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Dynamic security of islanded power systems with pumped storage power plants for high renewable integration – A study case

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Abstract: This work consists in assessing a real islanded power system from a dynamic security point of view, to support the planned installation, in the near future, of a hydro power plant with pumped storage, aiming to increase the integration of renewable energy. The analysed hydro power plant will include a Pelton turbine as it is a high-head hydro facility. Due to economic reasons, the adopted water pumping technology consists in fixed speed pumps coupled to induction motors with direct grid connection. It was possible to verify through detailed simulations of this power system's time domain behaviour that, even though the expected installation of this new power plant will bring additional frequency stability constraints, a robust technical solution may be found dealing with the new constraints without increasing the complexity of operation in this islanded power system. The conclusions obtained from this specific case are also valid for similar isolated power systems, namely when hydro pumping stations are being considered to increase time-variable renewable generation penetration.

1 Introduction

The integration of large shares of time-variable renewable generation in isolated power systems has been a challenging task as it is of the utmost importance ensuring robust power-frequency regulation capabilities, typically achieved by means of diesel-based synchronous units. The spinning reserve criteria traditionally defined by the system operators, together with the operational requirements of diesel units, may lead to the spillage of renewable generation during valley hours, unless energy-storage-based solutions, either based on electrochemical batteries or via pumped storage power plants, are used [1–5]. If adopting a battery-based solution, this allows the provision of fast frequency control. However, when the amount of energy to be transferred from valley to peak hours is large, this solution becomes less appealing from an economic perspective, because of increased unitary costs of energy storage capacity [6]. In these cases, in locations with adequate orographic and climatic conditions, the construction of a hydro power plant with pumped storage – sometimes involving the construction of artificial upstream and downstream reservoirs and mostly equipped with separate turbines and pumps – becomes the most suitable energy storage system to use [7]. In fact, for islanded power systems above a few MW, this alternative is technically more mature and economically more viable [8]. During valley conditions, the surplus of renewable power production is stored, by using the pumping units. Namely, in the specific case of wind power, these operating conditions are usually applied during the nights with favourable wind conditions. In high-load hours, the energy stored through water pumping can be recovered by the hydro turbines to replace expensive peak generation.

However, exploiting a pumped storage power plant in an islanded power system may largely change its power-frequency regulation capabilities and, therefore, assessing this solution's dynamic performance is decisive to assure the stability of the system. Having this is mind, the stability constraints inherent to an islanded network of a medium-sized European Atlantic island are assessed in this work. This island is expecting a larger penetration of renewable generation to operate in the coming years together with a pumped storage power plant. The analysed pumped storage power plant includes a Pelton turbine, as it is a high-head hydro facility. Due to economic reasons, the adopted water pumping technology consists in high pressure fixed speed pumps coupled to induction motors with direct grid connection. This choice was motivated by the results presented in [9], where the investigation of alternative technical solutions available in the market for the pumping units showed limited technical advantages from investing in variable speed solutions for these units.

In the present analysis, the following technical limitations are introduced by having such a pre-defined solution for the new hydro power station:

- The usage of Pelton hydro turbines for frequency control is restricted by the significant water starting time as a result of the high-head hydraulic circuit (because of the effects of water compressibility, water inertia and pipe wall elasticity in the penstock [10]), and also by the delayed opening time of the gate injectors used to prevent pressure issues in the penstock [7].
- The adoption of fixed speed induction motors for water pumping may lead to their sudden disconnection when faults occur in the grid, after the automatic action of the minimum voltage protection systems, due to the outspreading residual fault voltages.

So, the installation of the high-head pumped storage power plant with fixed speed hydro pumps may create critical stability issues. Firstly, a deficit of fast-acting frequency control may arise in the power system because of the hydro turbine restricted active power time response capabilities. Additionally, because of the substantial load dictated by fixed speed hydro pumps (particularly in valley scenarios), in the event of a short-circuit this consumption may suddenly be lost. Consequently, there may be a lack of downward spinning reserve causing the tripping of the synchronous machines that are providing secondary frequency control, because of reverse power flow.

