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Short-Term Management Of Hydropower: Definition, Assessment And Disposal Of Operational Flexibility

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SHORT-TERM HYDROPOWER OPTIMIZATION AND ASSESSMENT OF OPERATIONAL FLEXIBILITY

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Variations caused by uncertainties and introduction of intermittent energy resources into the Bulk Electric System require that hydropower systems have enough up and downward flexibility for control technologies such as dynamic optimal control load-following, automatic generation, to be effective. The objective of this paper is to present and discuss approaches for assessment of the level of the available operational flexibility as a function of dynamic states and control input. Test results based on the Federal Columbia River Power System managed by the Bonneville Power Administration are presented and demonstrate how operational flexibility can be assessed and which role it plays in real-time operation.

INTRODUCTION

The difficulties posed by the integration intermittent energy resources into existing power systems are emphasized in (Adams, 2010). They vary according to the production (influenced by weather conditions) and scale of the variable resource, its correlation with system load, and the flexibility of the power system in question (Lannoye, 2012). When these resources deviate from scheduled generation, dispatchable resources must make up for the deviation by either increasing or decreasing their generation to balance load & generation within the Bulk Electrical System (BES). To perform balancing regulations with a hydropower system means, in practice, to store water when there is less demand for later use when the demand for electricity is higher.

Considering the operation domain from the perspective of a hydropower, we can identify several uncertainties ξ due to model forecasting errors, outages, active demand responses, and dedicated customers, which cause significant mismatches between generation and load. Moreover, the system is limited by several high-priority operational constraints, such as reservoir capacities, ramping rates of turbines, and minimum stream flows, etc. These uncertainties and constraints affect many aspects of the system operation such as load following, automatic generation control, and risk management. From the system control perspective, such variability requires the system to have the ability to react to a sudden change of system condition and accommodate new state within an acceptable time and cost tolerance.

Hence, for smooth operation, one requirement of such a hydropower system is upward and downward operational flexibility.

The study of operational flexibility in hydropower systems is in its infancy. Furthermore, the literature that could be found for the study of operational flexibility in other fields lacks a unified framework for defining and evaluating operational flexibility. Recent attempts of assessing flexibility of power systems can be found in (e.g., Lannoye, 2011; Menemenlis et al, 2011). Ulbig et al. 2012 presents the Power Node Modeling framework with particular focus on hydropower units to assess the operational flexibility that hydropower can provide for balancing the fluctuation in both load demand and power generation using the German power system as a case study. In Makarov et al. 2009 and Menemenlis et al, 2011, the authors focused on the technical capabilities and related constraints of individual power system units to modulate power and energy in-feed into the grid, as well as out-feed from the grid, which they characterized and categorized by means of adequacy metrics, such as maximum available power capability π. The authors in Bouffard et al, 2011 see flexibility as the potential for capacity to be deployed within a certain timeframe, and associate flexibility with reserves. Menemenlis et al, 2011 illustrated the use of a flexibility index borrowed from the process control literature to evaluate a solution strategy that provides balancing reserves to mitigate wind generation uncertainties. A unit commitment algorithm is then used as a tool to balance the long- and short-term costs of providing flexibility.

For evaluation of a system's abilities to resist uncertainties, Swaney and Grossman proposed a flexibility evaluation index F which can be applied in any stable chemical operation process (Swaney and Grossman, 1985). As we have used it, flexibility index F is calculated to give intuitive measure of hydropower system flexibility to grid dispatchers. The index gives a flexibility measure to quantify the feasibility of operation of a given design over the specified range of the uncertain parameters and can be easily adapted to hydropower systems. This index is the basis of our methods.

This paper first defines operational flexibility. Secondly, this paper then outlines three methodologies for assessing operational flexibility of optimized hydropower system based on the position of the optimal solution in the feasibility region of the optimization problem. Finally, the methodologies will be illustrated in a case study in which chum salmon spawning largely determines the operational management of the FCRPS. In the conclusions, we indicate directions for further research to promote the continued development of objective measures of operational flexibility.

