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# Report

## Scheduling Toolchains in Hydro-Dominated Systems

Evolution, Current Status and Future Challenges for Norway and Brazil


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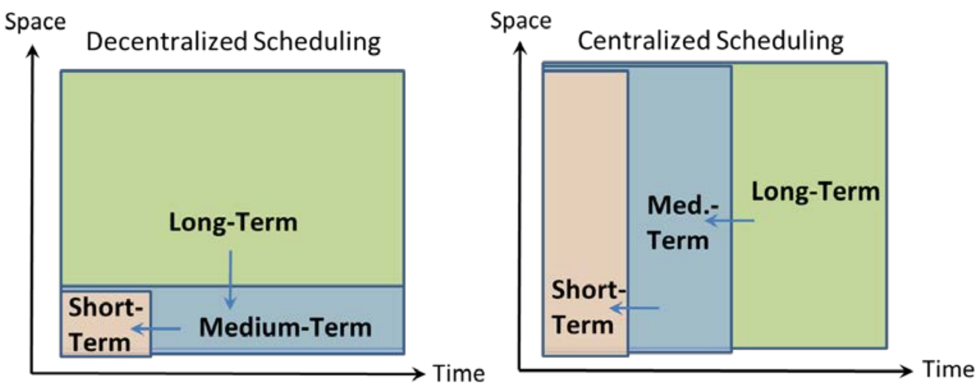



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**ABSTRACT**
This report elaborates on the toolchains applied for generation scheduling in the two countries Norway and Brazil. Both countries have vast hydropower resources, with numerous geographically widespread and complex reservoir systems. Although the underlying objective of the scheduling is essentially the same, the systems are operated in different market contexts, where the different stakeholders' objectives clearly differ. This in turn leads to different uses of the scheduling models and information flow between the models.

We review the main operational scheduling models and their overarching toolchains developed and maintained by the two research institutions SINTEF Energy Research and the Brazilian Electric Energy Research Centre (CEPEL). We identify the similarities and differences and try to shed light on the original ideas that motivated the creation of the models and toolchains. We also discuss the current state of these models and how they are being developed through R&D. With the great changes both two systems are expected to see in the future, we discuss the need to improve and extend the current toolchains.

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# 1 Introduction

## 1.1 Scope and Basic Terminology

The scheduling of generation resources is a key component of the electricity industry all over the world. In hydro-dominated systems, the generation scheduling problem becomes a very complex task due to the need to coordinate reservoir storages under uncertainty in inflow. This complexity is compounded by other uncertainties, e.g., in demand and power production from new renewable resources such as wind and solar generation. Moreover, the integration with other markets, such as natural gas and carbon markets, and the need for risk management adds additional complexity to the scheduling process. Consequently, an accurate and robust scheduling process requires detailed modelling of system components and uncertainties in optimization and simulation models that run in reasonable computational times.

This report concerns the field of operational generation scheduling in hydropower dominated systems. By ***operational*** we refer to the sequence of plans and strategies that are made leading to the actual operation of the system. By ***generation scheduling*** we here refer to the utilization of available generation resources in a system to satisfy the demand for electricity while meeting all relevant constraints. Thus, the generation scheduling problem in hydro-dominated systems involves both the establishment of long-term strategies for efficient use of water in the entire planning horizon as well as the short-term unit commitment problem.

This report elaborates on the approaches for generation scheduling in the two countries Norway and Brazil. Both the Norwegian and the Brazilian systems have vast hydropower resources, with numerous geographically widespread and complex reservoir systems, some of which with reservoirs having multi-year regulation capabilities. As we will explain later, the underlying objective of the scheduling is essentially the same for the two systems; to minimize the operational costs while meeting demands and satisfying all relevant constraints. On the other hand, the systems are operated in different market contexts, where the different stakeholders and their respective objectives clearly differ, leading to different uses of the models and information flow between the models.

We review the different scheduling ***models*** and their respective model ***toolchains***[1] developed and maintained by the two research institutions SINTEF Energy Research and the Brazilian Electric Energy Research Center (CEPEL). These models are, among other tasks, used for operative scheduling in both systems. We identify the similarities and differences in terms of toolchain design, solution methodologies and modelling details. Our aim is to represent "the whole picture", not just model by model. Another aim is to cover some of the history of the models, to shed light on the original ideas that motivated the creation of the models and toolchains, and the mechanisms facilitating phase-in of new models in the industry. The collected references can serve as a good starting point for further digging into the details.

Finally, we discuss the current state of these models and how they are being developed through R&D. With the great changes both of the two systems are expected to see in the future, we discuss the need to improve and extend the current toolchains.

[1] With *toolchain*, we refer to a set of computational models used to solve the task, and the information flow between them.

## 1.2 The Scheduling Problem

As a starting point we consider the generation scheduling problem as a single optimization problem, where the objective is to:

"*Minimize the expected*[2] *cost of operating the system over the planning period while meeting the demand for electricity and satisfying all system constraints.*"

Investment decisions are not taken into account in the scheduling process, although new generation or transmission facilities may be specified in the course of the horizon for the analysis.

The most important constraints can be generally stated as:

- Generation system constraints
- Transmission system constraints
- Security constraints
- Environmental constraints
- Hydraulic constraints

Depending on the organization of the electricity market, the "owner" of this problem will be more or less clearly defined. In the cases of Norway and Brazil, the market structures and problem owners are discussed in Section 1.2.1 and 1.2.2, respectively.

In hydropower systems, the water itself can be seen as a 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 one kWh today limits the ability to generate electricity in the future, and therefore there is an *opportunity cost* associated with the use of hydropower. Finding this opportunity cost is an essential part of the hydropower scheduling process. Methodologies for finding the opportunity costs are briefly discussed throughout this report, for an in-depth a historical recap on early methodological development the text in [1] is recommended.

The opportunity cost for hydropower is derived from all other costs for operating the system. Traditionally, these "other costs" have been dominated by the use of thermal plants[3] which are often assumed to have a fixed marginal cost. The balanced use of hydropower (negligible marginal cost, but limited and highly uncertain availability) and thermal power (fixed marginal cost, unlimited availability and low uncertainty in both marginal cost and availability) has traditionally been termed *hydrothermal* scheduling. In this report we will stick with the term *hydropower* scheduling to cover all aspects[4] of the scheduling.

One needs a sufficiently long planning horizon for the scheduling problem to capture the long-term dynamics of the largest hydropower storages. A measure for storage capability is the degree of regulation (DOR), expressed as the ratio between the reservoir capacity and the average annual inflow. In the case of Brazil and Norway the DOR for some of the largest reservoirs is multiple years. For such large-scale systems with multi-year storage capability the applied scheduling horizon should also stretch over multiple years. There are numerous uncertainties that should and can be taken into consideration for this long planning period, e.g., inflows to reservoirs, temperature-dependent demand, fuel and carbon prices, snow storage and wind and solar power. The treatment of uncertainties is essential to obtain robust schedules. The inflow to the

[2] Risk-aversion is applied in the Brazilian toolchain, as will be explained later.
[3] In this report the term *thermal plants* is loosely used to refer to plants fueled by coal, gas, nuclear, etc.
[4] From system-wide to self-scheduling and from long- to short-term.

reservoirs is the most important uncertainty to capture over the entire scheduling period, in order to balance schedules against the risks of energy deficit (dry periods) and water spillage (wet periods).

In the design of a scheduling model (or toolchain) to solve the scheduling problem, the granularity of the uncertainty will define the basic time resolution, or *decision stages*, within the model. The standard practice within the hydropower scheduling is to formulate the dynamic problem of type "hazard-decision", meaning that the uncertainties are revealed for 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 assuming that everything is perfectly known? Fortunately, inflows to reservoirs can be predicted fairly well for shorter time periods by use of rainfall forecasts and hydrological models. This has lead to decision stages of weeks or months.

Within each decision stage, the system will be challenged to serve the time-varying demand for electricity within its defined constraints. Thus, the granularity of the model should be refined to *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 level (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 few load blocks within the week down to minutes.

Returning to our initial problem formulation at the top of this section, it is clear that the optimization problem – with the long planning horizon and the many decision stages and time steps – becomes extremely large and complex for a realistically sized system. As operational scheduling typically is performed on a daily basis, the computational time allowed for solving the problem is limited. This has led to the need for a scheduling toolchain that split up the overall problem along the time axis to emphasize both on the long-term uncertainties and dynamics as well as the short-term details. The toolchain design and its use and users will be discussed throughout the report.

### 1.2.1 The Decentralized Approach in Norway

In the deregulated Norwegian system, the generation scheduling problem is owned by the producer. That is, the producer has the responsibility of generation scheduling of its own hydropower facilities. The 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*."

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. It also significantly simplifies the generation scheduling models.

The two major uncertainties are the inflows and the market price(s). As discussed in [2], there are several ways of obtaining a price forecast to be used in the hydropower scheduling. The preferred solution by many producers in the Nordic market is to use a fundamental[5] market model that simulates the price formation. Such market models typically take the cost-minimizing scope of the central dispatch models. The models are either run by the producer itself or by a third-party. The scheduling of hydropower resources is an integral part of such market models [3].

The constraints in the scheduling problem are tied to the power system and watercourse in which the producer operates its facilities. As will be discussed later on, the producer is not obliged to cover a specific part of the load in the system. Thus, the scope and size of the optimization problem is significantly reduced compared to the problem we defined in Section 1.2. Once a price forecast has been obtained, the producer should trust that the other player's planning is properly reflected in the forecast, and perform its scheduling focusing on the details of the local problem. In case the producer owns generation capacity based on other technologies (thermal, wind, etc.), these can in principle be scheduled separately from the hydropower. Similarly, watercourses that are not hydrologically connected can be scheduled separately.

In addition to the producer, several other agents benefit from hydropower scheduling models to support or monitor the market, some of these are listed below.

The **transmission system operator (TSO)** Statnett has the responsibility for operating the system securely, to continuously maintain the balance between supply and demand in the system. Statnett also has the responsibility for developing instruments for dealing with critical situations in the power system. A possible critical situation is abnormal hydrological situations, such as critically low reservoirs with a high risk of rationing. Consequently, the TSO needs to monitor the system state and also perform prognosis for the future on a regular basis. In addition, the Norwegian TSO computes marginal loss tariffs for transmission grid busbars on a weekly basis. These marginal loss tariffs constitute a component in the final price signals seen by market participants. Fundamental market models with detailed representation of the hydropower system are used to assist the above-mentioned purposes.

The **regulator** NVE performs hydropower scheduling at different levels (system-wide and local) to meet its tasks and responsibilities. In the operative environment, the regulator monitors the power system and market outcomes and has the responsibility for rationing if critical situations should occur.

More details on the market, the bid-based approach and the role of the TSO are presented in Section 2.

### 1.2.2 The Centralized Dispatch in Brazil

In the Brazilian centrally dispatched system, the operational scheduling problem is with the system operator. The Brazilian **independent system operator (ISO)** ONS is responsible for the central system optimization and dispatch according to rules agreed by the industry and approved by the **regulator** ANEEL [4]. In addition, the **market operator** (CCEE) is in charge of setting the spot prices in the short-term market.

The optimization problem becomes the same as defined in Section 1.2. The ISO can take an attitude towards the many uncertainties faced in the long scheduling period, so that the objective slightly changes to:

"*Minimize the risk-averse cost of operating the system over the planning period while meeting the demand for electricity and satisfying all system constraints.*"

[5] By *fundamental* models we refer to models that allow detailed representation of the market, such as supply, demand, network topology, and are able to reasonably replicate the inner workings of the same market.

The settlement of the electricity traded in the short-term market is carried out by Electrical Energy Commercialization Chamber (CCEE). The associated spot prices are based on the operation marginal costs calculated by the scheduling toolchain. 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. Currently there are four spot price zones (“submarkets”) and transmission loss allocation factors are used to compute the final price inside each submarket.

The monitoring of system supply security is carried out by the Ministry of Mines and Energy (MME) though the Brazilian Monitoring Committee of the Electrical Sector (CMSE) in accordance with reliability requirements defined by the Brazilian Energy Policy Council (CNPE). More details on the market structure, dispatch and spot prices setting approaches are presented in Section 3).

## 1.3 The Concept of a Toolchain

It is widely accepted that one cannot establish a single model to cope with the complexities and planning horizon of the hydropower operations scheduling problem [2] [4]. Thus, it has been become necessary to develop "chains" of models with different planning horizons and degrees of detail in system representation.

The scheduling models are normally part of a toolchain comprising long- medium- and short-term scheduling models and the coupling between those. This is illustrated in in Figure 1, and the details of this figure will be gradually discussed throughout this report. The modelling toolchain and its terminology is strongly incorporated in the system operation of the centrally planned Brazilian system and by the market players in the liberalized Nordic power market. That is, the concept of a toolchain is well understood and tested over a significant period of time by the relevant stakeholders in the two markets.

An important difference between the two countries practices lies in the formalism of the scheduling. The "centralized scheduling" in Brazil follows a formal approach guided by a legislative framework. On the other hand, there are no formal requirements to the "decentralized scheduling" approach in Norway. Consequently, the stakeholders can choose themselves what type of decision aid best fits their needs.

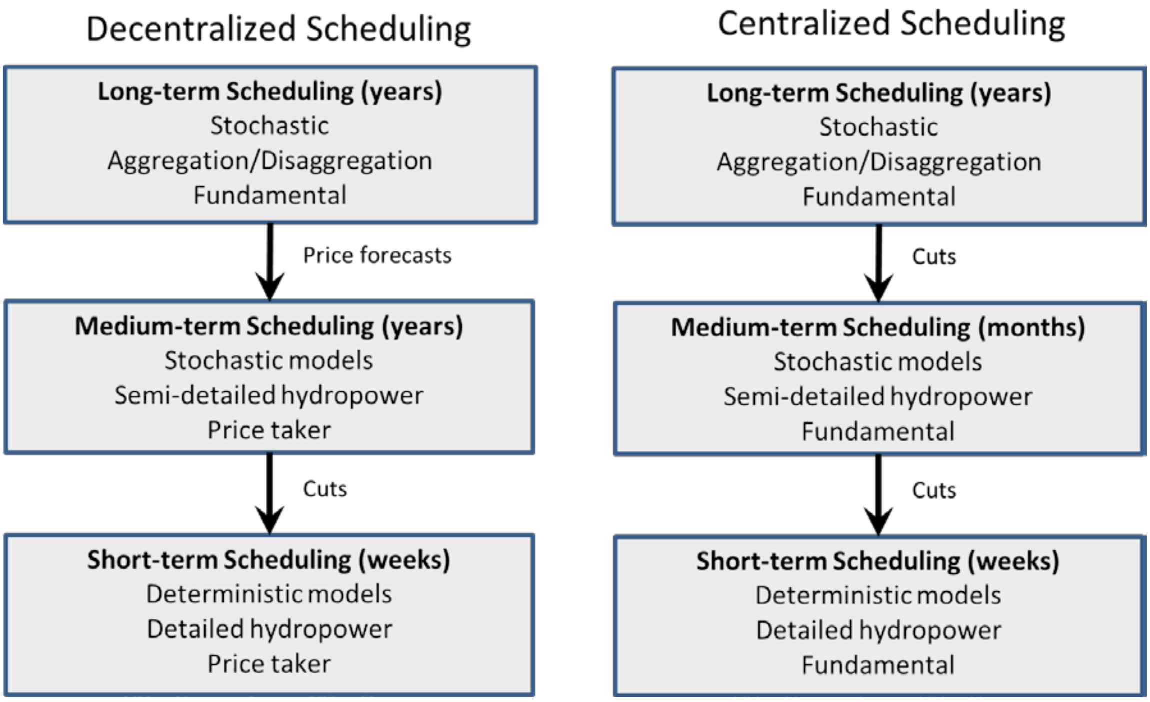


**Figure 1 Scheduling model toolchains for the decentralized (left) and centralized (right) systems. Models are illustrated with boxes, information flows with arrows.**

Realizing that the planning horizon needs to be long enough to account for the storage dynamics of the largest hydropower reservoirs, the concepts of *long-term strategic* and *short-term operational* planning has been separated. In this context we can consider the long-term models as strategic and the short-term models as operational. The medium-term models fall somewhere in between, this is different in Norway and Brazil, as explained below. The long-term strategic models serve to estimate strategies for using the water in the entire planning period. These are stochastic models where uncertainties in inflows and exogenous market prices are represented. 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 for dispatch and spot pricing in Brazil.

A clear difference between the two toolchains in Figure 1 is the geographical system boundary for the different models. In the centralized scheduling, all models represent the whole system. This is illustrated to the right in Figure 2, where the space dimension is kept constant and the time dimension 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 the emphasis on the operative decisions made by the latter model.  In the decentralized scheduling, the LTS model takes a fundamental market modelling approach, whereas the MTS and STS models takes the profit maximization objective for a geographically limited part of the generation system. That is, the MTS model is decomposed in space, but not in time[6] from the LTS model. The STS model is decomposed in time from the MTS.

[6] Here we assume that the MTS is done for a system comprising reservoirs with high DOR. If not, the MTS scheduling horizon can be significantly shorter than the LTS horizon.

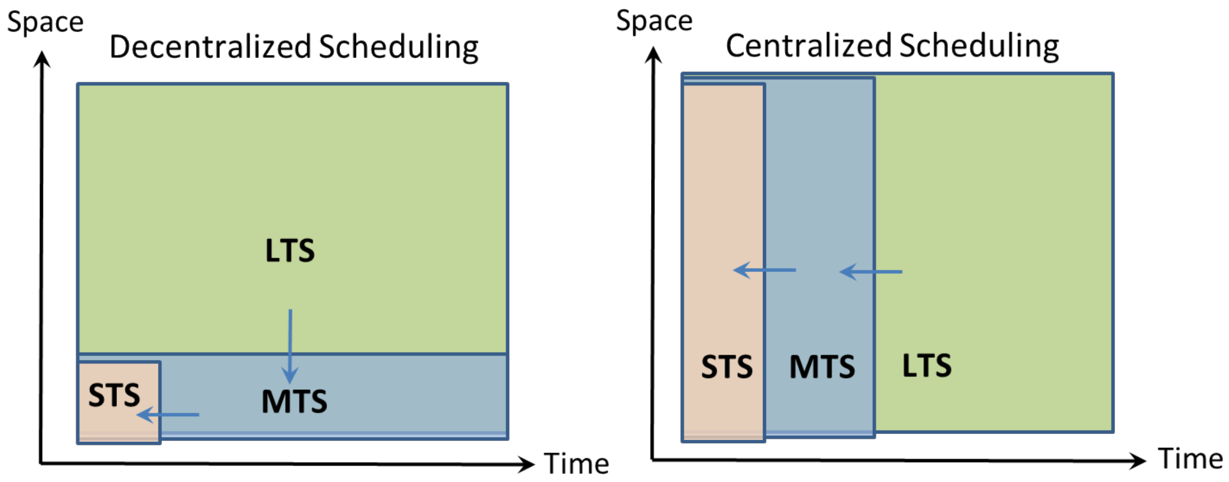


**Figure 2 Toolchains decomposition in time and space for the decentralized (left) and centralized (right) scheduling. Models are boxes, information flows are arrows.**

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. This hierarchical division makes sense from a data perspective, allowing the producer to emphasize on its core business.

The models need to be coupled to transfer information about the *system state* between them. This is indicated by the arrows in Figure 1 and Figure 2. In this context, the system state should comprise the decision variables or stochastic variables whose current decisions or outcomes impact the future system operation. Typically reservoir levels and the hydrological trend are treated as state variables, but others are also relevant, as will be discussed later.

It is worth noting that the information flow in both toolchains illustrated in Figure 1 goes 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, there would be no need for a feedback loop, and we would not need more than one model. However, the larger the differences in modelling the system become, the more concerned one should be about the importance of having some sort of upstream feedback from the shorter-term models. Model calibration through repeated runs of the toolchain can be considered an implicit upstream feedback which is not accounted for in Figure 2.

There are several possible principles for coupling scheduling models, e.g., through:

- Cuts[7]
- Prices
- Volumes
- Penalty functions
- Trust regions

[7] Cuts express the functional relationship between the stored water (or energy) in the reservoirs and the cost of operating the system, seen from the end of the planning horizon. Often referred to as Benders Cuts.

According to theory, the two first[8] (cuts and prices) provide the most economically efficient coupling principles. The three latter are in many cases overly conservative and/or inflexible and require a fair amount of problem tuning to provide satisfactory results. As indicated in Figure 1, the toolchains used in Brazil exclusively couple models by use of cuts. The coupling between models in the Brazilian toolchain is a formalized part of the models designed by CEPEL. In Norway, the coupling between LTS and MTS is by prices, due to the decomposition in space and not necessarily in time as shown in Figure 2. The MTM to STS coupling is normally guided by cuts. However, unlike the formalized Brazilian model couplings, the model couplings applied by hydropower producers in Norway are subject to variations.

[8] One can argue that the coupling by cuts is a type of price coupling. A separation is done here to clearly distinguish between prices as point estimates and cuts as hyperplanes (or linear constraints).

## 2 The Case of Norway

In the following we describe the basic properties of the Norwegian (and Nordic) power system, the market context, as well as the models and modelling toolchain provided by SINTEF Energy Research.

### 2.1 System Characteristics

The Norwegian power system is a part of the Nordic synchronous system connecting Norway, Sweden, Finland and Eastern Denmark. The electricity generation and demand in these countries for the year 2017 are shown in Table 1.

**Table 1 Electricity generation and demand for 2017 in the Nordic countries, in TWh.**

| | NORWAY[9] | SWEDEN[10] | DENMARK[11] | FINLAND[12] |
|---|---|---|---|---|
| HYDRO | 143 | 64 | 0 | 14 |
| THERMAL | 3 | 15 | 14 | 24 |
| NUCLEAR | 0 | 63 | 0 | 22 |
| WIND | 3 | 17 | 15 | 5 |
| DEMAND | 134 | 172 | 31 | 86 |

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 HVDC cables, as illustrated in Figure 3.

**Figure 3 Norway and its electrical connections to other countries, AC (red), existing HVDC (orange), HVDC under construction (green), HVDC currently under consideration (green stapled).**

[9] https://www.ssb.no/en/energi-og-industri/statistikker/elektrisitet/aar
[10] https://www.scb.se/en/finding-statistics/statistics-by-subject-area/energy/energy-supply-and-use/annual-energy-statistics-electricity-gas-and-district-heating/pong/tables-and-graphs/electricity-supply-and-use-gwh/
[11] https://www.nordicenergy.org/figure/nordic-electricity-generation-and-trade-2017/
[12] https://www.stat.fi/til/salatuo/2017/salatuo_2017_2018-11-01_tie_001_en.html

The total exchange capacity with neighboring countries is shown in Table 2. In addition to the 6020 MW that are operative today, the two cables towards UK and Germany will increase the total exchange capacity to 8820 MW. Yet another cable between Norway and Scotland is currently under consideration, as illustrated by the stapled green line in Figure 3.

