Welcome to tonight's City Council meeting!

The elected officials of the City of Bonners Ferry are appreciative of an involved constituency. Testimony from the public is encouraged concerning issues when addressed under the Public Hearing portion of the agenda. Any individual who wishes may address the council on any issue, whether on the agenda or not, during the Public Comments period. Normal business will preclude public participation during the business portion of the meeting with the discretion left to the Mayor and Council. Special accommodations to see, hear, or participate in the public meeting should be made at City Hall within two days of the public meeting.

Vision Statement

Bonners Ferry, "The Friendliest City", strives to achieve balanced growth, builds on community strengths, respects natural resources, promotes excellence in Government, and values quality of life. We are a city that welcomes all people.

AGENDA
CITY COUNCIL MEETING
Bonners Ferry City Hall
7232 Main Street
267-3105
February 2, 2021
6:00 pm

Join video Zoom meeting: https://zoom.us/j/17672764
Meeting ID: 176727634
Join by phone: 253-215-8782

PLEDGE OF ALLEGIANCE

PUBLIC COMMENTS

Each speaker will be allowed a maximum of three minutes, unless repeat testimony is requested by the Mayor/Council

REPORTS

Police/Fire/City Administrator/City Engineer/Economic Development Coordinator/Urban Renewal District/SPOT/Golf

CONSENT AGENDA – {action item}

1. Call to Order/Roll Call
2. Approval of Bills and Payroll
3. Approval of the January 19, 2021 meeting minutes

OLD BUSINESS

4. Discuss Visitors Center cleaning position (attachment) {action item}

NEW BUSINESS

5. **Electric** – Consider the Hydroelectric Control System review and recommendations from Ripplinger Engineering Laboratory (attachment) {action item}
6. **City** – Consider Office 365 migration and scope of service with Exbabylon (attachment) {action item}
7. **City** – Discuss possible wage audit (attachment) {action item}
8. **City** – Discuss purchases of less than $5,000 (attachment) {action item}

ADJOURNMENT

MINUTES
CITY COUNCIL MEETING
Bonners Ferry City Hall
7232 Main Street
267-3105
January 19, 2021
6:00 pm

Council President Rick Alonzo called the Council meeting of January 5, 2021 to order at 6:00 pm. Present for the meeting were: Council Members Adam Arthur, Valerie Thompson and Ron Smith. Also present were: City Attorney Andrakay Pluid, City Clerk/Treasurer Christine McNair, City Administrator Lisa Ailport, Economic Development Coordinator Dennis Weed and Police Chief Brian Zimmerman. Jerry Higgs, Denise Crichton, David Clark, Rose Shababy and Eric Lederhos.

Join video Zoom meeting: https://zoom.us/j/176727634
Meeting ID: 176727634
Join by phone: 253-215-8782

PLEDGE OF ALLEGIANCE

PUBLIC COMMENTS
Jerry Higgs said the Oath Keepers, Boogaloo Boys and Proud Boys have been added to the official list of terrorist groups.

REPORTS
City Administrator Lisa Ailport said the Electric Vehicle charging station rebate was received. The Water/Sewer position is generating interest. Dawson Brod passed his Commercial Driver's License (CDL) test.

Economic Development Coordinator Dennis Weed showed a segment from CBS news on the effects of the closure of the Canadian border crossing.

Ron Smith said the overall ridership for the SPOT bus has decreased 45%-56%. The SPOT bus is now allowed to deliver food to homes.

CONSENT AGENDA – {action item}
1. Call to Order/Roll Call
2. Approval of Bills and Payroll
3. Approval of the January 5, 2021 meeting minutes, January 12, 2021 Special Council meeting minutes, January 14, 2021 Special Council meeting minutes

Adam Arthur moved to approve the consent agenda. Rick Alonzo seconded the motion. The motion passed. Adam Arthur – yes, Valerie Thompson – yes, Rick Alonzo – yes, Ron Smith – yes

OLD BUSINESS

NEW BUSINESS
4. **Electric** – Consider authorizing the Mayor to sign the Network Operating Agreement with Bonneville Power Administration (attachment) {action item}

Mayor Staples asked if it is possible to wait until the next meeting to give Council enough time to completely review the document. Andrakay said it is possible. Adam asked if we currently have an agreement. Lisa said we do. This agreement does not include any monetary matters. Lisa said this agreement allows BPA to provide the City electrical services, this contract does not include any fiduciary obligations. Adam asked if there were any changes. Lisa said there is a collaborative group that recommends changes. Rick doesn't feel there is a problem signing this. Valerie Thompson moved to authorize the Mayor to sign the Network Operating Agreement and Exhibit C with Bonneville Power Administration. Rick Alonzo seconded the motion. The motion passed. Adam Arthur – yes, Valerie Thompson – yes, Rick Alonzo – yes, Ron Smith – yes

5. **Electric** – Consider authorizing the Mayor to sign the On-Call/Task Order Agreement with Financial Consulting Solutions Group, Inc (attachment) {action item}

Lisa said this group has helped us with the electric cost of service analysis. This agreement is to review the true-up for Idaho Forest Group. Rick Alonzo moved to authorize the Mayor to sign the On-Call/Task Order Agreement with Financial Consulting Solutions Group, Inc. Ron Smith seconded the motion. The motion passed. Adam Arthur – yes, Valerie Thompson – yes, Rick Alonzo – yes, Ron Smith – yes

6. **City** – Consider the draft City logo (attachment) {action item}
Lisa asked if this is the direction that Council wants to go. Ron asked if we will have one version of the logo. Lisa said we will have all three versions, but the circular version will be the main version.

7. **Street** – Consider the purchase of a Kubota Tractor (attachment) {action item}
Lisa said the purchase of equipment to maintain the new additions to the highway has been discussed for the last few years. This tractor comes with a snowblower and broom. Adam asked if we have something currently that is capable of doing the work. Lisa said the equipment we have is too big and too heavy and can damage the concrete and the grassy areas. Valerie asked if this will be able to do all of it. Lisa said mostly. Rick Alonzo moved to approve the purchase of a Kubota Tractor as described in the memo for a total purchase price of $33,870. Ron Smith seconded the motion. The motion passed. Adam Arthur – yes, Valerie Thompson – yes, Rick Alonzo – yes, Ron Smith – yes

8. **City** – Consider authorizing the Mayor to sign the contract with Innovate for mapping assistance (attachment) {action item}
Lisa said the City is in need of mapping assistance since an application was received that will involve the zone map and comprehensive plan. Lisa has full confidence in the contractor since she has worked with him personally. She knows his work ethic, workflow and his understanding of mapping systems. She feels Dan Spinosa will provide great leadership in this area. Ron asked if this has anything to do with mapping utilities. Lisa said yes. Valerie asked if we can use the information we currently have. Lisa said she is confident we will receive direction on how we can use our existing investments. Mayor Staples said he is apprehensive and wants to take some time and look at other options. Mayor Staples feels we are moving too fast and the rate schedule is relatively high. Valerie asked what other options the Mayor is considering. He has not had time to look at any other options. Rick asked if Lisa is willing to look at other options and bring this back to the next meeting. Lisa said that is possible, but she feels we will still be looking at the same company. Lisa said she has personal working experience with Mr. Spinosa and trusts his judgement and leadership. She will not have that knowledge of other contractors. Ron feels this is moving too fast as well. Adam asked if we expect to be over the $18,000. Lisa said she does not. Valerie Thompson moved to authorize the Mayor to sign the contract with Innovate so City mapping needs can be addressed as needed. Rick Alonzo seconded the motion. The motion passed. Adam Arthur – yes, Valerie Thompson – yes, Rick Alonzo – yes, Ron Smith – no

9. **City** – Discuss administrative approval of contracts (attachment) {action item}
Lisa said there have been several discussions regarding the ability to allow contracts to be approved by the appointed employees. Lisa said if Council is interested in pursuing this, a committee of staff members will be formed. Lisa likes the policy from the City of McCall. Mayor Staples asked if a contract has been approved with the need for payment come before Council. Lisa said the policy will state what is/is not authorized. Rick said he feels this is an expansion of what was done in the past and feels with parameters being established this would be a good thing. Valerie agrees that previously budgeted items shouldn't have to come before Council and feels if an item has not been budgeted it should come before Council. Ron asked about cost of services. Lisa said that will be described in the policy. Council agreed that this should be worked on.

10. **City** – Discuss the Visitors Center cleaning position {action item}
Christine said we have had a few peopled interested in the position but are not willing to take it since it is twice a day, every day. The restrooms are currently closed due to vandalism. Christine asked Council how they want to proceed in regard to hours of operation and frequency of cleaning. Mayor Staples asked the current hours. Christine said 24/7. Valerie asked if it is possible to clean them only once a day. Dennis said that will be difficult during the summer. Security and cameras were discussed. Adam asked if there is information on hours that are most used. Dennis said 6:00 am – 10:00 pm in the summer. This item was tabled until the next meeting.

