SECTION 5
FEASIBILITY STUDIES

Overview

The tasks identified on Figure 4-1 for reconnaissance studies are applicable for feasibility investigations as well. The emphasis changes from the performance of a preliminary economic analysis and identification of critical issues to study of the full range of issues necessary to support decisions. The work sequence will be similar and the guidance provided in the supporting guide manual volumes is directly applicable to the component investigations. This section presents a general strategy for performing the feasibility study and provides guidance on several topics, the most significant being project formulation.

Strategy

The addition of small hydropower generation to an existing facility is, with few exceptions, a single purpose project planning task. The overriding objective is to formulate a power addition project that is economically attractive and consistent with modern concepts of resource planning and management. Opportunities to enhance other purposes, such as recreation, water quality, and fish and wildlife, should be exploited where possible and where equitable cost sharing arrangements are feasible. Any adverse impacts must be mitigated in accordance with existing statutes. The planning should therefore focus on power addition requirements and impacts, and accommodate other resource management issues as they become evident during studies.

The planning strategy adopted by several federal agencies is conceptually suitable to the small hydro planning task. See for example *Planning Process-Multiobjective Planning Framework* (Corps of Engineers, 1975). The basic thrust is to proceed through several stages of planning increasing in detail and narrowing in focus. The feasibility study strategy can be characterized as successive performance of the tasks shown in Figure 4-1, increasing in specificity on each pass. With no prior studies, 3 passes (stages) would be likely with the final two stages perhaps blurred. A prior reconnaissance study performed as suggested in this manual reduces the successive passes (stages) to 2 maximum and quite likely only one (issues identified at the reconnaissance stage may need no further study). The substantive formulation/evaluation tasks will likely be performed successively to explore the range of project opportunities. Paragraphs following describe the project formulation activities in more detail.

Project Formulation

The selection of the installed capacity, the number of units, and the supporting ancillary physical works are the specific objectives of project formulation. The target in small hydro project formulation is to develop one or more proposals that have the greatest economic value consistent with the array of constraints that may modify the attractiveness of a purely economic formulation. Financial, legal, environmental, and public interest issues may significantly influence the final proposal or even prevent a hydro project from being developed. Performing the project formulation as is suggested herein in an open style and with sensitivity to the significant interfaces depicted on Figure 4-1 should assure that an economically attractive and acceptable project is produced by the formulation efforts.

A strategy for performing the power project formulation is depicted in Figure 5-1. Table 5-1 summarizes the pertinent reference sections in the supporting volumes of this manual. The chart is an expansion of the project formulation tasks that were described for reconnaissance studies. The significant interacting factors in the formulation are the nature of flow/head availability, the performance characteristics of the turbine equipment, and the configuration of the powerhouse structure needed to accommodate the specific generating equipment. The amount of energy that can be generated is dependent upon the range of flow that can be passed through the turbine and upon the head variation. The range of flow that can be utilized is therefore a function of the installed capacity, type of turbine (operating range and efficiency characteristics), and the number of units. Each of these variables affects the size and shape of the powerhouse. The strategy suggested in Figure 5-1 is designed to pragmatically accommodate the set of interacting variables in arriving at the formulated project features.

The strategy shown progresses through three stages of project feature sizing and selection. The first stage (ending with Select Installed Capacity) yields an estimate of the project installed capacity. The second (ending with Select Project Power Features) yields a selection of the number and type of turbine units, considering site conditions and trade offs between unit performance and energy generated. The final stage (ending with Refine Power Features) concludes the project formulation for power facilities. Note that information flow (from other elements of the feasibility study) to specific formulation tasks occurs as the formulation process proceeds. Although not shown, it should be evident that information flow to other than formulation tasks likewise takes place. The following paragraphs discuss the tasks in detail.

Initial Tasks. The first several tasks of the formulation strategy are basically repeats of formulation elements of the reconnaissance study discussed in Section 4. The amount of effort and significance of performance of these initial tasks will depend on whether or not a reconnaissance study was previously performed, the level of detail of the study, and whether the data that was used remains current. Note that prior reconnaissance findings and early feasibility level information flow to the tasks and therefore are assumed to provide the bases for improved estimates. The formulation benefit criteria or values may reflect, if available, additional (to reconnaissance) market studies, and the estimated power output may make use of improved data (e.g., adjusted flow-duration data), if available. A range of project installed capacities should be studied. Selection of installed capacities near a mid value corresponding to the installed capacity at 25% flow-exceedance (15%, 25%, and 35%, are good choices) should provide a reasonable initial array for analysis. Flow-duration analysis techniques described in Volume III are adequate at this stage and optimistic turbine performance criteria are appropriate.

The project benefit stream is developed in the same fashion as the reconnaissance estimates and the project cost estimate can be prepared using the functions and procedures presented and discussed in Section 4. Only costs associated with power features or directly affected by power features are needed. The capacity selection is performed by arraying the costs and benefits of each of the installed capacities investigated, and selecting the one that yields the highest net present value. Plotting capacity versus net present value (present worth benefits minus costs) is a simple and practical means of arraying the date to define the installed capacity to be subjected to additional study. Rate of return or annual cost computations could likewise be used to aid in the selection of the installed capacity.

Subsequent formulation tasks of Figure 5-1 are designed to develop refined estimates of capacity and output by progressively considering site conditions and constraints, turbine performance characteristics, and flow/head variability.

Formulate Power Features. The objective of this task is to formulate an array of project features to allow refinement of estimates of installed capacity, energy output, and project power costs. Specific site assessments and constraint information should be available from other concurrent studies and used for this task. The turbine selection methodology presented in Volume V provides overview guidance (Figure 2-1) and supporting charts and data.

Should only a single turbine type appear suitable, the significant remaining issue is that of the number and size of the units. More units of lesser capacity will result in higher cost but may be justified if performance characteristics and flow regime result in significantly more energy being generated. Several (at least three) proposals of capacity/number of units should be formulated for additional study. The total installed capacity, (e.g., sum of the units) of each alternative should most likely fall near the capacity selected in the previously completed task (say plus or minus 25%).

TABLE 5-1
PROJECT FORMULATION TASKS*/
MANUAL REFERENCE SECTIONS

Formulation Tasks	Volume	Manual Reference Section	Description
Initial Tasks	I	5	Par. of same title.
Formulate Power Features	V	2	Figure 2-1.
Refine Power Output Estimate	III	6	
Recompute Benefit Stream	II	3	
Cost Project Power Features	V, VI	ALL	
Select Project Power Features	I	5	Par. of same title.
Perform Sequential Routing	III	3	
Refine Power Features and Performance Characteristics	I	5	Par. of same title.
Finalize Project Costs/Benefits	II	2, 4	Tables 2-1, 4-3
	I	5	Par. "Project Cost Estimates".
	II	3	Par. "Hydroelectric Capacity and Energy".
Remaining Tasks	I	5	Par. of same title.

*Tasks identified are those shown on Figure 5-1 and are discussed in this section.

