Technical Session 1A (11:10 - 12:40)	**Long-term Hydropower Planning**	**Chair: Guilherme Matiussi, CCEE**	
	Effects of increased granularity in the modeling of Nordic hydropower on price formation in connected markets	Kristine Schüller	NTNU
	Risk aversion and consequences for reservoir operation	Birger Mo	SINTEF
	Can a deterministic nonlinear model outperform a stochastic linear one in multi-reservoir long-term hydropower scheduling?	Secundino Soares	UNICAMP
	Adaptive distributionally robust optimization for long-term hydropower scheduling	Mari Haugen	NTNU

Effects of increased granularity in the modeling of Nordic hydropower on price formation in connected markets

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1 Background

The increasing share of production from variable, renewable energy sources such as solar- and wind power is causing increased short-term uncertainty and price volatility. The Nordics, and especially Norway, have a large share of hydropower that can help balance the renewable energy production by acting as a flexible resource. In the last decade, the total transmission capacity between the Nordic and Continental European power systems has increased considerably, providing a tighter coupling between these asynchronous systems. The role of the Nordic region in a 100% renewable European electricity system is thus of great interest to investigate. Improved modeling of the Nordic region will not only affect the prices within the Nordics, but can also show interesting price effects in other connected markets. The objective of this research is to more accurately simulate the interplay between Nordic hydropower management and European market dynamics.

Considering the long-term uncertainties of the weather conditions that determine reservoir storages is essential for robust medium- and long-term hydropower scheduling [1]. Today, an increasing share of energy production is coming from variable, renewable energy sources, and this production depends on short-term uncertainties such as wind speed and cloud coverage. Thus, future power market models for modeling the Nordic power system will need to include both short- and long-term uncertainties. The optimization problem quickly becomes extremely large and complex when considering uncertainties on both the short- and long-term scale for multi-year planning horizons. This problem can be handled by using a scheduling toolchain built up of different models with different levels of detail and time scales. Usually results from the long- and medium-term models are used as input to the short-term model [1]. However, with the increasing importance of short-term effects it is important to know how they can influence the long-term planning as well. We will use a research prototype model for long-term operational hydropower planning that uses advanced spatial decomposition techniques in order to represent both long- and short-term uncertainties.

2 Objective

The objective is to investigate how increased granularity in the modeling of Nordic hydropower can affect the prices in markets with connection to the Nordics. Increasing the granularity in the long-term hydropower scheduling can affect the resulting marginal costs of water, i.e. the value of storing water for later use. This can alter hydropower scheduling strategies and power prices in the Nordics and in connected markets. The focus will be on the resulting price effects beyond the synchronous Nordic system.

3 Methodology

An open-source research prototype model for long-term operational hydropower planning will be used. The model finds the minimum cost dispatch in power systems with a large share of hydropower. It is based on stochastic dual dynamic programming (SDDP), a widely used algorithm that was introduced in [2]. In order to represent both long- and short-term uncertainties, the model uses advanced spatial decomposition techniques to coordinate the treatment of detailed hydropower and fine time-resolution. The code is available at `https://gitlab.sintef.no/energy/res100/resddp`.

The goal of the model is to find the expected marginal value of water in large-scale, renewable electricity systems. Costs and technical constraints related to system operation are modeled explicitly. Decomposition is used to construct a computationally efficient function for estimating water values for the aggregated hydropower system. A detailed formulation of the hydropower system is used to generate feasibility cuts, describing the feasibility space of the subsystem decision variables. This ensures control over the feasibility of the aggregated decisions. The method is further described in [3, 4].

4 Expected results

The results will include simulated power prices for a base case and for cases with increased granularity. Further, differences in dispatch patterns will be presented and discussed. The results will be analyzed with respect to computational efficiency and impact of the level of granularity. The focus will be on price effects in regions beyond the Nordic synchronous system. The contributions from this research include (i) Demonstration of the methodology presented in [3] on a wider system boundary, (ii) Analysis of price effects and changes in dispatch patterns resulting from increased granularity in the modeling of Nordic hydropower. The research will provide important insight into the economic effects of increased granularity in the modeling of Nordic hydropower in markets with connection to the Nordics.

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Risk aversion and consequences for reservoir operation

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Model-based analysis of future renewable electricity systems is highly complex, primarily because models must simultaneously evaluate both short- and long-term flexibility. This requires fine time resolution and detailed representations of the physical properties of production, transmission, storages and demand. Additionally, the problem involves stochastic dynamic optimization due to uncertainties related to weather variations (e.g., wind and solar power production, reservoir inflows, and temperature-driven demand fluctuations) and fuel price volatility. Short-term flexibility can be provided by resources such as batteries, run-of-river hydro, pumped hydro, or demand-side flexibility. Long-term flexibility, on the other hand, may rely on storage-based hydro or hydrogen, the latter which many consider a key enabler for the transition to a fully renewable electricity system.