**Table 2 Maximum exchange capacity between Norway and neighboring countries.**

| COUNTRY | MAXIMUM CAPACITY [MW] | TYPE | OPERATIVE |
|---|---|---|---|
| **SWEDEN** | 3500 | AC | Yes |
| **FINLAND** | 120 | AC | Yes |
| **DENMARK** | 1700 | DC | Yes |
| **NETHERLANDS** | 700 | DC | Yes |
| **UK** | 1400 | DC | Under construction |
| **GERMANY** | 1400 | DC | Under construction |
| **SUM** | **8820** | | |

Figure 4 shows the weekly accumulated inflow and demand for Norway[13] in TWh. The inflow is presented as average (solid-drawn line) and maximum/minimum registered values (stapled lines) whereas the demand is average values.

## 2.2 The Norwegian Hydro System

A brief description of the Norwegian hydropower system is presented in the following. For more details, the book [5] is recommended.

The Norwegian hydropower resources are spread over the entire country with the highest concentration in the (south) western part of the country. The large hydro systems that represent the major share of the total hydro generation capacity get their inflow from catchments at a medium or high elevation, typically from 400 meter and higher. In such areas, precipitation comes as snow in winter. The typical pattern is therefore that inflow is low during the winter, starting in November or December, depending on the actual elevation and latitude. A snow reservoir builds up during the winter. This starts melting from April to May, and melting may continue well into July for the highest elevations. During the snow melting, inflows are very high. The average values in May can be 10 times the average values in February and March, with the possibility of considerably higher extremes.

Demand is highest during the winter, due to low outdoor temperatures and high shares of electricity-based space heating. Thus, the load is peaking when the inflow is low and vice versa, as shown in Figure 4, so there is clearly a need to store the inflow for periods with high demand.

[13] The data are derived/extracted from a bit dated EMPS dataset representing Norway.

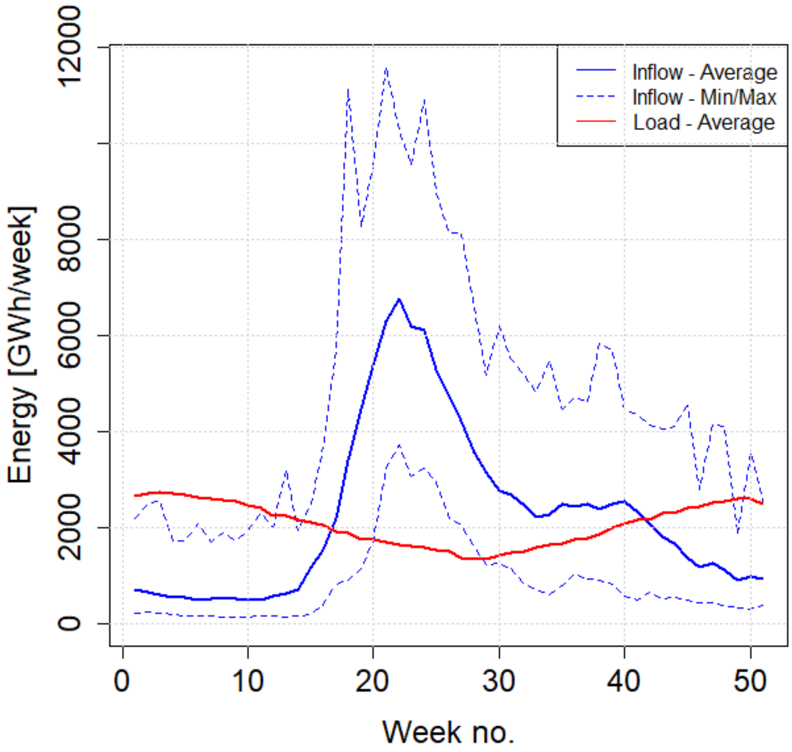


**Figure 4 Inflow (average, minimum and maximum) versus demand in Norway. All values are in GWh/week.**

There are more than 1000 reservoirs used for hydropower purposes in Norway with a total storage capacity of more than 86.5 TWh. These ranges from multi-annual storages to small lakes or ponds that can be emptied within the day. The Blåsjø reservoir is the largest with its 3105 $Mm^3$ (7.8 TWh) located 1050 m above sea level.

Figure 5 shows the reservoir volumes and regulation degrees for all reservoirs exceeding 10 $Mm^3$ in the Nordic system. The data are extracted from an up-to date EMPS[14] dataset of the Nordic system.

[14] EMPS is an acronym for "EFI's Multi-area Power-market Simulator", see https://www.sintef.no/en/software/emps-multi-area-power-market-simulator/

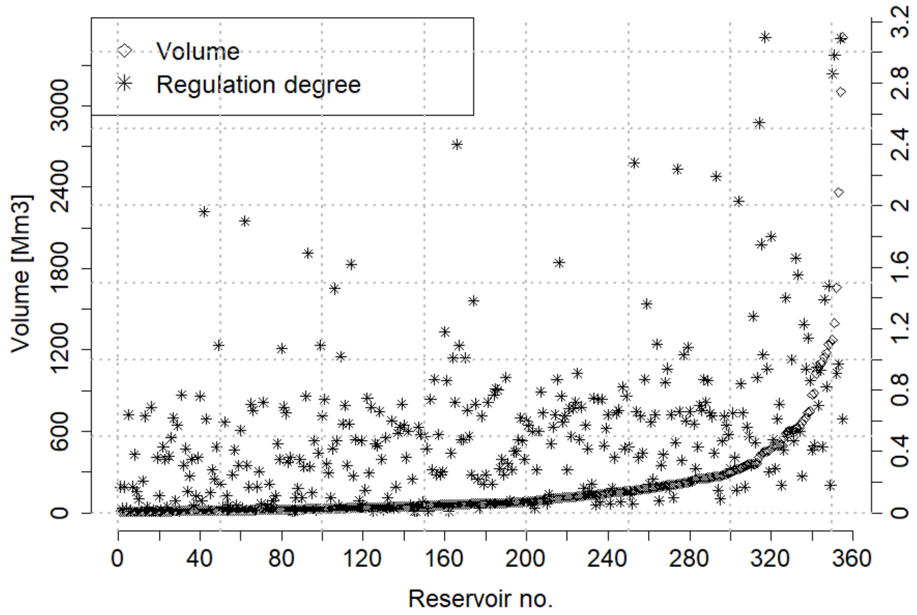


**Figure 5 Volume and regulation degree for reservoirs larger than 10 Mm3. The data are sorted based on volume, in increasing order. The corresponding DOR is plotted, referring to the right axis.**

Figure 6 shows the nominal head[15] for the registered hydropower plants in that same dataset. Most larger hydropower reservoirs are located at a medium to high elevation, releasing water to much lower altitudes. The nominal head is often quite large compared to the head variations. Approximately 2/3 of the reservoirs considered in Figure 5 and Figure 6 allow the reservoir level to vary less than 10 % of the nominal head.

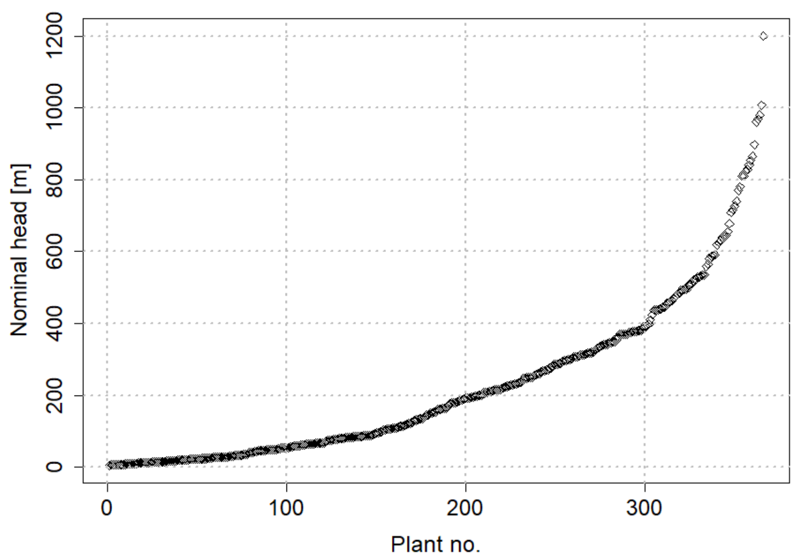


**Figure 6 Nominal head (in meters) for hydropower plants in the Nordic systems.**

[15] The nominal head is the head for which the turbines within the plant are commissioned.

## 2.3 Market Structure

The restructuring of the power system was introduced in Norway with the Energy Act in June 1990, being effective from January 1991. The basic organizational structure was established in 1992, and since then Norway had an open electricity market. This market was joined in later years by Sweden, Finland, Denmark and the Baltic countries to form what is today known as the Nord Pool market.

Today the ten largest producers account for about 70 % of the total production capacity in the Norwegian hydropower system. About 35 % of production capacity is owned by the state through Statkraft[16]. Other large and medium-sized Norwegian hydropower producers are primarily owned by counties or local municipalities.

In the following we describe the market structure before and after the restructuring that took place in the early 1990s. Focus is on hydropower scheduling and how the objectives and the major information flows have changed.

### 2.3.1 Before Restructuring

Prior to the restructuring Norway had for a long time practised a decentralized organizational structure where electricity to a large extent was produced and distributed by regional utilities. Just before the restructuring there were about 70 power generation companies and 200 distribution companies, many of them co-existing within local or regional *utilities*. These utilities were typically owned by the local municipalities. The distribution companies served as "retailers" being responsible to sell electricity to the consumers, and therefore being responsible for the local power balance. They bought this electricity from their local "wholesale" company, typically belonging to the same utility.

Statkraft was at that time responsible for 1/3 of the generating capacity and 70% of the transmission capacity. The regional utilities bought power from Statkraft and produced their own power to serve their demand obligations.

From a national system perspective, hydropower should be used in an optimal way taking into account aspects such as grid bottlenecks and exchange with neighbouring countries. It was also important to consider the forecasted demand and the risk of demand curtailment.

Already in 1971 there was a power exchange for spot power (named "Samkjøringen"), covering 4 regions in Norway. Statkraft had a legal monopoly on import/export of electricity to/from Norway at that time.

[16] https://energifaktanorge.no/en/om-energisektoren/eierskap-i-kraftsektoren/

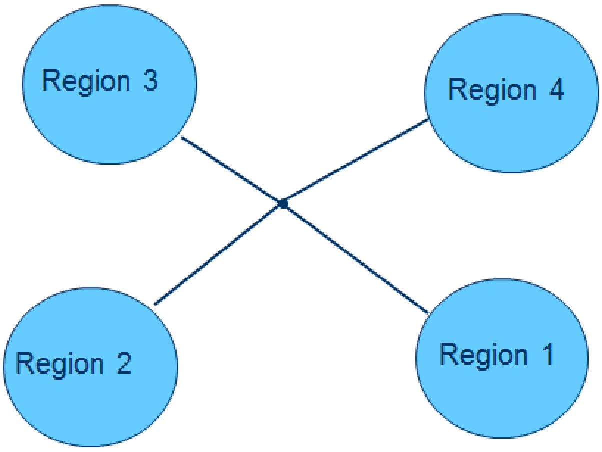


**Figure 7 The 4 regions of Samkjøringen.**

Utilities could participate in this exchange if they could cover the demand in their region through own generation or long-term contracts. Samkjøringen ensured that the marginal water value across the country was made visible to all, so that power was rationally exchanged between producers. The price in this market affected only the exchange of excess power on the wholesale market, and did not directly impact the consumer prices. A normal practice was to determine the power price seen by the consumers in the municipal council.

In spite of the power exchange facilitated by Samkjøringen, there was no central dispatch of the system. The operational decisions were made locally by the regional producers. The producer's challenge was to make optimal use of reservoirs and power plants within a river system, taking into account all relevant operational constraints, including security of their regional supply.

There were many arguments supporting the restructuring process. A primary goal was to establish an efficient and well-functioning market communicating the short-run marginal cost of electricity. As stated in [6] pricing according to the short-term marginal cost ensures efficient utilization of resources, and investment decisions should be based on the relationship between the short- and long-run marginal costs.

We will not go into detail about the arguments here, but list the most central below, and refer to [6] and [7] for more detailed explanations.

- **Avoid excessive investments.** Prices did not properly reflect the marginal costs in the system and there was more capacity available than consumers were willing to pay for.
- **Improve selection of investment projects.** The obligations to serve local demand led to cost-ineffective priorities.
- **Create incentives for cost reduction.**
- **Ensure equity among consumers.** Prices were decided by municipalities, which could lead to cross-subsidization. As an example, power intensive industries had artificially low electricity prices.
- **Obtain reasonable geographical variations in prices.**

### 2.3.2 After Restructuring

The electricity industry of the Nordic countries went through a major restructuring during the 1990s, institutionalized by the Energy Act of June 1990. The Energy Act is based on the principle that electricity production and trading should be market-based, while grid operations are strictly regulated. The power market should ensure effective use of resources and reasonable prices on electricity.

Two noticeable changes were introduced with the Energy Act:
- The market was opened for end-users
- The load obligations were removed from producers

The Energy Act paved the way for bid-based market clearing with marginal pricing schemes. In such as scheme, short-term price signals should guide long-term investments, and investment in generation is primarily decided by private actors.

A day-ahead wholesale market (Nord Pool) with significant competition was established. Later on, markets for intraday balancing and reserve procurement were established to support efficient system operation. The day-ahead market is described below.

The following roles has been present in the power market since the restructuring [8]:
- **Regulator:** Organized per country. Controlling the monopoly functions like network owners and system operator responsibilities. The national authorities also regulate trading in the physical and financial markets.
- **Market Operator:** The Nordic Power Exchange - Nord Pool. Is currently the only common market place for the Nordic power market. Bilateral trading is to some extent organized in minor market places.
- **Transmission System Operator (TSO):** Organized per country. Own their respective national main grid and are responsible for coordination between producers, consumers, and other network owners.
- **Network Owner:** Operates and maintains the network and is obliged to make third party access possible.
- **Market Players:** Producers, consumers, or traders who are registered as exchange members at Nord Pool or operate bilaterally.
- **Retailers:** Market players who sell electricity to end-users.

For more details on the deregulated Nordic market, see [7] and [8].

In general, the market players in the Nordic market have a mixed ownership structure with a predominance of public ownership.

#### 2.3.2.1 The Day-Ahead Market

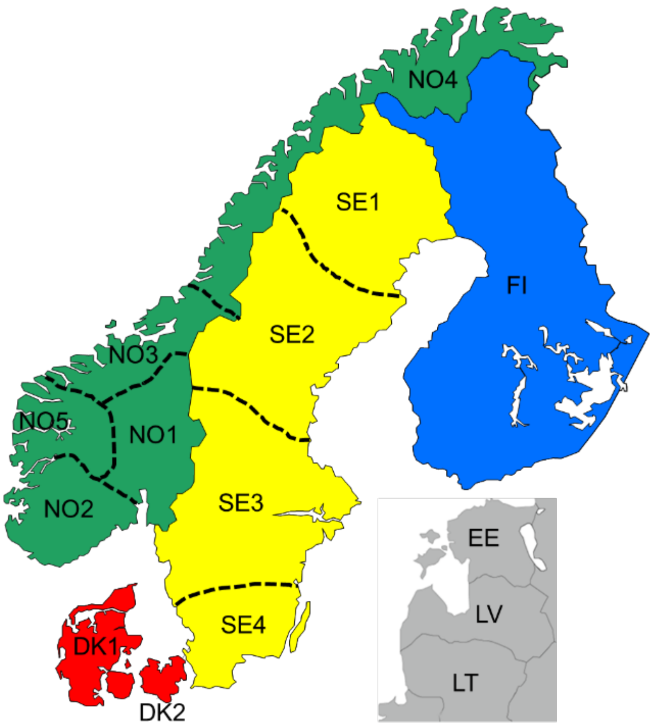


**Figure 8 Nord Pool Spot price areas.**

ELSPOT is Nord Pool's (NP) marketplace for trades in day-ahead physical electricity delivery. ELSPOT was established in 1993 as Statnett Marked AS, serving initially as a Norwegian market only. In 1996, Sweden joined the market and the exchange changed name to Nord Pool ASA. Later on, Finland and Denmark joined the exchange, and Nord Pool Spot AS was established as a separate company in 2002, while the financial markets were sold to NASDAQ. Currently, the rebranded Nord Pool AS is owned by the Nordic (Statnett, Svenska Kraftnät, Fingrid and Energinet.dk) and Baltic (Elering, Litgrid and Augstsprieguma Tīkls) TSOs.

The division into ELSPOT areas, or price areas, is a result of the combination of the TSO's projections of which areas and grid interfaces that will experience power transmission demand exceeding the grid capacity. Currently ELSPOT comprises 15 price zones, with 5 in Norway, 4 in Sweden, one for each of the Baltic countries, one in Finland and 2 in Denmark. In 2016 a total of 391 TWh was traded through ELSPOT.

The market is cleared once a day as an auction with marginal pricing. Market players who want to trade energy on the ELSPOT market, must send their bid volumes and prices to NP before 12:00 the day before physical delivery. The time-delay between clearing and physical delivery ensures that slow-ramping technologies, such as thermal and nuclear power plants, are given sufficient time to plan the up- and down-regulation of production. The bidding does not refer to individual plants and units and is thus on *portfolio basis* for the given price area. The system price is calculated based on all bids for the entire exchange area for each delivery hour the following day. The bids for buying and selling power are gathered in one curve for supply and one for demand. The intersection point of these curves defines the unconstrained, hourly *system price*, which serves as a reference price for the entire market. In case any of the resulting flows between price areas exceed their respective available transfer capacities (ATCs) in a given hour, the market is split to find valid flow values and separate *area prices* for that hour. The ATCs are provided on a daily basis by the TSOs, taking into account forecasted grid bottlenecks and possible security issues.

Trading is based on several types of orders, as defined by NP[17]. The largest share of the day-ahead trading is matched based on single hourly orders, and we briefly describe this order type below. A market player specifies the purchase and/or sales order for each hour, represented by a bid curve of price/volume-pairs. Once the price for each hour is determined, a comparison with a player's order for that day establishes the delivery for the player. The minimum requirement for a single hourly order is two price-steps, at minimum price -€500 and maximum price €3000, also known as a price independent order. A price-dependent single hourly order may consist of up to 62 price steps in addition to the current ceiling and floor price limits set by NP. NP linearly interpolates volumes between each adjacent pair of submitted price steps.

The TSOs monitors the market players' imbalances when bidding, cf. §8 in[18]. If a player acts in a way that causes significant imbalances in any direction over time, the regulator may withdraw its concession to produce. Thus, producers have strong incentives to be risk-averse when it comes to creating imbalances. In addition, imbalance settlement is done based on a two-price system, where deviations in the same direction of the imbalance are settled with the imbalance price, while imbalances in the other direction are settled with the spot-market price. This creates an additional incentive to be in-balance in the first place.

Urgent market messages (UMM) concerning maintenance and failures are updated within short time limits. In this way, all market participants get equal information at the same time.

Recently, a central algorithm for day-ahead market clearing across Europe has been phased into operation. This algorithm is known as EUPHEMIA and coordinates the cross-border trading between NP and the other European exchanges.

#### 2.3.2.2 Adjustment Towards Physical Operation

The ELSPOT market is often referred to as the spot market, but one may argue that this market is a forward market since the prices market players are finally exposed to are the real-time balancing market prices. However, ELSPOT is defined as a physical market as production and consumption have to send their day-ahead schedules to the according TSO. Although the market participants should not expect imbalances at the time of bidding, the time-delay between bidding and physical delivery allows imbalances to occur.

Since it is not possible to perfectly predict the weather and the system state for the next day, and since the cleared day-ahead volumes may not be feasible when considering physical operation, there will be a need to adjust the schedules. Balancing services are needed to continuously balance supply and demand at real time operation. More specifically, balancing services are needed to handle:

- **Outages** of power system components (power plants, transmission facilities, etc.). Such events are hard to predict and may cause severe system disturbances.
- **Weather dependent exogenous factors** (impacting e.g. demand and intermittent generation). Although forecasting methods continue to improve, weather forecast errors will always exist.
- **Structural imbalances** caused by the market design. These are imbalances that are due to the discrete time resolution of day-ahead and intraday markets. Obligations may change in large steps in between consecutive hours, whereas load and intermittent production changes are continuous. Both the granularity (hourly time resolution) and time difference between market closure and real-time operation leaves behind a need for balancing services.

[17] https://www.nordpoolgroup.com/
[18] https://www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/retningslinjer-for-systemansvaret/

- **Congestions** in the power grid that are not explicitly seen by the day-ahead and intraday markets. These are treated by use of manually regulated reserves.

When faced with an unbalanced portfolio, e.g. due to changes in weather conditions or (economically) unfortunate production plans, the Balance Responsible Parties (BRP) will in principle have two options:

a) Actively remove the imbalance by trading in the intraday market
b) Await the TSO's balancing service activation and imbalance settlement

#### 2.3.2.3 The Role of Hydropower Scheduling Models

In the context of operational decision making in the Nordic day-ahead market, hydropower scheduling models are of primary importance for hydropower producers in Norway in the process of preparing their bids to the spot market. The bids should reflect the future value of water as well as shorter-term operational constraints faced by the producer. Thus, the whole toolchain should ideally be run to provide decision support for the bidding process.

Once the producer knows the accepted bids, this can be translated into hourly power demands to be supplied by the whole portfolio of plants for the next day. This allows for re-scheduling of the producer's system to arrive at the best possible short-term production plan to be submitted to the TSO. This activity is often combined with the bidding in intraday and reserve capacity markets.

#### 2.3.2.4 The Use of Hydropower

Figure 9 serves to illustrate how Norwegian hydropower resources are operated in the liberalized market context. It shows a typical generation pattern for Norway, with data from the second week in 2019. This week was not particularly cold, and thus the load is not critically high. Keep in mind that practically all of the Norwegian generation stems from hydropower. From the figure a general pattern is clear; Norway exports power during day-time when load (and prices) are high, and imports power during night-time and in the weekend.

