DOCKETED

Docket Number:	16-AFC-01
Project Title:	Stanton Energy Reliability Center
TN #:	217461
Document Title:	Stanton Energy Reliability Center's Data Request Response, Set 1 (A1-A63)
Description:	N/A
Filer:	Patty Paul
Organization:	CH2M
Submitter Role:	Applicant Consultant
Submission Date:	5/5/2017 4:15:40 PM
Docketed Date:	5/5/2017

Private Client Sector
Sacramento Area Office
2485 Natomas Park Drive, Suite 600
Sacramento, CA 95833
916.920.0300
www.ch2m.com

May 5, 2017

Mr. John Heiser
Project Manager
Siting, Transmission and Environmental Protection Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814-5512

Subject: Stanton Energy Reliability Center (16-AFC-1) Data Request Response, Set 1 (A1-A63)

Dear John:

Attached are Stanton Energy Reliability Center, LLC's responses to California Energy Commission Staff Data Requests, Set 1 (Data Requests A1-A63) for the Stanton Energy Reliability Center (16-AFC-1) Application for Certification.

Please contact me at 916-798-8232 if you have questions about this matter.

Sincerely,

Douglas M. Davy, Ph.D.
Project Manager

Attachment

cc: Kara Miles, W Power, LLC
Paul Cummins, Wellhead Electric Company, Inc.
Scott Galati, Dayzen, LLC

DATA REQUEST RESPONSE

Responses to California Energy Commission Staff
Data Requests A1 through A63

In support of the

Application for Certification

For the

Stanton Energy Reliability Center

16-AFC-1

Prepared for

Stanton Energy Reliability Center, LLC

May 2017

CH2M Hill Engineers, Inc.
2485 Natomas Park Drive, Suite 600
Sacramento, CA 95833

Contents

Attachments

Tables

Acronyms and Abbreviations

AADT	Annual Average Daily Traffic
ADT	Average Daily Traffic
AFC	Application for Certification
AGC	Automatic Generator Control
ALUC	Airport Land Use Commission
BACT	Best Available Control Technology
BESS	Battery Energy Storage System
BIC	Battery Indication and Control
Btu/kWh	British thermal units per kilowatt-hour
CAISO	California Independent System Operator
CD-ROM	compact disk, read-only memory
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CHRIS	California Historical Resources Information System
CMP	Congestion Management Plan
CPUC	California Public Utilities Commission
CRHR	California Register of Historical Resources
CTG	combustion turbine generator
DMA	drainage management area
DPR	Department of Parks and Recreation
DR	Data Request
DRA	Data Requests, Series A
EGT® Hybrid	The EGT® hybrid system for co-operating gas turbines with batteries
ERC	Emission Reduction Credits
FAA	Federal Aviation Administration
GO	General Order
GSWC	Golden State Water Company
HARP	Hotspots Analysis Reporting Program
HRA	health risk assessment
ICU	Intersection Capacity Utilization
JFTB	Joint Forces Training Base
LAER	Lowest Achievable Emission Rate

LORS	laws, ordinances, regulations, and standards
LOS	Level of Service
MMcf/hr	million cubic feet per hour
MOC	Minimum On-Line Commitment
MW	Megawatt of electrical power
MSA	Meter Set Assemblies
NSR	New Source Review
OCTA	Orange County Fire Authority
O&M	Operations and Maintenance
PFR	Primary Frequency Response
PTE	Potential to Emit
PVC	polyvinyl chloride
RECLAIM	Regional Clean Air Incentives Market
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SERC	Stanton Energy Reliability Center
SLI	Joint Forces Training Base, Alamitos, airfield
SOC	State of Charge
SoCalGas	Southern California Gas Company
TOC	time of concentration
USGS	United States Geological Survey
WQMP	Water Quality Management Plan
V/C	volume-to-capacity ratio
WSI	Wellhead Services, Inc.

Introduction

Attached are Stanton Energy Reliability Center, LLC's (Applicant's) responses to California Energy Commission (CEC) Staff data requests (DRs) Set 1, numbers A1 through A63, for the Stanton Energy Reliability Center (SERC) (16-AFC-1). The CEC Staff served the data requests on April 5, 2017 as part of the Discovery process for SERC project licensing.

The responses are grouped by individual discipline or topic area. Within each discipline area, the responses are presented in the same order as presented by CEC Staff, and are keyed to the Data Request numbers (A1 through A63). New or revised graphics or tables are numbered in reference to the Data Request number. For example, the first table used in response to Data Request A15 would be numbered Table DRA15-1. The first figure used in response to Data Request A28 would be Figure DRA28-1, and so on.

Additional tables, figures, or documents submitted in response to a data request (supporting data, stand-alone documents such as plans, folding graphics, etc.) are found at the end of a discipline-specific section and are not sequentially page-numbered consistently with the remainder of the document, though they may have their own internal page numbering system.

5.1 Air Quality (A1-A14)

Correspondence regarding permit applications

A1. Please provide copies of all substantive District correspondence regarding the application to the District, including application supplements and e-mails, within one week of submittal or receipt. This request is in effect until the final Commission Decision has been docketed.

Response: All substantive South Coast Air Quality Management District (SCAQMD) correspondence regarding SERC air quality permitting will be supplied to CEC Staff within one (1) week of submittal or receipt.

Appendix 5.1A and 5.1E work sheets

A2. Please provide the updated spreadsheet versions of Appendix 5.1A and 5.1E worksheets with the embedded calculations live and intact.

Response: Unlocked copies of the spreadsheets used in both the operational and construction emission calculations will be provided under separate cover in a CD-ROM format. These confidential and proprietary files are supplied for CEC staff use only, and are not to be distributed or copied for any use not directly connected to Staff's environmental review of the SERC. Please note that some formulae cannot be unlocked as they are proprietary third-party commercial software.

Summary tables

A3. Please update the corresponding summary tables in Appendix 5.1A, 5.1E and AFC section 5.1.4.

Response: A revised and updated AFC Air Quality section/SCAQMD permit application with appendixes and supporting information have been submitted to the SCAQMD and docketed with the CEC under separate cover (April 28, 2017; TN#217343).

Modeling files

A4. Please provide the updated air quality modeling files for normal operation and commissioning periods.

Response: Modeling files reflecting modeling changes based on discussions with the SCAQMD that have taken place since the AFC was filed are submitted on CD-ROM under separate cover.

Summary tables

A5. Please update the corresponding summary tables in Appendix 5.1B and AFC section 5.1.7.

Response: A revised and updated AFC Air Quality section/SCAQMD permit application with appendixes and supporting information have been submitted to the SCAQMD and docketed with the CEC under separate cover (April 28, 2017; TN#217343).

Fumigation impacts

A6. Please evaluate whether the annual average case (Case 103 - 100 percent load at 65°F) represents worst case fumigation impacts, and provide the assumptions and data. If the annual *average case does not represent the worst case, please provide the worst case fumigation impact analysis, including a discussion of the assumptions and data that support the analysis.*

Response: The fumigation analysis was performed using the procedures outlined in Section 4.5.3 of Environmental Protection Agency (EPA) document EPA-454/R-92-019 (EPA, 1992a). The procedure compares the 1-hour concentration results between the fumigation and flat terrain impacts and if the fumigation concentrations are less than the flat terrain impacts, the effects of fumigation may be ignored.

The average annual case (Case 103) does not present the worst-case for fumigation impacts; rather, Case 103 was used in the AFC to determine whether fumigation impacts would need to be assessed. This case was selected as an average condition in order to verify that the fumigation impacts would be less than maximum impacts under normal dispersion conditions (as predicted by AERSCREEN), per the EPA guidance. This would also be expected to occur for the cold day cases (Cases 106 and 108) under partial turbine loads, which were also the screening cases which produced the maximum ground level concentrations.

To verify this, the stack parameters for Cases 106 and 108 were analyzed (Table DRA6-1). The latest versions (16216) of AERSCREEN and MAKEMET, as well as AERMOD (16216r), were used so that separate runs of AERSCREEN were not required to determine impacts under both normal dispersion conditions and fumigation conditions. Results of the two additional cases analyzed are shown below for the same AERSCREEN inputs as used in the previous analysis for a normalized emission rate of one (1) gram/second.

Table DRA6-1. Fumigation Impact Summary

	Case 103 Average Ambient Conditions, 100% Load		**Case 106** Cold Ambient Conditions, 100% Load		**Case 108** Cold Ambient Conditions, 20% Load	
Averaging Time (Unitized Impacts for 1 g/s)	**AERSCREEN Fumigation Impacts (μg/m³)**	**AERSCREEN Flat Terrain Impacts (μg/m³)**	**AERSCREEN Fumigation Impacts (μg/m³)**	**AERSCREEN Flat Terrain Impacts (μg/m³)**	**AERSCREEN Fumigation Impacts (μg/m³)**	**AERSCREEN Flat Terrain Impacts (μg/m³)**
1-hour	2.465	5.032	2.436	4.914	4.542	23.71
3-hour	2.465	5.032	2.436	4.914	4.542	23.71
8-hour	2.219	4.529	2.192	4.422	4.088	21.33
24-Hour	1.479	3.019	1.461	2.948	2.725	14.22
Distance (m)	7,850	213	7,920	216	5,019	64

The results of the analysis for all three cases demonstrate that the fumigation impacts are less than the maxima predicted by AERSCREEN in flat terrain. Since fumigation concentrations are less than the maximum overall AERSCREEN concentrations, no further analysis of fumigation impacts is required.

Existing and cumulative sources

A7. Please provide a copy of the District's correspondence regarding existing and planned cumulative sources located within six miles of the project site.

Response: A copy of the request to the District for the cumulative source inventory is attached to this response package (Attachment DRA7-1).

List of sources

A8. Please provide the list of sources to be considered in the cumulative air quality impact analysis.

Response: The list of cumulative sources will be submitted to the CEC for review and comment after the District has provided it to the Applicant.

Cumulative impact analysis

A9. Please provide the cumulative modeling impact analysis, including Stanton Energy Reliability Center (SERC) and other identified new and planned projects within 6 miles of the SERC site.

Response: The cumulative modeling and impact analysis will be provided following District approval of the list of sources to be included in the analysis.

CEQA mitigation strategy

A10. Please provide the mitigation strategy for all nonattainment criteria pollutants and their precursors to meet the Energy Commission's CEQA mitigation requirements, including NOx, VOC, SOx, PM10 and PM2.5.

Response: SERC, LLC is not proposing any CEQA emission-related mitigation as is typical with other projects. Due to emissions benefits inherent in the proposed project, mitigation is not necessary. First, as described below, the SERC provides emission free spinning reserve through the use of the EGT® Hybrid technology, which will lower emissions within the South Coast air basin by displacing generation of higher emitting, less efficient facilities that would operate, if not for the SERC. Second, notwithstanding the fact that the SERC provides these emission benefits to the basin, the SCAQMD will be providing offsets from its bank to offset the SERC emissions.

Emission Free Spinning Reserves Displaces Higher Emitting Facilities

As described in responses to Data Requests A11 and A12 below, the EGT® Hybrid integrates a battery energy storage system with gas turbine operations. This enables the SERC to provide 98 MW of natural gas-free, emission-free spinning reserves. Additionally, as described in the AFC and unlike a traditional peaking facility, the SERC was designed and is being permitted to provide reliability services within the local service area and is not designed solely to provide electricity during times of peak demand. This is demonstrated by the relatively small number of operation hours expected and reflected in the low Potential to Emit quantities being requested from the SCAQMD and CEC in the permit applications.

SERC, LLC engaged ZGlobal, a highly respected electricity market and transmission system engineering firm, to conduct a study to determine the effect on emissions within the basin from the integration of the EGT® Hybrid technology with grid operations. The study will be submitted under separate cover, but preliminary conclusions are that the EGT® Hybrid can provide reliability services to the local basin with fewer emissions than other thermal resources. The ZGlobal study used the PLEXOS Integrated Energy Model for a production cost simulation to derive hourly generation dispatch, nodal and aggregated load area prices, ancillary services marginal prices, and emissions, subject to transmission and other operational constraints. The results of the production cost runs were then used to calculate emission reductions. Specifically, the study found that the SERC as an EGT® Hybrid provide benefits of:

- Lowers overall dispatched heat rate in the system
- Provides for less commitment of higher-cost generators
- Provision of reserves from the SERC displaces reserve provision from other units, resulting in those units being more efficiently dispatched for energy or used for their ancillary services at a lower overall cost to the system

The model predicted that, for the vast majority of the time (approximately 77 percent of the time), the SERC will be dispatched to provide emission-free spinning reserve capacity.

In addition, the study found that SERC will cause avoided gas burn from other units by providing capacity to meet or maintain:

- Minimum On-line Commitment (MOC)
- Voltage support
- Spinning reserves
- Primary frequency response (PFR)
- High-speed regulation during system load peaks, allowing more efficient resources to provide energy

Once the ZGlobal study is finalized, SERC will provide estimates of the reduction in criteria pollutants and GHG that will result from the turn-down and displacement of specific units within the South Coast Air Basin.

SCAQMD Offsets

Pursuant to the SCAQMD New Source Review (NSR) Rule 1304 (d)(1)(A), SERC is not required to acquire emission reduction credits to offset project emissions since it will be a minor NSR source for NOx, PM10, SOx, VOCs and CO. SCAQMD regulations would therefore not require mitigation for emissions of any non-attainment pollutant. CEC standard practice for compliance with CEQA and the Warren-Alquist Act requires mitigation for all non-attainment pollutants and their precursors. However, as discussed above, the CEC has not yet licensed a facility that can provide emission-free spinning reserves and can demonstrate the displacement of higher emitting generating facilities. For purposes of discussion, we have included Table DRA10-1, which outlines the SCAQMD Offset Trigger Thresholds, the SERC Facility Potential to Emit (PTE), and the total offsets required by the SCAQMD Rules. If the SERC did not provide its inherent emissions reductions discussed above, the amount of mitigation the CEC would normally require would be equal to the SERC PTE.

Table DRA10-1. SCAQMD Emission Bank Credits Required By SERC

Pollutant	PM10/2.5	VOC	NO_x	SO_2	CO
SCAQMD Offset Trigger Thresholds, tpy	4	4	4	4	29
SERC Facility PTE, tpy	2.71	1.46	3.89	0.89	7.15
Total Offsets Required, tpy	0	0	0	0	0

Use of the SCAQMD Minor Source Bank

SERC is proposing that the CEC rely on the SCAQMD's offset account to fully mitigate the project's PTE for the purposes of CEQA. The SCAQMD has determined that providing offset exemptions and the Priority Reserve (as well as the minor source offset account, previously-administered Community Bank) is important to the NSR program and the local economy while encouraging installation of Best Available Control Technology (BACT). Therefore, SCAQMD has assumed the responsibility of providing the necessary offsets for exempt sources for minor NSR sources.

The SCAQMD tracks all emission increases that are offset through the Priority Reserve, as well as all increases that are exempt from offset requirements pursuant to SCAQMD Rule 1304 – Exemptions (Minor Source Offset Account). These increases are all debited from SCAQMD's federal offset accounts when they occur at federal major sources. For federal equivalency demonstrations, SCAQMD uses an offset ratio of 1.2-to-1.0 for extreme non-attainment pollutants (ozone and ozone precursors, i.e., VOC and NOx) and uses

1.0-to-1.0 for all other non-attainment pollutants (non-ozone precursors, i.e., SOx, CO, and PM10) to offset any such increases.

SCAQMD's NSR Rules and Regulations are designed to comply with federal and state Clean Air Act requirements and to ensure that emission increases from new and modified sources do not interfere with efforts to attain and maintain the federal and state air quality standards, while economic growth in the South Coast region is not unnecessarily impeded. Regulation XIII (NSR) regulates and accounts for all emission changes (both increases and decreases) from the permitting of new, modified, and relocated stationary sources within SCAQMD, excluding NOx and SOx sources that are subject to Regulation XX (Regional Clean Air Incentives Market, or RECLAIM).

One part of SCAQMD's NSR program is to offset emission increases in a manner at least equivalent to federal and state statutory NSR requirements. To demonstrate equivalency, the SCAQMD's NSR program implements the federal and state statutory requirements for NSR and ensures that construction and operation of new, relocated, and modified stationary sources does not interfere with progress towards attainment of the National and State Ambient Air Quality Standards. SCAQMD's computerized emission tracking system is used to demonstrate equivalence with federal and state offset requirements on an aggregate basis.

Two important elements of federal non-attainment NSR requirements are Lowest Achievable Emission Rate (LAER) and emission offsetting for major sources. As set forth in SCAQMD's BACT *Guidelines*, SCAQMD's BACT requirements are at least as stringent as federal LAER for major sources. Furthermore, the NSR emission offset requirements that SCAQMD implements through its permitting process ensures that sources provide emission reduction credits (ERCs) to offset their emission increases in compliance with federal requirements. As a result, these sources each comply with federal offset requirements by providing their own ERCs.

To support the use of the NSR offset program, Rule 1315, the Federal NSR Tracking System was adopted by the SCAQMD Board on February 4, 2011 to maintain SCAQMD's ability to issue permits to major sources that require offsets, but to also obtain offset credits from sources that are exempt from offsets under SCAQMD Rule 1304.

To support the offset program under Rule 1315, SCAQMD tracks all emission increases that are offset through the Priority Reserve or the Community Bank, as well as all increases that are exempt from offset requirements pursuant to Rule 1304 – Exemptions. These increases are all debited from SCAQMD's federal offset accounts when they occur at federal major sources.

As stated above, for federal equivalency demonstrations, SCAQMD uses an offset ratio of 1.2-to-1.0 for extreme non-attainment pollutants (ozone and ozone precursors, i.e., VOC and NOx) and uses 1.0-to-1.0 for all other non-attainment pollutants (non-ozone precursors, i.e., SOx, CO, and PM10) to offset any such increases. That is, 1.2 pounds are deducted from SCAQMD's offset accounts for each pound of maximum allowable permitted potential to emit VOC or NOx increase at a federal source and 1.0 pound is deducted for each pound of maximum allowable permitted potential to emit SOx, CO, or PM10 at a federal source. A more detailed description of federal debit accounting is provided in the Rule 1315 staff report and Rule 1315(c)(2).

Therefore, based on the requirements of Rule 1304 and the offset accounts/tracking requirements under Rule 1315, SERC proposes that the use of the SCAQMD offset account for minor NSR projects will fully mitigate the proposed project emissions of non-attainment criteria pollutants. Because SERC will displace higher emitting facilities with emission free spinning reserve, and the SCAQMD Rules require the offsetting by SCAQMD, additional CEQA air quality mitigation is unnecessary.

Battery integration

A11. Please describe how the battery component would be integrated with the combustion turbine operation.

Response: The EGT® Hybrid is similar to a hybrid car, which charges its battery using the gas engine and by regenerative braking, and then discharges the battery when there is a call for increasing speed or power. When the EGT® Hybrid is in operation, its control system is constantly monitoring and adjusting either the output of the LM6000 gas turbine, the battery energy storage system, or both. The primary variables that are co-optimized are energy or power demand (in MW) by the grid operator and State of Charge (SOC) of the battery system. As described in the AFC, the SOC is completely managed by the LM6000 with no charging from external sources. MW demand and SOC are described as follows:

- Energy demand is the quantity of MWs that the CAISO, as grid operator, is instructing the EGT® Hybrid to deliver to the grid
- SOC is the amount of stored energy left in the batteries at any given time that is available for discharge to the grid. The optimum range of SOC is from 20 to 90 percent for lithium-ion chemistry. The optimum SOC is 50 percent because, at 50 percent SOC, there is room to charge and energy available for discharge.

The EGT® Hybrid control system can generally be expected to follow the operations described in Table DRA11-1.

Table DRA11-1. EGT® Hybrid battery-turbine operation modes

<table>
<tr><th colspan="2" rowspan="2"></th><th colspan="3">Battery State</th></tr>
<tr><th>Discharging</th><th>Steady State Output of Zero</th><th>Charging</th></tr>
<tr><th rowspan="3">Turbine State</th><th>Decreasing MWs</th><td>The top of the SOC range has been achieved and battery needs to reduce SOC</td><td>The SOC is acceptable and total MW Demand has been reduced</td><td>Optimum SOC has not been achieved and total MW Demand has been reduced</td></tr>
<tr><th>Steady State Output</th><td>The top of the SOC range has been met and MW demand is not changing</td><td>The SOC is acceptable and MW Demand is not changing</td><td>Optimum SOC has not been achieved and total MW Demand is not changing</td></tr>
<tr><th>Increasing MWs</th><td>MW Demand is increasing and Bottom of SOC has not been reached.</td><td>MW Demand is increasing and Top of SOC has been reached.</td><td>MW Demand may be increasing or SOC may be low or both</td></tr>
</table>

Similar to a gas-hybrid automobile, the demands of the overall EGT® Hybrid system determine which source of energy provides the motive force. The integration of the gas-fired engine with the battery system is tightly controlled and finely tuned for optimal operations. The control system for the EGT® Hybrid is supplied by General Electric.

Emissions with integrated operation

A12. Please evaluate if the emissions would be affected by the integrated operation and how.

Response: As described in the response to Data Request A10, above, generally and systemically, the EGT® Hybrid has a positive effect on emissions and reduces them across the regional grid system and air basin. The EGT® Hybrid is capable of providing nominally 50 MW of emission-less, GHG-free spinning reserve ancillary services per LM6000 to the CAISO. When the EGT® Hybrid is providing spinning reserve, it is likely displacing another unit which would have otherwise delivered spinning reserve by burning natural gas at a power output that is less than full load, inefficiently and at relatively high emission rates. The result is that the displaced unit is either turned off or re-dispatched to a more efficient load point. Both outcomes result in reduced emissions from a system-wide and basin-wide perspective.

Battery capacity and energy

A13. Please explain how the battery size (capacity and energy) was determined and what factors were considered to reduce facility emissions?

Response: The battery was sized primarily to allow the integrated EGT® Hybrid to: a) have a smooth and continuous 10-minute ramping profile, and b) to perform as a spinning reserve and Automatic Generator Control (AGC) unit in the CAISO markets.

1. Spinning Reserve
   a. The battery allows the EGT® Hybrid to deliver qualified spinning reserve by meeting the following CAISO requirements (per Appendix K of the CAISO tariff):
      i. Immediately frequency responsive via a single 5 percent droop control circuit for the single integrated EGT® Hybrid. Droop is automatic and constitutes a primary frequency response.
      ii. Providing a minimum 10 percent of EGT® Hybrid full load within 8 seconds.
   b. The LM6000 gives the EGT® Hybrid a full range of operability (nominally 50 MW) for spinning reserve and duration (i.e. >30 minutes), also a spinning reserve requirement per Appendix K.
2. EGT® Hybrid performance in regulation (also known as AGC). The EGT® Hybrid has ultra-high speed and ultra-accurate voltage regulation performance. Because the battery is capable of very fast changes in discharge or charge rates, the EGT® Hybrid is capable of regulation accuracy in excess of 95 percent. The CAISO accuracy standard is $\geq$ 20 percent.
3. Facility emissions are being managed by more traditional methods; e.g., water injection and post-combustion controls.

Diesel-fueled equipment

A14. Please explain whether presence of the battery system eliminates the need for diesel-fueled internal combustion engine equipment such as for an emergency generator or fire pump?

Response: The fact that SERC will feature a battery system has no relationship to the fact that the SERC does not include diesel-fueled internal combustion engine equipment such as an emergency generator or fire pump. An emergency generator is typically required where "black-start" capability is desired. SERC is not being designed to provide black-start capability, thus no emergency generator is required. A diesel-driven fire pump is in many cases provided, along with onsite water storage, to provide a reliable supply of fire protection water in the event that there is not a reliable supply available (e.g. a municipal water system) with adequate flow and pressure to meet the needs of the plant fire protection systems. For SERC, Golden State Water Company's (GSWC's) distribution system has adequate flow and pressure available to meet the needs of the plant fire protection systems without the need for onsite pumps. Thus, a diesel-driven fire pump and onsite storage are not necessary.

Thermal plume modeling

A15. Please provide the updated thermal plume vertical velocity analysis if the related turbine operational parameters have beenrevised

Response: Stack parameters have not changed since the AFC was filed. Therefore, it is not necessary to modify the thermal plume vertical velocity modeling analysis.

Attachment DRA7-1
Letter to SCAQMD Requesting Cumulative Projects List

SOUTH COAST AQMD

PUBLIC RECORDS REQUEST FORM

Request Information

Date Stored

Time Stored

Public Record Request Nbr

Public Record Request Tracking Nbr
92687

Attention Requestor

Please fill out this form completely. You may include an attachment to the form, if necessary.

Requestor Information

Requestor Name
Gregory Darvin

Requestor Company
Atmospheric Dynamics, Inc.

Requestor Email*
DARVIN@ATMOSPHERICDYNAMICS.COM

Requestor Phone
(831)620-0481

Requestor Address
PO Box 5907

Requestor City
Carmel by the Sea

Requestor State
CA

Requestor Zip Code
93921

Type of Requested Record(s).

REQUESTED RECORDS. Please be as specific as possible in describing the records you are seeking. The more specific you are, the easier it will be to determine if such records exist in District files. Please contact the Public Records Unit if you need assistance in identifying District records.

Note: Permits to Operate, Equipment Lists, Notices of Violation, Notices to Comply, and Emissions Summaries are available through SCAQMD's FIND page at http://www3.aqmd.gov/webappl/fim/prog/search.aspx (you need to copy and paste this link into your browser).

Please Enter a description of the records you are requesting here:*
As part of the California Energy Commission (CEC) requirements for new power plants, I must prepare a cumulative modeling inventory of all sources located within 6 miles of the Stanton Energy Reliability Center (SERC).
SERC is located at the following address: 10711 Dale Avenue, Stanton, CA 90680. The UTM coordinate in NAD83 is 408764.96 meters easting, 3741169.32 meters northing.
We would like to obtain a list of all recently permitted projects with a potential to emit of 5 tpy or more located within 6 miles of SERC. This includes all projects that have received construction permits in 2016 and 2017 but are not yet operational and/or projects that are in the permitting phase.
For each project, we would need the location, emissions of criteria pollutants and stack parameters such as stack height, stack diameter, stack temperature and stack velocity.

Time Period of Documents Requested

Start Date*
1/1/2016

End Date*
4/25/2017

Requested Facility or Site Information (if applicable)

Note: You may only include one Facility or Site per Form.

Facility ID (if known)

Address

Facility Name (if known)

City

Zip Code

Requested Application or Permit List. (if applicable)

Please click the Add Button to the right to enter a Application/Permit Number

Supplemental Attachments

Supplemental Documents

Note: Please use the above button for attaching additional documents that will help define your public records request.

INSTRUCTIONS FOR REQUESTING RECORDS

(California Public Records Act, Govt. Code Sections 6250-6276.48)

1. In order to expedite your request, please fill out the form completely. Requests may also be submitted by phone at (909) 396-3700, by facsimile to (909) 396-3330, or by email to PublicRecordsRequests@aqmd.gov.

2. Requests must be for records prepared, owned, used, or retained by the District (Gov. Code Sec. 6252(e)). Requests should be for clearly identifiable records. The District is not required to create a new record in response to a request. The District will assist the requestor in making a request that describes reasonably identifiable records (Gov. Code Sec. 6253.1). Documents will not be provided if disclosure would infringe upon a copyright, trade secret, or is otherwise exempt in accordance with state law.

3. A search for facility records can only be conducted by one or all of the following:

-- a) Facility Name, Address, or Identification Number

-- b) Facility Application Number, or Permit to Operate Number; or

-- c) Facility Notice of Violation/Notice to Comply Number.

4. You will be notified within ten (10) days whether your request seeks copies of disclosable public records prepared, owned, used, or retained by this agency. In some cases, the District may need an additional 14 days to respond. If so, you will be notified in writing. You will also be provided an estimated date of when the records will be made available.

5. Communications regarding your request, and any records, will be provided by email, unless specified otherwise.

6. If the search for records finds the records voluminous, you will be notified of the approximate number of pages and/or length of time it will take to process your request.

7. If the records you requested have been marked confidential by the source of the record, you will be notified and given the option of continuing with the District's Trade Secret process.

8. If your request is to review records, rather than receive copies, the District will notify you once the records are gathered, and arrangements will be made for your review.

9. The charge for the direct cost of duplication is as follows: Paper Copies, $0.15/page each over 10 pages (first 10 pages are free); Copied CD's or flash drives, no charge; and Copied Audio Tapes, $5.00 each. After a preliminary estimate, advance payment may be required.

10. If the request is for information in an electronic format, the requestor shall bear the cost of producing a copy of the record, including the cost to construct the record and the cost of programming and computer services necessary to produce a copy of the record, when either of the following applies: (1) the District would be required to produce a copy of an electronic record and the record is one that is produced only at otherwise regularly scheduled intervals, or (2) the request would require data compilation, extraction, or programming to produce the record. (Gov. Code Sec. 6253.9(b)). The transfer of gathered electronic records onto CD, DVD or flash drive typically costs $10.00 each. An invoice will accompany your records when completed.

Note: For further information, please refer to the District's Guidelines for Implementing the California Public Records Act. The Guidelines are available in the lobby of the District Headquarters or on the District's web site at www.aqmd.gov.

Note: If you have questions pertaining to the submittal of a Public Records Act request, you may contact the Public Records Unit, (909) 396-3700, Tuesday through Friday, 7:00 a.m. to 5:30 p.m. Our Fax number is (909) 396-3330. Our email address is PublicRecordsRequests@aqmd.gov.

5.2 Biological Resources (A16-A23)

Western burrowing owl

A16. For western burrowing owl, provide results of reconnaissance surveys focused on observations of wildlife sign including burrows, scat, tracks, remains, and other distinguishing indicators. Include negative results (e.g. no sign detected) including if there was a lack of burrow surrogates or fossorial mammal dens that could be used by burrowing owl observed in the project area.

Response: Attachment DRA16-1 is a report of additional reconnaissance surveys focusing specifically on the western burrowing owl.

Generator tie-line route

A17. Provide a description of the land cover/vegetation communities of the generator tie-line route. Include in your description the dominant, co-dominant, and other associated plant species observed for each land cover type/vegetation community. Depending on the plant species identified, rare plant surveys may be required.

Response: SERC, LLC has approached SCE to request that they conduct a land cover/vegetation community survey within portions of the Barre Substation property that are part of the SERC project, such as the underground generator tie-line. The time frame for this study, according to SCE, will be approximately eight weeks. SERC, LLC will submit SCE's report of findings when it is available from SCE.

Based on aerial photographs, the land cover within the Barre Substation consists of three community types: 1) ruderal grasslands, 2) non-native landscape fenceline border, and 3) areas surfaced with gravel that are partially invaded with invasive and ruderal species. Portions of the generator tie-line that are not within the Barre Substation and under the control of SCE are located in Dale Avenue and at the margins of the SERC project site, which is a mowed ruderal grassland.

Generator tie-line right-of-way width

A18. Please provide the right-of-way width required for the new generator tie-line (half and full right-of-way). Note any differences in right-of-way width requirements due to terrain or adjacent land uses or structures. Please map the right-of-way on aerials and a series of maps based on USGS 7.5-minute topographic maps enlarged to a scale of 1"=1,000 feet. Please provide the Geographic Information Systems shape files for the right-of-way. Please indicate areas of any new right- of-way versus existing right-of-way.

Response: Attachment DRA18-1 is a series of maps showing the generator tie-line (and natural gas pipeline) route at the scale of 1"= 1,000 feet. Note, however, that the generator tie-line will be installed mostly within the SCE Barre Substation and, for that reason, will not require a right-of-way through private or public land, as SCE is the owner of the substation and will also be the owner and operator of the generator tie-line. Per SCE, the work area for the generator tie-line within the Barre Substation property will be approximately 50 feet wide.

Generator tie-Line installation

A19. Please describe how the generator tie-line would be installed, including the depth of cover provided over the generator tie-line, depth and width of the trench, or buried area, to install the generator tie-line.

Response: SCE will carry out the final design and construction of the generator tie-line, which will be installed under Dale Avenue and within the fenceline of the SCE Barre Substation. In design and construction, SCE must comply with the California Public Utility Commission's (CPUC's) General Order (GO) 128 (Rules for Construction of Underground Electric Supply and Communication Systems). SCE has indicated that the following are their typical specifications for construction of a 66 kV line:

- Trench width is approximately 19 inches
- Trench depth is 60 inches with 36 inches of cover
- There will be six 5-inch ducts made of polyvinyl chloride (PVC) pipe, encased in 5-sack cement
- Maximum of 1500-foot pull length from vault to vault. Maximum of 250 feet from vault to riser
- At least three pull-and-tensioning sites on Barre Substation property would be used. One pull site would be on the SERC site.

Generator tie-line area of disturbance

A20. Please provide the amount of temporary and permanent area disturbed for the generator tie-line and show the areas on aerials and also a series of maps based on USGS 7.5-minute topographic maps enlarged to a scale of 1"=1,000 feet for the following list items (a-d). Identify the temporary and permanent impacted areas (size in acres). Please provide the Geographic Information System shape files for the following:

a. generator tie-line
b. access route for construction (location and length of route)
c. construction staging areas (locations and size)
d. permanent (including on-going) and temporary vegetation removal (e.g. trees, shrubs, etc.) within and around the right-of-way.

Response: Attachment DRA18-1 contains maps with estimated temporary and permanent impact areas for the generator tie-line (and natural gas pipeline). These are estimates only and subject to modification by SCE when they complete final design for and construct the generator tie-line.

Natural gas pipeline right-of-way width

A21. Please provide the right-of-way width required for the new natural gas pipeline (half and full right-of-way). Note any differences in right-of-way width requirements due to terrain or adjacent land uses or structures. Please map the right-of-way on aerials and a series of maps based on USGS 7.5-minute topographic maps enlarged to a scale of 1"=1,000 feet. Please provide the Geographic Information Systems shape files for the right-of-way. Please indicate areas of any new right-of-way versus existing right-of-way.

Response: The pipeline will be constructed and operated by the Southern California Gas Company (SoCalGas) within the roadway of Dale Avenue, by franchise agreement with the municipalities through which the pipeline runs. According to SoCalGas, construction of the pipeline will require temporary working rights-of-way 30 feet wide. Where additional working space is available adjacent to the road, the construction right-of-way may expand to 50 feet to accommodate additional trench spoil or avoid underground utilities. Locations of the 50-foot-wide right-of-way segments will be determined during final construction planning and design. Attachment DRA18-1 is a set of maps showing the approximate location of the 30-foot-wide construction right-of-way. These maps show the estimated location of the pipeline and construction rights-of-way. Actual locations will be determined by SoCalGas during final design and construction planning and will take into consideration additional factors such as detailed mapping of existing utilities to be avoided.

Pipeline construction

A22. *Please provide the location and dimensions of boring and drilling entry and exit points where the pipeline is routed under existing drainages or infrastructure. Please provide construction details if the pipeline will be installed on existing structures such as overpasses or bridges that cross the existing drainages.*

Response: SCE has indicated that they will cross Ball Road, Cerritos Avenue, and Carbon Creek channels using jack-and-bore methods. These locations are indicated on maps of Attachment DRA18-1. SoCalGas's description of this method is as follows:

> Horizontal bores require entry pits measuring approximately 15 feet by 40 feet and receiving pits measuring approximately 10 feet by 20 feet to complete the crossing. Typically, bore pits are approximately 15 to 30 feet deep, and the bottom of the pit is stabilized with gravel prior to lowering the boring machine into the pit. If groundwater is encountered, it is pumped into a temporary holding tank, such as a Baker tank, for analysis prior to being discharged in accordance with federal, state, and local regulations. The pipe segments utilized for these operations will need to be approximately 20 feet in length.

No additional information regarding the channel crossings is available from SoCalGas at this time.

Natural gas pipeline areas of disturbance

A23. *Please provide the amount of temporary and permanent area disturbed for the natural gas pipeline. Show the areas on aerials and also a series of maps based on USGS 7.5-minute topographic maps enlarged to a scale of 1"=1,000 feet for the following list items (a-d). Identify the temporary and permanent impacted areas (acres) and please provide the Geographic Information System shape files for the following:*

a. natural gas pipeline
b. access route for construction (location and what length)
c. construction staging areas (locations and size)
d. permanent (including on-going) and temporary vegetation removal (e.g. trees, shrubs, etc.) within and around the right-of-way.

Response: Disturbance areas will include the following:

- Pipeline trench - 6 feet deep and approximately 4-6 feet wide. Will meet minimum cover depth of 6 inches
- Staging Yard A – One half-acre of open land at Dale and Standustrial Avenues, owned by SCE (parcel directly adjacent to and north of the SERC site).
- Staging Yard B – One half-acre area within a parking lot 700 feet south of the intersection of Crescent and Dale Avenues (open area on Dale Avenue surrounded by parking lot).

Access to the pipeline route will be along existing urban streets. Vegetation removal will not be necessary to construction the natural gas pipeline in Dale Avenue. The locations of proposed staging yards A and B are shown on Figure DRA18-1.

Attachment DRA16-1
Western Burrowing Owl Survey Assessment

TECHNICAL MEMORANDUM

Stanton Energy Reliability Center (16-AFC-1) Biological Reconnaissance Surveys

PREPARED FOR: Stanton Energy Reliability Center, LLC

PREPARED BY: Hannah Buckley/CH2M Engineers, Inc. (CH2M)

DATE: April 28, 2017

Introduction

Hannah Buckley (Staff Biologist/CH2M) conducted biological reconnaissance surveys for special-status plants, special-status wildlife, and nesting birds, with a focus on Western burrowing owl *(Athene cunicularia),* for the Stanton Energy Reliability Center, LLC (Project Owner) Stanton Energy Reliability Center (Project or SERC) (16-AFC-1) on April 24, 2017. These surveys were conducted in response to California Energy Commission Staff Data Request A16, as part of the Application for Certification proceeding for the SERC. Data Request A16 requested specific information based on reconnaissance surveys regarding the potential for burrowing owls to be present on the project site and associated construction staging areas.

Location and Background

The Project Area surveyed consists of the SERC project site, located on two connected parcels, Parcels 1 and 2, and two separate Staging Areas, Staging Areas A and B. The SERC project site is west of Dale Avenue, approximately 1,400 feet north of the intersection of Dale Avenue and West Katella Ave, in the City of Station, Orange County, California. Parcel 1 is 1.76 acres and consists of an undeveloped lot. Parcel 2 is 2.21 acres and is paved and used for vehicle and equipment storage. The Project Area also consists of two half-acre vacant lots, Staging Area A (which adjoins to Parcel 1) and Staging Area B, located within an inaccessible (fenced) parking lot 2.08 miles north of Parcel 1. Southern California Gas Company has identified Staging Areas A and B as possible laydown yards during construction of the Project's natural gas pipeline. Land uses in the immediate vicinity include commercial, industrial, residential, and developed/disturbed areas. Maps of the Project Areas are included in Figures 1, 2, and 3 (following page).

Survey Methods

The Project was reviewed for sensitive biological resources including United States Fish and Wildlife Service (USFWS) designated critical habitat (USFWS, 2017a), special-status plant and wildlife species, and sensitive vegetation communities (CDFW, 2003 and 2009a). Lists of potential special-status species were queried from USFWS (2017b, 2017c, and 2017d), California Natural Diversity Database (CNDDB) (CDFW, 2017), and the California Native Plant Society (CNPS) (2017). A 5-mile query was used for CNDDB and USFWS, and a query was conducted of nine USGS 7.5-minute quadrangles for CNPS. The results of these queries and other environmental analyses were reviewed prior to conducting the biological reconnaissance surveys.

Conventional survey protocols, including guidelines provided by the California Burrowing Owl Consortium (CBOC), USFWS, California Department of Fish and Wildlife (CDFW), and CNPS, were reviewed and implemented where appropriate (CBOC, 1997) (USFWS, 1996) (CDFW, 2009b) (CNPS, 2001). The Project area and suitable habitat for special-status wildlife and nesting birds within a 100-foot buffer were surveyed where access was permitted (Survey Area). Other potential environmental issues were noted if observed during the surveys.

Figure 1. The SERC project site
Parcel 1 (east of culvert) and Parcel 2 (west of culvert).

Figure 2. Staging Area A
Dale Avenue near Standustrial Avenue.

Figure 3. Staging Area B
Dale Avenue, 700 feet south of the intersection with Crescent Avenue

Special-Status Plants

The potential for special-status plants to occur in the Survey Area was assessed based on historical data and existing habitat. Areas with native soil and suitable habitat were surveyed for the presence of special-status plants within the appropriate floristic period.

Special-Status Wildlife

The potential for special-status wildlife to occur in the Survey Area was assessed based on historical data and existing habitat. The surveys in Parcel 1 and Parcel 2 focused on Western burrowing owl, including observations of wildlife sign including burrows, scat, tracks, remains, and other distinguishing indicators.

Nesting Birds

The Survey Area was surveyed for special-status bird species and species protected by the USFWS Migratory Bird Treaty Act (MBTA) and CDFW Fish and Game Codes. Trees, shrubs, man-made structures, and ground surfaces were surveyed for bird nests. The survey also focused on observations of courtship and behavioral cues. Tall substrates and potential habitat observed in inaccessible areas were surveyed using binoculars. A storm drain/water conveyance structure adjacent to the proposed project site was surveyed to the extent feasible.

Other Potential Environmental Issues

Other potential environmental issues, including potential threats to air quality, water quality, cultural resources, and potentially hazardous debris, were observed incidentally and noted as appropriate. The site was surveyed by walking meandering transects of the accessible areas and inaccessible areas were surveyed using binoculars.

Survey Results

Survey conditions are presented in Table 1, followed by survey results. Photographs are provided in Attachment A. A list of plant species observed within the Survey Area is provided in Attachment B. Lastly, a list of special-status plant species that have been documented within the regional vicinity is included in Attachment C.

Table 1. Weather Conditions

Date	Time (24-hour)	Project Location	Temperature (°F)	Wind (mph)	Cloud Cover (%)	Precipitation (None, Light, Moderate, Heavy)	Comments
4/24/2017	0945-1315	City of Stanton, California	70	7	60	None	Good visibility (10.0 miles); 60% humidity

Notes:

°F = degrees Fahrenheit
% = percent
mph = miles per hour

Special-status Plants

The Survey Area consists primarily of disturbed habitat on the Project site and an adjacent utility right-of-way, and areas of ruderal vegetation. The Survey Area within Parcels 1 and 2 and Staging Area A had been recently mowed. The dominant species in these areas is ripgut brome *(Bromus diandrus)*. Staging Area B was unmowed and its dominant species is foxtail brome *(Bromus madritensis)*. No special-status plants were observed in the Survey Area. A list of plant species observed during the survey is provided in Attachment B.

Special-status Wildlife

No special-status wildlife or signs of special-status wildlife were observed in the Survey Area. There were no observations of Western burrowing owl or sign including burrows, scat, tracks, remains, and other distinguishing indicators. The Survey Area lacked burrows, burrow surrogates, and fossorial mammal dens that could be used by burrowing owls. A concrete-lined storm drain/water conveyance structure adjacent to the proposed project site was surveyed and there were no observations of wildlife in this channel. Common wildlife species observed within or adjacent to the Survey Area included American crow (*Corvus brachyrhynchos*), common raven (*Corvus corax*), Eurasian collared dove (*Streptopelia decaocto*), barn swallow (*Hirundo rustica*), Western kingbird (*Tyrannus verticalis*), house finch (*Haemorhous mexicanus*), mourning dove (*Zenaida macroura*), killdeer (*Charadrius vociferus*), Northern mockingbird (*Mimus polyglottos*), white-crowned sparrow (*Zonotrichia leucophrys*), and rock pigeon (*Columba livia*).

Nesting Birds

No bird nests were observed in the Survey Area during the biological reconnaissance surveys. Male killdeer were observed flying high and calling repeatedly over presumed nesting territory on the gravel road running adjacent to Parcel 1 and through Staging Area A, but no nest sites were observed.

Other Potential Environmental Issues

One storage unit was identified within the Survey Area of Staging Area B (Attachment A, Photograph 7). Access to the site was restricted by fencing. Surveys completed using binoculars indicate there are no potential environmental hazards associated with the storage unit.

In addition, there is a concrete-lined storm drain/water conveyance structure adjacent to the proposed project site between Staging Area A and adjacent businesses on Standustrial Street (Attachment A, Photograph 4) as well as between Parcels 1 and 2 (Attachment A, Photograph 5), as stated earlier. Although no direct impacts are anticipated, best management practices (BMPs) should be implemented as appropriate during construction adjacent to this structure.

Summary and Recommendations

No special-status plants or wildlife were observed within the Survey Area. No impacts to special-status species are anticipated as a result of the Project. If construction activity is to occur during the nesting season, (typically February 1 to August 31) it is recommended that a pre-construction nesting bird survey take place to avoid impacting nesting birds.

References

California Department of Fish and Wildlife (CDFW). 2003. http://ecos.fws.gov/tess_public/pub/stateListingAndOccurrenceIndividual.jsp?state=CA&s8fid=112761032792&s8fid=112762573902. Wildlife and Habitat Data Analysis Branch, Vegetation Classification and Mapping Program.

California Department of Fish and Wildlife (CDFW). 2009a. *List of California Vegetation Alliances.* Biogeographic Data Branch, Vegetation Classification and Mapping Program.

California Department of Fish and Wildlife (CDFW). 2009b*. Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities.* Sacramento, California. http://www.dfg.ca.gov/bdb/pdfs/guideplt.pdf.

California Department of Fish and Wildlife (CDFW). 2017. California Natural Diversity Database (CNDDB). *RareFind5.* Electronic database. http://www.dfg.ca.gov/biogeodata/cnddb/mapsanddata.asp. Sacramento, California.

California Native Plant Society (CNPS). 2001. *Botanical Survey Guidelines of the California Native Plant Society.* December 9, 1983; revised June 2, 2001.

California Native Plant Society (CNPS). 2017. *Inventory of Rare, Threatened, and Endangered Plants of California.* http://www.rareplants.cnps.org/.

California Burrowing Owl Consortium (CBOC). 1997. *Burrowing owl survey protocol and mitigation guidelines.* Pages 171-177 in Lincer, J. L. and K. Steenhof (editors). 1997. The burrowing owl, its biology and management. Raptor Research Report Number 9.

United States Fish and Wildlife Service (USFWS). 1996. *Guidelines for Conducting and Reporting Botanical Inventories for Federally Listed, Proposed, and Candidate Plants.* April 22.

United States Fish and Wildlife Service (USFWS). 2017a. USFWS Critical Habitat for Threatened and Endangered Species GIS Database.

United States Fish and Wildlife Service (USFWS). 2017b. Candidate Species in California based on published population data. http://ecos.fws.gov/tess_public/pub/stateListingIndividual.jsp?state=CA&status=candidate.

United States Fish and Wildlife Service (USFWS). 2017c. Species proposed for listing in California based on published population data. http://ecos.fws.gov/tess_public/pub/stateListingIndividual.jsp?state=CA&status=proposed.

United States Fish and Wildlife Service (USFWS). 2017d. Threatened and endangered species listings and occurrences for California. http://ecos.fws.gov/tess_public/pub/stateListingAndOccurrenceIndividual.jsp?state=CA&s8fid=112761032792&s8fid=112762573902.

Attachment A
Site Photographs

Photograph 1. SERC Parcel 1
View facing west from the east end of the SERC project site.
Taken: 04/24/2017 at 1:03 p.m.

Photograph 2. Scarlet pimpernel
Found on the eastern end of the proposed project site, Parcel 1.
Taken: 04/24/2017 at 12:08 p.m.

Photograph 3. Project site and Staging Area A
View facing northeast.
Taken: 04/24/2017 at 12:27 p.m.

Photograph 4. Project site border and Staging Area A
View facing east.
Taken: 4/24/2017 at 12:29 p.m.

Photograph 5. Storm drain adjacent to the project site
Location between Parcels 1 and 2
Taken: 04/24/2017 at 12:20 p.m.

Photograph 6. Parcel 2
West end of the proposed project site, view facing west.
Taken: 04/24/2017 at 12:44 p.m.

Photograph 7. Staging Area B
Storage container on Staging Area B facing northwest.
Taken: 04/27/2017 at 10:00 a.m.

Photograph 8**.** Staging Area B
South end of Staging Area B, view facing northeast.
Taken: 04/24/2017 at 10:22 p.m.

Attachment B
Observed Plant Species

Observed Pant Species List Stanton Electric Reliability Project			
Common Name	**Scientific Name**	**Status Federal/State**	**Native or Non-native Species**
saltbush[1, 2, A, B]	*Atriplex* sp.	--/--	--
wild oat[1, 2, A, B]	*Avena fatua*	--/--	Non-native
black mustard[1, 2, A, B]	*Brassica nigra*	--/--	Non-native
ripgut brome[1, 2, A, B]	*Bromus diandrus*	--/--	Non-native
foxtail brome[1, 2, A, B]	*Bromus madritensis*	--/--	Non-native
bindweed[1, 2, A, B]	*Calystegia* sp.	--/--	Native
yellow star thistle[1, 2, A, B]	*Centaurea solstitialis*	--/--	Non-native
lamb's quarters[1, 2, A, B]	*Chenopodium album*	--/--	Native
southern crabgrass[1, 2, A, B]	*Digitaria ciliaris*	--/--	Non-native
yellow tansy mustard[1, 2, A, B]	*Descurainia pinnata*	--/--	Non-native
scarlet pimpernel[1, A]	*Anagallis arvensis*	--/--	Non-native
summer mustard[1, 2, B]	*Hirschfeldia incana*	--/--	Non-native
foxtail barley[1, 2, A, B]	*Hordeum murinum*	--/--	Non-native
goldenrain tree[2]	*Koelreuteria bipinnata*	--/--	Non-native
cheeseweed mallow[1, 2, A, B]	*Malva parviflora*	--/--	Non-native
annual yellow sweetclover[2, B]	*Melilotus indicus*	--/--	Native
great bougainvillea[B]	*Bougainvillea spectabilis*	--/--	Non-native
California wild grape[2]	*Vitis californica*	--/--	Non-native
Russian thistle[1, A]	*Salsola tragus*	--/--	Non-native
sow thistle[2, B]	*Sonchus* sp.	--/--	Non-native
Chinese elm[B]	*Ulmus parvifolia*		
California mountain ash[2]	Sorbus californica	--/--	Non-native

Project Location:
([1]) Parcel 1, ([2]) Parcel 2, ([A]) Staging Area A, ([B]) Staging Area B
Federal Designations:
(FE) Federally Endangered, (FT) Federally Threatened, (FPE) Federally Proposed Endangered, (FPT) Federally Proposed Threatened, (FSC) Species of Concern, (FC) Candidate
State Designations:
(SE) State Endangered, (ST) State Threatened, (SR) State Rare, (CSC) Species of Special Concern, (CFP) Fully Protected Species
California Native Plant Society (CNPS) Rare Plant Rank:
(1A) Presumed extinct in California; (1B) Rare, threatened, or endangered in California and elsewhere; (2) Rare, threatened, or endangered in California, but more common elsewhere; (3) More information is needed; (4) Limited distribution; (.1) Seriously endangered in California; (.2) Fairly endangered in California; (.3) Not very endangered in California.

Attachment C
Special-Status Species

ATTACHMENT C

Special-Status Species with Potential to Occur within the Regional Vicinity of the Stanton Energy Reliability Center

Species	Status[a] (Federal/ State/Other)	Habitat Requirements	Potential for Occurrence/ Nearest Identified Occurrence
Plants			
Chaparral sand-verbena *Abronia villosa* var. *aurita*	**---/---/ CNPS 1B.1**	Annual herb; blooms January through September. Occurs in coastal scrub and chaparral.	**Extirpated.** A historic record (1929) for this species was documented within the Santa Ana River. The population has been extirpated as a results of channelization. Suitable habitat for this species was not observed within the Project Area.
Parish's brittlescale *Atriplex parishii*	**---/---/ CNPS 1B.1**	Annual herb; blooms July through October. Occurs in shadscale scrub, alkali sink freshwater wetlands, vernal pools and wetland-riparian habitats.	**Not Expected.** A historic record (1881) for this species was documented within the vicinity of Buena Park. Suitable habitat for this species was not observed within the Project Area.
Davidson's saltscale *Atriplex serenana* var. *davidsonii*	**---/---/ CNPS 1B.2**	Annual herb; blooms April through October. Occurs in alkaline soil within coastal bluff scrub and coastal scrub communities.	**Not Expected.** This species was documented within the Seal Beach Naval Weapons Station in 1986. Suitable habitat for this species was not observed within the Project Area.
Southern tarplant *Centromadia parryi* ssp. *australis*	**---/---/ CNPS 1B.1**	Annual herb; blooms May through November. Occurs in grassland and upper edges of coastal marshes, often in disturbed areas.	**Not Expected.** The only occurrence of this species within 5 miles of the Project was last documented in Bolsa Chica in 2003. There is no suitable habitat for this species within the project area.
Salt marsh bird's-beak *Chloropyron maritimum* ssp. *maritimum*	**FE/SE/ CNPS 1B.2**	Annual herb; blooms May through October. Limited distribution at the higher zones of coastal salt marsh and coastal dune habitat.	**Extirpated.** Historic occurrence records for this species have been documented within the regional vicinity; however, the populations are expected to be extirpated. Suitable habitat for this species was not observed within the Project Area.
Los Angeles sunflower *Helianthus nuttallii* ssp. *parishii*	**---/---/ CNPS 1A**	Perennial herb; blooms August through October. Occurs in coastal marshes.	**Not Expected.** A historic occurrence record for this species was documented in Wintersburg (1924). Suitable habitat for this species was not observed within the Project Area.
Coulter's goldfields *Lasthenia glabrata* ssp. *coulteri*	**---/---/ CNPS 1B.1**	Annual herb; blooms July through February. Occurs in coastal marshes, playas, vernal pools and mesic grasslands.	**Extirpated.** A historic occurrence record for this species was documented in the vicinity of Cypress and is presumed to be extirpated (1932). Suitable habitat for this species was not observed within the Project Area.

ATTACHMENT C

Special-Status Species with Potential to Occur within the Regional Vicinity of the Stanton Energy Reliability Center

Species	Status[a] (Federal/ State/Other)	Habitat Requirements	Potential for Occurrence/ Nearest Identified Occurrence
Mud nama *Nama stenocarpa*	**---/---/ CNPS 2B.2**	Annual herb; unknown blooming period. Occurs in marshes and vernal pools.	**Not Expected.** This species has been documented within Anaheim Marsh and Fairview Park. Suitable habitat for this species was not observed within the Project Area.
Gambel's water cress *Nasturtium gambelii*	**FE/ST/ CNPS 1B.1**	Perennial herb; blooms April through October. Occurs in freshwater and brackish marshes.	**Extirpated.** A historic record (1908) for this species has been documented within the vicinity of Huntington Beach and is presumed to be extirpated because of development. Suitable habitat for this species was not observed within the Project Area..
Coast woolly-heads *Nemacaulis denudata* var. *denudata*	**---/---/ CNPS 1B.2**	Annual herb; blooms April through September. Occurs in coastal dunes.	**Not Expected.** This species was documented within Bolsa Chica in 2009. Suitable habitat for this species was not observed within the Project Area.
California Orcutt grass *Orcuttia californica*	**FE/FE/ CNPS 1B.1**	Annual grass; blooms April through August. Occurs in valley grasslands, vernal pools and wetland-riparian communities.	**Extirpated.** This species was documented near Lakewood, but is presumed to be extirpated. Suitable habitat for this species was not observed within the Project Area.
Brand's star phacelia *Phacelia stellaris*	**---/---/ CNPS 1B.1**	Annual herb; blooms March through June. Occurs in coastal dunes.	**Extirpated.** This species was documented within Byrant Ranch, near Long Beach, but is presumed to be extirpated. Suitable habitat for this species was not observed within the Project Area.
Salt Spring checkerbloom *Sidalcea neomexicana*	**---/---/ CNPS 2B.2**	Perennial herb; blooms March through June. Occurs in Creosote bush scrub, chaparral, yellow pine forest, coastal sage scrub, alkali sink and wetland-riparian.	**Extirpated.** This species was documented within Byrant Ranch, near Long Beach, but is presumed to be extirpated. Suitable habitat for this species was not observed within the Project Area.
Estuary seablite *Suaeda esteroa*	**---/---/ CNPS 1B.2**	Perennial herb; blooms May through October. Occurs in coastal salt marshes.	**Not Expected.** This species was documented within Bolsa Chica State Beach Park in 1973. Suitable habitat for this species was not observed within the Project Area.
San Bernardino aster *Symphyotrichum defoliatum*	**---/---/ CNPS 1B.2**	Perennial herb; blooms July through November. Occurs in seeps, marshes and mesic grasslands.	**Extirpated.** This species was near Tustin, but is presumed to be extirpated. Suitable habitat for this species was not observed within the Project Area.

ATTACHMENT C

Special-Status Species with Potential to Occur within the Regional Vicinity of the Stanton Energy Reliability Center

Species	Status[a] (Federal/ State/Other)	Habitat Requirements	Potential for Occurrence/ Nearest Identified Occurrence
Birds			
Burrowing owl *Athene cunicularia*	**---/---/S3**	Found in open, dry annual or perennial grasslands, deserts, and scrublands characterized by low-growing vegetation.	**Presumed Extant.** This species was last observed in Orange County at Seal Beach Naval Weapons Station. Suitable habitat for this species was not observed within the Project Area.
Ferruginous hawk *Buteo regalis*	**---/---/S3, S4**	Found in open grasslands, sagebrush flats, desert scrub, low foothills and fringes of pinyon and juniper habitats.	**Presumed Extant.** This species was south of Los Alamitos Armed Forces Reserve Center. Suitable nesting habitat for this species was not observed within the Project Area.
Swainson's hawk *Buteo swainsoni*	**---/ST/ S3**	Breeds in grasslands with scattered trees; requires adjacent suitable foraging areas such as grasslands supporting rodent populations.	**Possibly Extirpated.** This species was near Anaheim, but possibly extirpated. Suitable nesting habitat for this species was not observed within the Project Area.
Western yellow-billed cuckoo *Coccyzus americanus occidentalis*	**FT/ SE / S1**	Found nesting in riparian forest, along the broad, lower flood-bottoms of larger river systems.	**Extirpated.** This species was near Anaheim, but extensive development since the date of observation has eliminated nesting and foraging habitat. Suitable habitat for this species was not observed within the Project Area.
Least Bell's vireo *Vireo bellii pusillus*	**FE/ SE / S1**	Found in low riparian in vicinity of water or in dry river bottoms, below 2,000 ft.	**Possibly Extirpated.** The species was near Cerritos, occurrence is likely extirpated. Suitable nesting habitat for this species was not observed within the Project Area.
Mammals			
Western mastiff bat *Eumops perotis californicus*	**---/---/S3, S4**	Found in conifer a deciduous woodlands, coastal scrub, grasslands, chaparral, etc.	**Presumed Extant.** This species was documented in the vicinity of Buena Park in 1990. Suitable cliff, tunnel, high building or tree roosting habitat for this species was not observed within the Project Area.
Reptiles			

ATTACHMENT C

Special-Status Species with Potential to Occur within the Regional Vicinity of the Stanton Energy Reliability Center

Species	Status[a] (Federal/ State/Other)	Habitat Requirements	Potential for Occurrence/ Nearest Identified Occurrence
Western pond turtle *Emys marmorata*	**---/---/S3**	An aquatic turtle of ponds, streams, irrigation ditches, below 6,000 ft elevation.	**Possibly Extirpated.** This species was documented east of the city limits of Long Beach, in 1987. The species requires sandy banks or grassy open fields at least 0.5 km from water. Suitable habitat for this species was not observed within the Project Area.
Invertebrates			
Crotch bumble bee *Bombus crotchii*	**---/---/S1, S2**	Found in coastal California, east to the Sierra-Cascade Crest and south into Mexico.	**Presumed Extant.** This species was documented in the general vicinity of Fullerton. Suitable habitat for this species was not observed within the Project Area.
Western tidal-flat tiger beetle *Cicindela gabbii*	**---/---/ S1**	Generally found on dark-colored mud in the lower zone; occasionally found on dry saline flats of estuaries.	**Presumed Extant.** This species is presumed to be extant. Suitable habitat for this species was not observed within the Project Area.

Sources:

California Department of Fish and Wildlife (CDFW). 2017. California Natural Diversity Database (CNDDB). Search within 5 miles of MREC. April.

Calflora. 2017. Berkeley, California: The Calflora Database. Available at: http://www.calflora.org/

[a] Key to Status Designations:

Federal Designations:

(FE) Federally Endangered, (FT) Federally Threatened, (FPE) Federally Proposed Endangered, (FPT) Federally Proposed Threatened, (FSC) Species of Concern, (FC) Candidate

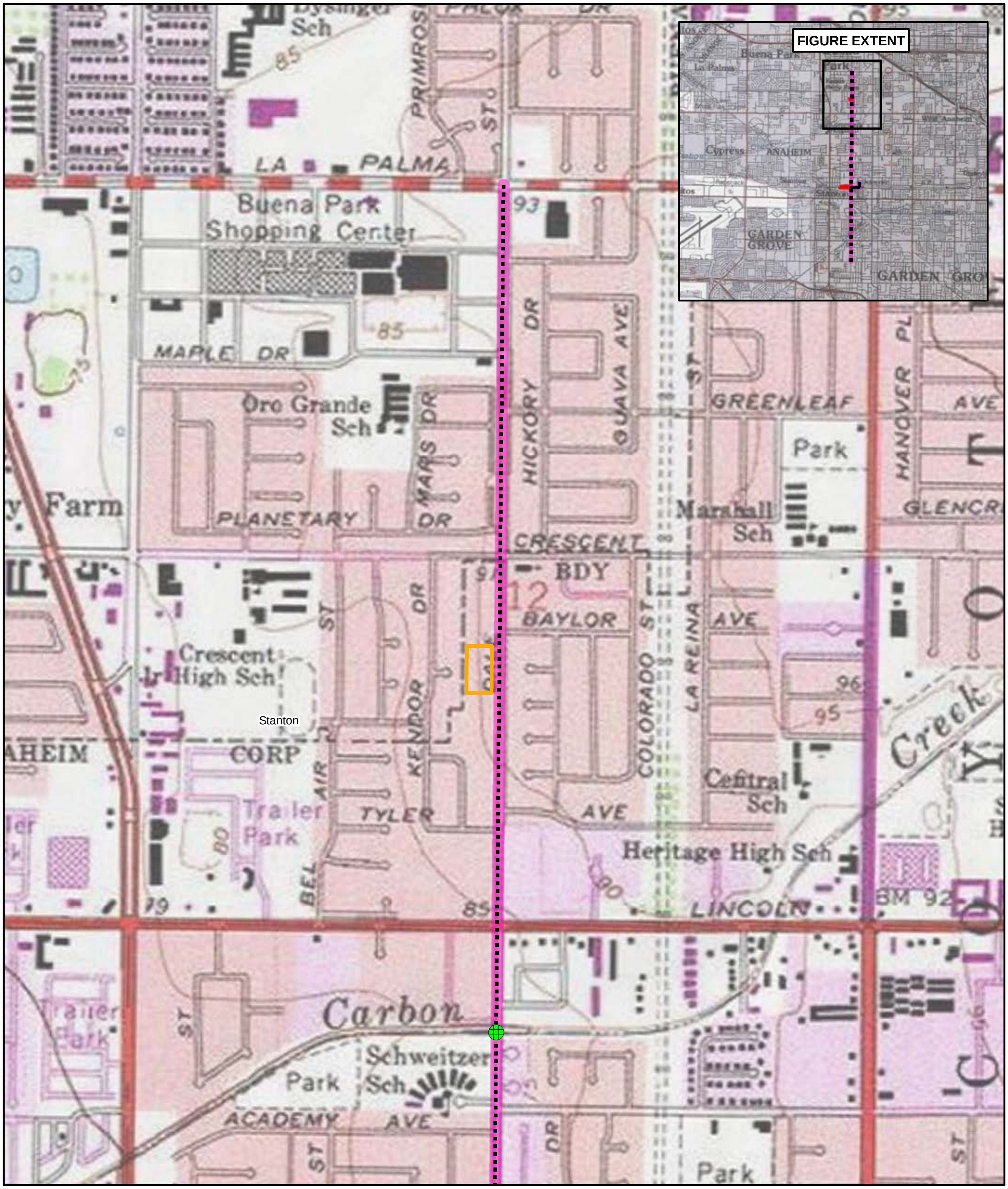
State Designations:

(SE) State Endangered, (ST) State Threatened, (SR) State Rare, (SSC) Species of Special Concern, (CFP) Fully Protected Species

California Native Plant Society (CNPS) Designations:

(1A) Presumed extinct in California; (1B) Rare, threatened, or endangered in California and elsewhere; (2) Rare, threatened, or endangered in California, but more common elsewhere; (3) More information is needed; (4) Limited distribution; (.1) Seriously endangered in California; (.2) Fairly endangered in California; (.3) Not very endangered in California.

Attachment DRA18-1
Generator Tie-Line and Natural Gas Pipeline Rights-of-Way



LEGEND

- JACK-AND-BORE CROSSING
- GEN-TIE LINE
- NATURAL GAS PIPELINE ALTERNATIVE ROUTE
- CONSTRUCITON STAGING AREA
- NATURAL GAS LINE 30' RIGHT OF WAY
- GEN-TIE 50' RIGHT OF WAY
- PROJECT SITE

N

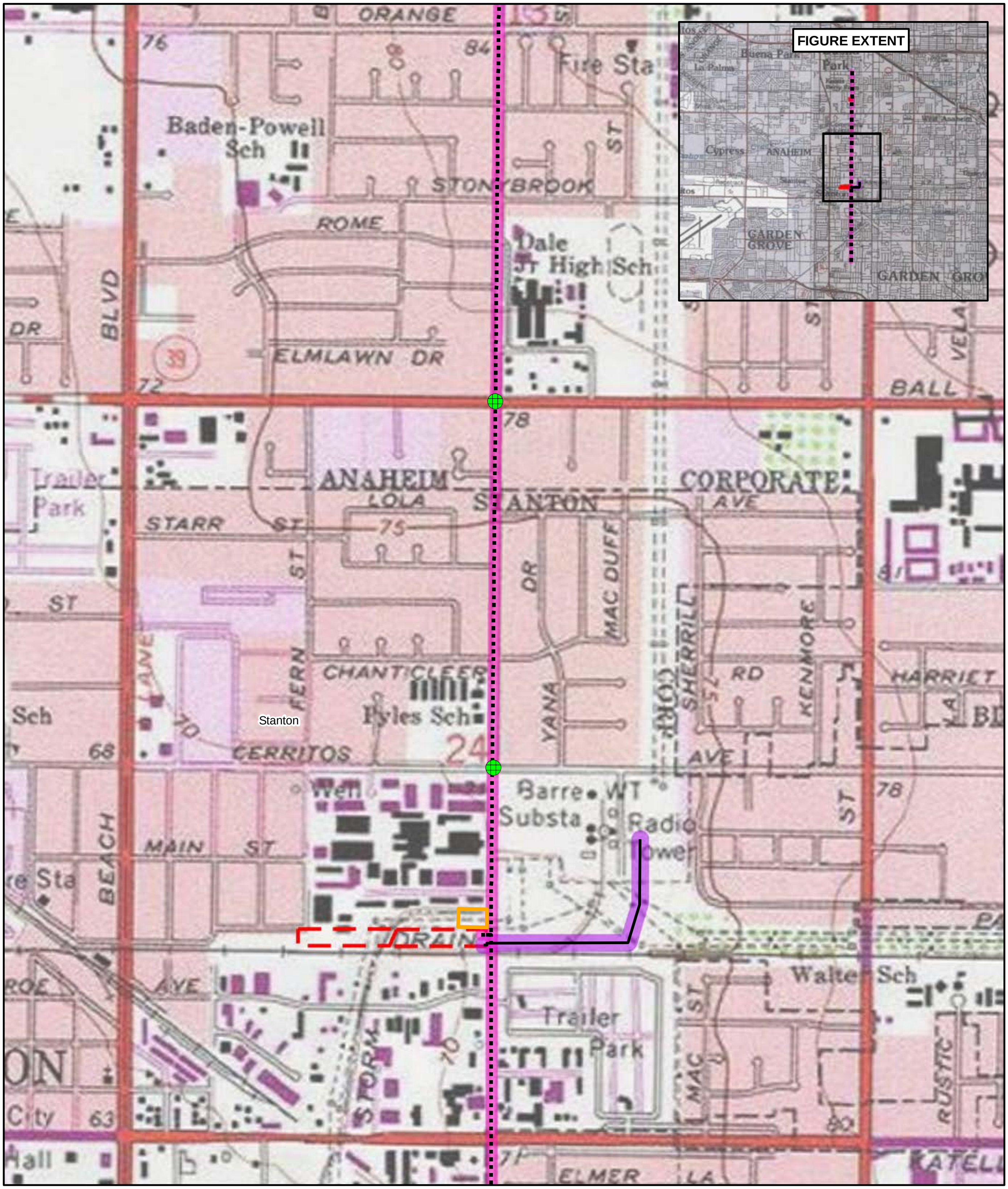
0 500 1,000 Feet

Source: Esri National Geographic (2013)

Figure DRA18-1a
Generator Tie-Line and Natural Gas Pipeline Rights-of-Way
Stanton Energy Reliability Center AFC
Stanton, California

ch2m

\\BROOKSIDE\GIS_SHARE\ENBG\00_PROJ\S\SERC\MAPFILES\WORKING\PIPEALT\FIG_1A_PIPELINES.MXD ET024983 5/2/2017 9:38:56 AM



LEGEND

- JACK-AND-BORE CROSSING
- GEN-TIE LINE
- NATURAL GAS PIPELINE ALTERNATIVE ROUTE
- CONSTRUCITON STAGING AREA
- NATURAL GAS LINE 30' RIGHT OF WAY
- GEN-TIE 50' RIGHT OF WAY
- PROJECT SITE

N

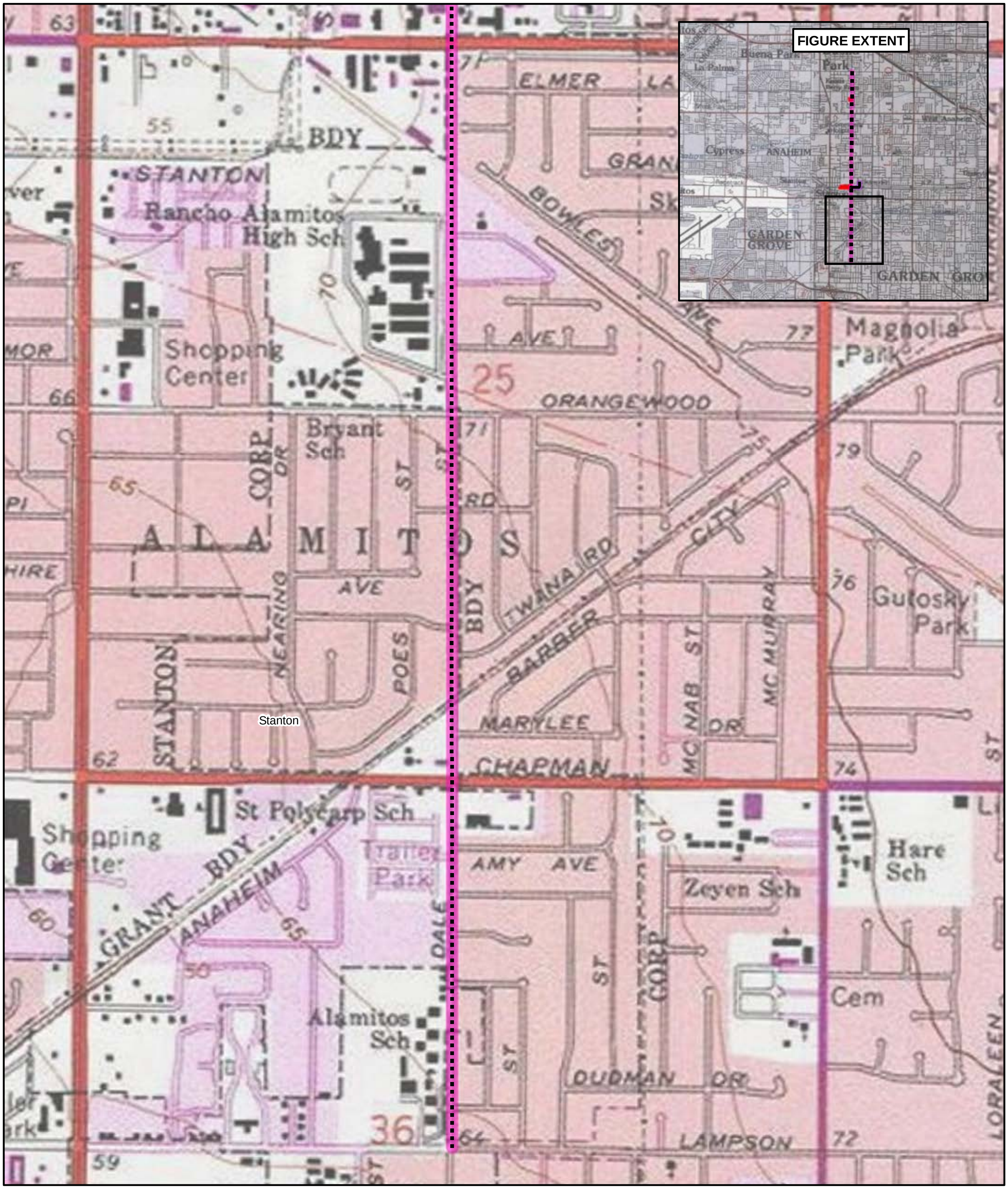
0 500 1,000 Feet

Source: Esri National Geographic (2013)

Figure DRA18-1b
Generator Tie-Line and Natural Gas Pipeline Rights-of-Way
Stanton Energy Reliability Center AFC
Stanton, California

\\BROOKSIDE\GIS_SHARE\ENBG\00_PROJ\S\SERC\MAPFILES\WORKING\PIPEALT\FIG_1B_PIPELINES.MXD ET024983 5/2/2017 9:37:18 AM

ch2m.



LEGEND

- JACK-AND-BORE CROSSING
- GEN-TIE LINE
- NATURAL GAS PIPELINE ALTERNATIVE ROUTE
- CONSTRUCITON STAGING AREA
- NATURAL GAS LINE 30' RIGHT OF WAY
- GEN-TIE 50' RIGHT OF WAY
- PROJECT SITE

N

0 500 1,000 Feet

Source: Esri National Geographic (2013)

Figure DRA18-1c
Generator Tie-Line and Natural Gas Pipeline Rights-of-Way
Stanton Energy Reliability Center AFC
Stanton, California

ch2m

5.3 Cultural Resources (A24-A26)

Topographic maps

A24. Please provide a series of maps (based on USGS 7.5-minute topographic maps enlarged to a scale of 1"=1,000 feet) that include the project site and all the proposed alternative routes of linear facilities. In addition to the project components, please depict the following:

a. The boundaries of all project rights of way;
b. The proposed project site, confirmation of the maximum dimensions of the ground disturbance associated with construction;
c. The proposed transmission line route, and a confirmation of the maximum dimensions of the ground disturbance associated with installation;
d. The proposed gas pipeline routes, a confirmation of the maximum dimensions of the ground disturbance associated with pipeline installation, location and any dimensions of boring and drilling entry and exit points where the pipeline is routed under existing drainages or infrastructure; and,
e. The proposed locations and dimensions of both temporary and permanent access roads that the project would construct, if any.

Response: Please see Attachment DRA18-1 for a map showing the generator tie-line and natural gas pipeline disturbance areas, respectively. Please note that, as indicated in the responses to Data Requests A18 and A21, construction and operation of the generator tie-line and natural gas pipeline will be done by SCE and SoCalGas, respectively, who have not completed final construction design for these facilities. Therefore, the dimensions provided are estimates based on industry practice and preliminary discussions with SCE and SoCalGas. New access roads will not be needed for the natural gas pipeline because it will be constructed in Dale Avenue and access will be along existing urban streets. Access to the generator tie-line is within the existing SCE Barre Substation.

Hobby City complex

A25. Please provide an updated evaluation of the Hobby City complex, including an evaluation for each resource previously documented. Evaluation should include:

a. DPR523 Update Form for each resource documented in 2006-2007.
b. A CRHR evaluation of all resources on the Hobby City parcels, considering all four criteria and all seven aspects of integrity individually and as parts of a potential historic district. Historical research, fieldwork, and related data should be used to support all recommendations.
c. If any resources at the Hobby City site are determined to meet the criteria for listing on the CRHR, provide an assessment of impacts to each newly identified historical resource.
d. Proposed mitigation measures for any significant impacts to historical resources.

Response: The Hobby City complex is a group of 17 properties with a variety of initial construction dates, which have been part of a specialty shopping center for hobbyists. Site records including DPR-523 forms and a historic district form from two separate recording events (2006 and 2007) for these properties were submitted along with the California Historical Resources Information Center (CHRIS) literature search results material provided with the AFC. Hobby City is within a mile of the project site and within one half-mile of one of the natural gas pipeline alternatives and for this reason was included in the literature search and general discussions of area properties (per CEC data adequacy requirements).

The Hobby City properties, however, are more than one half-mile from the project site and are not located on a parcel or lot that is adjacent to or borders on the project site parcel or a project-related above-ground linear right-of-way (such as an above-ground generator tie-line). Given the CEC's data adequacy requirements to record historic built environment properties in urban areas at a distance of one lot or parcel from the project site and above-ground linears, Hobby City was not recorded/updated for the AFC. At this distance from the Hobby City and given the large number of intervening properties, it would not be possible to see any element of the SERC, including the stacks or the single generator tie-line pole from Hobby City and so there would be no potential for SERC to adversely affect the setting of these properties or to indirectly affect them in some other way if they were to be found eligible for listing in the National Register of Historic Places or California Register of Historical Resources. The Hobby City properties are not within the area of potential project effects and so it is not necessary to update the site records for these properties.

Barre substation

A26. Request permission to access the Barre Substation. Provide copies of all communication (letters, emails, phone logs) with the owner (Southern California Edison) regarding access. Lack of access to a resource must be demonstrated.

a. Complete DPR 523 form(s) for all resources on the parcel identified as being 45 years or older or of exceptional importance.

b. A CRHR evaluation of all resources on the Barre Substation site, considering all four criteria and all seven aspects of integrity individually and as parts of a potential historic district. Historical research, fieldwork and related data should be used to support all recommendations.

c. If any resources at the Barre Substation site are determined to meet the criteria for listing on the CRHR, provide an assessment of impacts to each newly identified historical resource.

d. Propose mitigation measures for any significant impacts to historical resources.

Response: SERC, LLC has approached SCE to request that they conduct a cultural resources survey within portions of the Barre Substation property that are part of the SERC project, such as the underground generator tie-line, and that they record and evaluate the Barre Substation itself as a historic built environment resource. The time frame for this study, according to SCE, will be approximately eight weeks. SERC, LLC will submit SCE's report of findings when it is available from SCE.

5.5 Hazardous Materials Management (A27-A28)

Ammonia tank

A27. Please confirm that the aqueous ammonia tank would conform to the ASME code for Unfired Pressure Vessels, Section VIII, Division 1.

Response: The aqueous ammonia storage tank will be a carbon steel, flat-bottomed vertical tank designed and constructed in accordance with API 620, with a design pressure of 2.5 psig at 150 °F. The use of API 620 is consistent with Conditions of Certification for numerous CEC-licensed projects.

Ammonia deliveries

A28. Please detail how the aqueous ammonia deliveries would be handle

Response: While SERC will normally be unattended, there will be operations personnel onsite whenever ammonia deliveries are scheduled to occur to allow the delivery truck access into the site and to oversee the transfer of ammonia from the delivery truck to the onsite storage tank.

5.7 Noise and Vibration (A29-A31)

Battery recharge

A29. Please explain how many CTGs, if any, would be expected tooperate between 10 pm and 7 am in order to recharge the battery storage system.

Response: As described in Response to Data Request A11 above, the EGT® Hybrid operates similarly to a hybrid car. In the case of the EGT® Hybrid, the hybrid control software does not start the CTGs for the sole purpose of charging the battery energy storage system. The battery system is charged from the grid during times when battery storage is not being called upon, or from the CTGs when the CTGs have been otherwise dispatched to provide electrical support to the grid. Therefore, the SERC will never operate the CTGs between the hours of 10 pm and 7 am for the sole purpose of recharging the battery storage system. As described in the AFC, the SERC may be dispatched by CAISO to operate between the hours of 10 pm and 7 am, but only when there is a need for critical electrical reliability support. Historically, there has been little need for such reliability support during these nighttime hours. Based on the historical need for electrical generation during the hours from 10 pm to 7 am, it is unlikely that the SERC will operate between these hours.

Synchronous condenser mode

A30. Please explain how many CTGs, if any, would be expected to operate between 10 pm and 7 am in order to spin their generators into the synchronous condenser mode.

Response: The SERC can provide the same electrical benefits to the grid with the use of its battery energy storage system and inverters as would a CTG operating to spin the generators into synchronous condenser mode and can do so without CTG emissions. Therefore, SERC will not need to operate the turbines for the sole purpose of spinning the generators into the synchronous condenser mode between the hours of 10 pm and 7 am.

Future operation

A31. Please explain if due to possible changes in the electricity market, or for any other reasons, there may be a need in the future to potentially increase operation of the CTGs between 10 p.m. and 7 a.m. more than "infrequently" as identified in the AFC (AFC § 5.7.3.3.3).

Response: Please see the response to Data Request A29 above. Additionally, please see the air quality section of the AFC for a description of the number of hours that the SERC is being permitted to operate which, when compared with historically permitted peakers, will be a low number of annual hours. The SERC is not a peaking facility, but will have an operating schedule that will be based on providing reliability services, instead of energy during peak demand hours. Recent experience of SERC's Scheduling Coordinator with similar facilities suggests that, due to the achievement of higher renewable energy portfolio standards, the need for reliability-related operations occurs mostly during the morning and evening net-energy-load ramping periods—i.e., when solar power comes on line in the morning and drops off the grid in the afternoon and early evening—and not during the hours between 10 pm and 7 am.

With even higher renewable energy standards in the future, SERC expects that the need for reliability services to occur during daytime hours will continue or even increase. Therefore, the SERC will operate during the hours of 10 pm to 7 am very infrequently. SERC does not anticipate the electricity market changing in such a way that it will be dispatched by CAISO frequently at night.

5.9 Public Health (A32-A37)

Receptor numbers

A32. Please specify the HARP receptor number for each receptor listed in Table 5.9-1 and Table 4.9-8.

Response: Table DRA32-1 revises AFC Table 5.9-1 to include the Hotspots Analysis Reporting Program (HARP) receptor number for the receptors listed in the table.

Table DRA32-1. Nearest Sensitive Receptors by Receptor Type (with HARP receptor file number) (update of AFC Table 5.9-1)

Receptor Type (File #)	UTM Coordinates (East/North), m	Elevation, (feet above mean sea level)
Residence-North (8003)	409045, 3741578	76
Residence-East-Southeast (8001)	408837, 3741138	70
Residence-East (8002)	409295, 3741267	80
Residence-West (8005)	408445, 3741209	69
Residence-Northwest (8004)	408661, 3741578	72
Residence-Southwest (8006)	408456, 3740480	76
Residence-South (8007)	408899, 3740672	74
Worker (8009)	408776, 3741256	68
School (8046)	408831, 3741710	74
Hospital (8053)	407933, 3743250	73
Daycare (8065)	408349, 3742001	75
Nursing Home (8068)	408911, 3739688	72
Pre-School (8044)	408867, 3743741	76

Source: All coordinates from Google Earth (center location of each receptor location). Image date (2/2/2016).

The nearest school is greater than 1000 ft. from the SERC site, therefore no SCAQMD Risk notifications are required.

See Appendix 5.1D for a complete list of sensitive receptors analyzed in the HRA.

Table DRA32-2 updates AFC Table 5.9-8 to include the HARP receptor file values. This table is presented below with the revised HRA values as of 2/3/17.

Table DRA32-2. SERC HRA Summary (with HARP receptor file numbers) (update of AFC Table 5.9-8)

Receptor Type	Receptor #	UTM E	UTM N	Cancer Risk[a]	Chronic HI	Acute HI
MIR (PMI 1)	2617	409000	3741360	1.65E-7	.0000969	.00166
PMI 2	2674	409020	3741380	1.65E-7	.0000965	.00159
PMI 3	2673	409020	3741360	1.64E-7	.0000964	.00163
MEIR	8003	409045	3741578	1.23E-7	.0000721	.00122
MEIW[b]	8008	409012	3741221	9.43E-8	.0000553	.00144
Nearest school	8012	409311	3741517	1.19E-7	.0000696	.00100
Nearest health facility	8051	411233	3744268	4.99E-8	.0000292	.000411
Nearest daycare	8064	407611	3740470	3.35E-8	.0000196	.000864
Nearest convalescent home	8071	408716	3742848	4.34E-8	.0000255	.000617

[a] 30-year risk values.
[b] MEIW values have not been adjusted for a 25-year exposure due to the insignificance of the 30-year risk values.

Please note that the nearest receptors listed in Table 5.9-1 for the various receptor types may not be the maximally impacted receptor for that category of receptor as listed in Table 5.9-8 for purposes of health or risk impacts.

HARP2 receptor number

A33. Please confirm if the “Recp #” in Table 5.1D-7 is identical with the HARP2 receptor number.

Response: The receptor numbers in the HARP2 file match the values in Table 5.1D-7.

HRA modeling files

A34. Please provide the updated health risk assessment (HRA) modeling files for normal operation and commissioning periods.

Response: The updated health risk assessment modeling files are being provided to Staff under separate cover in electronic format on a CD-ROM.

HRA summary update

A35. Please update Table 5.9-8 SERC HRA Summary if there is anyrevision.

Response: Response: A revised and updated AFC Air Quality section/SCAQMD permit application and supporting information have been submitted to the SCAQMD and docketed with the CEC under separate cover (April 28, 2017; TN#217343).

5.10 Socioeconomics (A36-A37)

Operations staff

A36. Please clarify (a) whether any new remote offsite operations staff would be hired to monitor/operate the Stanton project and (b) if new staff is hired, how frequently would they work (e.g. full time equivalent, part-time)?

Response: No new hiring of remote operations staff is expected. The remote operations desk is staffed by a combination of full-time and part-time staff, and staffing is maintained at levels sufficient to ensure response times required by CAISO requirements for each unit being remotely controlled.

Onsite technician schedule

A37. Please clarify how frequently onsite technician(s) would conduct routine operations at the Stanton facility.

Response: SERC will engage Wellhead Services, Inc. (WSI) for local operation and maintenance of the facility. WSI's staff is responsible for Operations and Maintenance (O&M) of multiple facilities, and its overall staffing levels are established to ensure sufficient coverage of all facilities for which it is responsible. SERC anticipates that WSI may add 1 to 2 additional technicians in order to establish optimal staffing levels once SERC becomes operational.

Routine facility operations are expected to be normally conducted via remote operations personnel. The primary responsibility of O&M Technicians is to conduct facility maintenance, and to receive goods and materials for the facility, e.g. oversee proper offloading of aqueous ammonia. Although onsite technicians will locally control the units following maintenance tasks or during test runs, typical operations will be performed remotely. It is anticipated that O&M Technicians will be at the facility 1 to 3 days each week, and therefore may be present for unit operations in the event a CAISO dispatch instruction overlaps with their planned maintenance visit. However, onsite technicians will not typically be relied upon to conduct routine operations of the facility.

5.11 Soils and 5.15 Water Resources (A38-A41)

Pre-Construction drainage areas

A38. *Describe each discrete pre-construction drainage area (as defined by the local requirements listed above) and the volume of discharge expected during the design storm. Also describe the pre-construction time of concentration (TOC) for each drainage.*

Response: The existing site was delineated into two drainage management areas (DMA): DMA 1 and DMA 2. DMA 1 is 2.55 acres and DMA 2 is 0.81 acres. The following table identifies the flow volume and Time of Concentration (TOC) for each of the drainage management areas in the pre-construction condition. Attachment DA38-1 provides hydrologic and hydraulic model information.

Table DRA38-1. Times of concentration for two drainage management areas, pre-construction.

Drainage management area:	DMA 1	DMA 2
Area (acres)	2.55	0.81
TOC (minutes)	30.7	9.40
Design storm volume (ft^3)	8,664	7,100

Post-construction drainage areas

A39. *Describe each discrete post-construction drainage area (as defined by the local requirements listed above) and the volume of discharge expected during the design storm. Also describe the post-construction TOC for each drainage.*

Response: As stated in the previous response, proposed site was delineated into two drainage management areas: (DMA) DMA 1 and DMA 2. DMA 1 is 2.55 acres and DMA 2 is 0.81 acres. DMA 1 and DMA 2 represent the same area in the pre- and post-construction conditions. The following table identifies the flow volume and Time of Concentration (TOC) for each of the drainage management areas in the post construction condition.

Table DRA39-1. Times of concentration for two drainage management areas, post-construction.

Drainage management area:	DMA 1	DMA 2
Area (acres)	2.55	0.81
TOC (minutes)	30.1	28.9
Design storm volume (ft^3)	6,586	1,843

Discharge requirements

A40. *Describe how the proposed project would meet the Model WQMP post-construction discharge requirements for volume and TOC, including a description of any source controls, hydromodification controls, or treatment controls that could be utilized to achieve that goal.*

Response: The SERC project will meet Model Water Quality Management Plan (WQMP) post-construction discharge requirements for volume and TOC by not exceeding the pre-construction condition Volume and TOC by more than 5 percent in the post-construction condition as indicated by the WQMP Technical Guidance Manual. A WQMP will be developed for the project. Source control BMPs will include reduction of impervious area and impervious area dispersion. Hydromodification controls and treatment controls will consist of an infiltration basin within DMA 1 and DMA 2. The infiltration basins will provide retention of the Design Capture Volume to be stored and infiltrated on-site. The storage will be adequate to mitigate for increases in flow volume and reductions in times of concentration as indicated in the Tables DRA38-1 and Table DRA39-1 above.

Source controls

A41. *Describe where these controls would be located on the site and discuss whether they would result in a change of the project layout.*

Response: Both basins will be located on Parcel 2. One basin will surround the existing easterly inlet on Parcel 2 and one basin will surround the westerly inlet on Parcel 2. The basins will provide disconnection from the inlet by storing the Design Capture Volume prior to discharging to the inlet. Surface flows from Parcel 1 will be routed via a storm drain line to Parcel 2 and into the easterly basin prior to discharge from the site. The current site plan includes a footprint for the easterly basin. The site plan will need to be updated slightly to show the westerly basin. The footprint of the westerly basin can fit within the proposed DG gravel area surrounding the inlet.

Attachment DRA38-1
Hydrology and Hydraulic Modeling Information

```
****************************************************************************
              RATIONAL METHOD HYDROLOGY COMPUTER PROGRAM PACKAGE
             (Reference: 1986 ORANGE COUNTY HYDROLOGY CRITERION)
          (c) Copyright 1983-2011 Advanced Engineering Software (aes)
              Ver. 18.0  Release Date: 07/01/2011  License ID 1501

                            Analysis prepared by:




 ************************** DESCRIPTION OF STUDY **************************
 * Stanton Energy Reliability Center                                        *
 * Preconstruction Condition                                                       *
 * 2 Year Storm Event                                                       *
 **************************************************************************

  FILE NAME: XEAST.DAT
  TIME/DATE OF STUDY: 16:33 04/25/2017
============================================================================
  USER SPECIFIED HYDROLOGY AND HYDRAULIC MODEL INFORMATION:
============================================================================
                    --*TIME-OF-CONCENTRATION MODEL*--

  USER SPECIFIED STORM EVENT(YEAR) =    2.00
  SPECIFIED MINIMUM PIPE SIZE(INCH) =   6.00
  SPECIFIED PERCENT OF GRADIENTS(DECIMAL) TO USE FOR FRICTION SLOPE = 0.90
  *USER-DEFINED LOGARITHMIC INTERPOLATION USED FOR RAINFALL*

  SLOPE OF INTENSITY DURATION CURVE(LOG(I;IN/HR) vs. LOG(Tc;MIN)) = 0.5500
  USER SPECIFIED 1-HOUR INTENSITY(INCH/HOUR) = 0.5550

  *ANTECEDENT MOISTURE CONDITION (AMC) I ASSUMED FOR RATIONAL METHOD*

  *USER-DEFINED STREET-SECTIONS FOR COUPLED PIPEFLOW AND STREETFLOW MODEL*
     HALF-  CROWN TO   STREET-CROSSFALL:   CURB  GUTTER-GEOMETRIES:  MANNING
     WIDTH  CROSSFALL  IN-  / OUT-/PARK-  HEIGHT  WIDTH  LIP   HIKE  FACTOR
NO.   (FT)     (FT)    SIDE / SIDE/ WAY    (FT)    (FT)  (FT)  (FT)    (n)
===  =====  =========  =================  ======  ===== ====== ===== =======
  1   30.0     20.0    0.018/0.018/0.020   0.67    2.00 0.0313 0.167 0.0150

  GLOBAL STREET FLOW-DEPTH CONSTRAINTS:
    1. Relative Flow-Depth =  0.00 FEET
       as (Maximum Allowable Street Flow Depth) - (Top-of-Curb)
    2. (Depth)*(Velocity) Constraint =  6.0 (FT*FT/S)
  *SIZE PIPE WITH A FLOW CAPACITY GREATER THAN
   OR EQUAL TO THE UPSTREAM TRIBUTARY PIPE.*
  *USER-SPECIFIED MINIMUM TOPOGRAPHIC SLOPE ADJUSTMENT NOT SELECTED

****************************************************************************
  FLOW PROCESS FROM NODE    300.00 TO NODE    301.00 IS CODE =  21
----------------------------------------------------------------------------
  >>>>>RATIONAL METHOD INITIAL SUBAREA ANALYSIS<<<<<
  >>USE TIME-OF-CONCENTRATION NOMOGRAPH FOR INITIAL SUBAREA<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   341.00
  ELEVATION DATA: UPSTREAM(FEET) =     72.70  DOWNSTREAM(FEET) =     72.00

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =   25.086
```

```
 *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  0.897
 SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
  DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp         Ap     SCS   Tc
      LAND USE           GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
 NATURAL FAIR COVER
 "GRASS"                   B        0.88      0.30     1.000    50   25.09
 SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
 SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  1.000
 SUBAREA RUNOFF(CFS) =      0.47
 TOTAL AREA(ACRES) =      0.88   PEAK FLOW RATE(CFS) =      0.47

****************************************************************************
 FLOW PROCESS FROM NODE    301.00 TO NODE    302.00 IS CODE =  51
----------------------------------------------------------------------------
 >>>>>COMPUTE TRAPEZOIDAL CHANNEL FLOW<<<<<
 >>>>>TRAVELTIME THRU SUBAREA (EXISTING ELEMENT)<<<<<
============================================================================
 ELEVATION DATA: UPSTREAM(FEET) =     72.00  DOWNSTREAM(FEET) =     71.00
 CHANNEL LENGTH THRU SUBAREA(FEET) =   335.00   CHANNEL SLOPE =  0.0030
 CHANNEL BASE(FEET) =    5.00   "Z" FACTOR =   2.000
 MANNING'S FACTOR = 0.020   MAXIMUM DEPTH(FEET) =   1.00
 *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  0.802
 SUBAREA LOSS RATE DATA(AMC  I ):
  DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp         Ap     SCS
      LAND USE           GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN
 NATURAL FAIR COVER
 "GRASS"                   B        0.85      0.30     1.000    50
 SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
 SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  1.000
 TRAVEL TIME COMPUTED USING ESTIMATED FLOW(CFS) =       0.66
 TRAVEL TIME THRU SUBAREA BASED ON VELOCITY(FEET/SEC.) =   1.00
 AVERAGE FLOW DEPTH(FEET) =   0.13   TRAVEL TIME(MIN.) =   5.61
 Tc(MIN.) =   30.70
 SUBAREA AREA(ACRES) =     0.85       SUBAREA RUNOFF(CFS) =    0.39
 EFFECTIVE AREA(ACRES) =      1.73     AREA-AVERAGED Fm(INCH/HR) =   0.30
 AREA-AVERAGED Fp(INCH/HR) =   0.30  AREA-AVERAGED Ap =   1.00
 TOTAL AREA(ACRES) =        1.7         PEAK FLOW RATE(CFS) =       0.78

 END OF SUBAREA CHANNEL FLOW HYDRAULICS:
 DEPTH(FEET) =  0.14   FLOW VELOCITY(FEET/SEC.) =   1.06
 LONGEST FLOWPATH FROM NODE    300.00 TO NODE    302.00 =     676.00 FEET.

****************************************************************************
 FLOW PROCESS FROM NODE    302.00 TO NODE    303.00 IS CODE =  41
----------------------------------------------------------------------------
 >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
 >>>>>USING USER-SPECIFIED PIPESIZE (EXISTING ELEMENT)<<<<<
============================================================================
 ELEVATION DATA: UPSTREAM(FEET) =    68.50  DOWNSTREAM(FEET) =    64.50
 FLOW LENGTH(FEET) =    35.00   MANNING'S N =  0.013
 DEPTH OF FLOW IN  24.0 INCH PIPE IS   1.8 INCHES
 PIPE-FLOW VELOCITY(FEET/SEC.) =   7.59
 GIVEN PIPE DIAMETER(INCH) =  24.00    NUMBER OF PIPES =   1
 PIPE-FLOW(CFS) =       0.78
 PIPE TRAVEL TIME(MIN.) =   0.08    Tc(MIN.) =   30.77
 LONGEST FLOWPATH FROM NODE    300.00 TO NODE    303.00 =     711.00 FEET.

****************************************************************************
 FLOW PROCESS FROM NODE    303.00 TO NODE    303.00 IS CODE =  81
----------------------------------------------------------------------------
 >>>>>ADDITION OF SUBAREA TO MAINLINE PEAK FLOW<<<<<
============================================================================
 MAINLINE Tc(MIN.) =   30.77
```

```
 *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  0.801
 SUBAREA LOSS RATE DATA(AMC  I ):
  DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp         Ap     SCS
      LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN
 COMMERCIAL                 B        0.02      0.30     0.100    36
 SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
 SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.100
 SUBAREA AREA(ACRES) =    0.02      SUBAREA RUNOFF(CFS) =    0.01
 EFFECTIVE AREA(ACRES) =      1.75   AREA-AVERAGED Fm(INCH/HR) =  0.30
 AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap =  0.99
 TOTAL AREA(ACRES) =        1.7       PEAK FLOW RATE(CFS) =       0.79

****************************************************************************
 FLOW PROCESS FROM NODE    203.00 TO NODE    204.00 IS CODE =  21
----------------------------------------------------------------------------
 >>>>>RATIONAL METHOD INITIAL SUBAREA ANALYSIS<<<<<
 >>USE TIME-OF-CONCENTRATION NOMOGRAPH FOR INITIAL SUBAREA<<
============================================================================
 INITIAL SUBAREA FLOW-LENGTH(FEET) =   160.00
 ELEVATION DATA: UPSTREAM(FEET) =     70.00  DOWNSTREAM(FEET) =     68.30

 Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
 SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    5.745
 *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  2.017
 SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
  DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp         Ap     SCS   Tc
      LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
 COMMERCIAL                 B        0.80      0.30     0.100    36    5.74
 SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
 SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.100
 SUBAREA RUNOFF(CFS) =      1.43
 TOTAL AREA(ACRES) =      0.80   PEAK FLOW RATE(CFS) =      1.43

****************************************************************************
 FLOW PROCESS FROM NODE    204.00 TO NODE    205.00 IS CODE =  41
----------------------------------------------------------------------------
 >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
 >>>>>USING USER-SPECIFIED PIPESIZE (EXISTING ELEMENT)<<<<<
============================================================================
 ELEVATION DATA: UPSTREAM(FEET) =    65.50  DOWNSTREAM(FEET) =    64.00
 FLOW LENGTH(FEET) =    63.00   MANNING'S N =  0.013
 DEPTH OF FLOW IN   8.0 INCH PIPE IS   5.5 INCHES
 PIPE-FLOW VELOCITY(FEET/SEC.) =   5.63
 GIVEN PIPE DIAMETER(INCH) =   8.00    NUMBER OF PIPES =   1
 PIPE-FLOW(CFS) =       1.43
 PIPE TRAVEL TIME(MIN.) =   0.19    Tc(MIN.) =    5.93
 LONGEST FLOWPATH FROM NODE    203.00 TO NODE    205.00 =     223.00 FEET.

****************************************************************************
 FLOW PROCESS FROM NODE    205.00 TO NODE    206.00 IS CODE =  41
----------------------------------------------------------------------------
 >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
 >>>>>USING USER-SPECIFIED PIPESIZE (EXISTING ELEMENT)<<<<<
============================================================================
 ELEVATION DATA: UPSTREAM(FEET) =    64.00  DOWNSTREAM(FEET) =    63.60
 FLOW LENGTH(FEET) =   124.00   MANNING'S N =  0.013
 DEPTH OF FLOW IN  36.0 INCH PIPE IS   4.9 INCHES
 PIPE-FLOW VELOCITY(FEET/SEC.) =   2.47
 GIVEN PIPE DIAMETER(INCH) =  36.00    NUMBER OF PIPES =   1
 PIPE-FLOW(CFS) =       1.43
 PIPE TRAVEL TIME(MIN.) =   0.84    Tc(MIN.) =    6.77
 LONGEST FLOWPATH FROM NODE    203.00 TO NODE    206.00 =     347.00 FEET.
```

```
****************************************************************************
  FLOW PROCESS FROM NODE    200.00 TO NODE    201.00 IS CODE =  21
----------------------------------------------------------------------------
  >>>>>RATIONAL METHOD INITIAL SUBAREA ANALYSIS<<<<<
  >>USE TIME-OF-CONCENTRATION NOMOGRAPH FOR INITIAL SUBAREA<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   195.00
  ELEVATION DATA: UPSTREAM(FEET) =     69.90  DOWNSTREAM(FEET) =     68.50

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    6.725
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.850
  SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
   DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp        Ap     SCS   Tc
       LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
  COMMERCIAL                 B       0.81      0.30     0.100    36    6.72
  SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
  SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.100
  SUBAREA RUNOFF(CFS) =      1.33
  TOTAL AREA(ACRES) =      0.81   PEAK FLOW RATE(CFS) =      1.33

****************************************************************************
  FLOW PROCESS FROM NODE    201.00 TO NODE    202.00 IS CODE =  41
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING USER-SPECIFIED PIPESIZE (EXISTING ELEMENT)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    66.60  DOWNSTREAM(FEET) =    65.90
  FLOW LENGTH(FEET) =    81.00   MANNING'S N =  0.013
  ASSUME FULL-FLOWING PIPELINE
  PIPE-FLOW VELOCITY(FEET/SEC.) =   3.80
  PIPE FLOW VELOCITY = (TOTAL FLOW)/(PIPE CROSS SECTION AREA)
  GIVEN PIPE DIAMETER(INCH) =   8.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       1.33
  PIPE TRAVEL TIME(MIN.) =   0.36    Tc(MIN.) =    7.08
  LONGEST FLOWPATH FROM NODE    200.00 TO NODE    202.00 =     276.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    202.00 TO NODE    206.00 IS CODE =  41
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING USER-SPECIFIED PIPESIZE (EXISTING ELEMENT)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    65.90  DOWNSTREAM(FEET) =    63.60
  FLOW LENGTH(FEET) =   411.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN  36.0 INCH PIPE IS   4.1 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   2.94
  GIVEN PIPE DIAMETER(INCH) =  36.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       1.33
  PIPE TRAVEL TIME(MIN.) =   2.33    Tc(MIN.) =    9.41
  LONGEST FLOWPATH FROM NODE    200.00 TO NODE    206.00 =     687.00 FEET.
============================================================================
  END OF STUDY SUMMARY:
  TOTAL AREA(ACRES)     =        0.8  TC(MIN.) =      9.41
  EFFECTIVE AREA(ACRES) =      0.81  AREA-AVERAGED Fm(INCH/HR)=  0.03
  AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap = 0.100
  PEAK FLOW RATE(CFS)   =       1.33
============================================================================
============================================================================
  END OF RATIONAL METHOD ANALYSIS

♀
```

```
****************************************************************************
              RATIONAL METHOD HYDROLOGY COMPUTER PROGRAM PACKAGE
             (Reference: 1986 ORANGE COUNTY HYDROLOGY CRITERION)
          (c) Copyright 1983-2011 Advanced Engineering Software (aes)
              Ver. 18.0  Release Date: 07/01/2011  License ID 1501

                           Analysis prepared by:




 ************************** DESCRIPTION OF STUDY **************************
 * Stanton Energy Reliability Center                                        *
 * Postconstruction Condition                                               *
 * 2 Year Storm Event                                                       *
 **************************************************************************

  FILE NAME: PSEAST.DAT
  TIME/DATE OF STUDY: 11:33 04/26/2017
============================================================================
  USER SPECIFIED HYDROLOGY AND HYDRAULIC MODEL INFORMATION:
============================================================================
                    --*TIME-OF-CONCENTRATION MODEL*--

  USER SPECIFIED STORM EVENT(YEAR) =    2.00
  SPECIFIED MINIMUM PIPE SIZE(INCH) =   6.00
  SPECIFIED PERCENT OF GRADIENTS(DECIMAL) TO USE FOR FRICTION SLOPE = 0.90
  *USER-DEFINED LOGARITHMIC INTERPOLATION USED FOR RAINFALL*

  SLOPE OF INTENSITY DURATION CURVE(LOG(I;IN/HR) vs. LOG(Tc;MIN)) = 0.5500
  USER SPECIFIED 1-HOUR INTENSITY(INCH/HOUR) = 0.5550

  *ANTECEDENT MOISTURE CONDITION (AMC) I ASSUMED FOR RATIONAL METHOD*

  *USER-DEFINED STREET-SECTIONS FOR COUPLED PIPEFLOW AND STREETFLOW MODEL*
     HALF-  CROWN TO   STREET-CROSSFALL:   CURB  GUTTER-GEOMETRIES:  MANNING
     WIDTH  CROSSFALL  IN-  / OUT-/PARK-  HEIGHT  WIDTH  LIP   HIKE  FACTOR
NO.   (FT)     (FT)    SIDE / SIDE/ WAY    (FT)    (FT)  (FT)  (FT)    (n)
===  =====  =========  =================  ======  ===== ====== ===== =======
  1   30.0     20.0    0.018/0.018/0.020   0.67    2.00 0.0313 0.167 0.0150

  GLOBAL STREET FLOW-DEPTH CONSTRAINTS:
    1. Relative Flow-Depth =  0.00 FEET
       as (Maximum Allowable Street Flow Depth) - (Top-of-Curb)
    2. (Depth)*(Velocity) Constraint =  6.0 (FT*FT/S)
  *SIZE PIPE WITH A FLOW CAPACITY GREATER THAN
   OR EQUAL TO THE UPSTREAM TRIBUTARY PIPE.*
  *USER-SPECIFIED MINIMUM TOPOGRAPHIC SLOPE ADJUSTMENT NOT SELECTED

****************************************************************************
  FLOW PROCESS FROM NODE    500.00 TO NODE    501.00 IS CODE =  21
----------------------------------------------------------------------------
  >>>>>RATIONAL METHOD INITIAL SUBAREA ANALYSIS<<<<<
  >>USE TIME-OF-CONCENTRATION NOMOGRAPH FOR INITIAL SUBAREA<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   187.00
  ELEVATION DATA: UPSTREAM(FEET) =     73.00  DOWNSTREAM(FEET) =     71.50

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    6.468
```

```
*   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.890
SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
 DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp        Ap     SCS   Tc
     LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
COMMERCIAL                 B        0.17      0.30     0.100    36    6.47
NATURAL POOR COVER
"BARREN"                   B        0.25      0.30     1.000    72   11.17
SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.630
SUBAREA RUNOFF(CFS) =      0.64
TOTAL AREA(ACRES) =      0.42   PEAK FLOW RATE(CFS) =      0.64

****************************************************************************
  FLOW PROCESS FROM NODE    501.00 TO NODE    502.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    69.00  DOWNSTREAM(FEET) =    67.30
  FLOW LENGTH(FEET) =   331.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN   9.0 INCH PIPE IS   4.9 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   2.62
  ESTIMATED PIPE DIAMETER(INCH) =   9.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       0.64
  PIPE TRAVEL TIME(MIN.) =   2.11    Tc(MIN.) =    8.57
  LONGEST FLOWPATH FROM NODE    500.00 TO NODE    502.00 =     518.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    502.00 TO NODE    502.00 IS CODE =  82
----------------------------------------------------------------------------
  >>>>>ADD SUBAREA RUNOFF TO MAINLINE, AT MAINLINE Tc,<<<<<
  >>>>>(AND COMPUTE INITIAL SUBAREA RUNOFF)<<<<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   212.00
  ELEVATION DATA: UPSTREAM(FEET) =     72.70  DOWNSTREAM(FEET) =     71.30

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    7.070
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.799
  SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
   DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp        Ap     SCS   Tc
       LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
  COMMERCIAL                 B        0.13      0.30     0.100    36    7.07
  NATURAL POOR COVER
  "BARREN"                   B        0.21      0.30     1.000    72   12.21
  SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
  SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.656
  SUBAREA AREA(ACRES) =    0.34   INITIAL SUBAREA RUNOFF(CFS) =    0.48

  ** ADD SUBAREA RUNOFF TO MAINLINE AT MAINLINE Tc:
  MAINLINE Tc(MIN.) =    8.57
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.618
  SUBAREA AREA(ACRES) =    0.34      SUBAREA RUNOFF(CFS) =    0.43
  EFFECTIVE AREA(ACRES) =      0.75   AREA-AVERAGED Fm(INCH/HR) =  0.19
  AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap =  0.64
  TOTAL AREA(ACRES) =       0.8       PEAK FLOW RATE(CFS) =       0.97

****************************************************************************
  FLOW PROCESS FROM NODE    502.00 TO NODE    503.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
```

```
  ELEVATION DATA: UPSTREAM(FEET) =    66.80  DOWNSTREAM(FEET) =    66.50
  FLOW LENGTH(FEET) =    54.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN   9.0 INCH PIPE IS   6.2 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   2.97
  ESTIMATED PIPE DIAMETER(INCH) =   9.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       0.97
  PIPE TRAVEL TIME(MIN.) =   0.30    Tc(MIN.) =    8.88
  LONGEST FLOWPATH FROM NODE    500.00 TO NODE    503.00 =     572.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    503.00 TO NODE    507.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    66.40  DOWNSTREAM(FEET) =    66.00
  FLOW LENGTH(FEET) =    79.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN   9.0 INCH PIPE IS   6.4 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   2.86
  ESTIMATED PIPE DIAMETER(INCH) =   9.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       0.97
  PIPE TRAVEL TIME(MIN.) =   0.46    Tc(MIN.) =    9.34
  LONGEST FLOWPATH FROM NODE    500.00 TO NODE    507.00 =     651.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    507.00 TO NODE    507.00 IS CODE =   1
----------------------------------------------------------------------------
  >>>>>DESIGNATE INDEPENDENT STREAM FOR CONFLUENCE<<<<<
============================================================================
  TOTAL NUMBER OF STREAMS =  2
  CONFLUENCE VALUES USED FOR INDEPENDENT STREAM  1 ARE:
  TIME OF CONCENTRATION(MIN.) =    9.34
  RAINFALL INTENSITY(INCH/HR) =   1.54
  AREA-AVERAGED Fm(INCH/HR) =  0.19
  AREA-AVERAGED Fp(INCH/HR) =  0.30
  AREA-AVERAGED Ap =  0.64
  EFFECTIVE STREAM AREA(ACRES) =       0.75
  TOTAL STREAM AREA(ACRES) =       0.75
  PEAK FLOW RATE(CFS) AT CONFLUENCE =       0.97

****************************************************************************
  FLOW PROCESS FROM NODE    504.00 TO NODE    505.00 IS CODE =  21
----------------------------------------------------------------------------
  >>>>>RATIONAL METHOD INITIAL SUBAREA ANALYSIS<<<<<
  >>USE TIME-OF-CONCENTRATION NOMOGRAPH FOR INITIAL SUBAREA<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   213.00
  ELEVATION DATA: UPSTREAM(FEET) =     72.70  DOWNSTREAM(FEET) =     71.30

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    7.090
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.796
  SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
   DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp         Ap     SCS   Tc
       LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
  COMMERCIAL                 B       0.16      0.30     0.100    36    7.09
  NATURAL POOR COVER
  "BARREN"                   B       0.31      0.30     1.000    72   12.25
  SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
  SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.687
  SUBAREA RUNOFF(CFS) =      0.67
  TOTAL AREA(ACRES) =      0.47   PEAK FLOW RATE(CFS) =      0.67
```

```
****************************************************************************
  FLOW PROCESS FROM NODE    505.00 TO NODE    506.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    68.80  DOWNSTREAM(FEET) =    66.90
  FLOW LENGTH(FEET) =   382.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN   9.0 INCH PIPE IS   5.1 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   2.62
  ESTIMATED PIPE DIAMETER(INCH) =   9.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       0.67
  PIPE TRAVEL TIME(MIN.) =   2.43    Tc(MIN.) =    9.52
  LONGEST FLOWPATH FROM NODE    504.00 TO NODE    506.00 =     595.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    506.00 TO NODE    506.00 IS CODE =  82
----------------------------------------------------------------------------
  >>>>>ADD SUBAREA RUNOFF TO MAINLINE, AT MAINLINE Tc,<<<<<
  >>>>>(AND COMPUTE INITIAL SUBAREA RUNOFF)<<<<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   226.00
  ELEVATION DATA: UPSTREAM(FEET) =     72.70  DOWNSTREAM(FEET) =     70.80

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    6.912
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.822
  SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
   DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp        Ap     SCS   Tc
       LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
  COMMERCIAL                 B        0.13      0.30     0.100    36    6.91
  NATURAL POOR COVER
  "BARREN"                   B        0.19      0.30     1.000    72   11.94
  SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
  SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.645
  SUBAREA AREA(ACRES) =    0.32   INITIAL SUBAREA RUNOFF(CFS) =    0.47

  ** ADD SUBAREA RUNOFF TO MAINLINE AT MAINLINE Tc:
  MAINLINE Tc(MIN.) =    9.52
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.527
  SUBAREA AREA(ACRES) =    0.32      SUBAREA RUNOFF(CFS) =    0.39
  EFFECTIVE AREA(ACRES) =      0.79   AREA-AVERAGED Fm(INCH/HR) =  0.20
  AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap =  0.67
  TOTAL AREA(ACRES) =        0.8       PEAK FLOW RATE(CFS) =       0.94

****************************************************************************
  FLOW PROCESS FROM NODE    506.00 TO NODE    507.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    66.90  DOWNSTREAM(FEET) =    66.10
  FLOW LENGTH(FEET) =    49.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN   9.0 INCH PIPE IS   4.4 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   4.45
  ESTIMATED PIPE DIAMETER(INCH) =   9.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       0.94
  PIPE TRAVEL TIME(MIN.) =   0.18    Tc(MIN.) =    9.71
  LONGEST FLOWPATH FROM NODE    504.00 TO NODE    507.00 =     644.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    507.00 TO NODE    507.00 IS CODE =   1
----------------------------------------------------------------------------
```

```
  >>>>>DESIGNATE INDEPENDENT STREAM FOR CONFLUENCE<<<<<
  >>>>>AND COMPUTE VARIOUS CONFLUENCED STREAM VALUES<<<<<
============================================================================
  TOTAL NUMBER OF STREAMS =  2
  CONFLUENCE VALUES USED FOR INDEPENDENT STREAM  2 ARE:
  TIME OF CONCENTRATION(MIN.) =    9.71
  RAINFALL INTENSITY(INCH/HR) =   1.51
  AREA-AVERAGED Fm(INCH/HR) =  0.20
  AREA-AVERAGED Fp(INCH/HR) =  0.30
  AREA-AVERAGED Ap =  0.67
  EFFECTIVE STREAM AREA(ACRES) =       0.79
  TOTAL STREAM AREA(ACRES) =       0.79
  PEAK FLOW RATE(CFS) AT CONFLUENCE =       0.94

  ** CONFLUENCE DATA **
   STREAM       Q      Tc   Intensity   Fp(Fm)     Ap     Ae     HEADWATER
   NUMBER     (CFS)  (MIN.) (INCH/HR) (INCH/HR)         (ACRES)    NODE
      1        0.97    9.34    1.544  0.30( 0.19) 0.64       0.8     500.00
      2        0.94    9.71    1.511  0.30( 0.20) 0.67       0.8     504.00

  RAINFALL INTENSITY AND TIME OF CONCENTRATION RATIO
  CONFLUENCE FORMULA USED FOR  2 STREAMS.

  ** PEAK FLOW RATE TABLE **
   STREAM       Q      Tc   Intensity   Fp(Fm)     Ap     Ae     HEADWATER
   NUMBER     (CFS)  (MIN.) (INCH/HR) (INCH/HR)         (ACRES)    NODE
      1        1.90    9.34    1.544  0.30( 0.20) 0.66       1.5     500.00
      2        1.89    9.71    1.511  0.30( 0.20) 0.66       1.5     504.00

  COMPUTED CONFLUENCE ESTIMATES ARE AS FOLLOWS:
  PEAK FLOW RATE(CFS) =       1.90    Tc(MIN.) =     9.34
  EFFECTIVE AREA(ACRES) =       1.51   AREA-AVERAGED Fm(INCH/HR) =  0.20
  AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap =  0.66
  TOTAL AREA(ACRES) =        1.5
  LONGEST FLOWPATH FROM NODE    500.00 TO NODE    507.00 =     651.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    507.00 TO NODE    508.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    65.50  DOWNSTREAM(FEET) =    65.30
  FLOW LENGTH(FEET) =    48.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN  12.0 INCH PIPE IS   8.6 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   3.14
  ESTIMATED PIPE DIAMETER(INCH) =  12.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       1.90
  PIPE TRAVEL TIME(MIN.) =   0.26    Tc(MIN.) =    9.59
  LONGEST FLOWPATH FROM NODE    500.00 TO NODE    508.00 =     699.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    508.00 TO NODE    508.00 IS CODE =  82
----------------------------------------------------------------------------
  >>>>>ADD SUBAREA RUNOFF TO MAINLINE, AT MAINLINE Tc,<<<<<
  >>>>>(AND COMPUTE INITIAL SUBAREA RUNOFF)<<<<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   210.00
  ELEVATION DATA: UPSTREAM(FEET) =     75.33  DOWNSTREAM(FEET) =     70.50

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    5.488
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  2.068
```

```
  SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
   DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp         Ap     SCS   Tc
       LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
  COMMERCIAL                 B        0.05      0.30     0.100    36    5.49
  NATURAL POOR COVER
  "BARREN"                   B        0.15      0.30     1.000    72    9.48
  SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
  SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.779
  SUBAREA AREA(ACRES) =    0.20   INITIAL SUBAREA RUNOFF(CFS) =    0.34

  ** ADD SUBAREA RUNOFF TO MAINLINE AT MAINLINE Tc:
  MAINLINE Tc(MIN.) =    9.59
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.521
  SUBAREA AREA(ACRES) =    0.20      SUBAREA RUNOFF(CFS) =    0.24
  EFFECTIVE AREA(ACRES) =      1.72   AREA-AVERAGED Fm(INCH/HR) =  0.20
  AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap =  0.67
  TOTAL AREA(ACRES) =        1.7       PEAK FLOW RATE(CFS) =       2.04

****************************************************************************
  FLOW PROCESS FROM NODE    508.00 TO NODE    509.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    65.20  DOWNSTREAM(FEET) =    65.00
  FLOW LENGTH(FEET) =    36.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN  12.0 INCH PIPE IS   8.2 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   3.57
  ESTIMATED PIPE DIAMETER(INCH) =  12.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       2.04
  PIPE TRAVEL TIME(MIN.) =   0.17    Tc(MIN.) =    9.76
  LONGEST FLOWPATH FROM NODE    500.00 TO NODE    509.00 =     735.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    509.00 TO NODE    510.00 IS CODE =  31
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING COMPUTER-ESTIMATED PIPESIZE (NON-PRESSURE FLOW)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    65.00  DOWNSTREAM(FEET) =    64.90
  FLOW LENGTH(FEET) =   175.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN  18.0 INCH PIPE IS  12.8 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   1.52
  ESTIMATED PIPE DIAMETER(INCH) =  18.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       2.04
  PIPE TRAVEL TIME(MIN.) =   1.92    Tc(MIN.) =   11.68
  LONGEST FLOWPATH FROM NODE    500.00 TO NODE    510.00 =     910.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    510.00 TO NODE    510.00 IS CODE =  81
----------------------------------------------------------------------------
  >>>>>ADDITION OF SUBAREA TO MAINLINE PEAK FLOW<<<<<
============================================================================
  MAINLINE Tc(MIN.) =   11.68
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.365
  SUBAREA LOSS RATE DATA(AMC  I ):
   DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp         Ap     SCS
       LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN
  COMMERCIAL                 B        0.25      0.30     0.100    36
  NATURAL POOR COVER
  "BARREN"                   B        0.55      0.30     1.000    72
  SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
  SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.721
```

```
  SUBAREA AREA(ACRES) =    0.79      SUBAREA RUNOFF(CFS) =    0.82
  EFFECTIVE AREA(ACRES) =       2.51   AREA-AVERAGED Fm(INCH/HR) =  0.21
  AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap =  0.69
  TOTAL AREA(ACRES) =        2.5       PEAK FLOW RATE(CFS) =       2.62

****************************************************************************
  FLOW PROCESS FROM NODE    200.00 TO NODE    201.00 IS CODE =  21
----------------------------------------------------------------------------
  >>>>>RATIONAL METHOD INITIAL SUBAREA ANALYSIS<<<<<
  >>USE TIME-OF-CONCENTRATION NOMOGRAPH FOR INITIAL SUBAREA<<
============================================================================
  INITIAL SUBAREA FLOW-LENGTH(FEET) =   195.00
  ELEVATION DATA: UPSTREAM(FEET) =     69.90  DOWNSTREAM(FEET) =     68.50

  Tc = K*[(LENGTH** 3.00)/(ELEVATION CHANGE)]**0.20
  SUBAREA ANALYSIS USED MINIMUM Tc(MIN.) =    6.725
  *   2 YEAR RAINFALL INTENSITY(INCH/HR) =  1.850
  SUBAREA Tc AND LOSS RATE DATA(AMC  I ):
   DEVELOPMENT TYPE/      SCS SOIL   AREA      Fp        Ap     SCS   Tc
       LAND USE            GROUP   (ACRES)  (INCH/HR)  (DECIMAL)  CN  (MIN.)
  COMMERCIAL                 B        0.14      0.30     0.100    36    6.72
  NATURAL POOR COVER
  "BARREN"                   B        0.67      0.30     1.000    72   11.61
  SUBAREA AVERAGE PERVIOUS LOSS RATE, Fp(INCH/HR) =  0.30
  SUBAREA AVERAGE PERVIOUS AREA FRACTION, Ap =  0.844
  SUBAREA RUNOFF(CFS) =      1.16
  TOTAL AREA(ACRES) =      0.81   PEAK FLOW RATE(CFS) =      1.16

****************************************************************************
  FLOW PROCESS FROM NODE    201.00 TO NODE    202.00 IS CODE =  41
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING USER-SPECIFIED PIPESIZE (EXISTING ELEMENT)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    66.60  DOWNSTREAM(FEET) =    65.90
  FLOW LENGTH(FEET) =    81.00   MANNING'S N =  0.013
  ASSUME FULL-FLOWING PIPELINE
  PIPE-FLOW VELOCITY(FEET/SEC.) =   3.33
  PIPE FLOW VELOCITY = (TOTAL FLOW)/(PIPE CROSS SECTION AREA)
  GIVEN PIPE DIAMETER(INCH) =   8.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       1.16
  PIPE TRAVEL TIME(MIN.) =   0.40    Tc(MIN.) =    7.13
  LONGEST FLOWPATH FROM NODE    200.00 TO NODE    202.00 =     276.00 FEET.

****************************************************************************
  FLOW PROCESS FROM NODE    202.00 TO NODE    206.00 IS CODE =  41
----------------------------------------------------------------------------
  >>>>>COMPUTE PIPE-FLOW TRAVEL TIME THRU SUBAREA<<<<<
  >>>>>USING USER-SPECIFIED PIPESIZE (EXISTING ELEMENT)<<<<<
============================================================================
  ELEVATION DATA: UPSTREAM(FEET) =    65.90  DOWNSTREAM(FEET) =    63.60
  FLOW LENGTH(FEET) =   411.00   MANNING'S N =  0.013
  DEPTH OF FLOW IN  36.0 INCH PIPE IS   3.9 INCHES
  PIPE-FLOW VELOCITY(FEET/SEC.) =   2.82
  GIVEN PIPE DIAMETER(INCH) =  36.00    NUMBER OF PIPES =   1
  PIPE-FLOW(CFS) =       1.16
  PIPE TRAVEL TIME(MIN.) =   2.43    Tc(MIN.) =    9.56
  LONGEST FLOWPATH FROM NODE    200.00 TO NODE    206.00 =     687.00 FEET.
============================================================================
  END OF STUDY SUMMARY:
  TOTAL AREA(ACRES)     =        0.8  TC(MIN.) =      9.56
  EFFECTIVE AREA(ACRES) =      0.81  AREA-AVERAGED Fm(INCH/HR)=  0.25
  AREA-AVERAGED Fp(INCH/HR) =  0.30  AREA-AVERAGED Ap = 0.844
```

```
  PEAK FLOW RATE(CFS)   =       1.16
============================================================================
============================================================================
  END OF RATIONAL METHOD ANALYSIS

♀
```

DMA 1 - Parcel 1 - Preconstruciton Condition
```
================================================================================
*** NON-HOMOGENEOUS WATERSHED AREA-AVERAGED LOSS RATE (Fm)
    AND LOW LOSS FRACTION ESTIMATIONS FOR AMC I:

    TOTAL 24-HOUR DURATION RAINFALL DEPTH =    2.31 (inches)

    SOIL-COVER     AREA     PERCENT OF    SCS CURVE    LOSS RATE
      TYPE       (Acres)  PERVIOUS AREA    NUMBER    Fp(in./hr.)    YIELD
        1          1.75       98.80      69.(AMC II)    0.300       0.015

    TOTAL AREA (Acres) =     1.75
                          _
    AREA-AVERAGED LOSS RATE, Fm (in./hr.) =  0.296
                               _
    AREA-AVERAGED LOW LOSS FRACTION, Y = 0.985
================================================================================

--------------------------------------------------------------------------



    RATIONAL METHOD CALIBRATION COEFFICIENT = 0.93
    TOTAL CATCHMENT AREA(ACRES) =    1.75
    SOIL-LOSS RATE, Fm,(INCH/HR) =  0.296
    LOW LOSS FRACTION = 0.985
    TIME OF CONCENTRATION(MIN.) = 30.77
    SMALL AREA PEAK Q COMPUTED USING PEAK FLOW RATE FORMULA
    USER SPECIFIED RAINFALL VALUES ARE USED
    RETURN FREQUENCY(YEARS) =   2
      5-MINUTE POINT RAINFALL VALUE(INCHES) =  0.17
     30-MINUTE POINT RAINFALL VALUE(INCHES) =  0.40
      1-HOUR   POINT RAINFALL VALUE(INCHES) =  0.56
      3-HOUR   POINT RAINFALL VALUE(INCHES) =  0.98
      6-HOUR   POINT RAINFALL VALUE(INCHES) =  1.36
     24-HOUR   POINT RAINFALL VALUE(INCHES) =  2.31

--------------------------------------------------------------------------

    TOTAL CATCHMENT   RUNOFF  VOLUME(ACRE-FEET) =     0.04
    TOTAL CATCHMENT SOIL-LOSS VOLUME(ACRE-FEET) =     0.30

******************************************************************************
  TIME     VOLUME       Q    0.       2.5      5.0      7.5     10.0
 (HOURS)    (AF)      (CFS)
--------------------------------------------------------------------------
   0.10    0.0000     0.00  Q       .        .        .        .
   0.61    0.0000     0.00  Q       .        .        .        .
```

1.13	0.0001	0.00	Q . . . .
1.64	0.0001	0.00	Q . . . .
2.15	0.0001	0.00	Q . . . .
2.67	0.0002	0.00	Q . . . .
3.18	0.0002	0.00	Q . . . .
3.69	0.0003	0.00	Q . . . .
4.20	0.0003	0.00	Q . . . .
4.72	0.0004	0.00	Q . . . .
5.23	0.0004	0.00	Q . . . .
5.74	0.0004	0.00	Q . . . .
6.26	0.0005	0.00	Q . . . .
6.77	0.0005	0.00	Q . . . .
7.28	0.0006	0.00	Q . . . .
7.79	0.0007	0.00	Q . . . .
8.31	0.0007	0.00	Q . . . .
8.82	0.0008	0.00	Q . . . .
9.33	0.0008	0.00	Q . . . .
9.85	0.0009	0.00	Q . . . .
10.36	0.0010	0.00	Q . . . .
10.87	0.0010	0.00	Q . . . .
11.38	0.0011	0.00	Q . . . .
11.90	0.0012	0.00	Q . . . .
12.41	0.0013	0.00	Q . . . .
12.92	0.0014	0.00	Q . . . .
13.44	0.0015	0.00	Q . . . .
13.95	0.0017	0.00	Q . . . .
14.46	0.0018	0.00	Q . . . .
14.97	0.0020	0.00	Q . . . .
15.49	0.0022	0.01	Q . . . .
16.00	0.0030	0.03	Q . . . .
16.51	0.0204	0.79	. Q . . . .
17.03	0.0373	0.01	Q . . . .
17.54	0.0375	0.00	Q . . . .
18.05	0.0376	0.00	Q . . . .
18.56	0.0377	0.00	Q . . . .
19.08	0.0378	0.00	Q . . . .
19.59	0.0378	0.00	Q . . . .
20.10	0.0379	0.00	Q . . . .
20.62	0.0380	0.00	Q . . . .
21.13	0.0380	0.00	Q . . . .
21.64	0.0381	0.00	Q . . . .
22.15	0.0381	0.00	Q . . . .
22.67	0.0382	0.00	Q . . . .
23.18	0.0382	0.00	Q . . . .
23.69	0.0383	0.00	Q . . . .
24.21	0.0383	0.00	Q . . . .
24.72	0.0383	0.00	Q . . . .

0

TIME DURATION(minutes) OF PERCENTILES OF ESTIMATED PEAK FLOW RATE:
(Note: 100% of Peak Flow Rate estimate assumed to have
an instantaneous time duration)

Percentile of Estimated Peak Flow Rate	Duration (minutes)
0%	1446.2
10%	30.8
20%	30.8
30%	30.8
40%	30.8
50%	30.8
60%	30.8
70%	30.8
80%	30.8
90%	30.8

DMA 1 - Parcel 2 - Preconstruction Condition

```
==========================================================================
*** NON-HOMOGENEOUS WATERSHED AREA-AVERAGED LOSS RATE (Fm)
  AND LOW LOSS FRACTION ESTIMATIONS FOR AMC I:

  TOTAL 24-HOUR DURATION RAINFALL DEPTH =    2.31 (inches)

  SOIL-COVER    AREA     PERCENT OF   SCS CURVE   LOSS RATE
    TYPE     (Acres)  PERVIOUS AREA    NUMBER   Fp(in./hr.)   YIELD
      1        0.80       0.00      98.(AMC II)    0.010      0.901

  TOTAL AREA (Acres) =     0.80
                  _
  AREA-AVERAGED LOSS RATE, Fm (in./hr.) =  0.000
                      _
  AREA-AVERAGED LOW LOSS FRACTION, Y = 0.099
==========================================================================

----------------------------------------------------------------------------



  RATIONAL METHOD CALIBRATION COEFFICIENT = 1.05
  TOTAL CATCHMENT AREA(ACRES) =    0.80
  SOIL-LOSS RATE, Fm,(INCH/HR) =  0.000
  LOW LOSS FRACTION = 0.099
  TIME OF CONCENTRATION(MIN.) =  6.77
  SMALL AREA PEAK Q COMPUTED USING PEAK FLOW RATE FORMULA
  USER SPECIFIED RAINFALL VALUES ARE USED
  RETURN FREQUENCY(YEARS) =   2
    5-MINUTE POINT RAINFALL VALUE(INCHES) =  0.17
   30-MINUTE POINT RAINFALL VALUE(INCHES) =  0.40
    1-HOUR   POINT RAINFALL VALUE(INCHES) =  0.56
    3-HOUR   POINT RAINFALL VALUE(INCHES) =  0.98
    6-HOUR   POINT RAINFALL VALUE(INCHES) =  1.36
   24-HOUR   POINT RAINFALL VALUE(INCHES) =  2.31

----------------------------------------------------------------------------

  TOTAL CATCHMENT   RUNOFF  VOLUME(ACRE-FEET) =     0.16
  TOTAL CATCHMENT SOIL-LOSS VOLUME(ACRE-FEET) =    -0.01

***************************************************************************
  TIME    VOLUME      Q   0.      2.5      5.0      7.5     10.0
 (HOURS)    (AF)     (CFS)
----------------------------------------------------------------------------
  0.09    0.0001     0.03  Q       .       .       .       .
  0.20    0.0004     0.03  Q       .       .       .       .
```

0.32	0.0007	0.03	Q	.	.	.	.
0.43	0.0010	0.03	Q	.	.	.	.
0.54	0.0013	0.03	Q	.	.	.	.
0.65	0.0016	0.03	Q	.	.	.	.
0.77	0.0019	0.03	Q	.	.	.	.
0.88	0.0022	0.03	Q	.	.	.	.
0.99	0.0025	0.03	Q	.	.	.	.
1.11	0.0028	0.03	Q	.	.	.	.
1.22	0.0031	0.03	Q	.	.	.	.
1.33	0.0034	0.03	Q	.	.	.	.
1.44	0.0037	0.03	Q	.	.	.	.
1.56	0.0040	0.03	Q	.	.	.	.
1.67	0.0043	0.03	Q	.	.	.	.
1.78	0.0046	0.03	Q	.	.	.	.
1.90	0.0049	0.03	Q	.	.	.	.
2.01	0.0052	0.03	Q	.	.	.	.
2.12	0.0055	0.03	Q	.	.	.	.
2.23	0.0058	0.03	Q	.	.	.	.
2.35	0.0062	0.03	Q	.	.	.	.
2.46	0.0065	0.03	Q	.	.	.	.
2.57	0.0068	0.03	Q	.	.	.	.
2.69	0.0071	0.03	Q	.	.	.	.
2.80	0.0074	0.03	Q	.	.	.	.
2.91	0.0078	0.03	Q	.	.	.	.
3.02	0.0081	0.04	Q	.	.	.	.
3.14	0.0084	0.04	Q	.	.	.	.
3.25	0.0087	0.04	Q	.	.	.	.
3.36	0.0091	0.04	Q	.	.	.	.
3.48	0.0094	0.04	Q	.	.	.	.
3.59	0.0097	0.04	Q	.	.	.	.
3.70	0.0101	0.04	Q	.	.	.	.
3.81	0.0104	0.04	Q	.	.	.	.
3.93	0.0108	0.04	Q	.	.	.	.
4.04	0.0111	0.04	Q	.	.	.	.
4.15	0.0114	0.04	Q	.	.	.	.
4.27	0.0118	0.04	Q	.	.	.	.
4.38	0.0121	0.04	Q	.	.	.	.
4.49	0.0125	0.04	Q	.	.	.	.
4.60	0.0128	0.04	Q	.	.	.	.
4.72	0.0132	0.04	Q	.	.	.	.
4.83	0.0136	0.04	Q	.	.	.	.
4.94	0.0139	0.04	Q	.	.	.	.
5.06	0.0143	0.04	Q	.	.	.	.
5.17	0.0146	0.04	Q	.	.	.	.
5.28	0.0150	0.04	Q	.	.	.	.
5.39	0.0154	0.04	Q	.	.	.	.
5.51	0.0158	0.04	Q	.	.	.	.

5.62	0.0161	0.04	Q	.	.	.	.
5.73	0.0165	0.04	Q	.	.	.	.
5.85	0.0169	0.04	Q	.	.	.	.
5.96	0.0173	0.04	Q	.	.	.	.
6.07	0.0176	0.04	Q	.	.	.	.
6.18	0.0180	0.04	Q	.	.	.	.
6.30	0.0184	0.04	Q	.	.	.	.
6.41	0.0188	0.04	Q	.	.	.	.
6.52	0.0192	0.04	Q	.	.	.	.
6.63	0.0196	0.04	Q	.	.	.	.
6.75	0.0200	0.04	Q	.	.	.	.
6.86	0.0204	0.04	Q	.	.	.	.
6.97	0.0208	0.04	Q	.	.	.	.
7.09	0.0212	0.04	Q	.	.	.	.
7.20	0.0216	0.04	Q	.	.	.	.
7.31	0.0221	0.04	Q	.	.	.	.
7.42	0.0225	0.05	Q	.	.	.	.
7.54	0.0229	0.05	Q	.	.	.	.
7.65	0.0233	0.05	Q	.	.	.	.
7.76	0.0238	0.05	Q	.	.	.	.
7.88	0.0242	0.05	Q	.	.	.	.
7.99	0.0246	0.05	Q	.	.	.	.
8.10	0.0251	0.05	Q	.	.	.	.
8.21	0.0255	0.05	Q	.	.	.	.
8.33	0.0260	0.05	Q	.	.	.	.
8.44	0.0264	0.05	Q	.	.	.	.
8.55	0.0269	0.05	Q	.	.	.	.
8.67	0.0273	0.05	Q	.	.	.	.
8.78	0.0278	0.05	Q	.	.	.	.
8.89	0.0283	0.05	Q	.	.	.	.
9.00	0.0287	0.05	Q	.	.	.	.
9.12	0.0292	0.05	Q	.	.	.	.
9.23	0.0297	0.05	Q	.	.	.	.
9.34	0.0302	0.05	Q	.	.	.	.
9.46	0.0307	0.05	Q	.	.	.	.
9.57	0.0312	0.05	Q	.	.	.	.
9.68	0.0317	0.05	Q	.	.	.	.
9.79	0.0322	0.06	Q	.	.	.	.
9.91	0.0327	0.06	Q	.	.	.	.
10.02	0.0332	0.06	Q	.	.	.	.
10.13	0.0338	0.06	Q	.	.	.	.
10.25	0.0343	0.06	Q	.	.	.	.
10.36	0.0348	0.06	Q	.	.	.	.
10.47	0.0354	0.06	Q	.	.	.	.
10.58	0.0359	0.06	Q	.	.	.	.
10.70	0.0365	0.06	Q	.	.	.	.
10.81	0.0371	0.06	Q	.	.	.	.

10.92	0.0377	0.06	Q . . . .
11.04	0.0382	0.06	Q . . . .
11.15	0.0388	0.06	Q . . . .
11.26	0.0394	0.06	Q . . . .
11.37	0.0400	0.07	Q . . . .
11.49	0.0407	0.07	Q . . . .
11.60	0.0413	0.07	Q . . . .
11.71	0.0419	0.07	Q . . . .
11.83	0.0426	0.07	Q . . . .
11.94	0.0432	0.07	Q . . . .
12.05	0.0439	0.08	Q . . . .
12.16	0.0447	0.09	Q . . . .
12.28	0.0455	0.09	Q . . . .
12.39	0.0464	0.09	Q . . . .
12.50	0.0473	0.10	Q . . . .
12.62	0.0482	0.10	Q . . . .
12.73	0.0491	0.10	Q . . . .
12.84	0.0500	0.10	Q . . . .
12.95	0.0510	0.10	Q . . . .
13.07	0.0519	0.10	Q . . . .
13.18	0.0529	0.11	Q . . . .
13.29	0.0539	0.11	Q . . . .
13.40	0.0549	0.11	Q . . . .
13.52	0.0560	0.11	Q . . . .
13.63	0.0570	0.12	Q . . . .
13.74	0.0581	0.12	Q . . . .
13.86	0.0593	0.12	Q . . . .
13.97	0.0604	0.12	Q . . . .
14.08	0.0616	0.14	Q . . . .
14.19	0.0630	0.15	Q . . . .
14.31	0.0643	0.15	Q . . . .
14.42	0.0658	0.15	Q . . . .
14.53	0.0672	0.16	Q . . . .
14.65	0.0688	0.17	Q . . . .
14.76	0.0704	0.17	Q . . . .
14.87	0.0720	0.18	Q . . . .
14.98	0.0737	0.19	Q . . . .
15.10	0.0755	0.20	Q . . . .
15.21	0.0775	0.21	Q . . . .
15.32	0.0795	0.22	Q . . . .
15.44	0.0816	0.23	Q . . . .
15.55	0.0839	0.25	Q . . . .
15.66	0.0864	0.29	.Q . . . .
15.77	0.0892	0.32	.Q . . . .
15.89	0.0928	0.44	.Q . . . .
16.00	0.0975	0.57	. Q . . . .
16.11	0.1068	1.43	. Q . . . .

16.23	0.1152	0.37	.Q	.	.	.	.
16.34	0.1182	0.27	.Q	.	.	.	.
16.45	0.1205	0.23	Q	.	.	.	.
16.56	0.1226	0.21	Q	.	.	.	.
16.68	0.1244	0.18	Q	.	.	.	.
16.79	0.1260	0.17	Q	.	.	.	.
16.90	0.1276	0.16	Q	.	.	.	.
17.02	0.1290	0.15	Q	.	.	.	.
17.13	0.1303	0.13	Q	.	.	.	.
17.24	0.1314	0.12	Q	.	.	.	.
17.35	0.1325	0.11	Q	.	.	.	.
17.47	0.1336	0.11	Q	.	.	.	.
17.58	0.1346	0.11	Q	.	.	.	.
17.69	0.1355	0.10	Q	.	.	.	.
17.81	0.1365	0.10	Q	.	.	.	.
17.92	0.1374	0.09	Q	.	.	.	.
18.03	0.1382	0.09	Q	.	.	.	.
18.14	0.1390	0.07	Q	.	.	.	.
18.26	0.1397	0.07	Q	.	.	.	.
18.37	0.1403	0.07	Q	.	.	.	.
18.48	0.1409	0.07	Q	.	.	.	.
18.60	0.1415	0.06	Q	.	.	.	.
18.71	0.1421	0.06	Q	.	.	.	.
18.82	0.1427	0.06	Q	.	.	.	.
18.93	0.1432	0.06	Q	.	.	.	.
19.05	0.1438	0.06	Q	.	.	.	.
19.16	0.1443	0.06	Q	.	.	.	.
19.27	0.1448	0.05	Q	.	.	.	.
19.39	0.1453	0.05	Q	.	.	.	.
19.50	0.1458	0.05	Q	.	.	.	.
19.61	0.1463	0.05	Q	.	.	.	.
19.72	0.1468	0.05	Q	.	.	.	.
19.84	0.1472	0.05	Q	.	.	.	.
19.95	0.1477	0.05	Q	.	.	.	.
20.06	0.1481	0.05	Q	.	.	.	.
20.17	0.1486	0.05	Q	.	.	.	.
20.29	0.1490	0.05	Q	.	.	.	.
20.40	0.1494	0.05	Q	.	.	.	.
20.51	0.1499	0.04	Q	.	.	.	.
20.63	0.1503	0.04	Q	.	.	.	.
20.74	0.1507	0.04	Q	.	.	.	.
20.85	0.1511	0.04	Q	.	.	.	.
20.96	0.1515	0.04	Q	.	.	.	.
21.08	0.1519	0.04	Q	.	.	.	.
21.19	0.1522	0.04	Q	.	.	.	.
21.30	0.1526	0.04	Q	.	.	.	.
21.42	0.1530	0.04	Q	.	.	.	.

```
21.53    0.1534    0.04  Q      .      .      .      .
21.64    0.1537    0.04  Q      .      .      .      .
21.75    0.1541    0.04  Q      .      .      .      .
21.87    0.1544    0.04  Q      .      .      .      .
21.98    0.1548    0.04  Q      .      .      .      .
22.09    0.1551    0.04  Q      .      .      .      .
22.21    0.1555    0.04  Q      .      .      .      .
22.32    0.1558    0.04  Q      .      .      .      .
22.43    0.1562    0.04  Q      .      .      .      .
22.54    0.1565    0.04  Q      .      .      .      .
22.66    0.1568    0.03  Q      .      .      .      .
22.77    0.1571    0.03  Q      .      .      .      .
22.88    0.1575    0.03  Q      .      .      .      .
23.00    0.1578    0.03  Q      .      .      .      .
23.11    0.1581    0.03  Q      .      .      .      .
23.22    0.1584    0.03  Q      .      .      .      .
23.33    0.1587    0.03  Q      .      .      .      .
23.45    0.1590    0.03  Q      .      .      .      .
23.56    0.1593    0.03  Q      .      .      .      .
23.67    0.1596    0.03  Q      .      .      .      .
23.79    0.1599    0.03  Q      .      .      .      .
23.90    0.1602    0.03  Q      .      .      .      .
24.01    0.1605    0.03  Q      .      .      .      .
24.12    0.1606    0.00  Q      .      .      .      .
-----------------------------------------------------------------------
-----------------------------------------------------------------------
```

TIME DURATION(minutes) OF PERCENTILES OF ESTIMATED PEAK FLOW RATE:
(Note: 100% of Peak Flow Rate estimate assumed to have
an instantaneous time duration)

Percentile of Estimated Peak Flow Rate	Duration (minutes)
======================	=========
0%	1442.0
10%	176.0
20%	40.6
30%	20.3
40%	6.8
50%	6.8
60%	6.8
70%	6.8
80%	6.8
90%	6.8

DMA 2 - Parcel 2 - Preconstruction Condition

```
================================================================================
*** NON-HOMOGENEOUS WATERSHED AREA-AVERAGED LOSS RATE (Fm)
   AND LOW LOSS FRACTION ESTIMATIONS FOR AMC I:

   TOTAL 24-HOUR DURATION RAINFALL DEPTH =     2.31 (inches)

   SOIL-COVER     AREA     PERCENT OF    SCS CURVE    LOSS RATE
     TYPE      (Acres)  PERVIOUS AREA     NUMBER    Fp(in./hr.)    YIELD
       1        0.81       10.00      98.(AMC II)    0.300       0.888

   TOTAL AREA (Acres) =     0.81
                              _
   AREA-AVERAGED LOSS RATE, Fm (in./hr.) =  0.030
                                  _
   AREA-AVERAGED LOW LOSS FRACTION, Y = 0.112
================================================================================

--------------------------------------------------------------------------------



   RATIONAL METHOD CALIBRATION COEFFICIENT = 1.17
   TOTAL CATCHMENT AREA(ACRES) =    0.81
   SOIL-LOSS RATE, Fm,(INCH/HR) =  0.030
   LOW LOSS FRACTION = 0.112
   TIME OF CONCENTRATION(MIN.) =  9.41
   SMALL AREA PEAK Q COMPUTED USING PEAK FLOW RATE FORMULA
   USER SPECIFIED RAINFALL VALUES ARE USED
   RETURN FREQUENCY(YEARS) =   2
     5-MINUTE POINT RAINFALL VALUE(INCHES) =  0.17
    30-MINUTE POINT RAINFALL VALUE(INCHES) =  0.40
     1-HOUR   POINT RAINFALL VALUE(INCHES) =  0.56
     3-HOUR   POINT RAINFALL VALUE(INCHES) =  0.98
     6-HOUR   POINT RAINFALL VALUE(INCHES) =  1.36
    24-HOUR   POINT RAINFALL VALUE(INCHES) =  2.31

--------------------------------------------------------------------------------

   TOTAL CATCHMENT   RUNOFF  VOLUME(ACRE-FEET) =     0.16
   TOTAL CATCHMENT SOIL-LOSS VOLUME(ACRE-FEET) =    -0.01

******************************************************************************
  TIME     VOLUME      Q    0.       2.5      5.0      7.5     10.0
 (HOURS)    (AF)     (CFS)
--------------------------------------------------------------------------------
  0.00     0.0000     0.00  Q         .        .        .        .
  0.16     0.0002     0.03  Q         .        .        .        .
```

0.32	0.0006	0.03	Q	.	.	.	.
0.47	0.0010	0.03	Q	.	.	.	.
0.63	0.0014	0.03	Q	.	.	.	.
0.79	0.0018	0.03	Q	.	.	.	.
0.94	0.0022	0.03	Q	.	.	.	.
1.10	0.0026	0.03	Q	.	.	.	.
1.26	0.0031	0.03	Q	.	.	.	.
1.41	0.0035	0.03	Q	.	.	.	.
1.57	0.0039	0.03	Q	.	.	.	.
1.73	0.0043	0.03	Q	.	.	.	.
1.89	0.0048	0.03	Q	.	.	.	.
2.04	0.0052	0.03	Q	.	.	.	.
2.20	0.0056	0.03	Q	.	.	.	.
2.36	0.0061	0.03	Q	.	.	.	.
2.51	0.0065	0.03	Q	.	.	.	.
2.67	0.0069	0.03	Q	.	.	.	.
2.83	0.0074	0.03	Q	.	.	.	.
2.98	0.0078	0.03	Q	.	.	.	.
3.14	0.0083	0.04	Q	.	.	.	.
3.30	0.0088	0.04	Q	.	.	.	.
3.45	0.0092	0.04	Q	.	.	.	.
3.61	0.0097	0.04	Q	.	.	.	.
3.77	0.0101	0.04	Q	.	.	.	.
3.92	0.0106	0.04	Q	.	.	.	.
4.08	0.0111	0.04	Q	.	.	.	.
4.24	0.0116	0.04	Q	.	.	.	.
4.39	0.0121	0.04	Q	.	.	.	.
4.55	0.0125	0.04	Q	.	.	.	.
4.71	0.0130	0.04	Q	.	.	.	.
4.86	0.0135	0.04	Q	.	.	.	.
5.02	0.0140	0.04	Q	.	.	.	.
5.18	0.0145	0.04	Q	.	.	.	.
5.34	0.0150	0.04	Q	.	.	.	.
5.49	0.0155	0.04	Q	.	.	.	.
5.65	0.0161	0.04	Q	.	.	.	.
5.81	0.0166	0.04	Q	.	.	.	.
5.96	0.0171	0.04	Q	.	.	.	.
6.12	0.0176	0.04	Q	.	.	.	.
6.28	0.0182	0.04	Q	.	.	.	.
6.43	0.0187	0.04	Q	.	.	.	.
6.59	0.0193	0.04	Q	.	.	.	.
6.75	0.0198	0.04	Q	.	.	.	.
6.90	0.0204	0.04	Q	.	.	.	.
7.06	0.0210	0.04	Q	.	.	.	.
7.22	0.0215	0.04	Q	.	.	.	.
7.37	0.0221	0.04	Q	.	.	.	.
7.53	0.0227	0.05	Q	.	.	.	.

7.69	0.0233	0.05	Q	.	.	.	.
7.84	0.0239	0.05	Q	.	.	.	.
8.00	0.0245	0.05	Q	.	.	.	.
8.16	0.0251	0.05	Q	.	.	.	.
8.32	0.0257	0.05	Q	.	.	.	.
8.47	0.0263	0.05	Q	.	.	.	.
8.63	0.0270	0.05	Q	.	.	.	.
8.79	0.0276	0.05	Q	.	.	.	.
8.94	0.0283	0.05	Q	.	.	.	.
9.10	0.0289	0.05	Q	.	.	.	.
9.26	0.0296	0.05	Q	.	.	.	.
9.41	0.0303	0.05	Q	.	.	.	.
9.57	0.0310	0.05	Q	.	.	.	.
9.73	0.0317	0.05	Q	.	.	.	.
9.88	0.0324	0.06	Q	.	.	.	.
10.04	0.0331	0.06	Q	.	.	.	.
10.20	0.0338	0.06	Q	.	.	.	.
10.35	0.0346	0.06	Q	.	.	.	.
10.51	0.0353	0.06	Q	.	.	.	.
10.67	0.0361	0.06	Q	.	.	.	.
10.82	0.0369	0.06	Q	.	.	.	.
10.98	0.0377	0.06	Q	.	.	.	.
11.14	0.0385	0.06	Q	.	.	.	.
11.30	0.0393	0.06	Q	.	.	.	.
11.45	0.0402	0.07	Q	.	.	.	.
11.61	0.0410	0.07	Q	.	.	.	.
11.77	0.0419	0.07	Q	.	.	.	.
11.92	0.0428	0.07	Q	.	.	.	.
12.08	0.0438	0.08	Q	.	.	.	.
12.24	0.0449	0.09	Q	.	.	.	.
12.39	0.0460	0.09	Q	.	.	.	.
12.55	0.0473	0.09	Q	.	.	.	.
12.71	0.0485	0.10	Q	.	.	.	.
12.86	0.0498	0.10	Q	.	.	.	.
13.02	0.0511	0.10	Q	.	.	.	.
13.18	0.0524	0.10	Q	.	.	.	.
13.33	0.0538	0.11	Q	.	.	.	.
13.49	0.0553	0.11	Q	.	.	.	.
13.65	0.0567	0.12	Q	.	.	.	.
13.80	0.0582	0.12	Q	.	.	.	.
13.96	0.0598	0.12	Q	.	.	.	.
14.12	0.0615	0.13	Q	.	.	.	.
14.27	0.0633	0.15	Q	.	.	.	.
14.43	0.0652	0.15	Q	.	.	.	.
14.59	0.0673	0.16	Q	.	.	.	.
14.75	0.0694	0.17	Q	.	.	.	.
14.90	0.0717	0.18	Q	.	.	.	.

15.06	0.0741	0.19	Q	.	.	.	.
15.22	0.0767	0.21	Q	.	.	.	.
15.37	0.0795	0.22	Q	.	.	.	.
15.53	0.0825	0.25	Q	.	.	.	.
15.69	0.0860	0.28	.Q	.	.	.	.
15.84	0.0902	0.39	.Q	.	.	.	.
16.00	0.0961	0.52	. Q	.	.	.	.
16.16	0.1080	1.33	. Q	.	.	.	.
16.31	0.1187	0.32	.Q	.	.	.	.
16.47	0.1223	0.24	Q	.	.	.	.
16.63	0.1252	0.20	Q	.	.	.	.
16.78	0.1276	0.17	Q	.	.	.	.
16.94	0.1297	0.16	Q	.	.	.	.
17.10	0.1317	0.14	Q	.	.	.	.
17.25	0.1334	0.12	Q	.	.	.	.
17.41	0.1349	0.11	Q	.	.	.	.
17.57	0.1364	0.11	Q	.	.	.	.
17.73	0.1377	0.10	Q	.	.	.	.
17.88	0.1390	0.10	Q	.	.	.	.
18.04	0.1402	0.09	Q	.	.	.	.
18.20	0.1413	0.07	Q	.	.	.	.
18.35	0.1422	0.07	Q	.	.	.	.
18.51	0.1430	0.07	Q	.	.	.	.
18.67	0.1439	0.06	Q	.	.	.	.
18.82	0.1447	0.06	Q	.	.	.	.
18.98	0.1454	0.06	Q	.	.	.	.
19.14	0.1462	0.06	Q	.	.	.	.
19.29	0.1469	0.05	Q	.	.	.	.
19.45	0.1476	0.05	Q	.	.	.	.
19.61	0.1483	0.05	Q	.	.	.	.
19.76	0.1489	0.05	Q	.	.	.	.
19.92	0.1496	0.05	Q	.	.	.	.
20.08	0.1502	0.05	Q	.	.	.	.
20.23	0.1508	0.05	Q	.	.	.	.
20.39	0.1514	0.05	Q	.	.	.	.
20.55	0.1520	0.04	Q	.	.	.	.
20.70	0.1526	0.04	Q	.	.	.	.
20.86	0.1531	0.04	Q	.	.	.	.
21.02	0.1537	0.04	Q	.	.	.	.
21.18	0.1542	0.04	Q	.	.	.	.
21.33	0.1547	0.04	Q	.	.	.	.
21.49	0.1553	0.04	Q	.	.	.	.
21.65	0.1558	0.04	Q	.	.	.	.
21.80	0.1563	0.04	Q	.	.	.	.
21.96	0.1568	0.04	Q	.	.	.	.
22.12	0.1572	0.04	Q	.	.	.	.
22.27	0.1577	0.04	Q	.	.	.	.

22.43	0.1582	0.04 Q	.	.	.	.	
22.59	0.1586	0.04 Q	.	.	.	.	
22.74	0.1591	0.03 Q	.	.	.	.	
22.90	0.1595	0.03 Q	.	.	.	.	
23.06	0.1600	0.03 Q	.	.	.	.	
23.21	0.1604	0.03 Q	.	.	.	.	
23.37	0.1608	0.03 Q	.	.	.	.	
23.53	0.1613	0.03 Q	.	.	.	.	
23.68	0.1617	0.03 Q	.	.	.	.	
23.84	0.1621	0.03 Q	.	.	.	.	
24.00	0.1625	0.03 Q	.	.	.	.	
24.16	0.1629	0.03 Q	.	.	.	.	
24.31	0.1631	0.00 Q	.	.	.	.	

TIME DURATION(minutes) OF PERCENTILES OF ESTIMATED PEAK FLOW RATE:
(Note: 100% of Peak Flow Rate estimate assumed to have
an instantaneous time duration)

Percentile of Estimated Peak Flow Rate	Duration (minutes)
0%	1449.1
10%	178.8
20%	47.0
30%	18.8
40%	9.4
50%	9.4
60%	9.4
70%	9.4
80%	9.4
90%	9.4

DMA 1 - Parcel 2 - Preconstruction Condition

```
====================================================================
*** NON-HOMOGENEOUS WATERSHED AREA-AVERAGED LOSS RATE (Fm)
  AND LOW LOSS FRACTION ESTIMATIONS FOR AMC I:

  TOTAL 24-HOUR DURATION RAINFALL DEPTH =    2.31 (inches)

  SOIL-COVER    AREA     PERCENT OF   SCS CURVE   LOSS RATE
    TYPE     (Acres)  PERVIOUS AREA    NUMBER   Fp(in./hr.)   YIELD
      1        0.80       0.00      98.(AMC II)    0.010      0.901

  TOTAL AREA (Acres) =     0.80
                        _
  AREA-AVERAGED LOSS RATE, Fm (in./hr.) =  0.000
                            _
  AREA-AVERAGED LOW LOSS FRACTION, Y = 0.099
====================================================================

----------------------------------------------------------------------------



  RATIONAL METHOD CALIBRATION COEFFICIENT = 1.05
  TOTAL CATCHMENT AREA(ACRES) =    0.80
  SOIL-LOSS RATE, Fm,(INCH/HR) =  0.000
  LOW LOSS FRACTION = 0.099
  TIME OF CONCENTRATION(MIN.) =  6.77
  SMALL AREA PEAK Q COMPUTED USING PEAK FLOW RATE FORMULA
  USER SPECIFIED RAINFALL VALUES ARE USED
  RETURN FREQUENCY(YEARS) =   2
    5-MINUTE POINT RAINFALL VALUE(INCHES) =  0.17
   30-MINUTE POINT RAINFALL VALUE(INCHES) =  0.40
    1-HOUR   POINT RAINFALL VALUE(INCHES) =  0.56
    3-HOUR   POINT RAINFALL VALUE(INCHES) =  0.98
    6-HOUR   POINT RAINFALL VALUE(INCHES) =  1.36
   24-HOUR   POINT RAINFALL VALUE(INCHES) =  2.31

----------------------------------------------------------------------------

  TOTAL CATCHMENT   RUNOFF  VOLUME(ACRE-FEET) =     0.16
  TOTAL CATCHMENT SOIL-LOSS VOLUME(ACRE-FEET) =    -0.01

*********************************************************************
 TIME     VOLUME      Q   0.       2.5      5.0      7.5     10.0
(HOURS)    (AF)     (CFS)
----------------------------------------------------------------------------
 0.09     0.0001     0.03  Q       .       .       .       .
 0.20     0.0004     0.03  Q       .       .       .       .
```

0.32	0.0007	0.03 Q	.	.	.	.
0.43	0.0010	0.03 Q	.	.	.	.
0.54	0.0013	0.03 Q	.	.	.	.
0.65	0.0016	0.03 Q	.	.	.	.
0.77	0.0019	0.03 Q	.	.	.	.
0.88	0.0022	0.03 Q	.	.	.	.
0.99	0.0025	0.03 Q	.	.	.	.
1.11	0.0028	0.03 Q	.	.	.	.
1.22	0.0031	0.03 Q	.	.	.	.
1.33	0.0034	0.03 Q	.	.	.	.
1.44	0.0037	0.03 Q	.	.	.	.
1.56	0.0040	0.03 Q	.	.	.	.
1.67	0.0043	0.03 Q	.	.	.	.
1.78	0.0046	0.03 Q	.	.	.	.
1.90	0.0049	0.03 Q	.	.	.	.
2.01	0.0052	0.03 Q	.	.	.	.
2.12	0.0055	0.03 Q	.	.	.	.
2.23	0.0058	0.03 Q	.	.	.	.
2.35	0.0062	0.03 Q	.	.	.	.
2.46	0.0065	0.03 Q	.	.	.	.
2.57	0.0068	0.03 Q	.	.	.	.
2.69	0.0071	0.03 Q	.	.	.	.
2.80	0.0074	0.03 Q	.	.	.	.
2.91	0.0078	0.03 Q	.	.	.	.
3.02	0.0081	0.04 Q	.	.	.	.
3.14	0.0084	0.04 Q	.	.	.	.
3.25	0.0087	0.04 Q	.	.	.	.
3.36	0.0091	0.04 Q	.	.	.	.
3.48	0.0094	0.04 Q	.	.	.	.
3.59	0.0097	0.04 Q	.	.	.	.
3.70	0.0101	0.04 Q	.	.	.	.
3.81	0.0104	0.04 Q	.	.	.	.
3.93	0.0108	0.04 Q	.	.	.	.
4.04	0.0111	0.04 Q	.	.	.	.
4.15	0.0114	0.04 Q	.	.	.	.
4.27	0.0118	0.04 Q	.	.	.	.
4.38	0.0121	0.04 Q	.	.	.	.
4.49	0.0125	0.04 Q	.	.	.	.
4.60	0.0128	0.04 Q	.	.	.	.
4.72	0.0132	0.04 Q	.	.	.	.
4.83	0.0136	0.04 Q	.	.	.	.
4.94	0.0139	0.04 Q	.	.	.	.
5.06	0.0143	0.04 Q	.	.	.	.
5.17	0.0146	0.04 Q	.	.	.	.
5.28	0.0150	0.04 Q	.	.	.	.
5.39	0.0154	0.04 Q	.	.	.	.
5.51	0.0158	0.04 Q	.	.	.	.

5.62	0.0161	0.04	Q	.	.	.	.
5.73	0.0165	0.04	Q	.	.	.	.
5.85	0.0169	0.04	Q	.	.	.	.
5.96	0.0173	0.04	Q	.	.	.	.
6.07	0.0176	0.04	Q	.	.	.	.
6.18	0.0180	0.04	Q	.	.	.	.
6.30	0.0184	0.04	Q	.	.	.	.
6.41	0.0188	0.04	Q	.	.	.	.
6.52	0.0192	0.04	Q	.	.	.	.
6.63	0.0196	0.04	Q	.	.	.	.
6.75	0.0200	0.04	Q	.	.	.	.
6.86	0.0204	0.04	Q	.	.	.	.
6.97	0.0208	0.04	Q	.	.	.	.
7.09	0.0212	0.04	Q	.	.	.	.
7.20	0.0216	0.04	Q	.	.	.	.
7.31	0.0221	0.04	Q	.	.	.	.
7.42	0.0225	0.05	Q	.	.	.	.
7.54	0.0229	0.05	Q	.	.	.	.
7.65	0.0233	0.05	Q	.	.	.	.
7.76	0.0238	0.05	Q	.	.	.	.
7.88	0.0242	0.05	Q	.	.	.	.
7.99	0.0246	0.05	Q	.	.	.	.
8.10	0.0251	0.05	Q	.	.	.	.
8.21	0.0255	0.05	Q	.	.	.	.
8.33	0.0260	0.05	Q	.	.	.	.
8.44	0.0264	0.05	Q	.	.	.	.
8.55	0.0269	0.05	Q	.	.	.	.
8.67	0.0273	0.05	Q	.	.	.	.
8.78	0.0278	0.05	Q	.	.	.	.
8.89	0.0283	0.05	Q	.	.	.	.
9.00	0.0287	0.05	Q	.	.	.	.
9.12	0.0292	0.05	Q	.	.	.	.
9.23	0.0297	0.05	Q	.	.	.	.
9.34	0.0302	0.05	Q	.	.	.	.
9.46	0.0307	0.05	Q	.	.	.	.
9.57	0.0312	0.05	Q	.	.	.	.
9.68	0.0317	0.05	Q	.	.	.	.
9.79	0.0322	0.06	Q	.	.	.	.
9.91	0.0327	0.06	Q	.	.	.	.
10.02	0.0332	0.06	Q	.	.	.	.
10.13	0.0338	0.06	Q	.	.	.	.
10.25	0.0343	0.06	Q	.	.	.	.
10.36	0.0348	0.06	Q	.	.	.	.
10.47	0.0354	0.06	Q	.	.	.	.
10.58	0.0359	0.06	Q	.	.	.	.
10.70	0.0365	0.06	Q	.	.	.	.
10.81	0.0371	0.06	Q	.	.	.	.

10.92	0.0377	0.06	Q . . . .
11.04	0.0382	0.06	Q . . . .
11.15	0.0388	0.06	Q . . . .
11.26	0.0394	0.06	Q . . . .
11.37	0.0400	0.07	Q . . . .
11.49	0.0407	0.07	Q . . . .
11.60	0.0413	0.07	Q . . . .
11.71	0.0419	0.07	Q . . . .
11.83	0.0426	0.07	Q . . . .
11.94	0.0432	0.07	Q . . . .
12.05	0.0439	0.08	Q . . . .
12.16	0.0447	0.09	Q . . . .
12.28	0.0455	0.09	Q . . . .
12.39	0.0464	0.09	Q . . . .
12.50	0.0473	0.10	Q . . . .
12.62	0.0482	0.10	Q . . . .
12.73	0.0491	0.10	Q . . . .
12.84	0.0500	0.10	Q . . . .
12.95	0.0510	0.10	Q . . . .
13.07	0.0519	0.10	Q . . . .
13.18	0.0529	0.11	Q . . . .
13.29	0.0539	0.11	Q . . . .
13.40	0.0549	0.11	Q . . . .
13.52	0.0560	0.11	Q . . . .
13.63	0.0570	0.12	Q . . . .
13.74	0.0581	0.12	Q . . . .
13.86	0.0593	0.12	Q . . . .
13.97	0.0604	0.12	Q . . . .
14.08	0.0616	0.14	Q . . . .
14.19	0.0630	0.15	Q . . . .
14.31	0.0643	0.15	Q . . . .
14.42	0.0658	0.15	Q . . . .
14.53	0.0672	0.16	Q . . . .
14.65	0.0688	0.17	Q . . . .
14.76	0.0704	0.17	Q . . . .
14.87	0.0720	0.18	Q . . . .
14.98	0.0737	0.19	Q . . . .
15.10	0.0755	0.20	Q . . . .
15.21	0.0775	0.21	Q . . . .
15.32	0.0795	0.22	Q . . . .
15.44	0.0816	0.23	Q . . . .
15.55	0.0839	0.25	Q . . . .
15.66	0.0864	0.29	.Q . . . .
15.77	0.0892	0.32	.Q . . . .
15.89	0.0928	0.44	.Q . . . .
16.00	0.0975	0.57	. Q . . . .
16.11	0.1068	1.43	. Q . . . .

16.23	0.1152	0.37	.Q	.	.	.	.
16.34	0.1182	0.27	.Q	.	.	.	.
16.45	0.1205	0.23	Q	.	.	.	.
16.56	0.1226	0.21	Q	.	.	.	.
16.68	0.1244	0.18	Q	.	.	.	.
16.79	0.1260	0.17	Q	.	.	.	.
16.90	0.1276	0.16	Q	.	.	.	.
17.02	0.1290	0.15	Q	.	.	.	.
17.13	0.1303	0.13	Q	.	.	.	.
17.24	0.1314	0.12	Q	.	.	.	.
17.35	0.1325	0.11	Q	.	.	.	.
17.47	0.1336	0.11	Q	.	.	.	.
17.58	0.1346	0.11	Q	.	.	.	.
17.69	0.1355	0.10	Q	.	.	.	.
17.81	0.1365	0.10	Q	.	.	.	.
17.92	0.1374	0.09	Q	.	.	.	.
18.03	0.1382	0.09	Q	.	.	.	.
18.14	0.1390	0.07	Q	.	.	.	.
18.26	0.1397	0.07	Q	.	.	.	.
18.37	0.1403	0.07	Q	.	.	.	.
18.48	0.1409	0.07	Q	.	.	.	.
18.60	0.1415	0.06	Q	.	.	.	.
18.71	0.1421	0.06	Q	.	.	.	.
18.82	0.1427	0.06	Q	.	.	.	.
18.93	0.1432	0.06	Q	.	.	.	.
19.05	0.1438	0.06	Q	.	.	.	.
19.16	0.1443	0.06	Q	.	.	.	.
19.27	0.1448	0.05	Q	.	.	.	.
19.39	0.1453	0.05	Q	.	.	.	.
19.50	0.1458	0.05	Q	.	.	.	.
19.61	0.1463	0.05	Q	.	.	.	.
19.72	0.1468	0.05	Q	.	.	.	.
19.84	0.1472	0.05	Q	.	.	.	.
19.95	0.1477	0.05	Q	.	.	.	.
20.06	0.1481	0.05	Q	.	.	.	.
20.17	0.1486	0.05	Q	.	.	.	.
20.29	0.1490	0.05	Q	.	.	.	.
20.40	0.1494	0.05	Q	.	.	.	.
20.51	0.1499	0.04	Q	.	.	.	.
20.63	0.1503	0.04	Q	.	.	.	.
20.74	0.1507	0.04	Q	.	.	.	.
20.85	0.1511	0.04	Q	.	.	.	.
20.96	0.1515	0.04	Q	.	.	.	.
21.08	0.1519	0.04	Q	.	.	.	.
21.19	0.1522	0.04	Q	.	.	.	.
21.30	0.1526	0.04	Q	.	.	.	.
21.42	0.1530	0.04	Q	.	.	.	.

```
21.53    0.1534    0.04  Q      .      .      .      .
21.64    0.1537    0.04  Q      .      .      .      .
21.75    0.1541    0.04  Q      .      .      .      .
21.87    0.1544    0.04  Q      .      .      .      .
21.98    0.1548    0.04  Q      .      .      .      .
22.09    0.1551    0.04  Q      .      .      .      .
22.21    0.1555    0.04  Q      .      .      .      .
22.32    0.1558    0.04  Q      .      .      .      .
22.43    0.1562    0.04  Q      .      .      .      .
22.54    0.1565    0.04  Q      .      .      .      .
22.66    0.1568    0.03  Q      .      .      .      .
22.77    0.1571    0.03  Q      .      .      .      .
22.88    0.1575    0.03  Q      .      .      .      .
23.00    0.1578    0.03  Q      .      .      .      .
23.11    0.1581    0.03  Q      .      .      .      .
23.22    0.1584    0.03  Q      .      .      .      .
23.33    0.1587    0.03  Q      .      .      .      .
23.45    0.1590    0.03  Q      .      .      .      .
23.56    0.1593    0.03  Q      .      .      .      .
23.67    0.1596    0.03  Q      .      .      .      .
23.79    0.1599    0.03  Q      .      .      .      .
23.90    0.1602    0.03  Q      .      .      .      .
24.01    0.1605    0.03  Q      .      .      .      .
24.12    0.1606    0.00  Q      .      .      .      .
-----------------------------------------------------------------------------
--------------------------------------------------------------------------------
```

TIME DURATION(minutes) OF PERCENTILES OF ESTIMATED PEAK FLOW RA
(Note: 100% of Peak Flow Rate estimate assumed to have
an instantaneous time duration)

Percentile of Estimated Peak Flow Rate	Duration (minutes)
0%	1442.0
10%	176.0
20%	40.6
30%	20.3
40%	6.8
50%	6.8
60%	6.8
70%	6.8
80%	6.8
90%	6.8

DMA 2 - Parcel 2 - Preconstruction Condition

```
=======================================================================
*** NON-HOMOGENEOUS WATERSHED AREA-AVERAGED LOSS RATE (Fm)
  AND LOW LOSS FRACTION ESTIMATIONS FOR AMC I:

  TOTAL 24-HOUR DURATION RAINFALL DEPTH =    2.31 (inches)

  SOIL-COVER    AREA     PERCENT OF   SCS CURVE   LOSS RATE
    TYPE     (Acres)  PERVIOUS AREA    NUMBER   Fp(in./hr.)   YIELD
     1        0.81      10.00      98.(AMC II)   0.300      0.888

  TOTAL AREA (Acres) =     0.81
                      _
  AREA-AVERAGED LOSS RATE, Fm (in./hr.) =  0.030
                          _
  AREA-AVERAGED LOW LOSS FRACTION, Y = 0.112
=======================================================================

------------------------------------------------------------------------------


  RATIONAL METHOD CALIBRATION COEFFICIENT = 1.17
  TOTAL CATCHMENT AREA(ACRES) =    0.81
  SOIL-LOSS RATE, Fm,(INCH/HR) =  0.030
  LOW LOSS FRACTION = 0.112
  TIME OF CONCENTRATION(MIN.) =  9.41
  SMALL AREA PEAK Q COMPUTED USING PEAK FLOW RATE FORMULA
  USER SPECIFIED RAINFALL VALUES ARE USED
  RETURN FREQUENCY(YEARS) =   2
    5-MINUTE POINT RAINFALL VALUE(INCHES) =  0.17
   30-MINUTE POINT RAINFALL VALUE(INCHES) =  0.40
    1-HOUR   POINT RAINFALL VALUE(INCHES) =  0.56
    3-HOUR   POINT RAINFALL VALUE(INCHES) =  0.98
    6-HOUR   POINT RAINFALL VALUE(INCHES) =  1.36
   24-HOUR   POINT RAINFALL VALUE(INCHES) =  2.31

------------------------------------------------------------------------------

  TOTAL CATCHMENT   RUNOFF  VOLUME(ACRE-FEET) =     0.16
  TOTAL CATCHMENT SOIL-LOSS VOLUME(ACRE-FEET) =    -0.01

************************************************************************
 TIME     VOLUME       Q    0.       2.5      5.0      7.5      10.0
(HOURS)    (AF)     (CFS)
------------------------------------------------------------------------------
 0.00     0.0000     0.00  Q        .        .        .        .
 0.16     0.0002     0.03  Q        .        .        .        .
```

0.32	0.0006	0.03	Q	.	.	.	.
0.47	0.0010	0.03	Q	.	.	.	.
0.63	0.0014	0.03	Q	.	.	.	.
0.79	0.0018	0.03	Q	.	.	.	.
0.94	0.0022	0.03	Q	.	.	.	.
1.10	0.0026	0.03	Q	.	.	.	.
1.26	0.0031	0.03	Q	.	.	.	.
1.41	0.0035	0.03	Q	.	.	.	.
1.57	0.0039	0.03	Q	.	.	.	.
1.73	0.0043	0.03	Q	.	.	.	.
1.89	0.0048	0.03	Q	.	.	.	.
2.04	0.0052	0.03	Q	.	.	.	.
2.20	0.0056	0.03	Q	.	.	.	.
2.36	0.0061	0.03	Q	.	.	.	.
2.51	0.0065	0.03	Q	.	.	.	.
2.67	0.0069	0.03	Q	.	.	.	.
2.83	0.0074	0.03	Q	.	.	.	.
2.98	0.0078	0.03	Q	.	.	.	.
3.14	0.0083	0.04	Q	.	.	.	.
3.30	0.0088	0.04	Q	.	.	.	.
3.45	0.0092	0.04	Q	.	.	.	.
3.61	0.0097	0.04	Q	.	.	.	.
3.77	0.0101	0.04	Q	.	.	.	.
3.92	0.0106	0.04	Q	.	.	.	.
4.08	0.0111	0.04	Q	.	.	.	.
4.24	0.0116	0.04	Q	.	.	.	.
4.39	0.0121	0.04	Q	.	.	.	.
4.55	0.0125	0.04	Q	.	.	.	.
4.71	0.0130	0.04	Q	.	.	.	.
4.86	0.0135	0.04	Q	.	.	.	.
5.02	0.0140	0.04	Q	.	.	.	.
5.18	0.0145	0.04	Q	.	.	.	.
5.34	0.0150	0.04	Q	.	.	.	.
5.49	0.0155	0.04	Q	.	.	.	.
5.65	0.0161	0.04	Q	.	.	.	.
5.81	0.0166	0.04	Q	.	.	.	.
5.96	0.0171	0.04	Q	.	.	.	.
6.12	0.0176	0.04	Q	.	.	.	.
6.28	0.0182	0.04	Q	.	.	.	.
6.43	0.0187	0.04	Q	.	.	.	.
6.59	0.0193	0.04	Q	.	.	.	.
6.75	0.0198	0.04	Q	.	.	.	.
6.90	0.0204	0.04	Q	.	.	.	.
7.06	0.0210	0.04	Q	.	.	.	.
7.22	0.0215	0.04	Q	.	.	.	.
7.37	0.0221	0.04	Q	.	.	.	.
7.53	0.0227	0.05	Q	.	.	.	.

7.69	0.0233	0.05	Q	.	.	.	.
7.84	0.0239	0.05	Q	.	.	.	.
8.00	0.0245	0.05	Q	.	.	.	.
8.16	0.0251	0.05	Q	.	.	.	.
8.32	0.0257	0.05	Q	.	.	.	.
8.47	0.0263	0.05	Q	.	.	.	.
8.63	0.0270	0.05	Q	.	.	.	.
8.79	0.0276	0.05	Q	.	.	.	.
8.94	0.0283	0.05	Q	.	.	.	.
9.10	0.0289	0.05	Q	.	.	.	.
9.26	0.0296	0.05	Q	.	.	.	.
9.41	0.0303	0.05	Q	.	.	.	.
9.57	0.0310	0.05	Q	.	.	.	.
9.73	0.0317	0.05	Q	.	.	.	.
9.88	0.0324	0.06	Q	.	.	.	.
10.04	0.0331	0.06	Q	.	.	.	.
10.20	0.0338	0.06	Q	.	.	.	.
10.35	0.0346	0.06	Q	.	.	.	.
10.51	0.0353	0.06	Q	.	.	.	.
10.67	0.0361	0.06	Q	.	.	.	.
10.82	0.0369	0.06	Q	.	.	.	.
10.98	0.0377	0.06	Q	.	.	.	.
11.14	0.0385	0.06	Q	.	.	.	.
11.30	0.0393	0.06	Q	.	.	.	.
11.45	0.0402	0.07	Q	.	.	.	.
11.61	0.0410	0.07	Q	.	.	.	.
11.77	0.0419	0.07	Q	.	.	.	.
11.92	0.0428	0.07	Q	.	.	.	.
12.08	0.0438	0.08	Q	.	.	.	.
12.24	0.0449	0.09	Q	.	.	.	.
12.39	0.0460	0.09	Q	.	.	.	.
12.55	0.0473	0.09	Q	.	.	.	.
12.71	0.0485	0.10	Q	.	.	.	.
12.86	0.0498	0.10	Q	.	.	.	.
13.02	0.0511	0.10	Q	.	.	.	.
13.18	0.0524	0.10	Q	.	.	.	.
13.33	0.0538	0.11	Q	.	.	.	.
13.49	0.0553	0.11	Q	.	.	.	.
13.65	0.0567	0.12	Q	.	.	.	.
13.80	0.0582	0.12	Q	.	.	.	.
13.96	0.0598	0.12	Q	.	.	.	.
14.12	0.0615	0.13	Q	.	.	.	.
14.27	0.0633	0.15	Q	.	.	.	.
14.43	0.0652	0.15	Q	.	.	.	.
14.59	0.0673	0.16	Q	.	.	.	.
14.75	0.0694	0.17	Q	.	.	.	.
14.90	0.0717	0.18	Q	.	.	.	.

15.06	0.0741	0.19	Q	.	.	.	.
15.22	0.0767	0.21	Q	.	.	.	.
15.37	0.0795	0.22	Q	.	.	.	.
15.53	0.0825	0.25	Q	.	.	.	.
15.69	0.0860	0.28	.Q	.	.	.	.
15.84	0.0902	0.39	.Q	.	.	.	.
16.00	0.0961	0.52	. Q	.	.	.	.
16.16	0.1080	1.33	. Q	.	.	.	.
16.31	0.1187	0.32	.Q	.	.	.	.
16.47	0.1223	0.24	Q	.	.	.	.
16.63	0.1252	0.20	Q	.	.	.	.
16.78	0.1276	0.17	Q	.	.	.	.
16.94	0.1297	0.16	Q	.	.	.	.
17.10	0.1317	0.14	Q	.	.	.	.
17.25	0.1334	0.12	Q	.	.	.	.
17.41	0.1349	0.11	Q	.	.	.	.
17.57	0.1364	0.11	Q	.	.	.	.
17.73	0.1377	0.10	Q	.	.	.	.
17.88	0.1390	0.10	Q	.	.	.	.
18.04	0.1402	0.09	Q	.	.	.	.
18.20	0.1413	0.07	Q	.	.	.	.
18.35	0.1422	0.07	Q	.	.	.	.
18.51	0.1430	0.07	Q	.	.	.	.
18.67	0.1439	0.06	Q	.	.	.	.
18.82	0.1447	0.06	Q	.	.	.	.
18.98	0.1454	0.06	Q	.	.	.	.
19.14	0.1462	0.06	Q	.	.	.	.
19.29	0.1469	0.05	Q	.	.	.	.
19.45	0.1476	0.05	Q	.	.	.	.
19.61	0.1483	0.05	Q	.	.	.	.
19.76	0.1489	0.05	Q	.	.	.	.
19.92	0.1496	0.05	Q	.	.	.	.
20.08	0.1502	0.05	Q	.	.	.	.
20.23	0.1508	0.05	Q	.	.	.	.
20.39	0.1514	0.05	Q	.	.	.	.
20.55	0.1520	0.04	Q	.	.	.	.
20.70	0.1526	0.04	Q	.	.	.	.
20.86	0.1531	0.04	Q	.	.	.	.
21.02	0.1537	0.04	Q	.	.	.	.
21.18	0.1542	0.04	Q	.	.	.	.
21.33	0.1547	0.04	Q	.	.	.	.
21.49	0.1553	0.04	Q	.	.	.	.
21.65	0.1558	0.04	Q	.	.	.	.
21.80	0.1563	0.04	Q	.	.	.	.
21.96	0.1568	0.04	Q	.	.	.	.
22.12	0.1572	0.04	Q	.	.	.	.
22.27	0.1577	0.04	Q	.	.	.	.

```
22.43    0.1582    0.04  Q      .      .      .      .
22.59    0.1586    0.04  Q      .      .      .      .
22.74    0.1591    0.03  Q      .      .      .      .
22.90    0.1595    0.03  Q      .      .      .      .
23.06    0.1600    0.03  Q      .      .      .      .
23.21    0.1604    0.03  Q      .      .      .      .
23.37    0.1608    0.03  Q      .      .      .      .
23.53    0.1613    0.03  Q      .      .      .      .
23.68    0.1617    0.03  Q      .      .      .      .
23.84    0.1621    0.03  Q      .      .      .      .
24.00    0.1625    0.03  Q      .      .      .      .
24.16    0.1629    0.03  Q      .      .      .      .
24.31    0.1631    0.00  Q      .      .      .      .
-----------------------------------------------------------------------
-----------------------------------------------------------------------
```

TIME DURATION(minutes) OF PERCENTILES OF ESTIMATED PEAK FLOW RA
(Note: 100% of Peak Flow Rate estimate assumed to have
an instantaneous time duration)

Percentile of Estimated Peak Flow Rate	Duration (minutes)
======================	=========
0%	1449.1
10%	178.8
20%	47.0
30%	18.8
40%	9.4
50%	9.4
60%	9.4
70%	9.4
80%	9.4
90%	9.4

DMA 1 - Parcel 1&2 - Postconstruction Condition

```
==========================================================================
*** NON-HOMOGENEOUS WATERSHED AREA-AVERAGED LOSS RATE (Fm)
   AND LOW LOSS FRACTION ESTIMATIONS FOR AMC I:

   TOTAL 24-HOUR DURATION RAINFALL DEPTH =     2.31 (inches)

   SOIL-COVER     AREA      PERCENT OF    SCS CURVE    LOSS RATE
     TYPE      (Acres)   PERVIOUS AREA     NUMBER    Fp(in./hr.)    YIELD
      1         0.89        0.00       98.(AMC II)    0.010       0.901
      2         1.66      100.00       86.(AMC II)    0.300       0.187

   TOTAL AREA (Acres) =      2.55
                      _
   AREA-AVERAGED LOSS RATE, Fm (in./hr.) =  0.195
                          _
   AREA-AVERAGED LOW LOSS FRACTION, Y = 0.563
==========================================================================

----------------------------------------------------------------------------



   RATIONAL METHOD CALIBRATION COEFFICIENT = 0.96
   TOTAL CATCHMENT AREA(ACRES) =    2.50
   SOIL-LOSS RATE, Fm,(INCH/HR) =  0.195
   LOW LOSS FRACTION = 0.563
   TIME OF CONCENTRATION(MIN.) = 11.68
   SMALL AREA PEAK Q COMPUTED USING PEAK FLOW RATE FORMULA
   USER SPECIFIED RAINFALL VALUES ARE USED
   RETURN FREQUENCY(YEARS) =   2
     5-MINUTE POINT RAINFALL VALUE(INCHES) =  0.17
    30-MINUTE POINT RAINFALL VALUE(INCHES) =  0.40
     1-HOUR   POINT RAINFALL VALUE(INCHES) =  0.56
     3-HOUR   POINT RAINFALL VALUE(INCHES) =  0.98
     6-HOUR   POINT RAINFALL VALUE(INCHES) =  1.36
    24-HOUR   POINT RAINFALL VALUE(INCHES) =  2.31

----------------------------------------------------------------------------

   TOTAL CATCHMENT   RUNOFF  VOLUME(ACRE-FEET) =     0.23
   TOTAL CATCHMENT SOIL-LOSS VOLUME(ACRE-FEET) =     0.26

**************************************************************************
  TIME     VOLUME       Q    0.        2.5       5.0       7.5      10.0
 (HOURS)    (AF)      (CFS)
----------------------------------------------------------------------------
```

0.04	0.0000	0.00	Q	.	.	.	.
0.23	0.0003	0.04	Q	.	.	.	.
0.43	0.0009	0.04	Q	.	.	.	.
0.62	0.0016	0.04	Q	.	.	.	.
0.82	0.0022	0.04	Q	.	.	.	.
1.01	0.0028	0.04	Q	.	.	.	.
1.21	0.0035	0.04	Q	.	.	.	.
1.40	0.0041	0.04	Q	.	.	.	.
1.59	0.0048	0.04	Q	.	.	.	.
1.79	0.0054	0.04	Q	.	.	.	.
1.98	0.0061	0.04	Q	.	.	.	.
2.18	0.0068	0.04	Q	.	.	.	.
2.37	0.0075	0.04	Q	.	.	.	.
2.57	0.0081	0.04	Q	.	.	.	.
2.76	0.0088	0.04	Q	.	.	.	.
2.96	0.0095	0.04	Q	.	.	.	.
3.15	0.0102	0.04	Q	.	.	.	.
3.35	0.0109	0.04	Q	.	.	.	.
3.54	0.0117	0.04	Q	.	.	.	.
3.74	0.0124	0.05	Q	.	.	.	.
3.93	0.0131	0.05	Q	.	.	.	.
4.13	0.0138	0.05	Q	.	.	.	.
4.32	0.0146	0.05	Q	.	.	.	.
4.51	0.0153	0.05	Q	.	.	.	.
4.71	0.0161	0.05	Q	.	.	.	.
4.90	0.0169	0.05	Q	.	.	.	.
5.10	0.0176	0.05	Q	.	.	.	.
5.29	0.0184	0.05	Q	.	.	.	.
5.49	0.0192	0.05	Q	.	.	.	.
5.68	0.0200	0.05	Q	.	.	.	.
5.88	0.0208	0.05	Q	.	.	.	.
6.07	0.0216	0.05	Q	.	.	.	.
6.27	0.0225	0.05	Q	.	.	.	.
6.46	0.0233	0.05	Q	.	.	.	.
6.66	0.0242	0.05	Q	.	.	.	.
6.85	0.0250	0.05	Q	.	.	.	.
7.05	0.0259	0.05	Q	.	.	.	.
7.24	0.0268	0.06	Q	.	.	.	.
7.43	0.0277	0.06	Q	.	.	.	.
7.63	0.0286	0.06	Q	.	.	.	.
7.82	0.0295	0.06	Q	.	.	.	.
8.02	0.0304	0.06	Q	.	.	.	.
8.21	0.0314	0.06	Q	.	.	.	.
8.41	0.0324	0.06	Q	.	.	.	.
8.60	0.0333	0.06	Q	.	.	.	.
8.80	0.0343	0.06	Q	.	.	.	.
8.99	0.0353	0.06	Q	.	.	.	.

9.19	0.0364	0.06	Q	.	.	.	.
9.38	0.0374	0.07	Q	.	.	.	.
9.58	0.0385	0.07	Q	.	.	.	.
9.77	0.0396	0.07	Q	.	.	.	.
9.97	0.0407	0.07	Q	.	.	.	.
10.16	0.0418	0.07	Q	.	.	.	.
10.35	0.0429	0.07	Q	.	.	.	.
10.55	0.0441	0.07	Q	.	.	.	.
10.74	0.0453	0.08	Q	.	.	.	.
10.94	0.0465	0.08	Q	.	.	.	.
11.13	0.0478	0.08	Q	.	.	.	.
11.33	0.0491	0.08	Q	.	.	.	.
11.52	0.0504	0.08	Q	.	.	.	.
11.72	0.0517	0.08	Q	.	.	.	.
11.91	0.0531	0.09	Q	.	.	.	.
12.11	0.0546	0.09	Q	.	.	.	.
12.30	0.0562	0.11	Q	.	.	.	.
12.50	0.0581	0.12	Q	.	.	.	.
12.69	0.0600	0.12	Q	.	.	.	.
12.89	0.0619	0.12	Q	.	.	.	.
13.08	0.0640	0.13	Q	.	.	.	.
13.27	0.0661	0.13	Q	.	.	.	.
13.47	0.0683	0.14	Q	.	.	.	.
13.66	0.0705	0.14	Q	.	.	.	.
13.86	0.0729	0.15	Q	.	.	.	.
14.05	0.0754	0.16	Q	.	.	.	.
14.25	0.0781	0.18	Q	.	.	.	.
14.44	0.0811	0.19	Q	.	.	.	.
14.64	0.0843	0.20	Q	.	.	.	.
14.83	0.0876	0.21	Q	.	.	.	.
15.03	0.0913	0.24	Q	.	.	.	.
15.22	0.0952	0.25	.Q	.	.	.	.
15.42	0.0995	0.29	.Q	.	.	.	.
15.61	0.1043	0.30	.Q	.	.	.	.
15.81	0.1106	0.47	.Q	.	.	.	.
16.00	0.1205	0.77	. Q	.	.	.	.
16.19	0.1478	2.62	.	Q	.	.	.
16.39	0.1716	0.35	.Q	.	.	.	.
16.58	0.1766	0.27	.Q	.	.	.	.
16.78	0.1806	0.22	Q	.	.	.	.
16.97	0.1840	0.20	Q	.	.	.	.
17.17	0.1869	0.17	Q	.	.	.	.
17.36	0.1894	0.15	Q	.	.	.	.
17.56	0.1917	0.14	Q	.	.	.	.
17.75	0.1938	0.13	Q	.	.	.	.
17.95	0.1958	0.12	Q	.	.	.	.
18.14	0.1976	0.11	Q	.	.	.	.

18.34	0.1992	0.09	Q	.	.	.	.
18.53	0.2005	0.08	Q	.	.	.	.
18.73	0.2018	0.08	Q	.	.	.	.
18.92	0.2030	0.07	Q	.	.	.	.
19.11	0.2042	0.07	Q	.	.	.	.
19.31	0.2053	0.07	Q	.	.	.	.
19.50	0.2064	0.07	Q	.	.	.	.
19.70	0.2075	0.06	Q	.	.	.	.
19.89	0.2085	0.06	Q	.	.	.	.
20.09	0.2095	0.06	Q	.	.	.	.
20.28	0.2104	0.06	Q	.	.	.	.
20.48	0.2113	0.06	Q	.	.	.	.
20.67	0.2122	0.05	Q	.	.	.	.
20.87	0.2131	0.05	Q	.	.	.	.
21.06	0.2139	0.05	Q	.	.	.	.
21.26	0.2148	0.05	Q	.	.	.	.
21.45	0.2156	0.05	Q	.	.	.	.
21.65	0.2164	0.05	Q	.	.	.	.
21.84	0.2172	0.05	Q	.	.	.	.
22.03	0.2179	0.05	Q	.	.	.	.
22.23	0.2187	0.05	Q	.	.	.	.
22.42	0.2194	0.04	Q	.	.	.	.
22.62	0.2201	0.04	Q	.	.	.	.
22.81	0.2208	0.04	Q	.	.	.	.
23.01	0.2215	0.04	Q	.	.	.	.
23.20	0.2222	0.04	Q	.	.	.	.
23.40	0.2228	0.04	Q	.	.	.	.
23.59	0.2235	0.04	Q	.	.	.	.
23.79	0.2241	0.04	Q	.	.	.	.
23.98	0.2248	0.04	Q	.	.	.	.
24.18	0.2254	0.04	Q	.	.	.	.
24.37	0.2257	0.00	Q	.	.	.	.

TIME DURATION(minutes) OF PERCENTILES OF ESTIMATED PEAK FLOW RATE:
(Note: 100% of Peak Flow Rate estimate assumed to have
an instantaneous time duration)

Percentile of Estimated Peak Flow Rate	Duration (minutes)
0%	1448.3
10%	81.8
20%	23.4
30%	11.7
40%	11.7
50%	11.7

60%	11.7
70%	11.7
80%	11.7
90%	11.7

DMA 1 - Parcel 1&2 - Postconstruction Condition Routed

==

FLOW-THROUGH DETENTION BASIN MODEL

SPECIFIED BASIN CONDITIONS ARE AS FOLLOWS:
CONSTANT HYDROGRAPH TIME UNIT(MINUTES) = 11.680
DEAD STORAGE(AF) = 0.08
SPECIFIED DEAD STORAGE(AF) FILLED = 0.00
ASSUMED INITIAL DEPTH(FEET) IN STORAGE BASIN = 0.00

```
         INFLOW
           |
           |
           |
           V          __effective depth
      -------------     |  (and volume)
      |          |   |    |
      | detention |    |....V.............
      |  basin   |<-->|       outflow
      |          |    |.........__________
      -------------   |        |  \
           |        | storage |    basin outlet
           V        -----------
        OUTFLOW
```

DEPTH-VS.-STORAGE AND DEPTH-VS.-DISCHARGE INFORMATION:
TOTAL NUMBER OF BASIN DEPTH INFORMATION ENTRIES = 7

*BASIN-DEPTH (FEET)	STORAGE (ACRE-FEET)	OUTFLOW (CFS) **	**BASIN-DEPTH (FEET)	STORAGE (ACRE-FEET)	OUTFL (CFS) *
* 0.000	0.000	0.000**	1.000	0.080	1.700*
* 2.000	0.190	2.100**	2.500	0.260	2.200*
* 3.000	0.320	2.250**	3.010	0.330	2.250*
* 3.020	0.330	2.250**			

BASIN STORAGE, OUTFLOW AND DEPTH ROUTING VALUES:

INTERVAL NUMBER	DEPTH (FEET)	{S-O*DT/2} (ACRE-FEET)	{S+O*DT/2} (ACRE-FEET)
1	0.00	0.00000	0.00000
2	1.00	0.06633	0.09367
3	2.00	0.17311	0.20689
4	2.50	0.24230	0.27770
5	3.00	0.30190	0.33810
6	3.01	0.31190	0.34810
7	3.02	0.31190	0.34810

WHERE S=STORAGE(AF);O=OUTFLOW(AF/MIN.);DT=UNIT INTERVAL(MIN.)

DETENTION BASIN ROUTING RESULTS:

NOTE: COMPUTED BASIN DEPTH, OUTFLOW, AND STORAGE QUANTITIES OCCUR AT THE GIVEN TIME. BASIN INFLOW VALUES REPRESENT THE AVERAGE INFLOW DURING THE RECENT HYDROGRAPH UNIT INTERVAL

TIME (HRS)	DEAD-STORAGE FILLED(AF)	INFLOW (CFS)	EFFECTIVE DEPTH(FT)	OUTFLOW (CFS)	EFFECTIVE VOLUME(AF)
0.037	0.000	0.00	0.00	0.00	0.000
0.232	0.001	0.04	0.00	0.00	0.000
0.427	0.001	0.04	0.00	0.00	0.000
0.621	0.002	0.04	0.00	0.00	0.000
0.816	0.003	0.04	0.00	0.00	0.000
1.011	0.003	0.04	0.00	0.00	0.000
1.205	0.004	0.04	0.00	0.00	0.000
1.400	0.004	0.04	0.00	0.00	0.000
1.595	0.005	0.04	0.00	0.00	0.000
1.789	0.006	0.04	0.00	0.00	0.000
1.984	0.006	0.04	0.00	0.00	0.000
2.179	0.007	0.04	0.00	0.00	0.000
2.373	0.008	0.04	0.00	0.00	0.000
2.568	0.008	0.04	0.00	0.00	0.000
2.763	0.009	0.04	0.00	0.00	0.000
2.957	0.010	0.04	0.00	0.00	0.000
3.152	0.011	0.04	0.00	0.00	0.000
3.347	0.011	0.04	0.00	0.00	0.000
3.541	0.012	0.04	0.00	0.00	0.000
3.736	0.013	0.05	0.00	0.00	0.000
3.931	0.013	0.05	0.00	0.00	0.000
4.125	0.014	0.05	0.00	0.00	0.000
4.320	0.015	0.05	0.00	0.00	0.000
4.515	0.016	0.05	0.00	0.00	0.000
4.709	0.016	0.05	0.00	0.00	0.000
4.904	0.017	0.05	0.00	0.00	0.000
5.099	0.018	0.05	0.00	0.00	0.000
5.293	0.019	0.05	0.00	0.00	0.000
5.488	0.020	0.05	0.00	0.00	0.000
5.683	0.020	0.05	0.00	0.00	0.000
5.877	0.021	0.05	0.00	0.00	0.000
6.072	0.022	0.05	0.00	0.00	0.000
6.267	0.023	0.05	0.00	0.00	0.000
6.461	0.024	0.05	0.00	0.00	0.000
6.656	0.025	0.05	0.00	0.00	0.000
6.851	0.025	0.05	0.00	0.00	0.000
7.045	0.026	0.05	0.00	0.00	0.000
7.240	0.027	0.06	0.00	0.00	0.000

7.435	0.028	0.06	0.00	0.00	0.000
7.629	0.029	0.06	0.00	0.00	0.000
7.824	0.030	0.06	0.00	0.00	0.000
8.019	0.031	0.06	0.00	0.00	0.000
8.213	0.032	0.06	0.00	0.00	0.000
8.408	0.033	0.06	0.00	0.00	0.000
8.603	0.034	0.06	0.00	0.00	0.000
8.797	0.035	0.06	0.00	0.00	0.000
8.992	0.036	0.06	0.00	0.00	0.000
9.187	0.037	0.06	0.00	0.00	0.000
9.381	0.038	0.07	0.00	0.00	0.000
9.576	0.039	0.07	0.00	0.00	0.000
9.771	0.040	0.07	0.00	0.00	0.000
9.965	0.041	0.07	0.00	0.00	0.000
10.160	0.042	0.07	0.00	0.00	0.000
10.355	0.044	0.07	0.00	0.00	0.000
10.549	0.045	0.07	0.00	0.00	0.000
10.744	0.046	0.08	0.00	0.00	0.000
10.939	0.047	0.08	0.00	0.00	0.000
11.133	0.048	0.08	0.00	0.00	0.000
11.328	0.050	0.08	0.00	0.00	0.000
11.523	0.051	0.08	0.00	0.00	0.000
11.717	0.052	0.08	0.00	0.00	0.000
11.912	0.054	0.09	0.00	0.00	0.000
12.107	0.055	0.09	0.00	0.00	0.000
12.301	0.057	0.11	0.00	0.00	0.000
12.496	0.059	0.12	0.00	0.00	0.000
12.691	0.061	0.12	0.00	0.00	0.000
12.885	0.063	0.12	0.00	0.00	0.000
13.080	0.065	0.13	0.00	0.00	0.000
13.275	0.067	0.13	0.00	0.00	0.000
13.469	0.069	0.14	0.00	0.00	0.000
13.664	0.072	0.14	0.00	0.00	0.000
13.859	0.074	0.15	0.00	0.00	0.000

DEAD STORAGE FILLED WITH UNIT INFLOW(CFS) = 0.06

REMAINING UNIT FLOW IS 0.10 CFS.

14.053	0.075	0.10	0.02	0.01	0.001
14.248	0.075	0.18	0.04	0.05	0.003
14.443	0.075	0.19	0.06	0.09	0.005
14.637	0.075	0.20	0.08	0.12	0.006
14.832	0.075	0.21	0.09	0.15	0.007
15.027	0.075	0.24	0.11	0.17	0.009
15.221	0.075	0.25	0.12	0.19	0.010
15.416	0.075	0.29	0.13	0.21	0.011
15.611	0.075	0.30	0.15	0.24	0.012
15.805	0.075	0.47	0.19	0.28	0.015
16.000	0.075	0.77	0.26	0.38	0.021

16.195	0.075	2.62	0.64	0.76	0.051
16.389	0.075	0.35	0.51	0.97	0.041
16.584	0.075	0.27	0.41	0.78	0.033
16.779	0.075	0.22	0.33	0.62	0.026
16.973	0.075	0.20	0.27	0.50	0.021
17.168	0.075	0.17	0.22	0.41	0.017
17.363	0.075	0.15	0.18	0.34	0.014
17.557	0.075	0.14	0.15	0.28	0.012
17.752	0.075	0.13	0.13	0.24	0.010
17.947	0.075	0.12	0.11	0.20	0.009
18.141	0.075	0.11	0.10	0.18	0.008
18.336	0.075	0.09	0.08	0.15	0.007
18.531	0.075	0.08	0.07	0.13	0.006
18.725	0.075	0.08	0.07	0.12	0.005
18.920	0.075	0.07	0.06	0.11	0.005
19.115	0.075	0.07	0.05	0.10	0.004
19.309	0.075	0.07	0.05	0.09	0.004
19.504	0.075	0.07	0.05	0.08	0.004
19.699	0.075	0.06	0.04	0.08	0.004
19.893	0.075	0.06	0.04	0.07	0.003
20.088	0.075	0.06	0.04	0.07	0.003
20.283	0.075	0.06	0.04	0.07	0.003
20.477	0.075	0.06	0.04	0.06	0.003
20.672	0.075	0.05	0.04	0.06	0.003
20.867	0.075	0.05	0.03	0.06	0.003
21.061	0.075	0.05	0.03	0.06	0.003
21.256	0.075	0.05	0.03	0.06	0.003
21.451	0.075	0.05	0.03	0.05	0.003
21.645	0.075	0.05	0.03	0.05	0.002
21.840	0.075	0.05	0.03	0.05	0.002
22.035	0.075	0.05	0.03	0.05	0.002
22.229	0.075	0.05	0.03	0.05	0.002
22.424	0.075	0.04	0.03	0.05	0.002
22.619	0.075	0.04	0.03	0.05	0.002
22.813	0.075	0.04	0.03	0.05	0.002
23.008	0.075	0.04	0.03	0.05	0.002
23.203	0.075	0.04	0.03	0.04	0.002
23.397	0.075	0.04	0.03	0.04	0.002
23.592	0.075	0.04	0.02	0.04	0.002
23.787	0.075	0.04	0.02	0.04	0.002
23.981	0.075	0.04	0.02	0.04	0.002
24.176	0.075	0.04	0.02	0.04	0.002
24.371	0.075	0.00	0.02	0.03	0.001

DMA 2 - Parcel 2 - Postconstruction Condition

```
==========================================================================
*** NON-HOMOGENEOUS WATERSHED AREA-AVERAGED LOSS RATE (Fm)
   AND LOW LOSS FRACTION ESTIMATIONS FOR AMC I:

   TOTAL 24-HOUR DURATION RAINFALL DEPTH =     2.31 (inches)

   SOIL-COVER     AREA      PERCENT OF    SCS CURVE    LOSS RATE
     TYPE      (Acres)   PERVIOUS AREA     NUMBER    Fp(in./hr.)    YIELD
       1         0.14        0.00       98.(AMC II)    0.010      0.901
       2         0.67      100.00       86.(AMC II)    0.300      0.187

   TOTAL AREA (Acres) =     0.81
                        _
   AREA-AVERAGED LOSS RATE, Fm (in./hr.) =  0.248
                            _
   AREA-AVERAGED LOW LOSS FRACTION, Y = 0.689
==========================================================================

--------------------------------------------------------------------------


   RATIONAL METHOD CALIBRATION COEFFICIENT = 1.00
   TOTAL CATCHMENT AREA(ACRES) =    0.81
   SOIL-LOSS RATE, Fm,(INCH/HR) =  0.248
   LOW LOSS FRACTION = 0.689
   TIME OF CONCENTRATION(MIN.) =  9.56
   SMALL AREA PEAK Q COMPUTED USING PEAK FLOW RATE FORMULA
   USER SPECIFIED RAINFALL VALUES ARE USED
   RETURN FREQUENCY(YEARS) =   2
     5-MINUTE POINT RAINFALL VALUE(INCHES) =  0.17
    30-MINUTE POINT RAINFALL VALUE(INCHES) =  0.40
     1-HOUR   POINT RAINFALL VALUE(INCHES) =  0.56
     3-HOUR   POINT RAINFALL VALUE(INCHES) =  0.98
     6-HOUR   POINT RAINFALL VALUE(INCHES) =  1.36
    24-HOUR   POINT RAINFALL VALUE(INCHES) =  2.31

--------------------------------------------------------------------------

   TOTAL CATCHMENT   RUNOFF  VOLUME(ACRE-FEET) =     0.06
   TOTAL CATCHMENT SOIL-LOSS VOLUME(ACRE-FEET) =     0.10

**************************************************************************
  TIME     VOLUME      Q   0.       2.5      5.0      7.5      10.0
 (HOURS)    (AF)     (CFS)
--------------------------------------------------------------------------
```

0.07	0.0000	0.00	Q	.	.	.	.
0.23	0.0001	0.01	Q	.	.	.	.
0.39	0.0002	0.01	Q	.	.	.	.
0.54	0.0003	0.01	Q	.	.	.	.
0.70	0.0004	0.01	Q	.	.	.	.
0.86	0.0006	0.01	Q	.	.	.	.
1.02	0.0007	0.01	Q	.	.	.	.
1.18	0.0008	0.01	Q	.	.	.	.
1.34	0.0009	0.01	Q	.	.	.	.
1.50	0.0011	0.01	Q	.	.	.	.
1.66	0.0012	0.01	Q	.	.	.	.
1.82	0.0013	0.01	Q	.	.	.	.
1.98	0.0015	0.01	Q	.	.	.	.
2.14	0.0016	0.01	Q	.	.	.	.
2.30	0.0017	0.01	Q	.	.	.	.
2.46	0.0019	0.01	Q	.	.	.	.
2.62	0.0020	0.01	Q	.	.	.	.
2.78	0.0021	0.01	Q	.	.	.	.
2.93	0.0023	0.01	Q	.	.	.	.
3.09	0.0024	0.01	Q	.	.	.	.
3.25	0.0025	0.01	Q	.	.	.	.
3.41	0.0027	0.01	Q	.	.	.	.
3.57	0.0028	0.01	Q	.	.	.	.
3.73	0.0030	0.01	Q	.	.	.	.
3.89	0.0031	0.01	Q	.	.	.	.
4.05	0.0033	0.01	Q	.	.	.	.
4.21	0.0034	0.01	Q	.	.	.	.
4.37	0.0035	0.01	Q	.	.	.	.
4.53	0.0037	0.01	Q	.	.	.	.
4.69	0.0038	0.01	Q	.	.	.	.
4.85	0.0040	0.01	Q	.	.	.	.
5.01	0.0041	0.01	Q	.	.	.	.
5.17	0.0043	0.01	Q	.	.	.	.
5.32	0.0045	0.01	Q	.	.	.	.
5.48	0.0046	0.01	Q	.	.	.	.
5.64	0.0048	0.01	Q	.	.	.	.
5.80	0.0049	0.01	Q	.	.	.	.
5.96	0.0051	0.01	Q	.	.	.	.
6.12	0.0052	0.01	Q	.	.	.	.
6.28	0.0054	0.01	Q	.	.	.	.
6.44	0.0056	0.01	Q	.	.	.	.
6.60	0.0057	0.01	Q	.	.	.	.
6.76	0.0059	0.01	Q	.	.	.	.
6.92	0.0061	0.01	Q	.	.	.	.
7.08	0.0063	0.01	Q	.	.	.	.
7.24	0.0064	0.01	Q	.	.	.	.
7.40	0.0066	0.01	Q	.	.	.	.

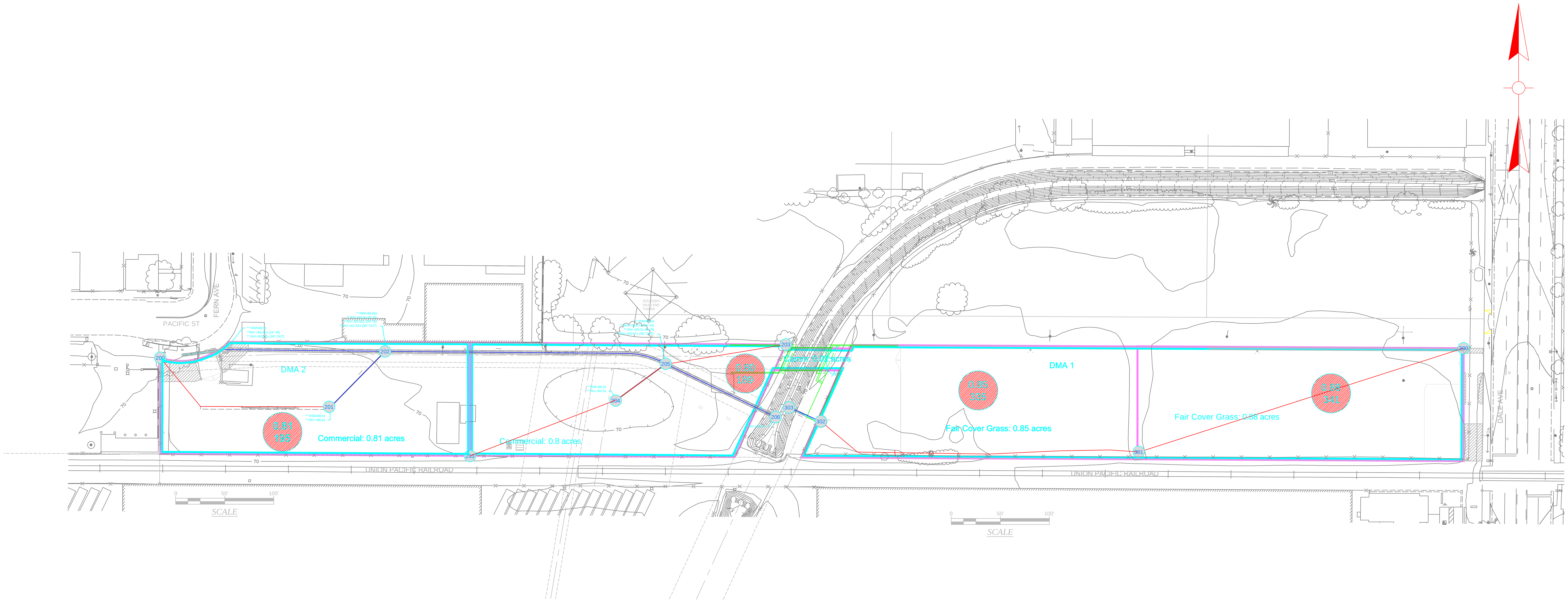
7.56	0.0068	0.01	Q	.	.	.	.
7.71	0.0070	0.01	Q	.	.	.	.
7.87	0.0071	0.01	Q	.	.	.	.
8.03	0.0073	0.01	Q	.	.	.	.
8.19	0.0075	0.01	Q	.	.	.	.
8.35	0.0077	0.01	Q	.	.	.	.
8.51	0.0079	0.01	Q	.	.	.	.
8.67	0.0081	0.01	Q	.	.	.	.
8.83	0.0083	0.02	Q	.	.	.	.
8.99	0.0085	0.02	Q	.	.	.	.
9.15	0.0087	0.02	Q	.	.	.	.
9.31	0.0089	0.02	Q	.	.	.	.
9.47	0.0091	0.02	Q	.	.	.	.
9.63	0.0093	0.02	Q	.	.	.	.
9.79	0.0095	0.02	Q	.	.	.	.
9.95	0.0098	0.02	Q	.	.	.	.
10.10	0.0100	0.02	Q	.	.	.	.
10.26	0.0102	0.02	Q	.	.	.	.
10.42	0.0104	0.02	Q	.	.	.	.
10.58	0.0107	0.02	Q	.	.	.	.
10.74	0.0109	0.02	Q	.	.	.	.
10.90	0.0111	0.02	Q	.	.	.	.
11.06	0.0114	0.02	Q	.	.	.	.
11.22	0.0116	0.02	Q	.	.	.	.
11.38	0.0119	0.02	Q	.	.	.	.
11.54	0.0121	0.02	Q	.	.	.	.
11.70	0.0124	0.02	Q	.	.	.	.
11.86	0.0127	0.02	Q	.	.	.	.
12.02	0.0130	0.02	Q	.	.	.	.
12.18	0.0133	0.03	Q	.	.	.	.
12.34	0.0136	0.03	Q	.	.	.	.
12.49	0.0140	0.03	Q	.	.	.	.
12.65	0.0144	0.03	Q	.	.	.	.
12.81	0.0148	0.03	Q	.	.	.	.
12.97	0.0152	0.03	Q	.	.	.	.
13.13	0.0156	0.03	Q	.	.	.	.
13.29	0.0160	0.03	Q	.	.	.	.
13.45	0.0164	0.03	Q	.	.	.	.
13.61	0.0169	0.03	Q	.	.	.	.
13.77	0.0173	0.04	Q	.	.	.	.
13.93	0.0178	0.04	Q	.	.	.	.
14.09	0.0183	0.04	Q	.	.	.	.
14.25	0.0188	0.04	Q	.	.	.	.
14.41	0.0194	0.05	Q	.	.	.	.
14.57	0.0200	0.05	Q	.	.	.	.
14.73	0.0207	0.05	Q	.	.	.	.
14.88	0.0214	0.05	Q	.	.	.	.

15.04	0.0221	0.06	Q	.	.	.	.
15.20	0.0229	0.06	Q	.	.	.	.
15.36	0.0237	0.07	Q	.	.	.	.
15.52	0.0247	0.07	Q	.	.	.	.
15.68	0.0257	0.08	Q	.	.	.	.
15.84	0.0272	0.15	Q	.	.	.	.
16.00	0.0299	0.26	.Q	.	.	.	.
16.16	0.0379	0.95	. Q	.	.	.	.
16.32	0.0448	0.10	Q	.	.	.	.
16.48	0.0459	0.07	Q	.	.	.	.
16.64	0.0468	0.06	Q	.	.	.	.
16.80	0.0475	0.05	Q	.	.	.	.
16.96	0.0482	0.05	Q	.	.	.	.
17.12	0.0487	0.04	Q	.	.	.	.
17.27	0.0493	0.04	Q	.	.	.	.
17.43	0.0497	0.03	Q	.	.	.	.
17.59	0.0502	0.03	Q	.	.	.	.
17.75	0.0506	0.03	Q	.	.	.	.
17.91	0.0509	0.03	Q	.	.	.	.
18.07	0.0513	0.03	Q	.	.	.	.
18.23	0.0516	0.02	Q	.	.	.	.
18.39	0.0519	0.02	Q	.	.	.	.
18.55	0.0522	0.02	Q	.	.	.	.
18.71	0.0524	0.02	Q	.	.	.	.
18.87	0.0527	0.02	Q	.	.	.	.
19.03	0.0529	0.02	Q	.	.	.	.
19.19	0.0531	0.02	Q	.	.	.	.
19.35	0.0533	0.02	Q	.	.	.	.
19.51	0.0535	0.02	Q	.	.	.	.
19.66	0.0538	0.02	Q	.	.	.	.
19.82	0.0540	0.01	Q	.	.	.	.
19.98	0.0541	0.01	Q	.	.	.	.
20.14	0.0543	0.01	Q	.	.	.	.
20.30	0.0545	0.01	Q	.	.	.	.
20.46	0.0547	0.01	Q	.	.	.	.
20.62	0.0549	0.01	Q	.	.	.	.
20.78	0.0551	0.01	Q	.	.	.	.
20.94	0.0552	0.01	Q	.	.	.	.
21.10	0.0554	0.01	Q	.	.	.	.
21.26	0.0555	0.01	Q	.	.	.	.
21.42	0.0557	0.01	Q	.	.	.	.
21.58	0.0559	0.01	Q	.	.	.	.
21.74	0.0560	0.01	Q	.	.	.	.
21.90	0.0562	0.01	Q	.	.	.	.
22.05	0.0563	0.01	Q	.	.	.	.
22.21	0.0565	0.01	Q	.	.	.	.
22.37	0.0566	0.01	Q	.	.	.	.

```
22.53    0.0567    0.01  Q      .      .      .      .
22.69    0.0569    0.01  Q      .      .      .      .
22.85    0.0570    0.01  Q      .      .      .      .
23.01    0.0572    0.01  Q      .      .      .      .
23.17    0.0573    0.01  Q      .      .      .      .
23.33    0.0574    0.01  Q      .      .      .      .
23.49    0.0576    0.01  Q      .      .      .      .
23.65    0.0577    0.01  Q      .      .      .      .
23.81    0.0578    0.01  Q      .      .      .      .
23.97    0.0579    0.01  Q      .      .      .      .
24.13    0.0581    0.01  Q      .      .      .      .
24.29    0.0581    0.00  Q      .      .      .      .
-----------------------------------------------------------------------
-----------------------------------------------------------------------
```

TIME DURATION(minutes) OF PERCENTILES OF ESTIMATED PEAK FLOW RATE:
(Note: 100% of Peak Flow Rate estimate assumed to have
an instantaneous time duration)

Percentile of Estimated Peak Flow Rate	Duration (minutes)
0%	1443.6
10%	28.7
20%	19.1
30%	9.6
40%	9.6
50%	9.6
60%	9.6
70%	9.6
80%	9.6
90%	9.6



0 100' 200'

SCALE

Subcatchment Boundaries

Existing Drainage Pipe Flowpaths

Drainage Management Area Boundary

Surface Flowpaths

AES Software Model Node Number

Subcatchment Area (ac) and Surface Flowpath Length (ft)

0 100 200 Feet

NOTES:

REV	DATE	DESCRIPTION	DRAWN	REV	DATE	DESCRIPTION	DRAWN

WSP | PARSONS BRINCKERHOFF

Stanton Energy Reliability Center, LLC
650 Bercut Dr, Suite A - Sacramento, CA 95811
Phone: 916-492-9486 Fax: 916-880-5318

DRAWN – DATE –
ENG. APPROVAL – DATE –

DRAWING TITLE
Hydrology Map of Existing System
Figure 1

SIZE D | FSCM NO. | DWG NO. C–201 | REV B

SCALE 1"=50' | PROJECT STANTON | SHEET 1/1

P:\SERC\inbox\peter\Drainage_Study – Standard\Existing-Drainage_Study.dwg
2017-05-01 5:51 PM

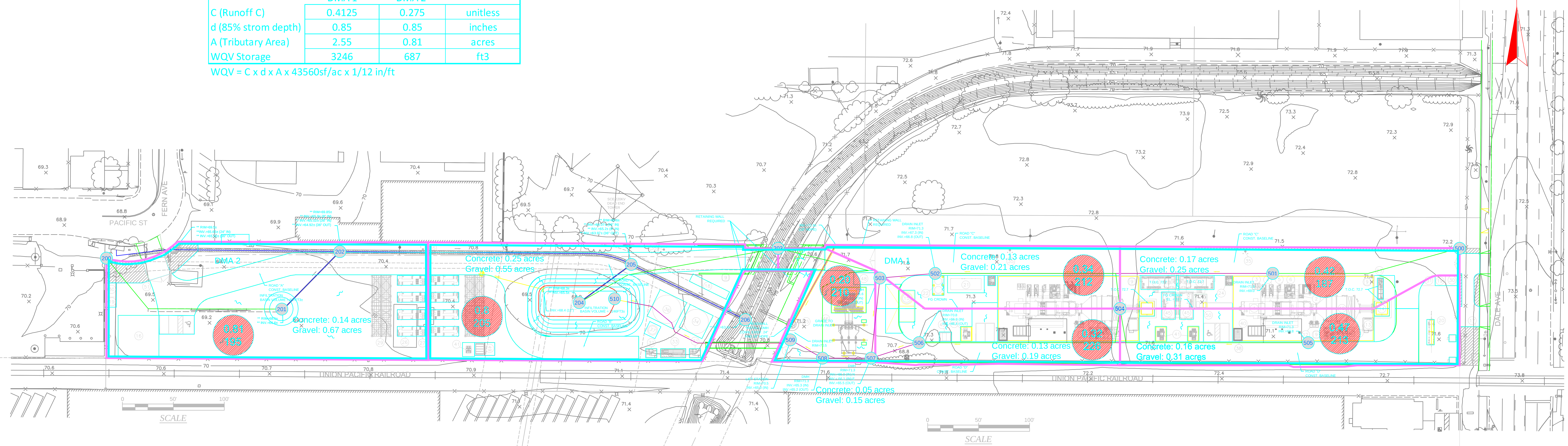
Post Construction Condition Time of Concentration Adjustment

	DMA 1	DMA 2	
Area	2.55	0.81	acres
Toc	9.41	9.5	minutes
Time to fill WQV	20.6	19.4	minutes
adjusted TOC	30.1	28.9	minutes

Water Quality Volume Summary Table

	DMA 1	DMA 2	
C (Runoff C)	0.4125	0.275	unitless
d (85% strom depth)	0.85	0.85	inches
A (Tributary Area)	2.55	0.81	acres
WQV Storage	3246	687	ft3

WQV = C x d x A x 43560sf/ac x 1/12 in/ft



0 100' 200'

SCALE

Subcatchment Boundaries

Existing Drainage Pipe Flowpaths

Proposed Drainage Pipe Flowpaths

Proposed Surface Flowpaths

AES Software Model Node Number

Drainage Management Area Boundary

Subcatchment Area (ac) and Surface Flowpath Length (ft)

0 100 200 Feet

NOTES:

REV	DATE	DESCRIPTION	DRAWN	REV	DATE	DESCRIPTION	DRAWN

Stanton Energy Reliability Center, LLC
650 Bercut Dr, Suite A - Sacramento, CA 95811
Phone: 916-492-9486 Fax: 916-880-5318

DRAWN – DATE –
ENG. APPROVAL – DATE –

DRAWING TITLE
Hydrology Map of Proposed System
Figure 2

SIZE D | FSCM NO. | DWG NO. C-201 | REV B
SCALE 1"=50' | PROJECT STANTON | SHEET 1/1

5.12 Traffic and Transportation (A42-A52)

Average daily traffic

A42. Please explain how AADT was converted to ADT and provide data calculations.

Response: Two sets of traffic data were obtained; Average Annual Daily Traffic (AADT) from Caltrans for the state highways (I-5, I-405, SR 22, and SR 39) and Average Daily Traffic (ADT) from the Orange County Transportation Authority for the local study roadways. The AADT were not converted to ADT because both types of traffic data are considered reasonable estimates of roadway use for this type of planning level analysis. According to Caltrans, the AADT traffic count year is from October 1 through September 30 and the resulting counts are adjusted to an estimate of AADT by compensating for seasonal influence, weekly variation and other variables which may be present. Caltrans uses AADT for presenting a statewide picture of traffic flow, evaluating traffic trends, computing accident rates, planning and designing highways and other purposes.

Traffic calculations

A43. Please provide an appendix of traffic calculations for the Traffic and Transportation AFC section.

Response: The traffic calculations that were performed are shown in AFC Tables 5.12-4 and 5.12-7, which present the volume to capacity ratio (V/C) of the study roadways. The V/C ratio is a simple calculation of the daily traffic divided by the capacity of the roadway. As stated in Section 5.12.1.2, Existing Traffic Conditions and Level of Service Analysis, turning movement counts are not available for any of the local intersections; therefore, LOS could not be calculated. Instead, LOS information contained in the 2015 Congestion Management Plan (CMP) was reviewed to assess the general operating conditions in the study area where data were available.

Intersection existing LOS Summary table

A44. Please provide an updated, "Existing (2015) Intersection LOS Summary" table. In this table include the type of control (e.g. signal, stop sign), AM and PM peak LOS and ICU for all intersections. In addition, include the intersections of Dale Avenue and Katella Avenue and Dale Avenue and West Cerritos Avenue.

Response: The type of traffic control has been added to the information provided in the AFC as Table 5.12-5, "Existing (2015) Intersection LOS Summary" (see Table DRA44-1). LOS data is not available for the intersections of Dale Avenue and Katella Avenue and Dale Avenue and West Cerritos Avenue.

Table DRA44-1. Existing (2015) Intersection LOS Summary*

Intersection	Traffic Control	AM Peak Hour		PM Peak Hour	
		ICU	LOS	ICU	LOS
Beach Blvd./Edinger Ave./I-450 Southbound Ramps	Signal	0.67	B	0.76	C
Beach Blvd./Bolsa Ave.	Signal	0.82	D	0.78	C
Beach Blvd./SR 22 Eastbound Ramps	Signal	0.55	A	0.51	A

Table DRA44-1. Existing (2015) Intersection LOS Summary*

Intersection	Traffic Control	AM Peak Hour		PM Peak Hour	
		ICU	LOS	ICU	LOS
Beach Blvd./SR 22 Westbound Off Ramp	Signal	0.73	C	0.69	B
Beach Blvd./Katella Avenue	Signal	0.71	C	0.68	B
Beach Blvd./SR 91 Eastbound Ramps	Signal	0.47	A	0.55	A
Beach Blvd./SR 91 Westbound Ramps	Signal	0.51	A	0.59	A
Beach Blvd./I-5 Southbound Ramps	Signal	0.61	B	0.65	B

*The LOS results were obtained from the 2015 CMP and are based on traffic counts collected in 2015.

Intersection LOS summary plus project table

A45. Please provide a table labeled, "Existing (2015) Intersection LOS Summary Plus Project Construction". In this table include the type of control (e.g. signal, stop sign), AM and PM peak ICU and LOS for all intersections and include construction traffic. Include the intersections of Dale Avenue and Katella Avenue and Dale Avenue and West Cerritos Avenue.

Response: It is estimated that the project will generate 78 morning peak hour trips and 78 afternoon peak hour trips. Based on the project trip distribution, percentages in AFC Table DRA45-1 below present the existing LOS summary with the number of project-added trips anticipated to travel through the intersections. As previously stated LOS could not be calculated because turning movement counts are not available for any of the local intersections.

Table DRA45-1. Existing (2015) Intersection LOS Summary + Project Added Trips

Intersection	Traffic Control	Existing Conditions*				Project-Added Trips
		AM Peak Hour		PM Peak Hour		
		ICU	LOS	ICU	LOS	
Beach Blvd./Edinger Ave./I-450 Southbound Ramps	Signal	0.67	B	0.76	C	21
Beach Blvd./Bolsa Ave.	Signal	0.82	D	0.78	C	22
Beach Blvd./SR 22 Eastbound Ramps	Signal	0.55	A	0.51	A	48
Beach Blvd./SR 22 Westbound Off Ramp	Signal	0.73	C	0.69	B	48
Beach Blvd./Katella Avenue	Signal	0.71	C	0.68	B	48
Beach Blvd./SR 91 Eastbound Ramps	Signal	0.47	A	0.55	A	23
Beach Blvd./SR 91 Westbound Ramps	Signal	0.51	A	0.59	A	21
Beach Blvd./I-5 Southbound Ramps	Signal	0.61	B	0.65	B	14

*The LOS was not calculated for the Existing + Project conditions because intersection turning movement counts are not available.

Heavy haul route

A46. Please provide a detailed heavy haul route indicating the point of origin, truck route, and the project entrance (Parcel 1- Dale Avenue or Parcel 2- Fern Avenue and Pacific Street) to be used for oversized project components.

Response: All heavy haul and oversize project components deliveries will be made to Parcel 1 from Dale Avenue. Heavy haul routes will be as generally described in AFC Section 5.12.1.3, and are expected to be comprised of those routes listed in the following table. As illustrated in the Table DRA46-1, all heavy haul loads are expected to be delivered to the Dale Avenue project entrance, i.e. Parcel 1, with no heavy haul loads anticipated for Parcel 2 – Fern Avenue and Pacific Street. Attachment DRA46-1 shows the locations of these routes.

Table DRA46-1. Heavy Haul Routes

Route #	1	2	3	4
Point of Origin	SR 39 southbound from either I-5 or SR 91	SR 39 southbound from either I-5 or SR 91	SR 39 northbound from either I-405 or SR 22	SR 39 northbound from either I-405 or SR 22
Truck Route	Proceed southbound from SR 91 & SR 39 junction for approximately 3.1 miles to W. Cerritos Ave. Turn left onto W. Cerritos and proceed eastward for 0.5 miles to Dale Ave. Turn right onto Dale Ave and proceed southward for approximately 0.23 miles. Turn right (west) into the SERC project site.	Proceed southbound from SR 91 & SR 39 junction for approximately 3.6 miles to W. Katella Ave. Turn left onto W. Katella and proceed eastward for 0.5 miles to Dale Ave. Turn left onto Dale Ave and proceed northward for approximately 0.27 miles. Turn left (east) into the SERC project site.	Proceed northbound from SR 22 & SR 39 junction for approximately 2.1 miles to W. Katella Ave. Turn right onto W. Katella and proceed eastward for 0.5 miles to Dale Ave. Turn left onto Dale Ave and proceed northward for approximately 0.27 miles. Turn left (east) into the SERC project site.	Proceed northbound from SR 22 & SR 39 junction for approximately 2.6 miles to W. Cerritos Ave. Turn right onto W. Cerritos and proceed eastward for 0.5 miles to Dale Ave. Turn right onto Dale Ave and proceed southward for approximately 0.23 miles. Turn right (west) into the SERC project site.

Heavy haul and hazardous materials deliveries

A47. Please provide a detailed discussion of the oversized/heavy components and hazardous materials deliveries that would require the use of the Parcel 2 entrance.

Response: Deliveries of oversized or heavy components will not be made via the Parcel 2 entrance. All heavy haul deliveries will be to Parcel 1 as described in the response to Data Request 46. Components containing hazardous substances that will be delivered via the Parcel 2 entrance are likely limited to auxiliary transformers and lithium ion battery system modules. These components are all expected via standard, legal-load truck deliveries. Use of the vehicle bridge between Parcel 1 and Parcel 2 is planned for movement of construction vehicles, construction materials, and construction personnel, but is not planned for movement of truckloads of oversized, heavy, or hazardous materials.

Utility bridge design

A48. Please provide design specifications of the utility bridge including, dimensions, weight capability (ability to support vehicles), and bridge purpose (e.g. infrastructure support, worker pedestrian, vehicle access).

Response: SERC will have two new bridges crossing the Orange County Flood Control District storm water channel that bisects the project site: 1) a utility bridge that will support piping, electrical conduits, and cable tray, but no foot traffic or vehicles; and 2) a vehicle bridge that will be used for foot traffic and vehicles. SERC LLC is interpreting this Data Request to pertain to the vehicle bridge. SERC proposes to use a pre-cast concrete design for the vehicle bridge, similar to the design of an existing bridge that crosses the same channel just south of the project site (at the mini storage facility). Attachment DRA48-1 is a preliminary design of the SERC vehicle bridge. The bridge will have an overall width of 24 feet and will be designed for AASHTO HS20-44 truck loading.

Utility bridge construction schedule.

A49. Please provide a construction schedule for the utility bridge

Response: SERC LLC has not yet developed a detailed construction schedule for the traffic bridge, but intends to construct the bridge at the very beginning of the overall project's construction phase. The precast concrete design was selected in order to minimize the construction duration allowing the bridge to provide early access between the two project parcels.

Passengers/car

A50. Please provide clarification for the "Workers (1.5 passengers/car)" row in Table 5.12-14.

Response: This row represents the carpool rate assumed for the work force assumed to be 1.5 passengers per car.

Form 7460-1

A51. Please provide a copy of the submitted FAA Form 7460-1, as well asthe FAA's Determination prior to staff's publication of the Preliminary Staff Assessment.

Response: SERC structures (stack height at 70 feet above ground level and generator tie-line pole at 60 feet above ground level) will not exceed FAA notification requirements under Title 14 CFR, Part 77 and so will not cause a hazard to air navigation or require notification of the FAA. The 14 CFR 77 requirements for FAA notification are as follows:

- *Construction more than 200 feet above ground leve*l – SERC structures will not exceed 70 feet above ground level, so notification is not required.
- *Notification zone surrounding public or military airports or heliports*—Notification would be required if any project-related element would penetrate an imaginary surface extending at a slope ratio of 100:1 (the 100:1 surface) extending outward from the nearest point of the nearest runway. The nearest airport to SERC is the Joint Forces Training Base (JFTB), Los Alamitos (SLI). Analysis of the 100:1 surface indicates that notification would be required if the stack were to reach an elevation of approximately 190 feet above sea level at the SERC site. The SERC stack height is approximately 140 feet above mean sea level, so notification is not required.
- *Restricted airspace in approaches to public or military airports or heliports* –Analysis of the imaginary restricted airspace surfaces associated with the JFTB SLI airfield indicate that notification would be

required if the SERC stack were to approach 260 feet above mean sea level. The SERC stack height is approximately 140 feet above mean sea level, so notification is not required.

SERC does not meet these criteria for FAA notification.

Airport Land Use Commission

A52. Please submit the Stanton project notification letter sent to the ALUC and the ALUC's response prior to staff's publication of the Preliminary Staff Assessment.

Response: Notification of the Orange County Airport Land Use Commission (ALUC) would be required if the project site were located within the Planning Area of the JFTB and the SLI airfield. The ALUC defines the airfield's Planning Area as follows (Orange County ALUC 2016):

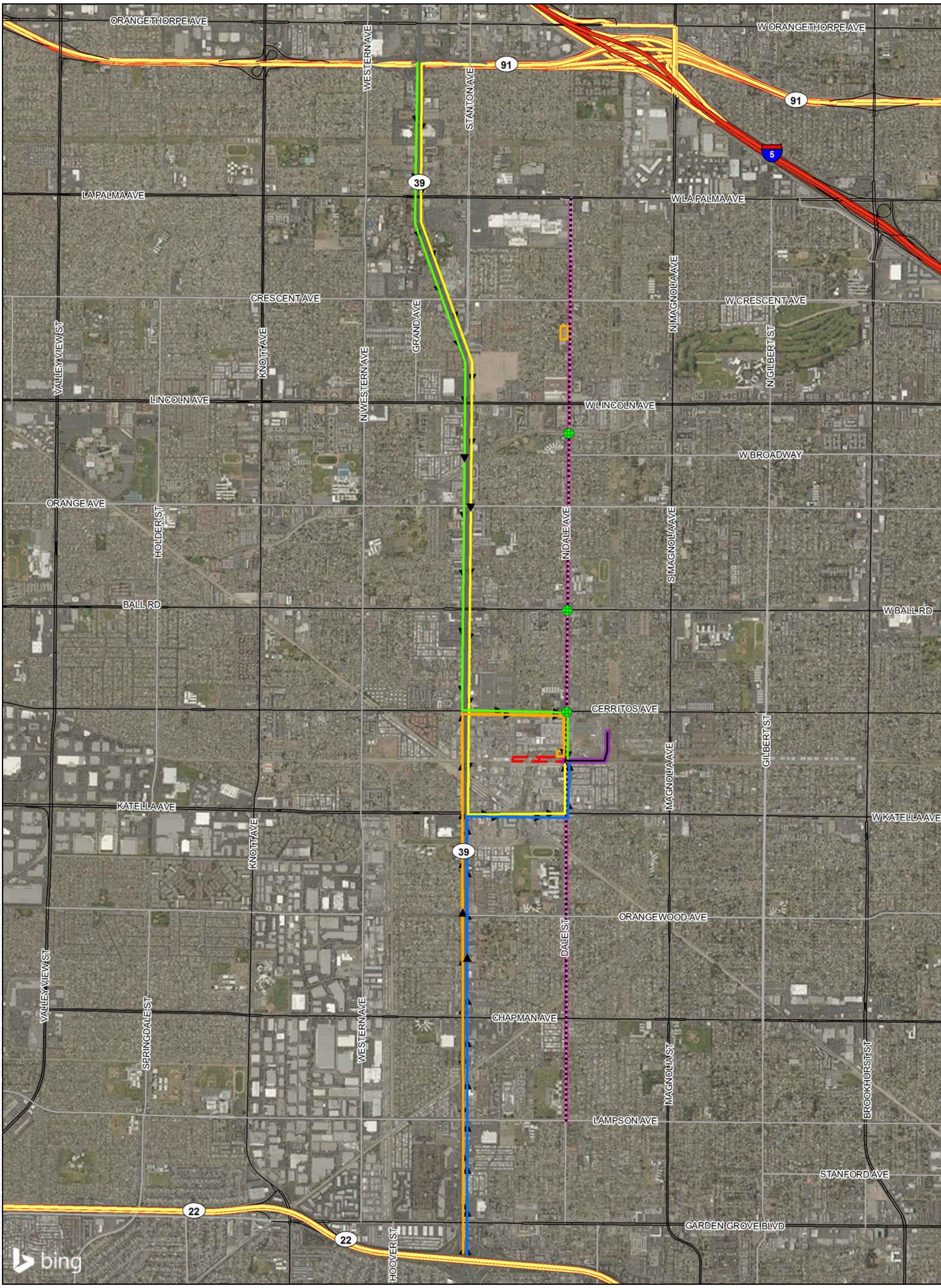
> The Commission has adopted and defined as its Planning Areas for JFTB, Los Alamitos all area within the 60 dB CNEL Contour and all area that lies above or penetrates the 100:1 Imaginary Notification Surface as defined in FAR Part 77.21.
>
> Outside of the 60 dB CNEL Contour, or other areas of special concern as delineated by the FAA and adopted by the commission, local agencies are required to submit only those matters which contemplate or permit structures that would penetrate the 100:1 Imaginary Surface for notice to the FAA as defined in FAR Part 77.21 or are at an elevation of 200 feet or more above ground level.

Based on figures shown in the AELUP, the project site is not within the 60 dB CNEL contour area surrounding the JFTB. As stated in the response to Data Request A51, above, no structure that is part of the project would penetrate the 100:1 imaginary surface or be at an elevation of 200 feet or more about ground level. Therefore, although the project site is within the horizontal 20,000-foot notification area for JFTB, Los Alamitos, it is outside of the planning area, taking into consideration the 100:1 surface and notification of the ALUC on behalf of the CEC (acting under its over-arching licensing authority in lieu of the local permitting agency, City of Stanton), is not required.

References:

Orange County Airport Land Use Commission. 2016. Airport Environs Land Use Plan for Joint Training Base, Los Alamitos. Amended 2016. http://www.ocair.com/commissions/aluc/docs/JFTB-AELUP2016ProposedFINAL.pdf. Accessed April 13, 2017.

Attachment DRA46-1
Heavy Haul Routes



LEGEND

- JACK-AND-BORE CROSSING
- GEN-TIE LINE
- NATURAL GAS PIPELINE ALTERNATIVE ROUTE
- HEAVY HAUL ROUTE 1
- HEAVY HAUL ROUTE 2
- HEAVY HAUL ROUTE 3
- HEAVY HAUL ROUTE 4
- CONSTRUCITON STAGING AREA
- NATURAL GAS LINE 30' RIGHT OF WAY
- GEN-TIE 50' RIGHT OF WAY
- PROJECT SITE

N

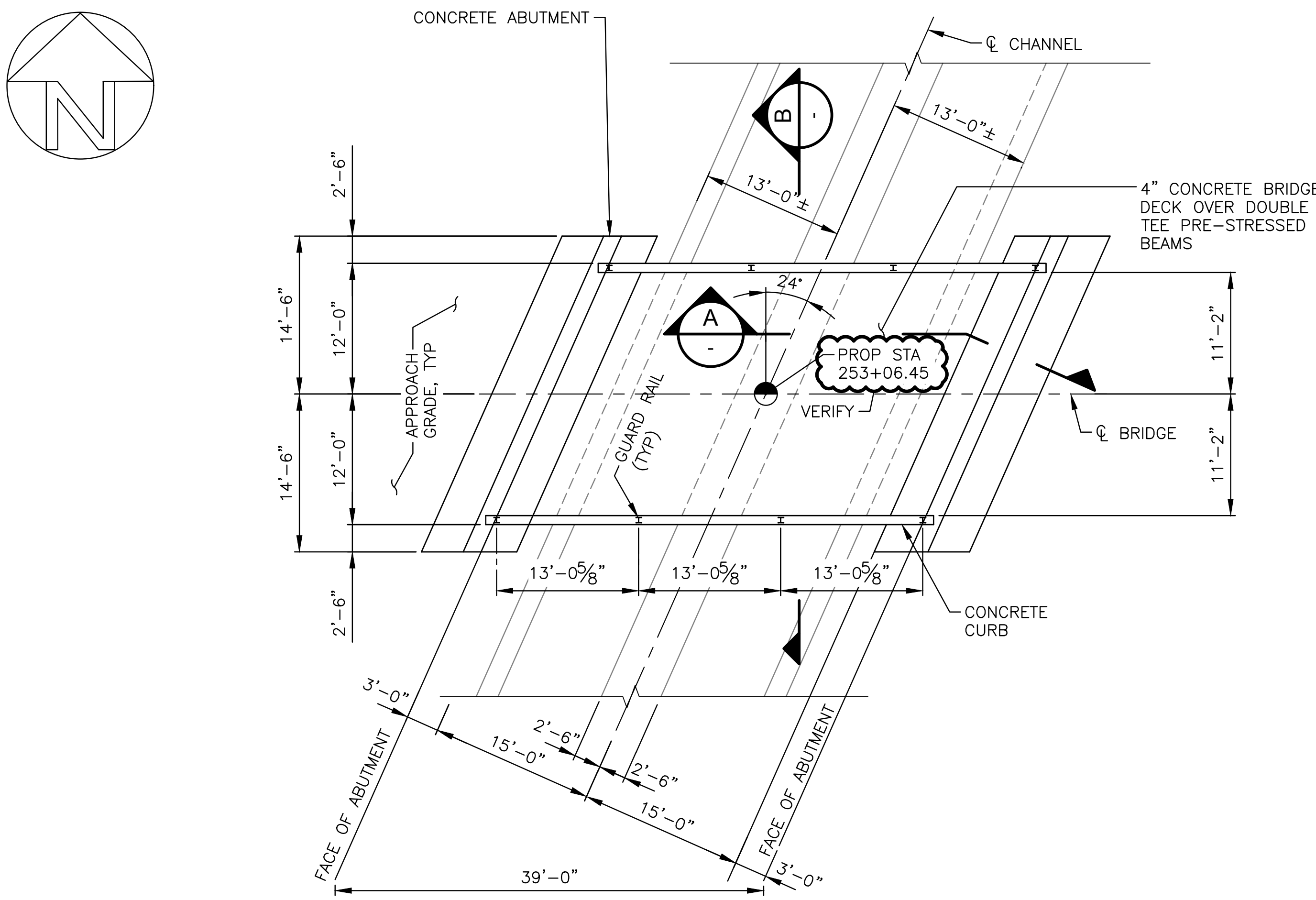
0 1,200 2,400 Feet

Figure DRA46-1
Heavy Haul Routes
Stanton Energy
Reliability Center AFC
Stanton, California

\\BROOKSIDE\GIS_SHARE\ENBG\02_TEMPLATES\LAYOUT_TEMPLATES\ENG_11X17_TEMPLATE_PORTRAIT_20161114.MXD ET024983 11/14/2016 10:23:15 AM

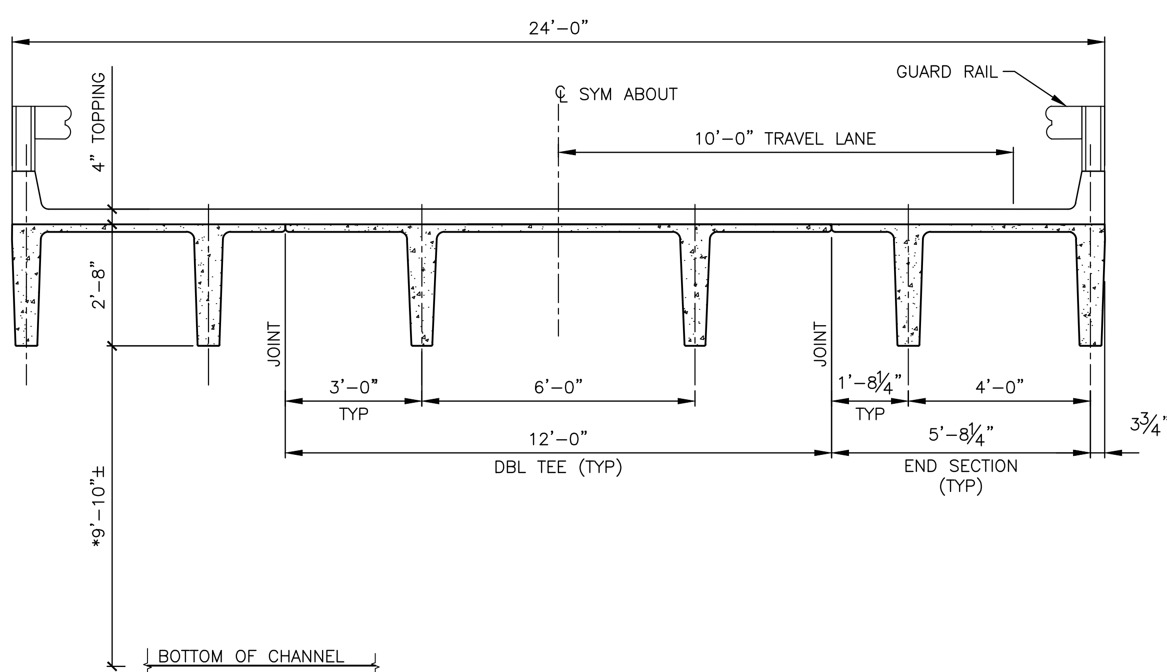
ch2m.