By performing transient time domain simulations of the studied power system, in this work, a robust technical solution was found by readjusting the settings of the available resources, namely, by re-evaluating the following conditions: a) dispatch management of diesel units; b) under-frequency load shedding system; c) fault-ride-through and frequency protection settings of the installed wind parks. This solution was based on the analysis of scenarios with extreme (worst case) operating conditions from the perspective of the dynamic stability/frequency control. By ensuring security for these extreme scenarios, system security will be guaranteed for all scenarios.

The structure of this paper starts, in Section 2, by describing the general methodology that was followed for this study. Next, Section 3 provides an overview of the analysed power system as well as on the simulation results obtained for this study case. Lastly, in Section 4, the main outcomes from the conducted analysis are presented.

2 Applied methodology

Typically, in islands, the power system security assessment is constrained by the aim of having no shedding of distribution feeders after disturbances. Assuming this, the following security goal was considered in the stability study formulation: *none of the disturbances usually considered by the network operator for system security assessment lead to under-frequency shedding of distribution feeders*. Foreseen disturbances comprise N-1 contingencies or symmetrical faults in the transmission or distribution system.

By following a worst-case-based approach, the performed dynamic stability studies were focused on scenarios with extreme operating conditions from the perspective of the dynamic stability/ frequency control. Namely, two extreme operating scenarios were assessed: a) *Windy valley scenario* – maximised wind power generation fed by maximum pumping; b) *Maximum Renewable Energy Sources (RES) scenario* – maximum renewable power penetration, including the power infeed from the hydro turbine, without pumping needs.

In the windy valley scenario, wind power is maximised by assuming that all the hydro pumps are at their maximum power. Assuming that fast-acting frequency control is only available on diesel units and that these units are the ones responsible for secondary frequency control, the system's active power-frequency control needs restrict the diesel dispatch, namely the spinning reserve criteria, the must-run units and the minimum number of connected generators. Therefore, the defined valley scenario provides the following worst-case conditions: a) minimum upward diesel spinning reserve; b) minimum downward diesel reserve needed to counterbalance the disconnection of pumping units, for instance following a grid fault.

Within this scenario, the role of the Pelton turbine was assessed for the provision of fast frequency regulation capabilities, which is directly linked to the need of installing two penstocks (for simultaneous operation of the Pelton turbine and high pressure pumps). In order to evaluate this, the stability analysis was conducted for the following two alternative solutions: a) Individual penstock case – a synchronous condenser mode is assumed for the Pelton turbine operation (i.e., with no mechanical power but with the synchronous generator and excitation system connected to the grid); b) Two separate penstocks – adopting such a configuration raises the overall investment costs of the hydro facility but allows the hydro pumps and turbine to operate simultaneously with power-frequency control from the Pelton turbine [7].

In the maximum RES scenario, a higher load is assumed in order to dispatch all the installed renewable generation, including the hydro turbine, without breaking the technical restrictions of diesel dispatch and without the need of pumping consumption. As the pumps are not in service, the Pelton turbine can operate in frequency regulation mode even in the case where only an individual penstock is built. Due to the significant integration of wind generation, the post-disturbance transient period following faults can be crucial in this scenario. In fact, even state-of-the-art wind turbines suited with advanced grid functionalities (e.g. fault-ride-through modes) may suffer an acute reduction of the active power provision directly after a fault, followed by an upward ramping period where the pre-fault active power value is restored [11]. As typically there are no pumps in operation in scenarios with higher loads, in the event of a fault, the loss of wind generation cannot be counterbalanced by the pump units tripping. Consequently, the defined maximum RES scenario provides the following worst-case conditions: minimum upward diesel spinning reserve to counterbalance the wind power transient loss that follows a grid fault.

3 Study case results

3.1 Islanded system characterisation

The network considered in this work is a medium-sized island located in the European region of the Atlantic Ocean. Ten diesel power units are installed in the local thermal power plant, adding up to an installed capacity of 50 MW (4 × 2 MW, 4 × 5 MW, 2 × 11 MW). Wind power generation is provided by two separate wind parks, including 14 ENERCON variable speed synchronous generators with individual rated powers of 0.9 MW (10 × 0.9 MW, 4 × 0.9 MW). A geothermal power plant with a capacity of 3.5 MW and a Municipal Solid Waste (MSW) power plant with a capacity of 2 MW, comprise synchronous machines with pre-defined active power outputs. For the period being analysed, the typical minimum load is around 15 MW, usually occurring at night, and the maximum load is near 32 MW. Aiming to maximise renewable energy production, a pumped storage power plant is expected to be in operation comprising: (1) a Pelton turbine coupled to a synchronous machine (rated power: 7 MW); (2) six fixed speed hydraulic pumps, individually powered by squirrel cage induction motors (rated power: 1.25 MW each).

