAGE REALLOCATION

The likely acceptable reallocation project development would require formulation and implementation of mitigation measures to offset the loss in flood control performance. In effect, the benefits from increased power production would have to be greater than the cost of the mitigation measures needed to assure the same (or nearly so) flood control performance.

Certainly there are individual sites that indicate attractive potential for energy increases and these sites should be identified and pursued. From a national standpoint, however, the impact of reallocating flood control storage to power storage to meet future energy needs will be small.

Alterations To Operational Rule Curves

The potential energy increases possible from reallocating flood control storage at existing power reservoirs are considered to be the upper limit increase that could be developed. Changes in operating rules which might reflect some of the reallocation benefits would therefore be less than the reallocation benefits and therefore, no additional specific attempt was made to quantify these increases.

Coordinated Operation of River Projects

The Mid-Columbia River System is a major system of hydro projects found in this study to have implemented system wide coordinated operation of their reservoirs. There are no available estimates of increases in average annual energy resulting from the automated system. However, the seven projects within the system have been able to operate within one foot or so of maximum head. This would indicate a net head increase of 3 to 4 feet over the total gross head of about 900 feet (Dunstan 1979). This is a relatively small increase in head, yet, this system is so large the equivalent capacity increase would be more than 50 MW. A corresponding increase in average annual energy at these seven sites would be about 245 GWh. No attempt was made to estimate potential energy increases on a nationwide basis due to coordinated operations but it should be noted that the Mid-Columbia System represents an ideal set of circumstances for increased output due to coordinated operation of river projects that is not readily evident elsewhere.

Chapter 6

INCREASED OUTPUT IN PERSPECTIVE

6.1 INTRODUCTION

This chapter contains discussion of the following items: the major issues involved in trying to increase energy output at existing plants, the addition of capacity for peaking purposes, a brief section attempting to place the hydropower potential at existing plants in perspective, and an assessment of the data and evaluation methods used in this study.

6.2 MAJOR ISSUES

What are the major issues involved when adding capacity to and/or increasing the energy output at an existing plant? Anytime the operation of a water resource project is altered there will be environmental, social, technical, and economic impacts that must be reconsidered. Impacts of developing hydropower nationwide at both existing and undeveloped sites are treated in detail in separate National Hydropower Study volumes. Only those major items pertinent to altering the generating capability at existing hydropower plants are discussed in this section.

There are a limited number of "actions" that are possible for increasing the energy output at existing hydropower sites. These actions and their purposes are listed below.

Actions considered	Purpose
Add units	Increase flow through plant
Replace or modify old units	Increase flow through plant Increase plant efficiency
Increase power storage	Increase flow through plant Increase head on plant
Improve system operation	Increase flow through plant Increase head on plant

Note that the list of purposes consist of only three categories - increased flow through the plant; increased head on the plant; and increased plant efficiency. A number of environmental concerns have continually appeared during the consideration of the above actions such as fluctuating reservoir levels, minimum flows for fisheries, and water quality downstream from the plant. These are discussed in other volumes. Two issues surfaced that are discussed here. The first is whether incentives should be made available to enhance development of additional energy at existing sites. The second is should the basis for determination of flood control storage be reviewed to determine if the risk of encroachment into current flood control space is worth the additional hydroelectric power benefits.

Incentives For Hydropower Development

The development of hydropower has become particularly attractive due to increasing of alternative energy sources. The cost of importing oil was less than 3 dollars per barrel until 1973 and has risen to as high as 41 dollars per barrel with the December 1980 price increases. The increasing desire to reduce oil imports by U.S. residents was indicated by a recent California survey by Mervin Field in October 1980. Sixty-six percent of the people surveyed felt that it was "extremely important" to reduce oil imports. This percentage compared with forty-six percent in August of 1978.

Approximately 96 percent of the existing plants containing 95 percent of the total installed hydroelectric capacity were sized and constructed prior to 1973. Many of the systems that these plants were designed for included thermal power plants that were fueled by relatively cheap oil. It does appear that many of these existing hydroelectric plants would have been sized at higher design capacities had the fuel prices been at the levels they are at today. This higher capacity would have the potential to replace some thermal generation and thus, reduce oil demand.

While this study has shown that the potential energy increases at existing hydroplants are modest compared to current energy output it still seems appropriate to encourage additional energy development at promising sites. Certainly the national desire to reduce oil imports is high and the need for additional energy is obvious.

Reallocation of Flood Control Storage

Reallocation of flood control storage, for any purpose, is a sensitve issue. Of course the people within the potential flooding zone will be concerned if their flood protection is reduced by even minor amounts. This fear alone might be sufficient to stop implementation of a new reallocation plan regardless of its benefits. This study has shown that, from a national standpoint, embarking on a large program of reallocation for existing hydropower reservoirs would not return large scale returns in terms of energy increases. However, this should not deter individual site reviews of existing plant design and storage allocations using updated information based on actual plant operations. It is possible that project design conditions will change so that a portion of the originally required flood control storage can be reallocated to power storage with negligible effects on flood damage below the dam and on other project purposes. On the other hand, the possibility also exists that the original flood control storage at some of the older sites might be inadequate based on current storage sizing standards.

6.3 CAPACITY ADDITIONS

Installing additional capacity at an existing powerplant is done to increase the amount of energy produced by the plant or to enable the plant to operate at a lower plant factor thereby providing peaking energy. The main topic of this report has been the discussion of increasing energy generation by adding, replacing, or modifying units, and/or operational changes. This section addresses the concept of adding capacity with little or no change in annual energy production and explains the attractiveness of such additions.

Peaking Hydroelectric Developments

Hydroelectric developments are usually classified according to the nature of the load being served and by the character of the site being developed. Hydroelectric projects which are developed to provide capability to meet peak load demands are designed to operate at full capacity for short periods of time (a few hours) in order to insure that the associated utility system will have sufficient capacity to meet the daily peaks in demand or to prevent loss of load when outages result in the loss of generating or transmission capability. Hydroelectric plants are unsurpassed as sources of peaking capacity during system emergencies which result from unscheduled outages. This advantage of the hydroelectric plant results from its ability to go from no load to full load in just a few seconds (Federal Energy Regulatory Commission 1979).

The long-term average runoff at a particular project site depends upon the hydrologic conditions in the upstream area. Operation of a power storage reservoir can reduce high flows and increase low flows but will not appreciably affect the long-term average flows. The manner in which the flows available at a site are utilized to generate power depends upon the amount of storage available at the project, the hydraulic and electrical capabilities of the plant, streamflow requirements downstream from the plant, and the characteristics of the electric load to be served. If sufficient storage is not available to operate a plant for peaking, or if the downstream needs of navigation, recreation or other uses mandate minimum flow, the power may be produced at generally uniform levels and used in the base portions of system loads, and excesses can be used to reduce thermal generation. If flow releases can be varied, or if re-regulation of flow releases is possible, the power project will generally be operated at a low plant factor to supply the peak portions of system loads.

Use of a project's available energy to generate power at a low plant factor can increase by several times the dependable capacity that would be available under base load operation (Federal Energy Regulatory Commission 1979). The cost of enlarging a hydroelectric project to provide operation at a lower plant factor may involve only the addition of penstocks and generating units at the same dam and reservoir. In such cases the incremental cost of the added capacity is less than the cost of alternative electric capacity. If a re-regulating reservoir does not exist, one is often required. The cost of adding such a reservoir frequently precludes the addition of peaking capacity.

Pumped storage facilities are a special type of hydroelectric project designed to meet peak demands. These plants are peak-load plants that pump all or a portion of the water supply used for power generation. Essentially, they consist of a tail water pond, river, or natural lake and a head water pond. During times of peak load water is released from the head water pond through the penstocks to operate the generating units during the peak load. During off-peak hours, the units are reversed (or pumps used) to pump the water from the tailwater pond to the head water pond, (Creager 1950). Pumped storage plants are negative energy producers, i.e., approximately three units of energy are used for pumping for every two units of energy produced. Pumping is performed, however, during off peak (night) hours and on weekends when demand is low and excess capacity is available. Energy is generated by the plant during peak demands when existing conventional hydro, fossil, and nuclear plants do not have enough capacity to meet the demand (Federal Energy Regulatory Commission 1979). Operation of a pumped storage plant to meet peak loads is identical to that of all peak load hydroplants. The only difference is that for conventional units streamflow refills the head water pool whereas for pumped storage plants water must be pumped to refill or partially refill the head water pool. Since peaking conventional and pumped storage units are similar in operation additional discussions will be limited to conventional plants but will generally be applicable to operation and implementaion of pumped storage projects.

Characteristics of Capacity Additions

Capacity additions are installed at plants where storage either at the site or upstream is available and daily pondage is acceptable. The additional capacity allows the plant to operate at higher capacity for a shorter period of time (lower plant factor) and still produce approximately the same amount of energy.

Capacity additions which modify plant operation to meet peak loads can create severe impacts. The discharge of high flows for short periods can, for example, increase downstream erosion, create fluctuating water surfaces both in the upstream pool and the downstream channel, and disrupt fish and wildlife and their habitat. These problems are site specific but can make what would seem like a very economical addition non-implementable. As a result thermal generating plants to provide peaking capacity may be easier to implement. However, hydroelectric powerplants have many distinct advantages over thermal plants. Operation and maintenance costs are relatively low, and the plants can be designed for automatic supervisory control from a remote location. Hydroelectric plants have long life and low depreciation expenses. Unscheduled outages are less frequent and downtime for overhaul is of short duration because hydroelectric machinery operates at relatively low speeds and temperatures, and is relatively simple. A hydroelectric unit is normally out of service about two days per year due to forced outages and about seven days of scheduled maintenance. The average outages rates of modern thermal electric units are several times greater (Federal Energy Regulatory Commission 1979).

The ability to start quickly and make rapid changes in power output makes hydroelectric generation particularily suitable for carrying peak loads and for assisting in the supply of spinning reserve (units operating at no load or partial load with excess capacity readily available to support additional load). If operating at partial load, they are able to respond very rapidly to sudden demands for increased power. Also, hydroelectric plants do not consume water, contribute to air pollution, or add heat to rivers and streams.

Operation of Peak-Load Hydroplants

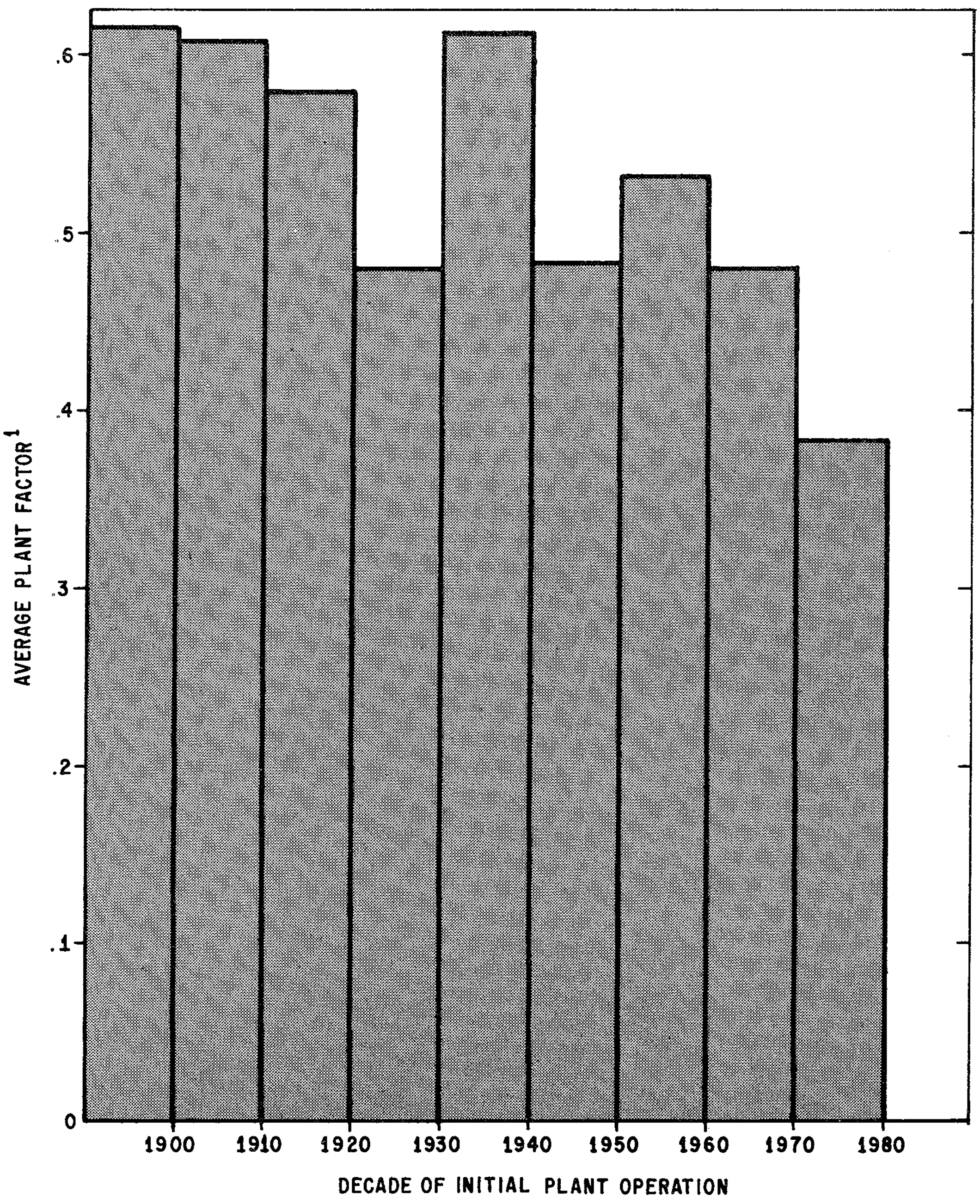
Run-of-river hydro plants with either daily or weekly pondage can effectively be used as peaking plants providing the capacity is available. The plants provide peaking capacity during minimum river flow to meet maximum load demands by daily storage of river flow. When river flows approach the average flow the plant would generate more of the time and thereby fall farther down on the load curve. When full plant discharge is available during high flows, the plant would generate full time and then be considered part of the base load generation (Creager 1950).

