Assessment Of Various Unit Control Architectures

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Abstract:

Governor systems are required to always meet or exceed the performance and reliability requirements of IEEE 125 "Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators", as well as meeting expanding NERC Reliability Standards.

Very careful consideration must be given when designing replacement plant or unit controllers. Historically unit control subsystems such as Turbine Governor, Excitation, and Generator Protection Devices, were dedicated separate devices. Attempts have been made to consolidate the governor, voltage regulator and other specialized control functionality into a single integrated unit or plant controller platform. "Lessons Learned" by utilities in recent years show that some of these designs can be non-responsive, non-compliant to standards, and may even be considered dangerous.

Using real-world examples, this paper will describe the potential for current and future difficulties with this type of integrated control scheme, discuss situations where the integrated system strategy may be used successfully, and identify the critical issues to consider when developing a controls retrofit strategy.

Introduction:

Traditionally, generating stations have depended upon a number of unique systems and devices for the protection and control of both the Prime Mover and Generator. Some examples of auxiliary systems are excitation, voltage regulators, synchronizers, governors, and generator protection. Over years of experience, each of these specialties have progressively advanced into, very unique and individual, complex fields of expertise. Initially, having separate controllers required very costly and complex intercommunication schemes. But today, the advanced digital communications among controllers and supervisory control systems dramatically simplify the 'connectivity' design.

Since the arrival of digital control systems, now around twenty years ago, industry has experimented with **amalgamating** some or all of these discrete systems. These completely integrated systems have only been successfully utilized in a very limited number of applications, typically in very small facilities. For major generating stations, most system designers have returned to using dedicated pieces of equipment for each specialty.

The following examples describe actual projects, and will illustrate several points to consider before selecting a 'style' of control integration. Although the problems encountered focus on the Speed Governor, the point of this paper is to illustrate there can be serious deficiencies in every specialty system, when they are administered without proper application experience.

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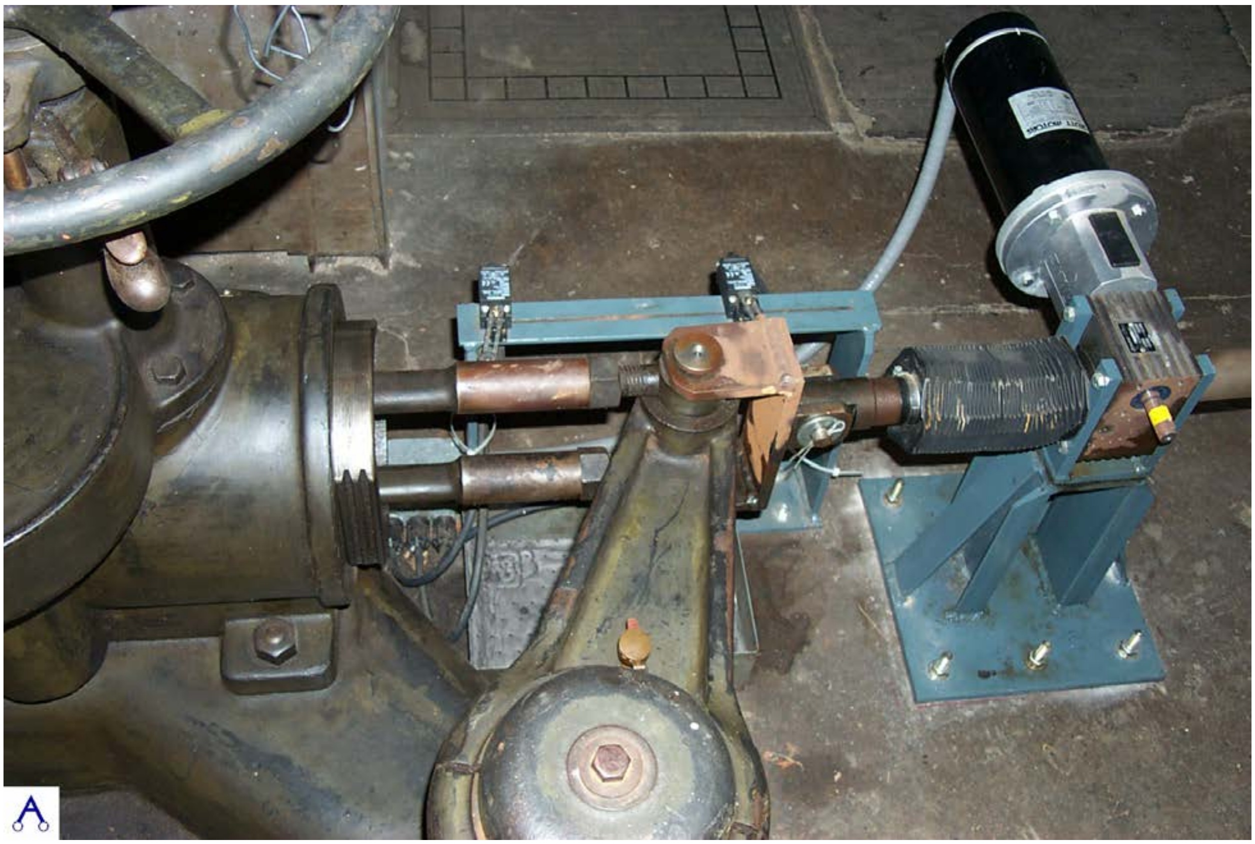
Example #1: A Successful Single (Plant Level) Controller for the entire facility.

