Interconnection System Impact Re-Study Report
Generation Interconnection Request # GI-2016-12

80MW Solar Photovoltaic Generating Facility
Boone 115kV Substation
Pueblo County, Colorado

Xcel Energy - Transmission Planning West
Xcel Energy
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Executive Summary

The GI-2016-12 is an 80MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Point of Interconnection (POI) requested is Public Service Company of Colorado's (PSCo's) Boone 115kV Substation. The proposed Commercial Operation Date (COD) and backfeed date of the Generating Facility are November 1, 2019 and October 1, 2019, respectively. Since the Generating Facility is still in the study phase, the proposed back-feed date is not achievable.

Per the interconnection request, GI-2016-12 was studied for both Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). For both ERIS and NRIS evaluations, the 80MW rated output of GI-2016-12 is assumed to be delivered to Public Service Company of Colorado (PSCo) native load, so existing PSCo generation is used as its sink.

The results of the single contingency analysis (P1 and P2-1) are given in Table 2. The overload on the Leetsdale – Monaco 230kV can be mitigated by reconductoring the limited sections of the line to a new rating of 503MVA. The overload on the MidwayPS 230/115kV transformer can be mitigated by replacing the 150MVA transformer with a 280MVA capable unit. The overloads on the Midway 345/230kV and Waterton 345/230kV can be mitigated by installing a second 345/230kV, 560MVA transformer at Midway Substation and a second 345/230kV, 560MVA transformer at Waterton Substation. The costs of these PSCo Network Upgrades are given in Table 7 below. In addition to the new overloads listed above, GI-2016-12 caused an increase in the Benchmark Case overloads in the CSU and TSGT systems. Therefore CSU and TSGT have been identified as Affected Systems for GI-2016-12.

CSU and TSGT have been identified as Affected Systems for GI-2016-12. PSCo has informed the Affected Systems regarding the contingency overloads on their facilities. Mitigation measures for each of the contingency overloads on the Affected Systems must be identified and addressed by the Affected Systems in order for GI-2016-12 to achieve NRIS of 80MW.

The transient stability analysis determined that all generating units are stable (remain in synchronism), display positive damping and the maximum transient voltage dips are within the acceptable dynamic performance criteria.

The short-circuit and breaker duty analysis determined that no breaker replacements are needed at the POI station and/or in neighboring PSCo stations.

The total estimated cost of the PSCo transmission system improvements required for GI-2016-12 to qualify for:

- **ERIS is $6.805 Million (Tables 5 and 6); and**
- **NRIS is $30.283 Million (Tables 5, 6 and 7)**

The ERIS and NRIS results above are contingent upon the mitigation of all overloads and

Network Upgrades identified in Attachment 1.

If there is a change in status of one or more higher-queued Interconnection Requests due to withdrawal from the queue or changing from NRIS to ERIS, and the Network Upgrades identified for the higher queued Interconnection Requests are not constructed, the Network Upgrade costs would become the responsibility of GI-2016-12 to the extent they are necessary to interconnect GI-2016-12. A restudy will be performed as needed to identify the new Network Upgrade responsibilities.

For GI-2016-12 interconnection:

NRIS (after required transmission system improvements) = 80MW

ERIS (after required transmission system improvements) = 80MW (output delivery assumes the use of existing firm or non-firm capacity of the PSCo Transmission System on an as-available basis)

Note: NRIS or ERIS, in and of itself, does not convey transmission service.

Introduction

The GI-2016-12 (GI) is an 80MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Generating Facility will be comprised of forty (40) FS2200-US inverters connected to twenty (20) 4MVA generator step-up transformers. The twenty (20) 4MVA generator step-up transformers will connect to an 80MVA main step-up transformer which will connect to the Boone 115kV Primary Point of Interconnection (POI) using a Generator Interconnection Customer owned 115kV tie-line. The geographical location of the transmission system near the POI is shown in Figure 1 below.

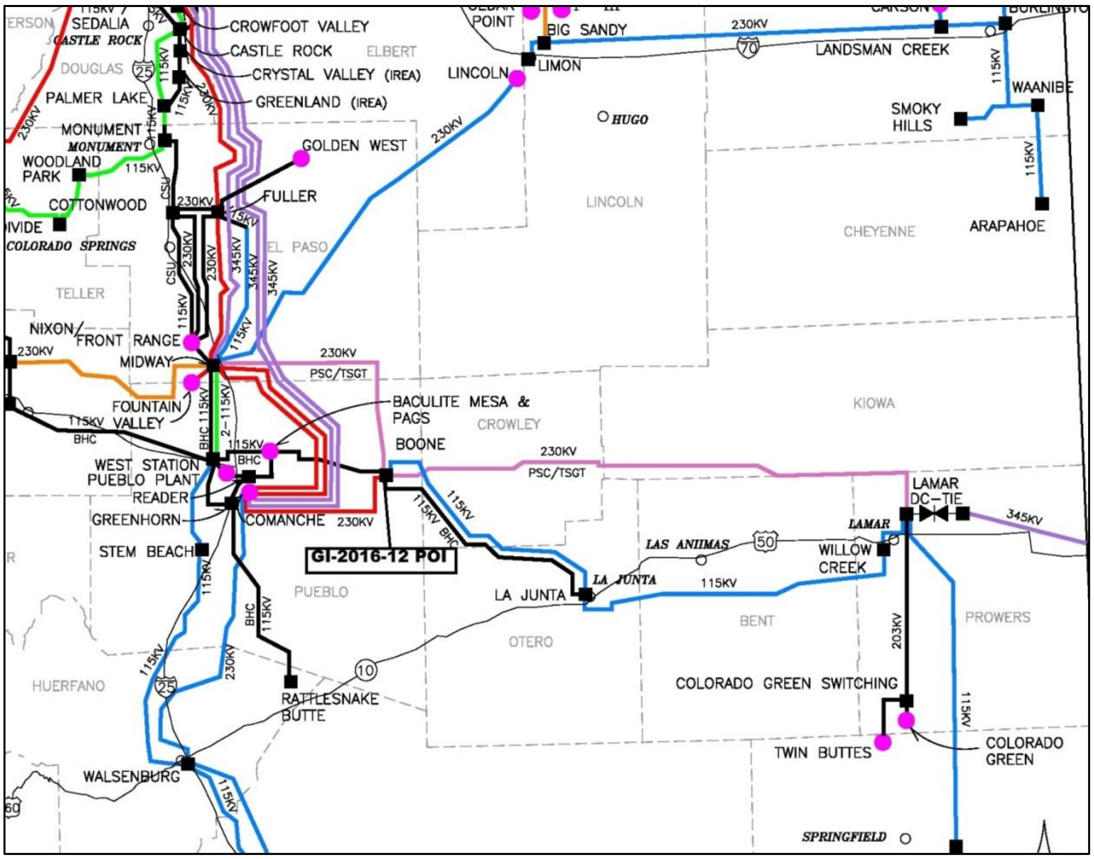


Figure 1 - GI-2016-12 Point of Interconnection and Study Area

The proposed Commercial Operation Date (COD) of the GI facility is November 30, 2019. The proposed back-feed date is October 1, 2019. Since the GI is still in the study phase, the proposed back-feed date is not achievable.

The main purpose of this Interconnection System Impact Re-Study is to determine the system impact of interconnecting 80MW of new generation at the Boone 115kV Substation. Per the Interconnection Study Request, the GI was studied for both Energy Resource Interconnection

Service (ERIS)[1] and Network Resource Interconnection Service (NRIS)[2]. For both ERIS and NRIS evaluations, the 80MW rated output of the GI is assumed to be delivered to Public Service Company of Colorado (PSCo) network load, so existing PSCo generation is used to sink the GI output.

Study Scope and Analysis Criteria

The scope of this report includes steady state (power flow) analysis, transient stability analysis, short circuit analysis, and scoping level cost estimates. The power flow analysis identifies thermal and voltage violations in the PSCo system and the neighboring systems as a result of the interconnection of the GI. Several single contingencies were studied. The transient stability analysis verifies that all generating units within the PSCo transmission system and the neighboring systems remain stable (in synchronism), have positive damping and satisfy acceptable dynamic performance criteria. The short circuit analysis determines the maximum available fault current at the POI and identifies if any circuit breaker(s) within the PSCo station(s) exceed their breaker duty ratings and need to be replaced.

PSCo adheres to applicable NERC Reliability Standards and WECC Reliability Criteria, as well as its internal transmission planning criteria for studies. The steady state analysis criteria are as follows:

P0 - System Intact conditions:
Thermal Loading: <=100% of the normal facility rating
Voltage range: 0.95 to 1.05 per unit
P1 & P2-1 – Single Contingencies:
Thermal Loading: <=100% Normal facility rating
Voltage range: 0.90 to 1.10 per unit
Voltage deviation: <=8% of pre-contingency voltage

The study area is the electrical system consisting of PSCo's transmission system and the neighboring transmission systems that may be impacted by or that could impact interconnection of the GI. The study area for GI-2016-12 includes WECC designated zones 121, 700, 703, 704, 705, 709, 710, 712, 752 and 757.

The same list of contingencies was run on the benchmark case and the study case, and the results were compared.

[1] Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

[2] Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission system (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as all other Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

For PSCo facilities, thermal violations attributable to the GI included any facilities without a pre-existing thermal violation but resulted in a thermal loading >100% post the GI addition and contributed to an incremental loading increase of 2% or more to the benchmark case loading. For non-PSCo facilities, thermal violations attributed to the GI include all new facility overloads with a thermal loading of >100% and existing thermal overloads that increased by 1% or more from the benchmark case overload post the GI addition.

The voltage violations attributed to the GI included any new voltage range and voltage deviation violations.

Transient stability criteria require that all generating machines remain in synchronism and all power swings should be well damped (positive damping) following a contingency event. Also, transient voltage performance should meet the following WECC Disturbance-Performance criteria:

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for all contingencies
- For all contingencies, following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- For contingencies without a fault, voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds

Serial Cumulative Power Flow Case Creation

The Base Case used for the power flow analysis originated from the 2023HS case built for the 2018 TPL1 Work Group of the Colorado Coordinated Planning Group (CCPG). As part of the case build effort for the TPL1 work group, the case was reviewed by PSCo and neighboring utilities within the CCPG foot print. All transmission planned projects in PSCo's 10 year transmission plan that are expected to be in-service before July 2023 are modeled in the Base Case, consistent with the case season and year. These projects are described at: (http://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/Q1_2019_Transmission_Plan.pdf)

This includes the following projects:

- Shortgrass 345kV Switching Station – ISD 2020
- Shortgrass – Cheyenne Ridge 345kV line – ISD 2020
- Graham Creek 115kV Substation – ISD 2021
- Husky 230/115kV Substation – ISD 2021
- Cloverly 115kV Substation – ISD 2021
- Ault – Husky 230kV line – ISD 2021
- Husky - Graham Creek – Cloverly 115kV line – ISD 2021
- Monument – Flying Horse 115kV Series Reactor – ISD 2021

- Gilman – Avon 115kV line – ISD 2022
- Upgrade Villa Grove – Poncha 69kV Line – ISD 2021
- Upgrade Poncha – San Luis Valley 115kV line – ISD 2021

The following PSCo FAC8 terminal equipment upgrade operational and maintenance projects for which PSCo has plans to increase the line ratings have been modeled at their future ratings in the Base Case:

- Waterton – Martin2 tap 115kV line was modeled at 189MVA
- Malta – Twin Lakes 115kV line was modeled at 143MVA
- Twin Lakes – Otereo 115kV line was modeled at 143MVA
- Otero – Buena Vista 115kV line was modeled at 150MVA
- Buena Vista – Ray Lewis 115kV line was modeled at 136MVA
- Ray Lewis – Poncha 115kV line was modeled at 164MVA
- Arapahoe – SantaFe – Daniels Park 230kV line was modeled at 560MVA
- Daniels Park – Prairie1 230kV line was modeled at 576MVA
- Greenwood – Monaco 230kV line was modeled at 503MVA
- Leetsdale – Monaco 230kV line was modeled at 470MVA
- Poncha – Smelter town 115kV line was modeled at 114MVA
- San Luis Valley – Sargent 115kV line was modeled at 120MVA

The Base Case also modeled the Sargent – Poncha 115kV line closed.

The following additional changes were made to the Tri-State Generation and Transmission (TSGT) model in the Base Case per further review and comment from TSGT:

- 30MW San Isabel Solar tapping Ludlo Tap – Pinon Canyon 115kV line
- 80MW TSGT_0809 solar facility tapping Gladstone – Walsenburg 230kV line
- 80MW TSGT_STEM_PV solar facility at Stem Beach 115kV bus
- Fuller – Vollmer – Black Squirrel 115 kV line modeled at 173 MVA

The following additional changes were made to the Black Hills Energy (BHE) model in the Base Case per further review and comment from BHE:

- Fountain Valley – DesertCove 115kV line was modeled at 171MVA. Planned upgrade project in 1/2021
- Fountain Valley – MidwayBR 115kV line was modeled at 171MVA. Planned upgrade project in 1/2021
- Pueblo West Substation – ISD 1/2021
- Skyline Ranch Substation – ISD 10/2021
- West Station – Greenhorn 115kV line Rebuild – ISD 9/2022

The following additional changes were made to the Colorado Springs Utilities (CSU) model in the Base Case per further review and comment from CSU:

- The Cottonwood – Tesla 34.5kV line is modeled open and Kettle Creek – Tesla 34.5kV line is modeled closed on the CSU system

- Grazing Yak Solar – ISD 2020
- Cottonwood 230/115kV auto-transformer replacement – ISD 2019
- Nixon – Kelker 230kV line uprate – ISD 2019

The Base Case model includes the existing PSCo generation resources at the time of this study.

The Base Case was updated to include the higher-queued generation with LGIAs (active or suspended) and their associated Network Upgrades. In addition, all higher-queued generation in the current PSCo Generation Interconnection Request (GIR) queue and their associated Network Upgrades are modeled. The higher-queued LGIAs modeled are GI-2009-8, GI-2010-8, GI-2014-2, GI-2014-12, GI-2014-13 and GI-2014-14. The higher-queued GIRs modeled are: GI-2014-6, GI-2014-8, GI-2014-9, GI-2016-4, GI-2016-7 and GI-2016-9. While the higher-queued NRIS requests are dispatched at 100% nameplate, the higher-queued ERIS requests are dispatched at 0MW.

The following PSCo Network Upgrades identified in the higher-queued GIRs are modeled in the GI-2016-12 Base Case:

- MidwayPS 230/115kV, 100MVA transformer replaced with 150MVA unit – Network Upgrade assigned to GI-2014-12
- Increase Greenwood – Prairie3 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-7
- Increase Daniels Park – Fuller 230kV line rating to 577MVA – Network Upgrade assigned to GI-2016-7
- San Luis Valley – Poncha 230kV line #2 – Network Upgrade assigned to GI-2016-9
- PonchaBR – MidwayPS 230kV line – Network Upgrade assigned to GI-2016-9
- Increase Ray Lewis – Buena Vista Tap 115kV line rating to 150MVA – Network Upgrade assigned to GI-2016-9
- Increase Daniels Park – Prairie3 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
- Increase Daniels Park – Prairie1 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
- Increase Daniels Park – Fuller 230kV line rating to 802MVA – Network Upgrade assigned to GI-2016-9
- Increase Greenwood – Prairie1 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-9
- Increase Greenwood – Monaco 230kV rating to 637MVA – Network Upgrade assigned to GI-2016-9

The Benchmark Case was created from the Base Case by changing the generation dispatch to reflect a heavy south to north flow on the Comanche – Midway – Jackson Fuller – Daniels Park transmission system. This was accomplished by adopting the generation dispatch given in Table

1 below. The generation dispatch of the neighboring systems was provided by those neighboring utilities.

Table 1 – Generation Dispatch Used to Stress the Benchmark Case (MW is Gross Capacity)

Bus Name	ID	Status	PGen (MW)	PMax (MW)	Owner
APT_DSLS 4.1600	G1	0	0	10	BHE
BAC_MSA GEN113.800	G1	1	90	90	BHE
BAC_MSA GEN213.800	G1	1	90	90	BHE
BAC_MSA GEN413.800	G1	1	35	40	BHE
BAC_MSA GEN413.800	G2	1	35	40	BHE
BAC_MSA GEN413.800	S1	1	20	24.8	BHE
BAC_MSA GEN513.800	G1	1	30	40	BHE
BAC_MSA GEN513.800	G2	1	30	40	BHE
BAC_MSA GEN513.800	S1	1	20	24.8	BHE
BAC_MSA GEN613.800	G1	1	0	40	BHE
BUSCHRNCH_LO0.7000	1	1	20	60	BHE
BUSCHRWTG1 0.7000	G1	1	14	28.8	BHE
E_CANON 69.000	G1	0	0	8	BHE
PP_MINE 69.000	G1	0	0	3	BHE
PUB_DSLS 4.1600	G1	0	0	10	BHE
R.F.DSLS 4.1600	G1	0	10	10	BHE
RTLSNKWNDLO 0.7000	G1	1	22	60	BHE
ALMSACT1 13.800	G1	0	17	17	PSCo
ALMSACT2 13.800	G2	0	19	14	PSCO
COGENTRIX_PV34.500	S3	1	19.5	30	PSCO
COMAN_1 24.000	1	1	357	360	PSCO
COMAN_2 24.000	C2	1	365	365	PSCO
COMAN_3 27.000	C3	1	788	780	PSCO
COMAN_PV 34.500	S1	1	102	120	PSCO
CO_GRN_E 34.500	W1	1	64.8	81	PSCo
CO_GRN_W 34.500	W2	1	64.8	81	PSCo
FTNVL1&2 13.800	G1	1	36	40	PSCO
FTNVL1&2 13.800	G2	1	36	40	PSCO
FTNVL3&4 13.800	G3	1	36	40	PSCO
FTNVL3&4 13.800	G4	1	36	40	PSCO
FTNVL5&6 13.800	G5	1	36	40	PSCO
FTNVL5&6 13.800	G6	1	36	40	PSCO
GSANDHIL_PV 34.500	S1	1	12.4	19	PSCO
JKFULGEN 0.6900	W1	1	200	249.43	PSCO
LAMAR_DC 230.00	DC	0	101	210	PSCO

SOLAR_GE 34.500	S2	1	19.5	30	PSCO
SUNPOWER 34.500	S1	1	33.8	52	PSCO
TWNBUTTE 34.500	W1	1	60	75	PSCO
SI_GEN 0.6000	1	1	6.1	30	TSGT
STEM_PV 0.4800	PV	1	80	100	TSGT
TBII_GEN 0.6900	W	1	60	76	TSGT
TSGT_0809 0.6200	PV	1	80	100	TSGT

For the power flow analysis, the Study Case for GI-2016-12 was created by adding the GI-2016-12 model to the Benchmark Case. The GI was modeled using the modeling data provided by the Customer. The modeling data was missing the Primary Frequency Response characteristics in the REPC_a model as required per PSCo Open Access Transmission Tariff Attachment N, so they were modeled using the following settings:

	Customer Data	Modified Data
frqflg	0	1
Ddn	20	20
Dup	0	-20
Fdbd1	0	-0.0006
Fdbd2	0	0.0006

The 80MW output of GI-2016-12 was sunk uniformly to the PSCo units outside the study area.

