USING DYNAMIC SIMULATION TO EVALUATE ATTEMPERATOR OPERATION IN A NATURAL GAS COMBINED CYCLE WITH DUCT BURNERS IN THE HEAT RECOVERY STEAM GENERATOR

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ABSTRACT

A generic training simulator of a natural gas combined cycle was modified to match operations at a real plant. The objective was to use the simulator to analyze cycling operations of the plant. Initial operation of the simulator revealed the potential for saturation conditions in the final high pressure superheater as the attemperator tried to control temperature at the superheater outlet during gas turbine loading and unloading. Subsequent plant operational data confirmed simulation results. Multiple simulations were performed during loading and unloading of the gas turbine to determine operational strategies that prevented saturation and increased the approach to saturation temperature. The solutions included changes to the attemperator temperature control setpoints and strategic control of the steam turbine inlet pressure control valve.

1. NOMENCLATURE

Acronyms and variables

CT1	Combustion turbine one. Lead CT
CT2	Combustion turbine two. Lag CT
EGT	Turbine exhaust gas temperature
F-water	Water flow rate to attemperator
F-HPSH	Steam flow through HPSH
HPSH	High-pressure superheater
HRSG	Heat recovery steam generator
IPC	Inlet pressure controller: Regulates MCV to maintain main steam pressure setpoint when “in”
IPC62, 75, 86	IPC is “in” at 62, 75 or 86 barg respectively
MCV	Main steam control valve
OTS	Operator training simulator
P-HPSH	Pressure at exit of HPSH
P-Main	Pressure at inlet to high-pressure steam turbine (i.e., Main steam pressure)
RH	Reheater
T	Temperature
TCV	Temperature control valve
Tex	Final HPSH exit temperature (Fig. 14 only)
T-HRSG Air In	Air inlet temperature to the HRSG
T-sat	Saturation temperature

2. INTRODUCTION AND METHOD

A power plant operator training simulator (OTS) is, as the name suggests, generally used for training plant operators. It can also be used as a means of instrumentation and control checking. It is, however, not common to use the simulator as a tool to examine operational scenarios to examine and solve operational difficulties or desired improvements. A cooperative work agreement was entered between the National Energy Technology Laboratory (NETL) and the National Rural Electric Cooperative Association (NRECA) with the objective being to analyze plant cycling operations of an NRECA member’s natural gas combined cycle (NGCC), using the NETL generic NGCC dynamic simulator as a tool to examine possible negative impacts to (or from) equipment because of procedural or equipment operations. This generic simulator is a full scope operator training simulator of a 2-on-1 combined cycle and is presented in other publications [1, 2]. The real NGCC plant chosen for cooperative work was Plant Dell in Arkansas, owned by the Associated Electric Cooperative Inc. (AECI). The NETL generic NGCC dynamic simulator was modified to match the Plant Dell configuration and operation and then used to investigate alternative operations or potential design enhancements that would reduce damage to equipment, and improve operability and operational flexibility. It was desired that recommendations for improved cycling operations arising from the simulation studies could be realistically tried by Plant Dell operators without introducing negative consequences. This approach was recently used by General Physics in an EPRI project to examine frequent cycling in large coal fired plants [3].

After a visit to the plant it was decided that a good candidate for the study would be the attemperator operation during loading and unloading of the gas turbine between ~30 and 120 MW. This scenario was chosen because saturated steam conditions existed at the inlet to the final high pressure superheater (HPSH). It should be noted that this issue was identified in pre-simulation runs of the model prior to the plant visit. After confirmation during the plant visit, the simulator was refined in the attemperator area of operation and studies were conducted to look at ways to move steam conditions further away from saturation. Some other possible items to study, but not discussed here, would be the rate of temperature change around the superheaters and improving pressure retention in the high-pressure steam drum.

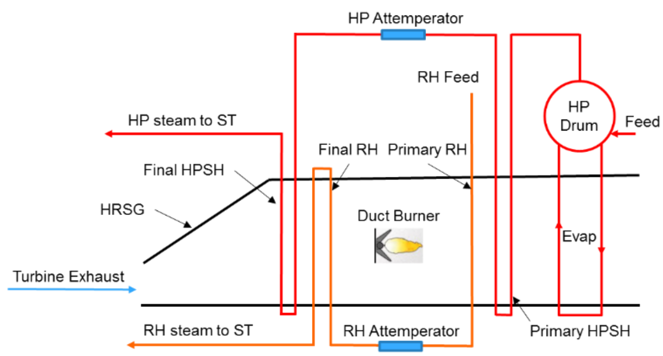

Figure 1. Schematic showing location of duct burner in between RH superheaters

The following is a brief overview of the plant and some characteristics that make the attemperator operation more challenging. The plant is a 2-on-1 combined cycle using two GE7FA.02 gas turbines and one D11 steam turbine. On a hot (308°K) day, each combustion turbine (CT) output is about 151 MW at full load. The steam from the two three-pressure heat recovery steam generators (HRSGs) is enough to make 165 MW of power from the steam turbine (ST). Each HRSG design includes a duct burner. Fig. 1 shows a schematic of the duct burner location, which is in between the reheat (RH) superheaters.

