Clean-development-mechanism-based optimal hydropower capacity design

Amir Hatamkhani and Hosein Alizadeh

ABSTRACT

This paper deals with optimal design of a hydropower project's capacity when an analyst may take into account different economic analysis approaches and considerations including market price method, alternative thermal power plant method, externalities and clean development mechanism (CDM). We formulate the problem using mixed-integer nonlinear programming including an economic objective function and governing hydropower constraints. Due to non-convexity of the program, we employ an effective simulation-optimization approach coupling particle swarm optimization (PSO) and Water Evaluation and Planning (WEAP) software which we customize for hydropower simulation using scripting capabilities of the software. The developed modelling framework is applied to the Karun II hydropower project in Iran, where we aim CDM-based optimal design of the project and also compare two economic hydropower analysis methods, i.e. market price and alternative thermal plant. Results show how inclusion of externality and CDM can affect the project's design and measures.

Key words | clean development mechanism, economic analysis, Karun II hydropower project, optimal design, particle swarm optimization, WEAP

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INTRODUCTION

Clean development mechanism (CDM) is a market-based and project-based mechanism defined in the Kyoto Protocol (IPCC 2007) to foster sustainable development in developing countries and greenhouse gas emission reductions by developed countries (Kirkman *et al.* 2012) through allowing emission-reduction projects in developing countries to earn certified emission reduction (CER) credits where they can be traded and used by industrialized countries to meet part of their emission reduction targets under the Kyoto Protocol (UNFCCC 2007). Under the Kyoto Protocol, countries can meet treaty obligations by investing in projects that reduce or sequester greenhouse gases elsewhere (Dinar *et al.* 2013). Among all, hydropower projects (HPPs) are of interest under the CDM because they directly displace greenhouse gas emissions if they contribute to sustainable development (Purohit 2008), where particularly small hydropower plants (SHPs) have attracted renewed interest worldwide (Cheng *et al.* 2017).

While in recent decades CDM has been effectively participating to finance renewable energy projects (Thomas *et al.* 2011), there has been considerable debate about CDM's shortcomings and failing to contribute to sustainable development (Olsen 2007) and rural development (Subbarao & Lloyd 2011), mainly due to not financing projects that help in the long-term transition of energy sectors towards renewable technologies (Pearson 2007), extremely uneven distribution of CDM projects across countries (Boyd *et al.* 2009), scarcity of those technologies and sectors that have dominated the early stages of CDM experience (Boyd *et al.* 2009), etc. Given that HPPs, despite many positive externalities, may have negative externalities (Mattmann *et al.* 2016; Zheng *et al.* 2016) mainly because of alteration of rivers' flow regimes (Kibler & Alipour 2017) and emission of substantial amounts of greenhouse gases (Zhang *et al.* 2015), for example where the power plants are installed in tropical forests (Fearnside 2016), CDM-sponsored HPPs

actually fail to contribute to sustainable development more than 'business as usual' (Rousseau 2017) and therefore HPP has been criticized for non-conformance to additionality and sustainability objectives originally set out in the Kyoto Protocol (Koo 2017).

Various modifications have been proposed to help CDM achieve the predefined goals, e.g. restricting projects' eligibility (Pearson 2007), modifying projects' assessment frameworks (Subbarao & Lloyd 2011), policy-based adjustment to CERs (Boyd et al. 2009), establishing international standards for sustainability assessment of CDM projects (Olsen & Fenhann 2008; Boyd et al. 2009), extracting CDM's rent potential using profit tax (Muller 2007), and making the CDM a sector-based mechanism (Pearson 2007). Nevertheless, CDM still remains attractive because of its important potentials and significant contribution in financing development projects, predominantly hydroelectric and wind power projects (Thomas et al. 2011; Martins et al. 2013), and there are also considerable efforts to improve CDM's attractiveness to investors of renewable energy sectors (Carmichael et al. 2015).

Economic analysis of HPP is an integral part of the project's design and operation, while associated economic analysis tools and methods are still restricted. Accordingly, USACE (1985) proposed two traditional alternatives (alternative thermal plant method (ATPM) and market price method (MPM)) for economic analysis of HPPs. While the former characterizes benefits related to an HPP based on the opportunity cost concept where an equivalent thermal power plant is taken as the best alternative for the HPP, the latter easily estimates the benefits based on the hydro-energy's sale price. In addition to usual benefit and cost terms of HPP, Ranasinghe (1994) took into account in monetary terms the costs of some environmental impacts related to both HPP and its best alternative. Recently, Zheng et al. (2016) developed an externality evaluation model for HPPs which is capable of separately quantifying positive and negative externalities. Now it is not difficult to include CDM in economic analysis of different electricity systems, incorporating HPP, using the United Nations Framework on Climate Change (UNFCCC)'s guidelines (e.g. UNFCCC 2016, 2017); however, there is a lack of models or methods which are designed particularly for HPPs and can consider CDM in investment analysis besides other significant benefits and cost terms; it is an important issue within the scope of our paper.

Another issue which is within our paper's scope is optimal hydropower design, where optimal values for design parameters such as hydraulic and structural design of a tunnel and surge tank (Fathi-Moghadam et al. 2013), installed capacity (IC), normal water volume and minimum operation volume (Mousavi & Shourian 2010), number of units, tunnel length and diameter, and turbine's design head and flow (Najmaii & Movaghar 1992) are determined using optimization models. Most of these models incorporate either pure technical objectives, cost effectiveness measures (e.g. Hreinsson 1990; Anagnostopoulos & Papantonis 2007) or simple MPM-based benefit assessment (e.g. Najmaii & Movaghar 1992; Mousavi & Shourian 2010) for economic analysis. Raeisi et al. (2016) were the first to employ ATPM to optimize an HPP's design.

In this paper we propose a new model for optimal HPP design which is capable of taking into account detailed benefits, environmental and social externalities, and CDM-based financing in addition to traditional capital and operation and maintenance (O&M) costs terms and technical considerations. In the following, first the problem of optimal HPP design is formulated using mathematical programming. Then the problem is solved employing a simulation-optimization approach where a hydro-economic-energy simulation module built upon Water Evaluation and Planning (WEAP) software is coupled to a particle swarm optimization (PSO) algorithm. Finally the model is applied to a case study in Iran, i.e. Karun II dam and hydropower plant project.

MATHEMATICAL PROGRAM

Optimal design of a hydropower plant, which includes a dam and a power plant, can be carried out based upon purely technical objectives such as maximizing total or firm energy and/or economic objectives such as minimizing (net) cost or maximizing net benefit. In this research, some economic objective functions of maximizing net benefit of energy production are considered. Here, net benefit means present value of benefits achieved from generating electricity using a hydropower project minus present value of costs related to construction, operation and maintenance

of the dam and the power plant. The objective functions, which are proposed with more detail in the next section, are different with respect to how they analyze benefits of a hydropower project.

Other water users and requirements in the system (located downstream of the dam), including ecosystem protection, municipal and industrial water consumption, irrigation-based food production and water-based recreation, are taken into account through priority-based water supply constraints. In other words, a generic form of the objective function is building upon economic performance of hydropower generation, where performances of other mentioned water users and requirements are formulated in terms of constraints.

The economic objective functions generally can be formulated using net present value measures as:

$$Max\ NPV(NWL, IC_{HPP}) = PVB(NWL, IC_{HPP}) \\ - PVC(NWL, IC_{HPP}) \\ - \alpha^{Penalty} \times \sum_p (1 - Cov_{min,p}) \quad (1)$$

where PVB represents present value of benefits achieved from generating electricity using a hydropower project and PVC stands for present value of costs related to construction, operation and maintenance of the dam and the power plant. Both PVB and PVC are nonlinear functions of main decision variables of the dam's normal water level (NWL), NWL, and IC of the hydropower plant, IC_{HPP}; more details on the functional forms will be proposed below under 'Economic module'. The objective function includes a penalty term due to the deficit in supplying other water demands, where $Cov_{min,p}$ is minimum coverage related to the demand sites associated with the pth priority level and $\alpha^{Penalty}$ stands for penalty factor associated with that priority level.

