Coordinated hydro power plant simulation for multi-reservoir systems

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INTRODUCTION

Hydro reservoirs can serve several purposes, but their use falls mainly in one of two categories: hydro-power production and water consumption. The great flexibility, low operation costs and low carbon impact of hydro turbines turns them into a desirable technology in the generator mix of power systems. In addition, sustainability and environmental concerns support their use in current power systems, jointly with other renewable energy sources, like wind and solar energy. However, the stochastic nature of river inflows hinders their long term use and advises the use of planning tools. Additionally, water consumption (be it human consumption, farming needs or crop irrigation) plays an important role in our society and economy. Hence, it also requires the use of planning tools in order to balance present and future requirements.

This work presents a simulation tool that is employed at Iberdrola to help in the preparation of medium term hydroelectric production schedules. The main objective of the simulation is to follow the guidelines given by a long term hydrothermal problem, while avoiding spillages and failures to fulfill water release agreements. With this last objective in mind, the simulation algorithm is structured around several phases that aim at coordinating the operation of all the elements in the basin.

Broadly speaking, simulation allows considering all the details in the operation of the reservoirs and power plants. In order to handle this complexity, Object Oriented Program-

ming (OOP) is used in this tool to help in abstracting this operation. Combining these two approaches keeps an elaborate view of the operation while providing a flexible design that eases the integration of new topologies.

This paper is organized as follows: first, section 2 provides an overview of previous works to help focus the simulation algorithm presented in this work; after this, section 3 describes the data model employed for the simulation, which determines the computations to be performed; afterwards, section 4 thoroughly describes the simulation algorithm and the specific details for some entities; later, section 5 presents the implementation of the simulation algorithm, as well as some numerical results to show its practical use; and finally, section 6 presents the conclusions that can be extracted from this work.

STATE OF THE ART

When planning the operation of watersheds, there are mainly two approaches: optimization and simulation. Optimization techniques can be applied to obtain optimal operation policies, whereas simulation techniques compute the outcome that will derive from some previously optimized operation rules. The two approaches are complementary, since a first step could use an optimization problem and then use its results to feed a more detailed simulation model.

The main features of multi-reservoir system models can be summarized as:

1. Whether it is based on simulation or optimization.
2. The focus area of the model: energy production, water consumption, hydrological processes, ...
3. The level of detail of the river topology model, ranging from unconnected reservoirs to the complete network representation.
4. Whether the nonlinearities of the model (for instance, when computing the water content of the reservoir knowing the water head, or when computing the energy production) are explicitly considered or approximated.

5. Whether stochasticity is considered or not.

Among the simulation models, (Marques et al. 2006) and (Bosona and Gebresenbet 2010) focus on long term studies. (Marques et al. 2006) focuses on irrigation uses: it analyses surface and pumped ground water use by agricultural irrigation in California, and represents the effect that water prices have on the use of both sources of water (surface and pumped ground water) and its impact on water reserves. The aim of (Bosona and Gebresenbet 2010) is shifted towards energy production: it adjusts the guiding curves for a north Ethiopia hydro power plant in order to improve its energy production. The adjustment of the operation rules also leads to a reduction in the losses due to evaporation, releasing the water before it gets lost for production purposes.

Among short term simulation models, the authors of (Navon et al. 1988) focus on energy production: they simulate a power plant located in Israel for a time scope of a week with hourly detail. They compute the commitment of thermal units and afterwards they schedule hydro production with the objective of reducing the thermal production costs incurred by that commitment. Another approach is taken by (Ziervogel and Hughes 1998), which presents a combination of models that allows to simulate the operation of river basins where some water releases are forced due to environmental issues derived from new regulations. This simulation is guided by operation rules that are adjusted heuristically by the operators of utilities. With a similar hydrological approach but a lower level of detail, the simulation model in (Wang et al. 2005) takes into account the soil characteristics and precipitations in the drainage basin, among other details, in order to compute the water discharge of the watershed in the short term. This latter work employs an Object Oriented Programming approach to develop the tool for the simulation model, in a similar fashion to what is done in the present work.

Switching to the optimization approach, a review of the usual methods can be found in (Labadie 2004) and, focused in the short-term operation, in (Farhat and El-Hawary 2009). Among long term models, (Cerisola et al. 2012) and (Goor et al. 2011) use Stochastic dual

Dynamic Programming. Both of them consider the river network in full detail, and (Goor et al. 2011) also include the irrigation requirements for the multi-reservoir system. When facing the nonlinearities that arise when computing the production corresponding to some water release, they take different approaches: (Goor et al. 2011) considers a linear convex hull approximation of that production function of the water release, whereas (Cerisola et al. 2012) approximates the nonlinear function by discrete envelopes, resulting in a mixed integer linear problem.

Authors of (Karamouz et al. 2005) and (Guo et al. 2011) use medium term models for optimizing the operation over a year, with monthly detail, using Dynamic Programming to solve a linear problem for the planning of hydro power generation. (Karamouz et al. 2005) also takes into account other water uses that have to be fulfilled, such as irrigation or human consumption. Finally, (Scott and Read 1996) uses a medium term model for the operation of a hydro reservoir in the electricity market including energy contracts, which is solved by applying Dual Dynamic Programming.

Concerning short-term optimization models, (Tufegdzic et al. 1996) solves a short-term model that seeks to maximize hydro energy production, applied to the complex hydrological system of Tasmania. It uses a combination of a MILP model for the commitment of 54 interconnected hydro units followed by an LP problem to schedule the final production of these power plants. (Catalao et al. 2009) includes the electricity market, and so it solves the non-linear short-term problem of allocating hydro production in a deregulated sector. Non-linearities arise from the production function that depends on power plant efficiency, water head and water release flow, while the relation between reservoir volume and water head is linearized, as well as the efficiency of the power plant that depends non-linearly on the reservoir water head.

Between those groups of techniques, a mixed approach can be taken to optimize the results of complex simulations. For instance, (Koutsoyiannis et al. 2002) determines the right values for the operation rules for the reservoirs using a general optimization problem

that tunes those parameters for the underlying simulation that operates the reservoirs.

Up to this point, most of the works take a high level approximation of the physical processes underlying the river basin operation. At the lower level, hydrological processes can be simulated to reproduce the physical behavior of the system, considering surface and ground water flows, and the sedimentation and erosion processes. (Migliaccio and Srivastava 2007) provides a review of the most relevant hydrological models applied to agricultural lands. For instance, the already mentioned (Wang et al. 2005) simulates a hydrological model close to the details of the physical characteristics of the watershed, providing a general framework not restricted to a particular use of the model.