Attachment DRA48-1
Preliminary Design, Vehicle Bridge



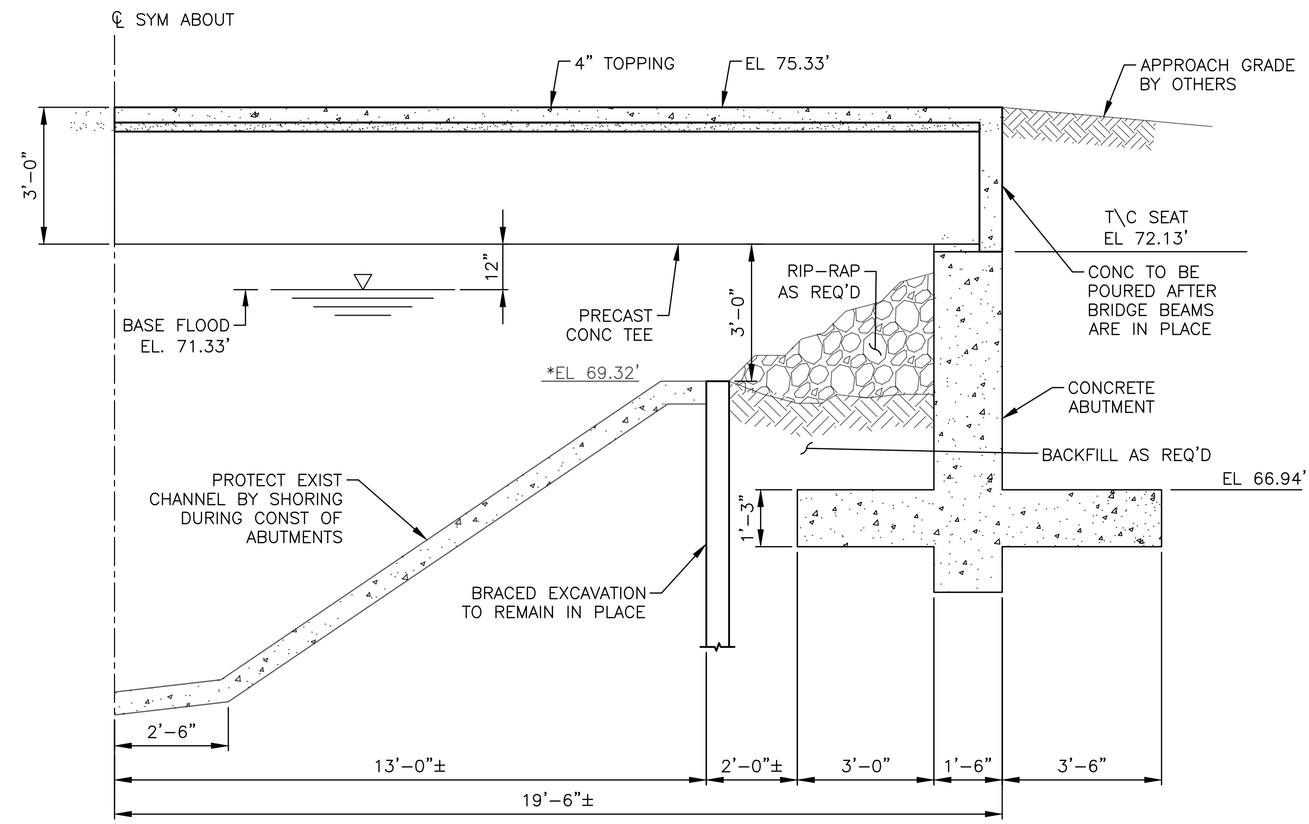
PLAN

SCALE: 1/8"=1'-0"



SECTION B

SCALE: 1/2"=1'-0"



SECTION A

SCALE: 1/2"=1'-0"

NOTES:

1. PRECAST PRESTRESSED DOUBLE TEE SECTION SHALL BE DESIGNED IN ACCORDANCE WITH AASHTO FOR HS20-44 TRUCK LOADING.
2. DOUBLE TEE SECTION SHALL BE DESIGNED IN ACCORDANCE WITH PCI.
3. * – ASTERISK DENOTES FIELD DIMENSIONS TO BE VERIFIED PRIOR TO CONSTRUCTION.
4. BASE FLOOD PLAIN ELEVATION IS BASED ON ORANGE COUNTY FLOOD CONTROL DISTRICT GUIDELINES.

Source: Parsons Brinckerhoff, Drawing No. S-SK-001 Rev. B, 9/28/2016.

Figure DRA48-1
Preliminary Design, Vehicle Bridge
Stanton Energy Reliability Center AFC
Stanton, California

5.16 Worker Health and Safety (A53-A62)

Gas compressor enclosure

A53. Please describe the materials and design of the gas compressor's acoustical enclosure, including any gas shutoff and fire protection provisions.

Response: The acoustical enclosure that SERC will use is relatively small and encapsulates only the compressor itself. The enclosure has a sheet metal skin with acoustic absorbing material on the inside and is provided with a forced ventilation system. There are no automated gas shutoffs or fire protection systems on the gas compressor skid. There will be an automated emergency gas shutoff valve located between SoCalGas's Meter Set Assemblies (MSA) yard and the gas compressor skid (see Item 23 in AFC Figure 2.1-1a of the Project Description in the AFC).

Acoustical enclosure drawings

A54. Please include any currently available preliminary drawings forthe acoustical enclosure.

Response: Attachment DRA54-1 is a general arrangement drawing which shows the extent of the "sound enclosure". Attachment DA54-2 is a photograph of the gas compressor skid which shows the actual enclosure.

Fire protection main connections

A55. Please provide a written narrative clarifying if the Stanton facility would have two fire protection main connections to the same municipal supply provided by the Golden State Water Company.

Response: The unique configuration of the project site allows for connections at two locations within the GSWC distribution system to provide increased reliability. For example, if a GSWC pipeline feeding one of the connections needed to be isolated for repair, fire protection water could still be supplied to SERC from the second connection.

Fire protection loop

A56. Please provide a site plan indicating where each connection to the Golden State Water Company would be located and where the connections would feed into the project's fire protection loop.

Response: Attachment DRA56-1 shows GSWC's water distribution system in the vicinity of the SERC project site. The two connections for SERC are identified, the first being west of the project site to an 8-inch diameter main near the intersection of Pacific Street and Fern Avenue and the second being east of the project site to an 8-inch diameter main in Dale Avenue. The specific routing of onsite fire protection piping has not yet been designed. Given the two supply connections, the onsite piping will likely consist of a single east-west pipeline running between the two connections, in effect, using the GSWC's distribution system as the loop.

Water pressure

A57. Please provide a written narrative demonstrating that the Golden State Water Company's supply pressure to the fire protection loop would be adequate for the site's fire protection needs without the addition of an on-site fire pump.

Response: Attachment DRA57-1 provides the results of hydrant flow calculations that GSWC performed for hydrants adjacent to the two proposed connections for SERC fire protection water. The locations of the two hydrants are identified in Attachment DRA56-1. Hydrant FH-2459, located near the intersection of Pacific Street and Fern Avenue, is projected to be capable of discharging 1500 gpm while maintaining a residual pressure of 67 psig. Hydrant FH-2275, located in Dale Avenue, is projected to be capable of discharging 1500 gpm while maintaining a residual pressure of 65 psig. At a fire flow of 2000 gpm, SERC LLC estimates a residual pressure of 48 to 50 psig per the equation in Section 4.10.1.2 of NFPA 291. Allowing a pressure drop of 8 psig across the required detector check assembly leaves a residual pressure of 40 to 42 psig available for onsite fire protection needs. Given this range of residual pressures, onsite pumping will not be required.

Operation and safety programs

A58. Please provide a written narrative clarifying how all of the operation and safety programs would be administered and to whom the site specific training would be given.

Response: The facility will be operated by WSI. Per WSI O&M standards, all WSI employees will receive the necessary health and safety training prior to performing or managing work at the plant site. As applicable, WSI employees and contractors performing services at the site, and visitors to the site, will receive site-specific health and safety orientation and training. Site-specific health and safety orientation and training materials will be located in a designated area of the site warehouse (see AFC Figure 2.1-1b, Item #16).

Safety data sheets

A59. Please provide a narrative explaining where the site-specific Safety Data Sheets would be kept on site.

Response: Site-specific Safety Data Sheets will be maintained in a designated area of the site warehouse (see AFC Figure 2.1-1b, Item #16).

Lock out/tag out

A60. Please provide a written narrative detailing how the Lock Out/Tag Out program would be administered on site given that there does not appear to be a control room or central command location on site.

Response: WSI employees and contractors will be required to adhere to WSI Lockout/Tagout Program (WSI Safety Manual WSM-006). The Lockout/Tagout program and all necessary instruments to administer the program will be located in a designated area of the site warehouse (see AFC Figure 2.1-1b, Item #16). In addition, the remote operations center will electronically log equipment service status.

Fire protection/battery installation

A61. Please provide a written narrative detailing what fire protection and life safety systems would be provided for the lithium-ion battery installations.

Response: The equipment enclosures that will house the lithium-ion cells will be outdoors and be rated for outdoor service. The enclosures will use an FM200 fire suppression system. Additionally, the enclosures will not have any internal walkways or internal personnel access ways. The enclosures will not be occupied spaces, and all battery hardware will be accessed by maintenance personnel from the exterior of the enclosure via removable panels or doors that can be opened. Maintenance personnel will be required to wear appropriate personal protective equipment (PPE), in accordance with the requirements of the Orange County Fire Authority (OCFA), National Fire Protection Association and other relevant standards.

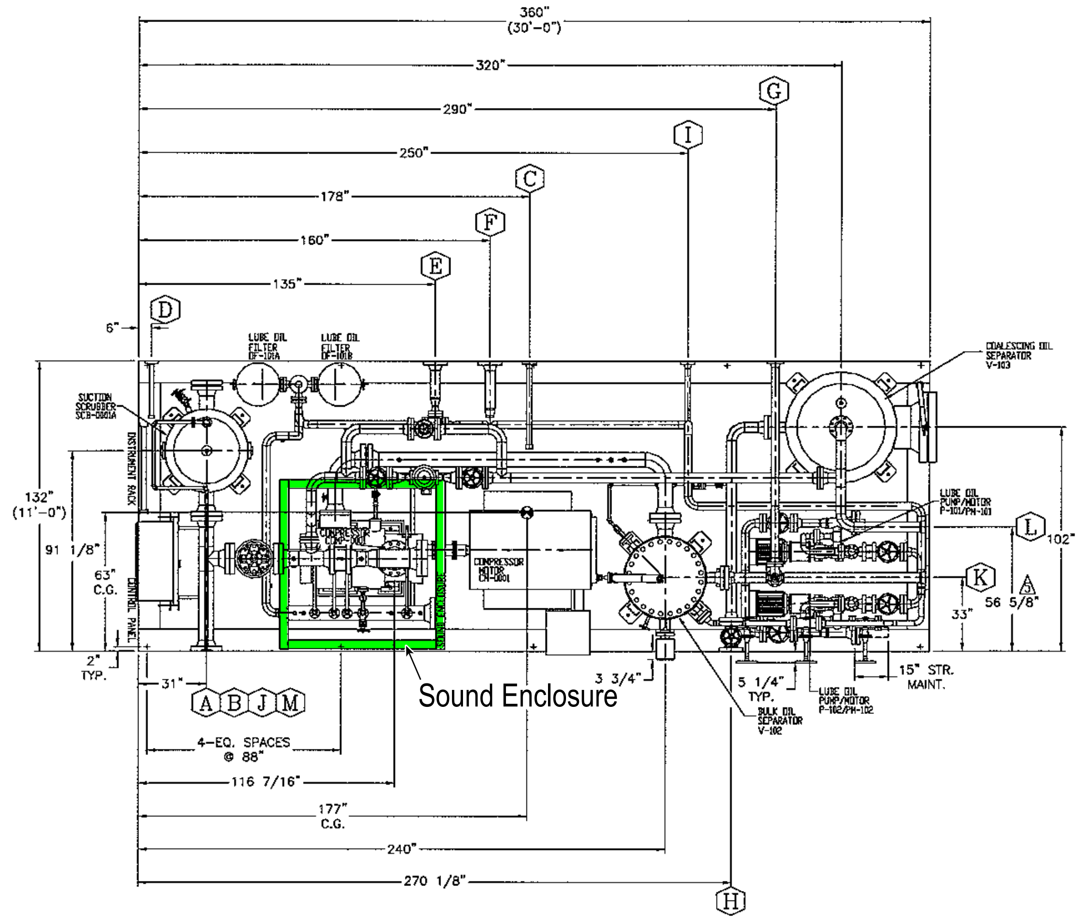
Fire prevention/battery installation

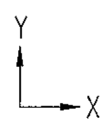
A62. Please provide a written narrative of the general procedures and life safety measures that would be provided to help prevent and control any incipient fires in the lithium-ion battery installation.

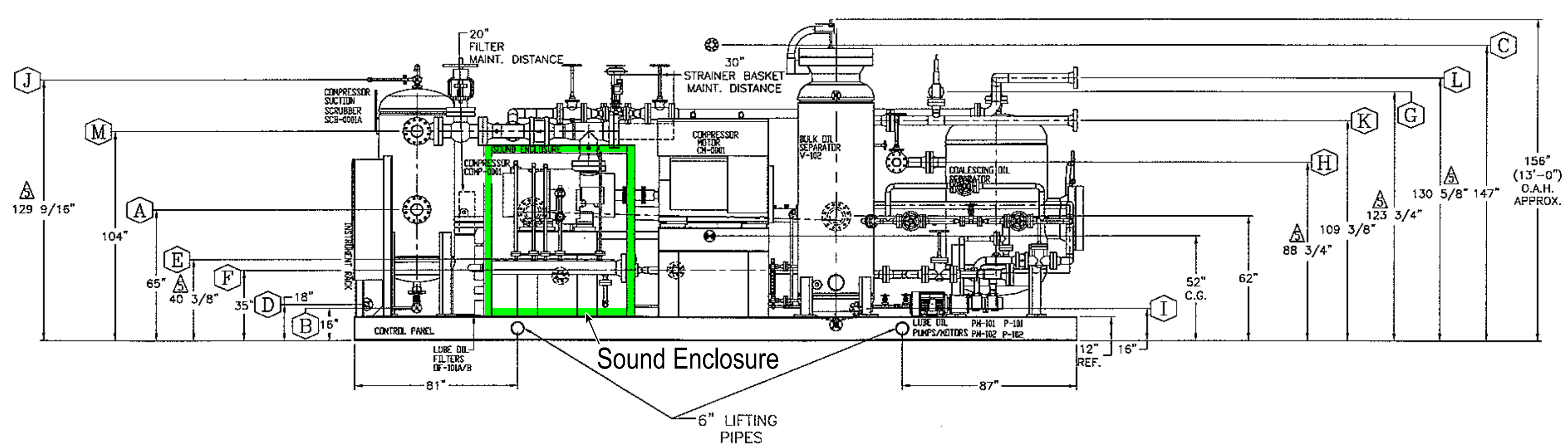
Response: The SERC will have two battery energy storage systems (BESS): one for each turbine. Each BESS will use lithium-ion battery cells. Every other cell in the lithium-ion battery systems will be monitored for temperature by a Battery Indication and Control (BIC) system. The BIC continually monitors all temperatures, and determines what level of fire prevention response, if any, is needed. If any temperature sensor reaches an unacceptable temperature, portions of or all of the BESS will be shutdown (which will help prevent a fire from starting), and the facility control and monitoring system will provide an alarm and operator notification. After proper lock-out, tag-out, proper cooldown, and Job Safety Analysis, maintenance personnel can inspect the equipment that was overheating and repair as necessary.

In the event the battery does not cool down and the over-temperature advances to a fire, an inert gas fire suppression system (FM200 or equal) will detect the fire, release the inert gas, shut down battery system operation, initiate local alarm, and notify remote monitoring agencies to notify the OCFA. Personnel will follow the site Emergency Action Plan to muster at an assembly point in the event of fire and wait for the OCFA.

Attachment DRA54-1
General Arrangement
Gas Compressor Sound Enclosure







CUSTOMER CONNECTIONS

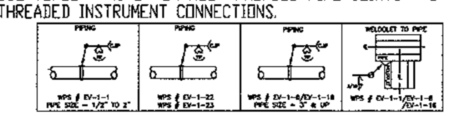
DESIGNATION	DESCRIPTION	SIZE&RATING
A	GAS INLET	6"-600# RFWN FLANGE
B	SCRUBBER DRAIN	1"-600# RFSW FLANGE
C	VENT HEADER	2"-600# RFWN FLANGE
D	INSTRUMENT AIR HEADER	1 1/2"-150# RFSW FLANGE
E	FIN FAN OIL RETURN	4"-600# RFWN FLANGE
F	FIN FAN OIL SUPPLY	4"-600# RFWN FLANGE
G	PSV TO SAFE AREA	4"-150# FLANGE
H	GAS OUTLET	4"-600# RFWN FLANGE
I	DRAIN HEADER	2"-600# RFWN FLANGE
J	PSV TO FIRE SAFE AREA	1"-150# RFSW FLANGE
K	FIN FAN GAS SUPPLY	4"-150# RFSW FLANGE
L	FIN FAN GAS RETURN	4"-150# RFSW FLANGE
M	MANUAL BY-PASS	6"-600# RFWN FLANGE

ALLOWABLE PIPE NOZZLE LOADS

SIZE	AXIAL FORCE (LBS.) FX	VERTICAL FORCE (LBS.) FY	LATERAL FORCE (LBS.) FZ	AXIAL MOMENTS (IN.LBS) MX	VERTICAL MOMENTS (IN.LBS) MY	LATERAL MOMENTS (IN.LBS) MZ	RESULTANT FORCE (LBS.) F	RESULTANT MOMENTS (IN.LBS) M
6"	± 555	± 1388	± 1110	± 16650	± 8325	± 8325	± 1862	± 20392
4"	± 370	± 925	± 740	± 7400	± 3700	± 3700	± 1241	± 9063
3"	± 278	± 694	± 555	± 4164	± 2082	± 2082	± 931	± 5100
2"	± 185	± 463	± 370	± 1850	± 925	± 925	± 621	± 2266
1 1/2"	± 139	± 347	± 278	± 1041	± 521	± 521	± 466	± 1275
1"	± 93	± 231	± 185	± 463	± 231	± 231	± 310	± 567
3/4"	± 70	± 174	± 140	± 260	± 130	± 130	± 233	± 319

GENERAL NOTES

1. ALL DIMENSIONS ARE IN INCHES.
2. ALL CUSTOMER CONNECTIONS ARE +/- 1/4".
3. ALL PIPING SHALL BE DONE IN ACCORDANCE WITH ASME/ANSI B31.1.
4. ALL BUTT WELDS SHALL BE FULL PENETRATION.
5. ALL THREADED CONNECTIONS EXCEPT PLUGS SHALL BE SEAL WELDED.
6. ALL FLANGE BOLT HOLES TO STRADDLE N/S & VERT. CENTERLINES.
7. ALL BURRS & SHARP EDGES SHALL BE REMOVED.
8. UNLESS OTHERWISE SPECIFIED, ALL TUBING SHALL BE 304 SS. 3/8"OD (0.035") WALL. TUBE FITTINGS ARE SWAGELOK.
9. ALL PIPING & TUBING SHALL BE ADEQUATELY SUPPORTED OR FASTENED.
10. COMPLETE SYSTEM SHALL BE PRESSURE TESTED PNEUMATICALLY @ 780 X 1.1 PSIG.
11. COMPLETE SYSTEM SHALL BE SHIPPED WITH 10 PSIG DRY NITROGEN.
12. ALL FLANGE SEALING SURFACES SHALL BE PROTECTED.
13. COATING SYSTEM
    SURFACE PREP: SSPC-SP-6 (COMMERCIAL BLAST CLEANING)
    PRIMER: AMERON, AMERCOAT 68HS, 3.0 MILS, RED-BROWN
    TOP COAT: AMERON, AMERSHIELD, 5.0 MILS, MEDIUM ANSI 70 GRAY
14. COMBINED SKID WEIGHT CENTER OF GRAVITY= ⊕
15. SKID BASE MUST BE FILLED WITH CONCRETE (BY CUSTOMER).
16. COMPRESSOR TO BE FILLED WITH OIL, PRIOR TO SHIPMENT.
17. SPIRAL WOUND GASKETS W/ GRAPHITE FILLER SHALL BE USED.
18. NET WEIGHTS IS SAME AS SHIPPING WEIGHT.
19. ALL PIPING DOWNSTREAM OF OIL FILTERS SHALL BE BUTT WELDS.
20. USE TEFLON PASTE FOR ALL THREADED PIPE JOINTS AND ALL THREADED INSTRUMENT CONNECTIONS.



MACHINERY WEIGHTS

(TOLERANCE +/-10%)

NET WEIGHT	:	77,000# (APPROX.)
OPERATING WEIGHT	:	80,000# (APPROX.)

Source: Kobelco Edti Compressors, Inc., Drawing No. ES-395-011 Rev. 5, 5/5/2009.

Figure DRA54-1
General Arrangement, Natural Gas Compressor Acoustical Enclosure
Stanton Energy Reliability Center AFC
Stanton, California

Attachment DRA54-2
Gas Compressor, Photograph

Figure DRA54-2
Natural Gas Compressor, Photograph
Stanton Energy Reliability Center AFC
Orange County, California

Attachment DRA56-1
GSWC Water Distribution System

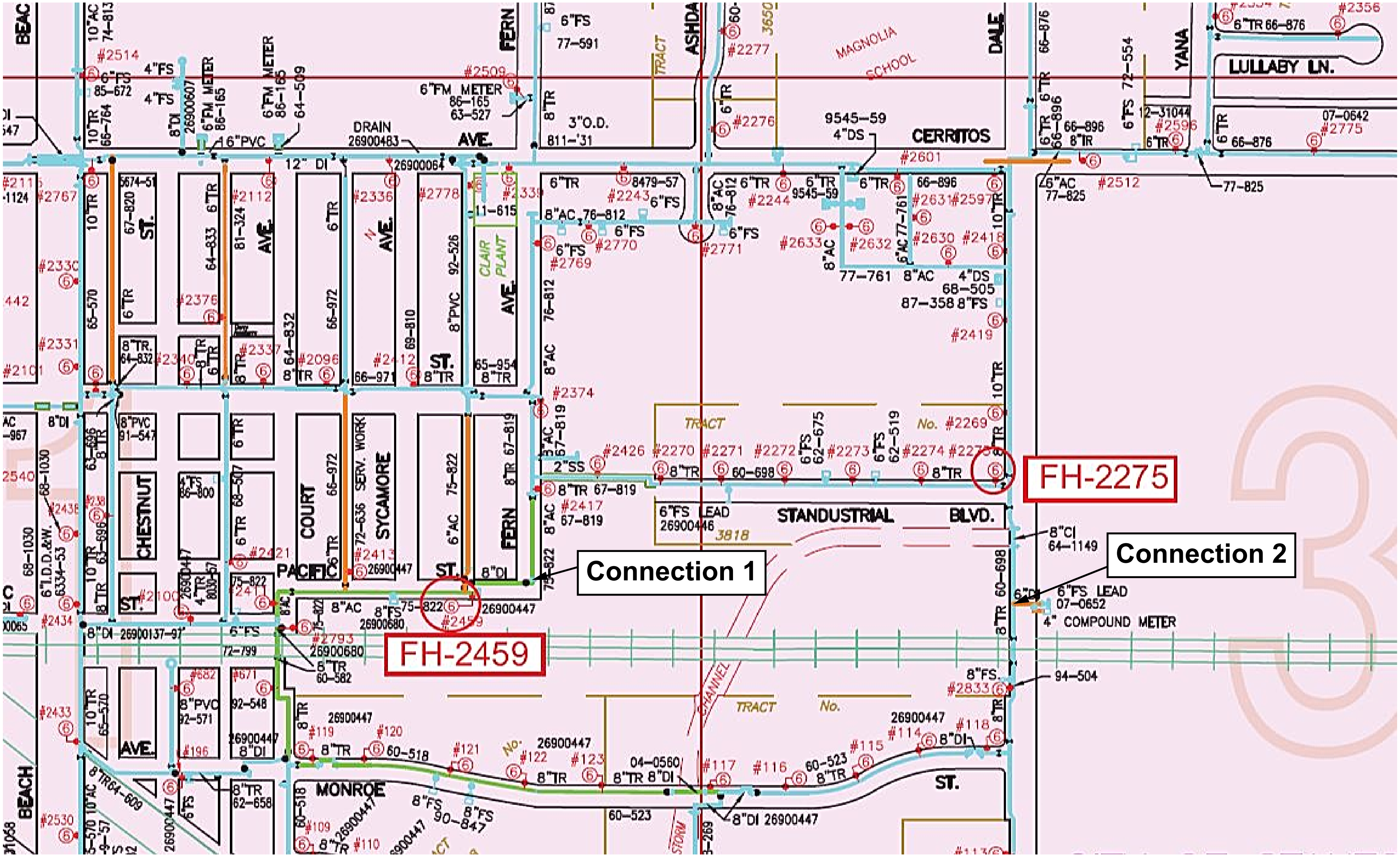


Figure DRA56-1
Connection Points with
GSWC Distribution System
Stanton Energy Reliability Center AFC
Orange County, California

ch2m

Attachment DRA57-1
Hydrant Flow Calculation Results

OCFA WATER AVAILABILITY FORM

SECTION A: To be completed by customer

Project Name: Stanton Energy Reliability Center OCFA SR #: ASSIGNED UPON PLAN SUBMITTAL

Project Address: 8230 Pacific Street City: Stanton

Applicant Phone #: (916) 492-9486 Fax #: (916) 880-5318

Area of largest building (See Note) ft²; Construction type? (check one): IA IB IIA IIB IIIA IIIB IV VA VB

(Const. Type I, not occupied)

Is this building sprinklered throughout? (check one) ☒ N ☐ Y

(**NOTE** Planned use is for an unstaffed, remotely operated electric generating unit. No occupied areas or rooms are included.)

SECTION B: To be completed by local water department/district

Customer to provide results to OCFA

Water Department/District: GOLDEN STATE WATER COMPANY

Test location (indicate address or cross-streets & provide reference map): PACIFIC ST W/O FERN AVE

Hydrant number(s) (if applicable): FH-2459

Elevation of test hydrant: 65' EST feet above sea level

Date of Test[1]: MODEL Time of test[1]: — am pm

[1] Test to be performed as close as possible to the time that the lowest flows and pressures are expected (e.g., M-F, 6:00 – 9:00 am and 5:00 - 9:00 pm)

FLOW TEST RESULTS *TEST INFORMATION IS VALID FOR 6 MONTHS FROM DATE TEST IS PERFORMED*			
Static pressure:	77 psi	**Residual pressure:**	67 psi
Observed flow:	1,500 gpm	**Flow calc'd at 20 psi:**	4,700 gpm

☒ Check the box if the test information above was obtained in a manner other than an actual flow test (i.e. by computer modeling).

~~Based on fluctuations known to exist at the site of the test, provide estimated values for the following:~~			
~~**Maximum static pressure**~~	~~psi~~	~~**Minimum static pressure**~~	~~psi~~
~~**Minimum residual pressure**~~	~~psi~~	~~**Minimum residual flow**~~	~~gpm~~

I have witnessed and/or reviewed this water flow information and by personal knowledge and/or on-site observation certify that the above information is correct.

Name: STAN YARBROUGH Company/Agency: GSWC

Signature: Stan Yarbrough Title: OPERATIONS ENGINEER

Date: 6/15/16

OCFA WATER AVAILABILITY FORM

SECTION A: To be completed by customer

Project Name: Stanton Energy Reliability Center OCFA SR #: ASSIGNED UPON PLAN SUBMITTAL

Project Address: 10711 Dale Avenue City: Stanton

Applicant Phone #: (916) 492-9486 Fax #: (916) 880-5318

Area of largest building (See Note) ft²; Construction type? (check one): IA IB IIA IIB IIIA IIIB IV VA VB

(Const. Type I, not occupied)

Is this building sprinklered throughout? (check one) [X] N [ ] Y

(**NOTE** Planned use is for an unstaffed, remotely operated electric generating unit. No occupied areas or rooms are included.)

SECTION B: To be completed by local water department/district

Customer to provide results to OCFA

Water Department/District: GOLDEN STATE WATER COMPANY

Test location (indicate address or cross-streets & provide reference map): DALE NW COR STANDUSTRIAL

Hydrant number(s) (if applicable): FH-2275

Elevation of test hydrant: 69' EST feet above sea level

Date of Test[1]: MODEL Time of test[1]: — am pm

[1] Test to be performed as close as possible to the time that the lowest flows and pressures are expected (e.g., M-F, 6:00 – 9:00 am and 5:00 - 9:00 pm)

FLOW TEST RESULTS *TEST INFORMATION IS VALID FOR 6 MONTHS FROM DATE TEST IS PERFORMED*			
Static pressure: 75	psi	**Residual pressure:** 65	psi
Observed flow: 1500	gpm	**Flow calc'd at 20 psi:** 4,350	gpm

[X] Check the box if the test information above was obtained in a manner other than an actual flow test (i.e. by computer modeling).

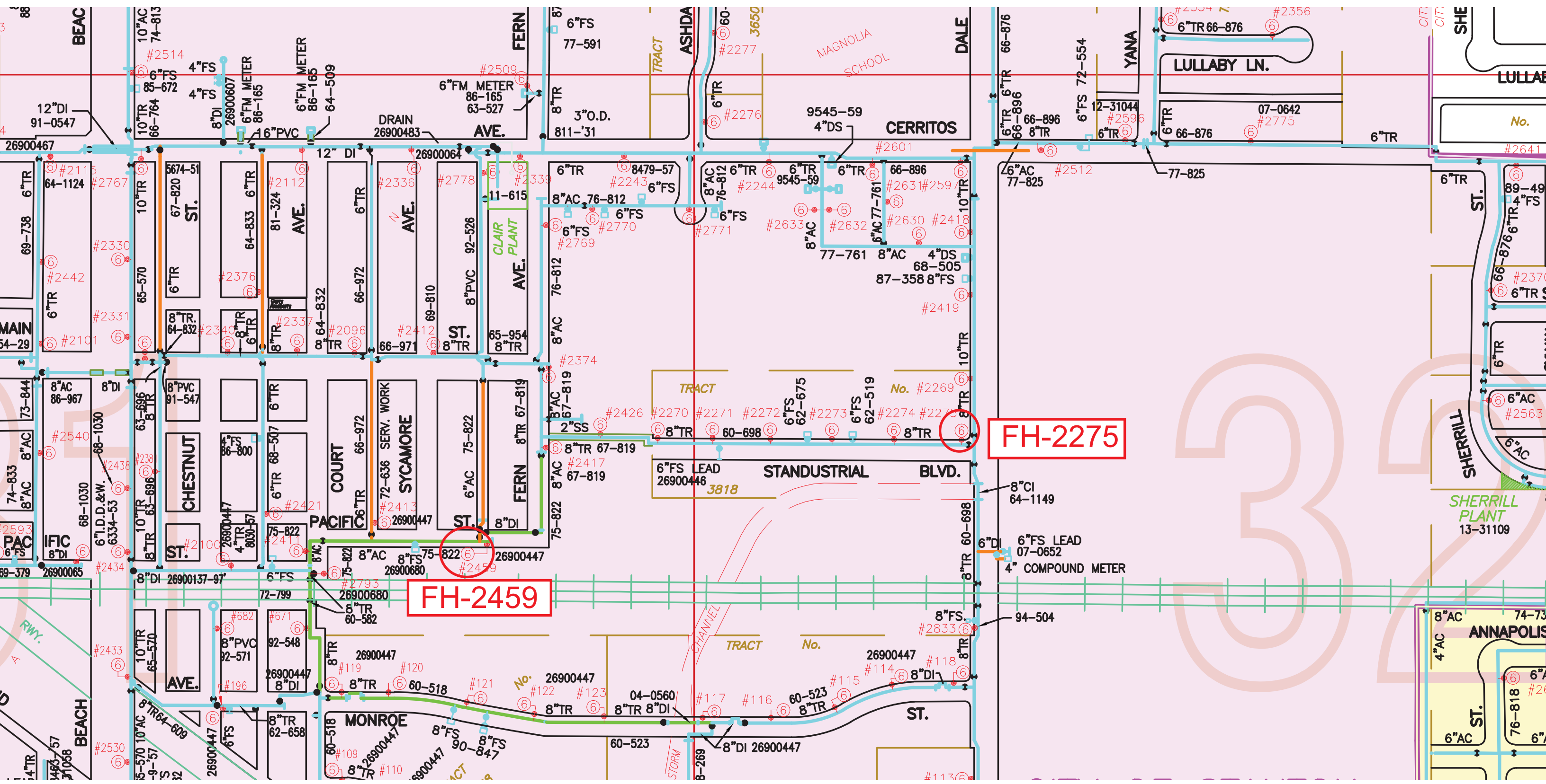
~~Based on fluctuations known to exist at the site of the test, provide estimated values for the following:~~			
~~**Maximum static pressure**~~	~~psi~~	~~**Minimum static pressure**~~	~~psi~~
~~**Minimum residual pressure**~~	~~psi~~	~~**Minimum residual flow**~~	~~gpm~~

I have witnessed and/or reviewed this water flow information and by personal knowledge and/or on-site observation certify that the above information is correct.

Name: STAN YARBROUGH Company/Agency: GSWC

Signature: Stan Yarbrough Title: OPERATIONS ENGINEER

Date: 6/15/16



FH-2275
FH-2459
CERRITOS
AVE.
STANDUSTRIAL
BLVD.
PACIFIC
ST.
MONROE
ST.
CHESTNUT
COURT
SYCAMORE
FERN
DALE
YANA
LULLABY LN.
SHERRILL
ANNAPOLIS
BEACH
MAGNOLIA
SCHOOL
TRACT
No.
CLAIR PLANT
SHERRILL PLANT
13-31109
4" COMPOUND METER
6"FS LEAD
07-0652
94-504
8"CI
64-1149

3.0 Transmission System Engineering (A63)

Cluster 7 Phase II Report

A63. Provide a complete Queue Cluster 7 Phase II report that includes study of the 10-MW battery storage. The distribution analysis part of the report should be coordinated with SCE and approved by the California ISO for interconnection of nominal output of a 98 MW generation plant. The study should include a distribution analysis of the SCE system with the proposed project and a mitigation plan for any identified sub-transmission and distribution reliability criteria violations. Also, identify the reliability and planning criteria utilized to determine the reliability criteriaviolations.

Response: SERC has submitted three separate, active interconnection requests with SCE as the plans for SERC configuration have evolved over time. The sequence of interconnection requests follows:

- A Cluster 7 Interconnection Request, WDT1187, was filed before SCE's procurement authority (for MWs and technology types) had been determined by the CPUC. SERC had incomplete guidance at that time about what type of interconnection would ultimately be needed. Phase I and Phase II Study Reports have been received for WDT1187, and the Phase II Study Report was previously submitted to the CEC.
- After SCE's procurement authority was determined, SERC filed an additional Interconnection Request in Cluster 8, WDT1293, to determine via a load study if there would be any charging issues if energy storage were developed at the SERC site in lieu of (or in addition to) the 150 MW of synchronous generation that was requested in SERC's Cluster 7 Interconnection Request. Phase I and Phase II Study Reports have been received for WDT1293.
- SERC then filed an Interconnection Request in Cluster 9 (WDT1391), which consolidated both technologies (two LM6000s and up to 50 MW of energy storage) in a single request. The Phase I Study Report has been received, and a Phase II study report is expected in December 2017. The Phase I Study Report is included with this response as Attachment DRA63-1.

All three of these Interconnection Requests (Interconnection Queue Positions WDT1187, WDT1293 & WDT1391) seek to deliver energy/services to the same Energy Delivery Point (the Barre 66 kV bus), and are intended to be mutually exclusive; i.e., only one of the positions will be converted to a Large Generator Interconnection Agreement. The two remaining positions will be cancelled. Since SERC already has a study pending, via its Cluster 9 Interconnection Request, for two LM6000s plus 50 MWs of energy storage, SCE determined that a request to study that same configuration via Cluster 7 would be confusing and inefficient. SCE and SERC have considered the identified impacts from each of the three interconnection requests as they work to identify the ultimate interconnection configuration and associated impacts.

However, pending completion of the Cluster 9 Phase II report, SERC offers the following observations. The Cluster 7 Phase II Study Report was for an interconnection of 150 MW of synchronous generation and represents the largest and maximum potential impact to the Barre Substation, the surrounding 220 kV system, 66 kV distribution circuits, and remote substation facilities. The Cluster 7 Phase II Study did not identify any requirements to re-conductor any transmission lines (neither 66 kV nor 220 kV) and all other works that were required were completely within the footprint of existing SCE substations. Similarly, the Cluster 9 Phase I Study did not identify any requirements to re-conductor any transmission lines (neither 66 kV nor 220 kV) and all other works that were required were completely within the footprint of existing SCE substations. The Cluster 9 Phase II Study is not expected to find any conclusions that materially vary from previous studies.

With respect to the reliability and planning criteria used to determine the reliability criteria violations, in all of the studies, SCE used a standard approach to determining overloaded facilities or voltage deviations. SCE modeled all of the proposed facilities in the Cluster, and then performed a model run (using General Electric PSLF software) that tested for every possible contingency per Western Area Coordinating Council criteria. The results of the modeling (and a description of the modeling assumptions and reliability criteria) are included in the Cluster 9 Phase I Study Report.

Attachment DRA63-1
Phase I Cluster Study Report, Cluster 9

Queue Cluster 9 Phase I Interconnection Study Report

SCE Metro Area Report

Final Report

1/17/2017

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

TABLE OF CONTENTS

Appendices

A. INTRODUCTION

In accordance with the California Independent System Operator (CAISO) Generator Interconnection and Deliverability Allocation Procedures (GIDAP) Tariff Appendix DD, this Queue Cluster 9 (QC9) Phase I Study was performed to determine the combined impact of all the QC9 Phase I projects on the CAISO Controlled Grid. There were sixty-one (61) QC9 Phase I generation projects in Southern California Edison (SCE), Valley Electric Association's (VEA), and DCR Transmission ,LLC service territory modeled in the Phase I Study. Five (5) general study areas were formed based on the electrical impact among the generation projects: Northern Bulk Area, Eastern Bulk Area, East of Pisgah (EOP) Bulk Area, North of Lugo (NOL) Bulk Area and Metro Bulk Area. This report focuses on the Metro Area which covers the LA Basin but focuses on the Orange County area encompassed by Alamitos, Del Amo, Center, Lewis, Laguna Bell, Mesa, Lighthipe, Barre, Villa Park, Serrano, Chino, Viejo, Santiago, Johanna, and Ellis Substations. This report focuses on the Metro Area study and provides the following:

- Transmission system impacts caused by the addition of QC9 Phase I projects requesting interconnection in the area.
- System reinforcements necessary to mitigate the adverse impacts under various system conditions of the QC9 Phase I projects requesting interconnection in the area.
- A list of required facilities and maximum cost responsibility, based on unit cost, for Reliability Network Upgrades (RNUs) and Local Delivery Network Upgrades (LDNUs) assigned to each QC9 Interconnection Request (IR).
- A good faith cost estimate of the Interconnection Facilities (IF) cost.
- A cost estimate of Area Delivery Network upgrades (ADNUs) identified as needed to increase area generation deliverability beyond Transmission Plan Deliverability.

To determine the system impacts caused by QC9 Phase I projects, the following studies were performed:

- Steady State Power Flow Analyses
- Transient Stability Analyses
- Reactive Power Deficiency Analyses
- Short-Circuit Duty (SCD) Analyses
- Deliverability Assessment
- Service Date and Commercial Operation Date Assessment

A.1 QC9 Phase I Generation Project Interconnection Information

A total of nine (9) generation projects totaling 344.0 MW are seeking interconnection into the Metro Area.

Four (4) generation projects with a total maximum output of 299 MW included the SCE's Non-CAISO controlled subtransmission system in the Area as shown in Table A.1. This table lists the entire generator project's essential data obtained from the SCE WDAT Generation Queue. Additionally, there are five (5) generation projects totaling a maximum output of 45.0 MW included the SCE's Non-CAISO controlled distribution system in the Area as shown in Table A.2.

Table A.1: SCE QC9 Projects (Subtransmission)

#	SCE#	Deliverability Status	Technology Type	Project Size (MW) [1]	Point of Interconnection (Point of Delivery)	COD
1	WDT1390	FC	Photovoltaic	20	Chestnut 66 kV Bus (Johanna 220 kV Switchrack)	12/01/2019
2	WDT1391	FC	Gas Turbine/Storage	149	Barre 66 kV (Barre 220 kV Switchrack)	12/15/2019
3	WDT1396	FC	Storage	30	Johanna-Camden 66 kV Line (Johanna 220 kV Switchrack)	12/31/2018
4	WDT1401	FC	Photovoltaic/ Storage	100	Bolsa 66 kV (Barre 220 kV Switchrack)	12/31/2019
			Total	299		

Table A.2: SCE QC9 Projects (Distribution)

#	CAISO/SCE#	Deliverability Status	Technology Type	Project Size (MW) [2]	Point of Interconnection (Point of Delivery)	COD
1	WDT1388	FC	Storage	10	Johanna 12 kV Circuit (Johanna 220 kV Switchrack)	10/1/2019
2	WDT1392	FC	Storage	10	Johanna 12 kV Circuit (Johanna 220 kV Switchrack)	11/15/2018
3	WDT1393	FC	Storage	10	Johanna 12 kV Circuit (Johanna 220 kV Switchrack)	11/15/2018
4	WDT1397	FC	Storage	6	Solitaire 12 kV Circuit (Johanna 220 kV Switchrack)	9/1/2019
5	WDT1398	FC	Storage	9	Yahtzee 12 kV Circuit (Johanna 220 kV Switchrack)	9/1/2019
			Total	45.0		

A.2 Study Objectives

This QC9 Phase I Study was performed in accordance with Section 6.2 of Appendix DD of the CAISO Tariff, which states that the Phase I Study shall:

i. Evaluate the impact of all Interconnection Requests received during the Cluster Application Window in 2016 on the CAISO Controlled Grid.
ii. Preliminarily identify all Local Delivery Network Upgrades (LDNUs) and Reliability Network Upgrades (RNUs) needed to address the impacts of the CAISO Controlled Grid of the Interconnection Requests.
iii. Preliminarily identify for each Interconnection Request required Interconnection Facilities.
iv. Assess the Point of Interconnection selected by each Interconnection Customer and potential alternatives to evaluate potential efficiencies in overall transmission upgrades costs.

[1] These values represent the MW values as shown in SCE's Interconnection Queue. Actual MW delivered at the POI for each project is discussed in the corresponding Project's Appendix A.

[2] These values represent the MW values as shown in SCE's Interconnection Queue. Actual MW delivered at the POI for each project is discussed in the corresponding Project's Appendix A.

v. Establish the maximum cost responsibility for LDNUs and RNUs, based on unit cost, assigned to each Interconnection Request, until the issuance of the Phase II Interconnection Study Report.
vi. Provide a good faith estimate of the cost of Interconnection Facilities for each Interconnection Request.
vii. Provide a unit cost estimate of Area Delivery Network Upgrades (ADNUs) for each Generating Facility in a Queue Cluster Group Study.

The Phase I Interconnection Study will consist of a short-circuit analysis, a stability analysis to the extent the CAISO and applicable Participating TO(s) reasonably expect transient or voltage stability concerns, a power flow analysis, including off-peak analysis, and an On-Peak Deliverability Assessment (and Off-Peak Deliverability Assessment which will be for informational purposes only) for the purpose of identifying LDNUs and estimating the cost of ADNUs, as applicable.

The Phase I Study report shall set forth the applicable cost estimates for RNUs, LDNUs, ADNUs and Participating TOs Interconnection Facilities that shall be the basis for Interconnection Financial Security Postings under GIDAP Section 11.2 and 11.3 where the cost estimations applicable to the total of RNUs and LDNUs are based upon the Phase I Interconnection Study (because the cost estimation for the subtotal of RNUs and LDNUs were lower and so establish maximum cost responsibility under GIDAP Section 10.1), the Phase I Study report shall recite this fact.

The Phase I Interconnection Study will provide, without regard to the requested Commercial Operation Dates of the Interconnection Requests, a list of RNUs and LDNUs to the CAISO Controlled Grid that are preliminarily identified as required as a result of the Interconnection Requests in a Group Study or as a result of any Interconnection Request studied individually and Participating TO's Interconnection Facilities associated with each Interconnection Request, the estimated costs of ADNUs.

The Phase I Study analysis was performed to identify the conceptual IF, Plan of Service RNUs, RNUs, LDNUs, ADNUs, and Distribution Upgrades necessary to safely and reliably interconnect the QC9 Phase I projects and provide the requested deliverability. An estimated cost and construction schedule for these facilities are provided in this report.

B. STUDY ASSUMPTIONS

B.1 Load and Intertie Flow Assumptions

The 2021 On-Peak reliability cases modeled 24,716 MW of load (1-in-10 load forecast). The 2021 Off-Peak reliability cases modeled 10,696 MW, approximately 45% of On-Peak load.

The Deliverability Assessment On-Peak case modeled 23,648 MW load (1-in-5 load forecast) in the SCE system with an import target as shown in Table B-1 of Appendix B.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study area.

B.2 Generation Dispatch Assumptions

Generation assumptions for the area are shown in the tables[3] provided in Appendix B. Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf . In the On-Peak Deliverability Assessment, the On-Peak Qualified Capacity for proposed Full Capacity generation projects is set to 100% of the requested P_{Max} for solar generation initially. The On-Peak Qualified Capacity may be adjusted to 93% for solar generation if a mix of different fuel type generations is identified in the Deliverability Assessment as the 5% Circle for a transmission limitation. The On-Peak Qualified Capacity for the energy storage facilities are set to their respective 4-hour discharging capacity. In the Off-Peak Deliverability Assessment, the proposed Full Capacity wind generation is dispatched at its maximum nameplate output and solar generation at 85% of its nameplate output.

In both the On-Peak and the Off-Peak Reliability Assessment, all generation is dispatched at 100% for the study area or sub-areas.

B.3 CAISO-Approved Transmission Project Assumptions

QC9 Phase I Study included the modeling of all CAISO-approved transmission projects in the area base cases that are not yet fully constructed and placed into service.

B.3.1 Upgrades Identified through the Generation Interconnection Process which are included in an executed Generator Interconnection Agreement (GIA):

i. Previously Identified Vincent SCD Mitigation

The need to replace the following four 50 kA 500 kA circuit breakers to increase the rated interrupting current was identified as part of the QC3&4 studies:

- Pos. No.2 CB722
- Pos. No.5 CB852 and CB952
- Pos. No.6 CB862

The timing for the installation and completion of the breaker upgrades are contingent on future development of generation projects requesting interconnection. The identification of need was based on the assumption that all queued generation projects actually materialize and are interconnected as energy only. Timing to implement this incremental SCD mitigation is currently estimated at 27 months from the date the need is identified to be required.

B.3.2 Upgrades Identified Through the CAISO Transmission Plan

Studies performed under the CAISO Transmission Plan have identified the need for transmission upgrades. CAISO approved transmission upgrades include the following:

i. Eldorado-Harry Allen 500 kV Project

[3] These tables reflect the latest project information at the time the study was performed and may not reflect the numerous changes to the queue (i.e. withdraws, project size reductions, etc.) that have taken place during the course of the study.

The project consists of constructing a new 500 kV transmission line from Harry Allen 500 kV Substation to the joint-owned Eldorado 500 kV Substation both located in Nevada. The current estimated in-service date of this project is 2020.

ii. Santiago Synchronous Condenser
The project consists of installing a 225 MVAR synchronous condenser system at SCE's Santiago 220 kV Substation. The current estimated in-service date of this project is 2017.

iii. Delany-Colorado River 500 kV (DLCR) Project
The project consists of constructing a new 500 kV transmission line from Delaney 500 kV Substation located in Arizona to SCE's Colorado River 500 kV Substation. The current estimated in-service date of this project is 2020.

iv. Eldorado Line Swap Project
The project consists of reconfiguring the Eldorado-Moenkopi and Eldorado-Mohave 500 kV T/Ls to eliminate the adjacent circuit transmission corridor contingency of the Eldorado-Lugo and Eldorado-Mohave 500 kV T/Ls per WECC regional criteria which drives an overload problem. The current estimated in-service date of this project is June 2018.

v. Eldorado-Lugo Series Capacitor Project
The project consists of upgrading the series capacitor banks located at Eldorado and Lugo Substations on the Eldorado-Lugo 500 kV T/L to a rating of 3,300 A (normal) and 3,960 A (emergency). The project also includes equipping the Eldorado-Lugo 500 kV T/L terminating positions at Eldorado and Lugo Substations with 4,000 A rated equipment. The current estimated in-service date of this project is June 2019.

vi. Lugo-Mohave Series Capacitor Project
The project consists of upgrading the series capacitor banks located at Lugo and Mohave Substations on the Lugo-Mohave 500 kV T/L to a rating of 3,300 A (normal) and 3,960 A (emergency). The project also includes equipping the Lugo-Mohave 500 kV T/L terminating positions at Mohave Substations with 4,000 A rated equipment. The current estimated in-service date of this project is June 2019.

vii. Mesa Loop-In Project
The project consists upgrading the substation to include a 500 kV switchrack and three 500/220 kV transformer banks served by looping the Vincent-Mira Loma 500 kV transmission line, Rio Hondo-Laguna Bell 220 kV transmission line and Goodrich-Laguna Bell 220 kV transmission line in-and-out of the Mesa substation. These upgrades are currently estimated to be completed in 2020.

viii. Laguna Bell Corridor Upgrade Project
The project consists of upgrading the Mesa-Laguna Bell No. 1 and No. 2 and Mesa-Lighthipe 220 kV lines to their conductor ratings. The project includes upgrading the Laguna Bell-Mesa No.1, southern portion of the Laguna Bell-Rio Hondo (portion that will become the future Laguna Bell-Mesa No.2 220 kV) and the Mesa-Lighthipe 220 kV lines to their conductor rating by replacing terminal equipment at Laguna Bell and Lighthipe Substations and removing transmission line clearance limitations on one span each of the Laguna Bell-Mesa No. 1 and Lighthipe-Mesa 220 kV lines. These upgrades are currently estimated to be completed in 2020.

ix. Victor Loop-In Project

The project consists of looping the existing Kramer-Lugo No.1 and No.2 220 kV transmission lines into the existing Victor Substation in order to mitigate transient voltage dip concerns identified under loss of both the existing Lugo-Victor No.1 and No.2 220 kV transmission lines. As part of the Project, both the Mojave Desert RAS and HDPP RAS described below will be modified to reflect the system topology change. Upon completion of the project, the existing Kramer-Lugo No.1 and No.2 220 kV transmission lines will become the Kramer-Victor No.1 and No.2 220 kV lines and the Lugo-Victor No.3 and No.4 220 kV transmission lines. The current estimated in-service date of this project is December 2016.

Due to the construction requirements of the upgrades discussed above, all queued projects in the EOP Area may be subject to increased exposure to congestion management, i.e. generation curtailments while upgrades are under construction. The extent of congestion is dependent on many factors including the actual in-service date of queued generation projects.

B.4 Existing Remedial Action Scheme (RAS) and Operating Procedures

B.4.1 El Segundo N-2 Remedial Action Scheme

The El Segundo N-2 RAS is contingency based, generation-tripping scheme that trips pre-selected generating units at El Segundo Energy Center (ESEC). When ESEC generation is high the loss of the El Nido-La Fresa No.3 and El Nido-La Fresa No.4 220 kV transmission lines will overload El Nido-La Cienega 220 kV transmission line.

The El Segundo N-2 RAS monitors the status and loading of the following three (3) lines:

- El Nido-La Fresa No. 3 220 kV Transmission Line
- El Nido-La Fresa No. 4 220 kV Transmission Line
- El Nido-La Cienega 220 kV Transmission Line

B.4.2 Operating Procedures

Existing System Operating Bulletins (SOB) and Operating Procedures (OP) may be relevant for QC9 Study. These include, but are not limited to, the following:

- Critical System Voltage
- System Voltage Control

Additionally OP, which may include curtailing the output of the QC9 projects during planned or extended forced outages may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' COD.

B.5 Mitigation Identified through the Generation Interconnection Process which is not included in an executed GIA

The following summarizes mitigation identified through the Generation Interconnection Process which is not included in an executed GIA but were assumed in place for the pre-QC9 Phase I analysis in order to enable full stressing of the system are as follows:

B.5.1 Network Upgrades

i. Barre 220 kV SCD Mitigation

Overstressed circuit breakers were identified to be triggered on all of the Barre 220 kV circuit breakers with the inclusion of QC7 Phase II Projects in the LA Basin Area. Drivers for the Barre 220 kV SCD include assumptions corresponding to existing repower of units classified as Once-Through-Cooling (OTC) as well as interconnection of new generation resources. As part of QC7 Phase II, the recommended mitigation involved lowering fault duty at Barre by developing operating procedures that would limit the operation of Metro Area generation near the Barre Substation. Such reliance would be expanded to include new QC8 Phase II generation units seeking interconnection near the Barre Substation.

ii. El Segundo N-2 Remedial Action Scheme Modification

Queue Cluster studies performed as part of QC3&4 identified that the inclusion of additional generation within the El Segundo Corridor requires adding such new generation to an existing El Segundo RAS. Changes to load demand forecast have resulted in the identification of need for additional arming points to monitor for loss of additional transmission facilities. The current RAS monitors for loss of two of the following 220 kV transmission lines:

- El Nido – La Fresa No.3 220 kV
- El Nido – La Fresa No.3 220 kV
- El Nido – La Cienega 220 kV

Reductions to the load demand forecast have identified the need to expand this RAS to include monitoring of the Chevmain-El Nido and converting the RAS from an N-2 contingency RAS to an N-1 and N-2 contingency RAS.

B.5.2 Distribution Upgrades

i. Barre 66 kV SCD Mitigation

As part of the interconnection study for a previously queued ahead project, the need to replace 66 kV circuit breakers at Barre was identified. Currently, the breakers requiring upgrade to support queued ahead project(s) are as follows:

- Pos. No.16 CB19 and CB20
- Pos. No.18 CB23 and CB24
- Pos. No.20 CB27 and CB28
- Pos. No.23 CB33 and CB34
- Pos. No.24 CB35 and CB36
- Pos. No.25 CB37 and CB38
- Pos. No.27 CB41 and CB42
- Pos. No.28 CB43 and CB44
- Pos. No.30 CB47 and CB48
- Pos. No.31 CB49 and CB50
- No. 1 CAP Bank CB100

The timing for the installation and completion of these breaker upgrades are contingent on future development of generation projects requesting interconnection within the Barre 66 kV Subtransmission System. Consequently, generation projects seeking interconnection outside of the Barre 66 kV Subtransmission System do not require these upgrades to enable interconnection. Lastly, the timing to implement this SCD mitigation is currently estimated at 27 months from the date that the GIA for project(s) triggering need is executed, authorization to proceed (ATP) is provided, financial security postings are made, and payment(s) as outlined in the GIA are satisfied.

ii. Villa Park 66 kV SCD Mitigation

As part of the QC7 Phase II studies, the need to replace the following 66 kV circuit breaker was identified:

- Pos. No.12 CB95

The timing for the installation and completion of the breaker upgrades are contingent on future development of generation projects requesting interconnection in the Metro Area as part of QC7 Phase II. Timing to implement this SCD mitigation is currently estimated at 27 months from the date that the GIA for project(s) triggering need is executed, Authorization to Proceed (ATP) is provided, posting of financial security is made, and payment(s) as outlined in the GIA are provided.

B.6 Pre-QC9 Affected System Transmission Upgrades

No transmission upgrades outside the CAISO controlled grid have been identified by any Affected System in the previous generation interconnection studies for the area. However, neighboring utilities may identify the need for physical upgrades within their system not identified in the studies.

B.7 Power Flow Base Cases

The QC9 Phase I Study power flow cases were developed from the CAISO approved transmission expansion base case series representing year 2021 load forecast (On-Peak and Off-Peak load conditions). These power flow study cases included all CAISO approved transmission projects impacting SCE's service territory, as well as all earlier queued Serial Group and cluster generation projects with associated Network Upgrades regardless of the in-service date. Analyses were also performed to determine if QC9 Phase I projects required Network Upgrades previously triggered but not yet having an executed GIA to address reliability concerns or provide for Full Capacity Deliverability Status.

The following power flow cases were used for the analysis in the area QC9 Phase I Study:

2021 On-Peak Full Loop Power Flow Case:
Power flow analyses were performed using SCE's On-Peak full loop base case (in General Electric Power Flow format). This base case was developed from base cases that were used in the SCE annual transmission expansion plan studies. It has a 1-in-10 year heat wave load level for the SCE service territory.

2021 Off-Peak Full Loop Power Flow Case:
Power flow analyses were also performed using the Off-Peak full loop base case in order to evaluate system performance due to the addition of Phase I generation projects during light

load conditions. The Off-Peak load was modeled approximately 45% of the On-Peak load level.

As discussed above, the power flow cases modeled all CAISO approved SCE transmission projects, regardless of their proposed in-service date. The power flow cases also modeled all Pre-QC9 Phase II generation projects regardless of their proposed COD. These generation projects were modeled along with their identified transmission upgrades necessary for their interconnection and/or delivery for those projects which have an executed GIA.

B.8 Deliverability Base Cases

B.8.1 Master Deliverability Assessment Base Case

A master base case was developed for the QC9 Phase I On-Peak deliverability assessment which modeled all the Pre-QC9 Phase I and QC9 Phase I generation projects. The resources in the master base case are dispatched as follows:

- Existing capacity resources are dispatched at 80% of their summer peak Net Qualified Capacity (NQC).
- Proposed full capacity resources are dispatched to balance load and maintain expected imports, but not exceeding 80% of their summer peak NQC.
- Energy-Only (EO) resources are considered off-line.
- Imports are at the maximum summer peak simultaneous historical level by branch group as shown in Table B-1 in Appendix B.
- Non-pump load is at the 1-in-5 peak load level for CAISO.
- Pump load is dispatched within expected range for summer peak load hours.

B.8.2 Area Deliverability Assessment Base Case

The area deliverability assessment base case was developed from the master base case by dispatching all proposed full capacity resources in the area to 80% of their NQC.

C. RELIABILITY STANDARDS, CRITERIA AND METHODOLOGY

C.1 Reliability Standards and Criteria

The generator interconnection studies were conducted to ensure the CAISO Controlled Grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards.

C.1.1 NERC Reliability Standards

The studies analyzed the need for transmission upgrades and additions in accordance with NERC reliability standards, which set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the ISO, as a registered NERC planning authority, and the PTOs, as Transmission Planners, and are the primary standards for the interconnection of new facilities and system performance[4]:

- FAC-001: Facility Connection Requirements[5]

[4] http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States

[5] http://www.nerc.com/files/FAC-001-1.pdf; FAC-001 is applicable to the PTOs, but not to the CAISO

- FAC-002: Coordination of Plans for New Facilities[6]
- TPL-001-4: Transmission System Planning Performance Requirements[7]

C.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-3[8] Regional Criteria are applicable to the ISO as a planning authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.

C.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.[9] These standards cover the following:

- Address specifics not covered in the NERC reliability standards and WECC regional criteria.
- Provide interpretations of the NERC reliability standards and WECC regional criteria specific to the ISO Controlled Grid.
- Identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

C.1.4 Contingencies

The system performance with the addition of the generation projects will be evaluated under normal conditions (**Category P0**) and following loss of single or multiple Bulk Electric System (BES) elements as defined by the applicable reliability standards and criteria.

Single contingency (Category P1)

The assessment will consider all possible Category P1 contingencies based upon the following:

- 3Φ Fault with loss of one generator (P1.1)[10]
- 3Φ Fault with loss of one transmission circuit (P1.2)
- 3Φ Fault with loss of one transformer (P1.3)
- 3Φ Fault with loss of one shunt device (P1.4)
- SLG Fault with loss of a single pole of DC lines (P1.5)

Note(s):

1. The purpose of generation interconnection studies is to evaluate stressed system conditions due to the addition of new generators. Because Category P1.1 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. As such, Category P1.1 was not evaluated as part of the Phase I studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO.
2. Category P1.5 is not applicable in the Metro Area as no DC lines exist within this area. Category P1.5 was examined as part of the QC9 GIP studies performed for the East of Pisgah Area (Intermountain DC line) and Northern Area (Pacific DC Intertie).

Single contingency (Category P2)

The assessment will consider all Category P2 contingencies based upon the following:

[6] http://www.nerc.com/files/FAC-002-2.pdf
[7] http://www.nerc.com/files/TPL-001-4.pdf
[8] https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-3.docx
[9] http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf
[10] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

- Loss of one transmission line section without a fault (P2.1)
- SLG Fault with loss of one bus section (P2.2)
- SLG Fault with loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
- SLG Fault with loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Note(s):

1. Category P2.1 is not applicable for the Metro Bulk area as there are no multi-segmented bulk transmission lines.
2. Category P2.2 is only applicable at the Alamitos, Huntington Beach, Mira Loma, Mesa (future), San Onofre, Santiago, and Walnut Substations in the Metro area bulk system; however, all of the aforementioned substation designs are such that loss of one bus section does not result in any additional P2.2 impacts that are not already addressed as part of Category P1.
3. All of the Metro area bulk substations are designed as either double-bus, double-breaker or breaker-and-a-half configuration. Such design configuration results in Category P2.3 power flow conditions to be the same as Category P4. For stability, Category P4 would experience more severe performance due to the associated delayed clearing. As such, Category P2.3 will be examined as part of Category P4 power flow. Under stability analysis, if criteria violation is identified with delayed clearing, normal clearing will also be reviewed.
4. With the exception of the Walnut Substation, the substation design in this Metro area is such that loss of one bus-tie breaker does not result in any additional impact that is not already addressed as part of Category P1. As a result, the only Category P2.4 contingency requiring evaluation in the Metro area is loss of the SCE either the North bus section at Walnut, or the South bus section.

Multiple contingency (Category P3)

The assessment will consider selected Category P3 contingencies with the loss of a ***generator unit*** followed by system adjustments and the loss of the following:

- 3Φ Fault with loss of one generator (P3.1)[11]
- 3Φ Fault with loss of one transmission circuit (P3.2)
- 3Φ Fault with loss of one transformer (P3.3)
- 3Φ Fault with loss of one shunt device (P3.4)
- SLG Fault with loss of a single pole of DC lines (P3.5)

Note(s):

1. The purpose of generation interconnection studies is to evaluate stressed system conditions due to the addition of new generators. Because Category P3 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. As such, none of Category P3 was not evaluated as part of the Phase I studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO.

Multiple contingency (Category P4)

The assessment will consider selected Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5 and bus-tie-breaker for P4.6) attempting to clear a SLG fault on one of the following:

- generator (P4.1)
- transmission circuit (P4.2)

[11] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

- transformer (P4.3)
- shunt device (P4.4)
- bus section (P4.5)
- bus associated with the bus-tie-breaker (P4.6)

Note(s):

1. The purpose of generation interconnection studies is to evaluate stressed system conditions due to the addition of new generators. Because Category P4.1 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. In addition, the CAISO utilizes market re-dispatch protocols to ensure that adequate generation dispatch conditions are implemented following loss of any transmission element in Category P4 in order to maintain system performance within standards in anticipation of the next contingency. This re-dispatch may involve curtailment of the generation resources, including those studied as part of this queue cluster. As such, Category P4.1 was not evaluated as part of the GIP studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO.
2. Within the Metro Area impacting Orange County (QC9 sphere of influence), shunt devices are installed at Barre, Chino, Johanna, Laguna Bell, Olinda, Santiago, Viejo, Villa Park, Walnut, and Mira Loma substations. Except for Johanna, all substations are designed as a double-bus, double-breaker or breaker-and-a-half with all elements on bus which connects shunt device fully equipped with circuit breakers. This Category P4.4 power flow conditions are therefore the same as Category P1.4 power flow conditions for all stations except Johanna.
3. Category P4.5 (loss of multiple elements/bus section caused by a stuck breaker attempting to clear a fault on associated bus) results in the same power flow performance as Category P2.4 for the substations in the Metro area and therefore addressed under Category P2.4. Category P4.6 (loss of multiple elements/bus-tie breaker caused by a stuck breaker) results in the same power flow performance as Category P2.2 and/or P2.4 for the substations in the Metro area and therefore addressed under Category P2.2 and/or P2.4.
4. Category P4.6 (loss of multiple elements/bus-tie breaker caused by a stuck breaker) results in the same power flow performance as Category P2.2 and/or P2.4 for the substations in the Metro area and therefore addressed under Category P2.2 and/or P2.4.

Multiple contingency (Category P5)

The assessment will consider selected Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following:

- SLG Fault with loss of one generator (P5.1)
- SLG Fault with loss of one transmission circuit (P5.2)
- SLG Fault with loss of one transformer (P5.3)
- SLG Fault with loss of one shunt device (P5.4)
- SLG Fault with loss of one bus section (P5.5)

Note(s):

1. The purpose of generation interconnection studies is to evaluate stressed system conditions due to the addition of new generators. Because Category P5.1 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. As such, Category P5.1 was not evaluated as part of the GIP studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO.

2. Category P5 power flow conditions to be exactly the same as Category P4.1 (back-up protection results in delayed removal of faulted element) or the same as Category P4 (Zone 2 protection behaves similar to stuck breaker protection). As such, power flow will address Category P5 under Category P1 or Category P4 analysis.

Multiple contingency (Category P6)

Because the CAISO implements congestion management protocols that curtail generation resources under loss of a system element in preparation for the next contingency, the assessment assumed that the new generations could be curtailed following the first contingency as needed. Therefore, the assessment did not consider Category P6 contingencies which involve the loss of two or more (non-generator unit) elements with system adjustment between them. However, Category P6 is addressed as part of SCE's Annual Transmission Planning Process which ensures the system is adequate to maintain appropriate level of service to load demand.

Multiple contingency (Category P7)

The assessment will consider all possible Category P7 contingencies for the SLG fault with the loss of a common structure as follows:

- Any two adjacent circuits on common structure[12] (P7.1)
- Loss of bipolar DC lines (P7.2)

Notes:

1. Category P7.2 is not applicable in the Metro Area as no DC lines exist within this area. Category P7.2 was examined as part of the QC9 GIP studies performed for the East of Pisgah Area (Intermountain DC line) and Northern Area (Pacific DC Intertie).

Other Contingencies – Common Corridor, WECC Project Coordination, Path Rating and Progress Report Processes

The assessment will consider all possible contingencies for the SLG fault with

- Loss of two Adjacent Transmission Circuits[13] on separate towers.

The same performance criteria applicable to P7 contingencies are applied to these other outages.

All possible P1 (except for P1.1), P2, P7 and Other Contingencies are studied. Contingencies in Categories P3 through P6 are selected by taking into account the following factors:

- Amount of generation lost immediately following the outage
- Normal condition loading of a transmission facility
- Bus outages and breaker failures that cause disconnection of the entire bus during the transient period

In general, the contingency categories that allow system adjustment between outages may not be selected for study since the new generators being studied can be redispatched such that they do not contribute to any reliability concerns.

[12] Excludes circuits that share a common structure or common right-of-way for 1 mile or less.

[13] https://www.wecc.biz/Corporate/Project%20Coordination%20Path%20Rating%20and%20Progress%20Report%20Processes.docx

C.2 Steady State Study Criteria

C.2.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating under Category P0 normal conditions (no contingency). Normal overloads are identified in deliverability assessment and reliability study power flow analyses in accordance with Reliability Standard TPL-001-4. It is required that loading of all transmission system facilities be within their normal ratings under the Category P0 conditions.

C.2.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings under Category P1 to P7 contingency conditions. Emergency overloads are identified in the deliverability assessment and reliability study power flow analyses in accordance with Reliability Standards TPL-001-4. It is required that loading of all transmission system facilities be within their emergency ratings under the Category P1 to P7 contingency conditions.

C.2.3 Voltage Criteria

All buses within the ISO Controlled Grid that cannot meet the requirement in Table C.1 will be further investigated. Exceptions to this voltage standard granted by the ISO will be observed in the Phase I Study.

Table C.1: Voltage Criteria
(Bus voltages are relative to the nominal bus voltages of the system under study)

Voltage level*	Normal Conditions** (P0)		Contingency Conditions (P1 ~ P7)		Voltage Deviation	
	V_{min} (P.U.)	V_{max} (P.U.)	V_{min} (P.U.)	V_{max} (P.U.)	P1 ~ P3	P4 ~ P7
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
200 kV - 500kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

*Real-time operating system voltages in this area range from 520-535 kV for 500 kV systems and 225 kV-240 kV for 220 kV Systems.

**Most 500kV buses and many 220/230kV buses have specific requirements per applicable operating procedures. The normal condition bus voltages in the base cases shall be within the ranges per applicable operating procedure. The general V_{min} and V_{max} in this table applies to buses that does not have operating bus range specified otherwise.

C.3 Transient Stability Criteria

Transient stability analysis is a time-domain simulation that assesses the performance of the power system during (and shortly following) a system disturbance. Transient stability studies are performed to ensure system stability following critical disturbances on the system.

The system is considered stable if the following conditions are met:

1. All machines in the WECC interconnected system must remain in synchronism as demonstrated by relative rotor angles (unless modeling problems are identified and concurrence is reached that a problem does not really exist).
2. A stability simulation will be deemed to exhibit positive damping if a line defined by the peaks of the machine relative rotor angle swing curves tends to intersect a second line defined by the valleys of the relative rotor angle swing curves with the passing of time.

Corresponding lines on bus voltage swing curves will likewise tend to intersect. A stability simulation, which satisfies these conditions, will be defined as stable.

3. Duration of a stability simulation run will be ten (10) seconds unless a longer time is required to ascertain damping.
4. The transient performance analysis will start immediately after the fault clearing and conclude at the end of the simulation and;
5. A case will be defined as marginally stable if it appears to have zero percent damping and the voltage dips are within (or at) the WECC Reliability Criteria limits.

Performance of the transmission system is measured against the NERC Reliability Standards and WECC Regional Criteria. WECC Criteria TPL-001-WECC-CRT-3 requires for all Bulk Electric System Facilities that:

1. Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.
2. 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 all P1 through P7 events.
3. For Contingencies without a fault (P2.1 category event), 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.
4. All oscillations that do not show positive damping within 30-seconds after the start of the studied event shall be deemed unstable.

C.4 Voltage Stability and Reactive Power Margin Criteria

Table C.2 summarizes the voltage support and reactive power criteria of requirement WR1 of the WECC Regional Criterion TPL-001-WECC-CRT-2.2. The system performance will be evaluated accordingly.

Table C.2: Reactive Margin Analysis Criteria Summary[14]

Contingency Category	Reactive Power Criteria
P0 and P1	Voltage stability is required at 105% of forecasted peak load or transfer path flow
P2 ~ P7	Voltage stability is required at 102.5% of forecasted peak load or transfer path flow

C.5 Post-Transient Voltage Deviation Criteria

Contingencies that showed significant voltage deviations in the power flow studies will be selected for further analysis using the post-transient voltage deviation shown in Table C.1, which is more stringent than the WECC standard of 8% voltage deviation for single contingencies.

[14] Table 3 represents CAISO's interpretation of how NERC categories B and C would relate to the contingency categories defined in TPL-001-4.

C.6 Power Factor Criteria

Table C.3 summarizes the power factor criteria per the CAISO tariff for the projects.

Table C.3: CAISO Tariff Power Factor Analysis Criteria Summary

Generation Type	Power Factor Criteria
Asynchronous Generator[15]	0.95 leading to 0.95 lagging at the POI[16]
Synchronous Generator	0.95 leading to 0.90 lagging at generator terminals

C.7 Short Circuit Duty Assessment Criteria

C.7.1 Reliability Standards and Criteria

The short circuit analysis will be performed by simulating single-line-to-ground (SLG) and three-phase (3PH) bus faults, which represents the worst-case conditions to determine the maximum available fault current.

SCE uses the following policy to determine breaker replacement responsibility for cluster projects that overstress or increase overstress on existing circuit breakers:

- The fault duties are calculated before and after current cluster projects to identify any equipment overstress conditions. Three-phase (3PH) and single line-to-ground (SLG) faults are simulated without the current cluster projects, as well as with the current cluster projects, including the identified Reliability and Local Delivery Network Upgrades from the power flow analysis.
- All bus locations where the current cluster projects increases the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are identified. These are examined further to determine if any equipment is overstressed as a result of the current cluster interconnections and corresponding network upgrades.

The responsibility to finance short circuit related Reliability Network Upgrades identified shall be assigned to all contributing IRs (projects) pro rata based on their short-circuit duty contribution. Furthermore, if a proposed network upgrade contributes to the adverse short circuit impact, such contribution shall be allocated to the projects triggering the need of the network upgrade based on the same factors used to allocate the proposed network upgrade cost. The project short-circuit duty contribution includes the direct contribution from the generation project and the network upgrade short circuit duty contribution allocated to the generation project.

C.7.2 Interconnection Queue Post QC9 Phase I Projects

Interconnection queue short-circuit duty (SCD) studies were performed to determine the impact on circuit breakers with the interconnection of QC9 Phase I projects to the transmission system. The interconnection queue considered all existing and earlier queued generation interconnection projects and corresponding upgrades into the starting base cases as a pre-condition prior to adding the QC9 Phase I projects. In addition, the interconnection queue included all CAISO approved

[15] An induction, doubly-fed, or electronic power generating unit(s) that produces 60 Hz (nominal) alternating current, such as solar PV, wind, battery storage generator, etc.

[16] The CAISO Tariff requires that projects be able to meet power factor requirements of 0.95 lagging and 0.95 leading at the POI, if studies identify the need based on meeting reliability and safety requirements. The requirement will change pending FERC approval of ISO's compliance filing to FERC Order 827.

transmission projects and all SCE approved non-CAISO upgrades and system modifications (such as open Mira Loma AA-Bank) into the starting base case as a pre-condition prior to adding the QC9 Phase I projects. The fault duties were calculated to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the QC9 Phase I projects to establish the starting base line.

The QC9 Phase I projects, including the identified Reliability and Local and Area Delivery Network Upgrades from the power flow and stability analysis, were added to the starting base line and the fault duties were recalculated to identify the incremental impacts associated with the inclusion of the QC9 Phase I projects.

C.7.3 Ground Grid Evaluation of SCE Substations

The short circuit studies identified substations where the QC9 Phase I projects increased the substation ground grid duty by 0.25 kA or more. The SCE substations flagged to have ground grid duty concerns are disclosed in Section D.5 of the QC9 Phase I area group report.

C.8 Deliverability Methodology

C.8.1 On-Peak Deliverability Assessment Methodology

The assessment was performed following the On-Peak Deliverability Assessment methodology (http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf).

The main steps of the On-Peak deliverability assessment are described below.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool was used to identify potential deliverability problems. For each analyzed facility, an electrical circle was drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% or greater:

- Distribution factor (DFAX) = (Δ flow on the analyzed facility / Δ output of the generating unit) *100%

  or
- Flow impact = (DFAX * NQC / Applicable rating of the analyzed facility) *100%.

Load flow simulations were performed, which study the worst-case combination of generator output within each 5% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5% Circle were increased starting with units with the largest impact on the transmission facility. No more than twenty units were increased to their maximum output. In addition, no more than 1,500 MW of generation was increased. All remaining generation within the Control Area was proportionally displaced, to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased more than 1,500 MW, the impact of the remaining amount of generation to be increased was considered using a Facility Loading Adder. The Facility Loading Adder was calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs was also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders was negative, the impact was set to zero and the flow on the analyzed facility without applying Facility Loading Adders was reported.

C.8.2 Local Deliverability Constraints and Area Delivery Constraints

In the Phase I study, the CAISO performed two rounds of deliverability assessments to, first, identify any transmission system operating limits that constrain the deliverability of the modeled generators, and second, determine LDNUs and ADNUs to relieve those constraints. The first round of the deliverability assessment modeled all the generation projects requesting Full Capacity or Partial Capacity Deliverability Status in accordance with the On-Peak Deliverability Assessment Methodology. The transmission system operating limits identified during the assessment are divided into two categories: local deliverability constraints and area deliverability constraints.

Local deliverability constraints tend to have the following characteristics:

- The generators whose deliverability they constrain (generators inside the 5% DFAX circle) are all located on a few buses electrically close to each other.
- Relieving these constraints does not trigger high cost upgrades.

Area Deliverability Constraints tend to have the following characteristics:

- The generators whose deliverability they constrain (generators inside the 5% DFAX circle) are spread over at least one and possibly more grid study areas or resource areas identified in a resource portfolio used in the TPP.
- In the first round of the Phase I deliverability assessment, relieving these constraints may trigger high cost upgrades, driven by excessively large MW amounts of new generation behind the area deliverability constraint.
- In some potential situations the ISO may classify as an area deliverability constraint a constraint that constrains the deliverability of generators electrically close to each other and is triggered by an exceptionally large volume of generation. This could occur, for example, when there is an exceptionally large volume of IRs in a relatively smaller local sub-area within one of the resource development areas identified in the TPP portfolios and relieving the constraint requires expensive upgrades. This potential situation was raised as a concern by some stakeholders, and we determined that in such cases, if they occur, the appropriate remedy would be to reclassify the constraint as an area deliverability constraint based on the recognition that it would serve a substantial volume of generation projects within the study area.

The categorization of ADNU versus LDNU is based on the deliverability constraint that triggers the need of the DNU. With the exception of RAS mitigating deliverability constraints, ADNUs are transmission upgrades or additions to relieve Area Deliverability Constraints and LDNUs are to relieve Local Deliverability Constraints.

C.8.3 Identification of Area Delivery Network Upgrades

The CAISO performs a second round of the deliverability assessment identify facilities necessary to provide the incremental deliverability between the level of TP Deliverability and additional amount necessary for the MW capacity amount of generation targeted in the Phase I study. The additional amount is referred as Phase I Incremental MW in the report.

For each Area Deliverability Constraint, a base case was developed such that the TP Deliverability is fully utilized. Then the Phase I Incremental MW was added. The ADNUs were then identified to support the deliverability of the Phase I Incremental MW.

C.9 In-Service Date & Commercial Operating Date Assessment Methodology

The in-service date is evaluated for feasibility by examining the timeline to install facilities requirement to interconnect the generation project and maintain system reliability.

D. SCE RELIABILITY ASSESSMENT RESULTS

D.1 Steady State Reliability Assessment

This assessment is comprised of Power Flow Analysis and Reactive Power Deficiency Analysis.

Power flow analysis and reactive power deficiency analysis were performed to ensure that SCE's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001-4, as well as other NERC/WECC reliability standards, with the proposed interconnection. The results of these analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. The reactive power deficiency analysis also determines whether the asynchronous facilities proposed by the interconnection projects are required to provide 0.95 leading/lagging power factor at the POI.

The study results for this QC9 Phase I Study will be communicated to neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from neighboring entities is solicited to ensure coordination of transmission systems.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. The CAISO and SCE cannot guarantee that the QC9 Phase I generation projects can operate at maximum rated output, 24 hours a day, year round, without adverse system impacts, nor can the CAISO and SCE guarantee that these projects would not have adverse system impacts during the times and seasons not studied in this Phase I study.

D.1.1 Bulk[17] System Steady State Study

i. Power Flow Study Results

Based on the assumptions listed above, the addition of the QC9 Phase I projects did not trigger any thermal overloads or create voltage violations on the Bulk System in the Metro Area.

ii. Power Flow Study Observations & Notes

(a) System Voltage

With appropriate power factor correction, no base case system voltage issues were identified as part of the QC9 Phase I study.

[17] 500 kV and 220 kV level

(b) Reactive Power Deficiency

There were no projects seeking interconnection in the Metro area bulk system in QC9 Phase I.

iii. Reliability Assessment Mitigations

Based on the findings of the steady state study, no upgrades are triggered by the QC9 Phase I projects to mitigate thermal overloads.

D.1.2 66 kV System Steady State Study

A separate Subtransmission Area Report was developed that strictly focuses on the analysis conducted for projects interconnecting at the 66 kV level (Non-CAISO controlled facilities) within the Metro Area. Please refer to the applicable Subtransmission Assessment Report included in the QC9 PI report package for further information related to 66 kV system area steady state study.

D.2 Transient Stability Assessment

Limited transient stability analysis was conducted using the On-Peak and Off-Peak full loop base cases to ensure that the transmission (500/220 kV) system remains stable with the addition of QC9 Phase I generation projects. The generator dynamic data used for the study are confidential in nature and are provided with each individual project report.

Disturbance simulations were performed for a study period of 10 seconds to determine whether the QC9 Phase I projects will create any system instability during a variety of line and generator outages. For SCE's Metro area transmission system, selected line and generator outages within the Metro Area were evaluated. The outages were consistent with Category P1 to P7 and the WECC Regional Planning Criteria.

The transient stability study concluded that, with the addition of the QC9 Phase I projects proposed system upgrades in place as well as assuming each project can provide 0.95 power factor correction at their POI, the transient stability performance of the system is acceptable. Transient stability plots for On-Peak load conditions are provided in Appendix F.

D.3 Post Transient Voltage Stability Assessment and Results

The previous cluster analysis concluded that the asynchronous generating facilities are required to provide leading/lagging power factor correction at the POI.

A post-transient voltage stability analysis was performed for this QC9 Phase I Study. The post-transient analysis focused on evaluating the system (500/220 kV) after the inclusion of all transmission upgrades and the use of the identified RAS, assuming all new generation projects meet the power factor requirements. Under such conditions, the post-transient study showed acceptable system performance.

D.4 Energy Storage Charging Analysis

There were no energy storage projects seeking interconnection in the Metro area bulk system as part of QC9. A separate Subtransmission Assessment Report was developed that strictly focuses on the analysis conducted for projects interconnecting at the subtransmission voltage level, (Non-CAISO controlled facilities) if applicable. Please refer to the Subtransmission Assessment Report included in the QC9 PII report package for further information related to the subtransmission energy storage charging analysis, if applicable. Similarly, for projects interconnecting at the distribution level (33 kV and below, Non-CAISO controlled facilities), the energy storage charging analysis information is provided in the Appendix A report, if applicable.

D.5 Short Circuit Duty Assessment Results

D.5.1 Interconnection Queue SCD Results

The QC9 Phase I SCD results and corresponding circuit breaker evaluations identified that the inclusion of the QC9 Phase I projects seeking interconnection to SCE facilities under CAISO control do trigger the need for additional SCD mitigations that are not already identified in Section B.3 and Section B.5. The section below provides the effective three-phase-to-ground and single-phase-to-ground duties for those transmission, subtransmission, and distribution substations that have been identified to require mitigation in Section B.3 and Section B.5, and which the inclusion of QC9 Phase I projects seeking interconnection to SCE facilities under CAISO control exacerbate the overstressed condition. Results at all locations where SCD was increased by at least 0.1 kA are provided in Appendix H.

1. **Interconnection End of Queue SCD Results – Transmission**
   The QC9 Phase I SCD results and corresponding circuit breaker evaluation did not identify any additional transmission level (220 kV and 500 kV) circuit breaker upgrades for QC9 Phase I generation projects seeking interconnection to the CAISO Controlled Grid.

2. **Interconnection End of Queue SCD Results – Subtransmission**
   The QC9 Phase I SCD results and corresponding circuit breaker evaluations did identify additional SCE subtransmission voltage (66 kV and 115 kV) circuit breaker upgrades for QC9 Phase I generation projects seeking interconnection to the CAISO Controlled Grid. In addition, circuit breaker upgrades may be required within the subtransmission (66 kV and 115 kV) for those projects seeking interconnection to SCE's Distribution System. Additional details are available in the Subtransmission Assessment Report provided as an attachment to the Appendix A.

   The effective three-phase-to-ground and single-phase-to-ground duties at subtransmission source bus locations requiring queued ahead SCD mitigation are shown in Table D.5.2.1 and Table D.5.2.2, respectively.

Table D.5.2.1
Effective Three-Phase-to-Ground Duties at Subtransmission Source Locations
Requiring Queued Ahead SCD Mitigation

Substation	Voltage	Pre QC9 Phase I			Post QC9 Phase I			Cluster Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Antelope	66	37.5	30.9	37.5	40.3	29.5	40.3	2.8	2.8
Moorpark C	66	22.2	54.6	27.7	22.4	54.8	28	0.2	0.3

* Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards.

Table D.5.2.2
Effective Single-Phase-to-Ground Duties at Subtransmission Source Locations

Requiring Queued Ahead SCD Mitigation

Substation	Voltage	Pre QC9 Phase I			Post QC9 Phase I			Cluster Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Antelope	66	23.9	23.1	23.9	25.5	21.7	25.5	1.6	1.6
Moorpark C	66	19.8	44.2	24.8	20.3	43.7	25.3	0.5	0.5

* Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards.

3. **Interconnection End of Queue SCD Results – Distribution**
   The QC9 Phase I SCD results and corresponding circuit breaker evaluations did not identify any additional SCE low voltage distribution (33 kV and below) circuit breaker upgrades for QC9 Phase I generation projects.

D.5.2 SCD Mitigation Discussion

As discussed above, studies did identify overstressed breaker conditions with the inclusion of QC9 Phase I. It is important to note, however, that QC9 Phase I may ultimately be assigned SCD mitigation responsibility discussed in Section B.5 depending on a number of factors which includes Operational requirements (evaluated as part of Phase II) and potential withdrawals of queued ahead projects currently triggering the need for such upgrades. Since upgrades identified in Section B.5 are not currently in an executed GIA, cost assignment to QC9 Phase I for such upgrades will occur if the need is ultimately determined to be triggered by QC9 Phase I, unless such upgrades are included in an executed GIA by the time QC9 is identified as the ultimate triggering cluster.

1. **Interconnection End of Queue SCD Results – Transmission**
   No additional transmission level (CAISO Controlled) circuit breaker upgrades were identified with the inclusion of QC9 Phase I.

2. **Interconnection End of Queue SCD Results – Subtransmission**
   With the inclusion of QC9 Phase 1 additional 66 kV circuit breaker upgrades were identified at the source buses.

   <u>Subtransmission Mitigation</u>

   - Antelope 66 kV Subtransmission System

     The details regarding this mitigation are available in the Subtransmission Assessment Report provided as an attachment to the Appendix A, if applicable.

   - Moorpark A 66 kV Substation

     1) Replace four (4) circuit breakers (#68, #70,#72,#73).

3. **Interconnection End of Queue SCD Results – Distribution**
   No additional circuit breaker upgrades were identified with the inclusion of QC9 Phase I.

D.5.3 Ground Grid Evaluation of SCE Bulk Power Substations Results

The results of the application queue SCD studies were also utilized to identify any SCE substations (CAISO controlled) that may have duty problems on the existing substation ground grid due to the inclusion of the QC9 Phase I projects. The application queue ground grid analysis flagged for further review a total of forty (40) existing substations where the QC9 Phase I Projects increased the substation ground grid duty by at least 0.25 kA. Additional review will be performed as part of Phase II to determine if any of these locations will require a detailed ground grid analysis to be performed in support of QC9 Phase I projects.

The results identified (17) SCE subtransmission voltage (66 kV and 115 kV) locations for QC9 Phase 1 generation projects seeking interconnection to the CAISO Controlled Grid that may require ground grid review. However, review of non-source subtransmission locations may be required within the subtransmission (66 kV and 115 kV) for projects seeking interconnection on SCE's Distribution System. Additional details are available in the Subtransmission Assessment Report provided as an attachment to the Appendix A.

Any location identified to require a detailed ground grid analysis will be assigned a one-time cost for such study. These costs will be allocated to the generation projects with significant SCD contributions or the group of generation projects if the SCD contribution is the result of an upgrade assigned to a specific group of projects. Specifically, the costs for the ground grid study of each flagged substation are assigned to project(s) in the area in which the flagged substation resides. For example, if Whirlwind 220 kV substation, which is an SCE substation in the Northern Area, is flagged for a ground grid study, the associated costs for the ground grid study will be assigned to each QC9 PI project in the Northern Area.

E. DELIVERABILITY ASSESSMENT RESULTS

The Deliverability Assessment comprises of On-Peak and Off-Peak deliverability assessments. The CAISO Balancing Authority Area (BAA) including the bulk system was monitored for any adverse impacts.

E.1 On-Peak Deliverability Assessment

E.1.1 Deliverability Constraints to be mitigated by RAS

There are no deliverability constraints identified for the QC9 Phase I projects in the Metro Area.

E.1.2 Local Deliverability Constraints and LDNUs

There are no local deliverability constraints identified for the QC9 Phase I projects in the Metro Area.

E.1.3 Area Deliverability Constraints and ADNUs

There are no area deliverability constraints identified for the QC9 Phase I projects in the Metro Area.

E.1.4 Deliverability Assessment Mitigation

There are no upgrades triggered by QC9 Phase I projects in the Metro Area in the on-peak deliverability assessment.

E.2 Off-Peak Deliverability Assessment

Refer to off-peak reliability assessment in Section D.1.

F. SCOPE OF NETWORK AND DISTRIBUTION UPGRADES

The mitigation requirements triggered by QC9 Phase I projects, based on the results described in Sections above, are as follows:

F.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades are discussed in detail in each individual project report (Appendix A).

F.2 Reliability Network Upgrades

There is no identified Reliability Network Upgrade for QC9 Phase I projects in the Metro area.

F.3 Local Delivery Network Upgrades

There are no identified Local Delivery Network Upgrades for QC9 Phase I projects in the Metro Area.

F.4 Area Delivery Network Upgrades

There are no identified Area Delivery Network Upgrades for QC9 Phase I projects in the Metro Area.

F.5 Distribution Upgrades

For those Projects connecting to the Distribution level, there may be Distribution Upgrades allocated to specific projects as determined in their corresponding Subtransmission Assessment Report and/or individual Appendix A reports.

G. COST AND CONSTRUCTION DURATION ESTIMATES FOR UPGRADES

The cost estimates are based on the published unit costs, when applicable. Customized costs were developed when the unit costs did not reflect the unique circumstances of a project. The customized costs may include: anticipated purchase of land rights, licensing, environmental studies and requirements, looping lines into substations, new switchyards, substation upgrades not included in unit costs, and SCE’s Interconnection Facilities.

Regardless of the requested Commercial Operation Date (COD), the actual CODs of the QC9 projects are dependent on the completed construction and energizing of the identified Network Upgrades. Without these upgrades, the new generators may be subject to CAISO’s congestion management, including generation tripping. Based on the needed time for permitting, design, and construction, it may not be feasible to complete all the upgrades needed for this cluster before the requested CODs.

Costs for each generation project are confidential and are not published in the main body of this report. Each IC is receiving a separate Appendix A report, specific only to that generation project, containing the details of the IC’s cost responsibilities.

The total estimated cost of the system upgrades allocated to the Metro Area projects are provided in Appendix E.

H. AFFECTED SYSTEMS COORDINATION

The CAISO has established an affected systems coordination process for the interconnection requests to the CAISO Controlled Grid. The CAISO cannot study comprehensively the impacts of the Generating Facility on the transmission systems of Affected System operators. The CAISO does not have detailed information about Affected Systems on a transmission-element level, nor does the CAISO know the details of the various reliability and operating criteria applicable to the Affected Systems. In addition, because the operation of transmission systems and NERC reliability standards change over time, the

CAISO cannot presume to know all of the impacts of these changes on Affected Systems. As such, the CAISO has shared its study plan and Base Cases with the Potentially Affected Systems[18] before the Cluster 9 Phase I Study was performed and will invite all Potentially Affected Systems to the Cluster 9 Phase I Study Results Meeting where the CAISO will share its study results with those Potentially Affected System operators that have executed Non-Disclosure Agreements.

Potentially Affected System operators will not have the opportunity to categorize themselves as an Identified Affected System[19] until after the Interconnection Customer has posted its initial Interconnection Financial Security. Within thirty (30) calendar days after receiving notice of which projects have posted their initial Interconnection Financial Security, the CAISO will request that Potentially Affected System operators advise the CAISO in writing that either: (i) the CAISO should consider the electric system to be an Identified Affected System (regardless of whether a system impact study has been conducted); or (ii) the electric system is not an Affected System. Upon receipt of such notification from all Potentially Affected System operators, the CAISO will notify the Interconnection Customer of the Identified Affected Systems.

To ensure a safe and reliable interconnection to the CAISO Controlled Grid, six (6) months before the Initial Synchronization Date of the Generating Facility, the Interconnection Customer shall provide documentation to the CAISO, in accordance with the Generation Interconnection and Deliverability Allocation Procedure (GIDAP) Section 3.7, and GIDAP Business Practice Manual (BPM) Section 6.1.4, confirming that the Identified Affected System operators have been contacted by the Interconnection Customer, and (i) that any system reliability impacts have been addressed (or that there are no system impacts); or (ii) that the Interconnection Customer has taken all reasonable steps to address potential reliability system impacts with the Identified Affected System operator but has been unsuccessful.

Affected systems coordination for interconnection requests to Participating TO's sub-transmission or distribution system that are not under CAISO control is managed by the Participating TO.

H.1 Potential Affected System – Power Flow Results

The addition of all QC9 projects in the Metro Area may increase flows on Affected Systems. Under certain outage conditions, the projects could also trigger certain overloads that are not identified in this report. As such, all QC9 projects in the Metro Area are required to work with Affected Systems and mitigate any overloads/violations triggered as a result of the QC9 projects.

H.2 Potential Affected System – SCD Results

With the addition of all QC9 projects in the Metro Area, the Generation Interconnection Studies identified an increase in SCD throughout the system. The table below shows the SCD increment to neighboring utilities due to the addition of all QC9 projects:

Short-Circuit Duty Evaluation of Adjacent Facilities Impacted by QC9PI

Short-Circuit Duty Evaluation of Adjacent Facilities Impacted by QC9PI

Substation		Entity		

[18] "Potentially Affected System" shall mean an electric system in electric proximity to the CAISO's controlled grid that may be an Affected System.

[19] "Identified Affected System" shall mean an Affected System operator who either stated that it should be considered an Affected System or whose electric system has been identified by the CAISO as potentially impacted by a generator interconnection through the applicable study process.

	Voltage (kV)		Three-Phase Cluster Impact (kA)	Single Line-to-Ground Cluster Impact (kA)
Eldorado	500	SCE	5.6	6.2
Lugo	500	SCE	5.6	4.5
McCullough	500	LADWP	5.2	5.7
Mead	500	WALC	1.3	0.9
Midway	500	PG&E	1.6	0.5
Moenkopi	500	APS	0.2	0.0
Mohave	500	Joint	0.9	3.9
Palo Verde	500	APS	0.3	0.3
Victorville	500	LADWP	0.8	0.6
Bob tap	230	VEA	10.2	8.3
Eldorado	230	Joint	1.2	1.2
Eldorado	220	SCE	16.0	18.9
Inyo	230	LADWP	0.0	0.0
Julian Hinds	220	MWD	0.0	0.0
Laguna Bell	220	SCE/City of Vernon	1.1	-0.1
Lewis	220	SCE/City of Anaheim	0.8	0.4
Magnolia	230	Nevada	0.2	0.1
Merchant	230	SDG&E	0.9	0.9
Mirage	220	IID	0.2	0.1
NSO	230	Nevada	0.9	0.7
Sylmar	230	LADWP	1.3	1.0
Wildlife	220	City of Riverside	0.1	0.0
Blythe	161	WALC	0.0	0.0

I. ENVIRONMENTAL EVALUATION, PERMITTING, AND LICENSING

Environmental Evaluation, Permitting, and Licensing information is provided in Appendix K of this report.

J. ITEMS NOT COVERED IN THIS REPORT

J.1 Conceptual Plan of Service

The results provided in this study are based on conceptual engineering and a preliminary Plan of Service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of the Final Engineering and Design.

J.2 Customer's Technical Data

The study accuracy and results for the QC9 Phase I Study are contingent upon the accuracy of the technical data provided by the each IC for their respective IR(s). Any changes from the data provided as allowed by the tariff would need to be submitted in Appendix B prior to commencement of the Phase II study. Any changes that extend beyond the modifications allowed prior to commencement of the Phase II Study will need to be evaluated following the Material Modification Assessment to determine if such change results in a material impact to queued-behind generation requests. These change(s) would only be allowed if it is determined that there is no material impact to queued-behind requests.

J.3 Study Impacts on Neighboring Utilities

Results or consequences of this QC9 Phase I Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO-controlled Grid, etc. Refer to Affected Systems Coordination Section for further details.

J.4 Use of Participating TO Facilities

The IC is responsible for acquiring all property rights necessary for the IC's Interconnection Facilities, including those required to cross PTO facilities and property. This Interconnection Study does not include the method or estimated cost to the IC of PTO mitigation measures that may be required to accommodate any proposed crossing of PTO facilities. The crossing of PTO property rights shall only be permitted upon written agreement between PTO and the IC at PTO's sole determination. Any proposed crossing of PTO property rights will require a separate study and/or evaluation, at the IC's expense, to determine whether such use may be accommodated.

J.5 Participating Transmission Owner Interconnection Handbook

The IC shall be required to adhere to all applicable requirements in the PTO Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

J.6 Western Electricity Coordinating Council (WECC) Policies

The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

J.7 System Protection Coordination

Adequate Protection coordination will be required between PTO-owned protection and IC-owned protection. If adequate protection coordination cannot be achieved, then modifications to the IC-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

J.8 Standby Power and Temporary Construction Power

The QC9 Phase I Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the in-service date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Participating TO prior to the in-service date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Participating TO to receive and pay for such retail service.

J.9 Licensing Cost and Estimated Time to Construct Estimate (Duration)

The estimated licensing cost and durations applied to this project are based on the project scope details presented in the study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

J.10 Network/Non-Network Classification of Telecommunication Facilities

The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's generation tie-line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for RAS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the PTO substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC9 Phase I, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for QC9 Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

J.11 Ground Grid Analysis

A detailed ground grid analysis may be required as part of the final engineering for the project at the PTO substations whose ground grids were flagged with duty concerns.

J.12 Subsynchronous Interaction Evaluations

Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SSI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

A study will need to be performed to evaluate the SSI between generating facilities and the transmission system for projects interconnecting in close electrical proximity of series capacitor banks on the transmission system to ensure that the Project does not damage SCE's control systems. The SSCI study will require that the IC provide a detailed PSCAD model of its Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required prior to initial synchronization of the Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the IC.

It is the IC's responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

Each IC is receiving a separate Appendix A report, specific only to that generation project, defining if the project is required to undertake this additional analysis. Each identified IC is 100% responsible for any studies related to the SSR or SSTI. The only study that SCE will perform (at the IC's expense) is for SSCI.

J.13 Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the PTO electrical system; as well as establish the technical requirements to interconnect the Project to the POI that was evaluated in the QC9 Phase I study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in interconnection agreements agreed to by PTO, CAISO and the IC.

J.14 Potential Changes in Cost Responsibility

The IC is advised that interconnection of its proposed Generating Facility may be dependent upon the construction of certain Network Upgrades, which are currently the obligation of projects ahead of its proposed Generating Facility in the interconnection queue. These other potential network upgrades are referenced in Section B.5 of the Area Report and outlined in Attachment 2 to the ICs final PI or PII Study Report (Appendix A).

Whether the IC becomes responsible for all or a portion of these other potential network upgrades depends upon several factors, some of which are unknown at the time of this study. However, in an effort to alert the IC to its maximum cost responsibility for Network Upgrades, were these other potential network upgrades to become the obligation of the IC, SCE has included the IC's proportionate cost responsibility for these upgrades under the other potential network upgrades section in Attachment 2 to this report. The IC is not required to post Interconnection Financial Security for these other potential network upgrades, but the prospective obligation to finance and construct these other potential network upgrades is included in the IC's maximum cost responsibility.

The obligation to finance and construct these other potential network upgrades is governed by Sections 4.6.8 and 10.3.2 of the GIP and 14.2.2 of the GIDAP.

K. DEFINITIONS

A Bank	A transformer at a substation, which converts 220 kV into 115 kV or 66 kV
AA Bank	A transformer at a substation, which converts 500 kV into 220 kV or 115 kV
ADNU	Area Delivery Network Upgrade
Bank	A combination of single and/or three-phase transformers connected to supply energy to a three-phase load
BES	Bulk Electric System
CAISO	California Independent System Operator Corporation
CDWR	California Department of Water Resources
COD	Commercial Operation Date
Deliverability Assessment	CAISO's Deliverability Assessment
EO	Energy-Only Deliverability Status
FC	Full Capacity Deliverability Status (also known as FCDS)
FERC	Federal Energy Regulatory Commission
GF	Generating Facility
GIA	Generator Interconnection Agreement
GIP	Generator Interconnection Procedures
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
IC	Interconnection Customer
IID	Imperial Irrigation District
LDNU	Local Delivery Network Upgrade
LFBs	Local Furnishing Bonds
N-1	Outage of a single transmission facility
N-2	Simultaneous outage of two transmission facilities
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity as modeled in the Deliverability Assessment:
PG&E	Pacific Gas and Electric Company
Phase I	QC9 Phase I Study
P_{Max}	Maximum generation output
P_{Min}	Minimum generation output
POCO	Point of Change of Ownership
POI	Point of Interconnection
POS	Plan of Service
PTO	Participating Transmission Owner (also known as Participating TO)
RAS	Remedial Action Scheme (previously known as SPS)
RASRS	Remedial Action Scheme Reliability Subcommittee
RNU	Reliability Network Upgrade
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SVC	Static VAr Compensator
TPP	CAISO's Transmission Planning Process
TPD	Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan
VEA	Valley Electric Association
WAPA	Western Area Power Administration
WDAT	Wholesale Distribution Access Tariff
WECC	Western Electricity Coordinating Council

Appendix A:
Individual Project Report

Please refer to separate document

Appendix B:
System Assumptions

Please refer to separate document

Appendix C:
Contingency Lists for Outages

Please refer to separate document

Appendix D:
Power Flow Plots

Please refer to separate document

Appendix E:
Cost and Construction Duration Estimates for Upgrades

Please refer to separate document

Appendix F:
Transient Stability Plots

Please refer to separate document

Appendix G:
Not Used

Appendix H:
Short Circuit Calculation Study Results

Please refer to separate document

Appendix I:
Not Used

Appendix J: Bulk Area Report for Reliability Study of Charging Energy Storage (if applicable)

Please refer to separate document

Appendix K:
Environmental Evaluation, Permitting, and Licensing

Please refer to separate document

Appendix A – WDT1391

Stanton Energy Reliability Center, LLC

Stanton Energy Reliability Center II

Queue Cluster 9 Phase I Report

January 18, 2017

This study has been completed in coordination with the California Independent System Operator Corporation (ISO) per Southern California Edison Company's Wholesale Distribution Access Tariff (WDAT), Attachment I Generator Interconnection Procedures (GIP)

No.	Date	Document Title	Description of Document
1	1/18/2017	Queue Cluster 9 Phase I Appendix A Report	Final Phase I Interconnection Study Report

TABLE OF CONTENTS

ATTACHMENTS

A. INTRODUCTION

Stanton Energy Reliability Center, LLC, the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison (SCE) for their proposed Stanton Energy Reliability Center II (Project). The Project requested a Point of Interconnection (POI) at Southern California Edison Company's (SCE) Barre 66 kV Switchrack Section C, located in Orange County, CA, and delivery to the CAISO Controlled Grid at SCE's Barre 220 kV[1] Substation. The IC elected Full Capacity Deliverability Status (FCDS) for the Project. The IC desires an In-Service Date (ISD) of October 15, 2019 and a Commercial Operation Date (COD) of December 15, 2019. Such dates are specified in the Project's IR. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project after the Generator Interconnection Agreement (GIA) has been executed and filed at the Federal Energy Regulatory Commission (FERC) for acceptance.

In accordance with FERC approved SCE's WDAT Attachment I Generator Interconnection Procedures (GIP), the Project was grouped with Queue Cluster 9 (QC9) Phase I projects to determine the impacts of the group as well as impacts of the Project on the ISO Grid.

An Area and Subtransmission Assessment Report have been prepared separately identifying the combined impacts of all projects on the ISO Grid and to distribution facilities served out of the Barre 66 kV Subtransmission System, respectively. This Appendix A report focuses only on the impacts or impact contributions of the Project at the local distribution system, and is not intended to supersede any contractual terms or conditions specified in the GIA.

The report provides the following:

1. Transmission system impacts caused by the Project.
2. Distribution system impacts caused by the Project.
3. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions.
4. A list of required facilities and an estimate of the Project's cost responsibility and time to construct[2] these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

Additionally, the Project encompasses energy storage equipment that required additional analysis be performed to evaluate the impacts of the charging facility within SCE's Distribution System. These analyses focused on the charging[3] aspects of the charging facilities in the Barre 66 kV Subtransmission System and consider various levels of load demand with minimal generation dispatch within the local Distribution system.

[1] Identification of facility voltages (220 kV) are shown consistent with SCE System Operating Bulletin 123. However, all studies were predicated on the base voltages reflected in the Western Electricity Coordinating Council (WECC) base cases. For the SCE bulk power system, the WECC base cases reflect 230 kV and 500 kV base voltages; consequently, all per-unit calculations presented were based on 230 kV and 500 kV voltages

[2] It should be noted that construction is only part of the duration of months specified in the study, which includes detailed engineering, licensing, and other activities required to bring such facilities into service. These durations are from the execution of the GIA, receipt of all required information, funding, and written authorization to proceed from the IC as will be specified in the GIA to commence the work.

[3] Charging is defined as when the Project draws energy from the grid to "charge" the Project-associated charging facilities.

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the charging facilities, identifies system limitations that may restrict the charging facility's ability to charge during certain demand conditions, and provides a high-level explanation of potential exposure to charging restrictions on the distribution system in addition to identifying distribution system improvements, which would mitigate such restrictions to charging. The study assumed that the energy storage device will be charged from the grid.

All the equipment and facilities comprising the Project's Generating Facility are located in Stanton, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) forty (40) energy storage inverter units with an output of 1.25 MW each, (ii) two (2) gas turbine synchronous generator units with an output regulated to 50.8 MW each for a installed capacity of 50 MW and 101.6 MW, respectively, as measured at the inverter terminals, (iii) the associated infrastructure, (iv) meters and metering equipment, (v) appurtenant equipment, and (vi) 2.8 MW of auxiliary loads.

Based on the technical data provided for the collector system equivalent, pad-mount and main transformer banks, the total internal project losses were identified to be 1.9 MW. Losses on the gen-tie were identified to be 3.32 MW. Subtracting losses from the gross 151.6 MW would result in a POI delivery of 148.2 MW which is in excess of the IC's requested 148.1 MW POI delivery amount. Consequently, the IC must implement a control system or install a limiting device to ensure the Generating Facility (GF) output will not exceed 148.1 MW (net) as measured at the high side of the main transformer banks to limit the Point of Interconnection delivery amount to the requested 148.1 MW.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1. Below also is Figure A.2, a map that illustrates the location of the Project. Moreover, the Project information is summarized in Table A.1 below.

Figure A.1: Project Plan of Service & IC Facilities One-Line Diagram

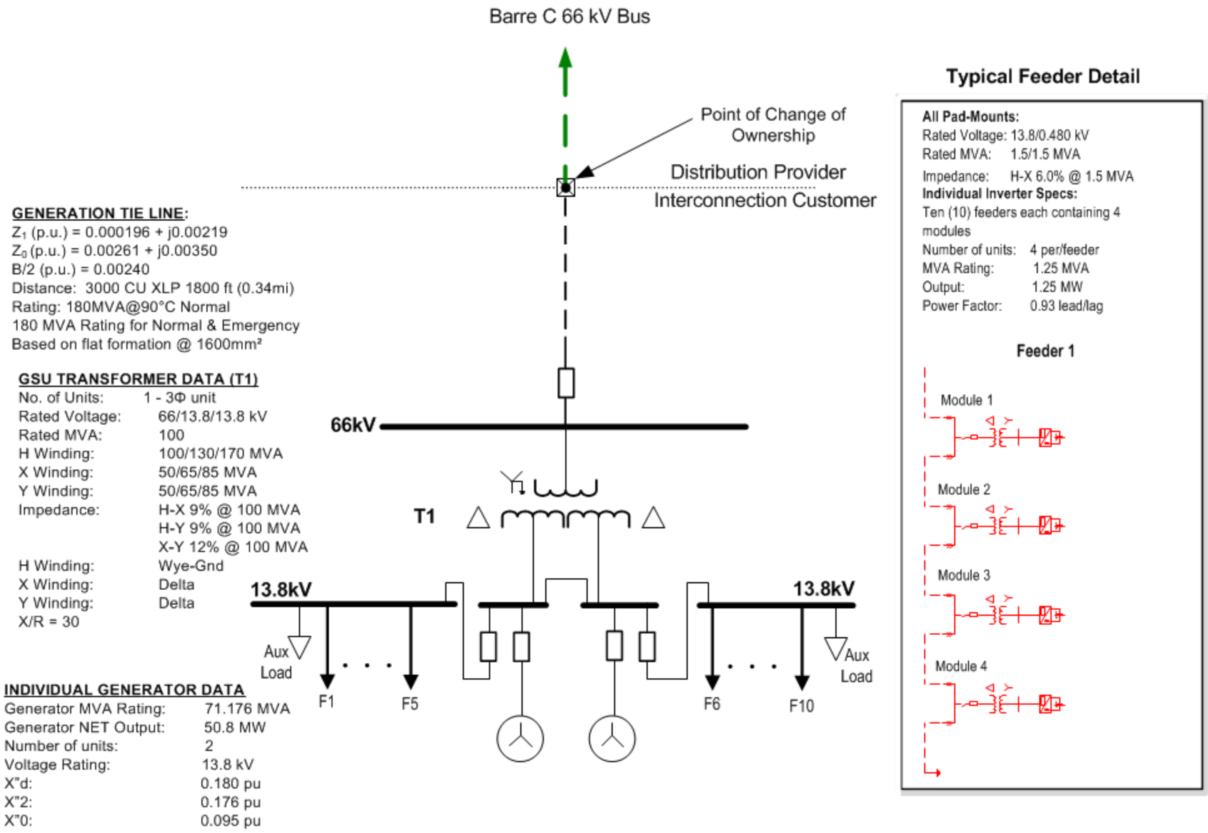


Figure A.2: Project Location Map

Table A.1 Project General Information per IR

Project Location	10711 Dale Street Stanton, CA 90680 Orange County Latitude: 33.807053 Longitude: -117.985299
Distribution Provider's Planning Area	Distribution Provider's Metro Bulk Area
Interconnection Voltage	66 kV
POI	Distribution Provider's Barre 66 kV Switchrack (C Section)
Requested Maximum Project Output as measured at POI (Note 1)	148.1 MW
Number and Types of Generators	Forty (40) 1.25 MW GE Brilliance Power Inverters for a combined gross output capability of 50 MW at the inverter terminal
Power Factor Range for Inverters	Lead 0.93 / Lag 0.93
Number and Types of Generators	Two (2) Brush BEM Ltd. Synchronous Generators for a combined gross output capability of 142.352 MW at the inverter terminal
Power Factor Range for Synchronous Units	Lead 0.93 / Lag 0.93
Step-up Transformer(s)	Main Transformers (x1) 66/13.8/13.8 kV (YG-D-D), 100/130/170 MVA H-X Impedance Value: 9% @ 100 MVA H-Y Impedance Value: 9% @ 100 MVA X-Y Impedance Value: 12% @ 100 MVA X/R=30 Padmount Transformers (x40) 34.5/0.480 kV (Y-D), 1.5 MVA H-X Impedance Value: 6.0% @ 1.5 MVA X/R=6
Generator Auxiliary Load	2.8 MW
Internal Generating Facility Losses	1.9 MW
Gen-Tie	6,000 FT of bundled 3000 CU XLP and 400 FT bundled overhead 954 AL SAC for SCE
Estimated total losses on Generation Tie Line	Negligible
Maximum Net Output at Generating Facility (High-Side of Main Transformer) to achieve requested POI Delivery (Note 2)	148.1 MW
ISD	October 15, 2019
Initial Synchronization Date/Trial Operation	November 15, 2019
COD	December 15, 2019

Note 1: The MW output at the POI varies under different operating conditions.

Note 2: The IC is reminded that this value is tied to the generation tie-line (gen-tie) losses. The estimated Maximum Net Output value at POI and gen-tie Losses illustrated above are contingent upon the accuracy of the technical data provided by the IC, and are subject to change should the IC change its gen-tie parameters during the final engineering and design phase of the Project.

Based on the technical data provided, the Project is requesting to install more megawatts (151.6 MW) as measured at the inverter/converter terminal which will result in more than the requested 148.1 MW delivery at the POI. As a result, the Project will need to be limited to not exceed the values shown under Maximum Net Output as metered on high-side of the main transformer.

B. STUDY ASSUMPTIONS

For detailed assumptions regarding the group cluster analysis, please refer to the QC9 Phase I Area Report. Below are the assumptions specific to the Project:

1. The Plan of Service (POS) is defined as the facilities needed to interconnect the Project to SCE's Distribution System. The following is the POS assumed for the Project.

   The Project was modeled as interconnecting -149 MW of battery storage through the Barre Substation 66 kV "C" Bus via one 66 kV generation tie-line (gen-tie).

2. The following facilities will be installed by SCE and **are included** in this Interconnection Study report:

   (i) Relocate 3A bank position from position 10 to position 13.

   Remove:

   - One (1) 60 foot high X 45 foot wide 66 kV dead end structure for the 3A bank
   - Approximately 1200 feet of 1590 kcmil Aluminum Conductor Steel Reinforced conductor that was connected from the bank to the position 10
   - Approximately 400 feet of ½ ground wire 7 stranded steel for the bank's dead end to the position 10
   - Approximately 500 feet of 605 kcmil Aluminum Conductor Steel Reinforced conductor for the bank position
   - Two (2) 66 kV 3000A 40 kA Mitsubishi Circuit Breakers with associated structure
   - Two (2) 3000A horizontal group-operated disconnect switch with associated structure
   - One (1) 3000A vertical disconnect switch with ground attachment
   - One (1) 3000A vertical disconnect switch
   - Two (2) 69,000-197/115X115/69V connected phase-to-phase potential transformers with associated structure

   Install:

   - One (1) 60 foot high X 45 foot wide 66 kV dead end structure with foundation for the 3A bank
   - Six (6) 72 KV Lighting arresters
   - Approximately 1200 feet of 1590 kcmil Aluminum Conductor Steel Reinforced conductor that needs to be connected from the bank to the new position 13
   - Approximately 500 feet of ½ ground wire 7 stranded steel for the bank's dead end to the position 13
   - Approximately 500 feet of 605 kcmil Aluminum Conductor Steel Reinforced conductor for the bank position
   - Two (2) 66 kV 3000A 40 kA Mitsubishi Circuit Breakers (CB #7 & 8) with associated structure and foundation

- Two (2) sets of 3000A horizontal group-operated disconnect switch with associate structure and foundation (6 in total)
- One (1) set of 3000A vertical disconnect switch with ground attachment (3 in total)
- One (1) 3000A vertical disconnect switch (3 in total)
- Two (2) 69,000-197/115X115/69V connected phase-to-phase potential transformer with associated structure and foundation
- Approximately 400 feet of 7/C#12 (Control), 4/C#8 (Current), 2/C#10 (DC) to connect the new Circuit Breaker at the switchyard to the Control Room
- Two (2) LED lighting fixtures

(ii) Relocate the bus sectionalizing circuit breakers from position 9 to position 12
Remove:

- One (1) 66 kV 3000A 31.5 kA Seimens Circuit Breaker (Circuit Breaker #5) with associated structure
- One (1) 66 kV 3000A 40 kA MEP CB (Circuit Breaker #6) with associated structure
- Four (4) 3000 A horizontal group-operated disconnect switch with associated structures
- Approximately 300 feet of 1272 KCMIL SAC conductor (connected from disconnect switch to the Circuit Breaker for the bus sectionalizing breakers)
- Approximately 200 feet of 1590 KCMIL Aluminum Conductor Steel Reinforced conductor (connected from the bus to the disconnect switches for the bus sectionalizing breaker)
- Approximately 200 feet of 2156 KCMIL Aluminum Conductor Steel Reinforced conductor (to create a position for the new bus sectionalizing two circuit breakers at position 12)

Install:

- Two (2) 22 foot wide by 29 foot high 66 kV dead-end steel structures with foundations
- Two (2) 66 kV 3000A 40 kA MEP Circuit Breakers with associated structures and foundations
- Six (6) 72 KV Lighting arresters
- Three (3) 3000 A horizontal group-operated disconnect switch with associated structures foundations
- One (1) 3000 A horizontal group-operated disconnect switch with associated structure foundation and grounding attachment
- Approximately 300 feet of 1272 KCMIL SAC conductor (connected from disconnect switch to the circuit breaker for the bus sectionalizing breaker)
- Approximately 200 feet of 1590 KCMIL ACSR conductor (connected from the bus to the disconnect switches for the bus sectionalizing breaker)
- Approximately 200 feet of 2156 KCMIL ACSR conductor (to connect the bus conductor, due to removal of bus sectionalizing two Circuit Breakers (5 &6))
- Approximately 400 feet of 7/C#12 (Control), 4/C#8 (Current), 2/C#10 (DC) to connect the new Circuit Breaker at the switchyard to the Control Room
- Two (2) LED lighting fixtures

(iii) Install the Interconnection Facilities portion for a new 66 kV position to terminate the Barre–WDT1391 66 kV Line. Equip position 11 for the new gen-tie line. This work includes the following:

- One (1) 22 foot wide by 29 foot high 66 kV dead-end steel structure with foundations
- Six (6) risers with associated structures and foundations
- One (1) set of 72 KV Lighting arresters (3 in total)
- Approximately 5000’ of 1000 JCN underground cable into a new 6-5” duct
- One (1) 2X3 5” duct bank
- Two (2) 66 kV 2000A 40 kA SF6 gas circuit breaker with associated foundation
- Two (2) sets of 66 kV 2000A horizontal group-operated disconnect switches (6 switches in total) with associated structure and foundation
- One (1) set of 66 kV 2000A vertical group- operated disconnect switches (3 switches in total)
- One (1) set of 66 kV 2000A vertical group-operated disconnect switches with ground attachment (3 switches in total)
- Three (3) 69,000-197/115X115/69V potential transformers with associated structures and foundations
- Approximately 600 feet of 1590KCMIL ACSR conductors to equip the position
- Approximately 400 feet of 7/C#12 (Control), 4/C#8 (Current), 2/C#10 (DC) to connect the new circuit breaker at the switchyard to the Control Room
- Two (2) LED lighting fixtures

- The segment of a 66 kV generation tie-line inside the Barre 66 kV substation property line.
- The segments of each one of the two generator – owned telecommunications channels inside the Barre Substation property line.
- Lightwave, channel banks, and associated equipment at Barre Substation and at the Facility.
- The required retail and wholesale load meters.

NOTE: SCE installation does not include metering, potential transformers, current transformers, and metering cabinet. The SCE meters will be connected to the generator – owned potential and current transformers to be installed for their ISO metering.

3. The following facilities are to be installed by the Interconnection Customer and are not included in this Interconnection Study report:
    - The 66 kV generation tie-line from the Generating Facility to the last structure outside the Barre Substation property line
    - The fiber optic cables to provide two diversely routed telecommunication paths required for the line protection relays
    - The required ISO metering equipment (potential and current transformers and ISO meters) and metering cabinet for SCE retail and wholesale load meters

    NOTE: The metering potential and current transformers installed for the ISO metering will also be used for the SCE owned retail and wholesale load meters.

- The 66 kV following line protection relays to be installed at the Generating Facility end of the 66 kV generation tie-line:
    - Two (2) line current differential relays via two (2) diversely routed dedicated digital communication channels to Chestnut Substation.

4. Preliminary Protection Requirements

- Protection requirements are designed and intended to protect the Participating TO's transmission system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one line diagram depicted in line item #7 in Attachment 1.

- The IC is responsible for the protection of its own system and equipment and must meet the requirement in the Participating TO's Interconnection Handbook provided in Attachment 4.

3. Environmental Activities, Permits, and Licensing

i. Internal Substation Scope:

- SCE will perform all environmental studies and monitoring of all SCE internal substation construction activities.
- SCE's scope of work would not require a California Public Utilities Commission license.
- This study assumes that SCE's level of disturbance during construction would not require development and implementation of a Stormwater Pollution Prevention Plan.

ii. 66 kV Generation Tie Line Scope:

- SCE's scope of work will not require a California Public Utilities Commission license.
- Environmental Services (ES) will act as the environmental liaison between the SCE team and IC team, and the lead for regulatory agency communication.
    - Collaborate with the IC during the environmental study phase on proposed study methodologies and findings, as studies are being planned and performed for SCE's scope of work.
    - Review IC's California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documents, technical studies, surveys, and other environmental documentation addressing SCE's scope of work (IC to include SCE's scope of work in their environmental document).
    - Review of internal (SCE/ES) existing technical documents when available
    - Regulatory agency communication, consultation, and reporting
    - Permit acquisition
    - Support SCE team in developing the project description, including scope changes during permitting/pre-construction or construction.
    - Communicate scope changes to the IC's environmental team, discuss/approve subsequent actions including new surveys as necessary
    - Prepare environmental requirements for construction clearance
    - Develop communication plan
    - Construction monitoring oversight
    - General Order 131-D Consistency Determination and Environmental Evaluation

- Environmental Awareness/Worker Environmental Awareness Program (WEAP) training
- Pre-construction coordination field visit
- Construction and post-construction site assessments

This study assumes the IC performs all environmental studies and prepares draft environmental permit applications related to the installation of SCE's Interconnection Facilities and Upgrades. The IC's responsibilities include, but are not limited to notifications to the Native American Heritage Commission (NAHC) and follow-up notifications to the tribes and individuals in the NAHC contact list, performing cultural and paleontological resources records searches, performing cultural resources inventories (survey and recording), performing testing and evaluation and/or data recovery of archaeological sites as applicable, and providing the appropriate documentation in the form of inventory reports, research design and/or data recovery reports as applicable, cultural and paleontological monitoring when/if required, and arranging curation agreements for artifacts and fossil specimens collected, performing a California Natural Diversity Database search, performing a habitat assessment, performing protocol or focused surveys for species with the potential of occurring in identified suitable habitat, conducting jurisdictional delineations for wetlands or other regulated waters, preparing draft environmental permit applications, performing pre-construction biological resource surveys, performing biological resource monitoring during construction, performing cultural and paleontological monitoring during construction, mitigation costs including, but not limited to, offsite/compensatory mitigation and onsite restoration, and developing mitigation plans or other environmental reports or submittals, if required, to support installation of SCE's Interconnection Facilities and Upgrades.

Prior to commencing work and during execution of work, the IC must collaborate and obtain ES concurrence on all work outlined above. Should the IC-performed environmental studies, surveys, or monitoring not meet the Federal or State industry standards in accordance with Applicable Laws and Regulations, and as determined by ES, the IC shall be obligated to remedy deficiencies under SCE/ES's direction, or ES shall undertake additional environmental studies, surveys, or monitoring at the sole expense of the IC. If these scenarios occur, the cost estimate must be updated to reflect the changes to the assumptions.

This study is based upon the scope listed in the Attachment 1. If the scope is altered, this Project's estimate is no longer valid and the estimate must be reviewed and updated.

4. Other Items Considered

- **Other Potential Distribution Upgrades**: The Project is dependent upon the installation of the Storage Management System (SMS). The installation of the SMS was triggered by prior queued projects which currently hold the cost responsibility for the upgrade. In the event that: (i) the interconnection requests for one or more of such projects are withdrawn; (ii) any of the interconnection agreements for such projects are terminated prior to the in-service date of such distribution upgrade; or (iii) it is determined by the Distribution Provider that some or all of such distribution upgrade currently assigned to earlier-queued projects are no longer required by such projects but are required for the Project at hand, then the Interconnection Customer may be responsible for the costs of other potential distribution upgrade(s). The Interconnection Customer's cost responsibility for any distribution upgrade costs not already identified in this study report will be reflected in an addendum report or GIA amendment. Therefore, in the event that prior queued projects do not execute a GIA and the SMS is still required, the Project may be allocated up to 100% responsibility related to the initial programming (backbone) of the SMS.

- The battery storage component of the Project will need to be metered separately. The IC should be prepared to install multiple sets of metering (i.e. separate sets of PTs & CTs and supporting metering equipment) for the Project to separately meter their wholesale and retail loads. Additionally, the Project may also need to connect any component that will be connected as a wholesale load to a dedicated transformer separate from the transformer that will serve their retail load.

- The battery storage component of the Project will need to be metered separately. The IC should be prepared to install multiple sets of metering (i.e. separate sets of PTs & CTs and supporting metering equipment) for the Project to separately meter their wholesale and retail loads. Additionally, the Project may also need to connect any component that will be connected as a wholesale load to a dedicated transformer separate from the transformer that will serve their retail load.

5. Charging Facility Considerations:
    - This study assumes that the IC Generating Facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the energy storage facility demand profile per SCE requirements.
    - In order to ensure limits are communicated in a timely and reliable manner, the IC is responsible for providing reliable communications between the Project and the Point of Interconnection to transmit the required telemetry data as outlined in the Interconnection Handbook. Should the communication channel fail, the Project's operating limits will automatically revert to zero (no charging allowed).
    - Depending on the study results, the Project may need to participate in the Storage Management System (SMS).
    - An SMS, which at this stage is a technical concept, is under development to incorporate the increased amount of energy storage applications to SCE's Distribution System with minimal distribution upgrades. It is assumed that a SMS or similar system will be available prior to the In-Service Date of the energy storage facility and further details will be available during the detailed engineering and design phase of the Project. The SMS will actively communicate allowable Project limits under charging mode to maintain safe and reliable operation of the distribution system.
    - The energy storage component of the Project will need to be metered separately from the retail load components. The IC should be prepared to install multiple sets of metering (i.e. separate sets of potential and current transformers and supporting

metering equipment) for the Project. Additionally, the Project may also need to connect the energy storage component to a dedicated transformer

- For this study, an additional reliability assessment for the charging of storage component was evaluated. Please refer to Attachment 8 for additional details.

C. RELIABILITY STANDARDS, STUDY CRITERIA AND METHODOLOGY

The generator interconnection studies were conducted to ensure the CAISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards. Refer to Section C of the Area Report for details of the applicable reliability standards, study criteria, and methodology.

D. POWER FLOW RELIABILITY ASSESSMENT RESULTS

Discharging Analysis of the Project

I. Steady State Power Flow Analysis Results – Bulk Electric System

The study indicated that QC9 Metro Area projects, including this Project, do not contribute to any facility overloads following evaluation under all conditions outlined per NERC Standard TPL-004-1. The study included all existing and prior queued transmission upgrades on the Bulk Electric System. Consequently, the Project is not allocated cost for any Reliability Network Upgrades identified to address power flow issues. The details of the power analysis are provided in the Metro Bulk Area Report.

II. Steady State Power Flow Analysis Results – Subtransmission System

1. Thermal Overloads

The Barre 66 kV Subtransmission Assessment indicated the Project does not contribute to overloads to any facility under Base Case or Single Contingency scenarios with all existing and prior queued transmission upgrades on the Barre 66 kV Subtransmission System. Consequently, the Project is not allocated cost for any Distribution Upgrades identified to address power flow issues. The details of the power flow analysis are provided in Barre 66 kV Subtransmission Assessment. The results identified in this section assume QC9 Phase I Projects dispatched at their requested maximum output.

While there were no thermal overloads, the Power Flow Analysis found that loss of the Barre 4A 220/66 kV Transformer Bank would result in loss of service to everyone connected on the Barre C Section.

2. Voltage Performance

The Project is required to provide power factor regulation capability (0.95 lead/lag at POI). With the Project providing power factor regulation, no voltage performance issues were identified.

3. Required Mitigations

With the Project providing the required 0.95 leading/0.95 lagging power factor regulation, the Project will require anti-islanding protection for loss of the Barre 4A 220/66 kV Transformer Bank. Furthermore, the Project will not be allowed to operate under such outage condition.

Charging Analysis of the Project

I. Steady State Power Flow Analysis Results – Bulk Electric System

Under charging conditions, the study did not identify any power flow issues on the Bulk Electric System not addressed via the use of CAISO Congestion Management or via already approved transmission upgrades. Consequently, the Project is not allocated cost for any Reliability Network Upgrades identified to address power flow issues related to charging operation.

II. Steady State Power Flow Analysis Results – Subtransmission System

1. Thermal Overloads

The group study indicated that the Project contributes to Base Case overloads on the Barre No. 4A 220/66 kV Transformer Bank. In addition the study identified single contingency overload under loss of Barre 1A or 3A and closure of sectionalizing breakers. The details of the analysis and overload levels are provided in the Barre 66 kV Subtransmission Assessment Report. Furthermore, the power flow analysis found that loss of the Barre 4A 220/66 kV Transformer Bank would result in loss of service to everyone connected on the Barre C Section.

2. Voltage Performance

The Project is required to provide power factor regulation capability (0.95 lead/lag at POI). With the Project providing power factor regulation, no voltage performance issues were identified.

3. Required Mitigations

With the Project providing the required 0.95 leading/0.95 lagging power factor regulation, the Project will require anti-islanding protection for loss of the Barre 4A Transformer Bank and will not be allowed to operate under such an outage condition. Furthermore, under such a condition whereby an outage of either the Barre 3A or 4A transformer bank on the Barre AB 66 kV Bus Section is followed by closure of the sectionalizing breakers, the Project will not be allowed to operate.

The Project will also require use of a storage management system (SMS) to restrict charging in order to address overloads on the Barre 4A Transformer Bank.

E. SHORT-CIRCUIT DUTY RESULTS

Short-circuit studies were performed to determine the fault duty impact of adding the Phase I projects to the distribution system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in Phase I is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in Section 4 of the GIP.

1. Short-Circuit Duty Study Input Data

The IC provided technical data for the identified inverter (specified in Section 2). SCE compared the technical data provided against manufacturer data, if the manufacturer Short-Circuit Duty (SCD) information for the specific inverter was available. If the technical data provided by the IC differed from the inverter manufacturer data, then SCE utilized the manufacturer data in the SCD analysis. In this case, SCE utilized the IC data.

Synchronous Generation Data for Each Generation Unit
X"d - Subtransient reactance fault contribution: 0.180 P.U.
X'd - Transient reactance fault contribution: 0.176 P.U.
X - Synchronous reactance fault contribution: 0.095 P.U.

Inverter/Converter Based Generation Data for Each Generation Unit
Maximum Fault Contribution: 1.5 P.U.

Generation Tie-Line:
Gen-tie impedance is negligible due to short distance.

Collector System:
Collect system assumed negligible for BESS Projects

Generation Step-Up and Pad-Mount Transformers
Technical details are provided above in Table A-1.

2. Short-Circuit Duty Study Results

All bus locations where the Phase I projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of Phase I interconnections and corresponding network upgrades, if any.

As discussed in Section B.5.1 of the Area Report, short circuit duty at Barre 220 kV was found to exceed the maximum nameplate ratings of all existing 220 kV breakers. Physical upgrades would necessitate replacement of all circuit breakers with a currently non-SCE standard higher rated 220 kV breaker which will necessitate in excess of $70 million and require over 48 months to implement. Because the need is currently viewed as temporary in nature and is impacted by timing of the ultimate disposition of the existing OTC units, the recommended mitigation involves implementing an operating procedure which would restrict the number of generation units that can operate (i.e., "spin") to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA. Such restrictions may impact operations of queued projects which provide significant short-circuit duty contribution to the Barre 220 kV bus. If the queued ahead Project that triggered the need for 220 kV breaker mitigation as part of QC7 Phase II, WDAT 1189, subsequently withdrawals the operational restriction would require further evaluation to determine if the QC9 Phase I projects still trigger the need for breaker replacements.

Additionally, the QC7 Phase II studies identified a number of 66 kV circuit breakers on the Barre AB and C Sections that required upgrade under an assumption that the Barre 66 kV sectionalizing bus breakers were closed (during loss of an A-Bank) with the QC7 Project in-service and operational. As part of the analysis, an additional review was performed which evaluated the potential use of an operating scheme and/or procedure to disconnect the Project anytime the Barre 66 kV sectionalizing bus breakers are closed in order to reduce SCD at Barre 66 kV. QC9 Projects will also need to be disconnected to reduce SCD under closure of sectionalizing CB's.

The responsibility to finance short-circuit related Reliability Network Upgrades (RNU) and Distribution Upgrades (DU) identified through a Group Study shall be assigned to all IRs in that Group Study pro-rata on the basis of SCD contribution of each Generating Facility.

Please refer to the QC9 Phase I Area Report and Barre 66 kV Subtransmission Assessment for the QC9 Phase I breaker evaluation discussion, which identified overstressed circuit breakers at the SCE buses, and Attachment 2 for the pro-rata allocation with corresponding estimated costs (if any) for the Project, based on SCD contribution at each location. The SCD studies determined that this Project did not trigger any breaker replacements with the restriction that the Project disconnect following closure of the Barre 66 kV sectionalizing CB's.

3. **Potential Affected Systems**
The SCD incremental increase to neighboring utilities due to the addition of all QC9 Phase I projects are provided in the Area Report (Section H.2). The studies determined that this project does not provide any incremental duty to neighboring utilities.

4. **SCE Substations with Ground Grid Duty Concerns**
The short-circuit studies flagged for further review a total of seven (7) existing substations where the Phase I projects increased the substation ground grid duty by at least 0.25 kA. Additional review will be performed as part of Phase II to determine if any of these locations will require a detailed ground grid analysis performed as part of project execution once GIAs are in place and projects proceed forward towards interconnection.

F. TRANSIENT STABILITY EVALUATION

With the Project providing 0.95 power factor correction as measured at the POI and including the required mitigation identified above, transient stability performance was found to be acceptable. Refer to Sections C.3 and D.2 of the Area Report, for additional details pertaining to the Phase I transient stability evaluation criteria and assessment results, respectively. The Project will be required to have out of step and anti-islanding projection for the synchronous and inverter based generating units, respectively, to disconnect the project anytime the Barre 4A Transformer Bank is lost. Furthermore, the Project will not be allowed to operate under such outage condition.

G. POWER FACTOR REQUIREMENTS

Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the POI at a power factor within the range of 0.95 leading and 0.95 lagging[4]. Additionally, the generation system must be designed to accommodate a Voltage and/or VAR schedule provided by SCE. SCE will determine if the Voltage and/or VAR schedule is necessary based on future re-arrangements of SCE's Distribution System.

[4] The current CAISO Tariff requires that projects be able to meet power factor requirements of 0.95 lagging and 0.95 leading at the POI, if studies identify the need based on meeting reliability and safety requirements. The requirement will change pending FERC approval of CAISO's compliance filing to FERC Order 827.

H. DELIVERABILITY ASSESSMENT RESULTS

1. **On Peak Deliverability Assessment**
   The Project does not contribute to any deliverability issues.

2. **Off- Peak Deliverability Assessment**
   The Project does not contribute to any off-peak deliverability issues.

3. **Required Mitigations**
   No Delivery Network Upgrades are required.

I. INTERCONNECTION FACILITIES, NETWORK UPGRADES, AND DISTRIBUTION UPGRADES

Please see Attachment 1 for the Distribution Provider's Interconnection Facilities (IFs), Reliability Network Upgrades (RNUs), Delivery Network Upgrades (DNUs), and Distribution Upgrades (DUs) allocated to the Project. Please note that SCE will not "reserve" the identified IFs for the proposed POI. The identified scope/facilities will be allocated to the Project upon the successful execution of the GIA and SCE has completed the detailed design and engineering of the facilities according to tariff timelines.

J. COST AND CONSTRUCTION DURATION ESTIMATES

To determine the cost responsibility of each generation project in Phase I, the CAISO developed cost allocation factors (Attachment 3) for RNUs, Local Delivery Network Upgrades (LDNUs), and Area Delivery Network Upgrades (ADNUs). Attachment 2 provides the 'constant' 2016 dollars and their escalation to the estimated COD year for IFs, RNUs, DNUs, and DUs, which the Project was allocated cost.

For the QC9 Phase I Study, the estimated COD is derived by taking into account time requirements to complete the QC9 Interconnection Process and tender a draft Generator Interconnection Agreement (GIA). A GIA is not scheduled to be tendered until after the completion of the QC9 Phase II Studies, CAISOs Annual Reassessment and the CAISOs Transmission Planning Deliverability (TPD)[5] Allocation Study Process. The QC9 Phase II Study is scheduled to start on May 2017 and be completed by November 2017. Subsequently, the Annual Reassessment effort and TPD Allocation Study does not commence until late January or early February 2018. The TPD Allocation Study is scheduled to be completed by April 2018. If the CAISO and SCE can make a determination that the TPD Allocation Study Process outcomes do not change the scope requirements for the project, a letter will be provided at the end of April 2018[6] informing the IC that there will be no changes to their Network Upgrades requirements and GIA negotiations can begin. Otherwise, further re-assessment will be performed for the project. If updates to scope, cost and schedule are developed, an updated Interconnection Study report will be issued to the IC by the end of July 2018. The GIA negotiations commence after either the issuance of the letter of no change to the project's Network Upgrades requirements at the end of April 2018 or upon issuance of the updated Interconnection Study report at the end of July 2018. Provided the Project does not elect to Park for one (1) year, the letter issued by the CAISO and/or the updated Interconnection Study reports will be used as the basis to negotiate the GIA. Assuming a three (3) month timeframe for GIA negotiations after the draft GIA has been issued to the IC, the earliest an executable GIA can be expected is either August 2018 or November 2018 depending on TPD Allocation Study

[5] Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan
[6] The TPD Allocation Process is estimated to be completed in April 2018. The actual date may vary.

Process results. QC9 Phase I assumed the duration of the work element begins in December 2018, which accounts for the negotiation and execution of a GIA and submittal of required funds by the IC.

Based on the above, the requested IC In-Service Date (ISD) of October 15, 2019 cannot be met due to the estimated 27-month timeline identified for the Plan of Service (POS) facilities and potentially a SMS required to interconnect the Project. Following the standard interconnection process, the ISD should be modified accordingly. The IC should note that a 35% Income Tax Component of Contribution (ITCC) will be assessed for IFs, DUs, and RNUs above the $60K/ MW repayment cap allocated to the Project. Attachment 2 to your Interconnection Study report contains a potential ITCC estimate[7] based on the Phase I cost in this study. It does not represent the “maximum ITCC exposure” of the Project. Attachment 3 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the Network Upgrades maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the GIA development phase once the IC submits the TP Deliverability Allocation Study Process options form used to confirm the acceptance, waiver (parking), or denial of the awarded deliverability assigned to the Project.

K. SCE TECHNICAL REQUIREMENTS

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider’s Interconnection Handbook provided in Attachment 4.

The IC is responsible for complying with IEEE Standard 519-2014 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems on SCE’s Transmission System.

L. SUBSYNCHRONOUS INTERACTION EVALUATIONS

Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SSI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

For projects interconnecting at the 220 kV voltage level and above in close electrical proximity of series capacitor banks on the transmission system a study will need to be performed to evaluate the SSI between Generating Facilities and the transmission system. Given the Project location, it will not be necessary to perform these evaluations.

M. ENVIRONMENTAL ACTIVITIES, PERMITS, AND LICENSING

Please see Appendix K of the Area Report.

N. AFFECTED SYSTEMS COORDINATION

Please see Section H of the Area Report.

[7] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities. For Network Upgrades, costs that are not subject to transmission credits and/or exceed the $60k/MW cap will be subject to ITCC (35%). For Option A facilities: The maximum ITCC exposure is calculated by applying the following formula: (IF*35%) + ((RNU Costs – (Project MW*($60k/MW)))*35%) + (DU*35%). For Option B facilities: The maximum ITCC exposure is calculated by applying the following formula: (IF*35%) + ((RNU Costs – (Project MW*($60k/MW)))*35%) + (DU*35%)

O. ITEMS NOT COVERED IN THIS STUDY

1. **Conceptual Plan of Service**
   The results provided in this study are based on conceptual engineering and a preliminary POS and are not sufficient for permitting of facilities. The POS is subject to change as part of detailed engineering and design.

2. The study does not include analysis related to the power output rate of change that may occur due to the following or other conditions:

   - System morning start up for solar systems. That is when each morning the generating facility commences to generate and export electrical energy to the electric system.
   - Cloud Cover. Solar generating facilities have significant generation output variation (Variability) which can have an impact on electric system voltage profiles.
   - The customer's generating facility will have equipment, software, and the appropriate controls in place to be able to control the generation output rates of change, as specified by SCE, in order to maintain appropriate voltage levels under all conditions including, but not limited to, the conditions identified above. Upon execution of the appropriate Interconnection Agreement, SCE will provide the Interconnection Customer the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the electric system as well as SCE's electric system configuration but other parameters may be considered. Therefore, changes to the ramp rate control scheme may be required from time to time as required by increased generation, changes in the electric system topology, or other changes in the electric system.

3. **IC's Technical Data**
   The study accuracy and results for the Phase I Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided as allowed by the tariff would need to be submitted in Attachment B prior to commencement of the Phase II study. Any changes that extend beyond the modifications allowed prior to commencement of the Phase II Study will need to be evaluated following the Material Modification Assessment to determine if such change results in a material impact to queued-behind generation requests. These change(s) would only be allowed if it is determined that there is no material impact to queued-behind requests.

4. **Study Impacts on Neighboring Utilities**
   Results or consequences of this Phase I Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short-circuit duties outside of the ISO Controlled Grid, and sub-synchronous resonance (SSR). Refer to Affected Systems Coordination Section of the Area Report for additional information.

5. **Use of Distribution Provider Facilities**
   The IC is responsible for acquiring all property rights necessary for the IC's Interconnection Facilities, including those required to cross the Distribution Provider's facilities and property. This Phase I Study does not include the method or estimated cost to the IC of Distribution Provider mitigation measures that may be required to accommodate any proposed crossing of the Distribution Provider's facilities. The crossing of Distribution Provider property rights shall

only be permitted upon written agreement between Distribution Provider and the IC at the Distribution Provider's sole determination. Any proposed crossing of Distribution Provider property rights will require a separate study and/or evaluation, at the IC's expense, to determine whether such use may be accommodated.

6. **Distribution Provider's Interconnection Handbook**
   The IC shall be required to adhere to all applicable requirements in the Distribution Provider's Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

7. **Western Electricity Coordinating Council (WECC) Policies**
   The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

8. **System Protection Coordination**
   Adequate Protection coordination will be required between Distribution Provider-owned protection and IC-owned protection. If adequate protection coordination cannot be achieved, then modifications to the IC-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

9. **Standby Power and Temporary Construction Power**
   The Phase I Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the ISD of the Interconnection Facilities. Should the Project require standby power or temporary construction power from the Distribution Provider prior to the ISD of the IFs, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such retail service.

10. **Licensing Cost and Estimated Time to Construct Estimate (Duration)**
    The estimated licensing cost and durations applied to this Project are based on the Project scope details presented in this Phase I study. These estimates are subject to change as the Project's environmental and real estate elements are further defined. Upon execution of the GIA, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

11. **Network/Non-Network Classification of Telecommunication Facilities**
    The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for the RAS were assumed based on tripping of the generator's breaker in lieu of tripping the circuit breakers at the Distribution Provider's substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of Phase I, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified

for Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

12. Ground Grid Analysis

A detailed ground grid analysis will be required as part of the detailed engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

13. Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the SCE electrical system; as well as establish the technical requirements to interconnect the Project to the POI that was evaluated in the Phase I Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in GIAs agreed to by the Distribution Provider, ISO, and the IC.

14. Process for Initial Synchronization Date/Trial Operation Date and COD of the Project

The IC is reminded that the ISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before Initial Synchronization Date/Trial Operation Date and COD. The NRI uses a bucket system for deliverables from the IC that are required to be approved by the CAISO. The first step of this process is to submit an "ISO Initial Contact Information Request form" at least seven (7) months in advance of the planned Initial Synchronization Date. Subsequently an NRI project number will be assigned to the project for all future communications with the CAISO. The Distribution Providers have no involvement in this NRI process except to inform the IC of this process requirement. Further information on the NRI process can be obtained from the CAISO Website using the following links:
New Resource Implementation webpage:
http://www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx

NRI Checklist:
http://www.caiso.com/Documents/NewResourceImplementationChecklist.xls

NRI Guide:
http://www.caiso.com/Documents/NewResourceImplementationGuide.doc

15. Potential Changes in Cost Responsibility

The IC is advised that interconnection of its proposed Generating Facility may be dependent upon the construction of certain Network Upgrades, which are currently the obligation of projects ahead of its proposed Generating Facility in the interconnection application queue. These other potential network upgrades are referenced in Section B.5 of the Area Report and outlined in Attachment 2 to the ICs final Phase I or Phase II Study Report (Appendix A).

Whether the IC becomes responsible for all or a portion of these other potential network upgrades depends upon several factors, some of which are unknown at the time of this study. However, in an effort to alert the IC to its maximum cost responsibility for Network Upgrades, were these other potential network upgrades to become the obligation of the IC, SCE has included the IC's proportionate cost responsibility for these upgrades under the other potential network upgrades section in Attachment 2 to this report. The IC is not required to post Interconnection Financial Security for these other potential network upgrades, but the prospective obligation to finance and construct these other potential network upgrades is included in the IC's maximum cost responsibility.

The obligation to finance and construct these other potential network upgrades is governed by Sections 4.6.8 and 10.3.2 of the GIP and 14.2.2 of the GIDAP. Both the GIP and GIDAP contain similar language, which is summarized as follows:

1) If the earlier-queued generating facilities that have cost responsibility for the other potential network upgrades withdraw prior to executing a GIA (or the filing of an unexecuted GIA at FERC), the following will occur:

    a. The ISO and SCE will evaluate whether the other potential network upgrades are still needed to support the interconnection for later-queued generating facilities.

    b. The ISO and SCE will reapportion the cost of the other potential network upgrades to the later-queued generating facilities that require the upgrades.

    c. Steps (a and b) will occur as a result of the ISO's Annual Reassessment as set forth in Section 7.4 of GIDAP and Section 6.2.9.2 of the ISO's GIDAP business practice manual.

    d. The reapportioned cost of the other potential network upgrades will be reflected in the reassessment report as outlined in the ISO's Annual Reassessment process, which will be reflected in the GIAs of the responsible parties.

2) Please refer to Section 10.3.2 of the GIP and Section 14.2.2 of the GIDAP for additional requirements regarding treatment of other potential network upgrades for ICs that select an Option (B) Generating Facility.

16. ISO Market Dispatch
This study did not evaluate any potential limitations that may be driven by the ISO market under real-time operating conditions.

17. Please note that the Distribution Provider has made its best efforts to convey as much information as possible based on information provided by the IC about its proposed Project. The information contained herein may indicate to ICs that a project of its magnitude may be better suited to interconnect at higher voltage levels, or downsize as to not incur significant amount of restrictions. Any determination to change POIs or downsize is purely at the IC's discretion and would be subject to a Distribution Provider's material modification review pursuant to the tariff.

18. Future Charging Restrictions
Charging restrictions not identified in this study may occur in the future if the underlying operating assumptions prove to be significantly different than the conditions evaluated in this study.

Attachment 1:
Interconnection Facilities, Network Upgrades and Distribution Upgrades
Please refer to separate document

Attachment 2:
Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Please refer to separate document

Attachment 3:
Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility

None identified in theQC9PI Study.

Attachment 4:
Distribution Provider’s Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider’s Interconnection Handbook (separate document)

Attachment 5:
Short-Circuit Duty Calculation Study Results
Please refer to the Appendix H of the Area Report

Attachment 6:
Interconnection Customer Provided Project Dynamic Data

Attachment 7:
SCE Northern Hemisphere Import Nomogram
Please refer to separate document

Attachment 8:
Subtransmission Assessment Report
Please refer to separate document

Queue Cluster 9 Phase I - Attachment 1
WDT1391– Stanton Energy Reliability Center II
Interconnection Facilities, Network Upgrades, and Distribution Upgrades

To determine the cost responsibility of each project in QC9, the California Independent System Operator Corporation (ISO) developed cost allocation factors (Attachment 3) for Reliability Network Upgrades and Local Delivery Network Upgrades. The ISO developed the $/MW cost rate for incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades. The Interconnection Facilities are the sole cost responsibility of the Project. The Interconnection Facilities, Network Upgrades, and Distribution Upgrades allocated to the project are listed below.[1]

1. Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities.** The Interconnection Customer shall:

(i) Install a substation with one (1) 66/13.8 kV main step-up transformer with a 9 percent impedance on a 100 MVA base.

(ii) Install an 1800 foot 3000 CU XLP 66 kV line extension, with the normal (continuous) rating of 1,575 A and the emergency (four-hour) rating of 1,575 A, from the Generating Facility to a position designated by the Distribution Provider, outside of the Distribution Provider's Barre Substation, where Interconnection Customer shall install a structure designed and engineered in accordance with the Distribution Provider's specifications (Last Structure). This line extension will be referred to as the Barre–WDT1391 66 kV Line. The right-of-way for Barre–WDT1391 66 kV Line shall extend up to the edge of the Barre Substation property line.

(Note: The Barre–WDT1391 66 kV Line name is subject to change by the Distribution Provider based upon its naming criteria. Should the Barre–WDT1391 66 kV Line name be changed, the GIA may be amended to reflect such change.)

(iii) Install All-Dielectric-Self Supporting (ADSS) fiber optic cable on Barre–WDT1391 66 kV Line to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide one of two telecommunication paths required for the line protection scheme, and the Remote Terminal Unit (RTU). A minimum of eight (8) strands within the ADSS

[1] Upgrades described in this Attachment 1 are based on the Distribution Provider's preliminary engineering and design. Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

fiber optic cable shall be provided for the Distribution Provider's exclusive use into Barre Substation.

(iv) Install appropriate ADSS fiber optic cable from the Generating Facility to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide the second telecommunication path required for the line protection scheme. A minimum of eight (8) strands within the fiber optic cable shall be provided for the Distribution Provider's exclusive use. The telecommunication path shall meet the Applicable Reliability Standards criteria for diversity.

(v) Own, operate and maintain both telecommunication paths (including the fiber optic cables and appurtenant facilities), with the exception of the terminal equipment at both Barre Substation and at the Generating Facility, which terminal equipment will be installed, owned, operated and maintained by the Distribution Provider.

(vi) Allow the Distribution Provider to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider's terminal equipment and protection engineering requirements; allow the Distribution Provider to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(vii) Provide required data signals, make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's RTU in accordance with the Interconnection Handbook. The space provided for the RTU must be at a location that would allow twenty-four (24) hour access for the Distribution Provider's personnel.

(viii) Make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's telecommunications terminal equipment in accordance with the Interconnection Handbook. The space provided for the Distribution Provider's telecommunications terminal equipment must be at a location that would allow twenty-four (24) hour access for the Distribution Provider's personnel.

(ix) Extend the ADSS fiber optic cables for the two telecommunication paths to an Interconnection Customer provided and installed patch panel located adjacent to the Distribution Provider's telecommunications terminal equipment specified above.

(x) Install all required ISO-approved compliant metering equipment at the Generating Facility, in accordance with Section 10 of the ISO Tariff.

(xi) Install a metering cabinet and metering equipment (typically, potential and current transformers) at the Generating Facility to meter the Generating Facility retail load, as specified by the Distribution Provider. The metering cabinet must be placed at a location that would allow twenty-four hour access for the Distribution Provider's metering personnel.

(xii) Install a metering cabinet and metering equipment (typically, potential and current transformers) at the Generating Facility to meter the Generating Facility wholesale load, as specified by the Distribution Provider. The metering cabinet must be placed at a location that would allow twenty-four hour access for the Distribution Provider's metering personnel.

(xiii) Allow the Distribution Provider to install, in the metering cabinet provided by the Interconnection Customer, meters and appurtenant equipment required to meter the retail load at the Generating Facility.

(xiv) Allow the Distribution Provider to install, in the metering cabinet provided by the Interconnection Customer,wholesale meters and appurtenant equipment required to meter the wholesale load at the Generating Facility.

(xv) Install relay protection to be specified by the Distribution Provider to match the relay protection used by the Distribution Provider at Barre Substation, in order to protect the Barre–WDT1391 66 kV Line, as follows:

1. Two (2) line current differential relays connected via diversely routed dedicated digital communication channels to Barre Substation. The make and type of current differential relays will be specified by the Distribution Provider during detailed engineering of the Distribution Provider's Interconnection Facilities.

(xvi) Install all equipment necessary to comply with the power factor requirements of Article 9.6.1 and the voltage schedules requirements of Article 9.6.2 of the GIA.

(xvii) Install disconnect facilities in accordance with the Distribution Provider's Interconnection Handbook to comply with the Distribution Provider's switching and tagging procedures.

(xviii) Acquire the necessary rights-of-way for the Interconnection Customer's Interconnection Facilities.

(xix) Perform the necessary environmental studies and obtain permits for the Interconnection Customer's Interconnection Facilities, as well as, perform the environmental activities as described in the Distribution Provider's Interconnection Facilities and Distribution Upgrades.

(b) **Distribution Provider's Interconnection Facilities.**

(i) **Barre Substation.**

1. Install the interconnection facilities portion for a new 66 kV position to terminate the Barre–WDT1391 66 kV Line. This work includes the following:
   a. One (1) dead-end substation structure
   b. Three (3) 66 kV voltage transformers with steel pedestal support structures.
   c. One (1) 66 kV line drop.

2. Install the following relays to protect the Barre–WDT1391 66 kV Line:
   a. Two (2) line current differential relays connected via diversely routed dedicated digital communications channels to the Generating Facility.

(ii) **Barre–WDT1391 66 kV Line Extension.**

Shall install an appropriate number of 66 kV sub-transmission structures including insulator/hardware assemblies between the Last Structure and the dead-end substation structure at Barre Substation. The actual number and location of the sub-transmission structures and spans of conductor will be determined by the Distribution Provider following completion of detailed engineering of the Distribution Provider's Interconnection Facilities. The Phase I Interconnection Study assumed two (2) TSP structures, three (3) vaults, and approximately 12,000 ft 3000 kcmil Al conductor between the Barre switchrack and the generation side.

(iii) **Telecommunications.**

1. Install all required lightwave, channel banks, and associated equipment (including terminal equipment), supporting protection and SCADA requirements at the Generating Facility and Barre Substation for the interconnection of the Generating Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such telecommunication equipment as part of the Distribution Provider's Interconnection Facilities.
2. Install appropriate length of fiber optic cable, including conduit and vaults, from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation to extend the fiber optic cable into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during detailed engineering of the Distribution Provider's Interconnection Facilities.

3. Install appropriate length of fiber optic cable, including conduit and vaults, to extend the Interconnection Customer's diverse telecommunications from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during detailed engineering of the Distribution Provider's Interconnection Facilities.

(iv) **Real Properties.**
The Distribution Provider shall obtain easements and/or acquire land for the installation of the Distribution Provider's Interconnection Facilities, including any associated telecommunication equipment for the Barre–WDT1391 66 kV Line.

(v) **Environmental Activities, Permits, and Licensing.**

The Interconnection Customer shall perform environmental studies and prepare draft environmental permit applications related to the installation of the Distribution Provider's Interconnection Facilities. The Interconnection Customer shall obtain the Distribution Provider's approval of proposed study methodologies, documents resulting from environmental studies, and draft permit applications intended for the Distribution Provider's use. Distribution Provider shall review the Interconnection Customer's proposed study methodologies, documents resulting from environmental studies, and draft permit applications intended for the Distribution Provider's use. The Distribution Provider shall obtain licensing and permits, as required. The Interconnection Customer shall be responsible for performing pre-construction activities and construction monitoring and related activities.

(vi) **Metering.**
Shall install meters and appurtenant equipment required to meter the retail load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

Install meters and appurtenant equipment required to meter the wholesale load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

(vii) **Power System Controls.**
Shall install one (1) RTU at the Generating Facility to monitor typical battery storage elements such as MW, MVAR, terminal voltage and circuit breaker status

for the Generating Facility and plant auxiliary load, and transmit the information received thereby to the Distribution Provider's Grid Control Center. Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain the RTU as part of the Distribution Provider's Interconnection Facilities.

2. Network Upgrades.

(a) **Stand Alone Network Upgrades.**
None identified as part of the the Phase I Interconnection Study.

(b) **Other Network Upgrades.**

(i) **Reliability Network Upgrades.**
None identified as part of the the Phase I Interconnection Study.

(ii) **Delivery Network Upgrades**

1. **Area Delivery Network Upgrades.**
   None identified as part of the the Phase I Interconnection Study.

2. **Local Delivery Network Upgrades.**
   None identified as part of the the Phase I Interconnection Study.

3. Distribution Upgrades. The Distribution Provider shall:

(a) **Barre Substation.**

(i) Install the Interconnection Facilities portion for a new 66 kV position to terminate the Barre–WDT1391 66 kV Line. This work includes the following:

1. Relocate 3A bank position from position 10 to position 13.
   <u>Remove:</u>
   1. One (1) 60 foot high X 45 foot wide 66 kV dead end structure for the 3A bank.
   2. Approximately 1200 feet of 1590 kcmil Aluminum Conductor Steel Reinforced conductor that was connected from the bank to the position 10.
   3. Approximately 400 feet of ½ ground wire 7 stranded steel for the bank's dead end to the position 10.
   4. Approximately 500 feet of 605 kcmil Aluminum Conductor Steel Reinforced conductor for the bank position.
   5. Two (2) 66 kV 3000A 40 kA Mitsubishi Circuit Breakers with associated structure.

6. Two (2) 3000A horizontal group-operated disconnect switch with associated structure
7. One (1) 3000A vertical disconnect switch with ground attachment
8. One (1) 3000A vertical disconnect switch
9. Two (2) 69,000-197/115X115/69V connected phase-to-phase potential transformers with associated structure

Note: Removal Cost is the Interconnection Customer's non-refundable one time cost.

Install:

1. One (1) 60 foot high X 45 foot wide 66 kV dead end structure with foundation for the 3A bank.
2. Six (6) 72 KV Lighting arresters.
3. Approximately 1200 feet of 1590 kcmil Aluminum Conductor Steel Reinforced conductor that needs to be connected from the bank to the new position 13.
4. Approximately 500 feet of ½ ground wire 7 stranded steel for the bank's dead end to the position 13.
5. Approximately 500 feet of 605 kcmil Aluminum Conductor Steel Reinforced conductor for the bank position.
6. Two (2) 66 kV 3000A 40 kA Mitsubishi Circuit Breakers (CB #7 & 8) with associated structure and foundation.
7. Two (2) sets of 3000A horizontal group-operated disconnect switch with associate structure and foundation (6 in total).
8. One (1) set of 3000A vertical disconnect switch with ground attachment (3 in total).
9. One (1) 3000A vertical disconnect switch (3 in total).
10. Two (2) 69,000-197/115X115/69V connected phase-to-phase potential transformer with associated structure and foundation.
11. Approximately 400 feet of 7/C#12 (Control), 4/C#8 (Current), 2/C#10 (DC) to connect the new Circuit Breaker at the switchyard to the Control Room.
12. Two (2) LED lighting fixtures.

(ii) Relocate the bus sectionalizing circuit breakers from position 9 to position 12

Remove:

1. One (1) 66 kV 3000A 31.5 kA Seimens Circuit Breaker (CB) (Circuit Breaker #5) with associated structure.
2. One (1) 66 kV 3000A 40 kA MEP CB (Circuit Breaker #6) with associated structure.
3. Four (4) 3000 A horizontal group-operated disconnect switch with associated structures.
4. Approximateky 300 feet of 1272 KCMIL SAC conductor (connected from disconnect switch to the circuit breaker for the bus sectionalizing breakers).

5. Approximately 200 ft of 1590 KCMIL Aluminum Conductor Steel Reinforeced conductor (connected from the bus to the disc sws for the bus sectionalizing breaker).
6. Approxiamtely 200 ft of 2156 KCMIL Aluminum Conductor Steel Reinforced conductor (to create a position for the new bus sectionalizing two Circuit Breakers at position 12).

Install:

1. Two (2) 22 foot wide by 29 foot high 66 kV dead-end steel structures with foundations.
2. Two (2) 66 kV 3000A 40 kA MEP Circuit Breakers with associated structures and foundations.
3. Six (6) 72 KV Lighting arresters.
4. Three (3) 3000 A horizontal group-operated disconnect switch with associated structures foundations.
5. One (1) 3000 A horizontal group-operated disconnect switch with associated structure foundation and grounding attachment.
6. Approximately 300 feet of 1272 KCMIL SAC conductor (connected from disc sw to the Circuit Breaker for the bus sectionalizing breaker).
7. Approximately 200 feet of 1590 KCMIL ACSR conductor (connected from the bus to the disconnect switch sws for the bus sectionalizing breaker).
8. Approximately 200 feet of 2156 KCMIL ACSR conductor (to connect the bus conductor, due to removal of bus sectionalizing two Circuit Breakers (5 &6)).
9. Approximately 400 feet of 7/C#12 (Control), 4/C#8 (Current), 2/C#10(DC) to connect the new Circuit Breaker at the switchyard to the Control Room.
10. Two (2) LED lighting fixtures.

Install the Interconnection Facilities portion for a new 66 kV position to terminate the Barre – WDT1391 66 kV Line. Equip position 11 for the new line.This work includes the following:

1. One (1) 22 foot wide by 29 foot high 66 kV dead-end steel structure with foundations.
2. Six (6) risers with associated structures and foundations.
3. One (1) set of 72 KV Lighting arresters (3 in total).
4. Approximately 5000’ of 1000 JCN underground cable into a new 6-5” duct.
5. One (1) 2X3 5” duct bank.
6. Two (2) 66 kV 2000A 40 kA SF6 gas circuit breaker with associated foundation.
7. Two (2) sets of 66 kV 2000A horizontal group-operated disconnect switches (6 switches in total) with associated structure and foundation.
8. One (1) set of 66 kV 2000A vertical group- operated disconnect switches (3 switches in total).
9. One (1) set of 66 kV 2000A vertical group-operated disconnect switches with ground attachment (3 switches in total).

10. Three (3) 69,000-197/115X115/69V potential transformers with associated structures and foundations.
11. Approximately 600 feet of 1590KCMIL ACSR conductors to equip the position.
12. Approximately 400 feet of 7/C#12 (Control), 4/C#8 (Current), 2/C#10(DC) to connect the new Circuit Breaker at the switchyard to the Control Room.
13. Two (2) LED lighting fixtures.

(b) Perform ground grid study.

(c) **Install Storage Management System**

(i) Power System Control

- Create Storage Management System program in Energy Management System (EMS) to support charging aspect of energy storage project.
- Service and test Storage Management System

(d) **Power System Controls.**
Point additions to the existing RTU at Barre Substation to accommodate new relay, protection, status, and alarm.

(e) **Real Properties.**
Obtain easements and/or acquire land for the installation of the Distribution Upgrades.

(f) **Environmental Activities, Permits, and Licensing.**

Perform the required environmental activities related to the installation of the Distribution Provider's Distribution Upgrades. The Distribution Provider shall obtain licensing and permits, as required.

4. Affected System Upgrades
Not used.

5. Point of Change of Ownership.

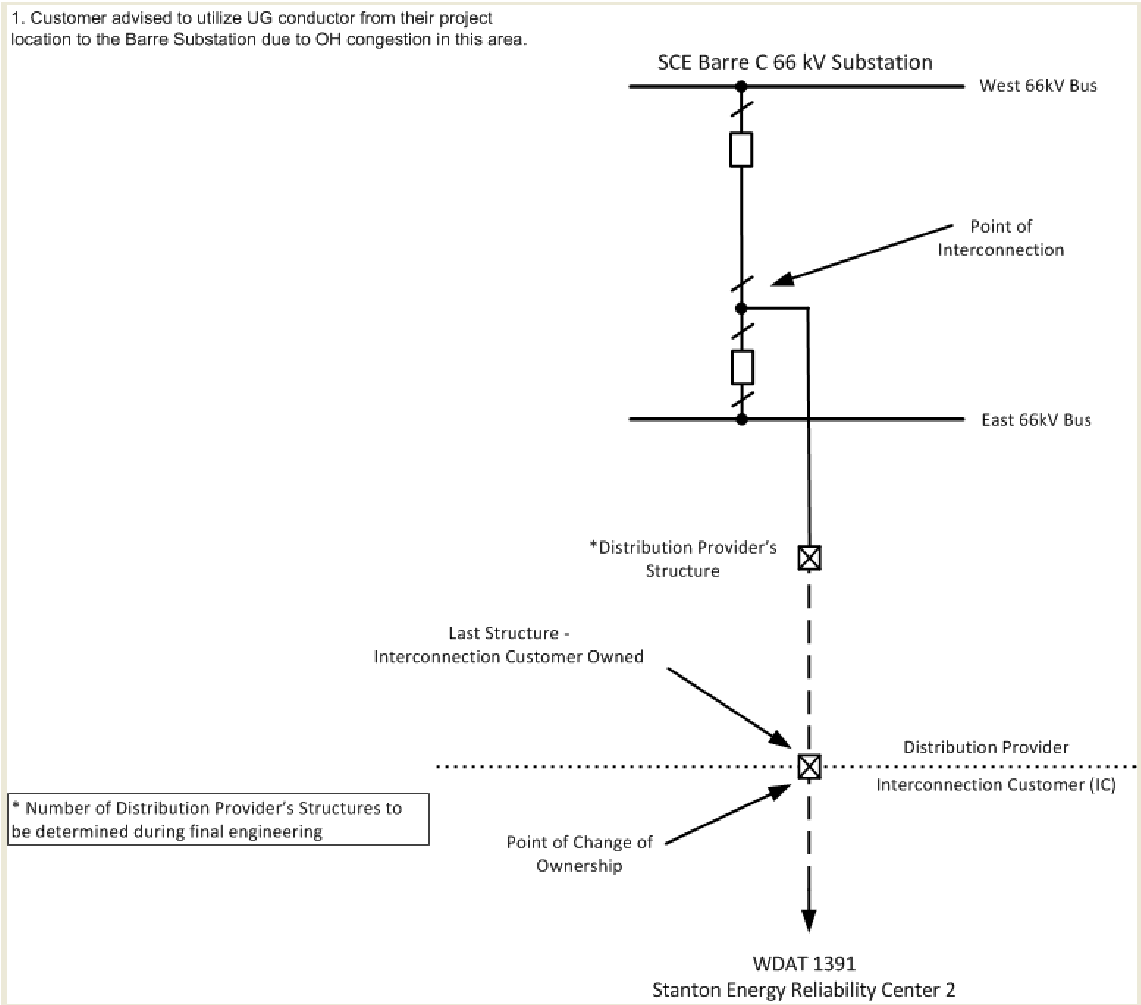
(a) Barre–WDT1391 66 kV Line: The Point of Change of Ownership shall be the point where the conductors of the Barre–WDT1391 66 kV Line are attached to the Last Structure, which will be connected on the side of the Last Structure facing Barre Substation. The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last Structure to the Interconnection Customer's Generating Facility. The Distribution Provider will own and maintain Barre Substation, as well as all circuit breakers, disconnects, relay facilities and metering within Barre Substation, together with the line drop, in their entirety, from the Last Structure to Barre Substation. The Distribution Provider will own the insulators that are used to attach the Distribution Provider-owned conductors to the Last Structure.

(b) Telecommunication ADSS fiber optic cable: The Point of Change of Ownership shall be the point where the ADSS fiber optic cable for the Barre–WDT1923 66kV Line is attached to the Last Structure.

(c) Telecommunication diverse fiber optic cable: The Point of Change of Ownership shall be the point at an Interconnection Customer installed and owned pole located at a position designated by the Distribution Provider outside the Distribution Provider's substation, or a Distribution Provider owned vault, where the Interconnection Customer's fiber optic cable is connected to the Distribution Provider's fiber optic cable.

6. Point of Interconnection. The Distribution Provider's Barre 66 kV switchrack.

7. One-Line Diagram of Interconnection to Barre 66 kV Substation.



QC9 Phase I Study Report Attachment #2

Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Project #: WDT1391

Cost Category	Costs per Category w/o ITCC (A)	One Time Costs (Note 1) (B)	Total Costs w/o ITCC (C=A+B)	Total Escalated Costs w/o ITCC	Estimated Time for Licensing, Permitting, & Construction (Months)	Maximum Escalation Duration (Months)
	Constant 2016 Dollar in $1000s (Estimate)	Constant 2016 Dollar in $1000s (Estimate)	Constant 2016 Dollar in $1000s (Estimate)	Escalated to OD Year in $1000s	(Note 3,4,5, 9, & 10)	(Note 3,4,5, 9, & 10)
Interconnection Facilities						
Transmission	$0	$0	$0	$0	27	27
Sub-Transmission	$4,719	$0	$4,719	$5,341	27	27
Substation	$789	$0	$789	$893	27	27
Licensing	$0	$0	$0	$0	27	27
Real Properties	$51	$0	$51	$58	27	27
Metering Services	$35	$0	$35	$39	27	27
Environmental Services	$68	$0	$68	$77	27	27
Power System Controls	$72	$0	$72	$82	27	27
Transmission Telecom	$0	$0	$0	$0	27	27
IT Telecommunications	$951	$0	$951	$1,076	27	27
Interconnection Facilities Total	**$6,686**	**$0**	**$6,686**	**$7,566**	**27**	**27**
Distribution Upgrades						
Substation	$1,988	$5,856	$7,844	$8,876	27	27
Environmental Services	$23	$0	$23	$26	27	27
Power System Controls	$0	$27	$27	$30	27	27
Storage Management System						
Storage Management System (Incremental cost to add project)	$0	$27	$27	$31	27	27
Distribution Upgrades Total	**$2,010**	**$5,910**	**$7,920**	**$8,962**	**27**	**27**
SCE Cost Assigned to the Project	**$8,696**	**$5,910**	**$14,606**	**$16,528**	**27**	**27**

Other Potential Distribution Upgrades (Note 13-14)	Costs per Category w/o ITCC	One Time Costs (Note 1)	Total Costs w/o ITCC	Total Escalated Costs w/o ITCC	Estimated Time for Licensing, Permitting, & Construction (Months)	Maximum Escalation Duration (Months)
Distribution Upgrades						
Storage Management System Initial Programming (Backbone for SMS)	$506	$0	$506	$572	27	27
Other Potential Upgrade Total:	**$506**	**$0**	**$506**	**$572**	**27**	**27**

WDT1391 **148.1 MW**

Income Tax Component of Contribution (ITCC) Potential		
Element	**ITCC @ 35% Constant Dollar in $1000s (2016)**	**ITCC @ 35% Escalated Dollar in $1000s (OD)**
IF, excludes One Time Cost (Calculation: (IF+SPS IF) * 35%)	**$2,340**	**$2,648**
RNU Refer to Note 11 below for Calculation	**$0**	**$0**
LDNU Refer to Note 12 below for ITCC treatment	**N/A**	**N/A**
DU, excludes One Time Cost (Calculation: DU* 35%)	**$704**	**$796**
ADNU Refer to Note 12 below for details on ITCC treatment	**N/A**	**N/A**

Max Duration for ITCC Calculation	**27**

Note 1: One time costs item(s) will be treated as applicable per the specified facilities or upgrade classification. They may be reimbursable depending on their classification.

Note 2: Distribution upgrades are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute Generator Interconnection Agreements.

Note 3: The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental, licensing, and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

Note 4: Each facility or upgrade category may contain multiple work element construction durations. The longest estimated construction duration is shown under the C.O.D Dollar Duration column.

Note 5: SCE's Phase I cost estimating is done in 'constant' dollars 2016 and then escalated to the estimated O.D.year. For the QC9 study, the estimated C.O.D. Dollar is derived by assuming the duration of the work element will begin in December 2018, which is the CAISO tariff scheduled completion date of the QC9 Phase II study plus: the TPD Allocation, Annual Reassessment Effort , and the interconnection agreement signing period and submittal of required funds by the IC. For instance, if a work element is estimated to take a total of 24 months (detail engineering, design, procurement, licensing and construction), then the estimated C.O.D. would be December 2020. If an IC's requested C.O.D. is beyond the estimated C.O.D. of a work element, the IC's requested C.O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not provided by the IC in time for the Participating TO to perform the work within these time frames, the information provided in Table above may be subject to change.

Note 6: Individual O&M charges for the above estimated construction costs will be identified and communicated during the Generator Interconnection Agreement process.

Note 7: The Estimated Time to Construct (duration in months) is the schedule for the PTO to complete detail engineering, design, procurement, licensing, and construction, etc., and other activities needed to construct and bring the facilities and upgrades into service. Such activities are from the execution of the Generator Interconnection Agreements, and receipt of: all required information, funding, and written authorization to proceed from the IC, as will be specified in the Generator Interconnection Agreement, to commence work. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

Note 8: The escalation factors to convert the estimated cost (in 'constant' 2016 dollars) to the estimated C.O.D. are found in the posted SCE 2016 Per Unit Cost Guide on the CAISO website:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Note 9: Estimated Time to Construct durations are from completion of any preceding facilities and upgrades required.

Note10: The C.O.D. Dollar for the IF and RNU/Dist. Plan of Service facilities was escalated using the requested Project C.O.D when the requested Project C.O.D was beyond the identified ETC of the IF and RNU/Dist. Plan of Service facilities. In such instances there is a different duration (months) in the ETC and C.O.D. Dollar escalation duration columns.

Note11: RNUs are subject to ITCC on funds above the repayment maximum ($60 k/MW) of the Project. The ITCC corresponding to the RNUs, when applicable, was calculated by applying the following formula:
[Total Project allocated RNU Costs – {(Project MW Size)* ($60k)}]*35%

Note12: LDNUs and ADNUs may be assessed 35% ITCC. However, presently the ITCC corresponding to LDNUs and ADNUs cannot be quantified due to their dependency on TPD allocation awarded to the Project and accepted by the Interconnection Customer ("IC") several months after the Phase II studies are complete. Consequently, the maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming acceptance, waiver (parking), or denial of awarded deliverability to the Project.

Note 13:This cost estimates represent the ICs final Phase I maximum cost responsibility for RNUs and LDNUs pursuant to Section 4.5.4 of the GIP or Section 10 of the GIDAP

Note 14: Cost estimates refers to "Other Protential Distribution Upgrades" reflect the ICs proportionate share of other potential upgrades as such upgrades have been identified in section B of the Appendix A Report. While other potential upgrade costs are included in determining the ICs maximum cost responsibility, the IC will not be required to post IFS for these costs until such time they are directly assigned to the IC as reflected in the GIA or an amendment thereto.

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Leading the Way in Electricity℠

The Interconnection Handbook

Southern California Edison Company

Rev. 1.7

*This document is controlled by the originating SCE T&D organization. When downloaded and printed, this document becomes **UNCONTROLLED**, and users should check with the originator to ensure that they have the latest version. This applies to the remainder of the document*

Approved by:

Original Signed by — *12/29/2016*

Jorge Chacon, Manager Generator Interconnection Planning — ***Date***

Transmission & Interconnection Planning Grp.

Introduction and Summary of Technical Requirements

Southern California Edison Company's (SCE) Interconnection Handbook (Handbook) is broken up into three distinct parts based on the customer project type that are being connected, planned to be connected, or facility additions and modifications to existing customer facilities interconnected to the SCE's electric system.

The three parts of the handbook address:

- Generator Interconnections;
- Transmission Interconnections, and
- End-User Facility Interconnections

Collectively these types of interconnections are referred to in the Handbook as "Interconnected Facility (INTFAC)."

The Handbook specifies what is necessary for facilities to interconnect to SCE's electric system (Requirements), or locations where SCE is the operating agent, which shall be referred to as "SCE's electric system". These Requirements provide for safe and reliable operation of SCE's electric system.

As a Transmission Owner (TO), SCE is required to provide and maintain a Handbook to guide entities that need to interconnect to SCE's electric system. Please note that generators directly connecting to SCE transmission facilities must also adhere to the California Independent System Operator's generation interconnection procedures. This is because these facilities are under CASIO operational control and they perform the Transmission Operator (TOP) function for them.

Link to CAISO Fifth Replacement FERC Electric Tariff:
http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

1.1 Introduction

1.1.1 Purpose of Interconnection Handbook

The Handbook was written to provide SCE's customers an overview of the Requirements to address interconnection requests, and to support compliance with NERC Reliability Standard, FAC-001-2, and Facility Connection Requirements. It also provides a means to facilitate communication of technical information to SCE regarding the INTFAC, and are **not meant to be used as a design specification** for the INTFAC.

SCE's Requirements do not cover all aspects of the necessary technical criteria applicable to an INTFAC project, and the final design of facility connections to the SCE's electric system will be subject to SCE review and approval on a case-by-case basis.

The Handbook considers the following general items that need to be addressed by customers in their interconnection request to SCE:

- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Please note some of the items in the list above do not apply to all applicable entities – and some applicable entities may have requirements that are not included in the list. SCE has compiled a list of additional technical standards and criteria that the INTFAC must adhere to, as referenced in the Requirements, and is provided in Appendix A.

Once the initial facility information has been provided SCE will determine and communicate any additional project-specific technical requirements necessary from the INTFAC. It is in the customer's best interest to discuss their project plans with SCE prior to making any major financial commitment such as the purchasing or installation of equipment.

SCE will follow notification procedures for new or modified facilities in the Transmission Control Agreement (TCA) per Section 4.2.3, with respect to the California Independent System Operator (CAISO) Register.

In addition, customers may also inquire about SCE's interconnection procedures and for notification of new or modified generation, transmission, and end-user facilities from the following contact:

Contact	Mailing Address
Manager, Grid Interconnection & Contract Development	P.O. Box 800 2244 Walnut Grove Avenue Rosemead, California 91770

1.1.2 Conformity

The INTFAC shall comply with all applicable NERC Reliability Standards, WECC Reliability Criteria and Guidelines, along with any WECC, SCE and CAISO system planning and performance guidelines for its facilities. SCE will not assume any responsibility for complying with mandatory reliability standards for such facilities and offers no opinion whether the Interconnection Customer must register with NERC pursuant to Section 215 of the Federal Power Act. If required to register with NERC, the INTFAC shall be responsible for complying with all Applicable Reliability Standards for its facilities.

The INTFAC is responsible for conforming to applicable:

- Federal Energy Regulatory Commission (FERC) Rules, Regulations, and Orders
- North American Electric Reliability Corporation (NERC) Standards
- Western Electricity Coordinating Council (WECC) Regional Criteria, Policies, and Guidelines
- California Independent System Operator (CAISO) Planning Standards
- SCE Reliability Criteria, as well as good engineering and utility practice.

1.1.3 Requirements are Subject to Change

These Requirements are subject to change. INTFACs have the responsibility to ensure that they comply with the most recent version of the Interconnection Requirements. The current version may be accessed at SCE's internet site:

Link to most recent copy of the Interconnection Handbook

Each page of the Handbook displays its effective date in the upper right hand corner.

1.1.4 Applicability

Upon execution of an Interconnection Agreement per the appropriate tariff, the INTFAC should make reference to this document in its entirety during the construction process.

PART 1

Generator Interconnection Requirements

This document is controlled by the originating SCE T&D organization. When downloaded and printed, this document becomes ***UNCONTROLLED****, and users should check with the originator to ensure that they have the latest version. This applies to the remainder of the document.*

Contents

Section 1 Generator Interconnection Overview

The Generator Interconnection Section specifies what is necessary for generation facilities to interconnect to SCE's electric system, and gives customers an overview of the Requirements to address interconnection requests. It also provides a means to facilitate the communication of technical information to SCE regarding the generation facilities interconnecting to SCE's electric system.

Throughout this section the term "Producer" shall refer to the owner, its agents, or the operator of facilities being interconnected to SCE's electric system that includes performing the functions of supplying energy and a service (exclusive of basic energy and transmission services) to support the reliable operation of the transmission system.

Section 2 Parallel Systems

These Requirements apply to interconnecting generating facilities that intend to operate in parallel with SCE's electric system, and ultimately deliver power to the CAISO grid (directly to the transmission system, or via SCE's Distribution system).

Subject to FERC, California Public Utilities Commission (CPUC) regulations, and SCE approval, a Producer may elect to operate a generator facility in parallel with SCE or as a separate system with the capability of non-parallel load transfer between the two independent electrical systems. Induction generators, and some systems using inverter devices, must be operated in parallel to produce energy. Synchronous generators may be operated either in parallel or as a separate system. However, please note that the Requirements provided in this document are applicable to interconnecting generators intending to operate in parallel.

2.1 Parallel Operation

A parallel system is one in which the Producer's generating facilities can be operated while connected to SCE's electric system. A consequence of such parallel operation is that the parallel generator becomes a part of SCE's electric system, and must, therefore, be considered in planning the protection of SCE's electric system.

2.2 Need for Protective Devices

Prudent electrical practices require that certain protective devices (relays, circuit breakers, etc.) specified by SCE must be installed at any location where a Producer desires to operate its generating facilities in parallel with the SCE system. The purpose of these devices is to promptly disconnect the Producer's generating equipment from the SCE system when faults or abnormal operation jeopardize the reliable operation of equipment or the safety of personnel. Other modifications to electrical system configuration or protective relays may also be required in order to accommodate parallel generation. SCE assumes no responsibility for determining protective equipment needed to protect Producer's facilities.

2.3 Hazards

SCE's transmission and distribution lines are subject to a variety of natural and man-made hazards. Among these are lightning, earthquakes, wind, animals, automobiles, mischief, fire, and human error. Producer's electric systems are subject to these same hazards but not nearly to the same degree because SCE's electric system has greater exposure to these hazards.

The electric problems that can result from these hazards are principally short circuits, grounded conductors, and broken conductors. These fault conditions require that damaged equipment be de-energized as soon as possible to ensure public safety and continued operation of the remainder of SCE's electric system.

Where SCE controls the only source of supply to a given transmission or distribution line, it has the sole responsibility to install protective equipment to detect faulted equipment or other operating abnormalities and to isolate the problem from the remainder of SCE's electric system. A non-SCE generating facility connected to and operated in parallel with an SCE line represents another source of power to energize the line. Accordingly, SCE requires that such facilities also have adequate protective devices installed to react to abnormal electric system conditions and isolate from SCE's electric system.

2.4 Islanding

Generating facilities operating in parallel with SCE's electric system must also be equipped to detect another condition referred to as "islanding." Islanding is the abnormal operating condition where a portion of SCE's electric system and loads become isolated from the remainder of SCE's electric system while still connected to and receiving energy from generating facilities within an electrical island. When islanding occurs, all generating facilities within the electrical island must be disconnected to prevent continued operation.

The protective devices and other Requirements identified in Section 3 are intended to provide protection against hazards, such as those noted above, by ensuring that parallel generating facilities are disconnected when abnormal operating conditions occur. The following sections reflect the fact that these Requirements are typically minimal for small installations, but increase in scope and/or complexity as the size of the generation installation increases. SCE may require voltage and frequency protective functions or relays to detect islanding and shut down generation during periods of islanding.

2.5 UPS

Uninterruptible Power Supply (UPS) systems will be classified as either a separate or a parallel system depending on the following criteria. If such UPS systems are not capable of transfer of electric power from the emergency source to SCE's electric system, they will be classified as a separate system generating facility. If such UPS systems are capable of transfer of power, they must meet the Requirements for parallel generation.

Section 3 Protection Requirements

Protective devices (relays, circuit breakers, synchronizing equipment, etc.) must be installed for the protection of SCE's electric system as required by SCE. Generally, the protective devices may differ with the relative electrical capacity of the installation. The larger the installation, the greater the effect it may have on SCE's electric system. For instance, a manual disconnecting device must be provided by the Producer, but the form of this device will vary with the service voltage and generating facility capacity.

While some protection requirements can be standardized, the detailed protection design highly depends on the Producer's generator size, type and characteristics, number of generators, interconnection line characteristics (i.e., voltage, impedance, and ampacity), as well as the existing protection equipment and configuration of SCE's surrounding electric system. Fault duty, existing relay schemes, stability requirements, and other considerations may impact the selection of protection systems. Consequently, identical generation facilities connected at different locations in SCE's electric system can have widely varying protection requirements and costs. The varying protection requirements will be used to define the corresponding Telecommunications requirements, (See Section 8.)

For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles. Project stability studies may indicate that faster clearing times are necessary. To ensure the reliability of the electric system, protective relays, and associated equipment require periodic maintenance/replacement. Typically the frequency of transmission line relay replacement does not exceed once every fifteen (15) years, but equipment failure, availability of replacement parts, system changes, or other factors may alter the relay system replacement schedule.

Categories: SCE's Requirements identify three different categories for Producer generating facilities connecting to the SCE electric system each with distinctive protection Requirements. These categories are:

1. Interconnection voltage above 34.5 kV
2. 200 kVA and above capacity, interconnection voltage 34.5 kV or below
3. Less than 200 kVA capacity, interconnection voltage 34.5 kV or below

Aggregation: Where multiple generating facilities (with a single owner) are allowed to connect to SCE's electric system through a single point of interconnection, the interconnection is said to have aggregated generating facilities. The appropriate category of aggregated generating facilities is calculated by summing the KVA ratings of the multiple generators.

Disclaimer: The categories above have been established for convenience and are based on urban/suburban circuits with normal load density. The final decision as to the specific requirements for each installation will be made by SCE depending on several factors that could include Producer load magnitude, the magnitude of other load connected to that circuit/system, available short circuit duty contribution, and other conditions SCE deems prudent.

The Protection Requirements of the above three categories are described in Sections 3.1 to 3.3. These sections include Figures 3a through 3i to illustrate typical installations of protection equipment. The following is a legend of device numbers referred to in these figures:

Legend

Protective Device Numbers and Description

4	Master Contactor
25	Synchronizing or Synchronism Check
27	Under-voltage
32	Power Direction
40	Loss of Field Detection
46	Current Balance
47	Voltage Phase Sequence
50	Breaker Failure
51	Time Over-current
51G	Ground Time Over-current
51N	Neutral Time Over-current
51V	Voltage Restrained/Controlled Time Over-current
59	Over-voltage
59G	Over-voltage Type Ground Detector
67V	Voltage Restrained/Controlled Directional Time Over-current
78	Loss of Synchronism (Out-of-Step)
79	Reclosing Relay
81O	Over-frequency
81U	Under-frequency
87	Current Differential
87L	Transmission Line Differential
NOTE:	For additional information on device numbers, refer to ANSI C37.2.

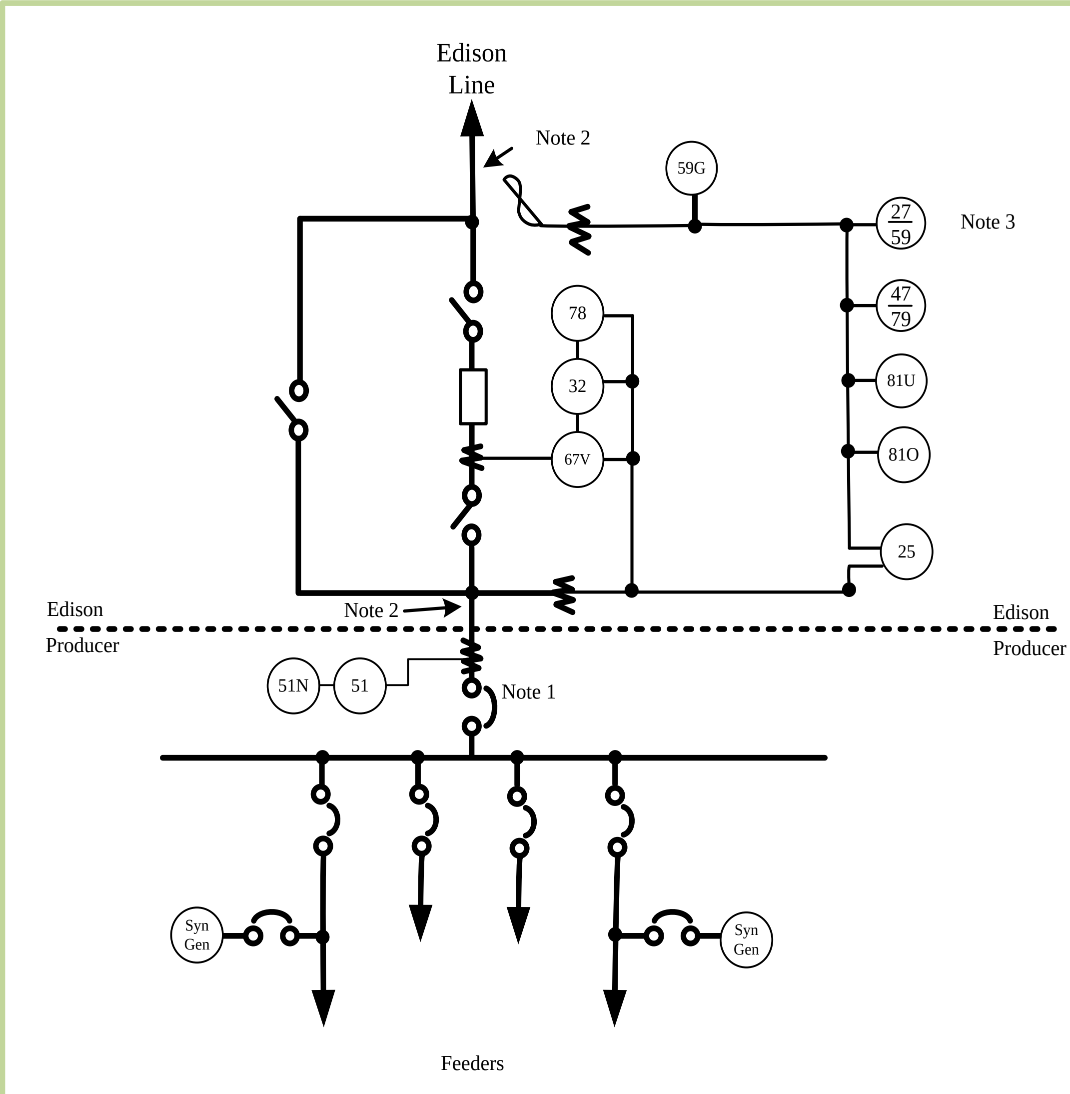
3.1 Category 1: Voltage Over 34.5 kV

This Category is limited to generating facilities interconnecting at a single point with interconnection voltage above 34.5 kV. This requirement applies to all interconnections to the CAISO Controlled Grid, and to interconnections to SCE owned and operated facilities above 34.5 kV.

Typical Installations

Figures 3a, 3b and 3c show typical installations with the SCE interface.

Figure 3a: Typical Synchronous Parallel Generation with Assumed SCE Owned Protection (> 34.5 kV)



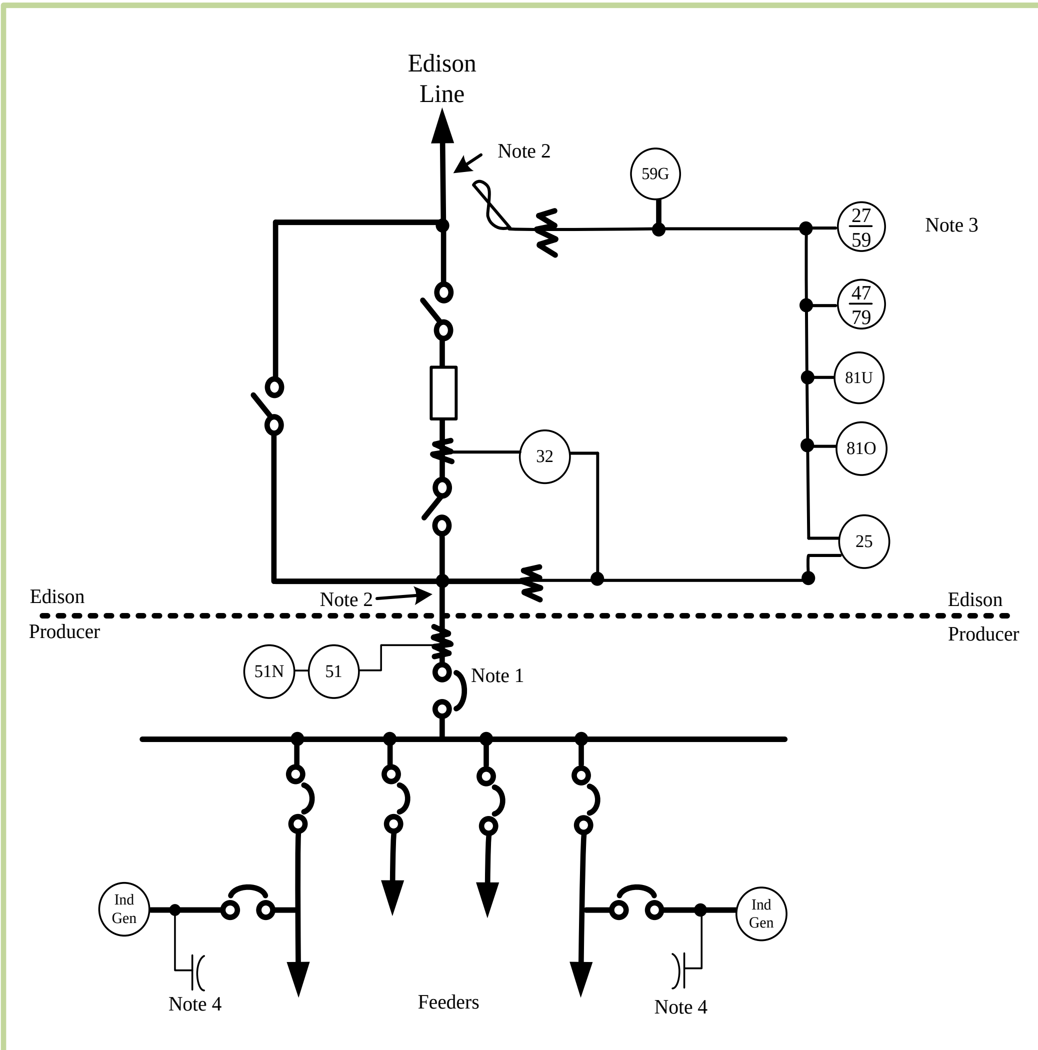
Notes: 1 Producer's main breaker or switch.

2. Transformation, if required, may be by SCE or the Producer.

3. Relay operates on two different phase-to-phase voltages.

Not all Producer-side protective relaying is shown.

Figure 3b: Typical Induction Parallel Generation with Assumed SCE Owned Protection (>34.5 kV)

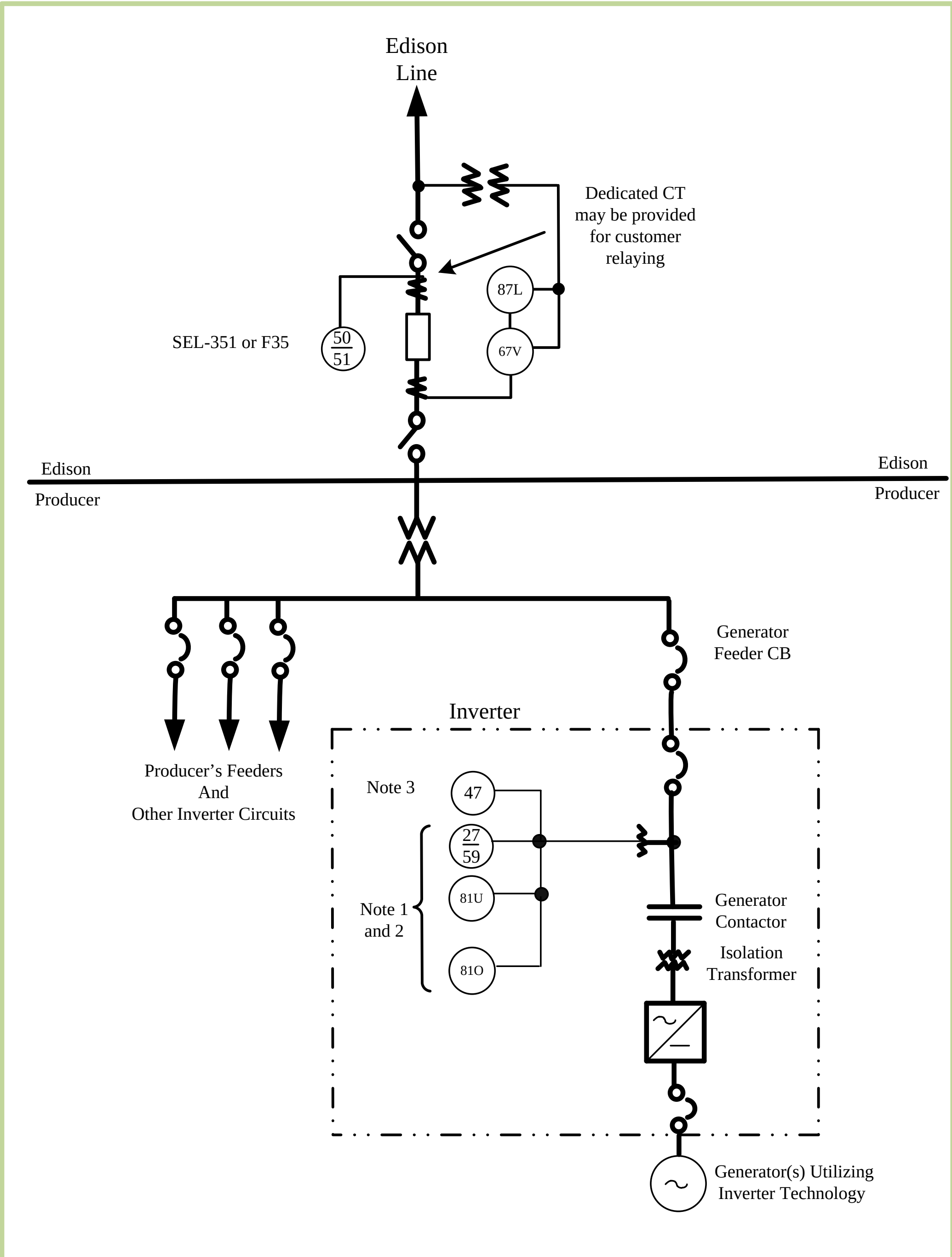


Notes:
1. Producer's main breaker or switch.
2. Transformation, if required, may be by SCE or the Producer.
3. Relay operates on two different phase-to-phase voltages.
4. See Section 5.8.

Not all Producer-side protective relaying is shown.

For induction generation interconnection facilities, the Producer is responsible for installing the appropriate VAR supporting equipment at its facility to maintain unity power factor at the point of interconnection.

Figure 3c: Typical Parallel Generation Utilizing Inverter Technology Assumed SCE Owned Protection (>34.5 kV)



Notes:
1. **Producer's main breaker or switch.**
2. **Transformation, if required, may be by SCE or the Producer.**
3. **Relay operates on two different phase-to-phase voltages.**

Not all Producer-side protective relaying is shown.

4. Grounding transformer or ground detector (by Edison or the Producer.) Required unless main transformer is wye-grounded-delta

5. Protective and synchronizing relays required if the Producer desires to serve isolated load during Edison outage. If not provided at main circuit breaker, these functions should be provided at generator breaker.

3.1.1 Specific Requirements for Category 1

a) Typically SCE-owned and controlled circuit breaker to isolate generation facilities during SCE's electric system disturbances.

b) Producer-owned and controlled circuit breaker or disconnect switch (as required – refer to Section 5.11 Isolating Equipment Requirements and Switching & Tagging Rules) at the main to disconnect for Producer system trouble. If desired, SCE may permit the Producer to trip and/or close the SCE breaker by remote control. If synchronizing is to be done with SCE, SCE will install synchronizing supervision relays and telecommunications as required.

c) Producer to provide synchronizing relays or equipment at the main, generator, and other breakers as appropriate. Either induction starting, automatic synchronizing, or manual synchronizing supervised by a synchronizing relay must be provided by the Producer.

d) Induction starting will be permitted only where the inrush will not exceed SCE prescribed limits. Producer shall never attempt to parallel its system with SCE's electric system when the Producer's synchronizing facilities are malfunctioning or inoperative. Manual synchronizing without a supervising relay is not permitted. Automatic synchronizing may be required for synchronous generators which contribute short circuit current exceeding 5 (%) percent of the pre-existing short circuit current at the point of interconnection with SCE's distribution system.

e) Protection related telecommunications may be required as determined by SCE Protection Engineering.

3.1.2 SCE-owned and maintained protective relays which perform the following functions

a) Short Circuit Protection (Devices 51V or 67V, 51N or 59G)
The designated relays will detect faults on the SCE electric system to which the Producer's generating facility is connected. Generally, the phase relays are voltage restrained overcurrent type or impedance torque controlled overcurrent type. Occasionally, pilot relays or transferred tripping relays may be required. In ground fault protection, a directional overcurrent relay or ground fault voltage detector may be used. A grounding transformer may be required to avoid dangerous overvoltages which could occur during accidental isolation of the line from the main system while the generator is in operation. Adequate grounding can be provided either by the use of a wye-grounded-delta main power transformer or by installing an appropriate grounding transformer. To limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization. Devices 51V or 67V are normally omitted for induction generator installations because of the absence of sustained fault currents from these generators.

b) Islanding Protection (Devices 27/59, 81-O, 81-U)
During the course of fault clearing or due to accident, equipment malfunction, or malicious mischief, it is possible for a SCE circuit/system to become separated from the main system, leaving customers on the circuit supplied from the Producer's generator. In order to protect customers from abnormal voltage or frequency excursions under these conditions, and to facilitate rapid restoration of normal service, relays for islanding protection are required. Generally, these relays will provide over and under frequency functions and three phase over- and under-voltage functions with instantaneous overvoltage tripping. For generating facilities aggregating 10 MW and greater, SCE may elect to use a voltage phase comparison system (Telesync) for islanding protection while retaining the voltage and frequency relays for backup.

c) Breaker Closing/Reclosing Control (Devices 25, 47/79)
It is important that the closing of the SCE circuit breaker be controlled so that it can only be closed when it is safe to do so. Inadvertent closing of the circuit breaker could result in paralleling out of synchronism or energizing of de-energized facilities, and hazardous conditions could result. The required logic for manual closing of the SCE breaker is:

- The line side of the breaker is energized with proper voltage and phase sequence, the load side of the breaker is de-energized and the Producer's main breaker (or generator breaker) is open, or
- Synchronism check across the breaker is satisfactory which, in most cases, indicates that either the breaker bypass switch is closed or interconnection with the Producer already exists elsewhere.

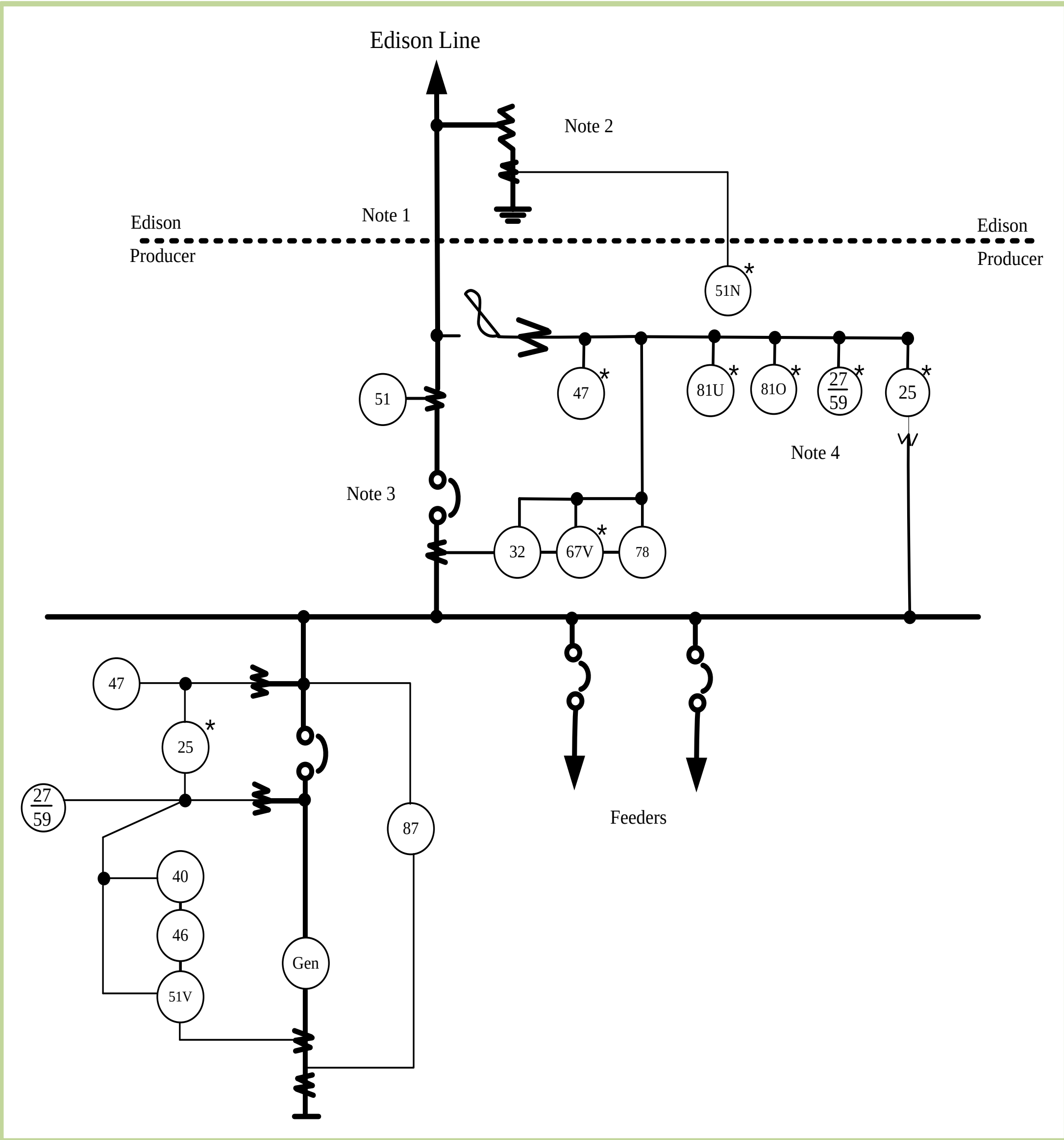
In order to provide the best continuity of service to the Producer, automatic reclosing of the SCE breaker subsequent to fault clearing is engineered into the control circuitry. If the trouble is permanent, the breaker will trip again and lockout. No further reclosing will take place until the breaker has been reclosed manually. The required conditions for automatic reclosing are the same as for manual closing. Where provision is made for closing of the SCE circuit breaker by the Producer, the required conditions for closing will be the same as for manual closing by SCE. The Producer's closing control will enable SCE's synchronizing relay to close the breaker.

d) Loss of Synchronism (Device 78)
Operation of the Producer's synchronous generator out of synchronism with SCE may cause large voltage fluctuations to SCE's customers and may cause severe damage to the generator. If SCE determines that the relative capacities of its system and of the Producer's generating facility are such that this situation is likely to occur or for those installations which have experienced such voltage fluctuations, specific relays for detection of loss-of-synchronism (out-of-step) will be required.

3.2 Category 2: Total Generation 200 kVA and Above, Voltage at 34.5 kV or Below

All installations in this Category require SCE review of the protective functions to be provided by the Producer. Refer to Figures 3d, 3e and 3f for typical installations. Producers must ensure their compliance to SCE's telemetering Requirements as stated in Section 7 of these Requirements.

Figure 3d: Typical Synchronous Parallel Generation with Assumed Producer Owned Protection (> 200 kVA, < 34.5 kV)

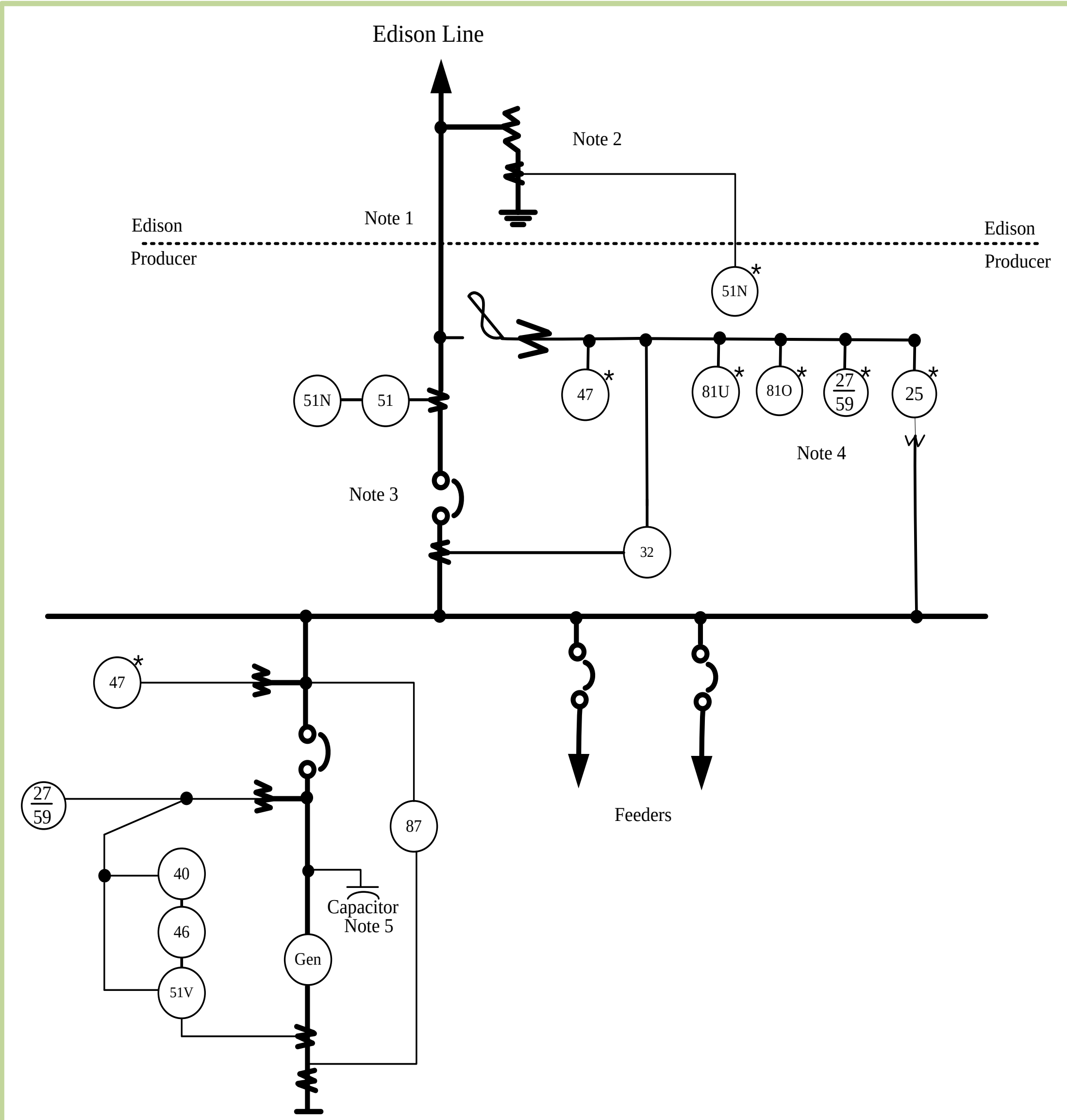


Notes:

1. Transformation (as required) by SCE or the Producer.
2. Grounding transformer or ground detector is required to be supplied by SCE unless the main transformer is wye-grounded-delta. (See 3.2.3.d for requirements)
3. Protective and synchronizing relays required if the Producer desires to serve isolated load during SCE outage. If not provided at main circuit breaker, these functions should be provided at generator breaker.
4. Two phase-to-phase connected or three phase-to-neutral connected relays required.

"*" Indicates devices required by SCE. Others are shown as conventional practice.

Figure 3e: Typical Induction Parallel Generation with Assumed Producer Owned Protection (> 200 kVA, < 34.5 kV)



Notes: 1. Transformation (as required) by SCE or the Producer.

2. Grounding transformer or ground detector is required to be supplied by SCE unless the main transformer is wye-grounded-delta. (See 3.2.3.d for requirements)

3. Protective and synchronizing relays required if the Producer desires to serve isolated load during SCE outage. If not provided at main circuit breaker, these functions should be provided at generator breaker.

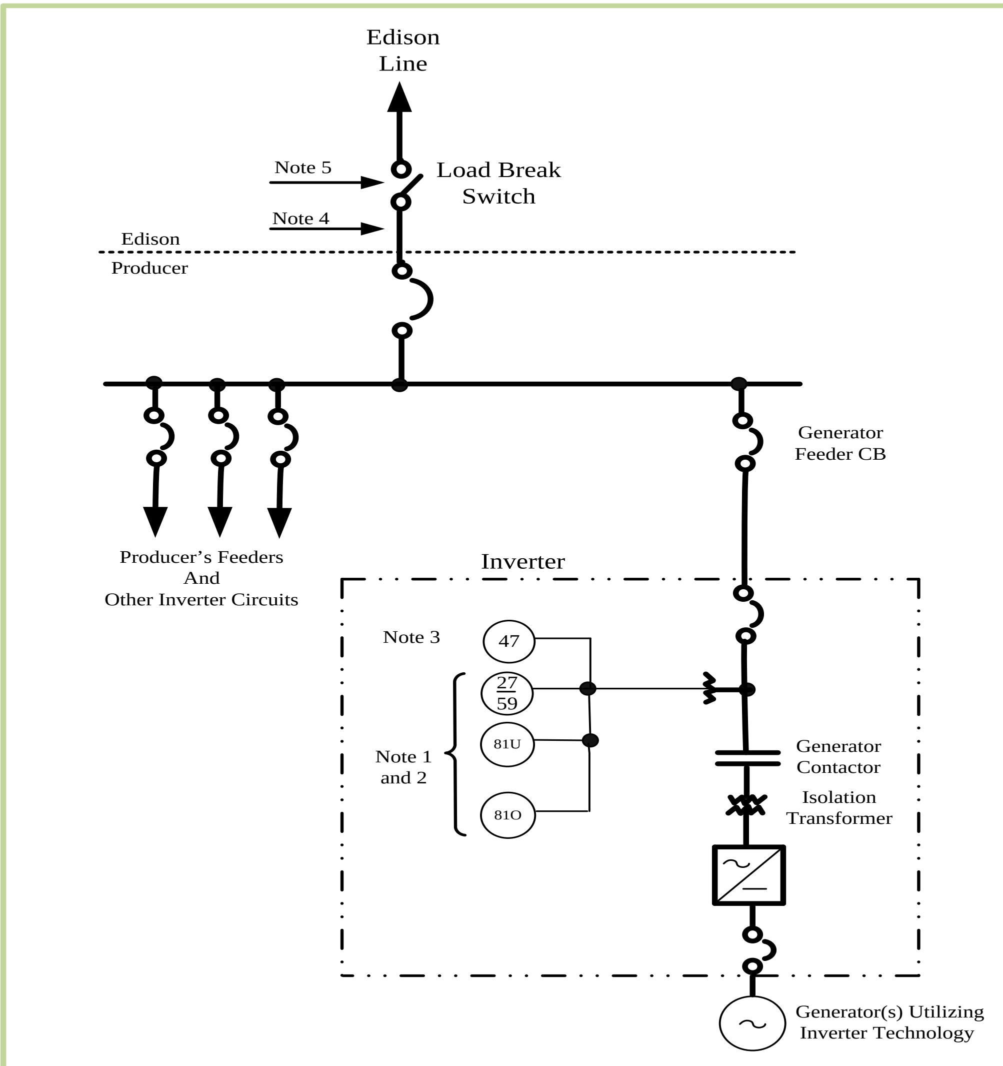
4. Two phase-to-phase connected or three phase-to-neutral connected relays required.

5. Refer to Section 5.8.

"*" Indicates devices required by SCE. Others are shown as conventional practice.

For induction generation interconnection facilities, the Producer is responsible for installing the appropriate VAR supporting equipment at its facility to maintain unity power factor at the point of interconnection.

Figure 3f: Typical Parallel Generation Utilizing Inverter Technology With Assumed Producer Owned Protection (≥ 200 KVA, ≤ 34.5 kV)



Notes:

1. **Protective devices required by SCE for all installations.** $\frac{27}{59}$ shall be a 3Ø unit or two 1Ø units.
2. UL1741 certified inverters meet noted protection requirements without additional relays provided all inverters are UL1741 compliant.
3. Recommended for three phase generators.
4. Transformation as required by SCE or the Producer.
5. Load break switch to be installed when required by SCE's Distribution Design Standards.
6. Drawing does not show metering requirements.
7. Producer is responsible for other protective devices not shown on the diagram because of large variations with type of inverter.

3.2.1 The Producer shall provide adequate protective devices

a) Detect and clear the generator(s) from short circuits or grounds on SCE's electric system serving the Producer.

b) Detect the voltage and frequency changes that can occur if the SCE electric system serving the Producer is disconnected from the main system, and clear the Producer's generating facilities from the islanded system.

c) Prevent reparalleling the Producer's generation, after an incident of trouble, unless the SCE service voltage has been of normal magnitude and frequency continuously for a pre-determined period of time (typically five minutes).

3.2.2 Protection devices which may be required to satisfy the above Requirements

a) Phase over-current trip devices (Device 51, 51V, or 67V)

In most cases these will have to be voltage-restrained or voltage-controlled over-current relays in order to provide coordination with SCE relays.

b) Residual over-current or over-voltage relays to trip for ground faults on the SCE electric system **(**Devices 51N or 59G)

The required type of device (51N or 59G) depends on the characteristic of SCE's interconnecting system. Contact SCE for information for a specific location.

c) Under/over voltage relays (Device 27/59)

Two over/under voltage relays measuring different phase-to-phase voltages or three over/under voltage relays each measuring a phase-to-neutral voltage is required. A single multiphase over/under voltage relay is acceptable if it has separate voltage measurement elements for each phase or phase pair. Under voltage relays should be adjustable from 75-90% of nominal voltage and have time delay to prevent unnecessary tripping on external faults. Over voltage relays should be adjustable from 110-120% of nominal voltage and be instantaneous or a combination of instantaneous and time delayed. Setting changes with temperature variation should not exceed +2 volts over the expected temperature range.

d) Under/over frequency relays (Device 81-O or 81-U)

The under-frequency relay should be adjustable from 56.4 -59.5 Hz and the over-frequency relay from 60.5 to 61.7 Hz. Setting change with temperature variation over the expected range, or voltage variation over ±10%, should not exceed ±0.05 Hz.

e) Phase sequence under-voltage relay (Device 47/27)

To permit paralleling only when SCE voltage and phase sequence are normal.

f) Automatic Separation: In some cases, protective devices supplied with the generating equipment will meet some or all of these Requirements, provided that it is acceptable to trip the generator whenever the SCE source is lost. If the Producer desires to automatically separate from SCE and commence isolated operation upon loss of the SCE source, additional devices will be necessary to effect the separation.

g) Large Generators: In specific installations, particularly with large generators (over 10,000 kVA), SCE may require specific additional protection functions such as loss of excitation, loss of synchronism and over-excitation protection, if these conditions would have an impact on SCE's electric system.

3.2.3 Other protection devices for Category 2 Generation

a) Utility Quality Relays: Depending on the size of the generating facility and the size of the distribution or subtransmission system to which it is connected, SCE may require the Producer to utilize "utility quality" protective relays. Such relays have more stringent tolerances and more widely published characteristics than "industrial quality" relays and have the ability to coordinate protective settings with utility settings. This Requirement will be invoked only if the generating facility is large enough to require close coordination with SCE relays. In general, installations aggregating less than 1,000 kVA will not be subject to this Requirement.

b) Relay Operation Recorders: All protective devices supplied to satisfy the Requirements in Category 2 generating facilities shall be equipped with operation indicators (targets) or shall be connected to an annunciator or event recorder so that it will be possible to determine, after the fact, which devices caused a particular trip.

c) Relay Testing: All protective devices supplied to satisfy the Requirements in this Category shall be tested by qualified personnel prior to SCE approving parallel operation, and at intervals at least as frequent as those used by SCE for the relays protecting the line(s) serving the Producer. These intervals are given in Table 5.3, in Section 5. Lines traversing fire hazardous areas are required to have their relays tested annually before May 1st. Special tests may also be requested by SCE to investigate apparent missed operations. Each routine or special test shall include both a calibration check and an actual trip of the circuit breaker from the device being tested. For each test a report shall be prepared and sent to SCE listing the tests made and the "as found" and "as left" calibration values.

d) Four-wire Multi-grounded Neutral Distribution Circuits: In projects where the Producer is served from an SCE four-wire multi-grounded neutral distribution circuit, adequate grounding must be provided to ensure neutral stability during accidental isolation of the line from the main system. This is necessary to avoid dangerous over-voltages on other customers served from phase-to-neutral connected distribution transformers. Adequate grounding can be provided either by the use of a wye-delta main power transformer or by installing an appropriate grounding transformer. In order to limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization.

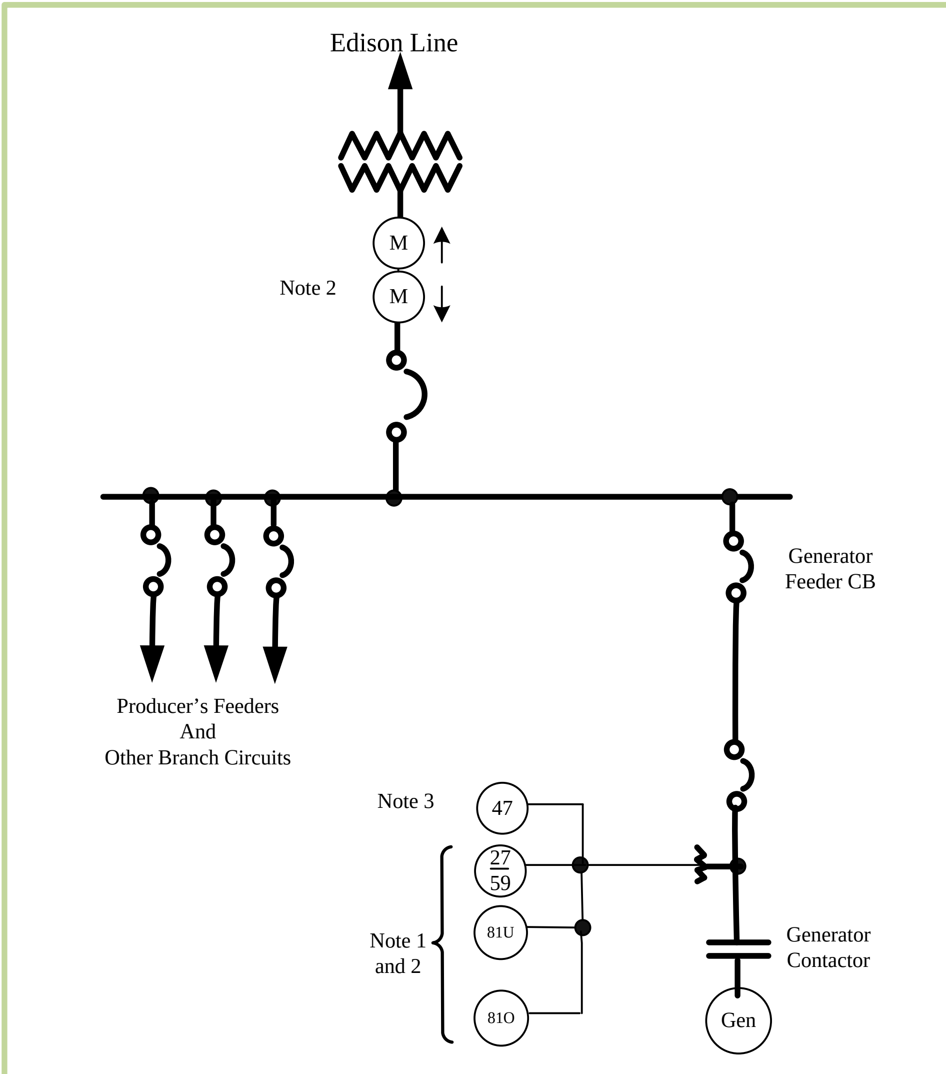
3.2.4 Exemption For Installing Phase Over-current Protective Devices

Where induction generators or static inverters are employed rather than synchronous machines, the phase over-current protective devices required by SCE generally will be waived since these generation sources will not deliver sustained over-currents. All other specified protective devices are required.

3.3 Category 3: Total Generation Less Than 200 kVA, in Voltage at 34.5kV & Below

The following Requirements for small generating facilities are based on an assumed low density of parallel generation on the serving circuit. Other Requirements may be imposed should the density exceed a tolerable limit. Refer to Figure 3g.

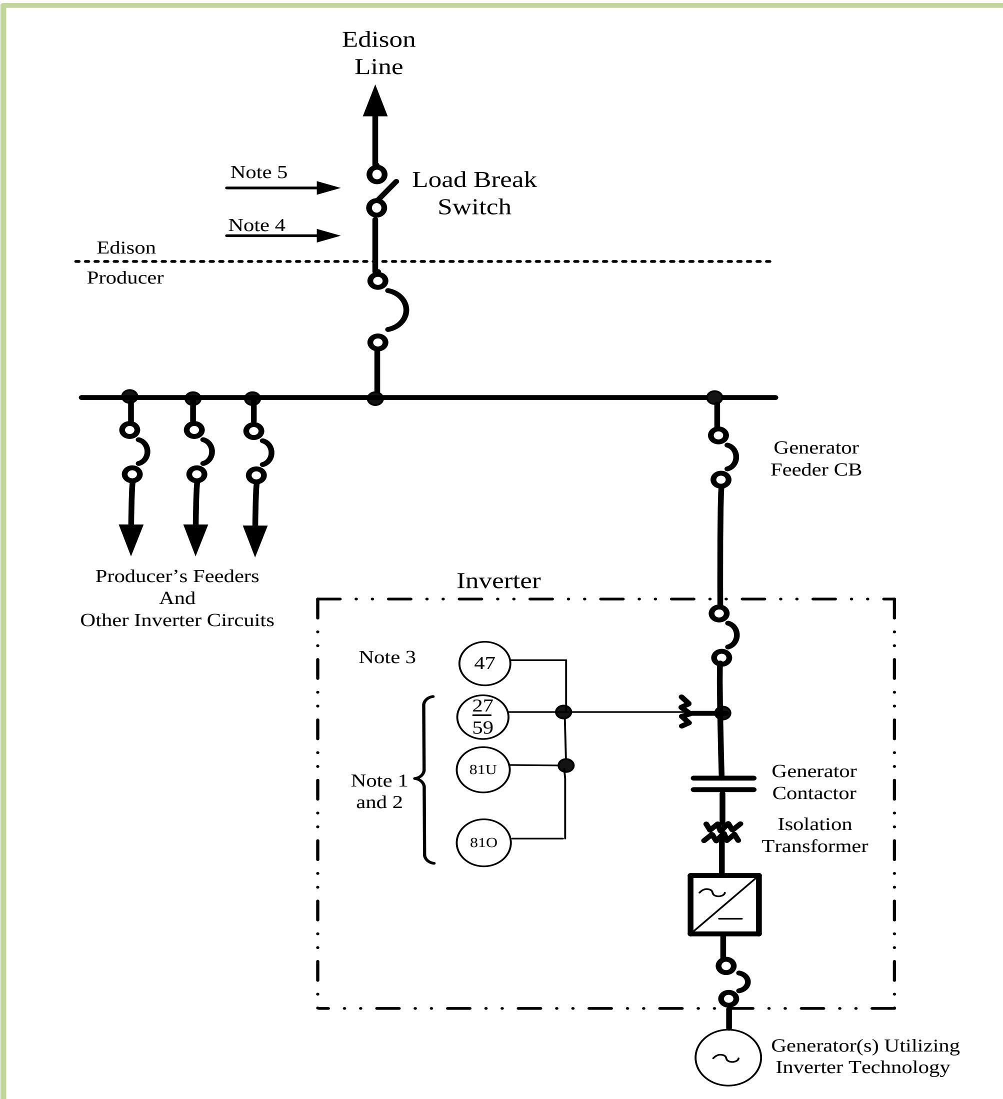
Figure 3g: Typical Parallel Generation Under 200 kVA



Notes:

1. **Protective devices required by SCE for all installations. Other protective devices for generator not shown because of large variations with type of generator.**
2. **Self-contained metering is typical.**
3. **Required for three phase generators.**

Figure 3h: Typical Parallel Generation Utilizing Inverter Technology With Assumed Producer Owned Protection (< 200 KVA, ≤ 34.5 kV)



Notes:

1. Protective devices required by SCE for all installations. $\frac{27}{59}$ shall be a 3Ø unit or two 1Ø units.
2. UL1741 certified inverters meet noted protection requirements without additional relays provided all inverters are UL1741 compliant.
3. Recommended for three phase generators.
4. Transformation as required by SCE or the Producer.
5. Load break switch to be installed when required by SCE's Distribution Design Standards.
6. Drawing does not show metering requirements.
7. Producer is responsible for other protective devices not shown on the diagram because of large variations with type of inverter.

a) Line Voltage Relay or Contactor: Producer generator controls are to be equipped with a line voltage relay or contactor which will prevent the generator from being connected to a de-energized or single-phased (if normally three-phase) source. This relay is to disconnect the generator from a de-energized utility line and prevent its reconnection until the line has been re-energized by SCE and has maintained nominal voltage and frequency continuously for a pre-determined period of time (typically five minutes).

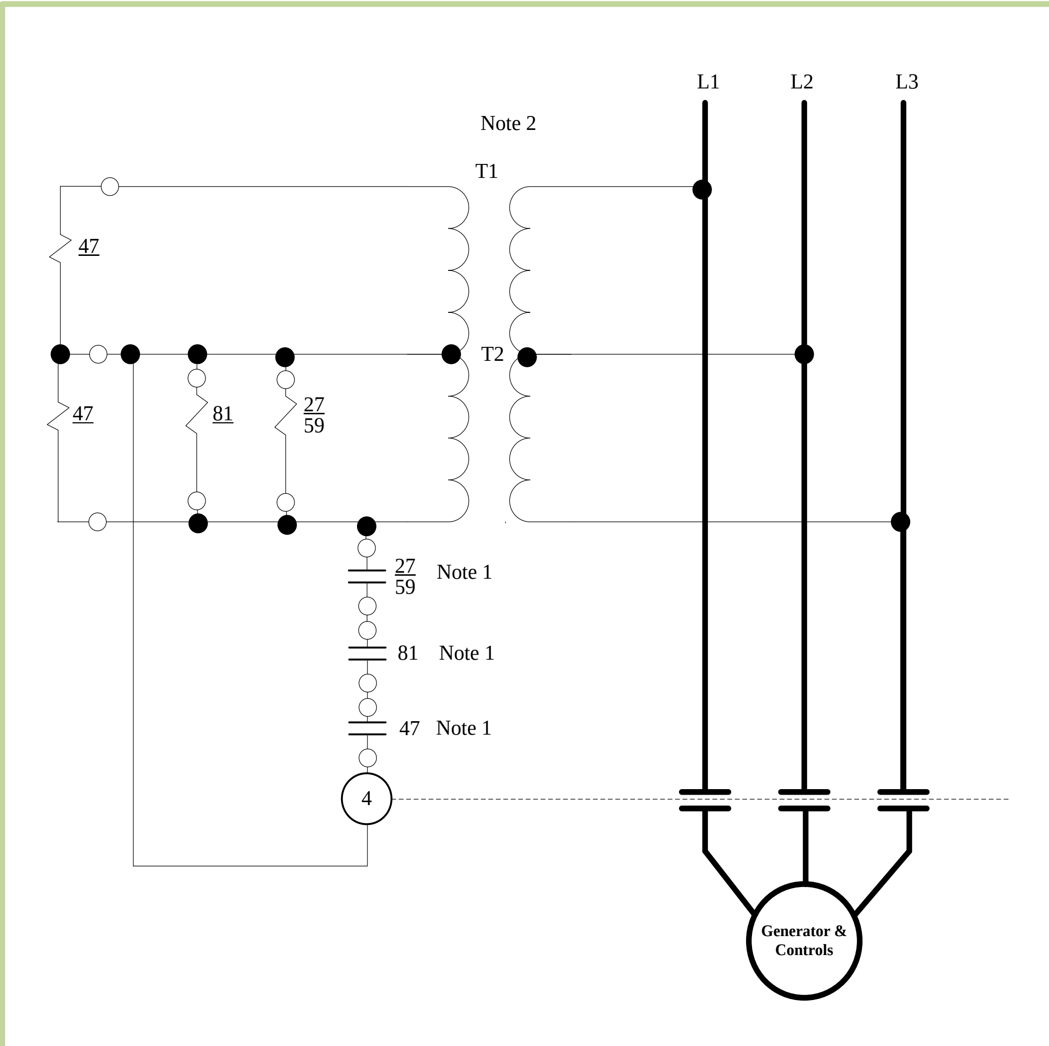
b) Relays to Detect Islanding: Producer generators are to be equipped with over/under frequency and over/under voltage relays for islanding detection. These relays must meet the specifications listed in Section 3.2.2, paragraphs (c) and (d). The relays may be arranged to de-energize the contactor as shown in Figure 3f. The Producer generator islanding protection must be able to detect an islanded condition and cease to energize SCE's distribution system within two seconds. Other requirements may be imposed on those installations unable to meet this requirement.

c) Fault Detection: The Producer shall provide adequate protective relays to detect and clear the generator(s) from short circuits or grounds on SCE's electric system serving the Producer.

d) Four-wire Multi-grounded Neutral Distribution Circuits: In projects where the Producer is served from an SCE four-wire multi-grounded neutral distribution circuit, adequate grounding must be provided to ensure neutral stability during accidental isolation of the line from the main system.

Figure 3i: Typical Relay/Contactor Arrangement Under 200 kVA

This drawing is intended to show the relay/contactor arrangement only. Other over-current or switching devices may be required by local authorities.



Notes: 1. Contacts closed with normal voltage, frequency and phase sequence.

2. Control transformers as required to match relay/contactor voltage to supply voltage. Arrangement shown is for three phase system. For single phase omit L3, T1, Dev. 47.

e) Dedicated Distribution Transformer: SCE may require the Producer to be served through a dedicated distribution transformer which serves no other customers. The purpose of the dedicated transformer is to confine any voltage fluctuations or harmonics produced by the generators to the Producer's own system.

f) Harmonic Requirements for Inverters: See "Voltage Imbalance and Abnormal Voltage or Current Waveforms" Section 5.10.

g) SCE Telecommunications: Typically not required for protective purposes in Category 3 generating facilities except as required to coordinate with SCE's protective relays.

h) Exception to Protection Devices: Producers generating facilities may, as an alternative to the Requirements specified in this Category 3 generating facility section above, utilize an approved inverter/interface device meeting applicable safety and performance standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers ("IEEE"), and accredited testing laboratories such as Underwriters Laboratories ("UL"). These Requirements include, but are not limited to, the provisions of IEEE Standard 929, IEEE Standard 1547, and UL Standard 1741.

3.4 Breaker Duty and Surge Protection

3.4.1 SCE Duty Analysis

The recognized standard for circuit breakers rated on a symmetrical current basis is IEEE Standard C37.010-1999(R2005), "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and ANSI/IEEE Standard C37.5 for circuit breakers rated on a total current basis. SCE will review breaker duty and surge protection to identify any additions required to maintain an acceptable level of SCE system availability, reliability, equipment insulation margins, and safety. Also, the management of increasing short-circuit duty of the transmission system involves selecting the alternative that provides the best balance between cost and capability. System arrangements must be designed so that the interrupting capability of available equipment is not exceeded.

When studies of planned future system arrangements indicate that the short-circuit duty will reach the capability of existing breakers, consideration should be given to the following factors:

a) Methods of limiting duty to the circuit breaker capability, or less:
   1. De-looping or rearranging transmission lines at substations;
   2. Split bus arrangements.

b) Magnitude of short circuit duty.

c) The effect of future projects on the duty.

d) Increasing the interrupting capability of equipment.

e) The ability of a particular breaker to interrupt short circuits considering applicable operating experience and prior test data.

Please note that SCE performs an annual short circuit duty analysis, which may include reevaluation of the facility breakers.

3.4.2 Customer Owned Duty/Surge Protection Equipment

In compliance with Good Utility Practice and, if applicable, the Requirements of SCE's Interconnection Handbook, the Producer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the generation facility to any short circuit occurring on SCE's electric system not otherwise isolated by SCE's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of SCE's electric system. Such protective equipment shall include, but not limited to, a disconnecting device and a fault current-interrupting device located between the generation facility and the SCE electric system at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The Producer shall be responsible for protection of the generation facility and other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The Producer shall be solely responsible to disconnect their facility if conditions on SCE's electric system are impacted by the generation facility.

Section 4 Miscellaneous Requirements:

4.1 Power System Stabilizers (PSS)

All new Producers' synchronous generators, larger than 30 MVA and interconnecting at a voltage 60 kV or higher are required to install PSS with a suitable excitation system, unless an exemption has been obtained from WECC. Suitable excitation systems are defined in the WECC report; "Criteria to Determine Excitation System Suitability for PSS," dated December 1992.

Unless an exemption has been received from the WECC, all new generators are assumed suitable for PSS, and must abide by the following Requirements:

a) The generator excitation system must be equipped with a power system stabilizer (PSS). The PSS improves stability in the electrical system when system power disturbances occur.

b) The PSS equipment must be approved by SCE prior to installation and operation.

c) The PSS must be calibrated and operated in accordance with WECC standard procedures for calibration, testing, and operation of PSS equipment.

d) Calibration and test reports must be submitted to SCE for review and approval. The generating facility shall not be considered operational until calibration of the PSS has been performed to SCE's satisfaction.

e) The PSS shall be properly maintained and in service when the generator is on line for power production.

   In addition to the foregoing Requirements, Producers must conform to all applicable current or future WECC Criteria. Specific to PSS, these Criteria currently include "WECC Power System Stabilizer Design and Performance Criteria," approved by the Technical Operations Subcommittee, September 15, 2003.

4.2 Governor "Droop" Shall Be Set At 5%

All new Producers' generators having suitable systems must comply with the WECC minimum operating reliability criteria for governor droop.

These Requirements are necessary to provide an equitable and coordinated system response to load/generation imbalances. Governor droop shall be set at 5%. Governors shall not be operated with excessive dead-bands, and governors shall not be blocked unless required by regulatory mandates.

4.3 Wind Turbine Generating Facilities

4.3.1 Wind Turbine Set-Back Criteria

a) The Producer shall locate its wind-driven generating unit such that it does not encroach onto SCE transmission right of way or edge of any electric operating property.

b) b) The Producer shall be responsible for performing its appropriate grounding requirements for its wind-driven generating units.

4.3.2 Generator Electric Grid Fault Ride-Through Capability and Power Factor Criteria

SCE currently supports a Low Voltage Ride-Through Criterion that the WECC has adopted to ensure continued reliable service. The Criteria are summarized as follows:

a) Generator is to remain in-service during system faults (three phase faults with normal clearing and single-line-to-ground with delayed clearing) unless clearing the fault effectively disconnects the generator from the system.

b) During the transient period, the generator is required to remain in-service for the low voltage and frequency excursions specified in WECC Disturbance-Performance Table of “Allowable Effects on Other Systems” as applied to load bus constraint. These performance criteria are applied to the generator interconnection point, not the generator terminals.

c) Generators may be tripped after the fault period if this action is intended as part of a Special Protection Scheme.

d) This Standard will not apply to individual units or to a site where the sum of the installed capabilities of all machines is less than 10MVA, unless it can be proven that reliability concerns exist.

e) The performance criterion of this Standard may be satisfied with performance of the generators or by installing equipment to satisfy the performance criteria.

f) The performance criterion of this Standard applies to any generation independent of the interconnected voltage level.

No exemption from this Standard will be given because of minor impact to the interconnected system. This criterion also applies to existing generators that go through any refurbishments or any replacements.

4.4 Reclosing Circuit Breakers and Hot Line Reclose Blocking

Because most short circuits on overhead lines are of a temporary nature, it is SCE's practice to reclose the circuit breakers on such lines within a few seconds after they have automatically tripped. This practice improves continuity of service to all SCE's customers. The protective relays specified by SCE for parallel generation interfaces are intended to disconnect the generating facilities from faulty or isolated lines before reclosing occurs. Should the Producer desire additional protection against the possibility that reclosing might occur with his generator still connected to the line (a potentially damaging occurrence for synchronous generators), SCE can provide, at the Producer’s expense, "Hot Line Reclose Blocking" at the necessary points on its system. Transfer trip protection may be required to facilitate restoration of service to SCE’s customers. SCE's preference is to avoid such equipment because of the possible adverse effects on service continuity and the problems of moving or rearranging the equipment to accommodate system changes. Costs for installing, maintaining, and/or rearranging such equipment will be borne by the Producer(s) requesting the equipment.

4.5 Unbalanced Currents

Producers with three-phase generators should be aware that certain conditions in the utility system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the Producer to protect its equipment from excessive negative sequence currents.

4.6 Sub-Synchronous Resonance Studies

Generators installed near series compensated lines or Flexible Alternating Current Transmission Systems (FACTS) may be exposed to Sub-Synchronous Resonance (SSR) conditions which must be evaluated by the Producer. SSR occurs when the network natural frequencies (below fundamental frequencies) coincide with the turbine-generator torsional-mode frequencies causing the turbine-generator to stress that may result in shaft failure. The turbine-generator and the system may interact with SSR into two main ways: Torsional Interaction (TI) and Torque Amplification (TA). In order to evaluate a potential SSR condition on a new generator installation near series compensated lines or FACTS devices a screening study needs to be conducted to identify any TA or TI impact on the series compensation level or FACTS devices controls. If a case is identified by the initial screening process (Frequency Scanning Study) a more detailed time domain study is required to quantify the potential damage and provide with mitigation measures. Customer owned transmission lines that have a series capacitor attached to the line and wish to interconnect to SCE, must demonstrate to SCE that SSR studies have been performed on their line.

4.7 Automatic Voltage Regulators (AVR)

Generating units 10 MVA and larger shall be equipped with automatic voltage control equipment. All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. These generating units shall not be operated in other control modes (e.g., constant power factor control) unless authorized to do so by the balancing authority. The control mode of generating units shall be accurately represented in operating studies.