A power flow analysis was performed and the results of the Benchmark Case and Study Case were compared to determine the impacts of the interconnection of GI-2016-12. The steady state analysis was performed using PTI's PSSE Ver. 33.6.0 program and the ACCC contingency analysis tool.

Transient stability analysis was performed using General Electric's PSLF Ver.21.0_02 program. Three phase faults were simulated for selected single and multiple contingencies using standard clearing times. The voltage and frequency of transmission buses in the study area, and the relative rotor angle of generators in the study area were recorded and analyzed. PSLF's DYTOOLS EPCL program was used to simulate the disturbances.

Power Flow Analysis Results

The results of the single contingency analysis (P1 and P2-1) are given in Table 2 below.

Table 2 Power Flow Analysis Results

Note – Thermal overloads for single contingencies are calculated using the normal rating of the facility. All overloads are in red.

Table 2 – Summary of Thermal Violations from Single Contingency Analysis										
				Facility Loading Without GI-2016-12		Facility Loading With GI-2016-12				
Monitored Facility (Line or Transformer)	Type	Owner	Branch Rating MVA (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	% Change	NERC Single Contingency	Network Upgrade Assigned to GI
Leetsdale – Monaco 230kV	Line	PSCo	470	468.1	99.6%	478.5	101.8%	2.2%	Buckley – Smoky Hill 230kV	GI-2016-12
MidwayPS 230/115kV	Xfmr	PSCo	150	143.2	95.5%	154.3	102.9%	7.4%	Boone – MidwayPS 230kV	GI-2016-12
Midway 345/230kV	Xfmr	PSCo	560	555.4	99.2%	569.8	101.7%	1.5%	Daniels Park – Fuller 230kV	GI-2016-12
Waterton 345/230kV	Xfmr	PSCo	560	546	97.5%	562.2	100.4%	2.9	Daniels Park – Fuller 230kV	GI-2016-12
Palmer Lake – Monument 115kV	Line	CSU	108	168.3	155.8%	174.4	161.5%	5.7%	Daniels Park – Fuller 230kV	GI-2014-8
Brairgate S – Cottonwood S 115kV	Line	CSU	150	170.5	113.7%	172.5	115.0%	1.3%	Cottonwood N – KettleCreek S 115kV	GI-2014-8
Cottonwood N – KettleCreek S 115kV	Line	CSU	162	176.7	109.1%	178.7	110.3%	1.2%	Brairgate S – Cottonwood S 115kV	GI-2014-12
Kelker E – Templeton 115kV	Line	CSU	131	141.2	107.8%	142.8	109%	1.2%	Kelker W – Rock Island 115kV	GI-2016-7
Kelker W – Rock Island 115kV	Line	CSU	162	168.2	103.8%	169.8	104.8%	1.0%	Kelker E – Templeton 115kV	GI-2016-9
Monument – Gresham 115kV	Line	CSU	145	159.9	110.3%	164.9	113.7%	3.4%	Daniels Park – Fuller 230kV	GI-2016-9

Table 2 – Summary of Thermal Violations from Single Contingency Analysis										
				Facility Loading Without GI-2016-12		Facility Loading With GI-2016-12				
Monitored Facility (Line or Transformer)	Type	Owner	Branch Rating MVA (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	% Change	NERC Single Contingency	Network Upgrade Assigned to GI
Vollmer – Fuller 115kV	Line	TSGT	173	197.6	114.2%	202.8	117.2%	3.0%	Daniels Park – Fuller 230kV	GI-2016-7
Vollmer – Black Squirrel 115kV	Line	TSGT	173	197.6	114.3%	202.8	117.2%	3.0%	Daniels Park – Fuller 230kV	GI-2016-7
Black Forest - Black Squirrel MV 115kV	Line	TSGT	143	168.6	117.9%	173.6	121.4%	3.5%	Daniels Park – Fuller 230kV	GI-2016-7

The following new facility overloads are caused by the addition of GI-2016-12:

- Leetsdale – Monaco 230kV line loading increased from 99.6% to 101.8% (PSCo facility)
- MidwayPS 230/115kV transformer loading increased from 95.5% to 102.9% (PSCo facility)
- Midway 345/230kV transformer loading increased from 99.2% to 101.7% (PSCo facility)
- Waterton 345/230kV transformer loading increased from 97.5% to 100.4% (PSCo facility)

The overload on the Leetsdale – Monaco 230kV can be mitigated by reconductoring the limited sections of the line to a new rating of 503MVA. The overload on the MidwayPS 230/115kV transformer can be mitigated by replacing the 150MVA transformer with a 280MVA capable unit. The overloads on the Midway 345/230kV and Waterton 345/230kV can be mitigated by installing a second 345/230kV, 560MVA transformer at Midway Substation and a second 345/230kV, 560MVA transformer at Waterton Substation. The cost of these PSCo Network Upgrades is given in Table 7 below. In addition to the new overloads listed above, GI-2016-12 caused an increase in the Benchmark Case overloads in the CSU and TSGT systems. Therefore, CSU and TSGT have been identified as Affected Systems for GI-2016-12. For facility overloads that existed in the Benchmark Case, where the addition of GI-2016-12 caused an increase in the pre-existing Benchmark Case overload, the pre-existing overloads are assigned to the higher-queued GIs as noted in Table 2 above. However, GI-2016-12 is responsible to mitigate overloads on facilities caused by the GI-2016-12 project itself, taking into consideration the Network Upgrades that would be mitigated by the higher queued projects.

PSCo has informed the Affected Systems regarding the contingency overloads on their facilities. Mitigation measures for each of the contingency overloads on the Affected Systems must be identified and addressed by the Affected Systems in order for GI-2016-12 to achieve NRIS of 80MW.

The Interconnection Customer is responsible to design and build the GI to meet the Primary Frequency Response as required by OATT. As stated in the "Serial Cumulative Power Flow Case Creation" section, the modeling data provided by the Customer has been modified to account for the Primary Frequency Response requirements stated in PSCo OATT. These modifications are based on engineering judgement and only reflect modifications to modeling data.

Voltage Regulation and Reactive Power Capability

The Interconnection Customer is required to interconnect its Large Generating Facility with PSCo's Transmission System in accordance with the *Xcel Energy Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater Than 20 MW* (available at:

http://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Interconnection/Interconnections-POL-TransmissionInterconnectionGuidelineGreat20MW.pdf).

Accordingly, the following voltage regulation and reactive power capability requirements at the POI are applicable to this interconnection request:

- To ensure reliable operation, all Generating Facilities interconnected to the PSCo transmission system are expected to adhere to the *Rocky Mountain Area Voltage Coordination Guidelines (RMAVCG)*. Accordingly, since the POI for this interconnection request is located within Southeast Colorado - Region 4 defined in the *RMAVCG*; the applicable ideal transmission system voltage profile range is 1.02 – 1.03 per unit at regulated buses and 1.0 – 1.03 per unit at non-regulated buses.
- Xcel Energy's OATT (Attachment N effective 10/14/2016) requires all non-synchronous Generator Interconnection Customers to provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging at the high side of the generator substation. Furthermore, Xcel Energy requires every Generating Facility to have dynamic voltage control capability to assist in maintaining the POI voltage schedule specified by the Transmission Operator as long as the Generating Facility does not have to operate outside its 0.95 lag – 0.95 lead dynamic power factor range capability.
- It is the responsibility of the Interconnection Customer to determine the type (switched shunt capacitors and/or switched shunt reactors, etc.), the size (MVAR), and the locations (34.5kV or 230kV bus) of any additional static reactive power compensation needed within the generating plant in order to have adequate reactive capability to meet the +/- 0.95 power factor and the 1.0 – 1.03 per unit voltage range standards at the POI.

  Finally, it is the responsibility of the Interconnection Customer to compensate their generation tie-line to ensure minimal reactive power flow under no load conditions.

The Interconnection Customer is required to demonstrate to the satisfaction of PSCo Transmission Operations prior to the commercial in-service date of the generating plant that it can safely and reliably operate within the required power factor and voltage ranges (noted above).

Transient Stability Study Results

The transient stability analysis for GI-2016-12 simulated nine disturbances in the Study Case.

Table 3 Transient Stability Analysis Results

Stability Scenarios						
#	**Fault Location**	**Fault Type**	**Facility Tripped**	**Clearing Time (cycles)**	**Post-Fault Voltage Recovery**	**Angular Stability**
1	Boone 230kV	3ph	Boone 230/115kV Transformer	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
2	Boone 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
3	Boone 230kV	3ph	Boone – Comanche 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
4	Boone 230kV	3ph	Boone – Midway 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
5	Comanche 345 kV	3ph	Comanche#3 generator	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
6	Lamar 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
7	MidwayPS 230kV	3ph	All Fountain Valley gas units	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
8	MidwayPS 345kV	3ph	MidwayPS – Waterton 345kV line & Midway 230/345kV xfmr	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
9	Comanche 345kV	3ph	Comanche – Daniels Park 345kV 1 &2	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping

As shown in Table 3 above, the interconnection of GI-2016-12 produced no adverse system stability impact. The following results were obtained for every case and disturbance analyzed:

- ✓ No machines lost synchronism with the system
- ✓ No transient voltage drop violations were observed
- ✓ Machine rotor angles displayed positive damping

Transient stability plots showing surrounding bus voltages, bus frequencies, generator terminal voltages, generator relative angles, generator speeds, and generator power output for each of the disturbances run for each study scenario have been created and documented in Appendix A. Furthermore, it is the responsibility of the Interconnection Customer to ensure that its generating facility is capable of meeting the voltage ride-through and frequency ride-through (VRT and FRT) performance specified in the NERC Reliability Standard PRC-024.

Short Circuit and Breaker Duty Analysis

The calculated short circuit levels and Thevenin system equivalent impedances at the Boone 115kV POI are shown in Table 4.

Table 4 – Short Circuit Parameters at the Boone 115kV POI

	Before GI-2016-12Interconnection	After GI-2016-12 Interconnection
Three Phase Current	14135A	14552A
Single Line to Ground Current	13116A	14753A
Positive Sequence Impedance	0.516+j4.835ohms	0.516+j4.835ohms
Negative Sequence Impedance	0.535+j4.830ohms	0.535+j4.830ohms
Zero Sequence Impedance	0.748+j6.001ohms	0.472+j4.659ohms

A preliminary breaker duty study did not identify any circuit breakers that became over-dutied”[3] as a result of adding this generation.

Costs Estimates and Assumptions

The Transmission Provider has specified and estimated the cost of the equipment, engineering, procurement and construction work needed to interconnect GI-2016-12. The results of the engineering analysis for facilities owned by the Transmission Provider are summarized in Tables 5 and 6.

[3] “Over-dutied” circuit breaker: A circuit breaker whose short circuit current (SCC) rating is less than the available SCC at the bus.

Table 5: “Transmission Provider’s Interconnection Facilities” includes the nature and estimated cost of the Transmission Provider's Interconnection Facilities and an estimate of the time required to complete the construction and installation of such facilities.

Table 6: “Network Upgrades Required for Interconnection (applicable for either ERIS or NRIS)” includes the nature and estimated cost of the Transmission Provider's Network Upgrades necessary to accomplish the interconnection and an estimate of the time required to complete the construction and installation of such facilities.

Upgrades identified in Tables 5 and 6 are illustrated in Figure 2 which shows the physical and electrical connection of the Interconnection Customer’s Generating Facility to the Transmission Provider’s Transmission System. The one-line diagram also identifies the electrical switching configuration of the interconnection equipment including, without limitation: the transformer, switchgear, meters, and other station equipment.

The Transmission Provider has also specified and estimated the cost of the equipment, engineering, procurement and construction work of additional Network Upgrades required for NRIS. The results of the engineering analysis for facilities owned by the Transmission Provider are summarized in Table 7.

Table 7: “Additional Network Upgrades Required for NRIS” includes the nature and estimated cost of the Transmission Provider's additional Network Upgrades required for NRIS and an estimate of the time required to complete the construction and installation of such facilities.

Conclusion:

The total estimated cost of the PSCo transmission system improvements required for GI-2016-12 to qualify for:

- **ERIS is $6.805 Million (Tables 5 and 6); and**
- **NRIS is $30.283 Million (Tables 5, 6 and 7)**

For GI-2016-12 interconnection:

NRIS (after required transmission system improvements) = 80MW

ERIS (after required transmission system improvements) = 80MW (output delivery assumes the use of existing firm or non-firm capacity of the PSCo Transmission System on as as-available basis).

The ERIS and NRIS results above are contingent upon the mitigation of all overloads and Network Upgrades identified in Attachment 1.

If there is a change in status of one or more higher-queued Interconnection Requests due to withdrawal from the queue or changing from NRIS to ERIS, and the Network Upgrades

identified for the higher-queued Interconnection Requests are not constructed, the Network Upgrade costs could become the responsibility of GI-2016-12 to the extent they are necessary to interconnect GI-2016-12. A restudy will be performed as needed to identify the new Network Upgrade responsibilities and Contingent Facilities required for GI-2016-12.

Note: NRIS or ERIS, in and of itself, does not convey transmission service.

Table 5 –Transmission Provider's Interconnection Facilities

Element	Description	Cost Est. (Millions)
PSCo's Boone 115kV Bus	Interconnect Customer to tap at the Boone 115kV Bus The new equipment includes: • One 115kV gang switch with MOD • Three 115kV Arrestors Three 115kV metering CT/PT Units • Station controls • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures • Associated transmission line communications, fiber, relaying and testing.	**$0.763**
	Transmission line tap into substation.	**$0.055**
	Siting and Land Rights support for siting studies, land and ROW acquisition and construction	**$0.03**
	Total Cost Estimate for Transmission Provider's Interconnection Facilities	**$0.848**
Time Frame	**Site, design, procure and construct**	**18 Months**

Table 6 - Network Upgrades Required for Interconnection (applicable for either ERIS or NRIS) *

Element	Description	Cost Est. (Millions)
PSCo's Boone 115kV Bus	Interconnect Customer to tap at the Boone 115kV The new equipment includes: • Five 115kV breakers • Eleven 115kV gang switches • Station controls • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures • Associated transmission line communications, fiber, relaying and testing.	**$5.957**

	Siting and Land Rights support for substation construction	**N/A**
	Total Cost Estimate for Network Upgrades for Interconnection	**$5.957**
Time Frame	**Site, design, procure and construct**	**18 Months**

*** Contingent upon completion of the Network Upgrades for Interconnection listed in #1 #2 of Attachment 1.**

Table 7 –Network Upgrades Required for NRIS *

Element	Description	Cost Est. (Millions)
5281 Leetsdale-Monaco 230kV Line	Uprate line to 503MVA. Scope includes structure and hardware replacements, new rating is 503MVA.	$1.358
Midway 230/115kV Bus	Replace existing XFMR with 280MVA unit.	$5.209
Midway 345/230kV Bus	Install new 560MVA XFMR and associated breakers (4), switches (8), structures, and station controls.	$7.579
Waterton 345/230kV Bus	Install new 560MVA XFMR and associated breakers (4), switches (9), structures, and station controls.	$9.332
	Total Cost Estimate for Network Upgrades for Delivery (NRIS)	**$23.478**
Time Frame	**Site, design, procure and construct**	**36 Months**
	Total Project Estimate	**$30.283**

*** Contingent on completion of Network Upgrades listed in Attachment 1**

Cost Estimate Assumptions

- Appropriations level cost estimates for Interconnection Facilities and Network/Infrastructure Upgrades for Delivery have a specified accuracy of +/- 30%.
- Estimates are based on 2019 dollars (appropriate contingency and escalation applied).
- Labor is estimated for straight time only – no overtime included.
- Lead times for materials were considered for the schedule.
- Estimates are developed assuming typical construction costs for previously completed projects. These estimates include all applicable labor and overheads associated with the siting support, engineering, design, material/equipment procurement, construction, testing and commissioning of these new substation and transmission line facilities.