When designing the model, an important decision is whether to consider or not the interconnections between the different elements in the river basin. For instance, some multi-reservoir models do not take into account these connections, for the sake of simplicity (like (Afzali et al. 2008) and (Guo et al. 2011)). Other models consider just one power plant (for instance, see (Navon et al. 1988), (Scott and Read 1996), (Ziervogel and Hughes 1998), (Bortolossi et al. 2002), (Bosona and Gebresenbet 2010)) or a set of non-connected reservoirs (see (Karamouz et al. 2005)), and thus no river network has to be modeled. Finally, some models consider a set of connected reservoirs including a network representation of the river (see (Tufegdzic et al. 1996), (Koutsoyiannis et al. 2002), (Wang et al. 2005), (Marques et al. 2006), (Catalao et al. 2009)), where water releases from upstream elements reach downstream elements during the simulation process. This additional level of complexity may pay off by providing a more realistic operation plan.

Besides, there are also other different uses that fall outside of the scope of this paper. One that has gained some attention in the last few years is the use of reservoir models in coordination with renewable energies like wind generation, in order to help integrate these energies thanks to the hydropower flexibility in regulation, as it is discussed in (Vogstad et al. 2000) and (Castronuovo and Peças 2004).

This paper presents a simulation model, which aims to reproduce the real operation of

river basins oriented to hydropower production. It follows the guidelines provided by a long term hydrothermal mathematical programming model, but enforces real world constraints that had to be left out of this optimization model. The time scope of the simulation model is one or more years, which falls under the long term category, although the time step is the day, so planning results can be used in the short term. The simulation models takes a high level view of the system, not considering detailed hydrological processes, but takes into account the river basin network. However, since it is a high level daily model and the distances between pairs of elements are usually moderate, the simulation model does not consider the time required for water to travel from one element to another in the basin. Previous work can be found in (Latorre et al. 2008), with an early version of the data model and simulation algorithm. This work includes new features such as the use of volume areas to manage reservoirs, the consideration of unit outages, a more precise operation of pumping units, the justification of the spillage reduction in the simulation process, ...

DATA MODEL

The first issue that needs to be figured out in the simulation model is the data representation, since this may determine some characteristics of the simulation algorithm. In the case of watersheds, the representation should meet the following requirements:

- A general framework to define the basin topology, so it allows new elements to be easily added to the simulation model.
- A flexible design to permit complex management rules.

In a rather natural way, the basin elements are represented by means of a graph. This approach is taken, implicitly or explicitly, by some of the previous works in the literature dealing with multiple interconnected reservoirs, such as (Koutsoyiannis et al. 2002), (Tufegdzic et al. 1996) and (Catalao et al. 2009). This graph represents the basin elements by nodes linked by arcs that model the river and channel connections. Four main types of nodes have been identified:

- Reservoirs like lakes and big ponds, either associated to power plants or in a location that determines inflows to other elements.
- Power plants, possibly consisting of multiple generation units.
- Channels that artificially divert water from its natural way.
- River confluences that share components (i.e. channels limiting common water release) among the elements on the meeting rivers.

Notice that reservoirs and power plants are modeled independently, in order to take into account run-of-the-river plants and big standalone reservoirs. Hence, run-of-the-river and regulating power plants will be represented both by power plant nodes. This leaves the release decision to reservoirs, although in the case of regulating power plants, the set of reservoir and power plant are in the real world operated as a single entity.

Usually, river basins are formed by one main river and possibly some tributary rivers that join and flow into the sea. This structure can be abstracted and represented by a tree, which is a connected graph with no cycles. A graph is said to be connected if there is a path connecting every two nodes in the graph. In the watershed case, this means that every two elements of the watershed are connected by a set of river stretches, which is true for the case of a single basin. Also a graph does not contain cycles if there are not two different paths connecting any pair of nodes. This means that there are no two ways water can flow from one element to another in the basin.

This second condition on the graph (for them not to have cycles) is not always fulfilled in the watershed case, mainly due to the presence of artificial channels that usually move water from one river to another, while these two rivers might meet downstream. This and other similar topologies constitute a cycle, and represent a problem for the simulation algorithm (more precisely, in its second stage as it will be described in 4). To solve this problem, which might lead to the incorrect simulation of remedy actions, a second simplified graph has to be considered where all the cycles are removed. The removal of these cycles involves prioritizing paths in the river basin and removing the secondary paths in the cycles. This

simplified graph will be used for the computation of the remedy actions in the simulation algorithm.

This data organization is well suited for OOP, since all nodes share some common data and methods to represent and operate the topology. This common behavior can be associated with a common base class for the nodes, and the simulation specifics can be located on the derived classes for each type of node. This represents inheritance, one of the main characteristics of OOP (Schildt 2002). Other OOP characteristic is data encapsulation, which in this case helps by hiding the internal data representation of the node and providing access to data through an interface that will guarantee the correctness of these accesses. Finally, another OOP feature is polymorphism, which allows the definition of methods with the same name and similar semantics, but applied to different classes. For instance, all node types will have a method called 'ComputeWaterRelease', whose specific semantic and computations depend on the node type.

SIMULATION ALGORITHM

The main target of the daily simulator, as already stated, is to follow the long term guidelines provided by a stochastic hydrothermal model that considers longer time scopes. Since the simulator is able to compute the behavior of power plants, reservoirs and channels, more accurately than the hydrothermal model, the guides provided by the latter have to be adapted to:

- Particular situations of the simulated yearly series. The longer term model considers multiple scenarios in order to obtain a robust solution against all of them. However, the simulator has to operate the best way considering just one scenario, as real time operation does.
- Detailed technical constraints that cannot be taken into account in the hydrothermal model. Daily operation might include complicated rules, such as coordination rules between power plants or operation limits depending on specific reservoir situations.

Modeling those constraints in the mathematical programming problem may imply the use of more binary variables, increasing the problem size and complexity, rendering it useless for most practical purposes.

Note that blindly following the hydrothermal model rules during the simulation might lead to some hydrological problems in the river basin, due to the simplified view this model has of the hydrological part of the electric system. The kind of problems it might encounter are the excess or lack of water at different points of the river basins, where technical limits or water release agreements have to be fulfilled. On the one hand, water spills need to be avoided, because they mean a waste of energy and a possible risk in case they cannot be correctly handled. On the other hand, electric utilities must honor agreements concerning water release or water availability at some locations of the basin. If there is not enough water to fulfill these agreements, severe penalties may be applied to the utility. Thus, the simulation algorithm performs several passes in order to reduce these situations as much as possible.

