TUF ASSESSMENT OF AN ABNORMAL LOAD REJECTION EVENT AT DARLINGTON NGS

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ABSTRACT

The main purposes of reactor system code development are to support plant operation and to assist in safety analysis. To illustrate the operational support activities of the TUF code, the assessment of a simple case of abnormal load rejection event at Darlington NGS is described. The main assessment of this event examines the flow conditions at the steam generators and the possible impact on the turbine. This assessment demonstrates the TUF capability in the operational support analysis for CANDU reactors.

1. INTRODUCTION

Every operating reactor plant has encountered many abnormal operating events that require station engineers to find out the root causes and to analyze the possible impact on plant components. Those events may not become a safety issue in plant operation. Nevertheless, supporting analysis of the abnormal events is an integral part in plant operation. To achieve that, in addition to the simulation of normal operating procedures, the reactor system codes should have the capability to allow users to specify different operational conditions including the malfunction of components and controllers, and operator actions. An accurate simulation of automatic controller actions and operator interventions is a must in any plant operational support analysis.

In operational support analysis, the reactor system codes are often used to provide detailed information not available in the plant data logs. This detailed information is required to support further investigation and to assess the possible impact on plant components. For example, turbine load rejection is one of the normal events in plant operation. However, on September 25, 1995, an event occurred in Darlington Unit 2 which resulted in a spurious signal being introduced to the load rejection module of Turbotrol (TT4). This spurious signal, which lasted for about 2.2 seconds, resulted in the TT4 load rejection module being activated. As expected, the reactor was stepped back, and the Atmospheric Steam Discharge Valves (ASDVs) and Condenser Steam Dump Valves (CSDVs) were opened. However, the turbine was not run down as expected. At about 24 seconds following the event, a second load rejection occurred and this time it was a true load rejection. The load rejection module responded correctly to the second signal. The Turbotrol attempted to maintain turbine load at 100 % FP, but could not as steam pressure fell rapidly, and the steam generator pressure control (SGPC) unloaded the turbine using the -5 %/s channel. To assess the possible impact that this event may have on the steam generators and the turbine, detailed information is required about the steam flow rate and the steam separation conditions in the steam generators before the actual load rejection. Unfortunately, either very limited or no relevant data were available from the digital control computer (DCC). The station engineer requested the use of TUF to provide this information.

Light water enters the steam generator as feedwater near the bottom of the outlet end of the tube bundles. After reaching saturation temperature in the preheater, feedwater enters the tube bundle area and is further heated producing steam. As the steam and water mixture leaves the top of the tube bundle area it passes through cyclone separators above the tube bundle. The wet steam which leaves the top of the primary cyclone separators is reduced in moisture content but is still not acceptable for the turbine. This wet steam is passed then through steam scrubbers where the moisture is further removed. Any droplets entrained in the steam entering the turbine would rapidly erode the turbine blade. In any abnormal operating event when the off-take steam flow is much larger (about 50 % or more) than the nominal steam flow at 100 %FP, or the swelling water level is above the scrubbers (or secondary cyclones), the effectiveness of the steam separation in the steam generator is a concern in plant operation. In the abnormal load reduction event at Darlington, the possible steam flow out of the steam generator was about 170 % of the nominal full power value (only 5 out of 6 CSDVs were available at the time of the event).

In this paper, the relevant physical models in TUF associated with this abnormal load rejection event are presented and the assessment of this event is described.

2. RELEVANT PHYSICAL MODELS IN TUF MODULES

The general description of the TUF code models can be found in Reference 1. The relevant physical models in TUF associated with this event are discussed below. The following normal controller actions are taken in a load rejection event: (1) the turbine is unloaded using the -5%/s channel, (2) a process interrupt to open the steam control valves occurs, (3) a reactor stepback is initiated after two sampling intervals (0.5 second), and (4) the reactor power control resets to alternate mode. In this event, the turbine rundown was not initiated.

Process Interrupt and Reactor Stepback

When a turbine trip or unload signal occurs, the normal computation of the reactor power setpoint by SGPC is suspended. A process interrupt is generated and SGPC enters the poison prevent mode. When turbine power is above 60 %FP, both the ASDVs and CSDVs (the CSDVs are subject to condenser vacuum limitations) are opened fully for two sampling intervals (i.e. 4 seconds), after which the ASDVs and CSDVs return to normal control by SGPC. When turbine power is between 30 %FP and 60 %FP, the ASDVs and CSDVs are opened to the valve positions calculated by the SGPC program; after the two sampling intervals, the valves return to normal control by SGPC. When turbine power is below 30 %FP, then the interrupt is ignored and the ASDVs and CSDVs are allowed to open under normal operation of the SGPC program.