- PSCo (or its Contractor) crews will perform all construction, wiring, and testing and commissioning for PSCo owned and maintained facilities.
- The estimated time to site, design, procure and construct the Transmission Provider's Interconnection Facilities and Network Upgrades for ERIS is approximately 18 months after authorization to proceed has been obtained.
- The estimated time to site, design, procure and construct the network upgrades for delivery for is approximately 36 months after authorization to proceed has been obtained.
- It is anticipated that a Certificate of Public Necessity and Convenience (CPCN) will not be required for the construction of Transmission Provider Interconnection Facilities and the Network Upgrades for NRIS.
- The Solar Generation Facility is not in PSCo's retail service territory. Therefore, no costs for retail load metering are included in these estimates.
- Line and substation bus outages will be necessary during the construction period. Outage availability could potentially be problematic and further extend the estimated site, design, procure and construction time, causing further delays to the requested back-feed date .
- Estimates do not include the cost for any Customer owned equipment and associated design and engineering.
- The Customer will be required to design, procure, install, own, operate and maintain a Load Frequency/Automated Generation Control (LF/AGC) RTU at the Customer Substation. PSCo / Xcel will need indications, readings and data from the LF/AGC RTU.
- Power Quality Metering (PQM) will be required on the Customer's 230kV line terminating into the POI.
- Customer will string optical ground wire (OPGW) cable into the substation as part of their transmission line construction scope.

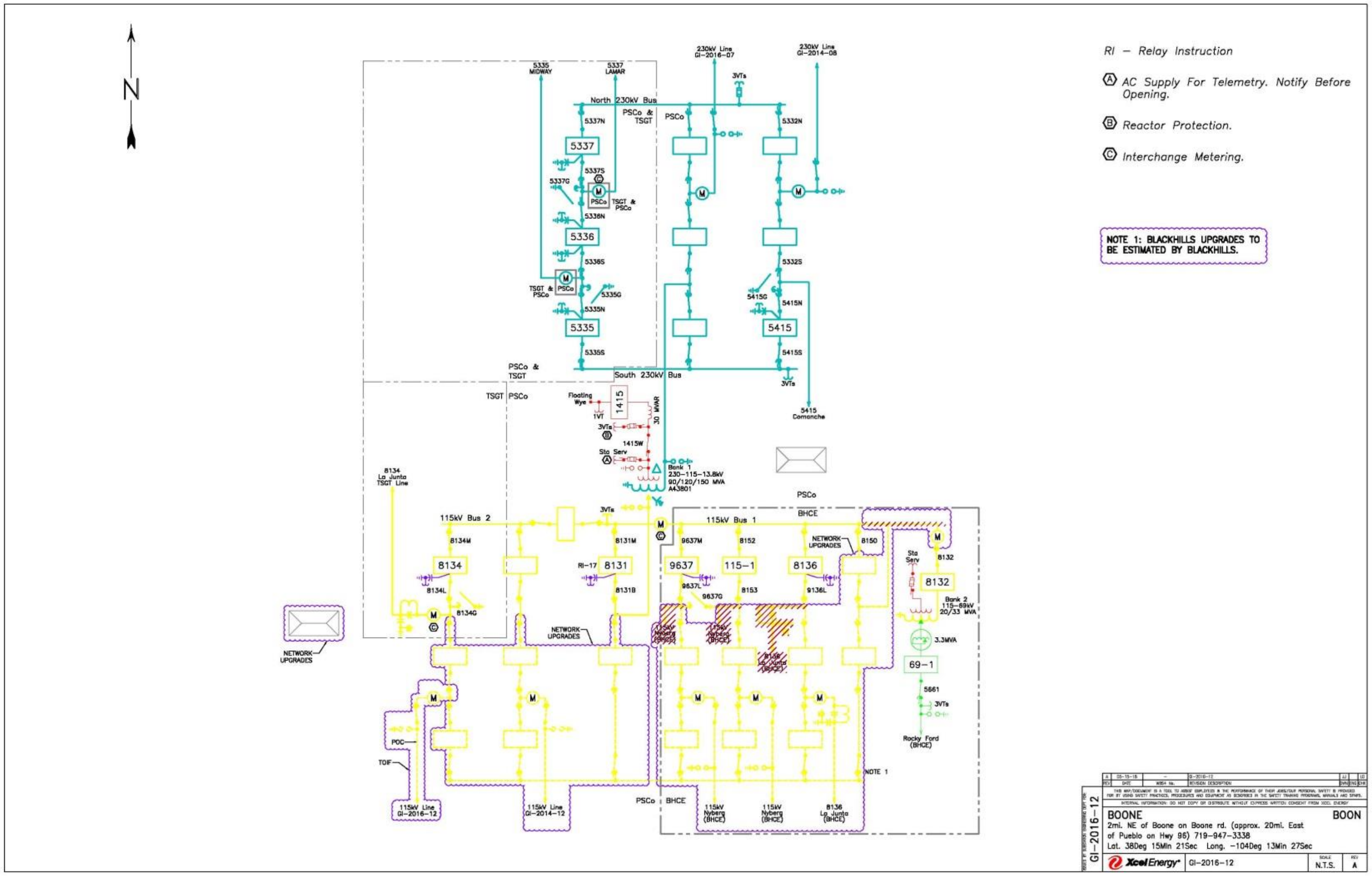


Figure 2 – Preliminary one-line of the GI-2016-12 POI within the Boone 115kV Substation

Attachment 1 – **Contingent Facilities Assigned to GI-2016-12**

Following is the list of the unbuilt Interconnection Facilities and Network Upgrades upon which the GI-2016-12 request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for re-studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

1. Network Upgrades for Interconnection identified for higher-queued Generation Interconnection Requests: GI-2014-12 (please refer to the corresponding Facilities Study report for details)
2. Network Upgrades for Interconnection assigned to GI-2016-12 (refer to Table 5 and 6 of this report)
3. The following Network Upgrades assigned to the higher-queued Generation Interconnection Requests
   - MidwayPS 230/115kV, 100MVA transformer replaced with 150MVA unit – Network Upgrade assigned to GI-2014-12
   - Increase Greenwood – Prairie3 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-7
   - Increase Daniels Park – Fuller 230kV line rating to 577MVA – Network Upgrade assigned to GI-2016-7
   - Increase Ray Lewis – Buena Vista Tap 115kV line rating to 150MVA – Network Upgrade assigned to GI-2016-9
   - Increase Daniels Park – Prairie3 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
   - Increase Daniels Park – Prairie1 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
   - Increase Daniels Park – Fuller 230kV line rating to 802MVA – Network Upgrade assigned to GI-2016-9
   - Increase Greenwood – Prairie1 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-9
   - Increase Greenwood – Monaco 230kV rating to 637MVA – Network Upgrade assigned to GI-2016-9

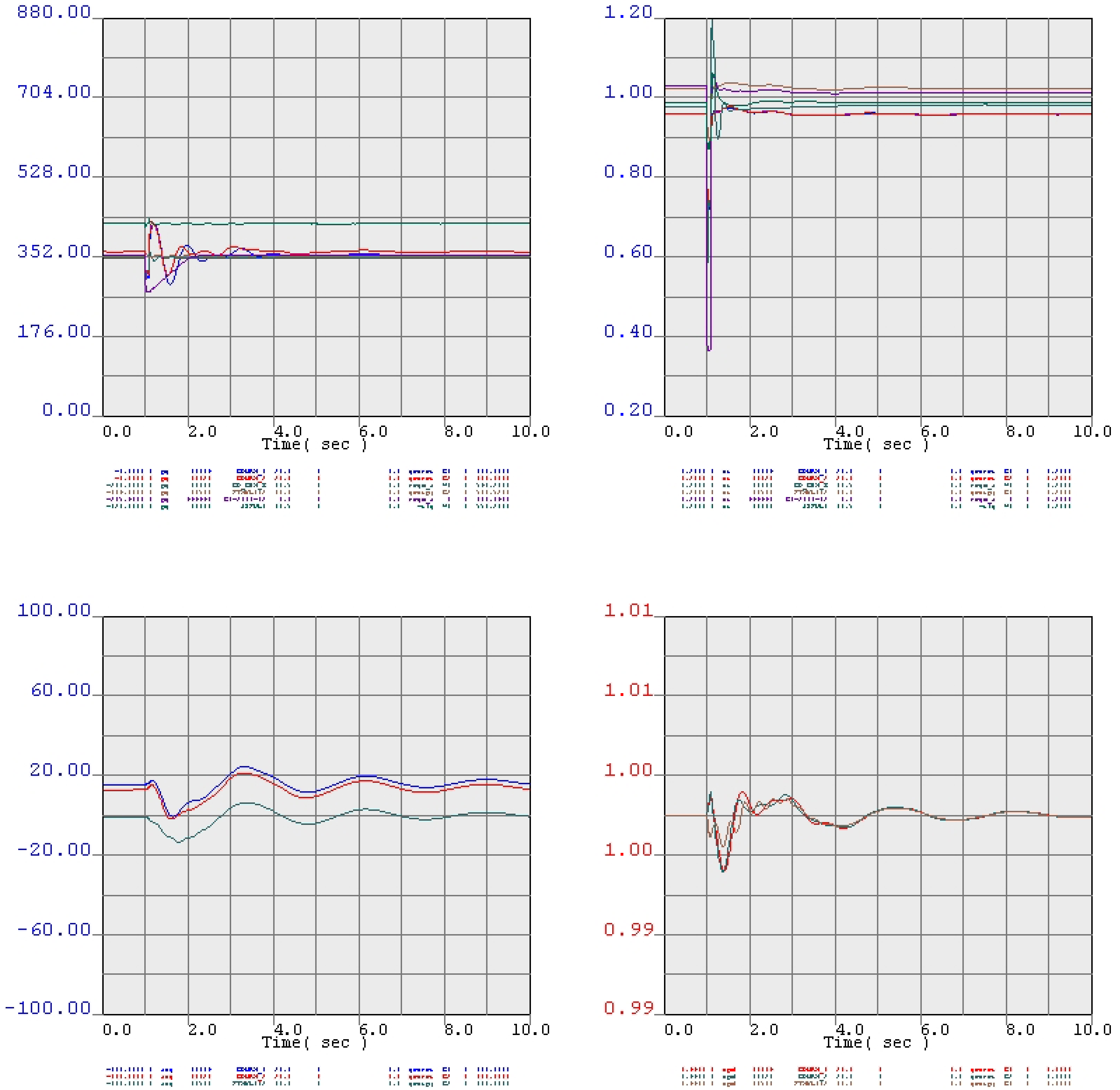
4. The following Network Upgrades required for GI-2016-12 (refer to Table 5 above for PSCo facilities costs)
   - Uprate the Leetsdale – Monaco 230kV line to 503MVA (PSCo facility)
   - Replace the MidwayPS 230/115kV, 150MVA transformer with 280MVA capable unit (PSCo facility)
   - Second Midway 345/230kV, 560MVA transformer (PSCo facility)
   - Second Waterton 345/230kV, 560MVA transformer (PSCo facility)

There are Network Upgrades needed to mitigate incremental overloads on the pre-existing Affected Systems facility overloads caused by GI-2016-12 (as listed in Table 2 above). The GI Customer is responsible for working with the Affected System and the higher-queued GI to make sure the Network Upgrades are in-service before the GI can achieve full NRIS as requested.

5. The following unbuilt transmission projects modeled in the Base Case
   - PSCo's Monument – Flying Horse 115kV Series Reactor project
   - PSCo's project to upgrade Villa Grove – Poncha 69kV Line
   - PSCo's project to upgrade Poncha – San Luis Valley 115kV line
   - PSCo's terminal upgrade project to uprate the Waterton – Martin2 tap 115kV line to 189MVA
   - PSCo's terminal upgrade project to uprate the Malta – Twin Lakes 115kV line to 143MVA
   - PSCo's terminal upgrade project to uprate the Twin Lakes – Otero 115kV line to 143MVA
   - PSCo's terminal upgrade project to uprate the Otero – Buena Vista 115kV line to 150MVA
   - PSCo's terminal upgrade project to uprate the Buena Vista – Ray Lewis 115kV line to 136MVA
   - PSCo's terminal upgrade project to uprate the Ray Lewis – Poncha 115kV line to 164MVA
   - PSCo's terminal upgrade project to uprate the Arapahoe – SantaFe – Daniels Park 230kV to 560MVA
   - PSCo's terminal upgrade project to uprate the Daniels Park – Prairie1 230kV line to 576MVA
   - PSCo's terminal upgrade project to uprate the Greenwood – Monaco 230kV line to 503MVA
   - PSCo's terminal upgrade project to uprate the Leetsdale – Monaco 230kV line to 470MVA
   - PSCo's terminal upgrade project to uprate the Poncha – Smelter town 115kV line to 114MVA
   - PSCo's terminal upgrade project to uprate the San Luis Valley – Sargent 115kV line to 120MVA
   - TSGT's planned project to uprate the Fuller – Vollmer – Black Squirrel 115 kV line to 173 MVA
   - BHE's planed project to uprate the Fountain Valley – DesertCove 115kV line to 171MVA
   - BHE's planned project to uprate the Fountain Valley – MidwayBR 115kV line to 171MVA

- BHE's Pueblo West Substation
- BHE's Skyline Ranch Substation
- BHE's West Station – Greenhorn 115kV line Rebuild project
- CSU's project to close Tesla - Cottonwood 34.5kV line and open the Kettle Creek – Tesla 34.5kV line
- CSU's new Cottonwood 230/115kV auto-transformer replacement
- CSU's Nixon – Kelker 230kV line uprate project

The higher-queued GIRs modeled in this study report are: GI-2009-8, GI-2010-8, GI-2014-2, GI-2014-6, GI-2014-8, GI-2014-9, GI-2014-12, GI-2014-13, GI-2014-14, GI-2016-4, GI-2016-7 and GI-2016-9. In case of withdrawal of any of these higher-queued GIs or change in status from NRIS to ERIS, the Contingent Facilities assigned to GI-2016-12 would be updated as needed.



