GRC Transactions, Vol. 41, 2017

Geothermal Turbine Control System Retrofit Case Study

Jeff Schleis

EthosEnergy – Optimization & Upgrades

Keywords

Geothermal, Governor, Controls, Retrofit

ABSTRACT

Geothermal power plants remain a valued member within the renewable market. With the ability to perform turbine power uprates, older units with OEM analog control systems continue to play a part. However, the original systems can be beyond their serviceable life. Uprates to the turbine may require changes to the control system that are difficult or impossible to perform. While balance-of-plant systems have been upgraded to current technology, the turbine control system remains a problem. Upgrading the turbine control system to current technology can solve these problems and also open the door to other benefits.

1. Introduction

Obsolescence plagues owners of turbine control systems. Everyone in the plant knows of the problem, but there is usually not enough pain to make the upgrade. Operators just want the system to work like a thermostat in your home; as long as the setting dial seems to work, there isn't an issue. Technicians rarely modify or troubleshoot the system, so not having the detailed knowledge of the controller isn't a problem. Plant owners don't like to spend money to replace something that currently works. Obsolescence is only remedied when the control system no longer functions, a critical part costs too much to replace.

However, there are benefits to upgrading the turbine control system that are frequently overlooked. This paper will examine the benefits of a recent control system retrofit, beyond obsolescence, that were delivered to the plant.

2. Scope of Retrofit

For the project in this case study, the unit was originally a 55MW unit manufactured by Mitsubishi Heavy Industries (MHI) and installed in 1982. The control system was the original analog/digital Electro-Hydraulic Control (EHC) system also manufactured and installed by MHI.

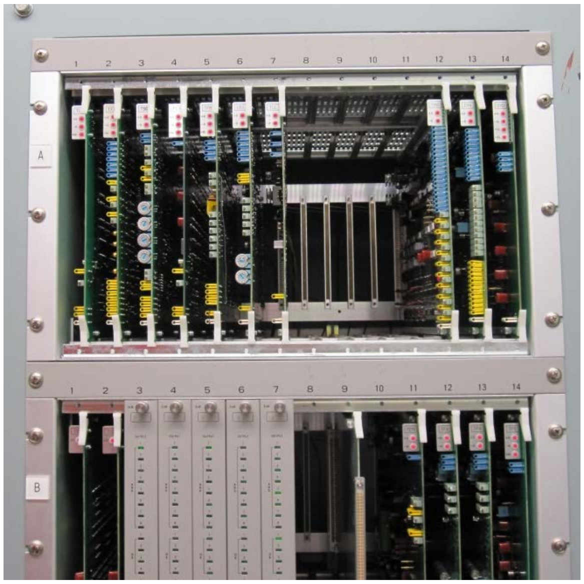

Figure 1: Original MHI Electro Hydraulic Control System

The scope of the retrofit was to replace the original controls with a Rockwell ControlLogix controller. Limited but critical field instrumentation was also upgraded based on historical equipment failures.

Rheostats to monitor valve position were replaced with RVDTs (rotary variable differential transformer). Also, an obsolete component of the system was the current-to-pressure "cup valves" that provide the hydraulic position signal to the governor valves, one for each valve. These were replaced with new Woodward Current-to-Pressure Converters (CPCs) that have a high dirt tolerance and a proven track record in these applications. Other than the control signal, the original control valve servomotors (actuators) and the valves themselves were left untouched.

All of the other instrumentation was reused, including the original speed sensors.

Outside of the EHC system, the original Westinghouse automatic synchronizer was replaced by a digital version, Woodward's SPM-D.

3. Modifications for Turbine Power Uprate

One of the driving factors for the control system improvement in this case was a simultaneous uprate of the turbine from an original 78MW maximum to an 84MW unit. This work was performed by the original equipment manufacturer (OEM) and although the control system would not be greatly affected, it was an opportune time to eliminate the obsolescence problem and also be sure there were not any issues preventing the governor from reaching the new maximum limit.

4. Steam Management

The most notable item that was removed from the original turbine control system was the bypass steam valve controls. Because the plant distributed control system (DCS) was retrofitted with Rockwell ControLogix, it was desirable to move all of the steam management controls into one system. After the DCS retrofit, the bypass steam controls were the only piece of the steam path that was not managed by the new DCS. This meant a different operator interface and limited control over when and how the bypass valves operated.

This simplified the turbine controls, and at the same time made the entire steam path manageable within one consistent system. The turbine is left to take all of the steam that is available, and the operator has full authority over the steam path.

5. Updated Safety Logic

The OEM turbine control system was analog based, and therefore some simplifications were made to make the original design more manageable. Complex failure algorithms were also not possible, or were too difficult to create. With the new turbine control system some advanced trip logics were implemented, along with additional enumeration of trip inputs.