11. **City** – Consider authorizing the closure of City Hall for training January 25, 2021 – January 28, 2021 {action item}
Christine said this is for the Tyler software programs. She is not sure how many of the clerk's employees will need to be involved. Valerie Thompson moved to close City Hall for training January 25, 2021 – January 28, 2021. Rick Alonzo seconded the motion. The motion passed. Adam Arthur – yes, Valerie Thompson – yes, Rick Alonzo – yes, Ron Smith – yes

ADJOURNMENT

The meeting adjourned at 7:13 pm.

CITY OF BONNERS FERRY

7232 Main Street
P.O. Box 149
Bonners Ferry, Idaho 83805
Phone: 208-267-3105 Fax: 208-267-4375

Memo

To: Mayor and City Council

From: Christine McNair, Clerk/Treasurer

Date: January 29, 2021

Re: Visitors Center Cleaning Position

Here are a few suggestions for the cleaning position:

Hours of operation: 8:00 am – 6:00 pm September 1 – April 14
8:00 am – 9:00 pm April 15 – August 31

Must be cleaned prior to opening. Police will lock the doors every night.

Rate of pay: $1,000 per month

MEMO

CITY OF BONNERS FERRY
CITY ENGINEER

Date: January 29, 2021
To: City Council
From: Mike Klaus, City Engineer
Subject: Moyie Hydro - Controls and Automation Analysis Report

Based on a contract from the fall of 2020 with Ripplinger Engineering Laboratory (REL), the City has received an analysis with recommendations for addressing the controls, programming, and automation issues at the Moyie Hydro. Terry Borden, of Adept Consulting worked under the direction of Craig Ripplinger (REL) to develop the attached report. Terry has extensive experience as a hydro system controls and operations leader.

The attached report provides a good summary of several controls and programming issues we have had at the Moyie powerhouse. During the analysis, Terry interviewed hydro staff, reviewed electrical drawings and programming, and produced an extensive list of recommendations for the City to consider. Currently staff is determining what recommended items in the report can by completed by staff, versus those items that will need to be completed by a contractor.

Moving forward, staff will work internally to complete items that we are capable of completing ourselves. Staff will also bring projects to Council for approval in the future that are derived from the attached report, that will require contractor help to complete.

Staff has reviewed this document and recommends Council adoption of the document as a basis for implementing controls and automation changes at the Moyie Hydro.

Please let me know if you have any questions.

Thank you,

Mike

Mike

Ripplinger Engineering Laboratories
Telephone: 509-892-1375
Internet: R.E.L@comcast.net
4117 N. Garry Rd.
Otis Orchards, WA 99027

REL

13 November 2020

Lisa Ailport and Mike Klaus, P.E.
City of Bonner's Ferry
7232 Main Street
Box 149
Bonner's Ferry, ID 83805

RE: Report Entitled "City of Bonners Ferry, Moyie River Hydroelectric Project Control System Review and Recommendations" (The Control System Review, CSR).

Dear Lisa and Mike:

I have reviewed the aforementioned report compiled by Terry Borden summarizing the efforts of the entire team of people from the City of Bonners, REL, Adept and independent Automation consultants. We agree with the findings, concerns and recommendations of this report.

REL was involved in the original project in 2006 with the task of setting the GE protective relay and Basler excitation settings as well as providing some basic on site information regarding hydro electric generator operations. The design, construction and implementation of the plant control systems were performed by others.

Unfortunately, plant legacy personnel were not fully integrated into the design process and this led to a control system design that was not familiar to plant operations personnel. Many of the control system operational characteristics have been modified or changed by automation personnel to the satisfaction of operations personnel. Some operational characteristics remain to be remedied. Therefore we agree with the recommendations of the CSR. Due to the nature of integrated control systems, the remedy of such systems requires a large investment of time and expenditure. We recommend this expenditure in order to bring the existing plant control system into conformance with the requirements of plant operations personnel and to industry standard operating procedures for both FERC and future operations personnel.

Fortunately, the control system installed in 2006 has provided adequate apparatus and machinery protection for the plant during normal and unattended operation. However with the possible lack of protective relay and other spares this may become a problem in the near future.

We believe that a careful consideration of the findings and recommendations of the CSR should be undertaken.

Sincerely,

Craig Allen Ripplinger

Craig A Ripplinger, P.E.

PROFESSIONAL ENGINEER
REGISTERED
9066
STATE OF IDAHO
CRAIG A. RIPPLINGER

Craig A Ripplinger
11/16/20

City of Bonners Ferry, Moyie River Hydroelectric Project
Control System Review & Recommendations

November 13, 2020

By
Terry Borden, Adept Consulting

Table of Contents

Scope

Adept Consulting was contracted by Ripplinger Engineering Laboratories to perform the following services for the City of Bonners Ferry, Moyie River Hydroelectric Project.

1. Develop a list of known issues, anomalies, and reoccurring problems with the existing generator control systems that have not been resolved to date.
2. Review the Moyie Hydroelectric Project documentation and software backup protocols. Provide recommendations that address any identified short comings or risk.
3. Develop a list of identified projects and make recommendations based on any identified short or long term risks for continued reliability of the Project.
4. Review a list of critical control and protection system spare parts, identify risks, and provide recommendations.

Background

The Moyie River Hydroelectric Project operates four turbine AC generators having a plant capacity of just under 5 megawatts. In 2006, the City of Bonners Ferry under took a capital project to modernize its existing generator controls on all four generators. CH2M Hill and E.L. Automation provided the design, engineering and programming for the new control systems. Since completion of the upgrades in 2006, there has been a number of issues that have not been fully resolved.

Control System Architecture

Each generator is controlled independently and consists of an Allen-Bradley 1769-L32E CompactLogix PLC Control System, PanelView Touch Panel (HMI), Basler DECS-200 Excitation Controller, GE-489 Generator Management Relay, L&S Governor Control System, and miscellanies peripherally devices.

In addition to the independent generator control systems, there is also a Plant Master PLC and a plant wide operator interface (HMI) computer running Rockwell Automation FactoryView software and Win911 alarm notification software.

Control System Communications

Communications between individual PLC's, local HMI's and the plant wide HMI computer is done through a plant wide Ethernet network. Communications between the individual generator PLC's, DECs-200 exciters, and GE-489 relays is done though RS-485 Modbus communication.

Reported Issues and Questions

Based solely on the operator notes, the following issues and questions were complied, reviewed, investigated and in most cases commented on. Where issues were reported, all efforts were made to investigate only those issues without deviating unnecessarily from the original scope of work. If there was a problem or issue that was later reported to be corrected, it was not included here. At the conclusion, the next section titled "Observations and Findings" will provide additional details into what was discovered while investigating and answering the following issues and questions.

Question: Does a phase loss in one generator building call for a shutdown of the generators in that building? A phase loss relay was installed in generator buildings 2&4, is this relay tied into the generator shutdown circuits? How come there is not a phase loss relay in generator building 1&3? Note: Phase loss is monitoring the governor pump three phase power.

Based on the documentation provided (drawings, PLC program, etc.), there is no phase loss shutdown of the generators that can be determined. With that said, it does not mean that this phase loss monitor is not providing a shutdown or alarming function and was not documented. Any new electrical device, regardless of function should be clearly documented on the plant electrical drawings(s). Phase loss monitors provide an important protective function to critical three-phase equipment and should be integrated into the existing control and alarming circuits as appropriate for the equipment to be protected. If a phase loss monitor(s) were installed, it should be a simple matter of documenting the installation and reviewing the action scheme(s) if any.

Question: How come some DC power circuits are not separately fused or is this normal?

The short answer is that it depends. The engineer who designed the control system must take into account many factors when designing the protective devices required for the system. Some of those factors include applicable codes and standards, primary versus supplemental protection, selective coordination, individual equipment protection and isolation, safety, etc. Control system engineers and equipment designers must choose appropriate protective devices to maintain the safety and reliability of their products and systems. Circuit protection devices protect expensive systems by rapidly disconnecting power to components in the event of an abnormal operating condition. Even though guidance exists in the form of the various electrical codes and standards, the wide variety of product offerings and specifications can make the proper selection of circuit protection devices a challenge. An understanding of circuit types and circuit protection products is critical to achieving their proper application. With that said, I will assume you are talking about the protection on the load side of the 24VDC power supplies which would typically be considered supplementary protection.

Supplementary protectors are circuit protective devices which are built to comply with UL 1077. As the name implies, supplementary protectors serve to supplement the circuit protection that is already in place. Where UL 489 devices are tasked with conductor protection, protection of the load is the primary purpose of selecting a UL 1077 device. Supplementary protectors are specifically targeted at protecting control circuits, including some of the following types of loads: solenoids, test equipment, controller I/O, relay or contactor coils, computers, transformers, power supplies, process instruments, and other control equipment. To be applied properly, supplementary protectors require that some form of upstream, branch circuit protection already be in place in the installation. The benefits of supplementary protection include precise protection of the load components, a small installed size, tripping selectivity, fault current limitation, and in many cases, isolation capabilities of the load component(s) for maintenance and repair.