Automatic voltage regulation is assumed to be performed by all the synchronous generators. Diesel generators are responsible for primary and secondary frequency regulation. The amount of fast downward (negative) spinning reserve is, therefore, defined by the instantaneous diesel generation. The technical constraints for the dispatch of the diesel generators are the following: (1) a minimum of two generators connected to the grid, with at least one large and one medium size generator; (2) a minimum diesel spinning reserve equal to 50% of the combined RES power infeed from wind, geothermal and MSW.

3.2 Adopted dynamic model

The selected simulation platform to conduct dynamic simulation studies for this power system was MATLAB Simulink, using Simscape Power Systems^{TM} model libraries, as well as custom-designed models that were adopted for the ENERCON wind generators (these units are connected to the grid through full-scale converters). The considered parts of the grid's topology comprise the power plants and the transmission system (established at the 30 kV voltage level).

The adopted model for wind generators was designed to focus on their response seen from the grid's perspective. This response is predominantly characterised by the grid side converter interface. Specifically, in terms of the behaviour during faults, the following key functionalities were considered: a) For severe faults with voltages below 0.2 pu, the Zero Power Mode (ZPM) allows the generators to remain connected to the grid but without any power feed. b) For less severe faults (voltages ranging between 0.2-0.8 pu), the ENERCON functionalities provide a different fault-ride-through (FRT) mode (PQ Mode) which consists in maintaining the active/reactive current injection during the voltage dip within values equal to the pre-fault condition. As a consequence of this behaviour, during a fault, wind active power will be reduced due to the voltage reduction at the generator's terminals (n.b.: these machines were assumed to be operating with unitary power factor). After faults, a maximum gradient limits the active power recovery [11].

A separate model of pumps and turbine was chosen to represent the reversible hydro power plant. Pumping units are modelled by conventional induction machines, with nearby-connected capacitor banks compensating their significant power factor. With respect to the hydro turbine and its control system, the following models were used: a) *Turbine and hydraulic circuit*, represented by a linearised 4th-order model considering the elasticity of the water column, thus contemplating the water starting time and the penstock wave travel time [10]; b) *Speed governor*, modelled by a PID controller driving the opening position of the water injectors within the Pelton turbine, also including the opening limits and opening speed

Table 1 Main characteristics of the hydraulic circuit

penstock length	2370 m
penstock diameter	1.1 m
rated flow	2.4 m^3/s
hydraulic head	340 m

Table 2 *Windy valley scenario*

Generation		Pg [MW]	SR + [MW]	Consumption	Pc [MW]
Hydro gen.		0	7	Load	15.1
Diesel	G8	2.5	2.5	Hydro pumping	7.5
	G10	5.1	5.4		
Geothermal		3.5	–	-	-
Wind park 1		7.5	–		
Wind park 2		3	–		
Waste (MSW)		1.4	–		

Legend: Pg: active power generation; SR + : upward spinning reserve; Pc: active power consumption.

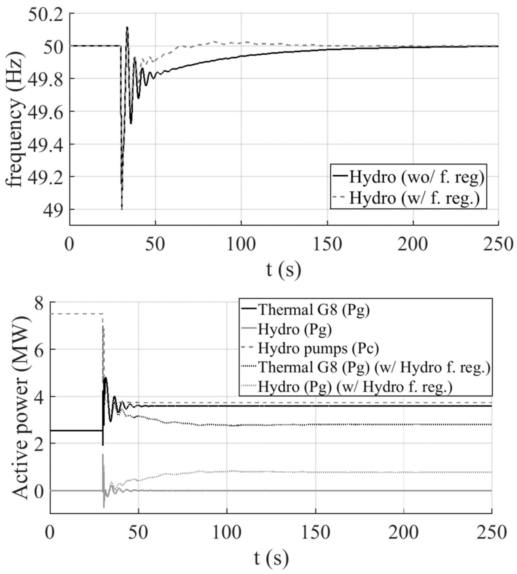

Fig. 1 *Windy valley scenario - G10 loss with/without freq. regulation provided by the hydro turbine, plus the shedding of 3 hydro pumps at 49 Hz. Legend: Pg and Pc – active power generation and consumption; f. reg – primary and secondary frequency regulation*