From the producer's perspective, the flexibility of hydropower enables the producer to schedule its generation to price-spike periods and thus achieve a higher average price per generated amount of electricity than the competing technologies.

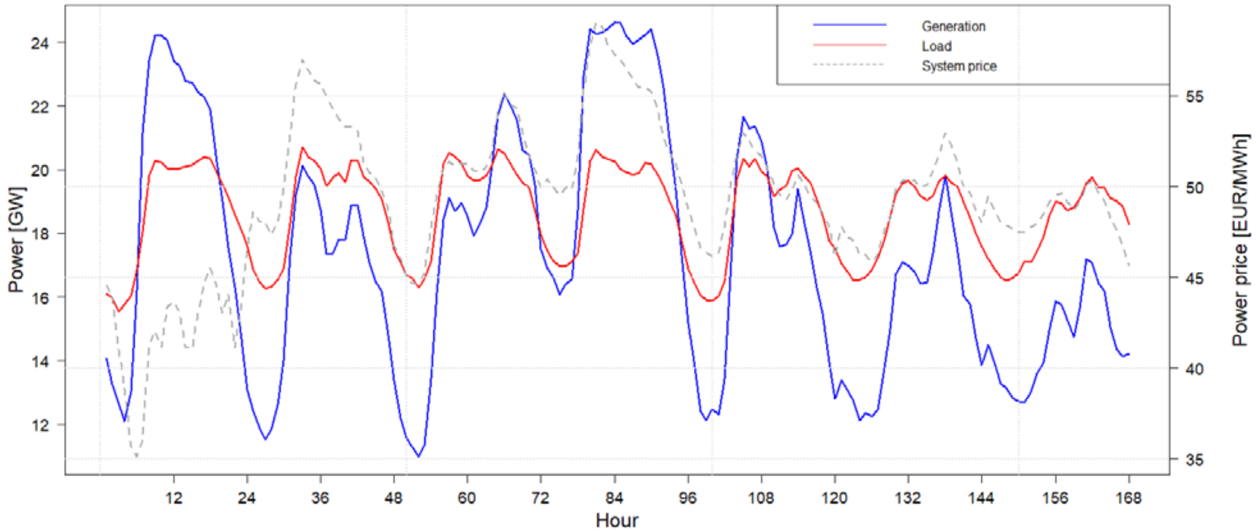


**Figure 9 Generation (blue) and consumption (red) for Norway in the second week in 2019. The Nordic market system price for the same period is shown as a stapled line. Data obtained from Statnett.**

## 2.4 A Historical View on Development on Methodologies at EFI and SINTEF

In this section we will visit some key reports and articles that describes the state of the scheduling toolchain developed and maintained at SINTEF Energy Research.

### 2.4.1 The Early Years (1960-1980)

The initial steps taken at Elektrisitetsforsyningens Forskningsinstitutt (EFI[19]) were reported in [9] in 1962. This work reports on a one-area model using the *water value method* published by [10] one year earlier. This method is founded on the principles of stochastic dynamic programming, but stores the water value (the derivative of the cost with respect to storage) instead of the cost itself. A brief description of the iterative procedure for finding the water value in a given decision period (week) *t* follows. Considering one aggregate reservoir and station operating in a market setting, with an updated vector of water values for discrete points in the reservoir for *t+1*. In the backward recursion, for a given reservoir state and inflow, one draws water from the reservoir according to a guessed water value for *t* and obtain the reservoir state at the end of *t*. An updated water value for *t+1* is then found by interpolating in the *t+1* water value vector. The mismatch between the guessed value for week *t* and the obtained water value for *t+1* is used to update the guessed water value in the next iteration. This principle of "operating along a constant water value" has proved to be computationally fast compared to solving the underlying optimization problem.

For this early one-area model, several assumptions were made that are still relevant today:

[19] EFI later merged with SINTEF Energi into SINTEF Energiforskning AS, and today known as SINTEF Energi AS (Norwegian) or SINTEF Energy Research (English)

- Inflow stochasticity was represented by historical records. Thus, one believes that the statistical properties of the historical records are representative for the future. At that time typically around 30 historical years were available.
- All reservoirs, stations and inflows are aggregated into one equivalent energy storage, plant and inflow, respectively.
- The reservoir was discretized into 10 segments, and monthly or even weekly time stages were used with a 1-2 year planning horizon. Water values were computed for each discrete point in each time stage with linear variations between points.
- A brief discussion on use of variable length on decision stages, short in the beginning and coarser at the end of the planning horizon.

A further elaboration on the concept of operational planning in hydro-dominated systems was presented in [11]. It is pointed out that the risk of energy shortage in such systems can only be eliminated at very high costs, and that a small shortage-risk is accepted, provided that further risk reduction is more costly than the value of lost load. The basic principles of the water value method for an aggregated system representation are discussed and illustrated in this article, and the basic principles for optimal disaggregation are discussed. As a general guideline, [11] states that, "*as long as the combined operation can be carried out so that no single reservoir is overflowing before all reservoirs are filled up, and so that no single reservoir is empty before all are empty, then the result is the same as if all reservoirs were added together*".

In 1965 EFI established a committee to consider how one could best use modern computational methods and technology to perform operational scheduling in the Norwegian system. The reasoning, explanations and conclusions from this committee are detailed in the extensive report [12]. We emphasize on some relevant points from this report below:

- A discussion on the system boundary for scheduling is presented. Three alternatives were considered: The whole nation, per region within Samkjøringen, or per utility. The committee recommended continuing performing the scheduling per utility. Thus, each utility should plan and schedule as an independent economic unit.
- The role of another committee, known as "Tørrårskomiteen"[20], was discussed. Tørrårskomiteen discussed issues related to reliability of supply, or more specifically adequacy of energy inflow in the hydropower system. Moreover, Tørrårskomiteen determined the cost curve associated with demand curtailment. The committee recommend the utilities to use the cost curve designed by Tørrårskomiteen, possibly adjusted according to local considerations.
- In this report, made in 1974, one look into the future (1980s) and sees that the system will change significantly with the Norwegian hydropower system tighter connected to the other Scandinavian countries, with significant amounts of nuclear and thermal power.
- The concept of water value computation is discussed, defining concepts, existing approaches (e.g. one- and two-system models and disaggregation through detailed drawdown model).

### 2.4.2 EFI Tools at The End of 1980s

A report describing the models developed by EFI for hydro scheduling was presented in 1988 [13] and is used as the basis for the following section.

At that time the main operational objective for the scheduling was to:

[20] The English translation would be something like "dry year committee".

"*Find and implement a sequence of operational decisions which minimizes the expected total variable cost, taking into account all technical and juridical constraints.*"

Where the major operational decisions where:
- Scheduling of a company's own generation
- Selling and buying power at the spot price power market ("Samkjøringen")
- Curtailment of firm power delivery during periods of critical inflow shortages

The obligation each power company had to deliver a defined amount of energy was an important premise for the above-stated objective. The resources available for serving the firm power load are illustrated in Figure 10. The scheduling problem involved pricing of each resource so that the cost of covering the load is minimized. The pricing of contractual rights, exchange with the surplus power market, thermal capacity and curtailment were assumed to be predetermined, leaving the major challenge to price hydropower resources.

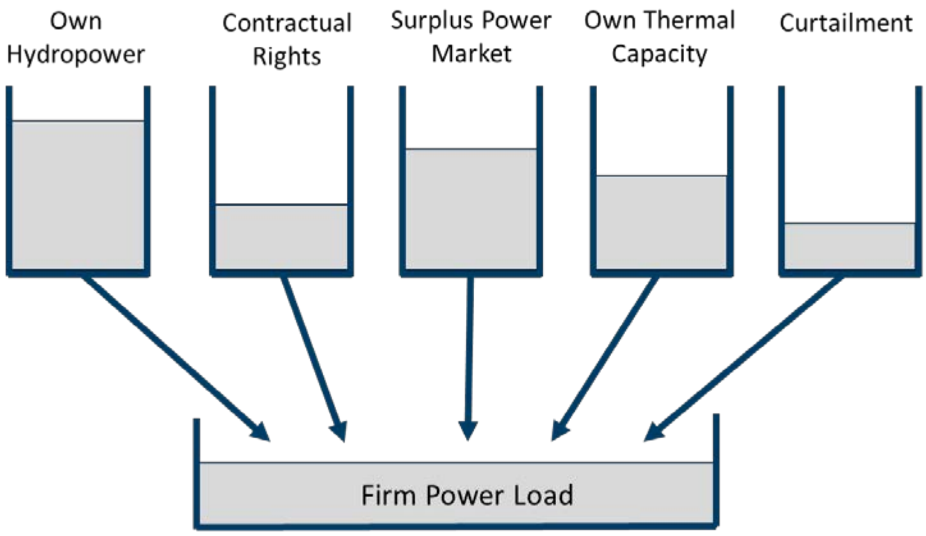


**Figure 10 Resources to cover firm power load [13].**

It was pointed out that the combination of long- and short-term "considerations" in the hydro scheduling process poses "severe computational problems" and thus necessitates a modelling toolchain. The adopted toolchain comprised long-, medium-, and short-term models.

**Long-term scheduling** could be performed using a *single reservoir model*, either as EFIs Single Reservoir Model (EFI-SRM) or EFIs Extended Single Reservoir Model (EFI-ESRM). Both considered the operation of a local hydropower system, computing water values for the aggregated hydropower description. Where EFI-SRM simulated operation using the aggregated system description, EFI-ESRM used a *detailed drawdown model* based on heuristics to take into account the hydropower details.

For more comprehensive planning of a larger system, EFIs Extended Power Pool Model (EFI-EPPM) was applied. EFI-EPPM is described in an early reference from 1982 [14]. It was suited for companies with production in several watercourses or for a large system comprising several production companies. Each subsystem was represented by an extended single-reservoir model. Subsystems were interconnected via a radial grid through a common coupling point.

The description of EFI-EPPM in [13] details the early version of (or forerunner to) the EMPS model. Water values were computed using the water value method [10], and could be determined using two basic modes. In the first mode each subsystem is treated individually without exchanging power with other subareas. In the second mode there is a shared responsibility to cover the firm load, accomplished through water value computation per subarea, system simulation using the water values as "marginal costs" and a feedback loop to iterate on the water value computation.

**Medium-term scheduling** could be performed by EFIs Medium-Term Model (EFI-MTM), which generally should apply the same geographical system boundaries, market description and load as EFI-EPPM. Note that this is similar to the centralized scheduling in Figure 1. As for EFI-EPPM the overall objective was to minimize expected variable costs.

The scheduling horizon could vary from several weeks up to one year. Depending on the length of the horizon, the inflow could be treated as deterministic or stochastic. If treated as stochastic, a scenario fan approach illustrated in Figure 11 was typically used, where the three scenarios correspond to the 25, 50 and 75 percentiles.

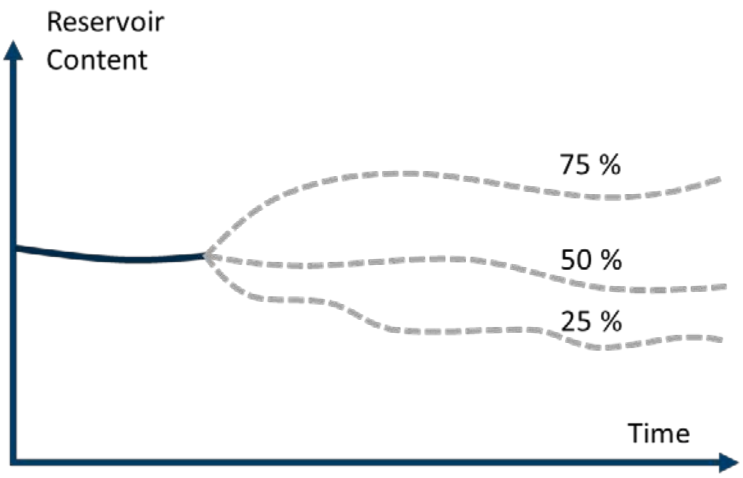


**Figure 11 EFI-MTM, stochastic approach [13].**

The coupling to the long-term scheduling could be provided in the form of feasible detailed reservoir ranges and aggregated water values provided by EFI-EPPM. The model applied a detailed hydro representation, but with extensive use of reductions. As an example, buffer reservoirs[21] in cascades were eliminated to form an equivalent cascade representation. The meshed electrical grid is modelled considering one busbar per subsystem, and losses were represented as a stepwise function of flow. EFI-MTM was cast as an optimization model solved by Network Linear Programming (NLP).

**Short-term scheduling** could be performed by EFIs Short-Term Model (EFI-STM), where the goal is to find the optimal production schedule for the next day. A scheduling period between 1-10 days was typically considered, treating inflows as deterministic.

[21] A buffer reservoir refers in this context to a reservoir that can be filled and emptied several times during the basic time step of the program.

The boundary conditions were provided from the EFI-MTM model, e.g., similar to the centralized scheduling in Figure 1. For small reservoirs, a final volume target was provided. For larger reservoirs, water values were used as end-point targets, possibly together with reservoir bounds.

The modelling of the hydropower system, the electrical grid and the market was similar to that in EFI-MTM, except for allowing shorter time steps. Also similar to EFI-MTM, EFI-STM was cast as an optimization model solved by NLP.

### 2.4.3 SINTEF Tools at The End of 1990s

As discussed in Section 2.3.2, the deregulation at the beginning of the 1990s removed the producer's obligation to serve load. This facilitated competition from external resources to serve the local load shown in Figure 10. Consequently, the objective of the scheduling was changed from minimizing costs in order to serve the load to maximize profit from selling to the market.

#### 2.4.3.1 The Need for Price Forecasting

In this transition, *price forecasting* became an essential activity for the hydropower producers [2], [3]. By price we here refer to the spot price of electricity, for which the day-ahead market price is believed to be a good indicator.

Such forecasts can be obtained in several different ways, either by the generation company itself or through an external third-party. In [3] three possible forecasting approaches are outlined, based on:
1) The prices in the futures market
2) Observations in historical prices
3) Fundamental simulation models

A price forecast should reflect the expected future price development as well as the uncertainty involved. It is needed in the hydropower scheduling, but also for the producer's risk management and expansion planning activities. The correlation between inflow and spot price as well as the price autocorrelation are significant and should be taken into account in the forecasting process. The weekly average spot price for the city of Oslo (today located in price area NO1) is plotted against the average reservoir filling degree is shown in Figure 12 to illustrate these correlations.

Approach 1) does not reflect much information on uncertainties and correlations, whereas approach 2) will typically lack long time series that are representative for the current and future power market. Thus, approach 3) became the preferred option for many producers. Fundamental simulation models do not depend on the existence of historical prices, and explain the prices based on the marginal costs/value of flexible system resources (generation, demand, storages, etc.). Moreover, fundamental models can incorporate planned and expected system changes such as new expansions, demand growth, changes in market structure, new overseas cables and changes in fuel prices. On the downside, models do not easily treat the psychological and risk-related impacts on market prices.

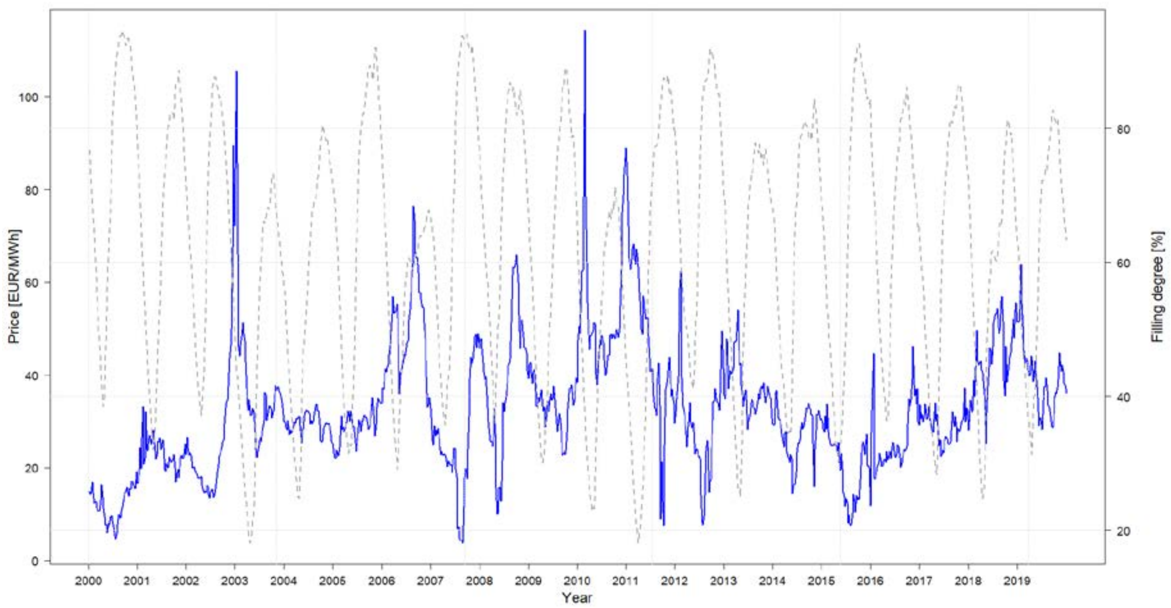


**Figure 12 The average weekly spot price for Oslo (blue line) vs. the average weekly filling degree (measured in energy and stated in percentage of maximum capacity) for the years 2000-2019[22].**

In [3] it is described how the EMPS model (formerly EFI-EPPM, and referred to as SEfAS LTG in that article) was taken into operational use for price forecasting after the deregulation. The authors state that, although created long before the deregulation, the need for the EMPS model increased after the deregulation, primarily due to the strengthened need for price forecasting. Six years of experience with spot price forecasting is reported, pointing to some important time sequences that were particularly challenging to forecast.

The scheduling tools reported in the following are founded on the assumption that the producer is a *price-taking* market player. This condition is necessary in a free and economically efficient market.

### 2.4.3.2 The Medium and Short-Term Modelling

The most used medium-term model at this time is a multi-scenario deterministic model. The model has a detailed representation of the local hydropower system being considered, with target reservoirs given from the long-term EMPS model. The model considers scenarios of joint inflows and prices, where the inflows are the same as for the EMPS model, and the prices the corresponding outputs from the EMPS. At the end of the 90s, a combined SDDP/SDP model later known as ProdRisk was being developed and tested as a medium-term model [15].

An increasing emphasis of detailed short-term planning was also seen in the end of the 90s, and an early variant of the program SHOP is described in [2].

[22] Data from Nord Pool Spot.

### 2.5 Applied Toolchain

Below the key models developed and maintained by SINTEF Energy Research are described, and the information flow between the models is discussed. The toolchain is illustrated in Figure 13 with model names in red. We emphasize that this is not a fixed toolchain used by market players, but rather the recommended and most established one. Emphasis is on operational scheduling, where the major output in the end is the market players' bids to the market operator and their schedules to the system operator.

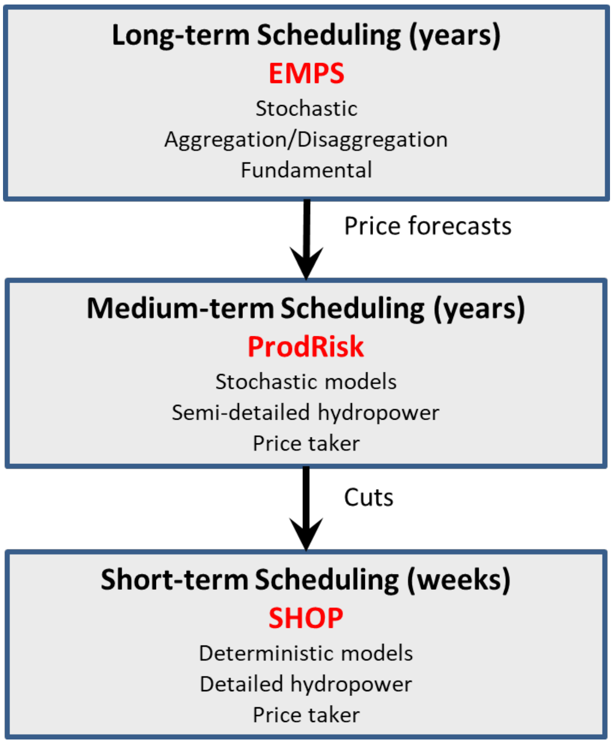


**Figure 13 Key models developed and maintained by SINTEF Energy Research.**

### 2.6 Long-Term Scheduling – EMPS

For the long-term scheduling we will primarily emphasize on the EMPS model which has been actively used by players in the Nordic market for decades.

#### 2.6.1 History and Background

The EMPS model was initially referred to as the "Power Pool Model" or the "Extended Power Pool Model", and the early development can be traced back to 1974. Much of the early history is presented in Section 2.4.

In this report we describe the operational uses of the EMPS model, which is primarily to generate price forecasts for medium-term scheduling, as indicated in Figure 13.

The EMPS model comprises two major parts: strategy evaluation and system simulation, jointly carried out on a detailed and an aggregated representation of the hydropower system, as illustrated in Figure 14. A brief description of each part is provided in the following. See [16] and [17] for recent in-depth descriptions.

### 2.6.2 Program Description

The EMPS model searches towards minimized system costs from operating a hydrothermal system, considering uncertainties in inflow, temperature-dependent load, wind power, exogenous power prices, etc. When used for operational scheduling purposes, the EMPS model is normally set up for a horizon of 3-5 years with weekly decision stages. Thus, uncertainties are known for a horizon of one week. The model can run with a sequential or aggregated time resolution, with down to hourly time resolution. The hydropower system is represented in detail, with physical reservoirs, waterways (discharge, bypass spillage), complex topologies including pumps, tunnels, etc. The hydropower generation capability is modelled on station level, aggregating the individual units within the station to an equivalent unit. The thermal units are described by a marginal cost and a capacity, with the possibility of including linearized start-up costs.

The model is based on a combination of optimization, simulation and heuristics. Model calibration is often crucial for obtaining reliable results, this can be done by the experienced user or automatically.

**Strategy evaluation**
In the strategy evaluation part the hydropower is represented as one equivalent energy reservoir per price area, as shown to the right in Figure 14. Non-coupled water values are computed for each of a defined number of price areas in step 3. These calculations are based on the *water value method* [10], with an overlaying hierarchical logic applied to treat the multi-reservoir aspect and the interconnection between areas.

**System simulation**
In the system simulation part, the optimal operational decisions for a sequence of historical weather scenarios are found. The entire process of finding the optimal operational decisions for one week is referred to as the weekly decision problem. The concepts of area optimization and detailed drawdown (step 6 in Figure 14) are elaborated in the following.

