

Gas Turbine Control. Modifications for: Availability and Limitation of Spinning Reserve and Limitation of Non-desired Unloading

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Abstract. This paper presents several modifications developed in a gas turbine control system. One of the modifications made in turbine control limits speed deviations to the governor. Consequently, this modification limits turbine power delivered - positive and negative - for Primary Control of Frequency purposes. In addition, this modification avoids that large, sudden power unloading takes place when the grid frequency recovers from a big dip, while original operational control modes are active. Together with complementary modifications made in the power plant centralized control, other turbine control modifications allow operators to adjust set points of grid frequency, dispatched power and required spinning reserve (positive and negative) which are established by the Dispatch Center of Argentinean electrical grid. Another modifications made in the power plant centralized control allows keeping the spinning reserve margins always available in spite of variations of maximum turbine power with weather conditions.

These modifications were developed in a 120 MW gas turbine, which is part of a combined cycle in Tucumán, Argentina.

Finally, several tests carried out on the turbine are presented together with operational records that were taken during system frequency disturbances. The tests and operational records show the behavior of the turbine power with and without the modifications made to its control system.

Index Terms

Frequency - Frequency control - Gas turbines - Governors - Power generation availability - Power generation control - Power generation scheduling.

1. Introduction

SEVERAL modifications were made to a gas turbine control system during its commissioning.

The gas turbine is MS9001(E) type, General Electric, with MARK V Speedtronic control system, with 120 MW of nominal power at 15 °C before evaporative coolers. This gas turbine, with another similar existing one, operates in combined cycle with a 150.1 MW steam turbine. Exhaust gases from each gas turbine are directed to its respective Heat Recovery Steam Generators (HRSG) and the resulting steam feeds the steam turbine. This combined cycle is

installed in a power plant owned by Pluspetrol Energy S.A. in El Bracho, Argentina.

To allow a new turbine "commercial operation" in the electrical grid, the network authority (CAMMESA) requires the owner to carry out several tests and studies. The tests that are conducted during turbine commissioning must verify some abilities of both the excitation and the turbine control systems. Some of the tests determine whether a turbine is qualified to participate in Frequency Primary Control (FPC). FPC originates an exclusive economic transaction between generators ([1] indicates method employed in Argentina and [2] presents a similar transactional mechanism).

Only the declared available value of spinning reserve is paid, no matter which is the effectively delivered power, and regardless if this delivered value is bigger than the declared one. Therefore, it is convenient to limit the effectively delivered spinning reserve to the declared value, avoiding unpaid turbine strains, which might result, among other non-desired consequences, in an anticipated maintenance.

Maximum operable power of gas turbines depends on weather conditions (temperature, pressure and humidity). These weather conditions keep changing during the day. Consequently dispatched power must be frequently corrected to have the required spinning reserve (defined as a fixed percentage of the maximum operable power) always available.

To avoid continuous operator's interventions, an automatic calculation was developed in the power plant centralized control. This automatic calculation estimates the maximum operable power in real time. The set point of dispatched power is then continuously readjusted in order to maintain the required spinning reserve always available.

One of the several commissioning tests required by CAMMESA consists of disturbing turbine control, simulating a big, sudden negative error in the measured turbine speed. During this test, some turbines trip due to high temperature of exhaust gases, while others reduce its

power (non-desired unloading) when the disturbance disappears.

This non-desired unloading has also been recorded during several system frequency disturbances. The records show that gas turbines reduce its delivered power when the system frequency tries to recover. Power reduction is greater than that expected by airflow reduction in axial compressor. This behavior is very harmful for the system frequency control. This not correct operation takes place when turbines are operating in its original "Pre-selected Load" and "Base Load" modes.

The above described considerations give technical and economic support to the modifications made in the control system of a gas turbine.

2. Regulation Overview

Since privatization of the Argentinean electric system at the beginning of 1990's, deep changes have occurred in economic transactions and arrangement structures of the electric market.

From an economic point of view, this new arrangement "splits" the system into Agents according to their activity, that is, Generators, Transporters, Distributors and Large Users. These companies presently form the Wholesale Electric Market (MEM in Spanish).

From a technical point of view, control and supervision and management of transactions between the companies were assigned to the Wholesale Electric Market Managing Company (CAMMESA in Spanish), with a board formed by all the Agents and whose chair is held by a state organization.

CAMMESA fulfills the Dispatcher technical function through the Dispatch Center (OED in Spanish).

Energy price is calculated according to the marginal cost of the system. This marginal cost is the production cost of the most expensive unit that should go into service to supply the demanded load. On an hourly basis, this price gives rise to a spot market, where generators sell their production at a price that varies every hour.