The stepback routine monitors the plant parameters and takes fast action to reduced the reactor power by dropping the mechanical control absorber (MCA) rods if a parameter is out of limits, or a reactor or turbine trip occurs. There are four variable speed MCA rods in the form of stainless steel sandwich tubes inserted into zircaloy guide tubes penetrating the core vertically. The rods are driven by electric motors through gear trains engaged by electromagnetic friction clutches and are driven in pairs. The MCA rods are mainly used to initiate a rapid power reduction and to provide reactivity override for negative fuel temperature effects. The reactivity rate when all MCA rods are falling under gravity is approximately -2 mk per second. The total reactivity for the MCA rods is -9.5 mk. While the rods are dropping, the program scans the reactor flux power and stops the rods when the power reaches the suitable pre-selected level, or the stepback condition clears. The pre-selected power level for a turbine trip is 60 %FP. However, in actual plant operations, the reactor flux power may not be exactly equal to 60 %FP when the rods are stopped. For example, it was 53 %FP in the case simulated here. This discrepancy may result from the following facts: (1) Signals from the two central pairs of flux detectors are used to determine whether the reactor power reaches the suitable low level or not in the station controller. In the code, the average neutron power calculated from the point kinetic model is used instead. (2) In the code, the flux tilt resulted from the dropping of MCA rods is neglected in the stepback program. In the station operation, the stepback can be initiated when four or more zone powers (total 14 zones) are greater than the preset tilt value (high zone flux signal).

ASDV and CSDV Controls

There are four ASDVs used for SGPC with a combined capacity of 10%FP steam flow. One valve is located on each of the four steam lines to the common steam header. All four valves operate simultaneously when controlled by

SGPC. One analog output signal is provided to each ASDV for control. The ASDV position is calculated from two terms: feedforward and feedback terms. The feedforward term is essentially the mismatch term between the reactor power and plant load. The feedback term is proportional to the error between the steam generator pressure and the steam generator pressure setpoint. In order to prevent undue oscillatory response of the ASDVs, compensation is provided by using a delay digital filter applied to the feedback term.

There are three pairs of CSDVs with a combined capacity of 70 %FP. They are used to bypass the turbine and discharge live steam to the condenser so that the reactor can continue to operate at the power level required to prevent a poison-out as a result of the unavailability of the turbine as a heat sink. Each pair of CSDVs has one analog output signal for all operating conditions. Similar to the ASDVs, the CSDV controller output is made up of two terms: a feedforward and a feedback term. The feedforward term is essentially a mismatch term between reactor power and plant load. This term allows the valves to respond quickly to any severe transients, such as turbine trip. The feedback term is proportional to the error between steam generator pressure and the setpoint. The SGPC calculates a permissible CSDV opening limit based on the turbine power level. The CSDV opening is limited so that the total steam flow to the condenser does not exceed 70 %FP.

Control Valve Characteristics

For steam control valves, there are three types of steam valve models available in the code: valves with valve sizing coefficients suggested by Fisher control valve designers, valves with test valve characteristics and butterfly valves. For the ASDVs and CSDVs, the tested data for the valve characteristic suggested by the manufacturer and the linear valve characteristics are used in the simulation. Based on the tested flow conditions (pressure and density), the valve discharge flow rate at different flow conditions are then calculated. For a given valve opening, the steam flow rate W under a pressure p and steam density ρ_g is given by

$$W = W_0 \sqrt{\frac{p\ \rho_g}{p_o\ \rho_{go}}} \qquad [1]$$

where the subscript o denotes the tested conditions. This equation is similar in form to the isentropic steam discharge model,

$$W = C_0 \sqrt{p\ \rho_g} \qquad [2]$$

where C_o is a function of the isentropic index, valve discharge coefficient, and the valve opening area.

Level Swelling Model in Steam Generator

Liquid entrainment at the top steam take-off line of the steam drum may be caused by any one of the following mechanisms: water spouting, interfacial shearing, and bubble bursting. The physical parameters that determine the liquid carry-over capability in the steam drum are steam outlet flow rate, swelling level, vapour generation rate and depressurization rate. This capability strongly depends on the steam generator size and the design of the cyclone separators. No correlations for the steam separation criterion are available in the literature for large scale steam generators such as those used in Darlington NGS (Figure 1).

In the previous safety analysis for Darlington NGS, the steam separation capability at the steam drum is externally estimated from the STGEN code which is then fed back to the SOPHT code simulation. Due to using different sets of wall frictional and heat transfer correlations in STGEN and SOPHT, the coupling between these two codes requires an iteration procedure and a sensitivity study. Similar to the STGEN code, a level swell model has been implemented in the TUF code to determine the steam separation capability in the steam drums. This model has been verified (Reference 2) against the top blowdown experiments for pressurizers. The level swelling model for steam generators implemented in the TUF code is briefly described here.

The extended steam drum (i.e. steam drum including downcomer) is separated into two regions: the top steam region and the bottom liquid (or two-phase) region. The total vapour and total liquid masses inside the extended steam drum are given by

$$\frac{dM_g}{dt} = W_{g,in} - W_{g,out} + F \qquad [3]$$

$$\frac{dM_f}{dt} = W_{f,in} - W_{f,out} - F \qquad [4]$$

where t is time, M_g and M_f are the mass of vapour and liquid, respectively, $W_{g,in}$ is the steam flow from the riser, $W_{g,out}$ is the main steam outlet flow of the steam generator, $W_{f,in}$ is the liquid flow from the riser, $W_{f,out}$ is the downcomer flow rate, and F is the vapour generation rate. The void fraction α'_g in the liquid region is calculated from

$$\frac{dM'_g}{dt} = - W_{gl} + F \qquad [5]$$

where W_{gl} is the vapour escape flow rate at the interface. The void fraction in the liquid region is calculated by

$$M'_g = V \alpha'_g \rho_g \qquad [6]$$

where V is the volume, ρ_g is the vapour density and α'_g is the void fraction in the liquid region.