It is worth noting that a DC power supply has limited available fault current that must be carefully considered when designing the rating of the supplementary protectors. Consider the design of a fuse or a miniature circuit breaker. Under a short circuit they are designed to operate when a significant amount of current is present, essentially from an "infinitely large" source with wire that is capable of carrying all the available current to the ground plane or opposite polarity. The protection device requires some amount of time to sense the high current levels. With a DC Power Supply, there is a limit to the available current. Circuit designers may oversize their power requirements to attempt to account for the need to supply sufficient current to trip these protective devices. With a circuit protection device (a fuse or circuit breaker) the circuit designer must account for additional current that may be required to trip the fuse or circuit breaker.

As you can see, there are many factors that go into selecting protective devices and we have only just scratched the surface. That is why it is imperative that careful consideration be given in the application and selection of protective devices in control systems and should only be done by a qualified engineer. See "Observations & Findings" for additional information.

Question: Are there shared PLC relays and if so, is this OK?

Not sure what is meant by "shared PLC relays". PLC Inputs provide indication of the state of field devices such as push buttons, selector switches, relay contacts, transducers, etc. PLC outputs on the other hand supply voltage or current signals to field devices such as lights, solenoids, relays, motor starters, actuators, etc.

I will assume you are talking about driving a single relay from two different PLC systems (outputs). There is nothing precluding the design engineer from not operating a single relay from two separate PLC systems or outputs if properly designed. Although this is not common, it is however done in applications where two separate PLC systems must operate a common device or function. As already mentioned, when this is done it must be carefully designed and certain codes or standards may apply.

Issue/Event: On 6/25/2020 placed generator 1 online in local/auto mode and built load to 650kW. Proceeded to place generator 3 online building RPM to 680 before turning sync switch on. Once the sync switch was turned on, the generator breaker immediately closed in and frequency was at 58 HZ. Load was not rejected and built load to 650kW. Went to generator 2 and found it offline due to a GPR electrical trip. When generator 2 was knocked offline there was no 86E or 86N lockout relay action. Computer alarm screen showed GPR Electrical Output Relay 2 active for generator 2. Why was generator 3 breaker allowed to close in with only 58 Hz? When generator 2 tripped offline, should there have been an 86E or 86N lockout relay action?

At this time, we do not know in this particular case why the generator breaker was allowed to close in with a 2Hz difference. When abnormal operating conditions occur or protective devices assert, it is very important that as much information be gathered at the time of the occurrence as is possible. Even the smallest details can become important in finding the root cause. Based on the drawings and documentation provided, there are only two conditions required to assert a 52G generator breaker close signal, PLC output relay 52GCL and sync check relay 25M.

The breaker close (52GCL) logic in the PLC is very simple and straightforward. If in local manual, an operation of the breaker close switch (52G/CS) by the operator will attempt to close the breaker. On the other hand, if in local or remote auto and the sync selection relay (25U) for that generator is energized along with the auto sync contact from the auto synchronizer (BE3-25A), the PLC will attempt to close the breaker. In both cases, the hardwired sync check relay (25M) contact must be closed in order to allow the breaker to close.

The 25M sync check relay provides contact closure when the slip frequency, phase angle, and voltage of the generator and bus are within predetermined limits. It should be noted that a simple sync check relay such as the 25M (PRS-250) should not be relied upon to ensure a smooth synchronization. Its purpose is to prevent a faulty synchronization with a generator significantly out of phase.

At the Moyie River Project, two generator synchronizing circuits go through a single synchronizing section of the MCP with a complicated arrangement of auxiliary relays and selector switch contacts to set up the various synchronizing scenarios. Due to the complexity of the circuitry and the large number of hidden failure points, troubleshooting a synchronizing problem can be very difficult. This complicated arrangement can be especially problematic where these devices monitor the same incoming and running voltage signals. If there is a problem that results in the application of incorrect voltage signals to the incoming or running circuits, a faulty synchronization could occur. Ideally, there should be no common-mode failure mechanisms between control functions and supervisory permissive functions that allow a faulty synchronization.

This event should not be dismissed and further investigation is warranted. See "Observations & Findings" for additional information.

Now to the question "When Generator 2 tripped offline, should there have been an 86E or 86N lockout relay action" The short answer is no. The HMI alarm screen for Unit 2 showed a "GPR Electrical Output Relay 2 Active" alarm. As currently programmed, the PLC will only issue a normal stop command if the status of Output Relay 2 in the GE-489 relay is active. Currently there are two alarm conditions programmed in the GE-489 relay for Unit 2 that will assert Output Relay 2, overcurrent and over frequency. The question becomes did the faulty synchronization of Unit 3 cause the GE-489 relay on Unit 2 to pick-up one of these two alarms? Most likely yes, the over frequency (60.5 Hz, 5.0s) alarm. An over frequency is most often associated with a rapid loss of system load, power governor action in a weak system, mechanical failure, etc. I believe when Unit 3 was placed online, the system saw a momentary large system load followed by a rapid loss of load causing a system over frequency condition.

See "Observations & Findings" for additional information on the "GPR Electrical Output Relay 2 Active" alarm and shutdown.

Issue/Event: On 7/3/2020 operator found both generators 2&4 offline with an 86E LOR action and no DC control power to the MCP panel. Operator found fuses FB-1 and FB-2 for the DC control power had both blown (opened). Blown fuses FB-1 and FB-2 were 5A fuses, drawings call for 10A fuses and operator replaced the fuses with the rating shown on the drawings. DC power was restored and generators were placed back online without issue. Generators 2&4 tripped offline at 1500hrs on 7/2/2020 (18hr outage). Why was there no alarms initiated to indicate that generators 2&4 tripped offline?

It does not appear that a failure of the 24VDC power source was contemplated with respect to alarming this condition to the operators. Based on operator notes dated 8/3/2020 a loss of communications was added to all PLC's to alarm a PLC fail (loss of power).

It was mentioned that both fuses FB-1 and FB-2 were blown and found to be 5A fuses which was not consistent with the as-built drawings and that is concerning. See "Observations & Findings" for additional information and recommendations.

Question: In reference to the issue of 7/3/2020, is there one or more 86E trip conditions for loss of DC control power? How come there is no hardwired signal back to the plant computer so that an alarm would be activated and the operator called out in such a case as this?

Yes, but only for the 125VDC control circuits. The 125VDC control power for the 86E, 86N, 94 and 52G circuits are being monitored for a loss of power. With the exception of the 86E, a loss of DC power to any one of the other circuits will trip the 86E lockout relay. If control power is lost to the 86E or the 52G circuits, the 94 will assert. As for the 24VDC control power, there is no direct monitoring of the 24VDC control power.

The plant computer hosts both the HMI software and operator notification software (Win911). The plant computer is a standard desktop computer that is not equipped for hardwired inputs. The Win911 software interrogates the FactoryTalk HMI software for alarm conditions based on how it has been configured. The Win911 software will dial out alarm messages either through a modem or voice over IP connection. The FactoryTalk HMI software in turn monitors the internal PLC tags for alarm conditions over the control system network (Ethernet). See "Observations & Findings" for additional information.

Issue/Event: On 7/11/2020 the main plant computer failed. Generators stayed online put there was no alarm call to the operators of this failure, how come?

If the plant computer fails, all software (Win911, FactoryTalk, etc.) running on that computer also stops working. There does not appear to be a means to detect and alarm a plant computer failure. See "Observations & Findings" for additional information and recommendations.

Issue/Event: On 7/22/2020 a test of the GPR 489 relay was conducted on generator 2. While the generator was running, the operators lowered the thrust bearing high temperature setpoint on the 489 until the unit tripped. The following alarms were shown on the main plant alarm screen:

- Alarm 40: unit 2 GPR active trip, alarm time 12:19:11 pm
- Alarm 44: unit 2 GPR bearing trip [output relay 4], alarm time 12:19:11 pm
- Alarm 10: unit 2 normal stop 86N relay trip, alarm time 12:19:07 pm
- Alarm 12: unit 2 generator circuit breaker trip, alarm time 12:19:07 pm
- Alarm 8: unit 2 E-Stop 86E relay trip, alarm time 12:19:07 pm
- Alarm 9: unit 2 E-Stop 86E relay trip by PLC, alarm time 12:19:07 pm

The 489 did not shutdown the generator as it shows info coming in four seconds after PLC trip. The 86N stop on all generators was supposed to have been eliminated from all generators so all would be 86E and close guard valve on shutdown from GPR or PLC.

