Feasibility Study and Equipment Selection for the Rwanguba Hydropower Plant in Isolated Operation

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Introduction

Hydropower is a key contributor to electricity supply in many regions worldwide, providing both renewable generation and valuable system flexibility. In remote areas, hydropower plays a crucial role in electrification by harnessing local resources. When operating in isolated mode, hydropower plants face additional challenges such as frequency and voltage stability, as well as the capability to perform black start and restore supply after a system outage. These challenges have been widely studied in the context of autonomous and renewable-dominated power systems [1-6]. Ensuring reliable operation under varying load conditions requires careful selection of the electromechanical equipment, civil engineering layout, and associated control strategies.

This paper presents the development of the Rwanguba hydropower plant in the Democratic Republic of the Congo, which is aiming to reinforce electricity supply in the city of Goma and its surroundings. The plant is designed with two generating units operating under a gross head of about 200 m and connected to the local grid in isolated mode.

First the methodology used at feasibility-stage to identify the optimal combination of turbine type and penstock layout for stable isolated operation is described. The study compares alternative configurations involving either Pelton or Francis turbines, combined with single or dual penstock arrangements. Both hydromechanical and hydroelectric models were developed using the SIMSEN simulation software to assess the plant's transient behaviour under various operating conditions. Particular attention was given to determining the maximum allowable load variations and for selecting the solution providing the most robust dynamic response. The study also includes a first qualitative comparison with on-site measurements recorded during commissioning tests, providing initial insights into the validity of the modelling approach and identifying directions for further investigation.

1.Project description

The Rwanguba hydropower plant is located in North Kivu province, Democratic Republic of the Congo, and was developed by Virunga Energies to strengthen the electrification of Goma and the surrounding region. Virunga Energies approached Hydro Power Plant (HPP), with whom they had already built two other power stations, to increase capacity with this new power station. The project was launched in collaboration with Hydro Power Plant (HPP), following the commissioning of two other hydropower plants in the area (1.5MW & 14MW).

The hydraulic scheme is designed for two generating units, each rated at 14 MW, operating under a gross head of 206 m and a nominal discharge of 8 m^3/s per unit. The final electromechanical solution adopted consists of two Francis turbines, each equipped with a flywheel to provide the additional inertia required for stable operation in isolated mode. The headrace system comprises two parallel ductile iron penstocks of about 4.5 km in length, one per unit. For cost optimization and transport feasibility, the penstocks were constructed with three successive diameters (2000 mm, 1800 mm, and 1600 mm), instead of a uniform diameter, thereby reducing material and transport costs. Construction was planned in two phases: the first unit was commissioned in October 2024 and is now in operation, while the second unit is currently under fabrication. Figure 1 shows the turbine runner, generator rotor, and flywheel prior to assembly, illustrating the main rotating components of the generating units and the additional inertia provided for stable isolated operation. The complete arrangement of one Francis turbine–generator unit inside the Rwanguba powerhouse is also presented in Figure 1. Figure 2 illustrates the construction of the two parallel ductile iron penstocks, each approximately 4.5 km long, which supply the generating units.

A major design challenge of this project was to ensure hydraulic and electrical stability during isolated operation, while respecting specific technical and financial constraints, especially considering the long penstock. In particular, the maximum dynamic overpressure in the long penstocks had to remain below 30 bar under all transient operating conditions, including emergency shutdowns and load rejection or acceptance. Furthermore, the client requested to avoid the use of a costly and complex pressure relief valve (PRV) solution and to limit the increase of generator inertia to a financially viable level.

Fig.1. (Left) Francis turbine runner, generator rotor, and flywheel before assembly at Rwanguba, (Right) View of the installed Francis turbine-generator unit at Rwanguba

Fig.2. (Left) The two 4.5 km ductile iron penstocks of the Rwanguba scheme during construction, (Right) aerial view of the penstock in operation

2. Methodology and System Modelling

2.1 Objectives of the Study

The primary objective of the feasibility study was to assess the capability of the Rwanguba hydropower scheme to operate stably in isolated mode consecutive to load variations. The target criterion was to maintain the grid frequency within ±10% of nominal during sudden power changes of +/- 2MW per unit. Hydropower units are known to be capable to provide fast load–frequency regulation in isolated systems featuring several sources of energies [7-10].