Hydroplants whose inflow is regulated by storage at the site or at upstream sites are most often used for peaking. The primary function of these plants is to carry short-time loads (peaks) and to serve in case of need as an instantly available reserve capacity for the system. Peak-load hydroplants permit more efficient steamplants to operate at more optimum (higher) plant factors. They also obviate the necessity for retaining in reserve many antiquated high-production-cost steamplants and for carrying so many steam units in hot reserve (Creager 1950). Units that are in hot reserve are producing steam and consuming fuel but are not loaded to capacity thereby being readily available to support additional load.

Growth of Peak Load Hydroplants

Developers of hydropower plants have utilized the capability of hydropower for meeting peak system loads. Several factors, mentioned previously, that make hydroplants well suited for use for peaking include the short response time from startup to loading, reduction of use of thermal units with associated high investment and fuel costs, and ability to provide spinning reserve without any associated fuel costs. Within the last several decades the average annual plant factors of hydroplants have been decreasing indicating that a majority of new plants have been sized to supply intermediate and peak load energy. Figure 6-1 shows the average plant factors by decade for 756 existing hydroplants (those plants in the NHS study data file which had a date for construction).

Most hydroplants have a potential for increased capacity. The amount of capacity increase would depend primarily on how much the plant factor can be reduced, the saleability of the output, and the physical downstream channel capacity. Several examples of recent capacity additions are displayed in Table 6-1. Each of the sites described in Table 6-1 are unique. The capacity of the Bonneville project is being doubled so that spills will be a rare event and so that the project can be operated as a peaking plant in conjunction with other peaking units upstream. The Libby project will require a re-regulating reservoir downstream from the project to reduce downstream flow fluctuations to be within an acceptable range. The Mayfield project is to have the forebay and power intake parapet walls raised five feet to accommodate the peaking operation. A fourth unit will also be



1 BASED ON SAMPLE OF 756 SITES, WEIGHTED BY CAPACITY.

Figure 6-1

AVERAGE PLANT FACTOR VS. INSTALLATION DATE

Table 6-1

CAPACITY ADDITIONS

Plant Name	Location	Capacity Initial (MW)	Capacity Additional (MW)	% Increase	Average Annual Energy Initial (GWh)	Average Annual Energy Additional (GWh)	% Increase	Annual Plant Factor Initial	Annual Plant Factor Additional Capacity	New Overall	Comments
Bonneville	Oregon	518.4	540.8	104	4,713	1,463	31	1.03	.31	.66	1, 2, 10
Libby	Montana	420	420	100	1,589	61	4	.43	.02	.22	1, 2, 7
Mayfield	Washington	120	40.5	33	650	54	8	.62	.15	.50	3, 5, 7
Brownlee	Oregon/Idaho	360	225	63	2,202	215	10	.70	.11	.47	3, 4, 7
Noxon Rapids	Montana	283	114	40	1,884	108	6	.72	.11	.54	3, 7, 8
Lake Texoma	Oklahoma/Texas	70	70	100	216	49	22	.35	.08	.22	2, 6, 9

Comments:
1. Under construction.
2. Source - Corps of Engineers Project Report
3. Source - FERC Memorandums.
4. Constructed 1980.
5. Contracting stage/completion 1982.
6. Recommended Plan 1980.
7. No change in firm energy.
8. Completed 1977.
9. Loss in firm energy of 6.3 GWh, gain in secondary energy 55.3.
10. Additional energy is all firm energy.

installed that will make the Mayfield hydraulic capacity practically match that of the upstream Mossyrock project hydraulic capacity thus significantly reducing fluctuations of the Mayfield reservoir.

The Brownlee project capacity addition will include the construction of a new powerhouse adjacent to the existing powerhouse to contain the fifth generation unit which will increase the capacity of the plant by 63 percent. In contrast, a fifth generation unit was installed in the Noxon Rapids project in the space provided during initial construction of the powerhouse. The addition to the Lake Texoma project is a recommended plan which would double the existing capacity of the plant.

The majority of these projects were conceived, planned, and recommended for construction in the late sixties and early seventies. Since that time, projections of growth in demand and need for additional generating capacity have been reduced (Marshall 1980). Factors causing this reduced growth rate are public awareness programs which results in reduced demand and peak load shifting, utility interties, and rate increases (increased fuel costs) which tend to make industry and business reduce their demands, (e.g., modification of processes, recycling water heat, and more efficient use of lighting). The demand forecasts for the year 2000 have dropped 35 to 40 percent between 1972 and 1978 (Marshall 1980). As a result of reduced demand and lower demand forecasts, utilities have delayed construction schedules and postponed some new plants.

6.4 HYDROELECTRIC POTENTIAL IN PERSPECTIVE

This section has been included to attempt to put the results of this study of existing plants into perspective. During the course of this study a massive amount of information was evaluated. Even though this report presents only those essential assumptions, procedures, and sufficient results to allow the reader to determine the reasonableness of the results, there is still a large amount of material to be digested. The main points of this study can be summed up by the following question. What are the approximate amounts and locations of potential energy increases and how can this potential be developed? Figure 6-2 shows graphically the location and amount of existing thermal and conventional hydroelectric capacity for the nine

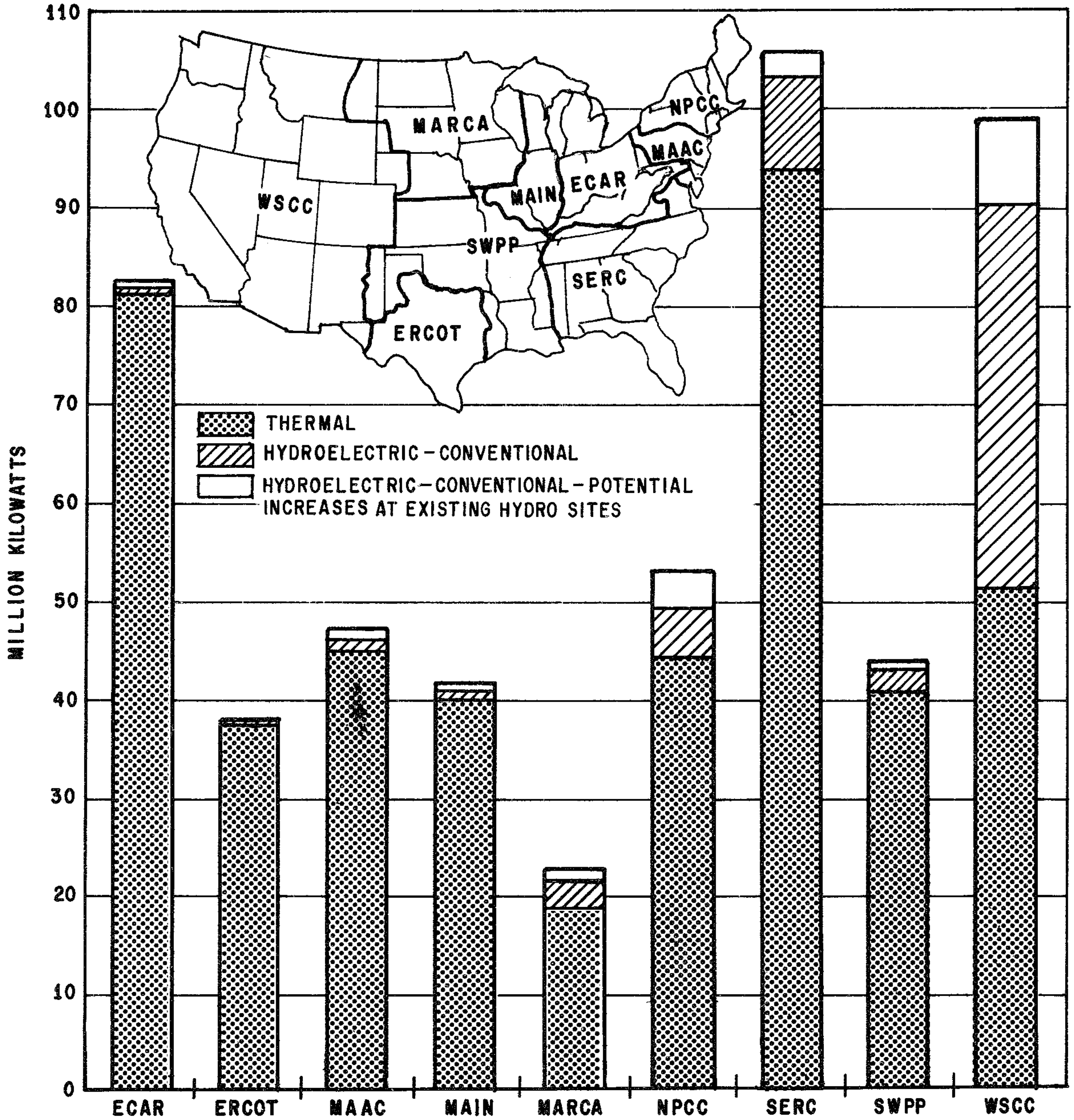
Electric Reliability Council areas (Federal Energy Regulatory Commission 1979). The potential capacity increases required to develop the estimated achievable energy increases for each of these regions are superimposed on Figure 6-2.

The total installed generating capacity from all sources is about 588,000 MW (Energy, Dept. of 1979). This capacity generates approximately 2,210,000 GWh (Harza 1980). In this total, about 272,500 GWh is produced by hydroelectric generation. If all of the hydropower potential at existing hydropower sites identified as achievable in this study were added, the total capacity would increase by about 2.7 percent and the total energy developed would increase by about 1.5 percent (30,000 GWh). This may appear to be a small increase, however, it would require about 60 million barrels of fuel oil (.164 million barrels per day) annually to produce the equivalent amount of electrical energy. Even a portion of this increase would assist in reducing the 8.0 million barrels per day (MBD) imported to meet the total U.S demand of about 18.5 MBD (Kalhammer 1979).

6.5 ASSESSMENT OF DATA AND EVALUATION METHODS

The investigation strategy adopted for this study was designed to yield reliable aggregate estimates of achievable increased energy at existing hydroelectric plants. It therefore seems appropriate to comment on the degree to which the data and technical evaluation methods support achievement of the study goal.

The basic site data on hydropower plant characteristics, available flow, reservoir storage allocations and other lesser data items were retrieved from the data files prepared for the National Hydropower Study and were augmented from a file developed and furnished by Shawinigan Engineering that was under contract to the Electric Power Reserarch Institute for performance of a research study (Shawinigan 1980). The resulting data base contents are tabulated in Table 1-2. Note that the data is complete for only a few of the categories, but in general they represent sites comprising a major portion of the aggregate existing installed capacity. Inference techniques were used to accommodate some of the missing items so that it was possible to evaluate all sites in the inventory except those without values for head and/or average



SOURCE: U. S. Department of Energy, Hydroelectric Power Evaluation, DOE/FERC-0031, August 1979.

Figure 6-2

ELECTRIC UTILITY GENERATING CAPABILITY BY REGIONAL ELECTRIC RELIABILITY COUNCILS JANUARY 1978

annual inflow. Comparisons made in evaluations to examine the consequences on incomplete data sets indicate that the error thus introduced is well within the overall accuracy appropriate for the intent of the study. In addition, preliminary screening type evaluations were performed to determine if major errors existed in specific site data items. Several were found and corrected. Duplicate sites that existed in the NHS files were deleted, and all sites that were designated pumped storage were removed. The resulting data set as used is judged to be appropriate and adequate for the nationally scoped assessment performed herein.

The evaluation strategy conceptually separated the evaluations for the physical improvement measures from the management or operational oriented improvements. The resulting estimates are not, however, additive, e.g., the energy increase from the measures evaluated for the two categories do overlap. The physical potential estimate due to the way it was performed includes virtually all of the energy output increase possible from all measures, including that attainable from storage reallocation. In other words, the energy increase from reallocation, with the exception noted below, is a subset of and therefore included within the estimate derived from the physical improvement evaluations. The energy increase estimate not captured in the physical improvements estimate is that contributed by the increased power storage utilization, reducing spills and thus routing an increased volume through the existing plant. The dominant factor in increased energy output through reallocation was reported in Section 5.2 to be increased head; in effect substantiating the notion that there is not significant spill occurring at these sites. The result is that the achievable increased energy in the aggregate is most accurately represented by the physical potential estimate. Reallocation is the mechanism by which increased head would be available for increased power generation. The major contribution of reallocation was presented as firming up the output, e.g., converting energy that would presently be characterized as secondary energy to firm energy that may in some instances be quite important.

A significant determinant of achievable increased energy output is the value assigned to this increase. The values assigned (power benefits) were developed from the FERC data set (Federal Energy Regulatory Commission 1978). The power values contained in the tables are based on, among other things, plant factor as an indicator of the appropriate location on the system load curve for the proposed generation. Note from the table that as plant factor decreases (gets closer to 0), the capacity value decreases and energy value increases, inferring probable displacement of combustion turbines for the lower plant factors. This likely results in greatly overvaluing generation from run-of-the-river type plants that might have low plant factors simply because their operation is intermittent. This would be increasingly true for additions to existing plants that would of necessity operate at lower plant factors. The net result is that energy for intermittent plants is overvalued and therefore the potential energy increase estimate made in this study may be slightly high. Extensive sensitivity analysis presented in Section 4.3 was performed partially in response to this issue.

The reader will note that the report does not explicitly estimate the cost (increase in annual damages) associated with reallocating storage from existing flood control space to power storage space. It was found impossible to perform the analysis on a national scale because of the dependence of increased damage on the specific flood control operations of each project and the relationship of the site to downstream damage for which data was not available. In addition the flood hydrology would have to include the resulting response in flood control system operations for which data also is not available on a national scale. The reallocation issue is a sensitive and potentially controversial one so that it was also difficult to make use of planned case study approaches to perform the estimate. On the positive side, however, it appears that the one case study that was performed and presented in Apendix C is reasonably representative in terms of flood damage, e.g., there is probably a relatively small increase in annual damage for the first increments of loss in flood control storage. Nonetheless, allocating storage space from flood control to power without compensation measures to provide essentially the same flood control performance is unlikely. Given the minimal increase in energy that results from major storage shifts (see Section 5.2) it seems that storage reallocation, as a means of increasing energy generation, is not a potentially major contributor. The potential that is available can probably be substantially obtained from operational changes thus avoiding the sensitive reallocation issue. Therefore, the lack of specific assessment of the damage increase impact of reallocation does not materially affect the results of the investigation.

