Hydropower Scheduling Toolchains: Comparing Experiences in Brazil, Norway, and USA and Implications for Synergistic Research

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Abstract

While hydropower scheduling is a well-defined problem, there are institutional differences that need to be identified to promote constructive and synergistic research. We study how established toolchains of computer models are organized to assist operational hydropower scheduling in Brazil, Norway, and the United States' Colorado River System (CRS). These three systems have vast hydropower resources, with numerous, geographically widespread, and complex reservoir systems. Although the underlying objective of the hydropower scheduling is essentially the same, the systems are operated in different market contexts and with different alternative uses of water, where the stakeholders' objectives clearly differ. This in turn leads to different approaches when it comes to the scope, organization, and use of models for operational hydropower scheduling and the information flow between the models. We describe these hydropower scheduling toolchains, identify the similarities and differences, and shed light on the original ideas that motivated their creation. We then discuss the need to improve and extend the current toolchains and the opportunities to synergistic research that embrace those contextual differences.

I. Introduction

The scheduling of generation resources is a key component of the electricity industry worldwide. In systems with a significant share of hydropower with long-term reservoir storage capacity, the generation scheduling problem becomes a very complex task due to the need to coordinate reservoir storages under uncertainty in water inflows. This complexity is compounded by other uncertainties, e.g., in demand and power production from new renewable energy resources such as wind and solar generation. The integration with other markets, such as natural gas and carbon markets, and the need for risk management add additional complexity to the scheduling process. Moreover, water resources may have priority uses that conflict with hydropower generation. Consequently, an accurate and robust scheduling process requires optimization and simulation models with detailed representation of system components and uncertainties that can be solved in reasonable computational times.

There is a plethora of hydropower scheduling approaches which can be categorized as toolchains, that is, a set of integrated computer models that link the overall scheduling problem across time, space, and water and power systems. A technical description of models and toolchains applied in Brazil and Norway is provided in Helseth and Melo [1], building on previous reviews such as Fosso et al. [2] and Maceira et al. [3]. Technical reviews of models for optimizing hydropower within a power system context are well covered in recent literature, such as for hydropower coordination with other generation technologies (de Queiroz [4]), hydropower scheduling in liberalized markets (Pérez-Díaz et al. [5]) and shorter-term hydropower optimization (Kong et al. [6]).

The model review in Voisin et al. [7] defines toolchains comprising of either a water model, a power system model, or the combination of both model types. A review of climate-driven hydropower simulation using continental scale hydrology models is provided in Turner and Voisin [8]. Literature of hydropower scheduling by water models at watershed scale typically focus on the enhanced value of climate services for hydropower generation or the

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coupling with power system models (Ibanez et al. [9], Daddi et al. [10]). There is, however, little understanding of the drivers of technical choices and tradeoffs motivating the diversity in integrated water-energy modeling toolchains for operational hydropower scheduling in hydro-dominated power systems. Specifically, the operational generation scheduling problem in hydro-dominated systems involves both the establishment of long-term strategies for efficient use of water across the entire planning horizon (Pérez-Díaz et al. [5], Maceira et al. [11]) as well as the short-term unit commitment problem (Kong et al. [6], Santos et al. [12]) to satisfy the demand for electricity while meeting all relevant constraints. While Oikonomou et al. [13] elaborate on data availability, computational tradeoffs and overall modeling approaches for hydro-dominated systems, we here further posit that institutions play a critical role in the technical approach to scheduling in hydro-dominated systems and specifically the organization of the toolchain covering multiple time horizons and purposes for water use.

To address how institutions influence hydropower scheduling, we perform a comparative analysis of toolchains for multi-horizon hydropower generation scheduling in three countries: Brazil, Norway and the US. The overarching objective is to highlight the diversity in regional benchmarks for hydropower scheduling in hydro-dominated regions with the purpose to discuss research directions that embrace this diversity. For Brazil and Norway, the system considered encompasses the entire country, whereas the system considered in the US is the Colorado River System and represents around 8% of the continental US hydro generation. As shown in Table I and Fig. 1, these systems have vast hydropower resources with numerous, geographically widespread, and complex reservoir systems, some of which with multi-year storage capabilities. Specifically, these systems are operated in different market contexts, where the different stakeholders and their respective objectives differ, leading to different uses of scheduling models and different information flows between them. The institutional context is different in all three systems resulting in toolchains being developed and maintained by entities with different missions; the Brazilian Electric Energy Research Center (CEPEL), the Norwegian research institution SINTEF Energy Research (SINTEF), and two governmental agencies over the CRS, where long-term hydropower dams operations (e.g. water supply) are managed by the Bureau of Reclamation (Reclamation) and short-term hydropower operations are guided by the Western Area Power Administration (WAPA). We acknowledge that there is large diversity in toolchains in the US, which has multiple power grids with different generation portfolios and load profiles, as well as markets, and ownerships. Nonetheless, the CRS is representative of hydropower operations constraints in the US due to Western Water Laws and regulation.

TABLE I
TECHNICAL CHARACTERISTICS OF THE HYDROPOWER SYSTEM IN BRAZIL, NORWAY, AND CRS.

Characteristic	Brazil[1]	Norway[2]	CRS[3]
Installed capacity, Hydro [GW]	109	34	4
Annual generation, Hydro [TWh]	396	141	8
System demand [TWh]	540	134	*[4]
Exchange capacity with other systems [GW]	1.8	9.0	*[4]
Number of hydropower plants	168	351[5]	60

We identify the similarities and differences across those three representative international systems in terms of toolchain design and solution methodologies. Furthermore, we synthetize how institutional structures have influenced the toolchains and identify possibilities for future research.

II. Hydropower Scheduling Concepts

Power generation scheduling models applied in hydro-dominated systems normally serve several purposes, covering system studies, expansion planning studies, and the provision of valuation or targets leading to operational decision aid. We emphasize on the latter use case, describing how the scheduling problem is decomposed into separate models interacting in a toolchain supporting operational decisions. In this section we introduce the scheduling problem and the toolchain concept.

