# 3. ECONOMIC AND FINANCIAL ANALYSIS

## 3.1 GENERAL

### 3.1.1 SCOPE AND OBJECTIVES

It is utmost essential that after technical feasibility of any hydroelectric project, the economic and financial feasibility should be worked out in order to provide economic and financial basis for deciding whether to implement the project. Moreover, this exercise is useful to examine the promising development options in sufficient detail to determine which are most attractive.

It is also now equally important to seek the environmental and social clearance as well. There is a growing tendency to take these factors into account in the economic analysis. While these tasks are central to project feasibility and integrate all of the information into a measure of economic desirability, the level of effort involved is relatively modest. The economic and financial analysis task will take approximately five to ten percent of the total feasibility study [UACE, 1979].

An economic appraisal is based on the benefits and costs form the viewpoint of society as a whole, while a financial appraisal is viewed from the perspective of the project sponsor, and states whether the tangible value of the output of the project will be sufficient to amortise the project loan, pay operation and maintenance costs, and meet the interest on other financial obligations.

In this chapter we will discuss, step-by-step, about the necessary information requirements, important issues and fundamental analytical tools for the economic and financial analysis of hydropower plants. Finally we will discuss some case studies of Pakistani hydropower projects.

### 3.1.2 INFORMATION REQUIREMENTS

The economic and financial analysis, per say, are the last but not least items required to be performed in the feasibility study. Therefore, the following information must be gathered in an orderly fashion before the appraisal can be conducted [Jiandong, 1996]. At this stage some of the following information should already be available from the previous exercise. However, pertinent issues are dealt herewith as felt necessary.

1. The project costs: the capital cost of civil engineering and electromechanical equipment, operating and maintenance costs; overhaul costs; the cost of environmental and social protection measures; useful life and economic life of the civil engineering and electromechanical equipment and their rate of amortisation.
2. The project benefits: Information on tangible and intangible benefits from the project.
3. The construction schedule: the period of construction, planning of staged development (if any), date of commissioning, etc.
4. Hydrological and hydropower parameter: annual and seasonal energy production, dependable capacity. Existing water uses and rights and potential costs that might be incurred to assure water availability.
5. Power market analysis: the energy purchaser and sponsor; rate of capacity and energy (tariff); market prices of materials and equipment; labour costs and their shadow prices obtained from the planning department of the government. Some aspects of power market analysis are dealt in this chapter.
6. The financing: the sources of fund, its yearly instalment during construction; interest rates; the basic economic and financial discount rate and rate of escalation.
7. The alternative energy sources**:** In general thermal power is taken as alternative sources. Its construction costs; energy costs, operation and maintenance costs, fuel prices, etc.
8. The environmental and socio-economic data: Impact identification and mitigation measures, acts, policies, institutional arrangements, codes concerning environmental and socio-economic management.
9. The other cost rates: fees necessary for a license and law procedures; categories of taxes and their rates; rates of insurance, etc.

### 3.1.3 PUBLIC VERSUS PRIVATE OWNERSHIP

In the present global economic recession context, many governments throughout the world, especially in developing countries, are now seeking to attract private financing in the hydropower development. In this context, it is utmost important to be clear about pertinent differences between private and public ownership.

Private ownerships are primarily concerned about the profit out of their investment, whereas the public ownership have other social responsibility, therefore lack of investment fund. There are two important differences between public and private project sponsors:

1. the taxes are levied on private project sponsors which increase the project cost
2. the private ownership entails high cost of capital than does public ownership due to property taxes on private ownership.

Because of the difference in the cost of capital, which can be as much as four to six percent, capital-intensive projects are not attractive to a private sponsor. The other deviation between private and public perception is the treatment of risk. Public entities rarely consider risk where as the private investor is mainly focused upon risk. The public sector is the guarantor as well as the financier. Private sector finance is risk averse. Investors need to assure themselves that the risk of non-repayment of the debt is effectively zero. The private investor is risk averted. J. Rashid (1994) has indicated a number of risks in private perceptions which are as follows:

- Sovereign risk
- Country risk
- Political risk
- Foreign exchange risk
- Inflation risk
- Interest risk
- Operating performance
- Project risk

In addition to this there might be land ownership and water right problems. The point of the above discussion is that even under complete liberalisation the public and private sectors will have some deviations in perception. In this regard some form of state control, by regulation, has to be maintained [Rashid, 1994].

Following are the additional important planning divergences in public and private perceptions (see Fig):

- Time horizon: The private investor has inherently short time horizons, long-term projections are viewed with suspicion.
- Revenue requirement: The private sector is profit oriented, whereas the public sector is socially responsible to maintain the utility without additional burden to the customers.
- System reliability considerations: Private concern will be cost minimisation and return maximisation. Capacity additions are essential for system reliability, but it will raise the cost of investment. Private sector will not add capacity in such case even when demand is rising rapidly. The next figure shows the contradiction between long and short term planning perceptions of public and private sectors:

| **LONG TERM CONCERN** | | | **SHORT TERM CONCERN** |
|---|---|---|---|
| Maximise Reliability | → | ← | Revenue Requirement |
| Prevent System Outages | → | ← | Minimise Energy Costs |

| | | | |
|---|---|---|---|
| Customer Satisfaction | → | ← | Financial Risk |
| Price Stability | → | ← | Hedge Against Uncertainty of Load Growth |

**Fig. 3.1: The planning perception of public and private sectors (after Rashid, 1994)**

In the view of above facts, a public sector least cost solution may result in an optimal mix which does not coincide with the least cost solution determined by the private investor(s). This would mean that the market will not be able to produce the 'desired' mix and will need intervention by means of regulating or transfer payments to induce the private sector to confirm to the society's optimal mix of generation. However, the state's intervention should be brought with care so that the private sectors are attracted to invest in the hydropower development of any nation [Rashid, 1994].

### 3.1.4 ECONOMIC AND FINANCIAL FEASIBILITY

Economic justification deals primarily with the development and application of benefit-cost analysis. The objectives of the economic feasibility are met by relating all project benefits to project economic costs. This relationship provides relevant comparisons of the feasibility of different hydroelectric configurations at a given site.

Financial feasibility, on the other hand, takes into account the availability of funds and relates financial costs to project revenues. Project financial costs are those incurred in construction, operating, and maintaining project work and facilities, and they are elements of the total cost considered in the benefit-cost analysis (economic feasibility).

In light of the foregoing discussion, it is obvious that different decision-making criteria may prevail in the public and private sectors for economic and financial feasibility study. In the following paragraphs we will investigate the possibilities of marketability of the high-head hydropower in the private and public sector's perspective.

## 3.2 POWER MARKET ANALYSIS

### 3.2.1 GENERAL

The collection and processing of data pertinent to market analysis have already been dealt in length in chapter "Data Collection and Data Processing". The present chapter is devoted to the survey of power market analysis in the public and private sectors perspective.

The hydropower and particularly the high-head hydropower is ideal to serve peak demand. Owing to rapid start up and flexibility for changing power output quickly, the high head plants are particularly suitable for fluctuating load demand. The high head plants are also suitable for providing spinning reserve for emergencies. However, a variety of complex factors affect the marketability and value of output from high-head hydropower. These are dealt in length below:

### 3.2.2 INSTITUTIONAL FACTORS

#### 3.2.2.1 PURCHASING UTILITY

Marketing of hydropower energy may be possible in two ways: (1) Marketing by Investor-owned Utilities (IOU) and (2) Marketing through public utilities (PU). Marketing power to investor-owned utilities (IOU) may be complicated that if the project has significant quantities of dependable capacity. As already said that one of the objectives of an IOU is to make a profit. In fact the higher the dependable capacity the lower is its plant factor. The plant factor is the ratio of energy supplied to the installed capacity of plant to produce energy annually.

It is obvious that due to lower tariff of electricity, the IOU may opt for the plant with highest plant factor, i.e. for base load, which contradict with the objective of high-head hydropower. Moreover, the IOU may seek for the high rate of return for their investment, which invariably leads to unfeasibility of the high-head hydropower with their capital intensive and long gestation period characteristics. For example, the Minimum Acceptable Rate of Return (MARR) sought by the private sector is in the range of 20 % to 30 %.

On the other hand, the primary motivation of the public utility is to deliver the lowest-cost service while meeting reliability and other constraints. Marketing hydropower to these organisations should be relatively easy if it offers the system a cost saving.

### 3.2.3 HYDROELECTRIC CAPACITY AND ENERGY

#### 3.2.3.1 GENERAL

For the power market analysis of hydroelectric plants the value of development is based on two components: capacity and energy costs of the most likely alternative developments. Capacity cost is the payment made for the system reliability whereas the energy cost is to generate the revenue from a hydroelectric plant. To establish the value of a hydro project, the amount of alternate capacity that the hydro development can substitute for or is equivalent to, must be determined, as well as the cost of the energy the project will displace or replace.

#### 3.2.3.2 CAPACITY

A hydropower plant can substitute the equivalent amount of power from thermal plant. While dealing with the capacity of any hydropower plant there are two terms to be understood: (1) dependable capacity and (2) peaking capacity.

*Dependable Capacity*

As per the Federal Energy Regulatory Commission (FERC) definition, the dependable hydro capacity (Fig. 3.2) is the amount of load a hydroelectric plant can carry under adverse hydrologic conditions for the time interval and period specified of a particular system load. In other words, the dependable capacity in any month is that capacity that can be relied upon for serving system load and firm power commitments on the basis of the energy available in that month and its use as limited by the characteristics of the load to be served. [UACE, 1979].

In mixed power system, the dependable hydroelectric capacity is that capacity of the system of hydroelectric plants in serving, together with the other available system capacity, the maximum annual system peak load under the adverse hydrologic conditions. The adverse hydrologic conditions are usually based on the most adverse year of record. The period of peak system load depends on the particular utility and may occur during the winter or summer months. Where a portion of storage energy is scheduled to be held as a reserve for emergency use only, the dependable capacity should also include the reserve capacity value of such energy reserve.

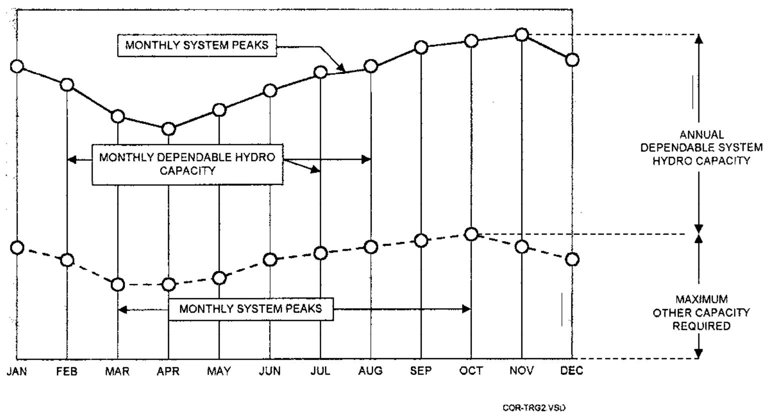



**Fig. 3.2: Annual dependable system of hydropower capacity.**

*Peaking Capability*
Hydropower with storage facility is usually meant for peaking. This peaking capability increases the project value to the local utility over what it would be in run-of- the -river operation even if there is no dependable capacity. storage capacity, turbine capacity and the flow regime must be integrated into a model by the hydrologic study to determine the amount of energy that may be shifted to peak periods.

### 3.2.4 CRITERIA FOR THE SUBSTITUTION OF THERMAL CAPACITY BY A HYDROPOWER PLANT CAPACITY

In order to establish a standard of comparison to assess the value of hydroelectric power, an analysis has been made of the costs associated with a modern coal-fired steam station. It is now necessary to consider how the cost of hydropower can be related to the cost of thermal power [Hunter and Blackstone, 1965].

There are two criteria necessary for determining the amount of thermal capacity a hydro plant can substitute for. These are the annual flow variability in the river and the most critical period for the utility. The measure is conservative because no consideration is given to the low forced-outage and maintenance rates of hydro plants when compared to thermal plants. It is also conservative to base the assessment on the most adverse year of record.

To consider the above mentioned factor a capacity credit of 5 to 15 percent due to low forced-outage rates and rapid emergency start-up for hydro facilities should usually be added to justify the use of hydropower against the thermal power.

There is another technique that might be used to account for both adverse years and forced-outage rates. This is explained by taking an example of a small hydropower plant (Fig 3.3) as outlined in UACE (1979). The power availability curve for the plant is prepared form daily stream flow records during the operation study as follows:

1. The critical period of utility system load must be established. This will generally include several months on either side of the system peak
2. The stream flow records during this period of the year from flow duration curve must be examined to establish if any of the periods of low flow are extremely rare occurrences during this period. If so, excluding them from the record may be justified.
3. With the stream flow records from 2 above; a histogram of the daily power producible from the proposed installation can be calculated.
4. The histogram can then be converted into the power availability curve shown in Fig 3.3. Note that the horizontal axis of the power availability curve is equal to one minus the cumulative probability that the capacity available will be less than or equal to the stated capacity.

5. The forced-outage rate adjustment and its rationale are clearly illustrated in Fig. 3.3 by showing the power availability curve for a thermal plant. Note that this two state on-and-off reliability model of a thermal plant is the simplest and is most commonly used. The thermal-equivalent capacity can then serve as the basis for negotiating capacity credits.

The amount of dependable capacity arrived at by any of the procedures described will almost always be less than the generator nameplate rating. Depending on the specific circumstances, assigning some value to the non-dependable capacity may be justified.

