ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 320
Salt Lake City, UT 84116

May 3, 2017

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: In the Matter of the Application of PacifiCorp d/b/a Rocky Mountain Power's Request for a Declaratory Ruling regarding Allocation of Interconnection Costs under the Public Utility Regulatory Policies Act.
Docket No. 17-035-25

Dear Mr. Widerburg:

Rocky Mountain Power (the "Company") hereby supplements its May 1, 2017, Request for a Declaratory Ruling in the above referenced matter.

In its Request, the Company referenced a representative system impact study that it intended to attach to its filing as <u>Attachment A</u>. Attached hereto is that system impact study, <u>Attachment A</u>, referenced in the Company's Request, for filing. The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred):	datarequest@pacificorp.com bob.lively@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

Informal inquiries may be directed to Bob Lively, Manager, Utah Regulatory Affairs at (801) 220-4052.

Sincerely,

Yvonne R. Hogle

Yvonne R. Hogle
Assistant General Counsel, Rocky Mountain Power

Cc: Service List

CERTIFICATE OF SERVICE

Docket 17-035-25

I hereby certify that on May 3, 2017, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services
Cheryl Murray - cmurray@utah.gov
Michele Beck - mbeck@utah.gov

Division of Public Utilities
Chris Parker - ChrisParker@utah.gov
William Powell - wpowell@utah.gov
Erika Tedder - etedder@utah.gov

Katie Savarin
Katie Savarin
Coordinator, Regulatory Operations

Attachment A

System Impact Study Report

Large Generator Interconnection
System Impact Study Report

Completed for

("Interconnection Customer")
Q0710

Proposed Point of Interconnection

PacifiCorp's Sigurd-Glen Canyon 230 kV transmission line

July 27, 2016

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1.0 DESCRIPTION OF THE GENERATING FACILITY

("Interconnection Customer") proposed interconnecting 240 MW of new generation to PacifiCorp's ("Transmission Provider") Sigurd-Glen Canyon 230 kV transmission line located in Kane County, Utah. The project ("Project") will consist of 159 Power Electronics FS1500CU inverters for a total output of 240 MW. The requested commercial operation date is December 19, 2019.

Interconnection Customer will NOT operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the Project "Q0710."

2.0 SCOPE OF THE STUDY

The interconnection system impact study shall evaluate the impact of the proposed interconnection on the reliability of the transmission system. The interconnection system impact study will consider Base Case as well as all generating facilities (and with respect to (iii) below, an identified network upgrades associated with such higher queued interconnection) that, on the date the interconnection system impact study is commenced:

(i) are directly interconnected to the transmission system;
(ii) are interconnected to Affected Systems and may have an impact on the interconnection request;
(iii) have a pending higher queued interconnection request to interconnect to the transmission system; and
(iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

The interconnection system impact study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The interconnection system impact study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The interconnection system impact study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of the cost responsibility and a non-binding good faith estimated time to construct.

3.0 TYPE OF INTERCONNECTION SERVICE

The Interconnection Customer has selected a *Network Resource (NR)* with *Energy Resource (ER)* type interconnection. The Interconnection Customer will select NR or ER prior to the Facilities Study.

4.0 DESCRIPTION OF PROPOSED INTERCONNECTION

The Interconnection Customer's proposed Generating Facility is to be interconnected to Transmission Provider's existing Sigurd – Glen Canyon 230 kV line. Figure 1 is a one-line diagram that illustrates the interconnection of the proposed Generating Facility to the Transmission Provider's system.

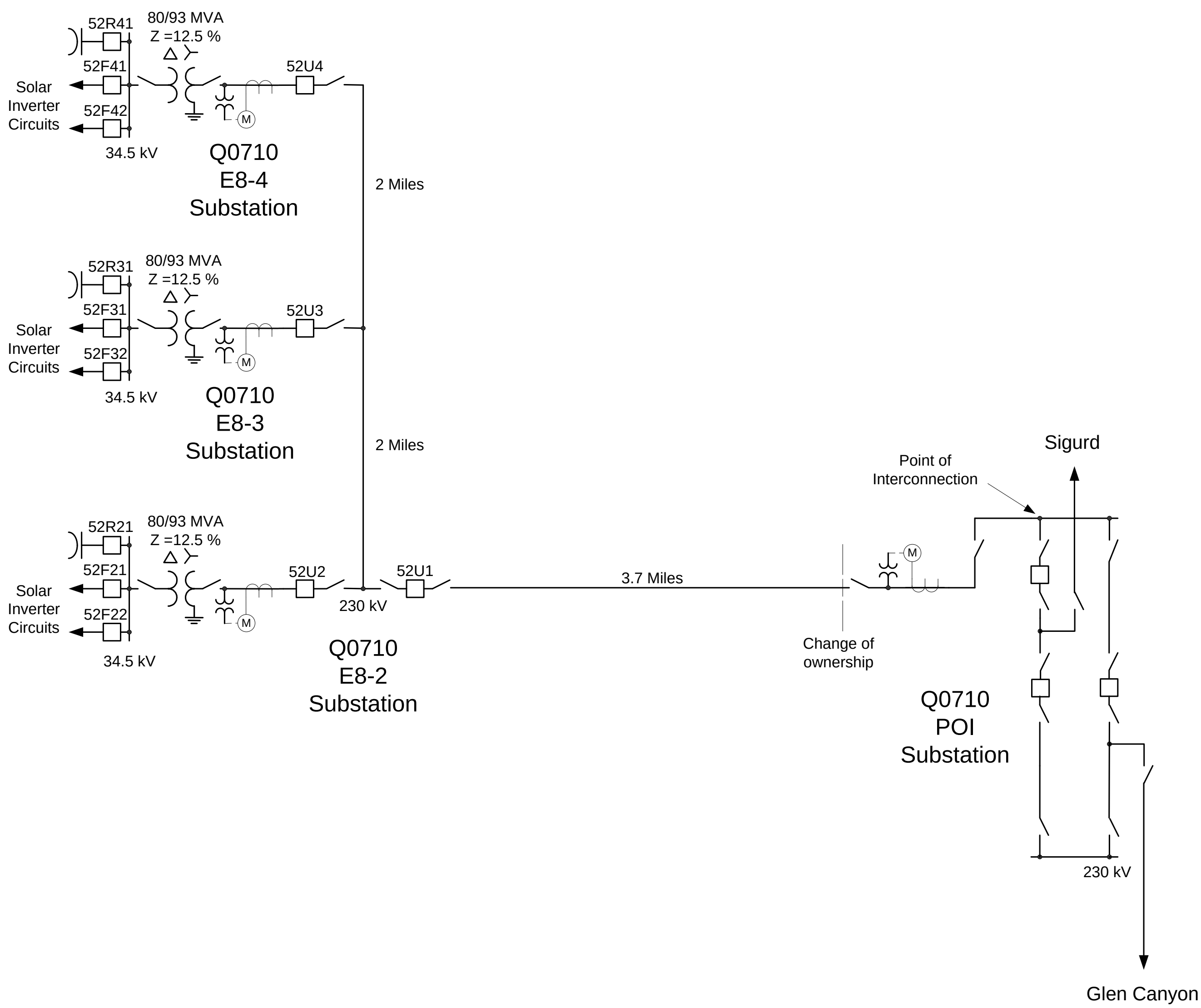


Figure 1: Simplified System One Line Diagram

4.1 Other Options Considered

The following alternative options were considered as potential points of interconnection for this Project: None.

5.0 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, and the results and conclusions could significantly change.
- The Transmission Provider reserves the right to restudy this project should the interconnection customer request a change in status to a Qualifying Facility.
- For study purposes there are two separate queues:
  - Transmission Service Queue: To the extent practical, all network upgrades that are required to accommodate active transmission service requests submitted prior to the Interconnection Customer’s generation interconnection request will be modeled in this study.
  - Generation Interconnection Queue: Interconnection facilities associated with higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer’s request for energy or network resource interconnection service in and of itself does not convey transmission service. Only a Network Customer may make a request to designate a generating resource as a Network Resource. Because the queue of higher priority transmission service requests may be different when a Network Customer requests network resource designation for this Generating Facility, the available capacity or transmission modifications, if any, necessary to provide Network Resource Interconnection Service may be significantly different. Therefore, the Interconnection Customer should regard the results of this study as informational rather than final.
- Under normal conditions, the Transmission Provider does not dispatch or otherwise directly control or regulate the output of Generating Facility. Therefore, the need for transmission modifications, if any, which are required to provide Network Resource Interconnection Service will be evaluated on the basis of 100 percent deliverability (i.e., no displacement of other resources in the same area).
- This study assumes the Project will be integrated into the Transmission Provider’s system on the Sigurd – Glen Canyon 230 kV line.
- The Interconnection Customer will construct and own any facilities required between the Point of Change of Ownership and the Project unless specifically identified by the Transmission Provider.
- Generator tripping will be required for certain outages. Also, generation curtailment up to 100% of its capacity will be required to resolve any operational issues identified in the area.
- Additional system reconfiguration/improvements related to prior queued interconnection projects are assumed to be in-service:
  1. Looping the existing 230 kV line between Parowan and West Cedar in and out of the Three Peaks substation and converting operation to 138 kV

2. Installing a second 345/138 kV transformer at Three Peaks as identified in the Network Resource section of a prior queue
3. Adding a second 230/138 kV transformer at Parowan substation
4. Increasing the Sigurd – Q0634 POI line rating to at least 345 MVA by fixing the spans on the 230 kV line to increase clearance
5. Installing a remedial action scheme related to Q589, Q0634 (loss of any of the Sigurd 345/230 kV transformers, loss of the Sigurd – Q0634 POI 230 kV line)

- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and the Transmission Provider's performance and design standards.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Transmission Provider's web site regularly for Transmission System updates at http://www.pacificorp.com/tran.html

6.0 ENERGY RESOURCE (ER) INTERCONNECTION SERVICE

Energy Resource Interconnection Service allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System and to be eligible to deliver electric output using firm or non-firm transmission capacity on an as available basis.

6.1 Requirements

6.1.1 Generating Facility Modifications

All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.

For synchronous generators, the power factor requirement is to be measured at the Point of Interconnection ("POI"). For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation.

The Generating Facility must provide dynamic reactive power to the system in support of both voltage scheduling and contingency events that require transient voltage support, and must be able to provide reactive capability over the full range of real power output.

If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility must be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization (or directive) from the grid operator is given to operate in another control mode (e.g. constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the POI. In general, Generating Facilities should be operated so as to maintain the voltage at the POI, or other designated point as deemed appropriated by Transmission Provider, between 1.00 per unit to 1.04 per unit. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions.

Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among Generating Facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing.

For areas with multiple Generating Facilities, additional studies may be required to determine whether or not critical interactions, including but not limited to control systems, exist. These studies, to be coordinated with Transmission Provider, will be the responsibility of the Interconnection Customer. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generating Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

Phasor Measurement Units (PMUs) will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

All generators must meet the Federal Energy Regulatory Committee (FERC) and WECC low voltage ride-through requirements as specified in the interconnection agreement.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

6.1.2 Transmission System Modifications

Transmission system improvements required to interconnect Q0710 as an Energy Resource are as follows:

1. Construct a new three-breaker 230 kV ring bus substation at the POI on the Sigurd – Glen Canyon 230 kV line with switches and line terminations (see Figure 1).

<u>Note: As this interconnection changes the system configuration and has the potential to affect a WECC rated transmission path, an in-depth special study will be required to identify if there is an interaction with TOT 2B1, TOT 2B2, TOT 2C, in coordination with neighboring utilities such as Los Angeles Department of Water and Power (LADWP), Arizona Public Service (APS), NV Energy and other interested parties. This study is mandatory prior to signing an interconnection agreement.</u>

6.1.3 Existing Circuit Breaker Upgrades – Short Circuit

The increase in the fault duty on the system as a result of the addition of the Generating Facility with 159 – 1500 kW inverters fed through 78 – 3 MVA 34.5 kV – 390 V transformers with 5.75% impedance then fed through three 230 – 34.5kV 80/93 MVA step-up transformer with 12.5 % impedance will not push the fault duty above the interrupting rating of any of the Transmission Provider's existing fault interrupting equipment.

6.1.4 Protection Requirements

The installation of protective relays for line fault detection will be required at the Transmission Provider's new 230 kV POI substation for the protection of the lines to the Interconnection Customer's collector substations and the lines to Sigurd and Glen Canyon substations. Transmission line current differential relay systems will be implemented on the line to the collector substation. The line relays to Sigurd and Glen Canyon substations will continue to use permission overreaching transfer trip logic. This will minimize the amount of relay work that will be required at Sigurd and Glen Canyon substations. The Transmission Provider will supply a panel containing line relays that will be installed at the collector substation E8-2. The relays in this panel will communicate with the relays at the POI substation over an optical fiber cable. This optical fiber cable will need to be installed on the transmission line between the POI and the collector substation E8-2. The Interconnection Customer will need to provide the outputs from two sets of current transformers on the tie line breaker at collector substation E8-2. These currents will be fed into the line relays. A three phase set of 230 kV voltage transformers will also be required at the collector substation for the line relays.

The Interconnection Customer will be responsible for the design, installation, and maintenance of the line protective relays for the 230 kV line between collector substations E8-2, E8-3 and E8-4. These relays will need to detect and clear 230 kV line faults in five cycles or less.

Elements in the line relays at the POI substation will monitor the voltage on the line to the collector substation. These elements will operate for under/over voltage and over/under frequency. If the voltage, magnitude or frequency, is outside of the normal operation range, these relays will send a transfer trip signal. The line relays at the E8-2 collector substation will receive the transfer trip signal and trip open all of the Interconnection Customer's 34.5 kV line breakers at that collector substation. This transfer trip signal will need to be forwarded on to the E8-3 and E8-4 collector substations to trip the 34.5 kV breakers at those substations.

6.1.5 Data (RTU) Requirements

In addition to the need for operational data and control at the POI substation data for the operation of the power system will be needed from the collector substations. This data can be acquired by installing RTUs at the collector substations.

Listed below is the data that will be acquired from the collector substations and from the POI and tie line substation.

From POI substation:
<u>Analogs:</u>

- Net Generation real power
- Net Generator reactive power
- Interchange energy register

From Collector substation E8-2

<u>Analogs:</u>

- E8-2 Transformer Net Generation real power
- E8-2 Transformer Net Generator reactive power
- E8-2 Transformer Interchange energy register
- 230 kV A phase voltage
- 230 kV B phase voltage
- 230 kV C phase voltage
- 34.5 kV feeder 1 real power
- 34.5 kV feeder 1 reactive power
- 34.5 kV feeder 2 real power
- 34.5 kV feeder 2 reactive power

- 34.5 kV capacitor reactive power
- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)
- Irradiance (W/m2)

Status:

- 230 kV breaker 52U-1
- 230 kV breaker 52U-2
- 34.5 kV breaker 52R21
- 34.5 kV breaker 52F21
- 34.5 kV breaker 52F22
- Line relay alarm

From Collector substation E8-3
Analogs:

- E8-3Transformer Net Generation real power
- E8-3 Transformer Net Generator reactive power
- E8-3 Transformer Interchange energy register
- 230 kV A phase voltage
- 230 kV B phase voltage
- 230 kV C phase voltage
- 34.5 kV feeder 1 real power
- 34.5 kV feeder 1 reactive power
- 34.5 kV feeder 2 real power
- 34.5 kV feeder 2 reactive power
- 34.5 kV capacitor reactive power
- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)
- Irradiance (W/m2)

Status:

- 230 kV breaker 52U-3
- 34.5 kV breaker 52R31
- 34.5 kV breaker 52F31
- 34.5 kV breaker 52F32

From Collector substation E8-4
Analogs:

- E8-4Transformer Net Generation real power
- E8-4 Transformer Net Generator reactive power
- E8-4 Transformer Interchange energy register
- 230 kV A phase voltage
- 230 kV B phase voltage
- 230 kV C phase voltage
- 34.5 kV feeder 1 real power
- 34.5 kV feeder 1 reactive power
- 34.5 kV feeder 2 real power
- 34.5 kV feeder 2 reactive power
- 34.5 kV capacitor reactive power
- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)
- Irradiance (W/m2)

Status:

- 230 kV breaker 52U-4
- 34.5 kV breaker 52R41
- 34.5 kV breaker 52F41
- 34.5 kV breaker 52F42

6.1.6 Substation Requirements

POI Substation:

To support the requested interconnection, the Project will require a new 230kV, three breaker ring bus POI substation. The substation will be approximately 270’ x 470’ (fence dimensions) based on the customer provided facility requirements. The following is a list of the major equipment required for this project:

3 – 230kV Power Circuit Breakers
6 – 230kV CCVTs
3 – 230kV CT/VT Metering units
13 – 230kV Switches
9 – 230kV Lightning Arresters
1 – 230kV SSVT

Collector Stations E8-2, E8-3, E8-4:

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer’s Generating Facility for the Transmission Provider to install a control house for any required metering, protection or communication equipment. This area will share a fence and ground grid with the

Generating Facility and have separate, unencumbered access for the Transmission Provider. AC station service for the control house will be supplied by the Interconnection Customer. DC power for the control house will be supplied by the Transmission Provider.

6.1.7 Communication Requirements

OPGW fiber cable will be installed on the Customer constructed 230 kV line between the Q0710 POI substation and the Customer's E8-2, E8-3, and E8-4 substations.

OPGW fiber cable will also be installed between the WAPA Glen Canyon substation and the Q0710 POI substation to implement transfer trip from Transmission Provider's Sigurd substation to the Q0710 POI substation and to implement transfer trip from WAPA's Glen Canyon substation to the Q0710 POI substation for line protection.

In addition to the relaying requirements, electronic communications is required from the Q0710 POI substation to Transmission Provider's dispatch centers. The OPGW and electronics installed in each location will be used to provide:

- channels for connecting the Q0710 substations' RTUs,
- a channel for the Q0710 POI substation RTU and the primary meter to Transmission Provider's dispatch centers,
- channels for voice OPXs at the E8-2, the E8-3, the E8-4, and the Q0710 POI substations,
- a channel for the backup meter as an RTU and
- Ethernet connection for MV-90 meter data access

The Q0710 Interconnection Customer is to provide a 125 V dc battery and charger system that will support the electronic communications equipment with at least 24-hour backup at each of the three Q0710 substations.

