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Level One HRSG Assessment
Consolidated Edison's East River Units 10 and 20

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Executive Summary

Structural Integrity conducted an assessment of the East River Units 10 and 20 Heat Recovery Steam Generators (HRSG) on the 3rd August 2010. Particular attention was given to the cycle chemistry control, flow-accelerated corrosion (FAC) and thermal transients. These units had experienced some severe FAC in the economizer circuits over the last few years, and the primary purposes of the current assessment were to determine if this FAC is now under control and whether there are any other possible areas of damage that should be investigated. The East River HRSGs benchmarked on a World Standard as "Average" which is considered appropriate at the time of a first full assessment. On the FAC side, it appears that the modifications adopted have removed the immediate serious concern in the economizer circuits but the assessment could not determine if the FAC mechanism has stopped, and also identified a number of other possible locations to inspect. On the cycle chemistry side, six cycle chemistry repeat situations were identified which when combined could lead to future corrosion and chemistry control problems. Three of the most important actions needed are to upgrade the cycle chemistry instrumentation to the World standard, to develop a set of limits, alarms and procedures for the operators, and to conduct a series of tests to simplify the overall chemical control on the units. On the thermal transient side the assessment identified a number of features relating to superheater drain effectiveness, attemperator drain design, steam temperature and drum pressure control, and economizer inlet quenching. Overall SI has outlined a series of action plans within the report which if addressed will confirm the possible damage mechanisms and put the East River HRSGs on the path to World Class performance.

1.0 Background

East River Units 10 and 20 are combined cycle/HRSGs designed to provide 1,600,000 lbs steam/hour at 535psia and 500°F into the New York City steam system. There is no condensate returned to the plant. The major equipment of each unit consists of:

a) A Vogt-Nem single-pressure HRSG with one drum designated on the heat balance diagram as “IP” (intermediate pressure). Downstream of the demin water pump is a vacuum deaerator which feeds the boiler feedpump. The shell of the DA is carbon steel. All the piping upstream of the DA is stainless. The piping downstream of the DA is also stainless up to the chemical injection location before the economizer inlet. The economizer is in two sections (EC 2 and EC 1) with headers which have divider plates to create a serpentine flow path. The headers and interconnections between the two economizer sections were manufactured in 106GrB as is the piping from the EC 1 outlet header to the steam drum. The economizers were manufactured with 178A electric resistance welded tubing and are finned. In the original design the tubes protruded up to 2in past the ID of the headers. The economizer inlet temperature is ~140°F and the outlet varies from ~ 470°F under the unfired base condition to ~ 390°F under 50% GT loading condition. There are five evaporator circuits with EV1 consisting of two harps being before the duct burner and the other four downstream. All the upper and lower headers are manufactured in 106GrB and the tubes 178A. The tubes in evaporators 1, 3, 4 and 5 are finned, whereas those in evaporator 2 are unfinned. The upper header outlet nozzles and riser pipes to the steam drum are manufactured in P22. There is a single pass SH manufactured with unfinned 178A tubing and with 106GrB headers and inlet and outlet nozzles. The steam conditions at 100% unfired conditions are: 533°F / 550psi and at 100% fired are 519°F / 595psi. There is terminal attemperation to bring the supply into the 500°F steam temperature requirement for the New York steam system. The attemperation supply is downstream of the boiler feed pump before the chemical injection.

b) GE 7FA Gas Turbine (GT). Each unit has a duct burner, SCR and CO catalyst.

c) Commercial operation date was April 2005. Operating fired hours and starts to August 2010 were: Unit #10: 89 starts; 38,200 hours, Unit #20: 78 starts; 38,078 hours.

d) The unit is base loaded during the day, and operates about 30% of the time with duct burners (fired) and about 30% of the time at minimum load (mainly overnight).

A few major observations from previous inspections and on prior damage/failure include:

e) There have been a number of HRSG tube failure (HTF) situations:
    i) 2007 in the economizer section of HRSG #10 at about mid-height. The leak was the 6th tube row from the gas inlet side of Economizer #2. No tube samples were taken. The HTF mechanism was assumed to be related to the tube seam weld.
    ii) SH failures located at alignment bars and wrapper. A stress analysis indicated that there was some differential expansion between the tubing and the wrapper.
    iii) In 2008 the plant changed the SH drain size pipe from 1 to 2 inch and eliminated elevated piping runs. The original 1 inch valves were reused.
    iv) In 2009 (at ~30,000 hours of operation) economizer failures in both units occurred due to flow-accelerated corrosion (FAC). The failures were located near to the cross-over piping in tubes just below the tube/upper header weld. FAC was evident in each of the economizer modules with the most serious damage being located at the inlet section of H12 and H13. Damage was also observed adjacent to the downstream side of the divider plates and in the cross-over pipes. Extensive investigations were undertaken which involved NDE/inspection, cycle chemistry review and initial optimization, and physical and computerized flow modeling. The last showed that extensive recirculation and severe turbulence was created by the tube protrusions into the headers. Both single- and two-phase conditions were originally thought to have been responsible but no evidence was found of any single-phase damage. Various solutions were designed and installed: flow straightening diffusers, replacement headers with fully welded divider plates, T11 tubes which were flush with the header ID, and P11 cross-over piping. The cycle chemistry control was also changed and is discussed in Section 3 below. No further FAC failures have occurred since the modifications.

f) On the visit day (3rd August 2010) the plant provided the following general inspection reports of the HRSGs by three companies: i) Alstom conducted inspections of Unit 10 in September 2008 and March 2010, and of Unit 20 in March 2008 and March 2010, ii) Vogt conducted an inspection in October 2009, and iii) Tetra made an inspection of both units in May 2008. Review of these inspection reports showed that the IP drums were in good condition but colored either grey or light red. In no inspections were the drums "ruggedly red". There were a number of observations about bowing in the SH. Alstom also made an inspection of the FAC failure situation in April 2009 and observed patches of deposits in EC2 and EC1 with up to 70 g/ft^2 of deposits. Consolidated Edison also provided a few additional reports following the visit. Tetra had conducted an inspection of both units in April 2007 (~16,000 operating hours) and indicated that measurements on economizer 1 and 2 at that time did not reveal any FAC concerns. The steam drums at that time were reported as uniformly grey with no visible deposits, but the photographs show some areas of red coloration. A number of photographs were included in a few of these reports of the internal surfaces of the deaerators which had the appearance of low temperature two-phase FAC: black areas which are deposited magnetite and random areas of white which look like bare metal. In 2008 the lower northwest corner SH header bumper was found bent in Unit 10. Also in 2008 some SH tube leaks due to inappropriate wrapper welds were identified and repaired in Unit 20.

g) A number of evaporator tubes from EV2 were removed from near the bottom of the circuit in 2009 and metallurgically analyzed by Structural Integrity for deposit loading. The deposits were dark brown and the deposit levels were ~7 g/ft^2. Observations of pitting on the tube surfaces were also made.

2.0 Benchmarking

The Consolidated Edison East River combined cycle/HRSG plant (Units 10 and 20) was benchmarked according to worldclass standards and scored 30, which is in the "Average" category. The HRSG Benchmarking Process is provided in Appendix A. In SI's experience this a good rating for a first assessment with lots of areas identified in this report for improvements which will put the East River units on the path to World Class performance. The following are the major areas which were identified as contributing to this ranking:

- HRSG tube failures (HTF) have occurred (Section 1e). However, the plant illustrated a good management approach for mechanism and root cause identification involving multi-disciplinary activities to address the problems.
- Each unit only has 8 out of 12 of the IAPWS Minimum Key Level of Cycle Chemistry Instruments and these are not alarmed for the operators. (see discussion of missing instruments and alarm situation in Section 3f).
- Total iron has been measured on both units about once/month in 2010. Samples are sent to GE Water for analysis (see discussion in Section 3d)
- Proactive temperature monitoring has been conducted on the economizer circuits in association with the FAC damage
- No written action plans are in place to address root causes or damage of potential HRSG tube failures (HTF). Areas needing this type of approach are delineated throughout the report (exs: thermal transients, deposits, FAC).

3.0 Chemical Control of the Plant

The cycle chemistry control aspects on the two units have changed a number of times since COD in an attempt to control the FAC in the economizer circuits and to minimize the levels of total iron in the cycle. The following represents a summary of information received on the visit day.

a) The makeup plant (City water, multi-media filters, cartridge filters, RO, EDI) provides water to the demineralized water storage silos which feed both Units. These storage tanks are vented to atmosphere. The water treatment plant effluent is monitored for specific conductivity, silica, and sodium. The ConEd Chemistry Staff reported that the calculated pH is between 5.5 and 6.0. There is no monitoring of the water between the storage tanks and the vacuum deaerator (DA) despite there being a sampling location (SP8). The transport piping is stainless steel.

b) The Feedwater. The DA feeds the economizer inlet (EI) via the boiler feedpump. The plant was designed to have chemical dosing between the DA and the EI. The piping from the injection location to the EI is carbon steel. Initially from COD the only chemical injection on each unit at this EI location was a proprietary phosphate (DrewPhos 2600) containing a polymer. This was changed on Unit 10 in early 2007 to another proprietary phosphate (DrewPhos PT) containing a polymer and with a $Na:PO_4$ molar ratio of 3:1. The same change was made on Unit 20 in the Fall of 2007. Review of historical data for both units during this time period revealed that the pH at the Economizer Inlet and Outlet on Unit 10 was typically in the range 8.1 to 8.9 up to about March 2009 then was increased. On Unit 20, up to the end of 2008 the pH range at the two locations was 8.5 to 9.1, whereas after January 2009 it increased into the range 9.1 to 9.4. Following the FAC damage/failures and at the same time that a dual chemical feed system (EI and drum) was introduced the chemical injection at the EI was changed to NaOH (as a 50% solution) injected continuously. This occurred on Unit 10 in October 2009 and on Unit 20 in April 2010. Review of historical data for both units from the introduction of the dual feed showed that the pH has been between 9.4 and 9.5 (around 1ppm NaOH) and oxygen at the EI has been between 10-50ppb. On the visit day the oxygen was ~20ppb and the pH was ~9.5 on both units. No data was reviewed of the typical oxygen levels at the EI prior to the introduction of the dual feed system.

c) Drum/Evaporator. At the time of the introduction of the dual feed system and the change of the feedwater injection to NaOH, it was decided to add two proprietary phosphate blends to the drum. The drum blowdown was also increased at this time to 3.3% from about 1% because of concerns about concentrating NaOH in the evaporator, but according to the plant chemistry staff the actual levels of NaOH were in the drum were not tested. The two phosphates are GE Optisperse HTP 78519 and HTP 78513. The former and most frequently used is referred to as a “Downblend” and is thought to contain sodium hexametaphosphate, phosphonic acid and methyl-ethanyl homopolymer, and has a $Na:PO_4$ molar ratio of about 1:1; the latter is referred to as an “Upblend” and is thought to contain sodium hexametaphosphate, phosphonic acid, sodium molybdate, sodium hydroxide, and methyl-ethanyl homopolymer, and has a $Na:PO_4$ molar ratio of about 3.8:1. The phosphate injection system is designed to maintain ~50 ppm of phosphate with a target $Na:PO_4$ molar ratio of ~3:1. Review of historical data for both units from the introduction of the dual feed showed that the actual molar ratio has been around 2.8:1 or lower with 40-50 ppm of phosphate and a pH between 10.3 and 10.5. On the visit day on units 10 and 20 the phosphate levels were ~43 ppm and the pH ~10.4. The importance of optimizing the $Na:PO_4$ molar ratio on boiler chemistry control and on steam carryover is provided in Section 4 j and k.

d) Total Iron. Despite the serious FAC damage and failure, iron has only been monitored about once per month. GE Water data for 2010 was provided for review during the visit but no information was available on the method of analysis. Economizer inlet levels on Unit 10 have been in the range 6-8 ppb and on Unit 20 they have been 17-23 ppb. If correct and accurate then both sets of values are very high. The economizer outlet values on Unit 10 have been 2-8 ppb with one set of values over 10 ppb; on Unit 20 only two values were recorded at 4 and 5 ppb. While this is not sufficient to make any conclusions, it does appear that there is not any large increase of iron across the economizer circuits as there had been during previous telecoms in July 2007 when almost double the iron levels (~40 ppb) were observed at the economizer outlets. The boiler blowdown iron levels have been considerably higher: on Unit 10 the values have been between 230-340 ppb and on Unit 20 only two samples were analyzed in 2010 between130-250 ppb. These results should be compared with Worldclass performance for all types of HRSG, which is considered to be less than 2 ppb in the feedwater and less than 5 ppb in each HRSG drum (SI’s “Rule of 2 and 5”). If Consolidated Edison decides to continue the cycle chemistry optimization to ensure minimum FAC in each unit then total iron monitoring will need to be conducted more frequently with a sampling procedure and analysis protocol. SI can provide assistance in this area if requested.

e) Steam. The steam is monitored for specific and cation conductivity and sodium after the attemperation which is supplied from after the boiler feedpump prior to feedwater chemical injection. On the day of the visit the cation conductivities on Units 10 and 20 were 0.43 and 0.2 µS/cm respectively. Most probably this difference was simply an instrument, maintenance or calibration error because the source of all the water for the two units is from the demineralized storage tank. A normal/target value of <0.3 µS/cm should be easily achieved on these units. There are no sodium instruments on any of the drums (blowdown or saturated/steam) and no information on drum carryover was available for review (see Section 4k for discussion on carryover).

f) Continuous On-Line Instrumentation. As mentioned in the Benchmarking section each unit has only 8 out of the12 minimum key instruments for units like East River with only one drum and evaporator circuits in relation to the International Standard from the International Association for the Properties of Water and Steam (www.IAPWS.org). The following ones are missing: a) Demineralized Water Pump Discharge or at Sampling Point SP8: sodium and cation conductivity; b) feedwater (at feed pump outlet or economizer inlet) at Sampling Point SP1: cation conductivity; c) Drum at Sampling Point SP2: cation conductivity. The most important of these is location a) because using this monitoring point on each unit would provide immediate identification if any contaminant enters the demineralized storage tank. It was reported by the operators that the 8 instruments are recorded in the control room along with a number of other water and steam/analyses (Diagram 2041) but that there are essentially no alarms. The normal ranges were reported to be old and have not been updated since the changes of chemistry treatments. This is a serious repeat situation which could result in the plant not being in full chemistry control for long periods of time.

g) Chemistry Monitoring of the plant. To supplement the on-line continuous analyzers or in-lieu of those not working or missing, the chemistry staff monitors the units once per day by grab samples. These records were provided during the visit day and the typical values or ranges have been included in various other sections of this report. It is obviously preferable for each unit to run on a full level of key instruments which are fully alarmed with up to date target and action levels for the operators.

h) Shutdown conditions. Some pitting had been observed in the metallurgical analysis to determine deposit loading on an evaporator tube. The plant operating staff indicated that a nitrogen blanketing system is installed but has never been used for HRSG shutdowns.