General overview

The general idea behind the simulation algorithm is to first compute the operation according to the general guidelines provided by the longer term model. This operation may cause undesired situations like those previously mentioned, and they have to be identified. Afterwards, the algorithm tries to minimize these problematic situations by adjusting the operation between the limits set by technical and operational rules. This is not a minimization in the strict sense, because this might involve the formulation of a mathematical program or a similar strategy to guarantee optimality. As it has been previously said, the aim of this work is to avoid the complexity of this approach. Instead, a heuristic is applied that under some assumptions provides similar results, as it will be shown.

The management heuristic used takes into account that the only elements that can help in solving an undesired situation at a specific location are those placed upstream in the river

basin. When the simulation finds these situations, it will compute how much the upstream elements can contribute to solve them. In the case of lack of water, each upstream reservoir might contribute releasing some of the water it holds over the minimum operation level, or any tighter value its operation may consider. The contributions of each element are summed to be applied where the problematic situation is found. Contrariwise, when there is excess of water, upstream water retention will be asked for. After this computation, the heuristic considers that the contribution of each upstream reservoir is proportional to its ability to modify its operation: if the set of upstream elements can solve a problem by releasing a 10% of their total reservoir water contents, each of the reservoirs in the upstream chain is asked to release that 10% of their volume.

This approach has some limitations, the most obvious one being that the daily process is myopic. When the problematic situations are solved for one day, there is no additional consideration about what might be best for the future operation of the system. Instead, it tries to move homogeneously all the reservoirs in the basin, not considering whether some places might be more or less appropriate to release or hold water depending on several factors: weather conditions, location in the basin, future maintenances, ... However, the long term guidelines provided by the hydrothermal coordination model should help in this sense to keep a balanced operation.

Bearing all of this in mind, the algorithm is organized around four stages: the first one simulates the watershed elements individually, and the rest of stages compute and apply corrections to the initial operation plan. A more detailed description of each stage follows:

1. First, it decides the operation of each element independently of the rest of the basin, as shown on figure 1. If the element is a reservoir, the options available for its management are more thoroughly detailed on section 4. Power plants and channels simply transport water through them, checking that physical limits are enforced. Finally, if the element is a river confluence, the details about the special simulation rules are provided in section 4. Any of these elements can consider natural water

inflows that come from rainfall or non modeled tributary rivers. These inflows are obtained from historical records, from a subset of them (such as humid or dry years) or from the weighted mean of these records. After these computations, another outcome is the information about the undesired situations that may have arisen on each element and their capability to solve possible downstream problems. In a natural fashion, this computation is performed element by element following the water natural flow in the river basin from its headwaters downstream. Additionally to these results, each element has to store the accumulated capabilities for the upstream elements. When an element transmits its capacity to solve downstream problems, it includes the capacity of upstream elements, and it does so by following downstream the simplified graph described in section 3 (without cycles). This way, it avoids considering this capacity multiple times downstream.

2. Afterwards, this initial program has to be modified to avoid the undesired situations found during the previous stage. The corrective actions needed are computed in this second stage in another pass over the basin elements. However, this time it proceeds upstream since this way it is able to transmit the changes required by downstream elements. In this moment, each element can decide if the situation it faces can be solved with the capability of upstream elements. Also, if it has to contribute to alleviate downstream problems, it is able to compute to which extent it has to modify its own operation and which modification has to be carried out by upstream elements.
3. Once the solutions to problems have been computed in the previous two stages, these modifications are applied and the final operation is obtained, concerning water releases and energy production, as well as reservoir volumes at the end of the day. Since the time unit considered is the day, power plant production is divided into peak and off-peak production for that day. This way, the simulation model can help to obtain economic values from the production schedule. In this sense, the general criterion is to allocate as much power production as possible in peak hours, where it might

replace the most costly thermal units. In order to reproduce the flow of water, this stage is performed on each basin element in downstream order.

4. Finally, a last post-process is applied once all the previous results are obtained. This stage computes final results such as reservoir energy valuation and producible energy.

With this stage structure, it can be guaranteed that the spillages and lack of water are solved as much as possible, on a daily basis. This is a similar result to what could be achieved with a optimization problem, as it will be shown. This result can be achieved by *reductio ad absurdum*. Let us assume that there is an undesired situation at some point of the basin, be it excess or lack of water, that after simulation has not been solved despite some upstream element can release some additional water or hold some water volume. If this upstream element can help to solve the problem, this means there is a physical connection from itself to the location of the problem, and the intermediate river connections are not saturated. A river connection would be saturated if it cannot hold more water while the problems require more water to arrive (or conversely for the lack of water). In case of non saturated connection, this physical connection between the problem location and the element to solve the problem will be followed by the first stage, and so there is no way for this additional capacity not to be taken into account during the computation of corrective actions in the second stage. Hence, this leads to contradiction with the initial assumption of unused residual capacity in the system.

Note that in this point it is of key importance the graph structure without loops already mentioned in section 3, because it guarantees that from an element downstream there is only one path. When transmitting downstream the ability to solve undesired situations, this avoids the risk of duplicating water accounting for problem solution, because it provides only one path on which this water will be used.

Reservoir management

When the simulation needs to process some element of the basin, a distinction has to be made between those elements that can regulate their water output flow and those that cannot. The latter are mainly power plants and channels, and they simply transport the water they receive unless their maximum flow is reached. However, this saturation contingency should rarely happen because the elements that do regulate water (namely the reservoirs) should avoid it, by deriving water to the spillage outputs.

Therefore, water management in the basin is mainly done by reservoirs. Their size determines to what extent each reservoir can regulate. Thus, the smaller ones will have less regulation capability (or it may not compensate doing so), whereas the larger ones will be responsible for the general operation of the river basin. Similarly, the location of the reservoir in the basin and the reservoir technical characteristics might make it ideal for the river basin coordination. Examples of this idea are large reservoirs with pumping units or reservoirs located at the river headwaters.