In this way, primary and secondary frequency control costs are included in the energy prices. Within this structure of arrangements and transactions, there is a compensatory payment for contributions of generators to primary and secondary frequency control ([3], Annex 23).

A. Spinning Reserve

To carry out frequency control, not only it is necessary to have adequate prime mover governing systems but also immediately available spinning reserve.

CAMMESA determines an optimal value of spinning reserve that minimizes the amount of additional costs for reserve availability and unsupplied electric energy.

Primary controls of frequency originate an economic transaction exclusively between generators.

Payment to a generator depends on its spinning reserve availability. Generators having a spinning reserve availability larger than that of the whole system get more payment than generators having a spinning reserve

availability smaller than that of the whole system, [3].

B. Qualification for Primary Control of Frequency

The method of payment utilized for frequency primary control gives economic value to the spinning reserve necessary to carry out system frequency control, but it does not measure the effort of each individual generator.

Due to this fact, a lot of technical criteria, which define abilities for turbine control system, have been established in Regulations.

Any unit that wants to participate in primary frequency control must meet regulations.

Expected behavior is checked by tests on the units.

Satisfactory tests provide qualification to operate commercially ([3], Technical Procedure N° 9).

In addition, models verified by tests improve the dynamic database used for power system studies.

C. Other Regulations

In Argentina, a generator must conduct system studies (Load flow, short-circuit and stability studies, among others), control system behavior simulations verified by tests, frequency disturbance tests, operational reliability studies and tests, etc. ([3], Technical Procedures N° 1 and N° 4), in order to qualify for commercial operation.

The different tests to verify parameters of synchronous machines, the abilities of control excitation systems and turbine control systems are based upon Recommendations from international organizations of standardization [5]-[7].

Results obtained in some of the above-mentioned tests carried out in gas turbines showed non-compliance with the Regulations in force. To correct this situation, several modifications were implemented in the gas turbine. These modifications are described further on.

3. Original Gas Turbine Control

Fig. 1 is a simplified block diagram of an MSA9001 (E) General Electric gas turbine and its MARK V Speedtronic control system showing the following input/output signals: Speed (N), Speed Reference (NRef), Power (Pe), outdoor Air Temperature (TA), average of Exhaust Gas Temperature (Tx) and Mechanical Power (Pm).

Fig.1 only shows the major components: the turbine, the gas valve and its servo, a Minimum Value Selector and three Control Blocks (Acceleration, Governor and Temperature). At the Minimum Selector Gate input, several signals compete for gas valve control.

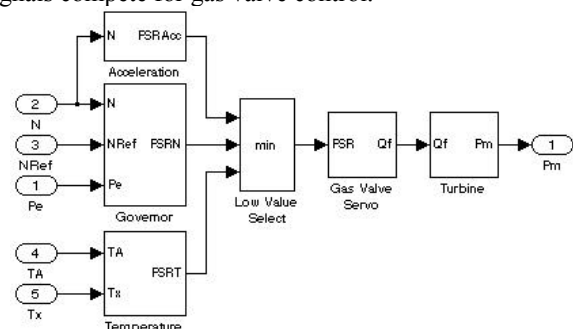


Fig. 1. Gas turbine. Simplified block diagram

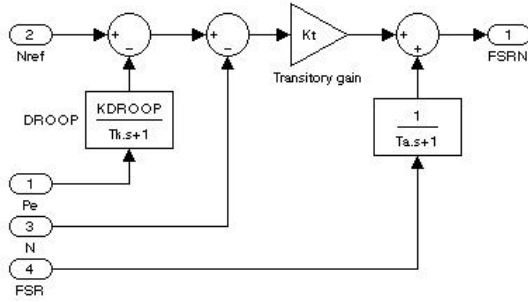


Fig. 2. Governor. Block diagram

Outputs of Governor (FSRN), Temperature Control (FNRT) and Acceleration Control (FNRAcc), which can have control of the gas valve, are also indicated in Fig. 1.

FSRAcc signal has control if the turbine accelerates over a predetermined value. FSRT signal is the output of temperature control of exhaust gases. FSRN signal is the Governor output. FSRN controls the turbine speed (N) when the unit is at no load condition or it controls mechanical power (Pm) when the unit is at load condition.

In the latter case, the Governor has a feedback from Power (Pe) that acts by means of droop, as it can be seen in Fig. 2. Droop is performed by a low-pass filter (Gain = KDROOP and time constant = Tk).

The governor has a transitory gain (Kt) and an integral action performed by means of feedback from the output of Minimum Value Gate (FSR) with a unitary gain low-pass filter (Time constant = Ta). Mechanical power (Pm) can be changed by modifying Speed Reference (NRef).

4. Gas Turbine Control. Add-on Modifications

Modifications made to the gas turbine control are described here. The consequences of these modifications are described in Section VII. All modifications were done adding a logic block in such a way that original as well as new operation mode may be used to operate gas turbine.