From the relationship between water level and volume and the void fraction in the liquid region, the swelling level L can be calculated from

$$L = f(\alpha'_f) \qquad [7]$$

where $\alpha'_f = \alpha_f + \alpha'_g$, $\alpha_f = 1 - \alpha_g$, and α_g is the total void fraction calculated from M_g.

The steam separation is in a failure mode when the swelling water level is higher than the critical height:

$$L > H_c \qquad [8]$$

where the critical height H_c is given by

$$H_c = H - H_d \qquad [9]$$

H is the total height of steam drum and H_d is the critical distance from the interface to the top of the steam drum; H_d is calculated from a correlation. This correlation, based on gravity and inertia forces, for the onset of liquid entrainment due to water spouting involves a Froude number which is evaluated at the entrance to the exit pipe.

3. TUF ASSESSMENT OF THE EVENT

The main assessment of the Darlington event is in the following items: (1) the operating conditions of the CSDVs and the governor valve, (2) the depressurization rate of steam generators, (3) the maximum water level in the steam generators, (4) the maximum steam flow leaving each steam generator, and (5) the separation capability of the steam generators. Items (2) and (3) are not the main concerns when simulating this event since this information is available in the DCC data logs. Item (4) is important in the assessment of the loading on the steam generators. The last item is the main concern; the separation capability of the steam generators determines the impact assessment on the turbine blade.

To address the first item, several cases with different operating conditions for the CSDVs and the governor valve were simulated. Different combinations of CSDV capacity and governor valve position were considered. Based on the comparisons between the simulation results and the available plant data, it has been concluded that 5 CSDVs at design capacity and the governor valve frozen at nominal full power position were probably the actual operating conditions of this event. Except that the turbine was not run down as expected, other operating conditions should have followed the design operating procedure. Therefore, these operating conditions are assessed to be the base case in the simulation.

The input data for the plant circuit is identical to that used in the simulation of the Class IV power failure (Reference 3). At the time of the event, the following assumptions were made for the base case: (1) The reactor was initially operated at 100 %FP, (2) The turbine did not rundown for the time simulated, (3) Following the initiation of process interrupt, 5 CSDVs were available (there are 6 CSDVs but only 5 were available in Unit 2 at the time of the event), (4) The stroke opening times for ASDVs and CSDVs are 2 seconds; the stroke closing times for ASDVs and CSDVs are 1 and 13 seconds, respectively, (5) The plant power and the feedwater flow transients from Unit 2 were used in the simulation. The third assumption is based on a sensitivity study to examine the actual plant operating conditions of the event. The fourth assumption is based on the valve characteristics suggested in plant operations. The last assumption is not necessary but was made in order to have the transient conditions as close to the plant data as possible. The simulation was performed up to the time (24 seconds) before the true load rejection occurred.

Comparison with Plant Data

When the reactor power dropped rapidly from 100 %FP to 53 %FP in 5 seconds due to the reactor stepback, the PHT system pressure dropped. Comparison of the TUF prediction to the measured station data for NE ROH (HD3) pressure is shown in Figure 2. It is noted that the station data were saved at 6 seconds intervals. During the first 5 seconds following the event, TUF over predicted the PHT system pressure. The drop of ROH pressure in the plant data at 5 seconds indicates that the actual timing of the ROH pressure dip is much faster than that predicted by the code.

Figure 3 shows the comparison of the TUF predicted pressurizer level transient to the plant data. In the first 10 seconds into the transient, TUF slightly over predicted the level. This is consistent with the ROH pressure prediction since during that period TUF over predicts the ROH pressure thus allowing less coolant outflow from the pressurizer to the PHT system, hence higher predicted pressurizer level. The overall pressurizer level transient is predicted well by the code.

Figure 4 compares the TUF predicted SG (SG2) pressure transient with Unit 2 data. It is noted that the station data for all steam generators were obtained from DCC storage period 2 (sampled every 6 seconds). TUF predicted results matches the station data well. This is an indication that the TUF prediction of the amount of steam leaving the steam generators is probably very close to that which occurred during the event.

The steam generator level control (SGLC) program regulates the feedwater control valve positions to maintain the water levels at their level setpoint (Reference 1). Figure 5 compares the TUF predicted SG (SG1) level transient with Unit 2 data. It is noted that the data were obtained from the narrow range level transmitter with the level tap about 10 m above that of the wide range (i.e. 10 m more than the actual water level). The only available station data was from DCC storage period 2. During the SG depressurization, due to CSDVs and ASDVs opening, the water level increased slightly. Based on the available station data, the level changed from the initial value of 14.4 m to about 14.7 m in about 5 seconds. TUF predicted less level increase than the plant data. At 5 seconds following the event, TUF level prediction is about 0.2 m below the plant data.