The Q0710 Interconnection Customer is to provide property, near each of the Q0710 substation control houses, for Transmission Provider supplied buildings that will house the Transmission Provider communications and RTU equipment.

6.1.8 Metering Requirements

Interchange Metering

Point of Interconnect Q0710 Substation:

The interchange metering will be designed bidirectional and rated for the total net generation of the Project including metering the retail load (per tariff) delivered to the Interconnection Customer. The Transmission Provider will specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratio's to be determined during the design phase of the Project.

The metering design package will include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One meter will be designated as a primary SCADA meter and a second meter will be designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA including per phase voltage and amps data.

An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.

Substation (E-8.2, E-8.3, E-8.4) Metering:
The metering for each of the three substations will be rated for the collector's station maximum planned generation and will be located at the high side of the step-up transformer. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratio's to be determined during the design phase of the Project.

The Transmission Provider will design and procure the collector revenue metering panels. The collector substation metering design package will be specified identical to the interchange metering panel. The Interconnection Customer shall install the revenue metering panels, instrument transformers, junction box and secondary lead conductors. The collector substation metering design package will include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block.

An Ethernet phone line is required for retail sales and generation accounting via the MV-90 translation system.

Station Service/Construction Power
The location of the project is not within the Transmission Provider service territory. The Interconnection Customer must arrange construction power with the electric service provider holding the certificated service territory rights for the area in which the load is physically located.

Please note, prior to back feed Interconnection Customer must arrange the retail meter service by the local provider for electricity consumed by the Project. Approval for back feed is contingent upon obtaining station service.

6.1.9 Transmission Line Requirements

Transmission Provider Connection to Q0710 POI Substation

Transmission Provider will loop the existing Glen Canyon – Sigurd 230kV transmission line through the new Q0710 POI substation. For the purposes of this study it has been assumed that the new Q0710 POI substation location is directly adjacent to the 230kV Transmission line near the town of Big Water.

Interconnection Customer Connection to Q0710 POI Substation

Transmission Provider will review the Interconnection Customer's design of the Interconnection Customer's transmission line connection to the Q0710 POI substation structure for general conformance with Transmission Provider's construction standards.

6.2 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Transmission Provider. Costs for any work being performed by the Interconnection Customer are not included.

Energy Resource Interconnection – Direct Assignment Facilities	
Q0710 POI to E8 collector stations – Fiber on new line	$353,000
Q0710 POI substation – Add meter, dead-end structure, switch	$801,000
Q0710 E8-2 collector substation – Add relaying, metering, and RTU	$1,002,000
Q0710 E8-3 collector substation – Add metering and RTU	$874,000
Q0710 E8-4 collector substation – Add metering and RTU	$878,000
Sub-total Direct Assignment Costs	**$3,908,000**
Interconnection – Network Upgrade Costs	
Q0710 POI to Glen Canyon – Add fiber on existing line	$822,000
Q0710 POI substation – Add 230 kV ring bus	$10,079,000
WAPA Glen Canyon substation – Add new relay settings and communication	$113,000
Glen Canyon communication site – Install fiber node	$222,000
Sigurd substation – Add new relay settings	$38,000
Glen Canyon to Sigurd 230 kV line – Loop through POI substation	$566,000

Sub-total Network Upgrade Costs	**$11,840,000**
Total Cost – ER Interconnection Service – Interconnection Only	**$15,748,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Transmission Provider to interconnect this Generator Facility to Transmission Provider's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

6.3 Schedule

The Transmission Provider estimates it will require approximately 24 months to design, procure and construct the facilities described in the Energy Resource sections of this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report appears to result in a timeframe that does support the Interconnection Customer's requested Commercial Operation date of December 19, 2019.

6.3.1 Maximum Amount of Power that can be delivered into Network Load, with No Transmission Modifications (for informational purposes only)

Zero (0) MW can be delivered on firm basis to the Transmission Provider's network loads without system improvements as the Sigurd – Glen Canyon (TOT 2B2) path is fully subscribed.

6.3.2 Additional Transmission Modifications Required to Deliver 100% of the Power into Network Load (for informational purposes only)

In order to deliver 100% of the power into Network Load the following improvements are required: See Section 6.1.2 and Section 7.1.2. Additionally, it is assumed that all facilities identified for prior queued projects are in service.

7.0 NETWORK RESOURCE (NR) INTERCONNECTION SERVICE

Network Resource Interconnection Service allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's Transmission System in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers. The transmission system is studied under a variety of severely stressed conditions in order to determine the transmission modifications which are necessary in order to deliver the aggregate generation in the area of the POI to the Transmission Provider's aggregate load. Network Resource Interconnection Service in and of itself does not convey transmission service.

7.1 Requirements

7.1.1 Generating Facility Modifications

Refer to section 6.1.2

7.1.2 Transmission System Modifications

As the northbound transmission capacity on the existing Sigurd – Glen Canyon 230 kV (TOT 2B2) transmission line is fully subscribed, interconnecting as a network resource will require the existing Sigurd – Glen Canyon 230 kV line capacity to be increased by at least 240 MW. Figure 2 is a one-line diagram that illustrates the interconnection of the proposed Q0710 Project to the Transmission Provider's system. Due to excessive line losses related to the level of power transfers necessary to accommodate the Q0710 Project output (approximately 540 MW), a 230 kV line from the Q0710 POI to Sigurd is uneconomical. Therefore, voltage transformation from 230 kV to 345 kV will be necessary and the existing 230 kV line from the Q0710 POI to Sigurd will be converted to 345 kV operation. Because the Glen Canyon end of the existing 230 kV line is owned and operated by Arizona Public Service, no voltage transformation between Q0710 POI and Glen Canyon substation is being proposed; however, the line will need to be reconductored.

<u>Transmission improvements required to interconnect Q0710 as a Network Resource are as follows:</u>

1. Move the existing Sigurd line termination from the 230 kV yard to 345 kV yard, and install one 345 kV circuit breaker and two new 345 kV deadend lattice towers
2. Install two 560 MVA 230/345 kV transformers and 345 kV circuit breakers at the Q0710 POI

3. Rebuild approximately 144 miles of the existing 230 kV line between Sigurd and the new Q0710 POI substation at 345 kV to at least 560/620 MVA (continuous/emergency)
4. Install two 30 MVAr line reactors on the converted 345 kV line between Sigurd and Q0710 POI substations at each end to avoid inadvertent reactive power due to line charging on the 345 kV line under light load conditions
5. Install a four breaker 230 kV ring bus configuration at the Q0710 POI
6. Install a 300 MVA (continuous rating) /420 MVA (emergency rating) 230 kV phase shifting transformer at the Q0710 POI substation to accommodate the flow of 410 MW through the PST in the event of the loss of the 230 kV tie line between the Q0710 POI substation to Q0710 collector substation (See Figure 2)
7. Remove and dispose of existing phase shifting transformer at Sigurd
8. Reconductor the existing 230 kV line between Q0710 POI and Glen Canyon substations or achieve higher 115° rating to at least 360/428 MVA (continuous/emergency) to prevent overload of 107% above the existing emergency rating for an outage of Q0710 POI to Q0710 collector substation
9. Build a new 345 kV line from Emery to Oquirrh substation line reactors; approximately 130 miles (see North of Huntington/Sigurd discussion below)

<u>Note: As this interconnection changes the system configuration and has the potential to affect a WECC rated transmission path, an in-depth special study will be required to identify if there is an interaction with TOT 2B2, TOT 2B1, TOT 2C, in coordination with neighboring utilities such as Los Angeles Department of Water and Power (LADWP), Arizona Public Service (APS), NV Energy and other interested parties. This study is mandatory prior to signing an interconnection agreement.</u>

<u>North of Sigurd Transmission Constraint</u>

There are a total of five 345 kV lines from Huntington and Sigurd that form the North of Huntington/Sigurd cutplane. These lines are

(1) Huntington – Spanish Fork 345 kV line
(2) Emery – Spanish Fork 345 kV line
(3) Mona – Huntington 345 kV line
(4) Sigurd – Clover – Mona # 1 345 kV line
(5) Sigurd – Clover – Mona # 2 345 kV line

Transmission capacity across the North of Huntington/Sigurd cutplane is fully committed for existing and requested transmission service. In order to deliver 240 MW of generation from the Q0710 Project to network load, an increase in the North of Huntington/Sigurd transmission capacity is required. Increasing the transfer capacity of this path will require the addition of a new transmission line along with 345 kV circuit breakers at the line terminations. For the purposes of this study, it is assumed that the new line would be a 345 kV line of approximately 130 miles in length running between the Transmission

Provider's existing Emery and Oquirrh substations, constructed with 2 x 1272 ACSR conductors per phase.

Until a new line across the North of Huntington/Sigurd cutplane can be constructed, the Transmission Customer will be required to limit scheduled power from this area (including the new facility) to amounts within the Transmission Customer's existing rights across the constrained path.

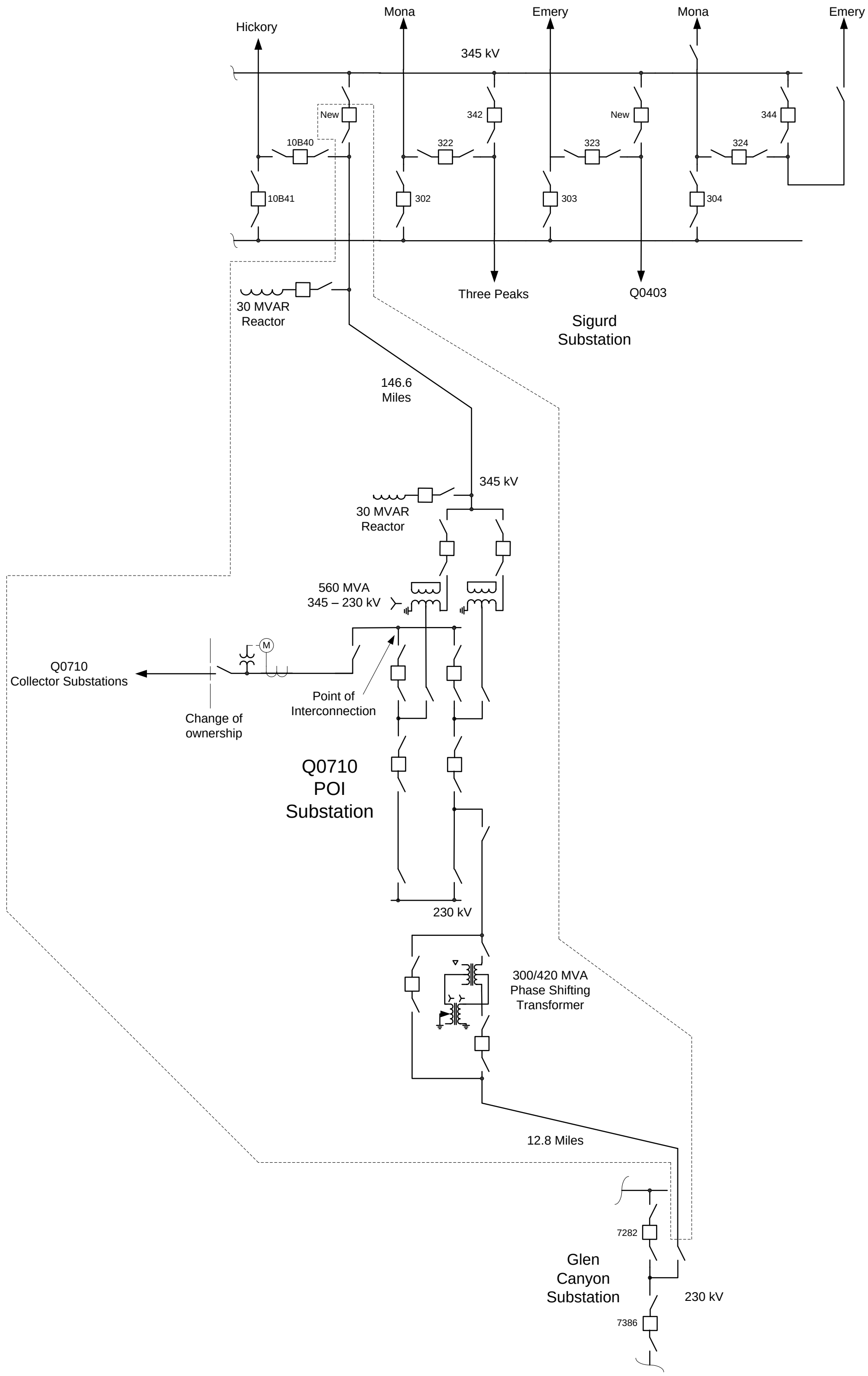


Figure 2: System One Line Diagram for Interconnecting Facility Operating as Network Resource (NR)

7.1.3 Existing Circuit Breaker Upgrades – Short Circuit

The increase in the fault duty on the system as a result of the addition of the Generating Facility with 159 – 1500 kW inverters fed through 78 – 3 MVA 34.5 kV – 390 V transformers with 5.75 % impedance then fed through three 230 – 34.5kV 80/93 MVA step-up transformer with 12.5 % impedance and then adding the transmission facilities to meet the requirement for the NR evaluation will not push the fault duty above the interrupting rating of any of the Transmission Provider's existing fault interrupting equipment.

7.1.4 Protection Requirements

At the Q0710 POI substation in addition to the protective relaying described in the ER section of this report the following will be required for the facilities to meet the NR requirements: Transformer relaying will be required for the phase shifting and the 345 – 230 kV transformers. The bus sections between the 230 kV ring bus and the three transformers will be protected with bus differential relay systems. Line current differential relay systems will be applied for the 345 kV line to Sigurd substation. The lines to Glen Canyon substation and the collector substations will continue to use the line protection systems described in the ER section. At Sigurd substation line current differential relays will be installed for the new 345 kV line.

7.1.5 Data (RTU) Requirements

At the POI substation the RTU planned for in the ER section will be expanded to accommodate the monitoring and control of the additional equipment that will be required. At Sigurd substation the existing RTU will be used to monitor and control the additional 345 kV breaker.

7.1.6 Substation Requirements

In addition to the substation modifications outlined in the ER section of this report, to support the above outlined transmission system modifications the following will be required for the facilities to meet the NR requirements: Remove the 230kV phase shifter yard at Sigurd substation and add a 345kV line position, with shunt reactor, for the Glen Canyon line conversion. At the new Q0710 POI substation, expand the substation to support a new 345kV line position (with shunt reactor), two new 345-230kV transformers, and a new 230kV phase shifter yard.

7.1.7 Communication Requirements

In addition to the ER electronic communications requirements, OPGW fiber cable will be installed on the 345 kV line between the Sigurd substation and the Q0710 POI substation to provide for the redundant line protection required on a 345 kV line. An optical repeater site, somewhere near the middle of the line, will be required due to the 147 mile fiber length.

Once the Q0710 POI substation site location has been finalized, it may be possible to install a cable from the Q0710 POI substation to the Sigurd substation. However, based on the preliminary POI location, the two existing Transmission Provider microwave site options available for microwave communications have no line-of-sight. This option may not be available to provide for the redundant electronic communications required for the protection of the 345 kV line, rather than the installation of approximately 147 miles of OPGW fiber.

7.2 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Transmission Provider. Costs for any work being performed by the Interconnection Customer are not included.

Network Resource

Q0710 POI substation – Expand yard for 345 kV	$40,830,000
Q0710 Fiber repeater communication site – Add communication repeater	$540,000
Sigurd substation – Add new 345 kV position	$8,900,000
Emery substation – Add new 345 kV position	$10,400,000
Spanish Fork substation – Add communications	$220,000
Oquirrh substation – Add new 345 kV position	$12,440,000
Q0710 POI to Sigurd – Add new 345 kV transmission line	$121,560,000
Emery to Oquirrh – Add new 345 kV transmission line	$196,520,000
Q0710 POI to Glen Canyon 230 kV line – replace conductor	$2,970,000
Total Network Resource Costs	**$394,380,000**
Total Cost – Energy Resource and Network Resource	**$410,128,000**

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Transmission Provider to interconnect this Small Generator Facility to Transmission Provider's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

7.3 Schedule

The Transmission Provider estimates it could take up to 120 months to permit, design, procure and construct the facilities described in the Network Resource sections of this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to perform the scope of work identified in the Network Resource sections of this report does not support the Interconnection Customer’s requested commercial operation date of December 19, 2019.

8.0 PARTICIPATION BY AFFECTED SYSTEMS

Transmission Provider has identified the following affected systems: Arizona Public Service Electric Company (APS)

A copy of this report will be shared with the each Affected System.

9.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

9.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Generation Interconnection Queue Requests considered:

Q#	MW
66	11
310	20
311	14
313	25
324	80
333	3.2
384	60
403	525
415	11
450	50
454	3
455	3
459	2.93
464	3
471	3
472	3
473	3
475	3
488	3
489	3
492	3
493	3
502	2.93
512	3
513	80
514	80
515	80
516	80
532	50

Q#	MW
539-A	80
539-B	50.4
551	80
564	80
582	130
589	80
631	99
632	2.99
634	99
636	99
641	58
642	58
649	10.3
684	20

9.2 Appendix 2: Property Requirements

Property Requirements for Point of Interconnection Substation

Requirements for rights of way easements
Rights of way easements will be acquired by the Interconnection Customer in the Transmission Provider's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Transmission Provider's Interconnection Facilities that will be owned and operated by Transmission Provider. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Transmission Provider's easement form.

Real Property Requirements for Point of Interconnection Substation
Real property for a POI substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Transmission Provider. Interconnection Customer will acquire fee ownership for interconnection substation unless Transmission Provider determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Transmission Provider's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Transmission Provider and are subject to the Transmission Provider's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Transmission Provider. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Transmission Provider with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Transmission Provider. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of

any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Transmission Provider unless waived by Transmission Provider.

2. Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Transmission Provider may require Interconnection Customer to procure various studies and surveys as determined necessary by Transmission Provider.

Operational: inadequate access for Transmission Provider's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Transmission Provider.

9.3 Appendix 3: Study Results

The Siemens PTI PSS/E version 33 program was used to evaluate the steady state performance of the system for each of the contingencies described in Table 1. The study area was limited to central and southern Utah. Since the POI is located on the existing Sigurd – Glen Canyon 230 kV line, the case was tuned to meet the maximum obligation on the following WECC Paths:

(1) Path 35 (TOT 2C): Path 35 consists of the 345 kV line between Red Butte and Harry Allen Substations. This path connects Southwest Utah to Nevada.
(2) Path 78 (TOT 2B1): Path 78 consists of the 345 kV line between Pinto and Four Corners Substations. This path connects southeast Utah into Arizona/New Mexico.
(3) Path 79 (TOT 2B2): Path 79 consists of the 230 kV line between Sigurd and Glen Canyon Substations. This path connects southern Utah to Arizona.

All three paths mentioned above have phase shifting transformers regulating in power flow control mode.

Study results indicate that system improvements/additions are required to interconnect the Q0710 Project. With the capacity on the Sigurd – Glen Canyon line fully allocated, interconnecting the 240 MW solar farm to feed network load requires rebuilding the existing 230 kV line from Sigurd to the POI to 345 kV with 2x30 MVAr line reactors (operation at 230 kV is not economical due to high losses), two 230/345 kV transformers at the Q0710 POI (560 MVA) to retain the TOT 2B2 transfer capacity of 300 MW and prevent generation trip as a part of one (N-1) 230/345 kV transformer outage at POI (which can be out of service for long duration), 230 kV line reconductor or achieve higher 115° rating between Q0710 POI and Glen Canyon substation to prevent overload, and 230 kV Phase Shifting Transformer at the Q0710 POI.

The POI – Glen Canyon line overloads to 107% above the existing emergency rating (360/428 MVA) for an outage of Q0710 POI to Q0710 collector substation. The phase shifting transformer (PST) should be rated at least 300 MVA (continuous rating) /420 MVA (emergency rating) to accommodate the flow of 410 MW through the PST following the loss of the 230 kV tie line between Q0710 POI to the Q0710 collector substation.

Using different cases considering the maximum obligation on the WECC Paths described above, both light load and heavy load conditions were studied.

Prior to interconnecting the Q0710 Project, no thermal and/or voltage issues are observed under N-0 conditions. Importantly, this assumes system modifications necessary to connect projects that are higher in the interconnection queue are in-service. These modifications include:

1. Looping the existing 230 kV line between Parowan and West Cedar in and out of the Three Peaks substation and converting operation to 138 kV
2. Installing a second 345/138 kV transformer at Three Peaks as identified in the Network Resource section of a prior queue

3. Adding a second 230/138 kV transformer at Parowan substation
4. Increasing the Sigurd – Q0634 POI line rating to at least 345 MVA by fixing the spans on the 230 kV line to increase clearance
5. Installing a remedial action scheme related to Q589, Q0634 (loss of any of the Sigurd 345/230 kV transformers, loss of the Sigurd – Q0634 POI 230 kV line)

Large Generator Interconnection

System Impact Study Report

Stability Study

Completed for

(“Interconnection Customer”)
Q0710

Proposed Point of Interconnection

PacifiCorp's Sigurd-Glen Canyon 230 kV transmission line

July 27, 2016

Table of Contents

Executive Summary

("Interconnection Customer") proposed interconnecting 240 MW of new generation to PacifiCorp's ("Transmission Provider") Sigurd-Glen Canyon 230 kV transmission line located in Kane County, Utah. The project ("Project") will consist of 160 Power Electronics FS1690CU inverters for a total output of 240 MW.

The requested commercial operation date is December 19, 2019.

The Interconnection Customer will not operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the project "Q0710."

Transient stability analysis was simulated for various local area disturbances in the 230 kV and 345 kV transmission network. Results identified that the 240 MW Power Electronics PV inverters as modeled will ride through ALL simulated local area contingencies.

The Project is required to operate in the voltage control mode maintaining the voltage at the Point of Interconnection based on voltage schedule provided by the Transmission Provider. Along with the voltage control the Project should at least have sufficient reactive capability to maintain the interconnection reactive exchange between 0.95 leading/lagging power factor measured at the point of interconnection. It is the responsibility of the Interconnection Customer to ensure that the Project is capable of achieving this power factor during all conditions.

The Project modeling is based on data provided by the developer and/or the developer's equipment suppliers.

1. Description of Project

The Interconnection Customer has proposed interconnecting a solar generation facility in Kane County, Utah, to the Transmission Provider owned existing Sigurd-Glen Canyon 230 kV transmission line. The Project includes three two-winding 230/34.5 kV transformers, three 34.5/0.42 kV transformers, and 159 Power Electronics FS1500CU inverters. A preliminary electrical single line diagram depicting the Project's interconnection at a new Point of Interconnection substation is shown in Figure 1.

Power from each inverter will be stepped up to 34.5 kV through a 3 MVA pad-mounted transformer. A 34.5 kV collection system will bring the combined power output to the collector substation where the power will be further increased to 230 kV through a 34.5/230 kV transformer.

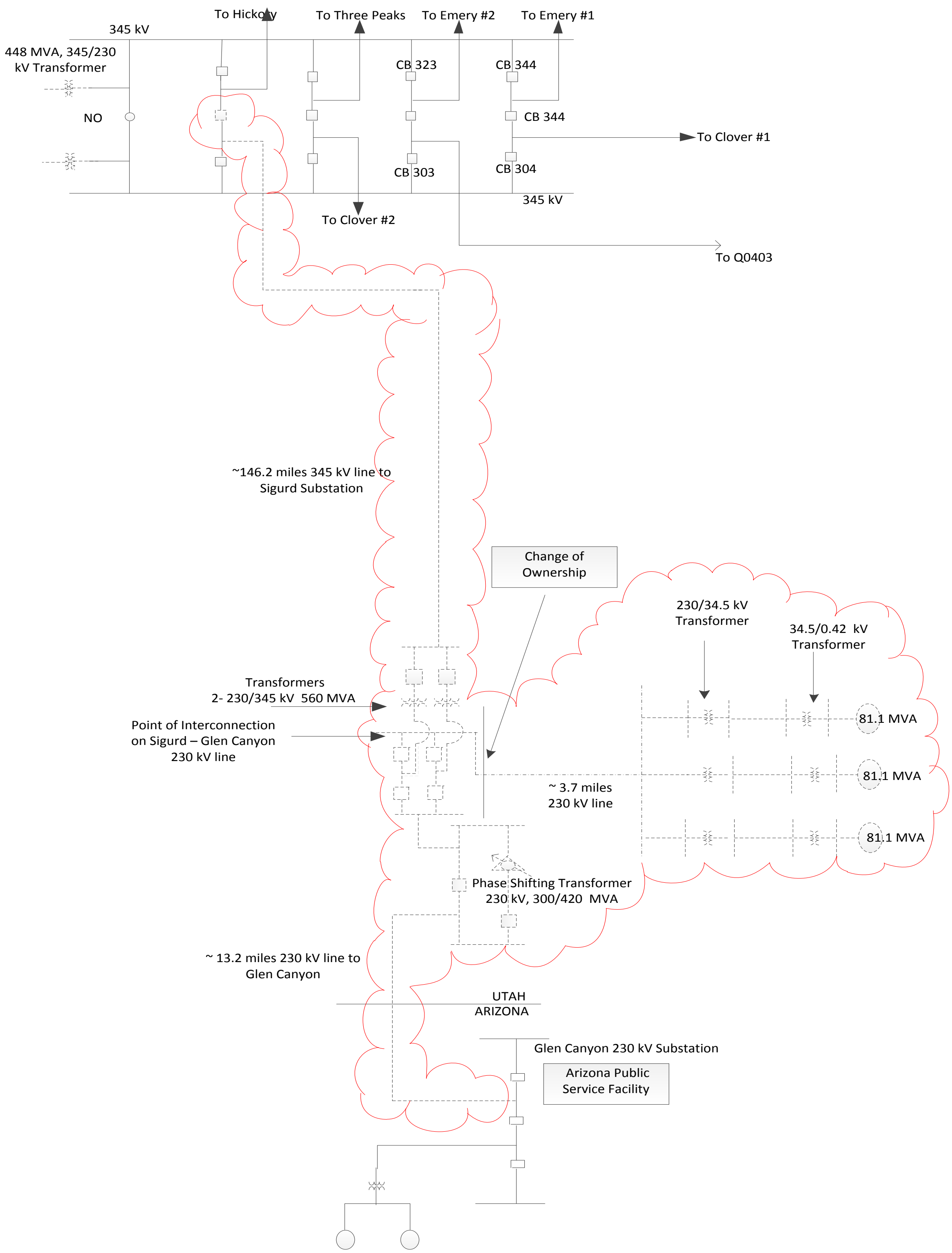


Figure 1. Single Line Diagram

2. Study Assumptions

The PSS/E version 33.4 program was used to evaluate system stability for each of the faults described in Table 1. In addition, the following assumptions were used in performing this study.

Study Period: The 2015 Heavy Summer WECC transmission power flow and dynamics data was used for this analysis.

Study Area: The study area was limited to the Project and the surrounding 345 kV and 230 kV transmission system in Southwest Utah.

Contingencies: The study simulated disturbances tabulated in Table 1.

Table 1. Transient Stability Analysis Contingencies

No.	Contingency Description
1	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – POI 345 kV circuit (3 cycles)
2	Three-phase fault on 345 kV bus at POI substation followed by loss of one 345/230 kV transformer (3 cycles)
3	Three-phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)
4	Three-phase fault on 230 kV bus at POI substation followed by loss of the POI – Glen Canton 230 kV circuit (4 cycles)
5	Three-phase fault on 230 kV bus at collector substation followed by loss of the POI – Collector substation 230 kV circuits (4 cycles).
6	Three-phase fault at the Sigurd 230 kV bus followed by loss of the Sigurd 345/230 kV transformer (4 cycles)
7	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – Clover 345 kV circuit (3 cycles)
8	Three-phase fault at the Hickory 345 kV bus followed by loss of the Sigurd – Hickory 345 kV circuit (3 cycles)
9	Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles).

Other Assumptions:

- Transient stability simulations were performed out to 10 seconds in order to determine system damping.
- Generating unit is a solid state inverter therefore the reactance data does not apply; the model assumes a very large reactance.
- The maximum reactive power capability of each inverter is specified at a power factor of +/- 0.95 at rated apparent power.
- The Power Electronics PV inverters are required to have zero voltage ride-through capability as shown in Figure 2; therefore, the inverters are designed to stay connected to the grid in the case of severe faults.
- In the study the full reactive capability of the generator at 0.9 power factor of full MW output was used for modeling purpose.
- It is assumed that under an islanding scenario the unit would automatically trip.
- Transient stability simulations were performed out to 10 seconds in order to determine system damping.
- Network upgrades identified from the power flow study were modeled in the case.
- For acceptable generator performance the Vdip CON (J) and Vup CON (J+1) has been changed to -99, 99 from 0.9, 1.1 as suggested by the PSLF model data base library.

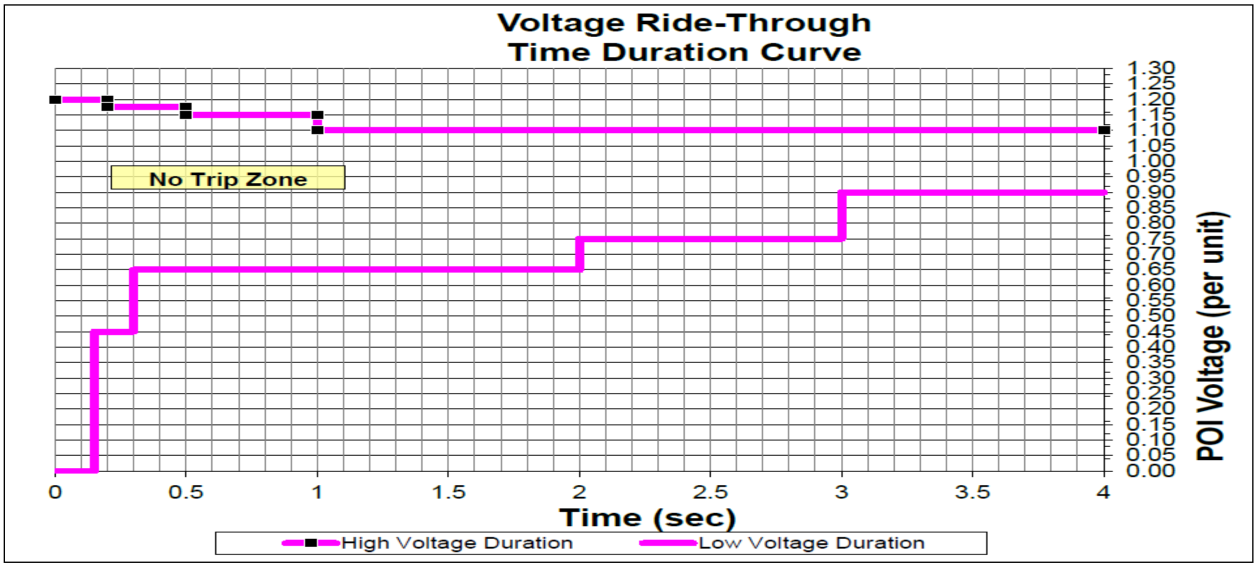


Figure 2. Voltage Ride-through Capability

3. Transient Analysis

The Generating Facility is required to ride through all 3-phase faults with normal clearing or single line-to-ground faults with delayed clearing for any event that doesn't disconnect the facility.

Transient stability results identified that ALL inverters with the model provided will ride through local area disturbances. A summary of contingency performance is provided in the following table.

Table 3. Transient Stability Analysis Contingencies

No.	Contingency Description	Stable
1	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – POI 345 kV circuit (3 cycles)	Y
2	Three-phase fault on 345 kV bus at POI substation followed by loss of one 345/230 kV transformer (3 cycles)	Y
3	Three-phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)	Y
4	Three-phase fault on 230 kV bus at collector substation followed by loss of the Q0710 POI – Collector substation 230 kV circuits (4 cycles).	Y
5	Three-phase fault at the Sigurd 230 kV bus followed by loss of the Sigurd 345/230 kV transformer (4 cycles)	Y
6	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – Clover 345 kV circuit (3 cycles)	Y
7	Three-phase fault at the Hickory 345 kV bus followed by loss of the Sigurd – Hickory 345 kV circuit (3 cycles)	Y
8	Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles).	Y

Transient stability plots are provided in **Appendix A and Appendix B**.

The Interconnection Customer should ensure that this loss of reactive power in the collector system does not impact the interconnection requirement for the reactive capacity to maintain required voltage at Point of Interconnection. In the study the full reactive capability of the generator for 0.9 power factor was used for modeling purpose.

The transient analysis showed significantly high transient over voltage on buses between POI 230 kV and machine terminal buses above 1.1 p.u. for the loss of the 230 kV phase shifting transformer connected south of the Q0710 POI substation and loss of 230 kV line between phase shifting transformer bus and Glen Canyon substation. The transient high voltage last for a very short period of time at the POI, at the Project collector bus and Project's machine terminal. Please see plots in the appendix for contingency 3 (Three phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)) and contingency 8 (Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles)).

4. Conclusions

The following conclusions have been reached through this analysis:

The addition of 159 Power Electronics PV inverters interconnecting to the existing Sigurd-Glen Canyon 230 kV transmission line located in Kane County, Utah, does not result in transient instability and the Project will ride through ALL simulated local area contingencies.

Simulation results are based on data provided by the Interconnection Customer with modification (mentioned in the assumption section) at the time of the study. The results can be used to help determine whether or not the Project facilities will meet the performance criteria including ride-through requirements which will be defined in the Interconnection Agreement, and, in some cases, may indicate that additional equipment is required in order to meet these requirements. However, ultimately it is the Interconnection Customer's responsibility to meet these requirements during actual operation on a daily basis and failure to do so can result in loss of interconnection privileges. Therefore, the results of these simulations should be regarded as informational rather than definitive, and do not relieve the Interconnection Customer of any performance responsibilities.

Finally, if the assumptions utilized in this study significantly change, PacifiCorp reserves the right to perform a re-study. Significant changes include, but are not limited to, development of new models which may impact performance as well as changes to the base case assumptions for planned future but as yet uncommitted transmission line and generation facilities.