A. Governor. Spinning Reserve Limitation

A modification was introduced in the gas turbine governor (MARK V) in order to limit the power changes due to frequency variation.

The modification, which is added to the original governor, consists on limiting speed deviation coming into the governor. In this way, the delivered power is limited just to the corresponding dispatched set points fixed by OED for frequency control purpose.

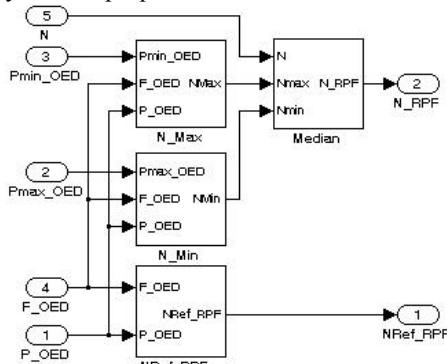


Fig. 3. Governor for FPC. Speed deviation Limiter. Block diagram

Fig. 3 shows a block diagram of this governor modification that generated a new control mode called "Governor for Primary Frequency Control" or "FPC".

Inputs for the new control logic are Speed (N) [p.u.], and the following dispatch set points from OED: Power (P_OED) [MW], Grid Frequency (F_OED) [Hz] and Power Margins - for Frequency Primary Control - Positive (Pmax_OED) [MW] and Negative (Pmin_OED) [MW].

These set points are introduced by operator into the plant control system (DCS). Set points are automatically send to MARK V from DCS.

Outputs of block diagram showed in Fig. 3 are Limited Speed (N_RPF) and Speed Reference (NRef_RPF). These outputs are connected to original Governor inputs Speed (N) and Speed Reference (Nref) - showed in Fig. 2- respectively, when the new control mode is activated.

Output of Block "Median" of Fig. 3 is the median value of its 3 inputs: N, Nmax and Nmin. In this way the Block "Median" of Fig. 3 limits speed (N) to a max/min values of Nmax and Nmin respectively. The signals NRef_RPF, Nmax and Nmin of Fig. 3 are equal to:

$$Nref_RPF = \frac{F_OED}{F_Nom} + KDROOP * \frac{P_OED}{TRATE} \quad [pu] \quad (1)$$

$$Nmax = \frac{F_OED}{F_Nom} + KDROOP * \frac{P_OED - Pmin_OED}{TRATE} \quad [pu] \quad (2)$$

$$Nmin = \frac{F_OED}{F_Nom} + KDROOP * \frac{P_OED - Pmax_OED}{TRATE} \quad [pu] \quad (3)$$

Where F_Nom is the Grid Nominal frequency (50 HZ in Argentinean Grid). These max/min speed limits correspond to power max/min limits of Pmax_OED and Pmin_OED respectively (Positive and Negative Power Margin).

If frequency deviation is higher than a fixed value, Negative Power Margin (Pmin_OED) is automatically modified to a fixed value. Both fixed values are adjusted in MARK V logic, and presently are set to 0.5 Hz and 80 MW respectively. This action makes possible the reduction of turbine power when an over frequency episode takes place in the grid and helps in recovering balance in the electrical system. These values for turbine unloading are coordinated in the grid with existing control system resources such as Automatic Generation Disconnection and Automatic Generation Reduction.

B. Power Plant Control. Spinning Reserve Availability

Maximum operable power of a gas turbine depends on weather conditions (temperature, pressure and humidity).

An algorithm introduced in the power plant centralized control (DCS) calculates the maximum operable power in real time using weather conditions as inputs. This algorithm is daily adjusted to real conditions of the equipment.

Operators raise turbine power to Base Load conditions, then an offset is determined by comparison between calculated and real values. This resulting offset is added to the corresponding set points of power signals (P_OED, Pmax_OED and Pmin_OED) for frequency primary control.

Plant operators receive from OED set points of Frequency, Power to dispatch and Power Margins for FPC.

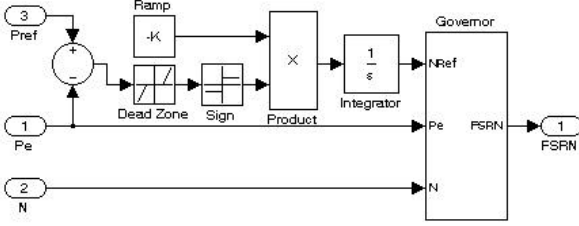


Fig. 4. Pre-selected Load. Block diagram

All power set points are given as a percentage of maximum operable power.

The power plant Centralized Control elaborates OED set points together with calculated maximum operable power and it periodically sends updated values for: F_OED, P_OED, Pmax_OED and Pmin_OED (Fig. 3) to turbine control (MARK V).