4.0 Corrosion and Cycle Chemistry Review and Preliminary Action Plans

The following items represent the various cycle chemistry and FAC reviews conducted and the preliminary Action Plans discussed during the visit day. Some additional explanations based on SI's experience with HRSGs around the world have been added here. The Consolidated Edison East River HRSGs have operated for about 38,000 hours and have experienced some serious FAC damage in the economizer tubing and headers. FAC is a damage mechanism heavily influenced by the cycle chemistry control and by the flow hydrodynamics. As already mentioned in the Background section a number of equipment and initial cycle chemistry modifications have been implemented which have to date prevented further damage and failure. But the primary emphasis moving forward in the chemistry and corrosion areas at this stage needs to be proactive. SI has experienced similar relatively good early operating experience following initial modifications to the cycle chemistry which with time has turned into further failure/damage due to allowing repeat cycle chemistry situations to continue.

Structural Integrity (SI) uses three key tools/processes to assess the current condition of the cycle chemistry on a combined cycle/HRSG plant and the potential for future failure/damage. The first involves benchmarking the plant's performance against other similar plants worldwide, and this is included in Section 2. The second identifies the cycle chemistry repeat situations which are occurring. The third process involves a review of the cycle chemistry and operating procedures which relate or influence the cycle chemistry. Analysis by SI staff of over 150 plant failure investigations and plant assessments of boiler and HRSG tube and steam turbine failures and damage, and FAC has clearly indicated that these incidents can all be related to a plant operating with a number of cycle chemistry repeat situations. By themselves, individual situations do not appear to be a concern, but when multiples are allowed to continue then failure/damage has either occurred or is going to happen in the future. Thus SI considers that identification of repeat situations is vital, and that these are critical to a plant's continued reliability. Action Plans are required for each with elimination within a 12 month period critical to the overall management aspects. Some general words are provided here in this report, but further reading is available. (R.B. Dooley, K.J. Shields, and S.J. Shulder. *How Repeat Situations Lead to Chemistry-Related Damage in Conventional Fossil and Combined Cycle Plants.* PowerPlant Chemistry, 2008, 10(10), pp 564-574). The paper is also available on the SI Website for downloading from the following URL: http://www.structint.com/files/public/nuclear_plant_services/PPChem_Repeats.pdf

Six repeat cycle chemistry situations were identified during the East River assessment:
i) Continuous on-line instrumentation which does not meet international standards.
ii) Up-to-date alarms are not available for the operators to match the revised chemistry treatments with the dual feed system.
iii) Corrosion products are measured infrequently and continue to be too high.
iv) Shutdown Protection is not used.
v) Carryover from the drum into steam has not been measured.
vi) Continually challenging the Status Quo of the chemistry treatment to ensure that FAC has been eliminated as an active mechanism, and that corrosion product transport is minimized.

The remainder of this Section itemizes the operational and chemical procedures and guidelines which need to be addressed and/or upgraded/revised to address the repeat situations.

Multi-pressure HRSGs typically experience two major areas of cycle chemistry influenced failure/damage: flow-accelerated corrosion (FAC) and under-deposit corrosion (UDC). Most proactive effort by plant staff is normally focused on these two areas. In the case of the East River HRSGs the evaporator/drum operates at about 560psi which is normally below the level of concern for UDC mechanisms, but this needs confirmation and SI uses the knowledge gained from analysis of the deposits and from understanding the processes leading to deposition to provide a more comprehensive assessment of the total chemistry on a plant. FAC remains a possible concern at East River so the emphasis of the assessment focuses here, but recognizes that deposits in the evaporator are intimately related to any corrosion and FAC that occurs in the feedwater and economizer circuits. Discussion also focused during the plant visit and in this report on four areas of cycle chemistry control and FAC: i) upgrading the instrumentation to the fundamental level required for a unit of this type (items a and b below), ii) continuing activity to understand FAC in the usual predominant areas (items c-h), iii) observations associated with deposits (item i), and iv) simplifying the cycle chemistry treatments and control (item j). The important area of drum carryover has been added to the discussion as item k.

a) Instrumentation and Control.

The most basic item of cycle chemistry control for HRSGs of the East River type is a fundamental or key level of chemistry instruments alarmed in the control room for the operators. As noted in Section 3f, the HRSGs at East River on the visit day had only 8 out of 12 of the Minimum Key Level of Cycle Chemistry Instruments required to provide unique protection for a combined cycle unit with one drum like East River which operates with addition of phosphate(s) to the drum. Table 1 shows the IAPWS level of instrumentation adapted to East River and the recent terminology for conductivity.

Table 1. IAPWS Minimum Key Level of Instrumentation for an HRSG Drum Unit operating with the Condensate/Feedwater on AVT(O) and IP Evaporator operating on a phosphate treatment.
(The full IAPWS Guidance Document can be downloaded from www.IAPWS.org)

Parameter	Sample Locations
Conductivity after cation exchange (cation conductivity)	Demineralized Water Pump Discharge (DWPD) Feedwater/Economizer Inlet (EI) IP Drum/Blowdown (BD) IP Steam (IPS)
Conductivity (specific conductivity)	Feedwater/Economizer Inlet (EI) IP Drum/Blowdown (BD)
pH	Feedwater/Economizer Inlet (EI) IP Drum/Blowdown (BD)
Sodium	Demineralized Water Pump Discharge (DWPD) IP Steam (IPS)
Dissolved Oxygen	Feedwater/Economizer Inlet (EI)
Phosphate	IP Drum/Blowdown (BD)

b) Implementation of the key instruments in Table 1 will provide an improved operating philosophy for cycle chemistry control, so that the plant will not need to continue taking grab samples once per day. A set of action levels will need to be developed for these new continuous instruments and translated into a set of alarms for the operators. A set of operating procedures should also be developed which the operators can clearly follow in the event of an alarm. The SI Chemistry Team has much experience in all these items and can assist Consolidated Edison if requested.

c) <u>Overall Chemistry Control and Other Approaches relating to Flow-accelerated Corrosion (FAC).</u>

Some general words on FAC in HRSGs are provided here in this report, but further reading is available (B. Dooley, *FAC in Conventional and Combined Cycle Plants*, Power Plant Chemistry, 2008, 10(2)). This paper is available on the SI Website at: http://www.structint.com/files/public/nuclear_plant_services/PPChemFACReview.pdf. The most recent paper on FAC in HRSGs was presented at the International FAC Conference, June 2010.

Both single- and two-phase FAC can occur equally in horizontal gas path (HGP) HRSG tubing, headers, risers and IP/LP drums. So it is important to recognize whether either type can occur in an HRSG because the potential solutions are different for each type. Much work has already been conducted on the FAC damage/failures in the East River economizers and the current detailed assessment of the cycle chemistry has clarified a number of aspects. Because of the level of oxygen at the EI (20-50ppb) and the absence of a reducing agent, the incidents of FAC must have been of the two-phase variant due to the massive recirculation determined by the flow modeling. The low pH range (8.1-9.1) reported in Section 2b in the timeframe when the FAC was very active could have been considered detrimental if single-phase FAC was active, but with the knowledge of the oxidizing environment this becomes negated. However, the same low pH range would have been very harmful for any two-phase flow areas. The change of the chemistry control and the introduction of a dual feed system has gone a long way to alleviating the environments conducive to FAC. The continuing relatively high oxygen level (10-50 ppb) at the EI provides sufficient oxidizing power to address single phase concerns. The injection of NaOH at the EI with an associated pH range of 9.4-9.5 provides elevated, but not total, protection against two-phase concerns. However, the second addition of phosphate into the drum complicates the overall chemistry control. Suggestions to address this are provided in item j below. Insufficient information on total iron measurements around the cycle was available, but the couple of analyses reviewed suggest that FAC is under better control in the economizer as there is no major increase between the economizer inlet and outlet. But it needs to be recognized that levels of iron in the range 6-8 ppb are much elevated above the 2 ppb which SI considers appropriate for units with FAC under control. The aspects of iron monitoring are covered in item e below.

Based on SI knowledge and assessments at HRSGs with single drums, the following two regions should be considered as possible locations needing further knowledge and inspection: i) economizer outlet tubes (SA178A), headers (SA 106B) and the economizer risers to the drum (SA 106B), operating between 390 and 470°F, and ii) evaporator outlet tubes (SA178A), and headers (SA 106B) operating ~480°F especially in regions with high steam quality with particular emphasis being given to any tube bends closest to the outlet headers.

d) The control of FAC in combined cycle/HRSG plants usually takes a three pronged approach: i) operating with an oxidizing chemistry, AVT(O) (no reducing agent added to the cycle), to control the single-phase component; ii) operating with an elevated pH (maybe up to 9.6 with Fe testing vital to determine the influence of pH increase) to control the two-phase component if present; and iii) monitoring (sampling and analyzing for total iron) to determine whether these approaches are successful. As already mentioned it was not possible to assess totally whether FAC is active on the East River units because no reliable comprehensive total iron monitoring has been conducted. SI suggests that the ConEd current FAC Program is updated into a comprehensive document which involves a combined approach of total iron monitoring together with various levels of inspection/assessment and optimization of the complex current chemical treatment.

e) Total iron measurements provide a vital indicator of whether FAC is under control in a combined cycle/HRSG plant, and comparison with SI's "Rule of 2 and 5" (total iron of less than 2 ppb in the feedwater [at the EI] and less than 5 ppb in the drum) provides an easy assessment tool to indicate how well FAC is under control. It is suggested that base line iron samples are taken at the DA outlet, feedwater (EI), economizer outlet, and the drum as soon as possible under the current dual feed cycle chemistry regimes prior to making any changes to the chemistry control. Routine testing of iron is not required on a daily or weekly basis following this chemical optimization: once every six months will suffice then. The sampling for iron should be conducted once the unit has achieved a stable load. SI has experience with proper sampling techniques for total iron analysis and can provide assistance if requested.

f) <u>East River Single-phase FAC Locations.</u> East River has not used a reducing agent and has measurable relatively high levels of oxygen in the feedwater downstream of the deaerator, so the likelihood of active single-phase FAC is very low. Observations however from the numerous inspection reports indicate that the drum surfaces are not "ruggedly red" and in most observations were described as "grey". Observations of the evaporator tube deposits also indicated "dark brown" internal surfaces, which are not entirely in-line with fully oxidizing single-phase flow. This may be part of the contribution to the high levels of iron around the cycle. The only possible improvement for the single-phase locations would be to increase the oxygen with controlled additions. The alternative process used in other HRSG plants is to close the DA vents, but in the case of East River this process would provide too much oxygen as the DA feed is the demineralized water storage silo.

g) <u>East River Two-phase FAC Locations.</u> The two-phase FAC damage in the economizer has been discussed in a number of Sections. Another important area of two-phase FAC concern is in the DA. The surface appearance in the deaerators described in the inspection reports is classic low temperature two-phase FAC which is typically found in air-cooled condensers and in the exhaust hoods of water-cooled condensers. The condensate entering the DA at ~62°F is not chemically treated and has a calculated pH of around 6. Any FAC which occurs in the DA has to be the source of the high level of iron at the economizer inlet because the downstream piping is stainless up to the NaOH injection and the measured iron in the makeup water to the DA is low (~2 ppb). It is well understood in the world of two-phase FAC that this low temperature variant can be dealt with by elevating the pH up to 9.8. Unless there are some amine treatments, which are acceptable for the steam supply system and/or meet FDA requirements, then there are not any other known approaches other than to "armor" the affected areas with a chromium containing material (weld overlay or plate). Any needed repairs must be made with such a material.