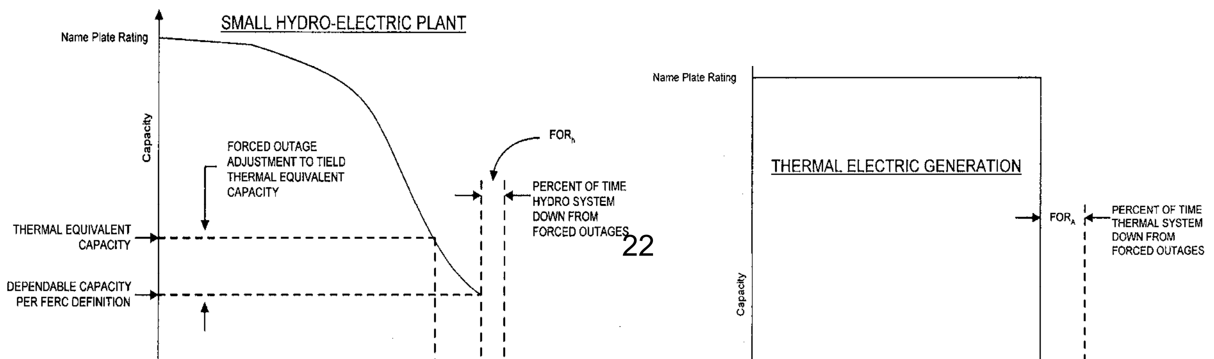


**Fig. 3.3: Capacity availability curves for (a) small hydro and (b) thermal plants (source: UACE, 1979)**

### 3.2.4.1 ENERGY

Project energy production is the amount of kilowatt-hours (kWh) input into the utility system or delivered to a final user. The power factor of generation can be an important factor in the value of energy, and, hence, it should always be stated. Because project revenues will ultimately be based on the energy delivered to the ultimate purchaser, care should be taken to account for all losses up to the point of ownership transfer. If extensive transmission is required, these losses must be included as well as step up transformer losses, generator and speed increaser losses, and station service use. Also, a loss due to forced outage should be included to avoid overstating the average annual energy output.

Energy production will vary on a yearly, monthly, and daily basis. Annual and monthly variability can be portrayed in a number of ways. One desirable method is to consider the annual energy production as a random variable and construct annual production histograms and cumulative probability distributions as in Fig. 3.5. This curve can be useful in assessing project risk.

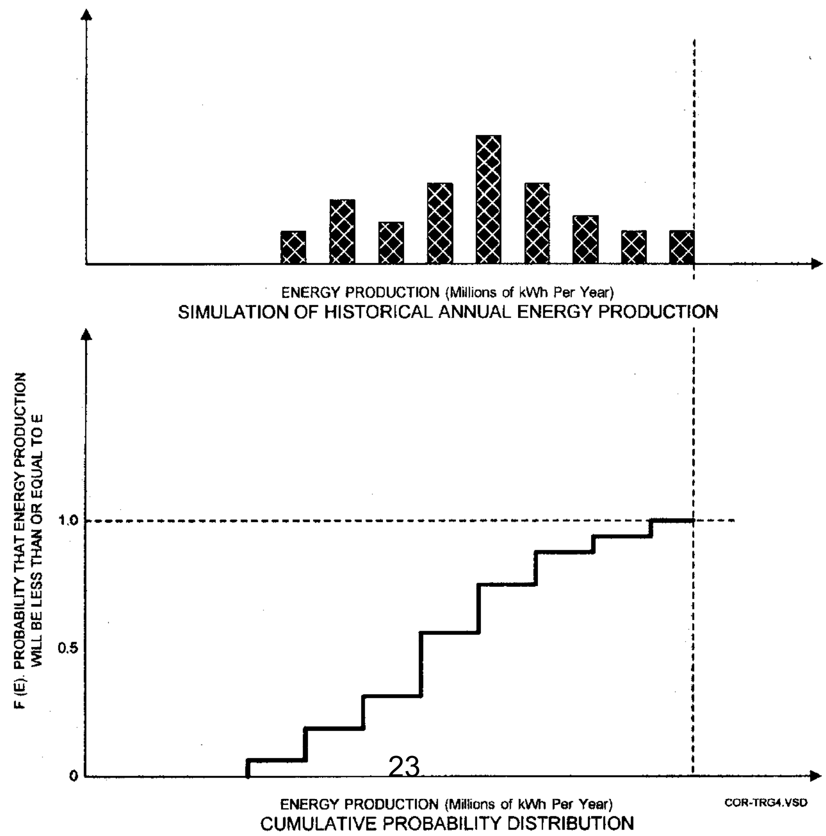


**Fig. 3.4: Annual energy production histogram and cumulative probability distribution. (source: UACE, 1979)**

The seasonality of power production can be portrayed as in Fig. 3.6. This curve is useful for assessing in broad terms how the project output would fit into a utility system and the effects of adding capacity. For example, if the project of Fig. 3.6 were located in a summer peaking utility, it is apparent that adding to installed generation capacity will do little to increase the project's ability to serve system peak-load.

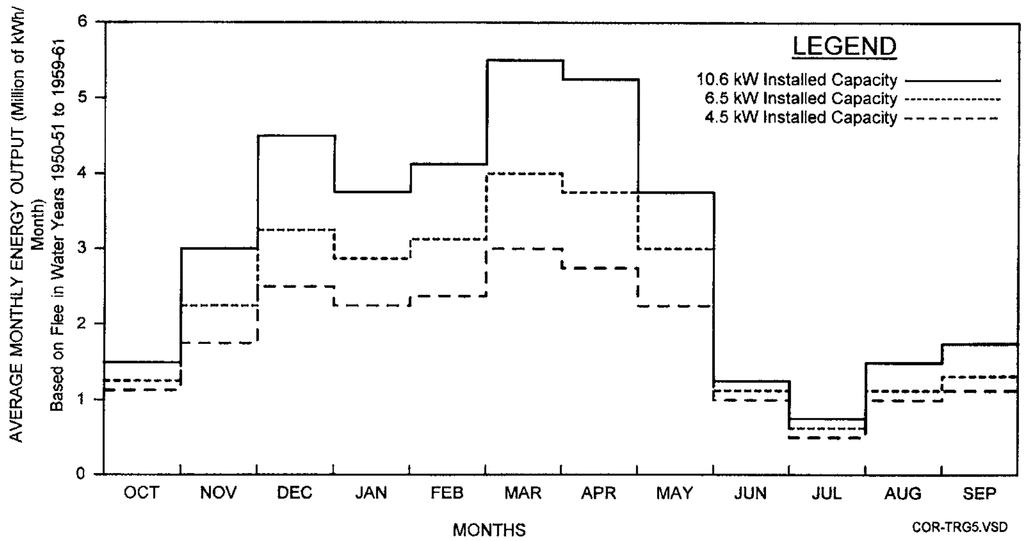



**Fig. 3.5: Average monthly energy output. (source: UACE, 1979)**

### 3.2.4.2 DETERMINATION OF VALUE OF CAPACITY AND ENERGY

Value of capacity and energy output of a hydropower plant is determined based on the costs of equivalent alternatives available to the prospective power purchaser. Therefore the value of a hydropower plant can vary widely, based on the potential purchaser.

*Determination Of Opportunity Cost As A Basis For Establishing Hydropower Value*

The value of a hydro project is determined by the power purchaser's opportunity to reduce existing costs while maintaining the same level of service using the following procedure:

1. Equivalent situations with and without the hydropower project are determined.
2. The projects maximum value to the purchaser is determined by taking the difference in the total cost between the two cases without assigning the cost of hydropower project.
3. The difference in the total cost, after including the actual cost of the hydro project, is the net value of the project and represents the opportunity cost.

Since the project's value is established by looking at the power purchasers and the costs of their alternatives, a particular purchaser can significantly alter a project's value. For example; industrial or other end user power purchasers generally require electric service to be more reliable. If the reliability is not guaranteed by the hydropower plants alone then they have to maintain some sort of a standby service arrangement with the local utility. This will ultimately affect the value of a hydropower plant. On the other hand, the utility systems with higher-cost fuels will find hydropower project attractive because of the cost of fuels displaced by it. The above saying will be clarified using two simple numerical examples described in UACE (1979) as follows:

*Example 1: User As Power Purchaser*
Problem:
Find out the gross value of small hydro output to an end user, such as an industrial plant, municipality or irrigation district, is the maximum cost reduction the purchaser can achieve without assigning any cost to the small hydropower plant. It is to be sure that the user is receiving the same level of service from local utility before and after the addition of small hydropower output.

Expected Result:
The purchaser will find the small hydro output attractive if the actual hydro costs are less than the maximum cost reduction. If so, a net cost reduction will be achieved. This example is slightly modified but contains all the essential elements that need to be understood.

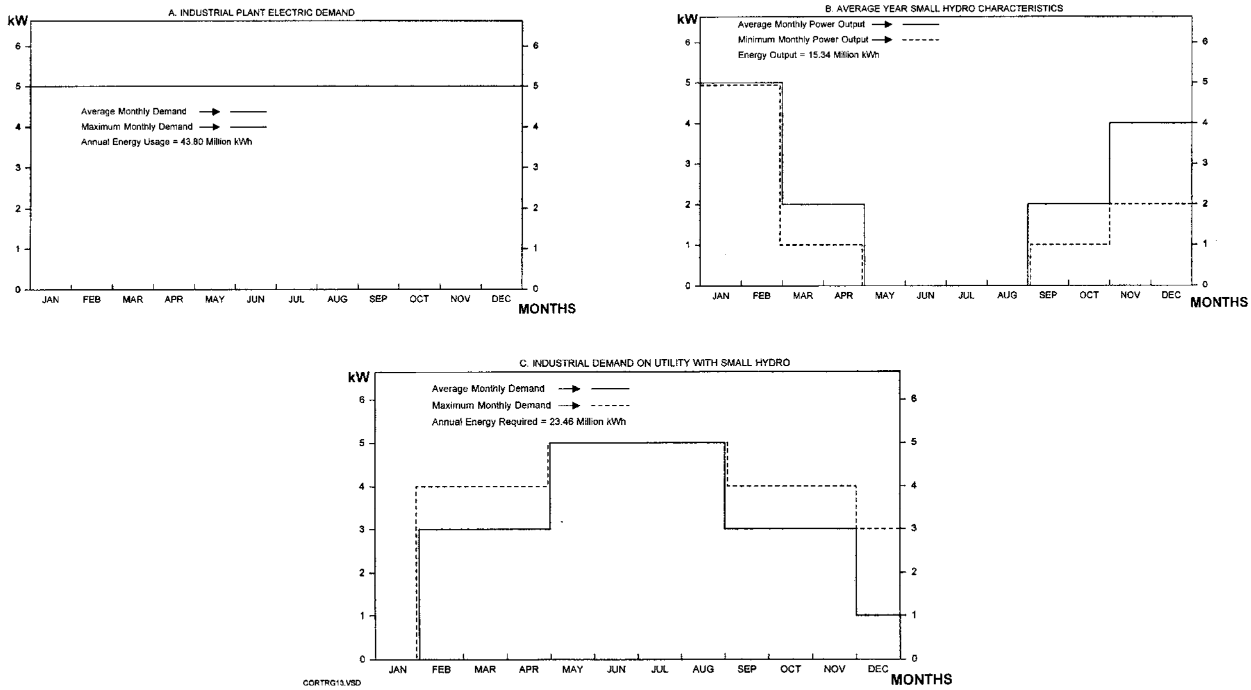
Data Input:
Fig. 3.6 specifies the load characteristics (the user load should be typified either through utility or user-metering records) of the industrial purchaser and the average monthly as well as minimum monthly power production of the small hydro project (Fig. 3.6b.). The minimum monthly value will determine the billing demand. The industrial plant is assumed to have a continuous demand of 5,000 kW (Fig. 3.6a). The small hydro project has maximum production in the winter months and drops to zero during the summer. No dependable capacity is present. Fig. 3.6c shows the industrial purchaser's demand on the local utility system (standby service) after including the small hydropower.

A simplified utility tariff for general and standby service is shown in the next table as follows:

**Table 3.1: Simplified Rate Schedule**

| General Service | Standby Service or Auxiliary Service |
|---|---|
| Rate:<br>Demand charge = $6.00 per kW demand per month Energy Charge = 3.5c per kWh per month | Rate:<br>Same as general service. |
| Minimum Bill:<br>The demand charge on 10 percent of maximum demand. | Minimum Bill:<br>$3.00 per kW of contract demand |
| Billing Demand:<br>The maximum 15-minute measured demand during the month, but not less than 90 percent of the highest demand in the preceding three months.<br>(Note: This type of clause is known as a billing demand ratchet clause. The effect of a billing demand ratchet is to increase demand charges to a customer). | Contract Demand:<br>The maximum demand the customer will place on the utility system. The utility will not meet a demand higher than the contract demand. |

Result:
The next two tables calculate the annual utility-supplied electricity cost to the industrial purchaser with and without the small hydro project. With all things equal the maximum value of the small hydro project is
$1893000 - $1305700 = $587300
i.e. $587300/153400 = 3.83 c per kWh.
Note that this is greater than just the energy displaced, i.e. 3.5 c per kWh. In this case the purchaser will not find the hydropower option attractive. However, this is not always the case and only the facts of the individual situation will determine the result.