Automatic operation avoids operator's errors in turbine dispatch and gives permanent availability of power margin for Frequency Primary Control, under any weather conditions.

C. Governor. New Fixed Load Mode

The original turbine "Pre-selected Load" operation mode uses a secondary control loop to calculate Governor Speed Reference (NRef) as shown in Fig. 4.

Power error is passed through a dead band and through a sign detector. Sign detector output ("1" for positive input sign, "-1" for negative input sign and "0" for 0 input) is multiplied by a ramp value (K) and connected to the integrator input. In the long term, the integrator forces power (Pe) to coincide, plus or minus the dead band, with power set point (Pref). When frequency deviations take place, power (Pe) is initially modified by governor actuation. This action is slowly modified by the secondary loop until power (Pe) reaches power set point (Pref), plus or minus the dead band, even if the system frequency does not recover.

A new operation mode was implemented to avoid non-desired power deviations when deep frequency disturbances occur in the grid.

This new mode, named "Fixed Load", is similar to "Pre-selected Load" mode when frequency has no deviations because both modes determine a defined turbine power, but the new mode does not react as the original one when frequency disturbances take place.

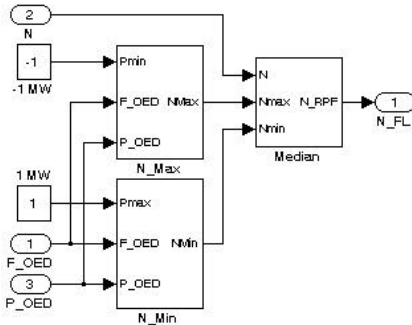


Fig. 5. Fixed Load. Block diagram

Control logic shown in Fig. 5 was added in MARK V to implement new "Fixed Load" mode.

Inputs of this added logic are Speed (N) [pu] and dispatch set points from OED for Grid Frequency (F_OED) [Hz] and for Power (P_OED) [MW].

Equivalent inputs showed in Fig. 3, Pmax_OED and Pmin_OED were replaced by fixed values of ± 1 MW respectively to define inputs Nmax and Nmin to block "Median" of Fig. 5.

Signals Nmax and Nmin are now equal to:

$$N_{max} = \frac{F_{OED}}{F_{Nom}} + KDROOP * \frac{P_{OED} + 1}{TRATE} [pu] \quad (4)$$

$$N_{min} = \frac{F_{OED}}{F_{Nom}} + KDROOP * \frac{P_{OED} - 1}{TRATE} [pu] \quad (5)$$

Limited Speed (N_FL) for this new "Fixed Load" mode is connected to input Speed (N) of block diagram of Fig. 2 (Original "Pre-selected Load" mode). Finally, dispatch set point for Power (P_OED) [MW] is connected to input Power Reference (Pref) of block diagram showed in Fig. 4.

In this way, added new mode "Fixed Load" ensures a maximum deviation of ± 1 MW from expected power value (Pref or P_OED), independently from whatever frequency deviation may occur. This new "Fixed Load" mode also includes the automatic modification of minimum power set point for frequency deviations higher than a fixed value.

In these situations the set point is switched from OED set point of Power (P_OED) minus 1 MW to a fixed value. Both fixed values are adjusted in MARK V logic. These fixed values are presently set to 0.5 Hz and 80 MW respectively.

D. Governor. Limitation of non-desired turbine unloading

Previously described add-on control logic (operation mode "Governor for FPC" in IV.A and operation mode "Fixed Load" in IV.C) also eliminates non-desired unloading.

Non-desired load reduction takes place with original operation modes "Base Load" and "Pre-selected Load" when a deep frequency disturbance disappears.

Original turbine control system (Fig. 1) can operate in the following modes: "Governor", "Pre-selected Load" and "Base Load". Fuel gas valve is controlled by governor output (FSRN) in the "Governor" (Fig.2) and "Pre-selected Load" (Fig.4) modes, and by temperature control output (FSRT) in "Base Load" mode.

1) Original Base Load mode

The logic for "Base Load" mode has a tracking that modifies Governor Speed Reference (NRef) in order to keep $FSRN \leq FSRT + 0.05$ in pu. The NRef is changed with a ramp whose slope is equivalent to 1 pu (1 pu = Rated Turbine Power) every 400 to 600 seconds.

When a negative frequency deviation takes place in the grid, Governor increases the FSRN signal to a higher value than $FSRT + 0.05$. If the recovery time of the grid frequency disturbance is long enough, the mentioned tracking starts working, reducing NRef until $FSRN \leq FSRT + 0.05$ in pu.

