UTILITY EXPERIENCE WITH GAS TURBINE TESTING AND MODELING

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INTRODUCTION

Previous panel papers have described testing for NERC and WSCC compliance [A] and testing and tuning of governors for compliance and island-mode performance [B]. This paper presents experience with testing of gas turbine plants for NERC and WSCC compliance. Testing has been performed on older analog-electronic and new digital-electronic units. The level of detail used in modeling and model availability in simulation programs are ongoing issues. Temperature limits and outer-loop controls such as pf/var controls and load-sharing have been seen to dominate plant performance.

EXAMPLE 1: ANALOG ELECTRONIC GOVERNOR/ SIMPLE-CYCLE GAS TURBINE

The following is an example of an analog electronic governor controlling a single-shaft, simple-cycle, heavy-duty gas turbine. This turbine can use either gas or liquid fuel; unit 1 was tested with liquid fuel and unit 2 with gas. Figure 1 shows a block diagram suitable for modeling the governor and turbine [C]. This model has recently been extended to combined-cycle plants [F]. The “as-found” settings at the time of the tests are listed in Table 1.

Table 1. Analog Electronic Governor/ Simple-Cycle Gas Turbine Model, Including Compensation, Droop and Temperature Control

Parameter	Description	Value
W	Gain = 1/ droop (pu MW / pu speed)	16.7
X	Governor lead time constant (s)	0.6
Y	Governor lag time constant (s)	1.0
Z	Governor mode (1=droop, 0=isochronous)	1
MAX	Demand upper limit (pu)	1.5
MIN	Demand lower limit (pu)	-0.1
a	Valve positioner	1
b	Valve positioner	0.05
c	Valve positioner	1
W_{MIN}	Minimum fuel flow	0.23
T_F	Fuel control time constant (s)	0.4
K_F	Fuel system feedback	0
E_{CR}	Combustion reaction time delay (s)	0.01
E_{TD}	Turbine and exhaust delay (s)	0.04
T_{CD}	Compressor discharge volume time constant (s)	0.2
T_R	Turbine rated exhaust temperature (°F)	950
T_T	Temperature controller integration rate (°F)	450
f1	$T_X=T_R-700*(1-W_F)+550*(1-N)$	
f2	$1.3*(W_F-0.23)+0.5*(1-N)$	
T_I	Inertia = 2*H	15.64

