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March 31, 2009

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
Lansing, MI 48911

Re: Wisconsin Public Service Corporation
2008 PSCR Reconciliation
MPSC Case No. U-15402-R

Dear Ms. Kunkle:

Enclosed for electronic filing is the Application and Direct Testimony and Exhibits of John G. Guntlisbergen, David J. Molzahn and Terry P. Jensky. A marked-up copy of the Notice of Hearing has been e-mailed to Cathy Bowers and Gloria Jones of your office.

Should you have any questions, please kindly advise.

Very truly yours,

Sherri A. Wellman

Digitally signed by: Sherri A. Wellman
DN: CN = Sherri A. Wellman C = US O = Miller Canfield OU = Miller Canfield
Date: 2009.04.01 15:22:56 -05'00'

Sherri A. Wellman

Enclosure(s)

cc w/enc via e-mail: John Guntlisbergen

SAW/tmb

LALIB:157977.2\130072-00001

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
WISCONSIN PUBLIC SERVICE CORPORATION	)	
for a power supply cost reconciliation proceeding	)	Case No. U-15402-R
for the 12-month period ended December 31, 2008.	)	

APPLICATION

WISCONSIN PUBLIC SERVICE CORPORATION ("WPS Corp" or the "Company") requests the Michigan Public Service Commission ("Commission") to approve WPS Corp's reconciliation of power supply costs and revenues pursuant to 1982 PA 304 ("Act 304") for the 12-month period, January 2008 through December 2008, and respectfully represents to the Commission as follows:

1. WPS Corp is a public service corporation organized under the laws of the state of Wisconsin, with its principal office located in Green Bay, Wisconsin, and is authorized to do business in the state of Michigan. WPS Corp is engaged, among other things, in the generation, distribution, and sale of electric energy in areas located in Northeastern Wisconsin and in the adjacent part of Menominee County in the Upper Peninsula of Michigan.

2. WPS Corp's Michigan retail electric business is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; and 1939 PA 3, as amended, MCL 460.1 et seq.

3. During 2008, WPS Corp provided retail electric service to its customers in the State of Michigan pursuant to electric rate schedules approved June 3, 1986, in Case No. U-8359; June 9, 1987, in Case No. U-8695; May 18, 1990, in Case No. U-9582; August 30, 1990, in Case No. U-9634; March 31, 1993, in Case No. U-10245; July 23, 2003, in Case No. U-13688; December 4, 2007, in Case No. U-15352; and pursuant to a power supply cost recovery ("PSCR") factor approved on April 1, 2008, in Case No. U-15402.

4. Pursuant to Section 6j(12) of Act 304, WPS Corp's power supply costs and revenues are required to be reconciled for the twelve-month period during which the 2008 factors were in effect. This application is filed pursuant to Section 6j(12).

5. Weston 3 is a 333 MW (net) base load, coal fired generating unit located near Wausau, Wisconsin. On October 6, 2007, at 4:04 AM, a lightning strike caused significant damage to Weston 3 resulting in a unit forced outage. The forced outage lasted 15 weeks, with the unit being returned to service on January 14, 2008. As of the filing of this Application, the causes of, and the extent of damage to the unit, have been fully investigated by the Company. Pursuant to the Commission's January 13, 2009 Order Approving Settlement Agreement issued in Case No. U-15008-R, WPS Corp was authorized to defer the 2007 Michigan retail jurisdictional portion of the PSCR costs associated with the lightning strike and subsequent forced outage of Weston 3, including interest calculated at the short term borrowing rate, to the 2008 PSCR reconciliation proceeding. Therefore, WPS Corp now seeks to recover the deferred 2007 Michigan retail jurisdictional portion of the replacement power supply costs associated with the Weston 3 outage as part of this proceeding.

6. WPS Corp represents that reconciliation of its power supply costs and revenues for the 12-months ending December 31, 2008, and inclusive of the deferred 2007 Weston 3

replacement power supply costs, results in a total net underrecovery of $306,544 including interest.

7. WPS Corp proposes to collect the underrecovery of $306,544 from its customers by rolling it into its 2009 PSCR costs.

8. WPS Corp is concurrently filing testimony and exhibits in support of this Application. WPS Corp represents that its proposals are just and reasonable and in the public interest.

WHEREFORE, WPS Corp prays that this Commission:

1. Make and publish its notice of hearing, and after notice of hearing;
2. Approve the reconciliation of the 12-month power supply costs and revenues as presented by WPS Corp;
3. Approve the reconciliation of the amounts WPS Corp underrecovered;
4. Find and determine that the power supply costs charged to WPS Corp's ratepayers during 2008 were reasonably and prudently incurred.
5. Approve the recovery of the deferred 2007 Michigan retail jurisdictional portion of the replacement power supply cost related to the Weston 3 outage as presented by WPS Corp.
6. Find and determine that WPS Corp should be authorized to roll-in the total net underrecovered amount of $306,544 into its 2009 PSCR plan costs.

7. Grant WPS Corp such other and additional relief as shall be lawful and proper.

Respectfully submitted,

WISCONSIN PUBLIC SERVICE CORPORATION

Sherri A. Wellman

Digitally signed by: Sherri A. Wellman
DN: CN = Sherri A. Wellman C = US O = Miller Canfield OU = Miller Canfield
Date: 2009.04.01 15:23:18 -05'00'

Dated: March 31, 2009

By: ______________________________

One of its attorneys
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LALIB:179110.1\130072-00022

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
WISCONSIN PUBLIC SERVICE CORPORATION	)	Case No. U-15402-R
for a power supply cost reconciliation	)	
proceeding for the 12-month period	)	
ended December 31, 2008.	)	

DIRECT TESTIMONY
OF TERRY P. JENSKY
ON BEHALF OF WISCONSIN PUBLIC SERVICE CORPORATION

Dated: March 31, 2009

DIRECT TESTIMONY OF
TERRY P. JENSKY

Q. Please state your name and business address.

A. My name is Terry P. Jensky. My business address is Wisconsin Public Service Corporation ("WPS Corp"), P.O. Box 19001, 700 North Adams Street, Green Bay, Wisconsin 54307-9001.

Q. By whom are you employed and in what capacity?

A. I am employed by WPS Corp as Vice President – Energy Supply Operations.

Q. Please describe your educational and professional background and experience.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of Wisconsin - Madison in 1976. I am a member of the National Society of Professional Engineers.

I serve on the Electric Power Research Institute Generation Council. I have co-authored three published papers on fossil plant maintenance and management. In 1995, I completed the Center of Creative Leadership Development Program. In 1997, I received an award from Hartford Steam Boiler my contributions to the development of its "Turbine Outage Optimization Program."

I have been employed with Integrys Energy Group, Inc. ("Integrys") for 31 years, all in the Power Generation area, and I have been employed by regulated and unregulated subsidiaries of Integrys. I accepted my current position in 2004 and have responsibility for the maintenance and operation of all of WPS Corp's generation.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe the October 6, 2007 lightning strike on the Weston Generating Station ("WGS") and the resulting impacts to the WGS, including the forced outage of, and significant damage to, Weston Unit 3. I will also describe WPS Corp's response to the lightning strike and outage, which resulted in the unit returning to service in only 95 days following repairs to the following major components: HP/IP turbine rotor, LP turbine rotor, generator rotor, turbine/generator lube oil tank and two boiler feed pump motors/fluid drives. Finally, I will describe the corrective actions that WPS Corp has taken to improve WGS facilities and practices in order to reduce the likelihood of a similar event in the future.

Q. Have you ever testified before a regulatory agency in the past?

A. Yes. I have testified before the Public Service Commission of Wisconsin.

Q. What happened at WGS on October 6, 2007?

A. In describing the events of that day, I rely on the root cause investigation undertaken for WPS Corp by Adult Education and Management Research Institute, Inc. ("AEMRI"), and the report prepared by AEMRI on its investigation, which is being sponsored by Mr. Molzahn as Exhibit A-2 (DJM-1) ("Report"). I participated in both the investigation and the preparation of the Report.

At a little after 4 a.m., lighting struck a 115 Kv transmission pole owned by American Transmission Company LLC ("ATCLLC") near the Weston Unit 3 building. AEMRI's investigation determined that the lightning strike created an uncontrolled power surge through the ground that impacted Weston Units 2 and 3, and initiated a series of events that caused a forced outage of, and significant damage to, Weston Unit 3.

Q. What damage did the lightning strike cause to Weston Unit 3?

A. The Weston Unit 3 turbine sustained damage to its bearings, main shaft systems, seals and generator field as a result of the unit running down from full speed (3600 rpm) to stop without lubricating oil following the loss of power to the Distributed Control System ("DCS").

Bearings – All of the main bearings (6 on the steam turbine generator) and exciter bearings (2) were damaged as a result of the loss of oil. The Babbitt bearing melted out of the bearing shells and the shells were damaged from contact with the rotating shaft system. The contact of the shaft system to the bearing shells resulted in overheating and an out-of-round condition.

Main Shaft System – The main shaft system consists of the high pressure/intermediate pressure ("HP/IP") rotor, the low pressure ("LP") rotor and the generator field rotor. The bearing journals of all three rotors were damaged and work hardened from friction in the damaged bearings and contact with the stationary casing components. The contact with the stationary components resulted in significant bending of the individual shafts.

Seals – All of the seals in the HP/IP section were damaged from contact with the HP/IP rotor as it coasted to a stop.

Generator Field – The generator field rotor was damaged in the hydrogen seal and bearing journal areas from contact with the bearing stationary components. The cooling fan blades on the field also made contact with the generator shroud resulting in aluminum contamination of the field windings.

Major damage occurred to Boiler Feed Pump Motors A and B and hydraulic couplings. The motor damage was significant enough to warrant complete replacement and/or rebuilding to both motor rotating and stationary components. Hydraulic coupling input shafts and drives also required complete replacement and/or rebuilds. Damage to the turbine/generator lube oil tank due to a hydrogen explosion required repair of the inspection doors. There was also significant damage to the bags on the A side baghouse. Although there was other minor damage found, it was insignificant compared to the damage listed above.

Q. How did the damage to Weston Unit 3 occur?

A. The power surge from the lightning strike immediately affected at least two plant components. First, it appears that the power surge tripped one set of Induced Draft ("ID") and Forced Draft ("FD") fans, which control the unit's furnace pressure. The loss of these fans with the unit operating at full power resulted in a boiler trip due to excessive furnace pressure. Upon a boiler trip, the unit is designed for the turbine to trip, and it did. These trips occurred less than a minute after the lightning strike.

The second component affected by the power surge from the lightning strike was the fuse on the primary circuit of the uninterruptible power supply (“UPS”) to the DCS, which controls the plant’s operating equipment through a computer software program. When the power surge caused this fuse, Fuse F204, to open, four of the five power supplies to the DCS were lost, including a battery backup power supply. The fifth “reserve” power supply on a separate circuit also failed due to a previously undetected circuit breaker control configuration error that prevented another breaker from closing following the loss of the other power supplies. As the result of these conditions, all power was lost to the DCS about 6 seconds after the turbine trip and 52 seconds after the lightning strike.

The loss of DCS prevented its software logic from generating control signals to ensure a safe and orderly coast down of the turbine/generator. These included signals to start the turning gear oil pump and the emergency bearing oil pump. As the result, the turbine/generator coasted down without sufficient bearing lubricating oil, causing the Babbitt bearing to melt, which in turn resulted in damage to the turbine/generator shaft journals. The loss of the DCS also shut off the generator hydrogen seal oil pump and prevented the startup of the emergency hydrogen seal oil pump. Without seal oil, hydrogen exhausted from the generator, ignited, and caused a fire on the turbine end of the generator and an explosion in the turbine lubricating oil storage tank. Finally, the loss of the DCS caused the boiler feed pump lubricating oil pumps to stop; damaging the boiler feed pump motors, hydraulic couplings, and associated equipment.

Most of this damage occurred within minutes of the loss of power to the DCS with the majority of the damage resulting from the loss of lubricating oil to the rotating elements of the turbine, generator and boiler feed pump motors.

Q. How did the WGS plant staff react to these events?

A. The WGS plant staff's reaction to the lightning strike and its aftermath is detailed in the Report. The loss of the DCS, the quickness of the damage to plant components, and the explosions and fires prevented the staff from controlling the plant following the boiler and turbine trips. AEMRI concluded, and I agree, that the operators carried out their responsibilities in accordance with plant procedures, including alarm response, emergent electrical line-up changes and fire response.

Q. What steps did WPS Corp take to bring Weston Unit 3 back into service?

A. The corporate department responsible for assessing and repairing the damage to the unit is Generation Services, which mobilized immediately after the event and had personnel on the Weston site the next day. Their activities can be summarized as follows:

Initial assessment – A walk-down of the unit was made and from the observed clearances at the oil seals it was apparent that the bearings were severely damaged, the shaft system had dropped and there had been potential for contact of the rotating shaft to the stationary components. At approximately 3:00 p.m. on October 7, 2007, Generation Services recommended to Generation Operations that the turbine be opened to allow for a complete inspection and repair of the damage.

Mobilization – ReGENco, WPS Corp's turbine service contractor, was notified of the forced outage on the day of the event and immediately mobilized technical direction, craft labor and tooling personnel and other resources to the site, which arrived the next day. That day, a preliminary schedule was established for turbine disassembly and generator electrical testing.

Planning – Prior to the event, Weston Unit 3 had a major overhaul scheduled for the fall of 2008. Extensive planning and scheduling had already been completed for this outage, along with budget estimates for maintenance and repair work. Much of this information was used for planning the October 2007 forced outage.

Damage assessment – The disassembly of the turbine started on October 8, 2007. As components were removed or exposed, a running list of the damage was compiled and a repair scope was developed.

Electrical testing of the generator indicated that the rotor had not made contact with the stator and that extensive repairs to the stator would not be required. The Alterrex and generator field rotor were removed and shipped to ReGENco's West Allis facility for inspection. A rings-off inspection of the field rotor revealed aluminum contamination in the windings, which indicated that a rewind of the rotor would be necessary. The rotor was inspected by ReGENco and General Electric, they provided proposals for the rewind. The work was awarded to General Electric based on shop schedule.

The main shaft system was removed and all three rotors were shipped to the ReGENco's West Allis facility for inspection. Extensive damage to the shaft system was found, which had resulted in shaft runout and bearing journal damage. ReGENco, General Electric and Alstom inspected the rotors and provided repair proposals. General Electric was selected as the repair provider based on repair scope and shop schedule.

All three rotors were shipped to the General Electric's Chicago Service Center for repair on October 29, 2007. Internal stationary components such as diaphragms, nozzles and bearings were sent to the ReGENco facility for inspection and repair. The HP/IP internal seal components were sent to TurboCare's Chickopee, Massachusetts facility for inspection and repair.

All inspections were overseen by WPS Corp Generation Services, which also approved the subsequent repairs. Cost estimates from the scheduled outage were compared to the repair estimates to ensure that the repair costs were not out of line. WPS Corp Supply Chain Services competitively sourced miscellaneous parts and consumables.

One day after the event, both damaged boiler feed pump motors were shipped to a local repair facility for disassembly and inspection. Inspections determined that the rotating elements of both motors would need to be replaced, and their stationary elements would require complete rebuilds. At that point, WPS Generation Services evaluated whether the damaged motors should be repaired or replaced. Due to schedule restraints with purchasing new motors, the decision was made to repair the existing motors. WPS Corp awarded L&S Electric the contract to rebuild the existing motors. The work schedule to complete these repairs was reduced by working substantial amounts of overtime and holidays. L&S Electric also states that a substantial amount of effort in procuring parts and materials was needed to shorten the delivery time. WPS Corp representatives visited the L&S Electric shop and one of their subcontracted repair facilities in order to ensure quality of work and delivery schedule.

Within 5 days of the event, both boiler feed pump hydraulic couplings were removed and shipped to the original equipment manufacturer, HowdenBuffalo, for disassembly and inspection. The inspection indicated that, due to the couplings running without bearing lubrication, both needed substantial repairs. An evaluation comparing full hydraulic coupling replacement versus repair was performed. The decision was made to repair the existing components due to delivery schedule concerns with replacement. Some amount of overtime was worked in order for the repair schedule to be met and WPS Corp representatives visited the repair shop in order to ensure work quality and schedule delivery. The bags in 3A baghouse were also replaced. The repairs to the turbine/generator lube oil tank were minor, requiring only repairs to the inspection doors.

Repaired components started to ship back to WGS in late November 2007. As the components were returned onsite, craft labor personnel levels were adjusted to accommodate the reassembly of the turbine/generator. A two shift, seven days a week schedule was utilized to perform the work. The last major component (the generator field rotor) was received on site on December 26, 2007. Complete reassembly of the machine was completed on January 7, 2008. Total outage time was 13 weeks, as compared to the 7-week planned 2008 outage for Weston Unit 3 which as a result of the lightning strike and forced outage was cancelled.

WPS Corp also performed a significant amount of inspections and tests on various other equipment to ensure that there was no damage beyond what was visually apparent. This equipment included motors, pumps, fans, compressors, pulverizers, breakers, and the main boiler. These inspections did not reveal any other major repair needs. The unit was returned to service with a minimum amount of issues or problems, considering the amount of damage from the event.

Q. Has WPS Corp taken corrective actions to reduce the likelihood of a similar event at the WGS?

A. Yes, WPS Corp has taken aggressive action to reduce the likelihood of this type of damage from occurring in the future. Modifications have been made to various plant equipment controls so that their required operation will occur independent of the DCS when called upon. Control modifications to equipment related to the turbine/generator include the Emergency Bearing Oil Pump, Emergency Seal Oil Pump, Turning Gear Oil Pump, Main Seal Oil Pump, and the Lube Oil Tank Vapor Extractor. Modifications were also made to the controls of other balance of plant equipment including the Boiler Feed Pump Lube Oil Pumps, Closed Cooling Water Pumps, Aux Cooling Water Booster Pump, Induced Draft Fan Oil Pumps and 3C Air Compressor. In each of these cases, upon loss of a DCS signal, the control system design has been modified to a configuration such that the equipment will operate as required.

In accordance with our lightning consultant's recommendation, and with ATCLLC's cooperation, WPS Corp has also bonded all of ATCLLC's on-site transmission poles, approximately 71 of them, to the WGS grounding system.

WPS Corp has also commenced several other initiatives. These include (1) upgrades to the DCS Uninterruptible Power Supply ("UPS") to add redundancy, (2) improvements in the runback capabilities of the Weston Unit 3 control system, (3) functional testing of critical breakers, (4) improvements in the preventative maintenance programs for our 480V breakers and the UPS, (5) improvements in the controls for the air heater and baghouse, and (6) enhancements to the design change and documentation processes. WPS Corp has also started a project to enhance the auxiliary power supply to Weston Unit 4 in order to add redundancy and reduce the interdependency between Weston Units 3 & 4.

Q. Does this complete your direct testimony?

A. Yes, it does.

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
WISCONSIN PUBLIC SERVICE CORPORATION	)	Case No. U-15402-R
for a power supply cost reconciliation	)	
proceeding for the 12-month period	)	
ended December 31, 2008.	)	

DIRECT TESTIMONY AND EXHIBIT
OF JOHN G. GUNTLISBERGEN
ON BEHALF OF WISCONSIN PUBLIC SERVICE CORPORATION

Dated: March 31, 2009

DIRECT TESTIMONY OF
JOHN G. GUNTLISBERGEN

Q. Please state your name, business address, and position.

A. My name is John G. Guntlisbergen. My business address is Integrys Energy Group, Inc. ("Integrys"), 700 North Adams Street, P.O. Box 19001, Green Bay, WI 54307-9001. I am the Manager of Electric Fuel Cost Recovery in the Regulatory Affairs Department of Integrys. Wisconsin Public Service Corporation ("WPS Corp" or the "Company") is a wholly-owned subsidiary of Integrys. Integrys resulted from the February 21, 2007 merger between WPS Resources Corporation and Peoples Energy Corporation.

Q. Please describe briefly your education, professional, and utility background.

A. In 1981, I graduated from St. Norbert College - De Pere, Wisconsin, with a Bachelor of Business Administration Degree in Accounting. After completing college I was employed by WPS Corp as a Depreciation Analyst and later as the Depreciation Supervisor in the Corporate Tax Department. While in the Corporate Tax Department, I performed depreciation studies on utility plant property, and determined book depreciation, tax depreciation and deferred taxes on an actual and forecasted basis. In 1993, I moved to the Rates and Economic Evaluation Department as a Rates Planner. I performed cost studies and rate impact studies for generation planning and long-range corporate planning. I participated in the analysis of transmission costs and the development of the transmission tariffs for filing with the Federal Energy Regulatory Commission. I performed electric and gas cost of service studies for the Michigan and Wisconsin jurisdictions. I have also worked with the power supply areas for WPS Corp and Upper Peninsula Power Company to develop Power Supply Cost Recovery ("PSCR") plans and in the reconciliation of the PSCR costs to revenues.

Q. Have you ever testified before a regulatory agency?

A. Yes. I have testified before the Public Service Commission of Wisconsin ("PSCW"), and I have presented testimony and testified before the Michigan Public Service Commission ("MPSC").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the WPS Corp's reconciliation of its actual power supply costs to the revenues it collected pursuant to its authorized base rates and Power Supply Cost Recovery ("PSCR") Clause for the 12-month period ended December 31, 2008. I also request the recovery of 2007 and 2008 replacement power costs related to outage resulting from the lightning strike at the Weston 3 generating plant.

Q. What is WPS Corp requesting in this proceeding?

A. WPS Corp requests Commission approval of the 2008 reconciliation of all power supply cost revenues received, whether included in base rates or collected pursuant to its PSCR clause, with the power supply costs booked by WPS Corp during 2008. WPS Corp also seeks to recover the deferred 2007 replacement power costs related to the lightning strike at Weston 3.

Q. Please generally describe WPS Corp's electric service as rendered in the State of Michigan.

A. WPS Corp renders electric service to about 9,000 customers in the southern part of Menominee County Michigan, which includes the City of Menominee and surrounding area. Total retail sales billed in the State of Michigan during 2008 were 286,894 MWh, which represented about 2% of WPS Corp's total corporate sales.

Q. Could you provide a brief description of the WPS Corp generation portfolio during the 2008 PSCR plan period?

A. Yes. With the addition of Weston 4 in July of 2008, WPS Corp has generating facilities with a current net dependable capacity ("NDC") rating of approximately 2125 MWs. WPS Corp owns and operates 8 coal units with a total NDC of 1186 MWs and jointly owns 3 coal units with a WPS Corp assigned NDC of 429 MWs that are operated by Alliant Energy Corporation. WPS Corp also has 467 MWs of simple cycle gas-fired combustion turbines and diesel generators, 40 MWs of hydro generation and approximately 3 MWs of wind generation.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit A-1 (JGG-1).

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes.

Q. Please describe Exhibit A-1 (JGG-1)?

A. Exhibit A-1 (JGG-1) shows the calculation of the overrecovery, including interest calculations, prepared by the Company in accordance with the provisions of 1982 PA 304.

Q. Please describe the overrecovery experienced by the Company for the 12-month period ending December 31, 2008.

A. WPS Corp over recovered the "principal amount" of $222,925 as shown on the line 3 of page 1 of Exhibit A-1 (JGG-1), through operation of its PSCR Clause during 2008. The $222,925 includes the 2008 collection of PSCR revenues over PSCR costs of $1,078,922 on line 1, plus the roll-in of the under collection from the 2007 PSCR reconciliation of ($855,997) on line 2. Page 2 of Exhibit A-1 (JGG-1) shows the over/underrecovery by month and the monthly interest calculation.

The average monthly balances for January through October 2008 were under collections. For these months, the interest rate applied was the Company's short-term debt rate, which varies by month. The dollar value for these months represent costs WPS Corp is to collect from the customers and totals ($21,999).

The average monthly balances for November through December of 2008 were over collections. For these months, the interest rate applied was the Company's authorized rate of return on common equity of 10.60% and represent costs that are to be returned to the customers. For these months, the total interest is $1,514.

The net of the interest to be charged to the customers for the months WPS Corp under-collected ($21,999) and the interest to be credited to the customers for months WPS Corp over-collected ($1,514), is ($20,485). This is shown on Exhibit A-1 (JGG-1) page 1, line 4 with supporting calculation on page 2.

Line 5 on page 1 of Exhibit A-1 (JGG-1) shows the total 2008 overrecovery of $222,925 plus the plan year interest of ($20,485), resulting in a net over recovered amount of $202,440.

Q. Please describe the inclusion of deferred replacement power supply costs incurred in 2007 as relating to the extended outage resulting from the lightning strike at the Company's Weston 3 generating plant.

A. As a matter of background, Weston 3 is a 333 MW (net) base load, coal fired generating unit located near Wausau, Wisconsin. On October 6, 2007, at 4:04am, a lightning strike caused significant damage to Weston 3 resulting in a unit forced outage. The forced outage lasted 15 weeks, with the unit being returned to service on January 14, 2008. Pursuant to the MPSC's January 13, 2009 Order Approviing Settlement Agreement issued in Case U-15008-R, WPS Corp was authorized to defer the 2007 Michigan retail jurisdictional portion of the PSCR costs associated with the lightning strike and subsequent forced outage of Weston 3 for the time period (October 6, 2007 through December 31, 2007). As shown at line 6 on page 1 of Exhibit A-1 (JGG-1), the deferred Weston 3 Replacement Power costs for 2007 totaled $489,182. Lines 7 and 8 show the interest of ($3,009) for 2007 and ($16,793) for 2008 calculated at the short-term borrowing rate related to the Weston 3 Replacement Power costs deferred in 2007. When the Weston 3 Replacement Power costs deferred plus interest ($508,984) is added to the net over recovery ending balance including interest for 2008, $202,440, this results in a net total under recovery of ($306,544) as shown on line 9 of page 1 of Exhibit A-1 (JGG-1). WPS Corp is proposing to roll-in the net total under-recovery of ($306,544) into its 2009 PSCR plan costs.

Q. Did the Company incur replacement power supply costs in 2008 as a result of the lightning strike at the Weston 3 generating plant?

A. Yes. The Weston 3 unit did not return to service until January 14, 2008. The replacement power supply costs associated with the 2008 period are reflected in the 2008 PSCR costs at line 22 on page 2 of Exhibit A-1 (JGG-1).

Q. Please describe the replacement power supply costs deferred associated with the Weston 3 outage for the period from October 6, 2007 through January 14, 2008.