The evaporator outlet tubes and headers have been suggested above as possible further two-phase susceptible FAC locations. However, the drum pH of ~10.4 due to the combined NaOH and phosphate additions should be high enough to provide adequate protection, and photographs within the inspection report of the riser entries into the IP drum looked in good condition, although generally grey. Similar knowledge is required for the appearance of the outlet tubes in to the headers.

h) Many plants with HRSGs initiate a comprehensive FAC inspection/NDE program as early in life as possible in parallel with the chemistry optimization and monitoring as outlined above. Following the visit, Consolidated Edison provided for review a copy the Central Operations Procedures document on "FAC Component Testing Program" (COP: 6-2-9) which had Executive Approved on June 14th 2010. The typical locations are delineated in item c). A Level One videoprobe inspection would help in this assessment. A level two UT or EMATS technique can be used as confirmation if anything is visible. Video probe studies have been conducted in HRSG units to clearly see FAC damage in the risers and outlet evaporator tubes. There appears to be easy access from the drum at East River. SI can assist Consolidated Edison to develop a comprehensive FAC inspection program if required.

i) <u>Overall Chemistry Control relating to Observation of Deposits in the East River HRSGs.</u>

Deposits on economizer and evaporator tubing as well as the surface coloration of any pressure vessels (DA, economizer and evaporator headers, and the drum) provide some of the best indicators of the current chemistry treatments as well as pointers to possible improvements. On the East River HRSGs, deposits have been measured in economizer and evaporator tubing and a few observations have been made of the surfaces of the DA and drum. Some concern was voiced during some of the initial chemistry discussions in 2007 about the heavy deposits in the economizer of around 70 g/ft^2 and the variability of the colors (red/brown and black) on the tube surfaces. Although no detailed analyses were conducted, it is now clear that these could have originated from three sources: a) feedwater corrosion products flowing in from the DA as discussed in Section 4g, b) the injection of phosphate and polymer at the EI, and/or c) from the two-phase FAC occurring in the economizer sections. The third is most likely as similar heavy deposits have been observed in other environments where two-phase FAC occurs locally. The operating pressure is not high enough in the economizer circuits to result in any UDC, but it is suggested that at the first suitable opportunity a number of tubes are removed from the outlet sections of EC1 and EC2 closest to the GT to document the current deposit loadings. There is very little risk of under-deposit corrosion or loss of heat transfer, but these analyses will provide a check on the iron monitoring which cannot be assessed video probe inspections.

Prior to the introduction of the dual chemical feed, one evaporator tube from EV2 was removed from near the bottom of the circuit in 2009 and metallurgically analyzed. The deposits were dark brown and the deposit levels were ~7 g/ft^2 which is relatively clean and may be due to the introduction of a polymer previously with the phosphate treatment at the EI or may be due simply to the tube sampling in an area where deposits are low. There is usually a direct relationship between the iron levels in the evaporator and the deposit levels. At East River the few measured iron levels from the drum have measured in the 100s of ppb. As one of the main indicators of the efficacy of the chemistry control is the level of deposits, SI suggests that at the first suitable opportunity it would thus be advisable to extract at least two evaporator tubes for examination to assess the deposition rate and the current level of internal deposits, their morphology and their composition (via chemical and metallographic analyses). SI can conduct the deposit analyses if requested. Particular attention should be paid to three aspects: i) the "normal" deposit density (g/ft^2), ii) optical metallography to determine the porosity and morphology of any deposits as well as the indigenously grown magnetite, and iii) elemental mapping across the deposits. It is suggested that the tube samples (SA 178A) are taken from the lead tubes (closest to the GT) of EV1 and EV2 outlet sections as near to the outlet (top) of the circuit as possible (480°F). If possible, samples should be taken from a tube adjacent to a side wall or the gap between side-by-side modules if any exist.

j) <u>Optimizing the Cycle Chemistry Control at East River.</u> Currently the cycle chemistry control is very complex with the dual feed system which involves two separate and different chemical treatments. These two treatments make the overall chemical control overly complex to produce representative pHs in the evaporator/drum and in the feedwater and economizer circuits to provide the necessary two-phase FAC protection. The pH in the evaporator/drum of 10.4-10.5 appears to be much elevated above the level needed to control any two-phase FAC in the evaporator circuit; whereas the pH of ~9.4 in the feedwater may not be elevated enough to provide two-phase protection in the economizer circuits. The other parts of this Section 4 have been suggested to answer the open question on whether FAC is now under control in the East River HRSGs. Once the results from the detailed iron monitoring, NDE/inspections and the deposit analyses in the evaporator and economizer tubing are known, then SI can make a better assessment of this FAC potential. The current chemistry control is discussed in Section 3c where the review indicated that the sodium to phosphate molar ratio is usually around 2.8:1 instead of the designed value of ~3.0, which is the most often used control point for HRSG drums operating on phosphate treatment to prevent acidic (ratios below 3.0) or severely alkaline conditions (ratios above 3.0) existing. If it is determined that the chemistry treatments need a further optimization, or that the current complex chemistry control could be simplified, then a couple of possible approaches could involve a series of short term tests. These would start with the current dual feed system as the base line condition and would involve obtaining a series of reliable iron measurements as outlined in Section 4e along with a representative understanding of the chemistry in the cycle following upgrading of the instrumentation to international standard. The second step would be to determine the NaOH levels in the drum without the two current phosphate/polymer feeds by using the blowdown to control levels of NaOH. A third step could involve the injection of only tri-sodium phosphate (not proprietary blended mixtures) at the EI and determine the level of phosphate and pH in the drum again using blowdown to control levels. Iron monitoring and the upgraded instrumentation would provide the necessary information. SI can work with Consolidated Edison, if requested, to develop such a simplified chemical program once the results from the other activities are known.

k) Carryover from the drum has not been conducted since commissioning. This needs to be rectified as this is a critical part of protecting the steam supply and is critically related to the operating sodium to phosphate ratio in the drum. Thus the total carryover from the drum should be measured on about a six month basis to ensure the integrity of the drum, the operational drum levels and whether the operating sodium to phosphate molar ratio is optimized. This is a simple test, which requires the concurrent sampling for sodium in the drum and in the saturated steam. Details of the process are provided in the IAPWS Carryover Guidance Document (www.IAPWS.org).

l) Time was not spent during the visit to conduct a comprehensive review of the current cycle chemistry guidelines, action levels, and operating policies and procedures. It is suggested that these should be updated after the instrumentation is brought up to the Minimum Key Level of Instruments and once the chemistry control has been optimized, if necessary, to control FAC, iron transport and deposition as outlined in this report. A new set of chemistry alarms will need to be developed once the chemistry and instrumentation have been upgraded. SI specializes in working with HRSG operators worldwide and can assist Consolidated Edison with any of the items mentioned above as well as assisting with training of the operators, if requested.

5.0 Thermal Transient Review and Preliminary Action Plans

The following items represent the various thermal transient reviews conducted and the preliminary Action Plans suggested/presented at the exit meeting on August 3, 2010. Some additional explanations have been added here based on further review of plant documents, operating data sent after the visit and on SI's experience with numerous units around the world. All of the suggestions below are worthy of ConEd's careful consideration. However, the two issues below are particularly noteworthy and pose significant potential for premature pressure part failure if not adequately addressed:

- Potential inadequate draining of the superheater, especially during cold startup, discussed in Section 5.0, a)
- Poor draining of attemperator piping discussed in Section 5.0, b)

a) Superheater Drains:

<u>Findings and Background Discussion</u>

Condensate forms in the superheater (SH) during cooling throughout the shutdown period and at a higher rate during every prestart purge. It is critical that all condensate be drained from the SH during all startups before significant forward steam flow begins. This requires that condensate be drained as fast as it forms during the pre-start purge and not be allowed to accumulate or become trapped in SH inlet piping. During all types of startups SH tubes heat up to near-exhaust gas temperature between gas turbine (GT) light off and establishing initial steam flow though the SH. Undrained condensate remaining in the HP inlet manifold when steam flow is established will be entrained by this steam and expelled from the SH selectively through some tubes, quenching (and shrinking) these tubes. Shrinkage of these tubes, relative to still hot neighboring tubes, results in a large bending stress at the offset tube-to-header connection with the potential to cause thermal fatigue damage. Severe quenching often results in global yielding of the tube thereafter evident as buckling out of line when the transiently quenched tubes return to the same temperature as other tubes in the same row. Many stretched SH tubes were reported during our site visit. This is an indication that these tubes have suffered significant quenching at least once during their life. The large, widely distributed population of buckled SH tubes indicates that it is likely that forward migration of condensate has occurred during many of the startups. It is probable that chilling and tube buckling occurs in a small proportion of the SH tubes during each such incident.

Forward migration of condensate into the SH outlet header and pipes is not anticipated to cause significant fatigue damage to these components unless it were to occur during a hot restart when the upper SH headers and piping remain near on-load operating temperatures.

The SH is currently equipped with one 2-inch drain connection located at the west end of the 12-inch SH inlet manifold that runs under and extends the width of the HRSG. Condensate formed in the SH, plus any spray water running back from the attemperator [see discussion in Section 5.0, b)] flows via gravity through eight vertical 6-inch SH inlet nozzles (4 per side-by-side module) connecting the 12-inch inlet manifold to SH inlet headers. The single 2-inch drainpipe is routed nominally level a short distance to a nominally level common drain manifold of about 10-inch diameter. The bottom of the common drain manifold is positioned only a few inches lower than the bottom of the SH inlet manifold during the hot condition and discharges to a below-grade atmospheric sump. The SH drain is controlled via a 1-inch automated MOV backed up by a 1-inch manual block valve in the 2-inch drainpipe. The SH drain is also connected to the common drain manifold via four parallel small-bore steam traps.

SH drain operation is reported to be fully automatic with no need for operator intervention. The reported current drain control logic opens the SH drain MOV during startup when GT ignition is detected. The MOV remains open for a minimum of one minute if drum pressure is in excess of 50 psig. Otherwise, it closes when drum pressure reaches 50 psig. Actual SH drain valve action observed via historical DCS data for the startup on 6/2/10 (Figure 1) indicates that the MOV opened quickly to 29% stroke when the GT ignited with drum pressure at zero. When drum pressure increased to 50 psig the MOV rapidly closed from a position of 43% stroke. It is uncertain what drain valve MOV action may have been between opening and closing since this data point indicates a “bad” signal during this period. It is assumed that the MOV remained open at some position between 29% and 43% stroke, but his cannot be verified via the data provided.

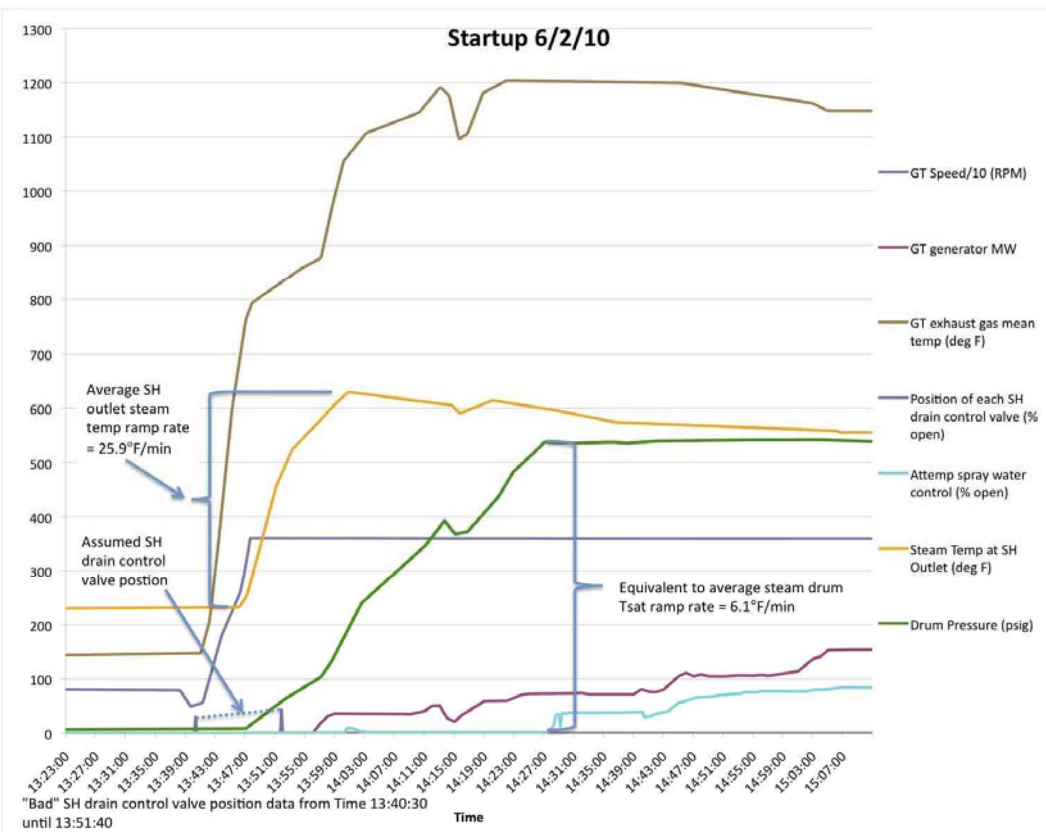

Figure 1 – Plots of DCS historical data for startup on 6/2/10

It was reported that after audible evidence of water hammer associated with SH drain operation the 1-inch SH drain piping was replaced with 2-inch pipe, substantial drainpipe elevation increases in the direction of drain flow were eliminated, and that the original 1-inch SH drain MOV and block valve were retained. The new 2-inch pipe size was chosen based upon condensate formation rate and two-phase drain flow capacity calculations performed by ConEd personnel. The automatic logic controlling the SH drain MOV was also modified to eliminate water hammer.

The ConEd condensate formation and drain flow capacity calculations are based on saturation temperature conditions in the SH during shutdown, which drop from 530psig to 160 psig. During the shutdown on 1/15/10 in Figure 7, no condensation occurred during the GT coast down to turning gear speed. During this period SH pressure dropped from about 530 psig to about 300 psig with the result that GT exhaust temperature remained about 250°F above saturation temperature. Condensation did not commence until about 40 minutes after GT firing ceased and by then was inconsequential.