For the water release for each reservoir, an initial decision is computed according to one of the following options:

- Using a pre-computed water release table. This table is computed by the longer term hydrothermal model, and provides a guide for the larger or more relevant reservoirs in the basin. For each week of the year, depending on the water stored in the reservoir under consideration, the water stored in another reference reservoir (a relevant one in the basin) and the natural inflows of the reservoir, the table stores the optimal water release for that reservoir. The use of the natural inflows to the reservoir is similar in this case to the inflows series used as climatic cues in (Ziervogel and Hughes 1998).
- Adjust the water release to drive the reservoir to a target volume. This is a simpler strategy that is applied to medium size reservoirs. The target volume can be either the maximum or minimum safe operation levels. The maximum volume can be chosen if the reservoir does not usually suffer flash floods, so the increase in the height in

the water head provides extra potential energy while keeping low the spillage risk. However, if there is some risk of flash floods to happen, the reservoir might choose to keep its volume low, therefore driving it to its minimum safe operation level.

- On the smaller reservoirs, applying strategies such as the previously mentioned ones usually does not pay off. Hence, these reservoirs follow a straightforward strategy: release as much water as they are receiving from the upstream river elements.

A similar process is performed to obtain initial pumping decisions, which may represent the short term economic pumping of the unit. In this case, the number of options is more limited: pumping can be obtained from a pre-computed table with a structure analog to the water release table (for the most relevant pumping units), can be freely allowed until the reservoir reaches a safety upper limit volume (for smaller or less relevant pumping units), or can be explicitly forbidden (for critical situations or specific analyses).

This is followed by an optional post-process phase where the water release or pumping is limited depending on the volume of the reservoir. Depending on the water volume the reservoir holds, the water discharge or pumping is upper and lower bounded by monthly values tuned by the reservoir operator. More precisely, there are six volume curves that in turn define five volume areas (defined by monthly values), which are described in the following in decreasing volume order:

- The maximum water level, which is not really a monthly value but the fixed maximum level the reservoir was designed for. Operating above this level might mean damaging the dam and causing uncontrolled spillages.
- The maximum safe operational level, which is set to avoid spills due to unexpected floods. This level may change monthly depending on the flash floods probability based on historical data.
- The upper operation guiding level sets the upper limit of the desired operation area for that reservoir, based on the experience of the operating utility.

- The lower operation guiding level provides the lower bound for the desired operation area already mentioned.
- The minimum safe operational level tries to ensure that, under general circumstances, there will be no lack of water when irrigation is required. This level may change monthly due to the rainfall expectation observed in historical records.
- The minimum water level, in a similar way to what was said for the maximum water level, is not a monthly value but rather a fixed level under which the reservoir cannot operate to produce with the associated power plant. This is usually the dead storage, although in some case bottom outlets may allow the use of this water without any power production.

Notice that this post process refines the initial decision from the water release or pumping table, or any of the alternative options. Theoretically, there should be no need to adjust the table results, so this post-process could be eliminated. Nevertheless, this allows to compute the table once (which can be a heavy computational task) and reuse the results while the assumptions do not change significantly. Furthermore, this allows eliminating the use of water release tables if the reservoir is not relevant enough to be introduced in the longer term model, setting a simple initial strategy, that is later refined with this post process.

As a peculiarity, the maximum safe operational level of a reservoir can also be given as a function of the inflows of water to that reservoir. This might be important at small reservoirs where the arrival of water from the tributary rivers produces an increase in the water level at the point of arrival of these inflows. In order to correctly model this, the maximum safe operational curve can also be given as a piecewise linear function of the water inflows to the reservoir. This approach can be used at the same time that the monthly volume level series, since the simulation will compare both and use the most restrictive value for each day.

A final stage of post process further limits water release or pumping to honor minimum release or irrigation agreements, and according to the number of generators available on subsequent power plants (which depends on maintenance schedules and outages, and also on

the water height level).

River confluences

Special traits that have to be carefully handled are the elements located at river confluences, where a tributary river flows into the main one. The need for this special treatment arises only when there are shared elements among the merging rivers, whose use by the converging rivers has to be externally coordinated. For instance, the most typical situation of this kind happens when each of the merging rivers holds a reservoir but there is a common power plant at the confluence. In this situation, the water releases from those reservoirs have to be coordinated to enforce the power plant maximum output. This maximum output has to be reduced when water release is taken from different reservoirs, to account for the reduction due to the time spent stopping the power plant and changing its configuration to drag water from other reservoir.

In order to correctly simulate these situations, a new type of element was included in the simulator which in turn groups the elements to be coordinated. In these sense, this element is a meta-element. The simulation algorithm described in section 4 performs a special simulation for this type of elements at each of its stages:

- In the first stage of the simulation, several steps are taken in order to coordinate the operation of the different elements contained in the river confluence element:

    1. First of all, each of the elements is simulated in the usual downstream order.
    2. If the total flow released does not exceed the power plant flow limit, no further computations for the river confluence element are needed, and the computations end at this step.
    3. If the total flow has to be reduced, all the elements divide their water release into essential and non essential water releases. Essential water releases are considered those required by minimum water release agreements (due to environmental or irrigation needs) or to avoid spillages in the reservoir. The rest

of the water release is considered to be non essential.

4. First, the simulation algorithm tries to solve the overflow by removing the non essential water releases. If this is possible, the simulation removes the non essential water releases following a user pre-specified priority order for this river confluence element, and the computations for this stage end here.
5. If there is no other solution than removing also essential water releases, then this is done after removing the non essential ones, also following the already mentioned priority order.

- In the following stages, the simulation of this river confluence element just proceeds to perform the individual simulation of the elements it contains in the order required by each stage, with no further coordination process for this meta-element.

Unit outages

In order to replicate the normal operation of the hydro power system, it is very important to simulate the outages of the generating units. This can prove useful in three aspects:

- First, by considering scheduled outages, simulation results will reflect each day the available power system capacity. This way, the results can be used to prepare the economic budget of the company, based on the mean evolution of the basin, but considering the already known outages to make it more accurate and realistic.
- A second aspect that has to be considered is that this allows to measure the effects of different maintenance schedules, thus providing a valuable tool to assess different options.
- Finally, if forced outages are introduced, simulation results will be closer to reality, and the stochasticity introduced this way will help to provide more robust results.

The simulation can take into account both types of outages of the generating units, both scheduled and forced ones. For the scheduled ones, the simulation algorithm needs to know

the programmed dates of the maintenance as well as the percentage of the unit power that will not be available. This way it can consider partial outages, which may represent the requirement to operate below nominal capacity due to maintenance works.

