OPTIMAL STOCHASTIC OPERATION PLANNING FOR LARGE SYSTEMS WITH HIGH PENETRATION OF VARIABLE RENEWABLE ENERGY ADDRESSING SHORT-TERM CONSTRAINTS

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ABSTRACT

Variable Renewable Energy (VRE) plays a critical role in the energy transition, but its high volatility poses challenges for expansion and operation. This study introduces a Stochastic Dual Dynamic Programming (SDDP) model for mid and long-term planning, focusing on a typical day (TD) approach. Applied to the Chilean system, the TD model significantly reduces computational time compared to the extended hourly model. Furthermore, enhancing the time resolution in policy calculation improves overall simulation accuracy compared to the non-chronological load duration curve (LDC) model. This research demonstrates the efficacy of the proposed methodology in addressing challenges related to increasing renewable energy penetration. By capturing essential flexibility requirements and accurately representing system dynamics, it enables efficient expansion and operation planning.

KEYWORDS. Operation planning. Flexibility in Electric Power Systems. SDDP.

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1. Introduction

Planning the expansion and operation of power systems is challenging because it requires proper modeling of the relevant elements, such as power plants, transmission lines, slow- and fast-response storages (hydro reservoirs and batteries). It is also necessary to represent the underlying uncertainties that affect the decision-making process (hydro inflows, outages, renewable sources, etc), the correct horizon (ranging from months to decades), and the adequate timescale. The SDDP algorithm [Pereira e Pinto, 1991] has been successfully applied to solve this problem for over 30 years.

Due to its complexity and the extensive computation time required to represent hourly timescale, it is usual to approximate the time resolution within each stage (week or month) using a load duration curve (LCD) approach for the expansion planning and operation policy phases. Nevertheless, the high volatility of the constantly growing renewable generation share, such as wind and solar power plants, imposes new challenges to mid- and long-term expansion and operation planning models because it requires modeling the system's dynamics at an hourly level to assess the flexibility needs of the power systems.

In this sense, it is necessary to represent variables (plants' generation, storage levels, etc) and constraints (load supply, transition equations, etc) for every hour. In addition, other operational constraints, such as unit commitment and ramping limits, may also play an important role. However, the straightforward model extension can significantly increase the problem's dimension leading to computational intractability for large systems. In order to reduce the computational burden, [Soares et al., 2021] proposed an expansion planning problem with the representation of typical days within each season. Although the model has been successfully applied, it relies on the solution of a mixed-integer programming problem which requires a scenario reduction technique for large systems.

This work proposes the same operation model for the recursive problem in the SDDP framework. This algorithm uses efficient decomposition techniques and high-performance computing in a distributed processing environment. Finally, we use this setting to solve the expansion planning problem and enhance the operating policy quality.

2. Optimization model

The SDDP algorithm divides the study horizon into stages and uses Benders cuts and state variables to couple decision-making processes. The cuts are hyperplanes that approximate the future cost function (FCF), representing the costs of future stages based on the present decision. The algorithm consists of two main phases: policy and simulation. The policy phase calculates the FCF, while the simulation phase provides detailed results. The general formulation of the recursive problem formulation for a single stage and scenario can be written as follows:

$$Q_t(\hat{v}_{t-1,B}) = \min \sum_{i \in G, b \in B} c_i g_{t,b,i} + \tilde{\mathcal{Q}}_{t+1}(v_{t,B}) \tag{1a}$$

subject to:

$$\sum_{i \in G} g_{t,b,i} + \sum_{i \in H} e_{t,b,i} + \sum_{i \in R} r_{t,b,i} = d_b \qquad \forall i \in H, \forall b \in B \tag{1b}$$

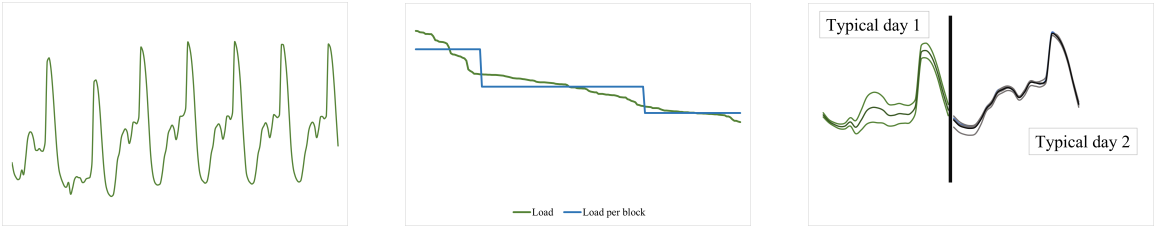
$$v_{t,b,i} = v_{t,b-1,i} + \hat{a}_{t,b,i} - u_{t,b,i} + s_{t,b,i} \qquad \forall i \in H, \forall b \in B \tag{1c}$$

$$v_{t,0,i} = \hat{v}_{t-1,B,i} \qquad \forall i \in H \tag{1d}$$

$$\{v_t, e_t, r_t, g_t\} \in \Phi \tag{1e}$$

Where G, H, and R represent the sets of thermal, hydro, and renewable plants in the problem; B is the number of discretized time blocks; all variables are indexed by the stage t, time block b and element index and v, u, s and a are the hydro storage value, water turbining, water spillage and water inflow respectively. The objective function is the minimization of the immediate cost in stage t, represented by the $\sum_{i \in G, b \in B} c_i g_{t,b,i}$, plus the expected future costs represented by $\tilde{\mathcal{Q}}_{t+1}(v_{t,B})$. Usual problem constraints are the load balance 1b and the water balance for each hydro reservoir 1c. Equation 1e represents other operational constraints, such as transmission network flows, unit commitment, complex water cascade, and others, that may apply according to the required level of detail.