## Fig. 3.6: Example demand pattern and small hydro output

## Table 3.2: Example industrial general service annual charges

| Month | Actual Demand (kW) | Billing Demand (kW) | Energy used (10^6kWh) | Demand* Charge ($) | Energy** Charge ($) | Total*** Charge ($) |
|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| January | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| February | 5000 | 5000 | 3,36 | 30000 | 117600 | 147600 |
| March | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| April | 5000 | 5000 | 3,6 | 30000 | 126000 | 156000 |
| May | 5000 | 5000 | 3,7 | 30000 | 129500 | 159500 |
| June | 5000 | 5000 | 3,6 | 30000 | 126000 | 156000 |
| July | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| August | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| September | 5000 | 5000 | 3,6 | 30000 | 126000 | 156000 |
| October | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| November | 5000 | 5000 | 3,6 | 30000 | 126000 | 156000 |
| December | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| | | Totals | 43,78 | 360000 | 1532300 | 1892300 |
| */ Clculated as Billing Demand, column (3), times General Service Demand Charge, $6/hr. | | | | | | |
| **/ Calculated as energy used, column (4), times energy charge, 3,5 c/kWh. | | | | | | |
| ***/ Sum of (5) and (6), or the minimum bill. | | | | | | |
| Assumptions | | | | | | |
| 1 | Demand as in Fig.1.5 (a) | | | | | |
| 2 | Rate schedule in Tab. 1.1 | | | | | |
| 3 | Minimum bill =0,1 x 5000 kW x $ 4/kW = $2000 per month | | | | | |

**Table 3.3: Example standby service annual charges for industrial user purchasing small hydro output**

| Month | Actual Demand | Billing Demand | Energy used | Demand* Charge | Energy** Charge | Total*** Charge |
|---|---|---|---|---|---|---|
| | (kW) | (kW) | (10^6kWh) | ($) | ($) | ($) |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| January! | 0 | 0 | 0 | 0 | 0 | 15000 |
| February | 4000 | 4000 | 2,02 | 24000 | 70700 | 94700 |
| March | 4000 | 4000 | 2,23 | 24000 | 78050 | 102050 |
| April | 5000 | 4000 | 2,16 | 24000 | 75600 | 99600 |
| May | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| June | 5000 | 5000 | 3,6 | 30000 | 126000 | 156000 |
| July | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| August | 5000 | 5000 | 3,72 | 30000 | 130200 | 160200 |
| September !! | 4000 | 4500 | 2,16 | 27000 | 75600 | 102600 |
| October!! | 4000 | 4500 | 2,23 | 27000 | 78050 | 105050 |
| November!! | 4000 | 4500 | 2,16 | 27000 | 75600 | 102600 |
| December!! | 3000 | 3600 | 0,74 | 21600 | 25900 | 47500 |
| | | Totals | 28,46 | 294600 | 996100 | 1305700 |
| */ Clculated as Billing Demand, column (3), times General Service Demand Charge, $6/hr. | | | | | | |
| **/ Calculated as energy used, column (4), times energy charge, 3,5 c/kWh. | | | | | | |
| ***/ Sum of (5) and (6), or the minimum bill. | | | | | | |
| !/ Minimum bill effective | | | !!/ Billing demand ratchet clause effective | | | |
| Assumptions | | | | | | |
| 1 | Demand as in Fig.1.5 (a) | | | | | |
| 2 | Rate schedule in Tab. 1.1 | | | | | |
| 3 | Minimum bill = 5000 kW x $ 3/kW = $15000 per month | | | | | |

*Example 2: Utility As Purchaser*
The following example illustrates how the value of power from a small hydro plant is calculated. To establish the value of power, information about both the small hydro project and the utility must be specified as shown in the next table.

**Table 3.4: Data for the calculation of power value**

| Small Hydroelectric Project | | Electric Utility |
|---|---|---|
| Type run-of-the- river | | System capability 6000 MW |
| Installed capacity | 7.5 MW | Peak Summer and lesser winter |
| Plant factor | 49% | Company's load duration curve see Fig. 3.7 |
| Average annual energy | 32.2 million kWh | |
| Peak production February to August | | |
| Dependable capacity | None | |

Value of the small hydro project:
Since this hydro project has no dependable capacity, its value is based on the cost of the fuels it can displace. The energy costs for each type of fossil-fired generation are calculated below. These costs are the plant heat rate times the cost of fuels expressed in the correct units. This is:

**Table 3.5: Fuel costs for different plant types**

| Plant Type | Average Heat Rate [Btu/kWh] | Fuel Cost [c/mil. Btu] | Energy Cost of Electricity [c/kWh] |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Coal-fired steam | 9,409 | 143.4 | 1.35 |
| Combined cycle | 9,044 | 276.5 | 2.5 |
| Gas turbine | 13,777 | 276.5 | 3.81 |

From the load duration curve (Fig. 3.7) at a minimum the small hydro plant would displace energy from base load coal-fired units. Therefore, the minimum value of the small hydro energy is 1.35 c/kWh. However, the value of this small hydro project is probably higher than this because it will frequently be displacing higher-cost electricity than that from the coal fired units. Making the assumption that the small hydro output occurs randomly with respect to the load-duration curve, the small hydro plant will be displacing energy from the three sources in proportion to the time these sources are the marginal energy source. From Fig. 3.7, it is seen that gas turbines are the marginal source 16 percent of the time, combined cycle units 44 percent of the time, and coal fired steam units 40 percent of the time.

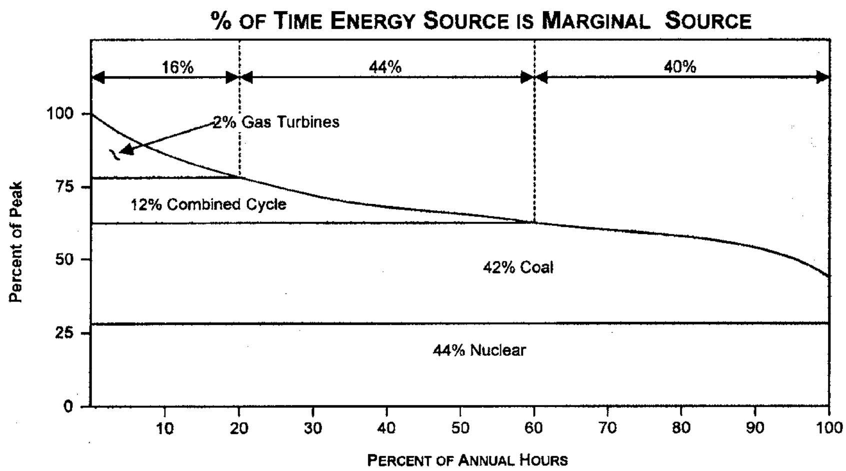



**Fig. 3.7: Annual load duration curve with energy by source superimposed (used in the power value calculation)**

These percentages can be used to calculate the weighted average value of small hydro output as:

Value = (0.16x3.81)+(0.44x2.50)+(0.40x1.35) = 2.25 c/kWh.
As is seen, this procedure substantially and justifiably increases the small hydro value.

### 3.2.4.3 MARKET ARRANGEMENT

The way in which small hydro output is marketed is an important factor in determining if financing will be available and at what price. It is imperative that adequate financial and legal consultation be obtained prior to entering into the actual power marketing agreement (PMA) or power purchase agreement (PPA).

As already mentioned that the hydropower is a capital intensive with long gestation period, the investors will be unwilling to assume any business or technical risk associated with the project. This means the principal and interest obligation associated with project financing must be assured with a high degree of certainty. This assurance can be obtained in four ways: (1) Occasionally the project will have sufficient financial strength on its own so that the risk to investors is acceptable without any guarantees; (2) Guarantees can be given by a creditworthy sponsor; (3) A credit-worthy power purchaser can 'guarantee' the debt service through the marketing agreement; or (4) A third party, such as a state government, can guarantee the debt service. These guarantees will generally be required for the duration of the project's financing.

*Time-Of-Day Consideration*
An incremental cost of electric energy is a function of the time of day. If the hydropower project has significant quantities of storage available for peaking power generation, then the marketing agreement should account for the higher value of energy displaced. This could be done either simply by adjusting a flat rate per kWh charge or by a complex rate, fully reflecting time of-day factors [UACE, 1979].

Let us discuss about the four potential types of marketing agreements available and their security effects on the project financing.

1. Cost Plus A Percentage Of Debt Service
This is a potential marketing arrangement, which has been used to secure financing for hydroelectric development. In this agreement, the power purchaser and the project sponsors enter into a 'power contract' for sale of all or a portion of the electric output. The power sponsor agrees to deliver all or part of the electric output and in return the power purchaser agrees to pay 'in all events' a pro rata share of 'all costs' of the plant, plus an additional fixed percentage of the pro rata share of debt service. Following are the advantages and disadvantages of this arrangement

**Table 3.6: Advantages and Disadvantages for cost plus percentage of debt service**

| Advantages | Disadvantages |
|---|---|
| All costs include operating costs; taxes; debt service, including principal and interest; costs of repair and replacement; costs associated with ownership, operation and maintenance etc | Due to the fixed compensation to the project sponsor at a constant amount for the duration of power contract, the fixed percentage of debt service may become a lesser percentage of the true value of the electricity. |
| The security of debt service repayment is obtained by power sponsor through the 'in-all-events' clause of the power contract which includes all unforeseen matters beyond the control of the power sponsor during the term of power contract agreement. | The power purchaser may receive a disproportionate share of the benefits. |

2. Cost Plus A Royalty Subject To Escalation
This type of power contract has been evolved to rectify some drawbacks of the first type of power contract and to secure financing for hydroelectric development. This power contract is very similar to power contract mentioned above. The difference is that in addition to the fixed percentage of debt service as compensation, the project sponsor receives a minimum per kWh payment, which is subject to escalation.

This type of contract provides the debt service security needed to obtain funds and also recognises that the future value of the project's output which is likely to rise. This combination leads to a desirable marketing plan for the project sponsors to pursue.

3. Sales Per Kilowatt-Hour.
In this type of power contract, the power sponsor sales the project's output on a per kWh basis, with the price being subject to adjustment based on an index. The power purchaser, on the other hand, simply pay for energy actually produced without the guarantee to cover 'all costs' as well as debt service in all events. In such case, either sponsor or third-party guarantees will be necessary to obtain project financing. Consequently, except with unusually attractive projects, one of the other forms of marketing the power output should be attempted.

4. Sales Per Kilowatt-Hour With Cost Guarantee And Balancing Account.
This type of arrangement values the plant output on a per kWh basis but also provides the revenue security necessary to obtain financing. Once again, the project sponsor agrees to supply electricity that the power purchaser agrees to purchase at a per kWh rate that is indexed. In addition, to provide security for debt service, the power purchaser agrees to pay 'all

costs'; the excess is used to reduce the balancing account balance, if any, with the remainder going to the project sponsor. If the project is economically sound, at the end of the financing periods the balancing account balance should be zero.

This contract has the two desirable characteristics of providing sufficient security to obtain financing and recognising that the future value of electricity will rise. This arrangement will also lead to greater sponsor revenues than in the cost plus escalating royalty contract described earlier. This is because a larger value will be subject to escalation.

## 3.3 ECONOMIC ANALYSIS

### 3.3.1 GENERAL

Economic analysis is one of the decision-making tools, which evaluates the time value of benefits and costs of a project in equivalent monetary terms. Economic analysis of hydropower projects concerns measuring both tangible and intangible benefits from the development and the costs expended for the implementation and maintaining the project throughout its economic life.

The objective of this type of analysis is to relate all project economic benefits to all project economic costs accruing to the project sponsor. The project's initial and recurring annual costs and annual revenues are equally important and are primary concern in both economic and financial analysis. However, other costs and benefits not included in the project financial analysis may properly be included in the economic analysis.

The appropriate scope of the analysis depends largely on the nature of the sponsoring organisation. If the sponsor is a private organisation then the analysis would include items directly affecting profitability from power generation. If the sponsor is a government utility then the analysis is done in broader scope, which may include flood control, recreation or other social benefits.

### 3.3.2 BASIC ELEMENTS OF ECONOMIC ANALYSIS

#### 3.3.2.1 COST AND BENEFIT STREAMS

Benefits and costs are broadly categorised as monetary and non-monetary. Most non-monetary benefits and costs can be quantified into dollar values if certain assumptions are made during the evaluation procedure. In all hydroelectric projects, the largest components of economic costs and benefits will be the present value of future cash inflows on the benefit side and the present value of the original and any future cash outlays on the cost side.[UACE, 1979].

The cost stream is composed of the capital costs, operation and maintenance costs, future replacements, quantified non-monetary costs and any other cost associated with the project affecting the project sponsor. The capital cost is the sum of money invested in a project including its interest during construction. Annual costs include the annual capital cost (the financial costs for loan amortisation and interests) and the annual operating and maintenance costs, the latter involving salaries, material expenses, water fees, overhaul expenses, insurance, interim replacement and administration, etc. If the capital cost of the transmission line is included in the total investment, then the annual cost will have two parts: power generation and power supply [Jiandong, 1996].

The benefit stream will include the value of power generation, quantified non-monetary benefits accruing to the sponsor, and other benefits. The direct benefit from the energy sale may be calculated using the following expression:

$$B_e = E_e(1-\beta)(1-\gamma)p \qquad \textbf{(3.1)}$$

with $B_e$ = benefit from energy sale

$E_e$ = effective annual energy generation, i.e. the total net energy output given out by the generator of the hydropower plant during the year after the deduction of energy loss in outage.

$\beta$ = plant use factor
$\gamma$ = grid loss factor
p = energy price

### 3.3.2.2 ECONOMIC LIFE OF PROJECT

The timing of the cost and benefit streams is important and must be accurately established. The economic life is the time, during which the project can be operated normally. The next table provides some information about the economic life of the water resources projects.

In Pakistan, the economic life of a hydroelectric plant is taken as 50 years and the economic life of 20, 25 and 30 years are taken for combustion turbine, combined cycle and steam turbine respectively. The number of economic life or interest period in the economic analysis is denoted by (n).