5.1 Speed Sensor Failure

The most complex addition was the speed sensing failure logic. There were three speed sensors made available for the governor function, and standard logic for control would be a median selection of the three. However, standard logic would also generate an immediate trip should two of the three speed signals fail. In this implementation, the trip only occurred after three speed sensors failed (an independent overspeed function also exists). If two speed sensors were to fail, the unit automatically performs a normal stop sequence. This logic increases the availability of the unit by using existing instrumentation, but continues to provide a level of safety required for the unit.

5.2 Startup Overspeed Prevention

A safety item added to the control system was introduced to mitigate overspeed issues during a startup of the unit. The idea is to prevent a problem that would be immediately obvious to an operator, but not typically implemented in governor logic. We know that very little steam is required to bring the unloaded generator to synchronous speed. As a standard practice, the main stop valve and governor stop valve positions are limited to a small opening before speed is sensed. If this feature was not in place, theoretically, the valve demand could reach 100% before an operator sees that the unit is not spinning.

Issues that can lead to this condition are not unusual and can include:

- The previous trip before this attempted start was due to shaft runout (vibration trip) and the speed sensors were damaged. No speed would be sensed by the control system, but the unit would be actually spinning during the start sequence.
- A sticking valve could cause the valve demand to wind up before the valve pops off the seat, resulting in an overspeed.
- Broken or damaged linkage in the valve actuation can result in a valve that cannot reach 100% open. Without a startup check, this might not be noticed until the unit is unable to reach full power.

5.3 Separate First-Out Indications

Finally, in the original system the trip circuit was a number of parallel path trip conditions in an energize-to-trip arrangement. Some of these conditions were provided with separate operator indications, but others were grouped together for simplicity. However, the grouped trips make troubleshooting trips harder as all of the possible trips in that circuit must be investigated, causing more down time to isolate a problem.

In the new system, a first-out capture algorithm was supplied with separate signals for each trip condition. The first-out operates at the millisecond level within the controller. Ambiguity in which event was the originating trip is in most cases eliminated.

6. Modified Sequencing

Upgrading the controller also brought flexibility and ease to change the turbine sequencing to meet plant needs. Two major areas were addressed to assist with plant operations.

6.1 Startup on a Single Steam Path

During commissioning of the unit, there were issues with valve sticking on one inlet path (see Figure 2). As a result, the software was configured to allow startup of the unit on just one steam path, instead of both. The unit was started up through synchronous speed on only one “side” of the unit. This sequence improvement increased operational flexibility and ultimately made the unit more available when inevitable valve issues arise.

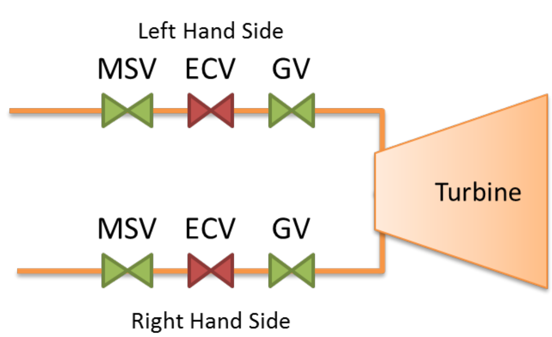

Figure 2: Turbine Control Valves (Left and Right Paths)

6.2 Unit Readiness

The original turbine stop sequence correctly turned off the subsystems after a shutdown. However, in some cases this was detrimental to the operations, such as when a restart was anticipated shortly after the shutdown timers expired. Additional time during the subsequent start sequence was used to restart the subsystems, potentially causing lost revenue. For example, maintaining the turning gear during short shutdown periods can minimize vibration hold points during startup.

The solution was to extend the subsystem operation when the plant expects a restart of the unit. A permissive was sent from the DCS to the turbine control system when it is necessary to maintain oil systems, gland steam, and turning gear operation, particularly when these systems were not required by the OEM sequence.

7. Plant Operations Integration

Over the years of operating the plant, the owner had a short wish list of operational improvements that became immediately possible with the upgrade of the turbine control system. Although these items are not revolutionary ideas, they do represent additional ways in which improvements can be made to the plant with the retrofit.

7.1 HMI Integration

Although an independent Human-Machine Interface (HMI) was supplied with the new control system, the graphics can be mimicked easily in the DCS. Because the Rockwell native FactoryTalk View visualization software was used for both the turbine control system and the DCS, the graphics could be directly copied between the two. Communication is also not an issue because both systems reside on the same Ethernet network.

Only a subset of the complete turbine control system graphics needed to be copied to the DCS so that an operator can had all of the plant information at the same station. Less time switching between physically different terminals translates to faster decisions by the operator, reducing risk.

7.2 Multiple Runbacks

Although the original system had multiple runback rates and setpoints, it was desirable for the plant to have additional ones defined. There was an increase from the three original runbacks to a total of four.

