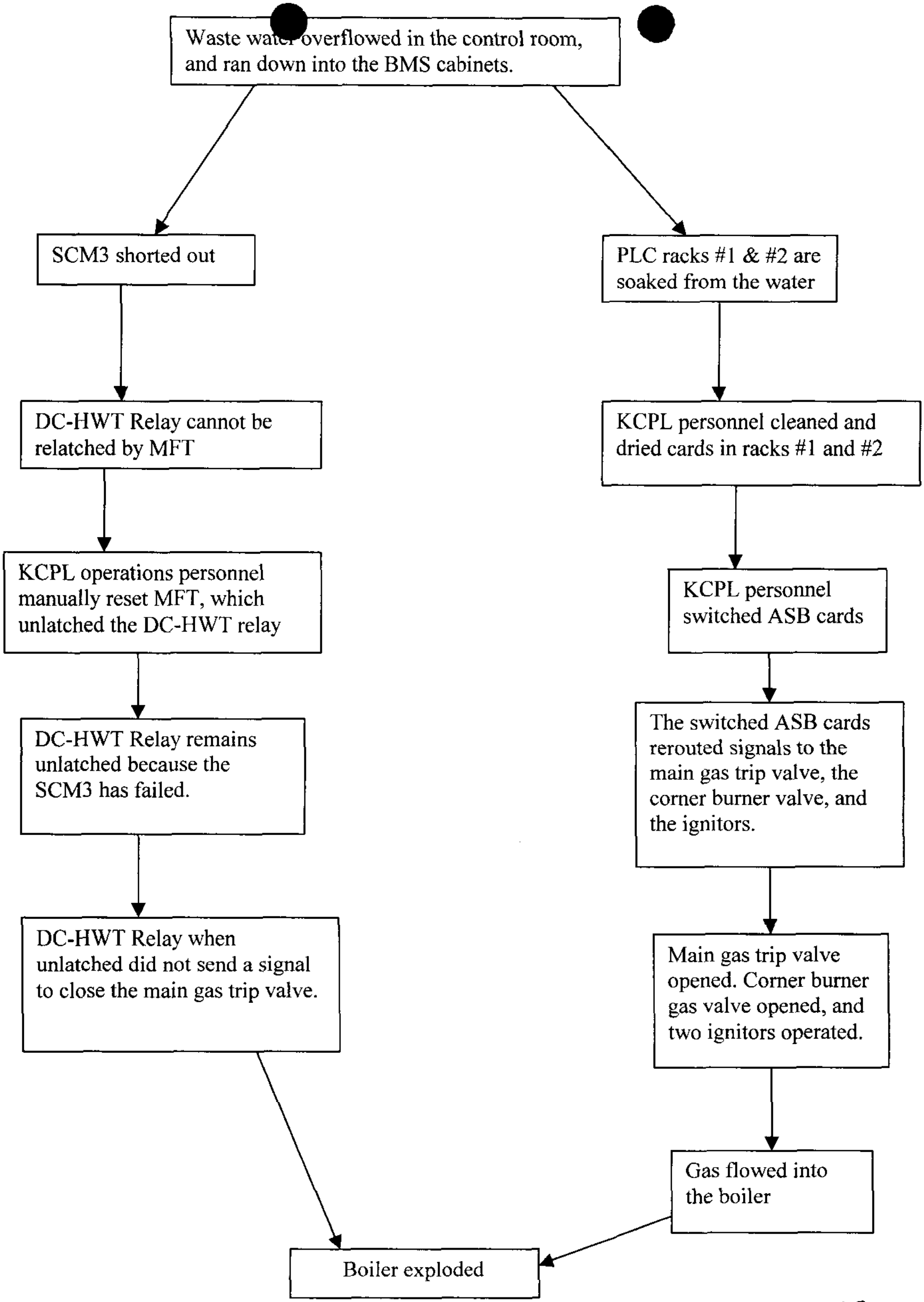
Waste wa overflowed in the control room, and ran down into the BMS cabinets.
SCM3 shorted out
DC-HWT Relay cannot be relatched by MFT
KCPL operations personnel manually reset MFT, which unlatched the DC-HWT relay
DC-HWT Relay remains unlatched because the SCM3 has failed.
DC-HWT Relay when unlatched did not send a signal to close the main gas trip valve.
PLC racks #1 & #2 are soaked from the water
KCPL personnel cleaned and dried cards in racks #1 and #2
KCPL personnel switched ASB cards
The switched ASB cards rerouted signals to the main gas trip valve, the corner burner valve, and the ignitors.
Main gas trip valve opened. Corner burner gas valve opened, and two ignitors operated.
Gas flowed into the boiler
Boiler exploded

Figure 1-7

APPENDIX C

Glossary

GLOSSARY

ELECTRICAL TERMS

Contact:

A contact in an electrical device is a point at which two conductors or wires are connected and disconnected. Physically a contact is usually two pieces of metal which, when brought together to touch each other, allow an electrical current to pass through. A light switch is an electrical device with a contact. When the switch is moved from one position to the other the contact opens or closes. In the closed position, the contact completes the circuit, electrical current flows to the light, and the light comes on. When in the open position, the contact opens and the electrical current cannot flow to the light , so the light is off.

