Minnesota Power's Boswell Unit 3 Environmental Compliance and Electrical Infrastructure Upgrades

Kent Ogston and David Bisel
Minnesota Power
30 West Superior Street
Duluth, MN 55802-2093

Christopher Ruckman
Burns & McDonnell Engineering Company
9400 Ward Parkway
Kansas City, Missouri 64114

Abstract
To meet government mandates for emissions, Boswell Energy Center Unit 3 was retrofitted with emission controls from 2006-2009. As part of this project, the entire auxiliary medium voltage electrical infrastructure was replaced due to capacity and interrupting capability issues. The overall goals of the project were to meet emission requirements while creating an operationally safer electrical infrastructure and maintaining unit net power production. The combined Unit 3 projects consisted of the environmental retrofit, turbine efficiency upgrades, dry ash handling, and duty cycle preservation projects which included the electrical infrastructure upgrades. The execution of these projects was a multiple discipline engineering effort, and the overall investment in Boswell Unit 3 as a result of these projects was approximately $300 million.

Introduction
Minnesota Power operates the Boswell Energy Center located in Cohasset, Minnesota. Boswell Unit 3 is a pulverized coal-fired unit originally designed by Combustion Engineering that was put into service in 1973. Boswell Unit 3 has a tangentially-fired steam generator and is currently rated at 380 MW (net) and 405 MW (gross). Minnesota Power began planning for an air pollution control retrofit project for Boswell Unit 3 in 2004. Initial studies for the project included a review of current and developing environmental regulations affecting the unit and extensive cost estimates for the installation of the equipment deemed necessary for future regulatory compliance.

When both Minnesota state and federal environmental regulations were solidified in 2006, Minnesota Power decided to implement an air pollution control retrofit project on Boswell Unit 3. This project, called the Boswell Unit 3 Environmental Improvement Project, included the addition of the following equipment:

- Low NO_x burners and an overfire air system for NO_x control
- Selective Catalytic Reduction (SCR) system for NO_x control
- Wet Flue Gas Desulfurization (FGD) system for SO_2 control
- Fabric filter baghouse for particulate matter and mercury control
- Activated carbon injection system for mercury control
- Induced Draft (ID) fans, motors, and variable frequency drives

Figure 1 – 3D Model of the Unit 3 Emissions Control Equipment.

The addition of this new equipment had a significant impact on the existing Boswell Unit 3 electrical infrastructure. Ultimately, new auxiliary transformers, a low-side generator breaker, and new 5kV and 15kV switchgear lineups were required. The design of these new systems and the steps taken to minimize electrical arc flash hazards are discussed in detail below.

Auxiliary Electrical System

Prior to the air pollution control retrofit project, the Unit 3 auxiliary electrical system was configured as shown in Figure 2 and consisted of a two-winding 22kV-4.16kV unit auxiliary transformer and a two-winding 115kV-4.16kV startup transformer serving both as a startup source for the unit and as a supply for loads that are common to other units at Boswell (coal handling, car thaw, etc.). The unit auxiliary transformer fed main breakers on auxiliary switchgear lineups 3A and 3B via the non-segregated phase bus duct tap at the secondary terminals of the transformer. Similarly, the startup transformer fed main breakers on the startup switchgear lineups 3A and 3B via a non-segregated phase bus duct tap connected at the secondary terminals. Tie breakers connected each auxiliary bus with the corresponding startup bus.