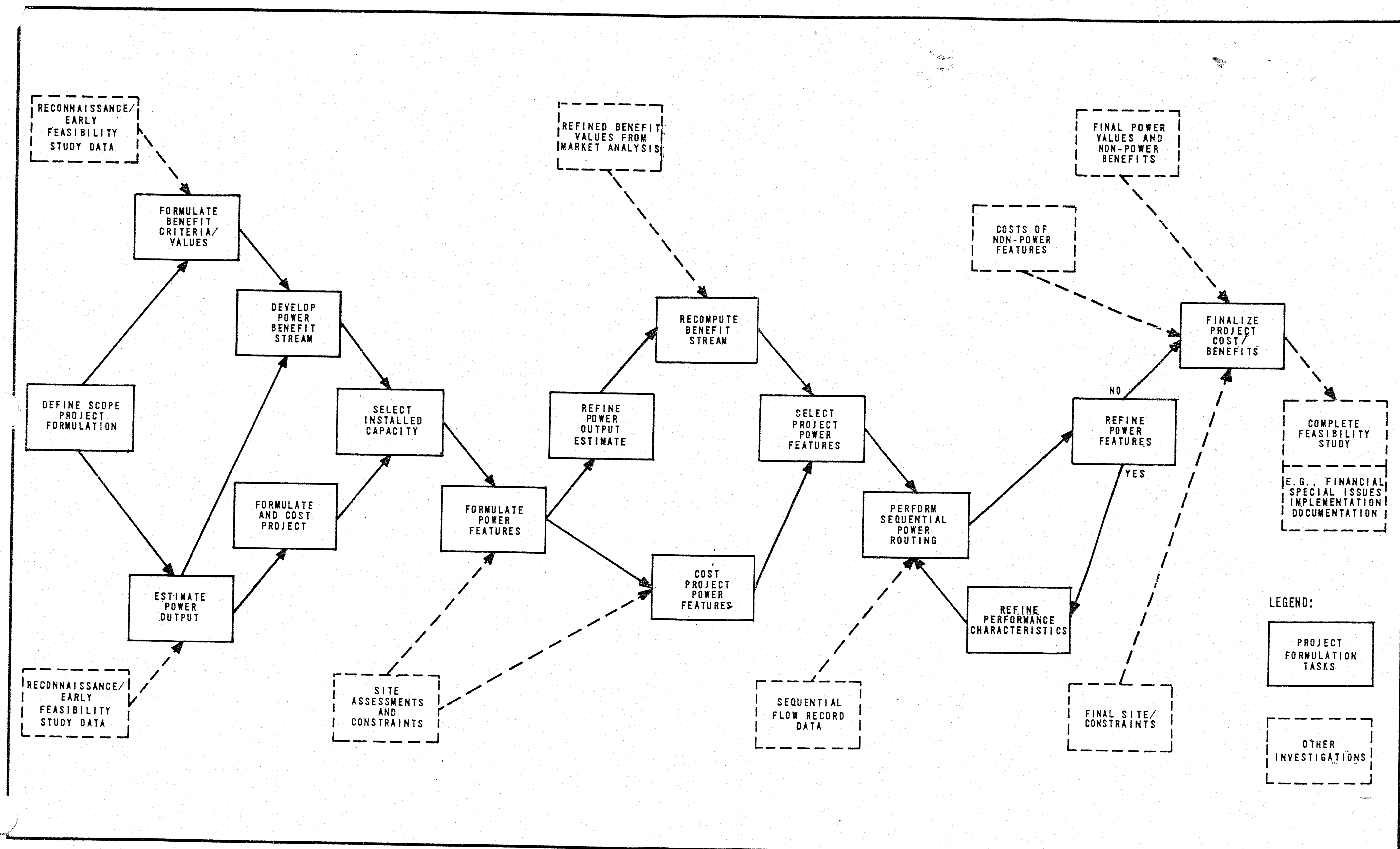

Figure 5-1. Project formulation components - feasibility

If more than a single turbine type seems suitable, and their performance characteristics are quite similar, the least costly is likely to be the best selection. If their performances are different (efficiency over operating range and limits of flow), alternatives for each turbine, and perhaps alternatives of multiple units, should be formulated for further analysis following the guidance of the previous paragraph.

Refine Power Output Estimate. A revised set (from the general data used in the initial tasks) of performance parameters (weighted efficiency and flow range) are to be used in computing refined capacity and energy values for each of the alternatives that were formulated. Flow duration techniques may continue to be adequate for this task. The alternative strategy of developing a continuous record of streamflow and performing sequential routing may be required for those instances in which significant water level fluctuations (e.g., changing head on turbines) are in evidence. See Section 6, Volume III for additional discussion.

Recompute Benefit Streams. Power values or power benefit criteria specific to the proposed project output should now be available. Capacity and energy values based on prevailing alternative power costs are the appropriate criteria. See Section 3, Volume II. A preliminary alternative set of values reflecting analysis of price shift trends should also be available for use (later) in testing the sensitivity of the project to price level changes. The power benefit stream for each alternative set of power features is computed and arrayed for further processing as the final output of this task.

Cost Project Power Features. The complete set of cost estimating charts, tables, and guidelines contained in Volumes V and VI are applicable. Care should be taken to make use of site assessment data and constraints to assure that the features for which costs are being estimated are physically feasible and sensible for the site. The cautions noted on the charts and tables of Volumes V and VI should be particularly noted so that specific layout and cost analysis will be performed if warranted. The output from this task is the initial construction cost, and annual operation, maintenance, repair, and replacement costs for each alternative set of power features.

Select Project Power Features. The power features selection is performed by arraying the cost and benefit streams for each of the alternative sets of power features and computing the net value of each. All other constraints being equal, the alternative exhibiting the highest net value should be selected. If a clear choice is not evident, reanalysis of the leading candidates using alternative power benefit values that include price shifts (representing for example rising fuel costs) should aid in narrowing the choice. The one or more (if still close) alternatives selected should be advanced to the next step in project formulation analysis.

The remaining tasks shown on Figure 5-1 provide for finalizing the power features, power output, and cost and benefit streams. Should the power output estimates from the refined sequential analysis not differ significantly from the prior estimates, additional refinement in the power features is unnecessary.

Perform Sequential Power Routing. The power output for use in completing the feasibility analysis should generally be developed by sequential power routing studies. If sequential routings were used in the previous analysis step, this task and the following task may be omitted. This added refinement assures that important sequential issues of fluctuating upstream and downstream water levels and flow passage by the site and the proper efficiency is selected for the turbine for partial turbine flows are properly incorporated in the analysis. Guidance for developing data and performing the sequential analysis is provided in Section 3 of Volume III. The sequential analysis should incorporate the performance (flow and efficiency) characteristics of the selected generating equipment. The analysis may be required for one or more of the alternatives that remain in contention.

Refine Power Features and Performance Characteristics. Sequential power analysis could yield information that would suggest refinement of turbine capacity/performance might be advantageous. Previous duration curve analysis necessarily required use of a single value (weighted) for head and a single value (average) for efficiency. The more complete simulation will accurately trace the turbine performance and may result in slightly higher or lower power and energy output estimates. The degree of variability (say plus or minus 10%) will suggest whether additional power feature refinement is warranted. The power output values developed at this stage will provide the basis for initiating development of power sales agreement should the feasibility findings be positive.

Although it is possible to perform the sequential power routing by hand methods, several of the computer programs mentioned in Volume III are available to public and private requestors and can be used to efficiently perform the analysis.

Finalize Project Cost/Benefits. The feasibility study findings will normally be presented in complete detail for the selected alternatives. Additional analysis and data (over that developed within the project formulation investigations) are needed to complete the economic feasibility assessment. If uncertainty has prohibited the selection of a single alternative, it may be necessary to present two or at most three alternatives in detail. Tables 2-1 and 4-3 of Volume II tabulate the categories of complete information needed for the feasibility assessment.

Construction cost estimates must be finalized for the power features and cost estimates for non-power features, such as integrity corrective actions, environmental enhancement and mitigation, and acquisition of water rights, lands, easements, and rights-of-way must be prepared. Studies performed to yield these latter estimates do not necessarily directly affect the power features selection and therefore can be performed concurrently with late stage formulation analysis. The integrity of the facility could well be adversely affected by the power features selected and should have been coordinated when performing the Formulate Power Features task. See paragraph Economic Analysis Cost Needs (later in this section) for additional comments on costs, benefits, discount rates, evaluation period, and cost escalation.

Project benefit estimates must also be finalized. Power benefits will be comprised of the product of the values of capacity and energy concluded from the marketing analysis and the dependable capacity (if any) and energy estimates derived from the sequential power routing analysis. Refinements of credits for dependable capacity and firm energy (see paragraph Hydroelectric Capacity and Energy, Section 3, Volume II, for amplification) should be determined and incorporated. A firm decision as to the incorporation of price escalation in the feasibility assessment is needed. It is suggested that if price escalation concepts are incorporated, the feasibility assessment also be performed and presented using price levels in existence at the time of study completion (e.g., a non-escalated project benefit analysis). Non-power project benefits should be estimated and incorporated as well at this stage. The non-power benefits that may be included should be carefully formulated so as to avoid discrediting the economic analysis. It seems prudent that only benefits that could be directly attributable to the project features be included. If a specific category (such as recreation, fisheries enhancement, etc.) is significant, a small scale analysis to separate costs for an incremental justification may be warranted.

Remaining Tasks. The other important elements of the feasibility analysis (e.g., financial, special issues, implementation, documentation) are directly influenced by the physical space and layout requirements of the specific power features selected and the resulting benefits and implementation costs. These assessments proceeded concurrently with project formulation tasks, receiving important inputs from the investigations. These other studies are now to be completed following the finalization of costs and benefits. The detail appropriate for concluding the remaining feasibility assessment tasks will depend on the economic feasibility finding. A positive finding will generally indicate implementation decision level detail is needed; a negative finding should probably result in terminating remaining studies. If a carefully staged study strategy, as suggested herein, has been followed, it should be the rare exception wherein the study has progressed to this point and a negative finding results.

Project Cost Estimates

Time streams of cash flow for both cost and income items are needed for economic and financial analysis. Time streams of cost are assembled from estimates of construction (physical facility) cost estimates, recurring costs, and indirect costs. Table 5-2 tabulates the array of cost items commonly needed to provide cost data for performance of economic and financial analysis. The following paragraphs discuss these items and suggest a systematic framework for dealing with cost issues.

Economic Analysis Cost Needs. Economic and financial analysis have been carefully defined as having distinctly different purposes, and consequently distinctly different (although very much similar) cost data. Economic feasibility analysis compares economic costs with project economic benefits. The comparison is properly made using a common value base. It is normal practice that costs and benefits be stated in the value terms existing at the time of feasibility study completion (e.g., stated in dollar values as of the study year). Federal government policies have generally also resulted in fixing price levels for valuing future costs and benefits in value terms as of the study date as well. The time frame commonly used for cost/benefit analysis begins the first year of project operation and extends through the project economic life. For example: a feasibility report may be completed in January 1980 (the dollar and price level year) with the project to begin operation in 1984 (the year the project benefits begin) and have an economic life extending until 2033 (50 years). The cost/benefit comparison would therefore be performed for the year 1984 using 1980 dollars and price levels. Project cost estimates for economic feasibility analysis using tables and charts presented in July 1978 dollars would be indexed upward to January 1980 dollar costs for use in the economic analysis. Recurring costs

TABLE 5-2
PROJECT COST ITEMS

- Construction
  - Power and Site Facilities
    - Electromechanical Features
    - Civil Features
  - Facility Integrity Works
  - Environmental Mitigation/Enhancement Works
  - Licenses
- Site Acquisition/Rental
  - Existing Works
  - Lands, Easements, and Rights-of-Way
- Recurring
  - Operation and Maintenance
  - Repair and Replacement
  - Water Rights/Use Fee
  - Headwater Benefits (Federal Power Act)
- Indirect
  - Engineering, Construction Management, and Other Studies
  - Interest During Construction
  - Administration and Management
  - Insurance

such as annual operation and maintenance would be forecast in 1980 dollars considering such issues as increased equipment needs and facilities age. Similar adjustment of the expected project benefits to assure they are likewise stated in 1980 dollars may be required. The alternative convention often adopted in the private sector is to state all project costs and benefits in dollar values as of the initial year of operation (e.g. escalate cost and benefit value for our example to represent 1984). Since small hydro projects are expected to be implemented in short time frames, the time and year statement of dollar values should usually not be critical.