The design and operation of a HRSG with a duct burner will be different than without. Given the same main steam design pressure (e.g., 124.1 barg (1800 psig)) and CT load, the duct burner design will have lower main steam pressure and flow rate with the duct burners off. For instance, given duct burning HRSG's with both CT's at full load, the high-pressure steam has a considerably lower pressure with the duct burner in both CT's off than when on: 89.6 barg (1300 psig) compared to 124.1 barg (1800 psig). Also, the steam flow through the final HPSH is reduced by 35% with the duct burner in both HRSGs off (at full CT load). The lower mass flow rate and pressure result in a lower residence time (volumetric flow) in the final HPSH and thus more heat pickup can be expected with resulting higher temperature from the final HPSH. Steady state results show that more water is needed to keep the HP attemperator temperature at setpoint with the duct burner off. Table 1 shows superheater steam conditions for the duct burner on and off at full load CT conditions. As can be seen, there is a higher steam temperature rise across the superheaters with the duct burner off. Note that the primary HPSH exit steam is desuperheated by 67°K (728°K to 661°K) with the duct burner off as opposed to only 8°K with the duct burners on (791°K to 783°K).

Table 1. Temperatures at the inlet and exit of the superheaters

Duct Burner State	Off		On	
	T_{inlet} °K (°F)	T_{exit} °K (°F)	T_{inlet} °K (°F)	T_{exit} °K (°F)
Final HPSH	**661 (731)**	831 (1036)	**783 (950)**	839 (1050)
Secondary RH	735 (863)	824 (1023)	790 (962)	840 (1053)
Primary RH	631 (677)	735 (863)	649 (708)	806 (992)
Primary HPSH	576 (578)	**728 (852)**	608 (634)	**791 (964)**

It will be seen in the results how this affects the attemperator operation, especially the HP attemperator during CT loading. Pearson, et al., studied attemperator performance extensively and using historical operational data they show numerous adverse situations [4]. This study is different in that a simulator is used to examine and improve operations, and the combined cycle HRSG is of the type that includes a duct burner.

Another important characteristic is that of the CT. An exhaust gas temperature (EGT) profile from plant data is shown with the red line in Fig. 2. As can be seen, and is well known by the plant operators, there is a sharp increase in temperature between the minimum load to ~65 MW and then a sharp temperature decrease to ~100 MW. It can be difficult for the final attemperator to maintain the setpoint temperature in this "hot-zone" and, if loading, for some time after passing through. But perhaps less well known to the operators is the additional concern regarding saturation conditions at the final HPSH inlet. This will be looked at in the following CT unloading and loading scenarios.

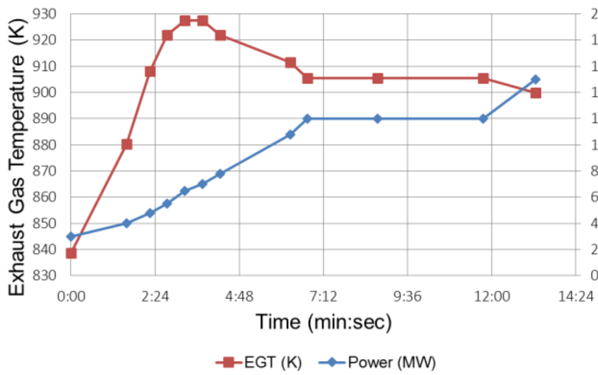

Figure 2. CT exhaust gas temperature profile during loading

3. RESULTS AND DISCUSSION

Results will be presented for two scenarios: unloading of the Lead CT (CT1) and loading of the Lag CT (CT2). Examining the Lag CT unloading and Lead CT loading would be beneficial, and could be done given more investigation. However, the proposed suggestions for the Lead CT unloading apply to the Lag CT. For the loading, the Lead CT is more complicated. Operations at plant Dell have recently used a strategy to load the ST during power ramp, which is like the suggestion given in this report of having the inlet pressure controller (IPC) "In" (see Summary, Loading bullet 1). So, the strategy has similar benefits. Then, the other suggestions in the summary should be applicable to the Lead CT loading.

3.1 Lead CT (CT1) Unloading Results

Data from a plant operation is shown in Fig. 3. The Lead CT (CT1) is unloaded from 120 MW to minimum load at a rate of approximately 14 MW/min and immediately shut-down. It can be seen that the final HPSH inlet temperature (T-HPSH In) reaches the saturation temperature (T-sat) and is within 14°K (25°F) over most of the load range. Thus, while the attemperator could maintain the final HPSH outlet temperature (T-HPSH Out) setpoint of ~824°K (~1023°F), the adverse saturated condition is present. Note that saturation occurs during the end of the unloading, but the temperature is within 28°K (50°F) of saturation during most of the unloading: general recommendations for limits range between 14 to 28°K (25 to 50°F).