Renewal of the main parts of the equipment or capital repair in civil engineering is needed after that period. In cash flow calculations we sometimes take the calculation period to be that which may equal the economic life of the equipment, in this case the residual value of the civil engineering should be considered as a future benefit in cost-benefit analysis; or we take the calculation period to be that which equals the economic life of the civil engineering, in this case the expenses in the renewal of the main parts of the equipment must be considered as future capital investment

**Table 3.7: Life in years for elements of hydraulic projects**

| | | | |
|---|---|---|---|
| Barges | 12 | Pipes: | |
| Booms, log | 13 | Cast-iron | |
| Canals and ditches | 75 | 2-4 in. | 50 |
| Coagulating basins | 50 | 4-6 in. | 65 |
| Construction equipment | 5 | 8-10 in. | 75 |
| Dams: | | 12 in. and over | 100 |
| Crib | 25 | Concrete | 20 |
| Earthen, concrete or masonry | 150 | Steel | |
| Loose rock | 60 | Under 4 in. | 30 |
| Steel | 40 | Over 4 in | 40 |
| Filters | 50 | Transite, 6 in. | 50 |
| Flumes: | | Transmission lines | 30 |
| Concrete or masonry | 75 | Tugs | 12 |
| Steel | 50 | Wood-stave | |
| Wood | 25 | 14 in. and Larger | 33 |
| Fossil-fuel power plants | 28 | 3-12 in. | 20 |
| Generators: | | Pumps | 18-25 |
| Above 3000 kva | 28 | Reservoirs | 75 |
| 1000-3000 kva | 25 | Standpipes | 50 |
| 50 hp-1000 kva | 17-25 | Tanks: | |
| Below 50 hp | 14-17 | Concrete | 50 |
| Hydrants | 50 | Steel | 40 |
| Marine construction equipment | 12 | Wood | 20 |
| Meters, water | 30 | Tunnels | 100 |
| Nuclear power plants | 20 | Turbines, hydraulic | 35 |
| Penstocks | 50 | Wells | 40-50 |

### 3.3.2.3 INFLATION

Escalation in the market value of power and project cost will occur over the project life. This escalation in price levels is composed of two components: inflation, or generalised price level increases, and real price increases due to shifts in supply-demand relationships for commodities.

If escalation is going to be included in the analysis, all the costs and benefits must be escalated in a consistent manner. Depending on the given project, different escalation rates for different portions of the project may be desirable. This is done by using the factor for the future value of a present sum with the inflation rate in the place of interest. This is:

$$P_t = P_o(1+e)^t \quad \textbf{(3.2)}$$

with $P_t$ = price t years in the future
$P_o$ = current price
t = years in future
e = inflation rate in

### 3.3.2.4 CASH FLOW

The benefit and costs streams over a period of economic or useful life of the project can be represented by a cash flow diagram Fig. 3.8. This graph shows cash flow with magnitude of expenditures, plotted vertically downward arrows, and receipts, plotted vertically upward arrows, and time represented on the horizontal scale.

The basic idea for economic equivalency calculation is to convert the value of benefits and costs that occur at different times to equivalent monetary amounts, recognizing the time value of money.

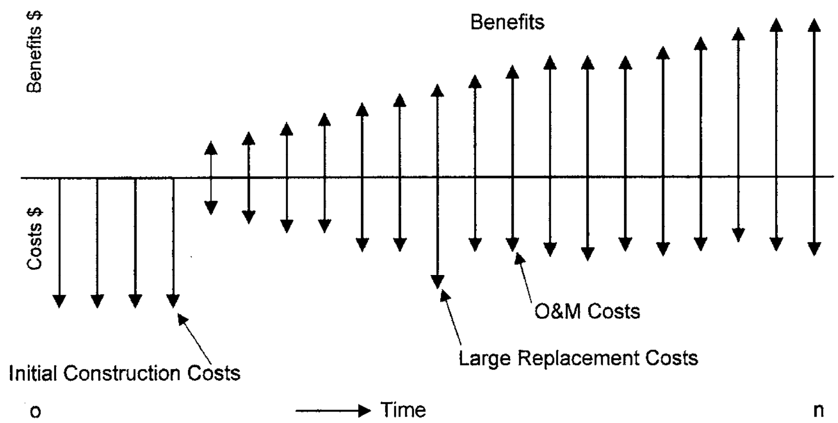



**Fig. 3.8: Cash-flow diagram**

Frequently used terms and its nomenclature in cash flow analysis are as follows:

*Discount Rate*

This is the cost of money reflecting the time value of money. The proper rate to be used for testing economic feasibility is the opportunity cost of capital to society. This is the rate of return that could be earned by investing the capital cost of the project in a venture of similar risk or an alternative marginal project. The social discount rates are different in different countries; usually it takes around 10 percent. For example, in Pakistan for the economic evaluation of hydropower plants the discount rate as minimum rate of return is taken as 12 %.

*Interest Rate*

This is the price paid for borrowing money expressed as a percentage of the amount borrowed or the rate of return (discount rate) applied in computing the equivalency of present worth and future worth. It is used to ascertain financial feasibility. The interest rate is set in the capital market and fluctuates with changes in the health of the economy and government fiscal and monetary policies. The nomenclature for an interest rate is (*I*)

*Present Value*
The present value or the present worth is the value or worth obtained by discounting all future costs and revenues into the present time frame so that they can be compared on a current monetary basis. The sum of these values represents the net present value. In other words, the present value is the sum of money at the present, the value of an investment at the present, or the value of money expended in the future discounted back to the present. This is denoted by (*P*).

*Future Value*
This is a sum of money at a future time, the value of a future investment, or the value of an expenditure at present discounted out to that future time. The future value is expressed by (*F*).

*Annual Equivalent Value*
This is a discounted uniform annual amount expended or paid that is equal to a present invested amount to cover some given activity over a fixed period of time. It is usually denoted by (*A*).

The process of mathematically obtaining the present value of future benefits and costs is called discounting. This recognises the time value of money in the form of the willingness to pay interest for the use of money.

Graphically the above mentioned terms are shown in the Fig. 3.9.

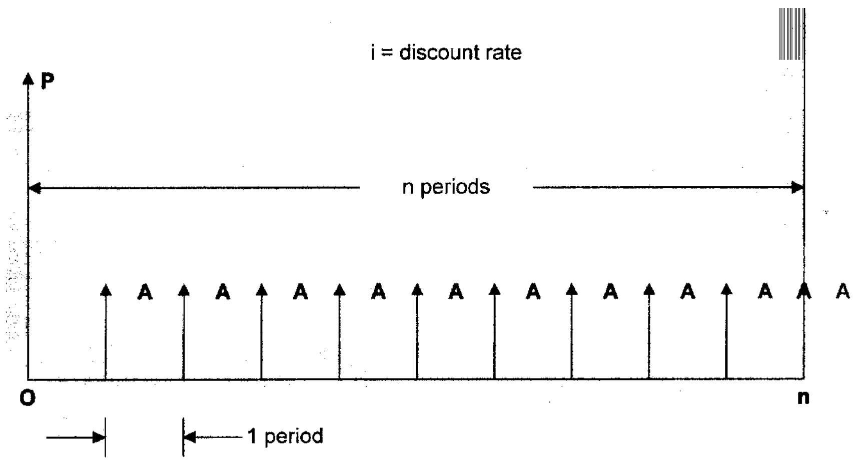



**Fig. 3.9: Definition sketch of discounting terms (Warnik, 1984)**

Let us briefly discuss about the discounting factors used in economic and financial analysis.

*Single-Payment Compound Amount Factor (SPCAF)*
This is the factor to convert an initially invested amount (P) or present value into the future amount or value (F) with an interest rate of (i) for a period of (n). A functional designation for SPCAF is (F/P, i, n) and expressed as follows. The derivation of this formula is shown as below.

$$\frac{F}{P} = (1+i)^n \qquad \textbf{(3.3)}$$

**Table 3.8: Derivation procedure of formula**

| Year Of Investment | Relationship Between Present And Future Value |
|---|---|
| 0 | $F = P$ |
| 1 | $F = P + P * i = P(1+i)$ |
| 2 | $F = P(1+i) + [P(1+i)]i = P(1+i)^n$ |
| . | . |
| . | . |
| n | $F = P(1+i)^n$ |

The standard functional representation was introduced by the American Society for Engineering Education (ASEE) should read as: given P, find F with interest i in n period in the future. In many engineering economic literature the value of the SPCAF is given in tabular form.

*Single-Payment Present Worth Factor (SPPWF):*
This is the factor, which converts the future accumulated amount for a given time frame with an interest rate into the present value. The functional designation of this factor is (P/F, i, n) and, obviously, is the inverse of the SPCAF as shown below:

$$\frac{P}{F} = \frac{1}{(1+i)^n} \quad \textbf{(3.4)}$$

*Uniform-Annual-Series Factors (UASF)*
Sometimes cash flow of equal magnitude will occur over a series of years. This provides a means of calculating a series of equal annual payments that is equivalent or equal to a present worth P, or a future worth value, F, based on a defined interest rate for discounting for a period of n. There are four frequently used terms for UASF as follows:

- Uniform-Series Present Worth Factor (USPWF)

This factor is concerned with the present-worth value of a series of equal payments made over some specified period of time and discounted at rate i. Graphically, this may be represented as below (Fig. 3.10):

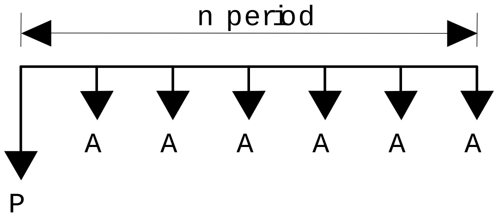



**Fig. 3.10: Uniform series cash flow over a uniform period**

Following the equation (3.2), the present worth of the above cash flow would be

$$P = \frac{A}{(1+i)} + \frac{A}{(1+i)^2} + \dots + \frac{A}{(1+i)^n} \quad \textbf{(3.5)}$$

Multiplying both sides by $(1+i)$, we get

$$P(1+i) = A + \frac{A}{(1+i)} + \dots + \frac{A}{(1+i)^{n-1}} \quad \textbf{(3.6)}$$

subtracting (3.5) from (3.6) and with some algebraic rearrangement, we get:

$$\frac{P}{A} = \frac{(1+i)^n - 1}{i(1+i)^n} \quad \textbf{(3.7)}$$

The factor $[(1+i)^n - 1]/i(1+i)^n$ is called the uniform-series present-worth factor and is functionally noted as (P/A,i,n).

- Capital Recovery Factor (CRF)

This is the inverse of USPWF. The factor is concerned with the capital recovery amount that is also known as annual debt service in financial terms. This is the annual uniform payments that are made and discounted at the rate i from a present worth. Functionally the CRF is noted as (A/P,i,n) and is equal to:

$$\frac{A}{P} = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{3.8}$$

- Sinking Fund Factor (SFF)

A sinking fund is a separate fund into which payments are made to accumulate some desired amount in the future. If we multiply both side of the equation (1.4) by P and rearrange it, then we get the following equation:

$$\frac{A}{F} = \frac{i}{(1+i)^n - 1} \tag{3.9}$$

The factor $i / [(1+i)^n - 1]$ is called the sinking fund factor (SFF) and is functionally noted as (A/F,i,n).

- Compound Amount Factor (CAF)

This factor is the inverse of the sinking fund factor and is also known as the uniform-series compound-amount factor (USCAF), which is functionally noted as (F/A, i, n) and is equal to:

$$\frac{F}{A} = \frac{(1+i)^n - 1}{i} \tag{3.10}$$

Compound amount is the value a series of payments compounded at rate i will have in the future.

*Uniform-Gradient Series Factors (UGSF)*

These factors are used to calculate present-worth or annual-equivalent amounts wherein the periodic payments are uniformly increasing (Fig. 3.11).

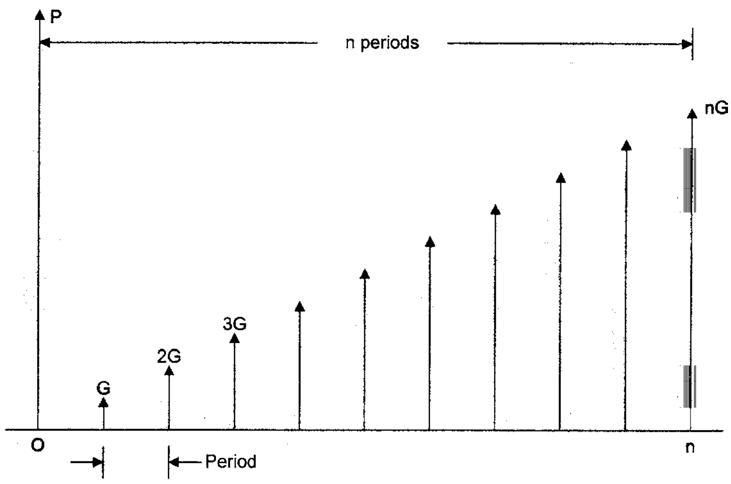



**Fig. 3.11: Gradient series cash-flow diagram**

The present worth uniform gradient series factor (PWUGSF) is functionally noted as P/G, i, n and can be determined by the expression:

$$\frac{P}{G}=\frac{(1+i)^{n+1}-(1+n*i+i)}{i^2(1+i)^n} \tag{3.11}$$

### 3.3.2.5 ECONOMIC EVALUATION CRITERIA

A number of frequently used decision criteria are available for evaluating the economic feasibility of hydropower projects. Economic decision criteria can be grouped into two classes: those most suitable for screening and those most suitable for ranking.

Screening refers to determining if a project has an acceptable economic return. Screening the various plans will yield those that have acceptable results; all others will be rejected as uneconomic developments. Ranking refers to determining the order of economic preference among projects. The ranking process helps choose which is the most economically desirable project among the group of acceptable plans.

