CHAPTER- 2

TECHNO-ECONOMIC STUDIES FOR CAPACITY AND UNIT SIZE OF HYDRO ELECTRIC SCHEMES
(Reviewed by Dr. S. K. Singal, AHEC)

2.1 Plant Capacity, Unit Size and Spare Capacity

2.1.1 Initial Development

Practice for determining plant capacity, unit size and spare capacity has been varying over the years. Initial small scale isolated development of hydro electrical power in India was confined to providing a reliable and continuously available energy for the load and was accordingly based on minimum dependable stream flows so that curtailment of load during dry years is minimized. Installation at hydro power plants and unit size was determined on this basis. The power supply was confined to isolated areas and normally one unit was provided as spare unit. This practice of determining hydro plant capacity was continued. However as demand increased integrated power systems consisting of hydro thermal regional and National grids emerged resulting in providing spare capacity (instead of spare unit) on the basis of forced outages in the grid. Additional capacity to utilize power available in wet months (secondary power) and for peaking was provided.

2.1.2 Recent Developments

Changes in the role of hydro power were necessitated because of the following reasons.

i) A large integrated hydro thermal power system has developed in which thermal, nuclear generating capacity is a very large portion of total capacity as shown below (1998).

<table>
<thead>
<tr>
<th>Type</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal</td>
<td>72.56%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2.52%</td>
</tr>
<tr>
<td>Hydro</td>
<td>24.90%</td>
</tr>
</tbody>
</table>

ii) Induction of large thermal/nuclear generating capacity in the interconnected grid provide dependable energy at flexible rate which is not dependent on vagaries of stream flow and thus provide for deficiency of energy during periods of low stream flow.

iii) Economic loading of the large capacity thermal generating station is required for overall system economies.

iv) Very high cost of nuclear and thermal energy and rapidly decreasing resources of fossil fuels has resulted in development and induction of non conventional power energy sources e.g. wind powers, small hydropower, solar power etc.

Accordingly hydro energy is used to greater economic advantage if energy supplied to the system by hydro source is maximized and spillage of water minimized and the energy is used for meeting peaking requirements. Off peak energy at low load time may be used for saving fossil fuel energy or for providing pumped storage hydro energy to provide increased system peak demands.

2.2 Economic Evaluation Criteria

2.2.1 Initial Development

Financial justification and economic evaluation was based on evaluating estimated initial costs or investment costs. Revenue for the project was the income derived from sale of power produced at the tariffs in force and thus compares financial return on the scheme with the electricity tariffs it is hoped to secure during the life of the plant.
2.2.2 Present Criteria

Principal investment and alternative cost criteria was recognized. According to these criteria, economic comparison between the proposed hydro scheme energy cost and an alternative, i.e. thermal station energy cost at the site etc, is made for the evaluation of development plans.

Accordingly computation of capacity and energy values at load centre for economic evaluation of power plants are made.

2.2.3 Present Objectives of Tariff Policy

The objectives of this tariff policy are to:

(a) Ensure availability of electricity to consumers at reasonable and competitive rates;
(b) Ensure financial viability of the sector and attract investments;
(c) Promote transparency, consistency and predictability in regulatory approaches across jurisdictions and minimize perceptions of regulatory risks;
(d) Promote competition, efficiency in operations and improvement in quality of supply.

Two-part tariffs featuring separate fixed and variable charges and Time differentiated tariff are being introduced on priority for large consumers (say, consumers with demand exceeding 1 MW). This would also help in flattening the peak and implementing various energy conservation measures.

2.3 Economic & Financial Analysis and Tariff Determination

Preliminary pre-investment economic studies are carried out to determine whether detailed feasibility studies are required. Cost for pre-investment stage may be calculated for Small Hydro (SHP) as given in Annexure-1 of the chapter. For detailed feasibility studies cost of electromechanical equipment may be calculated as per annexure-II. The civil engineering cost may also be calculated in similar way.

Large hydro of capacity more than 25 MW may require additional considerations.

Economic analysis is a quantitative evaluation of the economic feasibility of the project and gives a comparison between the benefits and costs of the projects over the life time of the project.

Financial analysis is a quantitative assessment of the ability of the project to repay the investment on a self-liquidating basis. Hence a project to be financially feasible, the anticipated revenue receipts over the life time of the project should be more than the project disbursements.

In both economic and financial analysis, recurring annual costs and revenues are of primary concern. However, some other costs and benefits like say recreational benefit available to the population because of the impoundment which may not yield revenue to the project is considered in the economic analysis but not in the financial analysis.

Financial analysis is different from economic analysis in many ways. In financial analysis net returns are considered to the equity capital while in case of economic analysis, net returns are to the society. In financial analysis prices are considered as market or administered prices and subsidies are considered as source of revenue. In economic analysis, prices are considered as shadow prices and subsidies are considered as society benefits. In financial analysis loans are considered as increased capital resources and interest or repayments are considered as financial cost. In economic analysis loan and interest or repayment are considered as transfer payment. Discount rate on future receipt/ expenditure is considered in both the cases for evaluation of the project.

2.3.1 Financial Terms and Parameters

2.3.1.1 Capital Cost

The capital cost of the project is the total installation cost including direct cost of all project components (such as civil works, electro-mechanical equipment and other direct cost), indirect costs, land,
establishment, financing cost, local area development charges, interest during construction etc. required to commission the project. It also includes the capitalized initial spares.

2.3.1.2 Financing Arrangements and Means of Financing

Timely availability of finances is a pre-requisite for completing a project within a prescribed time schedule. The finances could be arranged by the developer from various financial institutions based on his legal eligibility and credit worthiness. The financial institution would like to examine the proposal from view point of loan repayment capability, management capability etc. Financial institutions have different procedures and norms for extending loan facility and these could be obtained from them. Each State Government/Nodal Agencies have prescribed norms for making equity participation varying from 20% to 30% of the project cost. The means of finance is arrived at from the followings:-

(i) Contribution of promoters
(ii) Equity of developers
(iii) Loans from different financial institutions.
(iv) Grant in aid /subsidy from the Government

Phasing of expenditure: The cost of a project is spread over the construction period depending upon the payment terms with the executing agencies / suppliers. The following distribution of cost may be taken.

<table>
<thead>
<tr>
<th>S. No.</th>
<th>Construction Period (Years)</th>
<th>Phasing of Expenditure (%) in different years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Year 1</td>
</tr>
<tr>
<td>1.</td>
<td>1</td>
<td>100</td>
</tr>
<tr>
<td>2.</td>
<td>2</td>
<td>40</td>
</tr>
<tr>
<td>3.</td>
<td>3</td>
<td>25</td>
</tr>
<tr>
<td>4.</td>
<td>4</td>
<td>20</td>
</tr>
</tbody>
</table>

Interest during construction: Interest during construction (IDC) need to be computed based on withdraw schedule of loan as per phasing of expenditure on prevailing interest rate.

2.3.1.3 Debt Equity Ratio

It is the ratio of debt (loan) to the equity put in by the developer. In Small Hydro Projects (SHP) it is being considered as 70:30 based on the financing norms of leading financial institutions. For the debt equity ratio other than 70:30 and equity invested in foreign currency following is considered.

(i) If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan.
(ii) If the equity actually deployed is less than 30% of the capital cost, the actual equity shall be considered for determination of tariff.
(iii) The equity invested in foreign currency shall be designated in Indian rupees on the date of each investment.

2.3.1.4 Working Capital

Working Capital is the amount required for day to day running of the project after commissioning. The working capital requirement is computed in accordance with the followings.

(i) Operation & maintenance expenses for one month;
(ii) Receivables equivalent to 2 (two) months of energy charges
(iii) Maintenance spare @ 15% of operation & maintenance expenses

2.3.1.5 Discount Factor

Discount factor signifies the time value of money and is the cost to the capital investment. Discount factor is also the opportunity cost of the capital. The Government fixes the discount rates either by law or by notifications for the projects being funded by them. For investments by private sector, the usual practice of fixing discount rates is based on weighted average cost of capital. For an example, considering debt equity
ratio as 70:30, interest rate 13% and rate of return on equity (ROE) 20%, the discount factor comes out to 15.10%.

2.3.2 Financial Analysis

Financial analysis need to be carried out to evaluate various layouts based on installation cost, generation cost; benefits cost (B-C) ratio, net present value (NPV) and internal rate of return (IRR) on the basis of following criteria:

(i) Installation cost is minimum
(ii) Generation cost is minimum
(iii) B-C ratio is maximum
(iv) Net Present Value (NPV) is maximum
(v) Internal Rate of return (IRR) is maximum

2.3.2.1 Installation Cost

It is the cost in Rs. / kW determined by dividing the project cost from the installed capacity of the project.

2.3.2.2 Generation Cost

It is determined based on annual energy generation and annual cost. Annual cost for generation of electrical energy comprises operation and maintenance (O&M) including insurance cost, depreciation of works & equipment, interest on the capital borrowed and interest on working capital.

The annual energy generation is determined by using following expression.

\[ E = P \times 8760 \times \eta_T \times \eta_g \times P_L \]

Where,

- \( E \) is the energy in kWh
- \( P \) is the installed capacity in kW
- \( \eta_T \) is the efficiency of turbine
- \( \eta_g \) is the efficiency of generator
- \( P_L \) is the plant load factor

Energy available for sale: From the generated energy, following deductions are made to arrive at energy available for sale.

(i) Auxiliary consumption – The energy consumed by auxiliary equipment of the power generating station and transformer losses within the generating station are considered as auxiliary consumption. This may be taken as 1% of gross energy generated at generator terminal.
(ii) Plan availability – During the operation there may be some forced outage due to emergency shut downs and unplanned maintenance etc. On account of forced outage 5% of gross energy generated at generator terminal may be considered for deduction.
(iii) Water royalty – State government charges water royalty in the form of free power to the state. The water royalty may be nil for the plant up to 5 MW capacity and 12% of the gross energy generated at generator terminal may be considered for deduction for the plant having capacity 5 MW or more.

Sale price of electricity: The sale price of electricity generated is the price fixed with the state utility under power purchase agreement for a fixed duration. In the absence of any power purchase agreement, the levellised tariff may be taken as sale price.

2.3.2.3 Benefit-Cost Ratio

The benefit-cost (B-C) ratio is the ratio of the present value of future cash flows (benefits) to the present value of the capital and subsequent recurring costs over the useful life of the project.
Benefit-cost ratio (B-C ratio) = \frac{\text{Present value of benefits}}{\text{Present value of expenditure}}

The ratio is computed by considering the actual revenue and the actual expenses consisting of O&M, depreciation and interest charges. If the ratio is found greater than one, the project is considered viable.

**Present value of benefits:** The present value is determined at the time of first expenditure of the future stream of benefits based on a fixed value of discount rate.

The present value (PV) of a future cash flow is computed by using the formula given below:

\[ PV = \sum_{i=1}^{n} \left( \frac{CF_i}{(1 + d)^i} \right) \]

Where,

- \( PV \) is present value
- \( CF_i \) is Cash flow in year \( i \) starting with initial investment
- \( d \) is discount rate
- \( n \) is number of years of the schemes / projects (useful life of the project)

### 2.3.2.4 Net Present Value (NPV)

Net present value (NPV) is calculated as the difference of present value of benefits and present value of expenditure. NPV can be computed for various layouts under different types of schemes considered for analysis. The difference between the revenue and the expenses, discounted at a pre-determined rate is the net present value (NPV) of the investment. The computation is done over the life of the project. NPV should be positive for a financially viable project.