The simplest way to introduce forced outages in the simulation is by means of the forced outage rate and the expected repair time. Each simulated day, a sample is obtained from a uniform distribution to test if the unit is available or not. In case an outage has occurred, the unit will remain unavailable during the expected repair time.

In order to better represent forced outages, another more complex approach can be taken: the use of a bathtub curve. This model replaces the fixed forced outage by considering different failure rates depending on the time since the last repair:

- An initial phase, when the early failures take place, considers a failure rate that decreases as time passes.
- A second phase with a constant failure rate, representing the usual operation conditions.
- A final phase when failures increase again due to the wear out of the components.

In the simulation algorithm presented in this paper, the bathtub curve is represented by a piecewise linear approximation, with a linear approximation for each one of the three phases.

APPLICATION CASES

This section describes the application of the simulation algorithm to realistic cases. To be able to do so, a simulation tool has been developed for Iberdrola Generación. The practical implementation of the simulation tool relies on an Excel spreadsheet, which exposes a friendly environment for the end user and allows the preparation of the input data and reports based on simulation results. The computations are provided by means of Visual Basic for Applications (VBA) macros, which ease data input and output because of its tight integration with the spreadsheet environment. A possible downside of this approach is that

the support for OOP in VBA is limited; for instance, inheritance and polymorphism is not fully supported. However, during the development of this tool alternative coding techniques have been employed to overcome these difficulties while sticking as much as possible to the OOP paradigm.

Following subsections introduce some numerical examples of simulations, to help gain some insight on the capabilities of this simulation tool, including the analysis of the general results (subsection 5), a little example of spillage reduction (subsection 5), and how can it be employed in the assessment of decisions such as maintenance schedule evaluation (subsection 5) and power plant upgrade (subsection 5).

General numerical results

This section shows some general results from the simulation, applied to a river basin of realistic size with 19 reservoirs and 21 power plants with a total installed capacity of 1640 MW and 350 MW for the pumping units. Figures 2 and 3 show the general results for the whole river basin considered, when the inflows are taken from a representative year.

It can be seen that hydro inflows are high during winter and spring, and power production is higher during that part of the year. At the same time, pumping starts to work to avoid spillages and it is able to do so during spring and autumn, when reservoirs are not full, but it is not possible in winter. During summer and autumn, power production falls to around a third of winter production on average, even when inflows have fallen up to a 10% or 15% of winter inflows. When the natural year ends, inflows start to arrive again, thus causing spillages to appear once again.

The previous results are computed using the average year. The same simulation has been performed taking as an input a set of historic records (24 yearly series), to represent the variety of hydrological situations. The corresponding results are shown in figures 4 and 5. They show the same general behavior as the previous ones, with a smoother power production yearly profile. But the real difference can be seen in figure 5: spillages grow dramatically, because the more humid years are significantly more prone to spillages than

the average one. This means that in fact, spillages are a more complicated situation that can be thought of when considering the average year. Furthermore, since reservoirs contain a higher water volume, it is more difficult to apply corrective measures to operate in a safe region. This can be assured by the fact that pumping is reduced to a 38%, indicating that the reservoirs cannot pump from downstream reservoirs that might be spilling water because they are themselves close to spilling water. Adjusting production rules to avoid these spillages as much as possible is one of the main targets that can be handled with this simulation tool.

Spillage avoidance through pumping units

As it has been previously stated, the simulation algorithm tries to reduce spillages to a minimum through several simulation stages to coordinate the operation of all the elements of the river basin. To see this effect to some extent, this section presents results from a medium reservoir at the mouth of the river. This reservoir receives inflows from a long chain of reservoirs and power plants, which in some situations might release great volumes of water. This reservoir also receives inflows from a tributary river where a large reservoir and its power plant are located. This upstream reservoir helps the small one when it receives huge floods from the river chain, by pumping the excess of water to the reservoir at the tributary river. Table 1 shows what would be the yearly results if this pumping was not available, during a representative year close to the average of the historical records. It has to be noted that the pumping of the power plant is decided on the second stage of the simulation, to avoid the spillages in the downstream reservoir. For the sake of simplicity, in this example economic pumping has not been considered, although it could be introduced by means of a pumping table as it has been explained in section 4.

It can be seen that the amount of spillages is not very large, but they can be totally eliminated. This avoids the risks associated with this situation: uncontrolled water flow, possible damages to the dam,... It is interesting to note that the use of the pumping units does not involve an increase in the spillages of the upstream reservoir who is receiving this

water. It would make no sense to pump water to later spill it. But from the results in the table, it can be seen that this does not happen, because there are no spillages at the upstream reservoir.

The results show that the upstream power plant production is also increased, due to the new water volumes received through the pumping operation. Table 1 also shows the balance of water for the two reservoirs, i.e. the difference between the initial and final water volume. For the case when pumping is used, the reservoirs tend to increase their water content. This also happens when considering the results for the whole basin, since the water content of reservoirs is increased by a 2.7 %, not only because of these two reservoirs but also because of changes in the operation of other reservoirs close to these ones. The economic valuation of the increase in the production and the final water reserves, along with the energy that is not spilled, provides useful information to the utility in order to assess the effectiveness of the pumping units. It should be noted that this analysis does not include the economic pumping, which would be superimposed over the schedule computed by the simulation. Since the simulation does not consider the time detail under a day and it handles no information about the prices in the electric market, this cannot be done directly with the simulator. However, the results from the simulator could be combined with the economic valuation of this economic pumping cycle in order to obtain a full picture of the economic valuation of the operation of the pumping units.

Scheduled maintenance assessment

Maintenance scheduling has a great impact on the operation of power systems, since it limits the power production available in a specific moment, but also can have a great impact on the economic results of an electric utility. For instance, peak demand periods require units to be present in the system, for reliability and economic reasons. Hence, a careful schedule of maintenance has to be performed not to degrade the economic results of the utility. This is particularly convenient when referring to hydro power plants, which may incur in spillages if a flash flood happens during maintenance operations.

In this subsection, three possible maintenance timetables are compared in order to provide a taste of what this analysis could provide. Three options to allocate a one month maintenance period are simulated, considering the months of March, April or May. This maintenance must be performed on a power plant associated with a large reservoir, which can more easily handle a long maintenance period. This reservoir is located in the lower part of a long chain of reservoirs, near the mouth of the river, and is operated in the simulation under the guidance of a pre-computed production table. Yearly results for the three maintenance options are shown on table 2, providing a signal of the impact these alternatives could have.