Relay:

A relay is a device that acts like a switch. Most relays are made up of two parts, a solenoid coil and contacts. When an electrical current is applied to a solenoid coil, the plunger inside of the coil moves. Attached to this plunger are the contacts.

So when the plunger moves, the contacts change positions. A simple relay has two conditions usually referred to as "energized" or "de-energized". A relay can have two types of contacts, usually referred to as "normally closed" or "normally open" in the de-energized condition. A relay may have either normally closed or normally open types of contacts, or even both types of contacts. So when a relay in a de-energized condition with a normally open contact is energized the normally open contact will close. When this relay is de-energized, the contact will open.

A relay is usually operated from a control type circuit that may not be the same circuit the contacts are in. Some times a relay is used to control a higher voltage circuit using a lower voltage circuit to operate. Relays with multiple sets of contacts can control several electrical devices at the same time, and are used to automate a system.

Latching relay:

A more sophisticated type of relay is a latching relay. This type of relay usually has two solenoid coils instead of one. In order for the contacts to change from one position to the other and back, each coil must be energized. When one coil is energized, the contacts change position, and the relay will lock in that position (latched). In order for the contacts to change back to the original position (unlatched), the second coil must be energized. Typically when both coils are energized the relay remains latched.

Solenoid:

Wired wrapped around a hollow core containing a metallic plunger. When electric current is applied to the wire the electromagnetic field produced moves the plunger.

Programmable logic controller:

A device, which allows internal software programming to be written to interface with electrical inputs and outputs. The device can be programmed with logic steps that when one or more specific inputs are received, it can send one or more specific outputs. Programming allows for certain internal logic steps to be completed before other internal steps can be initiated or completed.

The input signals and output signals are routed through computer cards. These cards are positioned in slots in groups referred to as racks.

BURNER MANAGEMENT

Burner management system:

Large utility steam boilers have systems in place to reduce the possibility that hazardous conditions will occur. One such system is the burner management system (BMS). This system is used to minimize the hazards involved in burning fuel in a boiler. As with all systems, a BMS is somewhat limited in what it can prevent. No system can be designed to react to every scenario or situation that is possible under all circumstances. Human interaction is still an important risk factor.

Standards for the prevention of furnace/boiler explosions are provided in the National Fire Codes published by the National Fire Protection Association. These standards describe procedures for the safe operation of the fuel systems on boilers. The standards cover the burning of oil, natural gas, and coal. These standards outline what procedures are needed to burn fuel safely in a boiler.

The burner management system's main functions are to allow for the safe burning of fuel, and to manage the fuel usage properly. The heart of this system has been usually a system of relays. Today modern programmable logic controllers are used, as well as incorporating the burner management system into the distributed electronic control system, which is now somewhat a standard for power plants. Whatever type of devices are used, the fundamental issue is some type of interlocking system that prevents certain operations from occurring before certain other conditions are met.

Part of the BMS is a purge of the boiler before light off. In order to ensure there are no lingering combustible gases or raw fuel in the boiler before a spark or fire is introduced into the boiler, air is blown or drawn through the boiler by large fans for a specific amount of time. This amount of time is pre-determined and counted off with a purge timer. These large fans are used during normal operation of the boiler to supply air for the combustion of the fuel and to ensure the gases from the combustion are removed from the boiler.

The boiler has certain monitoring devices that indicate and track operating parameters and/or operating conditions. Certain conditions require the boiler to be tripped automatically, or the fuel stopped automatically. Some conditions for a boiler trip are furnace pressure high or low, low water level in the drum, loss of air flow, or loss of flame. A boiler is operated in such a manner that these conditions as well as many other parameters are monitored and adjusted by the boiler control system. The boiler operator monitors the operation of the boiler and the control system and may be required to make adjustments to prevent the boiler from operating at the conditions that would be unsafe.

The control system is designed to trip the boiler when certain conditions exist without any interaction from the boiler operator. A trip due to these conditions happens without operator intervention and usually without a determination if it is a false condition. Because the monitoring devices are not perfect, the operator also has the ability to trip the boiler manually if he decides there is a hazardous condition, or he believes the automatic devices are not operating correctly.

When the interlock device, sometimes referred to as the "Master Fuel Trip", is in the "tripped" position, it prevents fuel from entering the boiler. When it is in the "reset" position, it allows for other devices to operate allowing fuel to enter the boiler. For the interlock device to be in the reset position, certain conditions have to be met, one of which is a purge must have been successfully completed on the boiler. To allow the boiler to be lit off, the interlock device must be in the reset position. The interlock device then can be tripped to shut off fuel to the boiler. When the boiler is off the interlock device should be in the tripped position.

BOILER TERMS

Boiler light off:

The act of igniting a relative small amount of fuel to begin the process of bringing the boiler up to operating pressure and temperature. This is usually done with small burners called ignitors.

Ignitors:

A small burner used to start the process of bringing the boiler up to operating pressure and temperature. Ignitors usually use fuel oil or natural gas as a fuel. The ignitors are used to light off the main coal burners, and sometimes are used to insure the fire in the furnace is burning properly.

Burner:

A device where fuel and air enter, are mixed and then ignited at the exit of the device. Usually a boiler has several burners, and the largest boilers have several burners at several elevations of the furnace.