Constraints related to supplying other water demands are expressed as below:

$$SD_{i,y,t} \leq D_{i,y,t} \qquad \forall i, y, t \qquad (2)$$

$$Cov_{min,p} \leq \frac{\sum_{y,t} SD_{i,y,t}}{D_{i,y,t}} \qquad \forall p, i \in DS(p) \qquad (3)$$

where i represents an index related to municipal, industrial and agricultural demand sites, t is an index related to seasonal (intra-year, e.g. monthly) time periods, y stands for an index related to years, p is an index related to priority levels of supplying water demand, $D_{i,y,t}$ represents volume of water demand associated with the ith demand site in year y and season t, and $SD_{i,y,t}$ is volume of water actually allocated to the ith demand site in year y and season t. Also $DS(p)$ is a collection of the demand sites associated with the pth priority level. Inequality (2) emphasizes that volume of water which is actually allocated to a demand site at a time period should be less than or equal to volume of water demand of the site. Also, inequality (3) expresses that minimum demand coverage, $Cov_{min,p}$, among all demand sites associated with the pth priority level must be less than or equal to each demand site's coverage, represented by the fraction on the right hand side (r.h.s.).

The reservoir's water balance equation is stated by:

$$S_{y,t+1} = S_{y,t} + Q_{y,t} - EV_{y,t} - R_{y,t} \qquad \forall y, t \qquad (4)$$

where $S_{y,t}$ represents storage of reservoir at the beginning of the tth season of year y, $Q_{y,t}$ is reservoir inflow, $EV_{y,t}$ stands for net evaporation volume, and $R_{y,t}$ represents release volume, which equals sum of regulated release volume, $R_{y,t}^{Rg}$ and spillage volume, $R_{y,t}^{Spil}$. The reservoir's storage bounds are also considered as:

$$S_{min} \leq S_{y,t} \leq S_{max} \qquad \forall y, t \qquad (5)$$

where $S_{min}(= f_{VEC}(MOL))$ is minimum operation volume, $S_{max}(= f_{VEC}(NWL))$ is normal water volume (storage capacity), which are expressed using the reservoir's volume-elevation curve, $f_{VEC}(.)$, respectively in terms of minimum operation level (MOL), MOL, and NWL, NWL.

Volume of the reservoir at each time period is expressed by:

$$EV_{y,t} = EH_{y,t} f_{AVC}\left(\frac{S_{y,t} + S_{y,t+1}}{2}\right) \qquad \forall y, t \qquad (6)$$

which equals net evaporation height, $EH_{y,t}$, multiplied by the reservoir's area represented using area-volume

curve, $f_{AVC}(.)$, in terms of average reservoir storage of the period.

Reservoir operation policy of interest is considered using:

$$R_{y,t}^{Rg} = f_{OP}(S_{y,t}, Q_{y,t}) \qquad \forall y, t \qquad (7)$$

where $f_{OP}(.)$ is the operation policy as a function in terms of both reservoir storage and inflow. Also the reservoir's spillage is expressed using the below constraints:

$$Z_{y,t}^{Spill} \le \frac{S_{y,t}}{S_{max}} \qquad \forall y, t \qquad (8)$$

$$R_{y,t}^{Spill} \le BV \times Z_{y,t}^{Spill} \qquad \forall y, t \qquad (9)$$

where BV is a large value and $Z_{y,t}^{Spill}$ is a binary variable which determines spillage status of the reservoir. The binary variable equals 1 when the reservoir spills and equals zero otherwise. The constraints ensure that the reservoir spills only when storage exactly equals its capacity.

There are two important limitations on amount of generated energy. First, the generated energy cannot exceed the energy value calculated using the main energy production equation as below:

$$E_{y,t} \le \alpha_1^{CF} \xi H_{y,t}^e R_{y,t}^{HP} \qquad \forall y, t \qquad (10)$$

where $E_{y,t}$ represents energy generated by the power plant during the tth season of year y, $R_{y,t}^{HP}$ stands for turbine flow, which is the volume of water that is released from the reservoir and passes along the turbine tunnel and generates hydropower energy during the time period, $H_{y,t}^e$ is net head, which effectively takes part in energy generation at the beginning of the period, α_1^{CF} represents a conversion factor which equals 2.72 when head and flow are in meters and million cubic meters, respectively, and ξ is the generating efficiency. Generated energy is also limited to a potential value determined based upon IC as:

$$E_{y,t} \le 24 ND_{y,t} IC \qquad \forall y, t \qquad (11)$$

where $ND_{y,t}$ represents the number of days of tth season of year y, which when multiplied by 24 results in maximum

generating hours at the period, and $IC(= \gamma_W \xi H_{des} Q_{des})$ stands for IC of the power plant where γ_W, H_{des} and Q_{des} are the specific weight of water, turbine's design head, and turbine design flow, respectively.

Based on the power plant's performance curve, there are two ranges respectively associated with head and flow for which generating efficiency only slightly reduces relative to its maximum value, and therefore the power plant is only operated for these ranges of head and flow (USACE 1985). To account for this important consideration, here we formulate turbine flow, $R_{y,t}^{HP}$, as a piecewise linear function (Figure 1(a)) volume of regulated release, $R_{y,t}^{Rg}$. In a mathematical programming framework, the function can be expressed using the constraints below:

$$R_{y,t}^{HP} = R_{y,t}^{Rg} Z_{y,t}^{HPF,2} + R_{max}^{HP} \times (1 - Z_{y,t}^{HPF,1} - Z_{y,t}^{HPF,2}) \qquad \forall y, t$$
$$(12)$$

$$-BV \times Z_{y,t}^{HPF,1} + R_{min}^{HP} Z_{y,t}^{HPF,2} + R_{max}^{HP}$$
$$\times (1 - Z_{y,t}^{HPF,1} - Z_{y,t}^{HPF,2}) \le R_{y,t}^{Rg} \qquad \forall y, t \qquad (13)$$

$$R_{min}^{HP} Z_{y,t}^{HPF,1} + R_{max}^{HP} Z_{y,t}^{HPF,2} + BV$$
$$\times (1 - Z_{y,t}^{HPF,1} - Z_{y,t}^{HPF,2}) \ge R_{y,t}^{Rg} \qquad \forall y, t \qquad (14)$$

$$Z_{y,t}^{HPF,1} + Z_{y,t}^{HPF,2} \le 1 \qquad \forall y, t \qquad (15)$$

where $Z_{y,t}^{HPF,1}$ and $Z_{y,t}^{HPF,2}$ are binary variables associated with $R_{y,t}^{HP}$. Also, $R_{max}^{HP}(= max\{f_{TC}(TD), \alpha_2^{CF} \bar{\alpha}_Q Q_{des}\})$ represents the maximum tunnel flow that can take part in hydropower generation, where $f_{TC}(.)$ is flow capacity of the tunnel as a function of tunnel diameter, α_2^{CF} is a factor that converts flow rate to flow volume, and $\bar{\alpha}_Q$ is the maximum flow rate factor, which depends on the turbine type (e.g. for Francis turbine $\bar{\alpha}_Q$ is about 1.1). $R_{min,d}^{HP}(= \alpha_2^{CF} \underline{\alpha}_Q Q_{des}/NU)$ stands for minimum turbine flow that can take part in hydropower generation, where NU is number of the power plant's unit, $\underline{\alpha}_Q$ is minimum flow rate factor, which depends on turbine type and characteristics (e.g. for Francis turbine $\underline{\alpha}_Q$ is about 0.5), $\alpha_2^{CF} = 3600 T_{P,max} N_d$, where N_d is number of the days which the time step includes, and $T_{P,max}$ represents the number of planned peak hours per day.

Regarding the aforementioned considerations on the performance curve, we formulate effective net head, $H_{y,t}^e$, as a piecewise linear function (Figure 1(b)) of net head,
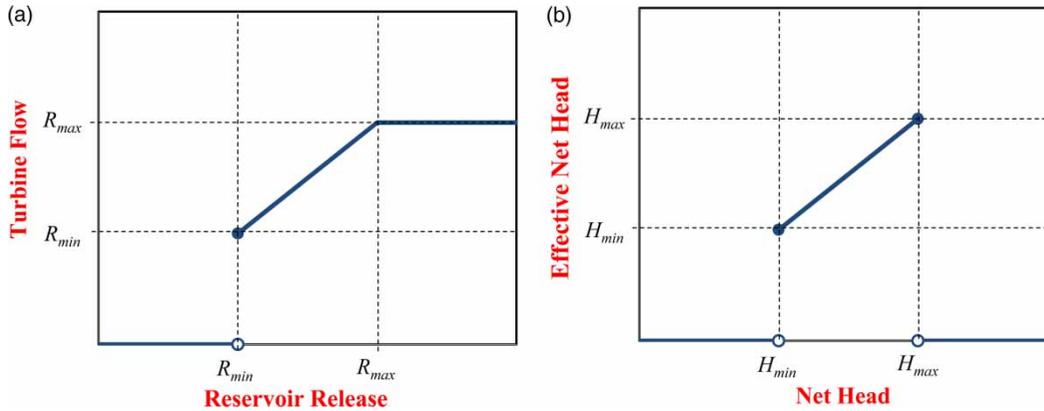
Figure 1 | Turbine curves for power plant: (a) volume of turbine flow, $R_{y,t}^{HP}$, as a function of regulated reservoir release, $R_{y,t}^{Rg}$; (b) effective net head, $H_{y,t}^{e}$, as a function of net head, $H_{y,t}^{Net}$.