In the area optimization (step 4 in Figure 14) the weekly aggregate hydro and thermal generation is in principle determined through a market clearing process based on the marginal water values calculated in the model's strategy part for each price area. The area optimization problem is formulated as an LP problem minimizing system costs subject to reservoir balances for each price area and power balance for each area and load period. Inflow, temperature-dependent firm demand, wind and solar power, and exogenous import/export power prices are normally treated as stochastic variables. The area optimization problem is solved for a given week and a given scenario.

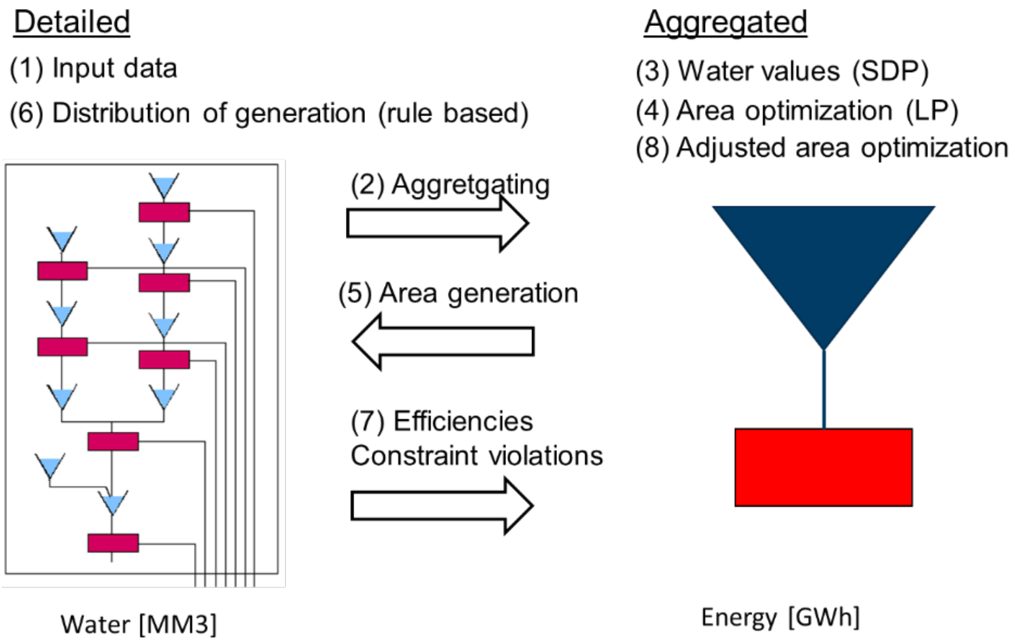


**Figure 14 Interplay between detailed and aggregated representation of the hydropower system in the EMPS model.**

A detailed heuristic drawdown model (step 6 in Figure 14) distributes the optimal hydro production among the available plants for each load period. In the heuristic drawdown, the goal is that the target production for an area is produced at a minimum expected future operating cost. This is made by seeking to minimize the risk of overflow in the filling season (summer) and avoid loss of power capacity caused by emptying reservoirs in the depletion season (winter). If the drawdown model finds that it is not possible to produce the sum hydro production given by the area optimization, the aggregate hydro area-model description is updated (in step 7) with information from the drawdown model, and a new area optimization is performed. This process is repeated until sum hydro production is feasible for all areas. More details on the basic principles of the heuristic drawdown model can be found in [13].

### 2.6.3 Related Recent R&D

The EMPS model has been continuously developed to address the evolving needs of the market participants. It is currently able to simulate (area optimization) with hourly time resolution. Below is a short description of some of the newest functionality.

- The code has been restructured to facilitate efficient parallel computations.
- A linear approximation of start-up costs on thermal units was introduced in the area optimization model, as described in [18]. This functionality captures the impact of start-up costs on simulated power prices.
- Embedding tradable green certificates ("el-certificates") [19].
- Embedding detailed power flow studies in terms of DC power flow and grid losses, allowing dynamic generation of flow-based constraints to the area optimization problem [17]. Such constraints are important to mimic the price formation in the future Nordic market, which most likely will be based on flow-based market clearing.
- Automatic calibration of the model. Search for the calibration parameters that lead to a defined criterion, typically the highest socio-economic surplus.

- A recent research project experimented with different methods for improving the EMPS aggregation and disaggregation methods [20]. Although some experiments gave promising results, a general conclusion was that it is difficult to improve the existing approximations and heuristics in the aggregation and disaggregation phases.
- In the ongoing research project PRIBAS[23], a key challenge is to add details to the hydrothermal scheduling problem so that the value of flexibility for the different generation technologies are properly reflected in the price formation for multiple electricity products. Some preliminary results are reported in [21].

## 2.7 Medium-Term Scheduling – ProdRisk

### 2.7.1 History and Background

ProdRisk is currently the most widely applied medium-term scheduling model in the Nordics and will be covered in the following. The first attempts on applying the SDDP method to the Norwegian system was reported [22]. The standard SDDP formulation fits well for minimizing system costs in a model representing the entire market, but was not applicable for a producer's regional hydropower scheduling. The price needs to be considered a part of the state space in the SDDP algorithm due to its strong autocorrelation. Thus, the problem should at least have the following three state variables; reservoir volume, inflows and market price. While the objective (maximize expected profit) is concave in the reservoir volume and inflow states, it is convex in the price state, and consequently the convexity requirement of the SDDP algorithm was challenged. Towards the end of the 1990s, a new method was developed to treat the market price as a stochastic exogenous variable within the SDDP algorithm. The method is based on a combination of SDP and SDDP, and is discussed in [23] and formulated in [15]. The latter reference describes the basic principles behind the ProdRisk model, while more recent updates are outlined in [24]. An earlier version of ProdRisk combined operational scheduling and hedging by future contracts in the financial market, controlling the risk level by setting revenue targets [25]. The current version of ProdRisk is risk-neutral, leaving financial trade as a separate activity.

### 2.7.2 Program Description

ProdRisk maximizes the expected profit from a hydropower portfolio subject to uncertainties in inflow and market price. The model is based on a combination of SDP and SDDP algorithm that can be solved using parallel processing, and where the subproblems are solved as LP problems.

It is primarily used for system planning, generation forecasting, maintenance planning and providing the coupling to the short-term model SHOP. In this report we are primarily interested in the coupling to the short-term scheduling.

The hydropower system is represented in detail, as illustrated in Figure 15, with physical reservoirs, waterways (discharge, bypass spillage), time-dependent environmental constraints, complex topologies including pumps, tunnels, etc. The hydropower generation capability is modelled on station level,

[23] https://www.sintef.no/en/projects/pribas-pricing-balancing-services-in-the-future-no/

aggregating the individual units within the station to an equivalent unit. All produced power is exchanged through a single bus bar, i.e., no grid constraints are assumed. A producer that wants to schedule several watercourses which are not hydraulically connected will typically run these separately.

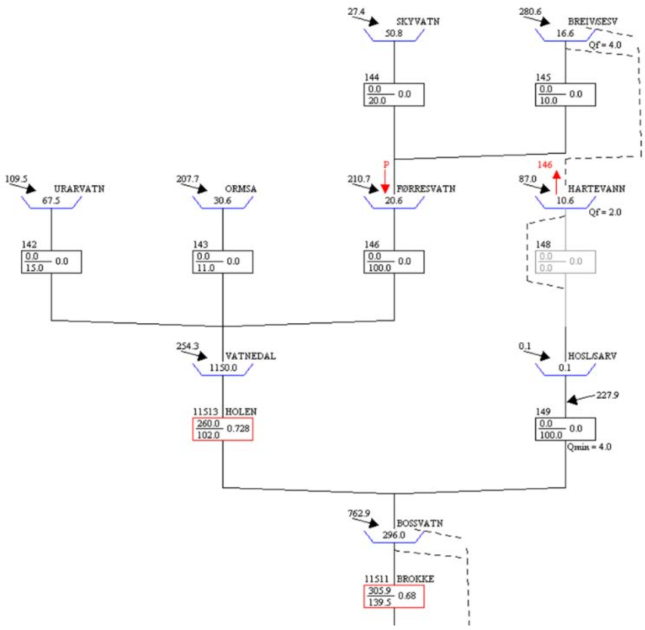


**Figure 15 Example of hydropower system topology.**

When used for operational scheduling purposes, ProdRisk is normally set up for a horizon of 2-5 years, depending on the regulation capability of the hydropower system. As for the EMPS model, the decision stages are one week, meaning that the uncertainties are known for a horizon of one week. The model can be run with a sequential or aggregated time resolution, with down to hourly time resolution.

A first-order vector auto-regressive model is used to represent time series of normalized weekly inflows, as outlined in [24]. This model is used in the backward pass of the algorithm, discrete noise values are either found by principal component analyses or by sampling from estimated residuals. The market price is represented in a discrete Markov chain that has been constructed based on the price forecast, as described in [26]. In the SDP/SDDP forward pass ProdRisk uses the historical price and inflow scenarios directly. This preserves the correlation between inflows and market prices in the forward pass.

### 2.7.3 Related Recent R&D

ProdRisk has been continuously developed to address the evolving needs of the market participants. Below is a short description of some of the newest functionality that has been implemented in ProdRisk or considered as algorithmic extensions.

- The code has been significantly restructured to facilitate efficient parallel computations.

- A linear approximation of start-up costs on hydropower stations was formulated in [27] and later included in ProdRisk.
- Extensions of the combined SDDP/SDP algorithm to incorporate the sales of reserve capacity in a liberalized market context were described in [28].
- Improved information flow between ProdRisk and the SHOP models as outlined in [29].
- Treatment of nonconvexities in the scheduling using stochastic integer dual dynamic programming (SDDiP) [30]. The SDDiP method is currently not suitable for operational use due to its extensive computation time.
- Different variants of the ProdRisk computer code has been tested as a market model:
    - In [27] on the Icelandic power system with grid constraints and wind power.
    - In [31] on the detailed Norwegian system, with 279 freely regulated reservoirs and 105 different inflow series as state variables.

## 2.8 Short-Term Scheduling – SHOP

The long and medium-term-models discussed so far are techno-economical models, where finding the expected marginal value of water is the key challenge. In contrast, the short-term scheduling takes water values as input and consider the physical representation at a finer level, so that the results can guide physical operation.

In addition, the short-term scheduling needs to be closely adapted to the decision sequences and input format required by the market design.

### 2.8.1 History and Background

The main principles behind the short-term model SHOP were established in the late 1980s, just before the restructuring took place in Norway. An early variant of the program was published in [32], which later was improved as outlined in the PhD-theses in [33]. A historic view on the successful development and application of SHOP is presented in[24].

### 2.8.2 Program Description

The key objective of SHOP is to maximize profit. The model is deterministic in the sense that market prices and inflows are assumed know for the entire planning horizon. SHOP is based on successive LP and may include MIP formulation.

SHOP includes components such as reservoirs, hydropower units, discharge gates, junctions, and thermal units. All physical details needed to provide implementable schedules are included. An example is the representation of water flows and pressures [34]. A firm load profile and a short-term market are also modelled. Further details on the technical modelling are provided in[25].

[24] https://www.sintef.no/en/latest-news/short-term-hydro-operation-planning-could-bring-in-billions/
[25] https://www.sintef.no/en/software/shop/

End-of-horizon valuation of stored water can be provided by Benders cuts from ProdRisk. The latest improvements in information sharing between ProdRisk and SHOP allows all three state variables in ProdRisk (reservoir volume, inflow and market price) to be properly accounted for in SHOP [29].

### 2.8.3 Related Recent R&D

SHOP has been continuously developed to address the evolving needs of the market participants and to ensure operational robustness. Below is a short description of some of the newest functionality that has been implemented in SHOP or considered as algorithmic extensions.

- A model for treating uncertainty in inflow and market prices within the short-term operational planning was developed and the rigorously tested, see [35]. The testing did not lead to any strong conclusions regarding the added value of stochastic modelling. The principles for treating uncertainties in the short-term scheduling are discussed in [36] and [37].
- The coordinated bidding in day-ahead and balancing markets [38].
- Going from a plant-based to unit-based model formulation in SHOP [39]. This means that the individual units within the plant are described in detail, which opens for even more detailed representation of the physics.
- SHOP allows optimization of reserve delivery from variable speed pumps as well as hydraulic short circuit operation of reversible turbines [40].
- In the ongoing research project *iScheduling*, the goal is to improve the short-term scheduling process based on recent advances in machine learning algorithms and hardware breakthroughs [41].

### 2.8.4 Decision Support

The SHOP model determines the unit commitment and dispatch plan for the coming days ahead, but can be run in different modes depending on the planning task at hand.

The short-term scheduling primarily serves to support three phases in the operational planning:
1) **Bidding in the day-ahead market**. In the case of the Nordic market, bids needs to be prepared as price-volume pairs on portfolio basis, as elaborated in Section 2.3.2. The schedules from SHOP must be directly applicable to the true hydropower system. A post-optimization simulator has been added to SHOP to verify physically correct results and provide an independent economic evaluation of the proposed schedule [42].
2) **Establish operational plans.** The producer needs to present a detailed operational plan for meeting the obligations from the day-ahead market.
3) **Participating in intraday and balancing markets.** This step has become increasingly important due to increasing volumes in these markets. As an example, hydropower producers participating in multiple energy and capacity markets may use SHOP to find the price for both primary, secondary and tertiary reserve deliveries[26].

[26] https://www.sintef.no/contentassets/6b622776fc0f4bab9b5168d69ba93da1/multi-market---bottcher.pdf

## 3 The Case of Brazil

In the following we describe the basic properties of the Brazilian power system, the market context, as well as the models and modelling toolchain provided by CEPEL.

### 3.1 System Characteristics

Brazil has a large transmission grid, approximately covering the same area as continental Europe. The interconnected grid is referred to as the National Interconnected System (SIN), comprising four interconnected subsystems: South, Southeast/Centre-West, North-East and North. An illustration of the transmission grid including the planned expansion towards 2024 is shown in Figure 16.

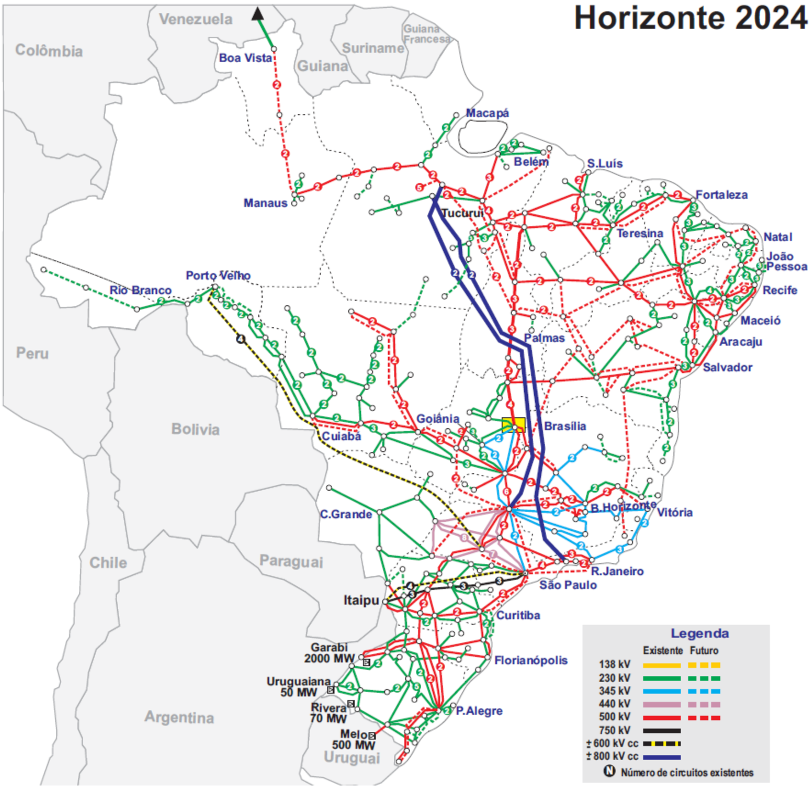


**Figure 16 The Brazilian National Interconnected System, including planned expansions towards 2024.**

The electricity generation and installed capacities per technology are shown in Table 3 and Table 4, respectively. Table 3 shows that renewable sources (hydro, biomass, wind and solar PV) accounted for 82 % of the total electricity generation in 2018, with hydropower accounting for 65 % alone. Hydropower and wind power accounted for 64 % and 8% of the installed capacity in 2017, respectively [43]. The share of hydropower has been higher in previous years, e.g., accounting for 85 % the total installed capacity of approximately 40 GW in 1984 [44].

In recent years, the installation of wind farms, especially in the North-East and South subsystems has increased significantly. Thermal power plants, usually located near the main load centers, play a relevant strategic role as they contribute to the reliability of the system. These plants are dispatched due to prevailing hydrological conditions, allowing the management of stocks of water stored in reservoirs of hydroelectric plants, to ensure future service.

**Table 3 Electricity generation in Brazil for 2018[27].**

| TECHNOLOGY | Generation [TWh] | Percentage |
|---|---|---|
| HYDRO | 389.0 | 65 |
| NATURAL GAS | 54.6 | 9 |
| BIOMASS | 52.3 | 9 |
| OIL | 9.3 | 2 |
| NUCLEAR | 15.7 | 3 |
| COAL | 14.2 | 2 |
| WIND | 48.5 | 8 |
| SOLAR PV | 3.5 | 1 |
| OTHER | 14.4 | 2 |
| **SUM** | **601.5** | **100** |

**Table 4 Installed generation capacity in GW per technology for 2017[28].**

| TECHNOLOGY | Capacity [GW] | Percentage |
|---|---|---|
| HYDRO | 104.2 | 64 |
| NUCLEAR | 2.0 | 1 |
| NATURAL GAS | 13.0 | 8 |
| COAL | 3.7 | 2 |
| OIL | 10.2 | 6 |
| BIOMASS | 14.7 | 9 |
| WIND | 14.4 | 9 |
| SOLAR | 1.8 | 1 |
| **TOTAL** | **164** | **100** |

The Brazilian National Interconnected System (SIN) is interconnected with Argentina (2250 MW), Uruguay (570 MW) and Paraguay. The energy integration with Paraguay runs via the Itaipu hydropower plant, which is located on the border between the two countries. The total consumption of energy in 2017 was 526 TWh, making the country a net exporter of energy[29].

These interconnection capacities are modest related to the installed generation capacity, and consequently the Brazilian power system is much more self-dependent than the Norwegian.

The consumption has grown at an average annual growth rate of 4.4 % the past two decades [43].

[27] EPE, Balanço Energético Nacional 2019, Relatório Síntese, Ano Base 2018.
[28] https://www.aneel.gov.br/documents/656877/14854008/Boletim+de+Informa%C3%A7%C3%B5es+Gerenciais+-+4%C2%BA+trimestre+de+2018/36e91555-141a-637d-97b1-9f6946cc61b3?version=1.2
[29] If including the commercial arrangement for importing significant amounts of Paraguay's share of power from Itaipu, Brazil will be a net importer.

## 3.2 The Brazilian Hydro System

The hydropower plants are distributed in 16 river basins in different regions of the country, see Figure 17 for an overview. A total of 162 hydropower plants are centrally dispatched[30].

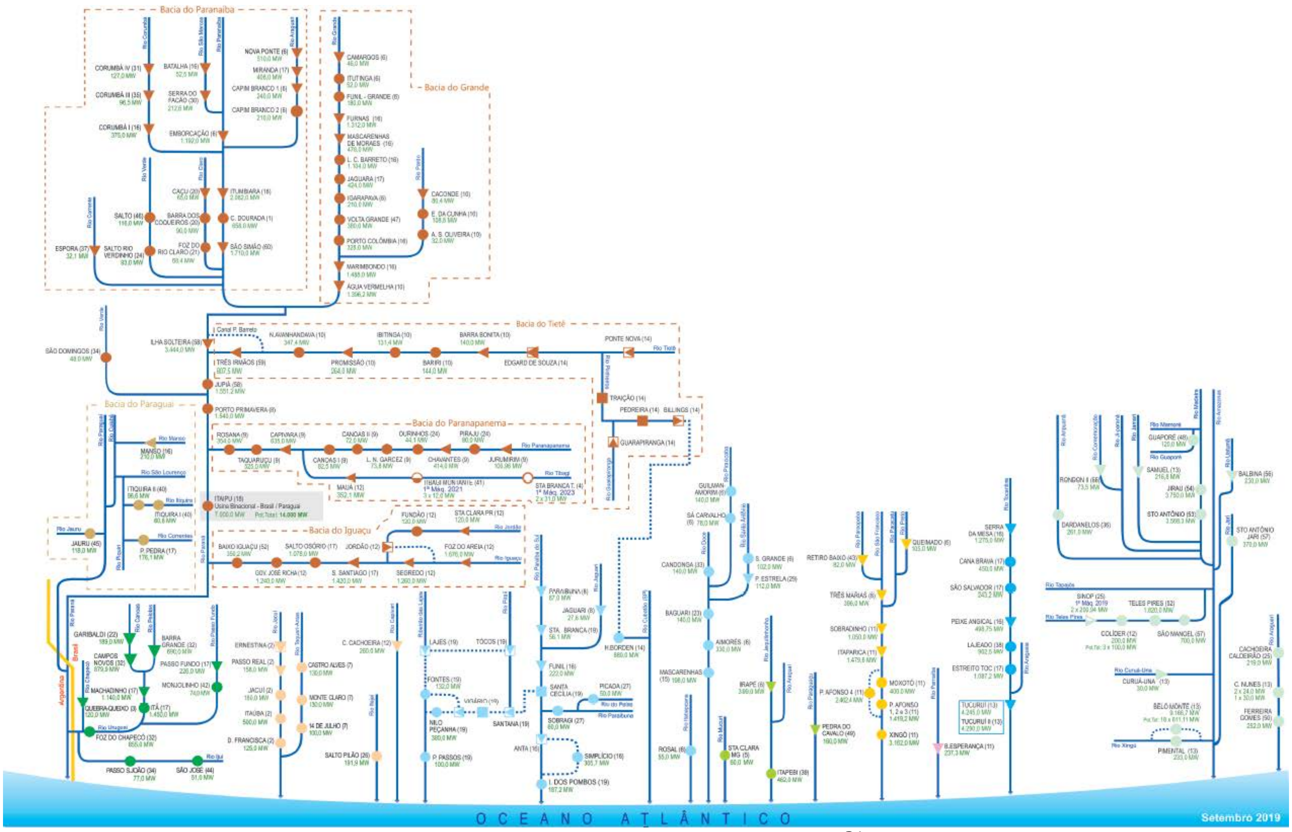


**Figure 17 Hydro system topology[31]**

The Serra da Mesa reservoir has the largest water volume, with 54400 Mm³ (43250 Mm3 active storage) over an area of 1,784 km². Figure 18 shows the volume and DOR for the 60 reservoirs with highest storage capacity in Brazil.