Based on the comparisons of the system parameters available from the DCC and the TUF predictions, it can be concluded that the plant operating conditions during this event are close to that described in the base case for TUF.

Assessment on SG Flow Conditions

The predicted steam flow through the governor valve is shown in Figure 6. The predicted flow rates through the CSDVs and a single ASDV are plotted in Figures 7 and 8, respectively. The total steam flow through the SG nozzle (for SG1) is displayed in Figure 9. The flow rate reaches its peak when the CSDVs become fully open at about two seconds. The peak flow rate is about 550 kg/s (nominal steam flow rate is 320 kg/s).

The swelling water level for SG2 is compared with the collapsed water level in Figure 10. The maximum swelling level is 16 m which occurs at 8 seconds. It shows that the swelling level is still below the elevation of the cyclones (level about 17 m), where the level at the main steam outlet nozzles is 18.1 m. The code predicts steam discharge only. The effectiveness of steam separation in the steam drums is still maintained. Therefore, it can be concluded that there is no impact on the turbine blade in this event.

Discussions

The following observations of this event are described:

(1). The end-point reactor power for a reactor stepback in the station operation is usually lower than the pre-selected power level. For example in this event, it was 53 %FP from the station data instead of the preset power level of 60 %FP. Similar results have been observed in other CANDU reactors. Therefore, in the input data, the end-point reactor power for the reactor stepback program due to a turbine trip should be set to 53 %FP for Darlington NGS.

(2). The plant data for the ROH pressure transients imply that there is a pressure dip at a transient time around 5 seconds resulting from the reactor stepback, much early than the code predicted. Also, the dip magnitude may be larger than that predicted by the code.

(3). The steam separation capability in Darlington steam generators will remain effective even when all six CSDVs are functional (note that only five CSDVs were functional) in this event.

4. CONCLUDING REMARKS

The physical parameters that are relevant to the September 25, 1995 event at Darlington Unit 2 of abnormal load rejection have been discussed. From the results presented here, it can be concluded that there is no impact on the turbine during this event. Also the TUF predictions are in good agreement with the plant data for this event. With the exception that the turbine that does not run down as expected, all other operating conditions follow the operating procedure. This simulation continues to enlarge the TUF code qualification base in the operational support analysis for CANDU reactors.

REFERENCE

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2. W.S. Liu, Level swelling in pressurizer and steam generators, Third International Conference on Simulation Methods in Nuclear Engineering, Montreal, Quebec, April 18-20, 1990.
3. W.K. Liauw, W.S. Liu, R.K. Leung and B.S. Phillips, TUF simulation of Darlington Class IV power failure, 16th Annual Conference of Canadian Nuclear Society, Saskatoon, Saskatchewan, June 4-7, 1995.