### 2.3.2.5 Internal Rate of Return

For a project to be financially viable, the anticipated project receipts must exceed the project disbursements, funds must be available, and the project must be able to service the debt.

Internal rate of return (IRR) is the discount rate at which present value of benefits becomes equal to the present value of expenditure. IRR is to be determined for useful life of the project after the plant is put into operation. If the internal rate of return is more than the interest rate (or cost of funding) for the project, the project is considered financially feasible.

### 2.3.3 Financial Evaluation

The financial evaluation is carried out to assess the financial viability/ soundness of the project from the point of view of developers and financial institutions. For evaluation of a project, the following aspects are of significant importance:

(i) Capital investment  
(ii) Construction period and phasing of expenditure  
(iii) Useful Life of the project  
(iv) Financial package i.e. amount of debt/ equity, interest rate, moratorium period, repayment period and repayment schedule, return on equity  
(v) Amount and timing of cash flows.  
(vi) Government incentives such as royalty, lease, banking and wheeling charges, tax concessions, grant, subsidies, are also taken into account.

The financial package should be as per the concerned state / central Government /regulatory commission norms. The following approaches for determining the financial viability are considered:

- Pay Back Period Method
- Net Present Value
• Internal Rate of Return Method
• Debt Service Coverage ratio (DSCR) Method

The First represent approximate method for assessing financial worth of a project. The latter two, based on discounted cash flow method, provide a more objective basis for evaluating financial soundness of a project over its life. These methods take account of both magnitude and timing of expected cash flows in each period of a project life and hence considered preferred methods for financial evaluation.

DSCR is computed by calculating the ratio of gross cash flows (Gross Revenue – O&M expenses including insurance – interest on working capital – income tax) and debt servicing expenses (interest on loan and term loan installment).

Payback period determines the number of years required for the capital to be recovered by the net revenues accruing from the project. The net revenue is computed after deducting the annual working expenses from the constant value money capital. Annual surplus/deficit is then computed by deducting interest from the net revenue. The sum of charge which is the sum of capital and annual surplus or deficit gives the number of years required for the capital to be recovered. This method does not take into account the value of money at different time.

The financial institutions consider IRR and DSCR as the preferred financial parameters for evaluation of the financial viability of the project.

2.3.4 Tariff Determination

2.3.4.1 Useful Life

Small Hydro Plant useful life is taken as 35 years.

2.3.4.2 Tariff Period

The tariff period is the period for which tariff is determined for sale of power based on prescribed norms by Government/ Regulatory authorities. Tariff period may be same as the useful life of the project or lesser. Here tariff period is considered same as the useful life of the project i.e., thirty five (35) years.

2.3.4.3 Tariff Design

The generic tariff is determined on levelised basis for the Tariff Period, considering the year of commissioning of the project as base year for fixed cost component.

For the purpose of levelised tariff computation, the discount factor equivalent to weighted average cost of capital is considered. Levelisation is carried out for the useful life of the project and Tariff is specified for the period equivalent to tariff period (in case it is different from the useful life).

2.3.4.4 Tariff Structure

The tariff for hydro projects consists of the following fixed cost components:

(i) Return on equity;
(ii) Interest on loan capital;
(iii) Depreciation;
(iv) Interest on working capital;
(v) Operation and maintenance expenses including insurance;

Return on equity

The value base for the equity is 30% of the capital cost or actual equity, whichever is less. The normative Return on Equity is 20 % per annum.
Interest on loan

Moratorium period: Moratorium Period is the holiday/deferment period on repayment of principal as well as interest on borrowed capital which would be equal to the construction period.

Loan tenure: Loan tenure or repayment period is considered 10 years (SHP) in addition to the moratorium period.

Interest rate

(i) The loans arrived at in the manner indicated above is considered as gross normative loan for calculation for interest on loan. The normative loan outstanding as on April 1st of every year is worked out by deducting the cumulative repayment up to March 31st of previous year from the gross normative loan.

(ii) In case any moratorium period is availed of by the generating company, depreciation provided for in the tariff during the years of moratorium is treated as repayment during those years and interest on loan capital is calculated accordingly.

(iii) For the purpose of computation of tariff, the normative interest rate shall be considered as prevailing or average long term prime lending rate (LTPLR) of State Bank of India (SBI) prevalent during the previous year plus 150 basis points.

Depreciation: The project cost is the Historical Cost of the asset. Provided that land is not a depreciable asset and its cost is excluded from the capital cost while computing the historical cost of the asset.

(i) The Salvage value of the asset is considered as 10% and depreciation is allowed up to maximum of 90% of the Capital Cost of the assets.

(ii) Depreciation per annum is based on ‘Differential Depreciation Approach over loan tenure and period beyond loan tenure over useful life computed on ‘Straight Line Method’. The depreciation rate for the first 10 years of the Tariff Period is 7% per annum and the remaining depreciation is spread over the remaining useful life of the project from 11th year onwards.

(iii) Depreciation is chargeable from the first year of commercial operation. Provided that in case of commercial operation of the asset for part of the year, depreciation is charged on pro rata basis.

Advance against depreciation: Advance against depreciation (AAD) is permitted in addition to allowable depreciation, in the manner given hereunder:

\[ \text{AAD} = \text{Loan repayment amount subject to a ceiling of 1/10th of loan amount minus depreciation as per schedule.} \]

Provided that Advance Against Depreciation is permitted only if the cumulative repayment up to a particular year exceeds the cumulative depreciation up to that year.

Provided further that Advance Against Depreciation in a year is restricted to the extent of difference between cumulative repayment and cumulative depreciation up to that year.

On repayment of entire loan, the remaining depreciable value is spread over the balance useful life of the asset.

Interest on working capital: Rate of interest on working capital to be computed as prevailing or equal to the average short term prime lending rate (STPLR) of State Bank of India (SBI) prevalent during the previous year plus 100 basis points.

The interest on working capital is calculated on normative basis notwithstanding that the licensee or the generating company has not taken working capital loan from any outside agency.

Operation and maintenance expenses: Operation and maintenance (O&M) expenses comprise operational cost including employee expenses, oil and lubricants, repair and maintenance (R&M), and other administrative & general expenses. O&M expenses may be taken @ 4% of the project cost per annum and escalated at the rate of 5% per annum.

CDM benefits: The proceeds of carbon credit from approved CDM (Clean Development Mechanism) project are used in tariff calculation in the following manner.
100% of the gross proceeds on account of CDM benefit to be retained by the project developer in the first year after the date of commercial operation of the power station. In the second year, 10% of CDM benefits shall be taken into account for tariff calculation which shall be progressively increased by 10% every year till it reaches 50%. The balance CDM benefit proceeds to be retained by the project developer.

**Taxes and duties:** The tariff determined as per provisions is exclusive of taxes and duties as may be levied by the concerned government. Any tax on generation is allowed as pass through on actual incurred basis subject to production of documentary evidence by the generating company.

### 2.4 Techno-economic (optimization) studies for plant capacity, unit size and spare capacity

Present practice is to carry out techno-economic studies for optimum utilization of energy resource to determine power plant capacity and unit size. Type of power plant and its interconnection with the grid affects characteristics and equipment selection. Plant capacity is dependant upon site data as regard effective head and flow. Interconnecting grid characteristics and operation of the plant impact size, capacity and characteristics of equipment.

#### 2.4.1 Site Data and Economics Criteria

The basic data for selection of capacity and unit size are the design flow of water and the net head on turbine. For interconnection with the grid data regarding size of grid and nearest location of grid substation and its voltage is required.

The initial input for the process is determining:

- (a) The hydraulic resource of river/canal/stream flow, and
- (b) The economic criteria to evaluate the project economic feasibility, including the value of energy, value of capacity, escalation rates, discount rate, etc. The project hydraulic data (water availability versus time) is obtained by reviewing historical records or estimated by other techniques. As a result of this analysis, an initial plant capacity is assumed. A trial number of turbines-generator units is also assumed at this stage. The next step is to determine, performance characteristics of the selected turbines and generators. Such characteristics are used in calculating the annual energy from the plant and its capacity. Outline dimensions of the turbines, generators and other major equipment are used to estimate the powerhouse dimensions and costs.

Economic analyses for a range of possible alternatives are conducted for the various capacities, annual generation, capital costs and economic criteria. If the project appears feasible, other plant capacities and alternative machinery solutions would be evaluated in the same manner until the optimal plant capacity is determined. If the initial plant capacity is not feasible, smaller capacities would be evaluated in a similar manner. After evaluating several alternatives, a range of solutions available for consideration can provide the potential developer with a basis for selection.

Maximum utilization of available potential energy from the energy resource is required depending upon present economic viability. Accordingly energy remaining unutilized and efficiency of operating equipment is an important consideration in deciding the number and size and type of generating units. Further rising cost of energy demands provision to be made for further capacity addition to utilize unutilized energy during seasonal excess water periods.

In case of unit size above 5 MW, plant capacity, unit size may also be determined on the basis of capacity as peaking station.

Following site conditions may affect the design of the powerhouse and the equipment.

- (a) Quality of water e.g. amount and size of sediments carried by the water in the area around the water intake or downstream of the desilting works; the presence of any living organism and any dissolved chemicals.
- (b) Local conditions; extremes of air temperature, humidity etc.
2.4.2 Power Equation

Power can be developed from water whenever there is available flow, which may be utilized through a fall in water level. The potential power of the water in terms of flow and head can be calculated with the following equation.

\[ \text{kW} = 9.804 \times Q \times H \times E \]

Where:
- \( Q \): quantity of water flowing through the hydraulic turbine in cubic meters per second.
- \( H \): available head in meters.
- \( E \): is the overall efficiency. For turbines with 300 mm runner diameter or more an overall turbine, generator, station use and deterioration, and transformer efficiency of 85% can be used for estimating the energy from a flow duration curve. Whenever the flow rate and/or the head vary, a more precise analysis of the efficiency of the hydraulic turbine is required. A value of 95% may be used for all other losses including generator, station use and deterioration, and transformer. Therefore, the total efficiency to be used in the power operation studies is the product of the turbine efficiency and all other losses (0.95). If the turbine and generator are coupled together with a speed increaser, the losses, other the turbine, may be estimated as 93%.

2.4.3 Capacity and Unit Size

Plant Rating - Water power studies determine the ultimate plant capacity and indicate the head at which that capacity should be developed. Techno-economic (optimization) studies are required to be carried out to determine optimum size and number of units to be installed. Considerations involved in determining generating capacity to be installed and optimum number and size of units to be selected at the site are as follows:

(a) Maximum utilization of energy resource.
(b) Maximum size of units for the net head available.
(c) Operating criteria.
(d) Spare capacity
(e) Optimum energy generation and cost of generation per unit.
(f) Part load operation
(g) World wide and local experience.
(h) Future provision

The generating capacity of a hydro power plant is expressed in kilowatt (kW) or megawatts (MW) and is selected based on a careful evaluation of several important parameters i.e. head, discharge and head flow combination.

Capacity optimization flow chart is given in figure 2.1.

2.4.4 Interconnection with Grid

Installed capacity, unit size, characteristics and design of the hydro plant are impacted by interconnection with grid. Installed capacity depends upon feasible peaking capacity requirement, spare capacity to be provided in the proposed power house for maintenance, spinning reserve and forced outages.