OPERATIONAL FLEXIBILITY

In the real-time operation, system operators take many control actions to mitigate the impact of possible contingencies. In this paper, we define operational flexibility of hydropower systems as in Lannoye, 2011 as the ability of a hydropower system to deploy its resources to respond to changes in the net load within predefined timeframe and cost threshold (net load is defined herein as the system load less power caused by the variability of wind, solar, etc. The associated flexibility index reflects the relative size of the largest deviation range to the size of target range $(\Delta\hat{\xi})$ per given time, which should be subjectively set by certain operational criteria. Therefore an operational flexibility index can be defined as

$$f(x, u, \Delta\hat{\xi}) = \|\Delta\xi^{max}\| / \|\Delta\hat{\xi}\|, \quad (1)$$

where $\|\cdot\|$ is the norm of the uncertain variable deviation, and measures the size of state deviation. Operational flexibility is a notion that can only be developed in relation to other factors and can only be defined within a specific problem formulation. Therefore, the flexibility index should be defined with respect to the physical variable to which we want the system to be flexible against.

In Lennert et al., 2011 and Crona, 2012, the factors which have the potential of affecting operational flexibility of hydropower are discussed in detail. From them, clearly the most fundamental attributes of the flexibility of a hydropower valley are the size of its reservoirs in relation to their discharge capacity and the river's flow and hydropower projects' capacity factors. It is not surprising that a project operating at what corresponds to rated power 10% of the time has more room for flexible operation compared to an identical project which is operating at its maximum capacity at 60% of the time.

The degree to which the water rights are fully utilized is seen as both one of the largest limitations and also source of possibilities when it comes to the flexibility of hydropower projects. When evaluating the operational flexibility of hydropower projects as in this paper, it does not suffice to look at individual projects. A project which is individually highly suitable, for example, for short term regulation, can in reality have its flexibility quite limited if downstream reservoirs have limited buffer capacity. If the upstream project is regulating its production without the downstream project being able to follow that regulation, it might lead to situations where the downstream project is forced to spill water in order to stay within its allowable reservoir limits. In actual operations, such effects have to be considered and will most probably limit the flexibility for the individual project. A demonstration of this principle will be seen later in the case study of the cascade of the FCRS, where a very large reservoir, Grand Coulee (GCL), is coupled downstream with some run-of-river reservoirs like McNary, which have limited turbine outflows.

There are several technical limitations which dictate how a hydropower project can be operated. One such limitation, which has a very direct influence on the flexibility of a project, has to do with how fast the discharge through a turbine can be changed. Furthermore, organizational related factors and operational strategies influence the operational flexibility of hydropower projects quite significantly, and are the main focus in this paper. As a consequence, the full reservoir volume is rarely used for short-term regulation purposes, which of course reduces the flexibility compared to the maximum theoretical capacity. A higher degree of short term regulation of a project would probably mean that some of the previous margins of flexibility would need to be reduced. If there are uncertainties regarding water rights, technical aspects, or other factors, it might be necessary to exercise extra precautions which could limit the way a project's flexibility is used.

In the next section, the definition of operational flexibility given here will be used to propose methods of its assessment.

ASSESSMENT OF AVAILABLE OPERATIONAL FLEXIBILITY

If assessment of operational flexibility is to be addressed, how do we determine the maximum allowed deviation ($\Delta\xi^{max}$)? There are mainly three methodologies, which are as follows:

- Approach 1: Evaluate the objective functional empirically for finite perturbations in the parameter vector around the solution.
- Approach 2: Find the minimum sized perturbation destroying the required property, or maximize over a criteria guaranteeing stability for all perturbation of a specified size.
- Approach 3: Estimate the functional Hessian approximation on the minimal solutions (Castillo, 2006, Pirnay et. al, 2012).

