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Hydropower Project Design Incorporating Submergence Costs

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Submergence of land is a major impact of large hydropower projects. Such projects are often also dogged by siltation, delays in construction and heavy debt burdens—factors that are not considered in the project planning exercise. A simple constrained optimization model for the benefit–cost analysis of large hydropower projects that considers these features is proposed. The model is then applied to two sites in India. Using the potential productivity of an energy plantation on the submergible land is suggested as a reasonable approach to estimating the opportunity cost of submergence. Optimum project dimensions are calculated for various scenarios. Results indicate that the inclusion of submergence cost may lead to a substantial reduction in net present value and hence in project viability. Parameters such as project lifespan, construction time, discount rate and external debt burden are also of significance. The designs proposed by the planners are found to be uneconomic, while even the optimal design may not be viable for more typical scenarios. The concept of energy opportunity cost is useful for preliminary screening; some projects may require more detailed calculations. The optimization approach helps identify significant trade-offs between energy generation and land availability.

Keywords: hydropower projects, extended benefit–cost analysis, submergence cost, optimization model.

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1. Introduction

Hydro-electric power (or hydropower) is the only major renewable source of electrical energy, accounting for 21% of the global generation of electrical energy (Energy Statistics Yearbook, 1984). Yet the percentage of exploitable hydropower potential developed to the mid-1970s was just 1·4%, 4·5% and 8·6% for Africa, Latin America and Asia respectively (Biswas and Biswas, 1976). Faced with a very rapidly increasing demand for energy, planners in developing countries propose to exploit this vast untapped potential over the next few decades. Hydro-electric power generation is expected to grow from 1953×10^9 kWh in 1984 (Energy Statistics Yearbook, 1984) to 7681×10^9 kWh by 2020 (Biswas, 1982). Most of this growth will be in the form of "large hydro facilities flooding large areas" (UNERG, 1981).

While planners continue to envision harnessing "rivers of energy", the past decade has seen growing opposition to large dam projects of any kind—hydro, irrigation, or flood control—on socio-economic and ecological grounds. The critics argue that the benefits claimed to accrue from these projects are exaggerated, non-existent or lop-sided, while the costs of the projects are doubly under-estimated as they neither reflect economic realities nor include environmental externalities (Goldsmith and Hildyard, 1984, 1986).

Given these two conflicting trends, there is an obvious need for better techniques for determining the optimum design and even desirability of any large hydropower project. Benefit–cost analysis, the major technique being used and likely to be used by decision-makers, needs to be modified to include the values of the broader environmental and social effects. Hufschmidt *et al.* (1983) have provided the general guidelines for such extended benefit–cost analyses of development projects of various kinds, and Dixon and Hufschmidt (1986) provide illustrative case studies. There have been a number of individual case studies of hydropower projects that highlight (often *post facto*) the shortcomings of particular projects and their sensitivity to alternative assumptions about the future (e.g. Norgaard, 1982), but a systematic and flexible procedure that may be followed by planners is still needed. In particular, mathematical programming models that are used regularly by water resource systems analysts for the planning and operation of water resources projects need to interface with extended benefit–cost analysis. This combination of models would help planners to determine the optimum project size in each case and to examine the project's viability under different scenarios of the future.

Multi-objective programming models have been proposed by some analysts (Pendse and Rao, 1985; Okorokov and Shchavelev, 1982), but this approach yields a set of non-inferior solutions that may not really help the decision-maker arrive at a decision. In this paper, we propose a simple constrained optimization model that attempts to encompass some of the problems peculiar to the benefit–cost analysis of large hydropower projects. Data for two project proposals from India are then used to illustrate how, even with limited information, it is possible to obtain sustantive insights into the factors that affect project viability.

2. Major issues

The adverse environmental impacts of large hydropower projects (many of which are common to other large dam projects) may be summarized briefly as follows:

(a) submergence impacts (loss of forested land, agricultural land, wildlife habitat, human habitat);

(b) streamflow disruption impacts (barrier to fish migration, upstream and downstream ecosystem disruption);

(c) impoundment impacts (earthquake hazard, flood hazard, health hazard, increased water loss, micro-climatic changes);

(d) construction impacts (roads, quarries, transmission lines and influx of labour population leading to land degradation and forest loss).

The submergence of land—forested and/or agricultural land—is often of major concern in developing countries where forests are diminishing rapidly, agricultural land is scarce, and the burgeoning human population has already occupied most of the natural niches. A substantial amount of land is invariably submerged by large hydropower projects because large reservoirs are constructed to store the river's runoff in a manner that ensures the availability of a certain amount of water for power generation in all seasons. For instance, the Tucurui project in Brazil submerged 216 000 ha of thick tropical forest land (Monosowski, 1983); the proposed Bhopalpatnam project in India may submerge 40 000–90 000 ha of mixed forest (Colchester, 1986); the two main reservoirs in the recently approved Narmada Valley project, also in India, will submerge 418 000 ha and 137 000 ha of dry deciduous forest (International Dams Newsletter, 1987). Therefore, as a first step towards incorporating the environmental costs, one should include the opportunity cost of land submergence in the benefit–cost analysis.