All new Producers' synchronous generators, regardless of size and interconnecting at a voltage 60 kV or higher, must abide by the following Requirements:

a) The synchronous generator shall have an excitation system with a continuously acting Automatic Voltage Regulator (AVR).

b) The AVR equipment must be approved by SCE prior to installation and operation.

c) The AVR must be calibrated and operated in accordance with WECC standard procedures for calibration, testing, and operation of AVR equipment.

d) Calibration and test reports must be submitted to SCE for review and approval. The generating facility shall not be considered operational until calibration of the AVR has been performed to SCE's satisfaction.

e) The AVR shall be properly maintained and in service when the generator is on line for power production.

Automatic voltage control equipment on generating units, synchronous condensers, and Flexible Alternating Current Transmission System (FACTS) shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by either the

- California Independent System Operator (CAISO) for generators directly connected to SCE owned portions of the Bulk Electric System; or
- SCE for generators connected to SCE's Local Distribution System, which are facilities not under CASIO operational control.

4.8 Underfrequency Relays

For voltage classes 161 kV and above, it is essential that the underfrequency protection of generating units and any other manual or automatic actions are coordinated with underfrequency load shedding relay settings. For further information, please refer to Section 3.2.2.d.

Since the facilities of SCE's electric system may be vital to the secure operation of the Interconnection, CAISO/SCE shall make every effort to remain connected to the Interconnection. However, if the system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect the system.

Intentional tripping of tie lines due to underfrequency is permitted at the discretion of SCE's electric system, providing that the separation frequency is no higher than 57.9 Hz with a one second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

4.9 Insulation Coordination

Insulation coordination is the selection of insulation strength and practice of correlating insulation levels of equipment and circuits with the characteristics of surge-protective devices such that the insulation is protected from excessive overvoltages. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety.

The Producer shall be responsible for an insulation coordination study to determine appropriate surge arrester class and rating on the generating facility's equipment. In addition, the Producer is responsible for the proper selection of substation equipment and their arrangements from an insulation coordination standpoint.

Basic Surge Level (BSLs), surge arrester, conductor spacing and gap application, substation and transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan.

4.10 Ratings

4.10.1 Facility Ratings

The ratings of facilities are the responsibility of the owner of those facilities. Ratings of facilities must conform to current NERC Reliability Standard governing Facility Ratings.

4.10.2 Ratings Provided by Equipment Manufacturers

Equipment installed on SCE's electric system is rated according to the manufacturer's nameplate or certifications, and ANSI/IEEE standards. The manufacturer's nameplate rating is the normal rating of the equipment. ANSI/IEEE standards may allow for emergency overloads above the normal rating under specified conditions and often according to an engineering calculation. Emergency loading may impact the service life of the equipment. In some cases the manufacturer has certified equipment for operation at different normal or emergency loads based on site-specific operation conditions. Older technology equipment is rated according to the standards under which it was built unless the manufacturer, ANSI/IEEE standards, or SCE's determination indicates that a reduced rating is prudent or an increase rating is justified.

4.10.3 Rating Practice

The normal and emergency ratings of transmission lines or the transformation facilities shall equal the least rated component in the path of power flow.

4.10.4 Ambient Conditions

Since SCE's territory is in a year-round moderate climate, SCE does not establish equipment ratings based on seasonal temperatures. That is, SCE standard ratings for normal and emergency ratings are the same throughout the year and reflect summer ambient temperatures coincident with ANSI/IEEE standards, i.e., 40°C (104°F). However, in some cases SCE may calculate site-specific ratings that consider the local ambient conditions based on ANSI/IEEE rating methods.

4.10.5 Transmission Lines

The transmission circuit rating is determined according to the least rated component in the path of power flow. This comprises of the transmission line conductor, the series devices in the line, the allowable current that will not cause the conductors to sag below allowable clearance limits, and the termination equipment.

4.10.6 Conductors

The transmission line conductor ratings are calculated in accordance with ANSI/IEEE 738-1993. For Aluminum Conductor Steel Reinforced (ACSR) conductor the normal conductor rating allows a total temperature of 90°C and the emergency rating allows 135°C. Similarly, for aluminum and copper conductors SCE permits 85°C and 130°C. For Aluminum Conductor Steel Supported (ACSS), SCE base the normal rating at 120°C, and 200°C for the emergency rating. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification.

4.10.7 Series and Shunt Compensation Devices

Series capacitor and reactors are only permitted to be loaded to ANSI/IEEE limits or as specified by the manufacturer. VAR compensators shall be rated according to the ANSI/IEEE standards where applicable and according to the manufacturer's limitations. These ratings are reported to CAISO Transmission Register. Shunt capacitors and reactors are not in the path of power flow so they are not directly a "limiting component." However, their reactive power capacity is reported to CAISO Transmission Register.

4.10.8 Terminal Equipment

Terminal equipment comprises: circuit breakers, disconnect switches, jumpers, drops, conductors, buses, and wave-traps, i.e., all equipment in the path of power flow that might limit the capacity of the transmission line or transformer bank to which it is connected. The normal and emergency ampere rating for each termination device is reported to CAISO in its Transmission Register.

4.10.9 Transformer Bays

The rating of a transformer bay is determined by the least rated device in the path of power flow. This comprises ratings of the transformer, the transformer leads, the termination equipment, and reduced parallel capacity where applicable. The transformer rating is compared to the termination equipment ratings and lead conductors to establish the final transformation rating based on the least rated component. All of the above ratings are reported to the CAISO Transmission Register.

4.10.10 Transformer Normal Ratings

The "normal" rating is the transformer's highest continuous nameplate rating with all of its cooling equipment operating. The only exception is when a special "load capability study" has been performed showing that a specific transformer is capable of higher than nameplate loading and for which the test data or calculations are available.

4.10.11 Transformer Emergency Ratings

A transformer's emergency rating is arrived at by one of two methods. First, if no overload tests are available then a 10% overload is allowed. Second, if a factory heat-run or a load capability study has been performed, the emergency rating may be as high as 20% above normal as revealed by the test. For transformers on the transmission system, i.e., primary voltage of 500 kV, the allowed duration of the emergency loading is 24-hours. For transformers with primary voltage of 161 kV to 230 kV, the allowed duration is thirty days.

4.10.12 Parallel Operation of Transformers

When two or more transformers are operated in parallel, consideration is given to load split due to their relative impedances such that full parallel capacity is not usually realized. The permissible parallel loading is calculated according to ANSI/IEEE standards.

4.10.13 Relays Protective Devices

In cases where protection systems constitute a loading limit on a facility, this limit is the rating for that facility. These limiting factors are reported to the CAISO Transmission Register and are so noted as to the specific reason, e.g., “limited to 725A by relay setting.”

4.10.14 Path Ratings

As stated in Section 2 of the WECC Procedures for Project Rating Review, new facilities and facility modifications should not adversely impact accepted or existing ratings regardless of whether the facility is being rated. New or modified facilities can include transmission lines, generating plants, substations, series capacitor stations, remedial action schemes or any other facilities affecting the capacity or use of the interconnected electric system.

4.11 Synchronizing of Facilities

Testing and synchronizing of a generation facility may be required depending on SCE’s electric system conditions, ownership or policy, and will be determined based on facility operating parameters. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect synchronization.

Appropriate operating procedures and equipment designs are needed to guard against out-of-sync closure or uncontrolled energization. (Note: SCE’s transmission lines utilize ACB phase rotation, which is different than the national standard phase rotation). The Producer is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of the facility.

Synchronizing locations shall be determined ahead of time; required procedures shall be in place and be coordinated with SCE. SCE and the Producer shall mutually agree and select the initial synchronization date. The initial synchronization date shall mean the date upon which a facility is initially synchronized to the SCE’s electric system and upon which trial operation begins.

For additional technical information regarding the synchronizing of generators refer to Section 3 Protection Requirements.

4.12 Maintenance Coordination and Inspection

The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of the generation facility and associated equipment, including but not limited to control equipment, communication equipment, relaying equipment and other system facilities. Entities and coordinated groups of entities shall follow CAISO procedures and are responsible for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

4.13 Abnormal Frequency and Voltages

4.13.1 Joint Reliability Procedures

Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

4.13.2 Voltage and Reactive Flows

CAISO shall coordinate the control of voltage levels and reactive flows during normal and Emergency Conditions. All operating entities shall assist with the CAISO's coordination efforts.

4.13.3 Transfer Limits Under Outage and Abnormal System Conditions

In addition to establishing total transfer capability limits under normal system conditions, transmission providers and balancing authority shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

4.14 Communications and Procedures

4.14.1 Use of Communication System

It is essential to establish and maintain communications with the SCE Grid Control Center (GCC), the Alternate Grid Control Center (AGCC) or a jurisdictional Switching Center should a temporarily attended station or area of jurisdiction become involved in a case of system trouble. It is equally important that communication services be kept clear of nonessential use during times of system trouble to facilitate system restoration or other emergency operations.

4.14.2 Special Protection Schemes Communication Equipment Requirements

Generation facilities will require the necessary communication equipment for the implementation of Remedial Action Schemes (RAS). This equipment provides line monitoring and high-speed communications between the Generation Facility breaker and the central control facility, utilizing applicable protocols. RASs may also be applied to generators that may be required to trip in order to relieve congestion on SCE's electric system. Thus, allowing a RAS to incorporate disconnection into automatic control algorithms under contingency conditions, as needed.

RASs are fully redundant systems. The following paragraph is an excerpt from the WECC Remedial Action Scheme Design Guide that specifies the Philosophy and General Design Criteria for RAS redundancy. *"Redundancy is intended to allow removing one scheme following a failure or for maintenance while keeping full scheme capability in service with a separate scheme. Redundancy requirements cover all aspects of the scheme design including detection , arming, power, supplies, telecommunications facilities and equipment, logic controllers (when applicable), and RAS trip/close circuits."*

Excerpt from: WECC Remedial Action Scheme Design Guide (11/28/2006)

4.14.3 Critical System Voltage Operation

Voltage control during abnormal system configurations requires close attention with consideration given to what operations will be necessary following loss of the next component. Voltages approaching 10% above or below the normal value are considered critical with rate of change being of principal importance.

Section 5 General Operating Requirements:

a) **System Operating Bulletins:** Generator facilities connecting into SCE's electric system may be subject to operating requirements established by SCE, the CAISO or both. SCE's general operating Requirements are discussed in the sections below. SCE may also require additional operating Requirements specific to a generator facility. If so, these Requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOBs and/or SSIs specific to a generator facility, and any subsequent revisions, will be provided by SCE to the Producer as they are made available.

b) **Producer's Responsibility:** It is the Producer's responsibility to comply with applicable operating requirements. Operating procedures are subject to change as system conditions and system needs change. Therefore it is advisable for the Producer to regularly monitor operating procedures that apply to its generating facilities. The CAISO publishes its operating procedures on its internet site, but it is prudent for the Producer to contact the CAISO for specific Requirements.

c) **Quality of Service:** The interconnection of the generator facility's equipment with SCE's electric system shall not cause any reduction in the quality of service being provided to SCE's customers. If complaints result from operation of the generator facility, such equipment shall be disconnected until the problem is resolved.

d) **SCE Circuits:** generator facilities are not permitted to energize any de-energized SCE circuit.

e) **Operate Prudently:** The Producer will be required to operate its facility in accordance with prudent electrical practices.

f) **Protection in Service:** The generating facility shall be operated with all of required protective apparatus in service whenever the generating facility is connected to, or is operated in parallel with, the SCE electric system. Redundant protective devices may be provided at the Producer's expense if the generator is to be operated in parallel during routine testing of or failure of a protective device. Any deviation for brief periods of emergency may only be by agreement of SCE and is not to be interpreted as permission for subsequent incidents.

g) **Added Facilities Documentation:** The Producer may not commence parallel operation of generator(s) until final written approval has been given by SCE. As part of the approval process, the Producer shall provide, prior to the commencement of parallel operation, all documents required by SCE to establish the value of any facilities installed by the Producer and deeded to SCE for use as added facilities. SCE reserves the right to inspect the Producer's facility and witness testing of any equipment or devices associated with the interconnection.

5.1 Generating Facility Records and Data

SCE requires generating facility operating records and data from the Producer in order for SCE to plan and reliably operate its electrical system. Some Producers may be subject to similar record and data obligations from the CAISO. If so, the Producer may satisfy many of SCE's operating record and data requirements by giving SCE permission to access the Producer's information held by the CAISO.

Table 5.1 illustrates typical sizes of generating facilities and typical means of communicating generating facility operating records and data to SCE. Typically, large and medium sized generating facilities are required to install real-time telemetering, but small generating facilities may be excluded from many record and data requirements. Section 7 of this document describes the real-time telemetering[1] hardware requirements. The following two sub-sections describe generating facility operating records and data Producers are required to submit to SCE by real-time telemetering, voice communication or equivalent means.

SCE will require submission of additional records if such records are necessary for SCE to reliably operate and plan its electrical system.

Generation up to 10 MW may rely on the Public Switched Telephone Network (PSTN) as the primary means of maintaining operating communications. Generation greater than 10 MW should provide an alternate means of communication in addition to the PSTN to insure availability in the event of unplanned outage or emergency.

Table 5.1: Typical Communication Requirements Per Generating Facility Size

Aggregate Generation Facility Size	Real-time Telemetering	Voice
Gen. ≥ 1 MW	Required	Required
Gen. < 1 MW	Maybe	Maybe

5.2 SCE

a) SCE requires some Producers to maintain operating communications with an SCE designated switching center. These communications provide SCE operating records and data about the Producer's generating facilities in order for SCE to reliably operate its electric system. Generally, Producers with generating facility capacity of 1 MW or greater will have these Requirements, but it may be necessary for SCE to receive generating facility records for smaller generators if needed for reliability. Table 5.2 illustrates typical required generating facility records and data. SCE may require Producers to provide additional records than those shown in Table 5.2.

Table 5.2: Typical Required Generating Facility Records and Data

<table>
<tr><th></th><th>Generation Facility Record</th><th>Typical Size of Aggregate Generation[2] Facility</th><th>Delivery Date or Primary Communication Mode</th><th>Delivery Location</th></tr>
<tr><td>1</td><td>System Parallel Operation Or Separation</td><td>> 200 kW</td><td>Timely by Voice</td><td>Designated SCE Switching Center</td></tr>
<tr><td>2</td><td>Scheduled And Unscheduled Outages</td><td>> 200 kW</td><td><u>Scheduled Outages</u>
Outage Duration — Adv. Notice
< 1 day — 24 Hours
1 day or more — 1 Week
Major overhaul — 6 Months
<u>Unscheduled Outages</u>
Timely
<u>Communication Mode</u>
<u>Voice</u></td><td>Designated SCE Switching Center</td></tr>
<tr><td>3</td><td>Levels Of Real And Reactive Power</td><td>≥ 1 MW</td><td>Real-time Telemetering</td><td>SCADA</td></tr>
<tr><td>4</td><td>Equipment Clearance</td><td>≥ 10 MW</td><td>Timely by Voice</td><td>Designated SCE Switching Center</td></tr>
<tr><td>5</td><td>Interruption event</td><td>> 200 kW</td><td>Timely after event by Voice</td><td>Designated SCE Switching Center</td></tr>
<tr><td>6</td><td>Gen. Circuit Breaker Status</td><td>≥ 10 MW</td><td>Real-time Telemetering</td><td>SCADA</td></tr>
<tr><td>7</td><td>Gen. on/off Status</td><td>≥ 10 MW</td><td>Real-time Telemetering</td><td>SCADA</td></tr>
<tr><td>8</td><td>Generator Terminal Voltage</td><td>≥ 10 MW</td><td>Real-time Telemetering</td><td>SCADA</td></tr>
</table>

[2] Aggregate generation is the total nameplate capacity of generating facilities at the generation site being interconnected or the total generation under one SCE account.

b) An interruption event is said to occur on an interconnection circuit when its closed energized circuit breaker has opened or trips and interrupts powerflow to/from SCE facilities. After experiencing an event, the Producer is required to submit the following event information to their Designated Switching Center in order for SCE to assess relay operations and system integrity.

- Date and time of trips by the interconnection circuit breaker
- Generation facility status at time of incident (real & reactive power generation)
- Relay operation indicator (target) operations
- Oscillograph or Sequence of Event recorder records.

5.3 Operating Data and Records the Producer Must Provide SCE Upon Request

a) The Producer will be required to keep a daily operations log (records) for the generating facility which must include levels of operating voltage, relay operations, information on maintenance outages, maintenance performed, availability, and circuit breaker trip operations requiring a manual reset. Producers with the necessary metering[3] will be required to log fuel consumption, cogeneration fuel efficiency kilowatts, kilovars, and kilowatt-hours generated and settings or adjustments of the generator control equipment and protective devices, and any significant events related to the operation of the generating facility, including but not limited to real and reactive power production; changes in operating status and protective apparatus operations; and any unusual conditions found during inspections. Changes in settings shall also be logged for Producer's generator(s) if it is "block-loaded" to a specific kW capacity.

b) SCE, after giving written notice to the Producer, shall have the right to review and obtain copies of metering records and operations and maintenance logs of the generating facility.

c) If a Producer's generating facility has a Nameplate Rating greater than one (1) megawatt, SCE may require the Producer to report to a designated SCE Switching Center twice a day at agreed upon times for:

- the current day's operation,
- the hourly readings in kW of capacity delivered, and
- the energy in kWh delivered since the last report.

[3] Generators operating under the FERC QF status have additional metering installed.

5.4 Calibration of Producer Owned Protective Apparatus

The Producer must test the protective apparatus it owns on a routine basis in order to provide correct calibration and operation of the devices. Required test intervals of these protective apparatus have been established as shown in Table 5.3.

These test intervals are based on the nominal system voltage at the point of interconnection to SCE. SCE may require the Producer, at the Producer's expense, to demonstrate to SCE's satisfaction the correct calibration and operation of the Producer's protective apparatus at any time SCE reasonably believes that the Producer's protective apparatus may impair the SCE electric system integrity.

Table 5.3: Required Test Intervals for Protective Devices

	Interconnection Voltage	Test Interval	Delivery Location
1	$\geq$200 kV	Every two years[1]	mail to: Manager, Grid Contracts, P.O. Box 800, 2244 Walnut Grove Avenue, Rosemead, California 91770
2	55 - 200 kV	Every four years[1]	mail to: Same
3	less than 55 kV	Every eight years[2]	mail to: Same
4	Frequency relays (all voltage levels) Electromechanical: Electronic:	Every two years four years	mail to: Same

1 The test interval may be extended by 2 years for self-monitoring microprocessor relays provided with failure alarms, e.g. from four years to six years.

2 Interconnection protective relays on interconnections to lines listed in System Operating Bulletin 22 (fire hazard areas) must be tested *annually* before May 1 of each year.

5.5 Disconnecting Service to a Generation Facility

Applicable agreements and tariffs may state criteria for disconnection of generating facilities which are interconnected to SCE's electric system. In general, generating facilities may be curtailed or disconnected if SCE determines that their operation creates a threat to personnel or the electric system.

5.6 Voltage Variations

a) **Voltage Regulation:** Operation of the Producer's generating facility shall not adversely affect the voltage regulation of that portion of SCE's electric system to which it is connected. Adequate voltage control shall be provided by the Producer to minimize voltage regulation on SCE's electric system caused by changing generator-loading conditions. The step-up transformer ratio must be chosen such that the Producer can meet its voltage regulation obligations over the expected range of SCE system voltages. Step-up transformers must be equipped with no-load taps which provide ±5% adjustment of the transformer ratio in 2.5% steps.

b) **Exception:** The tap Requirement will be waived if the Producer submits a study to SCE which demonstrates to SCE's satisfaction that the Producer can meet its voltage regulation obligations over the expected range of system voltages specified by SCE.

Generator voltage schedule and transformer tap settings will be specified by SCE, as necessary, or the CAISO to ensure proper coordination of voltages and regulator action. It is the Producer's responsibility to ensure voltage-VAR schedule compliance. The following table illustrates whether SCE or the CAISO specifies these schedules.

Table 5.4: Electric System Jurisdiction and Tap-setting Specification

Generating Facility Connected to:	**CAISO Controlled Transmission System**	**SCE Controlled Subtransmission or Distribution**
Voltage Schedule	Specified by CAISO	Specified by SCE, as needed
Transformer Tap Settings	Specified by SCE ±5% in 2.5% steps	Specified by SCE ±5% in 2.5% steps

c) **Transmission Voltages:** Expected transmission system operating voltages range from 160 to 164 kV for 161 kV nominal voltage, 220 to 240 kV for 220 kV nominal voltage, and 515 to 535 kV for 500 kV nominal voltage. Voltage regulation at a given location on the transmission system must follow the CAISO and SCE voltage schedules.

d) **Distribution and Subtransmission Voltages:** In order to supply and maintain proper voltages for SCE's customers as required by the CPUC, SCE's primary distribution voltages (2.4 to 34.5 kV) and subtransmission voltages (55 to 115 kV) may fluctuate by as much as ±5% from the nominal values (e.g., 12 kV ±5%; 34.5 kV ±5%; etc.). SCE uses various voltage regulation techniques to raise or lower primary distribution and subtransmission voltages in order to maintain the customer's service voltage at the desired level. Producers interconnected at primary distribution or subtransmission voltage levels must be able to withstand such voltage changes and to respond with proper power factor adjustment in order not to oppose or interfere with SCE's or the CAISO's voltage regulation processes.

5.7 VAR Correction

VAR correction will normally be planned for light load, heavy load and for system normal and contingency conditions. This is to be accomplished by providing transmission system VAR correction to minimize VAR flow and to maintain proper voltage levels. The planning of transmission system VAR requirements should consider the installation of shunt capacitors, shunt reactors and tertiary shunt reactors, synchronous condensers, FACTS and transformer tap changers. The guidelines for reactive planning are as follows:

5.7.1 Interconnection

SCE shall not be obligated to supply or absorb reactive power for the generator facility when it interferes with operation of SCE's electric system, limits the use of SCE interconnections, or requires the use of generating equipment that would not otherwise be required.

5.7.2 Subtransmission System

Not Applicable

5.8 Voltage Regulation/Reactive Power Supply Requirements

Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled and adequate reactive reserves shall be provided. If power factor correction equipment is necessary, it may be installed by the Producer at the facility, or by SCE at SCE's facilities at the Producer's expense.

Generator VAR schedules, as needed, will be specified by SCE or the CAISO to ensure proper coordination of voltages. It is the Producer's responsibility to ensure voltage-VAR schedule compliance. If power factor correction equipment is necessary, it must be installed by the Producer at its facility at the Producer's expense to ensure the power factor at the point of interconnection meets the criteria in Table 5.5.

Note that the generator power factor capability for WDAT service is likely to require equipment capable of operating over the range of 0.9 lag to 0.95 lead in order to meet the Tariff Point of Delivery requirements.

Table 5.5: Power Factor Criteria

Generating Facility Connected to:	CAISO Controlled Transmission System	SCE Controlled Subtransmission or Distribution
Power Factor	Generator has the capability of 0.90 lagging to 0.95 leading.	At point of delivery, 0.95 lagging to 0.95 leading.

5.8.1 Reactive Power Equipment – Induction Generators (in aggregate)

5.8.1.1 Facility Reactive Power Equipment Design

Producers shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits as they relate to their generator facilities.

Reactive power equipment utilized at a generator facility to meet SCE's Requirements must be designed to minimize the exposure of SCE's customers, SCE's electric system, and the electric facilities of others (i.e., other facilities and utilities in the vicinity) to:

a) severe overvoltages that could result from self-excitation of induction generators,
b) transients that result from switching of shunt capacitors,
c) voltage regulation problems associated with switching of inductive and capacitive devices.
d) unacceptable harmonics or voltage waveforms, which may include the effect of power electronic switching, and

e) Voltage flicker exceeding SCE Voltage Flicker limits as indicated in SCE Transmission Planning Criteria and Guidelines Figure 4-1 "VOLTAGE FLUCTUATION DESIGN LIMITS".

5.8.1.2 Facility Reactive Power Equipment Design - provide variable source

The reactive power equipment utilized at a generator facility to meet SCE's Requirements must be designed to provide a variable source of reactive power (either continuously variable or switched in discrete steps). For discrete step changes, the size of any discrete step change in reactive output shall be limited by the following criteria:

a) the maximum allowable voltage rise or drop (measured at the point of interconnection with SCE's electric system) associated with a step change in the output of a generator facility's reactive power equipment must be less than or equal to 1%; and

b) the maximum allowable deviation from a generator facility's reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the generator facility's maximum (boost) reactive capability.

5.8.2 Reactive Power Supply Requirements - Synchronous Generators

Producers connected to SCE's electric system and utilizing synchronous generators are required to generate or supply reactive power so that the generating facility does not impose any additional reactive power demand upon SCE other than the demand of loads within the facility. The Producer will not be permitted to deliver excess reactive power to SCE under normal operating conditions unless otherwise agreed to by SCE. Under emergency operating conditions, the Producer is permitted to deliver excess reactive power to SCE to ensure voltage schedule compliance.

Producers connected to the subtransmission system or bulk power system (above 34.5 kV) must have the voltage regulation equipment and generator reactive power capability to maintain a voltage schedule or reactive power schedule prescribed by SCE or, if applicable, the CAISO. Generators must be capable of operation over the power factor ranges designated in Table 5.5.

5.8.3 Reactive Power Supply Requirements - Inverter Systems

Forced-commutated inverters must meet SCE's reactive power supply Requirements of synchronous generators in 5.8.2. Line commutated inverters must be corrected to satisfy SCE's reactive power supply Requirements of induction generators in 5.8.1.

Inverters must also meet SCE's harmonic load limits based on IEEE Standard 519-1992. For further information on the assessment and mitigation of harmonics due to inverters, refer to "SCE Transmission Planning Criteria and Guidelines, Appendix F, HARMONIC LOAD LIMITS, APPLICATION OF IEEE STANDARD 519-1992 TO TRANSMISSION AND SUBTRANSMISSION PLANNING".

5.8.3.1 IEEE and UL Standards for Inverter Systems 200 kVA or Less

Inverter systems which conform to the recommended practices in IEEE Standard 929-19 and which have been tested and approved for conformance to UL Subject 1741, are considered to have met all SCE's reactive power supply Requirements.

5.8.4 Voltage and Reactive Control

5.8.4.1 Coordination

Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

5.8.4.2 Transmission Lines

Not Applicable to Generation.

5.8.4.3 Switchable Devices

Not Applicable to Generation.

5.9 Off-Nominal Frequency Requirements

Producer generating facilities that protect for off-nominal frequency operation should have relaying protection and generating equipment that accommodates, at a minimum, under frequency and over frequency operation for the following specified time frames in Table 5.6.

Table 5.6: WECC Off Nominal Frequency Limits

Under Frequency Limit	Over Frequency Limit	Minimum Time
> 59.4 Hz	60.0 to < 60.6 Hz	continuous operating range
≤ 59.4 Hz	≥ 60.6 Hz	3 minutes
≤ 58.4 Hz	≥ 61.6 Hz	30 seconds
≤ 57.8 Hz	N/A	7.5 seconds
≤ 57.3 Hz	N/A	45 cycles
≤ 57.0 Hz	> 61.7 Hz	instantaneous trip

Frequency relay settings must not allow less stringent operation of the generating facility than specified in the WECC Off Nominal Generation Requirements shown in Table 5.6, unless agreed to in writing by SCE and coordinated with SCE's abnormal frequency operation plan. It is the Producer’s responsibility to ensure conformance with the latest approved WECC Off Nominal Generation Requirements.

The CAISO is responsible for frequency control and therefore SCE can assume no responsibility for damage that occurs due to off nominal frequency operation. It is possible that the electrical network including SCE’s electric system may operate outside of the limits stated above. It is the responsibility of all Producers connected to SCE’s electric system to install equipment to protect against damage to Producer owned equipment from off-nominal frequency operation.

Generators that are required to use under-frequency detection for islanding must coordinate frequency threshold settings to ensure conformance with SCE's abnormal frequency operation plan. In general, detection and separation of generators under islanded conditions take precedence over sustained operation of these particular generators through system frequency deviation events.

5.10 Voltage Imbalance and Abnormal Voltage or Current Waveforms (harmonics)

Power quality problems are caused when voltage imbalances and harmonic currents result in abnormal voltage and/or current waveforms. Generally, if a generator facility's output degrades power quality to SCE's facilities, other generator or customer facilities, SCE may require the installation of equipment to eliminate the power quality problem.

5.10.1 Voltage Imbalance

The unbalanced voltage level (magnitude and phase), due to a generator facility to be connected at the transmission or subtransmission system level, may not exceed 1% at the Point of Common Connection[4] (PCC), under steady state system conditions. Under certain conditions (contingency conditions), SCE may allow higher levels of voltage imbalance if justified after a study conducted by SCE. In any event, the unbalanced voltage level created by a generator facility shall not exceed 1.5%.

It is the responsibility of Producers, with a generator facility connected to SCE's electric system to install adequate mitigation devices to protect their own equipment from damage that maybe caused by voltage imbalance condition.

5.10.2 Harmonics

Generator facilities s are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment in accordance to good engineering practice used at their facility to comply with the limits set by the current IEEE Standards.

5.10.3 Disconnection

SCE may disconnect any generator facility until the Requirements within this section of the Interconnection Handbook are met.

5.10.4 Photovoltaic Inverter Systems

Photovoltaic inverter systems which conform to the recommended practices in IEEE Standard 929-1999 and which have been tested and approved for conformance to UL Subject 1741 are considered to have met SCE's Requirements for voltage imbalance and abnormal waveforms.

[4] The PCC will generally be at the location of the revenue meter or the point of ownership change in the electrical system between SCE and the Producer. For customers served by dedicated facilities, the location of the PCC will be determined by mutual agreement between the Producer and SCE.

5.11 Isolating Equipment Requirements and Switching & Tagging Rules

5.11.1 Applicable to Generation Facilities connecting to voltages > 34.5KV

An isolating device must be installed and specific inter-company rules must be in place to ensure the safety of SCE personnel. The isolating device isolates the Generation Facility from the SCE Electric System and prevents inadvertent energization of the generation tie-line while personnel are performing maintenance and/or repair work on the Interconnection Facilities.

5.11.1.1 Manual Disconnects

The isolating disconnect shall be placed in the LINE disconnect position on the high side of the Producer's generation tie-line. A separate GROUND disconnect shall also be incorporated and placed in the line position on the high side of the Producer's generation tie-line.

For 230 kV and below, the disconnects must be 3-phase, gang-operated disconnects with a common operating handle. For 500 kV, each phase must be equipped with a disconnect having its own operating handle.

The operating handle of the LINE disconnect/disconnects must include a provision for locking the disconnect control handle/handles in the <u>open</u> positions. The operating handle of the GROUND disconnect/disconnects must include a provision for locking the disconnect control handle/handles in the <u>closed</u> positions.

For manual LINE disconnects, the device must:

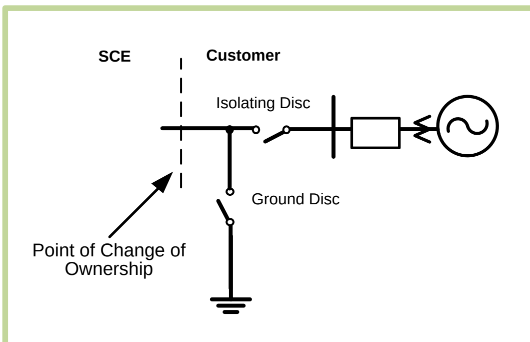
1. Provide unrestricted, 24-hour access to SCE personnel.
2. Allow visible[5] verification that separation has been accomplished.
3. Be capable of being locked in the open position.
4. Be clearly labeled with permanent signage.

[5] Visible means a visible break when the disconnect is in the open position. Here, visible verification should allow for visual inspection of the device. Typically, this switch should not be enclosed inside of a building or structure.

5.11.1.2 Switching and Tagging Rules

SCE and Producer shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. In accordance with SCE's switching and tagging rules, the Producer shall allow SCE to place its locks on the Producer's Interconnection Facilities, as may be required (specifically disconnect switches and/or circuit breakers on the Producer's terminus of the generation tie-line). The locking feature of disconnects may be utilized by either party when inter-company clearances are issued on the generation tie-line.

Figure 5a



5.11.2 Applicable to Generation Facilities connecting to voltages ≤ 34.5KV

The producer shall furnish and install a ganged, manually-operated isolating device near the Point Of Change of Ownership (POCO) (when SCE and applicant electrical systems connect also referred to as the Point of Common Coupling (PCC)) to isolate the Generating Facility from SCE's Electric System. See Figure 5a.

The device must:

1. Allow visible[6] verification that separation has been accomplished.
2. Include marking or signage that clearly indicates open and closed positions.
3. Be capable of being reached quickly and conveniently 24 hours a day by SCE personnel.
4. Be capable of being locked in the open position.
5. Be clearly labeled with permanent signage.

---

[6] Visible means a visible break; when the disconnect is in the open position, there is a visible separation between the contacts, and the separation may be observed without disassembling the device. Typically, this switch contains visible blades inside an enclosure.

5.12 Grounding Circuits and Substations

The Producers shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous voltage potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying equipment to be handled by personnel.

Reason for Substation Grounding

Substation grounding practices are outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding."

According to IEEE 80 – 2000 a safe ground grid design has the following two objectives:

- "To provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service." (IEEE 80 – 2000)
- "To ensure that a person in the vicinity of grounded facilities is not exposed to the danger of critical electric shock." (IEEE 80 – 2000)

> "People often assumed that any grounded object can be safely touched. A low substation ground resistance is not, in itself, a guarantee of safety. There is no simple relation between the resistance of the ground system as a whole and the maximum shock current to which a person might be exposed. Therefore, a substation of relatively low ground resistance may be dangerous, while another substation with very high resistance may be safe or can be made safe with careful design." (IEEE 80 – 2000)

Each substation ground grid is a unique design. The conditions at the site: soil type, soil resistivity, fault current, clearing time, size of the substation, and other grounds all factor into the design.

5.12.1 Nominal Voltage and Grounding

SCE's most common primary distribution voltages are 4, 12 and 16 kV depending on the geographic area. Other voltages are also used in specific areas. Subtransmission voltages are nominally 66 kV to 115 kV. Transmission system voltages are nominally 161 kV, 220 kV, and 500 kV. The majority of the 4, 12, and 16 kV circuits are effectively grounded, but some are operated with high impedance grounding. A substantial number of the effectively grounded circuits are used for four-wire distribution (phase to neutral connected loads). SCE will provide the Producer necessary information on the specific circuit serving their generator facility for proper grounding.

5.12.2 Grounding Grid Studies shall be conducted in the following situations:

Grounding calculations will be required for each new substation, and at existing substations, when the ground grid is altered or when major additions are made at a substation. A review of existing substation ground grids will be conducted by Engineering in the following situations, especially if triggered by interconnection requests – these shall be considered in queue order:

- Short Circuit Duty Changes
  1. Circuit breaker replacement for short-circuit duty reasons
  2. Addition of transmission or subtransmission line to a substation
  3. System changes causing a substantial change in the substation phase-to-ground short-circuit duty
  4. Addition or replacement of a transformer at a substation
  5. Addition of new generation causing a substantial change in the substation phase-to-ground short-circuit duty
- System Protection Changes
  1. Changes in system protection that significantly increases the clearing time for ground faults.
- Grounding Source Changes
  1. Grounding of ungrounded wye winding of a transformer
  2. Addition or major change of ground source at a substation
- Substation Changes
  1. Alterations to substation fences including additions, movement, and attachments to other fences. The removal of vegetation that blocks access to a substation fence is considered a fence alteration.
  2. Alterations to substation ground grids that change their size or increase the effective substation ground grid impedance.
  3. Sale or lease of substation property for other uses.
- A grounding review should be conducted any time a grounding problem is reasonably suspected.

5.12.3 Ground Mats

If the generator facility and SCE substation ground mats are tied together, all cables may be landed without any protection. However, if the generator facility and SCE substation ground mats are not tied together, all cables shall have protection at both ends. The design of cable protection, if any, on circuits used for protective relaying purposes shall be such that the operation of the protective relaying is not hampered when the cable protection operates or fails.

All generator facility ground mats shall be designed in accordance with good engineering practice and judgment. Presently the recognized standard for grounding is IEEE 80 "IEEE Guide For Safety in AC Substation Grounding." All ground mat designs should meet or exceed the requirements listed in this standard. If local governmental requirements are more stringent, building codes for example, they shall prevail. All Producers shall perform appropriate tests, including soil resistivity tests, to demonstrate that their ground grid design meets the standard for their generator facilities interconnected to SCE's electric system. Mats shall be tested at regular intervals to ensure their effectiveness.

Grounding studies shall be performed with industry-recognized software to determine if generator facility and SCE ground grids should be separate or tied together. This study will determine the maximum safe fault current for the ground grid design. It is suggested that the grid be designed for the maximum fault currents expected over the life of the facility.

If for any reason the worst-case fault current exceeds the design maximum fault current value due to changes in the Producer's facility or changes on the SCE system, the Producer shall conduct new grounding studies. Any changes required to meet safety limits and protect equipment shall be borne by the Producer.

The Producer is responsible to ensure that the Ground Potential Rise (GPR) of the generator facility's or interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the Producer. If it is elected to install separate ground grids for SCE and the generation facility, the Producer shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the generation facility.

Any ground grid design, which results in a GPR that exceeds 3,000 volts RMS for the worst-case fault or has a calculated or measured ground grid resistance in excess of 1 ohm, will require special approval by SCE.

5.12.4 Substation Grounding

The Producer shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying parts to be handled by personnel.

5.13 Non-SCE Pole Grounding

The Producer shall follow SCE Construction, Operation, and Maintenance requirements. The last Producer -owned structure before the point of interconnection which connects the Producer's generation facility to SCE's electric system shall be designed and constructed to meet SCE grounding requirements.

Generation facilities that will require SCE's crews to climb in order to construct, operate, or maintain SCE facilities shall be built to meet SCE all standards and specifications. Constructing to SCE specifications will ensure that SCE crews can perform work in accordance with internal safety practices identified within SCE's Accident Prevention Manual. This manual stipulates the proper training and equipment to safely climb and work. Examples of safety related requirements that:

- Climbing Steps
- Belt-Off Locations
- Grounding Locations
- Required PPE
- Jumper Cable Ownership

Grounding bolts and bases are the same as step bolts and bases. If SCE personnel will be or could be performing work on a non-SCE owned pole connecting a generator facility directly to SCE's electric system a dead-end structure adhering to SCE's Construction, Operation, and Maintenance standards, is required on that line in close proximity to the generation facility.

Please note that these requirements are for poles only. Non-steel or ungrounded poles will have; project-specific grounding requirements as determined by SCE.

Section 6 Revenue Metering Requirements

6.1 General Information

Revenue metering is required to measure the energy and capacity delivered and consumed by a Producer's station load. While functionally similar, there are varying Requirements for Producers depending on the nature and purpose of their generating facility and varying rules established by the authorities having jurisdiction over a Producer and SCE. Metering Requirements for Producers taking service under a FERC tariff, and retail service under CPUC regulations are set forth in Section 6.2.

In general, all CAISO revenue metering and associated equipment used to measure a generator's energy, and capacity output, shall be provided, owned, and maintained at the Producer's expense.

6.1.1 Retail Service

The retail metering requirements for retail service will be owned, operated, and maintained by SCE under SCE's Electrical Service Requirements (ESR) and in accordance with SCE approved tariffs.

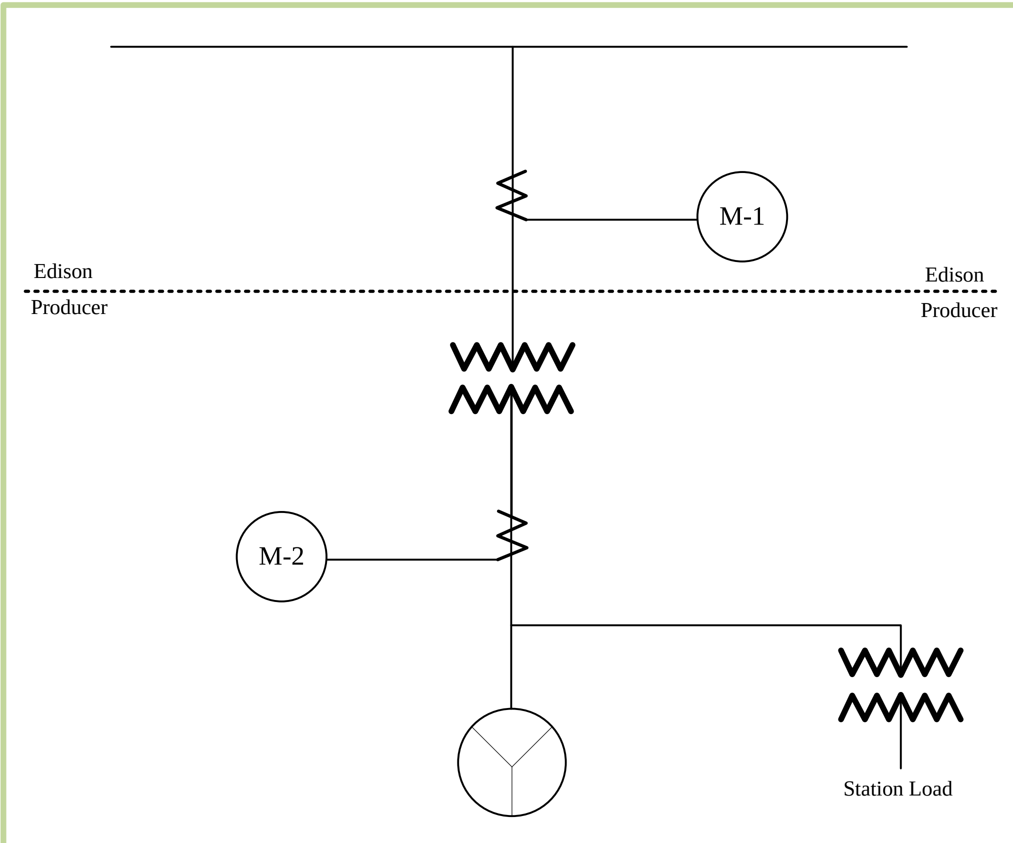
6.2 Revenue Metering Requirements for Generators

6.2.1 General Information

In order to measure energy and capacity delivered and scheduled with the CAISO, a Producer shall install all necessary meters, routers, telecommunications, and associated equipment to comply with the metering standards and requirements of the CAISO Tariff and Metering Protocol. As required by the CAISO Tariff, a Producer's metering facilities shall be certified by the CAISO. Further, retail service will be measured using an SCE owned meter including SCE owned metering PT's and CT's. However, a producer may install the required CAISO metering in tandem with the SCE owned metering. Figure 6a shows a typical SCE metering installation for a generating facility without departing load and Figure 6b also shows a typical CAISO customer owned meter and SCE owned meter in tandem on the customers' side of the fence and an SCE metering installation for SCE retail billing purposes on SCE property of a generating facility with departing load.

Figure 6a: Typical Metering Installation for a Generating Facility

Typical metering configuration for Generators taking service under the CAISO Tariff without CAISO metering installed on Producer's side of the interconnection with no departing load showing placement of SCE metering at M-1 or M-2, respectively.



M1 – SCE Billing Meter

M2 – SCE Billing Meter in an ESR Compliant Meter Cubicle

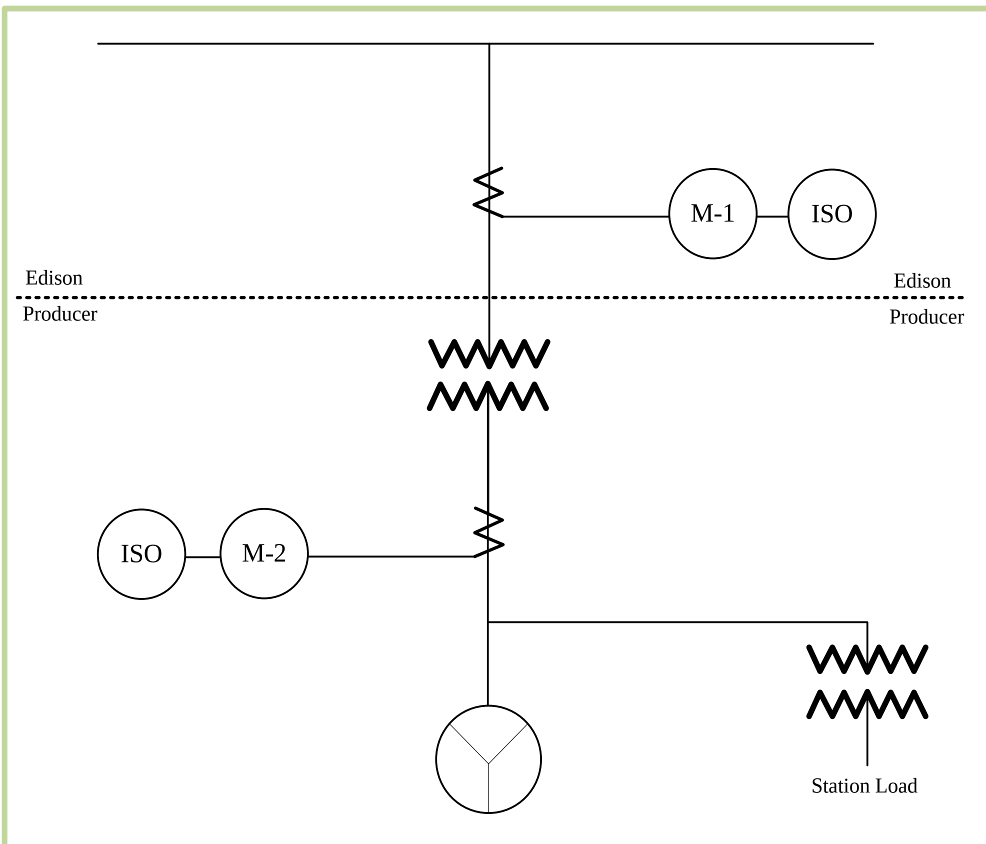
6.3 Location/Ownership of CAISO Metering Equipment

Applicable to Metering Installed on a Producer's Side of Interconnection

A Producer shall, at its expense, install, own, and maintain all CAISO metering equipment, including metering CTs/PTs, meters, routers, and telecommunication's equipment providing such equipment is installed on its assets and located on its side of the point of interconnection with SCE (Figure 6b).

Figure 6b: Location/Ownership of CAISO Metering Equipment for a Generating Facility

Typical metering configuration for Generators taking service under the CAISO Tariff with CAISO metering installed on Producer's side of the interconnection with no departing load showing placement of SCE metering at M-1 or M-2, respectively.



M1 – SCE Billing Meter

M2 – SCE Billing Meter in an ESR Compliant Meter Cubicle

If a Producer elects Direct Access service pursuant to SCE's Rule 22, it must comply with Rule 22 metering requirements for retail billing.

Section 7 Telemetering Requirements (Hardware)

7.1 Telemetering Requirements

For a high degree of service reliability under normal and emergency operation, it is essential that the Producer's generation facility and its associated Interconnection Facilities have adequate and reliable telecommunication facilities.

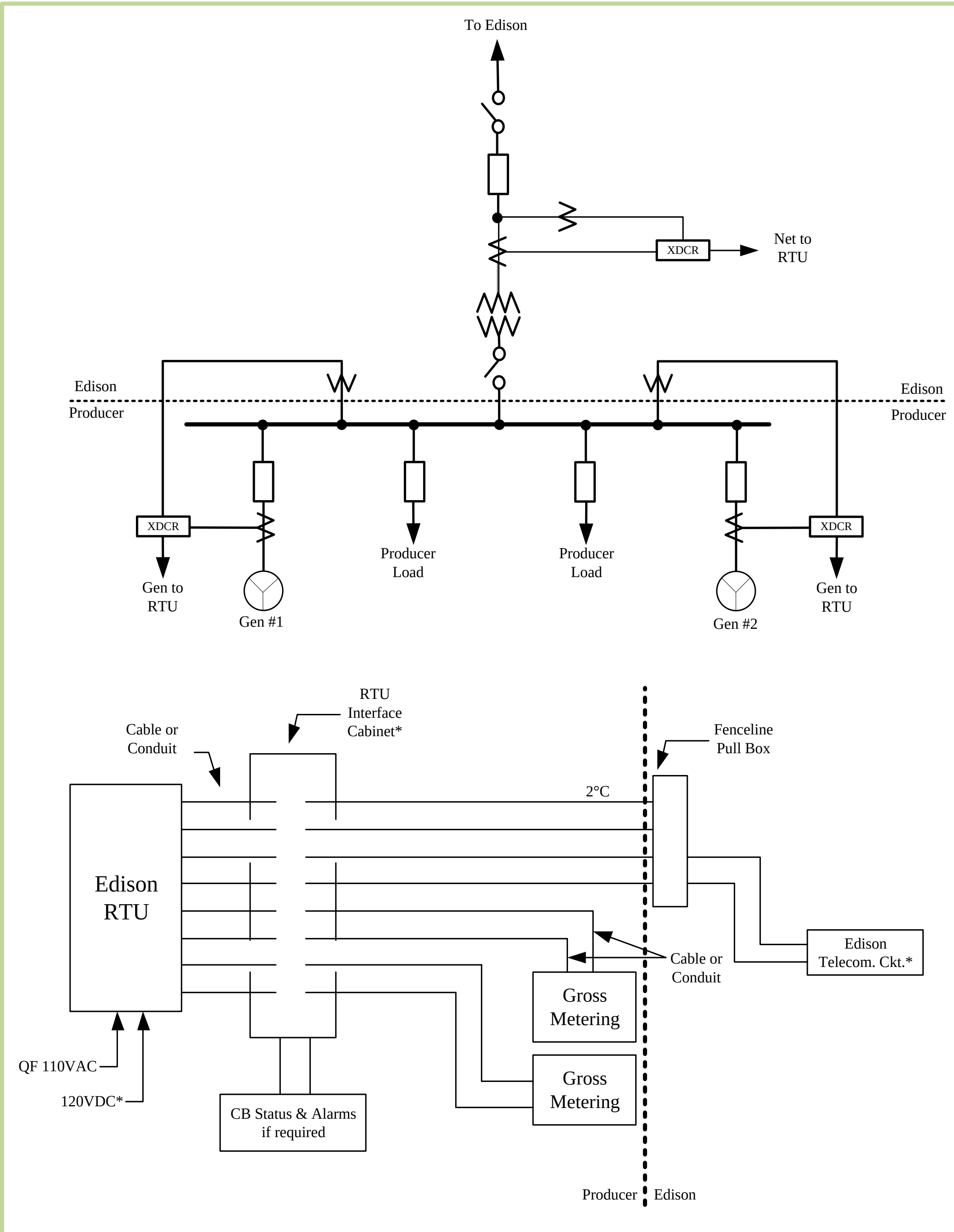
The Producer shall identify the following at the point of connection where its generation facility connects to SCE's electrical system: the requested voltage level, MW/MVAR capacity, and/or demand.

Producers with generating facilities 1 MVA nameplate[7], or larger, will require telemetering equipment and telecommunications at Producer's expense. For projects equal to or greater than 1 MVA but less than 10 MVA, real time SCADA telemetry of watts and vars only are required for total generation and customer load. For projects greater than 10 MVA, the telemetering equipment must transmit at minimum generator unit gross MW and MVAR, generator status, generator circuit breaker status, and generator terminal voltage. In addition, real time telemetering of project net MW and MVAR is required.

Wind generation facilities equal to or greater than 1 MVA nameplate will require real-time monitoring in most cases. (See Figure 7). It is the Producer's responsibility to comply with any CAISO telemetry requirements. These telemetry requirements apply to non-exporting-for-sale as well as exporting-for-sale generating facilities; refer to SCE System Operating Bulletin 510 for exemptions to certain non-exporting-for-sale generating facilities.

[7] For inverter based technology generator projects, the Gross Nameplate Rating is the AC nameplate rating of the inverter units.

Figure 7: Typical Remote Terminal Unit (RTU) Installation
1 MVA Nameplate OR MORE Generating Facility



*For generation 1 MVA or more.

7.2 Total Generation 1 MVA Nameplate or More

The following is a list of Requirements for the installation of a Real-Time Remote Terminal Unit (RTU) or equivalent device at the Producer's generating facility. Unless otherwise specified, all the facilities listed below are to be provided by the Producer.

At the customer's expense, SCE will purchase, configure, install, and commission the RTU. The size and point count of the RTU is determined based on the generation nameplate capacity as well as the number of data points to be monitored. SCE will own, operate, maintain, repair, control, alter, replace, and upgrade the RTU. The purpose of the RTU is to collect and concentrate customer facility and generation information for use on the SCE SCADA system to determine system loading, assist in Grid operation, and collect historical data.

7.2.1 The following specifications are to be used as informational guidelines to facilitate the RTU installation at the Generation Facility:

a) An interior location suitable for floor or wall mounting the RTU is required. The location should be reasonably close to the origin of telemetering signals or data concentrator. A control room or relay house is acceptable as long as the temperature range is within 0C to 70C. The HVAC requirements for fiber optic terminal equipment are more stringent than what is required for RTU equipment. Therefore, the requirements in this Section 7 will match those of Section 8: Telecommunications Requirements, whenever line protection or SPS specifies the use of fiber optic communications and its terminal equipment.

- Cable access can be either through the top or bottom of the RTU cabinet.
- Floor space for standard 8 foot tall, 19" free-standing rack (PREFERRED).
- Wall space for a single door cabinet 24 inches wide by 20 inches deep by 30 inches high. The wall mount cabinet weighs 125 pounds and is mounted with a ½ inch bolt through mounting tabs at each corner.

b) Provide a 120 VAC 15 Amp convenience power source to the RTU cabinet. This source will utilize a dedicated breaker labeled "SCE-RTU". A 4 foot coil is to be left at the RTU location and will be terminated by SCE inside the RTU cabinet.

c) Station DC power 10A @ 48VDC or 5A @ 125VDC (not shared with other equipment) run to the RTU cabinet for RTU power. The voltage to be supplied to the RTU shall be communicated to SCE PSC in order for SCE to procure the appropriate RTU. The circuit breaker shall label “SCE-RTU”. If DC power is not available, a 120 VAC circuit may be used as long as this circuit is sourced from an Uninterruptible Power System with a minimum of 4 hour backup.

d) One stranded AWG #8 conductor will be connected to station ground and run to the RTU cabinet by the customer.

e) The customer will run all data signal cables for physical I/O points to the RTU cabinet or to a near-by (6 feet or less) interface cabinet for termination. Data cables must be shielded with shield grounded at RTU end only. Twisted-pair stranded wire between AWG#16 and AWG#22 or twisted-pair solid wire between AWG#18 and AWG#24 may be used. Cables containing 6, 12, 25 and 32 pairs are typical. A 10 foot coil is to be left at the RTU location and will be terminated by SCE inside the RTU cabinet.

f) All analog quantities will be represented by a + / – 1 milliamp or a 4 to 20 milliamp current loop. The current loop may be shared as long as there are no grounds and it is not driven beyond the manufacturers specified limits. Physical status points will be presented by a dry contact available at the interface cabinet. All status points will utilize the Normally Open contacts of the customer provided isolation relay. The RTU will provide the contact wetting voltage.

g) The customer shall provide data communication cables for virtual I/O points directly to the RTU cabinet for termination. Typical data communication cables include standard CAT V (Ethernet) cables, Industrial Ethernet Cable, or Industrial RS-485 Cables such as Belden 3108A or equivalent.

h) Communication between the customer data concentrator and the Edison RTU shall be ModBus RTU, 9600 baud, 8 bits, 1 stop, no parity. Other data communication protocols shall be evaluated on a case-by-case basis.

i) Specific Telemetry Requirements:

GENERATOR SIZE AND TYPE	DATA ACQUISITION REQUIREMENT
GF with aggregate generation < 1 MVA	No remote telemetry is required
Non-Wind GF interconnected at ≤ 33kV with 1 MVA ≤ aggregate generation ≤ 10 MVA	Real-time (SCADA) telemetry required for total generation. Customer load data may be required and shall be evaluated on a case by case basis • Watts • VARs • Voltage
Wind GF ≥ 1 MVA	Real-time (SCADA) telemetry required for total project • Watts • VARs • Voltage • Entire Project CB Status[8]
GF with an aggregate plant ≥ 10 MVA	Real-time (SCADA) telemetry required for 2 of the following 3 parameters: • Total Gross Generation • Customer Load • Net flow to/from utility interface Plus the following: • Watts • VARs • Amps • Volts (Generator Bus) • Interface CB Status[9]

[8] All CB statuses contained in the entire projects

[9] The customer's high side main breaker status

Any single generating unit ≥ 10 MVA	Real-time (SCADA) telemetry required for each individual generating unit: • Watts • VARs • Amps • Volts (Generator Bus) • Unit CB Status[10]
Switchyards ≥ 55KV	Real-time (SCADA) telemetry required for: • Bus Voltage • Line MW • Line MVARs • Switchyard CB Status[11]

j) SCE's Grid Control Center (GCC) on a site-to-site basis may deem other status, protection alarms, or controls necessary. All ratings are based on the Gross Nameplate Rating.

k) ITBI ITS Network & Telecom Services Grid Projects will determine communications from the RTU to EMS.

l) The RTU cabinet can be delivered to the customer premises for mounting and conveniences to the customer.

m) 24-hour access to the RTU for maintenance by SCE's Power System Controls technicians.

7.3 Exemption for Cold-Iron and Emergency-Backup Generators

Note: These types of generators are not operated in parallel to SCE's electric system except for short times *(typically only several minutes)* while performing a "soft-transfer" of customer load between the generator and SCE's electric system. As such, the telemetry requirements of this section **do not apply** to Cold-Iron or Emergency-Backup generators.

[10] Individual Generating Unit CB Status

[11] Entire switchyard CB status

7.3.1 Cold-Ironing is the action of providing shore-side electrical power to a ship at berth while its on-board generator(s) are shut down.

a) Cold-Iron generator is a generator on board a ship which has the capability of Cold-Ironing.

b) The initial process of Cold-Ironing involves paralleling the ship's electrical system to SCE's electric system for a short duration while the ship's electrical load is transferred between the ship's generator and shore power. A Cold-Iron generator does not parallel to SCE's electric system beyond the initial transferring process.

7.3.2 Emergency-Backup Generation (EBG) is customer-owned generation utilized when disruption of utility power has occurred or is imminent.

a) When utilized, **following** a disruption, the customer would first disconnect from SCE's electric system prior to starting up the EBG.

b) When utilized **prior to** a disruption of utility power, the EBG would be started and loaded to carry the entire customer load, and then the customer would disconnect from SCE's electric system.

c) Upon resumption of utility power, the customer would first connect to SCE's electric system and then unload the EBG.

Section 8 Telecommunications Requirements

8.1 General Description

The following Requirements are for typical Telecommunications equipment installation at a generation facility and its associated Interconnection Facilities. Specific design and installation details are addressed during final engineering for facilities at each specific Point of Interconnection.

The telecommunications facilities to support line protection of the generator facility's interconnection depend on its specific protection needs and the existing telecommunications infrastructure in the area. Fiber optic (FO) communications matched with protective relays are used on transmission power lines for fast clearing. For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles.

As noted in Section 3, the selection of protection devices is dependent on the generator size and type, number of generators, the composition of the existing protection equipment, and the power line characteristics (i.e., voltage, impedance, and ampacity) of its interconnection and the surrounding area. Identical generator facilities connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs.

In cases where a second fiber optic (FO) telecommunication is required, for protection relay coordination or to support a SPS, the second FO path must comply with WECC guidelines governing diverse routing. The Producer will construct the communications path(s) between the generation facility and the point of interconnection. Primary path can be provided with a FO cable on its interconnection or as Fiber Optical Ground Wire (OPGW). Diverse routing will be required for secondary path. Telemetering data (SCADA) and line protection control signals will be transported on these paths.

If FO is not required for line protection or SPS, a leased T1 circuit may be used for telemetering (SCADA). See Section 8.6.

8.2 Fiber Optic Communications Paths:

The Producer will build the FO paths from the communication room at its generator facility to the point of interconnection with SCE. The Producer's OPGW or FO cable on its generator interconnection tie-line may serve as one path. If a diverse route is required, the Producer may elect to install FO cable in an underground conduit within the generator interconnection tie-line right-of-way to serve as the diverse route.

SCE shall design, operate, and maintain certain telecommunications terminal equipment at the generation facility or its associated Interconnection Facilities to support line protection, telemetering (SCADA), equipment protection, and SPS communications applicable to the project.

8.3 Space Requirements

The Producer shall provide sufficient floor space within a secure building at the generator facility site for SCE to install and operate up to two 8' x 19" wide communication equipment (EIA-310-D) racks. These racks shall contain telecommunication equipment to support SCADA, equipment protection, and SPS communications applicable to the project. SCE recommends separating the communications equipment into two racks when diverse protection and/or SPS circuits are required.

The Producer shall provide sufficient wall space adjacent to the SCE communication equipment rack(s) for a 36" x 36" x ¾" plywood backboard for leased or other related circuit termination. The plywood shall be clear of obstructions from adjacent equipment and painted with fire resistant gray semi-gloss enamel (Dunn-Edwards DE-1073, New Hope Gray or equivalent).

The Producer shall provide a working clearance of 49.5" (measured from the center of the rack) in front and behind the equipment rack(s) for the safety of installation and maintenance personnel. The working clearance specified provides a 36" unobstructed space for ladders and/or test equipment carts. Additionally, SCE considers telecommunications equipment racks to contain "live electrical equipment," which is consistent with the 36" working clearance specified in the National Electric Code.

SCE shall secure the equipment rack using the floor angles using only with ½"-13 stainless steel hardware. If the floor of the equipment room is concrete, Hilti HDI 1/2 "drop-in" anchors shall be used.

8.4 HVAC Requirements

The Producer shall provide and maintain suitable environmental controls in its generator facility equipment room, including an HVAC system to minimize dust, maintain a temperature of 30° C or less, and 5-95% non-condensing relative humidity.

The HVAC requirements for fiber optic terminal equipment are more stringent than what is required for RTU equipment. Therefore, whenever line protection or SPS specifies the use of fiber optic communications and its terminal equipment, the requirements of Section 7: Telemetering Requirements (Hardware) will match those in this Section 8.

NOTE: Environmental controls for microwave terminal equipment (when applicable) are generally more stringent than fiber optic terminal equipment.

8.5 Power And Grounding Requirements

Within its generator facility the Producer shall provide a connection point to station ground within ten (10) feet of the SCE communication equipment rack(s). SCE will provide and install cabling from the equipment rack(s) to the designated station ground termination to protect the communications equipment and service personnel.

The Producer shall provide two 10 Amp dedicated branch circuits from the 125 VDC station power to support the telecommunications equipment rack(s). The dedicated source breakers shall be labeled "SCE-Telecom A" and "SCE-Telecom B." If DC power is not available, two 15 amp 120 VAC circuits may be used as long as the circuits are sourced from an Uninterruptible Power System with a minimum of 4 hour backup. The power source shall not be shared with other equipment.

The Producer shall provide a 120 VAC 15 Amp convenience power source adjacent to the telecommunications equipment rack(s). As this source will be utilized for tools and test equipment by installation and maintenance personnel, UPS is not required. The Producer shall provide ample lighting for the safety of installation and maintenance personnel.

For RTU power and grounding requirements, refer to Section 7.

8.6 Telemetry and Leased T1 Line:

For projects requiring only a leased T1 circuit for RTU communications, the Producer shall:

a) Arrange with the local carrier to provide a T1 circuit from the generator facility to the nearest SCE service center or similar facility;

b) Provide conduit, raceway, copper cable, fiber optic cable as necessary for SCE to extend the leased circuit from the Local Exchange Carrier MPOE (Minimum Point of Entry or "demark") to the SCE communications equipment rack(s). The SCE equipment rack(s) shall be no more than 100' from the MPOE;

c) Incur the monthly cost of the leased T1; Provide conduit, raceway, copper cable, fiber optic cable to extend the RTU circuit from the communications equipment to the RTU or from a leased T1 communications circuit in the event the SCE RTU is not located within the same facility;

The SCE RTU and communications equipment rack(s) shall be no further apart than 100'.

8.7 Miscellaneous:

- While SCE may discuss telecommunication connection preferences for the Producer's generator facility, ultimately, SCE has final discretion regarding the selection of telecommunication connection equipment. The telecommunication connection must fit within the operating requirements, design parameters, and communications network architecture of the entire SCE telecommunications network.
- Because the use of microwave requires detailed engineering evaluation not performed within Interconnection Studies, the use of microwave as an option for the second diverse communications route to support protection of the interconnection will only be considered as part of final engineering and design.
- The use of other telecommunications such as satellite communication requires detailed engineering evaluation not performed within Interconnection Studies. As such, use of other telecommunications will only be considered as part of final engineering and design.

The Producer shall provide SCE employees and approved contractors unlimited access, 24 hours a day 7 days a week, to the communication equipment for maintenance and service restoration purposes.

Section 9 Property Requirements

9.1 Right of Way Requirements

The Producer must acquire the necessary Rights of Way requirements for their interconnection or transmission line, along with the Access requirements to the point of interconnection with SCE's facilities. The use of SCE Rights of Ways and/or property shall not be included in any interconnection proposals.

9.2 Transmission Line Crossing Policy

A "proposed "Interconnection Transmission line, or Rights of Way Access, crossing SCE Transmission line or Access easements or fee owned property must be submitted to SCE Real Properties organization for a separate review request and approval. For your reference, below are SCE's Transmission Crossing Policy guidelines:

- A new non-SCE owned transmission line of equal or lower voltage shall not be allowed the superior position and will cross under the existing SCE Facilities and/or the new facilities proposed prior to the new line, including facilities needed for queued-or-clustered--ahead generation.
- A new non-SCE owned transmission line, triggered by a generator facility, with higher voltage may be allowed the superior position than an SCE line if it adheres to G.O. 95[12] Grade "A" self-supporting Dead-end construction, and has a minimum of double insulator strings on both sides. SCE will regain the superior position if its lower voltage facilities are upgraded and are of equal or higher voltage than the non-SCE owned transmission line. Note: This will apply to all voltages.

[12] ***General Order No. 95. (G.O.* 95)** the "Rules for Overhead Line Construction" established by the California Public Utilities Commission is minimum requirements for designing and constructing overhead and underground electrical facilities. In some cases SCE Practices and Standards may be more stringent. The INTFAC must adhere to the appropriate requirements.

- A new non-SCE owned transmission line of higher voltage may be allowed the superior position if it crosses a multiple SCE circuit corridor (two circuits or more). However, this type of crossing needs to be reviewed, and approved by SCE, on a case-by-case basis.
- A new non-SCE owned transmission line, regardless of voltage, shall not be allowed the superior position if it crosses a circuit which terminates at a current or former nuclear power plant switchyard.

9.3 Infrastructure Property Requirements

Substation: The following approximate land requirements are needed for typical interconnection facilities (SCE owned substation) on the customer's property:

- 66kV Tap: 90 ft by 120 ft
- 66kV Loop: 150 ft by 120 ft
- 115kV Tap: 110 ft by 120 ft
- 115kV Loop: 170 ft by 200 ft

Minimum substation land requirements are subject to change according to engineering studies and interaction with SCE is required for final determination. The dimensions above include a required 10 ft. easement bordering the interconnection facility under the assumption that the customer owns the transformer and the land needed for the incoming line(s) is not included.

PART 2

Method Of Service/

End User Facility

Interconnection Requirements

Contents

Section 1 Method of Service / End User Facility Interconnection Overview

The Method of Service specifies what is necessary to interconnect a customer end user Facility to SCE's electric system, and provides these customers with an overview of the Requirements to address interconnection requests. It also provides a means to facilitate the communication of technical information to SCE regarding the end user Facilities interconnecting to SCE's electric system.

Section 2 Protection Requirements

Protective devices (relays, circuit breakers, synchronizing equipment, etc.) must be installed for the protection of SCE’s electric system as required by SCE. Generally, the protective devices may differ with the relative electrical capacity of the installation. The larger the installation, the greater the effect it may have on SCE’s electric system.

While some protection requirements can be standardized, the detailed protection design highly depends on the type and characteristics of the customer’s end user Facility (i.e., voltage, impedance, and ampacity), as well as the existing protection equipment and configuration of SCE’s surrounding electric system. Fault duty, existing relay schemes, stability requirements, and other considerations may impact the selection of protection systems. Consequently, identical end user Facilities connected at different locations in SCE’s electric system can have widely varying protection requirements and costs. The varying protection requirements will be used to define the corresponding Telecommunications requirements, **(See Section 7.)**

For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles. Project stability studies may indicate that faster clearing times are necessary. To ensure the reliability of the electric system, protective relays, and associated equipment require periodic replacement. Typically the frequency of transmission line relay replacement does not exceed once every fifteen (15) years, but equipment failure, availability of replacement parts, system changes, or other factors may alter the relay system replacement schedule.

2.1 Breaker Duty and Surge Protection

2.1.1 SCE Duty Analysis

The recognized standard for circuit breakers rated on a symmetrical current basis is IEEE Standard C37.010-1999(R2005), "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and ANSI/IEEE Standard C37.5 for circuit breakers rated on a total current basis. SCE will review breaker duty and surge protection to identify any additions required to maintain an acceptable level of SCE system availability, reliability, equipment insulation margins, and safety. Also, the management of increasing short-circuit duty of the transmission system involves selecting the alternative that provides the best balance between cost and capability. System arrangements must be designed so that the interrupting capability of available equipment is not exceeded.

When studies of planned future system arrangements indicate that the short-circuit duty will reach the capability of existing breakers, consideration should be given to the following factors:

a) Methods of limiting duty to the circuit breaker capability, or less:

   1. De-looping or rearranging transmission lines at substations;

   2. Split bus arrangements.

b) Magnitude of short circuit duty.

c) The effect of future projects on the duty.

d) Increasing the interrupting capability of equipment.

e) The ability of a particular breaker to interrupt short circuits considering applicable operating experience and prior test data.

Please note that SCE performs an annual short circuit duty analysis, which may include reevaluation of the facility breakers.

2.1.2 Customer Owned Duty/Surge Protection Equipment

In compliance with Good Utility Practice and, if applicable, the Requirements of SCE’s Interconnection Handbook, the owner shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of its end-user Facilities to any short circuit occurring on SCE’s electric system not otherwise isolated by SCE’s equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of SCE’s electric system. Such protective equipment shall include, but not limited to, a disconnecting device and a fault current-interrupting device located between the customer's end-user Facilities and the SCE electric system at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The owner shall be responsible for protection of the end-user Facilities and other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The owner shall be solely responsible to disconnect their facility if conditions on SCE's electric system are impacted by the customer's end-user Facilities.

Section 3 Miscellaneous Requirements:

3.1 Overhead & Underground Facilities Requirements

The customer shall ensure that its overhead facilities are constructed to a minimum of General Order 95 **Rules for** Overhead **Electric Line Construction** standards when facilities are built within California and to **National Electric Safety Code** standards when facilities are built outside of California. The customer shall ensure that its underground facilities are constructed to a minimum of General Order 128 **Rules for Construction of Underground Electric Supply and Communication Systems** when facilities are built within California and to National Electric Safety Code standards when facilities are built outside of California. Where facilities are intended to be owned by SCE, additional design requirements apply and must be consistent with SCE's design standards.

3.2 Automatic Voltage Regulators (AVR)

Automatic voltage control equipment on end user Facilities, synchronous condensers, and Flexible Alternating Current Transmission System (FACTS) shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the balancing authority operator which is the California Independent System Operator (CAISO).

3.3 Underfrequency Relays

Since the facilities of SCE's electric system may be vital to the secure operation of the Interconnection, the CAISO and SCE shall make every effort to remain connected to the Interconnection. However, if the system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect the system.

Intentional tripping of tie lines due to underfrequency is permitted at the discretion of SCE's electric system, providing that the separation frequency is no higher than 57.9 Hz with a one-second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

3.4 Insulation Coordination

Insulation coordination is the selection of insulation strength and practice of correlating insulation levels of equipment and circuits with the characteristics of surge-protective devices such that the insulation is protected from excessive overvoltages. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety.

The customer shall be responsible for an insulation coordination study to determine appropriate surge arrester class and rating on the end user Facilities equipment. In addition, the customer is responsible for the proper selection of substation equipment and their arrangements from an insulation coordination standpoint.

Basic Surge Level (BSLs), surge arrester, conductor spacing and gap application, substation and transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan.

3.5 Ratings

3.5.1 Facility Ratings

The ratings of facilities are the responsibility of the owner of those facilities. Ratings of facilities must conform to NERC Standard governing Facility Ratings.

3.5.2 Ratings Provided by Equipment Manufacturers

Equipment installed on SCE's electric system is rated according to the manufacturer's nameplate or certifications, and ANSI/IEEE standards. The manufacturer's nameplate rating is the normal rating of the equipment. ANSI/IEEE standards may allow for emergency overloads above the normal rating under specified conditions and often according to an engineering calculation. Emergency loading may impact the service life of the equipment. In some cases the manufacturer has certified equipment for operation at different normal or emergency loads based on site-specific operation conditions. Older technology equipment is rated according to the standards under which it was built unless the manufacturer, ANSI/IEEE standards, or SCE's determination indicates that a reduced rating is prudent or an increase rating is justified.

3.5.3 Rating Practice

The normal and emergency ratings of transmission lines or the transformation facilities shall equal the least rated component in the path of power flow.

3.5.4 Ambient Conditions

Since SCE's territory is in a year-round moderate climate, SCE does not establish equipment ratings based on seasonal temperatures. That is, SCE standard ratings for normal and emergency ratings are the same throughout the year and reflect summer ambient temperatures coincident with ANSI/IEEE standards, i.e., 40°C (104°F). However, in some cases SCE may calculate site-specific ratings that consider the local ambient conditions based on ANSI/IEEE rating methods.

3.5.5 Transmission Lines

The transmission circuit rating is determined according to the least rated component in the path of power flow. This comprises of the transmission line conductor, the series devices in the line, the allowable current that will not cause the conductors to sag below allowable clearance limits, and the termination equipment.

3.5.6 Conductors

The transmission line conductor ratings are calculated in accordance with ANSI/IEEE 738-1993. For Aluminum Conductor Steel Reinforced (ACSR) conductor the normal conductor rating allows a total temperature of 90°C and the emergency rating allows 135°C. Similarly, for aluminum and copper conductors SCE permits 85°C and 130°C. For Aluminum Conductor Steel Supported (ACSS), SCE base the normal rating at 120°C, and 200°C for the emergency rating. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification.

3.5.7 Series and Shunt Compensation Devices

Series capacitor and reactors are only permitted to be loaded to ANSI/IEEE limits or as specified by the manufacturer. VAR compensators shall be rated according to the ANSI/IEEE standards where applicable and according to the manufacturer's limitations. These ratings are reported to CAISO Transmission Register. Shunt capacitors and reactors are not in the path of power flow so they are not directly a "limiting component." However, their reactive power capacity is reported to CAISO Transmission Register.

3.5.8 Terminal Equipment

Terminal equipment comprises: circuit breakers, disconnect switches, jumpers, drops, conductors, buses, and wave-traps, i.e., all equipment in the path of power flow that might limit the capacity of the transmission line or transformer bank to which it is connected. The normal and emergency ampere rating for each termination device is reported to CAISO in its Transmission Register.

3.5.9 Transformer Bays

The rating of a transformer bay is determined by the least rated device in the path of power flow. This comprises ratings of the transformer, the transformer leads, the termination equipment, and reduced parallel capacity where applicable. The transformer rating is compared to the termination equipment ratings and lead conductors to establish the final transformation rating based on the least rated component. All of the above ratings are reported to the CAISO Transmission Register.

3.5.10 Transformer Normal Ratings

The “normal” rating is the transformer’s highest continuous nameplate rating with all of its cooling equipment operating. The only exception is when a special “load capability study” has been performed showing that a specific transformer is capable of higher than nameplate loading and for which the test data or calculations are available.

3.5.11 Transformer Emergency Ratings

A transformer’s emergency rating is arrived at by one of two methods. First, if no overload tests are available then a 10% overload is allowed. Second, if a factory heat-run or a load capability study has been performed, the emergency rating may be as high as 20% above normal as revealed by the test. For transformers on the transmission system, i.e., primary voltage of 500 kV, the allowed duration of the emergency loading is 24-hours. For transformers with primary voltage of 161 kV to 230 kV, the allowed duration is thirty days.

3.5.12 Parallel Operation of Transformers

When two or more transformers are operated in parallel, consideration is given to load split due to their relative impedances such that full parallel capacity is not usually realized. The permissible parallel loading is calculated according to ANSI/IEEE standards.

3.5.13 Relays Protective Devices

In cases where protection systems constitute a loading limit on a facility, this limit is the rating for that facility. These limiting factors are reported to the CAISO Transmission Register and are so noted as to the specific reason, e.g., “limited to 725A by relay setting.”

3.5.14 Path Ratings

As stated in Section 2 of the WECC Procedures for Project Rating Review, new facilities and facility modifications should not adversely impact accepted or existing ratings regardless of whether the facility is being rated. New or modified facilities can include transmission lines, end user Facilities, substations, series capacitor stations, remedial action schemes or any other facilities affecting the capacity or use of the interconnected electric system.

3.6 Synchronizing of Facilities

Testing and synchronizing of a customer's end user Facility may be required depending on SCE's electric system conditions, ownership or policy, and will be determined based on facility operating parameters. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect synchronization.

Appropriate operating procedures and equipment designs are needed to guard against out-of-sync closure or uncontrolled energization. (Note: SCE's transmission lines utilize ACB phase rotation, which is different than the national standard phase rotation). The owner of the end user Facilities is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of their facility.

Synchronizing locations shall be determined ahead of time; required procedures shall be in place and be coordinated with SCE. SCE and the owner of the end user Facility shall mutually agree and select the initial synchronization date. The initial synchronization date shall mean the date upon which a facility is initially synchronized to the SCE transmission system and upon which trial operation begins.

3.7 Maintenance Coordination and Inspection

The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of the customer's end user Facilities and associated equipment, including but not limited to control equipment, communication equipment, relaying equipment and other system facilities. Entities and coordinated groups of entities shall follow CAISO procedures and are responsible for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

3.8 Abnormal Frequency and Voltages

4.14.1 Joint Reliability Procedures

Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

3.8.1 Voltage and Reactive Flows

CAISO shall coordinate the control of voltage levels and reactive flows during normal and emergency conditions. All operating entities shall assist with the CAISO's coordination efforts.

3.8.2 Transfer Limits Under Outage and Abnormal System Conditions

In addition to establishing total transfer capability limits under normal system conditions, transmission providers and balancing authority shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

3.9 Communications and Procedures

3.9.1 Use of Communication System

It is essential to establish and maintain communications with the SCE Grid Control Center (GCC), the Alternate Grid Control Center (AGCC) or a jurisdictional Switching Center should a temporarily attended station or area of jurisdiction become involved in a case of system trouble. It is equally important that communication services be kept clear of nonessential use during times of system trouble to facilitate system restoration or other emergency operations.

3.9.2 Special Protection Schemes Communication Equipment Requirements

Customer end use Facilities will require the necessary communication equipment for the implementation of Remedial Action Schemes (RAS). This equipment provides line monitoring and high-speed communications between customer's breaker and the central control facility, utilizing applicable protocols. RASs may also be applied to end user Facilities that may be required to trip in order to relieve congestion on transmission facilities. Thus, allowing a RAS to incorporate disconnection into automatic control algorithms under contingency conditions, as needed.

RASs are fully redundant systems. The following paragraph is an excerpt from the WECC Remedial Action Scheme Design Guide that specifies the Philosophy and General Design Criteria for SPS redundancy.

> *"Redundancy is intended to allow removing one scheme following a failure or for maintenance while keeping full scheme capability in service with a separate scheme. Redundancy requirements cover all aspects of the scheme design including detection , arming, power, supplies, telecommunications facilities and equipment, logic controllers (when applicable), and RAS trip/close circuits."*

Excerpt from: WECC Remedial Action Scheme Design Guide (11/28/2006)

3.9.3 Critical System Voltage Operation

Voltage control during abnormal system configurations requires close attention with consideration given to what operations will be necessary following loss of the next component. Voltages approaching 10% above or below the normal value are considered critical with rate of change being of principal importance.

Section 4 General Operating Requirements:

a) **System Operating Bulletins:** An end user Facility connecting into SCE's electric system may be subject to operating requirements established by SCE, the CAISO or both. SCE's general operating Requirements are discussed in the sections below. SCE may also require additional operating Requirements specific to an end user Facility. If so, these Requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOBs and/or SSIs specific to the end user Facility and any subsequent revisions will be provided by SCE to the customer as they are made available.

b) **Responsibility for the Owner of an end user Facility:** The owner of an end user Facility is responsible for complying with all applicable operating requirements. Operating procedures are subject to change as system conditions and system needs change. Therefore, it is advisable for the customer to regularly monitor operating procedures that apply to its end user Facility. The CAISO publishes its operating procedures on its internet site, but it is prudent for the customer to contact the CAISO for specific Requirements.

c) **Quality of Service:** The interconnection of the customer's equipment with SCE's electric system shall not cause any reduction in the quality of service being provided to SCE's customers. If complaints result from operation of the customer's end use Facility, such equipment shall be disconnected until the problem is resolved.

d) **SCE Circuits:** Only SCE is permitted to energize any de-energized an SCE circuit.

e) **Operate Prudently:** The owner of an end user Facility will be required to operate its facility in accordance with prudent electrical practices.

f) **Protection in Service:** An end user Facility shall be operated with all of required protective apparatus in service whenever the end user Facility is connected to, or is operated in parallel with, the SCE electric system. Redundant protective devices may be provided at the customer's. Any deviation for brief periods of emergency may only be by agreement of SCE and is not to be interpreted as permission for subsequent incidents.

g) **Added Facilities Documentation:** The customer may not commence parallel operation of its end user Facility until final written approval has been given by SCE. As part of the approval process, the customer shall provide, prior to the commencement of parallel operation, all documents required by SCE to establish the value of any facilities installed by the customer and deeded to SCE for use as added facilities. SCE reserves the right to inspect the customer's end user Facility and witness testing of any equipment or devices associated with the interconnection.

4.1 VAR Correction

VAR correction will normally be planned for light load, heavy load and for system normal and contingency conditions. This is to be accomplished by providing transmission system VAR correction to minimize VAR flow and to maintain proper voltage levels. The planning of transmission system VAR requirements should consider the installation of shunt capacitors, shunt reactors and tertiary shunt reactors, synchronous condensers, FACTS and transformer tap changers. The guidelines for reactive planning are as follows:

4.1.1 Interconnection

Interconnection with other utilities will normally be designed with the capability of maintaining near-zero VAR exchange between systems. Entities interconnecting their electric system with SCE’s electric system shall endeavor to supply the reactive power required on their own system, except as otherwise mutually agreed. SCE shall not be obligated to supply or absorb reactive power for the customer’s end user Facility when it interferes with operation of the SCE electric system, limits the use of SCE interconnections, or requires the use of generating equipment that would not otherwise be required.

4.1.2 Subtransmission System

VAR correction will normally be planned for connection to 55 kV through 160 kV buses to correct for large customer VAR deficit, subtransmission line VAR deficit, and transformer A-Bank VAR losses, the objective being zero VAR flow at the high side of the A-Banks with VAR flow toward the transmission system on the high side of the A-Banks, if required. Adequate VAR correction shall be provided for maximum coincident customer loads (one-in-five year heat storm conditions), after adjusting for dependable local generation and loss of the largest local bypass generator.

4.2 Voltage Regulation/Reactive Power Supply Requirements

Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled and adequate reactive reserves shall be provided. If power factor correction equipment is necessary, it may be installed by the customer at its end use Facility, or by SCE at SCE's facilities at the customer's expense.

4.2.1 Facility Reactive Power Equipment Design

Customers shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

The reactive power equipment utilized by the interconnecting customer to meet SCE's Requirements must be designed to minimize the exposure of SCE's customers, SCE's electric system, and the electric facilities of others (i.e., other facilities and utilities in the vicinity) to:

a) severe overvoltages that could result from self-excitation of induction generators,

b) transients that result from switching of shunt capacitors,

c) voltage regulation problems associated with switching of inductive and capacitive devices.

d) unacceptable harmonics or voltage waveforms, which may include the effect of power electronic switching, and

e) Voltage flicker exceeding SCE Voltage Flicker limits as indicated in SCE Transmission Planning Criteria and Guidelines Figure 4-1 "VOLTAGE FLUCTUATION DESIGN LIMITS".

4.2.2 Facility Reactive Power Equipment Design - provide variable source

The reactive power equipment utilized by the interconnecting customer to meet SCE's Requirements must be designed to provide a variable source of reactive power (either continuously variable or switched in discrete steps). For discrete step changes, the size of any discrete step change in reactive output shall be limited by the following criteria:

a) the maximum allowable voltage rise or drop (measured at the point of interconnection with SCE's electric system) associated with a step change in the output of the customer's reactive power equipment must be less than or equal to 1%; and

b) the maximum allowable deviation from the customer's reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the customer's maximum (boost) reactive capability.

4.2.3 Voltage and Reactive Control

4.2.3.1 Coordination

Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

4.2.3.2 Transmission Lines

Although transmission lines should be kept in service as much as possible, during over-voltage system conditions a customer's transmission line(s) may be subject to removal from operation as a means to mitigate voltage problems in the local area. SCE will notify CAISO when removing such facilities from and returning them back to service.

4.2.3.3 Switchable Devices

Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

4.3 Voltage Imbalance and Abnormal Voltage or Current Waveforms (harmonics)

Power quality problems are caused when voltage imbalances and harmonic currents result in abnormal voltage and/or current waveforms. Generally, if an end user Facility degrades power quality to other SCE customer facilities or SCE's own facilities, SCE may require the owner of that end user Facility to install equipment to eliminate the power quality problem.

4.3.1 Voltage Imbalance

The unbalanced voltage level (magnitude and phase), due to a customer's end use Facility connected to SCE at the transmission or subtransmission system level, may not exceed 1% at the Point of Common Connection[1] (PCC), under steady state system conditions. Under certain conditions (contingency conditions), SCE may allow higher levels of voltage imbalance if justified after a study conducted by SCE. In any event, the unbalanced voltage level created by a customer's end use Facility shall not exceed 1.5%.

It is the responsibility of the owner of an end use Facility, connected to SCE's electric system, to install the adequate mitigation devices to protect their own equipment from damage that maybe caused by voltage imbalance condition.

4.3.2 Harmonics

Customers interconnecting to SCE's electric system are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment in accordance to good engineering practice used at their facility to comply with the limits set by the current IEEE Standards.

4.3.3 Disconnection

SCE may disconnect any Facility connected to its system until the above Requirements are met.

4.3.4 Photovoltaic Inverter Systems

Photovoltaic inverter systems which conform to the recommended practices in IEEE Standard 929-1999 and which have been tested and approved for conformance to UL Subject 1741 are considered to have met SCE's Requirements for voltage imbalance and abnormal waveforms.

[1] The PCC will generally be at the location of the revenue meter or the point of ownership change in the electrical system between SCE and the Producer. For customers served by dedicated facilities, the location of the PCC will be determined by mutual agreement between the Producer and SCE.

4.4 Grounding Circuits and Substations

A customer interconnecting its end user Facility to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous voltage potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying equipment to be handled by personnel.

Reason for Substation Grounding

Substation grounding practices are outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding."

According to IEEE 80 – 2000 a safe ground grid design has the following two objectives:

- "To provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service." (IEEE 80 – 2000)
- "To ensure that a person in the vicinity of grounded facilities is not exposed to the danger of critical electric shock." (IEEE 80 – 2000)

"People often assumed that any grounded object can be safely touched. A low substation ground resistance is not, in itself, a guarantee of safety. There is no simple relation between the resistance of the ground system as a whole and the maximum shock current to which a person might be exposed. Therefore, a substation of relatively low ground resistance may be dangerous, while another substation with very high resistance may be safe or can be made safe with careful design." (IEEE 80 – 2000)

Each substation ground grid is a unique design. The conditions at the site: soil type, soil resistivity, fault current, clearing time, size of the substation, and other grounds all factor into the design.

4.4.1 Nominal Voltage and Grounding

SCE's most common primary distribution voltages are 4, 12 and 16 kV depending on the geographic area. Other voltages are also used in specific areas. Subtransmission voltages are nominally 66 kV to 115 kV. Transmission system voltages are nominally 161 kV, 220 kV, and 500 kV. The majority of the 4, 12, and 16 kV circuits are effectively grounded, but some are operated with high impedance grounding. A substantial number of the effectively grounded circuits are used for four-wire distribution (phase to neutral connected loads). SCE will provide the customer necessary information on the specific circuit serving its end user Facility for proper grounding.

4.4.2 Grounding Grid Studies shall be conducted in the following situations:

Grounding calculations will be required for each new substation, and at existing substations, when the ground grid is altered or when major additions are made at a substation. A review of existing substation ground grids will be conducted by Engineering in the following situations, especially if triggered by interconnection requests – these shall be considered in queue order:

- Short Circuit Duty Changes
    1. Circuit breaker replacement for short-circuit duty reasons
    2. Addition of transmission or subtransmission line to a substation
    3. System changes causing a substantial change in the substation phase-to-ground short-circuit duty
    4. Addition or replacement of a transformer at a substation
    5. Addition of new generation causing a substantial change in the substation phase-to-ground short-circuit duty
- System Protection Changes
    1. Changes in system protection that significantly increases the clearing time for ground faults.
- Grounding Source Changes
    1. Grounding of ungrounded wye winding of a transformer
    2. Addition or major change of ground source at a substation
- Substation Changes
    1. Alterations to substation fences including additions, movement, and attachments to other fences. The removal of vegetation that blocks access to a substation fence is considered a fence alteration.
    2. Alterations to substation ground grids that change their size or increase the effective substation ground grid impedance.
    3. Sale or lease of substation property for other uses.
- A grounding review should be conducted any time a grounding problem is reasonably suspected.

4.4.3 Ground Mats

If the customer's end user Facility and SCE substation ground mats are tied together, all cables may be landed without any protection. If the customer's end user Facility and SCE substation ground mats are not tied together, all cables shall have protection at both ends. The design of cable protection, if any, on circuits used for protective relaying purposes shall be such that the operation of the protective relaying is not hampered when the cable protection operates or fails.

All ground mats shall be designed in accordance with good engineering practice and judgment. Presently, the recognized standard for grounding is IEEE 80 "IEEE Guide For Safety in AC Substation Grounding." All ground mat designs should meet or exceed the requirements listed in this standard. If local governmental requirements are more stringent, building codes for example, they shall prevail. All customers shall perform appropriate tests, including soil resistivity tests, to demonstrate that their ground grid design meets the standard. Mats shall be tested at regular intervals to ensure their effectiveness.

Grounding studies shall be performed with industry-recognized software to determine if customer and SCE ground grids should be separate or tied together. This study will determine the maximum safe fault current for the ground grid design. It is suggested that the grid be designed for the maximum fault currents expected over the life of the facility.

If for any reason the worst-case fault current exceeds the design maximum fault current value due to changes in the customer's end user Facility or changes on the SCE system, the customer shall conduct new grounding studies. Any changes required to meet safety limits and protect equipment shall be borne by the customer.

The customer is responsible to ensure that the GPR (Ground Potential Rise) of its or interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the customer. If it is elected to install separate ground grids for SCE and the customer, the facility shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the customer's end user Facility.

Any ground grid design, which results in a GPR that exceeds 3,000 volts RMS for the worst-case fault or has a calculated or measured ground grid resistance in excess of 1 ohm, will require special approval by SCE.

4.4.4 Substation Grounding

A customer connecting and end user Facility to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying parts to be handled by personnel.

4.5 Non-SCE Pole Grounding

A customer connecting its end user Facility to SCE's system shall follow SCE Construction, Operation, and Maintenance requirements. The last customer-owned structure shall be designed and constructed to meet SCE grounding requirements.

Customer facilities that will require SCE's crews to climb in order to construction, operate, or maintain SCE facilities shall be constructed so as to meet SCE standards and specifications. Constructing to SCE specifications will ensure that SCE crews can safely perform and complete the jobs at hand in accordance with SCE's Accident Prevention Manual that stipulate the proper training and equipment to safely climb and work. Examples of safety related requirements that:

- Climbing Steps
- Belt-Off Locations
- Grounding Locations
- Required PPE
- Jumper Cable Ownership

Grounding bolts and bases are the same as step bolts and bases. If there is the potential need to have SCE personnel work on non-SCE owned poles connecting the customer's end user Facility directly to SCE's electric system a dead-end structure adhering to SCE's Construction, Operation, and Maintenance standards, is required..

Please note that these requirements are for poles only. Non-steel or ungrounded poles will have; project-specific grounding requirements as determined by SCE.

Section 5 Revenue Metering Requirements

5.1 General Information

Revenue metering is required to measure the energy and capacity delivered and consumed by a customer. While functionally similar, there are varying Requirements for customers depending on the nature and purpose of their end user Facility along with varying rules established by the authorities having jurisdiction over both SCE and the customer. Metering Requirements for customers taking service under a FERC tariff, and retail service under CPUC regulations are set forth in Section 6.2.

In general, all CAISO revenue metering and associated equipment used to measure load shall be provided, owned, and maintained at the customer's expense.

5.1.1 Retail Service

The retail metering requirements for retail service will be owned, operated, and maintained by SCE under SCE's Electrical Service Requirements (ESR) and in accordance with SCE approved tariffs.

Section 6 Telemetering Requirements (Hardware)

6.1 Telemetering Requirements

For a high degree of service reliability under normal and emergency operation, it is essential that the customer's end user Facility have adequate and reliable telecommunication facilities.

The customer shall specify the following at the point of connection: the requested voltage level, MW/MVAR capacity, and/or demand.

6.2 Exemption for Cold-Iron and Emergency-Backup Generators

Note: These types of generators are not operated in parallel to SCE's electric system except for short times *(typically only several* minutes*)* while performing a "soft-transfer" of customer load between the generator and SCE's electric system. As such, the telemetry requirements of this section **do not apply** to Cold-Iron or Emergency-Backup generators.

6.2.1 Cold-Ironing is the action of providing shore-side electrical power to a ship at berth while its on-board generator(s) are shut down.

a) Cold-Iron generator is a generator on board a ship which has the capability of Cold-Ironing.

b) The initial process of Cold-Ironing involves paralleling the ship's electrical system to SCE's electric system for a short duration while the ship's electrical load is transferred between the ship's generator and shore power. A Cold-Iron generator does not parallel to SCE's electric system beyond the initial transferring process.

6.2.2 Emergency-Backup Generation (EBG) is customer-owned generation utilized when disruption of utility power has occurred or is imminent.

a) When utilized, **following** a disruption, the customer would first disconnect from SCE's electric system prior to starting up the EBG.

b) When utilized **prior to** a disruption of utility power, the EBG would be started and loaded to carry the entire customer load, and then the customer would disconnect from SCE's electric system.

c) Upon resumption of utility power, the customer would first connect to SCE's electric system and then unload the EBG.

Section 7 Telecommunications Requirements

7.1 General Description

The following Requirements are for typical Telecommunications equipment installation at a customer's end user Facility connecting to SCE's system. Specific design and installation details are addressed during final engineering for each specific Point of Interconnection.

The telecommunications facilities to support line protection at a customer's end user Facility connecting to SCE's system depend on its specific protection needs and the existing telecommunications infrastructure in the area. Fiber optic (FO) communications matched with protective relays are used on transmission power lines for fast clearing. For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles.

As noted in Section 3, the selection of protection devices is dependent on the characteristics (i.e., voltage, impedance, and ampacity) of customer's end user Facility and the surrounding area. Identical customer end user Facilities connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs.

In cases where a second FO telecommunication is required, for protection relay coordination or to support a SPS, the second FO path must comply with WECC guidelines governing diverse routing. The customer will construct the communications path(s) between its end user Facility and the point of interconnection. Primary path can be provided with a FO cable at the end user Facility or as OPGW (fiber Optical Ground Wire). Diverse routing will be required for secondary path. Telemetering data (SCADA) and line protection control signals will be transported on these paths.

If FO is not required for line protection or RAS, a leased T1 circuit may be used for telemetering (SCADA). See Section 8.6.

7.2 Fiber Optic Communications Paths:

The customer will build the FO paths from the communication room at its end user Facility to the point of interconnection with SCE. The customer's OPGW or FO may serve as one path. If a diverse route is required, the customer may elect to install FO cable in an underground conduit to serve as the diverse route.

SCE shall design, operate, and maintain certain telecommunications terminal equipment at the point of interconnection to support line protection, telemetering (SCADA), equipment protection, and SPS communications applicable to the project.

7.3 Space Requirements

The customer shall provide sufficient floor space within a secure building for SCE to install and operate up to two 8’ x 19” wide communication equipment (EIA-310-D) racks. These racks shall contain telecommunication equipment to support SCADA, equipment protection, and SPS communications applicable to the project. SCE recommends separating the communications equipment into two racks when diverse protection and/or SPS circuits are required.

The customer shall provide sufficient wall space adjacent to the SCE communication equipment rack(s) for a 36” x 36” x ¾” plywood backboard for leased or other related circuit termination. The plywood shall be clear of obstructions from adjacent equipment and painted with fire resistant gray semi-gloss enamel (Dunn-Edwards DE-1073, New Hope Gray or equivalent).

The customer shall provide a working clearance of 49.5" (measured from the center of the rack) in front and behind the equipment rack(s) for the safety of installation and maintenance personnel. The working clearance specified provides a 36” unobstructed space for ladders and/or test equipment carts. Additionally, SCE considers telecommunications equipment racks to contain “live electrical equipment,” which is consistent with the 36” working clearance specified in the National Electric Code.

SCE shall secure the equipment rack using the floor angles using only with ½”-13 stainless steel hardware. If the floor of the equipment room is concrete, Hilti HDI 1/2 “drop-in” anchors shall be used.

7.4 HVAC Requirements

The customer shall provide and maintain suitable environmental controls in the equipment room, including an HVAC system to minimize dust, maintain a temperature of 30° C or less, and 5-95% non-condensing relative humidity.

The HVAC requirements for fiber optic terminal equipment are more stringent than what is required for RTU equipment. Therefore, whenever line protection or SPS specifies the use of fiber optic communications and its terminal equipment, the requirements of Section 7: Telemetering Requirements (Hardware) will match those in this Section 8.

NOTE: Environmental controls for microwave terminal equipment (when applicable) are generally more stringent than fiber optic terminal equipment.

7.5 Power And Grounding Requirements

The customer shall provide a connection point to station ground within ten (10) feet of the SCE communication equipment rack(s). SCE will provide and install cabling from the equipment rack(s) to the designated station ground termination to protect the communications equipment and service personnel.

The customer shall provide two 10 Amp dedicated branch circuits from the 125 VDC station power to support the telecommunications equipment rack(s). The dedicated source breakers shall be labeled "SCE-Telecom A" and "SCE-Telecom B." If DC power is not available, two 15 amp 120 VAC circuits may be used as long as the circuits are sourced from an Uninterruptible Power System with a minimum of 4 hour backup. The power source shall not be shared with other equipment.

The customer shall provide a 120 VAC 15 Amp convenience power source adjacent to the telecommunications equipment rack(s). As this source will be utilized for tools and test equipment by installation and maintenance personnel, UPS is not required. The customer shall provide ample lighting for the safety of installation and maintenance personnel.

For RTU power and grounding requirements, refer to Section 7.

7.6 Telemetry and Leased T1 Line:

For projects requiring only a leased T1 circuit for RTU communications, the customer shall:

a) Arrange with the local carrier to provide a T1 circuit from the customer's end user Facility to the nearest SCE service center or similar facility;

b) Provide conduit, raceway, copper cable, fiber optic cable as necessary for SCE to extend the leased circuit from the Local Exchange Carrier MPOE (Minimum Point of Entry or "demark") to the SCE communications equipment rack(s). The SCE equipment rack(s) shall be no more than 100' from the MPOE;

c) Incur the monthly cost of the leased T1; Provide conduit, raceway, copper cable, fiber optic cable to extend the RTU circuit from the communications equipment to the RTU or from a leased T1 communications circuit in the event the SCE RTU is not located within the same facility;

The SCE RTU and communications equipment rack(s) shall be no further apart than 100'.

7.7 Miscellaneous:

- While SCE may discuss telecommunication connection preferences of the customer's end user Facility, ultimately, SCE has final discretion regarding the selection of telecommunication connection equipment. The telecommunication connection must fit within the operating requirements, design parameters, and communications network architecture of the entire SCE telecommunications network.
- Because the use of microwave requires detailed engineering evaluation not performed within Interconnection Studies, the use of microwave as an option for the second diverse communications route to support protection of the customer's end user Facility will only be considered as part of final engineering and design.
- The use of other telecommunications such as satellite communication requires detailed engineering evaluation not performed within Interconnection Studies. As such, use of other telecommunications will only be considered as part of final engineering and design.

After the communication equipment is installed and in operation, the customer shall provide 24 hours a day, 7 days a week accesses to SCE employees and approved contractors for planned maintenance and service restoration.

Section 8 Property Requirements

The customer must acquire the necessary Rights of Way requirements for their end use Facility along with the Access requirements to the point of interconnection with SCE's facilities. The use of SCE Rights of Ways and/or property shall not be included in any interconnection proposals.

8.1 Transmission Line Crossing Policy

The Interconnection Transmission line or Access Rights of Way that are proposed to cross SCE Transmission line or Access easements or fee owned property must be submitted to SCE Real Properties organization for a separate review request and approval. For your reference, below are SCE's Transmission Crossing Policy guidelines:

- A new customer transmission line of equal or lower voltage shall not be allowed the superior position and will cross under the existing SCE Facilities and/or the new facilities proposed prior to the new line.
- A new customer transmission line, triggered by a customer's end user Facility, with higher voltage may be allowed the superior position with G.O. 95[2] Grade "A" self-supporting Dead-end construction with minimum of double insulator strings on both sides. This will apply to all voltages. SCE will regain the superior position should SCE lower voltage facilities be upgraded in the future of equal or higher voltage than the customer's end user facilities.
- A new customer transmission line of higher voltage may be allowed the superior position if it is crossing a SCE multiple circuits corridor (two circuits or more), but this type of crossing will need to be reviewed on a case-by-case basis.
- A new customer transmission line, regardless of voltage, shall not be allowed the superior position if it is crossing a circuit which terminates at the switchyard for a nuclear power plant.

[2] ***General Order No. 95. (G.O.*** **95)** the "Rules for Overhead Line Construction" established by the California Public Utilities Commission is minimum requirements for designing and constructing overhead and underground electrical facilities. In some cases SCE Practices and Standards may be more stringent. The interconnecting customer must adhere to the appropriate requirements.

8.2 Infrastructure Property Requirements

Substation: The following approximate land requirements are needed for typical interconnection facilities (SCE owned substation) on the customer's property:

- 66kV Tap: 90 ft by 120 ft
- 66kV Loop: 150 ft by 120 ft
- 115kV Tap: 110 ft by 120 ft
- 115kV Loop: 170 ft by 200 ft

Minimum substation land requirements are subject to change according to engineering studies and interaction with SCE is required for final determination. The dimensions above include a required 10 ft. easement bordering the interconnection facility under the assumption that the customer owns the transformer and the land needed for the incoming line(s) is not included.

PART 3

Transmission Interconnection Requirements

Contents

Section 1 Transmission Interconnection Overview

The Transmission Interconnection Section specifies what is necessary to interconnect non-SCE owned Transmission Facilities to SCE's electric system, and provides these customers with an overview of the Requirements to address interconnection requests. It also provides a means to facilitate the communication of technical information to SCE regarding the generation facilities interconnecting to SCE's electric system.

Section 2 Protection Requirements

Protective devices (relays, circuit breakers, synchronizing equipment, etc.) must be installed for the protection of SCE’s electric system as required by SCE. Generally, the protective devices may differ with the relative electrical capacity of the installation. The larger the installation, the greater the effect it may have on SCE’s electric system.

While some protection requirements can be standardized, the detailed protection design highly depends on the type and characteristics of the interconnecting Transmission Facilities, (i.e., voltage, impedance, and ampacity), and the existing protection equipment and configuration of SCE’s electric system in the vicinity of the point of interconnection. Fault duty, existing relay schemes, stability requirements, and other considerations may impact the selection of protection systems. Consequently, identical transmission interconnection customers connected at different locations in SCE’s electric system can have widely varying protection requirements and costs. The varying protection requirements will be used to define the corresponding Telecommunications requirements, (See Section 6.)

For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles. Project stability studies may indicate that faster clearing times are necessary. To ensure the reliability of the electric system, protective relays, and associated equipment require periodic replacement. Typically the frequency of transmission line relay replacement does not exceed once every fifteen (15) years, but equipment failure, availability of replacement parts, system changes, or other factors may alter the relay system replacement schedule.

Protection Categories: SCE classifies Transmission Facilities connecting to SCE electric system into three distinct categories each having their own distinctive protection requirements.

The categories are:

1. Interconnection voltage 66 and 115 kV
2. Interconnection voltage 220 kV

Interconnection voltage 500 kV Protection requirements of these categories are described in Sections 2.1 to 2.3.

Disclaimer: These Protection Categories were established for convenience, and are based on urban/suburban circuits with normal load density. The final decision as to the specific requirements for each installation will be made by SCE.

The following is a legend of device numbers referred to in Sections 2.1 through 2.3:

Legend

Protective Device Numbers and Description

4	Master Contactor
21	Distance/Impedance
25	Synchronizing or Synchronism Check
27	Under-voltage
32	Power Direction
40	Loss of Field Detection
46	Current Balance
47	Voltage Phase Sequence
50	Breaker Failure
51	Time Over-current
51G	Ground Time Over-current
51N	Neutral Time Over-current
51V	Voltage Restrained/Controlled Time Over-current
59	Over-voltage
59G	Over-voltage Type Ground Detector
67V	Voltage Restrained/Controlled Directional Time Over-current
78	Loss of Synchronism (Out-of-Step)
79	Reclosing Relay
810	Over-frequency
81U	Under-frequency
87	Current Differential

NOTE: For additional information on device numbers, refer to ANSI C37.2.

2.1 Category 1: Voltage 66 and 115 kV

2-terminal radial line: Non pilot

Source substation (SCE):

(1) Main relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example D60

(1) Duplicate relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311C

Interconnection substation: (looking towards the line)

(1) Main relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example D60

(1) Duplicate relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311C

3-terminal or loop service: one pilot and one backup

Source substation (SCE):

(1) Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1) Backup relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example D60

(1) Fiber interface and digital communication path

Interconnection substation: (looking towards the line)

(1)Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1)Duplicate relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311C

(1) Fiber interface digital communication path

2.2 Category 2: Voltage 220 kV

Long line (>2 miles) – One pilot and one backup

Source substation (SCE):

(1)Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1)Backup relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example D60

(1) Fiber interface and digital communication path

Interconnection substation: (looking towards the line)

(1)Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1)Duplicate relay that provides Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311C

(1) Fiber interface digital communication path

Short line (< 2 miles) – dual pilot

Source substation (SCE):

(1)Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1)Duplicate relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90

(2) Fiber interface and two redundant and diverse digital communication path

Interconnection substation: (looking towards the line)

(1)Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1)Duplicate relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90

(2) Fiber interface and two redundant and diverse digital communication path

2.3 Category 3: Voltage 500 kV

Source substation (SCE):

(2) Communication based high-speed relays that provides high-speed protection (87L or POTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90, D60, SEL-411L

(1) Communication based high speed relay that provides Permissive Overeaching Transfer Trip Scheme (POTT) and Direct Transfer Trip (DTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-421

(2) Direct Transfer Trip Relays. Example RFL-9745's

(2) Fiber interface and two redundant and diverse digital communication path.

Interconnection substation: (looking towards the line)

(2) Communication based high-speed relays that provides high-speed protection (87L or POTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90, D60, SEL-411L

(1) Communication based high speed relay that provides Permissive Overeaching Transfer Trip Scheme (POTT) and Direct Transfer Trip (DTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-421

(2) Direct Transfer Trip Relays. Example RFL-9745's

(2) Fiber interface and two redundant and diverse digital communication path.

2.4 Breaker Duty and Surge Protection

2.4.1 SCE Duty Analysis

The recognized standard for circuit breakers rated on a symmetrical current basis is IEEE Standard C37.010-1999(R2005), "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and ANSI/IEEE Standard C37.5 for circuit breakers rated on a total current basis. SCE will review breaker duty and surge protection to identify any additions required to maintain an acceptable level of SCE system availability, reliability, equipment insulation margins, and safety. Also, the management of increasing short-circuit duty of the transmission system involves selecting the alternative that provides the best balance between cost and capability. System arrangements must be designed so that the interrupting capability of available equipment is not exceeded.

When studies of planned future system arrangements indicate that the short-circuit duty will reach the capability of existing breakers, consideration should be given to the following factors:

Methods of limiting duty to the circuit breaker capability, or less:

1. De-looping or rearranging transmission lines at substations;
2. Split bus arrangements.

a) Magnitude of short circuit duty.

b) The effect of future projects on the duty.

c) Increasing the interrupting capability of equipment.

d) The ability of a particular breaker to interrupt short circuits considering applicable operating experience and prior test data.

Please note that SCE performs an annual short circuit duty analysis, which may include reevaluation of the facility breakers.

2.4.2 Customer Owned Duty/Surge Protection Equipment

In compliance with Good Utility Practice and, if applicable, the Requirements within the Handbook, the owner of the Transmission Facilities being interconnected shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution those facilities may have related to any short circuit occurring on SCE's electric system, not otherwise isolated by SCE's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of SCE's electric system. Such protective equipment shall include, but not limited to, a disconnecting device and a fault current-interrupting device located between the customer's Transmission Facilities and SCE electric system at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The owner of the Transmission Facilities shall be responsible for protection of their equipment and other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The interconnecting Transmission Facilities owner shall be solely responsible to disconnect their facility if conditions on SCE's electric system are impacted by them.

Section 3 Miscellaneous Requirements:

3.1 Transmission Facilities Requirements

The customer shall ensure that its transmission facilities are constructed to a minimum of General Order 95 **Rules for Overhead Electric Line Construction** standards when facilities are built within California and to **National Electric Safety Code** standards when facilities are built outside of California. The customer shall ensure that its underground transmission facilities are constructed to a minimum of General Order 128 **Rules for Construction of Underground Electric Supply and Communication Systems** when facilities are built within California and to National Electric Safety Code standards when facilities are built outside of California. Where facilities are intended to be owned by SCE, additional design requirements apply and must be consistent with SCE's design standards

3.2 Sub-Synchronous Resonance Studies

Customer owned transmission lines that have a series capacitor attached to the line and wish to interconnect to SCE, must demonstrate to SCE that SSR studies have been performed on their line.

3.3 Sub-Synchronous Control Interaction Studies

Customer owned transmission lines that have a series capacitor attached to the line and wish to interconnect to SCE, must demonstrate to SCE that SSR studies have been performed on their line.

3.4 Automatic Voltage Regulators (AVR)

Automatic voltage control equipment, synchronous condensers, and Flexible Alternating Current Transmission System (FACTS) shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the California Independent System Operator (CAISO).

3.5 Underfrequency Relays

Since the facilities of SCE's electric system may be vital to the secure operation of the Interconnection, CAISO and SCE shall make every effort to remain connected to the Interconnection. However, if the system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect the system.

Intentional tripping of tie lines due to underfrequency is permitted at the discretion of SCE's electric system, providing that the separation frequency is no higher than 57.9 Hz with a one-second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

3.6 Insulation Coordination

Insulation coordination is the selection of insulation strength and practice of correlating insulation levels of equipment and circuits with the characteristics of surge-protective devices such that the insulation is protected from excessive overvoltages. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety.

The customer shall be responsible for an insulation coordination study to determine appropriate surge arrester class and rating on their Transmission Facilities interconnecting into SCE's system. In addition, the customer is responsible for the proper selection of substation equipment and their arrangements from an insulation coordination standpoint.

Basic Surge Level (BSLs), surge arrester, conductor spacing and gap application, substation and transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan.

3.7 Ratings

3.7.1 Facility Ratings

The ratings of facilities are the responsibility of the owner of those facilities. Ratings of facilities must conform to the current NERC Reliability Standard governing Facility Ratings.

3.7.2 Ratings Provided by Equipment Manufacturers

Equipment installed on SCE's electric system is rated according to the manufacturer's nameplate or certifications, and ANSI/IEEE standards. The manufacturer's nameplate rating is the normal rating of the equipment. ANSI/IEEE standards may allow for emergency overloads above the normal rating under specified conditions and often according to an engineering calculation. Emergency loading may impact the service life of the equipment. In some cases the manufacturer has certified equipment for operation at different normal or emergency loads based on site-specific operation conditions. Older technology equipment is rated according to the standards under which it was built unless the manufacturer, ANSI/IEEE standards, or SCE's determination indicates that a reduced rating is prudent or an increase rating is justified.

3.7.3 Rating Practice

The normal and emergency ratings of transmission lines or the transformation facilities shall equal the least rated component in the path of power flow.

3.7.4 Ambient Conditions

Since SCE's territory is in a year-round moderate climate, SCE does not establish equipment ratings based on seasonal temperatures. That is, SCE standard ratings for normal and emergency ratings are the same throughout the year and reflect summer ambient temperatures coincident with ANSI/IEEE standards, i.e., 40°C (104°F). However, in some cases SCE may calculate site-specific ratings that consider the local ambient conditions based on ANSI/IEEE rating methods.

3.7.5 Transmission Lines

The transmission circuit rating is determined according to the least rated component in the path of power flow. This comprises of the transmission line conductor, the series devices in the line, the allowable current that will not cause the conductors to sag below allowable clearance limits, and the termination equipment.

3.7.6 Conductors

The transmission line conductor ratings are calculated in accordance with ANSI/IEEE 738-1993. For Aluminum Conductor Steel Reinforced (ACSR) conductor the normal conductor rating allows a total temperature of 90°C and the emergency rating allows 135°C. Similarly, for aluminum and copper conductors SCE permits 85°C and 130°C. For Aluminum Conductor Steel Supported (ACSS), SCE base the normal rating at 120°C, and 200°C for the emergency rating. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification.

3.7.7 Series and Shunt Compensation Devices

Series capacitor and reactors are only permitted to be loaded to ANSI/IEEE limits or as specified by the manufacturer. VAR compensators shall be rated according to the ANSI/IEEE standards where applicable and according to the manufacturer’s limitations. These ratings are reported to CAISO Transmission Register. Shunt capacitors and reactors are not in the path of power flow so they are not directly a “limiting component.” However, their reactive power capacity is reported to CAISO Transmission Register.

3.7.8 Terminal Equipment

Terminal equipment comprises: circuit breakers, disconnect switches, jumpers, drops, conductors, buses, and wave-traps, i.e., all equipment in the path of power flow that might limit the capacity of the transmission line or transformer bank to which it is connected. The normal and emergency ampere rating for each termination device is reported to CAISO in its Transmission Register.

3.7.9 Transformer Bays

The rating of a transformer bay is determined by the least rated device in the path of power flow. This comprises ratings of the transformer, the transformer leads, the termination equipment, and reduced parallel capacity where applicable. The transformer rating is compared to the termination equipment ratings and lead conductors to establish the final transformation rating based on the least rated component. All of the above ratings are reported to the CAISO Transmission Register.

3.7.10 Transformer Normal Ratings

The “normal” rating is the transformer’s highest continuous nameplate rating with all of its cooling equipment operating. The only exception is when a special “load capability study” has been performed showing that a specific transformer is capable of higher than nameplate loading and for which the test data or calculations are available.

3.7.11 Transformer Emergency Ratings

A transformer's emergency rating is arrived at by one of two methods. First, if no overload tests are available then a 10% overload is allowed. Second, if a factory heat-run or a load capability study has been performed, the emergency rating may be as high as 20% above normal as revealed by the test. For transformers on the transmission system, i.e., primary voltage of 500 kV, the allowed duration of the emergency loading is 24-hours. For transformers with primary voltage of 161 kV to 230 kV, the allowed duration is thirty days.

3.7.12 Parallel Operation of Transformers

When two or more transformers are operated in parallel, consideration is given to load split due to their relative impedances such that full parallel capacity is not usually realized. The permissible parallel loading is calculated according to ANSI/IEEE standards.

3.7.13 Relays Protective Devices

In cases where protection systems constitute a loading limit on a facility, this limit is the rating for that facility. These limiting factors are reported to the CAISO Transmission Register and are so noted as to the specific reason, e.g., "limited to 725A by relay setting."

3.7.14 Path Ratings

As stated in Section 2 of the WECC Procedures for Project Rating Review, new facilities and facility modifications should not adversely impact accepted or existing ratings regardless of whether the facility is being rated. New or modified facilities can include transmission lines, generating plants, substations, series capacitor stations, remedial action schemes or any other facilities affecting the capacity or use of the interconnected electric system.

3.8 Synchronizing of Facilities

Testing and synchronizing of a customer's Transmission Facilities may be required depending on SCE's electric system conditions, ownership or policy, and will be determined based on facility operating parameters. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect synchronization.

Appropriate operating procedures and equipment designs are needed to guard against out-of-sync closure or uncontrolled energization. (Note: SCE's transmission lines utilize ACB phase rotation, which is different than the national standard phase rotation). The owner of the Transmission Facilities is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of the facility.

Synchronizing locations shall be determined ahead of time; required procedures shall be in place and be coordinated with SCE. SCE and the owner of the Transmission Facilities shall mutually agree and select the initial synchronization date. The initial synchronization date shall mean the date upon which a facility is initially synchronized to SCE's electric system and upon which trial operation begins.

3.9 Maintenance Coordination and Inspection

The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of the customer's Transmission Facilities and associated equipment, including but not limited to control equipment, communication equipment, relaying equipment and other system facilities. Entities and coordinated groups of entities shall follow CAISO procedures and are responsible for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

3.10 Abnormal Frequency and Voltages

3.10.1 Joint Reliability Procedures

Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

3.10.2 Voltage and Reactive Flows

CAISO shall coordinate the control of voltage levels and reactive flows during normal and Emergency Conditions. All operating entities shall assist with the CAISO's coordination efforts.

3.10.3 Transfer Limits Under Outage and Abnormal System Conditions

In addition to establishing total transfer capability limits under normal system conditions, transmission providers and balancing authority shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

3.11 Communications and Procedures

3.11.1 Use of Communication System

It is essential to establish and maintain communications with the SCE Grid Control Center (GCC), the Alternate Grid Control Center (AGCC) or a jurisdictional Switching Center should a temporarily attended station or area of jurisdiction become involved in a case of system trouble. It is equally important that communication services be kept clear of nonessential use during times of system trouble to facilitate system restoration or other emergency operations.

3.11.2 Special Protection Schemes Communication Equipment Requirements

Customer Transmission Facilities will require the necessary communication equipment for the implementation of Remedial Action Schemes (RAS). This equipment provides line monitoring and high-speed communications between the customer's breaker and the central control facility, utilizing applicable protocols. RASs may also be applied to individual transmission lines in order to relieve congestion on much larger portion of SCE's electric system. Thus, allowing a RAS to incorporate disconnection into automatic control algorithms under contingency conditions, as needed.

RASs are fully redundant systems. The following paragraph is an excerpt from the "WECC

Remedial Action Scheme Design Guide that specifies the Philosophy and General Design Criteria" for RAS redundancy. *"Redundancy is intended to allow removing one scheme following a failure or for maintenance while keeping full scheme capability in service with a separate scheme. Redundancy requirements cover all aspects of the scheme design including detection , arming, power, supplies, telecommunications* facilities *and equipment, logic controllers (when applicable), and RAS trip/close circuits."*

Excerpt from: WECC Remedial Action Scheme Design Guide (11/28/2006)

3.11.3 Critical System Voltage Operation

Voltage control during abnormal system configurations requires close attention with consideration given to what operations will be necessary following loss of the next component. Voltages approaching 10% above or below the normal value are considered critical with rate of change being of principal importance.

Section 4 General Operating Requirements:

a) **System Operating Bulletins:** The Transmission Facilities connecting into SCE's electric system may be subject to operating requirements established by SCE, the CAISO or both. SCE's general operating Requirements are discussed in the sections below. SCE may also require additional operating Requirements specific to a specific set of Transmission Facilities. If so, these Requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOBs and/or SSIs specific to a set of Transmission Facilities, and any subsequent revisions will be provided by SCE to the customer as they are made available.

b) **Owner of the Interconnecting Transmission Facilities' Responsibility:** The owner of the Transmission Facilities is responsible for complying with all applicable operating requirements. Operating procedures are subject to change as system conditions and system needs change. Therefore, it is advisable for the owner to regularly monitor operating procedures that apply to its generating facilities. The CAISO publishes its operating procedures on its internet site, but it is prudent for the owner to contact the CAISO for specific Requirements.

c) **Quality of Service:** The interconnection of the customer's Transmission Facilities with SCE's electric system shall not cause any reduction in the quality of service being provided to SCE's customers. If complaints result from operation of the customer's Transmission Facilities, such equipment shall be disconnected until the problem is resolved.

d) **SCE Circuits:** Only SCE is permitted to energize any de-energized an SCE circuit.

e) **Operate Prudently:** The owner of the Transmission Facilities will be required to operate its equipment in accordance with prudent electrical practices.

f) **Protection in Service:** The Transmission Facilities shall be operated with all of required protective apparatus. Redundant protective devices may be provided at the Interconnection customer's expense. Any deviation for brief periods of emergency may only be by agreement of SCE and is not to be interpreted as permission for subsequent incidents.

4.1 VAR Correction

VAR correction will normally be planned for light load, heavy load and for system normal and contingency conditions. This is to be accomplished by providing transmission system VAR correction to minimize VAR flow and to maintain proper voltage levels. The planning of transmission system VAR requirements should consider the installation of shunt capacitors, shunt reactors and tertiary shunt reactors, synchronous condensers, FACTS and transformer tap changers. The guidelines for reactive planning are as follows:

4.1.1 Interconnection

Interconnection with other utilities will normally be designed with the capability of maintaining near-zero VAR exchange between systems. Entities interconnecting their transmission system with SCE's e system shall endeavor to supply the reactive power required on their own system, except as otherwise mutually agreed. SCE shall not be obligated to supply or absorb reactive power for the customer's Transmission Facilities when it interferes with operation of SCE's electric system, limits the use of SCE interconnections, or requires the use of generating equipment that would not otherwise be required.

4.1.2 Subtransmission System

VAR correction will normally be planned for connection to 55 kV through 160 kV buses to correct for large customer VAR deficit, subtransmission line VAR deficit, and transformer A-Bank VAR losses, the objective being zero VAR flow at the high side of the A-Banks with VAR flow toward the transmission system on the high side of the A-Banks, if required. Adequate VAR correction shall be provided for maximum coincident customer loads (one-in-five year heat storm conditions), after adjusting for dependable local generation and loss of the largest local bypass generator.

4.2 Voltage Regulation/Reactive Power Supply Requirements

Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled and adequate reactive reserves shall be provided. If power factor correction equipment is necessary, it may be installed by the customer on its Transmission Facilities, or by SCE at SCE's facilities at the customer's expense.

4.2.1 Reactive Power Equipment – Induction Generators (in aggregate)

4.2.1.1 Facility Reactive Power Equipment Design

The owner of the interconnecting Transmission Facilities shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

The reactive power equipment utilized by the interconnecting customer to meet SCE's Requirements must be designed to minimize the exposure of SCE's customers, SCE's electric system, and the electric facilities of others (i.e., other facilities and utilities in the vicinity) to:

a) severe overvoltages that could result from self-excitation of induction generators,

b) transients that result from switching of shunt capacitors,

c) voltage regulation problems associated with switching of inductive and capacitive devices.

d) unacceptable harmonics or voltage waveforms, which may include the effect of power electronic switching, and

e) Voltage flicker exceeding SCE Voltage Flicker limits as indicated in SCE Transmission Planning Criteria and Guidelines Figure 4-1 "VOLTAGE FLUCTUATION DESIGN LIMITS".

4.2.1.2 Facility Reactive Power Equipment Design - provide variable source

The reactive power equipment utilized by customer's Transmission Facilities connecting to SCE's system to meet SCE's Requirements must be designed to provide a variable source of reactive power (either continuously variable or switched in discrete steps). For discrete step changes, the size of any discrete step change in reactive output shall be limited by the following criteria:

f) the maximum allowable voltage rise or drop (measured at the point of interconnection with SCE's electric system) associated with a step change in the output of the Transmission Facilities' reactive power equipment must be less than or equal to 1%; and

g) the maximum allowable deviation from an Interconnection customer's reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the Interconnection customer's maximum (boost) reactive capability.

4.2.2 Voltage and Reactive Control

4.2.2.1 Coordination

Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

4.2.2.2 Transmission Lines

Although transmission lines should be kept in service as much as possible, during over-voltage system conditions a customer's transmission line(s) may be subject to removal from operation as a means to mitigate voltage problems in the local area. SCE will notify CAISO when removing such facilities from and returning them back to service.

4.2.2.3 Switchable Devices

Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

4.3 Voltage Imbalance and Abnormal Voltage or Current Waveforms (harmonics)

Power quality problems are caused when voltage imbalances and harmonic currents result in abnormal voltage and/or current waveforms. Generally, if a customer's Transmission Facilities connecting to SCE's system degrades power quality to SCE's facilities, or other SCE customer facilities, SCE may require the installation of equipment to eliminate the power quality problem.

4.3.1 Voltage Imbalance

The unbalanced voltage level (magnitude and phase), due to a customer's Transmission Facilities connecting to SCE's system, may not exceed 1% at the Point of Common Connection1 (PCC), under steady state system conditions. Under certain conditions (contingency conditions), SCE may allow higher levels of voltage imbalance if justified after a study conducted by SCE. In any event, the unbalanced voltage level created by facilities interconnecting to SCE's system shall not exceed 1.5%.

It is the responsibility of customers connected to SCE's electric system to install adequate mitigation devices to protect their own equipment from damage that maybe caused by voltage imbalance condition.

[1] The PCC will generally be at the location of the revenue meter or the point of ownership change in the electrical system between SCE and the Interconnection customer. For customers served by dedicated facilities, the location of the PCC will be determined by mutual agreement between the Interconnection customer and SCE.

4.3.2 Harmonics

Facilities interconnecting to SCE's system are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment in accordance to good engineering practice used at their facility to comply with the limits set by the current IEEE Standards.

4.3.3 Disconnection

SCE may disconnect any Facility connected to its system until the above Requirements are met.

4.4 Grounding Circuits and Substations

Substation Grounding

Customers connecting Transmission Facilities to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous voltage potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying equipment to be handled by personnel.

Reason for Substation Grounding

Substation grounding practices are outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding."
According to IEEE 80 – 2000 a safe ground grid design has the following two objectives:

- "To provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service." (IEEE 80 – 2000)
- "To ensure that a person in the vicinity of grounded facilities is not exposed to the danger of critical electric shock." (IEEE 80 – 2000)

"People often assumed that any grounded object can be safely touched. A low substation ground resistance is not, in itself, a guarantee of safety. There is no simple relation between the resistance of the ground system as a whole and the maximum shock current to which a person might be exposed. Therefore, a substation of relatively low ground resistance may be dangerous, while another substation with very high resistance may be safe or can be made safe with careful design." (IEEE 80 – 2000)

Each substation ground grid is a unique design. The conditions at the site: soil type, soil resistivity, fault current, clearing time, size of the substation, and other grounds all factor into the design.

4.4.1 Nominal Voltage and Grounding

SCE's most common primary distribution voltages are 4, 12 and 16 kV depending on the geographic area. Other voltages are also used in specific areas. Subtransmission voltages are nominally 66 kV to 115 kV. Transmission system voltages are nominally 161 kV, 220 kV, and 500 kV. The majority of the 4, 12, and 16 kV circuits are effectively grounded, but some are operated with high impedance grounding. A substantial number of the effectively grounded circuits are used for four-wire distribution (phase to neutral connected loads). SCE will provide the customer the necessary information on the specific circuit serving its Transmission Facilities for proper grounding.

4.4.2 Grounding Grid Studies shall be conducted in the following situations:

Grounding calculations will be required for each new substation, and at existing substations, when the ground grid is altered or when major additions are made at a substation. A review of existing substation ground grids will be conducted by Engineering in the following situations, especially if triggered by interconnection requests – these shall be considered in queue order:

- Short Circuit Duty Changes
    1. Circuit breaker replacement for short-circuit duty reasons
    2. Addition of transmission or subtransmission line to a substation
    3. System changes causing a substantial change in the substation phase-to-ground short-circuit duty
    4. Addition or replacement of a transformer at a substation
    5. Addition of new generation causing a substantial change in the substation phase-to-ground short-circuit duty
- System Protection Changes
    1. Changes in system protection that significantly increases the clearing time for ground faults.
- Grounding Source Changes
    1. Grounding of ungrounded wye winding of a transformer
    2. Addition or major change of ground source at a substation
- Substation Changes
    1. Alterations to substation fences including additions, movement, and attachments to other fences. The removal of vegetation that blocks access to a substation fence is considered a fence alteration.
    2. Alterations to substation ground grids that change their size or increase the effective substation ground grid impedance.
    3. Sale or lease of substation property for other uses.
- A grounding review should be conducted any time a grounding problem is reasonably suspected.

4.4.3 Ground Mats

If the customer and SCE substation ground mats are tied together, all cables may be landed without any protection. However, if the customer and SCE substation ground mats are not tied together, all cables shall have protection at both ends. The design of cable protection, if any, on circuits used for protective relaying purposes shall be such that the operation of the protective relaying is not hampered when the cable protection operates or fails.

All customer ground mats shall be designed in accordance with good engineering practice and judgment. Presently the recognized standard for grounding is IEEE 80 "IEEE Guide For Safety in AC Substation Grounding." All ground mat designs should meet or exceed the requirements listed in this standard. If local governmental requirements are more stringent, building codes for example, they shall prevail. All customers shall perform appropriate tests, including soil resistivity tests, to demonstrate that their ground grid design meets the standard. Mats shall be tested at regular intervals to ensure their effectiveness.

Grounding studies shall be performed with industry-recognized software to determine if customer and SCE ground grids should be separate or tied together. This study will determine the maximum safe fault current for the ground grid design. It is suggested that the grid be designed for the maximum fault currents expected over the life of the facility.

If for any reason the worst-case fault current exceeds the design maximum fault current value due to changes in the interconnection customer's facility or changes on the SCE system, the customer shall conduct new grounding studies. Any changes required to meet safety limits and protect equipment shall be borne by the customer.

The customer is responsible to ensure that the GPR (Ground Potential Rise) of its interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the customer. If it is elected to install separate ground grids for SCE and the customer, they shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the customer's Transmission Facilities connecting to SCE's system.

Any ground grid design, which results in a GPR that exceeds 3,000 volts RMS for the worst-case fault or has a calculated or measured ground grid resistance in excess of 1 ohm, will require special approval by SCE.

4.4.4 Substation Grounding

The customer connecting Transmission facilities to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying parts to be handled by personnel.

4.5 Non-SCE Pole Grounding

A customer connecting Transmission facilities to SCE's system shall follow SCE Construction, Operation, and Maintenance requirements. The last customer-owned structure shall be designed and constructed to meet SCE grounding requirements.

Customer facilities that will require SCE's crews to climb in order to construction, operate, or maintain SCE facilities shall be constructed so as to meet SCE standards and specifications. Constructing to SCE specifications will ensure that SCE crews can safely perform and complete the jobs at hand in accordance with SCE's Accident Prevention Manual that stipulate the proper training and equipment to safely climb and work. Examples of safety related requirements that:

- Climbing Steps
- Belt-Off Locations
- Grounding Locations
- Required PPE
- Jumper Cable Ownership

Grounding bolts and bases are the same as step bolts and bases. If there is the potential need to have SCE personnel work on non-SCE owned poles connecting the customer's Transmission Facilities directly to SCE's electric system a dead-end structure adhering to SCE's Construction, Operation, and Maintenance standards, is required.

Please note that these requirements are for poles only. Non-steel or ungrounded poles will have; project-specific grounding requirements as determined by SCE.

Section 5 Telemetering Requirements (Hardware)

5.1 Telemetering Requirements

For a high degree of service reliability under normal and emergency operation, it is essential that the customer's Transmission Facilities connecting to SCE's system have adequate and reliable telecommunication facilities.

The customer shall specify the following at the point of connection: the requested voltage level, MW/MVAR capacity, and/or demand.

Section 6 Telecommunications Requirements

6.1 General Description

The following Requirements are for typical Telecommunications equipment installation on a customer's Transmission Facilities connecting to SCE's system. Specific design and installation details are addressed during final engineering for facilities at each specific Point of Interconnection.

The telecommunications facilities to support line protection of the on a customer's Transmission Facilities connecting to SCE's system depend on its specific protection needs and the existing telecommunications infrastructure in the area. Fiber optic (FO) communications matched with protective relays are used on transmission power lines for fast clearing. For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles.

As noted in Section 3, the selection of protection devices is dependent on the power line characteristics (i.e., voltage, impedance, and ampacity) of the customer's Transmission Facilities and the surrounding area. Identical non-SCE owned Transmission Facilities connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs.

In cases where a second FO telecommunication is required, for protection relay coordination or to support a SPS, the second FO path must comply with WECC guidelines governing diverse routing. The customer will construct the communications path(s) between their Transmission Facilities and the point of interconnection. Primary path can be provided with a FO cable on the customer's Transmission Facilities or as OPGW (fiber OPtical Ground Wire). Diverse routing will be required for secondary path. Telemetering data (SCADA) and line protection control signals will be transported on these paths.

If FO is not required for line protection or RAS, a leased T1 circuit may be used for telemetering (SCADA). See Section 6.6.

6.2 Fiber Optic Communications Paths:

The customer will build the FO paths from the communication room on its Transmission Facilities to the point of interconnection with SCE. The customer's OPGW or FO cable on its Transmission Facilities may serve as one path. If a diverse route is required, the customer may elect to install FO cable in an underground conduit in the right-of-way to serve as the diverse route.

SCE shall design, operate, and maintain certain telecommunications terminal equipment at the point of interconnection to support line protection, telemetering (SCADA), equipment protection, and SPS communications applicable to the project.

6.3 Space Requirements

The customer shall provide sufficient floor space within a secure building for SCE to install and operate up to two 8' x 19" wide communication equipment (EIA-310-D) racks. These racks shall contain telecommunication equipment to support SCADA, equipment protection, and SPS communications applicable to the project. SCE recommends separating the communications equipment into two racks when diverse protection and/or SPS circuits are required.

The customer shall provide sufficient wall space adjacent to the SCE communication equipment rack(s) for a 36" x 36" x ¾" plywood backboard for leased or other related circuit termination. The plywood shall be clear of obstructions from adjacent equipment and painted with fire resistant gray semi-gloss enamel (Dunn-Edwards DE-1073, New Hope Gray or equivalent).

The customer shall provide a working clearance of 49.5" (measured from the center of the rack) in front and behind the equipment rack(s) for the safety of installation and maintenance personnel. The working clearance specified provides a 36" unobstructed space for ladders and/or test equipment carts. Additionally, SCE considers telecommunications equipment racks to contain "live electrical equipment," which is consistent with the 36" working clearance specified in the National Electric Code.

SCE shall secure the equipment rack using the floor angles using only with ½"-13 stainless steel hardware. If the floor of the equipment room is concrete, Hilti HDI 1/2 "drop-in" anchors shall be used.

6.4 HVAC Requirements

The customer shall provide and maintain suitable environmental controls in the equipment room, including an HVAC system to minimize dust, maintain a temperature of 30° C or less, and 5-95% non-condensing relative humidity.

The HVAC requirements for fiber optic terminal equipment are more stringent than what is required for RTU equipment. Therefore, whenever line protection or SPS specifies the use of fiber optic communications and its terminal equipment, the requirements of Section 7: Telemetering Requirements (Hardware) will match those in this Section 8.

NOTE: Environmental controls for microwave terminal equipment (when applicable) are generally more stringent than fiber optic terminal equipment.

6.5 Power And Grounding Requirements

The customer shall provide a connection point to station ground within ten (10) feet of the SCE communication equipment rack(s). SCE will provide and install cabling from the equipment rack(s) to the designated station ground termination to protect the communications equipment and service personnel.

The customer shall provide two 10 Amp dedicated branch circuits from the 125 VDC station power to support the telecommunications equipment rack(s). The dedicated source breakers shall be labeled "SCE-Telecom A" and "SCE-Telecom B." If DC power is not available, two 15 amp 120 VAC circuits may be used as long as the circuits are sourced from an Uninterruptible Power System with a minimum of 4 hour backup. The power source shall not be shared with other equipment.

The customer shall provide a 120 VAC 15 Amp convenience power source adjacent to the telecommunications equipment rack(s). As this source will be utilized for tools and test equipment by installation and maintenance personnel, UPS is not required. The customer shall provide ample lighting for the safety of installation and maintenance personnel.

For RTU power and grounding requirements, refer to Section 7.

6.6 Telemetry and Leased T1 Line:

For projects requiring only a leased T1 circuit for RTU communications, the customer shall:

a) Arrange with the local carrier to provide a T1 circuit from the Customer's Transmission Facilities to the nearest SCE service center or similar facility;

b) Provide conduit, raceway, copper cable, fiber optic cable as necessary for SCE to extend the leased circuit from the Local Exchange Carrier MPOE (Minimum Point of Entry or "demark") to the SCE communications equipment rack(s). The SCE equipment rack(s) shall be no more than 100' from the MPOE;

c) Incur the monthly cost of the leased T1; Provide conduit, raceway, copper cable, fiber optic cable to extend the RTU circuit from the communications equipment to the RTU or from a leased T1 communications circuit in the event the SCE RTU is not located within the same facility;

The SCE RTU and communications equipment rack(s) shall be no further apart than 100'.

6.7 Miscellaneous:

- While SCE may discuss telecommunication connection preferences of the customer's Transmission Facilities connecting to SCE's system, ultimately, SCE has final discretion regarding the selection of telecommunication connection equipment. The telecommunication connection must fit within the operating requirements, design parameters, and communications network architecture of the entire SCE telecommunications network.

- Because the use of microwave requires detailed engineering evaluation not performed within Interconnection Studies, the use of microwave as an option for the second diverse communications route to support protection of the customer owned Transmission Facilities connecting to SCE's system will only be considered as part of final engineering and design.
- The use of other telecommunications such as satellite communication requires detailed engineering evaluation not performed within Interconnection Studies. As such, use of other telecommunications will only be considered as part of final engineering and design.

After the communication equipment is installed and in operation, the customer shall provide 24 hours a day, 7 days a week accesses to SCE employees and approved contractors for planned maintenance and service restoration.

Section 7 Property Requirements

7.1 Right of Way Requirements

The customer must acquire the necessary Rights of Way requirements for their transmission line, along with the Access requirements to the point of interconnection with SCE's facilities. The use of SCE Rights of Ways and/or property shall not be included in any interconnection proposals.

7.2 Transmission Line Crossing Policy

The Interconnection Transmission line or Access Rights of Way that are proposed to cross SCE Transmission line or Access easements or fee owned property must be submitted to SCE Real Properties organization for a separate review request and approval. For your reference, below are SCE's Transmission Crossing Policy guidelines:

- A new customer transmission line of equal or lower voltage shall not be allowed the superior position and will cross under the existing SCE Facilities and/or the new facilities proposed prior to the new line.
- A new customer transmission line, triggered by an INTFAC, with higher voltage may be allowed the superior position with G.O. 95[2] Grade "A" self-supporting Dead-end construction with minimum of double insulator strings on both sides. This will apply to all voltages. SCE will regain the superior position should SCE lower voltage facilities be upgraded in the future of equal or higher voltage than the customer's Transmission Facilities.
- A new customer transmission line of higher voltage may be allowed the superior position if it is crossing a SCE multiple circuits corridor (two circuits or more), but this type of crossing will need to be reviewed on a case-by-case basis.
- A new customer transmission line, regardless of voltage, shall not be allowed the superior position if it is crossing a circuit which terminates at the switchyard for a nuclear power plant.

[2] ***General Order No. 95. (G.O.* 95)** the "Rules for Overhead Line Construction" established by the California Public Utilities Commission is minimum requirements for designing and constructing overhead and underground electrical facilities. In some cases SCE Practices and Standards may be more stringent. The INTFAC must adhere to the appropriate requirements.

7.3 Infrastructure Property Requirements

Substation: The following approximate land requirements are needed for typical interconnection facilities (SCE owned substation) on the customer's property:

- 66kV Tap: 90 ft by 120 ft
- 66kV Loop: 150 ft by 120 ft
- 115kV Tap: 110 ft by 120 ft
- 115kV Loop: 170 ft by 200 ft

Minimum substation land requirements are subject to change according to engineering studies and interaction with SCE is required for final determination. The dimensions above include a required 10 ft. easement bordering the interconnection facility under the assumption that the customer owns the transformer and the land needed for the incoming line(s) is not included.

Glossary

Adverse (System) Effect/Impact – The negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Applicable Reliability Standards – The requirements and guidelines of NERC, the Applicable Reliability Council, and the Balancing Authority Area of the Participating TO's Transmission System to which the Generating Facility is directly connected, including requirements adopted pursuant to Section 215 of the Federal Power Act.

CAISO – California Independent System Operator.

CAISO Controlled Grid – The system of transmission lines and associated facilities of the parties to the Transmission Control Agreement that have been placed under the CAISO's Operational Control.

CAISO Tariff – The CAISO's tariff, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Direct Access (DA) – A service option where the customer obtains its electric power and ancillary services from Electric Service Provider (ESP), who is registered with the California Public Utilities Commission (CPUC). See SCE Tariff Books Rule 22 for more information.

Distribution System – Those non-CAISO-controlled transmission, subtransmission, and distribution facilities owned by the Participating TO's.

Effective Date – The date the Interconnection Handbook is published.

Element – Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

Emergency-Backup Generation (EBG) – Customer-owned generation utilized when disruption of utility power has occurred or is imminent.

Emergency Condition – A condition or situation: (1) that is imminently likely to endanger life or property; or (2) that, in the case of the CAISO, is imminently likely to cause a material adverse effect on the security of, or damage to, the CAISO Controlled Grid or the electric systems of others to which the CAISO Controlled Grid is directly connected; (3) that, in the case of the Participating TO, is imminently likely to cause a material adverse effect on the security of, or damage to, the Participating TO's Transmission System, Participating TO's Interconnection Facilities, Distribution System, or the electric systems of others to which the Participating TO's electric system is directly connected; or (4) that, in the case of the Interconnection Customer, is imminently likely to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities.

Facility – A set of electrical equipment that operates as a single electric system Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

FACTS – Flexible Alternating Current Transmission System

Federal Power Act – The Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.
FERC – The Federal Energy Regulatory Commission or its successor.

FO – Fiber Optic.

Generating Facility Capacity – The total capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Ground Potential Rise (GPR) – The voltage rise of a substation-grounding grid relative to a remote point. GPR is equal to maximum earth current into or out of the grid times the grid resistance. (The Earth current can vary from 0 to 100 percent of the fault current depending on fault location and neutral connections to the substation.) The interconnecting customer is responsible to ascertain that the GPR of the Producer's or interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the interconnecting customer. If it is elected to install separate ground grids for SCE and the interconnecting facility, the customer shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the interconnecting customer's facilities.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted
in the region.

Initial Synchronization Date – The date upon which an Electric Generating Unit is initially synchronized and upon which Trial Operation begins.

INTFAC – Short for "Interconnection Facility" which refers to all applicable facilities, such as generation, transmission, and end-user facilities.

Interconnection Handbook (Handbook)– A handbook, developed by the SCE and posted its website for customer use which describing the technical and operational requirements necessary for generators, transmission facilities, and end use Facilities to connect to SCE's electrical system. These requirements outlined in the Handbook provide for safe and reliable operation of SCE's electric system, and may be modified or superseded from time to time.

Metering Equipment – All metering equipment installed or to be installed for measuring the output of the Generating Facility, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

ModBus – A serial communications protocol published by Modicon in 1979 for use with its programmable logic controllers (PLCs). Simple and robust, it has since become a *de facto* standard communication protocol, and it is now amongst the most commonly available means of connecting industrial electronic devices.

NERC – The North American Electric Reliability Corporation or its successor organization.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, the California Independent System Operator Corporation, control area, or the Distribution Provider's requirements, including those set forth in Generation Interconnection Agreement.

OPGW – Fiber Optical Ground Wire.

Party or Parties – The Participating TO, CAISO, Interconnection Customer or the applicable combination of the above.

Point of Change of Ownership (POCO) – The point where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities.

Point of Interconnection – The point where the Interconnection Facilities connect with the Distribution Provider's Distribution System.

RTU – A **remote terminal unit (RTU)** is a microprocessor-controlled electronic device that interfaces objects in the physical world to a distributed control system or SCADA (supervisory control and data acquisition system) by transmitting telemetry data to the system, and by using messages from the supervisory system to control connected objects.

SCADA – (**supervisory control and data acquisition**) generally refers to industrial control systems (ICS): computer systems that monitor and control industrial, infrastructure, or facility-based processes such as electrical power transmission and distribution.

SCE's Electric System – Locations where SCE is owner and/or operating agent.

TOP – Transmission Operator

TO – Transmission Owner

Transmission Control Agreement (TCA) – As defined by the CAISO California Independent Fifth Replacement Electronic Tariff.

Transmission System – Those facilities owned by the Distribution Provider that have been placed under the CAISO's operational control and are part of the CAISO Grid.

Appendix A

Following is a list of the technical standards and criteria referenced within SCE's Interconnection Technical Requirements.

NERC/WECC Planning Standards

WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 80 Guide for Safety in AC Substation Grounding

IEEE 929 Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems

IEEE 519 IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems

IEEE C37.010-1999 IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

ANSI C84.1 Voltage Ratings for Electric Power Systems and Equipment

SCE Transmission Planning Criteria and Guidelines

WECC Minimum Operating Reliability Criteria

Overview of Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports

Next Review Date

This document shall be reviewed upon a change in the referenced documents that may impact this document.

Data Retention

This document shall be retained a minimum of 4 years from last WECC on-site audit and is stored in/on the Reliability Standards and Compliance Group document library.

Approval

T&D Organization	Signature	Date
Transmission & Interconnection Planning	Original Copy signed by Jorge Chacon	12/29/16

Revision History

Rev. No.	Date	Description of Revision	By	Next Review Date
1		Revised the Interconnection Handbook, Generators to incorporate interconnection requirements for new Generation, Transmission, and End User facilities	---	---
2	3/19/2009	Replaces all remaining referenced documents in Version 1, so that, this Interconnection Handbook will be used for new Generation, Transmission, and End User facilities	---	---
3	10/2/2009	Revised to incorporate new SCE approved wind turbines set-back criteria.	---	---
4	8/2/2010	Incorporated the new SCE approved Transmission Line Crossing Policy. This update resulted in a reconfiguration of Section 9 and added an additional page to the document.	----	----
5	10/5/2011	Sec# 3: Incorporated new diagrams for inverter based interconnections. Incorporated Third Party Protection Equipment Maintenance Responsibility Statement. Sec# 4.15.2: Removal of C-RAS reference from section. Sec# 7: Incorporated exemption of telemetry requirements for Cold Ironing Ships and Emergency back-up generators. And clarification of 1 MVA size definition. Sec# 8: Describe the necessary telecommunications requirements.	----	----
6	10/3/2012	Section 5.11: Isolating Equipment & Switching and Tagging Rules. Re-designed to clarify the need for Isolating Equipment, Inter-Company and Switching and Tagging Rules. Delineating the different voltage classes: (NEW Section) For Generation Facilities (GF's) connecting to voltages >34.5 kV. (NEW Section) For GF's connecting to voltages ≤ 34.5kV. Section 5.12: Grounding Circuit & Substation. Introducing the need for Grounding Studies at the POI for generation interconnection customers. Section 5.13: Non-SCE Pole Grounding. Introducing grounding requirements when Connecting to Customer-Owned Facilities for Generation Interconnections Sections 3: Protection. Updated the Introduction paragraph. Incorporated new Protection diagram for Inverter-based Technology >34.5kV. Section 7: Telemetering. Updated to include the purpose & definition of an RTU. Updated the HVAC Section to align with Telecom. Engineering's Temperature Requirements. Harmonized the Telemetry Requirements with SOB510. Put Telemetry Requirements in a Table format. Added provisions to how to handle "virtual IO." Section 8: Telecommunications. Updated the 3rd paragraph to align with the updates made in Section 3: Identical projects connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs. Updated the HVAC section, stipulating more stringent temperature requirements and pointing to the PSC Section.	----	----

Rev. No.	Date	Description of Revision	By	Next Review Date
		Included new fiber optic section to align with WECC standards and clarified miscellaneous options Section 9: Property Requirements. Removed the footprints for the building 220kV or 500kV Looping Stations. Increased the 66kV and 115kV Looping Station Footprints consistent with new Substation Standards. Introduced New Glossary Section. Section 8: Telecommunications. Updated the 3rd paragraph to align with the updates made in Section 3: Identical projects connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs. Updated the HVAC section, stipulating more stringent temperature requirements and pointing to the PSC Section. Included new fiber optic section to align with WECC standards and clarified miscellaneous options Section 9: Property Requirements. Removed the footprints for the building 220kV or 500kV Looping Stations. Increased the 66kV and 115kV Looping Station Footprints consistent with new Substation Standards. Introduced New Glossary Section.		
7	12/29/16	Handbook split into 3 major components based on interconnection type for customer ease of use. Introduction/ Summary rewritten to clearly articulate the new format for the Handbook. Transmission Interconnection Requirements revised to more clearly articulate Protection needs. Glossary of terms revised to identify only terminology used in the Handbook.		

Attachments

None

Distribution

Transmission and Interconnection Planning

Queue Cluster 9 Phase I – Appendix B

SCE Metro Area – System Assumptions

Appendix B: System Assumptions

1. Generation Assumption Tables

Generation assumptions for SCE's Metro System are shown in Table 1.1 Existing Generation (Existing Generation), Table 1.2 SGIP Existing generation projects (SGIPs Existing Generation), Table 1.3 Pre QC1 & QC2 SGIP Interconnection Request (Pre QC1 & QC2 SGIPs Interconnection Request), Table 1.4 Pre QC3&4 Phase II projects (Pre QC3&4 Phase II SGIPs), Table 1.5 Queue Cluster 3 and 4 Phase II projects (QC3&4 Phase II), Table 1.6 Queue Cluster 5 Phase II projects (QC5 Phase II), Table 1.7 Queue Cluster 6 Phase II projects (QC6 Phase II), Table 1.8 Queue Cluster 7 Phase II projects (QC7 Phase II) , Table 1.9 Queue Cluster 8 Phase II projects (QC7 Phase II), Table 1.10 Queue Cluster 9 Phase I projects (QC9 Phase I) and Table 1.11 summarizes the Rule 21 projects in the area.

Appendix B: System Assumptions

Table 1.1: Existing Generation

Locations	Type	Size (MW)
Alamitos	Steam	1910.0
Arco Generation	Gas	435.0
Barre Peaker	Simple Cycle-GT	47.0
Brea Power	Gas	27.5
Carbogen	Gas	34.0
Center Peaker	Simple cycle-GT	47.0
Clearwater	Combined Cycle	31.3
Chevmain	Other	76.0
Cimgen	Gas	27.0
DelGen	Gas	30.8
El Segundo	Steam	544.0
Etiwanda	Steam	640.0
Etiwanda Peaker	Simple Cycle-GT	46.0
Etiwanda MWD	Small Hydro	23.9
Harbor Cogen	Other	113.8
Hillgen	Biomass	50.0
Huntington Beach	Steam	520.0
Icegen	Gas	50.0
Inlands Generation	Gas	30.7
Inland Empire Energy Center	Combined Cycle	810.0
Long Beach	Simple Cycle-GT	230.0
Malburg	Combined Cycle	134.1
Mira Loma Peaker	Simple Cycle-GT	46.0
Redondo	Steam	475.7
Refuse	Biomass	12
Sanigen	Biomass	12.5
Serrfgen	Biomass	33.1
Simpson Generation	Gas	32
Walnut Creek Energy Park	Simple Cycle - GT	500
	Total (Existing)	**7034.4**

Appendix B: System Assumptions

Table 1.2: SGIPs Existing Generation

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	WDT	WDT387	Alder: Casmalia 12 kV Line	4.5
2	WDT	WDT374	Declez: Speedway 12 kV Line	3
3	WDT	WDT384	Etiwanda: Benny 12 kV Line	2.5
4	WDT	WDT359	Milliken: Seagrams 12 kV Line	2
5	WDT	WDT358	Milliken: Bacardi 12 kV Line	2
6	WDT	WDT388	Alder: Dorsey 12 kV Line	2
7	WDT	WDT444	Nogales: Trident 12 kV Line	1.6
8	WDT	WDT360	Declez: Speedway 12 kV Line	1.5
9	WDT	WDT375	Calabash 12 kV line	1.5
10	WDT	WDT915	Drambuie 12 kV Line	1.5
11	WDT	WDT1053	Firehouse: Extinguisher 12 kV line	1.49
12	WDT	WDT481	Carmenita: Loftus 12 kV Line	1.25
13	WDT	WDT480	Studebaker 12 kV Line	1.16
14	WDT	WDT1057	Wimbledon: Graf 12 kV Line	1
15	WDT	WDT1064	Gallatin: Stamper 12 kV line	1
16	WDT	WDT1083	Genamic: Guidance 12 kV Line	1
17	WDT	WDT367	Calabash 12 kV line	1
18	WDT	WDT910	Wimbledon: Chang 12 kV Line	1
19	WDT	WDT356	Milliken: Bacardi 12 kV Line	1
20	WDT	WDT450	Milliken: Bacardi 12 kV Line	1
21	WDT	WDT451	Milliken: Bacardi 12 kV Line	1
22	WDT	WDT525	Corona: Pulaski 12 kV Line	1
23	WDT	WDT327	Chino: Calmen 12 kV Line	1
			Total	**26.65**

Appendix B: System Assumptions

Table 1.3: Pre QC1&2 SGIPs Interconnection Request

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT426	Kimball: Mosquito 12 kV	1.5
2	WDT	WDT125	Rio Hondo 230/66 kV	8.0
3	WDT	WDT292	Santiago 230/66 kV	19.6
4	WDT	WDT1429	Center 66 kV Bus	10
5	WDT	WDT1430	Grapeland Peaker 66/12 kV Bus	10
6	WDT	WDT1447	Refoil 12 kV Line	7.92
7	WDT	WDT1382	Horoscope 12 kV Line	3
8	WDT	WDT1446	Scarlet 12kV Line	2.5
9	WDT	WDT1428	Titanium 12 kV line	2
10	WDT	WDT1376	Alder: Bolor 12 kV Line	2
11	WDT	WDT1372	Beijing 12 kV Line	2
12	WDT	WDT1406	Virgo 12 kV Line	2
13	WDT	WDT1237FT	Wimbledon: McEnroe 12kV Line	2
14	WDT	WDT1434	Splendora 12 kV Line	1.89
15	WDT	WDT1432	Studebaker 12 kV Line	1.58
16	WDT	WDT1063	Declez: Bamboo 12 kV line	1.5
17	WDT	WDT1433	Refoil 12 kV Line	1.4
18	WDT	WDT1061	Corona: Vassal 12 kV line	0.75
19	WDT	WDT1059	El Nido: Seabass 16 kV line	0.73
20	WDT	WDT926	Drambuie 12 kV Line	0.51
			Total	**80.88**

Appendix B: System Assumptions

Table 1.4: Pre QC3&4 SGIPs Interconnection Requests

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT473	Cucamonga: Earnhardt 12 kV	1.75
2	WDAT	WDT482	Carmenita: Orchardale 12 kV	1.33
3	WDAT	WDT483	Carmenita: Loftus 12 kV	1.25
4	WDAT	WDT484	Carmenita: Loftus 12 kV	1.5
5	WDAT	WDT485	Carmenita: Loftus 12 kV	1
6	WDAT	WDT486	Carmenita: Orchardale 12 kV	1.75
			Total	**8.58**

Table 1.5: QC3&4 Interconnection Request

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	702	TOT560	El Segundo 220 kV	435
			Total	**435**

Table 1.6: QC5 Interconnection Request

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	893	TOT642	Ellis 220 kV	938.61

Appendix B: System Assumptions

Total	**938.61**

Table 1.7: QC6 Interconnection Requests

#	SCE QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDT1003ISP	WDT1003	Brea 66 kV Substation (Olinda 230/66 kV)	5.0
			Total	**5.0**

Table 1.8: QC7 Interconnection Requests

#	SCE QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDT	WDT1206	Johanna: Rummy 12 kV	9.8
2	WDT	WDT1189	Barre AB 66 kV bus	150
			Total	**159.8**

Table 1.9: QC8 Interconnection Requests

#	SCE QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDT	WDT1293	Barre 66 kV bus	20
2	WDT	WDT1294	Estrella: Aquarius 12 kV	10
3	WDT	WDT1304	Orange: Pink 12 kV	8
			Total	**38.0**

Table 1.10: QC9 Interconnection Requests

Appendix B: System Assumptions

#	SCE QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDT	WDT1401	La Bolsa 66 kV	100
2	WDT	WDT1398	Yahtzee 12 kV Line	9
3	WDT	WDT1396	Johanna-Camden 66 kV line	30
4	WDT	WDT1393	Johanna 12 kV	10
5	WDT	WDT1397	Solitaire 12 kV	6
6	WDT	WDT1392	Johanna 12 kV	10
7	WDT	WDT1388	Poker 12 kV	10
8	WDT	WDT1391	Barre 66 kV	149.1
9	WDT	WDT1390	Chestnut 66 kV	20
			Total	**344.1**

Table 1.11: Rule 21 Interconnection Requests

#	CAISO QUEUE #	SCE Project ID	System	Size (MW)
1	Rule 21	GFID	Alamitos 220/66 kV	7.84
2	Rule 21	GFID	Barre 220/66 kV	7.32
3	Rule 21	GFID	Center 220/66 kV	10.81
4	Rule 21	GFID	Chino 220/66 kV	11.26
5	Rule 21	GFID	Del Amo 220/66 kV	1.16
6	Rule 21	GFID	Eagle Rock 220/66 kV	7.83
7	Rule 21	GFID	Ellis 220/66 kV	10.2
8	Rule 21	GFID	El Nido 220/66 kV	31.93
9	Rule 21	GFID	Etiwanda 220/66 kV	2.62
10	Rule 21	GFID	Hinson 220/66 kV	2.94
11	Rule 21	GFID	Johanna 220/66 kV	12.7
12	Rule 21	GFID	La Cienega 220/66 kV	8.5
13	Rule 21	GFID	La Fresa 220/66 kV	4.97

14	Rule 21	GFID	Laguna Bell 220/66 kV	0.61
15	Rule 21	GFID	Lighthipe 220/66 kV	11.65
16	Rule 21	GFID	Mesa 220/66 kV	0.57
17	Rule 21	GFID	Mira Loma 220/66 kV	8.15
18	Rule 21	GFID	Olinda 220/66 kV	0.89
19	Rule 21	GFID	Padua 220/66 kV	6.27
20	Rule 21	GFID	Rio Hondo 220/66 kV	0.85
21	Rule 21	GFID	Santiago 220/66 kV	20.32
22	Rule 21	GFID	Walnut 220/66 kV	3.45
23	Rule 21	GFID	Viejo 220/66 kV	5.14
24	Rule 21	GFID	Villa Park 220/66 kV	7.0
25	Rule21	GFID	Walnut 220/66 kV	3.5
			Total	**188.48**

2. Modeling and Dispatch Assumptions

In the on-peak and off-peak Reliability Assessments, generation dispatch assumptions were developed with the goal of stressing the transmission facilities that will ultimately deliver the output of the QC9 projects into the load centers of Orange County. In order for the output of the QC9 projects (located mostly in Orange County) to fully stress the impacted transmission lines, the LA basin generation was redispatched. The capacities of coastal generators that utilize Once-Through Cooling (OTC) were chosen to be reduced in anticipation of future restrictions that may be placed on these generators. This dispatch allowed for the proper reliability assessment of existing transmission facilities in the vicinity of the proposed QC9 project locations.

Appendix B: System Assumptions

3. Deliverability Study

Table B-1: On-Peak Deliverability Assessment Import Target

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville_BG	N-S	981	16
COI_BG	N-S	3770	631
BLYTHE_BG	E-W	72	0
CASCADE_BG	N-S	80	0
CFE_BG	S-N	-42	0
ELDORADO_MSL	E-W	405	0
IID-SCE_BG	E-W	702	0
IID-SDGE_BG	E-W		0
LAUGHLIN_BG	E-W	-42	0
MCCULLGH_MSL	E-W	0	316
MEAD_MSL	E-W	897	506
NGILABK4_BG	E-W	-137	168
NOB_BG	N-S	1544	0
PALOVRDE_MSL	E-W	2588	128
PARKER_BG	E-W	86	17
SILVERPK_BG	E-W	-3	0
SUMMIT_BG	E-W	13	0
SYLMAR-AC_MSL	E-W	340	311
Total		11254	2093

Queue Cluster 9 Phase I – Appendix C

SCE Metro Area – Contingency List of Outages

#

##

CATEGORY P1

##

ZONE 240 TO 244 - 150 KV TO 999 KV

##

THE PURPOSE OF THE GERNATION INTERCONNECTION PROCESS (GIP) STUDIES ARE TO EVALUATE STRESSED GENERATION CONDITIONS ON THE

SYSTEM

##

NOTE 1 - CERTAIN CATEGORIES WERE NOT EVALUATED AS PART OF THIS GIP STUDY BUT ARE ADDRESSED AS PART OF SCE'S ANNUAL EXPANSION

STUDIES PERFORMED IN COORDINATION WITH THE CAISO

##

CATEGORY P1.1

##

CATEGORY P1.1 WOULD NOT PROVIDE FOR SUCH STRESSED CONDITIONS, THAT THE STUDY RESULTS WOULD NOT PROPERLY IDENTIFY POTENTIAL

IMPACTS CORRESPONDING TO THE PROJECTS SEEKING INTERCONNECTION. AS SUCH, CATEGORY P1.1 WAS NOT EVALUATED AS PART OF THIS

GIP STUDY BUT IS ADDRESSED AS PART OF THE SCE'S ANNUAL EXPANSION STUDIES PERFORMED IN COORDINATION WITH THE CAISO.

##

CATEGORY P1.2 FAULT WITH LOSS OF ONE TRANSMISSION CIRCUIT

##

#

##

500 KV CIRCUITS

##

line_1201 "Line MIRALOMA 500.0 to SERRANO 500.0 Circuit 1" 1.000

line "MIRALOMA 500.00" "SERRANO 500.00" "1 " 1 0

0

line_1202 "Line MIRALOMA 500.0 to SERRANO 500.0 Circuit 2" 1.000

line "MIRALOMA 500.00" "SERRANO 500.00" "2 " 1 0

0

line_1203 "Line VINCENT 500.0 to MESA CAL 500.0 Circuit 1" 1.000

line "VINCENT 500.00" "MESA CAL 500.00" "1 " 1 0

0

line_1204 "Line RANCHVST 500.0 to SERRANO 500.0 Circuit 1" 1.000

line "RANCHVST 500.00" "MIRA81X2 500.00" "1 " 1 0

line "MIRA81X2 500.00" "SERRANO 500.00" "1 " 1 0

0

line_1205 "Line MESA CAL 500.0 to MIRALOMA 500.0 Circuit 1" 1.000

line "MESA CAL 500.00" "WEST TS 500.00" "1 " 1 0

line "EAST TS 500.00" "MIRALOMA 500.00" "1 " 1 0

line "WEST TS 500.00" "EAST TS 500.00" "1 " 1 0

0

line_1206 "Line ALBERHIL 500.0 to SERRANO 500.0 Circuit 1" 1.000

line "ALBERHIL 500.00" "SERRANO 500.00" "1 " 1 0

0

###

230 KV CIRCUITS

###

line_1207 "Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1" 1.000

line "ALMITOSE 230.00" "BARRE 230.00" "1 " 1 0

0

line_1208 "Line ALMITOSE 230.0 to CENTER 230.0 Circuit 1" 1.000

line "ALMITOSE 230.00" "CENTER 230.00" "1 " 1 0

0

line_1209 "Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2" 1.000

line "ALMITOSW 230.00" "BARRE 230.00" "2 " 1 0

0

line_1210 "Line ALMITOSW 230.0 to LITEHIPE 230.0 Circuit 1" 1.000

line "ALMITOSW 230.00" "LITEHIPE 230.00" "1 " 1 0

0

line_1211 "Line ARCO SC 230.0 to HINSON 230.0 Circuit 1" 1.000

line "ARCO SC 230.00" "HINSON 230.00" "1 " 1 0

0

line_1212 "Line ARCO SC 230.0 to HINSON 230.0 Circuit 2" 1.000

line "ARCO SC 230.00" "HINSON 230.00" "2 " 1 0

0

line_1213 "Line BARRE 230.0 to VILLA PK 230.0 Circuit 1" 1.000

line "BARRE 230.00" "VILLA PK 230.00" "1 " 1 0

0

line_1214 "Line CENTER 230.0 to OLINDA 230.0 Circuit 1" 1.000

line "CENTER 230.00" "OLINDA 230.00" "1 " 1 0

0

line_1215 "Line CENTER 230.0 to MESACALS 230.0 Circuit 1" 1.000

line "CENTER 230.00" "MESACALS 230.00" "1 " 1 0

0

line_1216 "Line CHINO 230.0 to MIRALOMW 230.0 Circuit 1" 1.000

line "CHINO 230.00" "MIRALOMW 230.00" "1 " 1 0

0

line_1217 "Line CHINO 230.0 to MIRALOMW 230.0 Circuit 2" 1.000

line "CHINO 230.00" "MIRALOMW 230.00" "2 " 1 0

0

line_1218 "Line CHINO 230.0 to SERRANO 230.0 Circuit 1" 1.000

line "CHINO 230.00" "SERRANO 230.00" "1 " 1 0

0

line_1219 "Line CHINO 230.0 to MIRALOME 230.0 Circuit 3" 1.000

line "CHINO 230.00" "MIRALOME 230.00" "3 " 1 0

0

line_1220 "Line DELAMO 230.0 to BARRE 230.0 Circuit 1" 1.000

line "DELAMO 230.00" "BARRE 230.00" "1 " 1 0

0

line_1221 "Line DELAMO 230.0 to CENTER 230.0 Circuit 1" 1.000

line "DELAMO 230.00" "CENTER 230.00" "1 " 1 0

0

line_1222 "Line DELAMO 230.0 to ELLIS 230.0 Circuit 1" 1.000

line "DELAMO 230.00" "ELLIS 230.00" "1 " 1 0

0

line_1223 "Line DELAMO 230.0 to LAGUBELL 230.0 Circuit 1" 1.000

line "DELAMO 230.00" "LAGUBELL 230.00" "1 " 1 0

0

line_1224 "Line EAGLROCK 230.0 to GOULD 230.0 Circuit 1" 1.000

line "EAGLROCK 230.00" "GOULD 230.00" "1 " 1 0

0

line_1225 "Line EAGLROCK 230.0 to MESA CAL 230.0 Circuit 1" 1.000

line "EAGLROCK 230.00" "MESA CAL 230.00" "1 " 1 0

0

line_1226 "Line EL NIDO 230.0 to LA FRESA 230.0 Circuit 3" 1.000

line "EL NIDO 230.00" "LA FRESA 230.00" "3 " 1 0

0

line_1227 "Line EL NIDO 230.0 to LA FRESA 230.0 Circuit 4" 1.000

line "EL NIDO 230.00" "LA FRESA 230.00" "4 " 1 0

0

line_1228 "Line EL NIDO 230.0 to LCIENEGA 230.0 Circuit 1" 1.000

line "EL NIDO 230.00" "LCIENEGA 230.00" "1 " 1 0

0

line_1229 "Line EL NIDO 230.0 to CHEVMAIN 230.0 Circuit 1" 1.000

line "EL NIDO 230.00" "CHEVMAIN 230.00" "1 " 1 0

0

line_1230 "Line ELSEGNDO 230.0 to EL NIDO 230.0 Circuit 1" 1.000

line "ELSEGNDO 230.00" "EL NIDO 230.00" "1 " 1 0

0

line_1231 "Line ELSEGNDO 230.0 to CHEVMAIN 230.0 Circuit 1" 1.000

line "ELSEGNDO 230.00" "CHEVMAIN 230.00" "1 " 1 0

0

line_1232 "Line ETIWANDA 230.0 to SANBRDNO 230.0 Circuit 1" 1.000

line "ETIWANDA 230.00" "SANBRDNO 230.00" "1 " 1 0

0

line_1233 "Line ETIWANDA 230.0 to RANCHVST 230.0 Circuit 1" 1.000

line "ETIWANDA 230.00" "RANCHVST 230.00" "1 " 1 0

0

line_1234 "Line ETIWANDA 230.0 to RANCHVST 230.0 Circuit 2" 1.000

line "ETIWANDA 230.00" "RANCHVST 230.00" "2 " 1 0

0

line_1235 "Line HARBOR 230.0 to HINSON 230.0 Circuit 1" 1.000

line "HARBOR 230.00" "HINSON 230.00" "1 " 1 0

0

line_1236 "Line HARBOR 230.0 to LBEACH 230.0 Circuit 1" 1.000

line "HARBOR 230.00" "LBEACH 230.00" "1 " 1 0

0

line_1237 "Line HINSON 230.0 to DELAMO 230.0 Circuit 1" 1.000

line "HINSON 230.00" "DELAMO 230.00" "1 " 1 0

0

line_1238 "Line LA FRESA 230.0 to HINSON 230.0 Circuit 1" 1.000

line "LA FRESA 230.00" "HINSON 230.00" "1 " 1 0

0

line_1239 "Line LA FRESA 230.0 to LAGUBELL 230.0 Circuit 1" 1.000

line "LA FRESA 230.00" "LAGUBELL 230.00" "1 " 1 0

0

line_1240 "Line LA FRESA 230.0 to REDONDO 230.0 Circuit 1" 1.000

line "LA FRESA 230.00" "REDONDO 230.00" "1 " 1 0

0

line_1241 "Line LA FRESA 230.0 to REDONDO 230.0 Circuit 2" 1.000

line "LA FRESA 230.00" "REDONDO 230.00" "2 " 1 0

0

line_1242 "Line LAGUBELL 230.0 to MESA CAL 230.0 Circuit 1" 1.000

line "LAGUBELL 230.00" "MESA CAL 230.00" "1 " 1 0

0

line_1243 "Line LBEACH 230.0 to LITEHIPE 230.0 Circuit 1" 1.000

line "LBEACH 230.00" "LITEHIPE 230.00" "1 " 1 0

0

line_1244 "Line LCIENEGA 230.0 to LA FRESA 230.0 Circuit 1" 1.000

line "LCIENEGA 230.00" "LA FRESA 230.00" "1 " 1 0

0

line_1245 "Line LITEHIPE 230.0 to HINSON 230.0 Circuit 1" 1.000

line "LITEHIPE 230.00" "HINSON 230.00" "1 " 1 0

0

line_1246 "Line LITEHIPE 230.0 to MESA CAL 230.0 Circuit 1" 1.000

line "LITEHIPE 230.00" "MESA CAL 230.00" "1 " 1 0

0

line_1247 "Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1" 1.000

line "MESA CAL 230.00" "REDONDO 230.00" "1 " 1 0

0

line_1248 "Line MESA CAL 230.0 to MESACALS 230.0 Circuit BT" 1.000

line "MESA CAL 230.00" "MESACALS 230.00" "BT" 1 0

0

line_1249 "Line MESA CAL 230.0 to VINCNT2 230.0 Circuit 2" 1.000

line "MESA CAL 230.00" "VINCNT2 230.00" "2 " 1 0

0

line_1250 "Line MIRALOMW 230.0 to WALNUTE 230.0 Circuit 1" 1.000

line "MIRALOMW 230.00" "WALNUTE 230.00" "1 " 1 0

0

line_1251 "Line OLINDA 230.0 to WALNUTE 230.0 Circuit 1" 1.000

line "OLINDA 230.00" "WALNUTE 230.00" "1 " 1 0

0

line_1252 "Line REDONDO 230.0 to LITEHIPE 230.0 Circuit 1" 1.000

line "REDONDO 230.00" "LITEHIPE 230.00" "1 " 1 0

0

line_1253 "Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000

line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0

0

line_1254 "Line SERRANO 230.0 to VILLA PK 230.0 Circuit 1" 1.000

line "SERRANO 230.00" "VILLA PK 230.00" "1 " 1 0

0

line_1255 "Line SERRANO 230.0 to VILLA PK 230.0 Circuit 2" 1.000

line "SERRANO 230.00" "VILLA PK 230.00" "2 " 1 0

0

line_1256 "Line VINCENT 230.0 to RIOHONDO 230.0 Circuit 1" 1.000

line "VINCENT 230.00" "RIOHONDO 230.00" "1 " 1 0

0

line_1257 "Line VINCENT 230.0 to RIOHONDO 230.0 Circuit 2" 1.000

line "VINCENT 230.00" "RIOHONDO 230.00" "2 " 1 0

0

line_1259 "Line VINCENT 230.0 to VINCNT2 230.0 Circuit BT" 1.000

line "VINCENT 230.00" "VINCNT2 230.00" "BT" 1 0

0

line_1261 "Line WALNUTE 230.0 to WALNUTW 230.0 Circuit 1" 1.000

line "WALNUTE 230.00" "WALNUTW 230.00" "1 " 1 0

0

line_1262 "Line RANCHVST 230.0 to PADUA 230.0 Circuit 1" 1.000

line "RANCHVST 230.00" "PADUA 230.00" "1 " 1 0

0

line_1263 "Line RANCHVST 230.0 to PADUA 230.0 Circuit 2" 1.000

line "RANCHVST 230.00" "PADUA 230.00" "2 " 1 0

0

line_1264 "Line RANCHVST 230.0 to MIRALOME 230.0 Circuit 1" 1.000

line "RANCHVST 230.00" "MIRALOME 230.00" "1 " 1 0

0

line_1265 "Line RANCHVST 230.0 to MIRALOME 230.0 Circuit 2" 1.000

line "RANCHVST 230.00" "MIRALOME 230.00" "2 " 1 0

0

line_1266 "Line MESACALS 230.0 to LAGUBELL 230.0 Circuit 2" 1.000

line "MESACALS 230.00" "LAGUBELL 230.00" "2 " 1 0

0

line_1267 "Line MESACALS 230.0 to RIOHONDO 230.0 Circuit 1" 1.000

line "MESACALS 230.00" "RIOHONDO 230.00" "1 " 1 0

0

line_1268 "Line MESACALS 230.0 to RIOHONDO 230.0 Circuit 2" 1.000

line "MESACALS 230.00" "RIOHONDO 230.00" "2 " 1 0

0

line_1269 "Line MESACALS 230.0 to WALNUTW 230.0 Circuit 1" 1.000
line "MESACALS 230.00" "WALNUTW 230.00" "1 " 1 0
0
line_1270 "Line GOODRICH 230.0 to GOULD 230.0 Circuit 1" 1.000
line "GOODRICH 230.00" "GOULD 230.00" "1 " 1 0
0
line_1271 "Line GOODRICH 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line "GOODRICH 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_1272 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 1" 1.000
line "LEWIS 230.00" "SERRANO 230.00" "1 " 1 0
0
line_1273 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 2" 1.000
line "LEWIS 230.00" "SERRANO 230.00" "2 " 1 0
0
line_1274 "Line LEWIS 230.0 to VILLA PK 230.0 Circuit 1" 1.000
line "LEWIS 230.00" "VILLA PK 230.00" "1 " 1 0
0
line_1275 "Line VIEJO 230.0 to CHINO 230.0 Circuit 1" 1.000
line "VIEJO 230.00" "CHINO 230.00" "1 " 1 0
0
line_1276 "Line MIRALOME 230.0 to OLINDA 230.0 Circuit 1" 1.000
line "MIRALOME 230.00" "OLINDA 230.00" "1 " 1 0
0
line_1277 "Line VINCNT2 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line "VINCNT2 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_1279 "Line GOODRICH 230.0 to GOULD 230.0 Circuit 1" 1.000
line 25001 24059 "1 " 1 0
0
line_1280 "Line GOODRICH 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line 25001 24091 "1 " 1 0
0

line_1281 "Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1" 1.000

line 24006 24016 "1 " 1 0

0

line_1282 "Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2" 1.000

line 24008 24016 "2 " 1 0

0

line_1283 "Line BARRE 230.0 to ELLIS 230.0 Circuit 1" 1.000

line 24016 24044 "1 " 1 0

0

line_1284 "Line BARRE 230.0 to ELLIS 230.0 Circuit 2" 1.000

line 24016 24044 "2 " 1 0

0

line_1285 "Line BARRE 230.0 to ELLIS 230.0 Circuit 3" 1.000

line 24016 24044 "3 " 1 0

0

line_1286 "Line BARRE 230.0 to ELLIS 230.0 Circuit 4" 1.000

line 24016 24044 "4 " 1 0

0

line_1287 "Line BARRE 230.0 to VILLA PK 230.0 Circuit 1" 1.000

line 24016 24154 "1 " 1 0

0

line_1288 "Line BARRE 230.0 to LEWIS 230.0 Circuit 1" 1.000

line 24016 25201 "1 " 1 0

0

line_1289 "Line DELAMO 230.0 to BARRE 230.0 Circuit 1" 1.000

line 24029 24016 "1 " 1 0

0

line_1290 "Line DELAMO 230.0 to ELLIS 230.0 Circuit 1" 1.000

line 24029 24044 "1 " 1 0

0

line_1291 "Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 1" 1.000

line 24044 24069 "1 " 1 0

0

line_1292 "Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 3" 1.000

line 24044 24069 "3 " 1 0

0

line_1293 "Line ELLIS 230.0 to JOHANNA 230.0 Circuit 1" 1.000

line 24044 24072 "1 " 1 0

0

line_1294 "Line ELLIS 230.0 to SANTIAGO 230.0 Circuit 1" 1.000

line 24044 24134 "1 " 1 0

0

line_1295 "Line ELLIS 230.0 to HUNTBCH1 230.0 Circuit 2" 1.000

line 24044 24369 "2 " 1 0

0

line_1296 "Line ELLIS 230.0 to HUNTBCH1 230.0 Circuit 4" 1.000

line 24044 24369 "4 " 1 0

0

line_1297 "Line JOHANNA 230.0 to SANTIAGO 230.0 Circuit 1" 1.000

line 24072 24134 "1 " 1 0

0

line_1298 "Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 1" 1.000

line 24131 24134 "1 " 1 0

0

line_1299 "Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 2" 1.000

line 24131 24134 "2 " 1 0

0

line_12100 "Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000

line 24131 24137 "1 " 1 0

0

line_12101 "Line VIEJO 230.0 to CHINO 230.0 Circuit 1" 1.000

line 25654 24025 "1 " 1 0

0

line_12102 "Line VIEJO 230.0 to S.ONOFRE 230.0 Circuit 1" 1.000

line 25654 24131 "1 " 1 0

0

line_12103 "Line BARRE 230.0 to LEWIS 230.0 Circuit 1" 1.000

line 24016 25201 "1 " 1 0

0

line_12104 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 1" 1.000

line 25201 24137 "1 " 1 0

0

line_12105 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 2" 1.000

line 25201 24137 "2 " 1 0

0

line_12106 "Line LEWIS 230.0 to VILLA PK 230.0 Circuit 1" 1.000

line 25201 24154 "1 " 1 0

0

##

CATEGORY P1.3 FAULT WITH LOSS OF ONE TRANSFORMER

##

tran_1301 "Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 1MIRLOM1T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOMW 230.00" "1 " 0 "MIRLOM1T 13.80"

0

tran_1302 "Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 2MIRLOM2T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOMW 230.00" "2 " 0 "MIRLOM2T 13.80"

0

tran_1303 "Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 3MIRLOM3T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOME 230.00" "3 " 0 "MIRLOM3T 13.80"

0

tran_1304 "Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 4MIRLOM4T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOME 230.00" "4 " 0 "MIRLOM4T 13.80"

0

tran_1305 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 1SERRAN1T 13.80" 1.000

tran "SERRANO 500.00" "SERRANO 230.00" "1 " 0 "SERRAN1T 13.80"

0

tran_1306 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 2SERRAN2T 13.80" 1.000

tran "SERRANO 500.00" "SERRANO 230.00" "2 " 0 "SERRAN2T 13.80"

0

tran_1307 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 3 0.00" 1.000

tran "SERRANO 500.00" "SERRANO 230.00" "3 " 0 " 0.00"

0

tran_1308 "Tran VINCENT 500.00 to VINCENT 230.00 Circuit 2VINCEN2T 13.80" 1.000

tran "VINCENT 500.00" "VINCENT 230.00" "2 " 0 "VINCEN2T 13.80"

0

tran_1309 "Tran VINCENT 500.00 to VINCENT 230.00 Circuit 3 0.00" 1.000

tran "VINCENT 500.00" "VINCENT 230.00" "3 " 0 " 0.00"

0

tran_1310 "Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 1VINCEN1T 13.80" 1.000

tran "VINCENT 500.00" "VINCNT2 230.00" "1 " 0 "VINCEN1T 13.80"

0

tran_1311 "Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 4VINCEN4T 13.80" 1.000

tran "VINCENT 500.00" "VINCNT2 230.00" "4 " 0 "VINCEN4T 13.80"

0

tran_1312 "Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 3RCHVST3T 13.80" 1.000

tran "RANCHVST 500.00" "RANCHVST 230.00" "3 " 0 "RCHVST3T 13.80"

0

tran_1313 "Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 4RCHVST4T 13.80" 1.000

tran "RANCHVST 500.00" "RANCHVST 230.00" "4 " 0 "RCHVST4T 13.80"

0

tran_1314 "Tran MESA CAL 500.00 to MESA CAL 230.00 Circuit 2MESA2T 13.80" 1.000

tran "MESA CAL 500.00" "MESA CAL 230.00" "2 " 0 "MESA2T 13.80"

0

tran_1315 "Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 3MESA3T 13.80" 1.000

tran "MESA CAL 500.00" "MESACALS 230.00" "3 " 0 "MESA3T 13.80"

0

tran_1316 "Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 4MESA4T 13.80" 1.000

tran "MESA CAL 500.00" "MESACALS 230.00" "4 " 0 "MESA4T 13.80"

0

tran_1317 "Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 1MIRLOM1T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOMW 230.00" "1 " 0 "MIRLOM1T 13.80"

0

tran_1318 "Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 2MIRLOM2T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOMW 230.00" "2 " 0 "MIRLOM2T 13.80"

0

tran_1319 "Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 3MIRLOM3T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOME 230.00" "3 " 0 "MIRLOM3T 13.80"

0

tran_1320 "Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 4MIRLOM4T 13.80" 1.000

tran "MIRALOMA 500.00" "MIRALOME 230.00" "4 " 0 "MIRLOM4T 13.80"

0

tran_1321 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 1SERRAN1T 13.80" 1.000

tran "SERRANO 500.00" "SERRANO 230.00" "1 " 0 "SERRAN1T 13.80"

0

tran_1322 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 2SERRAN2T 13.80" 1.000

tran "SERRANO 500.00" "SERRANO 230.00" "2 " 0 "SERRAN2T 13.80"

0

tran_1323 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 3 0.00" 1.000

tran "SERRANO 500.00" "SERRANO 230.00" "3 " 0 " 0.00"

0

tran_1324 "Tran VINCENT 500.00 to VINCENT 230.00 Circuit 2VINCEN2T 13.80" 1.000

tran "VINCENT 500.00" "VINCENT 230.00" "2 " 0 "VINCEN2T 13.80"

0

tran_1325 "Tran VINCENT 500.00 to VINCENT 230.00 Circuit 3 0.00" 1.000

tran "VINCENT 500.00" "VINCENT 230.00" "3 " 0 " 0.00"

0

tran_1326 "Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 1VINCEN1T 13.80" 1.000

tran "VINCENT 500.00" "VINCNT2 230.00" "1 " 0 "VINCEN1T 13.80"

0

tran_1327 "Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 4VINCEN4T 13.80" 1.000

tran "VINCENT 500.00" "VINCNT2 230.00" "4 " 0 "VINCEN4T 13.80"

0

tran_1328 "Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 3RCHVST3T 13.80" 1.000

tran "RANCHVST 500.00" "RANCHVST 230.00" "3 " 0 "RCHVST3T 13.80"

0

tran_1329 "Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 4RCHVST4T 13.80" 1.000

tran "RANCHVST 500.00" "RANCHVST 230.00" "4 " 0 "RCHVST4T 13.80"

0

tran_1330 "Tran MESA CAL 500.00 to MESA CAL 230.00 Circuit 2MESA2T 13.80" 1.000

tran "MESA CAL 500.00" "MESA CAL 230.00" "2 " 0 "MESA2T 13.80"

0

tran_1331 "Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 3MESA3T 13.80" 1.000

tran "MESA CAL 500.00" "MESACALS 230.00" "3 " 0 "MESA3T 13.80"

0

tran_1332 "Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 4MESA4T 13.80" 1.000

tran "MESA CAL 500.00" "MESACALS 230.00" "4 " 0 "MESA4T 13.80"

0

###

CATEGORY P1.4 FAULT WITH LOSS OF ONE SHUNT DEVICE

###

lshunt_1401 "LINE SHUNT @ MIRALOMA

lshunt "EAST TS 500.00" "MIRALOMA 500.00" "t" 1 1 0

0

svd_1402 "SVD BARRE 230.00" 1.000

svd "BARRE 230.00" "ei" 0

0

svd_1403 "SVD CHINO 230.00" 1.000

svd "CHINO 230.00" "ei" 0

0

svd_1404 "SVD EL NIDO 230.00" 1.000

svd "EL NIDO 230.00" "ei" 0

0

svd_1405 "SVD GOULD 230.00 " 1.000

svd "GOULD 230.00" "ei" 0

0

svd_1406 "SVD JOHANNA 230.00" 1.000

svd "JOHANNA 230.00" "ei" 0

0

svd_1407 "SVD LA FRESA 230.00" 1.000

svd "LA FRESA 230.00" "ei" 0

0

svd_1408 "SVD LAGUBELL 230.00" 1.000

svd "LAGUBELL 230.00" "ei" 0

0

svd_1409 "SVD LCIENEGA 230.00" 1.000

svd "LCIENEGA 230.00" "ei" 0

0

svd_1410 "SVD MIRALOMA 500.00" 1.000

svd "MIRALOMA 500.00" "ei" 0

0

svd_1411 "SVD MIRALOME 230.00" 1.000

svd "MIRALOME 230.00" "ei" 0

0

svd_1412 "SVD MIRALOMW 230.00" 1.000

svd "MIRALOMW 230.00" "ei" 0

0

svd_1413 "SVD OLINDA 230.00" 1.000

svd "OLINDA 230.00" "ei" 0

0

svd_1414 "SVD PADUA 230.00" 1.000

svd "PADUA 230.00" "ei" 0

0

svd_1415 "SVD RIOHONDO 230.00" 1.000

svd "RIOHONDO 230.00" "ei" 0

0

svd_1416 "SVD SANTIAGO 230.00" 1.000

svd "SANTIAGO 230.00" "ei" 0

0

svd_1417 "SVD VIEJO 230.00" 1.000

svd "VIEJO 230.00" "ei" 0

0

svd_1418 "SVD VILLA PK 230.00" 1.000

svd "VILLA PK 230.00" "ei" 0

0

svd_1419 "SVD VINCENT 500.00" 1.000

svd "VINCENT 500.00" "ei" 0

0

svd_1420 "SVD VINCENT 230.00" 1.000

svd "VINCENT 230.00" "ei" 0

0

svd_1421 "SVD WALNUTW 230.00" 1.000

svd "WALNUTW 230.00" "ei" 0

0

##

CATEGORY P1.5 IS NOT APPLICABLE IN THE METRO AREA AS NO DC LINES EXIST WITHIN THIS AREA.

##

CATEGORY P2

```
#########################################################################
# CATEGORY P2.1 LOSS OF ONE TRANSMISSION LINE SECTION WITHOUT A FAULT
#########################################################################
# CATEGORY P2.1 IS NOT APPLICABLE FOR THE METRO BULK AREA AS THERE ARE NO MULTI-SEGMENTED BULK TRANSMISSION LINES
#########################################################################
# CATEGORY P2.2 SLG FAULT WITH LOSS OF ONE BUS SECTION
#########################################################################
# CATEGORY P2.2 IN THE METRO AREA, SECTIONALIZING BUS TIES EXIST (OR WILL EXIST) ONLY AT ALAMITOS, HUNTINGTON BEACH, MIRA
# LOMA, MESA (FUTURE), SAN ONOFRE, VINCENT AND WALNUT. ALL METRO AREA SUBSTATIONS DESIGNS ARE SUCH THAT LOSS OF ONE BUS
# SECTION DOES NOT RESULT IN ANY ADDITIONAL P2.2 IMPACTS THAT ARE NOT ALREADY ADDRESSED AS PART OF CATGEGORY P1.
#########################################################################
# CATEGORY P2.3 SLG FAULT WITH LOSS OF ONE BREAKER (INTERNAL FAULT) (NON-BUS-TIE-BREAKER)
# HUNTINGTON BEACH, CHEVMAIN, EL SEGUNDO, REDONDO EXCLUDED BECAUSE THIS CATEGORY WOULD DECREASE GENERATION AND WOULD NOT PROPERLY STRESS THE CASE
# THESE CATEGORIES ARE ADDRESSED VIA SCE ATRA STUDY
#########################################################################
# BARRE 220 KV
bay_2301 "BARRE 220.00 1S"
 tran "BARRE 230.00" "BARRE 66.0" "1 " 0
 svd "BARRE 230.00" "ei" 0
0
bay_2302 "BARRE 220.00 3S"
 tran "BARRE 230.00" "BARRE 66.00" "3" 0
 svd "BARRE 230.00" "ei" 0
0
bay_2303 "BARRE 220.00 4S"
 line "BARRE 230.00" "DELAMO 230.00" "1"  1 0
 svd "BARRE 230.00" "ei" 0
0
bay_2304 "BARRE 220.00 5S"
 tran "BARRE 230.00" "BARRE 66.00" "4" 0
```

svd "BARRE 230.00" "ei" 0

0

bay_2305 "BARRE 220.00 6S"

line "BARRE 230.00" "LEWIS 230.00" "1" 1 0

svd "BARRE 230.00" "ei" 0

0

bay_2306 "BARRE 220.00 7S"

line "BARRE 230.00" "VILLA PK 230.00" "1" 1 0

svd "BARRE 230.00" "ei" 0

0

bay_2307 "BARRE 220.00 8S"

line "BARRE 230.00" "ELLIS 230.00" "4" 1 0

svd "BARRE 230.00" "ei" 0

0

bay_2308 "BARRE 220.00 9S"

line "BARRE 230.00" "ALMITOSW 230.00" "2" 1 0

svd "BARRE 230.00" "ei" 0

0

bay_2309 "BARRE 220.00 10S"

line "BARRE 230.00" "ALMITOSE 230.00" "1" 1 0

svd "BARRE 230.00" "ei" 0

0

bay_2310 "BARRE 220.00 11S"

line "BARRE 230.00" "ELLIS 230.00" "3" 1 0

svd "BARRE 230.00" "ei" 0

0

bay_2311 "CHINO 220 KV POS 5E"

svd "CHINO 230.00" "ei" 0

tran "CHINO 230.00" "CHINO 66.00" "1" 0

line "CHINO 230.00" "MIRALOMW 230.00" "2" 1 0

0

bay_2312 "BARRE 220.00 13S"

line "BARRE 230.00" "ELLIS 230.00" "1" 1 0 svd "BARRE 230.00" "ei" 0

0

#

CHINO 220 KV

bay_2313 "CHINO 220KV POS.2"

line "CHINO 230.00" "MIRALOMW 230.00" "2" 1 0

tran "CHINO 230.00" "CHINO 66.00 " "3" 0 " 0.00"

0

bay_2314 "CHINO 220 KV POS 7 INTERNAL FAULT"

line "CHINO 230.00" "MIRALOME 230.00" "3" 1 0

tran "CHINO 230.00" "CHINO 66.00 " "2" 0

0

bay_2315 "CHINO 220 KV POS 10 INTERNAL FAULT"

line "CHINO 230.00" "VIEJO 230.00" "1" 1 0

line "CHINO 230.00" "SERRANO 230.00" "1" 1 0

0

bay_2316 "CHIN0 220 KV POS 5W"

line "CHINO 230.00" "MIRALOMW 230.00" "1" 1 0

tran "CHINO 230.00" "CHINO 66.00" "3" 0

0

bay_2317 "CHINO 220 KV POS 7W"

line "CHINO 230.00" "MIRALOMW 230.00" "1" 1 0

tran "CHINO 230.00" "CHINO 66.00" "2" 0

0

bay_2318 "CHINO 220 KV POS 10W"

line "CHINO 230.00" "MIRALOMW 230.00" "1" 1 0

line "CHINO 230.00" "VIEJO 230.00" "1" 1 0

0

bay_2319 "CHINO 220 KV POS 5E"

svd "CHINO 230.00" "ei" 0

tran "CHINO 230.00" "CHINO 66.00" "1" 0

line "CHINO 230.00" "MIRALOMW 230.00" "2" 1 0

0

bay_2320 "CHINO 220 KV POS 7E"
 svd "CHINO 230.00" "ei" 0
 tran "CHINO 230.00" "CHINO 66.00" "1" 0
 line "CHINO 230.00" "MIRALOME 230.00" "3" 1 0
0
bay_2321 "CHINO 220 KV POS 10E"
 svd "CHINO 230.00" "ei" 0
 tran "CHINO 230.00" "CHINO 66.00" "1" 0
 line "CHINO 230.00" "SERRANO 230.00" "1" 1 0
0
#
ELLIS 220 KV
bay_2322 "ELLIS 220 KV POS 1 INTERNAL FAULT"
 line "ELLIS 230.00" "SANTIAGO 230.00" "1" 1 0
 line "ELLIS 230.00" "BARRE 230.00" "2" 1 0
0
bay_2323 "ELLIS 220 KV POS 2 INTERNAL FAULT"
 line "ELLIS 230.00" "JOHANNA 230.00" "1" 1 0
 line "ELLIS 230.00" "BARRE 230.00" "1" 1 0
0
GOODRICH 220 KV
bay_2324 "GOODRICH 220 KV POS 4 INTERNAL FAULT"
 line "GOODRICH 230.00" "GOULD 230.00" "1" 1 0
 line "GOODRICH 230.00" "MESA CAL 230.00" "1" 1 0
0
EL NIDO 220 KV
bay_2325 "EL NIDO 220 KV POS 1XN"
 line "EL NIDO 230.00" "ELSEGNDO 230.00" "1" 1 0
 tran "EL NIDO 230.00" "EL NIDO 66.00" "1" 0
 svd "EL NIDO 230.00" "ei" 0
0
bay_2326 "EL NIDO 220 KV POS 1N"
 line "EL NIDO 230.00" "CHEVMAIN 230.00" "1" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "1" 0

svd "EL NIDO 230.00" "ei" 0

0

bay_2327 "EL NIDO 220 KV POS 2N"

line "EL NIDO 230.00" "LCIENEGA 230.00" "1" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "1" 0

svd "EL NIDO 230.00" "ei" 0

0

bay_2328 "EL NIDO 220 KV POS 8N "

line "EL NIDO 230.00" "LA FRESA 230.00" "4" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "1" 0

svd "EL NIDO 230.00" "ei" 0

0

bay_2329 "EL NIDO 220 KV POS 9N"

line "EL NIDO 230.00" "LA FRESA 230.00" "3" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "1" 0

svd "EL NIDO 230.00" "ei" 0

0

bay_2330 "EL NIDO 230.00 POS 1XS"

line "EL NIDO 230.00" "ELSEGNDO 230.00" "1" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "3" 0

0

bay_2331 "EL NIDO 230.00 POS 1S"

line "EL NIDO 230.00" "CHEVMAIN 230.00" "1" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "3" 0

0

bay_2332 "EL NIDO 230.00 POS 2S"

line "EL NIDO 230.00" "LCIENEGA 230.00" "1" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "3" 0

0

bay_2333 "EL NIDO 220 KV POS 8S"

line "EL NIDO 230.00" "LA FRESA 230.00" "4" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "3" 0

0

bay_2334

line "EL NIDO 230.00" "LA FRESA 230.00" "3" 1 0

tran "EL NIDO 230.00" "EL NIDO 66.00" "3" 0

0

#

GOULD

bay_2335 "GOULD 220 KV POS 1W"

line "GOULD 230.00" "EAGLROCK 230.00" "1" 1 0

svd "GOULD 230.00" "ei" 0

0

bay_2336 "GOULD 220 KV POS 2W"

line "GOULD 230.00" "SYLMAR S 230.00" "1" 1 0

svd "GOULD 230.00" "ei" 0

0

bay_2337"GOULD 220 KV POS 3W"

tran "GOULD 230.00" "GOULD 66.00" "1" 0

svd "GOULD 230.00" "ei" 0

0

bay_2338 "GOULD 220 KV POS 4W"

line "GOULD 230.00" "GOODRICH 230.00" "1" 1 0

svd "GOULD 230.00" "ei" 0

0

bay_2339 "GOULD 220 KV POS 6W"

tran "GOULD 230.00" "GOULD 66.00" "2" 0

svd "GOULD 230.00" "ei" 0

0

#

HINSON 220 KV - ARCOGEN EXCLUDED

bay_2340 "HINSON 220 KV POS 1 INTERNAL FAULT"

line "LITEHIPE 230.00" "HINSON 230.00" "1" 1 0

line "HARBOR 230.00" "HINSON 230.00" "1" 1 0

0

```
# HARBOR GEN 220 KV
bay_2341 "HARBORGEN INTERNAL FAULT "
 line "HARBOR 230.00 " "HINSON 230.00" "1"  1 0
 line "HARBOR 230.00 " "LBEACH 230.00" "1"  1 0
0
# JOHANNA 220 KV
bay_2342 "JOHANNA 220 KV POS 1N"
 line "JOHANNA 230.00" "ELLIS 230.00" "1"  1 0
 tran "JOHANNA 230.00" "JOHANNA 66.00" "3"  0
0
bay_2343 "JOHANNA 220 KV POS 2N"
 line "JOHANNA 230.00" "SANTIAGO 230.00" "1"  1 0
 tran "JOHANNA 230.00" "JOHANNA 66.00" "3"  0
0
bay_2344 "JOHANNA 220 KV POS 1S"
 line "JOHANNA 230.00" "ELLIS 230.00" "1"  1 0
 tran "JOHANNA 230.00" "JOHANNA 66.00" "4"  0
 svd "JOHANNA 230.00" "ei" 0
0
bay_2345 "JOHANNA 220 KV POS 2N"
 line "JOHANNA 230.00" "SANTIAGO 230.00" "1"  1 0
 tran "JOHANNA 230.00" "JOHANNA 66.00" "4"  0
 svd "JOHANNA 230.00" "ei" 0
0
#
# LA FRESA 220 KV
bay_2346 "LA FRESA 220 KV POS 3XN"
 line "LA FRESA 230.00" "EL NIDO 230.00" "3"  1 0
 svd "LA FRESA 230.00" "ei"  0
0
bay_2347 "LA FRESA 220 KV POS 1XN"
 line "LA FRESA 230.00" "REDONDO 230.00" "1"  1 0
 svd "LA FRESA 230.00" "ei"  0
```

0

bay_2348 "LA FRESA 220 KV POS 2XN"

line "LA FRESA 230.00" "REDONDO 230.00" "2" 1 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2349 "LA FRESA 220 KV POS 2N"

line "LA FRESA 230.00" "EL NIDO 230.00" "4" 1 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2350 "LA FRESA 220 KV POS 3N"

tran "LA FRESA 230.00" "LA FRESA 66.00" "1" 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2351 "LA FRESA 220 KV POS 4N"

line "LA FRESA 230.00" "LCIENEGA 230.00" "1" 1 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2352 "LA FRESA 220 KV POS 6N"

tran "LA FRESA 230.00" "LA FRESA 66.0" "2" 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2353 "LA FRESA 220 KV POS 7N"

tran "LA FRESA 230.00" "LA FRESA 66.00" "3" 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2354 "LA FRESA 220 KV POS 9N"

line "LA FRESA 230.00" "HINSON 230.00" "1" 1 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2355 "LA FRESA 220 KV POS 10N"

line "LA FRESA 230.00" "LAGUBELL 230.00" "1" 1 0

svd "LA FRESA 230.00" "ei" 0

0

bay_2356 "LA FRESA 220 KV POS 11N"

tran "LA FRESA 230.00" "LA FRESA 66.00" "4" 0

svd "LA FRESA 230.00" "ei" 0

0

LAGUNA BELL

bay_2357 "LAGUNA BELL 220 KV POS 12N"

line "LAGUBELL 230.00" "LA FRESA 230.00" "1" 1 0

svd "LAGUBELL 230.00" "ei" 0

0

bay_2358 "LAGUNA BELL 220 KV POS 11N"

line "LAGUBELL 230.00" "MESA CAL 230.00" "1" 1 0

svd "LAGUBELL 230.00" "ei" 0

0

bay_2359 "LAGUNA BELL 220 KV POS 10N"

tran "LAGUBELL 230.00" "LAGUBELL 66.00" "4" 0

svd "LAGUBELL 230.00" "ei" 0

0

bay_2360 "LAGUNA BELL 220 KV POS 9N"

tran "LAGUBELL 230.00" "LAGUBELL 66.00" "3" 0

svd "LAGUBELL 230.00" "ei" 0

0

bay_2361 "LAGUNA BELL 220 KV POS 6N"

line "LAGUBELL 230.00" "DELAMO 230.00" "1" 1 0

svd "LAGUBELL 230.00" "ei" 0

0

bay_2362 "LAGUNA BELL 220 KV POS 5N"

line "LAGUBELL 230.00" "MESACALS 230.00" "2" 1 0

svd "LAGUBELL 230.00" "ei" 0

0

bay_2363 "LAGUNA BELL 220 KV POS 4N"

tran "LAGUBELL 230.00" "LAGUBELL 66.00" "2" 0

svd "LAGUBELL 230.00" "ei" 0

0

bay_2364

tran "LAGUBELL 230.00" "LAGUBELL 66.00" "1" 0

svd "LAGUBELL 230.00" "ei" 0

0

#

MIRA LOMA 500 KV

bay_2365 "MIRALOMA 500 KV POS 1X INTERNAL FAULT"

line "MIRA81X2 500.00" "RANCHVST 500.00" "1" 1 0

line "MIRA81X2 500.00" "SERRANO 500.00" "1" 1 0

0

bay_2366 "MIRALOMA 500 KV POS 2 INTERNAL FAULT"

line "LUGO 500.00" "MIRALOMA 500.00" "2" 1 0

tran "MIRALOMA 500.00" "MIRALOMW 230.00" "1"   0 "MIRLOM1T 13.80"

0

bay_2367 "MIRALOMA 500 KV POS 6 INTERNAL FAULT"

line "LUGO 500.00" "MIRALOMA 500.00" "3" 1 0

tran "MIRALOMA 500.00" "MIRALOME 230.00" "4" 0 "MIRLOM4T 13.80"

0

bay_2368 "MIRALOMA 500 KV POS 1XN"

line "MIRA81X2 500.00" "RANCHVST 500.00" "1" 1 0

svd "MIRALOMA 500.00" "ei" 0

0

bay_2369 "MIRALOMA 500 KV POS 1N"

line "MIRALOMA 500.00" "SERRANO 500.00" "2" 1 0

svd "MIRALOMA 500.00" "ei" 0

0

bay_2370 "MIRALOMA 500 KV POS 2N"

line "MIRALOMA 500.00" "LUGO 500.00" "2" 1 0

svd "MIRALOMA 500.00" "ei" 0

0

bay_2371 "MIRALOMA 500 KV POS 6N"

line "MIRALOMA 500.00" "LUGO 500.00" "3" 1 0

svd "MIRALOMA 500.00" "ei" 0

0

bay_2372 "MIRALOMA 500 KV POS 1XS"

line "MIRA81X2 500.00" "SERRANO 500.00" "1" 1 0

svd "MIRALOMA 500.00" "ei" 0

0

bay_2373 "MIRALOMA 500 KV POS 2S"

tran "MIRALOMA 500.00" "MIRALOMW 230.00" "1" 0 "MIRLOM1T 13.80"

svd "MIRALOMA 500.00" "ei" 0

0

bay_2374 "MIRALOMA 500 KV POS 4S"

tran "MIRALOMA 500.00" "MIRALOMW 230.00" "2" 0 "MIRLOM2T 13.80"

svd "MIRALOMA 500.00" "ei" 0

0

bay_2375 "MIRALOMA 500 KV POS 6S"

tran "MIRALOMA 500.00" "MIRALOME 230.00" "4" 0 "MIRLOM4T 13.80"

svd "MIRALOMA 500.00" "ei" 0

0

MIRA LOMA(E) 220 KV

bay_2376 "MIRALOMAE 220 KV POS 14N"

line "MIRALOME 230.00" "CHINO 230.00" "3" 1 0

svd "MIRALOME 230.00" "ei" 0

0

bay_2377 "MIRALOMAE 220 KV POS 15N"

tran "MIRALOME 230.00" "MIRALOMA 500.00" "4" 0 "MIRLOM4T 13.80"

svd "MIRALOME 230.00" "ei" 0

0

bay_2378 "MIRALOMAE 220 KV POS 16N"

line "MIRALOME 230.00" "RANCHVST 230.00" "2" 1 0

svd "MIRALOME 230.00" "ei" 0

0

MIRALOMA (W) 220 KV

bay_2379 "MIRALOMAW 220 KV POS 2S"

line "MIRALOMW 230.00" "CHINO 230.00" "1" 1 0 svd "MIRALOMW 230.00" "ei" 0

0

bay_2380 "MIRALOMAW 220 KV POS 3S"

line "MIRALOMW 230.00" "WALNUTE 230.00" "1" 1 0

svd "MIRALOMW 230.00" "ei" 0

0

bay_2381 "MIRALOMAW 220 KV POS 4S"

tran "MIRALOMW 230.00" "MIRALOMA 500.00" "1" 0 "MIRLOM1T 13.80"

svd "MIRALOMW 230.00" "ei" 0

0

bay_2382 "MIRALOMAW 220 KV POS 5S"

tran "MIRALOMW 230.00" "MIRALOMW 66.00" "5" 0

svd "MIRALOMW 230.00" "ei" 0

0

bay_2383 "MIRALOMAW 220 KV POS 6S"

tran "MIRALOMW 230.00" "MIRALOMW 66.00" "6" 0

svd "MIRALOMW 230.00" "ei" 0

0

bay_2384 "MIRALOMAW 220 KV POS 8S"

tran "MIRALOMW 230.00" "MIRALOMW 66.00" "7" 0

svd "MIRALOMW 230.00" "ei" 0

0

#

bay_2385 "MIRALOMW 220 KV POS 3 INTERNAL FAULT"

line "MIRALOMW 230.00 " "CHINO 230.00" "2" 1 0

line "MIRALOMW 230.00 " "WALNUTE 230.00" "1" 1 0

0

bay_2386 "MIRALOMW 220 KV POS 5 INTERNAL FAULT"

tran "MIRALOMW 230.00 " "MIRALOMW 66.00" "5" 1 0

line "MIRALOMW 230.00 " "WILDLIFE 230.00" "1" 1 0

0

bay_2387 "MIRALOME 220 KV POS 14 INTERNAL FAULT"

line "MIRALOME 230.00" "OLINDA 230.00" "1" 1 0 line "MIRALOME 230.00" "CHINO 230.00" "3" 1 0

0

bay_2388 "MIRALOME 220 KV POS 15 INTERNAL FAULT"

tran "MIRALOMA 500.00" "MIRALOME 230.00" "4" 0 "MIRLOM4T 13.80"

line "MIRALOME 230.00" "VSTA 230.00" "2" 1 0

0

bay_2389 "MIRALOME 220 KV POS 16 INTERNAL FAULT"

line "MIRALOME 230.00" "RANCHVST 230.00" "1" 1 0

line "MIRALOME 230.00" "RANCHVST 230.00" "2" 1 0

0

OLINDA 220 KV

bay_2390 "OLINDA 220 KV POS 1S"

tran "OLINDA 230.00" "OLINDA 66.00" "1" 0

svd "OLINDA 230.00" "ei" 0

0

bay_2391 "OLINDA 220 KV POS 2S"

line "OLINDA 230.00" "CENTER 230.00" "1" 1 0

svd "OLINDA 230.00" "ei" 0

0

bay_2392 "OLINDA 220 KV POS 3S"

tran "OLINDA 230.00" "OLINDA 66.00" "2" 0

svd "OLINDA 230.00" "ei" 0

0

bay_2393 "OLINDA 220 KV POS 6S"

line "OLINDA 230.00" "WALNUTE 230.00" "1" 1 0

svd "OLINDA 230.00" "ei" 0

0

bay_2394 "OLINDA 220 KV POS 7S"

tran "OLINDA 230.00" "OLINDA 66.00" "4" 0

svd "OLINDA 230.00" "ei" 0

0

#

bay_2395 "OLINDA 220 KV POS 6 INTERNAL FAULT" line "OLINDA 230.00" "MIRALOME 230.00" "1" 1 0

line "OLINDA 230.00" "WALNUTE 230.00" "1" 1 0

0

PADUA 220 KV

bay_2396 "PADUA 220 KV POS 2N"

line "PADUA 230.00" "RANCHVST 230.00" "1" 1 0

svd "PADUA 230.00" "ei" 0

0

bay_2397 "PADUA 220 KV POS 4N"

tran "PADUA 230.00" "PADUA 66.00" "2" 0

svd "PADUA 230.00" "ei" 0

0

bay_2398 "PADUA 220 KV POS 6N"

tran "PADUA 230.00" "PADUA 66.00" "3" 0

svd "PADUA 230.00" "ei" 0

0

bay_2399 "PADUA 220 KV POS 8N"

tran "PADUA 230.00" "PADUA 66.00" "4" 0

svd "PADUA 230.00" "ei" 0

0

RANCHO VISTA 500 KV

bay_23100 "RANCHO VISTA 500 KV POS 7 INTERNAL FAULT"

line "RANCHVST 500.00" "LUGO 500.00" "1" 1 0

tran "RANCHVST 500.00" "RANCHVST 230.00" "4" 0 "RCHVST4T 13.80"

0

RANCHO VISTA 220 KV

bay_23101 "RANCHO VISTA 220 KV POS 12 INTERNAL FAULT"

tran "RANCHVST 500.00" "RANCHVST 230.00" "4" 0 "RCHVST4T 13.80"

line "RANCHVST 230.00" "PADUA 230.00" "2" 1 0

0

bay_23102 "RANCHO VISTA 220 KV POS 11 INTERNAL FAULT"

line "ETIWANDA 230.00" "RANCHVST 230.00" "2" 1 0

line "PADUA 230.00" "RANCHVST 230.00" "1" 1 0

0

bay_23103 "RANCHO VISTA 220 KV POS 10 INTERNAL "

line "ETIWANDA 230.00" "RANCHVST 230.00" "1" 1 0

line "RANCHVST 230.00" "MIRALOME 230.00" "2" 1 0

0

RIO HONDO 220 KV

bay_23104 "RIOHONDO 220 KV POS 1N"

line "RIOHONDO 230.00" "MESACALS 230.00" "1" 1 0

svd "RIOHONDO 230.00" "ei" 0

0

bay_23105 "RIOHONDO 220 KV POS 2N"

tran "RIOHONDO 230.00" "RIOHONDO 66.00" "1" 0

svd "RIOHONDO 230.00" "ei" 0

0

bay_23106 "RIOHONDO 220 KV POS 3N"

tran "RIOHONDO 230.00" "RIOHONDO 66.00" "3" 0

svd "RIOHONDO 230.00" "ei" 0

0

bay_23107 "RIOHONDO 220KV POS 4N"

line "RIOHONDO 230.00" "VINCENT 230.00" "2" 1 0

svd "RIOHONDO 230.00" "ei" 0

0

bay_23108 "RIOHONDO 220 KV POS 7N"

line "RIOHONDO 230.00" "VINCENT 230.00" "1" 1 0

svd "RIOHONDO 230.00" "ei" 0

0

bay_23109 "RIOHONDO 22O KV POS 10N"

tran "RIOHONDO 230.00" "RIOHONDO 66.00" "4" 1 0

svd "RIOHONDO 230.00" "ei" 0

0

#

bay_23110 "RIO HONDO 220 KV POS 4 INTERNAL FAULT"

line "MESACALS 230.00" "RIOHONDO 230.00" "2" 1 0 line "VINCENT 230.00 " "RIOHONDO 230.00" "2" 1 0

0

SANTIAGO 220 KV

bay_23111 "SANTIAGO 220 KV POS 5"

line "SANTIAGO 230.00" "S.ONOFRE 230.00" "2" 1 0

line "SANTIAGO 230.00" "ELLIS 230.00" "1" 1 0

0

bay_23112 "SANTIAGO 220 KV POS 1N"

tran "SANTIAGO 230.00" "SANTIAGO 66.00" "1" 0

svd "SANTIAGO 230.00" "ei" 0

0

bay_23113 "SANTIAGO 220 KV POS 3N"

line "SANTIAGO 230.00" "JOHANNA 230.00" "1" 1 0

svd "SANTIAGO 230.00" "ei" 0

0

bay_23114 "SANTIAGO 220 KV POS 5N"

line "SANTIAGO 230.00" "S.ONOFRE 230.00" "2" 1 0

svd "SANTIAGO 230.00" "ei" 0

0

bay_23115 "SANTIAGO 220 KV POS 6N"

tran "SANTIAGO 230.00" "SANTIAGO 66.00" "3" 0

svd "SANTIAGO 230.00" "ei" 0

0

bay_23116 "SANTIAGO 220 KV POS 7N"

line "SANTIAGO 230.00" "S.ONOFRE 230.00" "1" 1 0

svd "SANTIAGO 230.00" "ei" 0

0

bay_23117 "SANTIAGO 220 KV POS 8N"

tran "SANTIAGO 230.00" "SANTIAGO 66.00" "4" 0

svd "SANTIAGO 230.00" "ei" 0

0

#

SERRANO 500 KV

bay_23118 "SERRANO 500 KV POS 1 INTERNAL FAULT"

line "SERRANO 500.00 " "MIRA81X2 500.00" "1" 1 0

tran "SERRANO 500.00 " "SERRANO 230.00" "1" 0 "SERRAN1T 13.80"

0

bay_23119 "SERRANO 500 KV POS 2 INTERNAL FAULT"

line "MIRALOMA 500.00 " "SERRANO 500.00" "2" 1 0

tran "SERRANO 500.00 " "SERRANO 230.00" "2" 0 "SERRAN2T 13.80"

0

bay_23120 "SERRANO 500 KV POS 3 INTERNAL FAULT"

line "SERRANO 500.00" "ALBERHIL 500.00" "1" 1 0

tran "SERRANO 500.00" "SERRANO 230.00" "3" 0

0

SERRANO 220 KV

bay_23121 "SERRANO 220 KV POS 1 INTERNAL FAULT"

line "SERRANO 230.00" "LEWIS 230.00" "1" 1 0

line "CHINO 230.00" "SERRANO 230.00" "1" 1 0

0

bay_23122 "SERRANO 220 KV POS 2 INTERNAL FAULT"

line "SERRANO 230.00" "LEWIS 230.00" "2" 1 0

line "SERRANO 230.00" "S.ONOFRE 230.00" "1" 1 0

0

bay_23123 "SERRANO 220 KV POS 3 INTERNAL FAULT"

line "SERRANO 230.00" "VILLA PK 230.00" "2" 1 0

tran "SERRANO 500.00" "SERRANO 230.00" "1" 0 "SERRAN1T 13.80"

0

bay_23124 "SERRANO 220 KV POS 4 INTERNAL FAULT"

line "SERRANO 230.00" "VILLA PK 230.00" "1" 1 0

tran "SERRANO 230.00" "SERRANO 500.00" "2" 0 "SERRAN2T 13.80"

0

LEWIS 220 KV

bay_23125 "LEWIS 220 KV POS 6 INTERNAL FAULT"

line "BARRE 230.00" "LEWIS 230.00" "1" 1 0

line "LEWIS 230.00" "SERRANO 230.00" "2" 1 0

0

bay_23126 "LEWIS 220 KV POS 5 INTERNAL FAULT"

line "LEWIS 230.00" "VILLA PK 230.00" "1" 1 0

line "LEWIS 230.00" "SERRANO 230.00" "1" 1 0

0

VIEJO 220 KV

bay_23127 "VIEJO 220 KV POS 1N"

tran "VIEJO 230.00" "VIEJO 66.00" "1" 1 0

svd "VIEJO 230.00" "ei" 0

0

bay_23128 "VIEJO 220 KV POS 3N"

tran "VIEJO 230.00" "VIEJO 66.00" "2" 1 0

svd "VIEJO 230.00" "ei" 0

0

bay_23129 "VIEJO 220 KV POS 4N"

line "VIEJO 230.00" "S.ONOFRE 230.00" "1" 1 0

svd "VIEJO 230.00" "ei" 0

0

bay_23130 "VIEJO 220 KV POS 3S"

line "VIEJO 230.00" "CHINO 230.00" "1" 1 0

svd "VIEJO 230.00" "ei" 0

0

VILLA PARK 220 KV

bay_23131 "VILLA PARK 220 KV POS 2N"

line "VILLA PK 230.00" "LEWIS 230.00" "1" 1 0

svd "VILLA PK 230.00" "ei" 0

0

bay_23132 "VILLA PARK 220 KV POS 3N"

tran "VILLA PK 230.00" "VILLA PK 66.00" "1" 0

svd "VILLA PK 230.00" "ei" 0

0

bay_23133 "VILLA PARK 220 KV POS 4N"

tran "VILLA PK 230.00" "VILLA PK 66.00" "2" 0 svd "VILLA PK 230.00" "ei" 0

0

bay_23134 "VILLA PARK 220 KV POS 6N"

tran "VILLA PK 230.00" "VILLA PK 66.00" "3" 0

svd "VILLA PK 230.00" "ei" 0

0

bay_23135 "VILLA PARK 22O KV POS 8N"

line "VILLA PK 230.00" "SERRANO 230.00" "1" 1 0

svd "VILLA PK 230.00" "ei" 0

0

#

bay_23136 "VILLA PARK 220 KV POS 8 INTERNAL FAULT"

line "SERRANO 230.00" "VILLA PK 230.00" "1" 1 0

line "BARRE 230.00" "VILLA PK 230.00" "1" 1 0

0

VINCENT 500 KV

#

bay_23137 "VINCENT 500 KV POS 1 INTERNAL FAULT"

line "VINCENT 500.00" "WIRLWIND 500.00" "3" 1 0

tran "VINCENT 500.00" "VINCNT2 230.00" "4" 0 "VINCEN4T 13.80"

0

bay_23138 "VINCENT 500 KV POS 5 INTERNAL FAULT"

line "VINCENT 500.00" "ANTELOPE 500.00" "1" 1 0

line "VINCENT 500.00" "LUGO 500.00" "2" 1 0

0

bay_23139 "VINCENT 500 KV POS 6 INTERNAL FAULT"

line "VINCENT 500.00" "LUGO 500.00" "1" 1 0

tran "VINCENT 500.00" "VINCENT 230.00" "3" 0

0

VINCENT 220 KV

bay_23140 "VINCENT 220 KV POS 1 INTERNAL FAULT"

line "MESA CAL 230.00" "VINCNT2 230.00" "2" 1 0

line "VINCNT2 230.00" "S.CLARA 230.00" "1" 1 0

```
0
bay_23141 "VINCENT 220 KV POS 2 INTERNAL FAULT"
 line "VINCNT2 230.00" "MESA CAL 230.00" "1"  1 0
 line "VINCNT2 230.00" "PARDEE 230.00" "1"  1 0
0
bay_23142 "VINCENT 220 KV POS 5 INTERNAL FAULT"
 line "PARDEE 230.00" "VINCENT 230.00" "2"  1 0
 tran "VINCENT 230.00"  "VINCENT 500.00" "2" 0 "VINCEN2T 13.80"
0
bay_23143 "VINCENT 220 KV POS 6 INTERNAL FAULT"
 line "VINCENT 230.00" "RIOHONDO 230.00" "2"  1 0
 tran "VINCENT 230.00" "VINCENT 500.00" "3" 0 " 0.00"
0
###################################################################
# CATEGORY P2.4 SLG FAULT WITH LOSS OF ONE BREAKER (INTERNAL FAULT - BUS TIE
BREAKER)
###################################################################
# EXCLUDED HUNTINGTON BEACH
# LONG BEACH 220 KV
bay_2401  "LONG BEACH 220 KV POS 3
 line "LBEACH 230.00" "LITEHIPE 230.00" "1"  1 0
 line "HARBOR 230.00" "LBEACH 230.00" "1"  1 0
0
###################################################################
# Category P3 (Multiple Contingencies)
# ################################################################
# The assessment will consider selected Category P3 contingencies with the loss of a generator unit followed by
# system adjustments and the loss of the following:
###################################################################
# 3F Fault with loss of one generator (P3.1)
###################################################################
# 3F Fault with loss of one transmission circuit (P3.2)
###################################################################
# 3F Fault with loss of one transformer (P3.3)
```

###

3F Fault with loss of one shunt device (P3.4)

###

SLG Fault with loss of a single pole of DC lines (P3.5)

###

SLG Fault with loss of both poles of the Pacific DC Intertie (WECC exemption)

###

Notes:

The purpose of Generation Interconnection Process (GIP) studies is to evaluate stressed generation conditions on

the system. Because Category P3 would not provide for such stressed conditions, the study results would not properly

identify potential impacts corresponding to the projects seeking interconnection. As such, none of Category P3 was

evaluated as part of the GIP studies but is addressed as part of SCE's annual reliability assessment performed in

coordination with the CAISO.

###

##

CATEGORY P4

##

THE ASSESSMENT WILL CONSIDER SLECTED CATEGORY P4 CONTINGENCIES WITH THE LOSS OF MULTIPLE ELEMENTS CAUSED BY A STUCK BREAKER

(NON-BUS-TIE-BREAKER) FOR THE P4.1-P4.5 AND BUS-TIE-BREAKER FOR P4.6) ATTEMPTING TO CLEAR A SLG FAULT ON ONE OF THE FOLLOWING:

IMPACTS THAT INCLUDE A P1 PLUS A BANK OR SHUNT DEVICES WERE EXCLUDED FROM THIS OTG FILE

WILL BE INCLUDED IN SEPERATE OTG FILE

##

P4.1 GENERATORS ARE NOT APPLICABLE FOR THIS STUDY

##

P4.2 TRANSMISSION CIRCUIT

##

MESA 500 KV

bay_4201 "MESA 500 KV POS 5"

line "VINCENT 500.00" "MESA CAL 500.00" "1" 1 0

tran "MESA CAL 500.00" "MESACALS 230.00" "4" 0 "MESA4T 13.80"

0

###

P4.3 TRANSFORMER

###

#

###

P4.4 SHUNT DEVICES

###

#

###

P4.5 BUS SECTION - RESULTS ARE THE SAME AS IN CATEGORY P2.2 AND ARE THEREFORE ADDRESSED UNDER CATEGORY P2.2

###

#

###

P4.6 BUS TIE BREAKER - RESULTS ARE THE SAME AS IN CATEGORY P2.2 AND ARE THEREFORE ADDRESSED UNDER CATEGORY P2.4 EXCEPT FOR WALNUT

bay_4601 "WALNUT 220 KV POS 7N STUCK BREAKER"

line "MESACALS 230.00" "WALNUTW 230.00" "1" 1 0

line "OLINDA 230.00" "WALNUTE 230.00" "1" 1 0

0

bay_4602 "WALNUT 220 KV POS 8N STUCK BREAKER"

line "MESACALS 230.00" "WALNUTW 230.00" "1" 1 0

line "MIRALOMW 230.00" "WALNUTE 230.00" "1" 1 0

0

###

CATEGORY P5 - MULTIPLE CONTINGENCY

###

THE ASSESSMENT WILL CONSIDER SELECTED CATEGORY P5 CONTINGENCIES WITH DELAYED FAULT CLEARING DUE TO THE FAULURE OF A

NON-REDUNDANT RELAY PROTECTING THE FAULTED ELEMENT TO OPERATE AS DESIGNED, FOR ONE OF THE FOLLOWING"

###

SLG FAULT WITH LOSS OF ONE GENERATOR (P5.1)

SLG FAULT WITH LOSS OF ONE TRANSMISSION CIRCUIT (P5.2)

SLG FAULT WITH LOSS OF ONE TRANSFORMER (P5.3)

SLG FAULT WITH LOSS OF ONE SHUNT DEVICE (P5.4)

SLG FAULT WITH LOSS OF ONE BUS SECTION (P5.5)

###

EXCLUDED P5.1 AS IT WOULD NOT PROVIDE SUCH STRESSED CONDITIONS, TO PROPERLY IDENTIFY POTENTIAL IMPACTS CORRESPONDING TO

THE PROJECTS SEEKING INTERCONNECTION. AS SUCH CATEGORY P5.1 WAS NOT EVALUATED

###

CATEGORY P5 POWER FLOW CONDITIONS ARE EXACTLY THE SAME AS CATEGORY P2 OR THE SAME AS CATEGORY P4.

###

CATEGORY P6 - MULTIPLE CONTINGENCIES

###

BECAUSE THE CAISO IMPLEMENTS CONGESTION MANAGEMENT PROTOCOLS THAT CURTAIL GENERATION RESOURCES UNDER LOSS OF A SYSTEM

ELEMENT IN PREPERATION FOR THE NEXT CONTINGENCY, THE ASSESSMENT DID NOT CONSIDER CATEGORY P6 CONTINGENCIES WHCIH

INVOLVES PREPARATION FOR THE NEXT CONTINGENCY, THE ASSESSMENT DID NOT CONSIDER CATEGORY P6 BUT IS ADDRESSED AS PART OF SCE'S

ANNUAL RELIABILITY ASSESSMENT PERFORMED IN COORDINATION WITH THE CAISO

###

CATEGORY P7 - MULTIPLE CONTINGENCIES

###

Category P7.1 Any two adjacent circuits on common structure

#

###

#

###

line_7101 "Line MIRALOMA 500.0 to SERRANO 500.0 Circuit 1 & Line MIRALOMA 500.0 to SERRANO 500.0 Circuit 2" 1.000

line "MIRALOMA 500.00" "SERRANO 500.00" "1 " 1 0

line "MIRALOMA 500.00" "SERRANO 500.00" "2 " 1 0

0

line_7102 "Line BARRE 230.0 to ELLIS 230.0 Circuit 1 & Line BARRE 230.0 to ELLIS 230.0 Circuit 2" 1.000

line "BARRE 230.00" "ELLIS 230.00" "1 " 1 0

line "BARRE 230.00" "ELLIS 230.00" "2 " 1 0

0

line_7103 "Line BARRE 230.0 to ELLIS 230.0 Circuit 3 & Line BARRE 230.0 to ELLIS 230.0 Circuit 4" 1.000

line "BARRE 230.00" "ELLIS 230.00" "3 " 1 0

line "BARRE 230.00" "ELLIS 230.00" "4 " 1 0

0

line_7104 "Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 1 & Line ELLIS 230.0 to HUNTBCH1 230.0 Circuit 2" 1.000

line "ELLIS 230.00" "HUNTGBCH 230.00" "1 " 1 0

line "ELLIS 230.00" "HUNTBCH1 230.00" "2 " 1 0

0

line_7105 "Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 3 & Line ELLIS 230.0 to HUNTBCH1 230.0 Circuit 4" 1.000

line "ELLIS 230.00" "HUNTGBCH 230.00" "3 " 1 0

line "ELLIS 230.00" "HUNTBCH1 230.00" "4 " 1 0

0

line_7106 "Line ELLIS 230.0 to SANTIAGO 230.0 Circuit 1 & Line JOHANNA 230.0 to SANTIAGO 230.0 Circuit 1" 1.000

line "ELLIS 230.00" "SANTIAGO 230.00" "1 " 1 0

line "JOHANNA 230.00" "SANTIAGO 230.00" "1 " 1 0

0

line_7107 "Line ELLIS 230.0 to JOHANNA 230.0 Circuit 1 & Line ELLIS 230.0 to SANTIAGO 230.0 Circuit 1" 1.000

line "ELLIS 230.00" "JOHANNA 230.00" "1 " 1 0

line "ELLIS 230.00" "SANTIAGO 230.00" "1 " 1 0

0

line_7108 "Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 2" 1.000

line "S.ONOFRE 230.00" "SANTIAGO 230.00" "1 " 1 0

line "S.ONOFRE 230.00" "SANTIAGO 230.00" "2 " 1 0

0

line_7109 "Line VIEJO 230.0 to S.ONOFRE 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000

line "VIEJO 230.00" "S.ONOFRE 230.00" "1 " 1 0

line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0

0

line_7110 "Line VIEJO 230.0 to CHINO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000

line "VIEJO 230.00" "CHINO 230.00" "1 " 1 0

line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0

0

line_7111 "Line CHINO 230.0 to SERRANO 230.0 Circuit 1 & Line VIEJO 230.0 to CHINO 230.0 Circuit 1" 1.000

line "CHINO 230.00" "SERRANO 230.00" "1 " 1 0

line "VIEJO 230.00" "CHINO 230.00" "1 " 1 0

0

line_7112 "Line CHINO 230.0 to SERRANO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000

line "CHINO 230.00" "SERRANO 230.00" "1 " 1 0

line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0

0

line_7114 "Line CHINO 230.0 to MIRALOMW 230.0 Circuit 1 & Line CHINO 230.0 to MIRALOMW 230.0 Circuit 2" 1.000

line "CHINO 230.00" "MIRALOMW 230.00" "1 " 1 0

line "CHINO 230.00" "MIRALOMW 230.00" "2 " 1 0

0

line_7115 "Line SERRANO 230.0 to VILLA PK 230.0 Circuit 1 & Line SERRANO 230.0 to VILLA PK 230.0 Circuit 2" 1.000

line "SERRANO 230.00" "VILLA PK 230.00" "1 " 1 0

line "SERRANO 230.00" "VILLA PK 230.00" "2 " 1 0

0

line_7116 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 1 & Line LEWIS 230.0 to SERRANO 230.0 Circuit 2" 1.000

line "LEWIS 230.00" "SERRANO 230.00" "1 " 1 0

line "LEWIS 230.00" "SERRANO 230.00" "2 " 1 0

0

line_7117 "Line BARRE 230.0 to VILLA PK 230.0 Circuit 1 & Line LEWIS 230.0 to VILLA PK 230.0 Circuit 1" 1.000

line "BARRE 230.00" "VILLA PK 230.00" "1 " 1 0

line "LEWIS 230.00" "VILLA PK 230.00" "1 " 1 0

0

line_7118 "Line BARRE 230.0 to VILLA PK 230.0 Circuit 1 & Line BARRE 230.0 to LEWIS 230.0 Circuit 1" 1.000

line "BARRE 230.00" "VILLA PK 230.00" "1 " 1 0

line "BARRE 230.00" "LEWIS 230.00" "1 " 1 0

0

line_7119 "Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1 & Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2" 1.000

line "ALMITOSE 230.00" "BARRE 230.00" "1 " 1 0

line "ALMITOSW 230.00" "BARRE 230.00" "2 " 1 0

0

line_7120 "Line DELAMO 230.0 to BARRE 230.0 Circuit 1 & Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2" 1.000

line "DELAMO 230.00" "BARRE 230.00" "1 " 1 0

line "ALMITOSW 230.00" "BARRE 230.00" "2 " 1 0

0

line_7121 "Line ALMITOSE 230.0 to CENTER S 230.0 Circuit 1 & Line ALMITOSW 230.0 to LITEHIPE 230.0 Circuit 1" 1.000

line "ALMITOSE 230.00" "CENTER 230.00" "1 " 1 0

line "ALMITOSW 230.00" "LITEHIPE 230.00" "1 " 1 0

0

line_7122 "Line DELAMO 230.0 to CENTER S 230.0 Circuit 1 & Line ALMITOSE 230.0 to CENTER S 230.0 Circuit 1" 1.000

line "DELAMO 230.00" "CENTER 230.00" "1 " 1 0

line "ALMITOSE 230.00" "CENTER 230.00" "1 " 1 0

0

line_7123 "Line HINSON 230.0 to DELAMO 230.0 Circuit 1 & Line ALMITOSW 230.0 to LITEHIPE 230.0 Circuit 1" 1.000

line "HINSON 230.00" "DELAMO 230.00" "1 " 1 0

line "ALMITOSW 230.00" "LITEHIPE 230.00" "1 " 1 0

0

line_7124 "Line DELAMO 230.0 to LAGUBELL 230.0 Circuit 1 & Line LITEHIPE 230.0 to MESA CAL 230.0 Circuit 1" 1.000

line "DELAMO 230.00" "LAGUBELL 230.00" "1 " 1 0

line "LITEHIPE 230.00" "MESA CAL 230.00" "1 " 1 0

0

line_7125 "Line LA FRESA 230.0 to LAGUBELL 230.0 Circuit 1 & Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1" 1.000

line "LA FRESA 230.00" "LAGUBELL 230.00" "1 " 1 0

line "MESA CAL 230.00" "REDONDO 230.00" "1 " 1 0

0

line_7126 "Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1 & Line LAGUBELL 230.0 to MESA CAL 230.0 Circuit 1" 1.000

line "MESA CAL 230.00" "REDONDO 230.00" "1 " 1 0

line "LAGUBELL 230.00" "MESA CAL 230.00" "1 " 1 0

0

line_7127 "Line LAGUBELL 230.0 to MESACALS 230.0 Circuit 2 & Line LITEHIPE 230.0 to MESA CAL 230.0 Circuit 1" 1.000

line "LAGUBELL 230.00" "MESACALS 230.00" "2 " 1 0

line "LITEHIPE 230.00" "MESA CAL 230.00" "1 " 1 0

0

#line_7128 "Line CENTER 230.0 to TOT663TAP 230.0 Circuit 1 & Line CENTER S 230.0 to TOT663TAP 230.0 Circuit 2" 1.000

#line "CENTER 230.00" "TOT663TAP 230.00" "1 " 1 0

#line "CENTER 230.00" "TOT663TAP 230.00" "2 " 1 0

#0

#line_7129 "Line MESACALS 230.0 to WALNUT 230.0 Circuit 1 & Line TOT663TAP 230.0 to MESA CAL 230.0 Circuit 1" 1.000

#line "MESACALS 230.00" "WALNUTW 230.00" "1 " 1 0

#line "TOT663TAP 230.00" "MESA CAL 230.00" "1 " 1 0

#0

#line_7130 "Line MESACALS 230.0 to WALNUT 230.0 Circuit 1 & Line TOT663TAP 230.0 to OLINDA 230.0 Circuit 1" 1.000

#line "MESACALS 230.00" "WALNUTE 230.00" "1 " 1 0

#line "TOT663TAP 230.00" "OLINDA 230.00" "1 " 1 0

#0

line_7131 "Line MIRALOMW 230.0 to WALNUT 230.0 Circuit 1 & Line OLINDA 230.0 to WALNUT 230.0 Circuit 1" 1.000

line "MIRALOMW 230.00" "WALNUTE 230.00" "1 " 1 0

line "OLINDA 230.00" "WALNUTE 230.00" "1 " 1 0

0

#line_7132 "Line OLINDA 230.0 to WALNUT 230.0 Circuit 1 & Line TOT663TAP 230.0 to OLINDA 230.0 Circuit 1" 1.000

#line "OLINDA 230.00" "WALNUTe 230.00" "1 " 1 0

#line "TOT663TAP 230.00" "OLINDA 230.00" "1 " 1 0

#0

line_7133 "Line MIRALOMW 230.0 to WALNUT 230.0 Circuit 1 & Line MIRALOME 230.0 to OLINDA 230.0 Circuit 1" 1.000

line "MIRALOMW 230.00" "WALNUTE 230.00" "1 " 1 0

line "MIRALOME 230.00" "OLINDA 230.00" "1 " 1 0

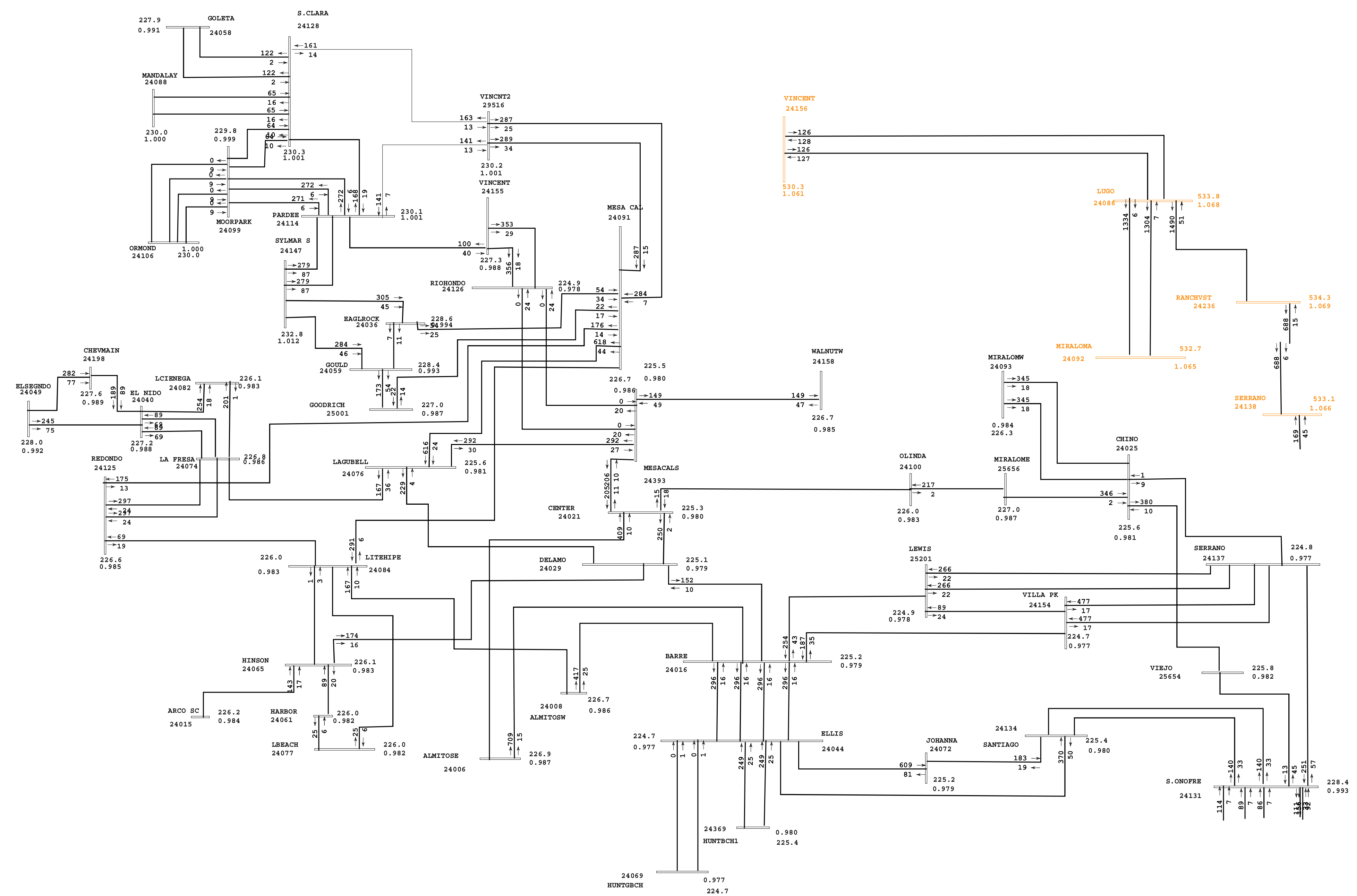
0

Category P7.2 Loss of a bipolar DC Lines is not applicable in the Metro Area as no DC lines exist within this area.

End of Contingency List, ## Contingencies Added to List

end

End of Contingency List, ## Contingencies Added to List



General Electric International, Inc.   PSLF Program   Thu Dec 22 09:48:05 2016   cases\PST21-p-main_QC9_metro.sav

MW/MVAR
draws\Metro(
Rating 1

QC9 Phase I Area Report Appendix E

Cost and Construction Duration Estimates for Upgrades in Area

Area: Metro

Table 1-1 Reliability Upgrades, Estimated Costs, and Estimated Time to Construct Time Summary

Upgrade	Constant 2016 Dollar in $1000s (Estimate)	Estimated Cost Escalated to OD Year in $1000s Note 8	Estimated Time to Construct (Months) Note 12
None			
Total	$0	$0	

*SCD Mitigation is the total allocated to the Area Projects only

Table 1-2 Local Delivery Network Upgrades, Estimated Costs, and Estimated Time to Construct Time Summary

Upgrade	Constant 2016 Dollar in $1000s (Estimate)	Estimated Cost Escalated to OD Year in $1000s Note 8	Estimated Time to Construct (Months) Note 12
None			
Total	$0	$0	

Table 1-3 Distribution Upgrades, Estimated Costs, and Estimated Time to Construct Time Summary

Upgrade	Constant 2016 Dollar in $1000s (Estimate)	Estimated Cost Escalated to OD Year in $1000s Note 8	Estimated Time to Construct (Months) Note 12
See applicable cost in attachment 2			
Total	$0	$0	

Table 1-4 Area Delivery Network Upgrades, Estimated Costs, and Estimated Time to Construct Time Summary

Upgrade	Constant 2016 Dollar in $1000s (Estimate)	Estimated Cost Escalated to OD Year in $1000s Note 8	Estimated Time to Construct (Months) Note 12
None			
Total	$0	$0	

Note 1: One time costs item(s) will be treated as applicable per the specified facilities or upgrade classification. They may be reimburseable depending on their classification.

Note 2: Distribution upgrades are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute Generator Interconnection Agreements.

Note 3: The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental, licensing, and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

Note 4: Each fcilities or upgrade category may contain multiple work element construction durations. The longest estimated construction duration is shown under the C.O.D Dollar Duration column.

Note 5: SCE's Phase I cost estimating is done in 'constant' dollars 2016 and then escalated to the estimated O.D.year. For the QC9 study, the estimated C.O.D. Dollar is derived by assuming the duration of the work element will begin in December 2018, which is the CAISO tariff scheduled completion date of the QC9 Phase I study plus: the TPD Allocation, Annual Reassesment Effort , and the interconnection agreement signing period and submittal of required funds by the IC. For instance, if a work element is estimated to take a total of 24 months (detail engineering, design, procurement, licensing and construction), then the estimated C.O.D. would be December 2019. If an IC's requested C.O.D. is beyond the estimated C.O.D. of a work element, the IC's requested C.O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not provided by the IC in time for the Participating TO to perform the work within these time frames, the information provided in Table above may be subject to change.

Note 6: Individual O&M charges for the above estimated construction costs will be identified and communicated during the Generator Interconnection Agreement process.

Note 7: The Estimated Time to Construct (duration in months) is the schedule for the PTO to complete detail engineering, design, procurement, licensing, and construction, etc., and other activities needed to construct and bring the facilities and upgrades into service. Such activities are from the execution of the Generator Interconnection Agreements, and receipt of: all required information, funding, and written authorization to proceed from the IC, as will be specified in the Interconnection Agreement, to commence work. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

Note 8: The escalation factors to convert the estimated cost (in 'constant' 2016 dollars) to the estimated C.O.D. are found in the posted SCE 2016 Per Unit Cost Guide on the CAISO website: http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Note 9: Estimated Time to Construct durations are from completion of any preceding facilities and upgrades required.

Note10: The C.O.D. Dollar for the IF and RNU/Dist. Plan of Service facilities was escalated using the requested Project C.O.D when the requested Project C.O.D was beyond the identified ETC of the IF and RNU/Dist. Plan of Service facilities. In such instances there is a different duration (months) in the ETC and C.O.D. Dollar escalation duration columns.