[1]For year 2020, according to EPE [14].
[2]For year 2020, according to SSB [15].
[3]For years 1950-1999 according to UWM [16].
[4]Indicates that CRS does not meet own demand, it is part of a larger system, see Fig.1.
[5]>10 MW installed capacity, according to (NVE, 2023).

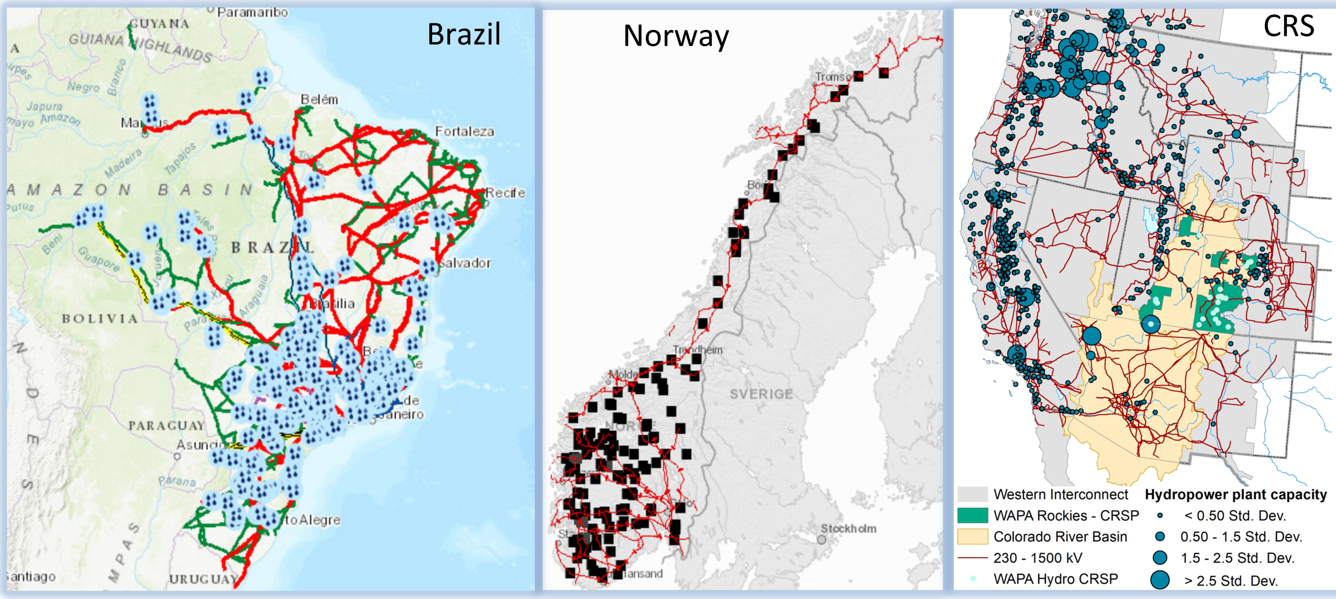

Fig. 1. Illustration of the Brazilian (left), Norwegian (middle) and CRS (right) power systems. The figures show the transmission grids. Hydropower stations are shown as blue dots for Brazil (>30 MW), black squares for Norway (>10 MW), and blue circles for CRS.

A. Scheduling Problem

As a starting point, we consider the system-level generation scheduling problem as a single optimization problem for which the objective is to:

Minimize the expected system operating costs over the planning period while meeting the electricity demand and satisfying all system constraints.

Mathematical models aimed at solving this generation scheduling problem are normally referred to as *fundamental* market models, in the sense that they allow a detailed physical representation of the market, such as supply, demand, network topology, and can reasonably replicate the inner workings of the same market. Investment decisions are not considered in the scheduling process, although new generation or transmission facilities may be specified during the horizon for the analysis. The basic group of constraints comprise those concerning the generation and transmission system, hydraulic topology, security of supply and environmental aspects. References (Maceira et al. [3]) and (Helseth et al. [17]) provide examples of how the optimization problem can be formulated in a fundamental market model.

In hydropower systems, the water itself can be seen as a cost-free resource, and the explicit variable cost of hydropower is very low. On the other hand, the current availability of water is limited, and the future availability is uncertain. Generating electricity today limits the ability to generate in the future, and therefore there is an *opportunity cost* associated with the use of hydropower. Finding the opportunity cost of water in hydropower systems is an essential part of the scheduling process. One needs a long planning horizon for the scheduling problem to capture the long-term dynamics of large hydropower storages. For the systems considered here, with multi-year storage capability, the applied planning horizon should stretch over multiple years.

There are numerous uncertainties that should and can be taken into consideration for this long planning period. For the availability of water, one needs to consider water uses and projections of water demands (flood control, water supply among other uses), climate indices and seasonal inflow forecasts, snowpack conditions, and groundwater levels. For the power system, uncertainties around the demand, availability of transmission and generation facilities, fuel and carbon prices, and variability in wind and solar power production need to be considered. The treatment of uncertainties is essential to obtain robust schedules. For the systems considered, inflow to reservoirs is the most important uncertainty to capture over the entire scheduling period, in order to balance schedules against the risks of energy (or water) deficit during dry periods and spillage during wet periods.

The scheduling problem is commonly formulated as a stochastic optimization problem for which efficient decomposition techniques can be applied. In the design of a stochastic optimization model, the granularity of the uncertainty will define the *decision stages* within the model. Uncertainties are revealed for a decision stage representing a short period of time ahead, and the decisions are taken based on this information. A central question is then: For how long can we plan into the future with a reasonable assumption that the uncertainties would not change the optimality of the plan? Fortunately, inflows to reservoirs can be predicted fairly well at a seasonal time scale in snowmelt dominated basin and at sub-monthly time scale with rainfall forecasts and hydrological models. This has led to decision stages of weeks or months for scheduling problems in hydropower systems with large reservoir capacities.

Within each decision stage, the system is challenged to serve the time-varying demand for electricity within its defined constraints. To reflect this, scheduling models may further discretize time into *time steps* within each decision stage. A time step represents a discrete period of time where all parameters are constant and can be aggregated according to load levels (as ”load blocks”) or be arranged in chronological order. The length of a time step in the variety of scheduling models considered in this report can range from a month down to a few minutes.

