CHAPTER 9

ECONOMIC EVALUATION OF HYDROPOWER PROJECTS

9-1. Introduction.

a. This chapter and supporting appendixes outline the procedures for computing hydropower benefits and discuss some of the economic evaluation problems relating to hydropower projects. Subjects covered include the conceptual basis for power benefits, definition of with-project and without-project conditions, computation of benefits using the alternative thermal plant and energy displacement methods, treatment of annual costs, scoping of hydro projects, financial feasibility studies, and special problems encountered in the economic analysis of hydro projects.

b. The basic approach to economic evaluation of water resources projects is contained in the Corps of Engineers' Planning Guidance Notebook (49). The Notebook includes the Water Resources Council document that serves as overall guidance for Federal water resources planning: Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies, dated March 10, 1983, which will be referenced simply as Principles and Guidelines (77).

c. This chapter discusses the concepts and procedures contained in the references mentioned above and generally covers analysis of only the power function. Analysis of hydropower as part of a multiple-purpose project is handled by incorporating the hydropower function in a multiple-purpose formulation analysis, with power benefits computed as described in this chapter.

9-2. Conceptual Basis for Hydropower Benefits.

a. Basis for Measuring Benefits.

(1) Section 1.7.2(b) of Principles and Guidelines states that the general measurement standard for estimating value is the willingness of users to pay for the project's output. It further suggests that it is not possible in most instances to measure willingness to pay directly. Four alternative techniques are proposed to obtain an estimate of the value of the project's output in lieu of direct measurement of willingness to pay. These are, in order of preference:

- actual or simulated market price
- change in net income
- cost of the most likely alternative
- administratively established values

(2) The first three measures stem from the willingness to pay criterion; the fourth, administratively set prices, relates to this criterion but also may reflect other social objectives and procedures. Only the first and third options can readily be applied to hydropower benefit evaluation, and these will be discussed in detail below.

(3) For a more detailed discussion of the conceptual basis of hydropower benefit evaluation, reference should be made to Volume VI of the National Hydroelectric Power Resources Study (48f).

b. Actual or Simulated Market Price.

(1) Where energy from electric powerplants is priced and sold at its marginal cost, where new powerplant additions are small compared to the system load, and where there is no likely private alternative to the proposed Federal hydropower project, actual or simulated market price can be used to calculate benefits. As a practical matter, market price is seldom used. There are two major reasons: (a) electric power is not normally priced at the marginal cost, and (b) the cost of the most likely alternative frequently puts a limit on the benefit value.

(2) Electric power at the retail level is normally priced at the average cost of generation (which includes costs of older powerplants as well as newer plants), rather than the marginal cost. Where this is the case, market price cannot be used for benefit calculations. PURPA rates and prices based on wholesale bulk power transactions among suppliers have been suggested as an indirect means of simulating market price. PURPA rates are the prices which utilities are required to pay developers for the output of small renewable power projects under the terms of the Public Utility Regulatory Policies Act of 1978 (PURPA). These rates, which are computed by the utilities and approved by state public utility commissions, are usually based on the utilities' long-run incremental power costs. The use of PURPA rates would be a valid method only (a) if these values are adjusted so that they would be comparable to the hydro plant costs in terms of evaluation criteria (discount rate, etc.), and (b) they are based upon the cost of new resources, rather than the cost of surplus power from existing resources. Because of the variations in the way PURPA rates are developed, and the difficulty in obtaining the backup data necessary to make these adjustments, the use of this approach is not encouraged.

(3) Perhaps a more basic reason that market price is not used is that there is usually a private alternative to the Federal hydropower project. If this is the case, the cost of the most likely alternative puts a limit on the benefit value. This can be illustrated with the following example. Assume that it is possible to measure power benefits directly with actual or simulated market prices and that the annual benefits attributable to a proposed Federal hydropower plant are $100,000. The annual cost of the hydropower plant is $70,000. Assume further that if the hydropower plant is not constructed, the increment of load to be carried by the proposed hydropower plant would be exactly met by a new utility-constructed thermal plant. In this case, the thermal plant would carry the same increment of load as the hydro plant, so it would also accrue annual benefits of $100,000. The annual cost of that thermal plant, based upon the same economic criteria used for the hydropower plant, is $80,000.

TABLE 9-1
Summary of Example Costs and Benefits

	Federal Hydro Project	Private Thermal Plant
Total annual benefit	$100,000	$100,000
Total annual cost	70,000	80,000
Annual net benefit	$30,000	$20,000

(4) Table 9-1 shows that the net benefit of the Federal hydropower plant would be $30,000. However, $20,000 of this would be reaped even if the hydro plant were not constructed, because the thermal plant would be constructed instead. In other words, the total benefits of $100,000 will be achieved whether or not the Federal hydropower plant is constructed, and the benefits of the Federal project are therefore limited to the resource savings of the alternative thermal plant, or ($80,000)-($70,000) = $10,000. Thus, the incremental effect upon the system of building the Federal project is not the achievement of the benefits, which will be realized in either case, but rather the avoidance of economic costs. Society's net willingness to pay for the Federal hydropower project is therefore the avoided cost of the alternative.

c. Cost of the Most Likely Thermal Alternative.

(1) Where a likely alternative to the Federal hydropower project exists (and whether or not total benefits are known), the appropriate form of evaluation is the alternative cost measure. Alternative costs can be measured in two ways:

- the cost of constructing and operating an alternative thermal plant or an increment thereof (the "alternative thermal plant" method)
- the value of generation (primarily fuel costs) from existing thermal plants that would be displaced by the output of the proposed hydro plant (the "energy displacement" method)

These methods are described in more detail in Sections 9-5 and 9-6, respectively. For some hydro projects, a combination of both methods would most accurately measure benefits. This would be handled by using the "alternative thermal plant" method and accounting for the displacement of existing generation through the energy value adjustment (Section 9-5e).

(2) Conservation measures, alternative hydropower projects, or other renewable resources may in some cases be viable alternatives to the hydro project under study. However, all of these options would be compared with the most likely thermal alternative in order to determine their relative economic merit. The treatment of conservation and alternative hydropower projects is discussed further in Sections 9-2e and 9-2f, respectively.

d. Need for Power.

(1) In order for any measure of benefits to be valid, there must be a need for the power (capacity or energy) that would be produced by the hydro plant during the period being considered. In most cases, therefore, it is necessary to either (a) demonstrate that there is a requirement for additional generating capacity within the service area of the system to which the hydro plant would be added, or (b) secure a statement of marketability from the regional Federal Power Marketing Administration (small projects only). Procedures for accomplishing both are described in Chapter 3.

(2) In some cases, a hydropower plant may be a cheaper source of energy than existing thermal generation. Since the project would not defer the need for new thermal capacity, a load-resource analysis of the type described in Chapter 3 would not be meaningful. Need would be established simply by demonstrating positive net benefits in an

analysis of energy benefits alone, using the "energy displacement" method described in Section 9-6.

(3) Export markets are sometimes a means of helping to support the need for a hydropower project. Although it would seldom be appropriate to base a substantial portion of the justification for a Federal hydropower project on extra-regional power markets, there may be some cases where benefits from export sales can be claimed. Examples would be (a) the sale of secondary energy which is surplus to the needs of the region, and (b) short-term sales of firm energy during periods of regional surplus. In these cases, benefits would be based upon the value of the power to the importing power system and not the price at which it would be sold to that system.

e. Nonstructural Alternative.

(1) Although this chapter primarily discusses benefits based upon the cost of the most likely thermal alternative, it is recognized that an NED plan may consist of "...a system of structural and/or nonstructural measures, strategies, or programs..." and that "Alternative plans should not be limited to those the Federal planning agency could implement directly under current authorities". (Principles and Guidelines, Sections 4.1.6.1(a) and (c). In addition, in some parts of the country (the Pacific Northwest, for example), state or regional policies may require that a specified cost advantage be credited to conservation in the analysis of alternative methods for meeting power demand. For these reasons, a nonstructural measure, such as conservation, may be a valid alternative. In general, nonstructural alternatives should be evaluated for projects which are not exempted from the requirements of Section V of Principles and Guidelines. Exempted projects are single-purpose, small scale projects of 25 megawatts or less, and projects of less than 80 megawatts that add power to existing Federal facilities.

(2) The term "nonstructural" as applied to hydropower is not limited to measures which are nonstructural in the engineering sense, but includes all measures which reduce the need for additional power generation resources. Thus, the term encompasses all measures, whether structural or nonstructural, which are commonly referred to as conservation. In general, conservation involves more efficient use, production, and generation of electricity. However, when evaluating conservation as an alternative (or set of alternatives) to a hydro project, it should be kept in mind that Principles and Guidelines requires that "...the without-project condition include the effects of implementing all reasonably expected nonstructural and conservation measures...". Thus, for a conservation measure to be an alternative, it must be one which is not already reflected in the power load forecast.

(3) In order to develop a meaningful analysis of a conservation measure, the costs and potential results of implementing the measure must be quantifiable. As a result, analyses of conservation options such as increased education of electricity consumers, legal restrictions on the use of electricity, and pricing should not be attempted unless an accurate measure of costs and results can be assumed. Within the foregoing constraints, there are a number of opportunities for conservation in all sectors (residential, commercial, and industrial), which include:

- insulation of existing buildings
- conservation standards for new buildings
- insulation of water heaters and hot water systems
- efficiency standards for household appliances
- load management
- changes in power plant operating schemes
- improvement of industrial process efficiencies
- power system interties

Specific measures to be considered for analysis for individual projects will vary according to the type of hydro project being studied (i.e., base load, peaking, or energy displacement), and which conservation programs are already in place in the study area.

(4) Because the electricity savings potential of each of the various possible conservation measures is technically and practically limited, economic comparisons between them and a hydropower project should be based upon cost-effectiveness (i.e., the option with the lowest cost, when computed on a comparable basis, is always the preferred option), rather than benefits as traditionally determined by the least-cost thermal alternative method. The cost-effectiveness approach permits the scheduling of a hydropower project in combination with less costly conservation measures which may not produce sufficient energy or capacity savings over the planning horizon to eliminate the long-term need for additional generation resources. The analysis of conservation should be done at the same level of detail as the analysis of the hydropower project and should include consideration of the following:

- identification of conservation measures expected to be implemented in the without-project condition.

- verification that the load forecast for the study area reflects implementation of expected conservation measures.

- identification of specific areas of electricity use where additional conservation is possible and potentially cost effective.

- determination of current levels of electricity use in each area identified above.

- determinations of the cost of each measure, including administrative costs.

- determination of economically feasible energy or capacity savings.

(5) The result of the study will be an array or supply curve of potential conservation measures from which specific measures may be selected for implementation in order of ascending cost. However, the analyst must insure that the aggregate savings of electricity, in terms of both capacity and energy, are accounted for such that the residual need for power generation resources is accurately shown. This analysis does not determine the economic feasibility of a proposed hydropower project, but establishes when it will be needed. In other words, it assumes that conservation measures available at a lower cost than the proposed hydropower project would be in place before the project would be constructed, presuming that the project is economically feasible (as determined, for example, by the most likely alternative method of computing power benefits).

(6) Additional information on the evaluation of nonstructural (conservation) measures may be found in Volume VI of the National Hydroelectric Power Resources Study (48f) and Volumes 1 and 2 of the Northwest Conservation and Electric Power Plan (29).

f. Use of Hydro as an Alternative. In cases where several candidate hydro plants exist, the most likely alternative to a given hydro plant may be one of the other hydro plants. In such cases, however, benefits attributable to the given hydropower plant would not be based on the cost of the alternative hydro plant. Instead, all of the candidate hydro plants would be evaluated and ranked to identify the best project. The benefits used in the ranking process would be based upon the cost of the most likely thermal alternative. This approach assures that the most cost-effective hydro plant is the first one to be considered for development.

9-3. Overall Approach in Computing Hydropower Benefits

a. Hydro Plant Output.

(1) Hydro plant output is measured in terms of both energy and capacity. Following are the most common ways in which output is measured:

- firm or primary energy
- secondary energy
- average annual energy (firm plus secondary energy)
- dependable capacity
- intermittent capacity

These values are obtained from power studies as described in Chapters 5, 6,and 7.

(2) In most cases, benefits are based on a project's average annual energy and dependable capacity. Where secondary energy has a substantially different value than firm energy, it may be necessary to evaluate the two energy components separately (see Section 9-10o).

(3) There are also cases where benefits may be based on energy output only. The energy-only approach would be applied primarily at hydro plants where (a) the energy displacement method is used (see Section 9-6), or (b) the project has no dependable capacity.

(4) In the past, credit has sometimes been given to intermittent capacity, but the development of procedures for basing dependable capacity on average availability (Sections 6-7b, g and k) has eliminated the need for evaluating intermittent capacity separately.

b. Computing Benefits. Power benefits are computed by applying unit "power values", representing the costs associated with the alternative thermal plant, to the capacity and energy output of the hydropower plant. For example:

Capacity benefit = (Dependable capacity, kW)(CV) (Eq. 9-1)

Energy benefit = (Avg. annual energy, kWh)(EV) (Eq. 9-2)

Total power benefit = (Capacity benefit) + (Energy benefit) (Eq. 9-3)

where: CV = Capacity value, $/kW-year
EV = Energy value, mills/kWh

The capacity value represents the per kilowatt annualized capital cost and other fixed costs associated with the thermal plant, and the energy value represents per kilowatt-hour fuel and variable O&M costs. The procedures for computing these power values are described in Sections 9-5 and 9-6.

c. Period of Analysis. Sections 1.4.12 and 2.1.2(c) of Principles and Guidelines specify the maximum period of analysis for water resources projects to be 100 years, and this period is normally used for new hydro projects. However, Principles and Guidelines further restricts the period of analysis to "...the period of time over which the project would serve a useful purpose." This results in a period of analysis of less than 100 years for certain types of hydro projects. For example, a 50-year project life is normally assumed for single-purpose off-stream pumped-storage projects, because the likelihood that changing technology will render a pumped-storage plant obsolete is considered to be greater than for conventional hydropower plants. Likewise, small single-purpose diversion type hydropower projects are sometimes designed for a 50-year rather than a 100-year service life. When adding a new powerhouse or additional units to an existing dam, an analysis must be made to determine the remaining useful life of the existing structure. The remaining life of the existing structure establishes the project life of the hydropower addition.

9-4. With- and Without-Project Conditions.

a. General.

(1) Careful definition of the with- and without-project conditions is essential to the proper evaluation of hydropower benefits. Sections 2.5.3, 2.5.5, and 2.5.6 of the Principles and Guidelines provide general guidance on definition of the with- and without-project conditions for hydropower with respect to existing resources, existing institutional arrangements, actions anticipated or underway, and treatment of conservation. The with- and without-project conditions must be examined somewhat differently, depending upon whether the alternative thermal plant method or the energy displacement method is used.

(2) As noted earlier, an important assumption underlies the alternative thermal plant method. That assumption is that the projected increment load growth will be met whether or not the proposed Federal hydropower project is constructed. Thus, the with-project plan describes how the system operates to meet anticipated power demand with the existing resources, the proposed new hydropower project, and, in some cases, some additional new generating resource. The without-project condition describes the operation of the system in meeting the same power demand with the same existing resources plus the mix of new resources that would be constructed in the absence of the proposed hydro plant.

(3) Theoretically, the addition of a hydro plant to a system could influence the timing and mix of new generation far into the future. The planner could evaluate this by using generation system expansion models, which select the most economic schedule of plants to

be installed to meet increasing power demands. These models consider both capital and operating costs in developing these plans. A model of this type could be applied alternatively to the with- and without-hydro project scenarios. The resulting difference in system costs would be the total benefit attributable to the hydropower plant. This approach should be considered when a proposed hydropower plant is large in relation to the size of the system that would incorporate it, because the plant will have a major long-term effect on system resource development. Section 7-5 describes how the without-project scenario might be developed for the analysis of a large off-stream pumped-storage plant.

(4) In most cases, however, the proposed hydro addition is small compared to the system and can be regarded as having only a short-term effect on the mix of thermal generation that will evolve. Thus, it is usually sufficient to identify a single thermal alternative and apply energy and capacity value adjustments to reflect system impacts.

(5) When the energy displacement method is used, it is assumed that the proposed hydro plant has no dependable capacity and will be used only for displacing generation at existing thermal plants. Thus, for small hydro projects, the addition of future resources will usually proceed in the same manner for both the with- and without-project scenarios. The only difference between the two scenarios would be in system operating costs (fuel plus O&M costs).

b. Identification of the System. The system is generally defined as the area where the power from the project will be used. Small hydro projects can frequently be analyzed in the context of a single utility. Larger projects may have to be analyzed in a multi-utility system or power pool area. Definition of the system should be made in consultation with the FERC regional office and the regional Federal Power Marketing Administration.

c. Individual Years to be Analyzed.

(1) The hydro project's economic life (Section 9-3c) establishes the period of analysis for benefit evaluation. The power system in which the hydro project would operate and the relative fuel prices of the plants operating in that system will change with time. In order to be theoretically correct, it would be necessary to examine the with- and without-project systems and compute benefits individually for each year of project life. However, this is often neither practical or necessary. Benefits are normally estimated either on the basis of a single "typical" load year or on a series of years representative of the system conditions that are expected to evolve over the life of the project.

(2) In most cases, a hydro plant reaches a relatively stable "mature" state of operation within a few years of its on-line date. Once a mature operation is achieved, the hydro project's impact on other plants in the system (and hence its benefits) can be assumed to be essentially constant through the end of project life. In cases where a hydro project is added to a large power system and where the resource mix is expected to remain relatively stable, it is sufficient to analyze a single year which would be representative of the project's long-term operation. The only time-oriented adjustment necessary would be to account for real fuel cost escalation (Section 9-5f) in computing costs for the alternative thermal plant. Most small hydro projects can be analyzed in this way.

(3) There are other cases where hydropower benefits would vary substantially with time, and in these cases, analyses would have to be made at intervals. Examples are:

- where the project is large and requires several years to be absorbed by the system load.
- where the resource mix is changing, and the hydro project's role changes with time.
- where the hydro project is constructed in stages.
- where the energy displacement method is used and the mix of displaced generation changes with time.
- where differential fuel price escalation changes system operation.

(4) The number of intervals to be analyzed depends upon the manner in which benefits vary with time. For example, if a large project requires several years to be absorbed in the load, benefits should be computed for each year until the project output is fully used (Figure 9-1). In most other cases, however, it is only necessary to examine a series of representative years that would be sufficient to describe how benefits change with time and interpolate to obtain benefits for intervening years (Figure 9-2). Because discounting minimizes the influence of benefits in distant years and system conditions are uncertain in those years, it is seldom necessary to examine system changes beyond project year 20.

d. Comparability.

(1) General. For a benefit analysis to be valid, project costs and benefits must be based on fully comparable economic criteria. The comparability requirement applies to comparison of alternative hydro

projects as well as to the comparison of the hydro project with the thermal alternative. The analyses must be comparable with respect to the following:

- discount rate
- price level
- treatment of inflation
- period of analysis
- treatment of insurance and taxes

(2) Discount Rate and Price Level. Section 1.4.11 of Principles and Guidelines states that the Federal discount rate published by the Water Resources Council shall be used to evaluate the economic feasibility of Federally financed projects. The costs of the hydropower project and the thermal plant must be based upon the same price level.

