



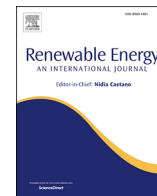
Evaluation of hydropower equivalents in electricity capacity expansion models

Downloaded from: <https://research.chalmers.se>, 2026-05-28 02:29 UTC

Citation for the original published paper (version of record):

Öberg, S., Göransson, L., Ek Fälth, H. et al (2026). Evaluation of hydropower equivalents in electricity capacity expansion models. *Renewable Energy*, 270.
<http://dx.doi.org/10.1016/j.renene.2026.125924>

N.B. When citing this work, cite the original published paper.



Evaluation of hydropower equivalents in electricity capacity expansion models

Simon Öberg^{a,*}, Lisa Göransson^a, Hanna Ek Fälth^b, Uli Rahmlow^c, Filip Johnsson^a

^a Division of Energy Technology, Chalmers University of Technology, Gothenburg, Sweden

^b Division of Physical Resource Theory, Chalmers University of Technology, Gothenburg, Sweden

^c Division of Electric Power and Energy Systems, KTH Royal Institute of Technology, Stockholm, Sweden

ARTICLE INFO

Keywords:

Hydropower equivalent
Energy systems modeling
Detailed hydropower
Future system

ABSTRACT

As a dispatchable and flexible carbon-free generator, reservoir hydropower provides a significant value to the electricity system. However, with an expected surge in the European electricity demand and an increasing share of variable renewable generation, the role of hydropower is expected to change. Yet, in capacity expansion models, the flexibility of hydropower tends to be overestimated due to an exceedingly simplified implementation, leading to underestimations of investments in other dispatchable technologies. This work aims to improve the representation of hydropower in such models by identifying important constraints from detailed hydropower models.

Three hydropower equivalents are applied to the Swedish hydropower system in an energy system model of northern Europe. It is concluded that an equivalent that captures the physical limitations of a river system is preferred, especially if grid expansion is an option within the model. The limitations pertain to not having water in the appropriate parts of the river system to facilitate sustained generation at high levels, losses due to spillage at bottlenecks, and the dispatch of water to avoid flooding of smaller reservoirs during periods with a low marginal cost of electricity. Regarding the future role of Swedish hydropower, the findings show that hydropower manages multiday variations in wind power production to a greater extent than the diurnal variations of the electricity demand.

1. Introduction

European electricity demand is expected to more than double by 2050 due to extensive electrification of transport and industry [1], with a large share supplied by variable renewable electricity (VRE) generation. Given the limited potential for hydropower expansion, its relative contribution is likely to decline in a system increasingly dominated by variable generation, implying a shift in the role of reservoir hydropower [2]. In addition, hydropower in Europe is affected by climate change, which alters water inflow patterns [3,4], as well as by environmental regulations such as the Water Framework Directive [5]. To accurately assess interactions between technologies and the future role of hydropower, it is essential to represent hydropower adequately in energy system models—particularly in the Nordic countries, where reservoir hydropower constitutes a significant share of the energy mix. Avoiding overestimation of hydropower flexibility is crucial, as this may

otherwise lead to an underestimation of the need for alternative technologies to meet electricity demand cost-effectively.

The flexibility of hydropower is limited in terms of: how plants and reservoirs are allocated along river systems; reservoir characteristics; and connecting waterways causing delay times within a river system [6]. Another important aspect is environmental permits, which impose limits on the minimum and maximum water levels and water flows. The more-technical aspects include head-dependent generation and limitations on discharge flow changes due to the risks of pressure waves and cavitation. Moreover, as hydraulic head¹ varies with upstream and downstream water levels—affected by both generation and inflow—hydropower operation constitutes a nonlinear system.

Several studies have included all or some of the abovementioned hydropower characteristics in detailed hydropower models. Due to the complex nature of hydropower, these studies have applied models that are non-linear [7–9], contain integer variables [7–10], or are stochastic

* Corresponding author.

E-mail address: simon.oberg@chalmers.se (S. Öberg).

¹ The height difference between the inlet and outlet, which is the potential energy converted to power in the turbine.

[11] (a linear model with high accuracy is presented in Ref. [6], for which the limitation primarily lies in data availability). However, due to computational limitations, such detailed implementations are not suitable for capacity expansion models that also include energy storage, electricity trade between regions, and demands that are flexible in time.

In capacity expansion models with high temporal resolution (typically hourly over at least one year), hydropower is commonly represented by aggregated turbine and reservoir capacities for each region, with generation constrained by minimum and maximum levels and inflows provided on an hourly basis. These models are typically solved under perfect foresight, allowing future inflows to be valued from the initial time step. This representation is widely used in the literature but tends to overestimate hydropower flexibility, as noted in Ref. [6] and discussed in Ref. [12].

One approach to avoiding overestimation of hydropower flexibility is to calibrate models to align with historical generation patterns. This can be achieved by adjusting parameters such as turbine and reservoir capacities or the relative shares of run-of-river and reservoir generation, as in Refs. [13,14]. Alternatively, non-physical constraints, such as ramping budgets, can be introduced to reflect operational limitations [15]. However, as future energy systems are expected to exhibit markedly different dynamics due to high shares of VRE, reliance on historically derived non-physical constraints may limit the model's ability to accurately assess the future role of hydropower.

Another approach to improving hydropower representation in energy systems modeling is the integration of different models through so-called soft-linking. This method combines the strengths of multiple models to provide a more detailed and accurate representation and has been applied in Refs. [16–19]. However, it introduces several challenges. The iterative process often requires simplification of the energy system model due to computational constraints, for example by limiting geographical scope, and may also lead to convergence issues. For instance, in Ref. [16], where the TIMES-Norway model is linked to the hydropower model EMPS (also used in Ref. [20]), convergence is achieved only when the system remains similar to its current structure, whereas the model fails to converge under scenarios with high shares of VRE and increased electricity price variability.

In summary, factors such as increasing electricity demand, a higher share of variable renewable generation, and changing precipitation patterns due to climate change are altering the operating conditions for hydropower. This study evaluates and compares aggregated hydropower representations derived from detailed hydropower models and grounded in techno-physical constraints. Using the Swedish hydropower system as a case study, the contribution is twofold: to support energy system modelers in selecting appropriate hydropower representations and understanding their impact on results, and to clarify the role of Swedish hydropower in future energy systems.

2. Method

This study applies a linear techno-economic optimization model to minimize total system costs under future projections of electricity, heating, and hydrogen demand. Using a greenfield approach, the model optimizes both investments and dispatch over a two-year period with hourly resolution and considers a scenario consistent with the European Union's 2050 emissions targets. Model input data, assumptions, and mathematical formulations are detailed in the Supplementary Material, while hydropower-specific components are described in the following sections.

Hydropower inflows are based on meteorological data for 1991 and 1992, selected for two reasons. First, they represent a dry and a wet year in the Swedish system, with inflows corresponding to 62 TWh and 73 TWh of electricity generation, respectively. Second, they precede the period of pronounced climate change impacts, allowing the application

of coefficients that adjust inflows to reflect projected climate change scenarios. Including additional years could improve robustness, particularly for sizing peak generation technologies such as gas turbines, as shown by Ullmark et al. [21]. However, optimizing for a perfectly balanced system is not the primary objective of this study.

The geographic scope of this study (Fig. 1) comprises 17 regions in northwestern Europe. As the focus is on Swedish hydropower, regions outside Sweden are included primarily to capture electricity trade and represent geographic smoothing effects. Hydropower-specific model extensions are described in Section 2.1, while the investigated scenarios are presented in Section 2.2.

2.1. Hydropower equivalents

This study evaluates three hydropower equivalents. In all cases, reservoir hydropower is represented by a single turbine and reservoir capacity per region, with hourly resolved inflows. Volumetric inflow data are sourced from the HBV model [22] and converted into hourly energy inflows per river using the hydropower dispatch model described in Ref. [23], before being aggregated at the regional level. The three representations—*Simple*, *Bi-level*, and *Extended*—are summarized in Table 1.

The Simple equivalent represents the hydropower formulation commonly used in high-resolution capacity expansion models and is described in Section 2.1.1. Its maximum generation is based on a detailed hydropower model by Amelin et al. [24] (hereafter *Detailed model 1*), while minimum generation is set to 10% of maximum capacity based on historical data. *Detailed model 1* provides near-complete coverage of Swedish hydropower across the ten major rivers and serves as the basis for the Bi-level equivalent (Section 2.1.2).

The Extended equivalent incorporates additional physical constraints using the method described in Ref. [25] and the model developed by Ek Fålh et al. [6] (hereafter *Detailed model 2*), as detailed in Section 2.1.3. Both *Detailed model 1* and *Detailed model 2* are profit-maximizing hydropower models driven by exogenous electricity price curves. While they capture operational aspects of river systems, they do not account for feedback effects on electricity prices, transmission constraints, or broader energy system interactions.