The cost relationships used in the evaluation were derived from several sources, including some (there have not been many) recently completed rehabilitation projects. The relationships are necessarily general so that each improvement measure at each site has an estimated cost that is consistent with other sites (and their peculiarities) and measures. The resulting estimates, taken in the aggregate, appear reasonable and consistent with the intended purpose of the study. A degree of verification was performed by comparing cost estimates generated by the evaluation procedures with recent rehabilitation projects. Appendix A documents 3 such comparisons.

In summary, the data and evaluation methods used are believed to provide reliable identification of the major factors influencing potential increases in energy output at existing sites and to yield sufficiently accurate estimates of achievable energy increase at the regionally aggregated level. Conclusions for any specific site would require more detailed site specific data and assessments.

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GLOSSARY

Abbreviations

alternating current	ac
barrel (42 gallons)	bbl
benefit-cost ratio	B/C
British thermal units	Btu
cents	¢
cubic feet	ft^3
cubic feet per second	cfs
cubic yard	cu yd
direct current	dc
dollars	$
efficiency in percent	E
feet	ft
flow in cfs	Q
gigawatt	GW
gigawatt-hours	GWh
gravitational constant	g
head in feet	H
Hertz	Hz
horsepower	hp
kilovolt	kV
kilovolt-ampere	kVA
kilowatt	kW
kilowatt-hours	kWh
megavolt ampere	MVA
megawatt	MW
megawatt-hours	MWh
percent	%
pound	lb
pounds per square inch	psi
revolutions per minute	r/min
square yards	sq yd

ALTERNATING CURRENT (ac)-an electric current that reverses its direction of flow periodically as contrasted to direct current.

AVERAGE LOAD-the hypothetical constant load over a specified time period that would produce the same energy as the actual load would produce for the same period.

BENEFIT-COST RATIO (B/C)-the ratio of the present value of the benefit stream to the present value of the project cost stream computed for comparable price level assumptions.

BENEFITS (ECONOMIC)-the increase in economic value produced by a project, typically represented as a time stream of value produced by the generation of hydroelectric power.

BRITISH THERMAL UNIT (Btu)-the quantity of heat energy required to raise the temperature of 1 pound of water degree Fahrenheit, at sea level.

BULB UNIT-TURBINE/GENERATOR-a unit consisting of a horizontal shaft hydraulic turbine and close coupled generator which are both enclosed in a single steel watertight bulb located directly in the water passage.

BUS-an electrical conductor which serves as a common connection for two or more electrical circuits. A bus may be in the form of rigid bars, either circular or rectangular in cross sections, or in form of stranded-conductor overhead cables held under tension.

BUSBAR-an electrical conductor in the form of rigid bars, located in switchyard or powerplants, serving as a common connection for two or more electrical circuits.

CAPACITOR-a dielectric device which momentarily absorbs and stores electrical energy.

CAPACITY-the maximum power output or load for which a turbine-generator, station, or system is rated.

CAPACITY VALUE-that part of the market value of electric power which is assigned to dependable capacity.

CAPITAL RECOVERY FACTOR-a mathematics of finance value used to convert a lump sum amount to an equivalent uniform annual stream of values.

CIRCUIT BREAKER-a switch that automatically opens an electric circuit carrying power when an abnormal condition occurs.

CONVERSION EFFICIENCY (simply efficiency)-the proportion of energy available in an initial condition (e.g., fluid energy for a turbine) that is converted to energy in the stated condition (e.g., mechanical energy for a turbine). Usually stated as a percentage.

COSTS (ECONOMIC)-the stream of value required to produce the project output. In hydro projects this is often limited to the management and construction cost required to develop the powerplant, and the administration, operations, maintenance and replacement costs required to continue the powerplant in service.

CRITICAL DRAWDOWN PERIOD-the time period between maximum pool drawdown and the previous occurrence of full pool.

CRITICAL STREAMFLOW-the amount of streamflow available for hydroelectric power generation during the most adverse streamflow period.

DEMAND-see LOAD.

DEPENDABLE CAPACITY-the load carrying ability of a hydropower plant under adverse hydrologic conditions for the time interval and period specified of a particular system load.

DIRECT CURRENT (dc)-electricity that flows continuously in one direction as contrasted with alternating current.

DIVERSION-the removal of streamflow from its normal water source such as diverting flow from a river for purposes such as power generation or irrigation.

DRAFT TUBE-that section of the turbine water passage which extends from the discharge side of the turbine runner to the downstream extremity of the powerhouse structure.

EARTH DAM-a dam constructed of earthen materials, such as sand, gravel, clay, glacial till, or a random mix.

ENERGY-the capacity for performing work. The electrical energy term generally used is kilowatt-hours and represents power (kilowatts) operating for some time period (hours).

ENERGY VALUE-that part of the market value of electric power which is assigned to energy generated.

EXCITER-an electrical device which supplies direct excitation to the generator field during startup of the unit. It may be a rotating shaft mounted type, or a static rectifier type.

FEASIBILITY STUDY-an investigation performed to formulate a hydropower project and definitively assess its desirability for implementation.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)-an agency in the Department of Energy which licenses non-Federal hydropower projects and regulates interstate transfer of electric energy. Formerly the Federal Power Commission (FPC).

FIRM ENERGY-the energy generation ability of a hydropower plant under adverse hydrologic conditions for the time interval and period specified of a particular system load.

FLASHBOARDS-these usually consist of timber planks installed horizontally between steel pipe pins located at the crest of a dam and are used to maintain a higher reservoir level. Generally, the flashboards are washed out during flood flows and must be replaced.

FLOOD FREQUENCY CURVE-a curve which displays the exceedance frequency of floods for a range of peak flow values.

FLOOD STORAGE CAPACITY-that portion of the reservoir capacity which is reserved for the temporary storage of flood waters to reduce downstream flows.

FORCED OUTAGE-the shutting down of a generating unit for emergency reasons.

FORCED OUTAGE RATE-the percent of scheduled generating time a unit is unable to generate because of forced outages due to mechanical, electrical or another failure.

FOREBAY-this generally refers to the reservoir area located immediately upstream of a dam or powerhouse.

FOSSIL FUELS-refers to coal, oil, and natural gas.

GENERATOR-a machine which converts mechanical energy into electric energy.

GIGAWATT (GW)-one million kilowatts.

GRAVITATIONAL CONSTANT (g)-the rate of acceleration of gravity, approximately 32.2 feet per second.

GRAVITY DAM-a concrete dam which has sufficient mass to be inherently stable under all externally applied loads.

GROSS GENERATION-the total amount of electric energy produced by a generating station or stations.

HEAD, GROSS (H)-the difference in elevation between the headwater surface above and the tailwater surface below a hydroelectric powerplant, under specified conditions.

HERTZ (Hz)-cycles per second.

HORSEPOWER-mechanical energy equivalent to 550 ft. lbs. per second of work.

HYDROELECTRIC PLANT OR HYDROPOWER PLANT-an electric power plant in which the turbine-generators are driven by falling water.

IMPOUNDMENTS-bodies of water created by erecting a barrier to flow such as dams and diversion structures.

INSTALLED CAPACITY-the total of the capacities shown on the nameplates of the generating units in a hydropower plant.

INTAKE STRUCTURE-a concrete structure arranged to control the flow of water from a reservoir to the ultimate point of use. This structure usually contains either intake gates, or large valves, for regulating the rate of flow and for shutoff purposes.

INTERCONNECTION-a transmission line joining two or more power systems through which power produced by one can be used by the other.

KILOVOLT (kV)-one thousand volts.

KILOVOLT-AMPERE RATING (kVA)-the output (kW) of a generator divided by the power factor.

KILOWATT (kW)-one thousand watts.

KILOWATT-HOUR (kWh)-the amount of electrical energy involved with a one kilowatt demand over a period of one hour. It is equivalent to 3,413 Btu of heat energy.

LOAD-the amount of power needed to be delivered at a given point on a electric system.

LOAD CURVE-a curve showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.

LOAD FACTOR-the ratio of the average load during a designated period to the peak or maximum load occurring in that period.

LOW HEAD HYDROPOWER-hydropower that operates with a head of 20 meters (66 feet) or less.

(AT) MARKET VALUE-the value of power at the load center as measured by the cost of producing and delivering equivalent alternative power to the market.

MEGAWATT (MW)-one thousand kilowatts.

MEGAWATT-HOURS (MWh)-one thousand kilowatt-hours.

MULTIPURPOSE RIVER BASIN PROGRAM-programs for the development of rivers with dams and related structures which serve more than one purpose, such as - hydroelectric power, irrigation, water supply, water quality control, and fish and wildlife enhancement.

NUCLEAR POWER-power released from the heat of nuclear reactions, which is converted to electric power by a turbine-generator unit.

OPERATING POLICY-(Operating Rule Curves)-the technical operating guide adopted for water resources projects to assure that authorized output of the project is acheived. Usually in the form of charts and graphs of reservoir release rates for various operational situations.

OUTAGE-the period in which a generating unit, transmission line, or other facility, is out of service.

(IN) PARALLEL-several units whose AC frequencies are exactly equal, operating in synchronism as part of the same electric system.

PEAK LOAD-the maximum load in a stated period of time.

PEAKING CAPACITY-the part of a system's capacity which is operated during the hours of highest power demand.

PELTON WHEEL-an impulse type hydraulic turbine which is shaped like a wheel and has a series of cast steel buckets attached to its periphery that receive the impact of a jet of water.

PENSTOCK-a large water conduit which is subjected to high internal pressure and is fully self-supporting.

PLANT FACTOR-ratio of the average load to the installed capacity of the plant, expressed as an annual percentage.

PONDAGE-the amount of water stored behind a hydroelectric dam of relatively small storage capacity used for daily or weekly regulation of the flow of a river.

POWER (ELECTRIC)-the rate of generation or use of electric energy, usually measured in kilowatts.

POWER FACTOR-the percentage ratio of the amount of power, measured in kilowatts, used by a consuming electric facility to the apparent power measured in kilovolt-amperes.

POWER POOL-two or more electric systems which are interconnected and coordinated to a greater or lesser degree to supply, in the most economical manner, electric power for their combined loads.

PROBABLE MAXIMUM FLOOD (PMF)-a hypothetical flood which is determined from an analysis of the maximum potential rainfall and runoff which could occur over a given area in a given length of time.

PUMPED STORAGE-an arrangement whereby electric power is generated during peak load periods by using water previously pumped into a storage reservoir during off-peak periods.

RATE OF RETURN ON INVESTMENT-the interest rate at which the present worth of annual benefits equals the present worth of annual costs.

REALLOCATION-the concept of changing the existing distribution in use of reservoir storage space to a new distribution. Reallocation of flood control storage to power storage would reduce reservoir storage space reserved for temporary storage of flood waters and increase the conservation storage available for power operation.

RECONNAISSANCE STUDY-a preliminary feasibility study designed to ascertain whether a feasibility study is warranted.

REVERSIBLE PUMP TURBINE-a Francis type hydraulic turbine which is designed to operate a pump in one direction of rotation, and as a turbine in the opposite direction of rotation. Good efficiencies can be achieved with both modes of operation.

ROTOR-the rotating inner portion of a generator consisting of windings surrounding the field poles which are dovetailed to the periphery of a laminated core.

RUNNER BLADES-the propeller like vanes of a hydraulic turbine which convert the kinetic energy of the water into mechanical power.

SCROLL CASE-the intake section of a large vertical shaft turbine, which has a scroll like shape in plain view.

SECONDARY ENERGY-all hydroelectric energy other than FIRM ENERGY.

SERVICE OUTAGE-the shut-down of a generating unit, transmission line or other facility for inspection, maintenance, or repair.

SLIDE GATE-a hydraulic gate which operates in vertical guides and has no wheels, rollers, or other friction reducing devices. Normally, such a gate must be opened or closed under balanced head conditions.

SLUICE GATE-a vertical shaft slide gate which is often used for passing water through a dam. Manual, or motor operated floor stands, are used to raise and lower sluice gates.

SMALL HYDROPOWER-hydropower installations that are 15,000 KW (15 MW) or less in capacity.

SPECIFIC SPEED-the speed in RPM at which a turbine of homologous design would operate, if the runner were reduced to a size which would develop one horsepower under a one-foot head.

SPHERICAL VALUE-a heavy duty valve generally used for penstock shutoff purposes on high-head projects. The valve body consists of a rotating sphere which provides a full port in the open position. Double seals of a retractable type are generally provided.

SPILLWAY DESIGN FLOOD-that pattern of flood inflow (hydrograph) which is to be used to size the spillway gates and determine the required freeboard for dam design purposes.

SPINNING RESERVE-generating units operating at no load or at partial load with excess capacity readily available to support additional load.

SPIRAL CASE-the steel inlet section for a Francis type turbine, which has a spiral shape in plan view.

STATOR-the stationary outer portion of a generator consisting of a frame, laminated magnetic core, and armature windings which carry heavy currents and high voltages.

STEAM-ELECTRIC PLANT-a plant in which the prime movers (turbines) connected to the generators are driven by steam.

SURGE TANK-a vertical chamber connected to the downstream end of a closed conduit. It usually has a free water surface and serves as a reservoir to decrease and dampen pressure surges during acceleration or deceleration of flow.

SURPLUS POWER-generating capacity which is not needed on the system at the time it is available.

SWITCHGEAR-the switches, breakers, and other devices used for opening or closing electrical circuits and connecting or disconnecting generators, transformers, and other equipment.

SYSTEM, ELECTRIC-the physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control, management or operating supervision.

TAILWATER LEVEL-the water level measured in the tailrace area immediately downstream from a hydro plant.

THERMAL PLANT-a generating plant which usesheat to produce electricity. Such plants may burn coal, gas, oil, or use nuclear energy to produce thermal energy.

THRUST BEARING-a bearing which supports the entire weight of the rotating parts of a vertical shaft turbogenerating unit, plus the maximum hydraulic thrust developed by the turbine.

TIMBER CRIB DAM-a dam constructed of timber crib cells filled with rock ballast and covered with sheathing on the water side to minimize leakage.

TRANSFORMER-an electromagnetic device for changing the voltage of alternating current electricity.

TRANSMISSION-the act of process of transporting electric energy in bulk.

TRASH RACK-a coarse screen constructed of flat steel bars at a prescribed spacing, which are welded to supporting steel beams. Trash racks are installed at water intake structures to prevent the entry of any relatively large debris.

TUBULAR TURBINE-an axial flow propeller type turbine which may have either a vertical, horizontal, or inclined shaft.