The damaging condensate forward migration incidents that have caused many tubes in the SH to permanently elongate and buckle (and have also developed thermal mechanical forces and stresses that contributed to the SH tube failures at the wrapper restraints) have almost certainly occurred during cold starts from pressures at or very close to atmospheric pressure. When at atmospheric pressure there is little or no static head (about 1 foot of condensate) available to drive flow from the bottom of the SH inlet manifold pipe through the single 2 -inch nominal diameter drain pipe and 1-inch drain control valve into the drain manifold.

Previous drain flow capacity calculations performed for other F-class HRSGs have always established that even when there is more than 3 feet of static condensate head available the minimum drainpipe and drain control valve sizes are determined by the near zero (1 psig) drum pressure case. The calculated condensation rate during the purge prior to cold near-zero pressure starts is typically of the order of 25% less than the condensation rate during the purge prior to a hot start from in excess of 500psig. The previous calculations also show that even when there is a static head of more than 3 feet available to drive flow through the drain line during zero pressure starts, the flow rate through the drain pipe and valve is reduced by a factor at least one order of magnitude larger than the reduction in condensation rate during the purge for cold versus hot starts. In the East River installation, it appears that during cold start conditions the head available between the drain connection on the bottom of the SH inlet pipe and the drain outlet into the drain manifold may be on the order of 1 foot of static head. In this case flow rate through the drain during zero pressure cold starts will be small. It is improbable that the new 2-inch drainpipe with original MOV and block valve are adequate. Even if the MOV was changed from 1-inch to 2-inch, it is still unlikely that there is sufficient dependable static head to cope with the condensation rate during cold, near-zero pressure starts. In addition, there appears to be a risk of back flow from the drain manifold into the SH inlet pipe whenever the SH drain valve is open, there is little or no pressure in the SH, and the drain manifold becomes slightly pressurized or flooded above the elevation of the bottom of SH inlet pipe.

Except in very severe cases, migration of undrained condensate through SH tubes cannot be observed via normal plant instrumentation. It is usually necessary to install a number of rapid response temporary tube temperature thermocouples in the SH to confirm the presence of condensate migration and quantify its severity. Six permanent tube metal temperature thermocouples are installed in the SH as part of the plant's control system [see discussion in Section 5.0, d)]. These permanent thermocouples are "tab welded" thermocouples with significant thermal inertia. While they would register severe condensate migration IF it occurred in a tube to which one of these thermocouples is attached, their high thermal inertia prevents them from responding sufficiently fast to register the fleeting temperature transients associated with typical condensate migration. Also, these thermocouples do not appear to be attached to tubes located in positions most likely to experience condensate migration.

<u>Suggested Action Items</u>

The existing SH drain system design (original 1-inch MOV restricting flow in new 2-inch pipe and single drain point from nominally horizontal SH inlet manifold) and operating practices (drains are not opened before startup or during the GT purge when condensate forms) increase the risk that un-drained condensate will migrate into the SH and cause thermal fatigue damage. Such damage may result in premature tube failure at tube wrapper attachments and tube-to-header connections. Listed below are several drain hardware, operating procedure, and control logic modifications that should be considered to eliminate this cumulative and invisible damage mechanism.

i) Water from condensation in pipes and SH tubes and/or from leaking attemperators cannot be expected to completely drain from the nominally level 12-inch SH inlet manifold located below the HRSG casing. Nominally level pipes in other HRSGs have been noted to accumulate water in pools due to permanent and/or transient humping and/or tilting when sufficiently sized drain points are not located at all permanent and transient low points. If pooling occurs in the SH inlet manifold because one, or more, permanent or transient low point occurs not at the single 2-inch drain point, such trapped water remains in the SH inlet manifold even after water ceases running from the single 2-inch drain and is carried up SH tubes when significant steam flow is initiated. Experience indicates that steam pipes and manifolds must be installed with a continuous minimum downward slope of 2% in the direction of steam flow to a suitably sized low point drain if the risk of pooling due to pipe distortion is to be avoided.

   As an alternative to the impractical solution of refitting the SH inlet manifold to achieve the foregoing 2% downward slope, it is suggested that additional drip legs with 2-inch drain connections be installed along the length of the SH inlet manifold to prevent water being trapped. As a minimum drain points should be located at each end and in the center of the SH inlet manifold. Depending upon whether the SH manifold contains permanent humps and low points, more than three drain connections may be required.

   Condensate formation rate during startup from 1 psig drum pressure should be calculated, then the results used to determine the minimum drainpipe and MOV sizes required. If the suggestions for improving attemperator piping drainage discussed in Section 5.0, b) are not to be implemented potential attemperator leakage flow rates should be added to the calculated SH condensation rate before establishing minimum acceptable drain component size. Previous experience suggests that three 2-inch drainpipes connected into a single 3-inch drainpipe with similarly sized MOV and block valve may be adequate. The foregoing is provided for information only and should not be used in lieu of unit specific design calculations.

Due to the very low static head available between the SH inlet pipe and the common drain manifold, as well as the risk of backflow from the drain manifold during periods of low SH pressure, it may be necessary to bypass the drain manifold prior to the purge, during the purge, and until drum pressure increases to around 30 psig. This has been successfully accomplished by others via discharging the SH inlet pipe drains directly to atmosphere near the HRSG, then transferring drains flow to the common drain system. If such an arrangement is considered personnel safety must be considered as well as appropriate MOV interlocks to prevent opening of SH drains to atmosphere when inappropriate and prevent opening of the SH drains to the common drain manifold when SH pressure is too low.

It is important when routing drainpipes to ensure that adequate flexibility is provided to accommodate all anticipated thermal transients. It is also important that drainpipes are not installed with upward slopes or vertical rise in the direction of drain flow. A continuous minimum downward slope of 2% is ideal, but probably not possible in this case due to the very low elevation of the SH inlet manifold. Check valves should be avoided in drainpipes due to the restriction in drain flow they cause.

Typical F-class HRSG SH drains are not equipped with traps like those found at East River. One reason for this is that the operating pressures and temperatures of these units typically exceed those acceptable for such traps. However, the absence of traps does not appear to create any problems for the typical HRSG. If ConEd is faced with the decision to eliminate the existing traps to provide room for the SH drain modifications above, it is suggested that reliable performance of the conventional SH drain system is much more important than whatever benefits the traps may provide. It should also be considered that should a trap malfunction it may provide a path for backflow into the SH inlet pipe should pressure in the common drain manifold be transiently higher.

ii) The existing drain operating practice of opening the SH MOV only after the GT is firing is typical of procedures recommended by most HRSG manufacturers. As discussed in Section 5.0, a) significant amounts of condensate can collect in the SH inlet manifold prior to GT ignition, particularly when the GT is cranking and unfired. Since all water in the SH inlet manifold must be completely removed prior to initiation of forward steam flow, it is important to ensure that the SH manifold is empty prior to initiation of the purge cycle and that the SH drain MOV is fully open during the purge.

It is suggested that SH drain operating procedures and logic be modified as follows:

- Open SH drain MOV for the period necessary to completely drain the SH inlet manifold prior to initiation of the pre-start purge. Visually verify that that the SH inlet manifold is completely drained prior to initiation of the purge cycle. If a properly located atmospheric tell-tail drain is not already available for safe visual verification of drain flow, then one should be installed.

- For startups initiated form drum pressures <50 psig: Modify SH drain MOV control logic to open the MOV to 100% during the pre-start purge and maintain 100% opening until drum pressure increases to a target value. This target drum pressure should be established via operational testing utilizing data obtained from the temporary SH tube temperature thermocouples discussed in Section 5.0, a), iii) below. Prior to establishing the optimum drain-closing pressure via the proposed operational testing continue to use the existing 50 psig closing pressure.

- For startups initiated from drum pressures >50 psig: Continue to utilize the existing SH drain MOV control logic (opens MOV for 1 minute). Via operational testing utilizing data obtained from the temporary SH tube temperature thermocouples discussed in Section 5.0, a), iii) below determine the optimum drain open time and MOV position for pressurized startup that reliably clears condensate from the SH (primary objective) and limits unnecessary or excessive drum pressure decay.

iii) In cases where there is uncertainty that the existing SH drain system configuration and operating practices can provide adequate drainage SI suggests the installation of temporary tube temperature thermocouples in the SH to determine if condensate migration is occurring during cold and/or warm startups. Following installation of the thermocouples, data is collected during startups initiated from zero drum pressure and from higher drum pressures typical of those experienced by the unit. Drain operating procedures (MOV opening/closing times/pressures, MOV opening position, etc) are varied during a series of startups to determine optimum drain control logic settings for various pressures.

In the case of the East River HRSGs it is felt that the current drain configuration has insufficient capacity during zero pressure startups and that continued condensate migration is very likely. Therefore it is suggested that ConEd proceed with implementation of the foregoing drain system modifications prior to installation of temporary tube temperature thermocouples. Temporary tube thermocouples should be installed in the SH at the time drain system hardware modifications are implemented. The thermocouples will be needed at that time to confirm that the modifications are successful in eliminating condensate migration. They will also be needed during the operational testing required to establish the optimum drain operating logic for startups from both zero and higher drum pressures. If ConEd wishes to confirm that the existing drain system is unable to prevent condensate migration prior to implementing hardware modifications, installation of the suggested thermocouples will be required to do so. If installed prior to hardware modifications some thermocouples are likely to need repair at the time hardware modifications are implemented. Should ConEd wish to pursue installation of temporary thermocouples SI will be pleased to provide installation guidance during the outage, interpretations of the data obtained and provide additional support in optimizing SH drain-operating procedures. Suggested thermocouple locations and installation procedures are provided with this report.

b) Attemperator Piping Drains:

<u>Findings and Background Discussion</u>

Steam flows from the eight 6-inch SH outlet nozzles into the side of a horizontal 20-inch main steam pipe. A single 1-inch drainpipe with manual valve is located on this pipe at the HRSG centerline. The steam travels up a vertical U-shaped section of 20-inch pipe into another horizontal 20-inch pipe in which the two attemperator nozzles are located at an elevation approximately 10 feet above the SH outlet. A 12-inch drip leg with a 1-inch drainpipe is located on the main steam pipe downstream of the attemperators at an elevation about 14 feet below the attemperators. See Figure 2. Any spray water introduced by the attemperator via valve leakage or inappropriate operation during low, or zero, steam flow conditions is likely to flow back into the SH. Since attemperator leakage and inappropriate operation are not planned events, the single 1-inch manual drain upstream of the attemperator is of no value in preventing backflow of water into the SH. A number of ductile overload and tube fracture events have occurred in other units that lack adequate attemperator piping drains.

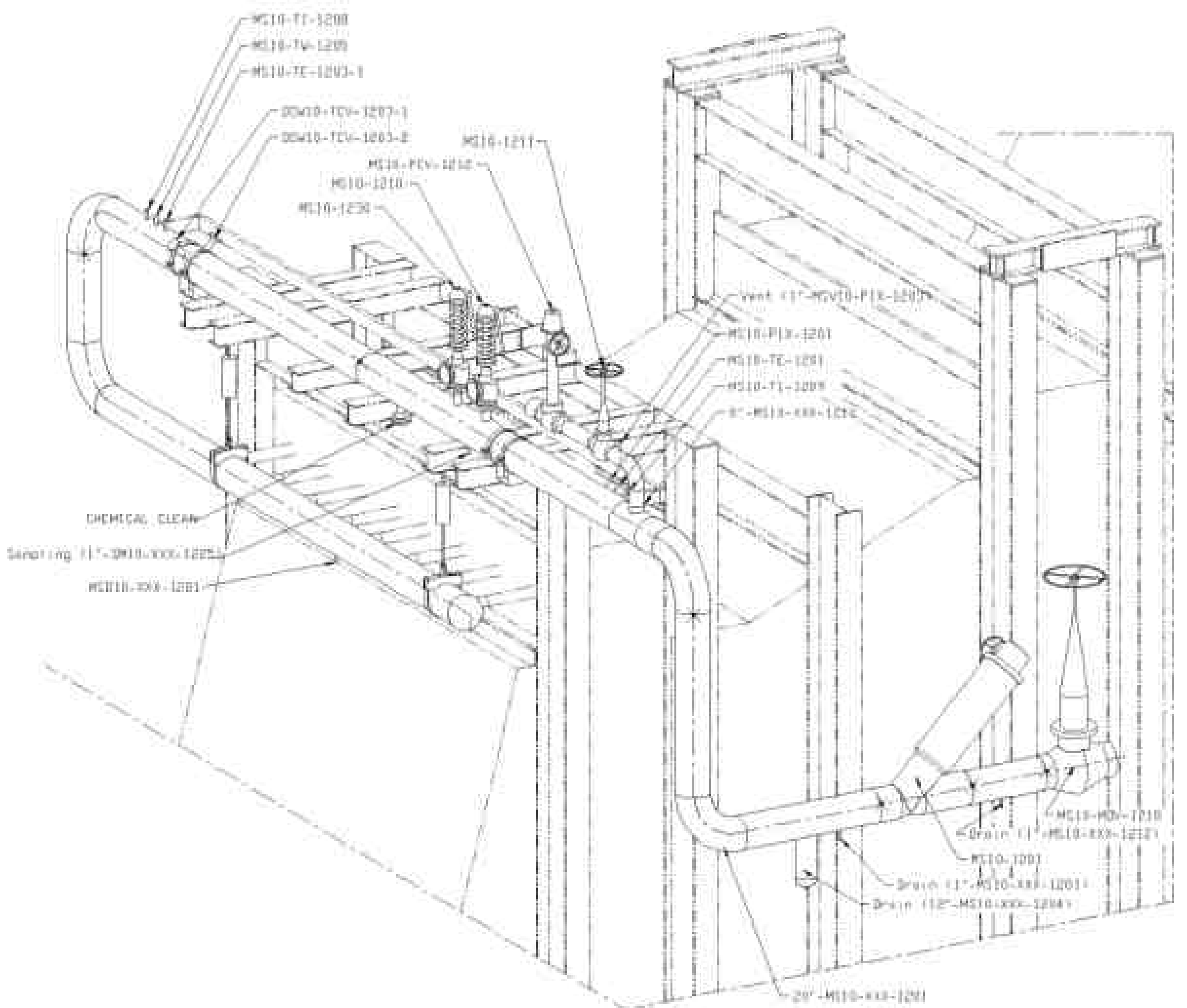

Figure 2 – Main steam pipe arrangement with SH outlets, attemperators and existing drains.