of the water injectors (limited to a total opening time of 15 s) [10]. Moreover, a speed droop was included together with an integral frequency controller; c) *Hydro generator*, represented by a salient pole synchronous machine (a 6th-order model that includes transient and sub-transient flux behaviour). The hydraulic circuit's main characteristics are summarised in Table 1.

3.3 Analysis of simulation results

1 *Power unit loss disturbance in windy valley scenario*

The defined windy valley scenario is described in Table 2. For the considered generation/consumption operating conditions, the most severe power unit loss disturbance consists in the tripping of G10 diesel unit, leaving the system with a diesel spinning reserve of 2.5 MW for a generation loss of 5.1 MW. As it was previously discussed, two different situations were considered: a) Accounting for the use of two separated penstocks, thus allowing the hydro turbine to provide some power-frequency control capabilities. b) A single penstock is used, and therefore no power-frequency regulation capabilities are provided by the hydro turbine.

Fig. 1 presents the time domain results obtained for the described situation, which includes the intentional shedding of three hydro pumps as frequency reaches 49 Hz in order to maintain the system's dynamic security. In fact, dynamic simulations showed that the frequency regulation capabilities provided by the pumped storage power plant have an insignificant influence in the first seconds after the disturbance. Given these limitations, the intentional tripping of the hydro pumps for low frequency conditions was the encountered strategy to prevent under-frequency shedding of distribution feeders. These results decisively favour the consideration of an individual penstock solution, since a negligible added value is obtained from installing two penstocks.

2 *Fault in a transmission line in windy valley scenario*

Regardless of the scenario under analysis, a fault situation anywhere in the transmission grid will provoke the tripping of all the connected fixed speed hydro pumps, due to a severe voltage dip. In the defined valley scenario, after the post-disturbance power recovery from the wind parks (after picking up from a ZPM situation), the power system will face a severe load loss of 7.5 MW (the hydro pumps consumption), comprising just 7.6 MW of diesel downward spinning reserve to provide frequency regulating actions. As presented in Fig. 2, this leads to a limit situation which may lead the diesel units to a reverse power flow condition and, consequently, to the tripping of these units followed by the overall system collapse. To avoid this, the adopted spinning reserve criteria must always include enough downward spinning reserve in diesel units to compensate the tripping of all the connected fixed speed hydro pumps. From the dynamic behaviour studies' perspective, the following minimum spinning reserve criterion was found to be suitable for this power system:

$$k \cdot Pc, \text{pumping} < Pg, \text{diesel}, \ \text{with}\, k \geq 1.1 \qquad (1)$$

3 *Fault in a distribution feeder in windy valley scenario*

For the same valley scenario, the worst case location for a symmetrical fault is in the beginning of the most loaded distribution feeder. This will cause not only the tripping of all the connected hydro pumps but also the loss of the faulted feeder (due to protection systems' action to isolate the fault). After the wind parks active power recovery (after picking up from a PQ control mode situation), the power system will face the most severe load loss, consisting of 9 MW (7.5 MW from the pumps and 1.5 MW from the feeder). Being the 7.6 MW of available downward spinning reserve insufficient, additional measures were necessary to deal with this possible deficit of downward spinning reserve during valley conditions. Dynamic simulations showed that, for this power system, an efficient technical solution consists in adopting an over-frequency relay for the largest wind park (wind park 1), by automatically disconnecting this facility when frequency reaches 51 Hz. The dynamic simulation results, obtained by adopting this strategy for the considered scenario and disturbance, are presented in Fig. 3. From these results, it was