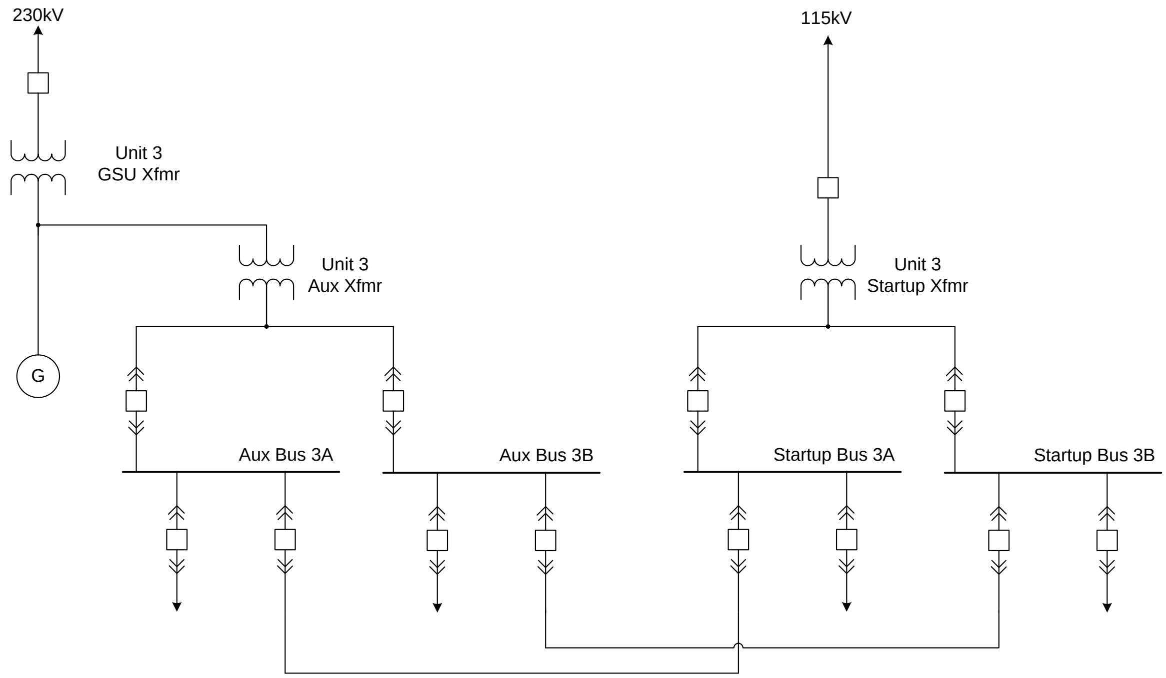

Figure 2 – Unit 3 Original One-Line

Based on the Air Quality Control System (AQCS) electrical loads submitted by the various AQCS equipment vendors and historical maximum loading on the existing electrical system, the total additional loading for Unit 3 was estimated at 14.8MW assuming a 95% power factor.

To assess the condition of the existing Unit 3 electrical equipment, short circuit and load flow studies were performed early in the project to determine how the new AQCS loads would affect the existing 4.16kV buses. The short circuit study indicated that the momentary currents were within 5% of the existing breaker rating and the interrupting ratings were not adequate for the existing or future conditions. The load flow study indicated that after AQCS loads were added, startup aux switchgear bus 3A was overloaded by approximately 17% and startup switchgear bus 3B was overloaded by approximately 14%. In addition, a preliminary arc flash assessment indicated incident energy levels on buses 3A and 3B of 60 cal/cm^2 and 49 cal/cm^2 respectively. According to NFPA 70E, when incident energy levels are above 40 cal/cm^2 additional consideration should be given to de-energizing the equipment before performing work.

Based on the studies, the existing 4.16kV, 2500A buses 3A and 3B were deemed incapable of supplying both normal running load and common load after the addition of the new AQCS equipment. Multiple upgrade options were considered for the Unit 3 electrical infrastructure. One option considered was to upgrade the existing startup and auxiliary transformers with new three-winding transformers each with a 4.16kV secondary winding and a 13.8kV tertiary winding. The 4.16kV winding would be connected to the existing system which would be left in its current configuration. The tertiary winding would be connected to a new 13.8kV switchgear lineup which would service the new ID fans and the remaining AQCS electrical loads. Another option given consideration was to add a low-side generator circuit breaker along with two new auxiliary transformers. With this option the auxiliary transformer would have the same 4.16kV secondary and 13.8kV tertiary winding configuration as described above and could be connected to the existing 4.16kV system or could be connected to new 3000A medium voltage switchgear that would replace all four existing Unit 3 4.16kV buses.