tran_1
Boone 230kV bus fault, lose Boone 230/115kV bank

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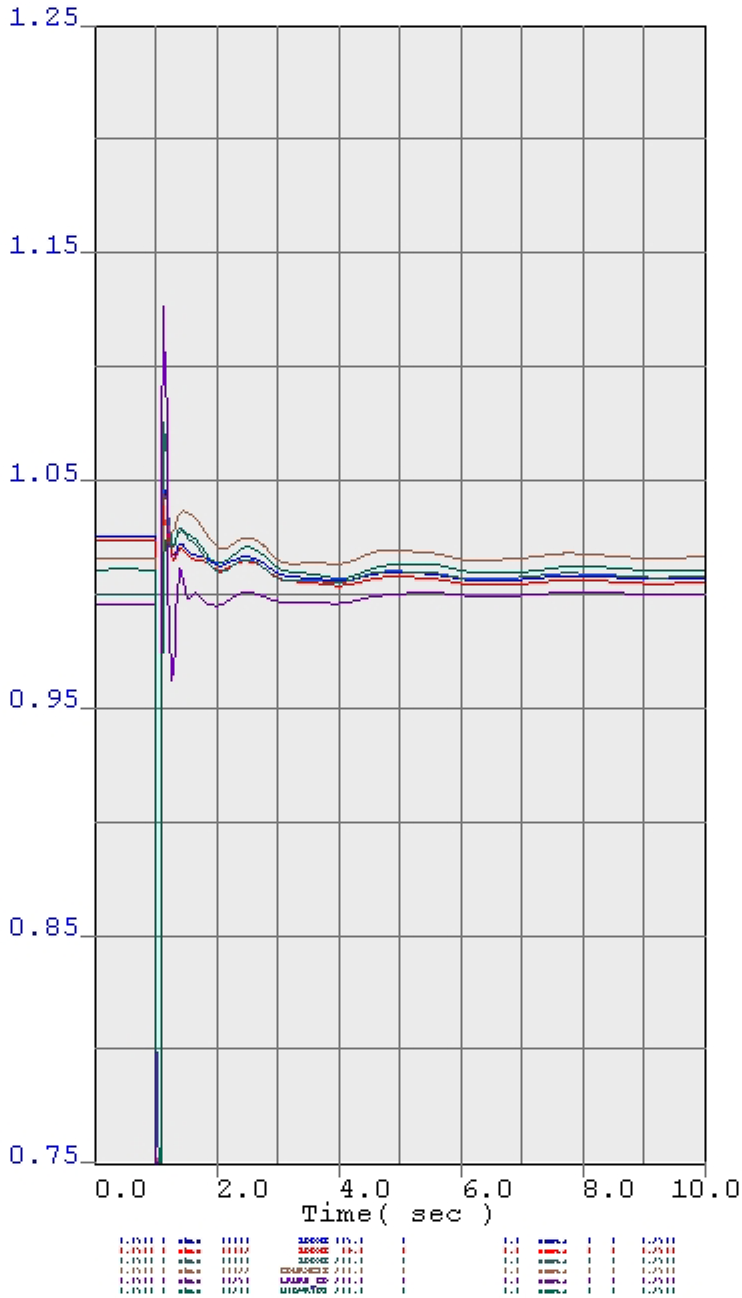
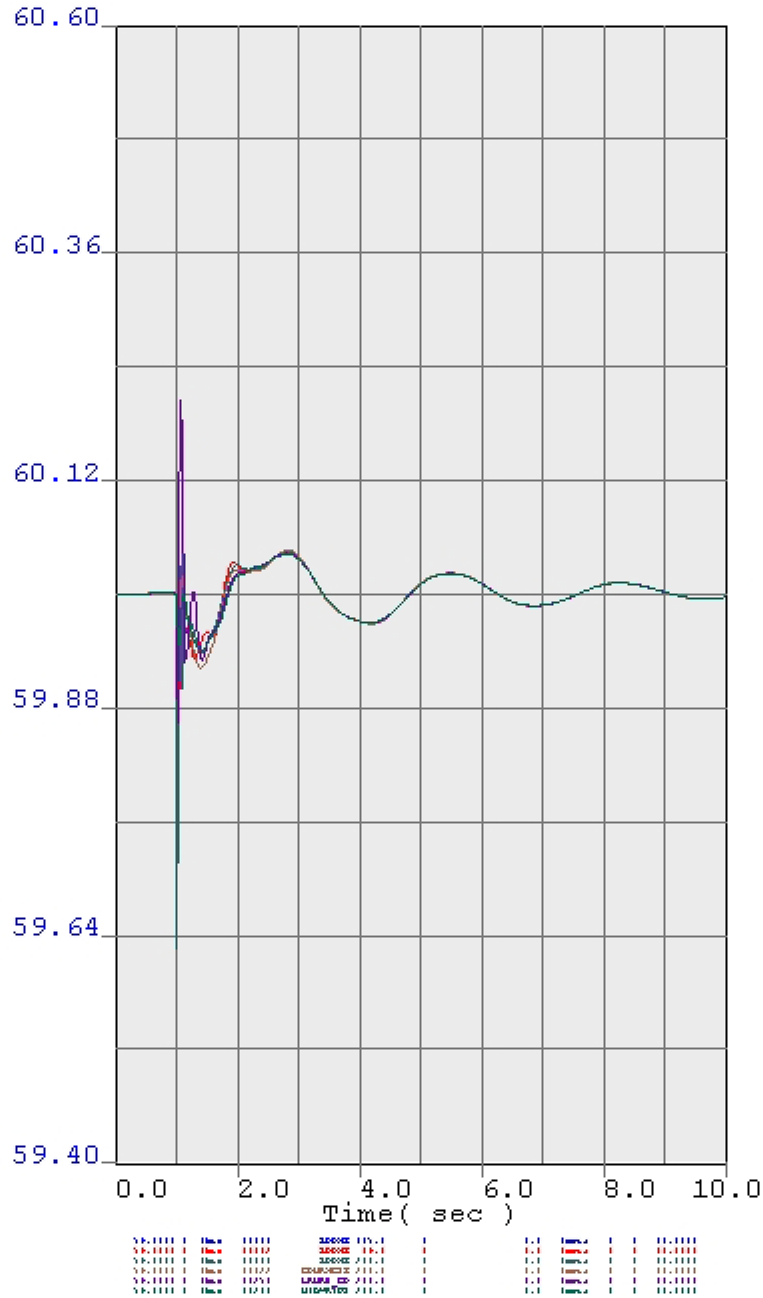
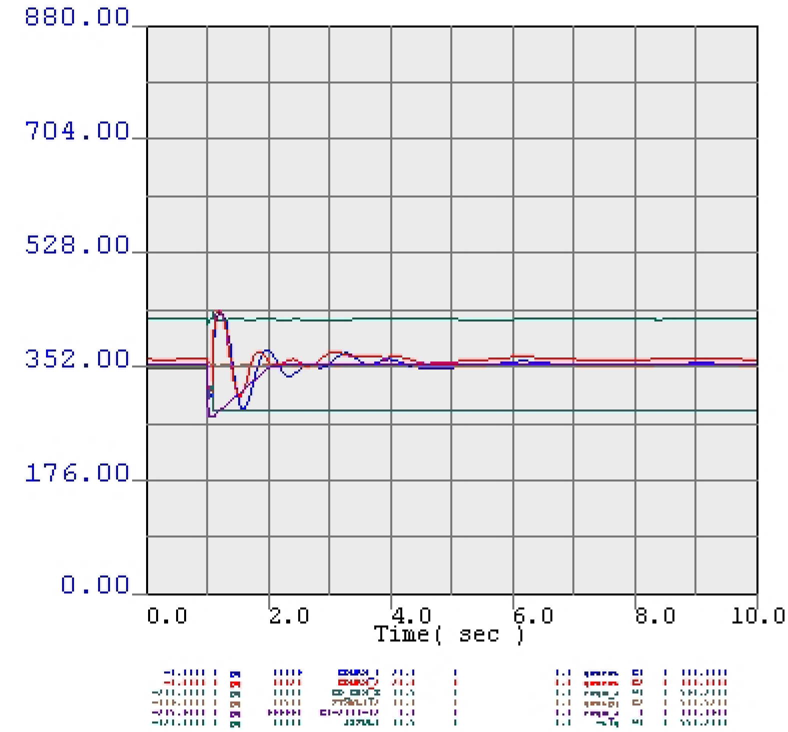
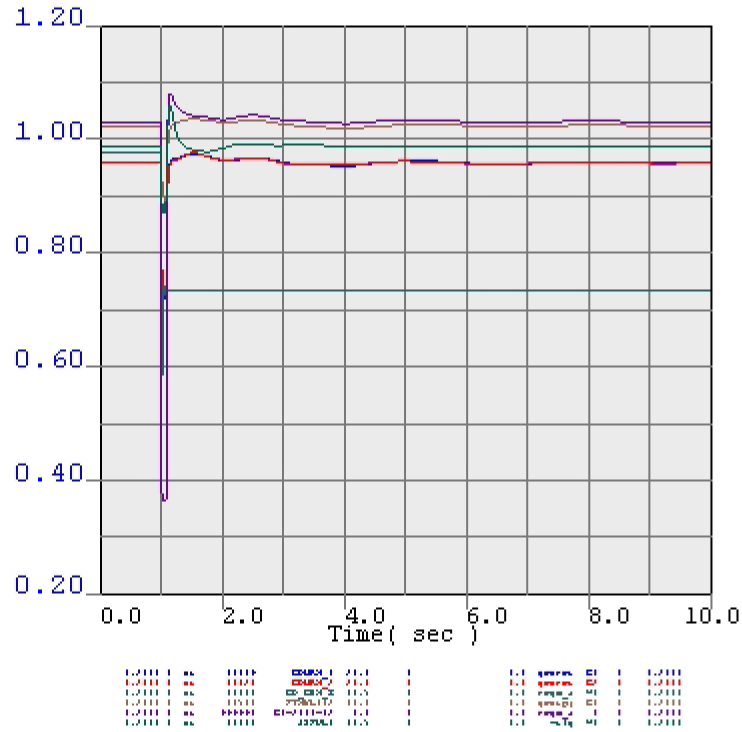
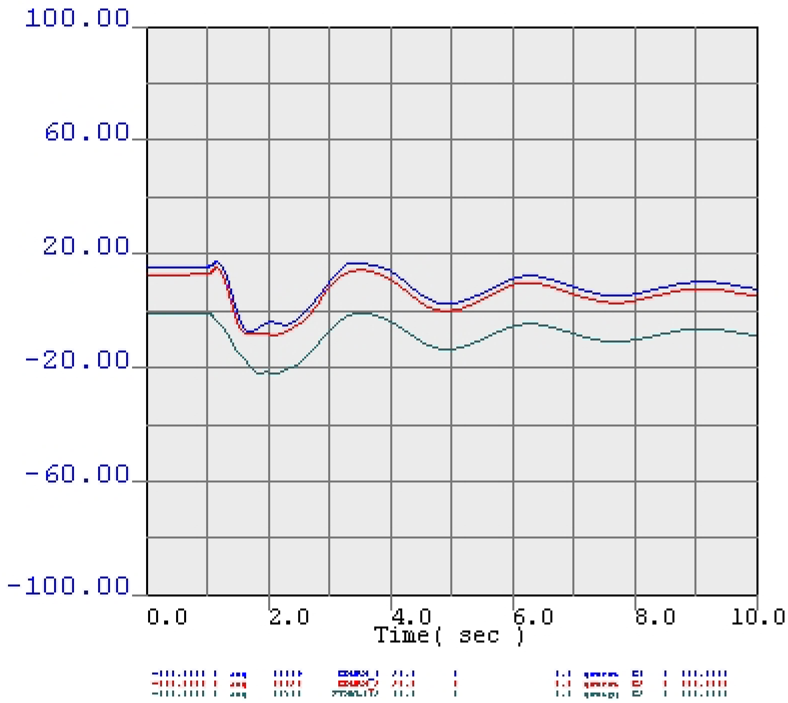


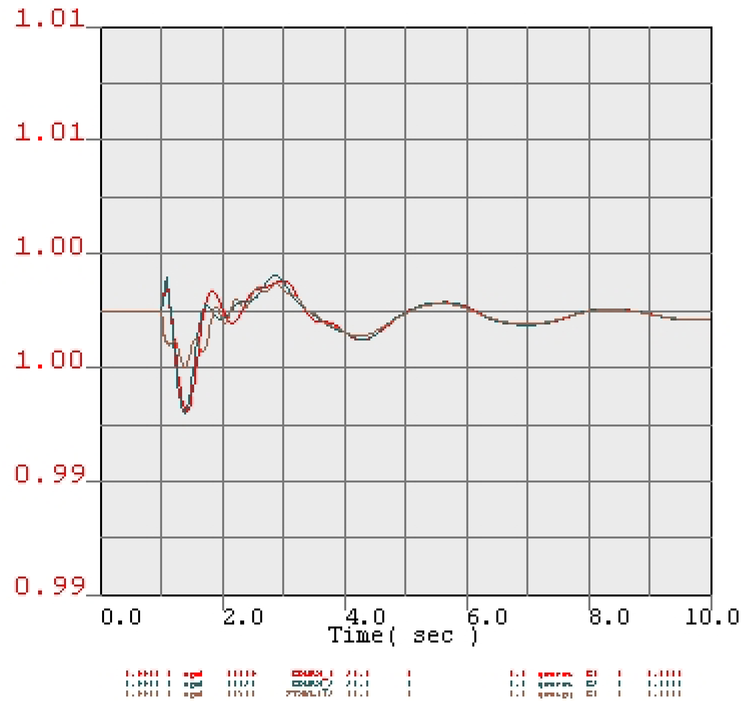


tran_1
Boone 230kV bus fault, lose Boone 230/115kV bank









Line_2
Boone 230kV bus fault, lose Boone-Lamar 230kV and Lamar gen

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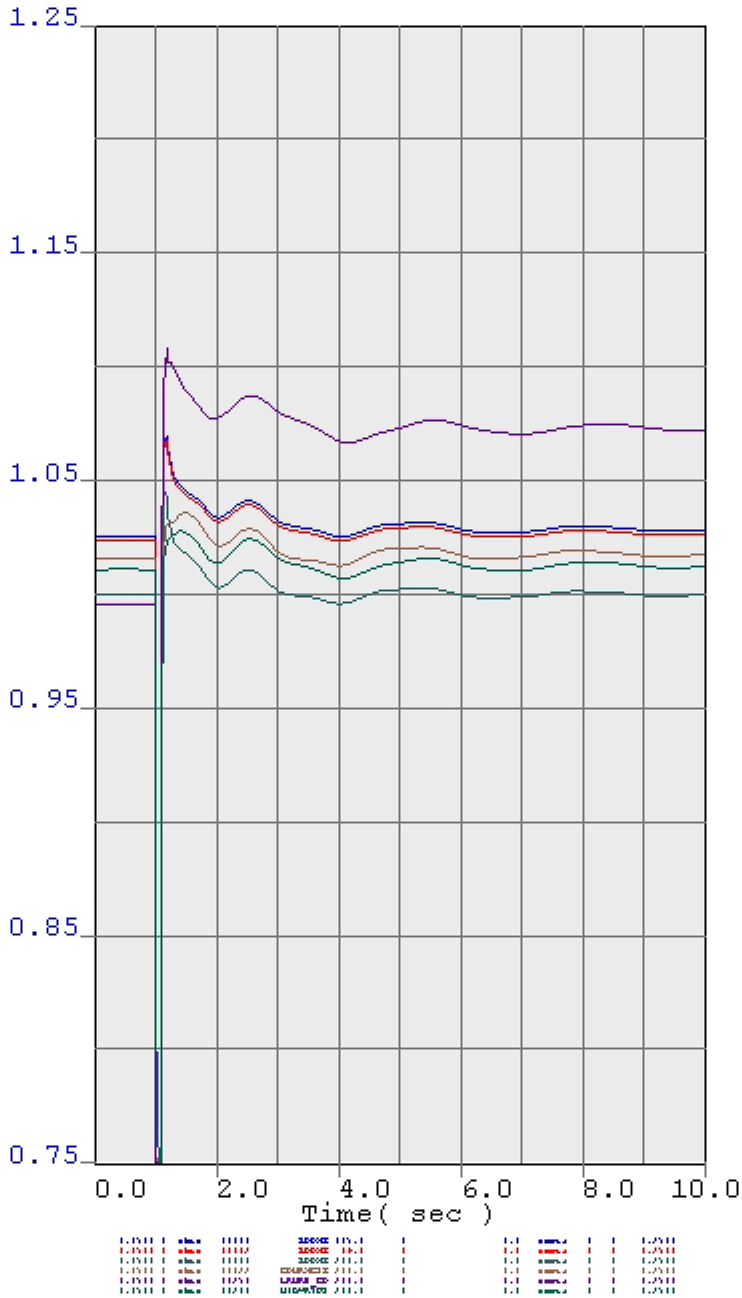