5. Appendices

Appendix A: Transient Stability Plots

Plotted Quantities in every plot in the Appendix

Plot A

Sr. No.	Trace Color	Plotted Quantity
1	Green	Voltage at Q0710 POI 230 kV in PU
2	Blue	Voltage at Sigurd 345 kV in PU
3	Cyan	Voltage at PST 230 kV in PU
4	Pink	Voltage at Clover 345 kV in PU
5	Black	Voltage at Huntington 345 kV in PU
6	Red	Voltage at Hickory 345 kV in PU

Plot B

Sr. No.	Trace Color	Plotted Quantity
1	Green	Voltage at Escalante Solar unit II
2	Blue	Voltage at Escalante Solar unit III
3	Cyan	Angle at Emery/Hunter unit 1
4	Pink	Angle at Huntington unit 1
5	Black	Angle at Lake Side I ST1
6	Red	Angle at Lake Side I ST1

Plot C

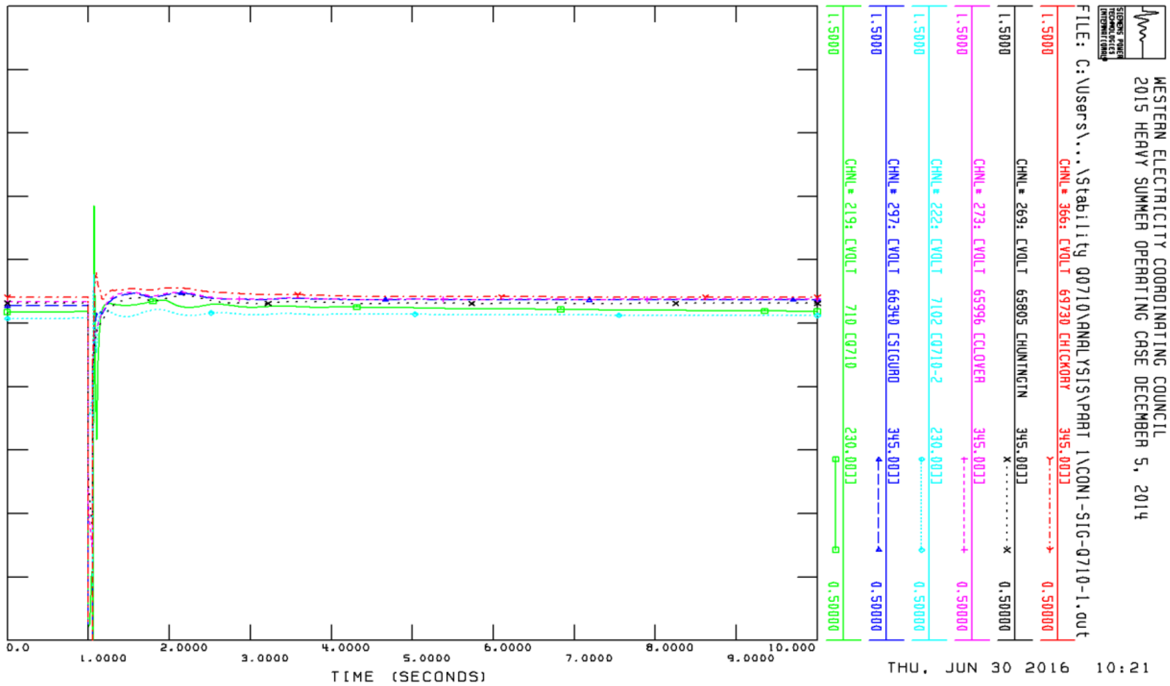
Sr. No.	Trace Color	Plotted Quantity
1	Green	Terminal voltage at G1
2	Blue	Terminal voltage at G2
3	Cyan	Terminal voltage at G3

Plot D

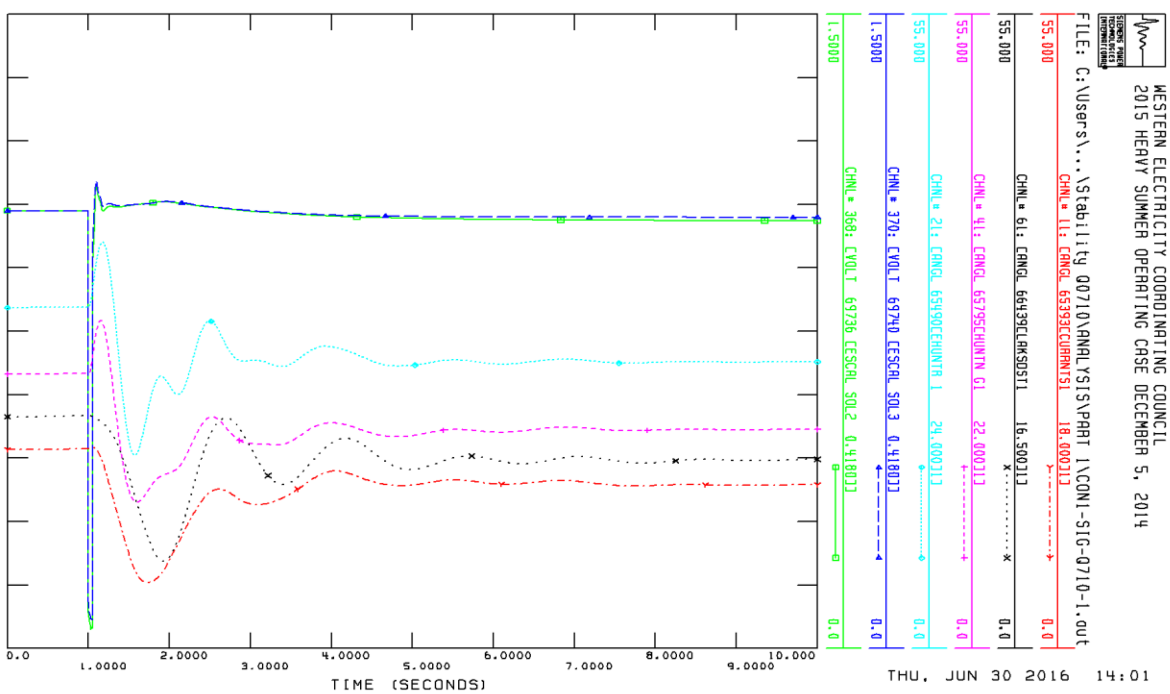
Sr. No.	Trace Color	Plotted Quantity
1	Green	Real Power through 34.5/.42 kV transformer Connected to Q0710 G1
2	Blue	Reactive through 34.5/.42 kV transformer Connected to Q0710 G1
3	Cyan	Real Power through 34.5/.42 kV transformer Connected to Q0710 G2
4	Pink	Reactive through 34.5/.42 kV transformer Connected to Q0710 G2
5	Black	Real Power through 34.5/.42 kV transformer Connected to Q0710 G3
6	Red	Reactive through 34.5/.42 kV transformer Connected to Q0710 G3

1. Three phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – POI 345 kV circuit (3 cycles)

Plot A



Plot B



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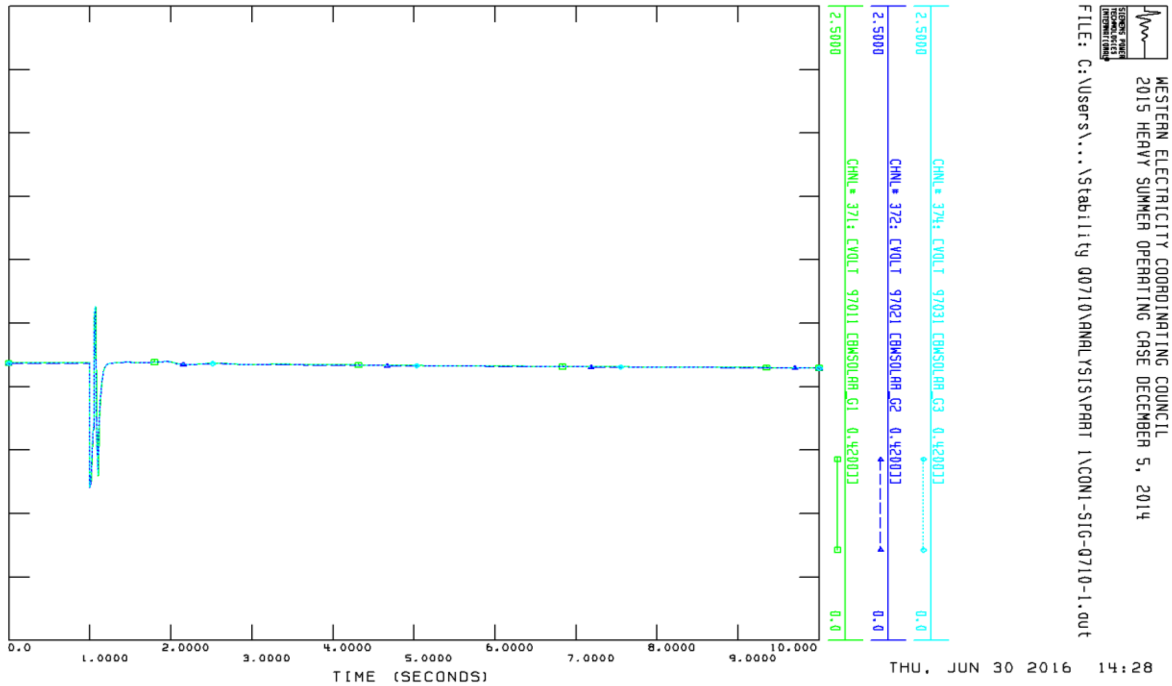

WESTERN ELECTRICITY COORDINATING COUNCIL
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THU, JUN 30 2016 14:28
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2.0000
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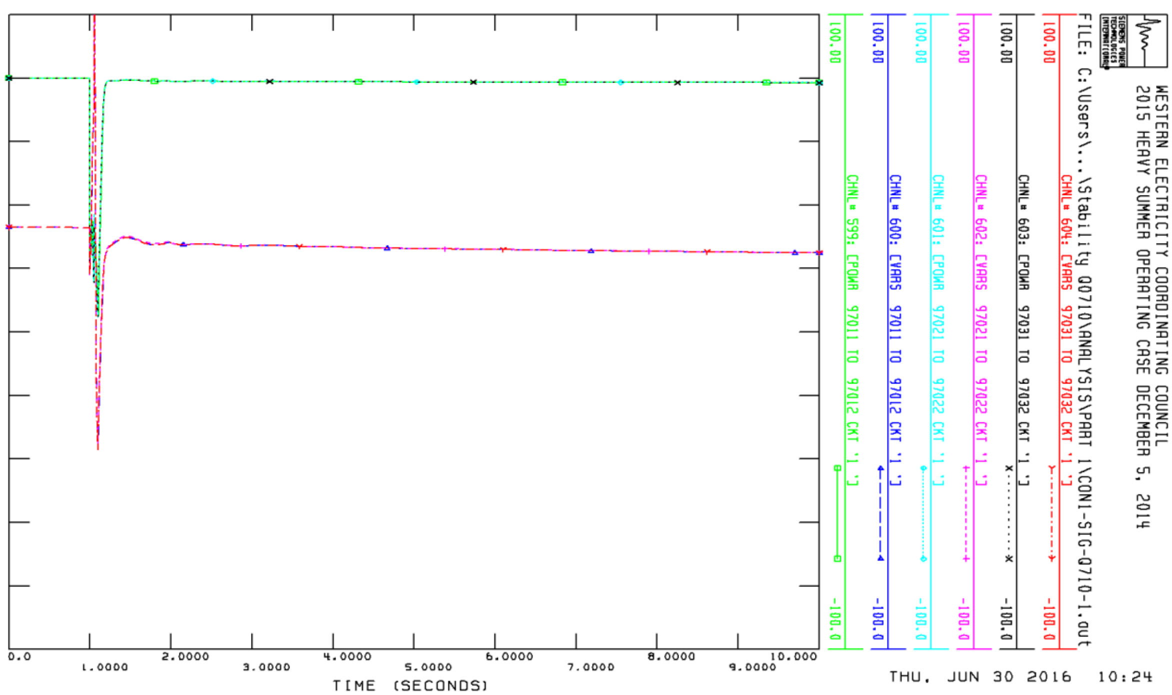
10.000
TIME (SECONDS)

Plot D



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1.0000
2.0000
3.0000
4.0000
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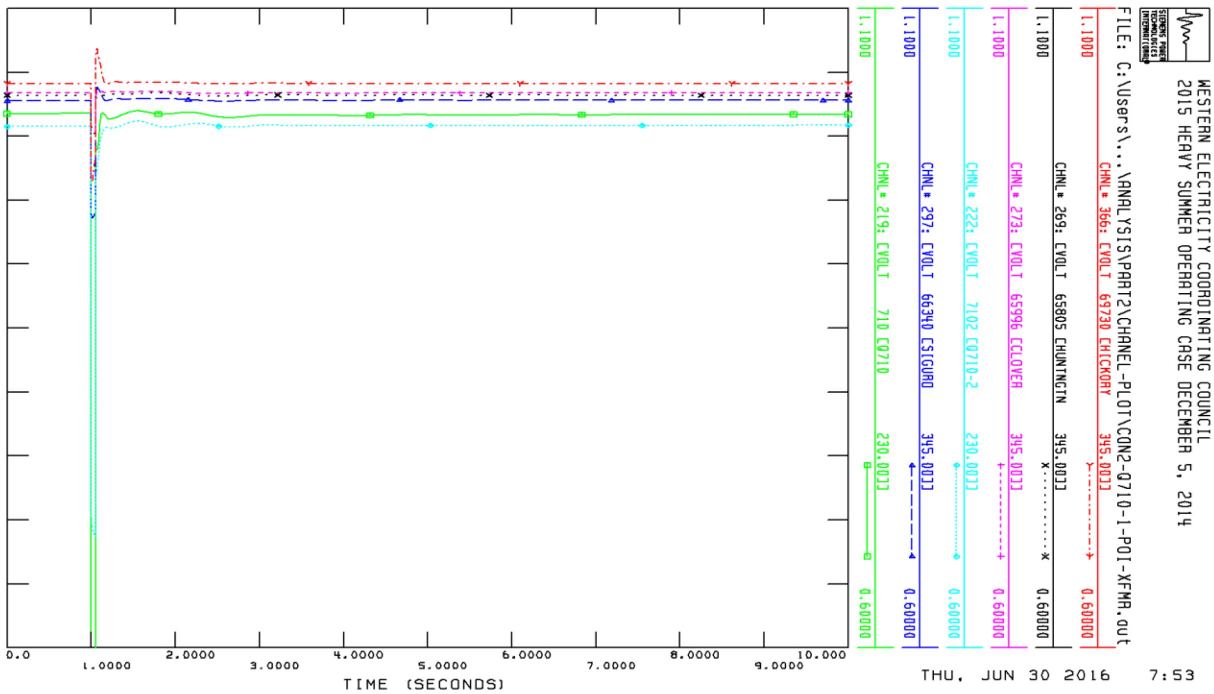
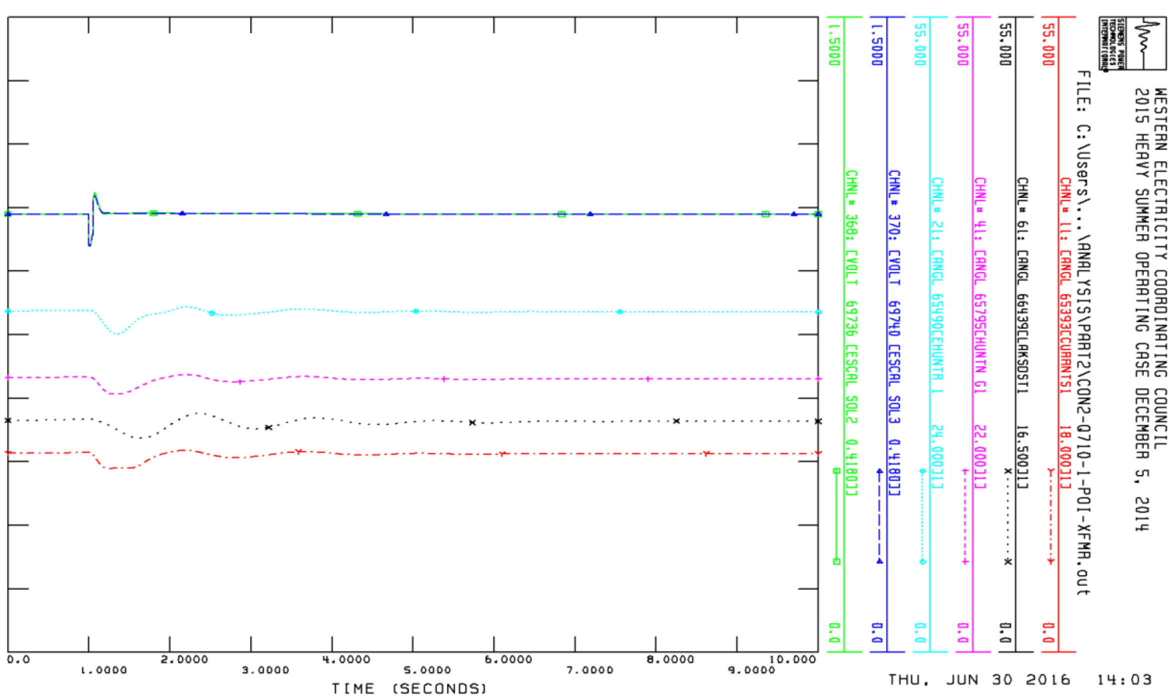
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