Variants of the solution algorithms stochastic dynamic programming (SDP) and stochastic dual dynamic programming (SDDP) are widely used in practice to solve stochastic and dynamic optimization problems that are formulated to represent the scheduling process. Both SDP and SDDP apply temporal decomposition, allowing each decision stage to be solved separately while its solution is coordinated with other decision stages through state variables. State variables carry information about the state of the system across decision stages, such as reservoir volumes at the beginning of each stage and the past inflows. A major difference between SDP and SDDP is that the latter does not discretize the state variables and is therefore better suited to represent systems with many reservoirs in a computationally efficient manner. As will be discussed in the following, the coordination between stages is often facilitated by*Benders cuts* (or just *cuts*). A cut is a linear inequality describing the future expected cost (or profit) as a function of the state variables. Cuts can be used to coordinate decision stages within dynamic programming algorithms, but also to share information between different models in a model toolchain.

B. Toolchain Concepts

The optimization problem outlined in the previous section – with the long planning horizon and the many decision stages and time steps – becomes extremely large and complex for a realistically sized system. Moreover, the detailed functional relationships in the water and power system are not always linear or not even convex, leading to the need for computationally expensive solution algorithms. The overall complexity of the problem has motivated the use of separate models for emphasizing either the long-term inflow uncertainty and reservoir dynamics or the detailed physical description of the system. As we shall see when describing the toolchains in Norway and for the CRS, the different decision makers and responsibilities have further motivated the development of separate models.

An early reference on the toolchain concept is Larson et al. [18], where principles for time-scale decomposition to schedule both multi-annual storage dynamics and short-term unit commitment decisions are discussed. Later, Pereira [19] states that *“(..) the complexities of the operations scheduling problem cannot be accommodated by a single model, and it becomes necessary to develop “chains” of models with different planning horizons and degrees of detail in system representation”*. Pereira [19] outlines a general toolchain and discusses the natural decomposition between models, the different models' time frames and level of details, and even the feedback from lower- to higher-level models to seek a global solution.

As operational scheduling is typically performed on a daily basis, the computational time allowed for solving the problem is limited. This has led to the need for scheduling toolchains that split the overall problem along the axes of time, modeling fidelity, and even system, to emphasize the long-term uncertainties and dynamics as well as the short-term details. The hydro scheduling may be an integrated part of a power system model, a water system model or both. As will be elaborated on later, Brazil and Norway integrate water and power models as part of the hydro scheduling, seeking to optimize the use of water for hydropower generation within the same modeling framework. In contrast, the hydro scheduling is separately integrated with water and power models for the CRS, where water models take a multi-purpose perspective. In all three systems it is customary to apply different models addressing different modeling fidelities and time scales.

The modeling toolchain concept has matured over time in various institutions, and it is widely accepted that one cannot establish a single model to cope with the complexities and various planning horizons of the hydropower

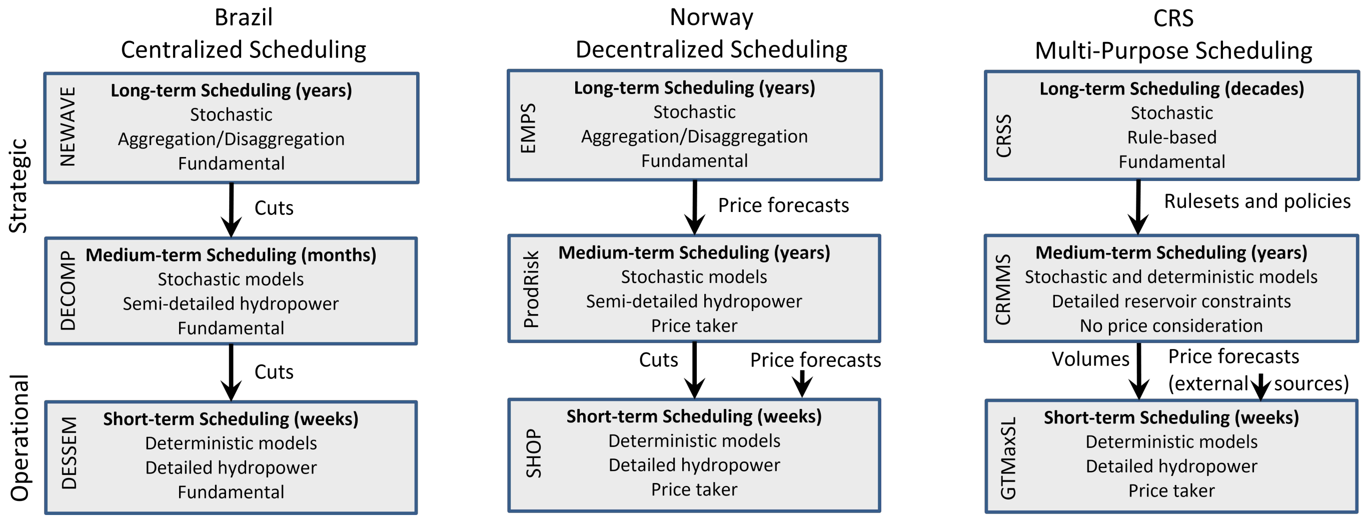

Fig. 2. Scheduling model toolchains. Models are illustrated with boxes, information flows with arrows.

operations scheduling problem. However, as we discuss in more detail below, the computational aspect is not the only reason for establishing a toolchain.

III. Diversity in Scheduling Toolchains

The different models we focus on in this paper as applied in Brazil, Norway, and in the CRS in the United States, are presented in this section. Fig. 2 summarizes the corresponding toolchains developed and maintained at CEPEL (Brazil), SINTEF (Norway) and at Argonne National Laboratory (ANL) and CADSWES-University of Colorado for the CRS. We separate between *long-term strategic* models used for finding the opportunity cost or volume targets of water and *short-term operational* models to provide decision support for the operational tasks; the medium-term models fall in between. We focus on hydropower scheduling as the interface of water and power system models and address the institutional context, before providing a brief overview of the hydropower scheduling models and toolchain from long-term to short-term operations. As indicated in Fig. 2, information flow between the models in the three toolchains is arranged by use of cuts, price forecasts, rule sets and policies, or volumes. Principles for coupling models within a toolchain are further discussed in Section V-B.