It can be seen that the month where the maintenance produces a lower impact on the spillages of the power plant is March, because the water inflows from rainfall and melt water are starting to arrive to the reservoir, and it still has place to accommodate them for later production. When the maintenance is located on April or March, the reservoir has a higher water volume during the maintenance, due to the already arrived spring rainfalls and melt water. The reduction of spillages may be the main objective from a reliability or safety point of view. However, when the maintenance takes place later during the year, this maintenance limits the capacity of the reservoir to discharge when it may be desired. This causes a delay of the discharge in time and thus the reservoir ends with a higher water volume content. This additional energy has to be taken into account when performing an economic valuation of the alternatives. From this economic perspective, the maintenance located in May may be the most profitable. The balance of these criteria has to be established by the utility operator, based on the characteristics of each case and their experience.

A similar analysis can be performed by the electric utility for evaluating alternative simultaneous maintenance plans for several power plants in the same river basin. This would compute the effects the different schedules might have when considering the detailed operation of the hydro power plants, because this level of detail might not be possibly considered in the maintenance scheduling problem due to its high complexity.

Generating unit upgrade

Electric utilities can consider two alternatives when increasing their installed capacity. The first one is to install new power plants, and build the corresponding reservoirs, for a better exploitation of hydrological resources. However, since this might involve flooding new fields, this option is not always permitted due to natural or regulatory constraints and popular rejection. Furthermore, in most developed countries there may be no locations for additional reservoirs without interfering in the operation of the existing ones. So the easier alternative involves upgrading exiting power plants. This avoids the cost of evaluation new potential locations and the physical costs of reservoir refurbishment. Still, the cost of the new generating units is present, and in this sense both analysis can take a similar approach.

This section presents a small case where the power plant of a small reservoir is a candidate for upgrading. This power plant is located in the middle portion of a river, in a chain of reservoirs that supply more water that it can employ for power production. This power plant consists of two generating units of 84 and 110 MW, that can handle a maximum flow of 610 m^3/s.

The cases under consideration are the upgrade of the smaller generating unit to different larger capacities, up to the value of the larger generating unit. Table 3 shows the cases that have been analyzed and the corresponding yearly results. Considering steps in the upgrade may not be totally realistic, since these capacities may no be available in values as close as those employed in the example. But this serves as an exercise for evaluating upgrade options. When data about possible installed capacities is available, these options should be the ones considered.

Reviewing the results, it can be seen that the first upgrade reduces spillages in an 8.7% and increases production around a 1.2%. This depicts the two main effects of power plant upgrade: allows producing more power when there is an excess of inflows, and also allows producing more energy also in a general situation. Regarding the other upgrade options, it can be seen that they further reduce spillages and turbine all the water that can be produced.

However, this additional production cannot be always be located at the peak hours, so its economic impact will vary and need further analysis. In this sense, another factor that has to be taken into account is the economic side of the investment. The purchase and installation of the new equipment must be contrasted with the increase in the power production economic outcome. This means that there may not be enough economic potential for these upgrades. This simulation tools provides a way to evaluate the economic return to balance the new investment costs, helping the utility to take an informed decision.

CONCLUSIONS

This paper has presented a simulation algorithm that represents the operation of hydrological power plants. In order to coordinate the operation of individual elements of the river basin, it follows the general guidelines of a long term model, while trying to reduce water spillages to a minimum. A simulation tool has been developed implementing this simulation algorithm, with an easy interface to allow the utility operator to simulate and adjust operations rule in order to attain the utility targets. Some of the potential applications of this simulation tool have been shown: general simulation in order to know in advance consequences of possible inflows forecasts, and how to assess several maintenance schedules and different upgrade plans. In general, this tool provides the operator a way to evaluate the outcome from forecasts of either water inflows or future operation situations.

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List of Tables

1 Yearly simulation results considering or not the pumping units 28
2 Yearly simulation results for different maintenance options 29
3 Yearly simulation results for the original situation (OR) and the considered upgrade options (U1-U4) for the set of historic inflow series 30

		With pumping	Without pumping
Upstream reservoir			
Water release	[hm^3]	978	681
Stored water balance	[hm^3]	-7	-29
Pumping	[hm^3]	319	0
Spillage	[hm^3]	0	0
Total production	[GWh]	921	635
Downstream reservoir			
Water release	[hm^3]	5591	5617
Stored water balance	[hm^3]	-29	-30
Spillage	[hm^3]	0	20
Spilled energy	[GWh]	0	7
Total production	[GWh]	1833	1842

TABLE 1. Yearly simulation results considering or not the pumping units

		Month of maintenance		
		March	April	May
Water release	[hm^3]	1087	1068	1027
Spillage	[hm^3]	21	36	32
Stored water balance	[hm^3]	(ref) 0	5	49
Total production	[GWh]	1036.9	1018.0	980.2
Spilled energy	[GWh]	20.0	34.5	30.9
Stored energy balance	[GWh]	(ref) 0	4.8	46.7

TABLE 2. Yearly simulation results for different maintenance options

		OR	U1	U2	U3	U4
Installed capacity	[MW]	84	95	100	105	110
Maximum flow	[hm^3]	270	299	312.7	326.3	340
Inflows	[hm^3]	6991	6991	6991	6991	6991
Water release	[hm^3]	6117	6193	6217	6231	6252
Spillage	[hm^3]	873	797	773	759	738
Total production	[GWh]	548.1	555.0	557.1	558.3	560.2

TABLE 3. Yearly simulation results for the original situation (OR) and the considered upgrade options (U1-U4) for the set of historic inflow series

List of Figures

1 Simulation diagram for the first stage 32
2 Inflows and production for the study case 33
3 Inflows, pumping and spillages for the study case 34
4 Inflows and production for the average of all the historic years 35
5 Inflows, pumping and spillages for the average of all the historic years 36