2. Three-phase fault on 345 kV bus at POI substation followed by loss of one 345/230 kV transformer (3 cycles)

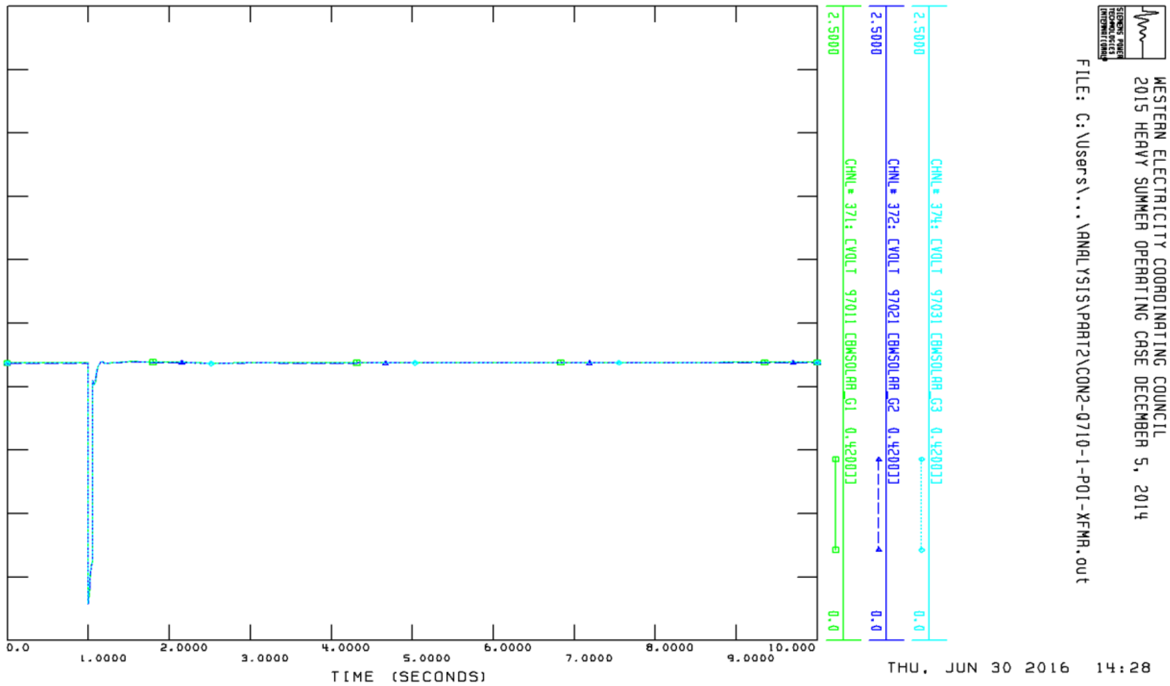
Plot A



Plot B



Plot C



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2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
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0.0
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0.0
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3.0000
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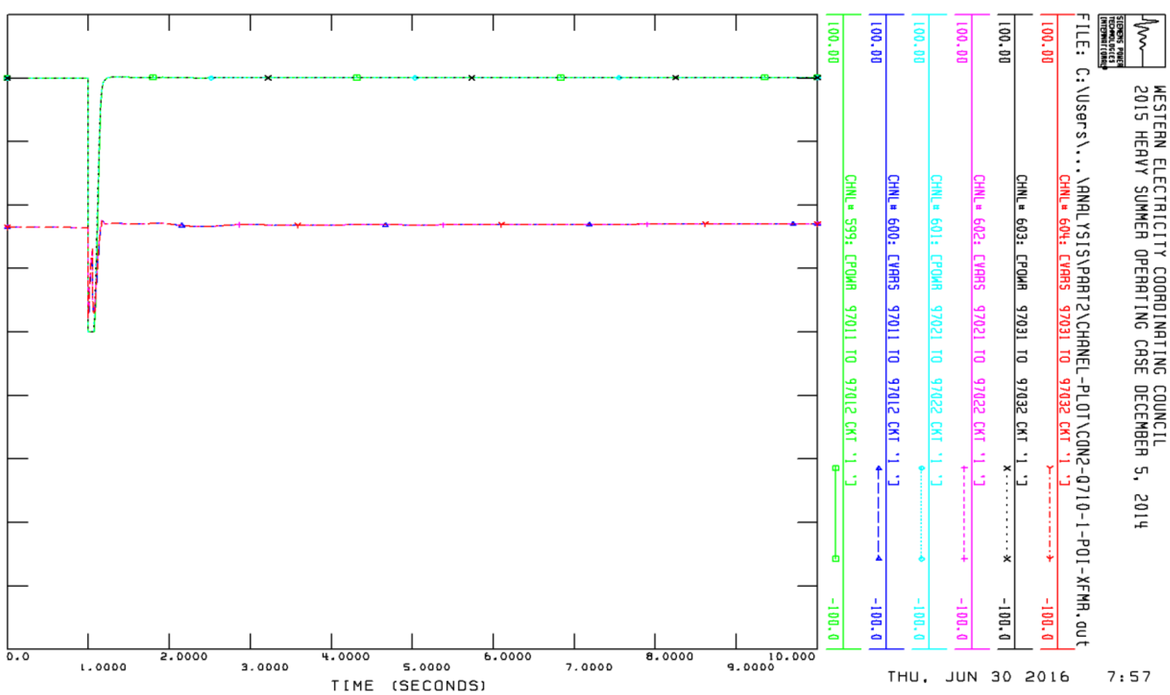
THU, JUN 30 2016 14:28

Plot D



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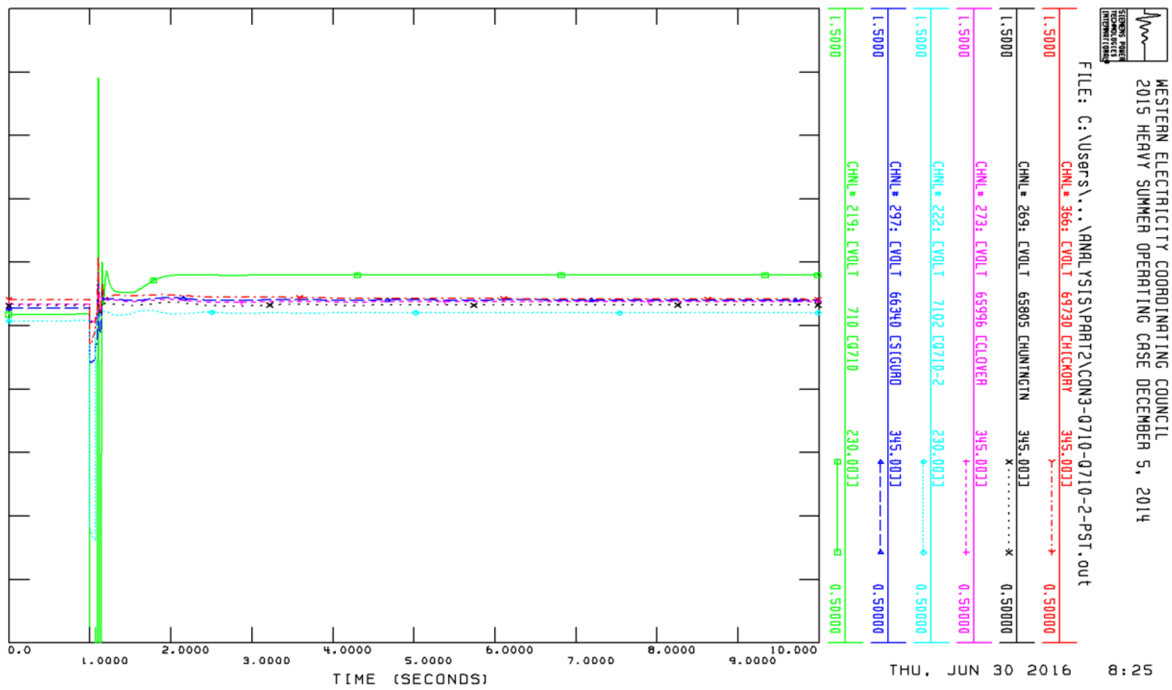
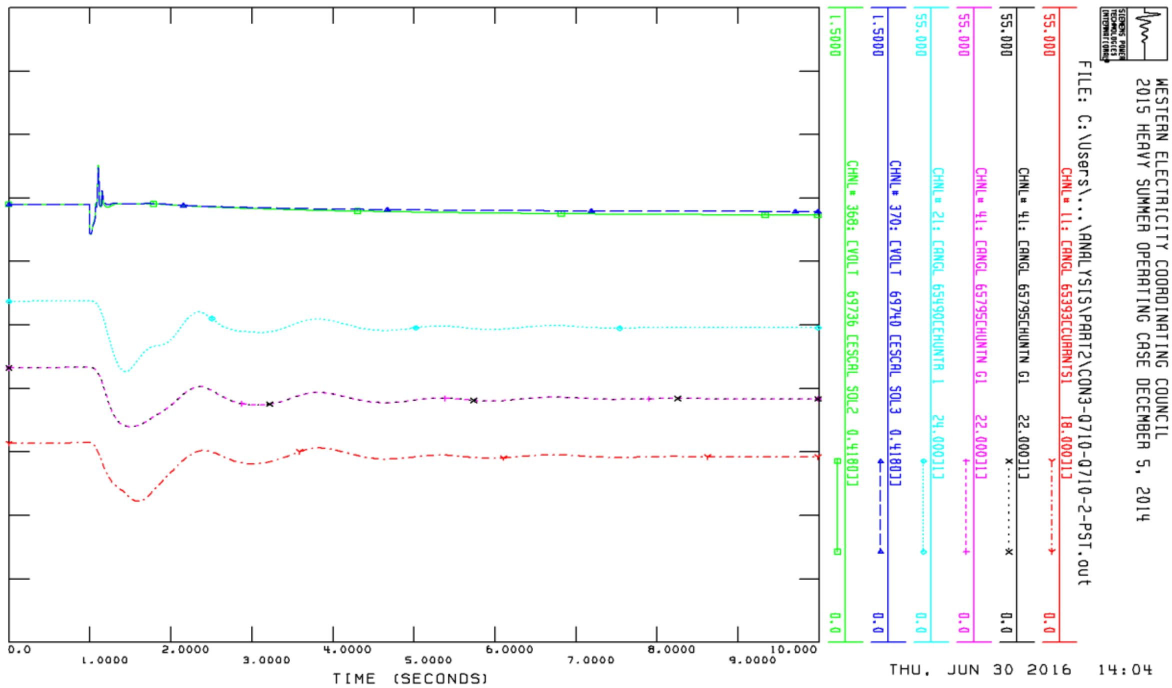
100.00
-100.0
CHNL# 600: [VARS 97011 TO 97012 CKT '1 ']
100.00
-100.0
CHNL# 599: [POWR 97011 TO 97012 CKT '1 ']
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, JUN 30 2016 7:57

3. Three phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)

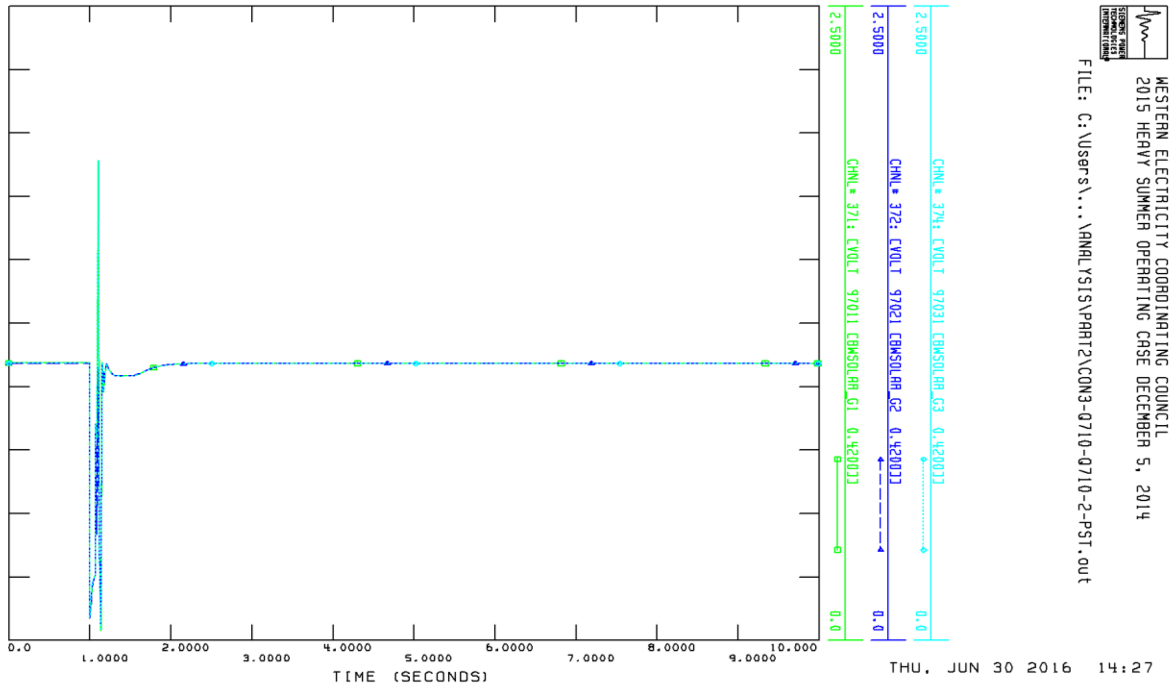
Plot A



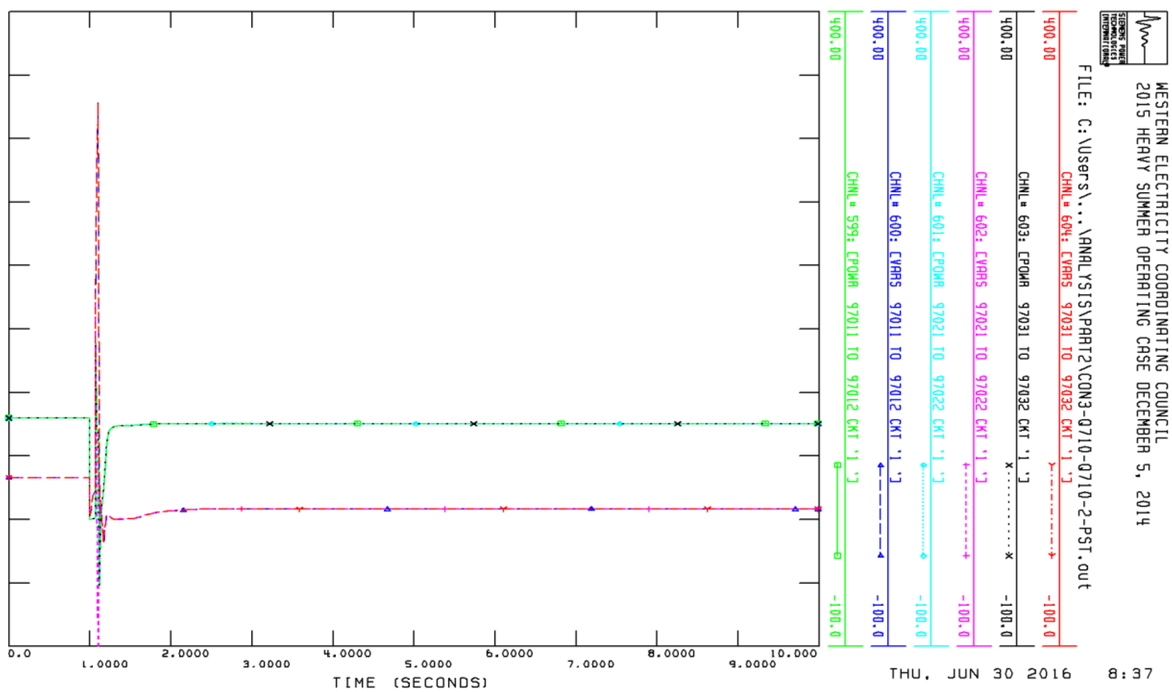
Plot B



Plot C

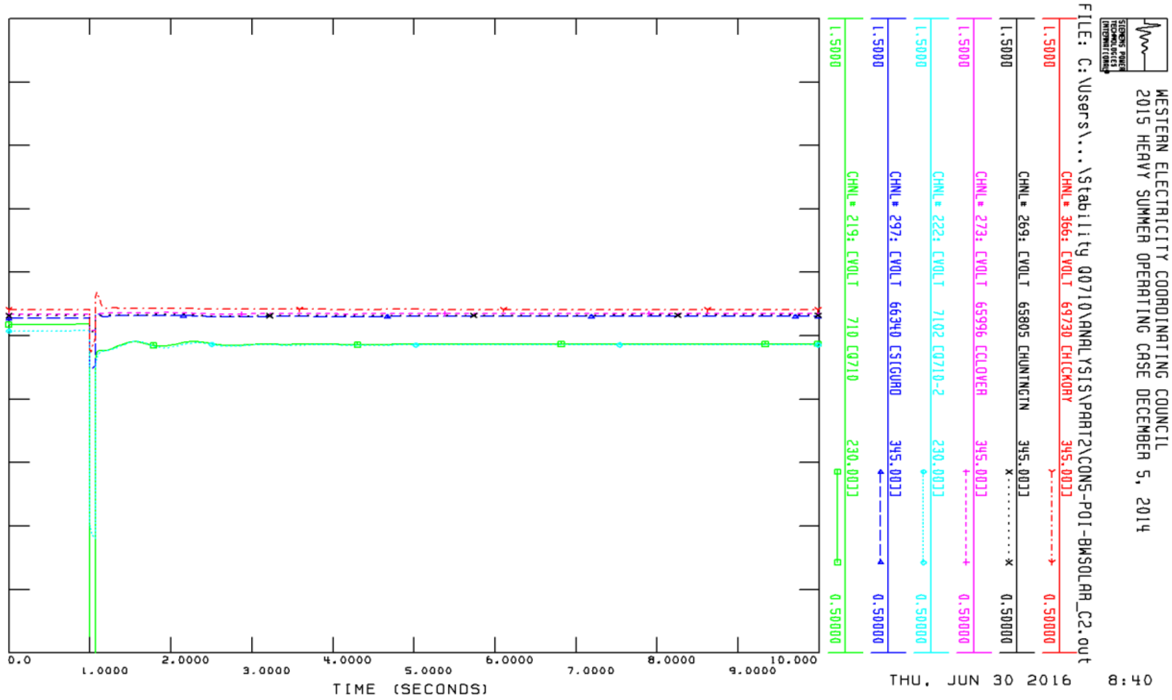

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART2\CON3-Q710-Q710-2-PST.out
CHNL# 374: [VOLT 97031 [BWSOLAR_G3 0.4200]]
CHNL# 372: [VOLT 97021 [BWSOLAR_G2 0.4200]]
CHNL# 371: [VOLT 97011 [BWSOLAR_G1 0.4200]]
2.5000
0.0
THU, JUN 30 2016 14:27
TIME (SECONDS)