$H_{y,t}^{Net}$. In the mathematical programming framework, the function can be expressed by the below constraints:

$$H_{y,t}^e = Z_{y,t}^{HPH,2} H_{y,t}^{Net} \qquad \forall y, t \tag{16}$$

$$\begin{aligned} - BV \times Z_{y,t}^{HPH,1} + H_{min} Z_{y,t}^{HPH,2} + H_{max} \\ \times (1 - Z_{y,t}^{HPH,1} - Z_{y,t}^{HPH,2}) \le H_{y,t}^{Net} \qquad \forall y, t \end{aligned} \tag{17}$$

$$\begin{aligned} H_{min} Z_{y,t}^{HPH,1} + H_{max} Z_{y,t}^{HPH,2} + BV \\ \times (1 - Z_{y,t}^{HPH,1} - Z_{y,t}^{HPH,2}) \ge H_{y,t}^{Net} \qquad \forall y, t \end{aligned} \tag{18}$$

$$Z_{y,t}^{HPH,1} + Z_{y,t}^{HPH,2} \le 1 \qquad \forall y, t \tag{19}$$

where $Z_{y,t}^{HPH,1}$ and $Z_{y,t}^{HPH,2}$ are binary variables. H_{max} ($= \bar{\alpha}_H H_{des}$) stands for the maximum head that can take part in hydropower generation, where H_{des} is turbine's design head and $\bar{\alpha}_H$ is maximum head factor. $\bar{\alpha}_H$ depends on the turbine type and characteristics (e.g. for Francis turbine $\bar{\alpha}_H$ is approximately 1.25). H_{min}($= \underline{\alpha}_H H_{des}$) represents the minimum head that can take part in hydropower generation, where $\underline{\alpha}_H$ is minimum flow rate factor, which depends on turbine type and characteristics (e.g. for Francis turbine $\underline{\alpha}_H$ is approximately 0.65). Also, the net head is stated by:

$$\begin{aligned} H_{y,t}^{Net} = \frac{f_{EVC}(S_{y,t+1}) + f_{EVC}(S_{y,t})}{2} - f_{TWC}(R_{y,t}) \\ - f_{HL}(R_{y,t}^{HP}, TD) \end{aligned} \tag{20}$$

where $f_{EVC}(.)$ represents elevation-volume curve of the reservoir, $f_{TWC}(.)$ is tail water elevation curve associated with the power plant, $f_{HL}(.)$ stands for power plant's head loss in form of a function of tunnel diameter, TD, and turbine flow, $R_{y,t}^{HP}$.

Firm energy, which is defined as maximum constant dependable energy, is expressed by:

$$Z_y^{FE} \times FE \le \sum_t E_{y,t} \qquad \forall y \tag{21}$$

$$\alpha^{TR} \le \sum_y Z_y^{FE} / Y \tag{22}$$

where FE represents firm energy of the power plant, Z_y^{FE} is a binary variable which equals 1 when the generated energy is equal to and greater than the firm energy during year y, Y is number of years, and α^{TR} stands for the target reliability level associated with firm energy. Also, secondary energy generated by the power plant during year y is stated as below:

$$SE_{y,t} = \sum_t E_{y,t} - FE \qquad \forall y \tag{23}$$

The mathematical program is of mixed-integer nonlinear type and according to the presence of several nonlinear equality constraints, the program is also non-convex.

SOLUTION APPROACH: PSO-AUTOMATED WEAP

In the preceding section the problem of optimal design of a hydropower project was formulated using mathematical

programming and we demonstrated that the program is complex and non-convex. In this section we propose a simulation-optimization solution approach where PSO and WEAP software are coupled. Although WEAP is a powerful software globally employed for integrated water resources planning, its hydropower simulation and economic analysis capability need more improvement; therefore, in this study we provided some complementary sub-modules using the scripting capability of WEAP, where both hydropower simulation and economic analysis are performed using related methods first proposed by USACE (1985), i.e. sequential streamflow routing (SSR) method for hydropower simulation and alternative thermal plant and market price methods for economic analysis of hydropower projects.

Figure 2 illustrates more details on the simulation-optimization model, named PSO-WEAP, which is actually an iterative algorithm. While the key role of the optimization module (PSO) is to determine new solutions which should be checked and simulated in each iteration, the main duty of the simulation module (automated WEAP) is to calculate the objective function, i.e. NPV, associated with the new solutions. The simulation module consists of three parts: (1) water allocation sub-module, (2) hydropower simulation sub-module, and (3) economic sub-module. The simulation module starts with a water allocation sub-module where the system's water resources are allocated to the demand sites using WEAP, which is iteratively run in an SSR framework to calculate the hydropower water requirement and allocate water based on it. Afterwards, the hydropower simulation module and economic sub-module are run, which respectively provide statistics of energy (firm and secondary) and terms of benefit and cost that finally are employed for objective function evaluation.
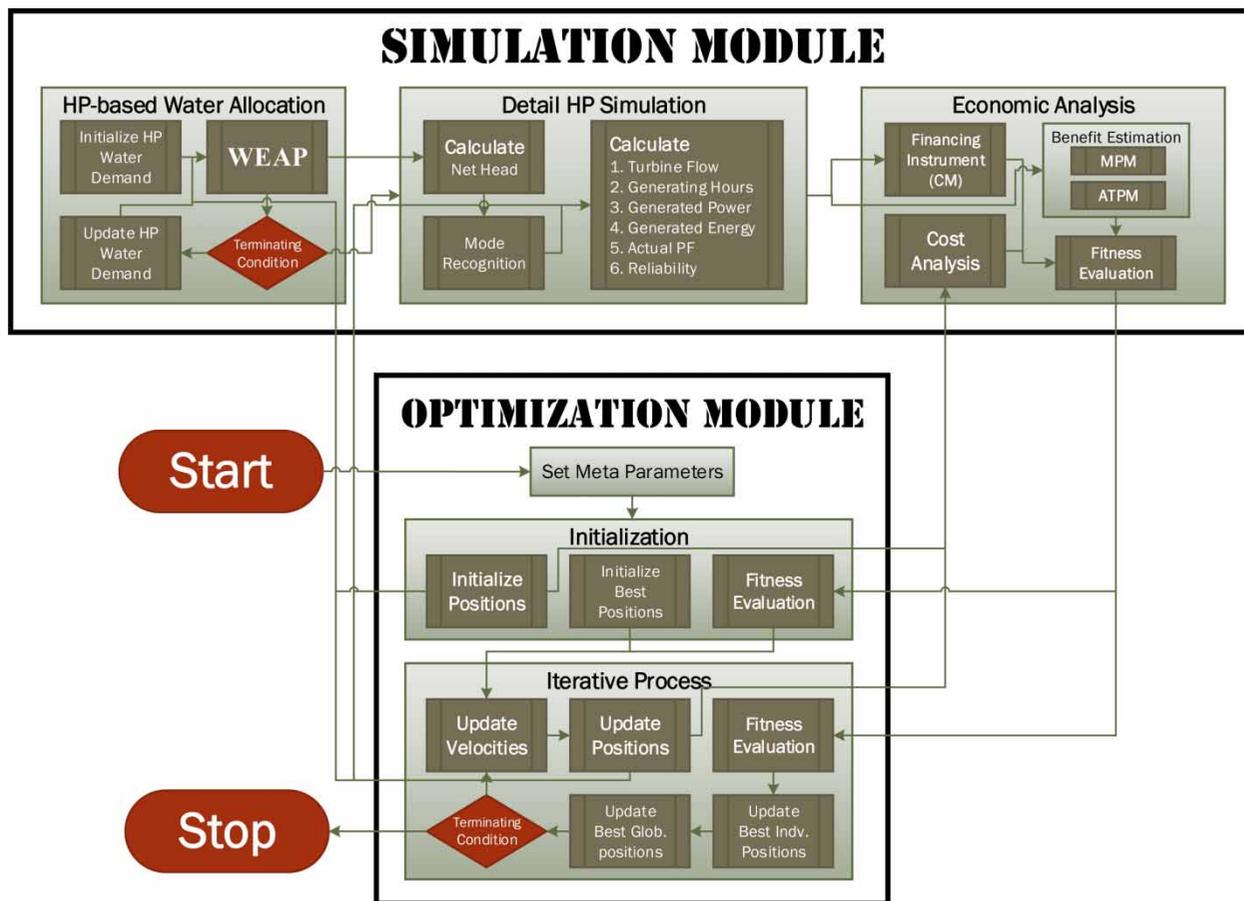

Figure 2 | Schematic of the simulation-optimization model.