2.4.5 Operating Criteria

Operating conditions and constraints affect the Electro-mechanical equipment and power station design.
Following hydraulic conditions affect the design of the unit and the plant:

(a) Head Variation in the Headrace and Tailrace.
(b) Operational constraints e.g. multipurpose scheme, environmental, fisheries etc.
(c) Attended or unattended operation and type of manpower available for O & M.
(d) Electrical conditions for plant operation e.g. isolated operation, parallel operation and grid connected (type of grid weak or strong).
(e) Whether peaking operation required.
(f) Maximum allowable up and down surge in head race.

![Diagram](image)

**Figure 2.1: Capacity, Unit Size and Number Optimisation Flow Chart**

### 2.4.6 Modern Practice

Present practice of determining unit size and spare capacity for mega and large project is explained with the help of studies carried out for Dehar power plant of Beas Satluj Link project (Para 2.5) with following observations.

a) Techno economic optimizing studies be carried out for capacity (Example at Para 2.5)
b) National Data on forced outages and planned maintenance is now compiled for the country by Central electricity Authority and that data be used for carrying out these studies. 
c) Probability studies as per latest available guidelines of IEEE/ASME/CEA be made for unit size.

2.5 Unit Size and Spare Capacity at Dehar Mega Hydro Power Plant – Example
(Based on a paper by author in 44th Annual Session of CBI & P -1971)

2.5.1 Introduction

The Beas-Sutlej Link Project is intended to divert River Beas water into River Sutlej through a system of tunnels and an open channel. Dehar power plant (figure 1.3.3) located at the end of the water conductor system develops a large block of hydro-electric power by the utilization of a drop of about 300 m (1,000 ft). A number of water power studies were carried out for the integrated water carrier system so as to arrive at a figure of minimum working capacity of 583 MW required to be installed at this power plant in the first stage. This figure represents water availability (based on historical records) in the snow fed river in the five dry months of November to March on 90% dependability basis. This capacity may be increased further to about 825 MW as a result of thermal installation in the grid for exploiting seasonal wet period inflows. Considerations involved in fixing the size of units at the power plant are discussed.

2.5.2 General Considerations

Substantial economies in the cost of equipment and civil structure are obtained by the installation of lesser number of bigger sized units in a high head power plant. Maximum economical unit size that can be installed at Dehar power plant for the working capacity was found out by evaluating the increase in spare generating capacity required as a result of increase in unit size. Evaluation of spare generating capacity for various unit size is dependent upon characteristics of existing power plants and the spare capacity already available in the grid to which Dehar power plant will be interconnected. Other considerations involved are part load operation of large sized units and transportation of heavy and big single piece package.

2.5.2.1 Unit Size

Limitation on the size of the unit is placed on the one hand by water turbine and on the other hand by system considerations. With the availability of better techniques and materials, hydraulic turbine design has undergone rapid advancement and very large sized medium and high head Francis type hydraulic turbine driven units have been made or proposed e.g. 600 MW units for third power plant at Grand Coulee and 450 MW per unit for the bath country pumped storage installation in USA according to Whippen (1974). Accordingly for the enlarged power system this trend to plants and units of larger sizes may continue with saving in both capital and operating costs. In India 6 units of 250 MW each have been installed at Nathpa Jhakri HEP on river Satluj in Himachal Pradesh and at Tehri hydro project on river Ganges in Uttarakhand. These are the largest hydro units installed.

Large size thermal (coal based) 500 MW unit size are operating and up to 1000 MW unit size Nuclear/thermal power plants are being planned. Accordingly hydro unit size limitation due to grid system consideration is of lesser importance.

2.5.2.2 Characteristics of Grid

Dehar power plant at that time was to feed an essentially hydro power grid. The generating capacity of various hydro power units including Dehar power plant as limited by head in different months of the year is given in Table 2.1.

Thermal power plant capacity likely to be available in the grid when Dehar power plant comes onto operation was not taken into consideration because thermal power would primarily be used to firm up secondary power and not much data regarding the same was available at the time.

There is a large variation in the generating capacity available for different months in a year because of the variation in the reservoir levels feeding the power plants at Bhakra and Pong. It is obvious that the peak firm load which can be connected to the system is limited by the power generated under minimum head
conditions (June) as per table 2.1. The secondary power available during higher heads and high water flow periods could only be considered as interruptible load and can be shed off when needed and as such was not taken into consideration for fixing spare capacity. Spare capacity of 141 MW existed in the power system without Dehar power plant as per details given in Table 2.2.

### 2.5.2.3 Load Characteristics

There was an appreciable seasonal variation of load. The monthly peak load expressed as percentage of maximum monthly load of June (capacity under minimum head conditions) is shown in Table 2.3.

A curve showing difference between monthly peak and daily maximum demand expressed as a percentage of monthly maximum demand in May/June at that time is shown in Figure 2.2.

**Table 2.1**

<table>
<thead>
<tr>
<th>Months</th>
<th>Pong Power Plant 4 x 60/36 MW Rated Head 215 ft.</th>
<th>Bhakra Power Plants Left bank (5 x 90/61) Right bank (5 x 120/80) Rated head 400 ft.</th>
<th>Nangal Power Plants</th>
<th>Dehar Power Plant Rated head 925 ft</th>
<th>Other Generating Plants: Bassi 3 x 15 MW; Joginder Nagar 4 x 10 MW; UBDC 4 x 10 MW</th>
<th>Available generating capacity as limited by head Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>3 MW 4 MW</td>
<td>5 MW 6 MW</td>
<td>7</td>
<td>125</td>
<td>8 MW</td>
</tr>
<tr>
<td>January</td>
<td>238</td>
<td>450 600</td>
<td>154 583+ Spare</td>
<td>125</td>
<td>2150+ Spare at Dehar</td>
<td></td>
</tr>
<tr>
<td>February</td>
<td>232</td>
<td>450 580</td>
<td>154 583+ Spare</td>
<td>125</td>
<td>2124+ Spare at Dehar</td>
<td></td>
</tr>
<tr>
<td>March</td>
<td>213</td>
<td>399 505</td>
<td>154 583+ Spare</td>
<td>125</td>
<td>1979+ Spare at Dehar</td>
<td></td>
</tr>
<tr>
<td>April</td>
<td>203</td>
<td>342 438</td>
<td>154 583+ Spare</td>
<td>125</td>
<td>1845+ Spare at Dehar</td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>182</td>
<td>311 410</td>
<td>154 583+ Spare</td>
<td>125</td>
<td>1711+ Spare at Dehar</td>
<td></td>
</tr>
<tr>
<td>June</td>
<td>157</td>
<td>305 400</td>
<td>154 583+ Spare</td>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>July</td>
<td>183</td>
<td>450 600</td>
<td>154 583+ Spare</td>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>August</td>
<td>240</td>
<td>450 600</td>
<td>154 583+ Spare</td>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>September</td>
<td>240</td>
<td>450 600</td>
<td>154 583+ Spare</td>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>October</td>
<td>240</td>
<td>450 600</td>
<td>154 583+ Spare</td>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>November</td>
<td>240</td>
<td>450 600</td>
<td>154 583+ Spare</td>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>December</td>
<td>240</td>
<td>450 600</td>
<td>154 583+ Spare</td>
<td>125</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: The power plant have since been renovated, modernized and uprated.

### 2.5.2.4 Scheduled maintenance and Seasonal Variation in Unit Capacities

As previously mentioned in the hydro system of the Punjab Power grid, there are the following two critical periods:

**Table 2.2**

<table>
<thead>
<tr>
<th>Power Plant</th>
<th>Minimum head in ft.</th>
<th>Number of Units</th>
<th>Power generated in MW</th>
<th>Spare generating capacity in MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bhakra Left</td>
<td>284</td>
<td>5</td>
<td>5 x 61 = 305</td>
<td></td>
</tr>
<tr>
<td>Bhakra Right</td>
<td>284</td>
<td>5</td>
<td>4 x 80 = 320</td>
<td>1 x 80 = 80</td>
</tr>
<tr>
<td>Ganguwal</td>
<td>-</td>
<td>3</td>
<td>2 x 24 + 1 x 29 = 77</td>
<td></td>
</tr>
<tr>
<td>Kotla</td>
<td>-</td>
<td>3</td>
<td>2 x 24 + 1 x 29 = 77</td>
<td></td>
</tr>
<tr>
<td>Joginder Nagar</td>
<td>-</td>
<td>4</td>
<td>4 x 10 = 40</td>
<td></td>
</tr>
<tr>
<td>Bassi</td>
<td>-</td>
<td>3</td>
<td>2 x 15 = 30</td>
<td>1 x 15 = 15</td>
</tr>
<tr>
<td>UBDC</td>
<td>-</td>
<td>4</td>
<td>3 x 10 = 30</td>
<td>1 x 10 = 10</td>
</tr>
<tr>
<td>Pong</td>
<td>156</td>
<td>4</td>
<td>3 x 36 = 108</td>
<td>1 x 36 = 36</td>
</tr>
<tr>
<td>Dehar</td>
<td>4 1st Stage</td>
<td></td>
<td></td>
<td>583 Spare</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>1570</td>
<td>141 MW + Spare at Dehar</td>
</tr>
</tbody>
</table>
Table 2.3

<table>
<thead>
<tr>
<th>Month</th>
<th>Maximum monthly load as percentage of maximum load of June</th>
<th>System peak load in MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>95.5</td>
<td>1498</td>
</tr>
<tr>
<td>February</td>
<td>95.5</td>
<td>1498</td>
</tr>
<tr>
<td>March</td>
<td>95.5</td>
<td>1498</td>
</tr>
<tr>
<td>April</td>
<td>100</td>
<td>1570</td>
</tr>
<tr>
<td>May</td>
<td>100</td>
<td>1570</td>
</tr>
<tr>
<td>June</td>
<td>100</td>
<td>1570</td>
</tr>
<tr>
<td>July</td>
<td>95.5</td>
<td>1495</td>
</tr>
<tr>
<td>August</td>
<td>95.5</td>
<td>1498</td>
</tr>
<tr>
<td>September</td>
<td>109.5</td>
<td>1718</td>
</tr>
<tr>
<td>November</td>
<td>109.5</td>
<td>1718</td>
</tr>
<tr>
<td>December</td>
<td>109.5</td>
<td>1718</td>
</tr>
</tbody>
</table>

i) The period of minimum generating capacity when the heads at Bhakra and pong reservoirs will be minimum. This period lies in May and June. Maintenance and inspection of gates, gate guides, etc. for Bhakra plants may be required to be carried out in the month of June when the head is minimum. Capacity outage amounting to not more than 80 MW for a period of one month was assumed during the month of June (minimum head) for this purpose.

ii) The period of low-water availability, i.e., about five months from December to April when water releases are low. During the above five months, however, the heads are high and lot of spare generating capacity is available. It was, therefore, obvious that planned maintenance and major overhauls could be carried out during these months except the maintenance of penstock gate guides, etc., as mentioned above. For determining the installed capacity required to be provided, we have to take into consideration the period (i) above.

Figure 2.2: Difference between monthly peak and daily maximum demand expressed as a percentage of monthly maximum demand for a typical month in May/June
2.5.2.5 Transportation of Heavy Packages

The transport of heavy packages to the site of power plant at Dehar was proposed by barrages in Bhakra Lake from the rail head at that place. It was estimated that a single piece package weighing about 70 tons could be transported without much difficulty.