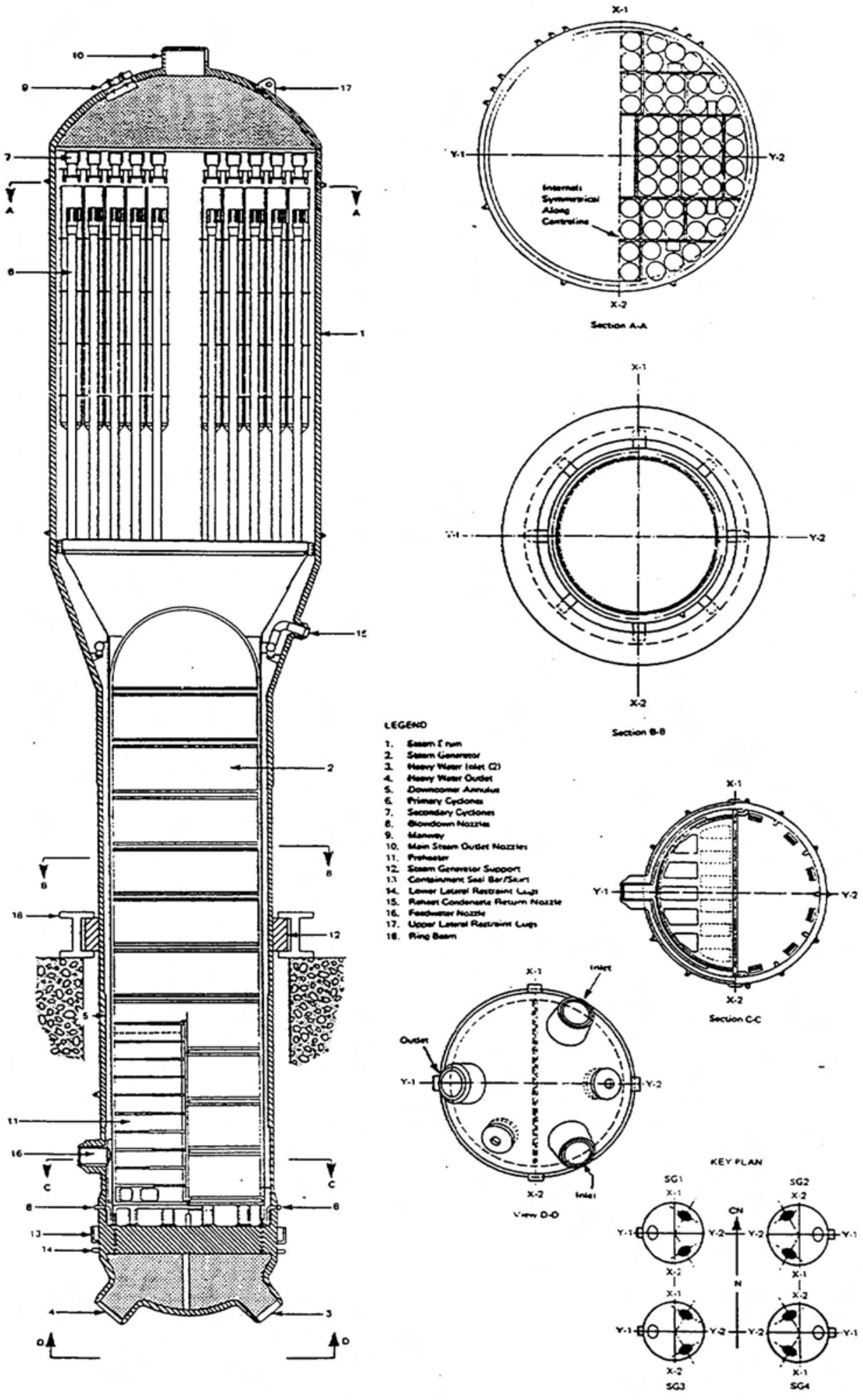

Figure 1. Steam generator of Darlington NGS

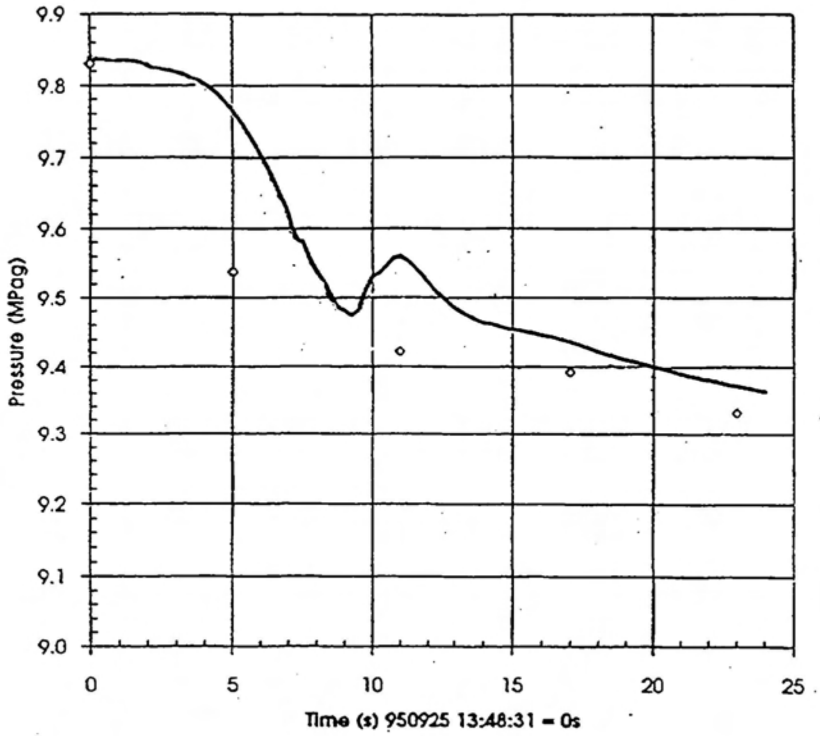

Figure 2. Comparison of ROH pressure (HD3 at NE) with plant data

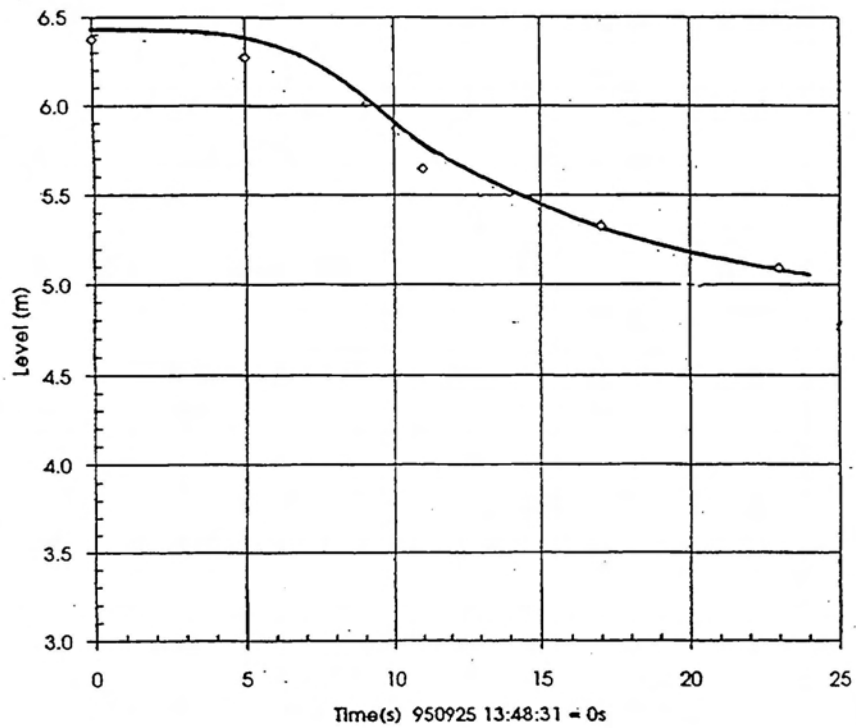