> The GE-489 relay did initiate the shutdown of the generator through its hardwired output contact (R4) that is directly wired into the 86N trip circuit. The four second delay shown on the HMI alarm screen is the result of the programmed communication delays in reading information from the GE-489 by the PLC, including some degree of communication delay between the PLC and HMI. See "Observations & Findings" for additional information.

Issue/Event: Received copies of the hand written operator notes from 5/13/2020 to 8/19/2020. Most of the entries in these notes reference Albert and Steve's presence at the plant and the work they had performed.

- 5/20/2020 – Recent work done by Steve and Craig on GSU and no wire or terminal block numbers installed, Steve to complete.
- 6/17/2020 – Albert looked at Manual/Local Auto/Remote switch on MCP and found that Manual was never connected to the governor cabinet.
- 7/8/2020 – Albert and Steve to install another relay or device to watch heartbeats of all generator PLC's and do some programming in the computer which both said they had no idea how.
- 8/3/2020 – Albert programmed in new logic in PLC. The alarms that he programmed in are; loss of communications master PLC, 1&3 PLC, and 2&4 PLC. If either one loses communications with each other an alarm will be issued. This was tested and the alarms called out on Win911. We still need a power supply for the master PLC installed so it does not share with 1&3 PLC.

Issue/Event: On 3/13/2020 generators 2 and 4 tripped offline. Both generators were in forebay control. Forebay and trash rack levels showing okay. Generator 2 showed alarms 8, 9 and 12. Generator 4 showed alarms 8, 9, 10, 12, 16 and 17. Both units were placed back online, 45 minutes later Generator 4 tripped offline and showed alarms 8, 9 and 12. Generator 4 was placed online the next day without any problems. What event did the PLC see to call for a shutdown?

It appears that the initial shutdown of Unit 4 was caused by an over-speed condition as indicated by the alarms. The second shutdown of Unit 4 and the shutdown of Unit 2 is not clear. There is not enough information to definitively know what caused those shutdowns. Currently there are approximately seven trip conditions in which no alarm will be generated. See "Observations & Findings" for additional information.

Question: If we have some alarms and shutdowns marked as "Alarms\Unit_1\AL\#" and some marked "Alarms\Master_PLC\#", does this mean ones marked "AL" are 489 and ones marked "PLC" are watched and generated by those devices?

No, the HMI software monitors each PLC for alarm conditions. The generator PLC's interrogate the status of the GE-489 relays through the RS-489 communications link and makes that information available to the HMI as programmed in the PLC's.

Observations & Findings

The following findings and recommendations are based solely on a review of the electrical drawings and PLC program code while investigating the above questions, issues, and events. Because most of the reported issues involved the basic generator controls (start, stop, alarming), the areas of power control, level control, TIV control and communications was not extensively reviewed to remain within the intended scope of the project.

Temporary Changes

In reviewing the documentation and PLC logic, there are temporary changes in the form of PLC forces and AFI's, jumpers, etc. The question is whether these temporary changes are recent or old, and whether the Moyie staff is fully aware of these temporary conditions. It is highly recommended that a complete review of all PLC program codes, drawings and notes be undertaken to find, document and track these changes if this is not already being done

Temporary changes to the control system through hardwired or software modifications should be documented and tracked for follow up. Many times temporary changes can easily be forgotten and only discovered much later by accident or if an abnormal problem arises as a result of these temporary changes.

Generator Shutdown Conditions

In power plants, when an abnormal shutdown of a generator occurs, it is imperative that operators know what the reason was for the shutdown. For example, to roll an 86 lockout relay or the PLC initiates a shutdown and there is no alarm telling the operator why, is unacceptable in a modern generator control system. Every abnormal shutdown condition should have a corresponding alarm.

While reviewing the generator shutdown circuits and associated PLC logic, several concerns were noted as follows:

1) There is overlapping redundancy for some shutdown conditions. This has the potential to cause confusion for operators. For example, a governor emergency stop (65E) condition will trip the 86E lockout relay directly (hardwired). In turn, that same governor emergency stop will

cause the PLC to initiate an 86E trip output to the same 86E lockout relay. Now we have two separate 86E hardwired trip signals for the same condition. You might say "Well what's the problem, it provides redundancy." and that is true. But let's look at the alarms the operator would most likely have received:

- Unit Emergency Stop 86E Relay Trip Alarm
- Unit Emergency Stop 86E Relay Trip by PLC Alarm
- Unit Generator Breaker Trip Alarm
- PLC Emergency Stop – Governor E-Stop Alarm
- Governor Emergency Stop Alarm

All of those alarms are true but they are not all necessary and just adds confusion. A better approach would be to receive only the following alarms:

- Generator Shutdown or Generator Breaker Trip
- 86E Lockout Relay Trip
- Governor Initiated Emergency Stop (65E)

As you can see, these alarms are all that is needed for the operator to know why the generator shutdown. Since the governor emergency stop relay (65E) is a hardwired contact to the 86E lockout relay circuit as well as an input to the PLC, the PLC only needs to alarm the condition.

When and where possible, it is preferred that trip conditions to lockout relays like the 86E and 86N be hardwired directly from the devices doing the monitoring in addition to providing a PLC input for alarming and control.

If the desire is to have redundant tripping capabilities, then the PLC should be configured for backup monitoring and supervisor (secondary) tripping only. Since all 86 lockout trip conditions are monitored by the PLC as well as the 86 lockout relays themselves, it would be a simple matter of developing logic that monitors both the 86 trip conditions and the 86 itself. If a trip condition is detected and the 86 lockout relay does not trip, after a short delay, then the PLC could attempt to trip the 86 lockout relay or take other measures and alarm that abnormal condition. This way you achieve redundant tripping capabilities without having two separate contacts attempting to assert an 86 lockout trip for the same condition at the same time and creating numerous alarms that only add confusion for the operators.

2) Some generator trip conditions are currently not being alarmed for an operator to know why the generator shutdown. As mentioned previously, all conditions that could cause a generator to shutdown abnormally needs to be communicated (alarmed) to the operator in such a way that they know the reason for the shutdown. For example, the GE-489 Output Relay 2 on Units 1 & 2, if asserted, will cause the generators to shut down. The operators will only receive a GPR output Relay 2 alarm but will not know the reason why. See "GPR Setting Inconsistencies" next for additional information and recommendations.

Another example to share that is disconcerting. If the Unit Local/Remote selector switch is in the "Remote Auto" position and the generator breaker is open, it will initiate an 86E lockout action by the PLC. Under this condition, the operator would not know why the PLC tripped the 86E lockout relay.

3) Currently all PLC alarms have a programmed delay before being captured and alarmed. In some cases, you may not want to delay the capturing of an abnormal condition. This is especially true where the alarm itself does not assert an action but only alarms the condition. Delaying an alarm or action is not uncommon and in some cases necessary or desirable. But when the alarm itself is only being used to capture an event, it is desirable that it be done as quickly as physically possible so even a momentary condition is captured and can be alarmed or displayed.

Since all of the PLC's have alarm delay timers programmed into the alarming logic is potentially problematic in some cases. For example, let's say the 12HX relay picks up momentarily (1sec), the 86N lockout relay will assert since there is a 12HX contact hardwired in the 86N trip circuit. In this example the operator would not receive an alarm as to the cause of the 86N shutdown since the 12HX input to the PLC is only captured and alarmed after a 1.5 second delay.

As you can see the operator would not know what caused the 86N lockout action. This is only one example and used here to stress the need to further analyze all of the generator PLC alarms and remove delays where they are not needed.

FYI, the alarm "PLC Normal Stop – Overspeed High Alarm" will never likely be seen as it is currently programmed in the PLC and if functional, is one of those redundancy trip conditions we discussed previously.

4) In reviewing the various abnormal conditions that can cause a generator shutdown, some conditions may not be appropriately placed in the correct shutdown circuits or logic. As in the previous example above with the over speed relay 12HX, when picked up will also immediately initiate a voltage regulator stop signal. If the 12HX initiates an 86N lockout relay action which is designed to delay opening the generator breaker until the load is reduced (speed no load), why would we initiate a voltage regulator stop before the breaker is opened? The voltage regulator stop interlocks are already designed to issue a voltage regulator stop signal once the generator breaker opens when an 86N lockout relay is asserted. This makes no sense and the loss of excitation can present serious operating conditions for both the generator and the system.

Currently there are 34 different conditions that can causes a generator to shut down. Of those 34 conditions, 29 are considered abnormal conditions (not operator initiated) and 7 of those <u>will not</u> generate an alarm at all. There are also approximately 7 redundant trip conditions. Based on the cursory review conducted, there are clearly issues and concerns with the current generator shutdown design and alarming. Because of the number of issues and concerns raised, it is highly recommended that a comprehensive analysis of the entire generator shutdown circuits and software logic be undertaken and changes made as necessary.