Each solution is actually a combination of project design decision variables, including the hydropower plant's IC and plant factor, and normal water and minimum operation levels corresponding to the reservoir. In the following, more details about each module and its sub-modules are proposed.

Simulation module: automated WEAP

WEAP software is distinguished by its integrated approach for water resources systems simulation and provides a comprehensive, flexible and user-friendly framework for both project and policy analysis. WEAP utilizes basic water balance equations for water allocation in river basin systems based on demand priorities and supply preferences.

The original version of WEAP is capable of hydropower simulation in addition to taking into account other water demands, including consumptive usages and instream flow requirements. However, there are some shortcomings and limitations in the hydropower simulation module of WEAP which need more improvement; it ignores some characterizing power plant's parameters such as IC, performance curve, and head loss; for hydropower-based water allocation in each time period, only the initial values of important variables such as reservoir storage and head are taken into account, and it ignores the effect of end of period reservoir storage and head; and it cannot provide some important details of hydropower simulation, e.g. statistics and characteristics of generated energy such as firm, secondary, peak and off-peak.

To overcome the aforementioned hydropower limitations of WEAP, we utilized scripting capabilities embedded in version 3.43 of the software. The scripts we wrote included three main phases for hydropower simulation: hydropower-based water allocation, detailed hydropower simulation and economic analysis, which are discussed below.

Hydropower-based water allocation

Hydropower water demand is essentially dynamic because it mainly depends on the net head, which is time variable according to its dependence on forebay (reservoir) water elevation, tail water level, and head loss, which are all time variables. Therefore, dynamics of mentioned factors should be properly dealt with for hydropower water demand modelling. Given that for planning purposes time is discretized to intervals as long as a week, a month or a season, time average values of the factors at each time period should be used, which are normally considered as an average of both the beginning and end of period values. Also, dependence of head loss and tail water on water flow are important and should be taken into account.

Although WEAP version 3.43 deals with hydropower for water allocation simulation, it cannot account for time average values and also functionality of head loss and tail water level, which may lead to significant approximations. In other words, using the modelling capabilities of WEAP, i.e. Expression Builder and Scripting, only the beginning-of-period values of the variables are accessible; also head loss and tail water level are introduced as fixed values. To overcome the mentioned limitations, here in this paper we employed an iterative numerical procedure for water allocation based on hydropower purposes using WEAP.

Detailed hydropower simulation

Based on water allocation results, i.e. time series of reservoirs storage and release, at the second main phase, detailed hydropower simulation is performed, where, corresponding to the power plant, time series of turbines' net head and discharge, the plant's generated power and energy and some performance measures such as plant factor and reliability, etc., are calculated. Accordingly, an essential energy equation is employed, which can be expressed by:

$$E = \xi \sum_i H_{n,i} Q_i T_i = \xi \sum_i H_{n,i} V_i \qquad (24)$$

where average net head, $H_{n,i}$, average turbine flow, Q_i, and generating hours, T_i, are three key factors contributing to hydropower energy generation; also ξ and i are generating efficiency and an index associated with time period, respectively. It is worth mentioning that by the parameter of generating hours, we mean number of hours for which the plant generates power during a time period. Also, the energy equation can be rewritten using volume of turbine flow in the time period, i.e. $V_i = Q_i T_i$. Based on the second presentation of the energy equation, it is clear that energy estimation is conditioned by at least two key factors: net head and volume of turbine flow. Given that the water

allocation module just prepares time series of storage and release of every reservoir, the mentioned key factors should be calculated based upon these two time series. At each time period and for each power plant, the value of the first key factor, i.e. net head, is calculated using $H_{n,i} = El_i - TWL - H_f$, where El stands for average forebay water elevation during the period, which is calculated using the reservoir's elevation-volume curve taking the reservoir's storage as argument; also, TWL is tail water level as a function of reservoir release, and H_f represents head loss. Volume of turbine flow depends on reservoir release, while the other factors, i.e. generating hours, generated power, and generated energy, are conditioned by both net head and reservoir release, as shown in Table 1. In this regard, detailed discussion is proposed in the following, where energy generation is conditioned by six main operation modes.

First mode. The first mode is related to the time when energy production diminishes because net head and/or reservoir release are out of the plant's performance range (USACE 1985). It means that the net head is less than the minimum allowable head, H_{min}, or greater than the maximum allowable head, H_{max}, or reservoir release is less than the minimum allowable release, R_{min}.

Second mode. The second mode and four other modes, which are explained in the following, are related to conditions where both net head and discharge are in the allowable ranges (performance curve) and are not limiting. At the second mode, the reservoir release is greater than the minimum allowable release threshold, R_{min}, but is less than a threshold value, $R'_{P,max}$, for which the plant generates a constant amount of power during whole peak hours. While in this mode power is constantly generated which is equal to P'_{max}, it is only generated in part of the peak hours, and the greater the reservoir release, the more generating hours there will be. Under this mode the plant does not generate energy during off-peak hours, and consequently all off-peak related factors diminish.

Third mode. Under the third mode the power plant is overloaded so that power is generated for the total peak hours, and the greater the release volume, the more generated power there will be. Again, under this mode the plant does not generate energy during off-peak hours.

Table 1 | Definition of detailed hydropower simulation modes

Mode	Net head H_n	Reservoir release R	Turbine flow		Generating hours		Generated power	
			R_P	R_{OP}	T_P	T_{OP}	P_P	P_{OP}
1st	$(-\infty, H_{min}) \cup (H_{max}, +\infty)$	$(-\infty, R_{min})$	0	0	0	0	0	0
2nd	$[H_{min}, H_{max}]$	$[R_{min}, R'_{P,max}]$	R	0	$\alpha_1 T_{P,max}$	0	P'_{max}	0
3rd	$[H_{min}, H_{max}]$	$[R'_{P,max}, R''_{P,max}]$	R	0	$T_{P,max}$	0	$P'_{max} + \alpha_2$	0
4th	$[H_{min}, H_{max}]$	$\begin{bmatrix} R''_{P,max}, \\ R''_{P,max} + R'_{OP,max} \end{bmatrix}$	$R''_{P,max}$	$R - R''_{P,max}$	$T_{P,max}$	$\alpha_3 T_{OP,max}$	P''_{max}	P'_{max}
5th	$[H_{min}, H_{max}]$	$\begin{bmatrix} R''_{P,max} + R'_{OP,max}, \\ R''_{P,max} + R''_{OP,max} \end{bmatrix}$	$R''_{P,max}$	$R - R''_{P,max}$	$T_{P,max}$	$T_{OP,max}$	P''_{max}	$P'_{max} + \alpha_4$
6th	$[H_{min}, H_{max}]$	$\begin{pmatrix} R''_{P,max} + R''_{OP,max}, \\ +\infty \end{pmatrix}$	$R''_{P,max}$	$R''_{OP,max}$	$T_{P,max}$	$T_{OP,max}$	P''_{max}	P''_{max}