[30] A. Diniz, presentation at ICSP 2019, "Key aspects in solving large scale stochastic power generation planning problems in practical systems: Application to the Brazilian case"
[31] http://www.ons.org.br/sites/multimidia/Documentos%20Compartilhados/Forms/DispForm.aspx?ID=3752

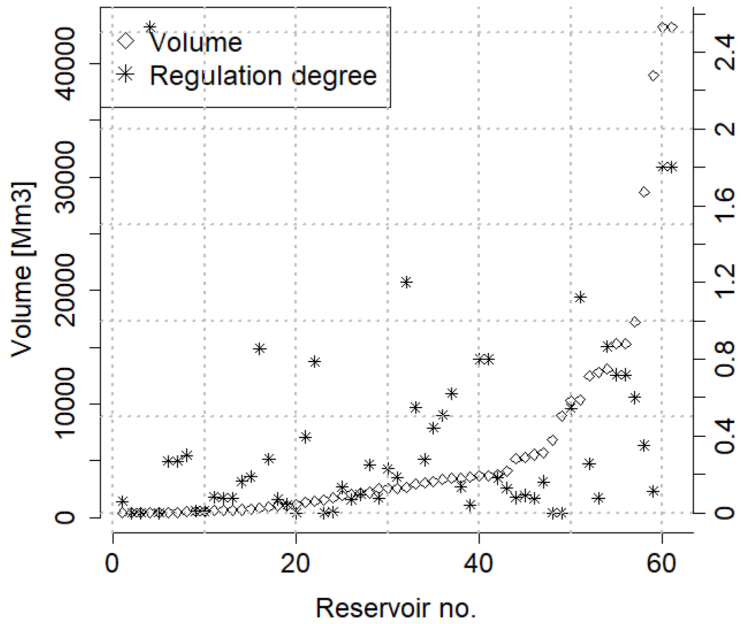


**Figure 18 Volume and regulation degree for the 60 reservoirs with highest storage capacity in Brazil. The data are sorted based on volume.**

Figure 19 shows the nominal head for the registered hydropower plants in that same dataset. Most larger hydropower reservoirs are located at a relatively low elevation, compared to the Norwegian case (see Figure 6 for a comparison). Only a few reservoirs have a head larger than 200 meters. Generation from hydropower plants with lower nominal head will typically be more sensitive to variations in reservoir level, and thus the importance of modelling head-dependency in the hydropower generation function [45].

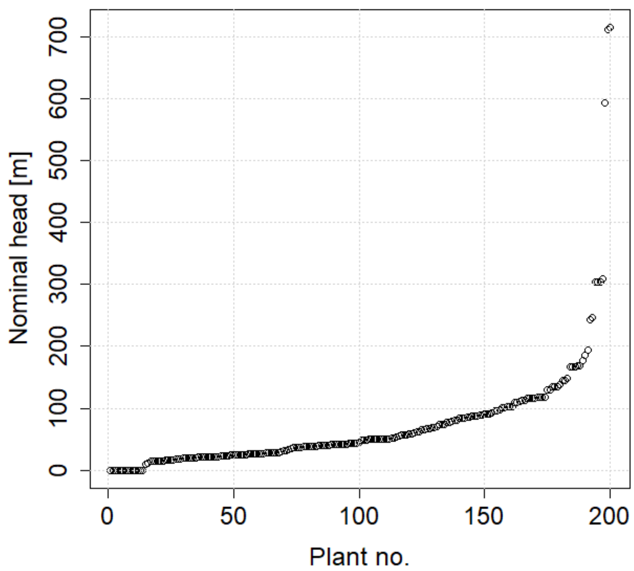


**Figure 19 Nominal head (in meters) for hydropower plants in the Brazilian system.**

## 3.3 Market Structure

Until the middle of the 1990s, the Brazilian electricity sector was predominantly made up of vertically integrated companies [46]. The largest share of generation and transmission over long distance and extra-high voltage were concentrated in federal state companies, with distribution and commercialization mainly concentrated in province-owned companies [47].

The expansion and operation planning activities were centralized and performed by Centrais Elétricas Brasileiras S.A. (Eletrobras), through the chairmanship of the System Planning Coordinating Group (GCPS) and the Interconnected Operation Coordinating Group (GCOI). The tariffs for the electricity services were based on the generation and transmission expansion marginal and average costs and on the operation marginal costs, with guarantee of remuneration. Regulation (normalizing and supervising) was exercised by the Department of Water and Energy (DNAEE) [47].

Nowadays, Eletrobras is the largest electricity producer with 1/3 of the total installed capacity in Brazil and with an ownership of 40% of the main transmission grid.

### 3.3.1 Restructuring – Mid-1990s

The reform of the model then in force began to be implemented in 1995, with the enactment of Law no. 9,074. With this Law, the first steps were taken in the direction of introducing competition in generation and commercialization, still creating the figures of the independent power producer (IPP) and the *free* consumer (new consumers with a load greater than or equal to 3 MW), besides establishing free access to the transmission and distribution grids. Still in 1995, the Brazilian government started the process of privatizing distribution companies (Discos), with the sale of the controlling of Escelsa and Light. In December 1996, Law no. 9,427 created the Electricity Regulatory Agency (Agência Nacional de Energia Elétrica – ANEEL), as main objectives to regulate and supervise sectoral activities. In turn, Law No. 9,478 (1997) created the National Energy Policy Council (CNPE), an advisory body to the President of the Republic, for the formulation of energy policies and guidelines.

In 1996, the Ministry of Mines and Energy (MME) created the Brazilian Electricity Sector Reform Project (RE-SEB Project), whose work group activities continued until 1997. The RE-SEB project followed in broad lines the original central pool of the British approach at that time, but with adaptations to recognize the predominance of the hydropower and the associated advantages. This culminated with the publication of Law 9,648 in May 1998, which led to, among others:

- Creation of the energy trader figure
- Establishment of the unbundling and segregation of the activities of generation, transmission, distribution and commercialization of electric energy, with limits to cross participation
- Encouragement of the gradual increase of free consumers
- Regulation of tariffs for captive consumers and with competitive and deregulated prices for free consumers
- All the new generators considered as IPPs
- The right to build new hydroelectric projects granted by the largest offer to the Union for the use of the public good
- Consideration of transmission and distribution activities as natural monopolies, subject to regulated tariffs.

Another important step towards stimulating competition in generation and commercialization was the creation of the Wholesale Energy Market (Mercado Atacadista de Energia – MAE) and the Brazilian Independent System Operator (Operador Nacional do Sistema Elétrico – ONS), both in 1998.

The MAE is the environment in which all electricity buyers and sellers can trade and where the spot price of energy is determined. The MAE was created by a multilateral agreement which is compulsory for all generators with installed capacity greater 50 MW and for all distribution and retail companies with consumption greater than 100 GWh per year. Large consumers with demand above the threshold for the free market (10 MW) can choose to become members of the MAE.

The main objectives of the MAE were to [4]:

- Set a price which reflects, in each time period, the marginal cost of energy on the system. This price supports the long term bilateral contracts;
- Provide a marketplace in which generators and retailers can trade their uncontracted energy;
- Create a multilateral environment to support the development of competition under which a retailer may buy from any generator and a generator may sell to any retailer.

In this environment, competition between generation companies were associated with the establishment of long-term bilateral contracts with loads. Bilateral contracts are financial instruments, which specify a contract price for a fixed volume of energy. In other words, generators receive a negotiated payment from loads and, in return, become responsible for their spot rates. These bilateral contracts were aimed at reducing exposure to spot prices.

The trading arrangements are based around a tight, centralized system optimization, scheduling and dispatch scheme. Based on the received technical data, the ONS establishes a generation schedule which describes which generation plants should be dispatched and the associated generation target in order to achieve least cost operation of the whole system. This schedule is obtained through the chain of optimization models developed by CEPEL that also calculates the water values. The water values form the basis for determining the spot price, i.e., MAE price in each period.

Generators and retailers were supposed to trade most of their energy via bilateral contracts. These contracts originate payments from retailers to generators. After deducting sales and purchases covered by bilateral contracts, the net requirements of generators and retailers are negotiated and settled in the MAE on a mandatory basis and are subject to the MAE price - that is why the spot prices of the MAE is called till today Settlement Prices for Differences (Preço de Liquidação das Diferenças – PLD).

Once the operation of the SIN is based on a centralized dispatch scheme, the generator does not have the control over its own generation, making it difficult to adopt individual hedge strategies against the hydrological risk. As an attempt to mitigate the financial exposure risk inherent in a hydrothermal system operating in a tight pool scheme, it has been established in the Brazilian system the Energy Reallocation Mechanism (MRE) [48], which will be addressed in Section 3.3.3.3.

### 3.3.2 Electricity Rationing – June 2001 to February 2002

As mentioned before, in this regulatory framework, the development of a hydropower project was granted to the ones that offered the largest monetary value for the project to the Federal Government (Union). The hydro- or thermal-power developers assumed the obligation to seek "loads", i.e., distributors and free consumers, to establish long-term energy purchase contracts (PPAs). However, in a system with predominantly hydroelectric production most of the time, the short-term marginal costs are low; if the loads had established PPAs with generators, they would have to pay higher long-term prices. Then the loads decided to act as “free-riders” and to not establish PPAs with generators since there was no real obligation to be long-term contracted. With no PPAs, the generators were unable to get financing for plants implementation. As a consequence, the expansion of generation capacity required to meet the demand growth did not materialize, and the demand for electricity increased more quickly than generation capacity [49]. In addition, the transmission grid was not adequately expanded in this period.

In summary, the power sector became progressively more vulnerable to the impact of adverse hydrological conditions. This came to a peak in the unusually dry summer of 2001. Water reservoir levels in many parts of the country fell to critical levels, compromising the ability to ensure reliable power supply. As a consequence, the country experienced electricity rationing in the period June 2001 - February 2002. Short-term options to increase electricity generation were relatively limited and so the brunt of the crisis response fell on the demand side, where the government implemented a quota programme that imposed on all residential, industrial and commercial consumers a monthly ceiling, set at 80% of their consumption for the previous year, and penalised excess consumption. This reduced electricity use by 20%, allowing Brazil to avoid the rolling blackouts that otherwise would have ensued. The crisis also had a prolonged impact on demand, with higher public awareness about energy use and efficiency meaning that total residential electricity demand returned to 2000 levels only in 2005.

### 3.3.3 Restructuring – After 2004

The previous regulatory framework (from the RE-SEB project) introduced many of the fundamentals of a competitive market; also, issues related to the operational planning and dispatch, as well as the electricity trading, were well outlined. However, the planning function was left to be discussed and detailed in a second moment, which did not happen. Hence, there was a broad breakdown of these activities. In addition, the fact that the obligation to seek "loads" to establish long-term contracts was transferred to the generators failed, leading to a situation where the generators were unable to obtain financing to build the plants. Consequently, the lack of investment in new generation and transmission capacities meant that the power sector became progressively more vulnerable to the impact of adverse hydrological conditions [49]. During this period, there was even a rationing of electric power of great scope, discussed in Section 3.3.2.

The rationing crisis had major repercussions for the Brazilian power sector. It generated new debate about how to ensure adequate investment, leading to revise the institutional framework of the electrical power sector.

In 2003, MME created a working group to carry out this task. The work was accomplished in December 2003 and the main objectives were to:

- Guarantee the security of electricity supply
- Promote low tariffs, through efficient energy contracting for regulated consumers
- Promote social inclusion in the Electric Sector, in particular through universal service programs

In March 2014 the MME proposal was converted into Laws nº. 10,847 - creation of the Energy Research Company (Empresa de Pesquisa Energética – EPE), responsible for expansion planning studies) and nº. 10,848 (New Energy Commercialization Law). Also, the Power Sector Monitoring Committee (Comitê de Monitoramento do Setor Elétrico – CMSE) was set up and the duties of some institutions have been redefined. This reform gave the State, within a continued commitment to market competition, a more proactive role in planning and financing new capacity.

### 3.3.3.1 Environments for Electricity Trading in Brazil

The introduction of competition for the long-term market was a milestone towards the creation of a more stable investment environment for new generation capacity, with positive impacts on the security of electricity supply [49]. Now loads have to be 100 % contracted.

In this context, two environments for electricity trading were initially established: a Regulated Contracting Environment (Ambiente de Contratação Regulada - ACR) and a Free Contracting Environment (Ambiente de Contratação Livre - ACL).

- ACR - Generators must participate in centralized public auctions to be able to sign PPAs with the regulated (captive) consumers supplied by the Discos, which must provide self-declaration of its forecasted loads for the next five years.
- ACL - Free consumers can procure their energy needs as they wish, as long as they are 100% contracted. Hence, supply and demand are free to negotiate the features of the contract, such as the electricity price, end of term, etc.

The introduced public auctions are a procurement mechanism for purchasing energy for captive consumers. Each winner in auctions is that one which offers the lowest price per kWh also limited to ceiling prices. In exchange, all distribution companies have an obligation to enter into PPAs (15 to 35-year duration) with each auction winner in proportion to their declared load forecasts. The successful generators can offer an assured future cash flow to obtain loans from banks to develop their projects, including the Brazilian National Development Bank. This auction scheme may occur at different times: 3 to 5 (nowadays, 7) years ahead for new generation, and 1 year ahead for existing ones. Auction prices are then passed on to electricity tariffs. Figure 20 depicts the trading environments for electricity in Brazil.

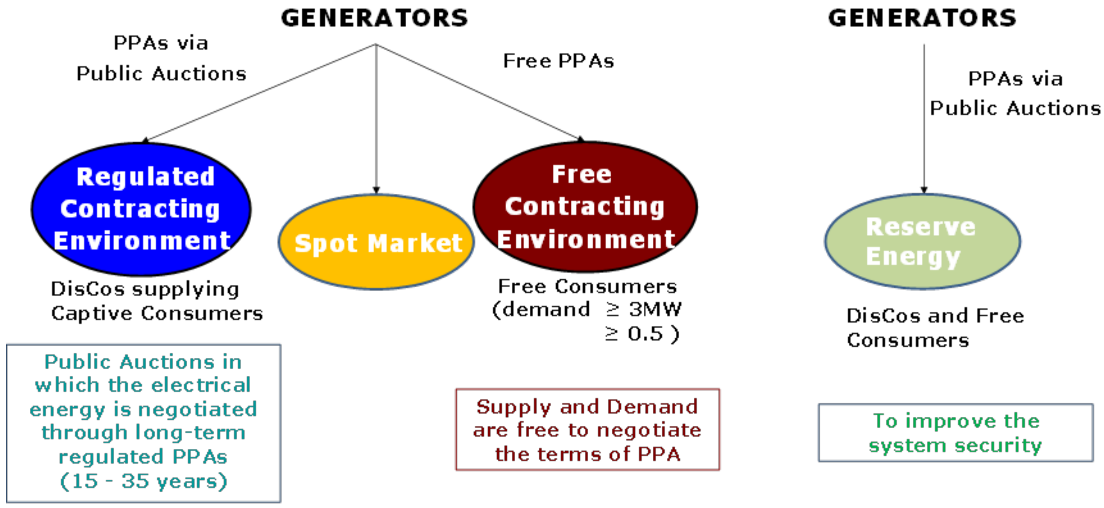


**Figure 20 Environments for Electricity Trading in Brazil.**

MME offers to bid a set of projects (hydroelectric and thermal) studied by EPE and considered the most economical to meet demand. Any generator is able to freely offer, for tenders, alternative projects to the set proposed by MME. It should be noted that hydropower plants need to obtain the Preliminary Environment License from the Environment Agency (IBAMA) to be eligible to participate in the auctions. Also, all contracts, which are financial instruments, must be covered by real power production capacity defined by a "plate number" called Assured Energy Certificate or "Physical Guarantee", which will be described later. In case of thermal power plants, there is also need to present Fuel Supply Purchase Agreement.

Besides the winners signing direct bilateral contracts with the Discos, there is another contract attached called Guarantee Linked Contract (CCG) which transfers the money from the final customers to the generator, thus preventing the Discos from making discretionary payments and, therefore, minimizing the default risk of the generators.

The Government does not interfere with the demand forecasts, which are directly declared by Discos nor does it take ownership for the energy contracts or provides payment guarantees. Also, Discos are allowed to enter into contracting adjustments to the Regulated Market one and two years in advance, re-contracting existing energy in annual auctions and receiving, or transferring, free of charge, surplus energy contracts from other Discos.

In addition, the differences between the production or consumption of energy in relation to the contracts held are settled on the spot market by the PLDs. Finally, there is also the possibility to procure energy through Reserve Energy Auctions aiming at to improve the system security; the contracted energy must be paid for both distribution companies and free consumers.

#### 3.3.3.2 Roles and Responsibilities

In the restructuring of 2004, new institutions were created and some existing ones had their roles and responsibilities redefined. Below are brief descriptions of some entities (and their acronyms) that are central in the Brazilian electricity sector and relevant in the remaining text. These entities are also depicted in Figure 22.

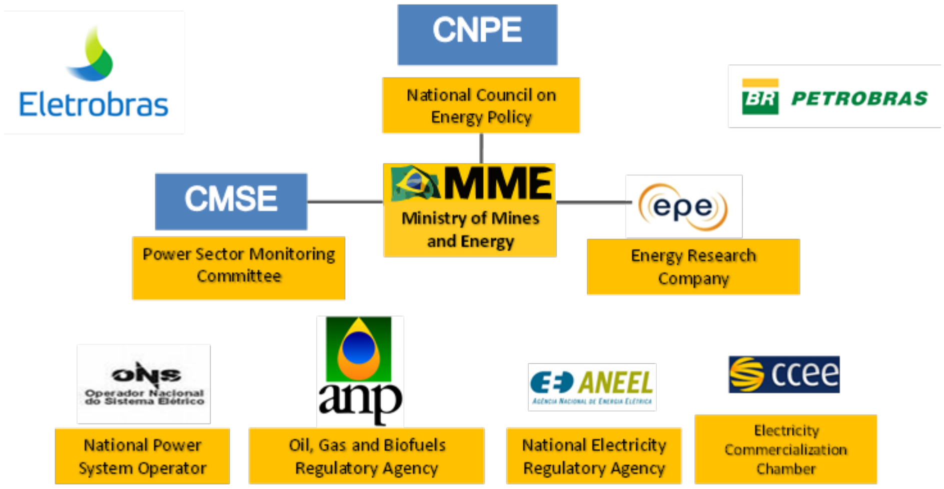


**Figure 21 Current Institutional Framework of the Electricity Sector in Brazil.**

National Energy Policy Council (**CNPE**): an advisory body to the President of the Republic, in charge of the following duties: proposal of the national energy policy to the President of the Republic, in articulation with other public policies; proposition of individual bidding for special projects in the Electric Sector, recommended by MME and proposition of the structural supply guarantee criterion.

Ministry of Mines and Energy (**MME**): formulation and implementation of policies for the Energy Sector, according to CNPE guidelines; exercise of the sector planning function; exercise of granting power; monitoring the security of supply in the Electricity Sector, through the CMSE and definition of preventive actions to restore security of supply in the case of conjunctural imbalances between supply and demand, such as demand management and/or contracting the conjunctural energy reserve of the interconnected system.

Electric Energy Regulatory Agency (**ANEEL**): mediation, regulation and inspection of the functioning of the Electric System; holding auctions for the concession of generation and transmission projects by delegation from the MME and bidding for the acquisition of energy for Discos.

National Agency for Petroleum, Natural Gas and Biofuels (**ANA**): responsible for regulating the oil and natural gas and biofuels industries in Brazil. It executes the national policy for the sector, with a focus on guaranteeing fuel supply and defending consumer interests, while also ensuring the quality of fuels sold to the final consumer. It also promotes bids and signs contracts on behalf of the Union for exploration, development and production activities.

Brazilian Independent System Operator (**ONS**): responsible for coordinating and controlling the operation of the electricity generation and transmission facilities in the National Interconnected System (SIN) and for planning the operation of the country's isolated systems, under the supervision and regulation of ANEEL. It's main objectives are: to promote the optimization of the operation of the electric energy system, aiming at the lowest cost for the system, observing the technical standards and reliability criteria established in the Grid Procedures approved by ANEEL; and ensure that all agents in the electricity sector have access to the transmission network in a non-discriminatory manner. The SIN operation is based on a centralized system optimization, scheduling and dispatch scheme, which is further described in Section 3.3.4.

Chamber for Commercialization of Electrical Energy (**CCEE**): took the role of MAE in managing the wholesale market and began to exercise the functions of accounting and financial settlement in the spot market; calculation of the Difference Settlement Price - PLD, used to value energy purchase and sale operations in the spot market; contract management of the Regulated Contracting Market and the Free Contracting Market; recording of generated energy and consumed energy data; hold power purchase and sale auctions at ACR, under the delegation of ANEEL; hold Reserve Energy auctions, under the delegation of ANEEL, and effect the financial settlement of the amounts contracted in these auctions.

Energy Research Company (**EPE**) **-** created with the main objective of developing the necessary studies so that the MME can fully exercise its role of executing energy planning, and with the following duties: studies to define the energy mix with an indication of the strategies to be followed and the goals to be achieved, within a long-term perspective; studies of integrated planning of energy resources; expansion planning studies for the electrical system (generation and transmission); foster studies on energy potential, including inventory of hydrographic basins and elaboration of technical, economic and socio-environmental feasibility studies for plants and obtaining the Preliminary License for hydropower projects.

Power Sector Monitoring Committee (**CMSE**): instituted within the scope of MME, with the function of permanently monitoring and evaluating the continuity and security of the electric energy supply throughout the national territory. Its duties include: monitoring the development and supply conditions of the activities of generation, transmission, distribution, commercialization, import and export of electric energy, natural gas and oil and its derivatives; periodically carry out an integrated analysis of security of supply for the electricity, natural gas and oil markets, considering the demand, supply and quality of energy inputs, the hydrological conditions and the prospects for gas and other supplies fuels. In addition to the MME, which presides, ANEEL, ONS, CCEE, EPE and the National Petroleum Agency for Petroleum, Natural Gas and Biofuels (ANP) also participate.