<u>Suggested Action Items</u>

To minimize the risk of such failures it is suggested that a 12-inch drip leg be installed in the main steam piping just upstream of the attemperators. Sizing of the drainpipe attached to this drip leg should take into account the maximum attemperator spray water flow anticipated during a worst-case leak or inappropriate operation event. While ConEd is under no obligation to retroactively comply, it is worth noting that the ASME Boiler and Pressure Vessel Code was amended in 2007 to require on new units a low point drain between the attemperator and SH where the risk of back-flow exists.

c) Attemperator Hardware:

Findings and Background Discussion

The East River HRSGs are equipped with attemperators in which the spray control valve trim is located internal to the spray nozzle. With its moving parts exposed to alternating severe thermal heating and quench-cooling cycles, this style of attemperator is notoriously susceptible to erratic operation, poor reliability, high maintenance costs, and overall poor performance in high temperature applications with frequent on-off attemperator operation. Most HRSG OEMs no longer provide integral attemperators on combined cycle units expected to experience cyclic duty. The lower operating temperatures to which these attemperators are exposed will result in thermal fatigue cycles in the attemperator hardware of moderate range, but the attemperators experience a relatively large number of these cycles since they must operate at low GT loads but are not required during periods of high GT load. These conditions may permit the existing attemperators to deliver better reliability than experienced in higher temperature HRSGs. However, it was reported that one of the East River attemperator nozzles failed by unscrewing from the attemperator body while in service in early 2010.

Suggested Action Items

A routine attemperator inspection program should be consistently executed. Work scope should include removal/inspection/repair of the spray nozzle, control valve, block valve and borescope inspection of the thermal liner and its attachment points (or steam pipe interior if no liner is installed). These inspections should be performed annually as a minimum interval.

d) DCS Historical Data Review:

Findings and Background Discussion

The plot of *Steam Temperature at SH Outlet* during the startup on 6/2/10 in Figure 1 indicates that SH outlet steam temperature increased at an average rate of 25.9ºF per minute. During the shutdown on 1/15/10 in Figure 7, the average SH outlet temperature ramp rate was less than –10°F per minute. The SH outlet header thickness is 0.593-inch. For a header of such moderate thickness these heating and cooling ramp rates provide substantial margin against thermal fatigue in the header.

The plot of Drum Pressure during the startup on 6/2/10 in Figure 1 indicates that drum saturation temperature increased at an average rate of 6.1ºF per minute. The plant's operating procedures list the maximum permissible drum saturation temperature ramp rate as 20ºF per minute. Assuming that the maximum drum saturation temperature ramp rate listed in the operating procedures is consistent with those calculated by the HRSG OEM, the actual ramp rate of 6.1ºF per minute observed during the 6/2/10 startup provides substantial margin against thermal fatigue damage to the drum.

To protect the carbon steel SH from excessive temperatures during startup the East River HRSGs are installed with six permanent thermocouples installed on tubes at the bottom of the SH near the inlet headers and three installed on tubes at the top of the SH near the outlet header. A "high select" feature in the DCS uses readings from the upper tube thermocouples to activate a *High SH Temperature* alarm if the tube metal temperature increases to 655°F. If upper tube temperature reaches 675°F the DCS generates a *High-High SH Temperature* alarm and begins a 15-minute time delay before automatic initiation of GT load runback if SH tube temperature remains above 675°F.

The plots of upper tube temperatures during the startup on 6/2/10 in Figure 3 indicate that during this startup event both the 655°F High temperature and the 675°F High-High temperature alarm points were exceeded and that the High-High tube temperature condition persisted beyond the 15-minute time delay required to initiate a GT load runback. The hottest instrumented SH tube reached a peak temperature of 714°F.

It has been demonstrated in other HRSGs via data from temporary tube metal temperature thermocouples distributed across the SH that during early startup SH tube metal temperatures vary greatly. This variation is due to non-uniform distribution of GT exhaust gas flow, higher velocity of exhaust gas through gaps at sidewalls and between modules, and non-uniform steam flow distribution through SH tubes at lower volumetric steam flow rates. While the three permanent upper SH tube temperature thermocouples appear to be located adjacent to the side wall and center module gaps where temperatures are typically higher, it may not be safe to assume that these three instrumented tubes actually represent worst case SH tube outlet temperatures during all startup conditions. In addition, a feature of the GE7FA GT is that its exhaust temperature is highest when passing through loads below the normal operation load range during startups and shutdowns. When operating in this load range, GT load runback can actually increase tube temperatures for a period of time rather than decreasing them. The carbon steel SH tubes, headers and piping are vulnerable to significant irreversible material properties degradation via decarburization when operated above about 800°F for periods of time that cumulatively exceed a few thousand hours. It is important to minimize the duration of excursions above the prescribed limit temperatures. The 655°F High temperature and the 675°F High-High temperature alarm points may seem significantly lower than temperatures that will cause material degradation, but this may be to provide adequate margin to accommodate those parts of components that may operate at temperatures significantly higher than those measured by the monitoring thermocouples.

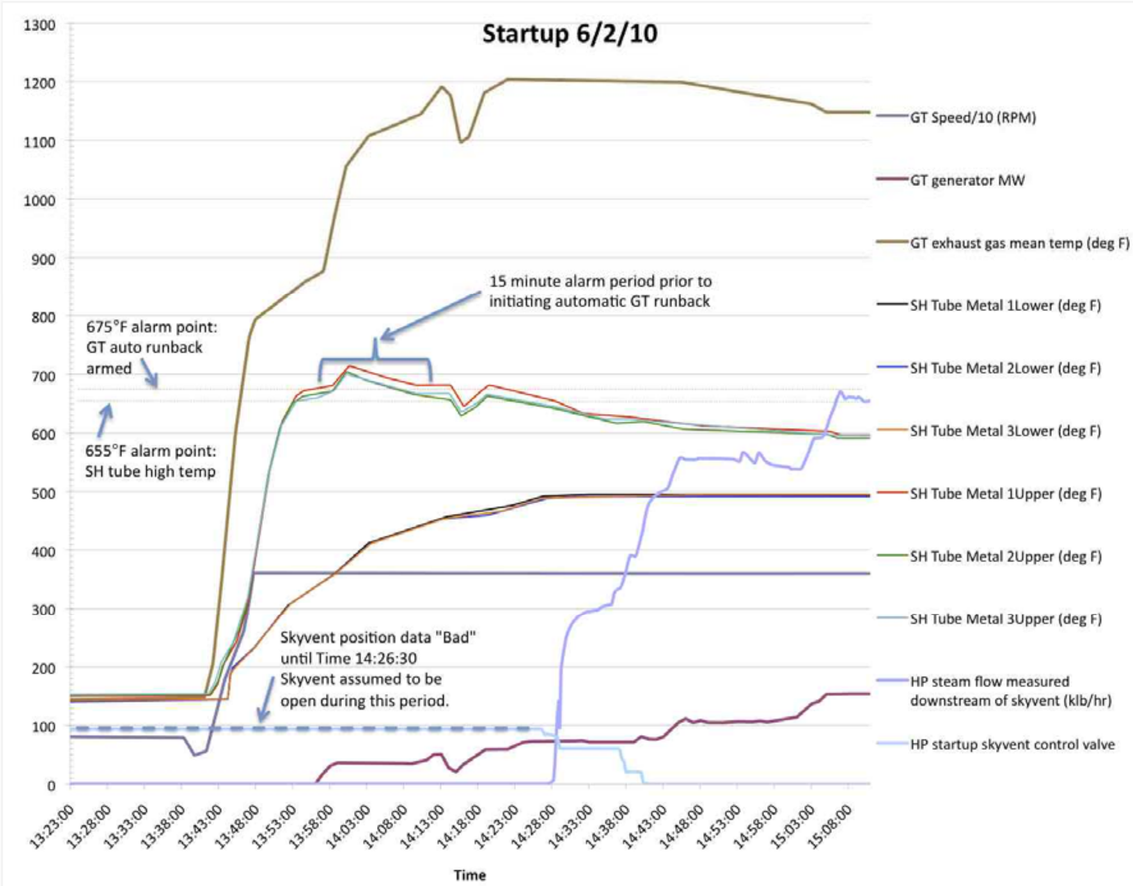

Figure 3 – Plots of DCS historical data for startup on 6/2/10

<u>Suggested Action Items</u>

It was reported during the site visit that the runback is triggered if the operator increases GT load too rapidly during startup. While it is apparent from Figure 3 that this protective feature worked as designed during this startup, it would be prudent to determine the optimum GT loading rates, GT load hold points, GT load hold durations, and SH steam flows required during startup to avoid triggering high SH temperature alarms and GT load runback. Once established, these parameters should be incorporated into the plant's written startup procedures and consistently observed. Consideration might also be given to automating these aspects of startup via their incorporation into the plant's DCS logic.

<u>Findings and Background Discussion</u>

The East River HRSG is equipped with a permanent SH outlet header wall temperature thermocouple. It is assumed that this thermocouple is welded to the outer header surface. The plot of *SH Outlet Header Wall Temperature* during the startup on 6/2/10 in

Figure 4 illustrates that the SH outlet header wall temperature is consistently close to that measured at the upper outer surface of the three SH tubes plotted in Figure 3. The header wall temperature plotted in Figure 4 and the SH upper tube temperatures in Figure 3 are consistently hotter than measured SH outlet steam temperature also plotted in Figure 4. The header wall temperature peaks at 714°F, as do the instrumented SH tubes discussed above. While at this peak temperature the header wall is approximately 85°F hotter than SH outlet steam temperature.

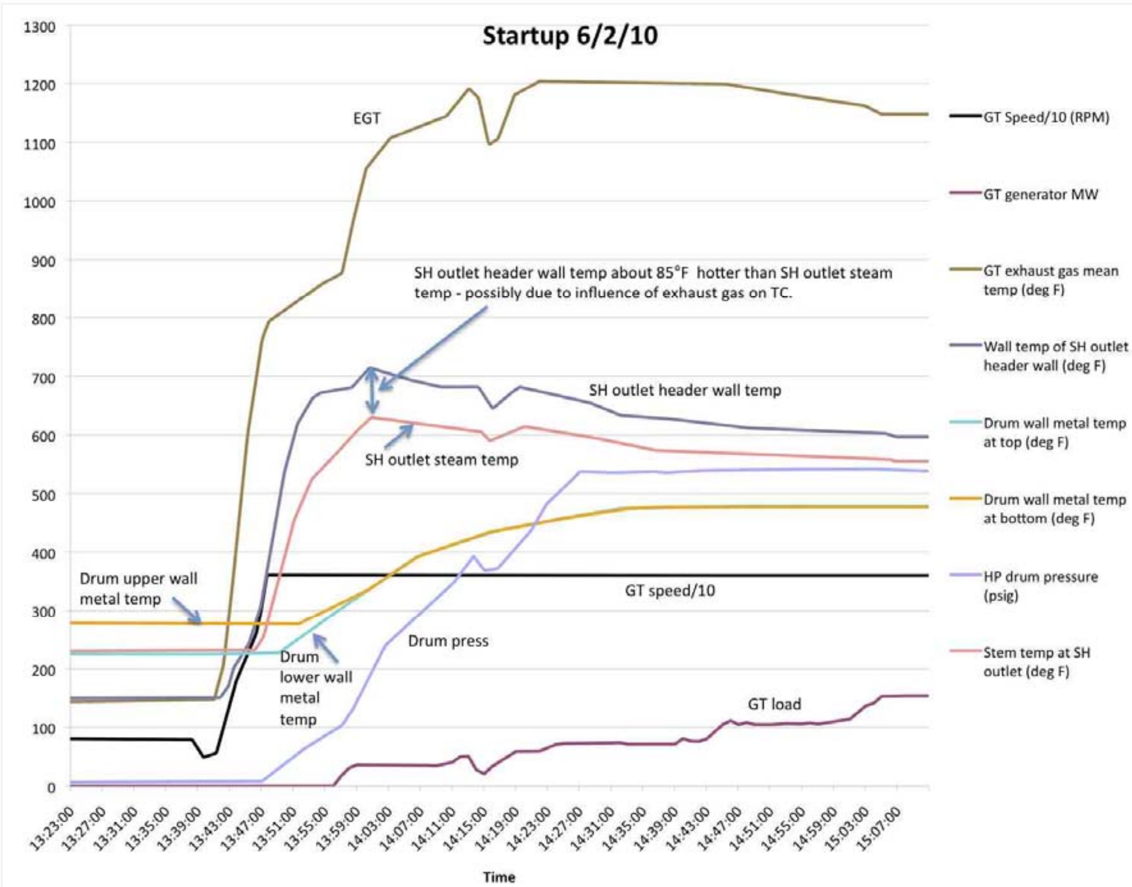

Figure 4 – Plots of DCS historical data for startup on 6/2/10

The plot of *SH Outlet Header Wall Temperature* during operation at higher GT load on 5/23/10 in Figure 5 indicates that the header wall temperature is consistently about 50°F hotter than SH outlet steam temperature during stable operation at GT loads above about 80MW. However, during the load reduction transient in Figure 5 the header wall temperature peaks briefly at 664°F, which is above the 655°F High SH tube temperature alarm point.