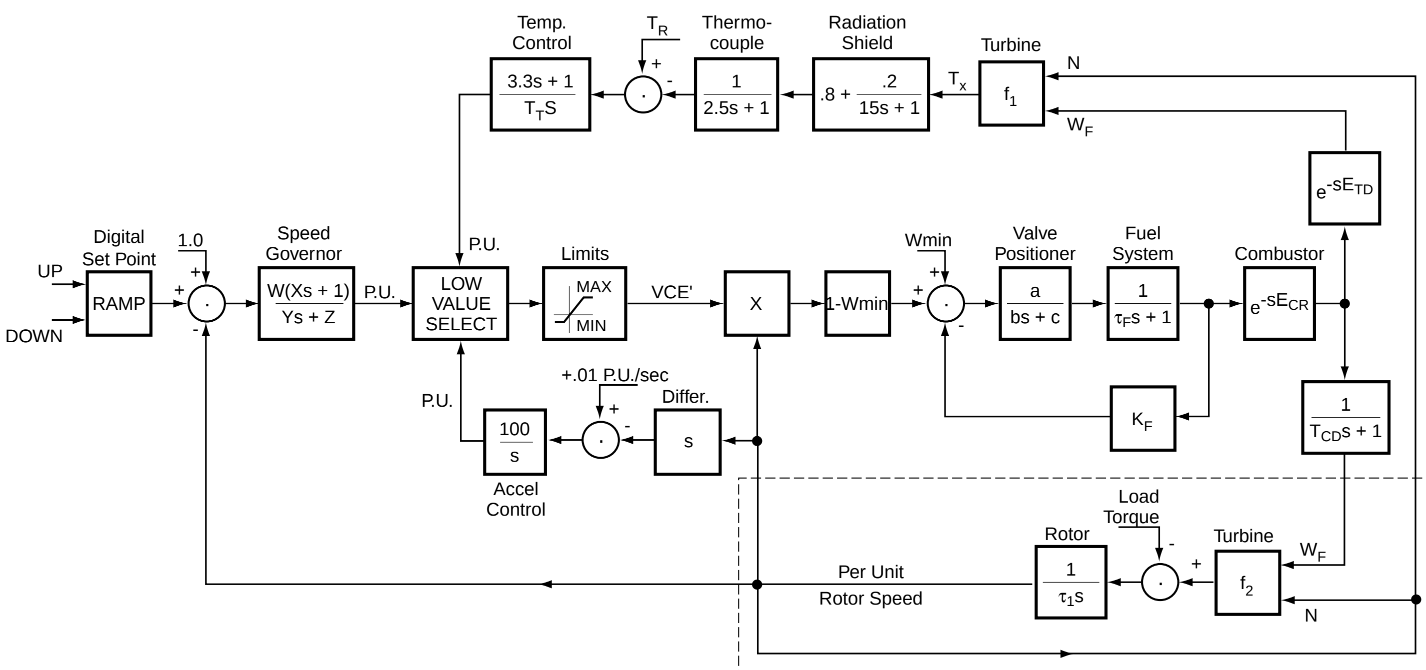

Figure 1. Analog Electronic Governor/ Simple-Cycle Gas Turbine Model

The measurements performed on this unit are described below. Table 2 contains a partial list of governor variables monitored during the tests.

Table 2.

Monitored Governor Signals
Speed Reference
Fuel Flow
Valve Position Demand
Power Turbine Speed
Valve Position
Turbine Exhaust Temperature

Governor Control

The governor implements three major control loops: start-up, speed and temperature. For the purposes of these modeling tests, the speed control, which is active during partial load conditions, receives the most attention. The reason for this is that during start-up, the unit is not on-line, and in temperature control mode, the governor will not respond to system frequency changes.

The primary valve demand control signal is selected by a low-value gate from the outputs of the three control loops. Lights on the control panel indicate the controlling mode.

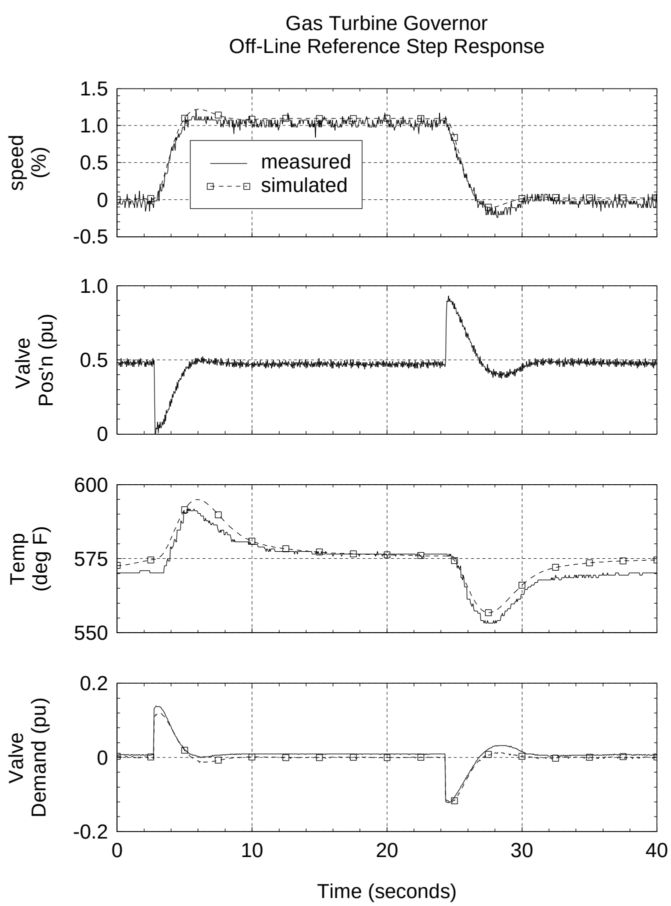

Figure 2

Speed Measurement Circuitry

The speed feedback signal to the governor is a pulse train supplied by two magnetic speed sensors mounted in proximity to a toothed wheel on the gas turbine compressor shaft. Both the pulse train and an analog voltage test point proportional to speed deviation were monitored during these tests.

In this implementation, test signals could be introduced on a spare analog input of the speed sensor module. The manufacturer's signal calibration of input V/ % speed was confirmed with off-line static and dynamic measurements.

Step input signals were introduced, and the speed measurement time constants, X and Y were measured. The speed measurement circuit did not implement the expected single time constant (lag) response; instead, a lead-lag arrangement was found. Investigation of the electronic card schematics confirmed that this was the correct transfer function, although it was not mentioned in the manufacturer's reference.