GPR Setting Inconsistencies

There is currently discrepancies in the output relay settings for the four GE-489 generator protective relays. In generating Units 3 & 4, Output Relay 2 is not being used, whereas in Units 1 & 2 it is being used for some alarm conditions. Based on the notes received and discussions with the operators, it was believed that the GE-489 settings were changed on all four generators to remove Output Relay 2 alarms. This is not the case and the reason operators are still receiving shutdown and alarms associated with Output Relay 2 on generating Units 1 & 2. The PLC's are currently programmed to perform a normal shutdown if they see Output Relay 2 asserted and the operators will only receive a "GPR Electrical Trip Output Relay 2" alarm.

The output relay settings on all four GE-489's should be configured the same. If the intent was to remove Output Relay 2 in the settings for all four generators, the PLC shutdown and alarm logic associated with Output Relay 2 should have been removed from the PLC program. This would have assured that the generators would not shutdown regardless of how the Output Relay 2 was configured in the GE-489 settings and would have also made Output Relay 2 available for future use.

Loss of Communications Monitoring and Heartbeat Circuits

Based on the operator notes received, there has been recent modifications/additions made to improve the monitoring for a loss of communications with each generator PLC. This change was due to a recent control system power failure on one of the generator's that resulted in no alarms being generated to alert the operator to the failure. Because this is a recent change and limited information was available, no assessment was made. With that said, while reviewing the electrical drawings in appears that the PLC watchdog contacts shown on the 86N circuit drawings may not be shown correctly. Also, the monitoring of the automatic voltage regulator health (heartbeat) is only an alarm condition. If the automatic voltage regulator heartbeat contact asserts, it indicates one of two conditions have occurred with the voltage regulator. Either the voltage regulator has no control power applied or the voltage regulator software has stopped executing normally. I do not believe that the only action that should be taken is an operator alarm under this condition. If the voltage regulator is not functioning normally, you would most likely want to take the unit offline immediately.

DC Power Supplies & Fusing

Based on a review of the electrical drawings and operator notes, the following recommendations are made:

1. When paralleling 24VDC power supplies for backup operation, there should be a blocking diode placed in series in each power supplies positive (+) output as recommended by the manufacturer.
2. Make sure that the sum of power consumption by load and diode is not greater than the rated wattage of one of the 24VDC power supplies.
3. Recently the Moyie staff found improperly sized fuses installed in the 24VDC power circuits resulting in a generator outage. Because of this discovery it is highly recommended that all fuses be checked for proper size and type.
4. Consider providing separate fuses and isolation capabilities for the digital panel meter and PanelView HMI on each generator. This will provide separate protection and isolation capabilities for these devices.

5. The 24VDC control power for the Plant Master PLC should be derived from its own 24VDC power supply(s) that is supplied from the 125VDC battery system. Just like the generators, the Plant Master PLC should be an independent system.

Alarms and Sequence of Events

In reviewing the operator notes, reference was made to an incident where several GE-489 alarms had been time stamped 4 seconds after the initial shutdown alarms were received. This had caused some confusion for the operators as to who first initiated the generator shutdown, PLC or GE-489. Based on the alarm time stamps, it would make it appear that the PLC initiated the trip when in fact it was the GE-489 that initially tripped the unit. This example illustrates that in the current design, the HMI and PLC cannot provide for true sequence of event reporting. Operators need to understand this limitation. When an event occurs and alarms are generated, the order in which the alarms are displayed and/or time stamped may not reflect the actual order in which the events occurred. This is especially true when there is a single event that generates multiple alarms. As currently programmed, the PLC reads the status of the GE-489 relays through multiple message instructions that are sequentially executed. Because of this configuration, operators can expect to see these kinds of delays when receiving GE-489 alarms as was seen in this incident. Also, there are other factors that can contribute to delays in capturing events and reporting such as alarm delay times, general communications delays, etc.

Synchronization

As already discussed in great detail for the event of 06/25/2020 in which Unit 3 breaker was allowed to close in at 58Hz, see "Reported Issues & Questions", there is concern for the current synchronization design for the generators and careful consideration should be given to redesigning the synchronization scheme. A good time to revisit this would be when the GE-489 relays are replaced.

What was not reported from the event of 06/25/2020 were the actions, if any, that were taken to address the concerns raised with the 25M sync check relay. If the 25M sync check relay was suspected of not functioning correctly, it should have been tested. Was this done? If not, how do you know the relay is functioning correctly now?

Normal Stop viruses Emergency Stop

In most generator control schemes there are two methods that are employed to take a generator offline, uncontrolled and controlled. Uncontrolled is when the generator breaker is immediately opened regardless of load conditions and a controlled shutdown first reduces load on the generator before opening the breaker. Uncontrolled stopping of a generator should be reserved for only emergencies (86E). Reducing load on the generator before opening the generator breaker is the preferred method of stopping a generator.

In the operator notes received, there was this comment: "The 86N stop on all generators was supposed to have been eliminated from all generators so all would be 86E and close guard valve on shutdown from GPR or PLC". The function of the 86N lockout relay is to detect those abnormal conditions that do not require an emergency stop of the generator, but rather a controlled stop. I would highly recommend that only those conditions warranting an emergency stop of the generator be in the 86E lockout circuit and the 86N remain as designed. If the desire is to close the guard valve when an 86N trip is detected, then change the control logic to do just that rather than eliminating the function and purpose of the 86N lockout relay in the generator shutdown design.

Voltage Regulator Control

The voltage raise, lower and breaker status (52G) signals to the Basler DECS-200 voltage regulator are provided through a serial communication link (RS-485) between the PLC and DECS-200. When it comes to critical generator control signals between controlling devices, it is preferred that those signals be hardwired if at all possible. This is preferred in generator controls because of the increased fault tolerance and reliability. It is recommended that these signals be changed to hardwired inputs to the DECS-200 voltage regulators. If this change is made, a failure of the RS-485 communications link would not impact the ability to control the generator.

Wire and Terminal Block Labeling

It was observed during the site visit that there has been some recent additions to the MCP panels. No labels were found for the new devices nor were there any wire labels on any of the wiring that was added. This should be corrected as well as inspecting all electrical panels for adequate labeling of devices, wiring and terminal blocks. Improperly or missing wire labels can greatly increase troubleshooting times.

Hardwired Alarm Notification Devices

Since the Moyie Project has only a software based alarm notification system, which is only functional if the HMI computer is running, may wish to consider adding a hardwired alarm notification device as a supplement to the existing Win911 notification system. These devices are self-contained with battery backup. The disadvantage of these devices is the limited number of alarm conditions that can be monitored. But combining the two systems may give the kind of redundancy that is perhaps desired when the plant is not occupied.

Drawing Updates

While reviewing the PLC programs and I/O drawings, there are some PLC inputs and outputs that are being used, but not shown on the electrical drawings. For example:

- Unit 2 Input I:8/8
- Unit 2 Output O:10/8
- Units 1, 2, 3, & 4 Output O:10/15

The electrical drawings should be updated to include the device that is connected to these inputs and outputs. See "Documentation" section for additional information on drawings.

Documenting Abnormal Conditions

When abnormal operating conditions occur and it is not apparent what caused it, documenting system conditions and settings is critical when troubleshooting or when performing a root cause analysis. Even the smallest details should not be overlooked. Some power plants have what is called an "Abnormal Generator Trouble Report" form that helps to guide the operators in documenting and capturing system conditions. This type of form is unique to each power plant and generator. The information gathered on these forms can greatly assist maintenance and engineering staff in finding and fixing a problem, especially when the problem cannot be replicated.

General PLC Program Observations

Only about 15% of the PLC program code is devoted to control of the generator, and the other 85% to alarming, HMI, and communications. The basic generator control functions programmed into the PLC's are not complex. In fact, they may be over simplified. Additional information on the governor control system configuration is required in order to further determine whether there are any concerns with the interface logic. As already mentioned, the power, level and TIV control was not reviewed along with HMI and communication logic.

Summary of Recommendations

Priority	Description	Notes
1	Test and ensure Unit 3 sync check relay (25M) is functioning correctly and the settings are correct.	
2	Correct the GE-489 Output Relay 2 settings and remove this shutdown and alarm condition from the PLC's.	This should only take about an hour to perform by current staff.
3	Make sure all generator abnormal shutdown conditions are captured and alarmed.	Currently there are 7 shutdown conditions that will not alarm.
4	Remove alarm delay times where not required.	This is needed to ensure that all abnormal conditions are captured.
5	Investigate temporary changes and either remove, make permanent, or document for follow-up.	
6	Investigate further the reason for the 12HX stop signal to the exciter and consider removing.	
7	Consider adding the voltage regulator failure (heartbeat) to the shutdown logic.	
8	Eliminate overlapping and redundant shutdown conditions and alarms.	
9	Review all generator abnormal shutdown conditions and ensure they are properly located for the desired action (86E, 86N).	
10	Add blocking diodes to the 24VDC power supply outputs and check all existing fuses for correct	

	size and type.	
11	Install a separate and dedicated 24VDC power source for the plant Master PLC.	
12	Add device labels and wire numbers to devices recently added to the MCP if not already completed.	
13	Provide separate fusing and isolation for the panel meters and PanelView HMI's.	
14	Consider changing the voltage regulator control signals from the PLC to hardwired verses RS-485 communications.	
15	Consideration should be given to redesigning the synchronization scheme and circuits to improve fault tolerance.	During GE-489 relay replacement project.