Figure 3. Comparison of water level in pressurizer with plant data

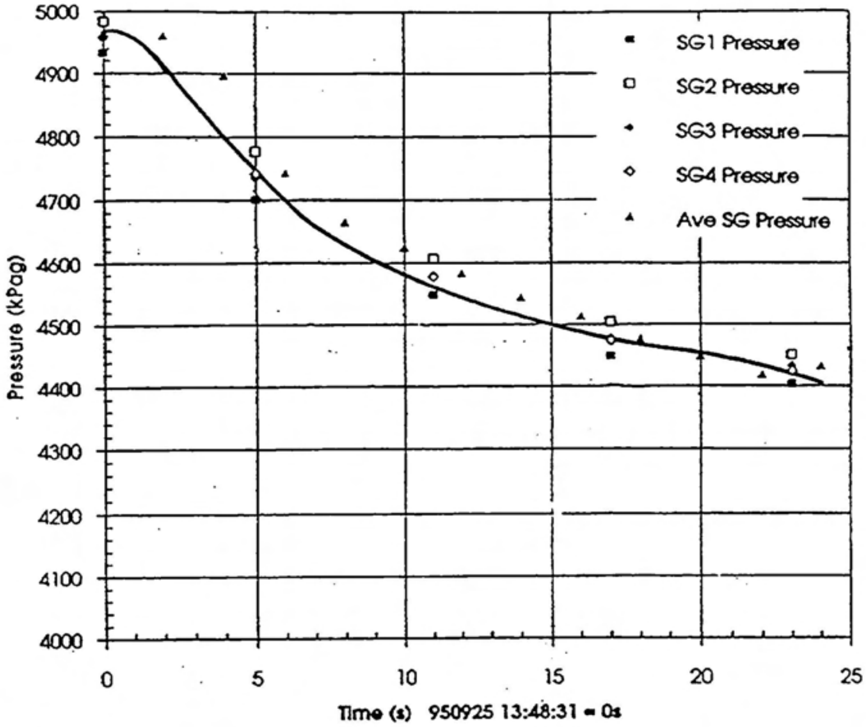

Figure 4. Comparison of steam drum pressure at SG2 (at NE) with plant data

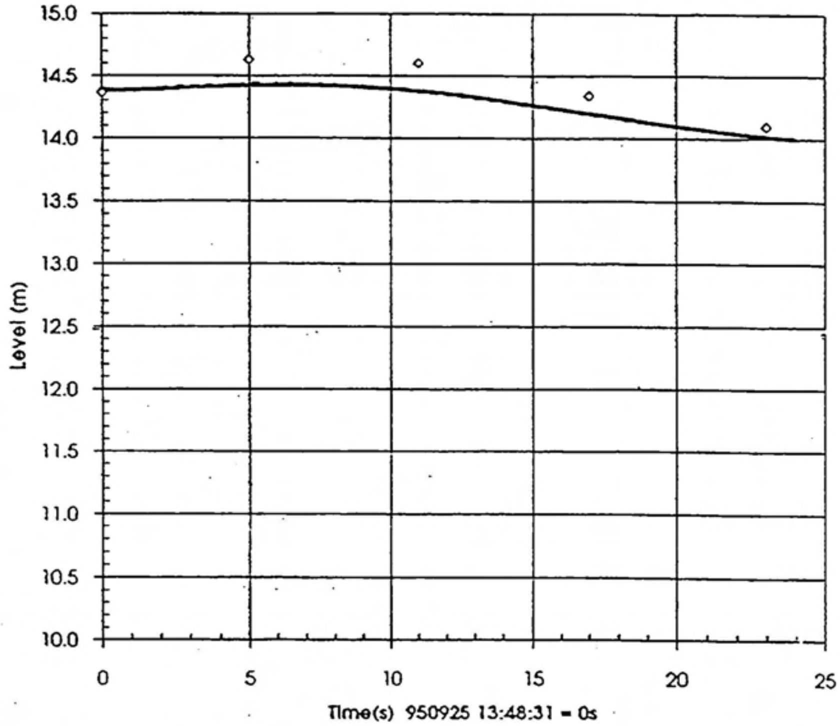

Figure 5. Comparison of steam generator water level with plant data at SG1