Burner vent valves:

The natural gas burner piping system has vent valves, which are opened when the boiler is taken off to remove any residual gas that may be present in the piping system. These vent valves are closed when the boiler is started up and when its burning natural gas.

Furnace:

That section of the boiler where the combustion of the fuel and air mixture takes place.

Boiler:

A piece of equipment consisting of pipe, headers and drums in which fuel is burned to turn water into steam.

Water tubes:

Steel tubes approximately 2" to 3" in diameter containing water usually surrounding the furnace area on four sides forming a square. The combustion of the fuel and air mixture in the furnace area heats the water inside the tubes to steam.

Furnace pressure/furnace draft:

The boiler is not a pressure vessel. Some parts of a boiler are designed as a pressure vessel, such as the steam drum and certain headers. A pressure vessel is designed specifically to operate at and maintain its integrity at certain pressures. A boiler steam drum may be designed to withstand an internal pressure of 3000 pounds per square inch. A boiler is made up of tubes welded together, but not in such a way as to make it a pressure vessel. The area of the boiler where the fuel burns is referred to as the furnace. The furnace pressure must be monitored to make sure it does not exceed the design limits. Both high pressure and low pressure are dangerous. High pressure would make the boiler furnace expand outward damaging anything close to the boiler and also would allow the fire or fuel to escape. Low pressure, or pressure below atmosphere in the furnace, would cause the boiler furnace to collapse in on itself.

Drum level:

The boiler is made up of four walls of tubes that contain water in them. The fire in the furnace causes the water to turn to steam. This steam rises and is collected in a large pressure vessel known as the steam drum. Also in this drum is water, which is fed down to the bottom of the furnace and into the wall tubes. The tubes that make up the walls of the furnace are made of steel so water must be inside of them to dissipate the heat from the fire or they will fail. Thus, it is important to keep water in the tubes, which is done by monitoring the level of water in the drum. If the level of water is low, then there is a possibility that the wall tubes could run out of water and could over heat and fail.

Air flow:

In order for combustion to take place in the furnace the fuel must have a certain amount of air available. Large fans called "draft fans" are run to supply air to the furnace for the combustion, and remove the gases resulting from the combustion from the furnace in order to make room for more fuel and air. Fans both push the air in and pull the combustion gases out of the furnace, or there are separate fans that push the air in and fans that draw the gases out of the furnace. On a pressurized boiler there are a set of forced draft fans. On a balanced draft boiler there are two sets of fans, forced draft and induced draft fans. Without proper air flow, or no air flow, and the fuel still entering the furnace a possible explosion could take place.

Loss of flame:

If there were no continuous sustainable fire in the furnace, there would be differing amounts of unburned fuel and air in the furnace, which could cause an unstable fire, which could lead to no fire. If the fuel were not shut off, there would be fuel entering a hot boiler. This fuel could ignite and lead to an explosion. Boilers are equipped with some type of device that will recognize a no flame condition in the furnace.

APPENDIX D

Estimation of waste water overflow

Estimation of the amount of waste-water overflow

NOTE: Based on information provided by KCPL

The sump pit for lift station #1 appears to be a fiberglass basin **60"** in diameter and **120"** deep, which calculates to **196** cubic feet of total volume. There is a float level control that determines the two levels in the basin at which the pumps will turn on and off. If these levels were known, Staff could make a better estimate of the volume of water. However this information has not been provided by KCPL to the Staff.

The Staff has made some assumptions and estimations in order to estimate the possible total amount of water that could have been pumped into the control room. In order to determine the likely volume of water, the estimated volume of the two pumps and piping must be removed from the total calculated volume. Also, there is a volume in the basin not used because (a) the pump requires a minimum level of water to operate, and (b) an allowance must be made because of the assumption that the floats for level control would not allow the water to reach the top of the basin. Subtracting these volumes from the total calculated volume leaves approximately **178** cubic feet. This volume will hold **1,330** gallons of water.

All of the actual amount of water the pit was designed to hold was pumped out of the basin because the level controls turned the pump on and turned it off. However, this does not mean that all of this water would have gone to the control room. The cleanout on the first floor was open and water was flowing out of it. Because the toilets on the third floor were at a higher elevation than the cleanout, the amount of water flowing out of the toilets could have been less than what was coming out of the cleanout opening. In addition the pumps could have been pumping a small amount through the constriction in the pipe to lift station #2.

Because of all these factors, Staff has no way to estimate accurately the amount of the water in the control room. **With waste water coming out the cleanout at a lower elevation than the toilets on the third floor level, it would be a fair assumption that less than the total amount of water went to the control room.** Based on this assumption, Staff estimates that less than 700 gallons of water were pumped to the control room.