A review of the criticisms of large dam projects—particularly those in developing countries—indicates that, in addition to the submergence of land, there are other negative features that are common to all the projects:

(a) High siltation rates lead to the reservoirs being silted up much earlier than expected and thus reduce the projects' lifespans. For instance, a report by the Central Board of Irrigation and Power (1977) shows that actual siltation rates for nine major dams in India were two to eight times greater than the estimated rates; similar experiences have been reported from a number of projects in other countries. Whereas siltation reduces the irrigation or flood-control capacity of an irrigation or flood-control reservoir only gradually, it affects hydropower projects more dramatically because the silt enters the penstocks and damages the turbines, which, if operated thereafter, would require frequent replacing at high cost.

(b) There is invariably a delay in the commissioning of these projects that delays the accrual of benefits. In India, the time interval between the submission of the project proposal and the completion of a project is typically between 10 and 20 years (Vohra, 1985).

(c) Delay increases interest costs during construction. Real inflation in the construction costs over and above the general inflation in the economy can also add to the costs of delay (Expert Committee, 1973). The cases cited by Vohra (1985) have cost overruns between 200 and 860%.

(d) Large dam projects are highly capital-intensive. Developing countries are often forced to borrow from external sources to supplement their own funds. This borrowing not only adds to the recurring cost of the project but also increases the country's indebtedness—a risk to its political and economic independence during periods of financial crisis.

(e) Whether the social discount rate over the life of the project will be high or low can affect project viability significantly. Planners are often accused of choosing the discount rate arbitrarily such that the project's viability is enhanced.

In view of the above list of negative factors, a sensitivity analysis with the discount rate and other parameters varying within the feasible range of their values is absolutely essential. The following optimization model incorporates these features in an extended benefit–cost analysis of large hydropower projects.

3. Optimization model—general form

The planning problem for a *single-site, hydro-only* project can be posed as an optimization problem in which the decision variables are the project's main dimensions and the objective function is some measure of the project's economic viability. The general form of our model uses data consisting of:

(a) site-specific data (area–capacity relationship, inflow record, generation head, dead storage requirement, evaporation rates);
(b) technical data (generator and turbine efficiencies, load parameters, dependability norm, details of submergible land);
(c) economic data (variation of project cost with dimensions, discount rate, price of electricity generated, value of produce from submergible land, project lifespan, construction time, inflation rates, etc.);

to determine the optimum values of the *decision variables:*

(i) monthly or seasonal withdrawals (i.e. volumes of water drawn for power generation),
(ii) reservoir storage capacity,
(iii) installed generation capacity,

so as to maximize the *objective function:*

net present value of returns minus costs (including the opportunity cost of land submergence),

subject to the *constraints:*

(i) hydrological continuity and minimum storage constraints,
(ii) other constraints such as allowable inter-seasonal variations in power generation, maximum submergible area, or minimum power generation.

The "net present value" (NPV) is the proper criterion for project design (Dasgupta *et al.*, 1972). However, the benefit-to-cost (B/C) ratio is often used by planning bodies because of constraints on capital availability; hence it is also calculated in our analyses. With the inclusion of the opportunity cost of land submergence, the NPV would be given by

NPV = PV(revenue from the sale of electrical energy over the operating life of the project)
minus PV(construction costs incurred over the construction time of the project)
minus PV(recurring costs—such as operation and maintenance costs—incurred over the operating life of the project)
minus PV(economic value of the land submerged by the reservoir calculated from the appropriate time till much beyond the operating life of the project),

where PV(...) represents the present value of the quantities in the parentheses.

While the first three terms in the above expression can be determined with reasonable accuracy, the economic loss due to the submergence of land is much less amenable to calculation. A review of past projects shows that large hydropower projects often submerge excellent natural forest growing on the slopes of the river valley and fertile agricultural land located at the valley bottom. The economic loss depends upon the estimated productivity of the land under a particular land use pattern and the economic value of the produce. A forest yields timber, fuel wood, fodder, green manure, and possibly additional products and environmental services. Agricultural land yields farm produce. Moreover, submergence of cultivated land automatically means displacement of the cultivators, which leads to expenditure on their rehabilitation.

The value of submerged land could be estimated case by case according to current and plausible future uses. Such a thorough approach is appropriate for projects which pass preliminary economic screening and yet remain controversial. In the past, however, land submergence cost has often been ignored, partly because of the difficulty in calculating it. Rather than not include the cost at all or go to considerable expense to determine the cost, we suggest the use of some simplifying scenarios.

Because energy is the output of hydro-electric projects, one reasonable way of estimating the opportunity cost of the submerged land would be to consider the energy opportunity cost of the project. Fuel wood and other biomass energy is frequently in great demand in developing countries. A net energy analysis has indicated that the potential biomass energy lost due to submergence may offset the energy generated by the project to a great extent (Lele and Subramanian, 1987). Alternatively, a natural forest could be maintained on the land and harvested in a sustainable manner.