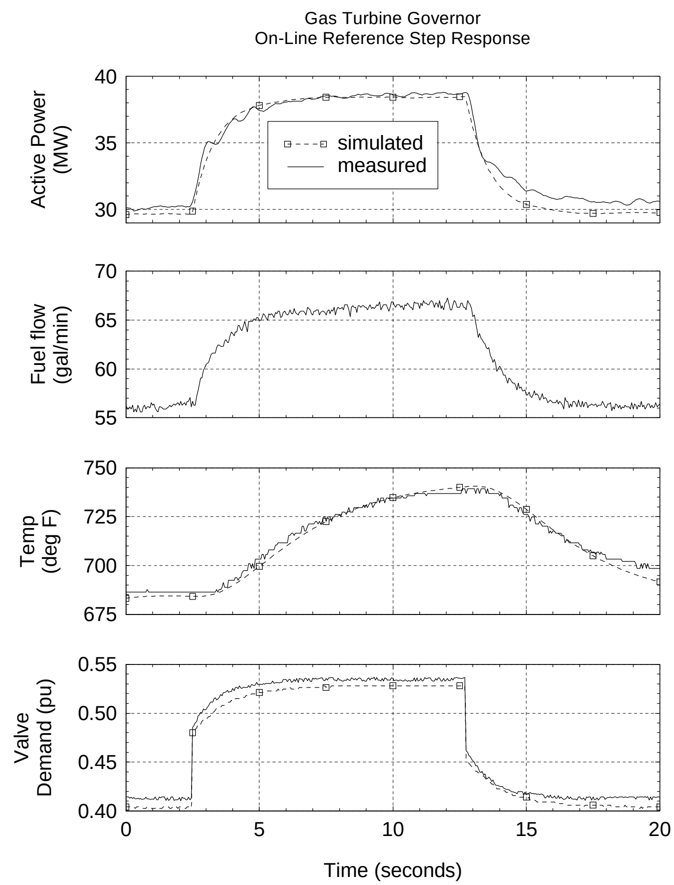

Figure 3

Permanent Droop

For on-line conditions, the governor operates in an open-loop configuration. Valve position or electrical power feedback is not used as feedback for permanent droop setting on these units. The measured speed signal is compared with the operator's set-point signal to generate a speed error. The relationship between the measured set-point signal and the active power output was confirmed by off-line and on-line steady-state measurements. The speed droop can be read from the slope of the resulting graph; e.g. % speed/% electrical power. The NERC droop requirement is 5%. Calibration of the droop value was required on several units tested.

Step Response Tests

Step changes of various amplitudes were introduced to the speed reference summing junction via a test voltage input to a speed sensor spare input. Figures 2 and 3 are comparisons of the measured and simulated responses of the closed-loop system. The as-found governor response is typically fast and well-damped and changes are seldom recommended for these units.

Temperature Control

The temperature control is a hard limit at the temperature set-point. It was tested by raising load until the units were operating in temperature control mode and then introducing speed reference step changes. The demand and unit output were held constant at the temperature set-point as per the design specification. The relationship of temperature to output power is shown in Figure 4. The discontinuity between 25% and 40% power is when the water injection and inlet guide vanes go into service.