Table 1 – Recommended Changes

Documentation

General

Control system documentation is one of the most overlooked components in a well maintained control system. The documentation process begins in the design phase and continues for the entire life of the system. In a well-designed control system, the documentation package provided to the end user is comprehensive, complete and accurate. Unfortunately most documentation packages suffer in one or more of those areas. To produce a good documentation package is time consuming and expensive. In a competitive market, this is one of those areas that is often sacrificed and easily overlooked. Unfortunately, it is the end users that pay the price for this substandard work.

How many times have you picked up a set of electrical drawings to only find that they do not accurately represent the current as-built conditions? Or a user manual that is no longer accurate or perhaps never was. What about that device that fails and during replacement you have no idea what the original (as-built) settings were. These types of failures in documentation increase downtime and cost, create frustration, risk safety, reliability and disseminate inaccurate information to operations and maintenance personnel. I think you are starting to get the picture of the importance that good control system documentation plays and it starts at the very beginning and does not end until the system is decommissioned.

The key to a good control system documentation package starts with the owner in developing a detailed project specification that includes the expectations for documentation before the project goes out to bid or the work is undertaken in-house. Remember, contractors are in the business of making money and will look for every opportunity to cut cost and increase profit. Details are the key when developing your expectations. The following list is an example of what you might expect in a medium size project. Keep in mind that this list may not be all inclusive or necessarily required for every project.

- Control System Functional Specification
- Comprehensive Electrical and Mechanical Drawing Packages
- Control System Operation and Maintenance Manuals
- Commissioning Plans and Procedures along with Commissioning Records
- Hardware and Software As-Built Setting Records
- Fully Documented Custom Software Codes
- Equipment Specific Operation and Maintenance Manuals
- Detailed Alarm Descriptions and Recommended Actions

Ideally all of the above should be provided in multiple copies in both hardcopy and electronic formats.

When the project is complete, the owner should have a documented plan on how and where those documents will be stored and updated. In addition to the above, the owner should develop and maintain control system change records and logs as well as documented backup procedures and processes.

In most power plants, a master copy of the above documentation is maintained in the control room or in a central location that is easily and quickly accessible to both operations and maintenance personnel. A single master set of hardcopy drawings should be maintained and immediately updated anytime a change is made to the control system. As mentioned above, control system change records and logs should be maintained and updated. These historical records should document the what, who and why of a change or replacement to a control system. Even the simplest change such as a relay or timer setting, or when backups are performed should be documented. This historical information can become critical when performing root cause analysis work, keeping operations and maintenance personnel informed of recent changes, or even to meet regulatory requirements.

With respect to documentation, the following observations and recommendations are solely based on the information provided at the time of this review. Adept Consulting received the following documents:

1. One black binder labeled "MRHP Start-up Documents, 322539 Moyie River Hydro SWGR & Control". This binder contained hand written drawings and notes, Mfg switchgear drawings with hand written notes, cable schedules, construction schematic drawings with hand written notes, and contract schematic drawings and schedules. Documents where dated very early 2006 and appear to have been used primarily for initial design and wiring installation/modifications. The documents in this binder do not indicate that they are in anyway representative of as-built conditions, but most likely used to assist in the initial wiring and modifications. These documents have little value with respect to being part of a final as-built documentation package.

2. One black binder labeled "Moyie River Powerhouse No. 2 Construction Drawings MCP 2, Unit 2, Synch 2&4, Unit 4: Schematic Drawings". This binder contained a complete set of MCP No. 2 electrical drawings dated early 2006, switch gear drawings, cable schedules with hand written notes and a second set of electrical control drawings. The title block on the electrical control drawings did not contain a revision block so it is unsure if these drawings are representative of the as-built conditions.
3. Nine (9) CD data disks containing varies electronic files including settings, backups, manuals, procurement specifications, etc.
4. Blue folder containing operator notes and comments.

In addition to the above, Adept Consulting also received by email electronic files that contained some electrical control drawings, PLC program files and GE-489 relay settings. These files were considered to represent current conditions and therefore were used extensively in the review process.

Electrical Drawings

The electrical drawings reviewed were consistent with industry practices, legible, and easy to follow. However, the following recommendations are made:

A master drawing book should be compiled that contains all electrical drawings relevant to the Moyie project and all drawings should represent the current as-built conditions. This book should be located in a central location and religiously kept updated. Do not have multiple copies of drawings scattered in various locations around the plant. This becomes problematic in that users may not be working with the most current conditions. It is not uncommon in many industrial plants to open an electrical panel and find a drawing(s) relevant to that electrical panel or equipment. In fact, many electrical enclosures have a built-in pocket designed specifically for that purpose. Drawings kept in electrical enclosures should be reserved for small dedicated machine type controls as supplied from the OEM. This practice should not be done in power plants. By having one master drawing book in one central location, all users know they are working with the most current drawings and it is much easier to maintain and manage. Copies of the master drawings should be made as may be required for troubleshooting, upgrade work, engineering studies, etc. But at the end of the day, the master copy is the only one that is considered to reflect current as-built conditions. When changes are made in the field, the master copy should be updated even if it is temporarily hand written.

Develop a policy and procedure for maintaining and updating drawings. This provides clear guidance and expectations to maintenance, operations and engineering staff on how they are to store, update and manage drawings. This policy should also address how electronic drawing files are managed.

It was apparent that some electrical drawings for the Moyie Project where not up to date. In some cases there were multiple copies stored in various locations with some showing hand written changes and others not.

Operations and Maintenance Manuals

The "Moyie Hydro-Electric Plant Operations Manual" received, was dated June 2007 and still showing to be in draft format. This was concerning in that this very important document was never finished or finalized, and may very well contain information that does not reflect current operating procedures or conditions. A power plant operations manual should be a living document that is continually updated. It is a key document used by operations staff, especially during abnormal operating situations and as a training document. A hardcopy of this document should reside in the control room or operations center and be readily available to the operator(s) at all times. The Moyie Project would be well served to complete and update this document. FERC does not look kindly on power plants that do not maintain up-to-date operations manuals.

A document titled "City of Bonners Ferry Moyie Dam RSView32-HMI Operators Manual" was also received and was dated September 2007. This document is outdated and most likely does not reflect the current HMI functions and screens. The same concerns expressed above with the plant operations manual apply here as well. This document is part of the overall operation manuals for the project. I would recommended that this document be updated and integrated into the "Moyie Hydro-Electric Plant Operations Manual" as one document.

The only maintenance manual received for review was the L&S Electric, Inc.'s Governor Model L&S-AB operation and maintenance manual. This manual is very well done and comprehensive. It is worth noting that the user manual states the following: "*The Operator interface program is not protected, and contains amongst the operations and tuning screens, <u>all of the configuration parameters and IO mapping for the particular governor application</u>. L&S Electric **strongly recommends** making a copy of this program to the customer's personal computer for future use in the event that the PLC or Operator interface needs replacement.*"

It is recommended that all equipment manuals be consolidated into one location (binders) and organized for easy access by both maintenance and operations staff. Most manufacturers can provide operation and maintenance manuals in PDF format at no cost.

Commissioning Documents

No formal commissioning documents or records were found, only a few hand written notes. These documents are critical during the commissioning phase for a new generator control systems and can provide an historical record of the as-commissioned conditions. A commissioning document provides several key functions. First, it defines the commissioning process or steps to ensure a safe startup of the equipment. Second, it defines the tests to be performed. And last, it provides an historical record of those tests results for future reference. A well done commissioning document will ensure that all control system functionality has been fully and completely tested, and that a generator is safe to be placed into service.

Because of the issues Bonners Ferry has had with abnormal generator operation and alarming, careful consideration should be given to developing and conducting some as-built functional tests. These tests could be conducted when generators are idle and staff is available.

Hardware and Software As-Built Setting Records

It is recommended that all hardware and software settings unique to each generator be recorded and added to the power plant documentation records. In some cases this can be a simple matter of printing a setting file. I recommend that both hardcopy and electronic backups be maintained of these settings for quick reference and recovery purposes.

Alarm Descriptions and Recommended Actions

It is highly recommended that a generator alarm reference be integrated into the existing operator manuals. In modern generator control systems there can be many if not hundreds of different alarms that can be generated. Sometimes these alarm messages are not very intuitive and leave operators wondering what the alarm is telling them, what are the conditions that triggered the alarm and what action should they take. There is nothing more frustrating for operators is to receive an alarm and not know what it means or what conditions triggered it, or what action to take if any. This type of document is very easy to develop by someone knowledgeable of the control system and can be very useful for operators, especially new ones in training. Below is an example of what you might expect to see in such a document.