REMOVE FROM HC

DATE 8/14/01

HC

Volume of basin = **3.1416 x 2.5 x 2.5 x 10 = 196.35 cu.ft.**

Estimated volume of basin for pump operation = **3.1416 x 2.5 x 2.5 x 3/12 = 4.9 cu.ft.**

Estimated volume of basin for float operation = **3.1416 x 2.5 x 2.5 x 6/12 = 9.82 cu.ft.**

Estimated volume of pump and piping = **3.73 cu.ft.**

Estimated volume of usable basin = **196.35 - 4.9 - 9.82 - 3.73 = 177.9 cu.ft.**

Water = **7.48 gal/cu.ft.**

Estimated gallons of water pumped = **7.48 x 177.9 = 1330.7 gallons**

Orig 1 of 1

HC

HAWTHORN 5
FEBRUARY 17, 1999
BOILER EXPLOSION
INVESTIGATION REPORT

REMOVE FROM HC
DATE 8/14/01 per Order
nh

KANSAS CITY POWER
& LIGHT COMPANY
KANSAS CITY, MISSOURI

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HAWTHORN 5
FEBRUARY 17, 1999
BOILER EXPLOSION
INVESTIGATION REPORT

KANSAS CITY POWER
& LIGHT COMPANY
KANSAS CITY, MISSOURI

Boiler Explosion
Hawthorn Unit No. 5
February 17, 1999

1.0 EXECUTIVE SUMMARY

At approximately 00:30 on the morning of 17 February 1999, the boiler of the KCPL Hawthorn Station Unit No. 5 was destroyed in an explosion. KCPL immediately initiated an in depth and extensive investigation of the cause of the explosion.

This report follows months of investigation by KCPL and others.

The Hawthorn Unit No. 5 was placed into service on 31 May 1969. It was a coal and gas fired plant rated at approximately 470 MW.

At the time of the explosion, the boiler was out of service for repairs. The outage started just after midnight on 13 February 1999 when the unit was shutdown to repair a boiler tube leak. The outage period was extended due to ongoing repairs on a Low Pressure Heater that could not be isolated from the condenser.

During this outage period, a sewer water overflow in the Unit No. 5 Control Room restroom on the afternoon of 16 February resulted in water flowing downward into an electrical equipment room (Computer Room) below the Control Room. The water overflow occurred when a plumbing contractor's sewer cleanout tool became lodged in a check valve. When a sewage lift station pump started up with the tool still lodged in the valve, sewer water was pushed through the Control Room toilet bowls and the ground level cleanout.

The sewer water contacted portions of the Burner Management System (BMS) located in the Computer Room. Some components of the BMS were damaged and others were merely wetted by this contact.

During cleaning, testing and replacing BMS components, the failure of a single component within the BMS permitted signals generated from these activities to cause the opening of the main gas valves at about 21:30. This valve opening was unknown to KCPL personnel. During continued troubleshooting efforts, which were undertaken in accordance with the Troubleshooting Guide provided by the OEM, two ignitors were activated continuously at about 23:00. The activation of these ignitors was unknown to KCPL personnel. None of these unintended and unexpected operations were identified as potential occurrences in the Troubleshooting Guide provided by the manufacture.

The immediate ignition of the gas discharged into the boiler furnace did not occur because of the boiler's natural draft, the configuration of the burners and the relative locations of the open gas burner valve and the igniters.

2.0 BACKGROUND

2.1 The Hawthorn Unit No. 5 was constructed in 1968 and 1969 at the Kansas City Power & Light Co. Hawthorn Station located adjacent to the Missouri River in Kansas City, Missouri. It was placed into service on 31 May 1969. (A Hawthorn Station site plan is included in Appendix 2.)

2.2 The Unit No. 5 Boiler was a Combustion Engineering 500 MW boiler producing 3,500,000 pounds per hour of primary steam (2,400 psig and 1,005°F) and 3,120,000 pounds per hour of reheat steam (780 psig and

1,005°F). The boiler was originally fired with coal and natural gas. At a later date, it was modified to burn fuel oil or combinations of coal and natural gas or fuel oil and natural gas.

2.3 The primary and reheat steam was delivered to the turbine (General Electric No. 170X335) rated at 468,540 kW at 3,600 rpm with steam at 2,400 psig and 1,000°F. The generator (General Electric No. 180X335) was a two-pole machine rated at 514.8 MW.

2.4 The boiler was originally constructed to operate as a positive pressure furnace. It was modified in 1978 to operate with the furnace at negative pressure. The fuel burners were located at the furnace corners with the northwest corner designated the "No. 1" corner and the other corners numbered in clockwise sequence. In each burner corner, there were five levels designated as A-B, B-C, C-D, D-E, and E-F from bottom to top level. Fuel oil burner nozzles were located at levels B-C and D-E only and were abandoned in place (not in service). Coal nozzles were located at each level and gas nozzles were at levels A-B, C-D and E-F. The gas services at each level included igniter gas, warm-up gas and main gas. (A gas burner drawing is included in Appendix 3. This is the known gas flow path into the boiler.)

2.5 The original control, alarm and data acquisition systems for Unit No. 5 were all analog/electro-mechanical based systems. Over time, portions of these systems were upgraded to include modern digital-based components or digital-based interfaces. By 1999, the Burner Management System

(BMS) included many of the original field devices (with routine replacements) with a Programmable Logic Controller (PLC). The other control systems for balance of plant, boiler feed pumps and combustion control were upgraded in 1996. The alarm system for Boiler, Turbine, and Generator Control (BTG) was upgraded in 1995 and the Data Acquisition System (DAS) was upgraded most recently in 1995.