In the high head Dehar power plant it was considered that a transformer section shall constitute the heaviest single piece package for the purpose of transport. A three phase transformer of even 106 MW size was estimated to weigh much more than 70 tons and as such cannot be transported without making special transport arrangements or by resorting to site assembling.

Single phase transformer units were accordingly proposed for this power house and were indicated to be within the transportable limits available at site.

2.5.2.6 Miscellaneous Consideration – Physical Layout, Part Load Operation, etc.

It was evident that for a power system with Dehar power plant of maximum working capacity of 583 MW, the studies should be carried out with the number of units of different tentative sizes varying from 6 to 4. More than 6 units of smaller size were considered to be too small to be economical while less than 4 units of over 200 MW size were rejected from considerations of part load operation, possible manufacturing difficulties, costlier transport arrangement and obviously larger spare capacities required. The layout of the power plant envisages 2 units on a common penstock header. Rough studies indicated that five units will not be economical and detailed studies for this case were also not carried out.

The capacity of the unit in each alternative considered was such that the system load is served with the same degree of reliability, the extra spare capacity required was incorporated into the units at Dehar.

2.5.3 Spare Generating Capacity

The plant peak capacity required in the system in any month must be equal to the sum of the monthly peak load, overhauling requirements and the capacity required for forced outages. The capacity required for forced outages is a function of the unit size and has accordingly an important bearing on the economical unit size to be installed at Dehar power plant. Probability studies were carried out to find out the capacity required for forced outage and thereby determine the reserve capacity required. These studies were carried out generally in accordance with Method 3 (interval between outages) of the American Institute of Electrical Engineers Sub Committee Report (1) for the following conditions.

2.5.3.1 Power system with Dehar power plant of peak capacity 583 MW

The following basic approach was developed to determine the reserve capacity required in the system.

(i) Determination by probability methods, the expected frequency and duration of forced outage of generating capacity in power system for the post Dehar period for different unit sizes at Dehar.

(ii) Scheduling all planned maintenance during high head periods when increased capacities are available.

(iii) Evaluation of the reserve capacity on the basis of the estimated 12 monthly peak load in a given year instead of the yearly maximum demands only.

(iv) Determination of monthly peaking factor to take into account the effect of variations in week day daily peak loads within each month on the required installed reserve.

(v) Evaluation of the help during emergencies from interconnections (with say Delhi and U.P. Grids) and from dropping of interruptible load and thus reduction of installed reserve accordingly (Now bigger Regional and National grid has been formed).
2.5.3.2 Expectation Of Forced Outage By Probability Methods

Expectations of forced outages were calculated by probability methods which gave results in terms of frequency, interval and average duration of outages. The mathematical steps involved in making these calculations have been explained in Appendix – III of the A.I.E.E. Committee Report. Forced outage rate of hydro electric units adopted was taken from the large compilation of this data by North West Pool of America on 387 hydroelectric generators of all capacities. An earlier collection of this data was made by A.I.E.E. subcommittee in 1949. Attempts were made to compile the figures of actual outage rates as per available data on Shannan, Ganguwal, Kotla and Bhakra power plants, but due to incomplete data for the purpose much lower figures for outage rates were obtained. The outage rates actually adopted are given in Table 2.4.

| TABLE 2.4 |
|-------------------------------|----------------|
| Forced Outage Rate of Hydro-electric Units | |
| 1. Forced outage rate (P) | 0.00723 |
| 2. Average duration (t) | 64.22 hrs. |
| 3. Average Interval (T) | 8,882 hrs. |

The forced outage rate derived above is predicated on machine exposure. Since the results of probability calculations were desired on a full time basis including scheduled maintenance time, the outage rate applicable to all machines is:

\[
P = \frac{64.22}{\left(8882 \times \frac{12}{11}\right) + 64.22}
\]

\[
= 0.0065848
\]

Assuming scheduled maintenance period of one month per year per machine.

In order to simplify calculations and reduce the volume of work total number of units were distributed in sub-groups with average capacities so that number of unit in each is approximately symmetrically distributed around the mean for the sub-system. The sub-groups chosen are given in Table 2.5. As explained earlier capacities in the minimum head period only were considered for the probability studies.

| TABLE 2.5 |
|-------------------------------|----------------|
| Group No. | Description of Power Plants | No. of Units | Average MW | Total MW |
| 1. | Bhakra Left and Bhakra Right Power Plants | 10 | 70 | 700 |
| 2. | Ganguwal, Kotal and Pong Power Plant | 10 | 30 | 300 |
| 3. | Joginder Nagar, Bassi and U.B.D.C. Power Plants | 11 | 11.5 | 126.5 |
| 4. | Dehar Power Plant | Working capacity = 583 MW No. of units and total installed capacity is required to be fixed. |

The results of each probability study were plotted in the form of 3 curves for: (i) the probability, (ii) average duration of outage, and (iii) the interval of forced outage. Detailed studies were carried out for a power system with the varying number of generating units at Dehar Power Plant. The results of probability studies with six units are shown in Figure 2.2 and with 4 units in figure 2.4. The capacity of machines at Dehar for the study was approximately assumed.
2.5.3.3 Spare Generating Capacity for Forced Outages

The maximum peak load that could be met and the available plant generating capacity (with 4 units of 165 MW at Dehar) during different months in a year are plotted in Figure 2.3. A perusal of this curve would reveal that the condition of minimum available plant capacity lasts for about one month in a year. For the rest of the period, due to higher heads, more plant capacity is available. Consequently the spare plant capacity required is to be of consequence for one month in a year for any forced or unforeseen plant outages. Further as already mentioned, a capacity of 80 MW may be required to be out for maintenance, etc., during this month. During the remaining periods of the year, the capacities available are higher and in months when more water flow is available, secondary power (considered interruptible load) could also be obtained from the power plants. A probability of once in 0.8 year forced outage indicated on the probability curves in figures 2.2 and 2.4 would actually mean a probability of once in about ten years forced outage (i.e., once in 8 x 12) because of possibility of the forced outage being of consequence only in the particular one month, i.e., (June) of the year. Provision against a probable forced outage occurring once in 10 years was considered quite sufficient and was assumed in the study for calculating reserve capacities. Accordingly these curves would indicate that for an outage of once in 10 years interval (i.e., an interval of 0.8 years on the curve) the following spare capacities are required in the grid for forced outage in the month of June:

<table>
<thead>
<tr>
<th>Outage Mag.</th>
<th>Outage Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power System with Dehar Power Plant (6 Units)</td>
<td>144 MW</td>
</tr>
<tr>
<td>Power System with Dehar Power Plant (4 Units)</td>
<td>170 MW</td>
</tr>
</tbody>
</table>

It was, therefore, obvious that spare capacity of 141 MW available in the power system without Dehar power plant (mentioned earlier) is quite sufficient. Further the spare capacities required to be provided for forced outage in the other months of the year for once in 10 years interval would be available because of higher heads.

2.5.3.4 Monthly Peaking Factor

To take into account the fact that a major forced outage is not likely to occur on the day of the monthly peak, a monthly peaking factor was taken into consideration. The average duration of a forced outage is of the order of a day only, so if we provide for 90 percent of the days and leave the 10 percent, the probability of once in 10 years will be virtually once in 100 years. The curve in Figure 2.5.1 shows that on 90 percent days the peak demand is about 2 percent value of that would be 32 MW. The total reserve in the system could, therefore, be reasonably reduced by 32 MW. As such actual reserve required for meeting forced outage is 144 – 32 = 112 MW for power system with 6 units at Dehar and 170 – 32 = 138 MW for power system with 4 units at Dehar.

2.5.3.5 Spare Generating Capacity Required at Dehar Power Plant

Spare generating capacity required in the system for meeting forced outages and planned maintenance with Dehar power plant of 6 units and 4 units is as below:

\[
\begin{align*}
\text{Power System with Dehar Power Plant of 6 units} &= 112 + 80 = 192 \text{ MW} \\
\text{Power System with Dehar Power Plant of 4 units} &= 138 + 80 = 218 \text{ MW}
\end{align*}
\]

Where 112 MW and 138 MW is the capacity required for forced outages for 6 and 4 units respectively, as worked out earlier and 80 MW is the capacity outage required for scheduled maintenance in low head period which is critical for generating capacity purpose.

Spare generating capacity equal to 141 MW was already available in the system without Dehar Power Plant. Therefore, spare capacity required to be provided at Dehar power plant for 6 units was (192-141) 51 MW and for four units (218-141) 77 MW.
2.5.3.6 Effects of Interconnection

It is evident that the capacity benefits resulting from future interconnection of power grids of adjoining states could be evaluated and deducted from reserve needed to take care of forced outages. It was considered that this capacity benefit should provide a safe margin over the spare capacity figures worked out above. In the expanding Punjab power grid there would be scope for adjustment in the capacities of new power plants, so as to fully exploit the benefits of the already constructed power plants.

2.5.4 Size of Units

2.5.4.1 The maximum working capacity of the power plant being 583 MW it was evident that a total installed capacity of 634 MW (583+51) would be required if 6 units are installed and 660 MW (583 + 77) would be required if 4 units are installed. The possible sizes accordingly assumed in the study worked out to:
(a) 6 units of 106 MW each.
(b) 4 units of 165 MW each.

Figure 2.3 – Forced outages Intervals and Durations - 6 machines of 106 MW each at Dehar

Figure 2.4 – Peak Load and spare plant capacity curves in post Dehar period
(Four 1st stage units of 165 MW at Dehar)
2.5.4.2 Four units of 165 MW each were selected for installation because of the following considerations:

- (i) Substantial economies in the cost of equipment and civil structures are obtained by the installation of lesser number of bigger size units in this high head plant.
- (ii) The system spare capacity with unit size of 165 MW is not very much increased.
- (iii) The units of 165 MW size was within the manufacturing range available in the country and can be transported to power plant site with the arrangements proposed.
- (iv) Part load operation of the units in the grid is not liable to present any difficulty.

2.5.5 Conclusion

In view of the studies carried out is was apparent that four generating units of 165 MW each be installed at Dehar power plant in the first stage so as to affect large economies in the cost of equipment and structure. Two future units (5 & 6) of 165 MW and were installed for peaking purposes when additional thermal capacity was available. Dehar power plant 1st stage 4 units were installed in 1972 to 1979 and 2nd stage (5 & 6) units were installed in 1983.

2.6 TECHNO ECONOMIC (OPTIMIZATION OF A CANAL DROP MEDIUM SIZE POWER HOUSE) FOR CAPACITY AND UNIT SIZE – Example

2.6.1 Flow Duration

Discharge data provided is given in Table 2.6, flow duration analysis was carried out for the discharge of the canal Table-2.7. Flow duration curve is also drawn and is given at figure-2.6.

2.6.2 Head

2.6.2.1 Gross head

Gross head is the difference in elevation of head water level (u/s) and tail water level (d/s). The full supply level in u/s is maintained for all discharges by automatic gates provided in the spillway, while tail water level varies
depending upon the discharge. The details of tail water depth and gross head for all discharges are shown in Table 2.7. Thus head varies with the discharge. Gross head varies from 8.00 to 9.83 m as shown in Table 2.7. The weighted gross head is the average of all these values which comes out to 8.53 m.