SINTEF has been developing hydro-thermal market models for many decades. The newest of these models is called FanSi [1]. In the Nordic market-based electricity system, these models are used for a range of purposes, including operational spot price forecasting, security of supply analysis, transmission investment decisions, and evaluations of possible future electricity systems. The FanSi model employs formal optimization to calculate the optimal utilization of short- and long-term flexibility resources. In recent years, it has been extensively used in research projects analysing potential future Northern European electricity systems. These studies focus on systems with a high share of wind and solar power production, balanced by Norwegian and Swedish hydro, batteries, and other fuel-based energy sources, depending on the timeframe under consideration.

The model has performed well in various analyses, with one notable exception: the simulated operation of long-term hydro storages has been considered too risky by hydro producers during prolonged dry and wet periods. Specifically, reservoir storages tend to be emptied too early in the winter or spring in dry years. Since Norwegian electricity production is 100% renewable, with hydro storage playing a critical role in the system and its security of supply, overly risky reservoir operation undermines the reliability of the results.

The presentation focuses on describing a newly developed risk-aversion functionality and demonstrating its impact on simulation results for a detailed model of a future renewable Northern European electricity system. The risk-aversion functionality is based on Conditional Value at Risk (CVaR) [2] and has been adapted to the optimization methodology used in FanSi. The simulation results include comparisons of reservoir operations and the probability distributions of simulated market prices for cases with and without the new functionality.

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Can a deterministic nonlinear model outperform a stochastic linear one in multi-reservoir long-term hydropower scheduling?

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I. Objective

Through numerical studies with single and multiple reservoir systems, the main differences between policies based on deterministic and stochastic approaches for long-term hydropower scheduling are presented, as well as the reasons for the better performance of deterministic nonlinear models for multi-reservoir systems.

II. Methodology

Long-term hydropower scheduling (LTHS) is formulated as a multistage stochastic nonlinear optimization model because it spans several years ahead on a monthly basis, future inflows are uncertain, and the hydropower generation and thermal cost functions are nonlinear. It is a rather complex problem for multi-reservoir systems because of the difficulty of simultaneously dealing with the uncertain and nonlinear aspects of the problem.

Stochastic Dual Dynamic Programming (SDDP) gives up the nonlinearity of the hydropower generation function by a piecewise linearization to handle the uncertainty of inflows through scenario techniques [1]. On the other hand, Model Predictive Control (MPC) [2] disregards inflow uncertainty, considering a single inflow scenario, to deal with hydropower generation nonlinearity.

III. Results

A. Single-reservoir systems

For single-reservoir LTHS, deterministic and stochastic policies can preserve the nonlinearity of the model, and therefore their comparisons can provide insights into the advantages of stochastic approaches. However, for a correct comparison, it is important to consider steady-state policies that allow simulations over the entire historical inflow record [3].

This case study considers the hydrothermal system composed of the Nova Ponte hydroelectric plant, located in the Central-West region of Brazil, and a thermal plant with the same capacity and quadratic generation cost, which meet a constant load demand. The hydro plant has effective water head of 96 m, average inflow of 294 m^3/s, and a useful storage of $10,380$ hm^3 [3].

Different steady-state operating policies were tested: Deterministic Dynamic Programming (DDP) based on average inflows, Stochastic Dynamic Programming (USDP) considering uncorrelated inflows, and Markovian Stochastic Dynamic Programming (MSDP) considering lag-1 correlation of inflows. The policies are shown in Fig. 1 for May (5) and November (11), corresponding to the beginning of the dry and wet seasons in Brazil, respectively. Other months have similar policies.

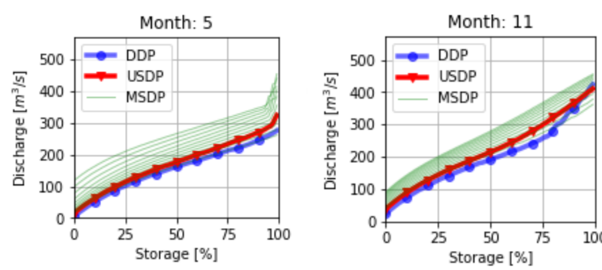

Fig. 1. Nova Ponte hydro plant DP operating policies

Fig. 2 shows the storage during the historical period from May 1951 to April 1960, which includes the sequence of the lowest historical inflows recorded since 1931. The DDP policy, being more conservative than the USDP and MSDP policies, keeps reservoir storage fuller and therefore is more efficient in critical periods of drought.