TURBINE-the part of a generating unit which is spun by the force of water or steam to drive an electric generator. The turbine usually consists of a series of curved vanes or blades on a central spindle.

TURBINE CLASSES-modern hydraulic turbines are divided into two classes; impulse and reaction turbines.

Impulse Turbines-an impulse turbine is one having one or more free jets discharging into an aerated space and impinging on the buckets of the runner, means of controlling the rate of flow, a housing and a discharge passage. The water supplies energy to the runner in kinetic form.

Reaction Turbine-a reaction turbine is one having a water supply case, a mechanism for controlling the quantity of water and for distributing it equally over the entire runner intake, and a draft tube. The water supplies energy to the runner in kinetic form.

Francis Turbine-a reaction turbine having a runner with a large number of fixed buckets, usually nine or more, to which the water is supplied in a whirling radial direction and can be designed for operating heads ranging from 50 feet to 2,000 feet.

Adjustable-Blade Propeller Turbine (KAPLAN)-a reaction turbine having a runner with a small number of blades, usually four to eight, to which the water is supplied in a whirling axial direction. The blades are angularly adjustable in the hub.

Fixed-Blade Propeller Turbine-a reaction turbine having a runner with a small number of blades, usually four to eight, to which the water is supplied in a whirling axial direction. The blades are rigidly fastened to the hub.

TURBINE-GENERATOR-a rotary-type unit consisting of a turbine and an electric generator. (See TURBINE & GENERATOR.)

UNIT EFFICIENCY-the combined overall efficiency of a hydraulic turbine and its driven generator.

UPRATING-increasing the generating capacity of a hydropower plant by either replacing existing equipment with new equipment or making improvements to the existing equipment.

VERTICALLY INTEGRATED SYSTEM-refers to power systems which combine generation, transmission, and distribution functions.

VOLTAGE OF A CIRCUIT-the electric potential difference between conductors or conductors to ground, usually expressed in volts or kilovolts.

WATT-the rate of energy transfer equivalent to one ampere under a pressure of one volt at unity power factor.

WHEELING-transportation of electricity by a utility over its lines for another utility; also includes the receipt from and delivery to another system of like amounts but not necessarily the same energy.

Appendix A

CASE STUDIES - MODIFICATIONS TO EXISTING PLANTS

APPENDIX A

CASE STUDIES - MODIFICATIONS TO EXISTING PLANTS

CONTENTS

LIST OF TABLES

Appendix A

CASE STUDIES - MODIFICATIONS TO EXISTING PLANTS

A.1 INTRODUCTION

Three case studies are included for the purpose of illustrating the nature of past uprate projects and to provide insight into the evaluation methods used in this report. The case studies were selected based on the uprating work actually done and the completeness of the uprate documentation. The case study sites are at Lay Dam and Wilson Dam located in Alabama and at Hoover Dam located in Nevada. At Lay Dam six old turbines and generators were replaced with higher capacity units. Eight existing turbines and generators were modified at Wilson Dam and six turbine runners were replaced at Hoover Dam.

For purpose of illustration, each case study is arranged into sections to provide the user an overview of the rehabilitation work done, rehabilitation studies undertaken, the results of the rehabilitation, and a comparison of the results by use of the evaluation methods used in this report with the actual rehabilitation as performed.

A.2 LAY DAM REHABILITATION

Rehabilitation of the Lay Dam and Powerhouse, located on the Coosa River near Clanton, Alabama, took place between 1964 and 1968. The rehabilitation work consisted of the following:

- The dam was raised 14 feet
- Six new mixed flow (Hybrid Francis/Propeller) turbines were installed to replace 6 old Francis turbines that were originally installed between 1912 and 1921
- Six new generators were installed to replace the 6 old generators
- New switchgear, transformer, and miscellaneous electrical and mechanical equipment was installed to replace old equipment
- The powerhouse was enlarged as a result of having to extend the draft tubes

Rehabilitation Studies

Initial studies started in 1955 when it was proposed to increase the capacity of the Lay Dam Powerplant by adding 2 new generation units of 43,000 kW each in a separate powerhouse. In addition, replacement of the six old units with new ones was considered but determined technically not feasible because turbine manufacturers were unable to provide units which could develop the full power potential of the river. In 1963 further discussions were held with turbine manufacturers and it was determined that due to improvements in turbine design, full river capacity could possibly be developed by six new units installed in the six existing positions. It was expected that some modifications would have to be made in the water passages and existing tubes. In 1964 two manufacturers submitted sealed bids which were held until their proposals were verified by model test data.

Results of Rehabilitation

The results of the rehabilitation study on capacity, efficiency and cost are as follows:

- The overall plant capacity was increased from 81,000 kW to 177,000 kW
- The unit capacity of units 1 through 4 were increased from 10,800 kW to 29,500 kW and the unit capacity of units 5 and 6 increased from 18,900 to 29,500 kW
- The flow through each unit was increased from 2,500 cfs to 4,850 cfs.
- The head through each unit was increased 14 feet from 70 to 84 feet
- The unit efficiency was not increased due to head losses from higher velocities through the existing intake, penstocks, and spiral cases. These were not modified except for minor configuration changes in the spiral cases
- Plant outage per unit averaged 5 months on a staggered scheduled to coincide with lower power demands
- Component first cost summary of the rehabilitation work indexed to January 1980 costs:

Component	Cost	Percent of Total
Turbines	11,700,000	20
Generators	8,660,000	15
Switchgear	2,100,000	4
Transformers	878,000	1
Switchyard	630,000	1
Powerhouse Civil	5,200,000	9
Dam Civil	30,000,000	50
Total	$59,168,000	100

Comparison of Rehabilitation Results With Evaluation Procedures

At this site there was significant increase in both the flow through the plant and the head on the plant. The actual rehabilitation at this site involved replacing six turbines and generators with higher capacity units totaling 177,000 kW. The actual cost to carry out this work was $59,168,000. In this study a site with more than 25 percent increase in capacity would initially be evaluated for adding units to attempt to capture as much of the potential energy increase as possible. The first costs to add the new capacity of 96,000 kW is about $42,000,000. If a total new plant was considered to replace the old plant the cost would be approximately $76,000,000. Replacement of existing units in this study would only have been evaluated if the add alternative was not feasible. The capacity increase due to replacement of the existing units would be limited to a 32 percent (Table A-1) increase bringing the total plant capacity to 107,000 kW, short of maximum potential. This replacement alternative included new turbines, rewinding of the generator stator coils, new transformers and miscellaneous civil works and costs about $20,000,000.

Table A-1

LAY DAM - CAPACITY IMPROVEMENTS

AS-CONSTRUCTED			EVALUATION PROCEDURES	
Item	Change (%)	Year of Manufacture	Allowable Change %	Reference Source
Turbines				
Units 1-4	173	1912-1921	32 1/	Fig. 3-1
Units 5-6	56	1912-1921	32	Fig. 3-1
Generators				
Units 1-4	173	1912-1921	80 2/	Fig. 3-3
Units 5-6	56	1912-1921	80	Fig. 3-3
Switchgear	0	1912-1921	35 3/	Chap. 3
Transformer	0	1912-1921	0 4/	Chap. 3

NOTES:

1/ Limit of allowable change based on year of manufacture.

2/ Increase is limited to turbine output, and illustrates that generator can be rewound to meet the allowable change, but would be inadequate to meet the capacity requirements for units 1-4.

3/ The allowable change indicates that existing switchgear has sufficient reserve capacity to satisfy new capacity which is limited by turbine uprating.

4/ Existing transformers predate 1940, therefore new transformers are required.

A.3 WILSON DAM REHABILITATION

Rehabilitation of the Wilson Dam powerplant, located on the Tennessee River in Lauderdale and Colbert Counties, Alabama, took place between 1965 and 1968. The rehabilitation work consisted of the following:

- Modification of 8 existing Francis turbines that were originally installed in 1925

- Modification of the 8 existing corresponding generators that were originally installed in 1925
- Minor structural changes were made to one draft tube
- Model studies were performed on 3 out of the 8 units
- Replacement of the old governors with new governors

Rehabilitation Studies

Studies were begun in 1959 to developed appropriate rehabilitation scheme for these units. The desired changes included: (1) Replacing the turbine runners because of their deteriorated condition; (2) enclosing and water cooling the generators to reduce maintenance; (3) converting to remote control of the units from the central electrical control room to reduce operating expense; and (4) increasing generating capability as much as possible for load peaking purposes. The manufacturers of the original turbines were first contacted to determine how much the power output of the units could be increased, what changes would be necessary, and what the turbine costs would be. These estimates indicated that an increase in the turbine rating of about 16% for Units 1 and 4 and about 31% for Units 5 to 8 was possible with new turbine runners and other minor turbine modifications. One reason for the smaller power increase of Units 1 to 4 is that the distance between runner centerline elevation and tailwater level is about 12 feet as compared to 7 feet on Units 5 to 8, thus turbine cavitation becomes a factor in obtaining increased power from these units.

The generator manufacturers advised that an increase in rating corresponding to the increased turbine power output could be obtained by rewinding the generator stators only. However, they recommended the stator iron be replaced also since it was known to be in poor condition and was causing increased power losses. So far as was known at that time, the other components of the generators were in satisfactory condition.

Three generator rehabilitation schemes were studied:

- Installation of new stators complete with air housings and coolers
- Installation of new stators only
- Rewinding the stators only

The first scheme was recommended because of the condition of the stator iron and because of the benefits accruing from reduced maintenance as a result of the enclosures.

The other major change recommended by a planning report issued in April 1963 was to install remote control for these units. This involved: (1) New cabinet-actuator governors for each unit; (2) elimination of the old governor fluid system and conversion of turbine servomotors for oil operation; (3) provision of automatic greasing equipment for the turbines; and (4) provision of necessary protective relays, switches, etc., for unit control and annunciation.

During the summer of 1963, a complete inspection was made of the waterways of seven of the eight units. The intake passages, spiral cases, draft tubes, and underwater turbine parts were found in relatively good condition. Small isolated areas of eroded or honeycombed concrete were found throughout the waterways, but only a few of these were serious enough to warrant repair. This inspection confirmed that rehabilitation of the turbines and generators was feasible without major changes or repair to the water passages and unit foundations.

Results of Rehabilitation

The results of modifications to the turbines and generators at Wilson Dam powerplant to obtain additional output is as follows:

- Nameplate capacities for Units 1-4 were increased from 20,000 to 23,000 kilowatts and for Units 5-8 from 26,000 to 30,960 kilowatts
- Total plant output for the 8 units modified was increased from 184,000 to 215,840 kilowatts

- Net head on Units 1-4 was changed from 95 to 86 feet and for Units 5-8 from 92 to 86 feet
- Horsepower rating of Units 1-4 remained at 30,000 but for Units 5-8 it changed from 35,000 to 42,000
- Design flows were not increased, they remained at 3,750 cfs for Units 1-4 and at 4,850 cfs for Units 5-8
- Component first cost summary of the rehabilitation work indexed to January 1980 cost:

Component	Cost	Percent of Total
Turbines	6,200,000	33
Generators	11,200,000	60
Switchgear	440,000	2
Transformers	0	0
Switchyard	0	0
Civil Works	925,000	5
Total	$18,765,000	100

Table A-2

WILSON DAM - CAPACITY IMPROVEMENTS

AS-CONSTRUCTED			EVALUATION PROCEDURES	
Item	Change (%)	Year of Manufacture	Allowable Change %	Reference Source
Turbines				
Units 1-4	15	1925	25	Fig. 3-1
Units 5-6	19	1925	25	Fig. 3-1
Generators				
Units 1-4	15	1925	75 1/	Fig. 3-3
Units 5-6	19	1925	75	Fig. 3-3
Switchgear		1925	35 2/	Chap. 3
Transformer		1925	0 3/	Chap. 3

NOTES:

1/ Increase is limited to turbine output, and illustrates that generator can be rewound to get required capacity, for all units.

2/ Existing switchgear has sufficient reserve capacity to satisfy turbine capacity increase.

3/ Existing transformers predate 1940 and have no reserve capacity and have to be replaced with new transformers.

Comparison of Rehabilitation Results With Evaluation Procedure

The increase in capacity at this site was less than 25 percent therefore the add units alternative was not considered. The actual rehabilitation work consisted of runner replacements and installation of new stators for the eight existing turbines and generators costing about $18,765,000, this compares with $13,000,000 based on cost curves developed during this study to replace the turbine runners, install new stators, and replace the trans- formers. Almost all of the differences in these two estimates was due to higher actual costs to install the new stators.

A.4 HOOVER DAM MODIFICATION

Replacement of four Francis turbine runners was undertaken at Hoover Dam on the Colorado River near Boulder City, Nevada, in 1965. Scheduled for 1981 is the replacement of an additional 2 runners. The first four runners replaced were for Units N1 through N4 which were originally installed in 1933. The latter two units, A3 and A4 were originally installed in 1948. The replacement work to date has consisted of the following:

- Replacement of 6 Francis runners with 6 new Francis stainless steel runners
- Model studies were performed for use in designing new replacement runners

Rehabilitation Studies

When the original runners in Units N1-N4 deteriorated past the point of economic repair the Water and Power Resources Service (formerly Bureau of Reclamation) issued specifications requiring model testing of the installation with a new runner designs. The results of this testing were used for the final design and manufacture of the 4 replacement runners.

When the studies were made for Units A3 and A4 it was determined that the 30 foot diameter penstocks were underutilized and that the new design should optimize the use of the existing waterways without modification. Final design called for a higher runner elevation which required slight modifications to the draft tube.