2.6.2.2 **Head Loss**

There will be head loss on account of trash rack loss and intake loss in the water conductor system. The total head loss was worked out as 0.30 m.

2.6.2.3 **Net head**

Net head is the head available for doing work on turbine i.e. gross head - head losses. The net head corresponding to different discharges is shown in Table 2.7. The weighted net head i.e. average of all net head values comes out to be 8.23 m. This was fixed as the design head.

2.6.3 **Number and Size of Units**

Water power studies carried out on monthly period basis to compute power potential (kW) available is shown in Table-2.7.

Power potential available at site varies from 8391 to 19884 kW:

Considerations involved in determining generating capacity to be installed and optimum number and size of units to be selected at the site are as follows:

1. Maximum utilisation of energy resource.
2. Maximum size of unit for the Net head available indigenously
3. Operating criteria
4. Spare capacity
5. Optimum energy generation and cost of generation per unit
6. Part load operation
7. World wide and Indian experience
8. Future Provision

2.6.3.1 **Energy Resource Utilisation**

Maximum utilisation of available potential energy from the precious resource is required depending upon present economic viability. Accordingly energy remaining unutilised and efficiency of operating equipment is an important consideration in deciding the number, size and type of generating units. Further rising cost of energy demands provision to be made for future capacity addition to utilise this unutilised energy. As shown in table 2.8, the installation of 2x9000 kW utilises all the available potential considering 10% overloading for some period.

2.6.3.2 **Unit Size**

Design head is the weighted average net head. Design head of 8.23 m was proposed to be adopted. This is the region of axial flow turbines with propeller runners. Type of turbines with propeller runners may include Kaplan/Semi Kaplan (Vertical/Horizontal axis), tubular, bulb, rim etc. Maximum size of standardised turbines available in this head range may not exceed 9000 kW. Propeller turbines may be operated at power outputs with flows from 40 to 105 percent. Head range for optimum operation is from 60 to 140 percent.

2.6.3.3 **Operating Criteria**

Entire power will be fed into the grid and will be utilised by State Electricity Board. For this purpose Two Nos. 66 kV single circuit lines were to be laid from nearest grid substations and existing power house of stage-I. Accordingly operation of the power house was governed by following considerations:
i) Independent operation of the power units is not required as there are no local loads and power units cannot take load fluctuations being canal power house.

ii) Peaking operation is not possible as there is no storage.

iii) Entire power will be fed into the grid.

Therefore the installation was optimised for energy benefits and not for capacity benefits.

Table 2.6: Flow duration curve

<table>
<thead>
<tr>
<th>% of time equalled or exceeded</th>
<th>Discharge (Cumecs)</th>
<th>Average Discharge (Cumecs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.33</td>
<td>306.98</td>
<td>293.14</td>
</tr>
<tr>
<td>16.67</td>
<td>302.20</td>
<td>259.84</td>
</tr>
<tr>
<td>25.00</td>
<td>267.59</td>
<td>241.23</td>
</tr>
<tr>
<td>33.33</td>
<td>251.88</td>
<td>234.04</td>
</tr>
<tr>
<td>41.67</td>
<td>248.06</td>
<td>224.33</td>
</tr>
<tr>
<td>50.00</td>
<td>245.00</td>
<td>223.70</td>
</tr>
<tr>
<td>58.33</td>
<td>216.51</td>
<td>201.53</td>
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<td>66.67</td>
<td>215.41</td>
<td>194.11</td>
</tr>
<tr>
<td>75.00</td>
<td>205.24</td>
<td>185.90</td>
</tr>
<tr>
<td>83.33</td>
<td>191.08</td>
<td>129.58</td>
</tr>
<tr>
<td>91.67</td>
<td>57.09</td>
<td>118.73</td>
</tr>
<tr>
<td>100.00</td>
<td>0.00</td>
<td>84.87</td>
</tr>
</tbody>
</table>

Figure 2.6: Flow Duration Curve
Table 2.7: Flow Duration, Power Potential and Energy Generation

<table>
<thead>
<tr>
<th>% of time equally or exceeded</th>
<th>Average Discharge (cum) (Q)</th>
<th>Tail Water Depth (m)</th>
<th>u/s FSL</th>
<th>d/s Water level (m)</th>
<th>Gross Head (m)</th>
<th>Net Head (m)</th>
<th>Power at (kW)</th>
<th>Power Potential Available QxHxη (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
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<td>(2x8000)</td>
</tr>
<tr>
<td>8.33</td>
<td>302.58</td>
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<td>246.32</td>
<td>238.32</td>
<td>8.00</td>
<td>7.70</td>
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<td>16000.00</td>
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<td>8.06</td>
<td>7.76</td>
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<td>7.85</td>
<td>19005.21</td>
<td>16000.00</td>
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<td>7.89</td>
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<td>246.32</td>
<td>238.09</td>
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<td>16000.00</td>
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<td>226.76</td>
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<td>8.60</td>
<td>8.30</td>
<td>16063.05</td>
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<td>202.15</td>
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<td>246.32</td>
<td>237.50</td>
<td>8.82</td>
<td>8.52</td>
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<td>91.67</td>
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<td>2.7</td>
<td>246.32</td>
<td>237.08</td>
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<td>11969.61</td>
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<tr>
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<td>103.17</td>
<td>2.11</td>
<td>246.32</td>
<td>236.49</td>
<td>9.83</td>
<td>9.53</td>
<td>8391.31</td>
<td>8391.31</td>
</tr>
</tbody>
</table>

Assumptions:

1. D/s Bed Level = 234.38 m
2. Combined Efficiency η = 87% (Turbine 90%; Generator 90%)
3. Head Loss = 0.30 m

2.6.3.4 Spare Capacity

Spare capacity at the power station is required only for maintenance or forced outage considerations. Spinning reserve capacity is not required as storage of water to take fluctuations is not available. Accordingly this capacity was fixed as follows:

i) Maximum one month in a year there may be no water and no power generation is possible. Planned maintenance normally requires about one month and can be carried out during this period. No provision for spare capacity on this account is required.

ii) The power was being fed into the grid. Forced outage duration of hydro units is small (days) and interval is large (month). Size of the unit is small & outage can be easily absorbed by grid. No specific provision on this account was considered necessary.

2.6.3.5 Optimum Energy Generation

For optimum energy generation following alternatives were considered to determine optimum number and size of units to be installed based on maximum energy generation at lowest generation costs.

1. 2 x 8000 kW
2. 3 x 8000 kW
3. 2 x 9000 kW
4. 3 x 6000 kW
5. 3 x 7000 kW

Annual energy generation, plant load factor, incremental additional generation of energy per kW of capacity added above minimum installed capacity (Alt. 1), energy remaining unutilised & generation cost per unit is worked out in Table-2.8. Basis/assumption made is as given below:
i) \[ P = 9.81 \times H \times Q \times \eta \]
Where,  
- \( P \) = Power in kW  
- \( H \) = Net head in m  
- \( Q \) = Discharge in cumecs  
- \( \eta \) = Turbine efficiency 91% x Generator efficiency 96% = 87%

Energy, \( E \) = \( Av \times Power \times 24 \times 365 \) in Units

ii) Kaplan turbines with adjustable blade and wicket gates can operate even up to 25% of its capacity at rated head. Typical efficiencies intimated by M/s Fuji Ltd. for their Bulb type of Kaplan units are as follows:

<table>
<thead>
<tr>
<th>Load</th>
<th>Efficiency</th>
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<tbody>
<tr>
<td>100%</td>
<td>93.4%</td>
</tr>
<tr>
<td>60%</td>
<td>93.4%</td>
</tr>
<tr>
<td>40%</td>
<td>91.7%</td>
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Table – 2.8: Alternative installations

<table>
<thead>
<tr>
<th>SI No.</th>
<th>Alternative</th>
<th>Annual Energy Generation</th>
<th>Incremental energy per kW of capacity above Alt. 1</th>
<th>Plant Load Factor</th>
<th>Annual Energy remains unutilized</th>
<th>Installation cost</th>
<th>Annual cost</th>
<th>Cost of generation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(kW)</td>
<td>(M Units)</td>
<td>(units) (%)</td>
<td>(M units)</td>
<td>Rs. (Lacs)</td>
<td>Rs. (Lacs)</td>
<td>Rs. (Lacs)</td>
<td>(Rs.)</td>
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<tr>
<td>1</td>
<td>2x8000</td>
<td>16000</td>
<td>....</td>
<td>93.26</td>
<td>14.40</td>
<td>8400</td>
<td>1722.00</td>
<td>1.32</td>
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<tr>
<td>2</td>
<td>2x8500</td>
<td>17000</td>
<td>5680.00</td>
<td>91.59</td>
<td>8.72</td>
<td>8650</td>
<td>1773.25</td>
<td>1.30</td>
</tr>
<tr>
<td>3</td>
<td>2x9000</td>
<td>18000</td>
<td>5070.00</td>
<td>89.33</td>
<td>4.26</td>
<td>8919</td>
<td>1828.40</td>
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<tr>
<td>4</td>
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<td>9900</td>
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<td>5</td>
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<td>2880.00</td>
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<td>0.00</td>
<td>11340</td>
<td>2324.70</td>
<td>1.60</td>
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Table – 2.9: Part Load Operation

<table>
<thead>
<tr>
<th>% of time equalled or exceeded</th>
<th>Average Discharge (cum)</th>
<th>Net Head (m)</th>
<th>Power Potential Available (kW)</th>
<th>No. of Machine</th>
<th>No. of Machine</th>
<th>No. of Machine</th>
<th>No. of Machine</th>
<th>No. of Machine</th>
<th>No. of Machine</th>
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<td>70.41</td>
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<td>52.45</td>
<td>1</td>
<td>98.72</td>
<td>1</td>
<td>93.24</td>
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</table>
This is true for most of the other types of construction of Kaplan turbines e.g. Vertical and Tube. Accordingly it was proposed to limit the operation up to 40%.

iii) The annual cost was worked out by assuming 20.50% of the total installation cost (O&M, Interest & Depreciation) for comparison purpose of various alternatives. The total cost of the power plant (2 x 9 MW) is as at A-8 of Annexure-2 of Chapter 2. The cost of electro-mechanical works and civil works etc. were based on the detailed project reports of the project. It may be seen from Table 2.8 that -

a) That large amount of energy remains unutilised in option 1 and 2.

b) That cost of energy generation for option 4 and 5 is relatively higher.

c) That incremental annual energy generation of power per kW of capacity above option 1 for option 5 is quite low to justify additional expenditure.

d) The cost of generation for 2x8500 and 2x9000 options is almost same while 2x9000 kW option will give more energy.

e) Considering 10% overloading, alternative 3 and 4 will generate almost total potential available.

f) Thus option 3 i.e. 2x9000 kW was considered optimum installation.

2.6.3.6 Part Load Operation

Energy available in monthly periods, number of units operating and percentage loading on the unit for different alternatives is shown in Table 2.9. Part load operation is in the acceptable range of Kaplan adjustable blade type of turbines.

2.6.3.7 Future Provision

Almost entire energy is utilised in the installation of 2x9000 kW considering 10% overloading for some period. Thus no future provision is required.

2.6.3.8 Indian Experience

A large no. of units up to unit size of about 5 MW to 18 MW in this head range have been installed in India recently.