Hence, rather than assume any single land use pattern as representative of the opportunity cost of the land, the following alternative scenarios could be considered.

Scenario I: The submergible land is covered with an energy plantation—an "Energy Scenario".

Scenario II: The submergible land is covered with a natural forest—a "Natural Forest Scenario".

Scenario III: Part of the submergible land is covered by a natural forest, part is under cultivation, and the rest is occupied by homes, commercial structures, etc.—an "Existing Land use Scenario".

As mentioned earlier, the data requirements of scenario III are prohibitive. Even scenario II requires data on the sustainable productivity of natural forests under specific soil–climatic conditions. Reliable data of this kind are not available in most developing countries. So, in our case studies, only the energy scenario is used in the detailed analysis; exploratory calculations are carried out for scenarios II and III. This general approach, with minor modifications, would be appropriate for many projects in developing countries.

4. The case studies

Two hydropower projects proposed on rivers located in the Western Ghats mountain range in India were analyzed using this model. They are the Koyna (Shivajisagar) project in Maharashtra state and the Bedthi (stage I) project in Karnataka state. Data used in the case of the Koyna project pertain to a proposal made in 1950 (Electric Grid Department, 1950)—a proposal that was subsequently rejected on protests from downstream users, but which contains the most detailed economic data on cost variation with size. Data for the Bedthi project are from a proposal made in 1979 (Karnataka Power Corporation, 1979). This proposal was shelved due to strong protests from environmentalists and the local populace. Some of the distinctive features of these dam sites and proposals are given in the appendix (Table A.1).

For both the projects, the following simplifying assumptions are made:

(a) The hydrological year from June 1 to May 31 consists of two distinct seasons, wet (June–November) and dry (December–May).

(b) The average net generation head (H) is constant. Variations in H due to changes in the reservoir levels are not more than 4–5% in either case because most of the head results from the location of the powerhouse well below the dam itself.

(c) The submerged area (A_{sub}) is linearly related to the reservoir's gross storage capacity (V). (This assumption is valid for the range of reservoir volumes considered.) Thus,

$$A_{sub} = a.V + b, \tag{1a}$$

where a and b are parameters of the area-capacity curve. Now V is the sum of the active storage capacity (K_a) and the dead storage capacity (K_d). Assuming that the dead storage capacity is determined independently from the siltation rate and dam life requirement, one can rewrite equation (1a) as

$$A_{sub} = a.K_a + b', \tag{1b}$$

where $b' = (b + a.K_d)$.

(d) Average seasonal load factors are the same for both seasons. This assumption was made by the public power corporations that planned the projects; though not valid operationally, we use it in the absence of detailed load forecasting and generation scheduling in the power systems.

(e) For the same reasons as (d) above, we assume that the generation capacity is required to be the same in both the seasons.

(f) The construction cost (C_{cap}) can be modeled as a function of three variables—the gross storage capacity V (which determines the dam size and hence the dam cost), the installed generation capacity P (which determines the electrical works' cost), and the peak power draft d—the maximum rate at which water is drawn for power generation (which determines the cost of the intake structure, pressure shaft, surge tank, etc.). Thus, in general,

$$C_{cap} = C(K_a, P, d), \tag{2}$$

where C is a general function. (V is replaced by K_a as before.)

From assumptions (a) and (b) above, the expression for the annual hydro-electric (hydel) energy generated—E_{hydel} (in kWh)—can be written as

$$E_{hydel} = k_1(D_1 + D_2), \tag{3}$$

where D_1 and D_2 are the volumes of water drawn for power generation in the wet and dry seasons respectively (in million cubic metres—Mm^3), and k_1 is the factor for converting Mm^3 of water discharged down the pressure shaft into kWh of energy generated. ($k_1 = 10^3 \times H[m] \times$ (gravitational acceleration) $[m/s^2] =$ (turbine and generator efficiency)/3·6).

The peak power draft in season i, d_i (in m^3/s), is given by

$$d_i = D_i/(4380 \times \mathrm{LF} \times 3{\cdot}6), \tag{4}$$

where LF is the seasonal load factor. Hence, the maximum peak power draft is given by

$$d = \max\ d_i, \tag{5}$$

and the installed generation capacity (in MW) is

$$P = k_1 \times d \times 3{\cdot}6. \tag{6}$$

In this particular case, with assumptions (c) and (d), D_1 is equal to D_2, and so $d_1 = d_2$ ($= d$, say).

Using equation (6) in equation (2), an expression for the construction cost in terms of only K_a and d can be obtained; it would be of the form

$$C_{\mathrm{cap}} = C'(K_a, d). \tag{7}$$

Depreciation charges are not included in a present-value analysis. The shorter lifespans of the turbines and generation equipment as compared to that of the dam result in periodically occurring replacement costs that are discounted to present value terms and added to the capital cost.

The recurring costs of the project are essentially the operation and maintenance costs; these are taken to be a fixed fraction of the capital cost. Also, if some part of the capital for the project is raised from external sources that charge interest at rates higher than the discount rate, then these additional annual charges are included in the annual recurring cost. Thus,

$$C_{\mathrm{rec}} = (\mathrm{OMC} + \mathrm{CRC}) \times C_{\mathrm{cap}}, \tag{8}$$

where OMC is the annual operation and maintenance charge rate and CRC is the additional capital charge rate (if any).