(3) Treatment of Inflation. Section 1.4.10 of Principles and Guidelines specifies that prices of goods and services used in economic analysis should be based on real exchange values (i.e., should exclude the effects of general inflation). The thermal plant

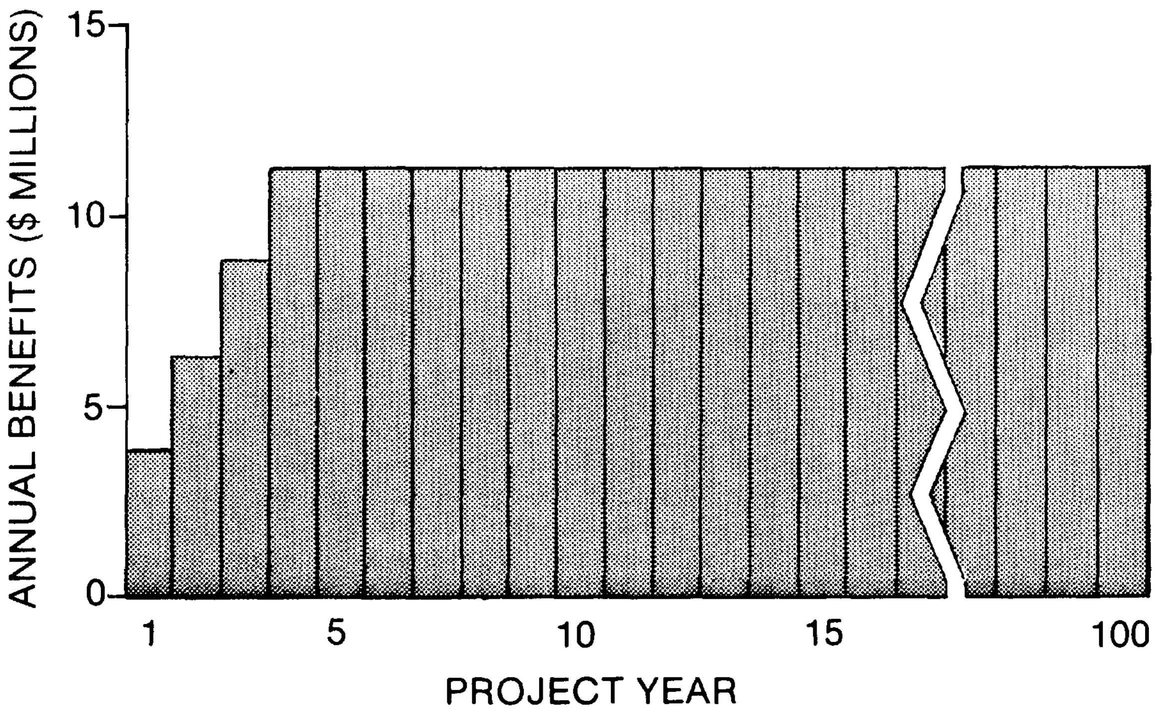


Figure 9-1. Plot of benefit stream for project requiring several years to be absorbed in system load

construction costs developed by FERC for computing power values are inflation-free costs. However, project costs developed by the Corps are frequently based on recent bid prices, which include an element of inflation. While suitable for budgetary purposes, these costs cannot be used for economic analysis until the inflation component has been removed, as specified in EM 1110-2-1306 (see also Sections 8-4g and 8-8d of this manual). Section 2.5.8(a)(5) of Principles and Guidelines gives guidance on relative price relationships, including the effects of real fuel cost escalation. That section also stipulates that fuel costs should reflect economic (market clearing) prices rather than regulated prices.

(4) Period of Analysis. It should be noted that the useful life of most thermal alternatives is 30 years, rather than the 50 to 100-year life assumed for the hydro plant. It is assumed that, should the alternative thermal plant be constructed, it would be replaced by an

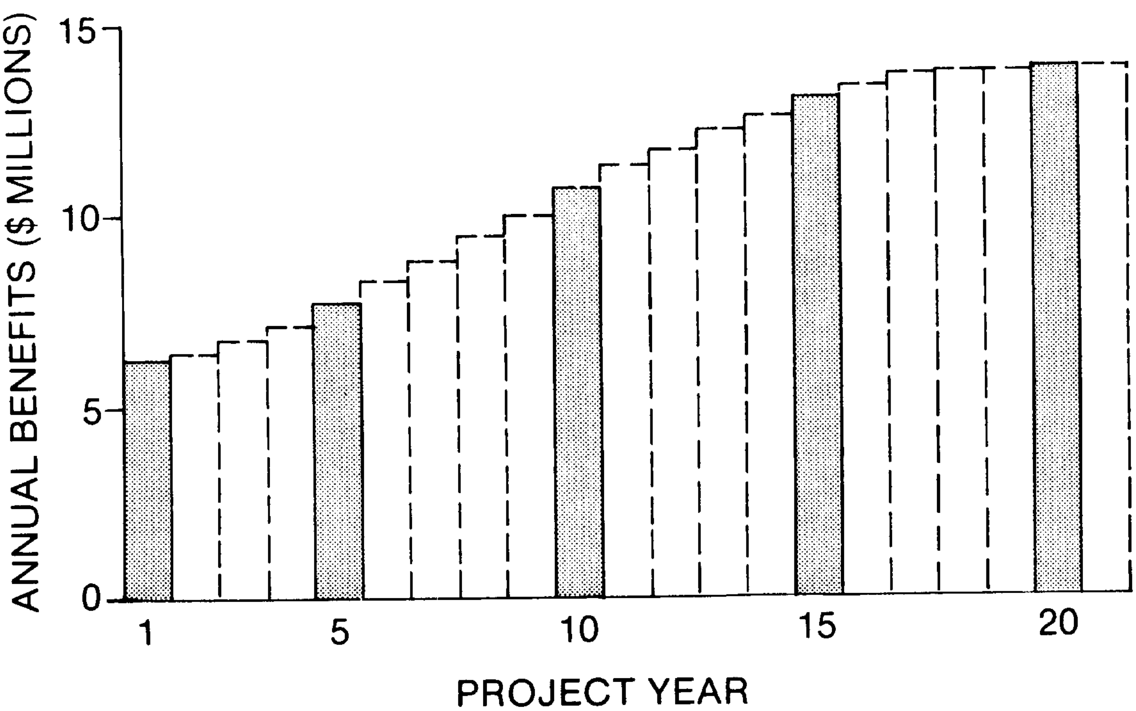


Figure 9-2. Plot of benefit stream for project where benefits vary with time
(NOTE: Benefits need be computed for the years shown as bars. Values for intervening years are obtained by interpolation).

identical plant at appropriate intervals through the hydro project's life (i.e., years 30, 60, and 90). As long as thermal plant cost increases over this period are limited to those resulting from general inflation, the amortized present value of the fixed costs for the series of identical thermal plants over 100 years (adjusted to remove the effects of general inflation) will be identical to the amortized present value of the initial thermal plant amortized over its 30-year life. As a result, power values are normally computed simply on the basis of the initial thermal plant's 30-year life. It is very likely that the replacement plants will not be identical to the initial plant, but it is difficult to predict 30 years in advance if the replacement plant will be more or less expensive (in today's dollars) than the initial plant. Because of the uncertainty about future inflation and because the present value of the future replacement plants is relatively small, basing power values on the initial thermal plant's service life is considered to be reasonable.

(5) Treatment of Insurance and Taxes. Section 2.5.8(a)(1) of Principles and Guidelines states that insurance and taxes shall be excluded from NED benefit analyses.

9-5. Alternative Thermal Plant Method

a. Basic Approach.

(1) The basic approach to computing power values when using the alternative thermal plant method is to identify all of the costs associated with the thermal plant and to segregate them into fixed cost (capacity cost) and variable cost (energy cost) categories. These costs are then converted to unit power values. In many cases, the hydro plant performs somewhat differently than the thermal alternative in a power system, and as a result, each has a somewhat different effect on the cost of operating the power system as a whole. This is accounted for by applying adjustments to the costs of the thermal alternative to reflect the differences in system costs.

(2) The general approach for computing alternative thermal plant costs has been developed by the Federal Energy Regulatory Commission (FERC), and it is described in detail in Hydroelectric Power Evaluation (72). A summary of this information follows in succeeding paragraphs. The main discussion applies to the development of power values for the alternative thermal plant method, where both energy and capacity values are required. A special section (9-6) is also included to describe how energy values are computed for use in the energy displacement method.

(3) FERC normally computes the power values used in the evaluation of power benefits at Corps projects (see Section 9-5k). However, the basis for deriving power values is described in this manual to give the planner the background necessary to apply these values.

b. Capacity Value. The capacity value is based on the fixed costs associated with the alternative thermal plant. The following cost components are included:

- construction cost
- interest during construction
- fuel inventory cost
- fixed O&M costs
- administrative and general expenses

These costs are amortized over the thermal plant's expected operating life (normally 30 years) at a fixed charge rate which includes the cost of money and depreciation. The resulting value is expressed in terms of dollars per kilowatt-year. Table 9-2 shows sample calculations deriving capacity values for coal-fired steam and combustion turbine power plants.

c. Capacity Value Adjustment.

(1) Operating experience has indicated that a hydro plant is normally more mechanically reliable than a thermal plant and, where operating limits do not restrict its operation, a hydro plant has more flexibility in terms of fast-start capability and quick response to changing loads. In order to reflect these characteristics, an adjustment is applied to increase the capacity value. This increase is applied because somewhat more thermal capacity is required than hydro capacity to reliably carry a given increment of peak load in a system. Recent studies by the Water and Energy Task Force resulted in the development of a method for evaluating these characteristics (78). This procedure is described in Sections 6-7 and O-2.

(2) Capacity values provided by FERC normally include a capacity value adjustment which reflects (a) the relative mechanical reliabilities of the hydro plant and its thermal alternative, and (b) a flexibility credit for hydro if appropriate. This capacity value adjustment can be described by the equation

TABLE 9-2
Unadjusted Power Values at Busbar 1/

	Coal-fired Steam	Combustion Turbine
Basic Data		
Plant size	500 MW	60 MW
Price level	July 1982	July 1982
Investment cost	$1360/kW	$268/kW
Fixed charge rate 2/	0.0878	0.0878
Plant life	30 years	30 years
Total O&M cost	$30/kW-year	$4.42/kW-year
Fuel cost	$1.68/million Btu	$7.41/million Btu
Heat rate	10,500 Btu/kWh	12,500 Btu/kWh
Annual plant factor	55 percent	7.5 percent
Capacity Value		
Amortized investment	$119.40/kW-year	$23.50/kW-year
Fuel inventory cost	1.40/kW-year	1.00/kW-year
Fixed O&M 3/	18.30/kW-year	0.00/kW/year
Administration and general expenses	5.20/kW-year	1.50/kW-year
Bus-bar cap. value	$144.30/kW-year	$26.00/kW-year
Energy Value		
Fuel cost	17.6 mills/kWh	93.0 mills/kWh
Variable O&M	2.4 mills/kWh	7.0 mills/kWh
Bus-bar energy value	20.0 mills/kWh	100.0 mills/kWh

1/ Busbar power values are at-thermal plant costs and do not include transmission costs and losses.
2/ Based upon interest rate of 7-7/8 percent and project life of 30 years.
3/ For coal-fired steam, 61 percent of operation and maintenance costs are assumed to be fixed and 39 percent are assumed to be variable. For combustion turbine, 100 percent of O&M costs are assumed to be variable.

TABLE 9-3
Adjusted Capacity Values at Load Center

	Coal-fired Steam	Combustion Turbine
At-market Capacity Costs		
Bus bar capacity value	$144.30/kW-year	$26.00/kW-year
Sending substation cost	1.30/kW-year	1.80/kW-year
Transmission line cost	7.50/kW-year	2.10/kW-year
Receiving substation cost	1.90/kW-year	0.30/kW-year
Total capacity cost	$155.00/kW-year	$30.20/kW-year
Transmission losses 1/	6.00/kW-year	0.50/kW-year
At-market capacity cost	$161.00/kW-year	$30.70/kW-year
Capacity Value Adjustment		
Hydro plant availability, HMA	0.98	0.98
Thermal plant availability, TMA	0.84	0.86
Flexibility adjustment, F	0.05	0.00
Capacity value adjustment 2/	0.22	0.14
Adjusted Capacity Value		
At-market capacity cost	$161.00/kW-year	$30.70/kW-year
Capacity value adjustment	35.40/kW-year	4.30/kW-year
At-market capacity value	$196.40/kW-year	$35.00/kW-year

1/ 3.9 percent for coal-fired steam and 1.7 percent for combustion turbine.
2/ Capacity value adjustment = ((HMA/TMA)x(1+F))-1

$$\text{Capacity value adjustment} = \frac{HMA}{TMA}(1 + F) - 1 \qquad \text{(Eq. 9-4)}$$

where: HMA = hydro plant mechanical availability
TMA = thermal plant mechanical availability
F = hydro plant flexibility adjustment

Table 0-1 lists representative values for HMA and TMA, and Section 0-2e discusses the flexibility adjustment. Table 9-3 shows the derivation of capacity value adjustments for the plants described in Table 9-2.

d. Energy Value. The energy value is based upon the variable cost associated with operation of the alternative thermal plant. This variable cost consists of the fuel costs and the variable portion of the O&M costs. Energy values are expressed in terms of mills/kWh. Table 9-2 shows the derivation of energy values for the example coal-fired steam and combustion turbine plants.

e. Energy Value Adjustment.

(1) The addition of a hydro plant to a system will often have a different effect on the operation of other powerplants in the system than if the thermal alternative were added instead. Some existing plants may be required to run more, and others may run less. The net result will be a difference in system operating cost, which must be accounted for when computing energy benefits.

(2) An example will illustrate why the proper accounting for system energy costs is important. This example is based on a 100 megawatt hydropower project having an average annual energy output of 175,000 MWh. Its average annual plant factor would be:

(175,000 MWh)/(100 MW X 8760 hours/year) = 20 percent.

The most likely alternative is assumed to be an oil-fired combustion turbine having an energy cost of 100 mills/kWh. Figure 9-3 shows how the power plants would be operated in the annual system load curve (a) with the hydropower project and (b) with the 100 MW combustion turbine alternative (the "without hydro" case). The operation of three existing power plants -- 100 MW of combined cycle (@ 70 mills/kWh), 100 MW of oil-fired steam (@ 55 mills/kWh), and 100 MW of gas-fired steam (@ 45 mills/kWh) -- are affected by which alternative is included in the system. The operation of other existing plants (those in the base load portion and in the extreme peak) are not affected and thus are not shown in the calculations.

(3) In the with-hydro system, the proposed hydro plant would operate at a 20 percent plant factor, while the combined cycle plant operates at 7 percent, the oil-fired steam at 11 percent, and the gas-fired steam at 16 percent. In the without-hydro system, the combustion turbine alternative is loaded above combined cycle, oil-fired steam, and gas-fired steam because it has a higher energy cost (100 mills/kWh). Thus, the energy alternative to the 20 percent plant factor hydro project is not a 100 MW, 20 percent plant factor combustion turbine, but 100 MW of combustion turbine operating at a 7 percent plant factor. The balance of the energy would come from running the three existing thermal plants at higher plant factors than in the with-hydro case.

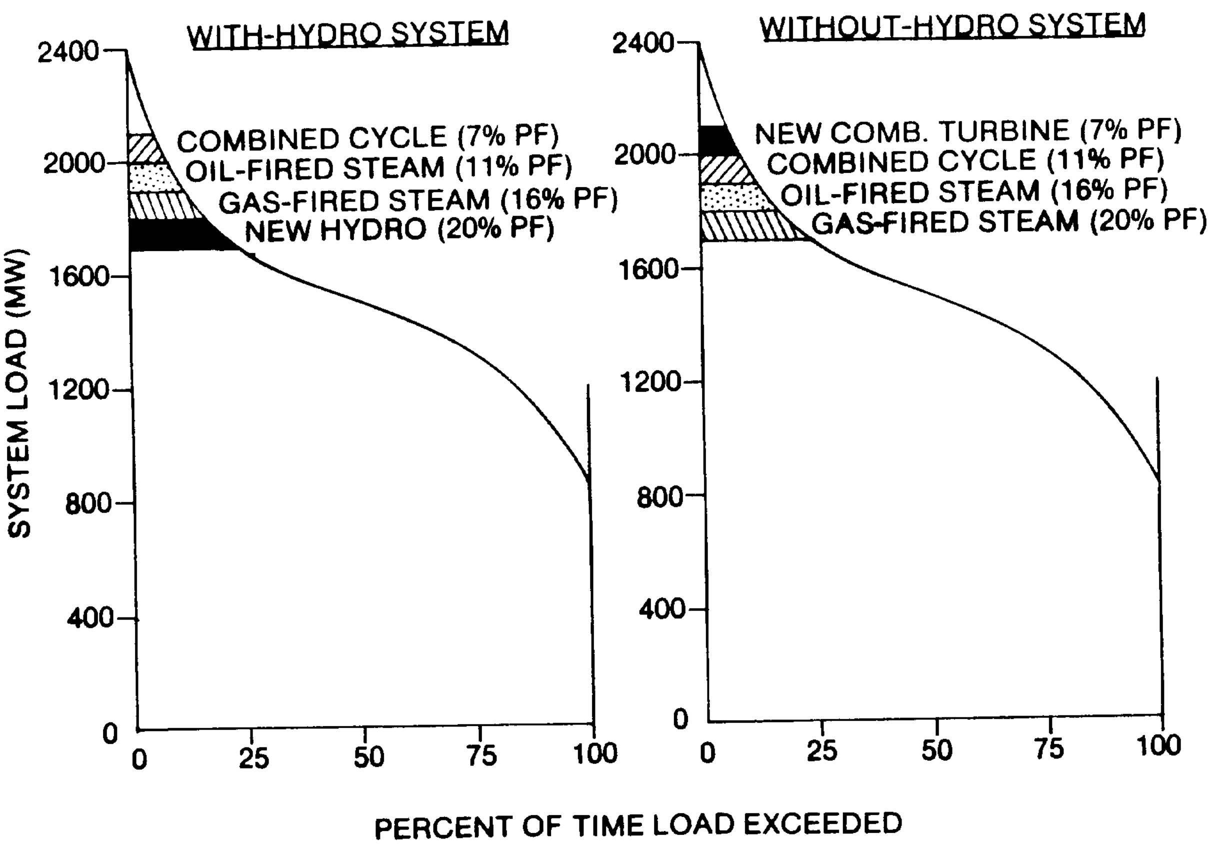


Figure 9-3. Differences in system operation which should be accounted for in making system energy value adjustment

(4) Thus, in order to determine the energy benefit of the hydro plant, it will be necessary to consider the operating costs of the three existing plants as well as the combustion turbine. Table 9-4 shows the computation of "system costs" for the two cases. In order to simplify the example, only the costs of the plants that operate differently in the two cases are shown. The total system cost would include the base load plants and plants operating in the peak as well. The difference in system cost is $12,500,000, and this is the net energy benefit that accrues to the hydro plant. The system energy benefit can be converted to a mills/kWh energy value by dividing it by the hydro plant's energy output:

Energy value = ($12,500,000)/(175,000 MW) = $71/MWh = 71 mills/kWh.