8. Maintenance Tools

Simplifying maintenance tasks is always a goal of improving technology. In the case of turbine control retrofits, two significant tasks are standard features. To access the new features, a password protected graphic on the HMI was developed with all of the test and maintenance functions.

8.1 Valve Stroking

When in an offline mode, independent stroking of each of the six steam valves is allowed. While the technician or operator can specify a position for a valve, the analog position feedback is compared to demand. Real-time and historical trends are available for a close comparison of these two values. This is useful in troubleshooting sticking valves or testing, following repairs.

8.2 Automated Valve Position Calibration

When maintenance is performed on the valve actuation or a position feedback device is replaced, it is necessary to calibrate the device. The turbine control system needs to record 0% and 100% valve opening as it relates to the signal that is input to the control system. In the original system, this calibration was a manual process that bounced between physical arrangement of the feedback device and tweaking rheostats to match open and closed positions with internal control system voltages.

However, with the new system, the position feedback device can be installed once, and the control system can be left to compensate for small physical differences. Combined with the valve stroking feature above, this feature allows the control system to digitally capture minimum and maximum feedback calibration. First, the operator or technician uses the valve stroking to operate a valve to an open or closed limit. Once the valve is visually confirmed to be at the limit, the operator can select a button on the HMI to sample the feedback input and use that value as one endpoint of the valve stroke. What could have taken hours in the old system is now resolved in minutes.

9. Overspeed Testing

Insurance companies recognize well the inherent risk in performing overspeed testing by operating the unit at the overspeed setpoint. New revisions to API and ISO standards speak to this by promoting electronic overspeed systems over mechanical ones. Electronic overspeed systems can improve diagnostics and can be designed to be online testable.

In this project, the mechanical overspeed mechanism was retained due to the common desire of the plant not to eliminate sources of protection. However, two features were added to improve this critical function. First, an electronic overspeed (that is independent of the governor overspeed) was added to the system. This digital two-out-of-three speed switch is capable of simulating speed signals and testing each channel one-by-one while the unit is running. Second, while the mechanical overspeed testing is procedure is being performed, the governor switches its overspeed setpoint just above the mechanical setpoint range. Normally, the governor overspeed trip would be bypassed during a mechanical overspeed test. This feature reduces the risk of this test when it is necessary to perform one.

10. Making the Retrofit Easier

During the design phase of the project, a particular focus was put on how to reduce the amount of installation time, while adhering to the design philosophy of the plant. As a result, we developed a panel design that made use of the existing cabinet structure (Figure 2) and left the existing field terminations (bottom of Figure 2) intact. This meant that none of the original field wiring needed to be touched, only short runs from the existing marshalling at the bottom of the cabinet to the new panel (Figure 3) were required.

Figure 2: Original MHI Electro Hydraulic Control System Cabinet

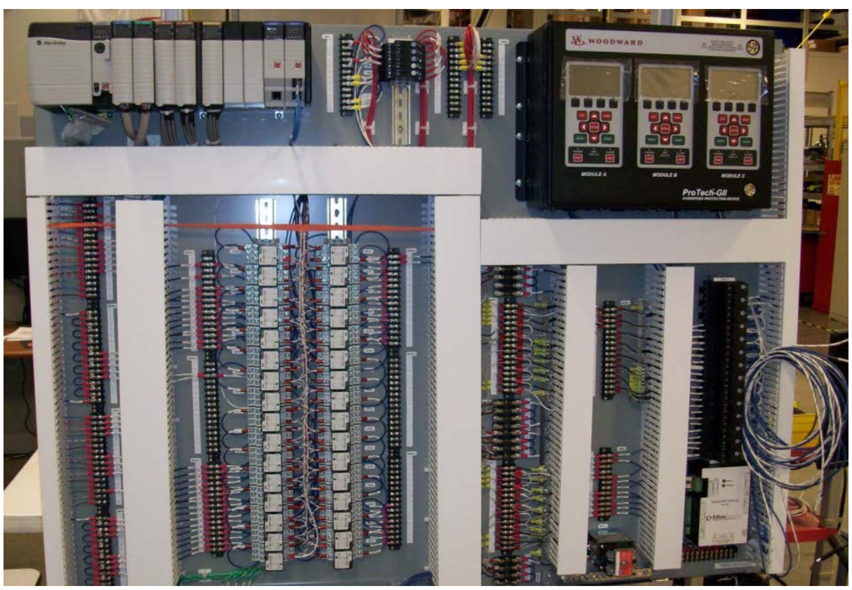

Figure 3: New Electro Hydraulic Control System Panel Insert

10. Conclusion

While obsolescence can be a driving factor for turbine control system retrofits, consider other benefits. In the retrofit project recently completed, the plant was able to identify and implement several enhancements to solve lingering problems and improve plant performance. Ultimately this translates to improved availability and decreased maintenance.