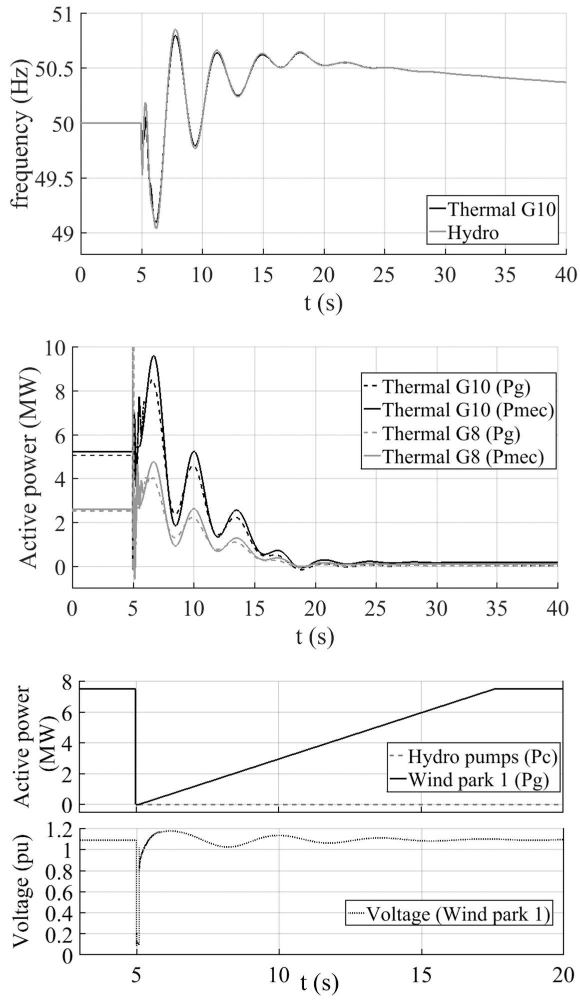

Fig. 2 *Windy valley scenario - Fault in a transmission line. Legend: Pmec - mechanical power*

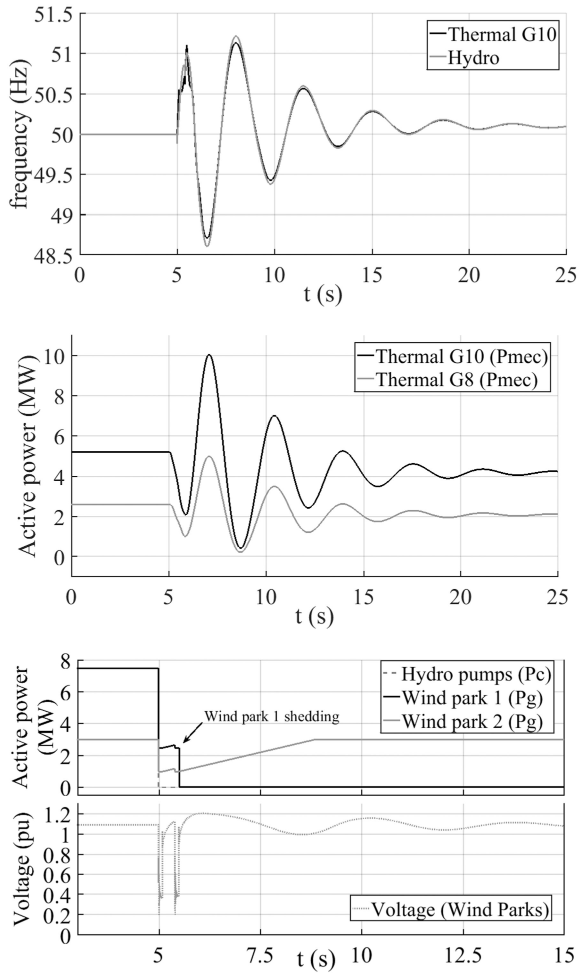

Fig. 3 *Windy valley scenario - Fault in the most loaded distribution feeder, plus the shedding of wind park 1 at 51 Hz*

Table 3 *Maximum RES scenario*

Generation		Pg [MW]	SR + [MW]	Consumption	Pc [MW]
Hydro gen.		4.3	2.7	Load	32.1
Diesel	G9	5	5.5	Hydro pumping	0
	G10	5	5.5		
Geothermal		3.5	–	-	-
Wind park 1		9	–		
Wind park 2		3.6	–		
Waste (MSW)		2	–		

Legend: Pg: active power generation; SR + : upward spinning reserve; Pc: active power consumption.

possible to conclude that the proposed over-frequency relay tripping strategy in the wind parks avoids a reverse power flow condition in the diesel generators, therefore being most suitable for this power system.