A. Brazil

1) System: The Brazilian power system covers approximately the same area as continental Europe. The interconnected grid is referred to as the National Interconnected System (SIN), comprising four interconnected subsystems. Thermal power plants play a relevant strategic role as they contribute to the reliability of the system, and the wind power capacity has grown significantly in recent years. SIN is interconnected with Argentina, Uruguay, and Paraguay.

The trading arrangements are based around a tight, centralized system optimization, scheduling and dispatch scheme. Based on the received technical data, the independent system operator (ISO) establishes a generation schedule using the toolchain described in the next section, that also calculates the water values used for determining the spot prices.

2) Toolchain Development: In 1977 Eletrobras and CEPEL completed the development of a computational model for hydrothermal coordination based on SDP, which was officially adopted for operational use in 1979. It then replaced the more heuristic rule-curve approach, marking an important step in the transition towards use of more formal optimization models in hydrothermal scheduling. The SDP-model was run every month to provide a balanced plan for use of hydropower and thermal resources to serve the system load at minimum cost. Details of the implementation and validation process are described in Terry et al. [20], highlighting the significant expected savings obtained by using the SDP model compared to the previously used rule-curve approach.

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At the end of the 1980s researchers at CEPEL developed the SDDP method, which was a significant methodological breakthrough for the long-term scheduling problem (Pereira [21], Pereira and Pinto [22]). Unlike SDP, there is no need to discretize the state variables with the SDDP method. In 1993, the SDDP algorithm was extended to account for serial correlations of the inflows to reservoirs through auto-regressive periodic models. Consequently, the SDDP method paved the way for considering multiple reservoirs in the long-term scheduling without compromising the computational complexity, leading to the development of the SDDP-based NEWAVE model in 1993. NEWAVE has later become the cornerstone of long-term scheduling in the Brazilian system. It has been used officially since 1998, associated with the institutional regulatory framework issued that year (Maceira et al. [3, 11]). Today, NEWAVE is officially adopted as the long-term strategic model in the toolchain in Fig. 2, and for expansion planning and commercialization studies. The NEWAVE model has the objective to minimize the expected operation cost for the Brazilian system over a 5 year planning horizon with monthly decision stages, considering uncertainty in inflow (Maceira and Bezerra [23]) and a risk measure (Maceira et al. [24]), exploiting parallel processing techniques (Pinto et al. [25]).

The medium-term model DECOMP takes the same system boundary and objective as NEWAVE, but with a detailed hydropower description and a planning horizon of typically a few months, where Benders cuts from the NEWAVE model provides the end-valuation of hydro storages (Diniz et al. [26]). It served as the official model for setting the spot price and to provide the weekly centralized dispatch of the Brazilian in the period 2000-2020. In this sense, DECOMP has served the role as both a medium- and short-term model. With the introduction of the shorter-term DESSEM model (Santos et al. [12]), the use of DECOMP has changed into a linkage between NEWAVE and DESSEM, as a medium-term model, as shown in Fig. 2. The overall problem formulation in DECOMP is cast as a multi-stage stochastic linear programming problem, applying a parallelized solution technique based on multi-stage Benders decomposition (dos Santos et al. [27]).

The development of the short-term DESSEM model started in 1998, triggered by the electricity sector reform project (RE-SEB) pointing to the need to evolve into a future hourly pricing scheme. DESSEM is intended for short-term operational planning of the Brazilian system with a typical horizon of one week, assuming no uncertainties, time steps of up to half an hour and with end-valuation of hydro storages by Benders cuts provided from the DECOMP model (Santos et al. [12]). The deterministic optimization problem is formulated as a mixed integer linear programming problem allowing a finer level of technical modeling than in NEWAVE and DECOMP. Since 2020 it has been used to determine the day-ahead scheduling of the system and from 2021 to establish hourly prices in Brazil.

The toolchain in Fig. 2 is used by the ISO to dispatch the hydro and thermal power plants, and for the wholesale electricity market by the market operator to calculate the electricity ”spot prices” (settlement prices for differences).

B. Norway

1) System: The Norwegian power system is a part of the Nordic synchronous system connecting Norway, Sweden, Finland and Eastern Denmark. The Norwegian system was restructured in 1991 and is part of the liberalized Nordic power market (Flatabo et al. [28]). Although the Norwegian generation is almost exclusively from hydropower, there are significant shares of wind, nuclear and conventional thermal power generation in the Nordic system. In addition, Norway can exchange power with other European countries through multiple HVDC cables. Thorough descriptions of the hydropower system and the Nordic market can be found in Hveding [29] and Wangensteen [30].

2) Toolchain Development: The initial steps for developing a computer model to solve the scheduling problem in Norway were made by Elektrisitetsforsyningens Forskningsinstitutt (EFI) in 1962 Johannesen and Nielsen [31] (EFI merged with SINTEF in 1998). The methodological approach was a variant of the SDP method from Stage and Larsson [32]. In 1965 EFI established a committee to assess the use of modern computational methods and technology to perform operational scheduling in the Norwegian system (EFI-komiteen for økonomisk drift av kraftverk [33]). Those early initiatives lead to the development of the EMPS model around 1974, initially referred to as the ”(Extended) Power Pool Model”. To cope with increased computational complexity of a large-scale interconnected system, a combination of optimization and system simulation was adopted in the EMPS model (Egeland et al. [34]), where the detailed hydropower system is treated in a rule-based approach (Flatabo et al. [35], Botnen et al. [36]). The development of the EMPS model continued as Norway restructured the system and market in 1991, with some of the more recent functionality described in Warland et al. [37], Wolfgang et al. [38], and Helseth et al. [39]. The current EMPS model typically covers the Northern-European power system with the objective to minimize system costs over a planning horizon of 3-5 years.