Modeling hourly variables and constraints allows a more realistic representation of the dispatch at the expense of high computational costs. The proposed methodology brings this new time timescale to the formulation suppressing the representation of every hour in a given stage. It assumes is possible to reach a good approximation by shrinking the hours into days with a similar profile, the so-called "typical days".



(a) Demand per hour (b) LDC with 3 blocks (c) Two typical days

Figura 1: Common approaches for intra-stage representation

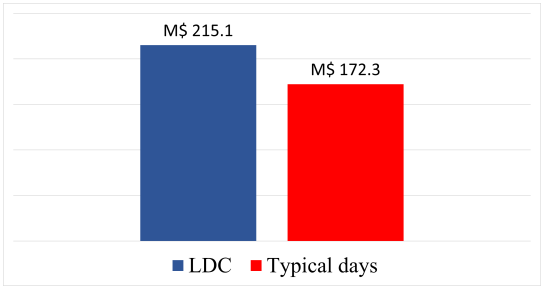
There are several methods for representing intra-stage time steps in the operation planning problem based on the demand curve in 1a. A commonly used approach is to employ the load duration curve (LDC), depicted in 1b in green. The LDC provides non-chronological time steps by assigning proportional load values, as indicated by the blue curve in 1b. In contrast, our proposed methodology takes a different approach. Starting from the demand per hour curve in 1a, we cluster the days into typical days based on their load profile characteristics. For each typical day, a 24-hour load profile is calculated by averaging the values of days with similar load shapes, as shown in 1c. By considering hourly variables, we can systematically incorporate operating constraints of thermal plants, including generation ramps, minimum downtime, uptime, and maximum uptime. To evaluate the impact of this more detailed representation, we conducted a series of computational experiments.

3. Computational results

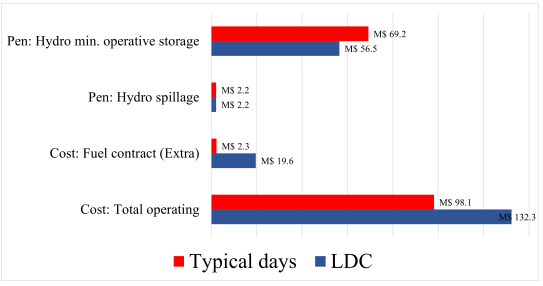
We applied the proposed methodology to the simplified Chilean system with a 1-year horizon with 52 weekly stages. We compared the results for the simulation with two policies: the first based on the load duration curve and the second using the typical days' representation.

The LDC-based model is a relaxed version of the typical days' model, and we expect its FCF to yield underestimated future costs compared to the typical days' policy. Consequently, the resources, e.g., water reservoirs, are poorly managed in the system, leading to 20 % higher operating costs as observed in Figure 2. We also compared the results from a simulation with the proposed TD methodology versus a simulation with the extended hourly representation presented in 1, using the same policy calculated with typical days.

We observed a relevant 13-fold reduction in the execution times and similar hourly operation profiles, as illustrated by the total hydro generation and total stored energy in hydro plants as

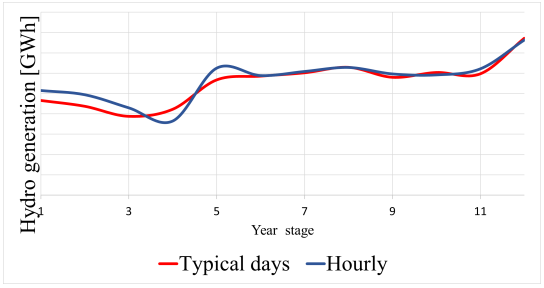


(a) Total operating costs

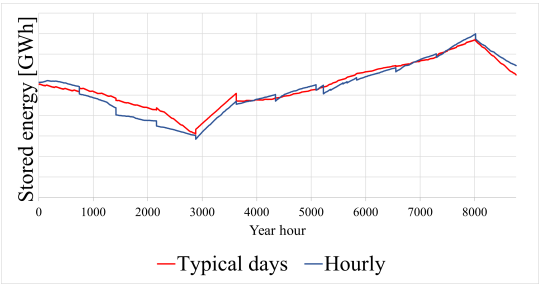


(b) Breakdown of total operating costs comparison

Figura 2: Operating costs results



(a) Total hydroelectric generation



(b) Stored energy of water reservoirs

Figura 3: Operating results

shown in figure 3.

4. Conclusions

Renewable energy participation in generation grows day after day in electric power systems. Its high volatility poses modeling challenges to the expansion and operation activities to assess flexibility requirements. The methodology proposed in this work allows a more realistic representation and an efficient framework for solving such problems.

The study conducted for the Chilean case yielded consistent results compared to the extensive hourly model, with a significant 13-fold reduction in execution time. Moreover, we observed better resource management with the typical days model in the operating policy, as opposed to the load duration curve model.

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