Table A-3

HOOVER DAM - CAPACITY IMPROVEMENTS

AS-CONSTRUCTED			EVALUATION PROCEDURES	
Item	Change (%)	Year of Manufacture	Allowable Change %	Reference Source
Turbines				
Units N1-N4	5.5	1925	20	Fig. 3-1
Units A3 & A4	16.0	1948	10	Fig. 3-1
Generators				
Units N1-N4	----	1933	67	Fig. 3-3
Units A3 & A4	----	1948	33	Fig. 3-3
Transformer				
Units N1-N4	----	1933	0	Chap. 3
Units A3 & A4	----	1948	20	Chap. 3
Switchgear	----		35	Chap. 3
Switchyard	----			Chap. 3

Replacement Results of Rehabilitation

The results for runner replacement in Units N1-N4 at Hoover Dam are as follows:

- The turbine rating was increased from 127,500 HP to 135,000 HP per unit
- The flow through each unit was increased from 2,610 cfs to 2,710 cfs
- The net head was reduced fom 510' to 480'
- The unit efficiency was increased 5% (2% due to improvement in runner design and 3% that previously were losses in old runners)
- Unit outage time averaged 6 weeks

The anticipated results for Units A3 and A4 are as follows:

- The turbine rating will be increased from 135,750 HP to 157,300 HP
- The flow per unit will increase from 2,640 cfs to 3,000 cfs
- The net head will be reduced from 525' to 490'
- The unit efficiency should increase 6% (3% due to improved efficiency and 3% due to loss in the existing runner)
- Component first costs summary of the rehabilitation work indexed to January 1980 costs:

Component	Cost 1/	Percent of Total
Turbines	3,738,000	91
Model Studies	391,000	9
Total	$4,129,000	100

1/ Installation was done by operating personnel.

Comparison of Rehabilitation Results With Evaluation Procedures

The Hoover Dam modification demonstrates that some uprates consist of only a single item; in this case, replacement of the runners with no modification of the generator. It is understood that the generators will be modified in the future. The costs to carry out this work was $4,129,000 including model studies. The cost curves indicated costs of $5,437,000 to replace the runners at Hoover. Since the actual installation was carried out by operating personnel, the lower actual costs could be attributed to unaccounted manpower costs. It should be noted that the guidelines used in this study assume that if the turbine is modified to obtain more capacity then the generator must be modified or replaced depending upon the magnitude of increase.

Appendix B

CASE STUDY - RESERVOIR REGULATION SCHEDULES

Appendix B

CASE STUDY - RESERVOIR REGULATION SCHEDULES

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CASE STUDY - RESERVOIR REGULATION SCHEDULES

B.1 INTRODUCTION

This case study presents the reservoir operation plan for Oroville Dam and Reservoir located on the Feather River in Northern California. The intent of this case study is to indicate the many items that are considered when developing a regulation plan and that these plans are normally based on major investigations. All of these items would have to be reconsidered if alterations of reservoir regulations were being evaluated to enhance hydropower output. Essentially all of the remaining portion of this appendix was excerpted from the Oroville Dam and Reservoir Report on Reservoir Regulation for Flood Control prepared in 1970 by the Corps of Engineers, Sacramento District Office.

B.2 DESCRIPTION OF PROJECT FEATURES

The Oroville Dam and Reservoir is a unit of the Feather River Project, which is a part of the California State Water Plan for development and utilization of water resources of California. Oroville Dam is located on Feather River, a tributary of Sacramento River, in the Feather River Canyon, about six miles upstream from the town of Oroville. It was built for multi-purpose functions: water supply, flood control, power generation, recreation and conservation. It satisfies water demands of the areas adjacent to the Feather River, and supplies additional water for diversion from Sacramento-San Joaquin Delta to areas of need in the San Joaquin Valley, San Francisco Bay area, and Southern California. The 750,000 acre-feet flood control storage space in Oroville Reservoir provides flood protection to the cities of Marysville, Yuba City, Oroville, and many smaller communities located in the flood plain; it prevents flood damage to about 283,000 acres of highly developed agricultural land and to important highway and railroad routes. The Oroville powerplant has a capacity of 644,250 kilowatts. The reservoirs created by the project will provide recreational facilities and controlled releases to the downstream channel to enhance the fish and wildlife resources of the lower Feather River.

The main features of the Oroville Project are the dam, reservoir, and powerplant. Pertinent data for this project is noted on Table B-1. Oroville Reservoir gross pool capacity is 3,538,000 acre-feet, of which 750,000 acre-feet are allocated for flood control storage. The minimum power pool is 852,000 acre-feet. Maximum storage during the spillway design flood is 3,814,000 acre-feet. The spillway structure, located in a saddle on the right abutment of the dam consists of an uncontrolled concrete weir with a 1,730 feet long ogee crest and the flood control outlet structure which is a broad-crested weir forming a sill for eight topseal steel radial gates. The maximum release through the flood control outlet with the reservoir water level at spillway design flood pool elevation is 296,000 c.f.s. A concrete lined chute conducts water from the gated outlet to the river.

Oroville powerplant is located underground in the left abutment of the dam. The installed capacity is 664,250 kilowatts, and its annual output under full project development will be 2,475,000,000 kilowatt-hours.

B.3 FLOOD CONTROL DESIGN REQUIREMENTS

Hydrologic Basis for Design

By agreement between the State of California and the Corps of Engineers, selection of the maximum flood control space requirement for Oroville Reservoir was based primarily on protection of urban and agricultural areas along Feather River below the reservoir against winter floods (rain or rain augmented by snowmelt) up to the magnitude of the Standard Project Flood, with permissible releases limited to a maximum of 150,000 c.f.s.

Flood Control Space Requirements

Advance planning studies indicated that to control the Standard Project Flood (through the initially determined 3,484,000 acre-foot capacity reservoir) with outlet capacity at the bottom of the flood control space limited to 75,000 c.f.s., and assuming 100 percent efficiency of operation, required a flood control reservation of 750,000 acre-feet. This space must be provided whenever the meteorological potential for the full Standard Project Storm, and ground conditions conducive to maximum runoff exist. These

Table B-1

OROVILLE DAM AND RESERVOIR

PERTINENT DATA

GENERAL

Drainage area	3,611 sq. mi.
Flows at damsite	
Mean annual natural (1912-1957)	4,138,000 ac-ft.
Mean annual project impaired (1921-1951)	3,490,000 ac-ft.

Maximum flows at damsite	
1907 (estimated)	230,000 cfs
1955	203,000 cfs
1964	250,000 cfs
Standard project flood	440,000 cfs
Spillway design flood	720,000 cfs

OROVILLE DAM AND RESERVOIR

Main dam (Earth and rolled rockfill)	
Crest elevation	922.0 ft.
Freeboard, above spillway design flood pool	5.0 ft.
Maximum height	770 ft.
Crest length	6,920 ft.
Spillway	
Flood control outlet (in right abutment)	
Sill Elevation	813.6 ft.
Top-seal radial gates	
Number and size	8 - 17.6 x 33.0'
Maximum release (Reservoir at spillway design flood pool)	296,000 cfs
Powerplant	
Capacity	644,250 kw
No. of turbines	6 (3 reversible)
Annual output	2,475,000,000 kw-hrs.

Reservoir Elevation	
Minimum power pool	640.0 ft.
Flood control pool	848.5 ft.
Gross pool	900.0 ft.
Spillway design flood pool	917.0 ft.
Storage capacity	
Minimum power pool	852,200 ac-ft.
Flood control pool	2,788,000 ac-ft.
Gross pool	3,538,000 ac-ft.
Spillway design flood pool	3,814,000 ac-ft.
Palermo outlet	
Elevation	551.25 ft.
Capacity	40 cfs
River outlets	
Elevation	228.0 ft.
Capacity	5,000 cfs

conditions are defined on the Flood Control Diagram (Figure B-1) and in the following paragraphs.

Minimum Release Requirements

In order to fully utilize downstream channel capacities and flood control space under all possible flood conditions, a release capability of 150,000 c.f.s. throughout the range of flood control space is desirable. A release capacity of 75,000 c.f.s. with the reservoir level at the bottom of the flood control storage space, and 150,000 c.f.s release capacity with the water level was determined to satisfy the flood control requirements.

Multiple Use of Reservoir Space

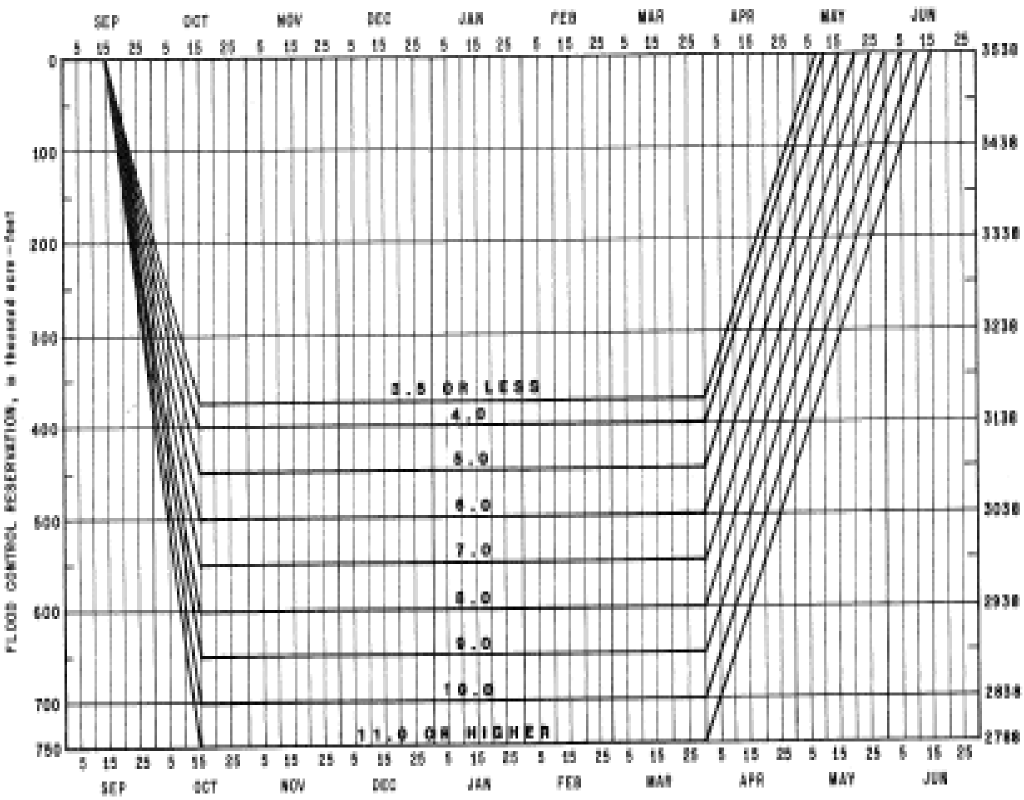
The flood control diagram is designed to permit use of flood control space for conservation purposes when use of such space is not required for accomplishment of flood control objectives. This is accomplished by use of a ground wetness index computed from accumulated basin mean precipitation. The index directly relates flood potential to wetness of the drainage basin. The adopted ground wetness index incorporates a daily reduction in the weight given previously occurring precipitation and is computed each day by multiplying the preceeding day's index by 0.97 and adding the current day's precipitation in inches, i.e.

$$\text{Par} = \text{Par}' \times 0.97 + \text{Precip}$$

Par = ground wetness index for the present day's operation
Par' = previous day's index
Precip = precipitation occurring since Par' was computed

Flood Control Diagram

The seasonal precipitation distribution criteria for the Central Valley of California indicates that the Oroville project drainage basin, with an average latitude of about 40^{o} and an average 3-day storm precipitation of about 9.3 inches, can experience full storm potential as early as 15 October and as late as 1 April. These criteria also show that the basin could have



SOURCE: Reservoir Regulation For Flood Control, Oroville Dam and Reservoir
U.S. Army Corps of Engineers, Sacramento, Calif. August 1970.

USE OF DIAGRAM

1. Parameters are computed daily from the weighted accumulation of seasonal basin mean precipitation by multiplying the preceding day's parameter by 0.97 and adding the current day's precipitation in inches.

2. Except when releases are governed by the emergency spillway release diagram currently in force (File No. 4-13-306), water stored in the flood control reservation, defined hereon, shall be released as rapidly as possible, subject to the following conditions:

   a. That releases are made according to the release schedule hereon.

   b. That flows in Feather River above Yuba River do not exceed 180,000 c.f.s.

   c. That flows in Feather River below Yuba River do not exceed 300,000 c.f.s.

   d. That flow in Feather River below Bear River do not exceed 320,000 c.f.s.

   e. That releases are not increased more than 10,000 c.f.s. or decreased more than 5,000 c.f.s. in any 2 hour period.

RELEASE SCHEDULE

ACTUAL OR FORECAST INFLOW (WHICHEVER IS GREATER) c.f.s.	FLOOD CONTROL SPACE USED ac-ft.	REQUIRED RELEASES c.f.s.
0 - 15,000	0 - 5,000	Power Demand
0 - 15,000	Greater Than 5,000	Inflow
15,000 - 30,000	0 - 30,000	Lesser of 15,000 or maximum inflow
0 - 30,000	Greater Than 30,000	Maximum inflow for flood
30,000 - 120,000	------------	Lesser of maximum inflow or 60,000 c.f.s.
120,000 - 175,000	------------	Lesser of maximum inflow or 100,000 c.f.s.
Greater than - 175,000	------------	Lesser of maximum inflow or 150,000 c.f.s.