Although the scheduling was performed locally by the vertically integrated utilities before the restructuring, the market liberalization emphasized the perspective of a hydropower producer as a market player. In this transition, price forecasting became an essential activity for the hydropower producers (Fosso et al. [2], Haugstad and Rismark [40]). Provided a price forecast, the individual producer could now take the perspective of a profit-maximizing entity without an obligation to serve the demand. For this purpose, a new method was developed for medium-term scheduling at a regional level, treating the market price as a stochastic exogenous variable within the SDDP algorithm (Gjelsvik and Wallace [41], Gjelsvik et al. [42], Mo et al. [43]). This method is implemented in the widely used medium-term scheduling model ProdRisk (Gjelsvik et al. [44]). While the medium-term scheduling is carried out for a smaller regional system, the planning horizon is typically close to what is used in the EMPS model.

The short-term model SHOP is used to inform market bidding and provide detailed schedules respecting the physical details in the hydropower system. The main principles behind the short-term model SHOP were established in the late 1980s (Fosso and Belsnes [45]), but it has been gradually adapted to better represent physical details and adapt to market development after the restructuring (Skjelbred [46]). SHOP essentially shares the same geographical scope and objective as ProdRisk but is deterministic in the sense that market prices and inflows are assumed known for the entire planning horizon (typically 1-2 weeks). SHOP is based on successive linear programming and may include a mixed integer linear programming formulation.

The models listed for Norway in Fig. 2 are maintained by SINTEF and is widely used for operational scheduling by the hydropower producers in the Nordic market. However, as will be discussed later and opposed to the Brazilian case, use of scheduling models is not mandatory in Norway.

C. Colorado River System

1) System: The Colorado River Basin encompasses 640,000 km^2 of southwestern North America. The drainage basin area includes all of Arizona, and parts of California, Colorado, New Mexico, Nevada, Utah, and Wyoming. Hundreds of hydroelectric dams along the river's main stem and tributaries have a combined generating capacity of approximately 4 GW, which is 5% of the total US conventional hydropower capacity. The federal hydroelectric dams are operated by Reclamation and the generated power is sold and delivered by the WAPA to preferred customers. Although both organizations are federal agencies, they operate independently (Karambelkar [47]). All the CRS hydropower plants are connected to the Western Interconnection (WI) power grid. WI, together with the Eastern Interconnection and the Texas Interconnection, are the 3 major synchronous grids that power North America. These grids are not synchronized to each other and are only connected via a few HVDC interconnectors through which a relatively low amount of electricity is exchanged. Hydropower generation is the second largest energy resource of the WI, after fossil fuels, accounting for about 30% of the total generation while inter-annual variability in water availability leads to $\pm$10% in overall hydropower generation.

2) Toolchain Development: Federal projects over the Colorado River Basin are the products of many legislations over decades that set hydropower as least priority use impacting seasonal and inter-annual planning, as well as define how hydropower rates are set. As a result, hydropower in CRS long- and mid-term planning is represented by a water model. The first mention of the Colorado River Simulation System (CRSS), the long-term water scheduling model for the Colorado River Basin, dates back to 1979 (Isaacson and Fall [48]). Before the 1990's, CRS water use policies (also known as the "Law of the River") were hardcoded within the CRSS model and updating the model to conduct policy studies was a large computational task that depended on a small number of highly trained individuals. In the 1990's, the logic of the CRSS model was implemented within the RiverWare™ software and is still known as CRSS (Wheeler et al. [49]). RiverWare is a general-purpose modeling tool developed at the Center for Advanced Decision Support for Water and Environmental Systems (CADSWES) at the University of Colorado under joint sponsorship by Reclamation and the Tennessee Valley Authority (TVA) (Zagona et al. [50]). CRSS is continually updated and maintained by Reclamation's Upper and Lower Colorado Basin Regions. The Colorado River Mid-term Modeling System (CRMMS) was also implemented in RiverWare to simulate the CRS medium-term (2 to 5 years) probabilistic water projections (Woodson et al. [51]).

The CRSS model is used by Reclamation for long-term water resources adequacy planning. CRSS uses historical inflows (from 1906 to present) to calculate the probable long-term CRS conditions. Due to the effect of climate

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change on the CRS system, dryer years have been accounted for with higher probability in the more recent years. CRSS is run multiple times a year to identify combinations of reservoir operations compliant to water supply contracts and environmental policies and inform customers about hydropower delivery expectations. Customer utilities use additional resource adequacy models to infer on the potential need for generating resources (also called "alternatives"). The CRSS model contains modeling "rule sets" that control the operation of the CRS mainstream reservoirs, including Lake Powell and Lake Mead. These rule sets are consistent with official operating policies, such as the 2007 Interim Guidelines (of the Interior Washington [52]). They describe how water is released and delivered under various hydrologic conditions with an aim to reflect actual operations. For example, some of these rules inform about water release volumes based on the dams' forebay elevation level (Gastélum and Cullom [53], Yi et al. [54]).

The CRMMS model is composed of two modes: the ensemble mode and the 24-month deterministic study mode. The ensemble mode calculates several operational scenarios using different inflow forecasts (or "traces") based on historical temperature and precipitation data provided by the Colorado river basin forecast center (CRBFC). Operational scenarios are calculated based on a predefined set of operating rules for each reservoir of the CRS. The most probable trace from the ensemble mode is used to initiate the 24-month study mode which has a higher fidelity in reservoir operations. Operational decisions associated with this trace are manually adjusted by individual dam's operators to satisfy more complex operating rules that are not modeled by the ensemble mode. The resulting adjusted operational decisions of this most probable trace are the output of the 24-month study mode. Such results include monthly turbine and bypass releases and end-of-month reservoir volumes and elevations. Both the CRMMS and the CRSS models have a monthly time resolution. The CRSS model has a 5 to 20 years horizon, whereas the CRMMS model has a 2-years horizon. The CRMMS 24-month study mode is run every month and results are published online.