Two design parameters were identified as critical to this capability: the safety closure time of the guide vanes (Francis) or injectors (Pelton), and the rotational inertia of the generating units. These parameters have opposite effects on system behavior. Shorter closure times reduce frequency deviations during load transients but increase water-hammer overpressures in the long penstocks during emergency shutdowns, whereas longer closure times mitigate hydraulic pressures but lead to larger frequency excursions. Increasing unit inertia generally improves frequency stability and maximum transient pressure induced by Francis turbine units, but induces significant mechanical and financial implications. Within this study, both inertia and closure times were treated as adjustable parameters in order to maximize the admissible load variation while respecting hydraulic and operational constraints.

To assess the feasibility of stable isolated operation, different electromechanical and civil engineering alternatives were investigated. On the electromechanical side, two turbine technologies were considered taking into account either Francis or Pelton turbine, as presented in Table1.

Tab.1. Turbine technologies considered for isolated operation

Turbine technology	Francis turbine	Pelton turbine
Output power	14 MW	14 MW
Rotational speed	750 rpm	375 rpm
Inertia	6’000 kg.m2	12’000 kg.m2
Mechanical time constant	2.8 s	1.3 s
Reference diameter	0.95 m	1.51 m

On the civil engineering side, two waterway layouts were examined. The first configuration involved a single ductile iron penstock supplying both units, consisting of two successive sections of 2.2 m and 2.0 m diameter, each 2,350 m long. The second configuration relied on two independent penstocks, one per unit, each composed intially of two sections of 1.8 m and 1.6 m diameter over the same lengths. Combining electromechanical and civil engineering solutions, four alternative solutions were investigated

It should be noted that the solution actually built on site differs slightly from the feasibility-stage layouts. Instead of two uniform-diameter sections per penstock, the constructed scheme comprises three successive sections of 2000 mm, 1800 mm, and 1600 mm. This adaptation was introduced to facilitate transport and reduce costs, while preserving the overall hydraulic performance.

2.2 Modelling Approach

The feasibility study was structured in two stages, each relying on transient simulations carried out with the SIMSEN software. Accurate modelling of hydraulic transients and electromechanical interactions is essential for assessing stability in islanded conditions [11-14]. SIMSEN provides a modular environment for hydroelectric analysis, allowing hydraulic, mechanical, and electrical subsystems to be modeled consistently within the same software.

2.2.1 Hydromechanical modelling

In the first stage, the objective was to identify which combination of turbine technology and penstock layout would provide the highest admissible load variation while requiring the lowest additional inertia. Four system configurations were investigated, combining two turbine options (Francis or Pelton) with two civil engineering layouts (single or dual penstock). The electrical part of the system, including generating units and electrical network with consumer loads, was modelled with simplified approach. A constant voltage U at the generator terminals, and pure resistive load R were assumed. This leads to a torque source modelling applied to the rotating mass, with the imposed torque adjusted to simulate constant power injection or rejection at the generator terminals. The unit rotational speed was governed solely by the balance between the hydraulic torque and the imposed electromagnetic torque. Figure 3 illustrates the SIMSEN model implemented for the Francis turbine option with two penstocks, including the hydraulic layout, the rotating masses, and the turbine PID speed governor.

Two categories of simulations were performed: (i) transient simulations to determine the safety closure times of the guide vanes (Francis) or injectors (Pelton), and (ii) system stability simulations to assess the load-variation capability in isolated operation. Safety closure times were derived from emergency shutdown scenarios and from the so-called Michaud peak, which generally represents the most critical overpressure condition, particularly for Pelton turbines [15]. This event may occur if all units are started simultaneously from standstill, or if they are connected to the grid with small guide vanes or injectors openings and then respond simultaneously to a sudden power setpoint increase or frequency drop, followed by an emergency shutdown at the worst possible instant triggered by any perturbation or electrical protection system. In such cases, the closure may coincides with the round-trip penstock reflection time of the pressure wave between the turbines and the upstream reservoir, leading to direct water hammer phenomena. In order to ensure a consistent comparison, all variants were simulated under the same transient pressure constraint, corresponding to a maximum dynamic overpressure of 30 bar at the penstock foot. This constraint was used to determine the admissible safety closure times for both Francis and Pelton options. System stability analysis consisted of load-variation simulations in isolated operation with turbine speed governor active. The governor is of PID type with parameters adapted to ensure stable rotational speed regulation. Based on these analyses, the most suitable electromechanical and civil engineering variant, in terms of maximum load variation amplitude and minimum inertia, could be selected for further detailed investigation.