A. The replacement power costs that were deferred are the replacement power costs incurred less fuel and variable O&M costs that were avoided. These deferred costs represent the incremental replacement power costs incurred due to the Weston 3 forced outage.

The Company incurred incremental replacement power costs of $23,669,380 on a corporate basis in 2007. This net incremental cost increase is based on the following costs and credits:

1. A cost of $33,740,641 to replace the generation lost from the Weston 3 unit.
2. A cost of $1,361,019 of increased purchased power costs due to upward pressure on the Locational Marginal Prices ("LMP") due to regional pricing impacts from the unavailability of Weston 3.
3. A cost of $592,388 to replace the generation lost from Pulliam Unit 6 due to the need to reduce NOx emissions as a result of the Weston 3 outage, in order to address NOx averaging requirements imposed by the Environmental Protection Agency's ("EPA") Acid Rain Law.
4. A credit of $11,821,287 related to fuel and related costs avoided by the Weston 3 unit, due to the outage.
5. A credit of $203,381 for avoided fuel and related costs for the Pulliam 6 generating unit, due to the reduced generation as a result of the Weston 3 outage, in order to address NOx averaging requirements imposed by the EPA's Acid Rain Law.

Incremental replacement power costs for January 2008 were $2,925,741 on a corporate basis and were determined using the same methodology used to determine the 2007 incremental replacement power costs.

Page 4 of Exhibit A-1 (JGG-1) shows the determination of the corporate replacement power costs, the Michigan retail jurisdictional deferral balance and the related interest.

Q. Does the Company offer any further support for the recovery of the replacement

power costs and related interest incurred in 2007 and 2008 as a result of the lightning strike at the Weston 3 generating plant?

A. Yes. The Company submits the testimony of Messrs. Jensky, and Molzahn in support of the recovery of the replacement power costs and related interest incurred in 2007 and 2008 as a result of the lightning strike at the Weston 3 generating plant.

Q. Would you please explain the interruptible customer "buyout" process and how it affects this PSCR reconciliation?

A. WPS Corp has an electric interruptible program for its Large Commercial and Industrial customers, which allows WPS Corp to interrupt service for two types of electric system conditions. The first condition is known as emergency interruption, and occurs when system demand, required operating reserves and firm transaction sales cannot be supplied by available generating capacity plus purchased energy. Customers are required to interrupt load during emergency interruptions. The second condition is known as "capacity related purchases," or "economic interruption", and occurs when system demand, required operating reserves and firm transaction sales cannot be supplied by available generating capacity; however, required purchased energy is available, but at a cost significantly higher than the cost of typical Company peaking generation. When an economic interruption is declared, the customer is required to reduce load to its firm nomination, or the customer may choose to "buyout" of the interruption and continue to purchase energy above its firm nomination, but at a significantly higher cost. The intent of the buyout provision is to allow the interruptible customers the option of purchasing the higher cost power. Because the cost of purchasing energy to supply these sales was included in purchased power costs, the total revenues received from the sales exceeding the firm nomination has been credited to the 2008 PSCR costs. Buyouts volumes and revenues have been included in non-firm sales.

Q. Section 6j(13) of 1982 PA 304 lists a series of costs or items the Commission shall disallow in a power supply cost reconciliation. Please comment on these as they relate to the reconciliation as shown in Exhibit A-1 (JGG-1).

A. WPS Corp does not believe that any of these statutory disallowances would apply to the Company's 2008 PSCR Reconciliation. Additionally, WPS Corp has received approval, pursuant to Section 6j(13)(b) of 1982 PA 304, of capacity charges in excess of six months associated with purchased power agreements in MPSC Case Nos. U-14422, U-14708, U-15008, and U-15402.

Q. What is your opinion as to the reasonableness and prudence of expenditures charged pursuant to the Company's PSCR plan during the reconciliation period?

A. All expenditures booked were reasonable and prudent.

Q. What is the Company's overall process that is used to manage power supply costs?

A. The following describes the extensive in-house procedures utilized by WPS Corp to manage power supply costs:

Within the Fuel Services Department, which is directly responsible for fuel procurement, policies and procedures have been developed to outline a series of rules and directives by which to conduct the fuel procurement operations. The procedures and policies include, but are not limited to:

1. Selection of a vendor through a competitive bid process;
2. Test burning of new coals at the facility to assure plant compatibility; and
3. The use of a bid security system to ensure fair competition.

WPS Corp reviews its ability to purchase economic energy from the Midwest Independent Transmission System Operator "(Midwest ISO") Energy Market or on a bilateral basis and purchases capacity for its system as required to meet reserve requirements.

As a participant in the Midwest ISO Energy Market, the Company is able to submit a generation offer for each generating asset and, if accepted, receives the locational marginal price "LMP" at each location for the power supplied to the market. At the same time, WPS Corp also purchases from the market all power required to meet its load obligations and pays the LMP at its load zone. The credits received by the Company for the sale of all of its generation to the Midwest ISO market act as an offset to the payments made by the Company to purchase all of its load requirements from the Midwest ISO market.

The LMP price paid to generators, and paid by the Load Serving Entity ("LSE"), is based on the highest cost generation offer that is accepted by the Midwest ISO for each hour. When there is congestion, the LMP rises on the "congested" side to reflect what is essentially a re-dispatch to accommodate the congestion. The LMP price paid also reflects the marginal cost of losses based on where and when the generation is being supplied to the market and where it is being delivered. This process assures that the lowest priced generators within the Midwest ISO market are operating, that generators are paid a reasonable market price and that the LSEs pay a market price that reflects marginal energy costs, marginal congestion and marginal loss costs.

In order to mitigate some of the effects of the day-ahead congestion pricing, an LSE is assigned Financial Transmission Rights ("FTR") based on historical transmission access. FTRs are credits or charges that offset some of the effects of the higher or lower prices that will be reflected in the LMPs due to congestion. Similarly, the Company receives loss distribution credits that offset some of the effects of the marginal loss pricing. The Company uses these credits to offset some of the increased purchased power costs of the Midwest ISO Energy Market.

Q. How did the Midwest ISO Energy Market affect 2008 power supply costs?

A. The Company incurred administrative charges of $2.1 million in 2008 from the Midwest ISO Energy Market compared to $2.8 million included in the plan. Marginal Congestion charges from the Midwest ISO were offset by FTRs received in 2008. Marginal Loss charges from the Midwest ISO were offset by loss distribution credits, to a level that reflected average loss costs prior to the start of the Midwest ISO Energy Market.

Q. Please provide a narrative comparison of the differences between the Company's 2008 planned and actual supply sources and costs, as shown on page 3 of Exhibit A-1 (JGG-1).

A. In total the actual power supply expenses on a $/MWh basis were lower than forecasted in the plan. Positive and negative variations exist as described below. All of these variations of course, resulted from reasonable and prudent management actions.

Hydro

Due to the low variable operating costs of hydro units, these units operate to the extent possible subject to water flow availability, which can vary significantly from year to year. The hydro generation for 2008 was lower than the plan for 2008 due to lower water flow availability than was forecasted in the plan.

Wind

Wind generation is highly variable, these units operate to the extent possible subject to wind conditions, which can vary significantly from year to year. The wind generation for 2008 was lower than the plan for 2008 due to worse than forecasted wind conditions for generation during the year.

Fossil

In total, the fossil plants experienced 10.09% lower actual total costs on a per MWh basis than forecasted. Listed below are specific details regarding plants with significant variations:

Pulliam (Generation MWh): Generation from the Pulliam units was lower in 2008 compared to the 2008 Plan mainly due to the Midwest ISO energy market prices paid for energy at the Pulliam site being lower than the incremental cost to operate the Pulliam Units for some hours in 2008. For those hours, it was more economic than forecasted, to purchase energy from the Midwest ISO energy market than to generate from the Pulliam units.

Pulliam (Costs/MWh): The $/MWh cost was $6.05 less than forecasted. Rail transportation costs were lower than forecasted and account for 75% of the variance. At the time the forecast was compiled the rail contracts were not completed. A rail transportation contract with lower pricing was put in place after the forecast was completed that significantly reduced the projected transportation costs.

Weston (Generation MWh): Generation from the Weston units was lower in 2008 compared to the 2008 Plan due to a number of items.
Weston 1 generation was 190,000 MWhs less than forecasted due to 2 factors, (1) a maintenance outage that was extended and (2) reduced generation for economic reasons.

The Weston 1 outage began on October 4, 2008, and was to install over-fired air and low NOx burners. Also performed was low pressure turbine work. The outage was extended to late November 2008 due to having to bore the low pressure turbine rotor. The unit was brought back on-line in late November and during normal over speed testing, a low pressure turbine rotating blade failed requiring removal of the turbine rotor and repair to the rotating blade which resulted in extending the outage through the end of 2008 and into January 2009. The extended outage resulted in lower generation than forecast of about 114,000 MWhs in 2008.

The Weston 1 outage was originally planned as a two week outage in the 2008 PSCR plan. However, the outage duration was revised from the 2008 PSCR plan due to the need to install NOx emission reduction equipment as part of the WPS Corp plan to meet the EPA Clean Air Instate Transport rule (CAIR) and reduce emission allowance purchases in 2009, The Company revised the original power supply plan to allow for the longer outage so that this work could be completed in 2008. The failure of the turbine rotating blade resulted from a crack propagating at the root of the tennion which was not detectable utilizing non destructive testing methods during the planned outage. The turbine rotor inspection methods and over-speed testing procedures utilized by the Weston plant were reasonable and prudent.

Weston 1 also experienced lower generation than forecasted by about 76,000 MWhs in 2008 due to the Midwest ISO energy market prices paid for energy at the Weston site being lower than the incremental cost to operate Weston 1 for some hours in 2008. For those hours, it was more economic than forecasted, to purchase energy from the Midwest ISO energy market than to generate from the Weston 1 unit.

Weston Unit 2 generation was less than forecasted by 65,000 MWhs due to 2 factors, (1) operational limitations and (2) economic reasons.

Weston 2 is experiencing increasing differential pressure across its air heaters, which is limiting the steam production of the unit and thus limiting generation. To address the increased air heater differential pressure WPS Corp is looking into replacement of the air heater baskets. WPS Corp has also found significant degradation in the radial seals of the air heaters, which also contributed to the reduction of steam generation. WPS Corp will be replacing the seal during the current planned outage. Operational limitations resulted in lower generation of about 14,000 MWhs for Weston 2.

Weston 2 also experienced lower generation than forecasted by about 51,000 MWhs in 2008 due to the Midwest ISO energy market prices paid for energy at the Weston site being lower than the incremental cost to operate Weston 2 for some hours in 2008. For those hours, it was more economic than forecasted, to purchase energy from the Midwest ISO energy market than to generate from the Weston 2 unit.

Weston 3 experienced lower generation than forecasted of about 100,000 MWhs due to (1) reduced generation resulting from the extended outage from the lightning strike in 2007 and, (2) reduced generation for economic reasons. However these factors were offset by increased generation from a shorter outage than was planned in the forecast.

The lightning strike on Weston 3 on October 6, 2007 caused significant damage to the unit's turbine generator and boiler feed pumps resulting in an unplanned outage of approximately 15 weeks in duration which, as I previously described, went into January 2008. The January 2008 generation was 95,000 MWhs less than forecasted for Weston 3, due to the outage for the lightning strike.

Weston 3 experienced lower generation than forecasted by about 122,000 MWhs in 2008 due to the Midwest ISO energy market prices paid for energy at the Weston site being lower than the incremental cost to operate Weston 3 for some hours in 2008. For those hours, it was more economic than forecasted, to purchase energy from the Midwest ISO energy market than to generate from the Weston 3 unit.

Weston 3 did experience higher generation of about 117,000 MWhs than forecasted in September and October 2008 due to elimination of the outage that was planned in the forecast. The elimination of the outage time in September and October 2008 resulted from completing 2008 planned outage work during the 2007 outage for the lightning strike.

Weston (Costs/MWh): The $/MWh cost was $2.06 less than the plan. Rail transportation costs were lower than forecasted and account for 75% of the variance. At the time the forecast was compiled the rail contracts were not completed. A rail transportation contract with lower pricing was put in place after the forecast was completed that significantly reduced the projected transportation costs.

Weston 4 (Generation MWh): Generation from the new Weston 4 unit was significantly lower in 2008 compared to the 2008 Plan due to delays in the unit reaching full power, which resulted in reduced generation of about 712,000 MWhs, and a number of forced outages and derates after the unit reached full power, which resulted in about 483,000 MWhs of reduced generation.

Weston 4 (Costs/MWh): The $/MWh cost was $1.97 less than the plan. Rail transportation costs were lower than forecasted and account for 75% of the variance. At the time the forecast was compiled the rail contracts were not completed. A rail transportation contract with lower pricing was put in place after the forecast was completed that significantly reduced the projected transportation costs.

Edgewater (Generation MWh): Generation from Edgewater was lower in 2008 compared to the 2008 Plan mainly due to the operator of the Edgewater 4 unit (Alliant Energy) conducting operational tuning of the boiler and combustion system to improve the overall operation and slagging characteristics of the boiler. The changes reduced the steam output of the unit to prevent excessive slag build up which was causing additional forced outages of the unit. The use of Tire Derived Fuel (TDF) was reduced on the unit to lower the overall sulfur dioxide emissions. The elimination of the TDF reduced the steam output capability of the boiler and electrical generation.

Edgewater (costs/MWh): The 2008 actual $/MWh price is higher than the 2008 plan due to higher than forecasted fuel surcharges The actual fuel surcharge ranged from 30% to 50% throughout the year compared to a forecasted fuel surcharge of 29%, resulting in increased costs of approximately $850,000 or $1.24/MWh.

Peakers

The gas-fired combustion turbine generation is highly variable and is affected by baseload unit outage schedules and peak demands. For 2008, the gas-fired combustion turbines were dispatched more than forecasted due to extended and unplanned forced outages on the fossil units that were greater than forecasted. The 2008 actual $/MWh cost is 9.24% greater than the 2008 Plan due to higher actual natural gas prices compared to plan.

Purchased Power

While "Actual" to "Plan" volume (MWh) of purchased power energy reflects an increase of approximately 17.1%, or 878,554 MWh, the purchased power $/MWh costs reflect a decrease of $8.30/MWh, or 12.38%. The MWh variance in purchased power needs for 2008 is the result of the delayed inservice date of Weston 4 and unplanned and unexpected generation plant outages. The increase in purchase power costs was due to the increased MWh volume purchase, but was mitigated by a lower than expected $/MWh price.

Included in the 2008 purchased power costs are realized hedging revenues of approximately $3,142,000. WPS Corp's exposure to the price risk of natural gas for 2008 was estimated to be nearly $93 million. With continued volatility in natural gas prices and the significant exposure to these prices, it was reasonable for the Company to use derivative instruments to manage or hedge a portion of the price risk of natural gas affecting its cost of purchased power for 2008, as approved in the Company's 2008 PSCR Plan. Natural gas prices were very volatile in 2008, but overall the hedged positions resulted in a decrease to WPS Corp's purchased power costs on a $/MWh basis. The Michigan jurisdictional portion of the realized hedging revenues for 2008 were about $65,000

Non-Firm Sales

Non-firm energy sales are directly related to a number of factors. Primarily, non-firm energy sales are closely tied to:

1. The availability of excess generation that could be sold into the peak and off-peak spot markets,
2. The prevailing market price of the energy product, and
3. With the implementation of the Midwest ISO Energy Market, the Midwest ISO dispatch of those resources to serve the energy market.

As a participant in the Midwest ISO Energy Market, the Company makes non-firm sales whenever its total generation plus purchased power dispatched by the Midwest ISO on a bid basis, exceeds its load requirements. Depending on unit outage schedules and market dynamics, WPS Corp has been dispatched to sell excess energy into the energy market. And to be expected, WPS Corp generally has more energy volume available to be sold into the off-peak energy market. For the 2008 Plan period, due to increased native-owned generation, WPS Corp had a 64.7%, or 300,220 MWh increase in non-firm sales volumes and a 66.2% increase in corresponding revenues. $/MWh levels for the 2008 actual volumes were up slightly, 0.91%.

Q. Please describe the startup issues and the resulting delays that occurred at the new Weston 4 generating unit.

A. In December 2007 and early January 2008, the Company experienced problems with the temporary steam-blowing system, which delayed the unit's ability to begin generating energy with coal from January to March 2008. Performance problems with the steam condenser, as well as excessive vibration in both of the condensate pumps, which is very unusual, delayed bringing the unit up to full power and performing startup testing. Then, on February 9, 2008, one of the unit's forced draft fans experienced a sudden, catastrophic failure. This failure was unexpected, as this piece of equipment is expected to operate for extended periods of time without significant maintenance. Without this fan, the unit could operate at no more than about 50% capacity. The unit was first synchronized on-line at 50% capacity in late March 2008.

No replacement for the forced draft fan was immediately available, thus the best option to get the unit back to full operation as quickly as possible was to rebuild the fan. This was completed and the fan reinstalled in early May 2008, at which time the unit was brought up to full power and startup testing resumed. The unit was fully available and reached its level of expected generation during the month of August 2008. Due to the delays in bringing the unit up to full power and subsequent startup testing, the Company experienced about 712,000 MWhs less generation in 2008 than was forecasted in the 2008 PSCR Plan for the months of January through August 2008.

Q. Please describe the forced outages and derates related to the problems with and/or failures of plant components that occurred after Weston Unit 4 was fully available.

A. In September 2008, the unit experienced a forced outage lasting 160 hours for repairs to a leak in the valve packing in the main steam desuperheating attemperator. A second forced outage for 120 hrs occurred in September while the plant resolved unit start up procedures related to the dry scrubber operation. Based on an interpretation of the unit's air permit by the Wisconsin DNR, the Company could potentially exceed the allowable SO2 emissions if it starts the unit as originally required by the equipment manufacturer on coal, because the dry scrubber cannot be utilized until it reaches a certain gas outlet temperature. The Company developed an alternative startup procedure using natural gas in order to avoid exceeding the emission limitations. The forced outage and the down time required to develop the alternate startup procedures on natural gas resulted in lower generation of about 97,000 MWhs in September 2008 compared to the 2008 PSCR Plan.

In October 2008, the unit experienced two forced outages related to failures of the feedwater heater safety valves and piping. The total outage time in October was 182 hours and resulted in about 94,000 MWhs less generation than forecasted in the 2008 PSCR Plan.

In November 2008, the unit experienced a forced outage and a derate for the equivalent of 63 hrs related to boiler feed pump problems. The Company experienced a second outage in November 2008, which extended through most of December 2008, related to excessive oxidation and exfoliation within the boiler superheater. The derates and the forced outages in November and December resulted in reduced generation of about 128,000 MWhs for November and 164,000 MWhs for December compared to the 2008 PSCR Plan.

Q. Please describe the outage and derate related to the excessive oxidation and exfoliation within the boiler superheater of Weston Unit 4.

A. The Weston 4 unit includes a super critical pressure boiler that operates with 1080 degrees F superheat main steam and reheat steam temperatures. In order to operate at this temperature, a special stainless steel alloy (“347”) was used for the boiler tubing in the hottest sections of the superheater and reheater.

At high superheater and reheater tube metal temperatures an oxide layer forms on the inside of the tube. Due to the differential in the coefficient of thermal expansion between the oxide layer and the parent metal, the oxide layer exfoliates during thermal cycles of the boiler. Some oxidation and exfoliation is expected to occur in these components in the early years of a coal plant's operation but this should not result in blockage and tube failure. If an excessive quantity of oxide exfoliates and remains in the lower U bends of the superheater, steam flow through the tube is reduced or stopped causing overheating and subsequent tube failure.

In 2008, within months of full power operation, the Weston 4 unit experienced tube failures in the superheater related to excessive oxidation and exfoliation. These tube failures required outages in November and December 2008 to clean and repair the tubes. These outages resulted in lower generation than forecasted in the 2008 PSCR Plan.

Q. Are the startup issues and the outage and derate issues related to the new Weston 4 unit common to new coal fired generating units?

A. The problems that caused the delays in the startup of the new Weston 4 unit and the subsequent outages and derates after the unit was fully available are not unique with the exception of the degree of exfoliation experienced in the superheater. Delays in the startup and outages caused by plant component failures or problems at new coal fired units are common occurrences as new plant components are put into service and tested, again with the exception of the excessive superheater exfoliation. The Company has acted reasonably and prudently on all issues regarding the startup and operation of the Weston 4 unit.

Q. What is the Company doing to address the outages related to the excessive oxidation and exfoliation and to stop them from continuing to occur?

A. WPS Corp will be conducting the annual planned outage for the Weston 4 unit starting March 20, 2009. Work during the planned outage will include inspection and cleaning of the superheater. In addition to the inspection work, the superheater will be instrumented with additional thermocouples to assist in identification of tube plugging caused by exfoliation. On February 25, 2009 the main steam and hot reheat steam temperatures where returned to the design conditions of 1080^{o}F. With the return to design temperature for main steam and hot reheat, the unit's heat rate and unit capacity will increase to the operational conditions previously achieved (which were greater than the original unit net capacity ratings estimated for the unit when WPS Corp requested authorization to construct from the PSCW). WPS Corp is currently evaluating options to reduce the short term forced outages associated with superheater 347 excessive exfoliation including periodic thermal cycling of the unit and short outages to operationally remove the oxide exfoliation from the superheater. WPS Corp is also evaluating options to improve long term operations including working with the original equipment manufacturer (B&W) and others to better predict the rate of oxide growth and exfoliation stabilization of 347, thermal cycling of the boiler to periodically remove exfoliated oxide and potential partial superheater replacement with materials not susceptible to oxide exfoliation. The options are still under review to determine the impacts on capacity, heat rate, outage schedules, cost and long term equipment maintainability.

Q. Please describe the transmission costs shown separately on page 3 of Exhibit A-1 (JGG-1) and explain any variance between the 2008 plan and actual costs.

A. The transmission costs shown on page 3 of Exhibit A-1 (JGG-1) are for network transmission service and related services from the American Transmission Company LLC, ("ATCLLC") and the Midwest ISO. WPS Corp received approval for PSCR treatment of ATCLLC and Midwest ISO charges beginning July 24, 2003, in its electric rate case order, U-13688, issued July 23, 2003.

The transmission costs included in the 2008 PSCR plan were based on estimates from the ATCLLC and Midwest ISO. Actual costs charged by the ATCLLC and Midwest ISO were higher by 3.39% than what they forecasted to the Company.

Q. Has the Company refunded a portion of the non-qualified decommissioning fund as a reduction to its power supply costs for 2008 as ordered in MPSC Case U-14040?

A. Yes. The Company sold the KNPP in July 2005 and began refunding the non-qualified decommissioning fund in August 2005. These reductions to the power supply costs for 2008 are shown on Page 2 of Exhibit A-1 (JGG-1), line 23.

Q. Has the Company included an increase in its 2008 power supply costs to reflect the amortization of $1,794,726 from January 2007 through July 2010 for the 2005 PSCR underrecovery, as ordered in the MPSC Case U-14272-R?

A. Yes. The Company has included an increase in its 2008 power supply costs to reflect the amortization of $1,794,726 from January 2007 through July 2010 for the 2005 PSCR underrecovery, as ordered in the MPSC Case U-14272-R as shown on Page 2 of Exhibit A-1 (JGG-1), line 24.

Q. Does that conclude your testimony at this time?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
WISCONSIN PUBLIC SERVICE CORPORATION	)	Case No. U-15402-R
for a power supply cost reconciliation	)	
proceeding for the 12-month period	)	
ended December 31, 2008.	)	

DIRECT TESTIMONY AND EXHIBITS
OF DAVID J. MOLZAHN
ON BEHALF OF WISCONSIN PUBLIC SERVICE CORPORATION

Dated: March 31, 2009

MADI_1861864.1

DIRECT TESTIMONY OF
DAVID J. MOLZAHN

Q. Please state your name and business address.

A. My name is David J. Molzahn. My business address is Wisconsin Public Service Corporation ("WPS Corp"), P.O. Box 19001, 700 North Adams Street, Green Bay, Wisconsin 54307-9001.

Q. By whom are you employed and in what capacity?

A. I am employed by WPS Corp as Director – Environmental and Nuclear Oversight.

Q. Please describe your educational and professional background.

A. I earned a Bachelor of Science degree in Electrical Engineering at the University of Wisconsin - Madison in 1978. I joined WPSC as a Plant Maintenance Engineer in January 1979. After spending 26 years in the nuclear department in a variety of positions, last as Director – Nuclear Oversight. I accepted my current position in the fall 2005.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present the results of WPS Corp's root cause investigation of the October 6, 2007 lightning strike, forced outage and damage at Weston Unit 3.

Q. Have you ever testified before a regulatory agency in the past?

A. Yes. I have testified before the Michigan Public Service Commission and the Public Service Commission of Wisconsin.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit A-2 (DJM-1), Exhibit A-3 (DJM-2) and Exhibit A-4 (DJM-3). All of these exhibits were prepared under my direction and supervision.

Q. Who performed the root cause investigation?

A. The root cause investigation was conducted by personnel from WPS Corp and a consulting firm, Adult Education and Management Research Institute, Inc. ("AEMRI"), that has deep experience in root cause analyses of events at nuclear and fossil electric power plants. The

AEMRI principal who led the Weston Unit 3 root cause investigation is Mr. Tracy Theesfeld, who was formerly a Senior Reactor Operator and Corrective Actions Process Manager with Commonwealth Edison. Mr. Theesfeld currently provides the electric power industry with performance improvement training and assessment, including root cause analyses of failure events. In addition to the Weston Unit 3 root cause investigation, Mr. Theesfeld has assisted WPSC with safety improvements and event investigation training in connection with the construction of Weston Unit 4. The report of the investigation is sponsored as Exhibit A-2 (DJM-1).

Q. What did the investigation find to be the root and contributing causes of the forced outage and damage to Weston Unit 3?

A. The investigation found two root causes and two contributing causes.

The first root cause is that the on-site transmission tower that was struck by the lightning was not bonded to the Weston Generation Station ("WGS") grounding system. If the tower had been bonded to the WGS grounding system, the power surge that impacted Weston Unit 3 may not have occurred.