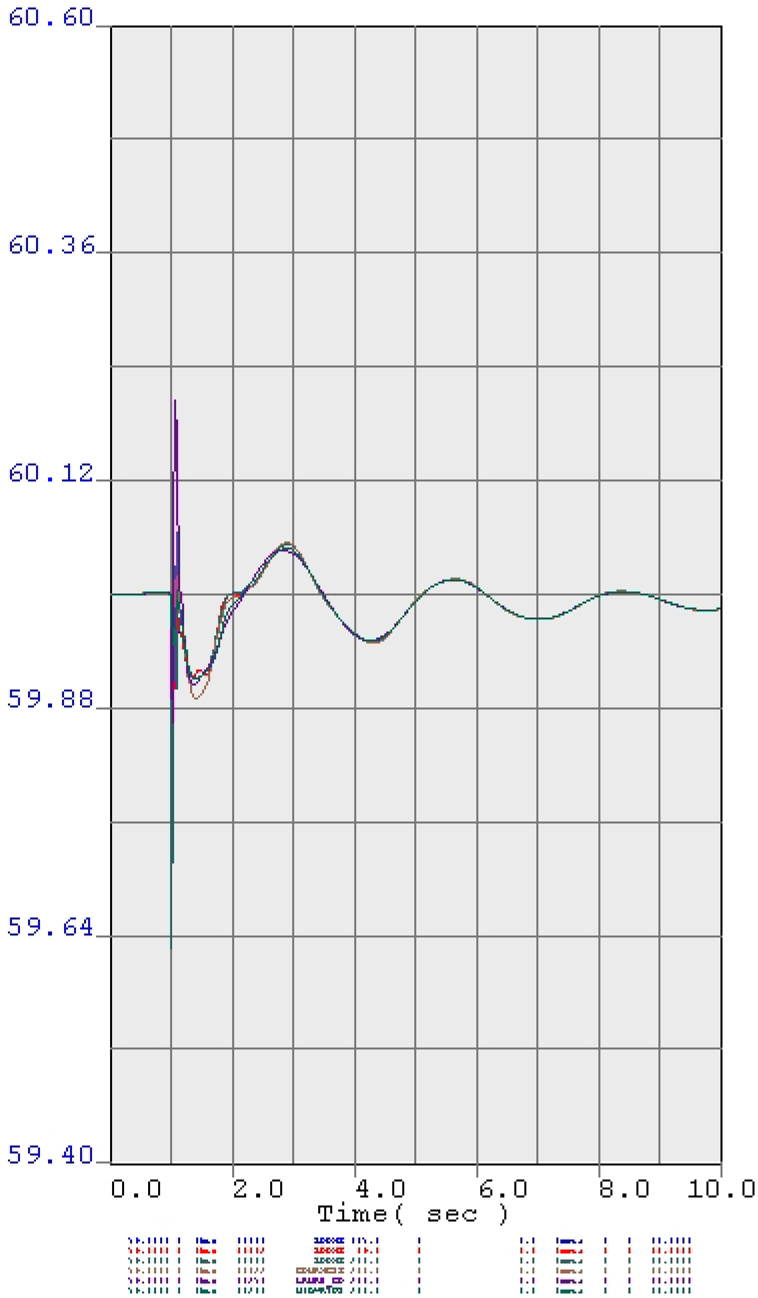

Line_2
Boone 230kV bus fault, lose Boone-Lamar 230kV and Lamar gen

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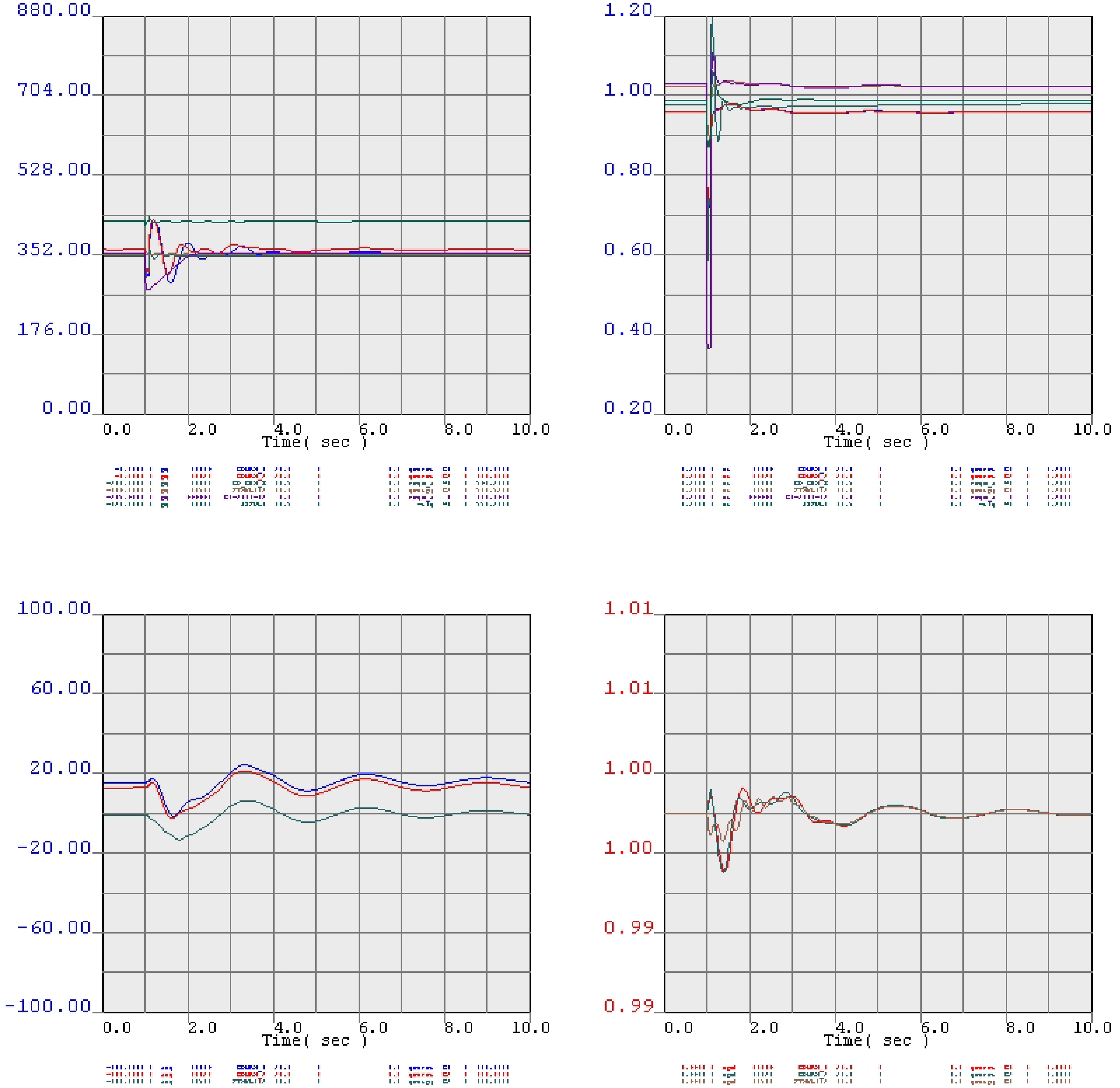
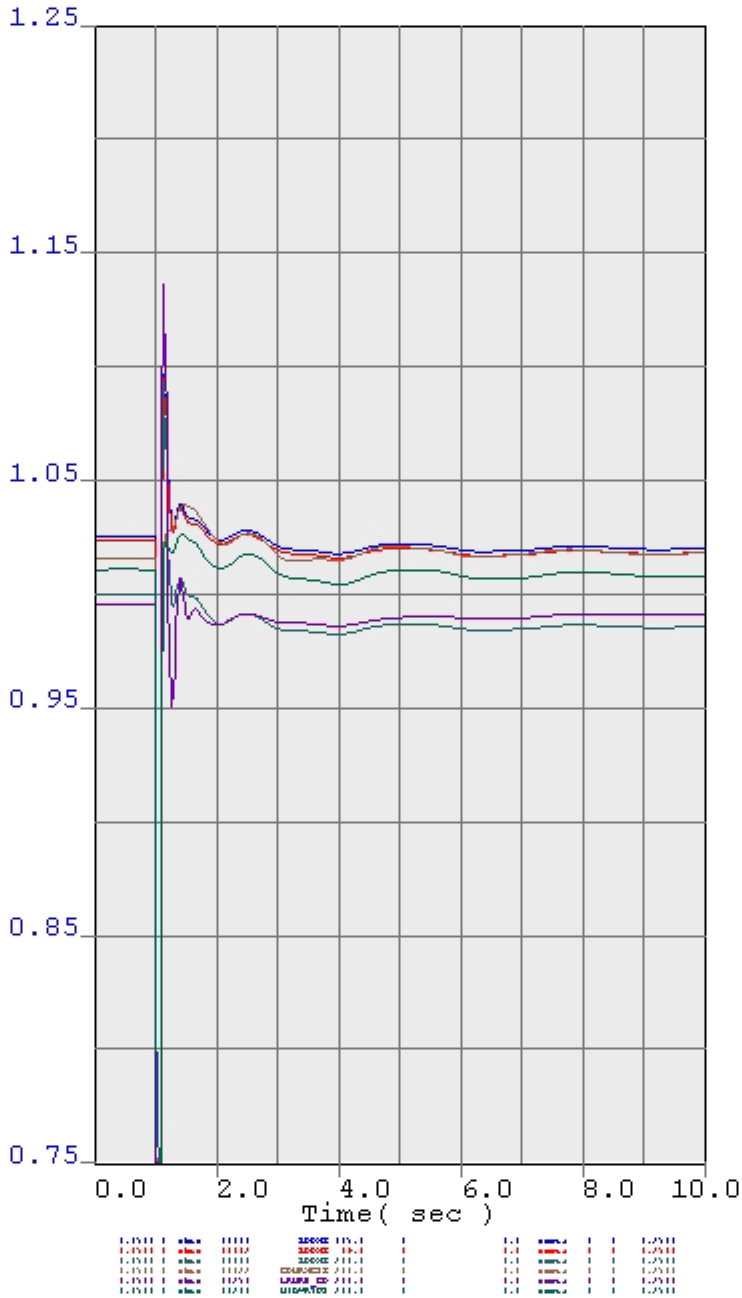
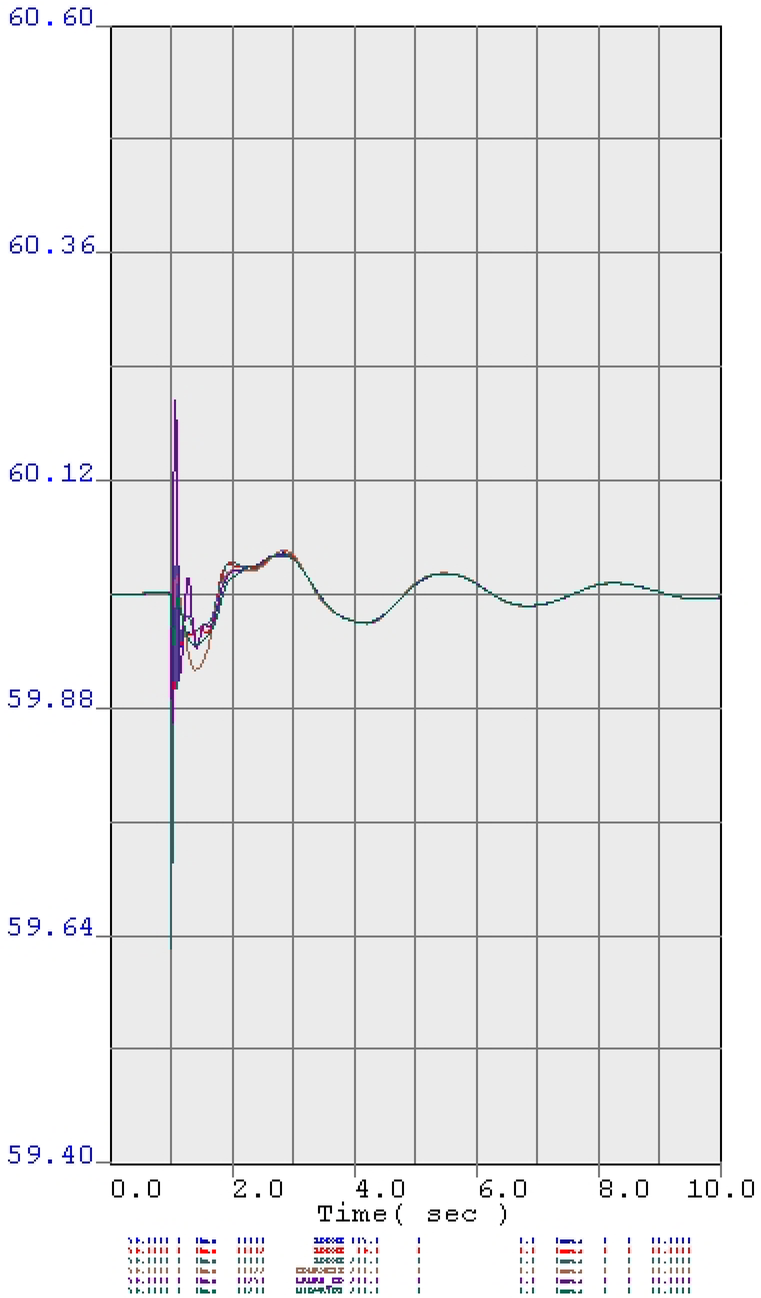


Line_3
Fault at Boone 230kV, lose Boone-Comanche 230kV





Line_3
Fault at Boone 230kV, lose Boone-Comanche 230kV

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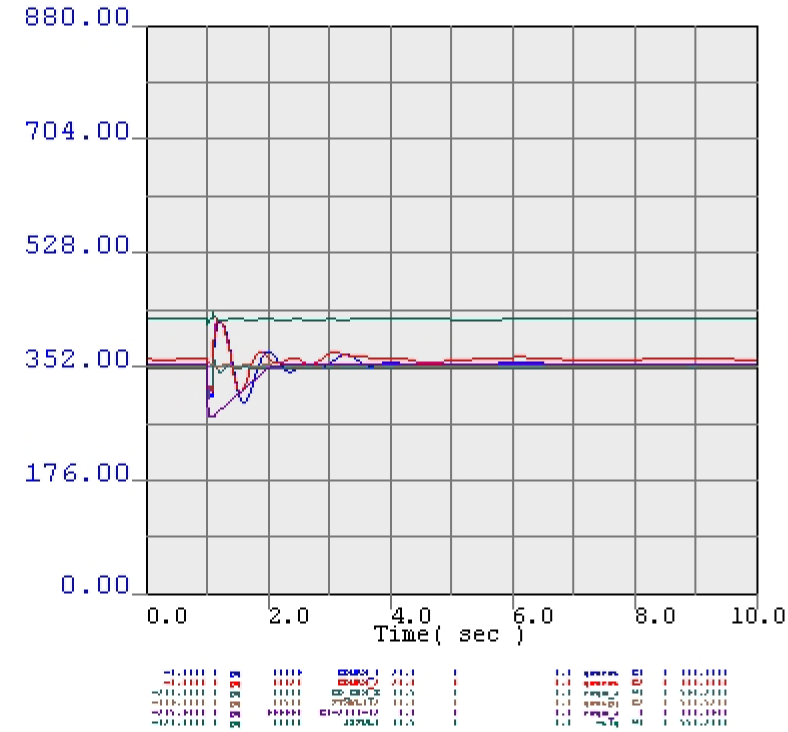
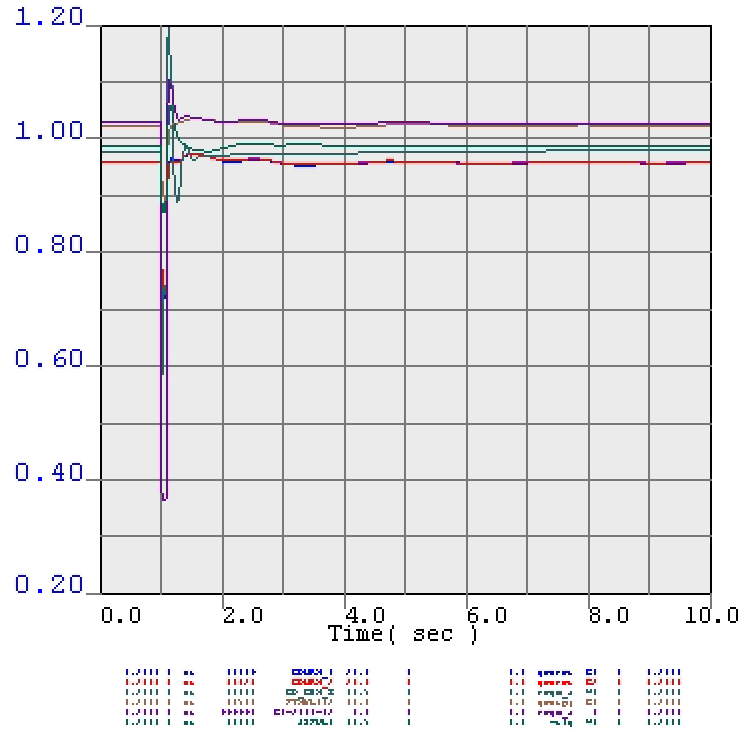
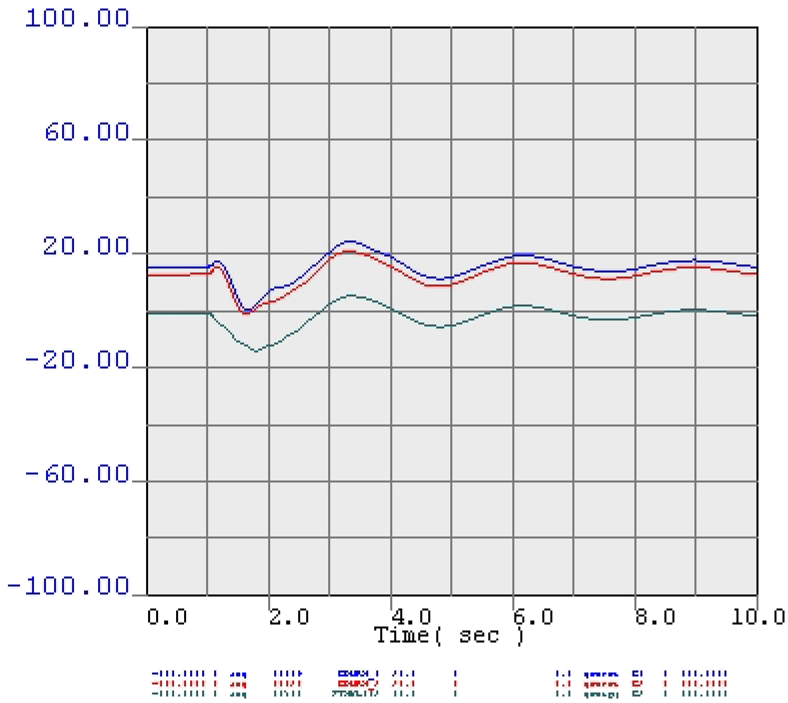
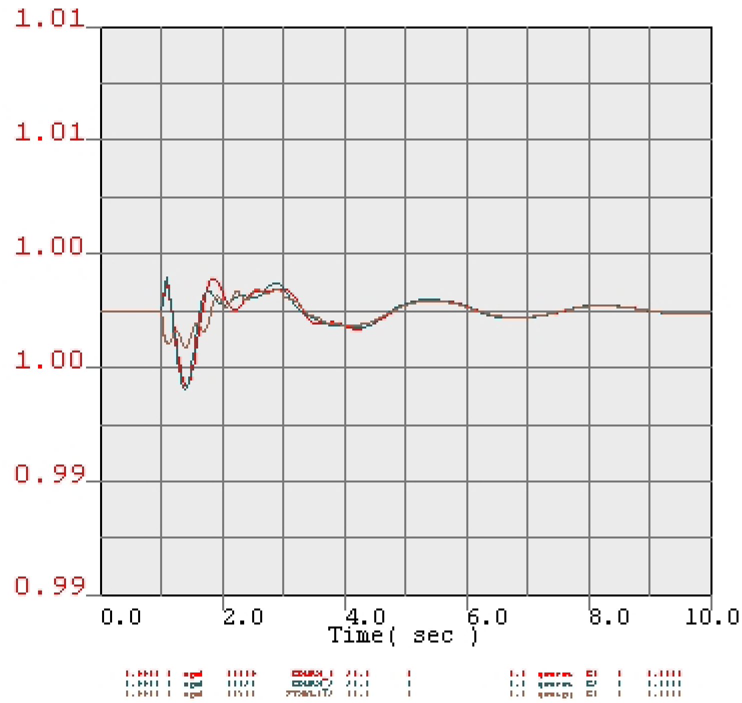
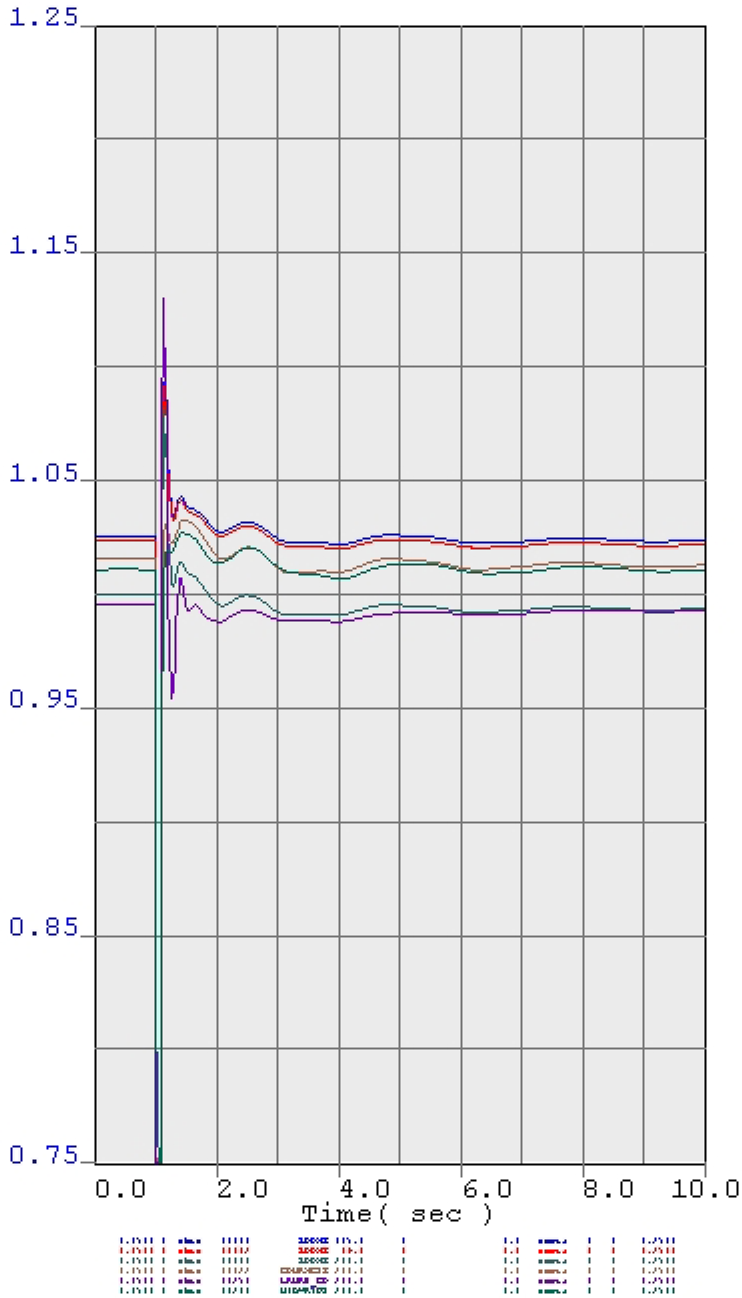