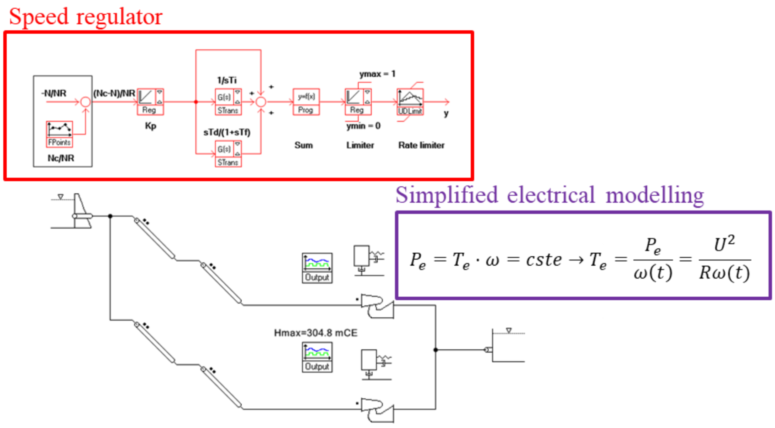

Fig.3. SIMSEN model of the Rwanguba hydroelectric scheme with simplified electrical modelling

2.2.2 Hydroelectrical modelling

In the second stage, the objective was to determine the maximum admissible load variation as function of the operating point of the generating units. This analysis was first performed with the SIMSEN model developed in the first stage, providing a reference evaluation of the load-variation capability across the hill chart. To assess the benefit of increased inertia, load-variation cases were computed with three and five times the initial unit inertia. A detailed hydroelectric model was then implemented to complement the hydraulic analysis and evaluate the influence of electrical components. In this model, synchronous generators were represented by a sixth-order Park's model with their excitation systems [16]. The excitation system was modeled as a Unitrol-type automatic voltage regulator with a voltage reference limiter. Consumer loads were represented as constant with fixed power factor, either unity or 0.8, in order to assess the impact of reactive power demand. The detailed hydroelectric SIMSEN model, combining the hydraulic system with synchronous generators, excitation system, and consumer loads, is presented in Figure 4.

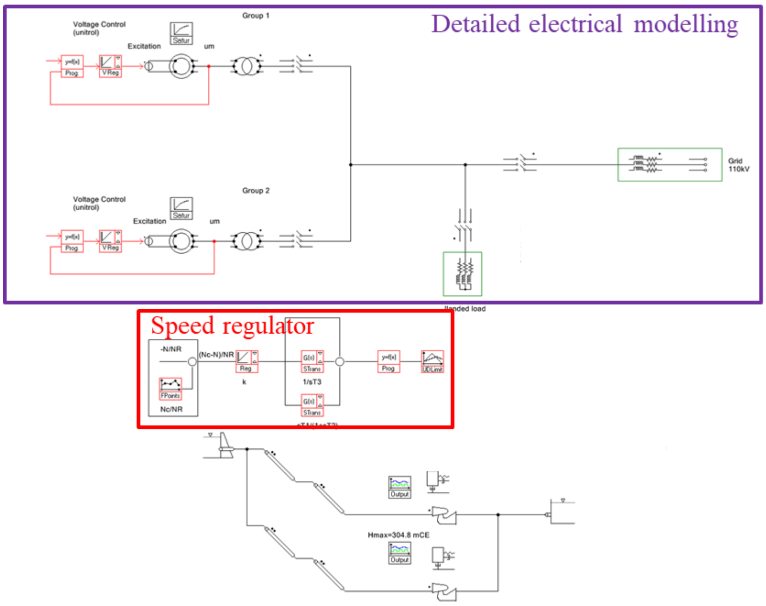

Fig.4. SIMSEN model of the Rwanguba hydroelectric scheme with detailed electrical modelling

3. Results

3.1 Variant selection

The first stage of the study aimed to compare the four electromechanical and civil engineering variants in order to identify the most suitable configuration for isolated operation. For each case, emergency shutdowns and Michaud peak scenarios were simulated to determine both the safety closure times of the guide vanes or injectors to respect the admissible overpressure limit in penstocks. Once this key parameter was set, load-variation simulations were performed to evaluate the frequency stability of each configuration. Two complementary approaches were adopted. In the first approach, the target power variation of +/- 2MW per unit was imposed and the minimum unit inertia required to limit frequency excursions to ±10% was determined. This analysis was performed for load acceptance and rejection with units operating at high output power where hydraulic power reserve is limited. In the second approach, the unit inertia was fixed and the maximum admissible power variation was evaluated. All variants were evaluated under the same overpressure constraint, which allowed a consistent assessment of the impact of turbine technology and penstock layout on the admissible closure times and load-variation capability. A synthesis of the results obtained for all four variants is provided in Table 2, summarizing the admissible closure times, minimum required inertia compared to the initial value and maximum load variations.