In the first approach we apply the divide and conquer method to repeatedly increase and decrease the perturb parameter $(\Delta\xi \in \Delta\hat{\xi})$, while checking for system feasibility. In the second approach we use the method in Swaney and Grossman, 1985. Following their definition, the flexibility evaluation index expresses the largest scaled deviation δ of any expected deviation Δξ+, Δξ- that the design d can handle, which is in accordance with our definition of operational flexibility. Mathematically, this idea can be expressed in terms of the feasibility function $FEAS_{S_0}(\Delta\xi, u; \bar{J})$ and the nominal solution S_0 as follows, $\Delta\xi^{max}$ is the solution of the following maximization problem:

$$\max_{\Delta\xi} \|\Delta\xi\| \quad (2)$$

s.t.

$$\max_{u\in U} FEAS_{S_0}(\Delta\xi, u; \bar{J}) = 1, \forall \Delta\xi \in \Delta\boldsymbol{\xi} \quad (3)$$

$u(\in U)$ represents the corrective actions u that can be taken within the response time threshold under certain operating procedure. The corrective actions space varies, depending on the response cost threshhold, denoted by $\bar{J}$ and the state deviation $\Delta\xi(\in \Delta\hat{\xi})$.

Several approaches exist in the literature to solve this type of problem. These include the work of Halemane and Grossmann, 1983 for the case that the solution lies at one of the vertices of parameter set $\in \Delta\hat{\xi}$, who proposed the evaluation of $FEAS_{S_0}(\Delta\xi, u; \bar{J})$ at each vertex of $\in \Delta\hat{\xi}$ and the selection of the largest one. The active set strategy proposed in Grossmann and Floudas, 1997 can identify non-vertex solutions and decomposes the problem into NLP sub problems corresponding to different active sets. This approach guarantees optimality to a restricted set of problems where $FEAS_{S_0}(\Delta\xi, u; \bar{J})$ are quasi-concave in Δξ and the constraint functions are jointly quasi-concave in u and Δξ and strictly quasi-convex in u for fixed Δξ. A branch and bound approach is proposed in Ostrovsky et al, 1994 based on the evaluation of upper and lower bound of the feasibility measure $FEAS_{S_0}(\Delta\xi, u; \bar{J})$.

In the third approach, second order sufficient conditions are checked numerically, and we propose to apply an NLP-based approach for robust computation of sensitivity differentials of optimal solutions with respect to the perturbation parameters. The basic sensitivity strategy for NLP solvers is derived through application of the implicit function theorem (IFT) to the KKT conditions of a parametric NLP (see Pirnay et. al, 2012 for further detail of the methodology). For NLP algorithms that use exact second derivatives, sensitivity can be implemented very efficiently within NLP solvers and provide valuable information with very little added computation (e.g. Solver sIPOPT).

In a multi-period optimization problem such as in our case, the flexibility measure for load can also be calculated for the different time stages k for a sliding window W by changing the objective function in Eq. 2 to the one in Eq. 4, so as to give an idea of the evolution of the flexibility of the system to the system operator.

$$\Delta P_k^{max} = \max_{\Delta P} \frac{1}{W} \sum_{w=1}^{W} \left(\left\| \Delta P_{k,w} \right\| \right) \quad (4)$$

where W is the size of the window. W is set to 1 if the evaluation of operational flexibility at each decision stage is required

Discussions of the advantages and drawbacks of the methodologies

The first approach, based on perturbation analysis, will suffer from a high computational cost associated to the required computations compared to the second and third approaches, which can lead to sensitivity estimation with relatively low cost. The problem described in the second approach falls into the robust optimization framework. A proper reformulation should be able to translate it into a mixed integer linear problem, which can be efficiently solved by commercial solvers. The main drawbacks of the third approach are attributed to: i) the numerical difficulties in the Hessian computation and ii) the issue of how does the Hessian describe the functional behavior for finite perturbations in the parameter vector.