Using the simulator, five cases were run for unloading of the Lead CT (CT1). A description of the legend item for the figures is given in Table 2. The HP800K and HP824K cases represent two different temperature setpoints that have been used at the plant during startup and shutdown. The HP800K

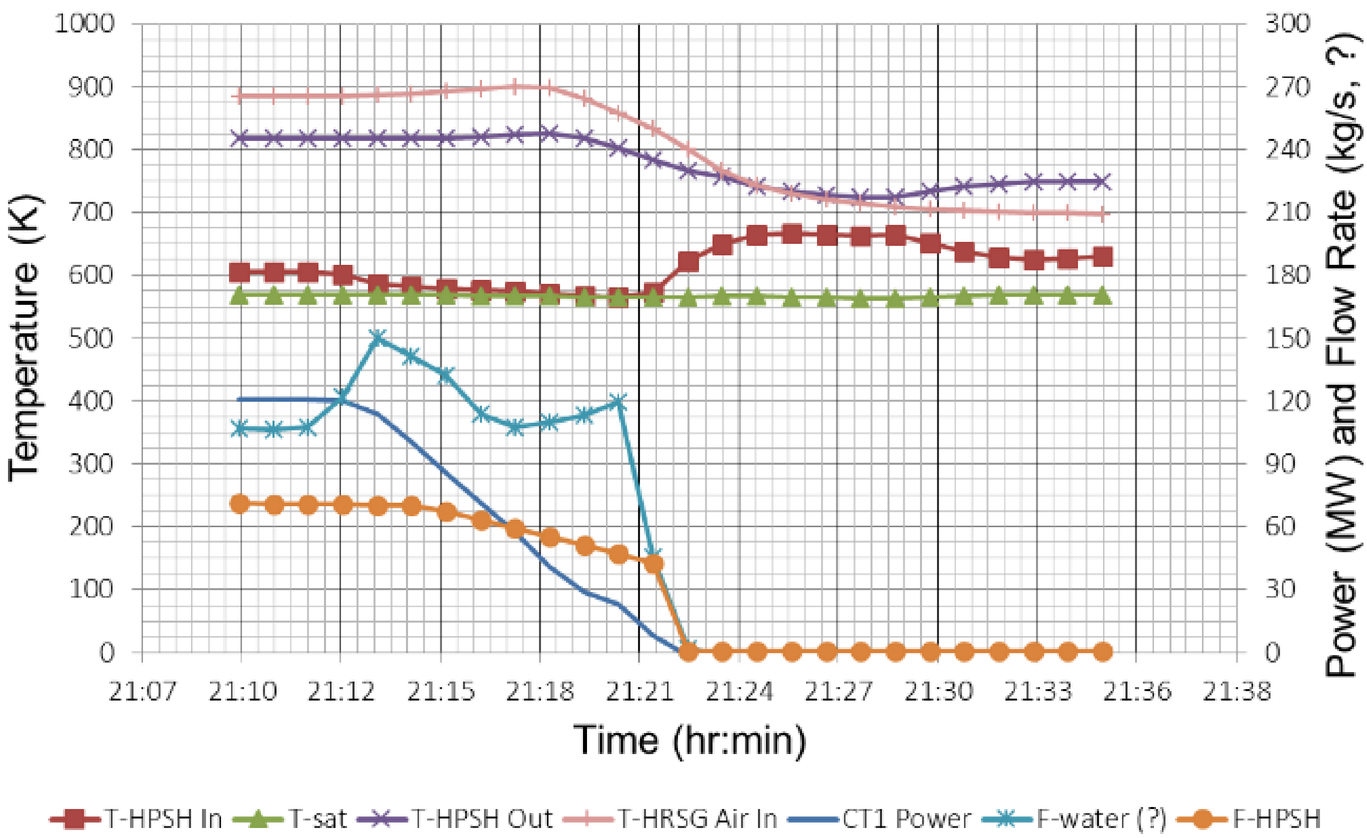

Figure 3. Some relevant data from the plant during unloading of CT1. Note that the water flow rate (?) is not dimensionally known.

Table 2. Simulator Scenarios for the unloading.

HP800K	The HP attemperator setpoint is 800°K (980°F), RH setpoint is 824°K (1023°F)
HP824K	The HP and RH attemperator have setpoints of 824°K (1023°F)
HP824K_RH836K	The HP attemperator setpoint is 824°K (1023°F), RH setpoint is 836°K (1045°F)
HP836K	The HP and RH attemperator have setpoints of 836°K (1045°F)
IPCin@76barg	The IPC is in at 75.84 barg (1100 psig), Attemperator setpoints are 836°K (1045°F)

case is an attempt by the operators to "get ahead" of an expected increase in the final HPSH exit temperature by decreasing the setpoint, which increases the water flow to the attemperator. The reason for showing the other cases will be given as the results are shown and explained.

Figures 4 through 8 will show results during an unloading of the Lead CT from 120 to 25 MW, with the Lag CT at a constant 154 MW. The load decrease is plotted on the secondary axis on all figures, and is approximately 14 MW/min until a load of 60 MW, and is then 10 MW/min.

Fig. 4 shows the approach to saturation at the inlet to the final HPSH (the inlet temperature minus the saturation temperature, with zero being saturation). Notably, the starting condition is the same for HP800K and HP824K, and this is because the attemperator temperature control valve (TCV) is fully open at a setpoint condition of 824°K (1023°F) as can be seen in Fig. 5. Given this, the behavior for HP800K and HP824K is similar during a significant part of the load decrease, until around 60 MW (360 seconds). The HP824K case then begins to move away more quickly from saturated conditions than HP800K. This shows the disadvantage to lowering the setpoint (i.e. the HP800K case) to get ahead. It only keeps the condition at saturation longer. Figure 6 shows the final HPSH exit temperature for all cases and a comparison of the temperatures shows why this happens. The temperature for the HP824K case dips below its setpoint and thus the attemperator water will begin to decrease. The HP800K case is still above its setpoint until the CT is almost at 25 MW. Naturally, this is ultimately all related to the CT exhaust gas temperature. To summarize this comparison, the HP800K case has not been advantageous with reducing the HPSH exit temperature and keeps the inlet temperature closer to saturation for a longer period.