R_P: volume of turbine flow during peak hours of a time period (month); R_{OP}: volume of turbine flow during off-peak hours of a time period; T_P: generating hours during peak hours of a time period; T_{OP}: generating hours during off-peak hours of a time period; P_P: generated power during peak hours of a time period; P_{OP}: generated power during off-peak hours of a time period; $R'_{P,max} (= 10^3 P'_{max}/9.81\xi H_n 3600 T_{P,max} N_d)$: maximum volume of reservoir release at the second mode; $R''_{P,max} (= 10^3 P''_{max}/9.81\xi H_n 3600 T_{P,max} N_d)$: maximum volume of reservoir release at the third mode; $R''_{OP,max} (= 10^3 P''_{max}/9.81\xi H_n 3600 T_{OP,max} N_d)$: maximum volume of turbine flow during off-peak hours of a time period; $P'_{max} (= min\{IC, 9.81 \times 10^{-3} \xi H_n Q_{max}\})$: maximum generated power at the second mode; $P''_{max} (= min\{\alpha_{OL} IC, 9.81 \times 10^{-3} \xi H_n Q_{max}\})$: maximum generated power at the third mode; IC: power plant's IC; $Q_{max} (= \bar{\alpha}^Q Q^{design})$: maximum turbine flow; $\bar{\alpha}^Q$: a factor related to maximum flow rate; Q^{design}: turbine's design flow; $\alpha_{OL} (\leq 1)$: overload coefficient; $T_{OP,max} (= 24 - T_{P,max})$: maximum off-peak generating hours; $T_{P,max}$: maximum peak generating hours; $\alpha_1 (= R/R'_{P,max})$: fraction of peak generating hours to planned peak hours at the second mode; $\alpha_2 (= R - R'_{P,max}/R''_{P,max} - R'_{P,max}(P''_{max} - P'_{max}))$: power generated due to overload operation in excess of P_{max} in the third mode; $\alpha_3 (= R_{OP}/R'_{OP,max})$: fraction of off-peak generating hours to maximum off-peak hours at the fourth mode; $\alpha_4 (= R_{OP} - R'_{OP,max}/R''_{OP,max} - R'_{OP,max}(P''_{max} - P'_{max}))$: off-peak generated power due to overload operation in excess of P'_{max} in the fourth mode.

Fourth mode. Under the fourth mode, reservoir release is so high that the power plant generates power during both peak and off-peak hours. While the plant is overloaded during peak hours, and thus both generated power and peak generating hours are maximum, during part of the off-peak hours the plant generates a constant amount of power, P'_{max}, for variable off-peak generating hours whose value depends on reservoir release, so that the greater the reservoir release, the more generating hours there will be.

Fifth mode. Under the fifth mode, reservoir release is so high that the power plant is overloaded during both peak and off-peak hours. For peak hours both generated power and generating hours are maximum, while during whole off-peak hours the power plant generates a variable amount of power whose value depends on the reservoir release volume, so that the greater the reservoir release, the more off-peak power there will be.

Sixth mode. Under the sixth mode, the reservoir releases a great volume of water so that the plant generates power with full overload capacity, P''_{max}, over the whole time period.

Other hydropower factors. After calculation of the key factors including flow, net head, generating hours, and power, it is possible to calculate other important hydropower factors. Accordingly, peak and off-peak generated energy are respectively estimated by:

$$E_P = \frac{9.81\xi H_n R_P}{3600 \times 10^6} \tag{25}$$

$$E_{OP} = \frac{9.81\xi H_n R_{OP}}{3600 \times 10^6} \tag{26}$$

Also, total energy equals summation of peak and off-peak generated energy, i.e. $E_T = E_P + E_{OP}$.

Since the above time series of energy are estimated, firm energy, *FE*, can be separately calculated using frequency analysis either for different generating hours, i.e. peak, off-peak and total, or for different time periods, i.e. monthly and annual. It is worth mentioning that, given a time series of each quantity of interest, e.g. power or energy, its firm (dependable) value is easily estimated by sketching a duration curve (USACE 1985). Moreover, time series of secondary energy is estimated by $SE = E_T + FE$.

Here, it should be mentioned that an example project of WEAP including the above described iterative procedure for hydropower-based water allocation, as well as detailed hydropower simulation, will be accessible to every interested reader who contacts the authors.

Economic module

Economic module is building upon two traditional hydropower benefit-cost analysis methods, i.e. MPM and ATPM. In this paper, the methods are augmented by extra considerations of CDM and the alternative thermal plant's externalities, respectively. Both methods incorporate two main parts to account for cost and benefit, separately. While the former parts of both methods are the same, the methods are different with respect to the latter part. In the following, after explaining how the terms related to cost are estimated, benefit analysis associated with the methods is discussed separately.

Cost analysis

Using cost analysis we estimate the hydropower plants' cost terms as functions of main design parameters. A hydropower plant includes two main parts – dam and plant. Both parts include individual capital and O&M costs, where the dam's related costs are mainly functions of the dam's NWL and the plant's related costs are functions of the plant's IC. Here we assume that capital and O&M costs are distributed over construction time period and operation time period, i.e. life time, respectively. Here, time reference is the beginning of the operation period. Accordingly, the present value of costs associated with the hydropower project is estimated by:

$$PVC_{HPP}(NWL, IC_{HPP})$$

$$= \sum_{y=-n_{HPP,C}}^{0} (C_{DCC,y}(NWL) + C_{PCC,y}(IC_{HPP})) \times (1+i)^{-y}$$

$$+ \sum_{y=1}^{n_{HPP,O}} (C_{DOMC,y}(NWL) + C_{POMC,y}(IC_{HPP})) \times (1+i)^{-y} \tag{27}$$

where NWL and IC stand for the dam's NWL and the plant's IC, respectively. y is an index related to yearly time steps and i is discount factor. Also, $n_{HPP,C}$ and $n_{HPP,O}$ represent the hydropower plant's construction and operation time periods, respectively. $C_{DCC,y}$ and $C_{DOMC,y}$ represent the respective dam-related costs of investment and O&M, and similarly, $C_{PCC,y}$ and $C_{POMC,y}$ stand for the plant-related costs of investment and O&M, respectively.

Market price method

MPM is building upon estimating incomes achieved from the sale of energy. Accordingly, the present value of benefit achieved by the hydropower project equals the present value of selling produced energy, which is estimated using the following equation:

$$
\begin{aligned}
PVB_{HPP}&(NWL, IC_{HPP}) \\
&= \sum_{y=1}^{n_{HPP,O}} (FPE(NWL, IC_{HPP}) \times FPEP_y + FOPE(NWL, IC_{HPP}) \\
&\quad \times FOPEP_y + SPE_y(NWL, IC_{HPP}) \times SPEP_y \\
&\quad + SOPE_y(NWL, IC_{HPP}) \times SOPEP_y) \times (1+i)^{-y} \quad (28)
\end{aligned}
$$

where FPE and $FPEP$ represent the generated annual firm peak energy and its sell price per kilowatt, respectively, and $FOPE$ and $FOPEP$ represent the generated annual firm off-peak energy during year y and its sell price per kilowatt, respectively. Furthermore, SPE and $SPEP$ represent the generated annual secondary peak energy and its sell price per kilowatt, respectively, and $SOPE$ and $SOPEP$ represent the generated annual secondary off-peak energy during year y and its sell price per kilowatt, respectively.

Alternative thermal plant method

The ATPM is an approach for estimating the hydropower plant's economic benefits (USACE 1985). The method is based on opportunity cost concept, where an equivalent thermal power plant (ATPP) is taken as the best alternative for the hydropower plant (HPP). ATPP is equivalent to HPP because both supply the same level of energy and power and also the same benefit achieved from selling generated energy. Therefore, the present value of benefit of HPP equals the present value of cost of ATPP. In addition to investment and O&M associated with ATPP, in this paper we consider social and environmental external costs related to ATPP. Therefore, the present value of benefit achieved by HPP is expressed using the following equation:

$$
\begin{aligned}
PVB_{HPP}(NWL, IC_{HPP}) &= PVC_{ATPP}(NWL, IC_{HPP}) \\
&= PVC_{CAP}(NWL, IC_{HPP}) \\
&\quad + PVC_{OM}(NWL, IC_{HPP}) \\
&\quad + PVC_{EXT}(NWL, IC_{HPP}) \quad (29)
\end{aligned}
$$

where the terms on the r.h.s. represent the present value of cost terms respectively associated with capital (construction), O&M and externality.

The IC of ATPP is determined using:

$$
IC_{ATPP}(NWL, IC_{HPP}) = \frac{FE(NWL, IC_{HPP})}{nhours \times PF \times TMA} \quad (30)
$$

where FE stands for firm energy generated by the hydropower project, $nhours$ is total number of hours which a year includes, PF represents the ATPP's plant factor, and TMA stands for thermal plant availability.