For the clear understanding of the methods of economic evaluation discussed below, we shall use a classical example presented in UACE (1979) with some modification. The parameters of a hypothetical hydropower project are:

**Table 3.9: Parameters of Hydropower Project**

| Description | Parameters |
|---|---|
| 1. Installed Capacity | 2 MW |
| 2. Annual energy production | 9.8 million kWh/year |
| 3. Plant factor | 56 percent |
| 4. Lump sum cost per kW | \$750 |
| 5. Annual O&M | \$45,000 |
| 6. Expected financing cost | 10 percent |
| 7. Construction period | 2 years |
| 8. Financing period | 12 years |
| 9. Escalation | 0.0 and 7.0 percent |
| 10.Value of energy | 2.5 c/kWh |

### 3.3.2.6 METHODS OF ECONOMIC EVALUATION:

There are four frequently used methods of economic evaluation which we discuss in brief below. However, there are others methods such as annual worth comparison and future worth comparison are dealt elsewhere in the literature [Warnik, 1984, Kaplan, 1983].

*Net Present Value (NPV) Comparison*

The Net present Value comparison requires converting all cash flows of net benefit to an equivalent present value. This can involve three important concepts in discounting practice: (1) salvage value, (2) future required replacement costs, and (3) project life or discounting period of analysis which is the most important element of NPV when comparing two alternatives. [Warnik, 1984]. If the project life of alternatives is different, then a least common multiple of lives must be used and identical replacement consideration made. The process of discounting all net benefit into the present value is shown in the next two tables.

**Table 3.10: Example Calculation of NPV; B/C Ratio without escalation**

| Escalation = | | 0 | % | Annual Energy Production = | | | 9800000 | kWh/y | |
|---|---|---|---|---|---|---|---|---|---|
| interest = | | 10 | % | Value of Energy = | | | 2,5 | c/kWh | |
| Year | Capital Cost (\$) | Other Costs (\$) | Total Costs (\$) (2+3) | PV of Costs (\$) (4X9) | Total Benefits (\$) | PV of Benefits (\$) (4X9) | Net Annual Benefits (\$) (6-4) | Present Value Factor | Net Present Value (\$) |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| 0 | 600000 | | 600000 | 600000 | 0 | 0 | -600000 | 1,000 | -600000 |
| 1 | 900000 | | 900000 | 818182 | 0 | 0 | -900000 | 0,909 | -818182 |
| 2 | | 45000 | 45000 | 37190 | 245000 | 202479 | 200000 | 0,826 | 165289 |
| 3 | | 45000 | 45000 | 33809 | 245000 | 184072 | 200000 | 0,751 | 150263 |
| 4 | | 45000 | 45000 | 30736 | 245000 | 167338 | 200000 | 0,683 | 136603 |
| 5 | | 45000 | 45000 | 27941 | 245000 | 152126 | 200000 | 0,621 | 124184 |
| 6 | | 45000 | 45000 | 25401 | 245000 | 138296 | 200000 | 0,564 | 112895 |
| 7 | | 45000 | 45000 | 23092 | 245000 | 125724 | 200000 | 0,513 | 102632 |

**Table 3.11: Example Calculation of NPV, B/C Ratio with escalation**

| Escalation = | | 7 | % | Annual Energy Production = | | | 9800000 | kWh/y | |
|---|---|---|---|---|---|---|---|---|---|
| interest = | | 10 | % | Value of Energy = | | | 2,5 | c/kWh | |
| Year | Capital Cost | Other Costs | Total Costs ($) | PV of Costs ($) | Total Benefits | PV of Benefits ($) | Net Annual Benefits ($) | Present Value Factor | Net Present Value |
| | ($) | ($) | (2+3) | (4X9) | ($) | (4X9) | (6-4) | | ($) |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| 0 | 600000 | | 600000 | 600000 | 0 | 0 | -600000 | 1,000 | -600000 |
| 1 | 963000 | | 963000 | 875455 | 0 | 0 | -963000 | 0,909 | -875455 |
| 2 | | 51521 | 51521 | 42579 | 280501 | 231819 | 228980 | 0,826 | 189240 |
| 3 | | 55127 | 55127 | 41418 | 300136 | 225496 | 245009 | 0,751 | 184079 |
| 4 | | 58986 | 58986 | 40288 | 321145 | 219346 | 262159 | 0,683 | 179058 |
| 5 | | 63115 | 63115 | 39189 | 343625 | 213364 | 280510 | 0,621 | 174175 |
| 6 | | 67533 | 67533 | 38121 | 367679 | 207545 | 300146 | 0,564 | 169425 |
| 7 | | 72260 | 72260 | 37081 | 393416 | 201885 | 321156 | 0,513 | 164804 |
| 8 | | 77318 | 77318 | 36070 | 420956 | 196379 | 343637 | 0,467 | 160309 |
| 9 | | 82731 | 82731 | 35086 | 450423 | 191023 | 367692 | 0,424 | 155937 |
| 10 | | 88522 | 88522 | 34129 | 481952 | 185813 | 393430 | 0,386 | 151684 |
| 11 | | 94718 | 94718 | 33198 | 515689 | 180746 | 420970 | 0,350 | 147548 |
| 12 | | 101349 | 101349 | 32293 | 551787 | 175816 | 450438 | 0,319 | 143524 |
| 13 | | 108443 | 108443 | 31412 | 590412 | 171021 | 481969 | 0,290 | 139609 |
| 14 | | 116034 | 116034 | 30555 | 631741 | 166357 | 515707 | 0,263 | 135802 |
| | 1563000 | 1037656 | 2600656 | 1946873 | 5649460 | 2566611,4 | | | 619738 |
| | | NPV OF PROJECT @ | | | 10 | % | 619738 | | |
| | | B/C | | | | | 1,32 | | |

In the table 3.10, if we set the first year of construction as the base year, the procedure is to discount the net benefit from each year to the base year, then to obtain their cumulative sum as follows:

$$NPV = \sum_{j}^{n} \frac{B_j - C_j}{(1+i)^j} \tag{3.12}$$

where j=1,2,3.....n

A diagram of equation (3.12) is shown in Fig. 3.12 where m is the construction period; A is the annual operation and maintenance costs, B is the annual benefit; P is the annual investment and C is the total of P and A.

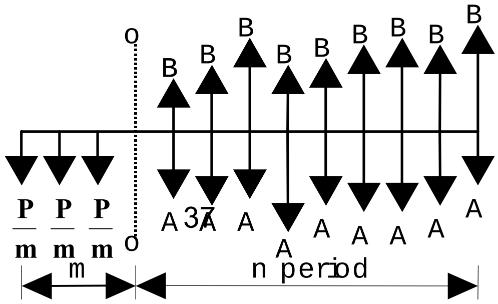


**Fig. 3.12: Cash flow diagram for NPV analysis**

It is to be noted the impact of an inflation in NPV illustrated in the table 3.11. Without escalating the benefit and cost streams the project has a negative NPV while including escalation indicates an economically feasible project.

The Net Present Value criterion incorporates all of the pertinent economic data into a consistent one-figure decision rule that allows projects to be both screened and ranked. The screening decision criterion is to reject the project if the NPV is less than or equal to zero for a given discount rate. Without constraints on the amount of capital available for the project, the project with highest NPV is ranked highest. Budget constraints should be checked in this case. [UACE, 1979].

*Benefit-Cost Ratio (B/C)*
The Benefit-cost ratio compares the present value of future cash inflows to the present value of the original and all subsequent outflow by dividing the inflows by outflows. If the B/C >1, then the project is said to be economically viable. The projects that have the ratio below one should be rejected. This is the most commonly used decision rule. The rule incorporates all the essential elements of a valid economic comparison. It can be determined using the following formula

$$\frac{B}{C}=\frac{\sum_{j}^{n} B_{j} \Big/ (1+i)^{j}}{\sum_{j}^{n} C_{j} \Big/ (1+i)^{j}} \qquad \textbf{(3.13)}$$

In the table 3.11 the present value of the escalating present value stream of benefits is $2..567 million and of the escalating present value stream of costs is 1.947 million. The B/C ratio is then 1.32 indicating an economical feasible project.

The B/C ratio can also be attained by converting the capital cost and its interest during the construction period to an annuity value. Therefore,

$$\frac{B}{C}=\frac{B}{(P+I)\frac{i(1+i)^{n}}{(1+i)^{n}-1}+A} \qquad \textbf{(3.14)}$$

with B = annual benefit
A = annual operation and maintenance costs
P = total investment
I = interest during the construction period
n = calculation period from the first year of commissioning

*Rate Of Return Comparison*
Rate of return is the rate of return over an investment. In public investment economics the rate of return refers to internal rate of return (IRR), which means the interest rate that makes the net present value (NPV) equal to zero. At this interest or discount rate the benefits equal to costs or the B/C ratio equal to one.

If the project has IRR less than expected cost of financing used to implement the project then the project is rejected. This criterion has the appeal of being expressed as percentage that is readily comparable with the expected cost of financing. In actual practice most companies, industries, or even government agencies set a limit on interest rate which is often called the 'minimum attractive rate of return,'(MARR). MARR is the lowest rate the decision-making entity will accept for expending investment capital. In Pakistan the MARR ranges from 8-12%. Like the NPV, internal rate of return incorporates all the pertinent economic data. The criterion does not, however, reflect any information on project scale, and, consequently, it cannot be used as the sole ranking criterion.

IRR is determined through an iteration process. In the foregoing example, for an escalated value, the NPV have been calculated with various interest rates, discount rate, and a graph is plotted. (Fig. 3.13). From this graph, it is clear that the IRR is equal to 15.9 % where the NPV is zero. If the government puts the MARR equals to 10 % then the project is said to be economical viable.

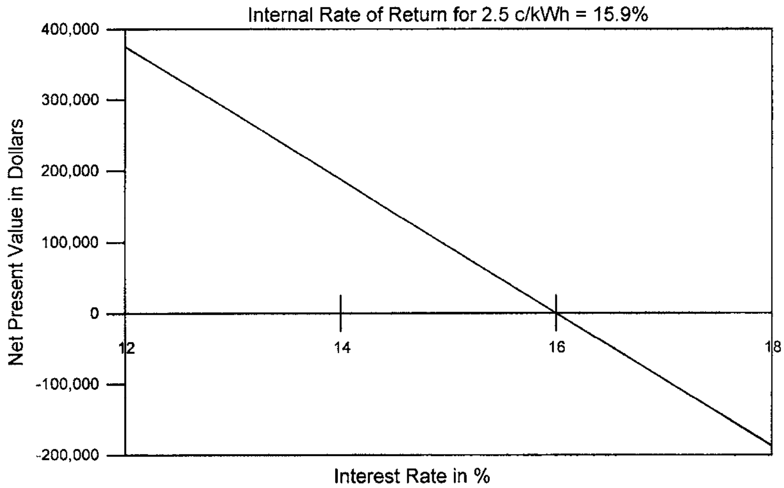



**Fig. 3.13: Determination of Internal Rate of Return**

*Net Benefit Comparison*
This is also known as the marginal costs and benefits method. This technique is useful to determine the best size of the project. There are two ways of expressing the net benefit of different alternatives requiring comparison.

In the first case the total present-worth of costs and benefits is plotted on a common axis against a scale or alternatives for development (Fig. 3.14). The vertical distance between the curves represents the net benefit. The slope of the benefit curve is known as the marginal benefit and the slope of the cost curve is the marginal cost. When the two curves have the same slope, or marginal benefit equals marginal cost, the maximum net benefit is reached. This is normally the optimum size or scale to develop the project being analysed. Under private investment policy the choice may be made to develop to a different scale based on some expected changes in economy, taxing policy, or inflation trends. In any case, net benefit can be used to compare different sizes of projects or alternatives.

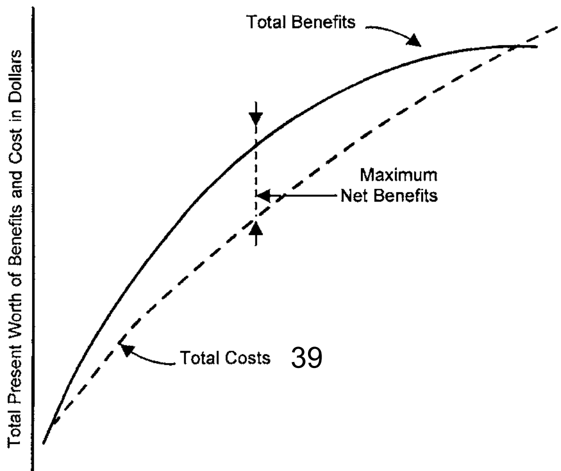


**Fig. 3.14: Graphic representation of net benefit (source Warnik, 1984)**

Another way of expressing net benefits is to plot the present-worth of benefits against the present-worth of costs for different scales of development or different alternatives. Fig. 3.15 shows graphically the significance of such a benefit-cost analysis.

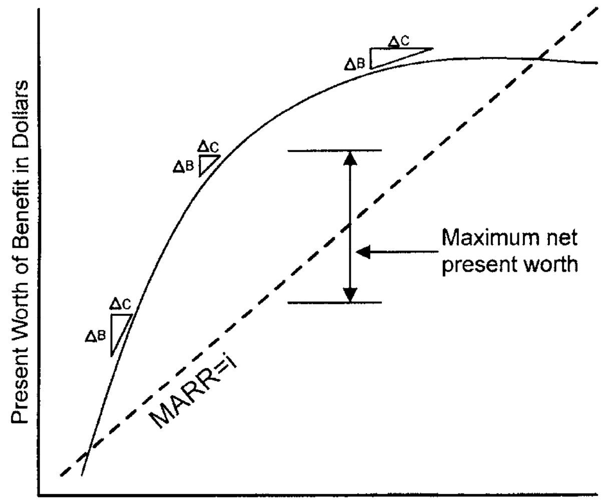



**Fig. 3.15: Graphic representation of benefits versus costs for varying size of development.**

Note that the 45° line represents the point where net present worth is zero and the marginal acceptable rate of return, MARR, is the i value that is used in the discounting of the benefits and costs. For the example illustrated, above the point of maximum net present worth of the unit return (benefit) from an increase in size of development is less than the present worth of unit expenditure or unit cost for that increase in size.