For case HP824K_RH836K, the RH attemperator setpoint is set to 836°K (1045°F), which effectively takes the RH attemperator out of service, so there is no water injected (the maximum reheat temperature during the transient was in fact 836°K). Note that we are looking at the effect the RH attemperation has on the final HPSH, not the RH section itself. As can be seen in Fig. 4 the starting distance from saturation at the inlet to the final HPSH is greater than the first two cases presented and is also consistently higher during the entire load

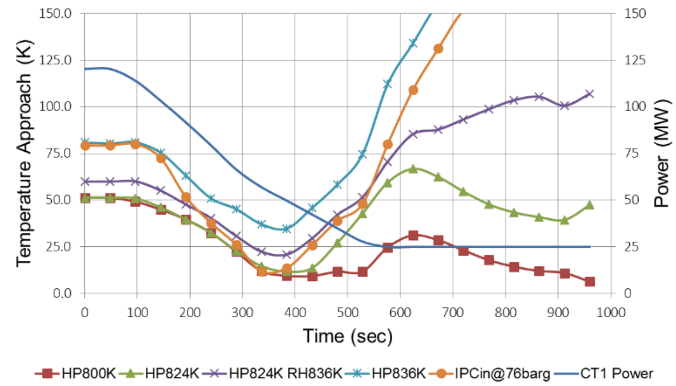

Figure 4. Approach to saturation at the inlet to the final HPSH (after the attemperator)

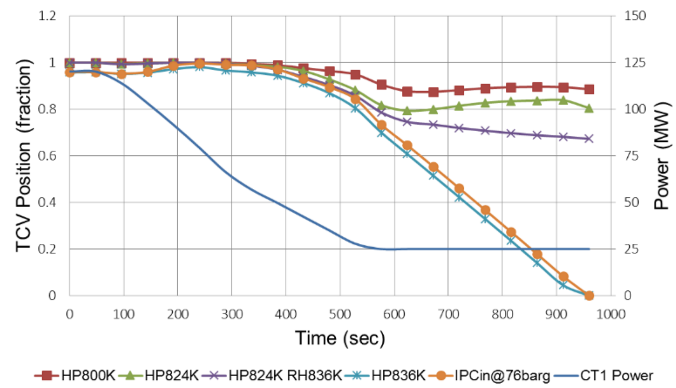

Figure 5. TCV position that controls water flow to the HP attemperator

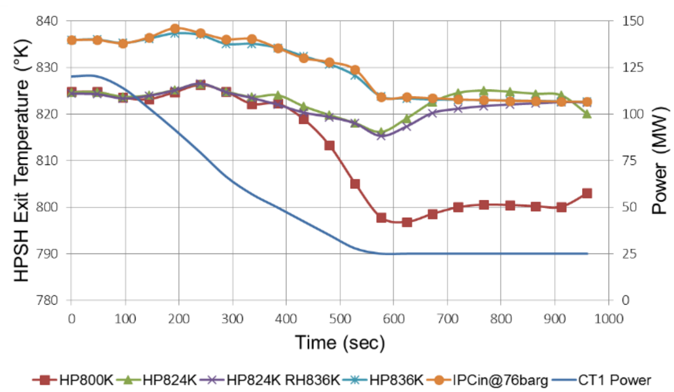

Figure 6. Controlled steam temperature at the final HPSH exit

decrease. The reason for this can be seen in the lower heat flux to the steam in the final HPSH, as shown in Fig. 7. The heat flux is governed by temperature differences between the air and steam side of the tube bundle and heat transfer resistance parameters dependent on fluid conditions such as the flow rate and pressure (or velocity).

In the next case, HP836K, the HP attemperator setpoint was increased from 824°K to 836°K (1023°F to 1045°F). As would be expected, less water is needed and so as seen in Fig. 4, the initial temperature approach to saturation is larger over the entire transient. There is also room for the TCV to open as