Tab.2. Simulation results for the four turbine–penstock variants, including safe closure times, minimum required inertia, and admissible load variations.

	Scenario	Parameter	Francis 1 penstock	**Francis 2 penstocks**	Pelton 1 penstock	Pelton 2 penstocks
Transient simulations	Michaud's peak	Safety closure time [s]	87.4	**61.7**	129.9	89.2
	Emergency Shutdown P100%	Minimum Inertia Factor [x Jinit]	1.3	**1.3**	---	---
Load-variation simulations	P100%-2MW/U	Minimum Inertia Factor [x Jinit]	16	**11**	60	34
	P84%+2MW/U		19	**13**	50	31
	3xJinit, P84%+ ΔPmax	ΔPmax [kW]	800	**1050**	350	450
	5xJinit, P84%+ ΔPmax		1120	**1400**	---	---

The comparative analysis of the results summarized in Table 2 highlights several trends. First, the admissible safety closure time is systematically shorter for the Francis solutions. Closure times are also shorter when two penstocks are used, since the flow velocity is lower in this configuration. For frequency regulation, the Francis variants required less additional inertia to achieve the project target power step variation of ±2 MW. Results show that it would require unrealistically high inertia multipliers. In particular in case of Francis turbine variant, an inertia increase of 19 times the initial value would be necessary for the single-penstock variant, and 13 times for the two-penstock variant. Such values would imply excessively large flywheels, which are not technically or economically feasible. As a consequence, the analysis strategy was adapted to determine instead the maximum admissible load variation for a reasonable increased inertia value. The Francis turbines with two penstocks provided the best performance, with larger admissible load variations than the other options. Nevertheless, the maximum values obtained remained below the original target of ±2 MW, confirming the difficulty of achieving this objective under the given hydraulic constraints. Finally, the comparison highlights that the Francis turbine with two penstocks offered the most robust compromise between hydraulic safety and frequency regulation performance. This configuration was therefore selected for the subsequent stage of the study. It should be mentioned that this optimal configuration is specific to this project layout and design constraints and should be assessed for a new one by using the same methodology.

Figure 5 compares the transient responses of the Francis variant with two penstocks and natural inertia multiplied by a factor 13 (left) and the Pelton variant with one penstock and natural inertia multiplied by a factor 50 (right) for two representative scenarios. In the upper plots, both units are initially stabilized at 84% of nominal power and subjected to a +2 MW load acceptance per unit. In the Francis case (upper left), the guide vane dynamics are not saturated by the safety closure times (i.e. linear variation) and the frequency deviation stabilizes after approximately 200 s. In contrast, for the Pelton case (upper right), the injector dynamics are saturated by the safety closure time and opens as fast as possible and the recovery of nominal frequency after the initial drop is significantly longer. This illustrates that, for Pelton units with a single penstock, the available hydraulic power reserve to compensate frequency deviations is limited, particularly for large injector openings and requires significantly higher unit inertia for the same frequency drop. The lower plots correspond to the determination of the maximum admissible load variation at the same operating point (84% of nominal power), constrained by a ±10% frequency deviation. The transient behavior is similar for both turbine types, with comparable time constants to re-establish nominal frequency. However, the amplitude of the admissible load variation is three times lower for the Pelton variant, confirming the superior capability of the Francis configuration under these conditions. Therefore, the Francis turbine variants with two penstock was selected.