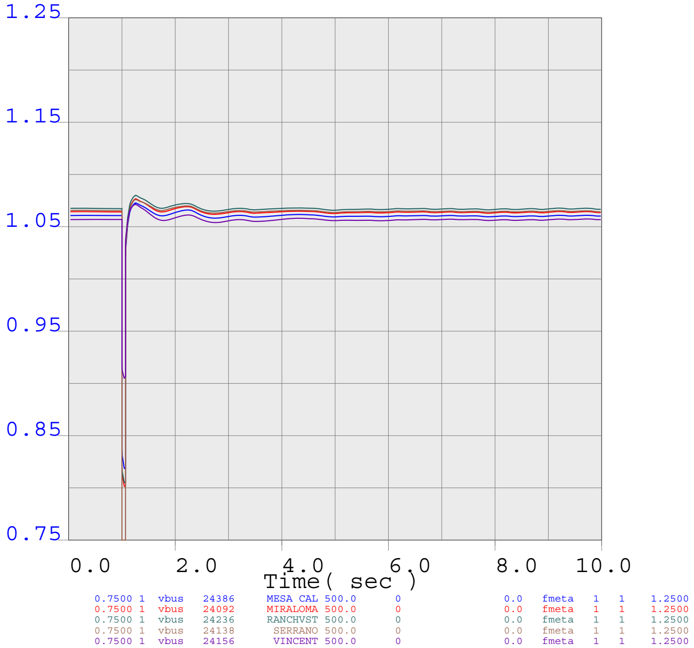
Note11: RNUs are subject to ITCC on funds above the repayment maximum ($60 k/MW) of the Project.The ITCC corresponding to the RNUs, when applicable, was calculated by applying the following formula:
[Total Project allocated RNU Costs – {(Project MW Size)* ($60k)}]*35%

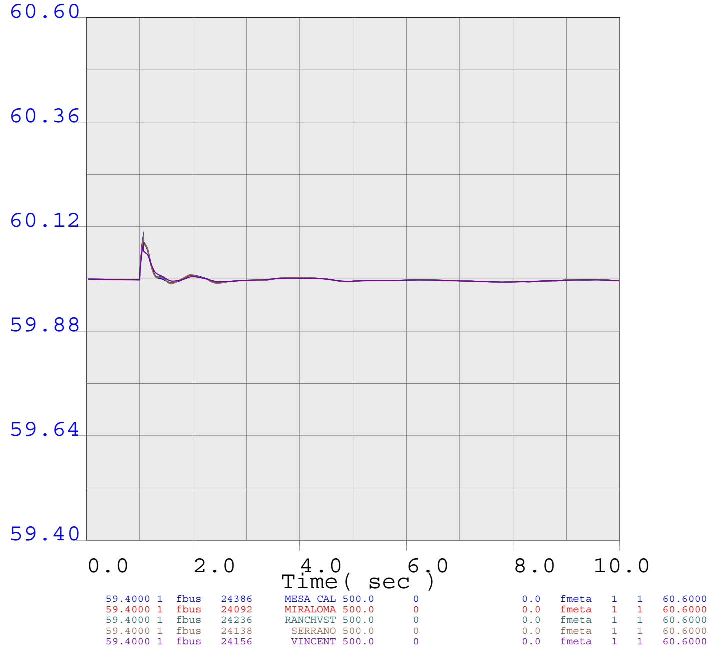
Note 12: The duration amounts specified in this table are the duarations specific to the upgrade only. These duration may differ from those in Attachment #2, since each project has distintive interconnection requisites.

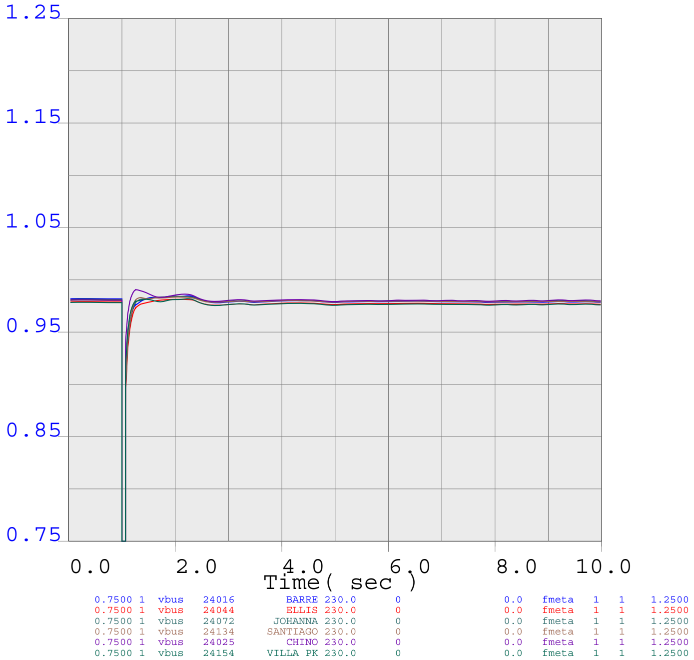
Queue Cluster 9 Phase I – Appendix F

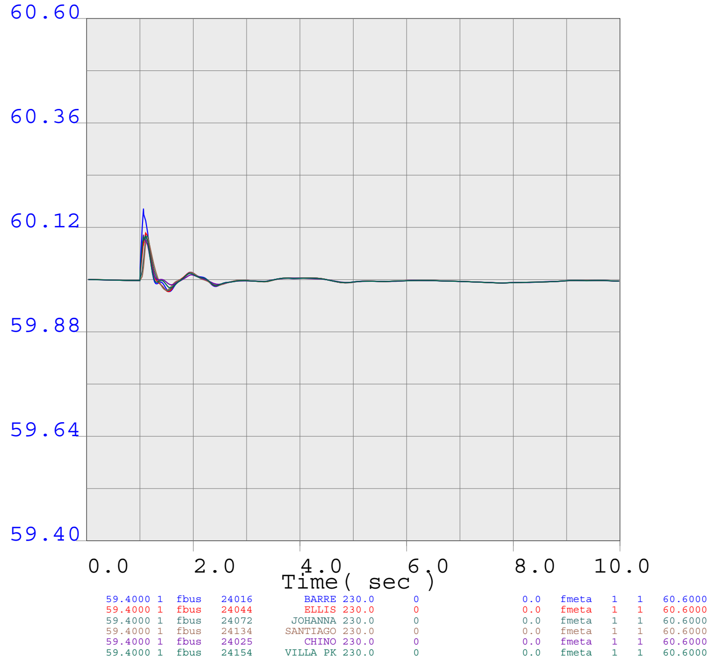
SCE Metro Area – Transient Stability Plots

METRO









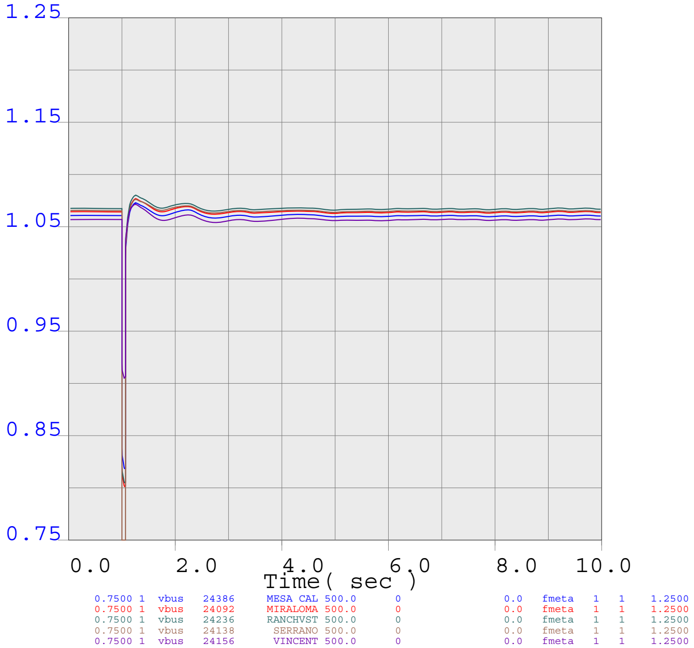
bay_2301
BARRE 220.00 1S
1 MW dispatch Case

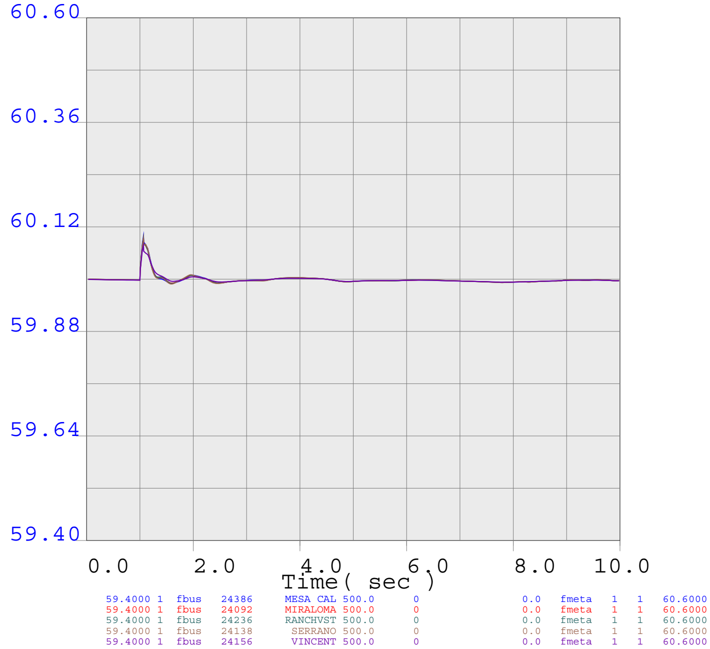
qc9p-bay_2301.chf

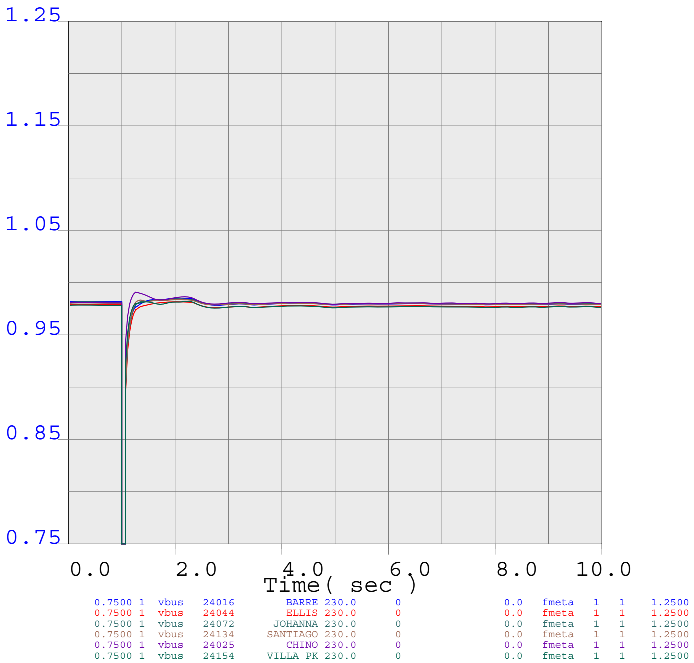
C:\DYTOOLS

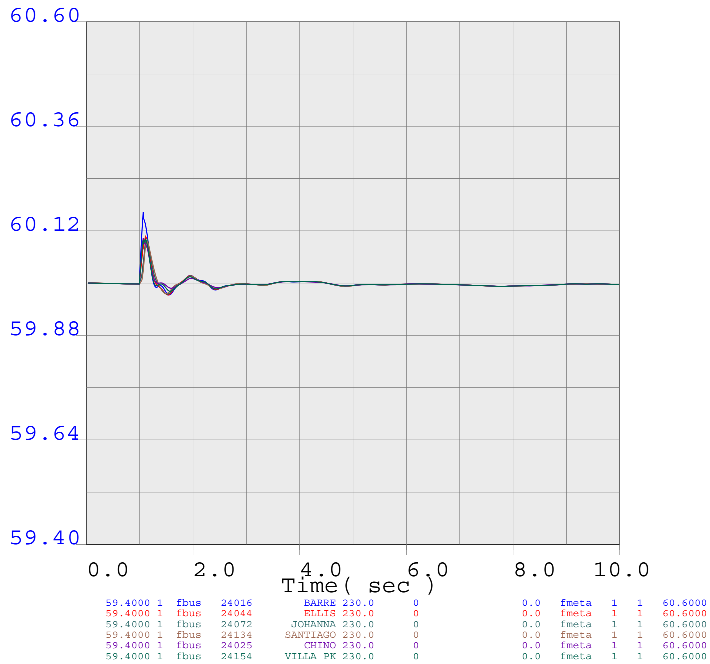
Thu Oct 20 08:53:33 2016

METRO









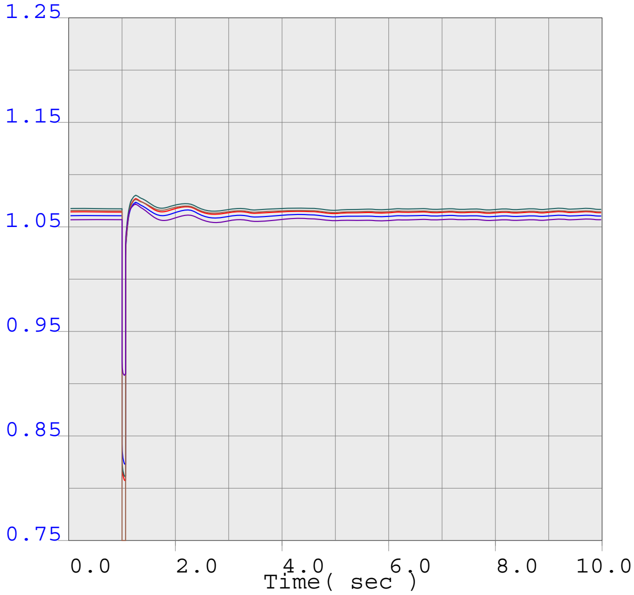
bay_2302
BARRE 220.00 3S
1 MW dispatch Case

qc9p-bay_2302.chf

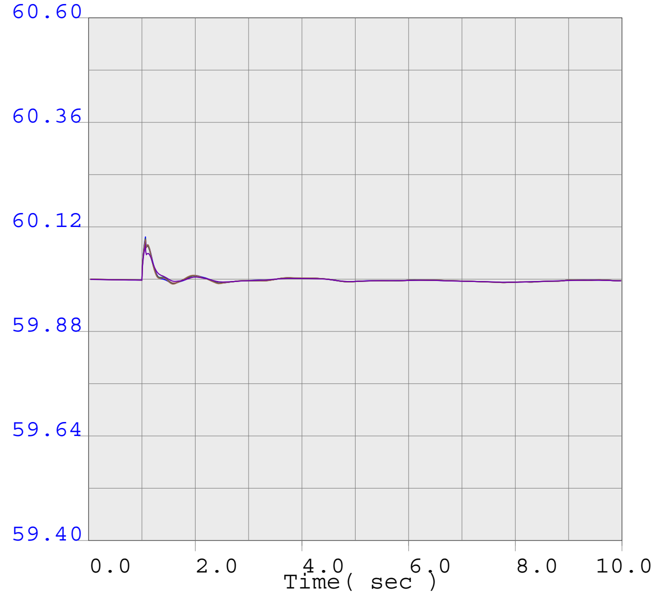
C:\DYTOOLS

Thu Oct 20 08:53:35 2016

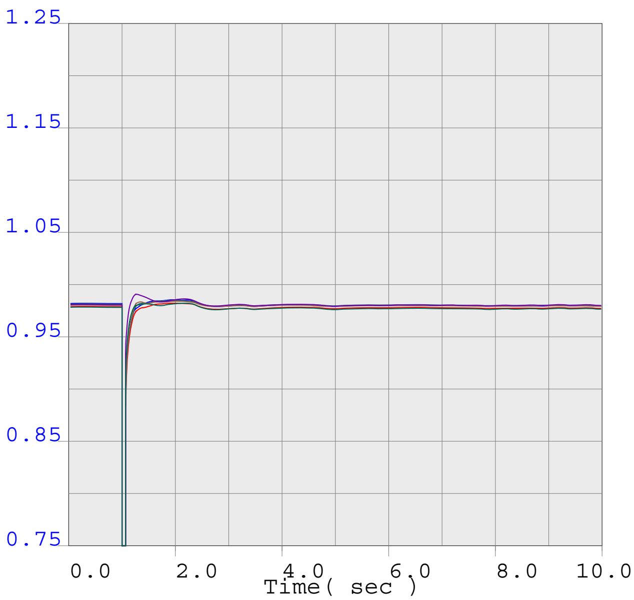
METRO



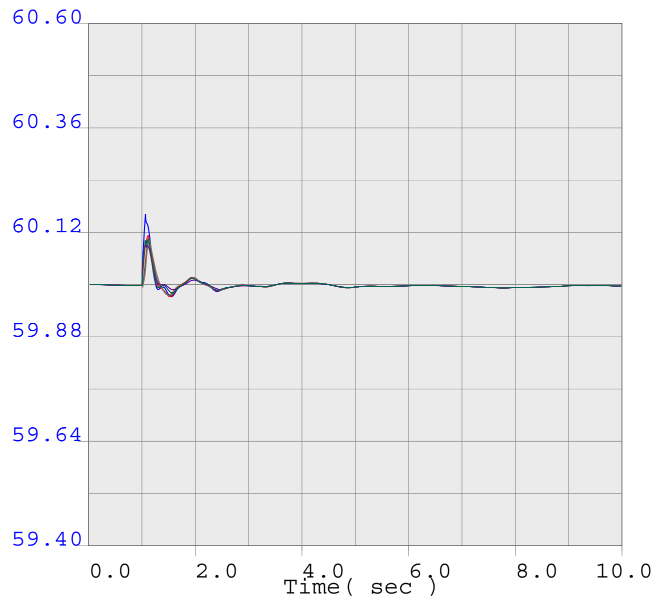
0.7500	1	vbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	60.6000

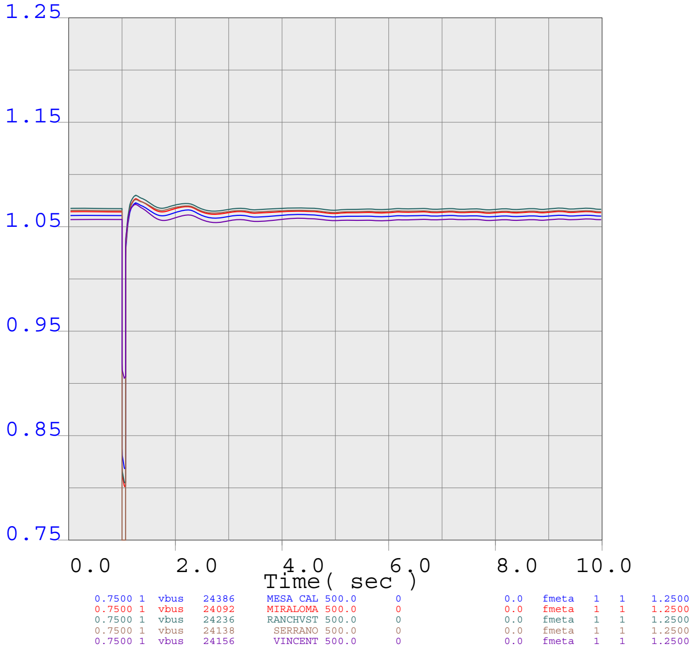
bay_2303
BARRE 220.00 4S
1 MW dispatch Case

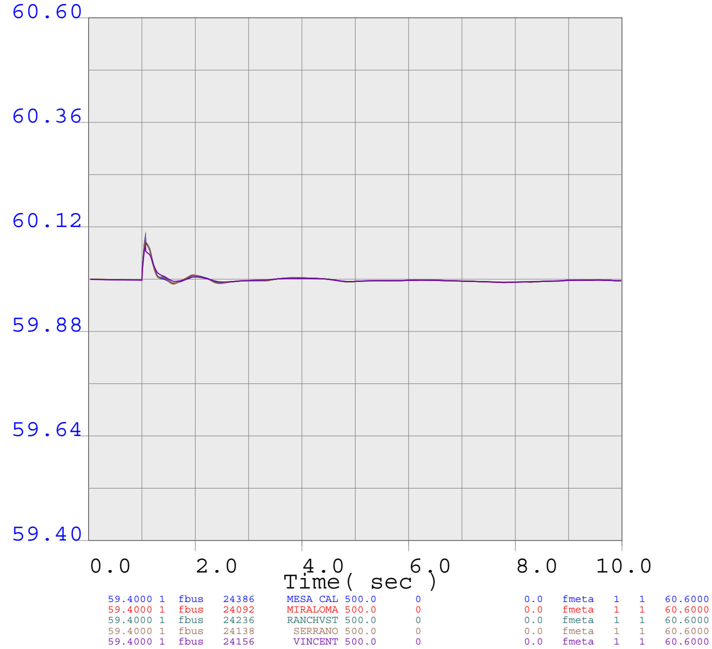
qc9p-bay_2303.chf

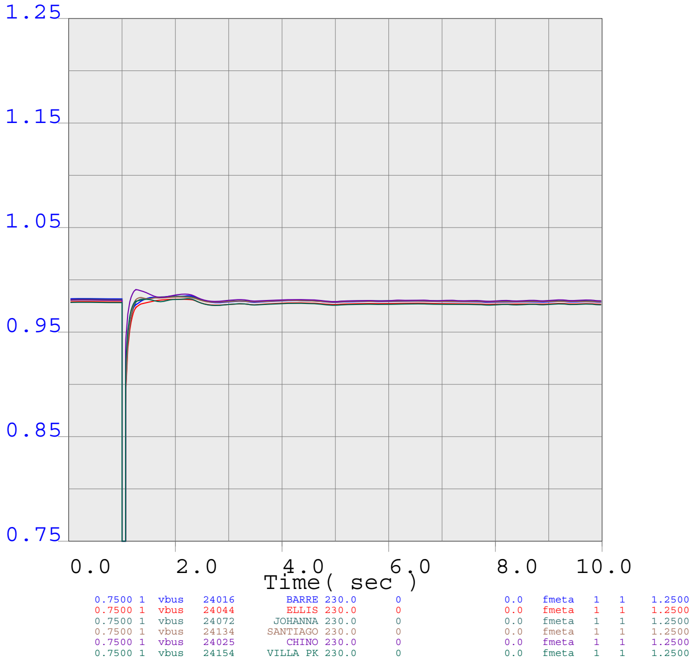
C:\DYTOOLS

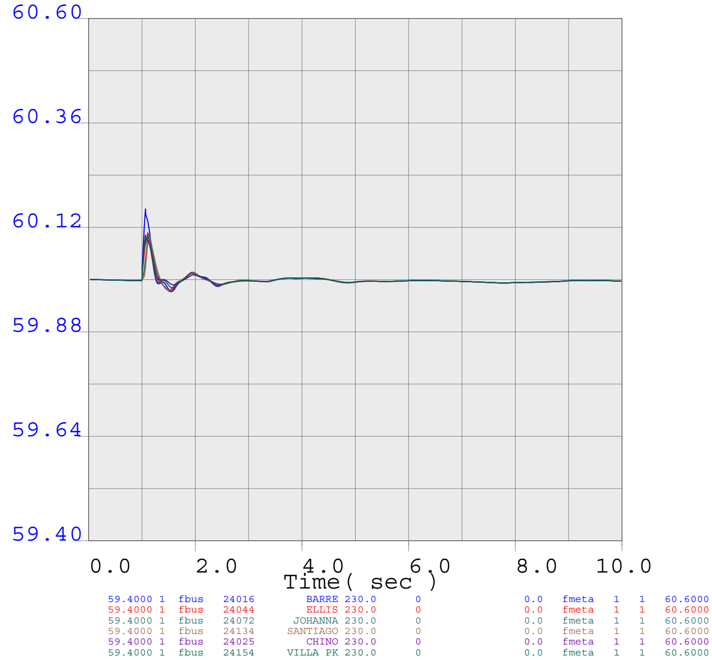
Thu Oct 20 08:53:37 2016

METRO





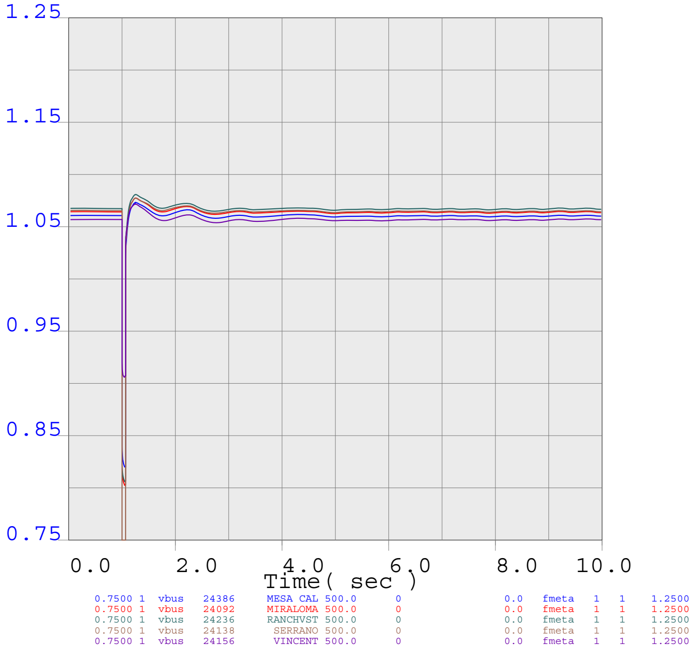


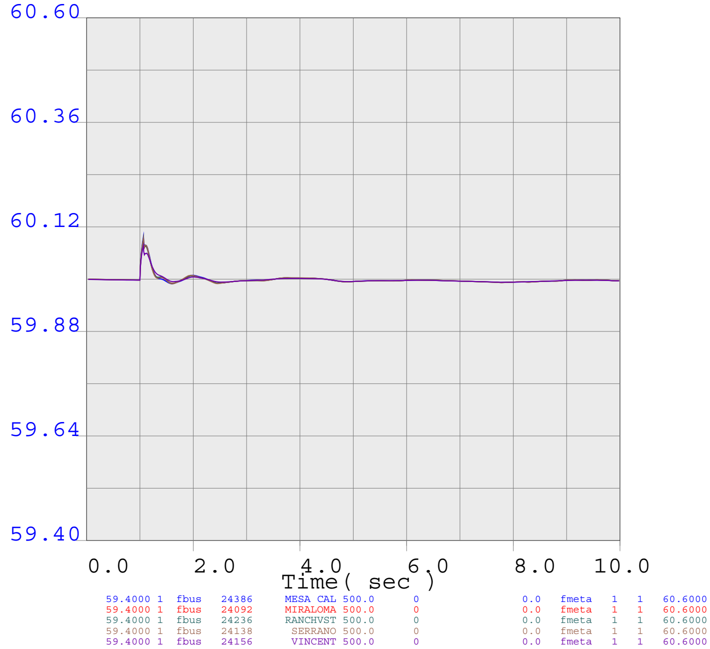


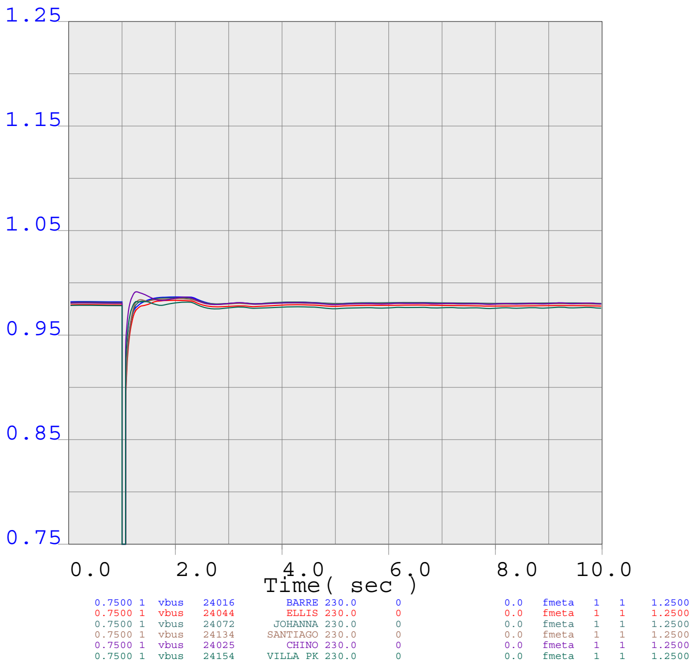
bay_2304
BARRE 220.00 5S
1 MW dispatch Case

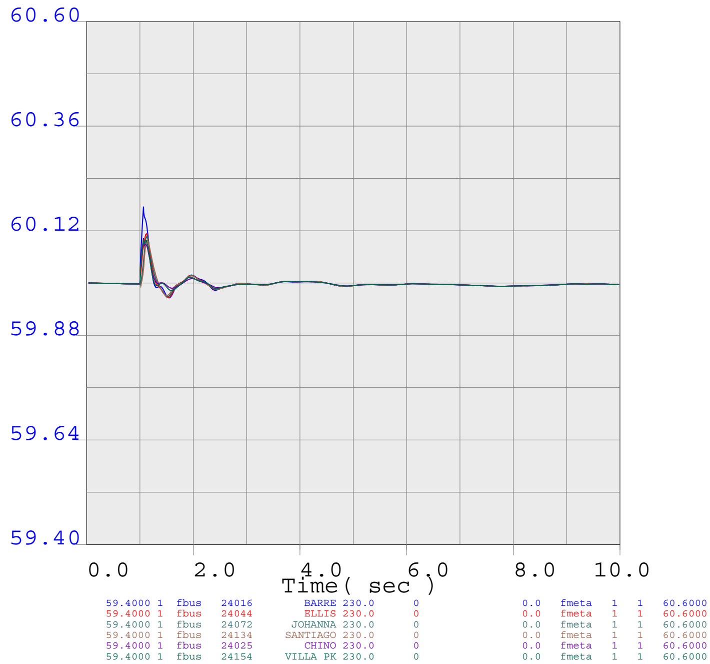
	qc9p-bay_2304.chf	C:\DYTOOLS Thu Oct 20 08:53:40 2016

METRO









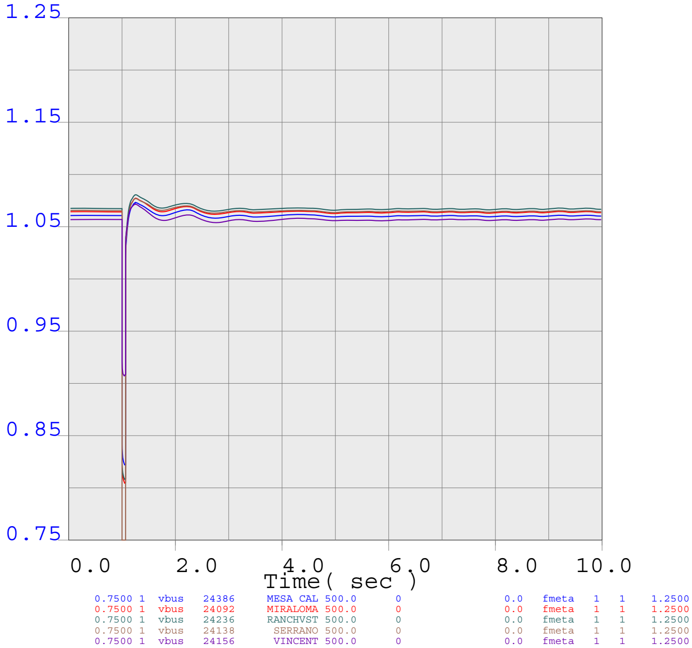
bay_2305
BARRE 220.00 6S
1 MW dispatch Case

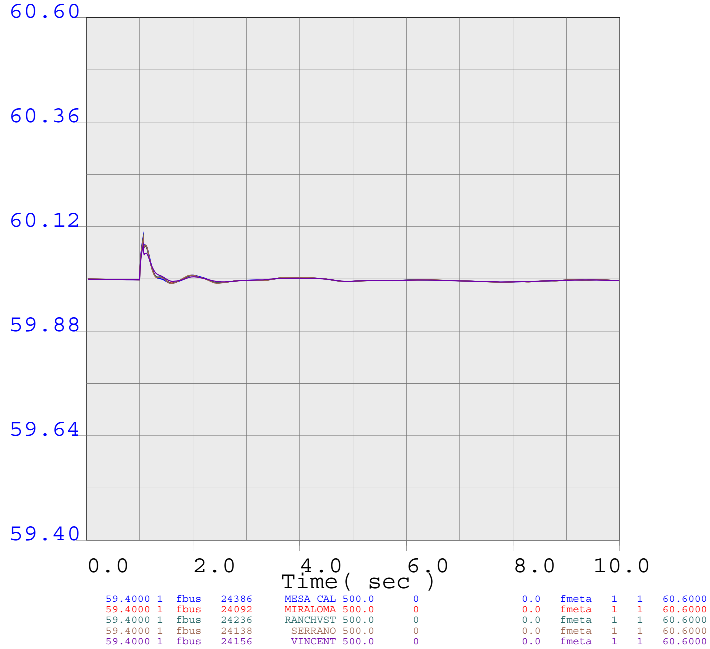
qc9p-bay_2305.chf

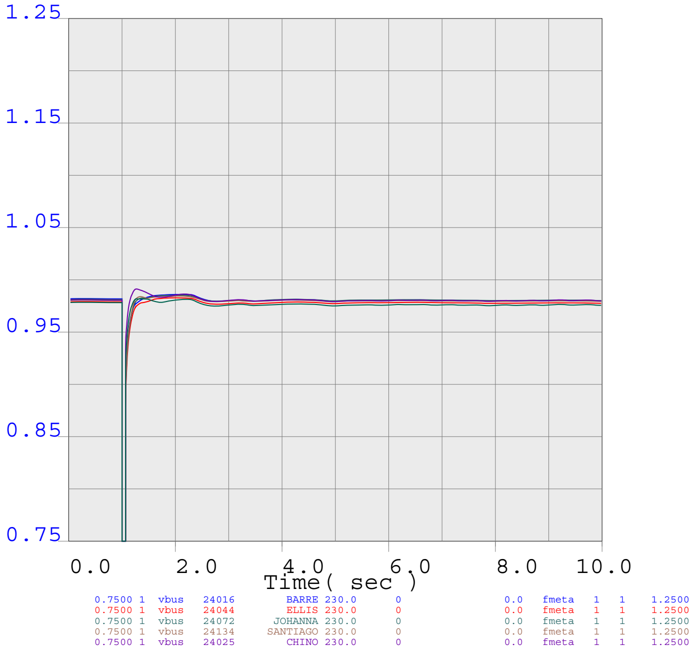
C:\DYTOOLS

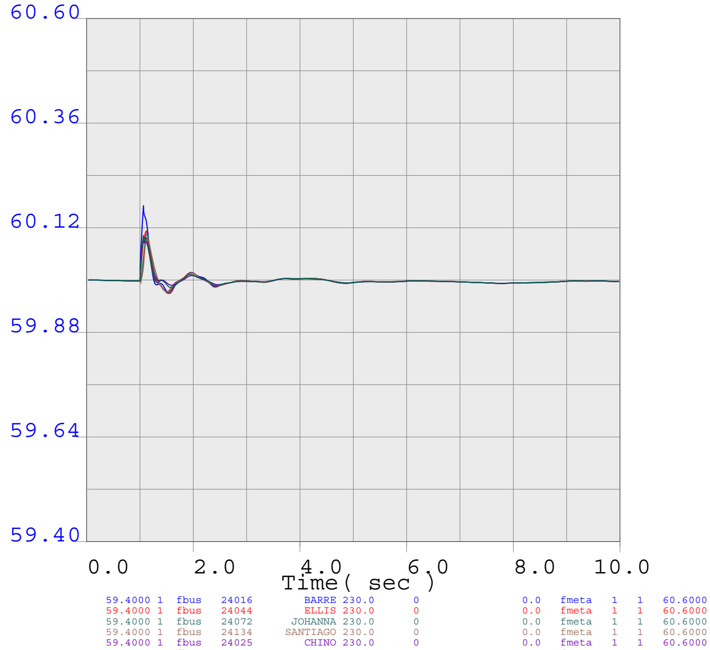
Thu Oct 20 08:53:42 2016

METRO









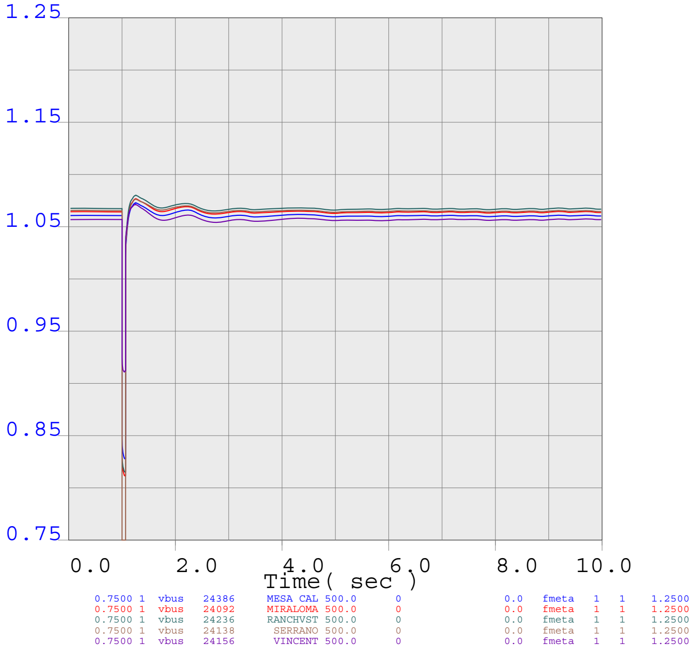
bay_2306
BARRE 220.00 7S
1 MW dispatch Case

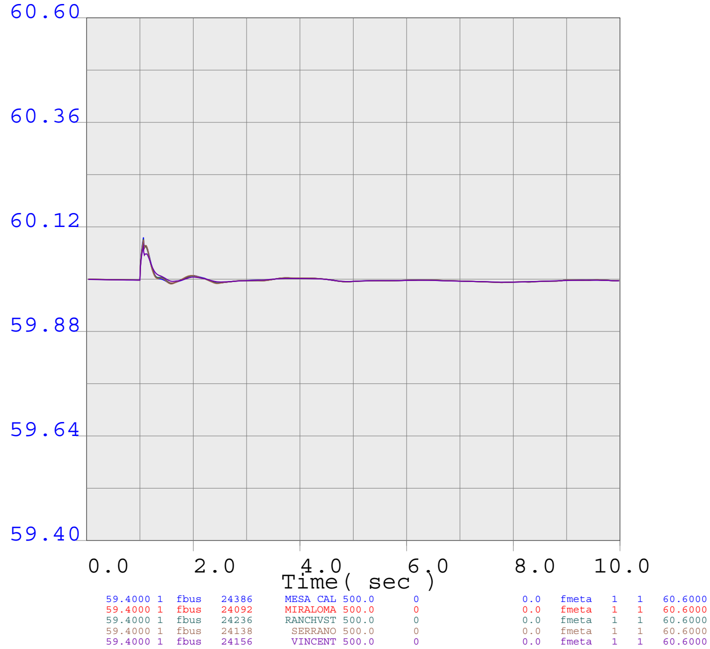
qc9p-bay_2306.chf

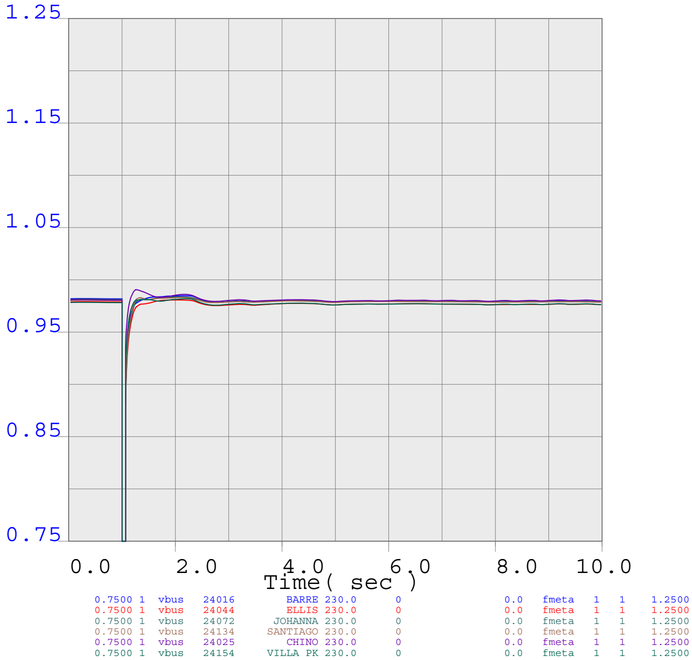
C:\DYTOOLS

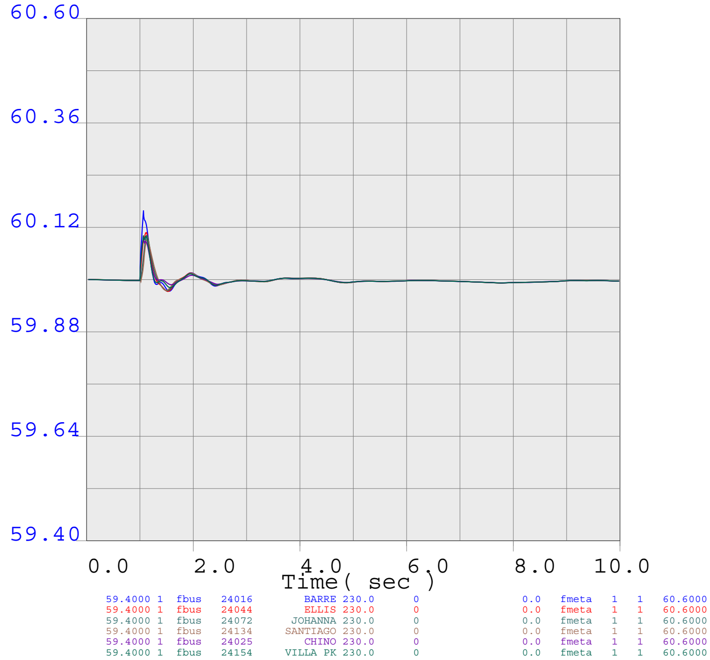
Thu Oct 20 08:53:45 2016

METRO









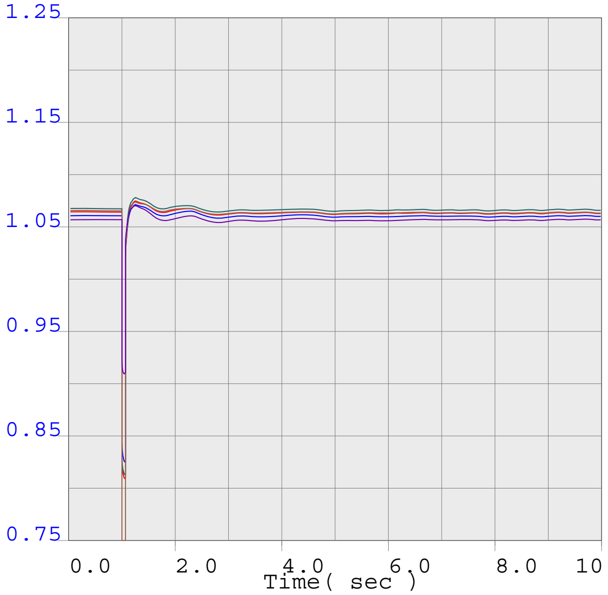
bay_2307
BARRE 220.00 8S
1 MW dispatch Case

qc9p-bay_2307.chf

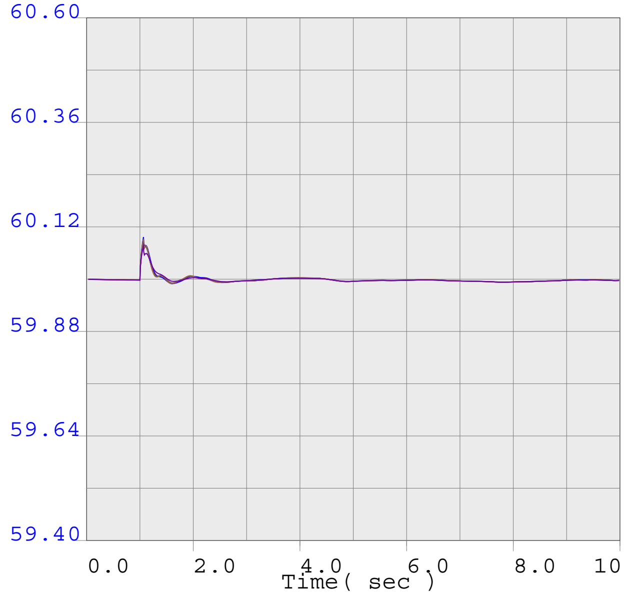
C:\DYTOOLS

Thu Oct 20 08:53:47 2016

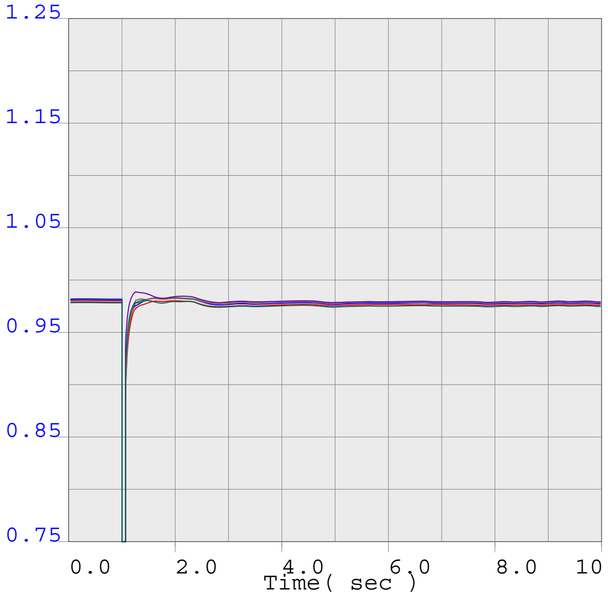
METRO



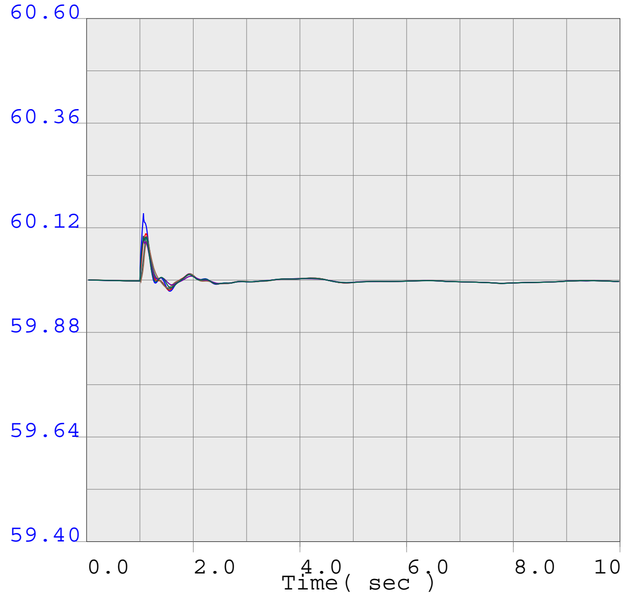
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

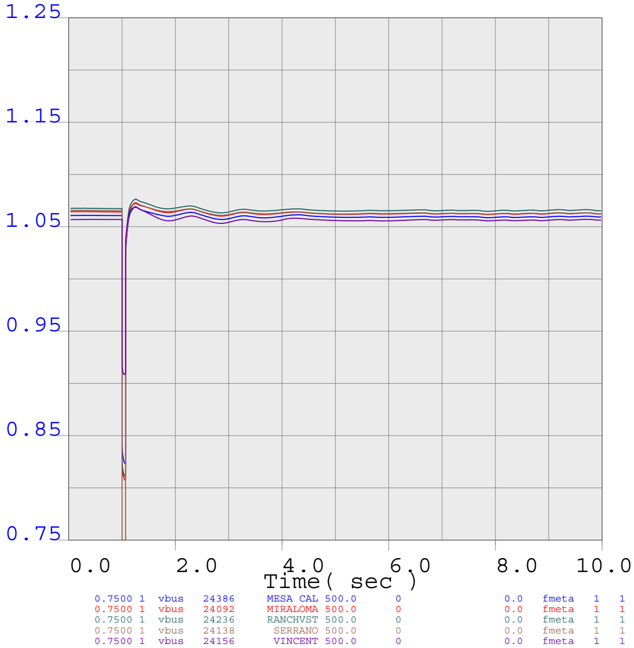
bay_2308
BARRE 220.00 9S
1 MW dispatch Case

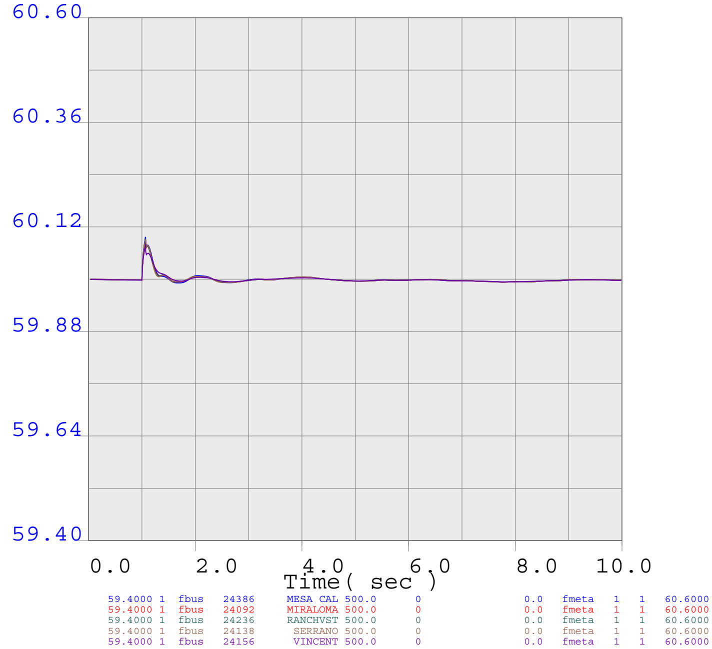
qc9p-bay_2308.chf

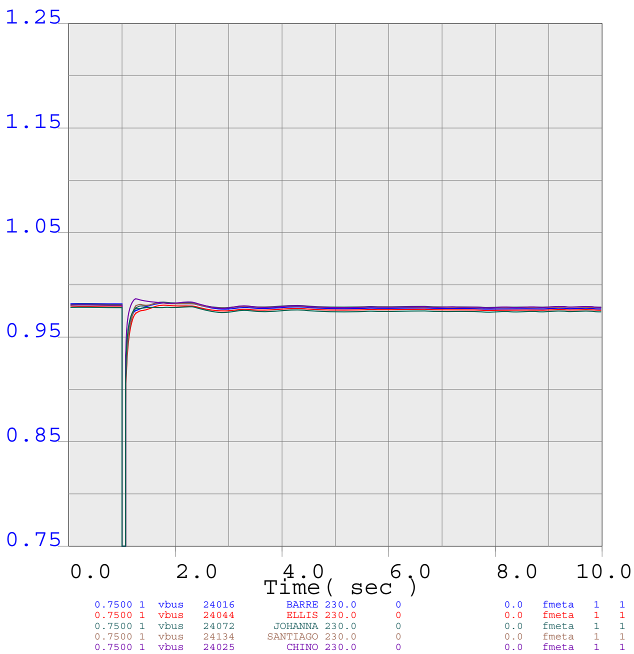
C:\DYTOOLS

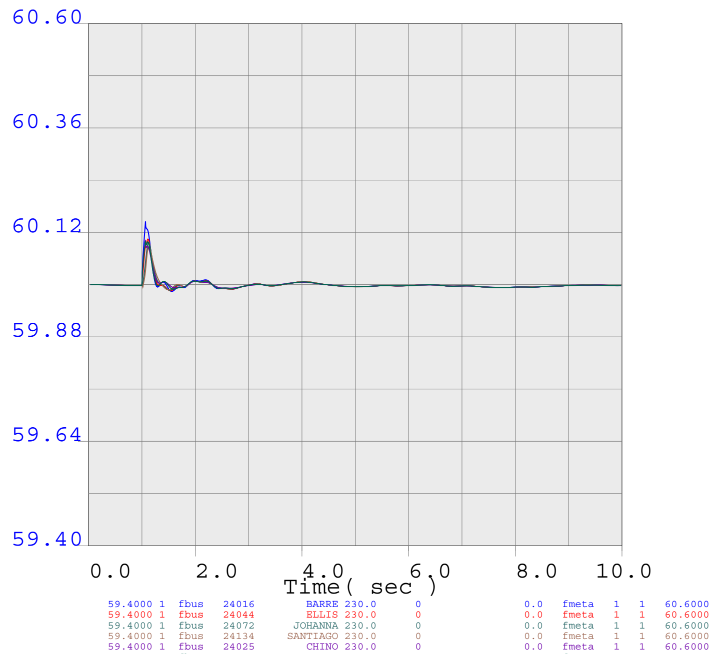
Thu Oct 20 08:53:49 2016

METRO









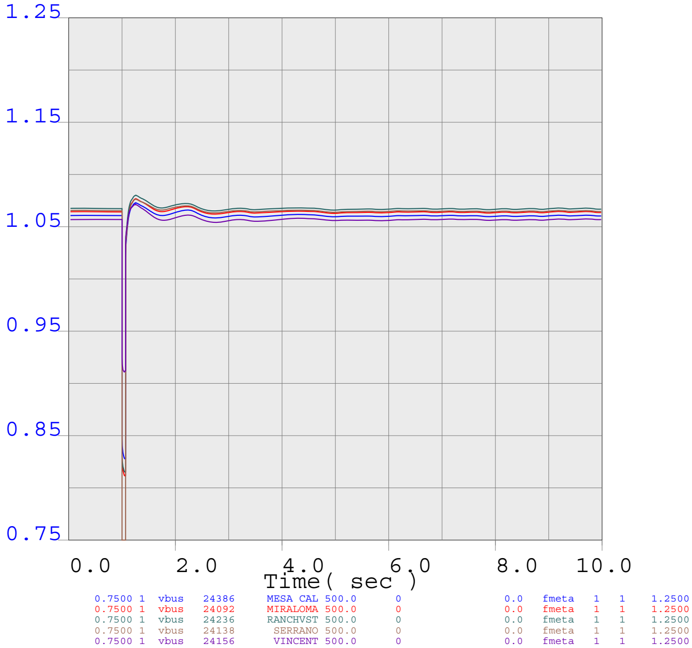
bay_2309
BARRE 220.00 10S
1 MW dispatch Case

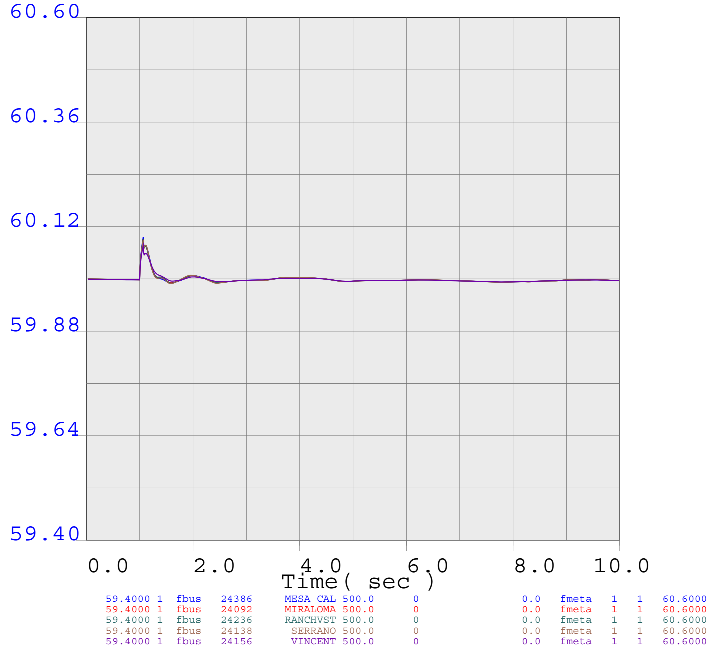
qc9p-bay_2309.chf

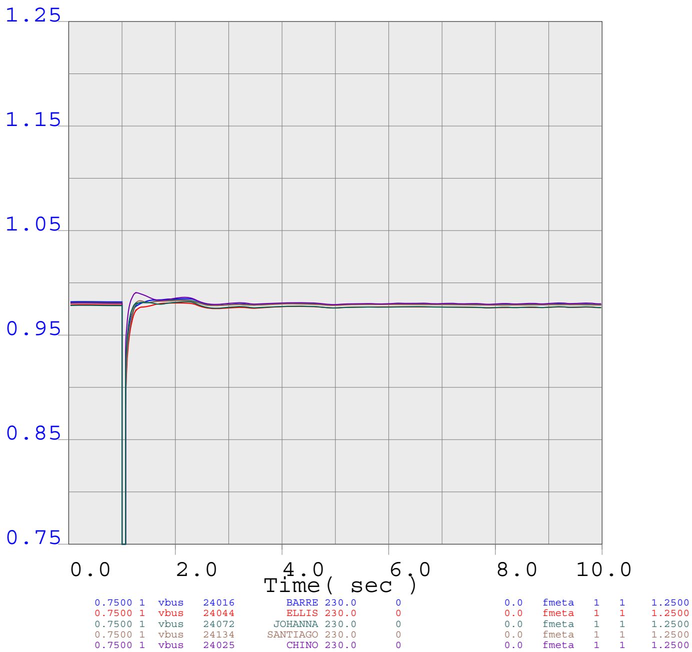
C:\DYTOOLS

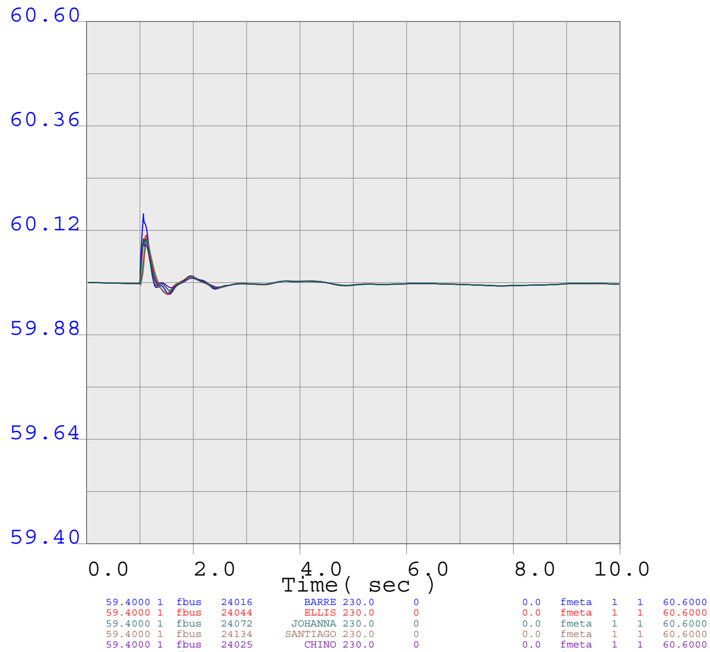
Thu Oct 20 08:53:51 2016

METRO









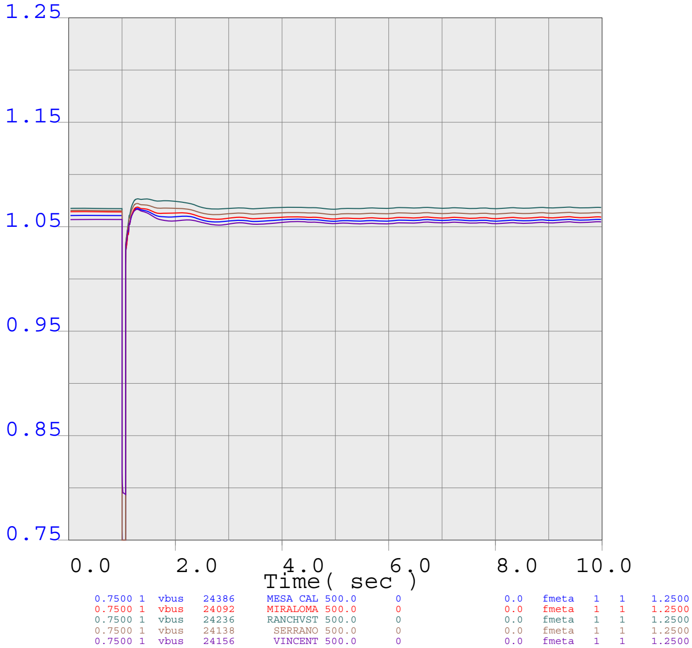
bay_2310
BARRE 220.00 11S
1 MW dispatch Case

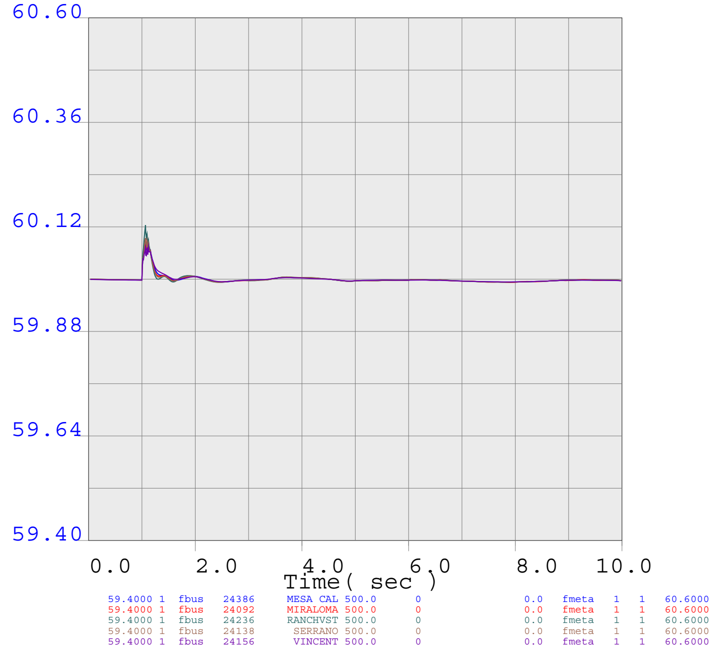
qc9p-bay_2310.chf

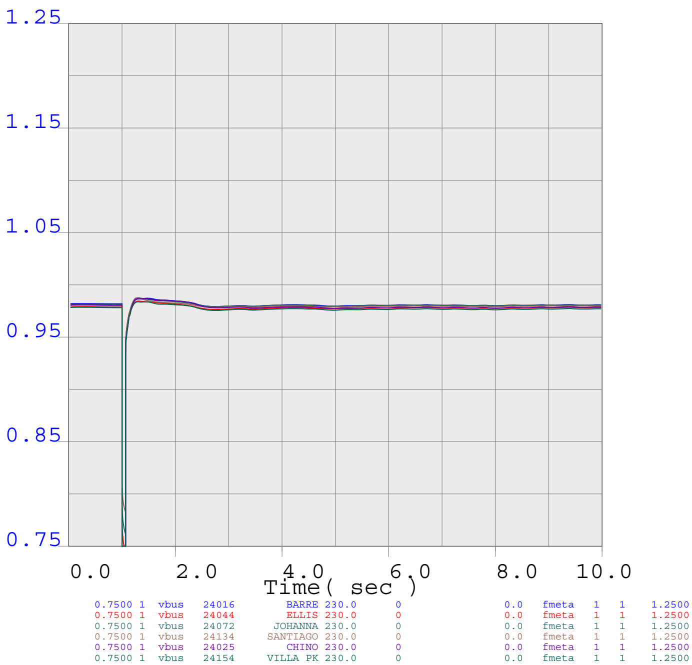
C:\DYTOOLS

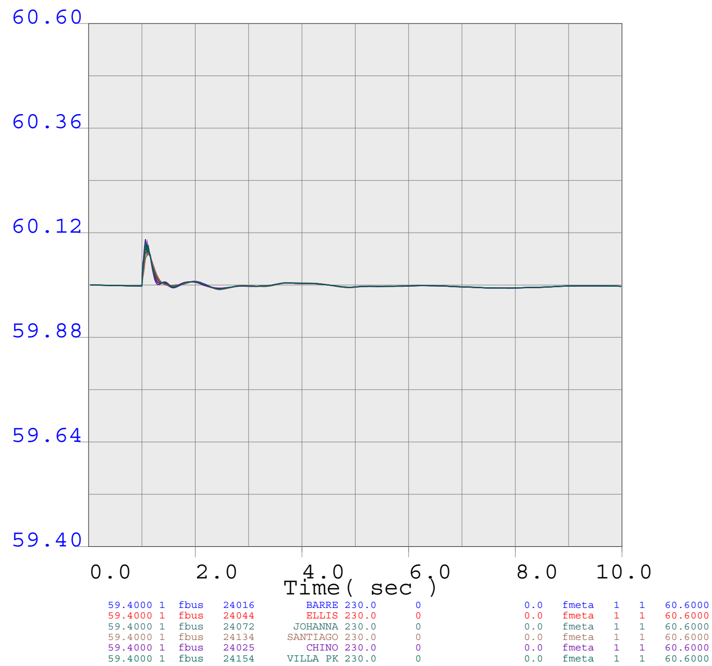
Thu Oct 20 08:53:53 2016

METRO









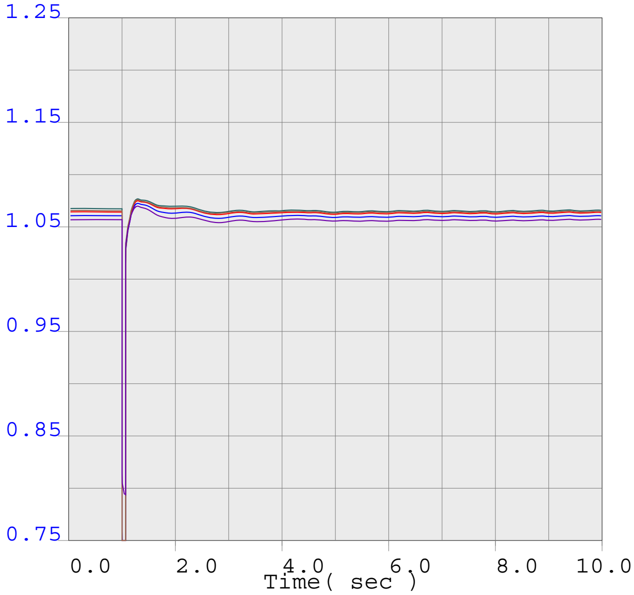
bay_23100
RANCHO VISTA 500 KV POS 7 INTERNAL FAULT
1 MW dispatch Case

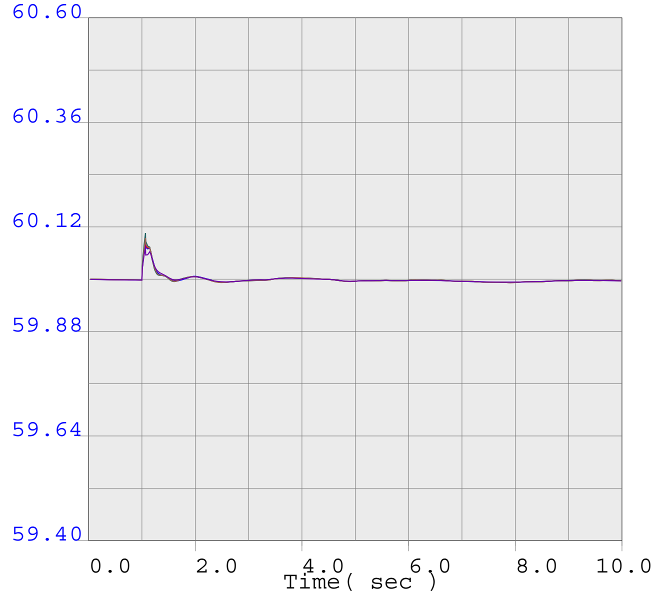
qc9p-bay_23100.chf

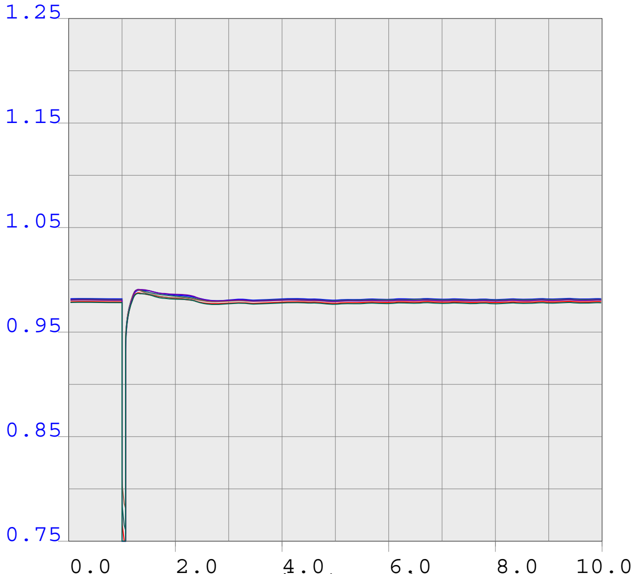
C:\DYTOOLS

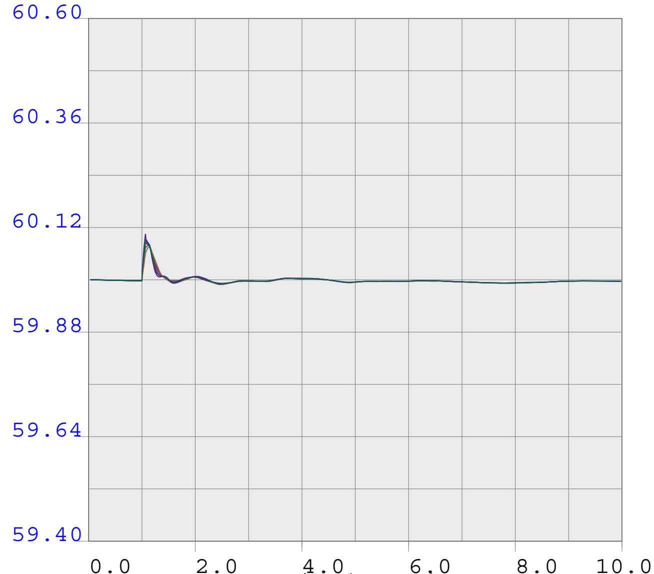
Thu Oct 20 08:53:55 2016

METRO









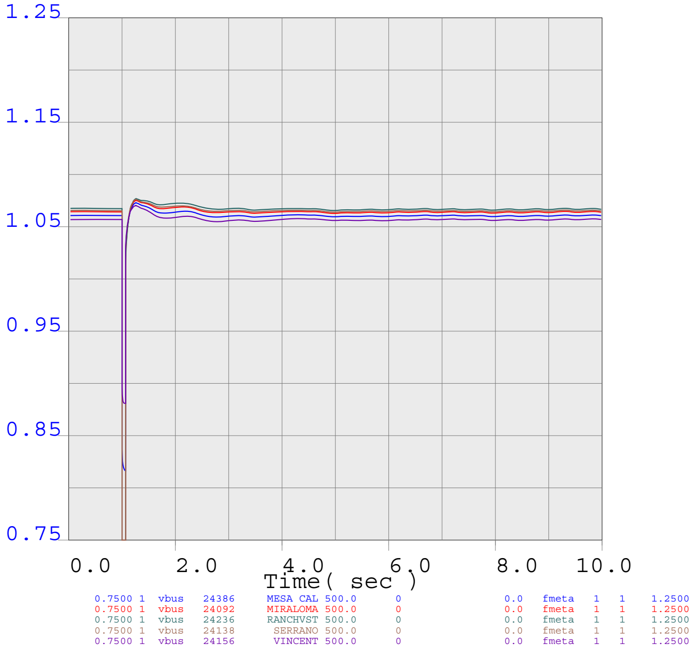
bay_23101
RANCHO VISTA 220 KV POS 12 INTERNAL FAULT
1 MW dispatch Case

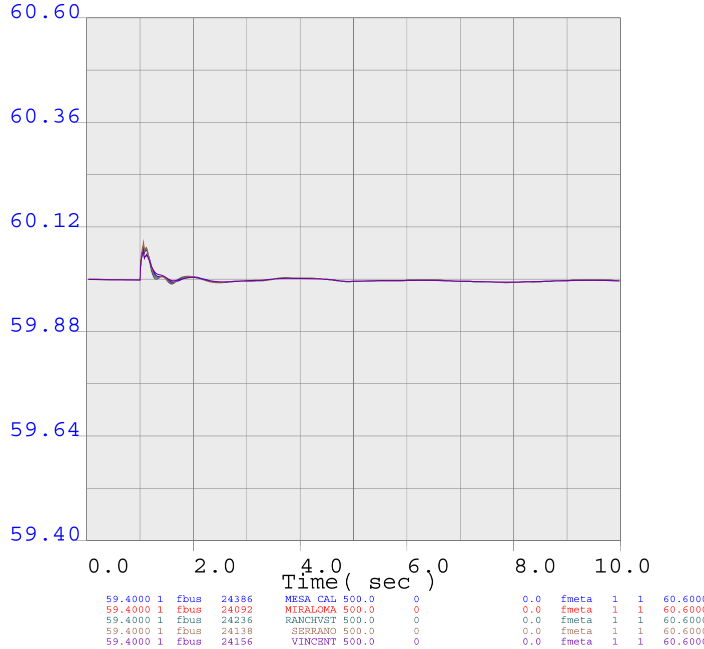
qc9p-bay_23101.chf

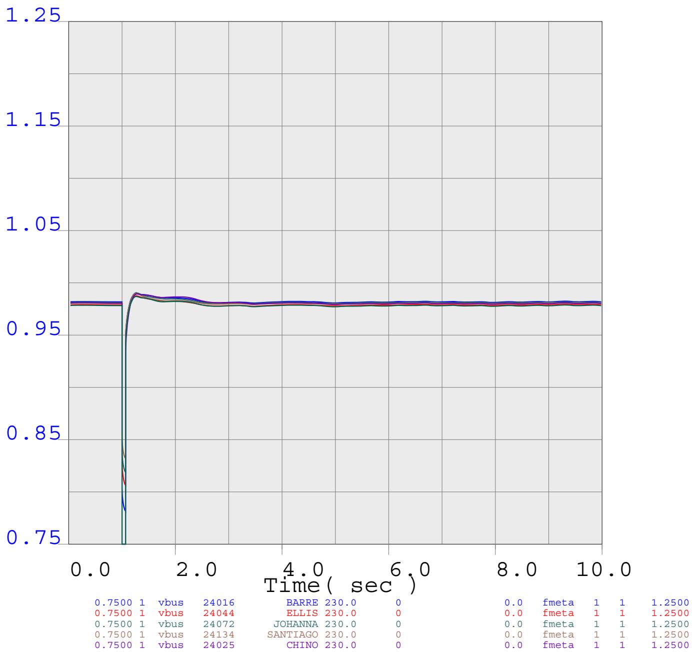
C:\DYTOOLS

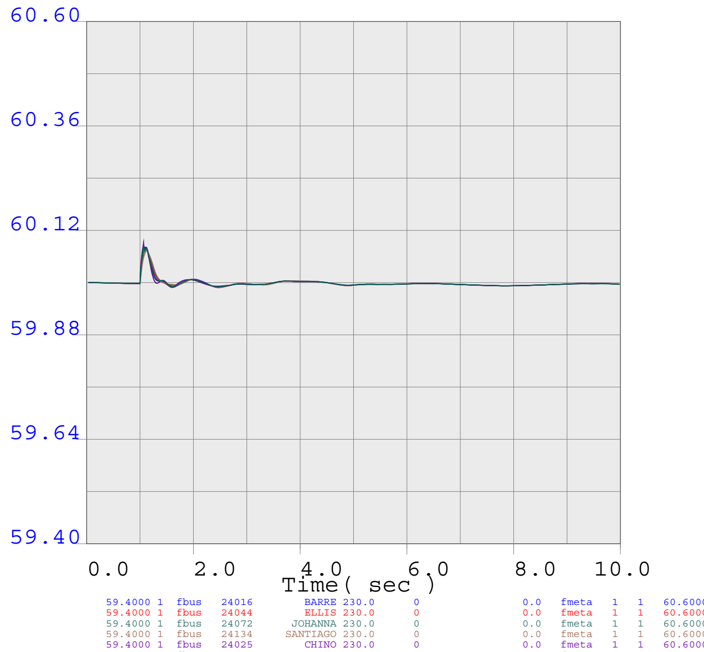
Thu Oct 20 08:53:57 2016

METRO









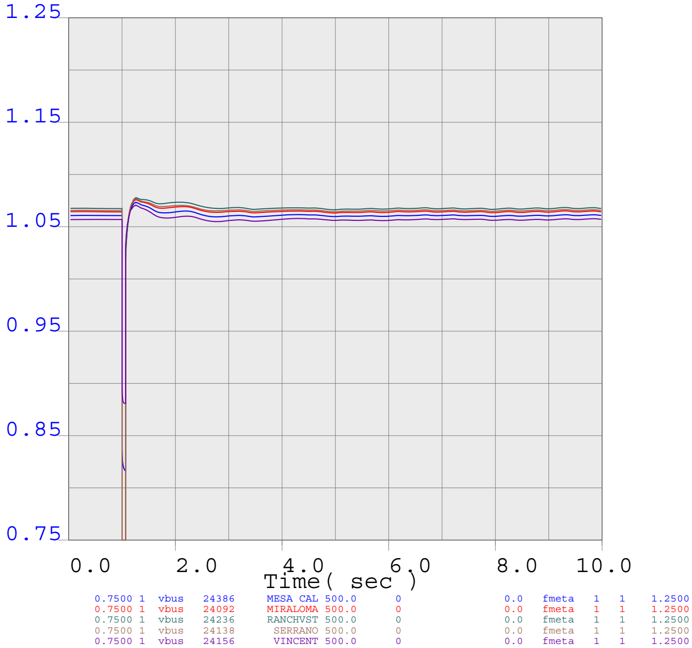
bay_23102
RANCHO VISTA 220 KV POS 11 INTERNAL FAULT
1 MW dispatch Case

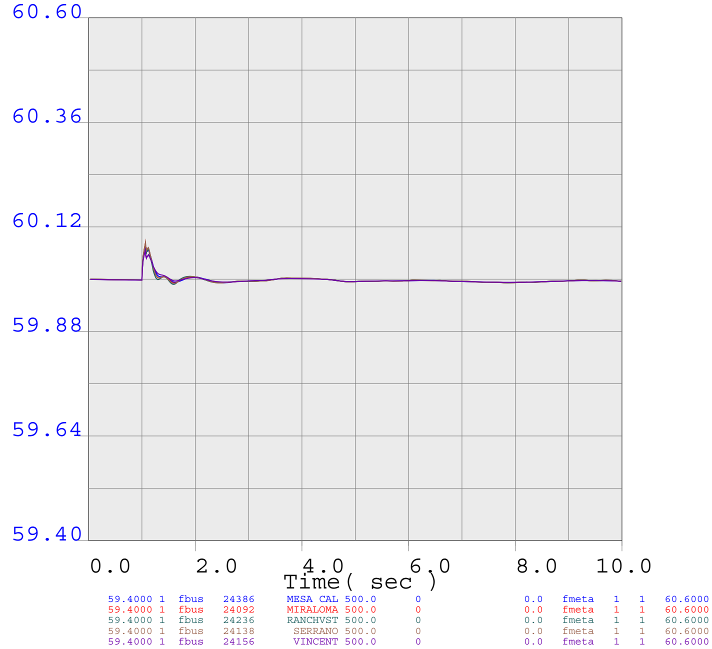
qc9p-bay_23102.chf

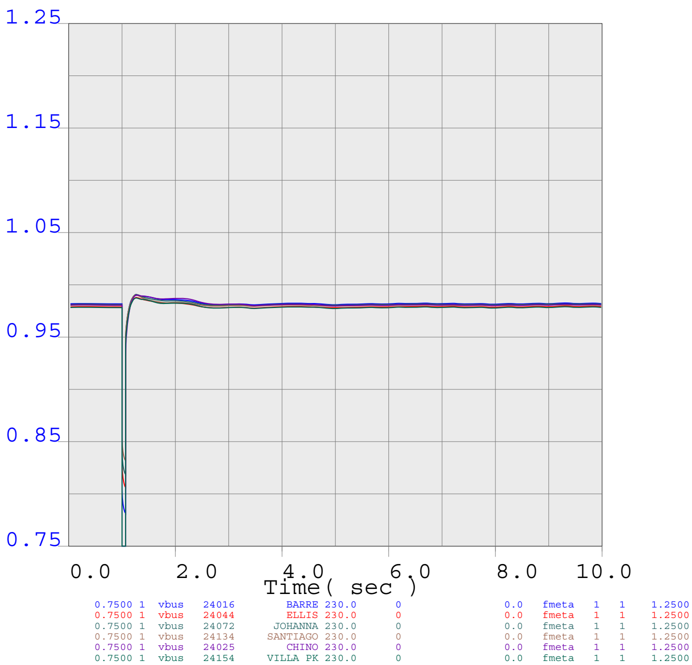
C:\DYTOOLS

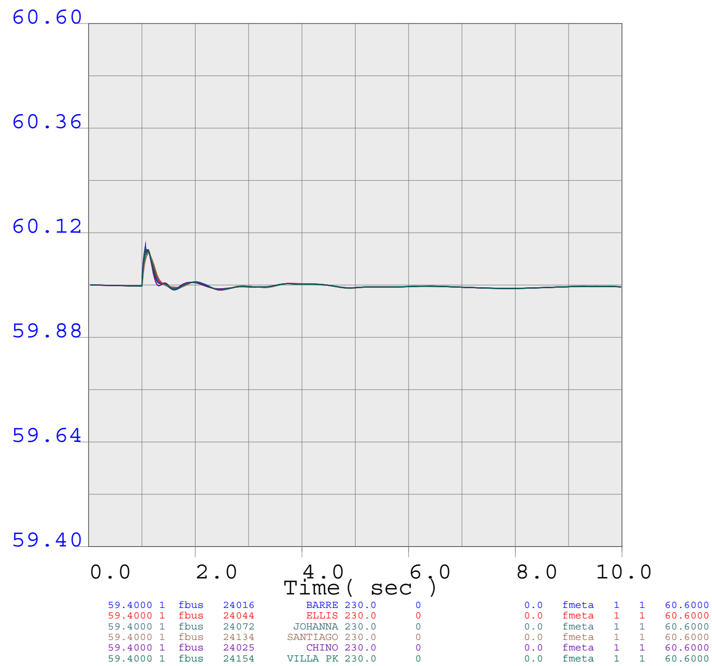
Thu Oct 20 08:53:59 2016

METRO









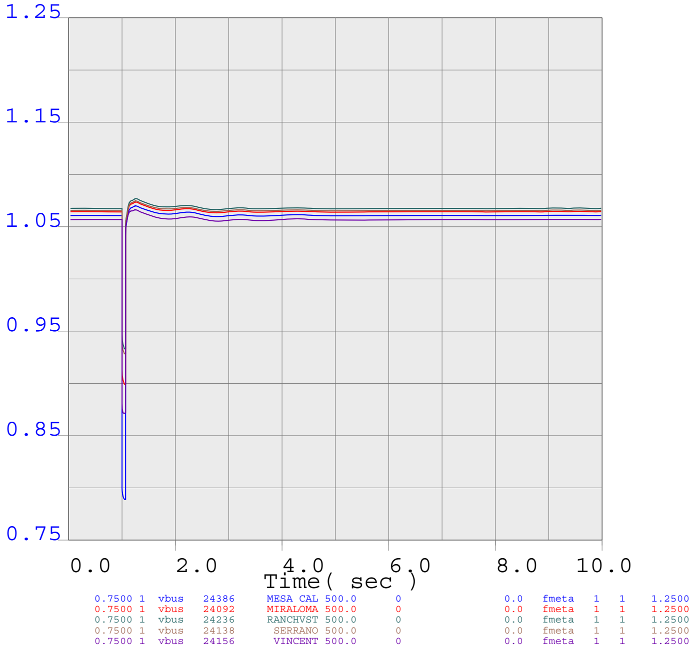
bay_23103
RANCHO VISTA 220 KV POS 10 INTERNAL
1 MW dispatch Case

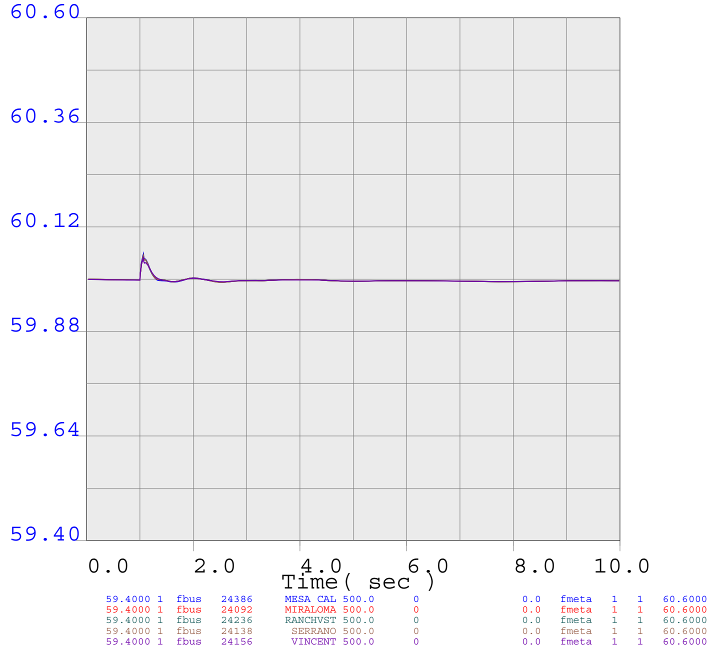
qc9p-bay_23103.chf

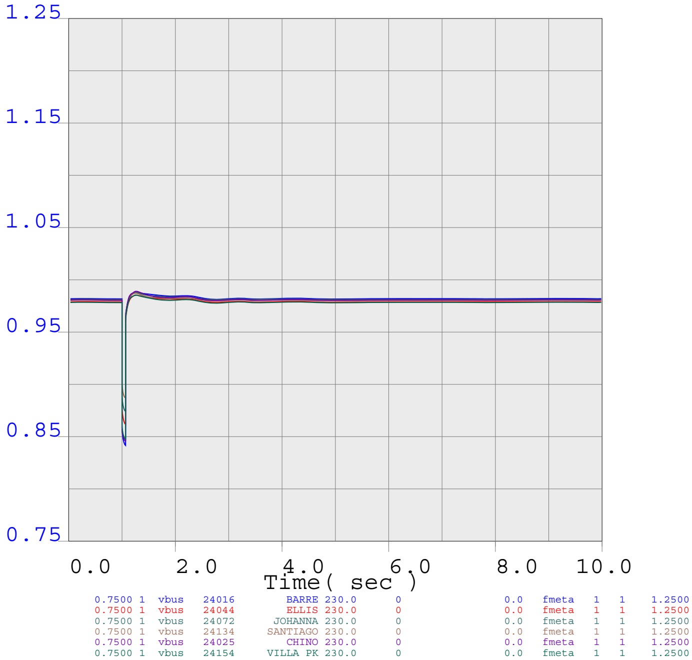
C:\DYTOOLS

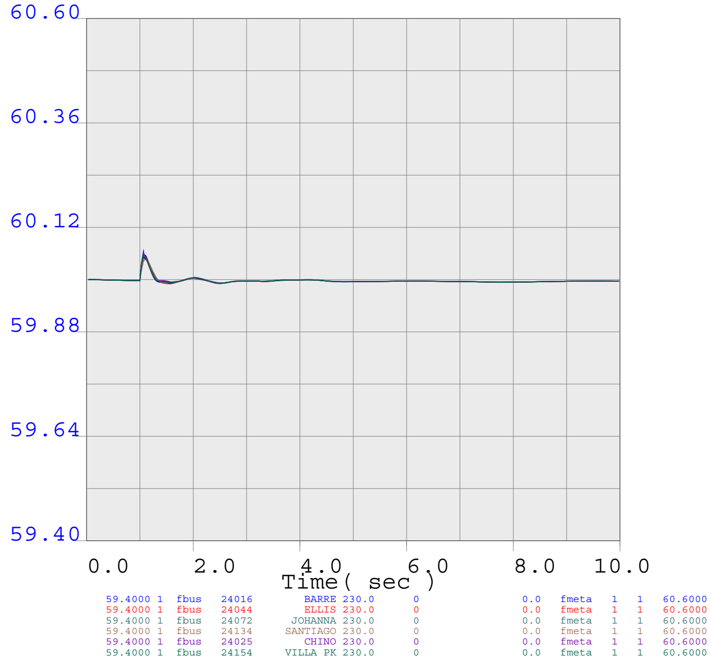
Thu Oct 20 08:54:01 2016

METRO









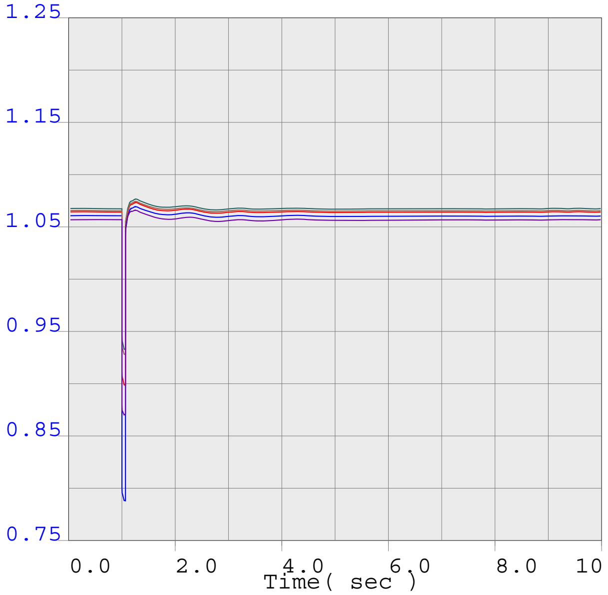
bay_23104
RIOHONDO 220 KV POS 1N
1 MW dispatch Case

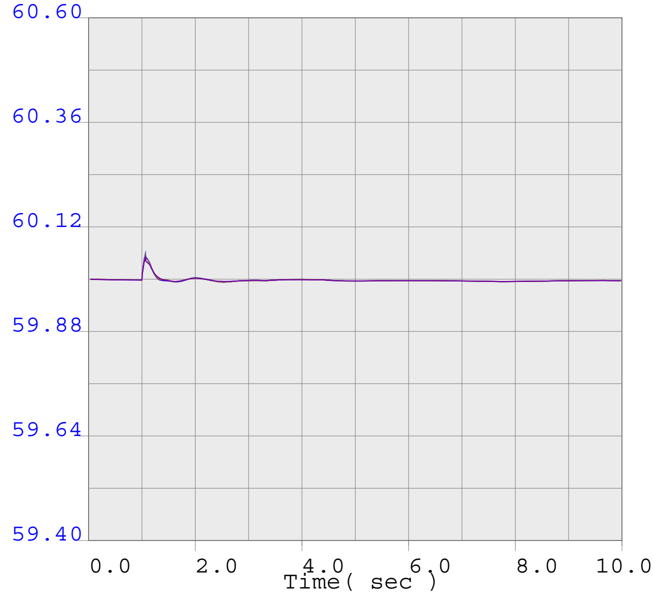
qc9p-bay_23104.chf

C:\DYTOOLS

Thu Oct 20 08:54:04 2016

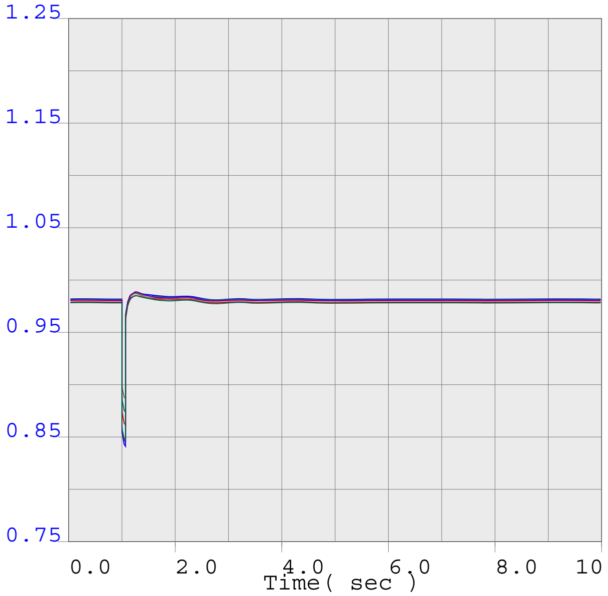
METRO

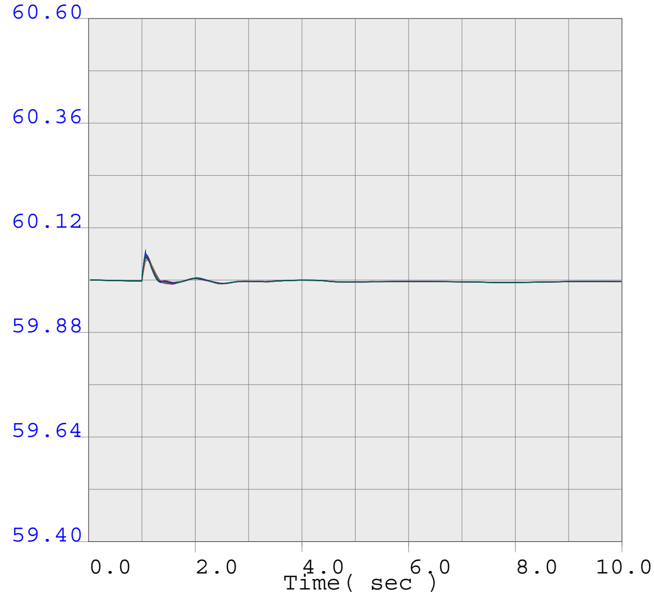




0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500

59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000





0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500

59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

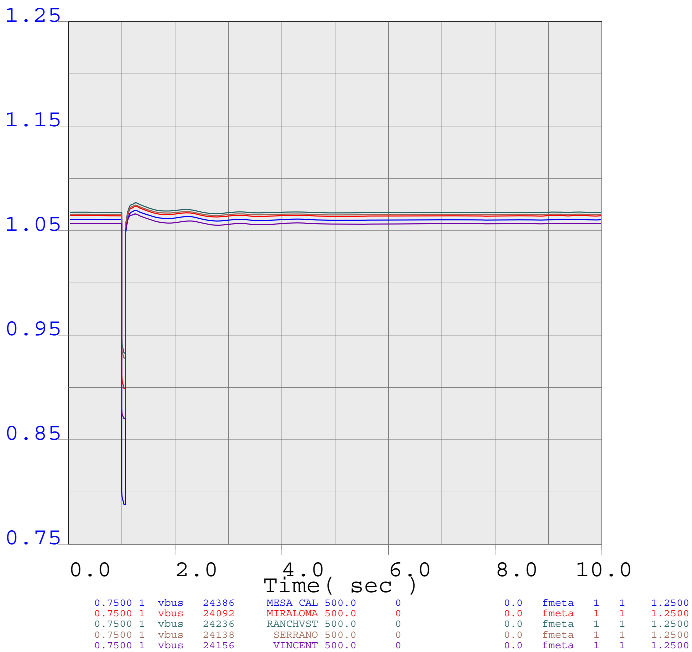
bay_23105
RIOHONDO 220 KV POS 2N
1 MW dispatch Case

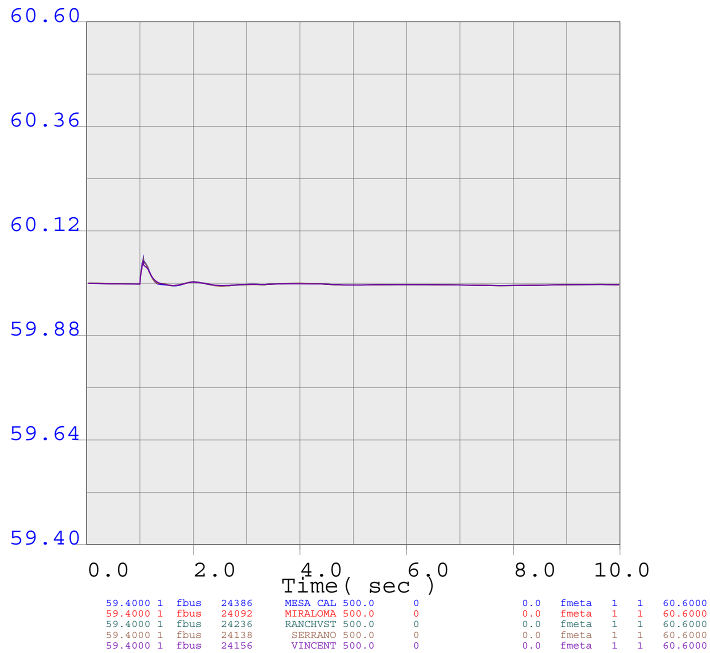
qc9p-bay_23105.chf

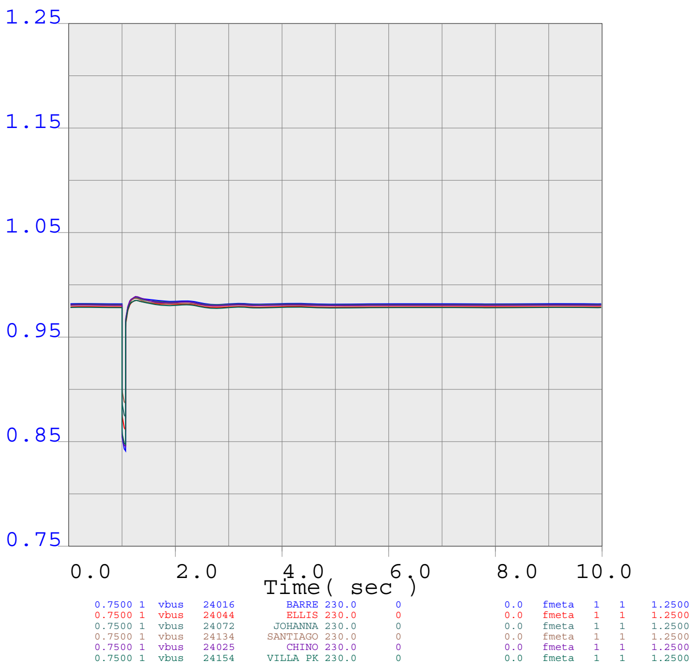
C:\DYTOOLS

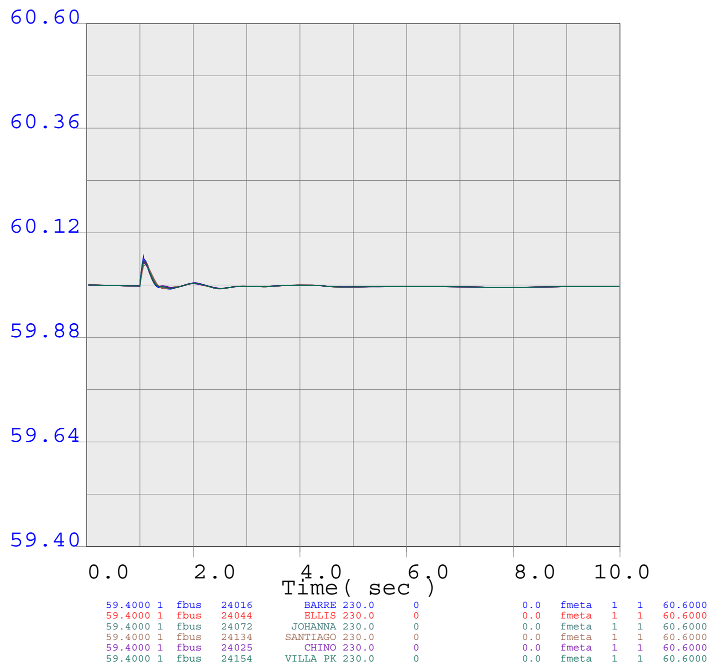
Thu Oct 20 08:54:06 2016

METRO









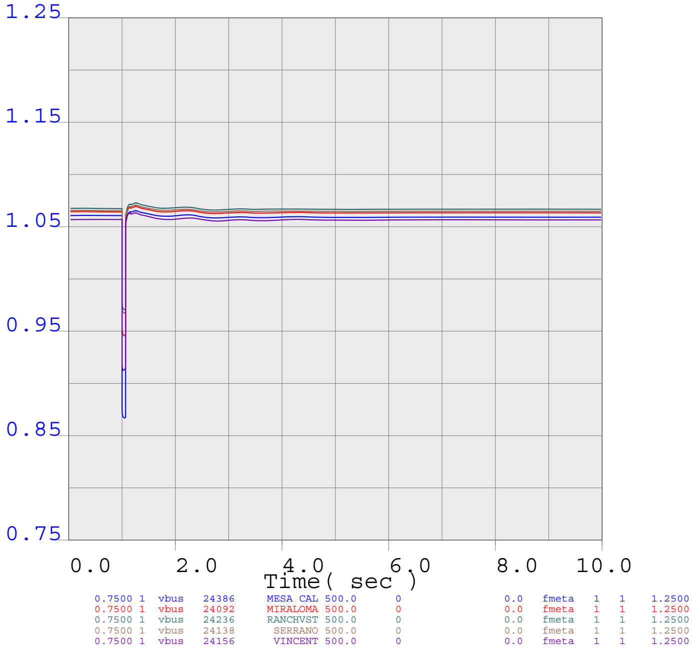
bay_23106
RIOHONDO 220 KV POS 3N
1 MW dispatch Case

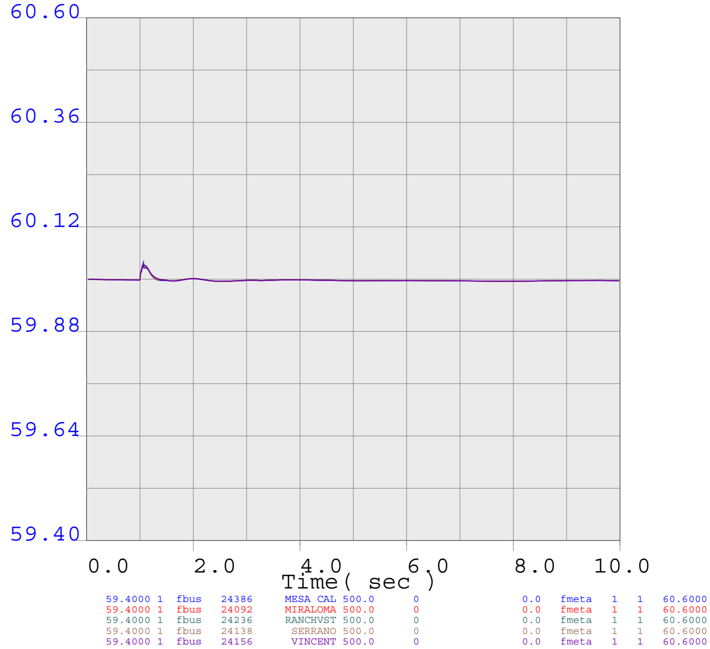
qc9p-bay_23106.chf

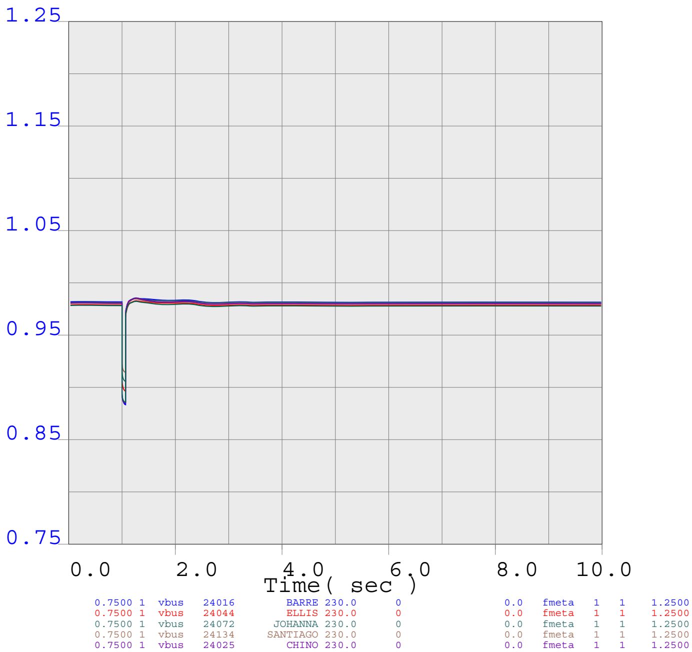
C:\DYTOOLS

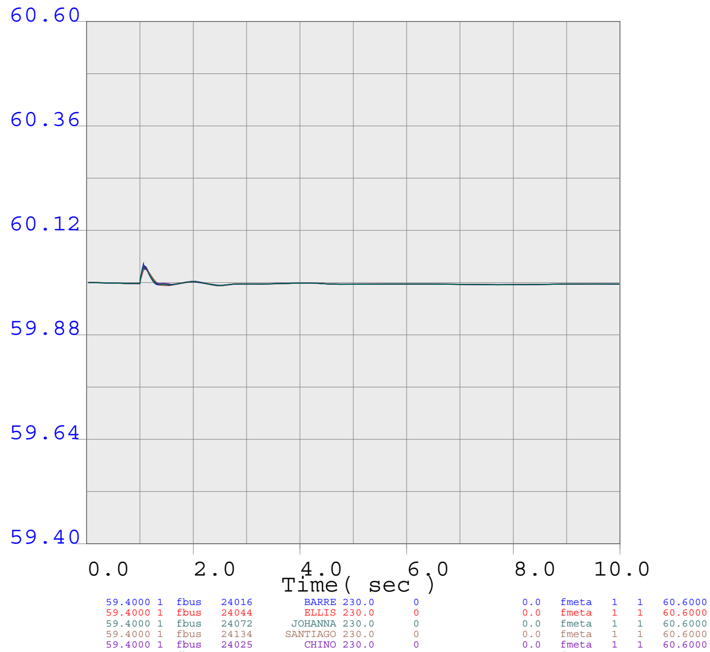
Thu Oct 20 08:54:08 2016

METRO









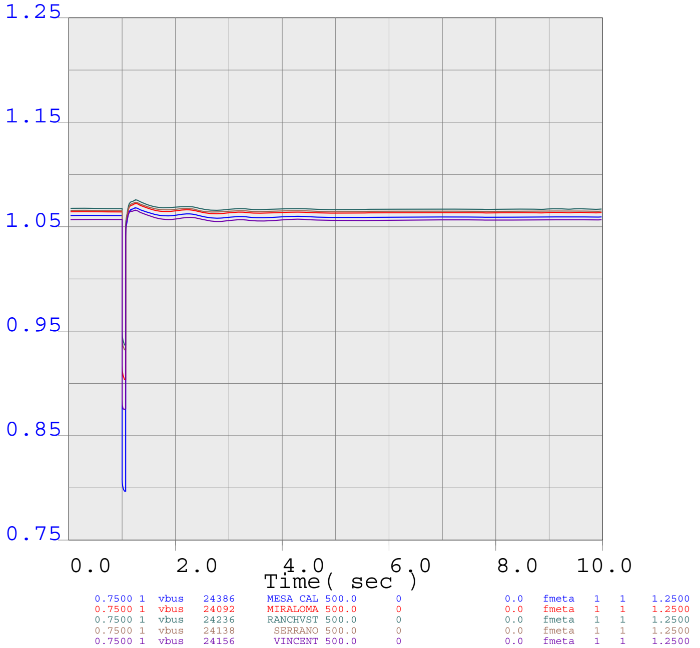
bay_23107
RIOHONDO 220KV POS 4N
1 MW dispatch Case

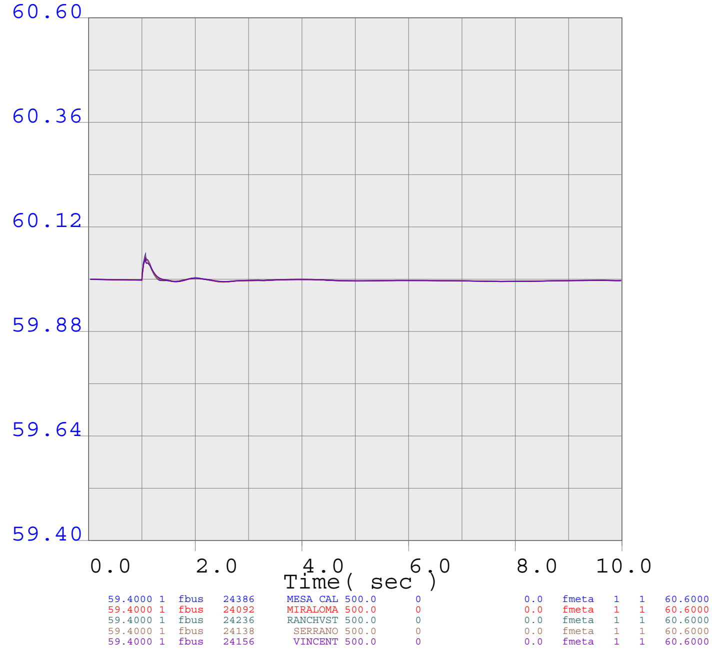
qc9p-bay_23107.chf

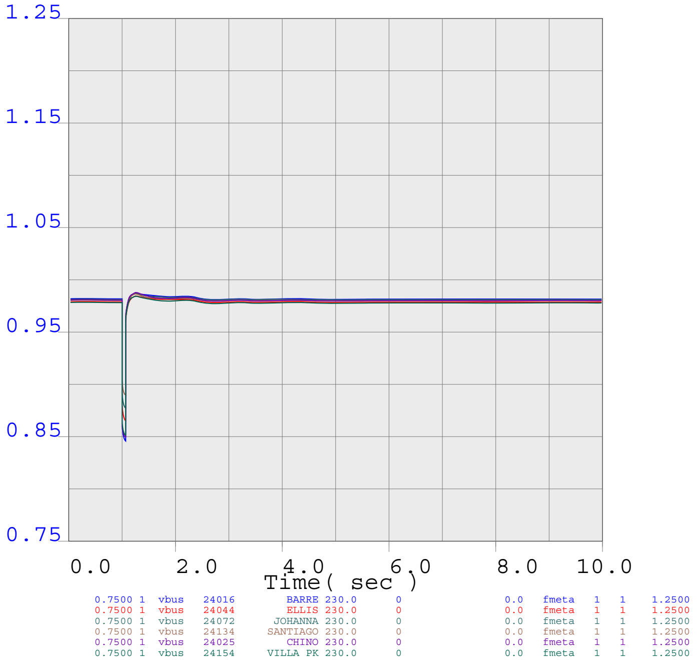
C:\DYTOOLS

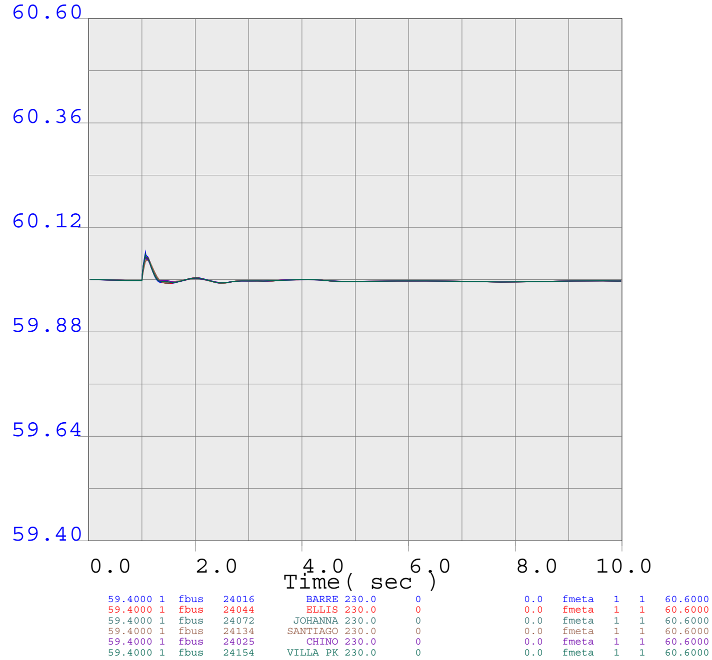
Thu Oct 20 08:54:11 2016

METRO









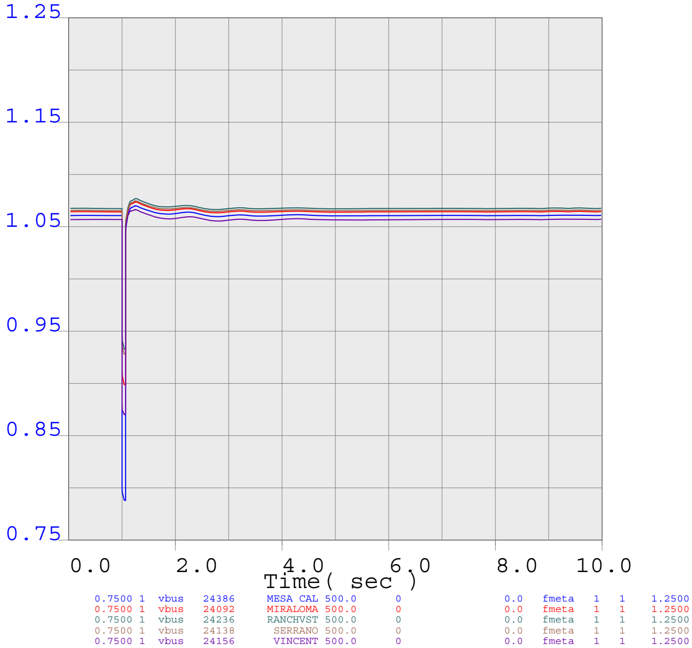
bay_23108
RIOHONDO 220 KV POS 7N
1 MW dispatch Case

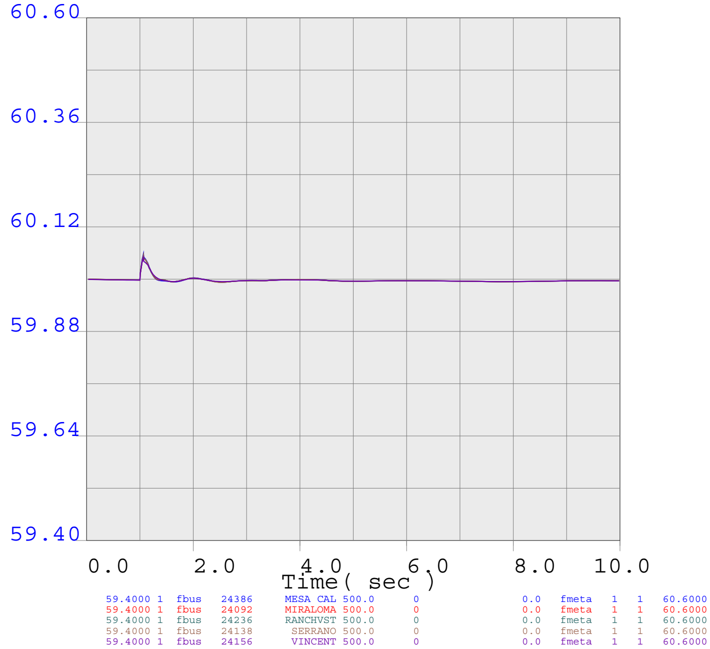
qc9p-bay_23108.chf

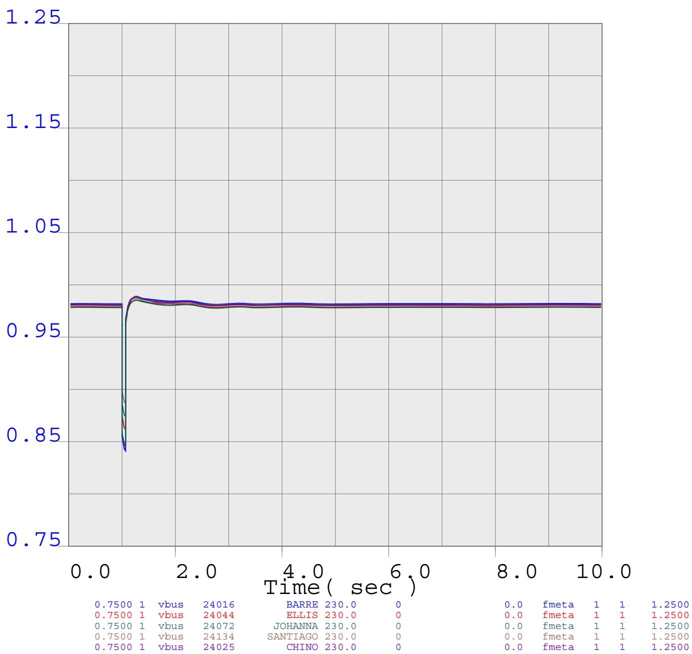
C:\DYTOOLS

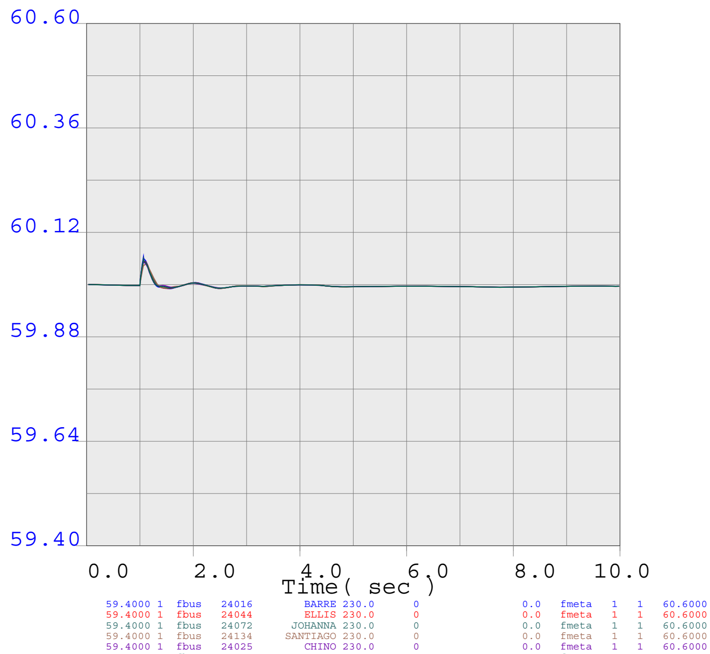
Thu Oct 20 08:54:13 2016

METRO









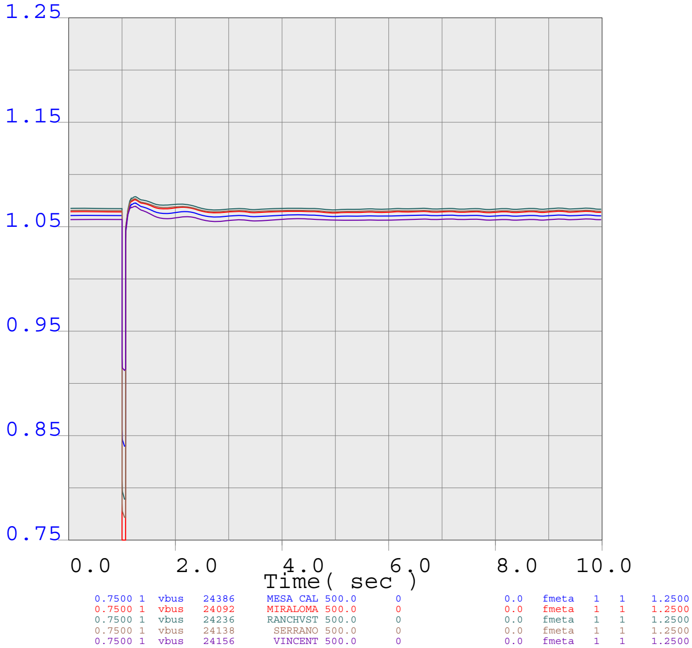
bay_23109
RIOHONDO 220 KV POS 10N
1 MW dispatch Case

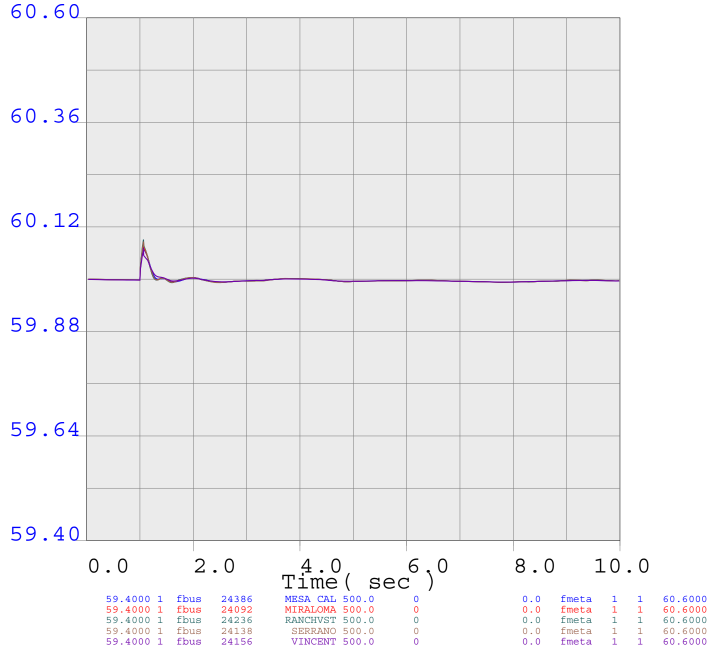
qc9p-bay_23109.chf

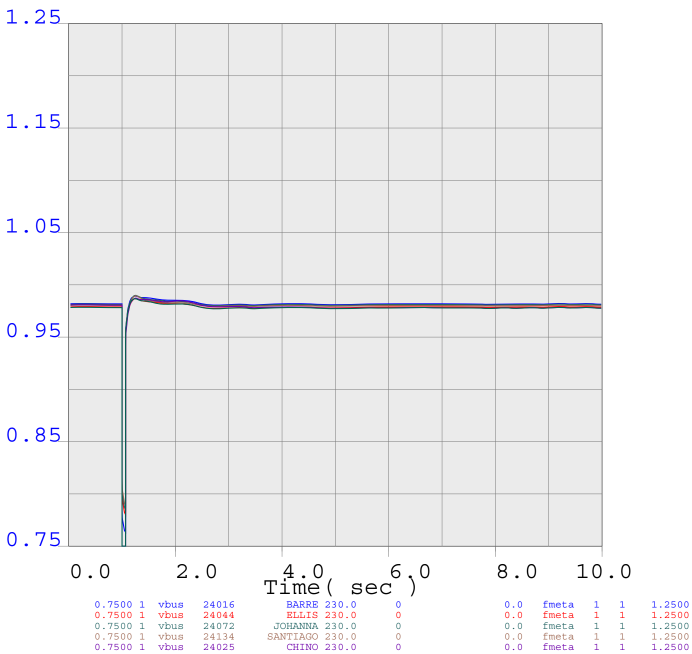
C:\DYTOOLS

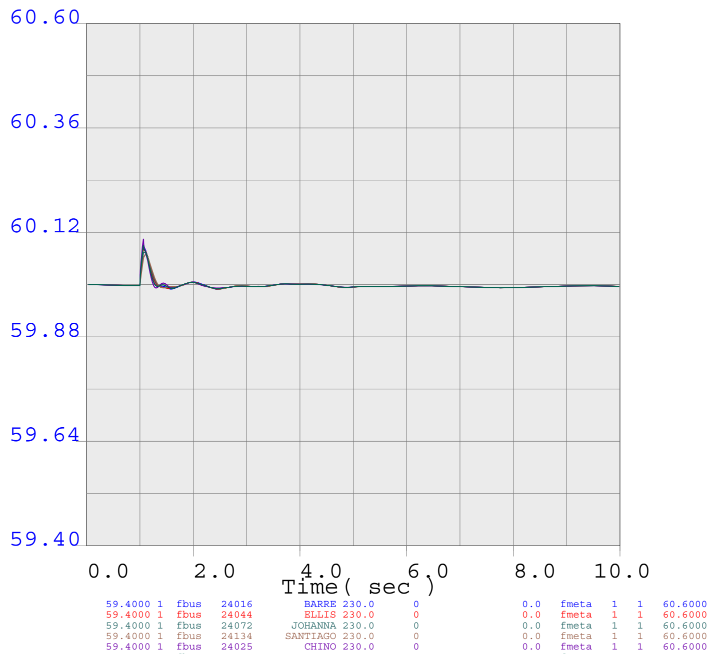
Thu Oct 20 08:54:15 2016

METRO









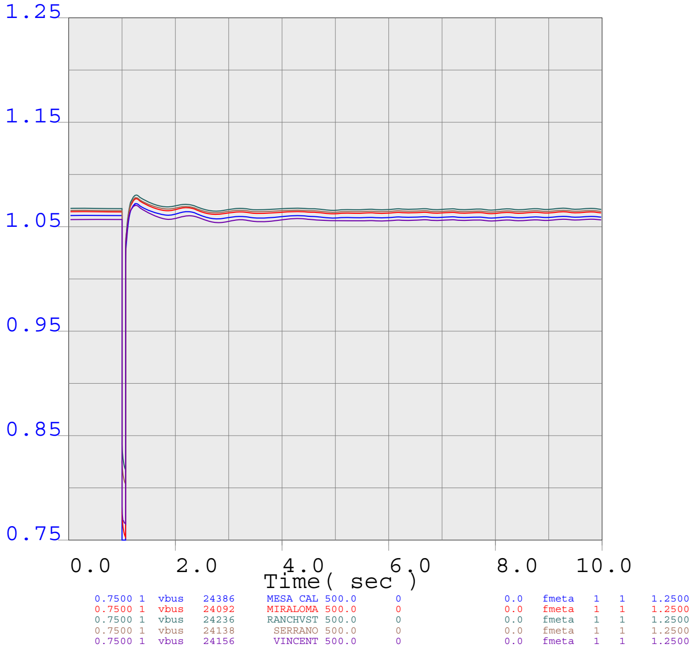
bay_2311
CHINO 220 KV POS 5E
1 MW dispatch Case

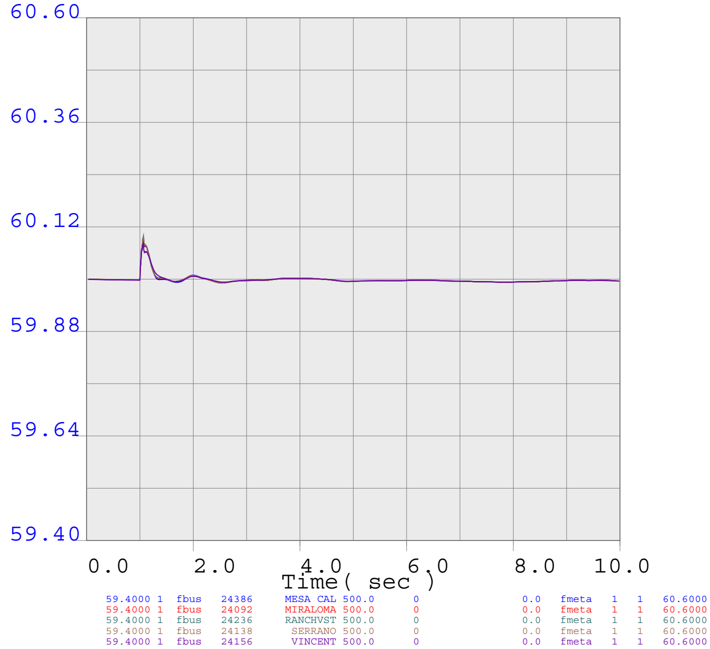
qc9p-bay_2311.chf

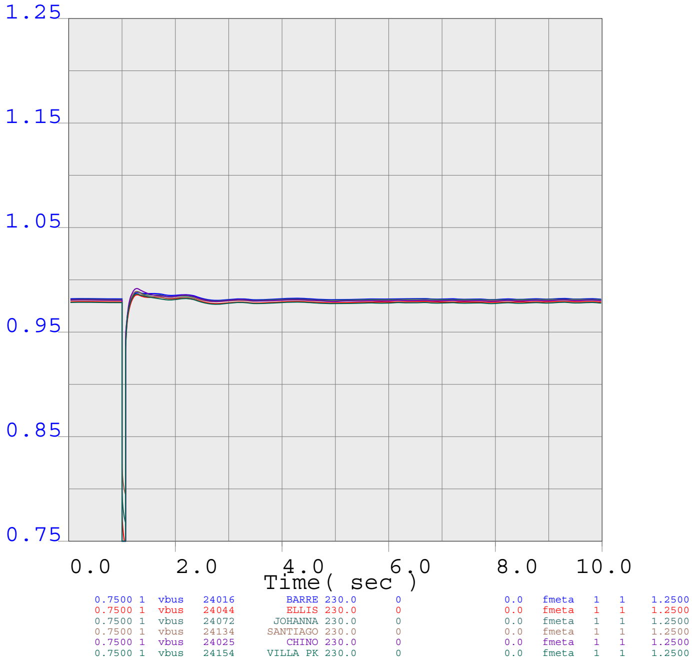
C:\DYTOOLS

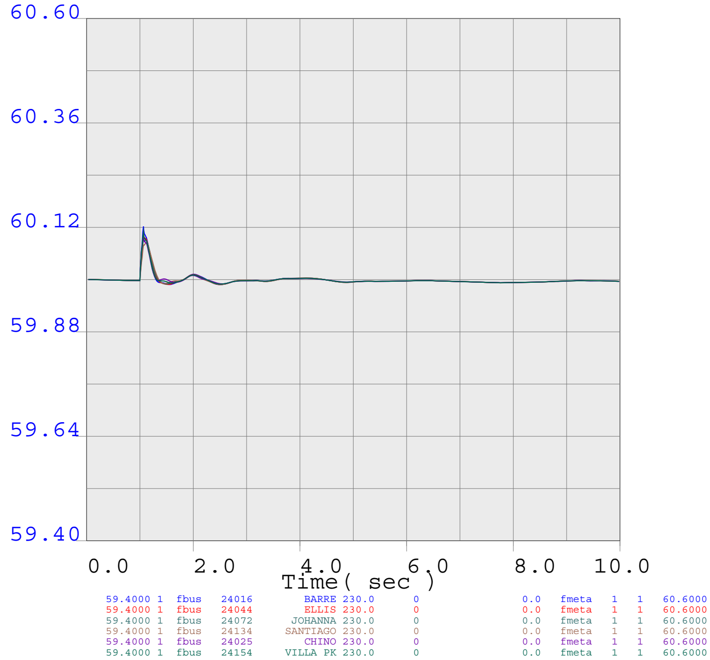
Thu Oct 20 08:54:17 2016

METRO









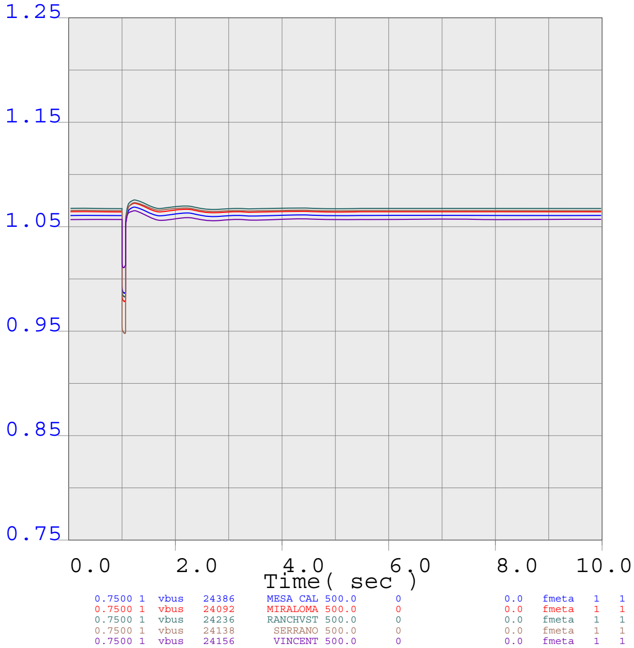
bay_23110
RIO HONDO 220 KV POS 4 INTERNAL FAULT
1 MW dispatch Case

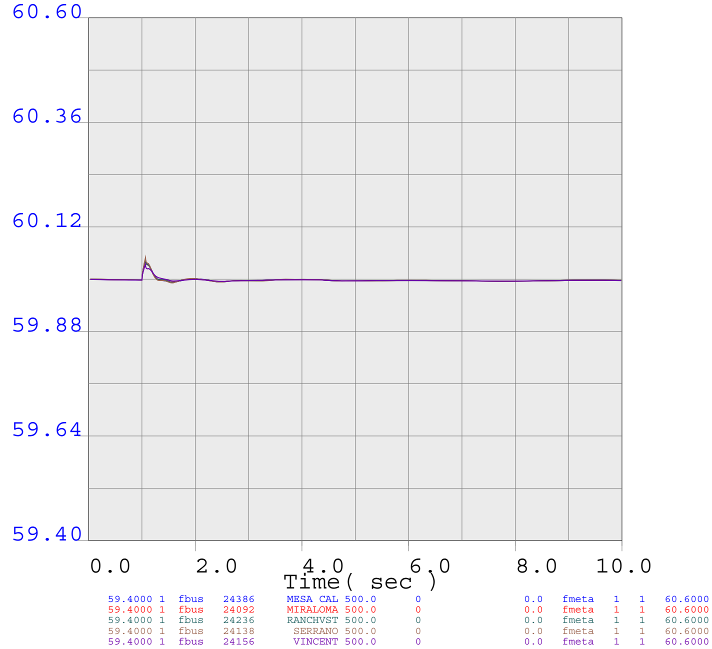
qc9p-bay_23110.chf

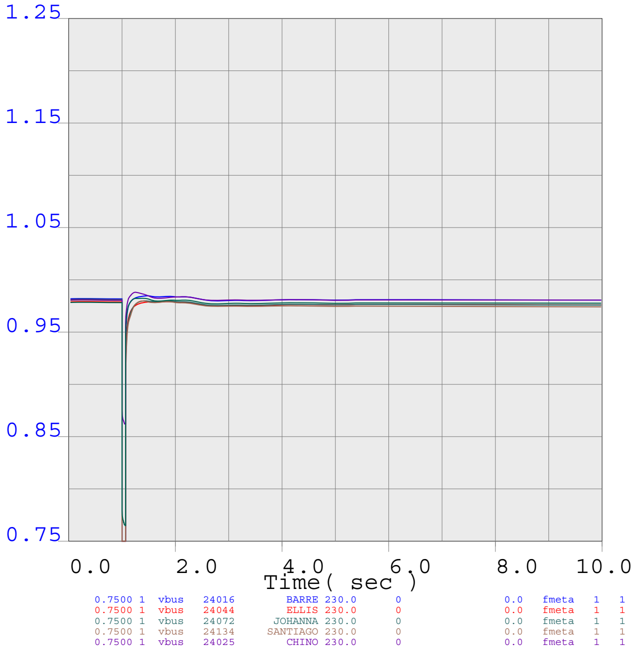
C:\DYTOOLS

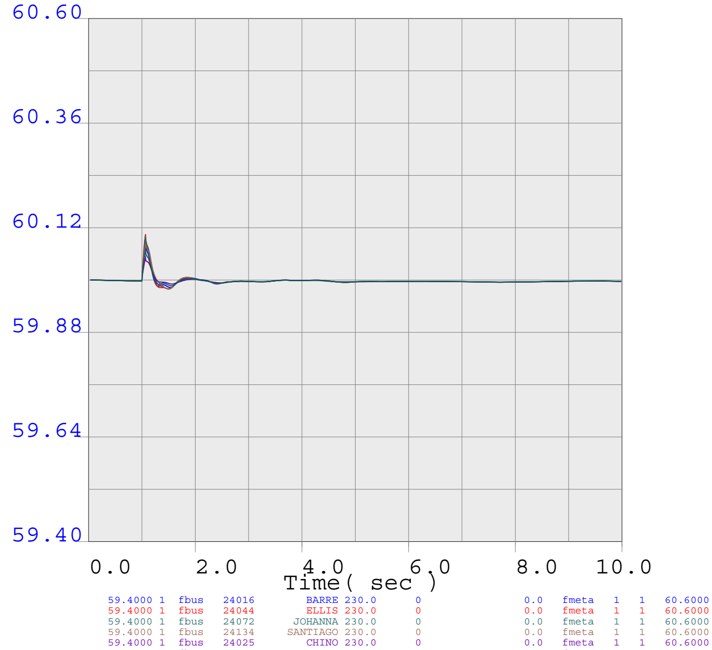
Thu Oct 20 08:54:20 2016

METRO









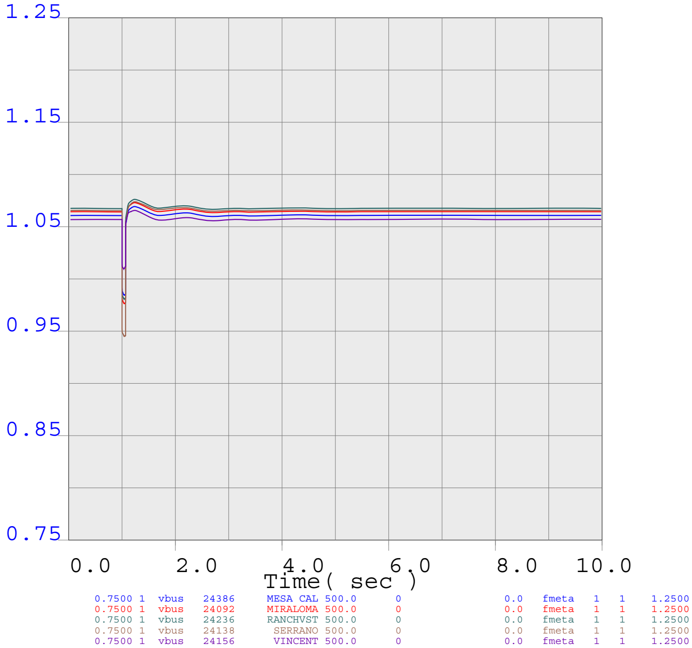
bay_23111
SANTIAGO 220 KV POS 5
1 MW dispatch Case

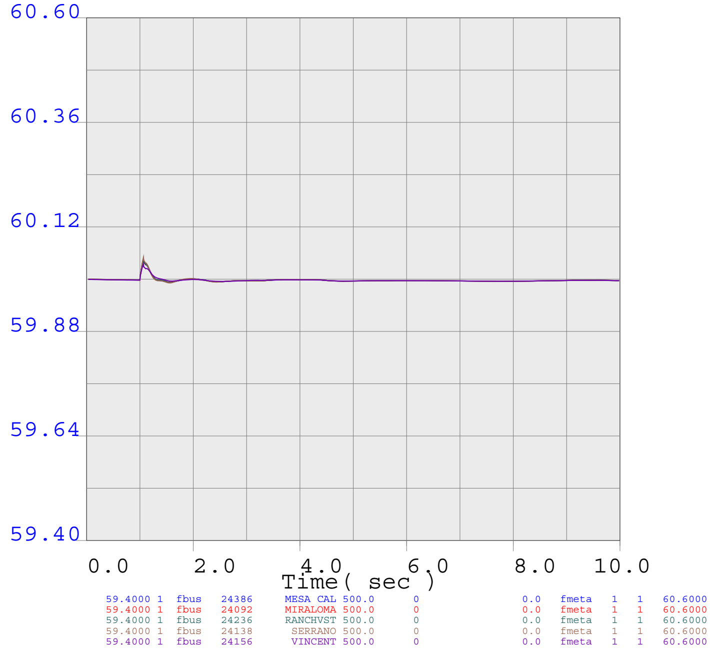
qc9p-bay_23111.chf

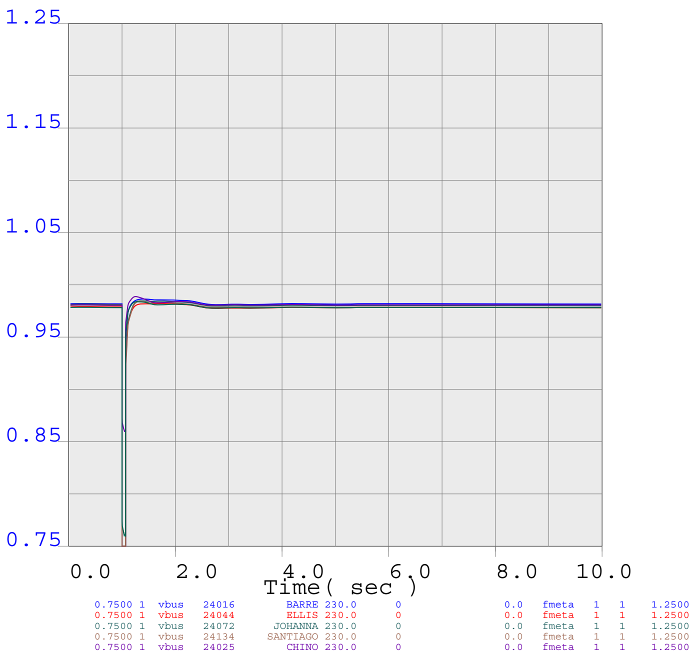
C:\DYTOOLS

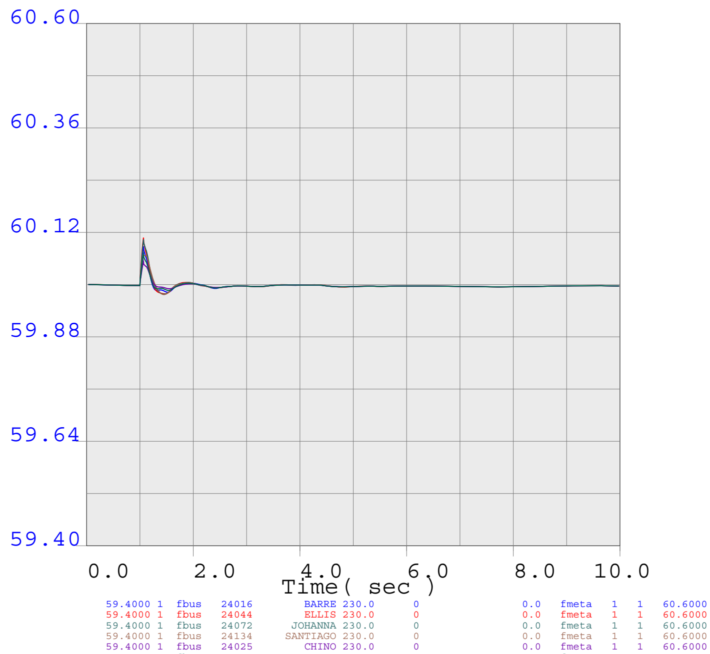
Thu Oct 20 08:54:23 2016

METRO









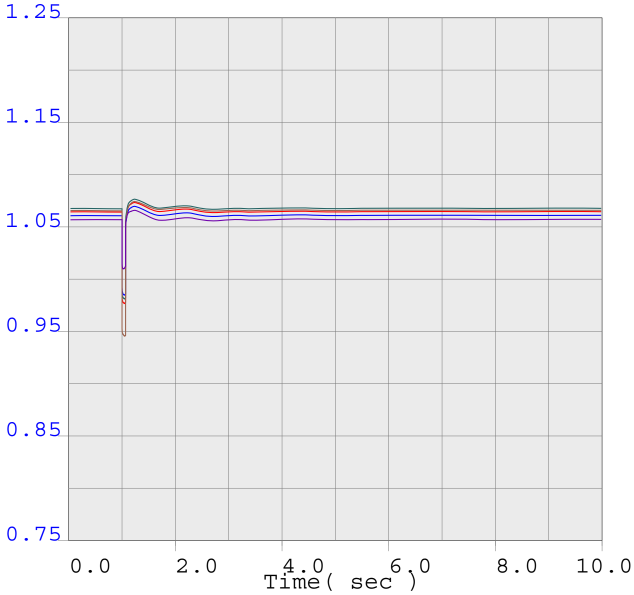
bay_23112
SANTIAGO 220 KV POS 1N
1 MW dispatch Case

qc9p-bay_23112.chf

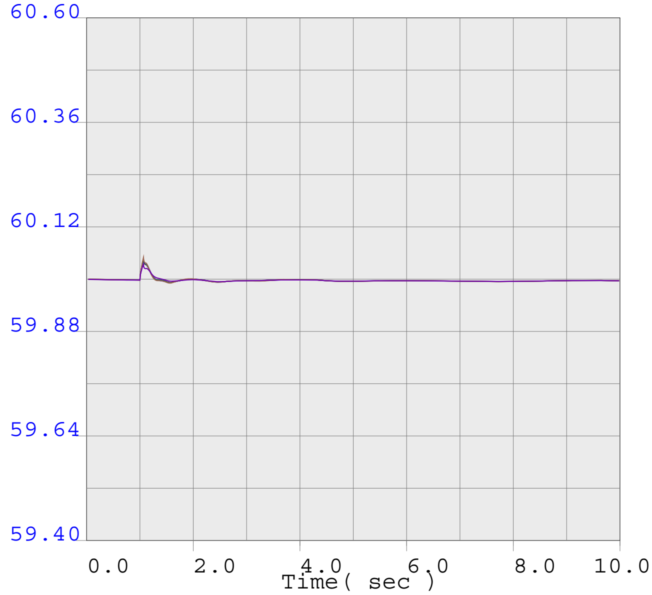
C:\DYTOOLS

Thu Oct 20 08:54:26 2016

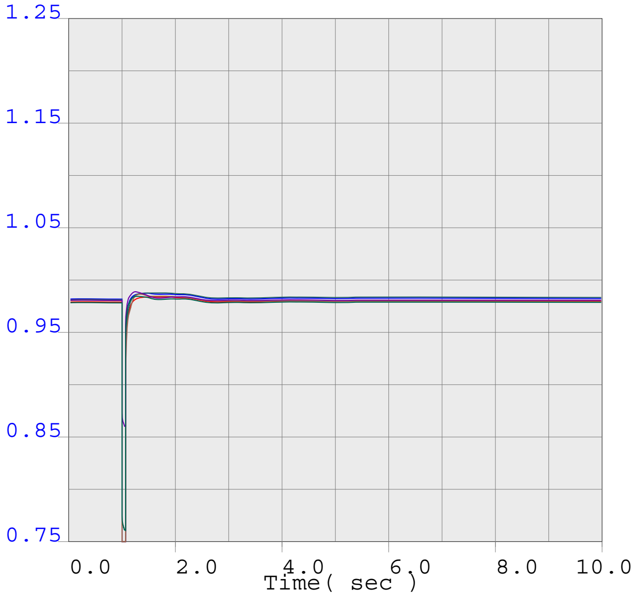
METRO



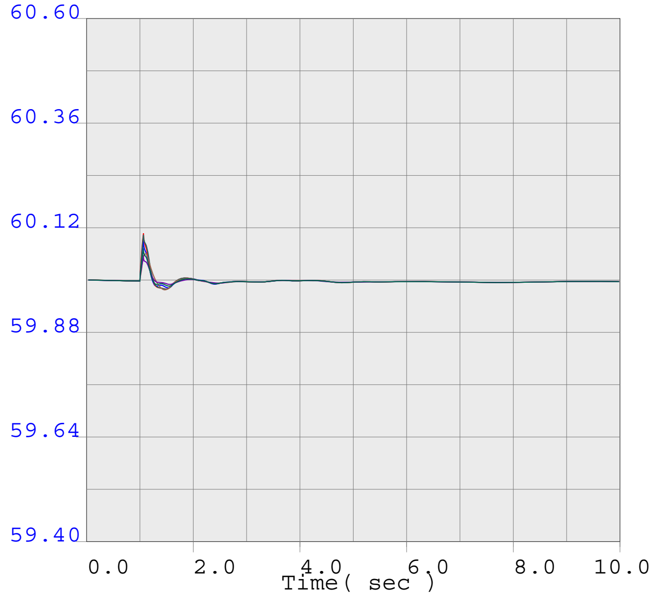
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

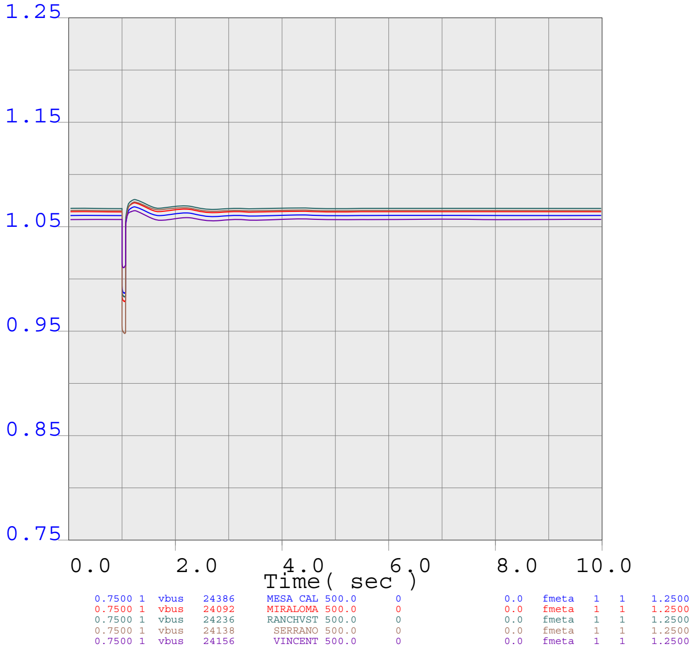
bay_23113
SANTIAGO 220 KV POS 3N
1 MW dispatch Case

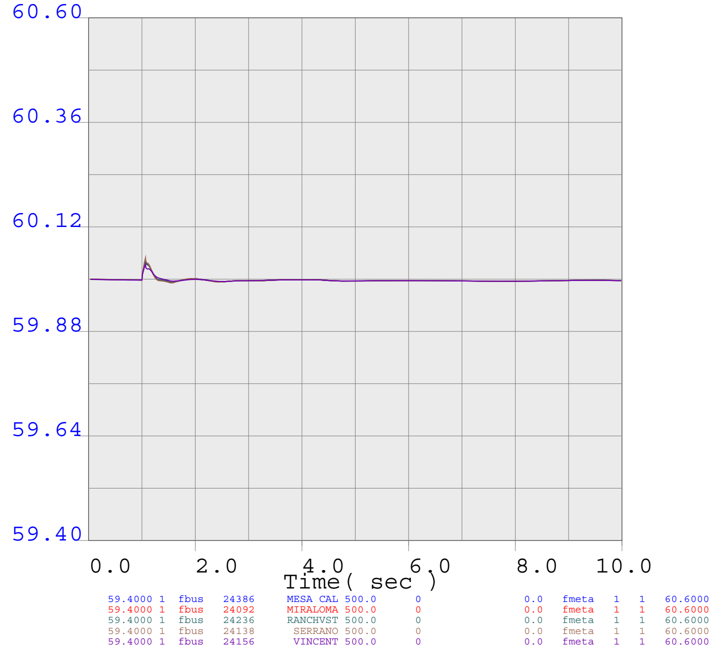
qc9p-bay_23113.chf

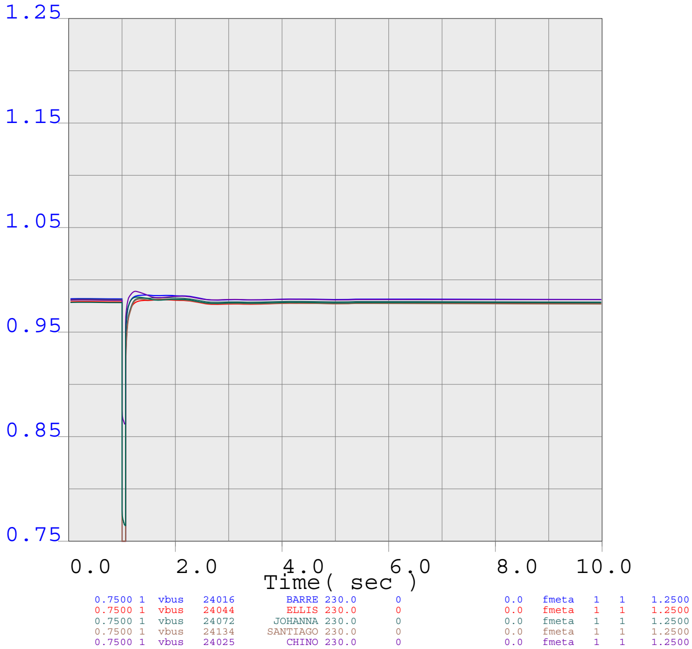
C:\DYTOOLS

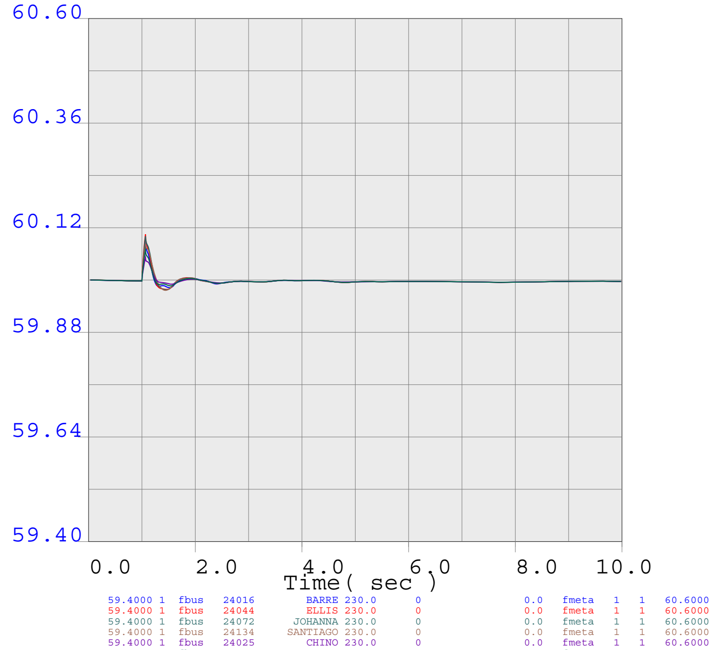
Thu Oct 20 08:54:30 2016

METRO









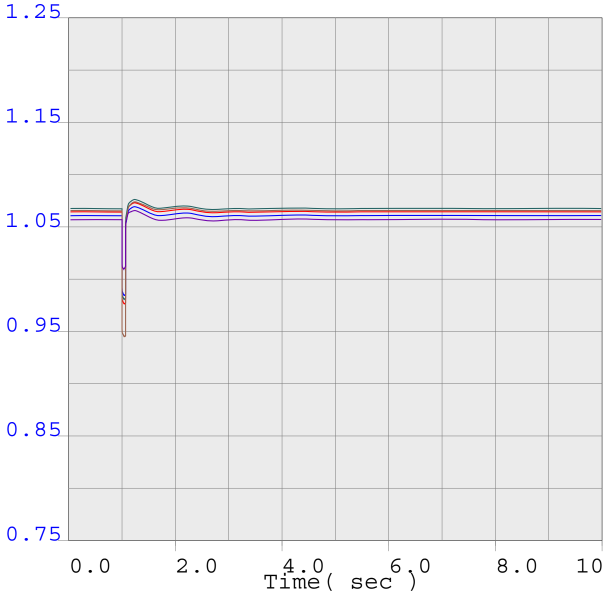
bay_23114
SANTIAGO 220 KV POS 5N
1 MW dispatch Case

qc9p-bay_23114.chf

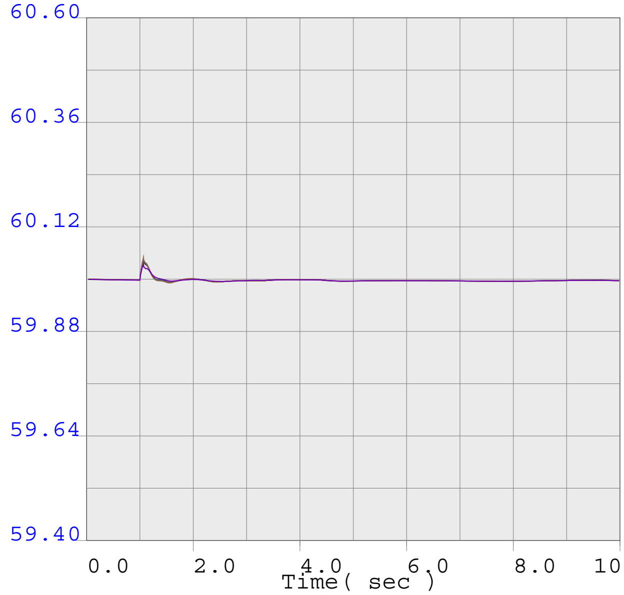
C:\DYTOOLS

Thu Oct 20 08:54:32 2016

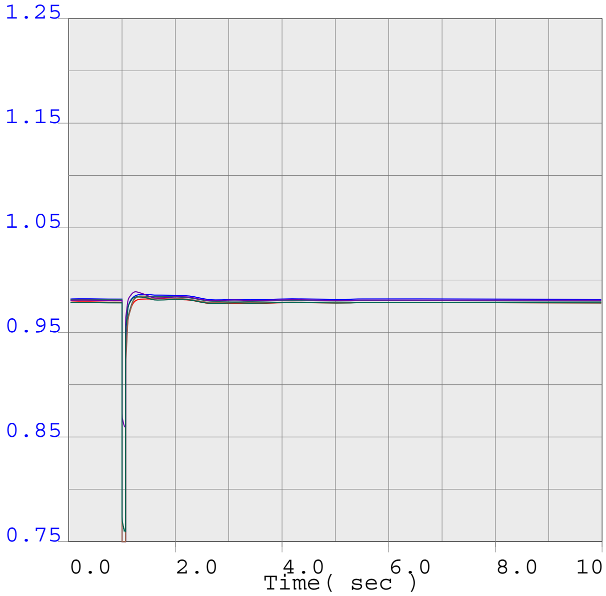
METRO



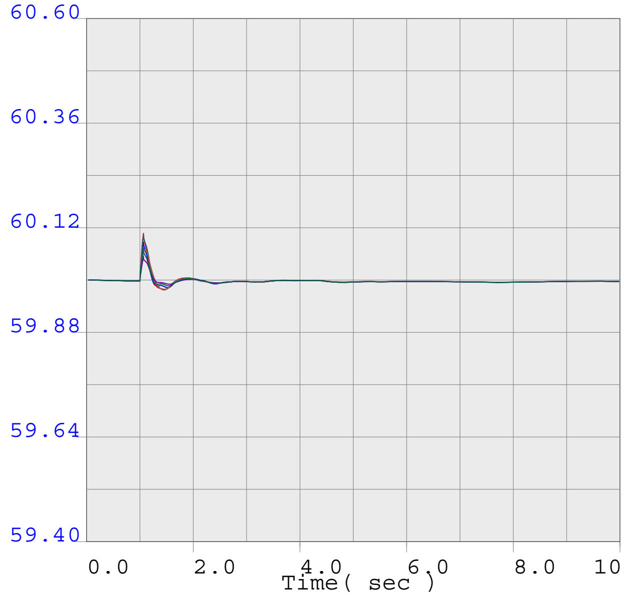
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

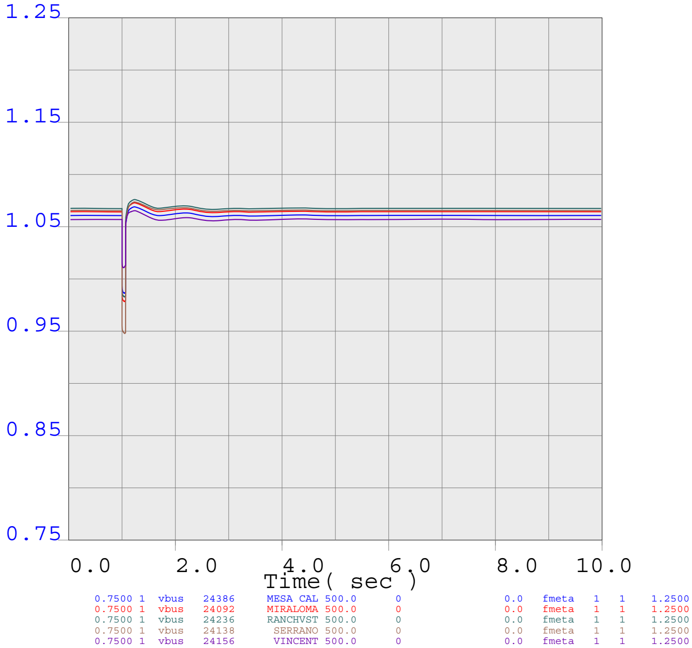
bay_23115
SANTIAGO 220 KV POS 6N
1 MW dispatch Case

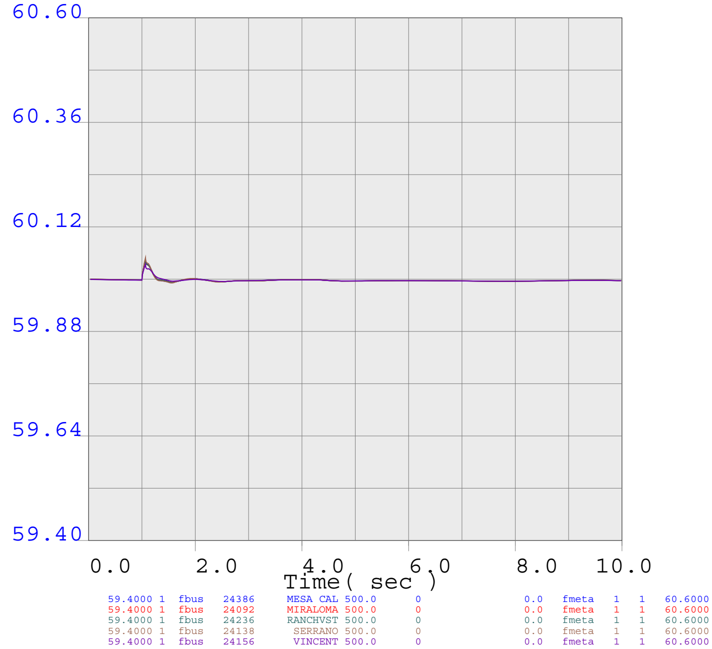
qc9p-bay_23115.chf

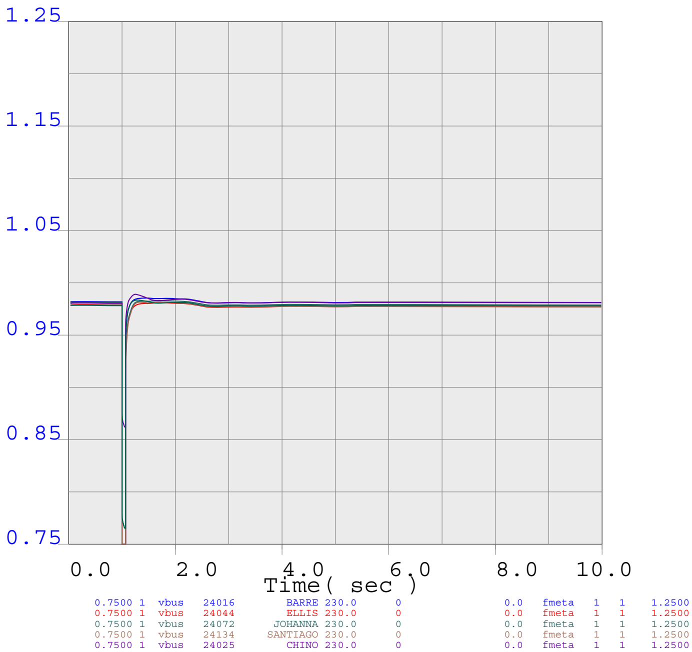
C:\DYTOOLS

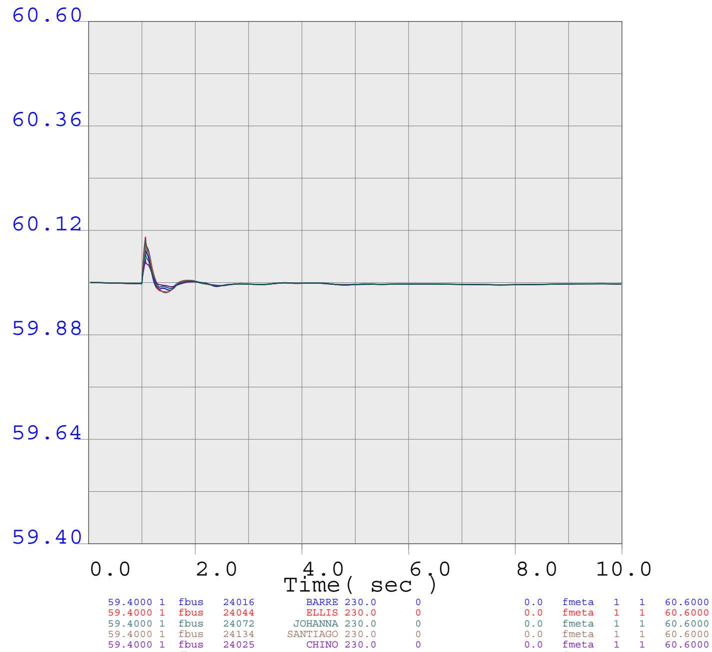
Thu Oct 20 08:54:35 2016

METRO









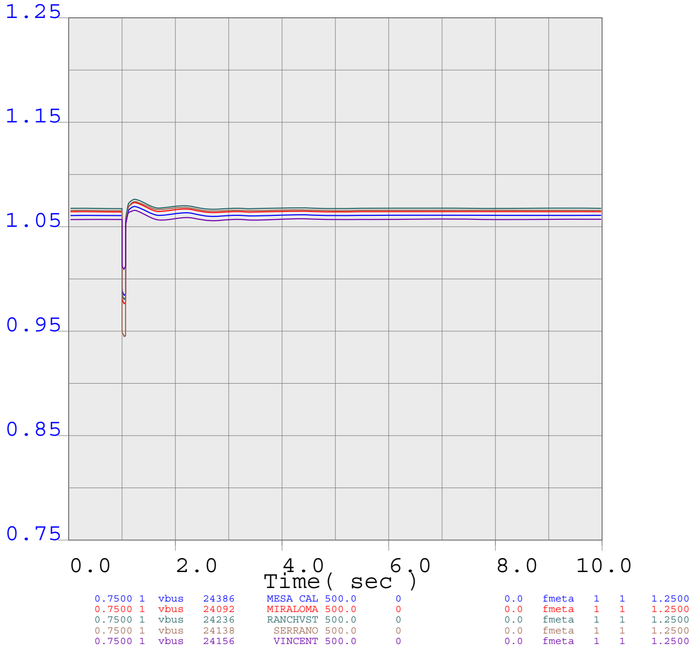
bay_23116
SANTIAGO 220 KV POS 7N
1 MW dispatch Case

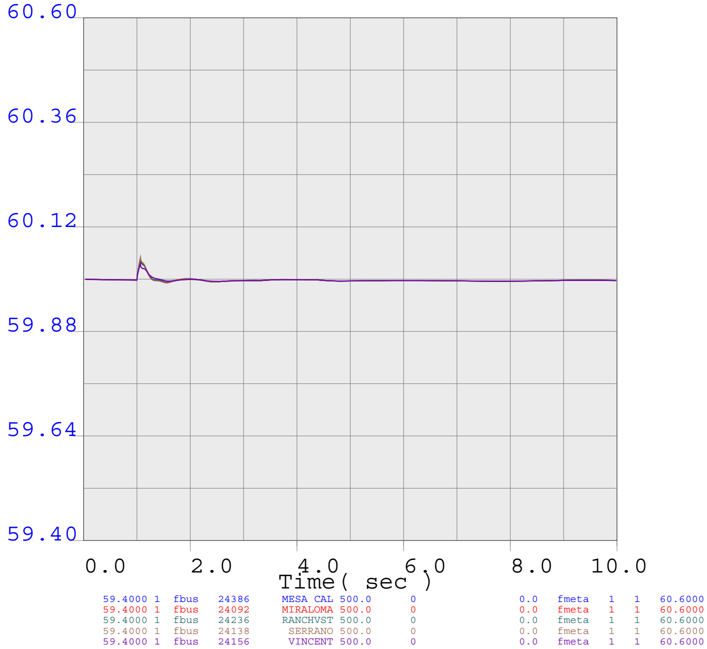
qc9p-bay_23116.chf

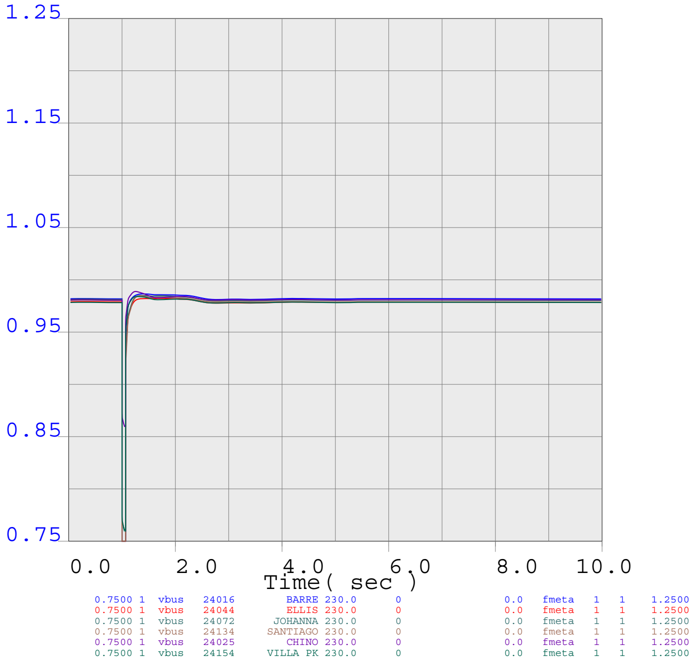
C:\DYTOOLS

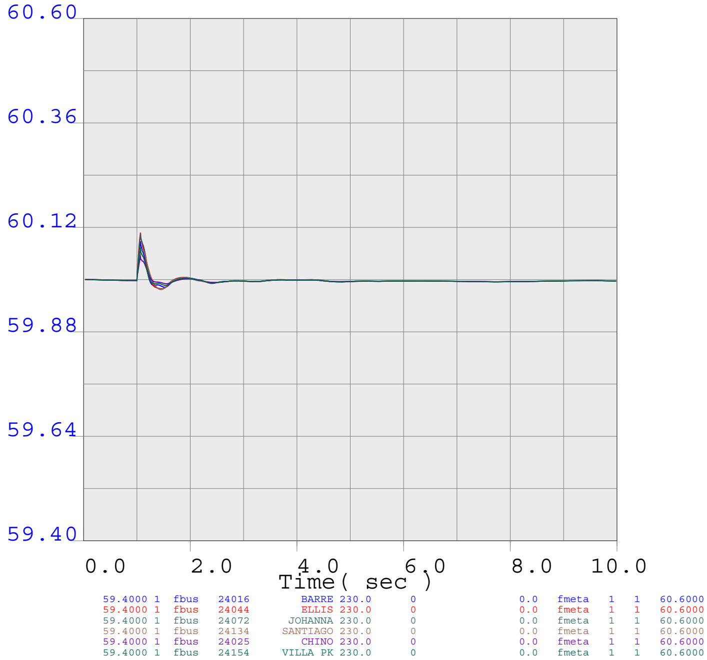
Thu Oct 20 08:54:38 2016

METRO









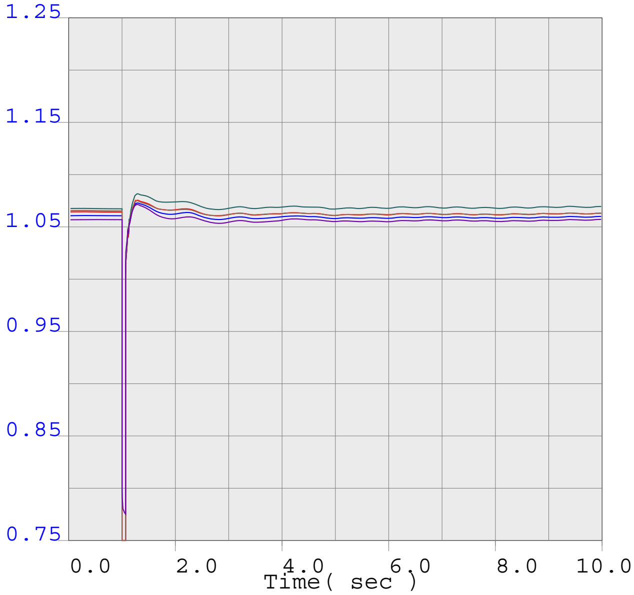
bay_23117
SANTIAGO 220 KV POS 8N
1 MW dispatch Case

qc9p-bay_23117.chf

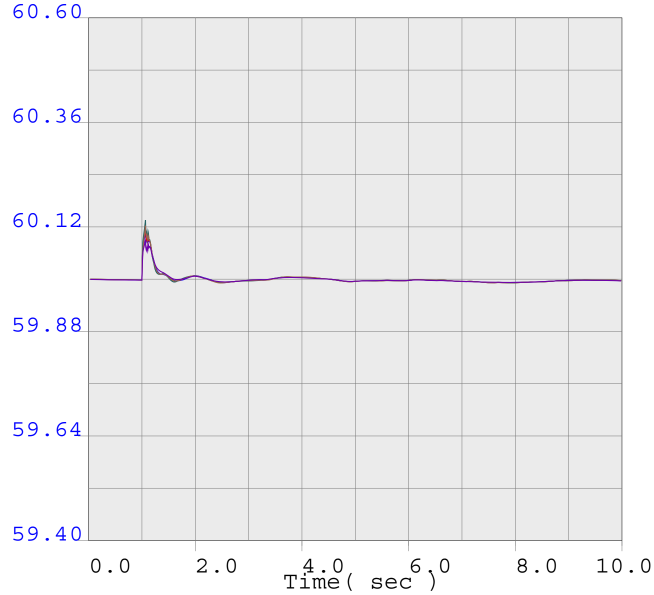
C:\DYTOOLS

Thu Oct 20 08:54:40 2016

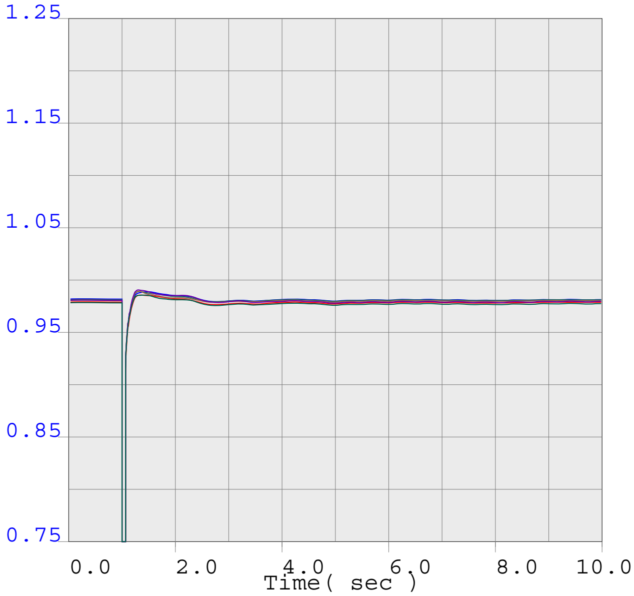
METRO



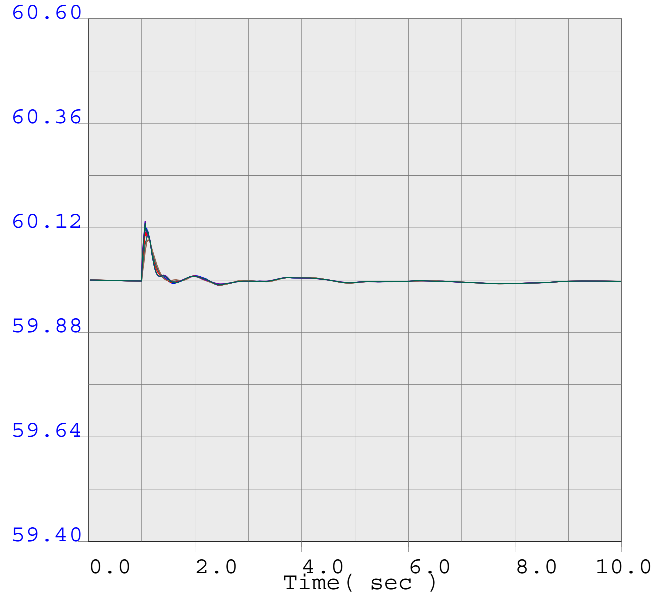
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

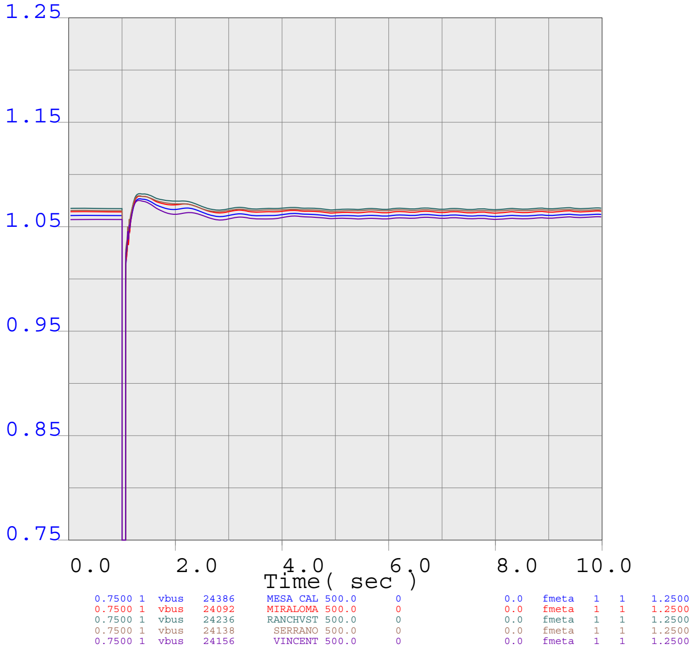
bay_23118
SERRANO 500 KV POS 1 INTERNAL FAULT
1 MW dispatch Case

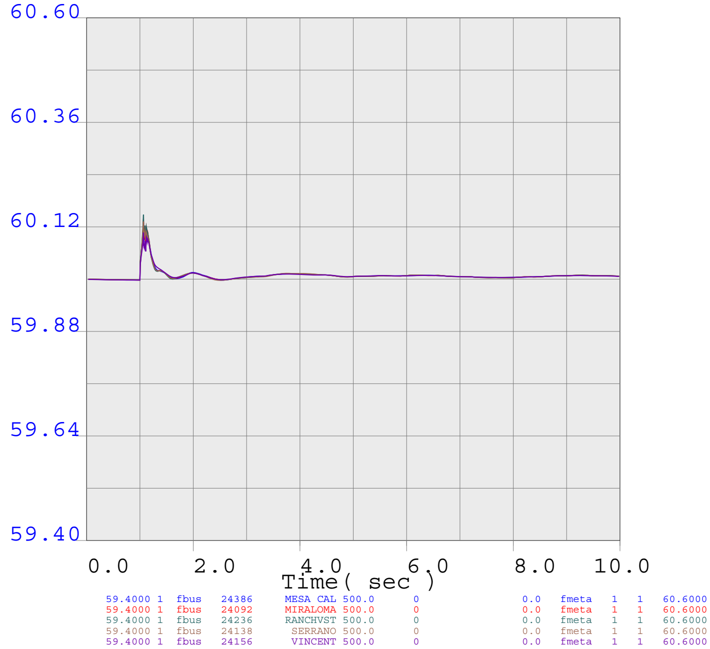
qc9p-bay_23118.chf

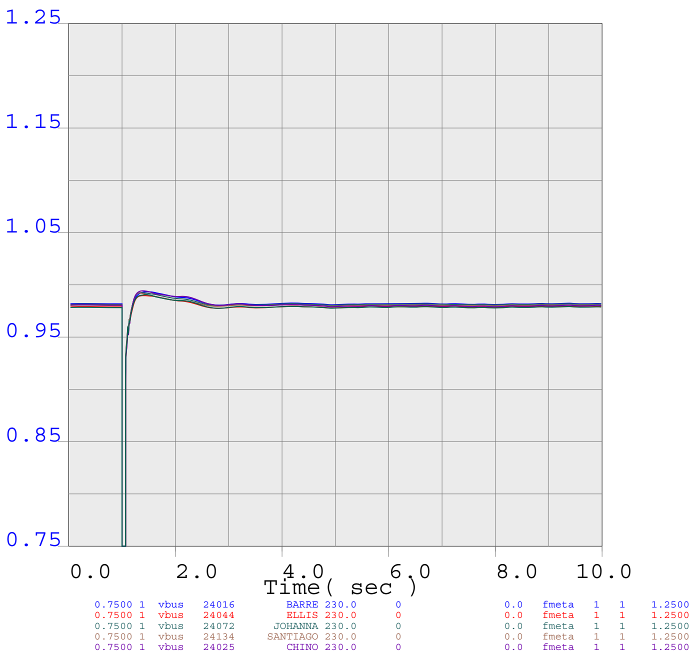
C:\DYTOOLS

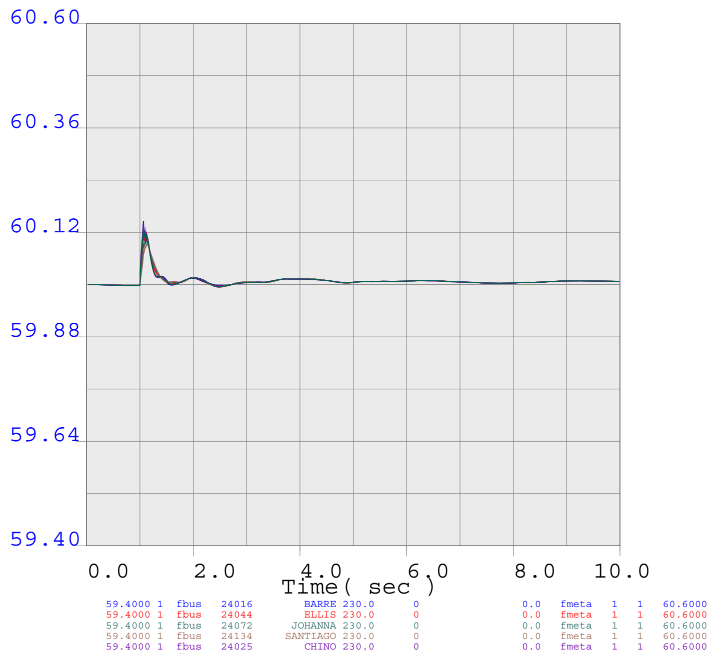
Thu Oct 20 08:54:42 2016

METRO









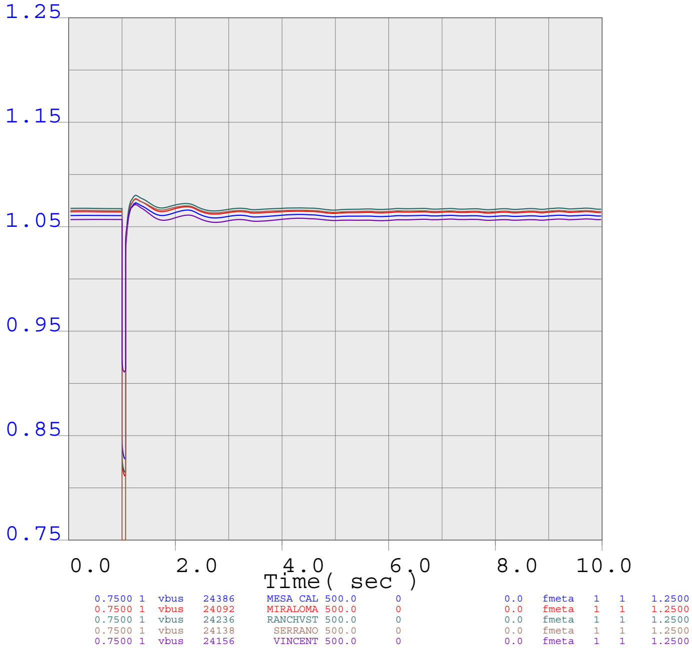
bay_23119
SERRANO 500 KV POS 2 INTERNAL FAULT
1 MW dispatch Case

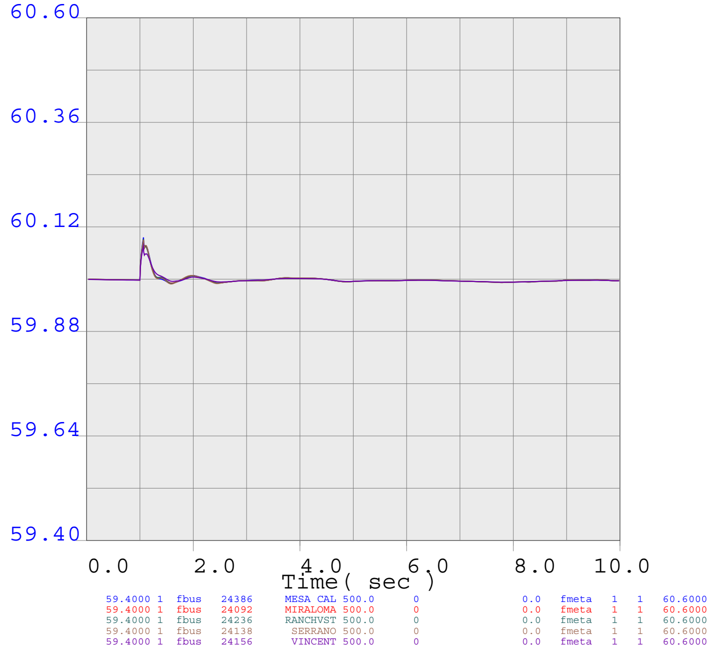
qc9p-bay_23119.chf

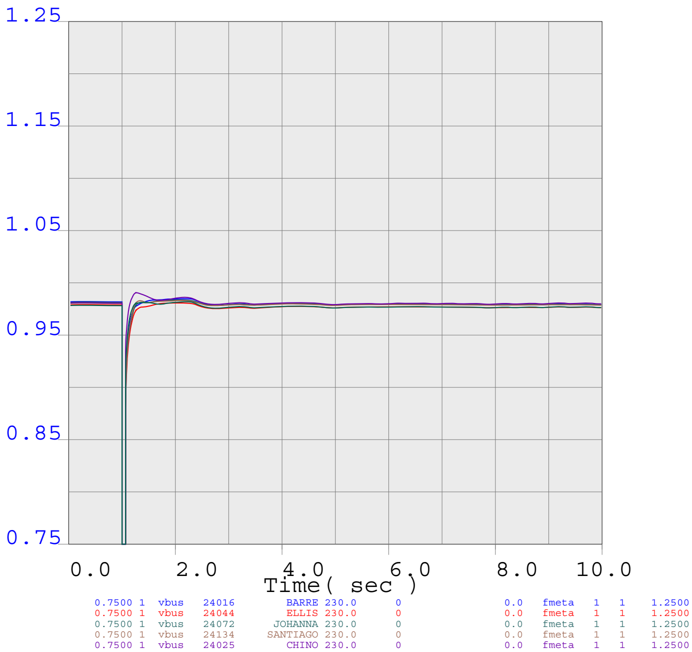
C:\DYTOOLS

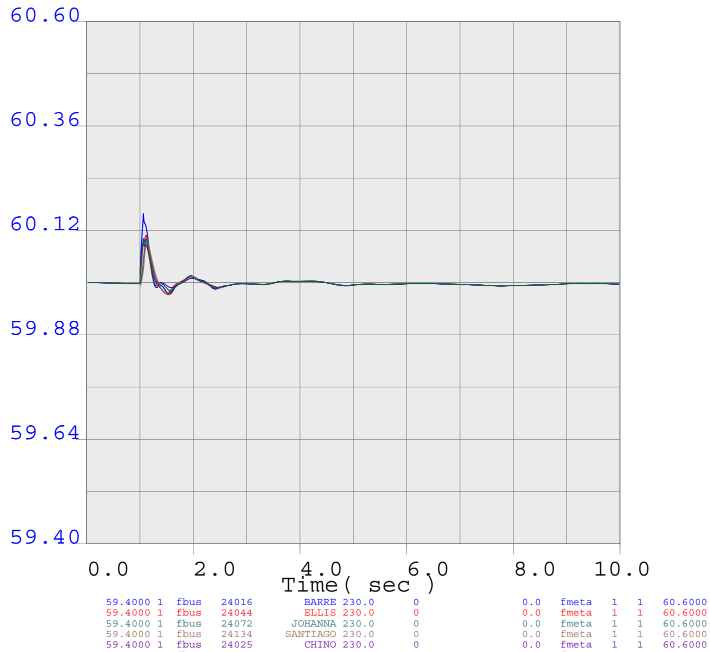
Thu Oct 20 08:54:43 2016

METRO









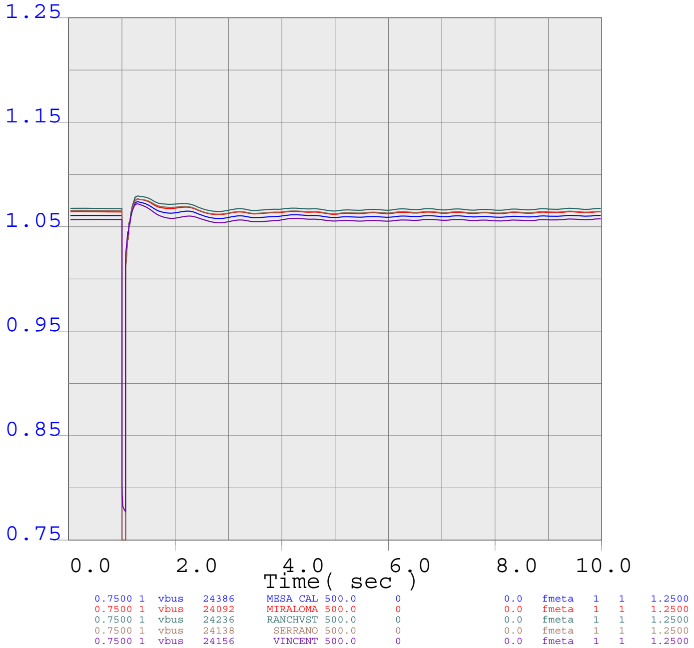
bay_2312
BARRE 220.00 13S
1 MW dispatch Case

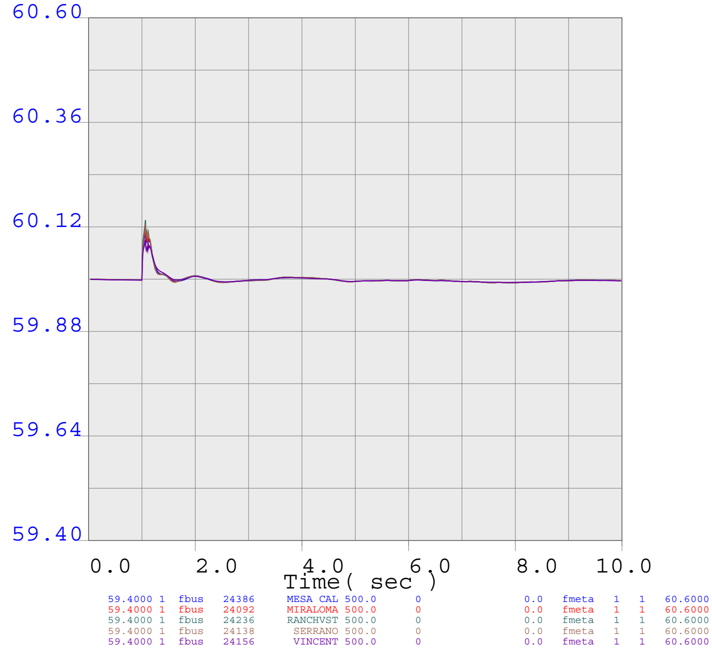
qc9p-bay_2312.chf

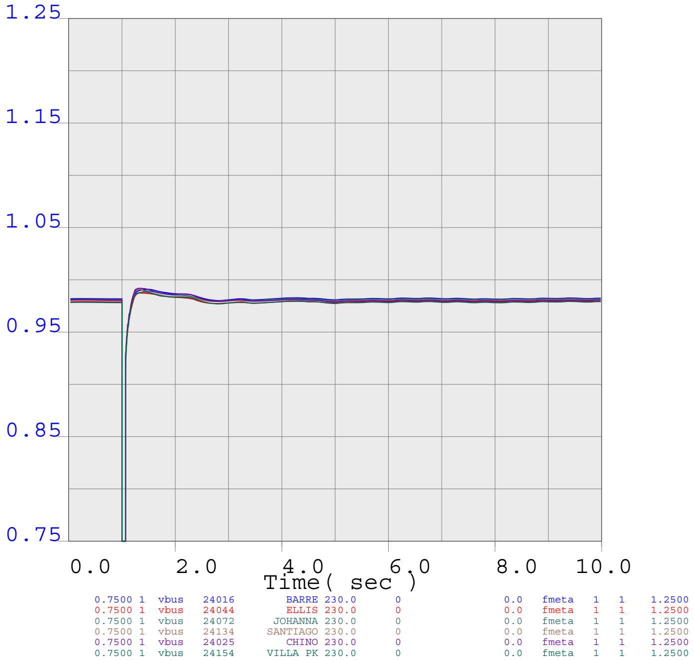
C:\DYTOOLS

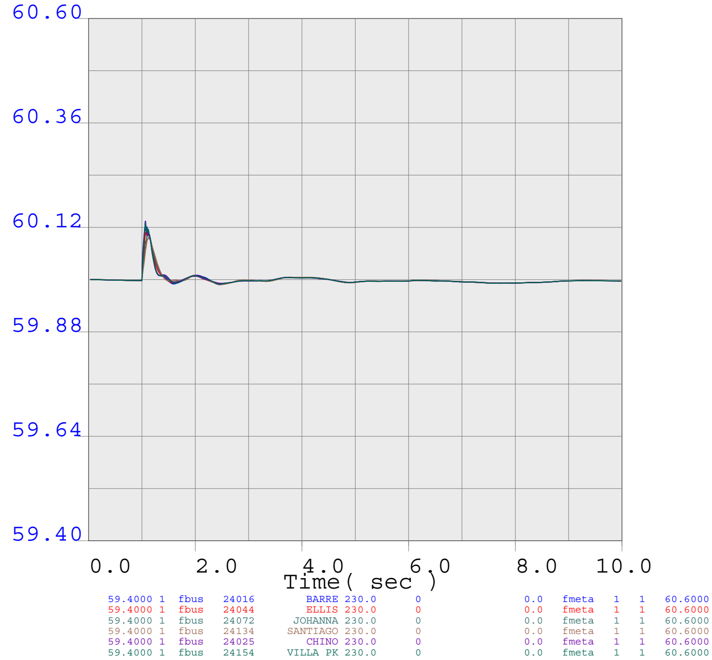
Thu Oct 20 08:54:46 2016

METRO





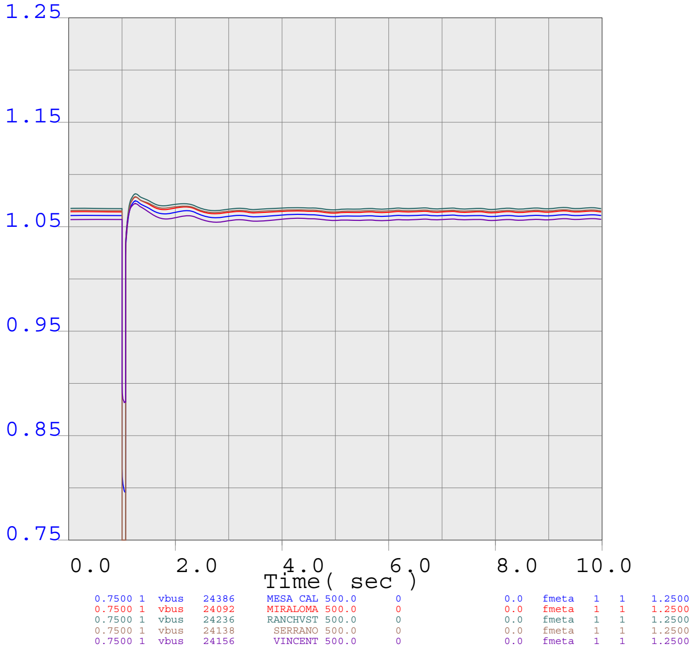


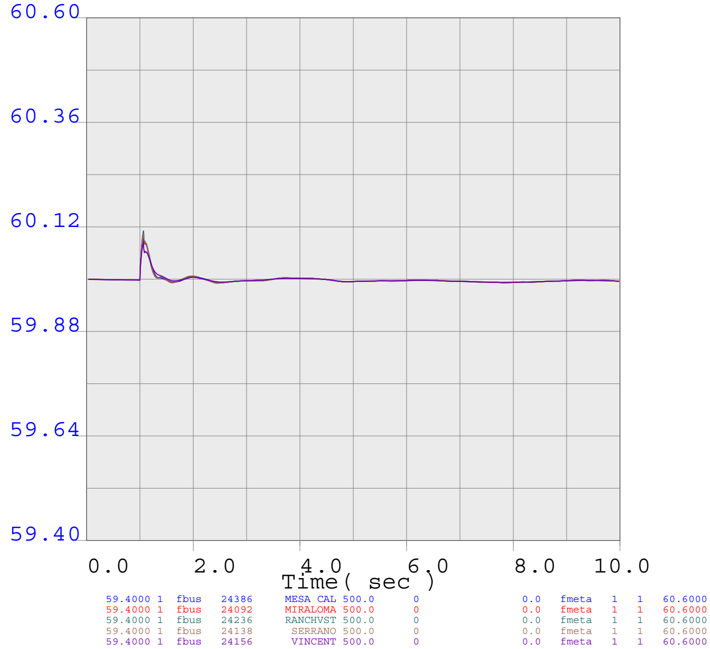


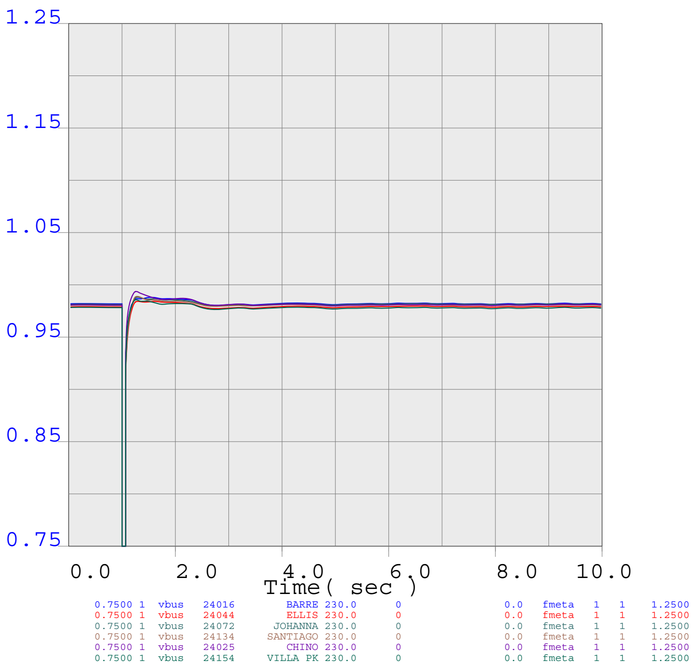
bay_23120
SERRANO 500 KV POS 3 INTERNAL FAULT
1 MW dispatch Case

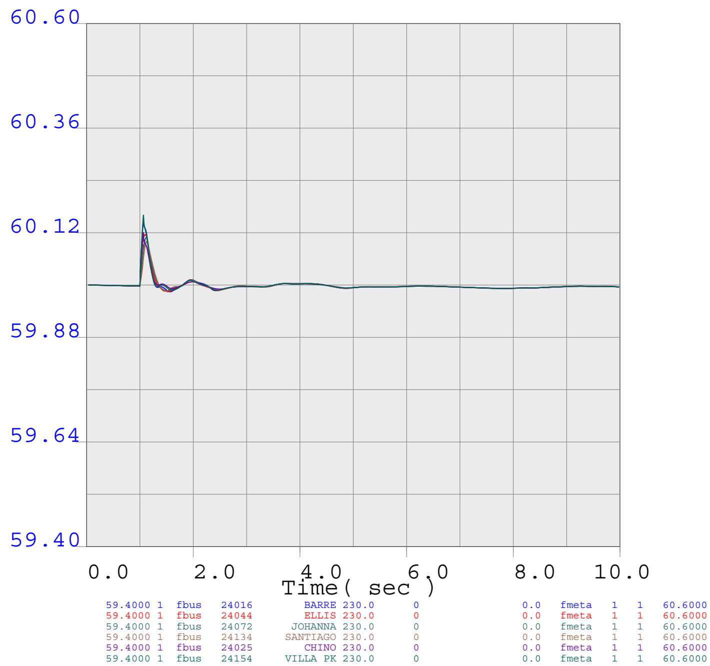
	qc9p-bay_23120.chf	C:\DYTOOLS Thu Oct 20 08:54:48 2016

METRO





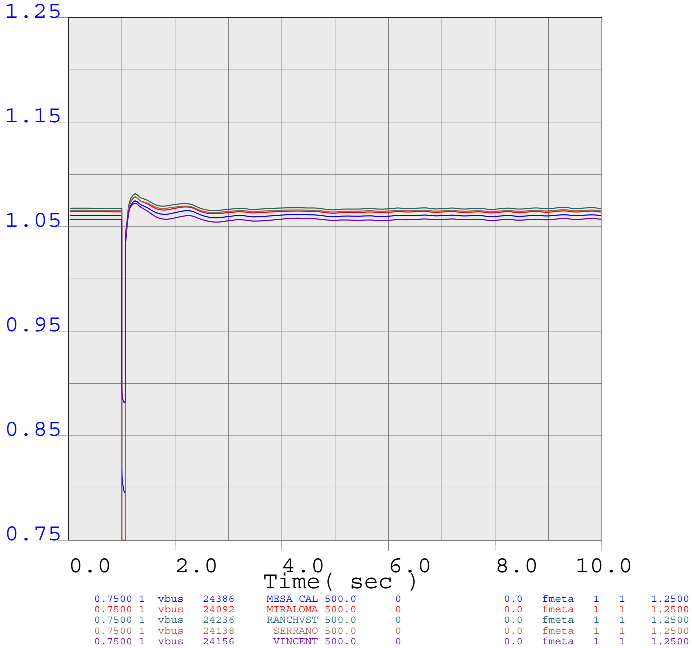


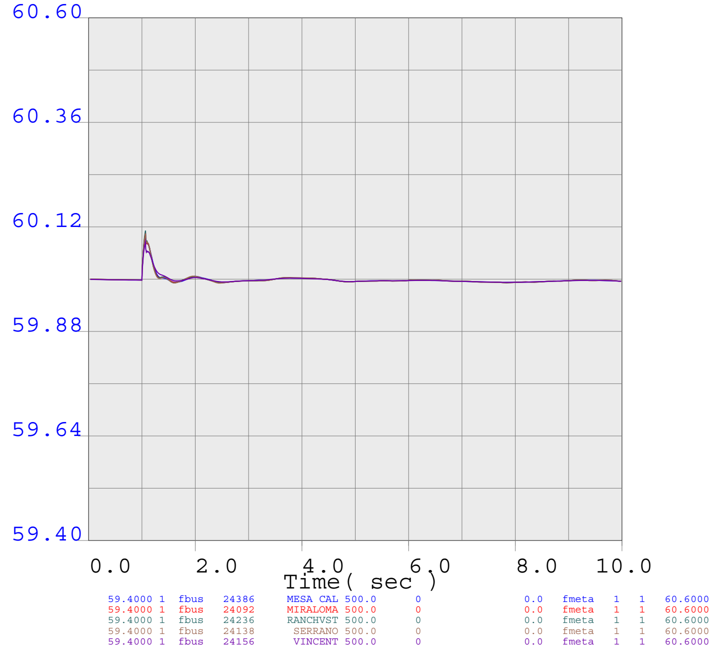


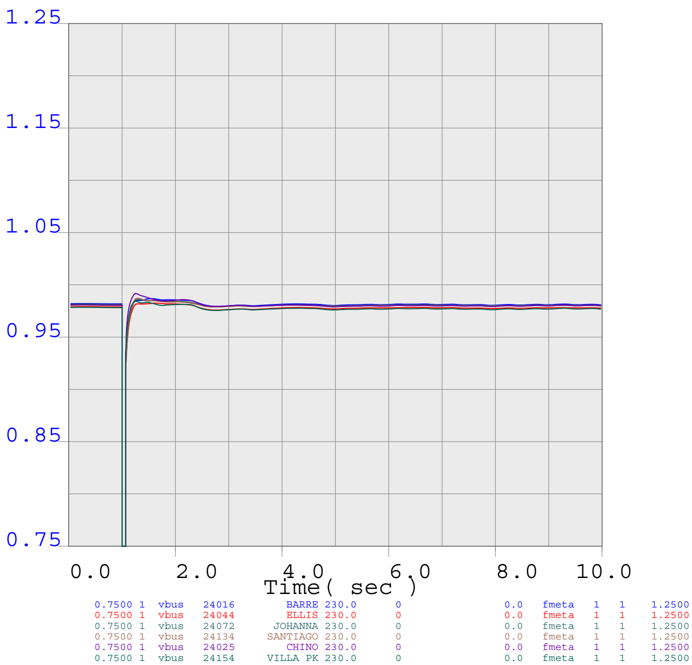
bay_23121
SERRANO 220 KV POS 1 INTERNAL FAULT
1 MW dispatch Case

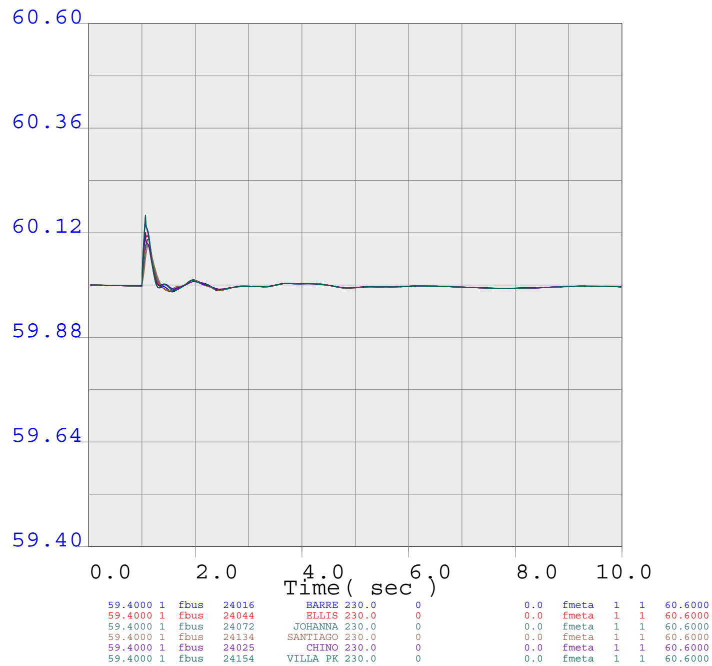
	qc9p-bay_23121.chf	C:\DYTOOLS Thu Oct 20 08:54:50 2016

METRO









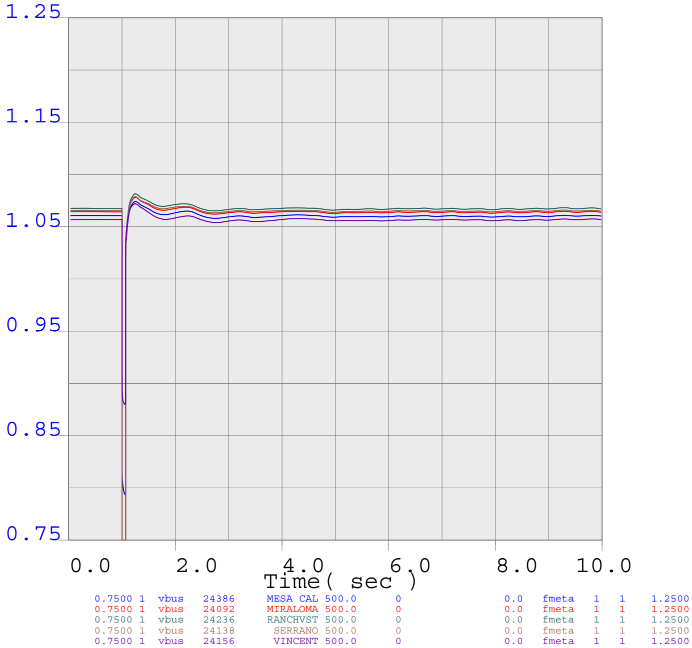
bay_23122
SERRANO 220 KV POS 2 INTERNAL FAULT
1 MW dispatch Case

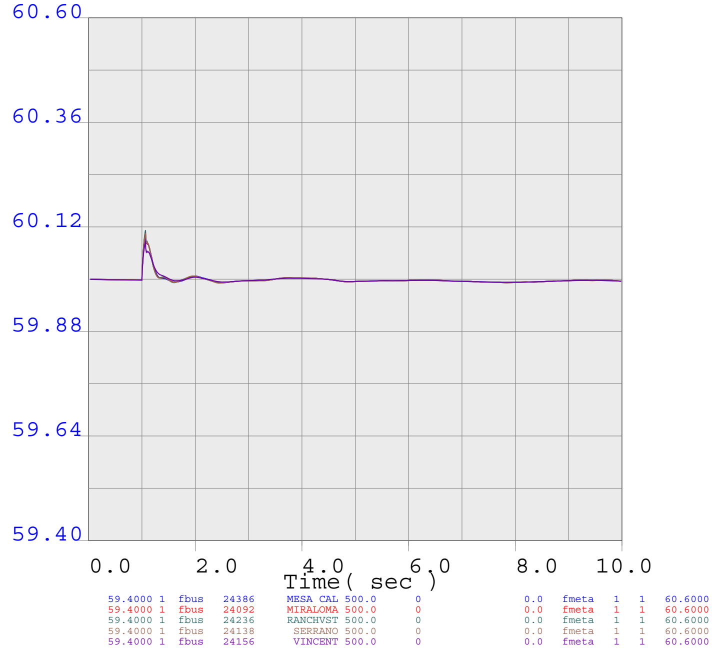
qc9p-bay_23122.chf

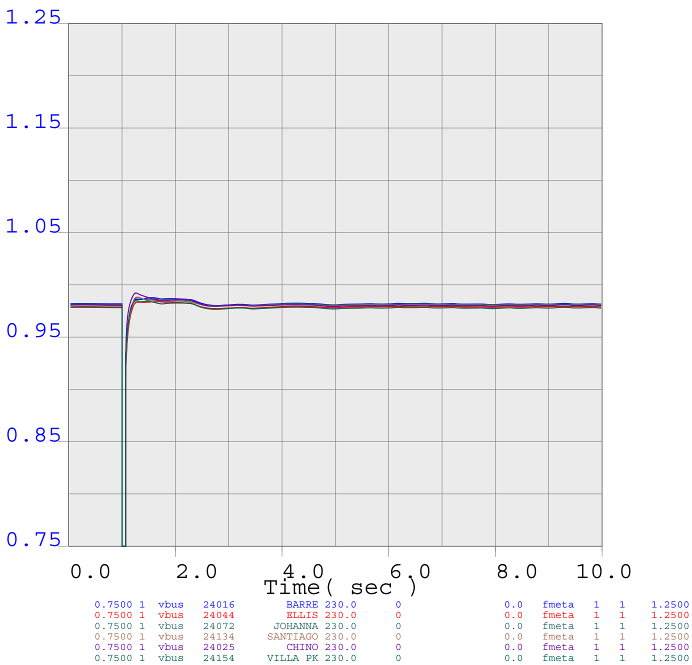
C:\DYTOOLS

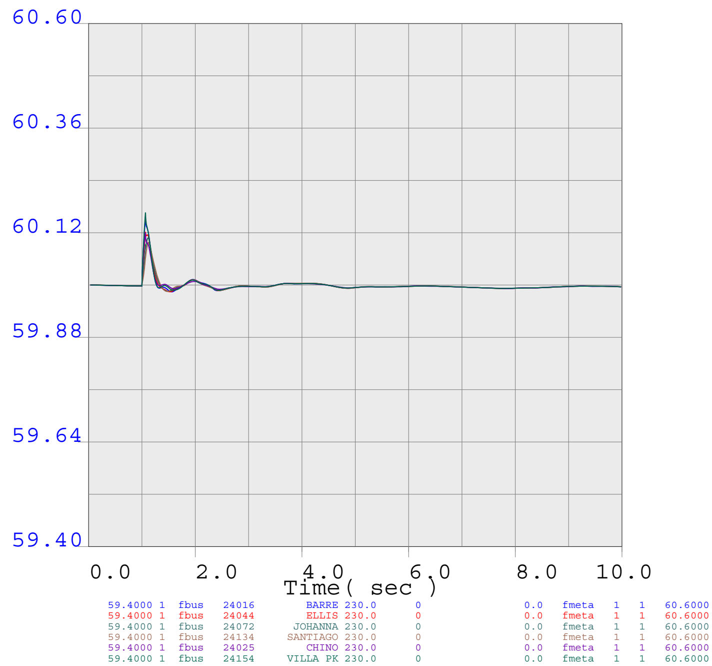
Thu Oct 20 08:54:52 2016

METRO









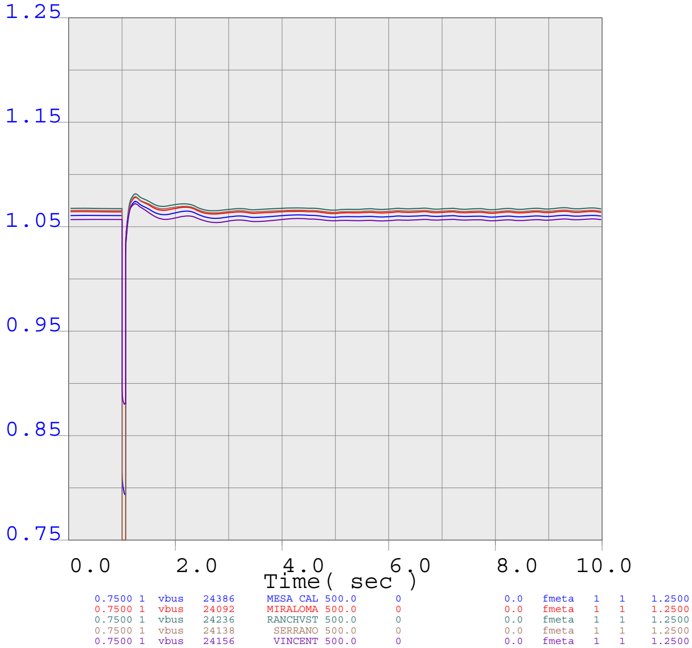
bay_23123
SERRANO 220 KV POS 3 INTERNAL FAULT
1 MW dispatch Case

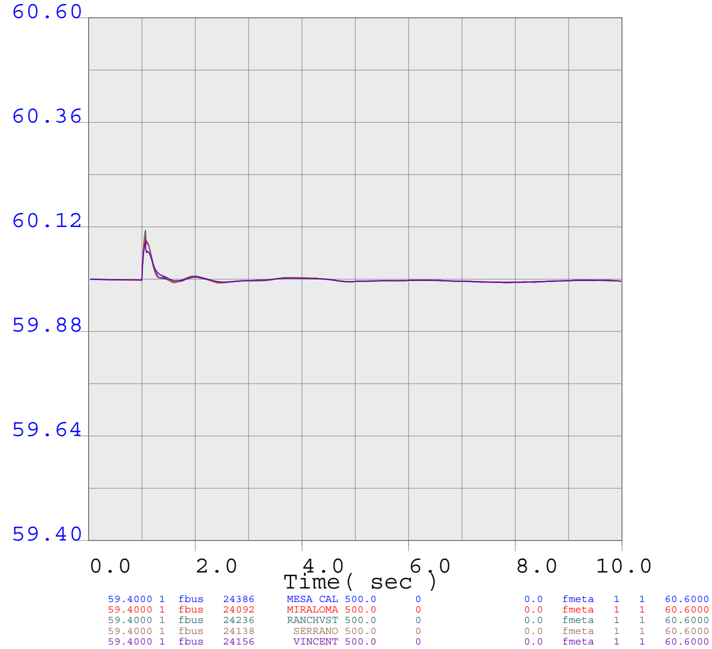
qc9p-bay_23123.chf

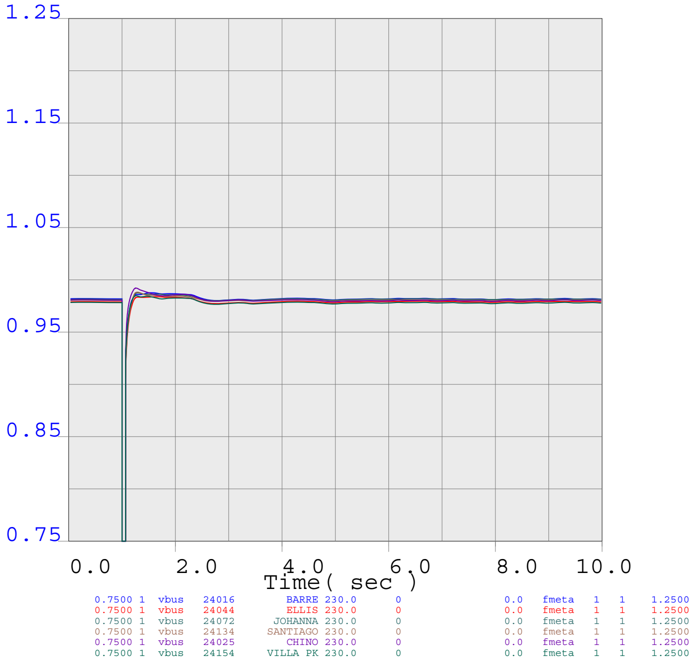
C:\DYTOOLS

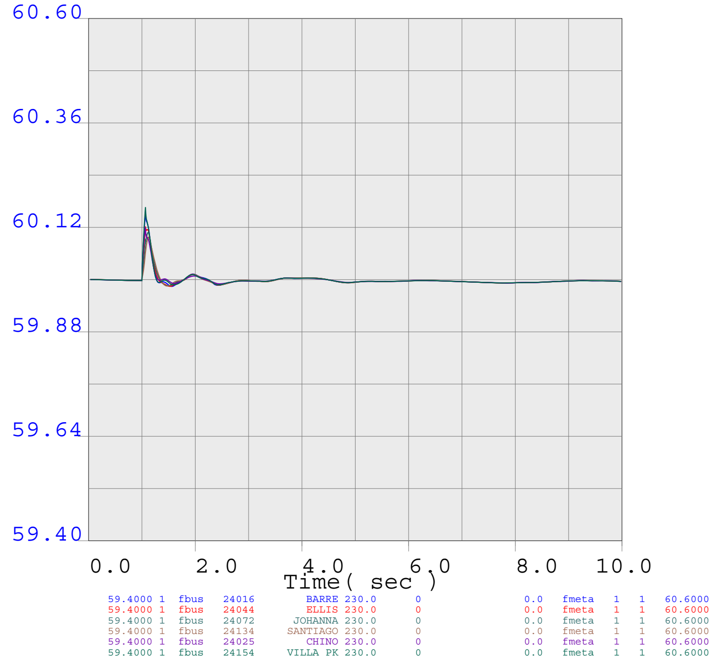
Thu Oct 20 08:54:54 2016

METRO









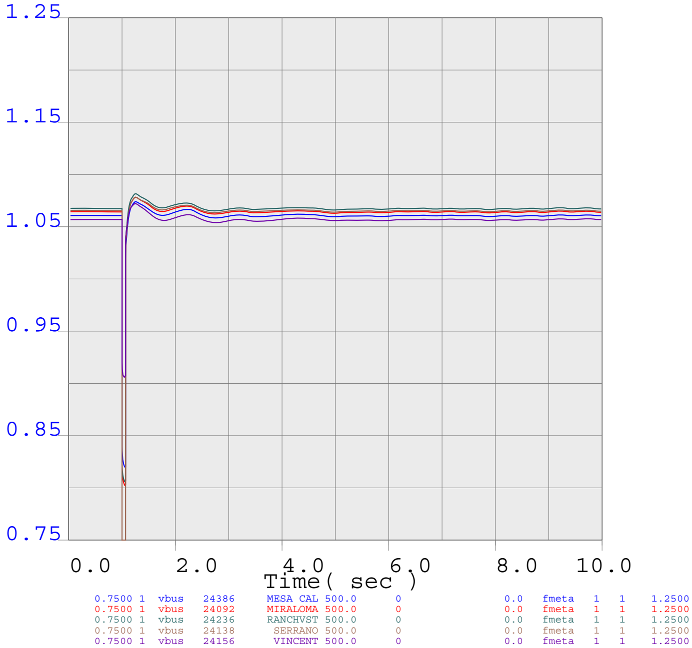
bay_23124
SERRANO 220 KV POS 4 INTERNAL FAULT
1 MW dispatch Case

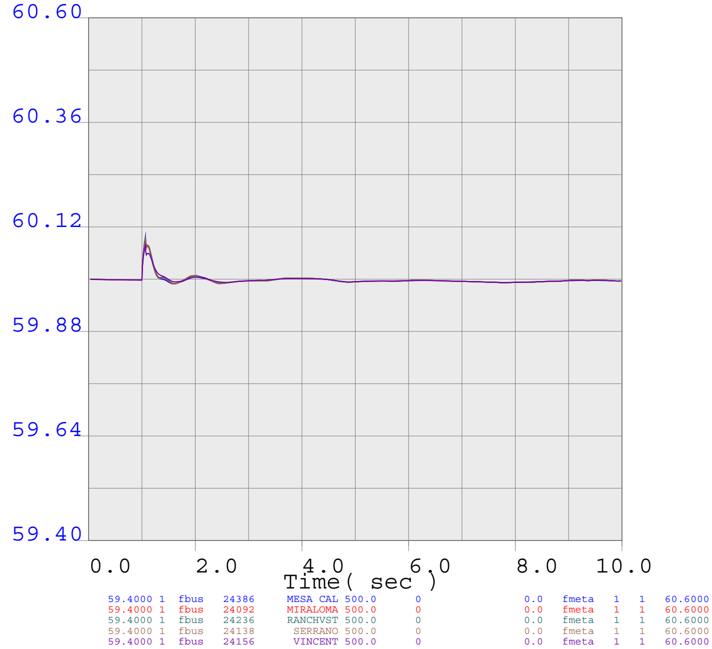
qc9p-bay_23124.chf

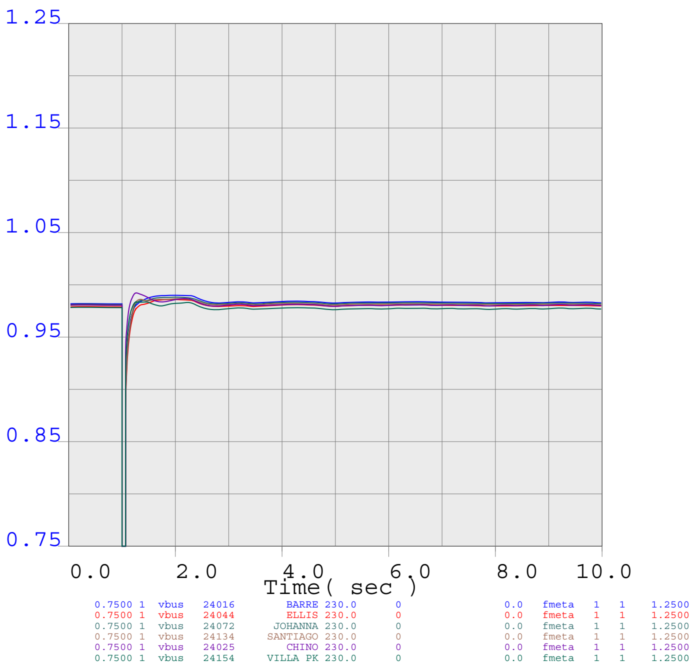
C:\DYTOOLS

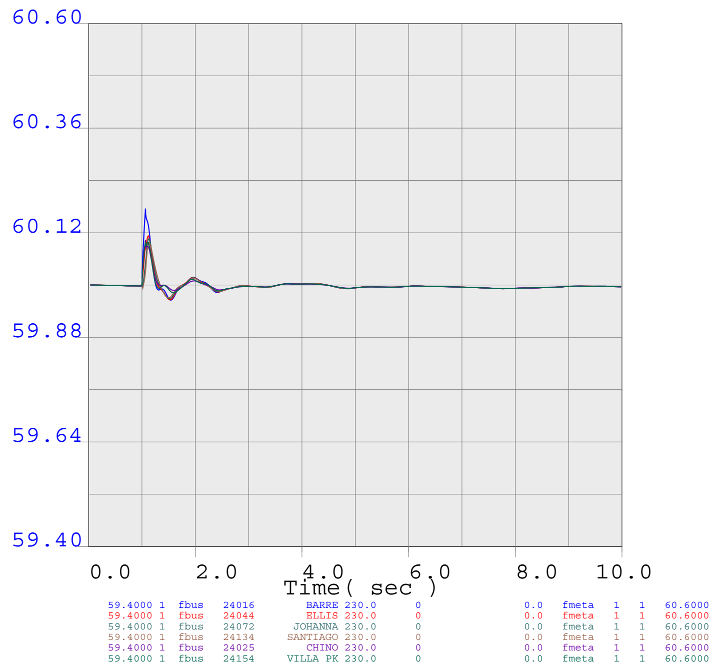
Thu Oct 20 08:54:56 2016

METRO









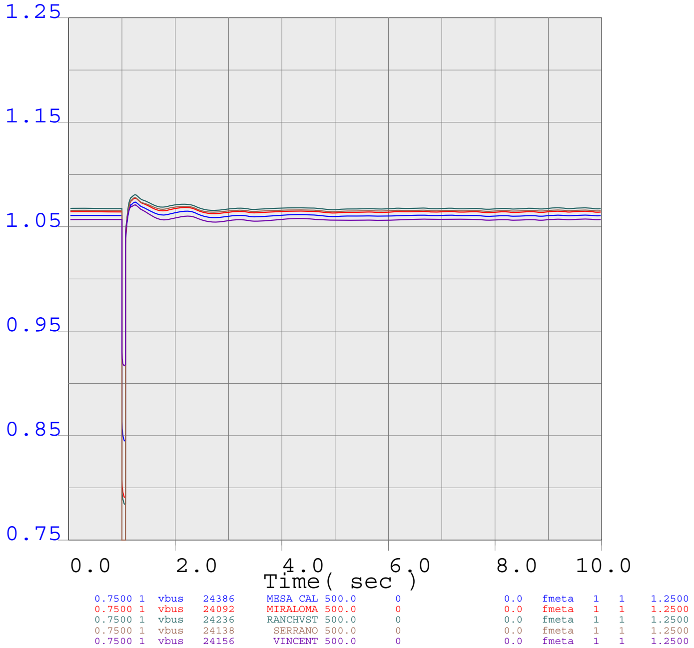
bay_23125
LEWIS 220 KV POS 6 INTERNAL FAULT
1 MW dispatch Case

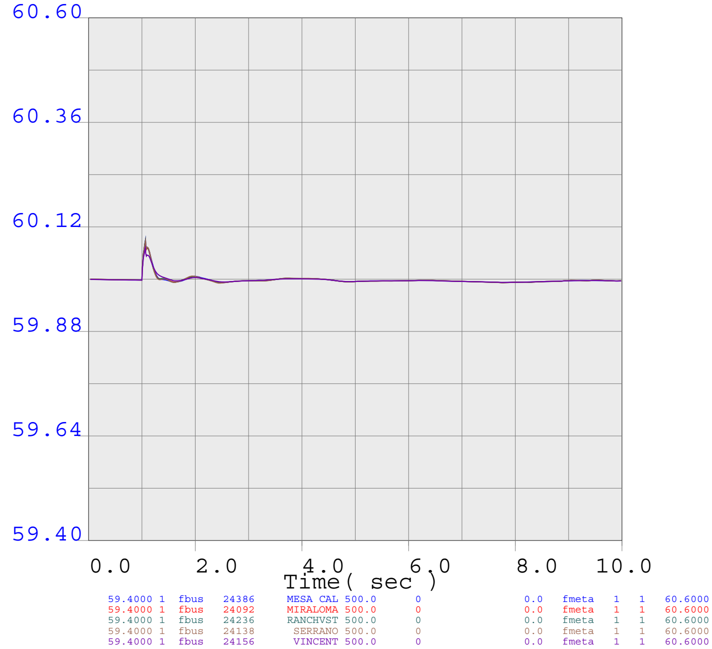
qc9p-bay_23125.chf

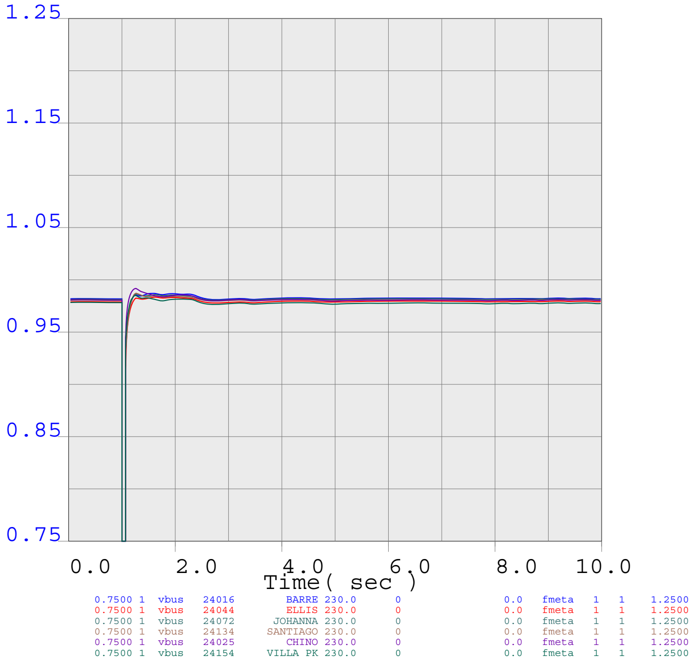
C:\DYTOOLS

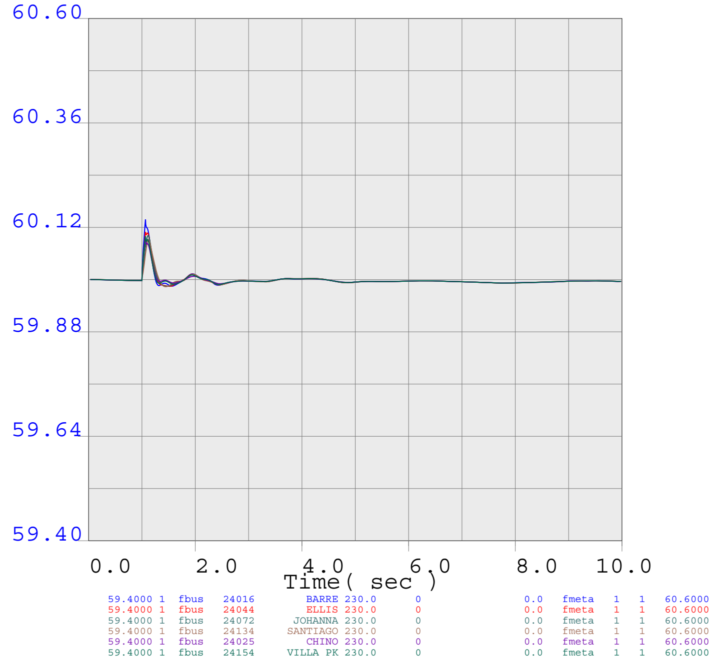
Thu Oct 20 08:54:58 2016

METRO









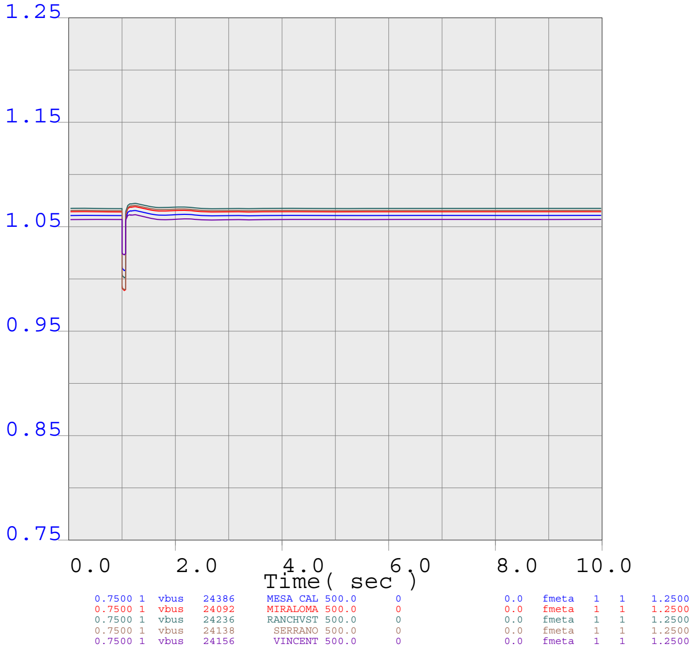
bay_23126
LEWIS 220 KV POS 5 INTERNAL FAULT
1 MW dispatch Case

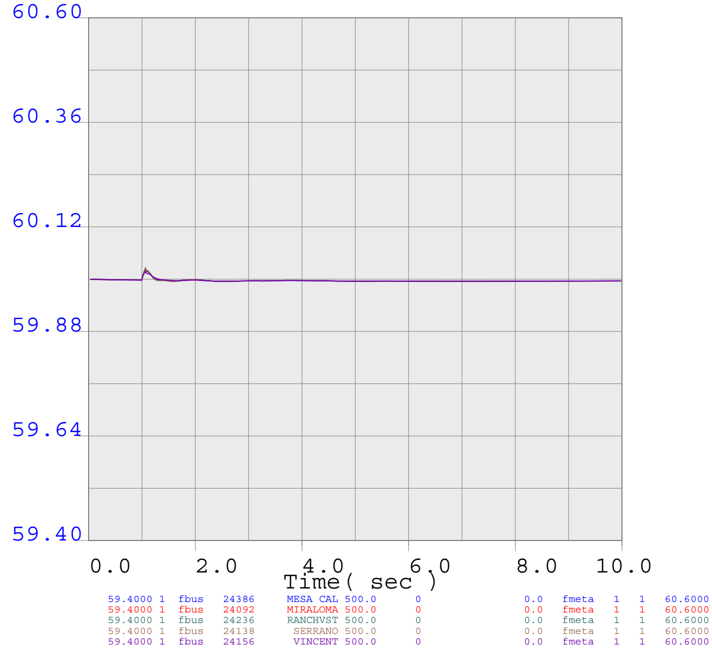
qc9p-bay_23126.chf

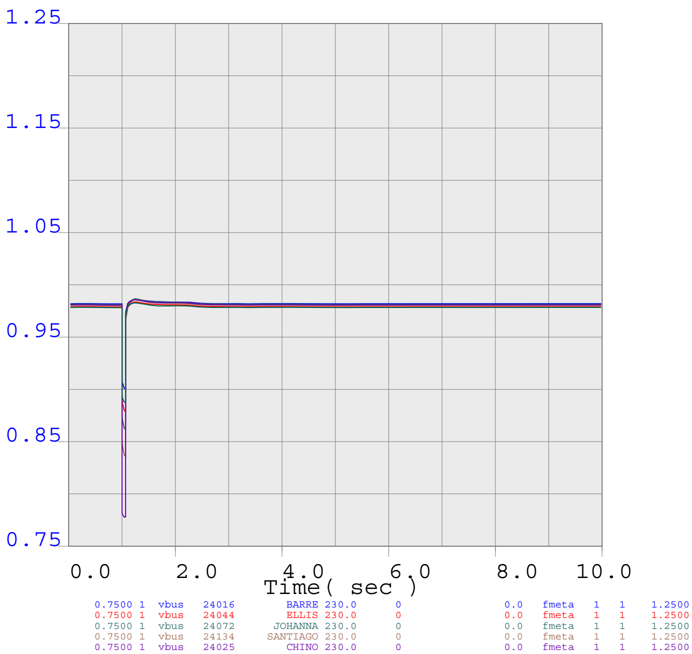
C:\DYTOOLS

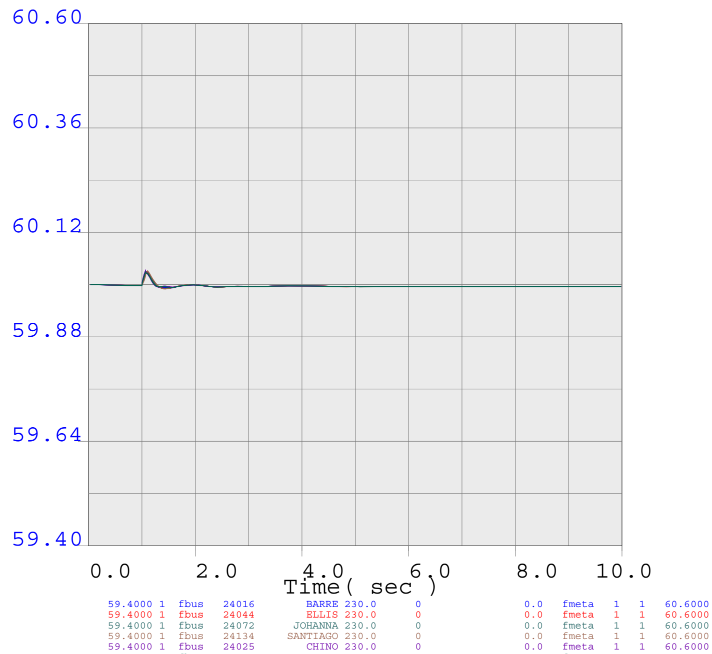
Thu Oct 20 08:55:00 2016

METRO









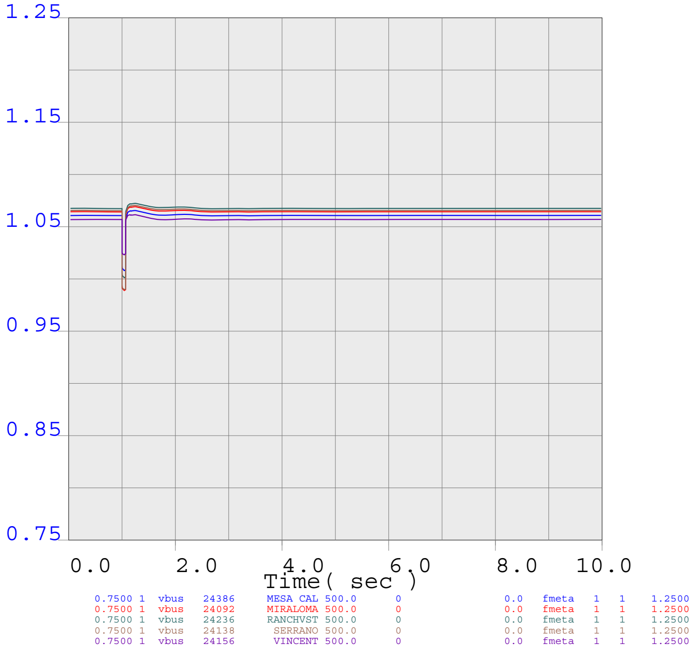
bay_23127
VIEJO 220 KV POS 1N
1 MW dispatch Case

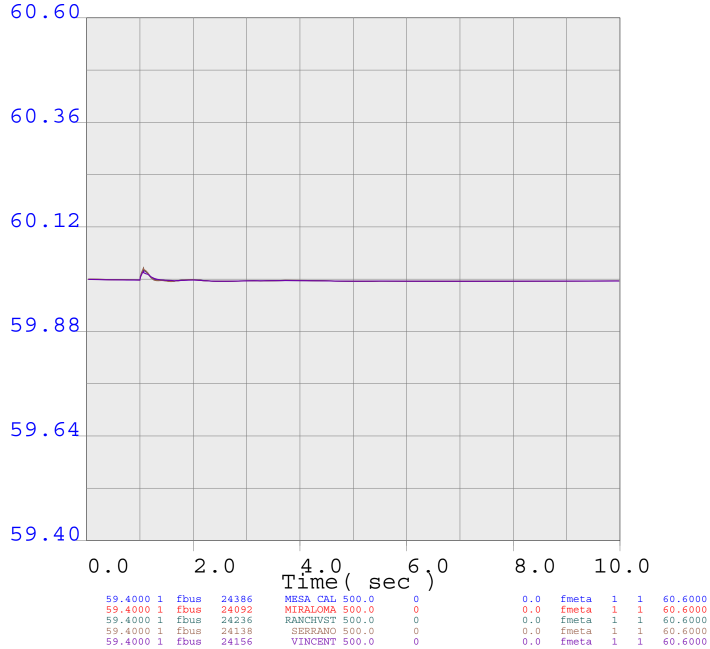
qc9p-bay_23127.chf

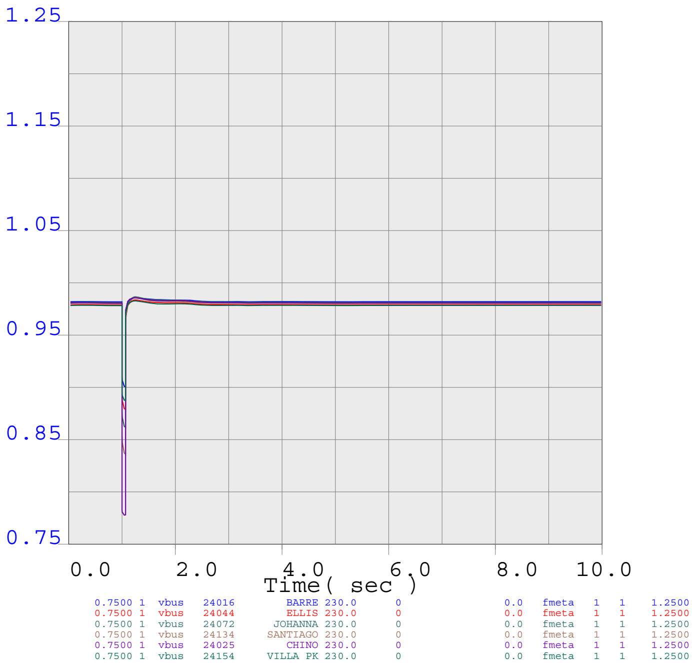
C:\DYTOOLS

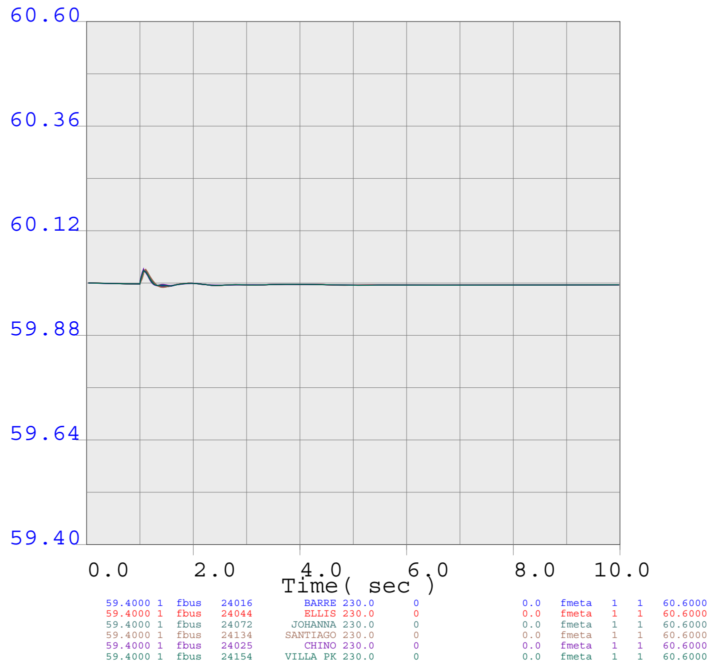
Thu Oct 20 08:55:03 2016

METRO









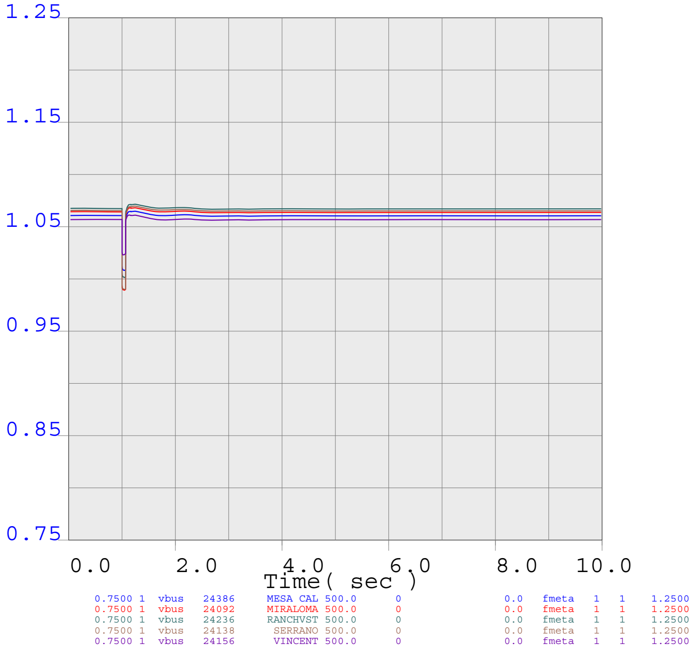
bay_23128
VIEJO 220 KV POS 3N
1 MW dispatch Case