In the late 1980s, WAPA received a federal court order to prepare an Environmental Impact Statement (EIS) on WAPA's power marketing from the Colorado River Storage Project (CRSP), a group of hydropower plants in the CRS. WAPA CRSP Management Center worked with ANL to develop a model able to simulate the hydropower operation of the CRSP dams. The objective of this EIS was to evaluate and compare a broad set of alternative marketing schemes and operations of the CRSP dams for power production. A simulation model was required that could evaluate the effect of the alternative hourly production patterns of hydropower and water release from CRSP dams. ANL developed an initial model called Hydro LP. The model later evolved into a more sophisticated model, GTMax, that could simulate several hydropower plants simultaneously (Ploussard and Palmer [55]). ANL copyrighted the GTMax model, which is now available as a commercial tool. WAPA's CRSP office uses an alternative version of the model that has been specifically tailored for the CRSP region: the GTMax Superlite (GTMaxSL) model. The GTMaxSL model uses linear programming to optimize the hourly generation and water release schedule from the CRSP dams while satisfying several policy constraints. Today, the model is used by WAPA on a daily basis and at a 1-3 month horizon by using monthly forebay elevations and water releases from the CRMMS' 24-month study as input data.

It should be noted that, due to the time resolution of the CRSS and CRMMS model (monthly), it is difficult for these two models to explore interactions between hydropower and river ecosystem objectives (Wheeler et al. [56]). On the other hand, despite its finer time resolution (hourly), the GTMaxSL model essentially focuses on water release rates from the largest CRSP dams and ignores several other environmental metrics (water temperature, salinity, etc.).

IV. Institutions Drive the Formalism

An important difference between the three countries' practices lies in the formalism of the multi-horizon scheduling, which we categorize as centralized, decentralized, and multi-purpose in the following. The *centralized scheduling* in Brazil follows a formal approach guided by a legislative framework. The same can be said about the *multi-purpose* scheduling in CRS where "the Law of the River" must be obeyed. On the other hand, there are no formal requirements to the *decentralized scheduling* approach in Norway. Consequently, the Norwegian stakeholders can choose themselves what type of decision aid best fits their needs.

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A. The Centralized Approach

In the Brazilian centrally dispatched system, the ISO is responsible for the central system optimization and dispatch according to rules agreed by the industry and approved by the regulator (ANEEL). The ISO establishes a generation schedule describing which generation plants should be dispatched and the associated generation target by use of the toolchain described in the Section III-A. The generators submit technical data of their plants, such as water levels in the reservoirs, rate of inflow, technical availability of the turbines, fuel, and operating costs for thermal plants. The ISO takes an attitude towards the uncertainties faced in the long scheduling period, so that the objective stated in Section II-A slightly changes to:

Minimize the risk-averse system operating costs over the planning period while meeting the electricity demand and satisfying all system constraints.

This risk-aversion towards critical inflow scenarios is explicitly represented in the long- and medium-term models by use of the Conditional value at Risk measure, as described in Maceira et al. [11].

B. The Decentralized Approach

In the deregulated Norwegian system, the producer has the responsibility to schedule its own hydropower facilities and does not have an explicit obligation to cover electricity demand. The overall scheduling problem can then be reformulated and distributed to the producer in the following form:

Maximize the profit over the planning period while satisfying all relevant constraints.

In a competitive market, the typical producer is assumed to be a price-taking and risk-neutral agent, so the problem can be rephrased to:

Given a forecast of future market prices: maximize the expected profit over the planning period while satisfying all relevant constraints.

This objective is seen in the medium- and short-term models. The price-taking assumption is a necessary condition for a free market to be economically efficient and is believed to hold fairly well for the Nordic market. The price decoupling significantly reduces the spatial scope of the medium- and short-term generation scheduling models. Risk aversion is handled financially, using forward and futures markets.

C. The Multi-Purpose Approach

Hydropower facility ownership in the US is either federal, public, or private. There are also ownerships through public-private and public-federal partnerships. Three federal agencies, U.S. Army Corps of Engineers, Reclamation, and TVA are authorized by Congress to own and operate hydropower plants. In this work we described the approach used by the federal agency Reclamation to schedule water for hydropower operation in the CRS. This approach essentially differs from the two approaches described above in that water resources are prioritized among multiple purposes, where water demand is of major priority.

Minimize the cost of operating the water system over the planning period while meeting the multi-purpose demand for water and satisfying all system constraints.

Once water usage has been scheduled, the entity in charge of scheduling power generation is left with the following challenge (Flatabo et al. [57]):

Given a forecast of future market prices, local electricity demand, and water availability: maximize the economic value of excess hydropower (i.e., after meeting local demand) for the planning period while satisfying all relevant constraints.

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The water objectives dominate the long- and medium-term models. The short-term scheduling has an emphasis on hydropower within long- and medium-term constraints as well as other environmental constraints.

V. Toolchains and Formalism

As summarized in Fig. 2, we identify the general need to have different models to address the long-, medium- and short-term scheduling problems. We consider the long-term models as strategic and the short-term models as operational. The medium-term models fall somewhere in between, as explained below. The long-term models are strategic in the sense that they estimate strategies for using the water over the entire planning period. These are stochastic models where inflow is the greatest source of uncertainty. The treatment of uncertainties is important, but adds significant complexity to such models, and the tradition has therefore been to compromise on the level of detail in the system description to arrive at models with reasonable computation times. Finally, the short-term models serve to further refine the level of technical detail for a short time-period subject to less uncertainty (often deterministic), and their results are used for operational decision aid in Norway and the CRS and for dispatch and spot pricing in Brazil.

A. Toolchain Decomposition

Decomposition of the three toolchains along the spatial and temporal axes is illustrated in Fig. 3. A clear difference can be seen in the decomposition along the spatial axes. In the centralized scheduling, all models represent the whole system. This is illustrated to the left in Fig. 3, where the space dimension is kept constant and the time horizon decreases when going from long-term scheduling (LTS), via medium-term scheduling (MTS) to short-term scheduling (STS). Thus, the decomposition along the time axis from LTS via MTS to STS naturally leads to emphasis on the centrally controlled operative decisions supported by the STS model.