### 3.3.2.7 OTHER ECONOMIC CRITERIA AND CONSIDERATIONS

Several other decision criteria are available for evaluating investment alternatives. These include the average rate of return (ARR) and the pay back method (PB), among others. The ARR method is similar to the IRR, but does not discount future cash inflows and outflows; thus it does not take into account the time value of money. PB is actually a measure of how quickly the original investment is returned in absolute dollars, and it ignores potentially great future gains.

In applying the foregoing methods of comparison, there are further considerations that must be made and evaluated on the cost and benefit sides of analysis. These include cost of money, depreciation and amortisation, interim replacement, insurance, and taxes. On the benefit or value sides of power economics, consideration must be given to the capacity value of the power and the simple energy value as well as other intangible socio-economic and environmental benefits. Some of these criteria and considerations are incorporated in the discussion of financial analysis.

### 3.3.2.8 CONSIDERATION OF UNCERTAINTY

Uncertainty is the lack of sureness about an outcome or quantity. Such uncertainty creates risk when an action is undertaken. In hydropower projects, uncertainty surrounds uncertain flow rate of the water, capital cost estimated, future annual costs, escalation rates, and the future value of energy. Because these quantities are not known with certainty, an outcome unfavourable to the project sponsor is possible. This risk should be analysed and minimised to the extent feasible. Various methods are available to analyse the uncertainty in the energy related investment, however we will deal with only two of them briefly here, which are highly used in practice. Readers are encouraged to refer Kaplan (1983) for details.

*Sensitivity Analysis*

It is defined as the investigation of the impact on the decision criteria of variations in the important project parameters taken one at a time. The analysis is very useful for examining the degree to which the overall project desirability could be affected by changes in parameters whose values may vary.

There are many uncertainties concerning investment, income, costs, interest rate, and economic life of the plant. In order to evaluate the effects of a variable quantity, a sensitivity analysis of the NPV determined for the foregoing example has performed. The following table presents only the summary of this analysis and shows how the present worth varies with the different scenario. The base case is taken for the interest rate of 10 % and the escalation of 7 %.

**Table 3.12: Sensitivity analysis for different scenario**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Table.... Sensitivity Analysis for different Scenario | | | | | | | | | |
| Base case: | | | | | | | | | |
| Escalation = | 7 | % | Annual Energy Produ | | 9800000 | kWh/y | | | |
| Interest = | 10 | % | Value of Energy= | | 2,5 | c/kWh | | | |
| Scenario | Capital Costs $ | Benefits $ | Other Costs $ | Economic Life (years) | Interest Rate % | NPV $ | B/C | Change in NPV % | Change in B/C % |
| **Base Case** | **1563000** | **5649460** | **1037656** | **14** | **10** | **619738** | **1,32** | **0** | **0** |
| Invest.+10% | 1719300 | 5649460 | 1037656 | 14 | 10 | 472193 | 1,23 | -24 | -7 |
| Invest.-10% | 1406700 | 5649460 | 1037656 | 14 | 10 | 767284 | 1,43 | 24 | 8 |
| **Benef. +10%** | **1563000** | **6214406** | **1037656** | **14** | **10** | **876400** | **1,45** | **41** | **10** |
| Benef. -10% | 1563000 | 5084514 | 1037656 | 14 | 10 | 363077 | 1,19 | -41 | -10 |
| O.Cost +10% | 1563000 | 5649460 | 1141422 | 14 | 10 | 572597 | 1,29 | -8 | -2 |
| O.Cost -10% | 1563000 | 5649460 | 933890 | 14 | 10 | 666880 | 1,35 | 8 | 2 |
| Interest+10% | 1563000 | 5649460 | 1037656 | 14 | 11 | 489234 | 1,26 | -21 | -5 |
| Interest-10% | 1563000 | 5649460 | 1037656 | 14 | 9 | 763879 | 1,38 | 23 | 5 |
| **Eco.Life +10%** | **1563000** | **5649460** | **1037656** | **15,4** | **10** | **882481** | **1,44** | **42** | **9** |
| Eco.Life -10% | 1563000 | 5649460 | 1037656 | 12,6 | 10 | 485489 | 1,25 | -22 | -5 |
| Pissimistic | 1719300 | 5084514 | 1141422 | 14 | 11 | 58741 | 1,03 | -91 | -22 |

From the table one may see that a change in the income has the greatest effect on the present worth and cost benefit ratio. Economic life, in this case, has also some effects in the present worth. Change in other costs (O&M costs) has insignificant influence, whereas, the investment, benefits and the interest rate are important items to check.

The sensitivity analysis provides important data for decision-making. It indicates on which variable quantities to be checked to get satisfactory results. Finally there is the possibility to determine admissible limits for each variable quantity, up to which the project would still be justified in terms of economic efficiency. As shown in the table 3.12, even a pessimistic evaluation, when all costs and interest rate increase by 10 % and the benefits decrease by 10 % but the economic life taking as base case, the hypothetical hydroelectric project is still economically justifiable to implement.

*Risk Analysis*
Risk may be defined as the probability of the occurrence of an unacceptable outcome [UACE 1979]. Among the various methods of evaluation account for risk, the discount rate approach and Monte Carlo simulation technique are popular. Readers may find description of these methods in Kaplan (1983), UACE (1979), etc.

The discount rate method accounts for risk by increasing the discount rate associated with a project. An increase in the discount rate will decrease the NPV, IRR or B/C ratio. In this way a project with more risk would have to meet higher requirements in order to be judged economically feasible. Fig. 3.16 shows an example of the sensitivity analysis using discount rate.

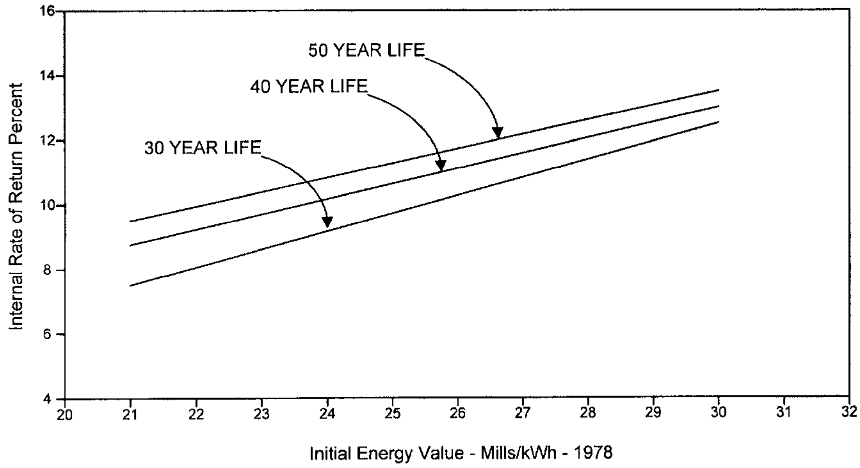



**Fig. 3.16: Example of risk analysis using discount rate method**

Monte Carlo simulation method considers the variation in parameters as stochastic elements. The risk analysis to be evaluated is to find the probability distribution of the criterion in terms of the variation in parameters. This method allows uncertainty in a number of the projects' parameters to be simultaneously accounted for and the impacts on the decision criteria can be quantified. Fig. 3.17(a) shows a graphical example of probability distribution of a project parameter using triangular probability distribution curve and Fig. 3.17(b) shows an example of probability of possible outcomes from Monte Carlo Simulation.

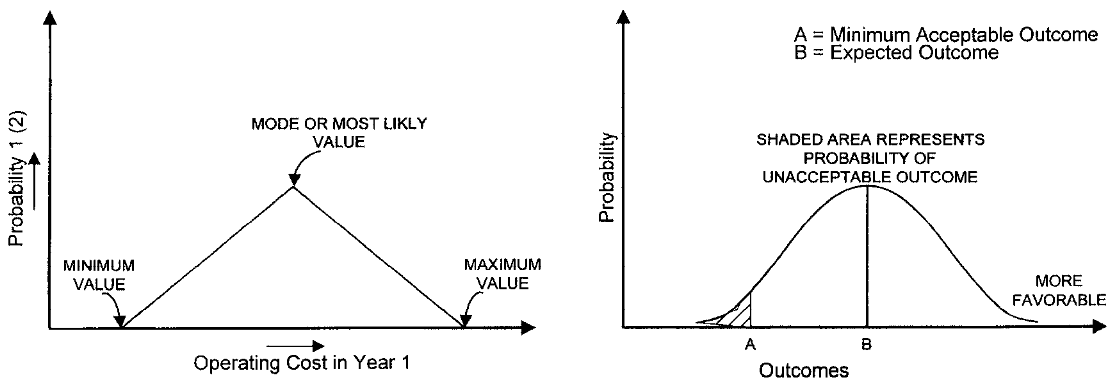



**Fig. 3.17: Example of risk analysis using (a) triangular probability distribution and (b) Monte Carlo simulation.**

#### 3.3.2.9 SUMMARY OF ECONOMIC ANALYSIS PROCEDURE

The following table summarises the steps in the economic analysis for hydropower project [UACE, 1979].

**Table 3.13: Economic Analysis Procedure [UACE, 1979]**

| Step | Description |
|---|---|
| 1 | Determine if inflationary or constant dollar analysis will be used. In an inflationary analysis, establish the general escalation rate. If items such as energy values or construction costs will be escalated at a rate different than the general inflation rate, determine the appropriate rate(s) |
| 2 | Establish the project economic life |
| 3 | Assemble the unescalated cost stream (by year) for the economic life of the project. This includes the capital costs by year, operation and maintenance, replacements, quantified nonmonetary costs and other costs |
| 4 | Assemble the unescalated benefit stream (by year) for the life of the project. This includes the value of power generation, quantified nonmonetary benefits, and other benefits |
| 5 | Escalate costs and benefits as determined in step 1 |
| 6 | Establish the appropriate discount rate |
| 7 | Calculate the economic evaluation criterion chosen for use |

## 3.4 FINANCIAL ANALYSIS

### 3.4.1 GENERAL

Financial analysis is done to establish the financial feasibility of the hydroelectric project. Financial feasibility may be defined as a project's ability to obtain funds for implementation and repay these funds on a self-liquidating basis [UACE, 1979]. Whether a project is feasible depends on the project's characteristics, the sponsor and purchaser, the requirements of those providing funds and the overall credit market as it affects the cost of borrowing which is the important part of the study.

This cost of borrowing is generally considered to be the sum of the real interest rate that compensates the lender for surrendering the use of funds, the purchasing-power risk premium that compensates for expected inflation, the business and financial risk, and the marketability risk associated with low-liquidity of a debt security. Since the projects will usually be sensitive to the costs of financing, all of the above factors must be considered in determining financial feasibility.

In the financial analysis of a capital-intensive projects such as hydropower project, inflation plays two important roles:

1. It contributes to the cost of capital. High inflation rates lead to higher costs of borrowing and annual debt service requirements.
2. Once the project is financed, it will generally enhance the project's net cash receipts as time passes. Since the financing plan generally fixes debt service payments, only a portion of annual costs (operation, maintenance, replacement, etc.) Is subject to escalation.

Due to inflation, the first few years of operation will be the more difficult financially. If the project is self-liquidating in its early years with or without inflation, then it is generally assured that the project is financially feasible.

For the project to be feasible, the minimum revenue requirement (MRR) must be met with a high degree of assurance. The project's annual MRR is the amount of funds required to pay all costs incurred by the project. This requirement is the prime consideration when project financing and the power market agreement are arranged.

### 3.4.2 CRITERIA FOR FINANCIAL EVALUATION

The criteria for financial evaluation consist of the determination of cost of service, financial net present value, financial internal rate of return, financial B/C ratio, the pay back period of investment and pay back period of the loan through a financial cash-flow analysis, a financial balance analysis and a cost-profit analysis. [Jiandong, 1996].

Cost of Service Calculation. Cost of service is the cost of producing electrical energy at the point of ownership transfer. It is also denoted by c/kWh as the value of energy. If the cost of service is less than the value of the energy produced, it should be possible to negotiate a marketing agreement that allows the project to be implemented while providing the needed security in debt service payments.

The cost of service is calculated using the following steps:

1. The lump sum estimated capital cost is disbursed according to the construction period.
2. The completed cost is determined adding escalation and interest during construction
3. With the completed cost estimate and the cost of financing specified the annual debt service is determined.
4. The debt service payments plus other escalating and constant annual costs are then summed to estimate total annual cost through the project financing period.
5. The cost of service is the ratio of the total annual cost to the average annual energy production yields.

These steps have been illustrated in the following two tables taking the data from foregoing example.

From the table 3.15 one can see that the initial periods for the hypothetical hydropower project are difficult because the value of energy cost is far less than the cost of service. However, over the financing period the cost of service will increase only by 1.17 times, whereas, due to inflation, the value of energy will rise two folds. The value of energy will be 33 % higher than the cost of service at the end of the financing period.

Sensitivity analysis is also necessary for providing additional information to the decision makers. In the foregoing example, the cost of financing poses the uncertainty and subject to sensitivity analysis. In many cases the projects are not immediately implemented at the completion of feasibility study. Over this period the cost of financing may vary. For this reason, the project sponsor may need a sensitivity analysis of the effect the financing cost has on the cost of service. Other project parameters that may be desirable to investigate include initial value of the project's energy, completed cost, operation and maintenance costs, and escalation rates.