The general expression for the submergence cost in terms of the area submerged is

$$C_{\mathrm{sub}} = \int_0^{A_{\mathrm{sub}}} \mathrm{VSUB} \times \mathrm{d}A_{\mathrm{sub}}, \tag{9a}$$

where VSUB is the economic value of the incremental submerged area, $\mathrm{d}A_{\mathrm{sub}}$. For the energy scenario, however, this expression can be simplified to

$$C_{\mathrm{sub}} = A_{\mathrm{sub}} \times f \times (\mathrm{W} \times \mathrm{WPRICE} - \mathrm{WCOST}), \tag{9b}$$

where W is the productivity of the energy plantation in tonnes/ha/yr), WPRICE is the (shadow) price of the fuel wood as calculated at the dam site in Rs/tonne, WCOST is the annual cost per unit area of the energy plantation (including the initial investment and the operational costs) in Rs/ha/yr, and f is the fraction of submerged land available for plantation. Using equation (1b), C_{sub} can be expressed in terms of K_a.

The final step is that of establishing the relationship between the seasonal withdrawals D_i and the active storage capacity requirement K_a. Most models which have reservoir capacity as a variable require the explicit inclusion of the hydrological continuity constraints and the minimum storage constraints (see Loucks *et al.*, 1981, pp. 236–238 for details). The constraints are framed in a manner that incorporates the seasonal evaporation losses and the dependability norm (the latter being the percentage of years in which the generation target is met). But this formulation increases the size of the optimization problem very substantially; moreover, being a linear-programming model, it requires the approximation of all non-linear relationships by piecewise-linear forms. However, in the absence of a flood-control storage requirement and other complicating constraints, one can use an algorithm relating the seasonal releases/withdrawals to the active storage capacity requirements to calculate K_a in each iteration of a direct-search method for solving constrained non-linear optimization problems. This algorithm not only reduces the size of the problem but also obviates the need for piece-wise linearizations. We used an improved version of the sequent-peak algorithm—outlined in Lele (1987)—in combination with a generalized reduced-gradient method.

Finally, the benefit accruing from each project is taken to be the annual revenue collected from the sale of the electrical energy generated (sold at EPRICE Rs/kWh) and the peak demand charges collected (at CAPPRICE Rs/MVA). This revenue is admittedly not the actual "value" of the electricity used by society, but then neither is any of the other cost figures truly representative of the actual social cost. The aim of this exercise is not to carry out a detailed "social benefit–cost analysis" but to focus on certain hitherto neglected aspects. Thus, the optimization problem becomes one of maximizing

$$\begin{aligned}\mathrm{NPV} = {} & \mathrm{PV}[(E_{\mathrm{hydel}})(\mathrm{EPRICE}) + (P)(\mathrm{CAPPRICE})] - \mathrm{PV}(C_{\mathrm{cap}}) \\ & - \mathrm{PV}[(C_{\mathrm{cap}})(\mathrm{OMC} + \mathrm{CRC})] - \mathrm{PV}[(A_{\mathrm{sub}})(f)(\mathrm{W} \times \mathrm{WPRICE} - \mathrm{WCOST})],\end{aligned}$$

subject to $D_1 = D_2$ and $D_1, D_2 >= 0$. The project is then considered to be "viable" if it has a *positive* net present value, or a benefit–cost ratio greater than 1.

5. Discounting and parameter values

In calculating the present value of the streams of various economic quantities, we incorporate the features mentioned in section 2 that are peculiar to hydro-electric projects. In particular, denoting the construction period by LCON and the operational lifetime of the project by LIFE:

(a) the revenue from the sale of electricity is taken to accrue from $t = \mathrm{LCON}$ to $t = \mathrm{LCON} + \mathrm{LIFE}$, whereas the submergence cost is assumed to be incurred from $t = 1$ to $t = \infty$—because forest once submerged cannot be brought back to life after the project has stopped operating (at least not without additional expenditure on reforestation);

(b) in the absence of any generalizable pattern, the construction cost is assumed to be distributed uniformly over LCON;

(c) the construction cost is assumed to inflate at a real rate of 3·3% per annum (Expert Committee, 1973);

(d) because prices of fuel wood and forest produce over the past 35 years exhibit substantial (3–8%) real inflation, a similar (3%) inflation is assumed in the price of fuel wood for the first 30 years of the analysis for both the projects.