The second root cause is that the power surge through the ground from the lightning strike caused a fuse (F204) to open on the primary output circuit of the uninterruptible power supply ("UPS") to the Distributed Control System ("DSC"), which resulted in the loss of four of the five sources of power to the UPS, including a battery backup supply. The reserve power supply on a separate circuit was not available due to a previously undetected error in the control configuration of a breaker (Breaker 52-3A). Had the lightning strike not caused Fuse F204 to open, or had Breaker 52-3A not been erroneously configured, power would have likely continued to the UPS and the DCS would have controlled the plant trip and avoided damage to the unit. Following the event, WPSC found Fuse F204 performed as designed and that, of the 18 breakers of its type in Weston Unit 3, Breaker 52-3A was the only one with this configuration error.

The first contributing cause was that no study was made as to whether cost-effective modifications to Weston Unit 3 could have reduced or eliminated trips of the unit upon the loss of an ID fan when the unit is operating at full power. Such trips have occurred infrequently since a baghouse was added to the unit to reduce air emissions.

The second contributing cause was that when the DCS was modified in 2000-2001, the control logic for various pieces of equipment, including several emergency oil pumps, was changed from a "fail closed" contact configuration upon a low oil pressure signal or loss of control power to a "fail open" contact configuration that required a DCS signal to start the pump. Had the design incorporated a "fail closed" contact configuration, or some alternate designed start circuit, the pumps would have started during the event on a low oil pressure signal independent of the DCS, and the damage to the unit's turbine/generator would have been averted.

<u>Root Cause #1: Lack of Bonding of Transmission Tower to Grounding System</u>

Q. Please describe WPS Corp's investigation of the grounding of electrical components and their relationship to the event.

A. Based on a separate study, WPS Corp concluded that the grounding system at the Weston site exceeded the applicable Institute for Electrical and Electrionics Engineers ("IEEE") safety standard with considerable margin, and that all of the generation-related facilities at the Weston site were properly bonded and the transmission poles at or near the site were properly grounded. The study prepared at WPS Corp's direction by Dr. A. P. Sakis Meliopoulos, the Georgia Power Distinguished Professor at the Georgia Institute of Technology and a Fellow of the IEEE, supports these conclusions. Exhibit A-3 (DJM-2) is the report of that study, which also concluded, however, that if the transmission poles had been bonded to the Weston site grounding system, the lightning strike would likely not have impacted the Weston 3 unit as it did.

Q. Was the lack of bonding between the transmission poles and the generating site grounding system an unsafe or otherwise unreasonable condition?

A. No. It is not common for transmission poles on or near a generating site to be bonded to the generating site's grounding system. The applicable IEEE safety standards, (a) Standard 665-1995, "IEEE Guide for Generating Station Grounding" and (b) Standard 1243-1997, "IEEE Guide for Improving the Lightning Performance of Transmission Lines," do not require such bonding. Transmission poles are typically bonded to a generating site only if site-specific conditions justify the additional expense of study, design and implementation.

Q. Was there nonetheless a recommendation that the transmission poles at or near the Weston generating site be bonded to the Weston grounding system?

A. Yes, this recommendation as made in Exhibit A-3 (DJM-2) was based on the unique soil conditions found at the site, the number of transmission poles that were installed at or near the Weston site when the Weston 4 generation unit was constructed, and the desire to avoid a similar lightning strike event in the future.

Q. What did WPS Corp do in response to that recommendation?

A. WPS Corp implemented the recommended bonding design. This involved bonding 71 transmission poles to the Weston site grounding system.

<u>Root Cause #2: Loss of Power Supply to the DCS</u>

Q. Please describe the design of the power supply to Weston Unit 3.

A. My Exhibit A-4 (DJM-3) provides simplified line drawings of the unit's electrical system, with focus on the DCS. Page 1 of the exhibit generally depicts the system at the time of the October 6, 2007 lightning strike. Page 2 generally shows the current system, with the modifications made since the lightning strike to reduce the risk of an event of this magnitude in the future. These drawings show the components of the electrical system that are the most relevant to the root cause investigation.

During normal unit operation, Weston Unit 3 receives power from its electric generator through the Main Auxiliary Transformer (MAT) and 6.9Kv Switchgear Buses 3A and 3B. These two switchgear buses supply power to the remaining plant 6.9Kv bus, the 6.9Kv motors, and all of the unit's 480v switchgear buses, including those that serve the DCS. There are also three offsite power feeds to the unit through the reserve auxiliary transformer ("RAT") 3A, RAT 3B and Essential Auxiliary Transformer ("EAT") 3. RAT 3A and RAT 3B provide offsite power to 6.9 Kv Switchgear Buses 3A and 3B, respectively. The source of power to the RATs is the east bus of the Weston Generating Station ("WGS") 115 Kv substation. RAT 3A is normally tied to Weston Unit 4. Upon a loss of power to the Weston Unit 3 MAT, as when the unit's turbine/generator trips, a "fast bus transfer" occurs that switches the unit's power feed from the MAT to RAT 3B. The EAT serves a 6.9Kv essential services switchgear bus that is connected to 6.9Kv Switchgear Bus 3A.

Q. What is the Distributed Control System (DCS) and how is power supplied to it?

A. The DCS is an equipment control system that provides a means of automatic control of plant components, both individually and as a coordinated plant system and sub-systems. The system consists of remote equipment controllers, a communications medium, and central control panels. The remote equipment controllers are devices that physically control the equipment. They are connected by a network for communication and monitoring. The network is connected to computerized central control panels that control the equipment by receiving information from the network and sending directions to the remote equipment controllers. Plant operators monitor the DCS using computer monitors and can manually override the DCS if necessary.

The DCS at Weston Unit 3 receives power from the 120/240vac UPS cabinet. The UPS cabinet includes an inverter, rectifier, voltage regulator, Fuse F204 and a static transfer switch. By the very nature of a UPS (and as the name implies), there are multiple power supplies to the UPS, so that one can reasonably assume that the DCS will have a power supply at all times. Prior to the 10/6/07 lightning strike, the Weston Unit 3 UPS was particularly robust in that it had five separate power supplies that could power the DCS load, as follows:

1) The main feed out of 480v Essential Service Motor Control Center (MCC) Bus 3C;
2) The Station Battery Charger 3A out of the 480v Essential Service MCC Bus 3C, which

supplies power to the 125v DC Bus;

3) The Station Battery Charger 3B out of the 480v MCC Bus 3B, which supplies power to the 125v DC Bus;

4) The Station Battery, which supplies power to the 125v DC Bus; and

5) The reserve feed out of 480v MCC 3A.

In addition to the Weston Unit 3 generator, the 480v Essential Service MCC Bus 3C can also be powered from two independent off-site power supplies:

1) 480v Switchgear Bus EE3 (powered from the 13.8Kv Substation through the 6.9Kv Essential Service Bus); and

2) 480v Switchgear Bus 3C (powered from the 115Kv Substation through the 6.9Kv Switchgear Bus 3A).

In addition to the two independent battery chargers, the 125v DC Bus also has a station battery as one of its power supplies. This bus supplies power to all plant DC operating equipment, including the turbine Emergency Seal Oil Pump (ESOP) and the Emergency Bearing Oil Pump (EBOP). This DC Bus will automatically supply power directly to the UPS and hence DCS upon loss of the main feed power supply.

The "reserve feed" supply comes from 480v Switchgear Bus 3A through 480v MCC Bus 3A. This power supply bypasses the UPS inverter and fuse F204 and supplies power directly to the UPS static transfer switch. Upon a loss of power to 480v Switchgear Bus 3A, Breaker 52-3A is designed to open and send a permissive to Breaker 52-3ABT to close. When Breaker 52-3ABT closes, it sends a power supply to 480v MCC Bus 3A from 480V Switchgear Bus 3B.

Q. With all of these power supplies, how did the DCS lose power after the October 6, 2007 lightning strike?

A. The DCS lost power because of an extremely remote coincidence of two unrelated failures in the UPS power supplies. The first failure was the opening of Fuse F204 caused by the voltage spike and uncontrolled power surge from the lightning strike on a transmission pole that was properly grounded but not bonded to the WGS grounding system. The opening of Fuse F204 cut four of the five power supplies to the UPS. This left the "reserve feed" from the

"3B" electric supply train. However, a previously undetected and incorrect configuration of the control wiring in Breaker 52-3A resulted in no permissive being sent to Breaker 52-3ABT to close when Breaker 52-3A was opened. This prevented the activation of the "reserve feed" power supply to the UPS.

Q. Had the Weston Unit 3 DCS ever lost power due to a lightning strike before?

A. No, although the WGS does have a history of being struck by lightning. The two most recent strikes before the October 6, 2007 event occurred in 2002 and in 2006. The 2002 strike was witnessed by an employee and occurred in the area of a 115 Kv transmission pole next to the Weston Unit 3 Main Power Transformer. The unit tripped shortly after the lightning strike. Power continued to be supplied to the DCS, both of the ID/FD fan sets continued to run, the unit underwent an orderly coast down, and there was no major damage to any plant equipment.

The specific location of the lightning strike on WGS that occurred in 2006 is not known, but the strike caused a failure of a relay on a breaker in the 46Kv substation that affected the essential services feed to Weston Unit 3 and an onsite combustion turbine, Weston Unit 31. Weston Unit 3 tripped on the loss of both ID fans, but DCS continued to operate and there was no damage to the plant as a result of the trip. The Boiler 3A feedwater pump tripped and both of the running ID fan lube oil pumps stopped. The DCS started both backup lube oil pumps as designed. In response to this event, WPS Corp reviewed the internal plant lightning suppression equipment on key plant control wiring systems, and installed suppression equipment on equipment that had been affected by lightning strikes in the past. In total, WPS Corp installed 89 surge suppressors in Weston Unit 3.

Q. Did any of the previous lightning strikes cause the Fuse F204 to open?

A. No. Historically there have been no problems with this fuse during any of the previous lightning strikes at the WGS. In fact, there have never been any operational issues with this specific fuse, and plant records indicate that a fuse had never opened at that location until October 6, 2007.

Q. What caused Fuse F204 to open on October 6, 2007?

A. The root cause investigation team concluded that the voltage spike from the lighting strike was seen at the alternate AC input to the static switch. This power surge came through the ground due to the lack of bonding between the transmission pole struck and the WGS grounding system. The rapid rise in voltage caused a momentary short on a circuit board in the UPS inverter, which caused an instantaneous exponential rise in current, which in turn caused Fuse F204 to open. Fuse F204 is a fast acting fuse designed to protect the UPS inverter circuit boards. Under these circumstances, Fuse F204 performed as designed, preventing damage to the UPS inverter. The original equipment manufacturer confirmed that the lightning strike could have elevated the ground plane voltage enough to open the Fuse F204.

Q. Please explain the incorrect configuration of Breaker 52-3A and its role in the loss of power to the DCS.

A. When Fuse F204 opened and power to the UPS was lost, the UPS static transfer switch should have switched to the "reserve feed" supply. The "reserve feed" supply is powered from 480v Switchgear Bus 3A through 480v MCC Bus 3A. After W3 tripped, power to 480v Switchgear Bus 3A was lost. In accordance with the electrical system design, when the power supply to 480v Switchgear Bus 3A is lost, Breaker 52-3A opens. When Breaker 52-3A opens, a permissive allows Breaker 52-3ABT to close, which repowers 480v Switchgear Bus 3A and 480v MCC Bus 3A restoring power to the "reserve feed" power supply. But in this instance, Breaker 52-3ABT did not close and the "reserve feed" to the UPS was not repowered. The root cause investigation determined that Breaker 52-3A did not send the required permissive for Breaker 52-3ABT to close due to an incorrect wiring configuration on a bell alarm relay contact of Breaker 52-3A. The contact, which is associated with the over-current protection for 480v Switchgear Bus 3A, was designed to be configured as a "normally closed" contact, but was mistakenly wired as a "normally open" contact.

Q. Are there other breakers of the same type as Breaker 52-3A used in Weston Unit 3?

Yes. Breaker 52-3A is one of the 18 on-site breakers including the spare breaker that can be used in this cubicle location to supply power to this 480v bus. As the unit is designed, all of these breakers should be wired the same with a "normally closed" contact configuration. Attachment G to the Report (Breaker Locations and Work History), Exhibit A-2 (DJM-1), shows all of the locations within the plant where this model breaker is used. After the October 6, 2007 lightning strike, WPSC inspected all 18 of these breakers to determine if any others had incorrectly configured breaker control contacts. The inspection determined that all of the other breakers are configured correctly. In other words, of the 18 breakers of this type used in the unit, the only incorrectly configured one was on the UPS "reserve feed" circuit when lightning caused Fuse F204 on the UPS main feed circuit to open. Each of these failures alone is highly improbable. The chance of them occurring in tandem is extremely remote.

Q. Did the root cause investigation determine how Breaker 52-3A came to be incorrectly configured?

A. No. The investigation team could not determine how the breaker came to be incorrectly configured. The investigation did identify the following facts relevant to this question:

1. This breaker model is used throughout the plant and in the mid-1990's WPS Corp undertook an effort to configure the breaker over-current control contacts for all of these breakers in the normally closed position. This effort allowed for any of the 18 breakers to be used in any plant application requiring it. The inspection after the October 6, 2007 lightning strike verified that all of these breakers were correctly configured as normally closed, except for the Breaker 52-3A that was in service.

2. In order to increase maintenance efficiency, spare breakers were purchased so that when an in-service breaker required maintenance, it was swapped with a spare. The breaker pulled out of service was then overhauled and typically placed into stock as a spare. This prevented any service interruptions during breaker maintenance. Spare breakers were not designated for particular installations and their actual installations were not tracked.

3. Breaker preventative maintenance ("PM") typically includes (a) checking clearances,

contact penetration and various resistance measurements, (b) disassembling the breaker to clean, inspect, and lubricate it, and (c) reassembling it. Once the breaker is reassembled, several simulated trip tests are performed.

4. In April 1998, Breaker 52-3A worked properly when called upon to perform its function during a plant trip.

5. Maintenance was last performed on Breaker 52-3A in mid-1998. Assuming this maintenance followed the standard practice, the incorrectly configured breaker was installed at the 52-3A location when it was swapped for the in-place breaker that had cycled earlier in the year. It is not known, however, when the bell alarm relay contact of this breaker was last re-wired.

Q. Why wasn't the incorrect bell alarm configuration of Breaker 52-3A discovered before the October 6, 2007 lightning strike?

A. The root cause investigation determined that preventative maintenance ("PM") was not performed on this breaker since it was placed in that location in mid-1998. Had the PM been performed at any time prior to the lightning strike, the breaker presumably would have been switched out with a correctly configured breaker. Because all of the other breakers of this type were found to be correctly configured after the event, we assume that the replacement breaker would have performed in accordance with the design and power would have been maintained to the UPS following both the unit trip and opening of Fuse F204.

There are several reasons why PM was not performed on this breaker. As the result of the mid-1990's effort to wire the controls for all breakers of this type in the normally closed position, the Weston Unit 3 maintenance staff believed that all of the breakers were properly configured when they switched this breaker out in mid-1998. The appropriate timing for PM of a breaker of this type is a matter of judgment. While the Weston plant PM program identifies a three-year frequency for breakers in general, the manufacturer of this type of breaker advised that the timing of PM should consider environmental conditions (i.e., humidity, dusty or dirty conditions) and the number of breaker operations, with a maximum of 500 between PM inspections. Exhibit A-4 (DJM-3) is an excerpt from the manufacturer's Instruction Book that pertains to breaker maintenance. Breaker 52-3A is in a clean location of the plant, and had not been cycled 500 times since it was installed in mid-1998. In fact, it is believed that Breaker 52-3A was never cycled between the time it was placed in service and when it was removed after the October 6, 2007 lightning strike.

Q. Are there any other ways that the incorrect bell alarm contact configuration of Breaker 52-3A could have been discovered before the October 6, 2007 lightning strike?

A. A maintenance practice common in nuclear plants is for critical plant breakers to be functionally tested either in the shop or in the test position after they are installed in breaker cubicles. A functional test of this type for Breaker 52-3A would include manually tripping the breaker after it was installed in its cubicle and verifying that a permissive to close would be sent to Breaker 52-3ABT. Had Breaker 52-3A been functionally tested in-place after it was installed, its incorrect control wiring configuration would have been discovered and corrected. However, functional testing of breakers was not a practice at Weston Unit 3, and is not a common practice at fossil plants.

Q. Can you support your assertion that functional breaker testing is not a common practice at fossil plants?

A. Yes, I can. WPS Corp is a member of the Fossil Operations and Maintenance Information System ("FOMIS"), which is an industry clearinghouse for information on fossil-fueled electric generation facility operation and maintenance practices, procedures and experience. Following WPSC's findings with respect to the as-found condition of Breaker 52-3A, WPS Corp sent an inquiry to FOMIS as to whether other facilities functionally test their breakers in-place following installation. Of the nine plants that responded, eight stated that they do not perform such testing and one stated that it did. This confirms our understanding that in-place functional testing of breakers following preventative maintenance work is not common among fossil plants.

Q. Has a Failure Modes and Effect Analysis (FMEA) been performed on the loss of power to the DCS?

A. Yes. AEMRI performed an FMEA on the UPS inverter to determine the impact that the opening of Fuse F204 would have had on this event.

Q. What is the purpose of a FMEA?

A. FMEA is a specific method of identifying the possible ways in which a system (or a device, process, or service) may fail and determining the risk associated with the failure. Its purpose is to identify and prevent known and potential problems before they affect an event.

Q. Has this fuse failed in the past?

A. This fuse has no history that shows any previous failure. It has only been replaced due to routine scheduled maintenance. Therefore, it was reasonable for plant personnel to believe that a failure of this fuse was highly unlikely. In addition, it was reasonable for plant personnel to assume that any failure of the fuse could be managed. The UPS power supply cabinet even provides an indication light to alert the operators that a change has occurred in the UPS power supply. Furthermore, the “reserve power” feed is designed to repower the UPS upon a failure of fuse F204.

Q. What are the conclusions from AEMRI’s FMEA review?

A. The managers and operators of Weston Unit 3 were correct in placing their trust in the multiple sources of power to the UPS. The failures that led to the damage at the plant followed the loss of multiple levels of defense and included both passive (Fuse F204 opening) and active failures (Breaker 52-3ABT not closing). The design of the power supplies to the UPS inverter shows that the risk associated with the FMEA would be determined to be of a low enough level that no further action (i.e., design enhancements) was warranted.

<u>Contributing Cause #1: Modeling to Address Unit Trip Upon Loss of ID/FD Fans</u>

Q. What is meant by a contributing cause in the Report?

A. A contributing cause is a causal factor in the failure scenario the correction of which would not necessarily prevent recurrence of the failure, but is deemed a significant enough issue to identify for further evaluation.

Q. Please describe the first contributing cause.

A. When a baghouse was installed on Weston Unit 3 in 2001 to reduce air emissions from Weston Unit 3, it introduced a restriction in the flue gas stream in order to capture the ash produced from coal combustion. The resulting reduction in the amount of pressure reduces the capacity of the ID fans, in this case apparently to the point that a single ID fan may not have adequate fan margin to maintain proper furnace pressure even with an automatic turbine runback.

The baghouse design change involved the modeling of numerous operating conditions, but no modeling was completed for turbine runback or single-fan operating conditions. Since the baghouse installation in 2001, the unit has experienced infrequent boiler trips upon the loss of one of the ID fans. The analysis necessary to determine the precise cause of these boiler trips, and whether there are cost-effective modifications to the unit to avoid them, has not been performed. Had additional modeling been performed, it ***might*** have identified cost-effective modifications to the plant that could have prevented unit trips upon loss of an ID fan. If WPS Corp's management had determined that preventing such unit trips justified such modifications, and if the modifications were made, then the unit may not have tripped following the loss of a set of ID/FD fans due to the October 6, 2007 lightning strike, and the ensuing damage would not have occurred.

Q. Why wouldn't WPS Corp seek to minimize trips of Weston Unit 3?

A. Trips of the unit are typically not significant in terms of cost or reliability. When the unit trips, in most cases it is brought back on line within three hours at minimal cost. Given the robustness of the power supply to the DCS, Weston Unit 3's managers and operators reasonably assumed that the DCS would not lose power and would ensure an orderly trip whenever one occurred. For these reasons, WPS Corp accepted a small increase risk of unit trips as a consequence of reducing the unit's air pollution.

It is also important to note that the unit can trip for any number of reasons, especially in response to a lightning strike. The October 6, 2007 lightning strike's impacts on Fuse F204 and one set of the unit's ID/FD fans were random results of an uncontrolled power surge through the ground. The unit tripped in 2002 in response to a lightning strike, even though both sets of fans continued to operate. In other words, even if the baghouse modeling had been done, and cost effective modifications were identified and implemented, it would not have necessarily prevented a unit trip in response to a lightning strike.

<u>Contributing Cause #2: "Fail Open" Contacts For Emergency Oil Pumps</u>

Q. Please describe the second contributing cause.

A. As part of the DCS design change, the power supply control logic for the plant components that were involved in the design change, including several emergency oil pumps, was changed from a "fail closed" contact configuration to a "fail open" control logic design that required a DCS signal to start the equipment. This change ensured that the DCS remained in control of the equipment under all circumstances. With respect to the emergency oil pumps, after this change, low oil pressure signals were no longer sent to the pump start circuitry but were instead sent to the DCS, which would process the signal and, if plant conditions required a pump start, the DCS would initiate a signal to the emergency pump start circuit.

The "fail open" configuration of the emergency oil pumps appears to have been accepted based on the assumption that the DCS would not lose power. The belief that the DCS would not lose power was supported and reinforced by the modification design team, which emphasized in its design the multiple power feeds to the DCS, including a battery backup power supply. The FMEA conducted by AEMRI supports the reasonableness of this belief.

Q. What role did this design change play in the damage to the unit following the lightning strike?

A. When the UPS lost all of its power supplies, no DCS signal could be sent to start the emergency oil pumps, and it was the loss of lube oil and seal oil to the turbine generator equipment that caused the damage to the, the turbine/generator bearings, the fire at the electrical generator, and the lube oil tank explosion.

Q. Is the "fail open" control logic configuration an optimal design for the emergency oil pumps?

A. No, it isn't. If one assumes that the UPS could lose power upon a unit trip, then one would take the additional step in the DCS design of determining on a component-by-component basis whether a "fail closed" control logic configuration should be used. With that assumption, the controls for the emergency oil pumps and other protective equipment should be configured a "fail closed" so that the equipment defaults to operating and performs its function.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

Wisconsin Public Service Corporation
Case No. U-15402-R
Application

Exhibit A-1 (JGG-1)

WISCONSIN PUBLIC SERVICE CORPORATION
2008 Plan Year Reconciliation Summary

Line:				
1	Principle amount of 2008 over-recovery		$1,078,922	
2	Roll-in of 2007 under-recovery (U-15008-R)		($855,997)	
3	Net over recovery balance for 2008 before interest			$222,925
4	Simple interest during 2008 plan year			($20,485)
5	Net over recovery ending balance for 2008 including interest			$202,440
6	Weston 3 replacement power costs deferred in 2007		($489,182)	
7	Weston 3 replacement power costs deferred interest from 2007		($3,009)	
8	Weston 3 replacement power costs deferred interest from 2008	3.433%	($16,793)	
9	Total under recovery to be rolled into the 2009 PSCR (Lines 5 + 6 + 7 + 8)			($306,544)

WISCONSIN PUBLIC SERVICE CORPORATION

Calculation of PSCR Plan Year Interest - 2008

	PSCR Roll-in 2007	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2008 Jan	Total	
1 Generation + Purchased Power Less Opp Sales		1,330,886	1,239,924	1,253,642	1,171,814	1,161,872	1,248,803	1,369,766	1,366,569	1,244,025	1,244,733	1,177,308	1,283,279		15,092,621	Monthly PSCR Reports, page 3 of 4
2 Less Losses & Company Use (Mwhs)		39,561	28,953	38,056	36,606	24,906	36,953	52,137	33,752	40,156	20,851	27,021	57,198		436,150	
3 Total Requirement Sales (Mwhs)		1,291,325	1,210,971	1,215,586	1,135,208	1,136,966	1,211,850	1,317,629	1,332,817	1,203,869	1,223,882	1,150,287	1,226,081		14,656,471	
4 Power Supply Cost ($'s)		61,695,801	53,332,700	52,714,225	53,135,979	36,566,141	43,110,409	50,171,781	45,848,820	41,955,756	45,684,529	44,483,859	48,588,306		577,288,306	Monthly PSCR Reports, page 3 of 4
5 Power Supply Cost per Mwh Sale($/Mwh)		47.78	44.04	43.37	46.81	32.16	35.57	38.08	34.40	34.85	37.33	38.67	39.63		39.39	
6																
7 Michigan Kwh sales Billed		24,248,820	24,940,023	25,647,734	23,901,649	21,851,068	23,353,291	23,785,011	25,193,534	22,344,558	23,378,880	22,623,186	25,626,676		286,894,430	
8 Michigan Kwh sales Unbilled Current Month		7,109,037	6,709,152	7,161,622	6,247,870	6,958,969	6,982,205	7,519,980	7,437,556	6,286,426	6,708,016	6,850,978	6,873,177		82,844,988	
9 Less Michigan Kwh Sales Unbilled Prior Month		(7,183,643)	(7,109,037)	(6,709,152)	(7,161,622)	(6,247,870)	(6,958,969)	(6,982,205)	(7,519,980)	(7,437,556)	(6,286,426)	(6,708,016)	(6,850,977)		(83,155,453)	
10																
11 Michigan Kwh Calendar sales Subject to PSCR		24,174,214	24,540,138	26,100,204	22,987,897	22,562,167	23,376,527	24,322,786	25,111,110	21,193,428	23,800,470	22,766,148	25,648,876		286,583,965	0.019553
12																
13 Power Supply Base Rates ($/Mwh)		40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70		
14 Applied PSCR Factor ($/Mwh)		0	0	0	0.00	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	5.45		
15																
16 Michigan Revenue Billed for PSCR		$986,927	$1,015,059	$1,043,863	$972,797	$972,154	$1,038,988	$1,058,195	$1,120,860	$994,109	$1,040,126	$1,006,506	$1,140,131		$12,389,715	
17 Michigan Revenue Unbilled Current Month		$289,338	$273,062	$291,478	$277,968	$309,605	$310,638	$334,564	$330,897	$279,683	$298,440	$304,800	$317,197		$3,617,670	
18 Michigan Revenue Unbilled Prior Month		($292,374)	($289,338)	($273,062)	($291,478)	($277,968)	($309,605)	($310,638)	($334,564)	($330,897)	($279,683)	($298,440)	($304,800)		($3,592,847)	
19																
20 Total PSCR Calendar Revenues		$983,891	$998,784	$1,062,278	$959,287	$1,003,791	$1,040,022	$1,082,121	$1,117,193	$942,896	$1,058,883	$1,012,866	$1,152,528		$12,414,538	
21																
22 Applicable PSCR Costs		$1,158,539	$1,098,390	$1,112,221	$1,118,771	$702,756	$830,771	$905,669	$866,656	$778,725	$872,677	$874,883	$1,015,558		$11,335,616	
23 Amortization of Non-Qualified Decom. Fund		($41,738)	($41,738)	($41,738)	($41,738)	($41,738)	($41,738)	($41,738)	($41,738)	($41,738)	($41,738)	($41,738)	($41,738)		($500,856)	
24 Amortization of 2005 PSCR Underrecovery		$41,738	$41,738	$41,738	$41,738	$41,738	$41,738	$41,738	$41,738	$41,738	$41,738	$41,738	$41,738		$500,856	
25 Total Cost of Power Supply		$1,158,539	$1,098,390	$1,112,221	$1,118,771	$702,756	$830,771	$905,669	$866,656	$778,725	$872,677	$874,883	$1,015,558		$11,335,616	
26																
27 Over/(Under) Recovery	($855,997)	($174,648)	($99,607)	($49,943)	($159,484)	$301,035	$209,251	$176,451	$250,537	$164,171	$186,206	$137,983	$136,970		$222,925	
28																
29 Beginning Recovery Balance		($855,997)	($1,030,645)	($1,130,252)	($1,180,195)	($1,339,679)	($1,038,644)	($829,393)	($652,942)	($402,404)	($238,234)	($52,027)	$85,955			
30 Ending Recovery Balance	($855,997)	($1,030,645)	($1,130,252)	($1,180,195)	($1,339,679)	($1,038,644)	($829,393)	($652,942)	($402,404)	($238,234)	($52,027)	$85,955	$222,925			
31 Average Recovery Balance		($943,321)	($1,080,449)	($1,155,224)	($1,259,937)	($1,189,161)	($934,018)	($741,167)	($527,673)	($320,319)	($145,131)	$16,964	$154,440			
32																
33 Interest Rate % - (Undercollection)		4.531	3.429	3.145	2.807	2.719	2.698	2.743	2.667	4.210	4.874	4.245	3.127		3.433	Average
34 Interest Rate % - Overcollection		10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60			ROE from last approved rate case
35 Monthly Interest		($3,562)	($3,087)	($3,028)	($2,947)	($2,694)	($2,100)	($1,694)	($1,173)	($1,124)	($589)	$150	$1,364		($20,485)	