3.0 INCIDENT

3.1 On Saturday, 13 February 1999, at 00:05, Hawthorn Unit No. 5 was removed from service to repair a tube leak on the lower boiler furnace nose. Other work planned during the outage included repair of a shell-side leak in the No. 4 Low Pressure (LP) feed water heater. The boiler was cooled and entered for the tube repair work by 11:50.

3.2 Repair work on both the tube leak and the No. 4 LP Heater continued through the day on Sunday, 14 February, and on Monday, 15 February (Presidents' Day holiday). By 00:05 on 16 February, the boiler tube repair work was complete and the boiler was released by operations at 01:00 for start-up. The No. 4 LP Heater repair was incomplete and the heater was isolated. A red hold was placed on the heater so that repairs could be completed while the unit was operating.

3.3 The Boiler was filled with water and warm-up gas burners were activated to start bringing the unit back into service. By 06:47 on 16 February, all levels (A-B, C-D, E-F) of the warm-up gas burners were active.

3.4 The start-up continued as the boiler pressure increased and feedwater and vacuum pumps were brought into service. The unit was nearly ready for rolling the turbine at 11:55 when Operations was not able to attain proper vacuum (for turbine operation) at the condenser. The cause of insufficient vacuum was traced to an isolation valve at the No. 4 LP Heater that was not holding. The boiler was placed in hot standby pending completion of the heater repairs. The warm-up gas burners were shutdown and all fire was out of the furnace by 13:55 on 16 February.

3.5 Shortly before 15:00, the toilets in the Unit No. 5 Control Room restrooms, located on the third level of the unit control block, overflowed and water drained through cutouts in the floor within the BTG Board. Sewage was also flowing out of the cleanout plug on the 1st floor where the plumbing contractor was working. The water flowed down two additional levels; a "Cable Room" on the second level and a "Computer Room" on the first level. Both of these rooms were located directly below the Control Room. Cleanup and checkout of the equipment was initiated by 15:15. (Drawings showing the Control Room, Cable Room, and Computer Room floor layouts/openings are included in Appendices 4, 5, and 6.)

3.6 The repair of the No. 4 LP Heater continued while the Computer Room equipment was cleaned, dried, tested and repaired as necessary. The boiler pressure continued to drop as it cooled.

3.7 The heater repair work and Computer Room work continued into 17 February.

3.8 At approximately 00:30 on 17 February 1999, the boiler exploded. (Aerial photograph showing the damage is included in Appendix 7.)

4.0 DISCUSSION

4.1 As the emergency response actions were winding down at the Hawthorn Station, KCPL assembled a team to investigate the incident. The team included members from the Hawthorn Station, from Engineering Services and from outside organizations. The investigation team operated independently, for the most part, from a parallel investigation commissioned by insurance interests. The two teams had access to a common set of source data and participated in some joint information recovery activities.

4.1.1 The investigation activity was initiated on 22 February 1999 and the first team meeting was held on 23 February. The initial activities undertaken were identification of the timeframe of interest, identification of potential witnesses, identification of activities within the timeframe and the available sources of information concerning those activities. The investigation team met weekly, as necessary, to review progress, share ideas and to assemble the story of what happened as it was developed.

4.2 The initial focus of the investigation was to identify sources of fuel, air and ignition and how they could be contributed to produce this incident in a boiler that was out-of-service.

4.2.1 The principal causal factors and relationships were found in two primary groups; those associated with the Sanitary Sewer System and those associated with the BMS. (Graphical presentation of the Hawthorn Explosion Timeline for these groups and parallel operations activities and data log documentation are included in the Appendix 1.)

4.2.2 The potential for coal as fuel or ignition sources was examined. No evidence of coal or coal dust involvement in the incident was identified. The balance of the investigation concerning fuel was concentrated on natural gas and control of gas valves.

4.3 Available very early in the investigation was gas flow rate data from the pipeline metering station, which was remotely recorded. This data, which was reported only once per hour, indicated there was a 15 MCFH gas flow when the Unit No. 5 Boiler was out-of-service after 14:00 on the day preceding the explosion. This flow rate was identified as the fuel consumed by an auxiliary boiler at the station. (The pipeline metering data is included in the Appendix 8.)

4.3.1 The total measured gas flow from 21:00 until 01:00 was 990 MCF. With the adjustment for continuing consumption to the auxiliary boiler, an incremental gas flow of 130 MCFH was identified for the hour beginning at 21:00 on 16 February. Subsequent increases in the flow rate were indicated at the next three hourly data points. The flow rate recorded for the hour after midnight (last data point) was 299 MCFH (corrected for the auxiliary boiler usage). Beginning at 21:30, an unknown amount of the total gas flowed to the boiler furnace. The precise amount of gas flowing into the boiler furnace was not estimated because three of the four main gas vent valves were determined to be open.

4.4 In investigating the point of gas entry to the boiler, the entire gas piping system was examined both in the drawings and control diagrams for the gas system and in the portions of the piping systems recovered during demolition work on the boiler debris. (Boiler Gas Header diagrams are included in the Appendix 9.)

4.4.1 Each of the gas supply systems (igniter, warm-up and main) extended to the three levels (A-B, C-D, E-F) and each corner where the gas burners were located. At each level, there were actuated values controlled by the Burner Management System (BMS) used to admit gas to the burner nozzles. The vertical runs of the gas headers each terminated in vent headers that connected each riser around the boiler perimeter. BMS controlled vent valves on the main gas headers were used to ensure there was no gas in the headers when the burners were not operating.