Table A.2 in the appendix lists the important parameters and the values or ranges of values used in the analyses. Assigning plausible values/ranges to these parameters is not an easy task, and it would be impossible to go into the details within the confines of this paper (the reader may refer to Lele, 1986, for details). However, the basic considerations need to be mentioned here. The lower value of LIFE—50 years—is a conservative estimate of the reduced life of the reservoir if actual siltation rates are in the range observed in similar catchments in India. Similarly, the higher value of LCON—12 years—is a conservative estimate based on historical data on the typical construction times for projects in India. The upper bound on the range of values for the discount rate (DR) was approximately the real interest rate prevailing in India in the early 1980s, whereas the lower bound is a typical value that was used by planners of water resources projects in the U.S.A. (Kreith and West, 1980). In the case where additional capital charges are incurred, they are calculated on the basis of the assumption that 50% of the capital for the project is raised from external agencies in the form of a loan to be repaid over 20 years in U.S. dollars with interest at the rate of 8% per annum while the project discount rate is 4%. For the calculation of the value of a hectare of an energy plantation, available data suggest that, under the soil-climatic regime prevailing at the sites, the productivity may be reasonably assumed to be 15 tonne of fuel wood/ha/year; the value of fuel wood is calculated by subtracting transport costs from the prices prevailing in nearby cities. (No market exists locally because the populace gathers fuel wood free of monetary cost.)

6. Energy scenario—results and discussion

The analysis for each of the projects is carried out according to the following pattern:

(i) A "best case" set of values for the parameters of interest—LIFE, LCON, DR and CRC—is identified. (Clearly, this is the case when the life of the project is the longest, the construction time the shortest, the discount rate the lowest and the external debt burden non-existent.) The project's optimum size is determined for this best case *without* including the submergence cost.

(ii) Parametric variations are carried out on the best case without including the submergence cost, with each parameter being varied to its other extreme.

(iii) The submergence cost (for scenario I) is then included, and the optimum project size and the corresponding NPV and B/C ratio are determined for some of the cases in (i) and (ii) above.

(iv) Possible favorable changes—like improvement in the load factor or real inflation in the price of electrical energy—and their effects on project viability for a typical set of parameter values are also examined.

(v) Finally, the designs proposed in the Detailed Project Reports (DPRs) are presented and analyzed for the typical case.

The results for the Bedthi and the Koyna project sites are given in Tables 1 and 2 respectively. It may be noted at the outset that the sensitivity of the optimum level of seasonal withdrawal to changes in the parameter values is different for the two projects. While the optimum value of D_1 $(=D_2)$ for Koyna does vary over some range, that for Bedthi seems to be "stuck" at 488·0 Mm^3. This results from a difference in the shape of the storage-yield curves (curves of storage capacity required versus seasonal withdrawal) for the two projects—the curve was "smooth" in the case of Koyna but not in the case of Bedthi.

TABLE 1. A benefit–cost analysis of the Bedthi Hydro-electric Project

Project life-span (years)	Construc-tion time (years)	Discount rate (%)	Addi-tional capital charges (%)	Seasonal with-drawals (Mm³)	Inst. capacity (MW)	Reser-voir volume (Mm³)	Submerged area (km²)	Capital cost†	Present recurring cost†	Value of submer-gence cost†	Revenue†	Net present value†	Benefit/cost ratio
(1) Submergence cost excluded													
100	6	4	0	488·04	151·8	860·86	51·5	1466·86	378·64	0	3862·02	2016·52	2·09
50	6	4	0	488·04	151·8	860·86	51·5	1466·86	331·93	0	3385·62	1586·82	1·88
100	12	4	0	488·04	151·8	860·86	51·5	1388·05	299·24	0	3052·21	1364·92	1·81
100	6	9	0	488·04	151·8	860·86	51·5	1141·06	129·51	0	1320·93	50·37	1·04
100	6	4	3·1	488·04	151·8	860·86	51·5	1466·86	1161·16	0	3862·02	1234·00	1·47
50	12	4	0	488·04	151·8	860·86	51·5	1388·05	262·33	0	2675·70	1025·33	1·62
50	12	6	0	488·04	151·8	860·86	51·5	1176·81	153·15	0	1562·06	232·10	1·17
50	12	9	0	488·04	151·8	860·86	51·5	959·34	76·20	0	777·18	−258·36	0·75
(2) Submergence cost included: Land cost for scenario I = Rs 2000/ha with real inflation @ 3% per annum for first 30 years													
100	6	4	0	488·04	151·8	860·86	51·5	1466·86	378·64	311·86	3862·02	1704·65	1·79
100	6	9	0	488·04	151·8	860·86	51·5	1141·06	129·51	137·85	1320·93	−87·49	0·94
50	12	4	0	488·04	151·8	860·86	51·5	1388·05	262·33	311·86	2675·70	713·46	1·36
50	12	6	0	488·04	151·8	860·86	51·5	1176·10	153·15	210·77	1562·06	21·34	1·01
50	12	9	0	488·04	151·8	860·86	51·5	959·34	76·20	137·85	777·18	−39·62	0·66
(3) Favourable changes													
(a) Load factor improves to 80%:													
50	12	6	0	488·04	113·82	860·86	51·5	1095·84	144·91	210·77	1462·06	110·55	1·08
(b) Revenue from electrical energy increases @ 1% per annum:													
50	12	6	0	488·04	151·8	860·86	51·5	1176·81	153·15	210·77	1665·60	124·88	1·08
(4) Analysis for DPR design‡ i.e., for annual withdrawal = 1100 Mm³													
50	12	6	0	550·0	171	1898·48	111·0	1618·29	213·75	454·31	760·37	−525·98	0·77
(100)	(6)	(10)	(0)		(210)	(1608·76)	(99·6)	{Annual cost = capital cost (= 1320·5) × FCR(= 13·1%) = 172·8 annual revenue = 180·2; therefore B/C ratio = 1·04}					

†Values in million Rs: base 1981.
‡Numbers in brackets are the values assumed and calculations made in the DPR; FCR = fixed charge rate.