Plot D

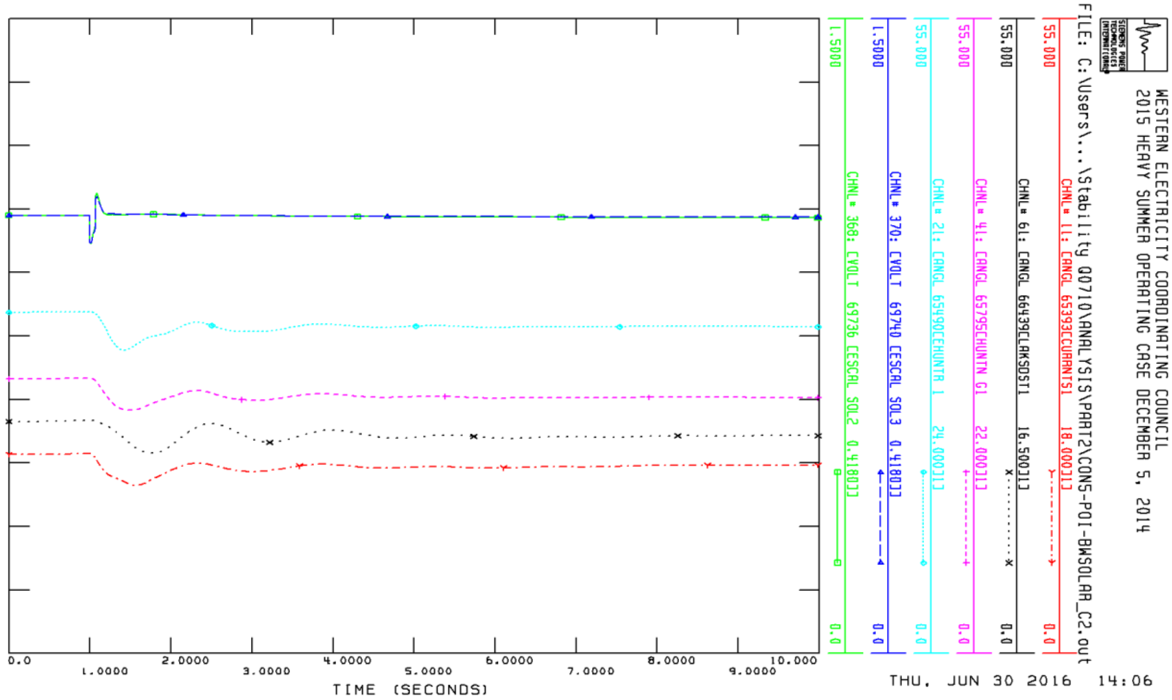

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART2\CON3-Q710-Q710-2-PST.out
CHNL# 604: [VARS 97031 TO 97032 CKT '1 ']
CHNL# 603: [POWR 97031 TO 97032 CKT '1 ']
CHNL# 602: [VARS 97021 TO 97022 CKT '1 ']
CHNL# 601: [POWR 97021 TO 97022 CKT '1 ']
CHNL# 600: [VARS 97011 TO 97012 CKT '1 ']
CHNL# 599: [POWR 97011 TO 97012 CKT '1 ']
400.00
-100.0
THU, JUN 30 2016 8:37
TIME (SECONDS)

4. Three phase fault on 230 kV bus at collector substation followed by loss of the Q0710 POI – Collector substation 230 kV circuits (4 cycles)

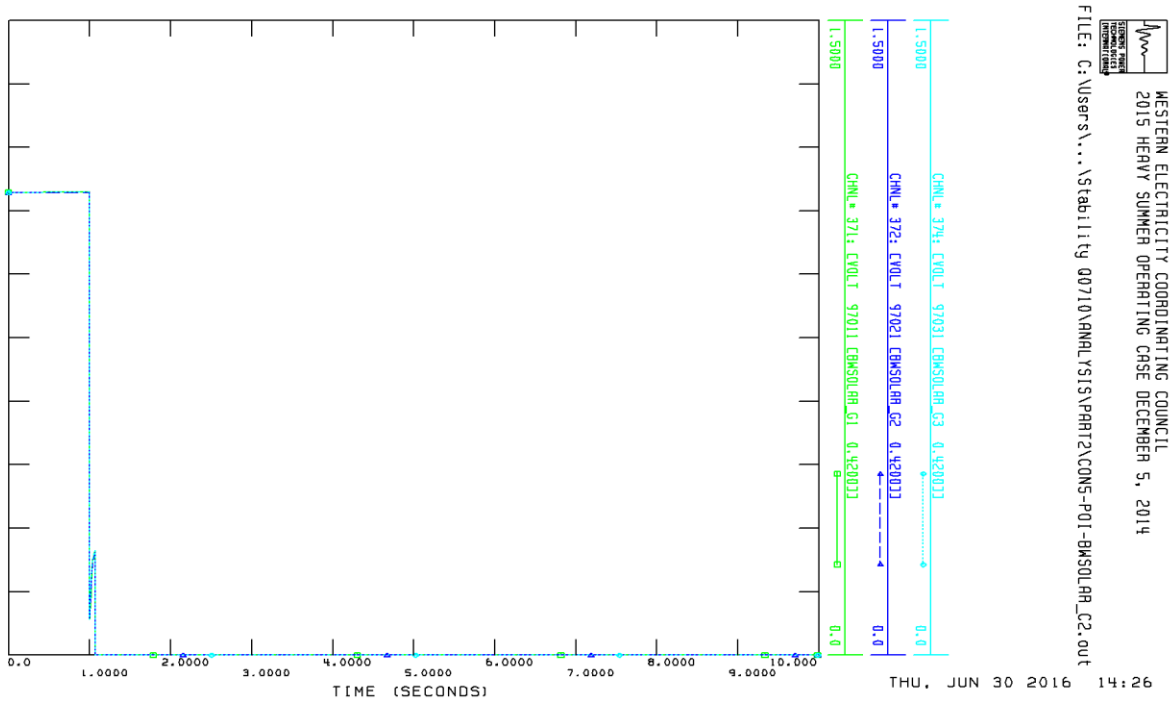
Plot A



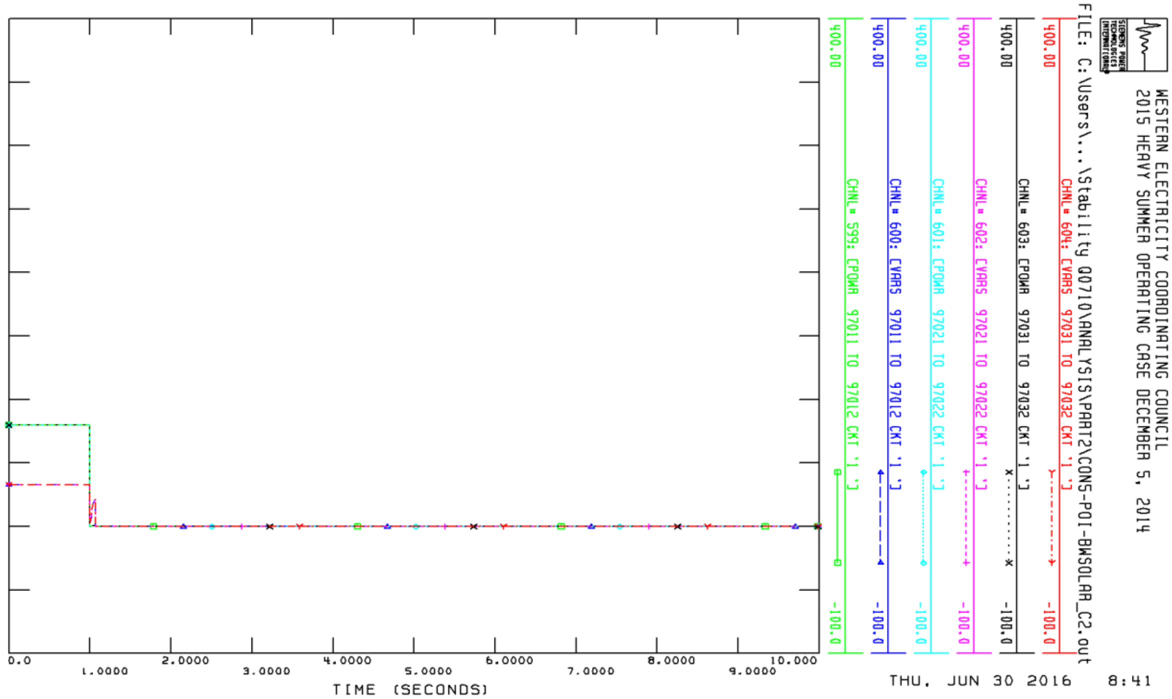
Plot B



Plot C

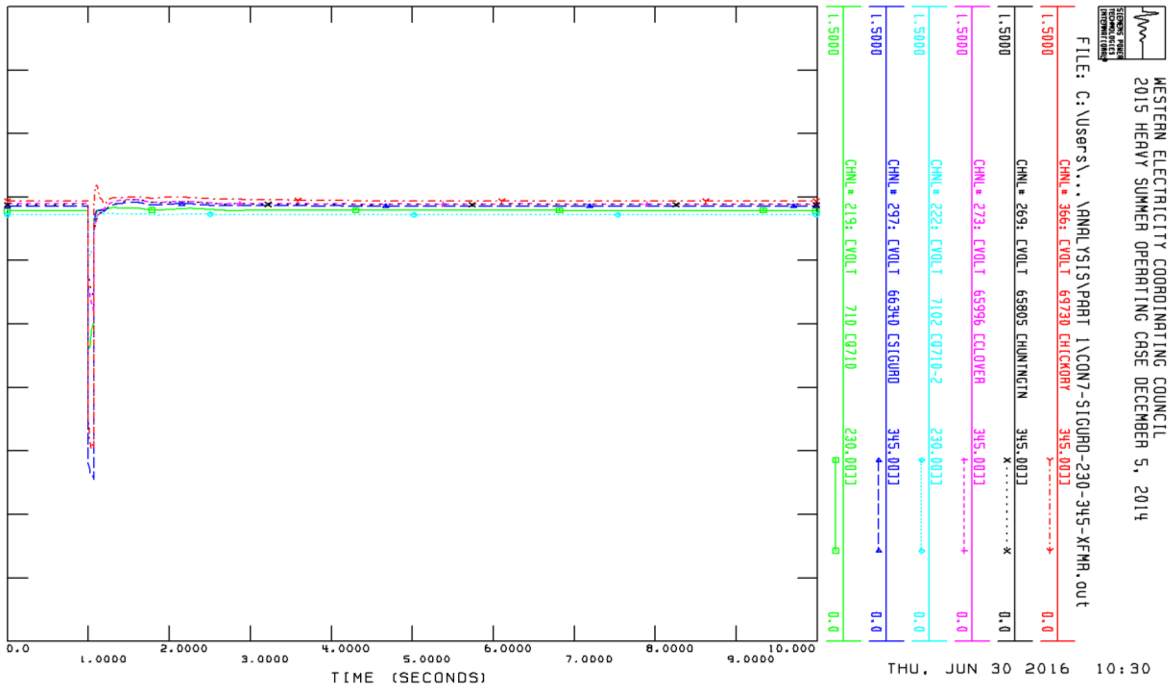

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\Stability Q0710\ANALYSIS\PART2\CONS-POI-BWSOLAR_C2.out
CHNL# 374: [VOLT 97031 [BWSOLAR_C3 0.4200]]
CHNL# 372: [VOLT 97021 [BWSOLAR_C2 0.4200]]
CHNL# 371: [VOLT 97011 [BWSOLAR_C1 0.4200]]
TIME (SECONDS)
THU, JUN 30 2016 14:26

Plot D

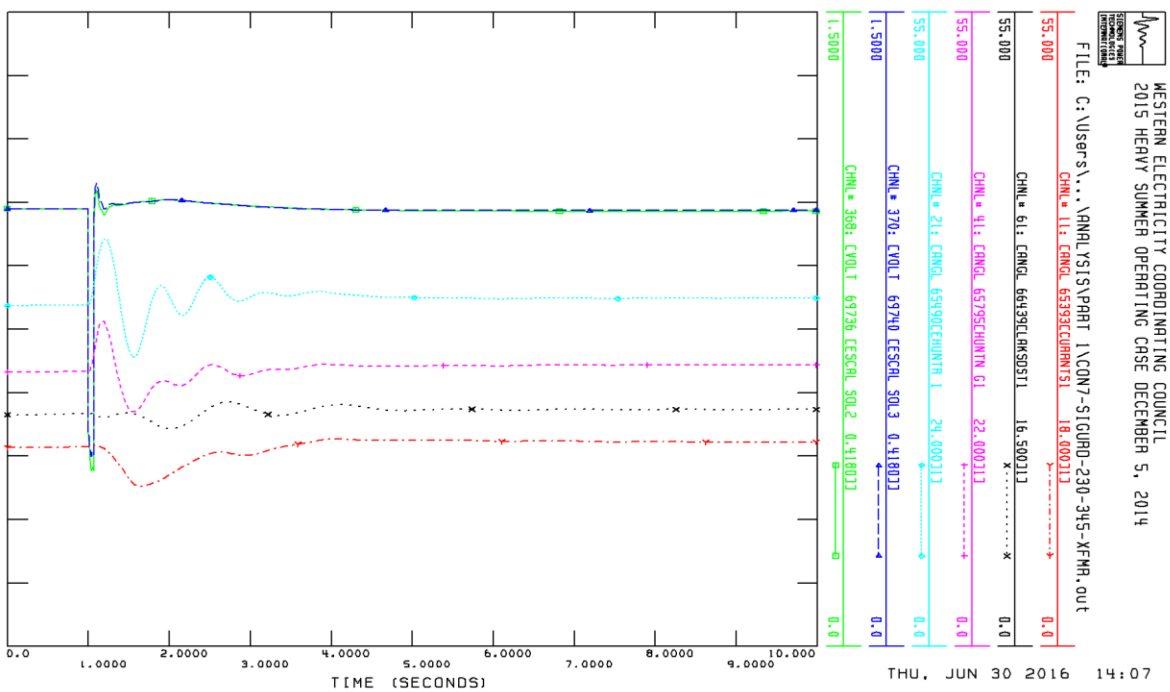

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\Stability Q0710\ANALYSIS\PART2\CONS-POI-BWSOLAR_C2.out
CHNL# 604: [VARS 97031 TO 97032 CKT '1 ']
CHNL# 603: [POWR 97031 TO 97032 CKT '1 ']
CHNL# 602: [VARS 97021 TO 97022 CKT '1 ']
CHNL# 601: [POWR 97021 TO 97022 CKT '1 ']
CHNL# 600: [VARS 97011 TO 97012 CKT '1 ']
CHNL# 599: [POWR 97011 TO 97012 CKT '1 ']
TIME (SECONDS)
THU, JUN 30 2016 8:41