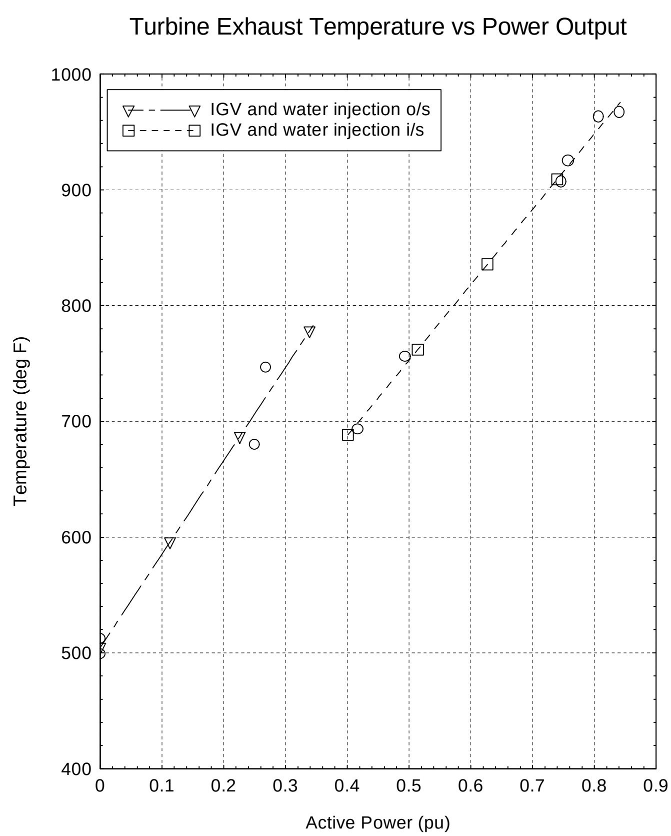

Figure 4

It should be noted that this is the normal mode of operation for most gas turbines, for peak efficiency. In this mode, speed droop control is not active for system frequency decreases; when frequency increases (or set-point decreases), droop control is restored.

Turbine Representation

The turbine, fuel control, and temperature sensing elements of the model were verified by comparing simulations using the model of reference [C] and measurements, such as the one shown in Figure 3. Unit 1 was tested with liquid fuel and unit 2 with gas. There were minor differences in model parameters for the two fuels.

For most studies, greatly simplified models could be used, incorporating just the droop control and one time constant for the turbine and two for the temperature sensing. The model shown is valid for loads greater than 40%, when water injection and inlet guide vanes are both in service.

EXAMPLE 2: DIGITAL ELECTRONIC GOVERNOR/ MULTI-SHAFT GAS TURBINE

The second example is a multi-shaft gas turbine, consisting of a low-pressure (LP) and high-pressure (HP) compressor stage. The unit is capable of operating on natural gas or liquid fuel. Depending on which fuel is used, the cycle is slightly different, primarily due to the locations of steam injection used to control NOX emissions and provide power boost. Gas fuel is used exclusively at this time. For the gas fuel manifold, steam is injected at the following locations: fuel nozzles, HP steam is injected at the Compressor Discharge Pressure (CDP) stage, LP steam is injected at the LP turbine. The steam injection increases the turbine output from a steady-state ambient power of 35 MW to over a 50 MW level.

The turbine is controlled by a pair of digital control systems, which handle all aspects of fuel, steam and water flow control. One of the controls is used as a sequencer, handling starts, stops and steam control, while the second unit operates as the fuel control.

The governor is a solid-state digital electronic control system implementing the three major control loops: start-up, speed and temperature. In modeling this unit for power system purposes the focus is on the fuel control logic. The fuel control logic accepts inputs from numerous transducers representing the operating levels of key compressor and turbine speeds, temperatures and pressures. Each of these quantities is compared against a set-point and the resulting error signals are compared by the control. The monitored signals are listed in Table 3. A Low Value Select block is used to determine which control loop is asking for the minimum fuel. This control is then given priority and drives the fuel valve actuator to control the combustor output.

Table 3.
<u>Monitored Governor Signals</u>

HP Compressor Discharge Pressure
Speed Reference
Power Turbine Speed
HP Compressor Speed
LP Compressor Speed
HP Compressor Temperature
LP Turbine Inlet Temperature
Gas Actuator Position

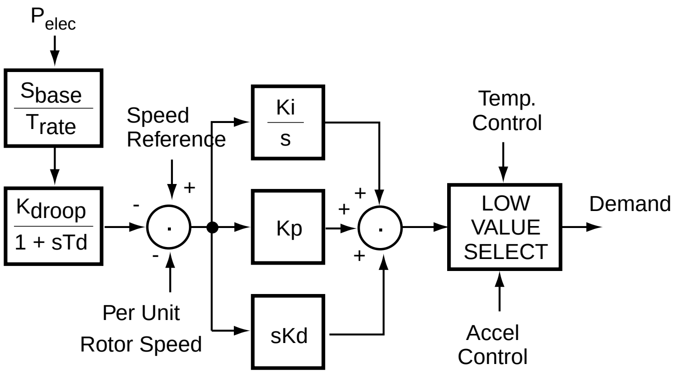

Figure 5. Gas turbine governor PID-droop control detail

The power turbine model used is the same as shown in Figure 1, mainly because it was available in the modeling program. The actual speed is compared with a reference and the error signal is applied to a proportional-integral-derivative (PID) control, shown in the detail Figure 5. The reference is obtained through a ramp function and is combined with a droop signal. The droop signal is generated from the HP Compressor Discharge Pressure rather than an output power signal. It is converted into an equivalent electrical power output value for use in the simulation model.