This system energy value is also known as the adjusted energy value. The difference between the 71 mill system energy value and the 100 mill combustion turbine energy value is the energy value adjustment, which in this case is a negative 29 mills/kWh. To select the combustion turbine as the thermal alternative but to ignore the energy value adjustment would have resulted in overstating the benefits by (175,000 MWh) x (100 mills/kWh - 71 mills/kWh) = $5,075,000.

(5) The energy value adjustment can be accounted for in two ways: (a) through the use of a simplified equation, and (b) through the use of a computer model which derives system production costs. The simplified or "short-cut" equation, which is discussed further in Section 0-3d of this manual and chapter 3 of reference (72), derives an energy value adjustment using average costs for thermal plants operating in the appropriate plant factor range: i.e., the average costs of those thermal plants that operate in the same general plant factor range as the hydro plant. For example, if the proposed hydro project has a plant factor of 30 percent (see Section 9-5h(6)), the average system energy cost might be based upon those thermal plants operating in the 30 percent plant factor range. The resulting energy value adjustment is deducted from the energy value of the thermal alternative to obtain the adjusted or system energy value. This approach provides an approximate value, which is satisfactory for preliminary studies. The sample energy value computations shown on Table 9-5 illustrate the use of the short-cut equation for computing the adjusted energy value. FERC uses the short-cut equation primarily for developing generalized power values for screening studies and where a system production cost model is not available.

(6) FERC uses a production cost model method for computation of most specific project power values. Computerized production cost models derive the system energy benefit directly, using the general procedure outlined in the example. This benefit can also be converted to a mills/kWh adjusted energy value if desired. The use of

TABLE 9-4
Computation of Difference in System Operating Costs

With-Hydro Project System

Combined cycle:
(100 MW)x(0.07)x(8760 hrs/yr)x(70 mills/kWh) = $4,300,000
Oil-fired steam:
(100 MW)x(0.11)x(8760 hrs/yr)x(55 mills/kWh) = $5,300,000
Gas-fired steam:
(100 MW)x(0.16)x(8760 hrs/yr)x(45 mills/kWh) = $6,300,000
Hydro:
(100 MW)x(0.20)x(8760 hrs/yr)x(0 mills/kWh) = $ 0

Total system cost = $15,900,000

Without-Hydro Project System

Combustion turbine:
(100 MW)x(0.07)x(8760 hrs/yr)x(100 mills/kWh)= $6,100,000
Combined cycle:
(100 MW)x(0.11)x(8760 hrs/yr)x(70 mills/kWh) = $6,700,000
Oil-fired steam:
(100 MW)x(0.16)x(8760 hrs/yr)x(55 mills/kWh) = $7,700,000
Gas-fired steam:
(100 MW)x(0.20)x(8760 hrs/yr)x(45 mills/kWh) = $7,900,000

Total System Cost = $28,400,000

Difference in system costs

$28,400,000 - 15,900,000 = $12,500,000

NOTE: Energy costs in this example do not include real fuel cost escalation.

TABLE 9-5
Adjusted and Escalated Energy Values at Load Center

	Coal-fired steam	Combustion turbine
Escalated Busbar Energy Cost		
Fuel cost	17.6 mills/kWh	93.0 mills/kWh
Fuel cost escal. factor 1/	1.88	2.08
Escalated fuel cost	33.1 mills/kWh	193.4 mills/kWh
Variable O&M cost	2.4 mills/kWh	5.2 mills/kWh
Escalated energy cost	35.5 mills/kWh	198.6 mills/kWh
At-Market Energy Cost		
Escalated energy cost	35.5 mills/kWh	198.6 mills/kWh
Transmission losses 2/	1.1 mills/kWh	1.2 mills/kWh
At-market energy cost, EC_t	36.6 mills/kWh	199.8 mills/kWh
Energy Value Adjustment		
Hydro project plant factor, PF_h	0.30	0.30
Thermal plant factor, PF_t	0.55	0.075
Avg. system energy cost, EC_d	60.0 mills/kWh	60.0 mills/kWh
Energy value adjustment 3/	19.5 mills/kWh	104.8 mills/kWh
Adjusted Energy Value		
At-market energy cost	36.6 mills/kWh	199.8 mills/kWh
Energy value adjustment	- 19.5 mills/kWh	- 104.8 mills/kWh
Adjusted energy value	17.1 mills/kWh	95.0 mills/kWh

1/ From Appendix P, Table P-5, for DOE Region 5, 1990 POL date.
2/ 3.0% for coal, 0.6% for combustion turbine
3/ Based on FERC short-cut equation:

$$\text{Energy value adjustment} = \frac{(PF_t - PF_h)(EC_d - EC_t)}{PF_h}$$

production cost models for power value work is discussed in a report prepared by Systems Control Inc. for the Corps of Engineers and the Bureau of Reclamation (33). Section 6-9f of this manual briefly describes the POWRSYM model, which is used by FERC for most of its power value work.

(7) It should be noted that where the hydro plant and its thermal alternative operate at markedly different plant factors, the energy value adjustment can be large, sometimes resulting in negative energy values (i.e., total system operating costs are higher with the proposed hydropower plant in the system than with the thermal alternative). However, energy value adjustments can be positive as well as negative, depending upon the nature of the effect on system operation. This is illustrated by Figure 9-4, which shows how adjusted energy values might vary with plant factor for a base load coal-fired steam alternative.

f. Real Fuel Cost Escalation.

(1) As discussed in Section 9-4d, NED costs and benefits are to be expressed in constant dollars: i.e., no accounting is to be made for future general price inflation. However, Principles and Guidelines (Section 2.5.8(a)(5)) does permit the escalation of fuel prices in real terms due to increasing scarcity and other factors.

(2) The Water and Energy Task Force has developed a procedure that accounts for real fuel cost escalation (78). This procedure is discussed in Appendix P to this manual. Generally, the Task Force recommends that escalation be limited to a maximum of 30 years from the present, although a shorter escalation period may be warranted in some cases due to limited availability of forecast data, uncertainty, or other factors. The Task Force further recommends that these future escalated costs be present-worthed to the project on-line date and then amortized to develop average annual energy values. Appendix P also describes a technique for developing multipliers that adjust base fuel prices directly to account for real fuel cost escalation.

(3) Real fuel cost escalation is applied only to the fuel component of the energy value, and not to the variable O&M cost. For example, a typical coal-fired energy value for DOE Region 5 would be 20.0 mills/kWh (in 1980 dollars), of which 17.6 mills/kWh represents the fuel cost and 2.4 mills/kWh variable O&M costs. If the proposed hydro plant is assumed to come on-line in 1990, the equivalent annual fuel cost multiplier would be 1.88 (Appendix P, Table P-5). The escalated energy value would then be

(17.6 mills/kWh) x (1.88) + 2.4 mills/kWh = 35.5 mills/kWh.

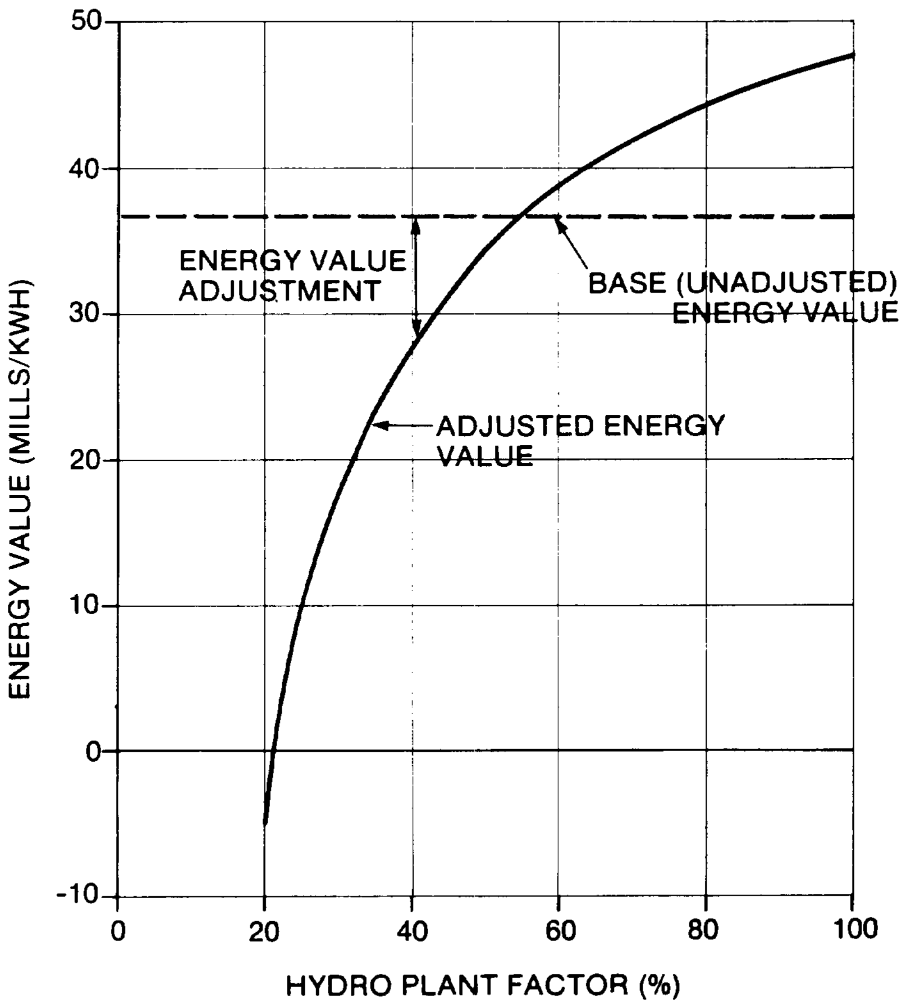


Figure 9-4. Example showing the effect of system energy value adjustment on energy values for base load coal-fired steam alternative.

Although real fuel price changes could have an effect upon operation and maintenance costs and other aspects of project evaluation, the effect is normally assumed to be small enough that it would not have any significant effect on the benefit analysis.

(4) The tables in Appendix P are for illustration purposes only. The most current fuel cost escalation rates available should be used. As noted in Appendix P, the Water and Energy Task Force suggests using Department of Energy (DOE) escalation rates when up-to-date estimates are available and their input assumptions are satisfactory. An alternative source of escalation data is the Data Resources, Inc. (DRI) Energy Review (4). The DRI projections are updated quarterly using current prices and other economic information; the regional data reflects local conditions more accurately than the DOE projections; and DRI provides specific information on fuel prices applicable to electric utilities. For these reasons, many Corps field offices elect to use the DRI escalation rates. Whichever rates are used, rationale should be provided for selecting those rates. FERC will normally use DOE escalation rates in their power value computations unless the Corps field office specifically requests that other rates be used.

(5) Power benefit computations should show the incremental effect of real fuel cost escalation on benefits. FERC provides supporting data with their power values (see Section 9-5k) to permit the computation of energy benefits with and without real fuel cost escalation so that Corps field offices can test alternative fuel cost escalation rates.

(6) Rising benefits resulting from real fuel cost escalation can have an effect upon the optimal on-line date for a hydropower project. For large projects especially, alternative on-line dates should be tested to determine if the first year that the project is needed (as determined from load-resource analyses) is in fact the date that yields the greatest net benefits. Chapter 9 of Volume VI of the National Hydroelectric Power Resources Study (48f) provides further information on the scheduling criterion.

g. Transmission Costs and Losses.

(1) Hydro project benefits and costs are normally compared at the "load center". Although a system's power demand is usually distributed over a wide area, for purposes of comparison it is usually possible to identify a single point of concentrated demand (such as a metropolitan area), which is designated as the load center. Transmission costs and losses associated with getting the power from the thermal plant to the load center must be computed and added to the capacity and energy values described above. Chapters 4, 10, and 11 of Hydroelectric Power Evaluation (72) describe techniques for accom-

plishing this. Tables 9-3 and 9-5 illustrate how these costs and losses are accounted for during the computation of typical power values. Transmission costs and losses must also be computed for the hydro plant (see Section 8-6). Figure 9-5 shows how the various cost components are accounted for in the normal "at-load center" benefit cost analysis.

(2) In the Pacific Northwest, it is sometimes difficult to isolate and assign specific segments of transmission line to individual hydro plants. In these cases, costs and benefits may be compared at the hydro site. This is done by applying generalized values for hydro plant transmission costs and losses to the "at-load center" energy and capacity values. Figure 9-6 shows how the cost components are accounted for in an "at-hydro site" benefit-cost analysis.

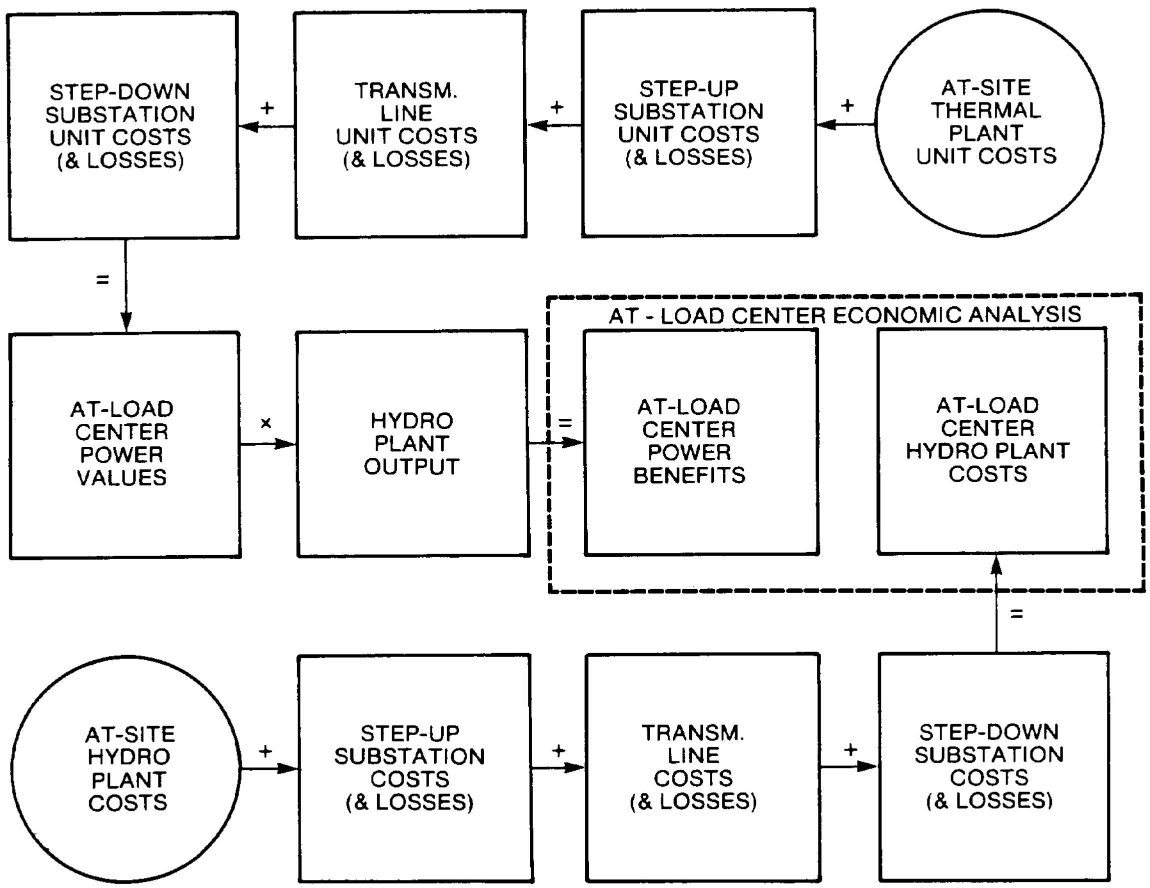


Figure 9-5. Schematic diagram showing accounting for transmission costs and losses in "at-load center" (at-market) economic analysis

h. Selection of the Most Likely Alternative.

(1) At the present time, five types of thermal power plants are being constructed by utilities in the contiguous United States, and these serve as the basis for power values. These plants, classified according to the type of load they serve, are as follows:

- base load: coal-fired steam and nuclear
- intermediate load: cycling coal-fired steam and combined cycle
- peaking: combustion turbine

In Alaska, Hawaii, Puerto Rico, and other isolated areas, oil-fired steam, gas- and oil-fired combustion turbines, or diesel may be the most likely thermal alternative for base load as well as intermediate and peaking service. Section 2-2d describes the general characteristics of the plants listed above.

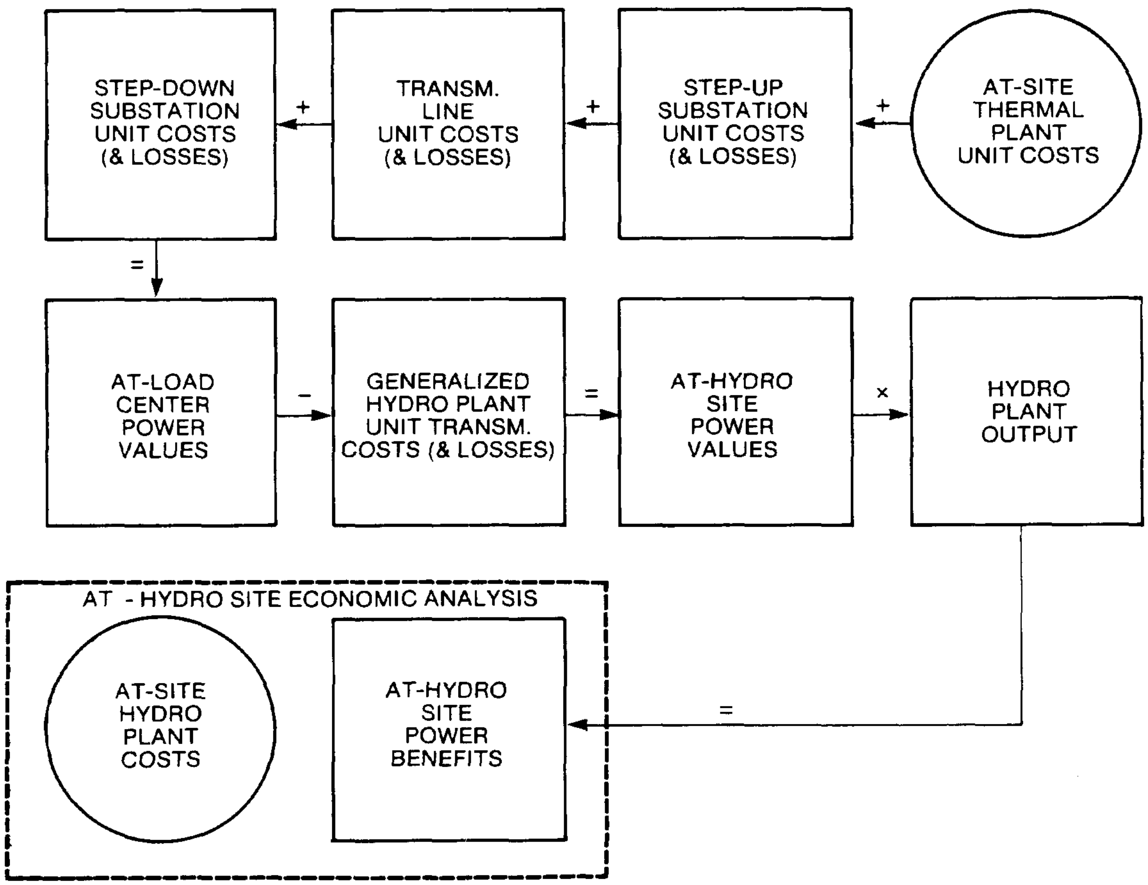


Figure 9-6. Schematic diagram showing accounting for transmission costs and losses in "at-hydro site" economic analysis

(2) To determine the least costly thermal alternative to a given hydro plant (with a given plant factor), several types of plants are usually considered. Capacity and energy values are computed for each. Selection of the appropriate alternative is accomplished as follows. In computing the energy values, energy value adjustments are applied as described in Section 9-5e. The energy value for each thermal plant is then converted to dollars per kilowatt-year and added to the corresponding capacity value to determine the total power value for each alternative. The plant with the lowest total power value is usually selected as the most likely thermal alternative. Table 9-6 shows power values for a 30 percent plant factor hydro plant based on three different thermal alternatives.