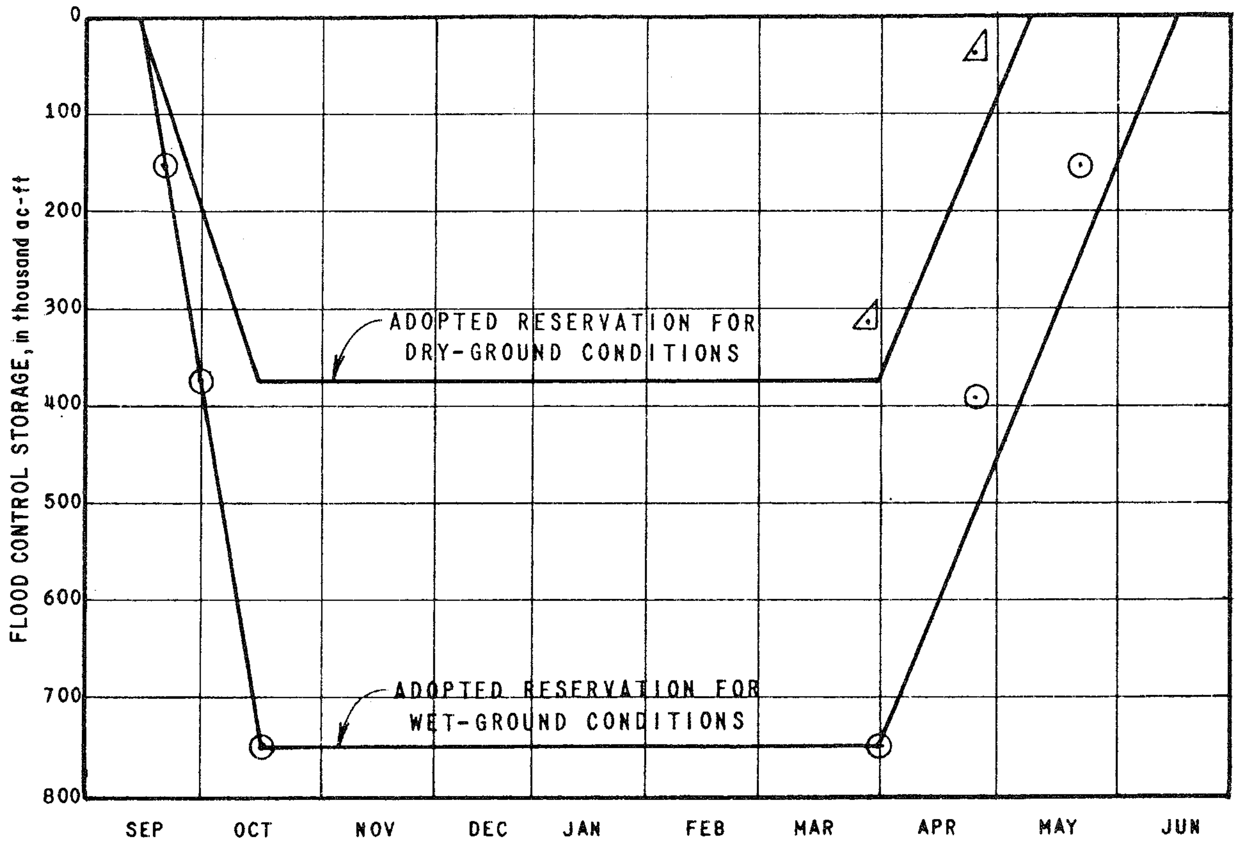
Figure B-1

FLOOD CONTROL DIAGRAM

80 percent of its potential as early as 2 October and as late as 27 April, and 60 percent of its full storm potential could be experienced as early as 18 September or as late as 23 May. Standard project protection, then, would require that sufficient space be available on these dates to control the flood that would result from these various percentages of the Standard Project Storm, considering ground conditions existing at the time. Under wet ground conditions, control of the full Standard Project Storm would require 750,000 acre-feet of flood control space. Under dry ground conditions it would require about half of this amount. Accordingly, 750,000 acre-feet of flood control space should be provided when the ground is wet, and 375,000 acre-feet should be provided under dry ground conditions between 15 October and 1 April of each year.

In order to determine space requirements prior to 15 October and subsequent to 1 April, alternative Standard Project Floods were computed for both wet and dry ground conditions using 80 percent of the Standard Project Storm, and for wet ground conditions using 60 percent of the Standard Project Storm. A summary of the results of these routings is shown on Figure B-2, where space requirements from 100 percent, 80 percent, and 60 percent routings on wet and and dry grounds are compared with the adopted space provisions. The slope of the drawdown line prior to 15 October was selected to equal exactly 25,000 acre-feet per day, and filling lines subsequent to 31 March slope at the rate of 10,000 acre-feet per day, so that accurate computation of flood control space is facilitated. These drawdown and filling rates can be easily accomplished within project operation restrictions.

In order to be reasonably conservative in providing protection against the Standard Project Flood, a wetness index of 11.0 was selected for provision of the full 750,000 acre-feet flood control space during the season of maximum storm potential. In the major storms studied, standard project ground conditions were not observed until a wetness index of 12.5 had been reached. A value of 3.5 was selected to represent dry ground conditions. The adopted flood control diagram with wetness index parameters is shown on Figure B-1.



⊙ Requirement under wet-ground conditions

△ Requirement under dry-ground conditions

SOURCE: Reservoir Regulation For Flood Control, Oroville Dam and Reservoir. U.S. Army Corps of Engineers, Sacramento, Calif. August 1970.

Figure B-2

SEASONAL FLOOD CONTROL SPACE REQUIREMENTS

When inflow and flood control storage are decreasing and no storms are forecast, releases may be decreased safely by steps to the rate which will maintain the currently required flood control storage reservation, or to the rate required by other uses of the reservoir, whichever is greatest. For this purpose, the maximum safe rate of reducing releases may be determined using Figure B-3.

B.4 GENERAL PROJECT OPERATION

Responsibility for Operation

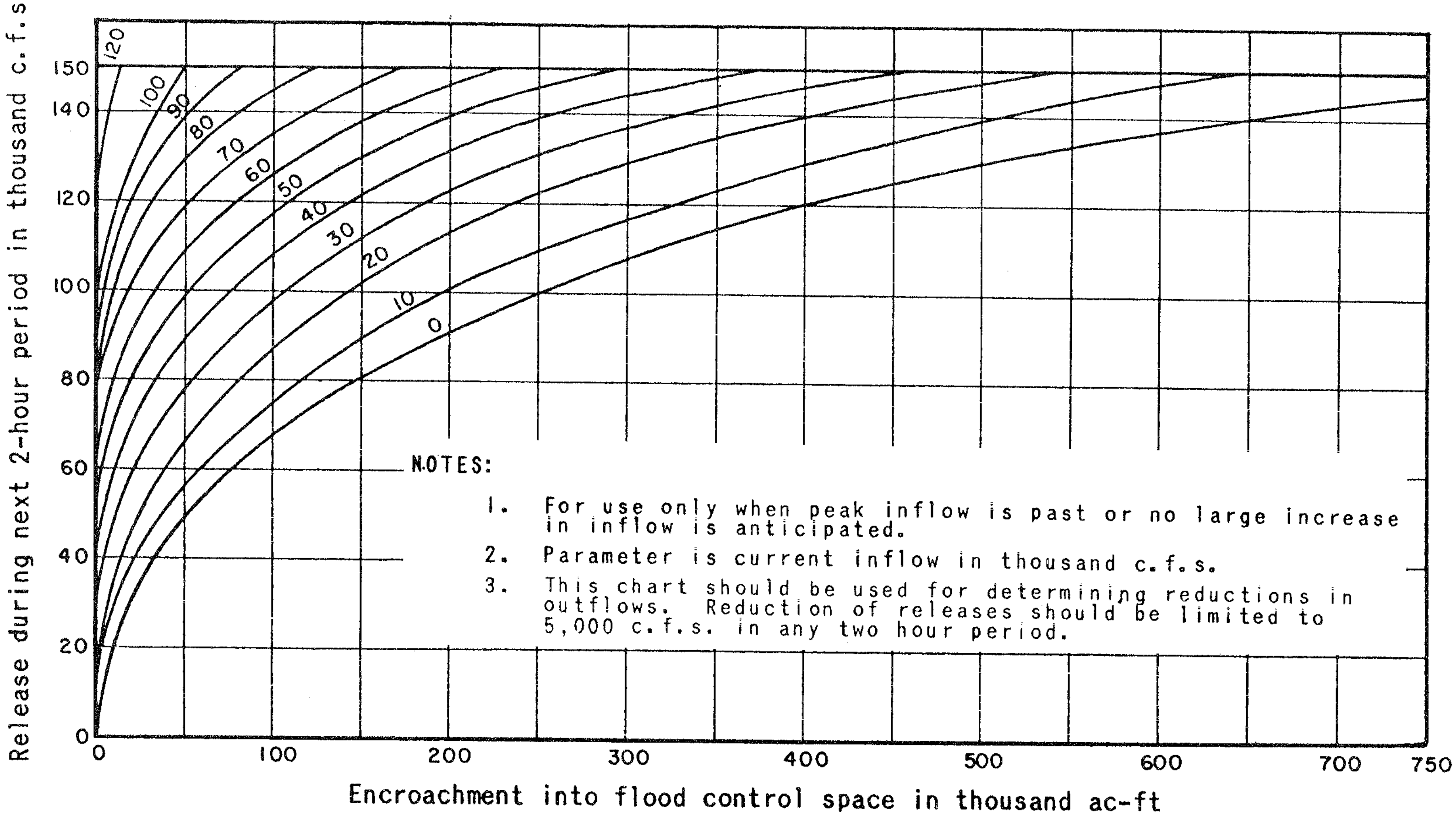
Oroville Reservoir is operated for flood control, irrigation, municipal and industrial water supply, and power generation. The Department of Water Resources of the State of California is responsible for the operation of Oroville Project.

The flood control operation is accomplished in accordance with rules and regulations prescribed by the Secretary of the Army pursuant to Section 7 of the Flood Control Act of 1944. The flood control diagram is shown on Figure B-1, and the emergency spillway release diagram on Figure B-4.

Upstream Regulation

Water resources development in the Feather River system consists of structures for hydroelectric power generation, irrigation, mining domestic, recreation, and debris-control uses. The total combined storage capacity of all the existing reservoirs is close to 2,000,000 acre-feet, of which 1,630,000 acre-feet is operated by the Pacific Gas & Electric Company for hydroelectric power generation.

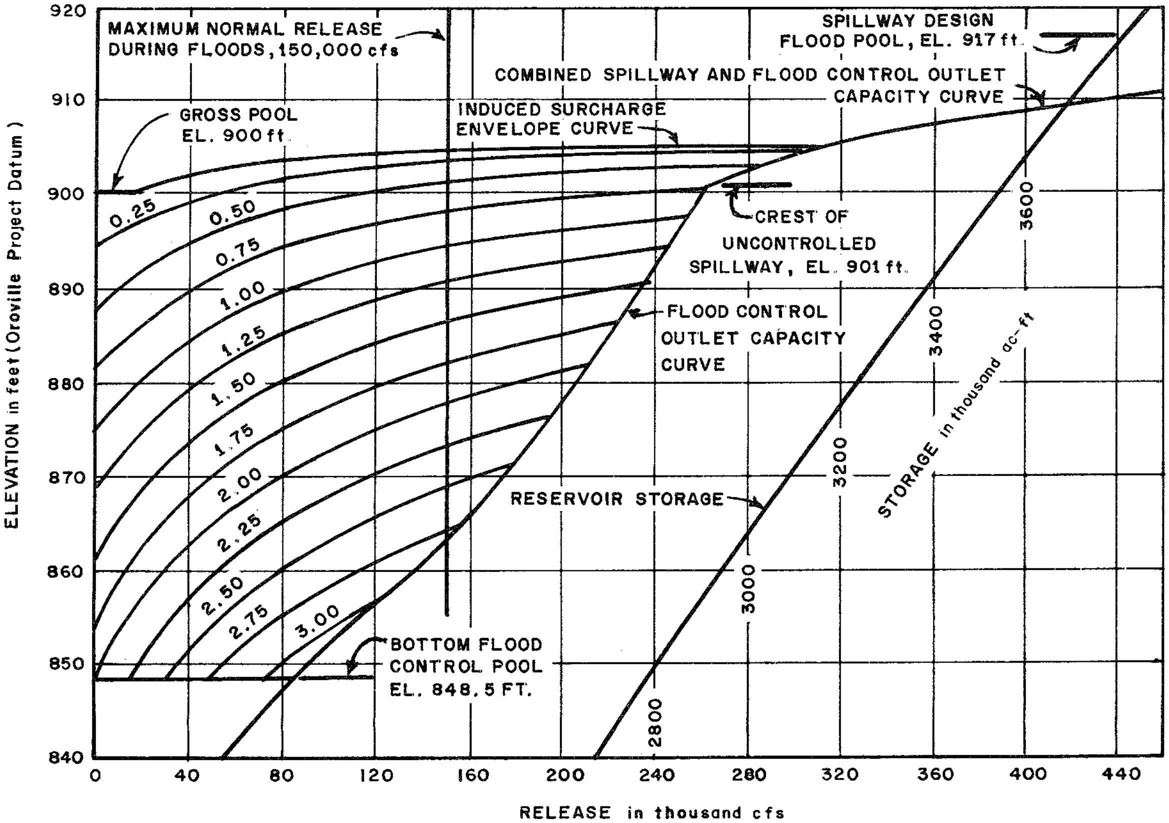
Of the many reservoirs located in the basin above Oroville Dam, the most important are: Lake Almanor, with a storage capacity of 1,308,000 acre-feet, completely controlling runoff from 507 square miles; Butt Valley Reservoir with a capacity of 50,000 acre-feet, completely controlling runoff from 75 square miles; and Bucks Lake, with a capacity of 103,000 acre-feet, completely controlling runoff from 28 square miles. The flood control function of these three reservoirs is reduction of the area tributary to Oroville Reservoir from



SOURCE: Reservoir Regulation For Flood Control, Oroville Dam and Reservoir. U. S. Army Corps of Engineers, Sacramento, Calif. August 1970.

Figure B-3

CRITERIA FOR REDUCTION OF FLOOD RELEASES



OPERATING INSTRUCTIONS

1. Follow regular flood control regulation schedule until larger releases are required by this schedule.
2. Adjust the spillway outflow each hour on the basis of the rate of reservoir elevation in feet for the preceding hour and the current reservoir elevation as indicated by the curves.
3. After the reservoir elevation starts to fall, maintain current gate openings until the flow has been reduced to 150,000 c.f.s.
4. Once operation in accordance with the emergency spillway release diagram is initiated, gate changes shall be made only in accordance with the above criteria.

NOTES:

1. Parameter values are the rate of rise in reservoir elevation in feet during preceding hour.
2. Sill of the flood control outlet is at elevation 813.6 feet. Ungated spillway crest is at elevation 901 feet.
3. Discharge through the flood control outlet is controlled by eight 17.6' x 33.0' gates with an additional 1730 feet of uncontrolled spillway above elevation 901 feet.

SOURCE: Reservoir Regulation For Flood Control, Oroville Dam and Reservoir. U. S. Army Corps of Engineers, Sacramento, Calif. August 1970.

Figure B-4

EMERGENCY SPILLWAY RELEASE DIAGRAM

3,611 square miles to 3,001 square miles. They have a combined storage capacity of 1,470,000 acre-feet and in the past they have completely regulated historical flood flows originating from their drainage areas. Other existing reservoirs have negligible influence on large floods.

Power Operation

Operation of Oroville Project for power production is based on integrating its power generating facilities with all other area power generating facilities to supply the area load. Minimum monthly kilowatt-hour output is provided under contract with the Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company (pre 1985).

Water releases conform with irrigation demands and flood control storage space requirements.