The project evaluation period can vary among project proponents. Federal agencies often use 100-years, 50-years, on special occasions, (Corps of Engineers, 1975), as the evaluation period (economic life). Public agencies, and private as well, often use the expected useful FERC license period of about 45 years (license period of 50 years less start-up time). Another commonly used period, most consistent among private investors, is the loan repayment period of 30 to 40 years. In the absence of specific guidance to the contrary, an economic life of 50 years is suggested.

The inclusion of cost and value changes in economic feasibility analysis must be handled with care. If all items in the economic comparison are changing at the same rate, inclusion of these changes in the feasibility assessment would affect the findings because the cost and benefit streams are different in time. Careful treatment of real and inflation affected discount rates, theoretically (Howe, 1971; Hanke et al., 1975), would result in identical conclusions with and without general price escalation (inflation) being considered. This is normally not performed and in practical fact is quite difficult. The usual result of including cost and value escalation in projects such as small hydro (large initial cost followed by a small operation and maintenance cost, and a long stream of project benefits) is to make them appear economically more attractive, e.g., benefits grow with time while costs increase slightly based on operation and maintenance. The impetus for including value changes is the conviction that benefits will continue to rise knowing that some benefit elements are increasing more rapidly than the general inflation rate, e.g., fossil fuel. The argument is that ignoring these value shifts leads to incorrect decisions, e.g., the project may appear infeasible when it should be found to be feasible.

In principle, a price level change economic analysis should forecast the change in value of all aspects of the feasibility assessment, both the cost side and its several components, and the benefit side (e.g., alternative fuel costs) and its several components. The cost and benefit streams are then constructed from these forecasts and the feasibility assessment performed. An alternative is to forecast only the relative difference (from the general inflation trend) for the critical items such as fuel and construction costs.

The argument against including price level change or general cost escalation in economic feasibility analysis is that change in price forecasting is fraught with pitfalls that are both institutionally and technologically dependent. The resulting analyses thus often becomes suspect and a candidate for subjective manipulation, i.e., a means of justifying projects. This criticism is most often levied against public projects rather than private investments. If cost and value change analysis are adopted for the economic analysis, considerable care should be taken to rigorously observe the basic principles and to document the critical value change forecasts.

Table 5-3 has been prepared to aide in computations that consider escalation of project annual costs and benefits over the life of the project. The reason for the caution against indiscriminate use of escalation in benefit analysis is evident from examination of values in the table. For example, using a project evaluation period of 40 years, general escalation rate of 6% and discount rate of 9% (values commonly used in investment decisions for non-federal public agencies), would result in multiplying the average annual benefits by 2.21. In effect more than doubling the value of the benefits!

Financial Analysis Cost Needs. Financial feasibility analysis develops the specific cash flow (dollars in and out of the accounts of the project) characteristics of the project. The need is therefore to forecast the amount and timing of cash outflow and revenue income as accurately as possible. It is common practice for the cash flow analysis to be constructed for the project implementation period; the first year of operation often being critical to project cash reserves. See Section 6, Volume II. Construction costs are therefore indexed to the actual date of contract award, interest during construction added to bring the base to the project initial operation date, and the revenue stream adjusted based on anticipated power sale contract provisions for payment of project output. Recurring costs (operations and maintenance) are frequently escalated based on increased costs to service aging equipment and on anticipated general cost inflation. Private sector economic analysis often is very near to a financial cash flow analysis because of the tendency to classify economic costs as the cash flow from project accounts and benefits as strictly contract revenues. In effect the scope of project costs and benefits are the "cash" impacts on the private developer.

If there were no cost inflation, no borrowing required, and if project revenues captured all project benefits exactly, the economic cost and benefit streams for the economic analysis would be identical to the cost and revenue cash flow streams for the financial analysis.

Construction Costs. Cost estimating charts and tables are included in Volume V and VI that encompass virtually all aspects of the civil and electromechanical features of power additions. The information is presented in July 1978 dollars and a method for indexing to future dates is included. Unusual site conditions, use of

TABLE 5-3
PLANNING PERIOD ESCALATION ADJUSTMENT RATIOS

DISCOUNT RATE (%)	ESCALATION RATE (%) 2	3	4	5	6	7	8
PLANNING PERIOD - 30 YEARS							
2	1.34	1.56	1.84	2.17	2.57	3.06	3.66
4	1.30	1.50	1.73	2.02	2.36	2.78	3.28
6	1.27	1.44	1.64	1.89	2.18	2.53	2.95
8	1.24	1.39	1.57	1.77	2.02	2.31	2.66
9	1.22	1.37	1.53	1.72	1.95	2.22	2.54
10	1.21	1.34	1.50	1.68	1.89	2.13	2.42
12	1.19	1.31	1.44	1.59	1.77	1.98	2.23
14	1.17	1.27	1.39	1.52	1.68	1.86	2.06
16	1.15	1.25	1.35	1.47	1.60	1.75	1.93
18	1.14	1.22	1.32	1.42	1.54	1.67	1.82
20	1.13	1.20	1.29	1.38	1.48	1.60	1.73
25	1.11	1.17	1.23	1.31	1.39	1.47	1.57
PLANNING PERIOD - 40 YEARS							
2	1.46	1.80	2.23	2.80	3.54	4.52	5.82
4	1.39	1.67	2.02	2.47	3.06	3.82	4.81
6	1.33	1.56	1.84	2.20	2.66	3.24	3.99
8	1.28	1.47	1.70	1.98	2.34	2.79	3.35
9	1.26	1.43	1.64	1.89	2.21	2.60	3.10
10	1.24	1.40	1.58	1.81	2.09	2.44	2.87
12	1.21	1.34	1.50	1.68	1.91	2.18	2.51
14	1.18	1.30	1.43	1.58	1.76	1.98	2.24
16	1.16	1.26	1.37	1.50	1.65	1.83	2.04
18	1.15	1.23	1.33	1.44	1.57	1.72	1.89
20	1.13	1.21	1.30	1.39	1.50	1.63	1.77
25	1.11	1.17	1.24	1.31	1.39	1.48	1.58
PLANNING PERIOD - 50 YEARS							
2	1.59	2.06	2.71	3.63	4.93	6.77	9.41
4	1.47	1.84	2.33	3.00	3.93	5.22	7.04
6	1.38	1.66	2.03	2.51	3.17	4.07	5.30
8	1.31	1.53	1.80	2.16	2.63	3.25	4.09
9	1.28	1.47	1.72	2.03	2.42	2.95	3.64
10	1.26	1.43	1.64	1.91	2.25	2.69	3.27
12	1.22	1.36	1.53	1.73	1.99	2.31	2.72
14	1.19	1.30	1.44	1.61	1.81	2.05	2.35
16	1.16	1.27	1.38	1.52	1.68	1.87	2.10
18	1.15	1.23	1.34	1.45	1.58	1.74	1.92
20	1.13	1.21	1.30	1.40	1.51	1.64	1.79
25	1.11	1.17	1.24	1.31	1.39	1.49	1.59
	2	3	4	5	6	7	8

ESCALATION RATE (%)

ADJUSTMENT RATIO EXAMPLE

GIVEN: Annual Energy Generation - 10 x 10^6 kWh

Value of Energy - 25 mills/kWh

Investment Cost* - $2,000,000

Annual O & M Cost - $30,000

Growth in Power Value - 6% per year

Growth in O & M Cost - 4% per year

Discount Rate - 9%

Planning Period - 30 years

* Already Escalated to Construction Date Using Cost Indices

NO ESCALATION

ANNUAL COST

Investment = $2. x 10^6 x 0.0973 = $194,600

O & M = 30,000

TOTAL $224,600

ANNUAL BENEFITS

Energy = 10. x 10^6 x $0.025 = $250,000

ESCALATION CONSIDERED

Ratio (6%, 9%) = 1.95

Ratio (4%, 9%) = 1.53

ANNUAL COST

Investment = $2. x 10^6 x 0.0973 = $194,600

O & M = $30,000 x 1.53 = 45,900

TOTAL $240,500

ANNUAL BENEFITS

Energy = $250,000 x 1.95 = $487,500

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an existing abandoned powerhouse, refurbishing equipment, etc., could result in the requirement to perform feasibility layouts and design, computing construction material quantities, and preparing a specific cost estimate. Prevailing industry cost estimating methods would be employed (see Case Studies). A common practice in estimating turbines and generators when costs are a critical issue, is to solicit preliminary quotes from equipment suppliers. Care should be taken to recognize the values as only estimates, not firm price bids. Supplier lists are included in Volume V.