CASE STUDY

In this case study, we focus on the integrated short-term management of hydropower production and marketing, for forecast horizons of up to 21 days, for the Federal Columbia River Power System (FCRPS) in the Columbia River basin in the Pacific Northwest, USA, as illustrated schematically in Figure 1.

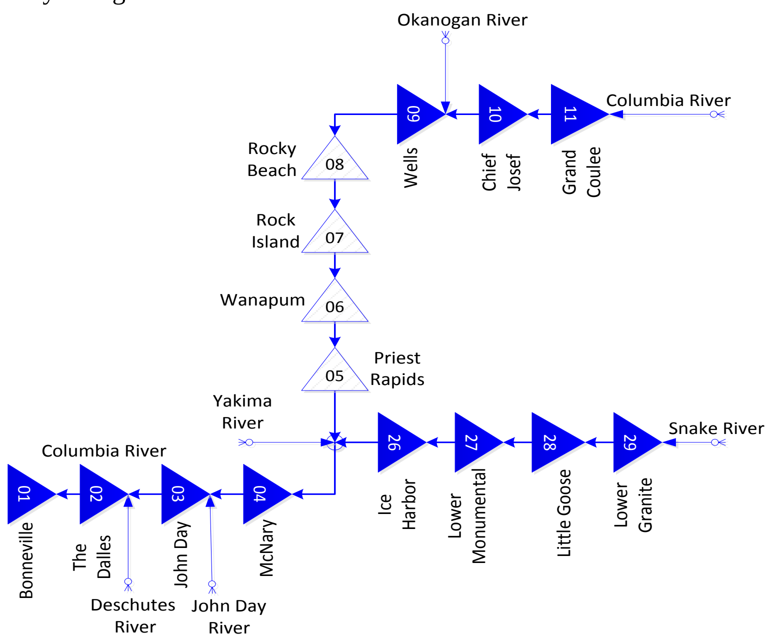


Figure 1: Scheme of the projects in the middle Columbia River.

The Federal Columbia River Power System is operated for multiple purposes, including flood control, irrigation, power production, navigation, recreation, and municipal water supply. The Bonneville Power Administration markets power production from the federal dams within the constraints and requirements for other river purposes; flood control, protection of fish listed under the Endangered Species Act, compliance with the Clean Water Act, and other requirements take precedence over power production. As part of its mission to market federal hydropower, BPA is the primary high-voltage transmission provider in the Columbia River Basin. In the past few years, there has been remarkable growth in wind power projects interconnecting to BPA's transmission grid (BPA Facts, 2012).

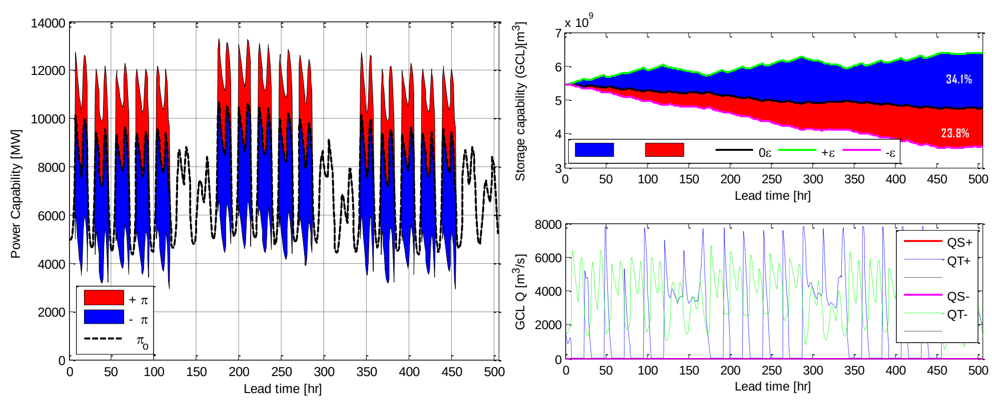
To illustrate our methodologies for operational flexibility, we study a scenario which focuses on chum salmon spawning operation of the FCRPS (Schwanenberg et al. 2014). They typically spawn in near-shore and tributary gravel bars in the lower Columbia River below Bonneville Dam. It is necessary to release enough water from Bonneville Dam at all times during the active spawning period (late November through December) for adult chum to access favorable spawning habitat. Typically, the operational goal is to release the fixed outflow from Bonneville Dam while utilizing upstream storage to regulate and absorb fluctuations. Releases from Grand Coulee Dam and management of available storage in the lower Columbia River projects are used to regulate flows such that Bonneville Dam can release at the required rate at all times