(3) Table 9-6 shows that coal-fired steam is the least costly alternative, and it would probably be used as the basis for the hydro project benefits. However, a distinction must be made between the "least costly" alternative and the "most likely" alternative. The least costly alternative is not always selected because there may be factors other than cost alone that dictate which thermal plants are viable alternatives. For example, combined-cycle plants may not be constructed in a given area due to an uncertain fuel supply, or nuclear plants may not be constructed because of siting restrictions. Thus, in some cases, the least costly alternative may not be selected as the most likely alternative because it is not implementable.

(4) Power values are frequently computed for specific hydroelectric plant installations, as shown in Table 9-6. Where scoping studies are being made to select plant size or where screening studies are being made to select the best sites, generalized power values may be developed for a range of hydro plant factors. They are usually presented in tabular form (see, for example, Table 9-7), but they can also be plotted in terms of hydro plant factor versus total power value in $/kW-yr.

(5) The graphic presentation is known as a screening curve and can be used to identify the appropriate alternative for each plant factor range. To be valid for use in hydropower project analysis, screening curves must reflect the capacity and energy value adjustments described in Sections 9-5c and 9-5e.

(6) It should be noted that the hydropower project plant factor enters into the computation of the total power values shown in Tables 9-6 and 9-7 and Figures 9-7 and 9-8, and in fact the screening curves are plotted using hydro plant factor as one of the variables. Hence, it is important that the proper hydro plant factor be used if the correct thermal alternative is to be selected. Since the hydro project's capacity benefits are based on dependable capacity (Sections 6-7 and 9-3), the hydro plant factor used for selecting the thermal

TABLE 9-6
Power Values for Thermal Alternatives to
30 Percent Plant Factor Hydro Project

	Combustion Turbine	Combined Cycle	Coal-fired Steam
Unadjusted energy value, mills/kWh	199.8	143.3	36.6
Energy value adjustment, mills/kWh	-104.8	- 13.9	-19.5
Adjusted energy value, mills/kWh	95.0	129.4	17.1
Adjusted energy value, $/kW-yr 1/	$249.70	$340.10	$ 44.90
Capacity value, $/kW-yr	35.00	75.40	196.40
Total power value, $/kW-yr	$284.70	$415.50	$241.30

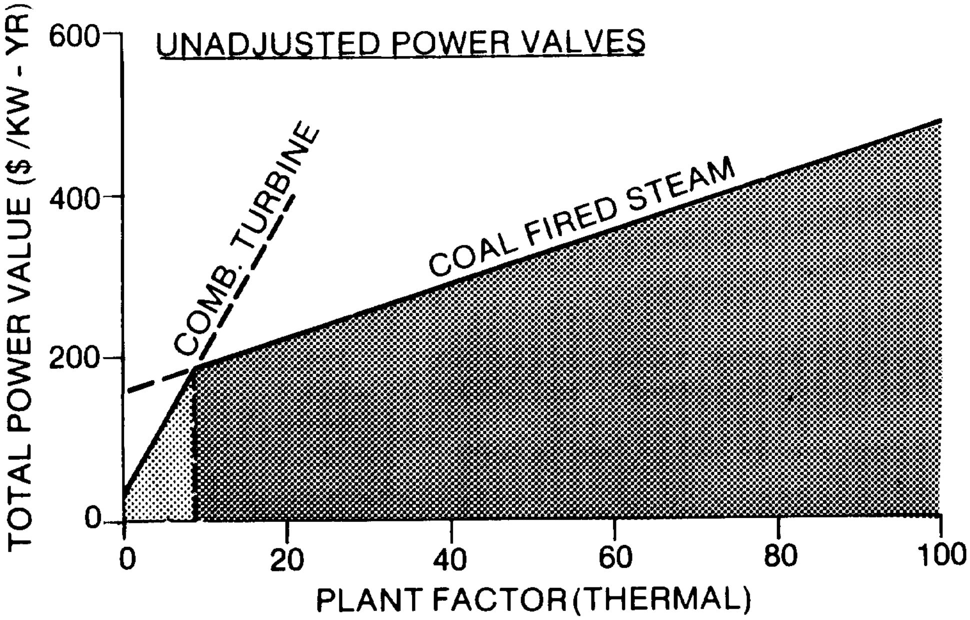
1/ To convert energy value from mills/kWh to $/kW-year, multiply the energy value by the number of hours in a year and the hydro plant factor. For example, for the combustion turbine:

$$\frac{(95.0 \text{ mills/kWh})\text{x}(8760 \text{ hrs/yr})\text{x}(0.30)}{(1000 \text{ mills/\$})} = \$249.70/\text{kW-year}$$

alternative should also be based on the hydro project's dependable capacity. In most cases, the hydro plant factor should also be based on the project's average annual energy, although for power systems where secondary energy cannot be readily marketed, the hydro plant factor shoud be based on firm energy (see Section 9-10o). For most cases, the hydro plant factor used for selecting the thermal alternative should be computed as follows:

$$\text{Hydro project plant factor} = \frac{(\text{Average annual energy, MWh})}{(8760 \text{ hours})(\text{Dependable capacity, MW})} \qquad \text{(Eq. 9-5)}$$

(7) Figure 9-7 illustrates typical screening curves, where combustion turbine is the alternative at low (or peaking) plant factors and coal-fired steam is the alternative at high (or base load)



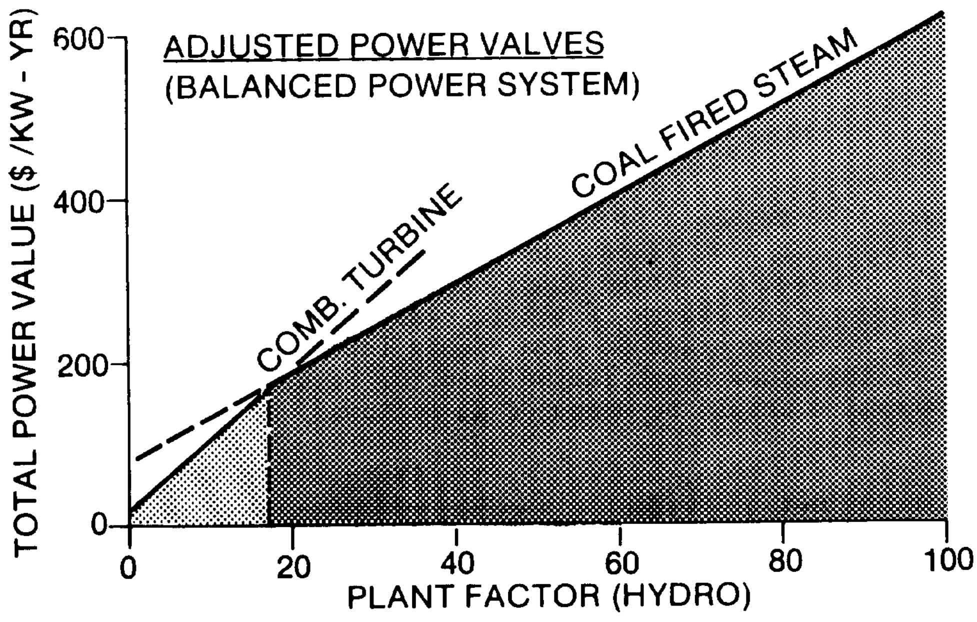
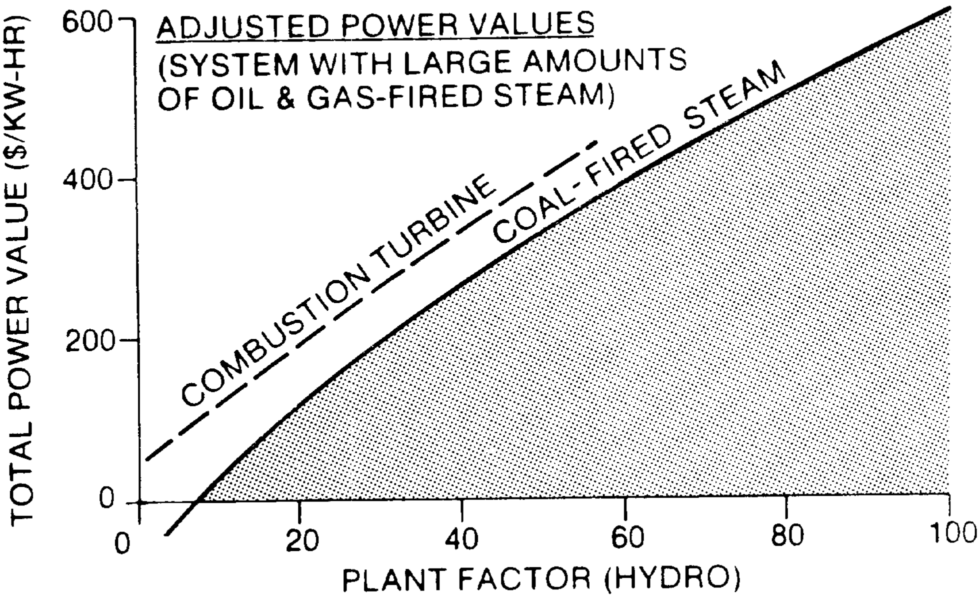


Figure 9-7. Comparison of screening curves based upon adjusted and unadjusted power values



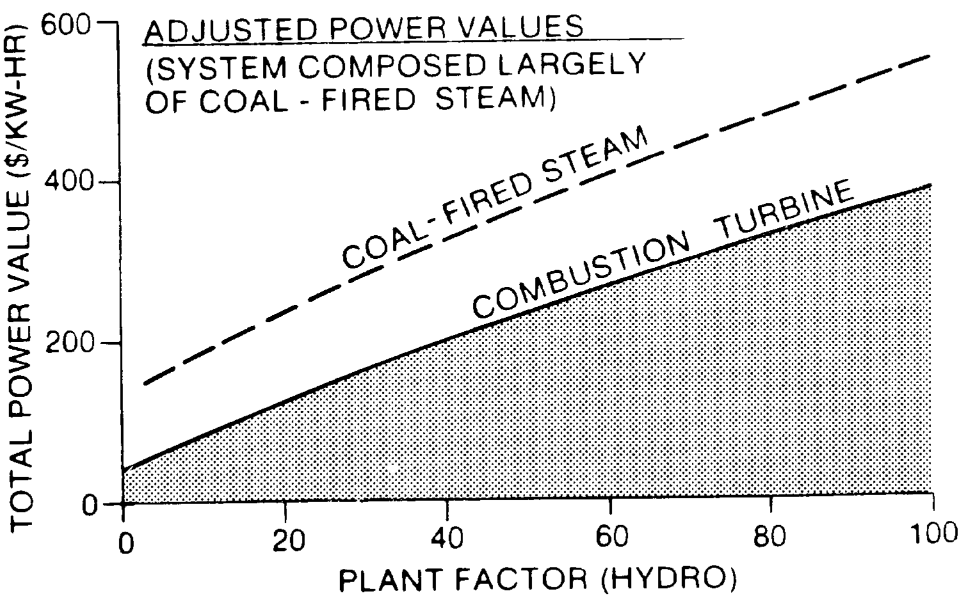


Figure 9-8. Screening curves based upon adjusted power values for two types of unbalanced power systems

TABLE 9-7
Generalized Power Values

Hydro Project Plant Factor (percent) 1/	Capacity Value ($/kW-year) 2/	Energy Value (mills/kWh) 3/	Total Power Value ($/kW-year) 4/
Combustion Turbine			
5	$35.00	269.7	$153
10	35.00	164.9	179
15	35.00	129.9	206
20	35.00	112.4	232
25	35.00	101.9	258
30	35.00	95.0	285
Coal-fired Steam			
10	$196.40	-68.7	$136
20	196.40	-4.4	189
30	196.40	17.1	241
40	196.40	27.8	294
50	196.40	34.3	347
60	196.40	38.6	399
70	196.40	41.6	451
80	196.40	43.9	504
90	196.40	45.7	557
100	196.40	47.1	609

1/ See Section 9-5h(6)
2/ These are adjusted capacity values, computed as shown on Table 9-3.
3/ These are adjusted energy values, computed as shown on Table 9-5.
4/ Total power value, $/kW-year =
(capacity value, $/kW-year) + (energy value, $/kW-year)

The energy value is converted from mills/kWh to $/kW-year as shown on Table 9-6.

plant factors. The upper curve is based on unadjusted thermal plant costs. A curve of this type might be used by utilities in determining the best mix of thermal resources. The lower curve is based on the same plant costs, but incorporates capacity and energy value adjustments (although not the same adjustments reflected in Table 9-7). Data from this curve would be used for developing power benefits. It can be seen from the lower curve that the break point between the combustion turbine and coal-fired steam alternatives would be a 17 percent plant factor. Compared to the unadjusted curve, the adjusted coal-fired curve has a steeper slope, and the total power values are higher at the high plant factors and lower at the low plant factors. The slope of the combustion turbine curve is flatter than the unadjusted curve, and the power values are lower at all but the lowest plant factors.

(8) The lower curve in Figure 9-7 illustrates power values for a system where a good balance of existing resources exists. A "good balance" refers to a mix of base load, intermediate, and peaking plants which is near optimum in terms of system operating costs. In some systems, changes in relative fuel prices, delays to planned new powerplants, or other factors may result in a "poor balance" (a mix of plants which is relatively expensive to operate).

(9) Where a poor balance exists, or where a system includes a large percentage of high-cost oil- or gas-fired steam generation, large energy value adjustments may result. In these situations, a screening curve may suggest a thermal alternative other than that which might be expected for a given plant factor, or the power values may be much higher or lower than expected on the basis of unadjusted thermal plant costs. For example, if a system has a disproportionate amount of peaking generation or high-cost steam generation, it would best be served by base load plants having low energy costs. The resulting power values (upper portion of Figure 9-8) would suggest that a hydro plant should be developed as a base load plant rather than as a peaking plant (i.e., the net benefit analysis would tend to favor the selection of a hydropower project having a higher plant factor than would have been selected for addition to a system having a good balance of existing resources). This is because the power values at the lower (peaking and intermediate) plant factors are substantially lower for this system compared to the balanced system, while the power values at the higher (base load) plant factors remain high. On the other hand, for a system having a large amount of low-cost base load generation, the adjusted power values (lower portion of Figure 9-8) would likely suggest the development of hydro for peaking.

i. Size of Thermal Alternative. Frequently, the size of a proposed hydro plant is much different than the normal size of the thermal alternative. For example, the least costly thermal alternative to a proposed 20 MW hydro plant as determined from the screening curve may be base load coal. The thermal alternative would not be a 20 MW coal-fired plant, but an increment of a standard-sized coal-fired plant (500 MW, for example). Thus, construction of the 20 MW hydro plant would defer but not replace the large coal-fired plant, or would make it possible to build a somewhat smaller coal-fired plant.

j. Combination of Alternatives.

(1) In some cases, the operation of a hydro plant may be such that it is not possible to select a single thermal alternative that is equivalent to the hydro plant, even through use of an energy value adjustment. An example would be a large hydro plant that provides some base load capacity and some peaking capacity. Another example might be a hydro plant that produces base load power for part of the year and peaking power for the rest of the year. In these cases, the least costly alternative that is nearly equivalent to the hydropower plant from an operational standpoint may be a mix of thermal plants.

(2) The following example illustrates how a mix of alternatives might be developed. Assume that minimum release requirements dictate that a portion of the capacity of a 100 MW, 40 percent plant factor hydro plant will be used for base load operation and the remainder will be used for peaking. The most likely alternative in this case may be a combination of coal-fired steam and combustion turbine capacity. By examining the operation of similar units in the power system, it may be found that new coal-fired steam plants operate at an average annual plant factor of 60 percent and combustion turbines operate at 10 percent. The mix would be computed by simultaneous solution of the following equations, where MW_c is the coal-fired capacity and MW_t is the combustion turbine capacity:

$$MW_c + MW_t = \text{Hydro plant capacity} = 100\ MW$$

$$(MW_c)x(60\%) + (MW_t)x(10\%) = (100MW)x(40\%)$$

$$MW_c = 60\ MW \qquad MW_t = 40\ MW$$

(3) In this example, construction of the hydro plant displaces the construction of a combination of thermal plants. A more common case is the situation where the hydro plant displaces the construction of a single thermal alternative, but in operation displaces a mix of thermal generation. Due to the hydrologic characteristics of the site, the hydro project may operate in the base load mode part of the year and in the peaking mode for the remainder of the year. The most effective way to deal with this problem is through the use of a system production cost model, such as POWRSYM (see Section 6-9f), which is able to model the day to day or week to week variations in hydro generation and thus properly identify the value of the energy displaced. Different thermal alternatives (or combinations of

alternatives) could be tested to determine which would be least costly, considering both capital costs (capacity values) and system operating costs from the POWRSYM model.

(4) Take for example a 200 MW hydro plant with a 30 percent annual plant factor that operates for peaking most of the time but as a base load plant during periods of high runoff. Three thermal alternatives might be considered: 200 MW of combustion turbine, 200 MW of coal-fired steam, and a combination of 100 MW of coal-fired steam and 100 MW of combustion turbine (other combinations could also be considered if necessary). Table 9-8 shows the computation of benefits for all three alternatives, the result being that the combustion turbine by itself is the least costly alternative in this case. Therefore, benefits should be based on these alternative costs. The hydro plant would replace the need for construction of 200 MW of combustion turbine capacity, and a portion of the hydro plant's energy output would provide peaking generation. The remainder of the hydro plant's output would displace some of the energy output of other plants in the system (base load thermal, etc.), but it would not eliminate the need for these plants.