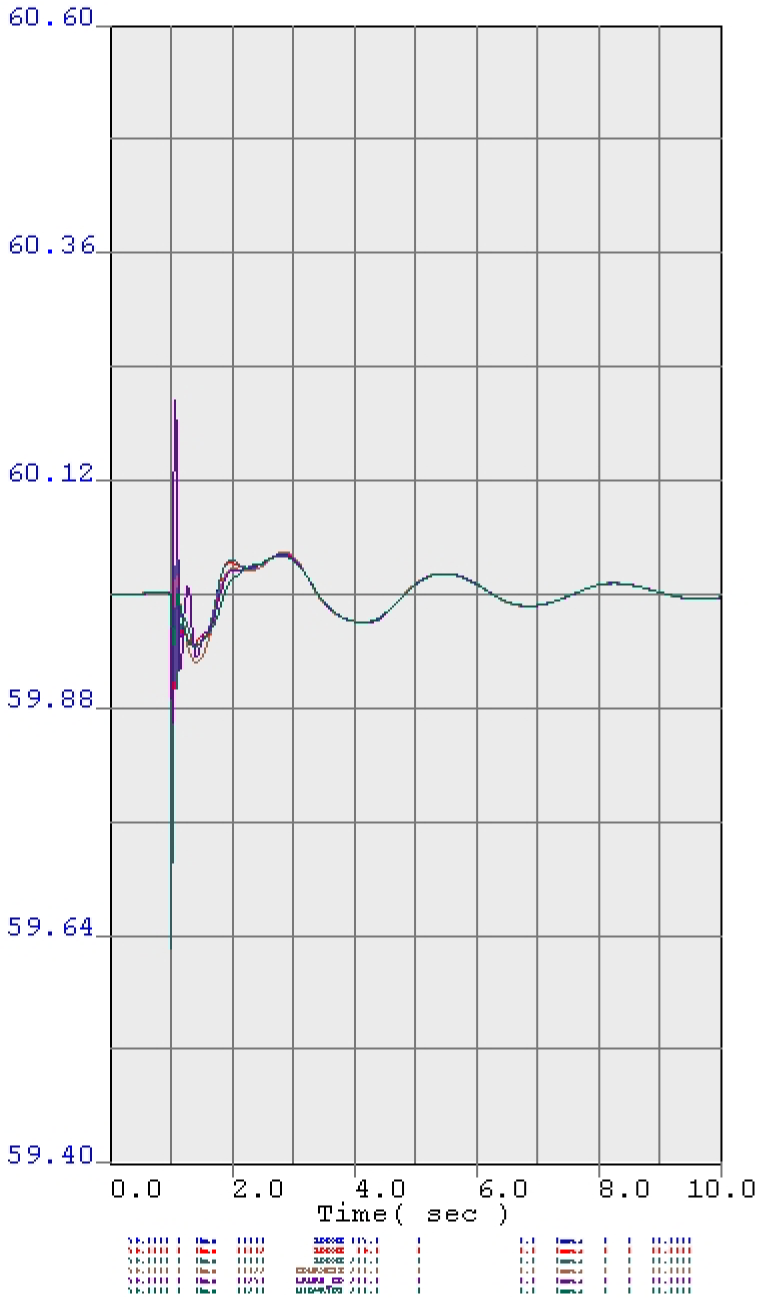






Line_4
Fault at Boone 230kV, lose Boone-Midway 230kV





Line_4
Fault at Boone 230kV, lose Boone-Midway 230kV

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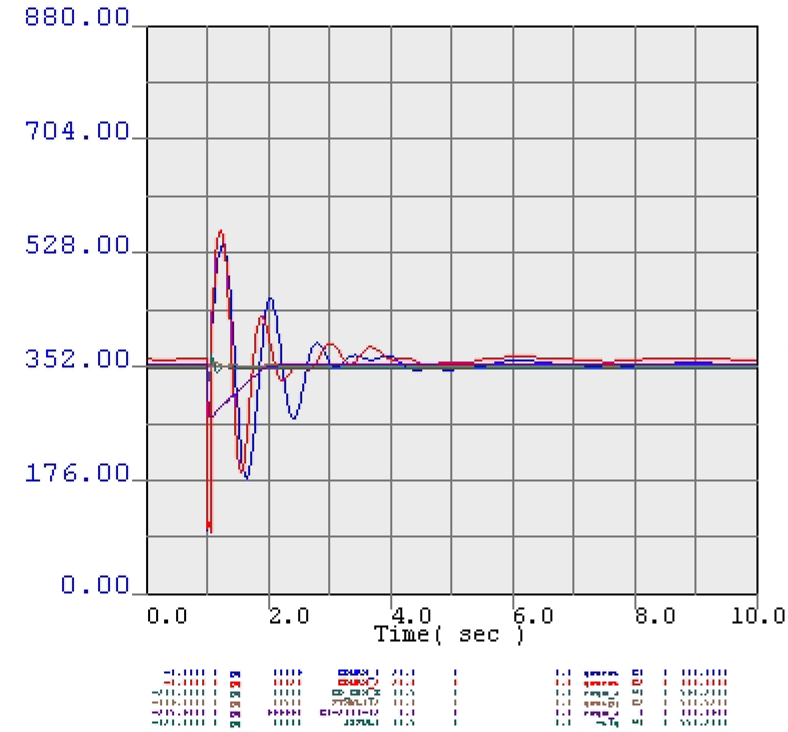

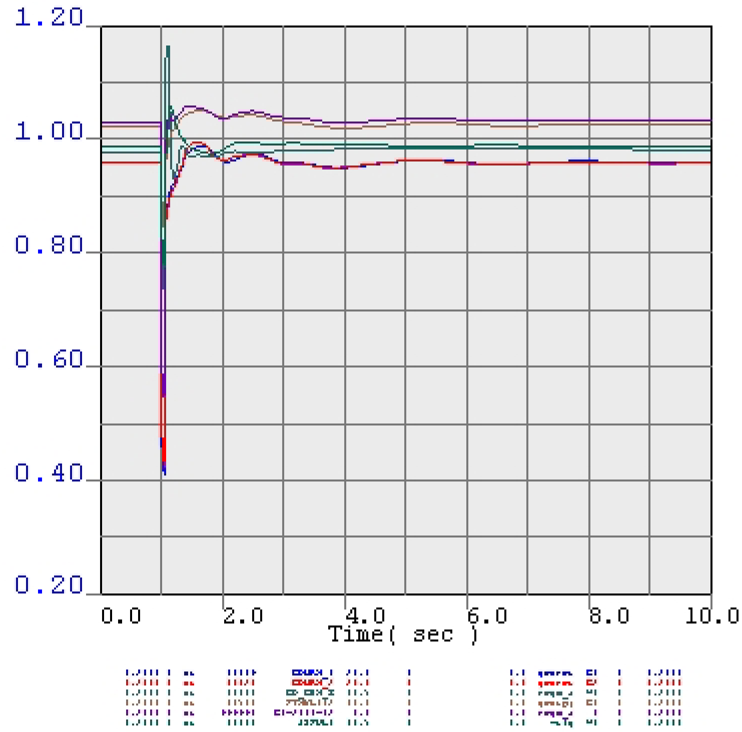

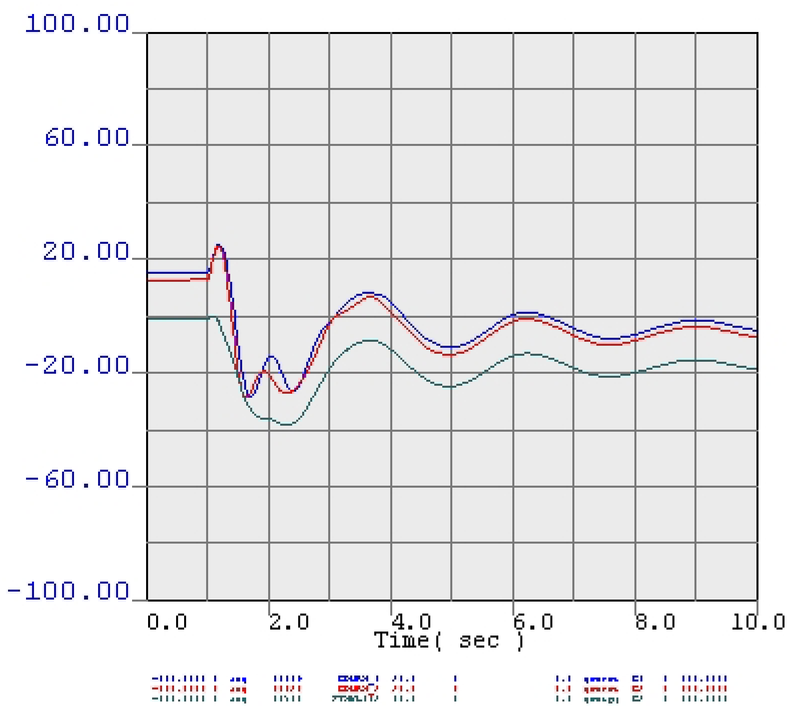

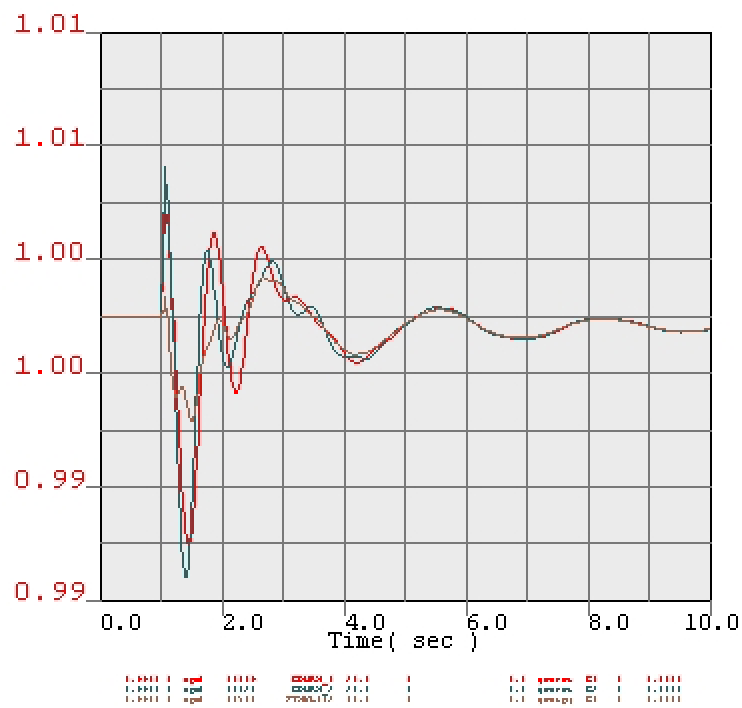

Line_5
Fault at Comanche 345kV, lose Comanche 3

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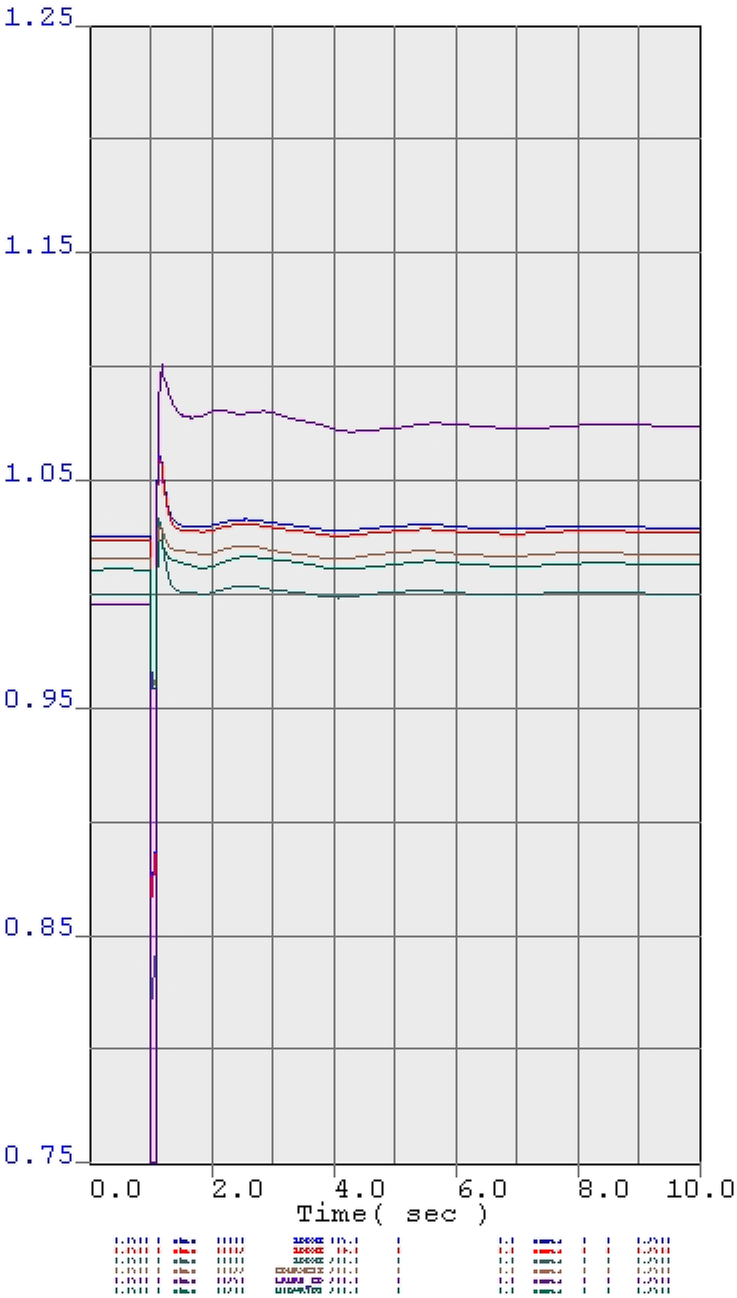

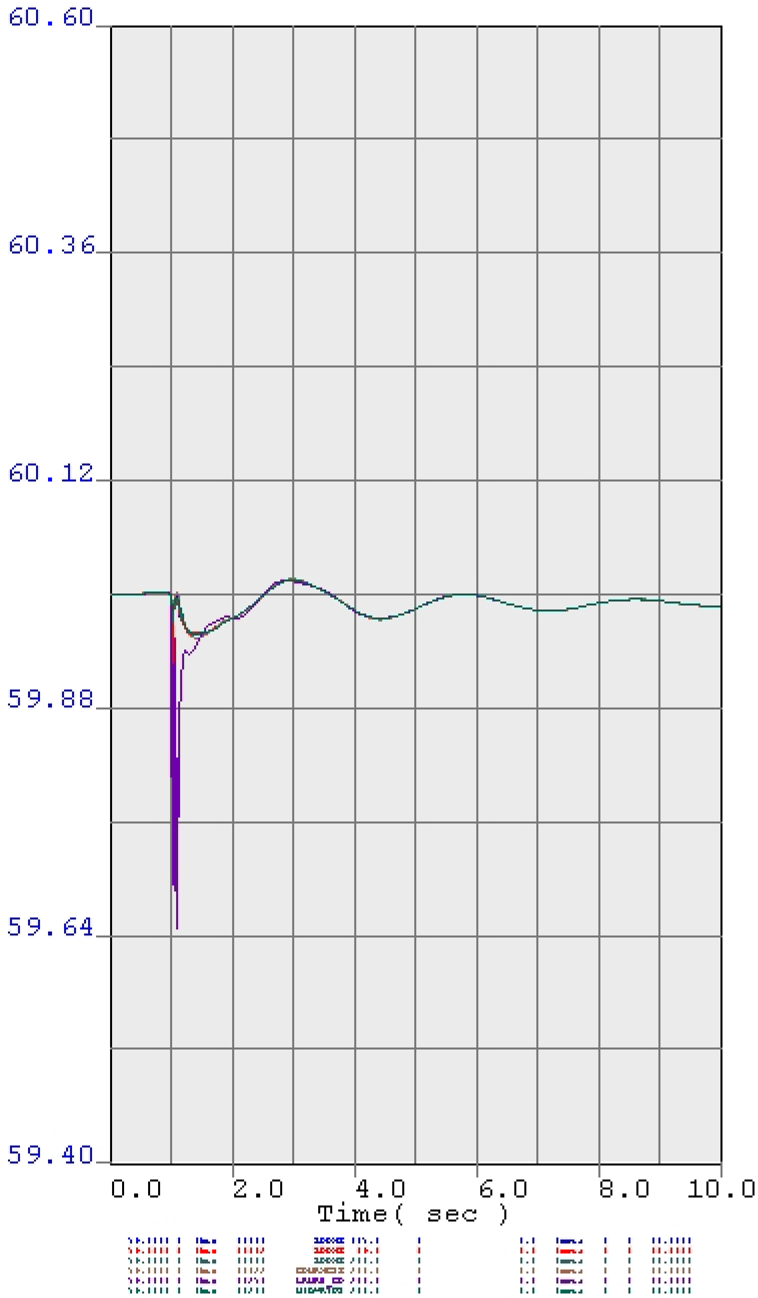

Line_6
Lamar 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

psec-run-Aggt_to_gi-2016-12-Line_6.chf

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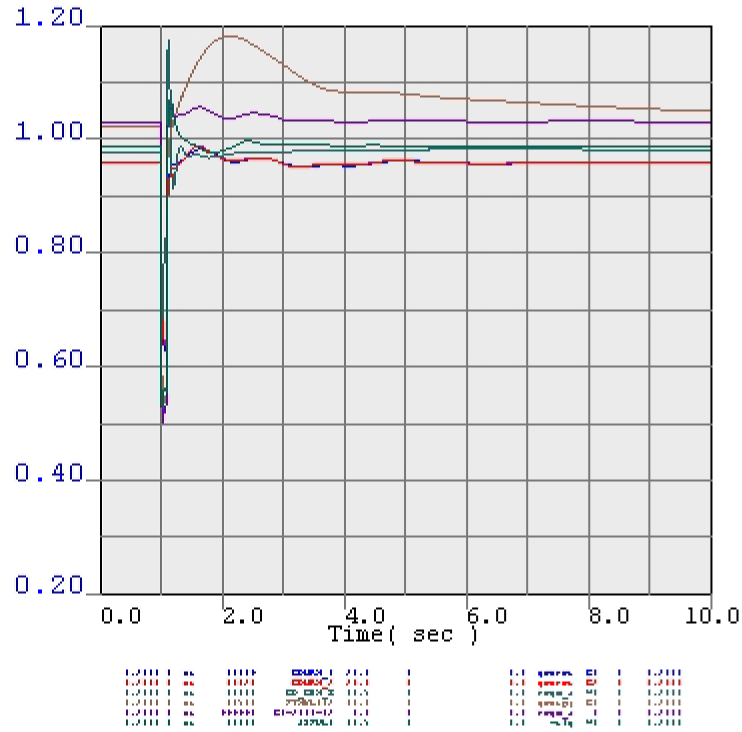