One example of the coordinated interaction between the sectorial entities is the development stages of a hydroelectric project [50] (see Figure 22), starting from the formulation of alternatives for the partition of the total water head (inventory studies), going through the feasibility studies where the preliminary environmental license, water availability declaration and the project sizing approval should be obtained from the social and environmental agencies, Water Regulatory Agency and ANEEL, respectively, which are prerequisites for entering public auctions; the winner in the auction process is in charge to develop the basic project that also includes the elaboration of the basic environmental plan report in order to apply to the environmental installation license; finally, in the executive design stage all necessary measures related to the plant, including the implementation of socio-environmental programs are decided and the environmental operating license is required to start the filling of the reservoir for the beginning of the operation.

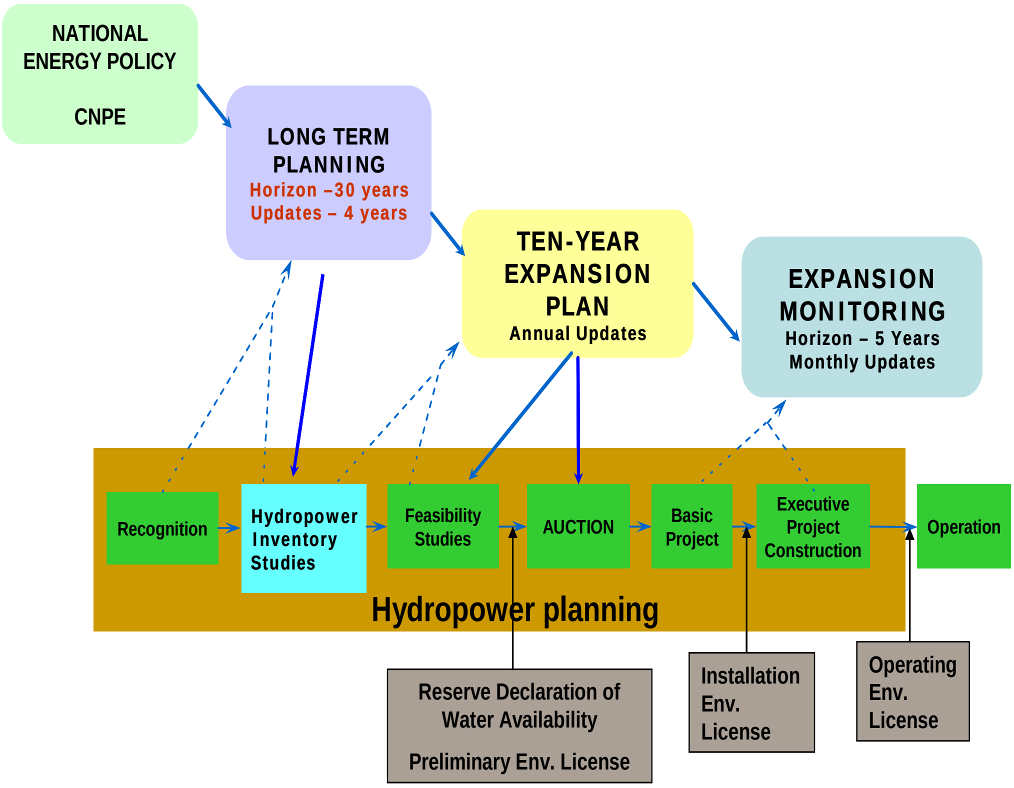


**Figure 22 Stages of hydropower development in Brazil [50].**

Inspired in the strategic uses of NEWAVE model in 2007 the National Council for Energy Policy issued an act calling MME to establish a Standing Committee for Analysis of Methodologies and Computational Programs of the Electric Sector – **CPAMP**, which was put in place by MME in 2008. The key objective of CPAMP is ensure consistency and integration of methodologies and computer programs used by MME, EPE, ONS and CCEE, in the following activities: expansion planning; operation planning and scheduling; electricity commercialization; definition and calculation of the physical guarantee and assured energy of the generation projects; and preparation of guidelines for conducting auctions for the purchase of electricity [51].

Also, any changes in methodologies and computer models must comply with the principles and guidelines proposed by MME and approved by CNPE. The members of CPAMP are MME (chair), ANEEL, EPE, ONS and CCEE; CEPEL takes part of all meetings and provides technical support for this committee. In 2019, a new act stated that the work resulting from the activities of CPAMP will be forwarded to the Minister of MME. Besides discussing and defining priorities for improvements in methodologies and computer programs, CPAMP also validates new developments, releases and key parameters of the official models, including the scheduling models.

#### 3.3.3.3 Energy Physical Guarantee/Assured Energy and the Energy Reallocation Mechanism

In the central dispatch scheme, owners of controllable power plants do not decide the physical output of their generation assets. Despite the synergistic gains from integrated operation, there are at least two relevant complexities with the central dispatch scheme for the Brazilian hydro-dominated system:

1) The long-term energy security. The dispatch of both hydropower and thermal plants depend on hydrological conditions, which are uncertain. A question that arises is what is the maximum amount of energy that a power plant can trade in the long-run, i.e., through PPAs. In Brazil this is called **Assured Energy** or **Energy Physical Guarantee**, which is calculated by a specific procedure, taking into account the overall system optimization, as outlined in this session.
2) The strong impact of hydrological conditions on the energy production of hydroelectric plants. The centralized dispatch scheme imposes a significant hydrological risk to the revenue streams of the plant owners and hinders the adoption of individual hedge strategies against hydrological risk. This is compensated through the **Energy Reallocation Mechanism (MRE)**, also discussed in this session.

**Energy Physical Guarantee (Garantia Física de Energia - GF)**
The GF is the maximum amount of energy, in MW-average, that a hydropower or thermal plant dispatched centrally by ONS can use to trade through contracts. It is computed by using the NEWAVE and SUISHI models in a specific procedure defined by MME comprising the following steps [52]:

a) Calculation of the total GF of SIN – corresponds to the maximum amount of energy that the SIN can supply ("critical load") given the supply guarantee criterion defined by CNPE (the equality between the expected operation marginal costs of and the expansion marginal cost, and still respecting an energy deficit risk limit of 5% in all subsystems)[32]. The total system GF is the result of an iterative process in which the energy demand in the subsystems are changed in each step until the energy supply adequacy criterion is met. For this, the NEWAVE model is applied using a static system configuration, horizon of 5 years and 2000 synthetic energy inflow sequences.

b) Division of total GF of SIN in hydropower and thermal energy blocks - at the end of the previous iterative process, the total GF is divided in two parts – a hydro block and a thermal block, based on the expected generation of the energy equivalent reservoirs (EERs) and thermal plants, respectively,

c) Apportionment of the hydro block among individual hydropower plants – as for the purpose of calculating GF the NEWAVE model represents the hydropower plants by EERs, it is necessary to

[32] In December 2019 CNPE changed the probabilistic part of the energy supply criterion and its implementation in NEWAVE is ongoing.

allocate the hydro block among the set of hydropower plants of the system to obtain individual GF certificates. This allocation is carried out in proportion to the *firm energy* of each hydropower plant. The firm energy corresponds to its average generation during the worst inflow period of the historical record – the so called critical period, and is calculated by simulating the operation of the individual hydropower plants of the purely hydroelectric system considering the largest demand that can be supplied without the occurrence of deficits. For this, the simulation model SUISHI is employed [52].

d) Apportionment of the thermal offer among individual thermal power plants - although the NEWAVE model already comprises the generation of thermal power plants individually, in this step adjustments are made to limit the GFs to the values of maximum availabilities.

GF is therefore a critical measure for each plant centrally dispatched by ONS, and especially for hydropower plants.

**Energy Reallocation Mechanism (MRE)**

The purpose of the MRE is to share the hydrological risk among all hydropower plants in the system. Through the MRE, each plant is assigned a fraction of the total amount of hydropower generated within a certain period. This fraction is found as the ratio between the GF computed for the individual plant and the sum GF of all hydropower plants. Thus, the MRE provides a mechanism to reallocate energy from plants that have generated above their GF to those who generated below. Consequently, through the MRE, revenues of an agent do not depend only on its actual generation. However, the regulation requires the individual GF for each plant to be revised every five years to reflect changes in generation capability. In each revision the change in the GF is limited to 5 % whereas the its change in the plant economic life span (35 years) is limited to 10 %. As discussed in [43], the MRE scheme cannot protect hydropower plants from hydrological risks impacting the country's hydropower portfolio as a whole, such as prolonged periods of drought[33].

The MRE rules can be summarized as follows [48]:

1) For each subsystem, its generation surplus/deficit is determined comparing its total hydro-generation with its total GF.

2) In each subsystem with generation surplus, the hydropower plants with generation deficit will receive "electricity rights" from the hydropower plants with generation surplus. After that, the remaining surplus of the subsystem will be allocated to compensate deficits in other subsystems.

3) If the total generation of the SIN is greater than its total GF, the difference is allocated among all hydropower plants of the system in proportion to their individual GF.

Note that, according to this scheme, the GF of a given hydropower plant can be physically allocated in a different subsystem than that one where the plant is located. In this case, if the spot prices are different in each subsystem, financial exposures can be observed, which may be significant in periods of high spot price differences. In addition to this, for a given period, if the total system's hydropower generation is lower than the system GF, all hydropower plants may be exposed to the spot price, depending on their levels of energy contracting.

[33] This problem was experienced with the critical inflows in 2014 and 2015. The set of hydropower plants together generated less than the total physical guarantee, at a time when the upper limit of the PLD was well raised, causing high financial consequences.

Generators are allowed to sell all of their GF via the regulated (ACR) and the free (ACL) markets. In 2017, the ACL accounted for almost 30 % of national electricity consumption and 77 % of industrial electricity consumption.

### 3.3.4 Centralized Dispatch

The ONS collects technical data from generators and loads to perform a centralized cost-based dispatch of the system, as illustrated in Figure 23. Hydro and thermal generators submit their technical data to the ONS, such as reservoir levels, inflow, availability of equipment/facilities, thermal efficiency, fuel and operating costs, etc.

ONS is responsible for physical dispatch across the entire system, with the objective of minimizing operating costs while ensuring system security. ONS uses the suite of computational models developed by CEPEL to determine the most efficient hourly production schedule for each plant. This means that hydropower plants are dispatched based on their expected opportunity costs.

### 3.3.5 Settlement

As described in Section 3.3.3.1, generators are obliged to sell their energy through the ACR and ACL markets. Contractual differences between generation and consumption are settled according to a difference settlement price (PLD). Thus, the generators receive a fixed payment for financial contracts through the markets and deviations in physical delivery are settled according to the PLD.

The PLD is often referred to as the "spot price". Currently, CCEE computes the PLD on a weekly[34] basis for light, medium, and heavy load levels in each of the four SIN subsystems. The PLD are computed ex ante, in the sense that computations are done for the week ahead based on expected values of inflow, equipment availability, loads, etc. The PLDs are found using the same mathematical models and data as for the ONS dispatch, and thus represents a sound estimate on the expected marginal costs of operating the system. CCEE runs the model toolchain developed by CEPEL to obtain the PLDs.

To determine the spot market price, only the major transmission constraints are taken into account. Therefore, the Brazilian interconnected system is divided into a small number of price zones (currently four), denoted as “submarkets” or “subsystems”, which reflect the effects of these more important transmission limitations. The PLDs are determined for each submarket and transmission loss allocation factors are used to calculate the final price for each generator and load inside each submarket.

Wholesale competition is facilitated through CCEE and is compulsory for all generators larger than 50 MW and loads with more than 100 GWh per year [4].

[34] It is envisaged that from January 1, 2021 on CCEE will calculate the PLD in an hourly basis.

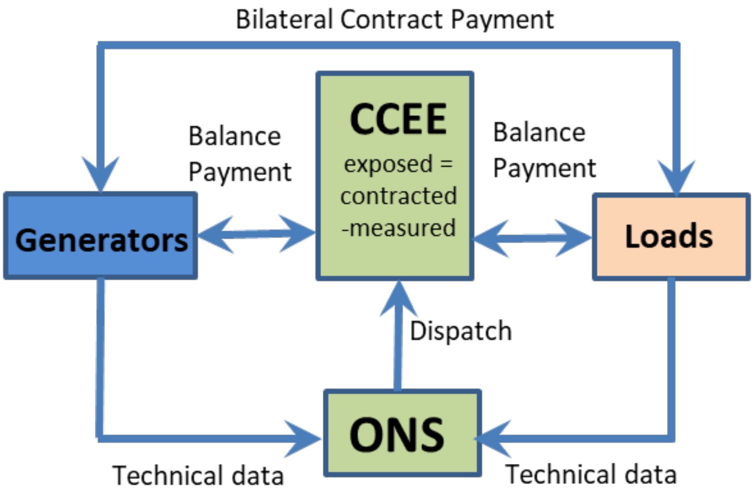


**Figure 23 Relationship between ONS, CCEE and market participators. Similar to [4].**

Figure 23 illustrates the financial settlement in the Brazilian market. Generators and Loads contract their energy in the ACL and/or ACR markets. Then they submit their technical data to ONS, which in turn determines the actual system dispatch. CCEE accounts for the differences between actual production and consumption, and the respective contracted amounts. Differences are settled in the market through the PLD.

Generators and loads also pay a yearly fixed transmission use of the system charge – TUOS ($/installed kW for generators and $/yearly peak for loads), which depends on their location.

An interesting comparison of spot price volatility, given by the standard deviation of the returns Rt = ln (Price *t* / Price *t-1*) was calculated by CCEE and is presented in Table 5. One can observe that the weekly and monthly volatility[35] of the PLD is less than the hourly and monthly volatilities[36] in the Alberta (Canada), Chile, PJM (USA) and Colombia markets. For comparison, the observed day-ahead price volatility in the Norwegian price area NO5 (western coast) over the 5 past years is reported in Table 6.

**Table 5 Hourly, weekly and monthly spot price volatility in selected markets[37].**

| País/Mercado | | Volatilidade horária | Volatilidade em base mensal |
|---|---|---|---|
| Canadá - Alberta | | 34,5% | 119,7% |
| Chile (P. Azucar) | | 26,0% | 90,0% |
| PJM | | 29,4% | 101,7% |
| Colômbia | | 16,3% | 56,6% |
| Califórnia (Independent System Operator) | | 29,8% | 103,1% |
| Brasil - Semanal (DECOMP) | Sudeste | 2,4% | 8,2% |
| | Sul | 2,4% | 8,2% |
| | Nordeste | 2,7% | 9,4% |
| | Norte | 2,2% | 7,8% |

35 Covering the period July 2018 to October 2019.
36 Covering the period 2013 to 2017.
37 CCEE presentation at CPAMP Methodology Working Group webinar, Rio de Janeiro, 18 June, 2020.

**Table 6 Spot price volatility for Norwegian price area NO5 (2015-2019).**

| Resolution | Volatility |
|---|---|
| **Hourly** | 6.5 % |
| **Daily** | 12.2 % |
| **Monthly** | 18.2 % |

## 3.4 Applied Toolchain

The chain of optimization and simulation models developed by CEPEL, shown in Figure 24, extrapolates the operation planning and also encompasses the expansion planning the activities, covering the long-term generation expansion planning (30-40 years ahead), the short-term generation expansion planning (so called ten year expansion planning), long/medium/short-term operational planning and unit commitment. It considers distinct planning horizons and degrees of detail in system representation and allows for a smooth and coordinated transition between decision making in each of the time horizons, being largely utilized in Brazil by the government, institutional agencies (MME, EPE, ANEEL, ONS and CCEE), utilities and power industry in general [53].

The main mathematical models comprise stochastic optimization models (NEWAVE, DECOMP), mixed integer linear optimization models (DESSEM, MELP), linear optimization model (MATRIZ), simulation model (SUISHI), synthetic inflow scenarios generation model (GEVAZP), streamflow and wind power forecasting models (PREVIVAZ, VENTOS), short-term load forecasting models (PrevCargaPMO, PrevCargaDessem), reliability model (CONFINT), flood control models (CHEIAS system), hydropower inventory of river basins model (SINV) and investment risk analysis model (ANAFIN). Additionally, methodologies and software to include the environmental issues in the generation expansion planning are also part of the tool chain.

The modelling toolchain concept has matured over decades in Brazil. An early reference on the concept is [54]. The author 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*.". The author outlines a general toolchain and discusses the natural decomposition between models, the different model's time frames and level of details, and even the feedback from lower- to higher-level models to seek a global solution.

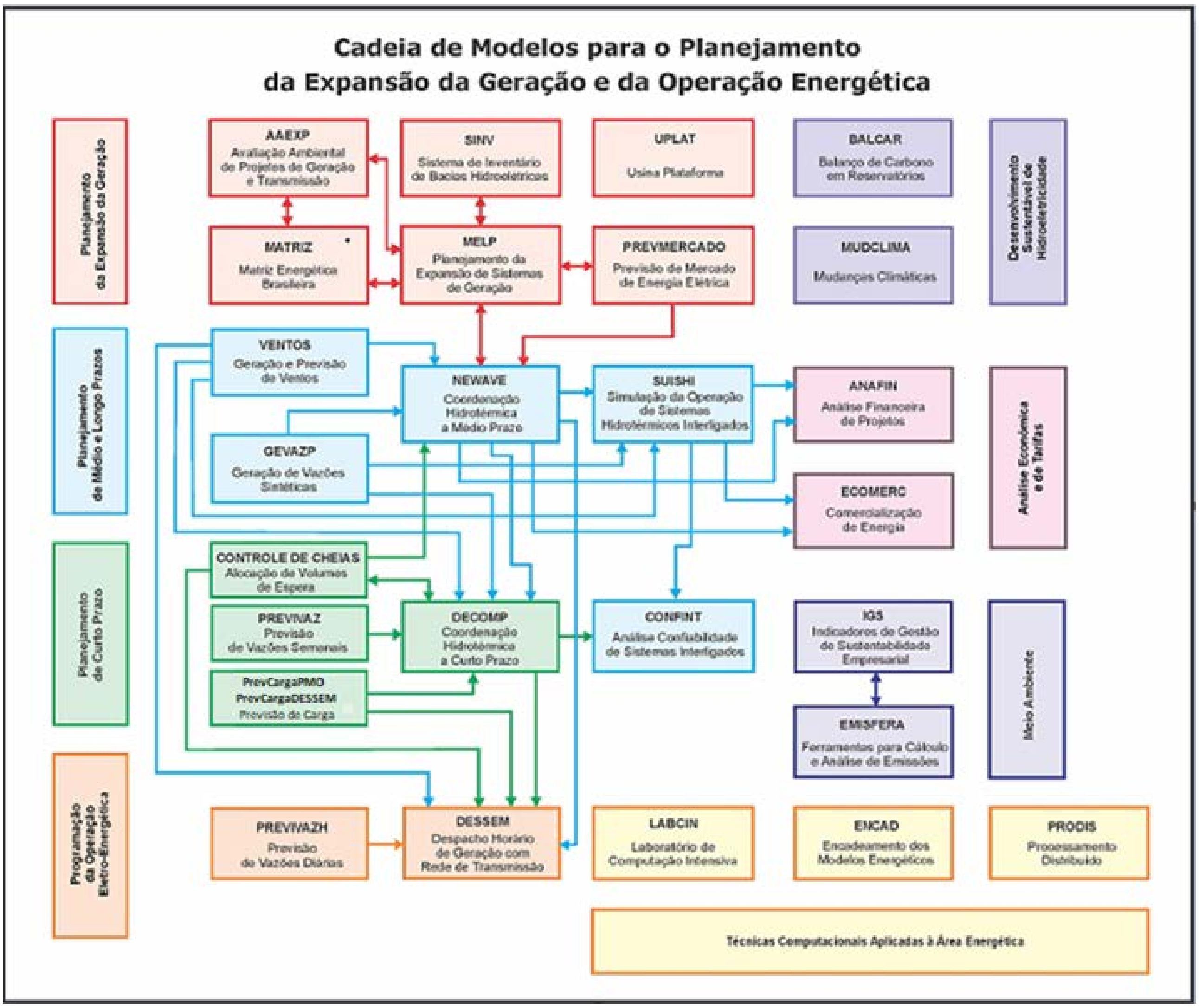


**Figure 24 Toolchain used for scheduling an planning of the Brazilian system [53].**

The Brazilian toolchain comprises a specific set of models, and defines how the operational planning should be carried out. Both system dispatch by ONS and pricing by CCEE is carried out by using the same toolchain and models[38]. This is a clear contrast to the Norwegian case, where the use of toolchains and models is not uniform.

Besides discussing and defining priorities for improvements in methodologies and computer programs, CPAMP also validates new developments, releases and key parameters of the official models, including the scheduling ones. It is part of the validation process to hold workshops followed by public consultations with interested parties on the improvements implemented in the computational models that will come into force in the near future. As an example, in 2019 public consultations were held on the adoption of the hourly price and the DESSEM model, and on the improvements of the NEWAVE model. As a result, the MME Minister published two acts in July 2019:

[38] However, there are some minor differences in how it is used.

- Regarding utilization of the DESSEM model:
  - As of January 1, 2020, the DESSEM model would be used for the purposes of programming the operation by ONS, according to the Grid Procedures to be approved by ANEEL.
  - As of January 1, 2021, the DESSEM model should be used for the purpose of forming the PLD, accounting and settlement by CCEE, preceded by a “shadow operation” until December 31, 2020 with the disclosure of the hourly PLD for informational purposes only.

- Approving the improvements in the NEWAVE model proposed by CPAMP, which included:
  - The use of the resampling technique in the forward pass of the SDDP algorithm to increase the accuracy of the cost to go function
  - Adoption of minimum operating volumes to enhance system supply security
  - A redefinition of risk aversion parameters (CVaR).

On top of that, new functionality and improvements in the operational planning models of the Brazilian toolchain are thoroughly tested before their use has been approved through a rigorous validation process organized by a task force coordinated jointly by ONS and CCEE, with the supervision of ANEEL, and the participation of all interested stakeholders in the electricity industry.

We describe the basics of this toolchain in the following, emphasizing on operational scheduling, where the major output in the end are the market short-term dispatch provided by the system operator and the "spot prices".