The generator circuit breaker option had a slightly higher capital cost but included many benefits such as increased system reliability, less downtime, reduced fault current during auxiliary transfers, and better protection against failures. Constructability was also a key factor in the final decision since the existing startup transformer foundation could not be used for a new, larger transformer. Finding a suitable alternate location for the new transformer was problematic due to obstructions created by existing equipment and structures. Adding a generator circuit breaker and eliminating the startup transformer mitigated these issues. Ultimately, a new electrical system topology was chosen as shown in Figure 3, consisting of a low-side generator circuit breaker, redundant auxiliary transformers, and new 3000A switchgear.

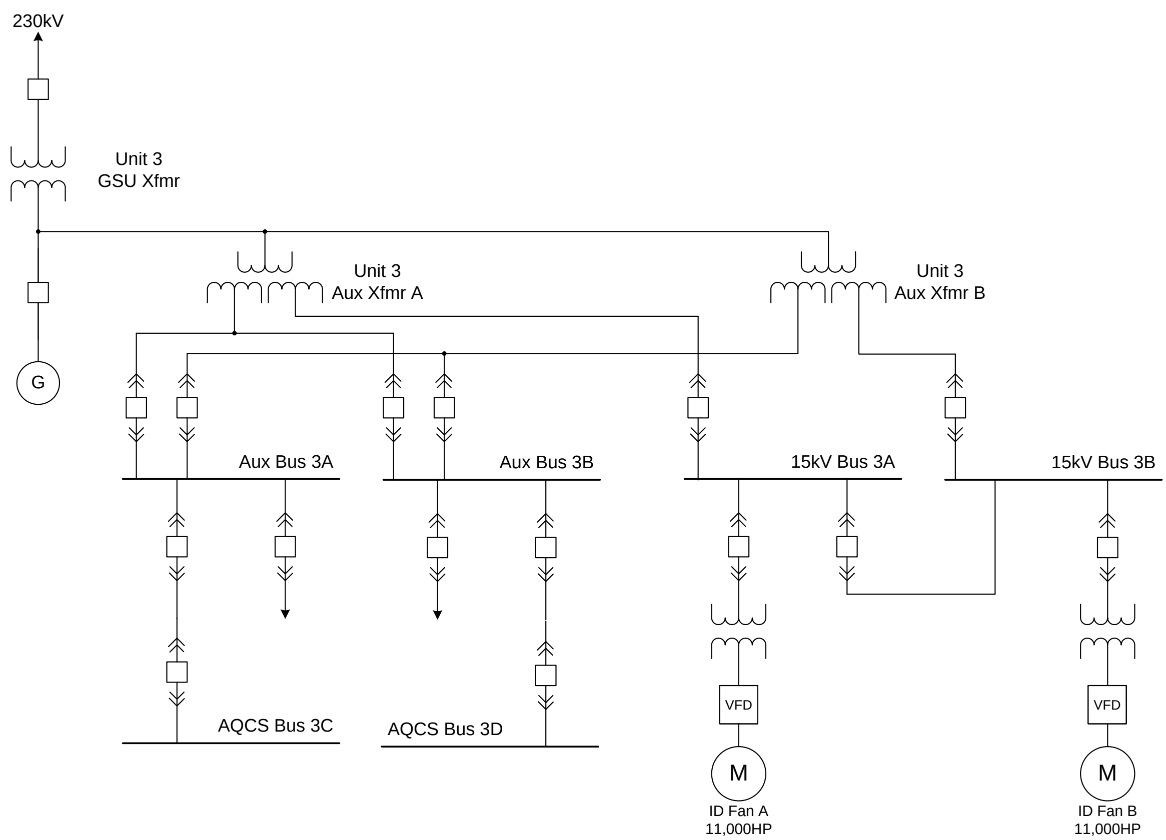

Figure 3 – Unit 3 Modified One-Line

Medium Voltage Switchgear

Because of Minnesota Power's emphasis on providing a safe working environment for employees, arc resistant medium voltage switchgear was selected for the project. Various arc resistant configurations were evaluated based on safety, redundancy, operational and maintenance requirements. Per IEEE C37.20.7 - *IEEE Guide for Testing Metal-Enclosed Switchgear Rated Up to 38 kV for Internal Arcing Faults*, two different levels of personnel accessibility to the switchgear are distinguished – Type 1 and Type 2. Equipment with a Type 1 accessibility designation has arc resistant features, as defined by IEEE C37.30.7, at the front of the switchgear only. Equipment with a Type 2 designation has arc resistant features around the entire perimeter of the switchgear (front, back, and sides). In addition to the standard accessibility types identified in IEEE C37.20.7, several optional arc resistant performance features can be specified by adding a suffix to the base accessibility designation. Suffixes B, C, and D are available. Suffix B provides protection for personnel working in the switchgear's low voltage compartment from an arcing fault in an adjacent compartment. Suffix C provides protection between adjacent compartments so that an arcing fault in one cubicle does not affect an adjacent cubicle in the switchgear. Suffix D is seldom used and applies only to accessibility Type 1 designs where, because of the location of the gear, the back and sides of the gear do not require the same arc resistance as the front. For instance, Suffix D switchgear can be specified where the front, rear, and left side of the switchgear are arc resistant but the right side is not.

For the Boswell Unit 3 project, arc resistant switchgear Type 2BC was chosen to provide maximum protection for personnel that may be working at the front, back, sides or in the low-voltage compartment of the switchgear. The C suffix option was selected to provide a degree of compartment-to-compartment protection and to minimize damage to adjacent switchgear sections in the event of an arc fault. Due to space constraints and the need for two-high breaker cubicles, an exception was made to the 2BC designation in the rear cable compartment which was designated as Type 2B only.