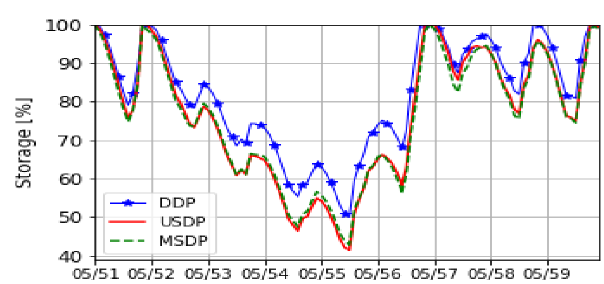

Fig. 2. Storage from May 1951 to May 1960

Table I summarizes the simulation results from May 1932 to April 2010 using the policies. The performance of MSDP is slightly better than that of USDP, which shows that the inflow correlations are not that significant. In fact, lag-1 correlations are high (around 0.9) in dry months, but low (around 0.5) in wet months so that the average correlation of inflows in Nova Ponte, weighted by the average monthly inflows, is only 0.67. The performance of DDP is only slightly lower than that of USDP, which means that the LTHS problem almost meets the Certainty Equivalence Principle.

TABLE I
AVERAGE RESULTS OF SIMULATION OVER HISTORICAL INFLOWS

Policy	**Cost** [$]	**Hydropower**[MW] Mean	Std. dev.	**Efficiency** $[MW/(m^3/s)]$	**Spillage** $[m^3/s]$
MSDP	6898	306.5	76.3	1.047	5.3
USDP	+0.6%	305.8	76.4	1.048	6.2
DDP	+0.7%	306.2	83.0	1.051	6.5

As expected from the differences in discharge policies, DDP provided the highest hydropower efficiency. However, it also provided the highest spillage, resulting in an increase of 0.7% on the expected average cost compared to MSDP.

B. Multi-reservoir systems

For multi-reservoir systems, a deterministic nonlinear policy can be implemented by MPC, a suboptimal open-loop feedback control policy where decision-making is given by the first-stage decision of the multistage deterministic nonlinear optimization model that arises from replacing random inflows with deterministic inflows based on expectations.

The MPC and SDDP policies were compared for the Base Case of the 10-year generation expansion planning of 2031, developed by EPE (Energy Planning Company of the Ministry of Mines and Energy). The simulation consists of 120 monthly stages starting on May 1st, 2021 (beginning of the dry season in Brazil), with the Brazilian Power System (BPS) in a critical situation of only 43% of stored energy. The study case considers a synthetically generated inflow scenario in which both models finished the simulation with almost the same stored energy.

Fig. 3 shows the stored energy of BPS, with MPC holding greater storage than SDDP. The average thermal generation, although higher on average (4%), is lower in standard deviation (15%), resulting in a 2.3% lower cost due to signficant savings in high-cost thermal generation.

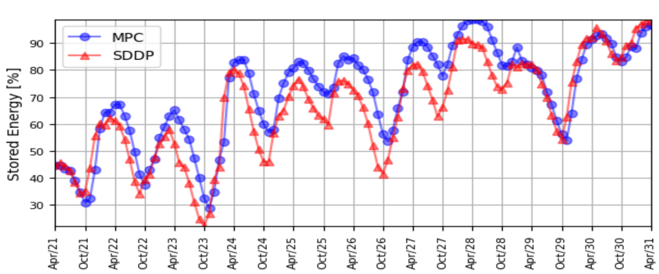

Fig. 3. Stored energy of BPS

Figs. 4-5 show the storage in the Rio Grande cascade composed of the hydro plants with accumulation reservoirs of Furnas, Marimbondo and Água Vermelha, from upstream to downstream, where MPC presents a well-defined pattern that keeps downstream reservoirs fuller, while SDDP presents greater volatility in storage at downstream reservoirs. As a result, Table II shows that MPC provides a higher average generation in the cascade, concentrated in downstream reservoirs. A similar pattern is observed in all cascades.