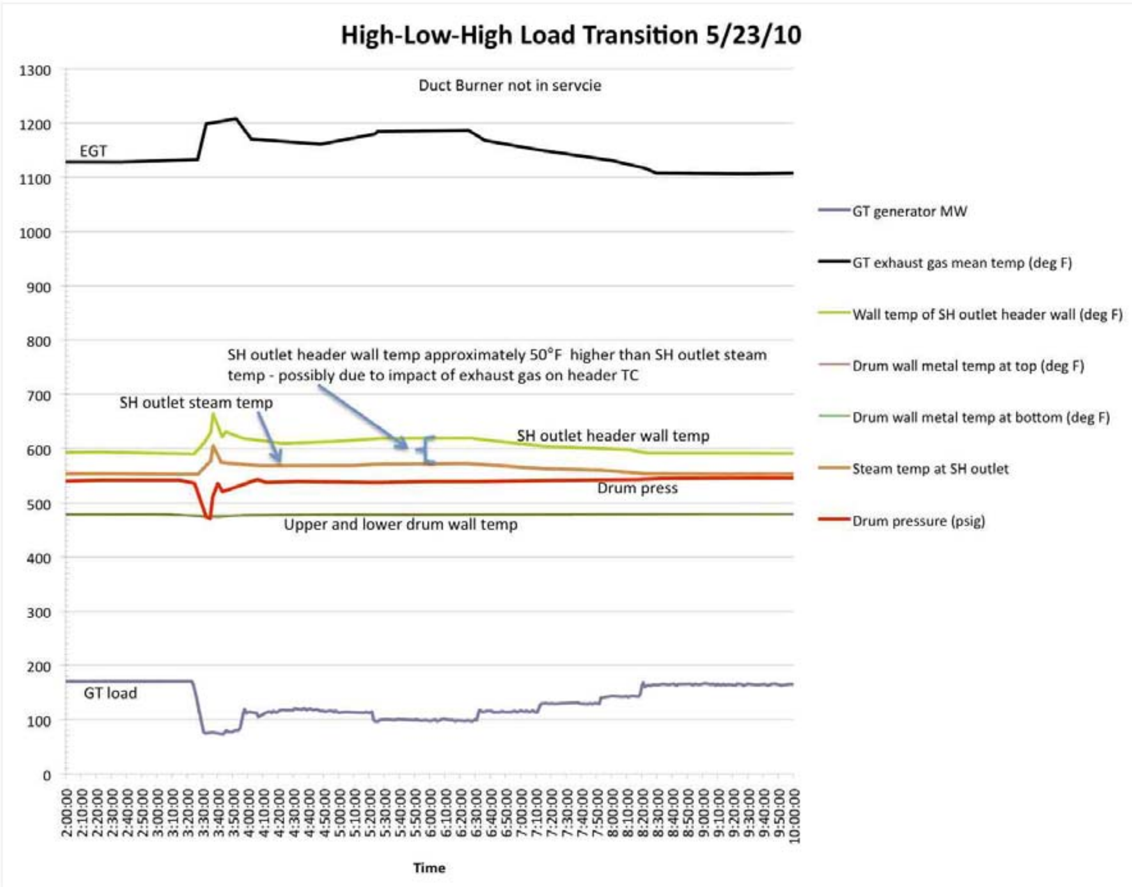

Figure 5 – Plots of DCS historical data during high-low-high GT load transition on 5/23/10

HRSG headers are typically partially shielded from direct exhaust gas impingement and are therefore primarily heated and cooled from the inner surfaces by the steam flowing through them. During startup when steam flow is very low a moderate mismatch between header outer surface temperature and the remotely located bulk outlet steam temperature thermocouple is not unusual. However, during stable periods of high steam flow significant difference between header wall and bulk steam temperatures, such as those in Figure 5, are not anticipated when the thermocouple attached to the outer surface of the header wall has been covered with thermal insulation such that it is not influenced by the temperature of the hotter gas flow across the back of the header.

<u>Suggested Action Items</u>

It is suggested that the SH header wall thermocouple should be inspected for any of the following conditions that may cause erroneously high readings:

– Thermocouple located in a position exposed to direct exhaust gas impingement

- Insecure attachment to the SH header wall
- Insufficient and/or incomplete covering of thermal insulation
- Additional thermal junctions introduced by defective thermocouple wiring
- Erroneous SH header wall thermocouple calibration.

Inspect the baffles intended to protect the SH outlet header from significant exhaust gas impingement for gaps and/or misalignment.

Check calibration and integrity of SH outlet steam temperature thermocouple.

Consider performing replication of the SH outlet headers' outer surface to determine if any metallurgical degradation associated with high temperatures has occurred, particularly if the foregoing thermocouple and gas baffle inspections indicate that the header surface temperatures presented in Figures 4 and 5 are accurate.

Findings and Background Discussion

The plots of *SH Tube Metal Temperature* during the GT load transitions on 5/23/10 in Figure 6 indicate that upper tube metal temperatures are consistently about 46°F hotter than SH outlet steam temperature during both high and low GT loads. The hottest tube temperature peaks at 664°F during the load reduction transient, which is above the 655°F High SH tube temperature alarm point. If tube thermocouples are properly insulated to protect them from exhaust gas impingement, during periods of high steam flow rates they should perhaps indicate tube temperatures closer to the temperature of the steam flowing through the tube.

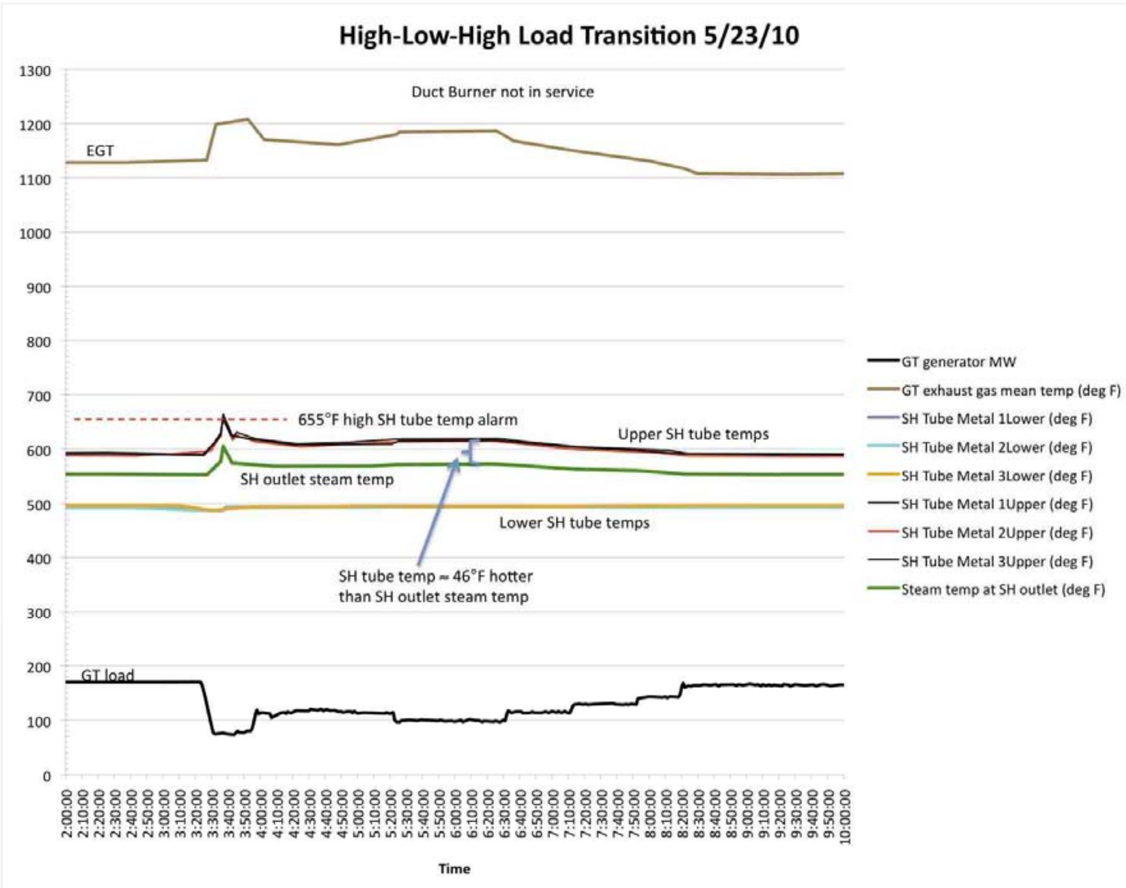

Figure 6 – Plots of DCS historical data during high-low-high GT load transition on 5/23/10

During the GT load reduction in Figure 6 GT load was lowered rapidly to about 73 MW. This load is the GE7FA GT's "hot zone" and results in exhaust temperature near the maximum (called the isotherm) in excess of 1200°F. When GT load was later increased slightly above 100 MW (presumably to clear the SH tube high temperature alarm) exhaust gas temperature and SH tube temperatures returned to values acceptable for longterm operation.

<u>Suggested Action Items</u>

It is suggested that the SH tube temperature thermocouples are inspected for any of the following conditions that may cause erroneously high readings:

- Insecure attachment to the SH tube
- Insufficient and/or incomplete covering of thermal insulation
- Additional thermal junctions introduced by defective thermocouple wiring

– Erroneous SH tube thermocouple calibration

Since the permanent SH tube thermocouples are installed on tubes located near the side walls and center module gap it is possible that the quantity of exhaust gas bypassing the SH through these gaps results in individual tube temperatures 46°F higher than the bulk steam outlet temperature as indicated in Figure 6. It is suggested that the gap seals along the SH sidewalls and center module gaps be inspected for damage and to ensure that the clearance between tubes and baffles is consistent with the OEM's recommendations.

Check calibration and integrity of SH outlet steam temperature thermocouple.

Consider performing replication of the outer surface near the top end of the hottest running SH tube instrumented with a permanent metal temperature thermocouple to determine if any material property degradation associated with high temperatures has occurred, particularly if the foregoing inspections indicate that the tube metal temperatures presented in Figures 3 and 6 are accurate.

It is suggested that transitions from high to low GT loads be conducted in a manner that avoids lowering GT load into the “hot zone” (typically below about 100MW). Some operators of the GE7FA GT who wish to operate below 100 MW have installed an optional GE control package called OPFLEX. In some cases OPFLEX is reported to lower the isotherm temperature by about up to 25°F to 30°F during startup and low load operation. It was reported during the assessment that the East River Units 10 and 20 are equipped with OPFLEX. GE has stated in the past that OPFLEX installations are customized to the particular unit and do not necessarily utilize the same features. It is suggested that ConEd consult GE to determine if the existing OPFLEX version already utilizes the isotherm reduction feature, and if this feature can be added if not already installed.

Findings and Background Discussion

The DCS historical data plots during the shutdown on 1/15/10 in Figure 7 show a spike increase in *Duct Burner Fuel Flow* after the GT has coasted to near zero speed and while exhaust temperature is about 700°F. Soon after forced cooling of the HRSG was initiated via unfired high speed cranking of the GT. It was reported that this spike is the result of depressurizing the duct burner fuel system in preparation for HRSG entry.