Figure 4 –New Arc Resistant 4.16kV Bus 3A

Early in the Boswell Unit 3 project the decision was made to duct the switchgear's overpressure venting devices outside the electrical equipment rooms via a common plenum running the length of the switchgear. This was due, in part, to the eight foot minimum clearance required between the top of the switchgear and the ceiling if a plenum is not added. Lack of a plenum would allow equipment above the switchgear such as cable tray and lighting fixtures to be subjected to hot exhaust gassed during internal faults. Since this equipment is not rated for the temperature and pressure of the exhaust gases during an arc fault combined with the possibility of nearby personnel being subjected to released gases, the plenum was required. During the design of the plenum system it was imperative that the exhaust vents be located in such a way that the escaping gases did not endanger personnel that could be working in the area. Manufacturer's recommendations (see Figure 5) were used to determine final exhaust locations. Venting outside the electrical equipment rooms eliminated the need to evaluate the building's structural capacity to withstand the pressure wave developed by the arc fault and eliminated the need to evaluate other equipment in the buildings that may have otherwise been compromised by the arc gases.

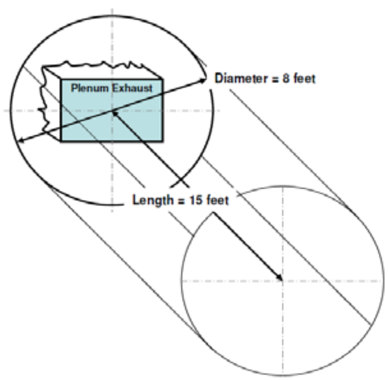

Figure 5 – Plenum Exhaust Clearance Zone (Courtesy ABB)

Even though the medium voltage switchgear selected for the project was arc resistant, the overall goal for electrical equipment on the project was to have an incident energy rating equal to or less than 8 cal/cm^2 (Hazard/Risk Category 2) in case the arc resistant features of the switchgear were compromised (i.e. a door was left open or inadequately secured) or otherwise failed during an arcing fault. To achieve an 8 cal/cm^2 incident energy rating for the new medium voltage switchgear, either a high or low impedance bus differential scheme, or a Bus Zone Tripping scheme can be selected. With the bus differential scheme, current is monitored on all connections in and out of the switchgear bus creating a differential zone of protection. If the sum of the currents into the zone does not equal the sum of the currents out of the zone a fault within the zone is assumed and all sources of power to the switchgear bus are tripped. With the Bus Zone Tripping scheme, the main and feeder breaker relays monitor current at the breaker, and pass blocking signals via hard-wire or communications to indicate the relative location of the fault.

As discussed in detail below, bus differential schemes should be designed with CTs in the furthest position from the breaker and may be either the high-impedance or low impedance variety depending on the number of breakers in the lineup. This scheme is best implemented on new switchgear when the CT locations can be designed prior to switchgear fabrication.