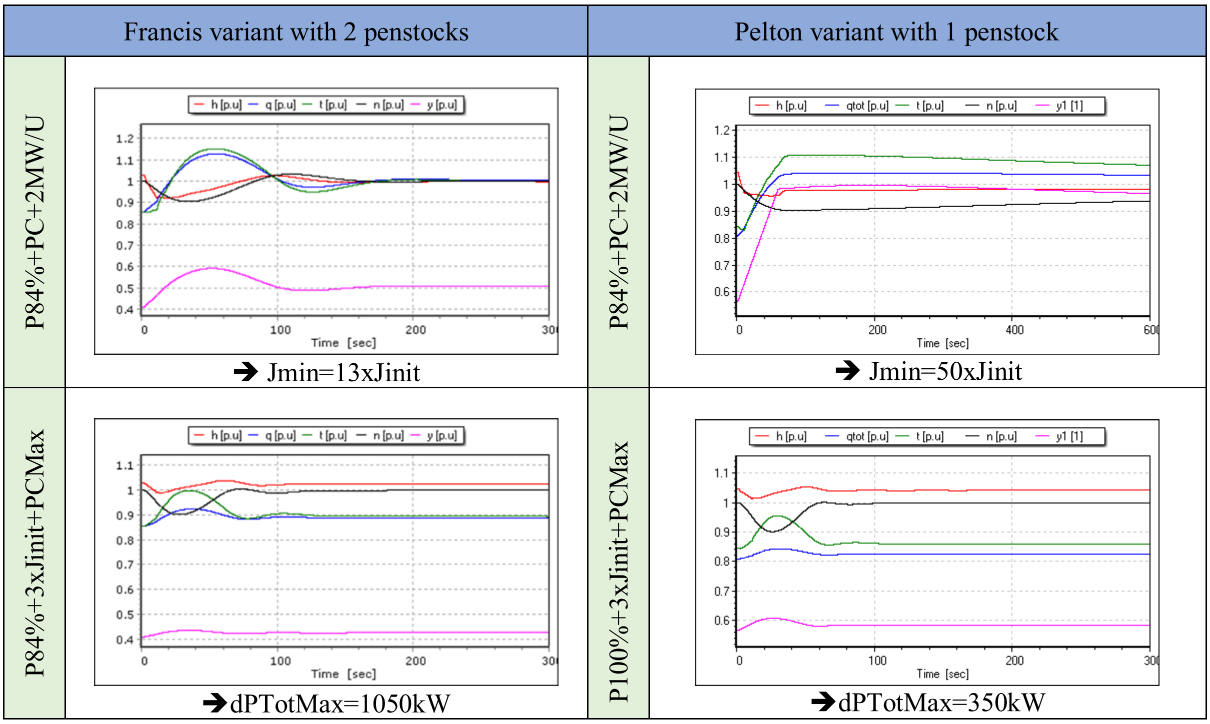

Fig.5. Comparison of transient responses for the Francis variant with two penstocks (left) and the Pelton variant with one penstock (right). Top: simulations to determine the minimum unit inertia required for a ±2 MW load variation. Bottom: simulations to determine the maximum admissible load variation for a fixed inertia. Variables shown include head (h), discharge (q), torque (t), rotational speed (n), and guide vane/injector opening (y), all in per-unit.

3.2 Maximum power variation curves as function of operating point

The second stage of the study focused on determining the curves of maximum admissible load variation as a function of the operating point of the generating units for the Francis turbine variant with two penstocks. The initial unit inertia was insufficient, as the system was unstable and could not ensure any power variation under this condition. Therefore, the analysis was conducted with increased inertia values corresponding to three and five times the initial inertia. For each inertia value, two curves were computed: one for load acceptance (increase of generation) and one for load rejection (decrease of generation). The results, shown in Figure 6, highlight a dependence on the operating point. The maximum admissible power variation decreased as the output power of the plant increased, indicating that the system is less flexible when operating closer to full load. Larger admissible variations were consistently obtained in the case of load rejection compared to load acceptance due to the output power curve as function of guide vane opening which saturates at maximum output power. Moreover, as expected, for a given operating point, the admissible variation was always greater with the higher inertia value, confirming the stabilizing effect of increased rotating mass. These results provided a detailed quantification of the load-variation capability of the selected configuration, highlighting both the beneficial effect of increased inertia and the asymmetry between load increase and load decrease. They also served as a reference for the subsequent analysis including the detailed electrical modelling and the impact of the load power factor.

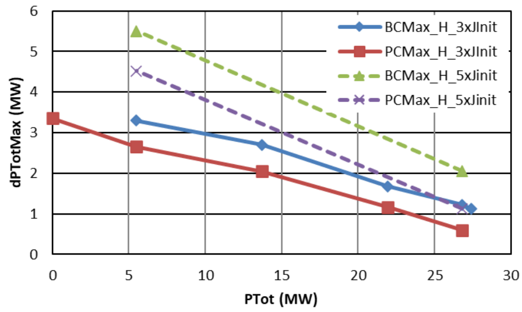

Fig.6. Maximum admissible load variation versus plant output for the Francis variant with two penstocks, with unit inertia increased by a factor of 3 or 5. Curves are shown for load acceptance (PCMax) and load rejection (BCMax).