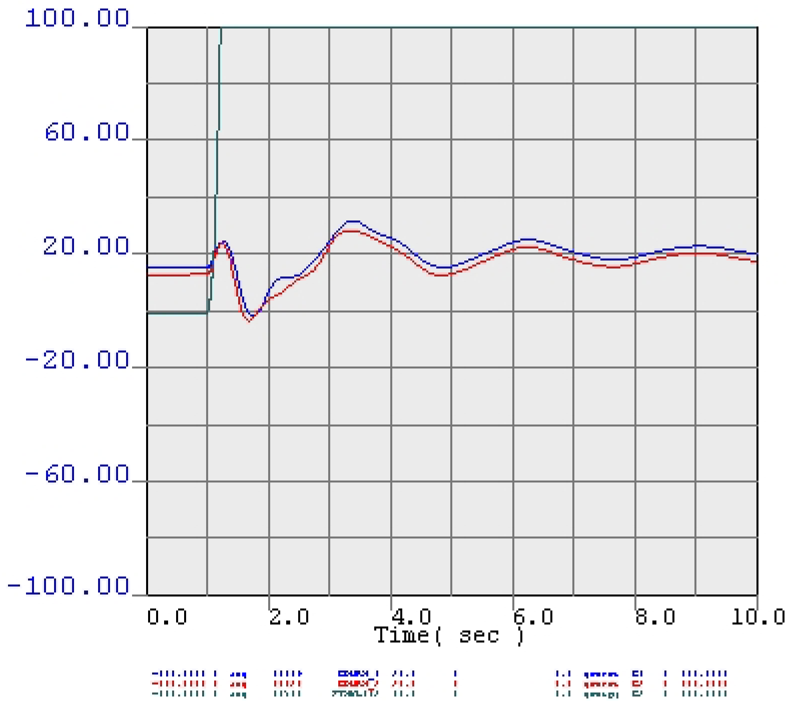

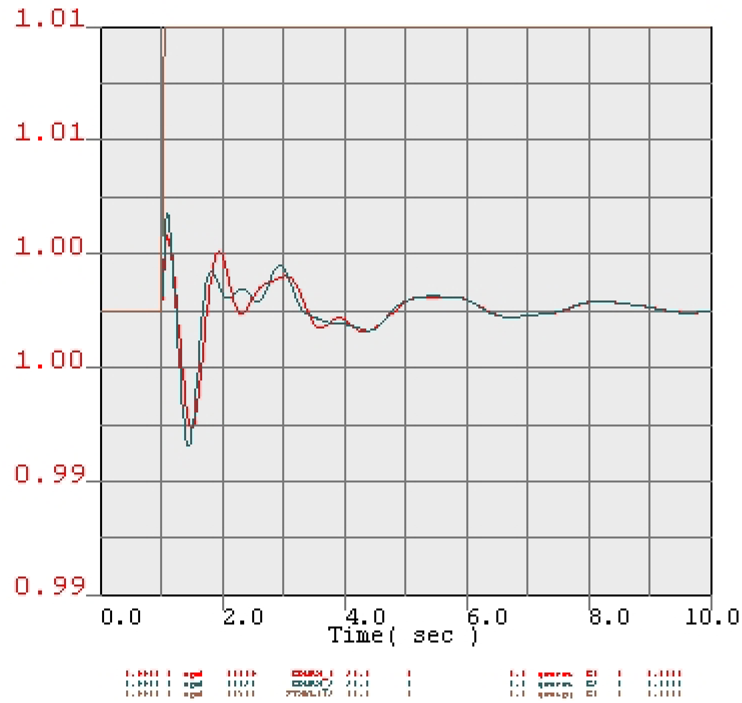

Line_7
Fault at Midway 230kV, lose Fountain Valley gen

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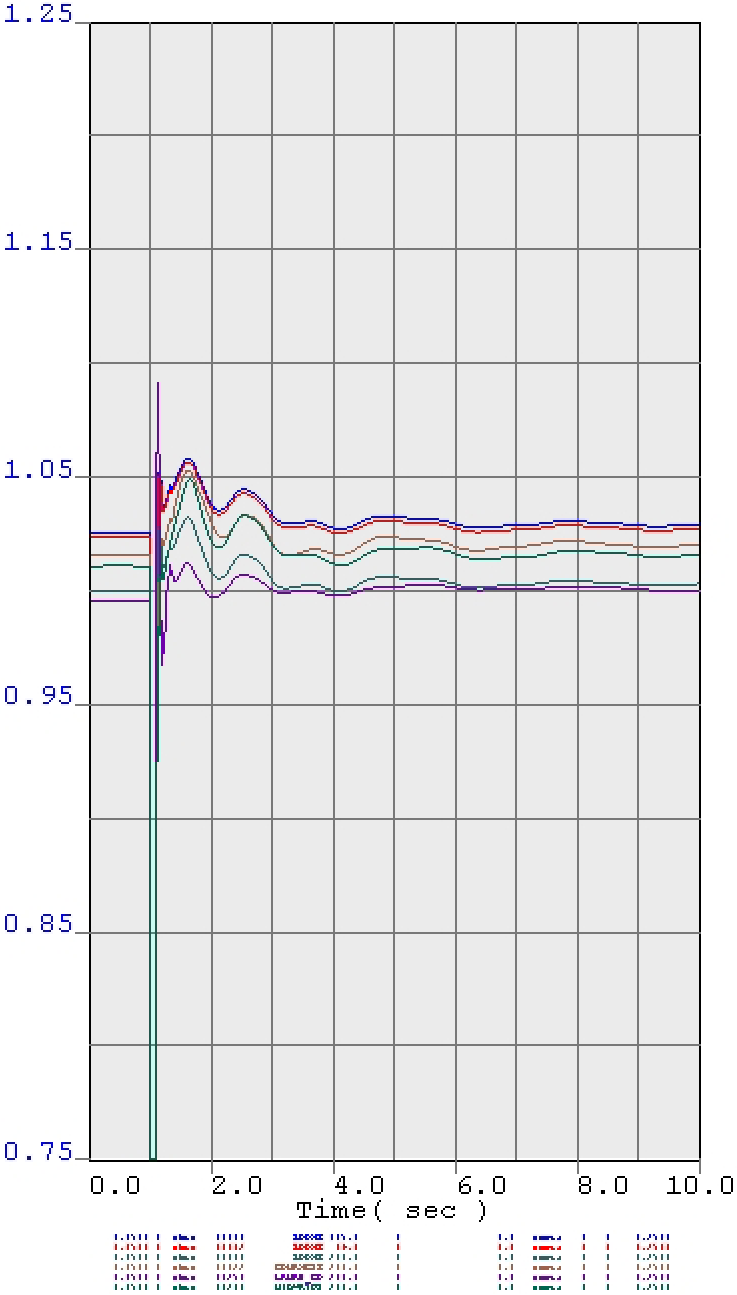

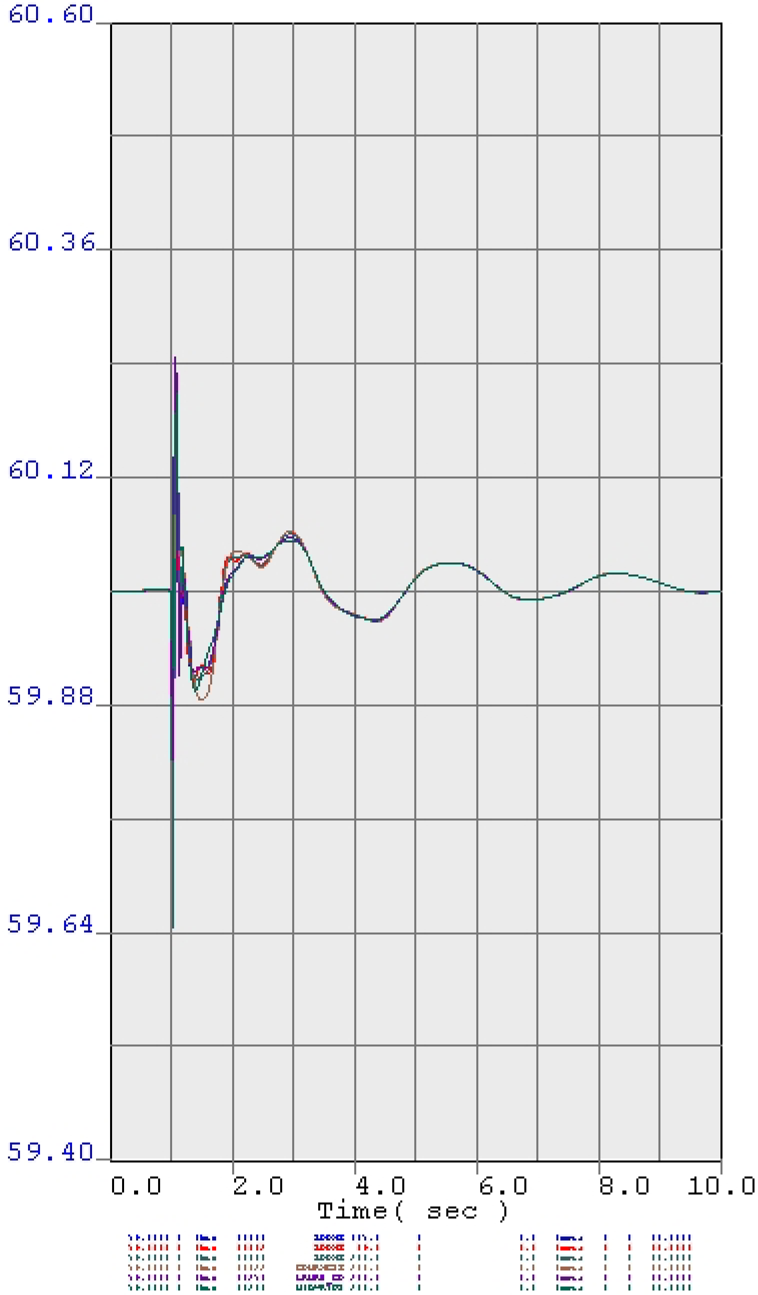

Line_7
Fault at Midway 230kV, lose Fountain Valley gen

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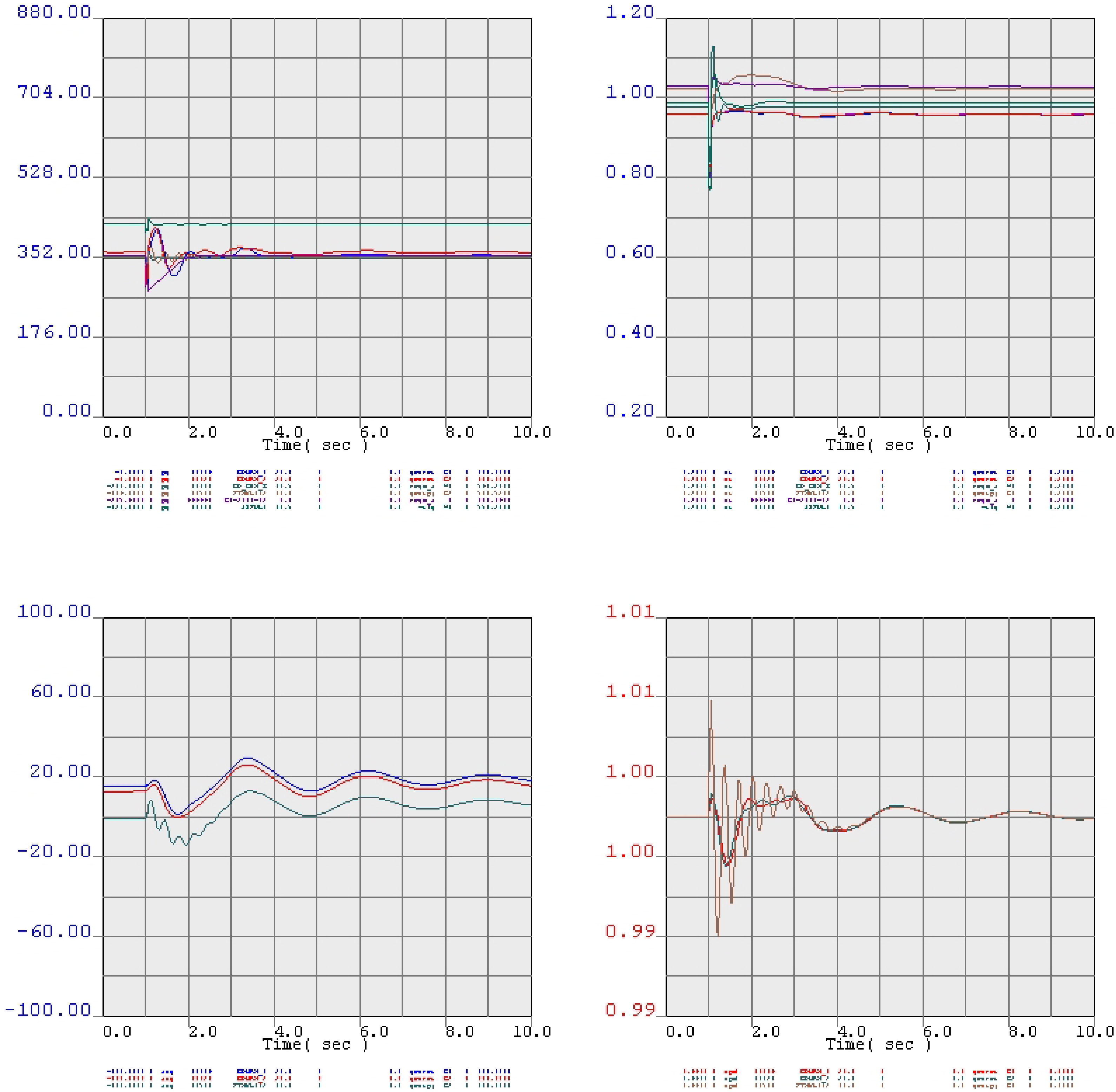
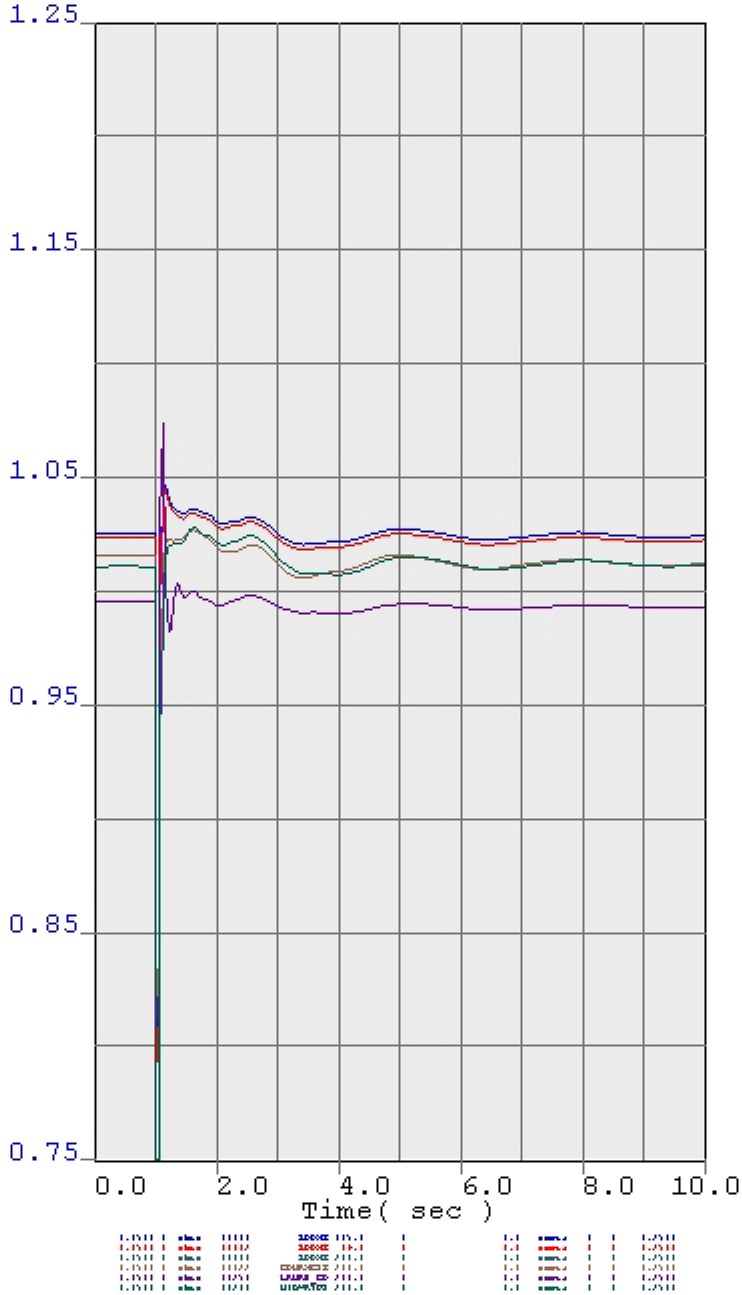
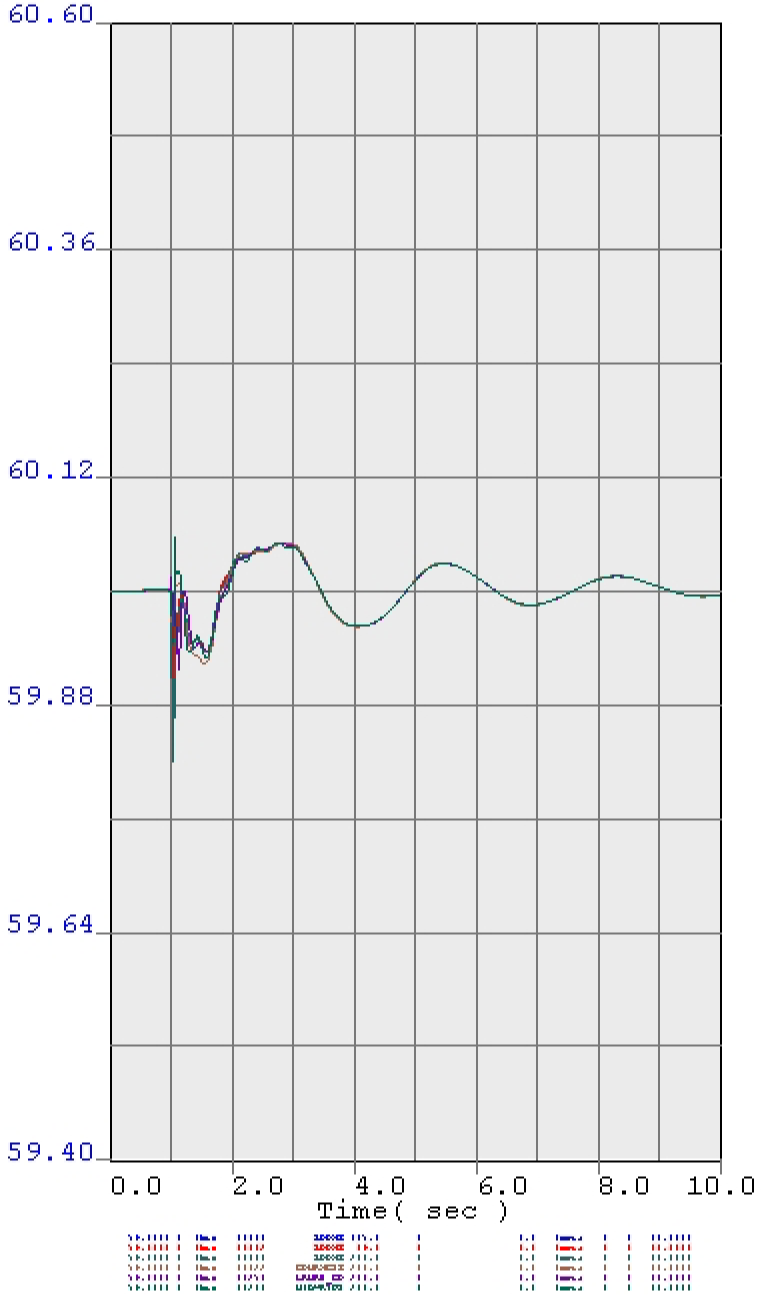