**Table 3.14: Annual Debt Service Calculation**

| | | | |
|---|---|---|---|
| Project Data | | | |
| Item | | Amount | |
| Cost of financing | | 10 | % per year |
| Financing period | | 12 | years |
| Construction period | | 2 | years |
| Construction Cost per year | | Shown below | |
| Construction Cost Escalation | | 7 | % per year |
| Lump-sum Project Cost Estimate | | 1500000 | $ |
| Capital Cost Calculation | | | |

**Table 3.15: Cost of Service Calculation**

| Escalation = | | 7 | % | Annual Energy Production = | | 9800000 | kWh/y |
|---|---|---|---|---|---|---|---|
| Cost of finance | | 10 | % | Value of Energy = | | 2,5 | c/kWh |
| Year of operat. | Bond Ammort. | Other Costs | Total Costs ($) | Average annual energy production | Cost of Service | Value of Energy | Difference in energy value |
| | ($) | ($) | (2+3) | (x1000000 kWh) | (cents/kWh) (4/5) | (cents/kWh) | (%) |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| 1 | 249666 | 45000 | 294666 | 9,80 | 3,007 | 2,500 | -20 |
| 2 | 249666 | 48150 | 297816 | 9,80 | 3,039 | 2,675 | -14 |
| 3 | 249666 | 51521 | 301187 | 9,80 | 3,073 | 2,862 | -7 |
| 4 | 249666 | 55127 | 304793 | 9,80 | 3,110 | 3,063 | -2 |
| 5 | 249666 | 58986 | 308652 | 9,80 | 3,150 | 3,277 | 4 |
| 6 | 249666 | 63115 | 312781 | 9,80 | 3,192 | 3,506 | 9 |
| 7 | 249666 | 67533 | 317199 | 9,80 | 3,237 | 3,752 | 14 |
| 8 | 249666 | 72260 | 321927 | 9,80 | 3,285 | 4,014 | 18 |
| 9 | 249666 | 77318 | 326985 | 9,80 | 3,337 | 4,295 | 22 |
| 10 | 249666 | 82731 | 332397 | 9,80 | 3,392 | 4,596 | 26 |
| 11 | 249666 | 88522 | 338188 | 9,80 | 3,451 | 4,918 | 30 |
| 12 | 249666 | 94718 | 344385 | 9,80 | 3,514 | 5,262 | 33 |

As already mentioned that the project's minimum revenue requirements must be guaranteed with high degree of certainty for the project to be able to attract funds for implementation. Following are the several ways to get a security for financing:

- Marketing arrangement: The power contract should meet the following conditions:
  - The contract must require payments sufficient to cover debt service in all events.
  - The capability of the power purchaser to give this assurance must be proven.
  - The power contract should generally be in force for the length of the financing period.
- Sponsor Guarantees: If the above-mentioned conditions are not mentioned in the power contract, the financial integrity of the project sponsor may be used as security.
  - In case of public entity, the issuing general obligation bonds (GOB) effectively secure the debt service. The GOB are referred to the taxing power of the public entity.
  - In case of private sponsor, the security for debt service is obtained through the real assets or general credit worthiness of the borrower.
- Power production as Security: This security is used, if the expected revenue from the project is adequate to cover all expenses and debt service. If the excess of revenue over costs

exceeds 25 to 30 percent of annual debt service, as a general rule the project can be financed [UACE, 1979].

### 3.4.3 FINANCIAL CASH-FLOW ANALYSIS

The method for financial cash-flow analysis is similar to the economic analysis. The cash-outflow includes the complete cost of the project including interest during construction and escalation, invest on fixed assets, annual operating and maintenance costs, financing for the renewal of electromechanical equipment during the calculation period, tax, royalties and insurance.

The cash-inflow consists of revenue from energy sales, returns on the residual value of fixed assets and others. A financial discount rate or cost of financing is used to find out the financial internal rate of return, the financial B/C ratio, and the static pay back period of investment. The pay back period is equal to the total of the years when the cumulative net cash equals or is greater than the total investment without discounting. This can be calculated using annual equivalent cost method.

The following table shows an example of calculating pay back period using annual equivalent cost. The input data for this example is taken from the forgoing example.

**Table 3.16: Annual equivalent cost used for the pay back period calculation.**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Escalation = | | 7 | % | Annual Energy Production = | | | 9800000 | kWh/y |
| Cost of finance | | 10 | % | Value of Energy = | | | 2,5 | c/kWh |
| Year of operation | Bond Ammortization | Other Costs | Total Costs ($) | Annual Benefits ($) | Net cash flow ($) | Sum of net Cash flow | | |
| | ($) | ($) | (2+3) | (6-4) | (8-7) | ($) | | |
| (1) | (2) | (3) | (4) | (8) | (9) | (10) | | |
| 1 | 249666 | 45000 | 294666 | 245000 | -49666 | -49666 | | |
| 2 | 249666 | 48150 | 297816 | 262150 | -35666 | -85333 | | |
| 3 | 249666 | 51521 | 301187 | 280501 | -20686 | -106019 | | |
| 4 | 249666 | 55127 | 304793 | 300136 | -4658 | -110677 | | |
| 5 | 249666 | 58986 | 308652 | 321145 | 12493 | -98184 | | |
| 6 | 249666 | 63115 | 312781 | 343625 | 30844 | -67340 | | |
| 7 | 249666 | 67533 | 317199 | 367679 | 50480 | -16861 | | |
| 8 | 249666 | 72260 | 321927 | 393416 | 71490 | 54629 | | |
| 9 | 249666 | 77318 | 326985 | 420956 | 93971 | 148600 | | |
| 10 | 249666 | 82731 | 332397 | 450423 | 118025 | 266625 | | |
| 11 | 249666 | 88522 | 338188 | 481952 | 143764 | 410389 | | |
| 12 | 249666 | 94718 | 344385 | 515689 | 171304 | 581693 | | |
| | | | | | 581693 | | | |

From the above table it is evident that the hypothetical hydropower project is able to pay back all its debt immediately after the 6$^{th}$ year of its operation.

### 3.4.4 CONSIDERATION OF SOCIAL AND ENVIRONMENTAL BENEFITS

#### 3.4.4.1 SOCIO-ECONOMIC BENEFITS

In general the high head hydropower sites are located in the remotest area of developing countries where its development may promote local and rural industries and agricultural development, improve the rural economic structure, develop social benefits, raise the living standards of rural residents and increase the income of local government. Rural electrification is bound to be reflected in raising the cultural level of people in rural areas, increasing the chance of employment and stabilising society. In fact the hydropower does not bring by it self the rural development rather it should be viewed as a catalyst of development only. Therefore, other rural development efforts should be carried out simultaneously to have a positive impact of hydropower development in the rural areas.

### 3.4.4.2 ENVIRONMENTAL AND ECOLOGICAL BENEFITS

The use of hydroelectricity will reduce the use of fossil fuel for energy and may reduce the deforestation and environmental pollution. Other factors such as beautifying the surroundings and promotion of tourism; are the benefits which should be solely assigned to hydropower projects.

All intangible benefits cannot be counted in terms of money. However, an approach should be made to encounter it. A long-term observation of past projects and case studies may be helpful to quantify the benefits.

The following flow chart in Fig. 3.18 summarises the procedure of economic and financial analysis.

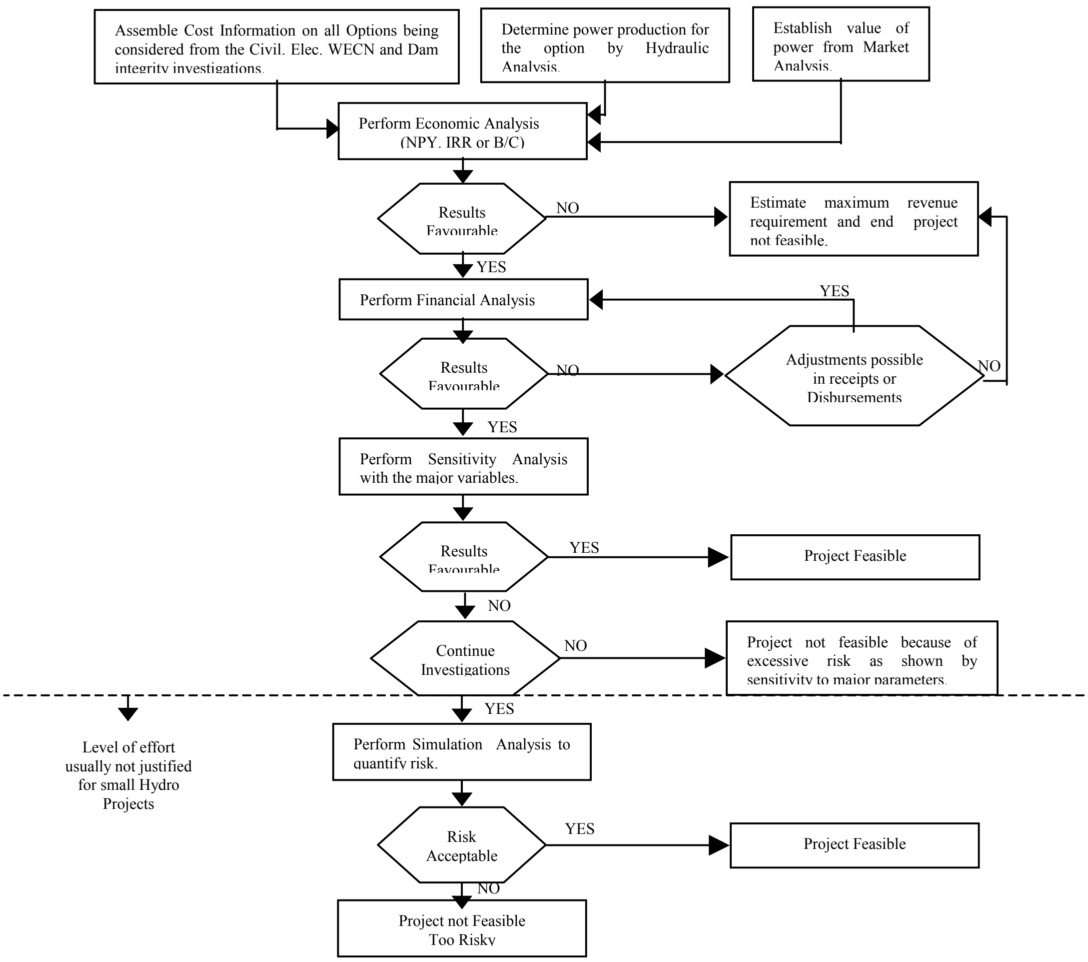



**Fig. 3.18 Flow chart of the procedure of economic and financial analysis.**

## 3.5 CASE STUDY GOLEN GOL HYDROPOWER PROJECT, CHITRAL, PAKISTAN

### 3.5.1 GENERAL

Economic analysis is a systematic and scientific approach to determine the programme of action by comparing the ex-ante performance with ex-post achievements, which essentially entail major socio-economic developments in their area of influence. Economic analysis seeks to ascertain the reward for investment and provides guidelines to establish the feasibility of the project. It is necessary that gains generated should exceed the cost of the goods and services used in its construction and operation. At least these gains must match or yield higher returns from an alternative investment. The primary objective of undertaking economic analysis is thus to determine whether the contribution of a particular project in the shape of added value benefits is adequate enough to justify use of scarce resources needed in the form of project investment costs. The economic justification of investment in a capital intensive project depends on three factors. Firstly, there is a need for the project, secondly, where technological options are available, the project represents the most economic choice of option; and thirdly, that investment in the project will produce an acceptable return to the national economy. This process involves the assessment of project benefits and identification of project costs over the economic life of the project.

The economic evaluation of Golen Gol Hydel Project will be carried out on the basis of power and energy generated by the project. As it has been established in previous sections on engineering that project will have 3 units of 35.36 MW capacity each. Hence the analysis will be carried out for three alternatives, i.e, without transmission cost (Alternative-1), with transmission cost up to Dir (Alternative-II) and up to Chakdara (Alternative-III) with necessary costs of civil works and associated electro-mechanical equipment. It is further assumed that proposed plant will run in integrated mode with the National Grid.

### 3.5.2 DERIVATION OF ECONOMIC COSTS AND BENEFITS

The economic analysis of the project requires that all costs and benefits must be evaluated at prices within the economy, which reflect their real worth. Major inputs into the scheme of economic analysis like costs and benefits including various components do not necessarily reflect their true opportunity cost to the economy because of distortions in market prices. Like many other developing countries, the prices of goods and services are distorted by subsidies and taxes in Pakistan too. The rate of foreign exchange has differed from its true opportunity cost. Due to disguised under-employment in agriculture and implications of minimum wage legislation in the industrial sector, the price of labour has generally been higher than its true opportunity cost. The purpose of economic analysis is, therefore, to evaluate the costs and benefits of the project at a level which reflects more accurately their true opportunity cost to the economy through techniques of accounting or shadow prices.

### 3.5.3 DERIVATION OF SHADOW PRICES

Shadow pricing has been used to find out true opportunity cost of capital as well as other inputs to determine the economic cost of this project to the national economy.

#### 3.5.3.1 OPPORTUNITY COST OF CAPITAL

For the purpose of economic study, shadow price of capital is defined as the opportunity cost of funds withdrawn from other uses and is considered equal to marginal cost of capital in the economy of Pakistan. World Bank has used 10% discount rate for rural electrification projects and 12% for evaluation of Kalabagh Dam Project. A discount rate of 12% has been widely used in Pakistan for economical evaluation of public sector projects by Planning Commission since mid 60's followed by a study of Havard Advisory Group on opportunity cost of capital. For the present study also, opportunity cost of capital of 12% has been adopted for assessment of economic feasibility of the project.

#### 3.5.3.2 SHADOW PRICE OF LABOUR

In cases where there is significant unemployment and under- employment in a local economy shadow wage rates for labour should be used which are considerably lower than actual wages paid. The objective in economic analysis is to use the opportunity cost in an alternative application. In Pakistan the situation is one of under-employment for unskilled labour rather than full-scale employment since there are labour shortages in rural areas in sowing and harvesting seasons. There is no employment problems for skilled labour as there are sufficient opportunities locally and in nearby oil producing countries.