To evaluate the role of electrical dynamics, the load-variation curves computed with the hydraulic model were compared to those obtained with the detailed hydroelectric model. As shown in Figure 7, the inclusion of generator and excitation dynamics modifies the admissible variations, particularly during load acceptance at high power. With the load power factor set to unity, corresponding to purely resistive loads, the results showed a reduction in the maximum admissible variation during load rejection. At the opposite, during load acceptance at high output power, the maximum admissible variation increased significantly. This improvement was attributed to the stabilizing effect of the voltage reference limiter in the excitation system, which limited voltage excursions and enhanced the system's ability to absorb additional load.

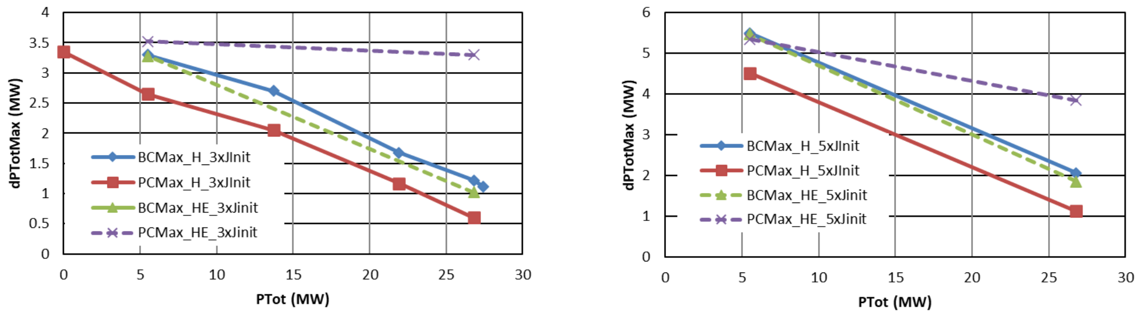

Fig.7. Influence of the hydroelectric model on maximum admissible load-variation curves for the Francis variant with two penstocks. Left: inertia ×3. Right: inertia ×5. Results from hydraulic (H) and hydroelectric (HE) models are shown for load rejection (BCMax) and load acceptance (PCMax).

To assess the effect of reactive power demand, simulations were carried out with consumer loads at unity power factor and at 0.8 power factor. The resulting curves, shown in Figure 8, reveal that lower power factors reduce the admissible load variation, particularly at high operating power. The additional reactive power demand had a detrimental effect on the dynamic stability of the isolated system, lowering its flexibility compared to the unity power factor case. These findings underline the importance of properly accounting for electrical dynamics and realistic load characteristics in feasibility studies of isolated hydroelectric plants, as they can strongly influence the estimated load-variation capability.

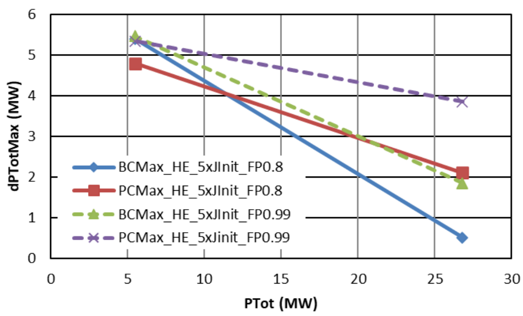

Fig.8. Effect of power factor on admissible load-variation curves for the Francis variant with two penstocks (inertia ×5). Results from the detailed hydroelectric model are shown for FP=1.0 and FP=0.8 lagging.

3.3 Synthesis

The comparison of the four variants demonstrated that the Francis turbines with two penstocks provided the largest admissible load variation in isolated grid operation and therefore represented the most suitable configuration for Rwanguba HPP. As expected, the analysis of the load-variation curves further confirmed that increasing the unit inertia was both necessary and beneficial to maximize the admissible load variation. At the same time, the maximum variation was found to decrease as the plant output increased, indicating reduced flexibility at high power output. An asymmetry between load rejection and load acceptance was also observed, with larger variations consistently possible during power reduction.

Moreover, the influence of the electrical system dynamics and load power factor was shown to be critical. The voltage reference limiter in the excitation system improved stability during load acceptance at high power, whereas reactive power demand (power factor 0.8) reduced the admissible variations for both load increase and decrease. This electrical modelling approach provided a refined assessment of the realistic performance limits of the Rwanguba scheme.

4. On-site measurements

During commissioning of the first generating unit, emergency shutdown tests were performed. Figure 9 compares the measured response of an emergency shutdown from 11.7 MW with the corresponding simulation. The results show very good agreement in terms of unit overspeed (dashed green line for measurement and violet curve for simulation) and penstock foot pressure (dashed black line for measurement and blue curve for simulation), thereby validating the hydraulic modelling used in the feasibility study.