This South Carolina facility is a small two-unit plant that originally had all manual controls, and was locally operated. The station has two 500kW vertical units, dating from 1926, and remains in service today. A controls refurbishment was completed in the late 1990's, and included a PLC for complete station monitor and control. The new controller is responsible for "Headgates to Tailrace". In addition to Trash-Rack Differential, through Brakes and Breaker commands, the PLC delivers full local and remote control of the entire plant. Generally, smaller stations have far fewer I/O requirements, and this system functions well with less than thirty-five I/O points total! The plant is so small, for example they do not have a station air system, nor even station batteries! At this level, automation and control integration may be can be successfully implemented at low cost, and can usually be completed by a local PLC vendor with little or no experience in Hydro Plant controls.

Typically, when these smallest of plants are modernized, the functioning Governor is converted into a simple Gate-Positioner (and will no longer contribute to grid stability.)



The original Woodward Gateshaft governors were physically retained, but were converted with electrically operated rack & pinion gate position assemblies.

Example #2: Unsuccessful Single (Plant Level) Controllers for the entire facility.

This example reflects two separate installations with the same type automation architecture, but with dramatically different problems. In comparison to the example above, these units are well over 200 Megawatts each and, as one would expect, have significantly more complex control, monitoring, and protection requirements. In both installations the controls were updated and designed to incorporate every auxiliary system into a single, integrated plant control and monitoring system.

The first installation was a complete controls upgrade that integrated all automation functionality into a single plant-level controller. American Governor was called in to examine *just* the unit speed governing subroutine, and we discovered several *critical oversights* that could create very dangerous situations! The vendor's process engineers programmed a complete and comprehensive plant controller, with synchronized control of motor starters through megawatt control, but they were clearly not governor specialists.

We discovered and compiled an assessment of about 90 other deficiencies and then proceeded to correct them. Although most might be considered simple oversights, some conditions represented serious control deficiencies that, uncorrected, could have caused serious misoperation of the turbine/generator.

From our reports to the owner:

- *Speed Switch / Proximity Probe Fault Detection - There is no method available to detect and annunciate the failure of either magnetic proximity probe or the speed switches they drive.*

- *EHI Manifold Fault Detection – EHI failures are not "remembered" and latched. If one of the redundant EHI's fail, the swap occurs to the other EHI, but the failed EHI is not locked out as faulty. If the second EHI fails, the controller will try to swap back to the previously failed EHI! This would result in a ping-pong effect where the gates continually ramp open and closed as the EHI's swap back and forth, adding ?? time to the trip sequence. Additionally if one of the EHI sides fails in the Open direction (due to debris or other valve or feedback malfunction) and one fails in the Close direction <u>the governor may not detect a complete loss of gate control.</u> It has also been discovered that a loss of the 4-20mA intermediate feedback to the servo valve, will result in the gates opening at the maximum hydraulic rate. While the governor will catch this, a concurrent failure in the other EHI will result in the same "ping pong" effect described above Without proper fault and error detection by the control system, the unit can be literally "out of control" for some time.*

- *When Off-line in Manual Generate, a switch to Auto Generate results in no PID control, and no Manual Gate Control. The PID is following and the Gate Position Raise/Lower control switches are disabled. It appears that the governor is not fully in either control mode. (HMI indicates Auto)*