TABLE 2. A benefit–cost analysis of the Koyna Hydro-electric Project

Project life-span (years)	Construction time (years)	Discount rate (%)	Additional capital charges (%)	Seasonal withdrawals (Mm³)	Inst. capacity (MW)	Reservoir volume (Mm³)	Submerged area (km²)	Capital cost†	Present recurring cost†	Value of submergence cost†	Revenue†	Net present value†	Benefit/cost ratio
(1) Submergence cost excluded													
100	6	4	0	1720·2	646·8	4650·0	182·3	589·67	120·66	0	915·14	204·81	1·29
50	6	4	0	1717·6	645·8	4629·4	181·6	588·78	105·21	0	801·06	106·67	1·15
100	12	4	0	1717·6	645·8	4629·4	181·6	538·11	95·21	0	722·17	88·86	1·14
100	6	9	0	1629·0	612·8	4082·6	162·1	383·87	39·32	0	296·42	−126·78	0·70
100	6	4	3·1	1717·6	645·8	4629·4	181·6	588·78	369·43	0	913·78	−44·44	0·95
50	12	6	0	1629·0	612·8	4082·6	162·1	407·58	46·50	0	350·53	−103·55	0·77
50	12	9	0	1629·0	612·8	4082·6	162·1	313·60	23·14	0	174·40	−162·30	0·52
(2) Submergence cost included: Land cost for scenario I = Rs 80/ha with real inflation @ 3% per annum for first 30 years													
100	6	4	0	1720·2	646·8	4650·0	182·3	589·67	120·66	47·46	915·14	157·34	1·21
100	12	4	0	1717·6	645·8	4629·4	181·6	538·11	95·21	47·27	722·17	41·58	1·06
50	12	6	0	1629·0	612·8	4082·6	162·1	407·58	46·50	28·52	350·53	−132·07	0·73
(3) Favourable changes													
(a) Load factor improves to 80%:													
50	12	6	0	1629·0	459·4	4082·6	162·1	355·23	41·86	28·52	350·53	−75·10	0·82
(b) Revenue from electrical energy increases @ 1% per annum:													
50	12	6	0	1629·0	612·8	4082·6	162·1	407·58	46·50	28·52	373·76	−108·86	0·77
(4) Analysis for DPR design‡ i.e., for annual withdrawal = 3385·4 Mm³													
50	12	6	0	1692·7	636·3	4520·0	177·7	422·65	48·20	31·26	364·23	−137·88	0·73
(100)	(6)	(10)	(0)		(660.0)	(4424.2)	(152.8)	{Annual cost = [capital cost (= 503·35) + land cost(= 10·0)] multiplied by FCR(= 7%) = 35·93; annual revenue = 53·08; therefore B/C ratio = 1·48}					

†Values in million Rs: base 1950.
‡Numbers in brackets are the values assumed and calculations made in the DPR; FCR = fixed charge rate.

Consider the results when the submergence cost is ignored:

(a) The best case yields a B/C ratio of 2·09 for Bedthi and of 1·29 for Koyna. Thus, given the best case situation, both the projects would be considered viable.

(b) A reduction in the project's operating life from 100 years to 50 years does not make either of the projects non-viable. The reduction in the NPV, however, is quite substantial—429·7 million Rs (at 1981 prices) in the case of Bedthi and 98·14 million Rs (at 1950 prices) for Koyna. This reduction is equivalent to an annual sum of 17 million Rs and 4 million Rs respectively. Since siltation limits reservoir life, it would be economic to spend up to 17 million Rs per year for 100 years in the case of Bedthi and up to 4 million Rs per year for 100 years in the case of Koyna to control soil erosion in the reservoir's catchment area. These values are comparable with the annual recurring charges for operation and maintenance, which are 19·5 million Rs for Bedthi and 6·2 million Rs for Koyna.

(c) A delay in the commissioning of the projects affects the NPV to about the same extent as the shortening of the reservoir life; the drop in the NPV is 33% for Bedthi and 57% for Koyna.

(d) The presence of an external debt burden affects the projects' viability even more significantly—in fact, in the case of Koyna, the NPV becomes negative, i.e., the project becomes uneconomic.

(e) Use of a typical market discount rate (9%)—instead of a low one that favours capital-intensive projects—affects both projects drastically. While the B/C ratio sinks to 0·70 for Koyna, making it completely uneconomic, it drops to 1·04 for Bedthi, which makes it uneconomic for all practical purposes.