2.1.1. Common constraints and the Simple equivalent implementation

Three constraints are applied to all hydropower implementations in this study, as given in Equations (1)–(3). The generation, $g_{r,t,p}$, in region r at time-step t for technology p is bounded by upper and lower limits according to Equation (1). The water balance is enforced in Equation (2), where the storage level $SL_{r,t}$ cannot exceed the storage level in the previous time-step plus the difference in any potential inflow or dispatch of water. Losses $L_{r,t}$ are included only in the *Extended* equivalent and are described in Section 2.1.3. Finally, storage levels are constrained by upper and lower bounds, as described by Equation (3). The *Simple* equivalent is defined solely by these three equations, with constant annual storage limits, whereas the *Bi-level* and *Extended* equivalents introduce additional constraints and seasonally varying storage bounds.

$$P_{r,p}^{\min} \leq g_{r,t,p} \leq P_{r,p}^{\max} \quad (1)$$

$$SL_{r,t+1} \leq SL_{r,t} + \text{inflow}_{r,t} - g_{r,t,p} - L_{r,t} \quad (2)$$

$$SL_{r,t}^{\min} \leq SL_{r,t} \leq SL_{r,t}^{\max} \quad (3)$$

$$\forall r, t, p \in R, T, P^{\text{Hydro}}$$

2.1.2. Bi-level hydropower equivalent

The *Bi-level* equivalent is derived from a bi-level optimization problem consisting of two nested levels. The lower level maximizes the profit

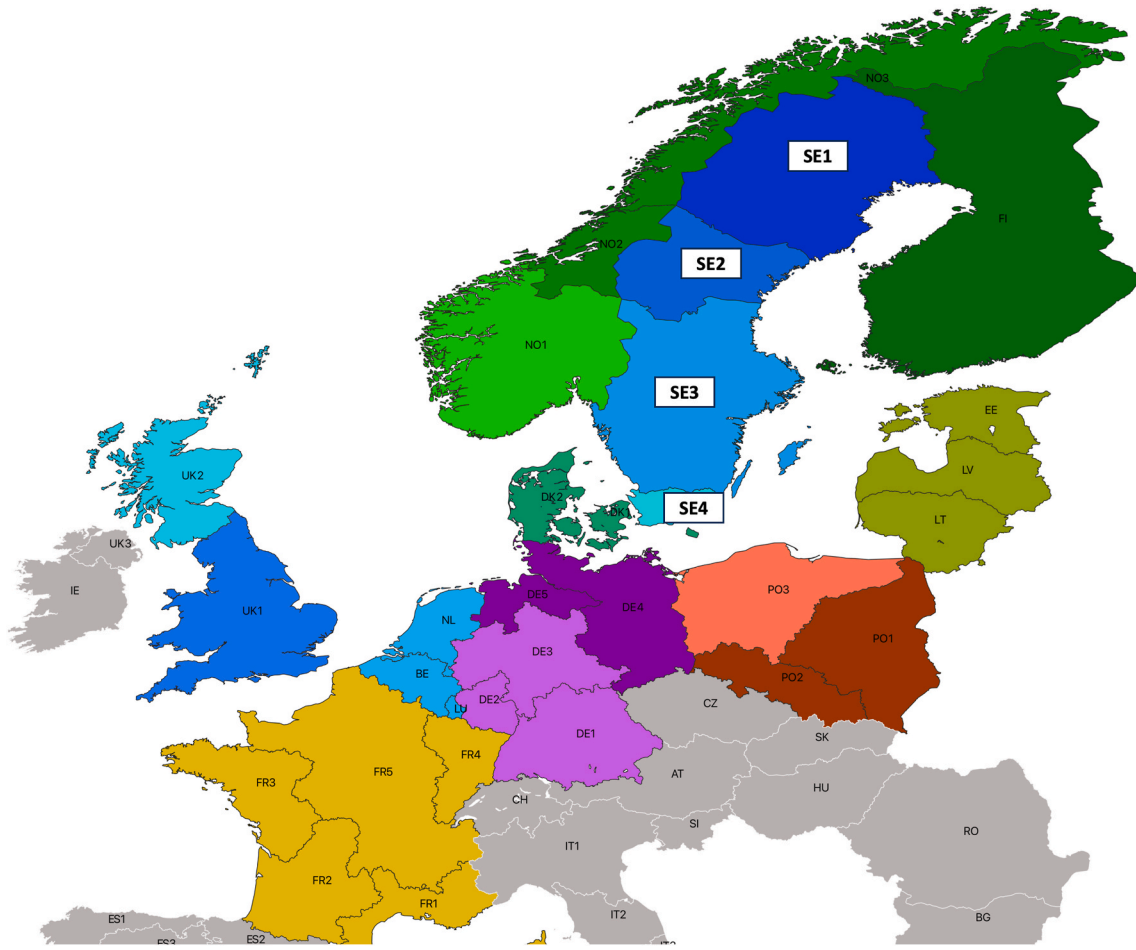


Fig. 1. Geographic scope of this work, with regions according to the color coding. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

Table 1
Summary of the three implementations used to represent hydropower.

	Simple equivalent	Bi-level equivalent	Extended equivalent
Minimum power	10%	From Bi-level equivalent	10%
Maximum power	X^a	From Bi-level equivalent	X^a
Seasonally dependent storage capacity		X^a	X^a
Ramping limitation		X^a	X^b
Maximum generation per rolling 168-h (1-week) period			X^b
Losses if weekly generation exceeds the threshold value			X^b
Minimum generation per rolling 24-h period			X^b

^a Detailed model 1.

^b Detailed model 2.

of *Detailed model 1* under a given electricity price profile. The upper level minimizes the hourly deviation in electricity generation between the detailed and equivalent models to determine the parameters listed in [Table 1](#). This procedure is described in Ref. [26].

A key feature of the *Bi-level* equivalent is that the optimized parameters (maximum and minimum generation limits, storage capacity, and ramping constraints) are seasonally dependent. This is achieved through an inflow clustering approach based on spectral clustering [27], resulting in different operational limits across seasonal periods, as detailed in [Appendix A](#). Ramping constraints are defined in Equations (4a) and (4b) for up- and down-ramping, respectively, where R_{1h} denotes the limiting parameter (GW), as reported in [Table A.1](#).

$$g_{r,t+1,p} - g_{r,t,p} \leq R_{1h} \quad (4a)$$

$$g_{r,t-1,p} - g_{r,t,p} \leq R_{1h} \quad (4b)$$

$$\forall r, t, p \in R, T, P^{Hydro}$$

2.1.3. Extended hydropower equivalent

The *Extended* equivalent includes three additional constraints relative to the *Bi-level* formulation. The first limits generation over rolling 168-h periods to capture local water scarcity during sustained high output. The second accounts for spillage losses past smaller power stations when generation exceeds a specified threshold within the same

period. The third introduces a minimum diurnal generation constraint, complementing the 10% hourly minimum, to prevent prolonged low-output operation that could otherwise lead to flooding of smaller reservoirs (although this is not explicitly modeled) during extended periods of low marginal electricity prices (e.g., during high wind output). The minimum diurnal generation, γ_{24h} , is set to 20% and defined in Equation (5), where $C_{r,p}$ denotes installed capacity. A sensitivity analysis is also conducted for values of 15% and 25%.

$$\sum_t^{t+24} g_{r,t,p} \geq C_{r,p} \cdot \gamma_{24h} \cdot 24 \quad (5)$$

$$\forall r, t, p \in R, T, P^{Hydro}$$

For the constraints limiting generation over rolling 168-h periods and associated losses, parameters are derived using *Detailed model 2* following the method in Ref. [25]. In brief, the model is exposed to periods of 1–3 consecutive weeks with very high electricity prices, enabling it to maximize generation and annual profit during these intervals. These periods are evaluated for each month across five meteorological years to capture sustained generation under varying hydrological conditions. To reduce perfect foresight effects, the simulation is initialized one week prior to each high-price period.

This setup allows sustained generation levels and associated losses to be assessed while accounting for river system characteristics, including interconnections between hydropower stations, intermediate reservoirs, environmental constraints, local inflows, and spillage. As differences between 1 and 3 week durations are minor, only the 1-week case is used in this study. The resulting sustained generation constraint is defined in Equation (6), where the sustained generation, SG_r , is a region-specific coefficient reported in Appendix A.

$$\sum_t^{t+168} g_{r,t,p} \leq C_{r,p} \cdot SG_r \cdot 168 \quad (6)$$

$$\forall r, t, p \in R, T, P^{Hydro}$$

The annual loss factor due to spillage past bottlenecks within a river system—arising from sustained high generation—is estimated at 0.2%–0.4% of annual generation per week of maximized output in *Detailed Model 2*. This corresponds to cases where the constraint in Equation (6) is binding. Details on the annual loss factor λ_r are provided in Appendix A.

Since losses are triggered only during periods of sustained high generation—though without a precise indication of when they first occur—a threshold value for weekly generation is introduced; any generation exceeding this threshold is subjected to a loss. The amount of generation that is susceptible to losses, $g_{r,t,p}^{for\ loss}$, is the weekly generation that exceeds the threshold defined as $SG_r - \Delta_{Loss}$, as calculated in Equation (7a). Consequently, short periods of high generation do not trigger any losses in the system.

The actual loss, $L_{r,t}$, is then calculated by multiplying the ratio of the generation that is susceptible to losses and the maximum generation that could be susceptible to losses ($\Delta_{Loss} \cdot C_{r,p} \cdot 168$) by the annual loss per week of maximized generation ($\lambda_r \cdot g_r^{annual}$), as displayed in Equation (7b). This yields a linear relationship between the threshold $SG_r - \Delta_{Loss}$ and the sustained generation limit SG_r . The threshold Δ_{Loss} is set to 10 percentage points below SG_r , with sensitivity cases of 5% and 15% also evaluated.

$$g_{r,t,p}^{for\ loss} = \sum_t^{t+168} (g_{r,t,p}) - C_{r,p} (SG_r - \Delta_{Loss}) \cdot 168 \quad (7a)$$

$$L_{r,t} = \frac{g_{r,t,p}^{for\ loss}}{\Delta_{Loss} \cdot C_{r,p} \cdot 168} \lambda_r \cdot g_r^{annual} \quad (7b)$$

$$\forall r, t, p \in R, T, P^{Hydro}$$

2.2. Scenarios

The work is divided into two parts, each with its own set of scenarios. The first part deals with the evaluation of the three hydropower equivalents presented in Section 2.1, while the second part considers the future role of Swedish hydropower.

2.2.1. Comparison of hydropower implementations

To evaluate the three hydropower equivalents, a scenario with substantial offshore wind expansion is considered. This expansion is imposed through mandated investments of 6 GW in SE4 and 16 GW in SE3, while also accounting for a decommissioning of existing nuclear power plants as they reach their technical lifetimes. The resulting *Wind* scenario is designed to be demanding in terms of flexibility, making it suitable for assessing the impact of constraints in the *Bi-level* and *Extended* equivalents. At the same time, it remains realistic, as projects totaling approximately 35 GW of offshore wind capacity are currently awaiting government approval in Sweden [28].

Two transmission expansion options are also analyzed. Both include fixed capacity increases based on ENTSO-E projections [29] (*Fixed*), while a second option (*Fixed + New*) allows for additional endogenous grid investments. The latter facilitates evaluation of hydropower constraints while minimizing the influence of transmission bottlenecks on dispatch outcomes.

2.2.2. Evaluating the future role of Swedish hydropower

To evaluate the future role of Swedish hydropower, three additional scenarios are analyzed alongside the *Wind* scenario described in Section 2.2.1, as summarized in Table 2. The *Cost Optimal* scenario does not impose any mandatory investments; however, it incorporates a lifetime extension of 5 GW of nuclear capacity in region SE3.