Cost estimates for facility remedial work (integrity rehabilitation) are not particularly amendable to generalization and therefore the feasibility design layout approach as described above is usually necessary. Guidance on major elements of cost for rehabilitation is included in Volume IV. Data contained in Volume VI for gates, valves, and penstocks may be helpful.

Cost estimating guides for environmental enhancement and mitigation works (such as fish hatcheries and ladders) are not included in this manual. The range of potential mitigation alternatives prohibits formulation of generalized data at this time. Specialists in such issues should be consulted if such features are determined to be a critical item in project development.

It is common practice to add a contingency to construction costs to allow for uncertainties and minor ommissions. Contingencies are often in the range of the 10% to 20% depending on project complexity. The construction cost components could each have a separate contingency applied if warranted. Normally a single contingeny value is applied to the sum.

Several acquisiton/rental fee type costs may need to be estimated. Land acquisition for siting power and other features may be required. Temporary and permanent easements and rights-of-way could likewise be needed.

Recurring Costs. The recurring costs include such items as operation and maintenance, repairs, replacements, and insurance (for private developers). The discussion in Section 4 is pertinent and repeated here. "Operation and maintenance costs can vary considerably depending on present staff resources of the project proponent, the site proximity to other sites, and the intended degree of on site operation requirements. The value used should not be less than a base (suggested as $20,000/year) and may range upwards to 4% if the project proponent cannot efficiently integrate the plant into their work program." Specific guidance is contained in the last section of Volumes V and VI.

Fees may be payable for use of water to generate power. Private developers at federal sites are likely to be required to pay an upstream storage fee. FERC also requires private developers (other than federal) to pay for any storage and re-regulating of the water supply above the project, provided that the upstream entity either holds a FERC license or permit, or is a federal agency. This is the so-called "headwater benefit." Other financial arrangements depending on the owner and project proponent may be needed. The purpose of the analysis (economic/financial) and the perspective of the proponent (federal, public, private) will determine the need and influence the degree to which the dollar transfers between the project development parties are included in project analyses.

Indirect Costs. The discussion in subsection Develop Cost Stream, Section 4 of this volume, is pertinent and is repeated here. "All investigations, management, engineering and administrative costs that are needed to implement the project and continue it in service are appropriately included in the project feasibility analysis." These indirect costs may be estimated directly (e.g., the analysis of the component factors) or included as a multiplier of the investment costs. Volumes V and VI suggest a multiplier of 20% of the total construction cost plus contingencies as a mid value. A table documenting the elements of this multiplier is included in the last section of both volumes.

Licenses, Permits, and Approals

The feasibility report is the primary source of the information needed to secure the necessary government approvals to proceed with project implementation. A discussion of these issues is included here to alert project investigators to their requirements with the view that parts of the feasibility investigation may be made to efficiently serve these information needs as well.

Federal, state and local governments all have certain requirements that must be satisfied prior to construction and operation of a hydropower plant. Some agencies within these governments only require notification while others require specific data about the project and issue licenses or permits for the construction and operation of the plant. Realizing that a list of all the local, state and federal agencies would be difficult if not impossible to create, a general discussion is provided about local, state, and federal responsibilities and types of agencies on the local and state level that are usually interested in a hydroelectric project. The federal agencies are coordinated for the most part through the federal licensing process. The Rollins Power Project case study (Exhibit II) includes a listing of the permits that were necessary to implement that project.

State and Local Requirements. States operate in several different ways. Some states have resources agencies which are comprised of most of the departments which need to be contacted. In this case coordination is generally straight forward. States that have separate agencies without a main coordination office require the applicant to contact each office individually to initiate compliance with state regulations. Agencies most often contacted are listed in Table 5-4. Many of these state agencies will also be contacted by federal agencies which have similar responsibilities but on a national level. Some state agencies may defer comment by pointing out that a federal license is required and they they will make comments and recommendations on the application for federal license. If comments are deferred compliance with state laws still apply and it would be useful to obtain the laws, regulations, and guidelines the agency will use to evaluate the application so that these concerns are addressed in the application. Some of the major state concerns are water rights, fish and wildlife habitat, water quality, compliance with environmental laws, and dam safety.

TABLE 5-4
STATE CONTACT AGENCIES

Department of Dam Safety
State Energy Office/Commission
Department of Fish and Game/Wildlife
Flood Control/Reclamation Board
Governor's Office
State Historical Preservation Officer
Department of Planning and Research
Public Utilities Commission
Resources Agency
Water Quality Control Board
Department of Water Resources
Division/Board of Water Rights

In most instances local governments, county or city planning department, will be the lead agency with respect to coordination within the state and compliance with state environmental laws. They may also have ordinances and laws concerning construction, employment, road weight limits, and possibly generation, to name a few, which should be complied with.

Federal Energy Regulatory Commission. The Federal Energy Regulatory Commission (FERC), Department of Energy, formerly the Federal Power Commission (FPC), is the lead federal agency and issues licenses for all non-federal hydroelectric projects which fall under their jurisdiction (Code of Federal Regulations, Title 18). Very few projects are exempt from FERC licensing requirements. Being the lead federal agency the FERC coordinates all comments on environmental statements, contacts all other federal agencies that require coordination, coordinates with the appropriate state governors offices and agencies, holds hearings with Administrative Law Judges presiding to settle legal and jurisdictional disputes, and issues a federal license for the construction and operation of the project. Other federal agencies which issue permits or approval which must be contacted individually are discussed later in this section.

Projects requiring a FERC license are divided into two classes based on installed capacity. Minor projects have an installed capacity of 2000 horsepower (1500 kW) or less while major projects have an installed capacity of more than 2000 horsepower. Applications for license are submitted directly to the FERC for processing and approval. Forms, procedures, and requirements for filing may be obtained from the FERC, Washington, D.C. office or any of their regional offices (see Exhibit I, Volume II). An application for a FERC major license for an unconstructed project must contain, in general, the following information:

Applicants name and address.
Applicants business status.
Description of the project (civil features).
Location of the project.
Lands and reservations of the U.S. affected by the project.
Description of ultimate scheme of development (electromechanical features).
Proposed use or market for the power.
Location and capacity of other electric facilities owned or operated by the applicant.
Description of any historical or archeological properties.
Detailed statement of environmental factors.
Other data which the applicant may consider pertinent.

This information is presented in the application in the form of Exhibits. Contents of an application for a minor license, plants with 2000 horsepower (1500 kW) or less installed capacity, are similar but do not require as much detail on most subjects (FERC, 1978). Also applications for proposed or existing plants at existing impoundments have slightly different requirements with respect to the detail required for some exhibits. In general, use of an existing impoundment does not create the same magnitude of environmental impacts as construction of a dam and new reservoir, thereby reducing the time, effort, and coordination required to evaluate the project. Small hydropower developments at existing impoundments are included in this last analysis and, therefore, applications can usually be processed in a shorter amount of time and with less expense than those projects proposing construction of a dam and reservoir.

The FERC also issues preliminary permits for projects of more than 2000 horsepower (1500 kW) installed capacity for the purpose of enabling the applicant to secure the data and perform the acts required by law for filing an application for the issuance of a license (Code of Federal Regulations, Title 18). The preliminary permit retains the application right of the applicant with respect to the site so that his application for license may not be preempted by another applicant's application. It would seem prudent for a developer to apply for a preliminary permit on completion of a positive reconnaissance study so as to establish his application right. The maximum duration for which a preliminary permit may be issued is three years and it may not be renewed.

U.S. Army Corps of Engineers. A permit must be obtained from the U.S. Army Corps of Engineers (or a negative determination that no permit is needed) to locate a structure, excavate, or discharge dredged or fill material in waters of the United States (Corps of Engineers, 1977) . Since most hydroelectric power plants are located in or adjacent to a river and require excavation, a permit must be obtained. The reference, U.S. Army Corps of Engineers Pamphlet (EP) 1145-2-1, provides the procedure for filing and the requirements for a permit. To initiate the process, contact the District Engineer who has jurisdiction over the area where the structure will be built. Request a copy of EP 1145-2-1, an application form (ENG Form 4345), and any special instructions that may not be furnished in the pamphlet.

The permit investigation process requires furnishing a detailed description of the location and nature of the proposed activity, including the purpose, use, type of structures, types of vessels (if any) that will use the facility, facilities for handling wastes, and the type, composition, and quantity of dredged or fill material.

Other Federal Agencies. Several other federal agencies become involved at the time of project implementation. Radio communication permits (for remote operation) are required by the Federal Communications Commission and construction that might obstruct airspace (transmission towers) must be reported to the Federal Aviation Administration. A Water Quality Certificate issued in accordance with Section 401 of the Federal Water Pollution Control Act is generally required. State organizations such as Regional Water Quality Boards are normally the administering agency.

Time, Cost, and Resources for Feasibility Studies

The time, cost, and manpower resources required to perform feasiblity studies for small hydroelectric power plant additions varies depending on expected plant size, site conditions, specific scope and depth of study, and availability of information (basic data and prior reconnaissance assessment). Each of the five support manual volumes provides general guidance on this topic in their respective subject areas. The following paragraphs discuss the range of costs and resources that are likely to be needed for the studies as a whole. The unique characteristics of each project should, however, be evaluated in scheduling use of in-house personnel or in procuring professional services for specific feasibility investigations.