4 *Maximum RES scenario*

Table 3 displays the operating conditions associated to the defined maximum RES scenario. No hydro pumping is taking place and so the hydro turbine is connected and providing limited primary and secondary frequency regulation.

For Table 3 operating conditions, the most severe N-1 disturbance consists in the loss of one diesel power unit. The results for this situation are presented in Fig. 4, showing no distribution feeder shedding conditions, meaning that, in this scenario, system security is maintained for N-1 disturbances.

For the same scenario, a symmetrical fault occurring in an arbitrary transmission line will lead to a significant temporary wind active power drop, since all the wind machines will enter in the ZPM control mode as a result of the short-circuit voltage sag. As the loss of wind production cannot be counterbalanced by the hydro pumps tripping strategy (these are not connected in this scenario), this kind of disturbance may create a transient insufficiency of fast upward spinning reserve. In this specific scenario, a total generation of 12.6 MW is transiently lost (due to having the wind parks in ZPM), as only 11 MW of fast-responding diesel reserve are available. As presented in Fig. 5, again the frequency control capability provided by the hydro turbine (offering a spinning reserve of 2.7 MW) proved to be limited, not being able to avoid the conditions for load shedding activation in the first seconds after the disturbance (n.b., the distribution feeder shedding scheme was not included in the dynamic simulations). Given the aforementioned results, extra measures were necessary in order to avoid load shedding and hence fulfilling the defined security criteria. For this power system, time domain simulations (see Fig. 6) showed that shedding of distribution feeders can be

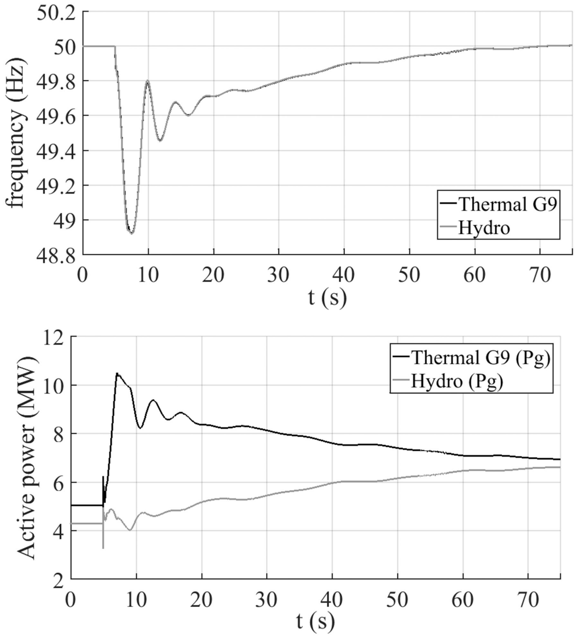

Fig. 4 *Maximum RES scenario- G10 loss*

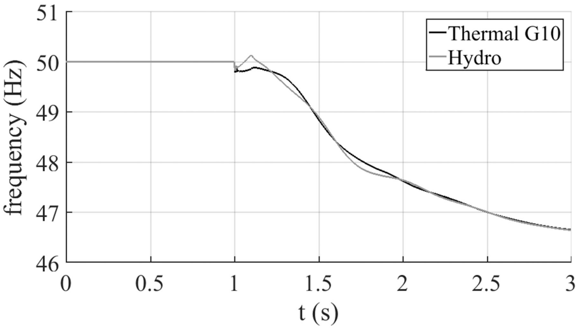

Fig. 5 *Maximum RES scenario - Fault in a transmission line*

avoided by increasing the value defined for the maximum active power recovery gradient in wind generators, after a FRT situation.