The *Nuclear* scenario includes mandated investments totaling 9 GW of nuclear capacity—8 GW in region SE3 and 1 GW in region SE4—in addition to a lifetime extension of 5 GW of existing nuclear capacity in SE3.

Finally, a less plausible scenario, included primarily as a system stress test, is the *Wind No Flex* scenario. This scenario enforces the deployment of 22 GW of offshore wind capacity while prohibiting any investments in hydrogen or heat storage across all modeled regions.

In assessing the future role of Swedish hydropower, transmission expansion is limited to the *Fixed* option, meaning that hydropower operation is influenced by existing grid bottlenecks.

Table 2

Summary of the model settings used for the evaluation of the future role of Swedish hydropower.

Technology and system assumptions	Scenarios for evaluation of the future role of Swedish hydropower			
	Wind	Cost Optimal	Nuclear	Wind No Flex
Enforced offshore wind power	22 GW	-	-	22 GW
Nuclear power				
- Life extension	-	5 GW	5 GW	-
- Enforced	-	-	9 GW	-
Hydrogen and heat storage	-	-	-	No
Transmission expansion	Fixed			

Table 3

Mean Absolute Error (MAE) normalized by the average generation level in Detailed Model 1, calculated for each price area and hydropower equivalent across the two meteorological years modeled.

Price areas	Mean Absolute Error normalized by the average generation level in Detailed Model 1		
	Simple	Bi-level	Extended
SE1	0.33	0.42	0.45
SE2	0.33	0.30	0.34
SE3	0.37	0.31	0.41
SE4	0.42	0.41	0.47

3. Results

The results presented in this section are organized into two subsections. The first subsection examines the differences among the three hydropower implementations, while the second subsection analyzes the role of hydropower in a future Swedish electricity system.

3.1. Comparing hydropower implementations

Section 3.1.1 evaluates hydropower operation under the three implementations relative to *Detailed Model 1*, while Section 3.1.2 presents a sensitivity analysis of parameter values for the *Extended* equivalent. Section 3.1.3 assesses system-level impacts of the hydropower implementations, including investments and marginal electricity costs across the different implementations.

3.1.1. Evaluating hydropower operation

As an initial comparison, the mean absolute error (MAE) relative to *Detailed Model 1*, normalized by its average generation, is calculated for the four Swedish price areas across the two modeled meteorological years. As shown in Table 3, all equivalents exhibit substantial deviations, with errors ranging from 30% to 47%. Overall, the *Bi-level* implementation performs best according to this metric, which is expected since its parameters are explicitly calibrated to minimize deviations from the detailed model by narrowing the range between minimum and maximum generation levels.

More unexpectedly, the *Extended* implementation shows the largest deviation. However, as demonstrated in the remainder of this section, qualitative differences reveal that the three implementations capture techno-physical constraints in distinct ways, leading to different impacts on marginal electricity costs, the value of water, and investments in other technologies.

In the detailed hydropower models (*Detailed models 1* and 2), dispatch responds to exogenous electricity prices but does not influence them; thus, part-load operation arises solely from techno-physical constraints. In contrast, in the energy systems model, hydropower affects electricity prices, and part-load operation may also be economically motivated.

Fig. 2 presents generation-duration curves for hydropower across the four Swedish regions for meteorological year 1992, comparing the three implementations (Table 1) with *Detailed model 1*. For reference, historical generation from eight years is also included, although one should keep in mind that the modeled system differs substantially from the Swedish electricity system in recent years.²

In the northern regions (SE1–SE2), discrepancies in maximum generation between *Detailed model 1* and historical data can be attributed to (i) uncertainties in inflows and prices not captured in the deterministic model, (ii) the exclusion of balancing markets, and (iii)

maintenance and outages [6]. In the southern regions (SE3–SE4), differences also reflect the limited inclusion of small-scale hydropower. Notably, both the detailed and system models represent the same subset of hydropower, although the *Bi-level* equivalent yields a lower maximum capacity.

In the *Simple* equivalent, part-load operation is only motivated if operation is constrained by reservoir levels or when the marginal value of water equals the marginal cost of electricity. This implementation yields the lowest share of part-load hours, with a characteristic pattern in SE4 where generation occurs predominantly at either minimum or maximum levels. This behavior becomes less pronounced further north, with SE1 exhibiting around 2000 h of part-load operation.

Introducing additional constraints, as in the *Bi-level* and *Extended* equivalents, results in generation profiles that more closely resemble *Detailed model 1*. In the *Bi-level* case, stepwise changes in generation—particularly in SE3—reflect seasonally varying operating limits. In the *Extended* implementation, part-load operation arises from constraints on sustained generation and minimum diurnal output.

To distinguish economically motivated from flexibility-constrained part-load operation, Fig. 3 shows hydropower generation alongside marginal electricity costs for region SE2. With fewer constraints, the *Simple* equivalent (Fig. 3a) shifts most generation to hours with high marginal costs, implying that part-load operation is primarily economically driven. Similarly, *Detailed model 1* allocates generation efficiently to high-price hours, but also exhibits reduced output across all price levels due to flexibility constraints.

It should be noted, however, that *Detailed model 1* operates under exogenous electricity prices, whereas the equivalents within the energy systems model jointly determine marginal costs with the rest of the system, making direct comparisons non-trivial. For the *Bi-level* and *Extended* equivalents (Fig. 3b and c), additional constraints limit the allocation of generation to high-price hours, resulting in lower output during such periods compared to the *Simple* equivalent.

Wind power, expected to supply a large share of future electricity demand in northern Europe [31,32], introduces net-load variations over periods ranging from days to weeks [33]. Accurately representing hydropower in such systems therefore requires capturing its ability to respond to these multi-day variations.

Figs. 4 and 5 illustrate hydropower dispatch over two six-week periods in region SE2. Fig. 4 shows a prolonged period of low wind generation, characterized by high electricity costs and increased stress on hydropower. During this period, the *Simple* and *Bi-level* equivalents operate near maximum capacity for almost four consecutive weeks, whereas the *Extended* equivalent exhibits a more dynamic profile, closely resembling *Detailed model 1*.

Allowing sustained maximum output over such extended periods is unrealistic under current environmental regulations [25] and may lead to an underestimation of the need for complementary resources during prolonged high net-load periods.

In contrast to Figs. 4 and 5 shows a six-week period characterized by low hydropower generation during periods of low marginal electricity costs (Equation S.(2)). The *Simple* and *Bi-level* equivalents exhibit extended periods of constant minimum generation, deviating from *Detailed model 1*, whereas the *Extended* equivalent produces a profile more closely aligned with the detailed model. This similarity arises from the minimum diurnal generation constraint (Eq. (5)).

A notable feature of *Detailed model 1* is the presence of frequent generation spikes of several GW, despite near-zero electricity prices. These spikes result from limited reservoir capacity in parts of the river system, requiring forced discharges when inflows and water levels are high. As the model maximizes profit, discharge is concentrated to instances when the electricity price is the most beneficial, even if they are only marginally higher than the prices in adjacent hours. While this behavior may be considered a modeling artifact, from a system perspective the total daily energy dispatch is more relevant than its hourly distribution, as the discharged water cannot be shifted to other

² Years 2010, 2015, 2016, 2019, 2020, 2021, 2022, and 2023. The selected years are based on the data availability from the Swedish Transmission System Operator, Svk [30].

Scenario Wind - with new transmission

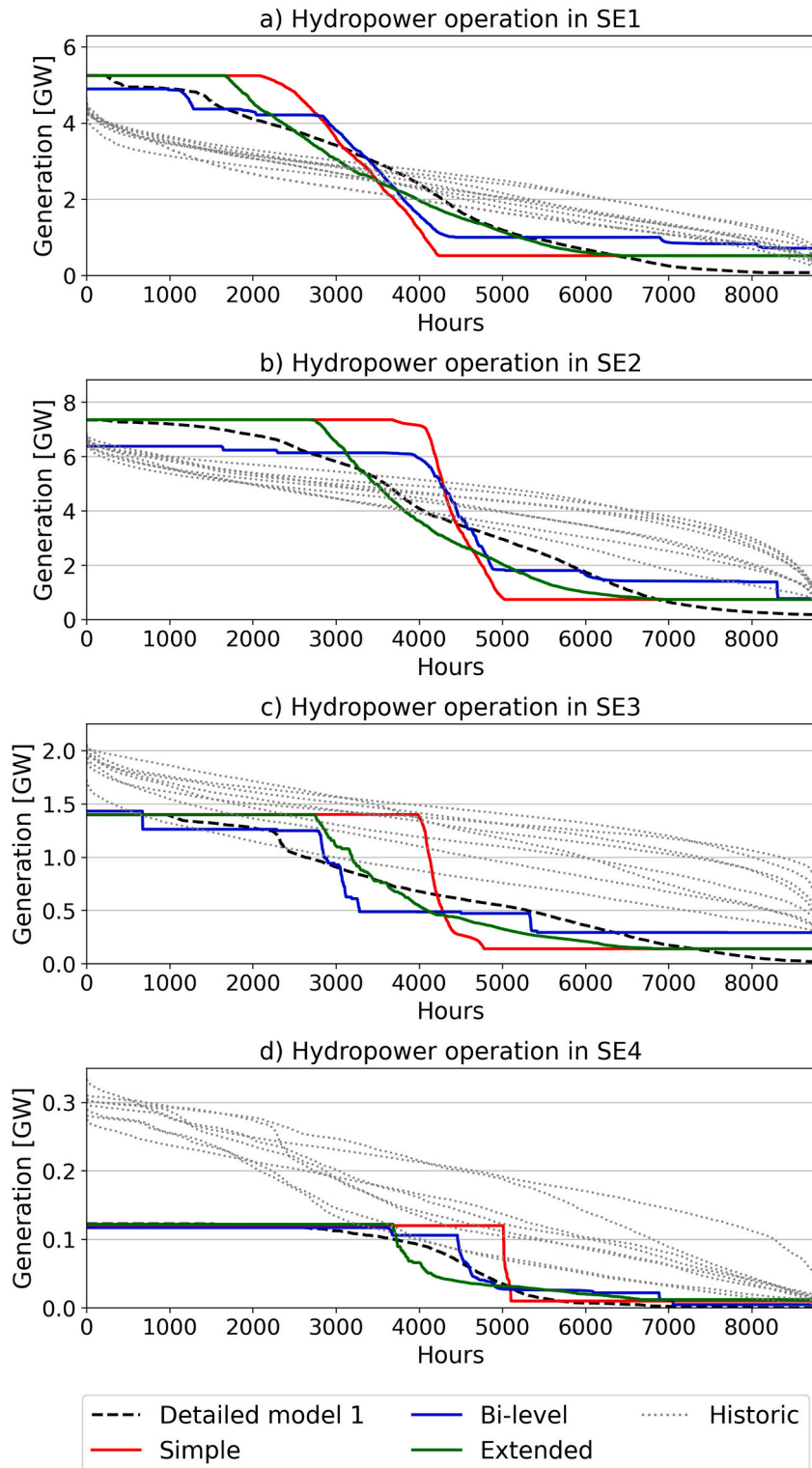


Fig. 2. Generation durations of hydropower in the four Swedish regions for the three hydropower equivalents evaluated with Detailed model 1 as reference, and with an expansion of transmission capacity allowed (Fixed + New).

periods.