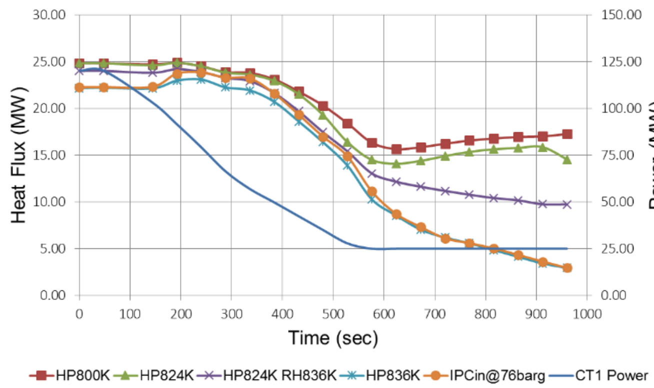

Figure 7. Heat Flux to the steam in the final HPSH

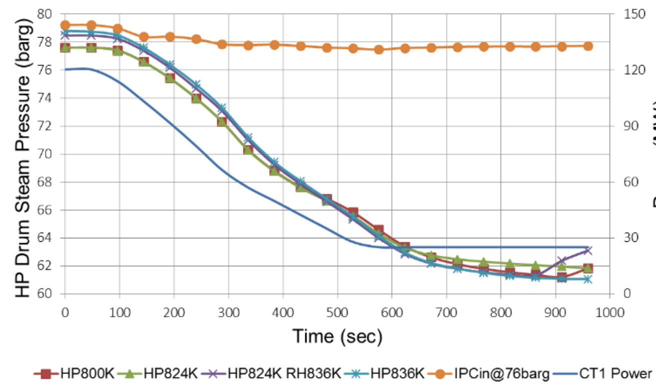

Figure 8. HP Drum pressure

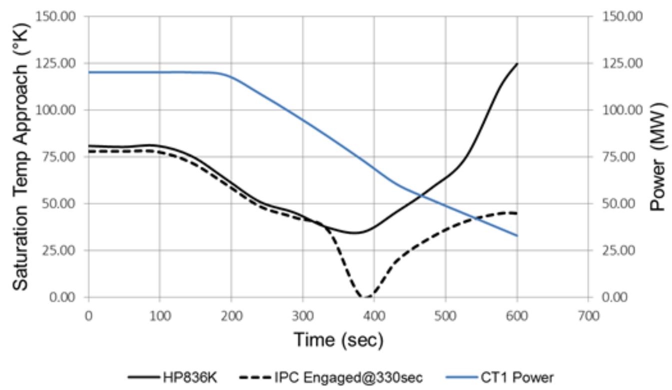

Figure 9. IPC engaging during the unloading

seen in Fig. 5. Using a higher setpoint may seem an obvious choice; however, it appears common practice to lower the setpoint due to concerns with the outlet temperature getting above a desired limiting temperature, 839°K (1050°F). In the case of the simulation, this was not problematic, as seen in Fig. 6. From the plant data where the setpoint was 824°K, it appears that the temperature can be kept within 3°K of the setpoint. This is more of a concern during loading since the steam flow is low and its rate of increase will lag the exhaust gas temperature increase.

Finally, a simulation study was performed where the IPC was engaged, or "in", at a pressure of 76 barg (1100 psig), with an attemperator setpoint of 836°K (1045°F). As shown in Fig. 4, the approach to saturation begins at the same point as the HP836K case as expected, but decreases at a faster rate and has a much closer approach to saturation. The engaged IPC closes the main control valve (MCV) to keep the upstream pressure at 76 barg, and this reduces the steam flow rate through the final HPSH which results in the observed behavior. Less steam flow means a greater increase in the exit temperature during the transient (for the same heat flux). While this is not unexpected, it is done to simulate a case where it is desirable to use the IPC as a means of keeping the drum pressure up to have it as high as possible during shutdown and thus a subsequent startup (see the drum pressure plotted in Fig. 8). The simulation shows that there is some risk of saturation at the HPSH inlet. Having the IPC engage during a transient was even more detrimental with respect to saturation than having it engaged beforehand, *especially* when the CT is going through the "hot-zone". The valve closing lowers the steam flow and additionally there is overshoot of the valve in trying to get to the control pressure. An example of this is shown in Fig. 9.

3.2 Lag CT (CT2) Loading Results

Data from plant operations in November 2014 is shown in Fig. 10. The Lead CT is at full load and the ST is accepting steam from the Lead HRSG. The Lag CT (CT2) is at 40 MW and is warming its HRSG, but is bypassing all steam to the condenser prior to loading at the 6:19 mark. Just prior to loading, at the 6:17 mark, the Lag system bypassed HP steam is transitioned to the ST. The bypass pressure (P-HPSH) is set at 69 barg (1000 psig) and the Main steam pressure going to the ST (from the Lead HRSG) is at 60.7 barg (880 psig). So when the steam flow is blended to the ST, the HPSH steam pressure drops and the Main steam pressure increases until only the pressure drop in between the pressure sensors remain, as seen in Fig. 10 around 6:20. The behavior of the steam flow through the final HPSH (F-HPSH) follows accordingly, with a rise and fall before beginning to rise again with the increased steam flow due to heating of the system from the exhaust gas temperature increase (T-HRSG Air In).

The steam turbine IPC controls pressure at the inlet to the Main Control Valve (MCV), not the inlet to the steam turbine. Thus, the valve will close to increase pressure. Unfortunately, there is no log data for the MCV position, but based on other data (the Main steam is at 60.7 barg (880 psig) prior to loading the Lag CT), it is assumed that the MCV is fully open and thus the IPC is essentially "out".

From Fig. 10, it can be seen that the final HPSH inlet temperature (T-HPSH In) reaches the saturation temperature and is within 14°K (25°F) for at least 6 minutes near the peak of the loading and somewhat after. The loading scenario is more difficult than the unloading (with respect to avoiding saturation) because a steam flow increase will lag the temperature increase during loading. The goal of the following simulation case studies was to look at possible strategies to move away from saturation conditions at the final HPSH inlet.