4.4.2 The igniter gas header flow was controlled through the BMS at the Igniter Gas Regulator (5-FG-137) and fed from the warm-up gas piping. The point of connection was downstream from the Igniter/Warm-up Gas Trip Valve (5-FG-91) so that valve 5-FG-91 blocked gas entry to both the igniter and warm-up gas systems. The igniter gas header piping was 3-inch at the control valve and decreased to 1-1/2-inch in the risers to the burners.

4.4.3 The warm-up gas header flow was controlled through the BMS at the Warm-up Gas Regulator (5-FG-93) and fed from the 24-inch gas line upstream of the main gas control valves. The warm-up gas piping was 8-inch at the control valves and decreased to 4-inch in the risers to the burners.

4.4.4 The main gas header flow was controlled through the BMS at the Main Gas Trip Valve (5-FG-24). The Constant Pressure Control Valve (5-FG-22) located upstream from valve 5-FG-24 was used to adjust the main gas header pressure. The actuated valves closest to the main gas header were the Main Gas Regulator (5-FG-25) and the Main Gas Minimum Pressure Regulator (5-FG-27). The main gas piping was 24-inch at the control valves (except 5-FG-25 which was 14-inch) and decreased to 12-inch in the risers to the burners.

4.4.5 The Main Gas Trip Valve (5-FG-24) and the Constant Pressure Control Valve (5-FG-22) were recovered. Both valves were partially open when examined after recovery. (Photographs of valve 5-FG-24 are included in Appendix 10.) The Constant Pressure Control Valve (5-FG-22) and the Main Gas Regulator Value (5-FG-25) were used to regulate the main gas pressure from 50 psig at the pipeline entry to a range of 1.5 to 30 psig in the main gas header. The Constant Pressure Control Valve and the Main Gas Regulator Valve (both butterfly valves) were not gas tight and may not be fully closed whenever the boiler is out-of-service. The Main Gas Trip Valve (plug) was intended to be gas tight and to isolate the gas piping from pipeline gas.

4.4.6 Data retrieved from the DAS showed that the main gas header was pressurized to 6.35 psig at 21:25 on 16 February. This indicated that the Main Gas Trip Valve was partially opened and the Main Gas Regulator valve controller was in the hand position and was throttling the supply pressure. A change in the main gas header pressure to 3.27 psig was recorded at 22:07. This indicated that more gas was released through the main gas header (i.e. the discharge rate increased and the pressure dropped). This information was consistent with the pipeline metering data that showed increased flow in the hour following 22:00.

The above information relative to how the main gas system was activated was developed during the gas piping system evaluation.

4.5 The Burner Management System (BMS) used a Programmable Logic Controller (PLC) to implement all burner operating and safety functions. The BMS incorporated multiple components including three Solenoid Coil Monitoring modules (SCM) and four PLC Racks each of which included several input/output boards (cards) and an ASB module. The PLC Racks were numbered 1 though 4. Rack 1 incorporated common (BMS functions) and headers, Rack 2 incorporated gas burners, Rack 3 incorporated gas burners/analog flame, and Rack 4 incorporated coal mills/air dampers. (PLC layout diagrams of Rack 1 and Rack 2 are included in Appendices 12 and 13.)

4.5.1 The Burner Management System resided in a multi-door cabinet with no dividers. Rack 1 and Rack 2 were the only ones affected by the water leak from the Control Room. Rack 1 was contacted by a greater amount of water than Rack 2.

4.5.2 Because the burner controls were being cleaned and tested during the period shortly before the explosion, the activities in the Computer Room and the potential results were examined closely. These activities started at 15:15 on 16 February and continued until the explosion.

4.5.3 By about 19:20 on 16 February, PLC Rack 1 was cleaned, dried and powered-up. There were no faults indicated. The next area worked on was the 117-volt AC circuit breaker that was found tripped. This led to a Solenoid Coil Monitoring 3 (SCM3) module, which was faulted. A replacement SCM3 was not available; thus, a replacement, assembled from components, was planned.

4.5.4 Although it was not known at the time of the explosion, the damage to the SCM3 was such that it could not relatch the DC-Hardwire Trip (DC-HWT) latching relay if that relay was reset. The SCM3 was faulted due to the water contact at approximately 15:00. The DC-HWT was latched when the unit was shutdown at approximately 14:00. This last known latching operation of the DC-HWT was based on no known alarms. After the explosion, the DC-HWT was tested and found to be operable.

a. When the DC-HWT relay was latched, two functions were performed. One set of contacts were opened and the PLC output signals to the Igniter/Warm-up Gas Trip Valve were prevented. A second set of contacts was closed signaling the air solenoid valve to the Main Gas Trip Valve to drive it toward the closed position. When the DC-HWT relay was unlatched during the troubleshooting, the output signals of the PLC's were enabled and the PLC's could directly control the valves.