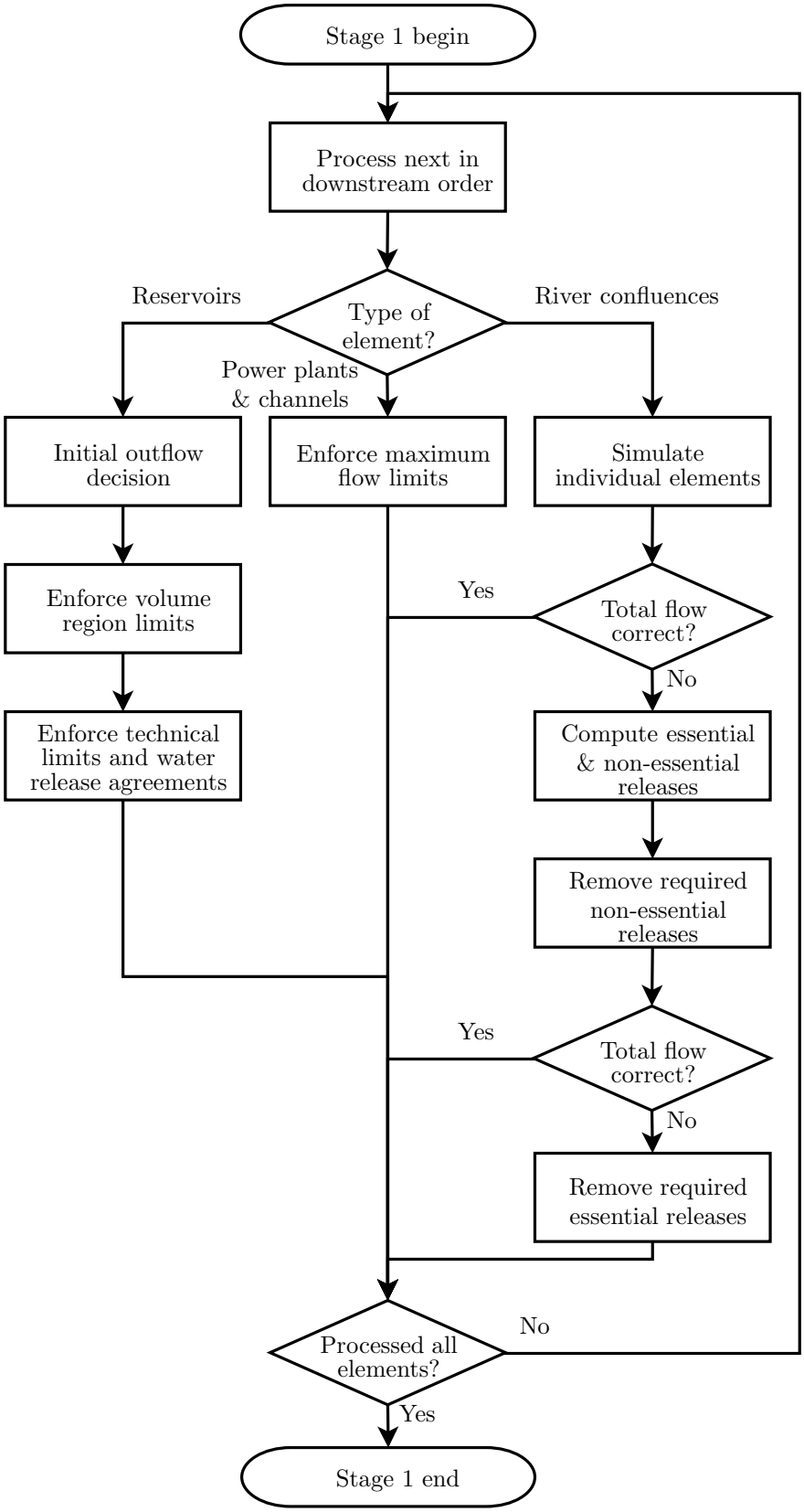


FIG. 1. Simulation diagram for the first stage

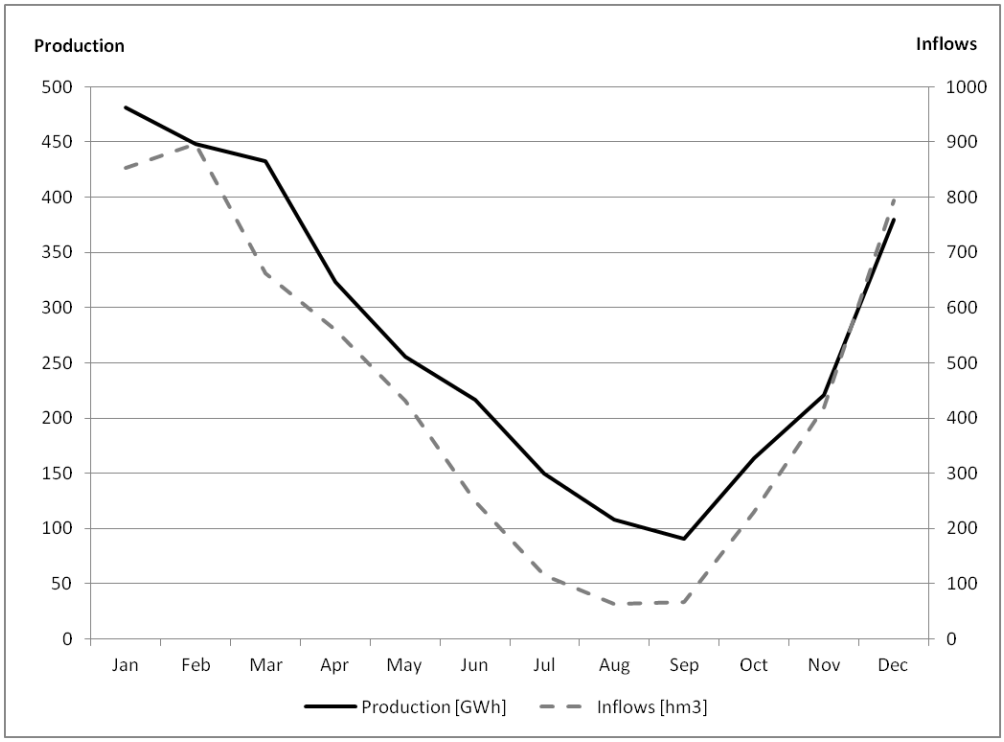


FIG. 2. Inflows and production for the study case

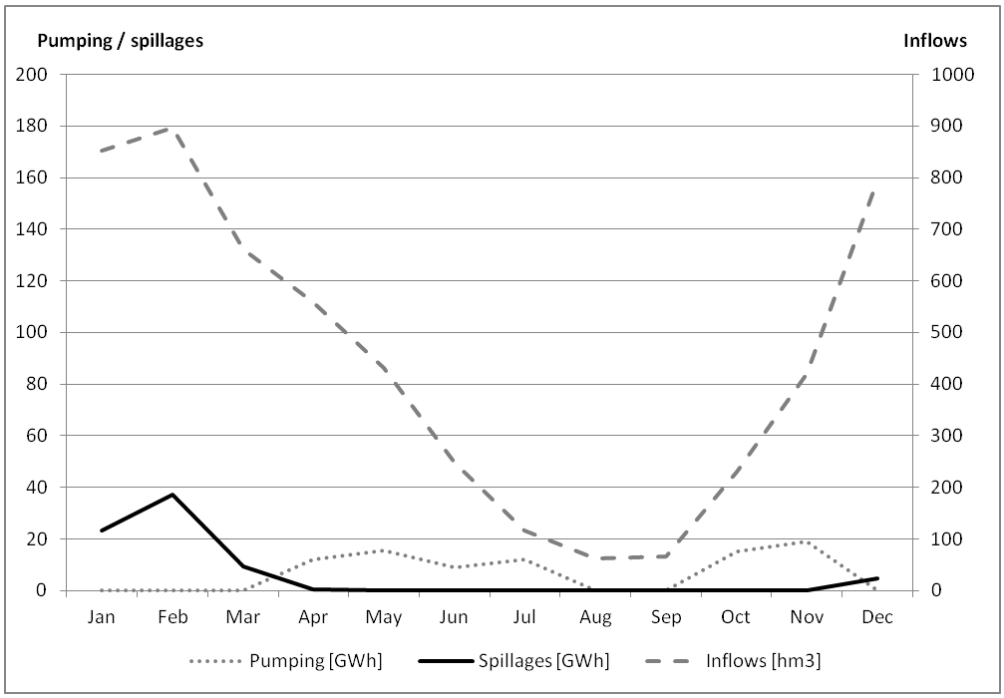


FIG. 3. Inflows, pumping and spillages for the study case