- *When wicket gates are not closed, you cannot enter maintenance mode. Maintenance mode is intended to troubleshoot problems,* ***and the problem may be that the gates do not close.***

- ***In 'Generate Mode', gate setpoint goes to 80% when exiting Maintenance Mode!***

- *Gate Position Switches – Verify that the software is configured for "fail safe" operation of the gate position switches for a loss of governor power or a loss of gate position feedback. In the event of a loss of governor power or a loss of gate position feedback, the state of the gate position* *switches must be driven to a default fail-safe state in order to avoid misoperation of other protective circuits in the powerplant due to erroneous or indeterminate signals from these primary switches.*

- *"In addition to many other items not explicitly documented."*

In another similar installation, it was discovered that although there were separate Unit and Governor Control Systems, the 'Outer Loop' Unit MW control was programmed for a very precise Megawatt control setpoint and in fact overrode the Governor's proper Droop control functions during on-line operation. With constant redirection by the Unit Controller, the Governor became nothing more than a Gate Positioner when on-line, in violation of NERC requirements. Further testing confirmed the Governor controller was operating as it should, but *only when* 'separated' from the Unit Controller. A software fix had to be implemented in the Unit Controller to allow a larger deadband in the MW Control algorithm. Dispatch and Operators were also retrained to *not* expect finite megawatt control; that some small movements around the MW setpoint *are to be expected*, as the unit is contributes it's 'fair share' to grid stability!

Lessons Learned:

With these examples and other field experience, the following are critical points to consider when designing a governor controls retrofit:

The single most important factor, is to consider the application experience of the system provider! If they have an outstanding record, and 20 years experience -- at the Paper Mill -- they probably cannot expect superior results trying to operate a Hydro Turbine. In the past 10-15 years, experience has proven that some programmers don't know what they don't know!

- By separating the governor system, real-time performance is not compromised by being part of a complex unit/plant control software package.

- All critical governor inputs and outputs are hard-wired for optimum performance in a stand-alone governor. Remote I/O approaches almost always suffer from data throughput and refresh rate issues, causing poor real-time governor performance. Additionally, critical **Safety and Protection** points are always hardwired from their source, local stand-alone governor offers a smaller physical footprint and positions the control closer to the I/O.

- Any future expansion of plant control with more input/output points or complex software algorithms (multiple unit scheduling, sequence of events recording, etc) will never degrade the response speed and performance of a standalone governor.

- Standalone Governor systems will **always** meet the requirements of IEEE 125 "Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators", and will **always** meet the FERC/NERC Standards for performance and reliability!

- Overall system reliability will be increased due to the inherent redundancy achieved with separate governor and unit controllers. A failure of the governor controller does not prevent proper operation of critical auxiliary equipment and a failure of the unit controller does not prevent a controlled shutdown of the unit.

- Installation, Acceptance Testing, Commissioning, Maintenance, and Troubleshooting of a separate governor will be *simpler* than with an integrated governor controller. With a separate governor controller, the governor functionally can be fully isolated from all auxiliary systems and tested completely independently; this is not at all possible with an integrated controller.

- The unit controller does not even have to be powered on to perform basic governor functionality, such as stroking the wicket gates in the dry. This can prove to be invaluable during outages and can assist with tricky lockout/tagout issues associated with an integrated controller.

- Current Ethernet and universal communications protocols make inter-system data exchange easier than ever. A standalone governor offers the same communication capabilities as modern protective relay and excitation systems. Like these other systems, loss of communication to a standalone governor does not cause unit shutdown.

- Individual specialties such as Protective Relaying, Excitation, and Governor Speed, have the irreplaceable application history and experience of their unique functions. Unfortunately for the industry, this application expertise is often overlooked, or even discarded!

Conclusion:

By combining specialty and safety equipment/systems, you are forced into sharing system resources, which can only result in compromises. The type and extent of the compromise must be carefully scrutinized. Unforeseen conditions can exist for **years** that could cause problems that were never initially considered. If you lose control of a lube-oil pump, you may wipe a bearing. If you lose control of the TURBINE, you could lose the plant!

Acknowledgments

The author sincerely thanks Roger Clarke-Johnson, Scott Ginesin, Jerry Runyan, Paul Silva, Gary Rosenberger, and Matt Roberts for their technical reviews and assistance with the preparation and development of this manuscript.

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