Conservation Operation

Operation for conservation is as follows:

- All inflow in excess of irrigation and power demands will be stored to the extent that conservation space is available
- Releases are in accordance with daily requirements as determined by the Department of Water Resources, State of California
- Releases to benefit downstream fishery are in accordance with fish agreement controls established by the State Department of Fish and Game and the U.S. Fish and Wildlife Service

Oroville Reservoir satisfies the water needs of the Feather River service area and, being a unit of the State Water Project, will also furnish a water supply to other areas in the State in need of water. With the exception of the water need in the local area, the conservation yield of Oroville Reservoir is integrated with surplus waters in the San Joaquin Delta for diversion and export, through conveyance and enroute-storage facilities, to the areas of water deficiency in the San Joaquin Valley, San Francisco Bay area, and Southern California. The estimated maximum conservation gross yield of

937,000 acre-feet at Oroville Reservoir will result in 870,000 acre-feet of water delivered in the service areas, 506,000 acre-feet of which will be for municipal and industrial water supply, and 364,000 acre-feet for irrigation use, including 113,000 acre-feet for the local Feather River Service areas. The municipal and industrial water supply is distributed on a uniform monthly basis, whereas the irrigation water demand is supplied primarily during the summer months. It has been estimated that the full demand on Oroville Reservoir will not develop until 1991.

Forecasts of Flood Runoff

Reliable computerized methods of forecasting the inflow hydrograph to Oroville Reservoir and local inflow below the reservoir have been developed by a State-Federal River Forecast Center. These forecasting schemes are based upon an analysis of historical periods of precipitation and involve the combining of precomputed antecendent indexes (AI), base flow, antecendent and forecasted rainfall, and unit-hydrograph ordinates. The AI is an index of the loss potential of the stream basin, or an index of the relationship between rainfall and surface runoff for a particular storm period. This index is computed from Brush Creek Ranger Station's precipitation data and Manzanita Lake's snow depth. The numerical value of this AI indicates the approximate number of inches of rain that would be required to produce one inch of surface runoff.

The effective basin-mean precipitation for six-hour intervals is estimated by using all available precipitation information adjusted for wind, freezing level, and snowpack data. This effective precipitation forecasted for succeeding intervals is based upon an analysis of the past, present, and forecasted synoptic weather situation used in conjunction with the actual observed antecedent precipitation and the U.S. Weather Bureau's Quantitative Precipitation Forecast (QPF).

B.5 FLOOD CONTROL OPERATION

Flood Control Operation Requirements

Oroville Dam and Reservoir is operated for flood control in accordance with flood control regulations prescribed by the Secretary of the Army. The flood control diagram, Figure B-1, and the emergency spillway release diagram, Figure B-4, define the schedule for flood control operation of Oroville Reservoir. The primary objectives of flood control operation are (1) to minimize flood damage downstream, and (2) to avoid causing damage, insofar as practicable, that would not have occurred under conditions without the project. The release schedule shown on Figure B-1 will provide protection for agricultural development within the floodway from frequently occurring floods, without sacrificing reservoir design flood (SPF) protection for lands outside the floodway.

A maximum of 750,000 acre-feet of space is dedicated to flood control, and whenever any part of this pace is not required for flood control, it may be used temporarily for other purposes.

Limitations on Storage and Releases

Operational limitations on storage in Oroville Reservoir are specified on the flood control diagram. Whenever water is stored in the flood control space it is released as rapidly as possible in accordance with the flood control diagram, Figure B-1. Feather River flows should not exceed 150,000 c.f.s. at Oroville, nor 180,000 c.f.s. and 300,000 c.f.s. above and below the mouth of Yuba River, respectively. Insofar as possible, the Feather River below Bear River should be limited to 320,000 c.f.s. During very large floods releases greater than 150,000 c.f.s. may be required, as indicated by the emergency spillway release diagram, in order to minimize uncontrolled spillway discharges. Releases from Oroville Dam are not be be increased more than 10,000 c.f.s. nor decreased more than 5,000 c.f.s. in any 2-hour period.

Emergency Operation of Gated Spillway

The emergency spillway release diagram (Figure B-4) indicates the release considered necessary to avoid endangering the structure without releasing quantities in excess of natural runoff. The diagram is based on computations of outflow required to limit storage to the capacity available, when only reservoir elevations and rate of rise are known and remaining inflow volume is estimated on the basis that inflow peak is past and that recession of flow will be somewhat steeper than the average recession observed in past floods. The diagram is thus designed to defer increases in emergency releases until it is certain that larger releases will be necessary. Accordingly, when such releases are indicated by the diagram, it is essential that they be made immediately in order that it will not subsequently become necessary to make larger releases.

Appendix C

CASE STUDY - REALLOCATION OF FLOOD CONTROL SPACE

APPENDIX C

CASE STUDY - REALLOCATION OF FLOOD CONTROL SPACE

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CASE STUDY - REALLOCATION OF FLOOD CONTROL SPACE

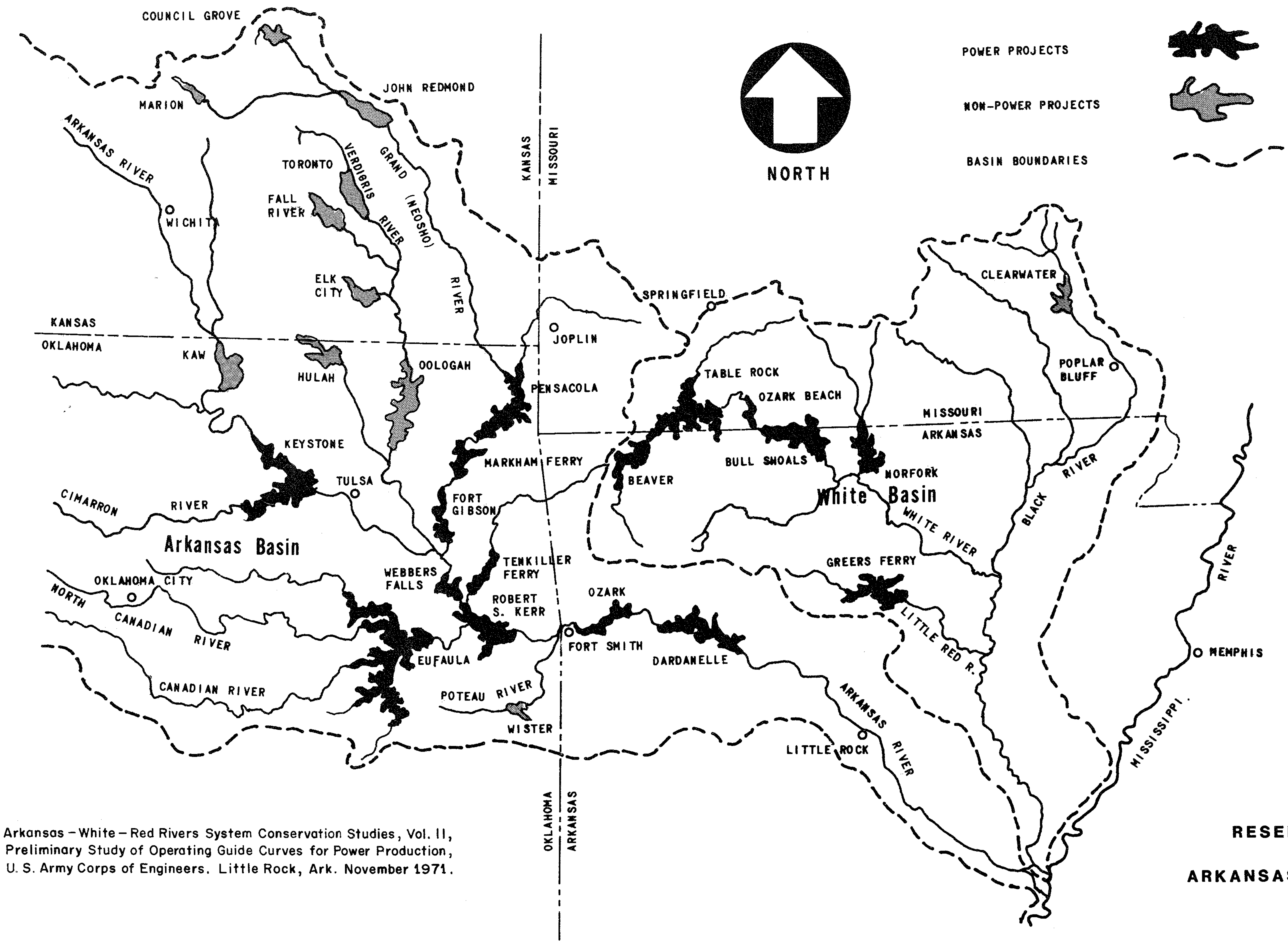
C.1 INTRODUCTION

A potential method of increasing energy output for a hydroelectric plant is to reallocate a portion of the flood control storage to conservation storage, thus, increasing the powerhead and the capability to control more volume for power generation. Two hydroelectric power systems were selected for case study analysis of reallocating various percentages of flood control storage to conservation storage. These systems (see Figure C-1 Arkansas - White River system) were selected because the reservoir systems had been previously computerized by the Southwestern Division of the U.S. Army Corps of Engineers (SWD).

C.2 ARKANSAS RIVER BASIN

The Arkansas River Basin located within seven States has a total drainage area of 160,000 square miles at its outlet to the Mississippi River. The total length of the Arkansas River is about 1,100 miles. The reservoir system model for this basin includes only the lower portion of the total basin (East of the 98th Meridian). The average annual runoff from the western portion of the basin is less than two inches as compared to a range of five inches to twenty inches over the eastern portion. This relatively minor amount of runoff and the long period of travel time for the subareas in the headwaters indicates that the smaller area would be more practical for system operations.

A schematic of this system is shown on Figure C-2. Pertinent information on existing projects is presented in Table C-1. There are ten projects with about four million acre-feet of power storage containing a total capacity of 823 MW. Four of these hydroelectric projects are also lock and dam projects. The remaining sixteen projects contain flood control storage of about 8.8 million acre-feet.

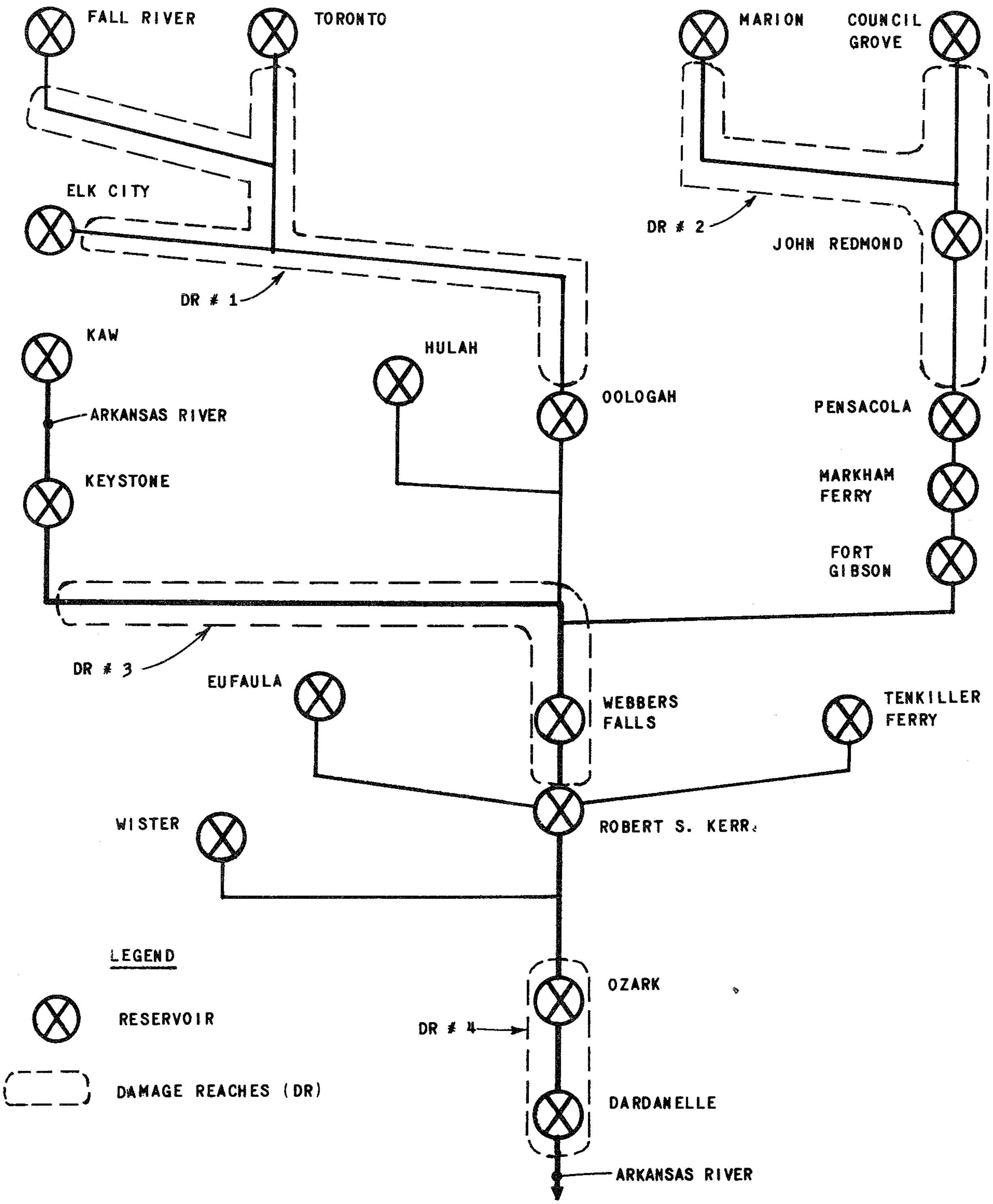


Source: Arkansas – White – Red Rivers System Conservation Studies, Vol. II, Preliminary Study of Operating Guide Curves for Power Production, U. S. Army Corps of Engineers. Little Rock, Ark. November 1971.