Table 4. Digital Gas Turbine Governor Model including PID, droop and temperature control

Parameter	Description	Value
Kdroop	Droop (pu speed/ pu MW)	0.05
Kp	Governor proportional gain	3.6
Ki	Governor integral gain	1.08
Kd	Governor derivative gain	1.8
Td	Droop time constant (s)	0.8
Sbase	Generator MVA base	56.667
Trate	Turbine MW base	48

The “as-found” settings at the time of the tests are listed in Table 4. Differences in the modeling exercise from the previous analog-electronic control are highlighted below.

Permanent Droop

Compressor Discharge Pressure (CDP) rather than valve position or electrical power feedback is used for permanent droop setting on this unit. The value of CDP versus output power is shown in the table below. The pressure extrapolated to generator rated output power was used with the tabulated CDP values to obtain the gain and offset parameters shown in the model as Wmin and (1-Wmin).

Active Power (MW)	Compressor Discharge Pressure (PSIa)
0.3	110.6
11	211.5
30	326.7
40	386.5
45	408.8
48	426.6

The droop circuit includes an intentional filter time constant, Td, of 0.8 s.

For modeling purposes, the measured active power output is compared with the set-point to calculate the droop value. The speed droop can be calculated from the table below by converting the measured values to per-unit generator quantities. The ratio of the speed reference change to the power change is the droop value, which is 5.5% speed/% electrical power for this unit. The droop value (Kdroop) shown in the model of Table 4 is based on the turbine power rating (Trate) of 48 MW. On this per-unit base, the droop value is 4.7% speed/% turbine power.

Active Power (MW)	Speed Reference (rpm)
0.3	3628
11	3681
30	3746
40	3780
45	3791
48	3808

PID Settings

The governor PID settings had to be converted to the model parameters Kp, Ki, Kd, using information from the manufacturer. The governor settings and corresponding model parameters are tabulated below.

Governor Parameters

P	0.165	Kp	3.6
I	0.35	Ki	1.08
D	0.2	Kd	1.8

Step Response Tests

Step changes of various amplitudes were attempted by modifying selected variables while in governor Service Mode. The results, one of which is shown in Figure 6, indicate that the selected changes are processed by the governor logic through a slow ramp function. Instead, load rejection results had to be used to confirm the manufacturer's PID parameters, as described below.

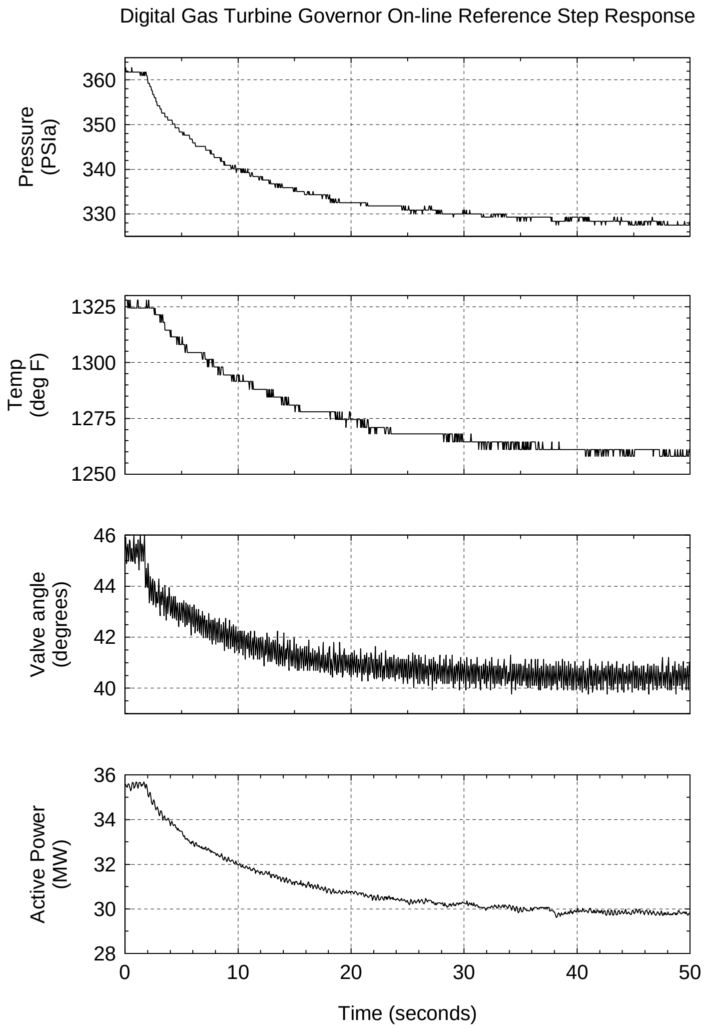

Figure 6.