The project is located in Chitral District in NWFP, where during harvesting period of crops, the labour supply is found to be scarce for construction or other economic activities. On the other hand the skilled labour force is not sufficient to meet the local needs of the area as observed in Chitral city and surrounding settlements. Therefore, shadow wage rates of 1.06 and 0.65 for skilled and unskilled labour, respectively, have been used for deriving economic cost.

#### 3.5.3.3 SHADOW PRICING OF MATERIALS

Most of the material inputs for various projects, i.e., steel, cement etc, are transported from down country involving high freight expenditures. It is, therefore, assumed that shadow rates for material may be used as 1.1, as used in the feasibility report of Kalabagh Dam Project. The results of shadow conversion factors have been applied to various components of project costs to derive adjusted economic costs.

#### 3.5.3.4 ECONOMIC COST

The economic costs have been derived by converting financial cost with adjustments for direct transfer payments like taxes, subsidies and interest during construction besides adjustments for distortions in the market prices of traded and untraded goods used in the project works. For this study, also economic costs of the project have been derived by removal of transfer payments (interest, taxes and subsidies) in addition to adjustment of cost of labour and material with appropriate shadow conversion factors. The economic cost of labour has been determined by applying shadow wage factors to the total labour cost which is equivalent to 38 percent of the local cost of the project with 40 & 60 percent as skilled and unskilled labour components respectively. The remaining components like cost of material and the locally manufactured goods 62% have been shadow priced with an appropriate conversion factor. The economic costs of the Golen Gol Hydro Power Project thus derived have been used in economic evaluation and summarised as follows:

**Table 3.17: Economic Cost Estimate [2]**

| Year | Alternative-I | Alternative-II | Alternative-III |
|---|---|---|---|
| 1 | 6.223 | 6.298 | 13.167 |
| 2 | 42.780 | 51.168 | 52.469 |
| 3 | 18.031 | 26.240 | 27.324 |
| 4 | 3.677 | 3.761 | 6.039 |
| TOTAL | 70.711 | 87.467 | 98.999 |

Exchange Rate 1US$ = Rs 40.00

### 3.5.4 ECONOMIC ANALYSIS FEASIBILITY - BENEFITS AT LRMC

Conventional project appraisal methodology based on equivalence alternative uses avoided cost concepts or treats the entire output of a generation project operating at maximum feasible load factor an addition to supplies value at the prevailing tariff.

The above approach does not take into account the impact of the proposed addition on the power system. A new generating station may contribute energy at its maximum possible, which will shift existing base load station either to intermediate or peak duty. The utilisation of these stations will fall and the net increase of output will be less than the gross generation from the project. The net increase of supply is to be valued at the governing tariff whereas the rest of the output should be valued in terms of savings in operating costs in the existing stations. Hydel power generations are generally evaluated in term of primary energy valued at the governing tariff where as secondary energy is value in term of fuel cost savings. This approach ignores the fact that power projects are part of an interlinked system and the impact of the project on other components needs to be taken into account.

Marginal cost of power supply is defined as the change in total cost of service resulting from small change in demand. This cost may change according to the place and time of use. Long run marginal costs signify economic efficiency. Long run marginal cost (LRMC) can be defined as the cost of serving additional or incremental demand in the long run, when investments can be made to minimise total costs. The main components of the LRMC structure are:

I Marginal Energy Costs (peak & off peak)
II Marginal Capacity Cost of Generation
III Marginal Transmission and Distribution Capacity Costs.

#### 3.5.4.1 MARGINAL ENERGY COSTS

For every hour of system operation, the marginal energy cost of the system is the incremental running cost of the plant best suited to accommodate demand variation. This marginal plant is usually the thermo electric unit with the highest running costs among those operated above their technical minimum.

#### 3.5.4.2 MARGINAL CAPACITY COSTS

*Generating Capacity*

Marginal capacity costs are expenses, which are necessary to be incurred in order to maintain reliability of service regardless of fuel cost. This usually means provision of capacity during peak periods. In predominant hydro system thermal generating capacity is usually required to ensure firm energy in dry years.

*Transmission And Distribution Capacity*

Network capacity costs related to the constraint of T&D capacity at the peak period of each network component and are calculated as long run averages.

*Capacity Cost By Voltage Levels*

Both marginal energy and capacity cost components are usually derived for the generation level and these need to be increased by system losses to be applicable at lower voltages of supply.

#### 3.5.4.3 APPLICATION IN PLANNING DECISIONS

LRMC constitute the best set of indicators to evaluate system changes at the margin. The expected system cost effect of an investment at the margin can be approximated as a sum of the following:

- Fuel savings under average operating conditions evaluated at marginal fuel costs for each hour block.
- Firm energy premium under dry year conditions.
- Peak capacity cost savings under peak conditions.

The cost comparison is more accurate than equivalent plant method. It is also applicable to evaluation of small projects.

### 3.5.5 VALUATION AT LRMC

The equivalence exercise described above does model the systems impact of adding hydel generation, however, the generation expansion scenario in Pakistan includes some aspects, which the equivalence basis does not capture. As the plants use various fuels with different efficiencies so the marginal energy cost differences are usually found, grouped into peak and off peak period. The present thermal generation in Pakistan is not optimal. Consequently, the expansion scenario includes addition of a large amount of base load capacity and existing thermal plants are initially relegated to peak duty and are subsequently retired and replaced by more efficient peaking gas turbines. The marginal costs developed considering the above include a portion of fuel saving due to substitution of more efficient base load generation of capability. The LRMC provides the best set of indicators to evaluate system changes at the margin. For application of LRMC for economic evaluation of hydel generating stations for grid interconnection the following need considerations:

*Marginal Energy Costs*

For every hour of system operation, the marginal energy cost of the system is the incremental running cost of the plant, best suited to accommodate demand variation. The estimate of long run marginal peak and off-peak energy cost at appropriate voltage levels substitute the two generating stations. The estimate of LRMC peak energy cost provides an indicator which signifies the value of the firm energy at peak hours that a hydel generating station can generate may be given. Secondary energy is valued at the LRM off-peak energy cost.

*Marginal Capacity Costs*
The marginal capacity cost estimate indicates the value the system places at capacity available in peak demand periods. These costs are added to LRM peak energy costs to simulate the total system costs at peak demand periods.

#### 3.5.5.1 TRANSMISSION ASPECTS

The hydel generating stations under analysis are located in mountainous areas of Pakistan, in some of these areas the grid system already exists and is serving both urban and rural loads. The impact of adding hydel generation upon transmission losses should also be included as a cost or a benefit, as the case may be. The LRMC cost estimates for capacity and energy at different voltage levels can be used as a proxy for capturing the geographic location impact of adding generation to the power system.

### 3.5.6 QUANTIFICATION OF BENEFITS

#### 3.5.6.1 LONG RUN MARGINAL COST

The benefits attributable to the project are proposed to be valued by the Long Run Marginal Cost (LRMC) of capacity, peak and off peak energy at different voltage levels. LRMC estimates and the benefits based on LRMC have been derived and presented in TABLE 3-1 to 3-4.

### 3.5.7 CONSUMER SURPLUS

The concept of consumer surplus as a measure of willingness to pay, is accepted by the loaning agencies such as World Bank and Asian Development Bank as an acceptable basis for assessing power benefits. The use of electricity confers benefits on consumers in excess of the price paid under tariff. The concept of consumer surplus has been used in the analysis of various power projects in Pakistan.

A minimum measure of willingness to pay is the electricity tariff, which ignores the fact that some customers may be willing to pay a higher price of electricity or at least might be willing to pay more for a part of their supply. The tariff reflects only the willingness to pay for the last or marginal unit, not necessarily the average willingness to pay for the total amount consumed. A reasonable measure of consumer surplus may be obtained by observing how much the consumers are prepared to pay to obtain energy from alternative sources. Customer willing to pay should be measured by the area under the pastulated demand curve for customers of various classes. It is represented by the sum of what the customer actually pays (the tariff plus the cost incurred for the wiring and appliances, necessary to make use of electricity) plus the consumer surplus which accrues to the user as a result of tariff being lower than his actual willing to pay. This total can be used to represent the amount, which the customer would be willing to pay for electricity supply or the amount that he would be willing to pay in order to avoid unserved demand.

In order to evaluate the benefits for the appraisal of the project on consumer surplus basis Kwh benefits/avoided costs of various consumer categories were developed/updated using Shydo /National Power Plan (NPP) data and summarised as under:

**Table 3.18: Benefits of the project on consumer surplus basis [2]**

| Consumer Categories | KWh Benefit / Cost [Rs.] | Weight [%]* |
|---|---|---|
| Domestic | 3.29 | 38.39 |
| Commercial | 4.44 | 4.25 |

| | | |
|---|---|---|
| Industrial | 3.18 | 30.27 |
| Agriculture | 2.58 | 17.75 |
| Others | 4.92 | 9.34 |

* Power system statistics 20th Issue.

### 3.5.8 THERMAL EQUIVALENCE BASIS

Economic evaluation of the project has also been undertaken on the basis of thermal equivalence as an alternate source of hydropower project to check its viability. This approach is based on thermal equivalent i.e. gas turbine plus oil fired steam (base case) and hydel combination (proposed/revised case).

The parameters used in thermal equivalent are as given:

**Table 3.19: Parameters for thermal equivalence basis [2]**

| Parameters | Gas Turbine | Oil Fired Steam |
|---|---|---|
| Annual energy (GWh) | 84 | 525.6 |
| Plant factor (%) | 16.67 | 75 |
| Installed Cost (Rs./kW) | 15,343 | 24,250 |
| Fuel type | Gas | Furnace Oil |
| Unit | $dm^3$ | ton |
| Fuel cost (Rs./unit)[1] | 84.7 | 3,584 |
| Fixed O & M % of capital cost | 3 | 2 |
| Specific fuel (kg./kWh)[2] | 12.5 | 0.28 |
| Useful economic life (years) | 20 | 30 |

1/ Fuel Prices at 1.5% p.a
2/ Gas CFT / kWh

### 3.5.9 RESULTS OF ECONOMIC ANALYSIS

On the basis of economic costs and benefits, economic analysis has been carried out by using LRMC, consumer surplus and thermal equivalent approaches in TABLES 3-5 to 3-17 in the appendix for the proposed hydropower project. The internal rate of return (E.I.R.R) of the project as summarised below, of the three alternatives, is higher than the opportunity cost of capital in Pakistan these days. The project has shown sound economic viability and quite lucrative for investment.

**Table 3.20: Economic Feasibility [2]**

| Alternatives | Internal Rate Of Return (%) | | | |
|---|---|---|---|---|
| | (LRMC 1) | (LRMC 2) | Consumer Surplus 100% | Thermal Equivalent |
| 1 | 17.61 | 17.11 | 20.51 | 18.70 |
| 2 | 16.51 | 16.06 | 19.28 | 15.17 |
| 3 | 14.70 | 14.28 | 17.62 | 13.14 |

### 3.5.10 SENSITIVITY ANALYSIS

Although the project has shown economic viability with higher rate of return and a positive benefit cost ratio at 12% discount rate. The project is, however, susceptible to different kinds of adverse circumstances like cost over-run, decrease in benefits etc. The economic feasibility of the project has been checked against 20% cost over-run, 10% decrease in benefits as well as combined impact of both variations, on the basis of LRMC, 100% consumer surplus and tariff+50% consumer surplus to see if the project remain feasible. The results show that project yields economically viable rates of return on different scenarios as follows:

**Table 3.21: Long run marginal cost (1) [2]**

| Sr. No. | Description | Internal Rate Of Return (%) | | |
|---|---|---|---|---|
| | | ALT I | ALT II | ALT III |
| 1 | Base case | 17.61 | 16.51 | 14.70 |
| 2 | 10% decrease in benefits | 15.61 | 14.62 | 12.94 |
| 3 | 20% cost over run | 14.58 | 13.61 | 12.01 |
| 4 | Combined impact of 2 & 3 above | 13.22 | 12.31 | 10.80 |

**Table 3.22: Long Run Marginal Cost (2) [2]**

| Sr. No. | Description | Internal Rate Of Return (%) | | |
|---|---|---|---|---|
| | | ALT I | ALT II | ALT III |
| 1 | Base case | 17.11 | 16.06 | 14.28 |
| 2 | 10% decrease in benefits | 16.09 | 15.05 | 13.34 |
| 3 | 20% cost over run | 15.03 | 14.03 | 12.40 |
| 4 | Combined impact of 2 & 3 above | 13.66 | 12.70 | 11.16 |

**Table 3.23: At 100 % Consumer Surplus Basis [2]**

| Sr. No. | Description | Internal Rate Of Return (%) | | |
|---|---|---|---|---|
| | | ALT I | ALT II | ALT III |
| 1 | Base case | 20.51 | 19.28 | 17.62 |
| 2 | 10% decrease in benefits | 18.82 | 17.48 | 15.95 |
| 3 | 20% cost over run | 17.65 | 16.24 | 14.79 |
| 4 | Combined impact of 2 & 3 above | 16.13 | 14.61 | 13.27 |

**Table 3.24: At tariff+50% consumer surplus**

| Sr. No. | Description | Internal Rate Of Return (%) | | |
|---|---|---|---|---|
| | | ALT I | ALT II | ALT III |
| 1 | Base case | 19.55 | 15.24 | 13.86 |

The project remains economically viable with economic rates of return exceeding 12% opportunity cost of capital in all such cases (Refer TABLE 3-18 to 3-21).

### 3.5.11 JUSTIFICATION OF THE PROJECT

The project is economically justifiable in view of supplying cheap power to poor people of remote isolated hilly areas in Chitral having severe climatic conditions in winter as well as preservation of natural forests. The electricity will act as a catalyst for development of basic industry, creation of employment opportunities and uplift of socio-economic conditions etc.

### 3.5.12 CONCLUSION

The project has shown sound economic viability in the form of positive rate of return and can be recommended for implementation.

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