Construction costs are distributed over ATPP's construction period, $n_{ATPP,C}$, while O&M costs are distributed over ATPP's life time, $n_{ATPP,O}$. Also, ATPP's O&M costs consist of three main parts: (1) fixed O&M cost, (2) variable O&M cost, and (3) fuel cost. Accordingly, the present value of construction and O&M are estimated using the following equations:

$$
\begin{aligned}
PVC_{CAP}(NWL, IC_{HPP}) &= \sum_{y=-n_{ATPP,C}}^{0} C_{CAP,y}(NWL, IC_{HPP}) \\
&\quad \times (1+i)^{-y} \quad (31)
\end{aligned}
$$

$$
\begin{aligned}
PVC_{OM}&(NWL, IC_{HPP}) \\
&= (C_{FOM}(NWL, IC_{HPP}) + C_{VOM}(NWL, IC_{HPP}) \\
&\quad + C_{Fuel}(NWL, IC_{HPP})) \times \left(\frac{P}{A}, i, n_{ATPP,O}\right) \quad (32)
\end{aligned}
$$

where $C_{CAP,y}$ represents the ATPP's construction cost over the yth year before starting operation of the plant and is estimated using a linear function of IC as $C_{CAP,-y}(NWL, IC_{HPP}) = \alpha_{-y}^{ATPP,CAP} \times \alpha_{CAP}^{ATPP} \times IC_{ATPP}(NWL, IC_{HPP})$, $\forall y = 0, \ldots, n_{ATPP,C}$, where $\alpha_{-y}^{ATPP,CAP}$ is a coefficient determining how the construction cost distributes over time and α_{CAP}^{ATPP} is construction cost per unit IC of ATPP. Also, C_{FOM} is the yearly uniform fixed O&M cost and is estimated as $C_{FOM}(NWL, IC_{HPP}) = \alpha_{FOM}^{ATPP} \times IC_{ATPP}(NWL, IC_{HPP})$, where α_{FOM}^{ATPP} is the fixed O&M cost per unit IC of ATPP. C_{VOM} represents the yearly uniform variable O&M cost and is estimated as $C_{VOM}(NWL, IC_{HPP}) = \alpha_{VOM,FE}^{ATPP} \times FE(NWL, IC_{HPP}) + \alpha_{VOM,SE}^{ATPP} \times SE(NWL, IC_{HPP})$, where FE and SE stand for firm and secondary energy, respectively, and α_{VOM}^{ATPP} is variable O&M cost per unit IC of ATPP. C_{Fuel} represents the yearly uniform fuel cost and is estimated using $C_{Fuel}(NWL, IC_{HPP}) = \dfrac{\alpha_{FE}^{Fuel} \times FE(NWL, IC_{HPP})}{HV_{FE} \times R_{FE}} + \dfrac{\alpha_{SE}^{Fuel} \times SE(NWL, IC_{HPP})}{HV_{SE} \times R_{SE}}$, where α^{Fuel} stands for cost related to fuel consumed for unit generated energy, HV is heating value of fuel, and R represents ATPP's efficiency.

External costs (externalities) are those project's costs which are imposed on society and the environment, and are not accounted for by the producers or the consumers of electricity. Electricity production using thermal power plants causes substantial environmental and human health damages, which depend on how and where the electricity is generated. While traditional cost-benefit analysis often excludes or downplays environmental and social effects, the existence of external costs can lead to market failure. Therefore, damages caused by ATPP are external costs and must be included in economic analysis and added to other thermal plant costs. External costs of ATPP incorporate the uncompensated monetary value of environmental and health damages caused by electricity generation. There are significant damages to human health, built environment, crops, forests and ecosystems, but the most thoroughly investigated among them are damages to human health. The most significant environmental impact associated with thermal power plants is airborne pollution caused by fuel combustion. The present value of external costs (PVC_{EXT})

can be calculated as below:

$$PVC_{EXT}(NWL, IC_{HPP})$$
$$= (\alpha_{FE}^{EXT} \times FE(NWL, IC_{HPP}) + \alpha_{SE}^{EXT} \times SE(NWL, IC_{HPP}))$$
$$\times \left(\frac{P}{A}, \ i, \ n_{ATPP,O}\right) \qquad (33)$$

where α_{FE}^{EXT} is the average external cost per unit of energy produced in a thermal power plant for replacing firm energy and α_{SE}^{EXT} is the average external cost per unit of energy produced in a thermal power plant for replacing secondary energy. Given that the life times of HPP and ATPP are not equal, it is necessary to repeat the projects.

CDM as a financing instrument

CDM can serve as a feasible way of financing a hydropower project. Therefore, the present value of financing the project using CDM, FPV_{CDM}, should be considered as a term contributing to hydropower benefits. Evaluation of FPV_{CDM} is based on the concept of CER credits. Using CDM, a country would be eligible to earn saleable CER credits at the expense of making emission-limitation commitment by means of an emission reduction project, e.g. hydropower plant. Each CER is equivalent to 1,000 kg of CO_2, which can be counted towards meeting Kyoto targets. Finally, present value of CDM can be stated in terms of benefit achieved from CERs income as follows:

$$FPV_{CDM}(NWL, IC_{HPP}) = \sum_{y=1}^{n_{HPP,O}} ER_y(NWL, IC_{HPP})$$
$$\times P_{CER} \times (1 + i)^{-y} \qquad (34)$$

where ER_y represents emission reductions in year y, and P_{CER} is price of CERs.

According to UNFCCC (2016), the emission reductions are calculated as follows:

$$ER_y(NWL, IC_{HPP}) = BE_y(NWL, IC_{HPP}) - PE_y - LE_y \qquad (35)$$

where BE_y is baseline emissions in year y, PE_y is the project's emissions in the year and LE_y is leakage emissions in the year; the units for all mentioned variables are the same and equal 1,000 kg CO_2 per year. The baseline

emissions equals baseline electrical energy generated in the year, EG_y, which is the same as electricity produced by the renewable generating unit multiplied by the grid emission factor, EF, as below:

$$BE_y(NWL, IC_{HPP}) = EG_y(NWL, IC_{HPP}) \times EF_{CO2, grid, y} \quad (36)$$

For most renewable energy projects, including hydropower, PE_y is considered equal to 0 (UNFCCC 2016). Nevertheless, for the following categories of project activities, project emissions have to be considered following the procedure described in the reference; these project emissions include (1) emissions related to the operation of geothermal power plants (e.g. non-condensable gases, electricity/fossil fuel consumption) and (2) emissions from water reservoirs of hydro power plants. According to UNFCCC (2016), if the energy generating equipment is transferred from another activity, leakage is to be considered.

Optimization module: PSO

As optimization module, we employ an evolutionary computation technique, PSO. The algorithm belongs to the wide category of swarm intelligence methods for solving global optimization problems (Kennedy & Eberhart 1995) and has been applied in a variety of water resources optimization problems. More details on algorithm, application and recent advances of PSO can be found in Eberhart et al. (2001), Mikki & Kishk (2008), Parsopoulos (2010), and Marini & Walczak (2015).

The reason for applying an evolutionary optimization algorithm, i.e. PSO, in this study is that the mathematical program is non-convex. Although analytical proof of the non-convexity is not easy in general, in the preceding section we demonstrated that the mathematical program is non-convex, at least due to the presence of several nonlinear equality constraints.

In PSO, the swarm consists of a set of N particles where each particle has individual velocity and position. Moreover, each particle has an individual memory, remembering the best position of the search space that it has ever visited. Therefore, each particle moves toward two main directions: the best position which the particle met (individual best

experience) and the best position which the whole swarm met (global best experience). Therefore, assuming a D-dimensional search space, and taking i as an index standing for a particle in the swarm, $X_i^n = (x_{i,1}^n, \ldots, x_{i,d}^n, \ldots, x_{i,D}^n)$ as a vector representing the particle's position, $V_i^n = (v_{i,1}^n, \ldots, v_{i,d}^n, \ldots, v_{i,D}^n)$ as a vector standing for the particle's velocity (displacement or position alteration), $P_i^n = (p_{i,1}^n, \ldots, p_{i,d}^n, \ldots, p_{i,D}^n)$ as a vector illustrating the best individual position, $P_g^n = (p_{g,1}^n, \ldots, p_{g,d}^n, \ldots, p_{g,D}^n)$ as a vector standing for the best global position, and n as a superscript illustrating number of current iteration, velocity and location of each cell of the particle updated at the end of the iteration are expressed by:

$$v_{i,d}^{n+1} = \chi(w v_{i,d}^n + c_1 r_1^n (p_{i,d}^n - x_{i,d}^n) + c_2 r_2^n (p_{g,d}^n - x_{i,d}^n)) \quad (37)$$

$$x_{i,d}^{n+1} = x_{i,d}^n + v_{i,d}^{n+1} \quad (38)$$

PSO's meta-parameters, which were presented in the above equations, include inertia weight, w, acceleration coefficients, c_1 and c_2, and constriction factor, χ, which should be determined prior to the algorithm's execution. Although PSO's meta-parameters should be problem-dependently estimated via a sensitivity analysis procedure, some researchers, e.g. Shi & Eberhart (1998), Carlisle & Dozier (2001), Pedersen (2010), and Yang et al. (2013), strove to propose some general rules.