2.6.3.9 Conclusion

As discussed above it is concluded that 2x9000 kW is the optimum installation at this site because –
1. 9000 kW standardised turbine is available in this head range
2. Almost entire energy is utilised in this installation
3. In the entire range of discharge available the units will generate power.
4. The installations of 3x6000 and 3x7000 kW, result in higher cost of energy generation.
5. The cost of generation in case of 2x8000 and 2x8500 kW installation is although marginally higher or same but energy remains unutilised is more in these options.
6. Cost of energy generation in case of 2x8500 and 2x9000 kW is almost same but more energy is generated in case of 2x9000 kW installation.

2.7 ECONOMICS OF PUMPED STORAGE SCHEME

2.7.1 Cost of Generation

Since pumped storage plants are generally negative energy projects, the method of working out the cost of generation for the conventional hydro scheme cannot be adopted for the pumped storage projects.

A method of working out the cost of generation is given below. The cost of generation has to be worked out with special allowance for the value of peak energy offered by the project, reckoning the extra energy generated at the base thermal or nuclear stations due to improvement in load factor by integrated operation.
Load carrying capacity contributed by the pumped storage project, assuming an equivalent thermal station A. MW (Say)

Corresponding energy at the L. F. of 60% to 75% applicable to the thermal station B. MU (Say)

Energy available from the pumped storage project C. MU (Say)

Balance energy to be contributed by the base thermal or nuclear station (B-C) MU

Energy required from the base thermal or nuclear source for off-peak pumping D. MU (Say)

Total energy contribution from base thermal or nuclear source B-C + D. MU

Cost of generation per kWh = \( \frac{P + Q + R + S + T}{B} \)

Where,
- \( P \) – Interest charges on the capital outlay of the pumped storage project;
- \( Q \) – O & M charges;
- \( R \) – Cost of total energy contribution from base thermal or nuclear source (i.e.) cost of the energy charges given in (vi) above.
- \( S \) – Depreciation
- \( T \) – Contribution to general reserve fund

**2.7.2 Cost per kW Pumped Storage Plant**

Since pumped storage plants are only peak load stations, the cost per kW should be considerably less than that for base thermal or nuclear stations.

**2.7.3 Advantages**

i) The plant can be installed at a lower cost per kW than an equivalent thermal or nuclear station.

ii) The plant provides largest amount of peaking power due to higher capacity installation.

iii) The capacity value of pumped storage project is not affected by the vagaries of monsoon, and 100% peaking capacity will be available even in drought seasons.

**2.8 RECENT TRENDS**

Recent Trends in Development of run of the river grid connected small hydro projects on low head flood control dams based on continuous generation of power during Mansoon months and small peaking power for the rest of the months (snow fed rivers/streams) is exemplified by Bathnahan and Aaraghat small hydro project in Bihar.

**2.8.1 Plant Capacity and Unit Size – Bathnahan -I SHP**

Bathnahan – I Project is a run of the river project on Parman River - a perennial Northern Himalayan River. These rivers are characterized by excess water periods May to September (snow melt and monsoon) and lean periods November to March. Monsoon period are prone to floods. Water power studies for 90 % dependable year are summarized in table 2.10.

### Table 2.10: Water Power Studies for 90% Dependable Year

<table>
<thead>
<tr>
<th>Month</th>
<th>Discharge for Power</th>
<th>Non Restricted Power Generation</th>
<th>Inflow</th>
<th>Out-flow for Power</th>
<th>Spilled Out</th>
<th>Generation</th>
<th>Energy Generated</th>
<th>Peaking Capacity</th>
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<tr>
<td></td>
<td>Cumeecs</td>
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<td>MCM</td>
<td>MCM</td>
<td>MCM</td>
<td>MW GWh</td>
<td>Hrs</td>
<td></td>
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<td>Jan.</td>
<td>22.36</td>
<td>0.89 0.34</td>
<td>57.97</td>
<td>41.33</td>
<td>16.64</td>
<td>0.66 0.45</td>
<td>1.63</td>
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<tr>
<td>Feb.</td>
<td>8.21</td>
<td>0.33 0.28</td>
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<td>21.29</td>
<td>0 0</td>
<td>0</td>
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<tr>
<td>Mar.</td>
<td>0.37</td>
<td>0.01 0.46</td>
<td>0.96</td>
<td>0</td>
<td>0.96</td>
<td>0 0</td>
<td>0</td>
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<tr>
<td>Apr.</td>
<td>16.42</td>
<td>0.65 0.81</td>
<td>42.56</td>
<td>41.07</td>
<td>1.49</td>
<td>0.65 0.47</td>
<td>1.72</td>
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<tr>
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<td>39.31</td>
<td>1.57 1.58</td>
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<td>0</td>
<td>1.62 1.1</td>
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<td>2.53 3.95</td>
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<td>517.76</td>
<td>37.85</td>
<td>7.64 5.22</td>
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<td>136.07</td>
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<tr>
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<td>222.16</td>
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<td>532.65</td>
<td>482.53</td>
<td>50.12</td>
<td>7.68 5.37</td>
<td>19.53</td>
<td></td>
</tr>
</tbody>
</table>

36
For 75% Dependable Year

Non Restricted Power Generation - 31.00 GWh
Peaking Power Generation - 28.06 GWh

2.8.2 Araraghat Small Hydro Project

Water power studies for Araraghat small hydro project on similar line in given in table 2.11.

A gated concrete structure (barrage) on the river length 153.5 meter is designed for Design flood of 2000 m³/s. Power house is proposed on the left bank of the river is isolated by a divide wall.

Installation of 8 MW is based on excess flow period discharge: unit size is 2 MW. Lean flow period generation of power is for high value peaking and presumably annual maintenance.

The project objectives are – hydro power generation improved irrigation and drinking water availability and contain floods etc.

The cost of power generation is estimated as Rs. 6.91 per unit in first year and second year Rs. 7.95 per unit. This is lower than the Alternative cost by thermal generation.

Table 2.11: Water Power Studies

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<th></th>
<th></th>
<th></th>
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<tbody>
<tr>
<td></td>
<td>in mm</td>
<td>in cumecs</td>
<td>in MCM</td>
<td>in m</td>
<td>in MW</td>
<td>in cumecs</td>
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<td>69.09</td>
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<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>69.09</td>
<td>Total</td>
<td>69.09</td>
</tr>
</tbody>
</table>
Guidelines for Cost Estimates for Pre Feasibility Studies (SHP)

1.1 Pre-Investment Economic Studies

1.1.1 Methodology

The methodology for the pre-investment economic studies after power potential has been defined as a result of initial studies/available data for environment clearance and to establish whether detailed feasibility studies are to be carried out. The procedure outlined is with special reference to small hydro because these hydro are generally not multipurpose. For large multi purpose hydro schemes suitable variations can be made.

1.1.2 Pre-Investment Feasibility

The components identified as important in pre-investment economic studies are shown in figure-2.7. The specific scope and purpose of the study should be defined and needed output products identified. The scope and purpose of this study is identified as pre-investment economic feasibility.

1.1.3 Contact Principal Agencies

Ministry of Energy (CEA) is responsible for large hydro. The ministry of non-conventional energy sources (MNES) is responsible for small hydro up to 25 MW. Specific programmes designed to encourage the development of hydroelectric are available. Each state has also issued guidelines for encouraging participation of private sector in this development. The terms and conditions for implementing small hydropower in private sector, including arrangements for purchase of power, banking etc have also been notified by most states.

1.1.4 Scope of Economic Evaluation

Unless developed in clusters, small hydro projects are generally single purpose power projects. As such, the economic justification is based on the value of power that can be generated. If other project features are to be considered in the economic evaluation such as irrigation, drinking water, flood control etc., they should be defined at this point and tasks related to their quantification formulated.

1.1.5 Define Power Potential

The value of power output from the proposed project, and the appropriate physical facilities are sensitive to the nature of the power potential. Is the plant likely to produce only energy or does it have potential for dependable capacity value as well? About how much output is likely and what is its variability. These are information items that are needed to assess market potential and provide formulation data.

1.1.6 Assess Market Potential

Potential buyers of power output should be identified so that value of power may be determined. Information important to determine the value of power includes: who is presently generating and selling power in the area, what types of generating equipment are in operation, and who the major customers are. Purchasers could include utilities, cooperatives, private industry and other institutions.

1.1.7 Capacity, Number and Size of Unit

Capacity, Number and size of units are a function of water available head etc. Several projects installed capacities should be investigated to estimate power potential which seems appropriate.
1.1.8 Develop Spillway Hydrology

The flood flows that must be passed, and the spillway capability to pass the flood events of rare occurrences are important for the design of the spillway.

1.1.9 Identify Physical Works

The power Generation and appurtenant works must be suitable to the intended installation and site. A specific preliminary design is not required but sufficient formulation to define likely machine type and possible configurations are needed to assess site issues, and to provide a basis for cost estimates.

1.1.10 Formulate Cost Project

Cost estimate for construction, site acquisition, operation and maintenance, and engineering and administration are needed to assess economic feasibility. To facilitate pre-feasibility estimates, available data on actual costs of projects recently constructed and data contained in design and development of model SHP self sustained projects E & M Equipment and Cost reduction in Volume – 1- Report by AHEC, IIT Roorkee for Power Finance Corporation Ltd. India Oct. 2002 have been analyzed to develop, charts and tables contained in this report. Figure-2.8 provides a basis for estimating the major share of construction costs in SHP for items that are governed by capacity and head, e.g., turbine, generator, and supporting electrical/mechanical equipment. The chart was developed by studying the generator and powerhouse costs for a variety of turbine types for a complete set of head/capacity values. The chart is, therefore, the locus of least cost points for head/capacity values shown. The reader is cautioned that this chart is based on the figures contained in other reports and least construction cost criteria governed for a site, site issues of space and configuration, and generation issues of performance ranges were not used. The chart should be adequate, however, for pre-feasibility estimates. For detailed cost estimates of SHP up to 15 MW at feasibility preparation stage reference may be made to Annexure -2. Installation of multiple units can be considered using these charts although the reinforcement of analysis might be questionable at this level of study. The multiple units may be critical to small hydro feasibility because of the goal of generating as much energy as possible from the available flow regime. Projects approaching the upper limits of small hydro capacity (5 MW) probably warrant using more detailed pre-feasibility level of study. The remaining components needed for preparing construction cost estimates are included in table 2.12 (A, B & C). Other cost items that may have surfaced during study of the critical issues (access etc.) should be estimated at this stage as well. In the absence of specific estimates for these additional items, uniform expenses allowance of up to 20% would be appropriate. The products of this task should be an array of costs for the range of installed capacities for which power estimates are prepared.
### TABLE - 2.12

**MISCELLANEOUS PRE-FEASIBILITY ESTIMATE COSTS**

(Cost base April 2000)

#### (A) PENSTOCK COST

<table>
<thead>
<tr>
<th>Effective head (Meter)</th>
<th>3</th>
<th>6</th>
<th>16</th>
<th>30</th>
<th>60</th>
<th>100</th>
<th>200</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Index (CI)</td>
<td>7.7</td>
<td>3.8</td>
<td>1.6</td>
<td>0.9</td>
<td>0.44</td>
<td>0.28</td>
<td>0.18</td>
</tr>
</tbody>
</table>

Installed cost (Rs in lacs) = CI x Penstock length (m) x Installed capacity (MW)

N.B.: For Micro hydro (up to 100 kW) with Shunt Load (Electronic Load) Governor the Installed cost will be 40% less

#### (B) SWITCHYARD EQUIPMENT COST

(Rs. in lacs)

<table>
<thead>
<tr>
<th>Plant Capacity (MW)</th>
<th>11 KV</th>
<th>33 KV</th>
<th>66 KV</th>
<th>132 KV</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>25</td>
<td>30</td>
<td>55</td>
<td>80</td>
</tr>
<tr>
<td>3</td>
<td>45</td>
<td>50</td>
<td>60</td>
<td>90</td>
</tr>
<tr>
<td>5</td>
<td>55</td>
<td>65</td>
<td>75</td>
<td>105</td>
</tr>
<tr>
<td>10</td>
<td>75</td>
<td>85</td>
<td>105</td>
<td>140</td>
</tr>
</tbody>
</table>

#### (C) TRANSMISSION LINE COST

(Rs. in lacs)

<table>
<thead>
<tr>
<th>Plant Capacity (MW)</th>
<th>length of transmission line (in Km)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1.5 Km</td>
</tr>
<tr>
<td>0.5</td>
<td>10</td>
</tr>
<tr>
<td>5.0</td>
<td>16</td>
</tr>
<tr>
<td>10</td>
<td>20</td>
</tr>
</tbody>
</table>

1.1.11 **Cost Streams**

The construction cost values developed in the previous paragraph need to be gathered, organized and analysed to permit expeditious performance of the economic feasibility calculations. The construction costs should be escalated to the study date.