The bigger the frequency drops in the grid, the greater the NRef reductions. For example, if after a long time the grid frequency recovers from a previous dip of about 1 Hz, the FSRN will be reduced in $(1 \text{ Hz} / 50 \text{ Hz}) / 0.04 = 0.5 \text{ pu}$ below its value before the disturbance, if the Governor droop is 4%.

The turbine mechanical power will be reduced in a similar value of about 0.5 pu. This represents a big power reduction taking into account that it occurs just when the grid frequency is being recovered.

After the grid frequency recovers, the tracking increases NRef with a positive ramp to obtain $\text{FSRN} \leq \text{FSRT} + 0.05$.

By this way, turbine power slowly returns to the value that it had previous to the frequency disturbance.

This non-desired behavior (turbine unloading) does not take place with the add-on logic. This is due to the fact that frequency deviation is limited at the Governor input, then, reduction of NRef is limited as well.

Consequently, the FSRN and power are limited when the grid frequency is being recovered. Frequency deviation is limited in order to obtain power deviations of $\pm 1 \text{ MW}$.

2) Original Pre-Selected load mode

The logic for “Pre-selected Load” mode (see fig. 4) modifies Nref in order to obtain selected power. The Nref is modified by a ramp whose slope is equivalent to 1 pu (1 pu = Rated Turbine Power) every 400 to 600 seconds.

When a negative frequency deviation takes place in the grid, Governor increases the FSRN signal.

If the recovery time of the grid frequency disturbance is long enough, the mentioned ramp acts reducing NRef until turbine power is equal to the pre-selected value.

In a similar way to “Base Load” mode, here the bigger the frequency drops in the grid, the greater the NRef reductions. The example given above for “Base Load” mode is applicable for this “Pre-selected Load” mode.

After the grid frequency recovers, secondary loop (Fig. 4) increase NRef with a positive ramp up to obtain a power equal to the pre-selected value.

By this way, turbine power slowly returns to the value that it had previous to the frequency disturbance.

This non-desired behavior (turbine unloading) does not take place with the add-on logic. Like in the “Base Load” mode, this is due to the fact that as frequency deviation is limited at the Governor input, then, reduction of FSRN and power are limited as well. Frequency deviation is limited in order to obtain power deviations of $\pm 1 \text{ MW}$.

5. Test Procedures

A. Frequency Disturbance

CAMMESA has a standardized test waveform for frequency disturbances, which takes into account the greatest frequency disturbances that may occur in the Argentinean power system.

This waveform is displayed in Table I ([3], ANNEX H, Technical Procedure N° 4).

TABLE I:
STANDARDIZED FREQUENCY DISTURBANCE

Time (sec.)	Frequency deviation (Hz)
0	0
2	-2
30-40	-1
100	-1
105-110	0

Results of tests performed in other gas turbines in Argentina with this kind of frequency disturbances are reported [4].

B. Procedures

This test only applies to gas turbines. Standardized frequency disturbance must be added to the measured turbine speed. In this way, the turbine control system reacts in the same way it does when a frequency dip takes place in the grid.

Mechanical power reduction, which normally appears as a consequence of turbine temperature rising due to lower airflow for combustion, does not take place. This happens because the speed of axial air compressor does not change when the test waveform is applied. Simulations must be conducted after estimating this mechanical power reduction.

Tests must be performed on each of the operational control modes to be qualified for commercial operation.

Tests must be done at a power between 90 % to 100 % of maximum operable power.

Tests performed in all the operational control modes used for Frequency Primary Control must be performed with a spinning reserve of 5%. All major variables must be recorded during the test for documentation purposes and can be used in later tests and simulations.

C. Simulations

Test simulations must be performed after the tests [3],[4].

As in standardized tests, the system frequency does not vary, the behavior of the turbine air compressor must be observed during the simulation with a real frequency disturbance in the grid.

Simulations must be carried out with models of turbine and control systems previously validated by identification tests ([3], ANNEX D, Technical Procedure N° 4).

Firstly, and to verify the validity of the utilized model, simulations must reproduce the standardized tests with frequency disturbance of CAMMESA. Finally, the behavior of turbine and its control must be simulated with a frequency disturbance in the grid, which should have the same waveform as that used for the standardized test.

6. Frequency Disturbances

A system disturbance monitor is installed in each power plant of the Argentinean grid. This monitor records any frequency disturbance taking samples each 10 seconds of power and frequency among other signals. By this way, the monitor records the behavior of the gas turbine during each

perturbation. Fig. 6a shows the record of Power (P_{e_m}) and Speed (N_m) measured in a gas turbine, similar to that described in this paper, during a frequency disturbance that took place on July 31, 1998. This turbine, the second gas turbine that nowadays is part of the combined cycle, was operating in open cycle during the above mentioned frequency disturbance. The turbine was operating in the original "Pre-selected Load" mode with a set point of 114 MW. Fig. 6a also shows that measured Power (P_{e_m}) went down when measured Speed (N_m) recovered from disturbances. This fact is not good for system frequency control. The gas turbine behavior was simulated with a model provided by the manufacturer and previously verified by tests. Simulation 1 was made with original turbine control meanwhile simulation 2 was made with add-on control logic.