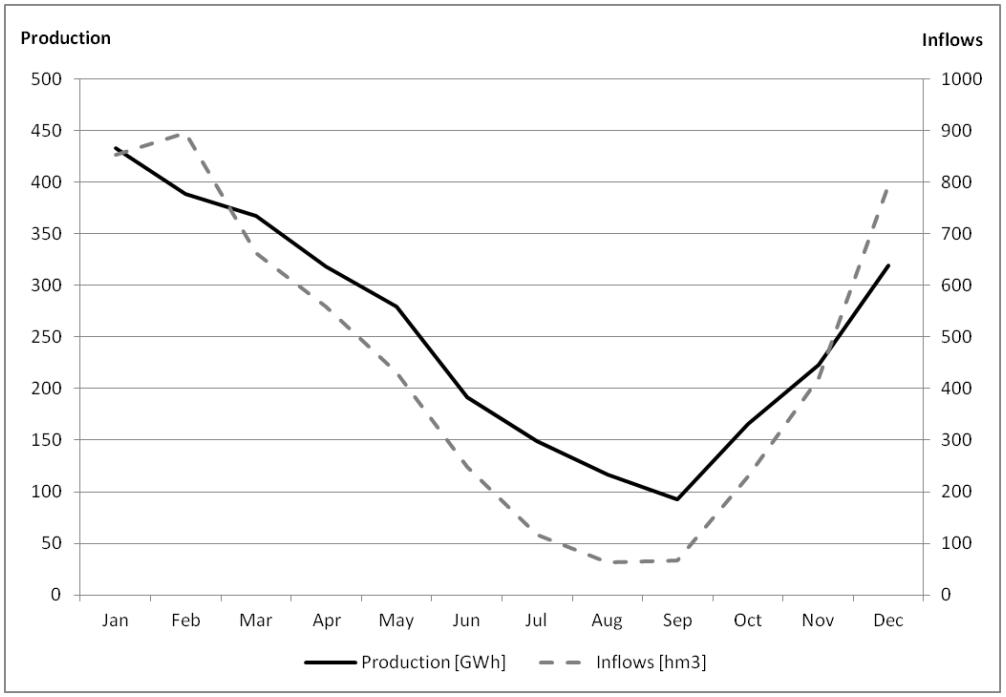


FIG. 4. Inflows and production for the average of all the historic years

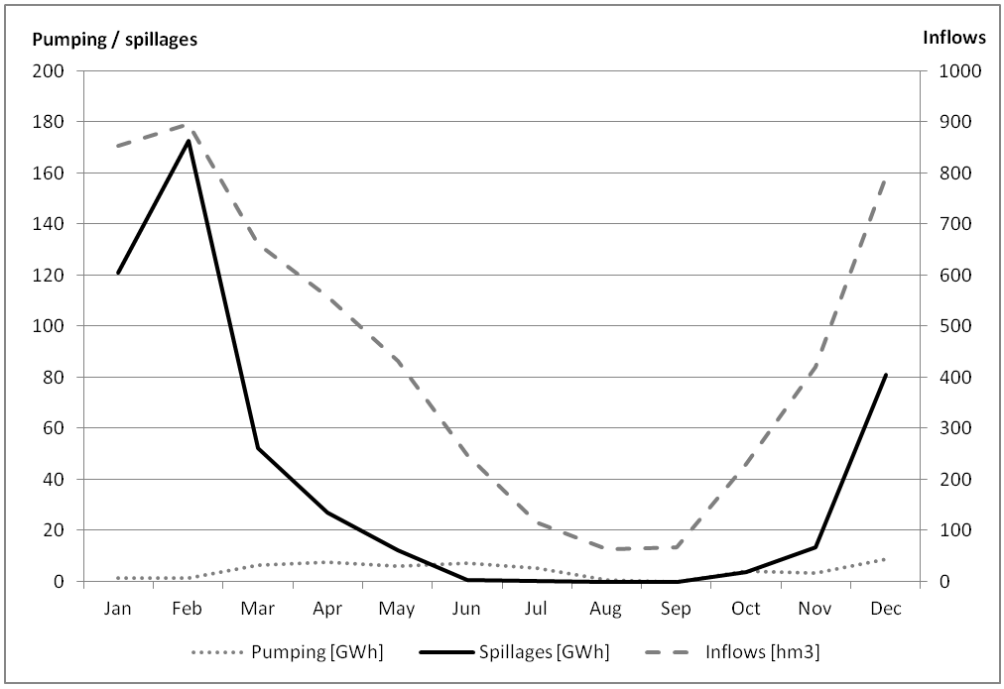


FIG. 5. Inflows, pumping and spillages for the average of all the historic years