It is recommended that the national capital cost index be used for escalation as a composite value for all items for the pre-investment cost estimates. Cost estimates are also needed for the non-physical works cost items. An allowance for unforeseen contingencies ranging from 3 to 6% should be added to the sum of the construction costs, the value depending upon a judgment as to the uncertainties. A mid value of 5% for contingencies is appropriate in the absence of more detailed analysis. All investigation, management, engineering and administration costs that are needed to implement the project and continuation of its services are appropriately included in the pre-investment determination, engineering, interest during construction, etc., of 15-20% be added. Total indirect costs to be added will therefore vary between 25% and 30%.
Figure 2.8 Cost Estimate based on Capacity and Head

Notes:

1. Estimated costs are based upon a typical or standardized turbine coupled to a generator either directly or through a speed increaser, depending on the type of turbine speed.

2. Costs include Turbine/generator and appurtant equipment, station electric equipment miscellaneous power plant equipment, powerhouse civil works including, excavation, tailrace, switchyard civil works, upstream slide gate, and construction and installation.

3. Costs not included are transmission line, penstock, construction and switchyard equipment. Refer table 2.12 A B & C for these cost.


5. The transition zone occurs as unit type changes due to increased head.

6. For a multiple unit powerhouse additional station equipment cost are 14 lacs + 4 0 lacs (n-1) where n is the total number of unit.

Micro Hydro Projects

For micro hydropower Projects (up to 100 kW unit size), cost estimates may be based on Table- 2.13

These units are proposed to be equipped with Non Flow Control turbines designed for runaway conditions and controlled by Shunt Load Governor (Electronic Load Controllers). The penstocks are designed for no water hammer conditions. The figure provides cost estimates for generating unit, power house diversion etc. Other components need to be added. Construction cost estimates for micro hydro projects are indicated in table -2.13.

Table - 2.13: Project Cost Estimates (Micro Hydro Projects)

<table>
<thead>
<tr>
<th>Micro Hydro Up to 100 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost including turbine, generator, electronic load controller with hot water system or ballast load; Power and control equipment, Power house and tail race structure, etc.</td>
</tr>
</tbody>
</table>
Notes:

1. Estimated costs are based upon a typical or standardised turbine (non flow control) coupled to generator either directly or through belt drive.
2. Costs include turbine/generator; Shunt load governor (Electronic load controller); Power house: Inlet wheel valve, Water ballast load; Construction and installation.
3. Penstocks/Channel; distribution lines costs etc are not included. Refer Table 1.1 for these costs.

1.1.12 Cost Escalation

For escalation of cost to study date Figure 2.9 gives the national capital cost index from 1987-88 to 1996-97. The cost in say 2001 can be upgraded 2000 by multiplying 2000 cost by a

\[
\text{Factor of escalation} = \frac{\text{Cost Index in Year 2000}}{\text{Cost Index in 2001}} = 1.08
\]

![Figure 2.9 National price Index](image)

1.1.13 Adopt Power Value

The power values needed are the value of energy that the project proposed could reasonably expect to receive for the sale of output, and dependable capacity of the project, if any. It is suggested that pre-feasibility values be adopted from values solicited from the central/state office in the case of potential sale to utilities, municipal organizations, or be extracted from existing rate schedules (available from the local utility office) in the case of potential sale to a private industrial buyer. A benchmark value that can often be used as the minimum value for energy can be the fuel replacement cost.

1.1.14 Develop Power Benefit Stream

The power generation benefits from the proposed project are the sum of the energy value times the energy production and the capacity value times the estimated dependable capacity (if any). In the absence of a private purchaser, the difference in their power bill with and without the proposed project is the benefit. The project benefit stream is the annual array of power benefits (plus other project benefits if determined to be appropriate). Project benefit streams should be prepared for the several installed capacities under study.

1.1.15 Determine Economic Feasibility

Economic feasibility is positive when the stream of benefits exceeds the stream of costs. It is suggested that the Internal Rate of Return method of characterizing project feasibility is employed. The Internal Rate of Return is the discount rate at which the benefits and costs are equal, e.g., the discount rate at which the benefit to cost
ratio is unity. This avoids the need at the pre-investment stage to adopt a discount rate and thus provides an array of economic feasibility results. The analysis should be performed for each of the installed capacities under study. The alternative is to compute a benefit cost ratio using the discount rate that represents the minimum attractive rate of return for the project proponent.

An example computation and display is elaborated in the end of this chapter. Should the outcome of the economic feasibility test appear uncertain, simple sensitivity analysis based on the important variables (power values/fuel costs, amount of energy/capacity, etc.) could significantly contribute to narrowing the band of uncertainty.

1.1.16 Identify Critical Issues

The potentially critical issues should be identified and action required to clarify their importance defined. The issues have been generally identified in this section but important variations may exist depending on project proposed, prior studies, location, etc. The issues that are likely to emerge are primarily related to legal and institutional factors and physical factors focused on the site.

1.1.17 Assess Legal/Institutional Issues

An assessment is needed at the pre-feasibility stage to define the mechanisms that are likely to be needed to implement a project (e.g. site ownership, legal authority to develop/sell power, access to power grids) and to appraise the action needed to overcome obstacles, should they exist.

1.1.18 Assess Site Issues

A site visit should be considered essential at this stage for (rare exceptions excluded) all pre-feasibility investigations of projects. Sketches and drawings may be made and/or existing ones verified defining space for plant sitting, terrain and construction features, operational status of facilities, and other items pertinent to the physical arrangement of the site, construction of the needed works, and transmission of the power to distribution facilities. The site visit by responsible professionals should be coordinated to provide for a reconnaissance stage integrity assessment as well.

1.1.19 Assess Financial Issues

Sufficient funds must be raised to construct the plant and adequate flow of revenues generated to provide for maintaining the plant in service, retiring loans, and producing a profit to the developer. The nature of likely financing needs to be defined, potential marketing and revenue arrangements described, and perhaps most important at this pre-investment stage, the probable cost of capital (interest rate of financing) determined.

1.1.20 Document Pre-Investment Findings

The findings of the pre-investment investigation should be documented for study by responsible authorities (public officials, boards of directors, private investors etc.); supporting studies, facts, and references described and codified to expedite performance of further studies; and should the finding be positive, a plan of action for the next steps outlined for execution by the project proposed.

1.1.21 Time, Cost and Resources For Reconnaissance Studies

The time, cost, and manpower resources required to perform pre-investment studies for small hydroelectric power plants will vary depending on expected plant size, site conditions, specific scope and depth of study, and availability of information (prior resource assessments and screening studies).

1.1.22 Example Pre-Feasibility Economic Analysis Plant Characteristics:

**Run of River Scheme**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Head</td>
<td>40 meter</td>
</tr>
<tr>
<td>Capacity</td>
<td>4 MW</td>
</tr>
<tr>
<td>Efficiency</td>
<td>80%</td>
</tr>
<tr>
<td>Penstock Length</td>
<td>100 m</td>
</tr>
<tr>
<td>Transmission</td>
<td>33 kV – 10km</td>
</tr>
<tr>
<td>Economic life</td>
<td>25 Years</td>
</tr>
<tr>
<td>Evaluation Date</td>
<td>1997</td>
</tr>
</tbody>
</table>
Average Yearly-
Energy Generated = 12.6144 MU
Selling Price = Rs. 2.25/unit

Investment Cost

<table>
<thead>
<tr>
<th>Component</th>
<th>Rs. in lacs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine, Generator and Civil</td>
<td>900</td>
</tr>
<tr>
<td>Additional Station, Equipment (Multi-unit)</td>
<td></td>
</tr>
<tr>
<td>Penstock (Table-1.1 (A) (0.72 x 100 x 4)</td>
<td>288</td>
</tr>
<tr>
<td>Switchyard Equipment (Table-1.1 (B)</td>
<td>58</td>
</tr>
<tr>
<td>Transmission Line (Table-1.1 (C)</td>
<td>65</td>
</tr>
<tr>
<td>Others (access, miscellaneous site construction)</td>
<td>--</td>
</tr>
<tr>
<td>Subtotal</td>
<td>1311</td>
</tr>
<tr>
<td>Escalation (April, 96 to April, 97 - figure – 1.9.13)</td>
<td>131.1</td>
</tr>
<tr>
<td>Contingencies at 10% - 20%</td>
<td>146</td>
</tr>
<tr>
<td>Subtotal</td>
<td>1442.10</td>
</tr>
<tr>
<td>Indirect @ 20%</td>
<td>262.2</td>
</tr>
<tr>
<td>Total Investment Cost (IC)</td>
<td>1704.3</td>
</tr>
</tbody>
</table>

Capital Recovery Factor:

The factor used to calculate the annual amount to be charged to project to recover capital investment.

\[
\text{Capital Recovery Factor} = \frac{r(1+r)^n}{(1+r)^n - 1}
\]

- \(r\) - Interest rate
- \(n\) - Life of project

Annual Cost:

Annualized Investment Cost is a function of discount rate and economic life of a project and is computed by multiplying the Total Investment Cost by the Capital Recovery Factor for the discount rate and economic life selected.

Operation and Maintenance (O&M) Cost @ 2% = 34.08

Total Annual Cost (sum of Annualized Investment Cost and O & M cost) and Total annual benefits have been calculated in the following Table 2.14.