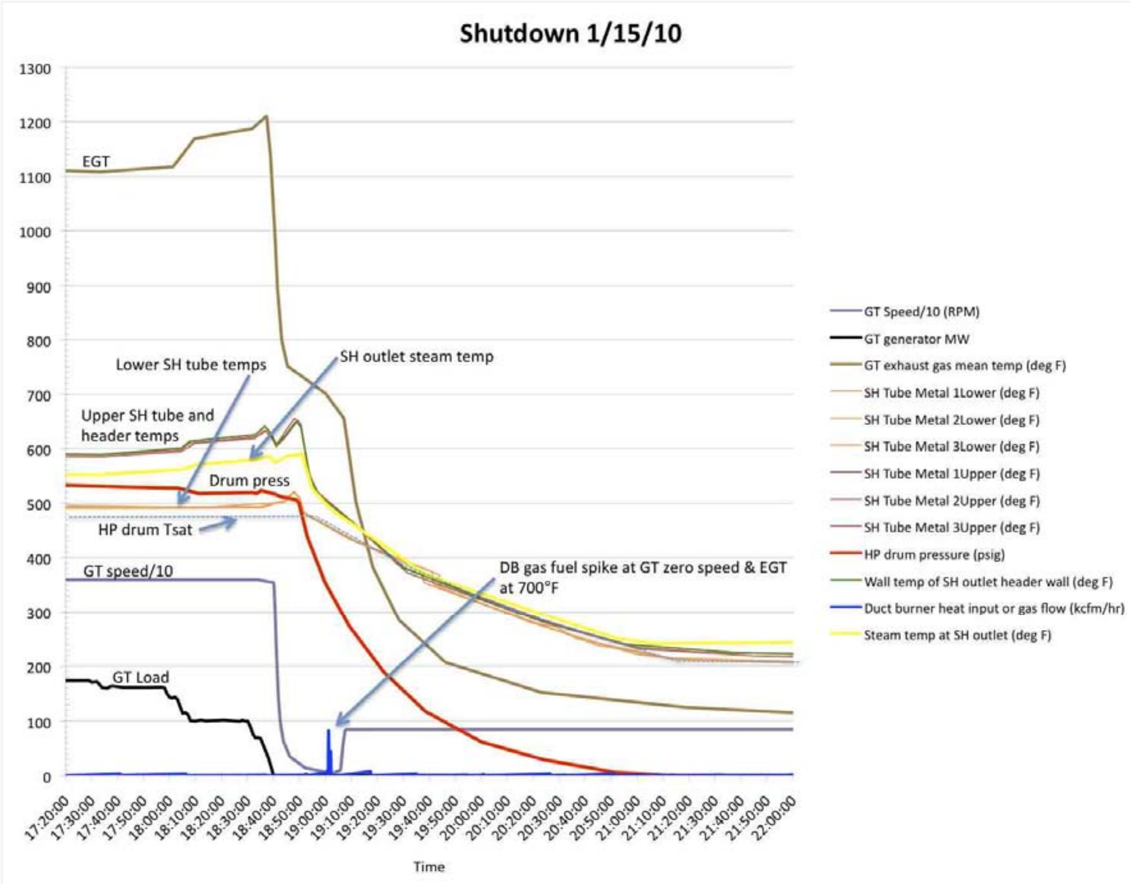

Figure 7 – Plots of DCS historical data during shutdown on 1/15/10

Suggested Action Items

The indicated gas path temperature in Figure 7 at the time of the duct burner fuel spike is well below the published auto ignition temperature of natural gas (1076°F). However, it is suggested that yet more margin of safety between auto ignition temperature and gas path components could be attained if the duct burner fuel release were delayed until well into the time period the GT is intended to perform high speed unfired cranking, but also a reasonable period before cranking is suspended.

Findings and Background Discussion

If overly aggressive initial firing rates are used when large duct burners are placed in service and/or overly aggressive firing rate increases occur, then excessive heat input to down stream evaporator tubes can result in abnormally rapid waterside deposit formation. This is due to a significant time delay between application of additional evaporator heat input and increase in evaporator circulation rate. Review of DCS historical data plots during the duct burner light off in Figure 8 and duct burner load increase in Figure 9 on 2/3/10 indicate no excessive changes in gas duct temperature downstream of the duct burners.

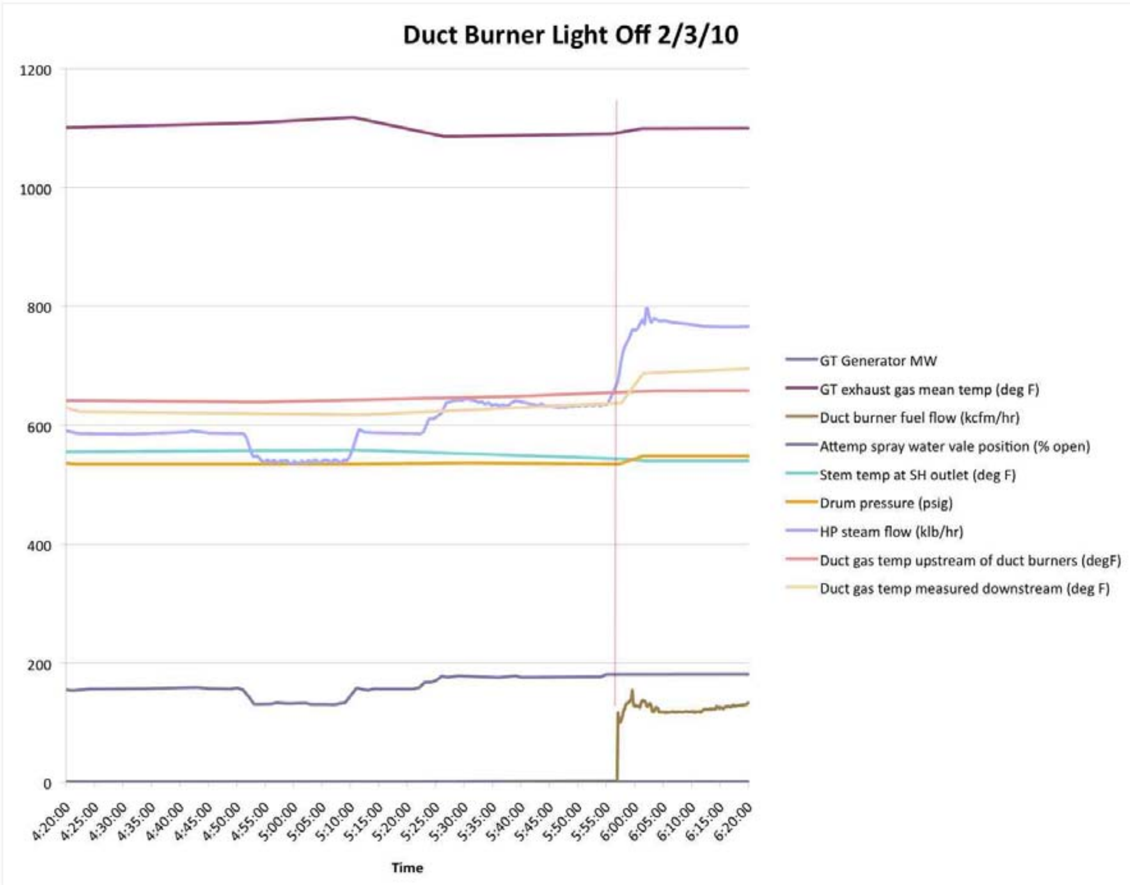

Figure 8 – Plots of DCS historical data during duct burner light off on 2/3/10

Irregularities in fuel gas distribution across duct burner runners and between one runner to another have in some other HRSGs created hot zones in the gas duct that resulted in excessive waterside deposits and under deposit corrosion. Permanent gas duct temperature probes are located near the HRSG sidewalls; hence their temperature indications are unlikely to be representative of peak gas temperature conditions in other locations across and from top to bottom in the gas duct. No instrumentation is currently installed in the East River HRSGs to give a quantitative indication of duct burner related gas temperature distribution. Installation of evaporator tube temperature thermocouples to confirm acceptable side-to-side and top-to-bottom gas temperature profiles during duct burner operation is possible, but generally too expensive to consider unless other indicators of a damaging gas temperature profile are present. Such indicators might include visual observation of non-uniform duct burner flames and discolored or distorted tubes and/or support structures downstream of the duct burner. No such indicators were noted during this assessment.

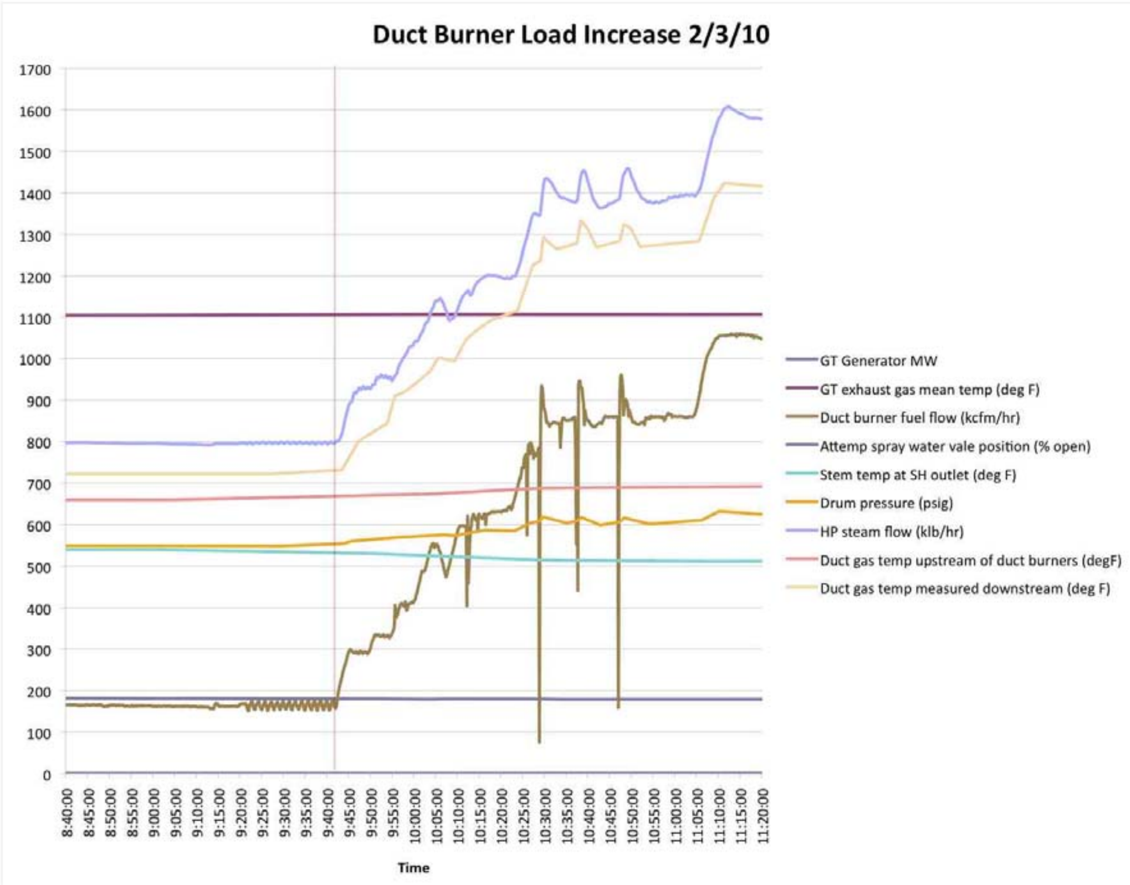

Figure 9 – Plots of DCS historical data during duct burner firing rate increase on 2/3/10

Suggested Action Items

It is suggested that waterside video inspections be conducted on a number of tubes positioned across the gas path. The inspections should be conducted on the first row of evaporator #2 tubes (immediately downstream of the duct burner) as well as evaporator tubes in other locations. Significant differences in deposit appearance should be further investigated via removal of tube samples for deposit analysis (see Section 4i).

Findings and Background Discussions

During the initial stages of startup (when drum swell eliminates the need to add water to the drum) there is minimal water flow in economizer tubes to remove heat. What flow there is during this period is provided by vents on each economizer upper header routed to the drum via a single 2-inch motor operated valve. Consequently, economizer tubes heat soak close to higher than normal temperatures during these near static conditions. The DCS historical data plots during the startup on 6/2/10 in Figure 10 show that exhaust gas exiting economizer #2 is between 124°F and 133°F when feed water flow is initiated. The initial feed water temperature is 86°F but very quickly increases to 141°F. This increase in feed water temperature indicates that the economizer-to-drum vent flow is insufficient to completely replace the 86°F water in the feed water piping with 141°F water from the DA storage tank (not surprising since there is no pressure differential between the economizer and the drum unless drum blowdown valves are opened relatively wide or significant feedwater flow is established. Tube temperature data from similar HRSGs has shown that when initial feed water flow rate is relatively low compared to normal flow rates, feed water will preferentially flow only in a few tubes closest to the economizer inlet nozzle. If tubes in the feed water inlet row of economizer #2 with little to no flow are assumed to be heat soaked to exhaust gas temperature, then they are chilled by approximately 38°F to 47°F when feed water flow is initiated. It is possible that some tubes near the economizer inlet nozzle are chilled to a lesser degree due some economizer-to-drum flow through the open vents. Non-uniform introduction of cooler feed water into heat soaked tubes results in some tubes of the feed water inlet pass being exposed to a chill while others remain for a short time at elevated temperature. Significant differences in the temperature of adjacent tubes creates bending stresses in tube-to-header weld connections and if repeated frequently will eventually result in tube failure.

The economizers in the East River HRSGs are of the cross flow harp configuration utilizing one-piece upper and lower headers. This configuration utilizes baffle plates inside the upper and lower headers to direct feed water alternately up and down through groups of tubes as the water passes from the inlet on one side of the harp to the outlet on the other side. As the water is heated in passing across the harp step changes in tube temperatures occur across the header baffle plates. When a one-piece lower economizer header is used, as in the East River HRSGs, thermal expansion of individual tubes is restricted. If the tube-to-tube temperature differences are too large, and occur too often, excessive bending stresses at tube-to-header welds can result in tube failure. Tube failures associated with cross-baffle temperature differences are more likely to occur in HRSGs exposed to very frequent start/stop operation. It is not anticipated to be a significant concern for the East River HRSGs due to their very limited number of startups.