A. Simulation with original turbine control (Simulation 1)

Fig. 6a shows a good concordance between the simulated ($P_{e_{s1}}$) and measured (P_{e_m}) Power. Fig. 6b shows simulations of Governor Output ($FSRN_{s1}$), Temperature Control Output ($FSRT_{s1}$) and Speed Reference ($Nref_{s1}$).

Turbine switched from Governor control ($FSRN_{s1}$) to Exhaust Gas Temperature control ($FSRT_{s1}$) as soon as frequency disturbance took place ($FSRT_{s1} < FSRN_{s1}$), because Governor Output ($FSRN_{s1}$) raised up due to the negative speed deviation.

Speed Reference ($Nref_{s1}$) went down due to tracking action, until $FSRN_{s1}$ was lower than $FSRT_{s1} + 0.05$ [pu].

This last condition was fulfilled when the frequency was recovering. Then, Governor had again gas valve control ($FSRN_{s1} < FSRT_{s1}$) and the secondary loop (shown in Fig. 4) increased Speed Reference ($Nref_{s1}$).

This fact allowed power to recover its initial value. The power plant event recorder indicated that, at time=600 s, the gas turbine operator changed power set point to 120 MW helping power recovery. Finally, power reached 115 MW and turbine switched from Exhaust Gas Temperature control to Governor control ($FSRT_{s1} > FSRN_{s1}$).

Speed Reference would have had a smaller value if the frequency disturbance would have remained more time in the value of approximately 0.985 [pu].

Consequently, turbine power would have reached a smaller value when the frequency disturbance disappeared.

B. Simulation with add-on logic control (Simulation 2)

For this simulation, frequency deviation is limited in order to obtain power deviations of ± 5 MW (higher than ± 1 MW, value nowadays set) to see the effects of add-on logic.

Fig. 6a shows that the unloading of the simulated Power ($P_{e_{s2}}$) is lower than the unloading of measured Power (P_{e_m}).

Fig. 6b shows simulations of Governor Output ($FSRN_{s2}$), Temperature Control Output ($FSRT_{s2}$) and Speed Reference ($Nref_{s2}$). It can be seen that variations of $FSRN_{s2}$ and $Nref_{s2}$ are lower than $FSRN_{s1}$ and $Nref_{s1}$, due to the add-on logic limitation action.

7. Tests Results

Results of tests performed on a 120MW gas turbine, MS9001(E) type from General Electric with MARK V Speedtronic control system, are shown and described herein. Tests were made with standardized frequency disturbance in all original operation modes: "Governor", "Pre-selected Load" and "Base Load".

Tests were also conducted in the developed new operation modes: "Governor for FPC" and "Fixed Load".

Only test results for new operation modes are shown.

Tests records have been plotted in figures 7 to 10:

- Part a) of figures: Power (P_e), Speed (N) and Disturbed Speed (N_{dist}). Maximum and Minimum Power set points are also displayed (P_{max_OED} and P_{min_OED} for "Governor for FPC" mode or fixed values of P_{max} and P_{min} for "Fixed Load" mode).
- Part b) of figures: Governor Output ($FSRN$), Temperature Control Output ($FSRT$) and Speed Reference ($Nref$).

Fig.7 displays the records of the test performed on the turbine in the new "Governor for FPC" operation mode.

This test was made at the following dispatch set points: $F_{OED} = 50$ Hz; $P_{OED} = 100$ MW; $P_{max_OED} = 102.5$ MW and $P_{min_OED} = 97$ MW.

During this test, temperature control did not reach to have valve control ($FSRN$ was always smaller than $FSRT$) because P_{max_OED} (102.5 MW) set point was smaller than power at Base Load (close to 113 MW).

Fig. 8 shows the records of another test conducted on the turbine in the new "Governor for FPC" operation mode.

This test was made at the following dispatch set points: $F_{OED} = 50$ Hz; $P_{OED} = 110$ MW; $P_{max_OED} = 120$ MW and $P_{min_OED} = 100$ MW.

During this test, temperature control had valve control ($FSRT$ smaller than $FSRN$) because power at Base Load (close to 113 MW) was smaller than P_{max_OED} set (120 MW).

In Fig. 8, it can also be seen that $FSRN$ was limited by the implemented new control logic and because of that, Governor Speed reference ($Nref$) was not varied by the tracking mechanism.