The results in Figs. 2–5 are based on model setups with endogenous expansion of transmission capacity (Fixed + New). Assuming instead a fixed transmission expansion based on the projections by ENTSO-E [29], the largest impact is observed for the Simple hydropower equivalent,

increasing part-load hours across all regions—particularly in SE2 and SE3 (Figures S.6–S.7). This indicates that, for an implementation that tends to overestimate hydropower flexibility, transmission constraints significantly influence dispatch patterns.

In contrast, the Bi-level and Extended equivalents are only marginally

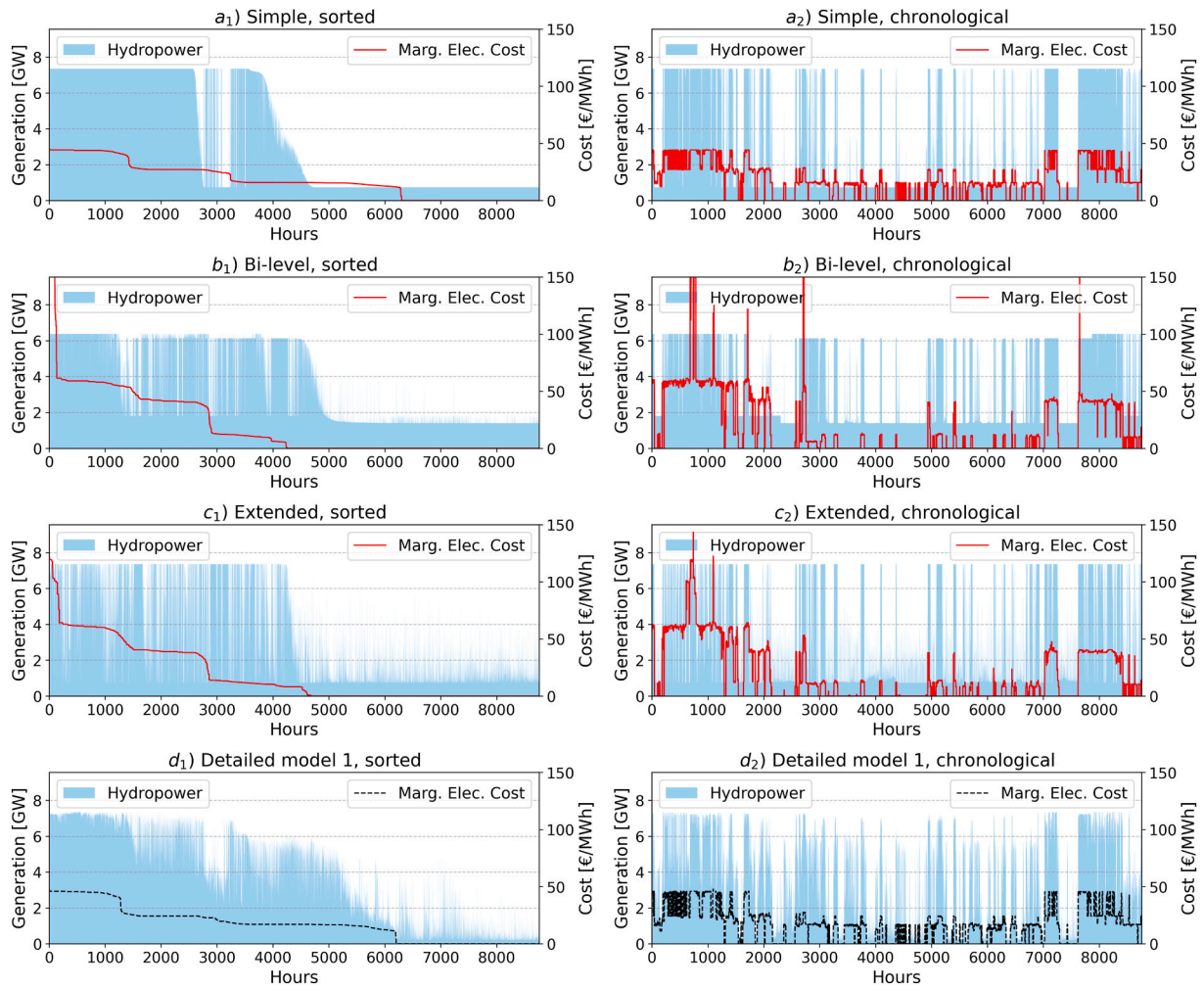


Fig. 3. Hydropower generation and marginal cost of electricity for region SE2 during Year 1991 for the Simple (a₁₋₂), Bi-level (b₁₋₂), and Extended (c₁₋₂) equivalents, and with Detailed model 1 (d₁₋₂) for comparison.

affected by restricted transmission expansion, suggesting that internal hydropower constraints play a more dominant role than interregional transmission limits in shaping dispatch.

3.1.2. Sensitivity analysis on parameter values

The dynamic generation profile of the *Extended* equivalent in Figs. 4 and 5 arises from the additional constraints introduced in Section 2.1.3. Fig. 6 presents the marginal values of these constraints, along with sensitivity results for minimum diurnal generation γ_{24h} and the loss threshold Δ_{Loss} for region SE2 (see Figures S.2–S.4 for all regions).

The marginal cost of the sustained generation constraint (Equation (6); Fig. 6b) is non-zero only infrequently, reflecting the limited occurrence of prolonged low-wind periods and the presence of flexible demand (e.g., hydrogen production). In contrast, the loss constraint (Equation (7); Fig. 6d) binds more frequently but with lower marginal costs, as it implies energy losses rather than directly limiting sustained output. Consistent with this, varying Δ_{Loss} has only a minor effect on overall generation, mainly affecting the upper range of part-load operation (Fig. 6c).

The minimum diurnal generation constraint (Equation (5)) has the largest impact, exhibiting the highest marginal costs and binding in up to 300 daily periods (Fig. 6f). As expected, higher values of γ_{24h} shift generation toward a more even distribution of part-load operation by constraining output to the lower range of generation levels, as shown in Fig. 6e. This highlights the impact of this constraint for capturing key techno-physical characteristics of river systems in simplified energy

system models (see also Figure S.5).

3.1.3. Impacts of the equivalents on the energy systems model

Applying different hydropower representations affects system outcomes beyond dispatch. Introducing additional constraints on hydropower flexibility, as in the *Bi-level* and *Extended* equivalents, shifts the cost-optimal capacity mix compared to the *Simple* equivalent. In Sweden, wind capacity increases by 4% and 6%, electrolyzer capacity by 6% and 2%, and hydrogen storage by 35% and 8% for the *Bi-level* and *Extended* equivalents, respectively. The large increase in hydrogen storage capacity for the *Bi-level* equivalent occurs in the northern-most region, SE1, reflecting reduced hydropower flexibility and a shift of flexibility to hydrogen supply. Battery capacity and storage are around 35% lower in the *Extended* case, primarily due to reduced solar PV deployment. In contrast, the *Bi-level* equivalent yields slightly higher battery capacity (+3%) and battery storage (+14%), as a consequence of lower hydropower capacity. At the system level, wind and gas turbine capacities increase by 2% and 5%, respectively, while solar PV decreases by 2% when hydropower constraints are included.

Fig. 7 presents the marginal cost of electricity (Equation S.(2)) and the marginal value of water (Equation S.(6)) for the three hydropower implementations (Fig. 7a–c) across regions SE1–SE4. Hydropower generate electricity based on the marginal value of water—i.e., the opportunity cost of using water at a given time—rather than its operating cost. When hydropower acts as the marginal unit, this value determines the electricity price, here referred to as being a price setter. The overlap