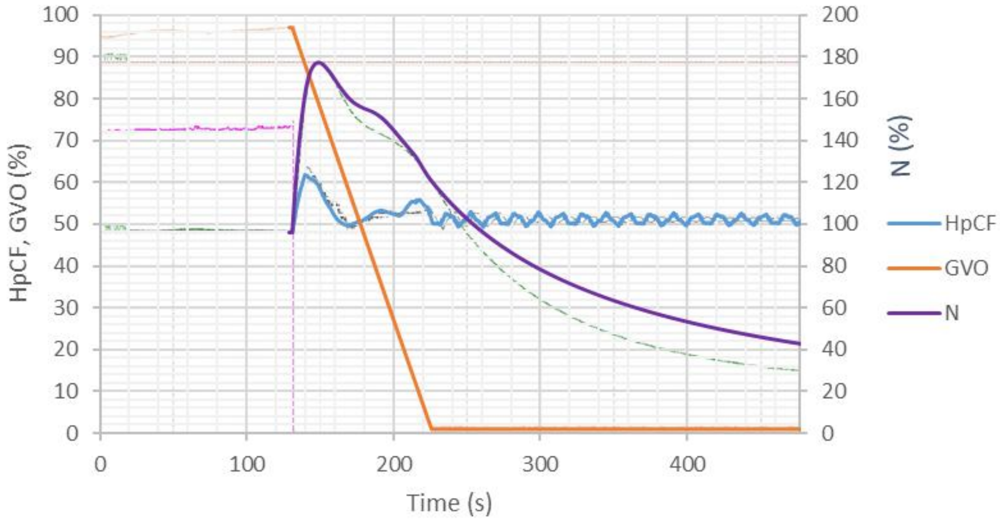

Fig.9. Measured response of the first Francis unit in isolated-mode operation at Rwanguba, showing distributor opening (GVO), power output, penstock pressure (HpCF), and rotational speed (N).

Following these tests, islanded-mode operation was investigated through load-variation experiments performed in conjunction with Matébé hydroelectric power plant in operation on the same electrical power system. The dynamic response of the first unit in isolated operation is illustrated in Figure 10, which displays the measured time histories of distributor opening, electrical power, penstock foot pressure, and rotational speed. These measurement results provide a qualitative basis for comparison with the simulated results. The recorded responses showed significant discrepancies with respect to the simulations, particularly regarding frequency dynamics. In practice, frequency excursions of 15 to 20%, induced by output power variation of 3MW, were observed well above the values predicted by the feasibility study. Nevertheless, load variation in isolated operation remained globally stable.

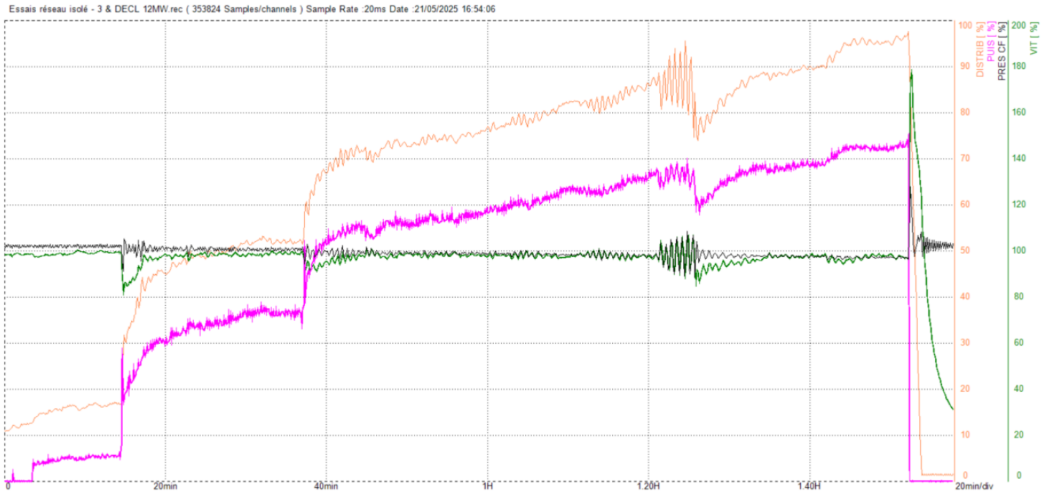

Fig.10. Measured response of the first Francis unit in isolated-mode operation at Rwanguba, showing distributor opening, power output, penstock pressure, and rotational speed.