Installing CTs for bus differential protection in existing switchgear installations is typically not practical either economically or physically. Bus Zone Tripping Schemes provide a method to accomplish this via high speed tripping similar to traditional bus differential relaying. This scheme should be applied to cover the same zone as bus differential, with CTs ideally installed in the furthest positions from the breaker as outlined below.

On the Boswell Unit 3 project, since new switchgear was being purchased, it was the consensus of the project team that bus differential protection should be included, as it provides the most secure high-speed tripping for all faults inside the differential zone, including arcing faults. The project purchased switchgear with a high-impedance bus differential scheme with CTs located in the furthest position from the breaker. With this scheme, the total clearing time for a bus fault was less than six cycles, including the five cycle breaker interrupting time.

CT Location

While designing the new medium voltage switchgear, much time and attention was paid to the location of current transformers (CTs) so that protective relaying could have the greatest potential impact on reducing arc flash hazards. Since the Boswell Unit 3 project purchased new switchgear the CT locations could be tailored to the desired protection scheme. However, when working with existing switchgear it can be difficult to retrofit CTs into optimal locations. For example, the existing Boswell Unit 3 switchgear had CTs located in some of the positions shown in Figure 6 below but was not equipped with bus differential relaying.

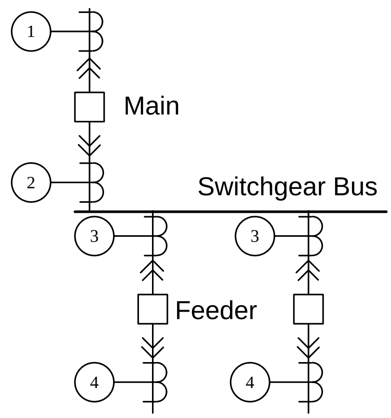

Figure 6 – Typical Medium Voltage Switchgear Lineup

For existing switchgear, where the main breaker has CTs only at Position 1 and lacks a bus differential, the time-overcurrent relay at the main breaker is used for bus protection and backup feeder protection. The Position 1 relay is set to coordinate with feeder relays at Position 3 or 4 and, as a result, is relatively slow since it is coordinated based on time. The relay at Position 1 also acts as the primary arc flash protection when racking or operating a feeder breaker. In this case, the relay at Position 1 needs to meet two opposing requirements - fast tripping for arc flash protection and slower tripping coordinated with the relays at Position 3 or 4 for a feeder fault. Medium voltage switchgear is typically fed from a transformer with differential protection. If the differential zone extends only to the CT at Position 1, and does not wrap the main breaker, a slow tripping condition (or no tripping at all) will result for an arc flash in the main breaker. This is due to the fact that it relies on the transformer high side overcurrent protection to clear the fault.

In cases where the main breaker has CTs only at Position 2, the time-overcurrent relay is used for bus protection and backup-up feeder protection while functioning like a relay at Position 1. In this case, the arc flash issues and the two opposing protection requirements (fast clearing for arc flash protection, and coordinated protection with the relays at position 3 or 4 for a feeder fault) are also the same. The main advantage of this CT position is that source transformer differential relaying will include the main breaker in the differential zone, allowing the fault to be cleared with high speed protection thereby reducing the arc flash hazard.

For feeder breakers the biggest advantage of CT Position 3 over Position 4 is protection for internal breaker faults. From an arc flash standpoint, however, the calculations for determining incident energy are still based on backup protection provided by the main breaker, since the fault may be on the bus side of the breaker contacts or on the bus side breakers stabs, which require the main breaker to clear the fault. CT Position 4 does not provide any protection for internal breaker faults but can provide an advantage if a Bus Zone Tripping (or Zone Interlocking) scheme is implemented as a backup to or in place of a bus differential scheme.

Bus Zone Tripping provides very fast clearing for faults in the zone between CTs at Position 1 and 4 and is best implemented using microprocessor based relays. Referencing Figure 7, the relay on the main breaker at Position 1 and the feeder breaker at Position 4 includes both an instantaneous (50) element and a standard time-overcurrent (51) backup element. The 50 element has a definite time delay of 2-3 cycles to allow time for the feeder relay to send a block from its 50 element. The blocking signals from the feeders can be hard-wired output contacts from each relay that are wired in parallel to an input on the main breaker at Position 1, or can be communicated individually using a relay-to-relay communications protocol like IEC 61850.