Load Rejection Results

Figure 7 displays the results of a partial load rejection test, started from an output of 15 MW. The digital set-point is switched from its on-line value to 100% when the generator synchronizing circuit breaker opens to minimize speed overshoot, resulting in no steady-state speed error as shown in the figure.

For this design, there is no difference between the off-line and on-line governor speed control settings, so a partial load rejection test may be used to confirm the on-line dynamic model. This is not the case for all designs, and there may be several different sets of parameters used depending on whether the governor is off-line, on-line in the bulk system or in island-mode. Care must be taken to ensure that the tested mode is the correct one for the system conditions being modeled.

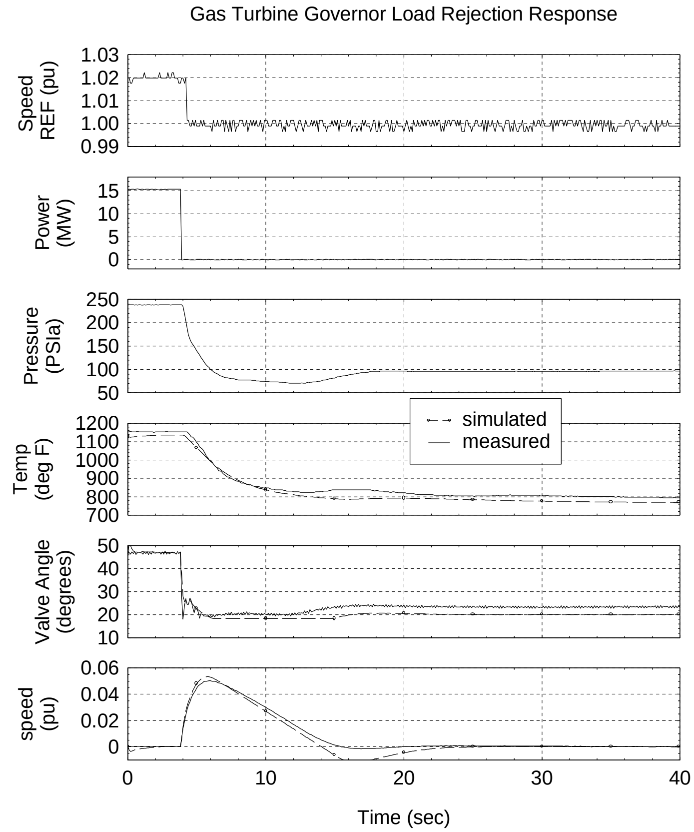

Figure 7.

Ambient Monitoring

When no external disturbance signals may be injected for testing, ambient monitoring may be performed in an attempt to use system frequency variations as the stimulus for governor response measurement. An example for a hydraulic unit is shown here. A four hour window of operation was recorded during evening load pickup. The governor can be seen to respond to changes in frequency as small as 0.03% as shown in the expanded view of Figure 8. The gate position response was simulated and the unit was found to have an effective droop of 2.5%, which is reduced from its droop setting of 5% by the action of the outer loop load control, described below.

The advantages of ambient monitoring are the following:

- does not require a detailed knowledge of the manufacturer's design
- normally poses a lower risk to the unit and power system
- may be possible to perform certain tests using existing station transducers and recorders

For many situations, ambient monitoring is not adequate. Normal system operation may not produce large enough changes in the measured quantities. Re-creating the operating conditions of concern may expose equipment to damage or interrupt customer supply. Staged tests must then be planned in which test disturbances or sudden changes in the unit operating conditions are introduced.