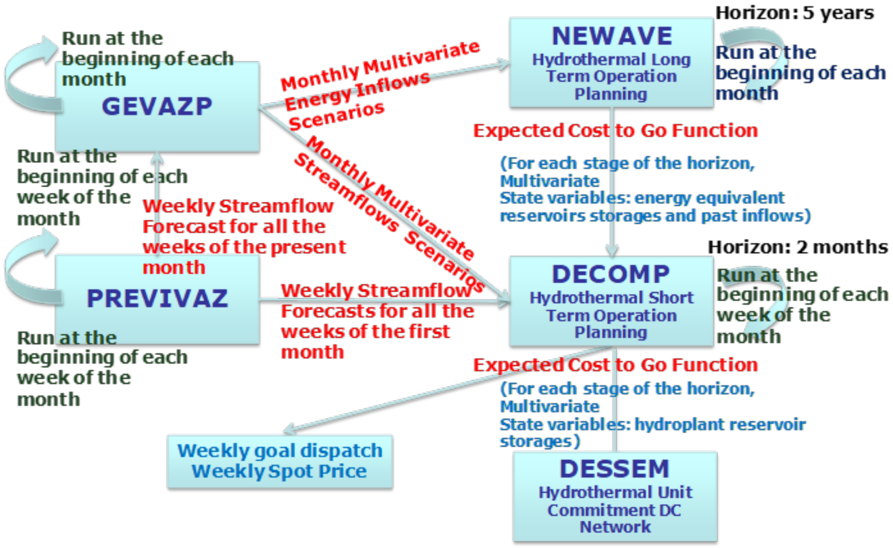


**Figure 25 CEPEL´s toolchain for the Brazilian generation expansion and operational planning [53].**

The procedure for executing the monthly energy operation plan and the day ahead scheduling of the SIN is depicted in Figure 25. At the end of each month, ONS runs GEVAZP [55] [56] that generates energy inflow sequences to each energy equivalent reservoir based on recent observed energy inflows. These sequences will be utilized by NEWAVE to construct a multivariate cost to go function for each month of the five-year horizon. These functions provide the expected system operation cost over the entire horizon, given the storage level of the subsystems at the beginning of the month and the previous observed energy inflows. Then, ONS runs DECOMP, which considers at the end of its two-month horizon the expected cost-to-go function produced by NEWAVE. In the first month, which is discretized in weekly steps, DECOMP model utilizes just one streamflow sequence for each hydropower plant of the system, produced by a runoff model for the first week and by a stochastic streamflow forecasting model PREVIVAZ [57] for the remaining weeks. In the second month an ensemble of streamflow sequences for each hydropower plant are generated by GEVAZP, conditioned to the streamflow forecasts of the previous month and the recent observed ones. At the end of this process DECOMP produces the weekly goal dispatch for all thermal and hydropower plants and the energy interchanges among subsystems. Additionally, it produces a multivariate cost-to-go function for each time step horizon which will be utilized by DESSEM model at the end of its horizon, to determine the hourly dispatch with a time horizon of up to one week and a time discretization of up to half-an-hour. Therefore DECOMP is run at end of each week of the month, always considering the cost-to-go function of NEWAVE model obtained at the end of the previous month while DESSEM is run every day taking into account the cost-to-go function of DECOMP obtained at the end of the previous week.

The key components in the current Brazilian operational scheduling toolchain are shown in Figure 20, ranging from the long-term NEWAVE model, through medium-term DECOMP model to the short-term DESSEM model. This figure also summarizes the main features of these optimization models and the rolling horizon scheme that is applied to coordinate them, by running them for each month *m* (NEWAVE), week *w* (DECOMP) and day *d* (DESSEM), with the time horizon and discretization shown in the table and updated information on reservoirs storages, inflows, load forecasts, etc. [58].

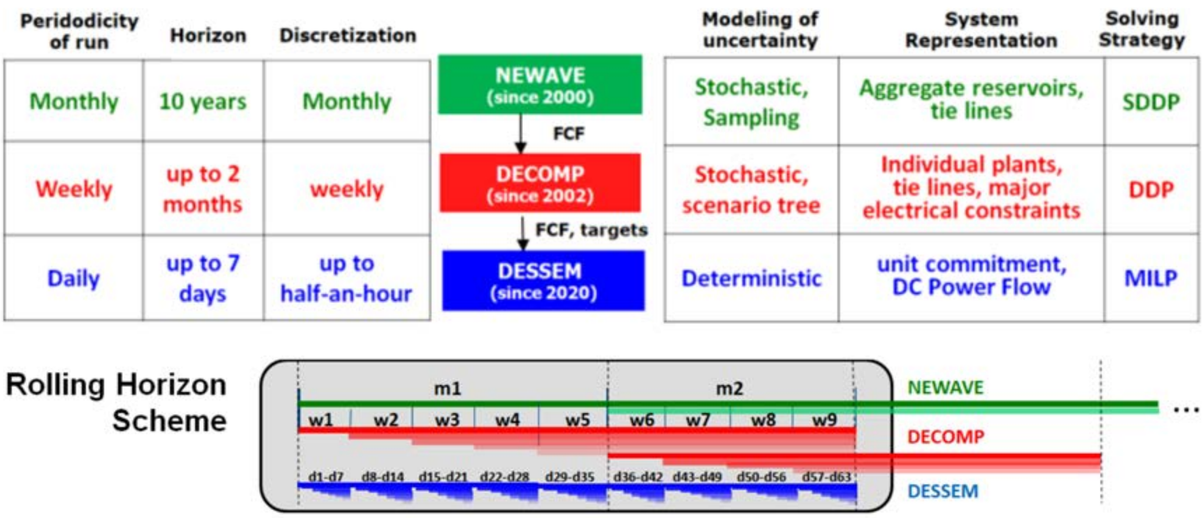


**Figure 26 Rolling horizon scheme for NEWAVE, DECOMP and DESSEM models [58].**

A brief description of each NEWAVE, DECOMP and DESSEM models with some more details on the couplings between models are presented in the following sessions.

## 3.5 Long-Term Scheduling – NEWAVE

We will first provide a brief coverage of how the early introduction of mathematical models for hydrothermal scheduling at CEPEL. After that focusing on establishment and gradual development of the NEWAVE model.

### 3.5.1 History and Background

As early as in 1977 Eletrobras and CEPEL completed the development of a computational model for hydrothermal coordination based on SDP, and this model 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 the hydrothermal scheduling.

An important improvement with the SDP model was the model's probabilistic treatment of security of supply [44]. The rule-curve approach applied a deterministic security criterion, ensuring that the load would be met under the occurrence of the worst historical inflow conditions. In contrast, the SDP model minimized the expected operation costs in the planning period, with inflow as a stochastic process and the possibility of rationing at a high cost.

The system operation at this time was organized as a pool structure, where utilities shared the costs of operating the system. Thus, the use of a mathematical model to minimize system costs naturally resembles system operation.

The new 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. The SDP model was thoroughly compared against the previously used rule-curve approach. Details of the implementation and validation process are described in [44], highlighting the significant expected savings obtained by using the SDP model.

The methodology is outlined in [44] and comprises the following steps:

- Aggregate the systems comprising the 50 major reservoirs in the system into one equivalent reservoir.
- Aggregate and convert reservoir inflows to energy inflows to the equivalent reservoir, and establish a stochastic inflow model for the equivalent reservoir.
- Apply SDP to find the optimal strategy for the aggregate reservoir.
- Disaggregate the aggregate hydropower generation to the detailed power stations, according to a set of rules.

The SDP model considered two state variables: The aggregate reservoir and the energy inflow in the previous month. These were discretized into 100 and 10 levels, respectively. A 5 year planning horizon with monthly decision stages was used.

Model mechanisms to protect the strategies against dry periods are discussed in both [44] and the risk-constrained SDP approach presented [59].

At the end 1980s researchers at CEPEL developed the SDDP method, which was a significant methodological breakthrough for the long-term scheduling [60] and [61]. Unlike SDP, there is no need to discretize the state variables with the SDDP method. In 1993, the SDDP algorithm was extended to take into account serial correlations of the inflows to reservoirs through auto-regressive periodic models, which allowed to consider the hydrological trend as state variable [62]. Consequently, the SDDP method paved the way for considering multiple reservoirs in the long-term scheduling without compromising the computational complexity. This development triggered the development of the SDDP-based NEWAVE model in 1993.

The NEWAVE model 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 in that year. Among other aspects, Law 9,648 called for the calculation and approval by the Regulator of the so-called “initial contracts” to phase in the existing contracts from the old. These initial contracts were based on the concept of power plant assured energy, which is obtained by solving long-term hydrothermal coordination problems in a procedure very similar to that described in Section 3.3.3.3. On the other hand, a new 500kV transmission line (North/South) also started its operation in 1998, and inaugurated the interconnection between the North/Northeast and South/Southeast subsystems, which were operated independently until that date. Due to the dimensions of these now four large and interconnected systems, the only existing methodology to deal with the associated long-term hydrothermal coordination problem was SDDP, and the only validated computational program based on this algorithm was NEWAVE. Therefore, the year of 1998 marks the first official use of the NEWAVE program in Brazil.

The NEWAVE model has many applications, but we will focus here on the long-term operational planning in the following, referred to as the Energy Operation Planning (PMO).

NEWAVE has been officially used by the ONS to dispatch the hydro and thermal power plants since 2000, and for the wholesale electricity market by MAE and later CCEE to calculate the electricity "spot prices" (PLD).

### 3.5.2 Program Description

The NEWAVE system boundary comprises Brazil, with a number of energy equivalent reservoirs (EER) within the four subsystems connected through a transmission grid. The four subsystems are the same for which spot prices are computed. Recently, the number of EERs in NEWAVE has increased from 4 (before 2015) to 9 and later to 12 in 2018. A schematic diagram of the hydropower in the Brazilian system and its aggregation into the 12 ERRs is presented in Figure 27.

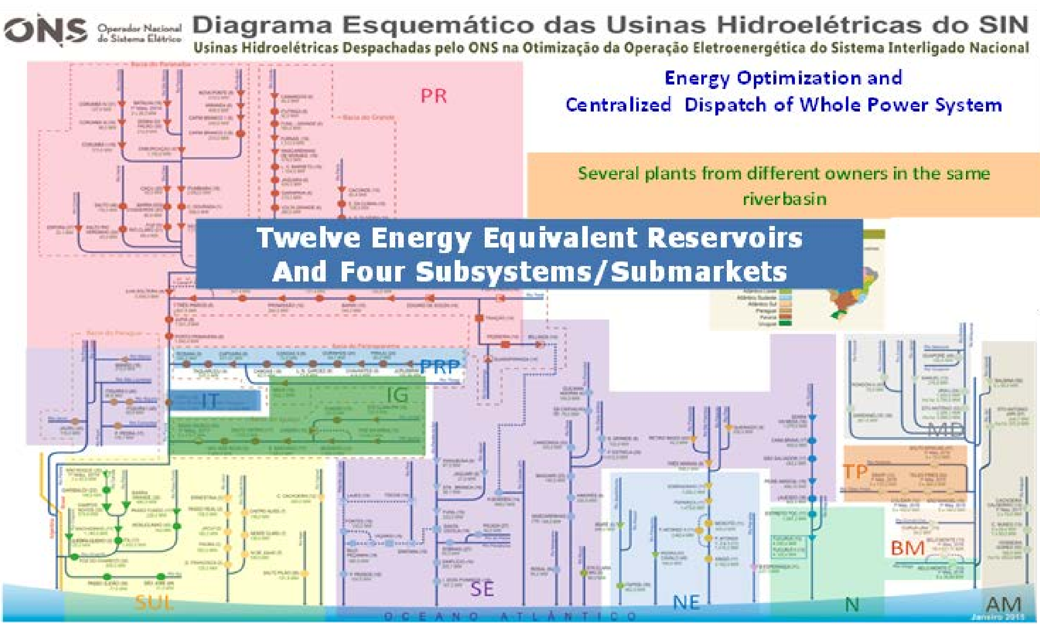


**Figure 27 Schematic diagram of the hydropower plants composing the 12 ERRs [52].**

Figure 29 shows the four SIN subsystems and the 12 EERs, where the EERs are distributed as follows: 3 in the North subsystem, 1 in the North-East, 6 in the South-East and 2 in the South. The properties of the EER is derived from the individual plants and reservoirs. Transmission corridors between subsystems are represented by their maximum capacities, i.e., the grid impedances are not reflected in the model. Transmission losses are accounted for using a constant loss factor. Thermal plants are modelled with their piecewise-linear and convex cost curve without considering start-stop costs.

NEWAVE treats the overall long-term scheduling problem formulation as a multi-stage stochastic linear programming problem, where energy inflows to the EERs are the stochastic variables. These energy inflows are synthetically generated from a stochastic model, based on a periodic autoregressive model PAR(p) of order p [55], [56].When used for monthly operational planning (PMO), the planning horizon is set to 5 years with monthly decision stages. An initial state is provided as input, defined by parameters such as the initial reservoir levels, the hydrological trend forecasts for fuel costs and maintenance plans.

The model is based on the SDDP algorithm, for which the basic principles are described in [61] and with the inflow as a state variable in [62]. We will not go into the details of how the SDDP algorithm solves the multi-stage problem, just mention a few characteristics. Each main SDDP iteration comprises a forward pass (simulation) and a backward pass (recursion). Benders cuts which approximates the future cost function are created in the SDDP backward iteration.

The NEWAVE model is run at the beginning of each month to provide operational strategy in the form of Benders cuts constraining the future cost function for the medium-term scheduling. These cuts express the future cost as a function of the system states. NEWAVE allows the following 3 state variables [51], [63]:

1) Volumes for each of the equivalent reservoirs
2) Hydrological trend (inflows), as described in [62]
3) Dispatch of LNG plants, as described in [64]

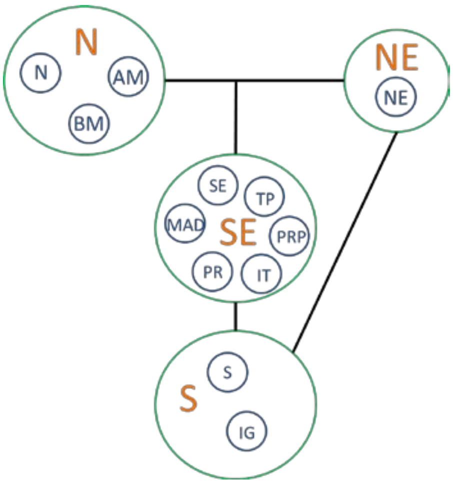


**Figure 28 Subsystems and EERs in the NEWAVE model.** [39]

[39] M. E. P. Maceira, presentation at ICSP 2019, "Hybrid Representation of Hydropower Plants and Inflow Scenarios Re-Sampling on SDDP: improvements in the official model used for operation planning of the Brazilian system"

### 3.5.3 Couplings with Other Models

Being a long-term model and at the top of the toolchain, NEWAVE does not receive explicit input from any of the other models in the toolchain.

The NEWAVE model provides Benders cuts to describe the future cost function at the end of the medium-term horizon. Energy equivalents are used to convert reservoir volumes and inflows between *energy* in NEWAVE to *water* in DECOMP. The same energy equivalent used when converting from individual to aggregated hydropower plants within NEWAVE is also used when converting water to energy in the future cost functions.

### 3.5.4 Recent Developments

The most recent developments in NEWAVE are summarized in [51] and are summarized below.

**More detailed description of hydropower**
As mentioned, the number of EERs in the model has increased from 4 originally to 12 recently. The motivation for this increase was to better capture the diversity of hydrological behaviour of river basins. A further increase in the resolution of hydropower representation has been tested in a *hybrid modelling approach*, allowing the NEWAVE model to represent hydropower plants individually in the entire or in parts of the planning horizon [51], [65]. This hybrid modelling facilitates a natural coupling between the long- and medium-term models through Benders cuts with similar number of reservoir states. The transition between individual and aggregated reservoirs is managed by summing up the contributions of each individual reservoir according to its reservoir level and constant efficiency.

**Computational efficiency**
Increasing the level of detail will also lead to increase computation times. Significant work has been done to decrease computation time by *parallelizing* the program, as described in [66]. Several techniques are successfully applied, such as load balancing, asynchronous communication, and local storage of cuts to minimize the need for communication.

**Risk aversion**
The original NEWAVE model sought to minimize the expected costs of operating the system over the scheduling horizon. Later on, it was found that this could lead to unacceptable operating states for the system operator, and a significant effort was made to improve the modelling by incorporating a risk aversion mechanism. Two major approaches were tested in the NEWAVE model: The Conditional value at Risk (CVaR) and Risk Aversion Surfaces (SAR).

- In the **CVaR** approach, the objective function is extended to comprise a convex combination of expected value and CVaR [67]. The basic principle is to define a ratio of the hydrological scenarios that should be given a higher weight in the objective function.

- The **SAR** approach[40] is more complex, including an iterative procedure for each SDDP stage/scenario with a separate inner-level optimization problem to provide feasibility cuts to the upper-level SDDP problem [68].

After a period of testing, the CPAMP recommended using the CVaR approach in the operative program, as elaborated in [51]. Two parameters must be given to the NEWAVE model; the weight of the CVaR term in the objective function of each time step, and the percentile at of the most expensive scenarios to be considered when computing the CVaR term. A comprehensive parametric analysis was carried out to arrive at the official parameters. These parameters should represent a reasonable trade-off between system security and generation costs.

After embedding the CVaR risk-aversion functionality, the SDDP solution procedure is similar to the risk-neutral case, except from the computation of Benders cuts in the backward iteration where the CVaR-term is included. Moreover, the computation of the upper bound (simulated costs from forward pass) is more complicated.

**Modelling of uncertainty**

The modelling of uncertainty in inflows has also been subject to recent improvements. NEWAVE considers uncertainty in energy inflow to the EERs, revealed per monthly decision stage. The energy inflow scenarios used during the forward and backward SDDP iterations are obtained through a periodic autoregressive model PAR(p) of order p. That is, energy inflow of a month is a linear combination of p inflows from previous months and a random noise. The stochastic model is inferred from a set of historical inflows, ensuring that the major statistical properties – such as mean, standard deviation, temporal and spatial correlation – are preserved.

A three-parameter lognormal distribution is fitted to describe the monthly residuals, as explained in [55]. Previously a simple random sampling was performed. Following the description and testing presented in [56], the K-means clustering technique has been applied in the NEWAVE sampling process in a procedure referred to as selective sampling. In brief, the K-means technique consists in reducing the cardinality of a large set of initial and equiprobable samples into a smaller and non-equiprobable sample set. Results show that the selective sampling enhances stability of the optimal policy as well as the robustness of the results when considering variations and increases in the sample set. In this context, it is worth noting that stability and robustness are important attributes of an operational model like NEWAVE.

Since 2013 the Northeast and part of the Southeast Brazilian regions have experienced a long drought period, whereas the South region is experiencing a long wet period [69]. During this period the average of the synthetic monthly inflow scenarios generated by the PAR(p) model had been presenting the usual prognostic of returning to the historical average roughly in some months (typically 6 months) although the unusual regime persisted. This behaviour indicates that the current PAR(p) time series model could be improved to represent longer memory in the generated inflows scenarios. In this sense, an extended memory approach for the PAR(p) model to overcome this drawback was developed and implemented in NEWAVE by including a new term in the periodic autoregressive regression given by the average of the 12 previous inflows [69]. Initial results show that the new term enhances the memory of model and prove better reproduction of the monthly autocorrelation function, which encouraged CPAMP to start the validation of this new approach.

As elaborated [70] convergence of the SDDP algorithm can only be guaranteed when re-sampling is applied in the forward pass. The use of re-sampling in the NEWAVE forward iteration has been introduced in [71],

[40] The SAR approach was originally proposed in M.V.F. Pereira, “Possible Enhancements in Risk Aversion Curve”, presented at ONS in March 2008, and was further extended in [68].

where samples are drawn from the continuous distribution rather than resampling from the discrete residuals. It is pointed out that the main objective of the NEWAVE model is not to solve the discrete-scenario mathematical problem, but rather to obtain an operational policy for the continuous distribution problem.

A better representation of intermittent renewables, such as wind power, is being developed on the NEWAVE, GEVAZP and DECOMP models[41]. The correlation between the energy inflows to the EERs and the wind speeds/production of the wind farms will be considered. Initially, wind speeds/production will not be state variables. From the hourly data provided for wind speed and wind production, synthetic wind speed/production monthly sequences will be generated.

Due to the growing concern about climate change and the impacts of increasing levels of greenhouse gas (GHG) emissions on climatic systems, a first approach to represent mitigation measures of climate change effects in the NEWAVE model was implemented by introducing constraints in the SDDP algorithm that represent the maximum limits of GHG emissions and also considering its violation cost in the objective function [72].

### 3.5.5 Decision Support

For more than 20 years, the NEWAVE model have been an official decision support tool by in several tasks of the Brazilian Electrical Sector, and have been routinely utilized by Government and Agencies (MME, ANEEL, EPE, ONS and CCEE) as well as by concessionaires (e.g., Eletrobras) and power industry in corporate decisions.

The application of NEWAVE includes the following routines:

- Expansion planning – MME, EPE
- Physical guarantee – MME
- Assessment of energy supply conditions – CMSE
- Public auctions for purchasing electricity in the ACL – ANELL, EPE, CCEE
- Operational planning (Monthly Operation Program and Annual Operation Plan) – ONS
- Spot price (PLD) calculation – CCEE.

This justifies the need of a very rigorous validation procedure of the CEPEL toolchain by CPAMP as well by a task-force coordinated jointly by ONS and CEPEL with supervision of ANEEL.

## 3.6 Medium-Term Scheduling – DECOMP

### 3.6.1 History and Background

The DECOMP model has served as the official model for setting the spot price (PLD) and to provide the weekly centralized dispatch of the Brazilian system since 2002 [73]. In this sense, it has served the role as

[41] CEPEL presentation at CPAMP Methodology Working Group webinar, Rio de Janeiro, 18 June, 2020.

both a medium- and short-term model. With the introduction of the shorter-term DESSEM model, the use of DECOMP has changed into a linkage between NEWAVE and DESSEM, as a medium-term model.

### 3.6.2 Program Description

The DECOMP objective is the same as in NEWAVE, namely to minimize the cost of system operation over the period of analyses, subject to uncertainty in inflow and a risk measure. The modelling of risk aversion is an integral part of the model, similar to the treatment in NEWAVE. The overall problem formulation can be seen as a multi-stage stochastic linear programming problem. The scenario tree is defined to have a limited number of nodes, making explicit solution of the full problem viable. The solution strategy is based on multi-stage Benders decomposition to solve the large-scale stochastic linear programming problem, but without the sampling that is done in SDDP. An early reference describing the multi-stage Benders decomposition method with a worked numerical example is presented in [74].

DECOMP is run on a weekly basis with weekly time steps for the first month and monthly steps from the second month on. The planning horizon can be up to one year, but is usually 2 months. Each time step is further divided into load blocks to represent the load duration curve within the week.