For this scenario, the main objective is to follow the load and evaluate the operational flexibility, i.e., assess the potential to maximize weekday (Monday-Friday) heavy load hour

(HLH) generation while meeting the defined constraints. Heavy Load Hours are defined as the 16-hour period starting from 06:00 and ending at 22:00. We first found the nominal solution of the optimization problem to minimize the quadratic penalty of the deviation between load and the hydropower generation. The optimization problem for a forecast horizon of 21 days with hourly time steps has 10080 dimensions (forebay elevation and total outflow for 10 reservoirs x 504 time steps). The pool routing equations result in 5040 equality constraints with 43084 nonzero elements in the equality constraint Jacobian. Environmental and power network constraints add another 38808 inequality constraints with 111217 nonzero elements in the inequality constraint Jacobian. A multi-threaded version of IPOPT 3.8.1 / HSL MA27 (Wächter & Biegler 2006) solves the optimization problem on a PC (Intel i5-3230M @ 2.60GHz) in about 4-10s. We then applied the methods described in Section 3 to evaluate the power capability for positive and negative load of the system for the HLH.

RESULTS

The optimization results in Figure 2 (a) indicate full compliance with the load balance and a maximal upward flexibility of 2717.6 MW as well as a maximum downward flexibility of 4620.4 MW by SSE = 9.136e-005 in HLH. For the downward flexibility, it is worth looking at the storage evolution of the storage reservoir GCL which denotes the main storage of the whole cascade. It can be seen in Figure 2(b) that the GCL dictates the downward flexibility of the system and that the available downward flexibility can be obtained only by storage capability without spill and within existing project operating limits, subject to weather and fish protection conditions. At the end of the simulation period, the storage of GCL by downward flexibility went up by 34 % in comparison to the nominal state evolution. This flexibility may allow BPA to release water days or weeks later for power generation when it is more valuable to the region.



(a) (b)

Figure 2: (a) Power and (b) Storage capability

Alternatively, this flexibility measure could be computed sequentially for different time horizons, or in a sliding window as described in section 3, so as to give an idea of the evolution of flexibility of the system to the system operator. The results for all hours are shown in Figure 3. The index in Eq. 1 is applied with $\Delta\hat{\xi}$ fixed to the maximum of the possible surplus or negative net load, depending on which one is large. NB: The main objective in this study was to test the methods in section 3 for assessing operational flexibility. Several conditions have been defined, such as assuming that all turbine units are in operation, which we know in real operations is not the case, and therefore, that our measures would overstate reality. Also, some constraints such as operational forebay limits are not confirmed, for example, Chief Joseph has been allowed to operate from 956.0-930.0m, but in reality the true operational range is just 956.0-950.0m. This condition may also further limit our power capability envelope.