Under the decentralized scheduling approach, the LTS model takes a fundamental market modeling approach, whereas the MTS and STS models takes the profit maximization objective under the price taker assumption for a geographically limited part of the generation system, representing the assets operated by the producer. That is, the MTS model is decomposed in space, but not necessarily in time from the LTS model, while the STS model is decomposed in time from the MTS model. Here we assume that the MTS is done for a system including one or more large-scale hydro reservoirs. If not, the MTS scheduling horizon can be significantly shorter than the LTS horizon. Besides from splitting up the problem for computational tractability, this division also allows the producer in the decentralized scheduling to naturally emphasize on the local weather forecasts and details in its respective water course in the MTS and STS. Depending on the size and capabilities of the hydropower producers, they will either prepare price forecasts in-house or buy those from a third-party. This hierarchical division makes sense from a data perspective, allowing the producer to emphasize on its core business.

While the centralized and decentralized approaches take the view of operating the electric power system at all timescales, the multi-purpose scheduling primarily relates to operation of the water system in the LTS and MTS and the electric power system in the STS. That is, the water system constraints are evaluated first, providing input parameters to the STS model. This is illustrated by the third dimension (labelled ”Purpose”) to the right in Fig. 3. Consequently, the LTS/MTS and STS models are to a larger extent formulated as different types of models involving different expertise.

B. Coupling Principles

The three toolchains discussed above provide more or less defined formats for soft-linking the individual models, as indicated by the arrows in Fig. 2 and Fig. 3.

As discussed in Helseth and Melo [1], there are two major principles for coupling hydropower scheduling models; by *dual* or *primal* information. Benders cuts and power prices are examples of dual information that are used when coupling models in Brazil and Norway. Model linking in the Brazilian toolchain is a formalized part of the models designed by CEPEL. In the toolchain shown in Fig. 2, cuts are used to pass information from the LTS to MTS and from the MTS to STS models (Diniz et al. [26]). These cuts express the expected cost of operating the system as a

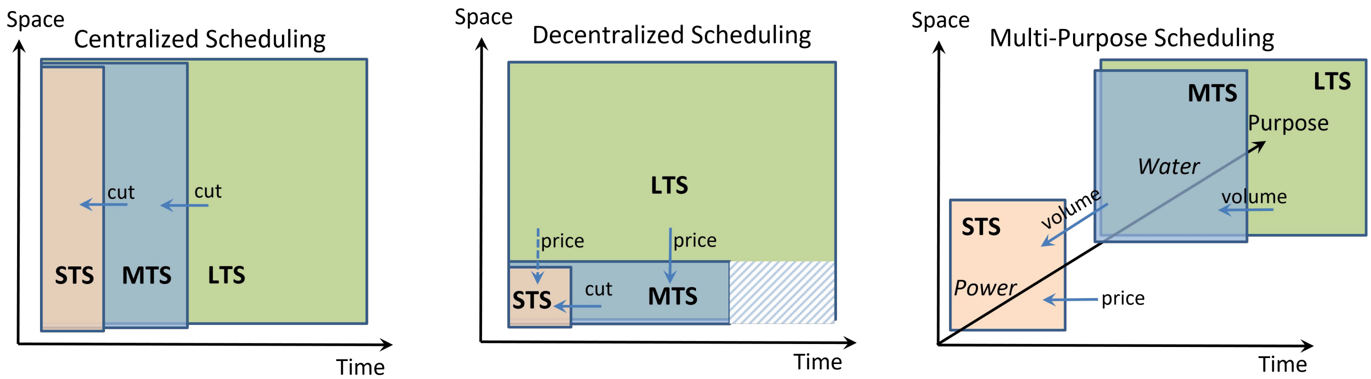

Fig. 3. Toolchain decomposition in time and space for the decentralized (left), centralized (middle), and multi-purpose (right) scheduling. Models are boxes, information flows between models are arrows.

function of the state variables, as seen from the coupling point between the models. Variables passing information between models are classified as state variables, typically being stored water (or energy) in reservoirs (or areas) as well as the trend of the stochastic variables.

Unlike the formalized Brazilian model linking, the model couplings applied by hydropower producers in Norway are subject to variations depending on the generation company. The LTS and MTS are typically coupled by power prices (Mo et al. [43]) under the assumption that the individual producer's scheduling will not impact these prices. As indicated by the stapled line in Fig. 3, the STS model needs exogenously defined power prices for the short-term planning horizon. These can be provided by the LTS model, by short-term fundamental market models (Helseth et al. [58]) or by other models or sources. The MTS and STS models may be coupled by cuts as outlined in (Gjerden et al. [59]).

In the CRS, the LTS informs both the MTS and the STS models by updating yearly/monthly water use policies based on primal information (water volumes) and identifying compliant rulesets. However, such policy updates have historically occurred only occasionally (once every few years). The coupling from the MTS model to the STS model is based on primal information, represented by water release volumes provided monthly.

It is worth noting that the information flows in all the three toolchains illustrated in Fig. 2 and Fig. 3 go from longer to shorter term models. There is no upstream feedback from the shorter to the longer-term models. If the models did all refer to the same system with a similar level of technical detail and representation of uncertainty, only differing in the length of the planning horizon, there would be no need for a feedback loop, and we would in principle not need more than one model. However, the larger the differences in modeling the system become between the three planning horizons, the more concerned one should be about the importance of having some sort of upstream feedback from the shorter-term models. Rather than explicitly defining feedback loops in Fig. 2 and Fig. 3, this can be seen as a continuous learning process, making sure that details relevant for the computation of dual and primal information are represented in the LTS and MTS models.

VI. Future Challenges

By design, we have framed the hydropower scheduling problem as an optimization problem from which the solution should support decisions related to power system operations. We highlight the role of institutions in the formalism and the propagation onto the modeling approach. In the following we discuss possibilities for further research aimed at improving and extending the current toolchains.

Variable renewable energy sources and short-term uncertainties

Over time, substantial effort has been put into improving details in the solution algorithms for the various models discussed here, facilitating more detailed model functionality at a finer time resolution. Together with improvements in computing power, operational decision making can gradually be carried out with finer precision. We expect that this development will be further triggered by the rapidly increasing shares of variable renewable energy sources (VRES), such as wind and solar power. Along with this development, the short-term variability and uncertainty associated with VRES is likely to challenge the design and algorithms applied by the current models and toolchains and request more feedback from the short- to long-term models. We see several research questions arising from the expansion of VRES:

- Given VRES short-term variability and uncertainty, to what extent do LTS and MTS models need to adopt details from the STS model to provide precise dual or primal information to the latter?
- How should one design models and toolchains that account for the uncertainty in VRES at different timescales? As an example, the joint representation of longer-term stochasticity in inflow and wind power has been investigated in long-term models such as Helseth et al. [17] and Maceira et al. [60], but the combined representation of short- and long-term uncertainties remains a challenge.
- How can the changing need for power system operating reserves and ancillary services caused by increased VRES penetration be captured within the toolchain? Recent research has emphasized on LTS (Helseth et al. [58]), MTS (Helseth et al. [61]) and STS (Aasgård [62]) models, while the coordinated treatment through the toolchain has received little attention.