Evaluating test results shown in Fig.8, it could be noted that in the new "Governor for FPC" operation mode, Speed Reference ($Nref$) was not reduced by original automatic tracking of $FSRN$ to $FSRT$ when temperature control had gas valve control.

Consequently, non-desired power reduction did not take place when the frequency disturbances disappeared.

Fig. 9 shows the records of the test conducted on the turbine in the new "Fixed Load" operation mode.

This test was performed at the following dispatch set points: $F_{OED} = 50$ Hz and $P_{OED} = 107$ MW.

For this test, standardized frequency disturbance was applied with positive sign to verify the automatic switching of the minimum power set point from "OED Power set point (P_{OED}) minus 1MW" to a fixed value, when frequency deviation is higher than a fixed value.

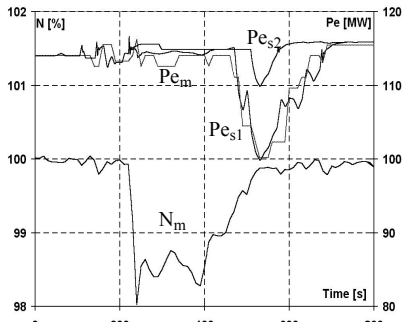


Fig. 6a. Pre-selected Load. System frequency disturbance.

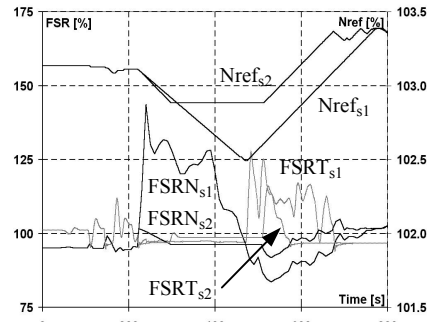


Fig. 6b. Pre-selected Load. System frequency disturbance.

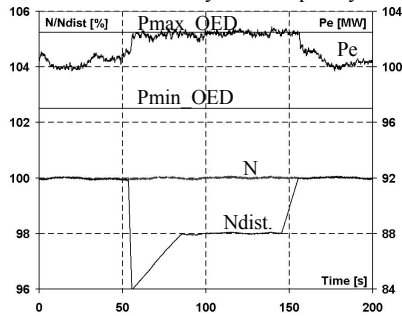


Fig. 7a. Governor for FPC. Negative standardized perturbation.

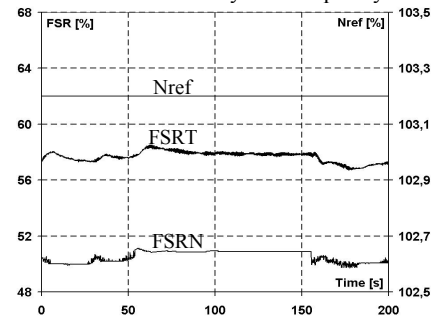


Fig. 7b. Governor for FPC. Negative standardized perturbation.

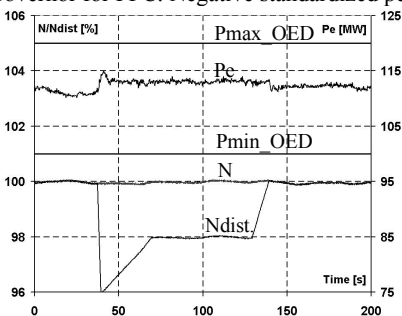


Fig. 8a. Governor for FPC. Negative standardized perturbation.

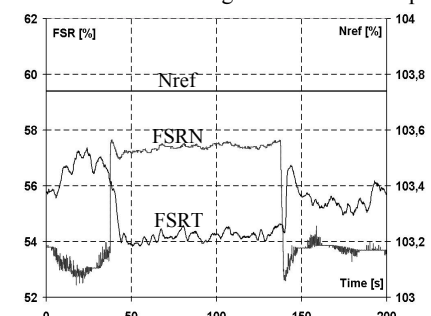


Fig. 8b. Governor for FPC. Negative standardized perturbation.

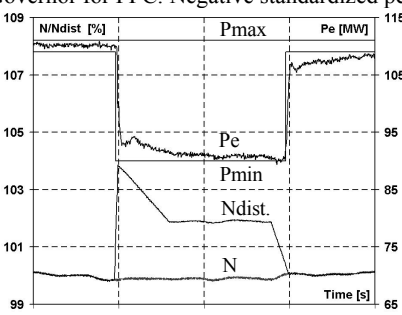


Fig. 9a. Fixed Load. Positive standardized perturbation.