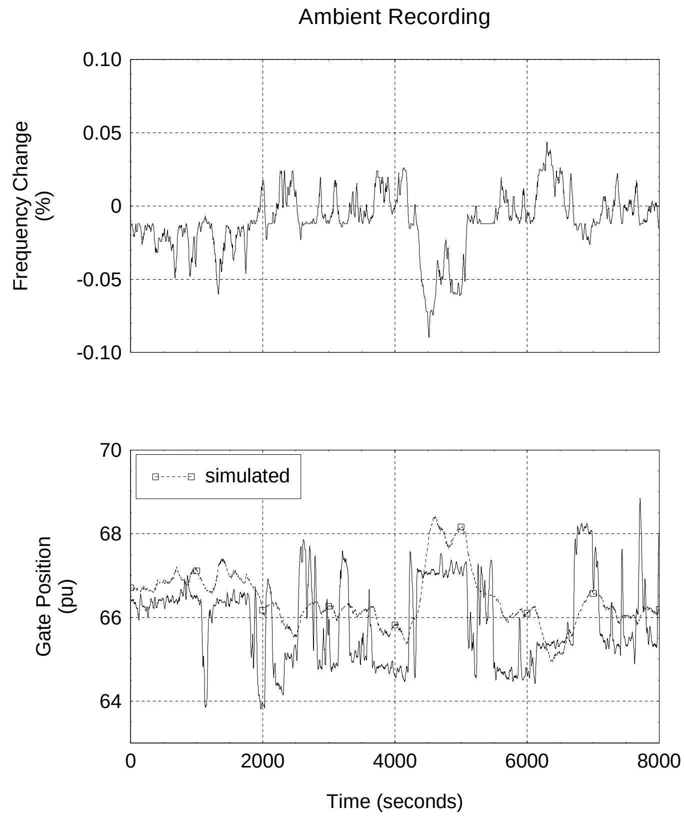

Figure 8.

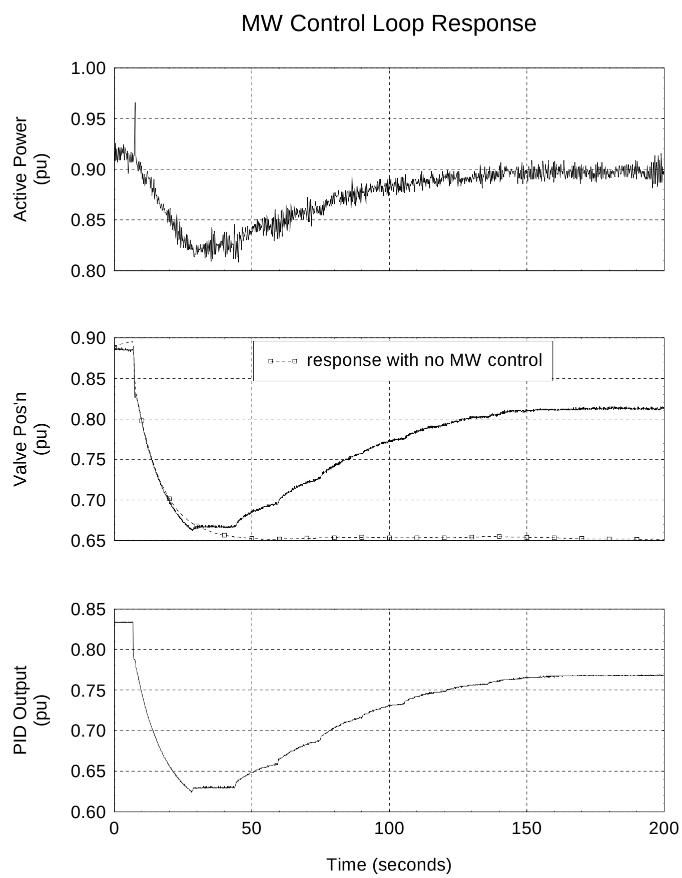

Figure 9.

OUTER LOOP CONTROLS

Load control

Some units are operated with an outer-loop active power controller. In this case, the digital Unit Controller produces a pulse to the governor raise or lower input that is proportional to the distance away from the MW set-point. The governor is programmed to ramp the reference at a rate of 0.3%/s when receiving these pulses.

This control was tested by introducing a speed reference step change and measuring the MW restoration. Its response is shown in Figure 9. As desired, the response is quite slow. The control does not exactly restore the pre-test MW value. This could be because of a deadband within the control, or it could be because of the resolution of the governor speed reference input. The controller can be seen issuing reference raise commands every 15 seconds after a 25 second initial delay. Each pulse produces approximately 2% change in gate position. As pointed out in reference [D], the load control must not cancel out normal governing action. The controller deadband and frequency supervision characteristics are presently the subject of a design review.

pf/VAr Controller

Many gas turbine units are equipped with a pf/VAr controller which is in service whenever the unit is on-line. This is an outer-loop control, which monitors generator stator reactive current and controls to a fixed VAr or pf set-point. The controller is often used in pf mode, controlling to unity power factor. The control structure is an "integrator with gain" feedback to the AVR set-point.