Wisconsin Public Service Corporation

Differences Between 2008 Actual and 2008 Plan Year

		2008 ACTUAL	2008 PLAN	% CHANGE
Fossil	Generation (Mwh)			
	Pulliam	2,104,295	2,175,165	-3.26%
	Weston	3,174,109	3,528,765	-10.05%
	Edgewater	634,928	686,302	-7.49%
	Columbia	2,306,810	2,337,135	-1.30%
	Weston 4	1,230,143	2,424,881	-49.27%
	Total Generation	9,450,285	11,152,248	-15.26%
	Costs($000's)			
	Pulliam	38,327	52,760	-27.36%
	Weston	60,153	74,148	-18.87%
	Edgewater	14,734	14,849	-0.77%
	Columbia	34,080	33,542	1.60%
	Weston 4	20,092	44,391	-54.74%
	Total Costs	167,386	219,690	-23.81%
	Costs/Mwh			
	Pulliam	18.21	24.26	-24.91%
	Weston	18.95	21.01	-9.81%
	Edgewater	23.21	21.64	7.25%
	Columbia	14.77	14.35	2.94%
	Weston 4	16.33	18.31	-10.78%
	Average Costs/Mwh	17.71	19.70	-10.09%
Hydro	Generation (Mwh)	196,628	285,530	-31.14%
	Costs ($000's)	0	0	
	Costs/Mwh	0	0	
Wind	Generation (Mwh)	17,776	18,979	-6.34%
	Costs ($000's)	0	0	
	Costs/Mwh	0	0	
Peakers	Generation (Mwh)	175,021	83,017	110.83%
	Costs ($000's)	20,663	8,972	130.31%
	Costs/Mwh	118.06	108.07	9.24%
Purchased Power	Mwh Purchased	6,017,445	5,138,891	17.10%
	Costs ($000's)	353,331	344,380	2.60%
	Costs/Mwh	58.72	67.01	-12.38%
Transmission	Network Charge	93,985	90,907	3.39%
LESS: Non-Firm Sales	Mwh Sales	764,533	464,313	64.66%
	Revenues ($000's)	58,077	34,953	66.16%
	Revenue/Mwh	75.96	75.28	0.91%
TOTAL	PSCR Mwh's	15,092,621	16,214,352	-6.92%
	PSCR Costs ($000's)	577,288	628,996	-8.22%
	PSCR Cost/Mwh	38.25	38.79	-1.40%

Wisconsin Public Service Corporation
Weston 3 Lightning Strike - Replacement Power Costs

Deferered Costs from 2007

Description	2007 Oct	2007 Nov	2007 Dec	2007 Total
Replacement Power Costs for Weston 3	10,284,362	10,370,051	13,086,228	33,740,641
Purchased Power Pricing impact	210,827	411,971	738,221	1,361,019
Replacement Power Costs for NOx Impact	139,338	190,789	262,261	592,388
Weston 3 Sales in Real Time MISO Mkt	-	-	-	-
Less Fuel Cost Avoided -Weston 3	(3,271,397)	(4,149,282)	(4,400,608)	(11,821,287)
Less Fuel Cost Avoided - for NOx Impact	(50,347)	(70,573)	(82,461)	(203,381)
Net Replacement Power Costs	**7,312,782**	**6,752,957**	**9,603,641**	**23,669,380**
Corporate Net Replacement Power Costs	7,312,782	6,752,957	9,603,641	23,669,380
MPSC %	2.0667%	2.0667%	2.0667%	
MPSC Deferral	151,136	139,565	198,481	489,182
MPSC Deferral Balance	151,136	290,701	489,182	
Interest Rate %	5.3750%	4.9160%	5.4330%	
MPSC Interest	338	905	1,765	3,009
MPSC Interest Balance	338	1,244	3,009	
MPSC Deferral+Interest Balance	151,474	291,945	492,191	492,191

Costs from 2008

Description	2008 Jan	2007 & 2008 Total
Replacement Power Costs for Weston 3	5,355,586	39,096,227
Purchased Power Pricing impact	160,333	1,521,352
Replacement Power Costs for NOx Impact	-	592,388
Weston 3 Sales in Real Time MISO Mkt	(608,221)	(608,221)
Less Fuel Cost Avoided -Weston 3	(1,981,957)	(13,803,244)
Less Fuel Cost Avoided - for NOx Impact	-	(203,381)
Net Replacement Power Costs	**2,925,741**	**26,595,121**
Corporate Net Replacement Power Costs	2,925,741	26,595,121
MPSC %	1.9553%	
MPSC Portion of Costs	57,208	546,390

Wisconsin Public Service Corporation

Case No. U-15402-R

Application

Exhibit A-2 (DJM-1)

Docket 6690-UR-119
Exhibit ___(DJM-1)

Root Cause Investigation

Weston 3 Plant Trip on October 6, 2007

June 13, 2008

Table of Contents

Contents

Table of Contents 2

EXECUTIVE SUMMARY 4

OVERVIEW SUMMARY OF EVENT 5

PROBLEM STATEMENT 6

METHOD OF INVESTIGATION 7

Assessment Approach 7

Investigation Team Members 7

Terms and Acronyms 8

Event Timeline 9

Initial Operator Response to the Event 9

Conclusions from Timeline Information 14

Document Review 14

Review of Operator Actions 14

Equipment Failure Mode Development 15

Review of the Design Specifications for the Equipment Affected 16

Effect of DCS Design Change on Operator Response 18

ELECTRICAL DESIGN 19

As-Built Design of the Weston 3 Electrical Distribution Systems 19

DCS Power 19

W3 RAT 3A Tie to W4 20

FAILURE ANALYSIS 20

Review of the Weston Site Grounding Grid System (Including Excerpts from Lightning Eliminators and Consultants Report (LEC) - Reference 1) 21

Inverter Open Fuse 22

Breaker Configuration 23

Induced Draft Fan 3B Trip 24

Damage to the Turbine/Generator (loss of oil) 25

Damage to the Boiler Feed Pump Motors and Drives 25

Fire at the Generator 26
Explosion at the Lube Oil Tank 26
Failure Mode and Effects Analysis 26
Conclusions from FMEA Review 28
PREVIOUS EVENT REVIEW 28
SAFETY ASSESSMENT 28
Industrial Safety 28
Environmental Impact 29
CONCLUSIONS 29
Initiating Event 29
Root Causes 29
Contributing Causes 29
REFERENCES 30
Specific 30
General 30

EXECUTIVE SUMMARY

Lightning struck an American Transmission Company (ATC) transmission tower located on Wisconsin Public Service Corporation's (WPSC) Weston generating facility in the early morning of October 6, 2007. The lightning strike initiated a series of events at the Weston 3 unit. The ground potential rise from the lightning strike resulted in a transmission grid voltage spike and a local ground disturbance that impacted Weston Units 2 and 3 (W2 and W3). Not impacted were Weston Units 1 and 4 (W1 and W4).

Immediately after the lightning strike, one set of Induced Draft (ID) and Forced Draft (FD) fans on W3 stopped running, which caused furnace pressure to increase. The evidence suggests that these fans stopped running when the lightning struck because the transmission pole was not bonded to the plant grounding system, resulting in a ground potential rise and an exponential power surge through the ground to the fans (and other unit components). The loss of one set of fans with the unit operating at full power results in a W3 boiler trip due to furnace high pressure, immediately followed by a turbine trip as designed. These trips occurred about 46 seconds after the lightning strike.

After the turbine tripped, the electrical distribution for the 6.9kV switchgear bus 3B performed a fast bus transfer as designed from the Main Auxiliary Transformer (MAT) to the Reserve Auxiliary Transformer (RAT) 3B. At that instant, all power was lost to the Distributed Control System (DCS) due to an open fuse in the primary output circuit of the Uninterruptible Power Supply (UPS). Investigation revealed that this fuse opened when the lightning struck because of the ground potential rise caused by the lack of bonding between the transmission pole and the plant grounding system. The "reserve feed" source designed to power the DCS and carry load under these conditions, was not available due to a circuit breaker control configuration error that was previously not detected. The complete loss of power to the DCS occurred just 52 seconds after the lightning strike.

Upon the loss of power to the DCS, the DCS logic could no longer generate control signals based on software program control, which led to extensive equipment damage at the plant within minutes. Operators were unable to take prompt corrective measures to prevent the damage because normal control of this equipment is through the DCS, and the simultaneous loss of all power supplies to the DCS was not believed to be possible. In addition to having little or no information about occurrences within the plant, the W3 staff's first priority was to contain and suppress the multiple fires in W3 that ignited within minutes of the lightning strike. Only after the fires were under control could the employees begin to try to manually start processes that lost power. In addition, design features of the DCS contributed to the extent of damage at the plant.

Even though extensive equipment damage occurred, no personnel were injured and there was never any danger posed to the public.

This investigation concluded that the forced outage and damage to W3 were initiated by the lightning strike on ATC equipment, and had the following root and contributing causes:

Root Cause #1: The transmission tower that was struck was not bonded to the Weston generating facility's grounding system. Had the tower been bonded to the grounding system, the ground potential rise that impacted W2 and W3 may not have occurred.

Root Cause #2: The power surge induced by the ground potential rise from the lightning strike caused a fuse (F204) to open in the primary output circuit of the uninterruptible power supply to the DCS system, causing a loss of the DCS system's normal sources of power along with the station battery backup supply. The breaker control configuration for Breaker 52-3A was incorrect, which resulted in the unavailability of the backup power supply to the DCS system. Had this breaker control configuration been correct, the DCS system would have remained operational and would have controlled the W3 unit trip, and prevented the resulting damage to the unit.

Contributing Cause #1: No modeling was performed for turbine runback or single-fan operating conditions when modifications were made to the W3 baghouse for environmental compliance purposes. Had this modeling been performed, it may have identified cost-effective modifications to the plant that could have prevented a unit trip upon loss of a set of ID/FD fans.

Contributing Cause #2: When the DCS system was modified, the power supply design for several emergency oil pumps was changed to a "fail open" contact arrangement upon low oil pressure signals. Had the design incorporated a "fail closed" contact arrangement the pumps would have started on a low oil pressure signal independent of the DCS, and prevented the damage to the unit.

OVERVIEW SUMMARY OF EVENT

At 04:04:25 security camera time on October 6, 2007, lightning struck ATC's 115Kv, T20 transmission line and transmission tower number 7. This tower is located approximately 250 yards northwest of the W3 power block. The ground potential rise from the lightning strike resulted in a transmission grid voltage spike and local ground disturbance. As documented on the DCS alarm/event log, at 04:04:27:28 DCS time a "Stop" signal was sent to the 3B ID/FD fans. A DCS "Load Setback in Progress" alarm was received at 04:04:28:03 due to the stoppage of the 3B ID/FD fans. With the stoppage of these fans, furnace pressure began to increase. At the high furnace pressure setpoint, the DCS responded by initiating a unit trip as documented by the "High Furnace Press First Out" alarm at 04:05:11:64. The unit trip was confirmed with the "Boiler Trip-Master Fuel LO Relay" and "Turbine Trip from Mark VI" alarms at 04:05:11:70, about 46 seconds after the lightning strike.

When the generator trips, the electrical distribution system associated with the 6.9 kV switchgear bus 3B is designed to perform a fast bus transfer from the MAT 3B to the RAT 3B. This occurred as designed approximately 6 seconds after the turbine trip. As this transfer occurred, power was lost to the DCS as a result of a fuse (F204) in the primary output circuit of the inverter that opened as a result of the power surge from the lightning strike. The loss of fuse F204 prevented the normal and backup offsite and onsite power supplies (including the station batteries) from supplying power to the DCS. The last remaining power source to the DCS (the “reserve feed”) was also not available due to a previously undetected circuit breaker control configuration error. As a result there was a complete loss of power to the DCS. The last alarm recorded by the DCS occurred at 04:05:17:21, approximately 6 seconds after the turbine trip and 52 seconds after the lightning strike.

The loss of power to the DCS prevented the DCS logic from generating control signals based on software program control. Neither the turbine/generator turning gear oil pump nor the emergency bearing oil pump automatically start upon loss of a DCS signal. Thus, the turbine/generator coasted down in speed without sufficient bearing lubricating oil. Without a supply of lubricating oil to the bearings, extensive heat built up due to friction and melted the bearing babbitt which resulted in damage to the turbine/generator shaft journals. The loss of the DCS also resulted in stoppage of the generator hydrogen seal oil pump and prevented the automatic start of the emergency hydrogen seal oil pump. Without seal oil, hydrogen exhausted from the generator, which resulted in a hydrogen fire on the turbine end of the generator and an explosion in the turbine lubricating oil storage tank. Both boiler feed pump (BFP) motors continued to rotate without lubricating oil for a period of time. This occurred because the electric power to the boiler feed pump motors remained available, while, upon loss of power to the DCS, the boiler feed pump lubricating oil pumps stopped. The loss of lubricating oil resulted in damage to the boiler feed pump motors, hydraulic couplings, and associated equipment.

The operators were unable to take prompt corrective measures to prevent these events from occurring because normal control of this equipment is through the DCS, and without the DCS the operators had little information about the events that were occurring within the plant. The plant staff’s first priority was to safely suppress the multiple fires in the plant. Only after the fires were under control could the employees begin to manually start processes that lost power. The majority of plant equipment damage occurred within the first few minutes following the loss of DCS.

PROBLEM STATEMENT

On October 6, 2007, W3 experienced a turbine run-back and subsequent unit trip. Several pieces of major plant equipment were effected (i.e., DCS power supply, turbine/generator, and the Boiler Feed Pump motors and hydraulic drives), a fire started at the main generator and on both BFP motors, and an explosion occurred in the turbine lubricating oil storage tank.

This investigation was undertaken to determine the root and contributing causes of these events.

METHOD OF INVESTIGATION

Assessment Approach

The first step of the investigation was to create a timeline of the events that occurred when W3 tripped on October 6, 2007. Multiple sources of information were used to create this timeline, beginning with a review of the DCS alarm/event log from W3 and then reviewing statements prepared by the individual operators.

Next, numerous documents were reviewed, including alarm response procedures, operating procedures, logic drawings, and equipment manuals, to determine actions the operators needed to take at the time of the event and to determine possible failure modes for each piece of major equipment affected. Interviews were then conducted to further understand the event and identify any contributing factors affecting the major events.

Information from the document review and interviews provided supporting and refuting evidence that was used to identify the causes of the event. This information was added to the timeline to create an event and causal factor chart for this event and used in the failure analysis to determine the root cause(s) and contributing cause(s) of this event.

Specific areas reviewed for failure analysis included the W3 trip, the loss of the DCS, the 3B ID/FD fan stop, turbine/generator damage, BFP motor and hydraulic drive damage, and an explosion at the turbine lubricating oil storage tank.

Investigation Team Members

Management Sponsor
Mark Maurer, Plant Manager, WPSC

Team Members
Thomas Larson (Team Leader), WPSC
Dave Braun, WPSC
John Hoard, WPSC
Gary Youngwirth, WPSC
Jeff Summy, AEMRI
Tracy Theesfeld, AEMRI

Terms and Acronyms

Contributing Cause(s) – causal factor(s) in the failure scenario that, while correction would not prevent recurrence, are deemed significant enough issues to identify for further evaluation

Initiating Event – natural phenomenon, equipment failure or human error that starts a chain of events that leads to undesired conditions

Root Cause(s) – the most basic causal factor(s) that, if corrected, precludes recurrence of this event

ACO – Auxiliary Control Operator
AEMRI – Adult Education and Management Research Institute, Inc.
AO – Auxiliary Operator
ATC – American Transmission Company
BFP – Boiler Feed Pump
CAM – Cause Analysis Map™
CMMS – Computerized Maintenance Management System
CO – Control Operator (*Carbon Monoxide when directly referenced to alarms*)
CO_2 – Carbon Dioxide
CR – Control Room
DC – Direct Current
DCS – Distributed Control System
EBOP – Emergency Bearing Oil Pump
ECR – Engineering Change Request
EFMC – Equipment Failure Mode Chart
ESOP – Emergency Seal Oil Pump
FD – Forced Draft
FMEA – Failure Modes and Effects Analysis
GOK – Fan Status Signal
GPR – Ground Potential Rise
H_2 - Hydrogen
HMI – Human Machine Interface
ID – Induced Draft
IEEE – Institute of Electrical and Electronics Engineers, Inc.
KV/kV/Kv – Kilo volts (1000 volts)
LEC – Lightning Eliminators and Consultants, Inc.
LO – Lock Out
MAT – Main Auxiliary Transformer
MCC – Motor Control Center
MSOP – Main Seal Oil Pump
OCB – Output Circuit Breaker
OEM – Original Equipment Manufacturer
PM – Preventative Maintenance
PO – Purchase Order

RAT – Reserve Auxiliary Transformer
SS – Site Supervisor
SWG/SWGR – Switchgear
TGOP – Turning Gear Oil Pump
UPS – Uninterruptible Power Supply
W3 – Weston 3
W4 – Weston 4
WPSC – Wisconsin Public Service Corporation

Event Timeline

Multiple sources of information, including the W3 and W4 DCS alarms, were used to create the event timeline shown in Attachment A: Event Timeline. Because inputs to the event timeline were obtained from various sources, and because all of the sources were not synchronized precisely, exact correlation of all times was not possible. The DCS alarm data does show event conditions within fractions of a second, so the data does provide reasonable assurance of conditions that alarmed. Security camera input, DEMAXX alarms, switchyard relay actuation, and information from the interviews and Operator Logs was added to the initial information provided by the DCS alarm/event log. Hundreds of alarms were received when the event occurred, but only those significant alarms used for this event investigation are shown in Attachment A and described below.

Initial Operator Response to the Event

This section provides a summary of the actions taken by the plant staff immediately after the lightning strike.

W3 Operations Staff

The W3 shift complement is comprised of five individuals: the shift supervisor and control room operator who are located in the control room and three auxiliary operators whose primary duties are to monitor equipment throughout the plant. The shift supervisor and control room operator are responsible for overall plant operations and they provide direction to the auxiliary operators based on DCS indication/alarms.

The following table provides a summary of the operators' responses to the lightning strike and the significant alarms received through the DCS immediately after the lightning strike. The table lists the alarms by DCS time, the total number of alarms, and denotes the alarms regarding significant components of the unit.

Time From DCS	Total Number of Alarms Received Significant Alarms	Plant Conditions or Operator Response
04:00:00		Before the lightning strike the W3 plant was operating near full load. The operations staff was performing normal routine duties and no maintenance activities were being conducted. Staff noted that there was a significant amount of lightning in the area that night.
04:04:25	This time is from the security camera and not from DCS. The time from these two systems may not be exactly the same.	Security camera records a lightning strike on ATC's 115Kv, T20 transmission line, transmission tower #7.
04:04:26	14 DCS alarms received Generator H_2 Panel Trouble alarm Turbine Intercept Valve #2 closes Fire Prot–any Pulverizer CO Lvl High	Numerous DCS alarms begin to annunciate in the W3 control room. The fire alarm indicates a potential fire in one of the unit coal pulverizers. Post-event review determined this alarm was inadvertent and no fire is believed to have existed at the time of the alarm. Other alarms believed to be erroneous, caused by the lightning strike.
04:04:27	7 DCS alarms received 3A FD fan deviation alarm 3B FD fan deviation alarm 3B FD fan trip alarm 3B ID fan trip alarm	The W3 control room operator immediately confirms the alarms indicating the loss of 3B ID/FD Fans using DCS indication. The unit cannot continue to operate at full load with the loss of these fans. From past experience the operator knows that the loss of these fans with the unit operating at full load has historically resulted in a unit trip. In anticipation of a unit trip, the W3 operator calls the W4 control room operator and requests that the "RAT 3A" be put back to "normal."
04:04:28	12 DCS alarms received Load Setback In Progress	The "Load Setback" alarm indicates that an automatic preprogrammed unit load reduction to 60% load is initiated due to the loss of the fans. The W3 operator's immediate action is to confirm that a unit load reduction is in progress.
04:04:29 to 04:04:34	36 DCS alarms received	Alarms received during this time period are those associated with a rapid load reduction of the unit. The control room operators continue to verify the automatic actions are occurring to maintain control of the plant and proceed to a plant shutdown condition.
04:04:35	9 DCS alarms received Air Heater 3A Air Inlet Pressure Windbox Pressure East Windbox Pressure West	These alarms indicate the boiler furnace pressure is increasing and the boiler will trip at the furnace high pressure trip set point, as expected during a "Load Setback" starting from full load condition
04:04:36 to 04:05:01	29 DCS alarms received	
04:05:02	Furnace Press High	The furnace high pressure alarm setpoint reached, as expected during a "Load Setback" starting from full load condition.
04:05:03 to 04:05:10	13 DCS alarms received	
04:05:11	4 DCS alarm received Boiler Trip-Master Fuel LO Relay Turbine Trip from MARK VI	A boiler and turbine trip occurs 46 seconds after the lightning strike. DCS controls still in place to shut the unit down in an orderly fashion, without damage.
04:05:12 to	76 DCS alarms received	

Time From DCS	Total Number of Alarms Received / Significant Alarms	Plant Conditions or Operator Response
04:05:13		
04:05:14	Boiler Trip-Loss of Fuel	This is the last alarm from the DCS.
04:05:17	Turb Gland Steam Htr Drnr Press Low	This is the last event logged to the alarm/event log from the DCS. At this point – 52 seconds after the lightning strike – automatic control of the plant is lost and the control room operators have no direct indication of the events occurring within the plant.

W3 Control Room Operator

During the first 51 seconds after the lightning strike, the W3 control room operator (1) receives 202 DCS alarms, (2) realizes that a unit trip is eminent, (3) notifies the Weston 4 control operators of the situation and directs them to take action to switch electrical transformer RAT-3A and associated bus to normal, and (4) has indication of a fire in the coal pulverizers. At the 52nd second the control room operator loses the DCS and all computer monitors go blank. He immediately begins to troubleshoot the reason for the loss of DCS. During troubleshooting he looks out the control room glass windows and observes steam bursting out of the turbine seals and flames coming out from between the turbine and generator. He immediately activates the turbine bearing fire protection system from the control room. With the use of hand held radios, the control room operator maintains communications with the plant's AOs.

W3 Shift Supervisor

During the initial minute of the event, the W3 shift supervisor is assessing all the alarms and confirming the immediate actions being taken by the control room operator in response to the various alarms. Shortly after the DCS is lost, the shift supervisor observes the steam bursting out of the turbine seals and flames coming out from between the turbine and generator. He confirms that the control operator activates the turbine bearing fire protection system, and contacts the W4 shift supervisor to provide a quick system status report. Recognizing the severity of the situation, the W3 shift supervisor dials 911 and requests support from the local fire department, and then calls the Wackenhut Security Supervisor to have security guide the fire department vehicles to the W3 turbine deck. He also makes phone calls to the Plant Manager and various other personnel to obtain help in securing the plant to a safe standby condition. A call from the W1 & W2 control room operators confirmed that they are safe, W1 is still operating but that W2 had tripped. As plant staff begins to arrive on site, the W3 shift supervisor begins to direct them to the areas of highest priority to investigate and take corrective action.

W3 Auxiliary Operators

All three W3 Auxiliary Operators (AO) are outside the control room performing their normal nightly rounds. At the time of the lightning strike, one of the AOs was in the circulating water building inspecting a circulating water pump. Initially he continues to perform his normal duties but later into the event he receives direction from both the W3 control room operator and the W3 shift supervisor to perform several equipment inspections. These inspections included going to the baghouse and taking action to ensure an adequate gas flow path was available for exhaust flue gas. The responsibility of this AO is mainly for support equipment not located within the turbine/generator and boiler building (i.e., baghouse, wastewater plant, cooling tower).