PSO's algorithm for solving a problem with maximization-type objective function can be summarized as (Marini & Walczak 2015):

1. Set the meta-parameters' values
2. Initialization. For each of the N particles:
   a. Initialize the position, X_i^0
   b. Initialize the particle's best position, $P_i^0 = X_i^0$
   c. Calculate the fitness of each particle, and if there is a j for which $f(X_j^0) \geq f(X_i^0) \forall i \neq j$, then initialize the best global position as $P_g^0 = X_j^0$
3. Until a stopping criterion is met, repeat the following steps:
   a. Update each particle's velocity according to Equation (37)
   b. Update each particle's location according to Equation (38)

c. Evaluate the fitness of each particle, $f(X_i^{n+1})$

d. If $f(X_i^{n+1}) \geq f(P_i^n)$, update the best individual position as $P_i^{n+1} = X_i^{n+1}$

e. If $f(X_i^{n+1}) \geq f(P_g^n)$, update the best global position as $P_g^{n+1} = X_i^{n+1}$

4. At the end of the iterative process, the best solution is represented by P_g^n.

Based upon a sensitivity analysis, we estimated the meta-parameters as $w = 0.9 \sim 0.4$ and $c_1 = c_2 = 1.8$ in the problem of hydropower optimal design. Also, using scripting capabilities of WEAP, we coded and linked the PSO algorithm to the simulation module.

RESULTS AND DISCUSSION

Karun II hydropower plant project

Karun River is the river with the highest flow and the only navigable river in Iran, where numerous development projects, including dams, irrigation districts, water transfers, and hydropower plants, are being operated or under construction or being studied. Among the projects, Karun II Hydropower Plant Project (Karun II HPP) includes a dam and a power plant whose site is located upstream of the operated Karun I HPP and downstream of the operated Karun III HPP on Karun River near Izeh city in southwestern Khuzestan Province (http://en.iwpco.ir/).

In this paper, we apply the proposed simulation-optimization model to determine optimal values of Karun II HPP's design parameters (decision variables), which include NWL, MOL and IC. Based on the results of a preliminary technical study (Dezab 2014a), for each decision variable, we consider an initial range only within which the variable can vary; the ranges include (664,672) meters above sea level (masl), (640,668) masl, and (200,800) megawatts, respectively, for NWL, MOL and IC. It is worth mentioning that the initial range of NWL is associated with topographical limitations.

For the simulation period (1958–2008), Dezab (2014a) estimated the time series of streamflow whose long-term average equals 299.7 cm. Also, they estimated the annual average of evaporation from the dam's reservoir

to be equal to 146.05 mm, the minimum baseline flow for protecting the downstream ecosystem to be equal to 24 cm, and HPP's head loss associated with design flow to be equal to 2.7 m. According to the guidelines of both TAVANIR and IWPCO, two important departments of the Ministry of Energy of Iran which are in charge of power system management and development, here we suppose the plant factor to be equal to 0.25 for the peaking project.

To estimate the economic parameters related to the alternative thermal plant, we use Table 2. Based on the study of Dezab (2014b) and also international documents of CDM analysis (UNFCCC 2016, 2017), we suppose some important assumptions: (1) Karun II HPP will be employed to generate electricity at peak load, and therefore, here we take large gas turbine and combined cycle power plants as the alternative thermal plants for firm and secondary energy generation, respectively; (2) construction period and life time of the HPP equal 7 and 50 years, respectively; (3) discount rate equals 8%; (4) exchange rate equals 25,000 Rials, i.e. Iranian currency, per Dollar and 35,000 Rials per Euro; (5) electricity's sale price equals 418.5 Rials/KWh (Energy Balance Sheet 2014); (6) emission factor, EF, related to CDM equals 0.715 tCO2/MWh (Ministry of Energy of Iran) and price of CERs, P_{CER}, is taken to be equal to 5 Euros/tCO2; (7) heating (calorific) value of fuel, HV, for natural gas and diesel equals 8,600 and 9,232 KCal/m^3, respectively; (8) due to limited natural gas supplies, for three months of the year, diesel is taken as alternative fuel; (9) cost associated with environmental pollutants' removal is considered based on World Bank (2000); and (10) average unit external costs of energy production associated with gas, steam and combined cycle power plants equal 413.3, 186.8 and 115.1 Rials/KWh, respectively.

In the following, results related to solving the problem of optimal design of KarunII HPP via the solution approach, i.e. PSO-automated WEAP, are presented.

Optimal design of Karun II HPP's capacity

To consider different possible economic analysis methods, i.e. objective functions, associated conditions, and in order to show advantages of the proposed modelling approach,

Table 2 │ Technical and economic information of thermal power plants (TAVANIR 2005)

Thermal plant	$n_{ATPP,C}$ (years)	$n_{ATPP,O}$ (years)	TMA (%)	R (%)	α_{CAP}^{ATPP}		α_{FOM}^{ATPP}	α_{VOM}^{ATPP}	
					(Euros/KW)	(Rials/KW)	(Rials/KW)	(Euros/KW)	(Rials/KW)
Combustion turbine	2	12	83	33.4	290	4.22e + 6	4.93e + 4	0.0568	2.60
Steam plant	5	30	72	41.2	677	7.91e + 6	1.81e + 5	0.0219	5.56
Combined cycle	5	30	81	50	519	7.21e + 6	8.36e + 4	0.0285	2.99

we define a number of scenarios including five main groups; Table 3 presents the properties of all the defined scenarios.

The first group of scenarios, i.e. S1, will assess the performance of MPM. The scenarios of the second group (S21–S25) will evaluate the impacts of taking into account CDM as a financing instrument inside MPM. S23 and S24 and S25 and S26 are defined to analyze the sensitivity of results to the CERs' price and discount rate, respectively. While all the scenarios of the third to the fifth groups will assess the performance of ATPM, each of the fourth and the fifth groups of scenarios, compared with the third group, take into account extra considerations of externalities and CDM. The properties of these groups of scenarios are similar to the two groups defined before. In the following, detailed results are proposed.

Market price method

In this section we compare optimal solutions achieved under two different groups of scenarios defined based on the MPM. Figure 3(a) and 3(b) illustrate the convergence trend of the simulation-optimization model for two objective functions built upon MPM and ATPM, respectively, where for each iteration, the figures illustrate objective function values (OFV), i.e. NPV, related to PSO's particle best (p-best) solutions. According to Figure 3(a), for the MPM case, the convergence is achieved after nearly 100 iterations. Also, the algorithm is so fast converging that in the emerging iterations, solutions with OFV as well as the final best optimal OFV can be seen. On the other hand, for the ATPM case, Figure 3(b) indicates that the convergence is also achieved after nearly 100 iterations; however, solutions

Table 3 │ Parameter values for scenarios associated with MPM

Scenario definition	Abbreviation	Parameters' values	
		P_{CER} (Euros/tCO$_2$)	i (%)
MPM	S1	–	8
MPM & CDM	S21	5	8
MPM & CDM – low CERs' price	S22	0.5	8
MPM & CDM – high CERs' price	S23	8	8
MPM & CDM – medium discount rate	S24	5	12
MPM & CDM – high discount rate	S25	5	16
ATPM	S3	–	8
ATPM & externalities	S4	–	8
ATPM & externalities & CDM	S51	5	8
ATPM & externalities & CDM – high CERs' price	S52	8	8
ATPM & externalities & CDM – low CERs' price	S53	0.5	8
ATPM & externalities & CDM – medium discount rate	S54	5	12
ATPM & externalities & CDM – high discount rate	S55	5	16
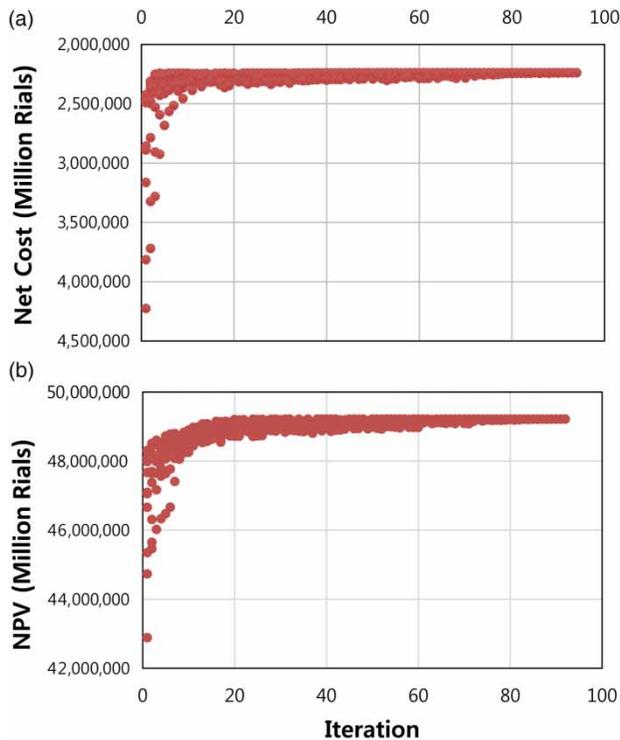
Figure 3 | Convergence trend of the simulation-optimization model: (a) market price method; (b) alternative thermal plant method.

with OFV as well as the final best optimal OFV can be seen after 20 iterations.