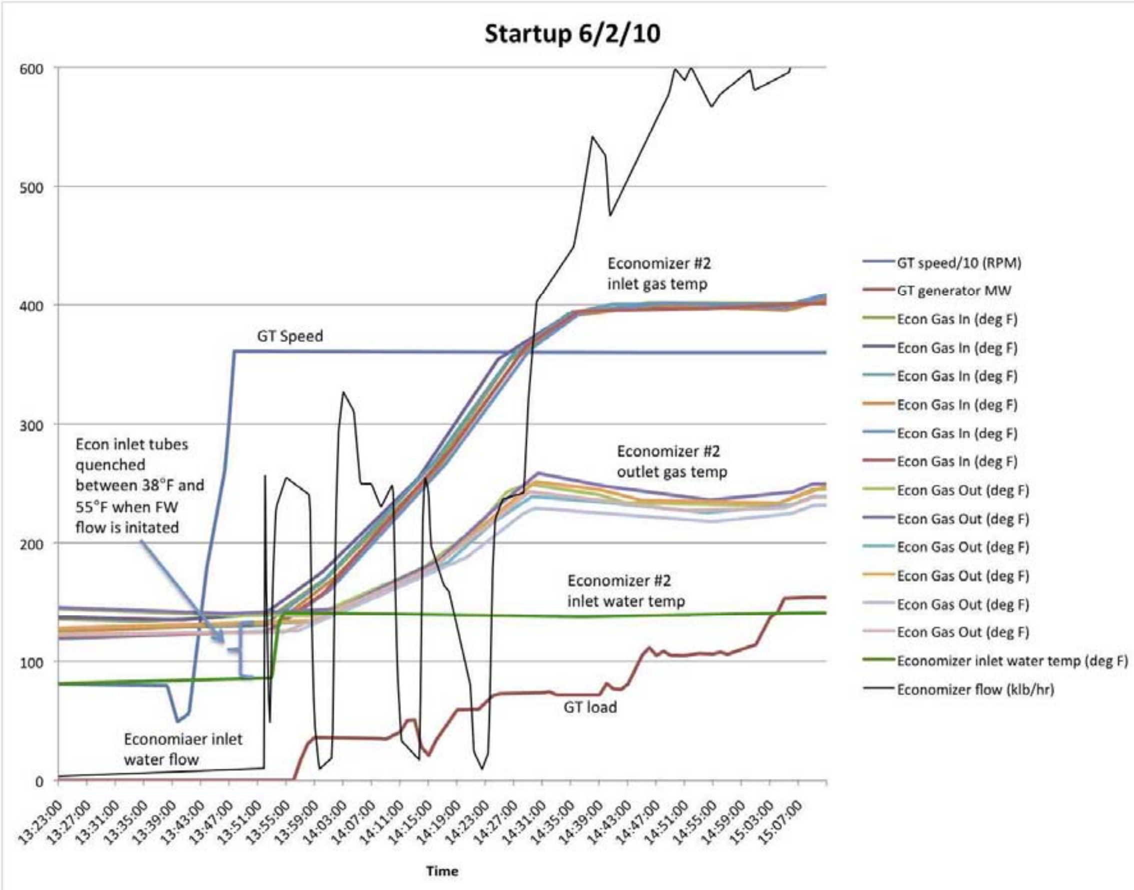

Figure 10 – Plots of DCS historical data during the startup on 6/2/10

<u>Suggested Action Items</u>

It appears that a slug of ambient temperature feed water in the piping upstream of economizer #2 causes the brief chill at the economizer #2 inlet. It is suggested that ConEd modify the East River startup procedures to minimize, or eliminate this event. This might be accomplished by opening a feed water pipe drain near the HRSG just prior to startup to provide sufficient flow to warm the feed water piping at the economizer inlet close to DA storage tank temperature. The economizer #2 inlet header drain should not be used for this purpose. If opened after the economizer has heat soaked, the drain's location on the far side of the lower header flow baffle from the economizer #2 inlet connection would cause the cool water in the feed water piping to flow into the economizer tubes replicating, or possibly further aggravating, the inlet chill. If a feed water drain located near the economizer #2 inlet that can be safely used for this purpose is not currently available, ConEd should consider installation of such a drain.

If the foregoing modification of the startup procedure does not significantly reduce the difference between economizer #2 exhaust gas outlet temperature and initial feed water inlet temperature, it is suggested that ConEd install temporary tube temperature thermocouples on tubes in the economizer #2 inlet pass to facilitate assessment of the potential for feed water chill during startup resulting in future tube failure. If thermocouples are installed to assess inlet chill, the installation of a few additional thermocouples are suggested to investigate the potential significance of cross-baffle tube temperature differences. Should ConEd wish to pursue installation of temporary thermocouples SI will be pleased provide installation guidance during the outage, interpretation of the data obtained, and provide support in identifying solutions if necessary. Suggested thermocouple locations and installation procedures are provided with this report.

e) SH Safety Valve Drains and Vents:

Background Discussion

The Consolidated SH safety valves installed on the East River HRSGs have a drain connection at the bottom-front of the valve body and another drain connection on the discharge elbow drain pan. A third connection is provided at the top-front of the valve body and is intended for use as a vent for air and steam in the upper valve body when the valve is open. If this vent flow is restricted by backpressure from the interconnected drains valve performance may be altered. This vent is typically piped so as to discharge to atmosphere in a location that takes into account personnel safety and prevents moisture from entering the vent pipe. The East River safety valves have the two drains and the body vent interconnected into a common drainpipe. See Figure 11. There have been cases reported where moisture from the drain system enters the valve body through the body vent connection resulting in corrosion of internal valve components and/or restriction of vent ID due to corrosion products. In such cases alteration of valve performance or failure of the valve to open can result.

Figure 11– SH safety valve drain/vent connections.

Suggested Action Items

It is suggested that ConEd contact the safety valve manufacturer, confirm the appropriate drain/vent piping configuration for the SH and drum safety valves, and modify the safety valve drain/vent piping if appropriate.

f) Economizer Drains:

Background Discussion

The current economizer maintenance drain valve arrangement poses a risk of developing significant tube-to-tube temperate differences during operation that can result in tube damage. East River's economizer drain valves are arranged with a single small bore "inboard" isolation valve in the drain line below each tube panel. Drain lines from these valves interconnect via a common manifold on which the second "outboard" isolation valve is installed. With use, leaks can be expected to develop in the seats of the inboard valves. When this occurs in two or more valves a bypass path is created through the drain system from economizer panels operating at higher feed water pressure (and colder temperature) to panels operating at lower pressure (but higher temperature). Even a small flow of cooler water continuously entering the hotter section header and tubes from the drain can chill the one or two tubes located above the leaking drain connection and develop significant differences between the majority of the tubes in that pass and the one or two tubes chilled by the cooler feed water leaking through the drain valves.

Suggested Action Items

It is suggested that consideration be given to installing a second small-bore isolation valve in each economizer small-bore drainpipe. These now “tandem” isolation valves should be operated in a “master/martyr” fashion (master valve always opened first and closed last) so that the master valve retains long term tight shutoff, preventing feedwater bypass through the drain system. Alternatively, periodic temperature measurements of economizer drainpipes adjacent to the inboard isolation valves will sometimes indentify leaking valves.

6.0 Summary of Major Action Items

Sections 4 and 5 have comprehensively identified areas which could lead to damage and possible failure on the East River HRSGs in the future. For each associated with the cycle chemistry, FAC and thermal transients SI has outlined the basis of Action Plans which could be developed and adopted by Consolidated Edison to ensure future reliability of the units. The following delineates the most important of these proposed activities:

a) Upgrade the cycle chemistry instrumentation to the International Standard (Section 4a)
b) Develop a set of cycle chemistry alarms, action levels and procedures for the operators (Section 4b)
c) Identify possible other areas of FAC in the deaerator, outlet evaporator tubing and in the risers from the economizer outlet to the drum (Sections 4c and g)
d) Develop a procedure for monitoring total iron around the cycle which can be used to assess the continuing FAC potential (Section 4e)
e) Conduct a series of tests to simplify the overall chemistry control of the units (Section 4j)
f) Assess the superheater drain effectiveness by calculating the condensate formation rate during a purge so that the optimum drain size can be calculated (Section 5.0, a, i)
g) Determine if extra drains are needed and modify existing drain operating practices (Section 5.0, a, i)
h) Conduct a field monitoring program to test the efficacy of the superheater drain system (Section 5.0, a, iii)
i) Upgrade the attemperators by installing a new drop pot and automatic drain (Section 5.0, b)
j) Modify the existing startup procedures to optimize the GT loading rates, hold points and load durations, and the SH steam flows to avoid triggering high SH temperature alarms and GT load runback (Section 5.0, d)

k) Modify startup procedures, and possibly feedwater pipe drains, to prewarm water sitting in the feedwater piping and minimize quenching at the economizer inlet (Section 5.0, d)

7.0 Concluding Remarks

FAC has been a predominant failure and damage mechanism in the early operating life of the East River HRSGs. Some excellent investigative work has been conducted by Consolidated Edison involving redesign of parts of the economizer sections and by cycle chemistry changes. The current assessment has indicated that these items have made the situation better, but cannot determine whether they have completely rectified the situation. Thus SI has suggested two main sequential steps. The first will help to confirm the efficacy of the changes by monitoring iron at locations in the cycle, removing tube samples for analysis from the economizer and evaporator circuits to determine the deposition processes, and some further NDE/inspections of two key locations. Based on the results from these studies, SI has suggested a second step involving possible improvements/optimizations for the cycle chemistry if it appears that FAC is still active. These chemistry changes, which mainly address the very complex dual feed (EI and drum) system involving different chemistries, could also be addressed to make the chemical treatments less complex. Another important item is to upgrade the chemistry instrumentation to the International Standard to provide better protection for operation and for the operators' control.

SI analysis of the East River HRSGs has identified a number of items very deserving of further consideration and action so as to ensure suitable component life and avoid premature failures due to thermal fatigue.

Having accumulated less than 100 starts, the East River HRSGs are very young from a thermal fatigue perspective. While the predominately continuous operation and relatively moderate design steam conditions significantly reduce the probability of thermal fatigue or creep failures when compared to HRSGs installed on F-class combined cycle installations, the possibility of thermal fatigue failures cannot be ruled out. SI analysis of thermal transients in the East River HRSGs has identified a number of items very deserving of further consideration and action so as to ensure suitable component life and avoid premature failures due to thermal fatigue.

The most urgent suggested actions are described in section 5.0, a) for effectively draining the SH during all startups, and in Section 5.0, b) regarding improved attemperator piping drains.

The suggested actions in Section 5.0, d) regarding avoiding SH over temperature conditions, in Section 5.0, d) regarding modification of startup procedures to eliminate economizer inlet chill, and in Section 5.0, e) regarding safety valve body vents are also important.

Appendix A

Benchmarking an Organization's Heat Recovery Steam Generator Longterm Reliability

Introduction

The important aspects of an organization's Heat Recovery Steam Generator Tube *Failure Reduction Program are:*

- *HRSG tube failures (HTF) – mechanisms and root causes*
- *Cycle chemistry influenced HTF*
- *Thermal transient/cycling influenced HTF*
- *How to optimize the cycle chemistry in the feedwater and evaporator circuits to avoid HTF*
- *How to identify the locations where thermally driven HTF could occur*
- *How to monitor thermal transients.*

Overall the program should identify the precursors to damage and HTF.

Organizations frequently ask how good or bad is their overall HRSG reliability program on a world ranking. To answer these questions, the HRSG Benchmarking Process was developed.

Much thought has been given to the Benchmarking topic, and the current assessment approach has been applied to over 100 combined cycle/HRSG operators worldwide and on every type of HRSG (horizontal, vertical, multiple-, dual- and single- pressure). It will provide an assessment for an organization of its overall approach to HRSG longterm reliability.

Assessment of an Organization's HRSG Longterm Reliability

Weighting	Factor	Points	Total
3	A. Total number of HTF over the last three years		
	❑ 0	0	
	❑ 1-2	1	
	❑ 3-5	2	
	❑ 5-10	3	
	❑ >10	4	
	Sub-total (Points x Weighting)		______
3	B. Number of chemically influenced HTF over last three years (Flow-accelerated corrosion, corrosion fatigue, hydrogen damage, acid phosphate corrosion, caustic gouging, pitting)		
	❑ 0	0	
	❑ 1-2	1	
	❑ 3-5	2	
	❑ 5-10	3	
	❑ >10	4	
	Sub-total (Points x Weighting)		______
3	C. Cycle Chemistry Instrumentation and Control. What percentage of the International Standard for instrumentation do you have? (The IAPWS Guidance Document is at www.IAPWS.org)		
	❑ 100%	0	
	❑ 90-99%	1	
	❑ 70-89%	2	
	❑ <70%	3	
	Sub-total (Points x Weighting)		______
2	D. Is reducing agent used in the feedwater (during		

Operation and/or shutdown)?

❑	Yes	1
❑	No	0

Sub-total (Points x Weighting) ______

2 E. What is level of iron in feedwater (generally during steady operation)?

❑	<5 ppb	0
❑	5-10 ppb	1
❑	11-20 ppb	2
❑	>20 ppb	3
❑	Don't know	3

Sub-total (Points x Weighting) ______

2 F. What is level of iron in LP Drum (generally during steady operation)?

❑	<5 ppb	0
❑	5-10 ppb	1
❑	11-20 ppb	2
❑	>20 ppb	3
❑	Don't know	3

Sub-total (Points x Weighting) ______

2 G. Has temperature monitoring been conducted on LP Economizer, Superheater and Reheater during Startup, Shutdown and Operation to identify damaging thermal transients (using specially installed thermocouples)

❑	Yes, all three	0
❑	Yes, on two	1
❑	Yes, on one	2
❑	No	3

Sub-total (Points x Weighting) ______

1 H. Do you have written Action Plans to address Root causes of HTF or potential HTF?

- ❑ Yes 0
- ❑ No 1

Sub-total (Points x Weighting) ______

1 I. <u>Do you have written Action Plans to address damaged tubing or potential damage tubing</u>?

- ❑ Yes 0
- ❑ No 1

Sub-total (Points x Weighting) ______

Total ______

<u>Rating System</u>

World Class	<5
Very Good	6-10
Above Average	11-25
Average Program	26-40
Below Average Program	41-45
Poor	46-55