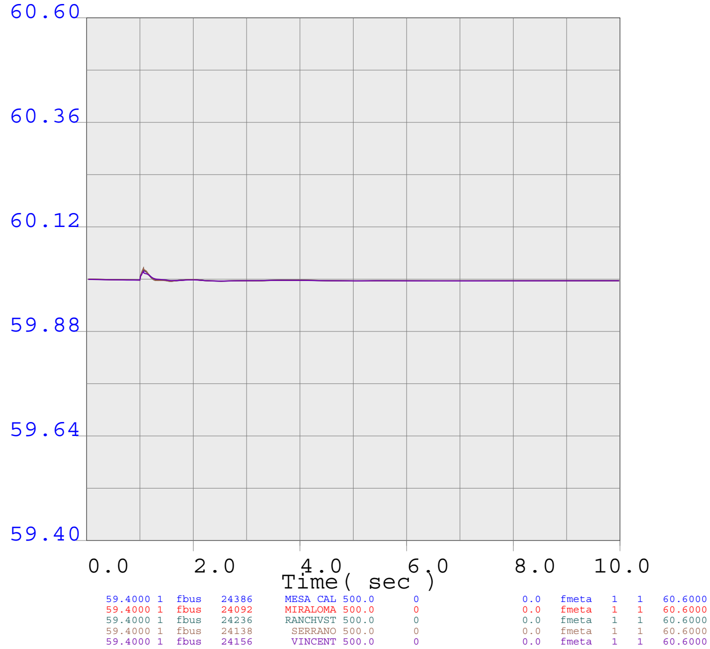
qc9p-bay_23128.chf

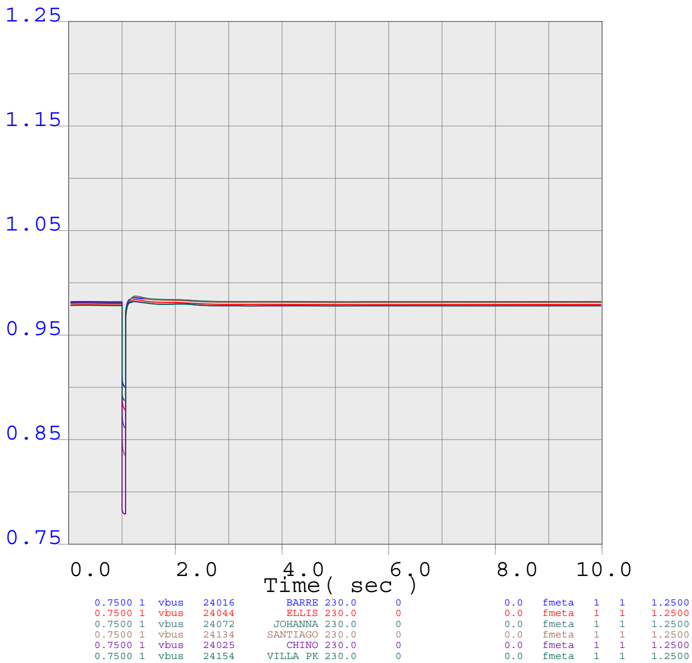
C:\DYTOOLS

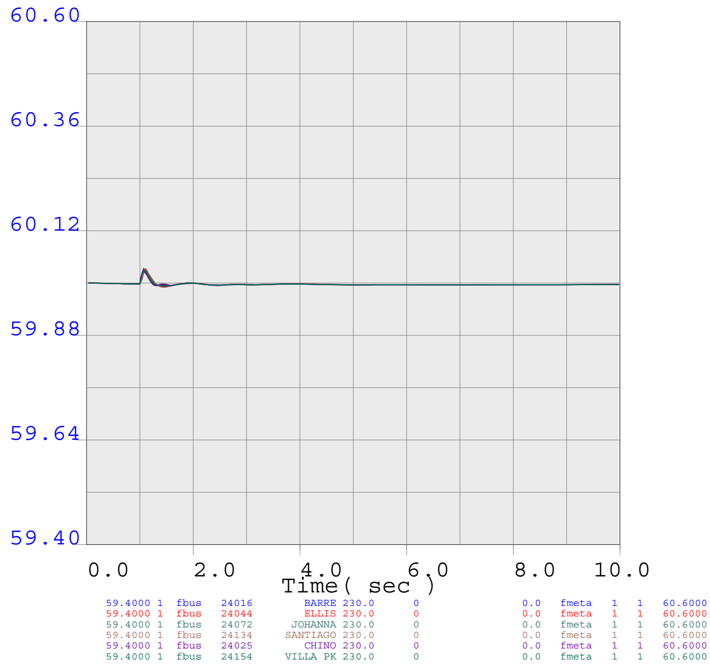
Thu Oct 20 08:55:05 2016

METRO









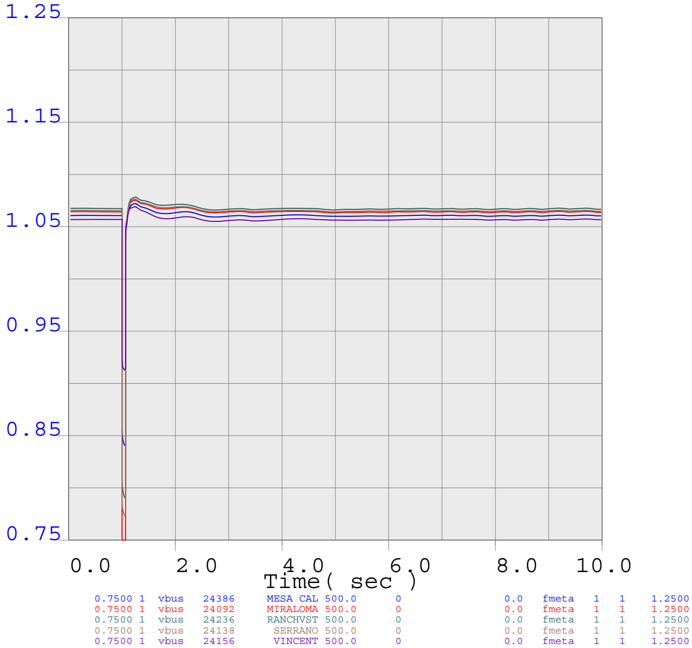
bay_23129
VIEJO 220 KV POS 4N
1 MW dispatch Case

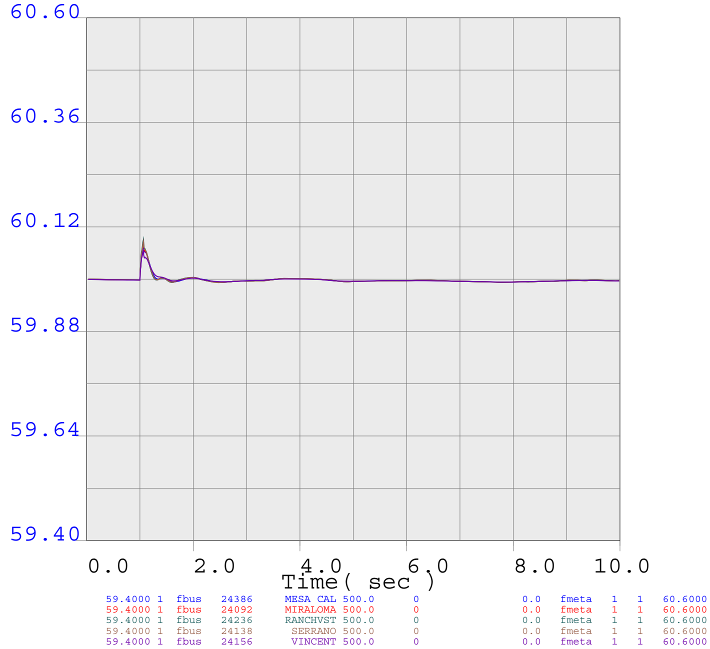
qc9p-bay_23129.chf

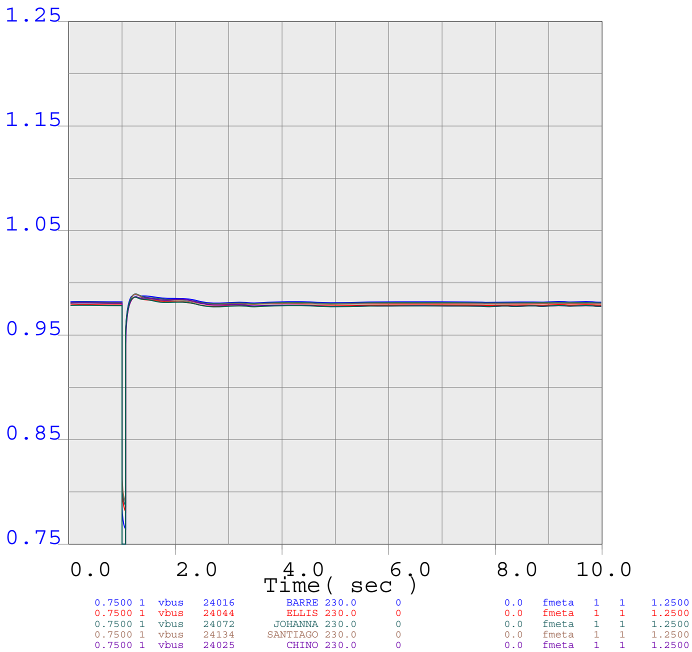
C:\DYTOOLS

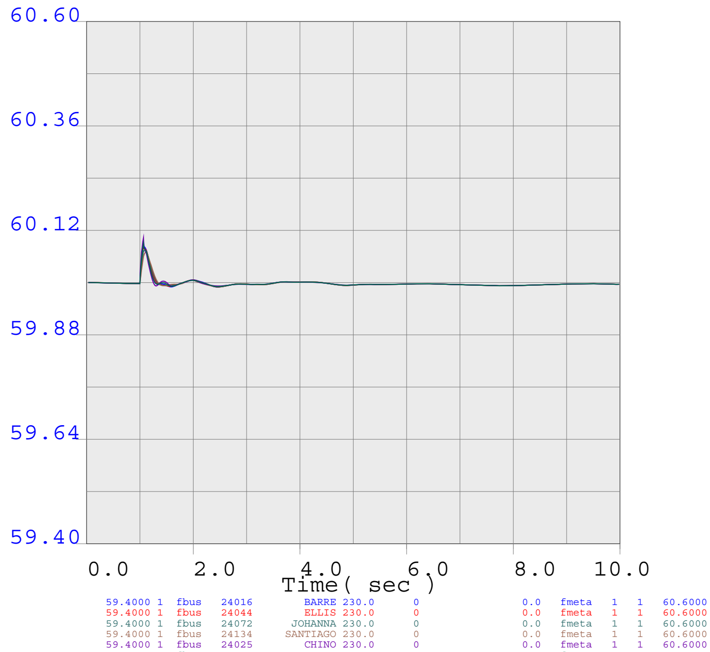
Thu Oct 20 08:55:07 2016

METRO









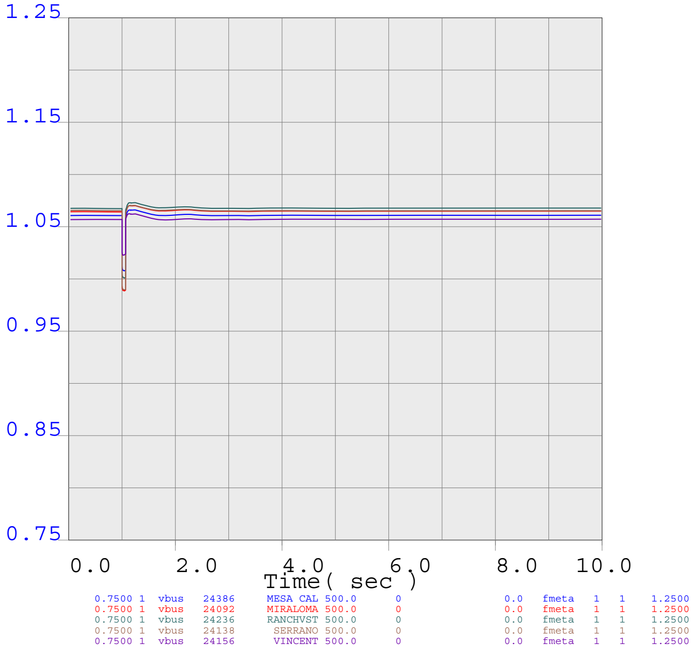
bay_2313
CHINO 220KV POS.2
1 MW dispatch Case

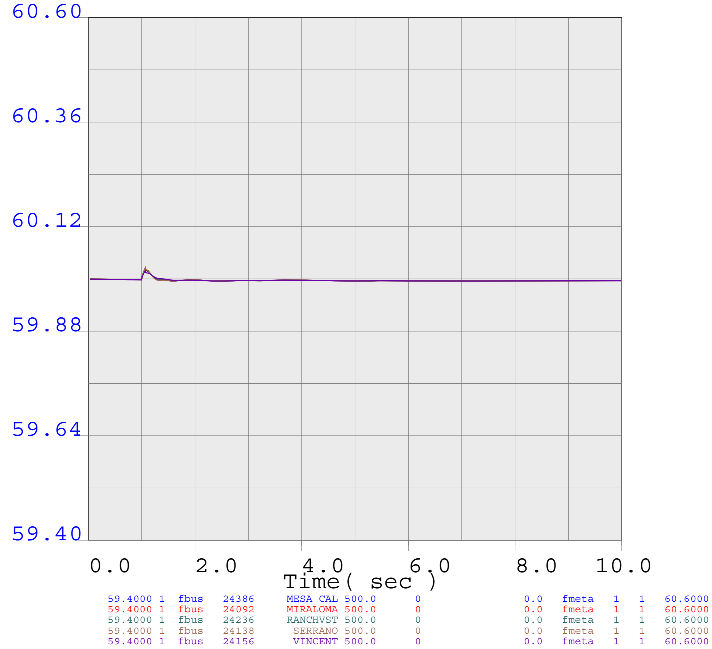
qc9p-bay_2313.chf

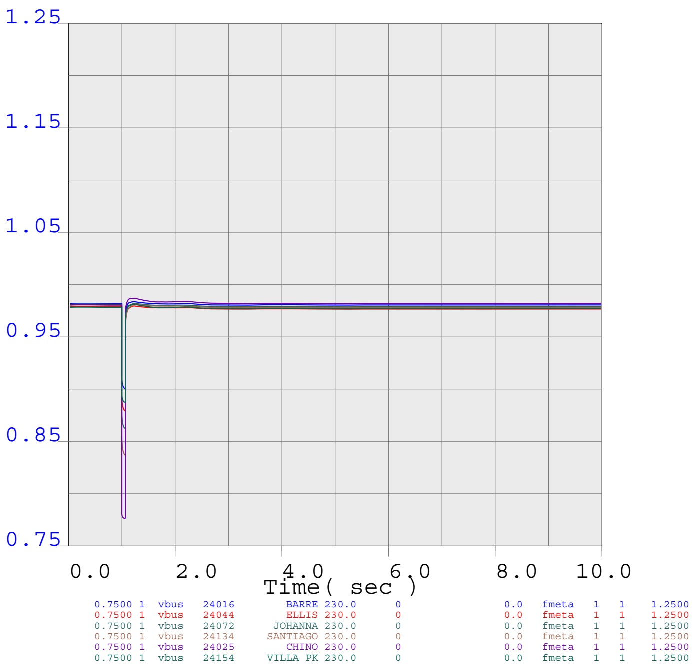
C:\DYTOOLS

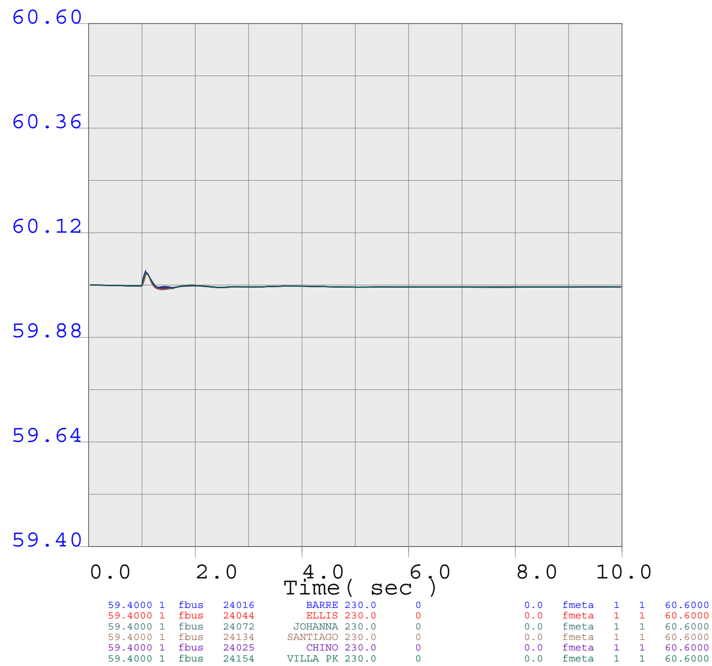
Thu Oct 20 08:55:09 2016

METRO









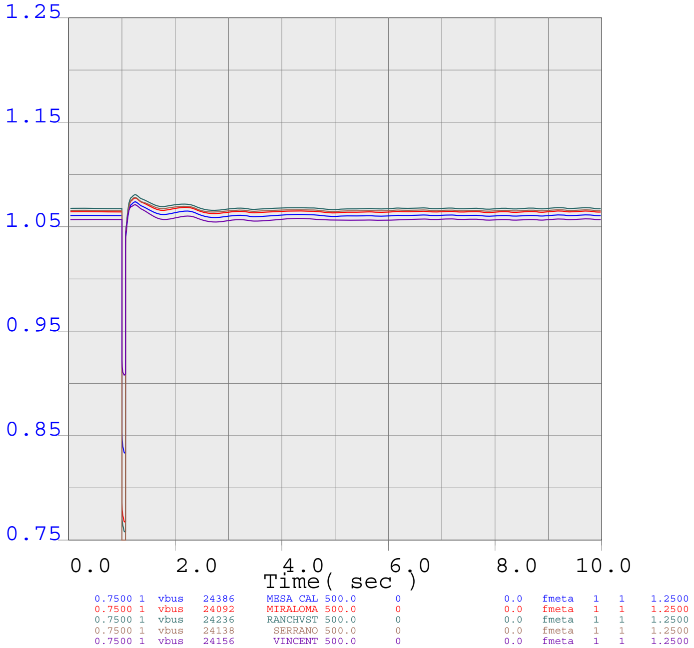
bay_23130
VIEJO 220 KV POS 3S
1 MW dispatch Case

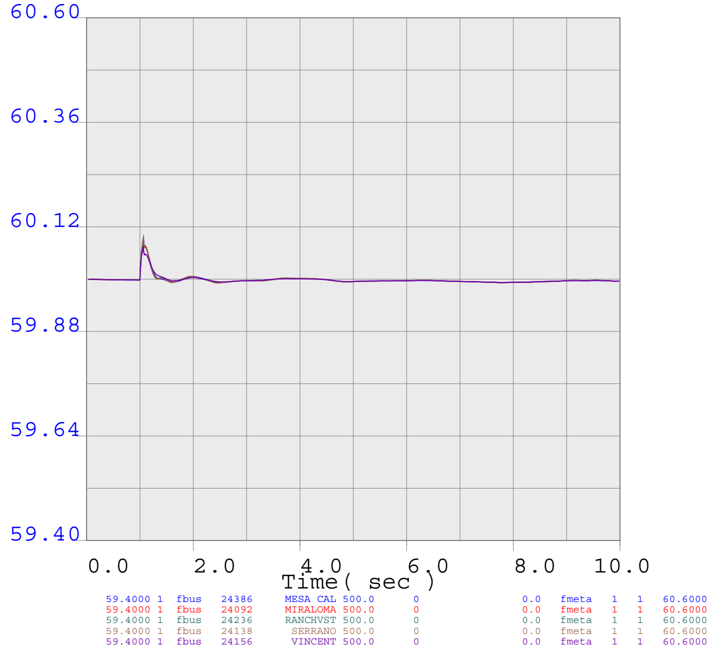
qc9p-bay_23130.chf

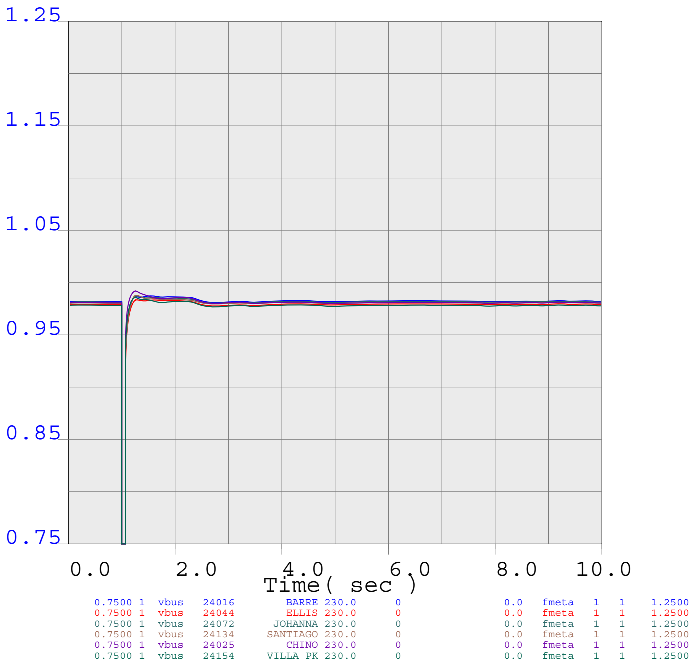
C:\DYTOOLS

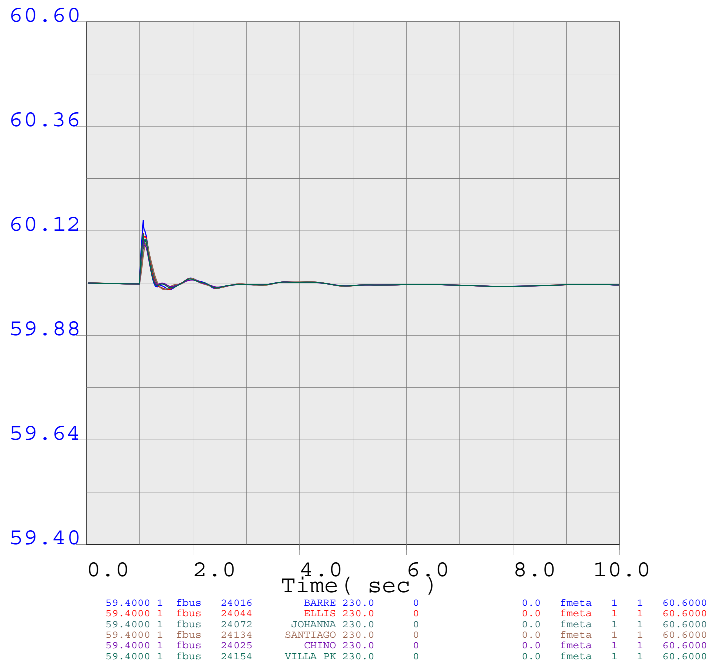
Thu Oct 20 08:55:11 2016

METRO









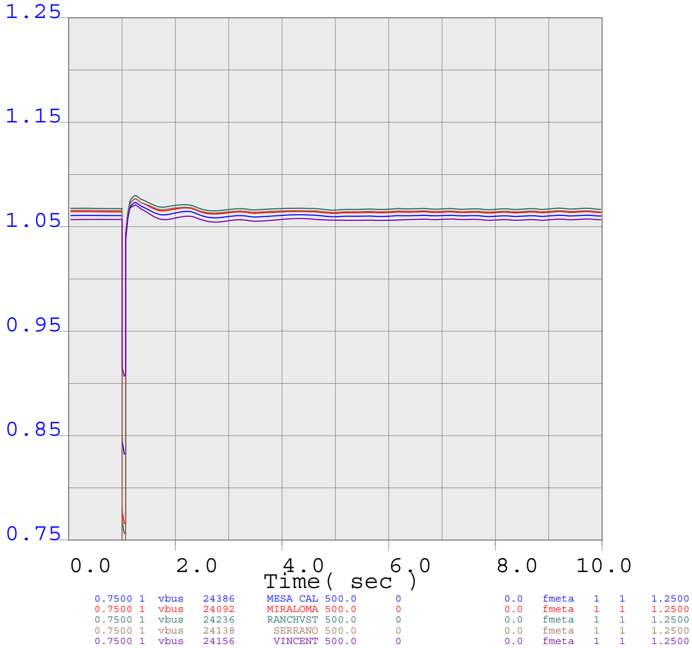
bay_23131
VILLA PARK 220 KV POS 2N
1 MW dispatch Case

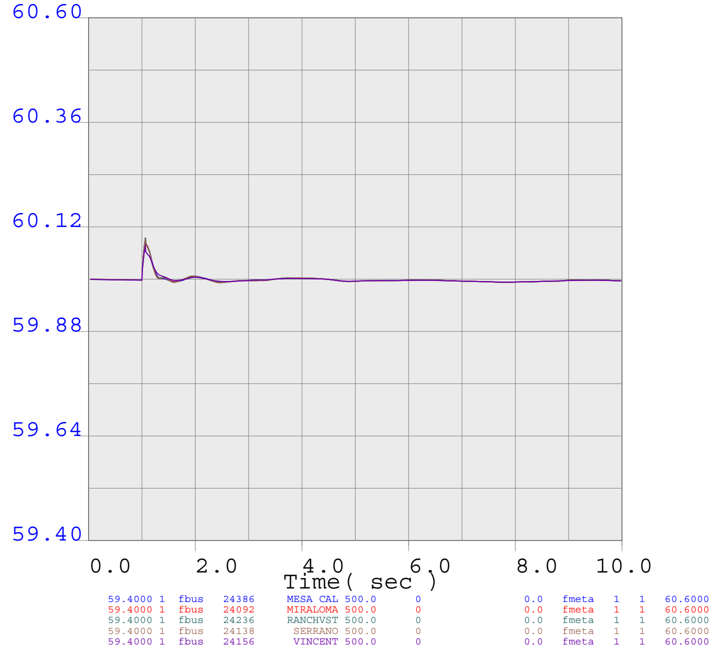
qc9p-bay_23131.chf

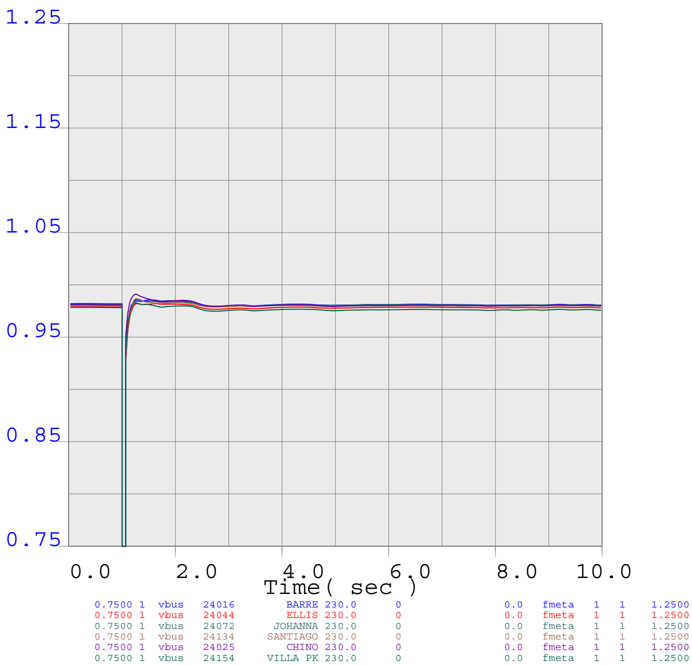
C:\DYTOOLS

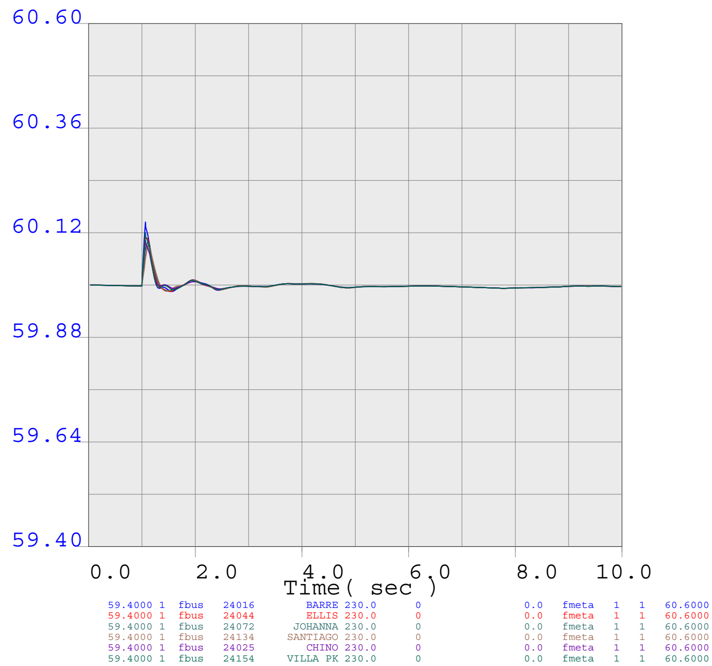
Thu Oct 20 08:55:13 2016

METRO









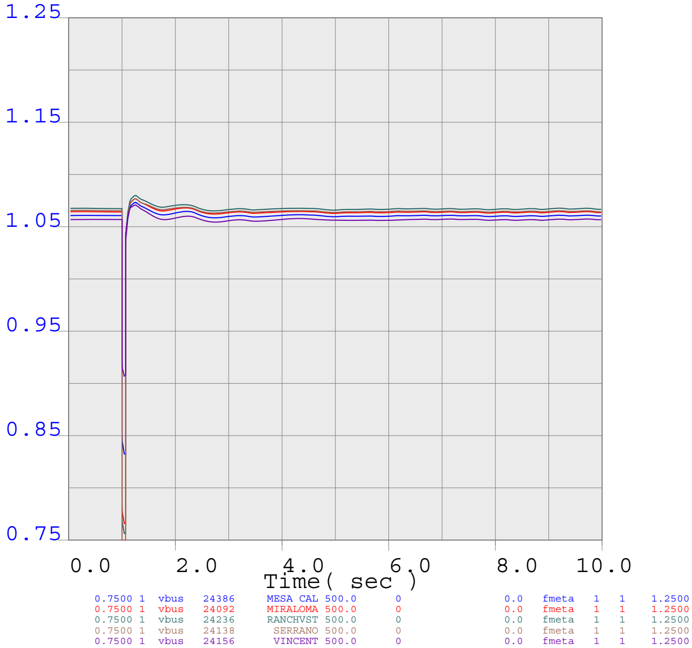
bay_23132
VILLA PARK 220 KV POS 3N
1 MW dispatch Case

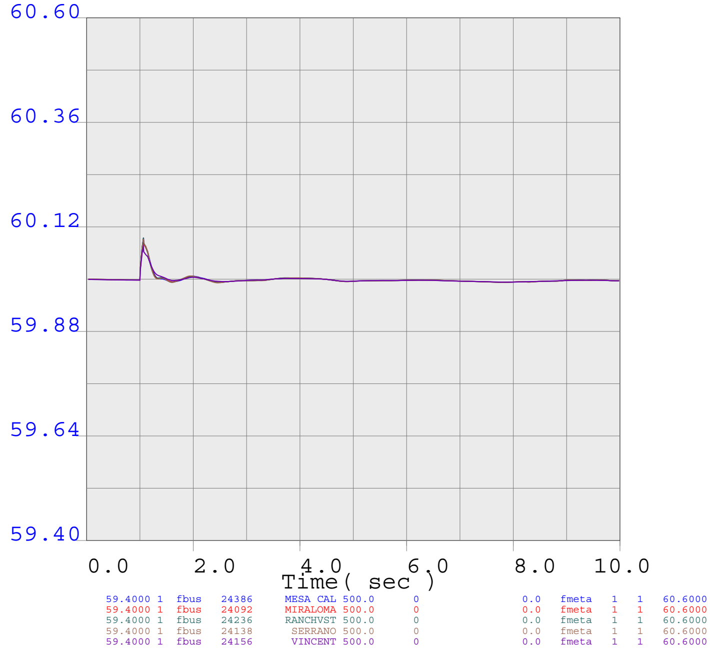
qc9p-bay_23132.chf

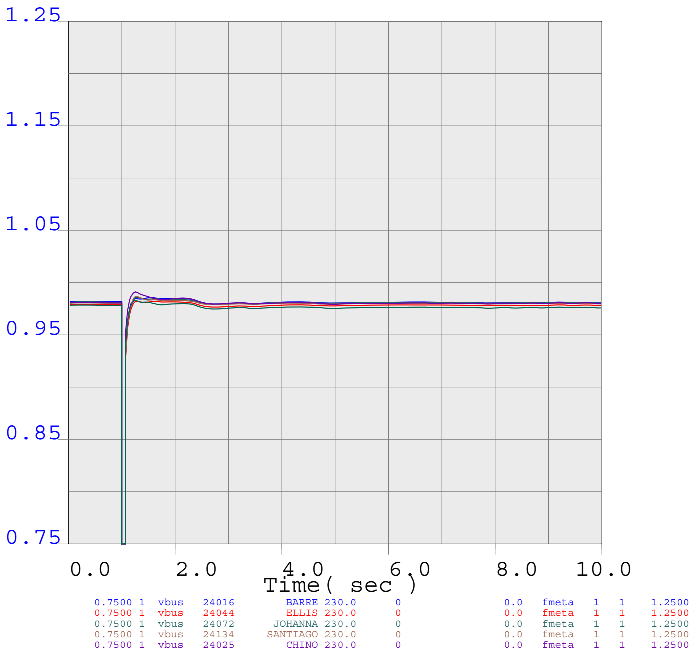
C:\DYTOOLS

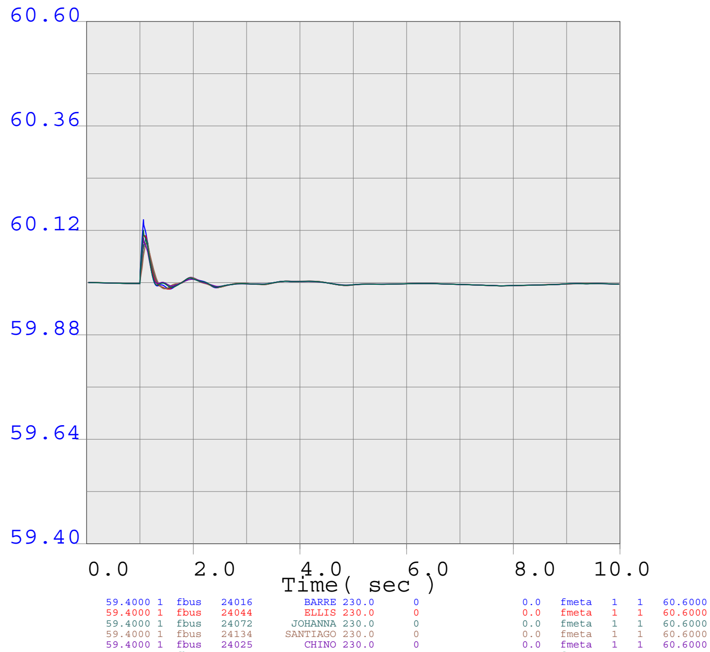
Thu Oct 20 08:55:15 2016

METRO









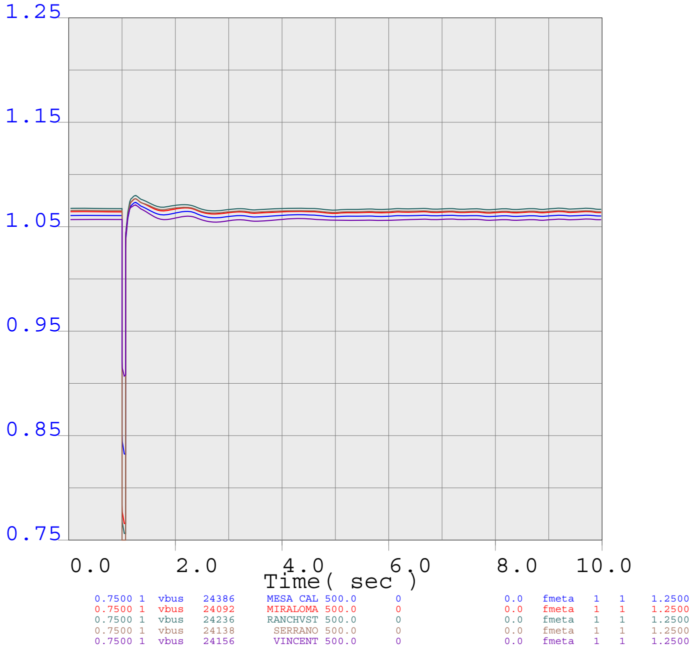
bay_23133
VILLA PARK 220 KV POS 4N
1 MW dispatch Case

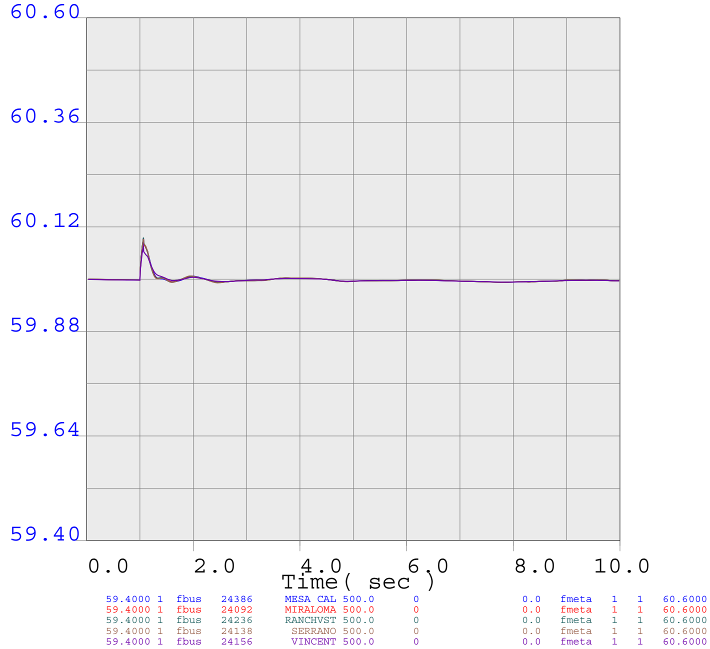
qc9p-bay_23133.chf

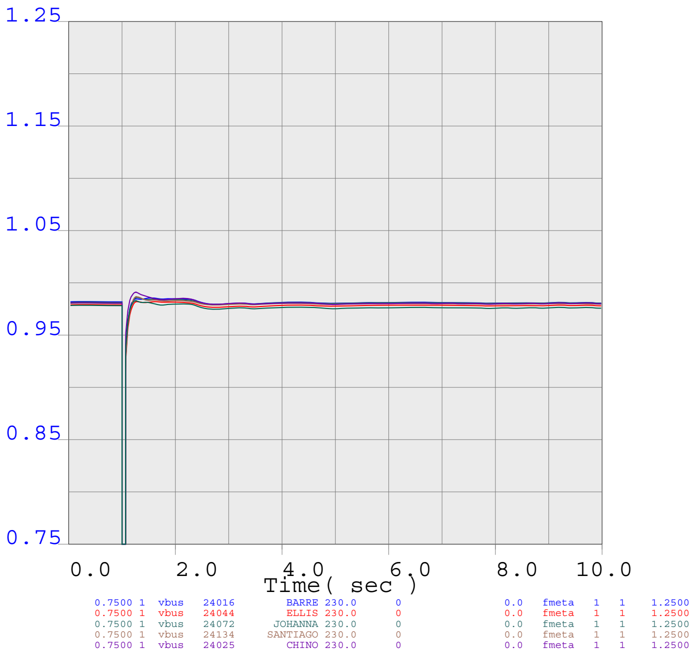
C:\DYTOOLS

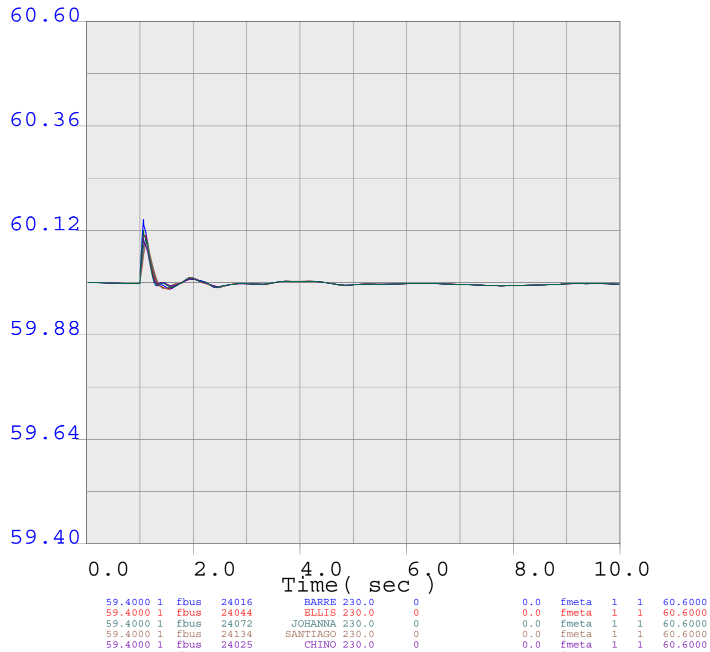
Thu Oct 20 08:55:17 2016

METRO









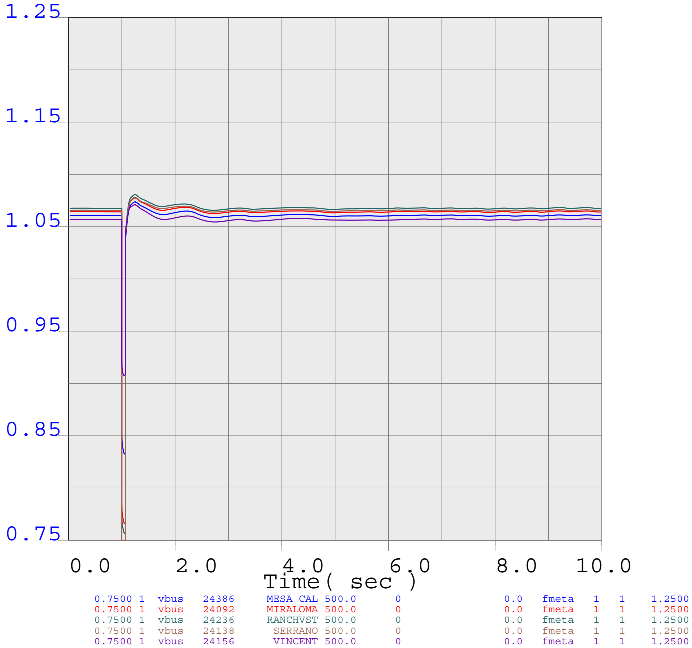
bay_23134
VILLA PARK 220 KV POS 6N
1 MW dispatch Case

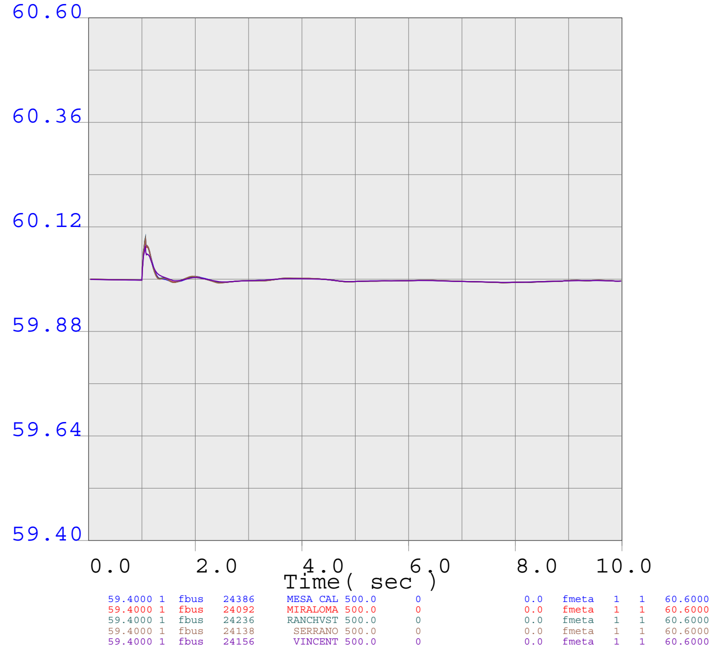
qc9p-bay_23134.chf

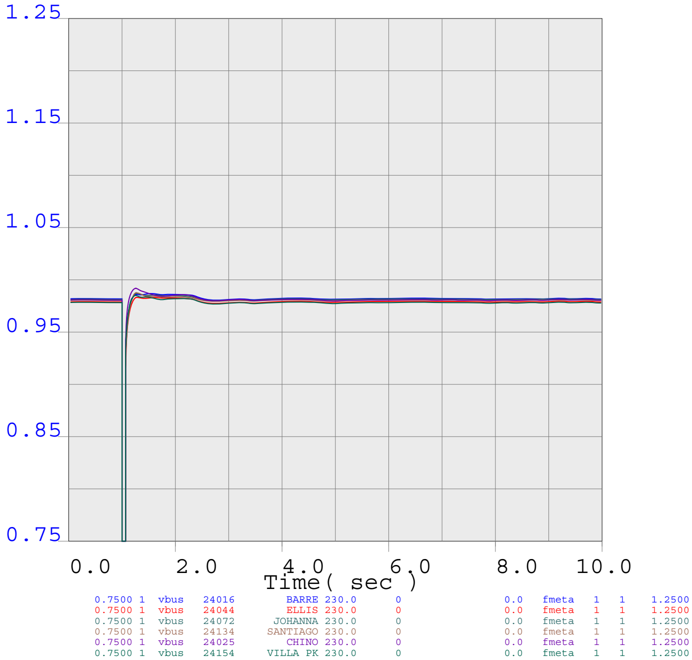
C:\DYTOOLS

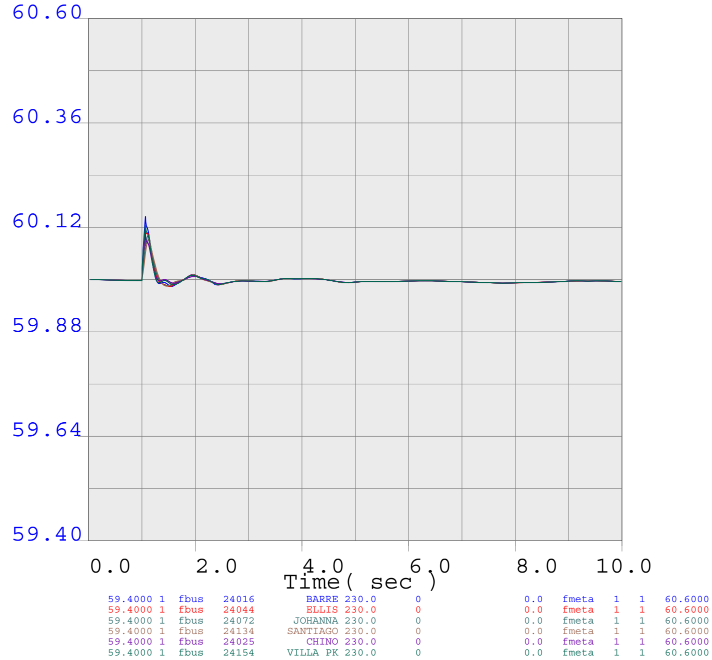
Thu Oct 20 08:55:19 2016

METRO



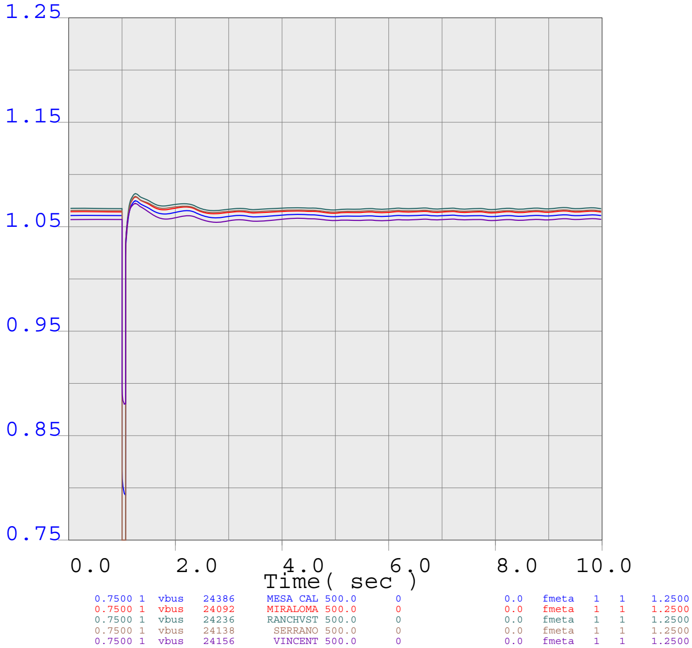


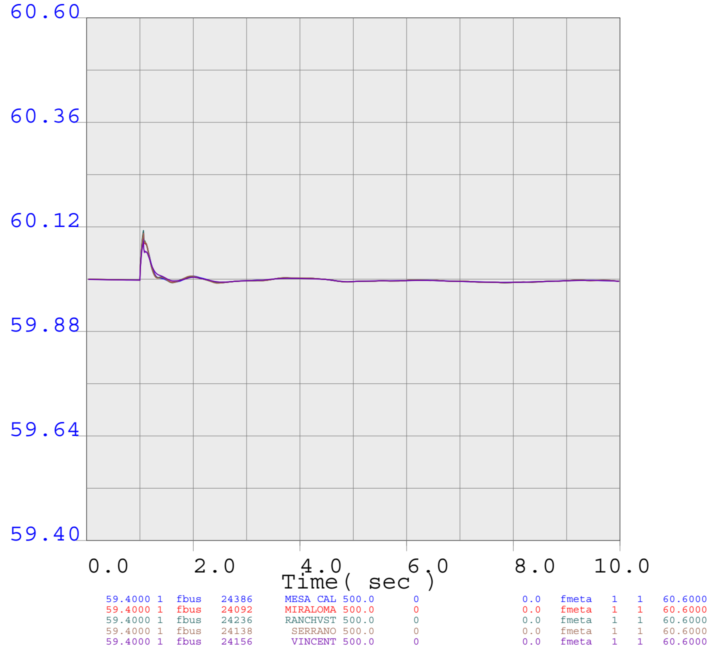


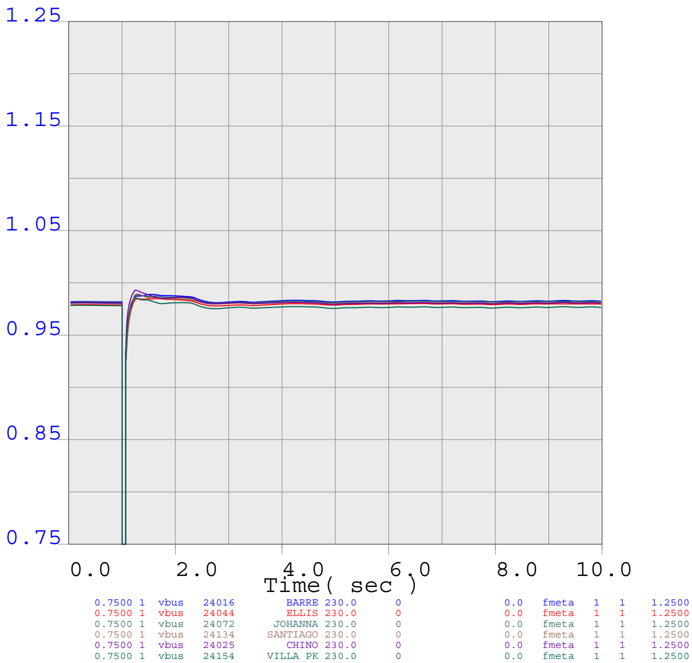


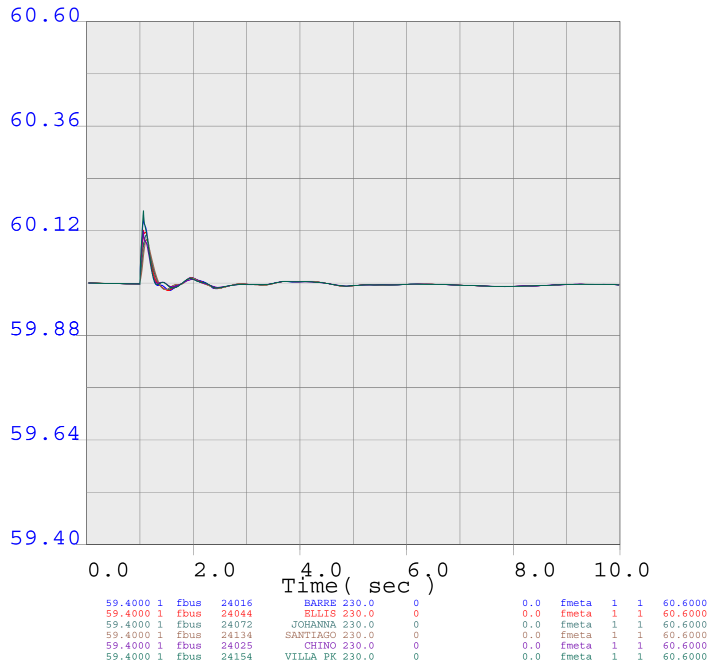
bay_23135
VILLA PARK 220 KV POS 8N
1 MW dispatch Case

METRO









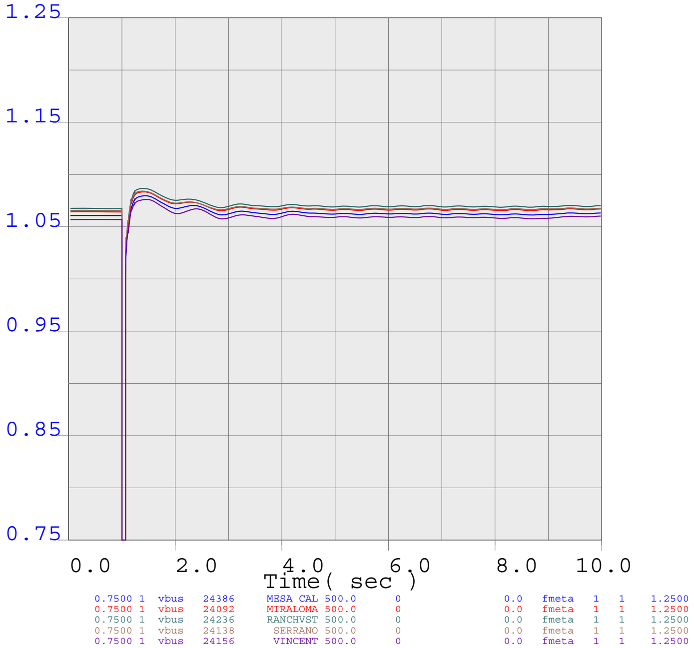
bay_23136
VILLA PARK 220 KV POS 8 INTERNAL FAULT
1 MW dispatch Case

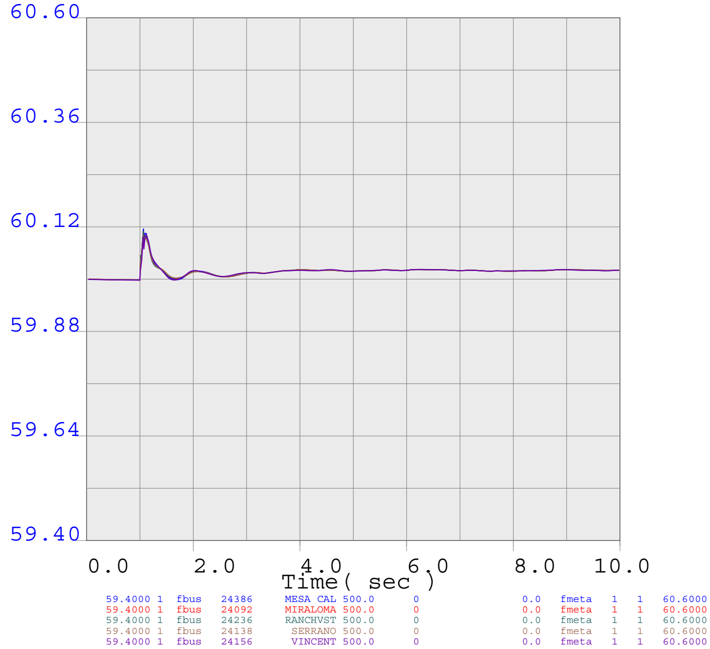
qc9p-bay_23136.chf

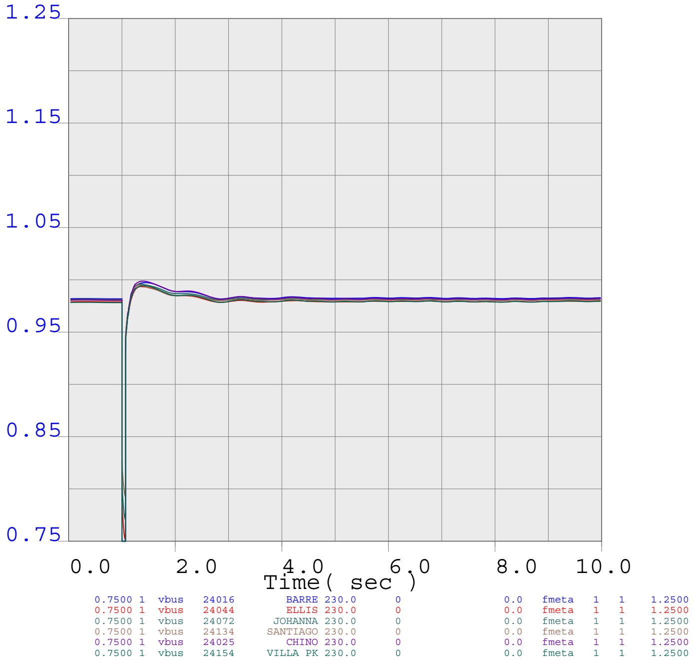
C:\DYTOOLS

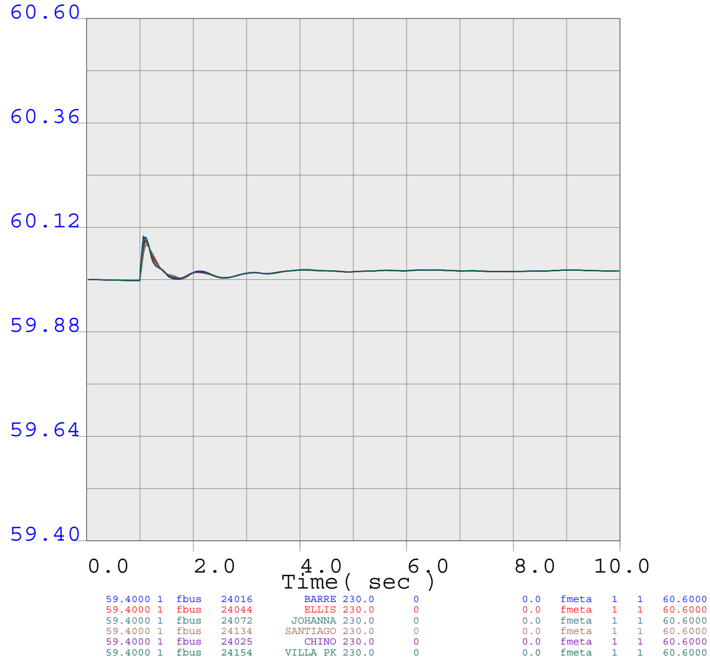
Thu Oct 20 08:55:23 2016

METRO









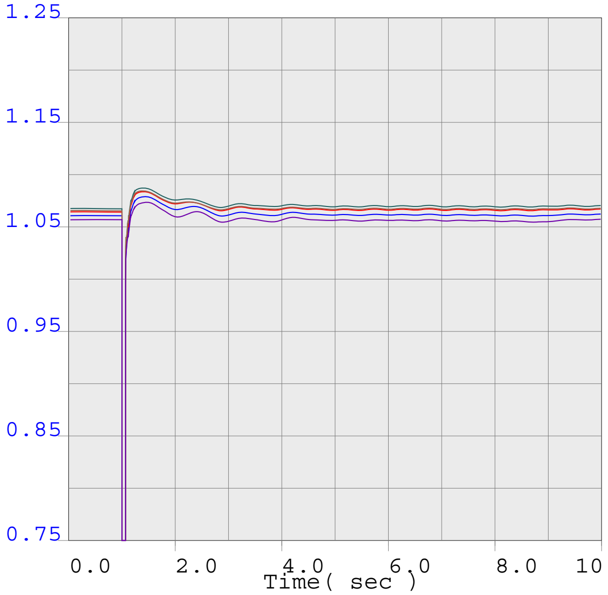
bay_23137
VINCENT 500 KV POS 1 INTERNAL FAULT
1 MW dispatch Case

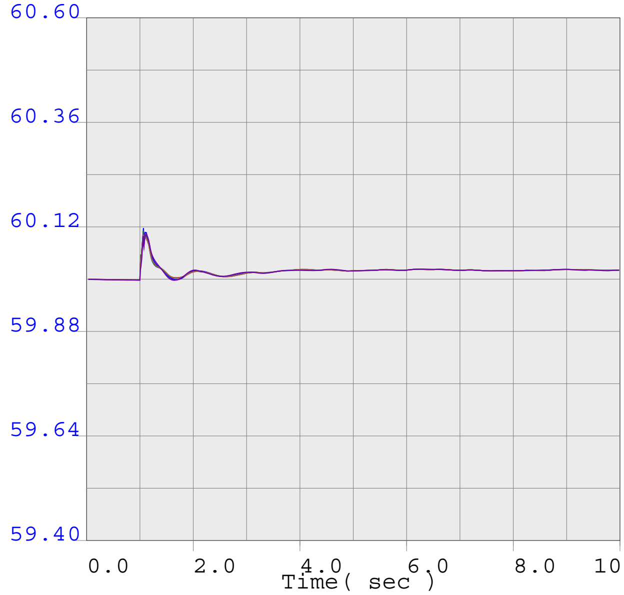
qc9p-bay_23137.chf

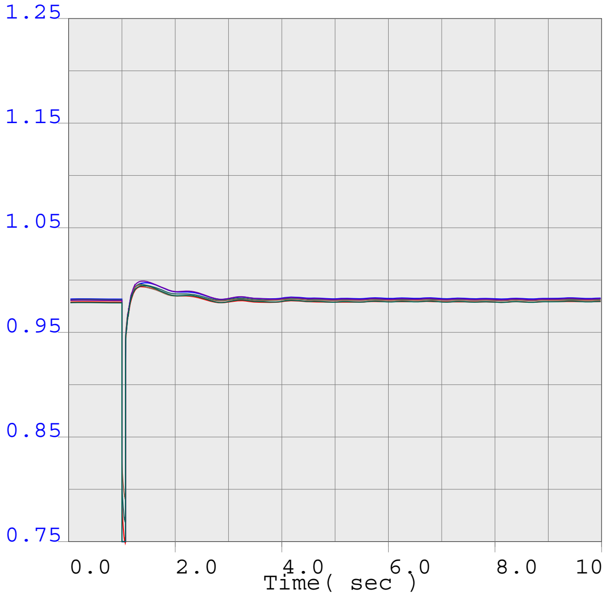
C:\DYTOOLS

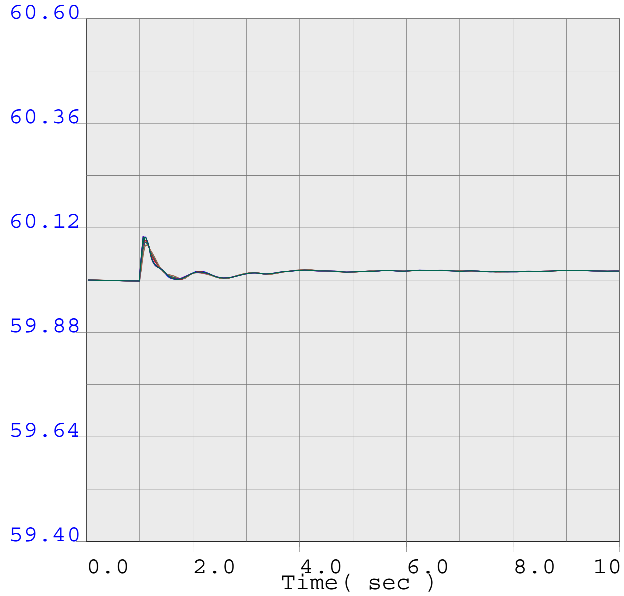
Thu Oct 20 08:55:25 2016

METRO









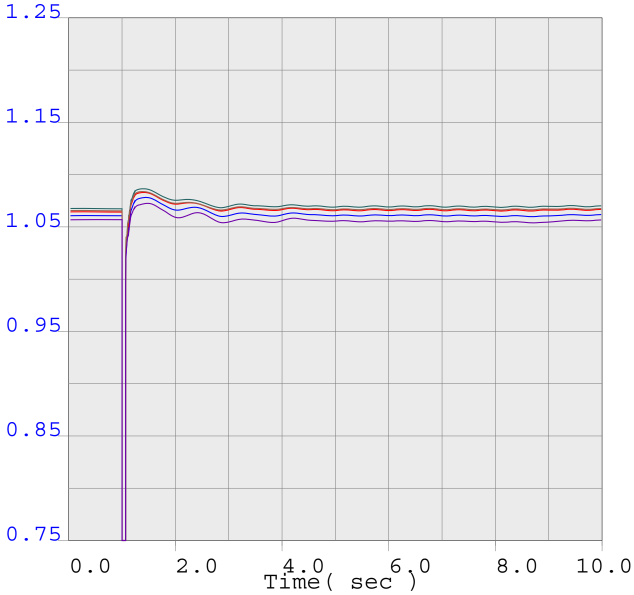
bay_23138
VINCENT 500 KV POS 5 INTERNAL FAULT
1 MW dispatch Case

qc9p-bay_23138.chf

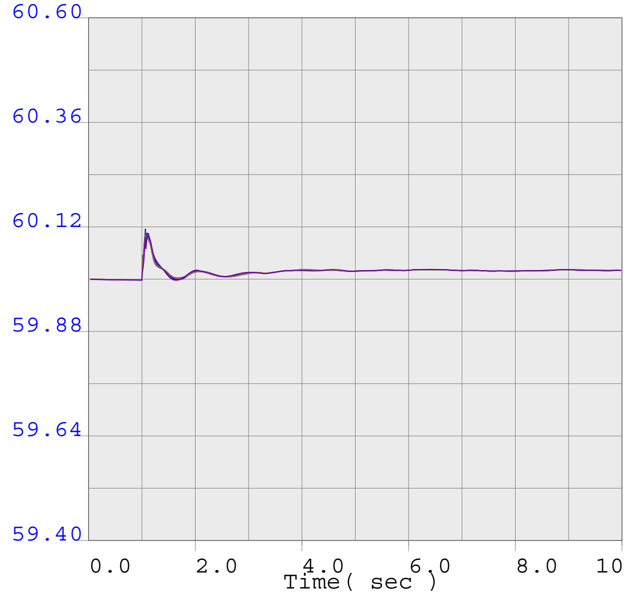
C:\DYTOOLS

Thu Oct 20 08:55:28 2016

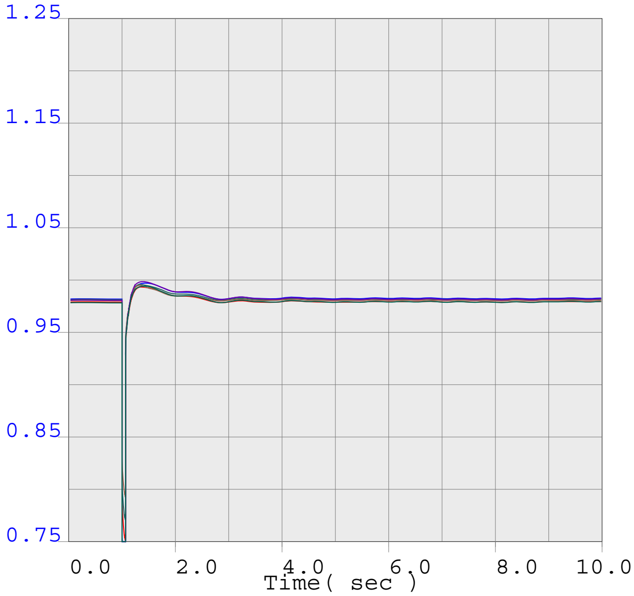
METRO



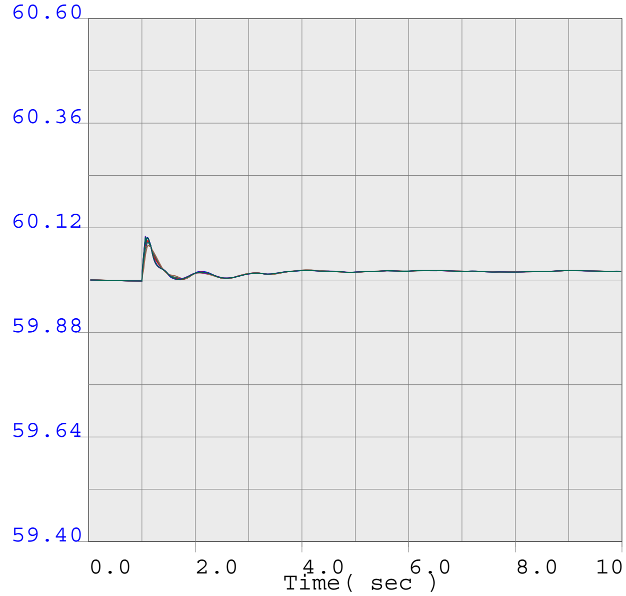
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

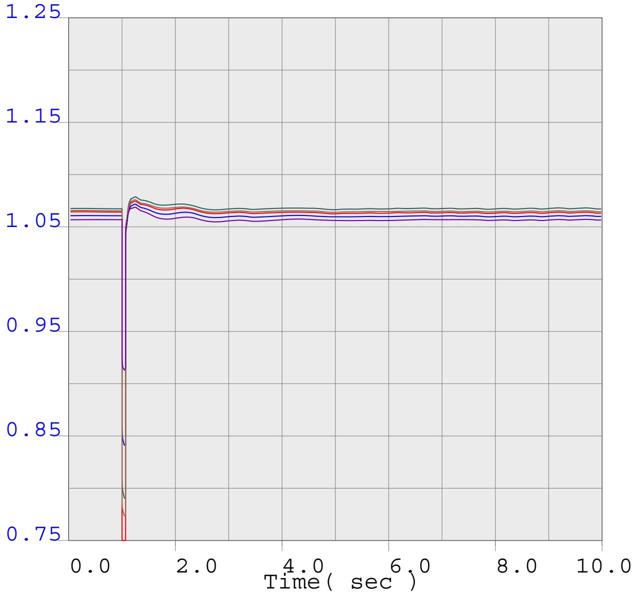
bay_23139
VINCENT 500 KV POS 6 INTERNAL FAULT
1 MW dispatch Case

qc9p-bay_23139.chf

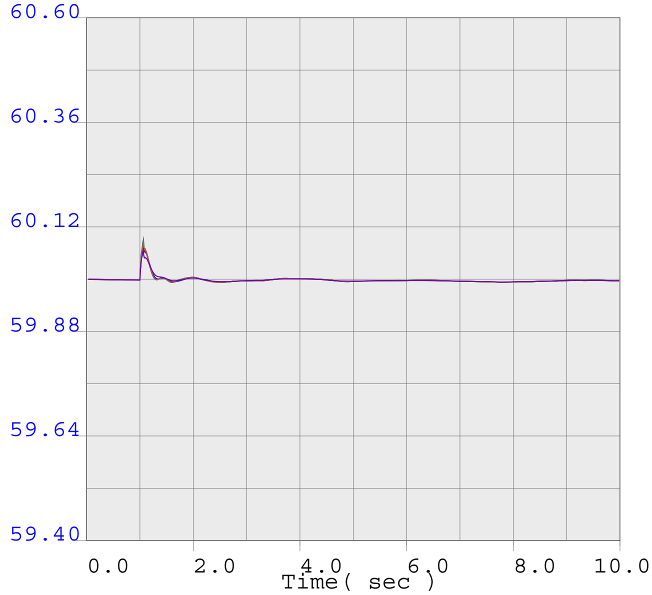
C:\DYTOOLS

Thu Oct 20 08:55:30 2016

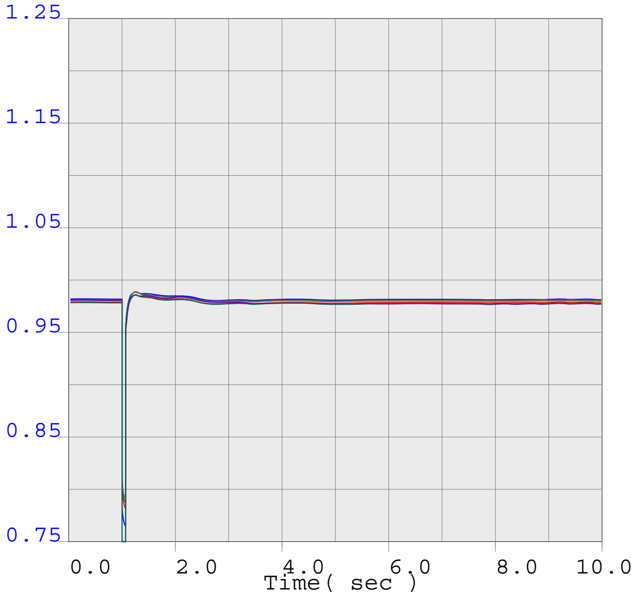
METRO



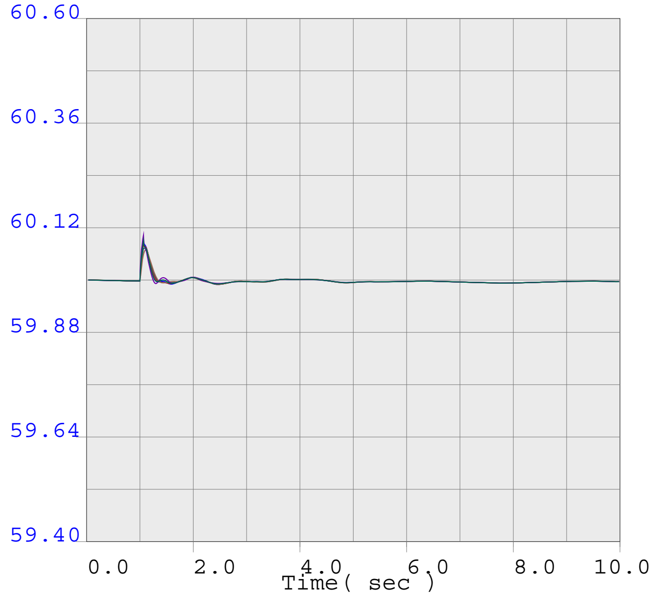
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

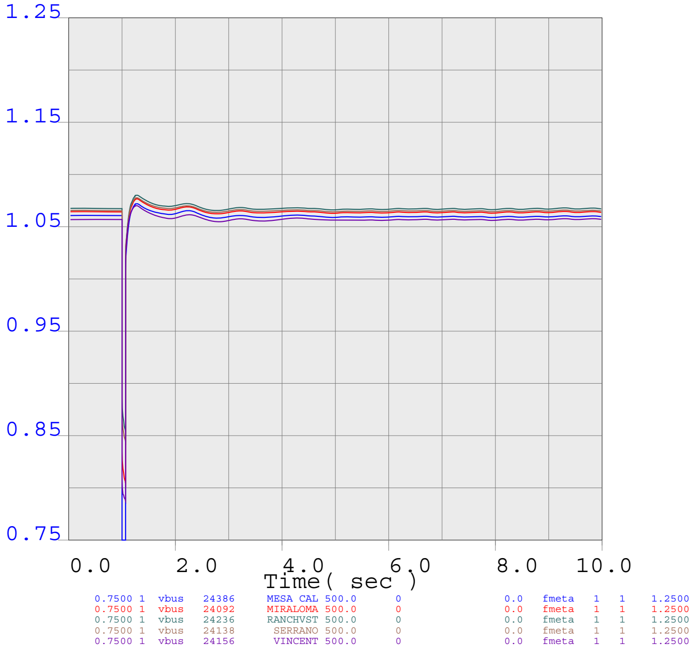
bay_2314
CHINO 220 KV POS 7 INTERNAL FAULT
1 MW dispatch Case

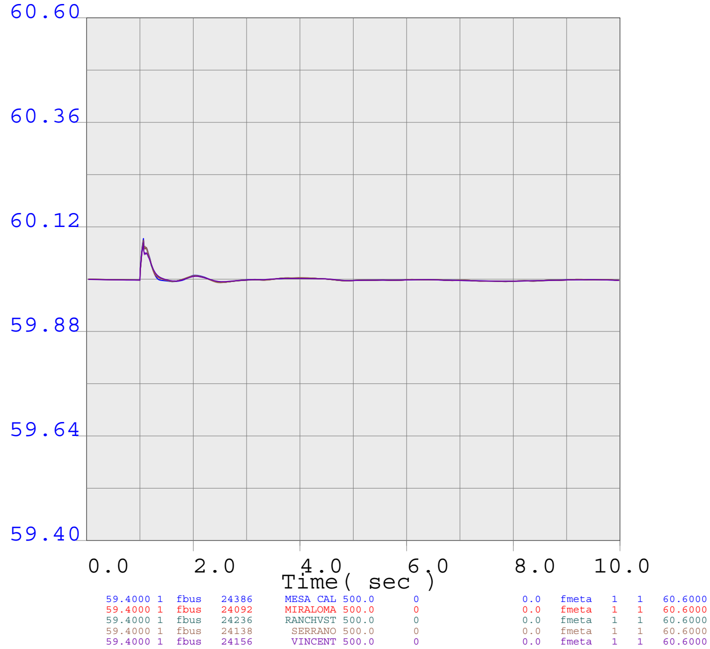
qc9p-bay_2314.chf

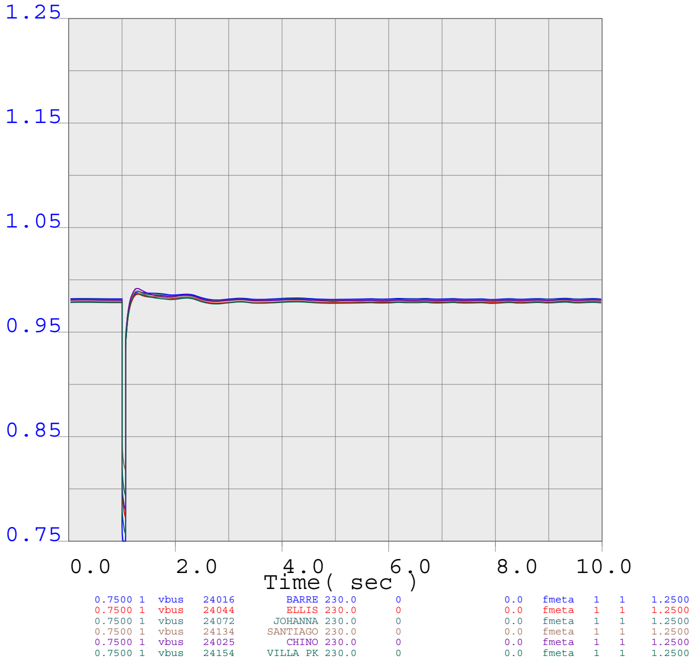
C:\DYTOOLS

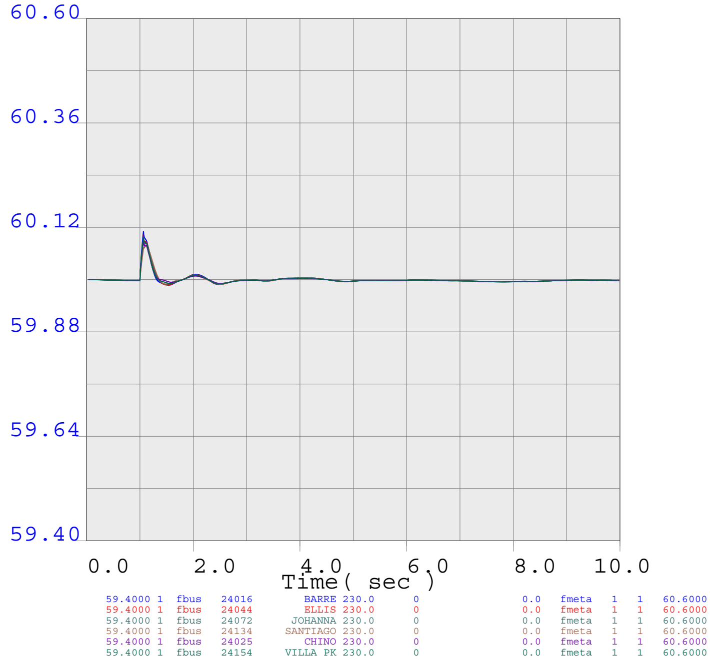
Thu Oct 20 08:55:32 2016

METRO









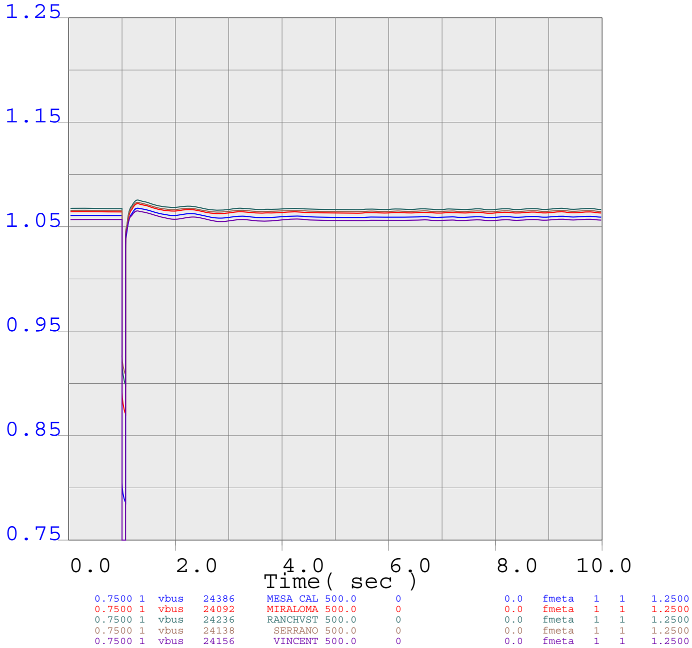
bay_23140
VINCENT 220 KV POS 1 INTERNAL FAULT
1 MW dispatch Case

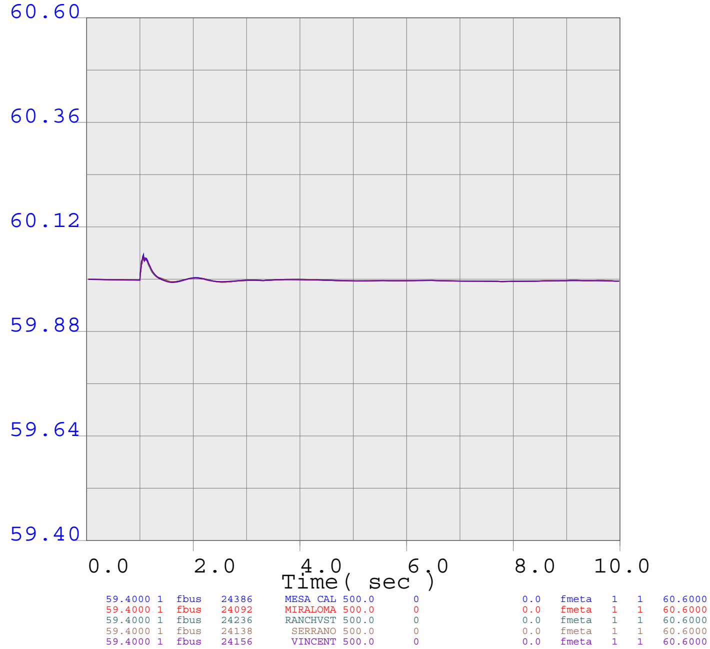
qc9p-bay_23140.chf

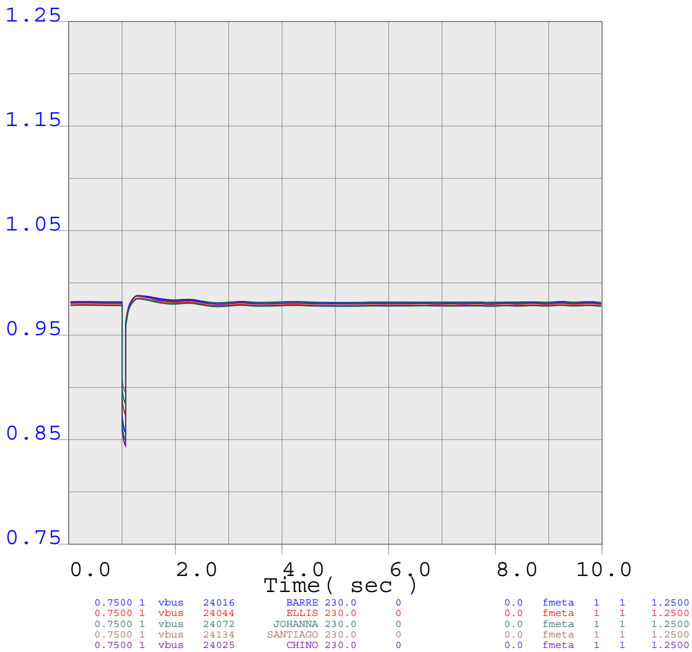
C:\DYTOOLS

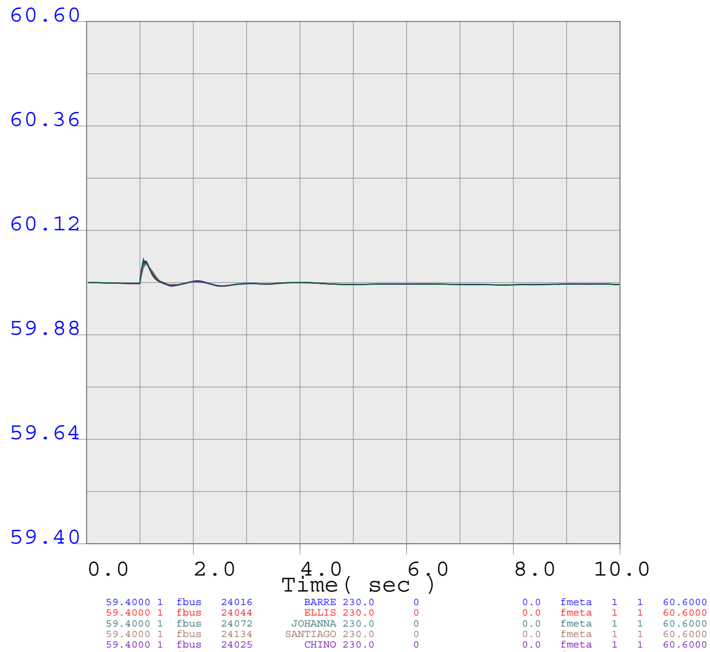
Thu Oct 20 08:55:34 2016

METRO









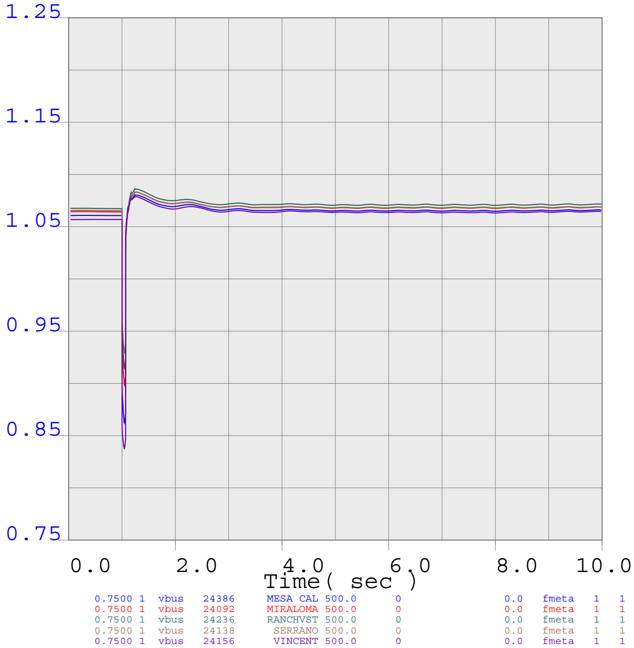
bay_23141
VINCENT 220 KV POS 2 INTERNAL FAULT
1 MW dispatch Case

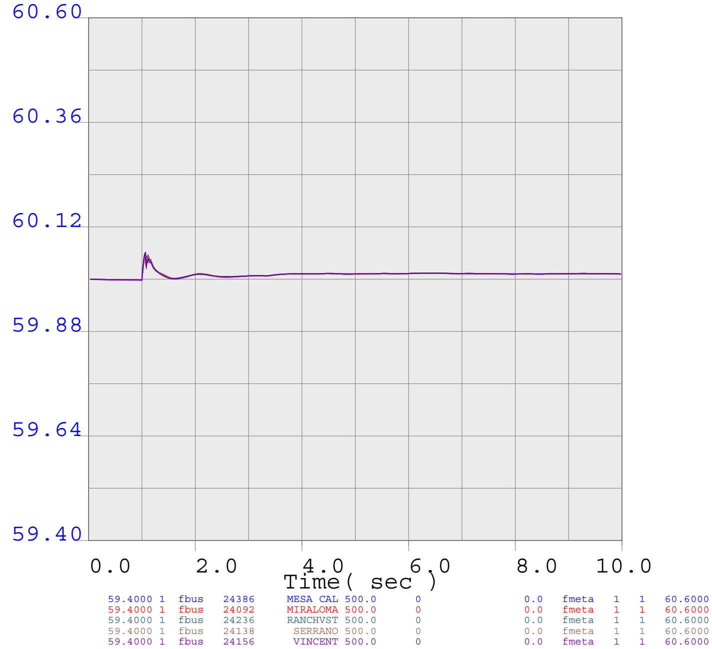
qc9p-bay_23141.chf

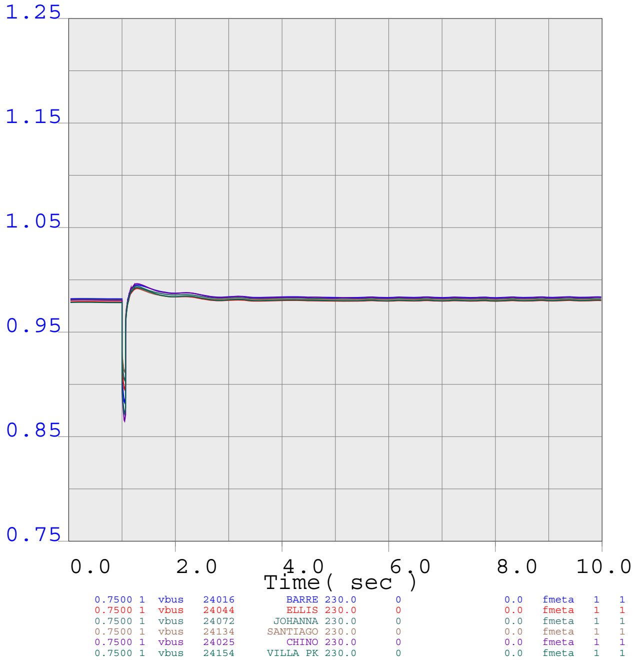
C:\DYTOOLS

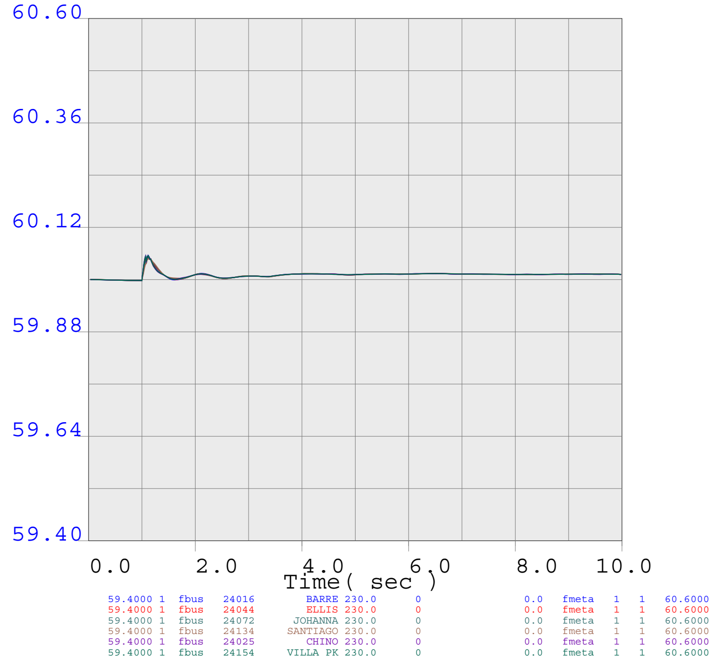
Thu Oct 20 08:55:37 2016

METRO









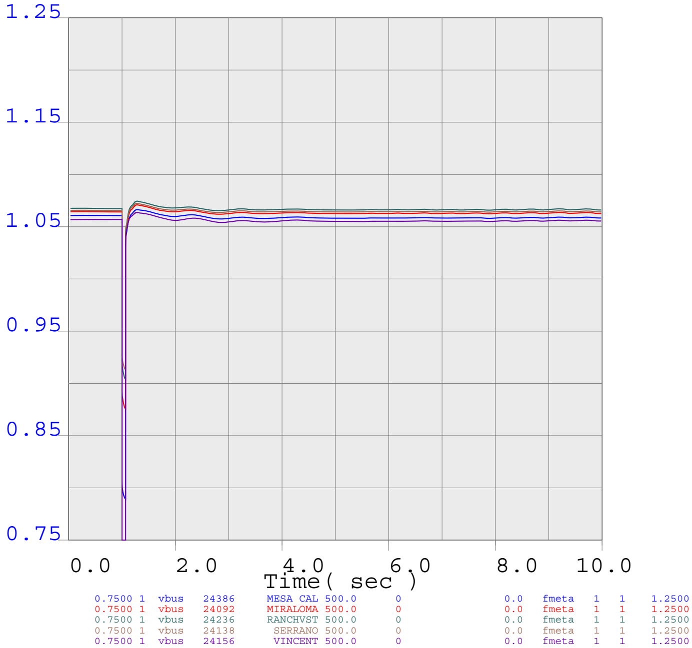
bay_23142
VINCENT 220 KV POS 5 INTERNAL FAULT
1 MW dispatch Case

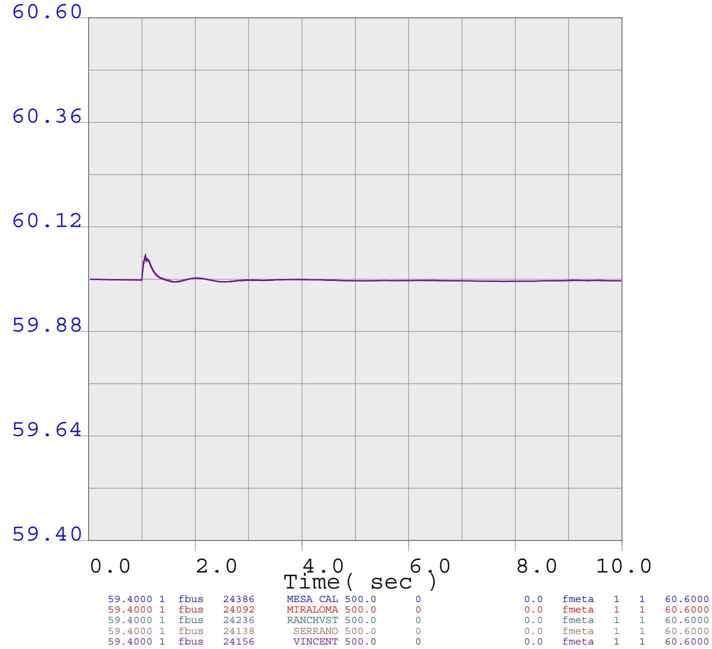
qc9p-bay_23142.chf

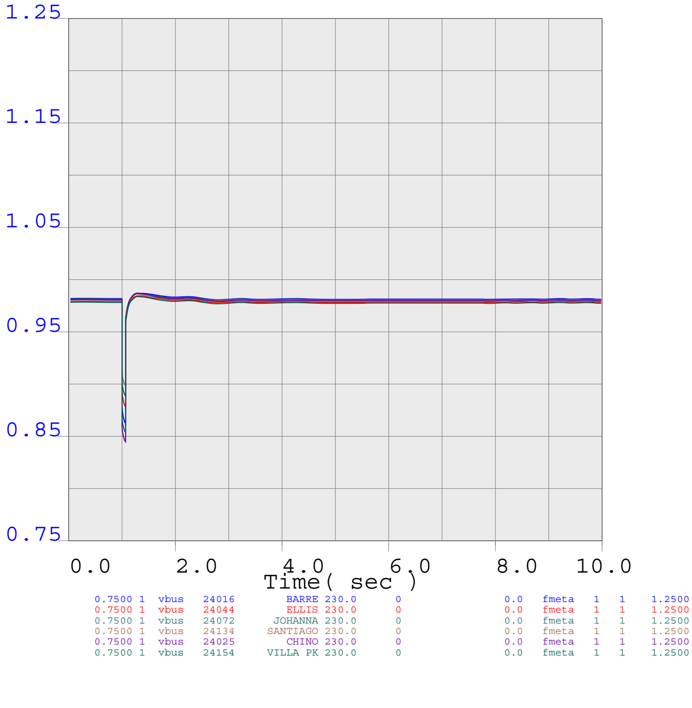
C:\DYTOOLS

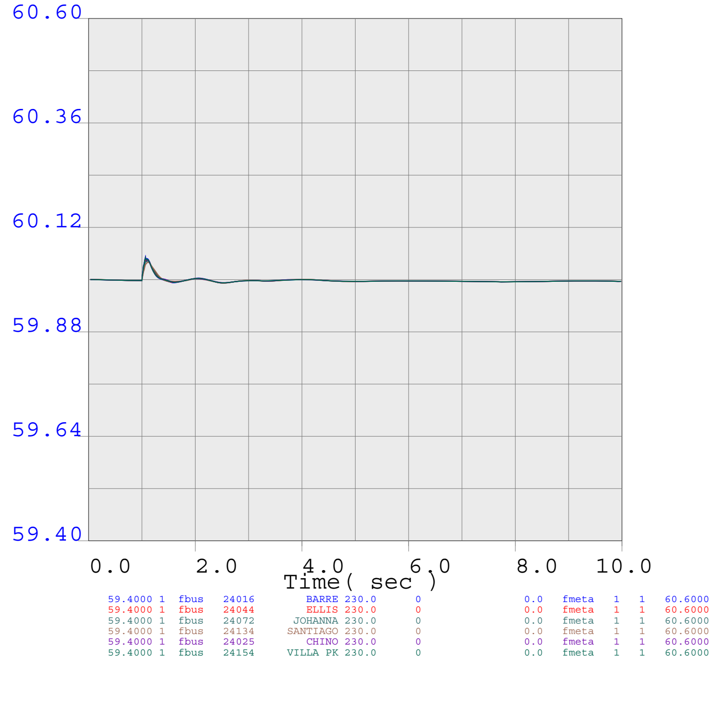
Thu Oct 20 08:55:39 2016

METRO









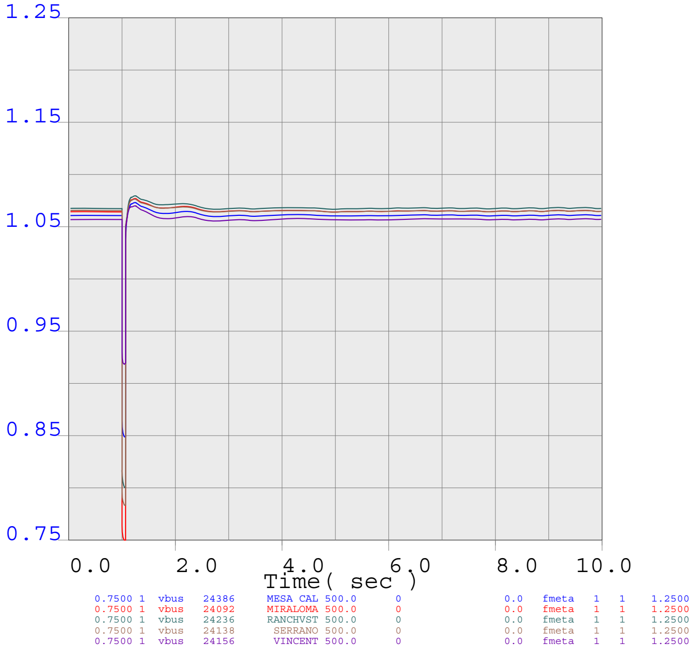
bay_23143
VINCENT 220 KV POS 6 INTERNAL FAULT
1 MW dispatch Case

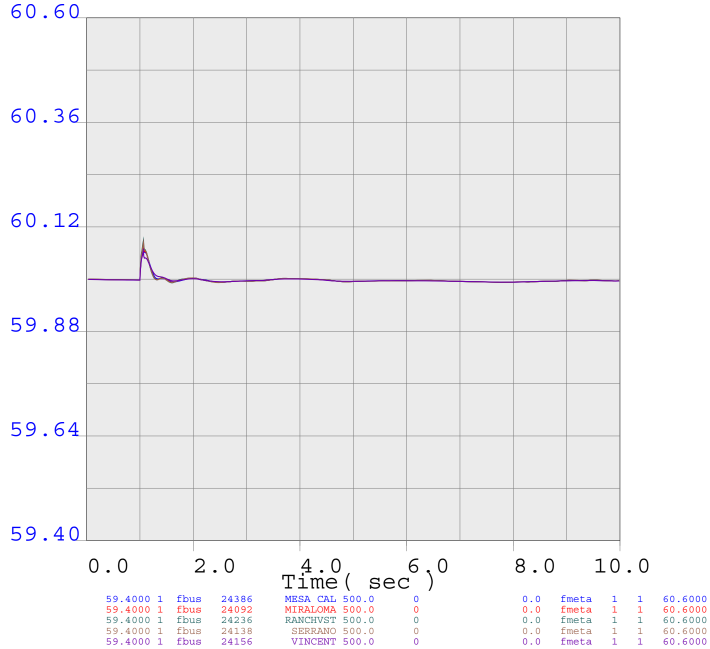
qc9p-bay_23143.chf

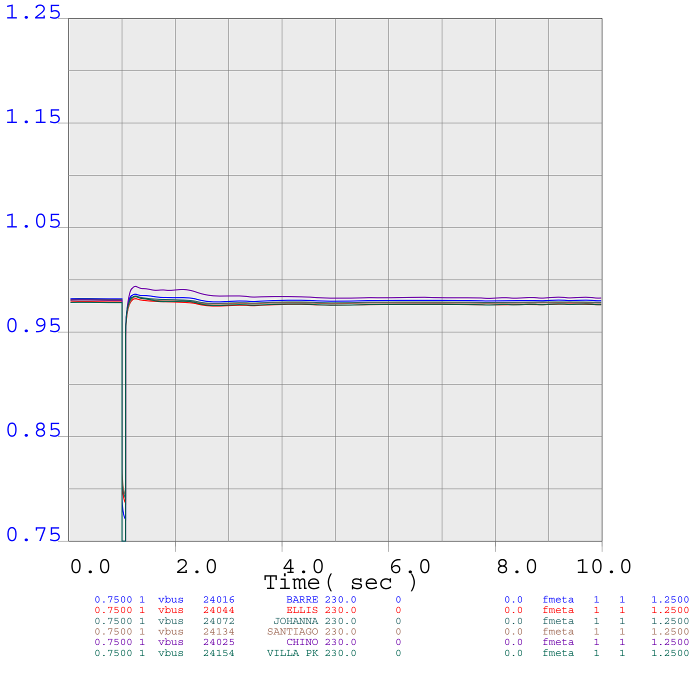
C:\DYTOOLS

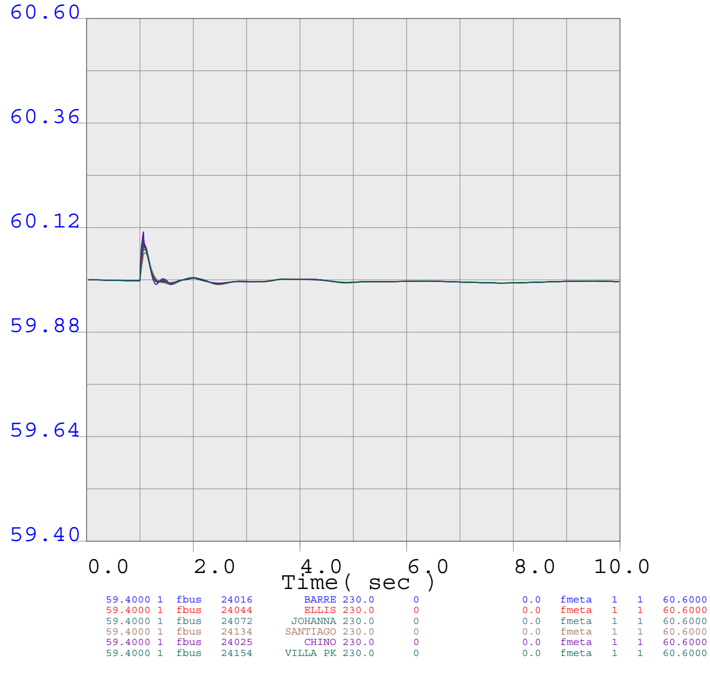
Thu Oct 20 08:55:41 2016

METRO









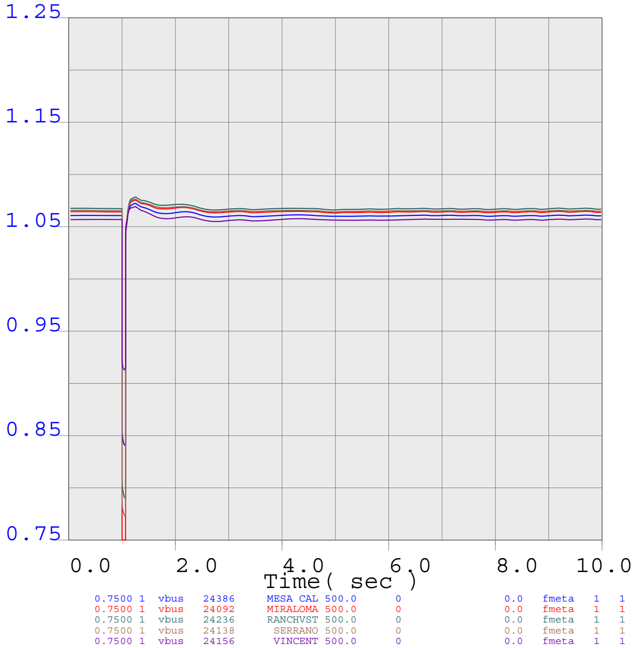
bay_2315
CHINO 220 KV POS 10 INTERNAL FAULT
1 MW dispatch Case

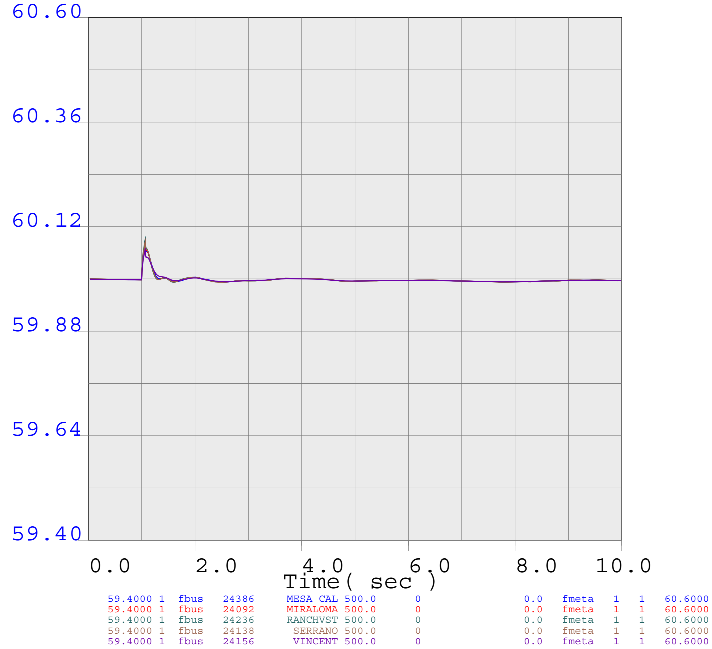
qc9p-bay_2315.chf

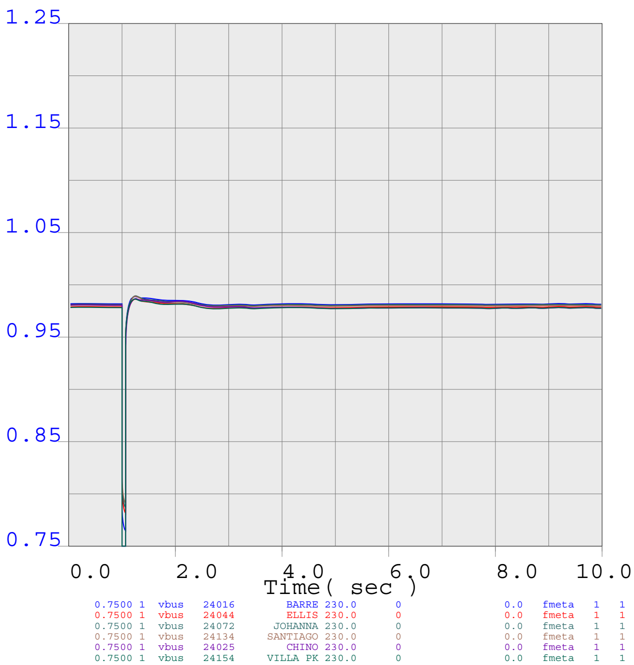
C:\DYTOOLS

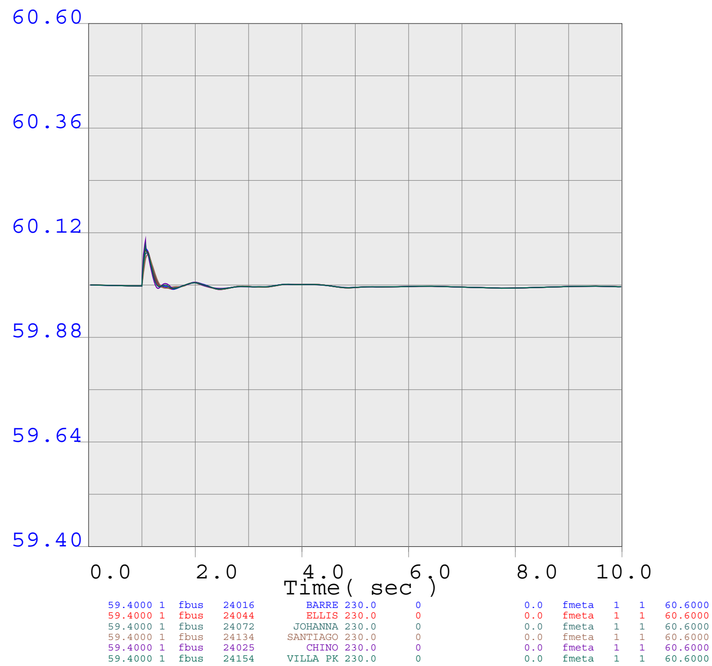
Thu Oct 20 08:55:43 2016

METRO









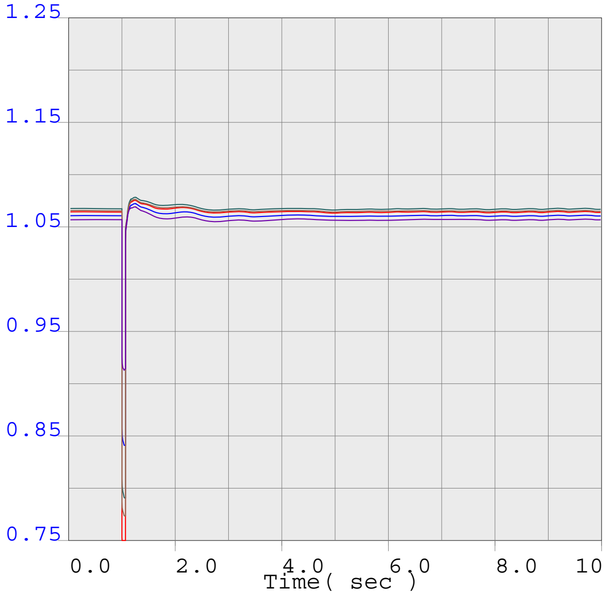
bay_2316
CHIN0 220 KV POS 5W
1 MW dispatch Case

qc9p-bay_2316.chf

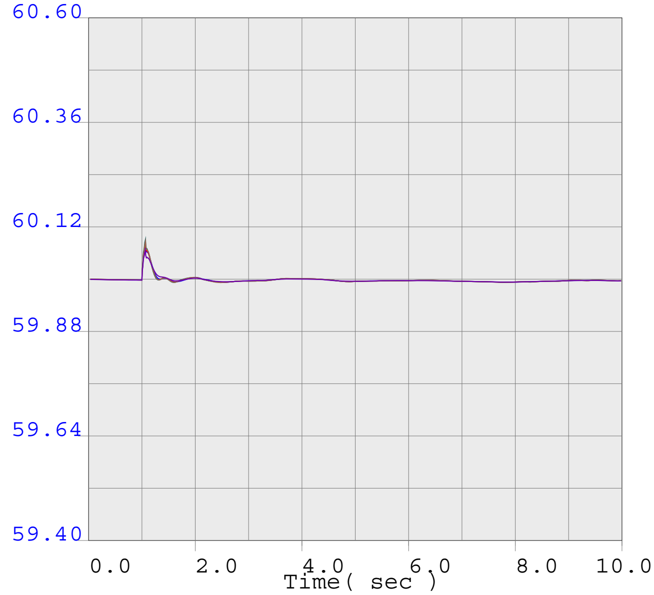
C:\DYTOOLS

Thu Oct 20 08:55:45 2016

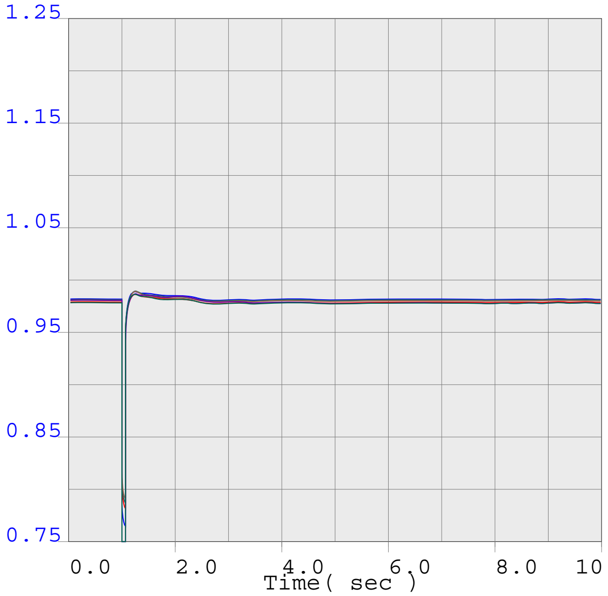
METRO



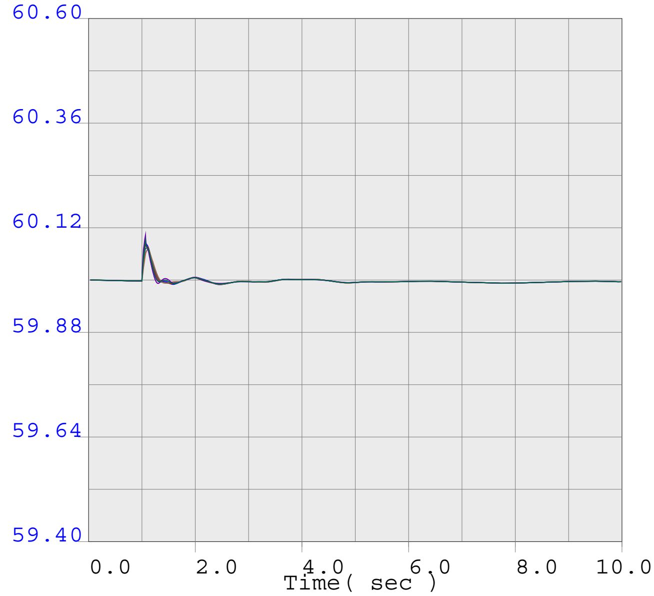
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500

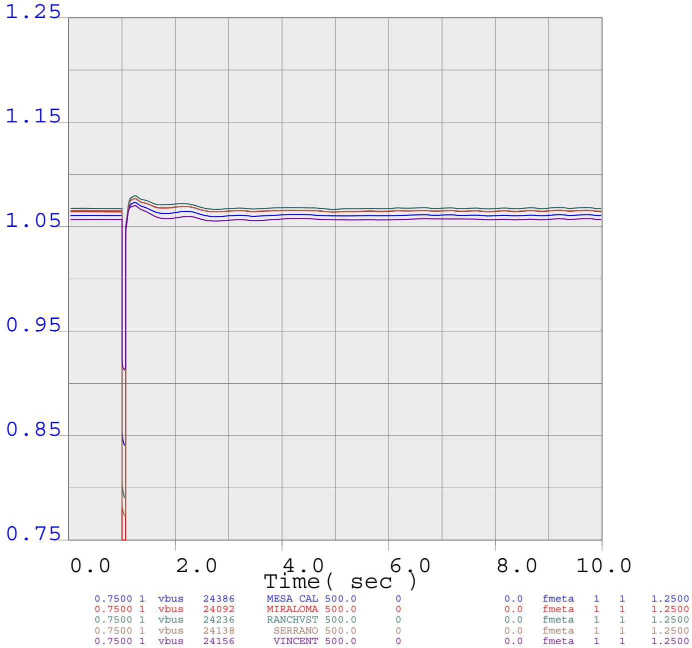


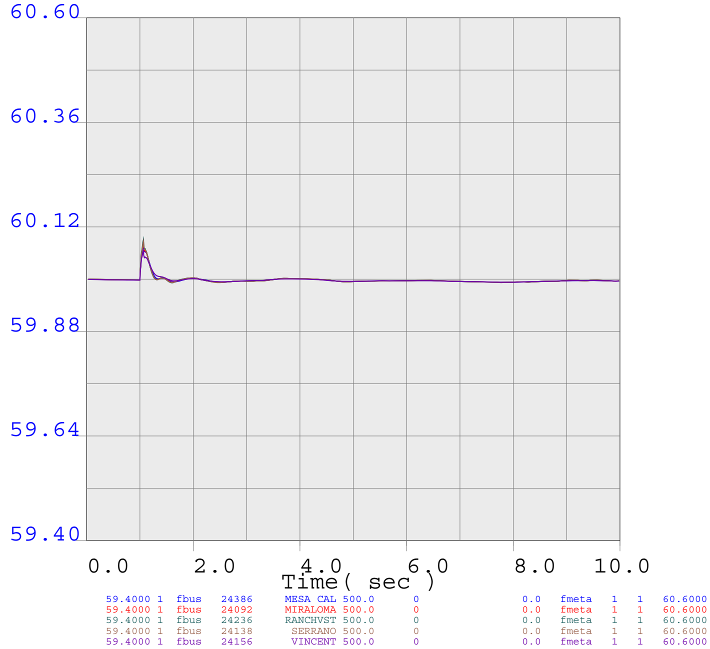
59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

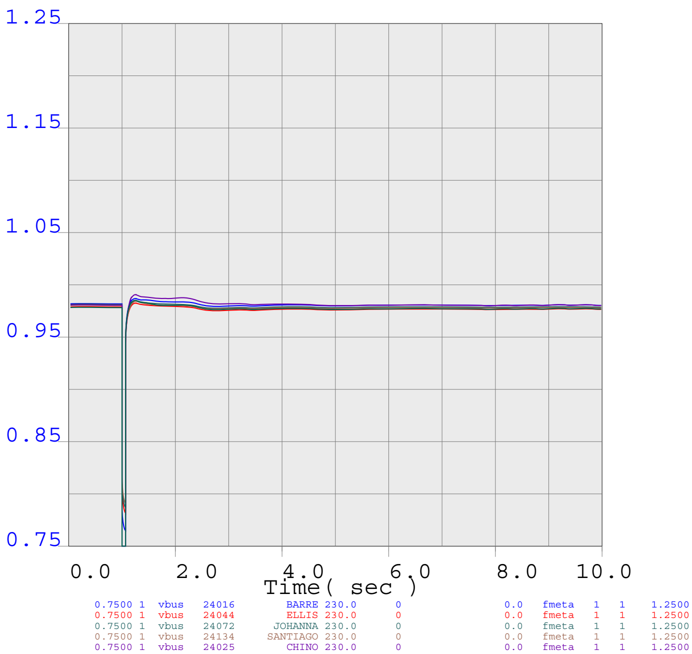
bay_2317
CHINO 220 KV POS 7W
1 MW dispatch Case

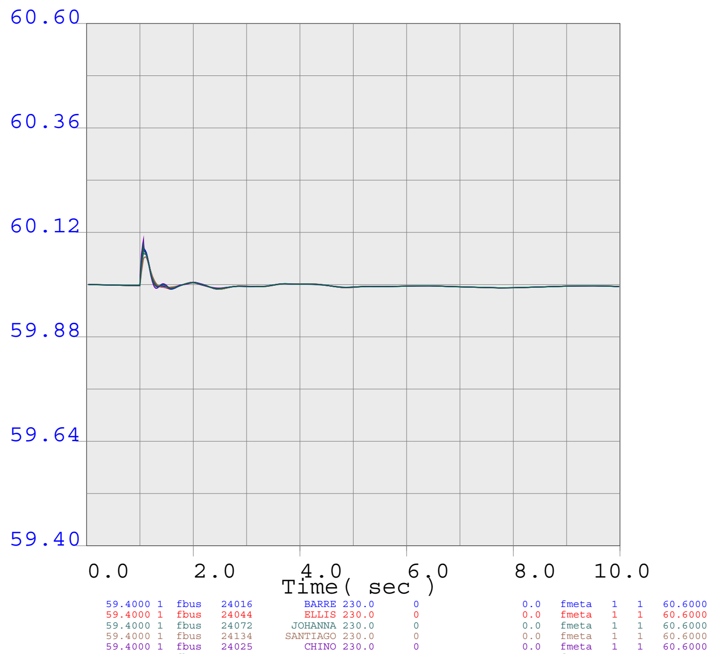
	qc9p-bay_2317.chf	C:\DYTOOLS Thu Oct 20 08:55:47 2016

METRO









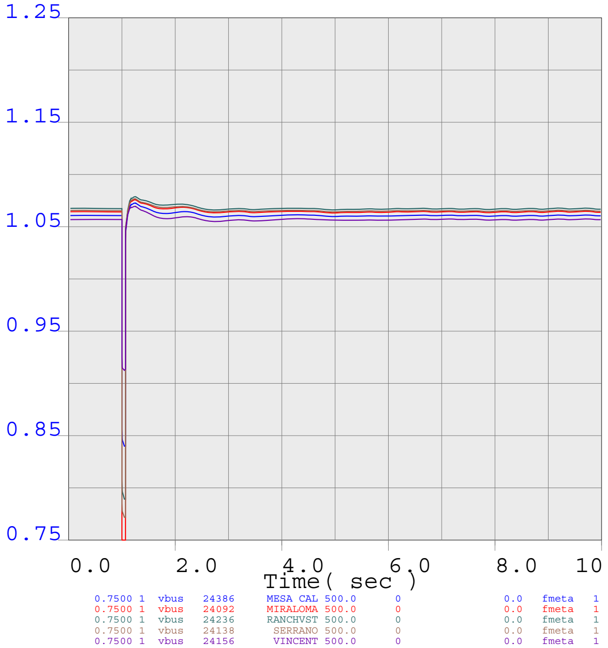
bay_2318
CHINO 220 KV POS 10W
1 MW dispatch Case

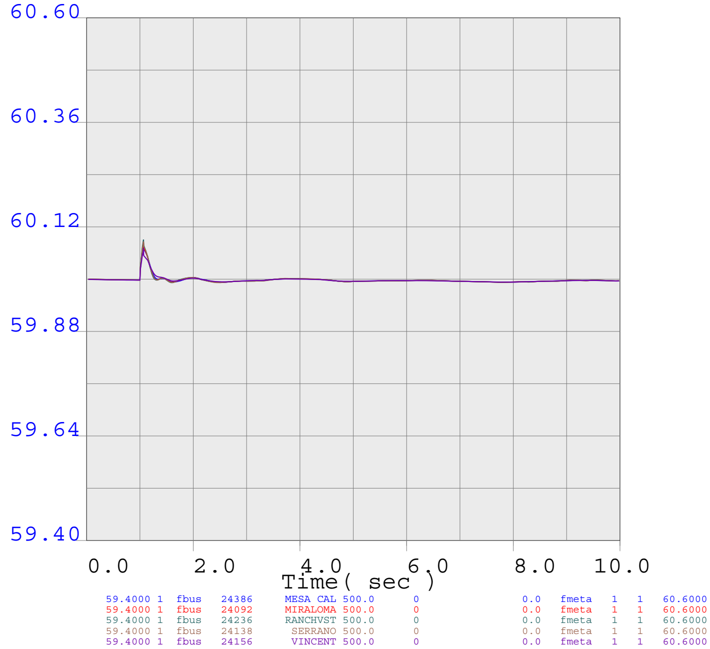
qc9p-bay_2318.chf

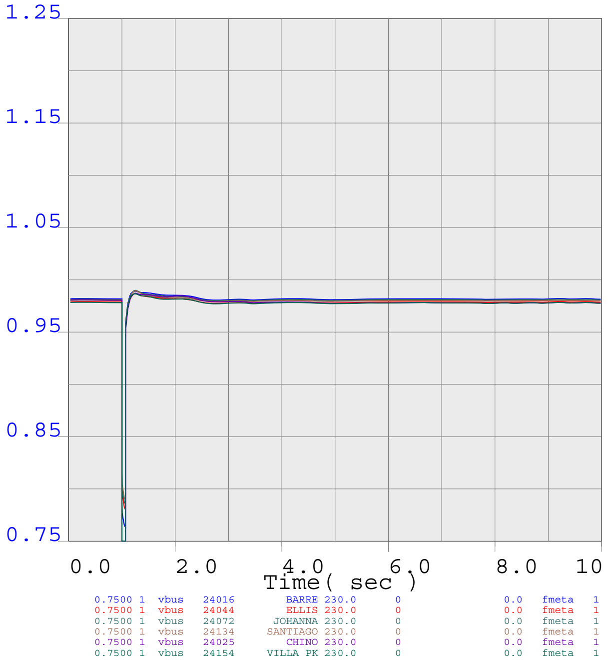
C:\DYTOOLS

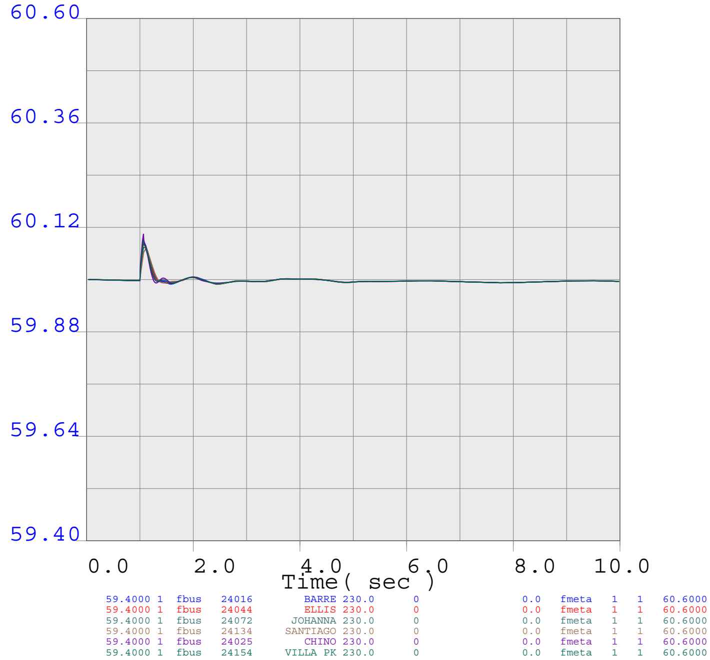
Thu Oct 20 08:55:49 2016

METRO









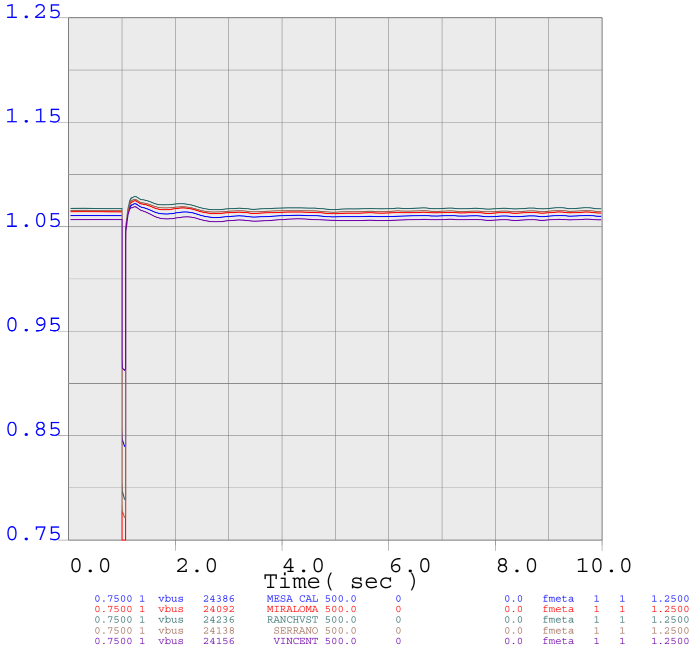
bay_2319
CHINO 220 KV POS 5E
1 MW dispatch Case

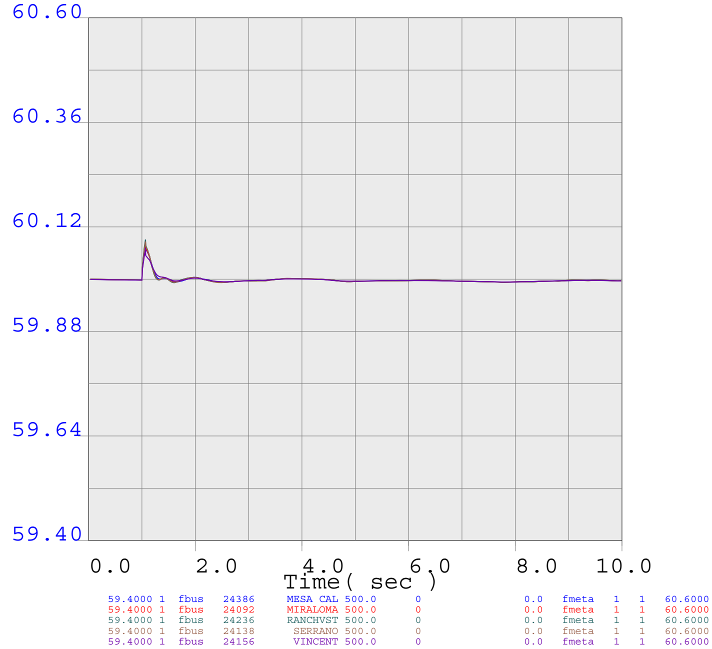
qc9p-bay_2319.chf

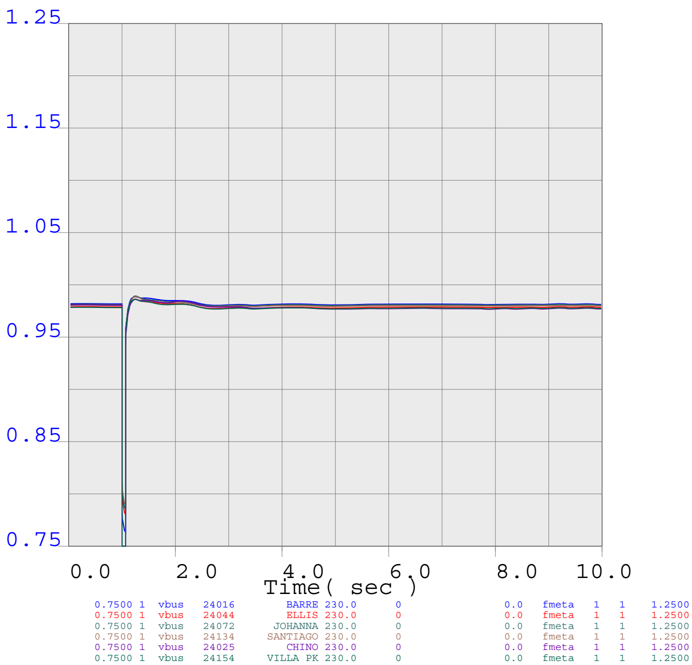
C:\DYTOOLS

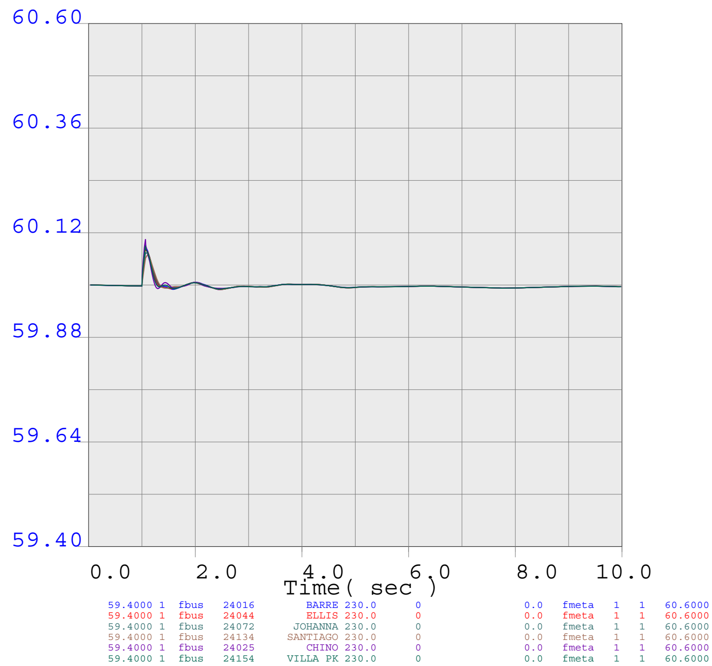
Thu Oct 20 08:55:52 2016

METRO









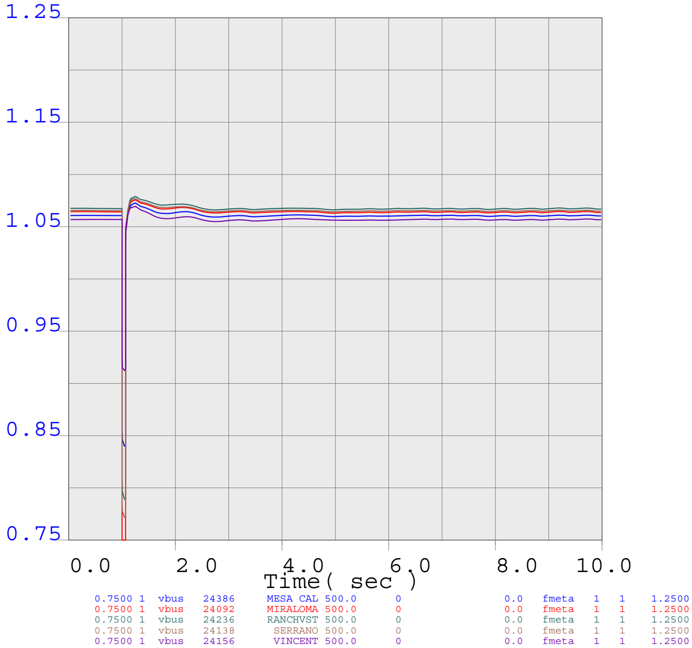
bay_2320
CHINO 220 KV POS 7E
1 MW dispatch Case

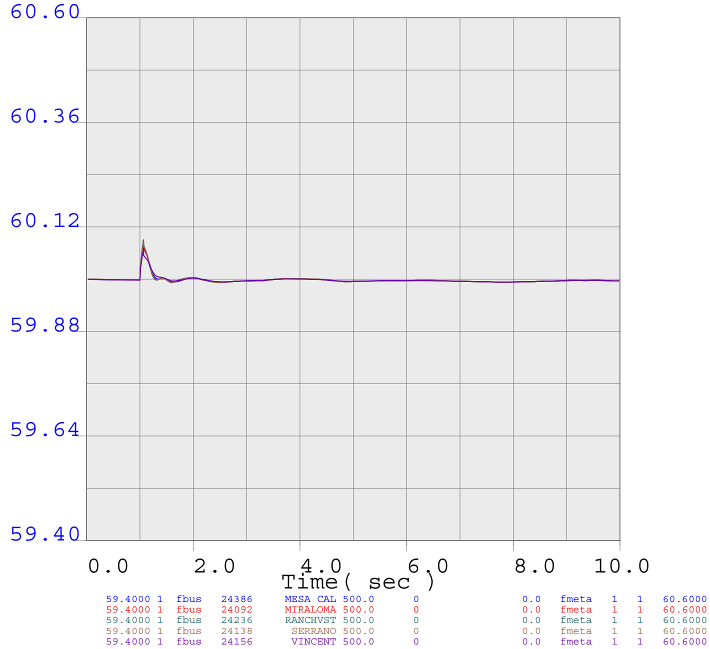
qc9p-bay_2320.chf

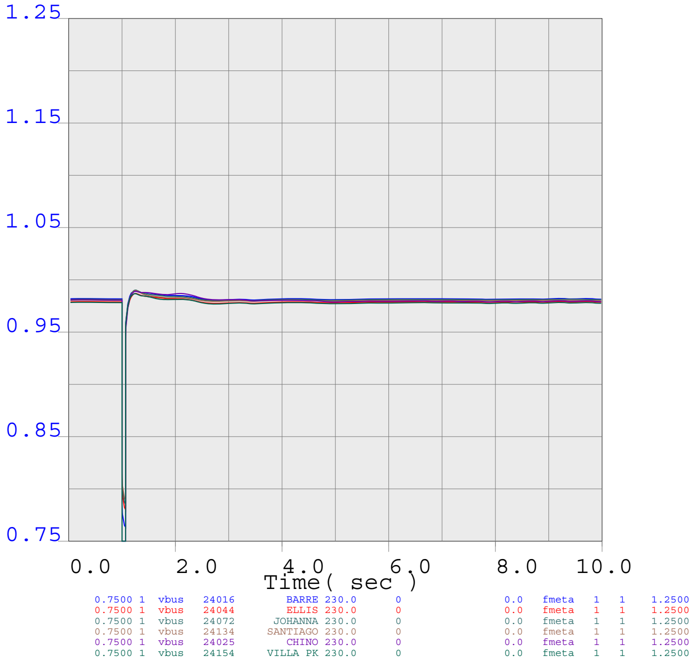
C:\DYTOOLS

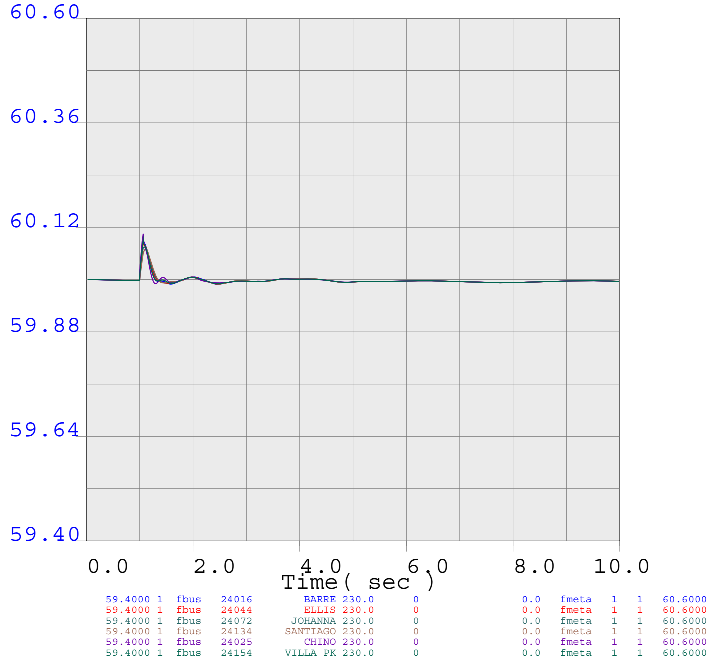
Thu Oct 20 08:55:54 2016

METRO









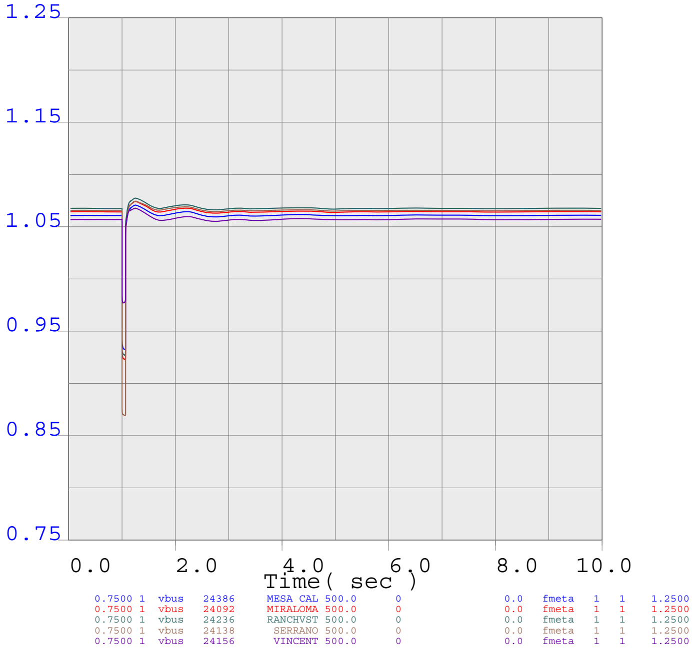
bay_2321
CHINO 220 KV POS 10E
1 MW dispatch Case

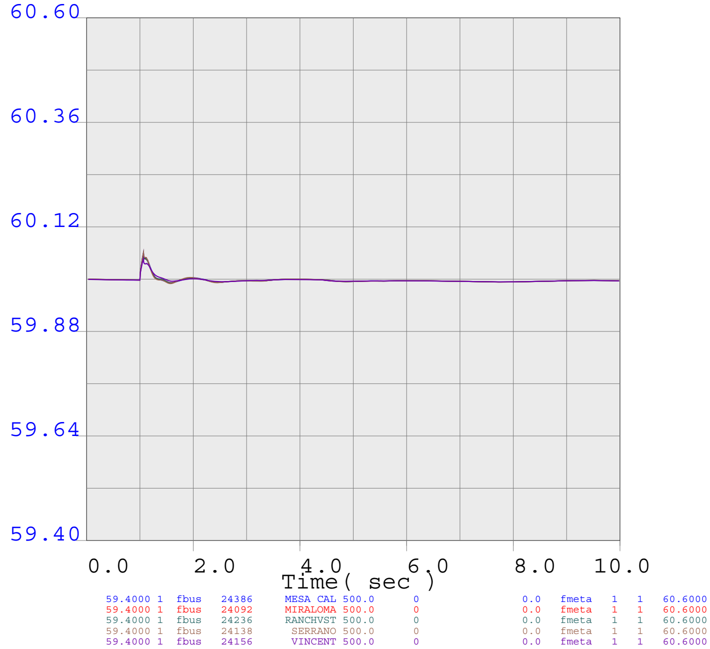
qc9p-bay_2321.chf

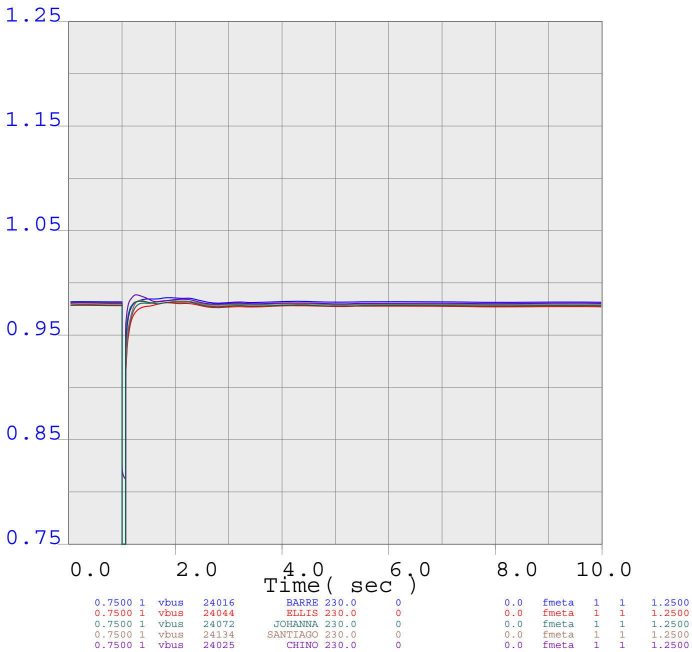
C:\DYTOOLS

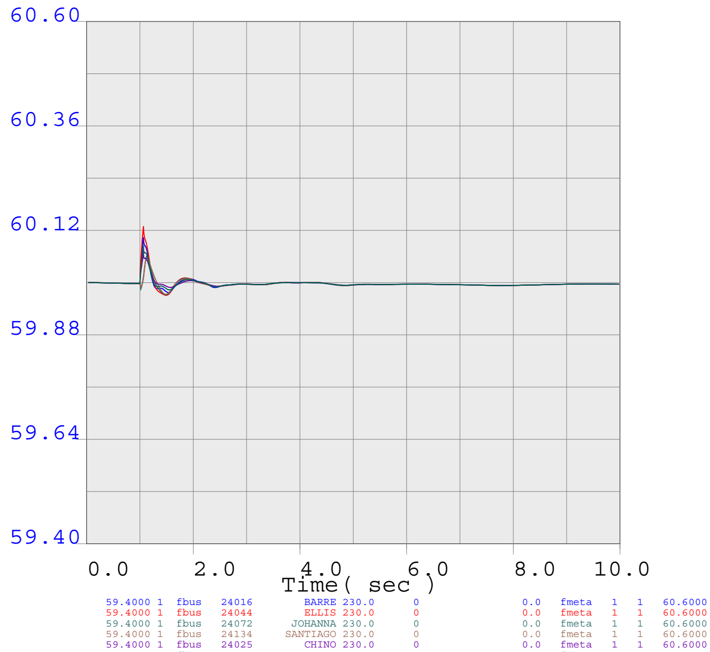
Thu Oct 20 08:55:56 2016

METRO









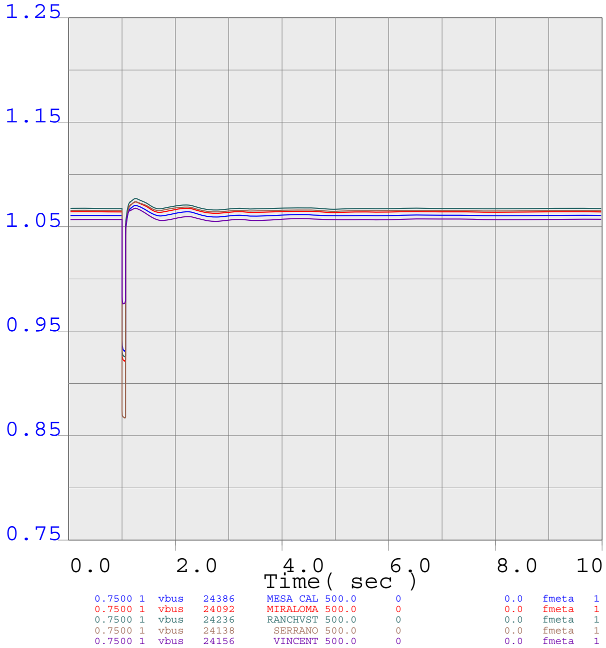
bay_2322
ELLIS 220 KV POS 1 INTERNAL FAULT
1 MW dispatch Case

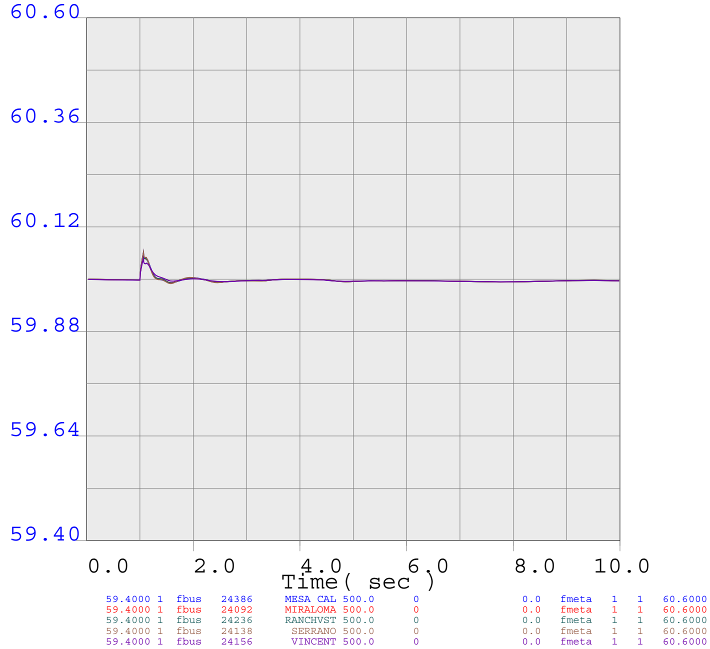
qc9p-bay_2322.chf

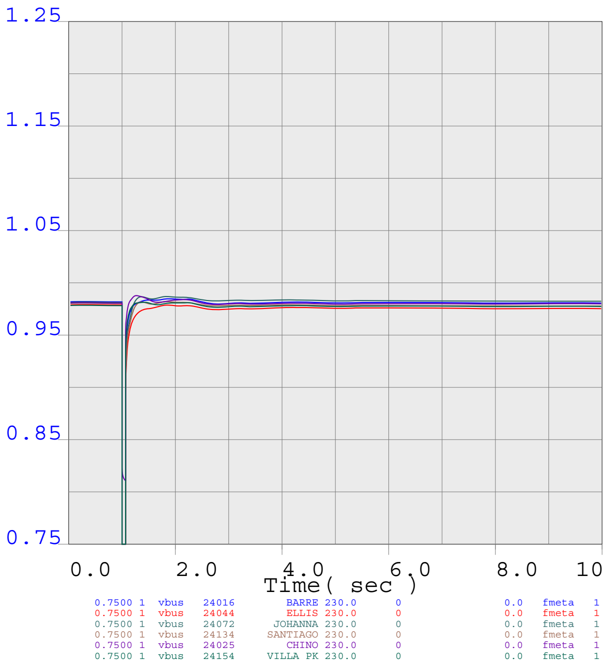
C:\DYTOOLS

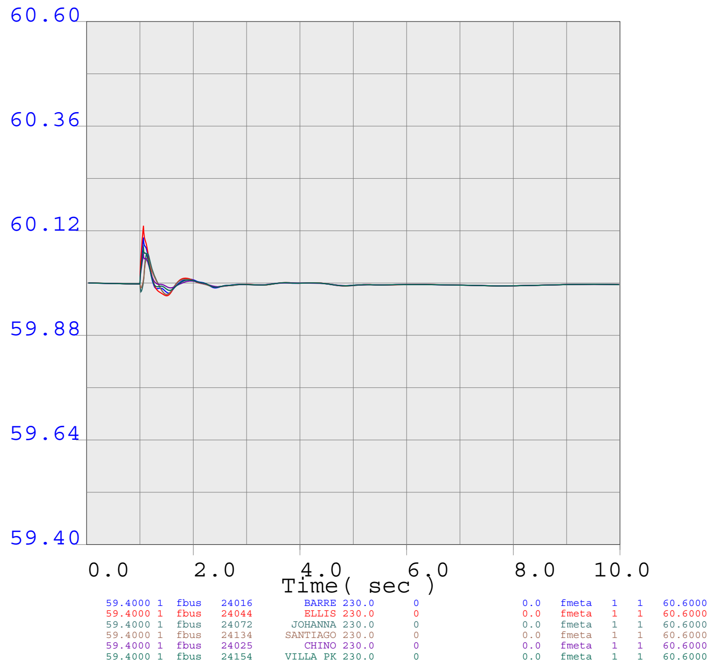
Thu Oct 20 08:55:58 2016

METRO









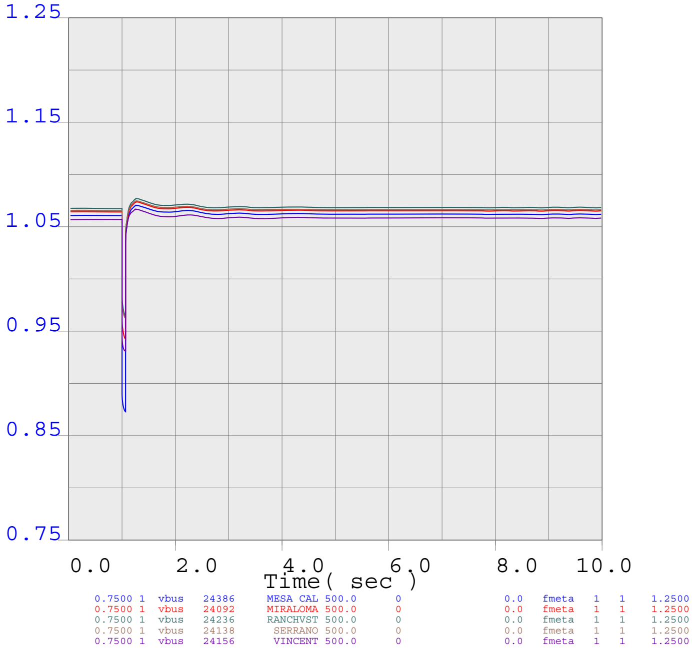
bay_2323
ELLIS 220 KV POS 2 INTERNAL FAULT
1 MW dispatch Case

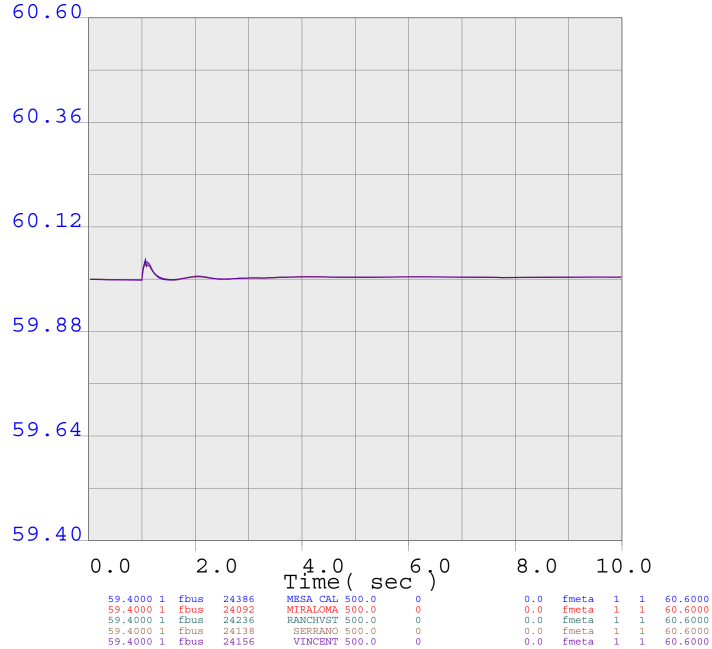
qc9p-bay_2323.chf

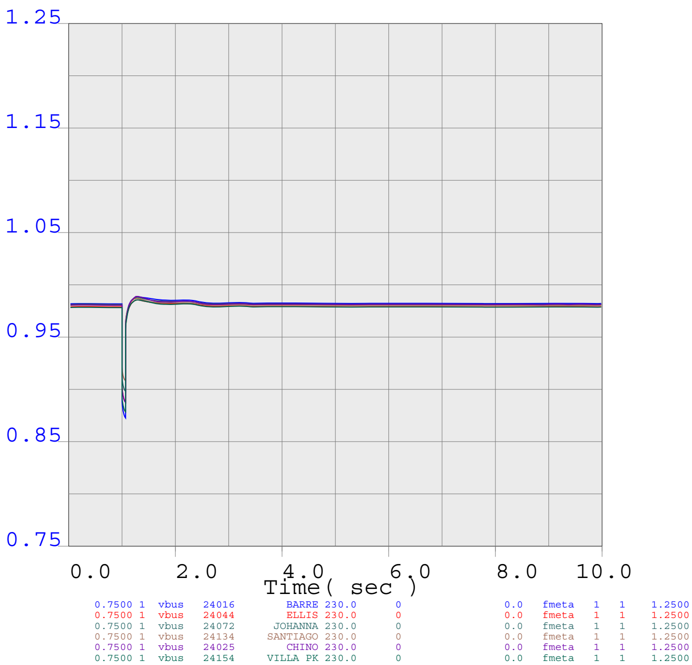
C:\DYTOOLS

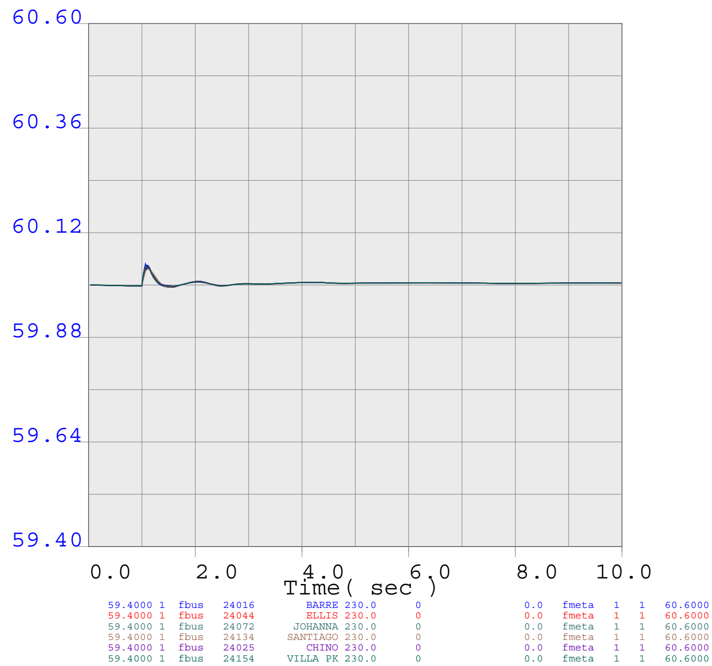
Thu Oct 20 08:56:00 2016

METRO









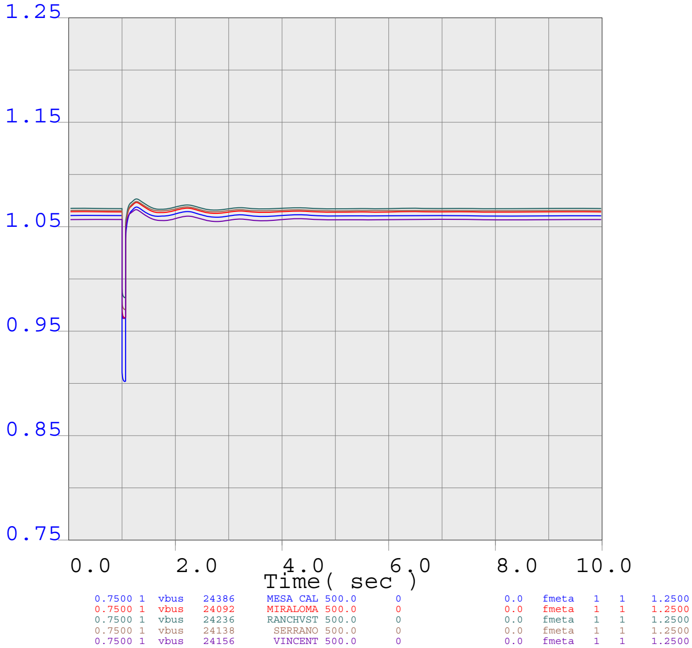
bay_2324
GOODRICH 220 KV POS 4 INTERNAL FAULT
1 MW dispatch Case

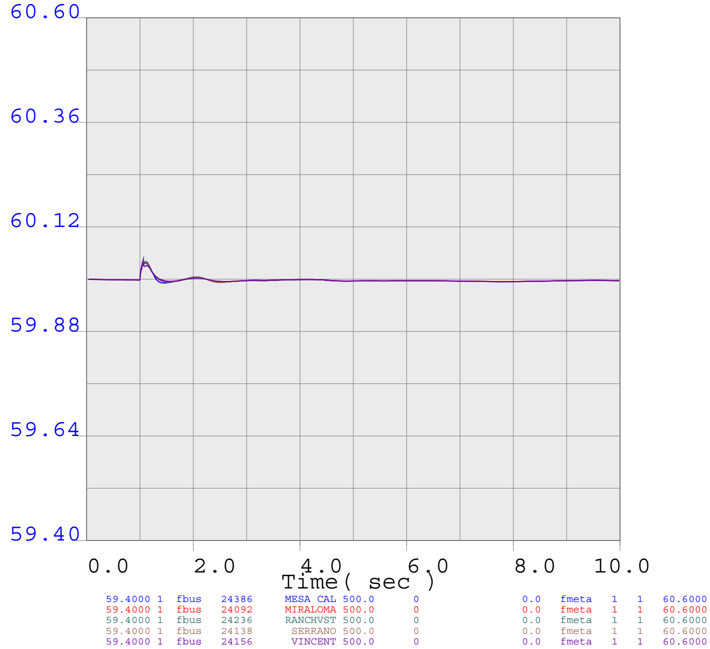
qc9p-bay_2324.chf

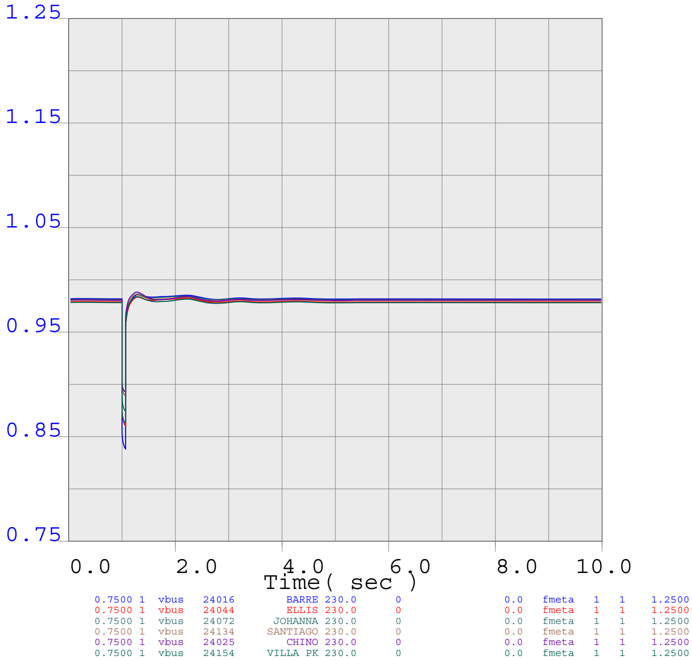
C:\DYTOOLS

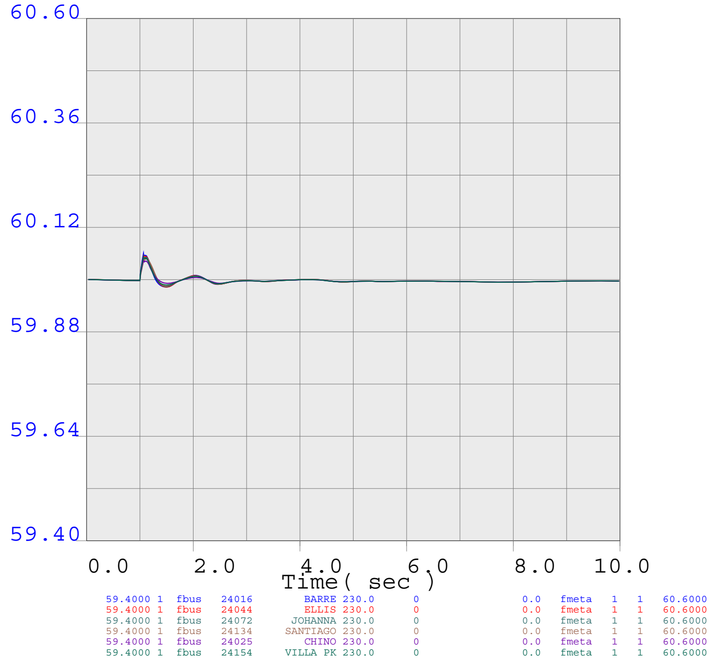
Thu Oct 20 08:56:02 2016

METRO









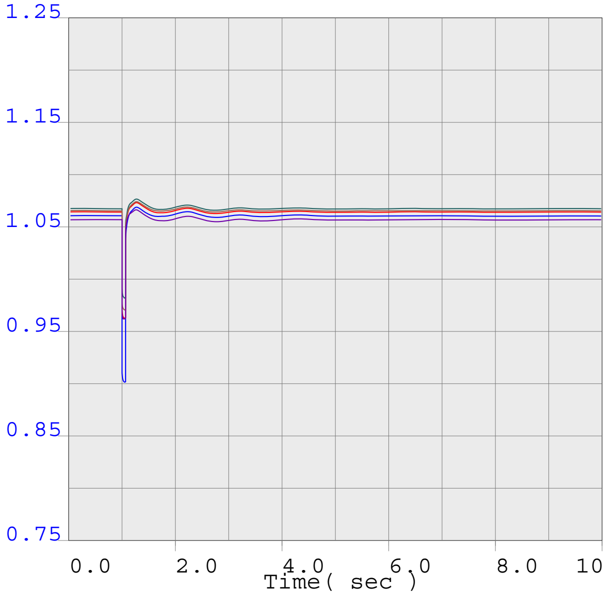
bay_2325
EL NIDO 220 KV POS 1XN
1 MW dispatch Case

qc9p-bay_2325.chf

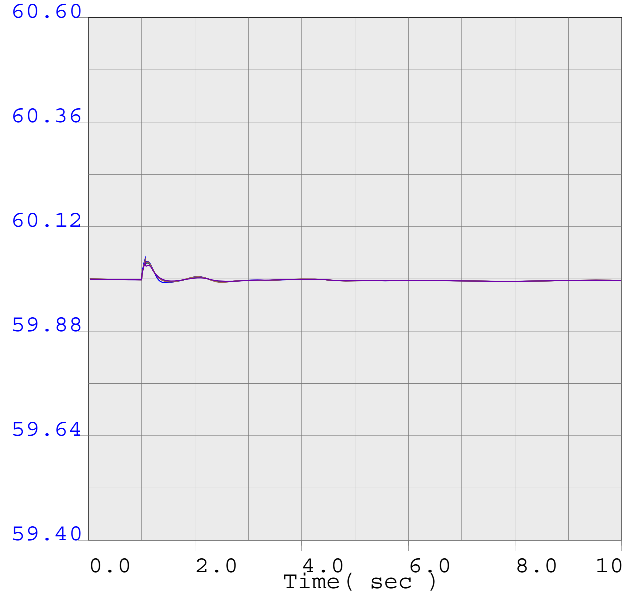
C:\DYTOOLS

Thu Oct 20 08:56:05 2016

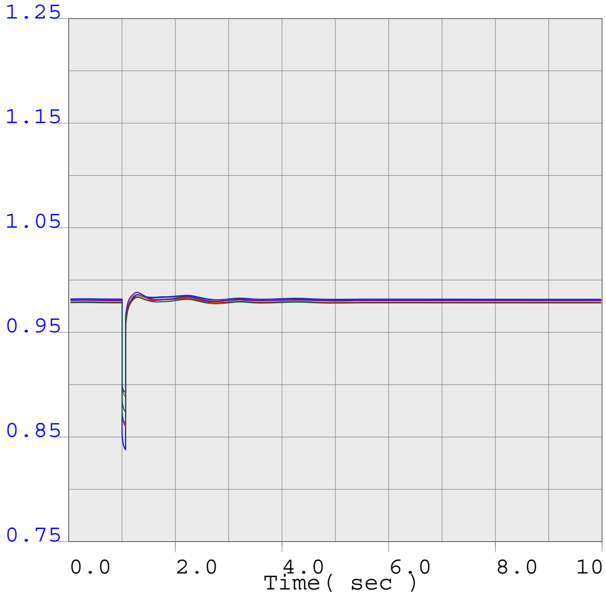
METRO



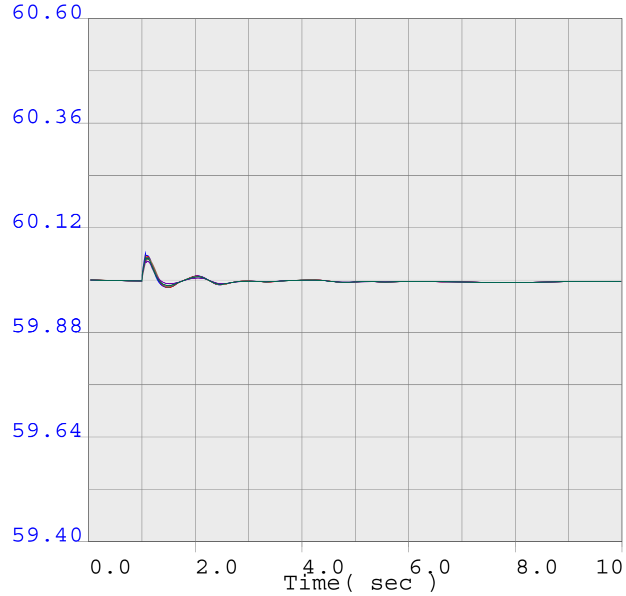

```
0.7500 1  vbus   24386   MESA CAL 500.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24092   MIRALOMA 500.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24236   RANCHVST 500.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24138    SERRANO 500.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24156    VINCENT 500.0   0      0.0  fmeta  1  1  1.2500
```




```
59.4000 1  fbus   24386   MESA CAL 500.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24092   MIRALOMA 500.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24236   RANCHVST 500.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24138    SERRANO 500.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24156    VINCENT 500.0   0      0.0  fmeta  1  1  60.6000
```




```
0.7500 1  vbus   24016      BARRE 230.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24044      ELLIS 230.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24072    JOHANNA 230.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24134   SANTIAGO 230.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24025      CHINO 230.0   0      0.0  fmeta  1  1  1.2500
0.7500 1  vbus   24154   VILLA PK 230.0   0      0.0  fmeta  1  1  1.2500
```




```
59.4000 1  fbus   24016      BARRE 230.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24044      ELLIS 230.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24072    JOHANNA 230.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24134   SANTIAGO 230.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24025      CHINO 230.0   0      0.0  fmeta  1  1  60.6000
59.4000 1  fbus   24154   VILLA PK 230.0   0      0.0  fmeta  1  1  60.6000
```

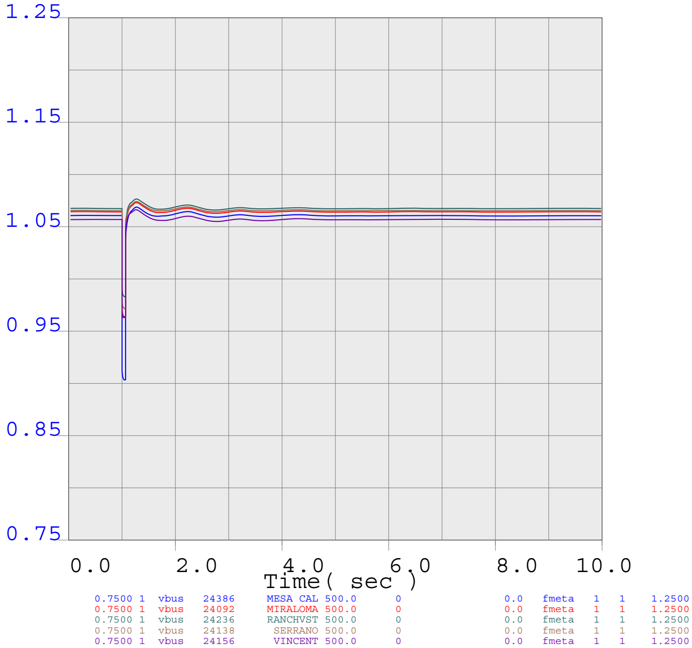
bay_2326
EL NIDO 220 KV POS 1N
1 MW dispatch Case

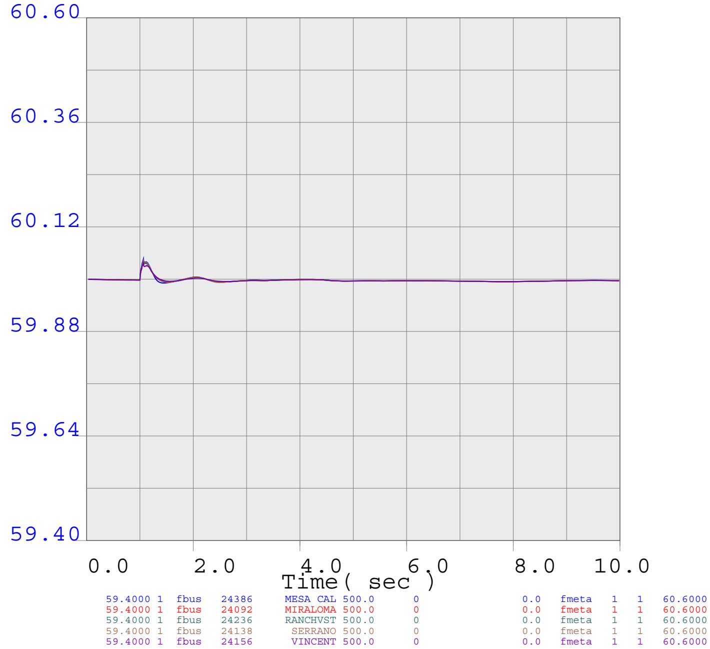
qc9p-bay_2326.chf

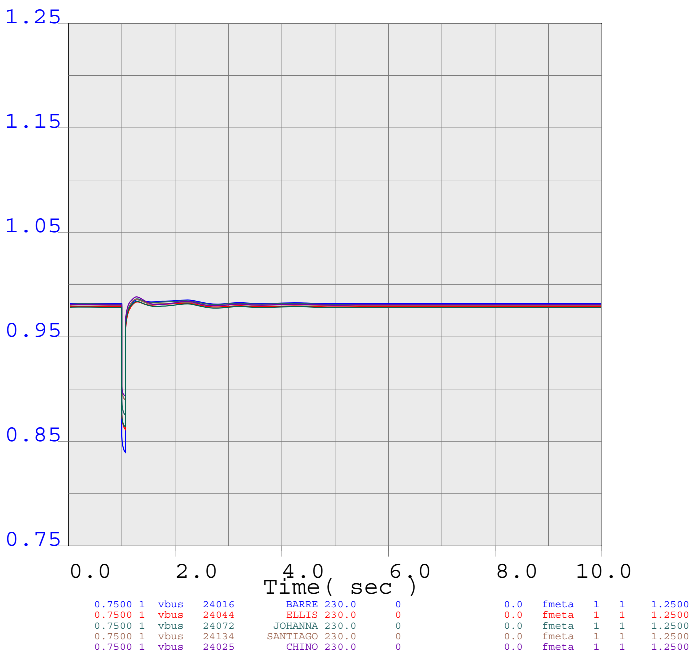
C:\DYTOOLS

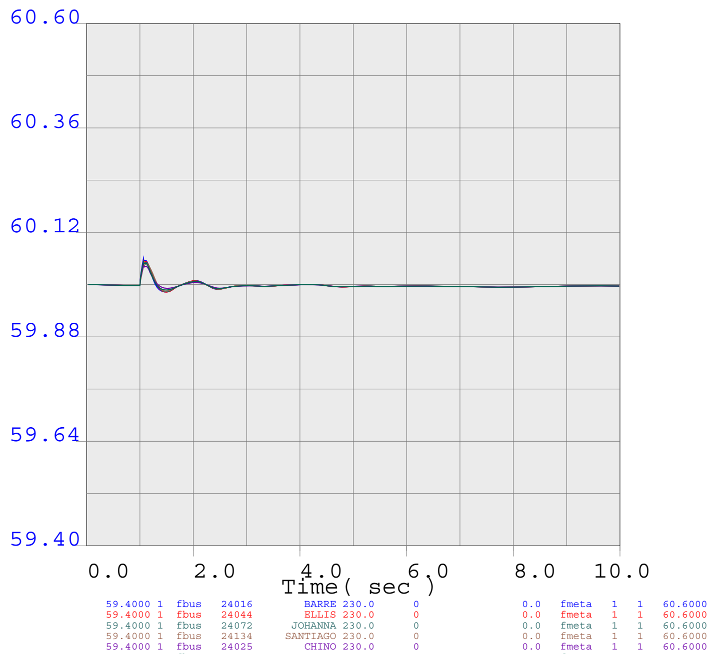
Thu Oct 20 08:56:07 2016

METRO









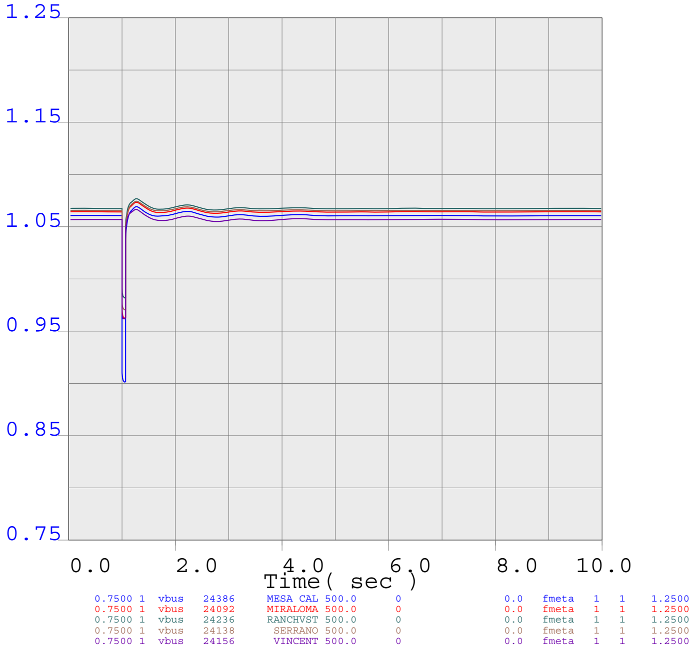
bay_2327
EL NIDO 220 KV POS 2N
1 MW dispatch Case

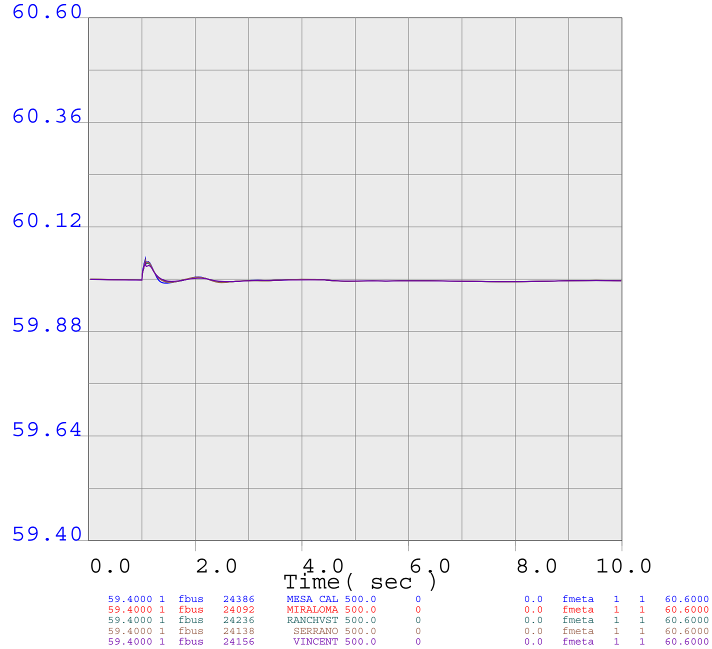
qc9p-bay_2327.chf

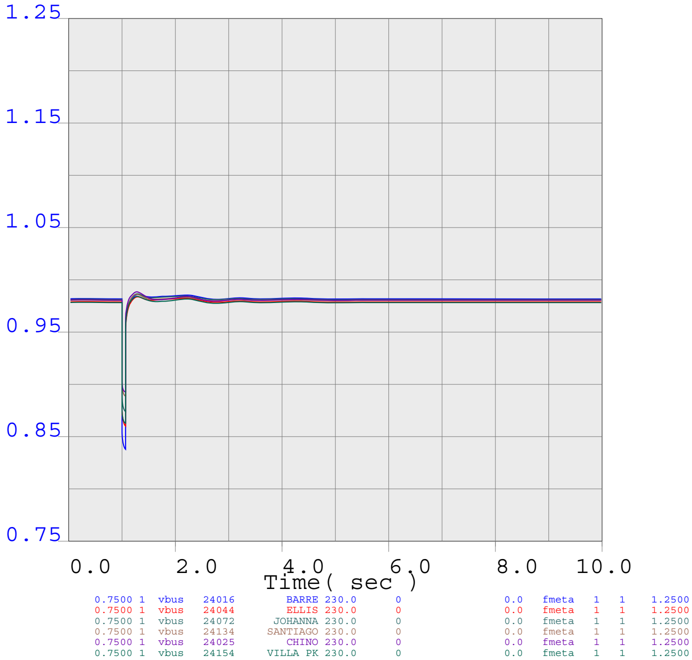
C:\DYTOOLS

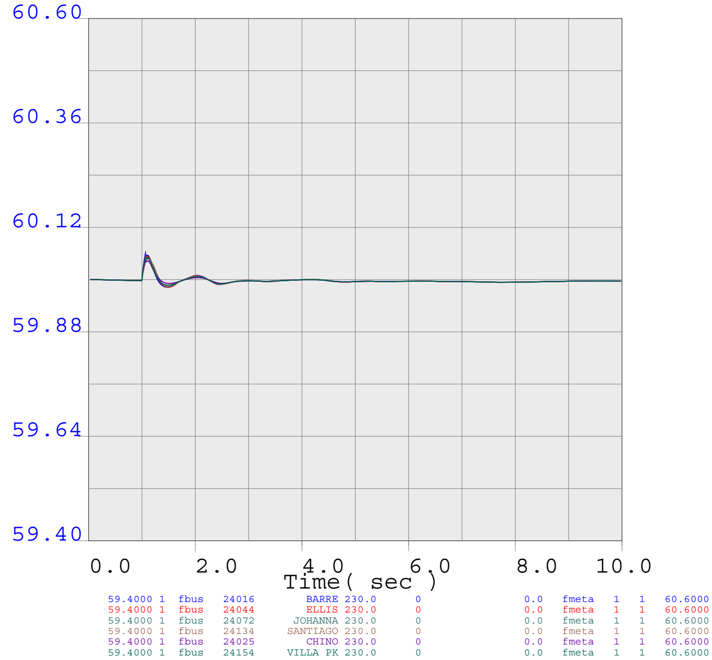
Thu Oct 20 08:56:09 2016

METRO









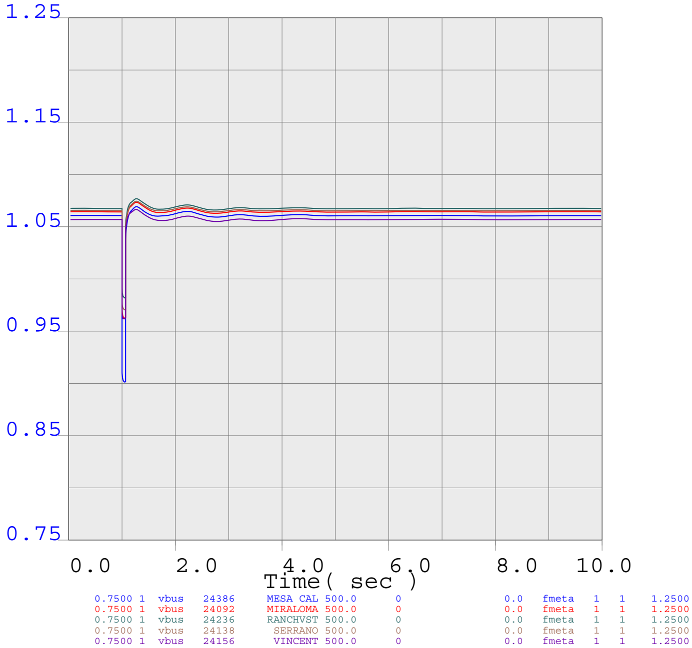
bay_2328
EL NIDO 220 KV POS 8N
1 MW dispatch Case

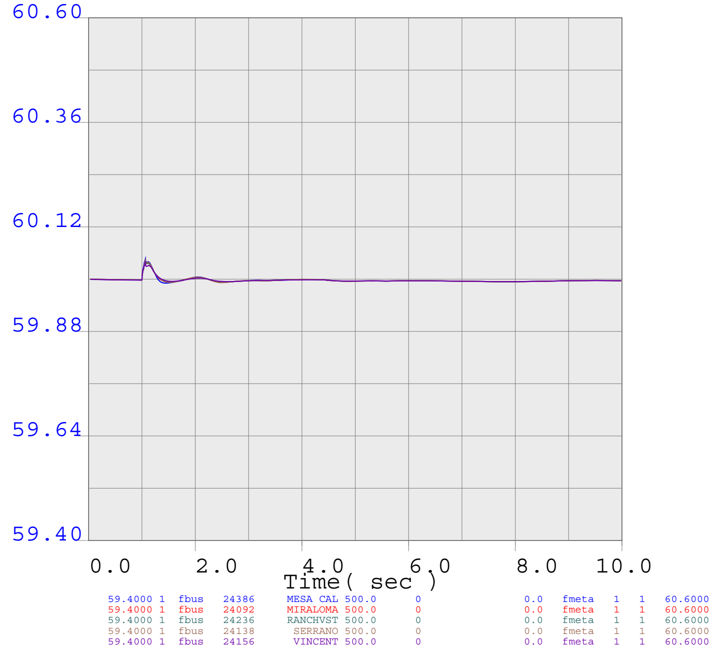
qc9p-bay_2328.chf

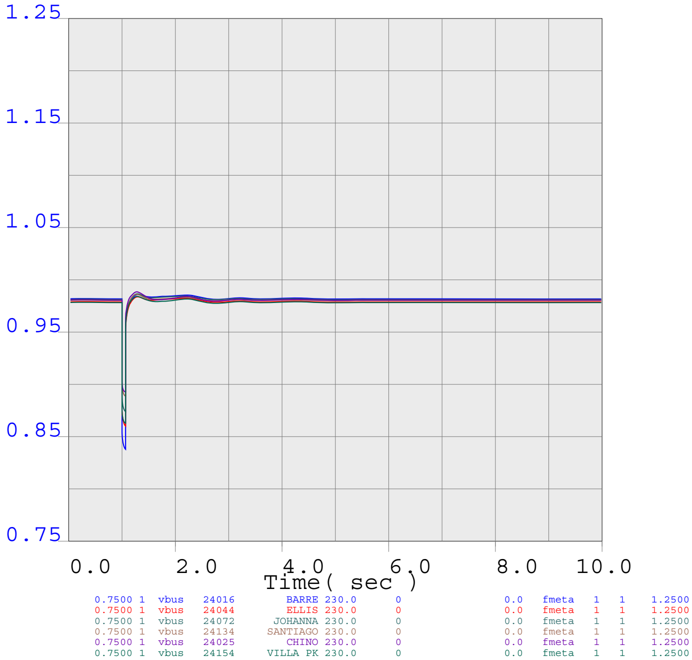
C:\DYTOOLS

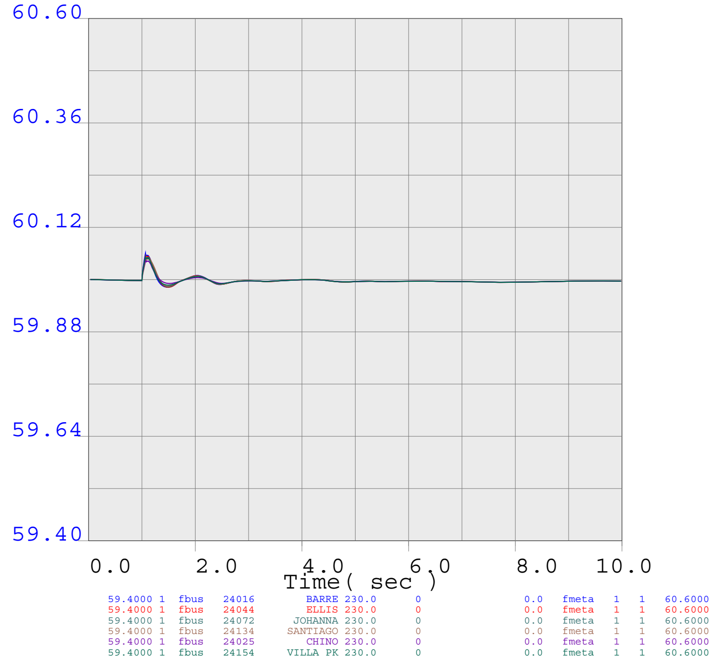
Thu Oct 20 08:56:12 2016

METRO









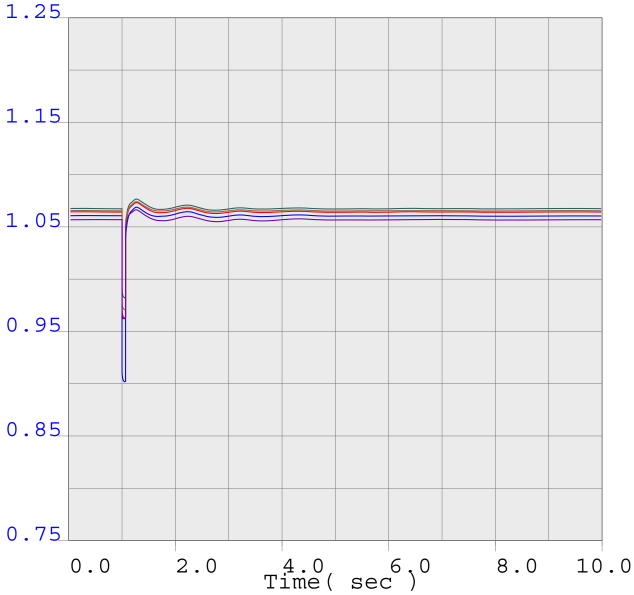
bay_2329
EL NIDO 220 KV POS 9N
1 MW dispatch Case

qc9p-bay_2329.chf

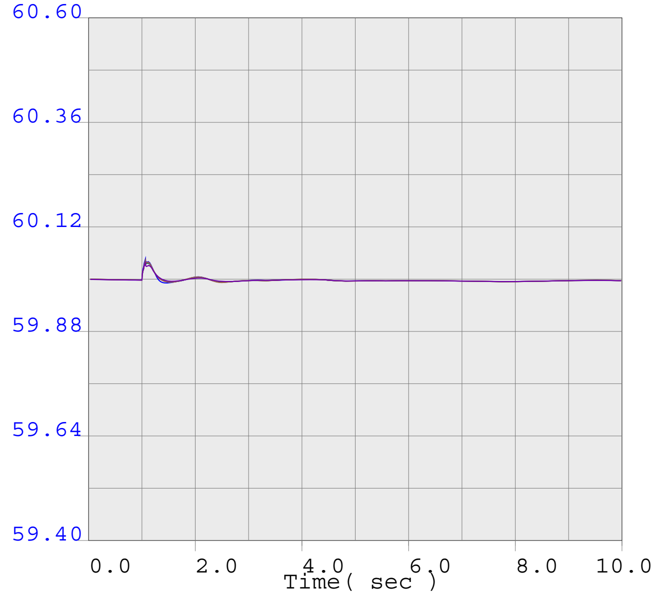
C:\DYTOOLS

Thu Oct 20 08:56:14 2016

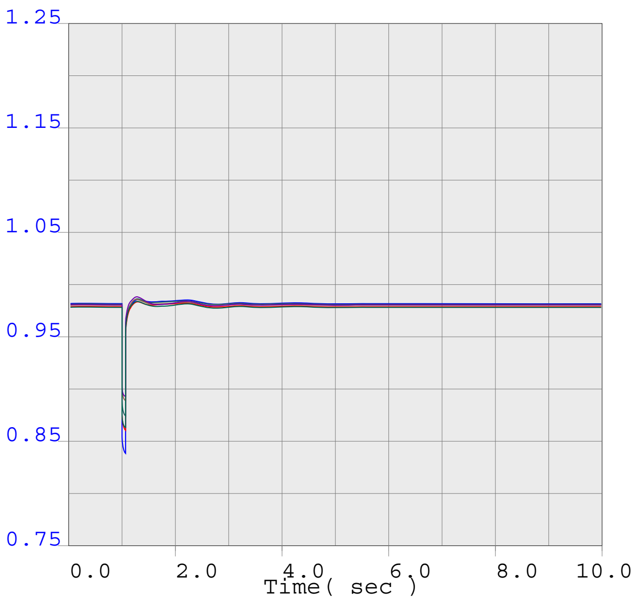
METRO



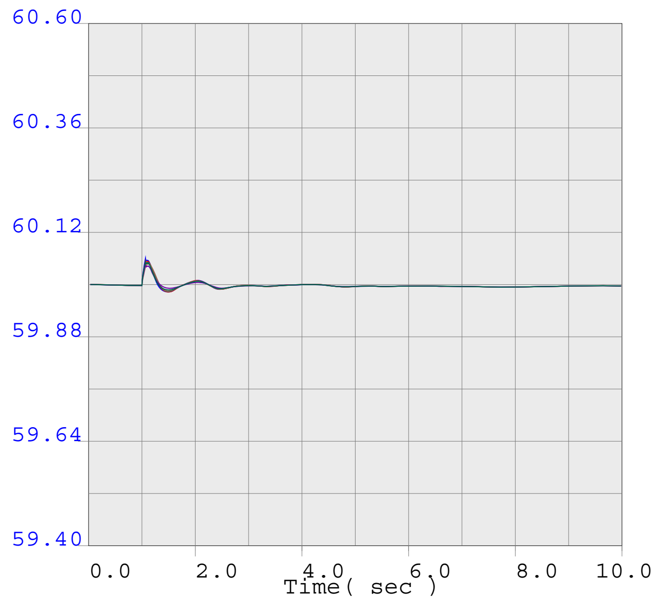
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

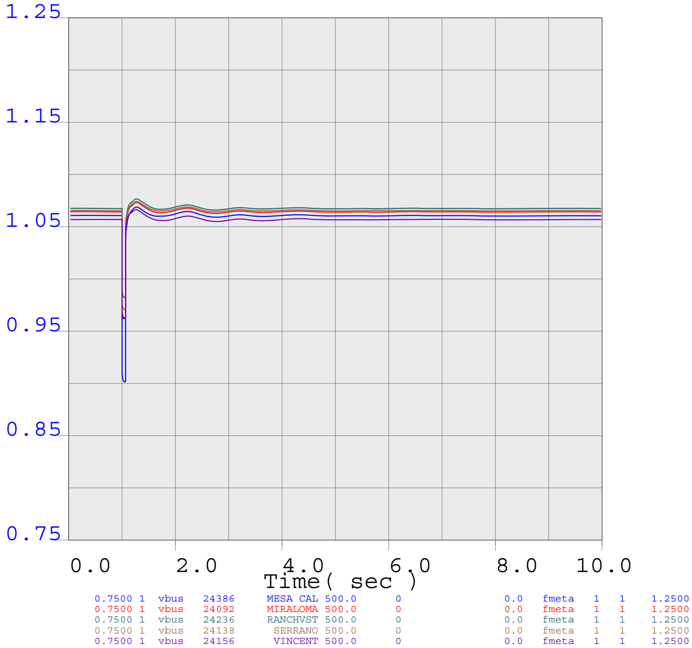
bay_2330
EL NIDO 230.00 POS 1XS
1 MW dispatch Case

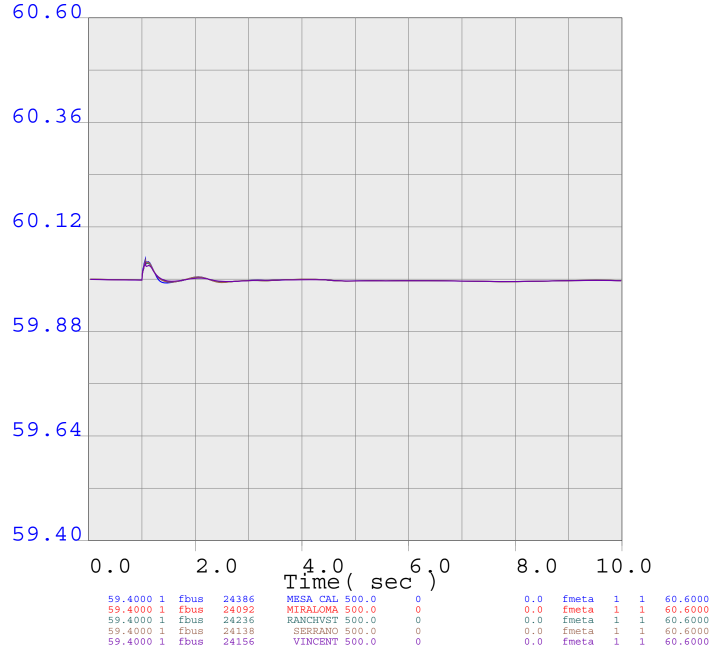
qc9p-bay_2330.chf

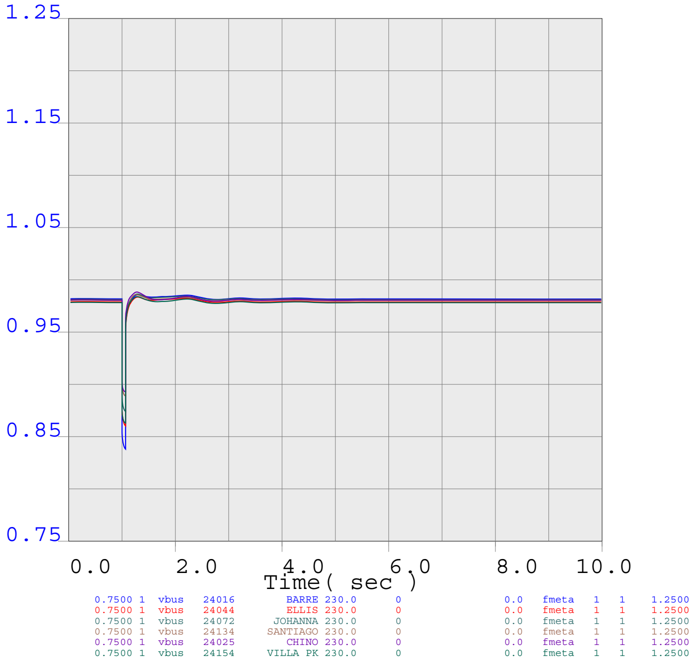
C:\DYTOOLS

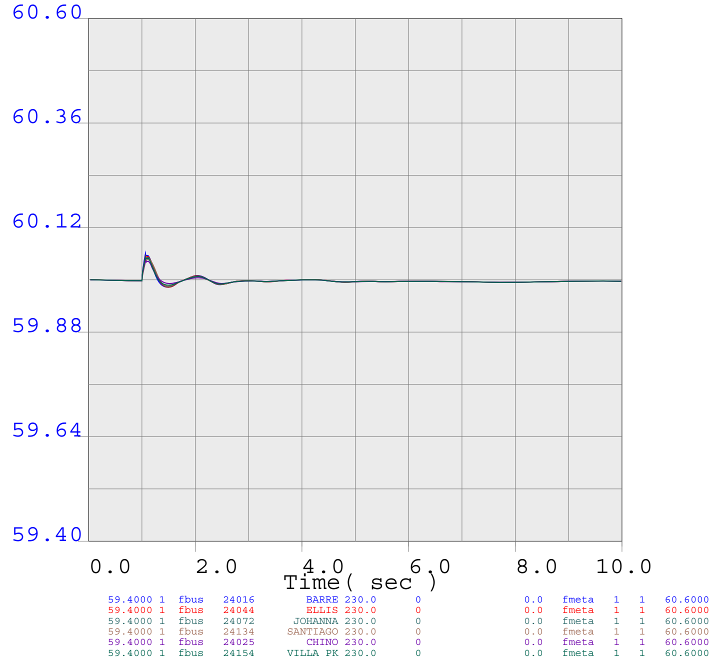
Thu Oct 20 08:56:17 2016

METRO









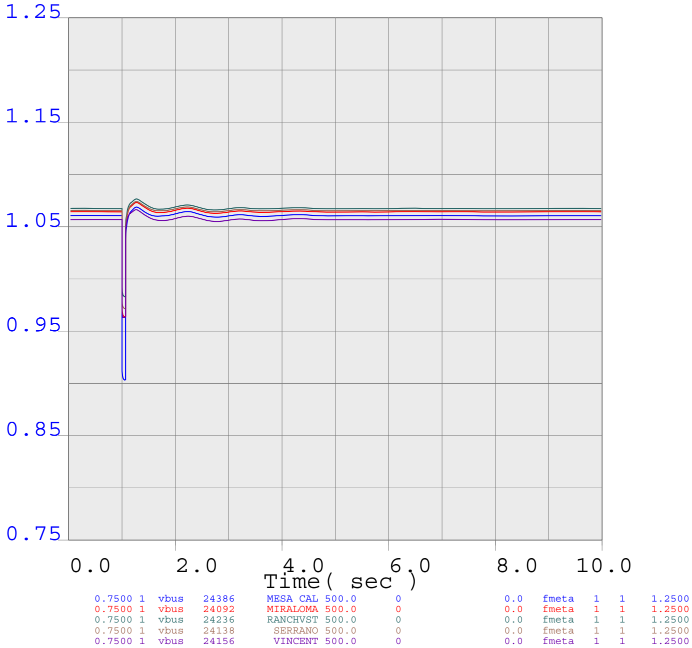
bay_2331
EL NIDO 230.00 POS 1S
1 MW dispatch Case

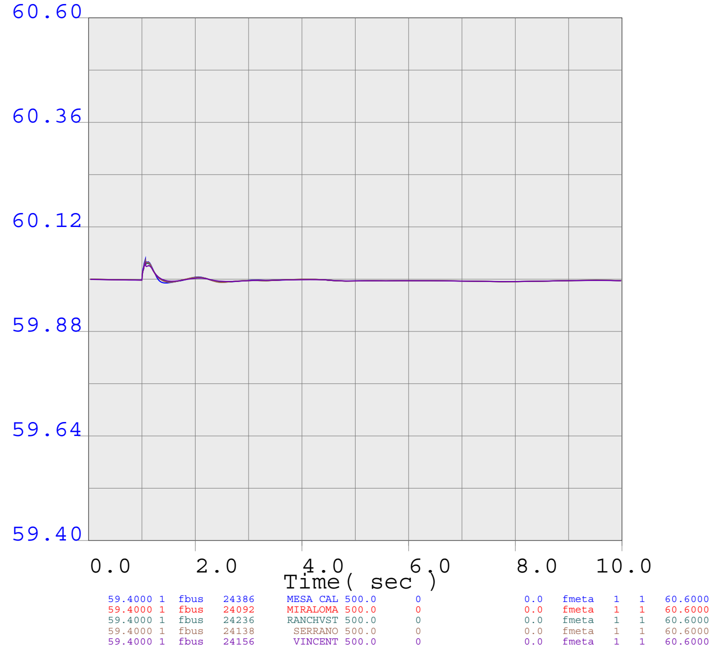
qc9p-bay_2331.chf

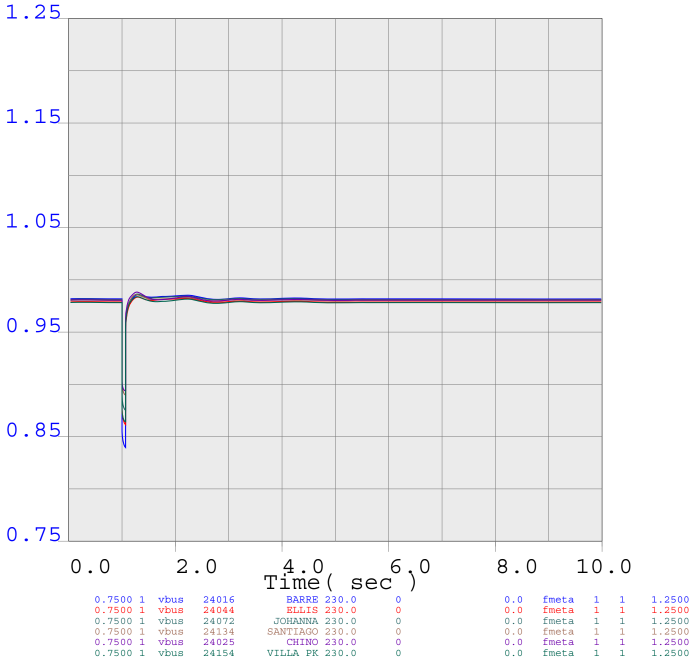
C:\DYTOOLS

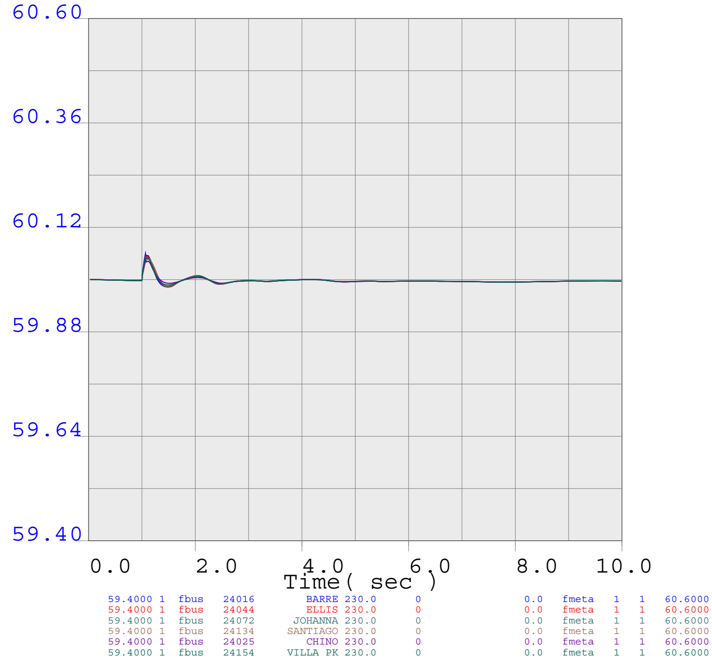
Thu Oct 20 08:56:19 2016

METRO









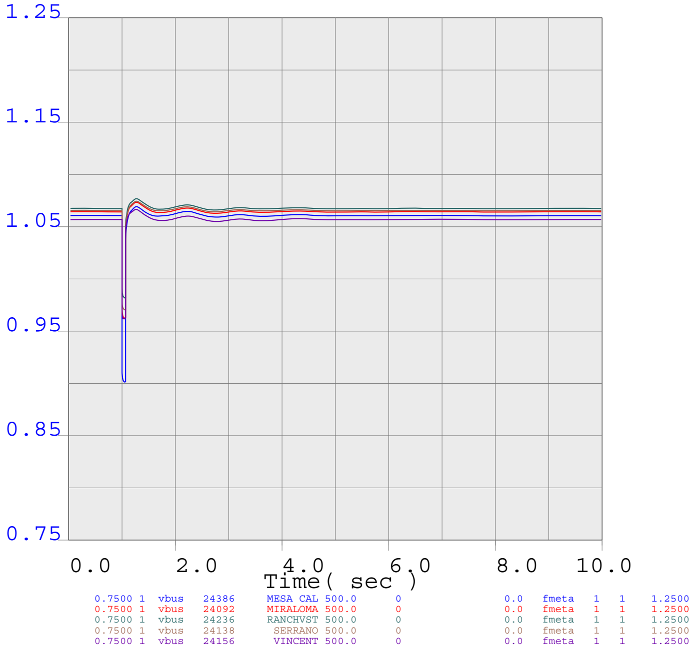
bay_2332
EL NIDO 230.00 POS 2S
1 MW dispatch Case

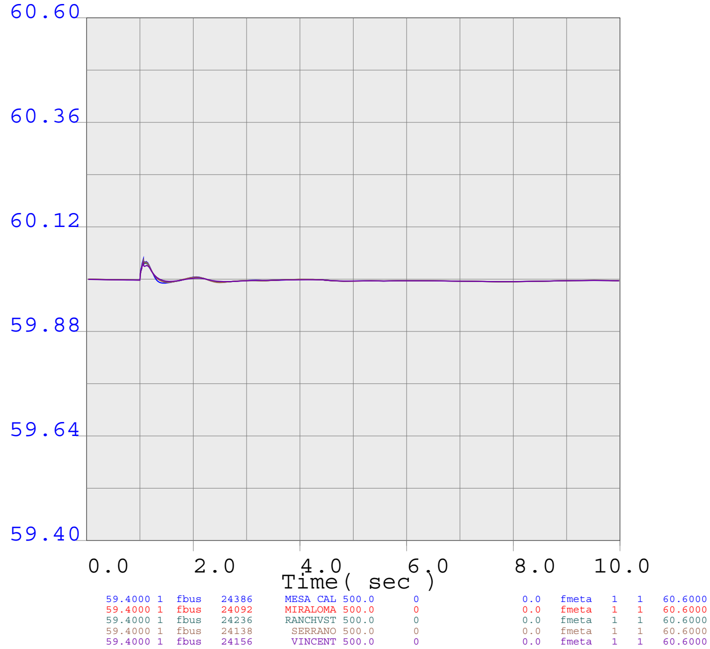
qc9p-bay_2332.chf

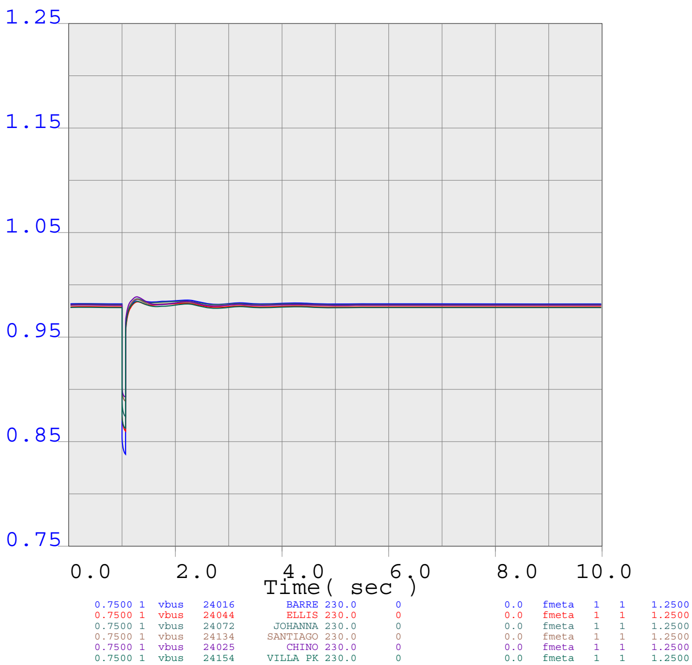
C:\DYTOOLS

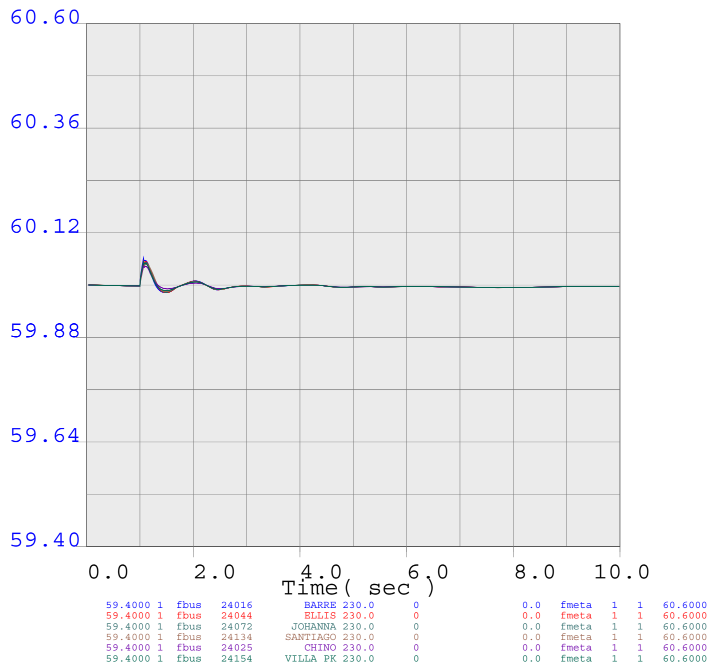
Thu Oct 20 08:56:21 2016

METRO





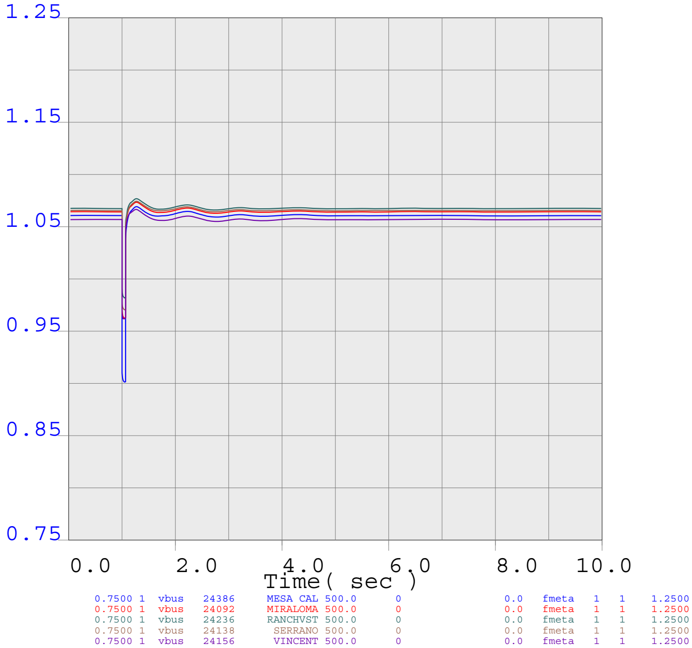


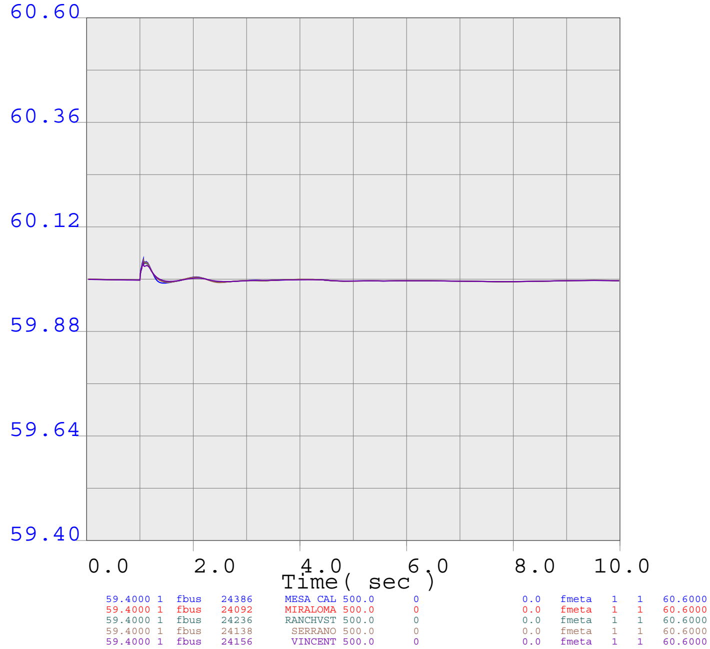


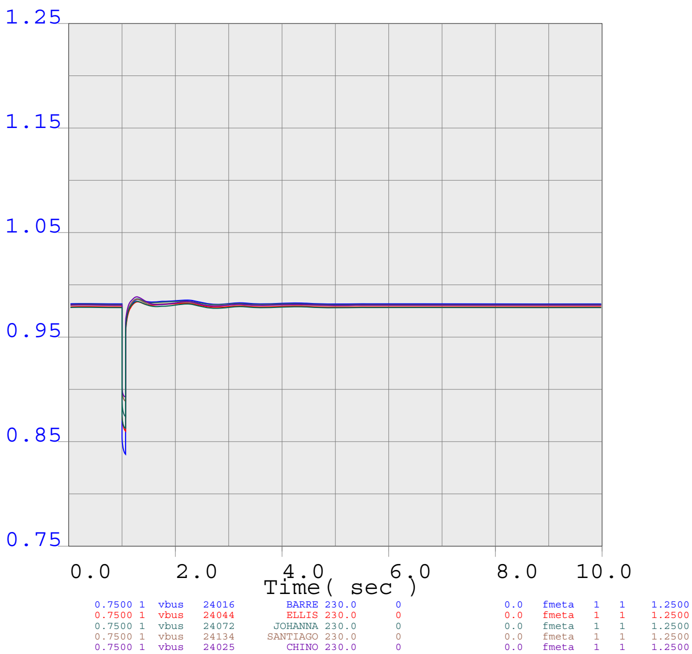
bay_2333
EL NIDO 220 KV POS 8S
1 MW dispatch Case

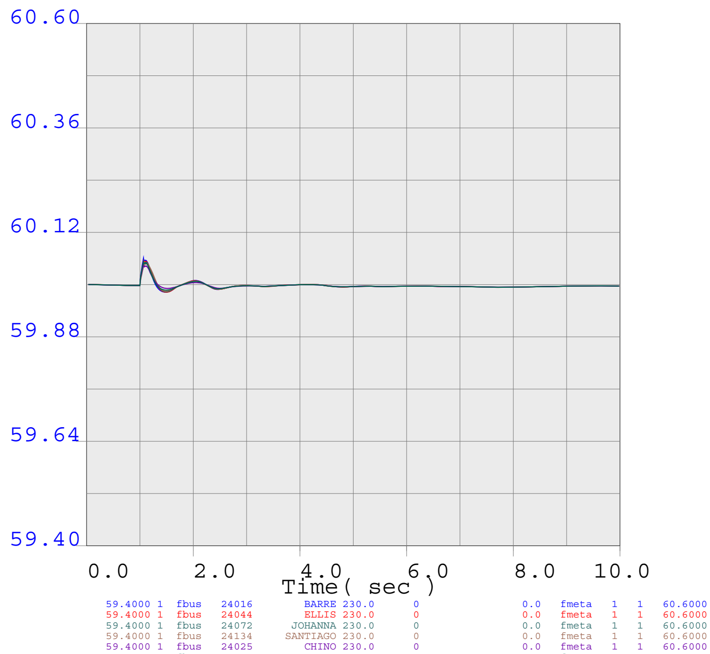
	qc9p-bay_2333.chf	C:\DYTOOLS Thu Oct 20 08:56:25 2016

METRO









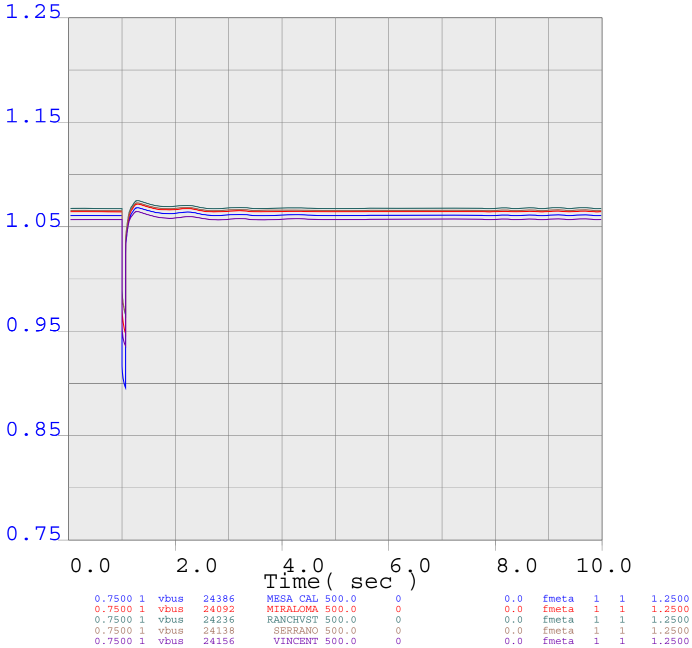
bay_2334
EL NIDO 220 KV POS 8S
1 MW dispatch Case

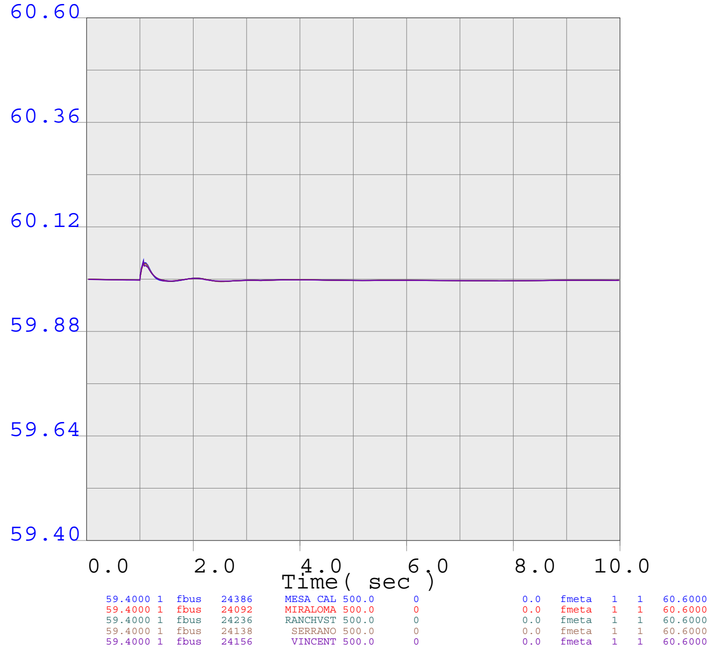
qc9p-bay_2334.chf

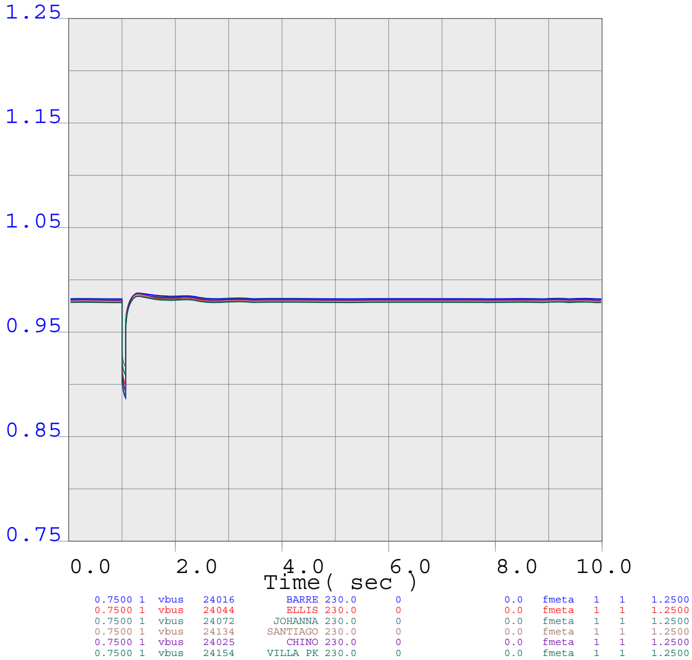
C:\DYTOOLS

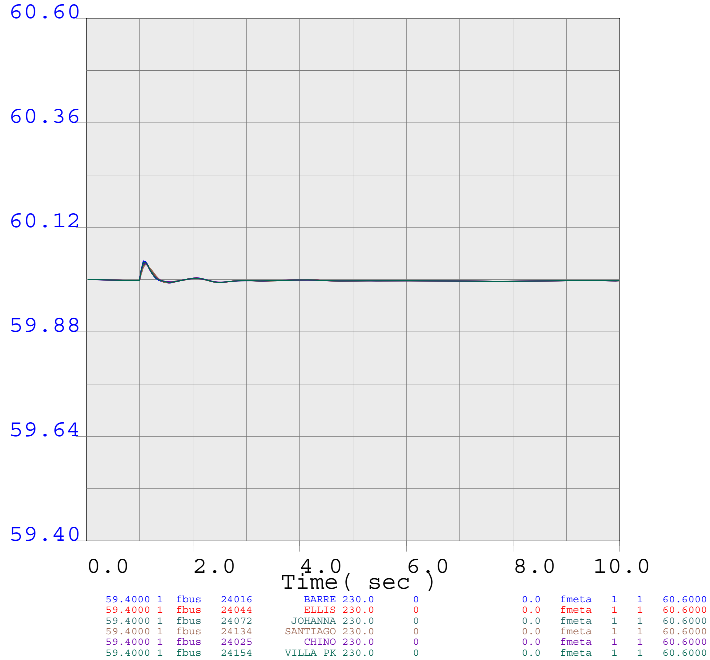
Thu Oct 20 08:56:27 2016

METRO









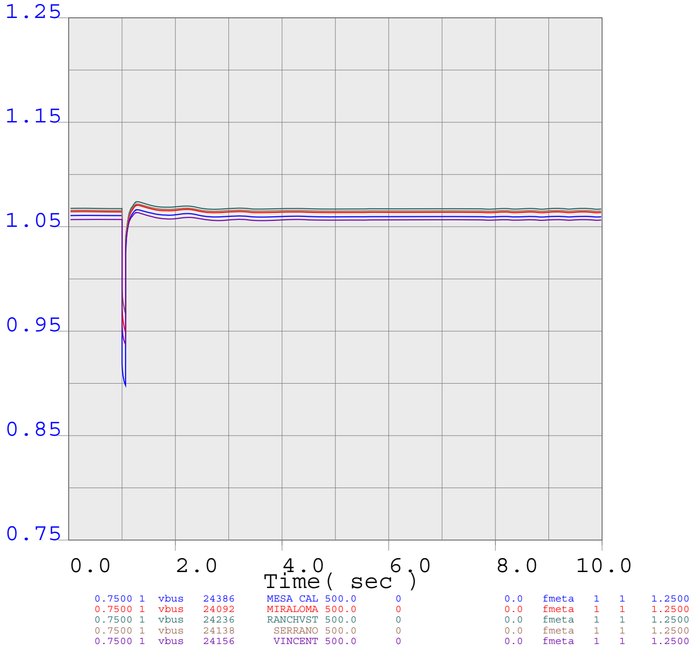
bay_2335
GOULD 220 KV POS 1W
1 MW dispatch Case

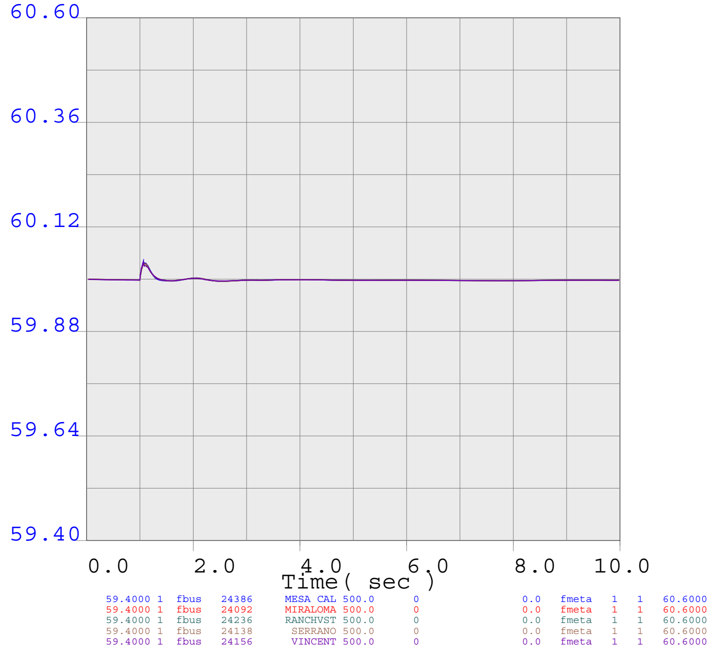
qc9p-bay_2335.chf

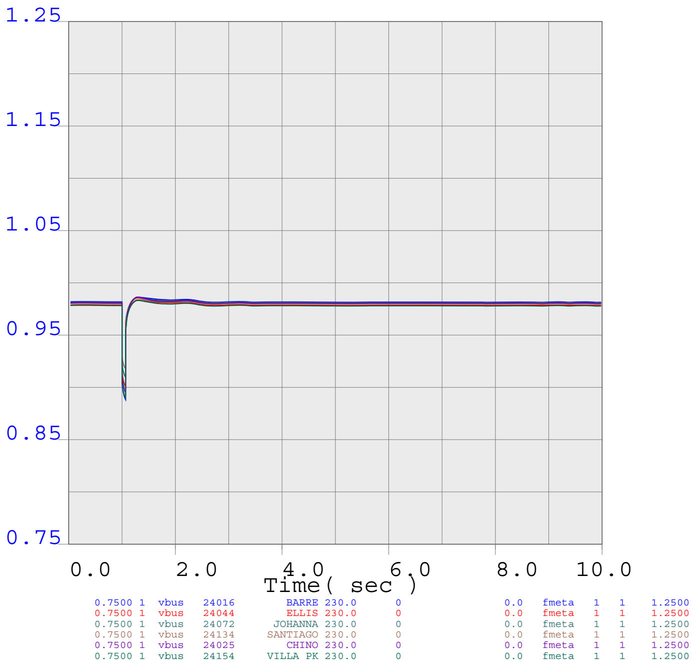
C:\DYTOOLS

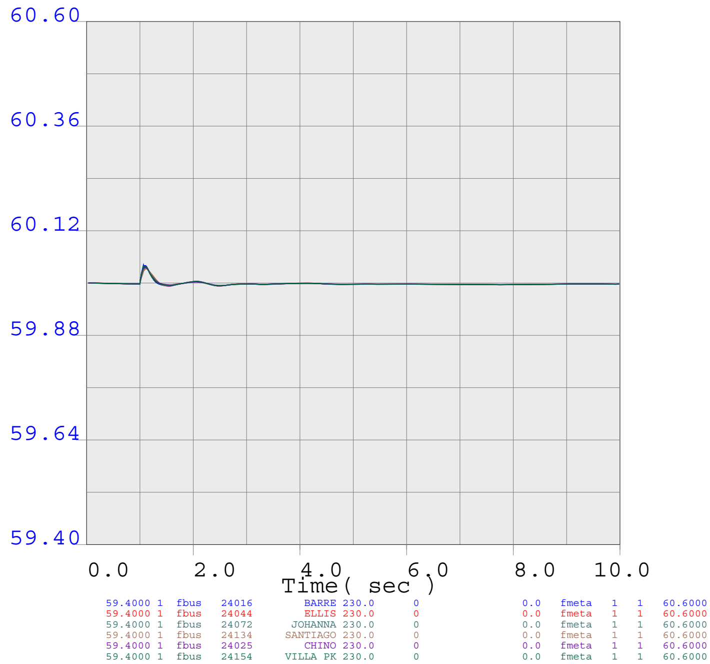
Thu Oct 20 08:56:31 2016

METRO









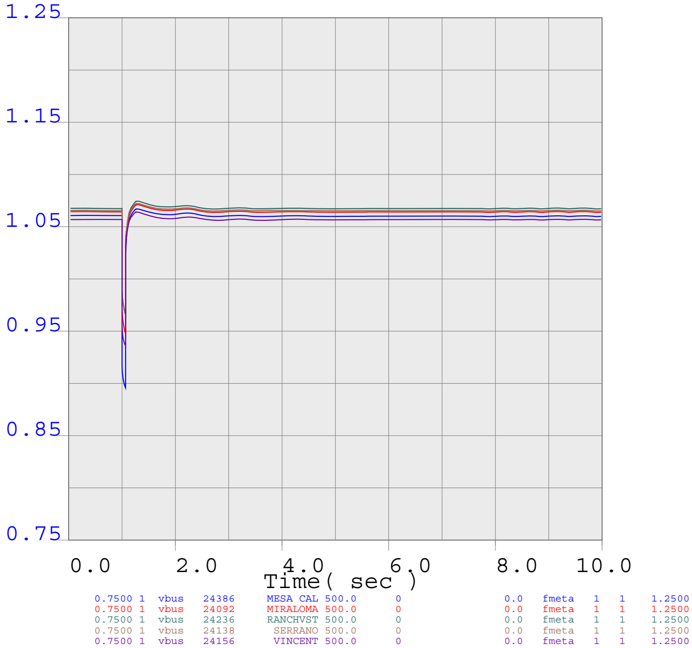
bay_2336
GOULD 220 KV POS 2W
1 MW dispatch Case

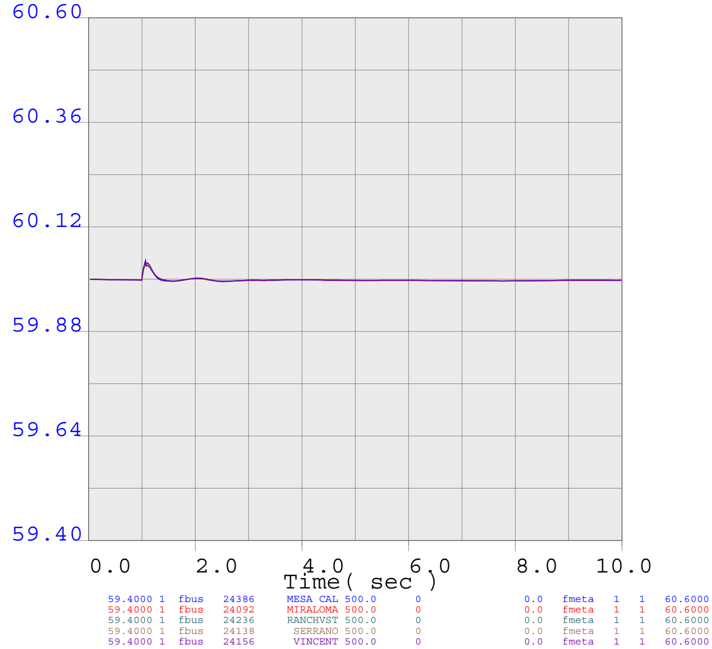
qc9p-bay_2336.chf

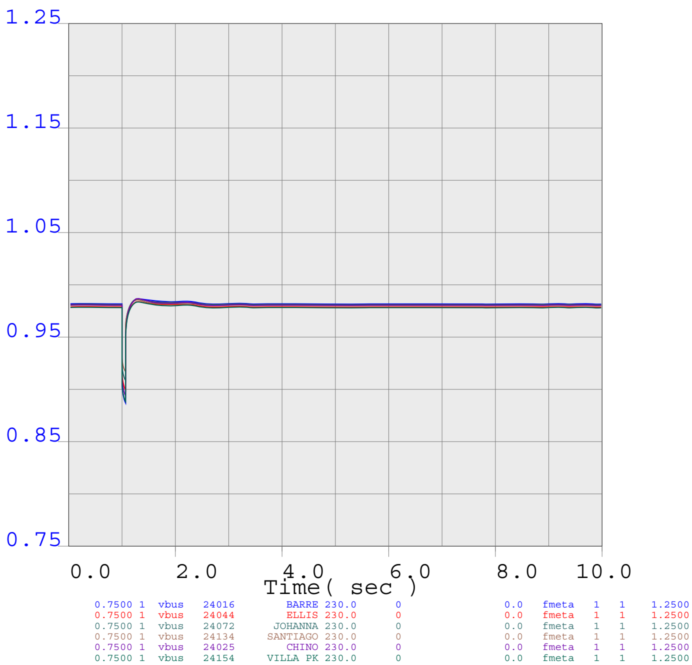
C:\DYTOOLS

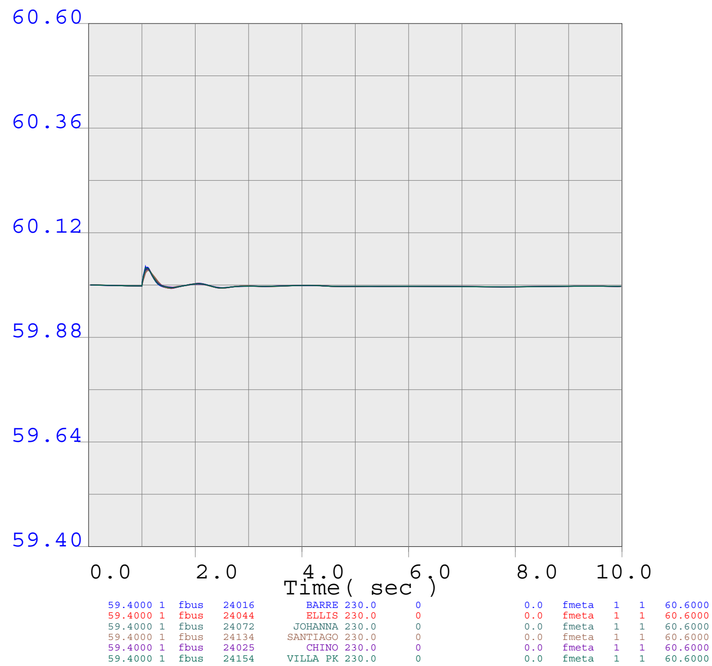
Thu Oct 20 08:56:34 2016

METRO









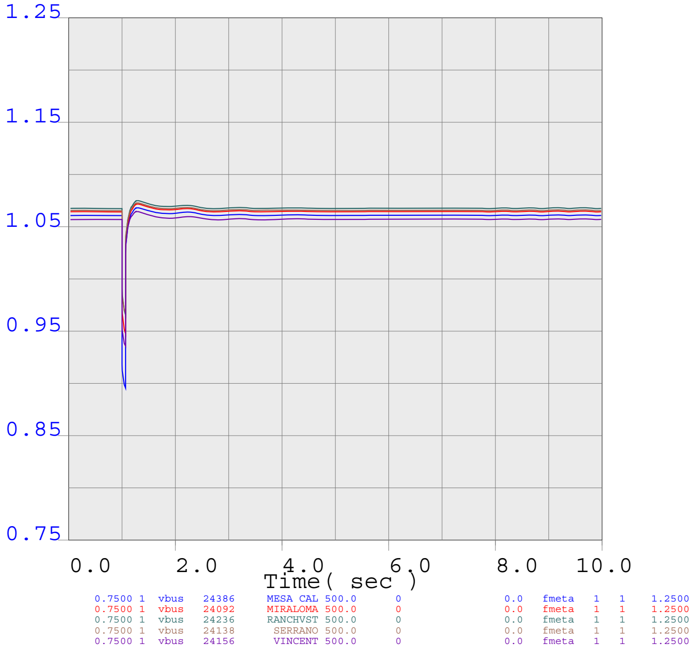
bay_2338
GOULD 220 KV POS 4W
1 MW dispatch Case

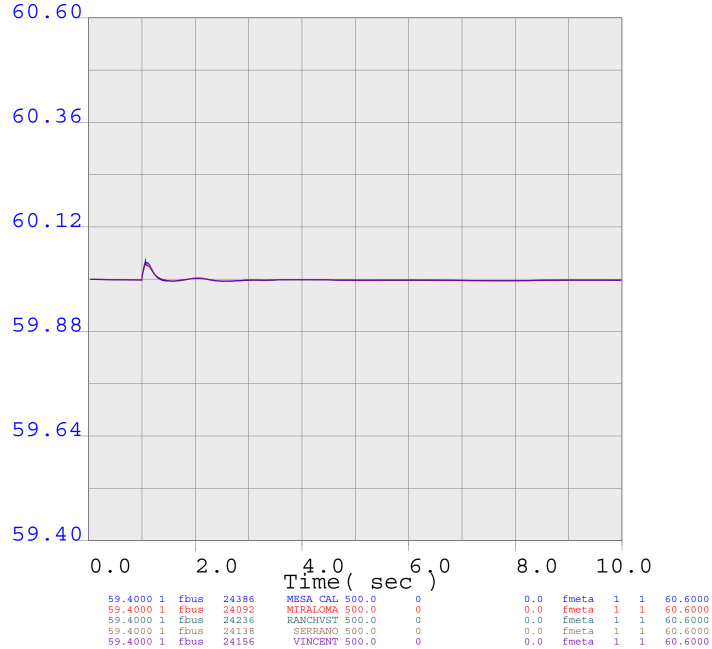
qc9p-bay_2338.chf

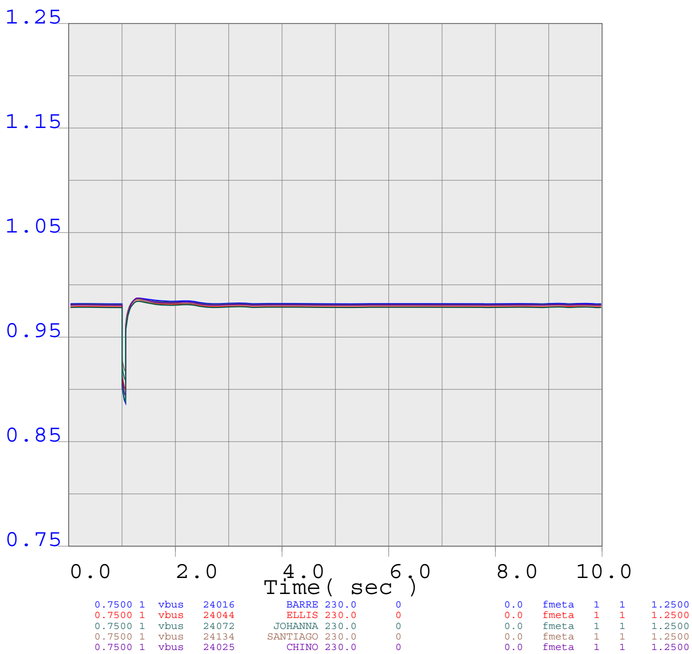
C:\DYTOOLS

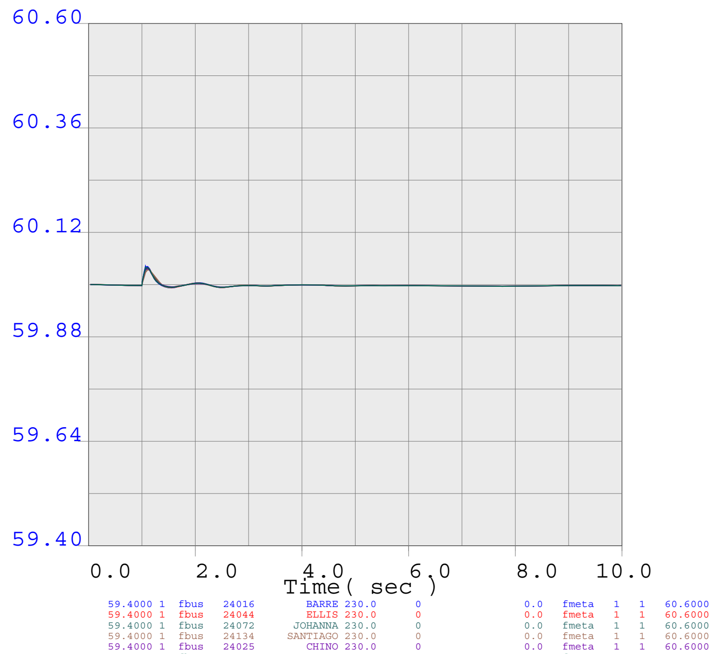
Thu Oct 20 08:56:37 2016

METRO









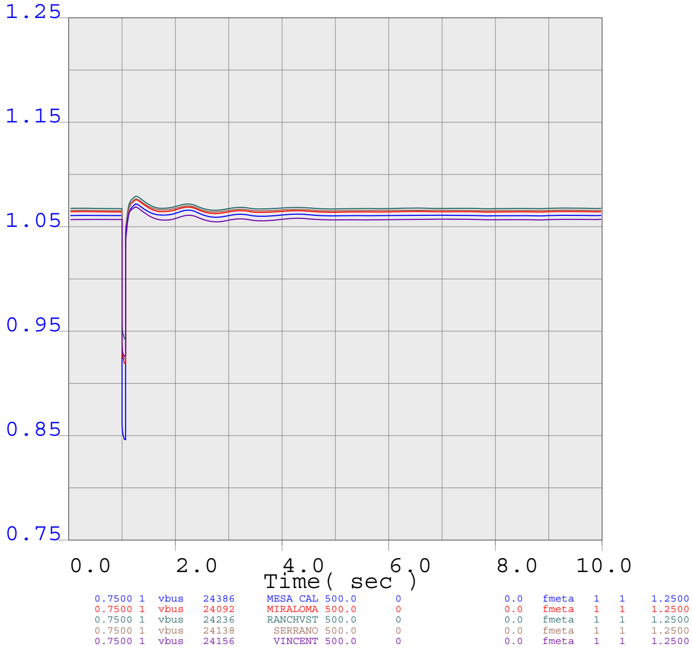
bay_2339
GOULD 220 KV POS 6W
1 MW dispatch Case