Wind scenario

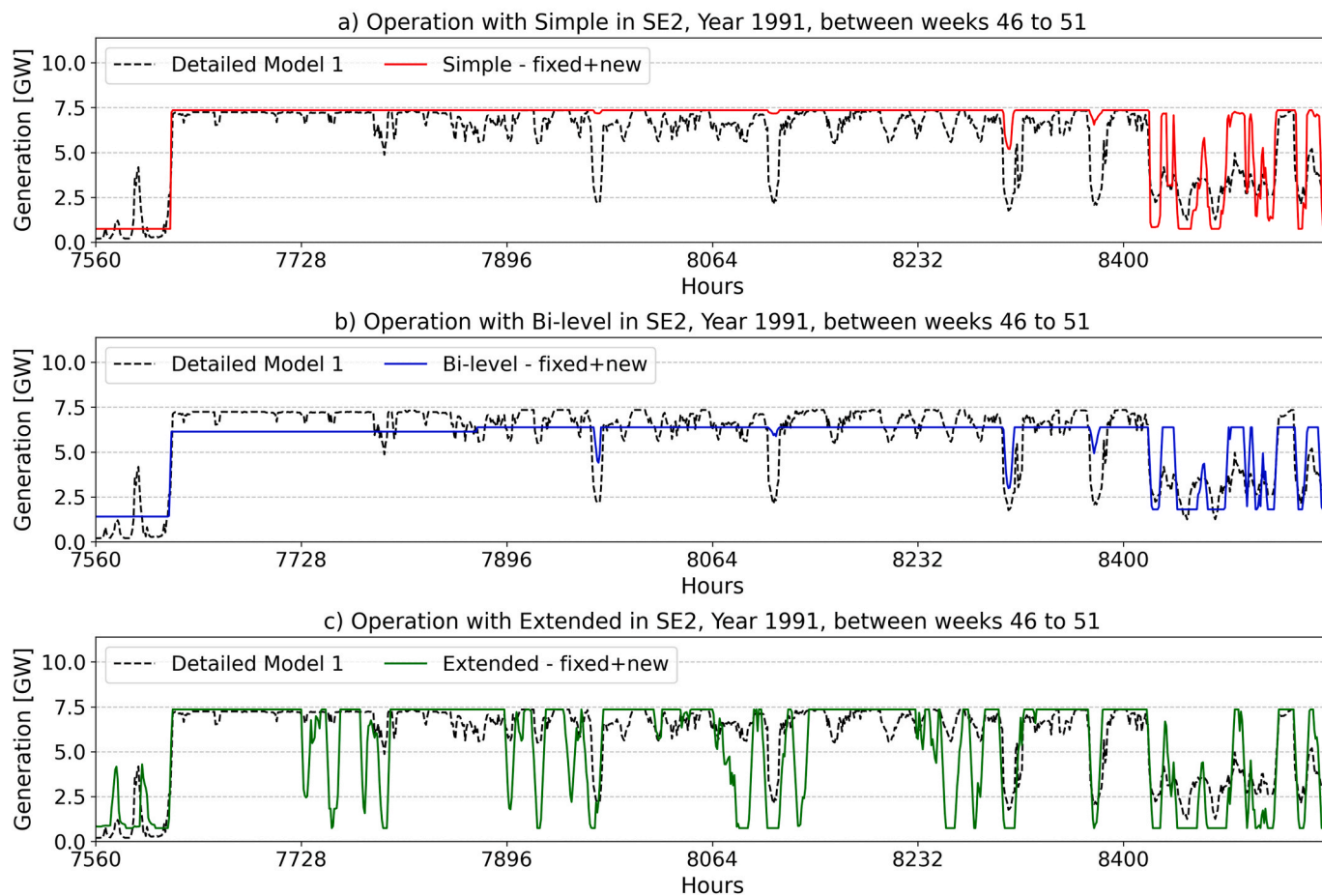


Fig. 4. A 6-week period with high levels of hydropower generation at the end of Year 1991 for the Simple (a), Bi-level (b), and Extended (c) equivalents, with the corresponding generation from Detailed model 1 as reference. Expansion of transmission capacity is allowed (Fixed + New).

between marginal electricity costs and water values indicates the share of hours during which hydropower sets the price. As shown in Fig. 7, this overlap is highest in the northern region SE1 for all implementations (e. g., 25% of hours for the *Simple* equivalent) and declines southwards, reaching 1% or less in SE4.

The *Simple* equivalent, despite exhibiting the fewest part-load hours, has the highest share of price-setting hours among the three implementations. This reflects its overestimated flexibility, which allows large volumes of water to be shifted in time. As a result, the marginal value of water varies little—particularly in SE1, where it remains constant throughout the year (Fig. 7a)—leading to an underestimation of the number of hours with a marginal electricity cost that is equal to zero.

Regarding the *Bi-level* equivalent, owing to the narrow interval between the minimum and maximum generation levels, the constraints on minimum and maximum generation are binding for the majority of hours during the year. A consequence of this narrow operational range is that the marginal value of water is zero for considerable parts of the year, as in Fig. 7b, which shows that hydropower production cannot increase even if there is additional water inflow during these periods. This means that the *Bi-level* implementation is the least-flexible implementation of the three evaluated, yielding a larger share of hours with a marginal electricity cost equal to zero.

Finally, the *Extended* equivalent, which has the same operational range as the *Simple* equivalent, albeit with additional constraints on minimum diurnal generation, sustained weekly generation, and losses, is displayed in Fig. 7c. Comparing the marginal water value with the corresponding value for the *Bi-level* equivalent, similar trends can be

seen, although without the long periods with zero values for the *Extended* equivalent. This indicates reduced—but not overly restrictive—flexibility, leading to a moderate number of hours with a marginal cost of electricity equal to zero compared to the other two implementations.

3.2. The future role of Swedish hydropower

This section evaluates the future role of Swedish hydropower across the four scenarios outlined in Table 2, using the *Extended* hydropower equivalent and assuming *fixed* transmission expansion based on ENTSO-E projections [29]. As a point of reference, the section begins with an analysis of recent developments.

Fig. 8 highlights the impact of increasing wind power generation. The right-hand panels show time series of hydropower and wind generation during the first 600 h of each year, while the left-hand panels summarize annual hydropower operation in terms of amplitude, duration, and frequency. Additional historical results (eight years) and a detailed description of the heatmaps are provided in the Supplementary Material.

Before 2020, hydropower operation—and southbound transmission flows—were closely linked to intra-day demand variations in southern Sweden. This is evident in Fig. 8a, where frequent operation at 6–8 GW over 15–20 h periods is observed. Since 2020, however, this pattern has weakened, as exemplified by the generation in 2023 (Fig. 8b).

This shift is driven by the expansion of wind power and increasing constraints on southbound transmission between SE2 and SE3 (see

Wind scenario

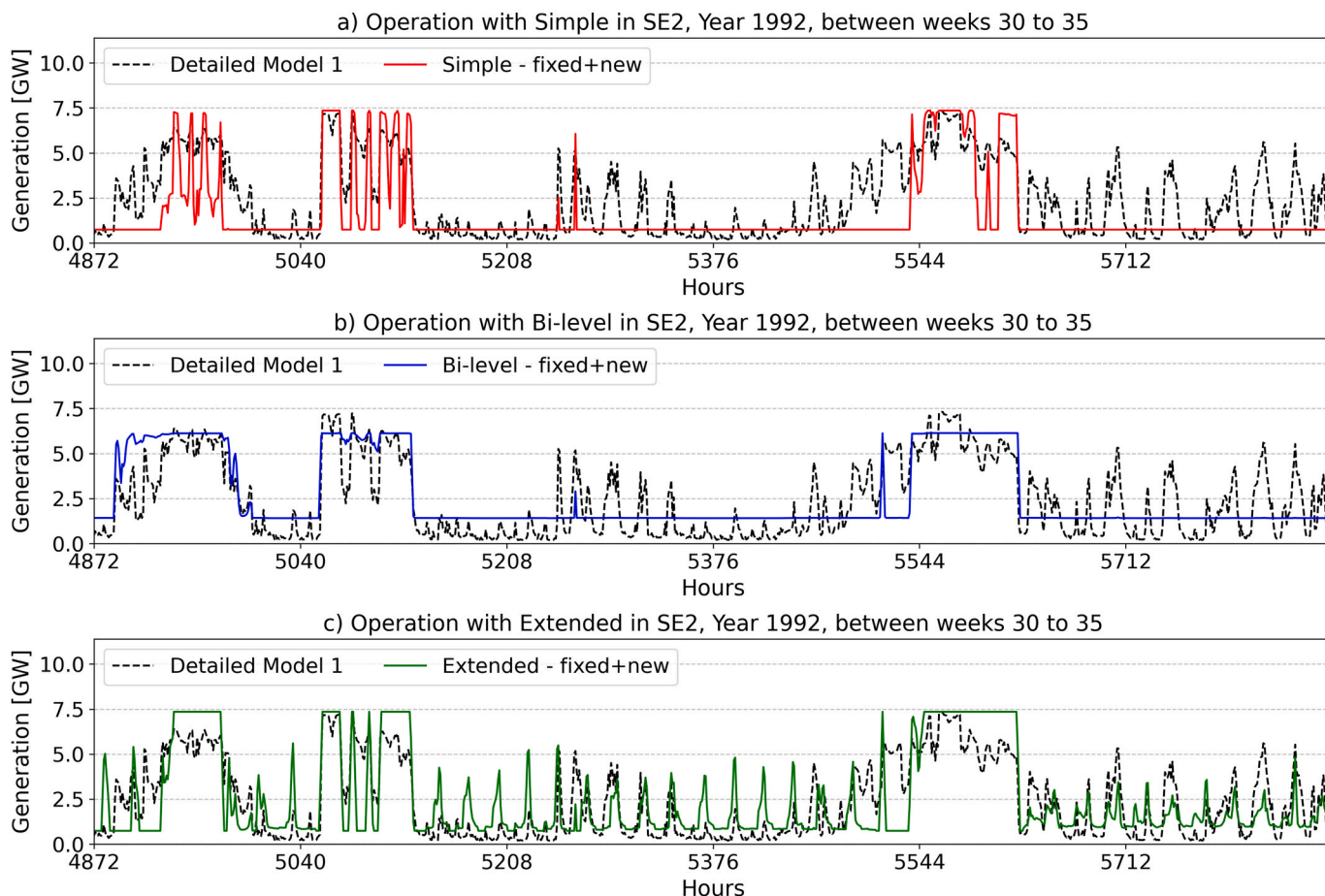


Fig. 5. A 6-week period with low levels of hydropower generation in the middle of Year 1992 for the Simple (a), Bi-level (b), and Extended (c) equivalents, with the corresponding generation from Detailed Model 1 as reference. Expansion of transmission capacity is allowed (Fixed + New).

Figure S.8). Prior to 2020, wind power was relatively limited and geographically balanced [34]. Since then, capacity has grown rapidly, primarily in northern Sweden [34], increasing southbound flows and, together with transmission constraints, altering hydropower operation patterns.

Fig. 9 shows the operational patterns for Swedish hydropower for the four future scenarios (Table 2). The hydropower generation patterns are, in general, quite similar for all of the scenarios investigated, although with tendencies towards more-frequent operation during periods of 12–15 h for the Nuclear scenario (Fig. 9c), and more operation with longer duration for the Wind No Flex scenario (Fig. 9d). Comparing the results in Fig. 9 with the historical dispatch patterns in Fig. 8, the trend of a weaker correlation between hydropower generation and intra-day load variations is preserved and strengthened in the future energy systems modeled, indicating that hydropower is mainly complementing wind power rather than balancing the demand.

The limited differences in hydropower operation across scenarios are explained by the similar electricity generation mixes in northern Europe (Figure S.9a), despite differing mixes within Sweden (Figure S.9b). This indicates that Swedish hydropower dispatch is largely driven by system-wide variations—particularly wind generation outside Sweden—rather than domestic developments.