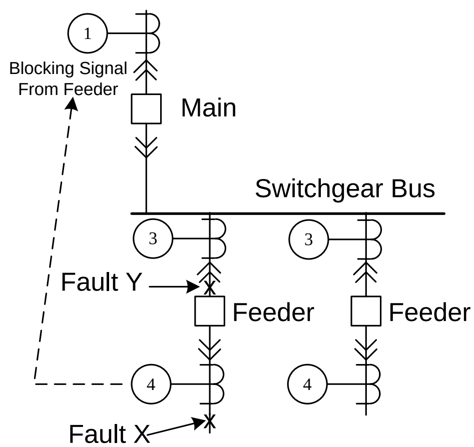

Figure 7 – Bus Zone Tripping Scheme

With a Bus Zone Tripping scheme, a fault at location X causes a 50 element in both the feeder breaker relay at Position 4 and the main breaker at Position 1 to pickup. Simultaneously, the feeder relay initiates a trip of the feeder breaker and sends a blocking signal to the main breaker's relay to prevent it from tripping. For a fault at location Y, the feeder relay's 50 element does not pickup and a block is not sent to the main breaker. In this case, the fault is quickly cleared by the unblocked definite-time 50 element in the main. If the CTs in this application were at Position 3 a fault at Y would cause the feeder relay to send a blocking signal to the main breaker relay and the fault would have been cleared by the main's much slower backup time-overcurrent element.

While the Bus Zone Tripping scheme is not as fast as the bus differential scheme (because of the intentional 2-3 cycle blocking time delay), it is much faster than traditionally coordinated time overcurrent protection. When applying a Bus Zone Tripping scheme it is important to consider the magnitude of both arcing currents (from calculations) and motor inrush when developing the pickup setting for the 50 element used to block the upstream breaker. If set too low, a blocking signal can be sent unintentionally and delay tripping for an actual bus fault.

Low Voltage Switchgear

Standard metal-enclosed low voltage switchgear was selected for the project using draw-out power circuit breakers with integral electronic trip units. Like the medium voltage equipment, the goal for low voltage electrical equipment on the project was an incident energy rating equal to or less than 8 cal/cm^2 (NFPA 70E Hazard/Risk Category 2). Given the high level of available fault current at the 480V system level, and the relatively long main breaker clearing time for a bus fault, arc flash mitigation methods were required to meet this incident energy goal.

Figure 8 –New 480V Metal-Enclosed Switchgear

The first arc flash mitigation method used for the low voltage switchgear is an optical arc sensing system utilizing a bare fiber optic loop installed in the rear cable compartment of the switchgear. This optical sensing system was supervised by a current detector connected to current transformers on the high-side of the main breaker. Upon sensing a flash and correlating it with an abrupt rise in current into the switchgear bus, the arc sensing relay will trip a lockout which isolates the bus from all incoming power sources. This scheme has an initial arc detection time of approximately 2ms and a total clearing time, (including a breaker interrupting time) of between five and six cycles.

When working with air circuit breakers, it is important to design the fiber optic cable route to avoid false operations due to the arc created in the breaker compartment during a normal breaker operation. After consulting with the breaker manufacturer, it was decided to route the fiber loop in the rear cable compartment, the main bus section, and each individual breaker compartment. Because the fiber was routed to the side of each breaker instead of over the arc chutes, it was felt that the risk was very small that an arc developed during normal breaker operation would cause an unintended operation of the scheme. If this were to become an issue in the future, the sections of bare fiber in each breaker cubicle could be covered.

During the construction phase of the project it was found that the fiber optic cable used for arc detection was too fragile to be routed in the switchgear prior to shipment. As the field power cables were being installed in the cable compartment, breaks in the fiber optic cable were common no matter how intentionally they were routed in areas thought to be out of the way of construction activities. On subsequent projects the choice has been made to install the fiber after the switchgear has been installed, and just before commissioning, to avoid potentially costly repairs and/or replacement of the cable.