However, such an adjustment – required for the specific case of maximum RES scenarios – will decrease the system security margin during faults in valley conditions, where the security problem is a result of the deficit of downward spinning reserve. Therefore, when adjusting the new value for the wind active power recovery gradient after a FRT situation, it was necessary to look for a robust solution applicable in any scenario. On the other hand, adopting an over-frequency shedding strategy for wind park 1, required for scenarios with connected hydro pumps, may create unnecessary wind power disconnections in the power system (as in the situation described in Fig. 6). Therefore, to minimise wind power disconnections, the adopted over-frequency shedding strategy in wind parks should be operational only during scenarios with connected hydro pumps.

4 Conclusions

This work describes the assessment of a real islanded power system from a dynamic security point of view, to support the planned installation, in the near future, of a hydro power plant with pumped storage, aiming to increase the integration of renewable energy. This hydro power plant will comprise Pelton turbines as it is a high-head facility. Due to economic reasons, the adopted water pumping technology will consist in fixed speed hydro pumps with direct grid connection.

Based on dynamic behaviour studies for extreme operating scenarios, it was possible to conclude that the role of the pumped storage plant is marginal for the provision of frequency control, despite the potential benefit it provides with respect to energy storage and to avoid the renewables' curtailment during valley

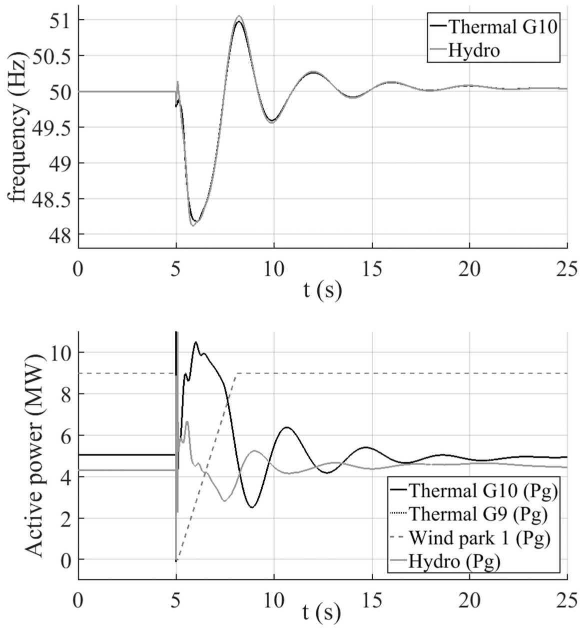

Fig. 6 *Maximum RES scenario - Fault in a transmission line, including an increased maximum active power recovery gradient in wind generators after a FRT situation*

hours. In fact, due to the characteristics of the hydraulic circuit, the frequency regulation capabilities provided by this power plant showed a negligible influence in the first seconds after a disturbance. Conclusively, no technical benefits were identified for the option of building independent penstocks (separating the hydraulic circuits of the Pelton turbine and the fixed speed hydro pumps) in this island's reversible hydro power plant.

Besides, additional measures must be adopted in order to avoid dynamic security problems in this islanded power system. Namely, to address the insufficiency of fast-responding upward spinning reserve caused by the hydro turbine's slow transient response, the following measures were identified as necessary for this power system:

- In the hydro pumps, setting an under-frequency shedding strategy to include these units in the upward spinning reserve;
- In the wind generators, increasing the pre-set value defined for the maximum active power recovery gradient, after picking up from fault-ride-through operation.

Moreover, a grid fault occurrence in such a small power system usually causes the tripping of the fixed speed hydro pumps due to low residual voltages occurring all over the system. So, in scenarios comprising large loads set by the hydro pumping units, the available resources must be specifically adjusted to avoid the deficit of downward secondary diesel reserve – which causes a reverse power flow in diesel generators and the subsequent tripping of these machines. Following this rationale, the measures identified to provide an effective and robust solution were:

- In the diesel dispatch, adopting an appropriate downward spinning reserve criterion able to outbalance the sudden disconnection of the fixed speed hydro pumps;
- In the wind parks, implementing an over-frequency shedding strategy, able to automatically disconnect some power production before having a reverse direction of diesel power production.

Despite the fact that the expected operation of this pumped storage power plant brings additional security hurdles that must be overcome, a robust technical solution was found without increasing this power system's operation complexity. The conclusions drawn from this specific power system can be carried for similar isolated networks, namely when hydro pumping stations are envisioned to allow the growth of RES penetration.

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