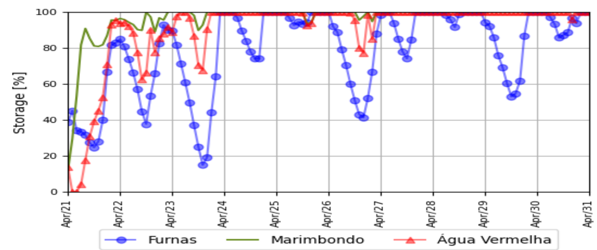

Fig. 4. Storage in the Grande river cascade according to MPC

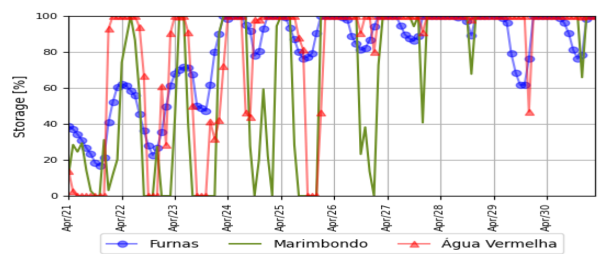

Fig. 5. Storage in the Grande river cascade according to SDDP

TABLE II
AVERAGE POWER GENERATION [MW]

	MPC	**SDDP**	**Difference**
Furnas	654	667	-13
Marimbondo	837	812	25
Água Vermelha	856	810	46
Total	2347	2289	58

IV. CONCLUSION

In single-reservoir LTHS, MSDP slightly outperforms DDP, which means that dealing with randomness and correlation of inflows does not provide a significant advantage. In multi-reservoir LTHS, MPC outperforms SDDP, which means that linearization of the hydropower generation function brings significant disadvantages to SDDP with more instable thermal generation and less efficient operating rules for cascaded reservoirs. Therefore, the benefits of accounting for the inflow randomness in SDDP do not overcome the benefits provided by nonlinear modeling of hydropower generation in MPC.

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Adaptive distributionally robust optimization for long-term hydropower scheduling

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Background

Future decarbonized power systems are expected to be tighter integrated and characterized by high levels of variable and unpredictable production from renewable energy sources. In this setting, hydropower systems will likely be developed to increase their flexibility by investing in higher installed capacity and pumping capabilities. To properly evaluate the value of hydropower flexibility, a detailed description of the hydropower assets and short-term variations, in addition to the long-term uncertainty in hydro inflows, will become more important. Planning the operation of hydropower reservoirs is typically formulated as multi-stage stochastic problems where weather-related factors are the major uncertainties[1]. These problems are traditionally solved by stochastic dynamic programming (SDP) or stochastic dual dynamic programming (SDDP). SDP is known for the “curse of dimensionality” and requires that complex hydropower systems are aggregated, thus lacking the opportunity to consider short-term flexibility in the calculation of the long-term strategy of individual reservoirs. SDDP allows for a detailed representation of hydropower but requires a convex problem formulation. Formulating the long-term hydrothermal scheduling problem as a two-stage stochastic linear problem solved in a rolling horizon using Benders’ decomposition has been proposed to mitigate these shortcomings [2]. The method is shown to be well suited to value the flexibility in the hydropower system.

However, the approaches based on stochastic programming operate under the premise that the underlying probability distributions are accurately identified, even though future scenarios themselves may be inherently uncertain. In addition, hydropower scheduling based on stochastic optimization models that focus on maximizing social welfare, may result in reservoirs being managed quite aggressively. Both aspects can result in operational strategies that are vulnerable to unexpected events in an increasingly uncertain future. To ensure the robustness of the scheduling scheme, Robust Optimization (RO) defines an uncertainty set that encompasses all uncertain variables and optimizes for the worst-case scenario within the set. Consequently, RO results could be conservative. Distributionally Robust Optimization (DRO) seeks to strike a balance between the conservative approach of RO and stochastic optimization by identifying the worst possible probability distribution within a family of distributions and performing optimization within this set called ambiguity set. Hence, DRO formulation will be more risk averse as the worst-case average cost over all distributions is minimized.

Objective

The objective of this work is to explore how a distributionally robust formulation of the long-term hydropower scheduling problem affects the long-term strategy for hydropower reservoirs.

Distributionally Robust Optimization is chosen for its ability to handle uncertainties in water inflow predictions and other relevant variables like power price dynamics. DRO does not rely on precise probability distributions; instead, it accounts for a range of potential distributions within a predefined set (ambiguity set). This approach is particularly advantageous for managing the inherent unpredictability and variability in hydropower operations, which are exacerbated by climate variability and market fluctuations.

Methodology

We build this work on the concept presented in [2], as it allows for a detailed formulation of the hydropower system, but use a distributionally robust formulation of the two-stage scenario fan problems and solve them in a rolling horizon using column-and-constraint generation. How the uncertainty in inflow is represented through different ambiguity sets will be evaluated, in addition to uncertainty in rationing price. The results from the DRO formulation are compared to the results from a stochastic formulation to demonstrate the benefits and weaknesses of our method.

Expected results

We will evaluate if adding some robustness to the hydropower scheduling problem by using DRO can improve the strategy and give more realistic operation of hydropower reservoirs. The results will include simulated power prices and reservoir trajectories for hydropower, in addition to the overall cost of operating the system.

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