At approximately 04:05 the second W3 AO is leaving the east side door of the sample room. Upon leaving the sample room the AO notes that the lights are out downstairs and he hears the "banging" sound of a tempering air damper shutting, coming from the area of "A" mill. He also notices that the A & B air compressors are in alarm. After performing an inspection of the compressors he clears the alarms and then goes to investigate the noise coming from the "A" mill area. Using his flashlight he inspects each mill (A through E) and notices the "D" mill is smoking. After reporting the smoke to the control room operator he is instructed to admit CO2 into the mill. As he is admitting CO2 into the "D" mill, the AO notices smoke coming from several other mills and so proceeds to admit CO2 into all mills "A-E". He then checks on the condition of the boiler feedwater pumps (BFP) which are in the general vicinity of the mills. He reports to the control room that although both BFPs are operating, their associated lube oil pumps are off. A minute later he reports to the control room that the "B" BFP motor was on fire. Then he hears what sounds like an explosion and runs out of the building. Running along the outside of the plant he meets up with the fire fighters who were setting up to put out the BFP fire. At that point the AO learns of the turbine room fire and escorts several fire fighters that were just arriving to the turbine/control room area. From there he is directed to provide support in starting several pieces of equipment and assisting the first AO with the baghouse

The third W3 AO is initially sent by the control room operator to attempt to put the turbine on turning gear and get the turbine turning gear oil pump operating from the local control station. After his initial attempts were unsuccessful, the AO runs to the turbine oil storage tank area where pump test start buttons are located. As he approaches this area an explosion occurs and he sees a large fire ball coming out of the turbine oil storage tank. As the fire ball subsides he returns to the area and tries to start the turbine/generator turning gear oil pump, the emergency bearing oil pump and the emergency seal oil pump but is unable to start any of them. He returns to the control room to take direction and provide support where needed including assisting the W4 Shift Supervisor in attempting to open the BFP 6.9Kv breakers.

W4 Operations Staff

The W4 shift complement is comprised of five individuals: the shift supervisor, control room operator (located in the W4 control room), two auxiliary operators whose primary duties are to monitor equipment throughout the plant, and a laboratory operator. The shift supervisor and control room operator are responsible for overall plant operations and they provide direction to the auxiliary operators based on DCS indication/alarms. The laboratory operator is responsible for the plant laboratory and was not involved in this event.

W4 Shift Supervisor

The W4 Site Supervisor is exiting the service building when he sees a "flash of lightning" and hears "what sounded like wires coming down." He immediately calls the W4 control room to obtain a unit status. Informed of the request by the W3 control operator to take action to switch electrical transformer RAT-3A and associated bus to normal, the W4 shift supervisor assumes that W3 was or soon would be offline. Aware of the importance to W3 of the low head service water pumps and the river water pumps following a plant shutdown, he directs a W4 AO to inspect and verify the status of the service water pumps. He then heads over to the river water pumps located by units W1 and W2 to verify their status and confirms that they are both operating. He then learns that W2 has tripped offline and heads over to the W2 control room to verify status and offer assistance. Upon hearing of the major problems at W3 he returns to W3 and proceeds to the control room. After entering the W3 service building on the way to the control room, he hears an explosion and assumes it is due to a mill full of coal (in fact it was the turbine oil storage tank). Once in the W3 control room, he verifies the blank DCS screens and is informed that the fire department is on the way to the plant. He is informed of the BFP status and the fact that the lube oil pumps are not operating. Leaving the control room with an AO he dons the required safety equipment and attempts to manually open the 6.9 Kv BFP supply breakers. His initial attempt to trip the breakers using the “hand jack” fails, so he opens the first breaker cubicle door and while preparing to trip the breaker manually, it trips open on its own with a loud bang and bright flash. This causes him to abort attempting to open the second breaker and instead decides plant electrician support is needed to open this breaker. Leaving the area he then meets up with the fire department personnel and prevents them from proceeding to the BFP area until the second breaker can be de-energized. He directs the AO to escort several of the fire department personnel to the turbine generator area and leaves the remaining personnel to monitor the BFP area. He then proceeds back to the W3 control room to assist in the recover effort.

W4 Control Operator

This individual keeps the W4 shift supervisor apprised on the W4 status and completes the required actions requested by the W3 control operator to switch electrical transformer RAT-3A and associated bus to normal.

W4 Auxiliary Operators

One of the W4 AOs checks the service water pumps as directed by the W4 shift supervisor and performs other support duties as directed. The second W4 AO continues to perform regular assigned duties and has only a minor support rule in connection with the W3 event.

W1 and W2 Operations Staff

None of the W1 and W2 staff is directly involved in the W3 event. Their primary responsibilities remain focused on issues responding to issues arising at those units due to the lightning strike.

Conclusions from Timeline Information

The timeline information makes evident three important conclusions:

First, a lightning strike initiated an event at the Weston generating facility that impacted the operation of W2 and W3. Although W2 tripped, there were no abnormal events or damage associated with the trip. The trip of W3, however, leads to significant damage to the unit.

Second, a great deal of activity occurred within a brief period of time following the lightning strike. Less than ten seconds after the lightning strike, the W3 turbine started a runback. Less than sixty seconds after the lightning strike, the W3 plant tripped, all indication and control of plant equipment was lost, and lubricating oil to the turbine and BFPs was lost. Within ten minutes of the lightning strike there were fires at four pieces of major W3 plant equipment.

Third, the operators responded to these events as a team that crossed unit boundaries, made repeated attempts to control equipment via remote and local actions with no indications or control via normal methods, and responded to the fires to minimize their impact.

The next step of the assessment was to evaluate the operator actions against the actions required by Weston plant procedures.

Document Review

The investigation team first reviewed the procedures in place at the time of the event that the operators were required to follow in response to the occurrences during the event. Next, the investigation team reviewed alarm response procedures, logic drawings, and equipment manuals to determine possible failure modes for each piece of major equipment affected. The investigation team next reviewed the design specifications for installation of the baghouse, the DCS, and the W3 RAT reconfiguration to Weston 4 to determine the basis and the detail behind the final design configuration of these modifications.

Review of Operator Actions

As indicated above, hundreds of alarms were received within sixty seconds of the lightning strike. Attachment B: Procedure Use Evaluation, compares the actions required by station procedure during this event against the actions taken by the operators during the event.

This review indicates that the operators carried out their responsibilities per procedures in each case reviewed. This included alarm response, emergent electrical line-up changes and fire response. Operators from W3 and W4 worked together and with outside support personnel. The loss of the DCS prevented an orderly unit trip, and resulted in the damage to the unit within minutes.

This review also identified several differences in nomenclature used for plant equipment. This did not seem to have an impact on this event.

The next step of the assessment was to determine the failure modes of the equipment affected.

Equipment Failure Mode Development

The investigation team reviewed alarm response procedures, logic drawings, and equipment manuals to determine possible failure modes for each piece of major equipment affected. Attachment C: Equipment Failure Mode Charts, contains the Equipment Failure Mode Charts (EFMCs) developed for various failure conditions at the plant the day of the event. The EFMCs were used to identify all possible causes for a condition and to show supporting or refuting evidence for each of those possible causes. In this manner, only those causes with possible or proven impact are considered in the final failure scenario.

The first EFMC identified the possible conditions that can cause a Boiler Trip (Master Fuel LO Relay). As shown on this chart, the boiler tripped due to a furnace high pressure signal. The inability of only the 'A' side ID/FD fans to control furnace pressure is consistent with similar recent events on loss of these fans. When the baghouse was installed in 2001, it introduced an increase in the amount of pressure drop that had to be overcome. This increased pressure drop appears to have reduced the amount of ID fan capacity to the point that a single ID fan may not have adequate fan margin to maintain proper furnace pressure even with an automatic turbine runback. Since the baghouse installation in 2001, the unit has experienced boiler trips upon the loss of one of the ID fans. WPSC has not performed the analysis necessary to determine the precise cause of these boiler trips, and whether there are cost-effective modifications to the unit to avoid such boiler trips.

The second EFMC identified the possible conditions that can cause a trip of 3B ID fan. This is discussed below in the Failure Analysis section of this report.

The third EFMC identified the possible conditions that can cause a failure of the DCS. As shown on this chart, the DCS lost power because the fuse F204 opened on the output side of the UPS inverter and because the "reserve feed" source was not available due to an incorrect breaker control configuration on breaker 52-3A. Each of these items is discussed below in the Failure Analysis section of this report.

The information revealed in the timeline and document review was used to create Attachment D: Event and Causal Factor Chart. This chart shows the relationship among the various failures that occurred and the causes identified for those failures. Interviews were conducted to further understand the relationships among these items.

Review of the Design Specifications for the Equipment Affected

In general, the investigation team had difficulty identifying detailed design specifications for baghouse and DCS modifications that were made prior to this event due to the limited written documentation supporting the modifications. The investigation team did not find written documentation that indicated if certain matters, such as impact of backpressure to the furnace post baghouse addition, contact default logic for important DCS control features, and the expected response of W3 to the loss of RAT 3A, were considered when these modifications were designed and implemented. The investigation team interviewed personnel who were involved with these plant modifications. The additional insight gained from these interviews led the investigation team to conclude that design alternatives, along with the resulting situations that might occur, were considered in most cases. Those design alternatives considered reasonable were then factored into the modifications. Specific information identified from the design document reviews follows.

Baghouse Design Change

The investigation team reviewed the W3 Baghouse Supply and Installation Specification No. WPS-W3-865. Included in this specification is a scope statement describing the model study to be performed of the baghouse. Equipment to be included in the model is specifically identified. Numerous operating conditions that should be modeled are included, ***but no modeling was completed for turbine runback or single-fan operating conditions. (Contributing Cause #1)*** The study criteria states, "The contractor shall model one flue gas ductwork path and assume the second path is symmetrical about the boiler centerline." The model appears to include the areas in which pressure is measured for general indication, but not the area in which the boiler trip pressure sensor is situated. The investigation team could not determine if this affected the plant trip response or not.

The investigation team reviewed data that confirmed that the plant has been able to sustain planned operation at less than 60% power with a single set of fans, but this has only been successful with the 'B' set of fans operating, not with the 'A' set of fans. There is no evidence that the plant can survive an electrical generator runback from full load with the loss of either set of fans.

DCS Design Change

The WPSC Power Plant Design and Construction Engineering Design & Review procedure 10.0, Rev. 6, 9/5/90, was reviewed to determine if WPSC had adequate design review criteria in place for the DCS that was modified in 2000-2001. This procedure states, "The Project Manager is responsible for the consideration of the design inputs outlined in Attachment 1." Attachment 1 is a list of twenty-six items to be considered for designs. These items include review of basic functions, performance requirements, review of codes and standards, impact on existing plant equipment, interface requirements and others. This procedure also requires that the Project Manager assure all modifications are made at a "quality level commensurate with the original plant specifications." It goes on to say, "The Project Manager is responsible for assurance that the design review process as outlined in this procedure is completed and documented." The procedure requires that design reviews be conducted by a qualified person as determined by the Project Manager or a Group Supervisor. The completed Design Reviews are to be documented on Form SC-29-1, and the meeting notes related to the Design Review Meetings are to be documented on Form SC-29-2. Each of these forms is to be maintained in the project file.

The Design & Construction procedure is a thorough procedure requiring detailed review of the design change. The investigation team reviewed the project file for the DCS modification to determine how the design change was managed and implemented. It appears that the design was implemented as a project under the Design & Construction procedure because there is a project close-out form filled out, but there is no Form SC-29-1 or -2 with the project file and there is no documented evidence of the detail to which the design review criteria were established or tested.

The project file did contain, however, the Conformed Purchase Order (PO) for the DCS (Specification No. WPS-W3-252916). This PO contains many of the detailed requirements listed in the WPSC procedures. There are specific references to the documents that will need to be changed or created at the site as a result of the new DCS. There are not, however, any checklists that indicate whether the final document changes were completed as required. For example, there is a general requirement for the Vendor to supply Operating and Maintenance Instructions and it identifies detailed descriptions of what those instructions will include, but there is no evidence that the instructions were ever received. The PO also contains general acceptance criteria such as functional requirements, factory testing and on-site testing, with specific references to more detailed methods of testing. There are not, however, any referenced results of those tests or any specific criteria identified for each step. For example, the PO states that the factory acceptance testing "shall demonstrate independent and concurrent execution of all specified system functions with all system hardware and software integrated together." It does not identify, however, what the specified system functions are. The PO also states, "Once the system is installed and checked-out, the Vendor shall run the Site Acceptance Test. The Site Acceptance Test is the same as the Factory Acceptance Test except that closed loop simulation of the control logic shall be replaced with the verification of the proper control response of the system to the actual process hardware with the loops in 'Automatic'." There is no list, however, of which control responses were tested and to which automatic function they were tested.

Members of the design team were interviewed, and they do not recall specific details regarding the design. Interviews indicated that plant personnel involved with the DCS project focused on reviewing the in-field DCS components against those shown on the design schematics. While this is certainly a necessary action, there is no evidence to demonstrate that a review was conducted to assure the DCS design changes were integrated into the plant as needed. Further complicating this issue, the DCS modification at Weston 3 was not a typical "full change" as occurred at many other plants, but was an "improvement" upon existing controls. A review of the communications that occurred at the time of the design change indicated several key points: Operations was involved in the early design of the project, personnel were concerned with and questioned the communications logic with critical plant equipment (specifically mentioning the ID Fans and BFPs among others), there was a suggestion that critical plant operation should be hardwired, vendor manuals for effected equipment were referenced, runback and power loss testing was not listed among the tests mentioned for completion, and, finally, there is a reference to the need for "a minimum of 5-7 days of testing before the unit can be synchronized to the system – if all goes well.” This testing schedule included “2-3 days for DCS check-out.” In response to the proposed testing schedule, there is a communication that states, “any option that does not have W3 on line and available for full load on April 29 will cost WPSC dollars that were not budgeted.” It goes on to say that a meeting should be set up at which “alternatives, with associated costs, can be evaluated and compared.” There is no indication as to what the final result of this meeting determined.

Design team members did not recall any specific details regarding the testing of the system or decisions made related to that testing. While they recalled an urgency to return the unit to operation, they did not state that undue pressures were placed on them. Although they recalled conducting operational testing, they did not recall any details of the testing or any design documentation related to the testing requirements. In other words, although the documents contained general requirements to conduct tests, it relied upon their cognitive skills to determine how to conduct a test. They felt comfortable with this approach because they had “considerable experience from W1&2” where they had previously installed a similar DCS modification.

There is also no indication that the OEM of the turbine/generator (or any other components) was consulted in making the design change to the DCS. The turbine/generator supplier (and other equipment suppliers) normally attempts to provide a configuration that ensures the design is robust enough to prevent catastrophic failures such as loss of bearing lubricating oil.

Effect of DCS Design Change on Operator Response

The W3 control room operator and W3 shift supervisor did not immediately recognize that the DCS had experienced a power loss, because the loss of operator control screen information does not necessarily mean that the DCS has lost power. This delay had no impact on the resulting equipment damage. Even if the DCS had been immediately re-energized, the computers require a few minutes to reboot and the majority of damage to plant equipment occurred within the first few minutes after loss of the DCS.

Interviews with the control room operators revealed their belief that a loss of power to the DCS could not occur based on its design. This belief was supported and reinforced by the modification design team, which emphasized the multiple power feeds available to the DCS. The multiple power feed design along with having a battery backup power supply feature led the design team and plant management to believe that a complete loss of power to the DCS was not possible absent a complete loss of all internal and external power supplies to the unit.

ELECTRICAL DESIGN

Attachment E: Weston 3 Electrical Diagrams, shows the electrical line-up of the plant on the day of the event. The breaker positions shown would be considered the normal plant breaker line-up.

As-Built Design of the Weston 3 Electrical Distribution Systems

The as-built design of the W3 electrical system consists of three main power feeds. (See Attachment E.1.) During unit operation the 6.9Kv switchgear buses 3A and 3B are fed from the MAT. These two buses supply power to the remaining plant 6.9Kv bus, the 6.9Kv motors, and all of the 480v switchgear buses. Bus E3 is a 6.9Kv Essential Services bus that is connected to 6.9Kv switchgear bus 3A through a normally closed tie breaker 52-AET. The 6.9Kv switchgear bus E3 services the essential plant equipment.

When W3 is off line, 6.9Kv switchgear buses 3A and 3B are supplied power from the plant's RATs (RAT 3A and 3B). The source of power to the RATs is from the substation's 115Kv, East bus. The automatic controlling system for the transfer from the MAT to the RATs, referred to as a fast bus transfer, occurs upon loss of power to the MAT and results in no electrical system disturbance when a transfer occurs. When W3 is off line and/or the RAT 3A source is unavailable, the 6.9Kv switchgear bus E3 can also be supplied power from the 46Kv substation through the 13.8/6.9Kv essential auxiliary transformer 3. The transfer to this power supply is automatic on loss of power to 6.9Kv switchgear bus 3A and occurs as a fast bus transfer.

DCS Power

The main power source for the W3 DCS is from the 120/240vac power supply cabinet. (See Attachment E.2.) This power supply cabinet is an Uninterruptible Power Supply (UPS) and includes an inverter, rectifier, voltage regulator, fuse F204 and a static transfer switch. During normal operation the UPS receives its power from 480v Essential Services Motor Control Center (MCC) 3C. The 480v Essential Services MCC bus 3C receives its power from 480v switchgear bus 3C which is supplied power through auxiliary transformer 3C from 6.9Kv switchgear bus 3A. (See green highlighted line on Attachment E.2.) The 480v Essential Services MCC 3C can also be powered from 480v switchgear bus EE3 through an automatic transfer switch. The 480v switchgear bus EE3 is supplied power from 6.9Kv switchgear bus E3 which is normally powered from 6.9Kv switchgear bus 3Awhen the unit is on line.

There are also multiple other methods for supplying power to the UPS. The UPS is connected to the plant's 125v DC bus. This bus is normally supplied power from 480v MCC 3B which is supplied power from the 6.9Kv switchgear bus 3B. The 125v DC bus also has a station battery as one of its power supplies. The 125v DC bus supplies power to all plant DC operating equipment, including the turbine Emergency Seal Oil Pump (ESOP) and the EBOP. This DC bus will automatically supply power directly to the inverter upon loss of the main feed power supply. (See orange highlighted line on Attachment E.2.) The remaining power supply to the UPS is labeled the "reserve feed". This source comes from 480v MCC bus 3A through a 480/240V transformer. This power supply bypasses the inverter and fuse F204 and supplies power directly to the UPS static transfer switch. The 480v MCC bus 3A is supplied power from 480v switchgear bus 3A. Upon loss of power to 480v switchgear bus 3A, breaker 52-3A opens and sends a signal to breaker 52-3ABT to close. Closing breaker 52-3ABT allows backup power to 480v MCC bus 3A from 480V switchgear bus 3B. (See blue highlighted line on Attachment E.2.) There are two battery chargers (1A and 1B) that could also be used to supply power to the 125v DC bus and supply power to the DCS load.

W3 RAT 3A Tie to W4

Prior to this event a decision was made to tie the W3 RAT 3A to the W4, 6.9Kv switchgear bus 2 and electrically isolate W3 and W4 by opening breaker 52-R3A. (See attachment E.3.) This decision was made in order to reduce the risk of losing the river water pumps upon the loss of W4 and subsequently having to take W3 off line. In this configuration, when breaker 52-M3A is opened (i.e., after a W3 trip), breaker 52-R3A will not fast bus transfer close and the 6.9Kv switchgear bus 3A will not transfer to RAT 3A and therefore will experience a loss of power. Power is manually restored back to 6.9Kv switchgear bus 3A (through breaker 52-R3A) only after the Weston 4 operators release RAT 3A back to the Weston 3 operators. The normal power supply (i.e., breaker 52-AET) to 6.9Kv switchgear bus E3 will open upon lost of power to 6.9Kv switchgear bus 3A. However, 6.9Kv switchgear bus E3 remains energized due to a fast bus transfer and closing of breaker 52-ME3 which supplies power to the bus from the 46Kv substation through the 13.8Kv/6.9Kv transformer. In this breaker configuration, 480v essential service MCC bus 3C is being powered from the 480v switchgear bus EE3 through the automatic transfer switch. This was considered an acceptable design since "main feed" continued to supply power to the UPS and the UPS still had multiple power supplies including a station battery backup power supply. Furthermore, even in the event of the loss of fuse F204, a "reserve feed" source was available to supply power to the UPS. However, in the event of both a unit trip and the loss of fuse F204, a fast bus transfer between 480v breakers 52-3A and 52-3ABT would have to occur due to the loss of power on 6.9Kv switchgear bus 3A. The fast bus transfer between these breakers would ensure the continued supply of power to 480v switchgear bus 3A and 480v MCC bus 3A using RAT 3B. After the fast bus transfer occurs between these 480v buses, power to the UPS would be from the "reserve feed" through the UPS static transfer switch.

FAILURE ANALYSIS

The event timeline indicates that lightning struck ATC's 115Kv, T20 transmission line and transmission tower number 7. This was confirmed in an e-mail from an ATC Senior System Protection Engineer sent to the WPSC Superintendant – Technical & Administrative Services. In the e-mail, the ATC Engineer stated,

> I have attached screen shots of both the Weston T20 421 relay that initiated the trip a[t] the Weston end, and the FALLS study identifying the lightning strike that caused the outage.
>
> The lightning strike caused a 3 phase 20kA fault, which was cleared by the T20 relays and 2 cycle breakers in approximately 3 cycles. Due to the high speed at which the fault was detected and cleared our digital fault recorders (DFRs) at Gardner Park and Weston (which were set with a 6 cycle operating delay) did not event for the fault. (The delays on both DFRs have been lowered to 2 cycles to capture events of this type in the future.)

This is significant information for at least two reasons. ***First, it confirms the lightning strike on the ATC tower as the initiating electrical event that caused the Weston plant outage. (Initiating Event)*** Second, it shows that not all electrical devices will detect and actuate to the very same event based upon their threshold of tolerance to the event. This became important while determining why various electrical devices reacted (or failed to react) in the manner they did during this event.

Attachment F: Weston 3 Electrical Prints-DCS Failure Related, illustrates the three failure modes of the UPS and also shows the effect of electrically connecting the W3 and W4 power supplies.

Review of the Weston Site Grounding Grid System (Including Excerpts from Lightning Eliminators and Consultants Report (LEC) - Reference 1)

Following the event, a site Electrical Engineer stated, “I have reviewed the design documents for the Weston 4 grounding system and identified no instance where the grounding system of Weston 4 negatively impacts the performance of the grounding system of Weston 3. In general, connecting the Weston 4 ground grid to the site ground should increase the overall surface area of ground conductors, which should decrease the impedance of the ground grid. A low impedance connection to earth ground is desirable. It should be noted, however, that construction activities may have damaged the existing ground system which may have decreased its effectiveness.” He identified a potential problem associated with the common ground grid for the site related to the safe touch and safe step voltages, and initiated the gathering of more information regarding this issue from the Black & Veatch engineers involved with the design before making a conclusive statement on this issue.

A visual ground inspection was conducted and several examples were found in which severed ground cable was exposed. Two disconnected ground rods were found and fencing was found disconnected from the grounds.

To determine the capability and functionality of the Weston site grounding grid system, LEC (an electrical contractor/consultant) was hired to model and test the grounding grid system at the site. Point-to-point measurements were taken to determine the status of the plant grounding grid system. A total of 106 point-to-point ground impedance measurements were performed. The following is a summary of the conclusions from the analysis.

- All of the tested ground connections within the 115Kv switchyard areas are bonded together.
- The 115Kv switchyard and the W1/W2 generator building are bonded together.
- The substation and transformer yard fences are bonded to the grounding system.
- The exposed ground conductors near the train tracks are bonded to the 115 kV substation ground.
- The majority of the ATC transmission line poles tested were found not to be bonded to the plant grounding system. Some of these poles do not carry shield wires, resulting in very high ground resistance. A direct lightning strike at these locations will result in very high Ground Potential Rise (GPR) and probably insulation flashover. Note: there were two overhead shield wires on tower #7.
- The plant's grounding system was found to meet the requirements of IEEE Standard 80™, 2000 edition (Guide for Safety in AC Substation Grounding) for personnel grounding protection.

The pole that was struck by the lightning is one of the poles that was tested and found not to be bonded to the Weston site grounding system. (Root Cause #1).

Previous lightning strike events had resulted in damage to certain plant equipment but nothing to the extent of the damage that occurred on October 6, 2007. In the spring of 2007, a third-party consultant reviewed the W3 internal plant lightning suppression systems and recommended that surge suppressors be installed on key plant control wiring. Weston 3 implemented these recommendations and installed 89 surge suppressors.

Inverter Open Fuse

The investigation team believes that the elevated voltage from the lighting strike was seen at the alternate AC input to the static switch (coming in through the grounding connection due to the lack of bonding between the transmission pole struck and the plant grounding system). This rapid rise in voltage caused the SCRs on line 1 (147P - dwg 015D17101) to momentarily short line 1 from the alternate AC source to line 1 (47P) from the inverter. This would have caused an instantaneous exponential rise in current, causing fuse F204 to OPEN. Fuse F204 is a fast acting fuse designed to protect the inverter section SCRs. In this scenario fuse F204 performed as designed, preventing damage to the inverter.

Extensive testing was performed by the Original Equipment Manufacture (OEM) for the UPS inverter after the event. (See reference 3.) Attempts were made to recreate the circumstances encountered at the time when the inverter experienced the failure of the output fuse F204. Various power supply transients (i.e. failures) were initiated that would have been similar to those that occurred during the actual event. The results of the testing determined that during these induced transients the UPS properly transferred to the battery and alternate power supply as designed. The OEM concluded that the inverter output fuse F204 performed as designed during the October 6, 2007 event to prevent damage to the inverter from an elevated ground potential condition. The elevated ground potential was a result of the lightning strike on a transmission pole not bonded to the plant's grounding grid system. During the event, the UPS static transfer switch transferred to the "reserve feed" source as a result of fuse F204 opening.