4.5.5 The investigation determined that at 15:22 when the Control Room reset the Master Fuel Trip it unlatches all hardwire trip relays, two AC and one DC. The BMS immediately recognizes that all permissives have not been satisfied to allow the MFT to remain unlatched. The BMS immediately sends signals to relatch the MFT and the three hardwire trip relays through the SCM modules. Because SCM3 was damaged by the water, it could not relatch the DC-HWT relay thus allowing the PLC to operate 5-FG-24 gas valve. The DC-HWT circuit as designed and installed by the Original Equipment Manufacturer (OEM) of the BMS had not been provided with redundancy or backup.

4.5.6 Cleanup of PLC Rack 2 was started using the same cleaning and drying procedures used successfully on PLC Rack 1. This was completed before 21:00 and the Rack was powered up. One fault indicator light was still illuminated and detailed trouble shooting was started using the Troubleshooting Guide provided by the OEM of the PLC. (Pages 37, 39, 87, and 89 of the PLC-5 Programmable Controller Troubleshooting Guide are included in Appendix 14.)

a. An ASB module (a communication and address module) in the PLC Rack 2 was suspected to be faulted and a replacement module was obtained from the station storeroom. When the new module was installed in PLC Rack 2 and the Rack was powered up, the fault light was still illuminated. Power to the Rack was shut off.

b. In order to verify that new module obtained from the storeroom was not defective, PLC Rack 1 was powered down, and the new module previously installed in Rack 2 was installed in Rack 1. The module removed from PLC Rack 1 was installed in Rack 2 and both Racks were powered up. No fault light was indicated on Rack 1 but the fault light on Rack 2 remained lit and Rack 2 was powered down. Because Rack 1 showed no fault lights on the ASB module, it was established that the replacement module was operative and thus the module was left in place and Rack 1 remained powered on. This activity was performed at approximately 21:25.

c. During the investigation, the OEM's PLC Troubleshooting Guide was reviewed. This Troubleshooting Guide neither mentioned nor explained the significance of setting the addressing switches on the ASB Module to personnel working on the PLC Racks. (A copy of the pertinent pages from the Troubleshooting Guide is included in Appendix 14.)

d. During the process of retrieving data, the OEM of the PLC and an outside consultant were brought in to retrieve and examine the as found state of the inputs and outputs of the PLC. While this was not known prior to the explosion, the investigation determined that the switching of the ASB modules allowed incorrect signals to be sent to all output boards in Rack 1 and Rack 2. It was determined that outputs from both PLC Racks could be correlated with gas valves and igniter actions.

e. As PLC Rack 2 was powered up and powered down with the ASB module switched from Rack 1, a momentary signal was sent to open the No. 1 corner, C-D level, main gas valve (5-FG-51). The valve was fitted with an air-operated actuator with the air admitted via a solenoid valve. A momentary signal to the solenoid would have produced opening movement of the gas valve. (A picture of valve 5-FG-51 is included in Appendix 11.)

f. In addition, as PLC Rack 2 was powered up and powered down, the No.1 corner, C-D level, igniter and the No. 3 corner, A-B level igniter were signaled to spark. This was also a momentary signal. No output signal was sent to the igniter gas valves to open, so there was nothing to ignite.

g. As PLC Rack 1 was powered up with the ASB module switched from Rack 2, a signal was sent to the main gas trip valve (5-FG-24) via the closed position limit switch until contact was broken by valve movement. The valve was fitted with an air-operated actuator with the air admitted via a solenoid valve. This was determined to be the time at which gas was admitted to the main gas header. The reconstructed time at which the PLC Rack 1 was powered up and the recorded time at which main gas header pressure was recorded (21:25, 16 February 1999) were consistent.

4.5.7 Troubleshooting continued on PLC Rack 2 after 22:00. The PLC input/output cards were pulled, checked and reinstalled one at a time with the PLC Rack 2 being powered up after each board was reinstalled.

a. It was determined that each cycle of powering up the PLC Rack resulted in momentary signals to open the No.1 corner, C-D level main gas valve (5-FG-51) and to turn on the igniters at level C-D of corner No. 1 and level A-B of corner No. 3. There were eight cards in the PLC Rack so consequently there were eight output signals transmitted due to powering up and powering down of the PLC Rack. The small variance between the recorded gas flow for the hour after 22:00 and that after 23:00 indicated that the valve was probably fully open shortly after 22:00.

b. Some time after 23:00, PLC Rack 2 was cleared of fault indications and it was powered up and left powered up. It was determined from the signal paths that the igniters in corner No. 1, C-D level and in corner No. 3, A-B level were probably arcing continuously from this point until the gas was ignited about 00:30.

4.5.8 From 23:00 until 00:30, the activity in the Computer Room was focused on assembling a substitute for the SCM3 module from components.

4.6 The Sanitary Sewer System was investigated because the water, which contacted the PLC components, originated in that system. (A diagram showing the applicable portions of the Sanitary Sewer System as well as a photograph of the damaged sewer pipe are included in the Appendices 15 and 16.)

4.6.1 The toilets for the Control Room were not flushing properly and a Control Operator log entry was made during the 11-7 shift on 15 February to use other facilities. Because this day was the Presidents' Day holiday, no plumbing contractor was called.