(5) FERC can account for this type of operation in the development of the adjusted energy values. However, the Corps field office must provide FERC with week-by-week values of hydro project energy output for a typical year in order to permit them to properly model the project. Where capacity varies over the course of the year, it should be specified by week also. In determining what mixes of power output (base load and peaking, for example) should be considered, it is important to coordinate these studies closely with the regional Federal Power Marketing Administration to insure that the proposed operations produce power which is marketable in the area power system.

k. Sources of Power Values.

(1) In most cases, the power values used by the Corps of Engineers are developed by the Federal Energy Regulatory Commission. FERC has experience in power value work and has access to the basic cost and power system operation data necessary to derive accurate power values. Also, there are advantages in having the power values developed by an independent agency. However, there are occasionally cases where the Corps may find it desirable to become directly involved in power value work. One example would be where FERC staff limitations preclude timely development of power values. Another might be the case of a large or complex hydro development, where it is necessary for Corps planners to understand the mechanics of power system operation so that they can properly evaluate the projects. Working directly with system models is one of the best ways of gaining

TABLE 9-8
Alternatives to a 30 Percent Plant Factor Hydropower Plant Operating Part-time as a Peaking Plant and Part-time as a Base Load Plant

	Coal-fired Steam	50-50 Mix	Combustion Turbine
Combustion turbine capacity, MW	-	100	200
Combustion turbine capacity value, $/kW-year	-	35.00	35.00
Combustion turbine capacity benefit, $1000	-	3,500	7,000
Coal-fired steam capacity, MW	200	100	-
Coal capacity value, $/kW-year	196.40	196.40	-
Coal capacity benefit, $1000	39,300	19,600	-
Average annual energy, gWh	525.6	525.6	525.6
System energy value, mills/kWh 1/	20.05	46.78	74.17
Energy benefits, $1000	10,500	24,600	39,000
Total benefits, $1000	49,800	47,700	46,000

1/ System energy value obtained from POWRSYM analysis of Southwest Power Pool system, 1995 load year, DRI real fuel cost escalation rates, and 1990 power on-line date.

this knowledge. Finally, there may be studies where a large number of alternative plan's sensitivity analyses are being considered, and having the Corps do some of the power value work will expedite the process. However, where the Corps is directly involved, it is important for Corps personnel to work closely with FERC in developing the basic data and making the analyses.

(2) Where neither FERC nor Corps staff are available to develop power values, consulting firms which have experience in evaluation of power generation alternatives may be retained. In these cases, the consultant should follow the general procedures outlined in this manual and in FERC's Hydroelectric Power Evaluation (72).

(3) Table 3-4 lists the address of each FERC regional office and Figure 3-3 shows the geographical areas served by each. Letters requesting power values for specific projects should provide the following information:

- location of project
- expected on-line date
- discount rate and price level to be used in the analysis
- installed capacity
- average annual energy
- annual distribution of generation (by week or month)
- a discussion of the type of operation planned for the project (i.e., peaking or base load) and any operating criteria which may limit the use of the powerplant
- who is to perform the hydrologic availability adjustments

For generalized power values, it is necessary to specify only the first three items, although general information on the types of hydro plants being examined would also be useful. For pumped-storage projects, an estimate of the cost of pumping energy should be requested also. It may be desirable in some cases to request power values based on energy displacement (Section 9-6) as well as values based on the usual alternative thermal plant method.

(4) To permit adequate review of the power benefit analysis, the Corps has requested FERC to provide the following supporting information when they transmit their power values:

- name of model used in developing power values
- market area or system simulated
- basic cost of alternative power source (unadj. power values)
- values of the adjustments applied to the base power values, including:
    - hydrologic availability factor (if applied by FERC)
    - flexibility adjustment
    - mechanical availability adjustment
    - energy value adjustment
- price level and discount rate
- cost and nature of transmission facilities and transmission losses included in power values
- real fuel cost assumptions, including:
    - escalation rates
    - source of escalation rates
    - escalation period
    - beginning and ending unit fuel prices
    - incremental effect of real fuel cost escalation on power values

1. Cost-indexing Power Values. It is sometimes necessary to cost-index FERC power values to make them consistent with the cost base established for the hydro project analysis. Capacity values may be indexed with the standard construction cost index used by the Corps field office or with the Whitman-Requardt Electric Utility Construction Cost Index, which is published in *Engineering News Record's* "Quarterly Cost Roundups." Energy values may be updated using an index based upon fuel prices obtained from DOE/Energy Information Administration's *Electric Power Monthly* (83). Information on fuel prices for peaking plants can be found in *Electric Power Quarterly* (84). These reports normally lag the dates upon which the fuel prices are based by several months. More recent values for both types of plants can be obtained directly from the Energy Information Administration's National Energy Information Center. Another source of data for indexing fuel prices is the DRI *Quarterly Energy Review* (4). Where the power values are a year or more out of date, updated power values should be requested from FERC.

9-6. Energy Displacement Method.

a. General. In some systems, the best use of a hydro project's energy output is displacement of generation (energy) from existing power plants rather than displacement of the construction of an increment of a new thermal powerplant. The energy displacement method should be considered for the evaluation of small hydro plants having little or no dependable capacity and for the assessment of hydro plants to be constructed in power systems having a high proportion of expensive oil- or gas-fired generation. This method computes only energy values. The value is based on the hydro plant displacing the most expensive generation on-line at any given time, and this will vary with time of day, time of week, and time of year.

b. Computerized Production Cost Model. The "energy displacement" energy value represents the system's marginal operating cost and can be estimated most accurately using a computerized hourly production cost model (Section 6-9f). The same general techniques used for developing energy values for the alternative thermal plant method (Sections 9-5d through 9-5g) apply to this method as well. The system marginal operating cost is a system cost and requires no further energy value adjustment. Real fuel cost escalation should be applied to all components when developing this system cost.

c. Manual Load-Duration Curve. Approximate energy values can be obtained manually from annual load duration curves. In order to provide an accurate estimate of the amount of time each type of generation is operating at the margin, the system load-duration curve must be adjusted to account for forced outages. This will cause the load duration to more closely represent a system generation-duration curve. Figure 9-9 and Table 9-9 show a simplified example of an energy value estimate performed using an annual load-duration curve. The upper portion of Table 9-9 shows the computation of the average energy value of 44 mills/kWh for the load year 1980.

d. Time-Related Factors. When the generation mix changes substantially with time, it is necessary to make energy value estimates at intervals during the first 10 to 20 years of project life. Real fuel cost escalation can be accounted for at the same time. Energy values can be computed for intervening years by interpolation, and an equivalent annual value can be derived by present-worthing techniques. Power benefits would then be computed simply by applying the equivalent annual energy value to the hydro project's energy output. Table 9-9 illustrates how the energy value might vary with time in response to changes in system mix and fuel cost escalation for the simplified system illustrated in Figure 9-9. Figure 9-10 and Table 9-10 show the computation of an equivalent annual energy value which reflects these changes.

e. Selection of Approach. The computerized production cost model models the impact of system costs and relative fuel costs most accurately and should be used when developing energy displacement values for feasibility level studies. Most FERC offices have the capability of doing this type of analysis. Where the energy value is developed using a production cost model, the hydro plant's energy output should be specified by week or month. Where a production cost model is not available, the manual load-duration curve method must be used. An annual curve can be used for reconnaissance level studies, but seasonal curves must be developed for more advanced studies. This is because generation at hydro plants usually varies seasonally and the mix of generation that would be displaced may vary seasonally as well.

f. Comparison with Alternative Thermal Plant Method.

(1) When using the energy displacement method, it is usually desirable to analyze benefits using the alternative thermal plant method as well, in order to verify that the fuel displacement method reflects the best use of the hydro project. The upper portion of Table 9-11 is an example of this comparison.

(2) When using the fuel displacement method for computing benefits, it is also necessary to show that the proposed hydro plant is the least costly way of achieving the benefits. The lower part of Table 9-11 shows that when both the hydropower plant and the thermal alternative (coal-fired steam) are compared using benefits based upon fuel displacement, the hydropower plant, since it is cheaper, accrues

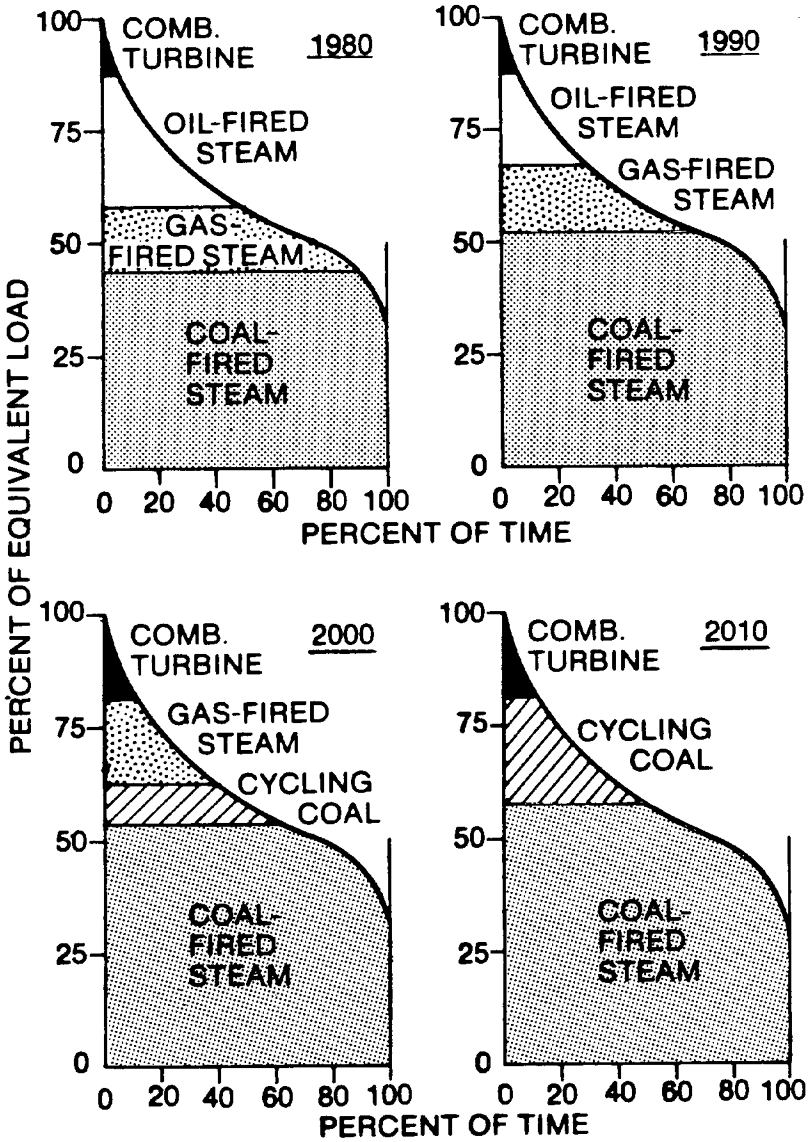


Figure 9-9. Example of variation in system generation mix with time: 1980-2010

TABLE 9-9
Variation of Average System Marginal Cost with Time

	Percent of Time on Margin Max.	Min.	Net.	Energy Value mills/kWh	Weighted Energy Value mills/kWh 1/
1980					
Combustion turbine	5	0	5	100	5
Oil-fired steam	50	5	45	55	25
Gas-fired steam	90	50	40	30	12
Coal-fired steam	100	90	10	20	2
System average			100		44
1990					
Combustion turbine	5	0	5	158	8
Oil-fired steam	30	5	25	90	22
Gas-fired steam	70	30	40	84	34
Coal-fired steam	100	70	30	32	10
System average			100		74
2000					
Combustion turbine	10	0	10	211	21
Oil-fired steam	40	10	30	125	38
Coal cycling plant	60	40	20	42	8
Coal-fired steam	100	60	40	36	14
System average			100		81
2010					
Combustion turbine	10	0	10	263	26
Coal cycling plant	50	10	40	46	18
Coal-fired steam	100	50	50	39	20
System average			100		64

1/ (Weighted energy value) =
(Energy value) x (Net percent of time on margin)

greater net benefits. Table 9-12 shows a case where the hydro plant again accrues greater net benefits when benefits are based on the fuel displacement method than when benefits are based on the coal-fired steam alternative, but here the coal-fired steam plant is less costly than the hydropower plant. Therefore, in this case, the plan with the greatest net benefits (+$40,000) is to construct the coal-fired steam plant for energy displacement. If the coal-fired plant is truly implementable and can be considered within the same time frame as the hydro plant, then the hydro plant should not be recommended, even though it is justified using the energy displacement method.

g. Combination of Methods. In some systems, there may be opportunities in the near term for displacement of high cost energy from existing thermal plants, but, in the long run, these thermal plants would be retired or replaced with other types of generation.

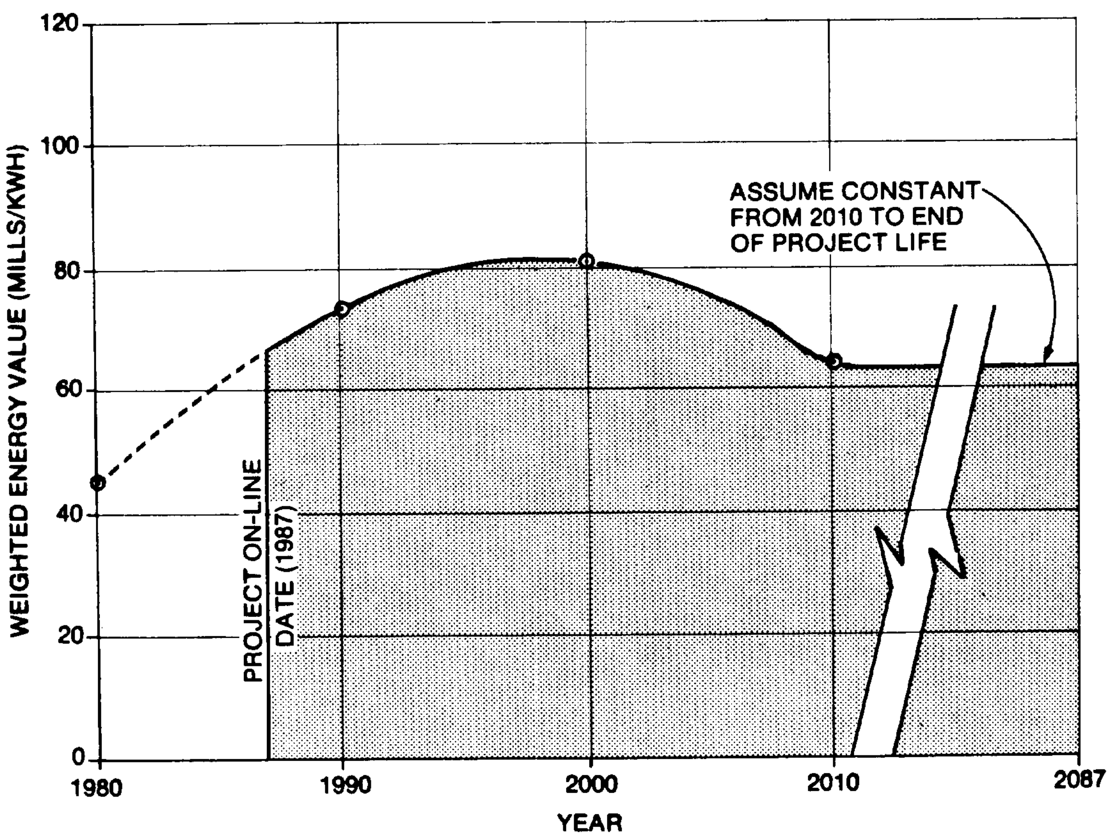


Figure 9-10. Variation of energy value with time due to fuel cost escalation and changes in system energy mix

TABLE 9-10
Equivalent Annual Energy Value Reflecting Real
Fuel Cost Escalation and Changes in System Generation Mix

Year	Years after POL	Fuel cost 1/ (mills/kWh)	Discount factor at 7-7/8%	Present worth (mills/kWh)
1980	-	44.0	-	-
1987	POL	67.8	-	-
1988	1	69.9	0.9270	64.8
1989	2	71.9	0.8593	61.8
.	.	.	.	.
.	.	.	.	.
2009	22	66.9	0.1887	12.6
2010	23	64.0	0.1749	11.2

Sum of present worth (years 1-23, growth period) = 799.3
Sum of present worth
(years 23-100, constant fuel price) 2/ = 141.4
940.7

Adjusted Energy Value 3/
Equivalent annual fuel cost, mills/kWh =
(940.7)x(A/P, 7-7/8%, 100 years) = (940.7)x(0.0788) = 74.1
Variable O&M cost, mills/kWh 4/ = 3.2
Total energy cost at bus bar, mills/kWh 5/ 77.3

1/ Values from Figure 9-10

2/ (64.0 mills/kWh)x(P/A, 7-7/8%, 100 yrs - P/A, 7-7/8%, 23 yrs) = (64.0 mills/kWh)x(12.69 - 10.48) = 141.4 mills/kWh.

3/

$$\frac{A}{P} = \frac{i}{1 - \frac{1}{(1+i)^n}} \quad \text{and} \quad \frac{P}{A} = \frac{1 - \frac{1}{(1+i)^n}}{i}$$

where: A/P = interest and amortization factor
P/A = present worth factor for equal annual payments
n = number of years
i = interest rate expressed as a decimal fraction

4/ Weighted combination of operation and maintenance costs for combustion turbine and coal-fired steam plants.

5/ Does not include transmission costs or losses.

TABLE 9-11
Comparison of Energy Displacement
and Alternative Thermal Plant Methods (Case A)

Cost of Hydropower Project Compared to Benefits Based on Energy Displacement and Coal-fired Steam

	Benefits Based on Energy Displacement	Benefits Based on Coal-fired Steam
Benefits, $1000	120 1/	100 2/
Costs, $1000 3/	80	80
Net benefits, $1000	40	20

Energy Displacement Benefits Compared to Cost of Coal-fired Steam and Hydropower Project

	Coal-fired Steam	Hydropower Project
Benefits, $1000 1/	120	120
Costs, $1000	100 4/	80 3/
Net benefits, $1000	20	40

1/ Benefits based upon energy displacement
2/ Benefits based upon alternative coal-fired steam plant
3/ Cost of hydropower project
4/ Cost of alternative coal-fired steam (same as 2/)

In the example shown on Figure 9-9, gas-fired steam is phased out by the year 2000 and oil-fired steam is phased out by 2010. Thus, in some cases, the hydro plant might best be used to displace generation from existing plants during the early years of project life, and replace an increment of new thermal generation during the remainder of its life. An analysis of this type would involve using both the energy displacement method and the most likely thermal alternative method. Each method would be applied to the appropriate portion of the project life, and present-worthing techniques would be used to derive an equivalent average annual benefit.