Table 4 presents detailed results of the simulation-optimization model including optimal solutions and OFV. As stated above under 'Karun II hydropower plant project', according to topographical characteristics and limitations of Karun II HPP's site, NWL and MOL cannot exceed 672 and 668 masl, respectively. On the other hand, the

long-term average of reservoir inflow is so high, about 300 m^3/s, that the upper bound constraints on both NWL and MOL are binding for all of the optimal solutions achieved under different scenarios. Furthermore, firm energy is also nearly fixed for all scenarios. This issue indicates that firm energy is mainly impacted by NWL and MOL.

For simple MPM scenario, S1, optimal OFV, i.e. NPV, is negative and equals -6.59×10^{12} Rials. This shows that the present value of cost exceeds the present value of benefit. Accordingly, employing MPM, the analyst can only anticipate attaining the cost-effective solutions.

When under scenario S21, CDM is taken into account as a financing instrument and CERs' sale price equals 5 Euros/tCO$_2$, considerable improvement of 33% increase in OFV ($2.17 \times 10^{+12}$ Rials) is seen, compared with S1. While for the simple MPM case, scenario S1, the optimal value of IC equals 424 MW, under S21 the optimal value of IC increases by 14% (58 MW); therefore, the results indicate that accounting for CDM can significantly impact optimal design and lead to improving the economic measure of the HPP. Moreover, the results demonstrate that inclusion of CDM in economic analysis leads to an increase of 2.5% (49 GWh) and 13% (123 GWh) in total energy and peak energy, respectively.

When CERs' sale price decreases to 0.5 Euros/tCO$_2$ under S22 or, inversely, increases to 8 Euros/tCO$_2$ under S23, NPV respectively decreases by 44% ($1.95 \times 10^{+12}$ Rials) or increases by 30% ($1.32 \times 10^{+12}$ Rials) compared with S21; therefore, we can state that the project's economic measure is quite sensitive to the CERs' price. Furthermore,

Table 4 | Results associated with optimal design of Karun II HPP using the simulation-optimization model under different scenarios

Scenarios

Item	Units	S1	S21	S22	S23	S24	S25	S3	S4	S51	S52	S53	S54	S55
IC	MW	424	482	431	501	289	195	498	503	509	509	503	450	180
NWL	Masl	672	672	672	672	672	672	672	672	672	672	672	672	672
MOL	Masl	668	668	668	668	668	668	668	668	668	668	668	668	668
NPV	1×10^{12} Rials	−6.59	−4.42	−6.37	−3.10	−8.27	−10.5	35.15	38.96	41.17	42.5	39.18	24.78	15.86
Tot. Energy	GWh	1,960	2,009	1,966	2,022	1,771	1,553	2,019	2,023	2,026	2,027	2,023	1,984	1,902
Firm Energy	GWh	1,393	1,393	1,393	1,393	1,399	1,392	1,393	1,393	1,393	1,393	1,393	1,393	1,396
Peak Energy	GWh	912	1,035	927	1,074	623	423	1,067	1,078	1,090	1,091	1,078	967	806

the optimal value of the IC is affected by change in the CERs' price, so that when the price decreases to 0.5 Euros/tCO$_2$ under S22 or, inversely, increases to 8 Euros/tCO$_2$ under S23, the IC decreases by 11% (51 MW) or increases by 4% (19 MW), respectively, compared with S21.

Table 4 additionally proposes the results of a sensitivity analysis on the value of the discount rate. As anyone may anticipate, the increase in discount rate has led to a decrease in OFV, so that when the discount rate increases to 12%, under S24, and 16%, under S25, a reduction of 25% (1.65 × 10^{+12} Rials) and 60% (3.91 × 10^{+12} Rials) is seen, respectively. This indicates how OFV is sensitive to change in the discount rate's value. Moreover, the optimal value of IC is sensitive to the discount rate, so that when the discount rate increases to 12%, under S24, and 16%, under S25, reductions of 40% (193 MW) and 60% (287 MW) in IC are seen compared with S21. According to Table 4, it is obvious that, when the discount rate's value increases to 12% and 16%, it leads to a dramatic reduction in total energy and peak energy of about 11% (238 GWh) and 40% (412 GWh), respectively.

Alternative thermal plant method

For all the third groups of scenarios associated with ATPM, i.e. S3, S4 and S5, both constraints related to upper bounds on NWL and MOL are binding, and similarly to the results of MPM scenarios, i.e. S1 and S2, optimal values of NWL and MOL equal 672 and 668 masl, respectively. Furthermore, given that both NWL and MOL remain unchanged under different scenarios, firm energy is nearly the same for all the scenarios.

Employing ATPM under S3 has led to an increase (17% or 74 MW) in optimal value of IC compared with MPM under S1, where the optimal value reaches 498 MW. Moreover, detailed results demonstrate that inclusion of externalities and/or CDM in the economic analysis method of ATPM slightly increases the design parameter of IC. On the contrary, the optimal value of IC is sensitive to the discount rate, so that when the discount rate increases to 12%, under S54, and 16%, under S55, respective reductions of 12% (59 MW) and 65% (329 MW) in IC are seen compared with S51.

Similarly to the IC, the value of total energy is nearly unchanged under all scenarios, again except for scenarios associated with sensitivity analysis on the discount rate, i.e. S54 and S55. Given that firm energy is about 1,400 MW (under all scenarios), secondary energy, for example, decreases 20% (159 GWh) under S55 compared with S51.

According to Table 4, the annual average generated peak energy is proportional to the IC, and the higher the IC, the more the average peak energy will be. For example, when IC decreases to 503 MW for S53 compared with S55, for which IC equals 509 MW, the annual average generated energy decreases to 1,078 GWh from 1,091 GWh. For another example, for both S4 and S53 with the same optimal value of IC (equals 503 MW), average peak energy is also the same, equalling 1,078 GWh.

In spite of the above discussed decision variables and measures, the economic measure of the project, i.e. NPV or OFV, is completely changing from one scenario to another. While NPV is negative and equals −6.59 × 10^{+12} Rials when MPM is taken under S1, the economic measure dramatically increases and reaches a positive value of +35.15 × 10^{+12} Rials for ATPM under S3. Accordingly, we can state that the value of the project's measure intensively depends on the economic analysis method, so that when employing MPM the analyst can find cost-effective solutions for which NPV is negative, while using ATPM he/she can anticipate attaining economically efficient solutions for which NPV is positive.

Inclusion of ATP's externalities as well as taking CDM's financial instrument into account in economic analysis has led to a slight increase of 11% (3.81 × 10^{+12} Rials) and 6% (2.21 × 10^{+12} Rials) in NPV. Moreover, according to Table 4, it is obvious that inclusion of externalities and/or CDM in the economic analysis of Karun II HPP does not significantly impact optimal design of the project.

CONCLUSIONS

This study dealt with developing a comprehensive hydro-economic simulation-optimization model for optimal hydropower projects' design. We proposed a novel method coupling PSO algorithm and WEAP software enhanced for hydropower simulation. Detailed results generally indicate that the economic analysis method, i.e. MPM or ATPM, completely influences the project's design and

(economic and energy) measures. Furthermore, we realized that inclusion of CDM and externality significantly affects the HPP's project design and measures, where magnitudes of the effects depend on the economic analysis method.

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