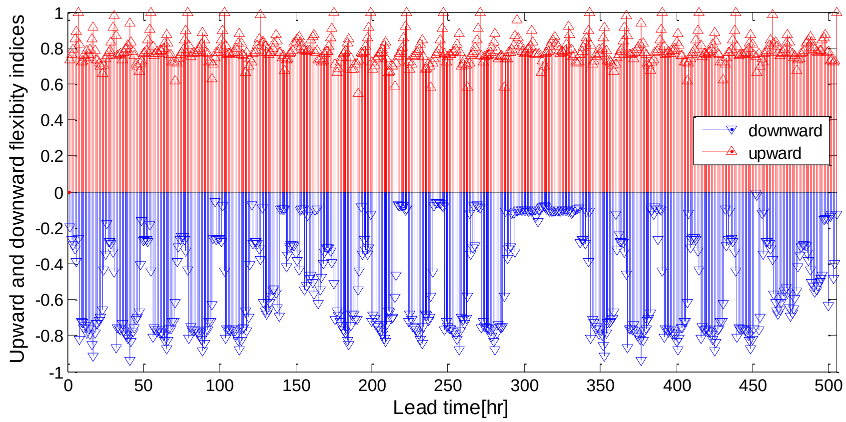
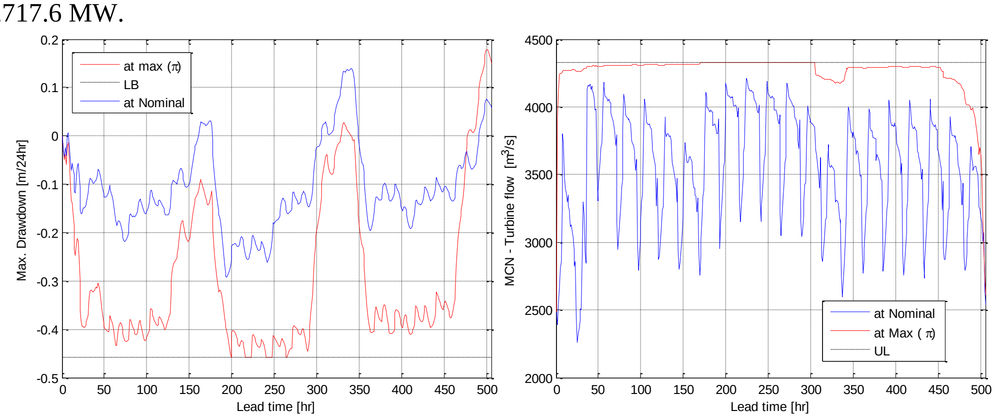


Figure 3: Flexibility with respect to maneuverability

The Figure 4(a) and (b) emphasize the factors that limit the upward and downward operational flexibility beyond the obtained values. Initially, as mentioned in Section 2 about factors affecting operational flexibility in hydropower systems, the reservoir sizes of the cascade, water rights, and the hydrologic coupling between them has great influence. The main reservoir, Grand Coulee, has a maximum drawdown limit of 1.5ft (0.4572 m) in a running 24 hour period. This limits the additional discharge from Grand Coulee and, consequently, the overall amount of energy generated in the cascadesince higher hydropower production in the cascade of the downstream run-of-the-river power plants in the Columbia River depend on this additional flow. Secondly, technical factors, such as the maximum installed turbine capacity of McNary (MCN), which is smaller than other projects in the cascade, have limitations to the whole system. In combination with the requirement of avoiding voluntary spill, it limits the total flow through the cascade of projects in the lower Columbia River. Furthermore, it reduces the system capacity for daily peaking in case of high power surpluses. Note that peaking is only possible if the maximum turbine capacity of a project is higher than the required average flow (see Schwanenberg et al, 2013). If both are the same, the turbine must run on full capacity continuously, and, therefore, does not do any peaking at all such as observed for the surplus of 2717.6 MW.



(a) (b)

Figure 4: (a) Drawdown at GCL, (b) Turbine flow of MCN

CONCLUSIONS

The operational flexibility in hydropower systems requirements are to address the uncertainty and variability associated with large amounts of intermittent resources as well as with load, which causes real-time balancing requirements to be variable and less predictable Therefore, in this paper methods of evaluation of the available flexibility as a quantitative measure of the position of the optimal position in the feasible region of the system were presented. A case study was presented to illustrate the methodologies, as a demonstration of how operational flexibility can be assessed, which role it can play in real-time operations.

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