Figure C-1

RESERVOIR LOCATIONS OF

ARKANSAS - WHITE RIVER SYSTEMS



Source: Copley, Ross, Analysis of Operation Plans for the Arkansas River Basin System of Reservoirs (Case Study A-2), 1979

Figure C-2 SCHEMATIC - ARKANSAS RIVER SYSTEM

Table C-1

ARKANSAS RIVER BASIN

RESERVOIR INFORMATION

PROJECT (River)	Year Initial Operation	Drainage Area Sq. Mi.	Average Annual Inflow cfs	Storage--Ac. Ft. Flood Control	Power	Inactive Or Dead	Total	Installed Capacity MW	Average Annual Energy MWh	Average Annual Plant Factor
Fall River Lake (Fall)	1948	585	420	234,500	15,000	6,900	256,400	-	-	-
Toronto Lake (Verdigris)	1960	730	570	177,800	10,800	11,100	199,700	-	-	-
Elk City Lake (Elk)	1966	634	290	239,500	44,450	350	284,300	-	-	-
Council Grove Lake (Neosho)	1964	246	150	63,800	41,100	-	104,900	-	-	-
Marion (Cottonwood)	1968	200	110	60,000	86,000	-	146,000	-	-	-
John Redmond Reservoir (Neosho)	1964	3,015	1,400	559,000	70,800	500	630,300	-	-	-
Oologah Lake (Verdigris)	1963	4,339	2,530	965,600	57,100	9,300	1,032,000	-	-	-
Hulah Lake (Caney)	1951	732	390	257,900	31,100	0	289,000	-	-	-
Kaw Reservoir (Arkansas)	1976	46,530	2,020	919,400	195,100	85,100	1,199,600	-	-	-
Keystone Lake (Arkansas)	1964	74,506	6,870	1,218,500	330,500	287,500	1,836,500	70.0	228,000	.37
Pensacola Dam (Grand)	1940	10,298	7,270	525,000	1,192,000	480,000	2,197,000	90.0	340,600	.43
Markham Ferry Dam (Grand)	1964	11,533	8,140	244,200	-	48,600	292,800	100.0	190,000	.22
Fort Gibson Lake (Grand)	1952	12,492	8,010	919,200	53,900	311,300	1,284,400	45.0	190,500	.48
Webbers Falls Lock & Dam (Arkansas)	1970	97,033	19,910	-	30,300	134,900	165,200	60.0	213,300	.41
Tenkiller Ferry Lake (Illinois)	1952	1,610	1,580	576,700	371,000	283,100	1,230,800	34.0	95,100	.32
Eufaula Lake (Canadian)	1964	47,522	5,680	1,468,000	1,465,000	865,000	3,798,000	90.0	260,300	.33
Robert S. Kerr Lock & Dam (Arkansas)	1970	147,756	26,680	-	79,500	414,100	493,600	110.0	459,000	.48
Wister Lake (Poteau)	1949	993	1,220	400,800	16,300	10,800	427,900	-	-	-
Ozark Lock & Dam (Arkansas)	1969	151,820	32,470	-	-	-	148,400	100.0	429,000	.49
Dardanelle Lock & Dam (Arkansas)	1969	153,703	37,160	-	-	486,200	486,200	124.0	613,000	.56
				8,829,900	4,089,950	3,434,750	16,503,000	823.0	3,018,800	.42

Procedure for Analysis

To establish a basis for comparison, the operation of the Arkansas reservoir system was simulated using the daily sequential reservoir operation computer model developed by SWD. The model operates with a long period of daily hydrologic input to simulate the system operation for a given set of demands for water and energy, while meeting physical and operational constraints. The average annual energy and expected annual flood damage are computed by the model.

The power requirements are given for the system and each power reservoir is assigned to a specific system. The system energy load varies by season and is different for weekdays and weekends. The energy requirement is first met by mandatory releases for other purposes. If the mandatory releases generate excess energy, the excess is credited to dump energy. If additional generation is required, it is satisfied from available power storage and turbine capacity. When system storage becomes low, deficiencies are met by purchasing thermal power. The thermal purchase function varies with the season and system power storage.

The consequences of increasing power storage by reallocating storage in projects with both flood control and power storage were determined using the system model with redefined storage. The results of the new simulation provide estimates of annual energy production as well as estimates of flood damage. By comparing the results of the second simulation with those of the first, the potential changes in energy production and flood damage were determined. On the Arkansas system, a total of 15% and 30% of the flood control storage at Keystone, Eufaula, Fort Gibson, and Tenkiller was reallocated to the power pool. This amounts to reducing the total systems flood control storage within the system by 7.1% and 14.2%, respectively.

Reallocation Results

The impact of the storage reallocation was to increase the average annual damage from flooding approximately 4% for a 7.1% loss of system flood control storage and a 7.1% increase for a 14.2% loss. The increase in average annual energy was approximately 1% for the 30% reallocation. The gain in energy for the 15% reallocation was not significant.

The system simulation results indicate less potential gain in energy, from increased power storage, than the results from the independent project analysis discussed in Chapter 5. The smaller gain in energy is primarily a result of the flood operation. During flood operation, the flood control storage is evacuated at a flow rate near the power capacity rate. By maintaining flows at that rate, there is less spill and a higher powerhead. When the flood pool is evacuated at a power capacity rate, most of the advantages that would accrue to reallocating the flood control storage has already been realized. This is indicated by the simulation results showing a very small incremental gain in average annual energy from reallocating the flood control storage to power storage. Also, the base condition system simulation indicated a higher average annual energy production than the base condition results discussed in Chapter 5. The simulation described in Chapter 5 did not release at hydropower rates during flood evacuations because that is not the way most Corps power projects are currently operated. Chapter 5 discusses in more depth the differences between these two simulations.

C.3 WHITE RIVER BASIN

The White River located in Missouri and Arkansas has a total drainage area at its outlet to the Mississippi River of 27,765 square miles. There are seven reservoir projects within the basin. A schematic of the basin is shown on Figure C-3. Project information is presented on Table C-2. With the exception of Ozark Beach, which is privately owned, all of the remaining reservoirs are owned and operated by the Corps of Engineers. Generation of hydroelectric power and flood control are major purposes of the reservoirs. There is no commercial navigation on the streams in this basin. Clearwater is the only project that does not generate power. Total installed capacity at the six hydropower projects is 834 MW with total existing power storage of about 5.7 million acre-feet. There is approximately 5.5 million acre-feet of flood control storage at six projects. Only Ozark Beach has no flood control storage. Note that only about 37 percent of the total basin area is controlled by downstream flood control storage projects.

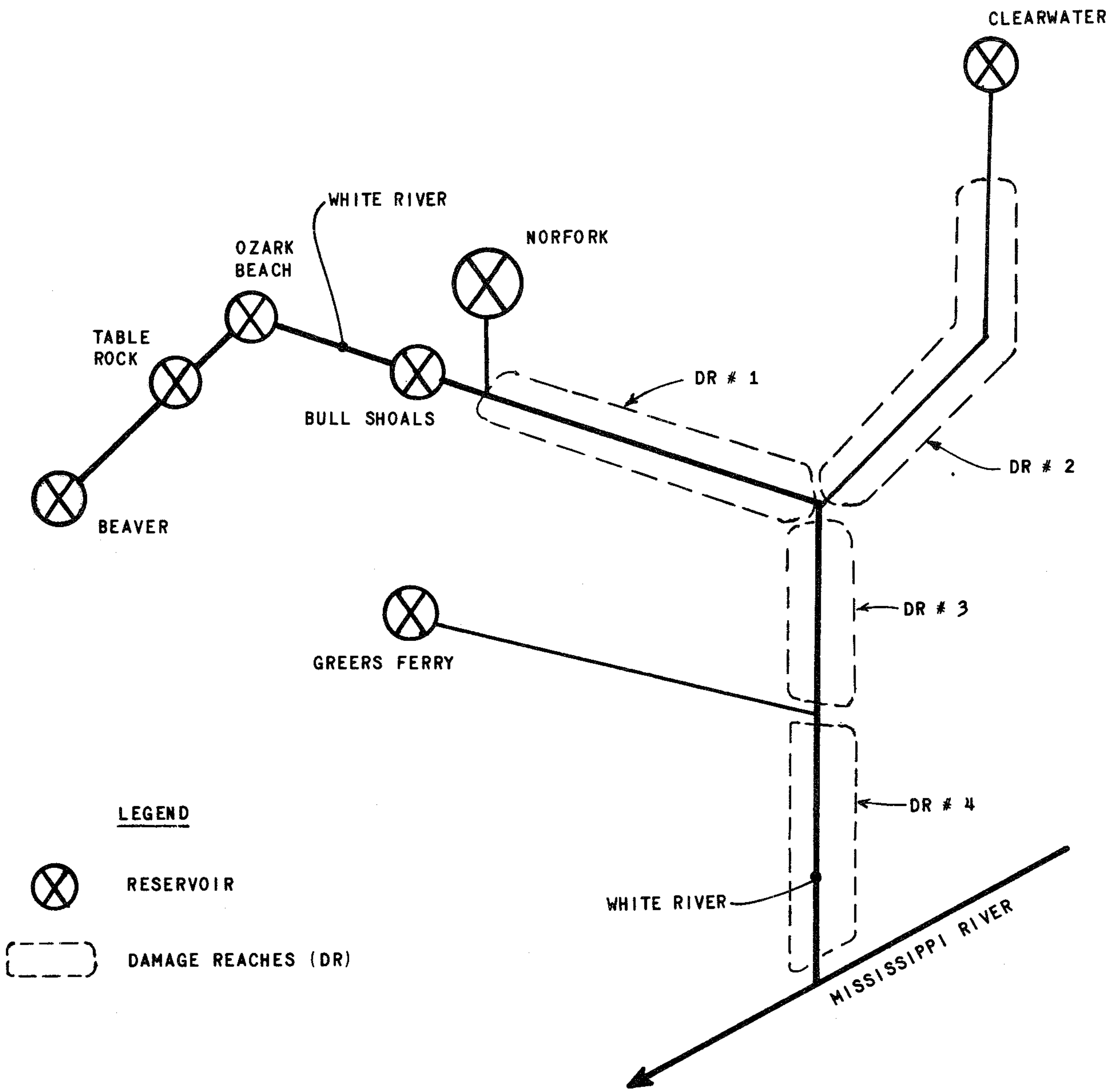


Figure C-3 SCHEMATIC - WHITE RIVER SYSTEM

Table C-2

WHITE RIVER BASIN

RESERVOIR INFORMATION

PROJECT (River)	Year Initial Operation	Drainage Area Sq. Mi.	Average Annual Inflow cfs	Storage--Ac. Ft.				Installed Capacity MW	Average Annual Energy MWh	Average Annual Plant Factor
				Flood Control	Power	Inactive or Dead	Total			
Beaver (White)	1965	1,186	1,560	300,000	925,000	727,000	1,952,000	112	172,000	0.18
Table Rock (White)	1961	4,020	3,600	760,000	1,182,000	1,520,000	3,462,000	200	495,000	0.28
Ozark Beach (White)	1913	4.500	4,495	-	13,500	14,500	28,000	16	94,000	0.67
Bull Shoals (White)	1951	6,036	6,240	2,360,000	1,003,000	2,045,000	5,408,000	340	785,000	0.26
Norfork (North Fork)	1944	1,806	2,280	732,000	707,000	544,000	1,983,000	70	184,000	0.30
Clearwater (Black)	1948	898	896	391,000	-	22,000	413,000	-	-	-
Greers Ferry (Little Red)	1964	1,446	2,310	934,000	1,910,000	-	2,844,000	96	189,000	0.22
Total Basin	-	27,765	-	5,477,000	5,740,500	4,872,500	16,090,000	834	1,919,000	0.26

Procedure for Analysis

The simulation procedures described for the Arkansas River System were also used on the White River System. In the White River System, five projects (Beaver, Table Rock, Bull Shoals, Norfork, and Greers Ferry) were analyzed for the reallocation of flood control storage. Since there is no power storage at the Clearwater project there was no reduction in flood control storage at that site. Two simulations were made with 30% and 50% of flood control allocated to power storage. The equivalent reduction in system flood control storage was 28% and 46%. On the White System, the firm energy demands were increased to make use of the additional power storage. The demands were not changed on the Arkansas System simulation. While increasing the firm energy demands is probably a more realistic assumption for the reallocation simulation; the results, in terms of increased average annual energy, are probably not appreciably affected.

Reallocation Results

The results for the White System were similar to those for the Arkansas. The increase in average annual damage was less for the White System. For the 28% reduction in system flood control storage allocation, the increase in damage was less than 1%. For a 46% loss in storage allocation, the increase in damage was 3.7%. One explanation for the smaller impact on flood damage is the higher firm energy demand. With the higher energy demand, the reservoirs will tend to have a lower pool when a flood occurs. Even though the flood control storage space is reallocated to the power pool, the storage is still there. If the space is available, then the power storage can be utilized for flood protection.

The increase in average annual energy on the White System was small, like the Arkansas. The gain from the 28% reallocation was less than 1% and for the 46% reallocation, is only 1.2% Again the operation of the system accounts for the small gain. With very little spill, the projects are already generating with most of the water. By generating out of flood control storage, the benefit of the higher head is obtained. The reallocation of flood control storage only provides a small additional gain in head and spill reduction.

C.4 SUMMARY

For these two systems, there is a small gain in average annual energy from reallocating significant portions of flood control storage to the power purpose. The indicated gains in average annual energy from the system simulations are smaller than those estimated from the individual project analysis discussed in Chapter 5. The primary reason for the smaller gains is the method of operating the projects. The SWD simulated system operation utilizes a large portion of stored flood waters for power production. By minimizing spills and operating for hydropower from the flood control pool, the majority of the potential gains that would accure to reallocating storage has already been achieved.

The increase in average annual damage from the reallocation of flood control storage appears relatively small for the two systems. Considering how much flood control storage was reallocated, it might appear that the amount of flood control storage available in the system is too large. However, the storage is still available in the power pool. By increasing the firm energy demand, the reservoir level may often be down in the power pool and thus have empty space for flood control storage. However, there would be potential problems when flooding occurred with the reservoir at higher levels of the power pool. The degree of protection provided by the project would be less than previously provided, and the expected annual damage would likewise be higher.

Considering the increased flood damage risks and the small gain in average annual energy, it appears that reallocation of storage would only be difficult to justify in any of these projects. However, serious consideration should be given to operate projects to minimize spills by making flood control release rates at the maximum power capacity rate at all U.S. sites in order to provide most of the potential gain from reallocating storage. The ability to operate for power out of the flood control pool would depend on the amount of flood control storage, the ability to forecast future flood inflows and the ability to evacuate the flood control space in a flood emergency. The nature of the problem would require a project by project analysis.

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