4.6.2 On the morning of 16 February, a plumbing contractor started working on the Control Room toilets. During the course of this work, a hydraulic jetting tool was inserted into a cleanout in a vertical pipe located below the Control Room toilet near ground level. During the repairs, it was concluded that the jetting tool was extended through a check valve located downstream from the cleanout and that the tool blocked the valve in the open position. It was also determined that the stoppage, which obstructed the Control Room toilet, was down stream from the check valve. The jetting tool was lodged in the check valve by approximately 13:00 on 16 February.

4.6.3 The check valve was the means of isolation of the Control Room gravity sewer line from the downstream pressure sewer line. The Control Room sewer line discharged into the pressurized sewer line fed from a sewage lift station on the north side of the unit. This sewage lift station collected waste from recently constructed buildings. The discharge from this sewage lift station was conducted underground to a second sewage lift station located at the southwest corner of Precipitator "A."

4.6.4 At about 15:00 on 16 February 1999, one of the two pumps in the sewage lift station (Lift Station #1 as shown in Appendix 15) was started (by float control). The sump was pumped into the discharge line until the level of the lift station well reached its low-level stop (by float control). The check valve was blocked open by the plumber's jetting tool and the pressurized line was partially obstructed. The pressurized sewer line was now open to the Control Room gravity sewer line allowing backflow through the open cleanout on the first level and the toilet bowls in the Control Room restrooms. This permitted sewer water entry to the Control Room.

4.6.5 Subsequent evaluation of the Sanitary Sewer System resulted in locating the area of stoppage, which apparently caused the toilet flushing problem in the Control Room. A section of polyvinyl chloride (PVC) pipe was found which was collapsed to the point that solids could build up over a period of time and block the remaining opening. This section of pipe was located at the southwest corner of Precipitator "A" just upstream from the second sewage lift station. Discoloration of the collapsed section of pipe indicated that it may have been heated by steam or hot water. A 12-inch concrete drainpipe was located nearby which connected to a manhole that carried blowdown steam and water from Unit 5 boiler.

4.7 The source of air for mixing with gas flowing into the boiler furnace was evaluated. A specific source was not identified. The development of an ignitable mixture was not evaluated in detail.

4.7.1 The forced draft fans and induced draft fans were turned off at 15:25 on 16 February 1999. After this point in time, the boiler was affected only by the natural draft that passed through the fan and secondary dampers, any non-gas tight access doors or penetrations and the stack. The boiler was also filled with water that was above the ambient temperature and the heat transferred to the air in the furnace would increase the natural draft.

4.7.2 After natural gas started flowing into the furnace at about 21:25 on 16 February, the density difference between natural gas (with a specific gravity of 0.6) and air would increase the draft similar to the density difference between cool and hot air. However, the gas flow of approximately 4,200 CFM may have been greater than the available boiler draft paths would support.

4.7.3 The generally accepted range of combustible mixtures of natural gas in air at standard conditions is 5 to 15%. This means that a lean mixture (<5%) cannot be ignited due to insufficient fuel content and a rich mixture (>15%) cannot be ignited due to insufficient oxygen. In order for the mixture to be ignited in the furnace on 17 February, the gas and air mixture had to be in the combustible range and in the vicinity of an ignition source.

4.7.4 The apparent ignition source was one of the igniters that were apparently operated intermittently after 21:25 on 16 February and continuous after 23:00. The active igniters were located on level C-D in the No. 1 corner and on level A-B in the No. 3 corner.

The delay in ignition (from about 21:25 on 16 February until about 00:30 on 17 February) was apparently caused by the burner configuration and the projection of the flow away from the closest igniter (at the No. 1 corner) and the density difference between the gas and air. In other words, the gas was projected upward and across the furnace, and away from the level C-D igniter. The gas flow may have gradually backfilled the furnace to the elevation of an operating igniter.

5.0 SUMMARY

a) The boiler explosion resulted from ignition of natural gas inside the boiler furnace.

b) The component failure within the BMS contributed to the released of gas into the boiler

c) There was no redundancy or backup in a fail-safe circuit in the BMS to prevent the single point component failure from permitting gas to enter the boiler.

d) The fuel safety design should not have permitted fuel into the boiler system during troubleshooting operations. The fuel safety design failed by not maintaining the fuel shut off.

e) Water caused the component failure in the BMS. This water originated in the Sanitary Sewer System.

f) The sanitary sewer water was expelled from the sewer system while the plumbing contractor was addressing an obstruction.

g) The Troubleshooting Guide of the OEM of the PLC Racks failed to alert the user to verify the correct address of the ASB module.

LIST OF APPENDICES:

Tab	Item
1	Hawthorn Explosion Timeline
2	Hawthorn Station site plan
3	Gas Burner Drawing (This is the known gas flow path into the boiler)
4	Control Room Floor Layout/Openings
5	Cable Room Floor Openings
6	Computer Room Layout
7	Aerial Photograph
8	Gas Pipeline Metering Data
9	Boiler Gas Header Diagrams (3)
10	Photographs of valve 5-FG-24(3)
11	Photograph of valve 5-FG-51
12	PLC Layout Diagram Rack 1
13	PLC Layout Diagram Rack 2
14	Pages 37, 39, 87 and 89 of the PLC-5 Programmable Controller Troubleshooting Guide
15	Sanitary Sewer System Diagram
16	Photograph of damaged sewer pipe.