Breaker Configuration

There were two breakers integrally involved in this event:
52-3A – Main Feed Breaker to 480V switchgear bus 3A (CMMS entity no. 3APX48E-1B)
52-3ABT – Tie Breaker between 480V switchgear 3A and 3B (CMMS entity no. 3APX48E–3C)

During the event, the 6.9Kv switchgear bus 3A lost power and breaker 52-3A opened due to under voltage as expected. When it opened, the breaker 52-3A should have provided a permissive to allow breaker 52-3ABT to close to maintain power to the 480V switchgear bus 3A, creating a power source for the "reserve feed" to the UPS. The signal to close the tie breaker was not sent due to the fact that the wiring on the bell alarm relay contact was reversed from the way the contact should have been wired for breaker 52-3A's configuration. There is no configuration for this breaker that would have called for the wiring to be as it was found following the event. The wiring within breaker 52-3A was properly designed as a normally closed contact, but was found configured as a normally open contact. ***The incorrect configuration of breaker 52-3A prevented the breaker 52-3ABT from receiving a close signal. (Root Cause #2)***

The investigation attempted to determine the reasons for breaker 52-3A's as-found configuration. This breaker is of a model (FPS4-50-1600A) that is used throughout the plant. In the mid 1990's plant management undertook an effort to wire the breaker control configuration for all of these breakers to be in the normally closed position. This would allow for any of the 18 plant breakers (including the spare) to be used in any plant application requiring this model breaker. Attachment G: Breaker Locations, shows all of the locations within the plant that this model breaker could physically be used. According to the work history associated with the breakers, the plant purchased a spare breaker to facilitate more efficient maintenance practices. When an in-service breaker required maintenance, the spare was typically swapped with the in-place breaker, which prevented any interruption of service functionality during breaker maintenance. The breaker pulled out of service was then overhauled and placed into stock as a spare. Spare breakers were not designated for particular installations. Thus, individual breakers may have been placed in various locations throughout the plant over the last 20+ years.

The PMs for these breakers follow the same work procedure, which references the OEM manual for breaker adjustments and maintenance. In order to perform this PM the entire breaker is disassembled, cleaned, adjusted and re-assembled. The OEM manual does not require the rewiring of the breaker control configuration (i.e., bell alarm wiring) during a routine preventative maintenance overhaul. However, plant personnel report that a typical breaker PM exceeds OEM standards and sometimes involves a complete tear-down of the breaker, including the unwiring and rewiring of the bell alarm.

A review of the work history for both breakers 52-3ABT and 52-3A was included as part of this investigation. (See Attachment C: Equipment Failure Modes Charts, Loss of Distributed Control

Systems section.) The plant had assigned a three year PM schedule for complete overhaul of these breakers, while the OEM manual provides guidance that takes into consideration environmental conditions (i.e., humidity, dusty or dirty conditions) and the number of breaker operations with a maximum of 500 between PM inspections. The PM for breaker 52-3ABT was last performed in 1997. The PM for breaker 52-3A was last performed during the summer of 1998. Each breaker was in a clean location of the plant and each was in an application in which it is very rare for the breaker to be cycled. In fact, the plant has no indication that the breakers were cycled since their last PM.

On April 8, 1998, these two breakers worked properly when called upon to perform their function. This indicates that the incorrectly configured breaker 52-3A was installed in the breaker cubicle when the existing breaker was replaced with a spare breaker during the PM activity performed in the summer of 1998. Had additional PM controls been in place to ensure a correctly wired breaker was installed or had breaker performance testing been performed at the 480V switchgear following breaker installation, it is likely the incorrect breaker control configuration would have been detected and corrected. In addition, following the event, the plant determined that all of the other breakers of this type within the plant were properly configured as normally closed. Therefore, had the plant-scheduled PM been performed on breaker 52-3A after 1998, it would likely have been replaced by a properly configured breaker and its configuration might have been corrected during post-removal PM work.

Induced Draft Fan 3B Trip

Two postulated failure scenarios have not been refuted. (See Attachment C: Equipment Failure Mode Charts, Induced Draft Fan 3B Trip section.) One involves the tripping of the motor ground fault protection relay (50G) in the fan motor control circuitry. The most compelling fact supporting this potential failure mode is the “trip indicating flag” on the 50G relay was found in the “tripped” position after the event. However, this should have resulted in an alarm via the DCS and there were no 50G alarms found on the DCS alarm/event log. We believe the 50G relay “actuated” and “dropped out” in a time period that was faster than the DCS scan period and thus did not record the relay operation. The investigation team believes that when the lightning entered the grounding system it raised the ground potential on the ground conductors for the 6.9kV switchgear. This potential difference of possibly thousands of volts, created increased current flow in the Current Transformers (CTs) associated with the 50G relay. This relay is designed to look for increased current difference between phases which would be indicative of a ground fault. This increased current (transmitted via the current transformers) likely caused the 50G relay to reach its phase current differential setpoint triggering the relay to actuate the protection scheme, i.e. opened the breaker. Because the CTs have a ratio of 50/5, less current on the secondary at the time of the lightning strike would look like high current on the motor leads to the relay, causing it to actuate. In this manner, the high voltage potential caused by the lightning could have 'tricked' the 50G into seeing a false high current differential.

The second potential failure mode includes initiation of a low lube oil pressure switch signal to the 3B ID fan control circuitry. There are two pressure switches for the ID fan lube oil system during fan operation. The first switch has a pressure set point of 32.6 psig. Upon reaching this set point the switch sends a signal to start the stand-by lube oil pump and also sends a signal to the

DCS (alarm #U3PSOLX079B). A review of the DCS alarm/event log indicates that this pressure set point was not reached since there was no alarm on the alarm/event log. The second pressure switch set point is activated at 27.7 psig. At this set point a signal is sent to the DCS to stop the ID fan (alarm # U3BAX06WBHSMS). A review of the DCS alarms reveals a stop signal was sent to the 3B ID fan by the DCS during the time period of elevated ground potential. The investigation team believes the elevated ground potential may have induced a voltage transient which activated the pressure switch. The pressure switch output sent a signal to the DCS which in turn sent a stop signal to the 3B ID fan. Had there been an actual low pressure condition, the first DCS alarm, #U3PSOLX079B should have appeared on the alarm/event log.

Damage to the Turbine/Generator (loss of oil)

The damage to the turbine/generator was caused by the loss of lube oil to the bearings. Under normal operating conditions oil is supplied to the turbine/generator bearings by virtue of a turbine shaft driven oil pump. During a unit trip condition the TGOP auto starts on low lube oil pressure. The investigation team determined that upon a loss of power to the DCS an auto start signal of the TGOP does not occur. The design prior to implementation of the DCS had a “fail closed” contact arrangement such that upon a low lubricating oil pressure signal a TGOP start signal was initiated. ***The post DCS design used a “fail open” contact arrangement. (Contributing Cause #2)*** This post DCS design did not auto start the TGOP upon loss of power to the DCS. This design was considered acceptable at the time of modification because the design team and plant management considered that a complete loss of power to the DCS was not a credible event. This same “fail open” contact arrangement was used for the backup Emergency Lube Oil Pump, which prevented it from starting. Without the TGOP and the EBOP, the turbine/generator coasted down in speed without lubricating oil being supplied to the bearings. The turbine coast down was approximately 10 minutes versus the expected 55 minutes when bearing lube oil is being supplied to the turbine bearings.

Damage to the Boiler Feed Pump Motors and Drives

The damage to the boiler feed pump motors and drives resulted from the control system failing to stop the motors. Except for a short time period when 6.9Kv switchgear bus 3A was de-energized, both of the boiler feed pump motors continued to operate during the event with no bearing lube oil. The bearing lube oil pumps are configured to stop upon a loss of DCS signal which occurred on loss of DCS power. The BFPs continue to operate until a DCS trip signal is received. The loss of power to DCS prevents a trip signal from being initiated from either control operator commands or normal DCS software control commands. Therefore, additional delays were encountered in stopping the boiler feed pump motors since local operator action at the switchgear was required. Furthermore, first responders who attempted to open the motor breakers by using the switchgear front panel controls did not realize that the original switchgear design only enabled these controls during breaker testing. Therefore, additional equipment (ie personal protective clothing and operating mechanisms) was required prior to operating the circuit breakers directly. All this effort took additional time.

Fire at the Generator

There was a short duration fire around the number five bearing at the generator. This was from the escaping hydrogen gas that was being released as a result of the loss of generator hydrogen sealing oil. The escaping hydrogen gas reached combustible concentration levels and an ignition source, which is believed to be sparks from the generator shaft grounding strap located at the number five bearing, resulted in a fire. The generator hydrogen seal oil was lost because the DCS project rewired the main seal oil pump start circuit to use a "fail open" contact design instead of the original “fail closed” design. Upon loss of DCS power the main seal oil pump stopped and the pump start contacts failed open and prevented the pump from re-starting. The emergency seal oil pump had a similar “fail open” contact arrangement as a result of the DCS project thus preventing it from starting. The fire was quickly extinguished when prompt operator action manually initiated the deluge system.

Explosion at the Lube Oil Tank

Due to the loss of the generator hydrogen seal oil, hydrogen gas was allowed to escape from the generator seals. Normally this hydrogen gas would have been self venting through the hydrogen detraining tank self venting system. However, it was found that the self venting system had a vent path that was blocked with a blank flange that was inadvertently left installed in the system from original construction. This allowed a collection of hydrogen gas to accumulate in the turbine lube oil storage tank area, which eventually ignited and resulted in an explosion from the turbine lube oil storage tank.

Failure Mode and Effects Analysis

The purpose of a Failure Mode and Effects Analysis (FMEA) is to identify and prevent known and potential problems before they affect a customer. FMEA is a specific method of identifying the possible ways in which a system (or a device, or a process, or a service) may fail and to determine the risk associated with the failure. In the case of the UPS inverter, a FMEA would be conducted to identify the potential problems that could lead to loss of power to the Essential Services Bus. Our interest in the FMEA is to determine the impact it would have had on this event had it been conducted for the UPS inverter fuse F204.

As illustrated in Attachment H: Failure Mode and Effects Analysis[1], FMEA identifies the probability of occurrence for a particular failure mode, the probability the failure will be detected and the severity of the identified failure. There are many ways to determine the values of these three attributes in either qualitative or quantitative measures. If quantitative values are available, they are used to determine specific frequencies. If qualitative values are used, they create a relative awareness of the problem. In either case, risk of failure is determined from these three

[1] FMEA charts modified from those shown in Failure Mode and Effects Analysis: FMEA from Theory to Execution, Second Edition, D. H. Stamatis, ASQ Quality Press, Milwaukee, WI, 2003.

attributes and a risk prioritization is determined. Although there is no single risk determination level used for all FMEAs, a common approach is to define the risk as minor, moderate, high or critical. Based upon the proposed risk, a decision is then made to take action, plan for the failure, or to do nothing about the proposed failure mode.

With reference to the severity guide in Attachment G, the severity of fuse F204 opening, with no other failure occurring, is minor. As described previously in the Electrical Design section of this report, upon loss of fuse F204, the UPS would transfer to the “reserve feed” power supply which would pick up the UPS load. In the event of a unit trip, a fast bus transfer between 480v breakers 52-3A and 52-3ABT would occur due to the loss of power on 6.9Kv switchgear bus 3A. The fast bus transfer between these breakers would ensure the continued supply of power to 480v switchgear bus 3A and 480v MCC bus 3A using RAT 3B. After the fast bus transfer occurred between these 480v buses should fuse F204 open, power to the UPS would be from the “reserve feed” through the UPS static transfer switch. Again, the effect with these two postulated failures occurring simultaneously would have been minor.

With reference to the occurrence guide in Attachment G, it would have been predicted that this fuse almost never fails. While work history shows that this fuse has been replaced in the past, it appears to be due to maintenance scheduling, not failure of the fuse. Because there is no history that shows a previous failure, an expected failure would have been highly unlikely.

With reference to the detection guide in Attachment G, the UPS power supply provides indication to alert the operators that a change in UPS power supply has occurred. The operators would then take action to respond to this change in indication. Thus, the change in indication would have ensured detection.

To determine the overall risk of this failure as shown in the risk prioritization guide in Attachment G, the product of the severity, occurrence and detection is determined. In this case, the overall predicted risk would have been 4 x 1 x 1 = 4. This means an overall risk assignment of 4 out of 1000 (the possibility of 10 x 10 x 10 = 1000 for worst case risk scenarios) would have been assigned. This is such a low risk assignment that, typically, no action would be taken to avoid this proposed failure.

To better understand why no action would be taken, it is worth discussing the ‘Single Failure Design Criteria’ to which most systems are built. Arguably, the most robust design criteria in the world are those used for building nuclear power plants. Appendix B to 10CFR50 is the General Design Criteria for Nuclear Power Plants. In this appendix, a *single failure* is defined as follows,

> A single failure means an occurrence which results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single failure occurrence are considered to be a single failure. Fluid and electric systems are considered to be designed against an assumed single failure if neither (1) a single failure of any active component (assuming passive components function properly) nor (2) a single failure of a passive component (assuming active components function properly), result in a loss of the capability of the system to perform its safety functions.

In other words, when designing *nuclear* safety systems the designers should assume that, if a passive component fails, the active components can be assumed to operate properly. In the case of fuse F204, the designers of the system should have assumed the active components (breakers that operate to provide power using the "reserve feed") operate properly. Thus, the design of the Weston 3 inverter would meet this criteria and the risk associated with the FMEA would be determined to be of a low enough level that no further action would have been taken.

Conclusions from FMEA Review

W3 management and staff were correct in placing their trust in the systems they had in place at W3. The design of the Weston 3 inverter would meet *nuclear* plant criteria and the risk associated with the FMEA would be determined to be of a low enough level that no further action was warranted.

PREVIOUS EVENT REVIEW

On July 30, 2002, at approximately 19:22, the Weston site sustained a lightning strike. The strike was witnessed by an employee in the area of the 115kv transmission pole next to the W3 Main Power Transformer. W3 tripped shortly after the lightning strike. There was no major damage to any plant equipment and the ID Fans continued to run throughout the event. There was no detailed event investigation documented following this event.

On August 2, 2006, at approximately 00:36, the Weston site sustained a lightning strike. It is not known where the lightning hit, but there were issues in the 46kV substation and W3 tripped on loss of both ID fans. The 3A BFP tripped and there were issues with the lube oil pumps on the BFP and the ID fans. There was no detailed event investigation documented following this event.

SAFETY ASSESSMENT

Industrial Safety

While significant equipment damage occurred during this event, no personnel were injured. A Generator Hydrogen fire started, but fire suppression was initiated and operated properly to extinguish the fire. An explosion occurred at the turbine lube oil storage tank, but pressure relieving doors operated properly to relieve the system pressure. Fires occurred at each BFP motor, but went out after each motor was de-energized.

Environmental Impact

During the event, there were seventeen six-minute air permit opacity exceedances due to the fact that the baghouse lost power and went into bypass. These exceedances were reported to the appropriate state agencies as required.

CONCLUSIONS

Initiating Event

The initiating event was a lightning strike on the ATC 115Kv, T20 line and transmission tower number 7. But for this initiating event, the subsequent events and damage to W3 on October 6, 2007 would not have occurred.

Root Causes

Our investigation revealed two root causes of this event. First, ***because the pole that was struck by the lightning was not bonded to the plant grounding system (RC#1),*** it resulted in a ground potential rise and power surge, which in turn caused the UPS Inverter output fuse F204 to open leading to the loss of power for all but one power supply to the DCS. It also likely caused one train of ID/FD fans to stop which led to the unit trip. Second, ***an incorrect breaker control configuration within breaker 52-3A (RC#2)*** caused the 480v tie breaker to not operate when needed to provide the DCS with the "reserve feed" power supply. Without the tie breaker going closed, the last remaining power supply to the UPS was lost. The loss of fuse F204 together with the incorrectly configured breaker led to a total loss of UPS power and DCS operation.

Contributing Causes

Since the modification to the W3 baghouse, the "turbine run back" that occurs with the loss of one set of ID/FD fans with the unit operating at full load, trips the unit. Numerous operating conditions were modeled for the modification, ***but no modeling was completed for turbine runback or single-fan operating conditions. (Contributing Cause #1)***

Plant design of control for various individual equipment oil systems prior to implementation of the DCS had a "fail closed" contact arrangement such that upon low oil pressure signals, a start signal was initiated for the associated oil pumps. ***The design for the modification of the DCS power supply system used a "fail open" contact arrangement. (Contributing Cause #2)***

REFERENCES

Specific

1. Final Report Dated December 14, 2007, Lightning Eliminators and Consultants – Titled – Wisconsin Public Commission Weston Generating Station Grounding System Evaluation
2. IEEE Standard 80 – 2000 Edition, Guide for Safety in AC Substation Grounding
3. Final Report Dated December 3, 2007, AMETEK Solidstate Controls – Titled – Client Services Report Form 02-180000 Rev. A

General

1. Alarm and event logs
2. Historical calibration sheets
3. Historical event information, i.e. past lightning strike events
4. Historical stock parts usages
5. Historical work order information
6. Interview notes
7. OEM manuals
8. Operating procedures
9. Operator equipment check sheets
10. Original construction information
11. Past project files, i.e. DCS installation Project (2001) and Baghouse installation project (2001)
12. Plant drawings

Attachment A: Event Timeline

Prior to 10/6/07

May, 2001	Weston 3 control system was retrofitted with a Distributed Control System (DCS)
8/4/2007	3A Reserve Auxiliary Transformer (RAT) is switched to supply W4 Switchgear 2
9/29/2007	Operations completed routine weekly testing of critical Turbine component operation

On 10/6/2007

03:26	Operations completes routine nightly turbine valve testing
04:04:25	Lightning strike occurs on transmission tower near W4 Cooling tower
04:04:26	U3 Generator H2 Panel Trouble alarm received Turbine Intercept Valve #2 closes Fire Protection – any Pulverizer CO Level High alarm received
04:04:27	3B ID and FD fans stop
04:04:28	Load Setback in progress Manual Runback to 60% load
04:04:30	Weston 2 OCBs open (Weston 2 trips off line)
04:05:02	Furnace Pressure High alarm received
04:05:10	Pulverizers 3D and 3E breakers open
04:05:11	High Furnace Pressure First Out boiler trip received Boiler Trip – Master Fuel Lock Out Relay received Turbine Trip from MARK VI received
04:05:12	Pulverizers 3A, 3B and 3C breakers open Boiler Lock Out Relay trips
04:05:17	Weston 3 losses all communication with DCS Operator HMI's go black
04:05:25	Weston 3 OCBs open (Weston 3 trips off line)
04:07:59	3A RAT is reconfigured to provide power to 3A 6.9 kV Bus

04:11	Fire occurs on Weston 3 generator near #5 bearing.
04:13	Fire at “B” BFP Motor
04:14	Explosion occurs at the Weston 3 turbine lube oil tank.
04:15	Turbine rotating element comes to a stop
04:19	Weston Shift Maintenance Supervisor calls 911 for fire department assistance
04:25	3B boiler feed pump 6.9 kV breaker trips
04:43	Rothschild Fire Department arrives
06:20	Weston Electrician manually closes 480 V breaker 52-3A
06:22:12	Weston 3 DCS is re-established
06:30	Recovery activities begin

Attachment B: Procedure Use Evaluation

While it is not feasible for the operators to recognize and respond at once to all the alarms received during this event, it is expected that they respond first to those initially received and then to those of most importance. Table 1 evaluates the immediate actions required by procedure against the actions taken by the operators for some of the more significant alarms received.

Table 1: Alarm Response

Alarm Received	Immediate Actions Required	Actions Taken during the Event
ID Fan 3B Trip	Reduce load to within opacity limits and then stabilize air flow.	The CO was responding to the load reduction when the unit tripped.
Turbine Intercept Valve #2 Closed	Verify the actual valve position and to take the unit off line in a controlled manner.	The CO was responding to the load reduction when the unit tripped.
Main Boiler Trip	Carry out the unit trip actions.	These actions could not be carried out immediately because of the loss of DCS.
Turbine Trip	Start the MSOP and TGOP if they are not already automatically started.	The CO directed the ACO to start this equipment.

This brief review of significant alarms indicated that the operators were responding in accordance with the alarm procedures. There are other procedures, however, that also applied during this event.

The Weston 3 CO was aware of the need to swap reserve auxiliary power supplies to 6.9 Kv switchgear bus 3A when the first alarms were received. As stated above, he called the Weston 4 operators and "told them to switch to normal on RAT 3A." It should be noted that, while the operators at Weston refer to this action as "switching to normal," it is actually referred to as "Abnormal System Operation" in the procedure. (The operators refer to this as "normal" because it is the line-up that W3 always used prior to the W4 electrical system energization.) Switching 6.9 KV switchgear bus 3A power supply is accomplished via WPSC Temporary Operating Procedure OPS-W4-temp-AP, Auxiliary Power Supply, Rev. 1. The purpose of this procedure is "to provide instructions to the W3 and W4 Control Room Operators on how to align electrical supplies from the Reserve Auxiliary Transformer, RAT, to the W4 Switchgear, SWG. These instructions cover both normal operations when W3 is running, and also in the event W3 trips." Following are the steps required per this procedure:

Table 2: Auxiliary Power Supply Process

Operator Action (Input)	Location	Actions Taken
1. Verify that W3 is off-line or will be off-line, and needs to receive power from 3A RAT.	W3 Control Room (CR)	W3 requested the power transfer.
2. Notify the Shift Leader ext 1916 of the plan to switch power sources for the 6.9KV SWG #2.	W4 CR	Notifications made via radio transmission of problems at Weston 3.
3. Notify the Site Maintenance Supervisor at ext 3266 of the plan to switch power sources for 6.9KV SWG #2.	W4 CR	Notifications made via radio transmission of problems at Weston 3.
4. Notify System Operating at ext 4111 of the plan to switch to switch power sources for 6.9KV SWG #2.	W4 CR	System Operations notified of general conditions at Weston as the problems progressed.
5. Following a plant trip of Weston 3, immediate action shall be taken in accordance with OP-51 Section 8.5 to complete the transfer of 6.9KV power supply from the MAT to the RAT.	*Not specified, but applies to W3*	Most of these actions could not be taken due to the loss of W3 DCS
6. Notify the W3 Control Room, ext 3265, if W3 is off-line, that when completing the following steps the feed breaker from 3A RAT to 6.9KV Bus 3A may auto close.	W4 CR	W3 Operations was aware of this and requested the power transfer
7. Close SWG #2 main feed breaker from 4B UAT, (SWG2 MB1).	W4 CR SWGR #2&3 screen	Verified via W4 alarms
Note: Following a trip of W3, when completing the following step, the Auto-Transfer-Scheme will automatically close the 52-R3A, Reserve Aux Transformer to 3A 6.9KV Bus, if the 86 Lock-Out relays have not been Reset. This automatic action is designed to provide power to 3A 6.9KV Bus as soon as it is available.		
8. Open SWG #2 main feed breaker from 3A RAT, (SWG2 MB2).	W4 CR SWGR #2&3 screen	Verified via W4 alarms
Warning: To minimize Safety, Environmental or Equipment Damage concerns The automatic transfer of power supply from the Main Aux Transformer to the Reserve Aux Transformer on Bus 3A should occur automatically. Manual actions described below should be taken without delay to restore power to Weston 3 if the automatic actions do not occur.		

Operator Action (Input)	Location	Actions Taken
9. Notify W3 Control Room that they can power 3A 6.9KV Bus from the RAT.	W4 CR	N/A
10. Remove Danger Card form switch for 52-R3A, Reserve Aux Transformer to 3A 6.9KV Bus, indicating that RAT 3A is feeding power to W4.	W3 CR	N/A
11. Close Bus 3A main feed breaker from RAT (52-R3A), if not automatically closed in step 8.	W3 CR	N/A
12. Open Bus 3A main feed breaker from MAT (52-M3A), if not automatically opened in step 8.	W3 CR	N/A
13. If power had been interrupted to Bus 3A, restart equipment as needed to place unit in stable condition.	W3 CR	N/A

As indicated by this review, the operators took the necessary actions to swap power to 6.9kV switchgear bus 3A. Because of the urgent nature of the request from the W3 operator, the W4 operator proceeded directly to the steps to transfer the power supply. The W3 shift supervisor was notified as the transfer progressed.

In addition to responding to plant alarms (while they were available) and plant electrical line-up needs, the W3 operators were also dealing with multiple fires. WPSC procedure WEM 4.31, Rev. D, the Plant Procedures Manual for Emergencies-Fire, "provides direction to WPSC employees and contractors involved with incipient, free burning and interior structural fires." This procedure required the following actions:

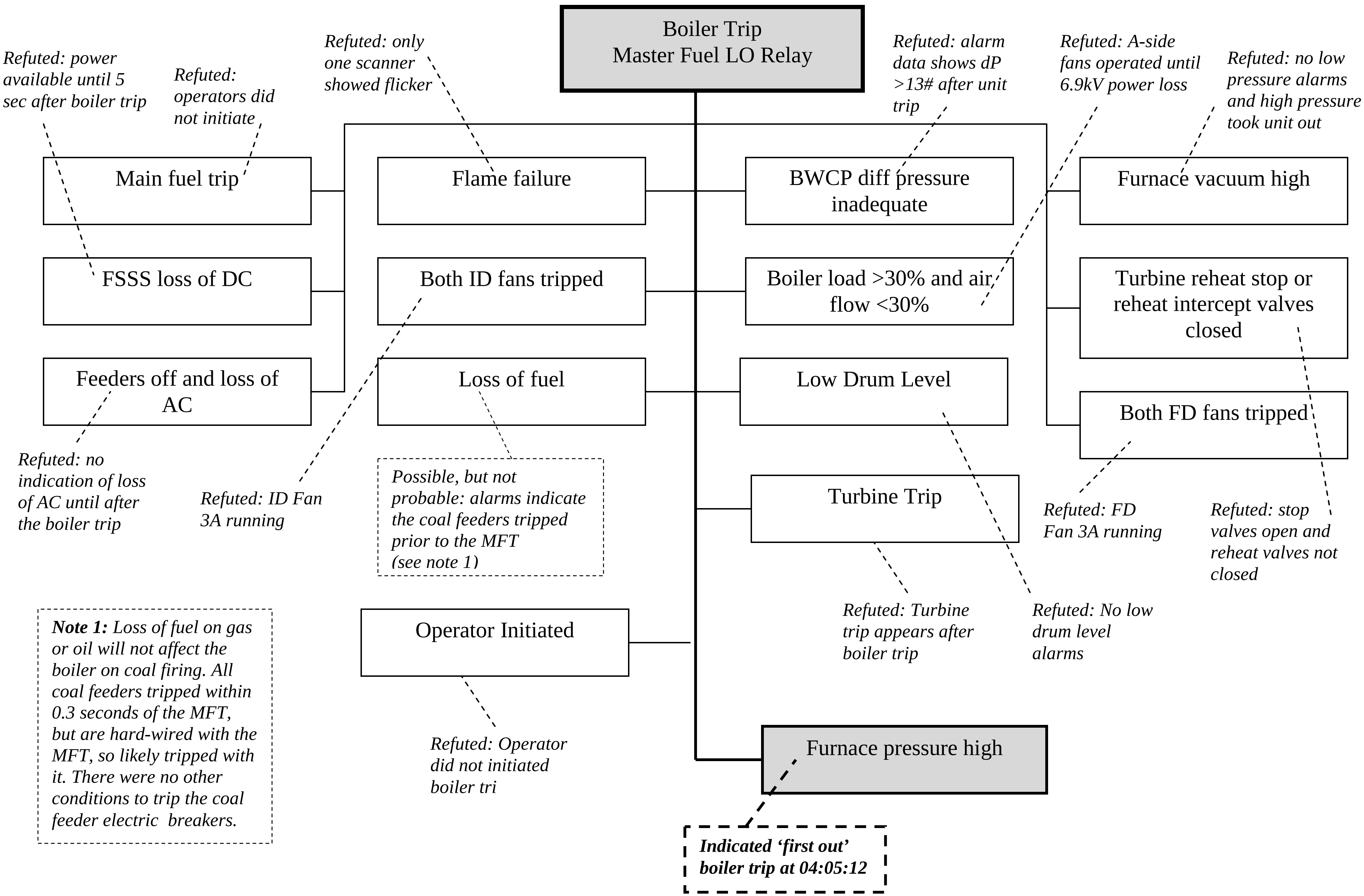
Table 3: Fire Response

Required Actions	Actions Taken during Event
For fires that cannot be immediately controlled, contact the Site Supervisor.	The W3 Shift Supervisor was contacted regarding each of the fires that occurred.
The Site Supervisor calls for Fire Department assistance.	The W3 Shift Supervisor called the local Fire Department.
The SS assigns specific personnel to advise and extend technical support to the Fire Department.	Personnel were assigned escort and support duties for the Fire Department.