The second arc flash mitigation method used for the low voltage switchgear was a switch and status light that plant personnel could use to enable an instantaneous protection element while performing maintenance on the equipment. This “maintenance mode” option was provided on both the main and feeder breakers. On the main breakers, the scheme used a contact from a switch located on the main breaker to enable a second settings group in the electronic trip unit that included an instantaneous element. An output from the trip unit initiated a blinking blue light on the main breaker door to positively alert maintenance personnel that the breaker is in maintenance mode, while an additional output contact from the trip unit was used to alert plant control room operators that maintenance was being performed on the bus and that normal relay coordination on the bus had been compromised. On the feeder breakers, the scheme used a contact from a switch mounted on the equipment being fed (motor control center, power panel, etc.) to enable the second settings group in the electronic trip unit. An output from the trip unit initiated a blinking blue light on the remote equipment to positively alert maintenance personnel that the breaker is in maintenance mode. As with the main breaker, an additional output contact from the trip unit was used to alert plant operators. For both the main and feeder breaker it is important that the schemes be designed as fail safe so that the electronic trip unit reverted to “maintenance mode” anytime the signal between the maintenance switch and the trip unit was lost.

Figure 9 – 480V Feeder Breaker

Figure 10 – Maintenance Switch at 480V Panel

As an additional means of reducing the probability of an internal arc flash, the low voltage switchgear was equipped with an insulated bus with metal barriers between adjacent cable termination compartments. With these enhancements if an arcing fault were to occur, it is less likely that gases produced by the fault would spread to adjoining switchgear sections and create additional arcs. It also reduces the probability that the arcing fault will escalate into a three-phase fault.

The 480V switchgear was purchased with an integrated high-resistance grounding system. This system reduces the available ground fault current to approximately five amps and allows the plant to continue operation while maintenance personnel locate and clear a fault. One of the disadvantages of a high-resistance grounded system is lack of selectivity. When a ground fault occurs, a zero-sequence overvoltage relay is used to detect the fault and alarm the operator. Unfortunately, the alarm only indicates the presence of a ground fault somewhere on the entire 480V system and does not indicated the fault's location. To help narrow the search for ground faults, zero-sequence current transformers were installed with a 50/5 ratio on the load terminals of every feeder breaker. Each current transformer is connected to a current input on a protective relay which provides an alarm to maintenance personnel indicating which feeder is faulted. By narrowing in on a specific feeder breaker, the overall time to locate the ground fault can be dramatically reduced.