TABLE 9-12
Comparison of Energy Displacement
and Alternative Thermal Plant Methods (Case B)

Cost of Hydropower Project Compared to Benefits Based on Energy Displacement and Coal-Fired Steam

	Benefits Based on Energy Displacement	Benefits Based on Coal-Fired Steam
Benefits, $1000	120 1/	80 2/
Costs, $1000 3/	100	100
Net benefits, $1000	20	-20

Energy Displacement Benefits Compared to Cost of Coal-Fired Steam and Hydropower Project

	Coal-Fired Steam	Hydropower Project
Benefits, $1000 1/	120	120
Costs, $1000	80 4/	100 3/
Net benefits, $1000	40	20

1/ Benefits based upon energy displacement
2/ Benefits based upon alternative coal-fired steam plant
3/ Cost of hydropower project
4/ Cost of alternative coal-fired steam plant (same as 2/)

9-7. Annual Costs. Standard Corps of Engineers cost-estimating procedures are to be used for developing hydro project annual costs. Data should be developed for amortized annual investment costs, interim replacement costs, and operation and maintenance costs. For pumped-storage plants, estimated annual pumping costs should also be included. Costs and benefits are usually compared at the load center, and the transmission costs associated with the hydro plant must be included (see Section 9-5g). Further information on computing hydro plant costs is provided in Chapter 8, including an example of a typical annual cost computation.

9-8. Scoping of Hydro Projects.

a. General. A number of alternative plans are usually considered when determining the best plan for developing a new dam site or modifying an existing project. This section lists some of the types of alternative developments that may be considered at hydro plants, illustrates several typical plant-sizing exercises, and discusses some of the scoping considerations unique to hydropower.

b. Types of Alternative Plans. Following is a list of some of the common alternatives that could be considered in selecting the proper development at hydro projects:

- alternative dam sites
- alternative project configurations
- alternative dam heights
- provision of seasonal power storage
- alternative seasonal power storage volumes
- provision of daily/weekly pondage (to firm peaking capacity)
- alternative plant sizes
- alternative sizes and numbers of units

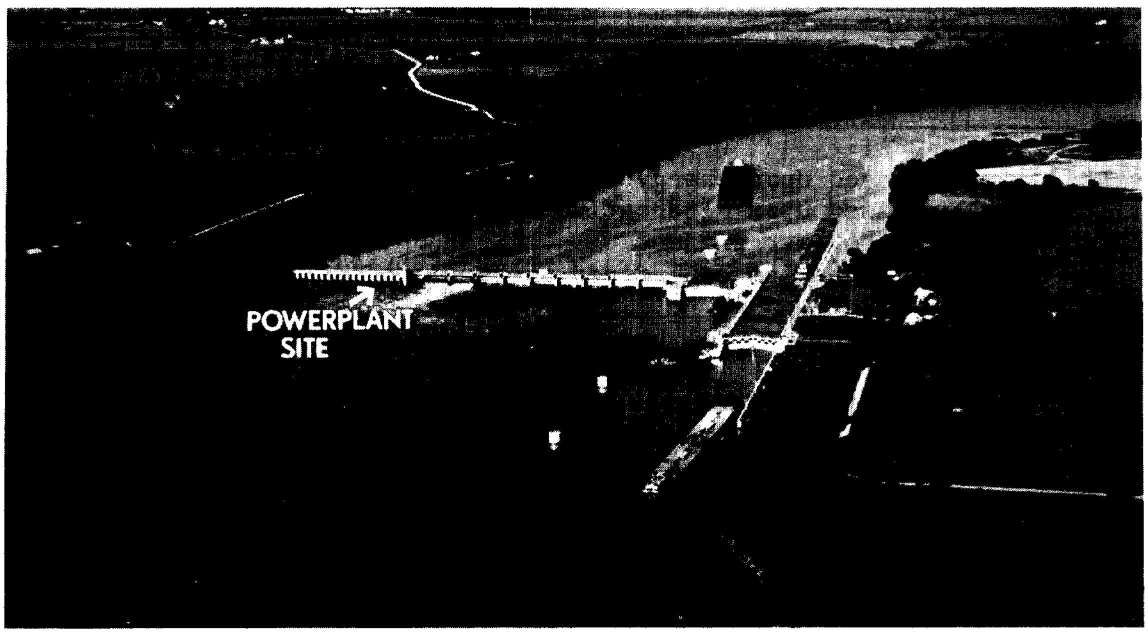


Figure 9-11. Potential small-scale hydropower installation at Dresden Island Lock and Dam. This is the same type of project as is illustrated in Table 9-14. (Rock Island District)

- alternative types of plant operation (peaking vs. base load, etc.)
- provision of reregulating dam (to firm up peaking capacity)
- installation of reversible units (to firm up peaking capacity)
- alternative development schemes (for multiple-project system)
- benefits based upon alternative thermal plant vs. energy displacement method
- use of hydro to provide system spinning reserve.

Obviously, not all of these alternatives need to be examined in detail for each project. Some apply only to new projects, some apply only to storage projects, and some apply only where operating and physical conditions permit use of hydro for peaking. Non-power operating limits and the needs of the power system, for example, may limit the range of alternatives that need to be examined in detail. The parameters listed above are, for the most part, single-purpose power considerations. Multiple purpose project planning adds another dimension to the scoping process. However, detailed examination of a wide range of alternatives is both expensive and time-consuming. Every effort should be made to reduce the range of alternatives to a reasonable number early in the planning process.

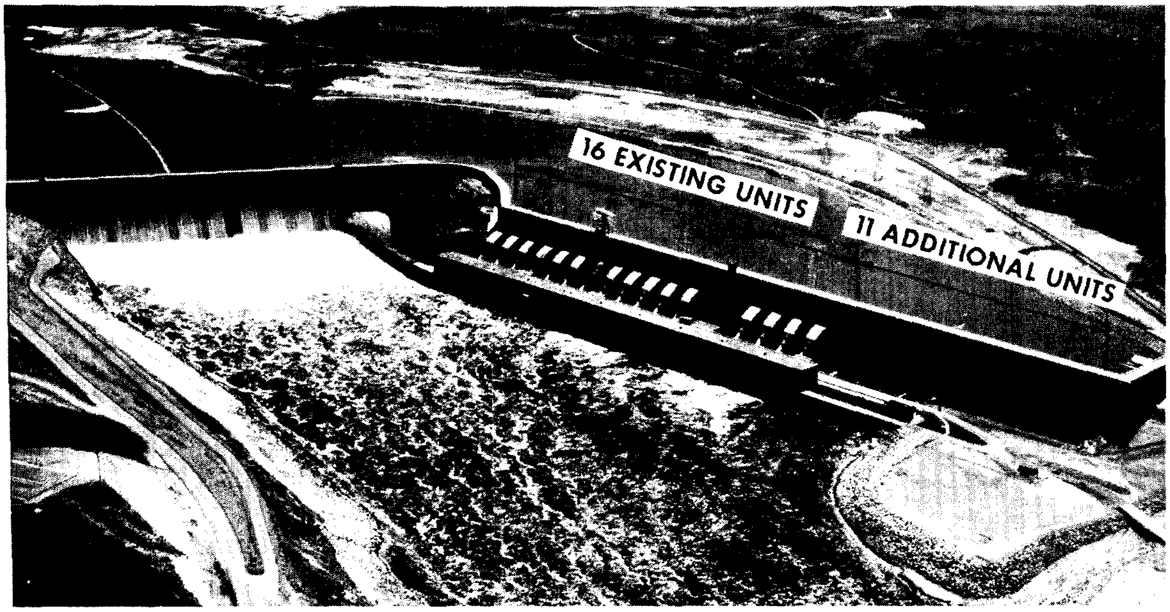


Figure 9-12. Powerplant expansion for peaking at Chief Joseph Dam. This is the same type of project as is illustrated in Table 9-15. (Seattle District)

c. Examples of Plant Sizing.

(1) General. One of the most common exercises relating to hydropower planning is plant sizing, and Chapter 6 describes the details involved in selecting a range of plant sizes. Tables 9-13 through 9-16 and Figures 9-13 through 9-16 illustrate some typical plant-sizing situations, including:

- single-purpose hydro project with storage
- small scale run-of-river hydro plant
- expansion of existing powerplant for peaking
- off-stream pumped-storage project

(2) High Head Storage Project. Note that in the case of the first example (Table 9-13 and Figure 9-13), storage as well as plant size is a variable (storage increases with pool elevation). Plant sizes based upon three different plant factors were tested for each pool elevation. This is a screening analysis, so generalized power values from Table 9-7 were used. The analysis shows that the higher pool elevations and firm plant factors in the 40 to 60 percent range yield the greatest net benefits, and these combinations would then be studied in greater detail.

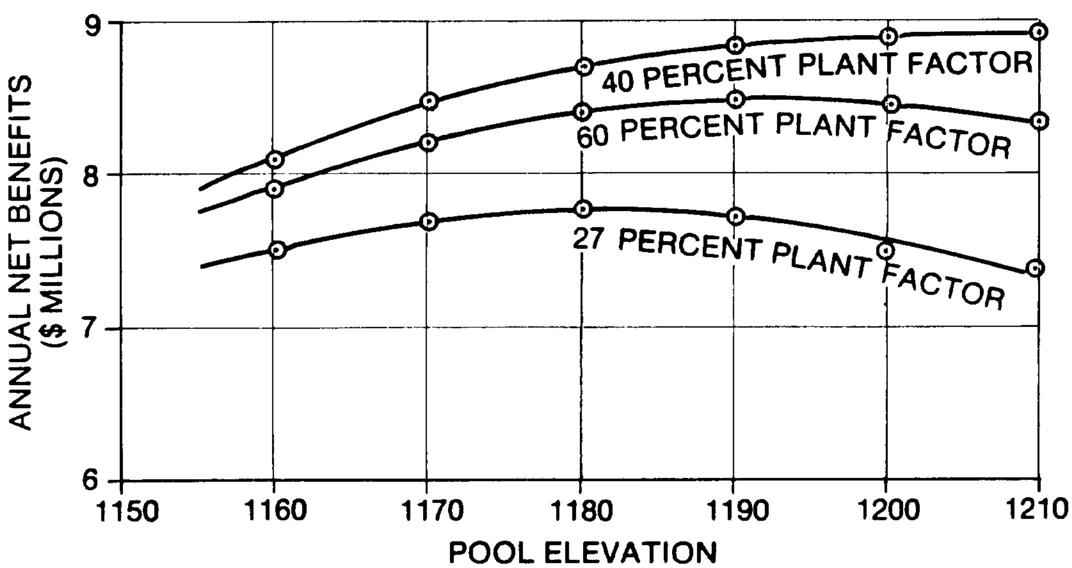


Figure 9-13. Net benefit analysis for high head storage project

TABLE 9-13
Net Benefit Analysis - High Head Storage Project

Pool Elevation	Installed Capacity (MW)	Dependable Capacity (MW)	Capacity Value 1/ ($/kW-yr)	Capacity Benefit ($1000)	Avg. Ann. Energy (gWh)
60% P. F.					
El. 1160	57.9	57.9	196.4	11,400	330.6
El. 1180	61.8	61.8	196.4	12,100	342.6
El. 1200	65.7	65.7	196.4	12,900	353.9
40% P. F.					
El. 1160	86.8	86.8	196.4	17,000	345.9
El. 1180	92.8	92.8	196.4	18,200	354.3
El. 1200	98.5	98.5	196.4	19,400	361.5
27% P. F.					
El. 1160	132.5	132.5	196.4	26,000	357.9
El. 1180	137.2	137.2	196.4	26,900	363.4
El. 1200	141.7	141.7	196.4	27,800	366.5

	Energy Value 1/ (mills/kWh)	Energy Benefit ($1000)	Total Benefit ($1000)	Annual Cost ($1000)	Net Benefit ($1000)
60% P. F.					
El. 1160	38.6	12,800	24,200	16,300	7,900
El. 1180	38.6	13,200	25,300	17,000	8,300
El. 1200	38.6	13,700	26,600	18,200	8,400
40% P. F.					
El. 1160	27.8	9,600	26,600	18,600	8,000
El. 1180	27.8	9,800	28,000	19,300	8,700
El. 1200	27.8	10,000	29,400	20,500	8,900
27% P. F.					
El. 1160	12.8	4,600	30,600	23,100	7,500
El. 1180	12.8	4,700	31,600	23,800	7,800
El. 1200	12.8	4,700	32,500	25,100	7,400

1/ Power Values From Table 9-7

(3) Small Run-of-River Project. In the case of the run-of-river project (Table 9-14 and Figure 9-14), dependable capacity is based on the average availability method (Section 6-7g). Since the project will be operated base load at plant factors in the 40 to 90 percent range, coal-fired steam was used as the alternative. Because of the variable seasonal distribution of the hydro energy output, energy benefits were based on values developed using a system production cost model (such as POWRSYM, see Section 6-9f).

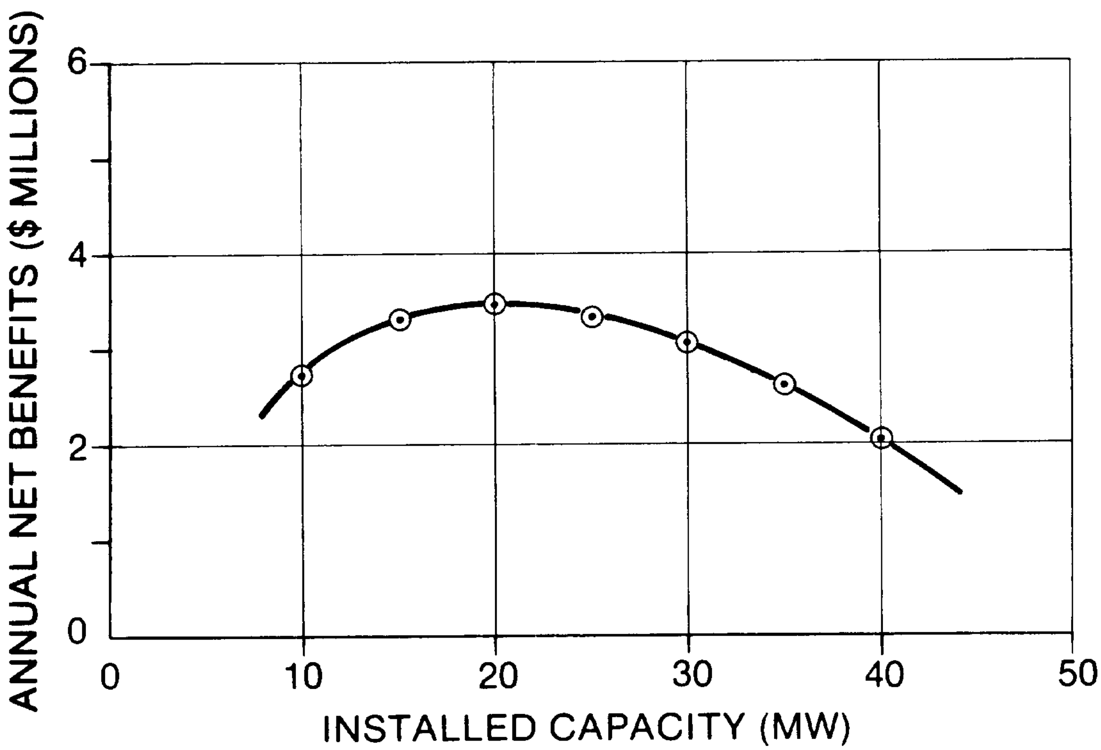


Figure 9-14. Net benefit analysis
for small run-of-river project

TABLE 9-14
Net Benefit Analysis - Small Scale Run-of-river Project

Installed Capacity (MW)	Hydrologic Availability (percent)	Dependable Capacity (MW)	Capacity Value ($/kW)	Capacity Benefit ($1000)
10.0	98.9	9.9	$196.40	1940
15.0	91.1	13.7	196.40	2690
20.0	78.1	15.6	196.40	3060
25.0	66.7	16.7	196.40	3280
30.0	57.3	17.2	196.40	3380
35.0	50.5	17.7	196.40	3480
40.0	45.0	18.0	196.40	3540

Installed Capacity (MW)	Average Energy (gWh)	Energy Value 1/ (mills/kWh)	Energy Benefits ($1000)	Total Benefits ($1000)	Annual Costs ($1000)	Net Benefit ($1000)
10.0	78.0	43.7	3410	5350	2590	2760
15.0	97.5	41.9	4080	6770	3430	3340
20.0	111.5	42.0	4680	7740	4270	3470
25.0	122.4	42.5	5200	8480	5110	3370
30.0	130.7	43.2	5650	9030	5960	3070
35.0	137.3	43.5	5970	9450	6800	2650
40.0	142.1	43.7	6210	9750	7640	2110

1/ Energy values from system analysis model, based on an alternative thermal plant having an installed capacity equivalent to the hydro plant (Equation 6-7).

(4) Powerhouse Expansion. In the case of the powerhouse expansion (Table 9-15 and Figure 9-15), the purpose of the added units is for peaking, so the combustion turbine was used as the thermal alternative ($35/kW-yr). The added hydro units pick up some energy that was previously being spilled, but this energy is generated in the off-peak months, so its value is limited to displacement of coal-fired steam generation from existing plants (36.6 mills/kWh). The major benefit attributable to the added units is the reshaping of the existing daily generation pattern. The larger plant capacity will permit water presently being spilled at night and on weekends to be stored for release during peak demand hours, when energy has a higher value. This increase in the value of existing generation is called the system energy benefit and is derived using a production cost model analysis. The benefits attributable to both the recovered spill and the reshaped existing generation are included in the energy benefits obtained from the production cost analysis.