This is supported by the marginal electricity costs shown in Figure S.10, which are similar for the *Wind*, *Cost Optimal*, and *Nuclear* scenarios. Larger deviations occur only in the *Wind No Flex* scenario, where the absence of hydrogen and heat storage increases total generation (Figure S.8a) and leads to substantial curtailment. However, this

scenario is considered less likely.

4. Discussion

As expected, the *Simple* equivalent tends to overestimate the ability of hydropower to shift generation to hours with high net load (i.e., periods of high electricity prices), thereby underestimating the need for other dispatchable technologies. Introducing constraints that reflect techno-physical limitations of river systems—primarily by limiting sustained generation at both high and low output levels—reduces this overestimation and shifts investments in both generation and storage technologies.

When assessing applicability to other hydropower-rich regions, several factors must be considered. Hydropower's role is strongly shaped by system context, such as the dominant VRE technology or, in systems with low VRE penetration, load variability. Consequently, constraints introduced to limit hydropower flexibility must be selected with care. In this study, wind power is the dominant VRE source; therefore, constraints are designed to limit sustained generation at both high and low output levels, reflecting the characteristic variability of wind generation. River system structure is also critical. Swedish hydropower is characterized by long, interconnected river systems with cascading reservoirs and complex hydrological dependencies. These features justify constraints on sustained generation to avoid unrealistic dispatch outcomes. Hence, the qualitative findings are primarily applicable to wind-dominated systems with strongly cascading river structures, while alternative formulations may be required in regions with different VRE

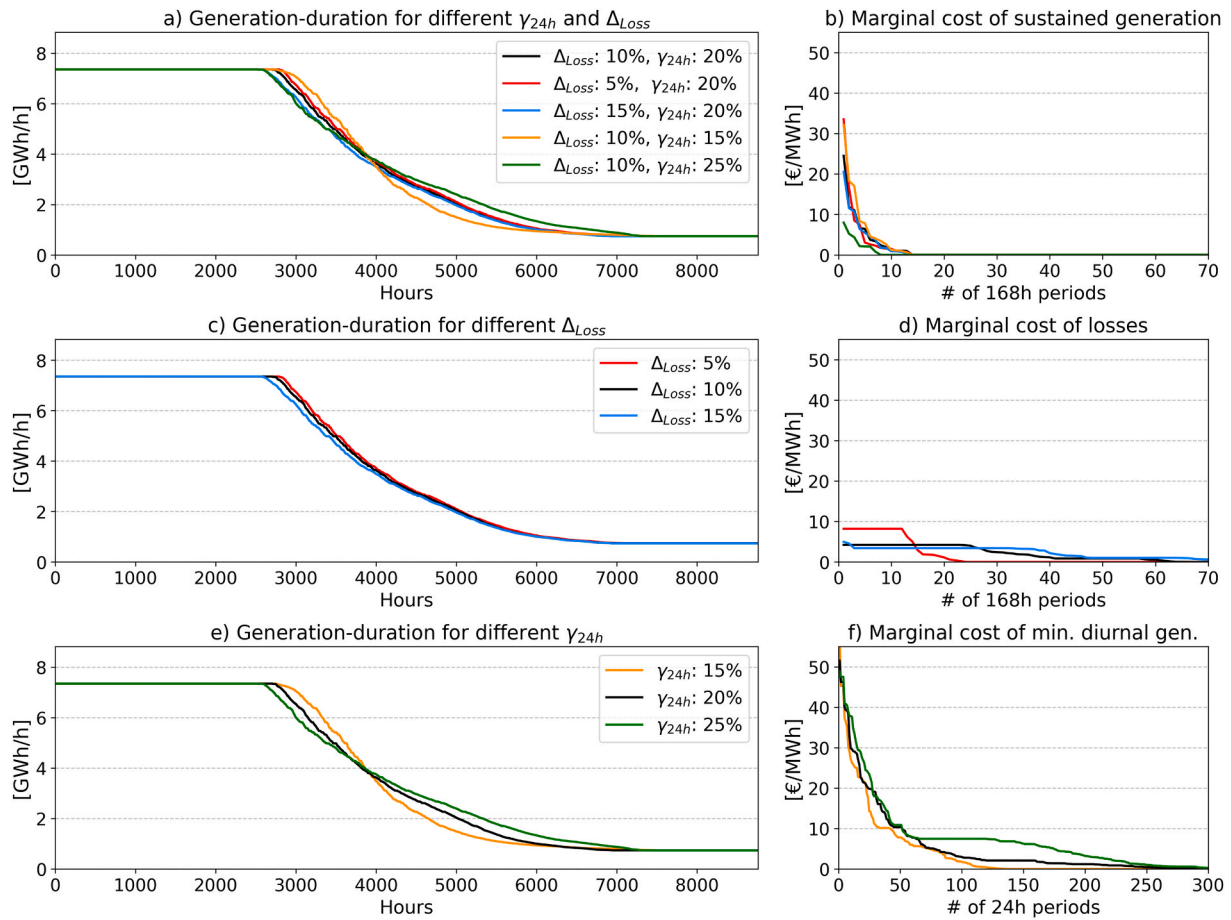


Fig. 6. The sorted generation profiles for different parameter values on Δ_{Loss} and γ_{24h} , together with the marginal cost of the three additional constraints (Equations (5)–(7)), applied in the Extended equivalent for the region SE2.

profiles or hydropower topologies.

In the present study, the quantitative difference between hydropower dispatch in the energy systems model and in a detailed hydropower model is assessed using the MAE. The results indicate that the evaluated hydropower equivalents exhibit relatively weak performance according to this metric, with errors ranging from 30% to 47%, suggesting that further refinement is warranted. However, the MAE alone is insufficient for an accurate comparison of the different equivalents, as they exhibit distinct impacts on investments, operational patterns, and electricity price formation. In other words, the equivalents display different strengths and weaknesses, each with differing implications for the energy system as a whole. An important consideration in such a quantitative comparison is that the energy systems model is not designed to replicate the dispatch of the detailed hydropower model. The detailed model is driven solely by an exogenous electricity price profile and does not capture interactions with the broader electricity system, such as transmission constraints, alternative generation costs, or flexible demand. Consequently, the central objective is not to reproduce identical dispatch patterns, but rather to ensure that similar trends are obtained and that the techno-physical limitations represented in the detailed model are appropriately reflected in the energy systems model.

For the *Bi-level* equivalent, a key limitation is its inability to reproduce dynamic transitions between high and low generation periods, often resulting in overly constant output compared to *Detailed model 1* (Figs. 4 and 5). This could potentially be improved by increasing model granularity (e.g., more plants in series, parallel, or V-shaped configurations, as suggested in Ref. [35]) and by transferring additional parameters from *Detailed model 1*, particularly those governing sustained high output and minimum generation levels over defined periods.

Using *Detailed model 2*, spillage constraints were found to significantly affect maximum sustained output over weekly periods [25], as controlled releases past smaller plants limit flexibility. Due to data constraints, spillage was represented using generalized assumptions rather than plant-specific limits, and some intricacies related to spillage were not addressed in the analysis due to data limitations. In addition, *Detailed model 2* is deterministic, whereas real-world uncertainty in inflows and prices would further reduce hydropower flexibility. As a result, the parameter for sustained generation (SG_r) should be interpreted as indicative rather than exact. Limitations on the maximum generation were only implemented for weekly periods in this study. To increase accuracy, the same method (reported in Ref. [25]) could be used to find similar, likely higher, numbers for shorter periods, such as a couple of days.

Finally, regarding investment impacts in Sweden, the *Simple* equivalent generally leads to lower investments in wind power, electrolyzers, and hydrogen storage compared to the *Bi-level* and *Extended* equivalents, while battery investments show no consistent pattern. This contrasts with Ramírez-Sagner and Muñoz [36], who find that simplified hydropower representations underestimate dispatchable capacity needs. However, at the system level, wind and gas turbine investments increase by 2% and 5%, respectively, while solar PV decreases by 2% under constrained hydropower representations (*Bi-level* and *Extended*), which is more consistent with [36].

5. Conclusion

This study evaluates aggregated representations of reservoir hydropower derived from detailed models and grounded in techno-physical