(f) For the more typical case when LIFE = 50 years and LCON = 12 years, the choice of discount rate can be quite important, and could determine whether the project is accepted or rejected.

Now consider the situation when submergence cost is included. It should be noted at the outset that, with a zero discount rate, the present value of C_{sub} is infinite and the projects would have to be rejected out of hand. The use of a discount rate equal to or greater than 4% means that, in effect, no value is placed on the economic benefits or costs accruing after about 75 years—clearly an approach biased against forests that yield low but everlasting benefits. In the case of a non-zero discount rate, it appears that while the submergence cost is comparable with the recurring cost (for Bedthi) or much lower (for Koyna), its inclusion may yet suffice to render a supposedly viable project non-viable. [Compare rows in section (2) in each table with the corresponding cases in section (1).] Clearly, ignoring this cost during project design is not justifiable.

It is possible that changes in the values of some other parameters may affect project viability favorably. For instance, as energy becomes scarcer, the average revenue from electrical energy may rise over time. Alternatively, proper planning may result in the load factor improving from 60% to 80%. The effect of either of these improvements (in a typical case set of values for the other parameters) turns out to be identical. For Bedthi, these improvements raise the B/C ration from 0·99 to 1·08, but they are not enough to make Koyna viable.

The analysis of the designs proposed in the Detailed Project Reports raises some interesting issues. The project size for Bedthi, determined using a thumb-rule of utilizing 90% of the average annual runoff (Karnataka Power Corporation, 1977), turns out to be too big. The project turns out to be not viable if more realistic parameter values are used in the economic analysis, and especially so if the submergence cost is included. But more importantly, it turns out that a reduction in the installed capacity of just 14%—from 175·6 MW (installed capacity for a seasonal withdrawal of 550 Mm^3) to 151·8 MW—results in a reduction in the storage capacity requirement of over 54%—from 1898·5 Mm^3 to 860·9 Mm^3. This highlights the importance of using an optimization model for project design. The Koyna project's DPR design is, on the other hand, quite close to the optimum, but then an economic optimization exercise *was* carried out in the Koyna DPR! However, in a situation where the parameter values are not the most favorable ones, this project ceases to be viable too.

7. Natural forest and existing land use scenarios

Estimates of the annual return on a hectare of natural forest and of agricultural lands under existing cultivation patterns in the Bedthi valley are as follows (personal communications from Centre for Ecological Sciences, Indian Institute of Science, Bangalore and Karnataka State Forest Department, Bangalore):

(a) Natural Forest	:	6590 Rs/ha/yr
consisting of		
timber (3·0 m^3/ha/yr at 2000 Rs/m^3)	:	6000 Rs/ha/yr
fuel wood (1·5 t/ha/yr at 200 Rs/t)	:	300 Rs/ha/yr
fodder (0·8 t/ha/yr at 175 Rs/t)	:	140 Rs/ha/yr
green manure (1·0 t/ha/yr at 150 Rs/t)	:	150 Rs/ha/yr
(b) Cultivation		
Paddy only (in wet season)	:	2200 Rs/ha/yr
Ragi only (in wet season)	:	950 Rs/ha/yr
Paddy (wet) and ragi (dry)	:	4600 Rs/ha/yr
Spice orchards (betelnut, pepper and cardamom)	:	50 600 Rs/ha/yr

Thus, the opportunity cost of submerging a unit area of natural forest or cultivated land is 2–25 times greater than that of a (hypothetical) energy plantation (2000 Rs/ha/yr). Based on the topography of the valley, it is possible to calculate the value of the land submerged by the reservoir of capacity 860·9 Mm^3. (This size corresponds to the optimum design in the best case situation.) Such a reservoir would submerge 51·5 km^2 of land, which would include 1430 ha of paddy cultivation, 384 ha of ragi cultivation, 190 ha of spice orchards, and about 2600 ha of natural forest. This apportionment works out to an annual value of 13·1 million Rs for the cultivated land and 17·4 million Rs for the forested land.

The reservoir would also displace 1500 people. The cost of resettlement is estimated to be at least 5000 Rs per person from a revised estimate for the Bedthi project (Sharma and Sharma, 1981), a value which implies a one-time cost of 3·8 million Rs.

Assuming that the prices of natural forest produce in India will continue to inflate at a real rate of 4% per annum for the next 30 years as they have for the last 35 years, the total present value of submerged land is:

$$\begin{aligned}PV(C_{sub}) &= (\text{annual value of agricultural produce} \times \text{PV factor})\\ &\quad + (\text{annual value of forest produce} \times \text{adjusted PV factor})\\ &\quad + (\text{rehabilitation cost})\\ &= (13{\cdot}1 \times 25) + (17{\cdot}1 \times 37{\cdot}7) + (7{\cdot}5) \text{ million Rs}\\ &= 979{\cdot}7 \text{ million Rs}\end{aligned}$$

This estimate reduces the NPV in the best case situation to 1036·8 million Rs—a reduction of 40%. The B/C ratio drops to 1·37. If any of the other parameters were less favorable, the NPV would become negative and the project would not be viable.