Fault_8
Fault at Midway 345kV, lose MidwayPS 345/20kV and MidwayPS - Waterton345kV line





Fault_8
Fault at Midway 345kV, lose MidwayPS 345/20kV and MidwayPS - Waterton345kV line

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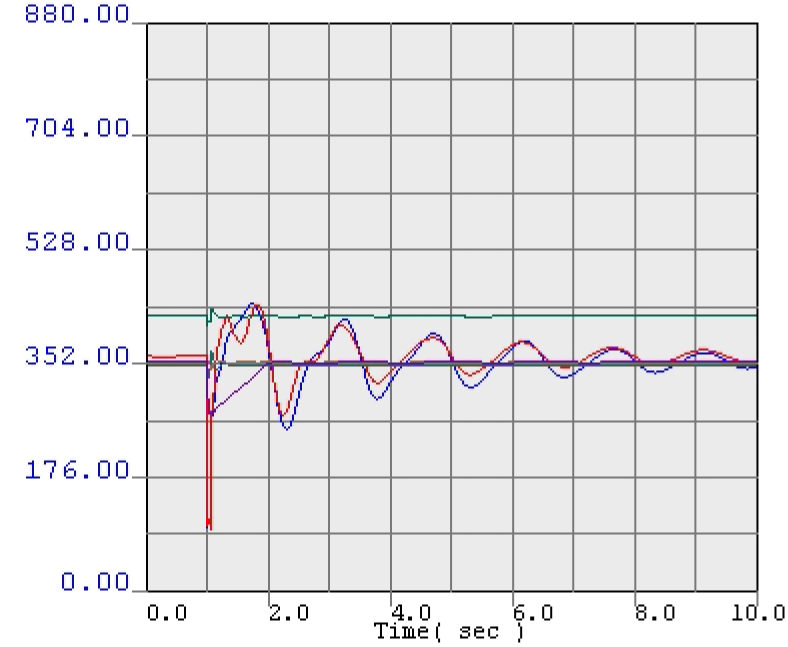

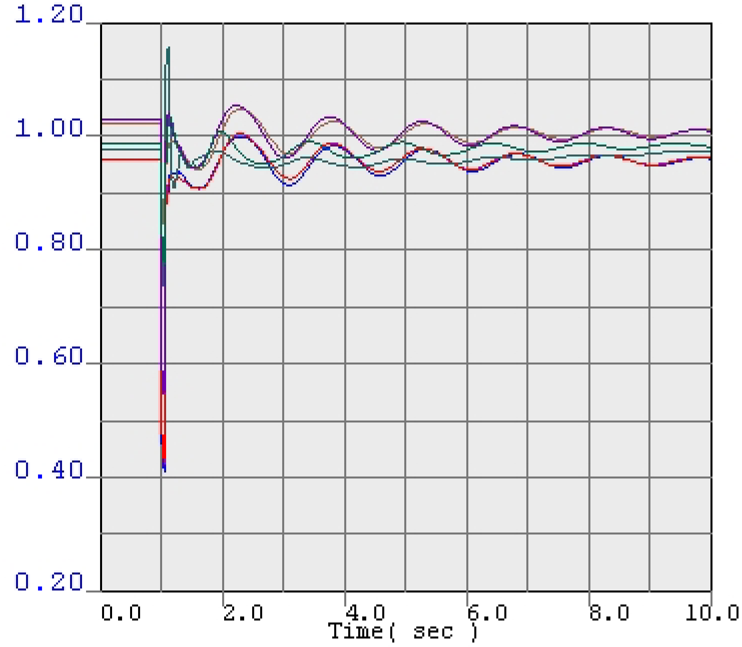

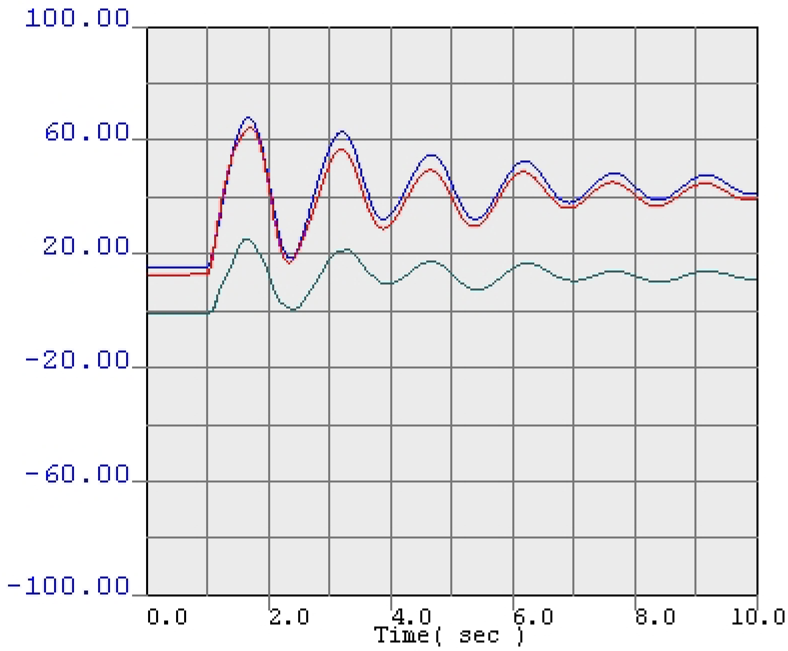

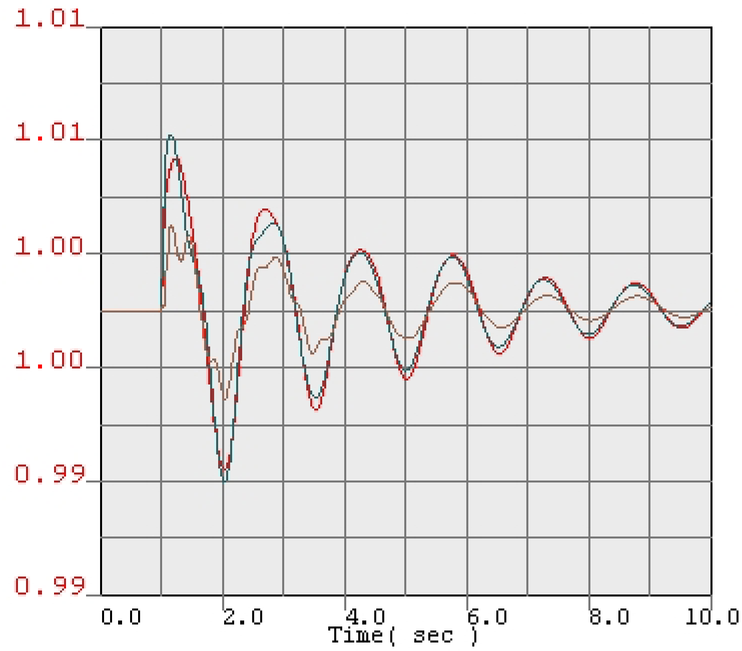

Fault_9
Fault at Comanche 345kV, lose Comanche - Daniels Park 345kV double circuit

psec-run-Aggt_to_gi-2016-12-Fault_9.chf

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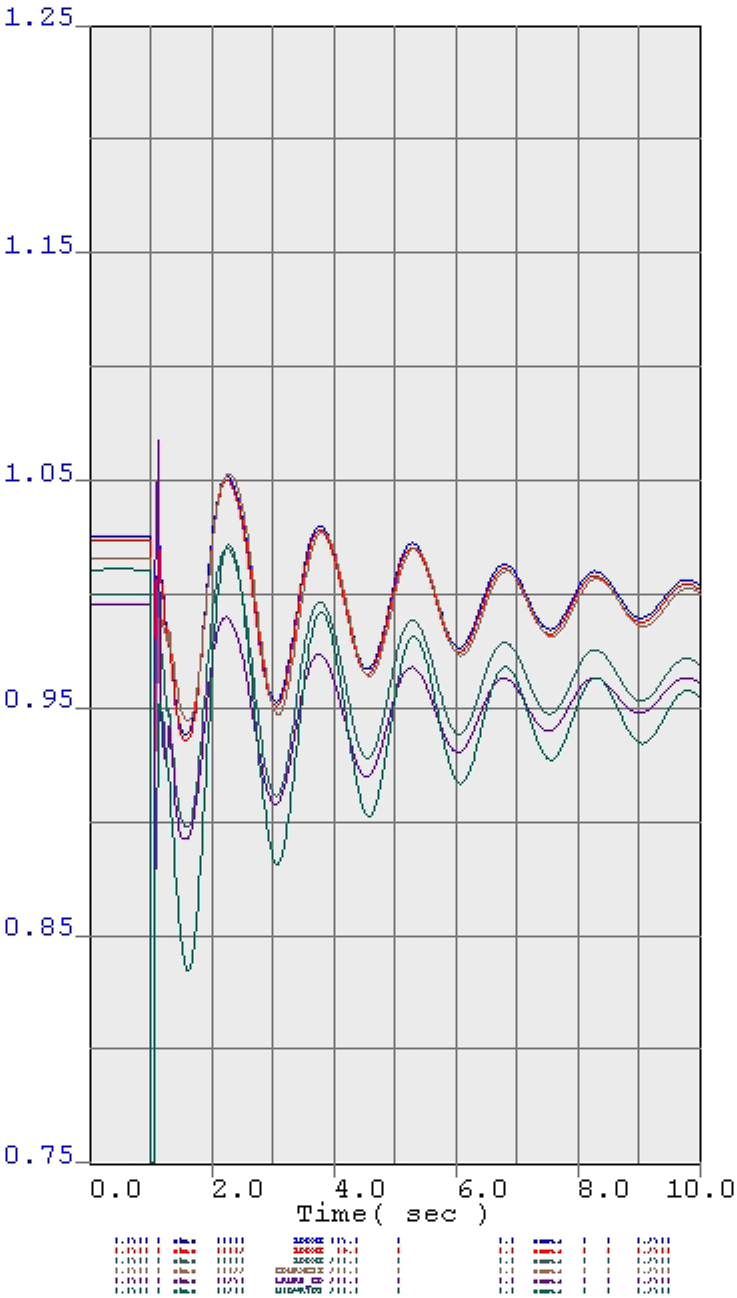

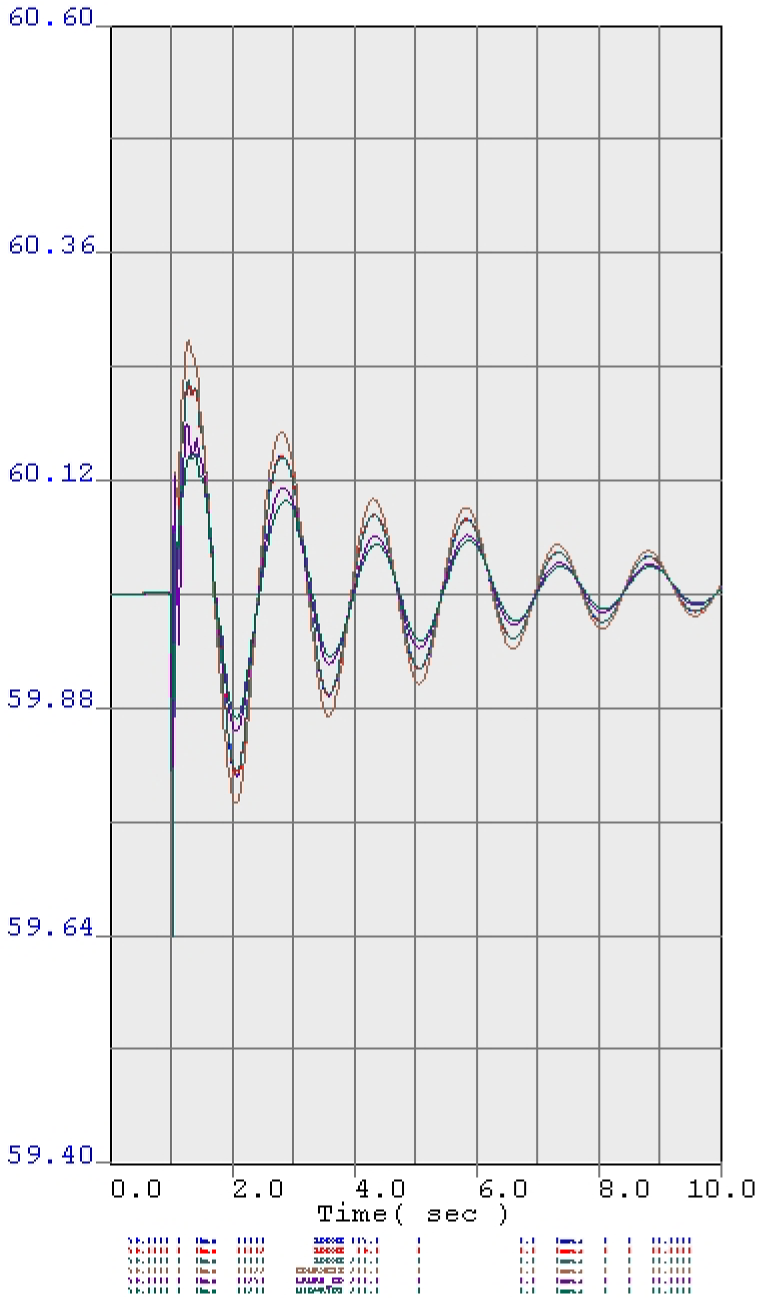

Fault_9
Fault at Comanche 345kV, lose Comanche - Daniels Park 345kV double circuit

psec-run-Aggt_to_gi-2016-12-Fault_9.chf

12_Apr revision\SIS\chans
Sat Jun 01 19:29:54 2019