Its adjustable settings are the time delay between pulses to the motorized voltage regulator set-point potentiometer, and the pulse width. To ride through system transient disturbances, the control should be as slow as possible, however, too long a setting will result in operator intervention and overshoot in the resulting unit operating point. The response shown in Figure 10 should be considered typical. As it is presently configured, the controller is unacceptably fast, and has no voltage supervision. As a result, this plant will provide no voltage support during system disturbances which affect reactive resources.

WSCC requires that pf/VAr controllers be switched off when required during system disturbances. The present AVR configuration does not allow this, and will likely be requested by WSCC to be changed. The AVR manufacturer indicated that the pf/VAr controller can be controlled by an external switch with the addition of some circuit board links and an external relay.

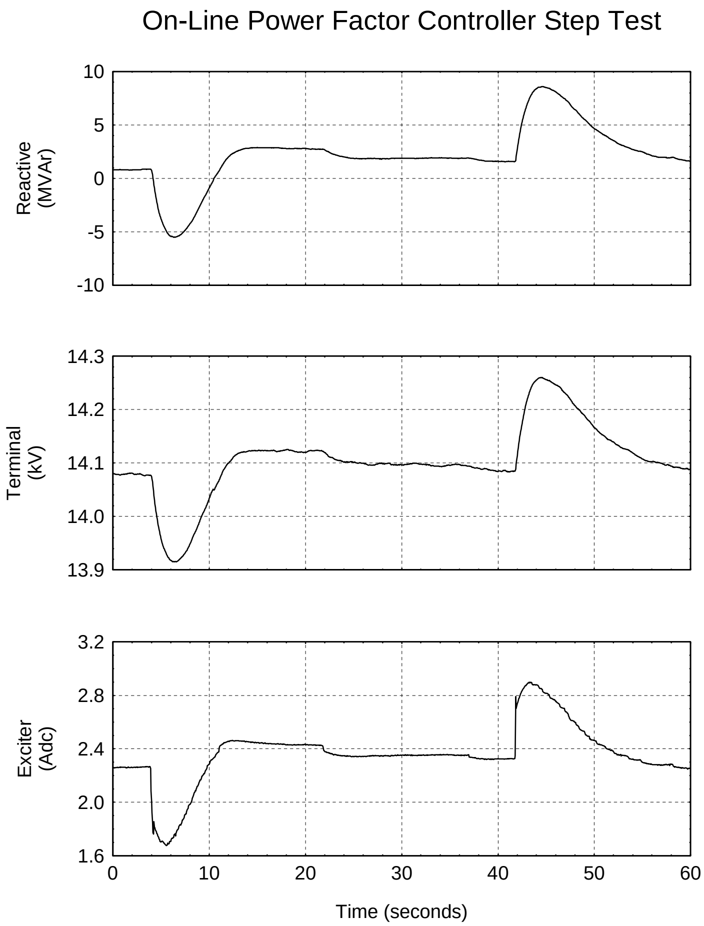

Figure 10.

Reference [E] provides a good review of Var controllers and their use. They are primarily intended to cater to distribution connected small generators, where voltage control is provided by the distribution utility tap-changing transformers and switchable shunt capacitor banks. Use on transmission-connected generators is strongly discouraged, and should only be undertaken after a comprehensive design review of the implementation and system impacts.

Conclusions & Recommendations

Two examples of gas turbine governor testing and modeling have been shown. The model structure should be selected prior to embarking on a testing program, to ensure that the necessary quantities are measured. Whenever possible, the final step in the process should be comparison of simulated results with measured data, preferably using the target simulation platform.

Emerging issues, which will require future study within the industry, include:

- Outer-loop controls, which adjust the speed reference set-point to obtain constant electrical power output conditions, are becoming popular. If not configured properly, these controls could have a negative impact on area frequency controls.
- New gas turbine controls, which are intended to optimize efficiency, should be designed carefully to ensure that they do not limit the unit's ability to respond to system frequency variations.
- Most new governors are implemented in digital electronics. While this has many advantages, it can make it difficult to introduce speed reference or feedback changes for testing the operation of the governor. Manufacturers are encouraged to add built-in test and measurement facilities.

References

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