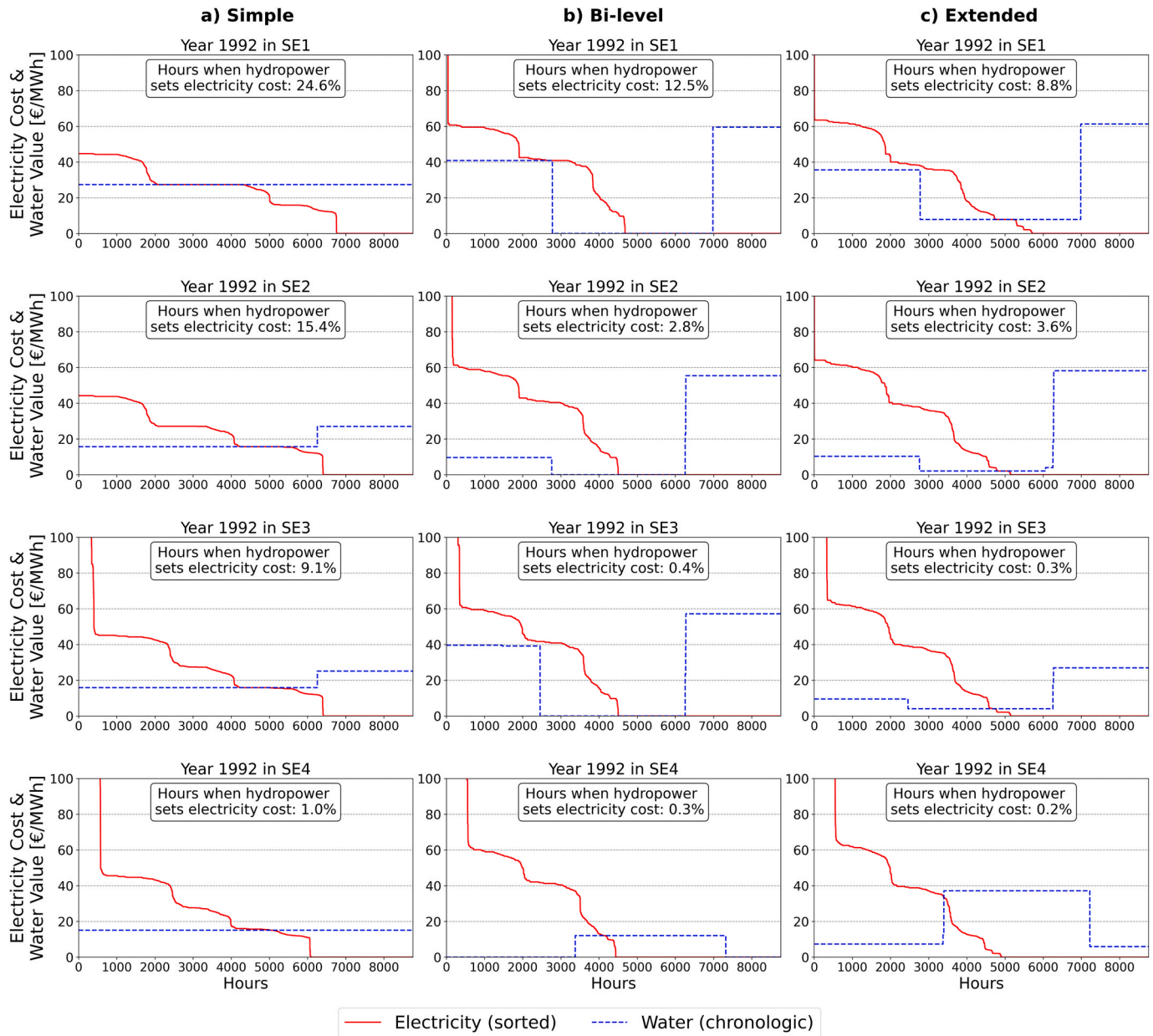


Fig. 7. The marginal cost of electricity (sorted) and the marginal value of water (chronological) for all Swedish regions and all hydropower equivalents when new investments in transmission capacity are allowed.

constraints rather than historical operating patterns. Using the Swedish hydropower system as a case study within a future decarbonized European energy system, it provides guidance on the selection of simplified hydropower representations and their implications for investments, operational patterns, and electricity price formation.

Two key aspects are identified when representing reservoir hydropower in energy system models: (i) when a more constrained representation is required, and (ii) which constraints should be included. Regarding the first, representations that capture physical system limitations—such as the *Extended* equivalent—are generally preferable, particularly for complex systems like Sweden's or when transmission expansion is modeled. However, such approaches require detailed system knowledge.

Regarding the second aspect, the additional constraints in the *Extended* equivalent significantly affect hydropower dispatch. These constraints reflect key physical limitations, including water availability within river systems, spillage losses at bottlenecks, and flood

management in smaller reservoirs. Implemented through rolling time constraints, they limit sustained operation at high and low output levels. Collectively, they reduce the overestimation of hydropower flexibility, thereby influencing investments in both generation and storage technologies.

Less constrained representations, such as the *Simple* equivalent, may be appropriate when hydropower plays a minor role or dominates the system to the extent that part-load operation is economically justified. In the latter case, the absence of internal constraints may be partially offset by transmission limitations, particularly when grid expansion is restricted.

The *Bi-level* equivalent reproduces several features of *Detailed model 1*, including similar operating hours within capacity bounds, while yielding investment and storage outcomes comparable to the *Extended* equivalent. However, it fails to capture dispatch during prolonged low-wind periods, and its use of seasonally defined generation bounds raises concerns regarding impacts on marginal values of water and electricity.

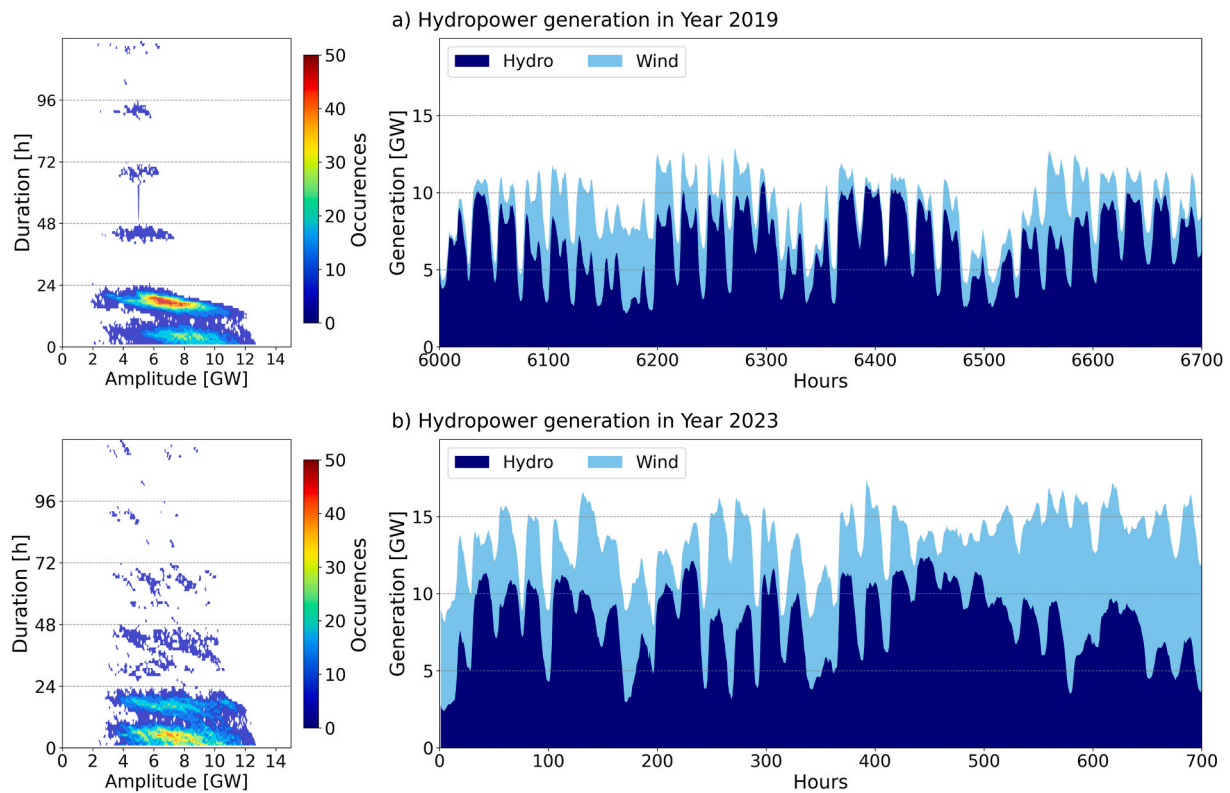


Fig. 8. Hydropower generation for Year 2019 (a) and Year 2023 (b); statistical data from the Swedish Transmission System Operator, SvK [30]. The left panels display the hydropower generation of the whole year while the panels on the right display a time-series of the first 700 h with both hydropower and wind power generation.

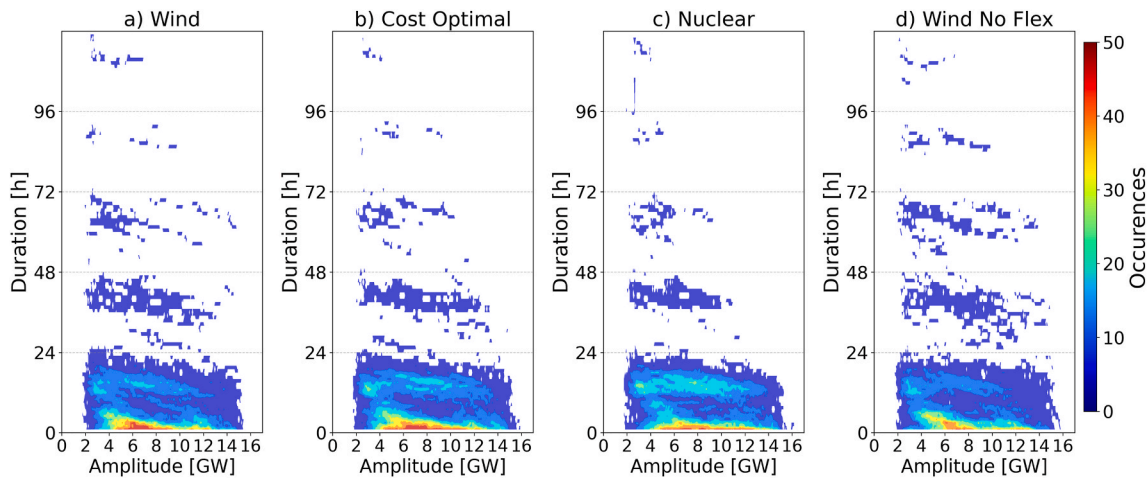


Fig. 9. Hydropower generation during meteorological Year 1991 for four future scenarios that consider the development of the electricity system.

Regarding the role of hydropower in a future Swedish electricity system, the results indicate a weakening—and further decline—of the correlation between hydropower generation and intra-day load variations. This suggests that hydropower increasingly complements wind power rather than balancing demand. Consequently, the value of operating hydropower at sustained high and low output levels over periods ranging from days to weeks increases, highlighting the importance of accounting for internal hydropower constraints in energy system models.

Furthermore, the development of the Swedish electricity system has a limited influence on hydropower dispatch. This is because variability is largely driven by wind power outside Sweden, and interconnected transmission capacity exposes Swedish hydropower to these dynamics

regardless of domestic system configurations.

CRediT authorship contribution statement

Simon Öberg: Conceptualization, Methodology, Visualization, Writing – original draft. **Lisa Göransson:** Methodology, Supervision, Writing – review & editing. **Hanna Ek Fålh:** Methodology, Writing – review & editing. **Uli Rahmlow:** Methodology, Writing – review & editing. **Filip Johnsson:** Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial

interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A

Table A.1

Input data for the Bi-level and Extended equivalents.