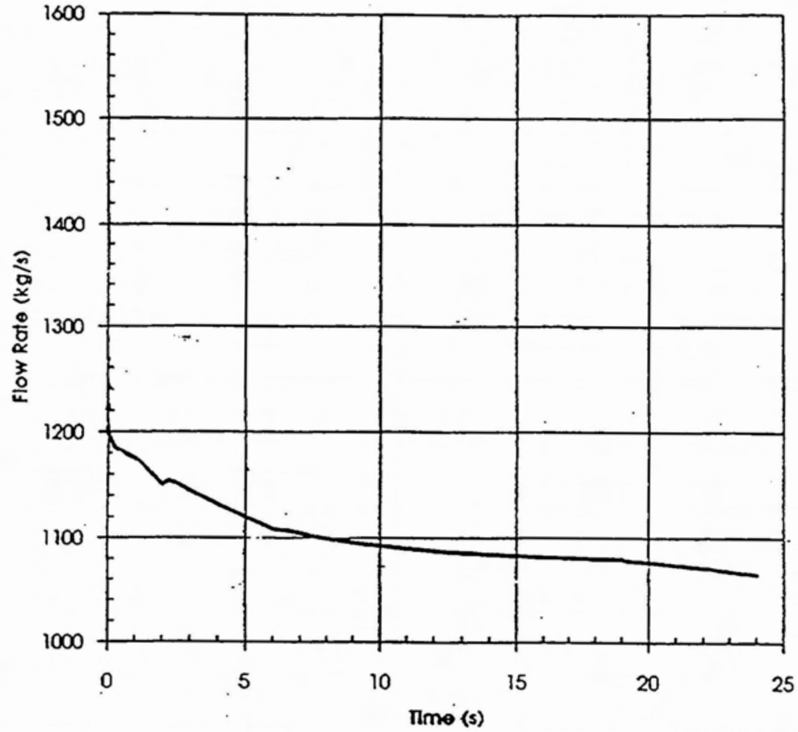

Figure 6. Total predicted steam flow rate through the governor valve

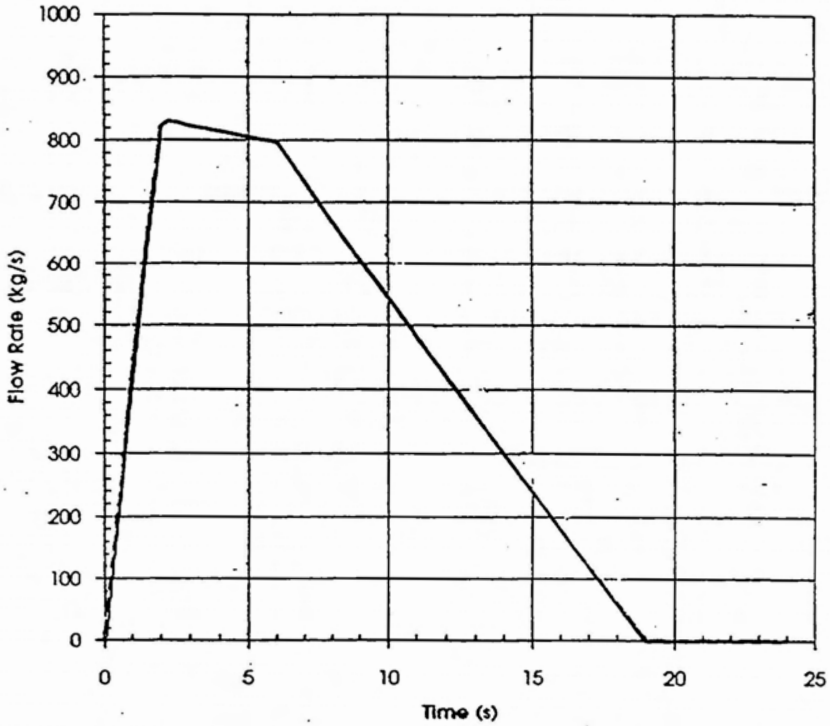

Figure 7. Total predicted steam flow rate through five CSDVs

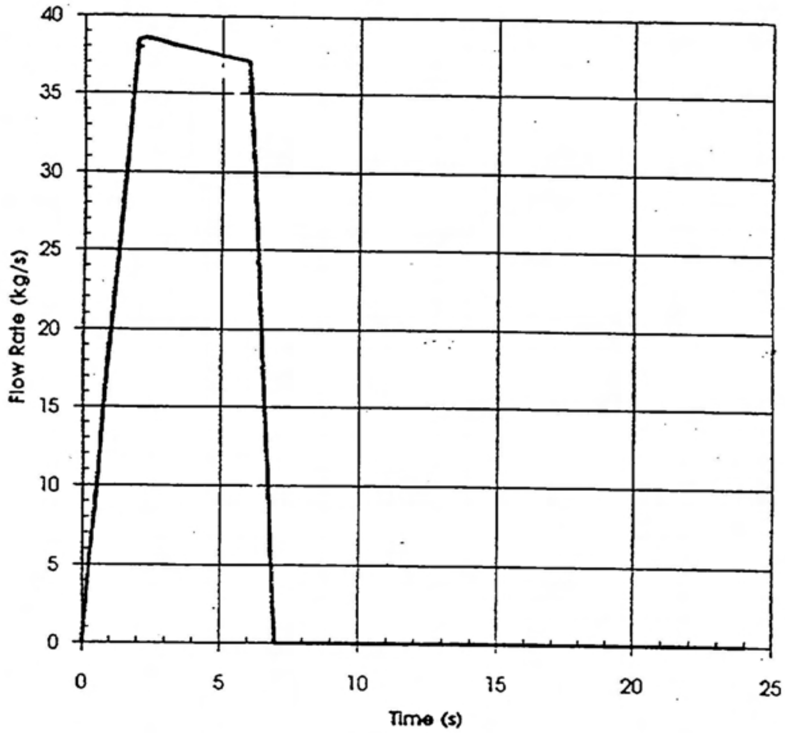