8. Concluding remarks

The model presented in this paper provides a reasonable approach for considering important externalities and uncertainties in the planning of large hydropower projects. In such projects, the optimum range of reservoir sizes and installed generation capacities is determined by certain site-specific factors. The purpose of an optimization model is to identify this optimum size or range of sizes. The analyses indicate that the optimum reservoir size is about 861 Mm^3 for the Bedthi project and between 4082 and 4650 Mm^3 for the Koyna project.

The aim of the planning process, however, is not only to determine the best project dimensions but also to determine whether the project should be undertaken at all. The manner in which the objective function is framed plays a crucial role here. In developing countries, large hydropower projects are planned and often executed by governmental agencies because they are considered to be critical "development" projects. It follows that they ought to be subjected to the broadest possible benefit–cost analysis, i.e., incorporating as many of the externalities and uncertainties as possible. Land submergence is often the major impact of such projects, but determining the exact value of the land submerged by the reservoir is a very difficult task. Nevertheless, assigning the land some minimum value based on a simple scenario and including it in the optimization exercise could be useful in two ways—it would eliminate some projects at the outset, and it would identify trade-offs between additional power generation and additional land submergence in a manner that may simplify decision-making. For instance, the Bedthi project would submerge only half the area if just 11% of the generation capacity was sacrificed.

The results of the case studies also highlight the importance of technical factors such as the lifetime and construction time of the project, and economic factors such as the discount rate and dependence on external investment funds. The siltation of reservoirs and reduction in their lives has bedevilled many dam projects, especially those in the tropics. Our analysis shows how investment in catchment area afforestation and management that brings about a reduction in the siltation rates may be extremely worthwhile. On the other hand, lack of such measures and poor project management may lead to the project being non-viable. In combination with the relatively higher discount rates that prevail in developing countries, such factors will invariably be "fatal" to project viability. If discount rates are low, the discounted value of the land submerged may increase much more (especially in the case of forested land that is becoming scarcer every day in third world countries).

Mathematical models such as the one presented here cannot incorporate all the complex and intangible social and environmental factors. Such models can, however, play a useful role in identifying the basic relationships between the quantitative planning variables, highlighting the trade-offs between some desirable and undesirable aspects/

impacts, and determining the effects of future changes in parameter values. This approach could prevent the perpetuation of planned tragedies in the name of development.

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Appendix

TABLE A.1 Distinctive features of projects analysed

Feature/Parameter	Bedthi	Koyna
Physical		
(1) average annual inflow (Mm^3)	1517·2	3958·1
(2) catchment area (km^2)	2230·0	896·1
(3) slope of area-capacity curve (km^2/Mm^3)	0·05738	0·03567
Technical		
(1) average net generation head (m)	359·0	477·6
(2) designed storage capacity (Mm^3)	1608·9	4424·2
(3) area submerged at FRL† (km^2)	99·6	152·8
(4) designed installed capacity (MW)	210·0	660·0
Economic‡		
(1) coefficient in construction cost function that is proportional to§		
(a) peak power draft (million Rs/cumec)	5·438	0·9176 (14·48)
(b) reservoir storage capacity (000 Rs/Mm^3)	462·74	18·90 (647·1)
(2) fixed cost (million Rs)	624·53	160·64 (2 073·5)

†FRL, full reservoir level.
‡Base years for costs are 1981 for Bedthi and 1950 for Koyna. Values for Koyna at 1981 prices are given in parentheses.
§The cost curves were actually non-linear and were approximated by a combination of linear and parabolic functions; the figures given here are for the first linear part of the cost curves.

TABLE A.2 Parameters used in the economic analysis

Parameter	Symbol	Value or range†
(1) *Relating to construction cost*:		
(a) construction cost coefficients		see Table A. 1
(b) real rate of inflation in construction costs		3·3% p.a.
(c) construction time	LCON	6–12 years
(2) *Relating to energy generated*:		
(a) seasonal load factor	LF	60–80%
(b) selling price of energy	EPRICE	Bedthi: 0·25 Rs/kWh Koyna :0·014 Rs/kWh 0–1%
(c) real rate of inflation in EPRICE in EPRICE		
(d) peak demand charges	CAPPRICE	Bedthi: 370 000 Rs/MVA Koyna: 10 000 Rs/MVA
(3) *Relating to the discounting process*:		
(a) social discount rate	DR	4–9% p.a.
(b) operation and maintenance charges‡	OMC	1–5% p.a.
(c) additional debt recovery charges‡	CRC	0–4·2% p.a.
(d) project life-span	LIFE	50–100 years
(4) *Relating to Scenario I*:		
(a) productivity of energy plantation	W	15 t/ha/yr
(b) price of fuel wood	WPRICE	Bedthi: 200 Rs/t Koyna: 6 Rs/t
(c) investment and operation cost	WCOST	Bedthi: 1000 Rs/ha/yr
(d) real rate of inflation in WPRICE for first 30 years		3% p.a.

†Base years for prices are 1981 for Bedthi and 1950 for Koyna.
‡These charges are given as a percentage of the total capital cost.