Scheduling in fully renewable systems

In the longer perspective, assuming a gradual phase-out of thermal generation, one can foresee a 100% renewable electricity system (Hansen et al. [63]). As a renewable generation technology, the flexibility provided by hydropower will be strongly needed in the transition towards a decarbonized power system (Botterud et al. [64]). In this context, new flexible technologies, e.g., related to demand response, batteries, integrated energy systems, and controllability of VRES will have impact on the opportunity costs of water. As the attributes of these flexible technologies differ from conventional thermal power plants, the methodologies in the current toolchains should be re-evaluated.

Algorithmic improvements

The models covered in this work are mainly based on optimization, but also involve simulation techniques and heuristics. While the applied algorithms are mature, we observe a development over time towards embedding more technical details and finer time-resolution. The corresponding increases in model sizes have been balanced with the improvements in computational power, to meet the requirements for maximum allowed execution times that typically follow tools for operational decision support. We expect the trend towards more detailed models to continue in the future, possibly amplified by the massive integration of VRES. Accurate representation of technical details may prove more important in LTS and MTS models but would significantly add to computation time. Thus, there will be a need for new or improved methodologies to accommodate increased model complexity. A possible direction for further research lies in improving existing algorithms, such as the stochastic dual dynamic integer programming (SDDiP) to handle nonconvexities in long- and medium-term scheduling models (Hjelmeland et al. [65]). Another direction goes towards reducing model complexity by new algorithms for system aggregation (Blom et al. [66]). Moreover, new directions need to be explored, embracing emerging technologies such as graphics processing units and quantum computers. Another new direction is the application of artificial intelligence and machine learning for hydropower scheduling, which has seen recent exploration (Riemer-Sorensen and Rosenlund [67]).

Environmental changes

Drivers of future hydropower scheduling include projection of future inflows, changes in water demand from land use change, urbanization, agriculture modernization and environmental regulation, alleviating extreme events such as flood and droughts. Hydropower scheduling must reflect the governance across stakeholders' interest, which in turn influences the formalism and constraints. Some examples:

- In Norway, the implementation of the EU Water Framework Directive and revisions of hydropower concessions will result in new types of environmental constraints that need to be respected in the hydropower scheduling (Schäffer et al. [68], Helseth et al. [69]).
- Since 2013 the Northeast and part of the Southeast Brazilian regions have experienced a long drought period, whereas the South region experienced a long wet period. These new climatic trends triggered improvements in the Brazilian LTS model (Treistman et al. [70]).

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- The impact of climate change on the water availability of the Colorado River is evaluated every 5 years by the Bureau of Reclamation looking at the entire river basin and the impact on the diverse water users (Reclamation [71]). The impact of climate change specifically on the CRS federal hydropower is also assessed every 5 years by the US Department of Energy looking at future hydropower generation (Kao et al. [72]). While climate change is important for long-term planning, on-going long-term drought is affecting not just the generation but also the operational capacity that is much needed for the integration of renewable energies. Work is underway to enhance decision making under uncertainties toward addressing water resources adequacy (Smith et al. [73]) which will spill over onto electricity resource adequacy studies (Cohen et al. [74]).

Data

There is a potential for harmonizing efforts to improve hydropower scheduling algorithms, models, and toolchains. Traditionally, new methodologies are verified on specific systems for which data are not open to the scientific community. This practice prevents full transparency and complicates validation and benchmarking without proper data access.

Making data openly available will benefit researchers and practitioners targeting a specific system, but also across systems. While some types of data are sensitive from a market or system security point of view, others can be made openly available. Open data representing the complete physical systems as well as fictitious test cases, such as in Diniz [75], are useful in this sense.

VII. Conclusions

We review three applied toolchains in the countries Brazil and Norway and for the Colorado River System in the United States. The historical line of development shows that the establishment and adoption of computer models and toolchains to inform operational decisions in hydro-dominated power systems is a lengthy process. We find that the institutions drive the formalism of the multi-horizon hydropower scheduling problem, and that toolchains represent this formalism.

Specifically, we identify the following formalisms for the hydropower scheduling toolchains. In the centralized approach used in Brazil, the applied models, and the couplings between them are officially defined, and the objective and system boundary are kept constant across timescales. In contrast, the scheduling of hydropower resources is essentially the responsibility of the producer in the decentralized approach used in Norway, with no explicit formalism on model use. Finally, in the multipurpose approach applied in the Colorado River System, sectoral models are used for specific horizons as water and electricity resources adequacy remain connected in policies but disconnected in operations.

Those formalisms are most often not brought forward in the literature when exploring advances in decision-making under uncertainties, reducing the ability for technical collaboration across countries and system operators. Despite the different formalisms, we identified common paths for future collaboration across toolchains specifically in the treatment of increased shares of VRES, environmental challenges, and finally related to improvements in the exploitation of data and computational performance of models, workflows, and toolchains.

As part of energy transitions and the evolving contribution of hydropower to power system operations, we note that different research directions are needed for different systems, ranging from potential to challenge the entire toolchain if institutions change drastically impacting the whole formalism, to new coupling approaches and computational tradeoffs associated with water availability and computational tractability.

This is a first paper that articulates the contribution of institutions in the formalism of hydropower scheduling across countries. This demonstration is critical in acknowledging that evolving hydropower contribution to the transforming power system will not be solely the product of technological innovation but also the fruit of institutional support. Another contribution of this study is therefore a call to the hydropower community to acknowledge the institutional context when presenting technological innovation and facilitate international collaboration.

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