Region	Inflow period	P_{\max} [GW]	P_{\min} [GW]	L_{\max} [GWh]	L_{\min} [GWh]	R_1 [GW/h]
SE1	Low	4.89	1.00	12,324	6117	2.13
	Medium	4.21	0.70	14,420	4094	0.96
	High	4.36	0.81	14,610	1745	0.84
SE2	Low	6.23	0.77	11,610	7700	0.97
	Medium	6.38	1.81	8567	2348	1.53
	High	6.14	1.38	12,475	1507	2.37
SE3	Low	1.43	0.47	1567	536	0.52
	Medium	1.26	0.29	1789	671	0.32
	High	1.25	0.48	1875	541	0.24
SE4	Low	0.11	0.01	109	0	0.22
	Medium	-	-	-	-	-
	High	0.12	0.02	21	0	0.07

Table A.2

Data defining the different inflow periods.

Region	Year	Inflow period	Hours
SE1	1991	Low	1–2351
		Medium	4608–7463
		High	2352–4607
	1992	Low	1–2831
		Medium	5328–6983
		High	2832–5327
SE2	1991	Low	-
		Medium	1–2303
		High	2304–7871
	1992	Low	7368–8760
		Medium	1–2903
		High	2904–7367
SE3	1991	Low	1–1895
		Medium	4656–7943
		High	1896–4655
	1992	Low	1–1559
		Medium	3334–8760
		High	1560–3333
SE4	1991	Low	5544–8760
		Medium	-
		High	1–5543
	1992	Low	1–359
		Medium	-
		High	360–4607

Table A.3

Maximum sustained generation, SG_r , per region and maximum annual loss factor per week of maximal generation, λ_r .

Region	SG_r	λ_r
SE1	77%	0.19%
SE2	86%	0.14%
SE3	76%	0.4%
SE4	100%	0.4%

Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.renene.2026.125924>.

References

- [1] D. Fraile, et al., "Getting Fit for 55 and Set for 2050 Electrifying Europe with Wind Energy," 2021.
- [2] IRENA, The changing role of hydro power - challenges and opportunities 25 (4) (2023), [https://doi.org/10.1016/0011-684X\(83\)90074-6](https://doi.org/10.1016/0011-684X(83)90074-6).
- [3] R. Scharff, L. Göransson, V. Walter, P. Berg, Y. Hundecha, E. Löfblad, Klimatförändringarnas inverkan på Vattenkraftens produktions- och Reglerförmåga, 2023. Stockholm.
- [4] V. Koestler, A. Østenby, C. Birkeland, F. Arnesen, I. Haddeland, Vannkraftverkene i Norge Får Mer Tilsig. Norges vassdrags- Og Energidirektorat (NVE) Rapport 50-2019, 2019.
- [5] European Commission, "Water Framework Directive."
- [6] H. Ek Fålh, N. Mattsson, L. Reichenberg, F. Hedenus, Trade-offs between aggregated and turbine-level representations of hydropower in optimization models, *Renew. Sustain. Energy Rev.* 183 (August 2022) 113406, <https://doi.org/10.1016/j.rser.2023.113406>, 2023.
- [7] R.M. Lima, M.G. Marcovecchio, A.Q. Novais, I.E. Grossmann, On the computational studies of deterministic global optimization of head dependent short-term hydro scheduling, *IEEE Trans. Power Syst.* 28 (4) (2013) 4336–4347, <https://doi.org/10.1109/TPWRS.2013.2274559>.
- [8] S.J.P.S. Mariano, J.P.S. Catalão, V.M.F. Mendes, L.A.F.M. Ferreira, Optimising power generation efficiency for head-sensitive cascaded reservoirs in a competitive electricity market, *Int. J. Electr. Power Energy Syst.* 30 (2) (2008) 125–133, <https://doi.org/10.1016/j.ijepes.2007.06.017>.
- [9] E.C. Finardi, E.L. Da Silva, C. Sagastizábal, Solving the unit commitment problem of hydropower plants via lagrangian relaxation and sequential quadratic programming, *Comput. Appl. Math.* 24 (3) (2005) 317–341, <https://doi.org/10.1590/S0101-82052005000300001>.
- [10] A. Borghetti, C. D'Ambrosio, A. Lodi, S. Martello, An MILP approach for short-term hydro scheduling and unit commitment with head-dependent reservoir, *IEEE Trans. Power Syst.* 23 (3) (2008) 1115–1124, <https://doi.org/10.1109/TPWRS.2008.926704>.
- [11] M.M. Belsnes, O. Wolfgang, T. Follstad, E.K. Aasgård, Applying successive linear programming for stochastic short-term hydropower optimization, *Elec. Power Syst. Res.* 130 (2016) 167–180, <https://doi.org/10.1016/j.epsr.2015.08.020>.
- [12] L. Hirth, The benefits of flexibility: the value of wind energy with hydropower, *Appl. Energy* 181 (2016) 210–223, <https://doi.org/10.1016/j.apenergy.2016.07.039>.
- [13] E. Nycander, L. Söder, An open dispatch model for the nordic power system, *Energy Strategy Rev.* 39 (Jan. 2022) 100775, <https://doi.org/10.1016/J.ESR.2021.100775>.
- [14] Sweco Energy Markets, "Apollo Power Market Model".
- [15] J. Gode, J. Holm, E. Löfblad, A. Rensfeldt, T. Unger, Systemkonsekvenser av miljöåtgärder i vattenkraften. www.energiforsk.se, 2022.
- [16] P. Seljom, E. Rosenberg, L.E. Schäffer, M. Fodstad, Bidirectional linkage between a long-term energy system and a short-term power market model, *Energy* 198 (May 2020), <https://doi.org/10.1016/j.energy.2020.117311>.
- [17] N. Stevanato, M.V. Rocco, M. Giuliani, A. Castelletti, E. Colombo, Advancing the representation of reservoir hydropower in energy systems modelling: the case of zambesi river basin, *PLoS One* 16 (12 December) (2021) 1–25, <https://doi.org/10.1371/journal.pone.0259876>.
- [18] W. Arnold, M. Giuliani, A. Castelletti, Floating photovoltaics may reduce the risk of hydro-dominated energy development in Africa, *Nat. Energy* 9 (5) (May 2024) 602–611, <https://doi.org/10.1038/s41560-024-01510-0>.
- [19] A. Carlino, et al., Hydroclimatic change challenges the EU planned transition to a carbon neutral electricity system, *Environ. Res. Lett.* 16 (10) (Oct. 2021), <https://doi.org/10.1088/1748-9326/ac243f>.
- [20] O. Wolfgang, A. Haugstad, B. Mo, A. Gjelsvik, I. Wangensteen, G. Doorman, Hydro reservoir handling in Norway before and after deregulation, *Energy* 34 (10) (Oct. 2009) 1642–1651, <https://doi.org/10.1016/J.ENERGY.2009.07.025>.
- [21] J. Ullmark, L. Göransson, F. Johnsson, Representing net load variability in electricity system capacity expansion models accounting for challenging weather-years, *Energy* 316 (Feb. 2025) 134346, <https://doi.org/10.1016/J.ENERGY.2024.134346>.
- [22] S. Bergström, The HBV model, in: V.P. Singh (Ed.), *Computer Models of Watershed Hydrology*, Water Resources Publications, 1995, pp. 443–476.
- [23] R. Scharff, et al., Klimatförändringarnas inverkan på vattenkraftens produktions- och reglerförmåga slutrapport från KLIVA-projektet. www.energiforsk.se, 2023.
- [24] M. Amelin, C. Englund, A. Fagerberg, Balansering av vindkraft och vattenkraft i norra Sverige - En studie av vattenkraftsmodeller, *Elforsk report 88* (2009). Stockholm.
- [25] H. Ek Fålh, F. Hedenus, L. Reichenberg, N. Mattsson, Through energy droughts: hydropower's ability to sustain a high output. <https://arxiv.org/pdf/2405.13530>. (Accessed 31 May 2024).
- [26] E. Blom, L. Söder, Accurate model reduction of large hydropower systems with associated adaptive inflow, *Renew. Energy* 200 (July) (2022) 1059–1067, <https://doi.org/10.1016/j.renene.2022.09.060>.
- [27] D. Lilja, E. Blom, L. Soder, Computing equivalent hydropower models in Sweden using inflow clustering. 2023 9th International Conference on Electrical Energy Systems (ICEES), 2022, <https://doi.org/10.1109/ICEES57979.2023.10110275>.
- [28] A.-S. Borglund, "Sverige saknar tydlig plan för havsvindkraft," *Tidningen Energi*. Accessed: March. 28, 2024. [Online]. Available: <https://www.energi.se/artiklar/2024/februari-2024/sverige-saknar-tydlig-plan-for-havsvindkraften/>.
- [29] ENTSO-E, System Needs Study - Opportunities for a More Efficient European Power System in 2030 and 2040, Brussels, Belgium, 2022.
- [30] Swedish TSO, "Production statistics Sweden." Accessed: October. 15, 2023. [Online]. Available: <https://mimer.svk.se/ProductionConsumption/Productio onIndex>.
- [31] G. Brindley, G. Willems, L. Ramirez, P. Cole, V. Klonari, J. Bickley, *Wind Energy in Europe - 2023 Statistics and the Outlook for 2024-2030*, 2023.
- [32] European Commission, A Clean Planet for all A European long-term Strategic Vision for a Prosperous, Modern, Competitive and Climate Neutral Economy, 2018.
- [33] I. Graabak, M. Korpås, Variability Characteristics of European Wind and Solar Power resources—A Review, *MDPI*. Jun. 01, 2016, <https://doi.org/10.3390/en9060449>.
- [34] Energimyndigheten, "Antal verk, installerad effekt och elproduktion." Accessed: November. 27, 2023. [Online]. Available: https://pxexternal.energimyndigheten.se/pxweb/sv/Vindkraftsstatistik/Vindkraftsstatistik/EN0105_1.px/table/tableViewLayout2/?loadedQueryId=e1241c10-f730-4531-8b74-8b9b91e8b02c&timeType=from&timeValue=0.
- [35] E. Blom, L. Söder, D. Risberg, Performance of multi-scenario equivalent hydropower models, *Elec. Power Syst. Res.* 187 (May) (2020) 106486, <https://doi.org/10.1016/j.epsr.2020.106486>.
- [36] G. Ramírez-Sagner, F.D. Muñoz, The effect of head-sensitive hydropower approximations on investments and operations in planning models for policy analysis, *Renew. Sustain. Energy Rev.* 105 (January) (2019) 38–47, <https://doi.org/10.1016/j.rser.2018.12.021>.