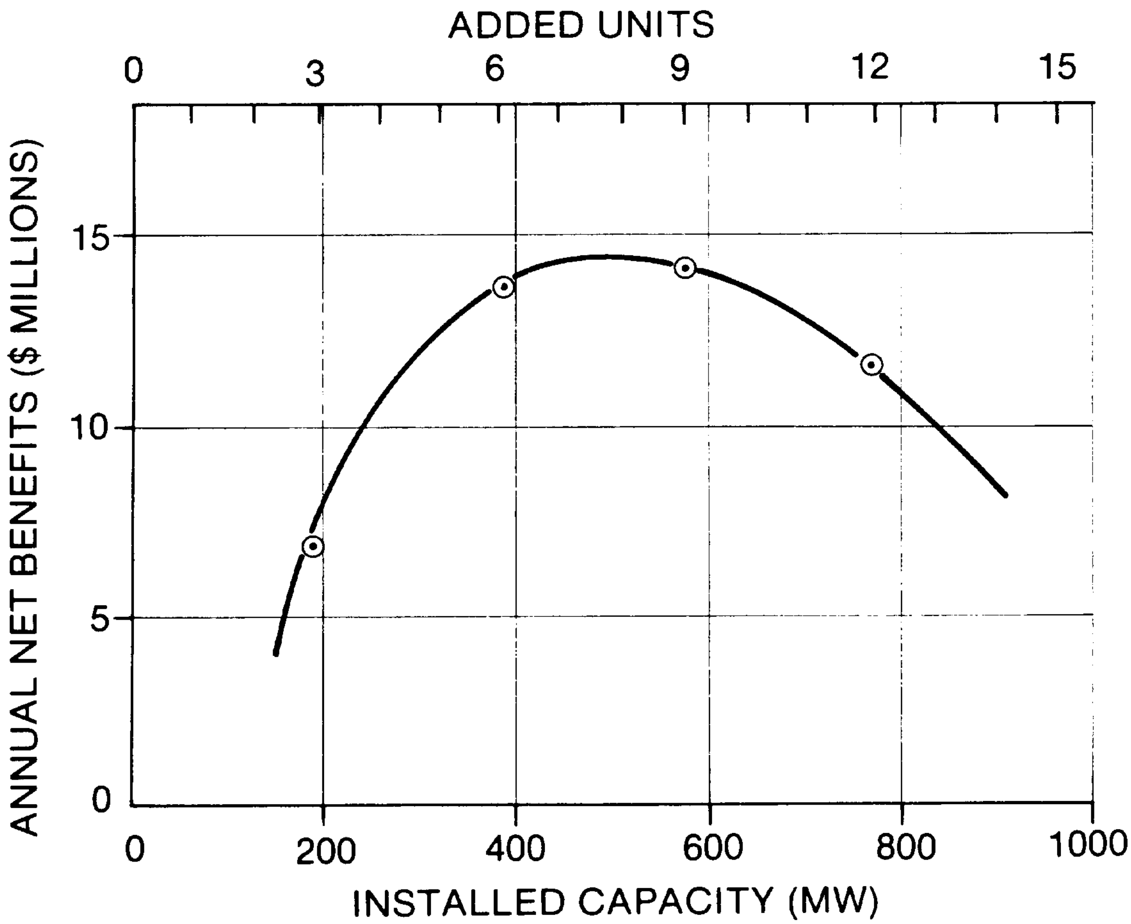


Figure 9-15. Net benefit analysis for powerhouse expansion for peaking

TABLE 9-15
Net Benefit Analysis - Powerhouse Expansion for Peaking Plant

Number of added units	3	6	9	12
Installed capacity, MW	192	384	576	768
Capacity Benefit				
Dependable capacity, MW	192	371	525	662
Capacity value, $/kW-yr 1/	35	35	35	35
Capacity benefit, $1000	6,700	13,000	18,400	23,200
Energy Benefit				
System energy benefit, $1000 2/	20,600	29,600	33,700	34,600
Net Benefits				
Total benefits, $1000	27,300	42,600	52,100	57,800
Average annual costs, $1000	20,400	29,000	37,400	46,200
Annual net benefits, $1000	6,900	13,600	14,700	11,600

1/ From Table 9-3
2/ From production cost model analysis

(5) Off-Stream Pumped Storage Project. For the off-stream pumped-storage project (Table 9-16 and Figure 9-16), it is assumed that the daily/weekly storage volume is fixed and that the variable is the number of hours of equivalent full-load generation that the project could produce each weekday with that storage volume. The 4.9 hour installation (405 MW) would be a daily cycle plant, while the other plants would have weekly cycle operations (Section 7-2d describes how a pumped-storage project's installed capacity can be determined, given the reservoir storage volume and the operating cycle). The net benefit analysis shows the 4.9 hour daily cycle plant to have the greatest net benefits, but a marketability analysis may show that the minimum number of daily hours of on-peak generation that power users are willing to purchase may be greater than 4.9 hours. Capacity benefits are based upon the combustion turbine peaking alternative, and energy benefits and average pumping cost values were obtained from production cost model analyses.

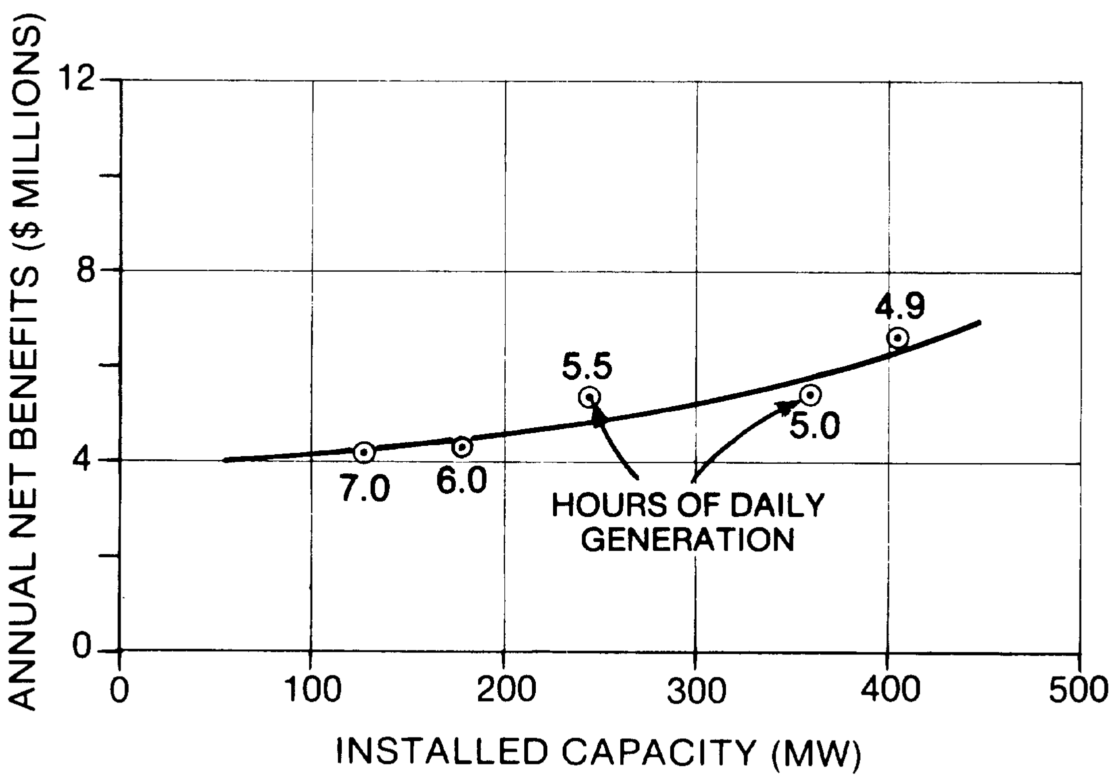


Figure 9-16. Net benefit analysis for off-stream pumped-storage project

TABLE 9-16
Net Benefit Analysis - Pumped-Storage Project

Hrs. of Daily Gen.	Installed Capacity (MW)	Plant Factor 1/ (percent)	Capacity Benefit 2/ ($1000)	Average Energy (gWh)	Energy Benefit 1/ ($1000)	Energy Value 3/ (mills/kWh)
4.9	405	6.2	14,200	220	21,100	96.0
5.0	359	6.8	12,600	213	19,800	92.9
5.5	246	10.5	8,600	226	19,500	86.3
6.0	183	12.5	6,400	200	16,400	82.0
7.0	128	16.0	4,500	179	14,000	78.2

Installed Capacity (MW)	Annual Project Costs ($1000)	Annual Pumping Cost 3/ ($1000)	Pumping Energy Value 4/ (mills/kWh)	Total Annual Costs ($1000)	Total 5/ Annual Benefits ($1000)	Annual Net Benefits ($1000)
405	16,700	12,000	38.2	28,700	35,300	6,600
359	15,500	11,500	37.8	27,000	32,400	5,400
246	11,300	11,400	35.3	22,700	28,100	5,400
183	8,700	9,800	34.3	18,500	22,800	4,300
128	5,800	8,300	32.4	14,100	18,500	4,400

1/ From production cost model analysis
2/ (Capacity benefit) = (Installed capacity) x ($35/kW). Installed capacity at this project is fully dependable.
3/ Energy value = (Energy benefit)/(Average annual energy)

4/ Pumping energy value = $\dfrac{\text{(Annual pumping cost)}}{\text{(Average energy)/(70\% cycle efficiency)}}$

5/ (Total annual benefit) = (Energy benefits) + (Capacity benefits)

d. Selection of Recommended Plan.

(1) Current Corps procedures and policies are to be followed in selecting the recommended plan. A key element in these policies consists of developing an NED plan. The NED plan is that plan which maximizes either net economic benefits or net NED benefits and is generally the plan which must be recommended for implementation. Special care must be taken in the formulation process to insure that (a) the recommended project's power operation is compatible with non-power river uses and other project functions, and (b) the project output can be used effectively in the power system and is readily marketable by the regional Federal Power Marketing Administration (PMA). To insure that this is done, close coordination with the PMA should be maintained throughout the planning process. Another important consideration is that the recommended plan must be a complete plan: i.e., all costs required to realize the project's benefits should be included. For example, if the project is to be a peaking facility, the cost of a reregulating dam or measures to protect the downstream channel and adjacent streambanks should be included.

(2) For some hydro projects, the NED plan may underdevelop the energy potential of the site. Recommending a plan which departs from the NED plan because it would more fully develop the site's potential is sometimes permitted, but such recommendations would have to be consistent with current Corps policy. Factors which have been be considered in the past for supporting a larger plant size include (a) reducing use of non-renewable resources, (b) reducing the adverse environmental impacts associated with thermal generation, (c) reducing dependence on foreign oil imports and the attendant economic and national security problems, and (d) enhancing project reliability and flexibility. Inflation-free analyses can also be used as sensitivity studies to assist in the selection of the proper plant size, and testing of alternative project on-line dates may also serve to identify a plan which yields greater net benefits. Another strategy which could ultimately permit full development of a site's potential would be to design the project for staged development. The initial installation could be based upon the current NED plan, but provision would be made for expansion in case additional generation should become economically feasible in the future. Such a design could include structural provisions for future units (Section 9-10b), or it could simply consist of allowing space for such an installation.

9-9. Financial Feasibility.

a. Section 5 of the Flood Control Act of 1944 (PL 78-534), as amended by the Department of Energy Reorganization Act of 1977 (PL

95-91), provides that electric power generated at Corps of Engineers reservoir projects that is not required in the operation of such projects shall be delivered to the Department of Energy for marketing. Rates for sale of such power are established to insure that the cost of producing and transmitting that power (including repayment of the Federal investment with interest) shall be recovered in a reasonable period. Fifty years has been established by law and administrative practice as the repayment period. The Act further specifies that preference in the sale of power shall be given to public bodies and cooperatives. Responsibility for marketing has been assigned to five regional Power Marketing Administrations (PMA's) within the Department of Energy.

b. To insure that the requirements of these Acts are met, the Corps includes in each feasibility report a statement from the appropriate regional PMA indicating that power from the project can be marketed and that project costs allocated to power can be repaid with interest in 50 years. Statements of this type should also be included in General Design Memoranda to confirm that the project continues to be financially feasible.

c. The discount rate and period of analysis used in a repayment study for a given project frequently differs from the discount rate and period of analysis used in the economic analysis. This is because different laws and procedures govern the repayment process analysis than govern Federal water resources planning. Primarily because of these differences, some projects that are economically feasible may not pass the financial feasibility test and vice versa.

d. Power from most Corps projects is marketed on a system basis, through one of several regional or river basin marketing arrangements. Power from these projects is marketed at average system rates, which reflect the costs associated with older, relatively inexpensive projects having low interest rates as well as the higher costs associated with newer projects. A project usually passes the financial feasibility test, because these average rates are substantially lower than would be required to amortize the costs of new alternative sources of power. Where generation is marketed on an individual project basis, financial feasibility is much more difficult to achieve.

e. The addresses and service areas of the regional PMA's are shown on Table 3-3. Requests for marketability and financial feasibility studies for projects located outside of the service areas of established PMA's should be addressed to:

Office of Power Marketing Coordination
Department of Energy
Room 6B-104, Forrestal Building
Washington, DC 20585

f. Letters of request to regional PMA's should include the following information:

- location of project
- installed capacity
- average annual energy output and seasonal distribution of generation
- anticipated power on-line date
- investment costs allocated to power
- annual OM&R costs allocated to power
- price level (year) of costs
- project life and interest rate
- description of expected power operation and any operating constraints which might restrict the use of the power.

g. The procedures and policies described above have been in effect since 1944. However, it should be noted that national water resources development policies continue to evolve. Care should be taken to insure that the latest policies and procedures are followed.

9-10. Special Problems.

a. Introduction. Because of the wide variety in potential hydro developments, and the wide variety and dynamic nature of power systems in which the hydro projects might be operated, it is not possible in a manual of this type to describe all of the types of analysis that might be encountered. However, some of the most commonly encountered special analysis problems are discussed in this section.

b. Minimum Provisions for Future Power Installations.

(1) At some projects, installation of power may not prove feasible at the time planning or design is initiated, but the addition of generation at a later date may be attractive. In other instances, increases in the value of power following authorization may render a previously unfavorable hydro installation feasible, but this finding may come too late in the design process to incorporate the powerplant in the initial construction phase. These situations are covered by

the Flood Control Act of 1938 and subsequent Flood Control and River and Harbor Acts, which state that:

> "Penstocks and other similar facilities adapted to possible future use in the development of hydroelectric power shall be installed in any dam authorized in this Act for construction of the Department of the Army when approved by the Secretary of the Army on the recommendation of the Chief of Engineers and the Federal Power Commission."

The Federal Power Commission is now the Federal Energy Regulatory Commission.

(2) Guidance for this type of analysis is contained in ER 1110-2-1, Provision for Future Hydroelectric Installation at Corps of Engineers Projects, which states that hydroelectric power potential must be investigated, where feasible, in conjunction with all Corps of Engineers water resources feasibility reports and/or design memoranda. In view of the increased value of energy, a number of Corps projects which are in planning and engineering or construction stages may support minimum provisions for future hydropower facilities. To obtain approval of the Secretary of the Army for incorporating minimum power provisions in these projects, a letter report or supplement to an applicable design memorandum should be forwarded to DAEN-ECE for review and OCE/HQ recommendation, and to the Secretary of the Army for approval. Minimum facilities should be those necessary to avoid major reconstruction and/or interruption to other project purposes should full power facilities be installed at some future date. The format and content of the required letter reports are discussed in ER 1110-2-1. The hydropower benefits would be computed in the same manner as for other types of hydropower studies.

(3) ER 1110-2-1 applies primarily to projects where minimum hydropower provisions were not installed in the initial construction stage. The same type of analysis must be applied where skeleton bays or other minimum provision for future units are included as a part of the installation. The incremental cost of these minimum provisions for additional units must in most cases be carried by the expected benefits accruing to those units. In these cases, coordination with FERC on the future units is usually handled as a part of the analysis of the initial installation.

c. Expansion of Existing Powerplants.

(1) Existing powerplants may be expanded to capture energy now being spilled, to increase a project's peaking capability, or for both reasons. Analysis of projects which are being expanded to capture spilled energy is relatively simple. Power benefits are based upon

the incremental increase in dependable capacity and average energy creditable to the added units. This type of analysis would be based upon either the displaced energy method or the alternative thermal plant method, using the least costly thermal alternative which is consistent with the type of operation planned for the added unit. For example, if the incremental plant factor were greater than 40 percent and the units would be operated in the run-of-river mode, the thermal alternative would probably be coal-fired steam. For lower plant factors, it may be necessary to test several alternatives to determine which is least costly.

(2) Analysis of added units for peaking is more complex. In most cases, the operation of the existing installation is changed in the process. Water originally passing through the existing units during off-peak hours would be shifted to the new units during the peak demand hours. The project would then be credited with (a) an increase in the value of some (or all) of the existing generation, (b) the dependable capacity credited to the added units, and (c) possibly some captured spill. Figure 9-17 illustrates how the daily generation pattern might be modified by plant expansion. The capacity benefits accruing to the added units will usually be based on combustion turbines, which have relatively low capital costs. Therefore, the bulk of the benefits from added units will usually come from the increased value of existing energy output. This increased value would be reflected in the system energy cost computations described in Section 9-5e. Section 9-8c(4) illustrates an example of a benefit analysis of added units for peaking.

(3) Evaluations of this type can be made with accuracy only by using hourly system production cost models. In requesting power values for this type of project, it is necessary to specify both energy and peaking capability by week or month, as well as the generation required to meet minimum flow requirements and any other operating constraints which might affect peaking operation.

(4) Development of a meaningful unit energy value is difficult during evaluation of added units for peaking, because many peaking additions result in the addition of little or no energy (in some cases, there may even be a net energy loss). If the units do capture additional energy, this energy is usually secondary energy produced in high flow periods rather than peaking energy. Two approaches can be taken to present energy benefits in lieu of the usual procedure of developing a unit energy value to be applied to the incremental energy output of the added units. Regardless of which approach is taken, it is important to keep in mind that the energy benefit would be a system energy benefit: i.e., the difference in total power system operating cost between the system with the added units and the system with the

thermal alternative. The first (and preferred) way to display this benefit would be to simply show the net system benefit, in dollars, as obtained from the system production cost studies.

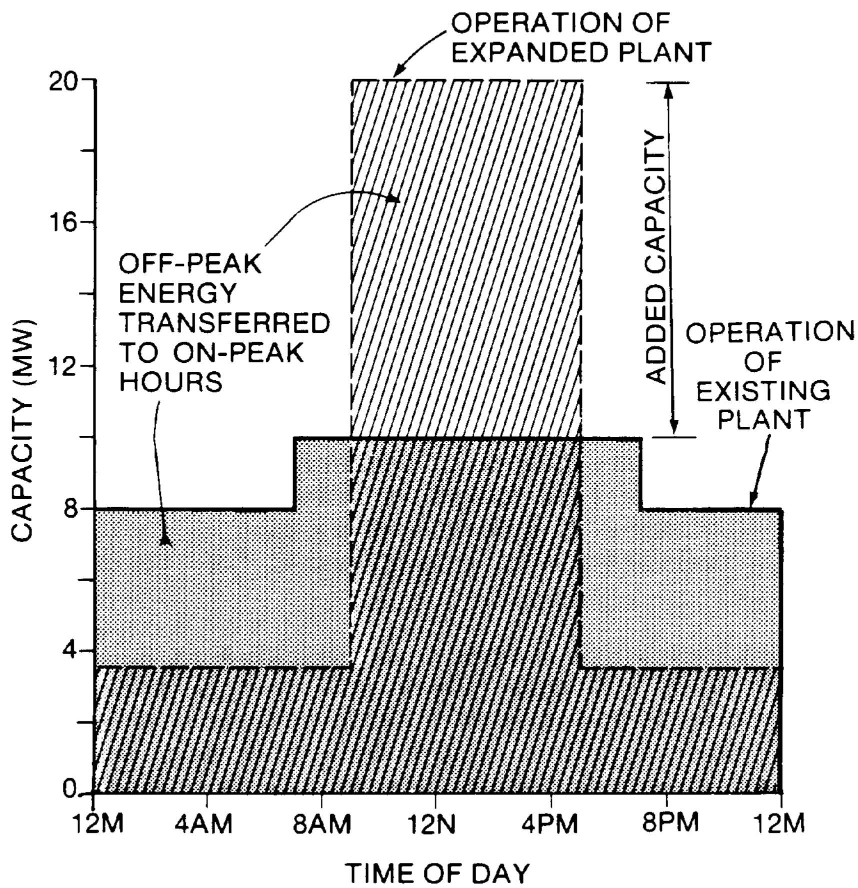


Figure 9-17. Modification of project operation resulting from plant expansion

(5) The second approach would be to combine the energy benefit with the capacity value to develop an "energy adjusted" capacity value. This approach is sometimes used by FERC. For example, a 200 MW peaking addition might produce a net annual system energy cost savings of \$10,000,000, compared to a system including an equivalent amount of combustion turbine capacity. Assume that the \$35.00/kW-yr capacity value developed in Table 9-3 applies here. The net system energy savings could then be applied as a unit value to the capacity value, as follows:

$$\text{Total capacity value} = \$35.00/\text{kW-yr} + \frac{(\$10{,}000{,}000/\text{yr})}{(200{,}000\ \text{kW})} = \$85.00/\text{kW-yr.}$$

d. Off-Stream Pumped-Storage Projects.