The American Society of Civil Engineers has published general guidelines for the performance of engineering services (ASCE, 1972). The guidelines suggest that professional services for projects in the small hydro category may cost from 6% to 10% as a proportion of construction cost. "Preliminary Phase" studies (those prior to final design) may require up to 40% of the basic compensation yielding total preliminary phase professional services costs of 2.5% to 4.0% of construction cost. Feasibility studies are generally acknowledged as comprising 1/3 to 1/2 of "Preliminary Phase" costs. Noting that marketing, financial, and increased special studies needed for the feasibility study are likely, the range of 1.5% to 3% of estimated construction cost seems appropriate.

Using 2.5% as a conservative estimate, feasibility study costs could range from $25,000 (80 to 110 man-days) for a 1 MW plant to $150,000 (600 to 750 man-days) for the larger plants. The time required to perform the feasibility study could range from 60 days for the small, relatively simple power addition to upwards of 6 to 9 months for larger more complex projects.

The participating professionals include civil, electrical, and mechanical engineers, power economists, and especially for private proponent projects, the services of financial specialists. Projects that significantly alter the flow regime or physical environment will likely need the services of water quality and fish and wildlife specialists.

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EXHIBIT I
GREAT FALLS HYDROELECTRIC PROJECT
CASE STUDY

CONTENTS

FIGURES

TABLES

SECTION 1
INTRODUCTION

This case study describes the feasibility investigation of the Great Falls Hydroelectric Project, located in and owned by the City of Paterson, New Jersey. It applies the methodology for preparing a feasibility study for small hydro power projects presented in this manual.

The project feasibility of the Great Falls project has already been determined by a feasibility report (Development and Resources Corporation, 1978) prepared for the City of Paterson. This case study provides a basis for comparing the procedures and methods described in the manual to the results obtained by in-depth feasibility study.

Overview of Findings

The following overview of the feasibility case study findings are categorized according to the five manual components, followed by a summary.

Hydrologic Studies. The hydrologic studies were based on daily average flow conditions for the period 1950-1960. These 10 years of data were assumed to be representative of the longer data period available for the period 1897-1976. The daily records for the 10-year representative period were used to simulate runoff and calculate the resulting potential energy production of between 22.1 million kWh and 32.3 million kWh on an annual basis with an installed capacity of between 5,100 kW and 7,875 kW.

Existing Facility Integrity. The Great Falls dam was built in the period 1838-1840 of large blocks of masonry stone with a total length of 315 feet and a height varying from 8 to 15 feet, and is of the gravity overflow design type. Field inspection of the dam showed there is significant deterioration and erosion of the existing stone masonry section to the point where about 10 percent of the stone section requires replacement. Several alternatives were examined in lieu of restoration of the dam and restoration of existing structure was chosen for historical reasons. The total cost of $1,056,700 was close to other alternatives. The powerhouse and appurtenant structures were found to be in good condition and could be utilized for the project after being refurbished.

Electromechanical Equipment. This investigation studied 17 alternatives involving four manufacturers of hydroturbine equipment. Of the 17, four were chosen for detailed comparisons as alternatives and are presented in this case study. The four manufacturers considered were Allis-Chalmers, Leffel, Ossberger, and Tampella. The estimated installed equipment costs in 1978 ranged from $2,933,850 to $5,074,100. It was determined that only after firm bids for turbine and generation equipment, guaranteed performance data, delivery times, and complete dimensional data had been obtained, could the final equipment selection be made.

Civil Features. The total costs of the civil works for this project, not including the dam restoration cost, were estimated at between $639,200 to $976,200, representing the four alternatives analyzed in the case study. These costs represent an average of 21 percent of the total project costs. This is consistent with the range of civil feature costs identified on Figure 1-1 of Volume 4 of the manual which placed the minimum civil features costs at 15 percent and the maximum at 45 percent.

Economic and Financial Analysis. The financing required to construct the project would vary from between 5.9 and 7.9 million dollars. This further breaks down into a first year (1981) annual cost ranging between $607,000 and $808,000 which includes debt amortization based on a 40-year project life, seven percent interest money, annual operating costs, and repair and replacement costs. The corresponding value of the energy produced would range from between $726,000 and $962,000 on an average production basis for the first year of operation.

The cost of service in 1981 dollars (the first year of project operation) would vary from 21 to 25 mills per kilowatt hour. This compares to a value of energy of around three cents per kilowatt hour in 1981, based on the energy generated at the Great Falls site replacing the fuel costs for oil fired generations.

Summary. The results of the feasibility study show that installed capacities between 5,400 and 10,500 kilowatts are possible for new equipment and that with the rehabilitation and upgrading of existing turbine and generation equipment 5,100 kilowatts could be realized. The average annual production would range between 22,000,000 and 37,000,000 kWh. The project would be run-of-the river. The feasibility study includes 17 alternatives, while this case selected four alternatives to cover the range of turbine equipment.

Project Description

The Great Falls Hydroelectric Project is located in the City of Paterson, New Jersey. The location of the existing powerhouse and diversion dam is indicated on Figure 1-1. The drainage area above the project site as measured at Little Falls is 762 square miles. The mean annual flow is 730 cubic feet per second. The facilities that make up the Great Falls Hydroelectric Generating Facility consist of a masonry stone diversion dam, concrete intake and forebay structure, gated concrete control structure, steel-lined penstocks, and powerhouse constructed of concrete and brick. The powerhouse is located immediately downstream of Great Falls, a natural rock barrier created by a massive basalt sill.

The site is owned by the City of Paterson, New Jersey, and has significant historical importance. The

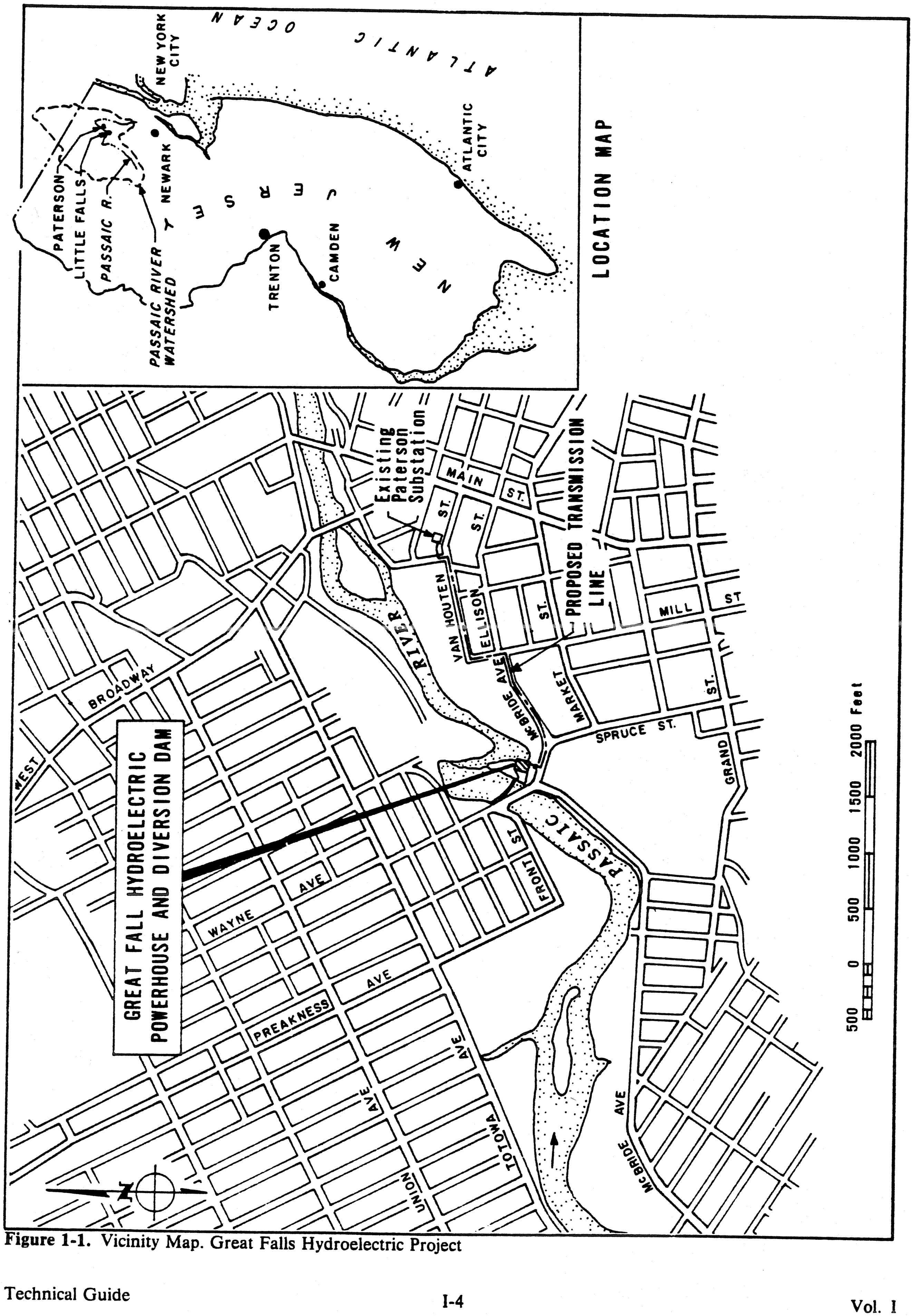


Figure 1-1. Vicinity Map. Great Falls Hydroelectric Project

water power from the site was developed as early as 1794 through a series of three raceways which promoted the establishment of many manufacturing plants. In 1912, waterwheels gave way to a hydroelectric plant. In 1914, the plant was completed and conversion to electrical power was begun by the mills in the area. The plant was decommissioned in 1969 after it was determined that the facilities were in need of major repairs. The raceways are still used in a limited way for water supply and for processing water for manufacturers.