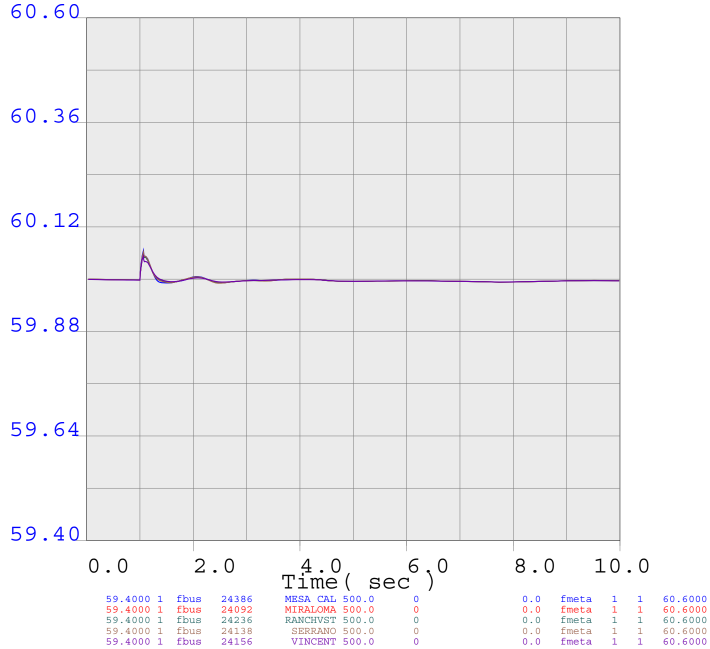
qc9p-bay_2339.chf

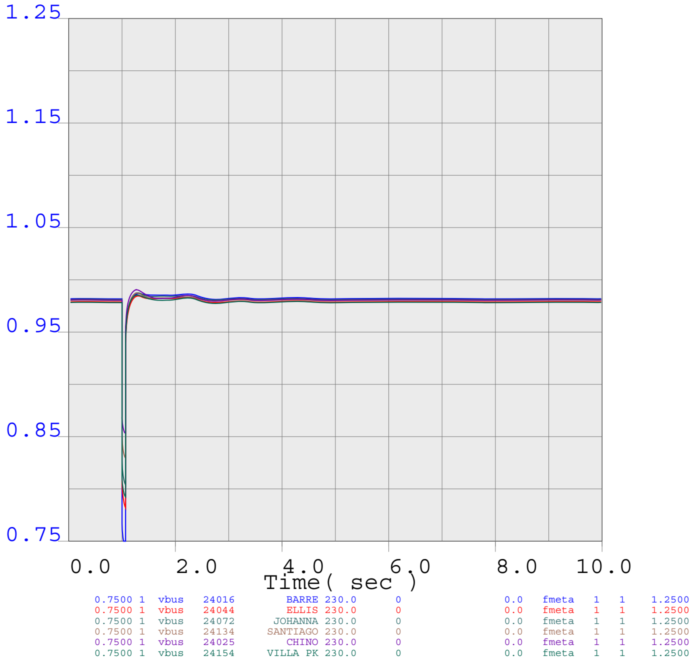
C:\DYTOOLS

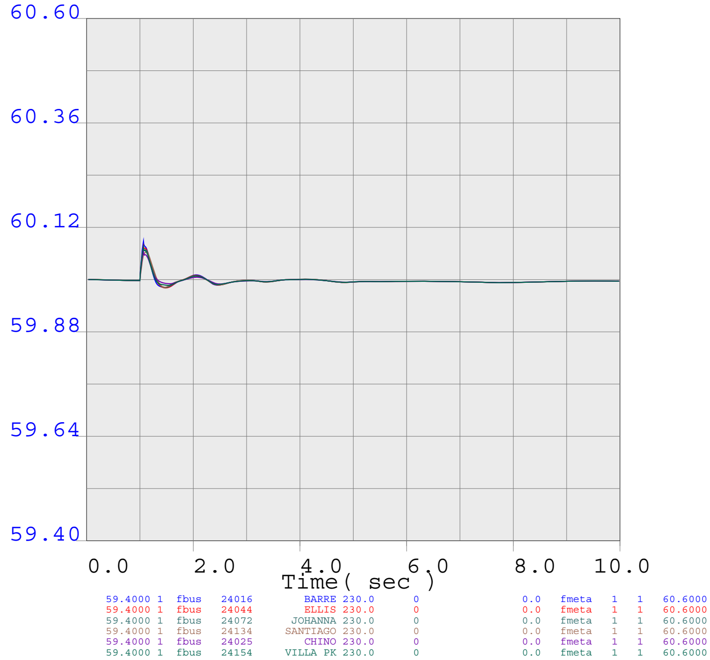
Thu Oct 20 08:56:40 2016

METRO









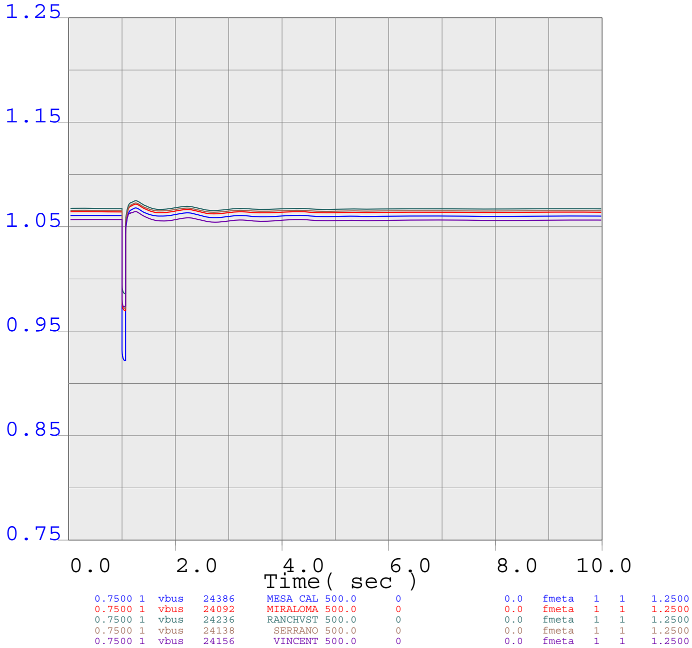
bay_2340
HINSON 220 KV POS 1 INTERNAL FAULT
1 MW dispatch Case

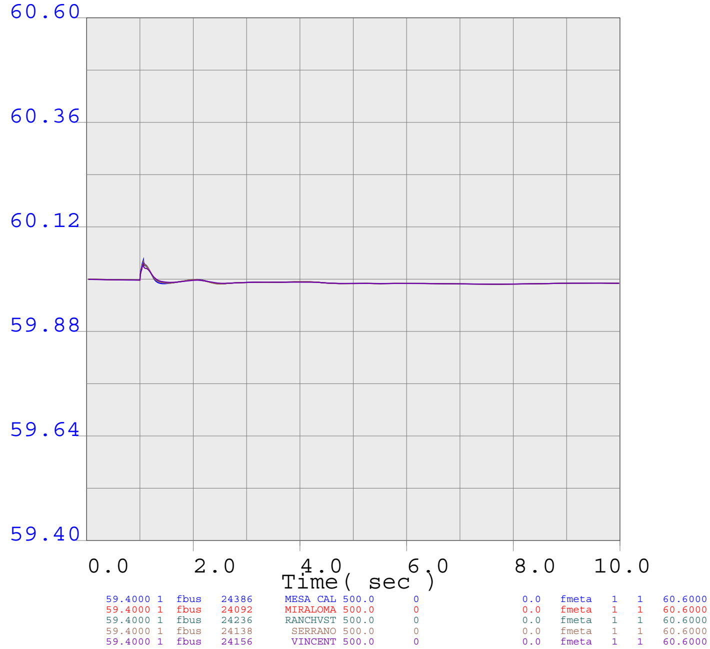
qc9p-bay_2340.chf

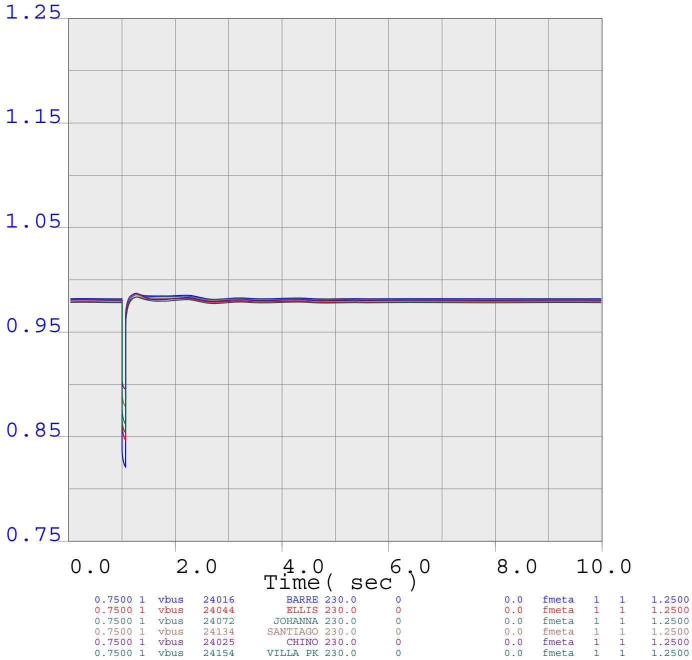
C:\DYTOOLS

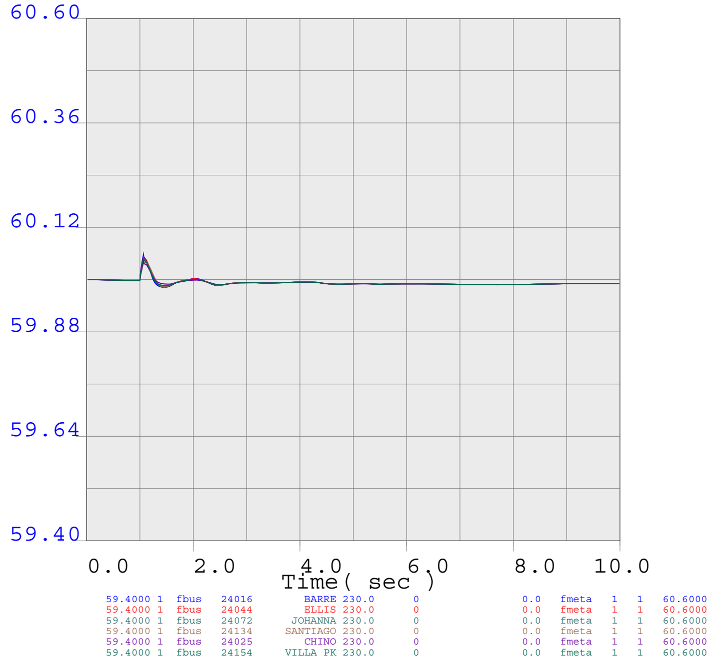
Thu Oct 20 08:56:45 2016

METRO









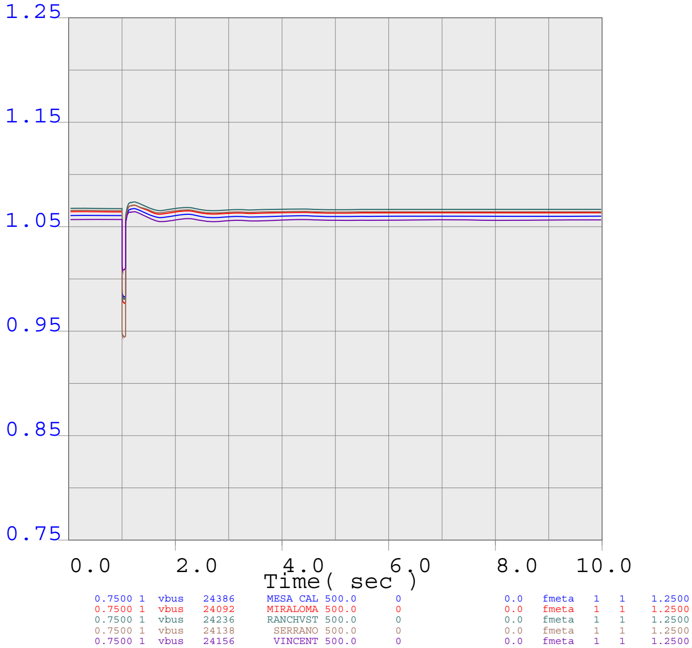
bay_2341
HARBORGEN INTERNAL FAULT
1 MW dispatch Case

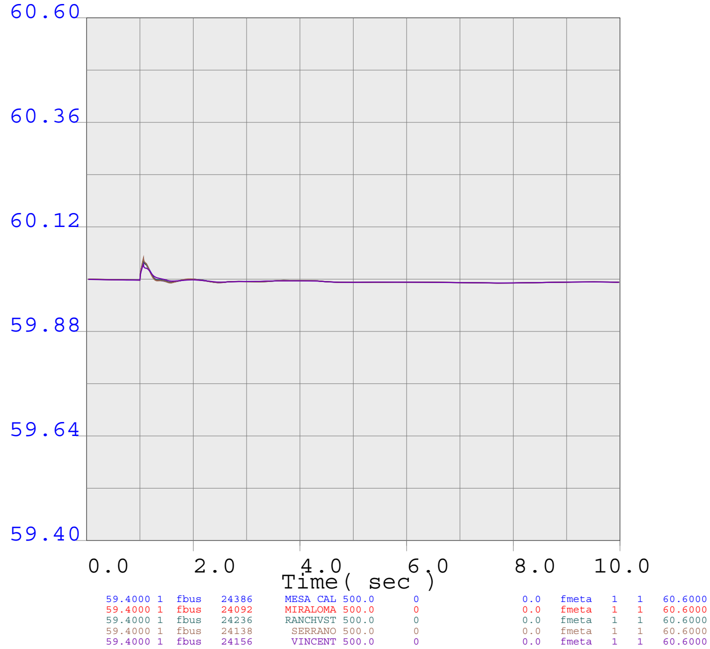
qc9p-bay_2341.chf

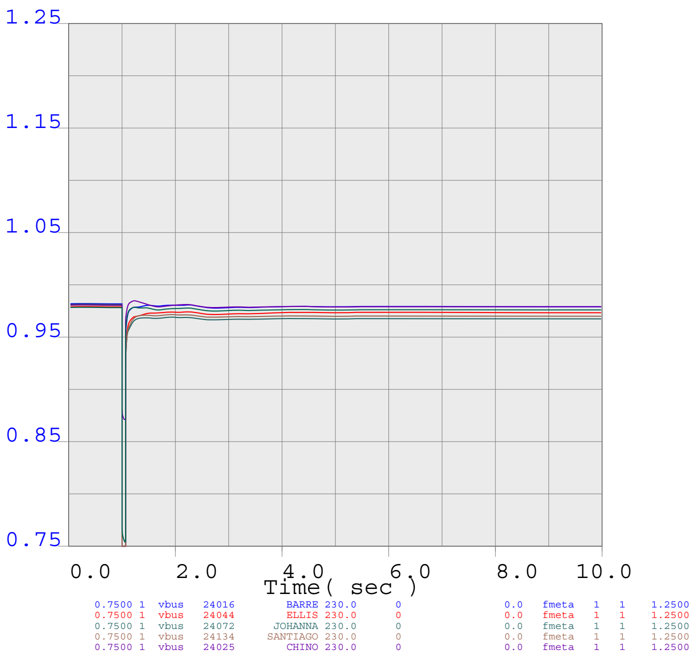
C:\DYTOOLS

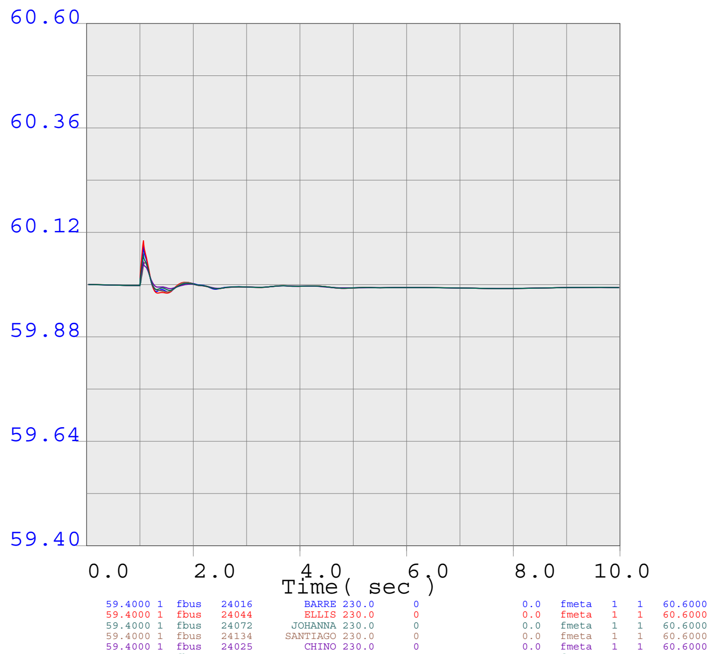
Thu Oct 20 08:56:53 2016

METRO









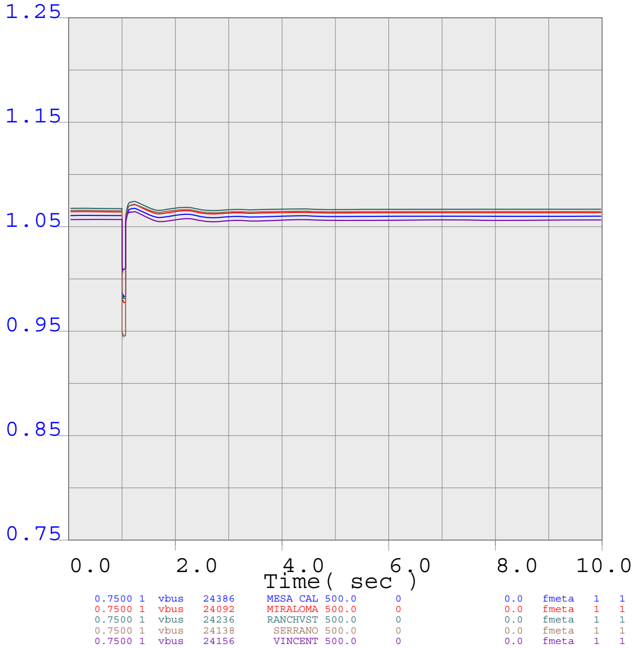
bay_2342
JOHANNA 220 KV POS 1N
1 MW dispatch Case

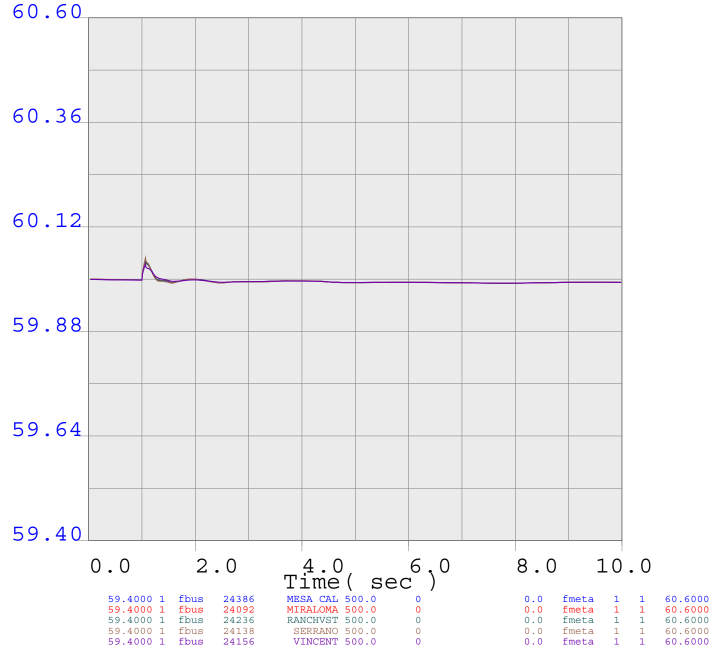
qc9p-bay_2342.chf

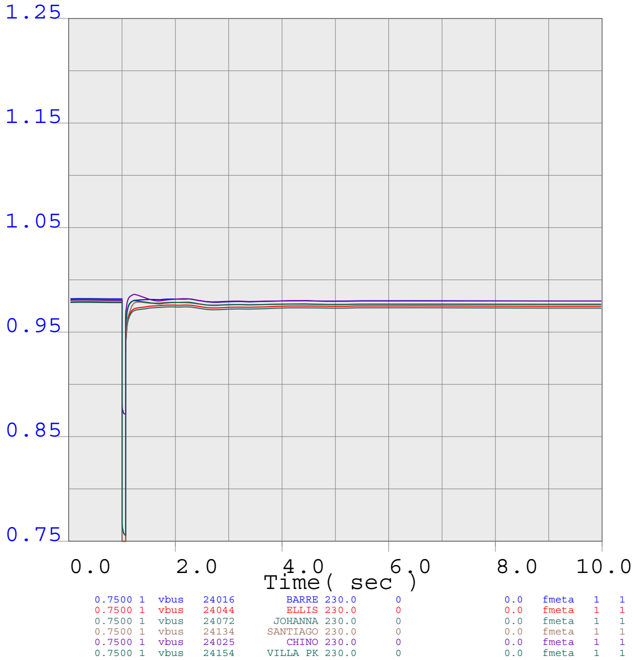
C:\DYTOOLS

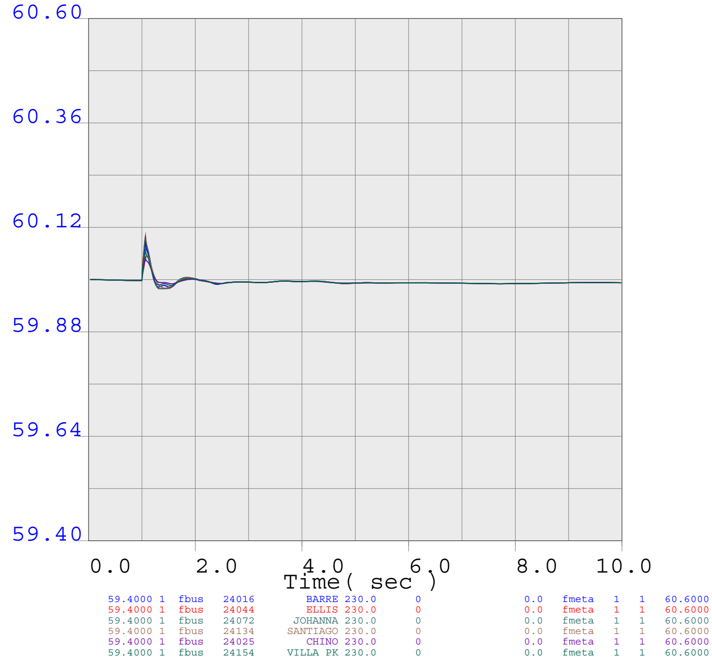
Thu Oct 20 08:57:03 2016

METRO









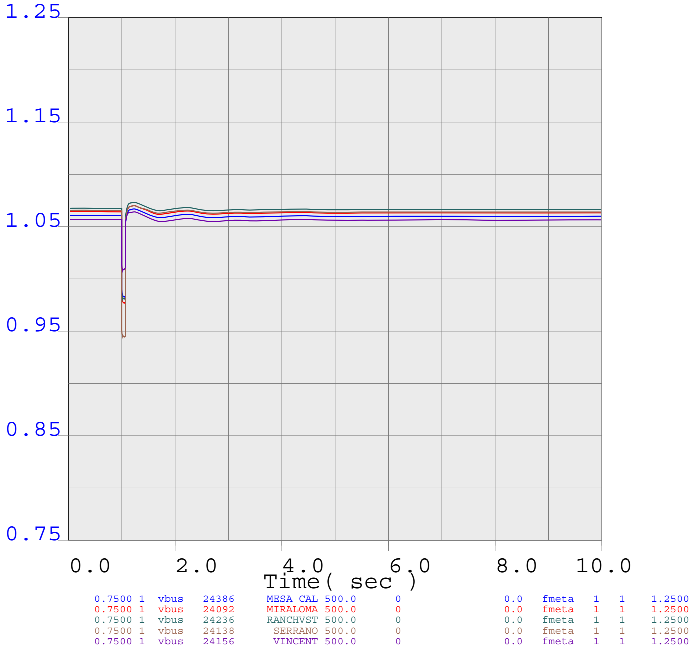
bay_2343
JOHANNA 220 KV POS 2N
1 MW dispatch Case

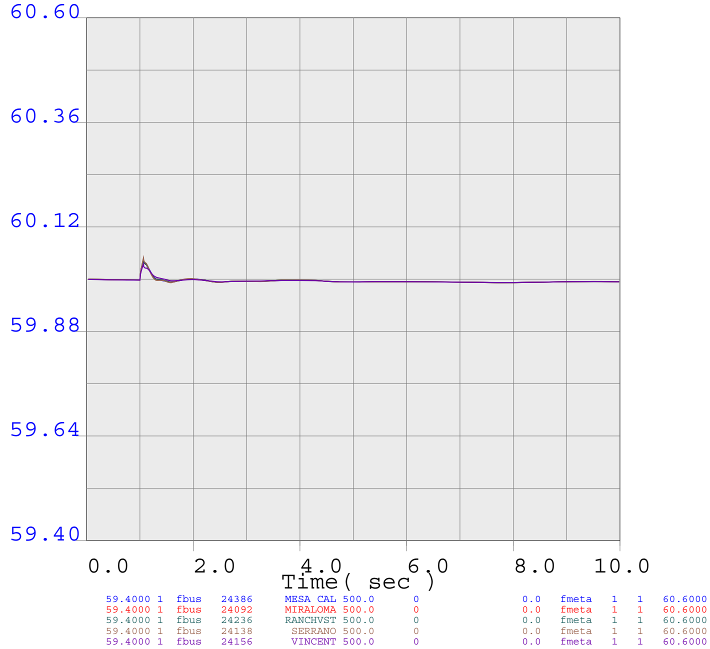
qc9p-bay_2343.chf

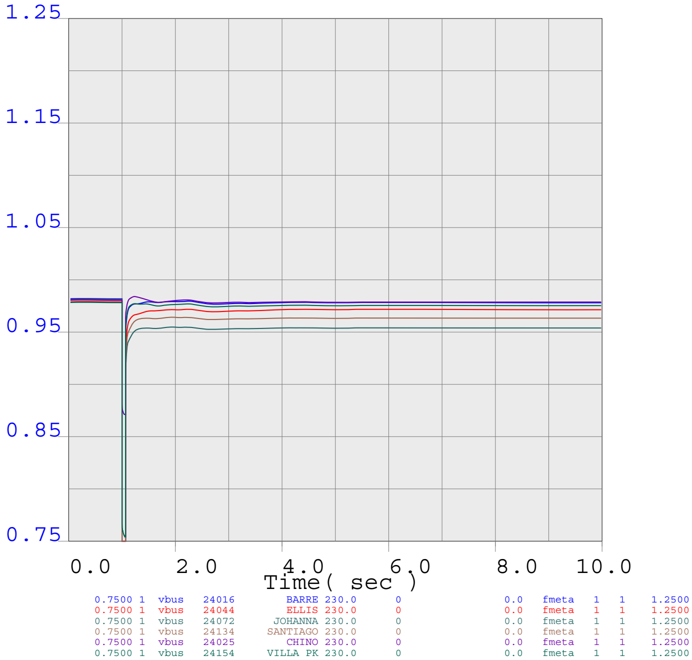
C:\DYTOOLS

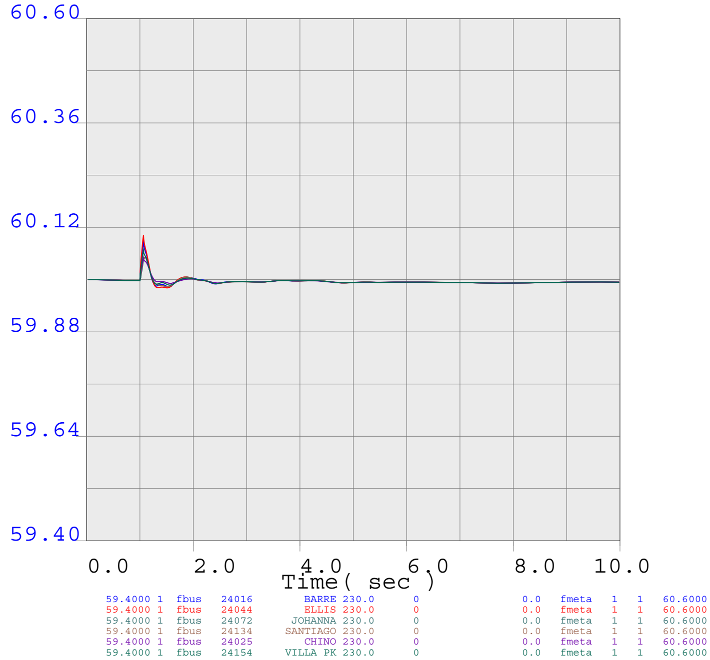
Thu Oct 20 08:57:13 2016

METRO









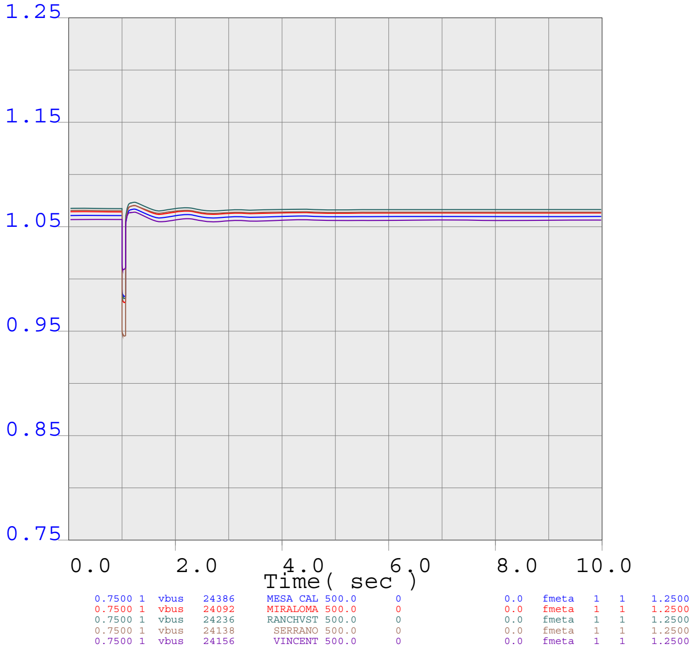
bay_2344
JOHANNA 220 KV POS 1S
1 MW dispatch Case

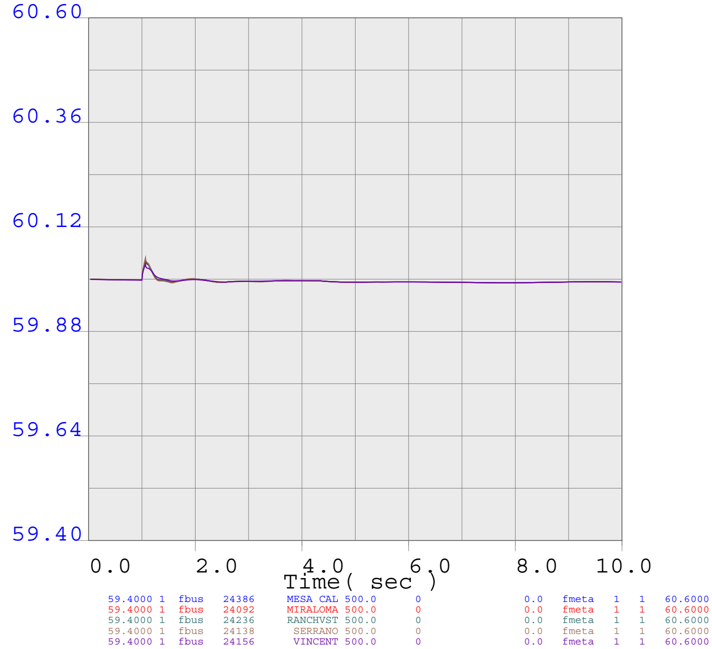
qc9p-bay_2344.chf

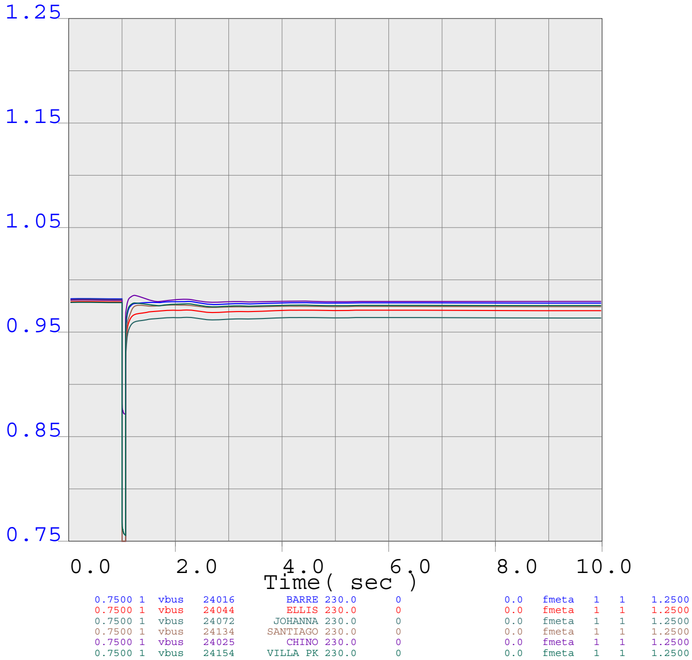
C:\DYTOOLS

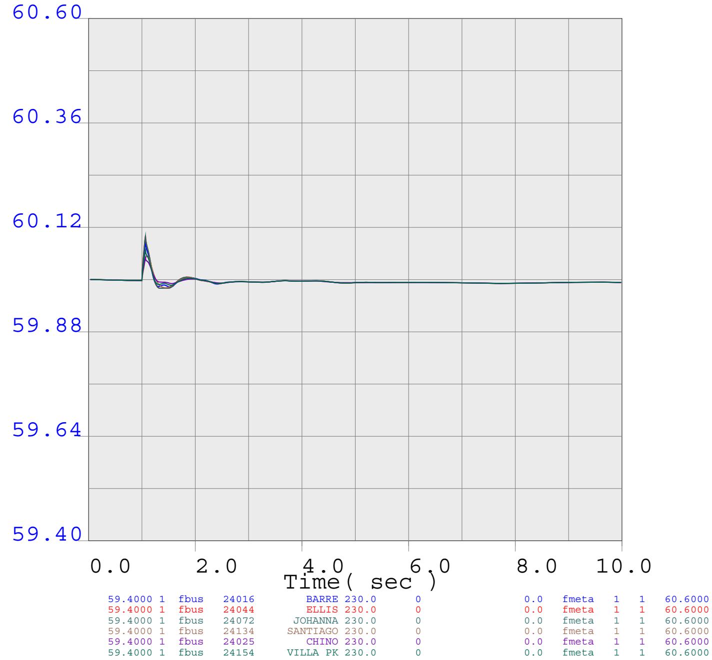
Thu Oct 20 08:57:16 2016

METRO









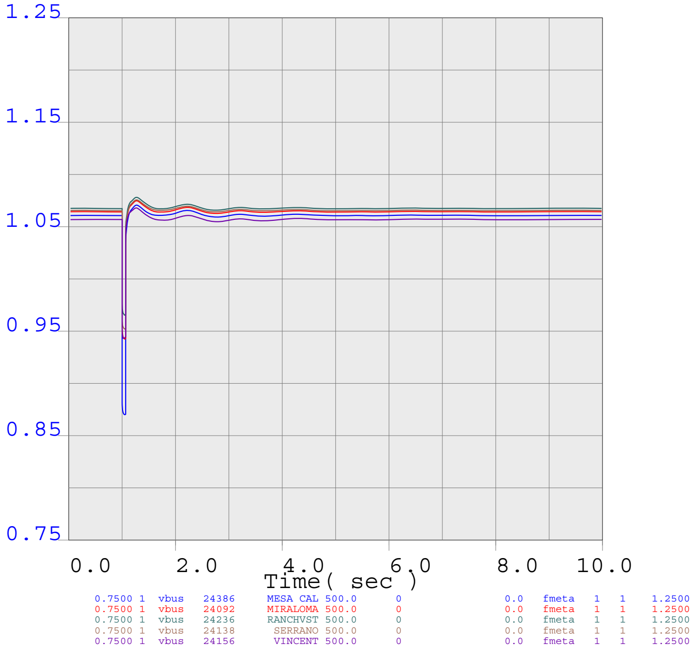
bay_2345
JOHANNA 220 KV POS 2N
1 MW dispatch Case

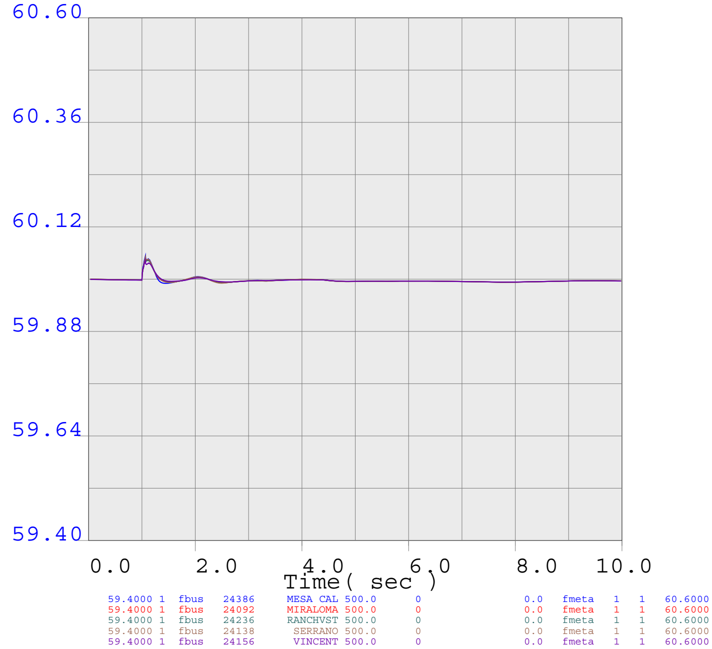
qc9p-bay_2345.chf

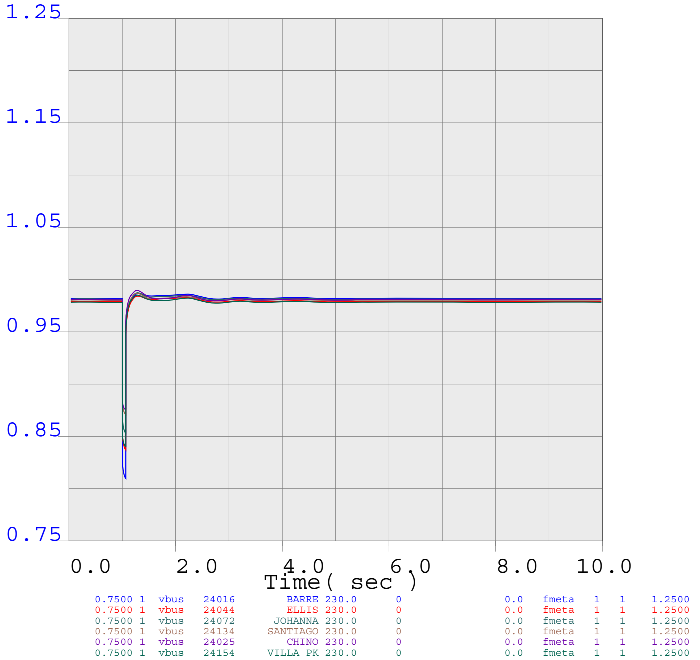
C:\DYTOOLS

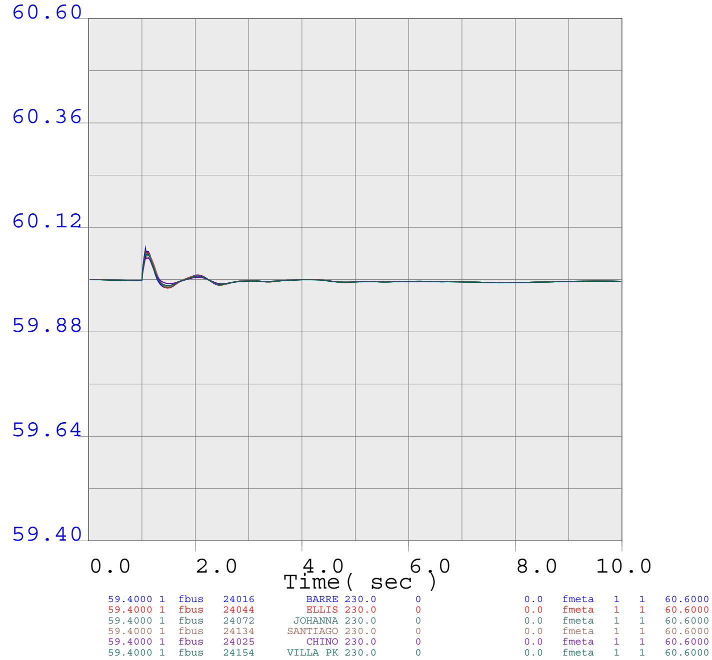
Thu Oct 20 08:57:19 2016

METRO









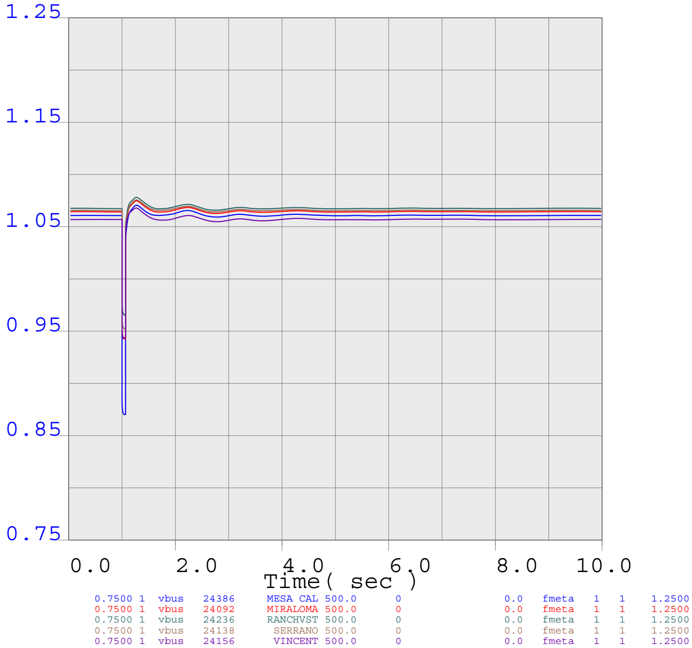
bay_2346
LA FRESA 220 KV POS 3XN
1 MW dispatch Case

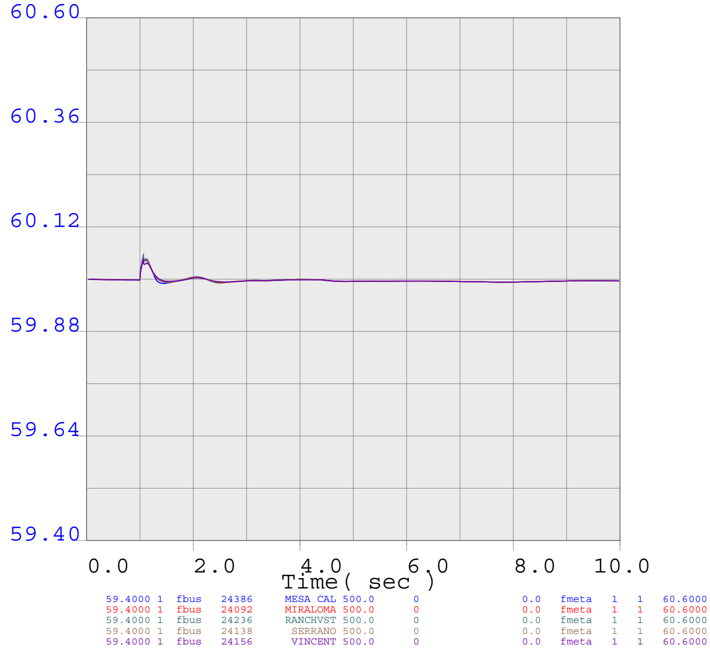
qc9p-bay_2346.chf

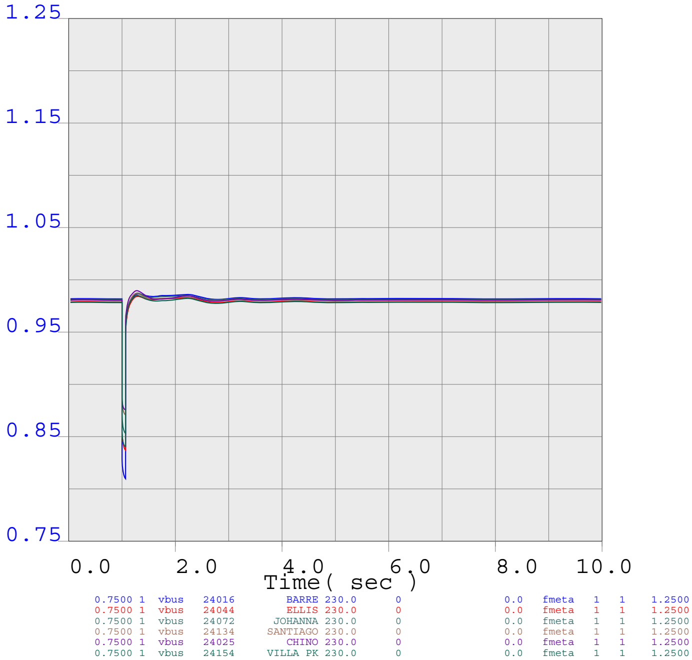
C:\DYTOOLS

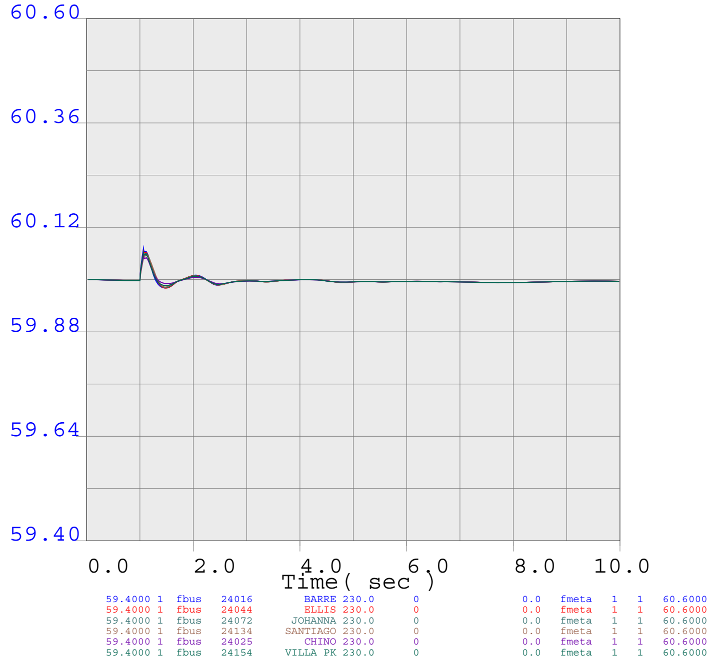
Thu Oct 20 08:57:22 2016

METRO









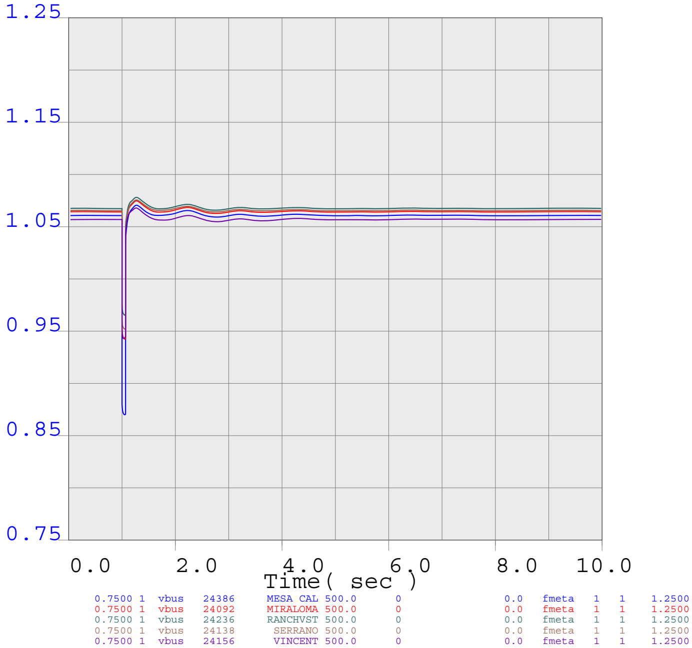
bay_2347
LA FRESA 220 KV POS 1XN
1 MW dispatch Case

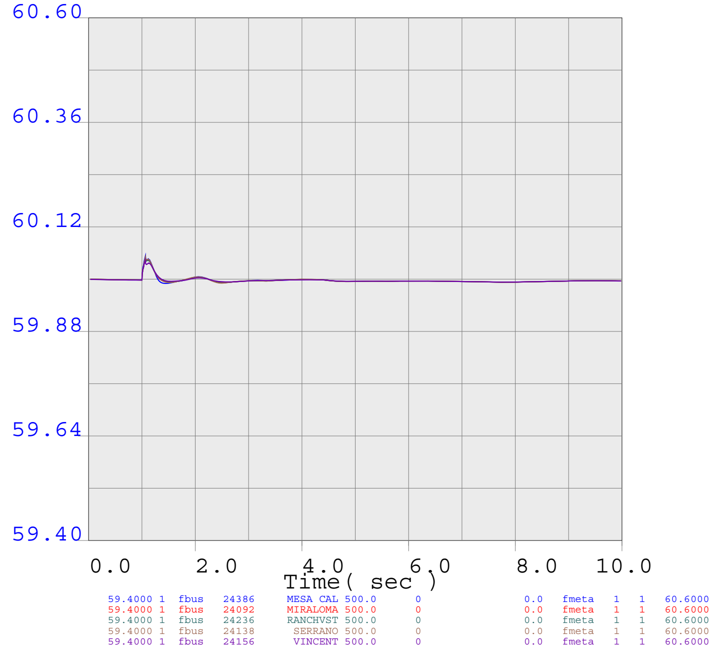
qc9p-bay_2347.chf

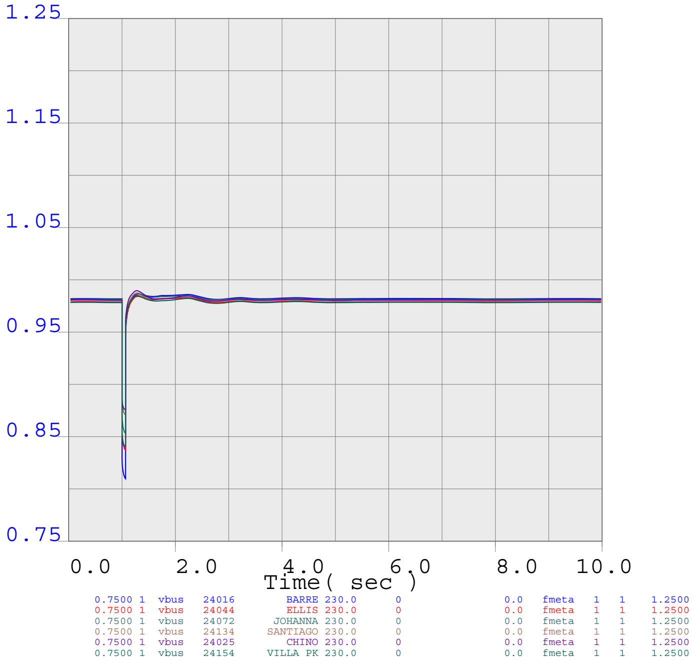
C:\DYTOOLS

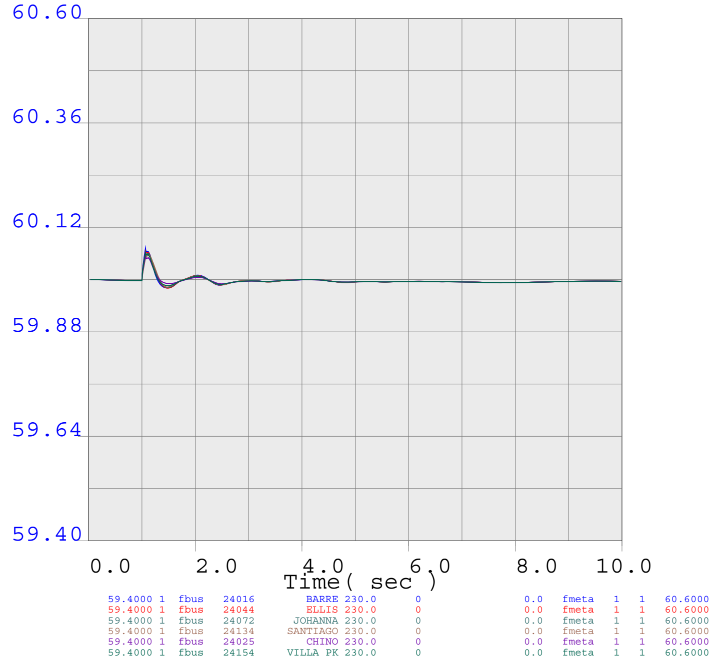
Thu Oct 20 08:57:27 2016

METRO









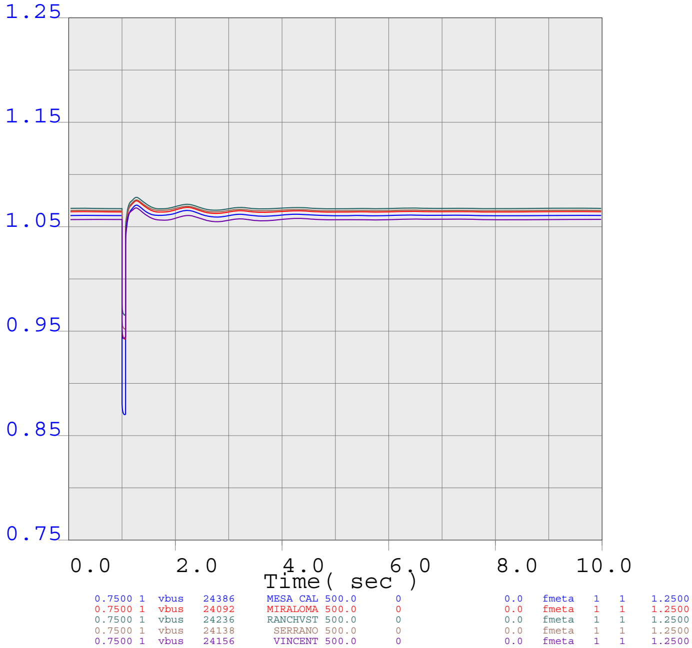
bay_2348
LA FRESA 220 KV POS 2XN
1 MW dispatch Case

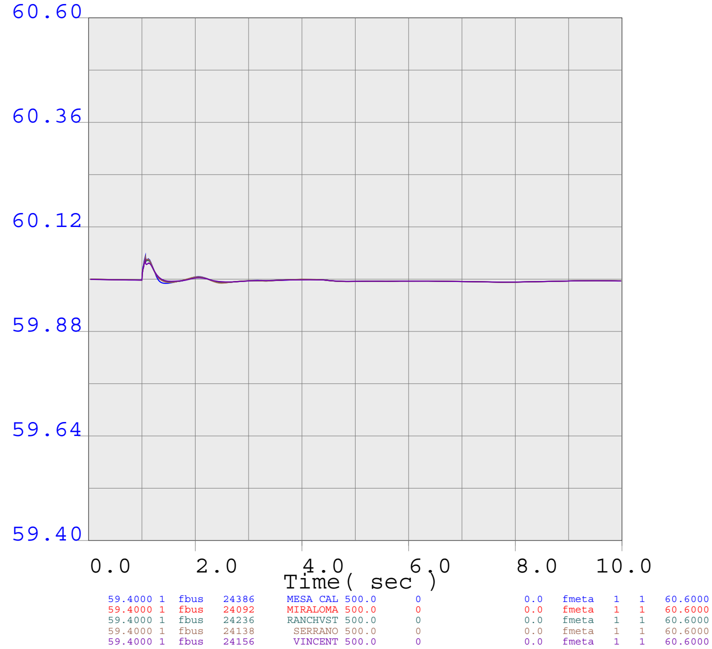
qc9p-bay_2348.chf

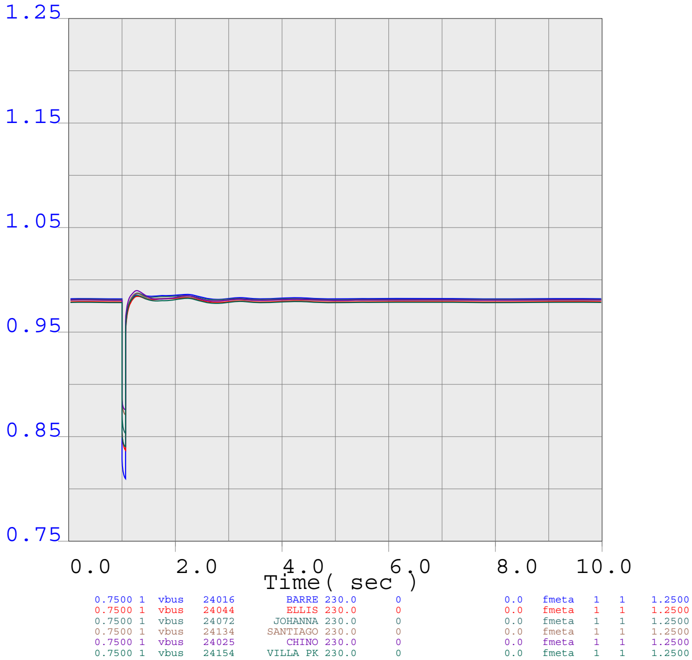
C:\DYTOOLS

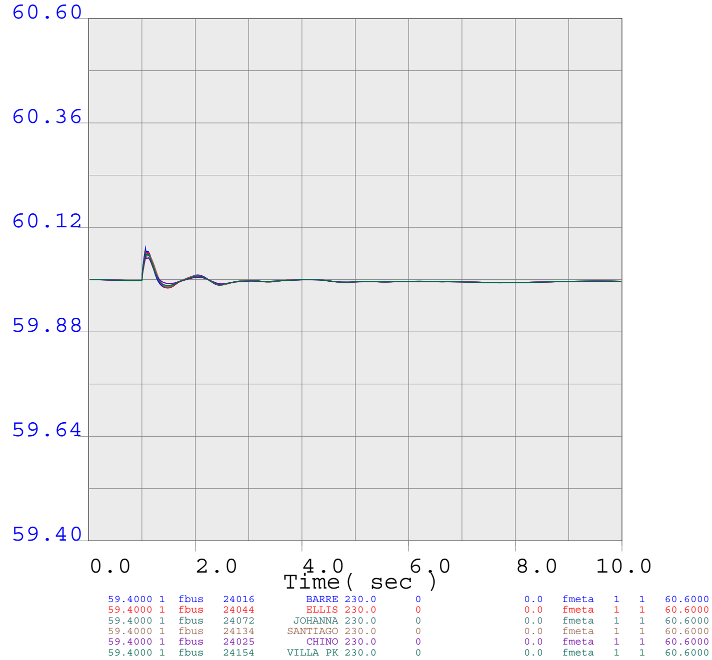
Thu Oct 20 08:57:29 2016

METRO









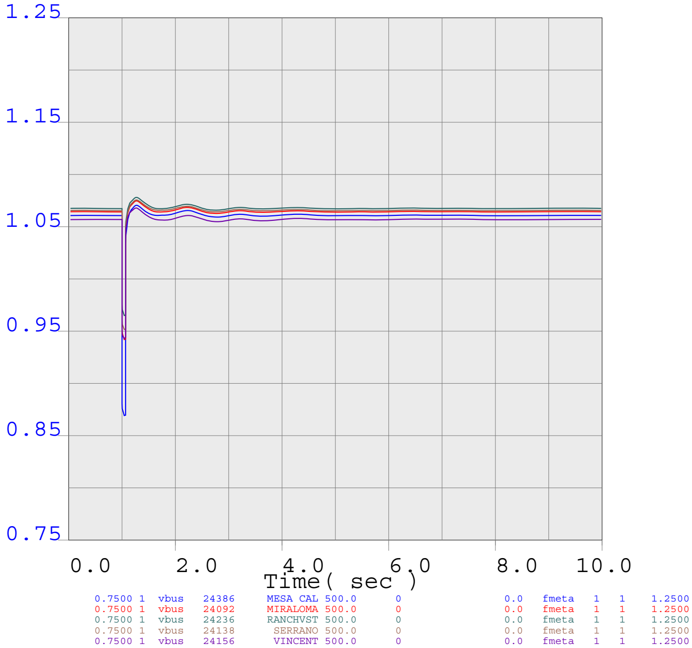
bay_2349
LA FRESA 220 KV POS 2N
1 MW dispatch Case

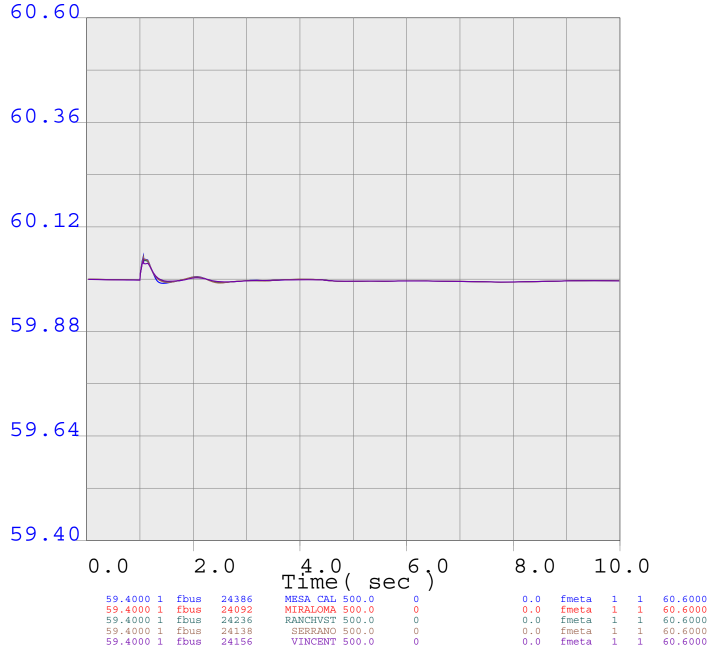
qc9p-bay_2349.chf

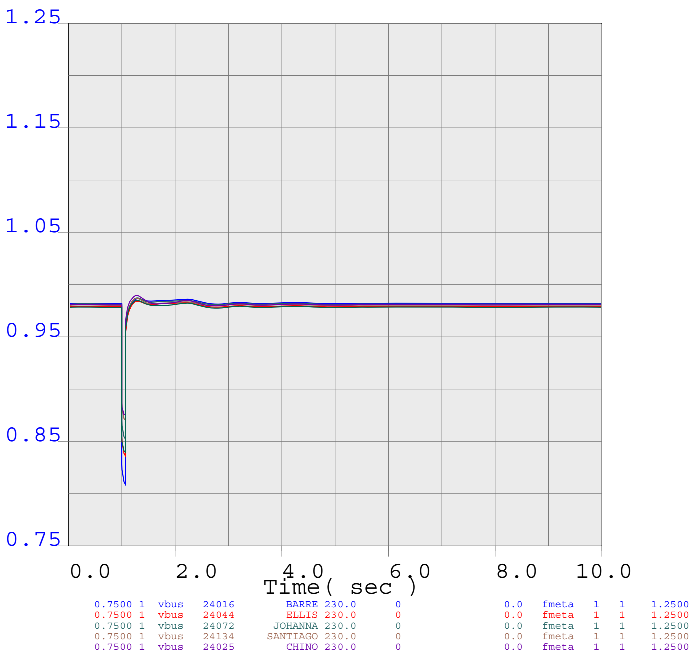
C:\DYTOOLS

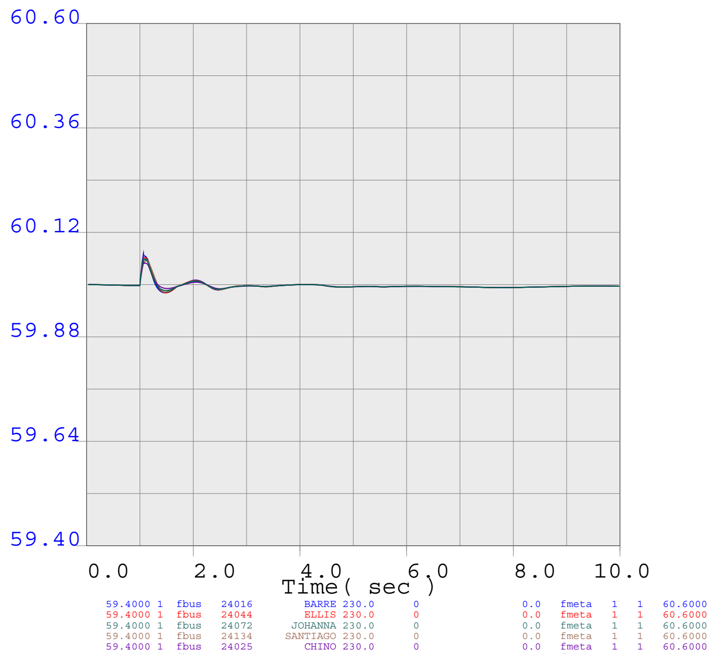
Thu Oct 20 08:57:31 2016

METRO









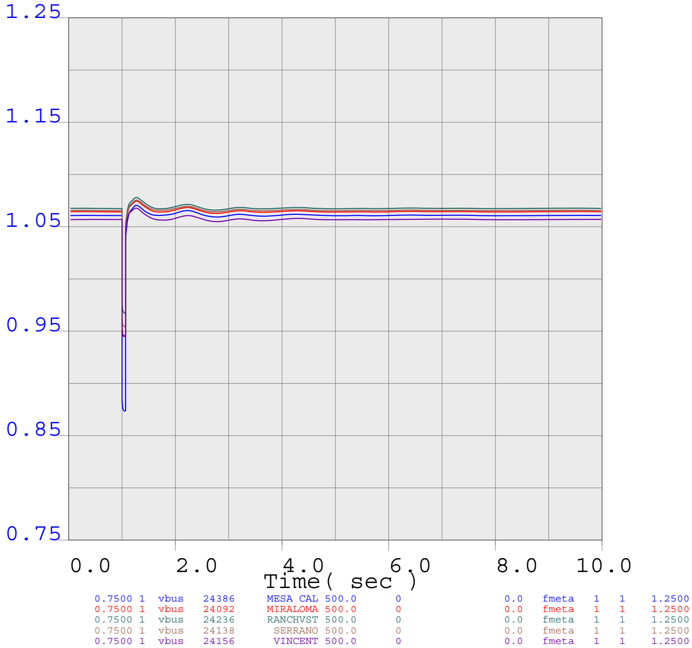
bay_2350
LA FRESA 220 KV POS 3N
1 MW dispatch Case

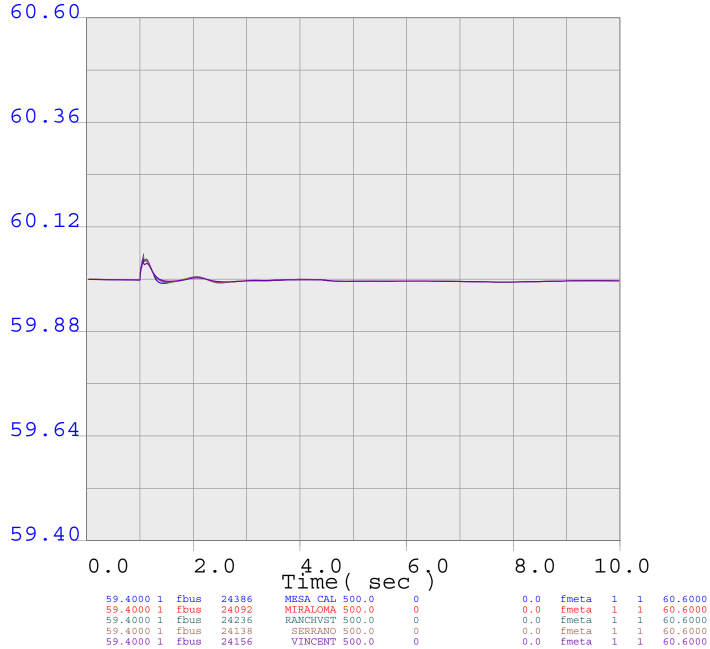
qc9p-bay_2350.chf

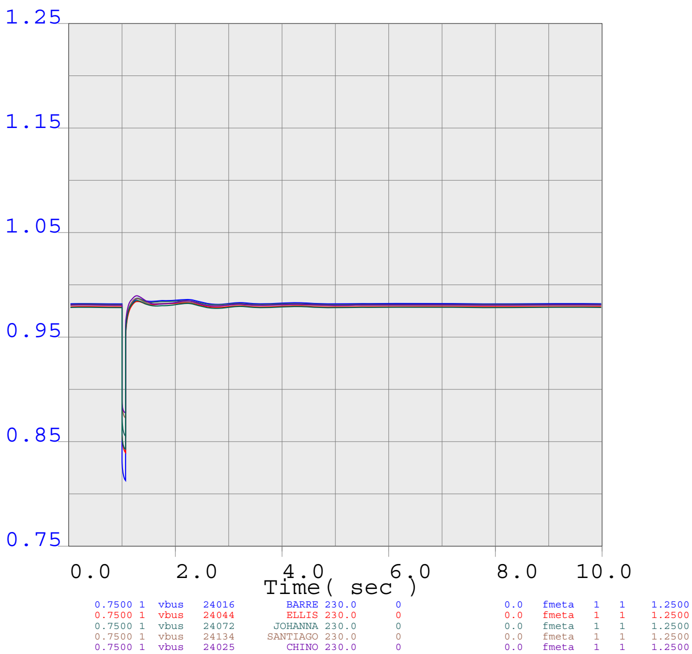
C:\DYTOOLS

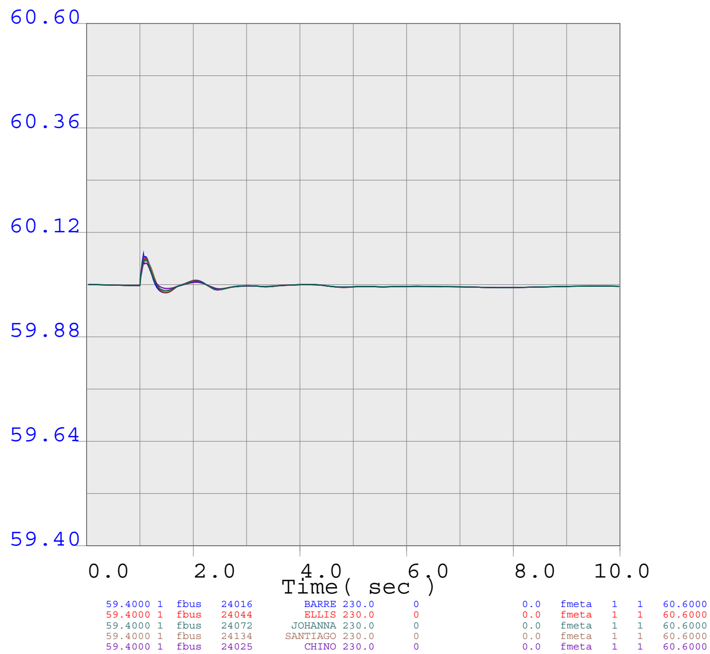
Thu Oct 20 08:57:34 2016

METRO









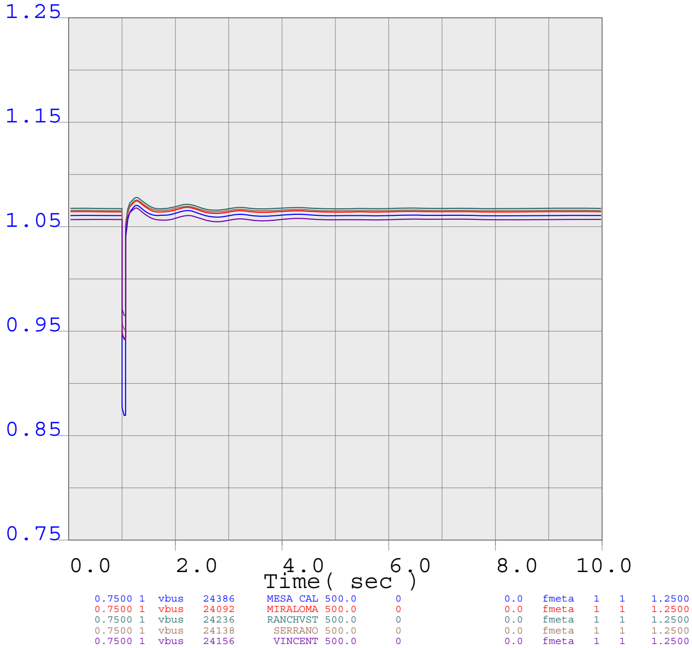
bay_2351
LA FRESA 220 KV POS 4N
1 MW dispatch Case

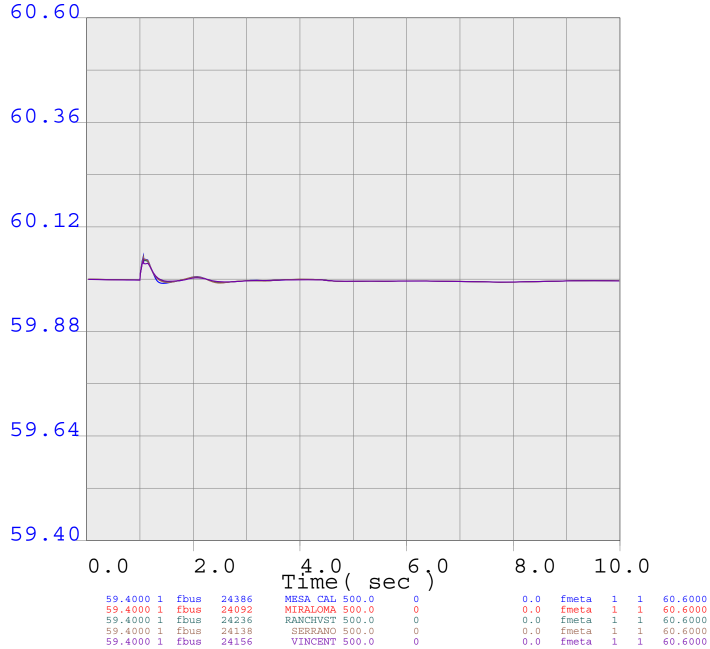
qc9p-bay_2351.chf

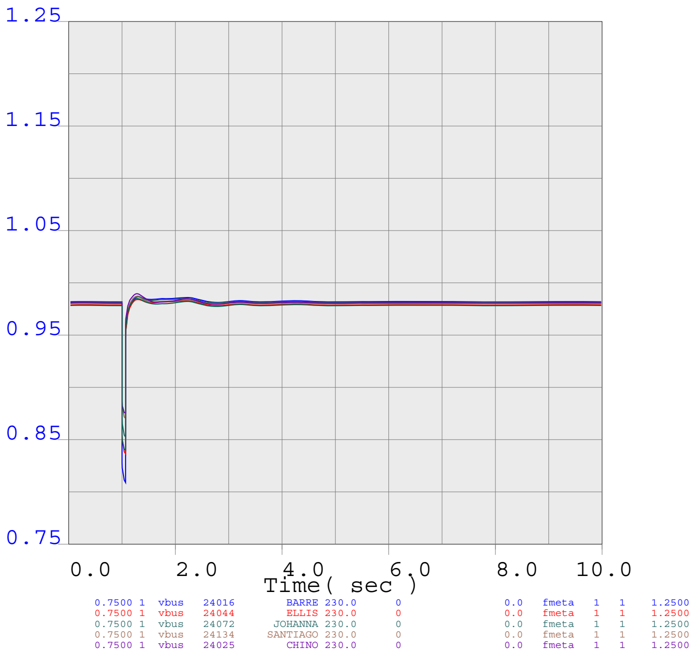
C:\DYTOOLS

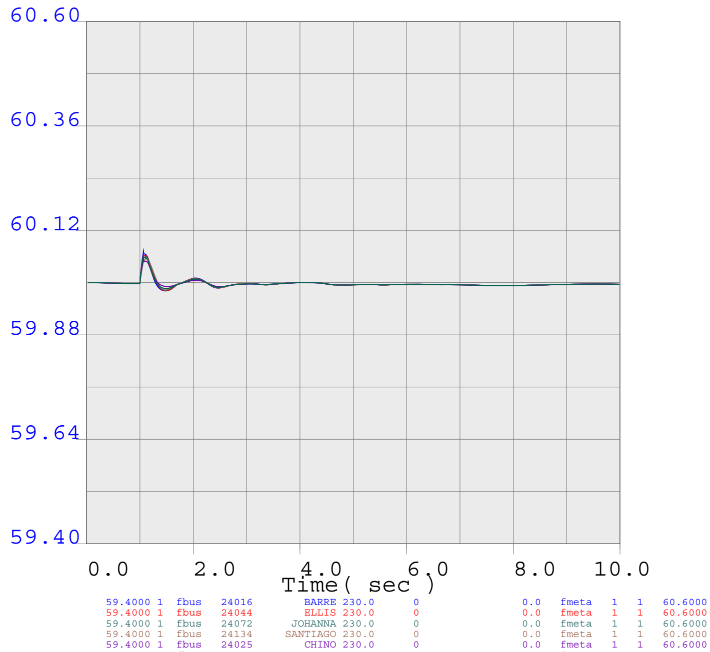
Thu Oct 20 08:57:37 2016

METRO









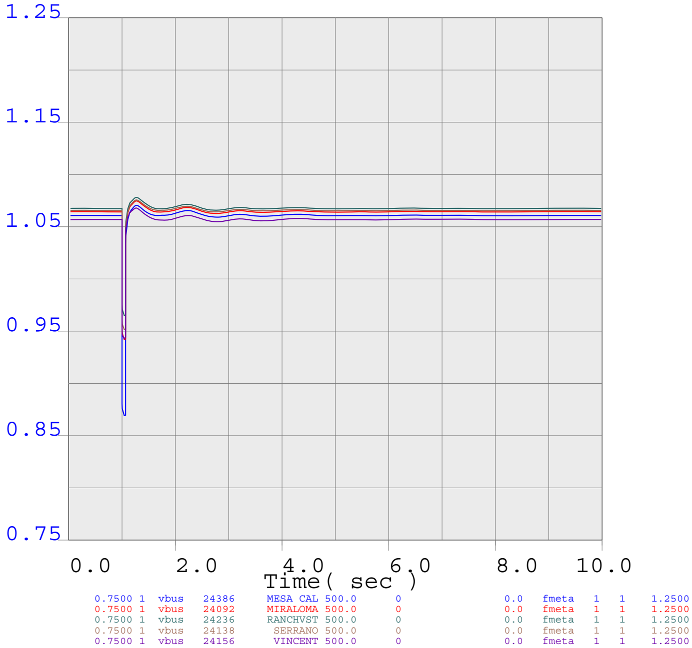
bay_2352
LA FRESA 220 KV POS 6N
1 MW dispatch Case

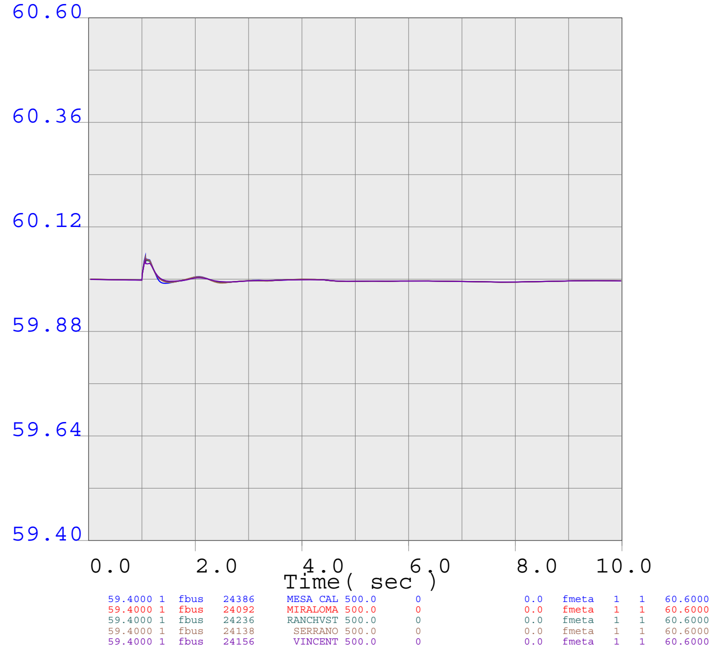
qc9p-bay_2352.chf

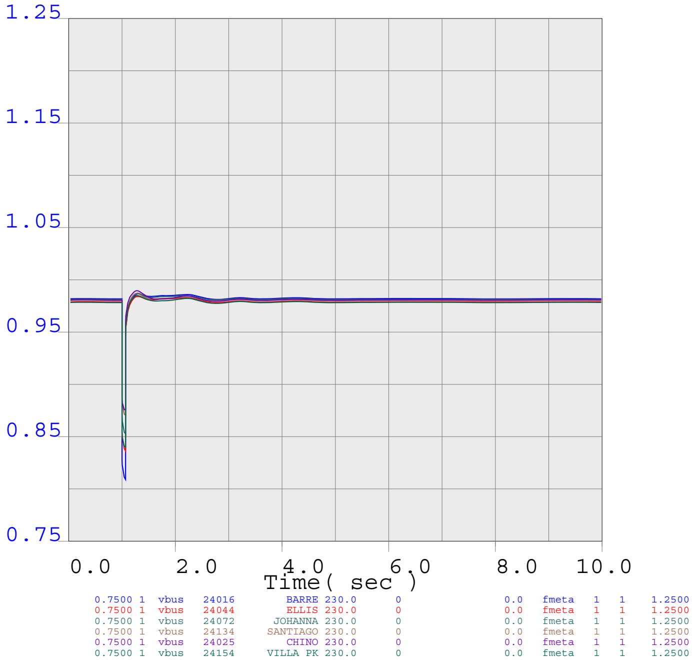
C:\DYTOOLS

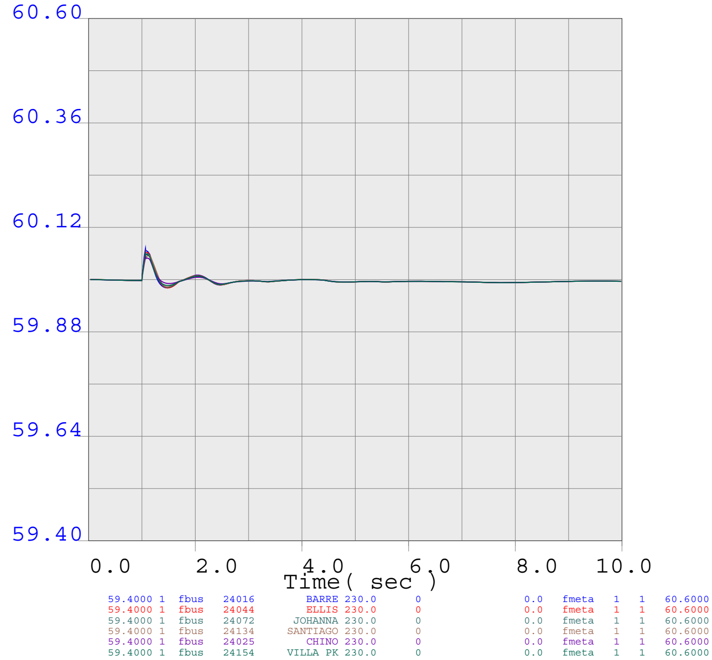
Thu Oct 20 08:57:39 2016

METRO









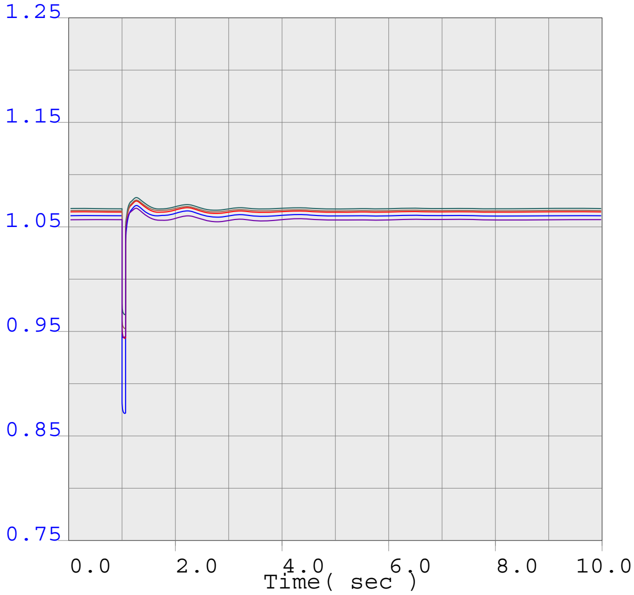
bay_2353
LA FRESA 220 KV POS 7N
1 MW dispatch Case

qc9p-bay_2353.chf

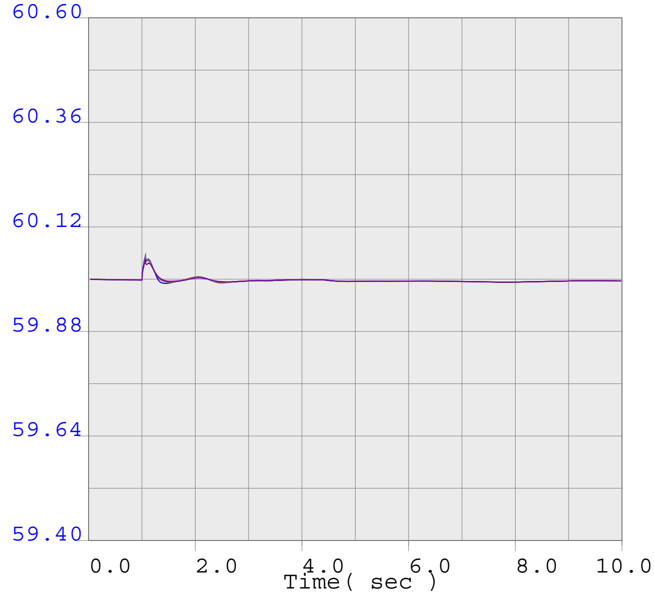
C:\DYTOOLS

Thu Oct 20 08:57:42 2016

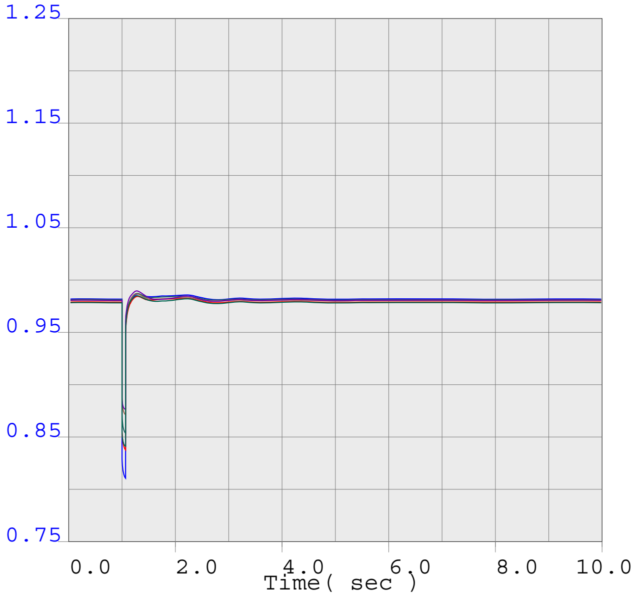
METRO



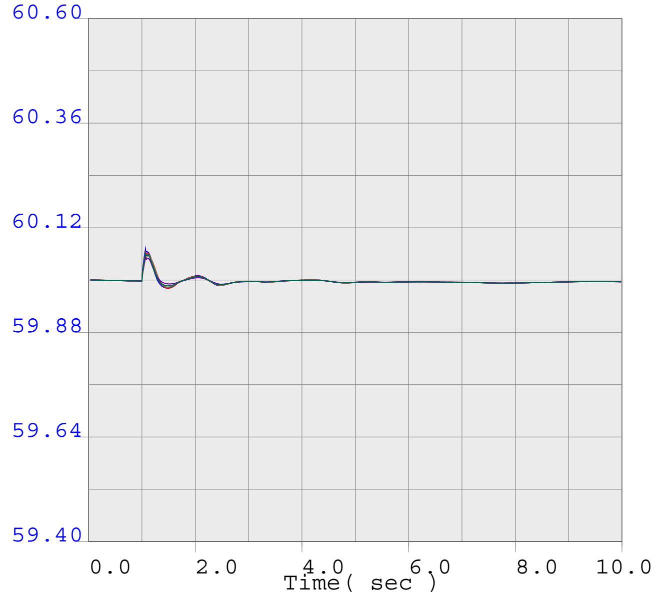
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

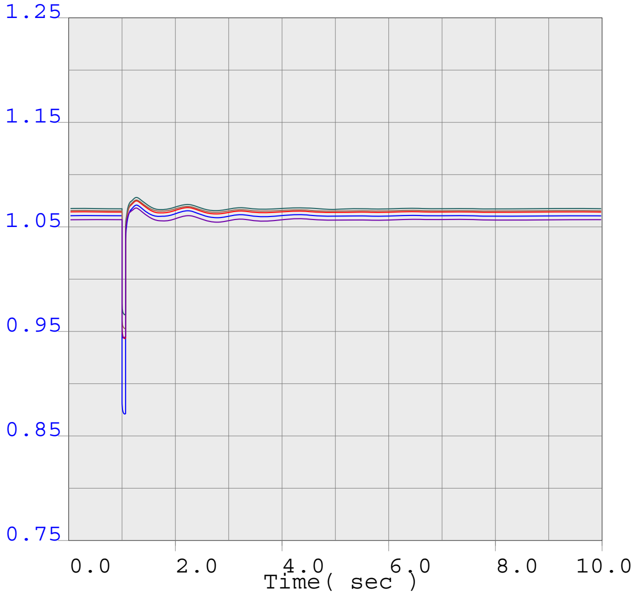
bay_2354
LA FRESA 220 KV POS 9N
1 MW dispatch Case

qc9p-bay_2354.chf

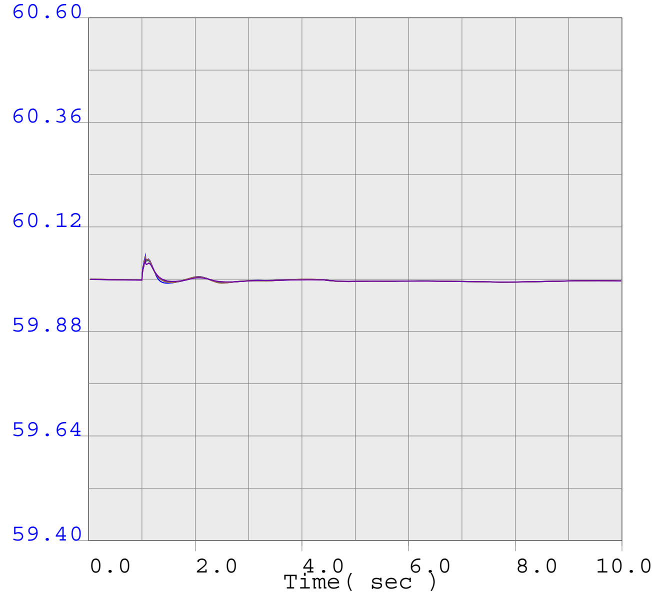
C:\DYTOOLS

Thu Oct 20 08:57:44 2016

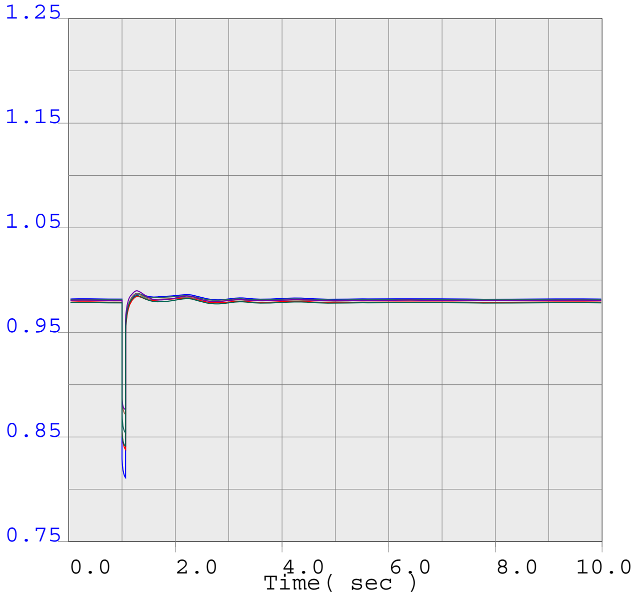
METRO



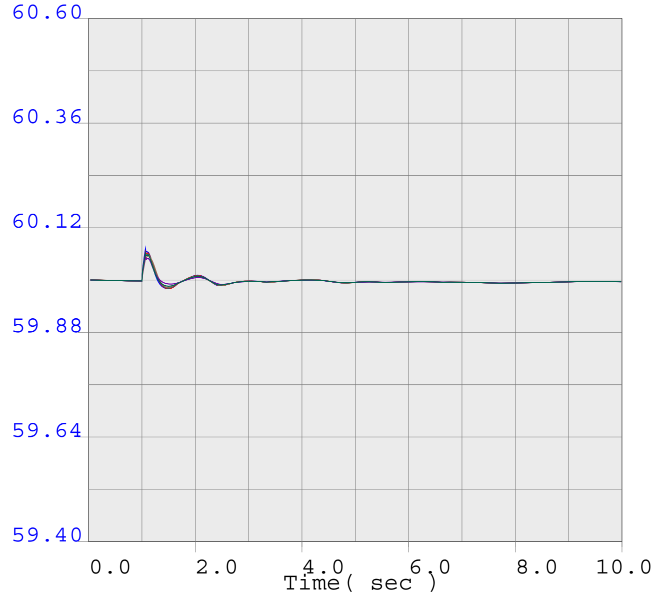
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

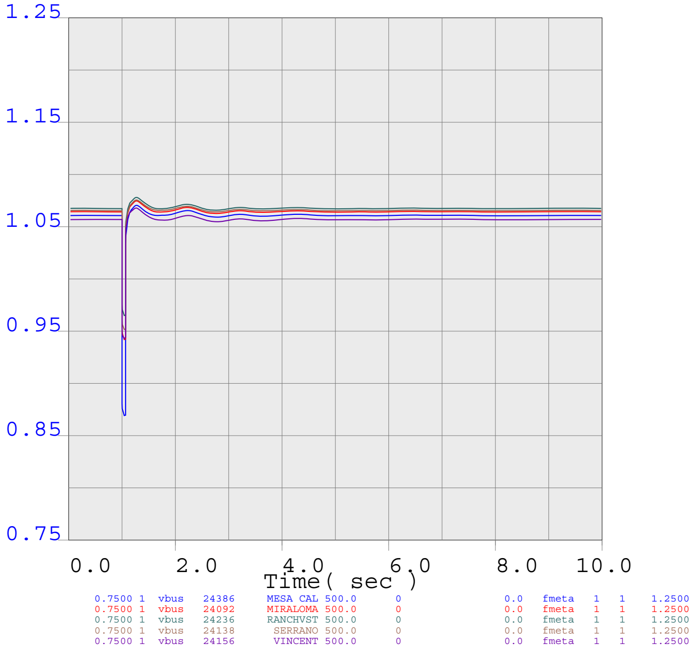
bay_2355
LA FRESA 220 KV POS 10N
1 MW dispatch Case

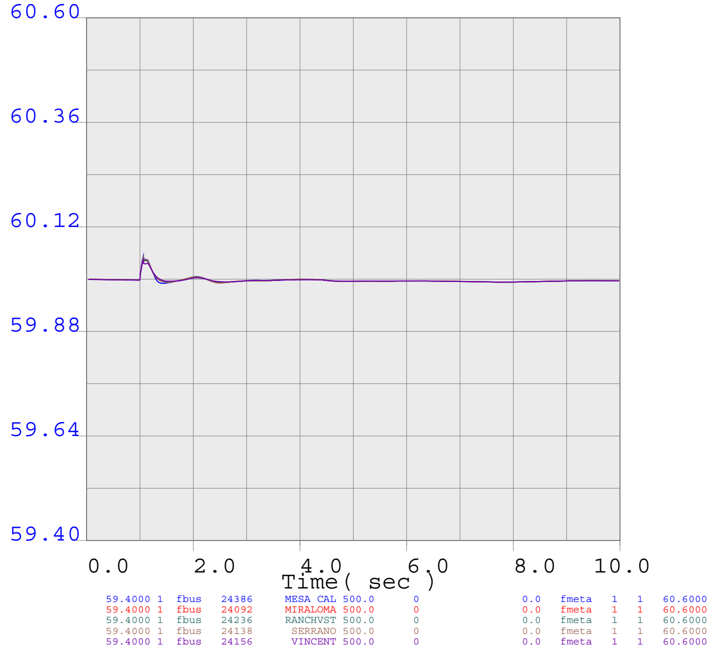
qc9p-bay_2355.chf

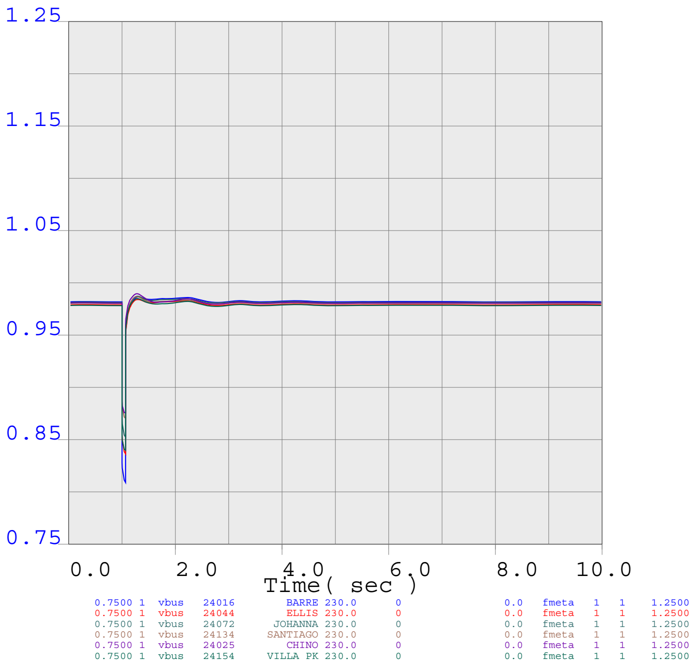
C:\DYTOOLS

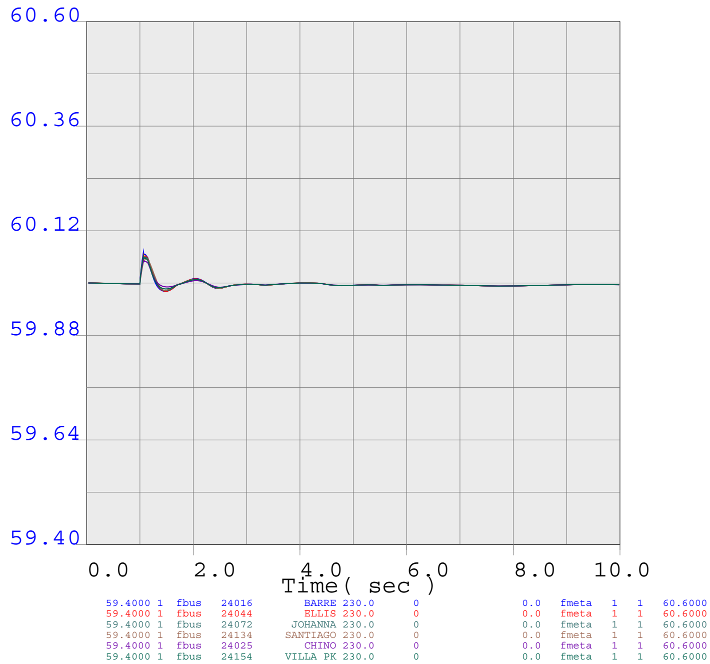
Thu Oct 20 08:57:48 2016

METRO









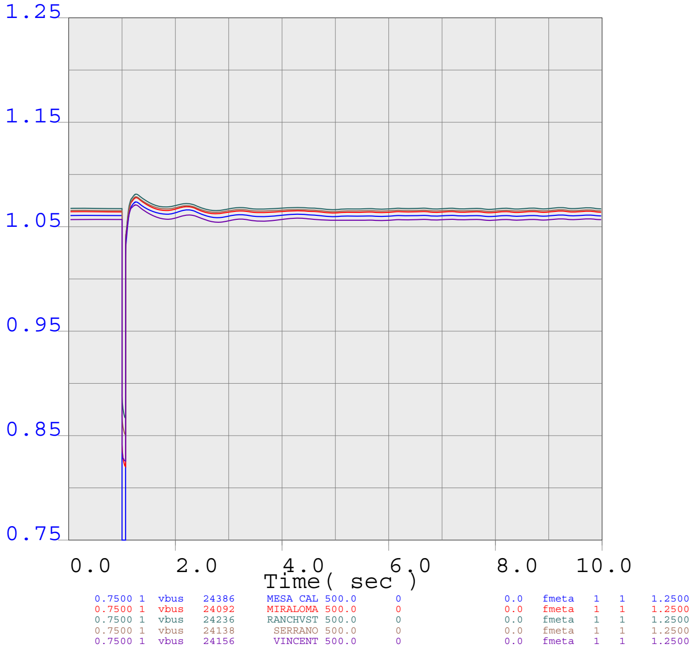
bay_2356
LA FRESA 220 KV POS 11N
1 MW dispatch Case

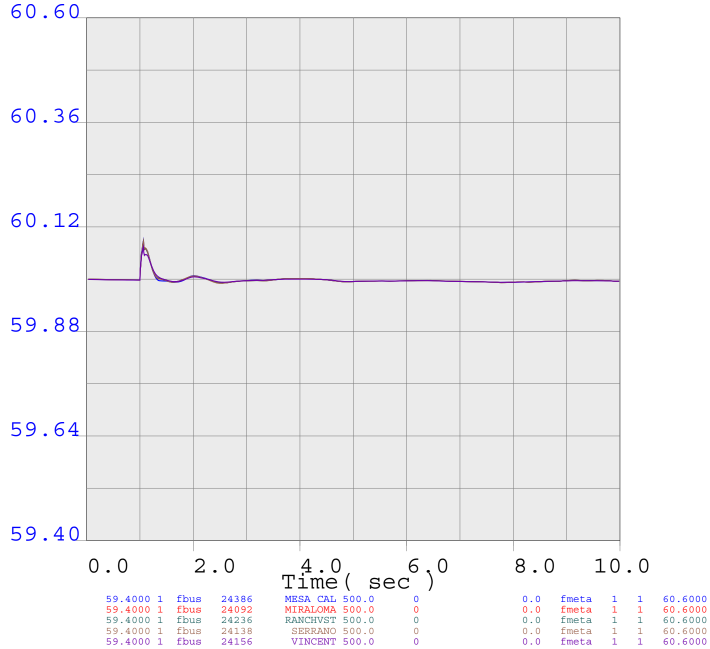
qc9p-bay_2356.chf

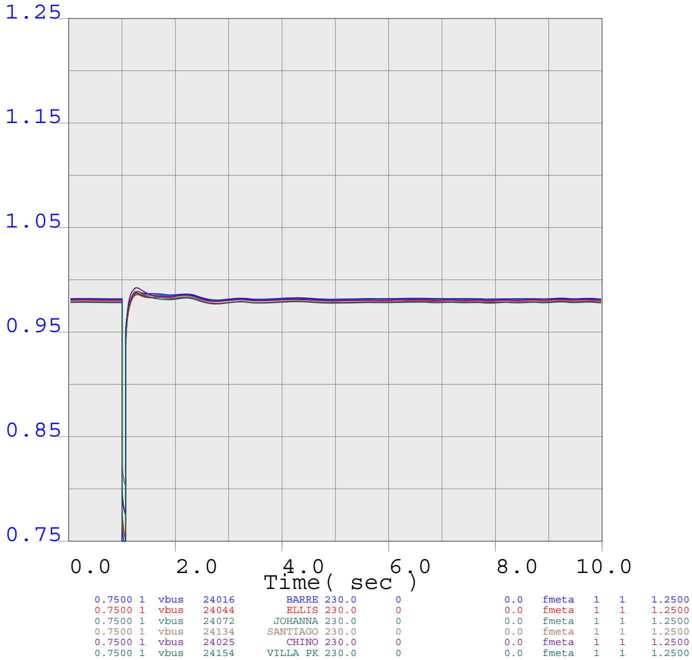
C:\DYTOOLS

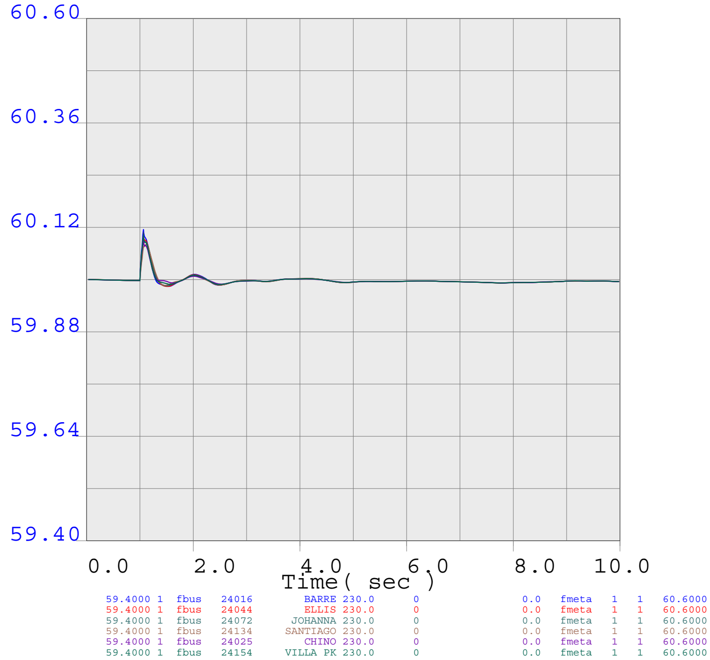
Thu Oct 20 08:57:51 2016

METRO









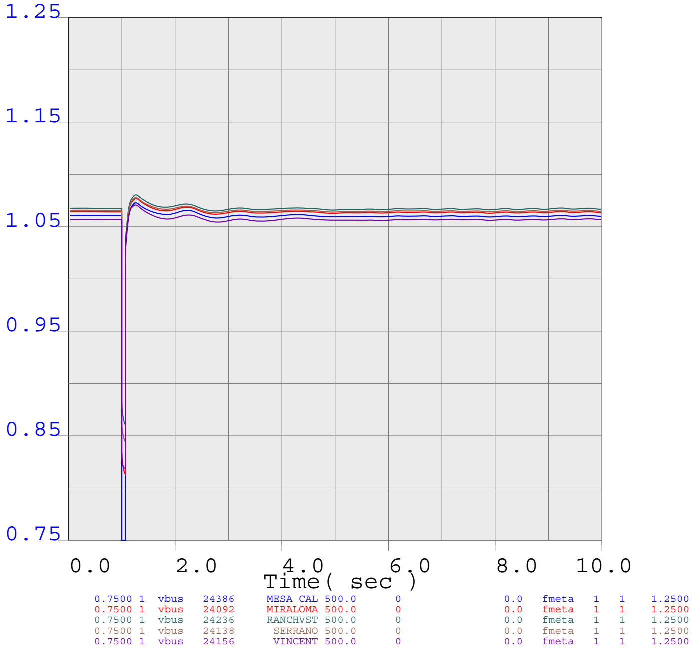
bay_2357
LAGUNA BELL 220 KV POS 12N
1 MW dispatch Case

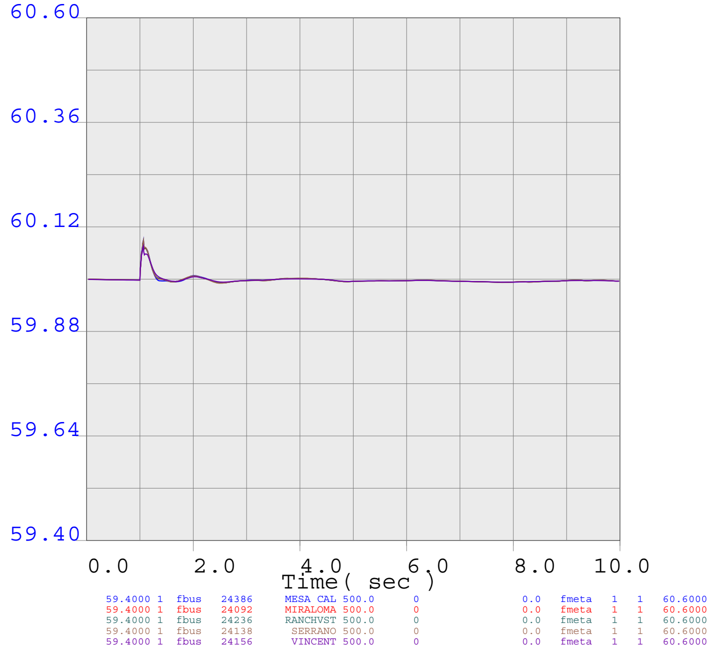
qc9p-bay_2357.chf

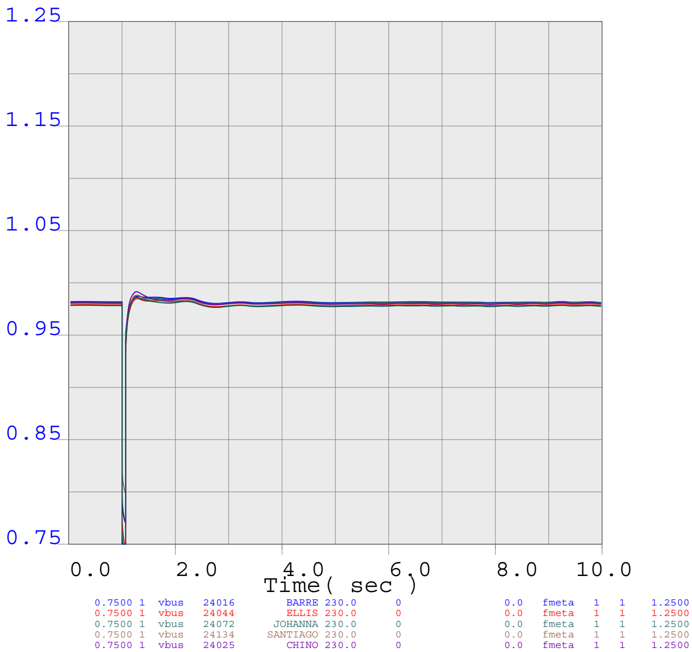
C:\DYTOOLS

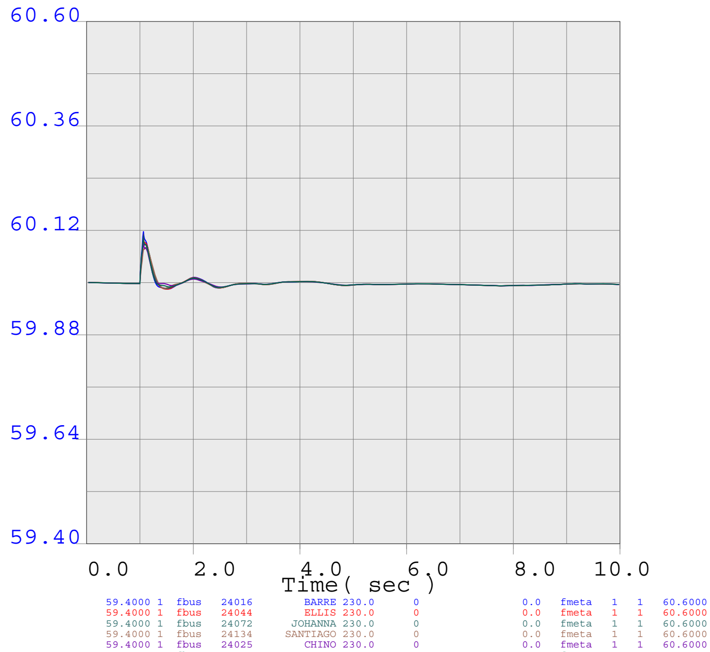
Thu Oct 20 08:57:53 2016

METRO









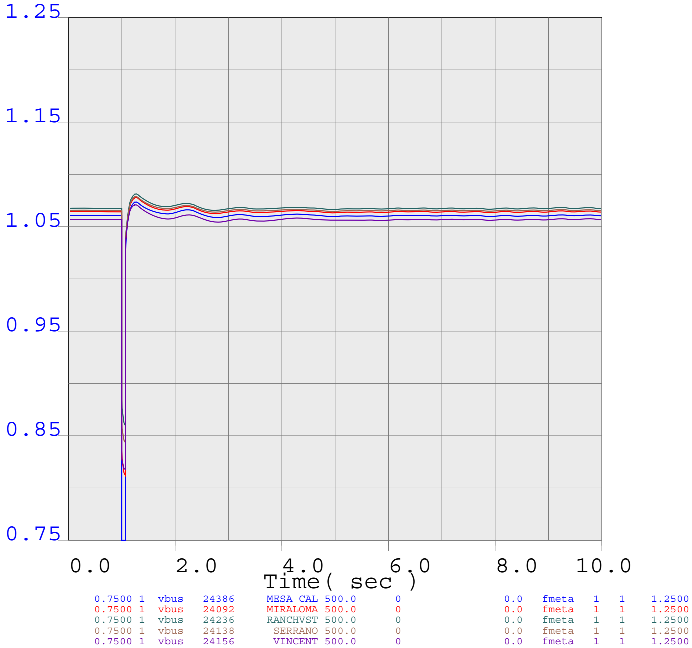
bay_2358
LAGUNA BELL 220 KV POS 11N
1 MW dispatch Case

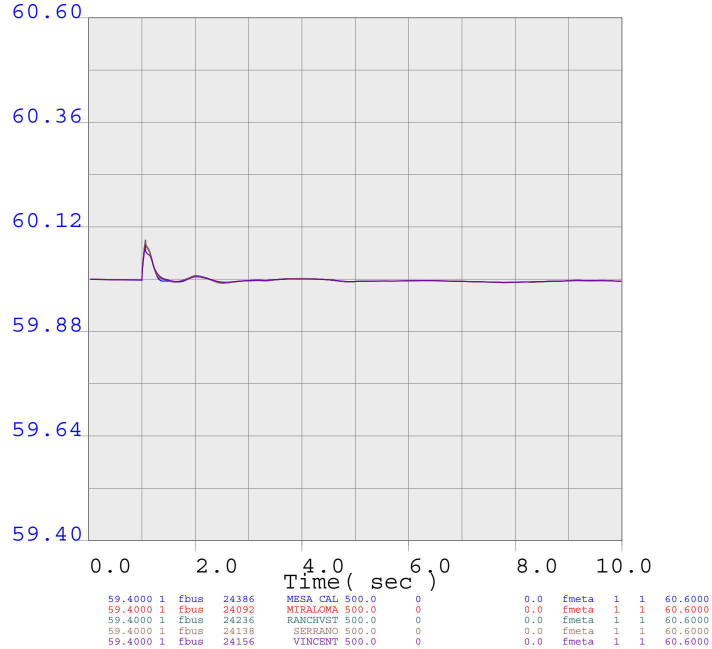
qc9p-bay_2358.chf

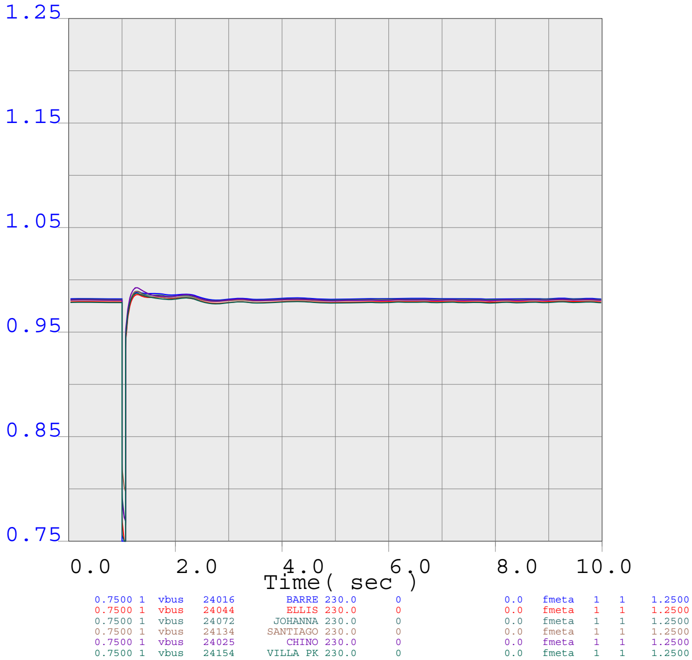
C:\DYTOOLS

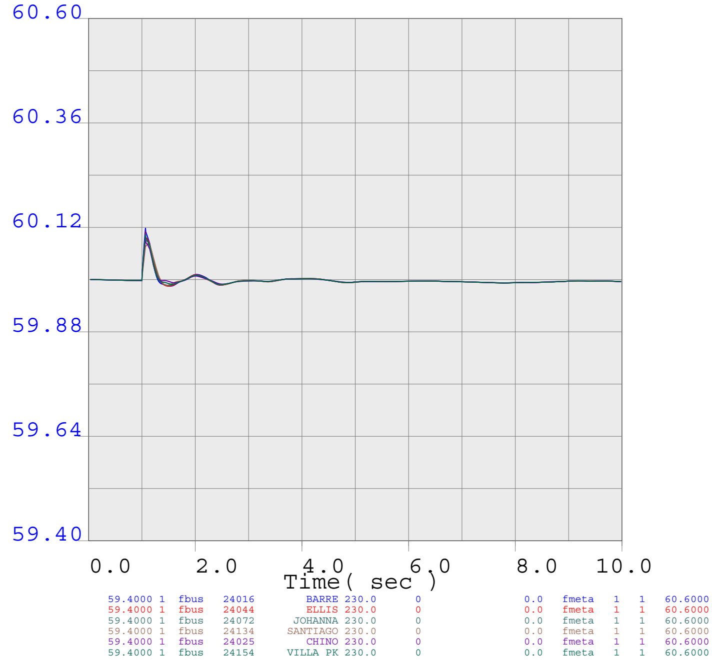
Thu Oct 20 08:57:56 2016

METRO









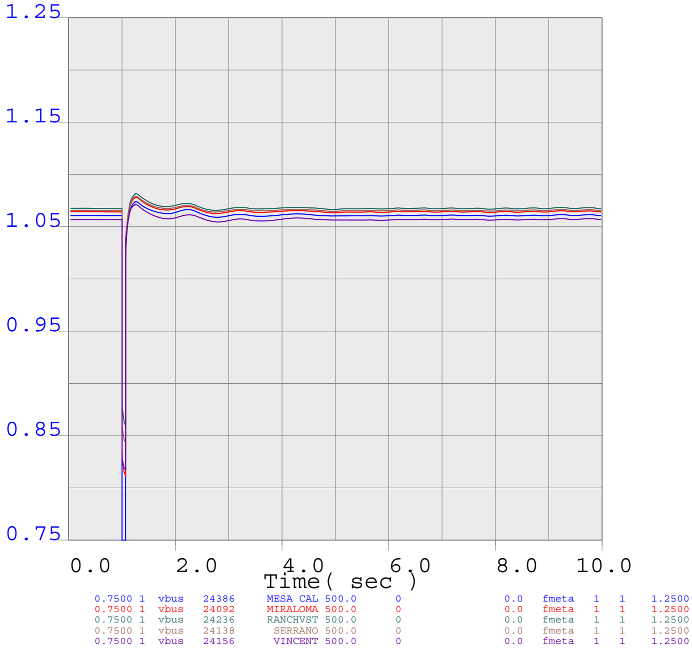
bay_2359
LAGUNA BELL 220 KV POS 10N
1 MW dispatch Case

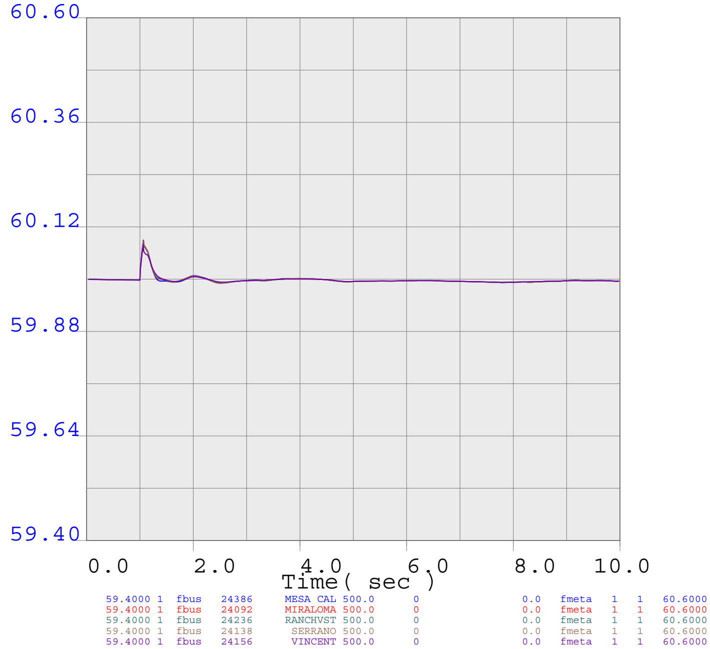
qc9p-bay_2359.chf

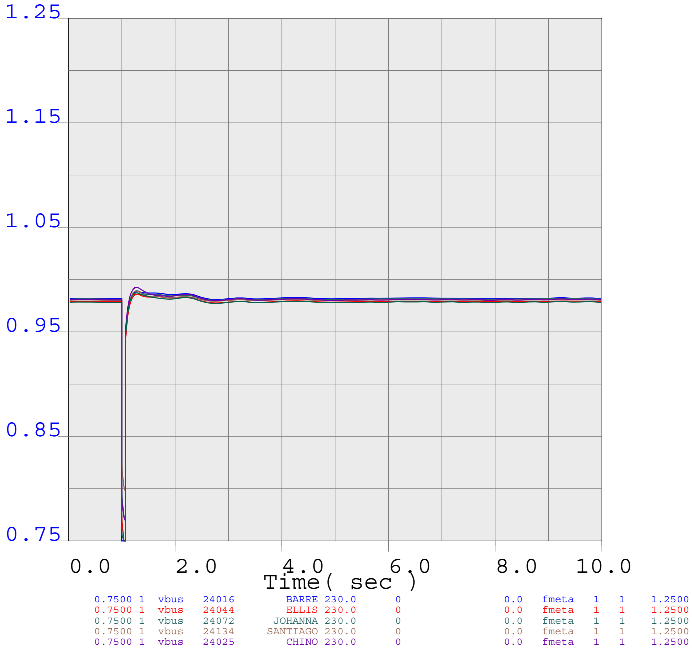
C:\DYTOOLS

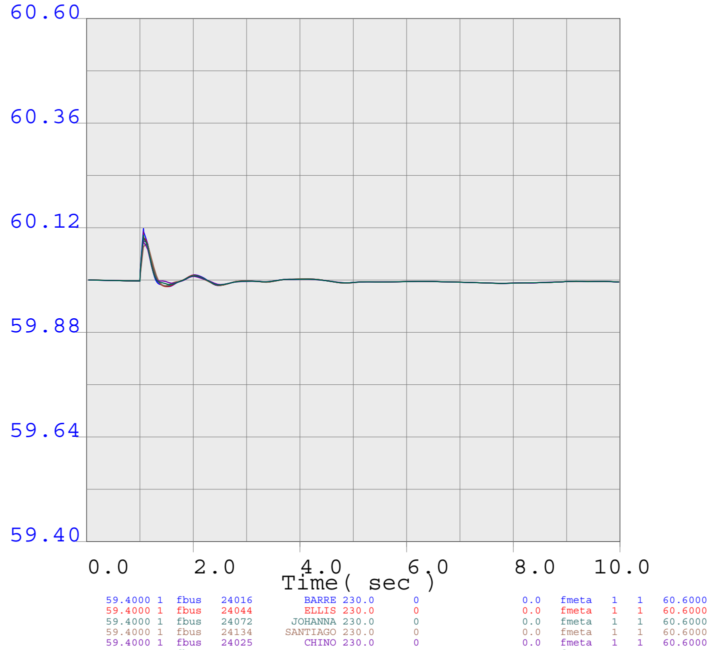
Thu Oct 20 08:57:59 2016

METRO









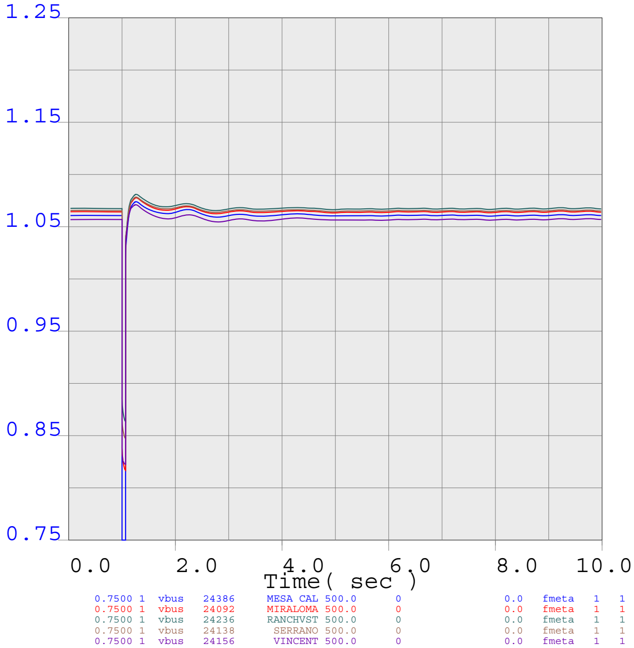
bay_2360
LAGUNA BELL 220 KV POS 9N
1 MW dispatch Case

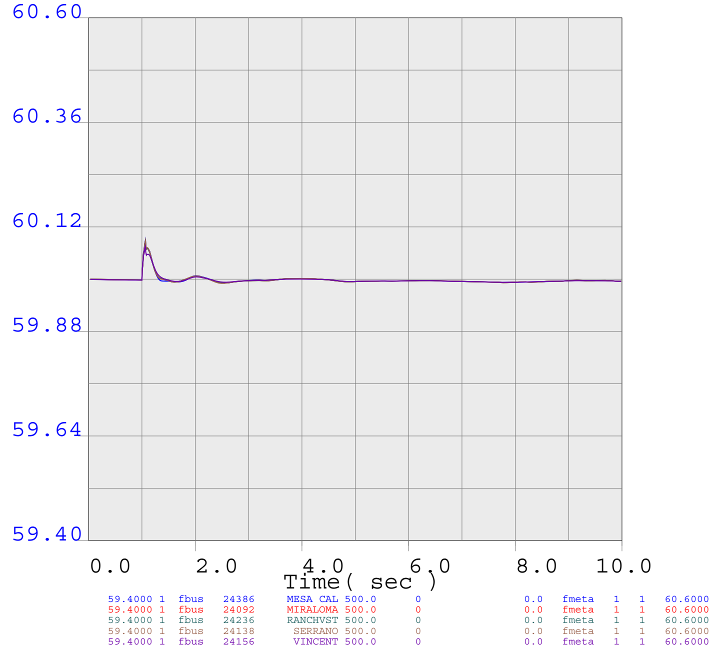
qc9p-bay_2360.chf

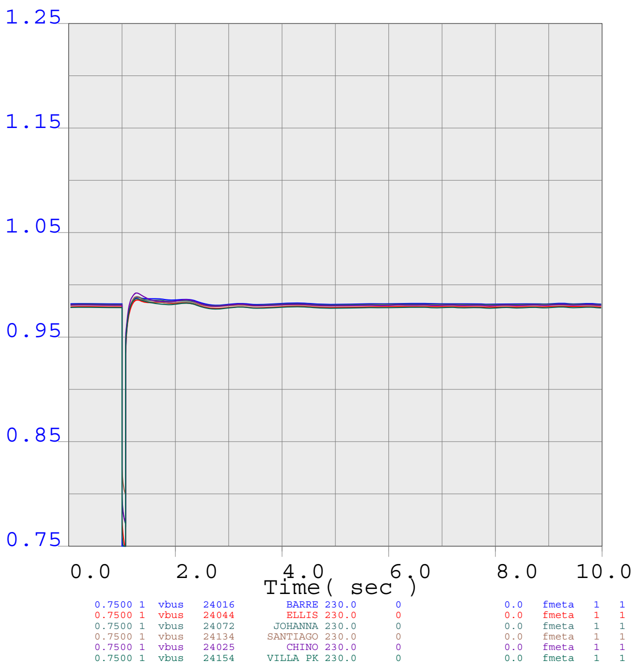
C:\DYTOOLS

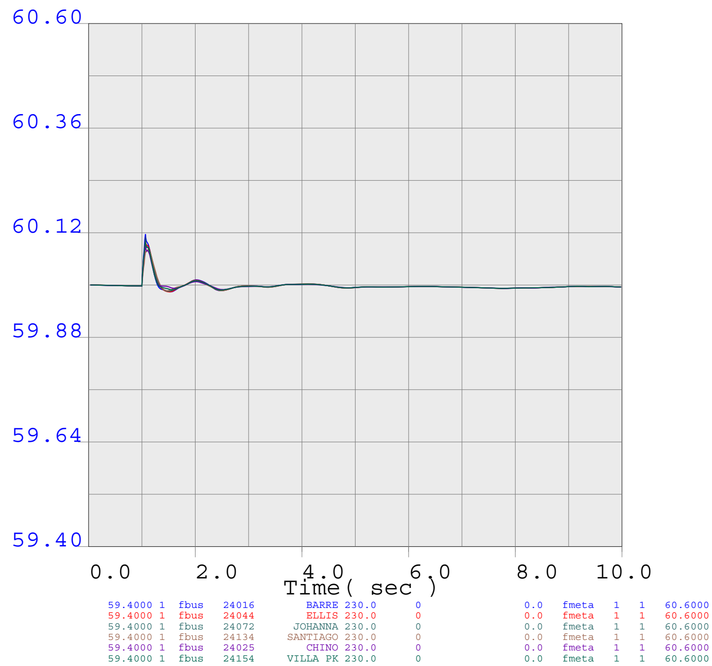
Thu Oct 20 08:58:02 2016

METRO









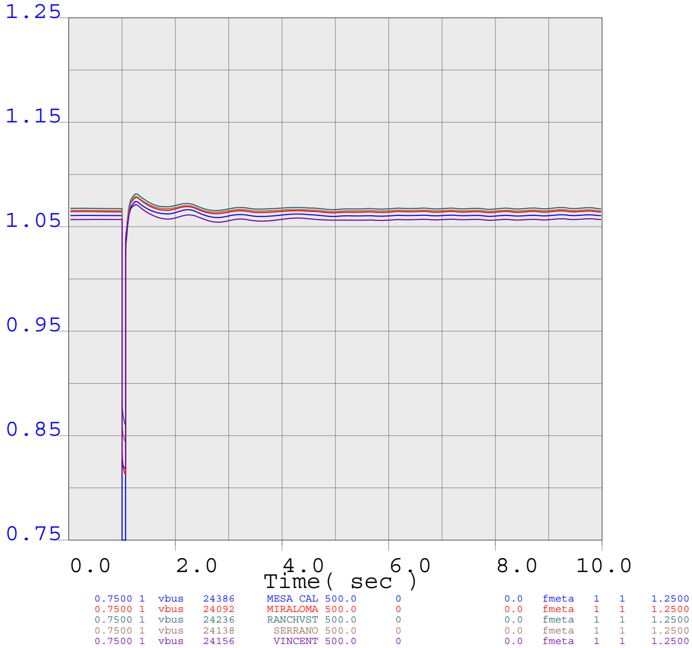
bay_2361
LAGUNA BELL 220 KV POS 6N
1 MW dispatch Case

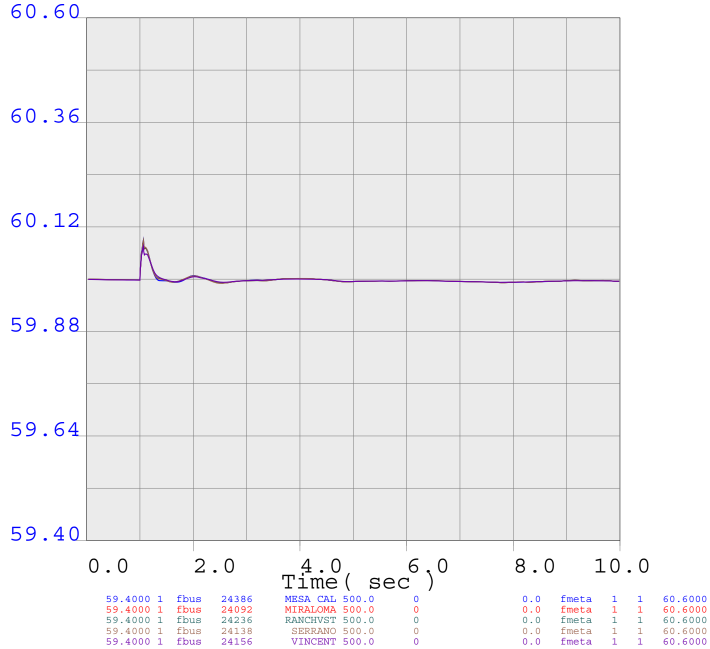
qc9p-bay_2361.chf

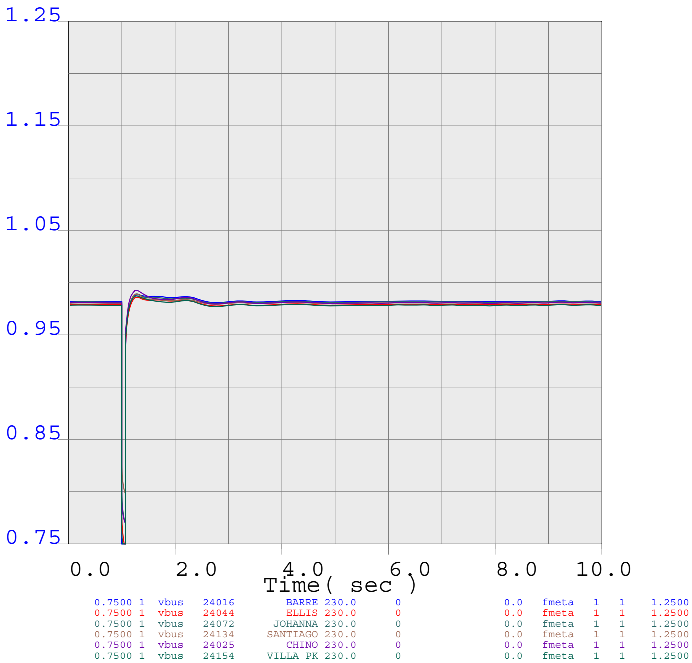
C:\DYTOOLS

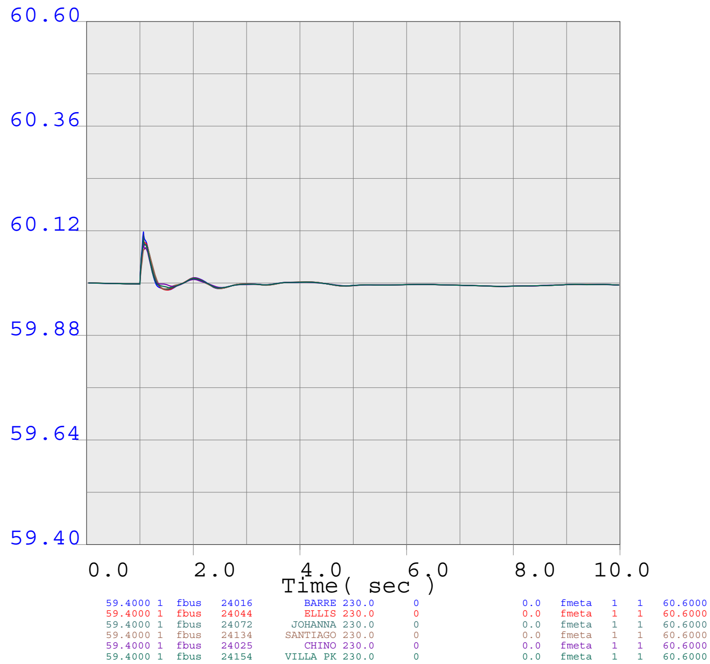
Thu Oct 20 08:58:04 2016

METRO









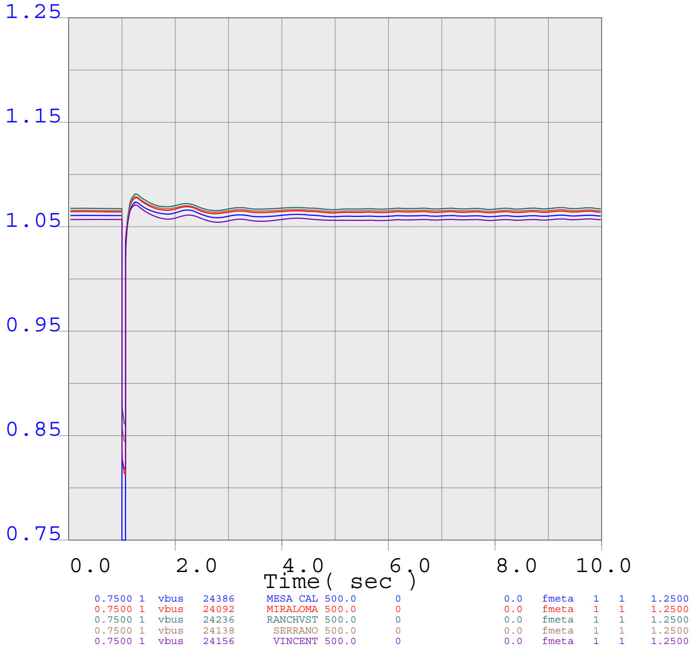
bay_2362
LAGUNA BELL 220 KV POS 5N
1 MW dispatch Case

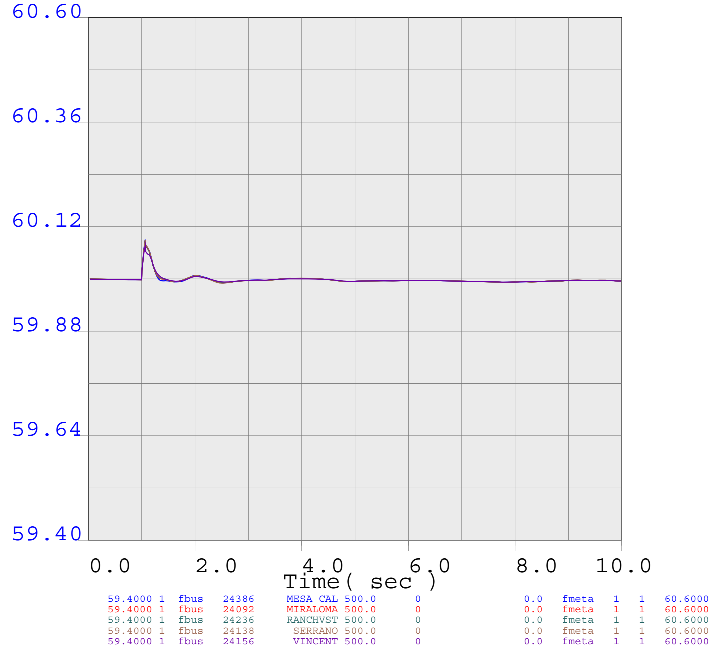
qc9p-bay_2362.chf

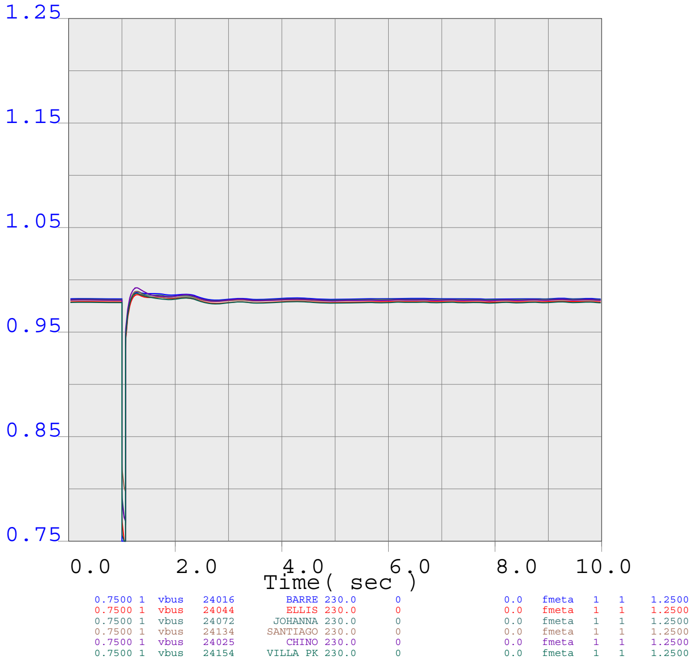
C:\DYTOOLS

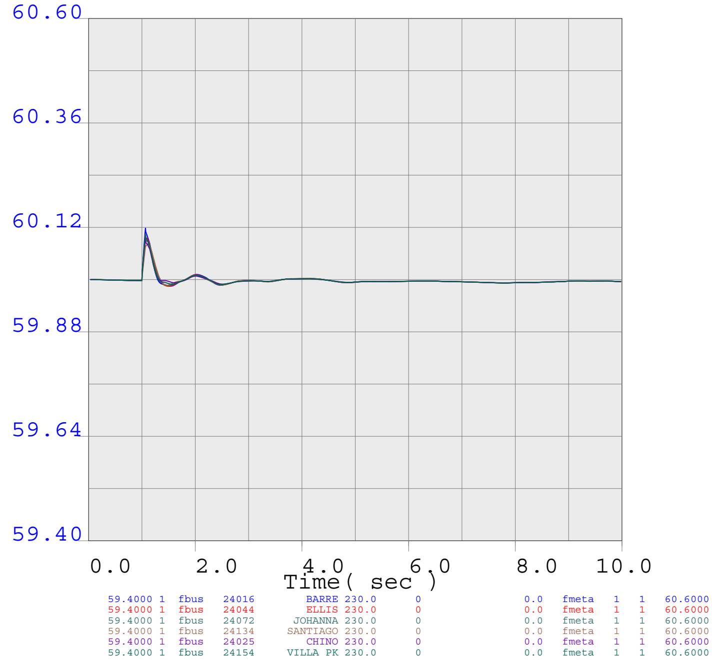
Thu Oct 20 08:58:06 2016

METRO









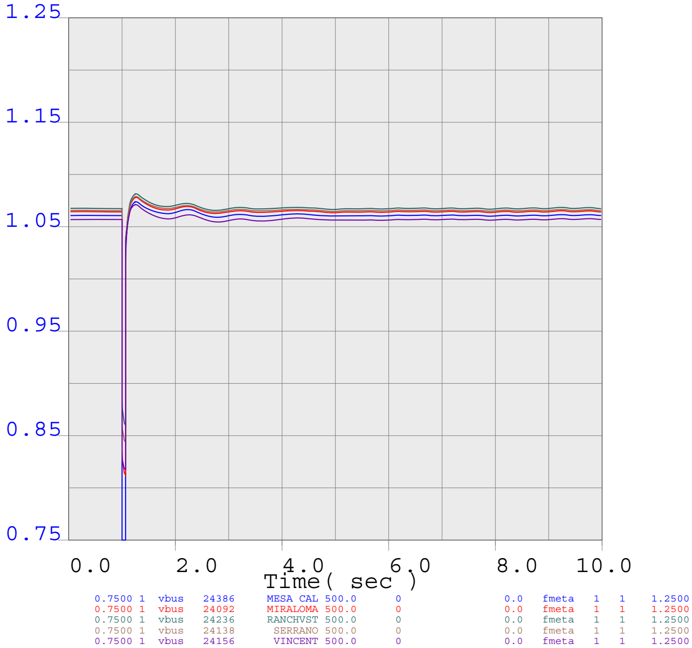
bay_2363
LAGUNA BELL 220 KV POS 4N
1 MW dispatch Case

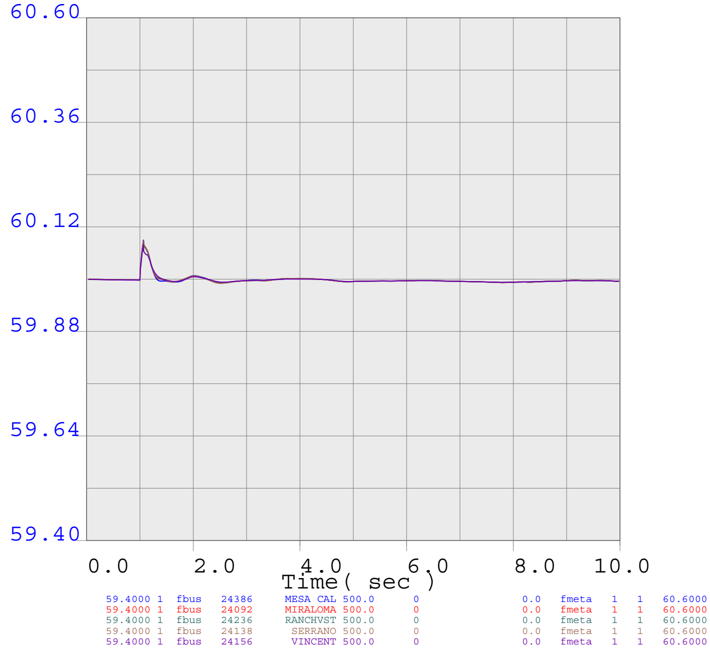
qc9p-bay_2363.chf

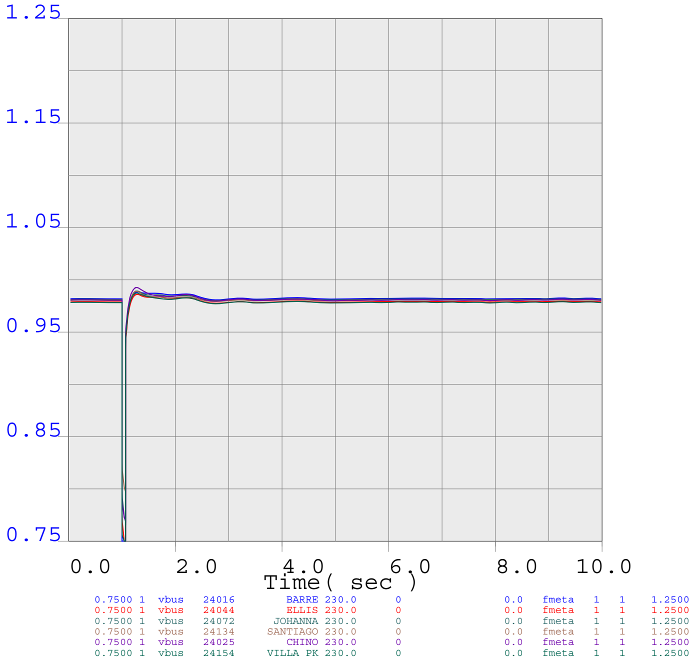
C:\DYTOOLS

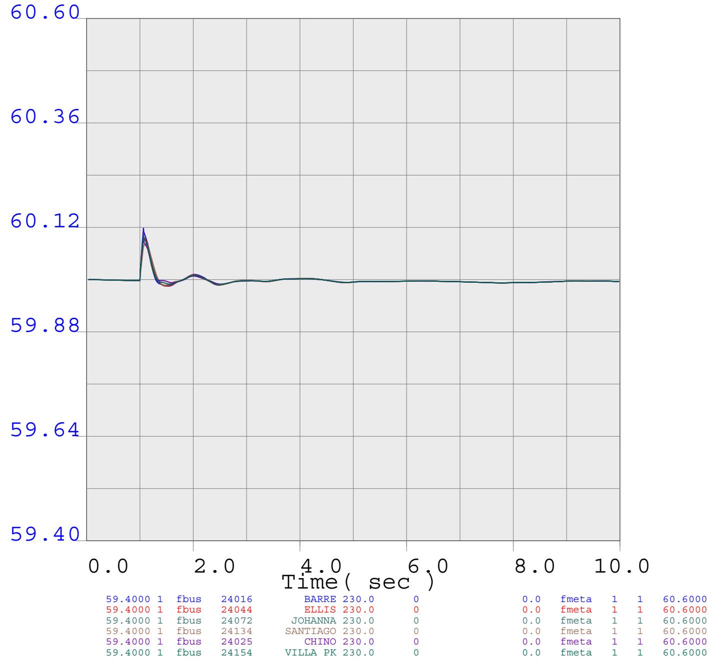
Thu Oct 20 08:58:08 2016

METRO









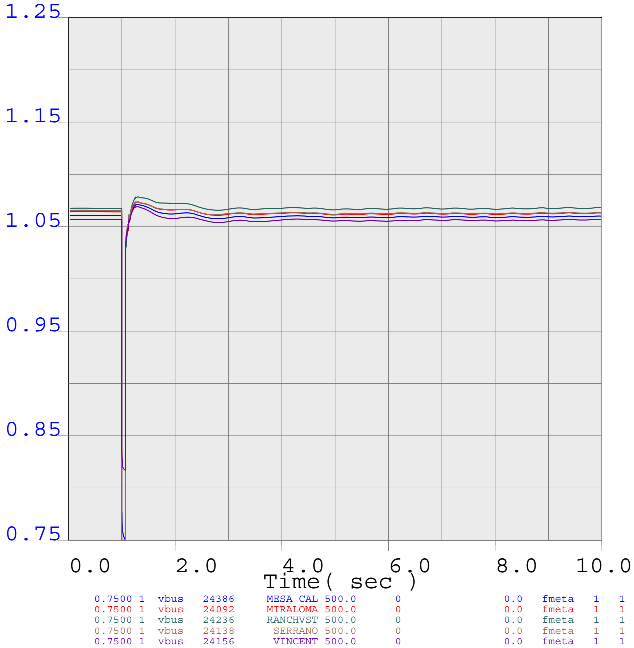
bay_2364
LAGUNA BELL 220 KV POS 4N
1 MW dispatch Case

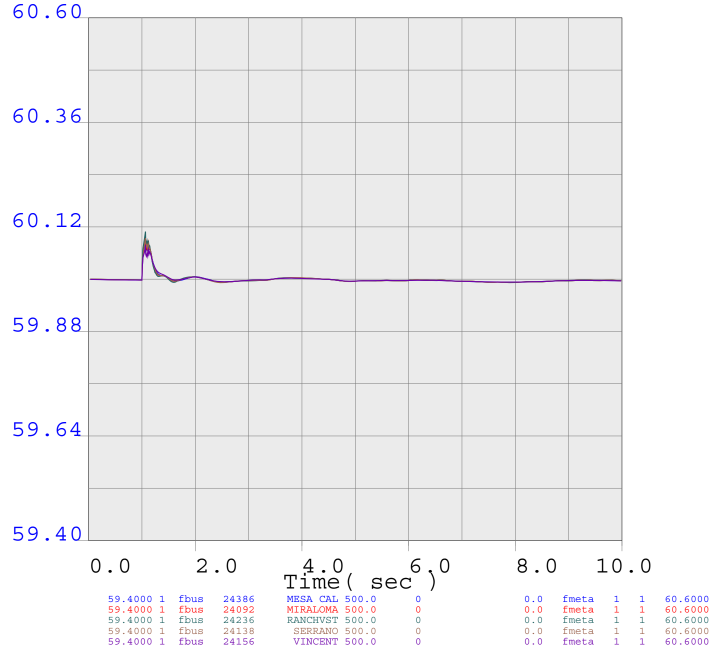
qc9p-bay_2364.chf

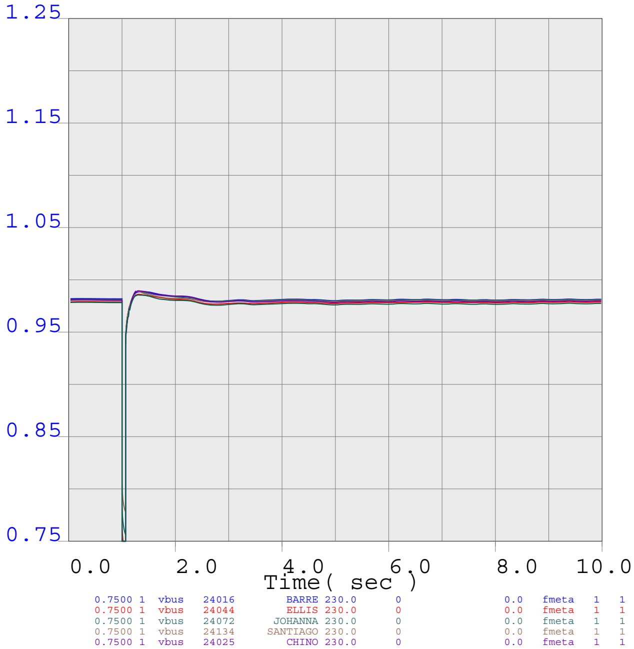
C:\DYTOOLS

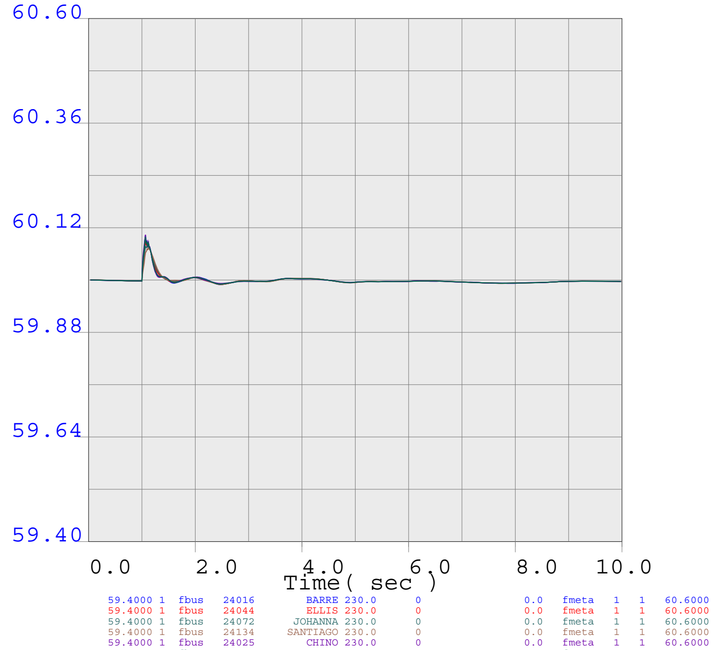
Thu Oct 20 08:58:11 2016

METRO









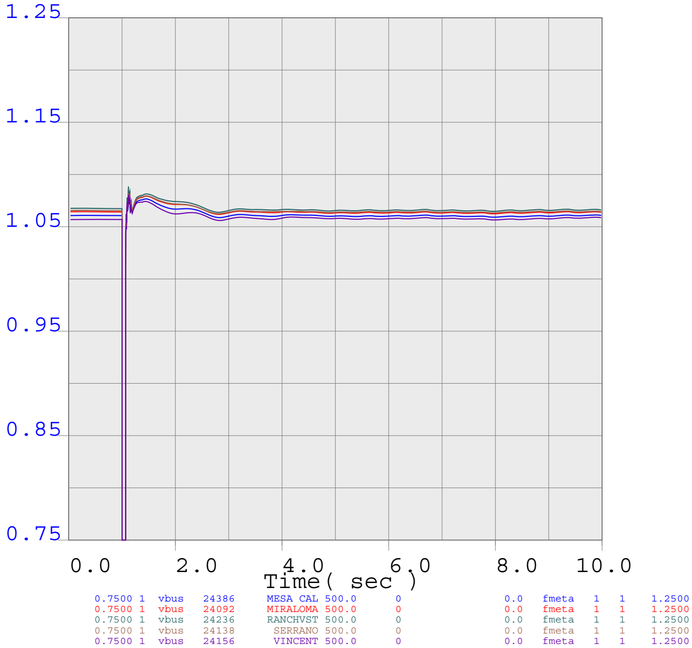
bay_2365
MIRALOMA 500 KV POS 1X INTERNAL FAULT
1 MW dispatch Case

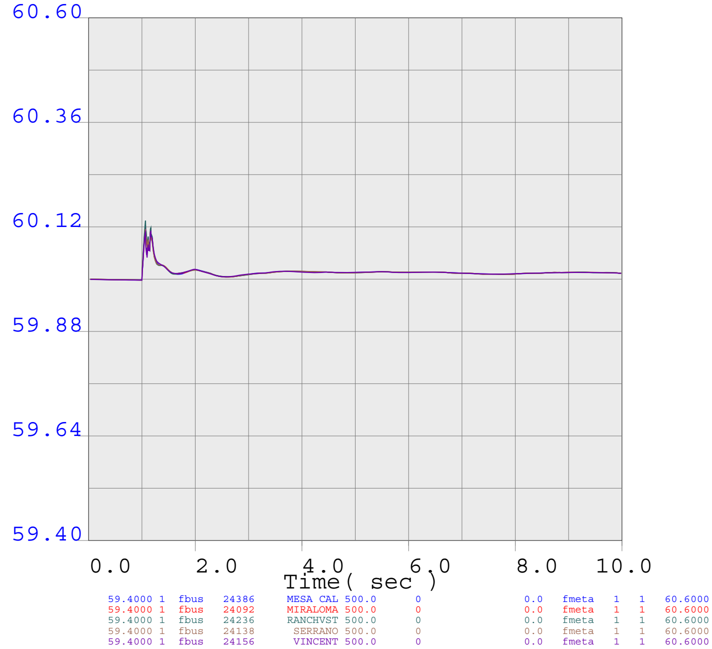
qc9p-bay_2365.chf

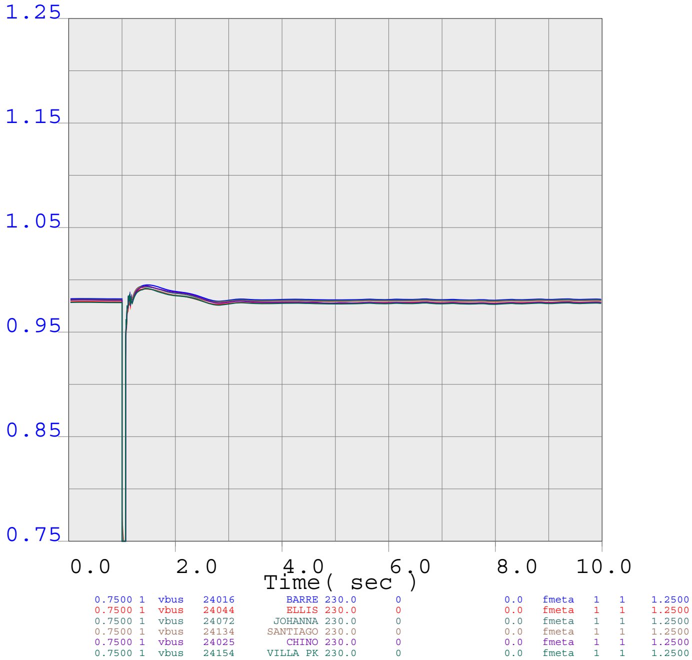
C:\DYTOOLS

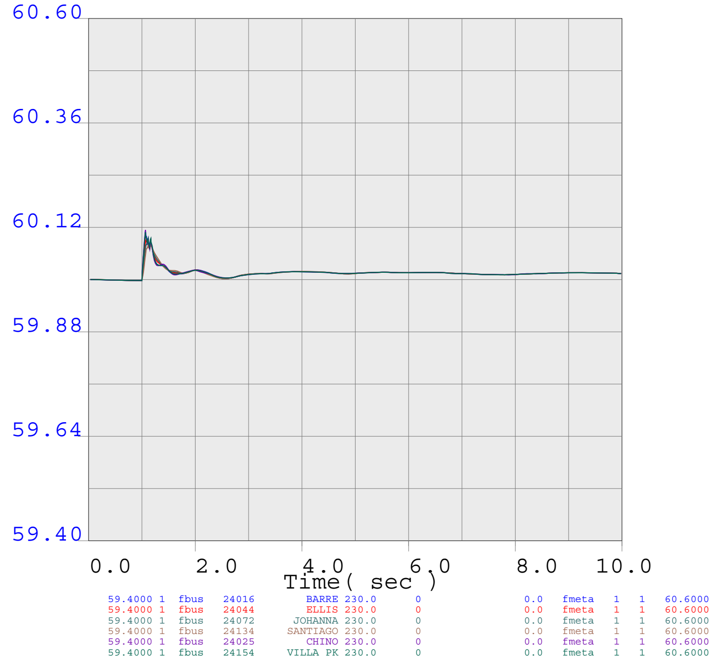
Thu Oct 20 08:58:13 2016

METRO









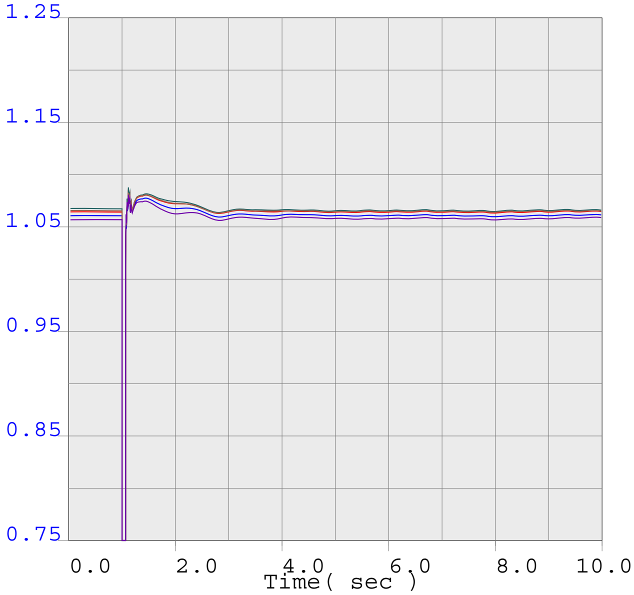
bay_2366
MIRALOMA 500 KV POS 2 INTERNAL FAULT
1 MW dispatch Case

qc9p-bay_2366.chf

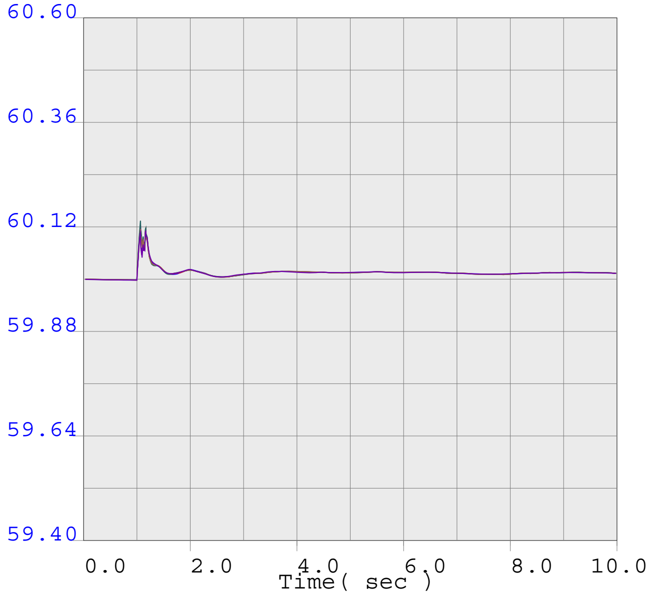
C:\DYTOOLS

Thu Oct 20 08:58:14 2016

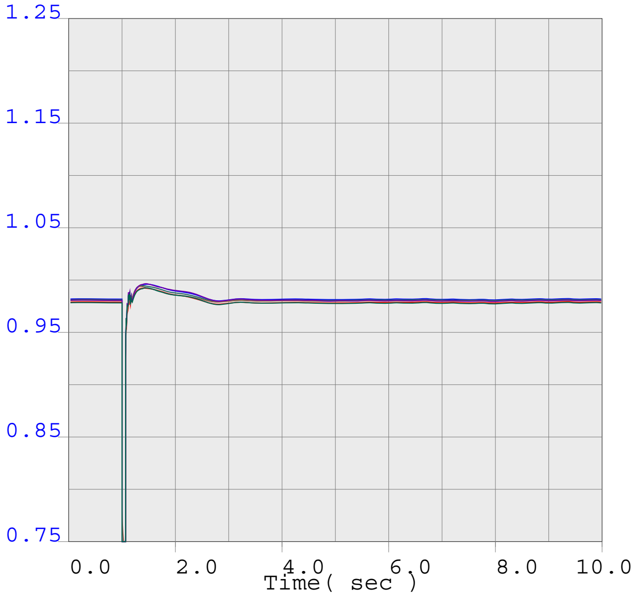
METRO



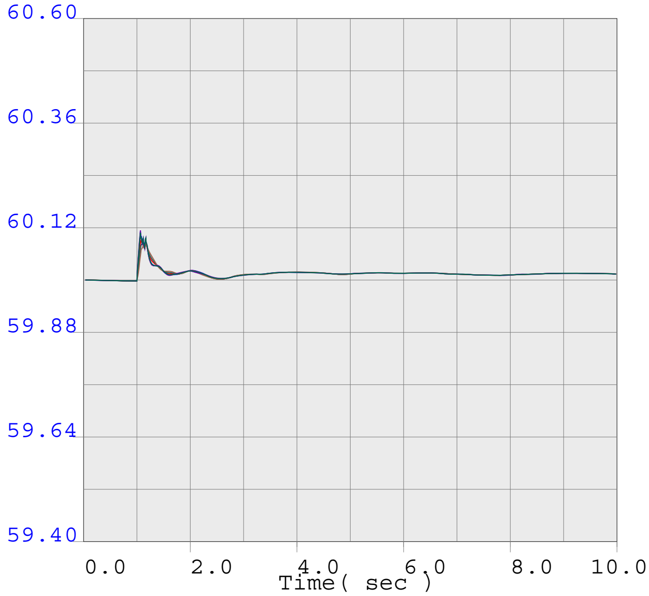
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

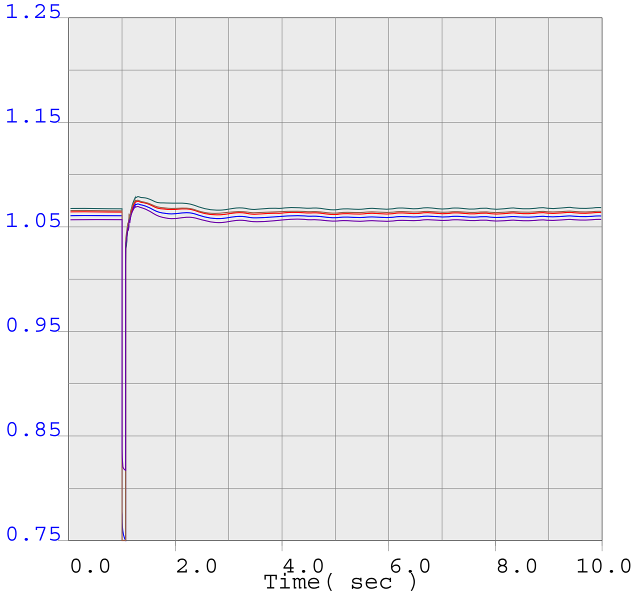
bay_2367
MIRALOMA 500 KV POS 6 INTERNAL FAULT
1 MW dispatch Case

qc9p-bay_2367.chf

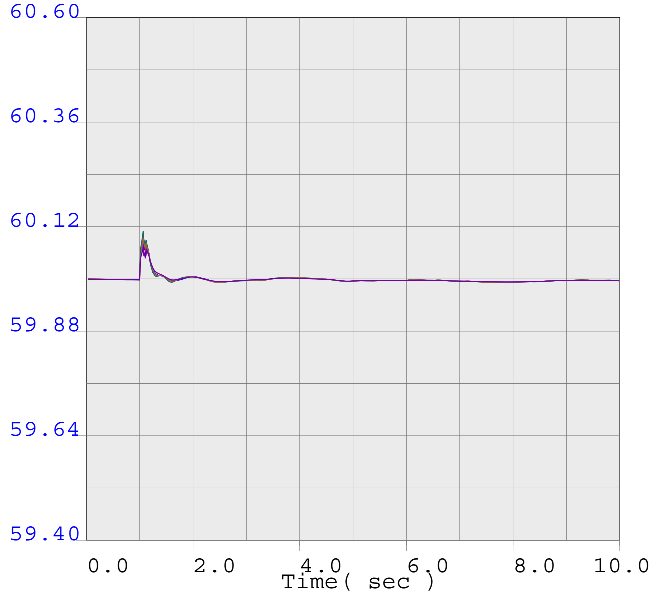
C:\DYTOOLS

Thu Oct 20 08:58:17 2016

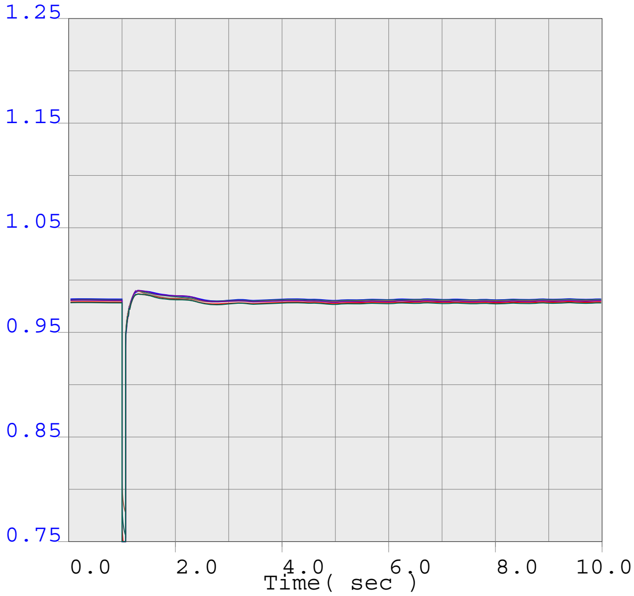
METRO



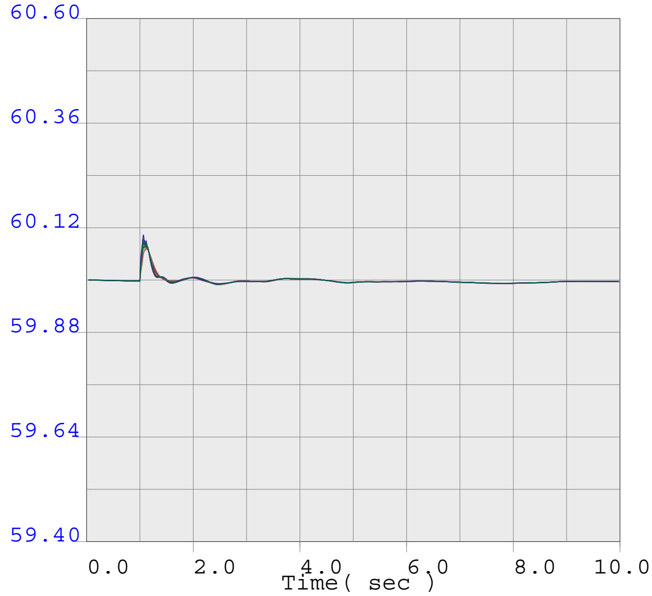
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

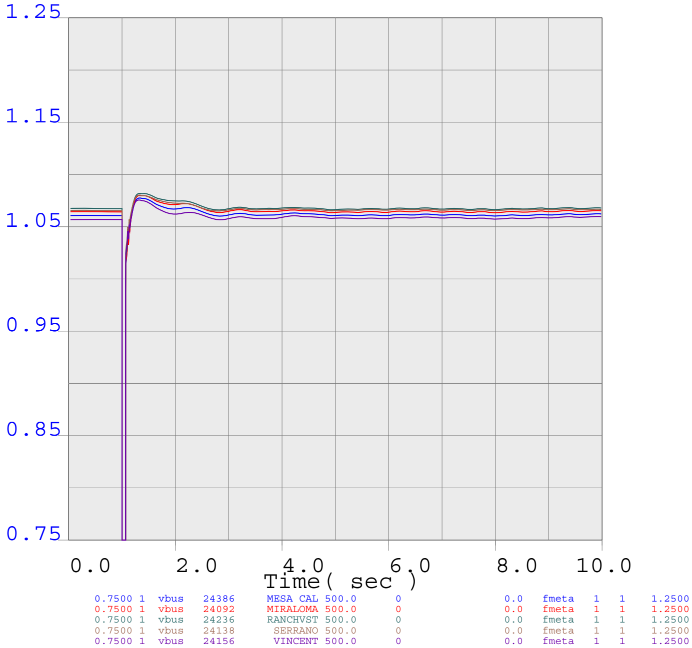
bay_2368
MIRALOMA 500 KV POS 1XN
1 MW dispatch Case

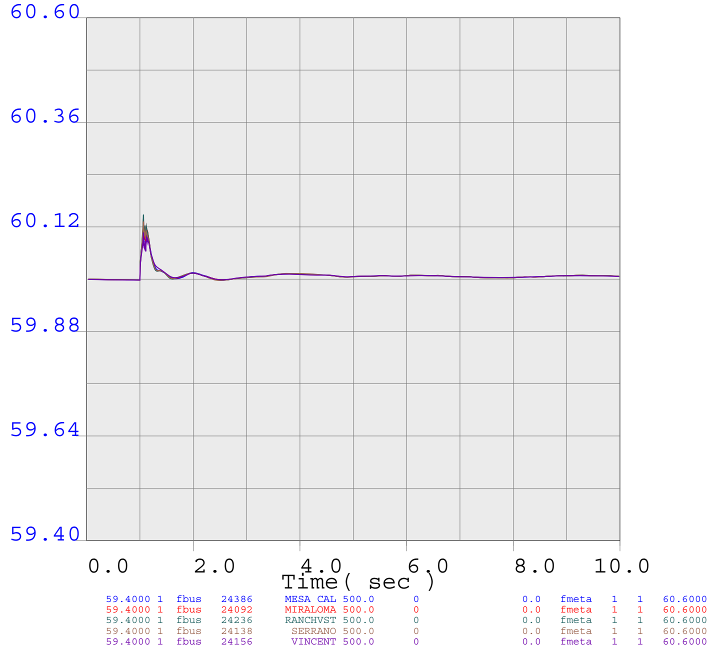
qc9p-bay_2368.chf

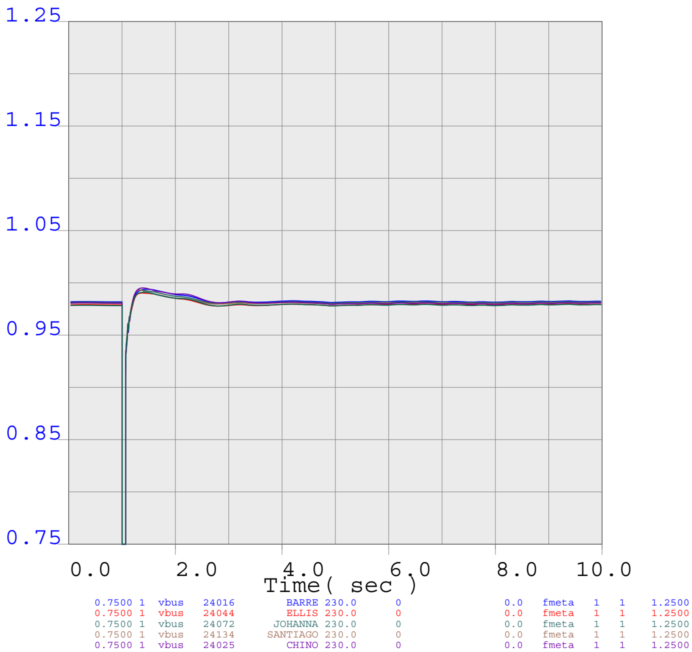
C:\DYTOOLS

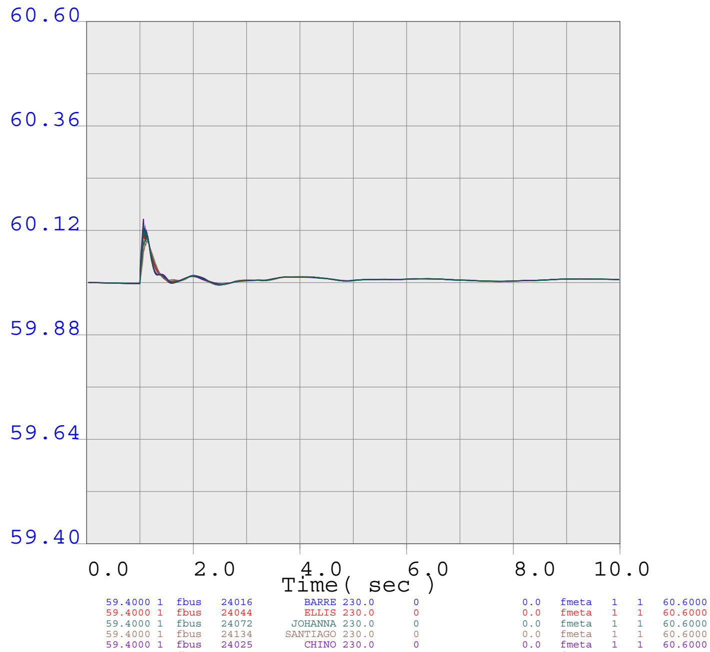
Thu Oct 20 08:58:19 2016

METRO









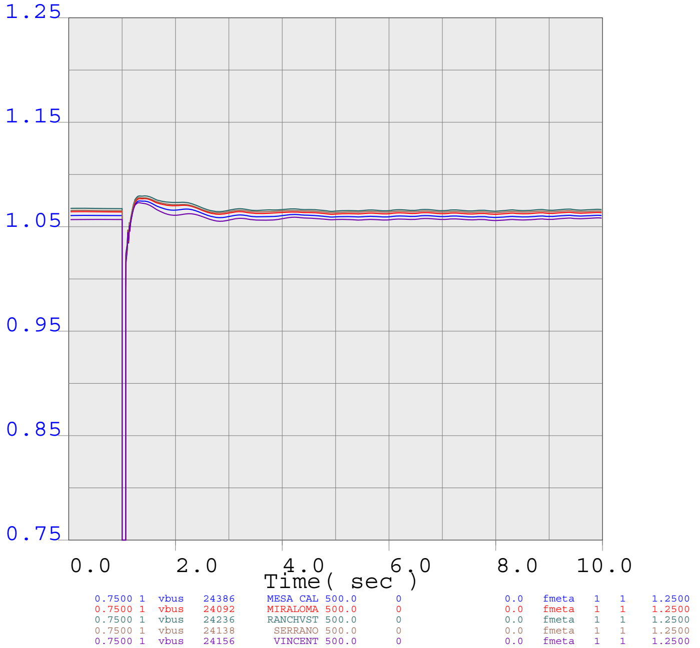
bay_2369
MIRALOMA 500 KV POS 1N
1 MW dispatch Case

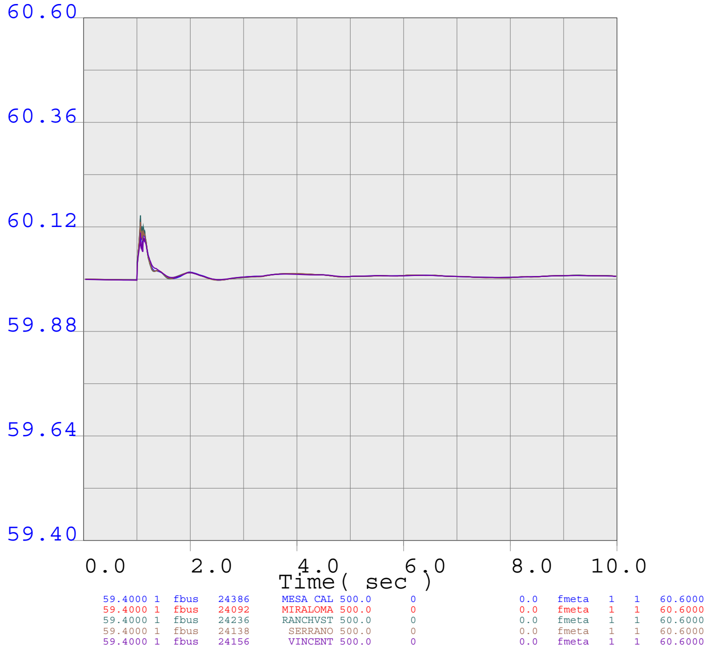
qc9p-bay_2369.chf

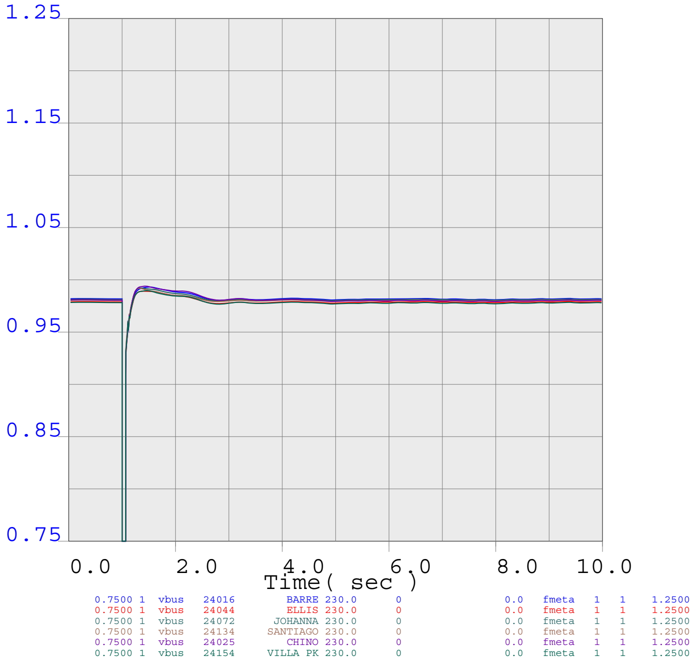
C:\DYTOOLS

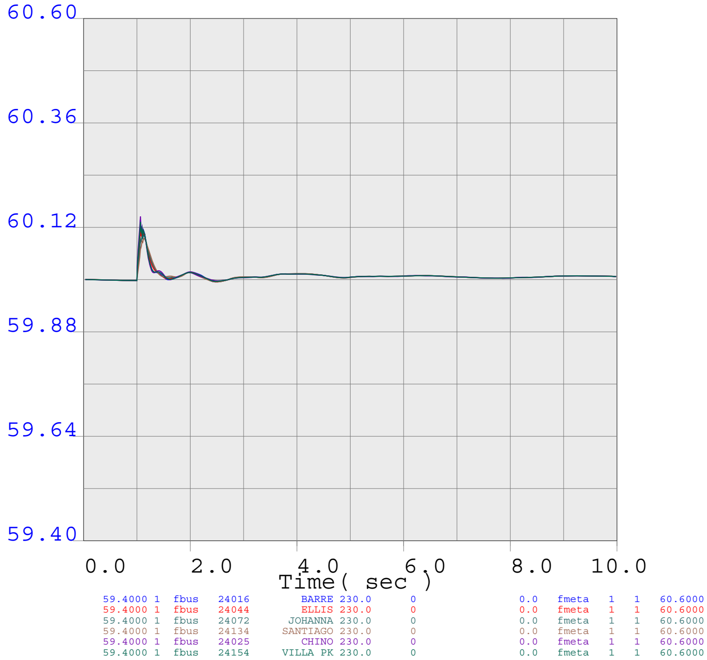
Thu Oct 20 08:58:21 2016

METRO









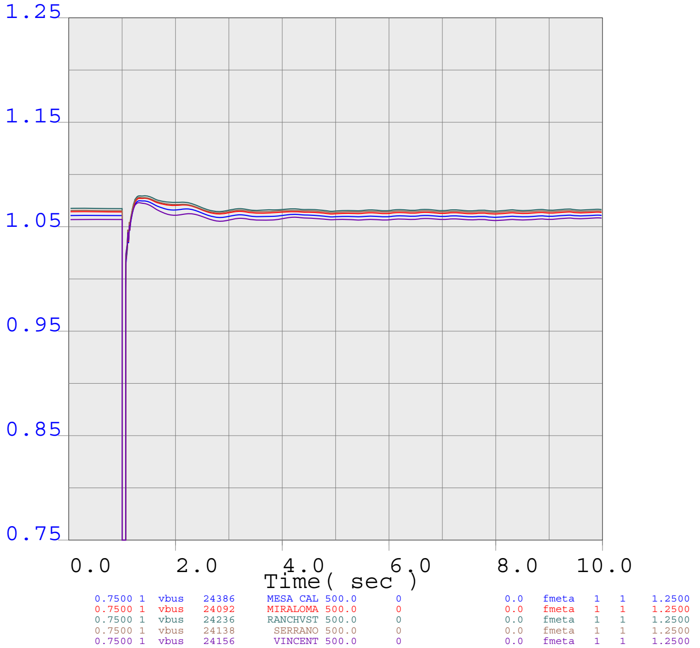
bay_2370
MIRALOMA 500 KV POS 2N
1 MW dispatch Case

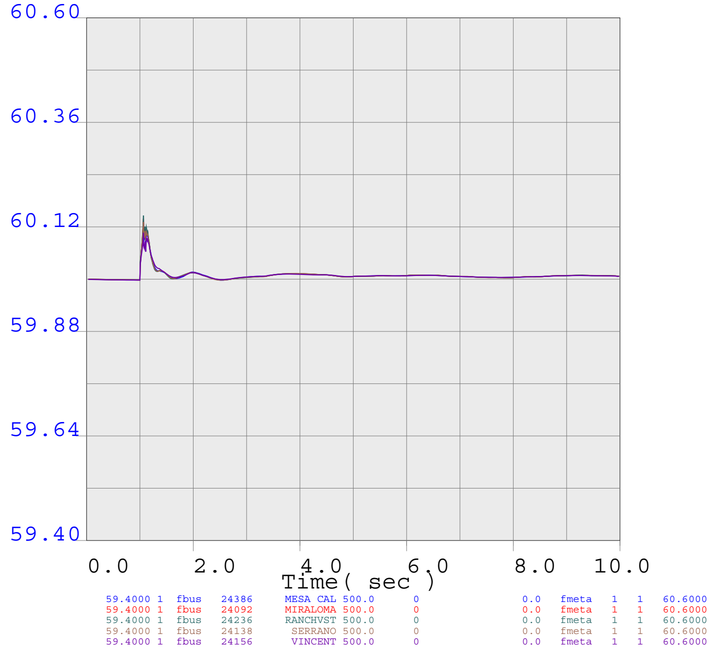
qc9p-bay_2370.chf

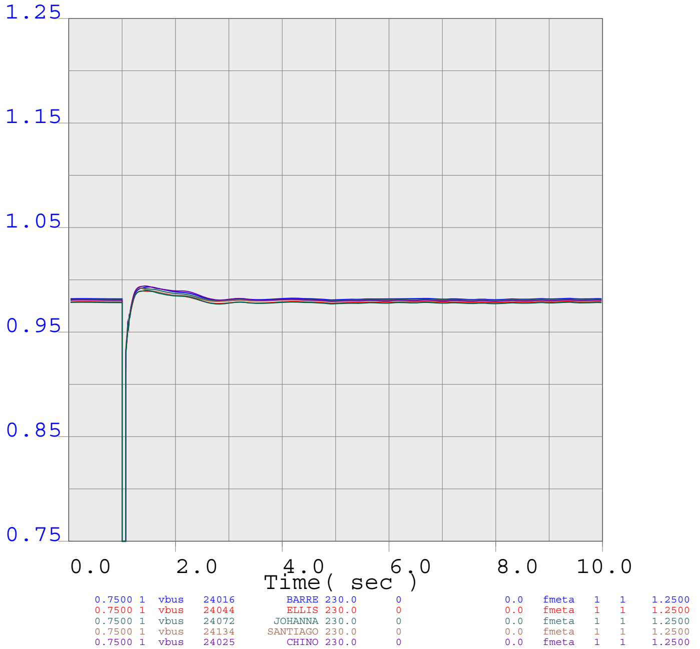
C:\DYTOOLS

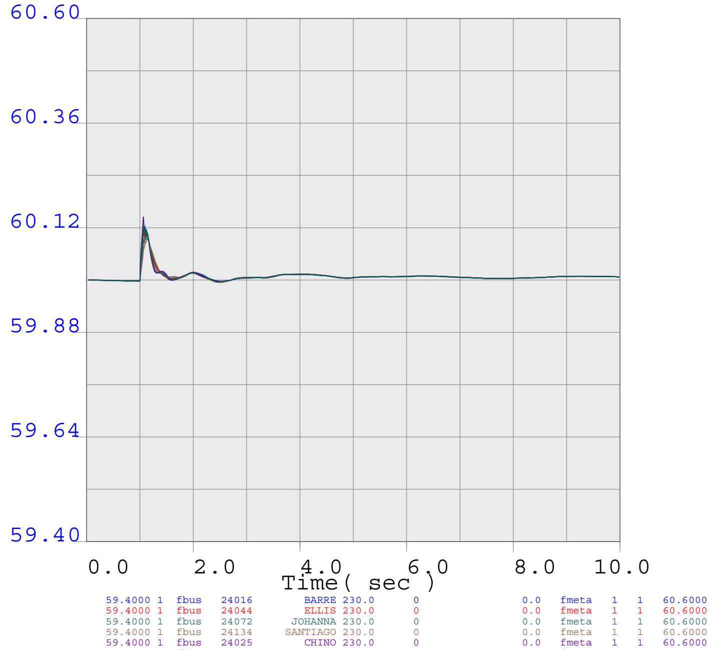
Thu Oct 20 08:58:23 2016

METRO









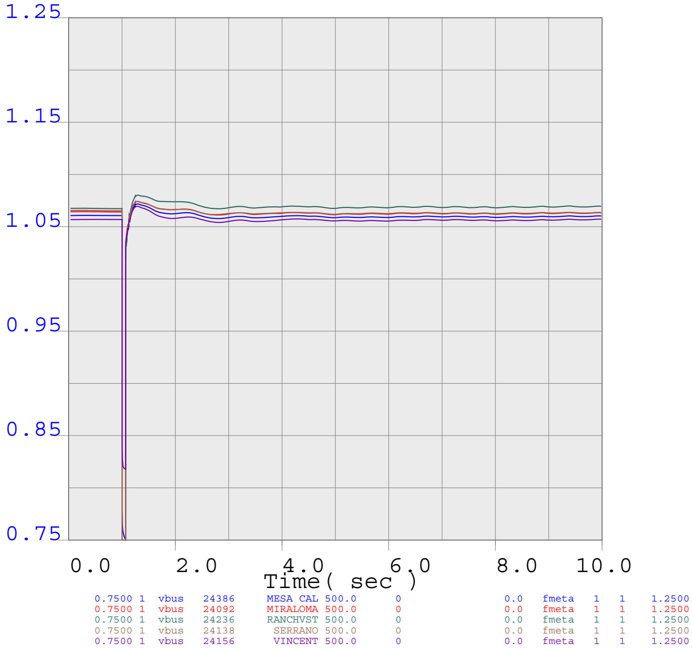
bay_2371
MIRALOMA 500 KV POS 6N
1 MW dispatch Case

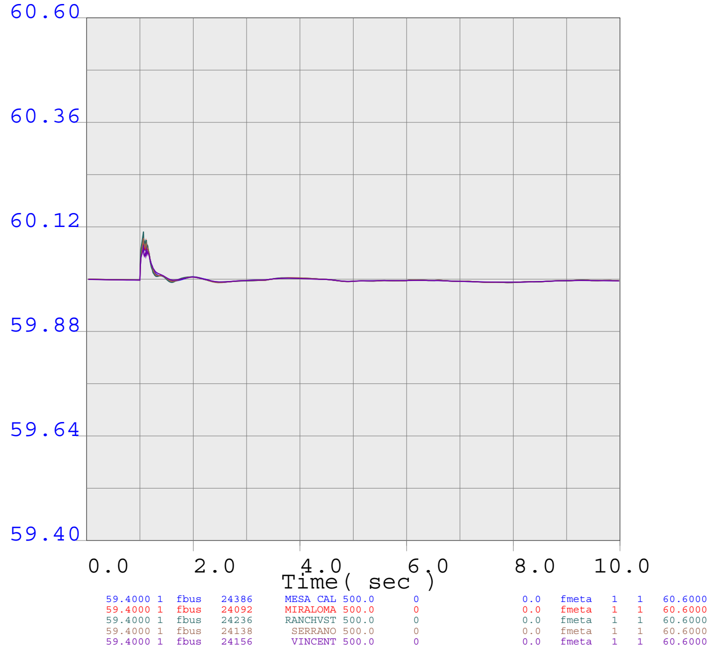
qc9p-bay_2371.chf

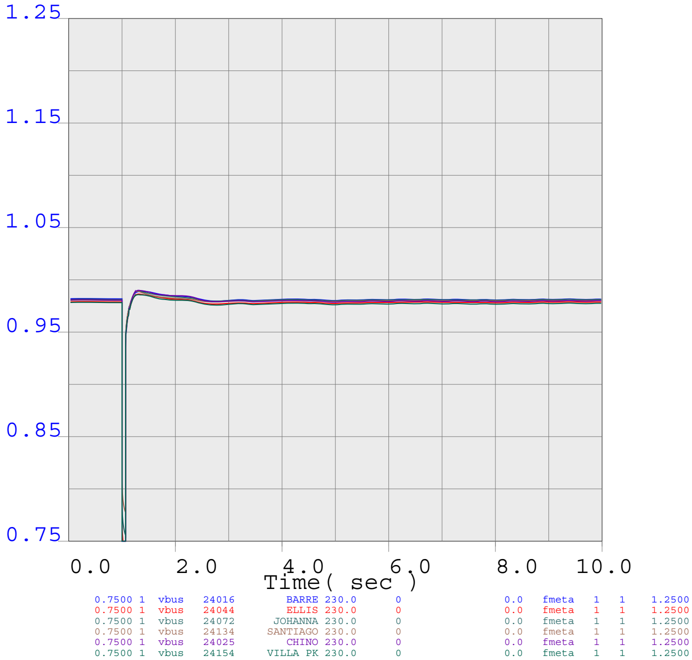
C:\DYTOOLS

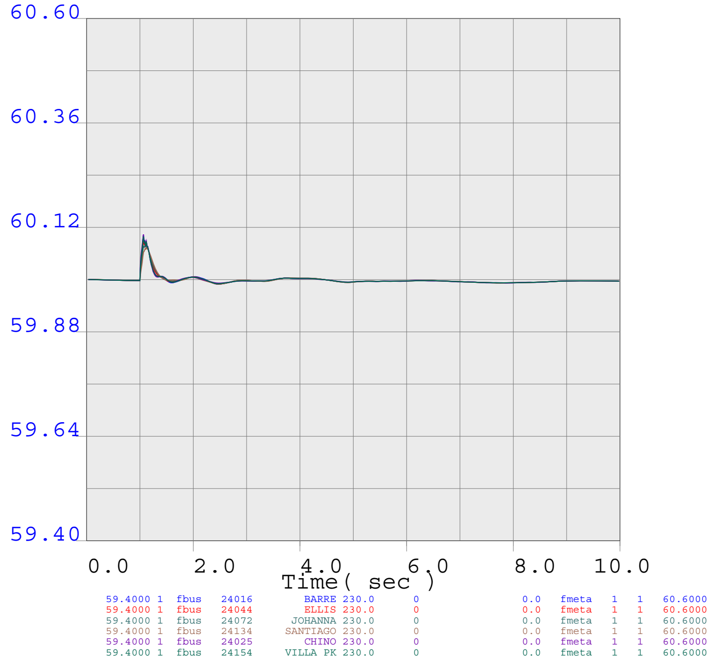
Thu Oct 20 08:58:25 2016

METRO









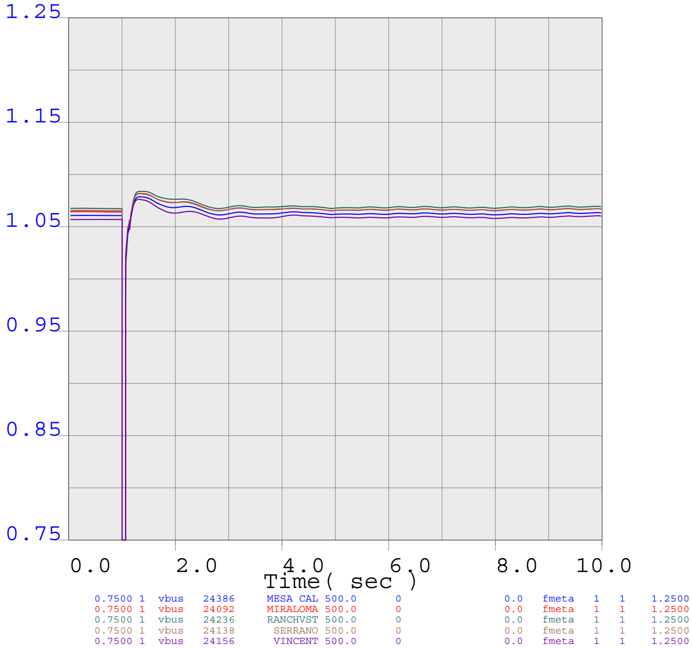
bay_2372
MIRALOMA 500 KV POS 1XS
1 MW dispatch Case

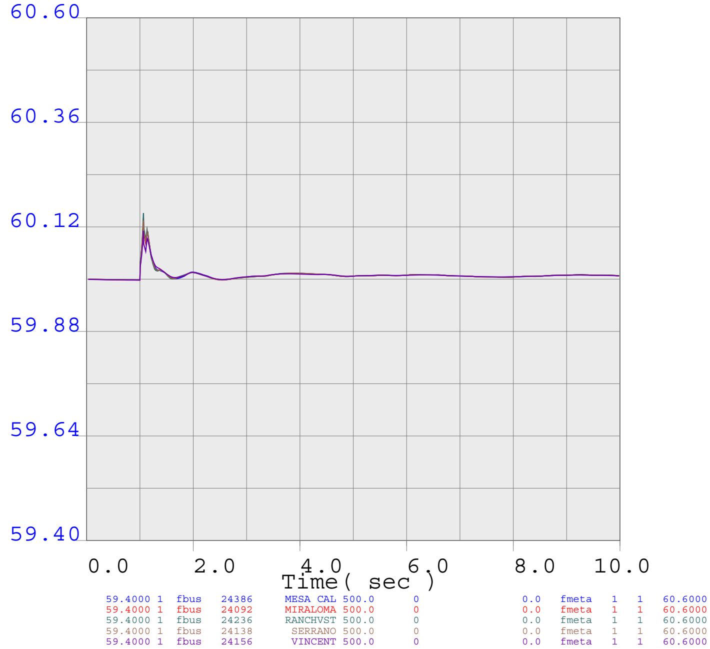
qc9p-bay_2372.chf

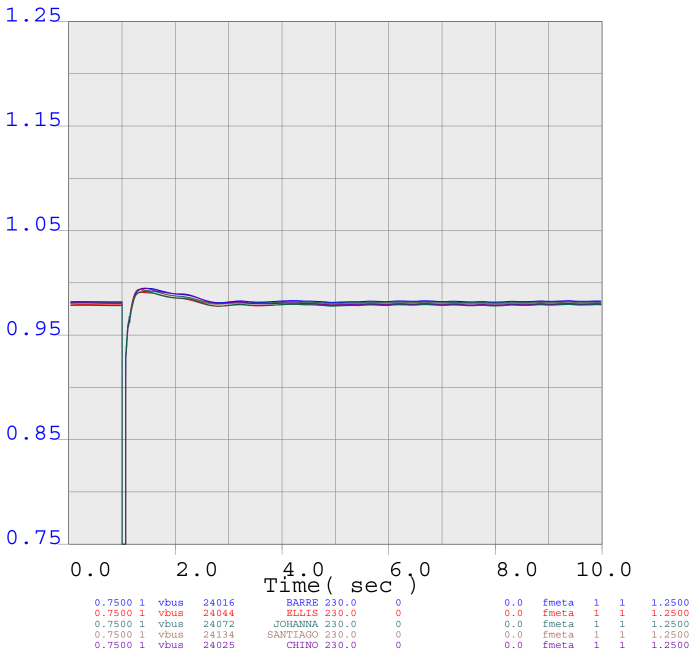
C:\DYTOOLS

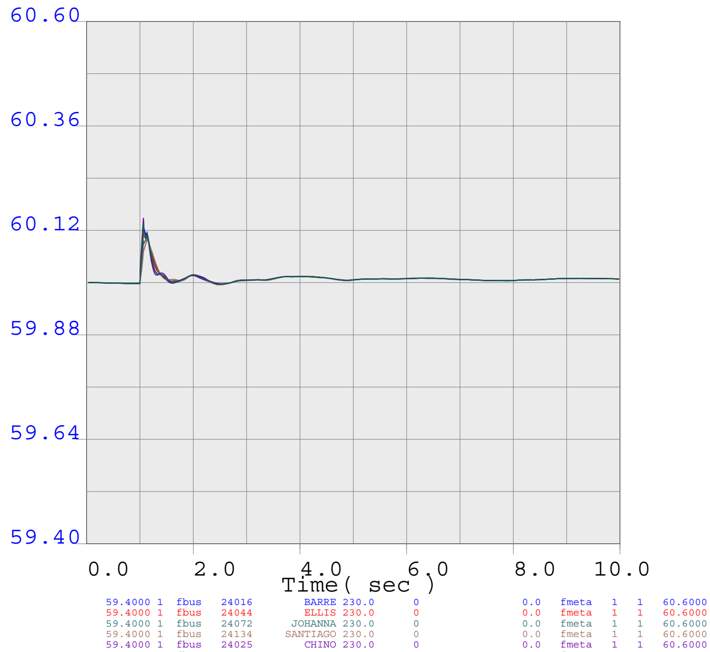
Thu Oct 20 08:58:27 2016

METRO









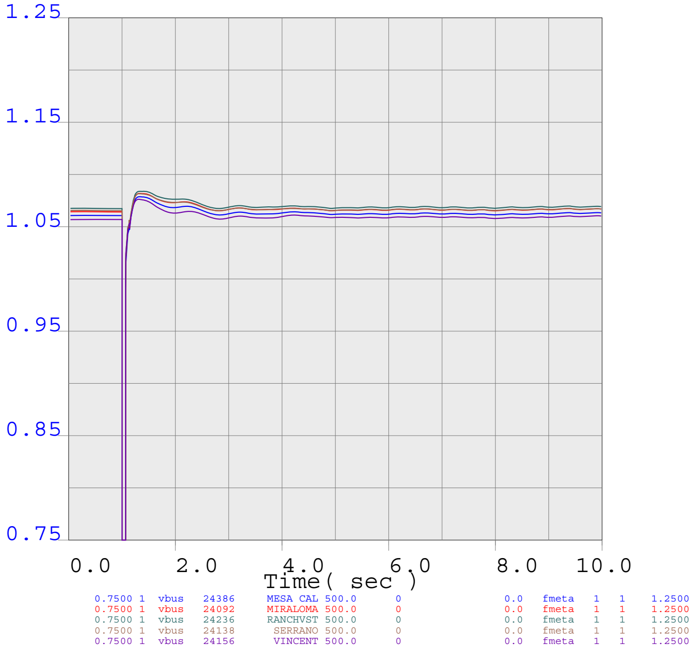
bay_2373
MIRALOMA 500 KV POS 2S
1 MW dispatch Case

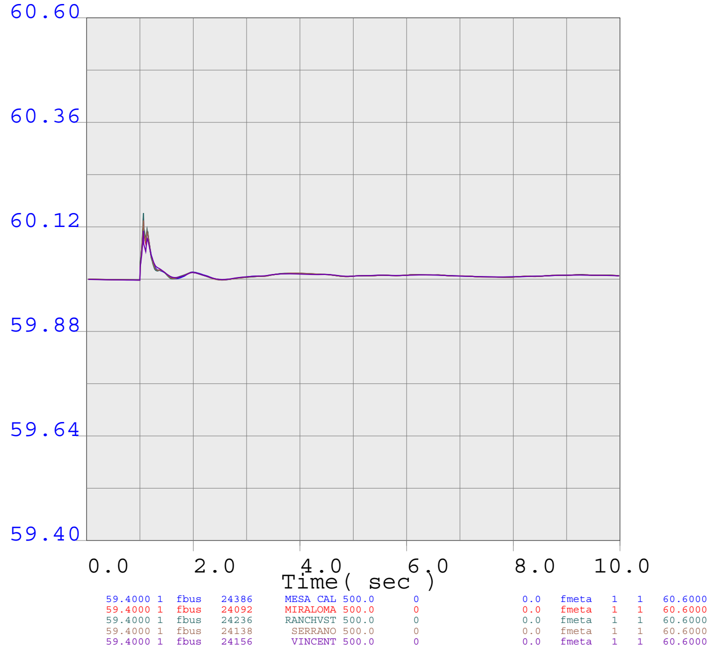
qc9p-bay_2373.chf

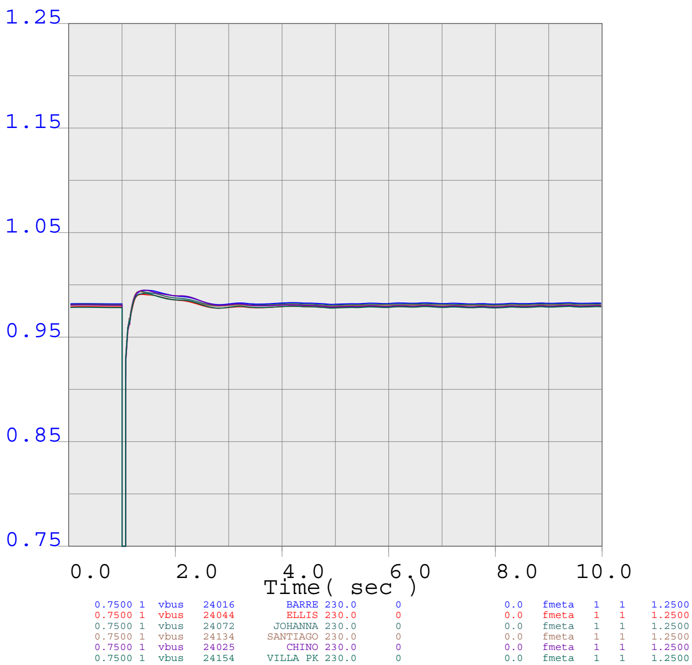
C:\DYTOOLS

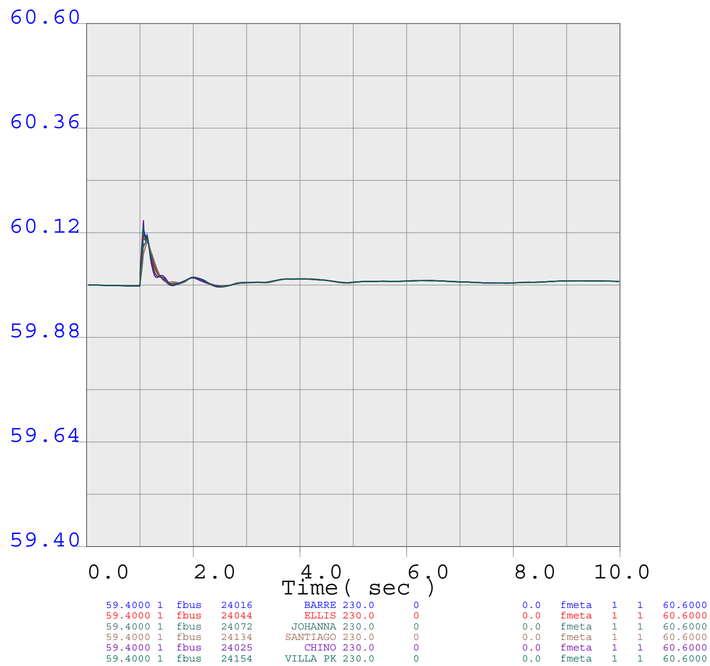
Thu Oct 20 08:58:31 2016

METRO









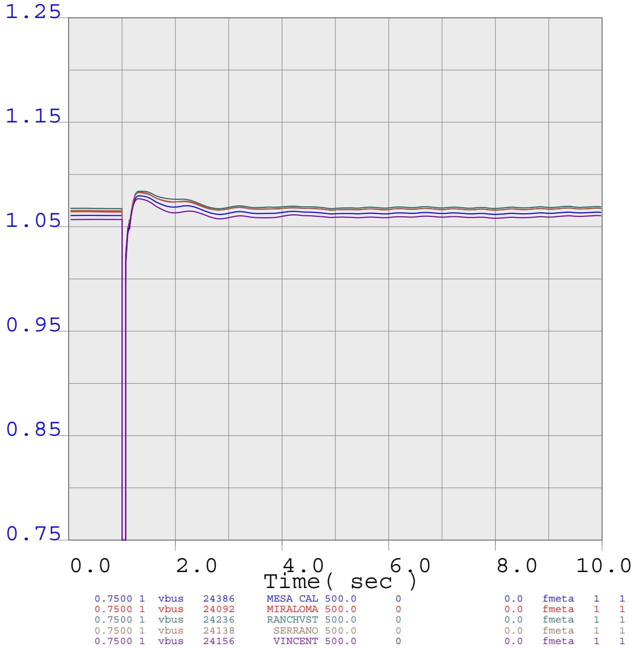
bay_2374
MIRALOMA 500 KV POS 4S
1 MW dispatch Case

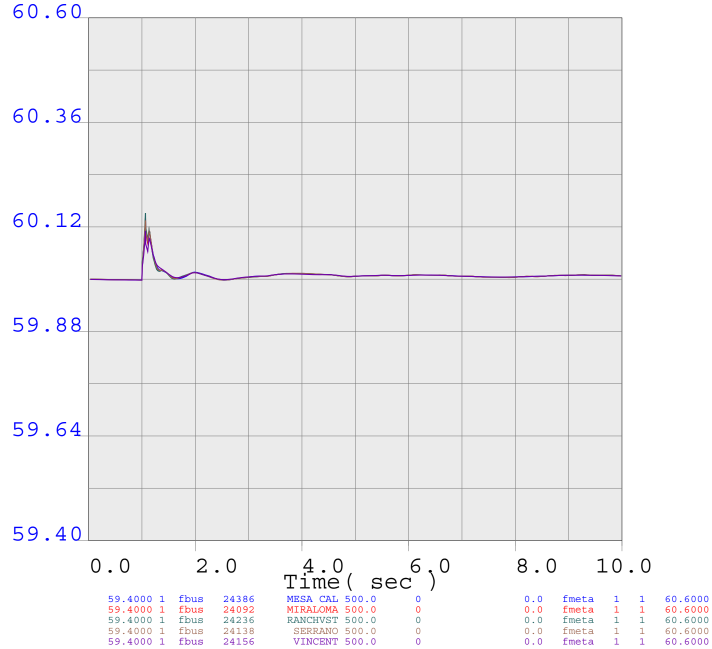
qc9p-bay_2374.chf

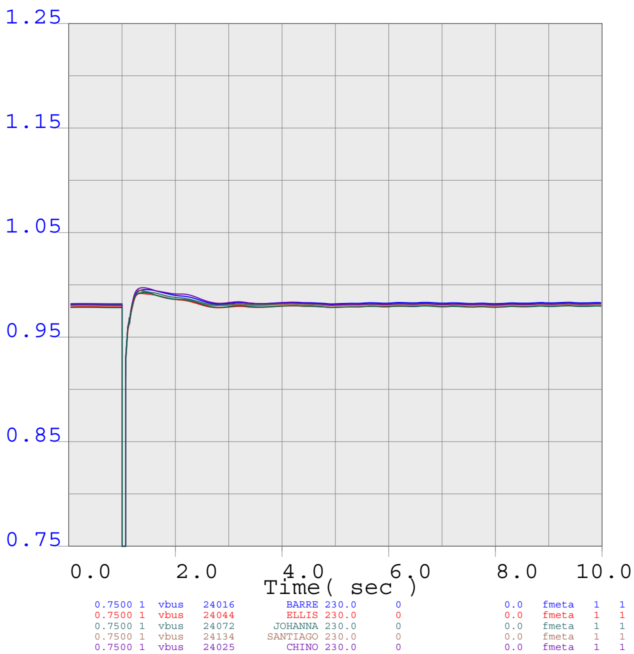
C:\DYTOOLS

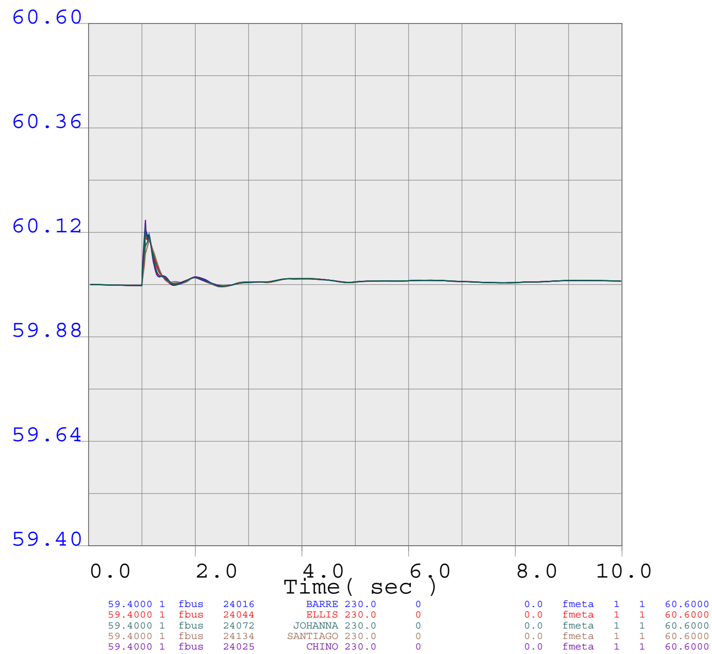
Thu Oct 20 08:58:33 2016

METRO









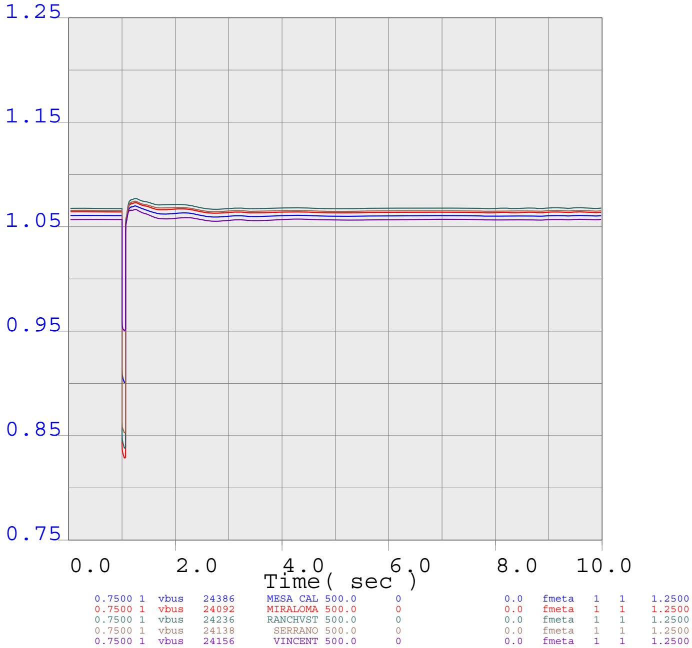
bay_2375
MIRALOMA 500 KV POS 6S
1 MW dispatch Case

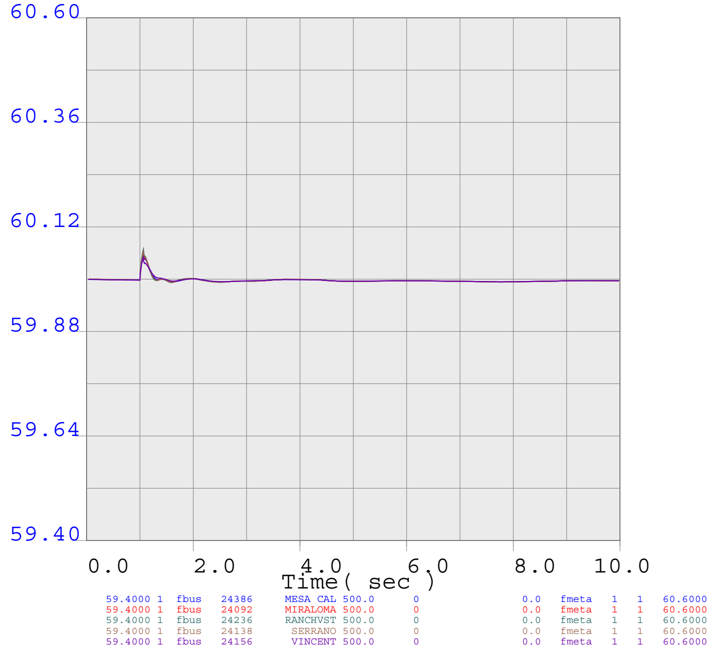
qc9p-bay_2375.chf

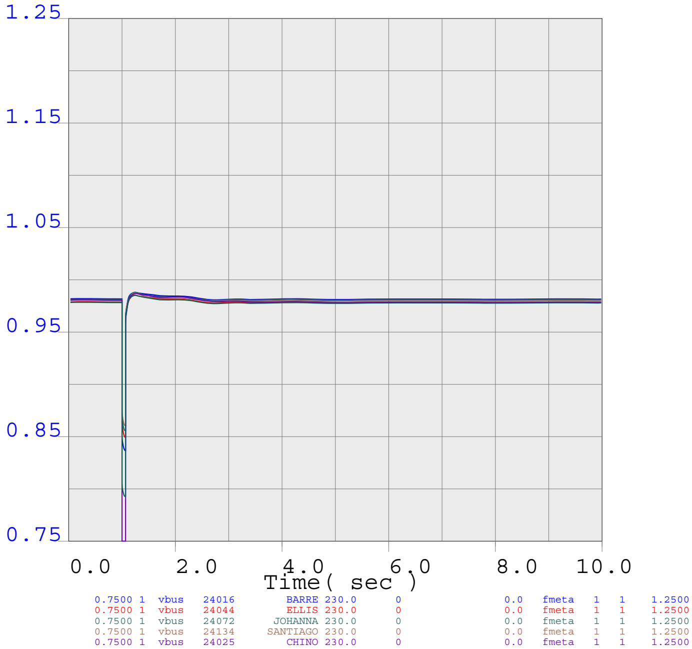
C:\DYTOOLS

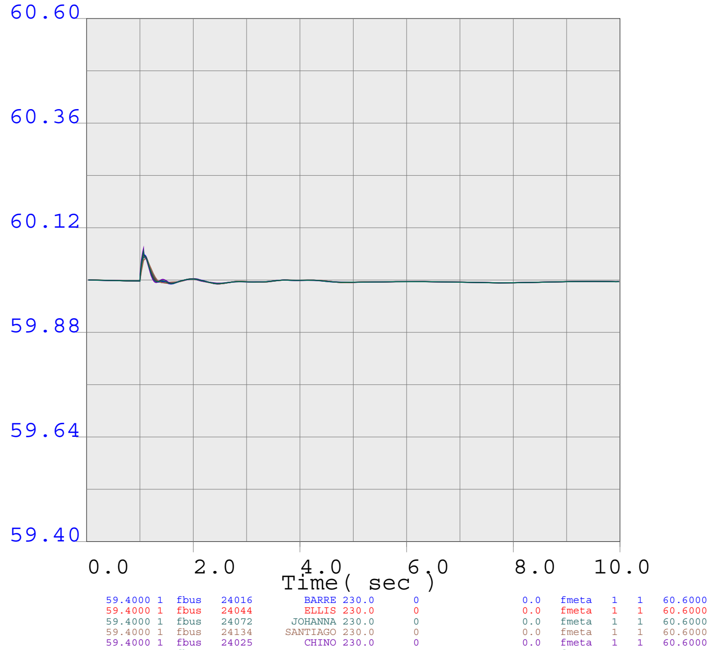
Thu Oct 20 08:58:35 2016

METRO









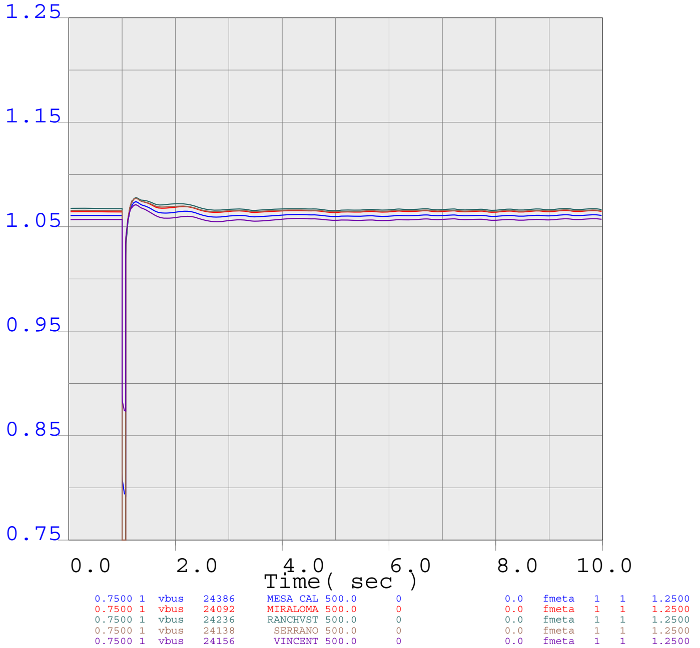
bay_2376
MIRALOMAE 220 KV POS 14N
1 MW dispatch Case

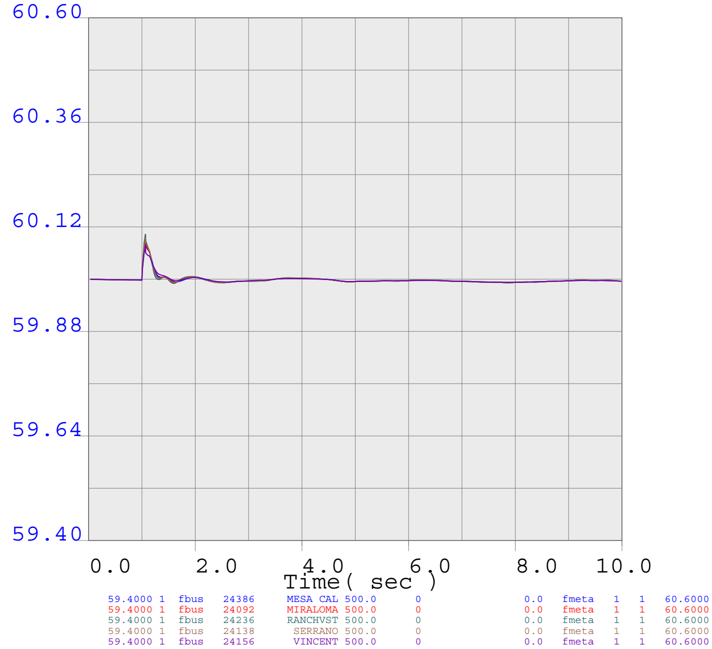
qc9p-bay_2376.chf

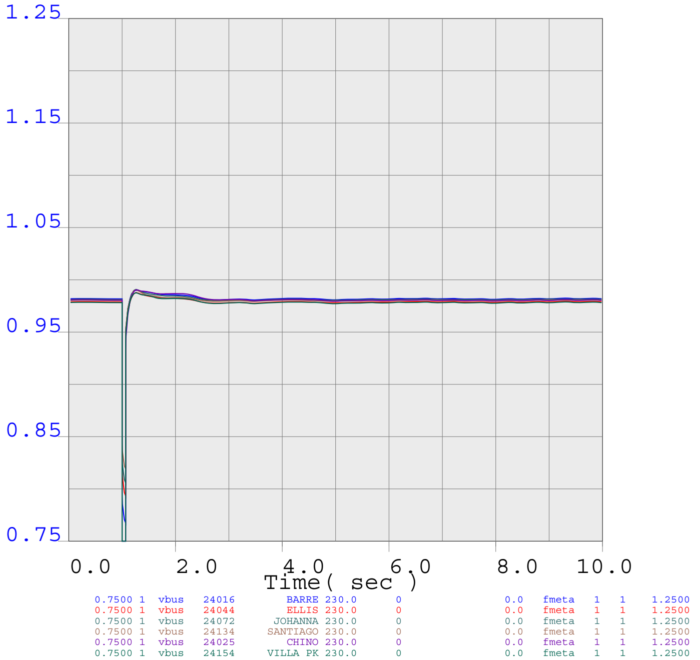
C:\DYTOOLS

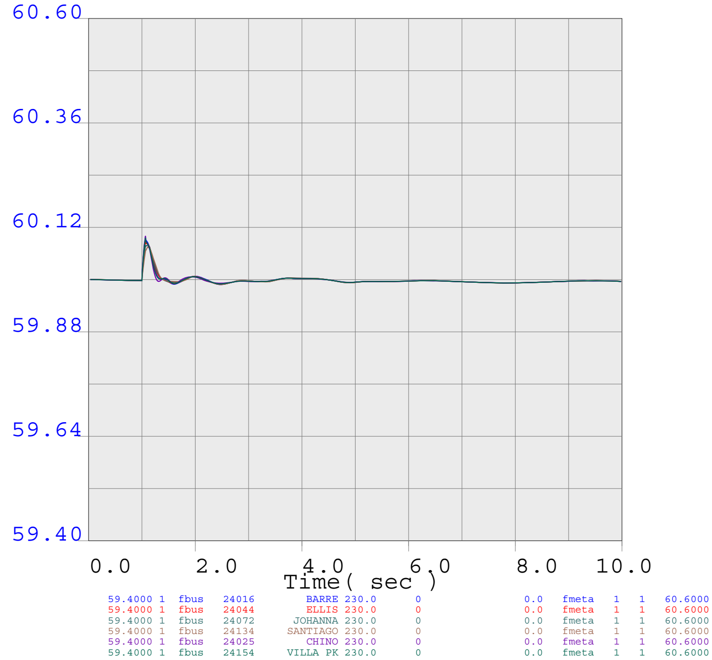
Thu Oct 20 08:58:38 2016

METRO









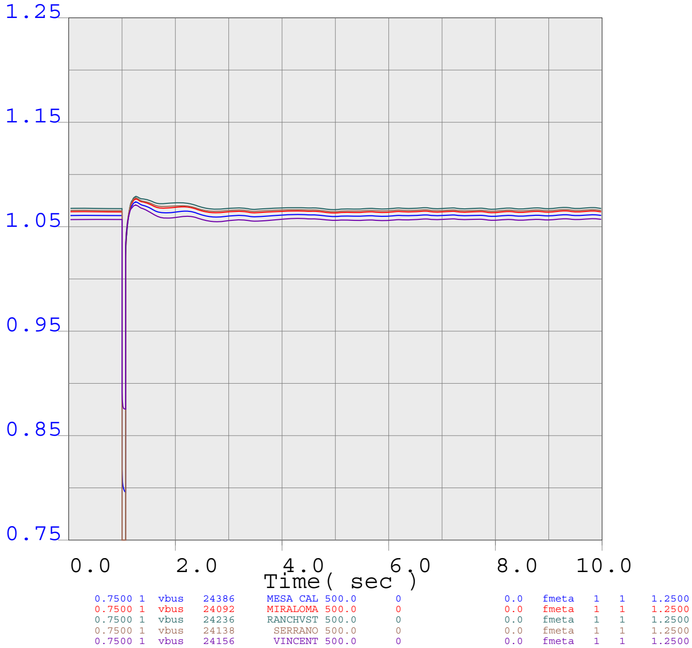
bay_2377
MIRALOMAE 220 KV POS 15N
1 MW dispatch Case

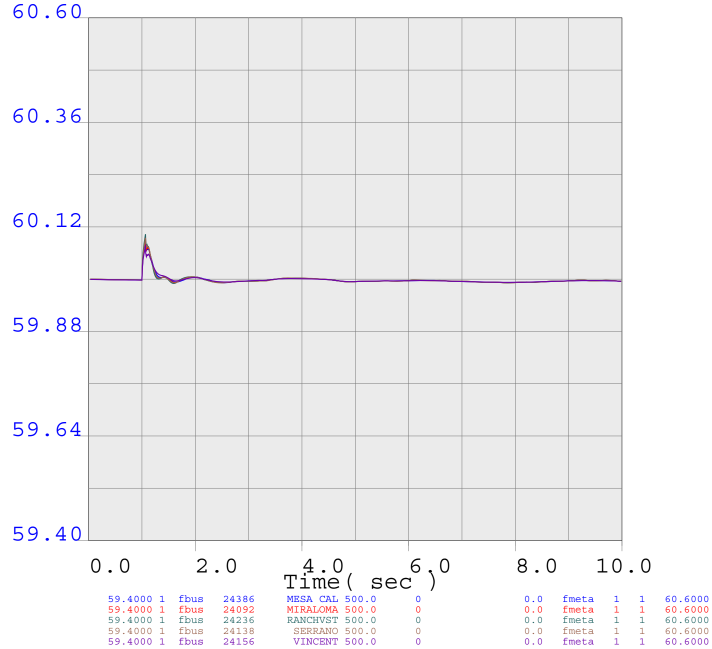
qc9p-bay_2377.chf

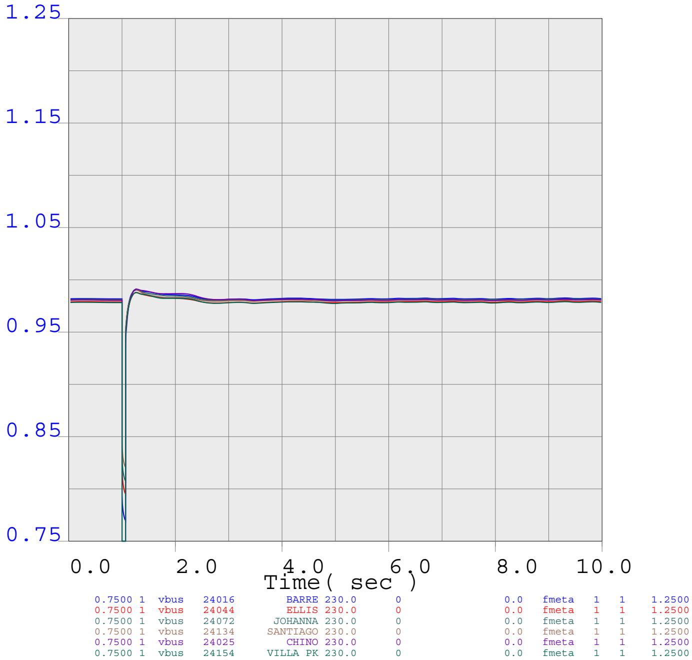
C:\DYTOOLS

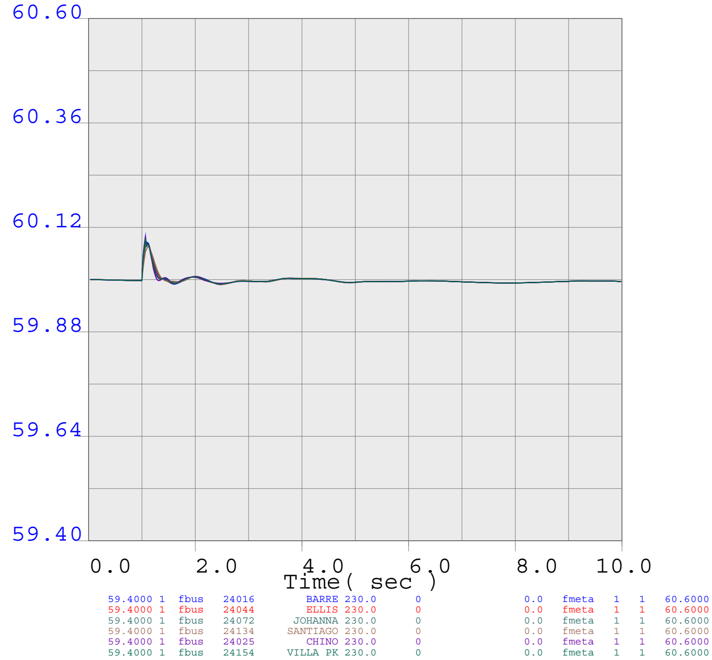
Thu Oct 20 08:58:40 2016

METRO









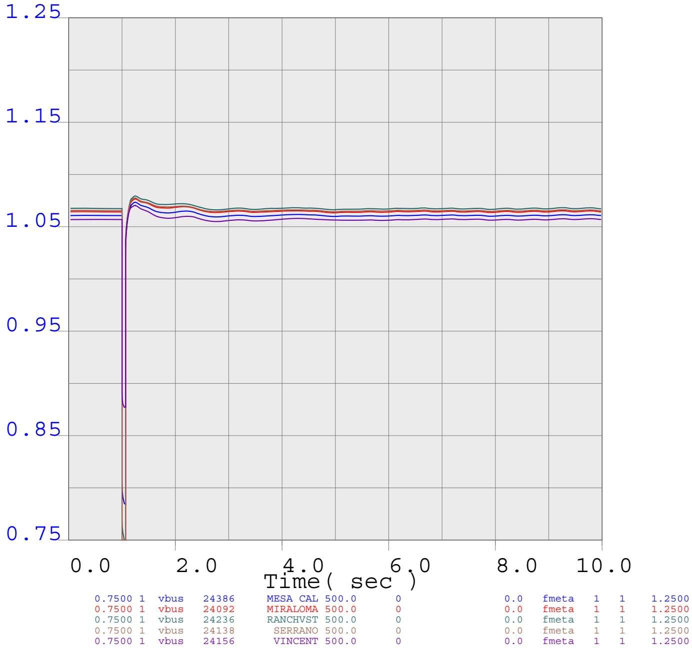
bay_2378
MIRALOMAE 220 KV POS 16N
1 MW dispatch Case

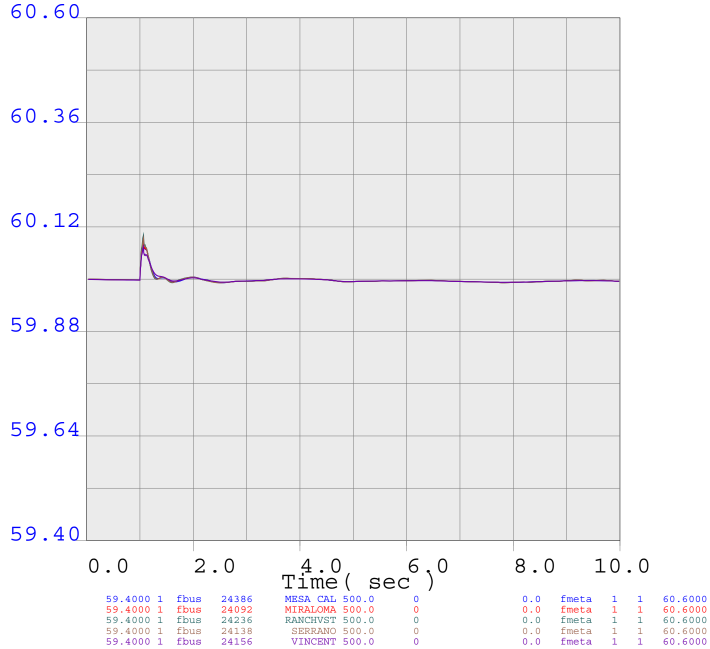
qc9p-bay_2378.chf

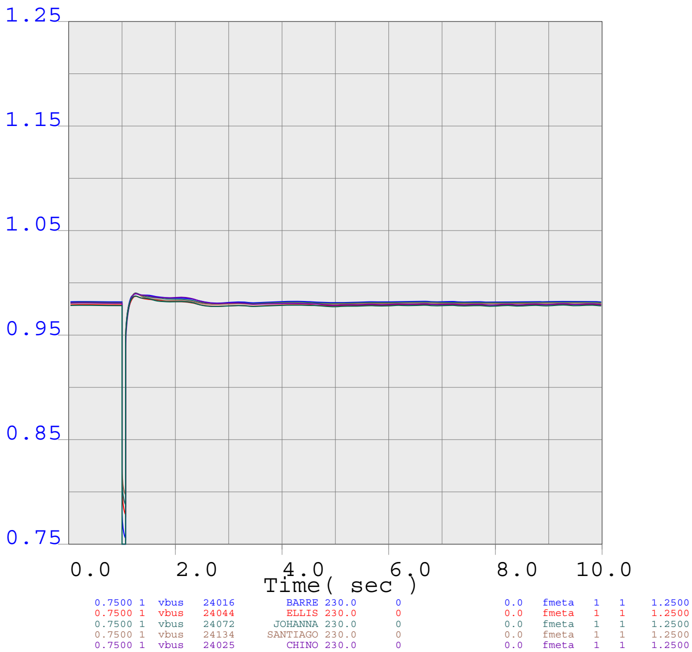
C:\DYTOOLS

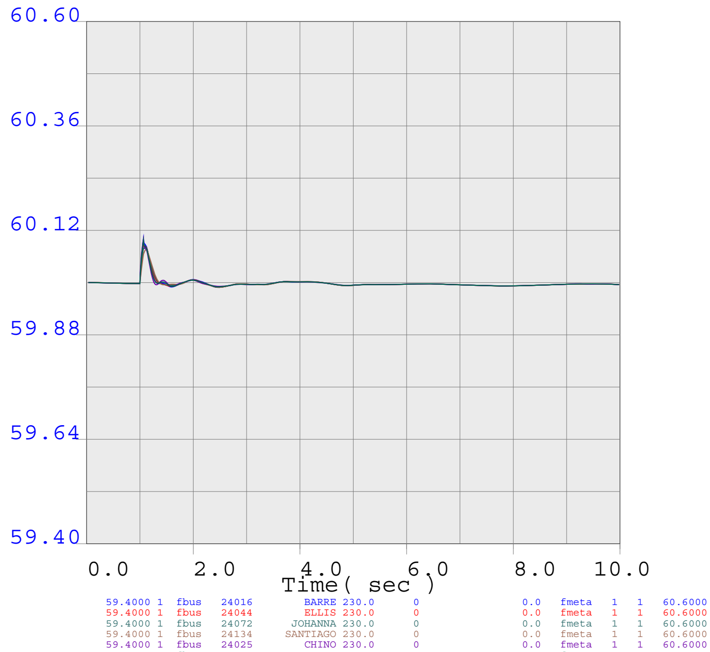
Thu Oct 20 08:58:43 2016

METRO









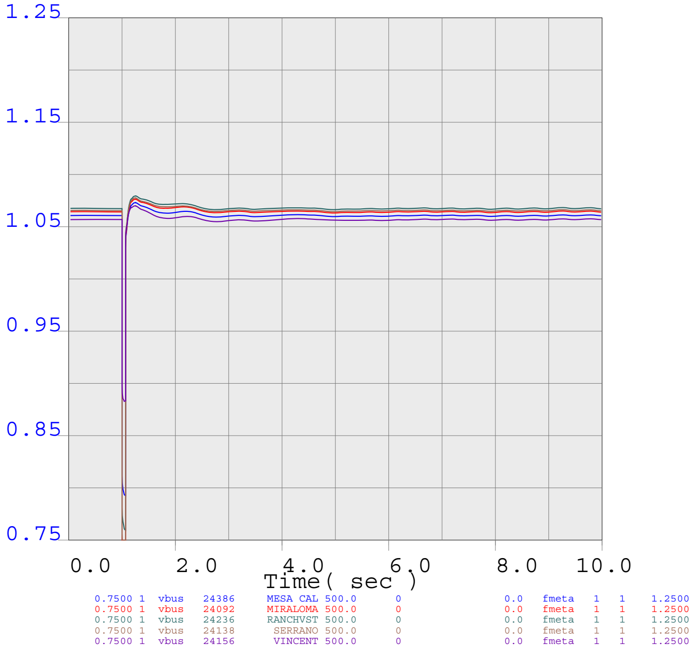
bay_2379
MIRALOMAW 220 KV POS 2S
1 MW dispatch Case

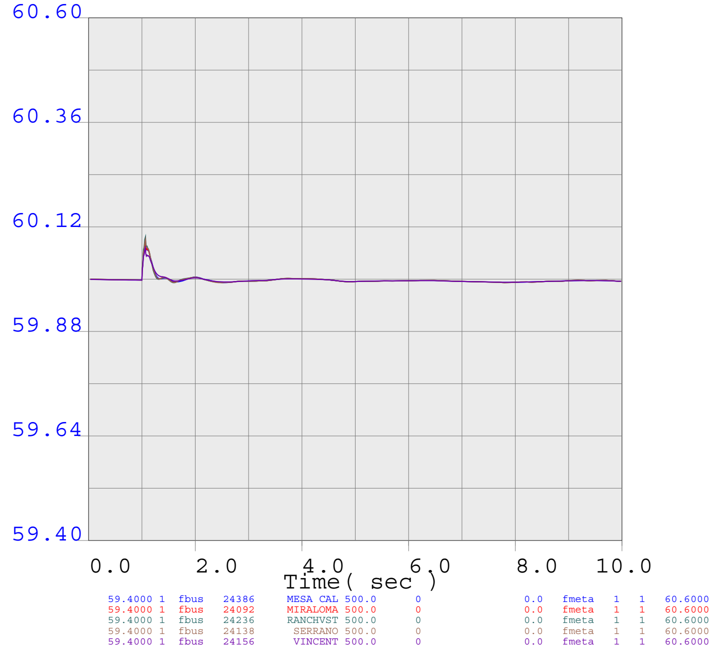
qc9p-bay_2379.chf

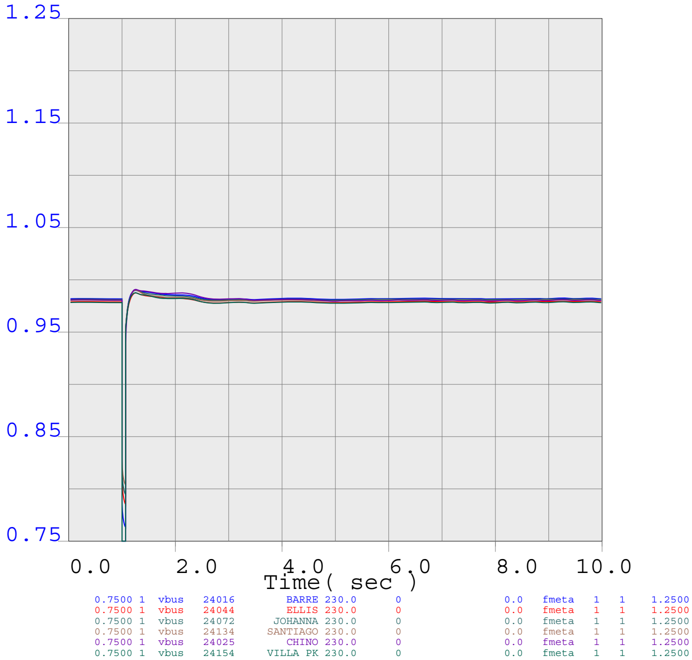
C:\DYTOOLS

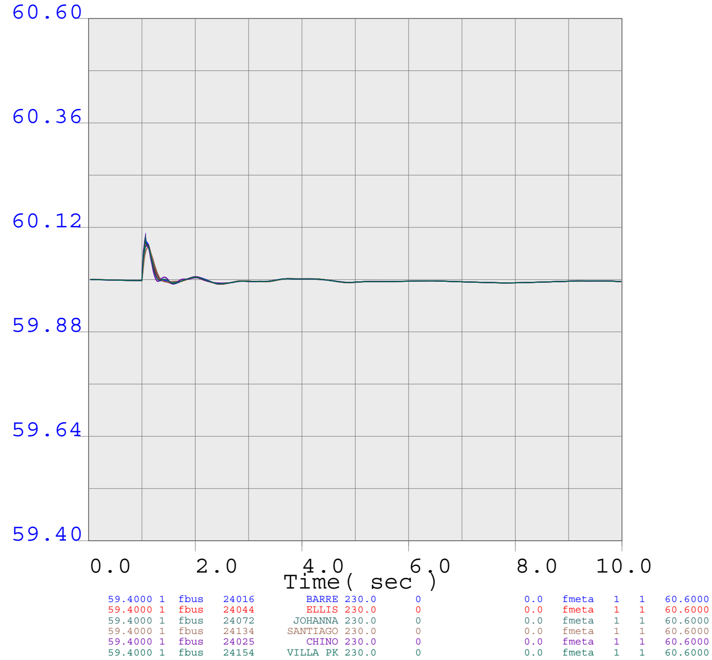
Thu Oct 20 08:58:45 2016

METRO









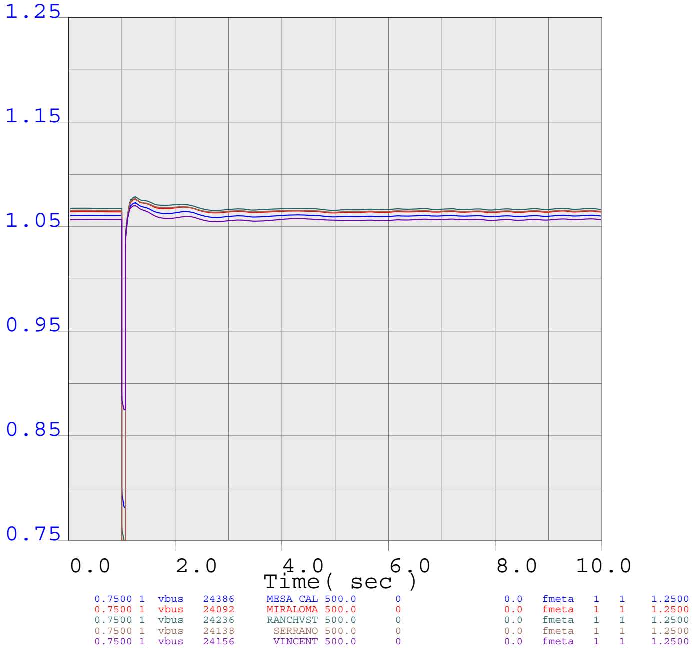
bay_2380
MIRALOMAW 220 KV POS 3S
1 MW dispatch Case