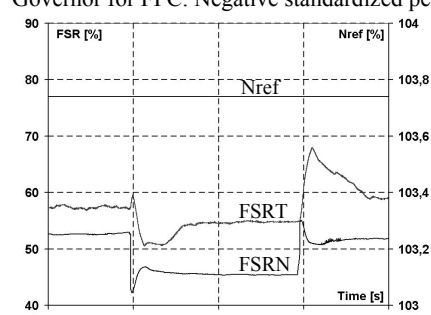


Fig. 9b. Fixed Load. Positive standardized perturbation.

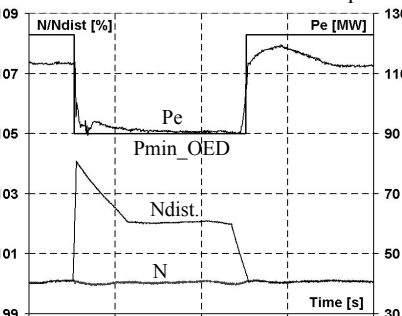


Fig. 10a. Base Load. Positive standardized perturbation.

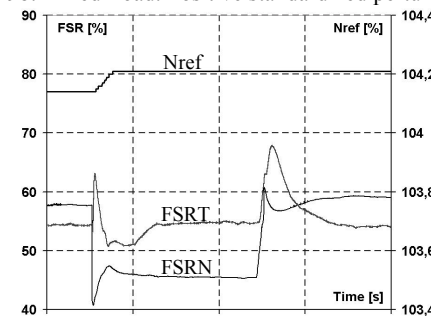


Fig. 10b. Base Load. Positive standardized perturbation.

During this test, both fixed values were adjusted in MARK V logic to 90 MW and 0.5 Hz respectively.

Fig. 9 shows that minimum power delivered was approximately 90 MW when standardized frequency disturbance was applied and the power delivered was recovered to $P_{OED} = 107 \text{ MW} \pm 1 \text{ MW}$ when standardized frequency disturbance was removed.

Fig. 10 shows the records of the test made on the turbine in "Base Load" operation mode with the new add-on control logic in the turbine control system.

This test was performed with standardized frequency disturbance waveform with positive polarity.

The test goal was to verify the change of P_{min_OED} to a fixed value (90 MW in this case) when a positive frequency deviation larger than a fixed value (0.5 Hz in this case) was detected (it can be seen in Fig.10a). Temperature control had gas valve control ($FSRT < FSRN$) before and after the application of frequency disturbance, while Governor had gas valve control ($FSRN < FSRT$) during the application of frequency disturbance.

Considering that frequency deviation was 1 Hz after the initial peak of 2 Hz, power would be reduced by droop (droop = 4% in this case) to approximately $(1/50)/0.04 = 0.5 \text{ pu}$ of TRATE (60 MW approximately) if the power lower limit would not have been active.

Turbine power unloading value was previously calculated under the simplified hypothesis that $FSRN \approx FSRT$ before the application of frequency disturbance. This is almost true for the tests performed. That is to say, turbine power could be reduced by 60MW during a real frequency disturbance (without axial compressor effect) to a final value of $113 \text{ MW} - 60 \text{ MW} = 53 \text{ MW}$, while during the test the power was limited to 90MW.

As it is shown in Fig. 10, add-on logic increased Speed Reference (N_{ref}) in order to give Minimum Power set point (P_{min_OED}).

Add-on logic also changed the value of the Minimum Power set point (P_{min_OED}) in order to obtain a minimum turbine power equal to 90MW during frequency disturbance.

Current setting of minimum value of power (P_{min_OED}) depends on HSRG temperature gradient stress due to sudden and big turbine power reduction and it also depends on changes in combustion modes into the turbine. Besides, these fixed values of frequency deviation and minimum power have been coordinated with automatic mechanisms, implemented in other generators of the electrical area, for power reduction and power disconnection (generator trips).

These automatic mechanisms allow grid frequency stabilizing after increasing frequency episodes.

8. Conclusions

Add-on logic control introduced in a gas turbine control and the technical and economic reasons that support these modifications have been explained.

Test records of turbine behavior and its control behavior

with and without the introduced modifications have been shown.

Behavior of gas turbine during frequency perturbation has been shown.

These modifications allow:

- Effectively limit power deviation over dispatch set point, when turbine governor is working for Frequency Primary Control purposes.
- Avoid non-desired turbine unloading after the frequency recovery from big dip episodes.
- Always available power margins for Frequency Primary Control by computing maximum operable power, under any weather conditions.
- Ease the operator's task of dispatching turbine within dispatch settings (Grid Frequency, Power and Power margins- for Frequency Primary Control- Positive and Negative) regulated by the National Dispatch Center.
- Limit turbine power unloading to a fixed value when over-frequency episodes take place in the grid.

It must be noted that the same modifications were introduced and tested in three other governors of similar gas turbines, including the other gas turbine of the combined cycle, mentioned in section 6.

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