In 1971, Congress declared the Great Falls site a National Historical Landmark and the City has since created a park in the area surrounding the Falls. The view of the Great Falls, located below the diversion dam, is considered to be a tourist attraction and release of approximately 200 cfs of water during the low flow summer months is required to maintain the Falls aesthetic appearance.

The project qualifies for a tax-exempt status since the total financing required is less than $10 million. This tax-exempt status has had some impact on the economic feasibility of the project.

A license to construct and operate the project has been filed with the Federal Energy Regulatory Commission (FERC) and is under review as of January 1979.

Project Formulation and Case Study Data

In August 1978 the Department of Community Development of the City of Paterson authorized consultant services for the preparation of a feasibility study for reactivating hydroelectric power at the Great Falls site. Earlier, in 1976, a reconnaissance level study was made that addressed itself to the Restoration of the Diversion Dam and Power Plant for the Great Falls Historic District. This previous study, coupled with data contained in the Passaic River Survey Report for Water Resource Development (U.S. Army Corps of Engineers, 1971) and the Flood Insurance Study of the Passaic River (U.S. Department of Housing and Urban Development, Federal Insurance Administration, 1975), as well as independent data collection, served as the basis for the case study.

The data and information presented in past reports have been put into the analysis framework as presented in the manual and all results were recalculated then compared.

SECTION 2
HYDROLOGIC STUDIES

This section describes studies performed to determine the adequacy of the facility to pass flood flows and to calculate energy production at the site. Uses of the guidelines contained in Volume III of the manual are indicated.

Passage of Flood Flows

Data. Adequate daily flow records are available for the Passaic River to allow flood frequency analyses to be performed. USGS daily average flow records are available for the Passaic River gage (USGS 01389500) from 1897 through 1976.

Topographic maps and river cross sections from the New Jersey State Riparian Streams and Waterways Survey of 1935 were used in assessing river hydraulics. Previous studies were utilized to obtain information on Passaic River flood flows and water surface profiles (U.S. Army Corps of Engineers, 1971) (U.S. Department of Housing and Urban Development, Flood Insurance Administration, 1975).

Flood Flow and Water Surface Elevation. Flood discharge frequency relationships included in the Passaic River Survey Report were used to establish the design flood flow of 23,500 cfs for an average return period of 100 years. The 100-year flood event provides a water surface elevation at the diversion dam that produces a loading condition appropriate for analysis of the dam's structural integrity under flood flow conditions. This report used the log-Pearson Type III distribution to establish the peak flow-exceedance interval relationship, as is recommended in Volume III of the manual.

River cross sections and the hydraulic characteristics of the current overflow dam structure were used to calculate headwater and tailwater rating curves. Some upstream flooding occurs for the 100-year flood event.

Analysis showed that the current overflow diversion structure is capable of passing the selected design flow. The structural integrity of the dam under flood conditions is examined in the Integrity Section. An analysis was also made to determine the flooding limits that would result from a breaching of the diversion dam. Results show that no downstream flooding would be caused by a dam breach.

One of the dam options considered was construction of a new concrete dam just downstream from the existing dam with a higher crest elevation of 120 feet. The structure was designed with gates so it would be hydraulically equivalent to the current structure. The required gate structure would be approximately 150 feet long and 10 feet high. This option has not been ruled out but for the purposes of this case study only repair of the existing structure was considered.

Power Production

Power production for all options was computed on a detailed level by sequential power routing using daily flow records and a detailed model of power generation. The simulation accounted for turbine and other equipment efficiencies, net head available to the turbines, multiple turbine scheduling, and scenic diversion over Great Falls in the summer months. Sequential power routing is the technique recommended in Volume III of the manual for use during the feasibility level investigation when the increased accuracy over flow-duration analysis is desirable.

Data and Assumptions. After examining the historical record from 1897-1976, project power output was calculated using the records for water years 1950-1960, a representative decade. The project was simulated as a run-of-the-river project because of the very small amount of working storage available. Consequently, flow was used as it occurred at the gage. Daily average flow was used since monthly average flows would tend to overstate power production in this case. The Passaic River has a fairly large flow variation, particularly in the fall and spring. To preserve the scenic value of Great Falls during the low flow months, 200 cfs for the hours between 10:00 a.m. and 8:00 p.m. during June, July, and August were planned for direction over the Falls, thus bypassing the powerhouse. Headwater and tailwater rating curves developed from river cross sections were used in calculating the net head availability to the turbines. All the options considered use of multi-turbines.

The turbine efficiencies were supplied by the manufacturers as a function of the specified flow and head availability. See Section V for a detailed comparison of turbine efficiencies. Other efficiencies and losses were used as shown below:

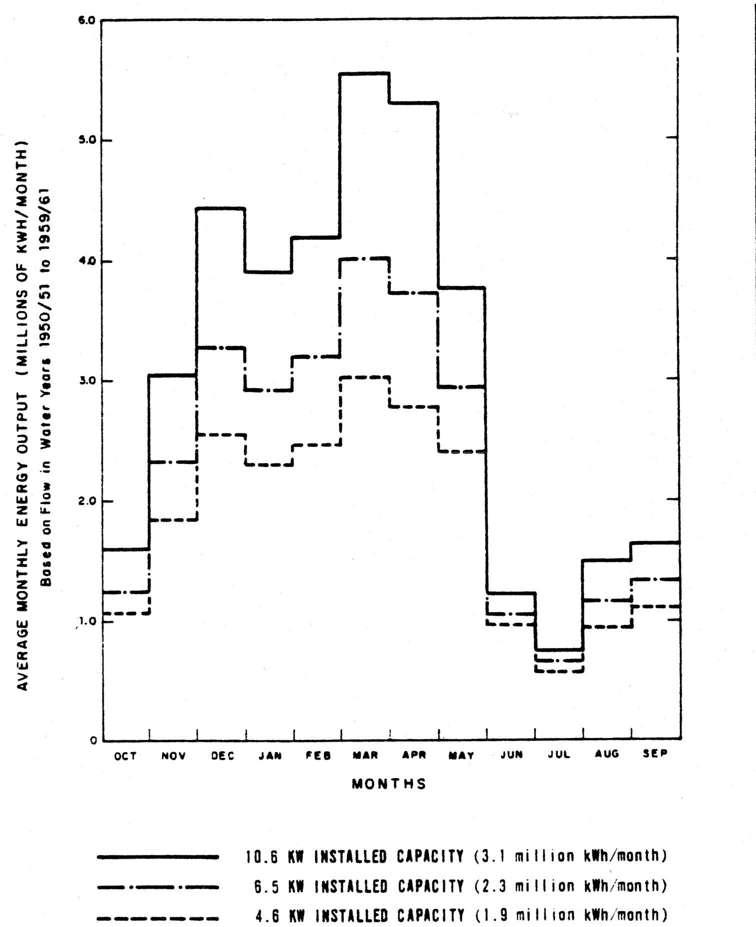
Item	Percent Loss
Single stage speed increaser	2.5
Double stage speed increaser	4.0
Generators over 1000 kW	5.0
Step-up transformers	2.0
Forced outages	3.0

Results. Energy production for the four options considered are shown on Figure 2-1. Also shown is the minimum energy production as a percentage of average annual production. These results show that on an annual basis substantial fluctuation occurs in energy production. For planning purposes, a worst case analysis was based on energy production at no more than 65 percent of average.

ENERGY PRODUCTION FOR FOUR ALTERNATIVES

	Alternative 1 Rehabilitation (Allis-Chalmers)	Alternative 2 New Horiz. Runners (Leffel)	Alternative 3 Cross Flow (Ossberger)	Alternative 4 Tube Turbines (Tampella)
Annual Energy Production				
Assumed Installed Capacity (kw)	5,100	7,500	6,800	7,875
Average (Millions of kwh)	24.4	30.8	27.9	32.3
Maximum	34.2	45.2	40.3	47.6
Minimum	17.1	20.1	18.7	21.0
Plant Factor (%) 1/	56%	49%	51%	48%
Minimum Production as % of Average	70%	65%	67%	65%

1/ Based on actual production and maximum possible production after accounting for all losses except forced outages.



AVERAGE MONTHLY ENERGY OUTPUT FOR THREE SIZES OF INSTALLED CAPACITY

Figure 2-1. Energy Production

The analysis allowed monthly average energy production to be compared for different sized installations. Figure 2-1 displays these results for three different installed capacities. As shown, additional capacity adds little to summer energy production.