Alarm Message	Description	Action
Alarm15:Unit 1 Unit Incomplete Start	This alarm is triggered if the generator unit enable relay (1-4EN) is active and either the generator breaker has not closed within 10 minutes while in auto mode, or in manual mode if the generator has not reached a speed of 684 rpm within 10 minutes after initiating a start of the generator.	Verify that the governor system is receiving a start permissive (1-69) and there are no alarms or faults showing on the governor system. If in Auto, verify that the auto synchronizer is functioning correctly. If in Manual, verify that the speed monitor tachometer is functioning correctly. Attempt to restart the generator.

Table 2 – Alarm Description Example

Backups

Based on the limited information received and discussions with the Moyie staff, it was not apparent that a formal software backup procedure or policy is in place. All software and setting files should be backed up after changes have been made as well as on an established schedule. These electronic files should be stored in a location and in such a way that they can be easily retrieved by maintenance personnel at the project site. An offsite backup copy of these files should also be maintained for emergency recovery in the event the onsite files are lost or corrupted. These offsite backup copies could reside on the corporate network that is routinely backed up or on a backup disc or other media that can be stored in a secure location. It is recommended that a backup file naming convention be established for consistency. When major software changes have been made, it is a good practice to retain a previous version in the event that you must restore the software to a previous known point.

Summary of Recommendations

Priority	Description	Notes
1	Update electrical drawings to as-built conditions.	
2	Update operations manuals.	
3	Develop policies and procedures for backing up all critical software and setting files.	
4	Assemble a master drawing book that contains all as-built electrical drawings.	
5	Develop policies and procedures for maintaining and updating drawings.	
6	Consider adding alarm descriptions and recommended actions to the existing operator manuals.	
7	Compile user and maintenance manuals into one location for easy reference.	

Table 3 – Documentation Recommendations

Potential Future Projects

On October 21, 2020 the Moyie project team met to discuss potential future projects. In attendance was Albert Solt, Craig Ripplinger, Adam Isaac, Brian Errett, Steve Neumeyer, Lisa Ailport, Pat Stevens, Kevin Cossairt, and Terry Borden.

The goal of this meeting was to establish a list of potential future projects that would improve operational reliability and safety at the Moyie River Hydroelectric Project. The following is a list of projects that the team felt should be further discussed and considered.

Fiber Optic Infrastructure

There is a desire and need to establish a fiber optic communications infrastructure between the Moyie Project, GSU substation, BPA substation and the City of Bonners Ferry. This fiber optic infrastructure, when installed, will provide the following benefits:

- Project monitoring through the addition and use of strategically placed cameras for increased operational monitoring, reduction in dam failure verification and notifications, and general project security monitoring.
- Electrical power system monitoring and a method for disconnecting interconnected generation (transfer-trip) in the event of a fault or other conditions where the utility source is lost.
- Remote access to generation plant automation systems for remote monitoring and troubleshooting by operations and maintenance personnel.

- Information sharing between the Project and the City offices. Improved backup and recovery of critical software and files.

Note: Currently there is a CARES Act funding that is underway that will bring fiber to within a mile of the Moyie Project. This project is slated to be completed before the end of 2020. When this project is complete, the team will reassess what may be required to bring the fiber the remaining way to the Moyie Project.

Local Distribution Load Reconfiguration

Currently there is a small number of commercial and residential loads being served between the GSU and BPA substations. In the event of a BPA substation trip, these loads would become islanded with the generation plant. To improve customer reliability, project isolation and system stability, it is desirable to relocate the distribution line feeding these loads to the BPA substation.

GE-489 Generator Management Relay Replacement

Currently each generator at the Moyie Project is monitored and protected by a GE-489 Generator Management Relay. In 2018, GE announced the discontinuation of manufacture and sale of the 489 relays. GE will continue to sell the 489 relays, subject to availability, until December 31, 2021.

Currently the Moyie Project has one spare GE-489 relay in stock. Careful consideration should be given to developing a replacement plan for the GE-489 relays. Although GE is recommending their newest generator management relay, the GE-889 as a replacement to the 489, this would be a good time to review the alternatives to the GE-889 that are on the market today.

The replacement of the GE-489 relays will provide opportunities for improvements to the existing protection and control schemes used by the generators in the form of improved communication options (Ethernet), dedicated synchronization capabilities, etc.

Wide Area SCADA Network

There was interest in considering the development of a city wide SCADA network for remote monitoring of the cities various utilities and systems. The key to developing a wide area network is the requirement for a dedicated and secure communications infrastructure (fiber, radio, microwave, copper, etc.) to support such a network. The fiber optic project mentioned previously between the Moyie Project and City Hall would certainly provide a good start to that end goal.

Improved Operator Communications

Currently the Moyie Hydroelectric Project has limited availability of cellular service. This limits the outside communications capabilities of the operator(s) during emergencies or other times when it is necessary for the operator(s) to be away from the control room. Improving communications at the project site will greatly increase response, monitoring and safety during emergencies or when system problems arise.

There are several options available that would improve the existing communications. 1) Install a cellular fiber optic repeater. This is a low cost, reliable and easy to install solution that will increase cell phone signal coverage without compromising signal strength. With the future installation of fiber to the project site, this would allow antennas to be mounted miles away from the cellular repeater. 2) Install a land based mobile radio system with the ability to make and receive calls as well as communicate to other mobile users. 3) Purchase a satellite phone for emergency use only. Table 4 provides some pros and cons for each of the above options.

Options	Pros	Cons	Cost
Cellular Fiber Optic Repeater	Relatively inexpensive, use existing cell phones	Requires fiber optic link between locations, cell tower with good signal strength within range of the fiber, repeater power requirements	*TBD
Mobile Radios	Mobile to mobile and mobile to phone communications, expandable	Initial equipment and installation costs, site survey to determine required access points required	*TBD
Satellite Phone	Can be used anywhere there is a clear view of the sky, no antenna or cables to install, minimal equipment to purchase, no installation costs	Reoccurring costs, will not work inside buildings	*TBD

Table 4 – Operator Communications Options
*TBD: To Be Determined

Physical Security

There was a desire by the team to consider improving physical security at the Moyie Project as well as at other city owned locations. Some of the recommendations were increased fencing, cameras with advanced features like motion detection and alarming, access monitoring and alarming.

Improved EAP Notification

Currently the Moyie Project is considered to be a high risk project by FERC because of the potential for loss of life downstream of the dam in the event of a catastrophic failure. The current time for detection and notification is too long, resulting in the potential for loss of life. FERC has asked that the Project consider improving detection and notification times to reduce this risk.

The installation of fiber and strategical placed cameras will improving remote monitoring and verification of project conditions when the project is unmanned. Improving the means of notification for downstream residences and business is also being considered. The goal of the team is to assess the feasibility and options for a downstream notification method.

PLC Control Systems Hardware & Software

The generator controls were upgraded in 2006 with state of the art programmable logic controllers (PLC) and associated equipment. The PLC system installed at the time was an Allen-Bradly CompactLogix Control System. The PLC hardware is still supported and sold today. Robust PLC equipment like the Allen-Bradley PLC's if properly maintained and operated within the environmental specifications, will have a very long life span. Nothing was observed that would indicate that the current PLC equipment needs replaced or upgraded at this time or within the very near future. With that said, the current PLC controller firmware is outdated and should be upgraded. A firmware upgrade of the PLC processor is not difficult or expensive. But it does require the correct version of programming software to perform the firmware upgrade. In addition, there may be some minor changes required in the PLC program, but these changes would be very minor if at all. It is recommended that the Moyie project team consider upgrading the Allen-Bradly PLC controller firmware in all PLC's.

Governor Controls

There were no serious issues or problems with the governor control systems that was reported by the team. There was however a concern raised with the use of DeviceNet by the governor control system. A DeviceNet network is a network that provides open, device-level control and information for simple industrial devices. DeviceNet is not obsolete yet. It is however on the downward trend in favor of Ethernet (EtherNet/IP, ProfiNet IO, Modbus TCP, OPC UA).

It is recommended that no further action be taken at this time or in the near future with the governor control system unless serious problems arise. FYI, the governor control system uses the same Allen-Bradley CompactLogix Controller System that is used for the generator controls.

Plant HMI Computer/Server

The team brought up the concern that the current plant HMI computers are no longer supported and should be replaced. The plant HMI software (FactoryView) and the Win911 alarm notification software are critical to the safe and reliable operation of the power plant. Every effort should be made to maintain these systems at peak performance and at current standards. Backup and recovery plans and methods should be developed to ensure that a failure of these critical systems can be quickly recovered. Since these computer systems are an open window into the generator control systems, it is imperative that robust security measures be implemented to prevent unauthorized remote access to these computers by unwanted persons. Remote access should be limited to just plant operators and IT personnel.