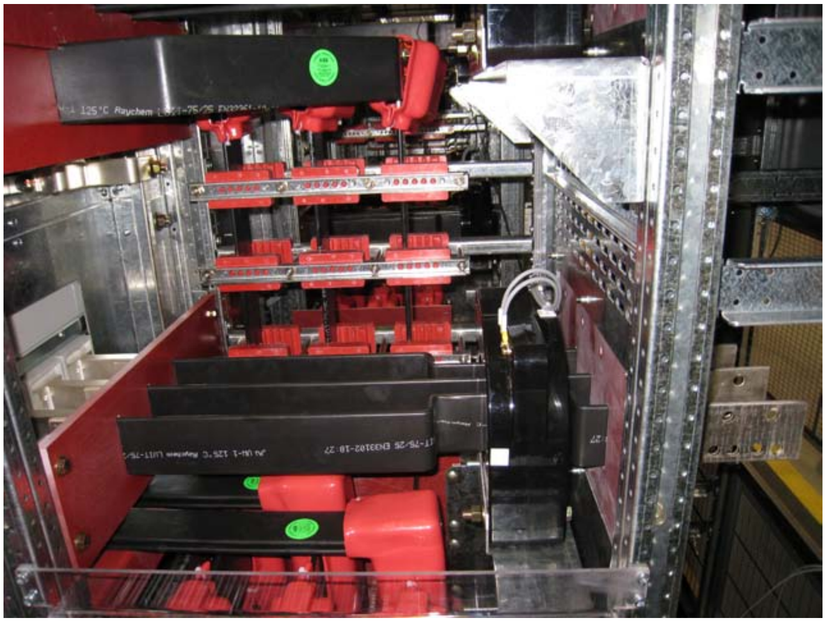

Figure 11 – 480V Switchgear Insulated Bus and Zero-Sequence CT

Turbine and Generator Upgrades

During the turbine efficiency upgrade portion of the project, the goal was to maximize the Net power output from this unit. Alstom Power supplied an upgraded HP-IP turbine that reused the existing GE outer case. The original turbine had a demonstrated capability of 375MW gross and 350MW net. The unit typically runs between 70 and 90 MVARS for a 99% power factor. The new turbine has a capability of 405 MW gross with a net generator URGE rating of 361 MW. The increased plant output more than offsets the additional station service load added during the project from the new AQCS equipment, as the net power output has increased by about 11MW as indicated in Figure 12.

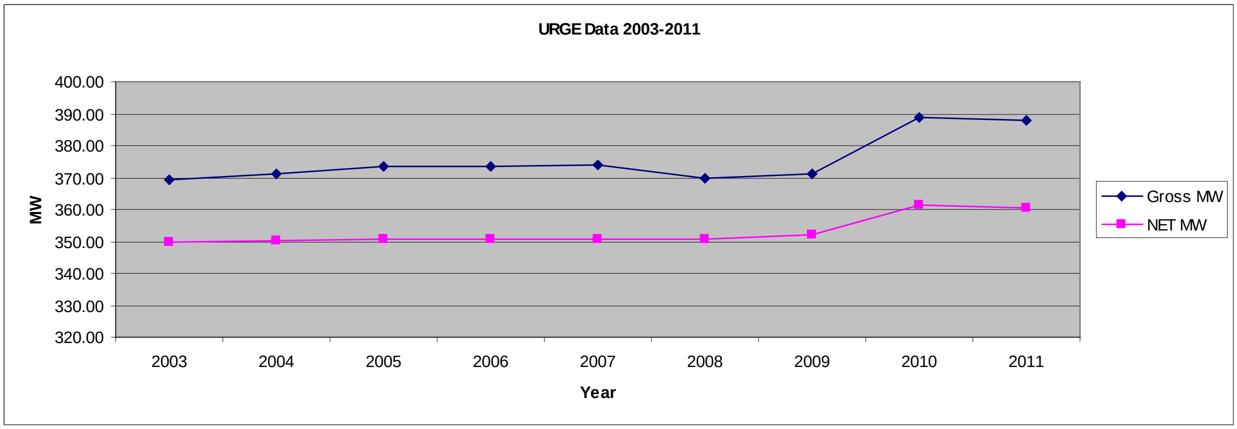

Figure 12 – Unit 3 URGE data for Net and Gross MW

In order to verify that the generator, iso-phase, and GSU systems could handle the additional output, studies were performed by GE and ABB. GE studied the generator itself as well as the iso-phase bus. The results of these studies indicate that the generator and exciter can handle the additional output. The original rating of the generator was 405MVA at a 90% power factor, where the new rating is 457.2 MVA at a 90% power factor. The iso-phase bus rating is sufficient to handle the additional load, so its rating remained unchanged at 12,000A (65 deg C rise, force cooled, 110 kV BIL, 1650 kA momentary). ABB performed a detailed study on the unit step up transformer, where the rating has remained unchanged at 380MVA.

Emissions Reduction

Emissions testing was performed on the AQCS equipment in January and February 2010 to determine if the systems met their specific design performance criteria. As noted in Figure 13 below, the performance of the FGD, SCR, and fabric filter baghouse exceeded the design performance criteria.

Constituent	**Baseline Filing Rate lb/MMBtu**	**Guarantee Rate lb/MMBtu**	**As Tested lb/MMBtu**
NO_x	0.37	0.05	0.029
SO_2	0.95	0.03	0.01
PM	0.21	0.0125	0.0105
Hg		90% Red.	94% Red.

Figure 13 – Boswell Unit 3 Emissions

Conclusion

Overall, the project was a great success as it exceeded its goals for emissions reduction, created an operationally safer electrical infrastructure, and was able to increase unit net power production. Several design methods used by the project team have been discussed for providing a reliable electrical infrastructure and reducing arc flash hazards for both medium and low voltage installations.