The use of daily flow also determines whether periods of non-generation occurred. For all of the options considered, extended periods of no production occur in the summer and, to a lesser extent, in spring and fall months. Consequently, the project has no firm capacity or energy and is strictly run-of-the-river.

SECTION 3
INTEGRITY ASSESSMENT

This section describes the investigation performed to assess the structural integrity of the existing diversion dam and to estimate the cost of rehabilitation of the dam. The lack of engineering records showing the diversion dam's dimensions or methods of construction required making the following assumptions in assessing the dam's structural integrity:

1. Assuming a representative cross section based on field observations and experience gained on similar structures.
2. Assuming the strength parameters of the dam's foundation based on a reconnaissance level engineering geologic investigation and engineering experience.
3. Assuming the strength properties of the granite stone building material for the dam and the cement mortar used to bond the granite stone together.

Loading Criteria

Loading criteria for use in analyzing the dam's structural integrity were developed from the 79 years of daily flow records for the Passaic River at the dam site. Flow frequency curves developed by use of the log-Pearson Type III analysis were used to establish the expected flow for a given frequency storm event. This information, when combined with the developed diversion dam's headwater and tailwater rating curves, allowed selection of appropriate water surface elevations for use in establishing the loading cases.

The design and loading criteria adopted to assess the dam's structural adequacy were based on three cases. These were 1) normal operating conditions, 2) normal flow conditions with .1 g horizontal seismic loading, and 3) flood conditions with the flow being increased from a normal 200 cfs to 23,500 cfs. The adopted criteria follows guidelines as suggested in Section 3, Volume 4 of the manual.

Results

Table 3-1 displays the results of the evaluation of the dam's structural integrity.

These results show that the existing dam has factors of safety below those generally regarded as acceptable for sliding and overturning. Historical records indicate that the original dam section was anchored "to the rocky bed with powerful clamps of iron." The condition of these "clamps" is unknown and to assure the safety of the restored dam for the full anticipated project life, it was decided to provide anchorage by means of a concrete slab placed on the upstream face of the dam. The concrete slab would be reinforced and dowelled to the dam section, and secured to the bedrock by steel anchors grouted into the foundation.

Restoration Costs

The estimated costs for restoration of the diversion dam were based on the preliminary designs, estimated construction quantities, unit costs from cost estimating guides and costs from other similar projects in the engineers' files (Dodge Guide to Public Works and Heavy Construction Costs, 1978 and Engineering News Record Quarterly Cost Roundup, 1978). These reference sources are identified in the manuals. Table 3-2 displays the estimated costs for restoration of the dam including contingencies, engineering and administration.

TABLE 3-1
STRUCTURAL INTEGRITY EVALUATION - DIVERSION DAM

Loading Condition	Uplift		Sliding		Overturning		Stresses (psi)	
	Req'd	Actual	Req'd	Actual	*Req'd	Actual	Toe	Heel
Case I Normal	1.50	2.9	1.50	1.66	2.0	1.55	21.6	4.2
Case 2 Seismic	1.25	2.9	1.25	0.81	1.5	1.15	29.9	5.3
Case 3 Flood Flow	1.25	2.2	1.25	1.16	1.5	1.15	29.7	11.4

*The factor of safety against sliding was calculated as being the difference between the summation of the horizontal and uplift forces multiplied by a sliding factor of 0.7 divided by the summation of the Vertical forces (USBR Design of Small Dams, 1965, p. 240).

TABLE 3-2
RESTORATION COSTS

Item	Unit	Quantity	Unit Cost $	Cost $
Cofferdam - first stage	LF	400	700	280,000
Cofferdam - second stage	LF	400	300	120,000
Dewatering	LS			75,000
Excavation - Earth	CY	1,800	10	18,000
Concrete - Reinforced	CY	275	200	55,000
Rock Anchors	LF	1,500	20	30,000
Reinforcing Steel	LBS	40,000	.40	16,000
Cofferdam Removal	LF	400	50	20,000
Replace Stone	CY	140	350	49,000
Reconstruct Stone	CY	350	250	87,500
Grouting Masonry	LS			18,000
Subtotal				768,500
Contingencies at 25%				192,125
Subtotal				960,625
Engineering and Administration at 10%				96,000
TOTAL				1,056,700

SECTION 4
CIVIL FEATURES

This section describes and estimates the cost of the project civil works, excluding the dam, which is presented in the Integrity Section. The Great Falls site has been designated a National Historic Landmark and has certain features and facilities that have been maintained and are suitable for use without additional repair or replacement. In addition, by having the site declared a National Historic Landmark, reuse of the site and facilities carries with it the responsibility of maintaining the exterior appearance of the existing facilities in an "as is" condition.

The civil features of the Great Falls Hydroelectric Project fall into the following categories in accordance with suggested guidelines contained in Volume VI of the manual, Section 1. These are: site preparation, hydraulic conveyance facilities, and powerhouse and appurtenant facilities.

The powerhouse configuration is fixed and therefore the turbine generator equipment selected was based on its being compatible with the existing powerhouse space.

Figure 1-3, Volume VI, graphically displays the steps that should be followed in determining the civil costs for a potential hydroelectric power project. Volume VI does not cover the civil costs associated with repair and rehabilitation or alteration of the impounding or diversion structure. This is covered in Volume IV of the manual. This is a civil cost and must be included to arrive at a total civil cost. In the following estimates, the steps in Figure 1-3, Volume VI, are followed where applicable.

Site Preparation

Since the site now has adequate parking, access, and drainage control, no site preparation costs are included.

Hydraulic Conveyance Facilities

These facilities include:

1. Repair of forebay, gatehouse and penstock inlet
2. Replacement of penstocks
3. Replacement of draft tubes, repair of tailrace, and installation of draft tube bulkheads
4. Cofferdamming

Forebay, Gatehouse and Penstock Inlet. Due to standing water in the forebay area, it was necessary to estimate the extent of repairs that will be required to the forebay intake structure as well as the forebay walls and penstock inlet gate structure. This estimate was based on visual observation, use of engineering drawings, engineering experience, use of vendor supplied estimates, and engineering calculations. It is important that on-site inspections and evaluations be made to complement any office calculations.

Cofferdamming. In order to perform repairs or undertake new construction in the dry, it is necessary that the work area be in a dewatered condition. Therefore, cofferdamming will be required to insure that the work area from the forebay inlet to the tailrace outlet be maintained in a dewatered condition. Cofferdamming cost estimates were developed from engineering experience on similar projects and use of cost estimating guides such as Dodge and Engineering News Record.

Penstocks. The existing steel riveted penstocks have deteriorated to the point where replacement is required. This was determined by site inspections and from discussions with personnel familiar with the plant's condition when it was in operation. Therefore, new penstocks will have to be fabricated, the old penstocks removed, and the new ones installed. The estimated cost for installing new penstocks was compared with the cost as determined by the use of Figure 3-1 in Volume VI.

In the case of the Great Falls power plant, costs in addition to those obtained by use of Figure 3-1 need to be included. These additional costs consist of removal of the existing penstocks and use of a higher unit price for the steel due to its special fabrication. There are four penstocks, each 8 feet 6 inches in diameter, and approximately 60 feet long.

Draft Tubes, Tailrace, Draft Tube Bulkheads. The amount of remedial or new construction work required is dependent on the type of turbine selected. Section 5 covering the Electromechanical Features presents the types of turbines investigated.

For the Allis-Chalmers and Leffel alternatives the draft tubes will require replacement; whereas the Ossberger and Tampella alternatives are complete packages which include the draft tube. The costs for the draft tube replacement alternatives were estimated by use of cost estimating guides (Dodge Guide to Public Works and Heavy Construction Costs, 1978 and Engineering News Record Quarterly Cost Roundup, 1978), engineering experience, and cost information in the engineers' files.

Bulkheads will be required at the discharge end of the powerhouse. Cost for the bulkheads was estimated from costs for similar facilities designed by the engineer.

Powerhouse and Appurtenant Facilities

The powerhouse and appurtenant facilities include:

1. Repair of water supply and sanitary facilities
2. Repair and replacement of broken windows, roof tiles, box gutters
3. Cleaning and repainting of all exposed metal work (stairs, piping, doors, etc.)

4. Cleaning of concrete surfaces in the interior of the powerhouse

5. Inspection and repair as needed to the powerhouse interior back wall

6. Rehabilitation of overhead traveling crane

7. Modification of existing powerhouse floor to accommodate turbine generator equipment.

The existing powerhouse is constructed of brick and reinforced concrete. Engineering drawings were located which show most details of the powerhouse and were utilized to the maximum extent possible.

Field inspection and building code requirements formed the basis for determining what types of repairs or replacements may be required. On-the-site inspections are needed to make reasonable estimates for existing powerhouses in which conditions vary considerably from site to site. The guidelines contained in Section 4, Volume VI of the manual, can only make one aware of the items that need to be considered. Therefore, no comparisons are made with the cost guidelines shown in Section 4, Volume VI.

Cost Estimates

Table 4-1 displays the estimated cost for three alternatives for repairing, altering, or constructing required civil features at the Great Falls Hydroelectric Project, not including the diversion dam rehabilitation.