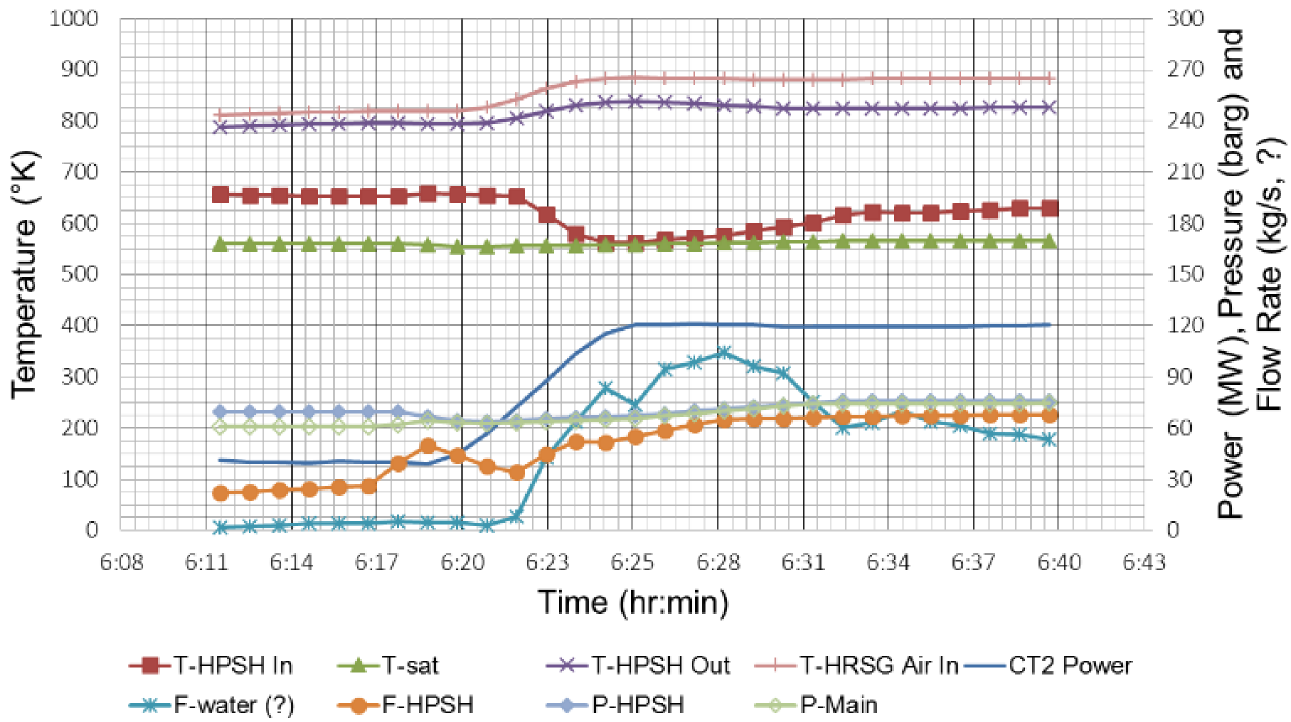

Figure 10. Some relevant plant data during loading of CT1. Note that the water flow rate is not dimensionally known

Three cases will be compared in the following results for the loading scenario simulation. This will compare IPC pressure settings of 62, 75 and 86 barg (900, 1100, and 1250 psig) as denoted by IPC62, IPC75, and IPC86 respectively. There is also a fourth case where the IPC is at 75 barg and the attemperator temperature control valve (TCV) limits the water injection based on an approach to saturation of 14°K (IPC75SatLim14K). While the plant does not employ a saturation limitation, other plants do; therefore, this scenario was added with results plotted (in Fig. 14 only). Note that for the IPC62 case, the MCV is open during the entire transient resulting in the IPC being "out" (the MCV fully open) in this case. Fig. 11 shows the resulting MCV position for each case.

For all cases the flow coefficient (i.e., orifice size) for the attemperator TCV was increased (compared to the unloading scenario) to increase the available water flow. Initial plant data seemed to indicate a limitation, but latter data indicated otherwise. It was thought best not to limit the water flow rate in the simulations. A TCV setpoint temperature of 824°K (1023°F) at the final HPSH outlet is used for all cases. The load rate is 13.5 MW/min. There is no desuperheating in the RH section for any of the cases since it is unnecessary: the RH exit temperature is 764°K (915°F) at the beginning of loading and 811°K (1000°F) by the end, well below limits.

The final HPSH exit temperature and the inlet approach to saturation are plotted together in Fig. 14. The controlled exit temperature profile is similar in all cases except for the saturation limited case where the exit temperature peaks out at 847°K (1065°F). In the simulation, there was no limit to the

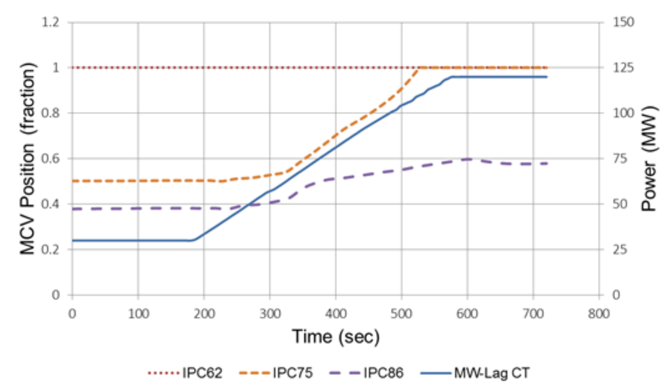

Figure 11. Main steam control valve (MCV) position with respect to load for the three cases