(1) Analysis of off-stream pumped-storage projects is in many ways similar to the analysis of added units for peaking. Energy benefits are based on conversion of low-value energy produced in off-peak hours to high value on-peak energy. In the process, the system loses energy due to inefficiencies in pumping, generating, and transmission. Capacity benefits are usually (but not always) based on combustion turbines. The net energy benefits are best computed by using an hourly system production cost model (Section 7-5). The energy benefits attributable to pumped-storage project operation can be presented in two ways: (a) the net system energy savings, which would be the difference in system operating costs with and without the pumped-storage project, and (b) the system energy benefits, which would have the pumping costs removed. However, because the value of the generation must be included on the benefit side of the benefit-cost equation and the value of pumping energy must be included on the cost side, the two components must be segregated (see Sections 7-5h, 8-5e, and 9-8c(5)).

(2) Most pumped-storage projects are operated on an economic dispatch (Section 7-2c). In these cases, the average annual energy and annual pumping energy requirements can be obtained only from the hourly production cost analysis. Where the system generation mix and/or the relative values of pumping energy and on-peak energy change with time, it will be necessary to make energy benefit analyses for a series of representative years covering the first 10 to 20 years of project life. Analysis of the benefits at intervals in the early years of project life is important because a pumped-storage project's value to the system frequently increases with time (see Section 7-3d).

(3) The analysis of a pumped-storage project is heavily dependent upon assumptions with respect to operating cycle and reservoir storage. These subjects are also treated in Chapter 7.

e. Reservoir System Power Benefits. One of the potential reasons for constructing a headwater storage project is to increase the power output of downstream projects. Downstream power benefits are very important, because the economic feasibility of the relatively expensive headwater storage projects often hinges on these benefits. Likewise, the feasibility of a downstream project is sometimes dependent on the availability of headwater storage regulation. System analysis is required to properly evaluate situations like these, where the benefits that accrue at one project are dependent on the operation of another project. Although the analysis of reservoir power system benefits is simple in concept, the application can be rather complex, especially if more than one reservoir is involved. Appendix Q describes how system power benefits are computed and allocated among the projects that make up a system.

f. Staging of Hydropower Projects.

(1) Most of the examples of power benefit analysis discussed in previous sections are based upon all of the hydro project's generating capacity coming on-line in a single year. At some projects, the capacity may be scheduled to come on-line in stages. Two types of staging situations may be encountered: (a) the absorption of a large project into the system load over a period of years and (b) the staging of various units over a period of time. In both cases, present-worthing techniques are used to convert the benefits, which vary in the early years of project life, to an average annual equivalent.

(2) In the first case, the major effect of staging will be on capacity benefits. A peak load-resource analysis would be made to determine the amount of capacity that is usable (and for which benefits can be claimed) year by year until the project is fully usable in the load. In some cases, there may be an effect upon energy benefits as well. For example, when a hydro project is added to a very small system, several years may be required to absorb the project's energy output. Table 9-17 illustrates benefit computations for a project of this type. The data on load and capacity requirements was obtained from a load-resource analysis of the type described in Sections 3-3 and 3-10. In most cases, however, the full energy output of a hydropower project can be used from the start. That energy which is not used to meet the increase in power demand would be used to displace existing generation.

(3) The second situation is where units are scheduled to come on-line at intervals over a period of years. Here, benefits are computed as they are realized and present-worthed to determine the average annual equivalent benefit. Care must be taken to insure that interest during construction (IDC) is properly accounted for on the

TABLE 9-17
Annual Benefits for Project Which Requires Several Years for its Output to Become Fully Usable

	1990	1991	1992	1993	1994	1995
System peak load, MW	99	102	105	108	111	115
Reserve requirement, MW	20	20	21	22	22	23
Total capacity required, MW	119	122	126	130	133	138
Existing capacity, MW	115	115	110	110	110	110
New capacity requirements, MW	4	7	16	20	23	28
Hydro project dependable capacity, MW	10	20	20	20	20	20
Useable dependable capacity, MW 1/	4	7	16	20	23	28
Capacity value, $/kW-yr	80	80	80	80	80	80
Capacity benefit, $1000	320	560	1280	1600	1600	1600
Hydro project average energy, gWh	75 2/	87.6	87.6	87.6	87.6	87.6
Energy value, mills/kWh 3/	60	60	60	60	60	60
Energy benefit, $1000 4/	4500	5260	5260	5260	5260	5260
Total benefit, $1000	4820	5820	6540	6860	6860	6860

1/ As limited by new capacity requirements
2/ Because only 10 of the new project's 20 MW of capacity is available during the first year (1990), the full 87.6 gWh of average energy cannot be utilized.
3/ No real fuel cost escalation is included in this example.
4/ It is assumed that the project's full energy output will be useable right from the project on-line date for displacing existing thermal generation.

delayed units. Where a high discount rate must be used, the IDC component may become substantial, and careful study must be made to insure that spreading out the on-line dates is justified.

(4) A variation of the second situation would be the case where a hydro plant is constructed initially as a base load plant and is later expanded to serve as a peaking plant. Present-worthing techniques would be used for determining average annual benefits here, also. However, if the project's operation changes markedly when it is expanded, the most likely alternative may change as well, and thus energy and capacity values used for computing benefits will also change. For example, the most likely alternative may switch from a base load thermal plant to either a mix of base load thermal and combustion turbines or combustion turbines alone. Where this is the case, the with-project scenario must include provisions for replacing any base load generation formerly carried by the hydro plant.

(5) In evaluating staged projects, it is important to test alternative on-line dates in order to determine the schedule which yields the optimum net benefits (see Chapter 9 of reference (48f)).

g. Reallocation of Storage. Because of the increasing cost of electrical energy, it may be desirable to examine the feasibility of reallocating unused or marginally valuable non-power storage or flood control storage space to power (or vice versa if the relative value of storage for non-power purposes increases markedly). For the case where additional storage is allocated to power, incremental power benefits would be computed based on the additional power output gained, which could include:

- additional capacity and energy resulting from increased head
- additional at-site and downstream energy and capacity gains resulting from increased seasonal power storage
- additional dependable capacity resulting from provision of daily/weekly storage (pondage)

Power benefits would be based on the general procedures described previously in this chapter. To determine whether the reallocation is economically feasible, the gain in power benefits resulting from the reallocation would be compared with the sum of (a) the incremental loss in benefits to those functions from which storage was transferred and (b) the cost of any required project modifications. A similar analysis would be made when storage is transferred from power to another function. Care should be taken in these analyses to insure that existing water rights are properly accounted for and that compensation is allowed for any water rights which must be purchased to permit the reallocation of storage.

h. Use of Falling Water Charges. Where a non-Federal entity constructs a powerplant at a Corps project, a falling-water charge is assigned to the developer so that he will assume an equitable share of the cost of the structure that provides the benefits he is realizing. These charges are mandated by Section 10(e) of the Federal Power Act (16 USC 803(e)(1976)) and are evaluated by the Federal Energy Regulatory Commission. The Corps of Engineers is not normally involved in this process. The FERC regulation for this purpose is published in the Federal Register, Vol. 49, no. 107, Section 11.2, dated 1 June 1984.

i. Design Analyses.

(1) Estimates of the value of power are sometimes used as the basis of power project design decisions, such as sizing of penstocks, design of transformers, etc. The value of power should be based on the same basic power values that were used in analyzing the power project in the planning stage. They should, however, be updated if necessary to reflect the same price level as the design costs. For some types of analysis (penstock design, for example), both energy and capacity values are involved. In these cases it is sometimes easier to use a total power value expressed in mills/kWh. This value can be computed as follows:

$$\text{Total power value (mills/kWh)} = EV + \frac{(CV) \times (PF)}{(8760 \text{ hours/year})} \qquad \text{(Eq. 9-6)}$$

where: CV = capacity value, \$/kW-yr
PF = hydro project plant factor, decimal fraction
EV = energy value, mills/kWh

(2) Some equipment, such as transformers, produce only an energy loss. However, if that loss is a firm energy loss, an increment of thermal capacity as well as energy will be required to replace it. Hence, analyses of this type of equipment should be based on the total power value, rather than the energy value alone.

(3) Other types of equipment (spare transformers, for example) are intended to improve the reliability of the hydro plant. For multi-unit plants, a change in reliability would affect primarily the capacity benefits. An estimate of the benefits achieved by an improvement in reliability can be estimated using the following equation:

TABLE 9-18
Reduction in Energy Loss Due to
Improvement in Equipment Reliability

Units Available	Energy (gWh)	Initial Conditions FOR	Initial Conditions Loss (gWh)	With Improvements FOR	With Improvements Loss (gWh)	Reduction in Loss (gWh)
1	51	$(0.03)^3$	0.001	$(0.02)^3$	0.000	0.001
2	32	$(0.03)^2$	0.029	$(0.02)^2$	0.013	0.016
3	16	0.03	0.480	0.02	0.320	0.160
Totals	99		0.510		0.333	0.177

$$\text{Benefit} = (IC)x(CV)x \frac{(\Delta \text{ Avail})}{100\%} \qquad \text{(Eq. 9-7)}$$

where: Δ Avail = the change in overall plant availability, in percent.
IC = installed capacity, kW

Alternatively, Δ Avail could be replaced in the equation by (Δ FOR), which is the change in overall plant forced outage rate, in percent.

(4) A change in reliability may also affect the energy output of the hydro plant, especially if it has only a few units. In computing the energy loss, each unit must be treated separately. Table 9-18 illustrates how the energy losses would be reduced at a three-unit plant where the overall forced outage rate is reduced from three percent to two percent. The incremental energy production per unit is obtained from routing studies or from generation-duration curves. The expected average energy losses due to outages would be based upon the sum of the probabilities that one, two, and three units would be out of service. The summation would be obtained from the equation

$$\text{Combined probability} = (FOR)^1 + (FOR)^2 + \ldots + (FOR)^n \qquad \text{(Eq. 9-8)}$$

where: n = total number of units in the powerplant.
FOR = unit forced outage rate

Since the incremental energy output of each unit is different, the individual outage probability components must be applied to the corresponding energy values: i.e., $(FOR)^1$ would have to be applied to the incremental energy output of Unit 3, $(FOR)^2$ to Unit 2, and $(FOR)^3$ to Unit 1. In the example shown in Table 9-18, the expected average annual energy loss would be reduced by 0.177 gWh. The current energy value applicable to the hydro project would be applied to determine the average annual benefits attributable to the improvement of equipment reliability. Using the coal-fired energy value from Table 9-5, the annual benefit would be

Annual benefit = (0.177 gWh) x (36.6 mills/kWh) = $6,500.

(5) The revenue rates charged by the regional Power Marketing Administration for power produced by the hydro plant should not be used as the basis of design decisions because they do not represent the economic worth of the power.

j. Delays to On-line Dates.

(1) Occasionally it is necessary to estimate the cost of delays to on-line dates for a powerplant or individual generating units that are already under construction. The only impact on the project's benefits would be an adjustment to account for real fuel cost escalation. Other than that, the delay would only result in slightly deferring the time period in which the benefits would be realized. However, there are two economic consequences which could have an impact on project costs. The first would be an increase in the interest during construction applicable to the costs allocated to power (either for the total plant or to specific generating units, depending upon the nature of the delay). The second would be the cost to the system of purchasing replacement power to meet loads during the period of the delay. A with- and without- analysis must be made to determine any increase in energy costs that would occur to the system because of the delay. This type of information can usually be obtained from the regional Federal Power Marketing Administration (PMA) that would market the power.

(2) The computation of the cost of delays can best be illustrated by an example. Assume that the project on-line date for a 10 MW single purpose power project will be delayed three months, causing it to be unavailable during the peak demand season. During these three months, the plant would have produced peak power at a 20 percent plant factor. In order to meet contractual obligations, the regional PMA has to purchase replacement power at an average cost of 80 mills/kWh. The project, which has a construction cost of

$10,000,000, is 99 percent complete, and the applicable project interest rate is 7-7/8 percent. The cost of the delay would be computed as follows:

Cost of replacement power
$= (10{,}000 \text{ kW})(0.20)(92 \text{ days})(24 \text{ hrs})(80 \text{ mills/kWh}) = \$350{,}000$

Interest during construction
$= (\$10{,}000{,}000)(0.99)(0.07875/\text{yr})(0.25 \text{ yr}) = \$190{,}000$

Total cost of delay = $350,000 + $190,000 = $540,000

(3) Lost revenues are normally not used for this type of analysis. The reasons for not using lost revenues are (a) there will be no loss in the project's lifetime power output, only a deferral of that output, and (b) revenues do not reflect economic values. A case where lost revenue might be used would be in litigation relative to the cost of delays, where it may be necessary to identify the cost to the Government. In these cases, the analysis should be based on lost revenues.

k. Cost of Hydro Plant Outages. Sometimes it is necessary to shut down an existing powerplant (or generating unit) for an extended period of time to modify equipment or the dam structure, or for special operational reasons. When this occurs, a cost is incurred as a result of lost generation, and this cost should be included in the analysis of the outage. The cost assigned to the lost generation should be based on the cost of replacement power, generally as described in the preceding section. The cost of replacement power may vary substantially from season to season, and therefore it may be desirable to schedule the outage for a season when the cost of replacement power is lowest. Where peaking capacity is involved, the outage should be scheduled outside of the peak demand period if possible.

l. Conservation.

(1) ETL 1110-2-216, Energy Conservation for Civil Works, provides guidelines for evaluating potential energy-saving measures at Corps installations, including hydroelectric projects. A savings in electrical energy use at a hydro plant makes that energy available to the power system. Where the measure is long-term or permanent, it will result in an incremental increase in the project's firm energy output. The value of this output would be based on the power values used in evaluating the total hydro project (updated to current price levels and interest rate). These values could be used most readily by converting them to a total energy value in mills/kWh, as described in paragraph 9-10i(1).

(2) It is frequently possible to implement an energy-saving measure relatively quickly. In these cases, it may be preferable to base the value of energy on the cost of displaced energy (Section 9-6) for the first few years (until the date that the long-term power source, the alternative thermal plant, would come on-line). For the remainder of the period of analysis, power values would be based upon the alternative thermal plant.

m. Plants Smaller than 25 MW. Section 2.5.4(b) of Principles and Guidelines states that "...for purposes of ensuring efficiency in the use of planning resources, simplifications of the procedures set forth in Section V are encouraged in the case of single purpose, small scale hydropower projects (25 MW or less), if these simplifications lead to reasonable approximations of benefits and costs." It should be noted, however, that the basic procedure for computing hydropower benefits is relatively straightforward, and where power values are provided in a timely manner by FERC, computation of benefits can be accomplished quite readily. Power value computations can be simplified by basing them on a single representative year (Section 9-4c) and using simplified techniques for estimating system energy value adjustments (Section 9-5e). Reducing the number of alternative hydro plans to a minimum early in the study will also help to keep study costs in line. Other simplifications may be used, depending upon the situation. For example, a marketability analysis may be substituted for a demand analysis in some cases (see Section 3-3). However, it should not be implied from Section 2.5.4(b) of Principles and Guidelines that a marketability analysis can be substituted for the economic evaluation.

n. Non-Federally Financed Projects.

(1) Federal policies being implemented at the time this manual was being prepared encourage the financing of power facilities at Federal Water Resources projects by non-Federal entities. A non-Federal entity planning to construct and operate the hydro plant will require a FERC license. Corps of Engineers involvement in this process relates primarily to technical issues, and not economic analysis.

(2) However, where the non-Federal entity provides funds and the Corps is authorized to construct and operate the plant, the Corps must prepare a feasibility report which would include an economic analysis. Section 2.5.10 of Principles and Guidelines permits an alternative hydropower benefit evaluation procedure that may be used for evaluating "...single purpose projects that are to be 100 percent non-Federally financed, provided that there are no significant incidental costs." In essence, the procedure permits evaluation using the non-Federal entity's financial criteria. However, the formulation of

alternative plans is still subject to the other provisions of Principles and Guidelines, including evaluation of incidental benefits and costs, compliance with environmental laws, and inclusion of appropriate mitigation. Through this process, the most financially attractive plan would be identified. Because benefits and costs of all alternative plans would be evaluated in a consistent way, the most financially attractive plan can be considered a surrogate for the NED plan.

(3) In developing this analysis, Corps planners should work closely with the non-Federal entity in order to select financial evaluation criteria which properly reflect that entity's situation, and to identify those alternative power sources which are actually available to that entity. It should be kept in mind that future revenue streams are more important than power "benefits" in the analysis of non-Federally financed projects. Assistance in developing evaluation criteria can also be provided by the appropriate regional Federal Power Marketing Administration.

(4) Section 2.5.10(b) of Principles and Guidelines suggests basing benefits on industry long-run wholesale prices as one approach. Where this approach is used, it must be carefully applied to insure that the long term contract prices reflect the energy and capacity characteristics of the proposed hydropower project. Another approach would be to do a conventional benefit analysis, using the cost of the most likely thermal alternative, but based on the non-Federal entity's financial criteria.

(5) It should be noted that as of the date of this manual, for the Corps to construct a project and a sponsoring non-Federal entity to receive the power output would require legislative exemption from that portion of the 1944 Flood Control Act which requires that project-produced power be delivered to the Department of Energy for marketing. (see Section 9-9).

o. Firm and Secondary Energy.

(1) In thermal-based power systems, both firm and secondary hydro energy are equally usable in the system load, and there is seldom any need to distinguish between the two (except, in some cases, for marketing purposes). Thus, the energy values developed as described in Sections 9-5 and 9-6 can be applied directly to the project's average annual energy to obtain energy benefits.

(2) However, it is sometimes necessary in hydro-based power systems to evaluate firm and secondary energy separately. If there is normally thermal energy in the system which can be displaced by the hydro secondary energy and the energy values incorporate a system

energy value adjustment (see Section 9-5e), it is usually not necessary to assign separate values to firm and secondary energy. There are at least three situations where separate energy would be required. The first would be in an isolated system, such as in Alaska, where there may be only a limited market for the secondary energy. The second would be in systems where a secondary market normally exists, but in periods of high runoff secondary energy production exceeds the market for such power. The third would be where an export market exists for secondary energy, and where the value of energy to the importing system is different than the value of secondary energy in the system in which the hydro plant is located.

(3) In such cases, firm energy benefits would be based on the energy values defined as described in Section 9-5, and the secondary energy would be evaluated based on an estimate of the amount that would be marketable and the value of the thermal energy that would be displaced by that which is marketable. For example, at a project in Alaska it may be found that, on the average, only about half of the secondary energy is marketable and that this energy could be used to displace existing oil-fired diesel generation. The value of this energy would then be based upon the cost of the diesel generation displaced, computed as described in Section 9-6, and the remainder of the secondary energy would have no value. FERC and the regional Federal Power Marketing Administrations can offer assistance in making this type of analysis.