TABLE 4-1
CIVIL FEATURES - COST ESTIMATE (DOLLARS)

FERC Account Number	Description	ALTERNATIVE 1 Manual Procedures	ALTERNATIVE 1 Feasibility Study	ALTERNATIVE 2 Manual Procedures	ALTERNATIVE 2 Feasibility Study	ALTERNATIVE 3 Manual Procedures	ALTERNATIVE 3 Feasibility Study
331	**STRUCTURES & IMPROVEMENTS:**						
	SITE PREPARATION:						
	Drainage System Erosion Control Final Grading Access Road Parking & Miscellaneous Site Features Environmental Construction Controls	--	N/A	--	N/A	--	N/A
	POWERHOUSE:						
	Structural Excavation Foundation Switchyard	Manual not applicable to site. 17,500	Lump Sum 170,000 Included in Acct. No. 350	Manual not applicable to site. 23,000	Lump Sum 170,000 Included in Acct. No. 350	Manual not applicable to site. 21,500	Lump Sum 132,000 Included in Acct. No. 350
332	**RESERVOIRS, DAMS & WATERWAYS**[1/]						
	Intake Trashracks	Not included in manual	75,000	Not included in manual	75,000	Not included in manual	75,000
	Intake Slidegates	80,000	112,000	80,000	112,000	80,000	112,000
	Penstocks	107,520	360,000	107,520	360,000	107,520	360,000
	Valves	--	N/A	--	N/A	--	N/A
	Bifurcation	--	N/A	--	N/A	--	N/A
	Tailrace	--	N/A	--	N/A	--	N/A
	Outlet Bulkheads (Slidegates)	20,000	24,000	20,000	24,000	20,000	24,000
	Cofferdamming & Pumping	Not included in manual	139,000	Not included in manual	139,000	Not included in manual	139,000
	TOTAL ACCOUNT 331, 332	Manual Procedures Costs not Complete For This Project	880,000	Manual Procedures Costs Not Complete For This Project	880,000	Manual Procedures Costs Not Complete For This Project	842,000
	TOTAL CIVIL COSTS		880,000		880,000		842,000
	CONTINGENCIES (25%)		220,000		220,000		210,500
	REGIONAL CORRECTION FACTOR		1.0		1.0		1.0
	CORRECTED CIVIL COSTS		1,100,000		1,000,000		1,052,500
	ENGINEERING, CONSTRUCTION MANAGEMENT & OTHER COSTS		110,000[2/]		110,000[2/]		105,250[2/]
	GRAND TOTAL		1,210,000		1,210,000		1,157,750

1/ Diversion Dam Rehibilitation Cost Not Included.

2/ Feasibility study used 10% for Engineering, Construction Management and Other Costs.

SECTION 5
ELECTROMECHANICAL EQUIPMENT

The Great Falls Study considered a full range of alternative turbine-generator equipment types. For this case study, four of the 17 alternatives examined and the costs of two compared with manual procedures contained in Volume V.

The four alternatives considered here represent equipment supplied by four different vendors and are summarized in Table 5-1. The turbine types and sizes selected were based on the following factors: available head in feet (gross head 70 feet); available flow in cubic feet per second on a daily basis (range 50 over 3000); use of available powerhouse space without alteration of its exterior (inside dimensions approximately 40 by 102 feet) due to historical considerations; rehabilitation of the existing four S. Morgan Smith Francis turbines, and installation of new turbine-generator equipment. The determination of turbine efficiency was made by using Figure 3-5 in Volume V of the manual and comparing it with vendor-supplied information. In the case of Alternative 1 it was found that the vendor-supplied information resulted in somewhat lower efficiencies than those obtained by use of manual curves.

Table 5-2 displays the comparison between the manual procedures and vendor supplied information of the turbine efficiencies for Alternative 1.

Description of the turbine units for the four alternatives contained in this case study are described below.

Alternative 1 - Allis-Chalmers (Rehabilitated Units)

This alternative investigated the rehabilitation of the four existing in-place S. Morgan Smith turbines. These units are Twin Francis horizontal units installed in 1923 and operated until 1969. Three of the units are rated at 1340 kilowatts and one is rated at 1080 kilowatts.

Alternative 2 - Leffel (Uprating Existing Units)

This alternative investigated the uprating of the existing four Francis-type units. The work required would be similar to Alternative 1 with the exception that all new parts would be provided. Only the middle portion of the existing pressure cases would be used along with the existing or replaced penstocks and draft tubes. To accommodate the new Francis-type runners and wicket gates it will be necessary to extend the pressure cases on each end. This extension can be accommodated without apparent need for structural modification. As a result of the uprating, new higher capacity generators will be needed, thereby necessitating some modification to the existing floor at the generator.

Based on vendor-supplied information the smaller units will operate over a flow range of 120 to 282 cubic feet per second with a net head of 67 feet. Its corresponding efficiencies would be 78 percent at 2/5 load to 90 percent at 4/5 load. The three larger units will operate over a flow range of 236 to 457 cubic feet per second. Their corresponding efficiencies would be 80 percent at 1/2 load to 90 percent at 9/10 load.

Alternative 3 - Ossberger (New Units)

The alternative investigated the installation of four new cross flow turbines manufactured by F.W.E. Stapenhorst, Inc. These units are modified impulse-type turbines with cylindrical runners. The turbines are low speed (136 rpm) and therefore speed increasers are provided to permit use of high speed (1200 rpm) standard generators.

The four cross flow generating set units would operate over a flow range of 76 to 378 cubic feet per second with their corresponding efficiencies being 80 percent at 1/5 load to 84 percent at 3/4 load.

Alternative 4 - Tampella (New Units)

The Tampella units investigated would be low specific speed adjustable blade propeller. The units can be set at a higher elevation than similar Allis-Chalmers units, which permits the use of vertical, conical-shaped draft tubes.

This arrangement results in significantly reduced structural modifications in the tailrace. However, the lower speed results in more costly generators. The generators would be supported integrally with the turbine, which also reduces the required structural modification but would necessitate removal of the generator when removal of the turbine is necessary. The Tampella unit includes an upstream butterfly valve to be used for shutoff, thus eliminating the need for the penstock headgates.

The four Tampella-supplied turbines would operate over a flow range of 106 to 530 cubic feet per second with their corresponding efficiencies being 70 percent at 1/5 load to 90 percent at 4/5 load.

Electromechanical Cost Comparisons

Retrofitting or rehabilitation of existing equipment is unique to itself and therefore use of guidelines contained in Volume V for determining costs is of limited assistance. Procedures illustrated by Figure 2-1 of Volume V were utilized to determine the electrical/mechanical equipment costs for comparison with those obtained by in-depth study.

Electrical/mechanical costs determined by use of the procedures and guidelines contained in Volume V were grouped into the following categories:

1. Turbine-generator equipment
2. Station electrical equipment
3. Switchyard equipment

TABLE 5-1

GENERATING UNIT ALTERNATIVES

Alternative	No's and Capacity (kW) of Units	Installed Capacity kW	Orientation	Turbine Type	Speeds-RPM Turbine	Speeds-RPM Generator	Generator Output Voltage	Turbine Manufacturer
1	1-1080 3-1340	5100 1/	H	DRF	1-514 3-450	1-514 3-450	2400	Allis-Chalmers
2	1-1290 3-2070	7500	H	DRF	1-400 3-327	1200 2/	4160	Leffel
3	4-1700	6800	H	CF	136	1200 2/	4160	Ossberger
4	3-2625	7875	V	AP	300	300	6300	Tampella

Legend:
- H = Horizontal
- V = Vertical
- DRF = Double Runner Francis
- CF = Cross Flow
- AP = Adjustable Blade Propeller

Notes:
- 1/ Generator Uprated
- 2/ Speech Increaser Provided

TABLE 5-2
ALTERNATIVE 1 - TURBINE EFFICIENCIES

Rated Capacity	Expected Efficiency	MANUAL PROCEDURE (FIGURE 3-5) Add Correction For Throat Dia. (1340 kW Unit)	Add Correction For Throat Dia. (1080 kW Unit)	Expected Efficiency (1340 kW Unit)	Expected Efficiency (1080 kW Unit)	VENDOR SUPPLIED INFORMATION[1] Expected Efficiency (1340 kW Unit)	Expected Efficiency (1080 kW Unit)
100%	88%	2.4%	2.1%	90.4%	90.1%	80%	79%
75%	89%	2.4%	2.1%	91.4%	91.1%	82%	83%
60%						77%	77%
50%	83%	2.4%	2.1%	85.4%	85.1%		
25%	73%	2.4%	2.1%	75.4%	75.1%		

1/ These efficiencies are based on rehabilitated turbine.

4. Miscellaneous power plant equipment
5. Special equipment

Cost comparisons between the manual and feasibility results for Alternatives 1 and 3 are shown in Table 5-3. Alternative 1 is a comparison of the rehabilitated Allis-Chalmers turbine and Alternative 3 compares results for the Ossberger turbine.

It should be noted that the total installed costs are higher using manual procedures than those found by the feasibility study. The costs were 10 percent higher for Alternative 1 (rehabilitated equipment) and 25 percent higher for Alternative 3 (new equipment). Vendor-supplied equipment quotes were assumed to have contingencies included. An item where there is a large cost difference is the transmission line cost. Part of this line will be overhead and a portion in underground conduit. The local utility, Public Service Electric and Gas Company (PSE&G), furnished the cost for this work. The cost difference for this item is in excess of 200,000 dollars.