5. Three phase fault at the Sigurd 230 kV bus followed by loss of the Sigurd 345/230 kV transformer (4 cycles)

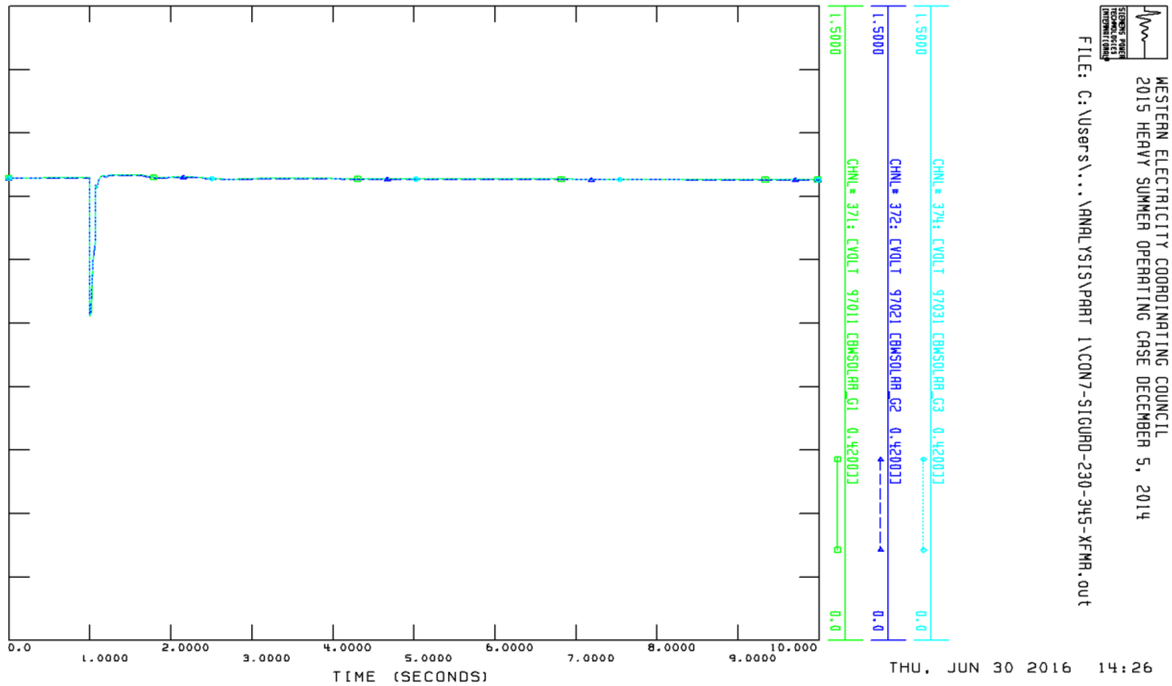
Plot A



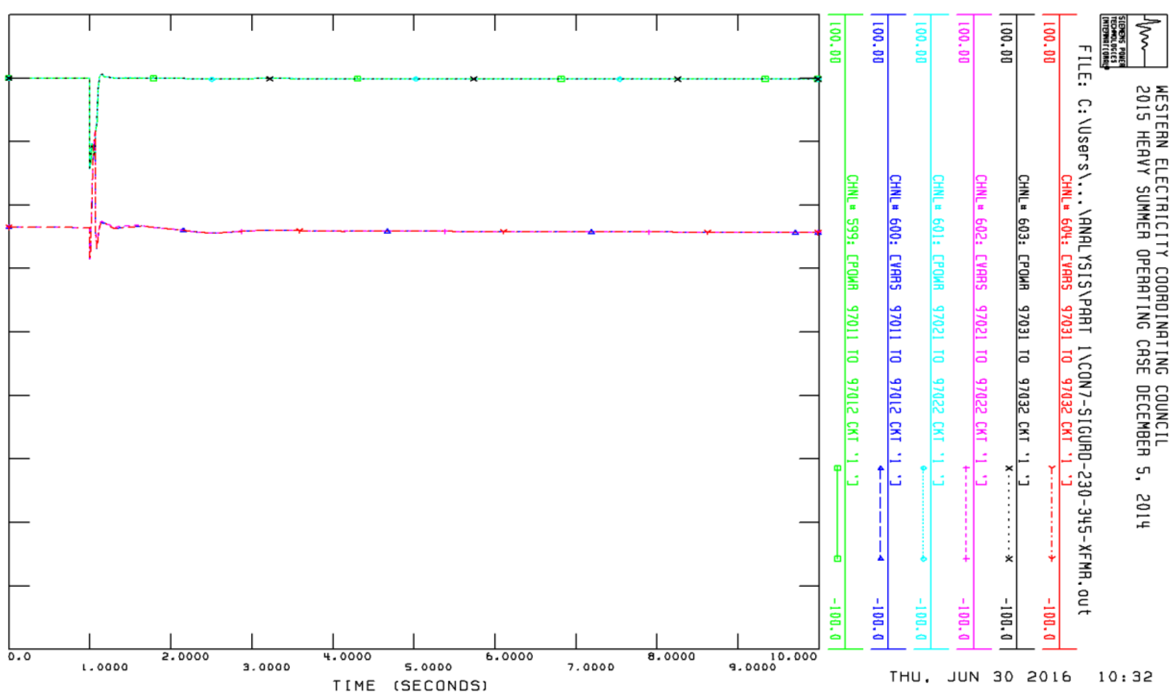
Plot B



Plot C

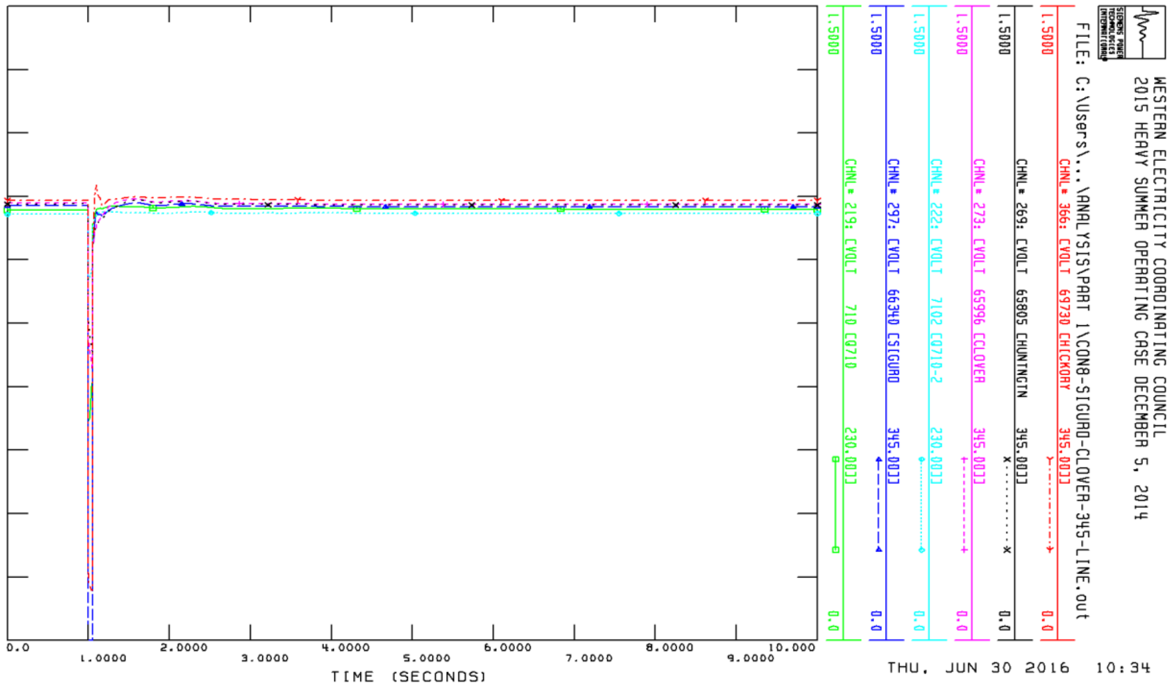

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON7-SIGURD-230-345-XFMR.out
CHNL# 374: [VOLT 97031 [BWSOLAR_G3 0.42000]]
CHNL# 372: [VOLT 97021 [BWSOLAR_G2 0.42000]]
CHNL# 371: [VOLT 97011 [BWSOLAR_G1 0.42000]]
1.5000
0.0
THU, JUN 30 2016 14:26
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

Plot D

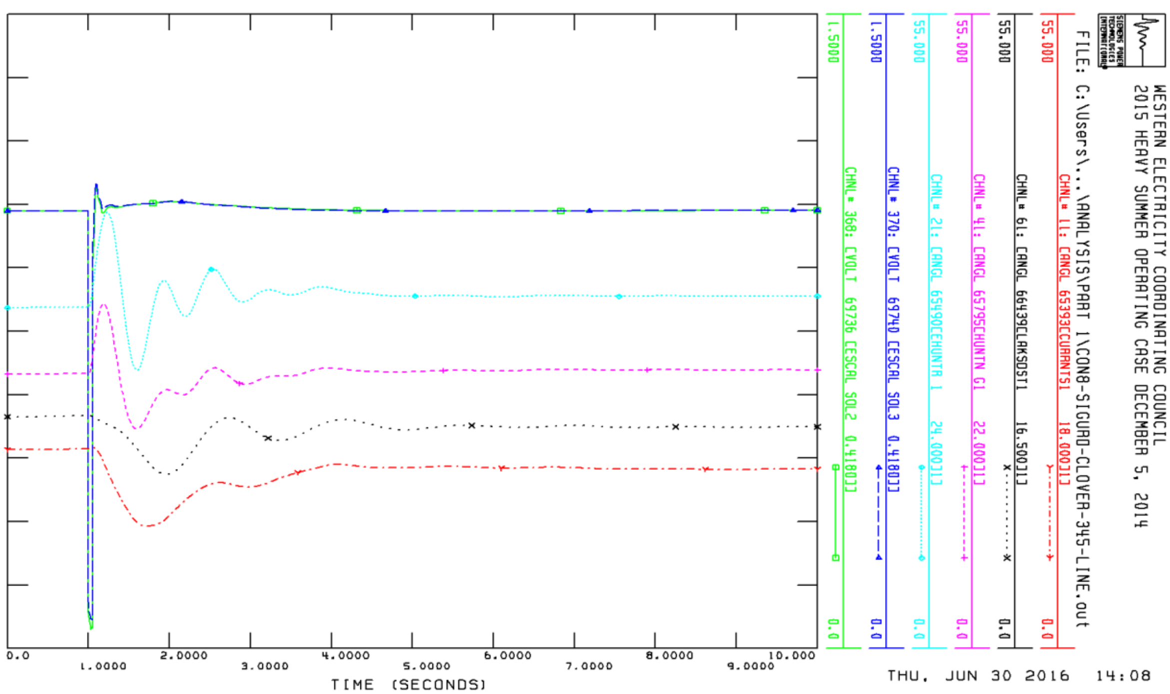

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON7-SIGURD-230-345-XFMR.out
CHNL# 604: [VARS 97031 TO 97032 CKT '1 ']
CHNL# 603: [POWR 97031 TO 97032 CKT '1 ']
CHNL# 602: [VARS 97021 TO 97022 CKT '1 ']
CHNL# 601: [POWR 97021 TO 97022 CKT '1 ']
CHNL# 600: [VARS 97011 TO 97012 CKT '1 ']
CHNL# 599: [POWR 97011 TO 97012 CKT '1 ']
100.00
-100.0
THU, JUN 30 2016 10:32
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

6. Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – Clover 345 kV circuit (3 cycles)

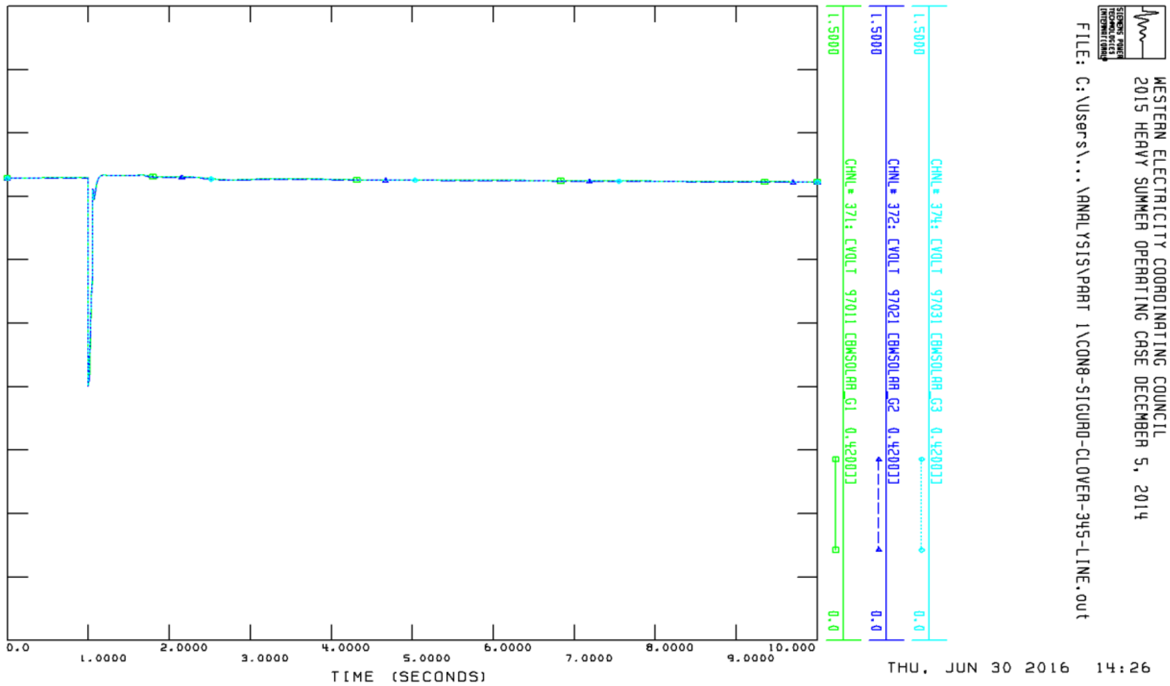
Plot A



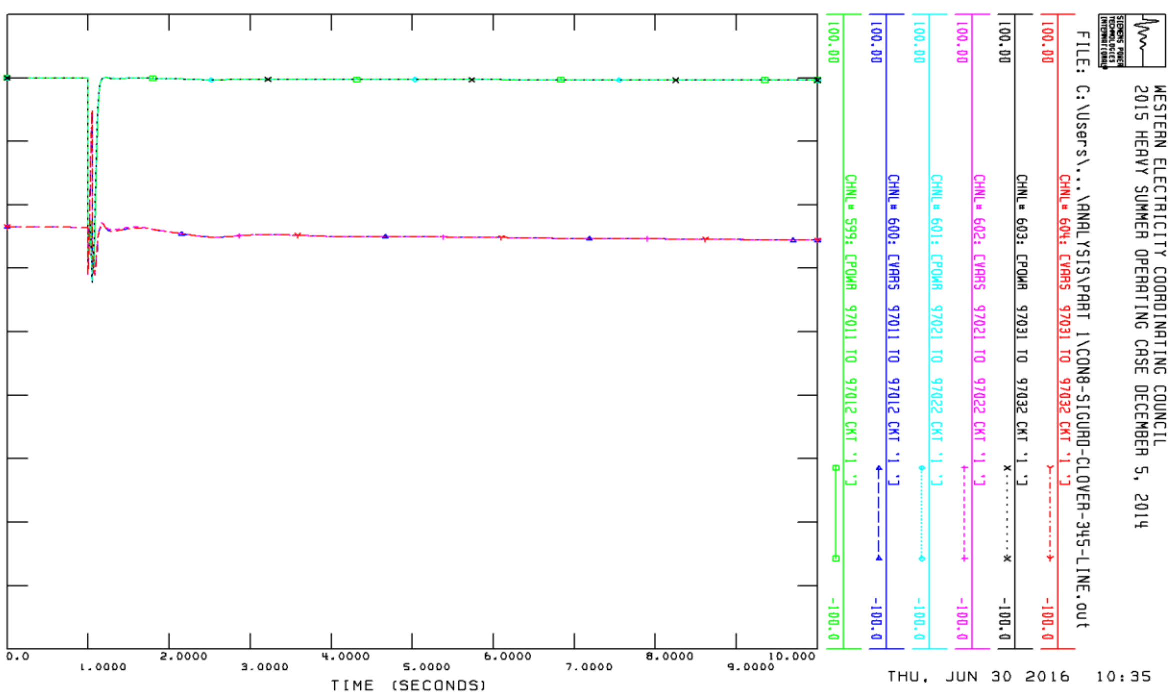
Plot B



Plot C

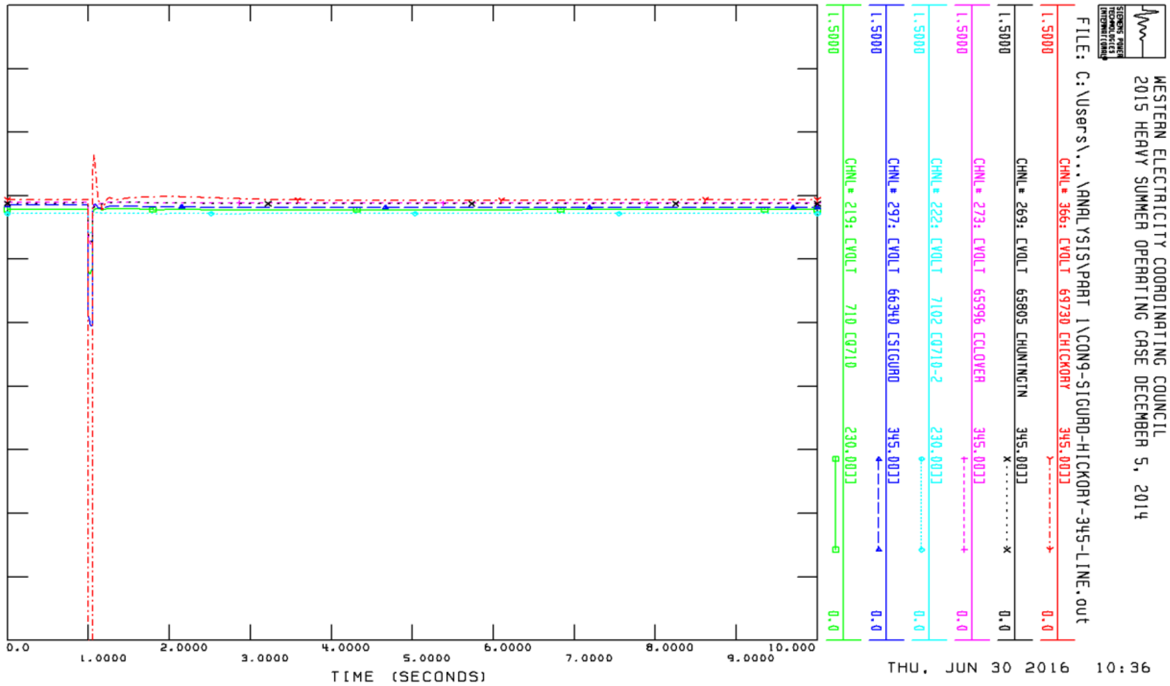

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON8-SIGURD-CLOVER-345-LINE.out
CHNL# 374: [VOLT 97031 [BWSOLAR_G3 0.4200]]
CHNL# 372: [VOLT 97021 [BWSOLAR_G2 0.4200]]
CHNL# 371: [VOLT 97011 [BWSOLAR_G1 0.4200]]
1.5000
0.0
THU, JUN 30 2016 14:26
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

Plot D

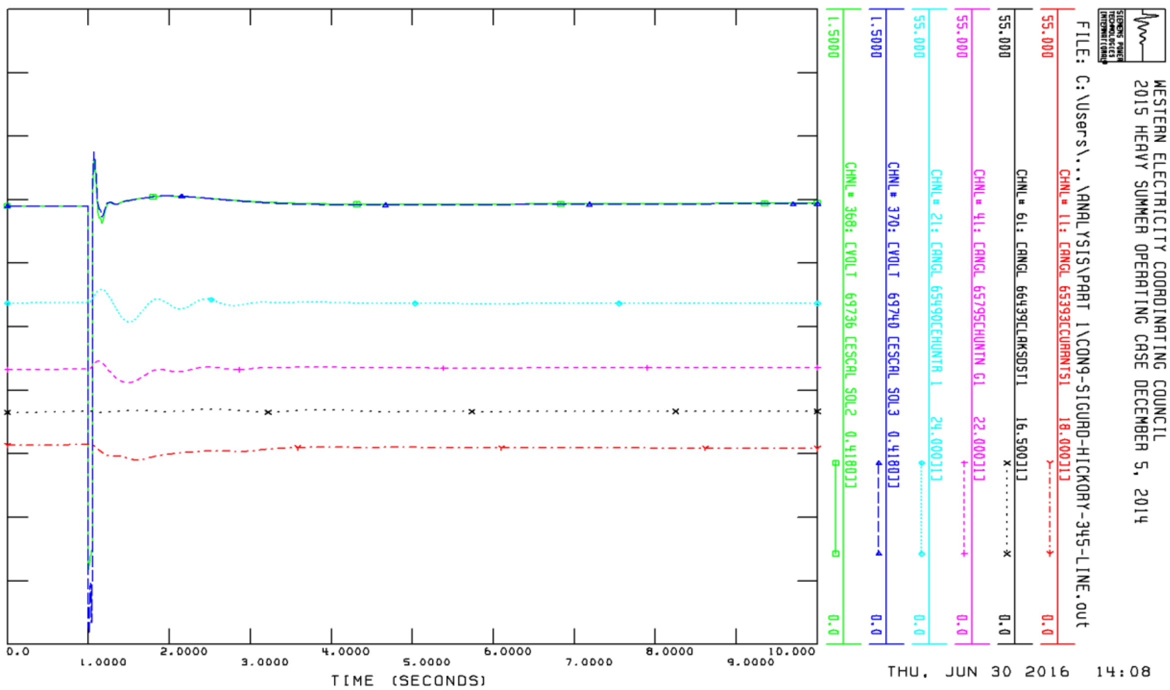

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON8-SIGURD-CLOVER-345-LINE.out
CHNL# 604: [VARS 97031 TO 97032 CKT '1 ']
CHNL# 603: [POWR 97031 TO 97032 CKT '1 ']
CHNL# 602: [VARS 97021 TO 97022 CKT '1 ']
CHNL# 601: [POWR 97021 TO 97022 CKT '1 ']
CHNL# 600: [VARS 97011 TO 97012 CKT '1 ']
CHNL# 599: [POWR 97011 TO 97012 CKT '1 ']
100.00
-100.0
THU, JUN 30 2016 10:35
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