Uncertainty in inflow is represented in a scenario tree with monthly resolution, typically provided by a statistical model [55]. The scenario tree is illustrated in Figure 29, also indicating the coupling to the NEWAVE long-term model.

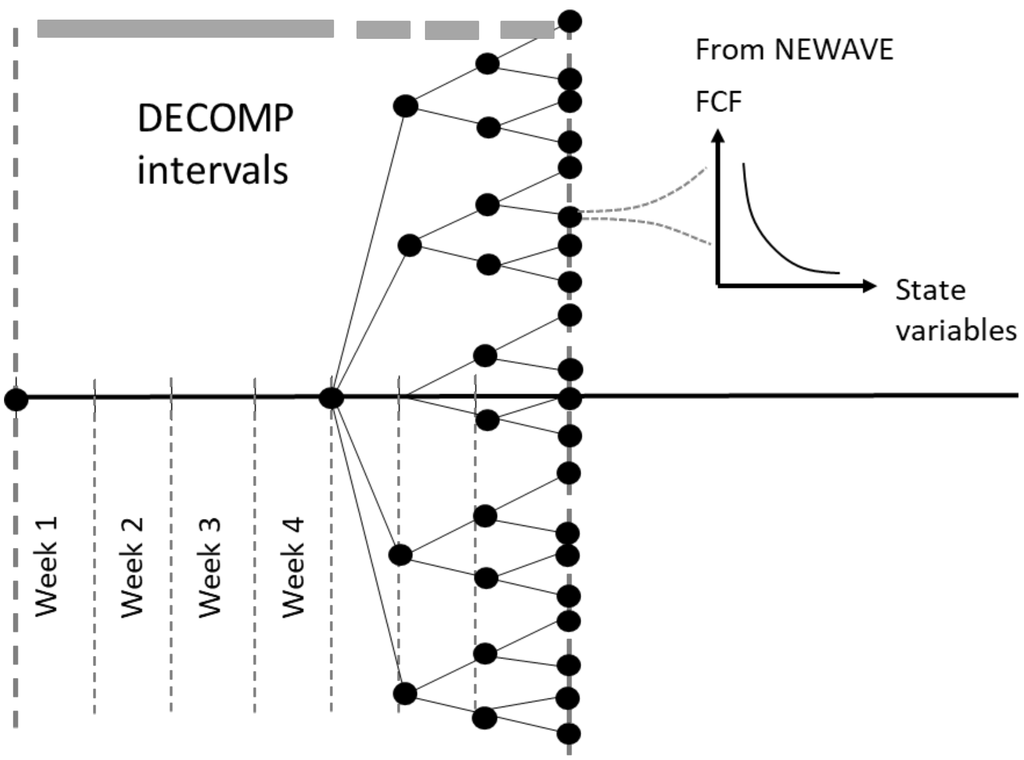


**Figure 29 DECOMP scenario tree with coupling to the NEWAVE model [73].**

The DECOMP model represents the system by:

- Detailed hydropower plants and waterways, including:
  - Water balances for each reservoir per decision stage. Release decisions are taken per load block.
  - Time-delays in rivers.
  - Hydropower production function by four-dimensional piecewise linear model [45].
  - Explicit modelling of evaporation and irrigation
  - Maintenance schedules.
- A transportation model for energy exchange between subareas.
- Grid constraints (using PTDFs) to represent known bottlenecks and security constraints.
- Wind, solar, biomass and small hydro plants that are not centrally dispatched are subtracted from the demand.

The mathematical model is linear and needs to be convex due to the decomposition algorithm. Certain constraints do not preserve convexity, e.g., maximum discharge which depends on water head. These are linearized around operating points obtained in an iterative fashion.

Thermal generators are modelled without considering start-up costs. Minimum generation limits can be defined as parameters to the model.

In DECOMP the overall problem is efficiently decomposed by node and solved by use of parallel processing. The state variables coupling consecutive steps within DECOMP are reservoir volumes, water flow from upstream plants with time-delay, and anticipated dispatch of LNG plants.

### 3.6.3 Couplings with Other Models

For each DECOMP leaf node shown in Figure 29, a description of the future cost function from NEWAVE is attached. The following state variables describe the link between the NEWAVE and DECOMP:

- End of horizon reservoir volumes
- Previous hydro inflows, due to the periodic autoregressive inflow model in NEWAVE.
- Generation from LNG plants scheduled for the future.

Energy equivalents are used to convert reservoir volumes and inflows between *energy* in NEWAVE to *water* in DECOMP. The same energy equivalent used when converting from individual to aggregated hydropower plants within NEWAVE is also used when converting water to energy in the future cost functions.

## 3.7 Short-Term Scheduling – DESSEM

### 3.7.1 History and Background

The development of the DESSEM project started in 1998, due to the fact that the final report of the electricity sector reform project (RE-SEB) pointed out the need to evolve into a future hourly pricing. In 1999, the first version of the DESSEM model was launched and was later described as a part of the toolchain in [4]. The model is intended for short-term operational planning of the Brazilian system with a horizon of some weeks and time-discretization of up to half an hour.

The primary use of the short-term model is to find:

a) The optimal dispatch of each generating unit for the next day
b) The marginal energy costs per busbar or submarket

### 3.7.2 Modelling Features

The DESSEM is a deterministic mixed integer linear optimization model aiming at minimizing the costs of operating the system for a short period of time provided a future cost function from the DECOMP model. A model horizon of up to two weeks can be applied with a time discretization of down to 30 minutes. DESSEM does not explicitly incorporate any risk measure, but the CVaR measure considered in the NEWAVE and DECOMP models is embedded in the future cost function provided by DECOMP.

Some details are briefly described below, see [58] for a comprehensive description of modelling details:

Component modelling:

- Generation from hydropower plants are represented as a function of volume, discharge and spillage, according to [45]. The convex envelope of this function is calculated a priori. Continuous variables are used when modelling the hydropower system, and start-up costs are not considered.
- Water balance in reservoirs and along rivers is accurately represented by fixed travel times or propagation curves, according to [75].
- The transmission grid is considered in a DC power flow model, including pre-defined security constraints. It is possible to include explicit computation of active power losses, according to [76].
- Thermal units are modelled with their marginal costs, generation capacity and a set of constraints constraining the flexibility of operation. In particular, ramping constraints both in regular and start-up/shut-down mode, minimum up and down times and start/stop costs are considered.

System-wide constraints:

- Power balances for each subsystem
- Reserve requirements per control area. Reserves can be delivered by both hydropower and thermal units
- Transmission corridor constraints represented by individual line flow limits, summation of line flow limits and additional pre-defined security constraints.
- A function describing the future cost as in terms of reservoir volumes and volumes in transit.

The consideration of the unit commitment on hydropower units is under development in DESSEM[42], to represent, for example, the operating range (discharge and minimum generation) in which each generating unit cannot operate and possible costs and constraints associated with for starting / stopping the units.

[42] CEPEL presentation at CPAMP Methodology Working Group webinar, Rio de Janeiro, 18 June, 2020.

### 3.7.3 Couplings with Other Models

DESSEM couples at the end of the study horizon with the future cost function provided by DECOMP. The reservoir volumes and the water "in transit" is accounted for. The coupling between DESSEM and DECOMP takes places on the deterministic part of DESSEM, i.e, before the tree in Figure 29 has started branching. Thus, there is only one deterministic inflow state being valid for the coupling point.

The coupling principle between DESSEM and DECOMP, including time-delays in rivers, is outlined in [75].

In addition to coupling through a future cost function, weekly exchange or thermal generation targets may also be established, according to the dispatch signalled by DECOMP.

### 3.7.4 Decision Support

At the time of writing, the DESSEM model has been taken into operational use for dispatch of the semi-hourly operation (by ONS, starting in January 2020) and is currently in the final phase of validation for determining the hourly energy price for the following day (by CCEE. From January 2021). CCEE is in charge of setting the spot prices in the short-term market, running the same models as ONS, but neglecting some inner system transmission constraints. Both for system dispatch and spot price calculation, the DESSEM model works together with the DECOMP and NEWAVE models as a decision support toolchain.

With respect to *system operation*, it is expected that DESSEM will better capture the short-term variation in operating costs. Thus, by introducing DESSEM in the modelling toolchain, the ONS will possess a decision support tool that better represents the physical details in the system operation. The whole process of dispatching the system is likely to be more transparent, since it to a larger extent can be explained by running the modelling toolchain.

When used for system operation, a detailed representation of the transmission grid is considered. Strict requirements to computation times and reproducibility has guided the implementation of the DESSEM model. A comprehensive algorithmic scheme presented has been designed to provide acceptable computation times, and care is taken with the use of parallel processing so that reproducibility can be ensured.

Concerning *pricing of electricity*, the introduction of DESSEM allows prices to be computed with a finer time resolution and more accurately reflect the marginal cost of electricity. Detailed grid constraints are omitted when computing prices. The pricing procedure follows four basic steps [58]:

1) Find the optimal solution of the MIP cost minimization problem
2) Fix commitment status of the units
3) Solve the continuous variant of the cost minimization problem and find nodal prices
4) Weight the nodal prices into a prices per subsystem

## 4 Summary

In the subsequent chapters we have elaborated on the applied toolchains for operational scheduling in the Norwegian and Brazilian system. Figure 31 and Figure 31 summarize the major characteristics of the models applied in the two toolchains. These figures are indicative for the typical case; obviously many of the models may be run in different modes with different planning horizons, time granularity and functionality.

Presentations of the market structures in Norway and Brazil were provided in Sections 2.3 and 3.3, respectively. Together with the introductory discussion in Section 1.2, the main similarities and differences in system boundaries and objective functions have already been explained. We will not revisit those here, but rather elaborate on some key differences between the two toolchains.

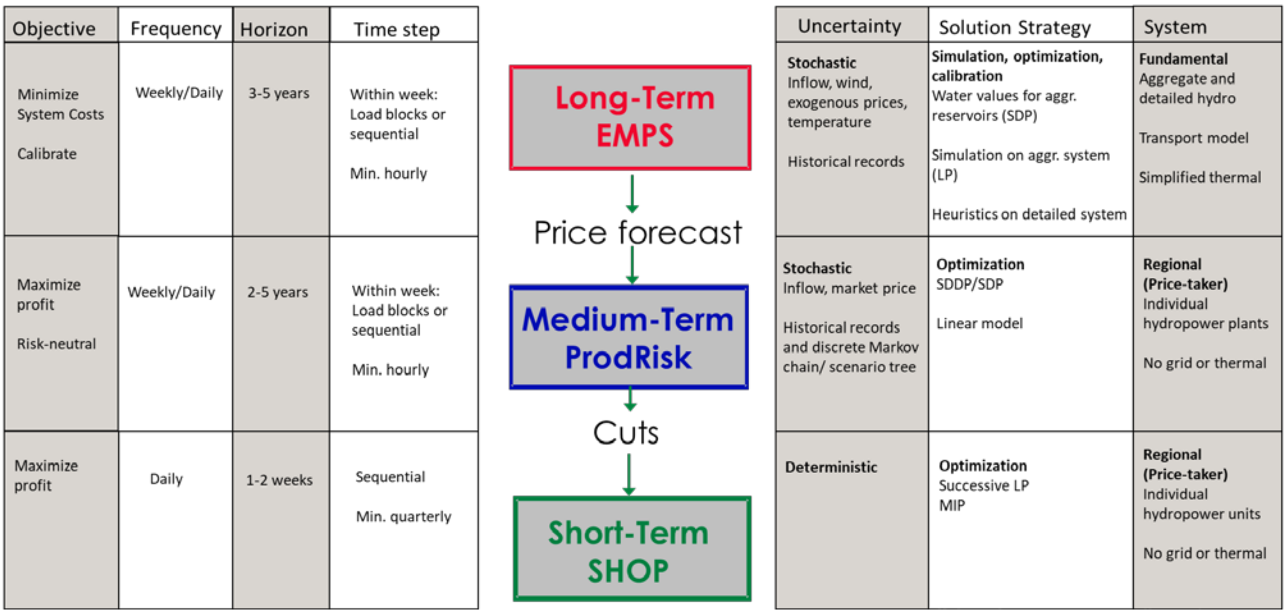


**Figure 30 Summary of model characteristics for the presented toolchain for Norway.**

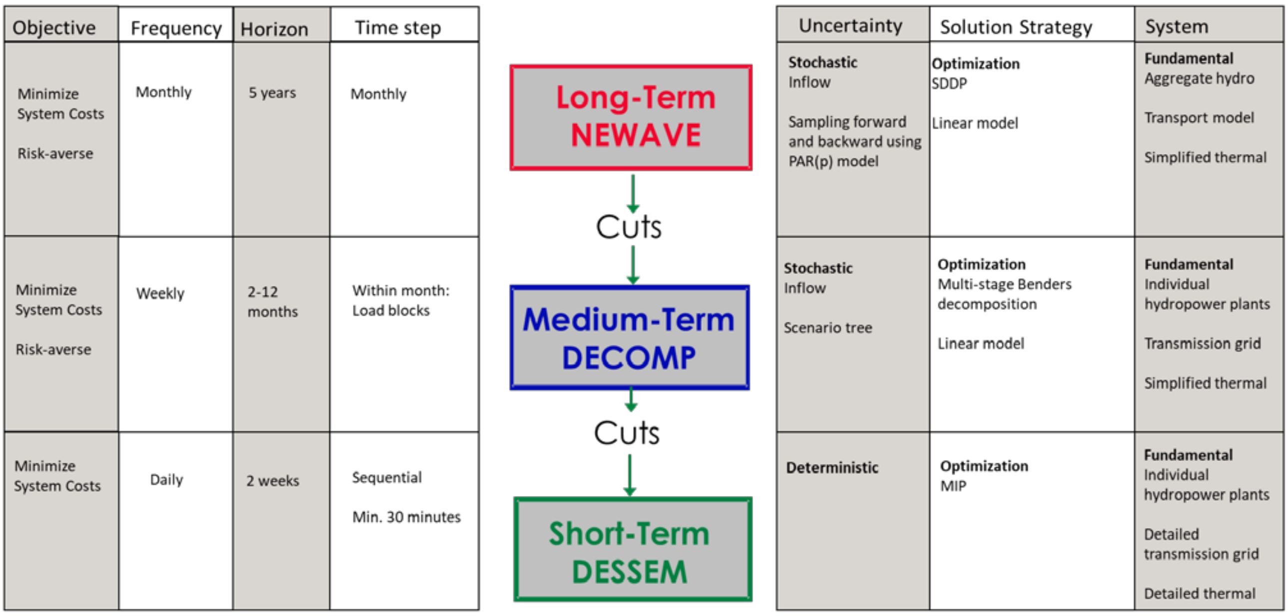


**Figure 31 Summary of model characteristics for the presented toolchain for Brazil.**

With basis in Figure 31 and Figure 31 we now emphasize on some significant differences between the two toolchains discussed in this report.

**Missing cost components:**

In the decentralized scheduling done in Norway, the producer will through the medium- and short-term scheduling try to optimize its profit by generating electricity in periods with favourable market prices. In this context, a good price forecast is one that closely resembles the outcomes of the actual market where electricity products are sold. In case of an efficient market, where the market prices reflect the marginal costs of electricity, the decentralized scheduling toolchain facilitates efficient use of resources. However, there are some system cost components that are not well captured in the decentralized toolchain used in Norway. As an example, the TSOs costs of redispatch due to congestions within price zones are not explicit. In theory, such costs will become more visible with an increasing number of price zones. Another example is the costs of ancillary services. For some of these services, such as (active) reserve capacity, separate markets exist and are organized by the TSO, and prices from these markets can be embedded in the scheduling as presented in [28]. For comparison, the centralized toolchain essentially tries to solve one big optimization problem by decomposing along the time axis using a uniform objective in all models. Thus, all system cost components can in principle be explicitly expressed in the toolchain.

**Treatment of uncertainty:**

The toolchains clearly differ in the treatment of uncertainty. The use of weekly decision stages in Norway and monthly decision stages in Brazil are choices that date back to the early creation of the scheduling models. It seems like these choices can be explained by differences in watercourses and hydrology. Another difference is the use of historical records versus model generated time series for uncertainty in inflow. Using historical records, possibly corrected for climatic trends, to represent future uncertainty in inflow is the preferred procedure by most market players in the Nordic market. Uncertainty in wind power generation and temperature-dependent load is often considered together with uncertainty in inflow in long-term models. Thus, the standard use of operative long-term models in the Nordic market involves direct use of historical weather records. The major motivation for working with historical data is to conserve correlations in both time and space which are not easily incorporated in stochastic models. In contrast, the Brazilian toolchain applies dedicated stochastic inflow models to provide inflows to both the long- and medium-term models.

**Strength of toolchain connections:**

With the increasing penetration of new renewable energy resources such as wind and solar generation, it will be increasingly challenging for the long-term models to capture short-term price variations. Aggregation of the system and the time-resolution in the long-term models may not longer be precise enough. This is particularly important in the decentralized scheduling where information from the long-term model (price forecasts) is connected closer in time to the short-term decision making. As illustrated in Figure 2, the medium-term scheduling process of the producer links to the forecasted market price for the entire long-term planning horizon.

As an example, consider a medium-sized hydropower reservoir with seasonal regulation capability, where the producer needs to find periods with high prices to produce to maximize profit. Consider an approximate price forecast that is correct on expectation, but shows too little short-term price variation compared to the accurate forecast, as illustrated by the red curve to the left in Figure 32. The stapled grey curve indicates a more accurate price forecast.

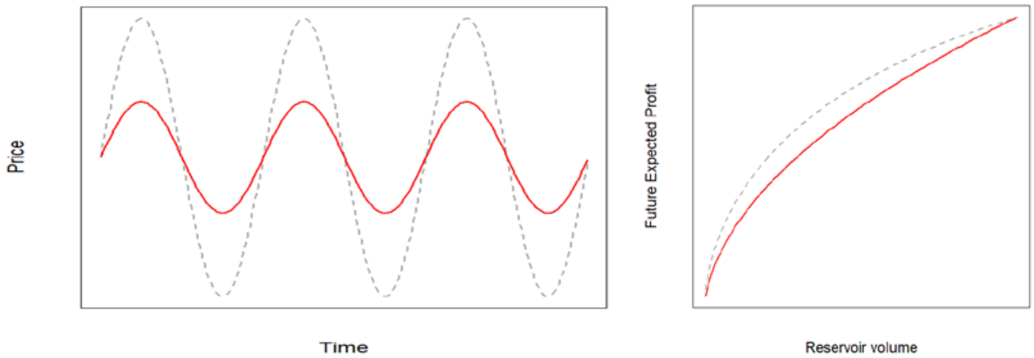


**Figure 32 Illustration of price forecast (left) and the corresponding future expected profit function (right). Accurate (grey, stapled) and approximated (red).**

The future expected profit function for the point in time coupling medium- and short-time will take the form shown to the right in Figure 32. Using the approximate forecast in the medium-term model would lead to future expected profit function (expressed through Benders cuts) that underestimates the future expected profit, as indicated with the red curve to the right in Figure 32. This figure also indicates that, with an approximate price forecast, if the reservoir volume is low, water values (gradients of the future expected cost function) are underestimated. Conversely, if the reservoir volume is high, water values are overestimated. These signals are passed to the short-term scheduling model.

In comparison, the signal from the long-term model in the centralized scheduling approach can be refined through the updated cuts that are computed in the medium-term scheduling. Based on this, one can argue that the short- and long-term models are more loosely coupled in the centralized scheduling.

**Risk aversion:**

Risk-aversion is explicitly embedded in the Brazilian toolchain, but is not in SINTEFs models. This difference can be explained by physical and historical observations. The Brazilian system is to a larger extent self-supplied, whereas Norway is strongly integrated with continental Europe, being a safeguard in critical situations. Moreover, Brazil has experienced severe droughts compromising energy security in recent times. Although not explicit, risk-aversion can be expressed through calibration in the EMPS model, e.g., by calibrating the model to avoid rationing prices. Another aspect is that the medium-term scheduling carried out by the producers normally relates to the physical markets for electricity, but still the attitude towards risk can be adjusted in the financial markets.

## 5 Future Challenges

How well are the model toolchains discussed in this report suited to provide decision support for the future power system (and market) operation? Some possible avenues for improvement are discussed below.

The **changes in generation mix**, towards higher shares of variable renewable energy sources, such as wind and solar power, and less thermal generation will change the role of hydropower as a provider of system services. Moreover, increased variability means that system constraints are challenged with higher frequency and magnitudes than before. For hydro-dominated systems this indicates a transition from an energy-constrained to a capacity-constrained system

- We expect an increased need for system services, such as inertia and reserve capacity, from hydropower. This will in turn impact the flexibility of hydropower. In addition to expressing such functionalities in the scheduling models, a finer time-resolution is needed to realistically capture the cost of providing these services.
- Increased importance of considering short-term uncertainties. The approximation error made in dynamic programming algorithms – using decision stages of one week (Norway) or month (Brazil) – will increase. This point may be more pronounced if significant shares of small-scale storages (such as batteries) and demand response is introduced in the systems.

Toolchains and models should be improved to face the changes in generation mix. In particular, it is reason to believe that current long-term models are too flexible for the future system, and thus are not capable of accurately valuating the water. The challenge is thus to improve the modelling of the physical system and to bring more short-term details and uncertainties to the long-term scheduling without scarifying (too much) computation time.

**Climate changes** leads to weather that is not predicted well when only relying on historical records. Relying too heavily on historical records to forecast the future may compromise secure system operation. Together with the increased need to forecast the output from wind and solar power, this points to the importance of improved high-dimensional stochastic models that integrate well with the toolchains.

The gradual increase in available **computing power** for the model users allows more details to be included in the models. For both toolchains being studied, model users seem to have reached a consensus on what is acceptable computation times for each type of model.

The **information passed between the toolchains** can be improved. There is no explicit information passed upstream in either of the toolchains. The points above illustrate that there may be a need for explicit upstream information flow. Moreover, there is a need for more information to flow downstream. As an example, when the hydropower producers in Norway see increased profits by actively participating in reserve capacity markets, reserve capacity prices can be computed in long-term models and fed to shorter-term planning.

By quantifying the so-called **time inconsistencies**, see [77], one will get important insight and guidance in improving the functionality in a toolchain. Obviously, the long-term models have to compromise on technical modelling details in order to assess the uncertainties. This leads to time-inconsistent (long-term) policies. But how important is each simplification? This question can be answered using a simulator set-up recreating the steps of the toolchain. Some examples that would be interesting to study.

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