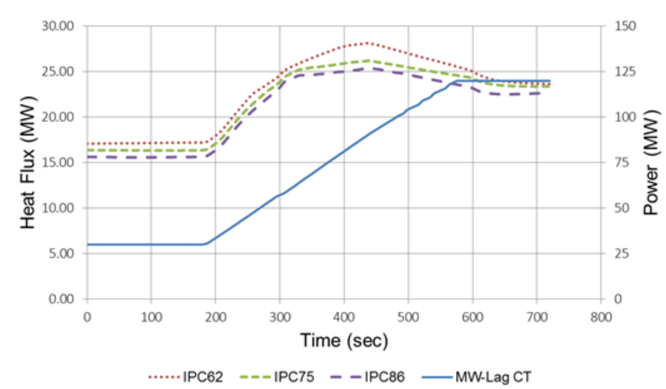

Figure 12. Heat Flux to the steam in the final HPSH

exit temperature; i.e. no runback of the CT, but this would certainly be a possibility in a real system (the runback temperature happens to be 847°K (1065°F) at plant Dell). Setting aside this case for the present, the other cases are interesting to compare. For all cases the temperature unfortunately reaches saturation (zero). However, for increasingly higher IPC settings there is less time at saturation, thus the situation is improved.

The heat flux comparison in Fig. 12 shows a lower heat flux with increasing pressure, which explains the results in Fig. 14 since this means less water injection is needed at the inlet to the HPSH to maintain the exit steam temperature. Less water means the approach to saturation will likely be greater (if not already saturated), given the same inlet temperature (which is almost the same for all cases) and flow rate.