Figure 8. Predicted steam flow rate through one ASDV

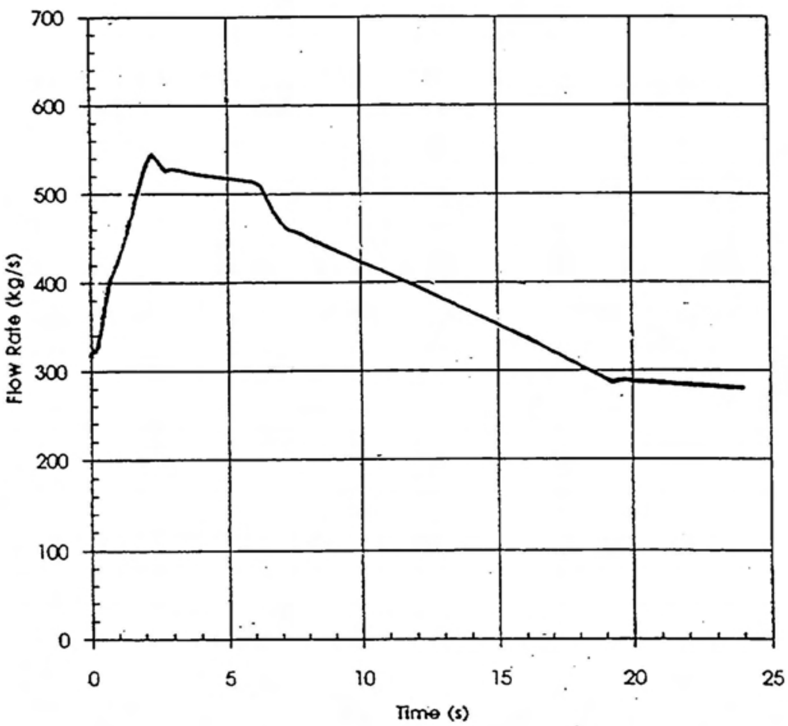

Figure 9. Predicted steam flow rate through the SG nozzle at SG1

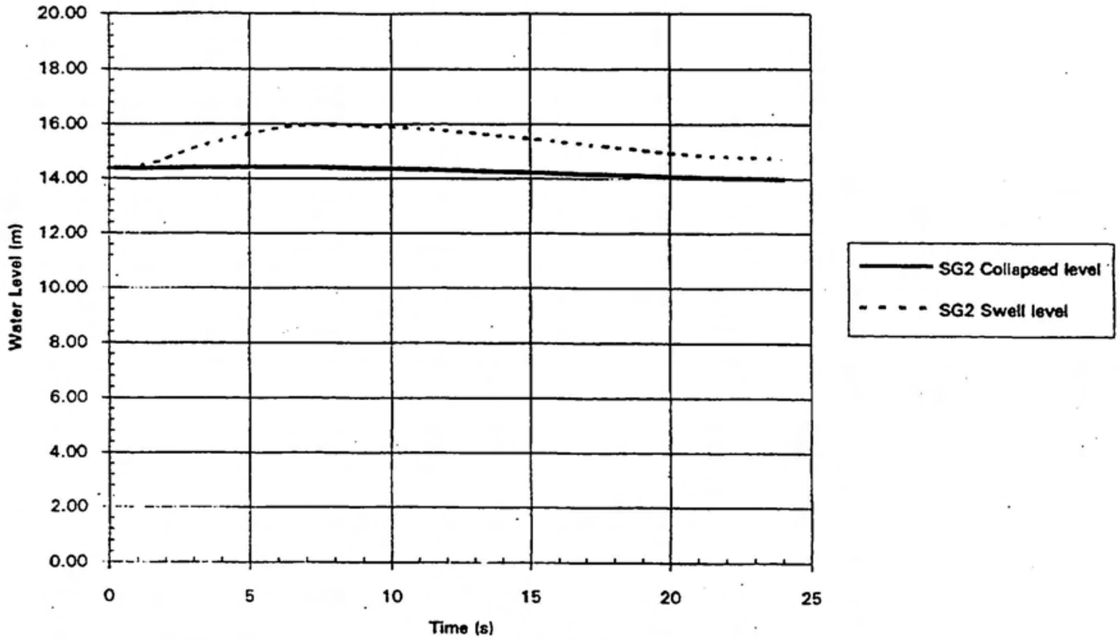

Figure 10. The predicted collapsed and swelling levels at SG2