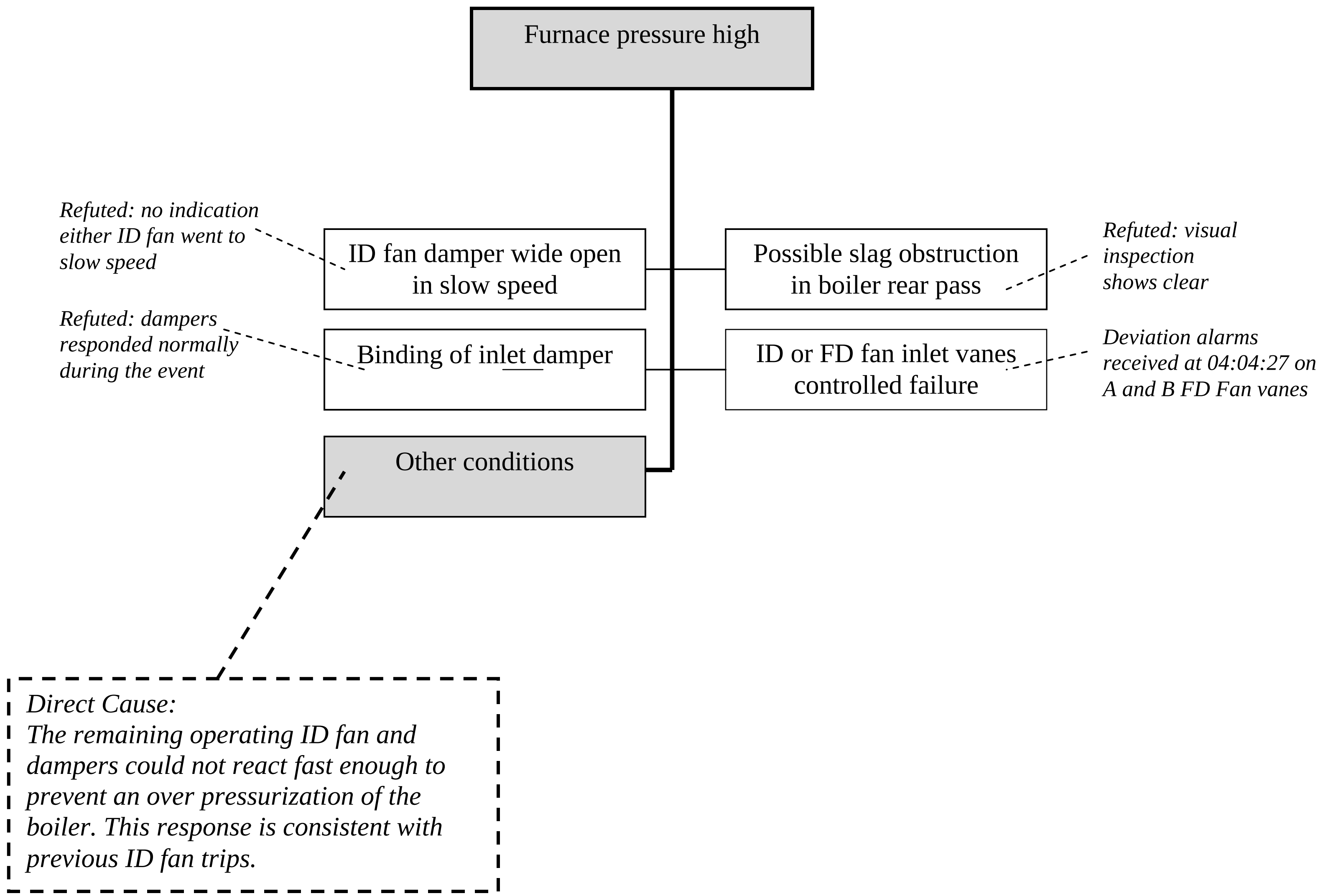
The operators carried out the actions per this procedure to call for help and to assist as necessary once that help arrived.

Attachment C:
Equipment Failure Mode Charts

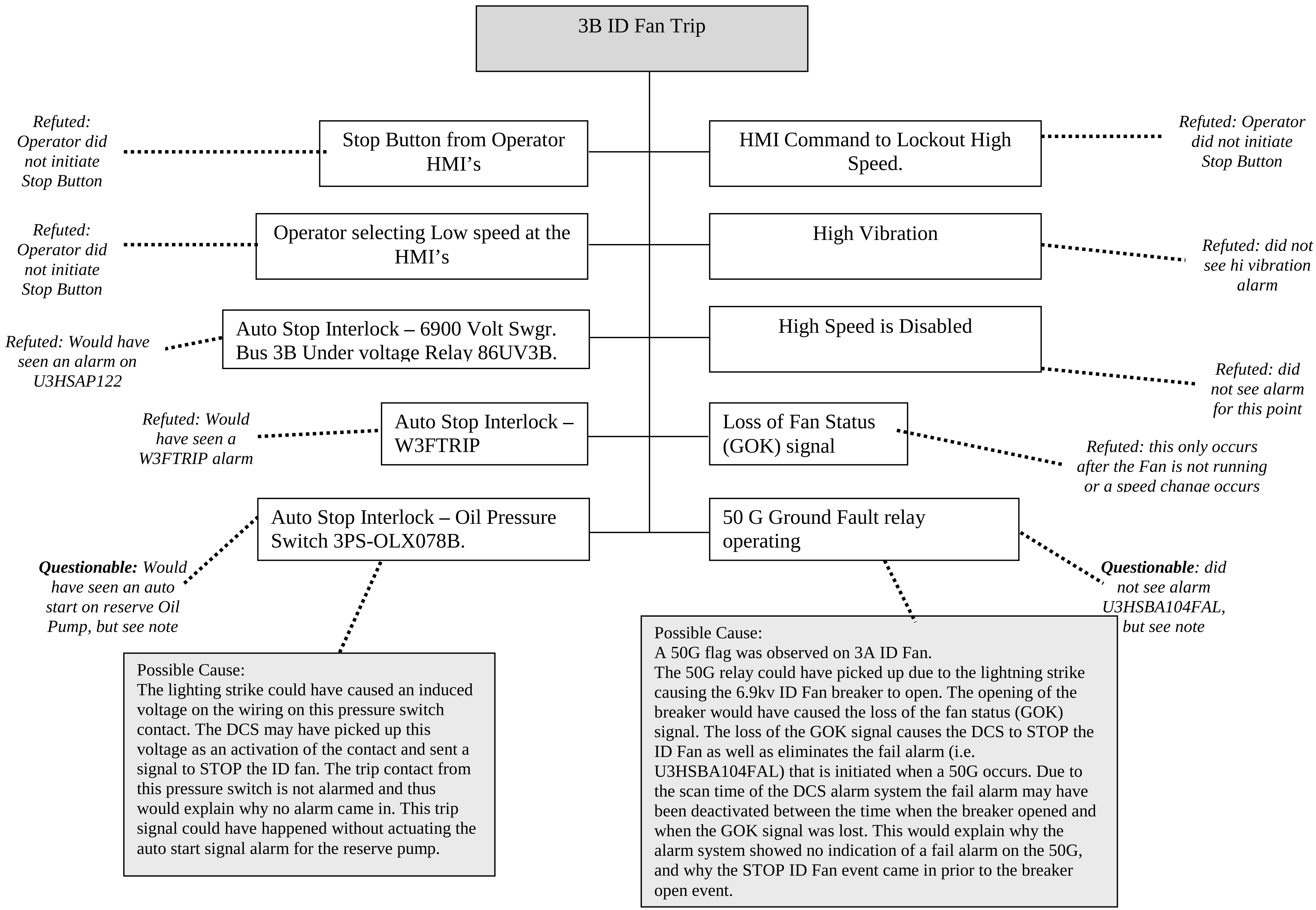
Weston 3 Boiler Trip, Sheet 1 of 2



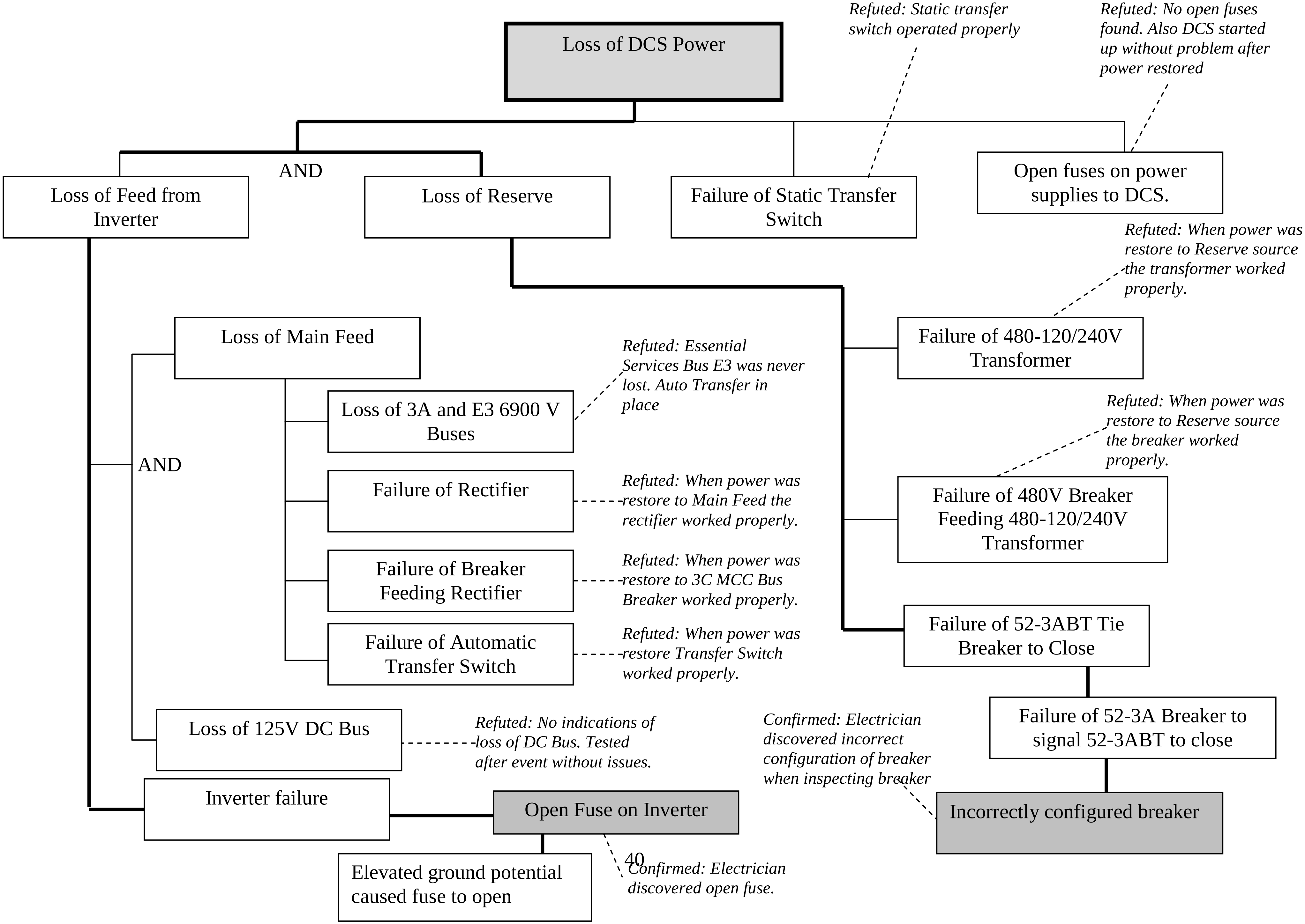
Weston 3 Boiler Trip, Sheet 2 of 2



Induced Draft Fan 3B Trip



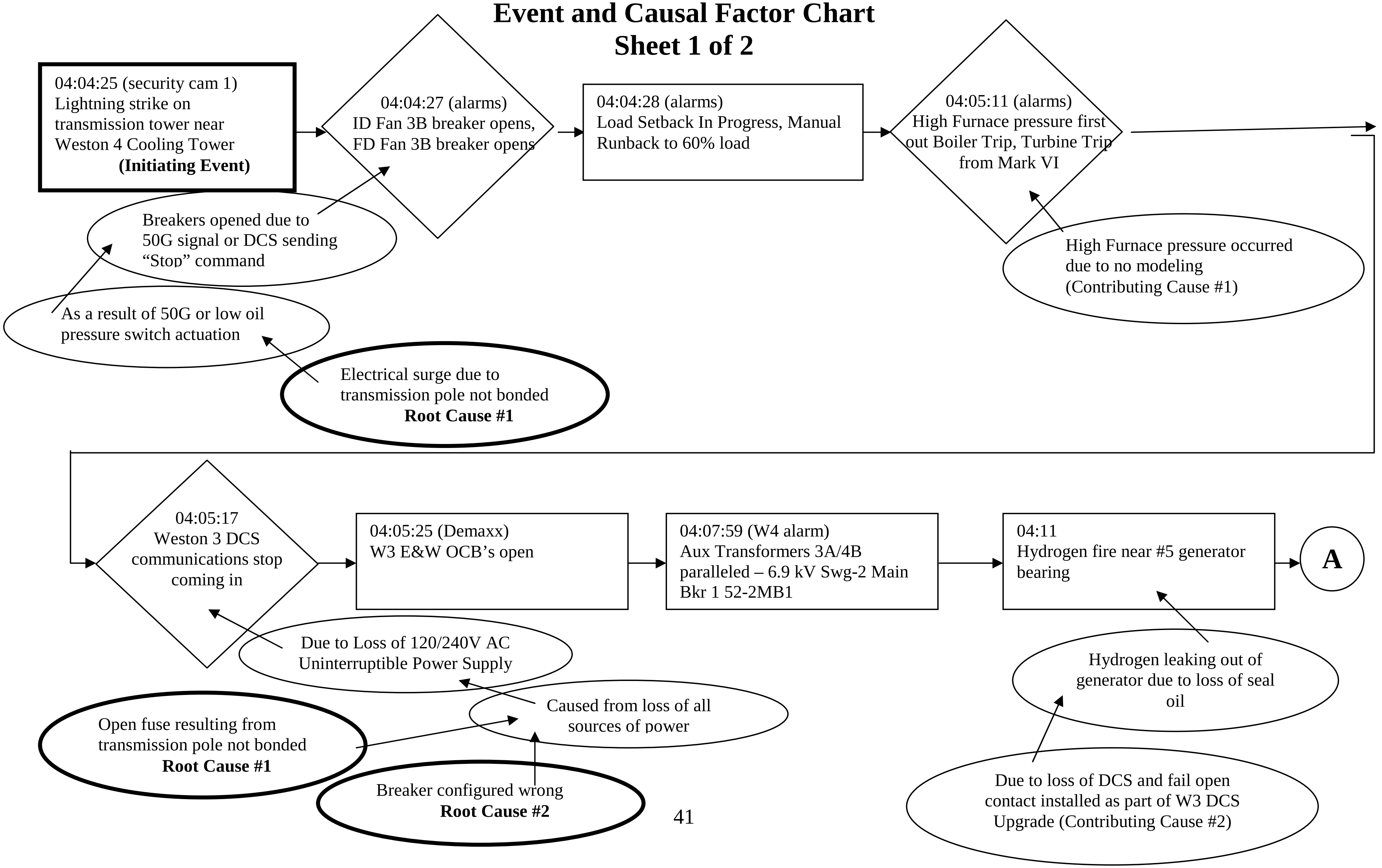
Loss of Distributed Control Systems



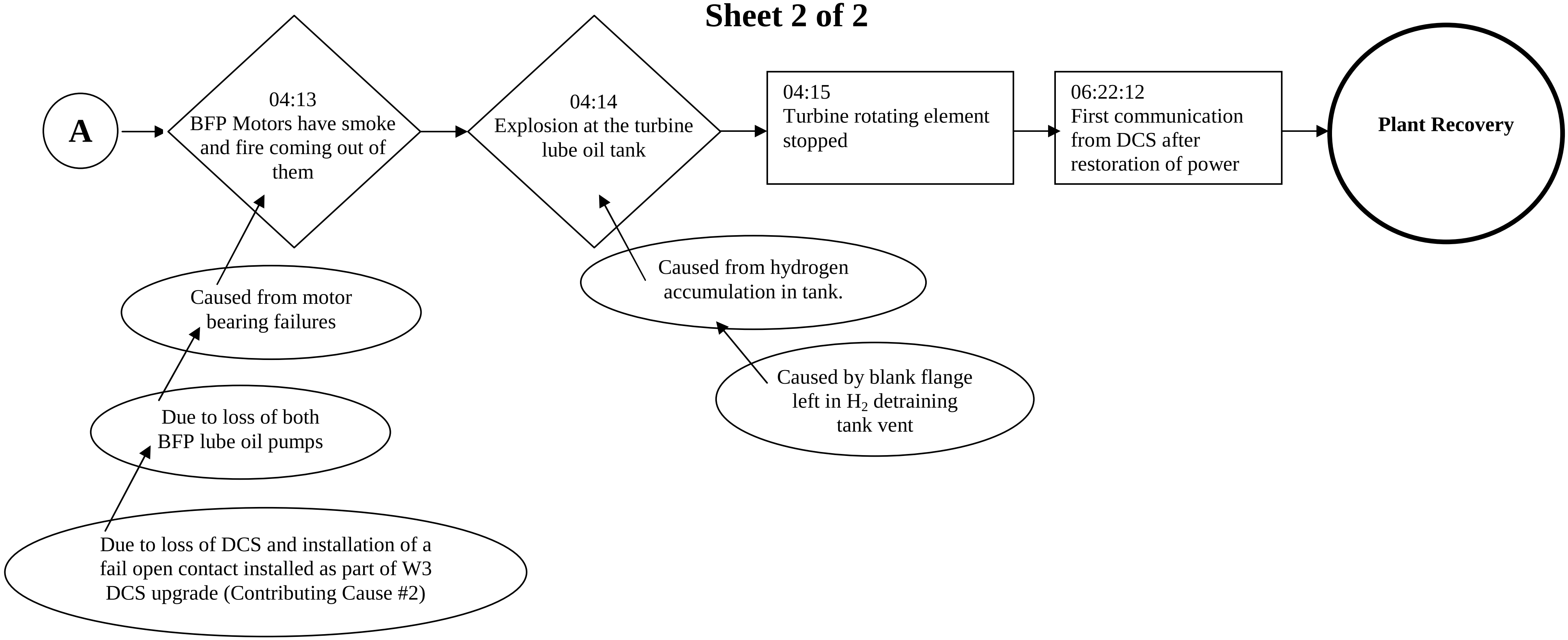
Attachment D

Event and Causal Factor Chart

Sheet 1 of 2



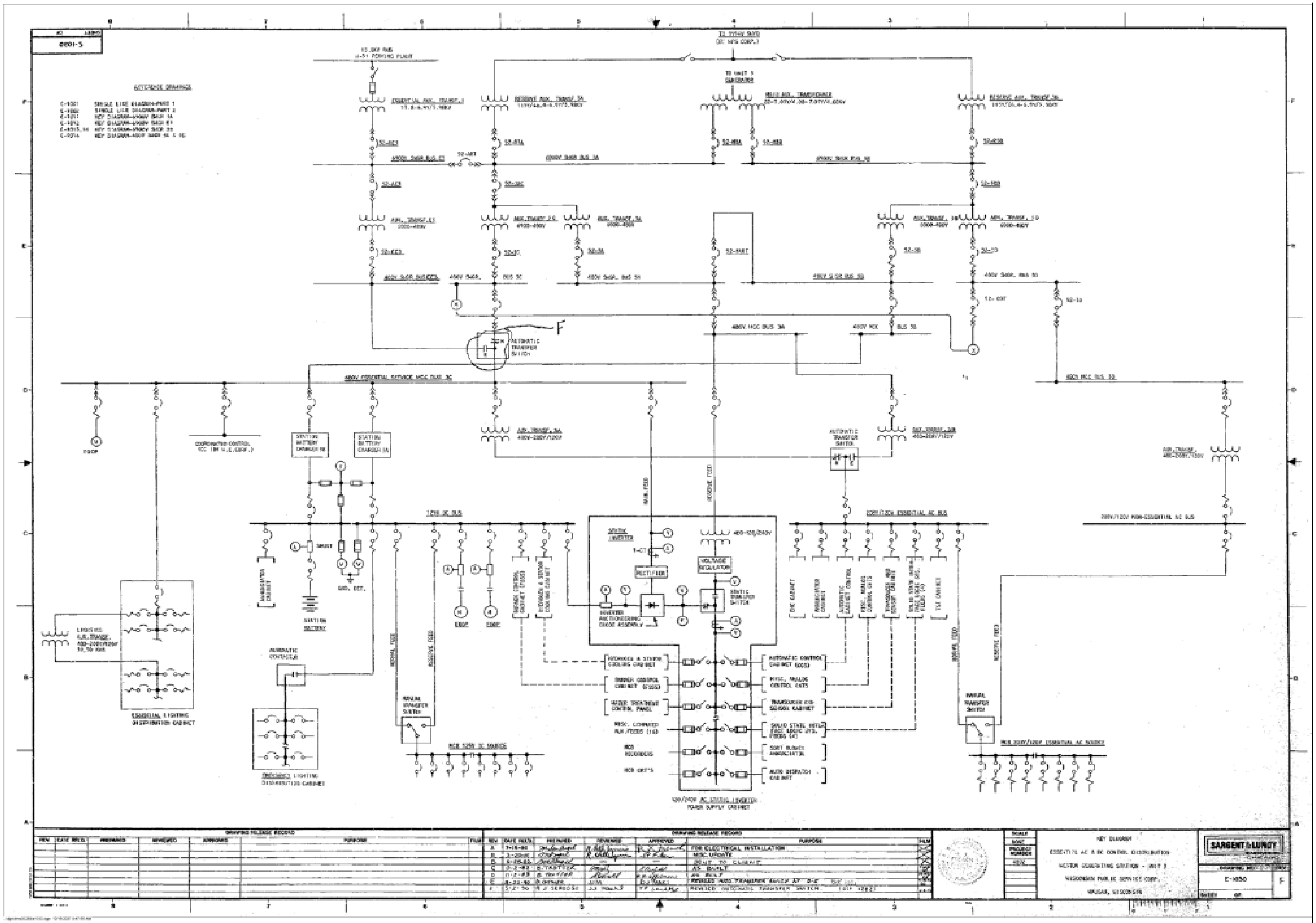
Attachment D
Event and Causal Factor Chart
Sheet 2 of 2