Summary of Future Projects

Priority	Project	Estimated Cost	Notes
1	Fiber Optic Infrastructure Installation	*TBD	
2	Plant Computer/Server Replacement	*TBD	
3	Operator Communications Improvements	*TBD	
4	Improved EAP Notification Methods	*TBD	
5	Control System Hardware &	*TBD	

	Software Updates		
6	Local Load Distribution Reconfiguration	*TBD	
7	Generator GE-489 Protective Relay Replacement	*TBD	
8	Wide Area SCADA Network	*TBD	

Table 5 – Future Projects
*TBD: To Be Determined

Spare Parts

Limited information was provided on spare parts. No assessment or recommendations are being provided at this time.

CITY OF BONNERS FERRY

7232 Main Street
P.O. Box 149
Bonners Ferry, Idaho 83805
Phone: 208-267-3105 Fax: 208-267-4375

TO: Mayor and City Council

FROM: Lisa Ailport, City Administrator

DATE: January 26, 2021

RE: **Office 365 Migration**

One of the tasks identified by our IT consultant early last year was the need to address our storage system and functionality of our mail server. Currently, the server is limited in both storage and firmware and can not be expanded upon. Consequently, the only way to address the need for additional storage is to replace the system with something new and/or different altogether. This task is important to us because accessing both existing and archived emails is an important part of conducting city business. Not to mention that many Freedom of Information Act request include both current and possibly archived emails.

In order to continue to receive emails, we have to continually eliminate older stored data on the mail server, and it is only a matter of time before either the system can no longer be accessible due to lack of firmware updates, or the storage "breaks" because of age, upkeep etc. Staff recommends fixing this issue, immediately.

In review of options with the IT manager, our recommendation to Council is to migrate to Microsoft Office 365, which operates as a "software-as-a-service" model and uses Microsoft's cloud-based email. What this means is the city would move all our stations to Office 365 which costs between $5.00-12.50 per month per station which includes the cloud-based email with the cost. The subscription provides access to updated versions of Microsoft products such as word, excel, outlook and PowerPoint.

To accomplish this our IT manager needs assistances. The attached estimated includes a cost for Xbabylon to assist in the migration of all our users to Office 365 and cloud-based services. Xbabylon anticipates that they will need about 24-40 hours of time to complete the migration much of that will likely occur offsite. Additionally, their standard cloud security configuration is a flat rate of $1,000.00.

A cost comparison for consideration is provided which includes the migration to Office 365 or keeping a similar set up to what we have now. Staying with the existing system does provide for times when we experience fewer expenses year to year, but we know we'll have peaks and valleys when it comes to required large investments. However, if migration is supported, staff anticipates cost savings will occur in staff time because we will have less management, less hardware purchases and more supported services by Microsoft. Also, updated versions of Microsoft software will be provided without the need of staff to install or do updates.

If we keep the current model, it is likely that we will have to purchase perpetual licenses every 3-5 years to keep up with changes that make older versions obsolete. Furthermore, we have already transitioned some stations to Office 365 due to the cost of purchasing perpetual licenses. We made the change to office 365 in the Police Department when we upgraded their computers to Windows 10. The cost to purchase at least eight perpetual licenses at one time at a cost of ±440 a piece was too much for the police department to cover. We currently have 11 Microsoft Office 365 monthly subscriptions we are paying for.

Below is an estimated cost summary of both keeping the existing mail server or going with the Office 365 option.

Estimated Yearly Reoccurring Costs	**Office 365**	**Mail Server**
Office 365- with hosted email	$4,500-$5,100.00	
Perpetual License		±2,500.00 (5 per yr.)
Barracuda license software		$1,800.00
Mail Server Hosting (sequel and exchange)		$2,000.00
Total	**$5,100.00**	**$7,300.00, plus**

Fixed Costs	**Office 365**	**Mail Server**
Xbabylon – mail migration	$6,800.00	

Staff recommendation is that we fully migrate to Office 365, software-as-a-service, instead of investing in another email server. It seems the appropriate time to do this is when we need to make system wide upgrades and updates. Consequently, we may be forced to do this in the future if Microsoft chooses to eliminate the static perpetual licenses. Moving to the migrated Office 365 does more than just update emails, it keeps up current with new Microsoft programs and allows us to free up our part time IT managers time now and in the future.

Please let me know if you have any questions.

exbabylon
professional IT solutions

Office 365 Migration Project

Client: City of Bonners Ferry

Updated: 12/29/2020

Revision: 1.0

Project Summary

Exbabylon will be managing the implementation and migration of the existing City of Bonners Ferry Exchange email and Microsoft Office platform to Microsoft Office 365 platform.

When completed, this project will accomplish/address the following goals:

1. New Microsoft Cloud and Azure AD Tenancy including Single Sign On (SSO) with on-premises Active Directory
2. All Exchange 2013 services will be handled by the secure Microsoft Office 365 cloud
3. Onsite Exchange server(s) will be demoted and removed
4. Sharepoint Online will be prepared and ready for on-premises migration

Project Scope

Most of the project work performed by Exbabylon will be performed remotely, with onsite visits as needed. A local, designated project manager will be assigned with weekly status calls between team members to ensure smooth migration.

Exbabylon will be performing the following as part of their role in this project:

- Engineer and plan Hybrid Migration of existing Exchange 2013 platform to Office 365 hosted Exchange
- Manage DNS and domain changes as needed
- Identify potential roadblocks
- Design strategy to overcome identified roadblocks
- Assist with Office 365 Licensing Agreement and contracts
- Configure on premise Exchange server and perform all server-side work
- Manage Microsoft Office 365 and all cloud-side configurations include Azure AD
- Work with client staff to identify phased user migration blocks
- Manage Mailbox, Public Folder Migrations
- Assist with end user support for initial migration batch
- Decommission existing Exchange server(s) once migration is complete
- Provide training for IT staff and management as needed for ongoing management
- Assist IT staff as needed remotely or onsite

The City of Bonners Ferry will be responsible for the following:

- Adjust and cleanup to existing network as needed for roll out to end users
- Provide access to on-premises environment including Domain Admin credentials
- Roll out upgrades of Office to all users as needed
- Perform Windows OS upgrades as needed to support Office 365
- Migrate users in designated phases and provide user support as needed
- Provide end user support before, during and post migration
- Configuring firewalls and network rules as needed

Project Timeline

Estimated project milestones are outlined below to give a rough outlook on what project timelines should be expected. This represents a conservative timeline which may be accelerated at various milestones depending on various elements and the speed at which the various batches can be handled by both Exbabylon and the client support team.

Jan 18 – Jan 31

- Complete Microsoft Agreement, Exbabylon
- Upgrade Windows and/or Office on all Workstations as required, City IT Staff
- Perform required updates on existing Exchange environment, Exbabylon
- Project Engineering & Planning, Exbabylon

Feb 1 – Feb 13

- Technical Connections to Office 365, Exbabylon
- Configure DNS and Staged Migration Components, Exbabylon
- Prepare & Perform Test Migration Batch, Exbabylon
- Identify First Stage Migration Users, client & Exbabylon

Feb 14 – Feb 20

- Perform First Stage Migration Batch, Exbabylon
- Support First Stage Migration Users, City IT Staff
- Review & Discuss First Batch Migration, Exbabylon & City IT Staff

Feb 21 – Mar 13

- Migrate Additional Users by Staged Batch, Exbabylon
- Support Migrated Users as Needed, City IT Staff
- Provide IT Staff Training
- Complete Cloud Security Review & Make Adjustments, Exbabylon & City IT Staff

Mar 14 – Mar 21

- Uninstall & Remove Existing Exchange 2013 Server(s), Exbabylon & City IT Staff
- Configure Sharepoint Online to initial baseline best practices, Exbabylon
- Perform Final Project Review, Exbabylon & City IT Staff

Estimated costs

Labor for this project has been estimated as follows:

Project Item Description	Estimated Cost
Engineering, Network & Server Labor *(Est. 24-40 hours @ $145/hr)*	$3,625-$5,800
Exbabylon Standard Cloud Security Configuration	$1,000
End User & Client Computer Support/Service (bills at $95/hr if needed)	0
Estimated Initial Project Total *(applicable tax not included)*	**~$4,625-$6,800***

Monthly Service	Estimated Cost
Microsoft 365 Business Standard (replaces ProPlus, see below)	20 @ $15
Microsoft 365 Business Basic	5 @ $5
Microsoft 365 Managed Security	$100
Total Estimated Monthly Service Cost	**$425/mo**
Less Existing Microsoft Office ProPlus Licensing	(11 @ $10)
Final Estimated Net Monthly Cost Increase*	**$315/mo***

*Other savings or cost reductions may be available including removal of on-premise email filtering services, future cost for Microsoft Exchange licensing and backup/storage costs which may not be necessary post migration.