One contributing factor is that the safety closure times implemented on site were approximately twice as long as those recommended in the study, which directly affected the transient response of the units. Moreover, the simulations assumed that Rwanguba was the sole source of generation in the islanded network and that the grid voltage remained constant, inducing constant electrical power consumption before and after the load change event. In reality, the tests revealed strong interactions with the neighboring Matebé plant, meaning that the voltage source could not be considered constant due to the dynamics of the interconnected electrical network. Indeed, the commissioning report further noted strong interaction between Rwanguba and Matébé power plants in islanded operation. This illustrates the practical challenges of coordinating multiple hydro plants in islanded operation by tuning all governors to operate in harmony.

These observations underline the limitations of the simplified assumptions set in the feasibility study. They point out the need for further tuning of the governors to improve the Rwanguba–Matebé system islanded operation stability.

5. Conclusions

The Rwanguba hydropower plant, located in North Kivu (DR Congo), was designed to reinforce electricity supply for the city of Goma with the installation of two Francis units operating under a gross head of 206 m. A feasibility study was conducted to assess its ability to operate stably in isolated mode. For isolated operation, the option of a pressure relief valve was discarded in favor of increasing the rotating inertia of the generating units, a passive and robust solution improving also the system stability. This feasibility study therefore investigated the implementation of increased inertia, with the objective of identifying the most effective electromechanical and civil engineering configuration to maximize the plant's load-variation capability under the given hydraulic constraints. It was shown that Francis turbines with two penstocks offered for Rwanguba power plant the most favorable configuration for isolated operation. With the increased inertia which is installed on site, the target load variation of ±2 MW is reachable when units operate at low output power. However at high output power, the load variation amplitude is strongly reduced due to the saturation of the output power curve as function of guide vane opening. Moreover it has been observed that the load variation capability is systematically larger for load rejection than for load acceptance. Electrical modelling further highlighted the role of excitation systems and power factor, with reactive power demand reducing flexibility. Preliminary on-site tests confirmed the overall stability of isolated operation but revealed larger frequency excursions than predicted. The difference between simulation and site measurements results are mainly attributed to the significant interactions with the neighboring Matébé plant which have been observed, and lay beyond the scope of the feasibility study. The purpose of the present study was limited to defining the most suitable electromechanical and civil engineering configuration (between Francis or Pelton turbines with increased inertia and one or two penstocks). A more detailed investigation including both power plants and the actual electrical network would be required to refine governor tuning parameters and further enhance grid stability.

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Pierre Pisterman graduated in Mechanical Engineering from French « Ecole Nationale des Arts et Métiers » and holds a Master in strategy from HEC Business school. (France). His family has been involved in the hydro business since 1906. He has around 20 years of experience in small and medium hydro turbines, first as project manager and, since 2015, as the CEO of Hydro Power Plant (HPP).

Michel Verleyen holds degrees in Civil Engineering (Construction) from the University of Liège, Belgium, and in Industrial Management from the Catholic University of Louvain, Belgium. He is responsible for the development and construction of hydroelectric plants around Virunga National Park, comprising five facilities with a total of nine turbines (60 MW).

Christophe Nicolet graduated from the Ecole polytechnique fédérale de Lausanne, EPFL, in Switzerland, and received his Master degree in Mechanical Engineering in 2001. He obtained his PhD in 2007 from the same institution in the Laboratory for Hydraulic Machines. Since then, he is director and principal consultant of Hydropower Dynamics Engineering SA in St-Sulpice, Switzerland, a company active in the field of optimization of hydropower transients and operation. He is also external lecturer at EPFL in the field of "Hydroacoustic in hydropower plants".

Abridged Abstract example

Feasibility Study and Equipment Selection for the Rwanguba Hydropower Plant in Isolated Operation
S. Alligné, Project Engineer, Hydropower Dynamics Engineering SA, Switzerland

The Rwanguba hydropower plant, located in North Kivu (DR Congo), was designed to reinforce electricity supply for the city of Goma with the installation of two Francis units operating under a gross head of 206 m. A feasibility study was conducted to assess its ability to operate stably in isolated mode. Four electromechanical and hydraulic variants were compared using transient simulations in SIMSEN. Results showed that Francis turbines with dual penstocks provided the most favorable option for frequency regulation. Further analyses highlighted the influence of excitation dynamics and load power factor on system flexibility. Preliminary on-site tests performed in islanded operation in conjunction with another hydroelectric power plant confirmed overall stable islanded operation, but revealed larger frequency excursions than predicted. These results are stressing the challenge of achieving stable operation in islanded grid.