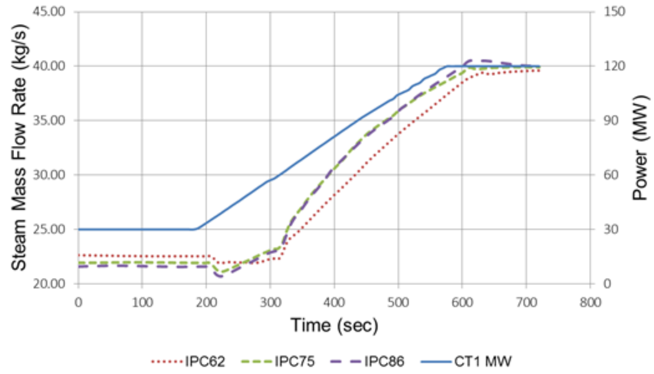

Figure 13. Steam mass flow rate through the final HPSH

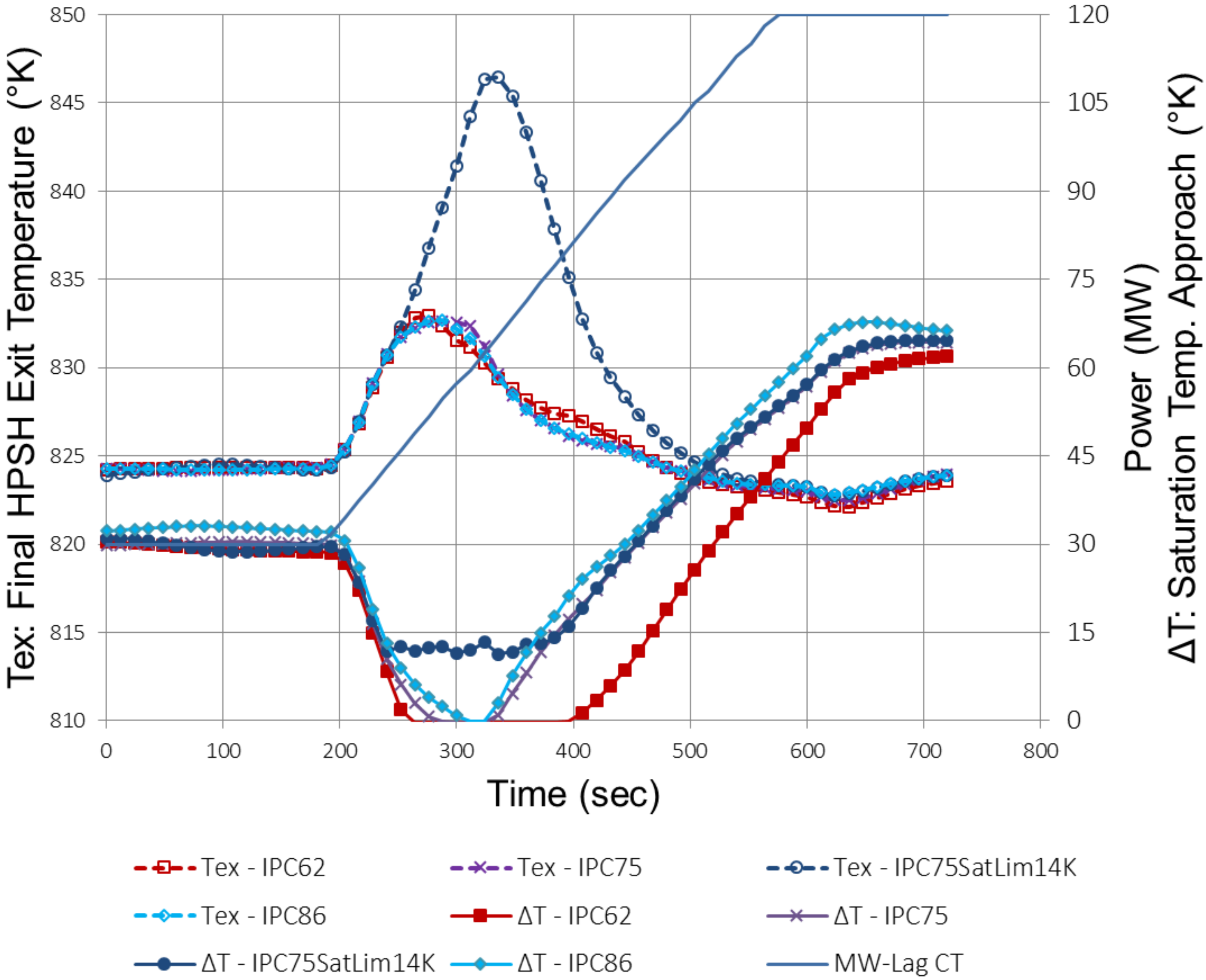

Figure 14. Approach to saturation at the inlet to the final HPSH (after the attemperator) and exit temperature of the final HPSH

There is some difference in the steam flow rate between the cases and, as would be expected, the initial steam flow rate is lower for increasingly higher IPC pressure settings, as seen in Fig. 13 from zero to 200 seconds. However, note that in the *transient* the relative steam mass flow rate is increasing at a faster rate for the IPC75 and IPC86 cases. This is because the MCV is opening during the transient and so there is a greater rate of flow increase compared to the IPC62 case where the IPC is already fully open. The idea is like a strategy currently employed at the plant for loading of the Lead CT where the steam turbine is loaded via the Load Command (i.e., opening the MCV) to increase steam flow in the final HPSH. Finally, even though the initial steam flow rate is lower for the higher IPC setting, it is countered by the higher saturation temperature. This is evidenced by the higher saturation approach.

The loading simulation results suggest that to lower the final HPSH outlet temperature (or increase the saturation approach) the IPC should be engaged with enough room for the MCV position such that it opens during the entire load transient, such as IPC86 (see Fig. 11). Furthermore, it appears that an increasingly higher pressure setting will improve the situation.

4. CONCLUSIONS

The following actions were suggested for trial at the plant:

4.1 Unloading

- Increase the HP attemperator TCV setpoint to the highest possible setting that will not exceed the final HPSH temperature limitation during the unloading on a hot day. For example, start with 830°K (1035°F) and if overshoot is still not problematic go to 833°K (1040°F), etc.
- Compare the temperature approach to saturation at the final HPSH inlet with the RH attemperator "On" (a setpoint low enough to be spraying water) and "Off". If the approach is smaller with the RH attemperator "On", then raise the setpoint so that it no longer desuperheats.
- Make sure the IPC does not engage *during* the unloading of either CT. Having it engaged *prior* to unloading might be allowable; although, doing so poses more risk with regards to saturation at the final HPSH inlet. But it is possible that by using a higher attemperator TCV setpoint - e.g. 836°K (1045°F) - a greater than 14°K saturation approach could be achieved. The advantage of this pre-engagement of the IPC during shut-down would be drum pressure preservation.

4.2 Loading

Recommendations here were a bit more difficult since too much overshoot of the final HPSH exit temperature would result in a CT runback. However, it was recommended to try the following:

- Load the Lag CT with the IPC In. Based on the data, it is suggested that the IPC pressure setpoint be set to 6.9 barg (100 psig) above the current process pressure, assuming the MCV is fully open at the time (i.e., the IPC is not controlling). If the MCV is not opening during the entire loading, then increase the IPC pressure setpoint, say by 10.3 barg (150 psig) instead of 6.9 barg (100 psig). Note that this is like the current plant practice of loading the ST (which opens the MCV valve) during the Lead CT loading.
- From the plant data, when the HP steam is blended, the Main steam is at a lower pressure, 62 barg (900 psig) than the bypassed steam 69 barg (1000 psig). It is better to have these pressures more equal, say with the bypassed steam 1.4 barg (20 psig) above the Main steam, or whatever the ΔP margin is used for the bypass valve closure. This will reduce the dip in steam flow as seen by F-HPSH in Fig. 10 between 6:19 and 6:22. Also, setting the bypass pressure closer to the Main steam pressure (900 psig) will allow the steam drum to warm up at a lower pressure, which may be advantageous when considering mechanical stress.
- The exit temperature profile of the plant data in Fig. 11 is like the results of the dynamic simulation; it also overshoots the setpoint of 824°K (1023°F), rising to 836°K (1045°F), before returning. It would seem beneficial to employ a strategy that increases the setpoint after the process temperature begins to come back down from 836°K (1045°F) (e.g., set to 833°K) so that the water flow to the attemperator backs off more rapidly. Of course, this setpoint change could be done manually by the operator. This setpoint change was tried manually during simulation runs and it had the expected benefit; however, it is probably more desirable to employ an automatic approach.
- A saturation limit on the HP attemperator TCV could be tried. The concern would be that the final HPSH exit temperature overshoots the limit that initiates a run-back.

It has been shown that an operator training simulator (OTS) has value beyond its traditional training and controls checkout function. In the case study presented here, an OTS was used effectively as a tool to examine, and suggest solutions to, final superheater operational issues at a power plant. An OTS could similarly be used for other scenarios of interest. For instance, drum pressure preservation during shutdown would be a good candidate. Condensation in superheater tubes is another possibility (from the author's brief investigation, at least in a comparative way - one scenario vs. another).

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