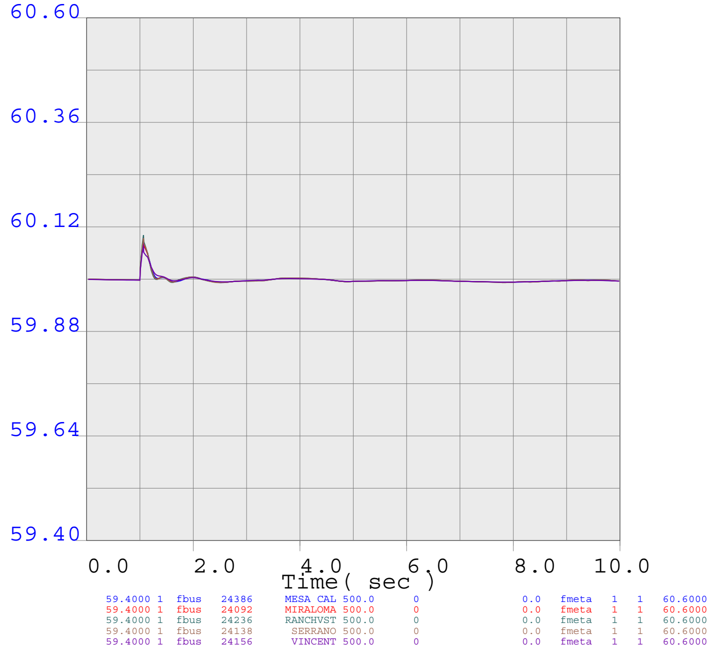
qc9p-bay_2380.chf

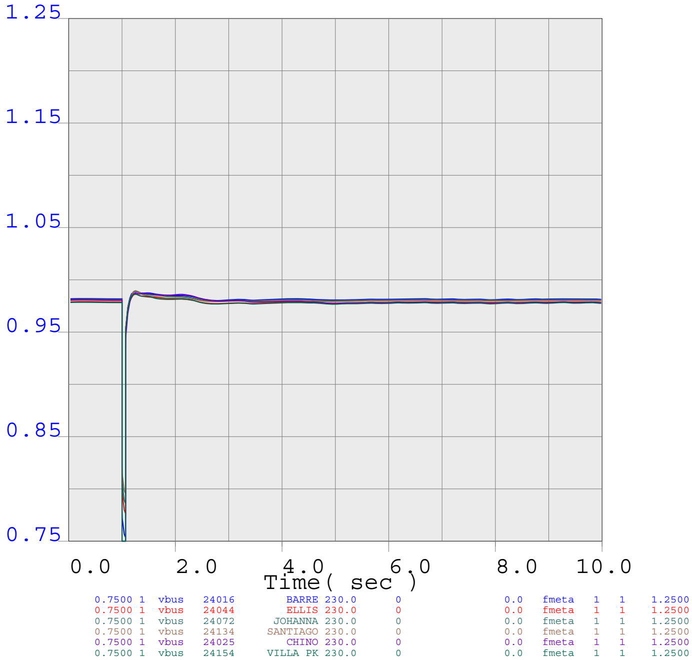
C:\DYTOOLS

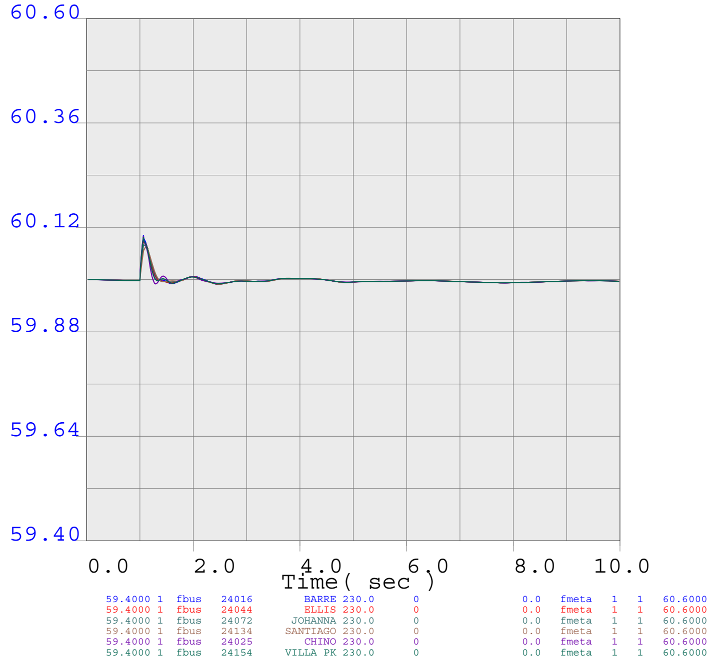
Thu Oct 20 08:58:48 2016

METRO









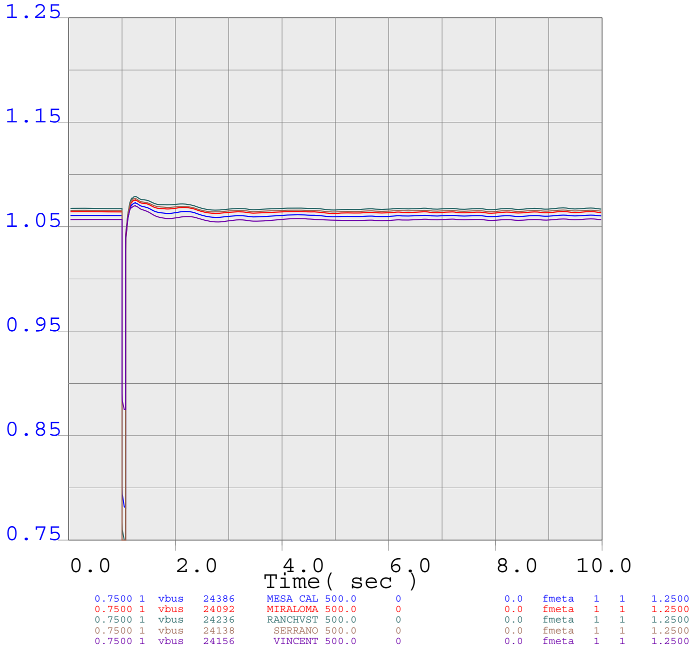
bay_2381
MIRALOMAW 220 KV POS 4S
1 MW dispatch Case

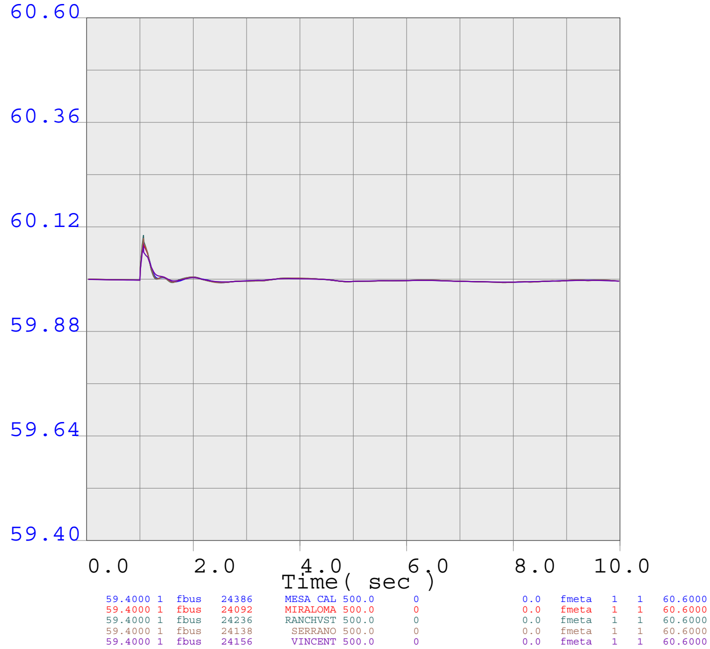
qc9p-bay_2381.chf

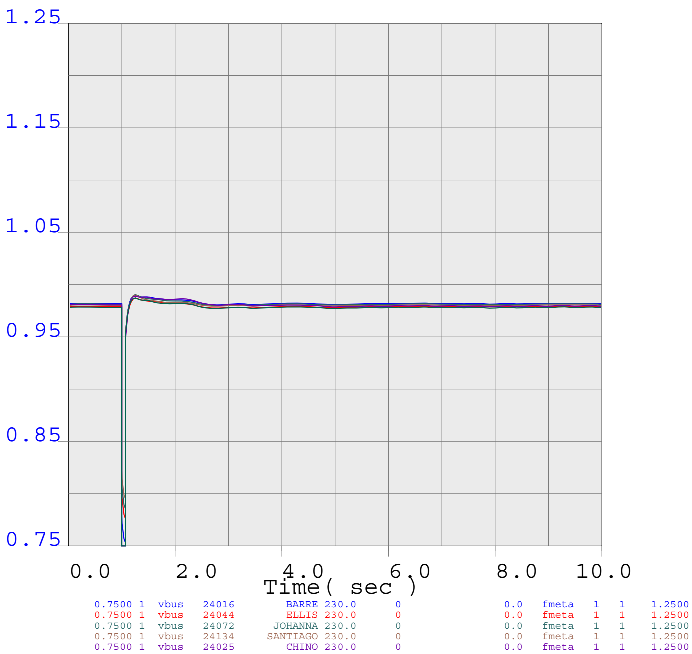
C:\DYTOOLS

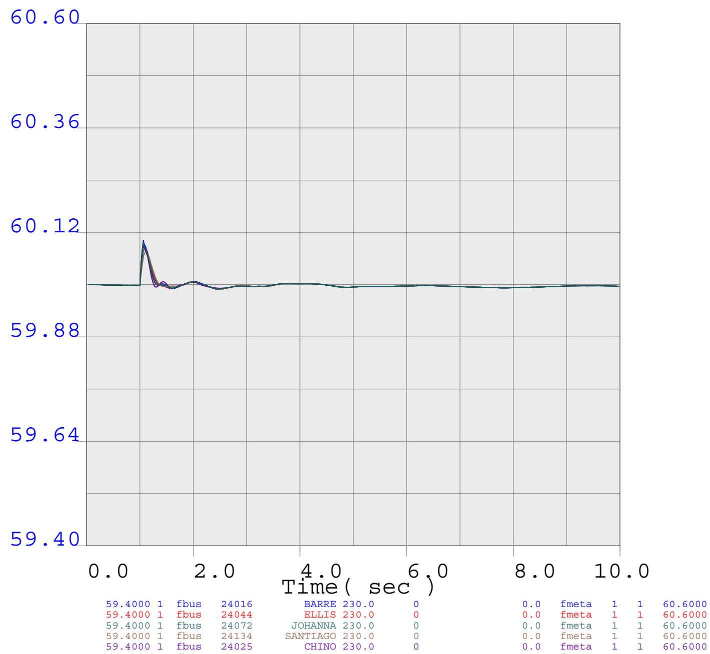
Thu Oct 20 08:58:51 2016

METRO









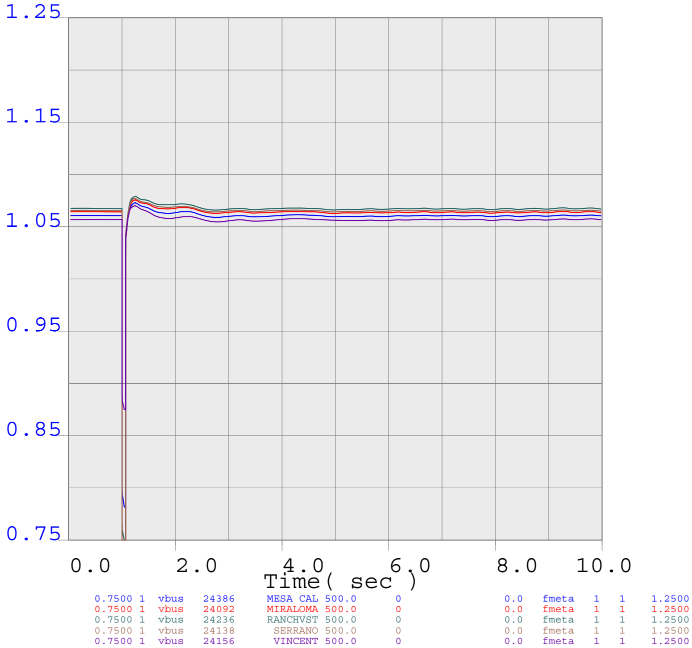
bay_2382
MIRALOMAW 220 KV POS 5S
1 MW dispatch Case

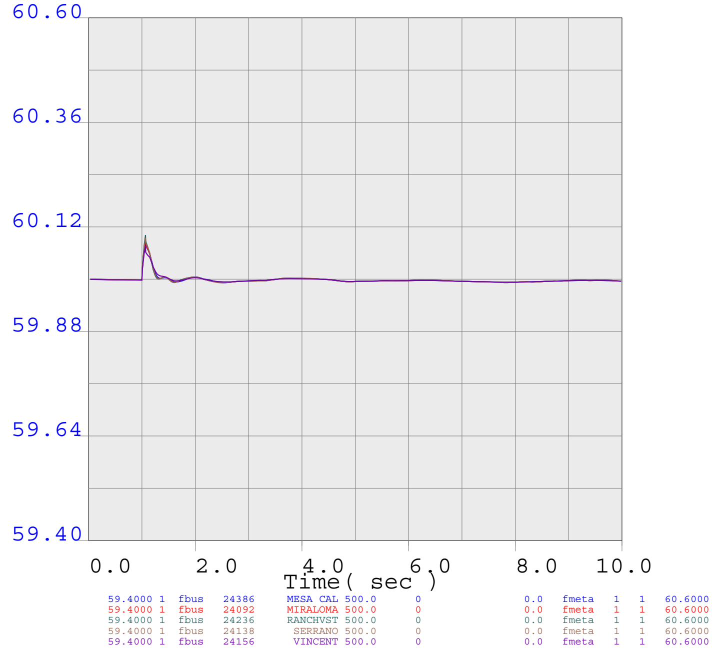
qc9p-bay_2382.chf

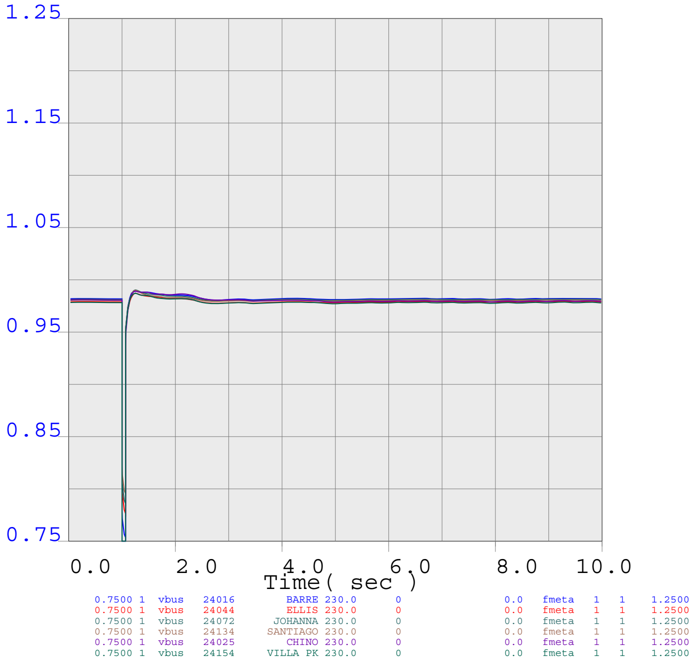
C:\DYTOOLS

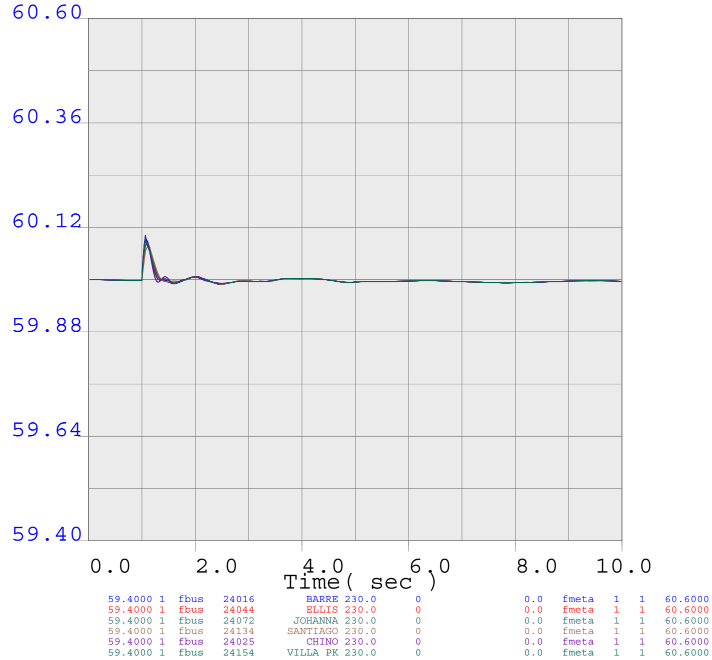
Thu Oct 20 08:58:53 2016

METRO









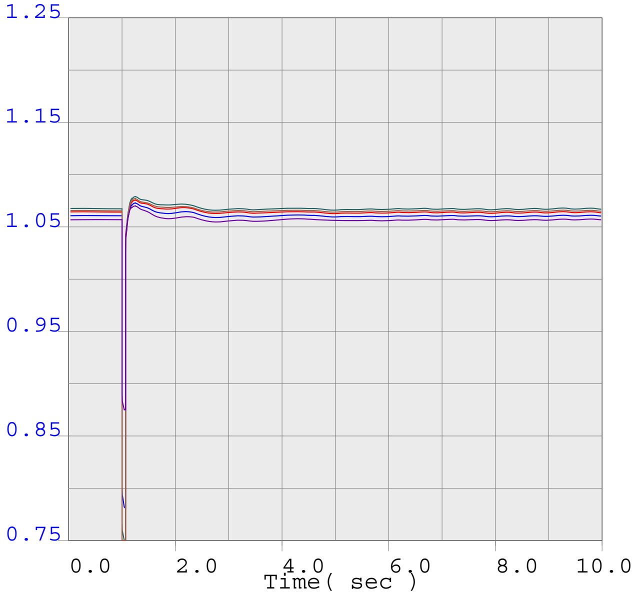
bay_2383
MIRALOMAW 220 KV POS 6S
1 MW dispatch Case

qc9p-bay_2383.chf

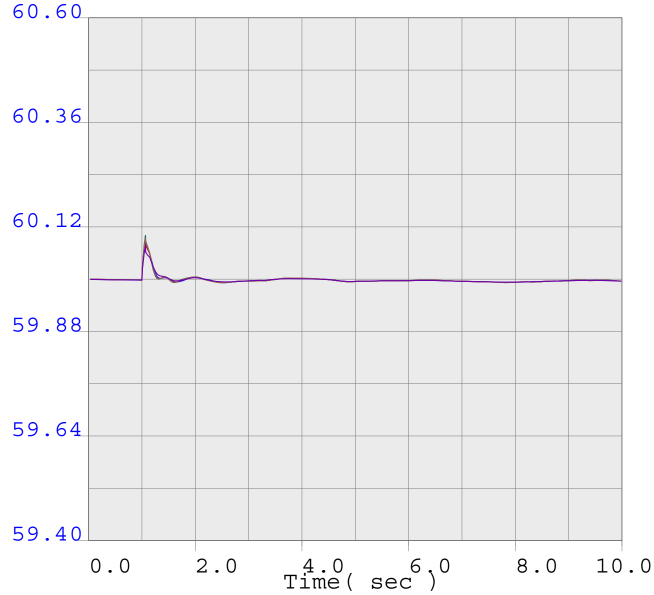
C:\DYTOOLS

Thu Oct 20 08:58:55 2016

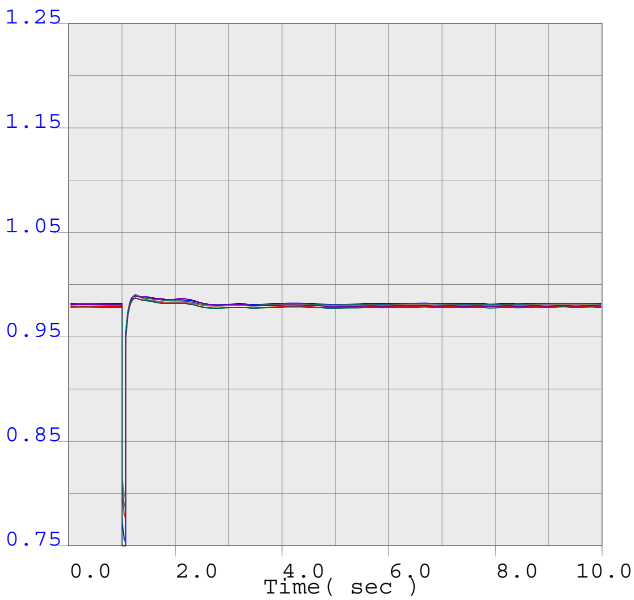
METRO



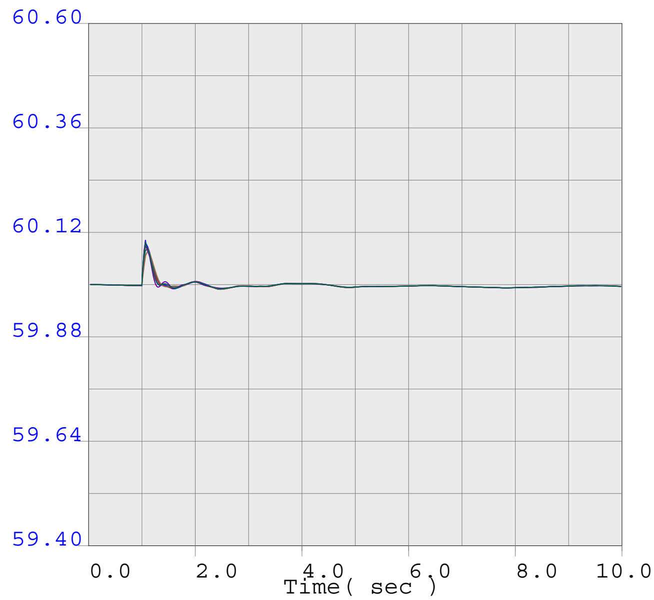
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

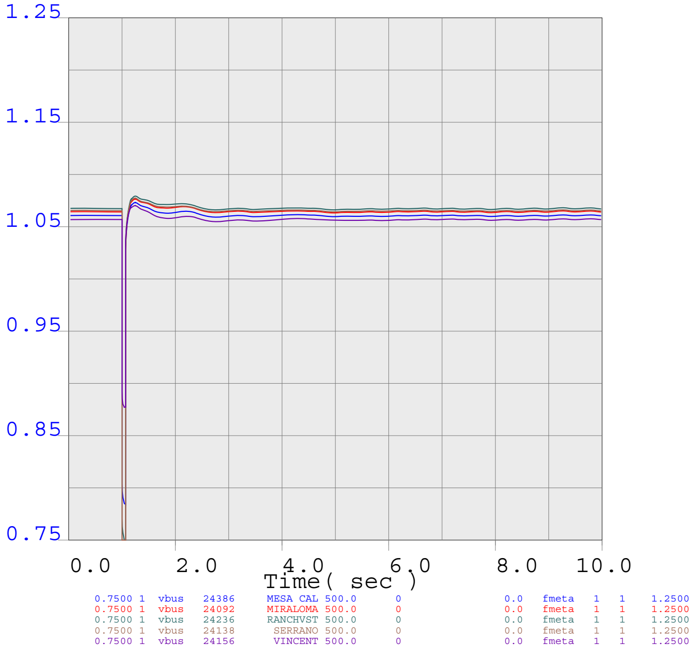
bay_2384
MIRALOMAW 220 KV POS 8S
1 MW dispatch Case

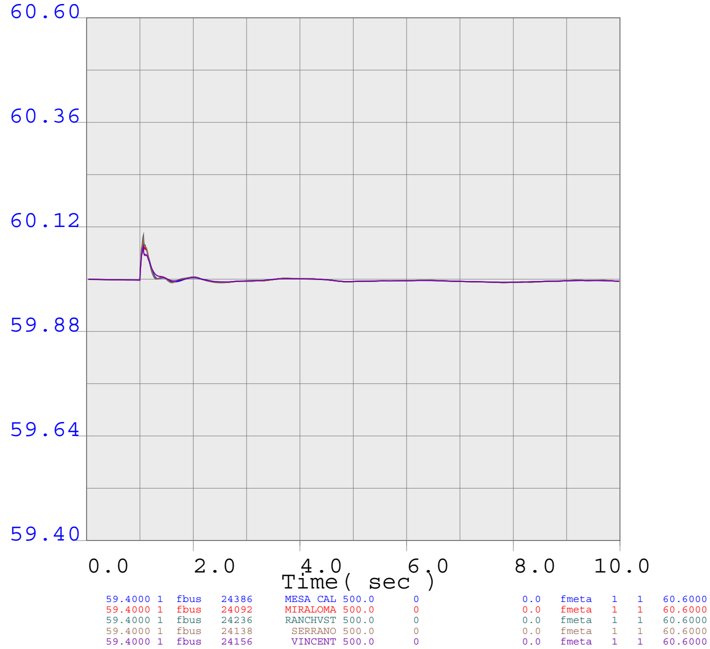
qc9p-bay_2384.chf

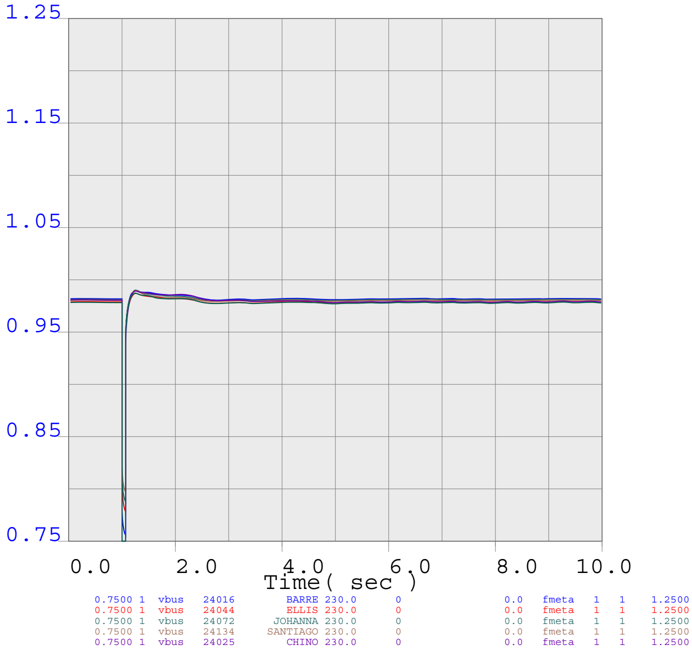
C:\DYTOOLS

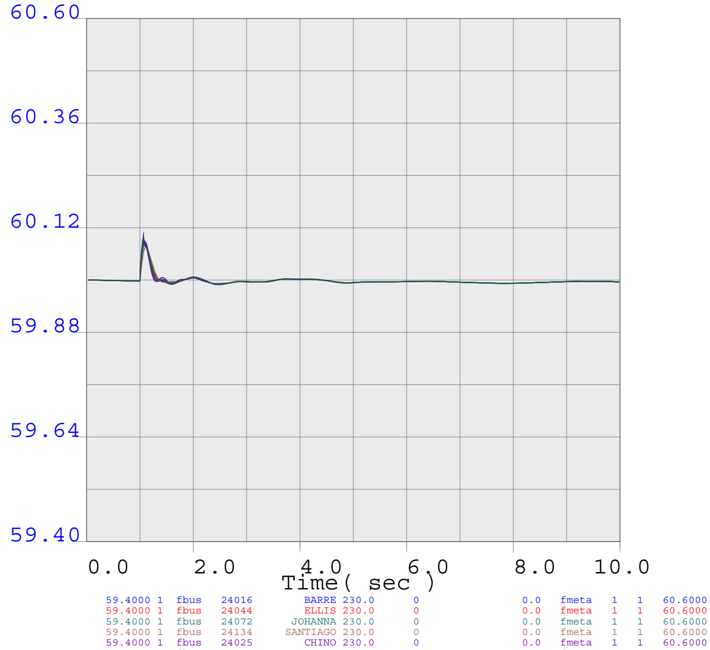
Thu Oct 20 08:58:57 2016

METRO









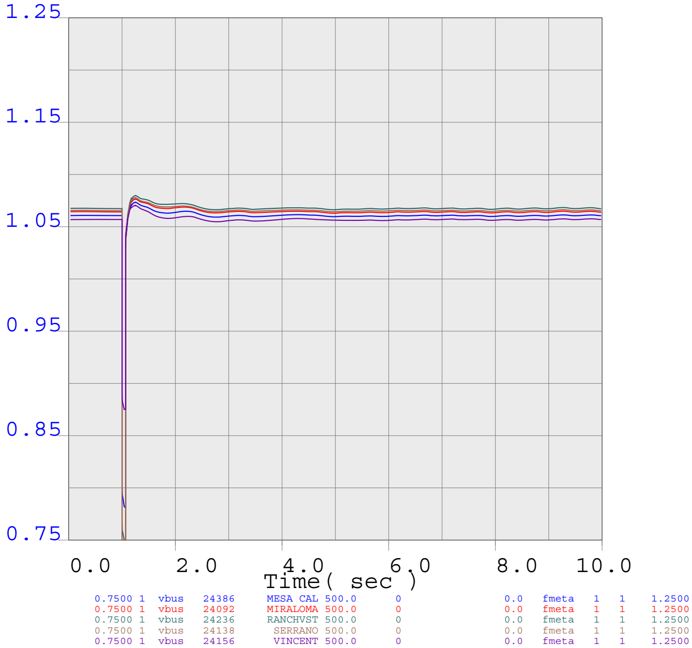
bay_2385
MIRALOMW 220 KV POS 3 INTERNAL FAULT
1 MW dispatch Case

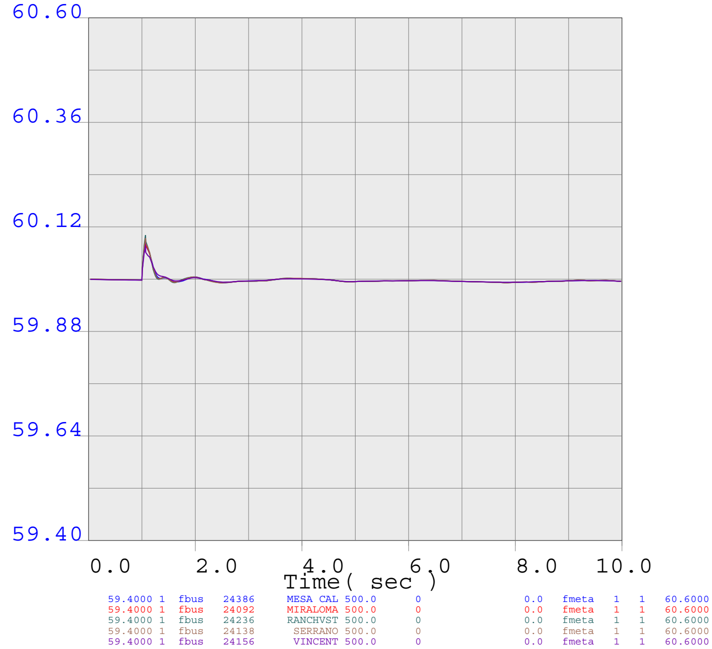
qc9p-bay_2385.chf

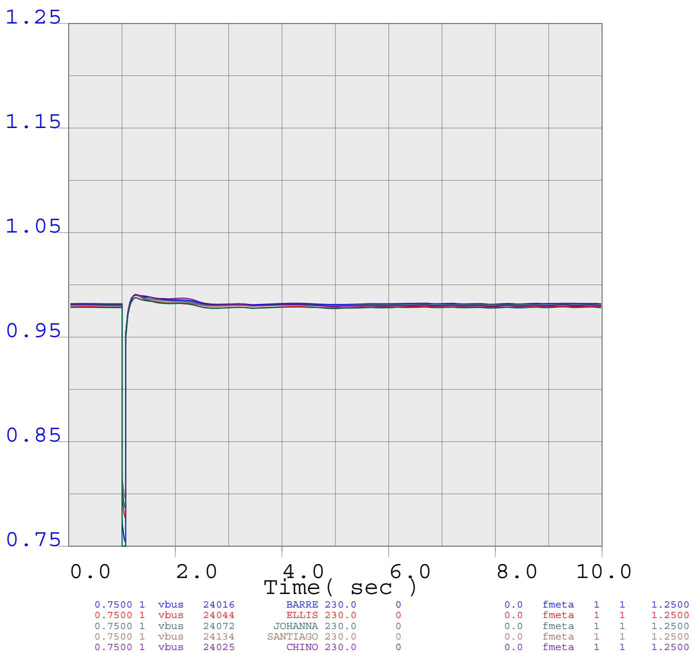
C:\DYTOOLS

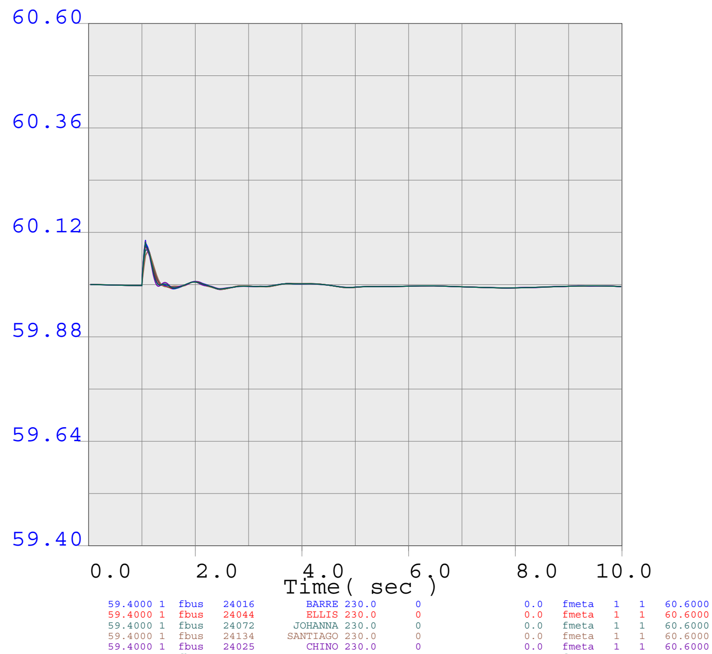
Thu Oct 20 08:59:00 2016

METRO









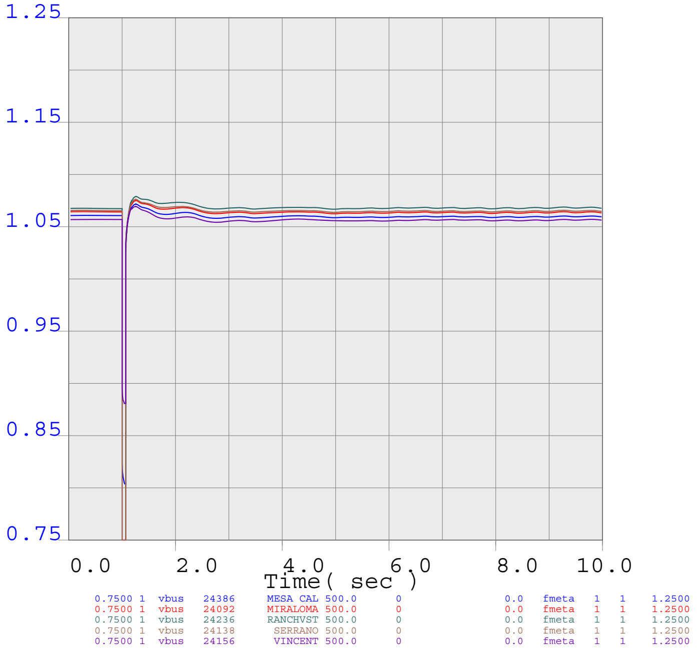
bay_2386
MIRALOMW 220 KV POS 5 INTERNAL FAULT
1 MW dispatch Case

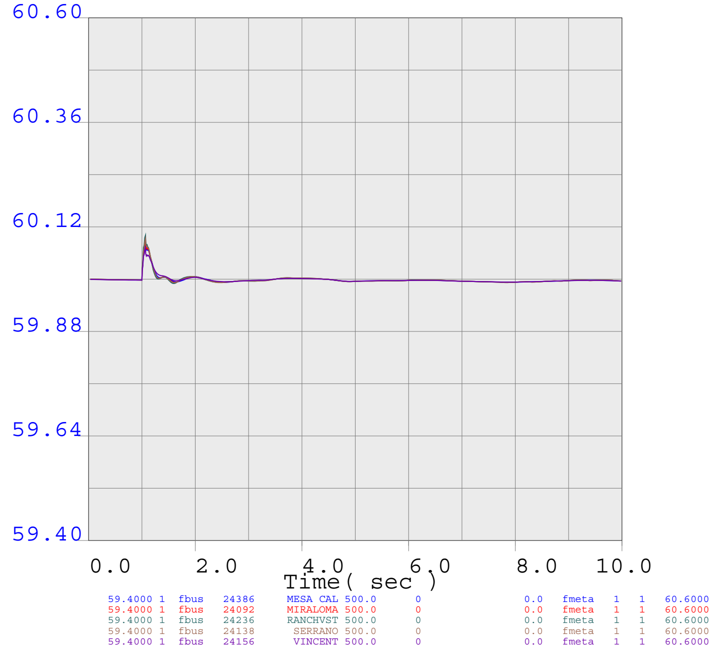
qc9p-bay_2386.chf

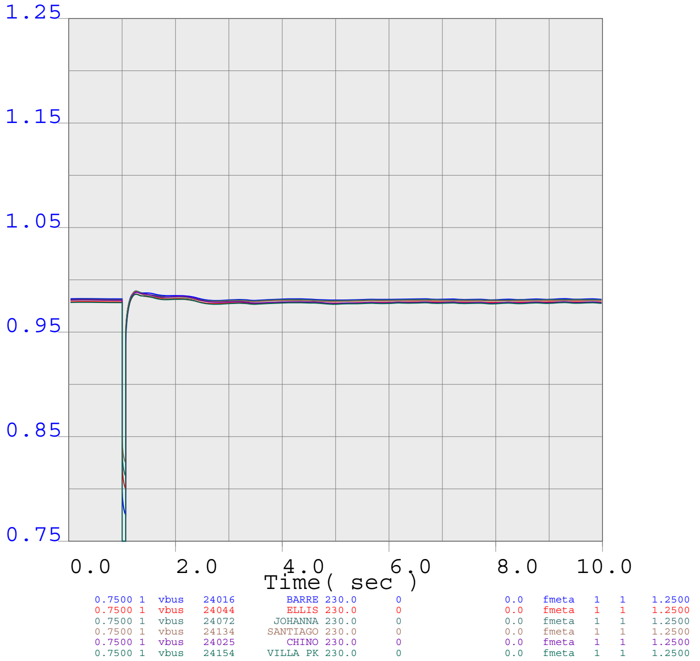
C:\DYTOOLS

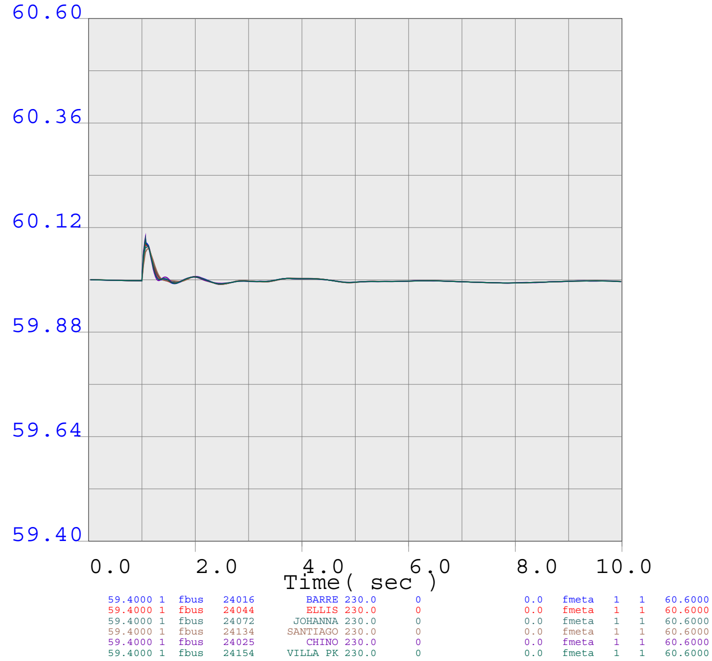
Thu Oct 20 08:59:02 2016

METRO









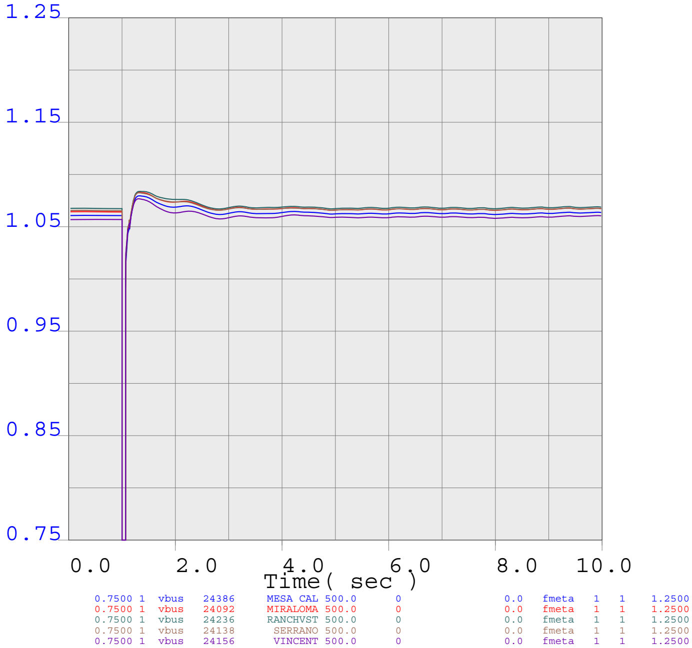
bay_2387
MIRALOME 220 KV POS 14 INTERNAL FAULT
1 MW dispatch Case

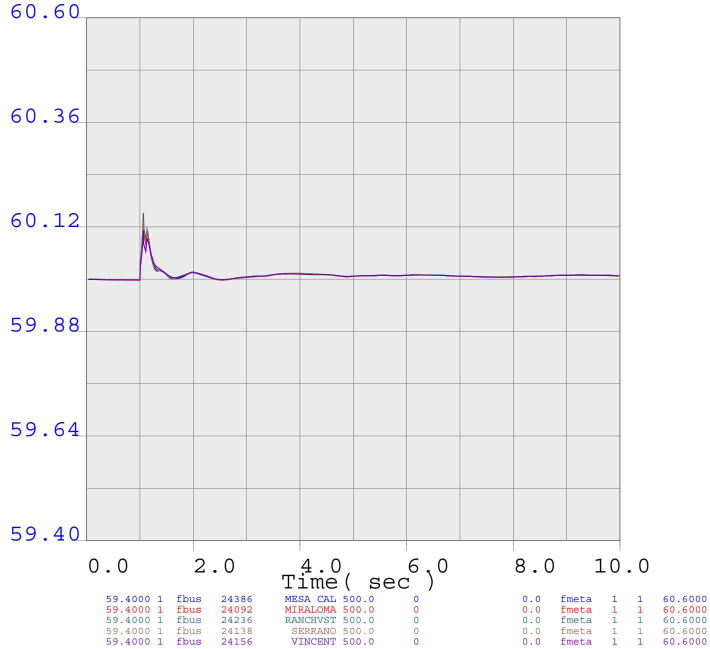
qc9p-bay_2387.chf

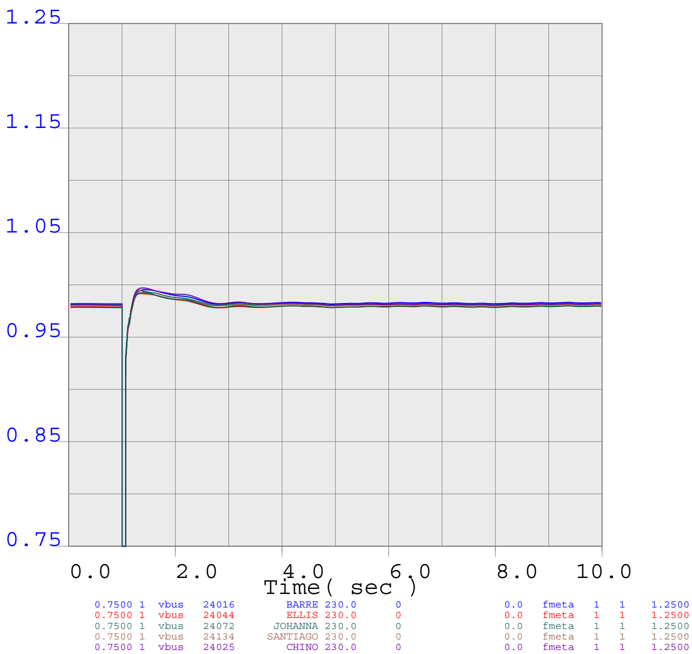
C:\DYTOOLS

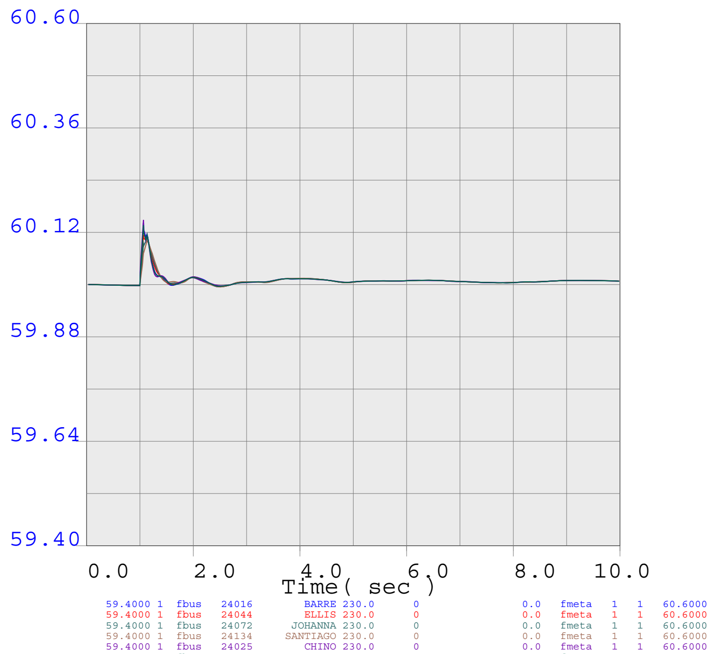
Thu Oct 20 08:59:04 2016

METRO









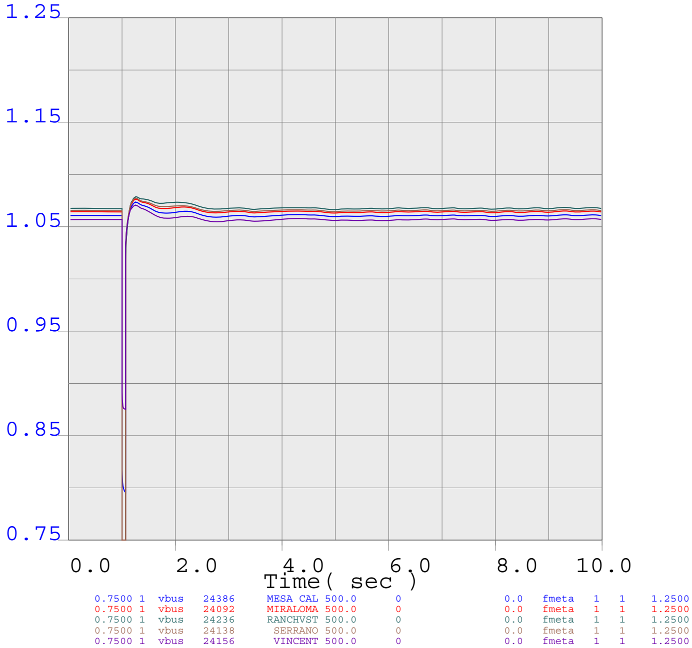
bay_2388
MIRALOME 220 KV POS 15 INTERNAL FAULT
1 MW dispatch Case

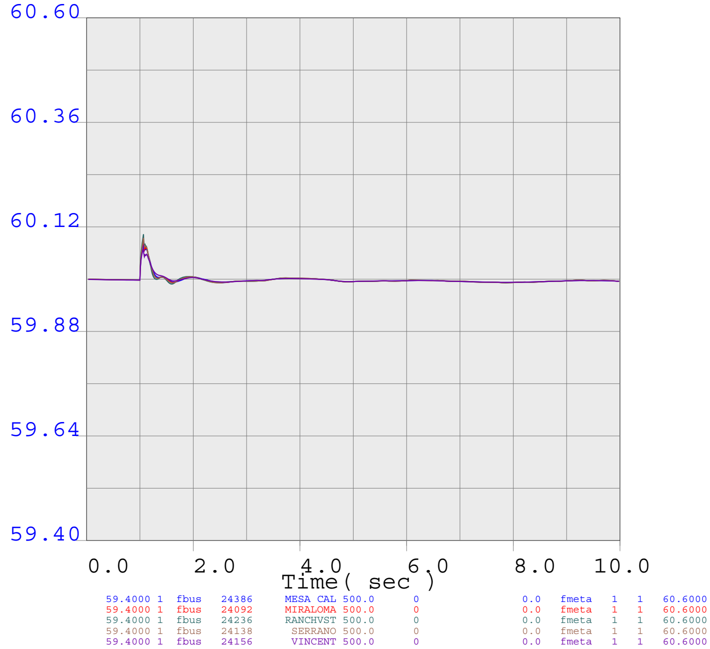
qc9p-bay_2388.chf

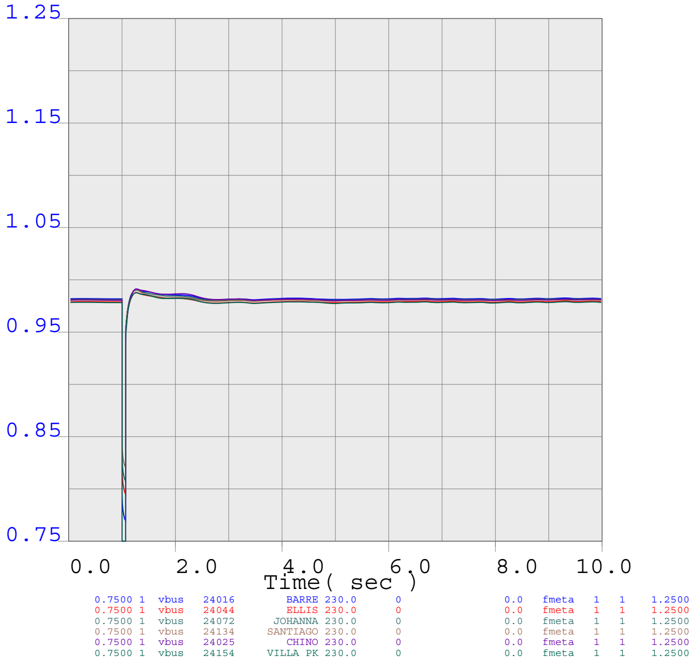
C:\DYTOOLS

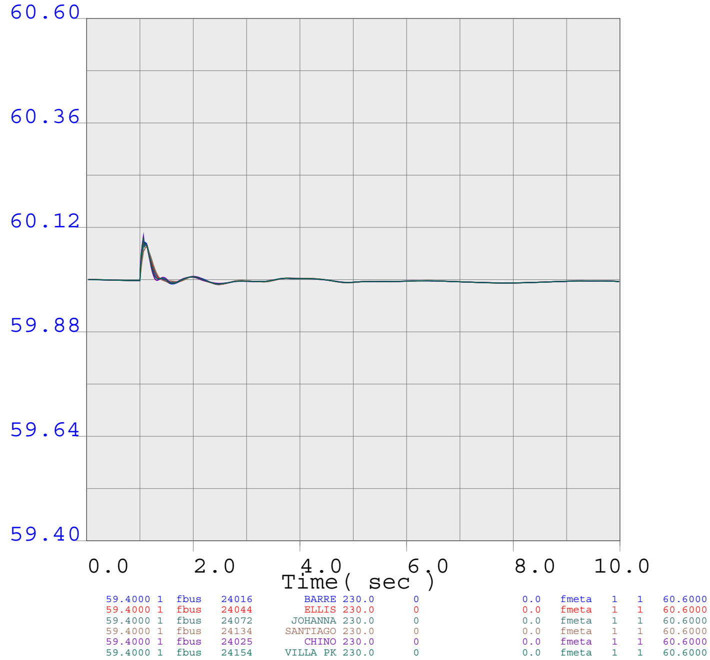
Thu Oct 20 08:59:06 2016

METRO









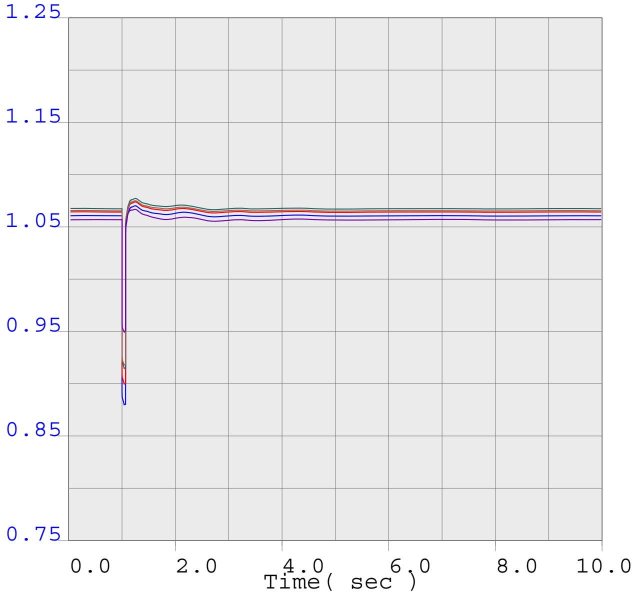
bay_2389
MIRALOME 220 KV POS 16 INTERNAL FAULT
1 MW dispatch Case

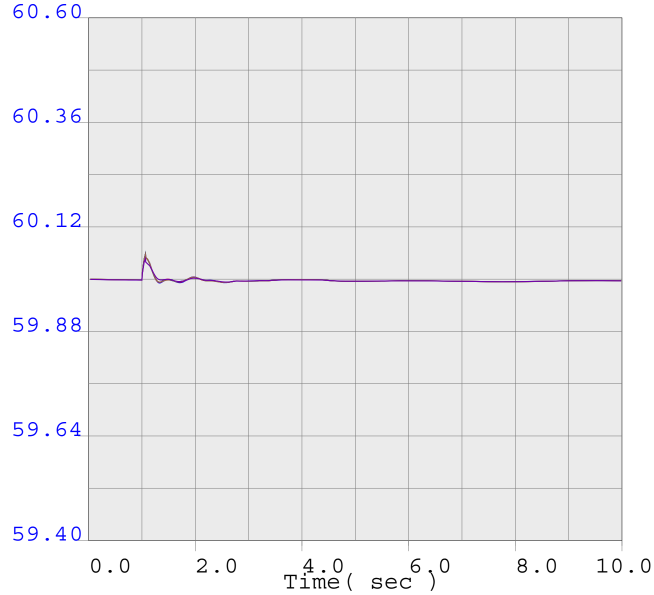
qc9p-bay_2389.chf

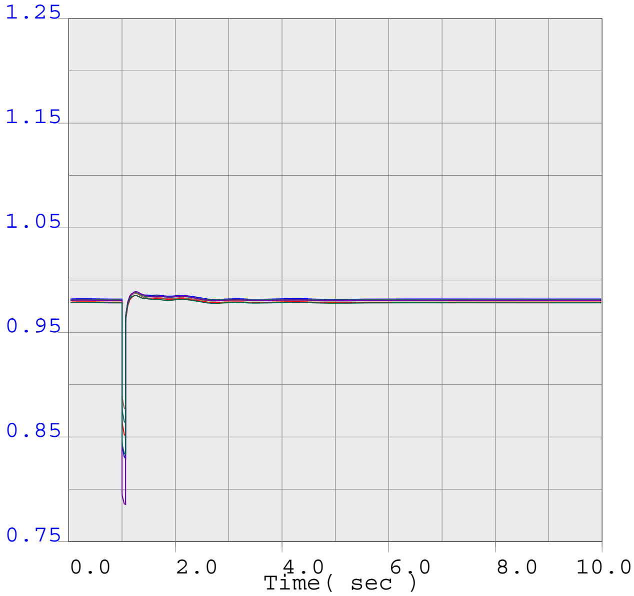
C:\DYTOOLS

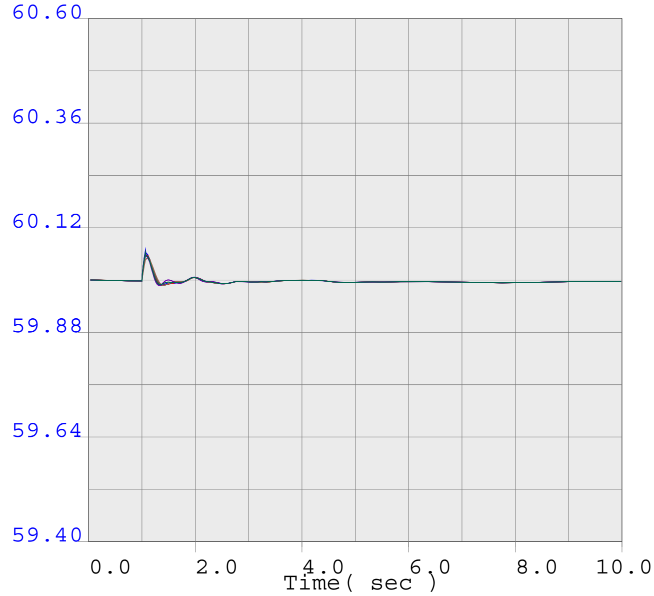
Thu Oct 20 08:59:08 2016

METRO









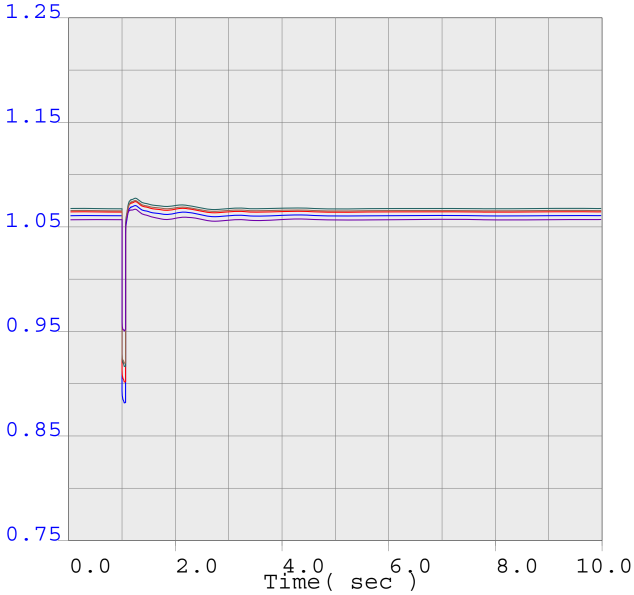
bay_2390
OLINDA 220 KV POS 1S
1 MW dispatch Case

qc9p-bay_2390.chf

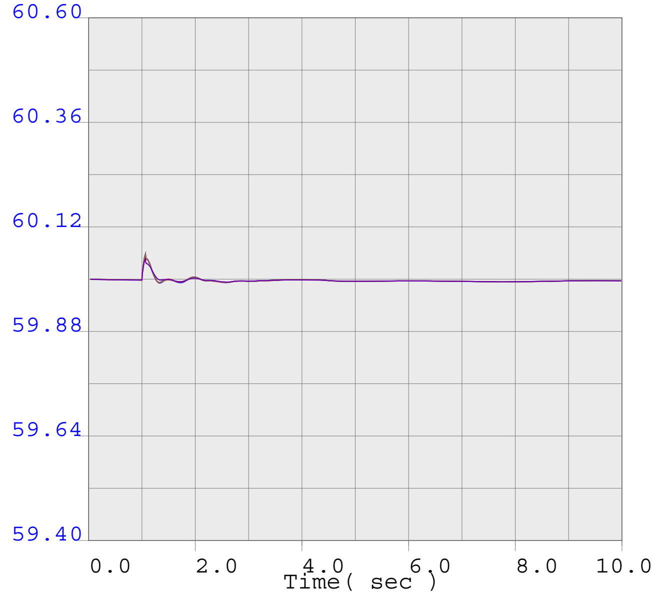
C:\DYTOOLS

Thu Oct 20 08:59:11 2016

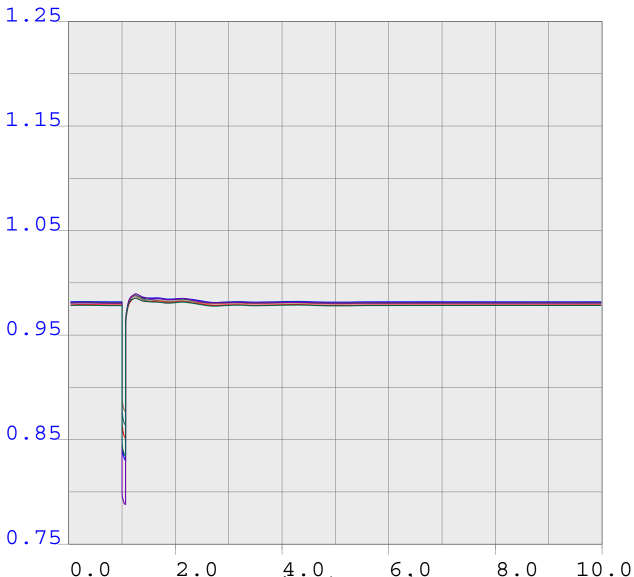
METRO



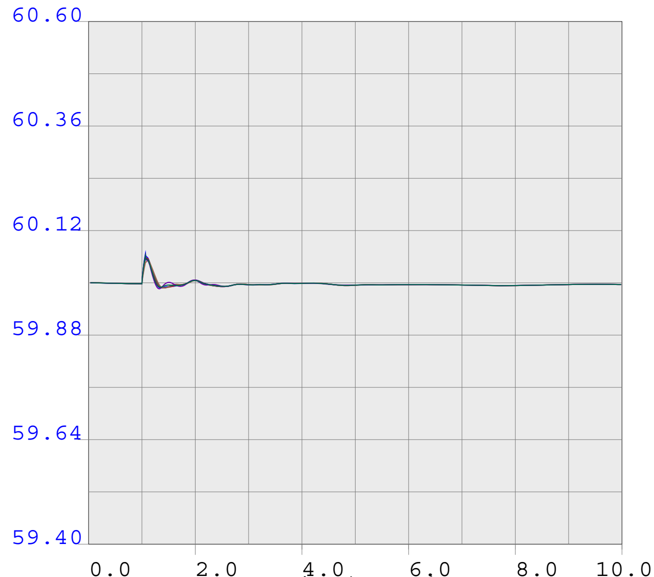
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

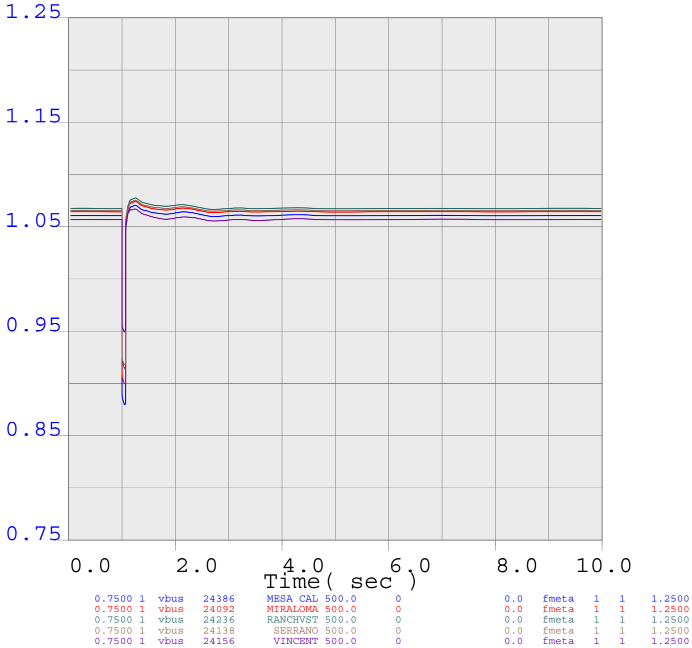
bay_2391
OLINDA 220 KV POS 2S
1 MW dispatch Case

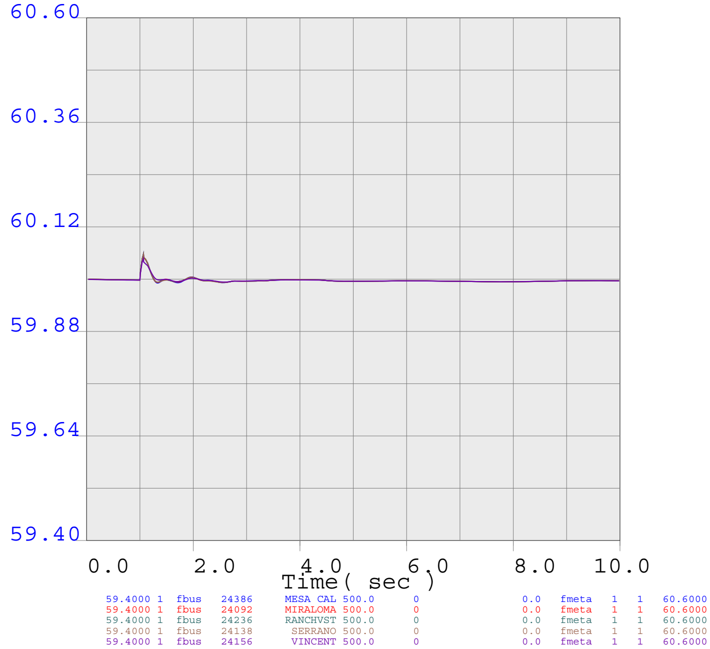
qc9p-bay_2391.chf

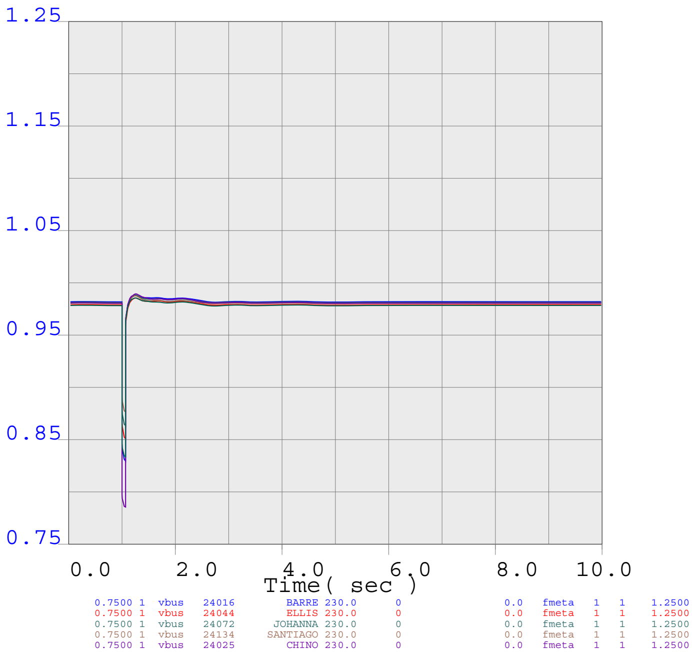
C:\DYTOOLS

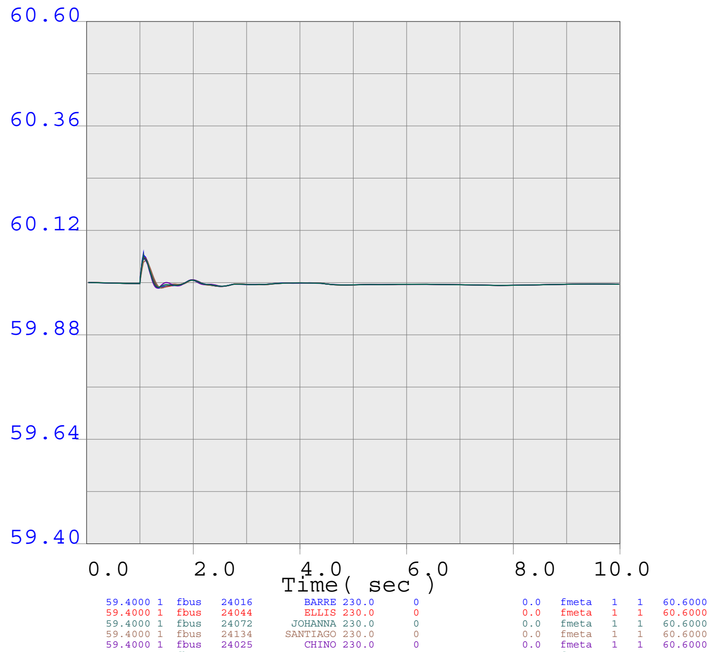
Thu Oct 20 08:59:13 2016

METRO









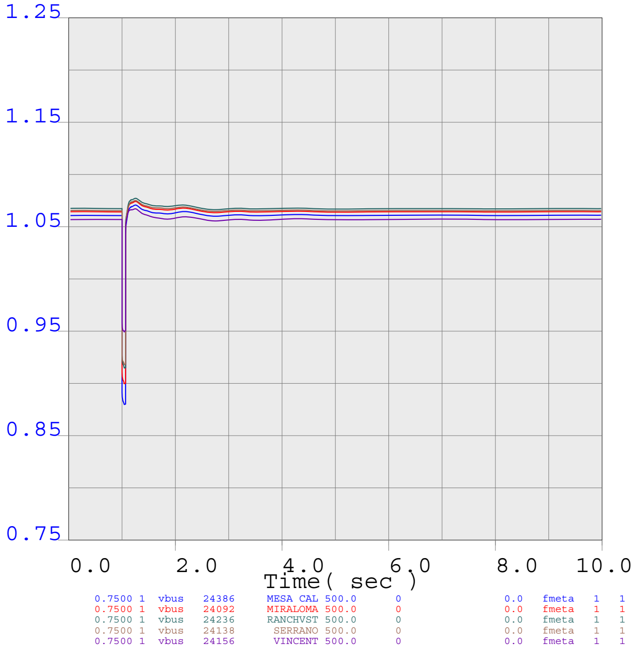
bay_2392
OLINDA 220 KV POS 3S
1 MW dispatch Case

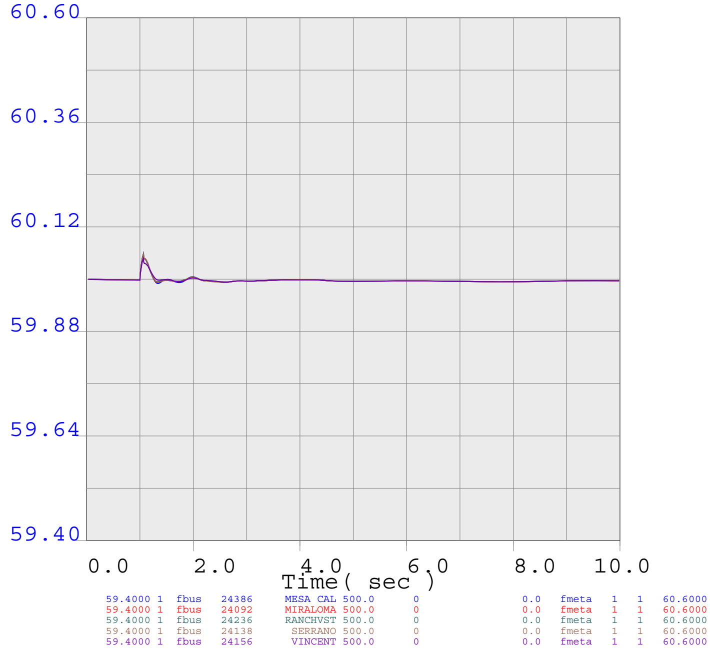
qc9p-bay_2392.chf

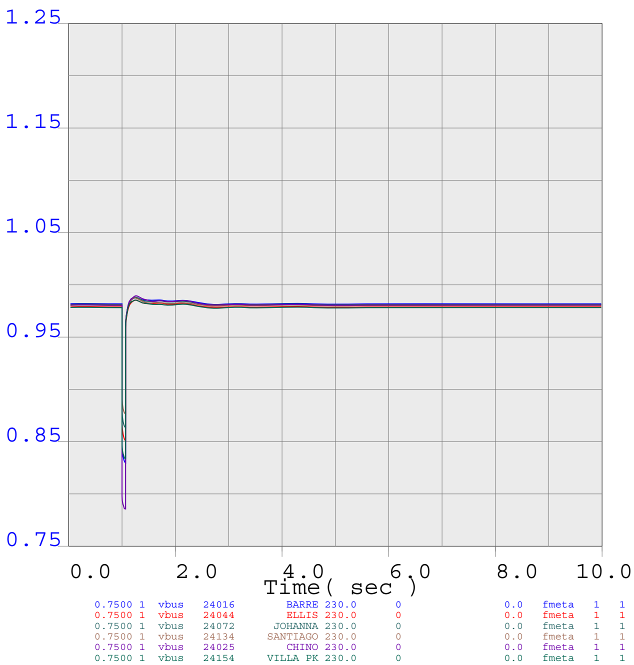
C:\DYTOOLS

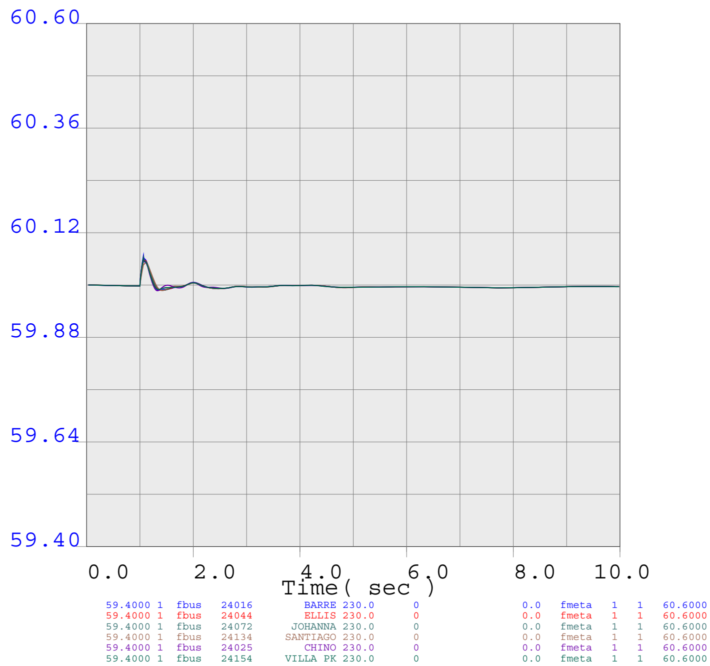
Thu Oct 20 08:59:16 2016

METRO









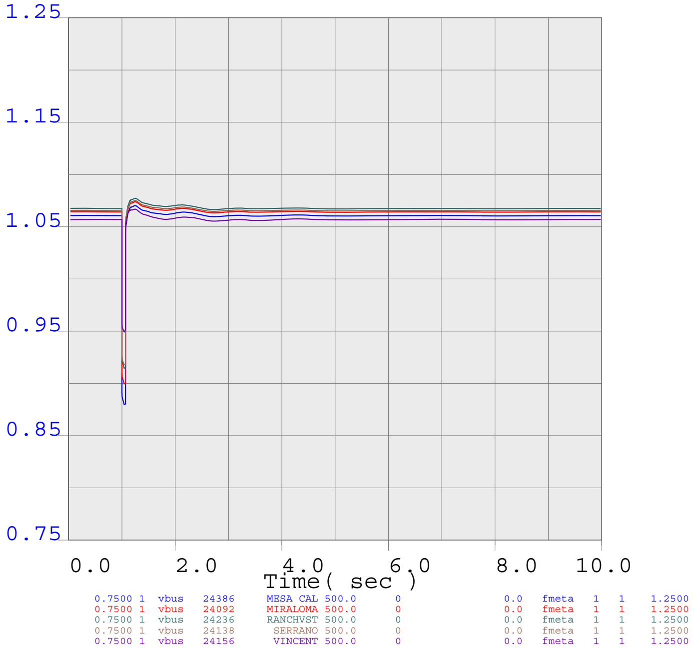
bay_2393
OLINDA 220 KV POS 6S
1 MW dispatch Case

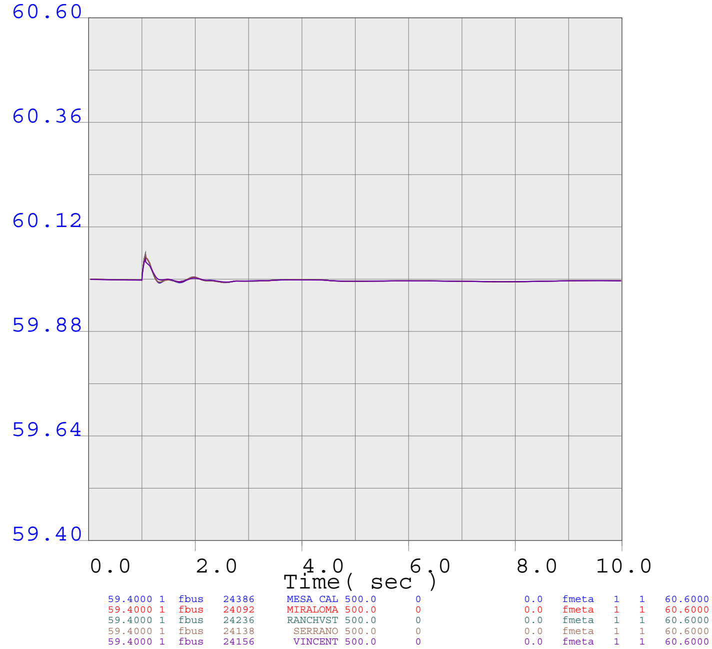
qc9p-bay_2393.chf

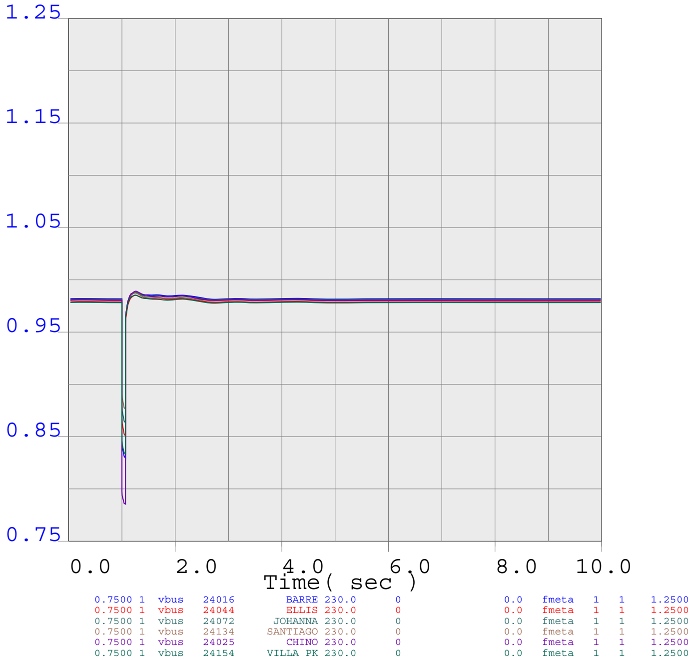
C:\DYTOOLS

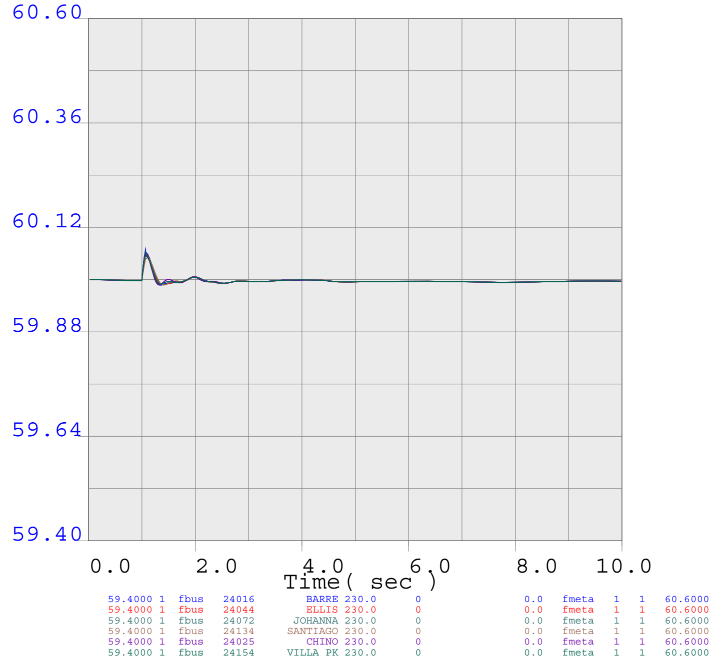
Thu Oct 20 08:59:20 2016

METRO









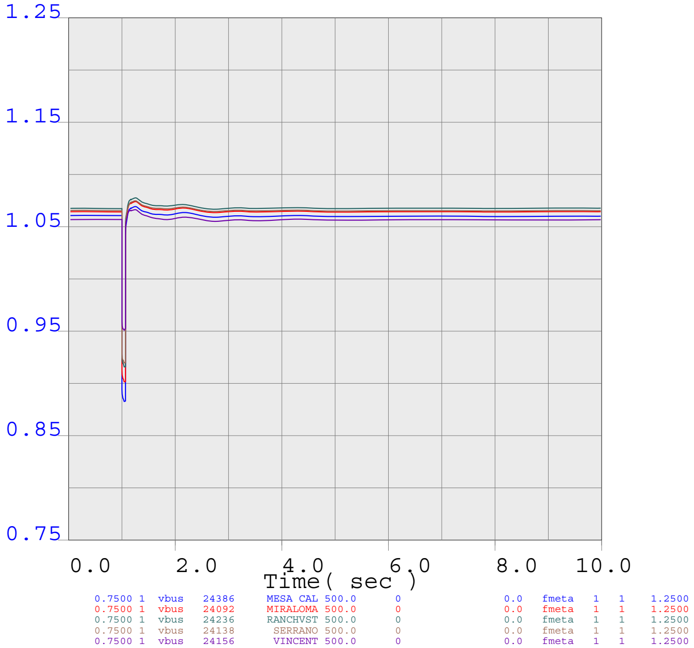
bay_2394
OLINDA 220 KV POS 7S
1 MW dispatch Case

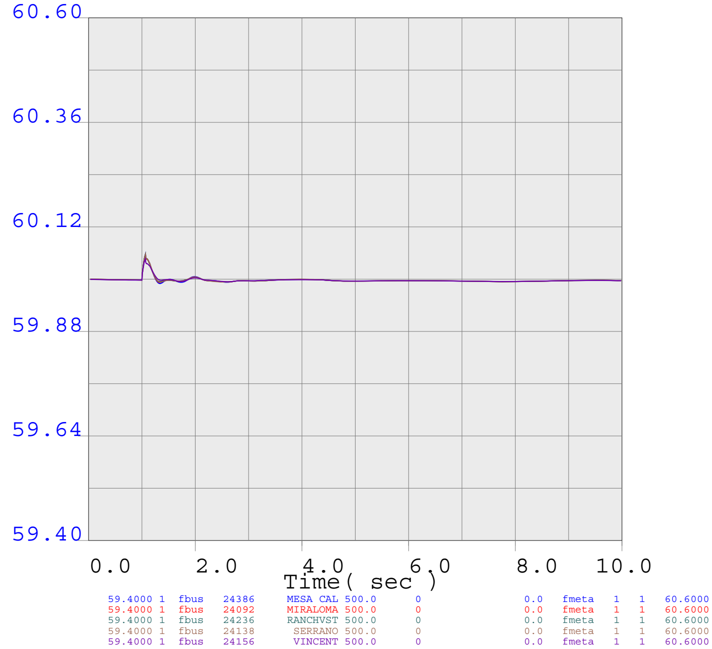
qc9p-bay_2394.chf

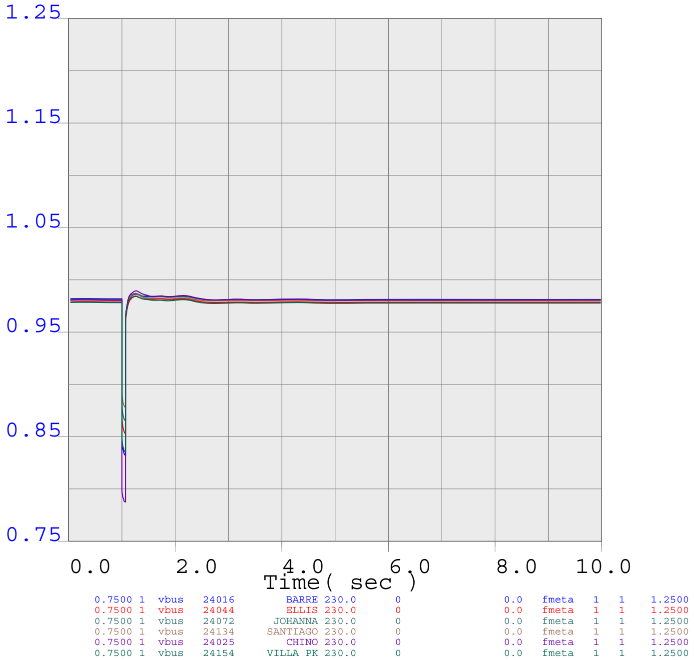
C:\DYTOOLS

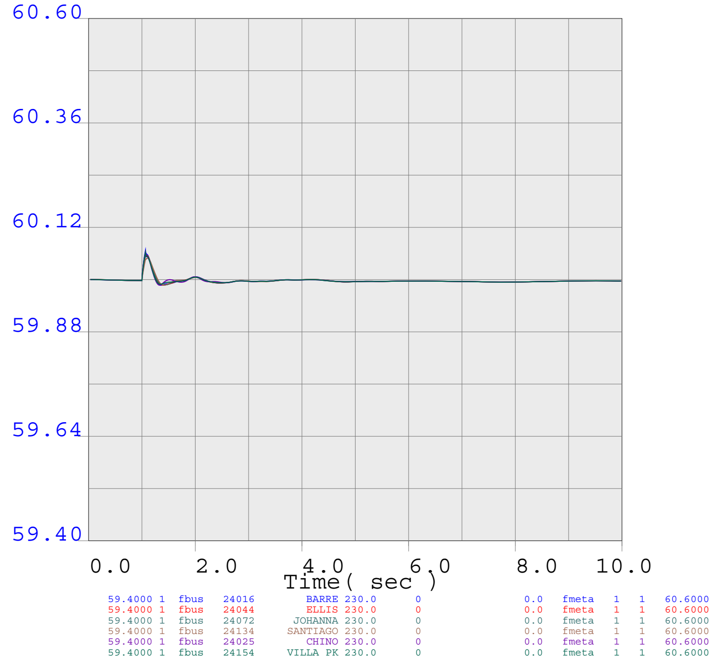
Thu Oct 20 08:59:23 2016

METRO









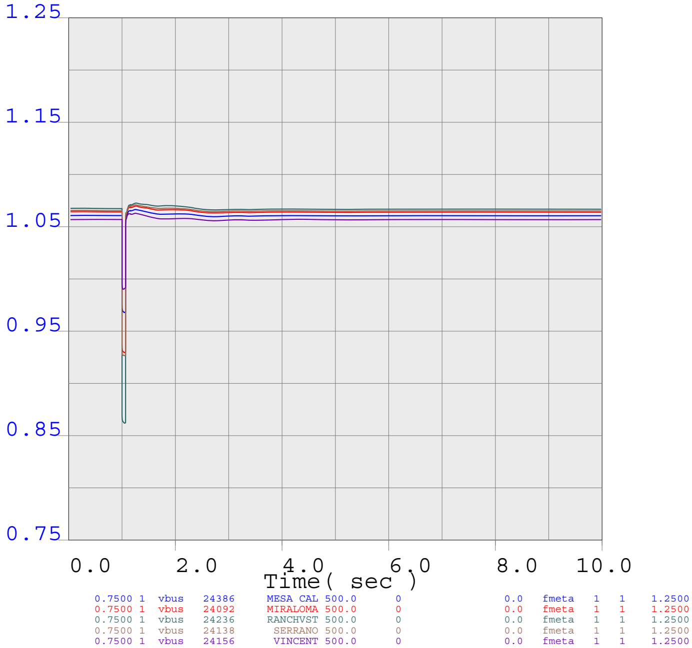
bay_2395
OLINDA 220 KV POS 6 INTERNAL FAULT
1 MW dispatch Case

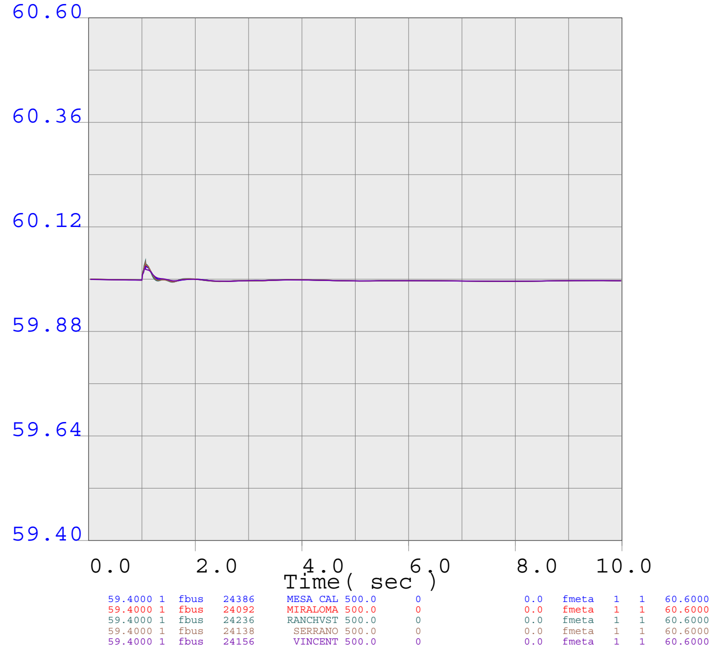
qc9p-bay_2395.chf

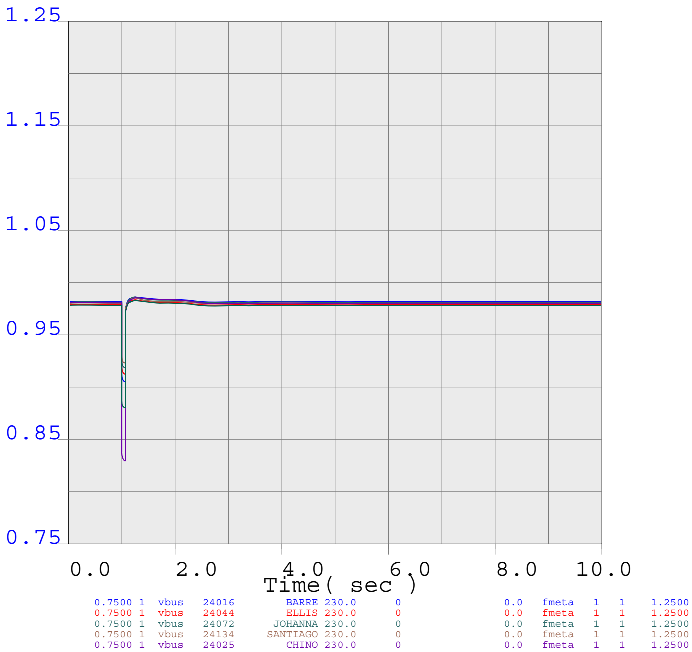
C:\DYTOOLS

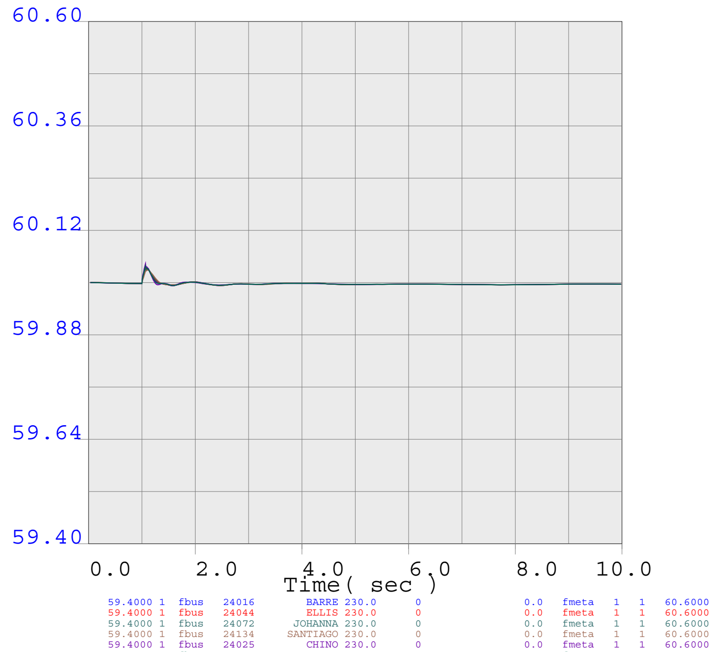
Thu Oct 20 08:59:25 2016

METRO









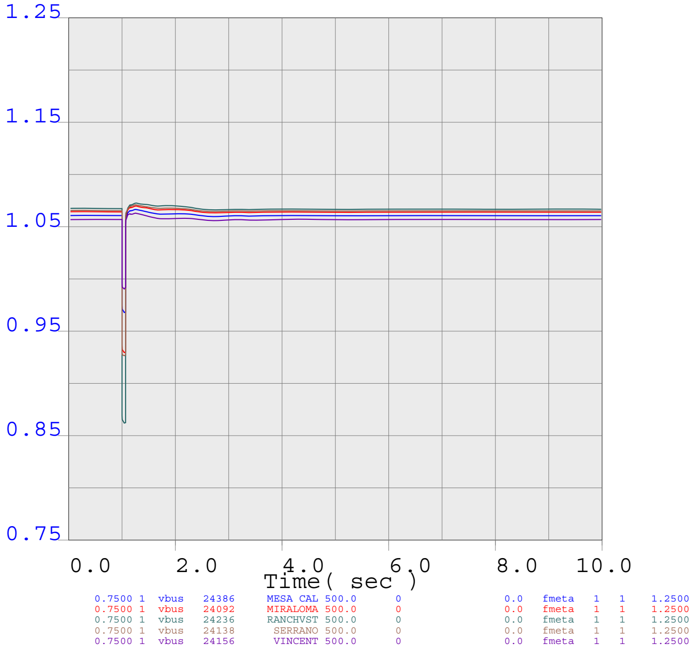
bay_2396
PADUA 220 KV POS 2N
1 MW dispatch Case

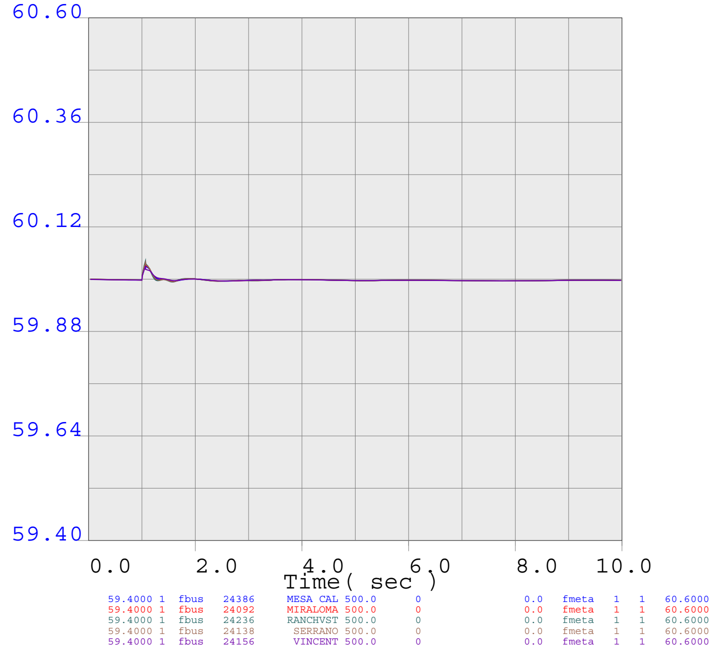
qc9p-bay_2396.chf

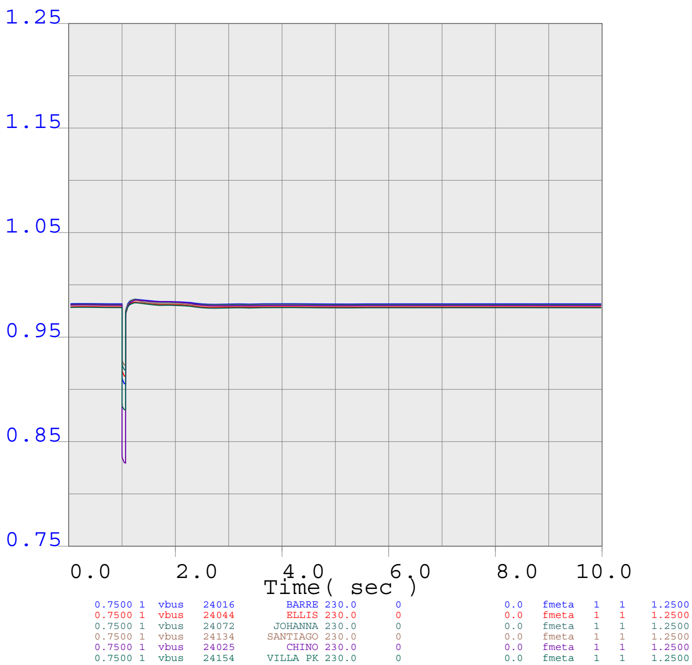
C:\DYTOOLS

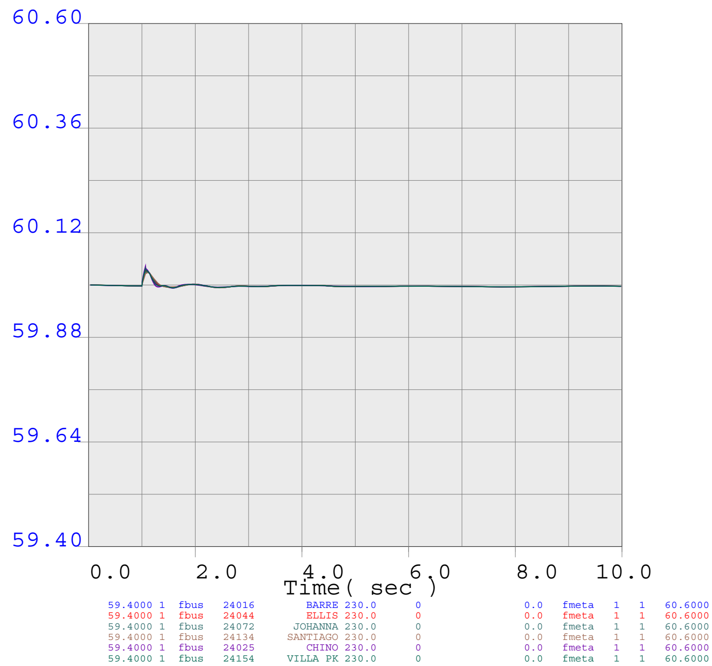
Thu Oct 20 08:59:27 2016

METRO









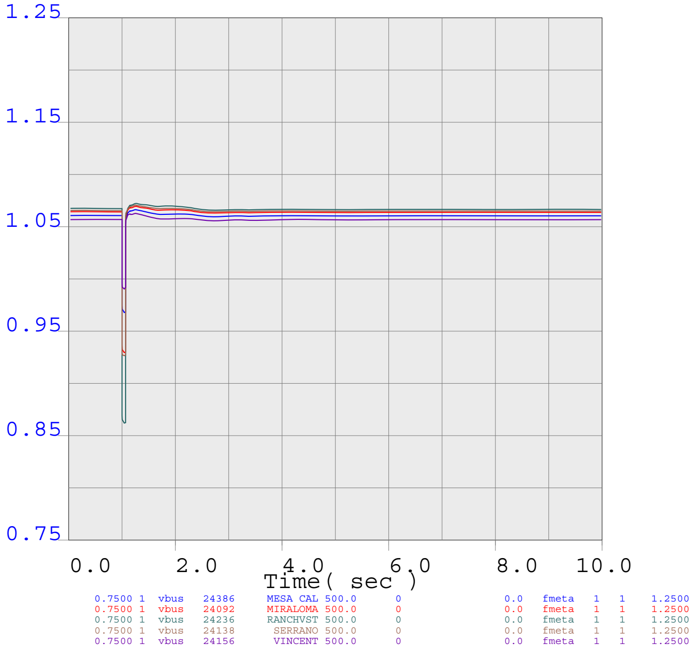
bay_2397
PADUA 220 KV POS 4N
1 MW dispatch Case

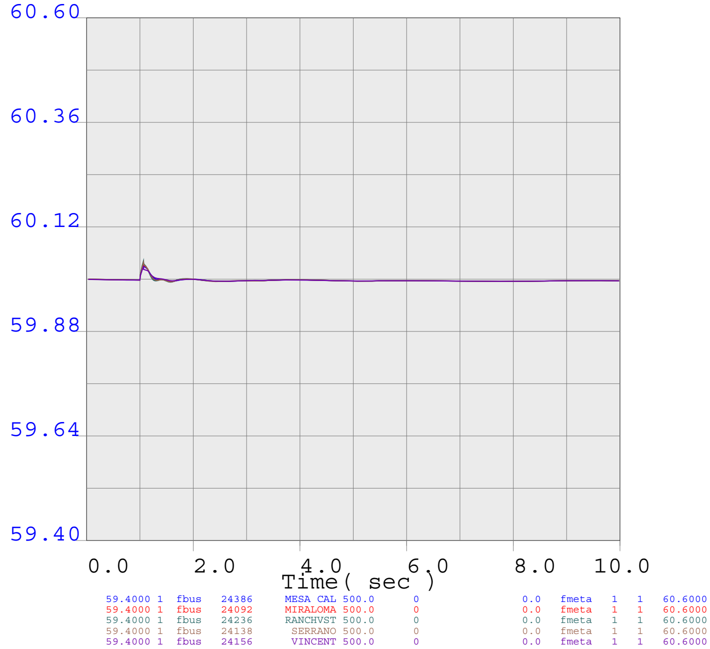
qc9p-bay_2397.chf

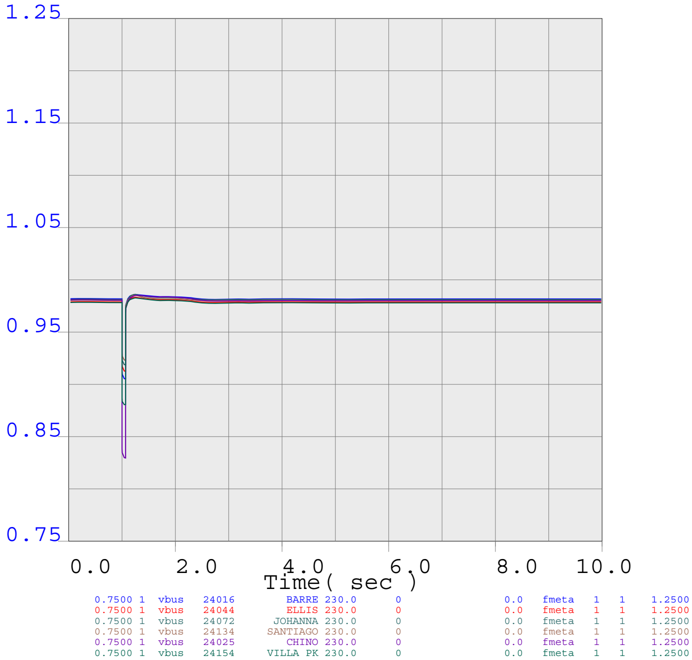
C:\DYTOOLS

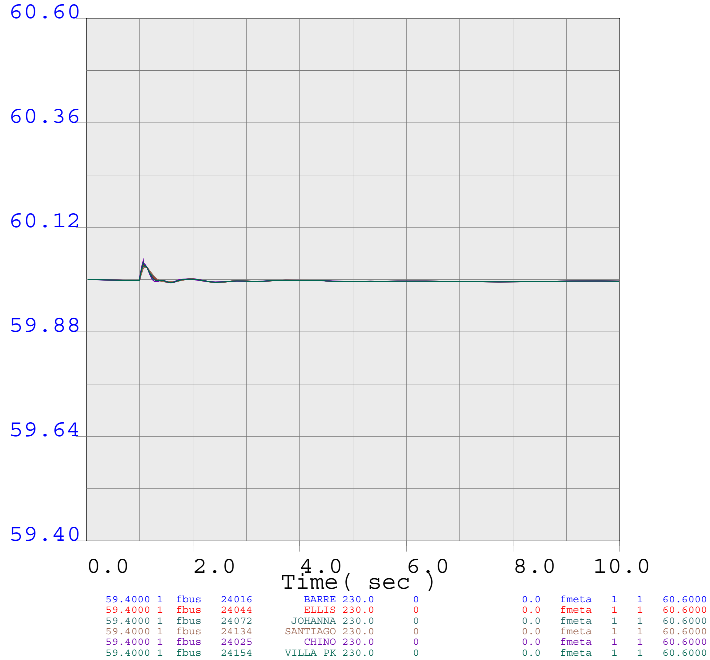
Thu Oct 20 08:59:29 2016

METRO









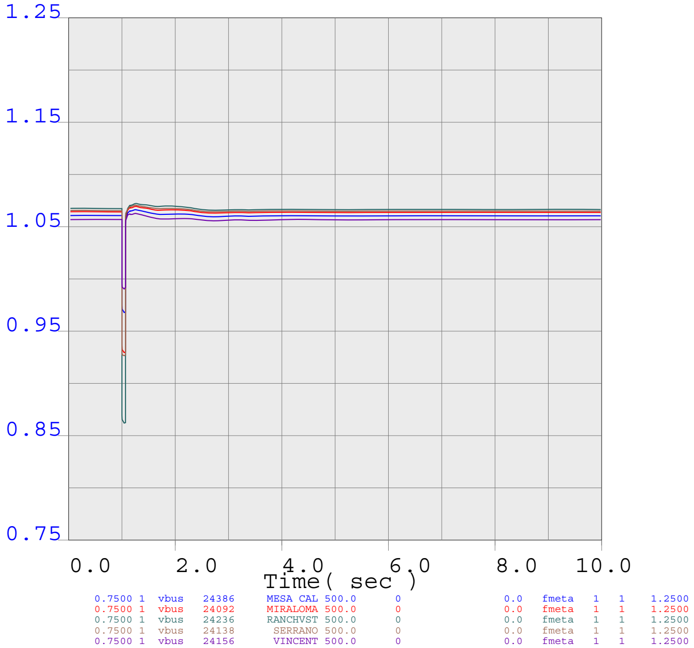
bay_2398
PADUA 220 KV POS 6N
1 MW dispatch Case

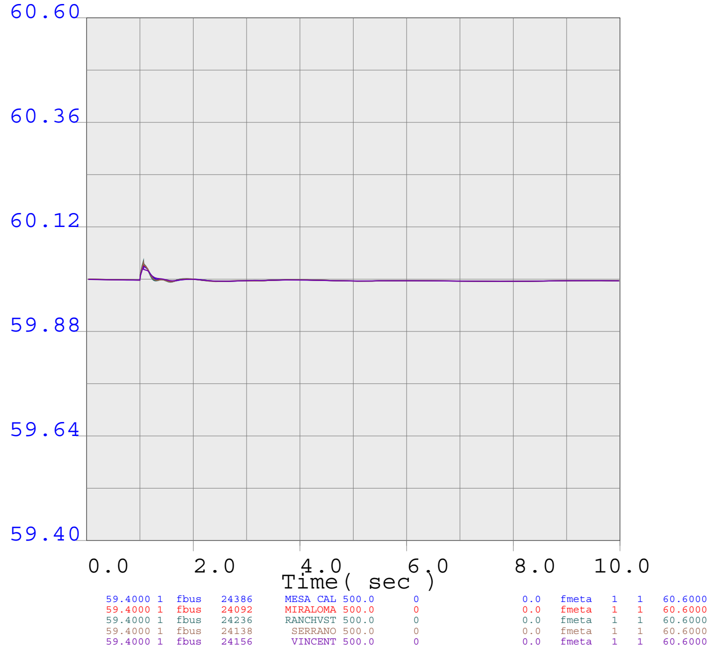
qc9p-bay_2398.chf

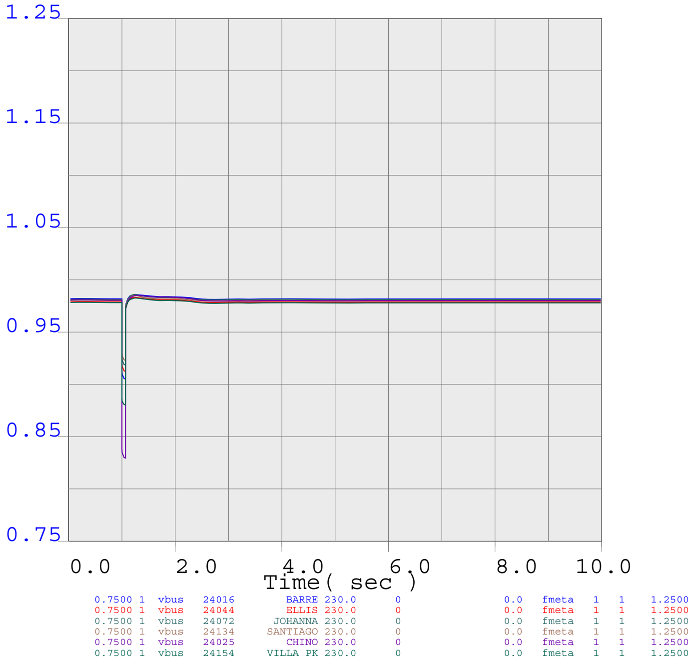
C:\DYTOOLS

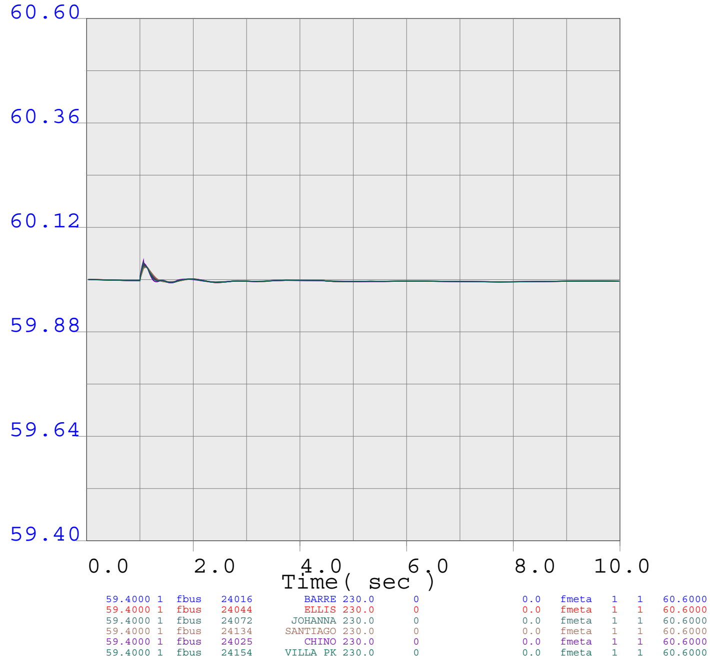
Thu Oct 20 08:59:32 2016

METRO









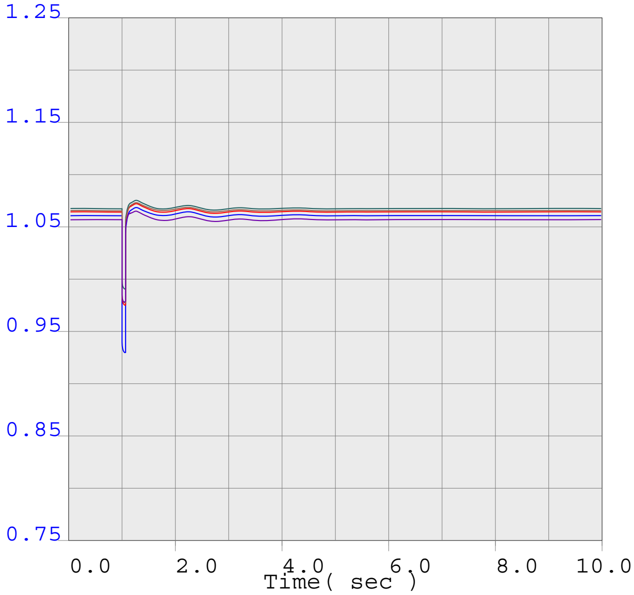
bay_2399
PADUA 220 KV POS 8N
1 MW dispatch Case

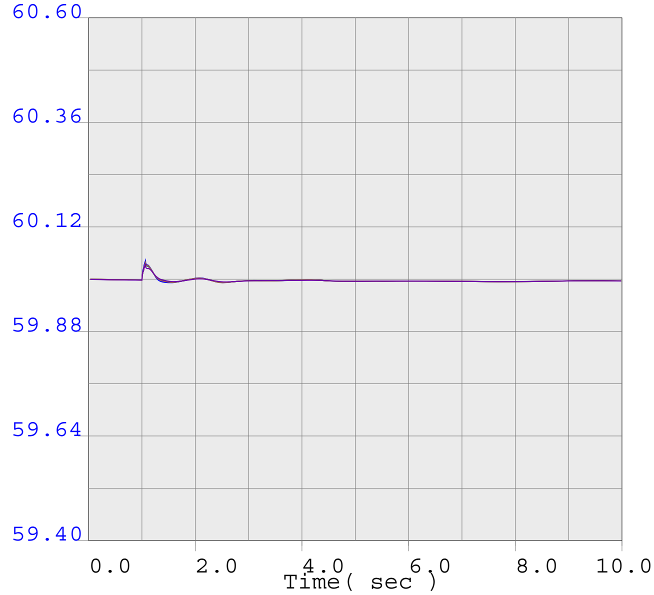
qc9p-bay_2399.chf

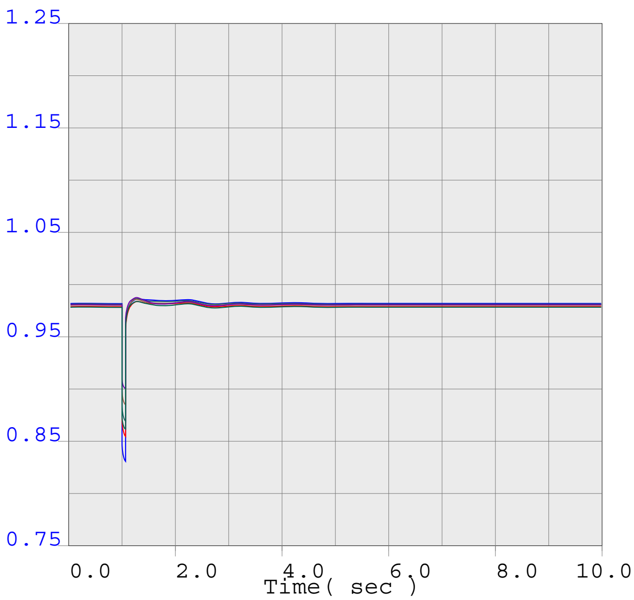
C:\DYTOOLS

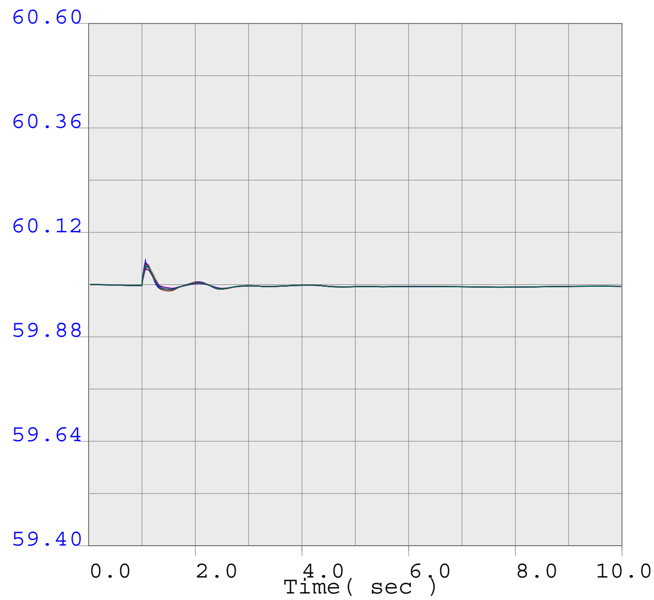
Thu Oct 20 08:59:35 2016

METRO





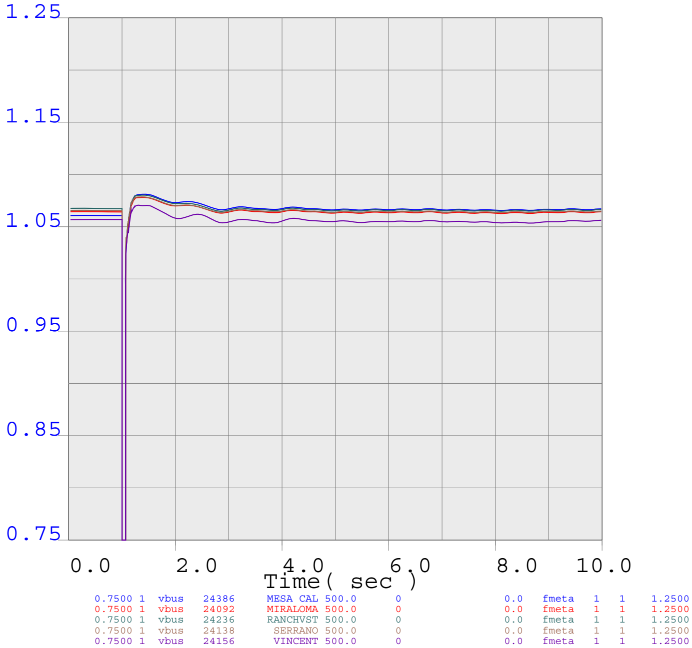


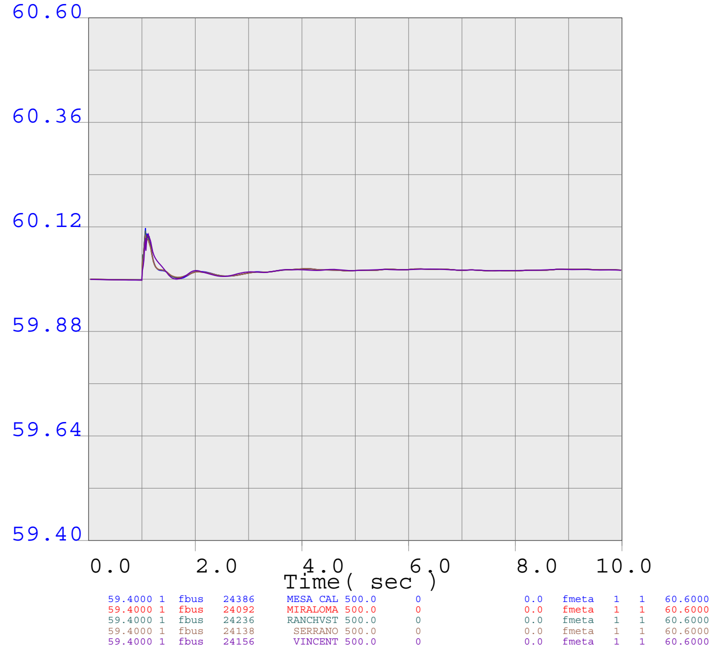


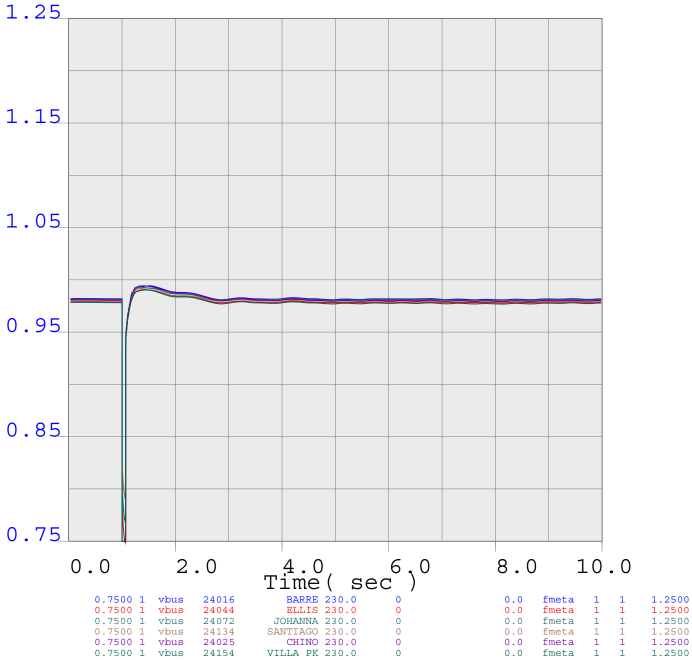
bay_2401
LONG BEACH 220 KV POS 3
1 MW dispatch Case

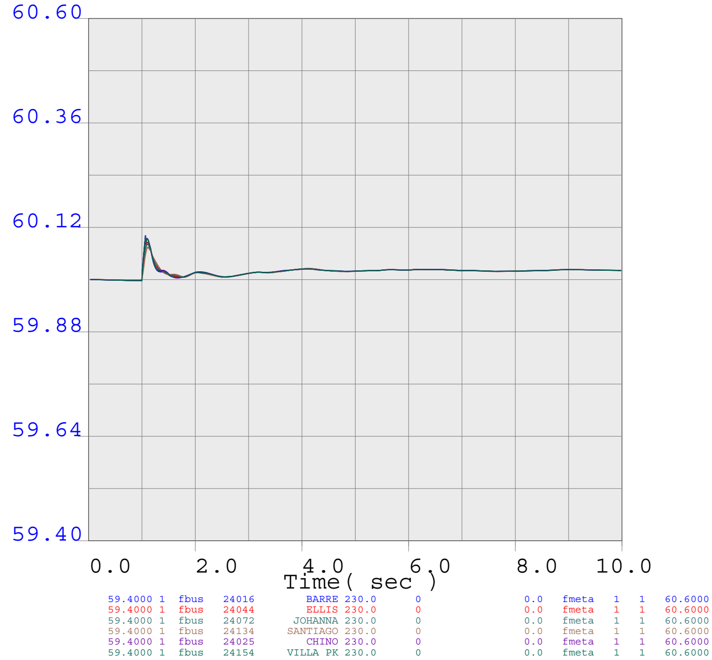
	qc9p-bay_2401.chf	C:\DYTOOLS Thu Oct 20 08:59:37 2016

METRO









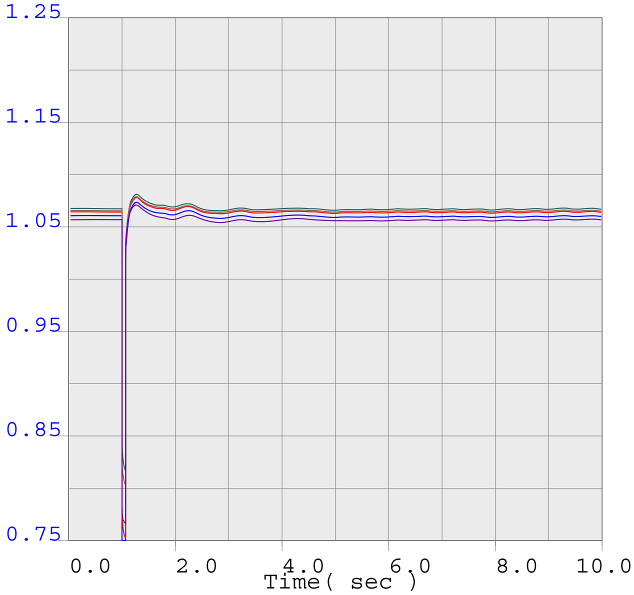
bay_4201
MESA 500 KV POS 5
1 MW dispatch Case

qc9p-bay_4201.chf

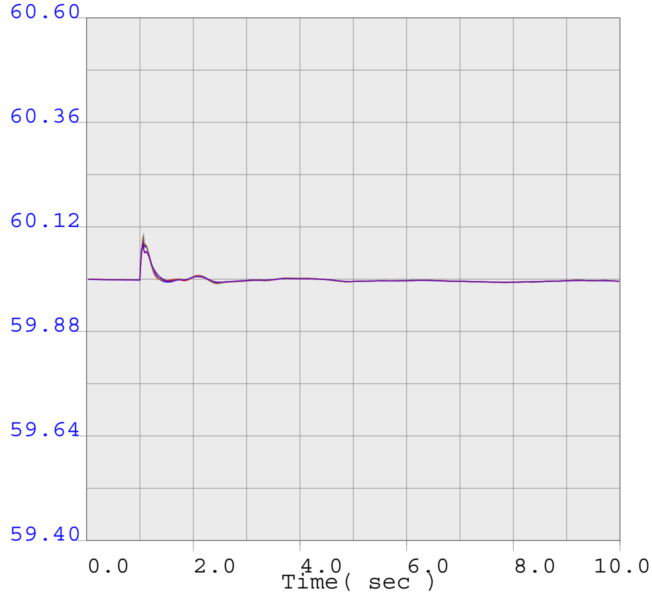
C:\DYTOOLS

Thu Oct 20 08:59:39 2016

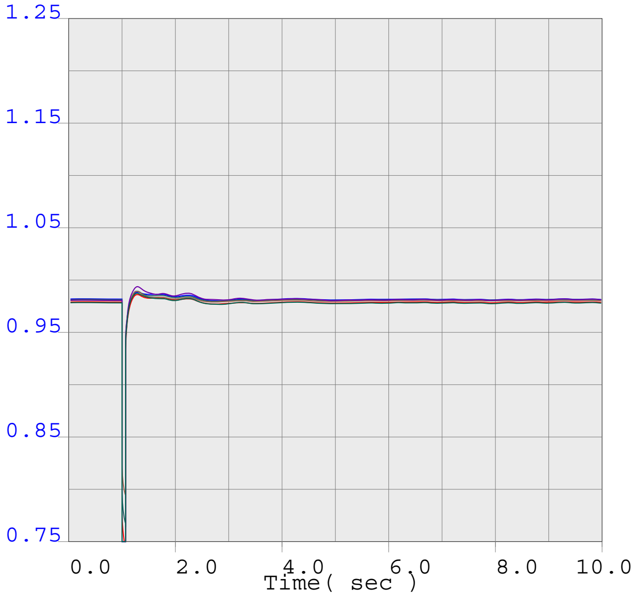
METRO



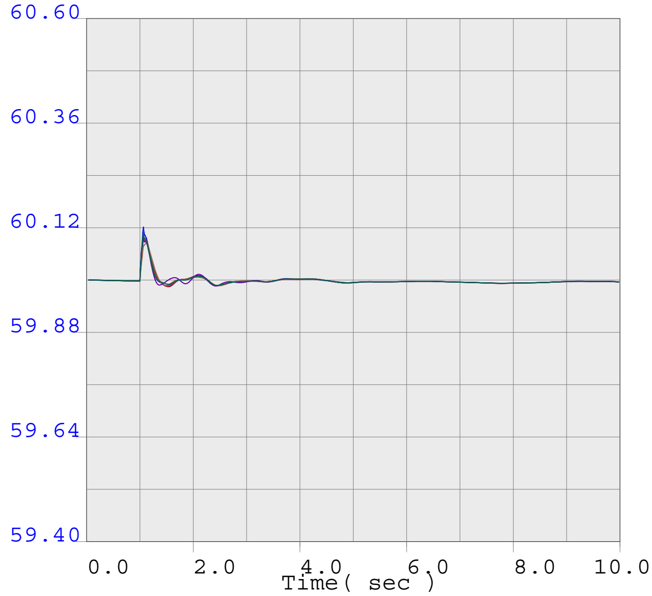
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

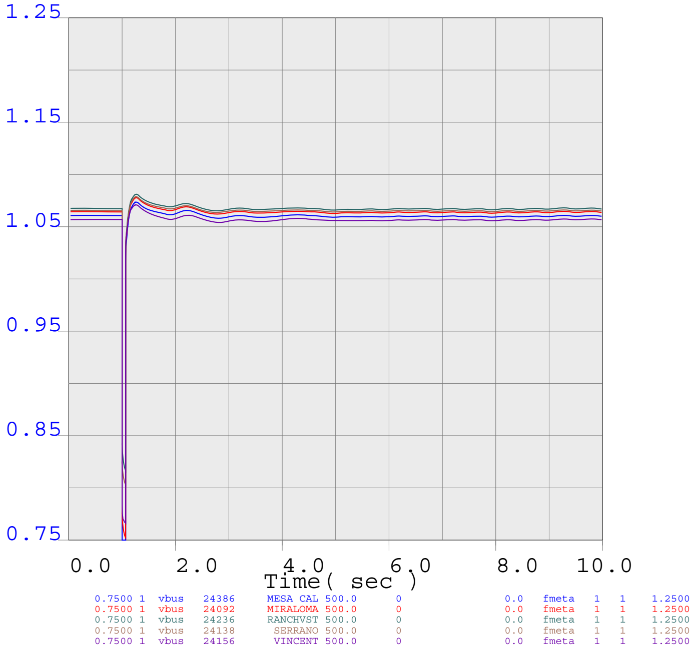
bay_4601
WALNUT 220 KV POS 7N STUCK BREAKER
1 MW dispatch Case

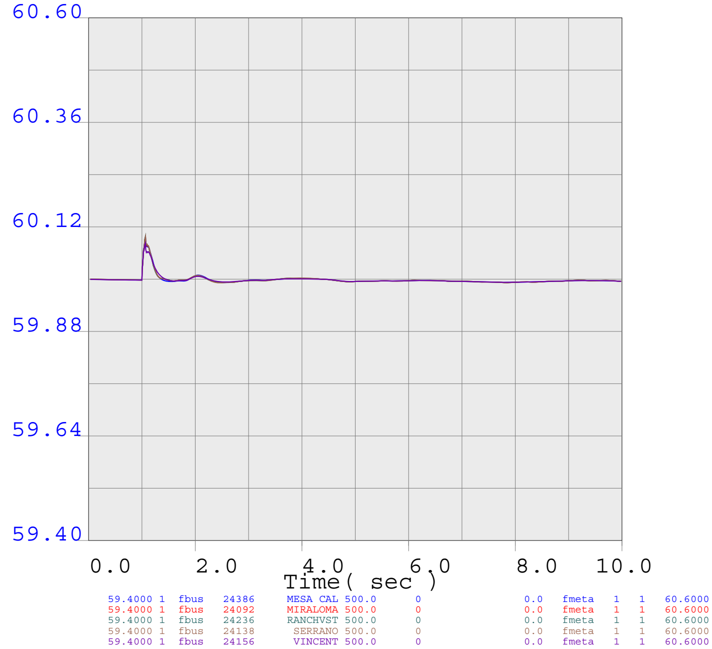
qc9p-bay_4601.chf

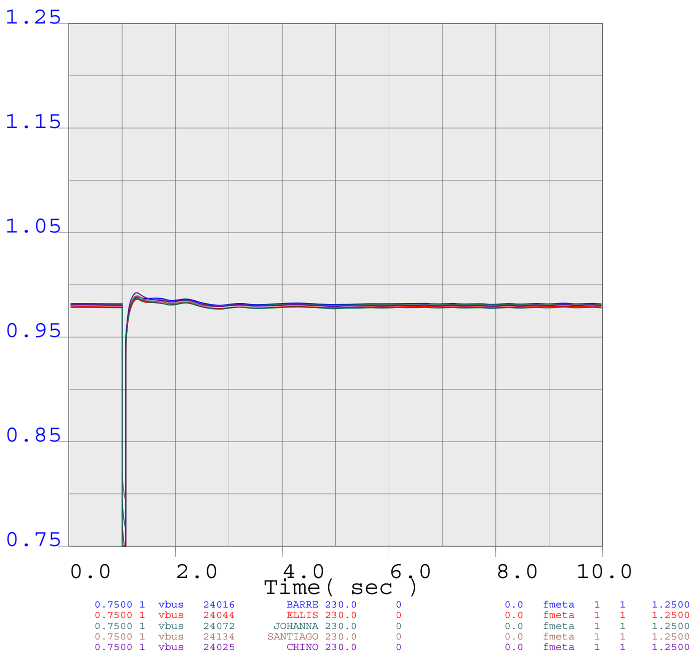
C:\DYTOOLS

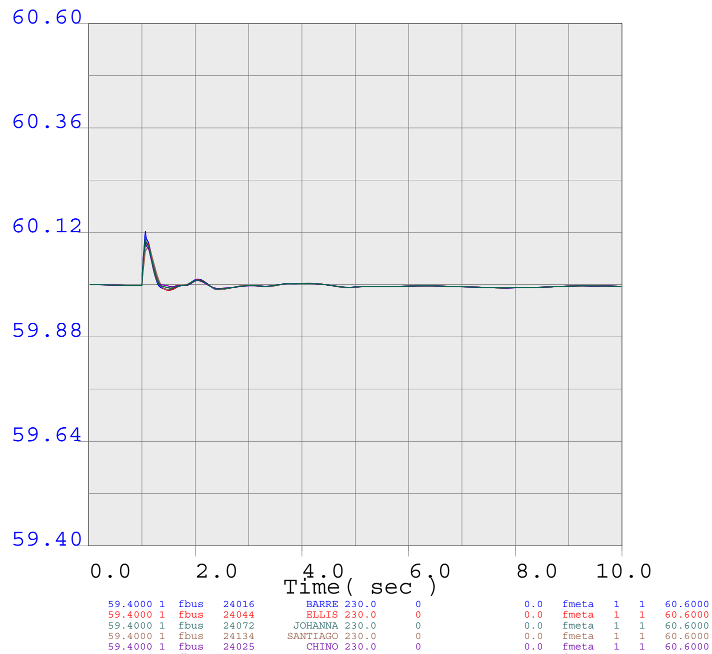
Thu Oct 20 08:59:41 2016

METRO









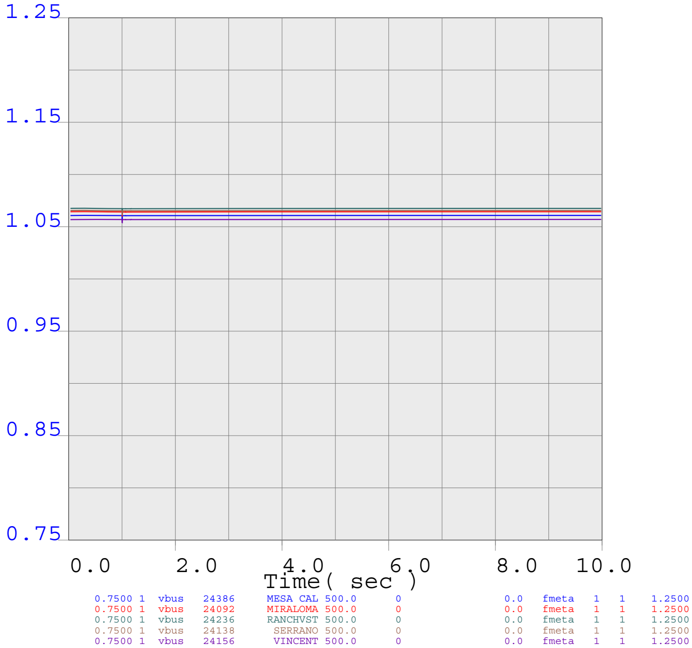
bay_4602
WALNUT 220 KV POS 8N STUCK BREAKER
1 MW dispatch Case

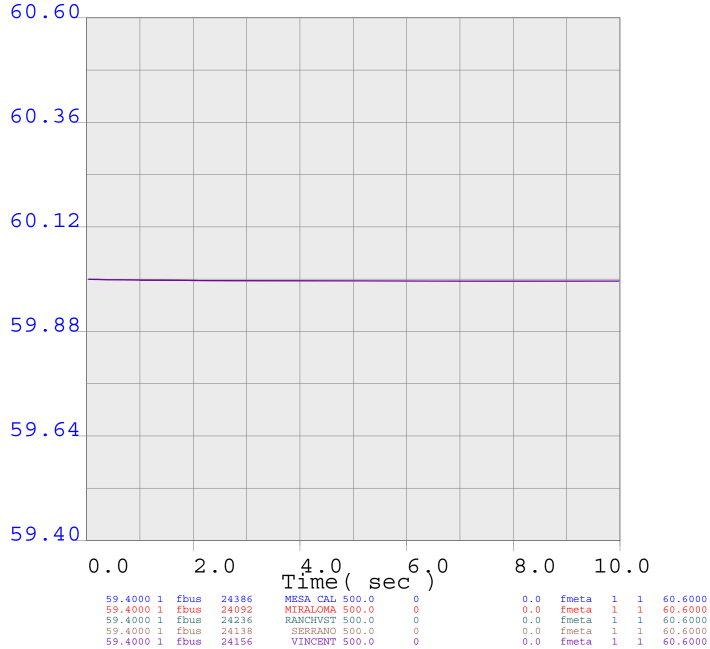
qc9p-bay_4602.chf

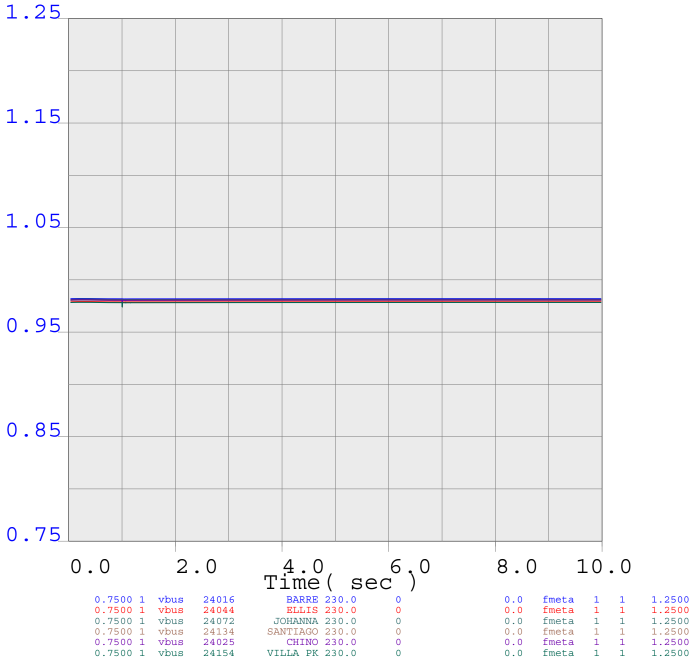
C:\DYTOOLS

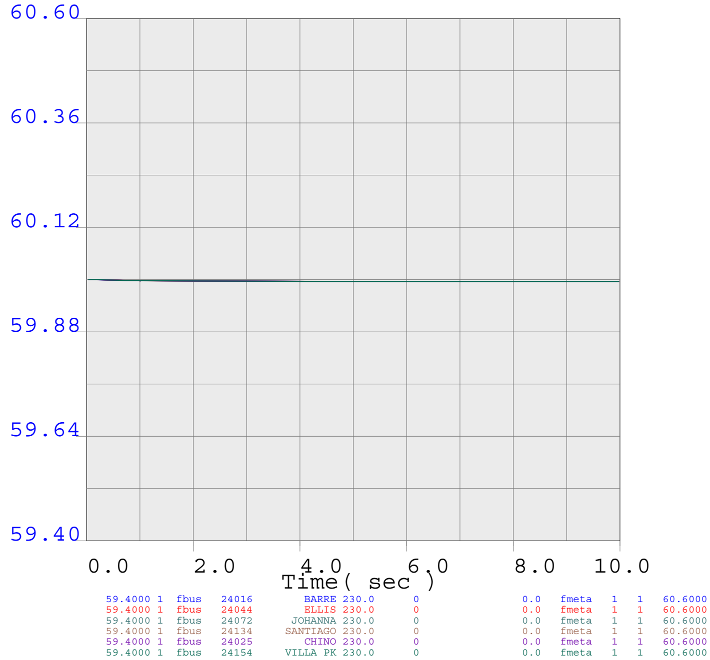
Thu Oct 20 08:59:44 2016

METRO









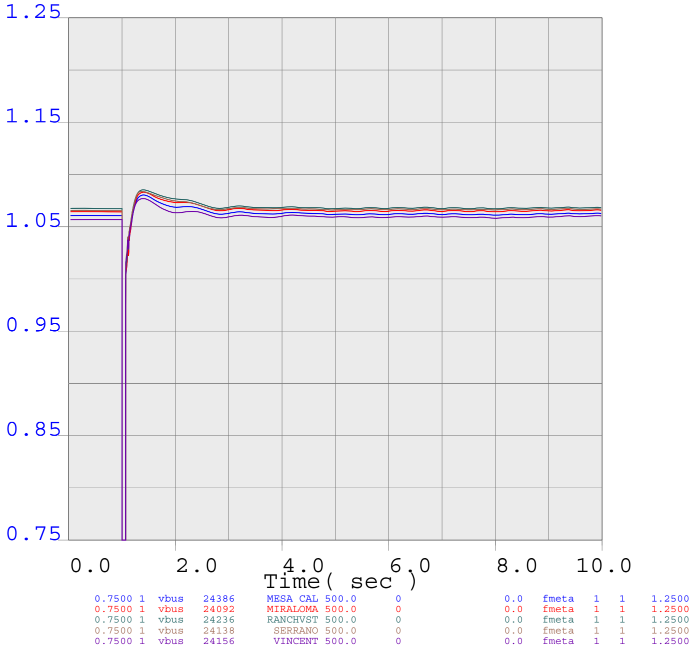
line_1201
Line MIRALOMA 500.0 to SERRANO 500.0 Circuit 1
1 MW dispatch Case

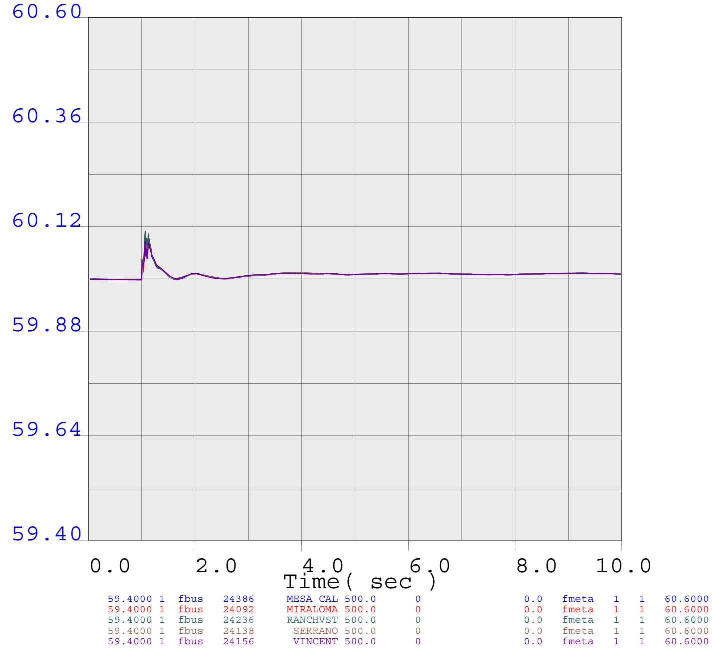
qc9p-line_1201.chf

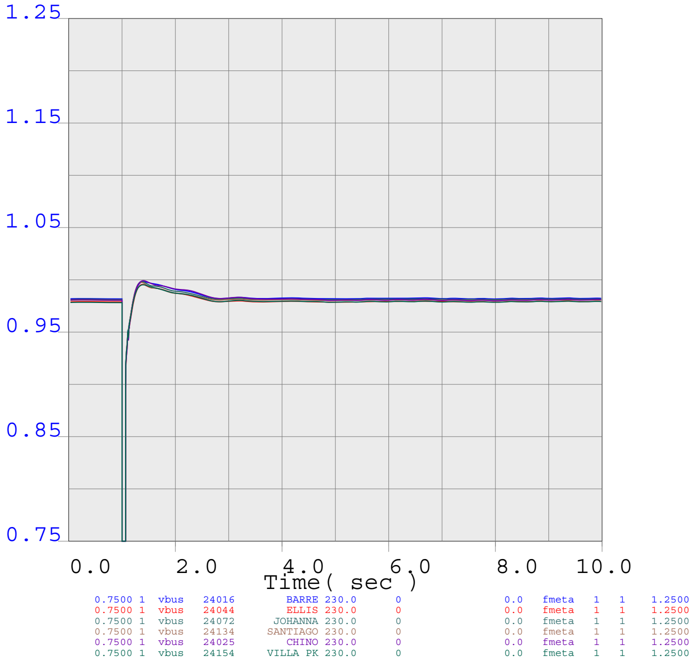
C:\DYTOOLS

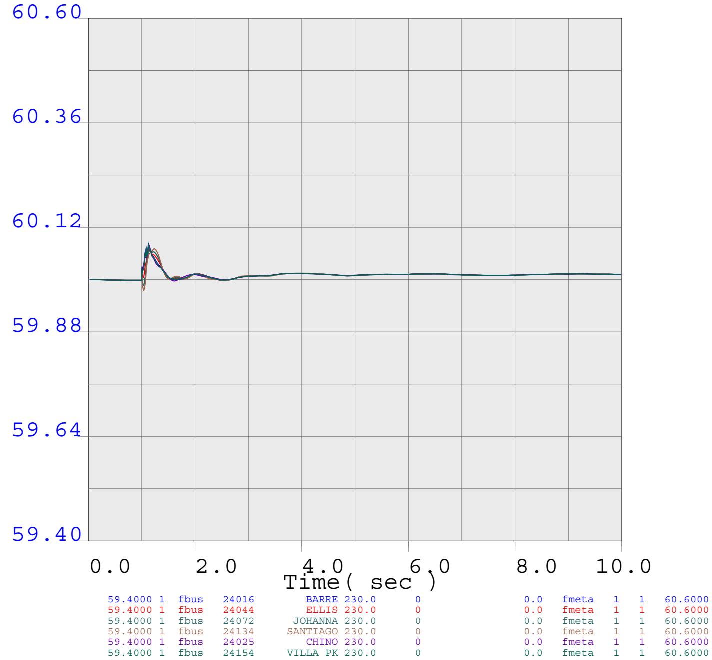
Thu Oct 20 08:59:47 2016

METRO









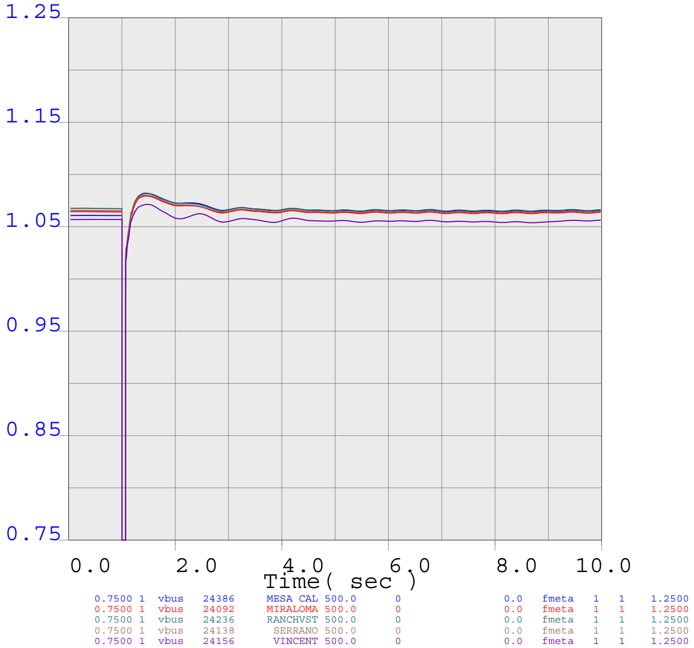
line_1202
Line MIRALOMA 500.0 to SERRANO 500.0 Circuit 2
1 MW dispatch Case

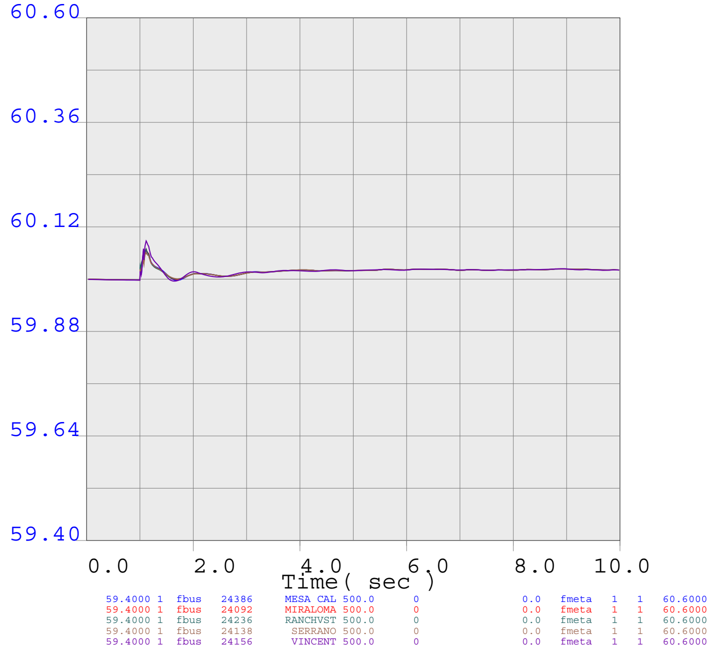
qc9p-line_1202.chf

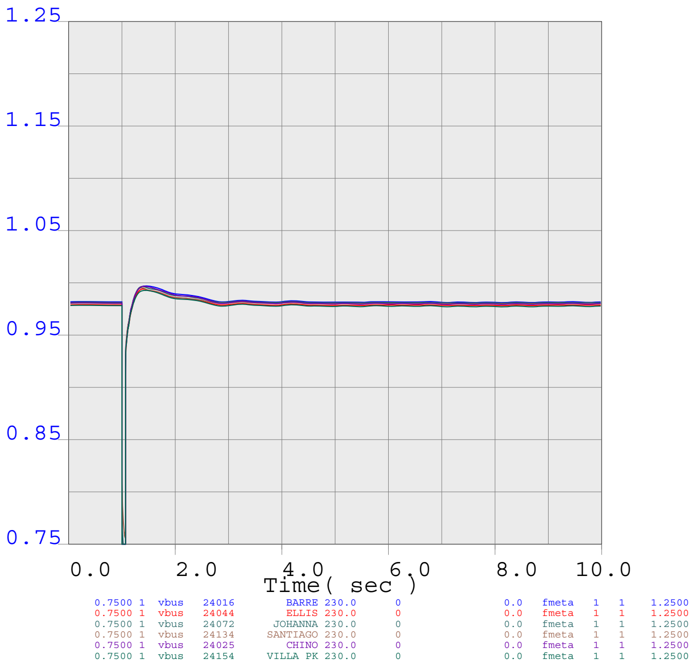
C:\DYTOOLS

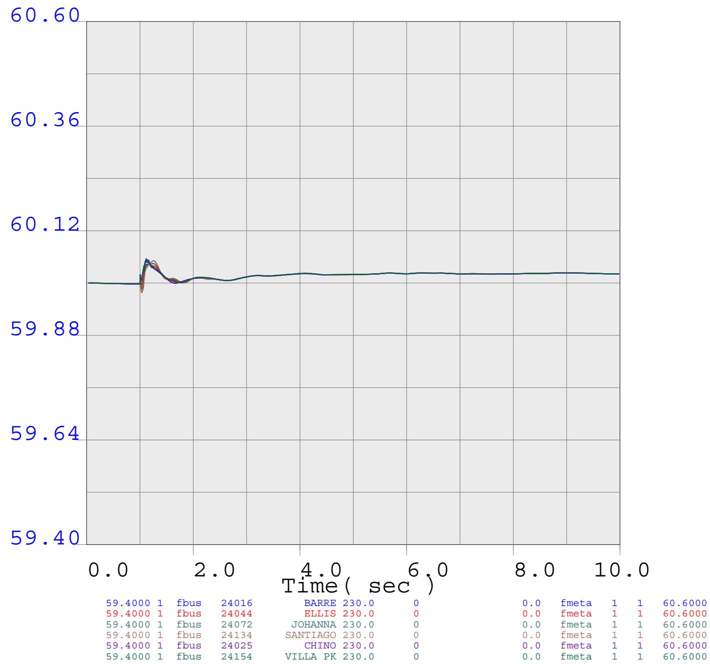
Thu Oct 20 08:59:49 2016

METRO









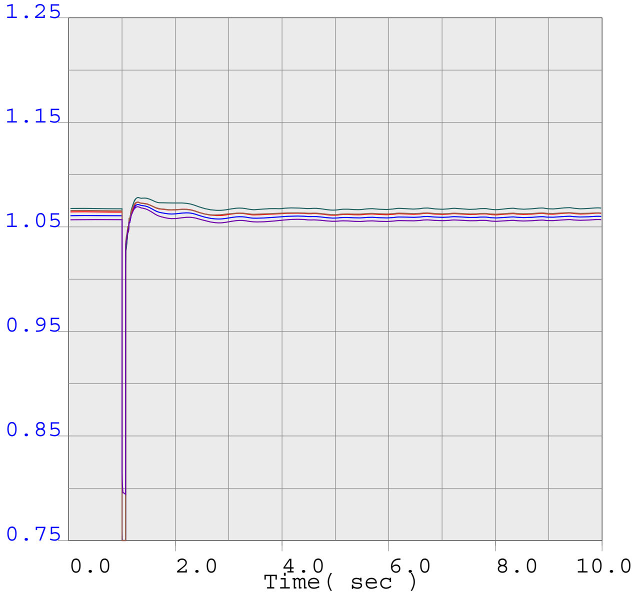
line_1203
Line VINCENT 500.0 to MESA CAL 500.0 Circuit 1
1 MW dispatch Case

qc9p-line_1203.chf

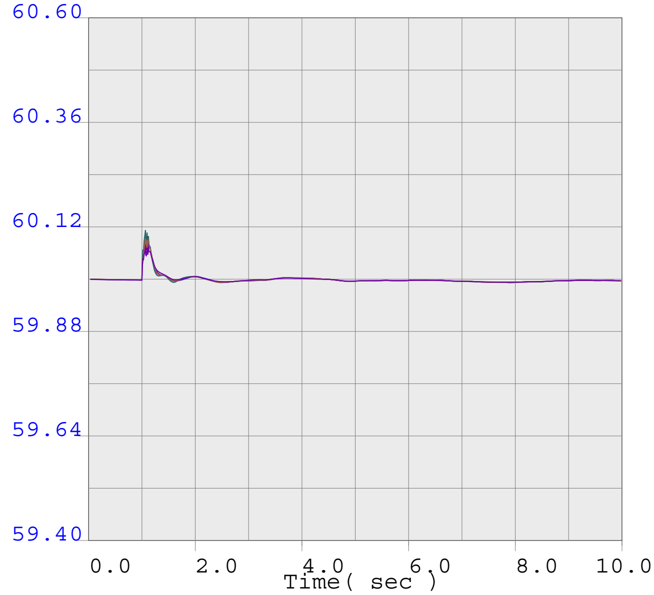
C:\DYTOOLS

Thu Oct 20 08:59:51 2016

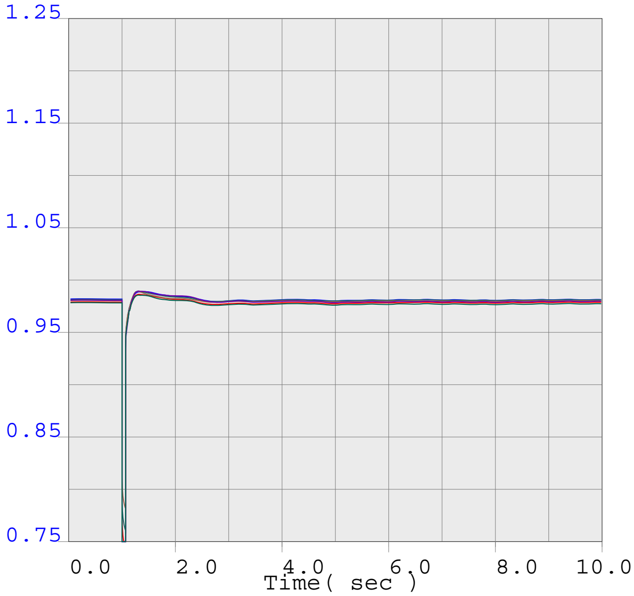
METRO



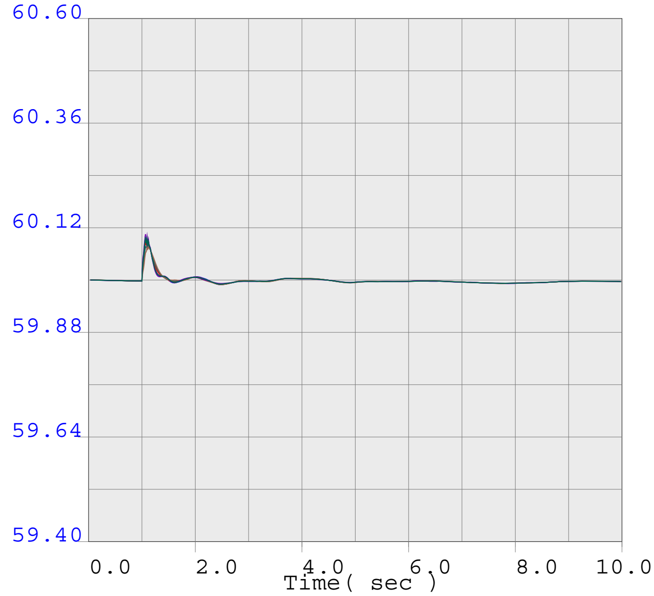
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

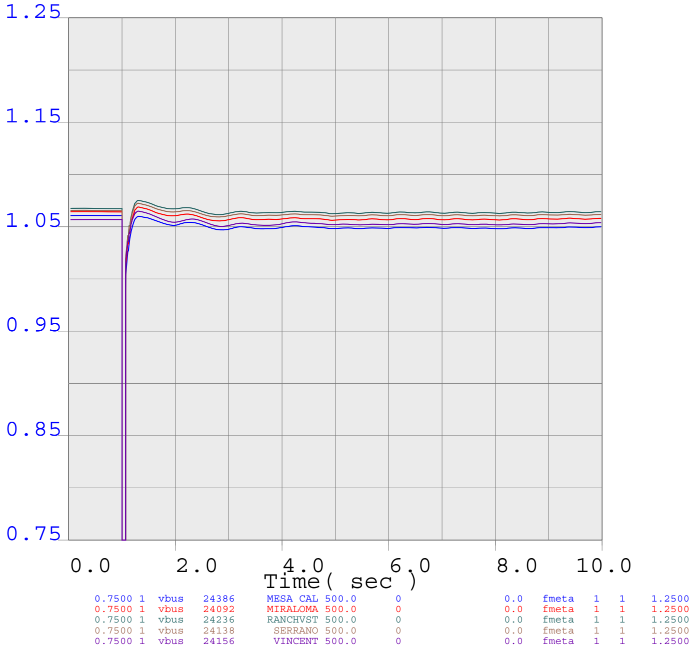
line_1204
Line RANCHVST 500.0 to SERRANO 500.0 Circuit 1
1 MW dispatch Case

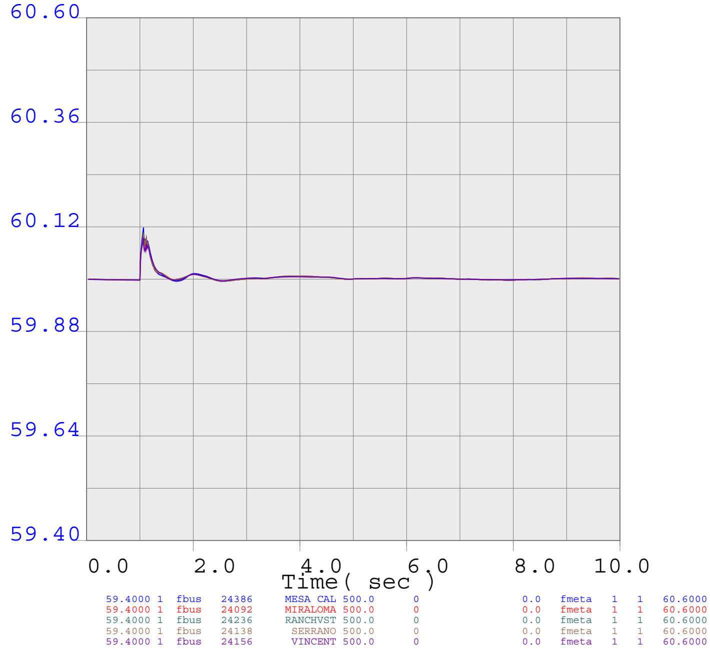
qc9p-line_1204.chf

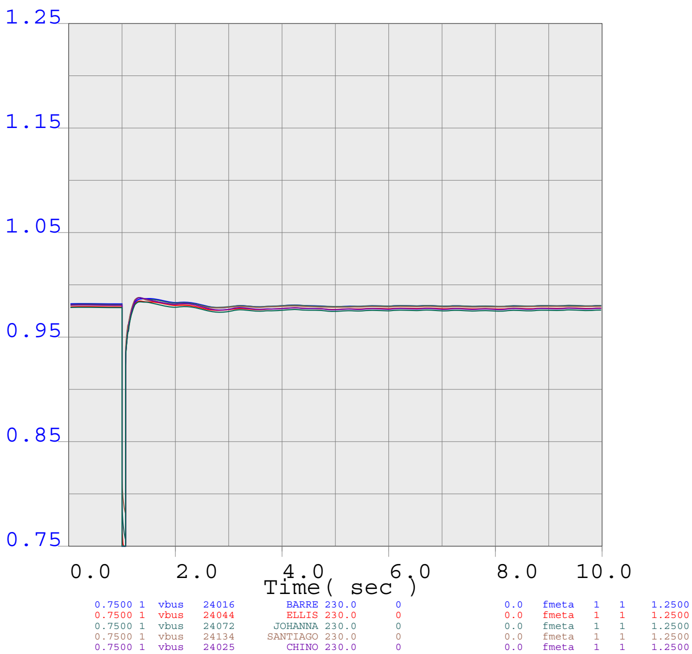
C:\DYTOOLS

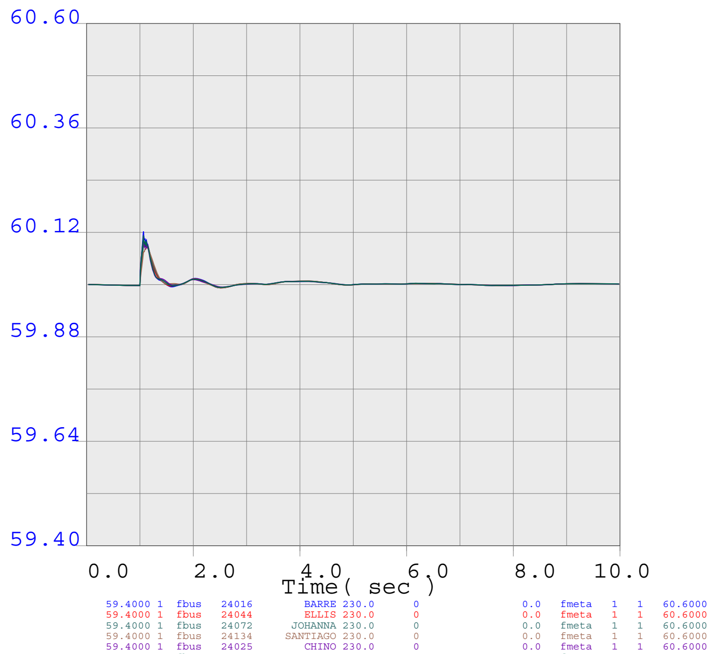
Thu Oct 20 08:59:54 2016

METRO









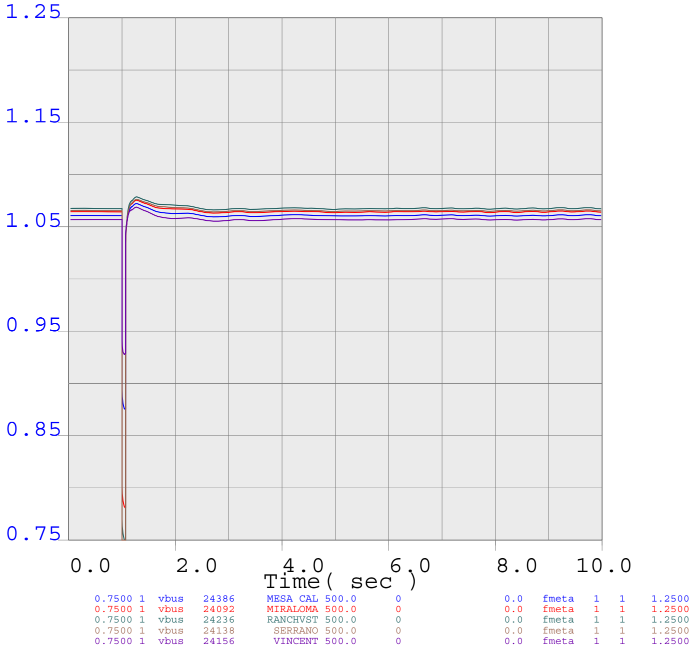
line_1205
Line MESA CAL 500.0 to MIRALOMA 500.0 Circuit 1
1 MW dispatch Case

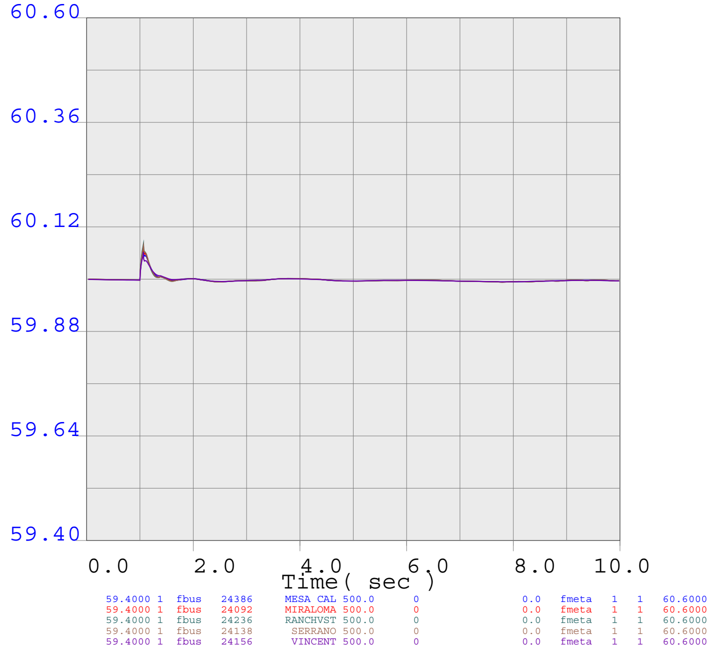
qc9p-line_1205.chf

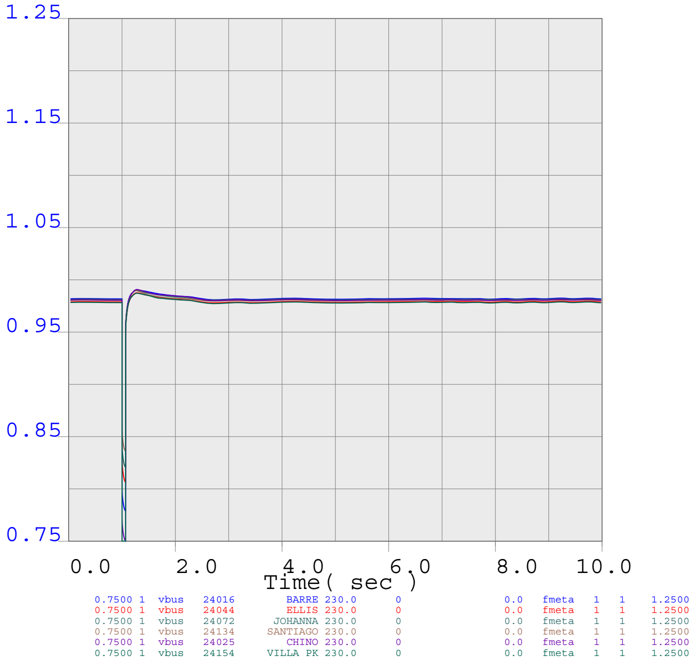
C:\DYTOOLS

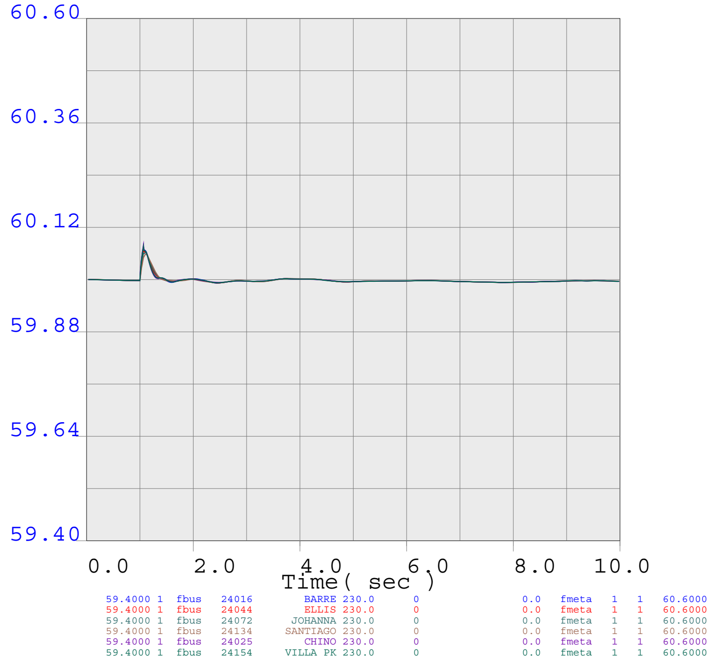
Thu Oct 20 08:59:57 2016

METRO





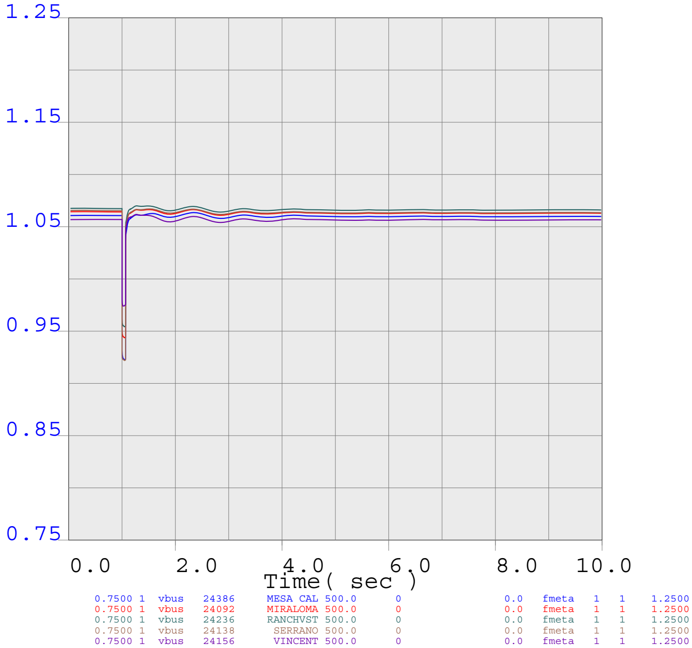


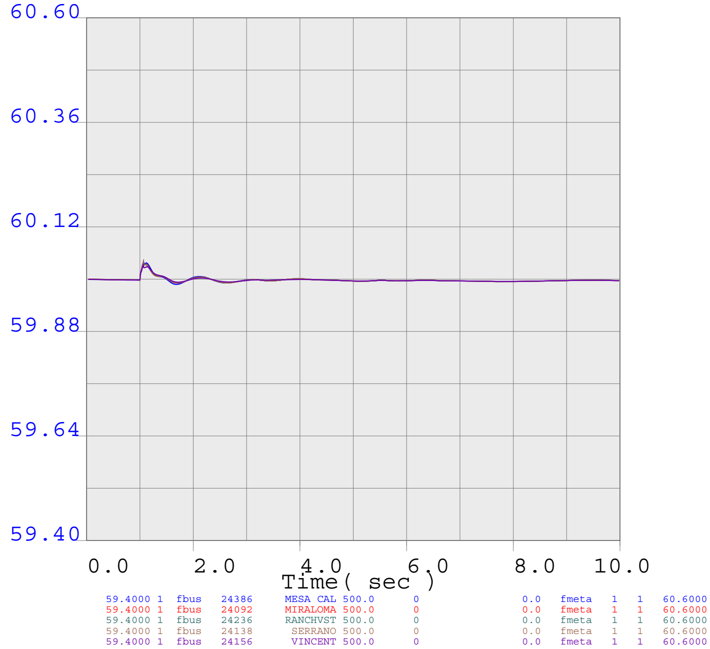


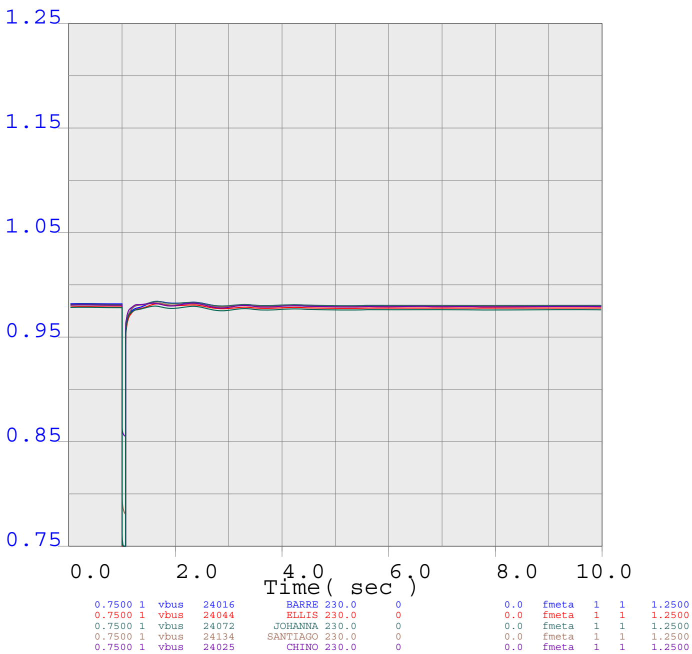
line_1206
Line ALBERHIL 500.0 to SERRANO 500.0 Circuit 1
1 MW dispatch Case

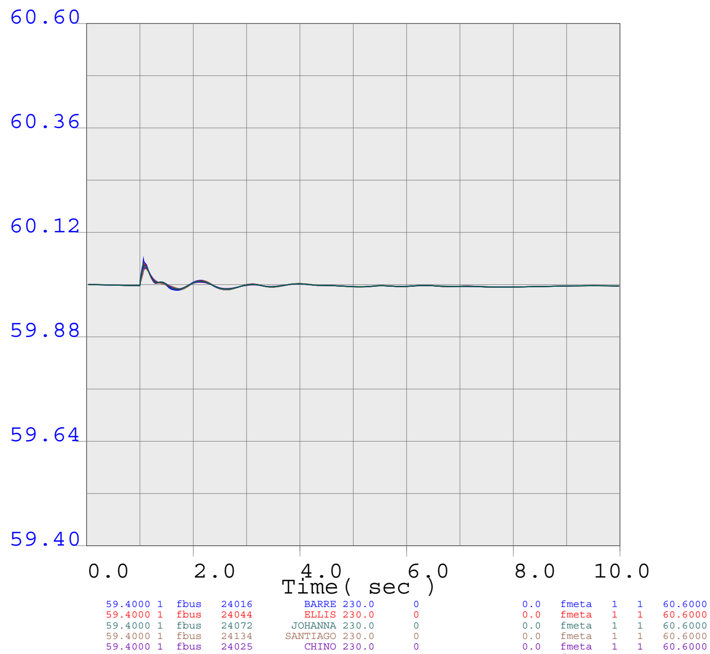
	qc9p-line_1206.chf	C:\DYTOOLS Thu Oct 20 09:00:00 2016

METRO









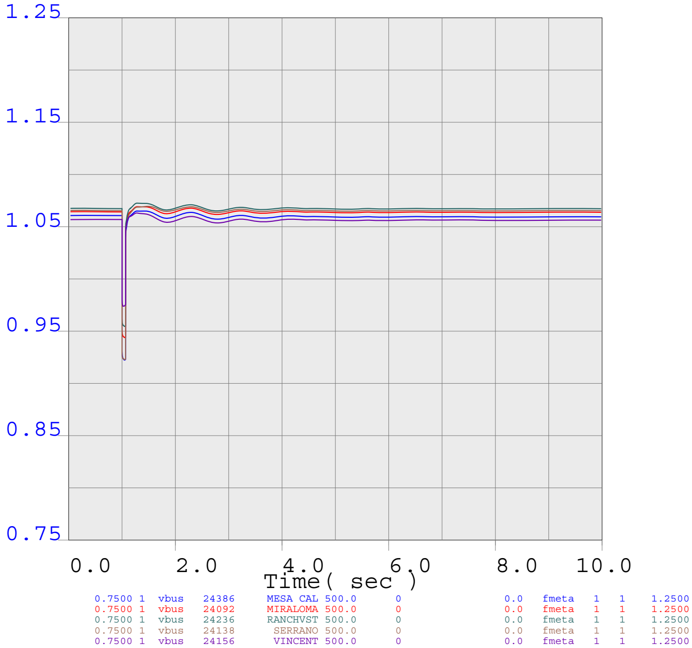
line_1207
Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1
1 MW dispatch Case

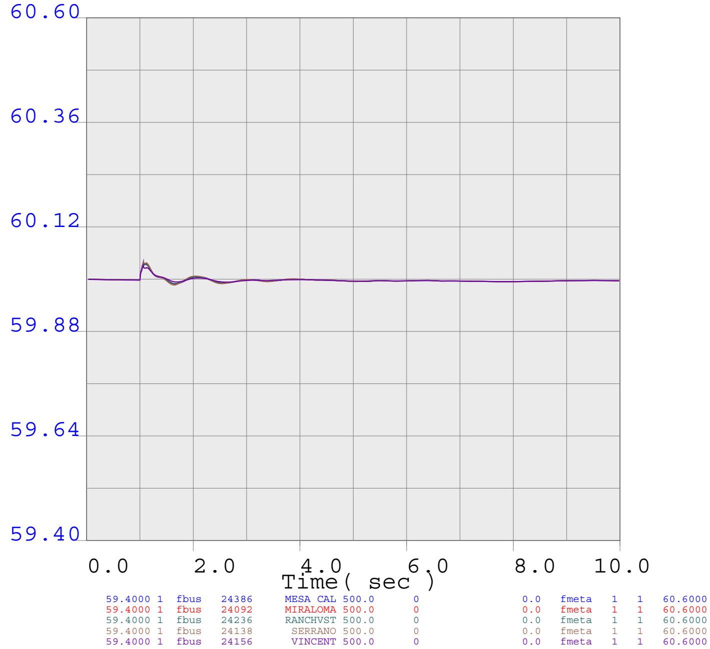
qc9p-line_1207.chf

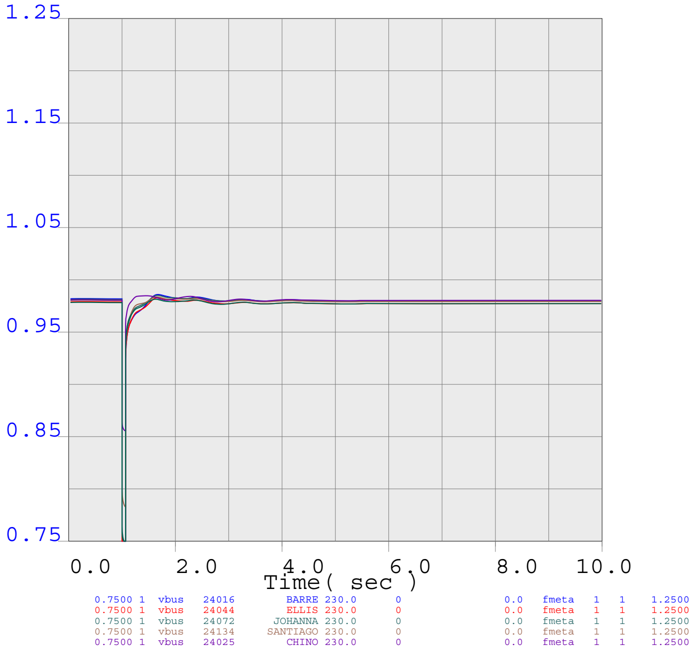
C:\DYTOOLS

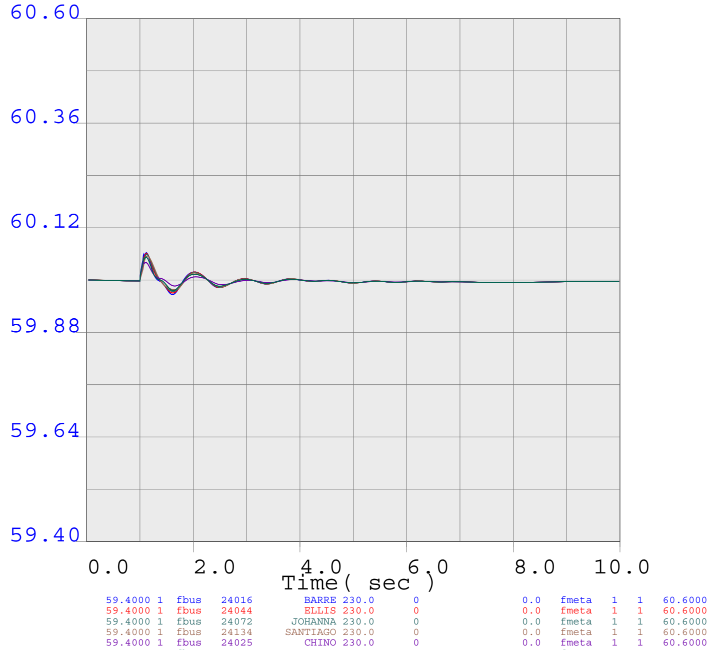
Thu Oct 20 09:00:02 2016

METRO









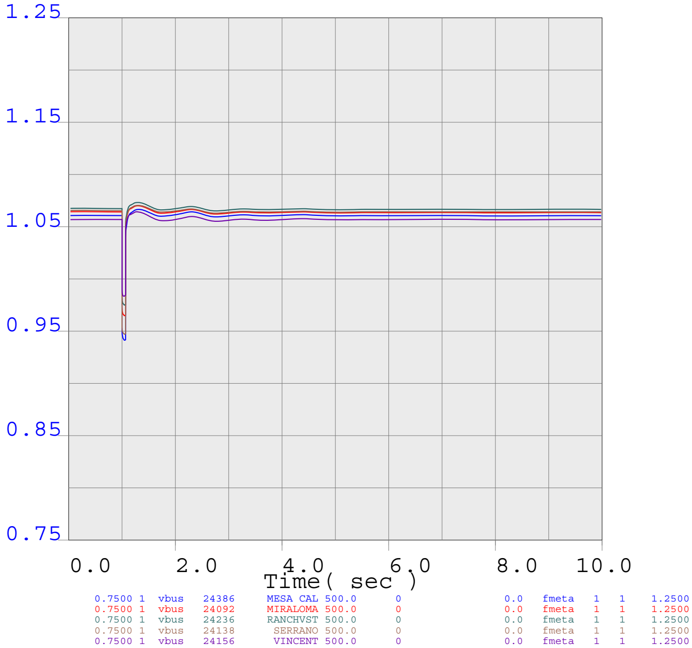
line_1208
Line ALMITOSE 230.0 to CENTER 230.0 Circuit 1
1 MW dispatch Case

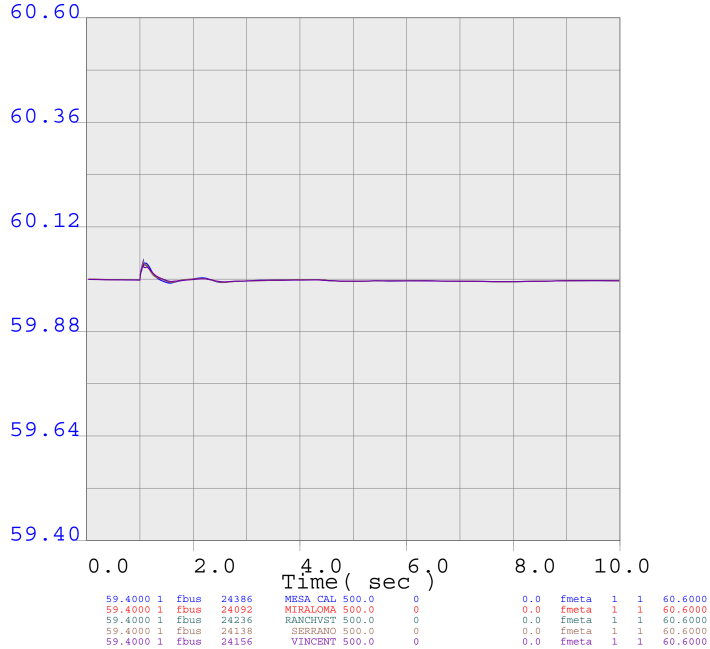
qc9p-line_1208.chf

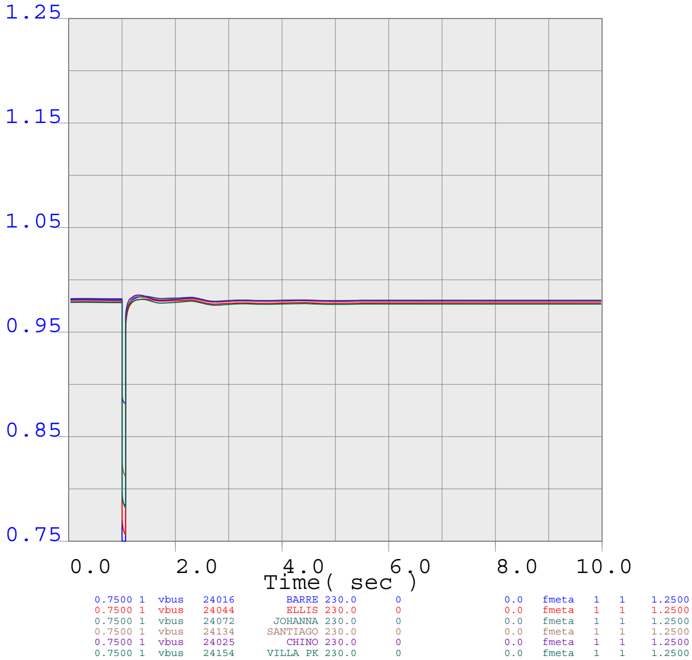
C:\DYTOOLS

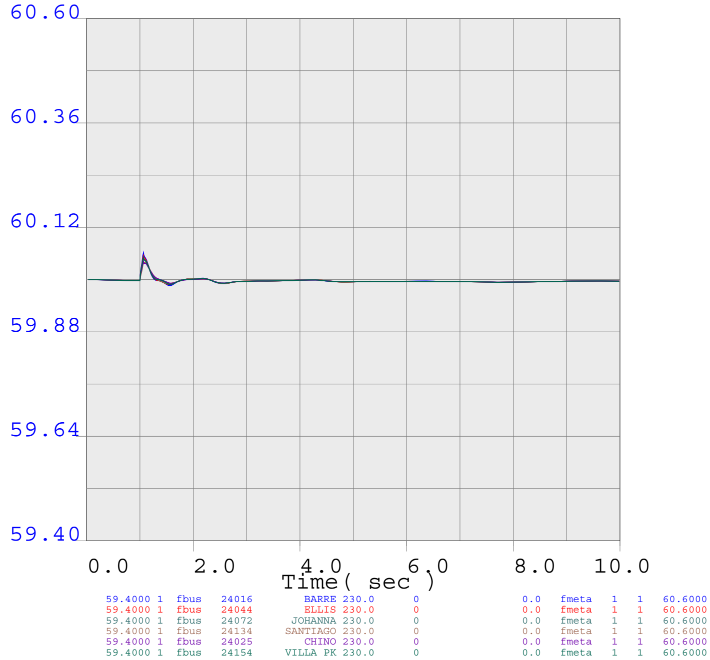
Thu Oct 20 09:00:05 2016

METRO









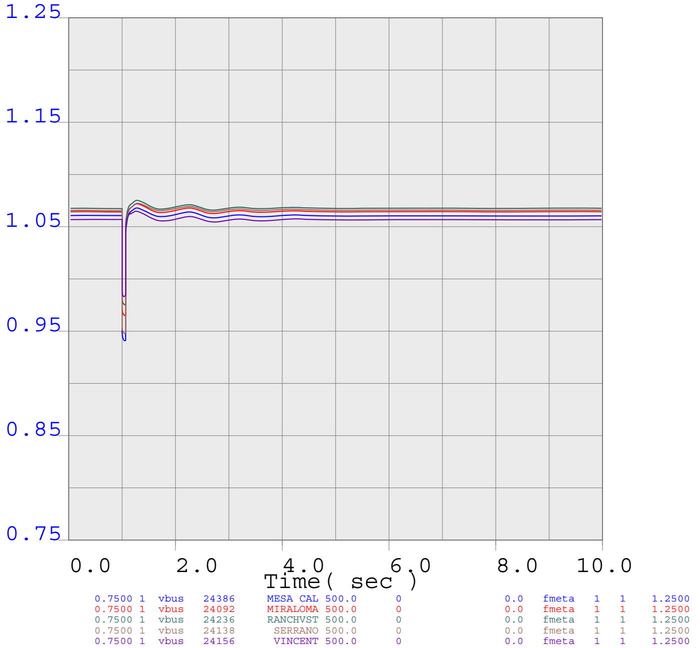
line_1209
Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2
1 MW dispatch Case

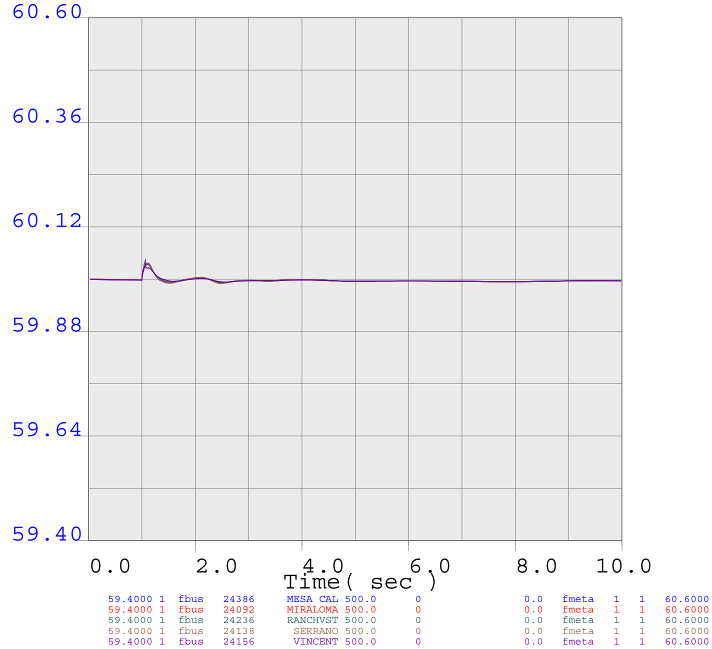
qc9p-line_1209.chf

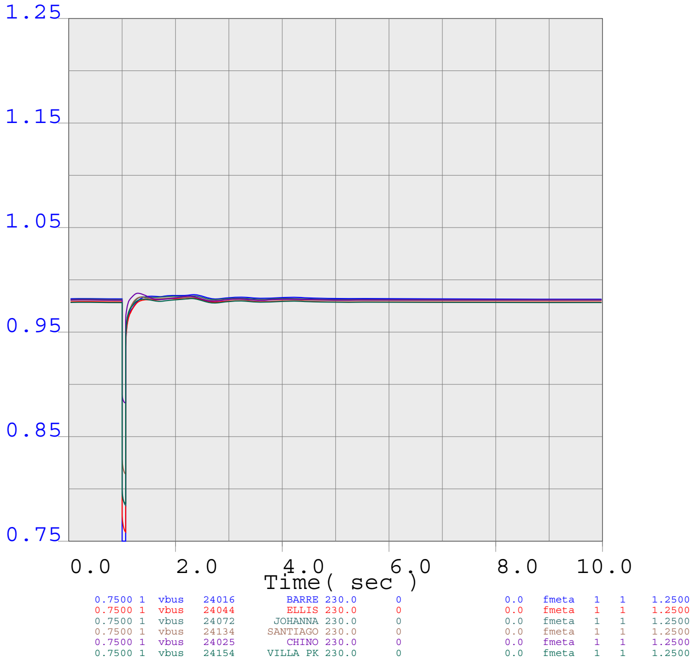
C:\DYTOOLS

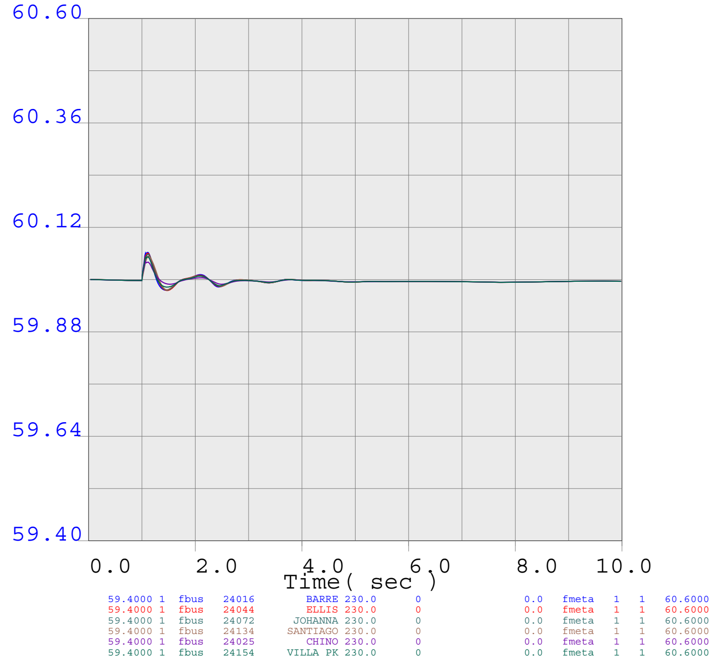
Thu Oct 20 09:00:07 2016

METRO









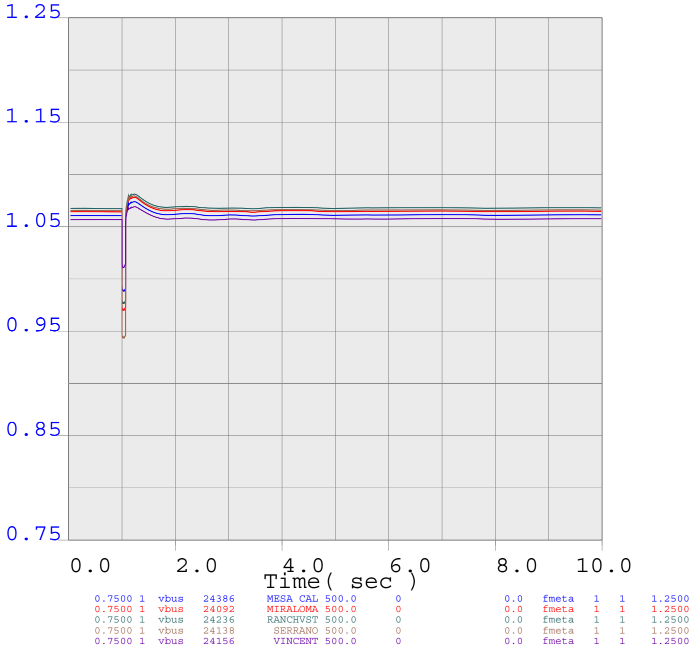
line_1210
Line ALMITOSW 230.0 to LITEHIPE 230.0 Circuit 1
1 MW dispatch Case

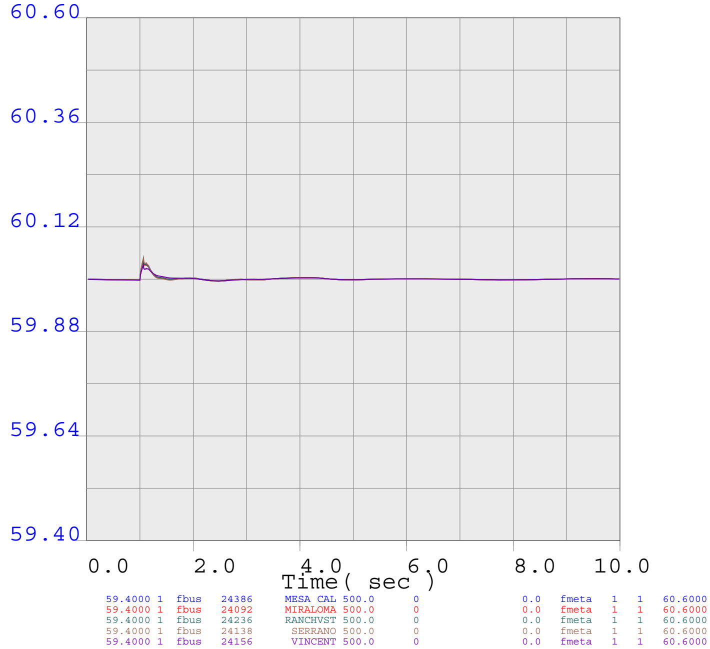
qc9p-line_1210.chf

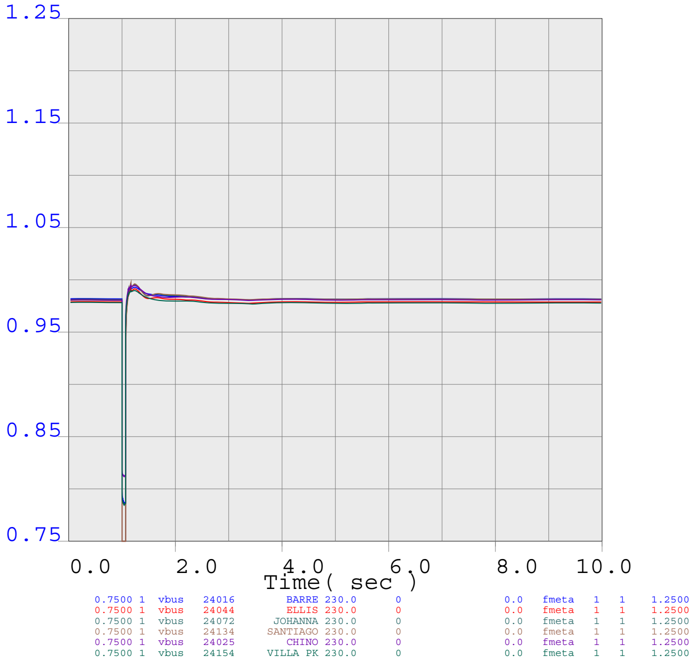
C:\DYTOOLS

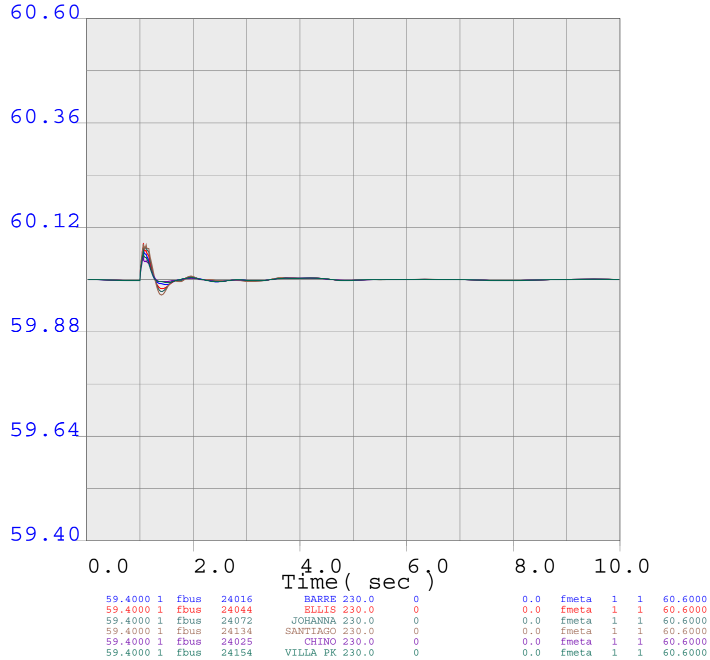
Thu Oct 20 09:00:09 2016

METRO









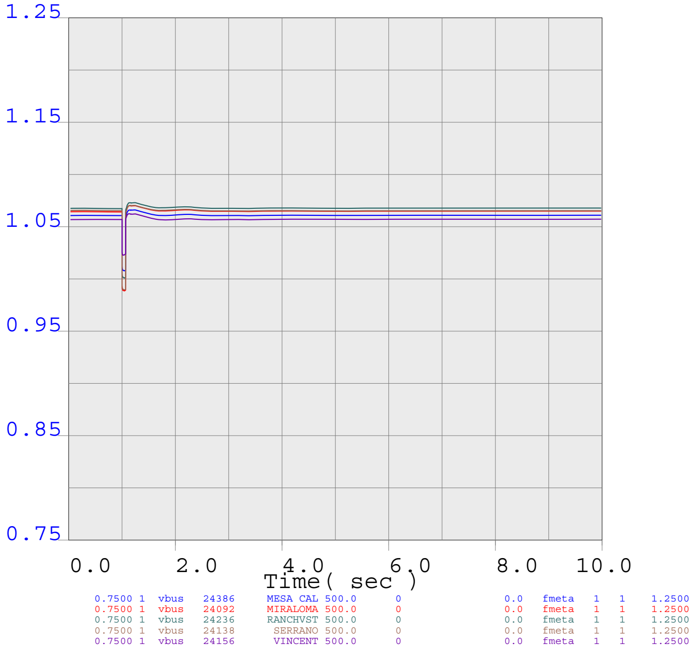
line_12100
Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1
1 MW dispatch Case

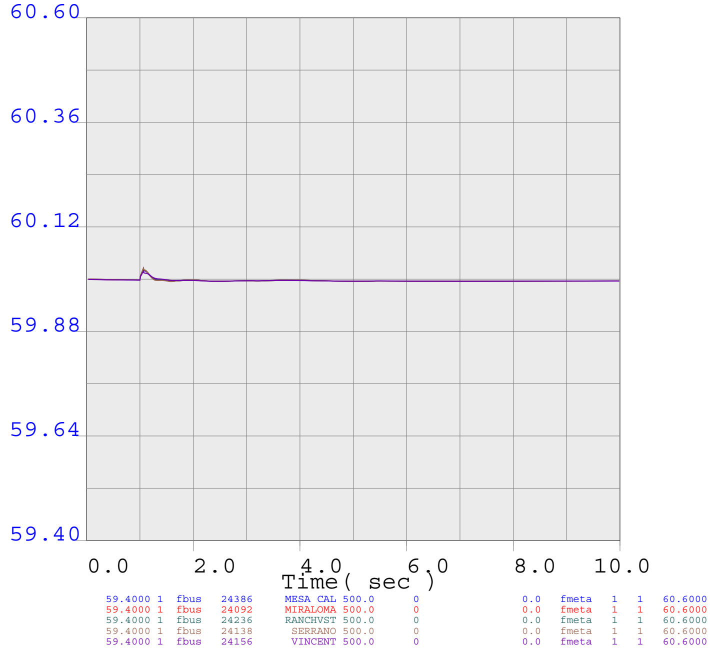
qc9p-line_12100.chf

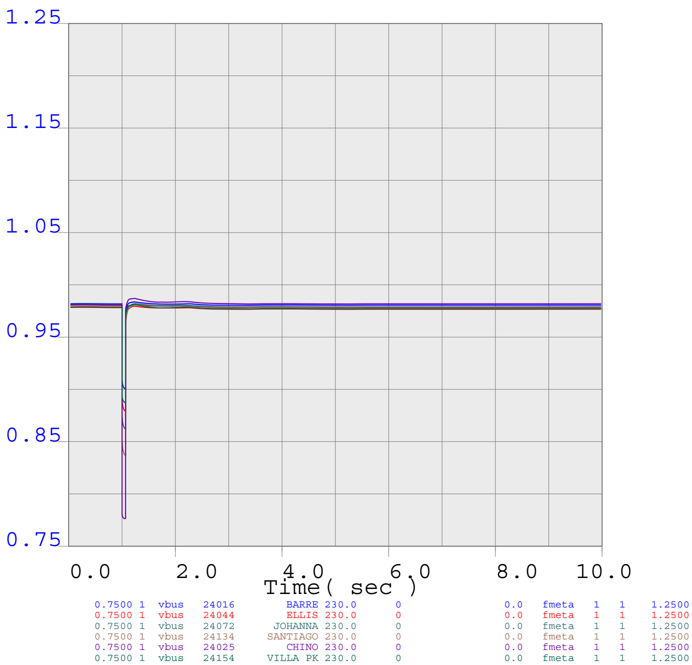
C:\DYTOOLS

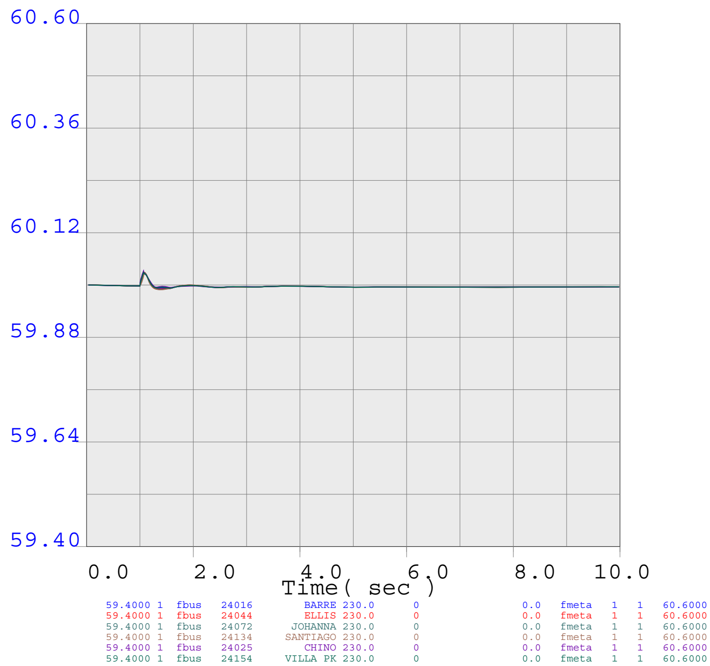
Thu Oct 20 09:00:11 2016

METRO









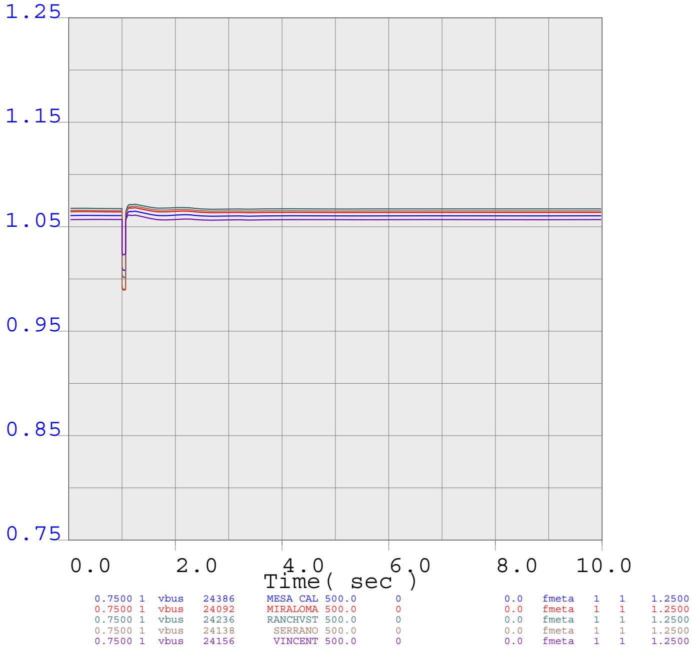
line_12101
Line VIEJO 230.0 to CHINO 230.0 Circuit 1
1 MW dispatch Case

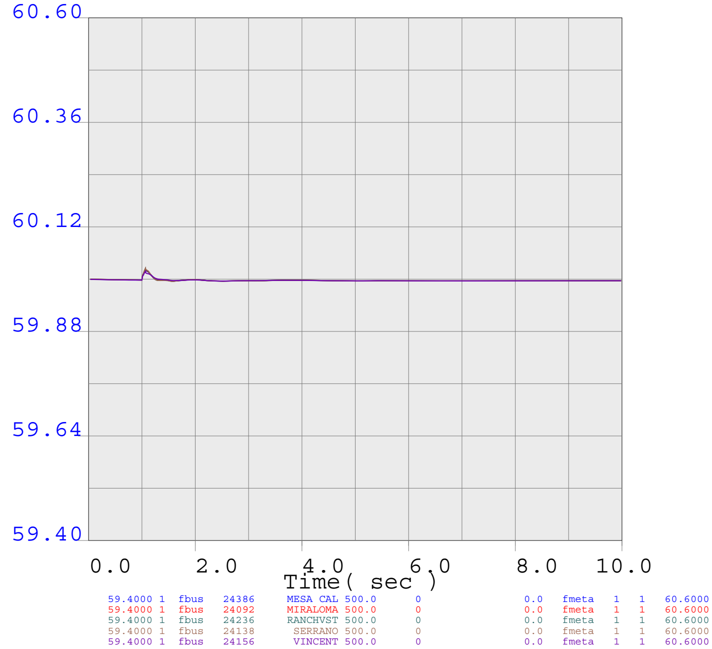
qc9p-line_12101.chf

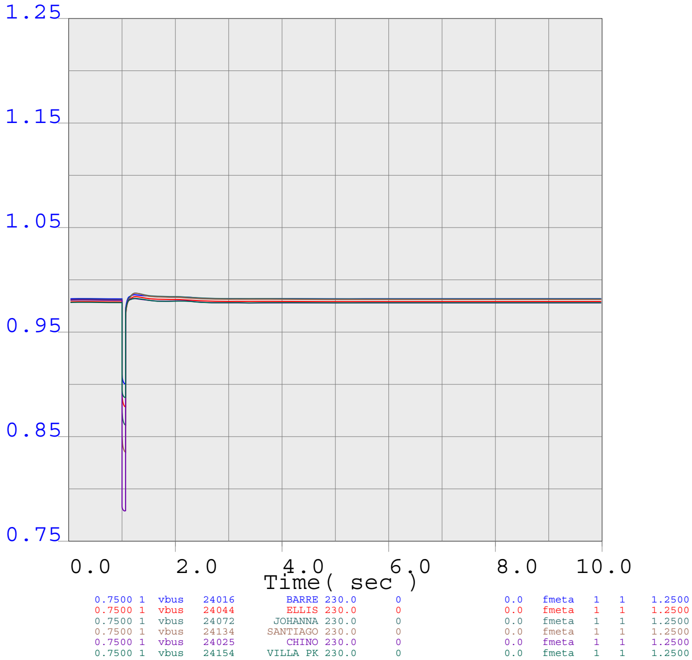
C:\DYTOOLS

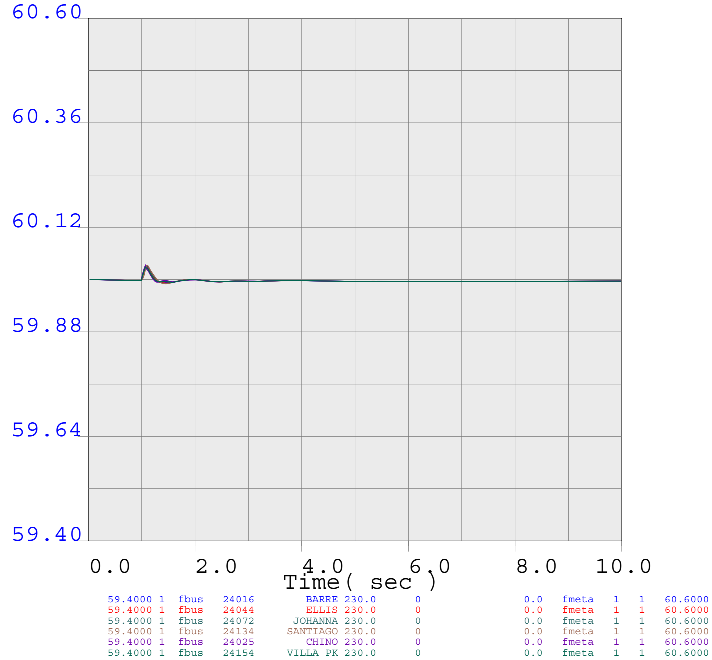
Thu Oct 20 09:00:13 2016

METRO





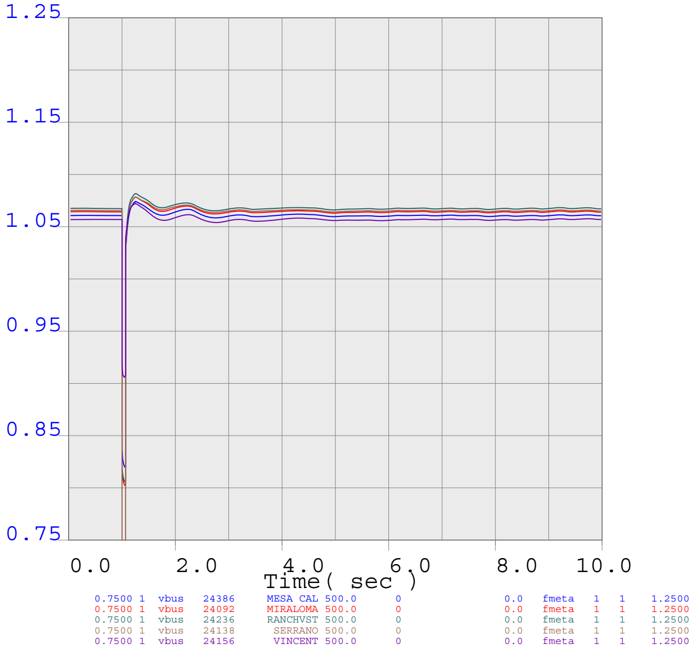


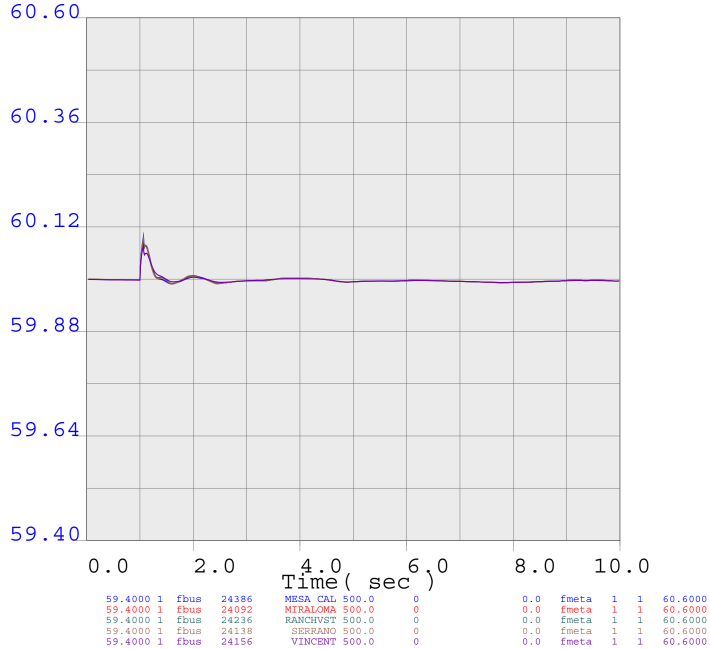


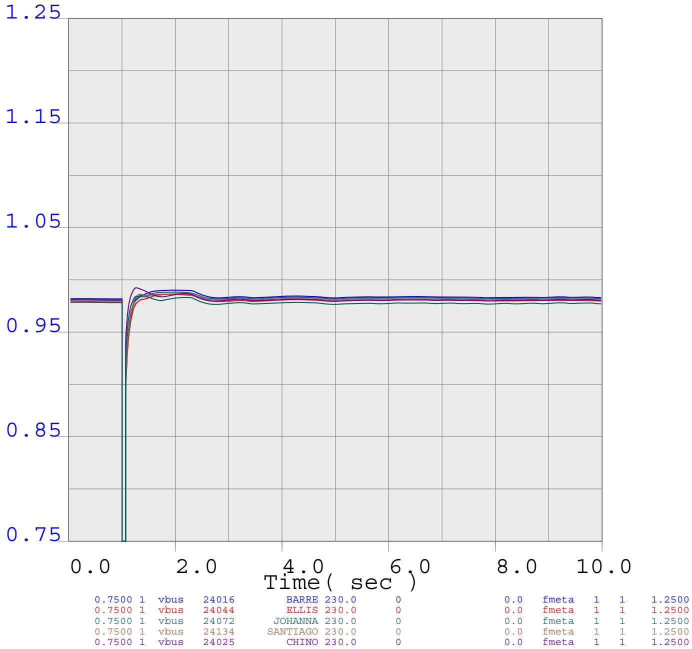
line_12102
Line VIEJO 230.0 to S.ONOFRE 230.0 Circuit 1
1 MW dispatch Case

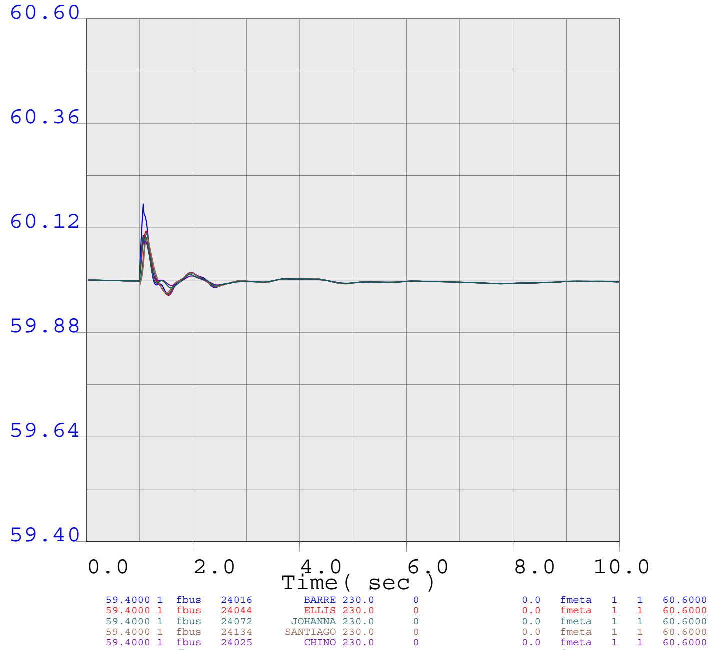
	qc9p-line_12102.chf	C:\DYTOOLS Thu Oct 20 09:00:16 2016

METRO









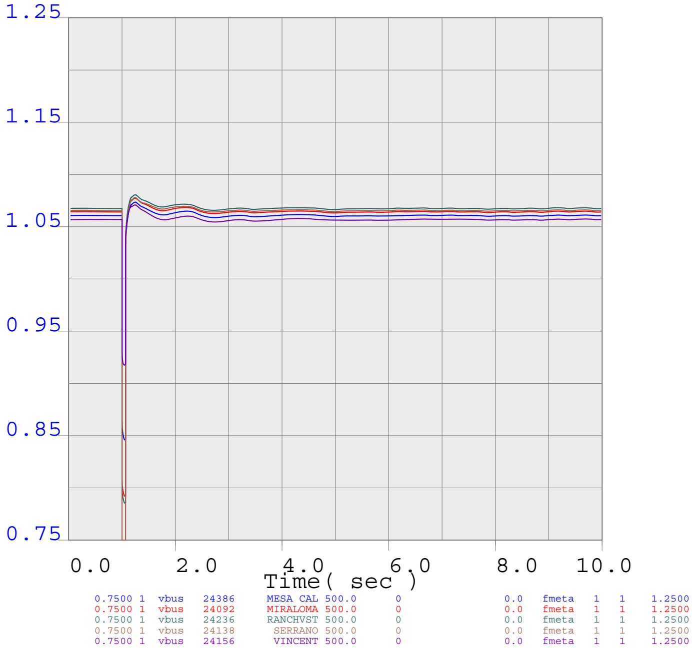
line_12103
Line BARRE 230.0 to LEWIS 230.0 Circuit 1
1 MW dispatch Case

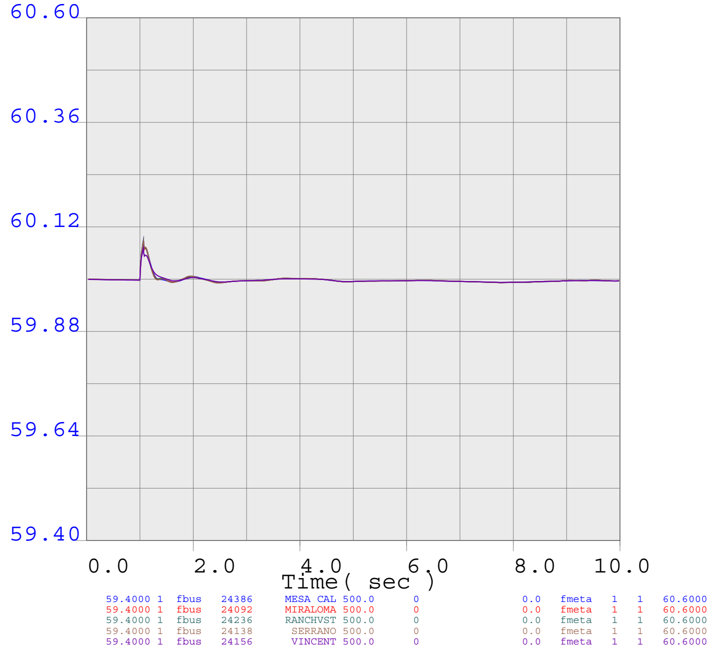
qc9p-line_12103.chf

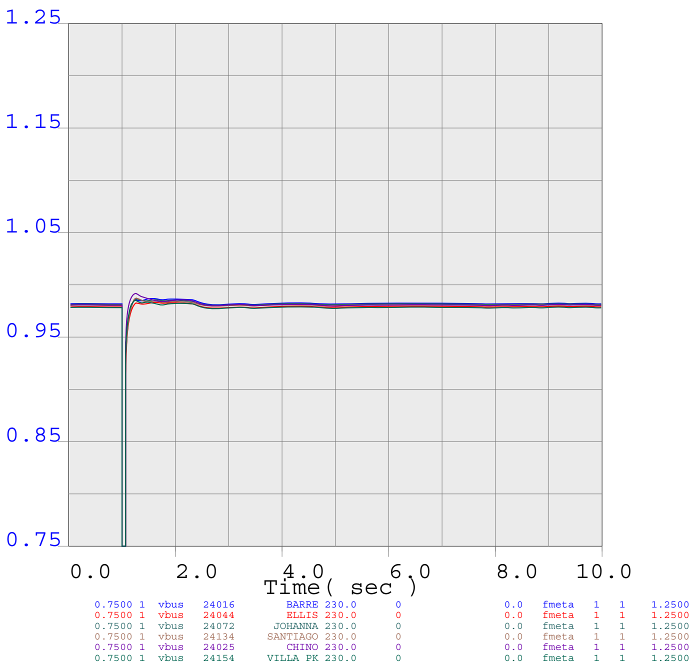
C:\DYTOOLS

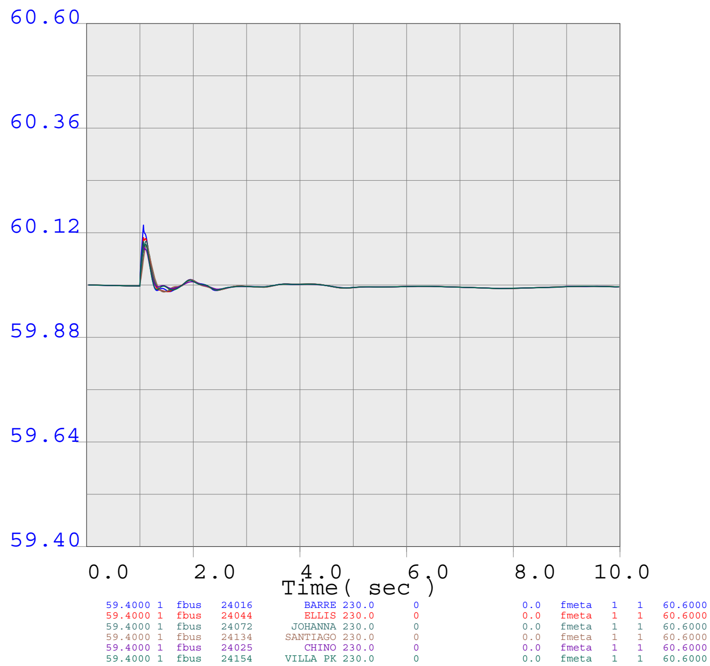
Thu Oct 20 09:00:19 2016

METRO









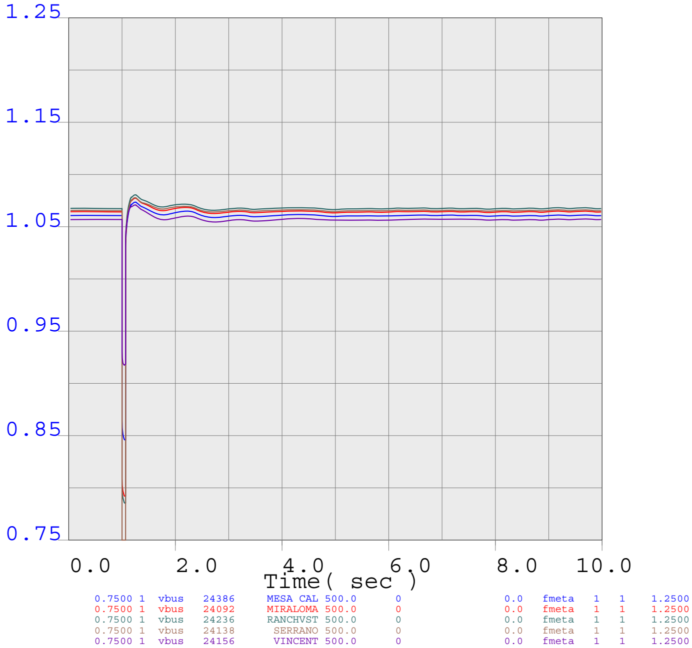
line_12104
Line LEWIS 230.0 to SERRANO 230.0 Circuit 1
1 MW dispatch Case

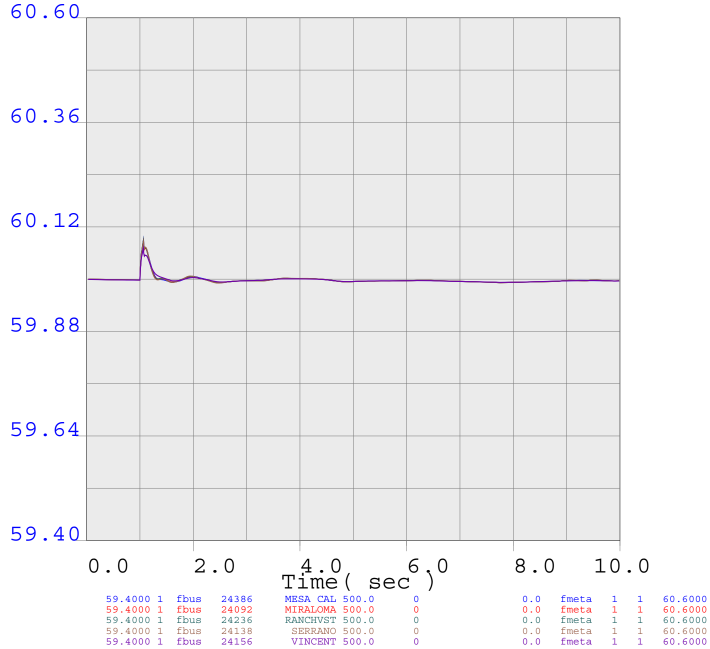
qc9p-line_12104.chf

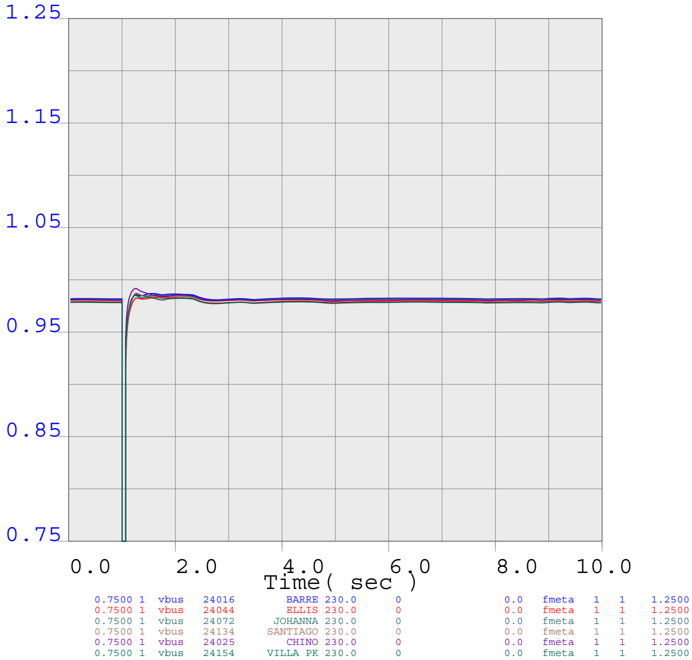
C:\DYTOOLS

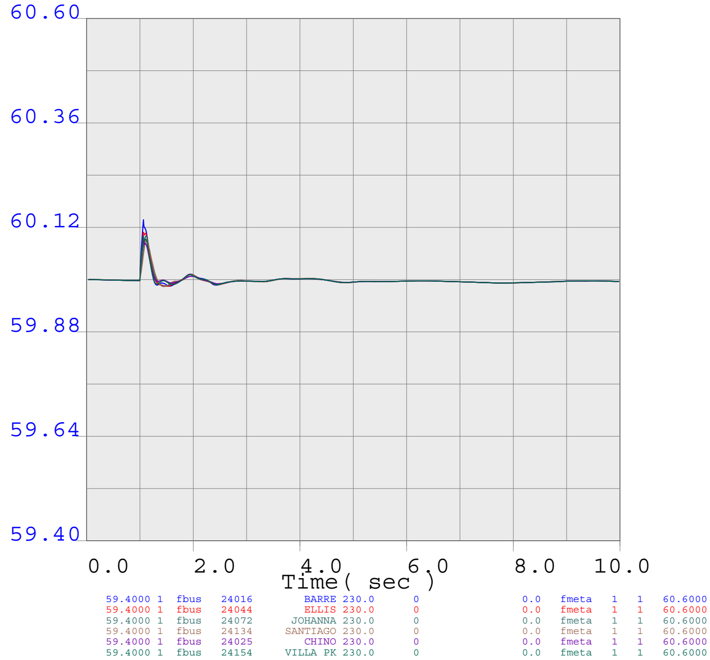
Thu Oct 20 09:00:22 2016

METRO









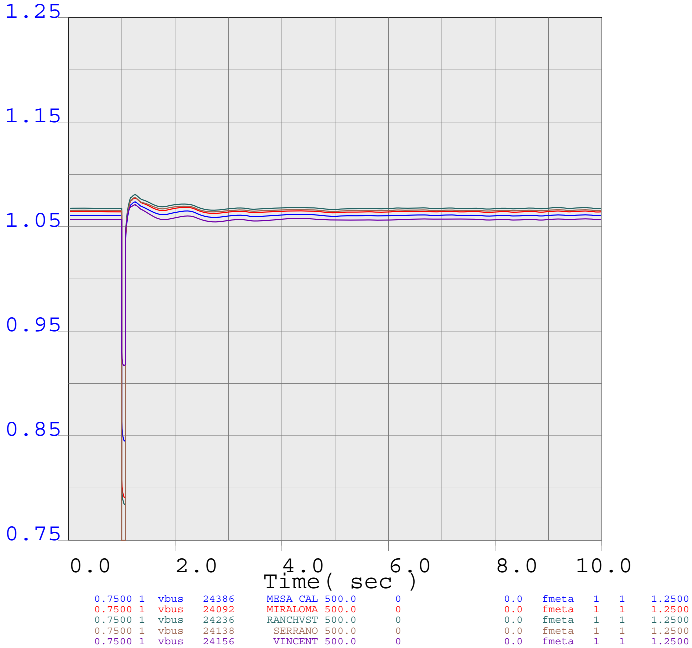
line_12105
Line LEWIS 230.0 to SERRANO 230.0 Circuit 2
1 MW dispatch Case

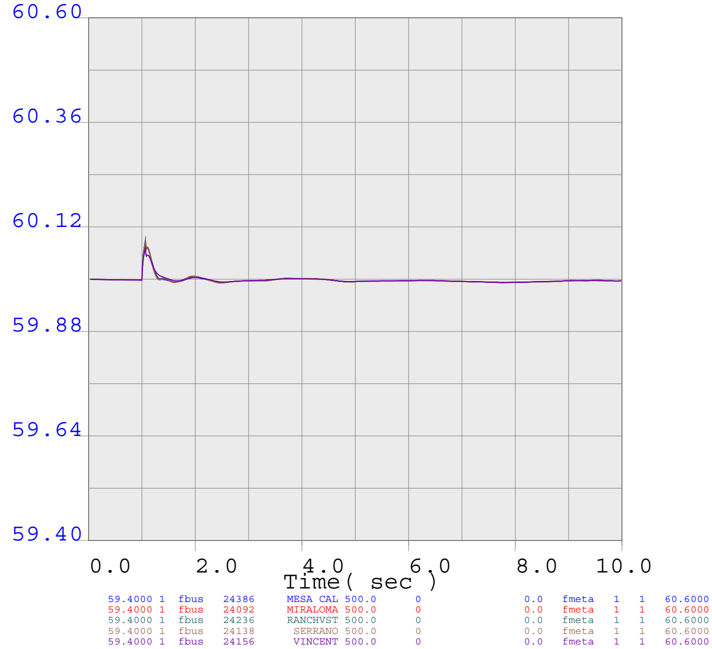
qc9p-line_12105.chf

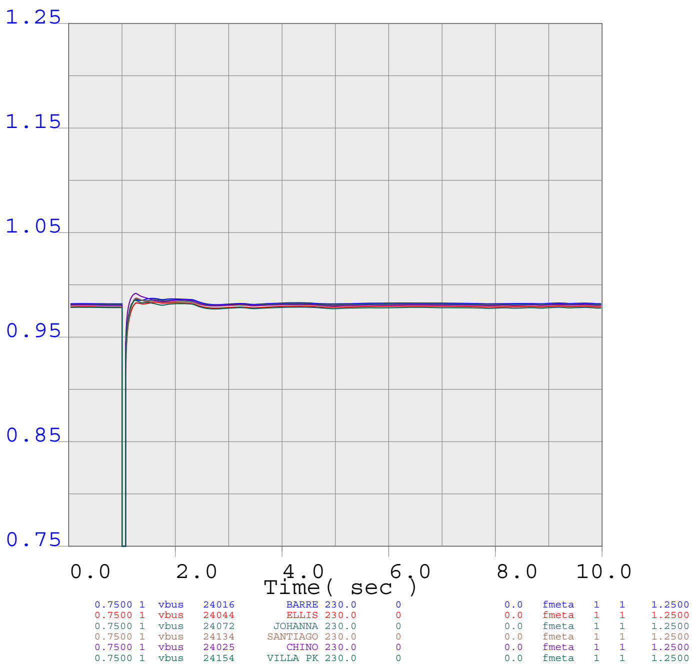
C:\DYTOOLS

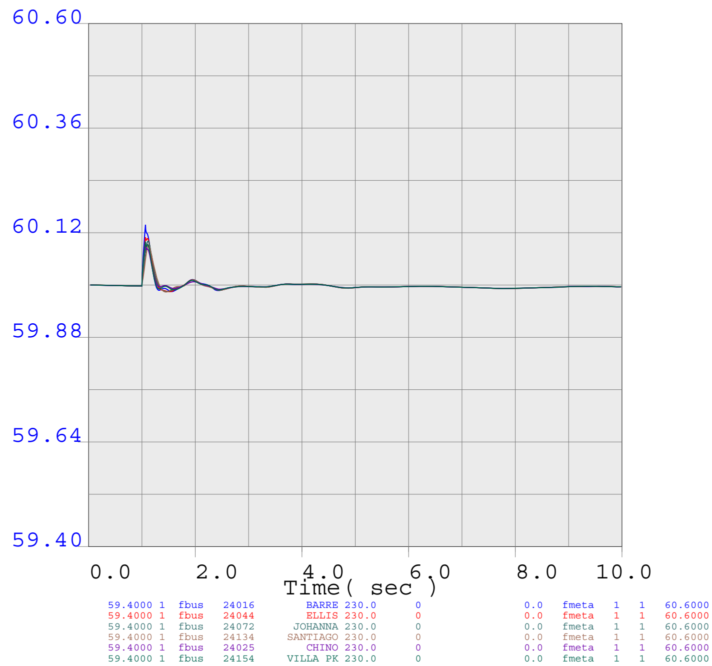
Thu Oct 20 09:00:24 2016

METRO









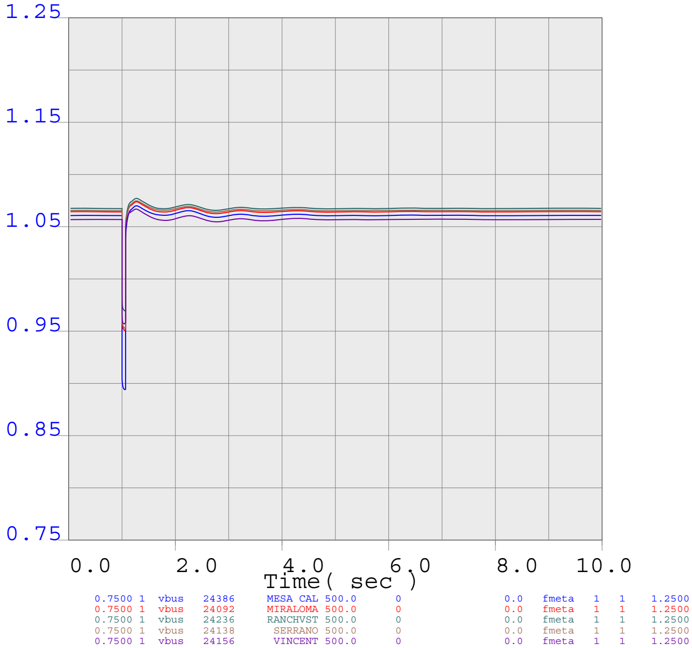
line_12106
Line LEWIS 230.0 to VILLA PK 230.0 Circuit 1
1 MW dispatch Case