The reconnaissance economic feasibility for the example is shown graphically in Figure 2.10 (a) and Figure 2.10 (b).
Table 2.14: Cost and Benefit Computation Table

<table>
<thead>
<tr>
<th>Discount Interest Rate (%)</th>
<th>Capital Recovery Factor</th>
<th>Annualized Investment Cost in Lacs (Col 2 x IC)</th>
<th>Total Annual Cost in Lacs (Col 3 + O&amp;M Cost)</th>
<th>Break Even Energy Value Rs./kWH (Col 4/ Energy Generation)</th>
<th>Total Annual Benefit in Lacs (Energy Generation x Selling rate)</th>
<th>Net Benefit in Lacs (Col 6 - Col 4)</th>
<th>B/C Ratio (Col 6 / Col 4)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12%</td>
<td>0.1275</td>
<td>217.30</td>
<td>251.38</td>
<td>1.99</td>
<td>283.824</td>
<td>32.44</td>
<td>1.13</td>
</tr>
<tr>
<td>14%</td>
<td>0.1455</td>
<td>247.98</td>
<td>282.06</td>
<td>2.24</td>
<td>283.824</td>
<td>17.64</td>
<td>1.01</td>
</tr>
<tr>
<td>16%</td>
<td>0.1640</td>
<td>279.51</td>
<td>313.59</td>
<td>2.49</td>
<td>283.824</td>
<td>-29.77</td>
<td>0.91</td>
</tr>
<tr>
<td>18%</td>
<td>0.1829</td>
<td>311.72</td>
<td>345.8</td>
<td>2.7</td>
<td>283.824</td>
<td>-61.98</td>
<td>0.82</td>
</tr>
<tr>
<td>20%</td>
<td>0.2021</td>
<td>344.44</td>
<td>378.52</td>
<td>3.0</td>
<td>283.824</td>
<td>-94.70</td>
<td>0.75</td>
</tr>
<tr>
<td>24%</td>
<td>0.2411</td>
<td>410.91</td>
<td>444.99</td>
<td>3.5</td>
<td>283.824</td>
<td>-161.67</td>
<td>0.64</td>
</tr>
<tr>
<td>26%</td>
<td>0.2608</td>
<td>444.48</td>
<td>478.56</td>
<td>3.79</td>
<td>283.824</td>
<td>-194.74</td>
<td>0.59</td>
</tr>
<tr>
<td>28%</td>
<td>0.2806</td>
<td>478.23</td>
<td>512.31</td>
<td>4.06</td>
<td>283.824</td>
<td>-228.49</td>
<td>0.55</td>
</tr>
<tr>
<td>30%</td>
<td>0.3004</td>
<td>511.97</td>
<td>546.05</td>
<td>4.32</td>
<td>283.824</td>
<td>-262.23</td>
<td>0.52</td>
</tr>
<tr>
<td>32%</td>
<td>0.3203</td>
<td>545.89</td>
<td>579.97</td>
<td>4.60</td>
<td>283.824</td>
<td>-296.15</td>
<td>0.49</td>
</tr>
<tr>
<td>34%</td>
<td>0.3402</td>
<td>579.80</td>
<td>613.88</td>
<td>4.87</td>
<td>283.824</td>
<td>-330.06</td>
<td>0.46</td>
</tr>
<tr>
<td>36%</td>
<td>0.3602</td>
<td>613.89</td>
<td>647.97</td>
<td>5.14</td>
<td>283.824</td>
<td>-364.15</td>
<td>0.44</td>
</tr>
</tbody>
</table>
Chapter-2: Annexure-2
Small Hydropower (SHP) - Electro-Mechanical Equipment - Cost Guidelines

REQUIRED DATA:

a) Turbine Flow Cumecs (Q)
b) Rated head, H, meters
c) Length of transmission lines (km)
d) Voltage of interconnecting grid sub station (kV)

**COMPUTE kW CAPACITY AVAILABLE FROM SITE Q x H x 9.804**

**USING A,KW AND H, SELECT SUITABLE TURBINE TYPE FROM CHAPTER-3**

**DETERMINE TURBINE EFFICIENCY AT RATED HEAD FIGURE 3.5.1**

**CALCULATE OVERALL PLANT EFFICIENCY & CAPACITY**

**COMPLETE COST ESTIMATE FIGURE A-1 to A-7**

**COST OF TURBINE/GENERATOR FROM FIGURE A-1 TO A-3**

**COSTS OF STATION ELECTRICAL EQUIPMENTS FRP, FOIGRE A-4**

**COST OF MISC. POWER PLANT EQUIPMENTS FORM FIGURE A-5**

**COST OF SWITCHYARD A-6**

**COST OF TRANSMISSION LINE FROM FIGURE A-7**

**ESCALATES COSTS TO CONSTRUCTIONS DATE CHAPTER Para 1.1.12**

**TOTALIZE & COMPUTE COST A-9 & A-8**

(Typical 9 MW, 9 M head Kaplan Turbines)

Figure 2.11: FRANCIS TURBINE COSTS
Notes:

1. Estimated costs are based upon a typical horizontal/vertical turbine directly coupled to the generator.
2. Cost includes turbine, generator, exciter, inlet valve, speed regulating governor and installation.
3. Installation costs are estimated at 15% of total equipment cost.
4. Cost index is April 2000.

Figure 2.12: COSTS WITH STANDARD PROPELLER TURBINE

Notes:

1. Estimated costs are based upon standardized Kaplan turbines directly coupled to the generator through a speed increaser.
2. Cost includes turbine with variable pitch blades and movable guide vanes, inlet butterfly valve, speed increaser, generator with exciter, speed regulating governor, controls and installation.
3. Installation costs are estimated at 15% of total equipment cost.
4. Deduct Rs. 20.25 lacs for fixed blade type
5. Cost index is April 2000.
Figure 2.13: COSTS WITH IMPULSE TURBINE

Notes:

1. Estimated costs are based upon typical single turbine directly coupled to the generator at high heads and coupled through a speed increaser at low heads.
2. Cost includes turbine, generator, exciter, inlet valve, controls and installation.
3. Cost index is April 2000.

Figure 2.14: STATION ELECTRICAL EQUIPMENT COSTS
Notes:

1. The major equipment is listed below:
   a) Battery and battery charger
   b) Station switchgear
   c) Station service transformers
   d) Bus, cable conduit and grounding
   e) Main control board
   f) Lighting system

2. Cost include freight and installation
3. Costs shown are for a single unit plant. For multiple units a cost for generator breakers and additional controls must be added. Add Rs. 20,000 + rs 30 lacks x (n-1) to the cost of a single unit plant of the same total kW capacity. (n = number of units).
4. Cost index is April 2000.

---

Figure 2.14: Miscellaneous Power Plant Equipment

Notes:

1. The major miscellaneous power plant equipment is listed below.
   a) Ventilation equipment
   b) Fire protection equipment
   c) Communication equipment
   d) Generation bearing cooling water equipment

2. Communication equipment includes alarm and communication facilities for unattended operation of unit, further cost figures should be obtained for very remote locations or integrations with complex communication networks.
3. All figures include a 15% factor for freight and installation.
4. Cost index is April 2000.
Figure 2.15: Switchyard Equipment Costs

Notes:

1. The major equipment is listed below.
   a) Main step-up transformer
   b) Line side circuit breaker
   c) Lighting arrestors
   d) Isolator switches
   e) Generator cables/bus ducts. (15 meters length)
   f) HV CT/PT/CVT
   g) HV bus bar conductor, insulators and hardware

2. Cost includes 25% for freight and installation.
3. Foundations and switchyard structure are included.
4. Cost index is April 2000.

<table>
<thead>
<tr>
<th>S. No.</th>
<th>Voltage level</th>
<th>Cost per km. (Rs. Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>11 kV</td>
<td>0.15</td>
</tr>
<tr>
<td>2.</td>
<td>33 kV</td>
<td>0.55</td>
</tr>
<tr>
<td>3.</td>
<td>66 kV</td>
<td>1.00</td>
</tr>
<tr>
<td>4.</td>
<td>132 kV</td>
<td>1.25</td>
</tr>
</tbody>
</table>

COST OF TRANSMISSION LINES

Notes:

1. Direct costs are construction and favorable conditions.
2. Costs should be increased for areas with more difficult access (up to 50% for swamplike or mountainous areas).
3. Costs should be increased for unfavorable
4. Cost Index April 2000
Abstract of Project Cost

<table>
<thead>
<tr>
<th>S.No.</th>
<th>Particular</th>
<th>Cost (Rs. in Lacs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I.</td>
<td>Works</td>
<td></td>
</tr>
<tr>
<td>1.</td>
<td>A-Preliminary</td>
<td>20.00</td>
</tr>
<tr>
<td>2.</td>
<td>B-Land</td>
<td>67.06</td>
</tr>
<tr>
<td>3.</td>
<td>C-Works (Civil Works)</td>
<td>2866.63</td>
</tr>
<tr>
<td>4.</td>
<td>K-Building</td>
<td>46.25</td>
</tr>
<tr>
<td>5.</td>
<td>M-Plantation</td>
<td>10.00</td>
</tr>
<tr>
<td>6.</td>
<td>O-Miscellaneous</td>
<td>132.00</td>
</tr>
<tr>
<td>7.</td>
<td>P-Maintenance</td>
<td>70.00</td>
</tr>
<tr>
<td>8.</td>
<td>O-Special T&amp;P</td>
<td>50.00</td>
</tr>
<tr>
<td>9.</td>
<td>R-Communication (Approach road)</td>
<td>6.00</td>
</tr>
<tr>
<td>11.</td>
<td>X-Environment and ecology</td>
<td>20.00</td>
</tr>
<tr>
<td>12.</td>
<td>Transmission lines – 2 lines 66 kV (cost as per Annex. -A7)</td>
<td>162.00</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>7981.24</strong></td>
</tr>
</tbody>
</table>

II Establishment 10% of I-Works excluding cost of land 791.42

III Ordinary T&P 1% of I-Works 79.81

IV Losses on Stock 0.25% of C-Works 7.17

V Suspense

VI Receipt and Recoveries(-) 20.45

VII Indirect Charges 79.81

1% of I-Works for audits and accounts

Grand Total Rs. 8919.00 Lacs

Electro-mechanical Equipment Costs

(Typical for 2 x 9 MW Kaplan with head 9 m and Interconnected by 66 kV Line)

<table>
<thead>
<tr>
<th>Particular</th>
<th>Rs. In Lacs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Horizontal Kaplan turbine coupled to generator to deliver 9000 kW</td>
<td>3200</td>
</tr>
<tr>
<td>complete with variable pitch blades; moving guide vanes; generator,</td>
<td></td>
</tr>
<tr>
<td>exciter governor as per figure A2 @ (2 x Rs. 800 Lacs per unit)</td>
<td></td>
</tr>
<tr>
<td>2. Station electrical equipment for 9 MW plant @ Rs. (2 x Rs.150 Lacs per</td>
<td>300</td>
</tr>
<tr>
<td>unit) (Annexure- A-5)</td>
<td></td>
</tr>
<tr>
<td>3. Miscellaneous power plant equipment (Annexure - A5) 2 x (50 Lacs/unit)</td>
<td>100</td>
</tr>
<tr>
<td>4. Switchyard equipment costs (Annexure - A6) 2 x (100 lacs/unit)</td>
<td>200</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>3800</td>
</tr>
<tr>
<td>Freight, insurance @ 3%</td>
<td>114</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>3914</td>
</tr>
<tr>
<td>Erection and commissioning @ 10%</td>
<td>392</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>4306</td>
</tr>
<tr>
<td>Unforeseen &amp; contingencies L.S.</td>
<td>235</td>
</tr>
<tr>
<td><strong>Grand Total</strong></td>
<td><strong>4531</strong></td>
</tr>
</tbody>
</table>
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