7. Three phase fault at the Hickory 345 kV bus followed by loss of the Sigurd – Hickory 345 kV circuit (3 cycles)

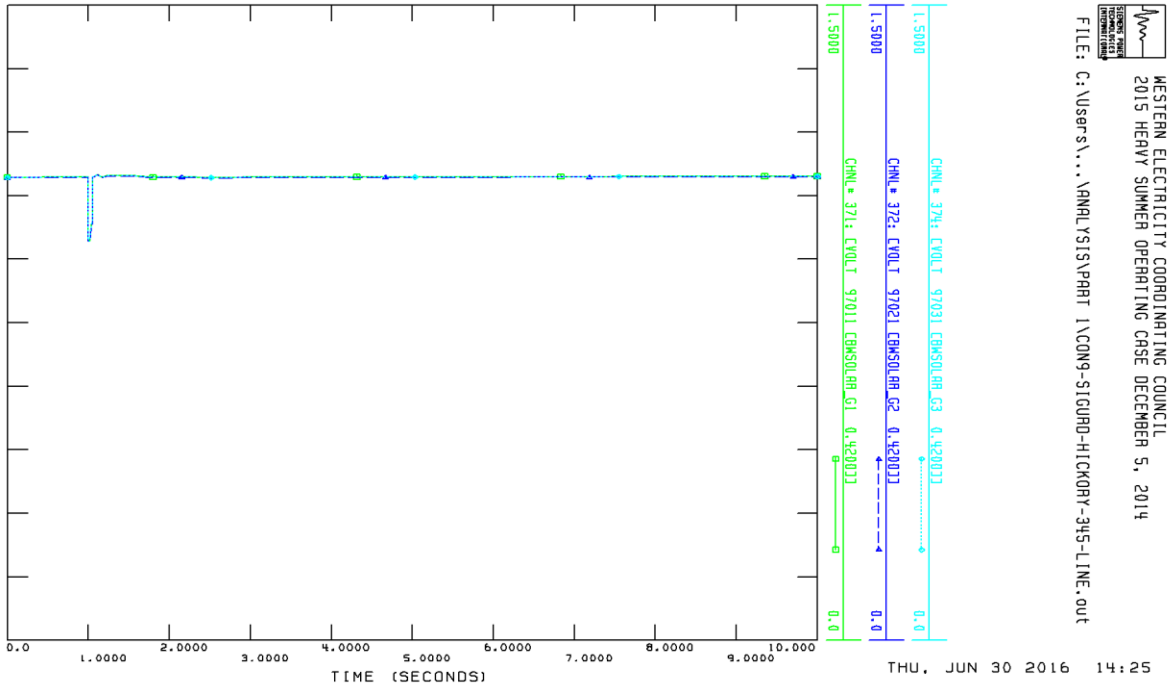
Plot A



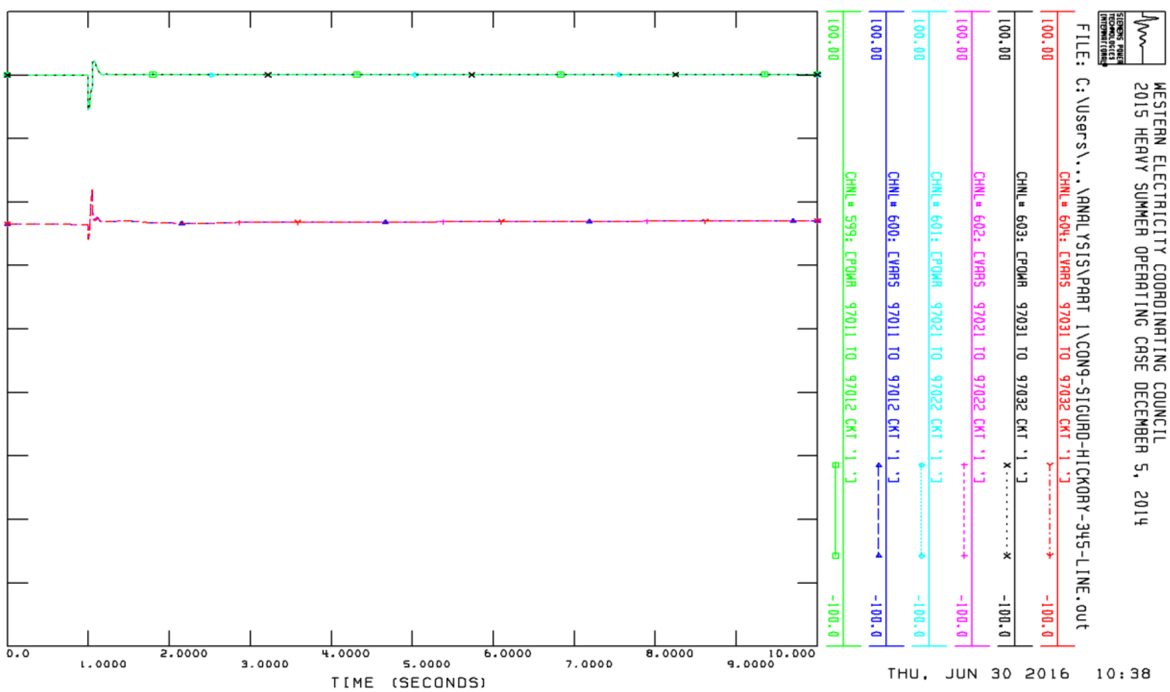
Plot B



Plot C

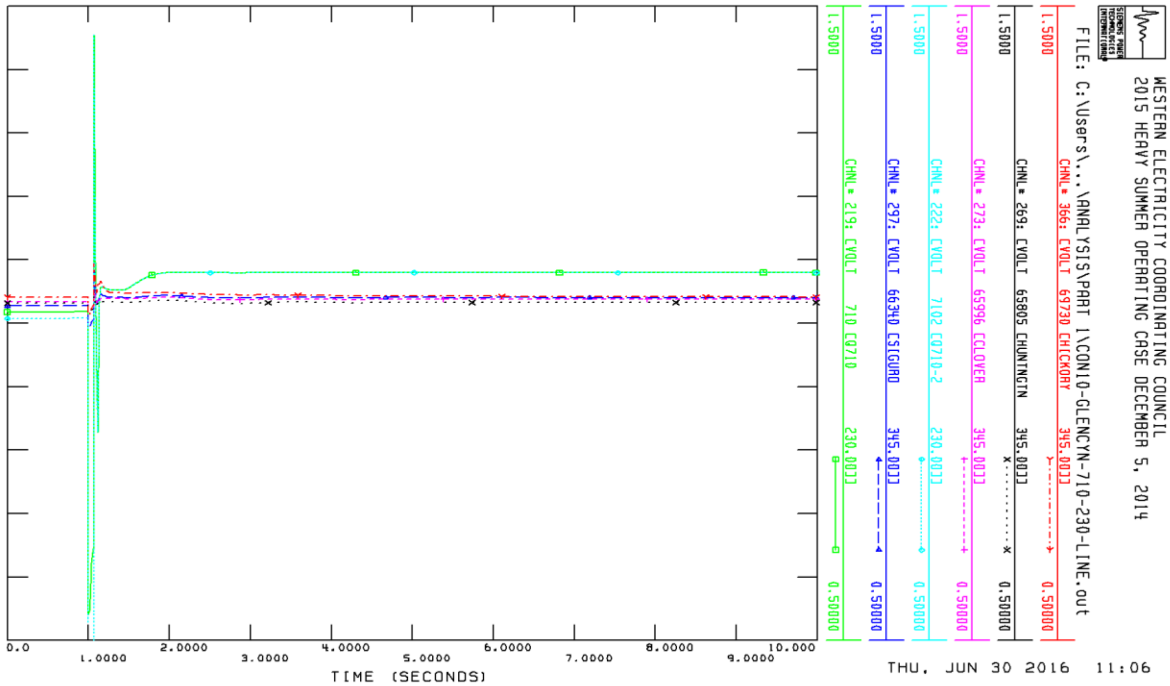

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON9-SIGURD-HICKORY-345-LINE.out
CHNL# 374: [VOLT 97031 [BWSOLAR_G3 0.4200]]
CHNL# 372: [VOLT 97021 [BWSOLAR_G2 0.4200]]
CHNL# 371: [VOLT 97011 [BWSOLAR_G1 0.4200]]
1.5000
0.0
THU, JUN 30 2016 14:25
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

Plot D

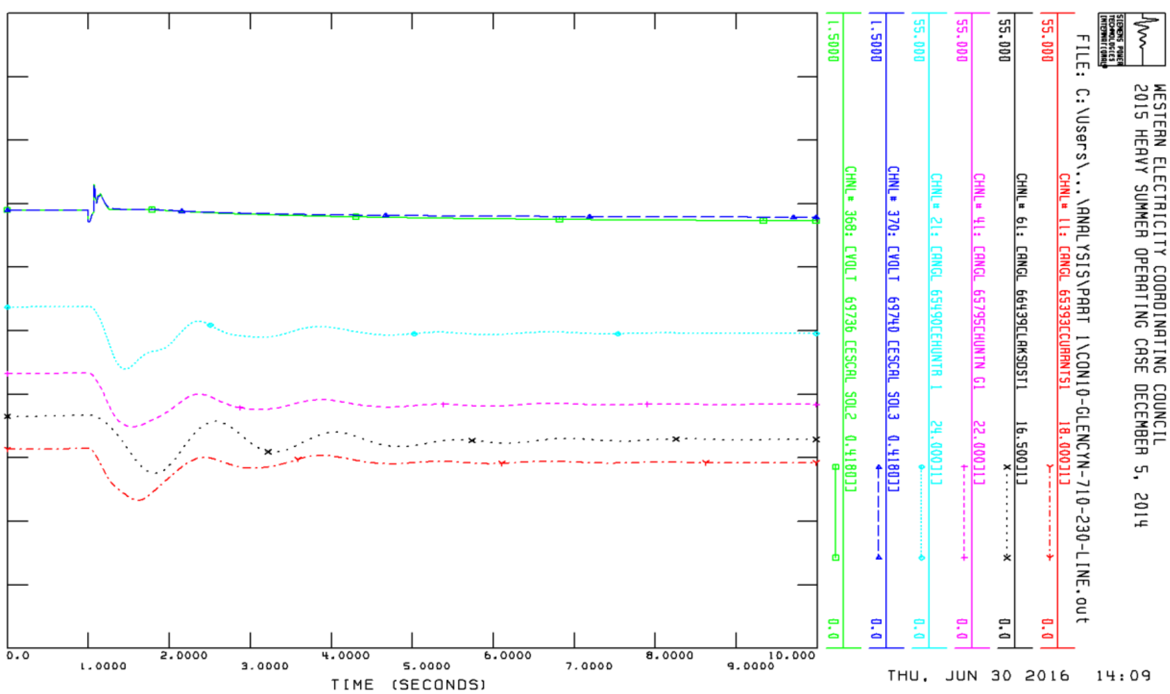

WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON9-SIGURD-HICKORY-345-LINE.out
CHNL# 604: [VARS 97031 TO 97032 CKT '1 ']
CHNL# 603: [POWR 97031 TO 97032 CKT '1 ']
CHNL# 602: [VARS 97021 TO 97022 CKT '1 ']
CHNL# 601: [POWR 97021 TO 97022 CKT '1 ']
CHNL# 600: [VARS 97011 TO 97012 CKT '1 ']
CHNL# 599: [POWR 97011 TO 97012 CKT '1 ']
100.00
-100.0
THU, JUN 30 2016 10:38
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

8 Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles)

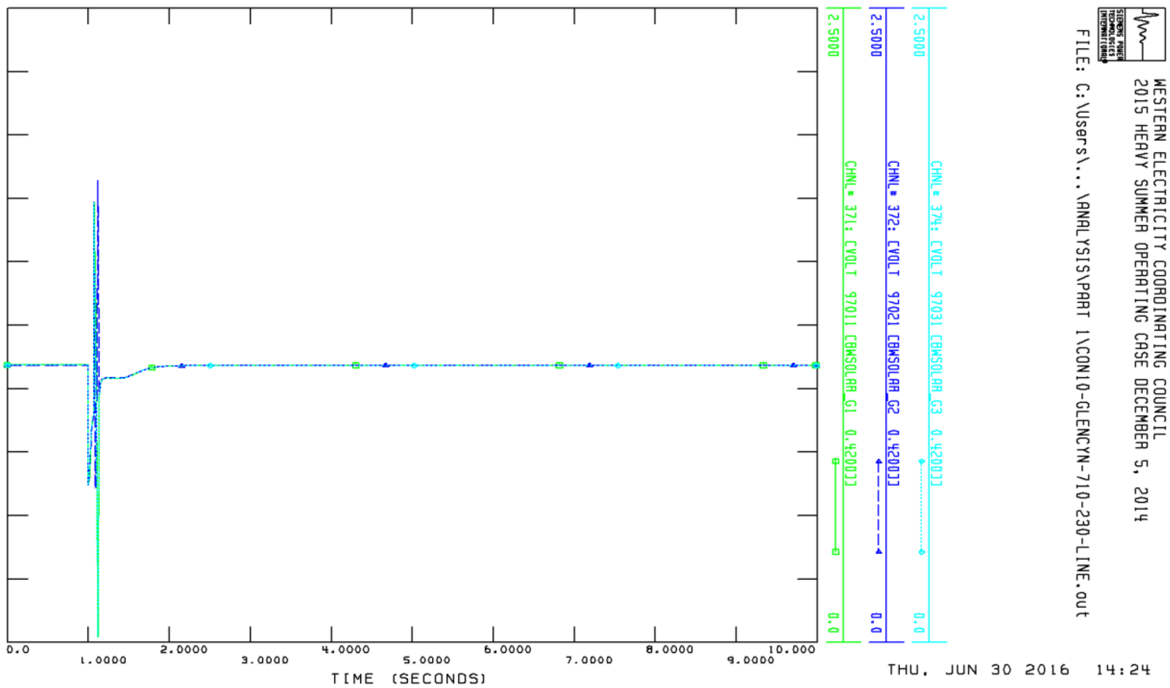
Plot A



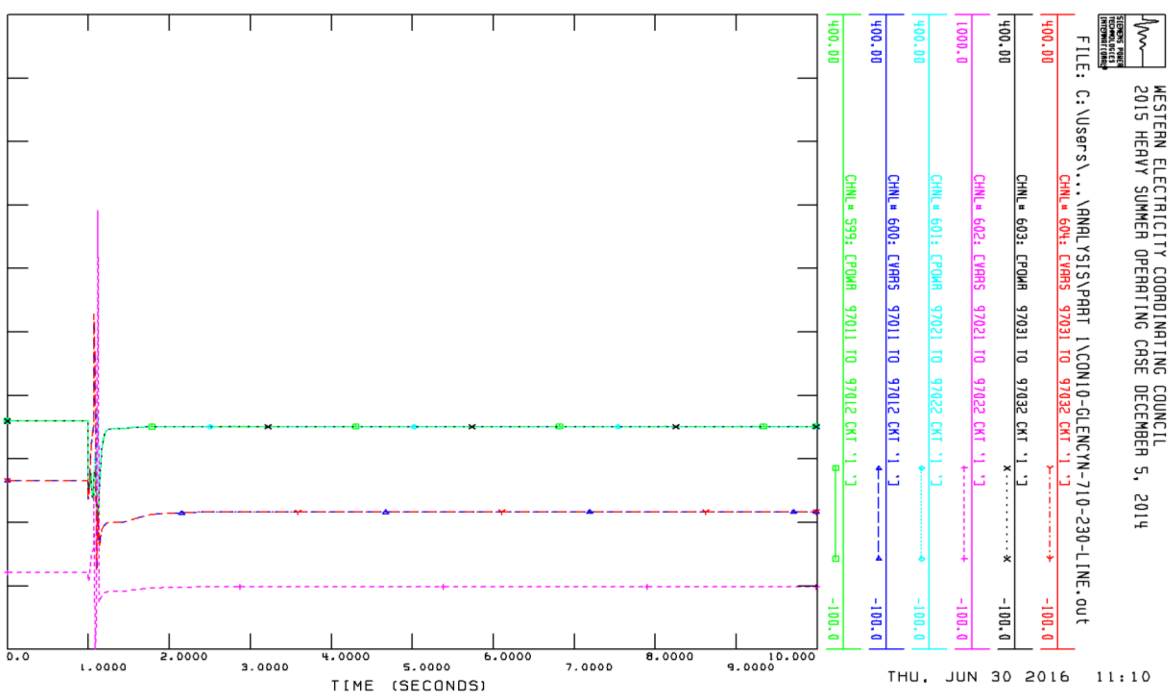
Plot B



Plot C


WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON10-GLENCYN-710-230-LINE.out
2.5000 CHNL# 374: [VOLT 97031 [BWSOLAR_G3 0.4200]] 0.0
2.5000 CHNL# 372: [VOLT 97021 [BWSOLAR_G2 0.4200]] 0.0
2.5000 CHNL# 371: [VOLT 97011 [BWSOLAR_G1 0.4200]] 0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, JUN 30 2016 14:24

Plot D


WESTERN ELECTRICITY COORDINATING COUNCIL
2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
FILE: C:\Users\...\ANALYSIS\PART 1\CON10-GLENCYN-710-230-LINE.out
400.00 CHNL# 604: [VARS 97031 TO 97032 CKT '1 '] -100.0
400.00 CHNL# 603: [POWR 97031 TO 97032 CKT '1 '] -100.0
1000.0 CHNL# 602: [VARS 97021 TO 97022 CKT '1 '] -100.0
400.00 CHNL# 601: [POWR 97021 TO 97022 CKT '1 '] -100.0
400.00 CHNL# 600: [VARS 97011 TO 97012 CKT '1 '] -100.0
400.00 CHNL# 599: [POWR 97011 TO 97012 CKT '1 '] -100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, JUN 30 2016 11:10