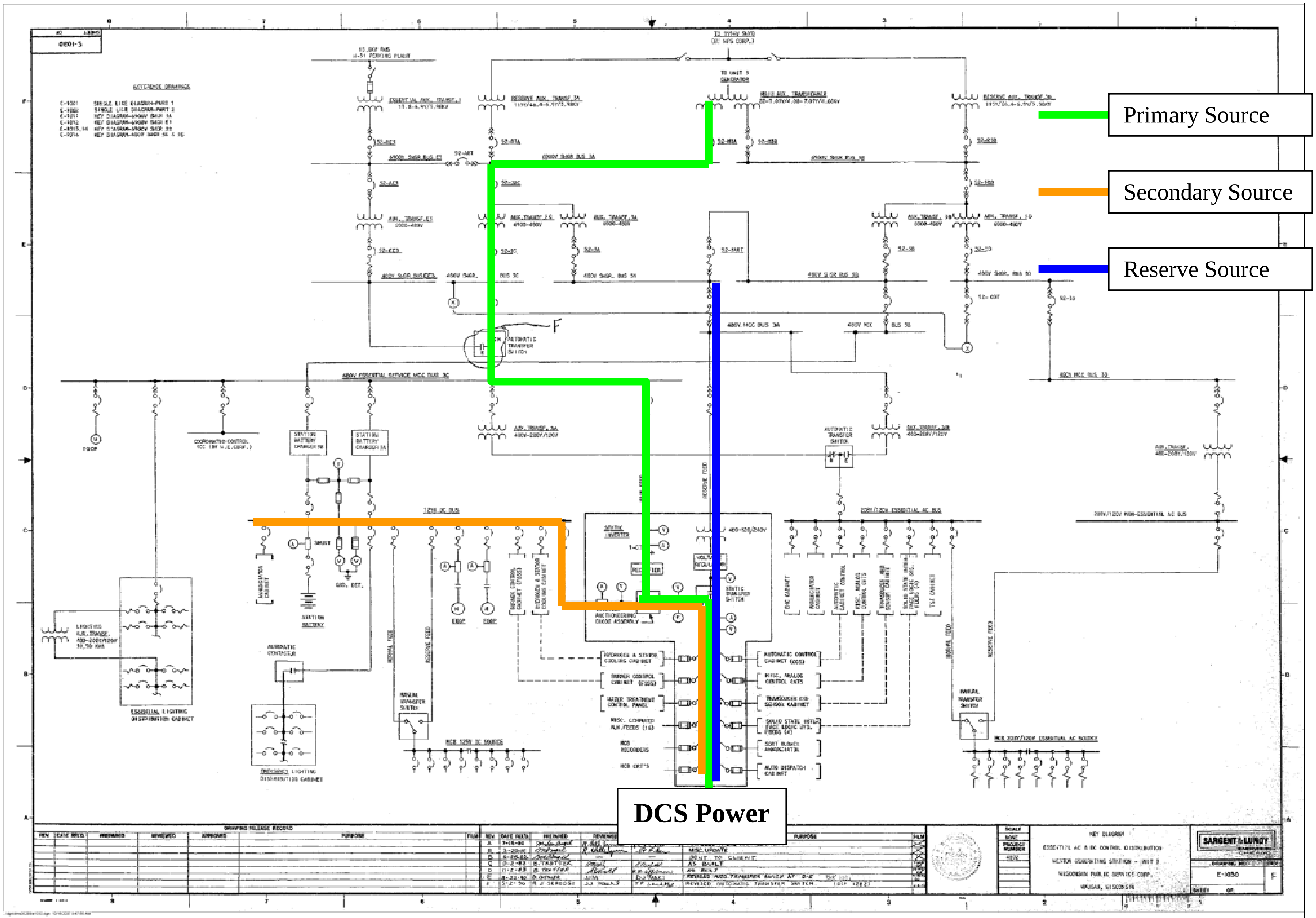
Attachment E

Weston 3 Electrical Diagrams

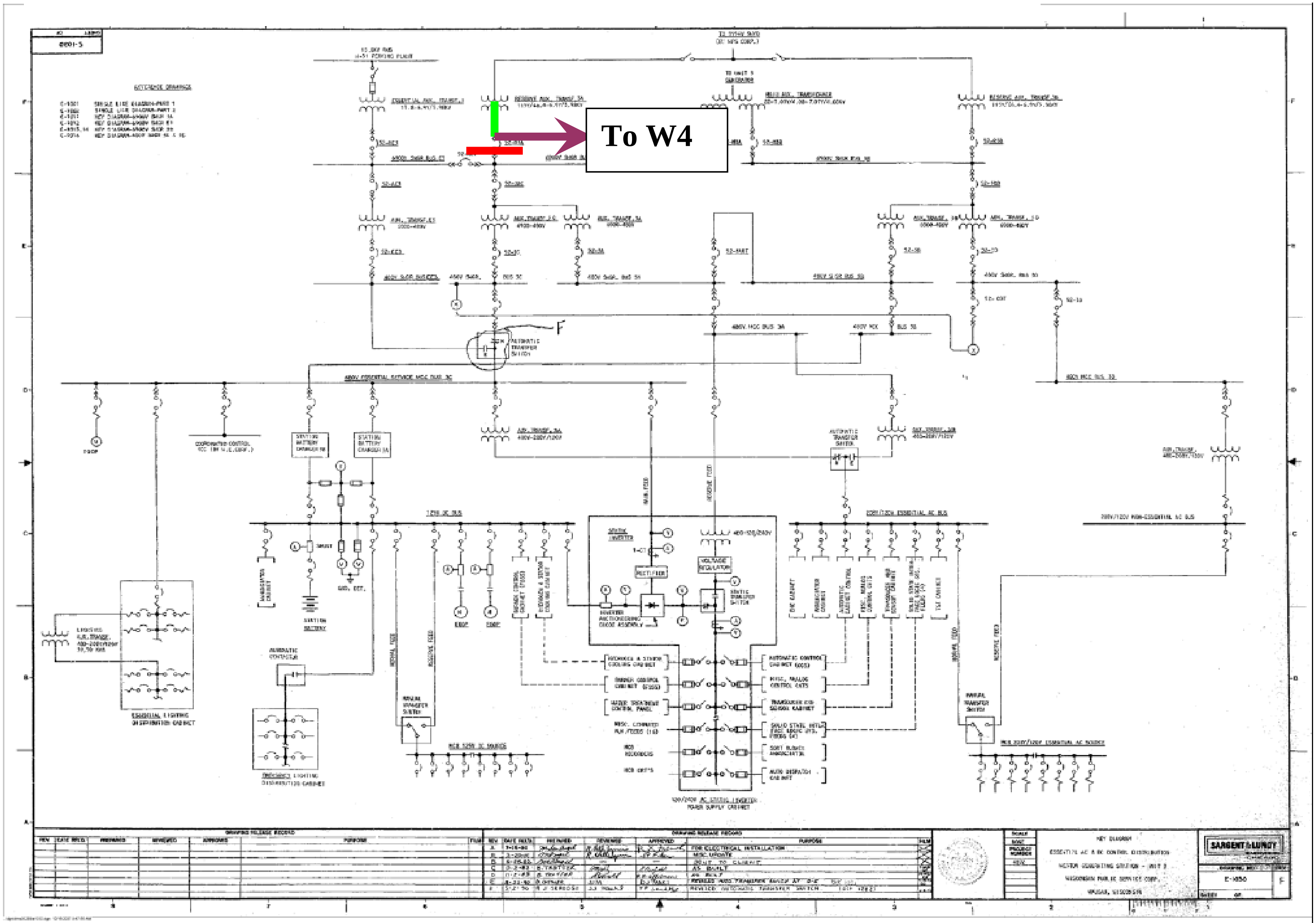
Attachment E.1 – Weston 3 As Designed Electrical System



Attachment E.2 – Weston 3 DCS Power Normal Power Supply



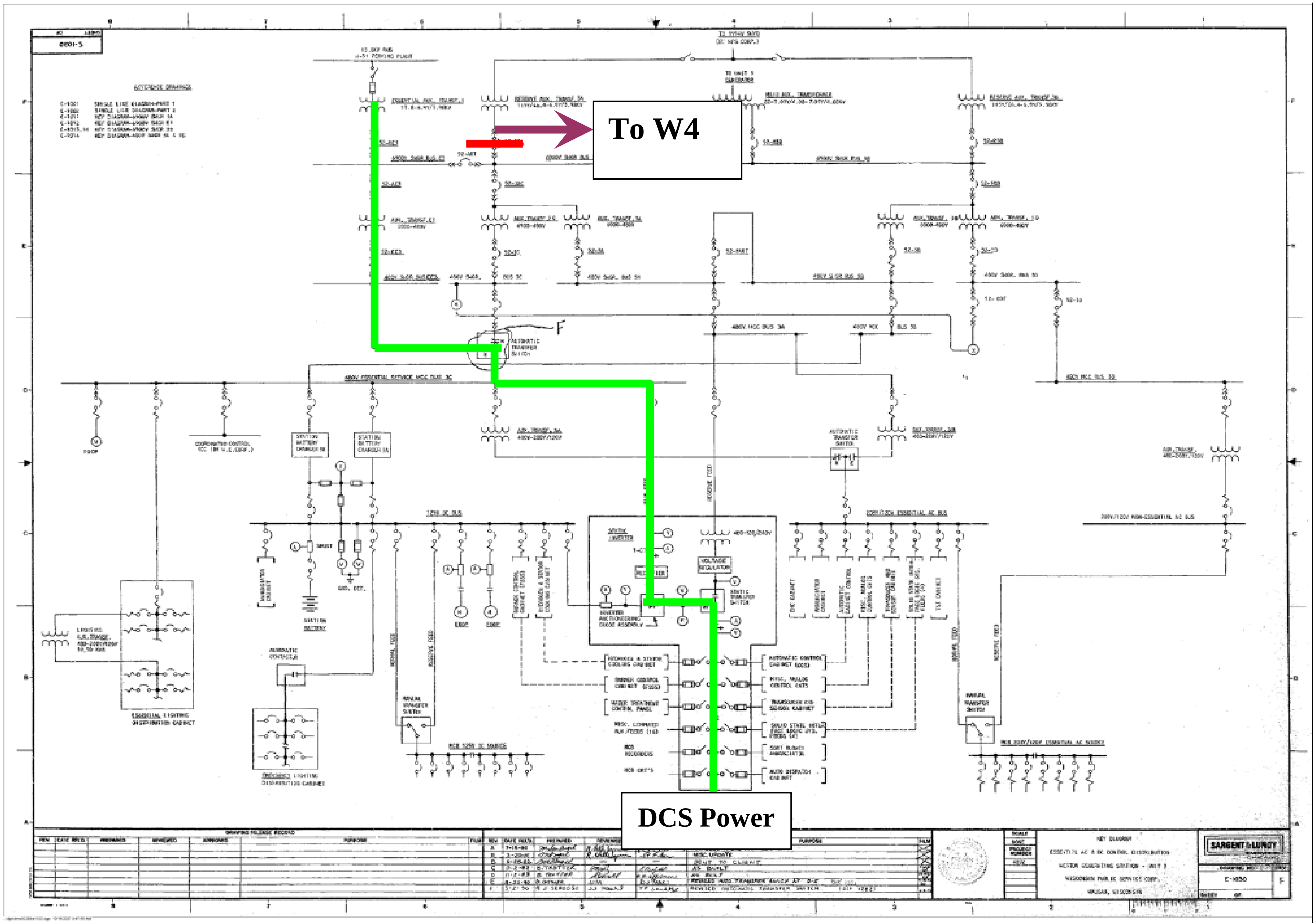
Attachment E.3 – Weston 3 RAT Tie to Weston 4



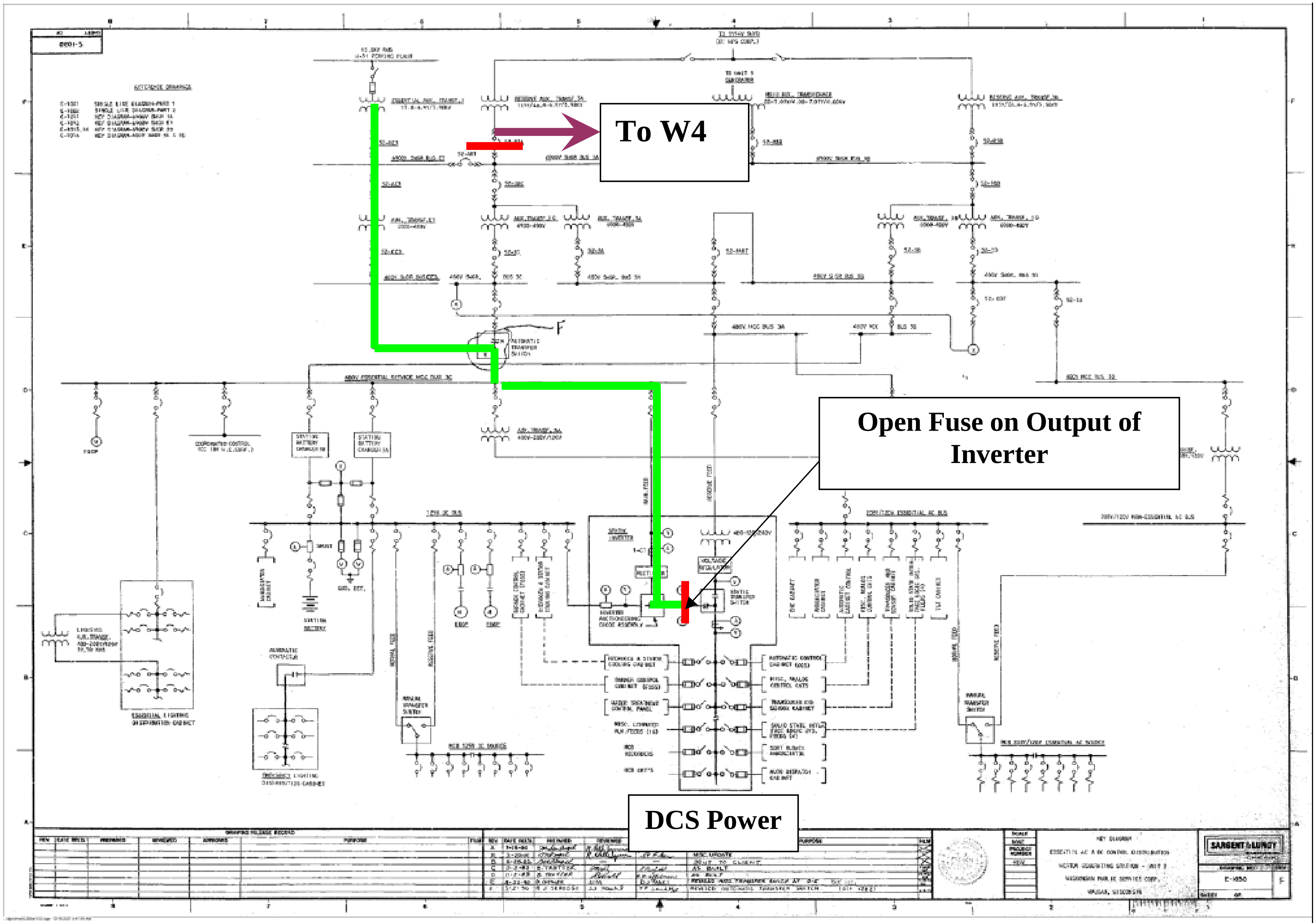
Attachment F:

Weston 3 Electrical Prints-DCS Failure Related

Attachment F – Normal Trip Condition with Weston 3 RAT Tie to Weston 4

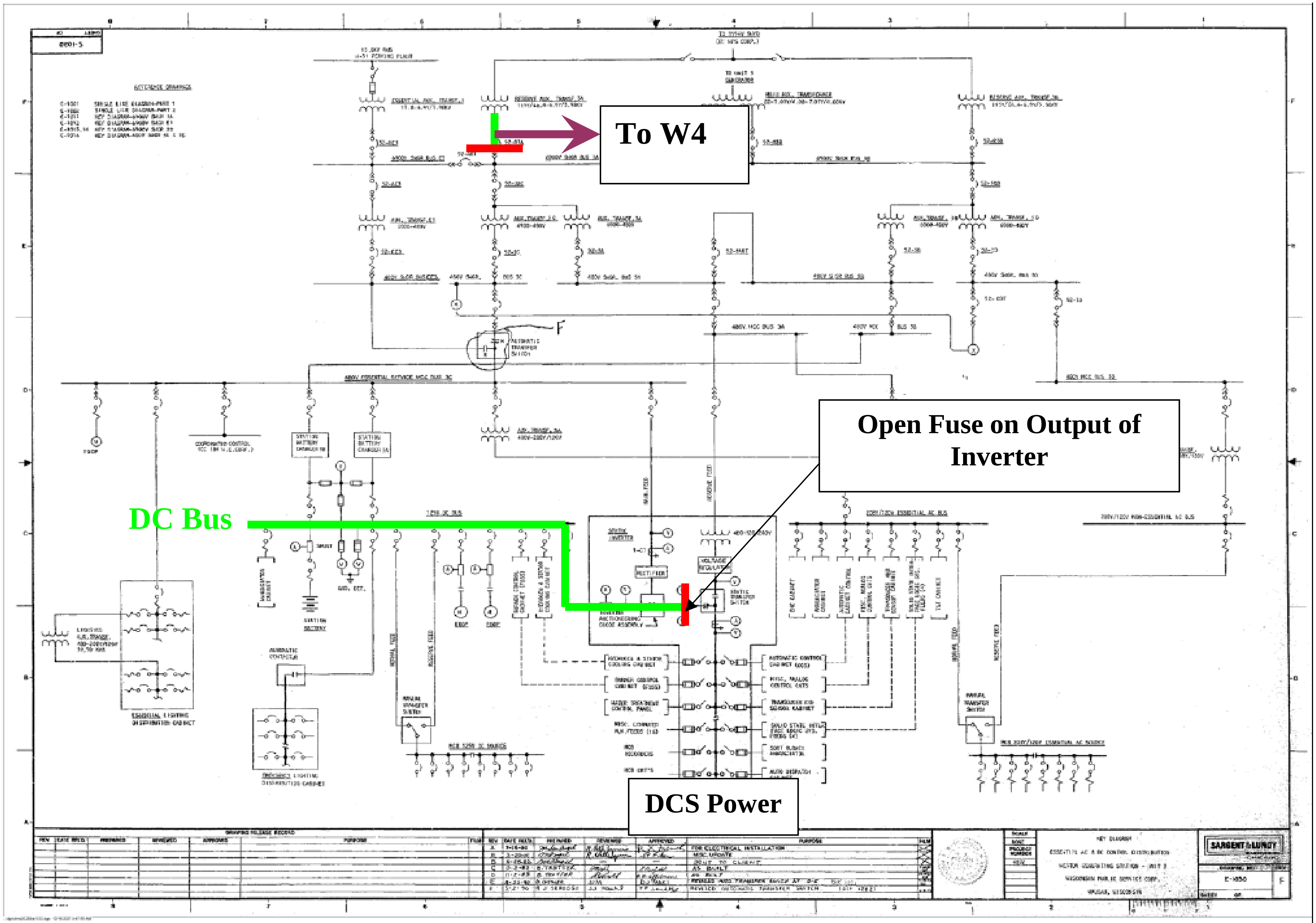


Attachment F.1 – First Line Failure



MADI_1472002.8

Attachment F.2 – Second Line Failure



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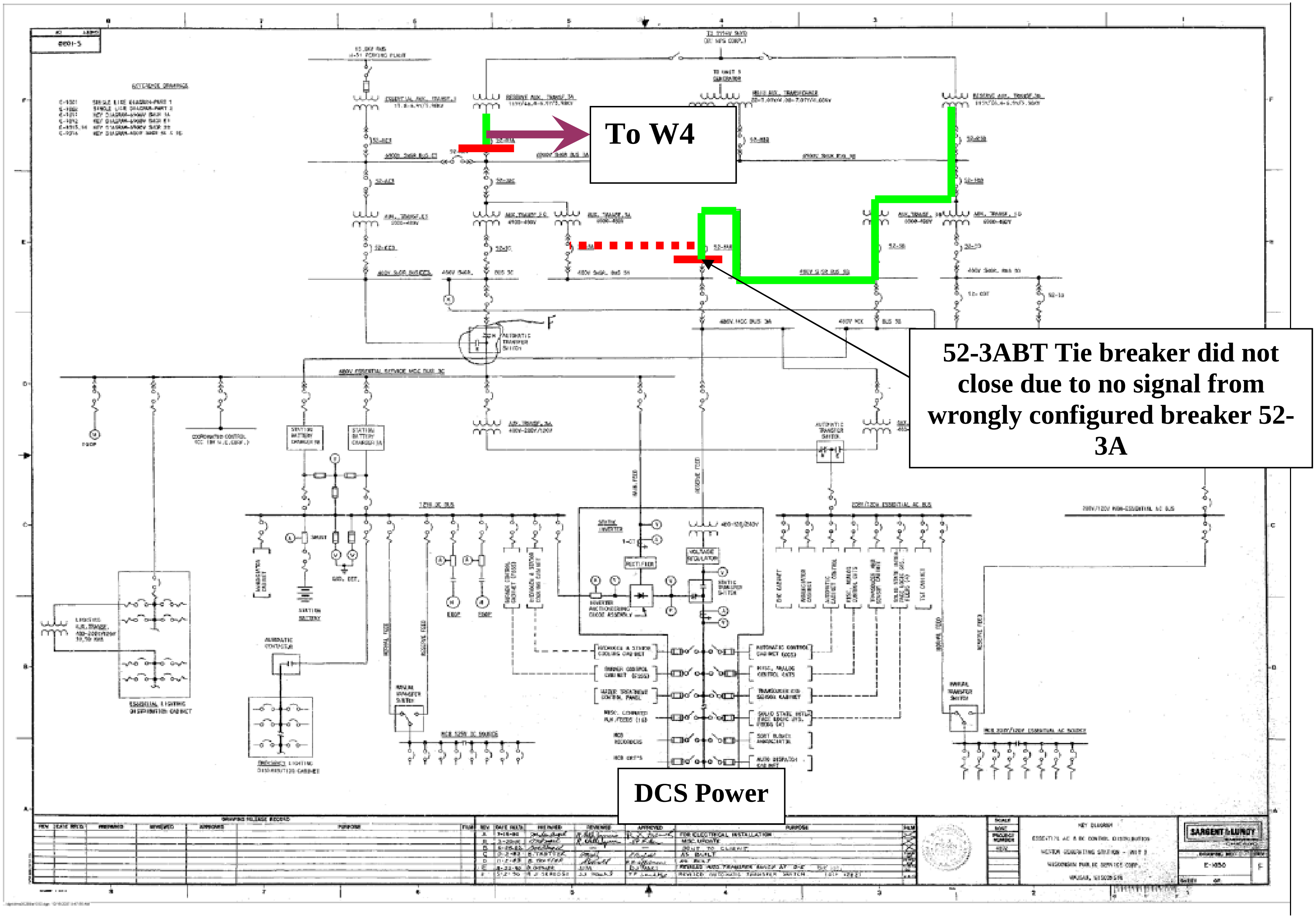
Attachment F.3 – Third Line Failure



MADI_1472002.8

Attachment G:

Breaker Locations

Breaker Locations

	Entity number	Name	Manufacturer	Model Number
1	3APX48E-1B	Switchgear-Main Feed To 480V Bus 3a Cubicle 1b	Federal Pacific Electric Co	FPS4-50-1600A
2	3APX48E-3C	Switchgear-Bus Tie Breaker 480V Bus 3a And 3b Cubicle 3c	Federal Pacific Electric Co	FPS4-50-1600A
3	3APX49E-5B	Switchgear-Main Feed To 480V Bus 3b Cubicle 5b	Federal Pacific Electric Co	FPS4-50-1600A
4	3APX50E-3C	Switchgear-Bus Tie Breaker 480V Bus 3c And 3d Cubicle 3c	Federal Pacific Electric Co	FPS4-50-1600A
5	3APX50E-5B	Switchgear-Main Feed To 480V Bus 3c Cubicle 5b	Federal Pacific Electric Co	FPS4-50-1600A
6	3APX51E-1B	Switchgear-Main Feed To 480V Bus 3d Cubicle 1b	Federal Pacific Electric Co	FPS4-50-1600A
7	3APX52E-1B	Switchgear-Main Feed To 480V Bus 3e Cubicle 1b	Federal Pacific Electric Co	FPS4-50-1600A
8	3APX52E-3C	Switchgear-Bus Tie Breaker 480V Bus 3e And 3f Cubicle 3c	Federal Pacific Electric Co	FPS4-50-1600A
9	3APX53E-1B	Switchgear-Main Feed To 480V Bus 3f Cubicle 1b	Federal Pacific Electric Co	FPS4-50-1600A
10	3APX57E-1B	Switchgear-Bottom Ash Building Main Feed To 480V Bus Rs3a Cubicle 1b	Federal Pacific Electric Co	FPS4-50-1600A
11	3APX58E-3B	Switchgear-Bottom Ash Building Main Feed To 480V Bus Rs3b Cubicle 3b	Federal Pacific Electric Co	FPS4-50-1600A
12	3APX59E-1B	Switchgear-Main Feed To 480V Bus Ch3a-1600a Cubicle 1b	Federal Pacific Electric Co	FPS4-50-1600A
13	3APX59E-3C	Switchgear-Crush Hse Bus Tie 480V Bus Ch3a/ch3b-1600a	Federal Pacific Electric Co	FPS4-50-1600A
14	3APX60E-5B	Switchgear-Main Feed To 480V Bus Ch3b-1600a Cubicle 5b	Federal Pacific Electric Co	FPS4-50-1600A
15	3APX61E-1B	Switchgear-Main Feed To 480V Bus Ch3c Cubicle 1b	Federal Pacific Electric Co	FPS4-50-1600A
16	3APX61E-3C	Switchgear-Bus Tie Breaker 480V Bus Ch3c And Ch3d Cubicle 3c	Federal Pacific Electric Co	FPS4-50-1600A
17	3APX62E-5B	Switchgear-Main Feed To 480V Bus Ch3d Cubicle 5b	Federal Pacific Electric Co	FPS4-50-1600A

Attachment H:

Failure Mode and Effects Analysis[2]

[2] FMEA charts modified from those shown in Failure Mode and Effects Analysis: FMEA from Theory to Execution, Second Edition, D. H. Stamatis, ASQ Quality Press, Milwaukee, WI, 2003.

FMEA Severity Guide

Effect	Rank	Criteria
No	1	No effect.
Very slight	2	Very slight effect on product or system performance.
Slight	3	Slight effect on product or system performance.
Minor	4	Minor effect on product or system performance.
Moderate	5	Moderate effect on product or system performance.
Significant	6	Product performance degraded, but operable and safe. Partial failure, but operable.
Major	7	Product performance severely affected but functional and safe. System impaired.
Extreme	8	Product inoperable but safe. System inoperable.
Serious	9	Potential hazardous effect. Able to stop product without mishap - time dependent failure. Compliance with government regulation in jeopardy.
Hazardous	10	Hazardous effect. Safety related - sudden failure. Noncompliance with government regulation.

FMEA Occurrence Guide

Occurrence	Rank	Criteria
Almost never	1	Failure unlikely. History shows no failure.
Remote	2	Rare number of failures likely.
Very slight	3	Very few failures likely.
Slight	4	Few failures likely
Low	5	Occasional number of failures likely.
Medium	6	Medium number of failures likely.
Moderately high	7	Moderately high number of failures likely.
High	8	High number of failures likely.
Very high	9	Very high number of failures likely.
Almost certain	10	Failure almost certain. History of failures exists from previous or similar designs.

FMEA Detection Guide

Detection	Rank	Criteria
Almost certain	1	Proven detection method available.
Very high	2	Proven computer analysis available.
High	3	Simulation or modeling.
Moderately high	4	Tests on early prototype system elements.
Medium	5	Tests on early prototype system components.
Low	6	Tests on similar system components.
Slight	7	Tests on product with prototypes with system components installed.
Very slight	8	Proven durability tests on products with system components installed.
Remote	9	Only unproven or unreliable techniques available.
Almost impossible	10	No known techniques available.

FMEA Risk Prioritization Matrix

System Function	Potential Failure Mode	Potential Effects of Failure	SEV	Potential Cause	OCC	Detection Method	DET	RPN	Contingency Action
Uninterruptible power to the essential systems bus	F204 opens	Loss of normal feed supply	4	Electrical system overload	1	Indication of transfer of power to reserve supply	1	**4**	none