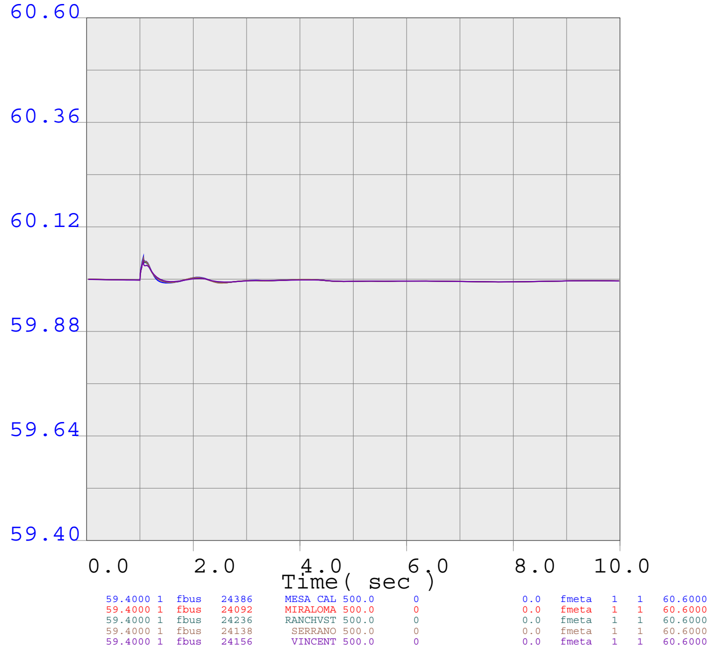
qc9p-line_12106.chf

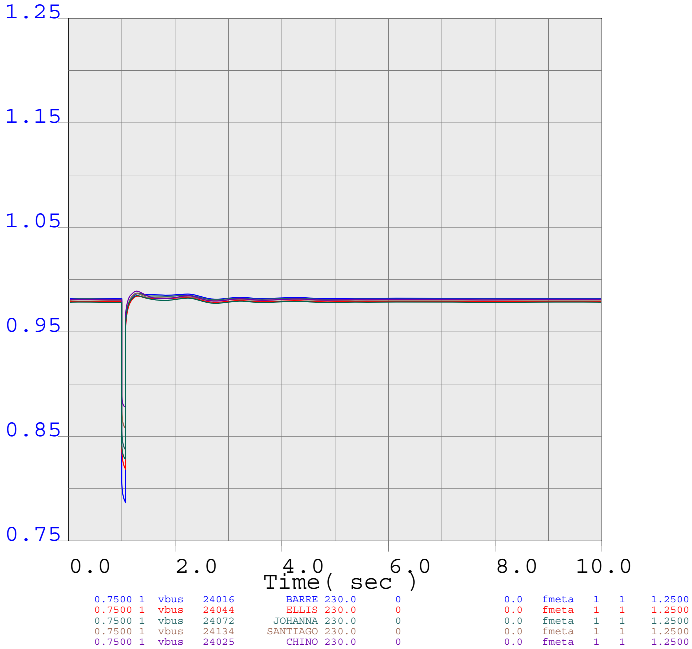
C:\DYTOOLS

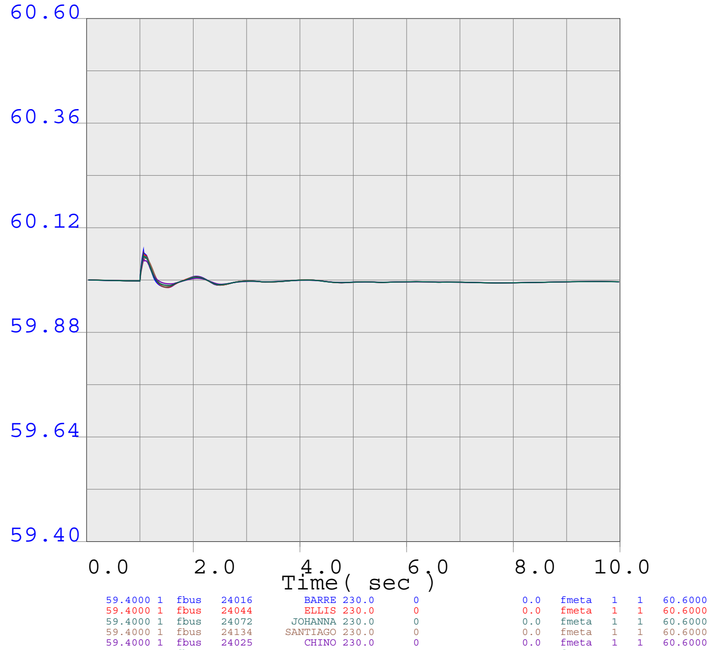
Thu Oct 20 09:00:26 2016

METRO









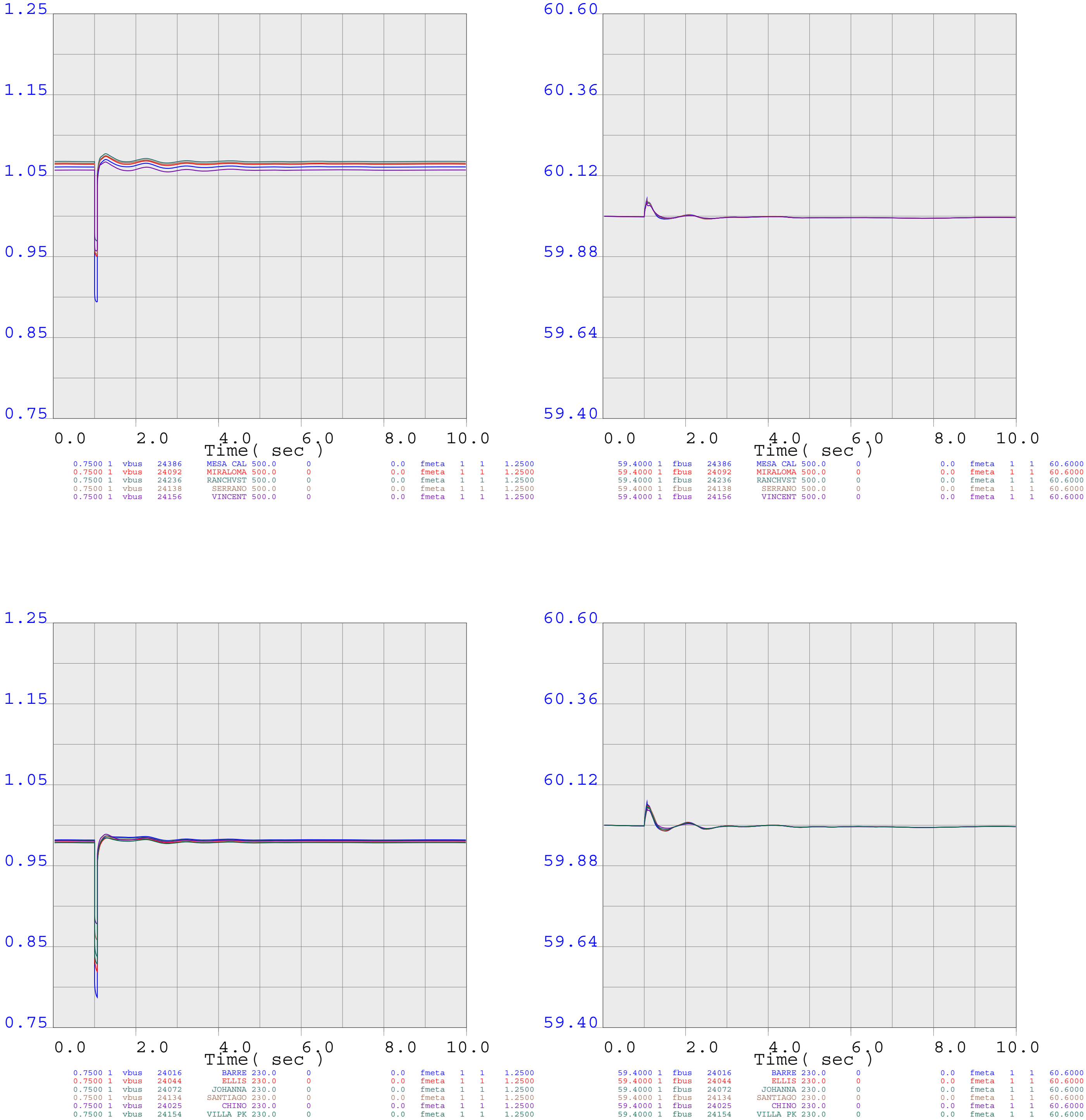
line_1211
Line ARCO SC 230.0 to HINSON 230.0 Circuit 1
1 MW dispatch Case

qc9p-line_1211.chf

C:\DYTOOLS

Thu Oct 20 09:00:29 2016

METRO



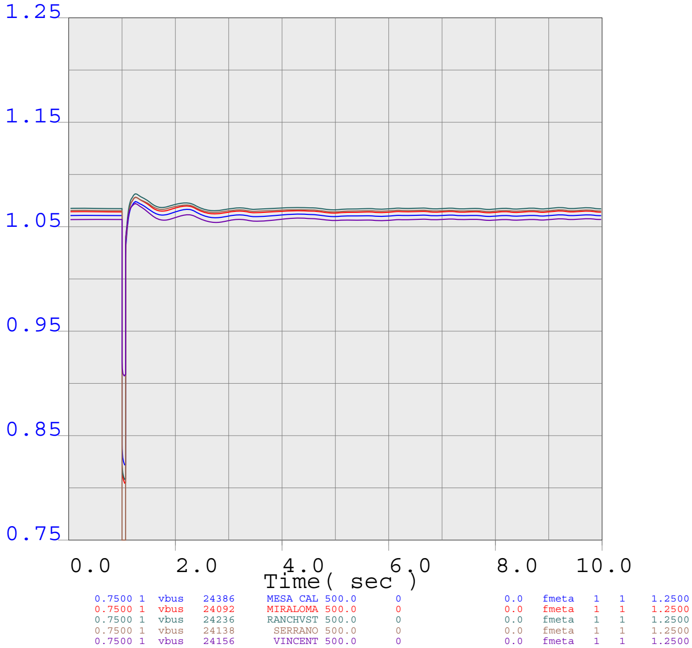
line_1212
Line ARCO SC 230.0 to HINSON 230.0 Circuit 2
1 MW dispatch Case

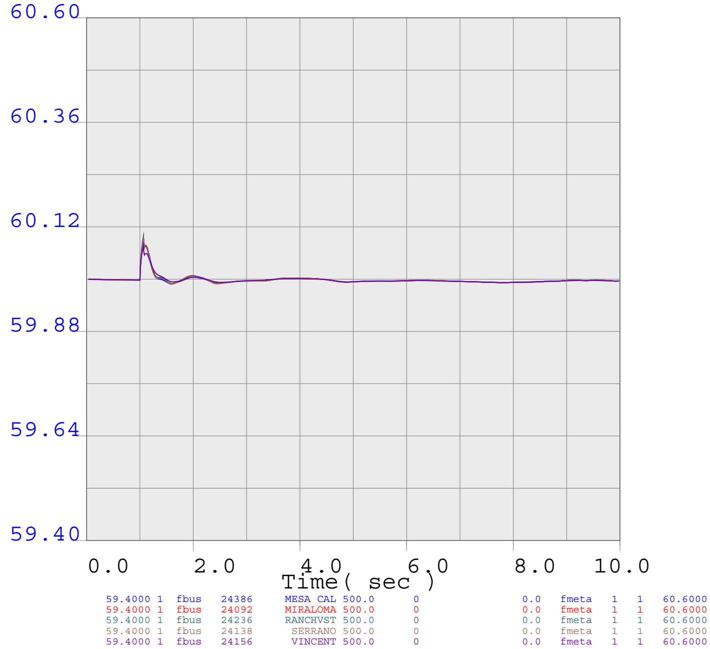
qc9p-line_1212.chf

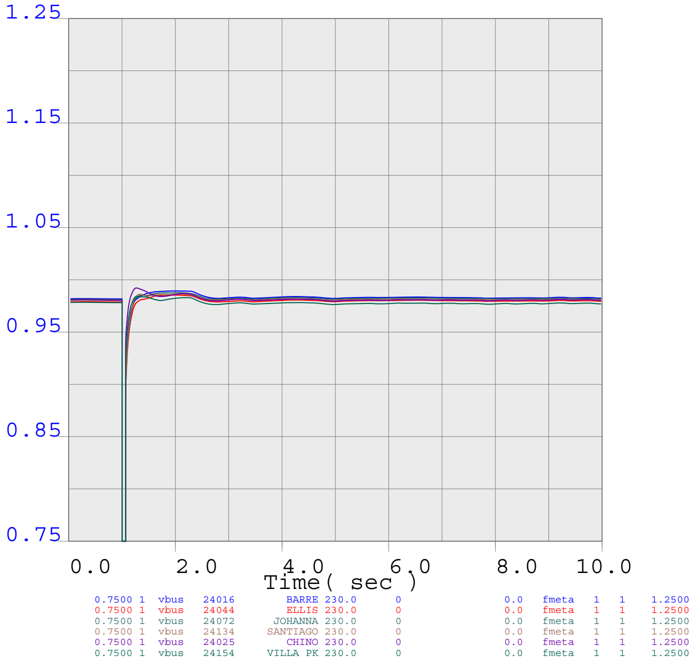
C:\DYTOOLS

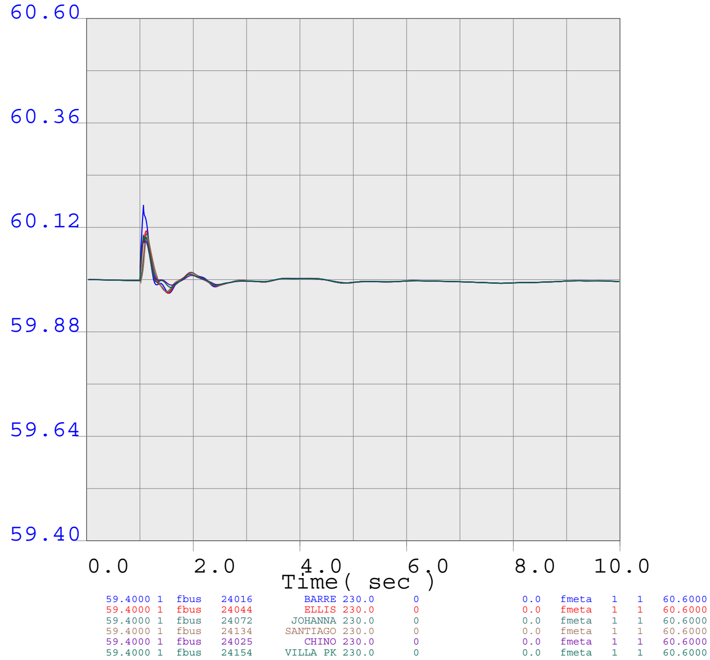
Thu Oct 20 09:00:32 2016

METRO





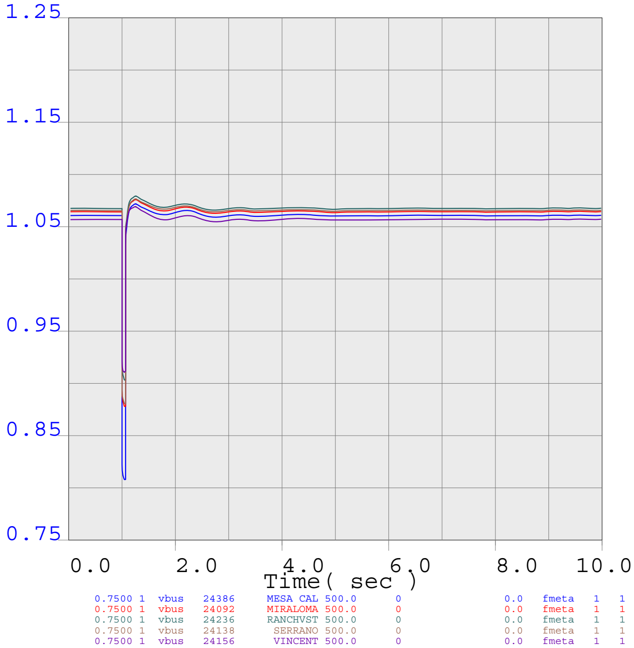


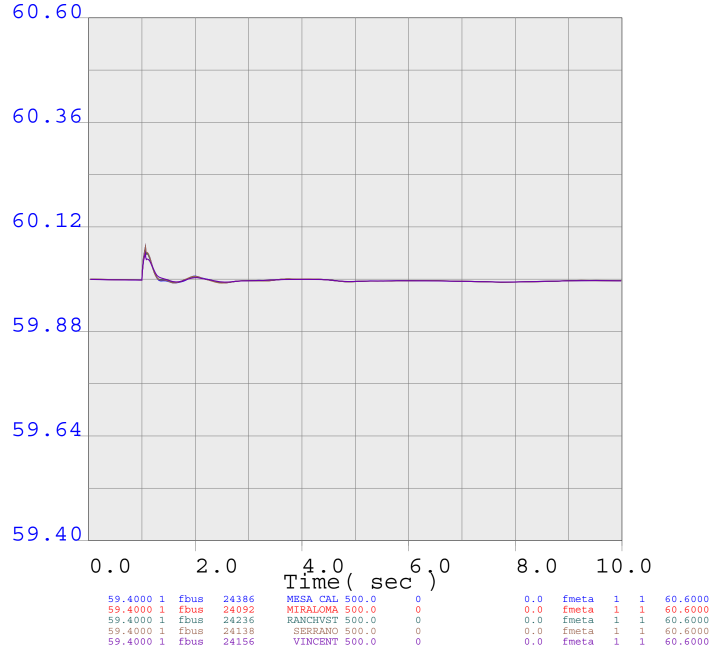


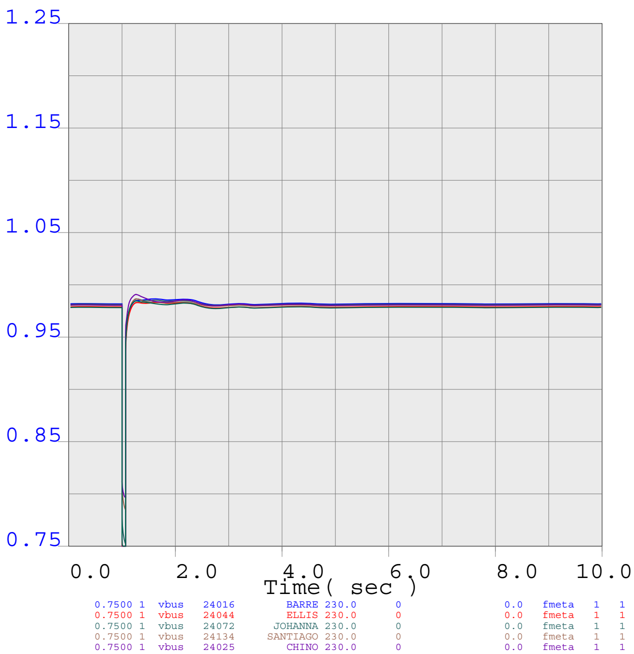
line_1213
Line BARRE 230.0 to VILLA PK 230.0 Circuit 1
1 MW dispatch Case

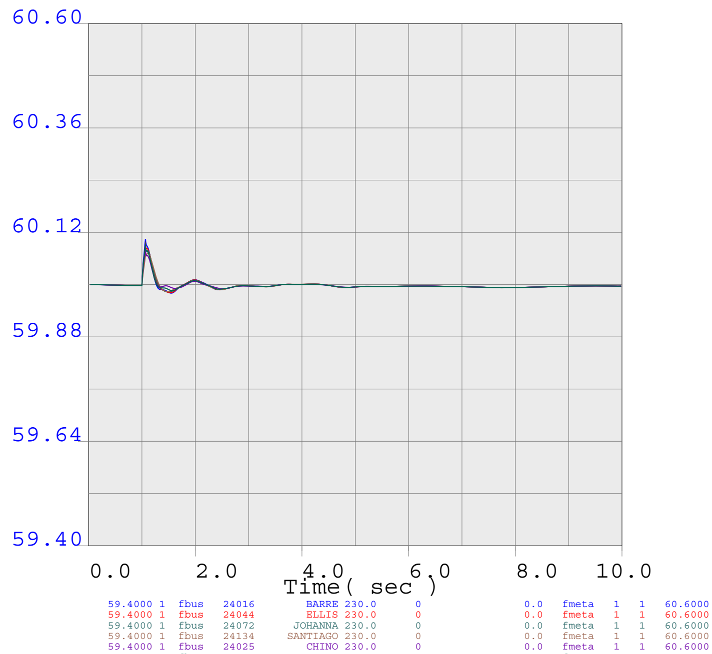
qc9p-line_1213.chf	C:\DYTOOLS Thu Oct 20 09:00:35 2016

METRO









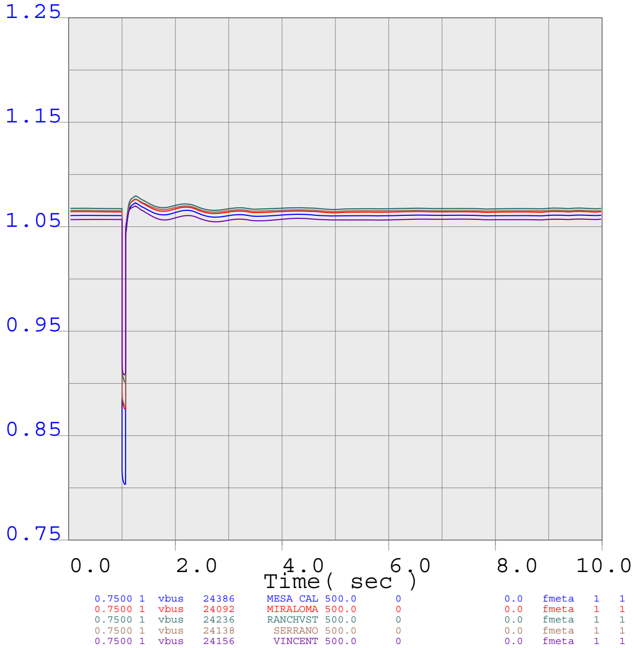
line_1214
Line CENTER 230.0 to OLINDA 230.0 Circuit 1
1 MW dispatch Case

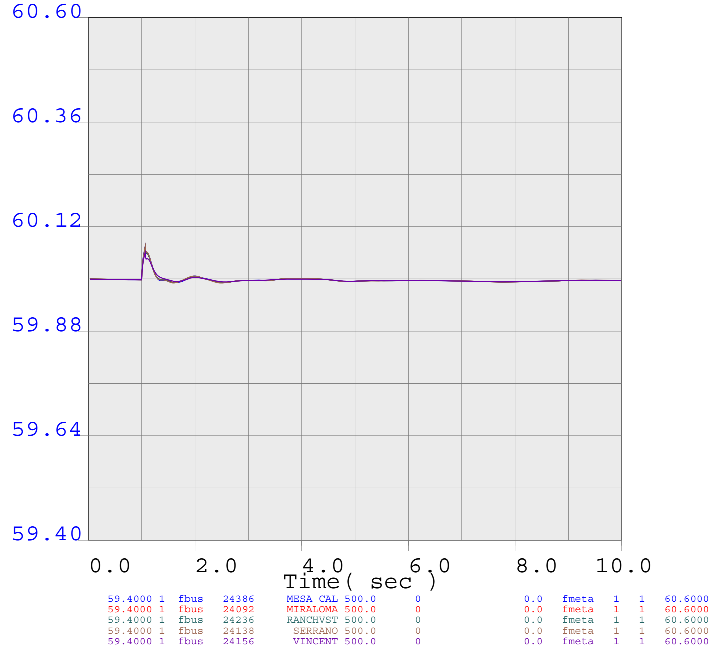
qc9p-line_1214.chf

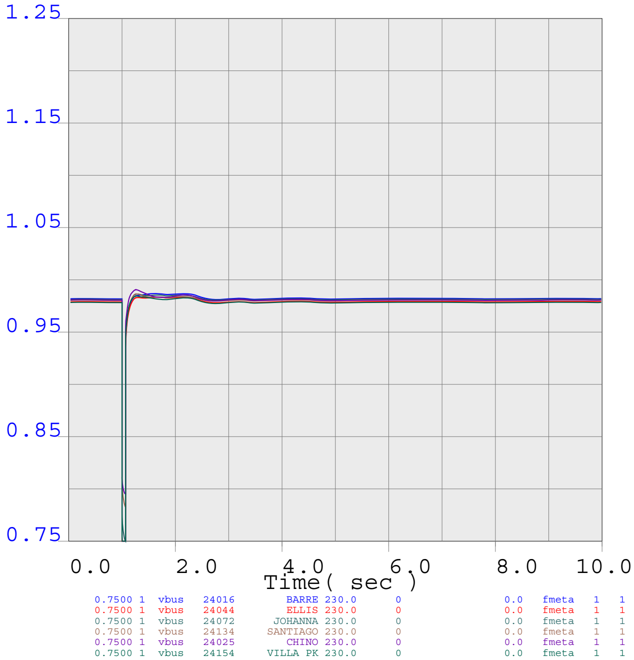
C:\DYTOOLS

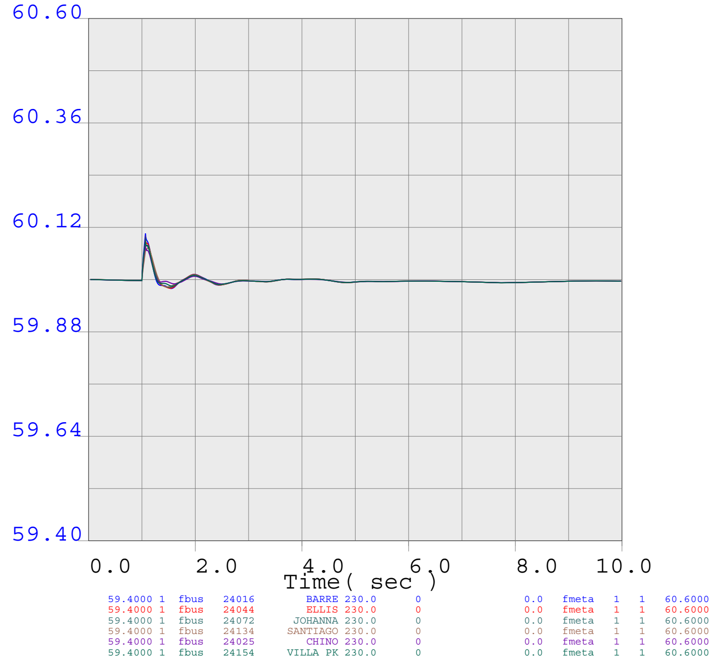
Thu Oct 20 09:00:37 2016

METRO









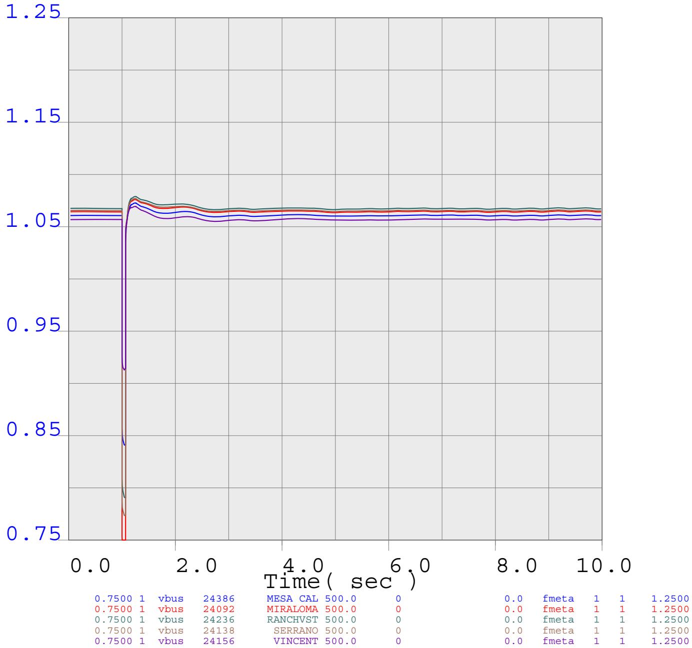
line_1215
Line CENTER 230.0 to MESACALS 230.0 Circuit 1
1 MW dispatch Case

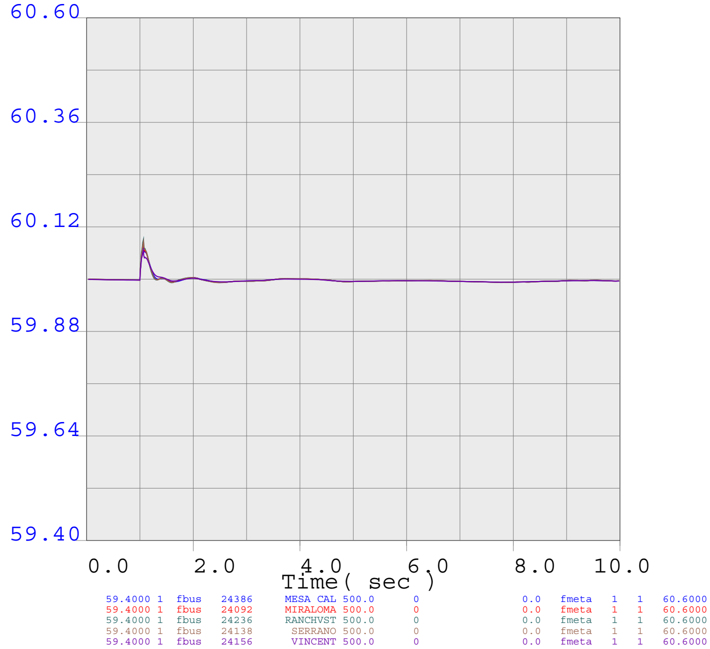
qc9p-line_1215.chf

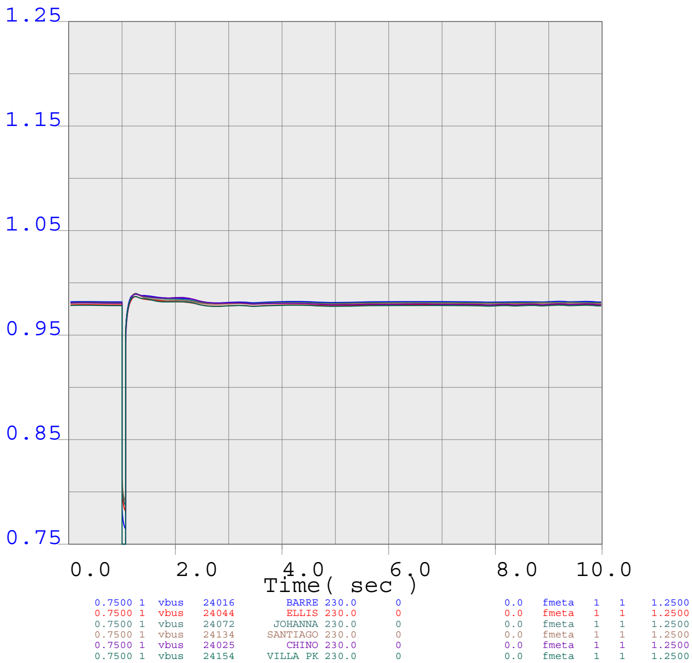
C:\DYTOOLS

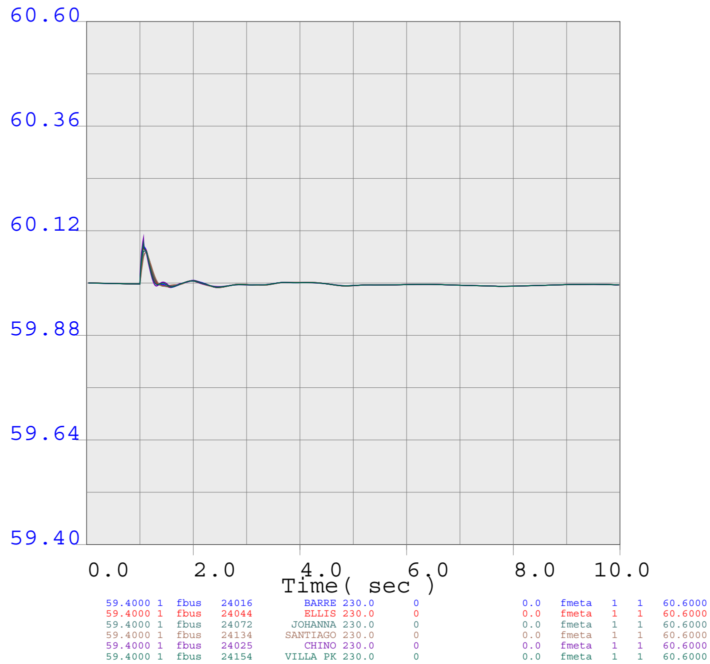
Thu Oct 20 09:00:39 2016

METRO









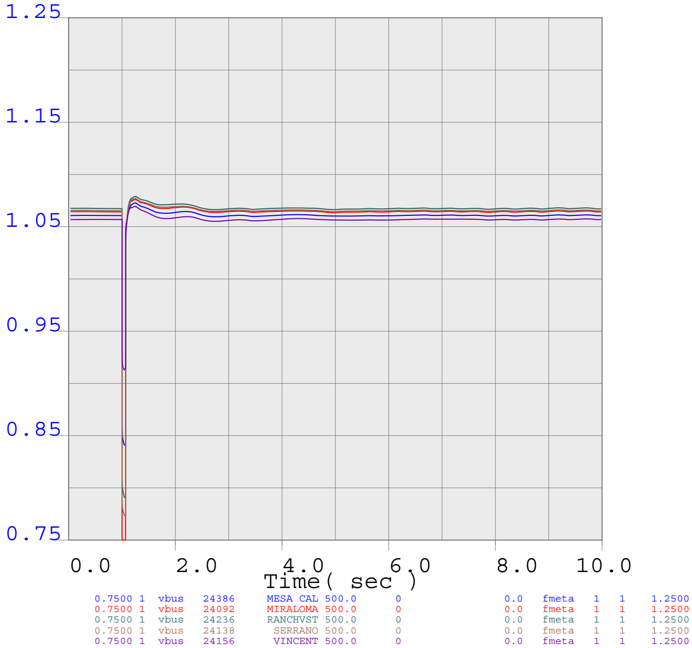
line_1216
Line CHINO 230.0 to MIRALOMW 230.0 Circuit 1
1 MW dispatch Case

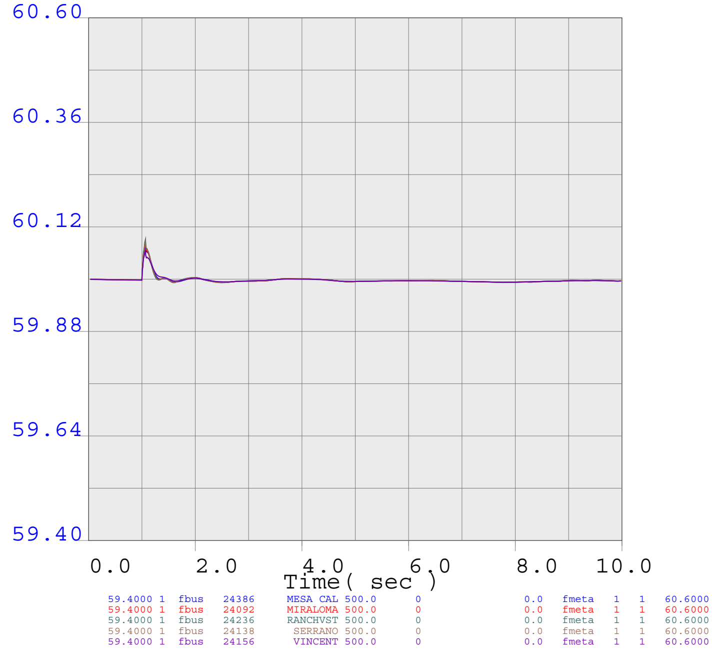
qc9p-line_1216.chf

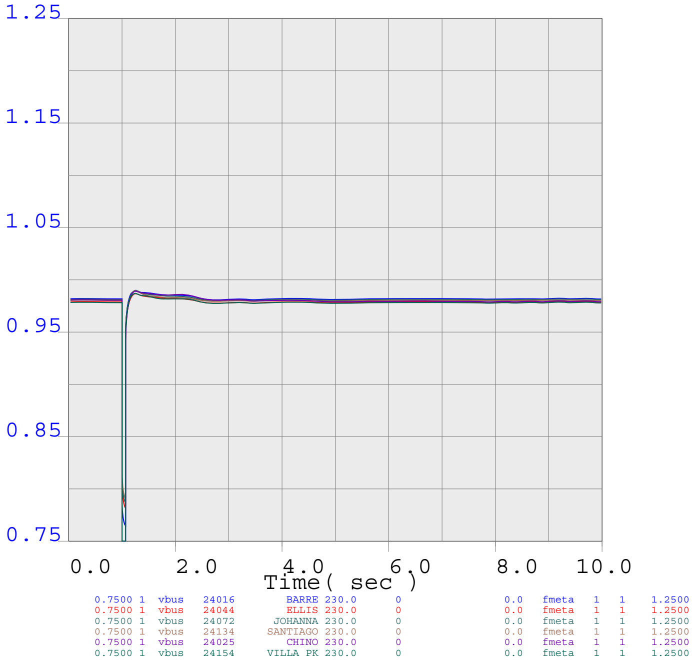
C:\DYTOOLS

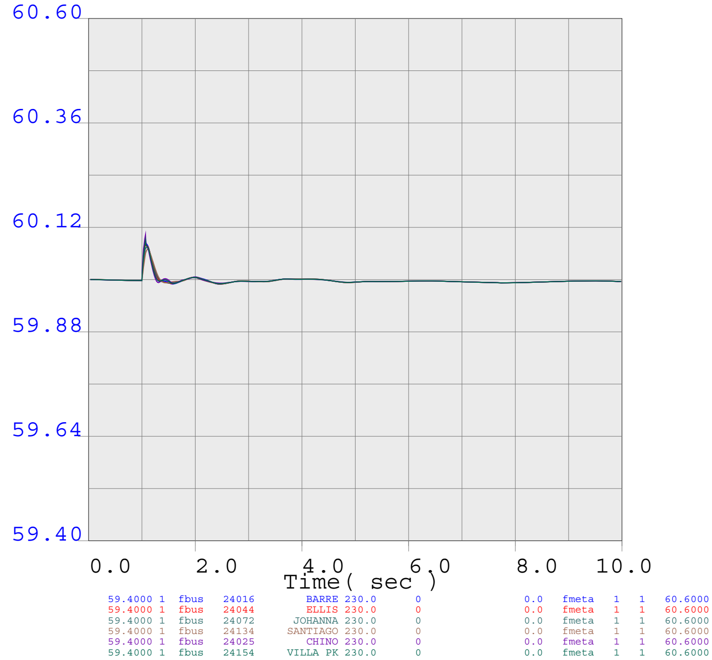
Thu Oct 20 09:00:41 2016

METRO









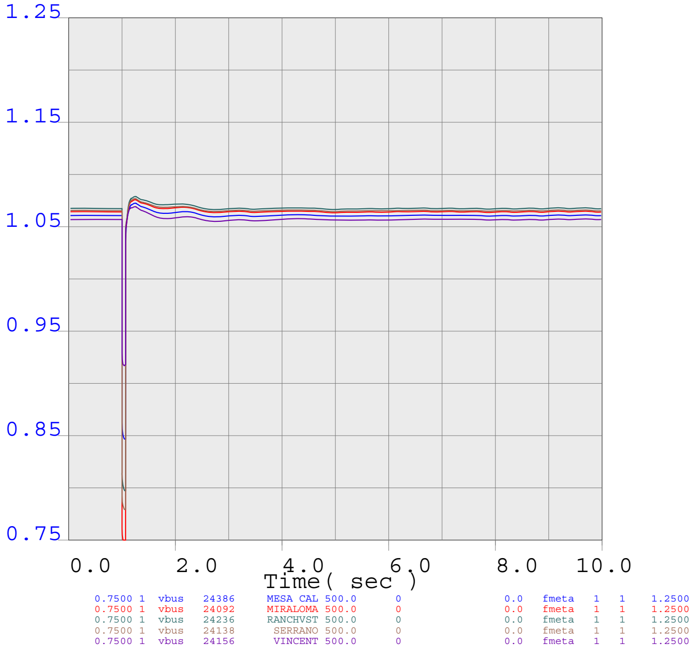
line_1217
Line CHINO 230.0 to MIRALOMW 230.0 Circuit 2
1 MW dispatch Case

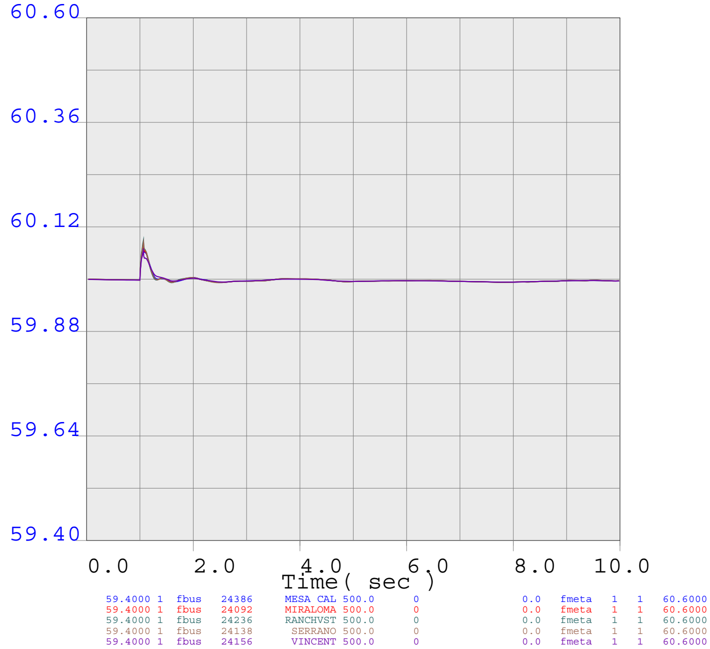
qc9p-line_1217.chf

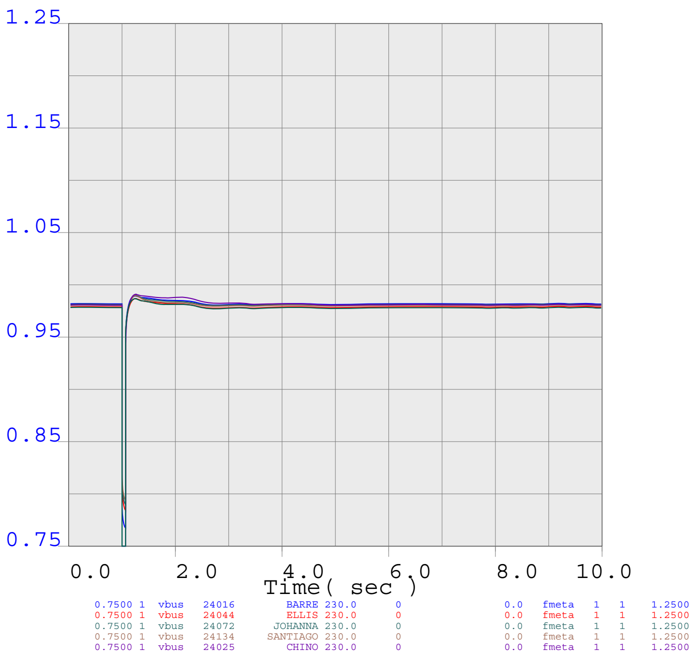
C:\DYTOOLS

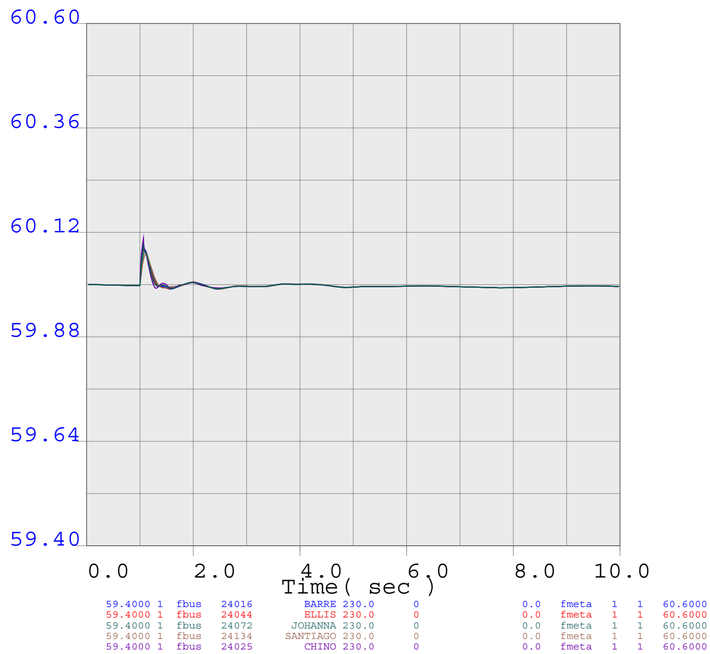
Thu Oct 20 09:00:44 2016

METRO









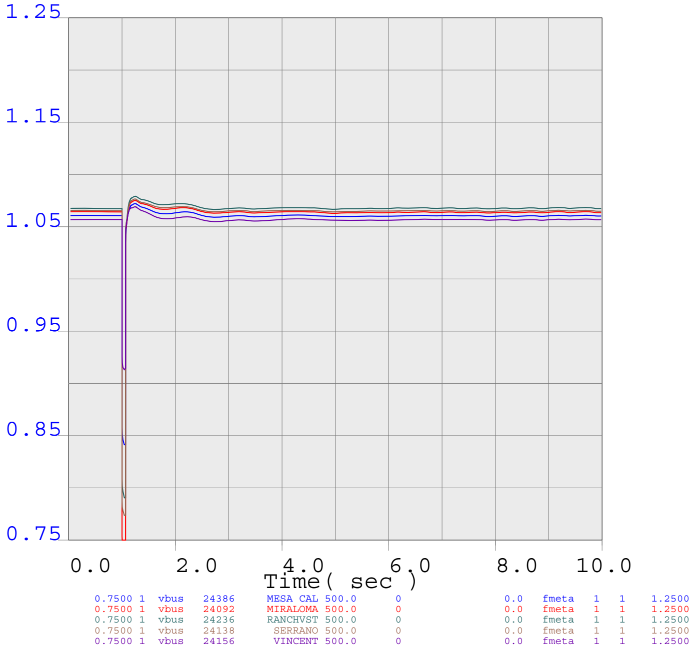
line_1218
Line CHINO 230.0 to SERRANO 230.0 Circuit 1
1 MW dispatch Case

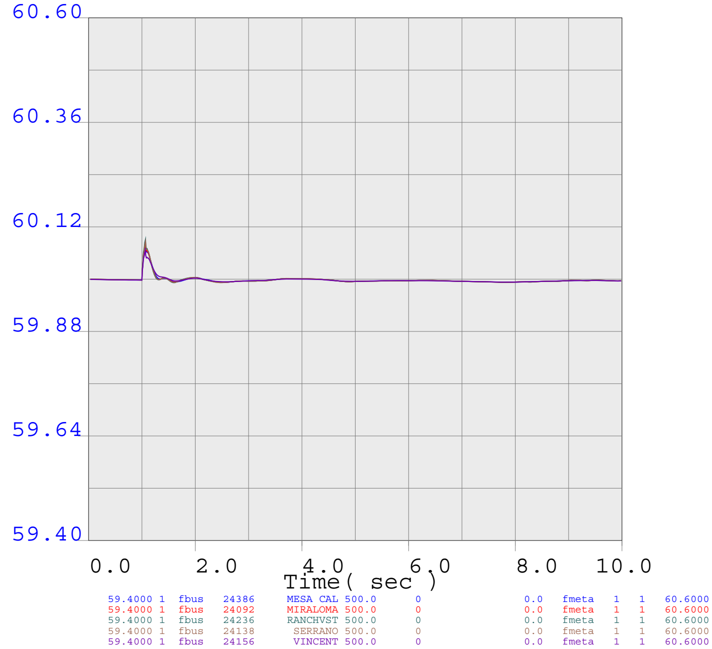
qc9p-line_1218.chf

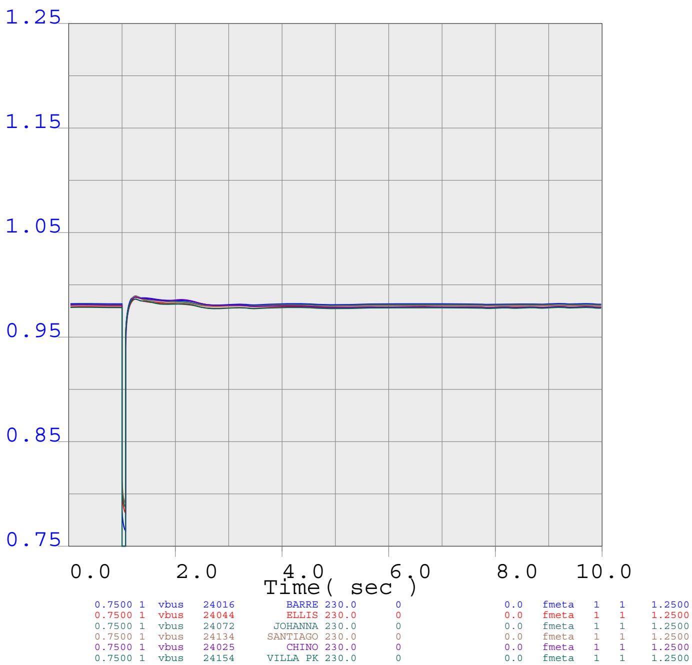
C:\DYTOOLS

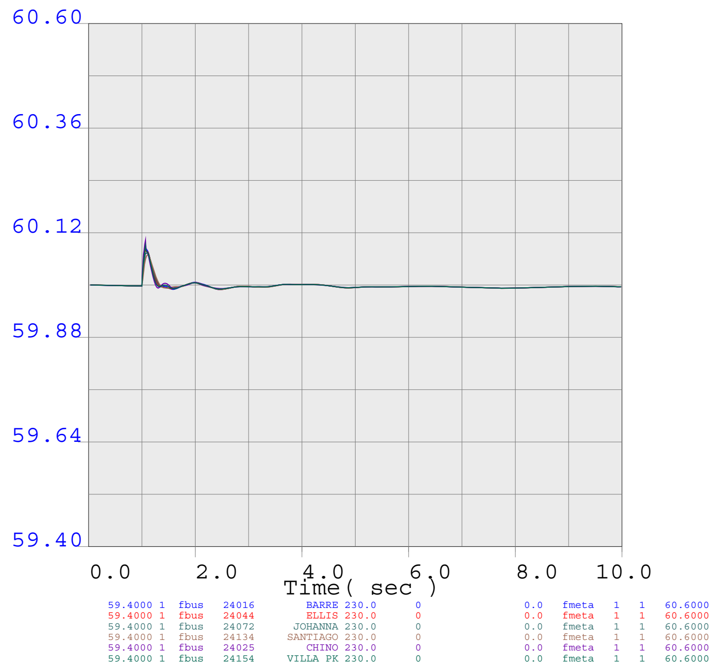
Thu Oct 20 09:00:47 2016

METRO









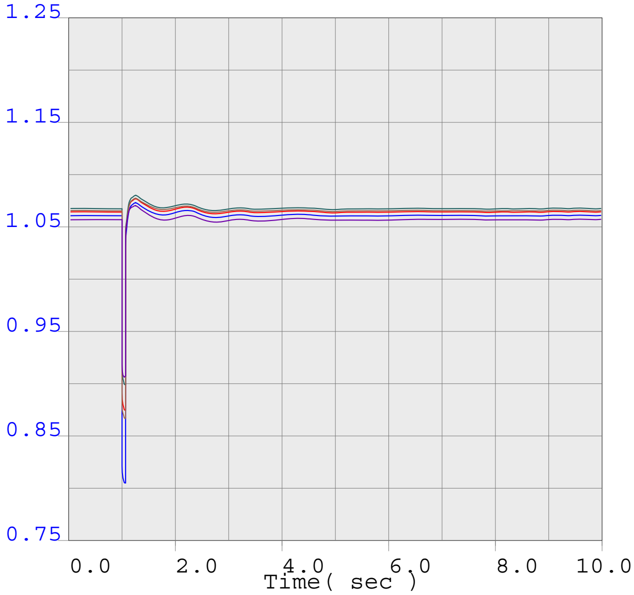
line_1219
Line CHINO 230.0 to MIRALOME 230.0 Circuit 3
1 MW dispatch Case

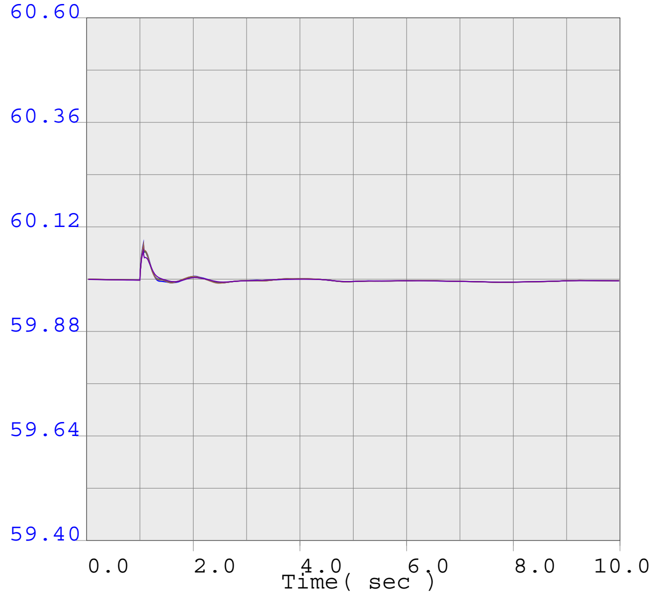
qc9p-line_1219.chf

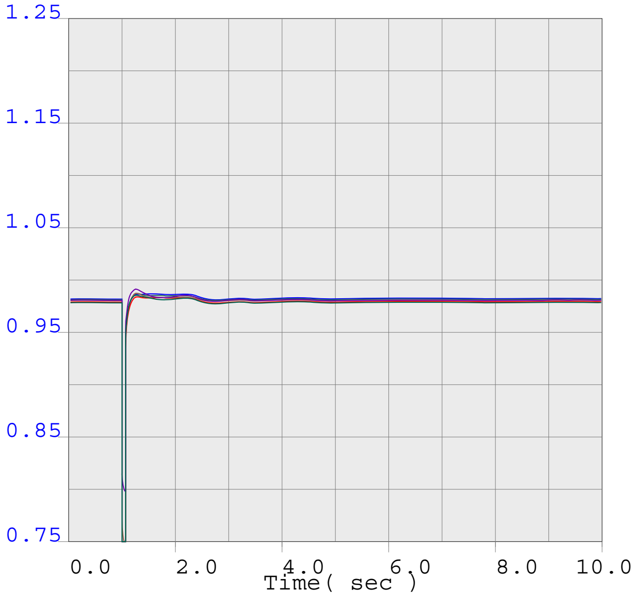
C:\DYTOOLS

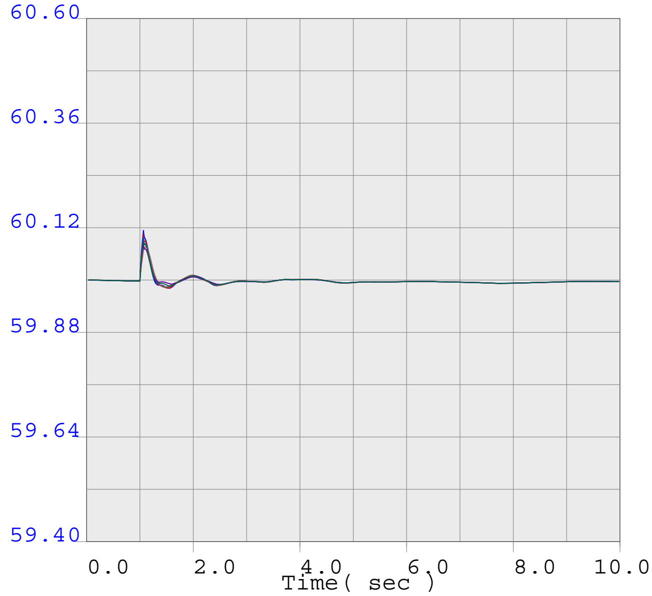
Thu Oct 20 09:00:49 2016

METRO









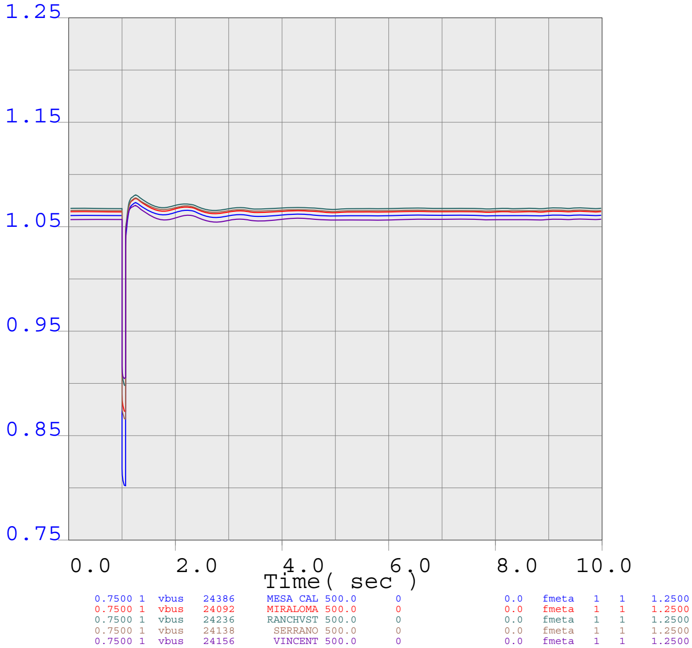
line_1220
Line DELAMO 230.0 to BARRE 230.0 Circuit 1
1 MW dispatch Case

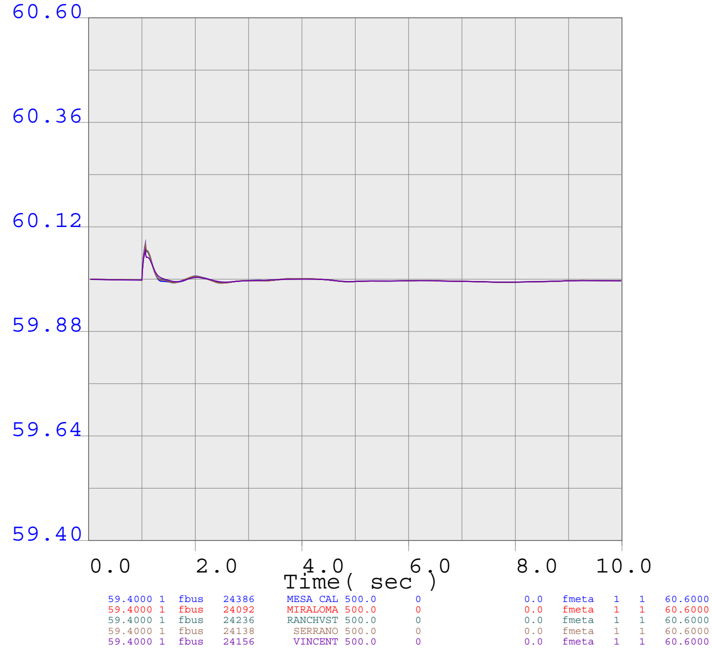
qc9p-line_1220.chf

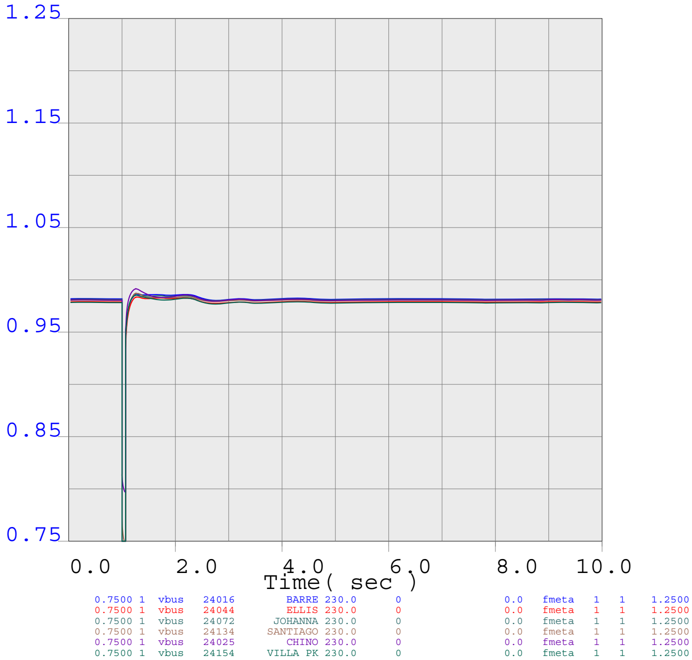
C:\DYTOOLS

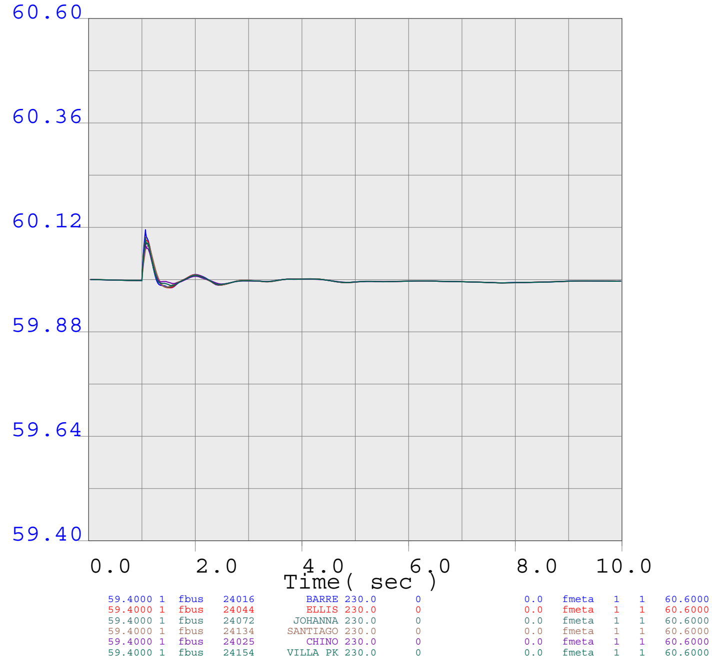
Thu Oct 20 09:00:51 2016

METRO





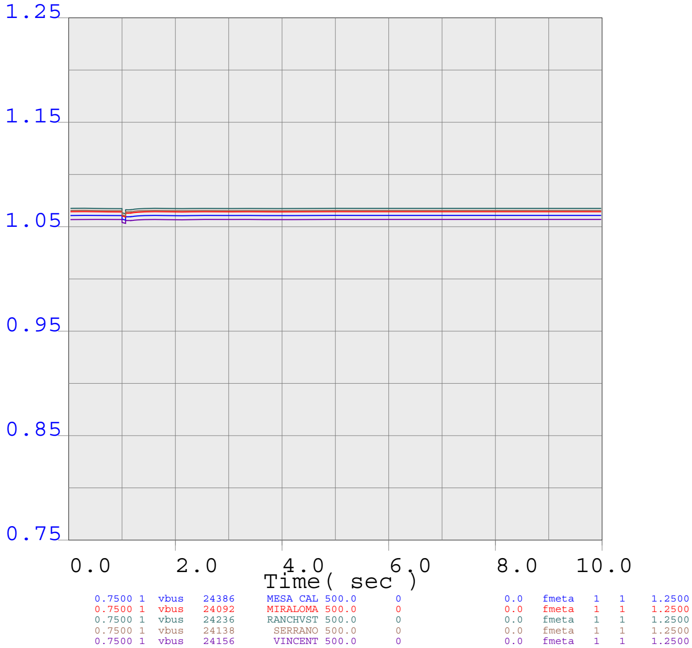


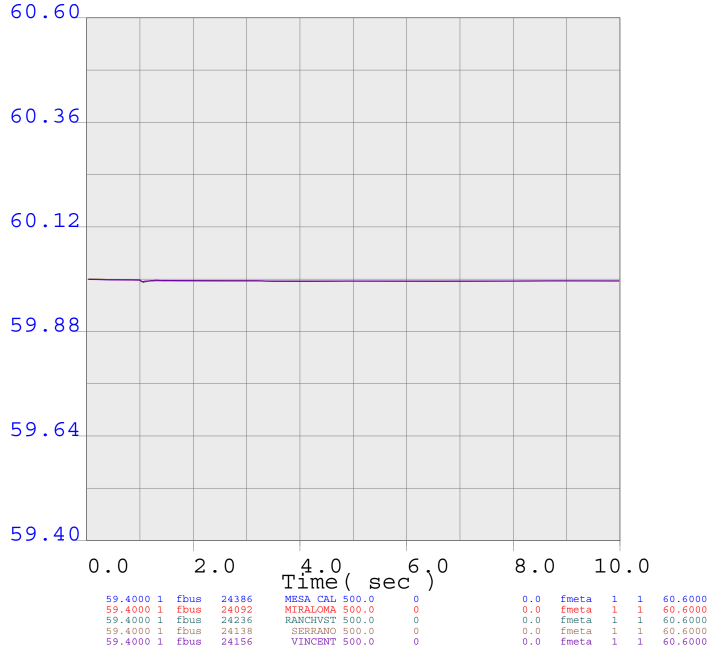


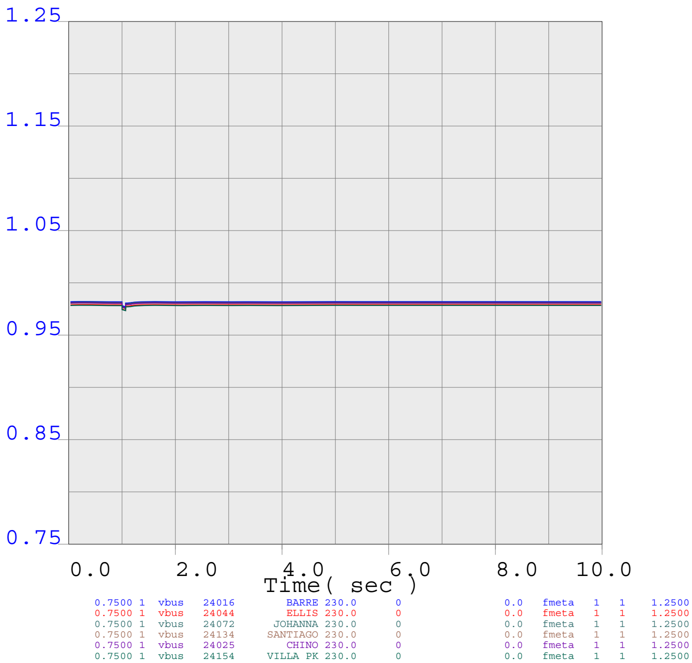
line_1221
Line DELAMO 230.0 to CENTER 230.0 Circuit 1
1 MW dispatch Case

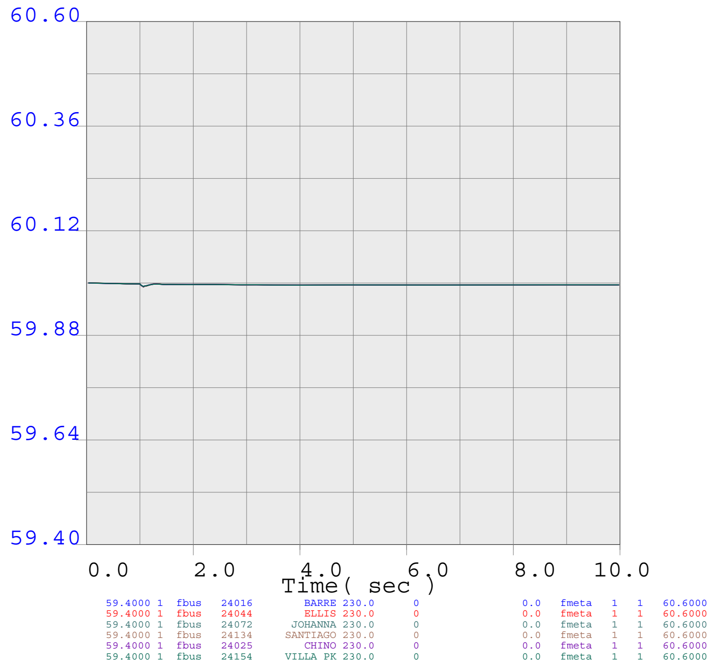
qc9p-line_1221.chf	C:\DYTOOLS Thu Oct 20 09:00:53 2016

METRO









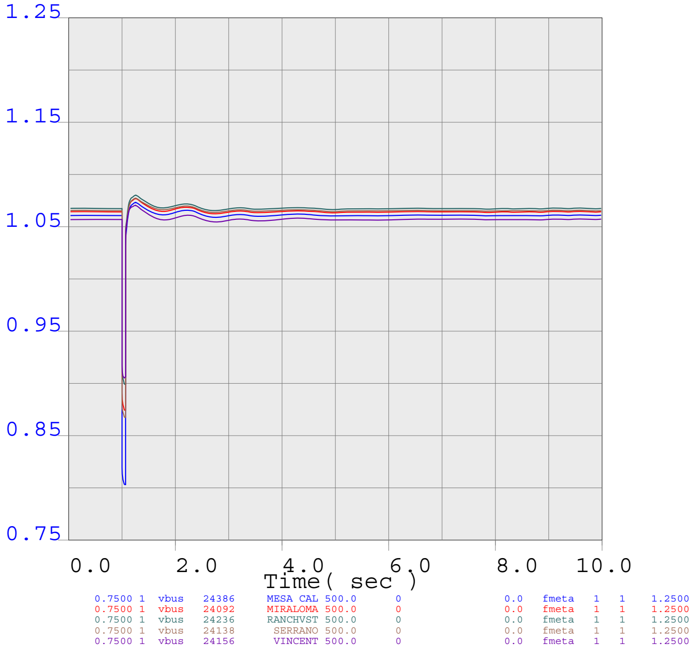
line_1222
Line DELAMO 230.0 to ELLIS 230.0 Circuit 1
1 MW dispatch Case

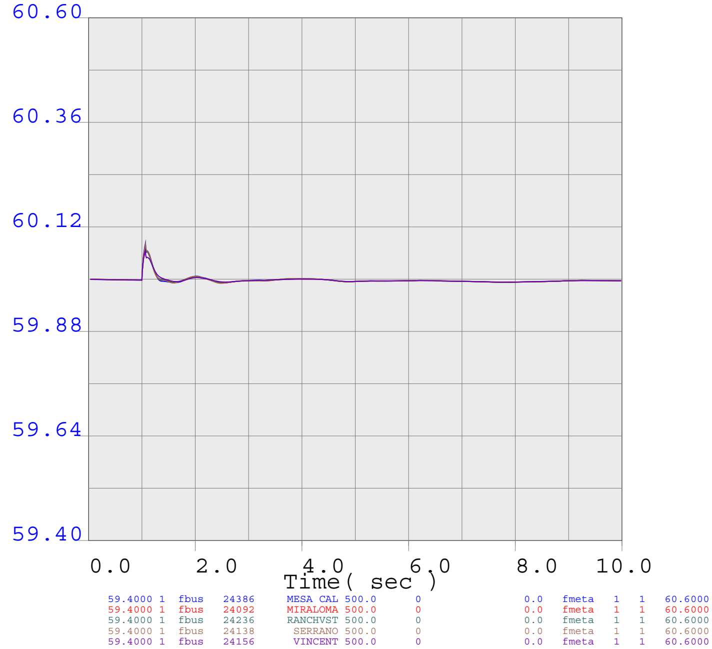
qc9p-line_1222.chf

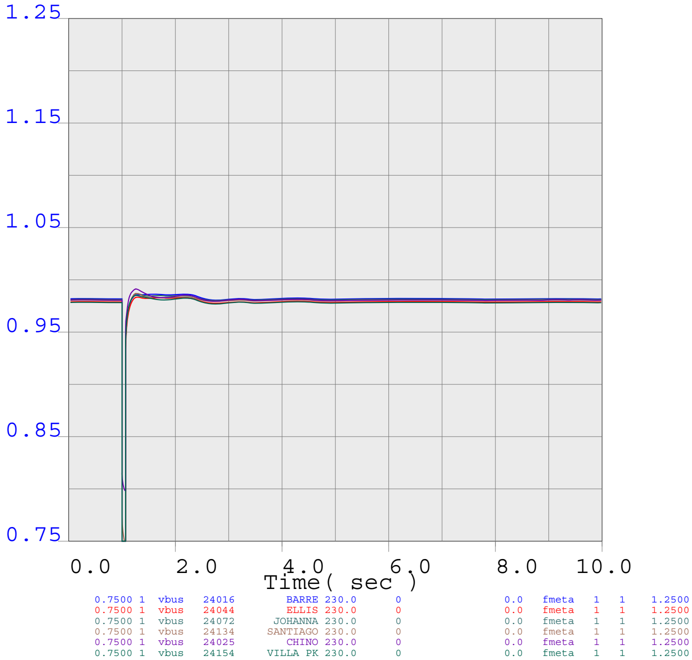
C:\DYTOOLS

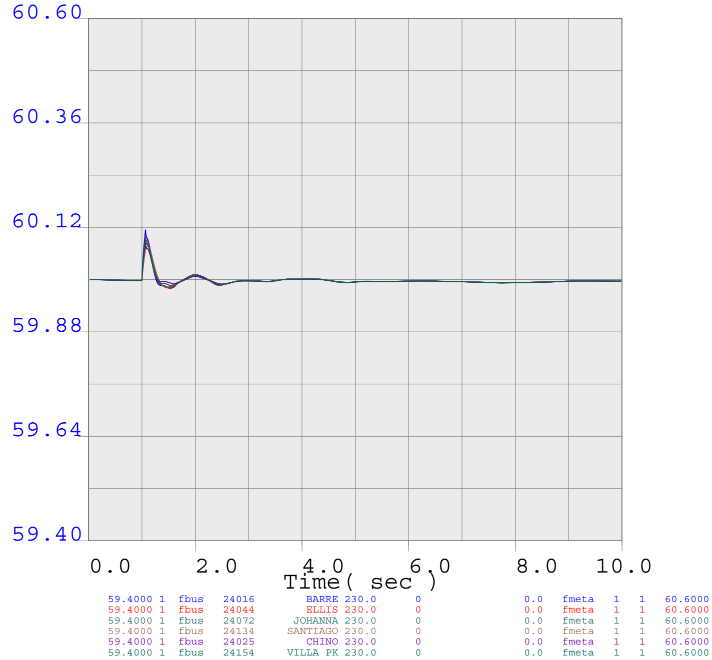
Thu Oct 20 09:00:55 2016

METRO









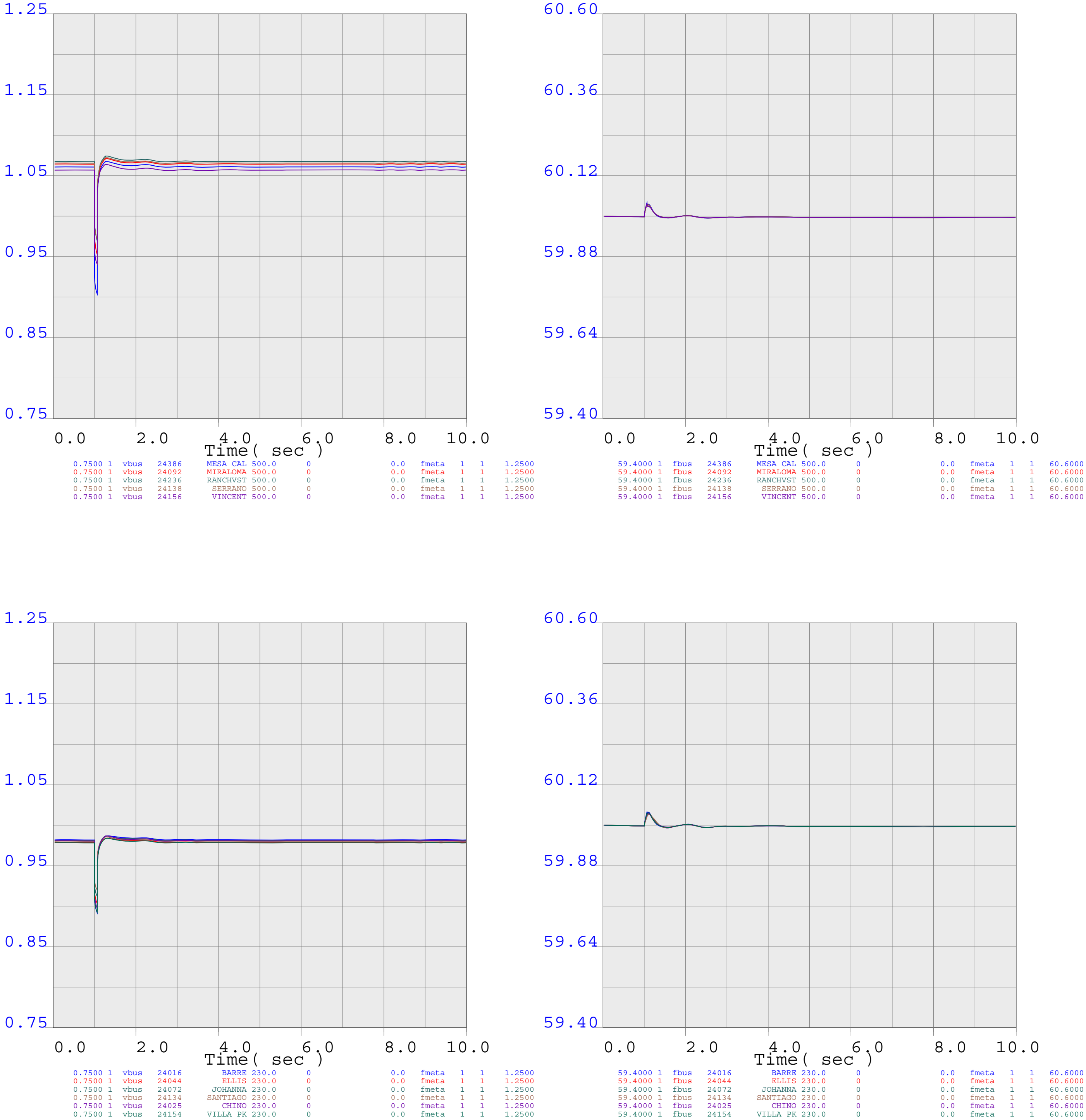
line_1223
Line DELAMO 230.0 to LAGUBELL 230.0 Circuit 1
1 MW dispatch Case

qc9p-line_1223.chf

C:\DYTOOLS

Thu Oct 20 09:00:57 2016

METRO



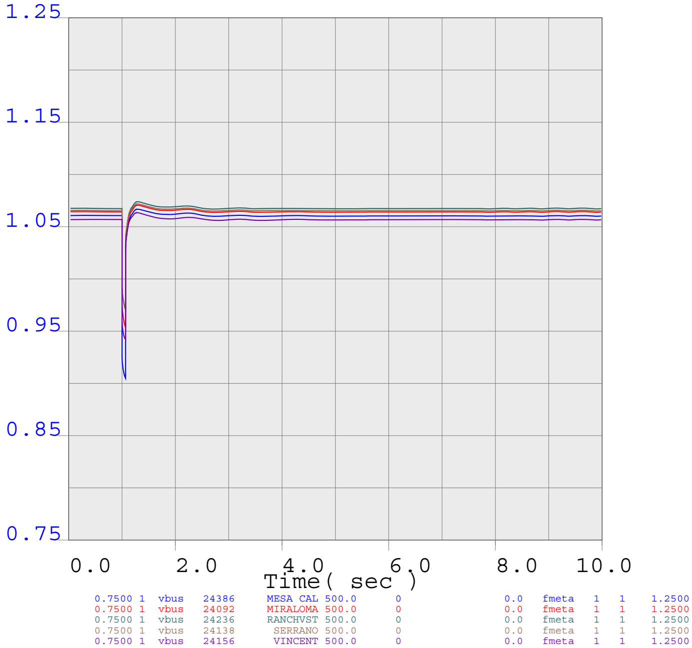
line_1224
Line EAGLROCK 230.0 to GOULD 230.0 Circuit 1
1 MW dispatch Case

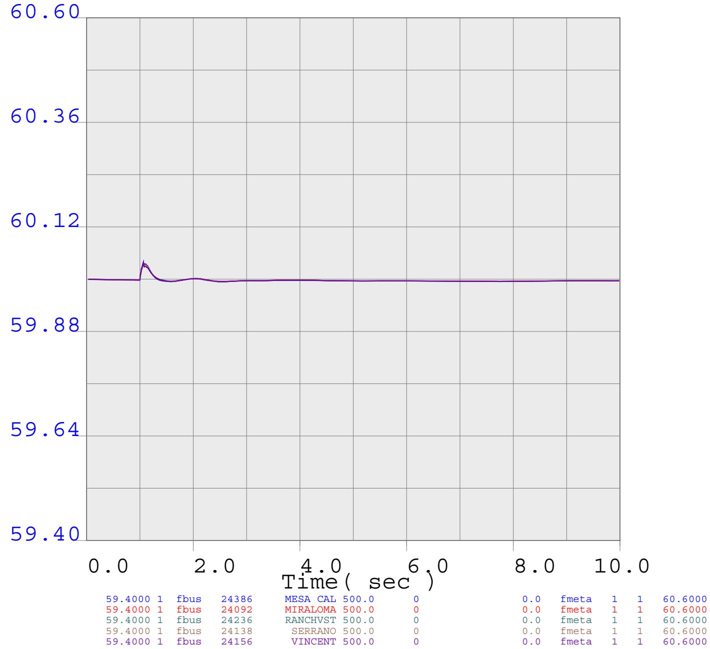
qc9p-line_1224.chf

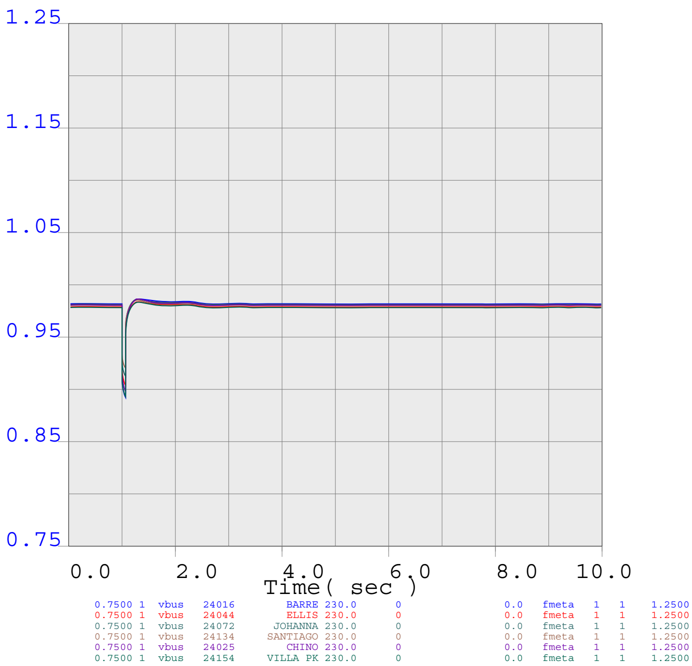
C:\DYTOOLS

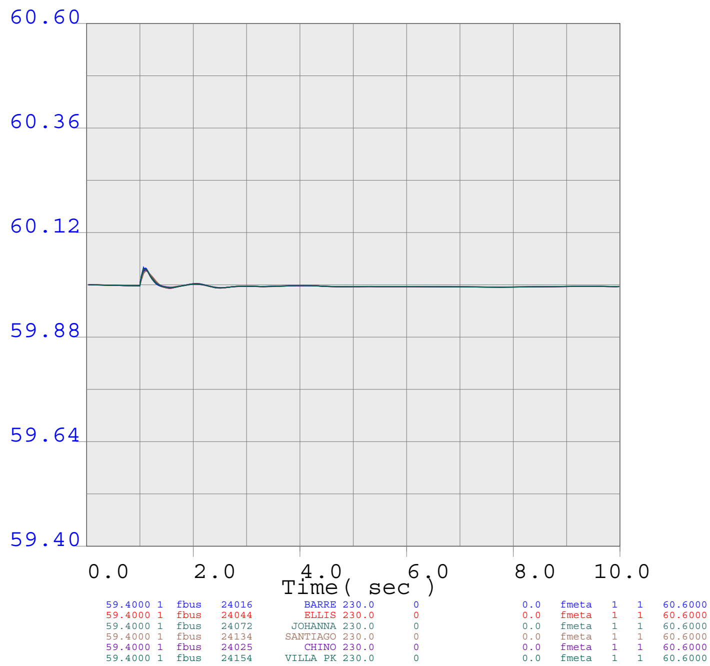
Thu Oct 20 09:01:00 2016

METRO









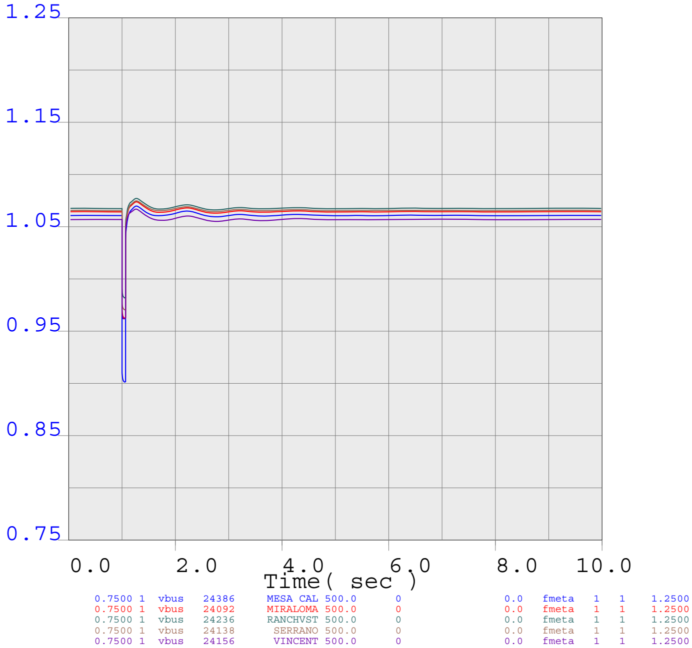
line_1225
Line EAGLROCK 230.0 to MESA CAL 230.0 Circuit 1
1 MW dispatch Case

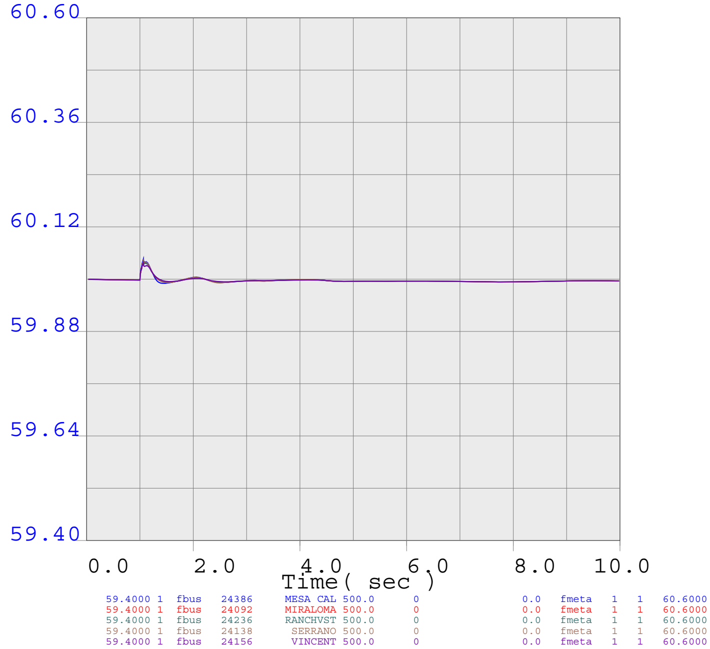
qc9p-line_1225.chf

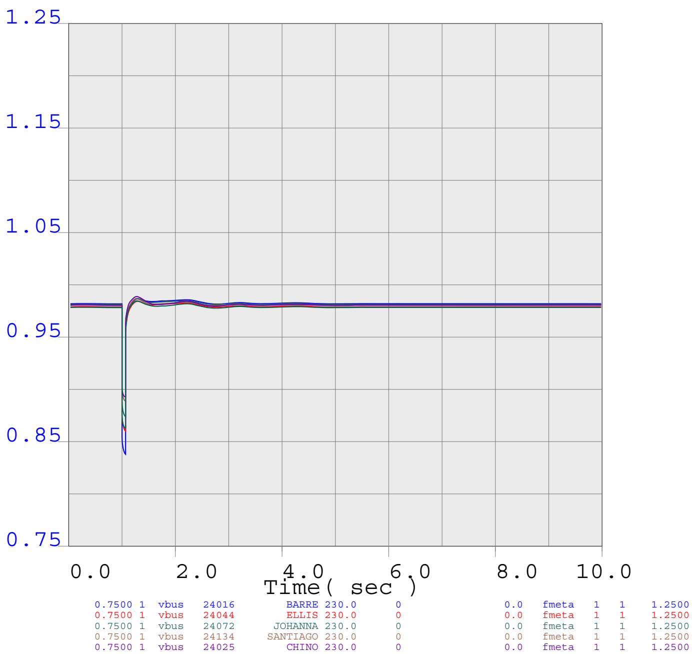
C:\DYTOOLS

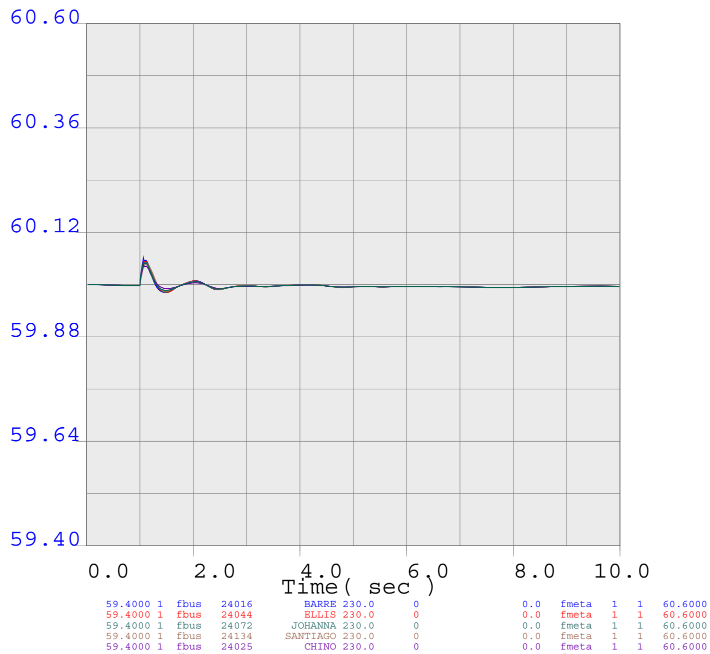
Thu Oct 20 09:01:02 2016

METRO









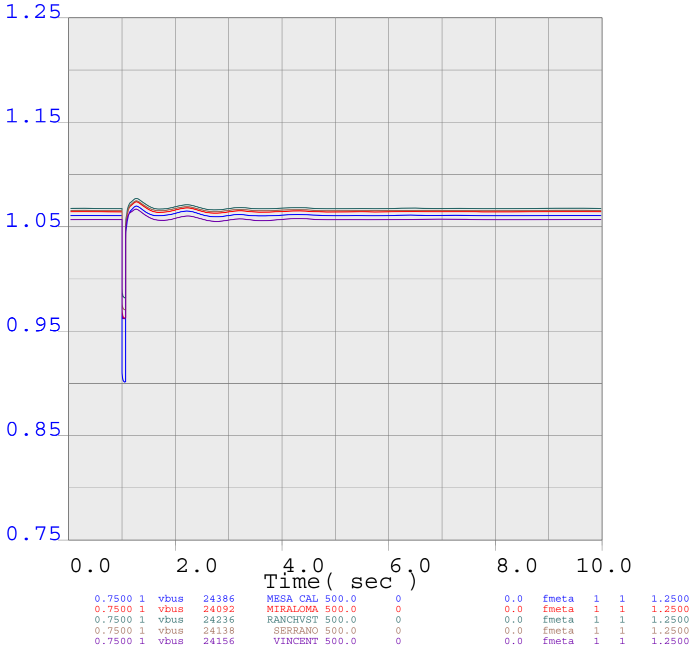
line_1226
Line EL NIDO 230.0 to LA FRESA 230.0 Circuit 3
1 MW dispatch Case

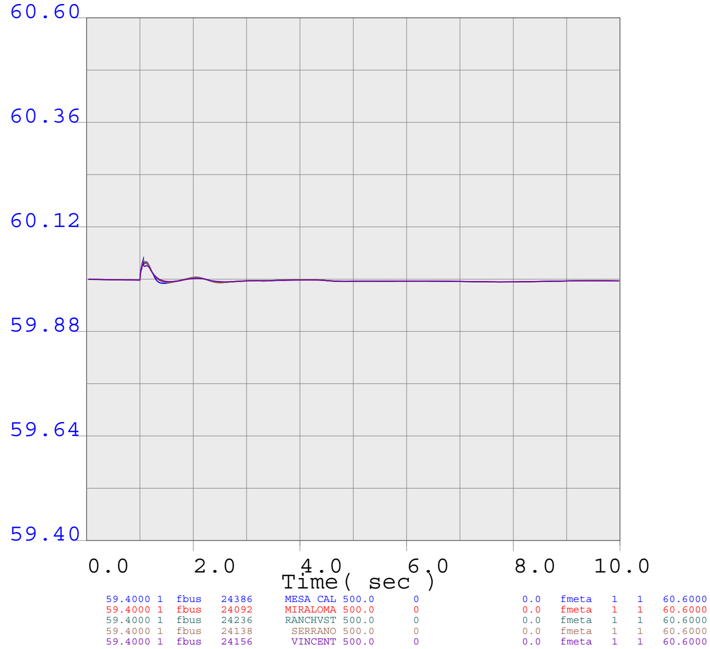
qc9p-line_1226.chf

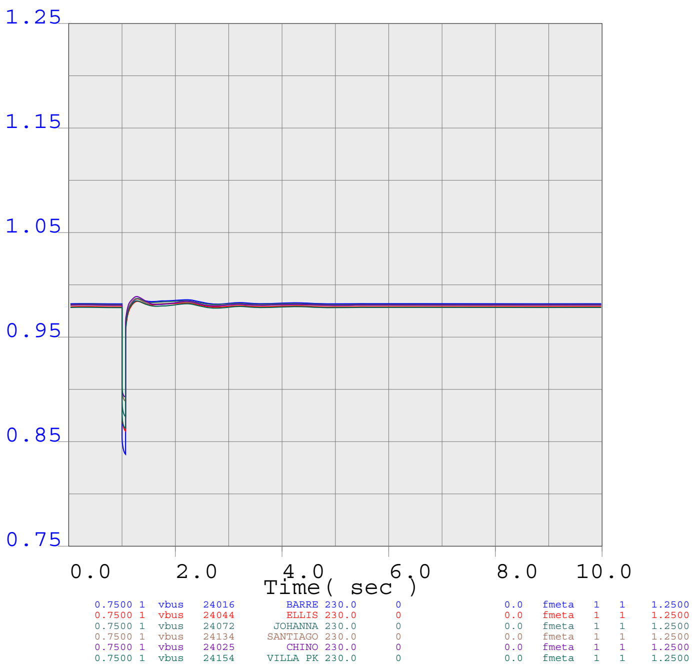
C:\DYTOOLS

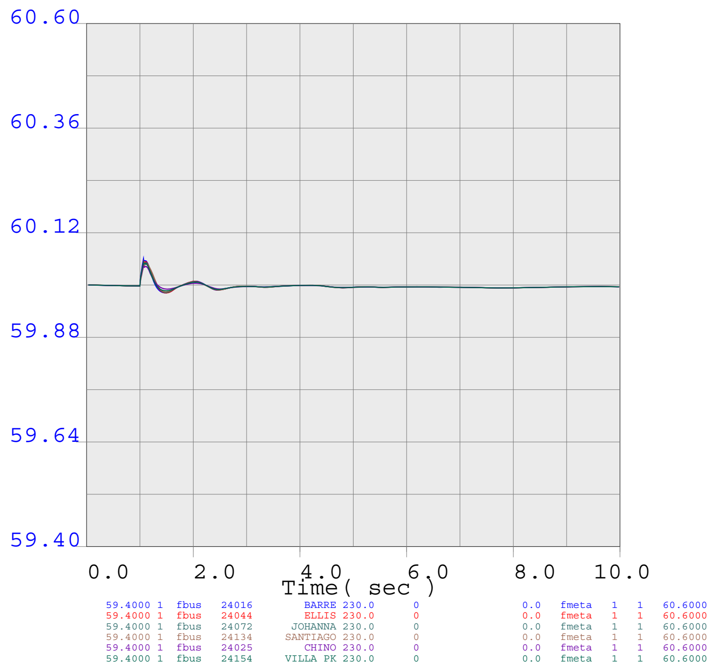
Thu Oct 20 09:01:04 2016

METRO









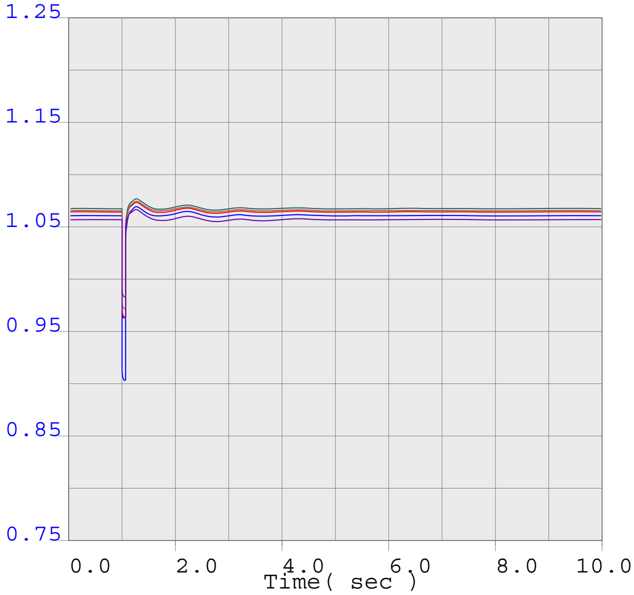
line_1227
Line EL NIDO 230.0 to LA FRESA 230.0 Circuit 4
1 MW dispatch Case

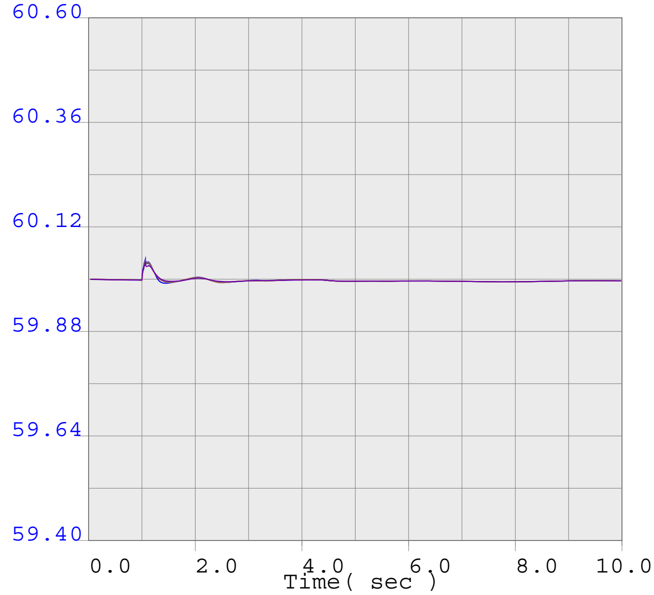
qc9p-line_1227.chf

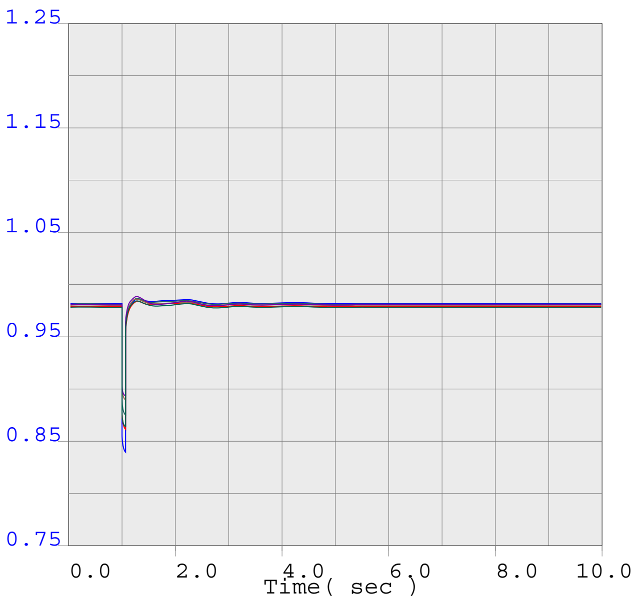
C:\DYTOOLS

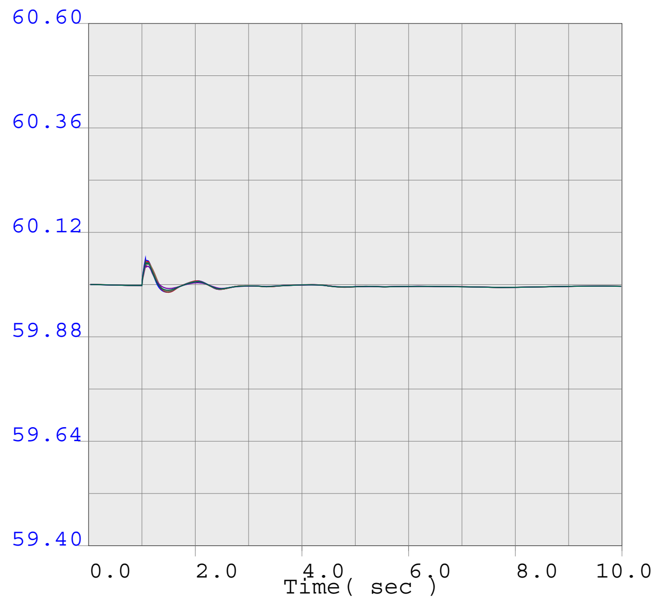
Thu Oct 20 09:01:05 2016

METRO









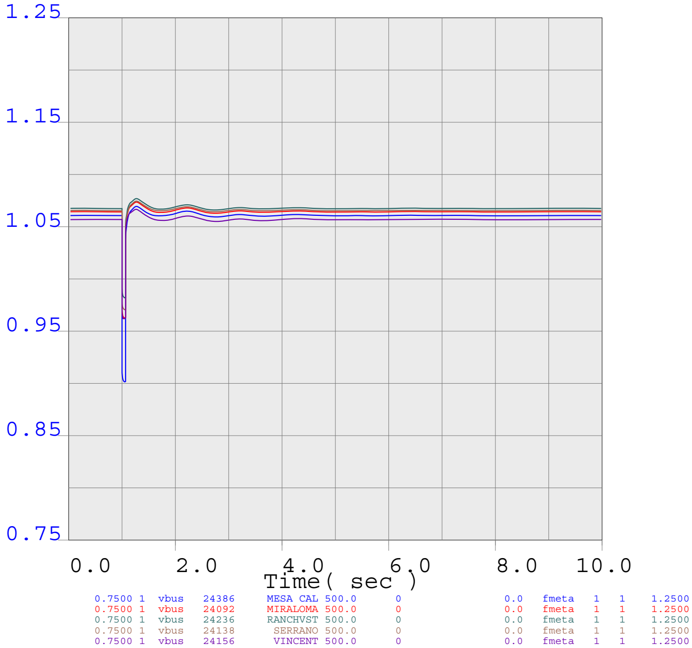
line_1228
Line EL NIDO 230.0 to LCIENEGA 230.0 Circuit 1
1 MW dispatch Case

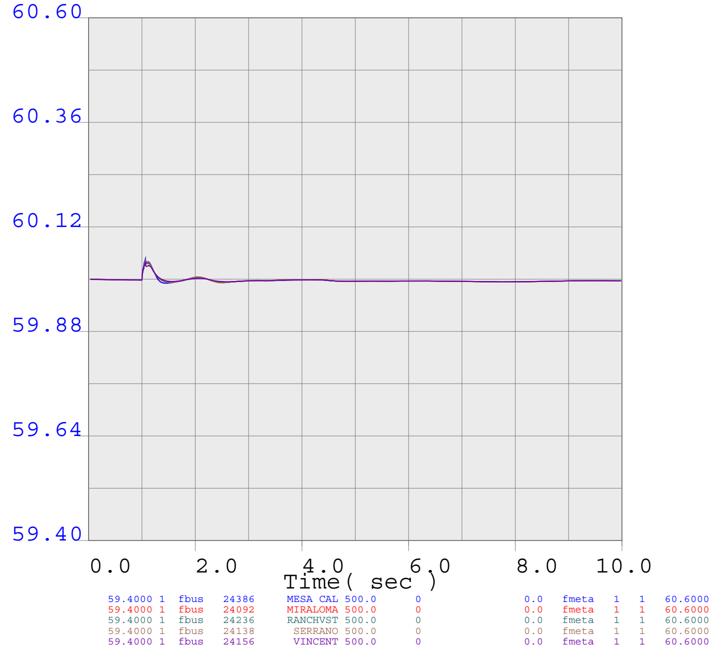
qc9p-line_1228.chf

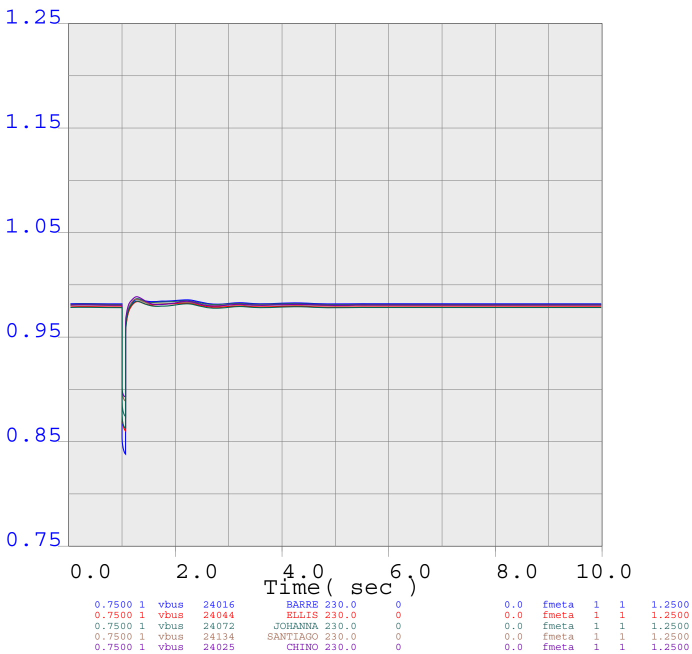
C:\DYTOOLS

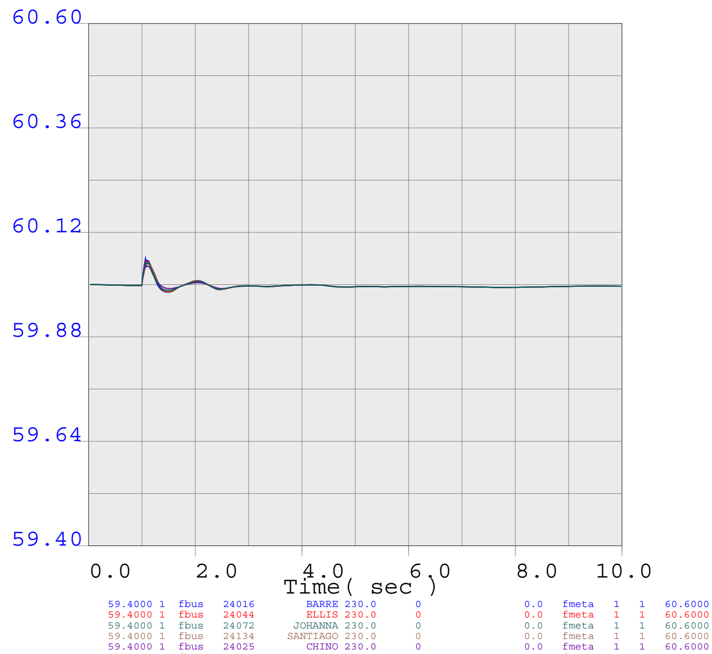
Thu Oct 20 09:01:07 2016

METRO





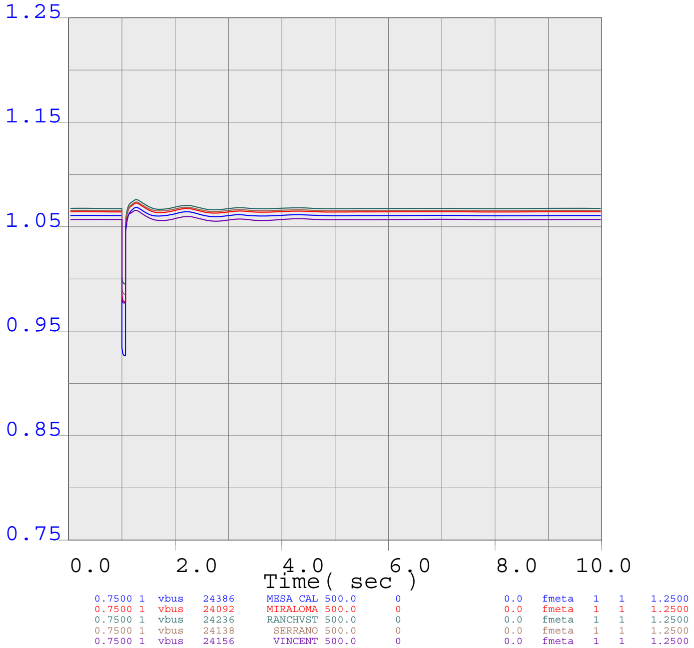


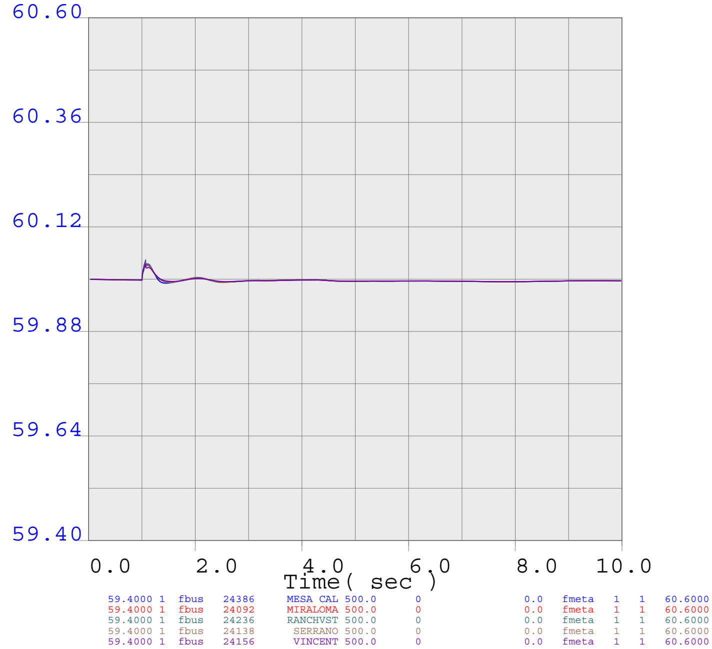


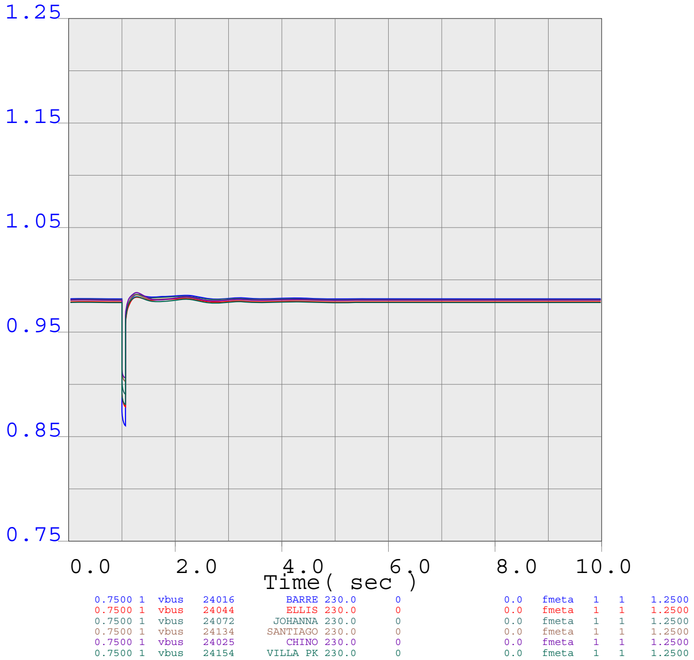
line_1229
Line EL NIDO 230.0 to CHEVMAIN 230.0 Circuit 1
1 MW dispatch Case

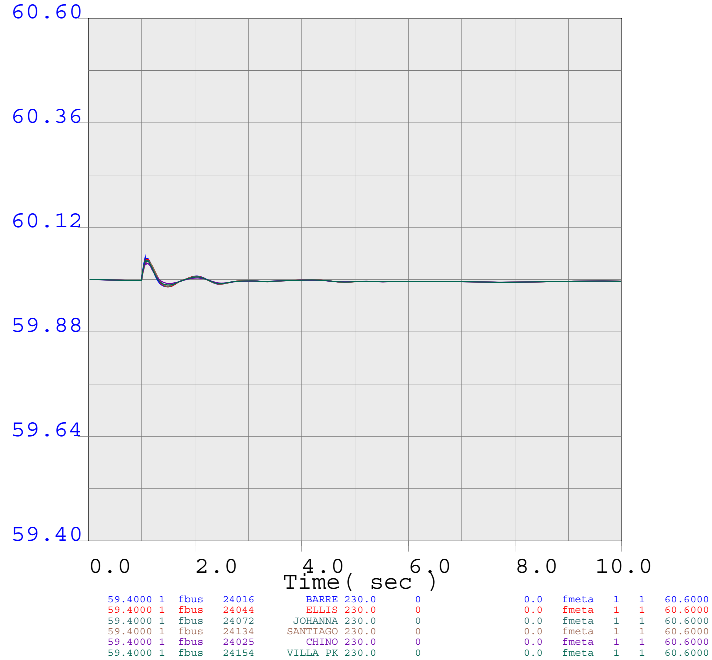
	qc9p-line_1229.chf	C:\DYTOOLS Thu Oct 20 09:01:09 2016

METRO









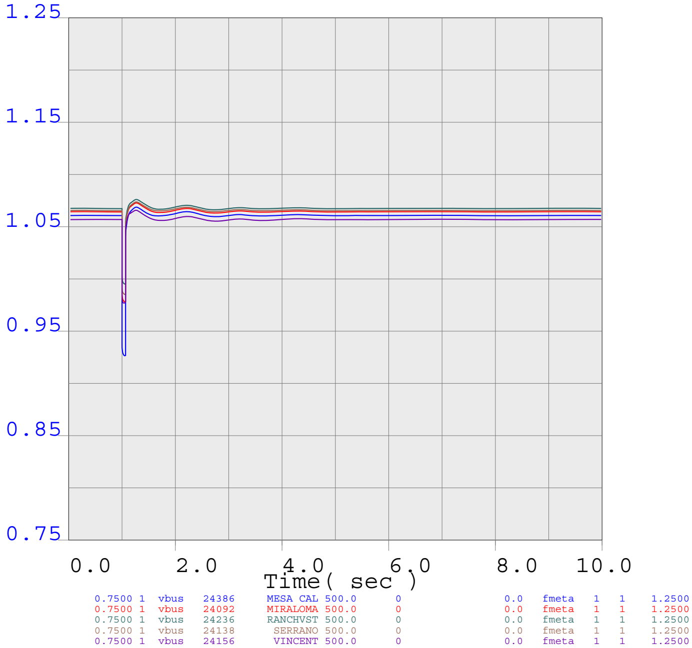
line_1230
Line ELSEGNDO 230.0 to EL NIDO 230.0 Circuit 1
1 MW dispatch Case

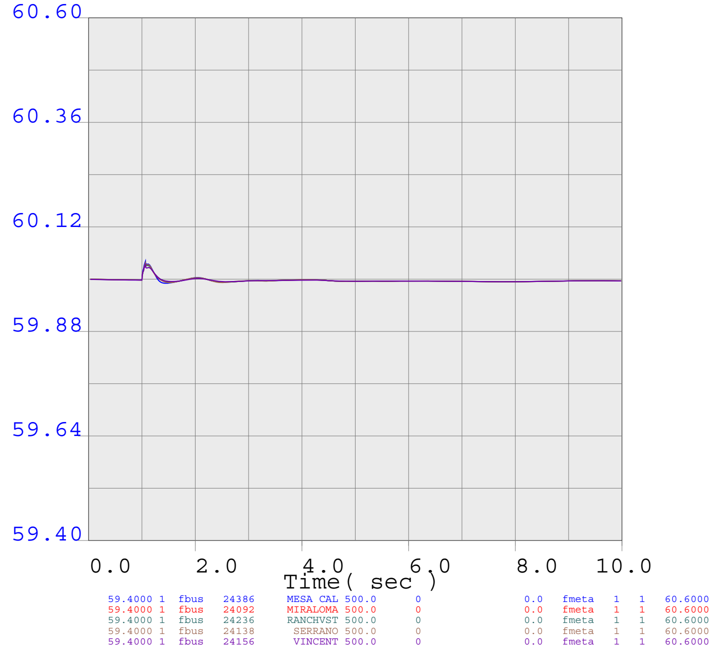
qc9p-line_1230.chf

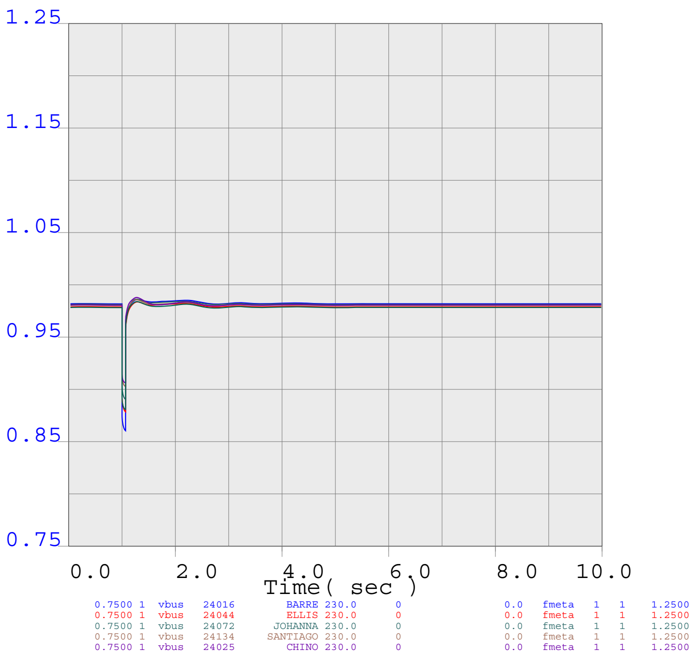
C:\DYTOOLS

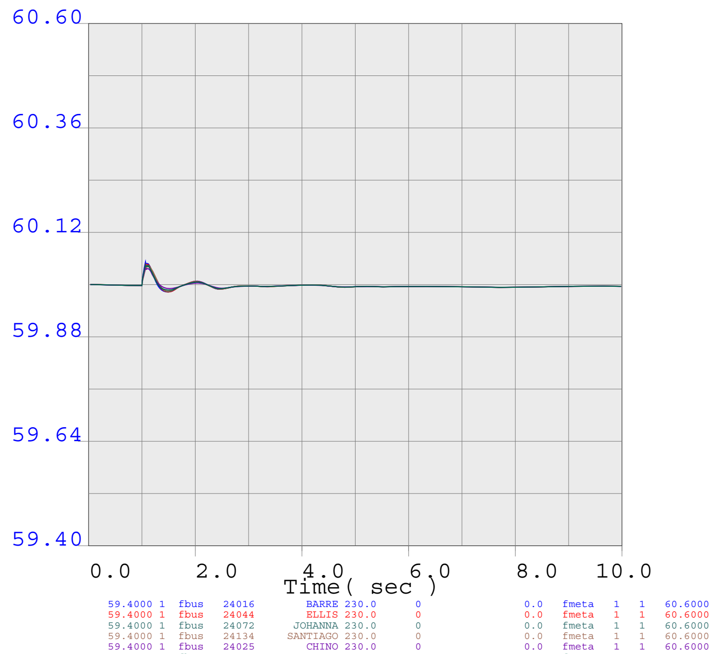
Thu Oct 20 09:01:12 2016

METRO









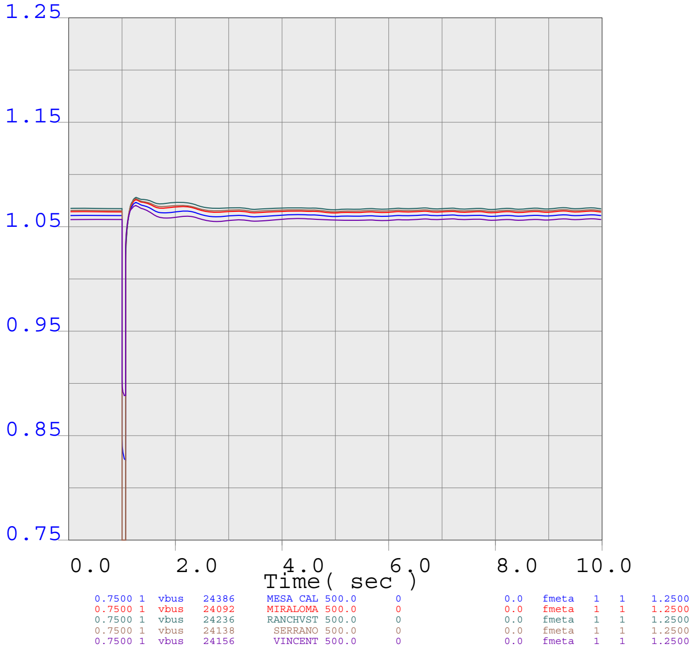
line_1231
Line ELSEGNDO 230.0 to CHEVMAIN 230.0 Circuit 1
1 MW dispatch Case

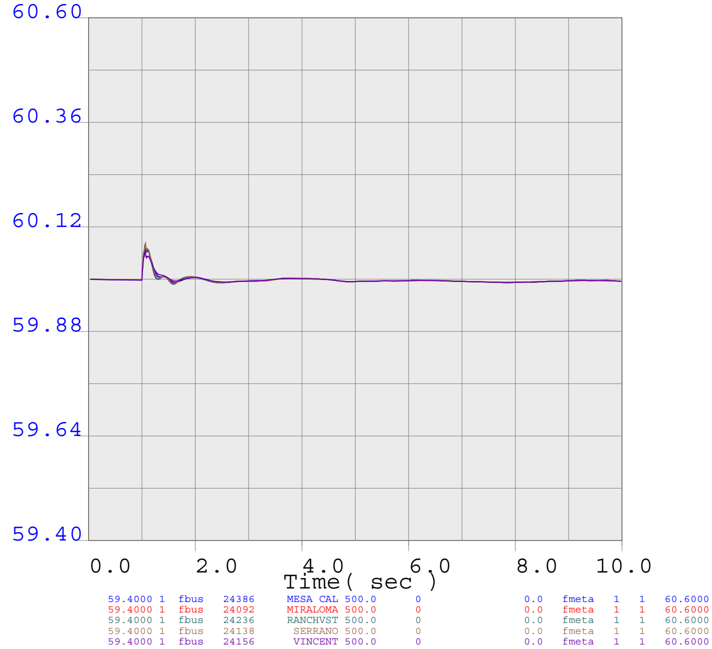
qc9p-line_1231.chf

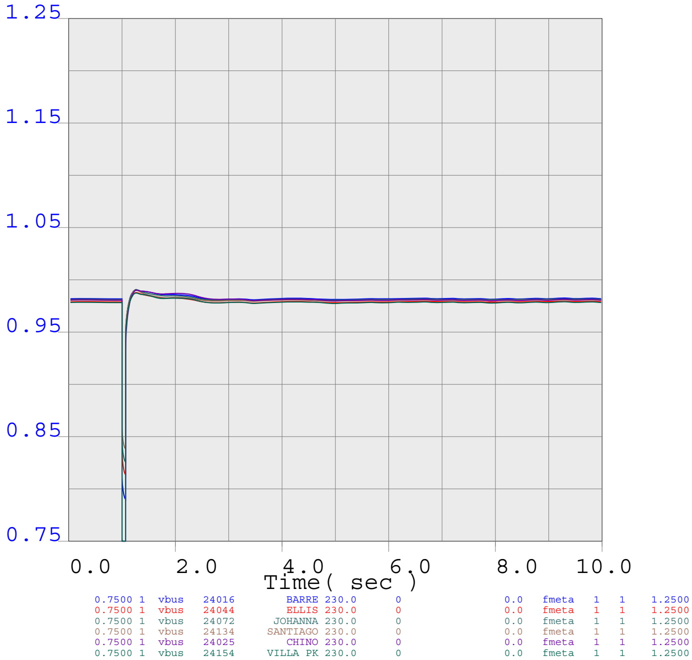
C:\DYTOOLS

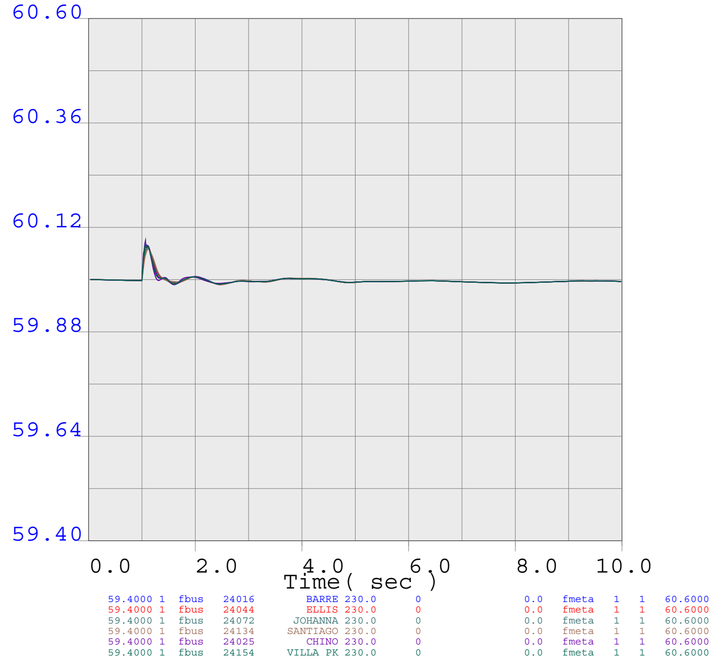
Thu Oct 20 09:01:14 2016

METRO









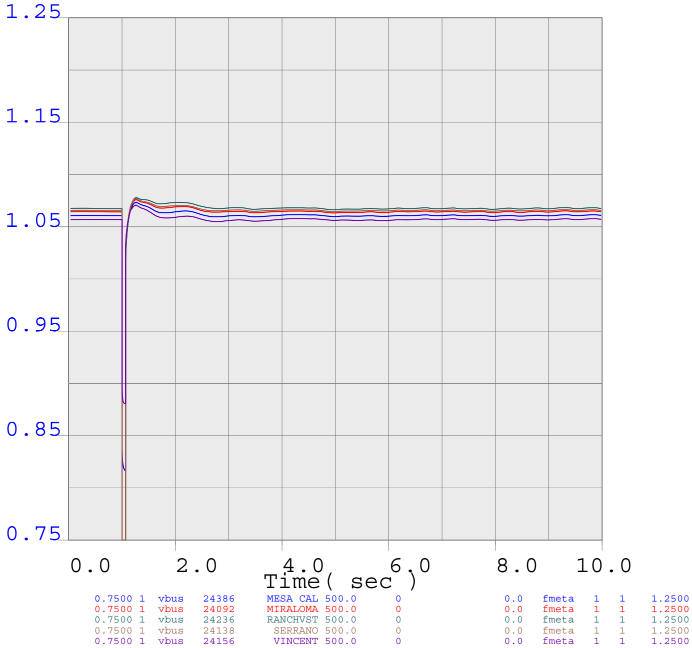
line_1232
Line ETIWANDA 230.0 to SANBRDNO 230.0 Circuit 1
1 MW dispatch Case

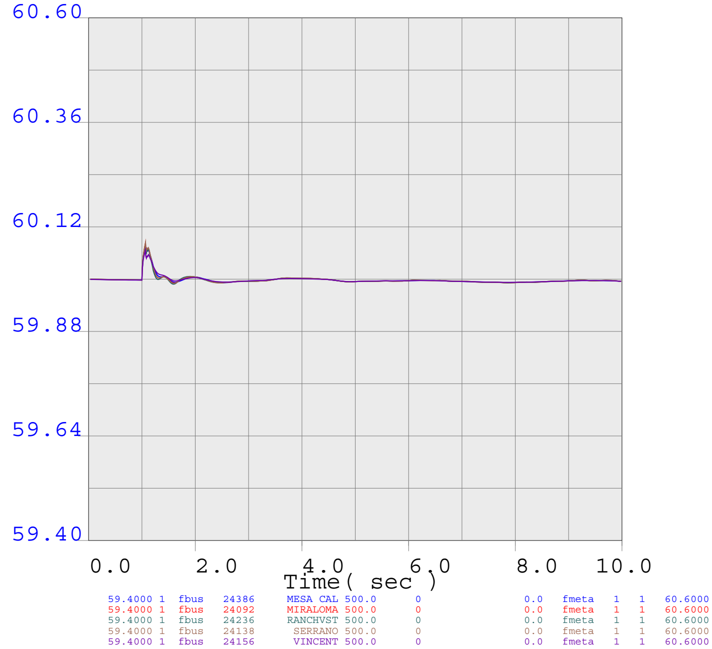
qc9p-line_1232.chf

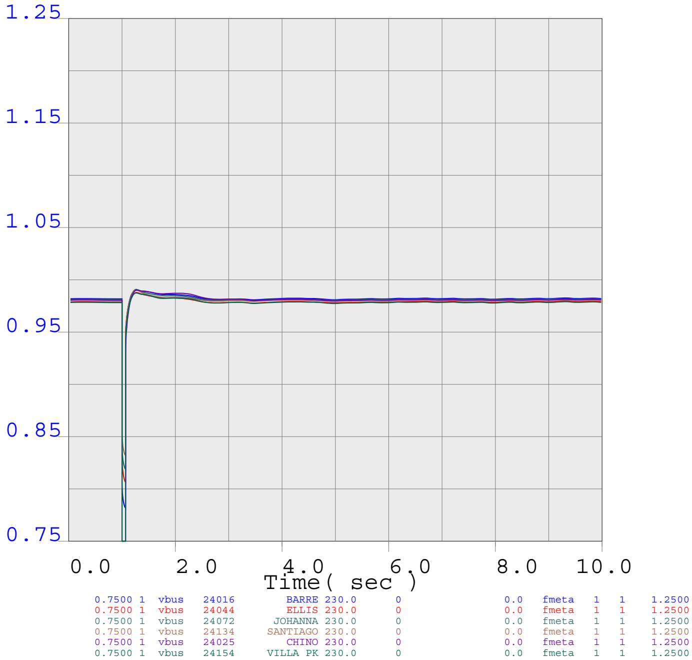
C:\DYTOOLS

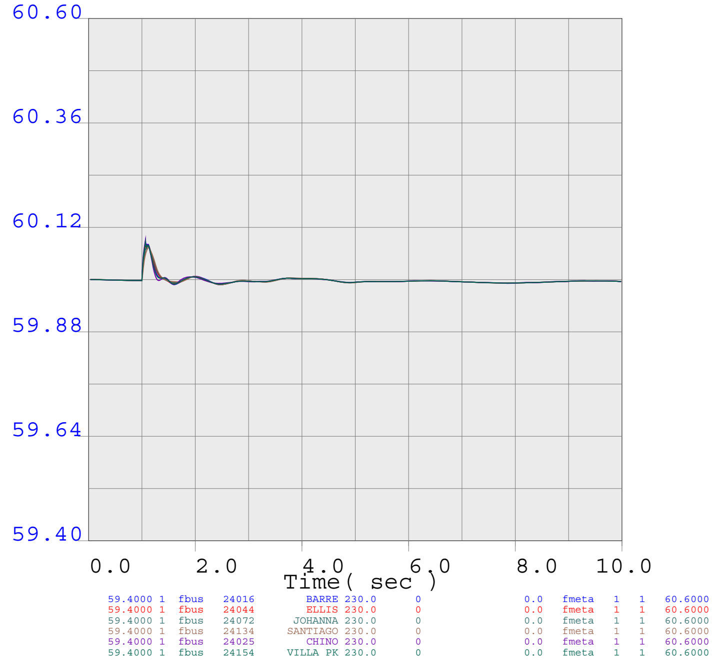
Thu Oct 20 09:01:15 2016

METRO





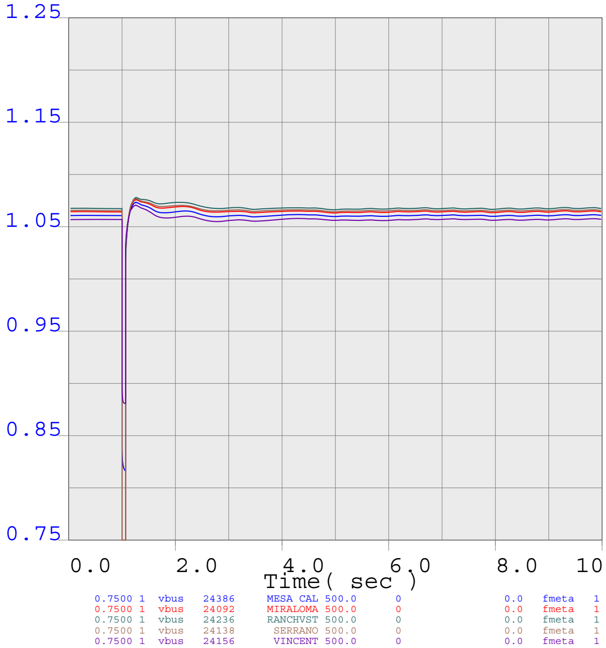


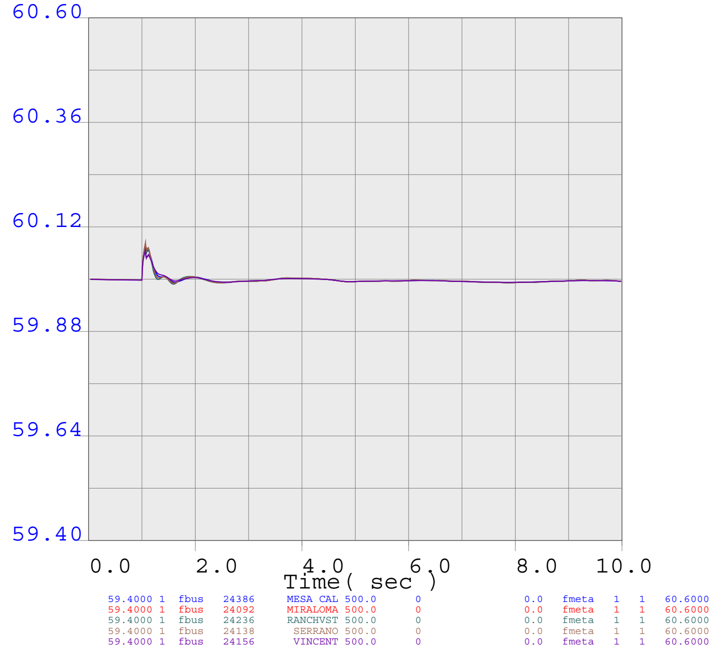


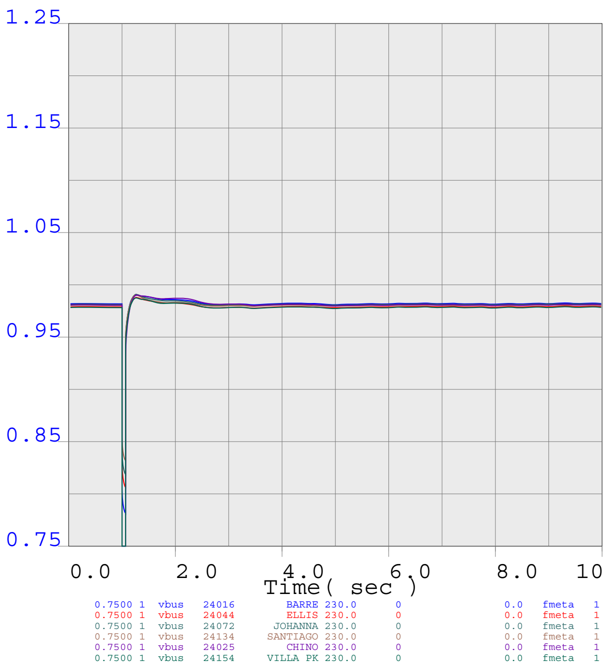
line_1233
Line ETIWANDA 230.0 to RANCHVST 230.0 Circuit 1
1 MW dispatch Case

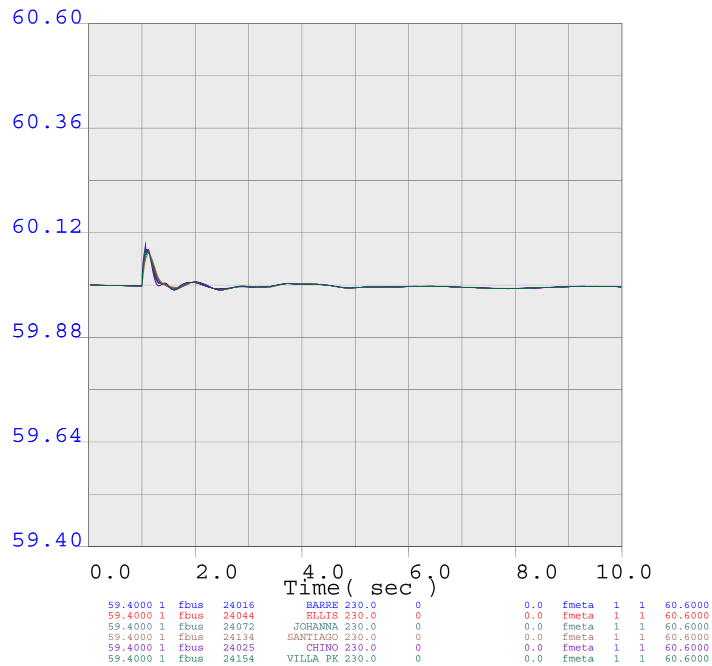
qc9p-line_1233.chf	C:\DYTOOLS Thu Oct 20 09:01:17 2016

METRO









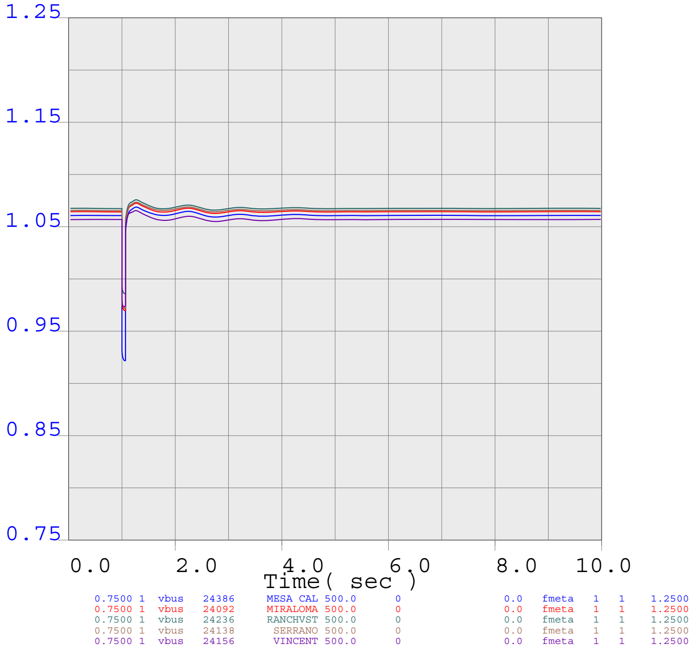
line_1234
Line ETIWANDA 230.0 to RANCHVST 230.0 Circuit 2
1 MW dispatch Case

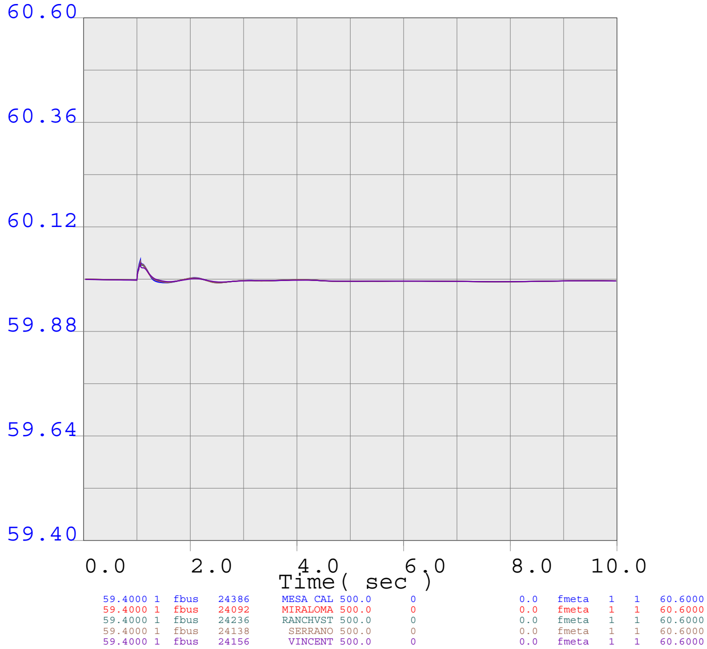
qc9p-line_1234.chf

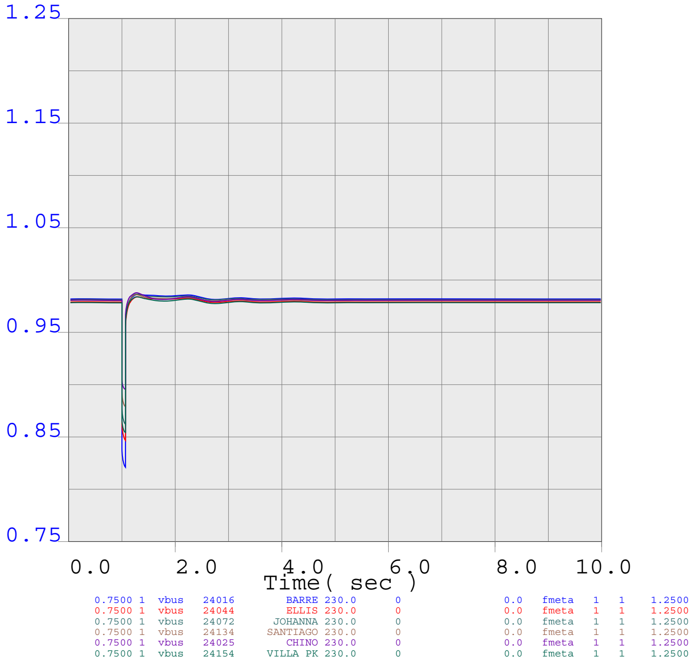
C:\DYTOOLS

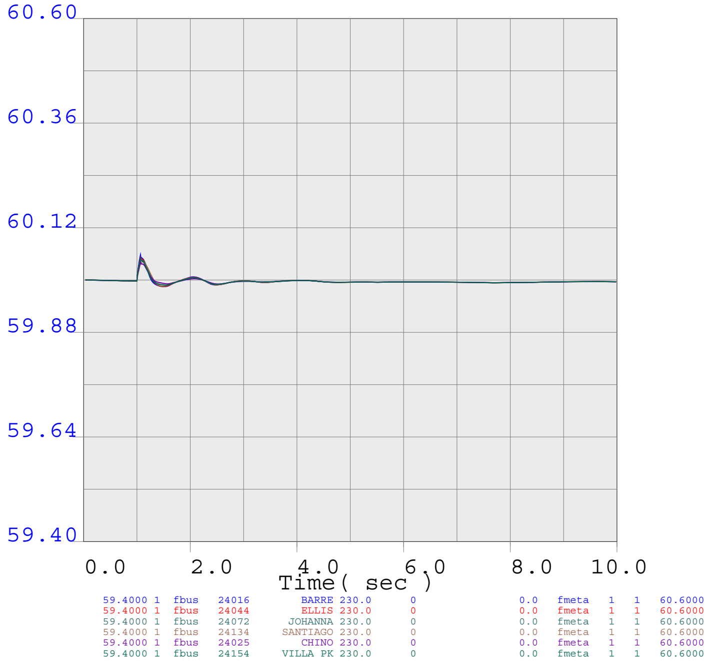
Thu Oct 20 09:01:19 2016

METRO









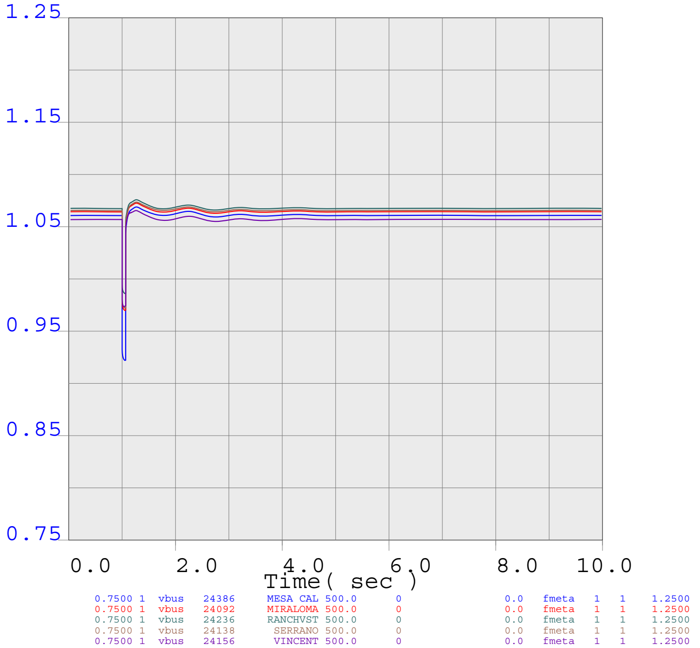
line_1235
Line HARBOR 230.0 to HINSON 230.0 Circuit 1
1 MW dispatch Case

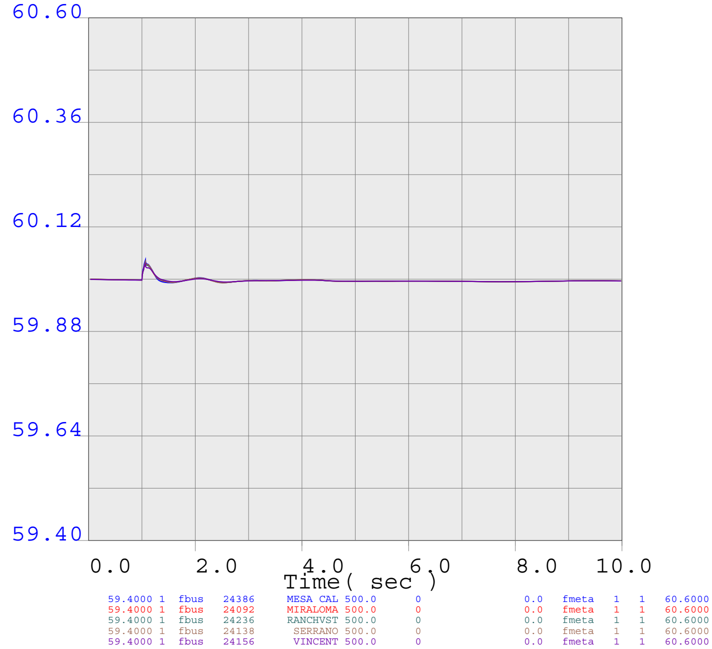
qc9p-line_1235.chf

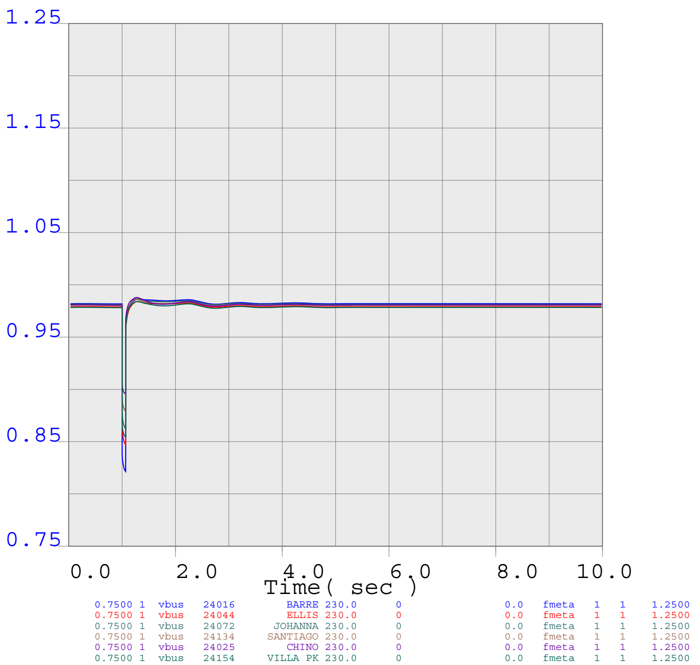
C:\DYTOOLS

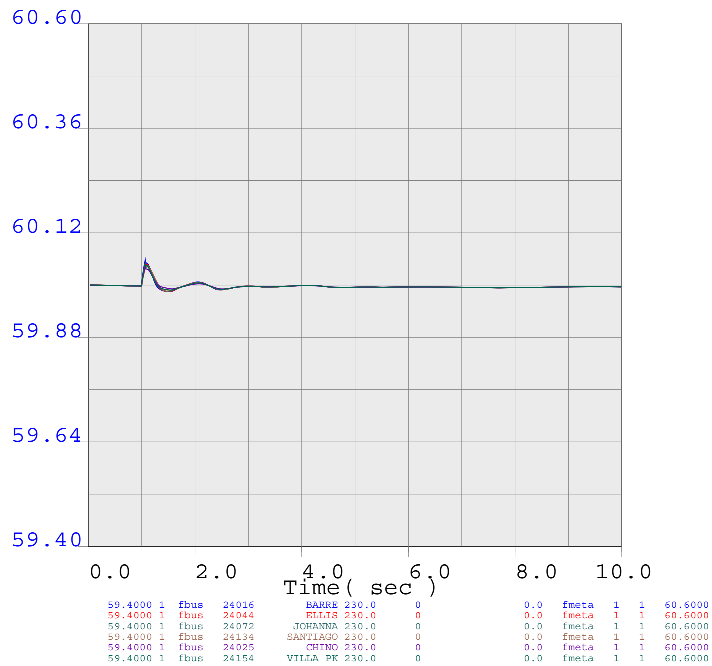
Thu Oct 20 09:01:21 2016

METRO









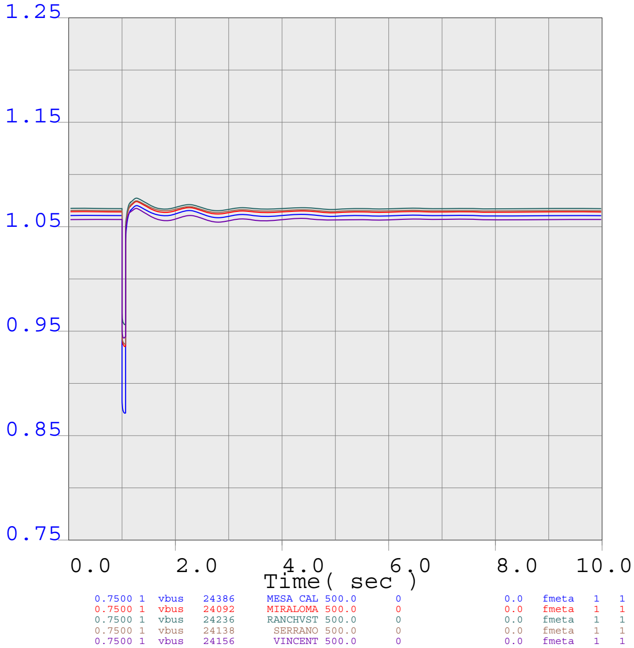
line_1236
Line HARBOR 230.0 to LBEACH 230.0 Circuit 1
1 MW dispatch Case

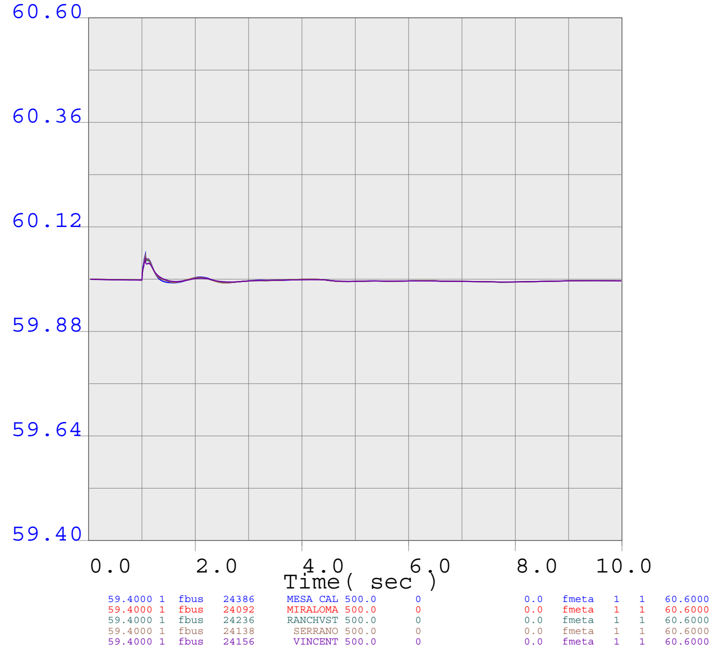
qc9p-line_1236.chf

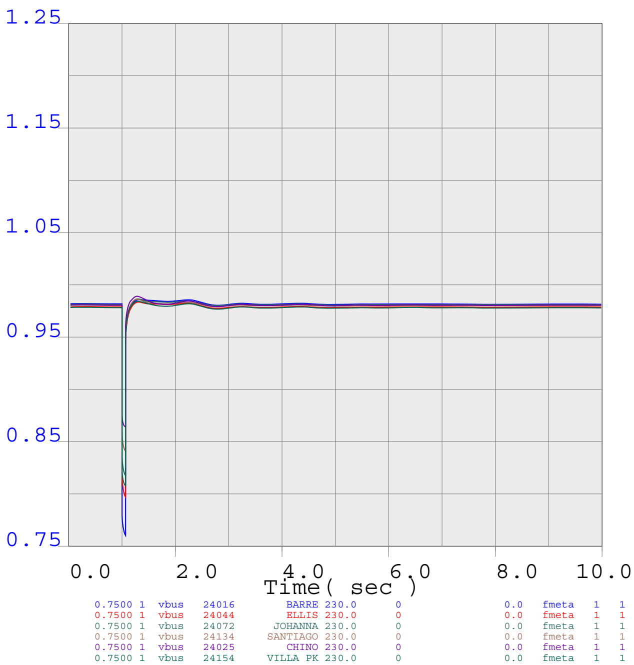
C:\DYTOOLS

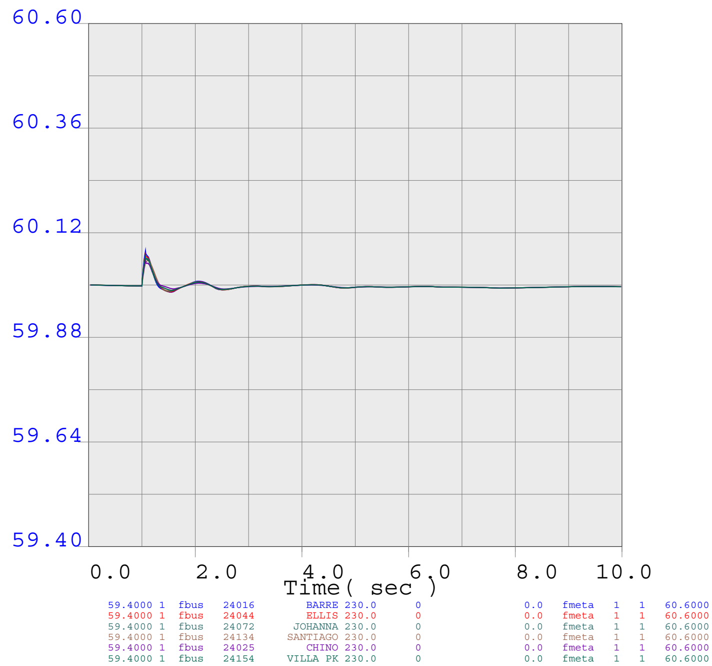
Thu Oct 20 09:01:23 2016

METRO









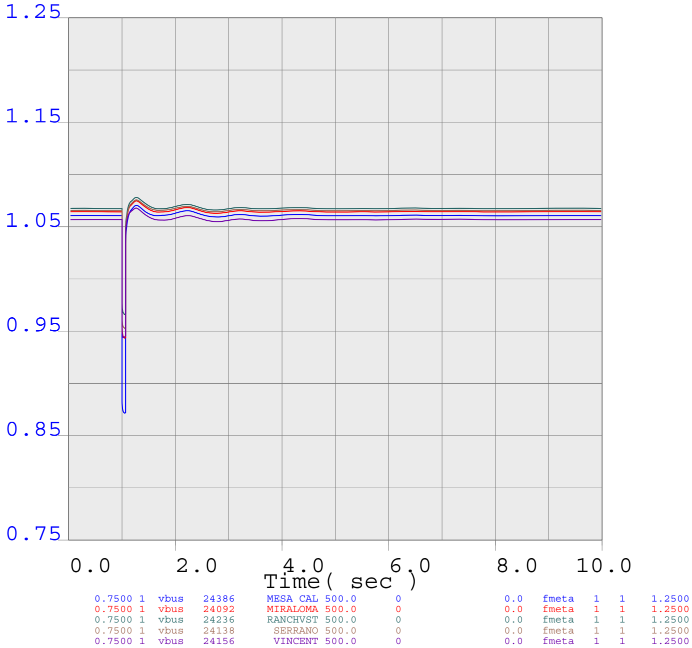
line_1237
Line HINSON 230.0 to DELAMO 230.0 Circuit 1
1 MW dispatch Case

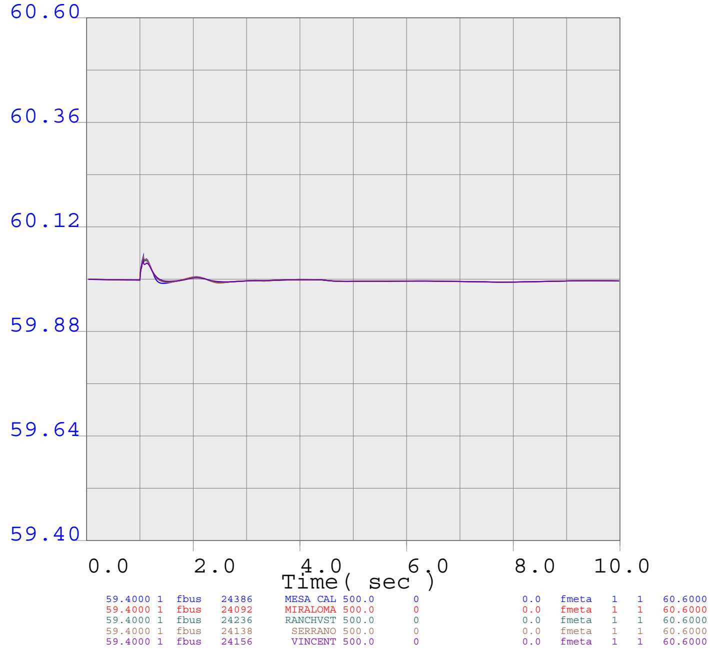
qc9p-line_1237.chf

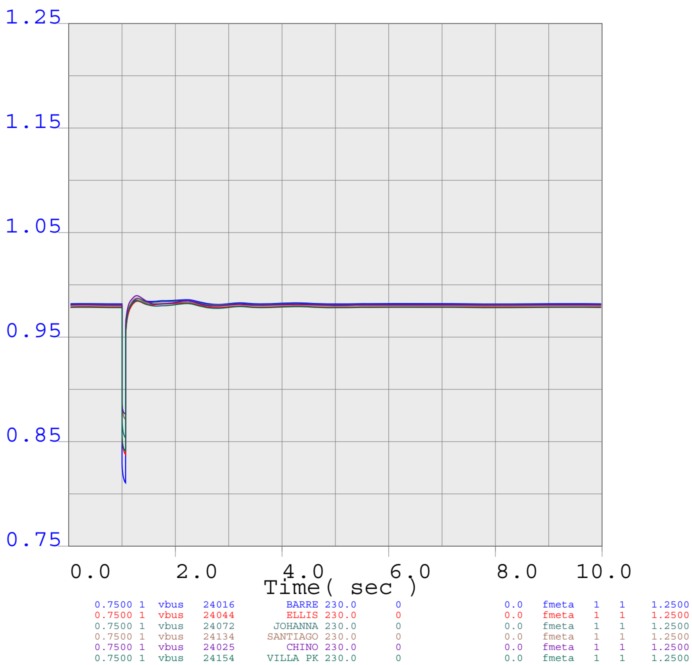
C:\DYTOOLS

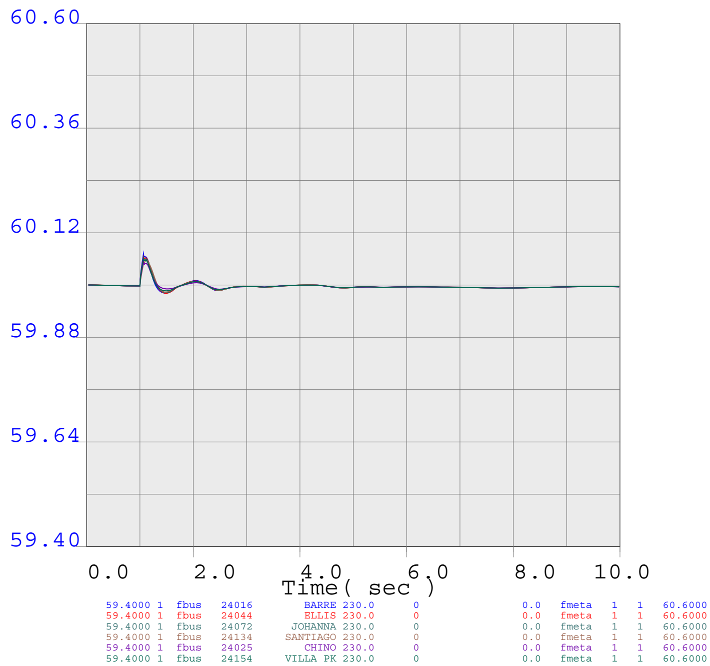
Thu Oct 20 09:01:25 2016

METRO









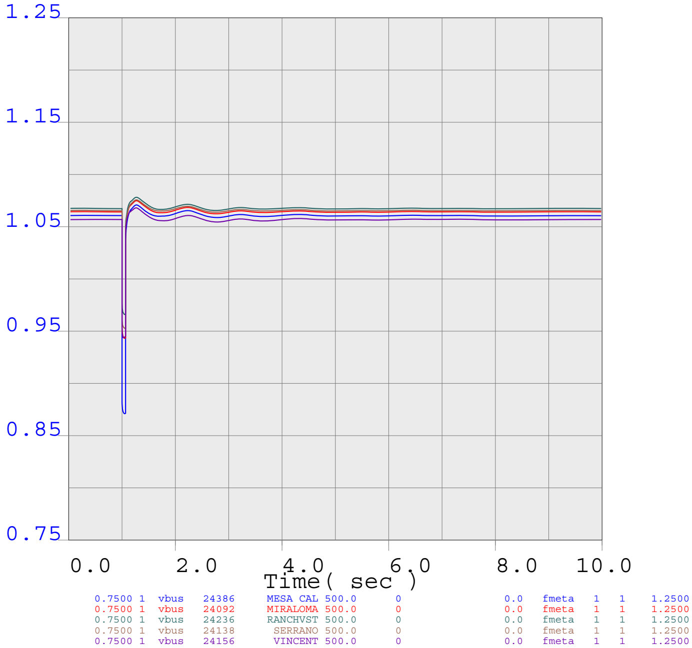
line_1238
Line LA FRESA 230.0 to HINSON 230.0 Circuit 1
1 MW dispatch Case

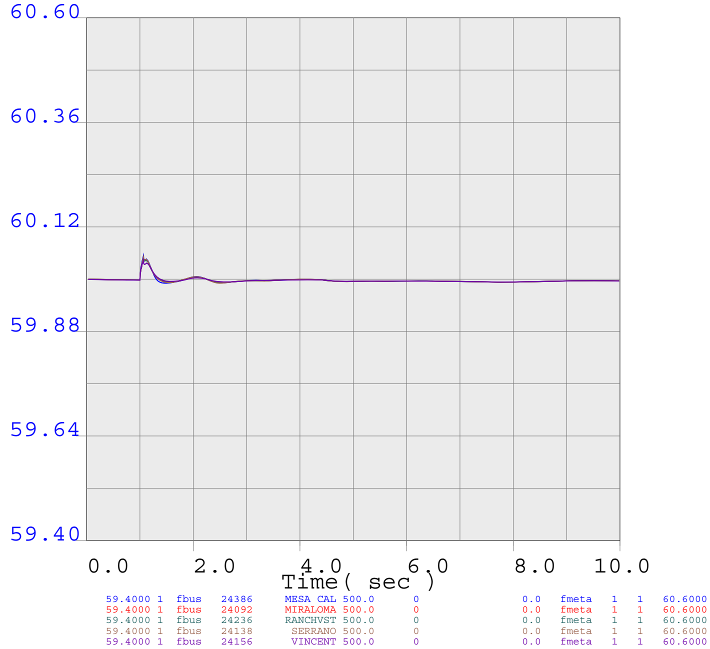
qc9p-line_1238.chf

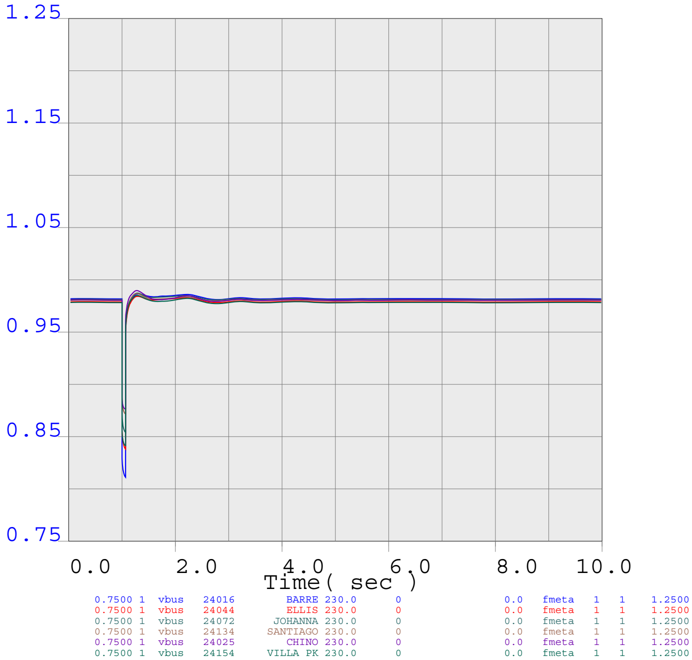
C:\DYTOOLS

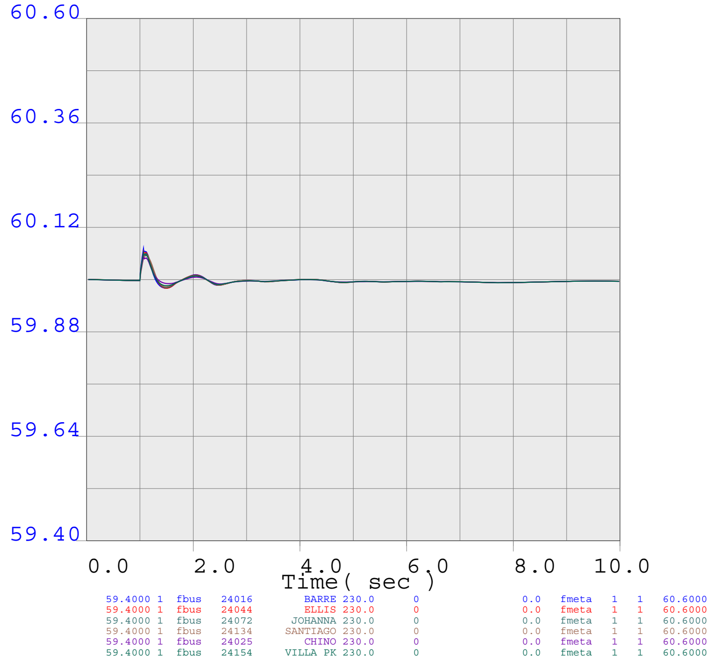
Thu Oct 20 09:01:27 2016

METRO









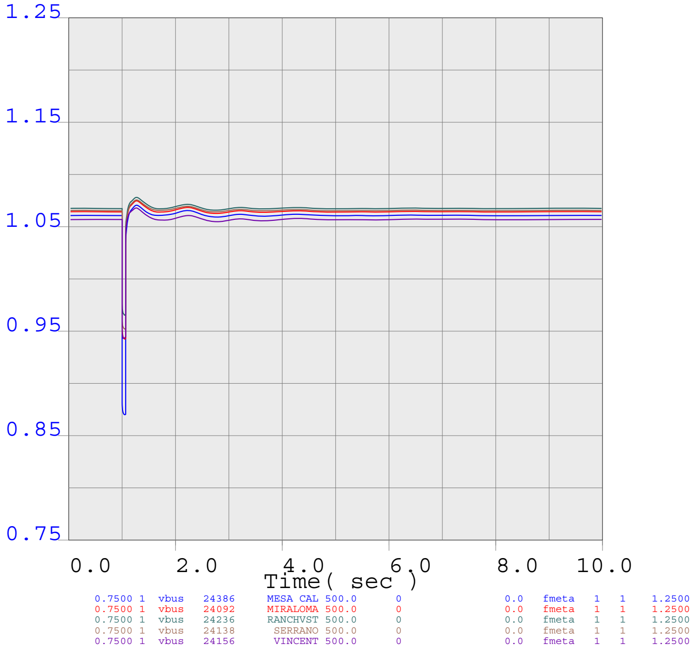
line_1239
Line LA FRESA 230.0 to LAGUBELL 230.0 Circuit 1
1 MW dispatch Case

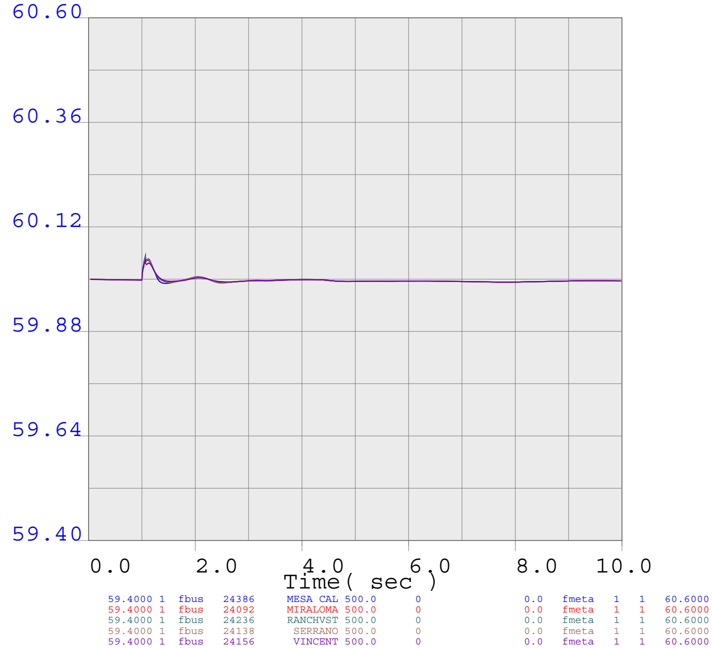
qc9p-line_1239.chf

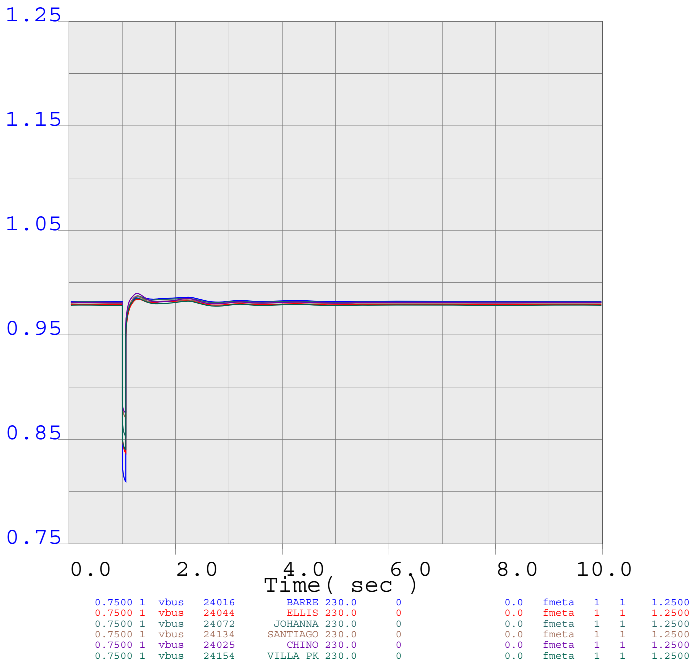
C:\DYTOOLS

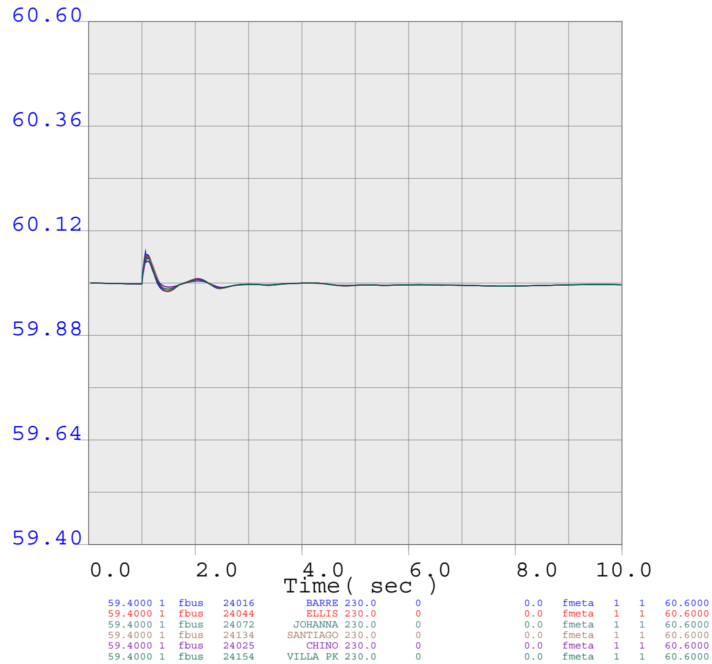
Thu Oct 20 09:01:29 2016

METRO









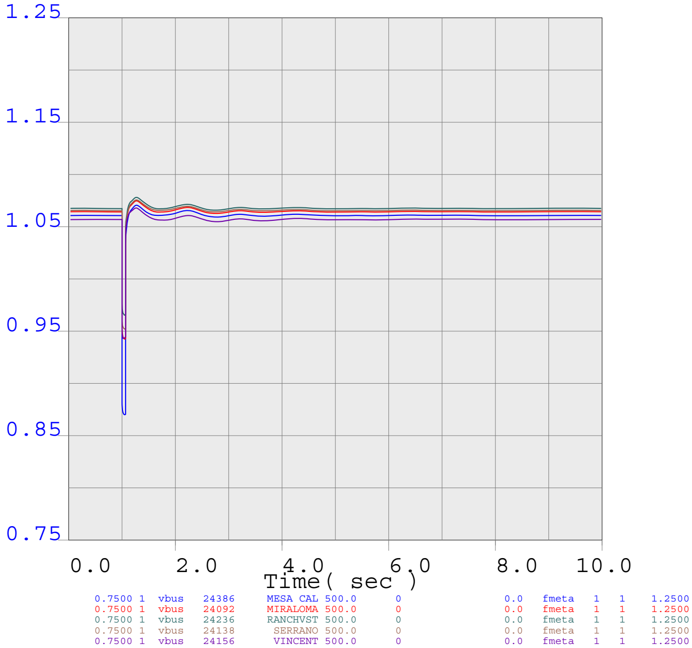
line_1240
Line LA FRESA 230.0 to REDONDO 230.0 Circuit 1
1 MW dispatch Case

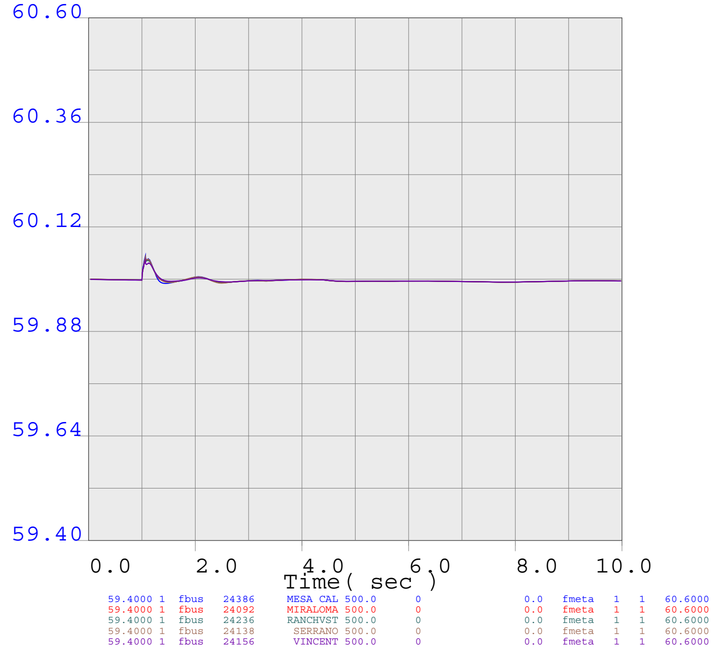
qc9p-line_1240.chf

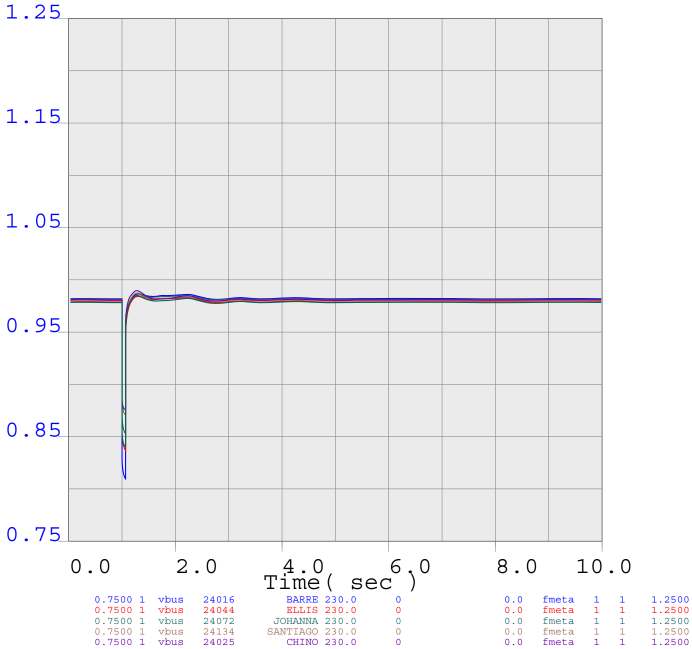
C:\DYTOOLS

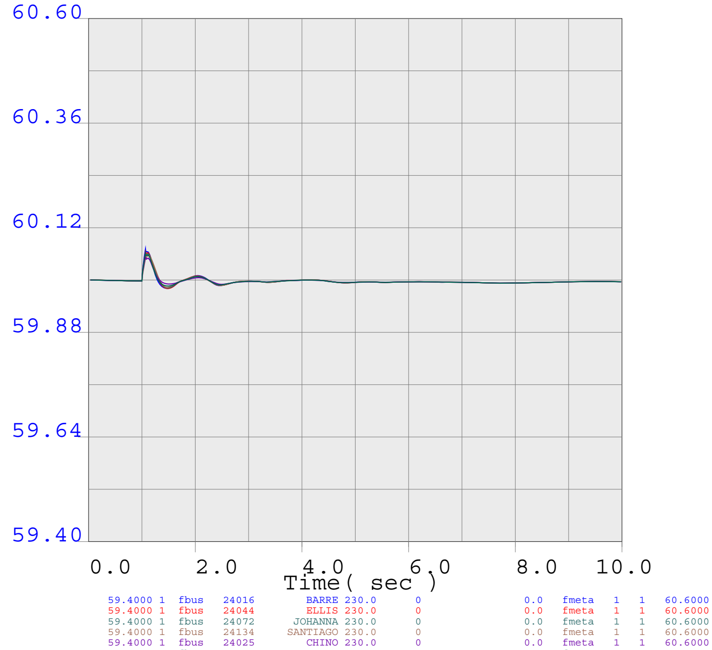
Thu Oct 20 09:01:31 2016

METRO





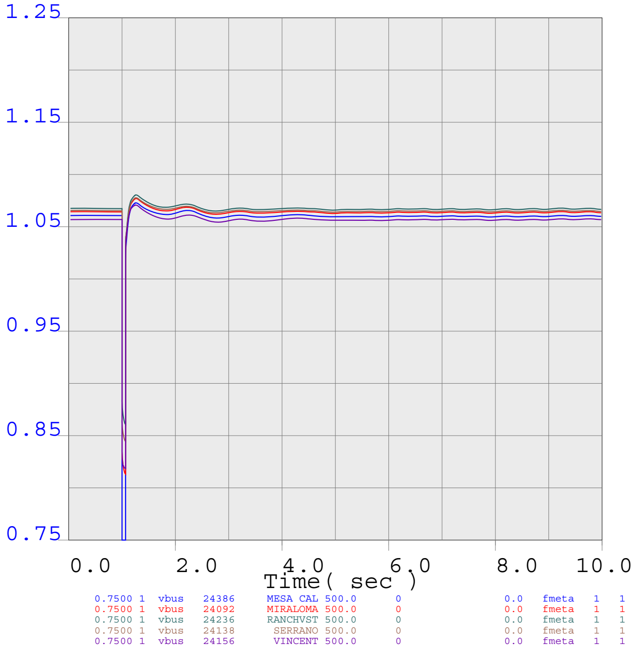


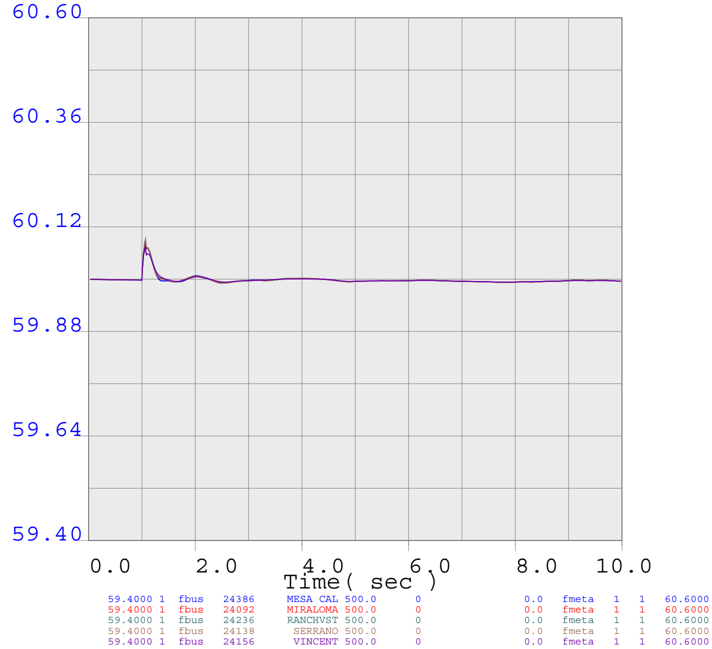


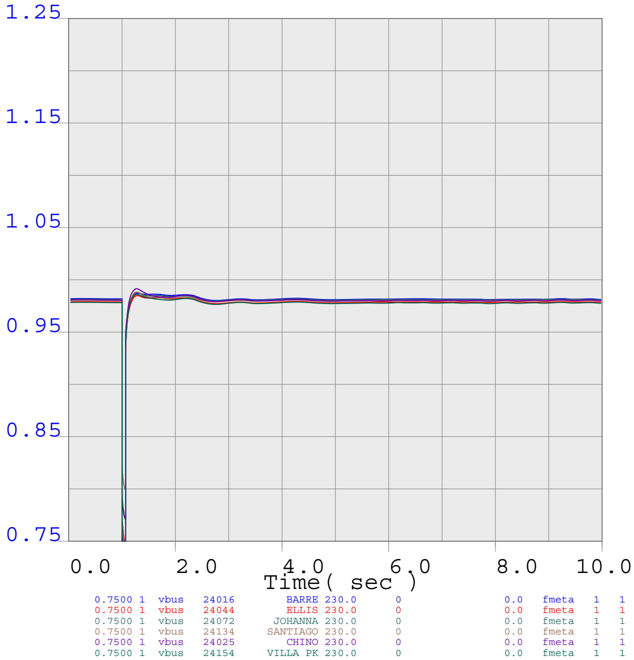
line_1241
Line LA FRESA 230.0 to REDONDO 230.0 Circuit 2
1 MW dispatch Case

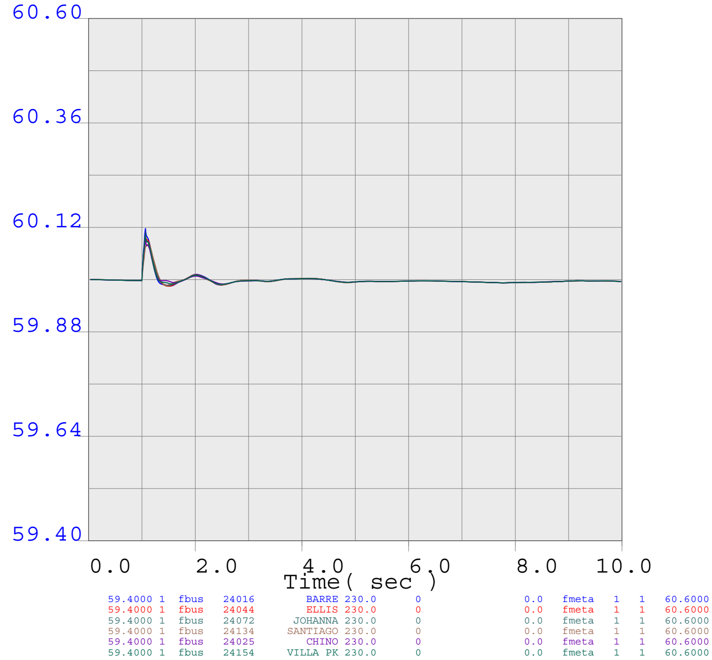
qc9p-line_1241.chf	C:\DYTOOLS Thu Oct 20 09:01:33 2016

METRO









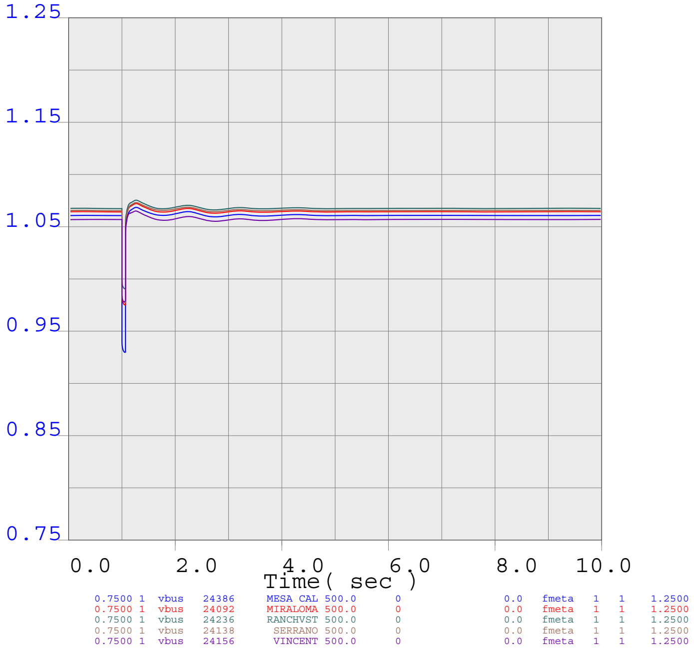
line_1242
Line LAGUBELL 230.0 to MESA CAL 230.0 Circuit 1
1 MW dispatch Case

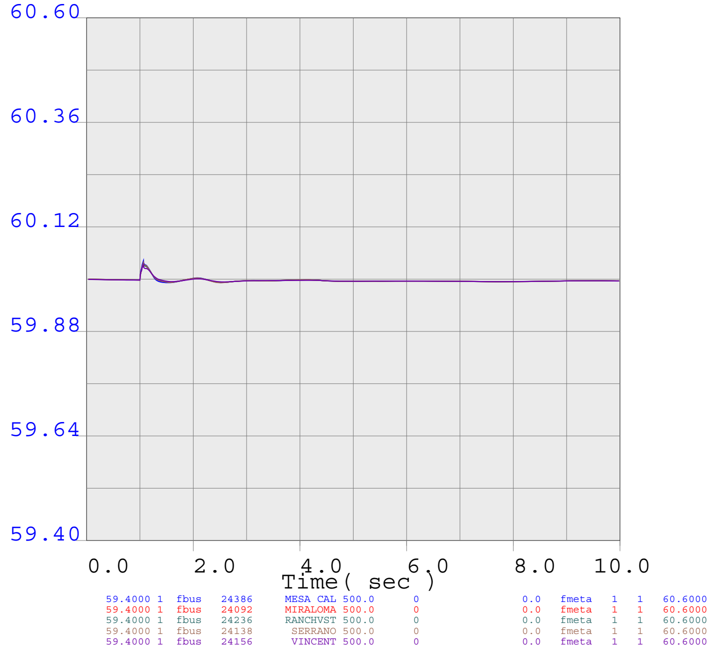
qc9p-line_1242.chf

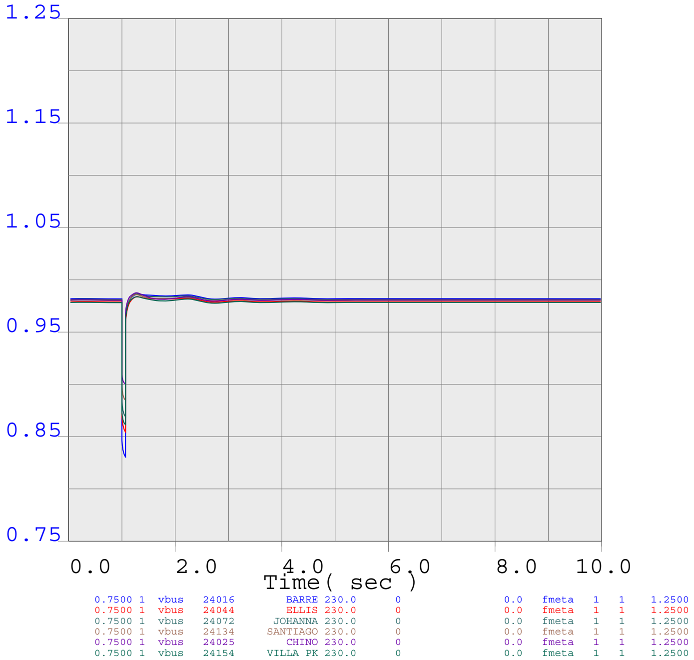
C:\DYTOOLS

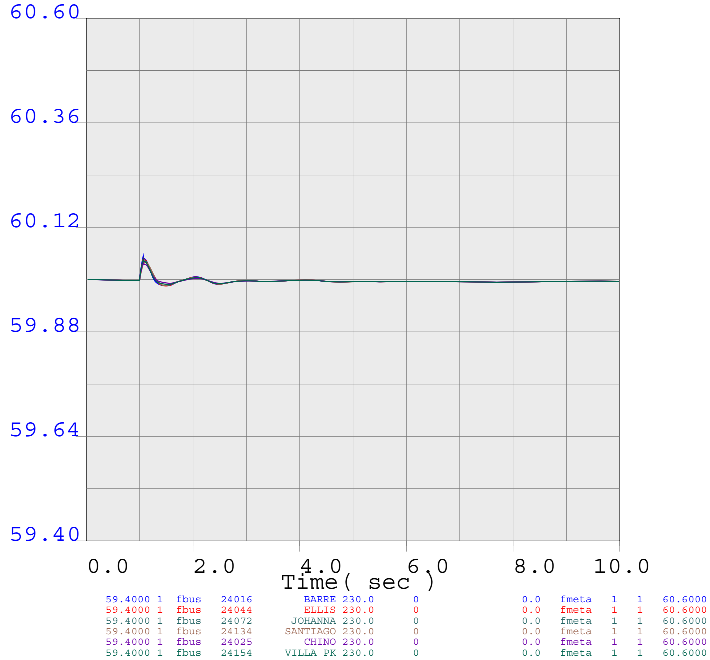
Thu Oct 20 09:01:35 2016

METRO









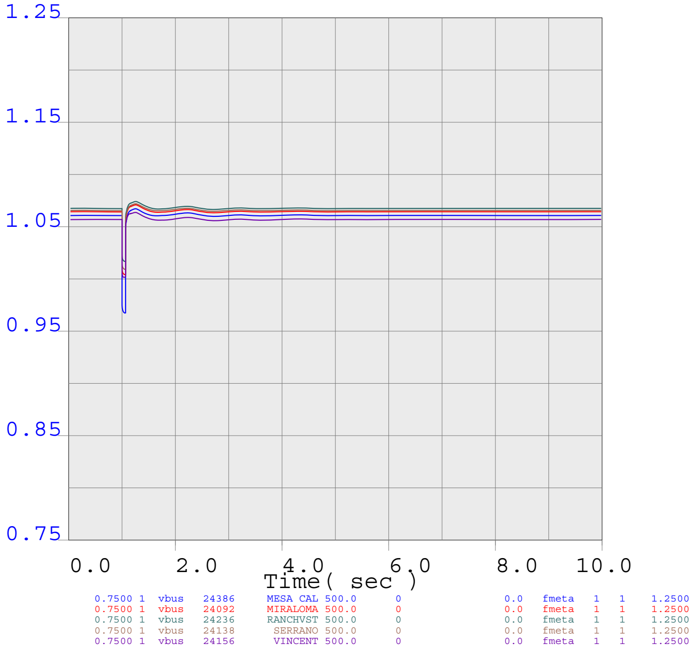
line_1243
Line LBEACH 230.0 to LITEHIPE 230.0 Circuit 1
1 MW dispatch Case

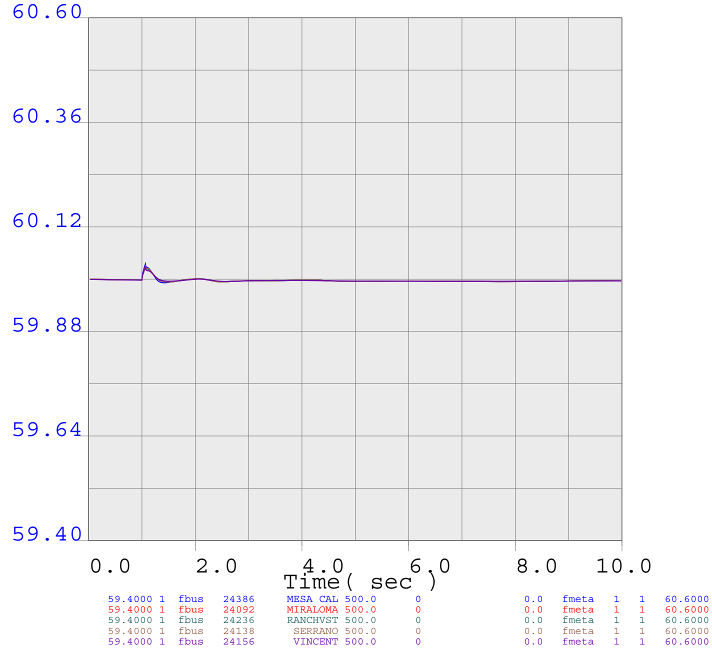
qc9p-line_1243.chf

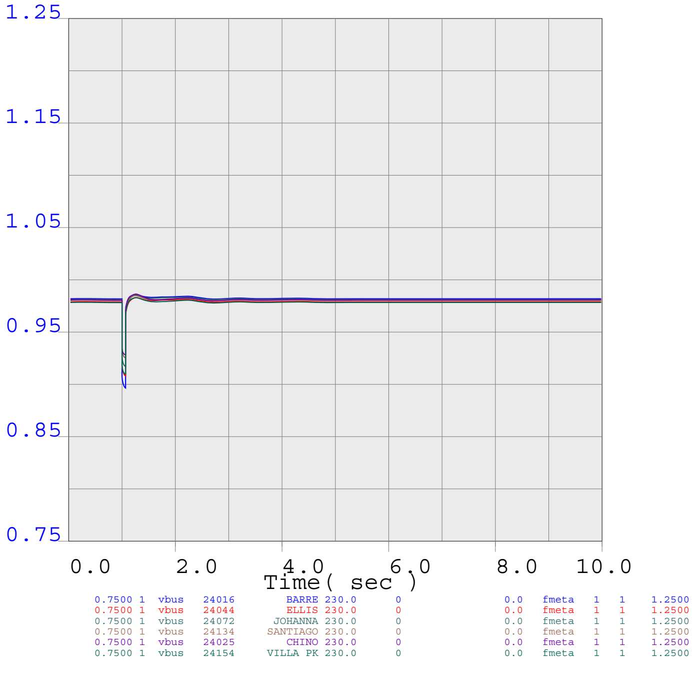
C:\DYTOOLS

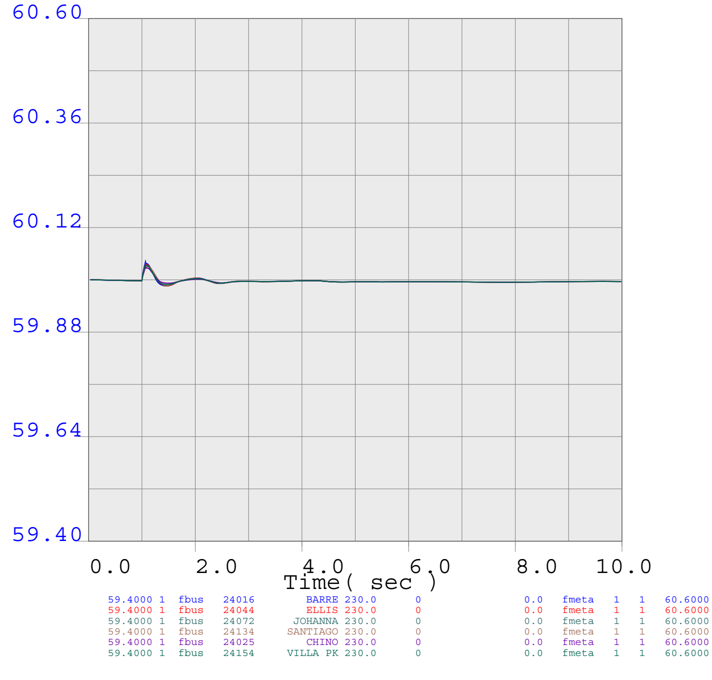
Thu Oct 20 09:01:37 2016

METRO









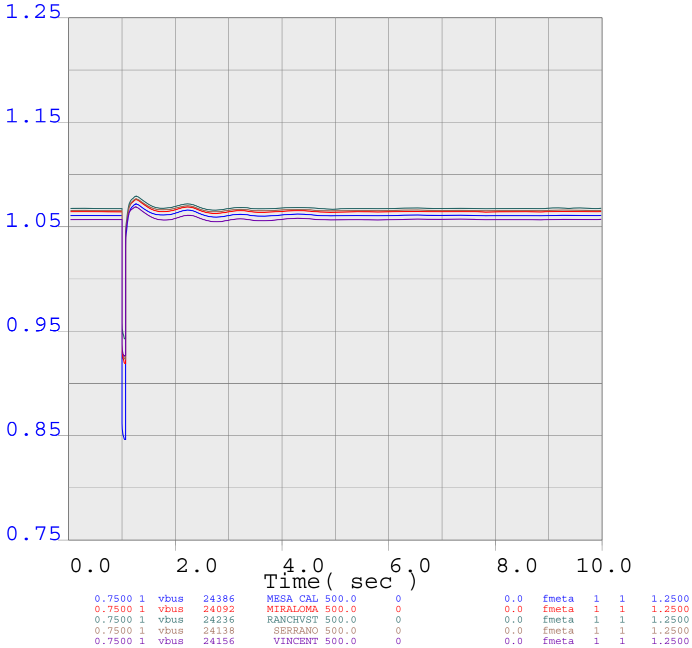
line_1244
Line LCIENEGA 230.0 to LA FRESA 230.0 Circuit 1
1 MW dispatch Case

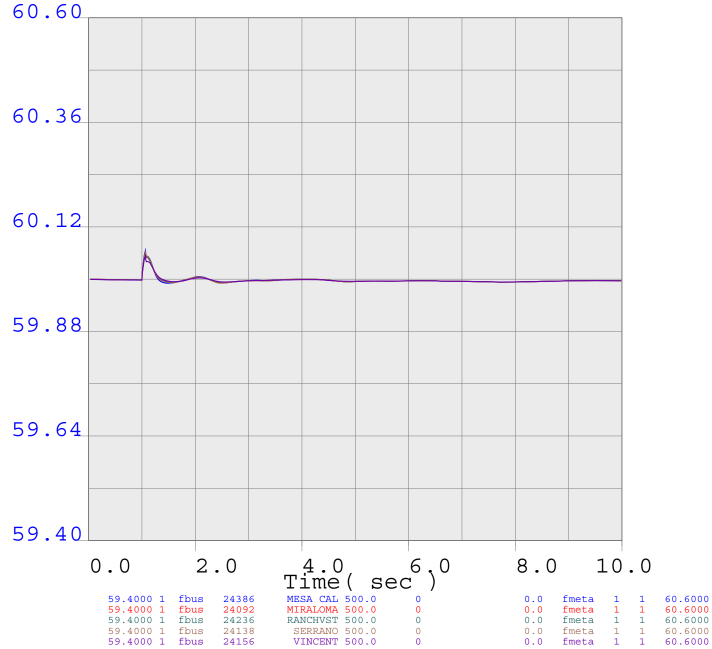
qc9p-line_1244.chf

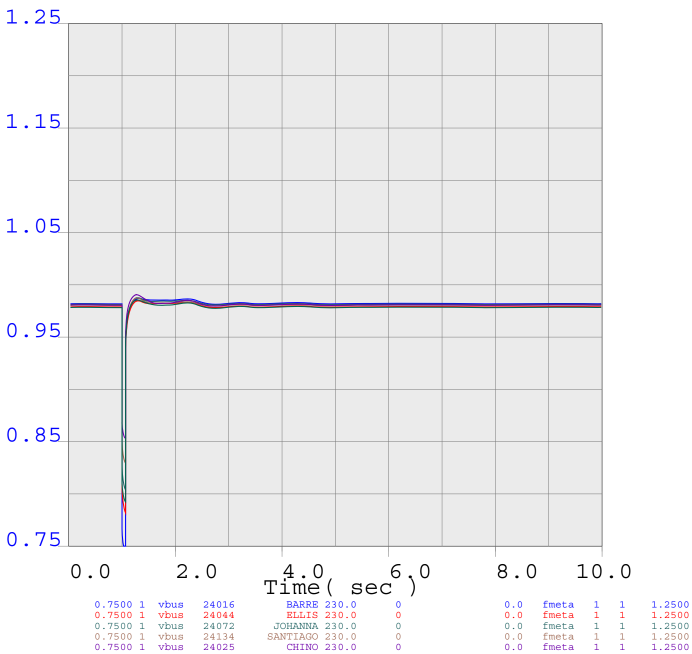
C:\DYTOOLS

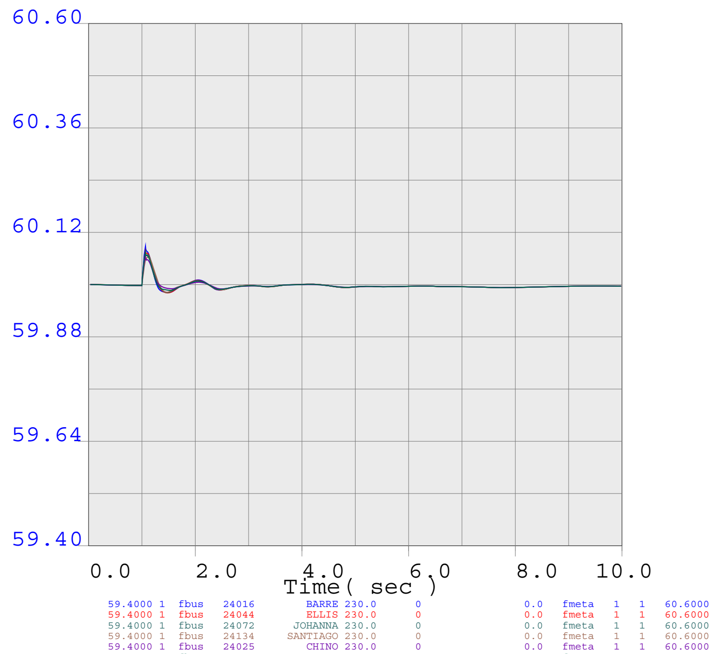
Thu Oct 20 09:01:39 2016

METRO









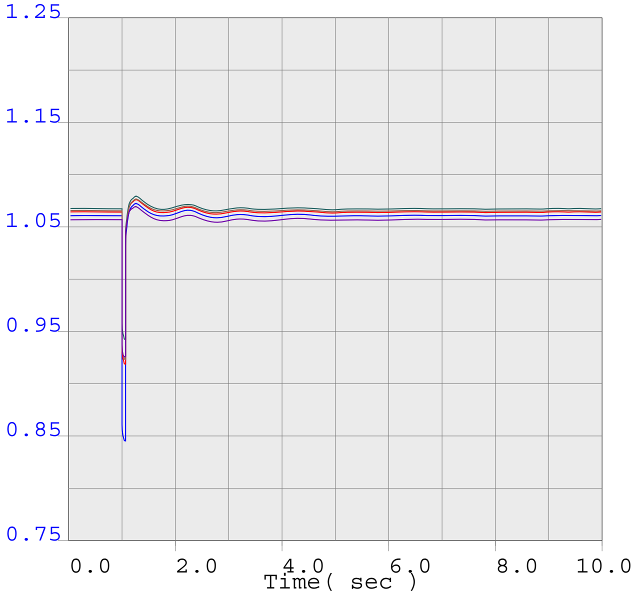
line_1245
Line LITEHIPE 230.0 to HINSON 230.0 Circuit 1
1 MW dispatch Case

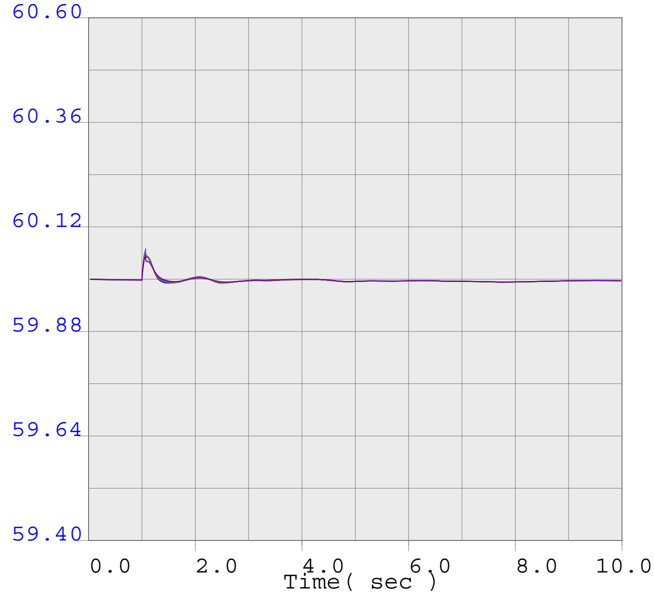
qc9p-line_1245.chf

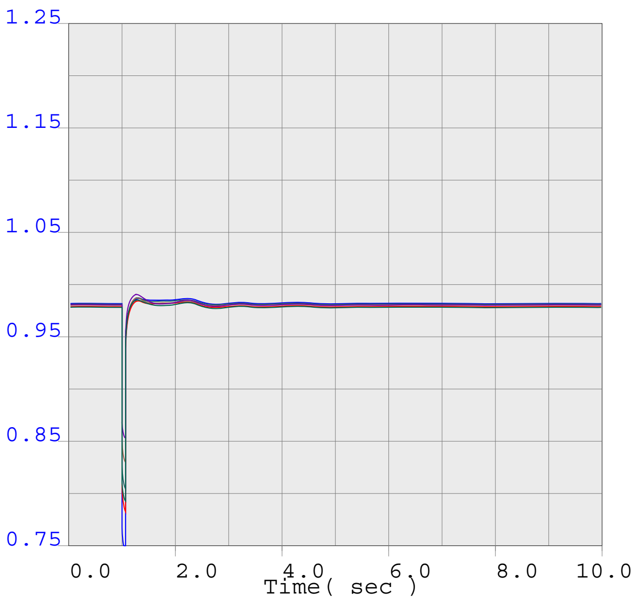
C:\DYTOOLS

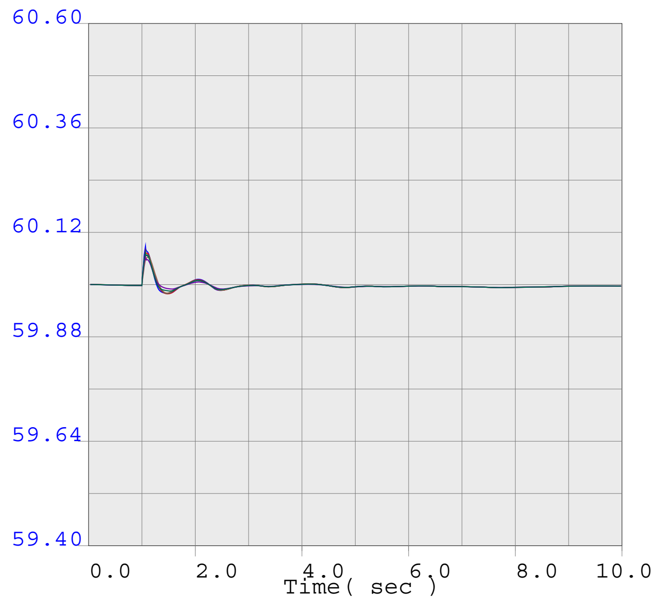
Thu Oct 20 09:01:41 2016

METRO









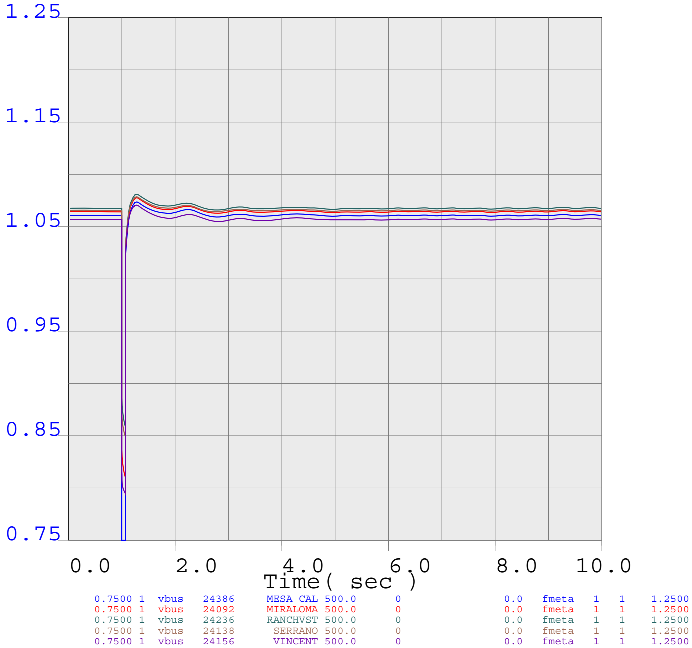
line_1246
Line LITEHIPE 230.0 to MESA CAL 230.0 Circuit 1
1 MW dispatch Case

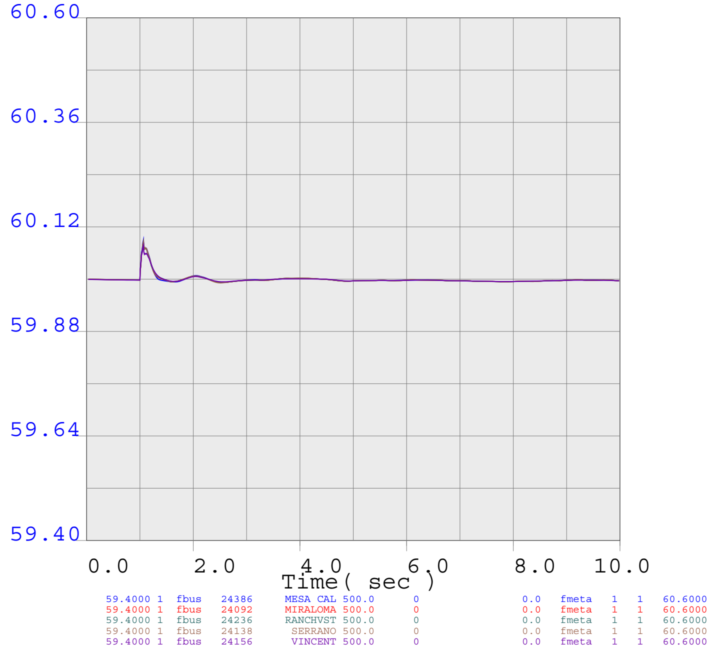
qc9p-line_1246.chf

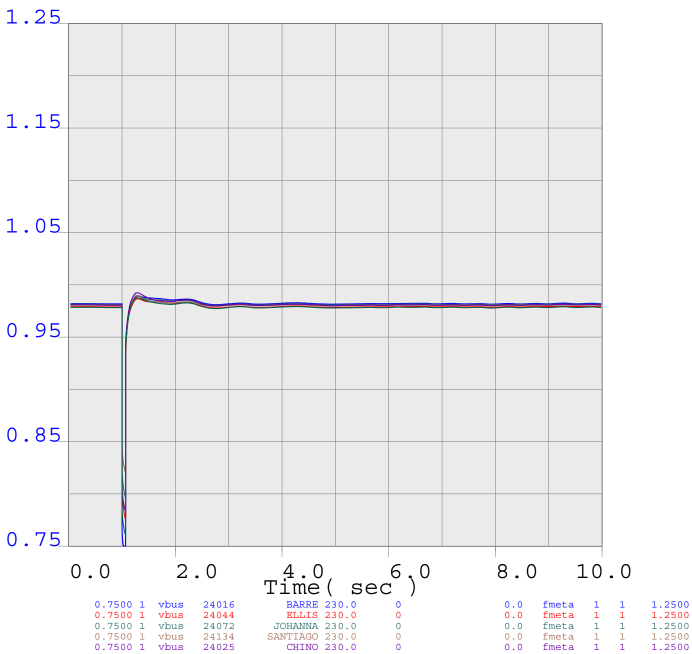
C:\DYTOOLS

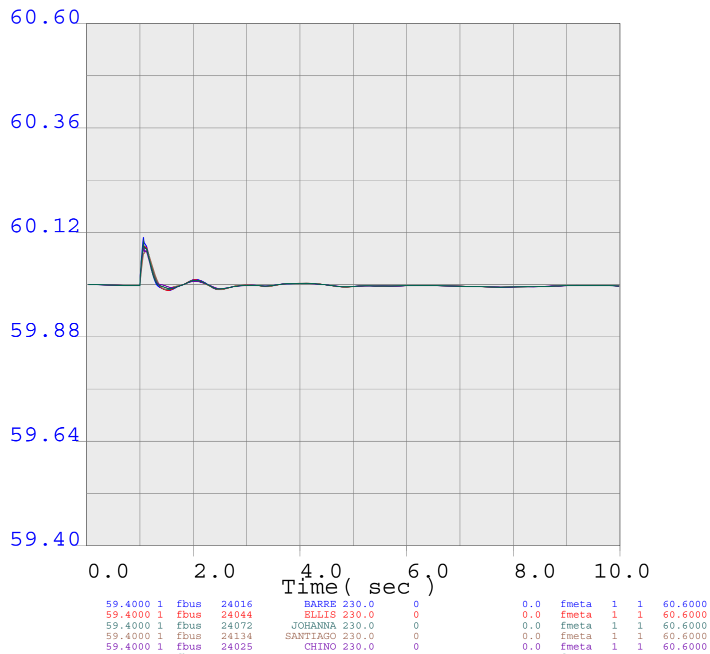
Thu Oct 20 09:01:44 2016

METRO









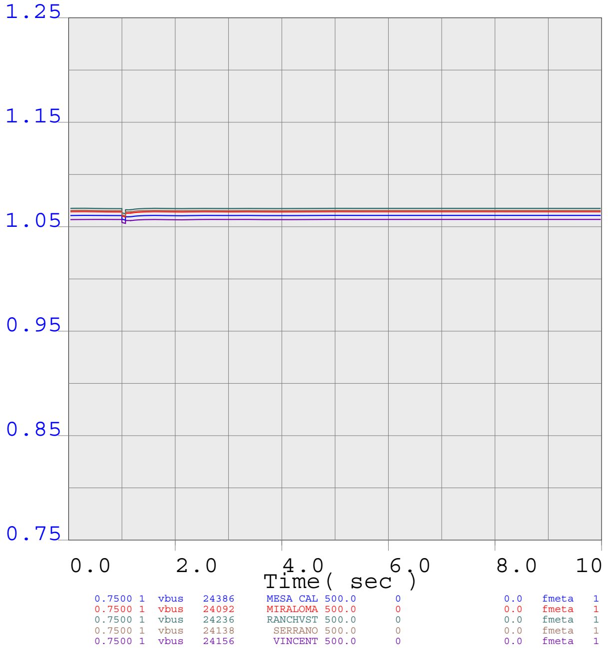
line_1247
Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1
1 MW dispatch Case

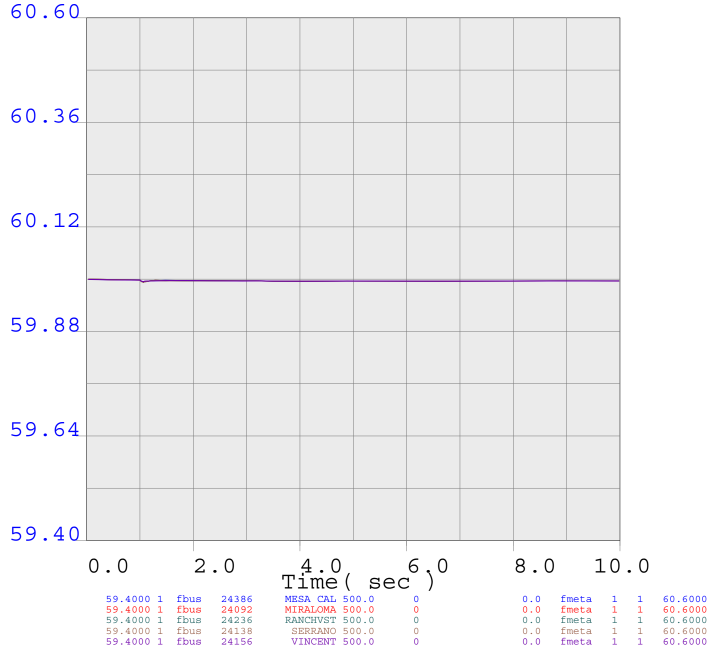
qc9p-line_1247.chf

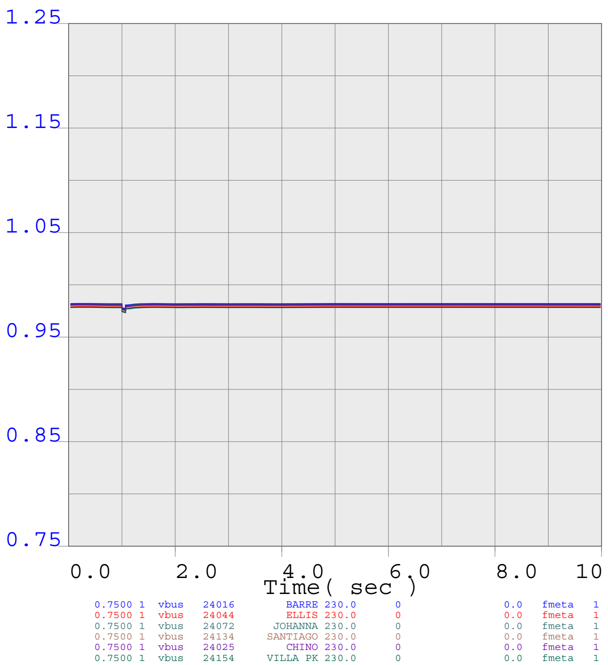
C:\DYTOOLS

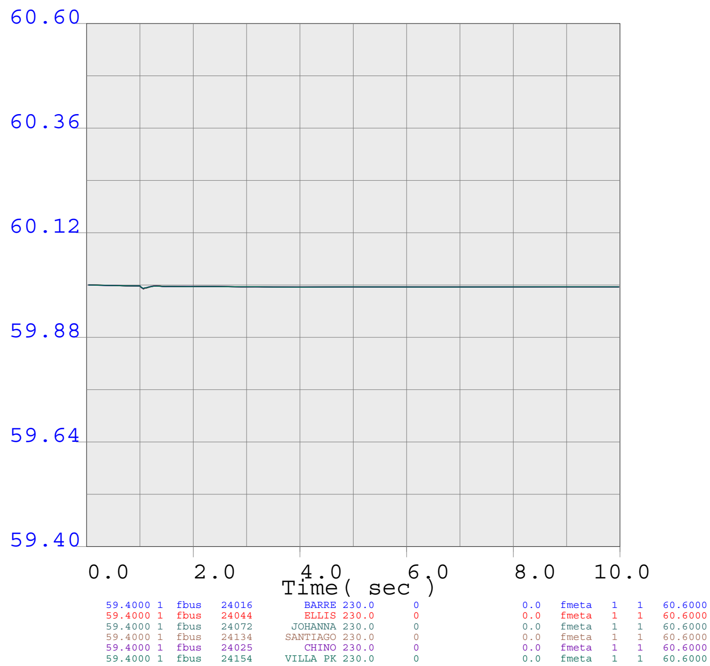
Thu Oct 20 09:01:46 2016

METRO









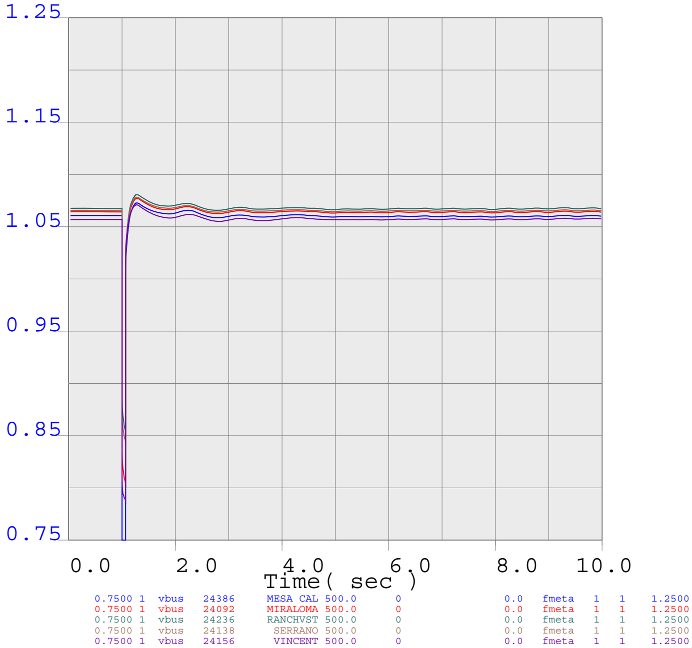
line_1248
Line MESA CAL 230.0 to MESACALS 230.0 Circuit BT
1 MW dispatch Case

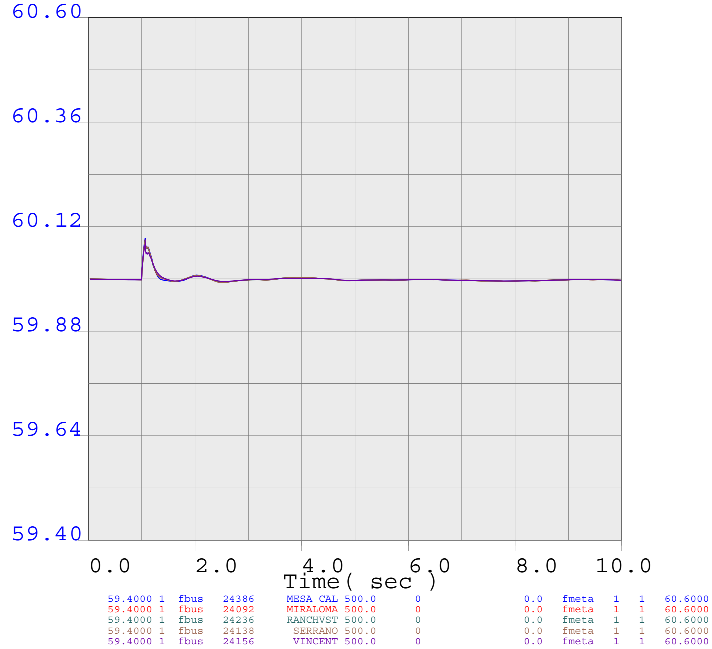
qc9p-line_1248.chf

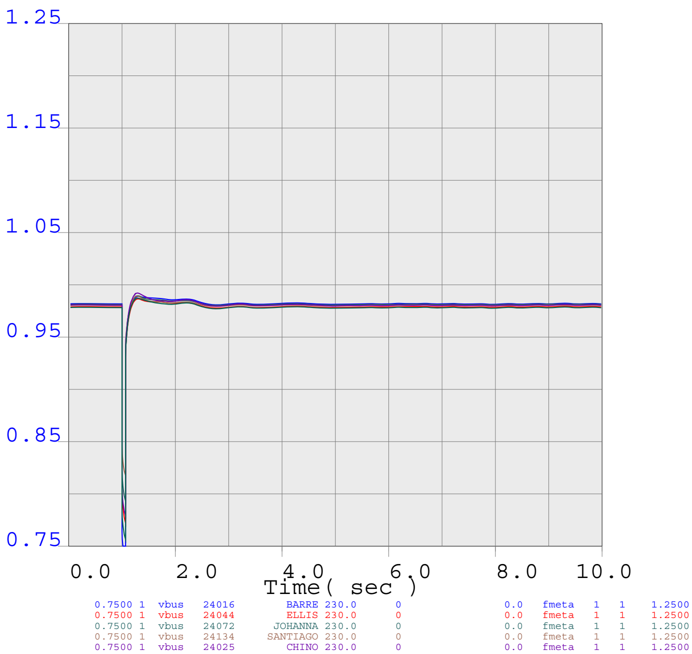
C:\DYTOOLS

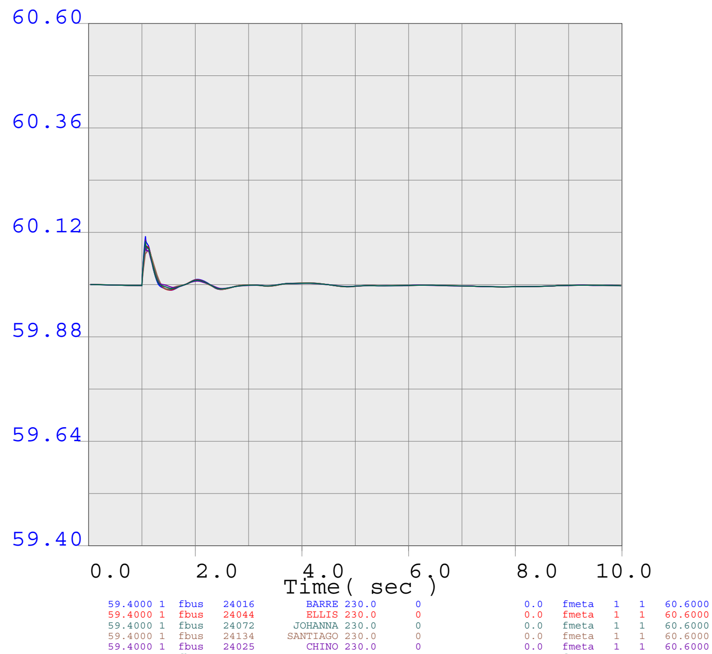
Thu Oct 20 09:01:48 2016

METRO









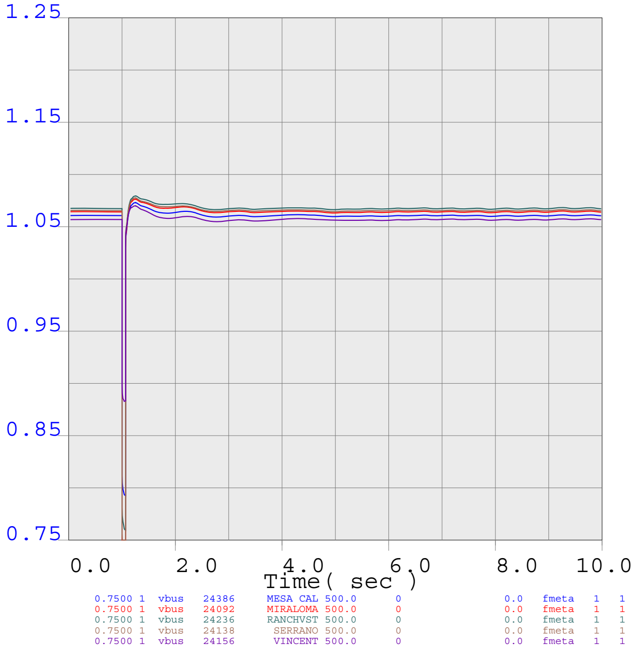
line_1249
Line MESA CAL 230.0 to VINCNT2 230.0 Circuit 2
1 MW dispatch Case

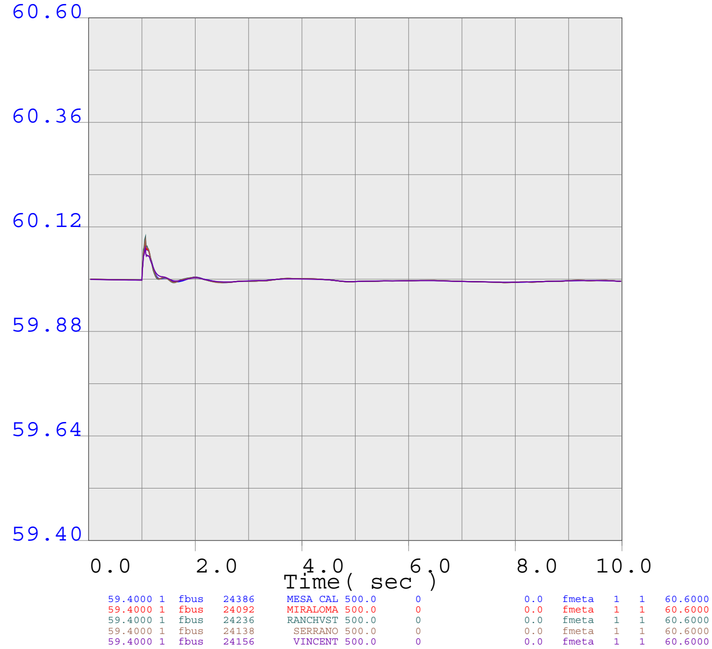
qc9p-line_1249.chf

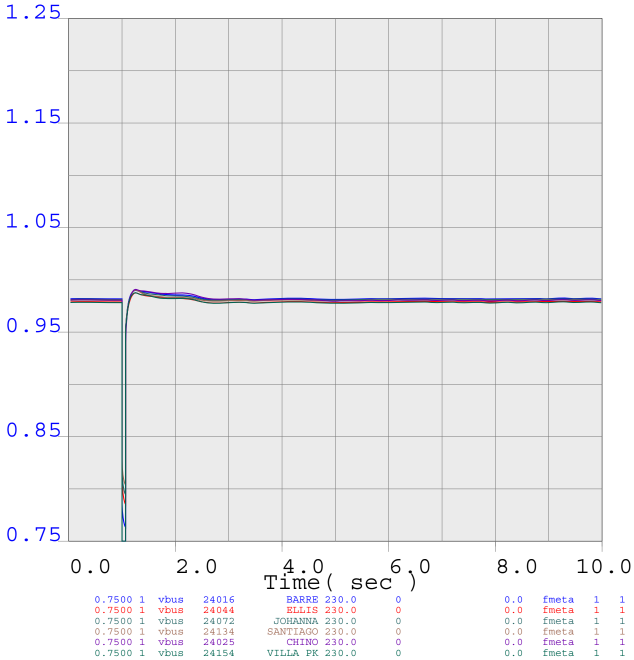
C:\DYTOOLS

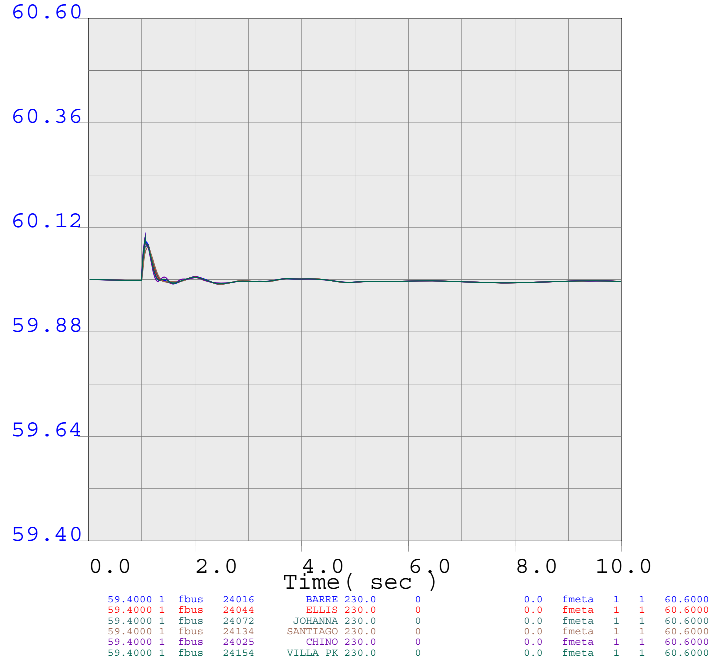
Thu Oct 20 09:01:50 2016

METRO









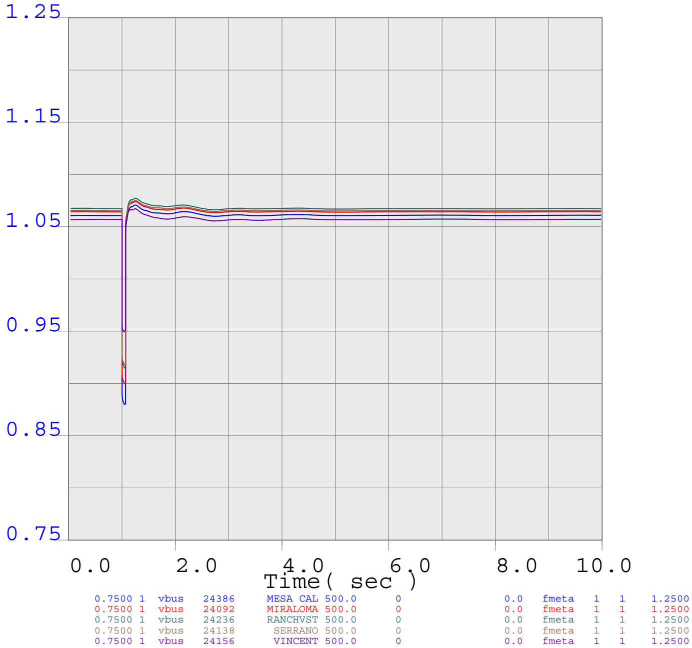
line_1250
Line MIRALOMW 230.0 to WALNUTE 230.0 Circuit 1
1 MW dispatch Case

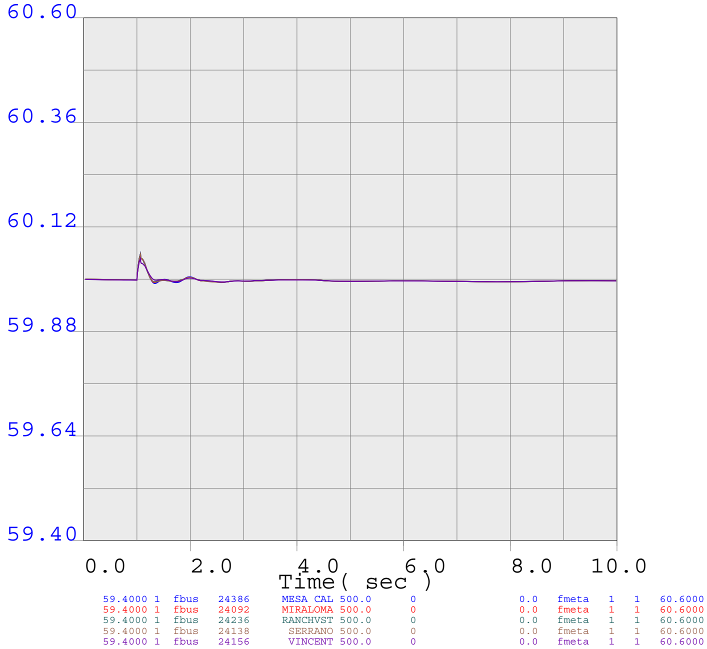
qc9p-line_1250.chf

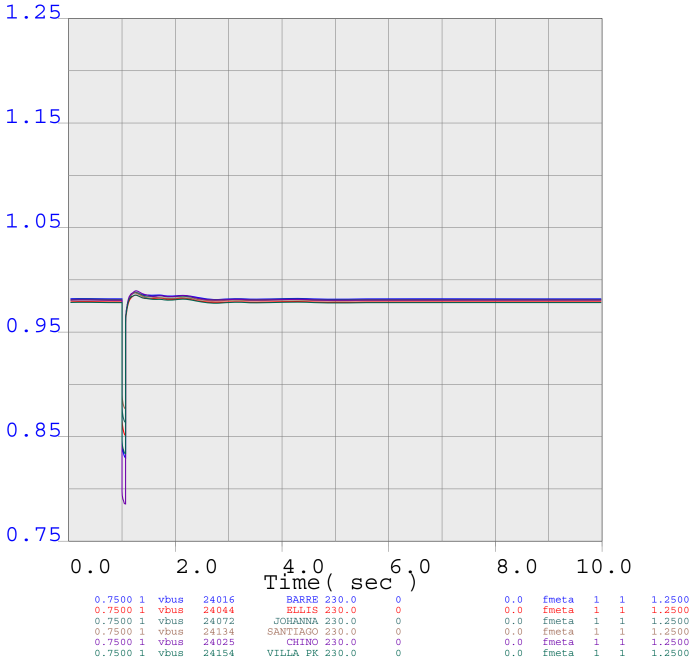
C:\DYTOOLS

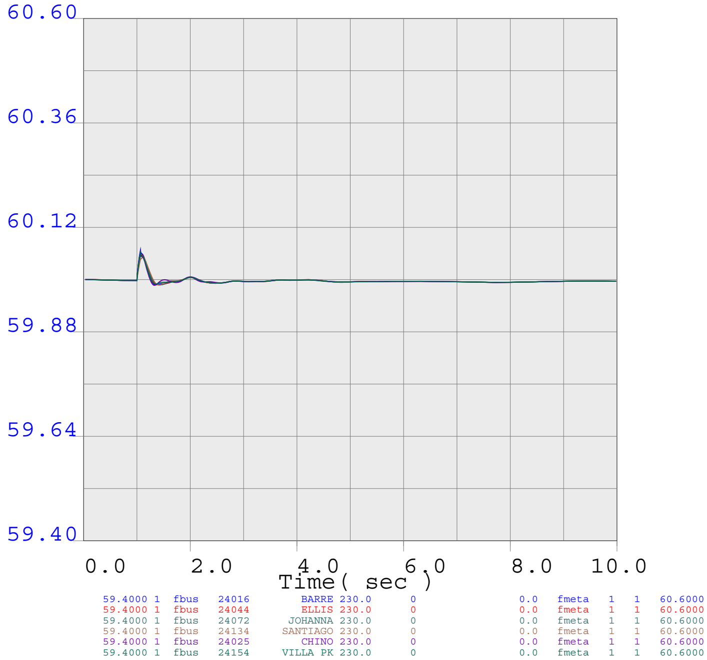
Thu Oct 20 09:01:52 2016

METRO









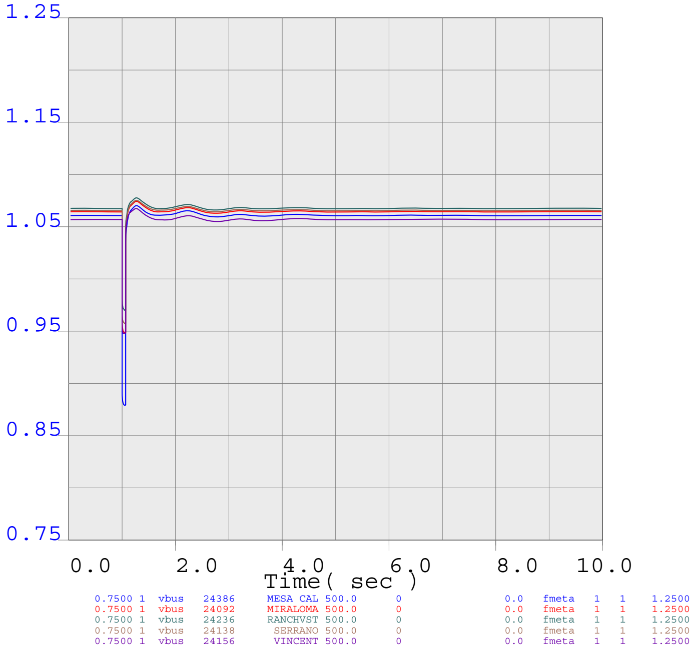
line_1251
Line OLINDA 230.0 to WALNUTE 230.0 Circuit 1
1 MW dispatch Case

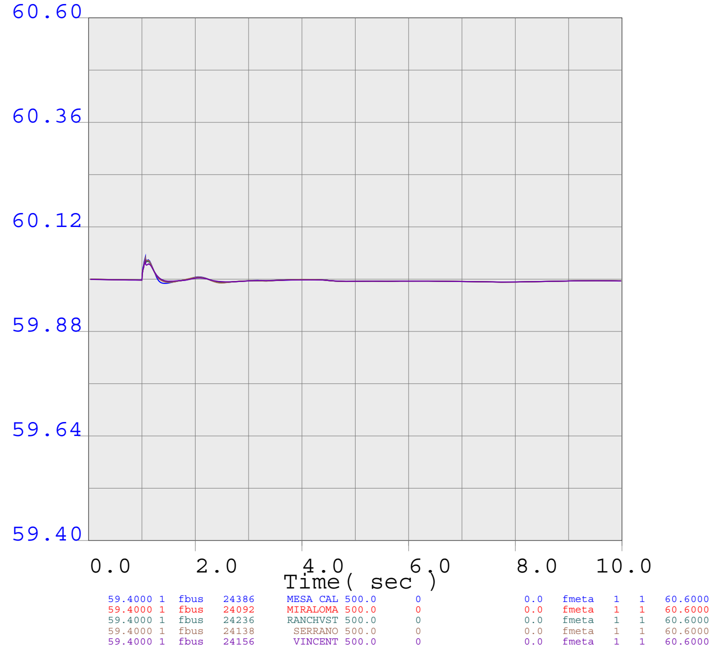
qc9p-line_1251.chf

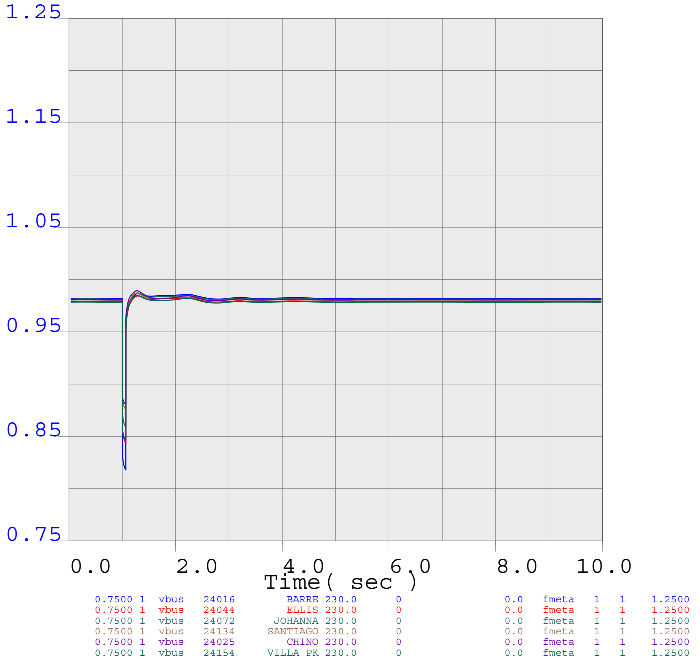
C:\DYTOOLS

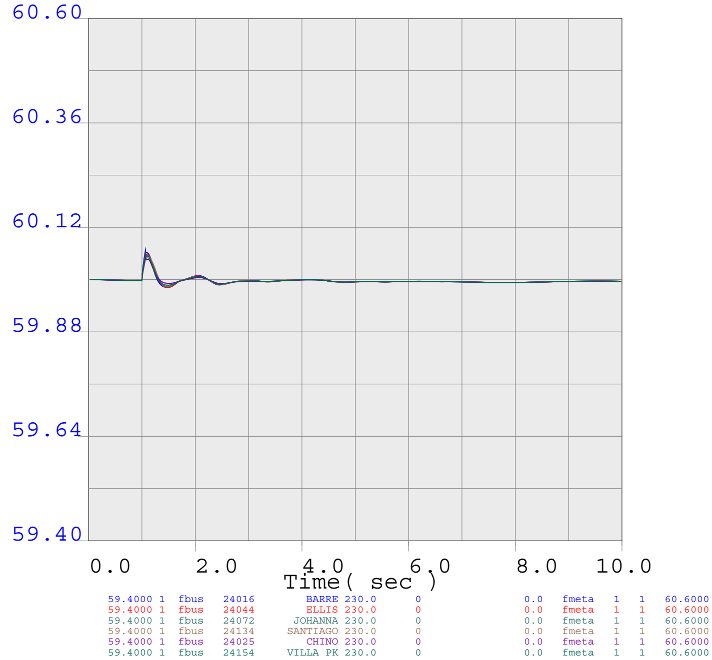
Thu Oct 20 09:01:54 2016

METRO









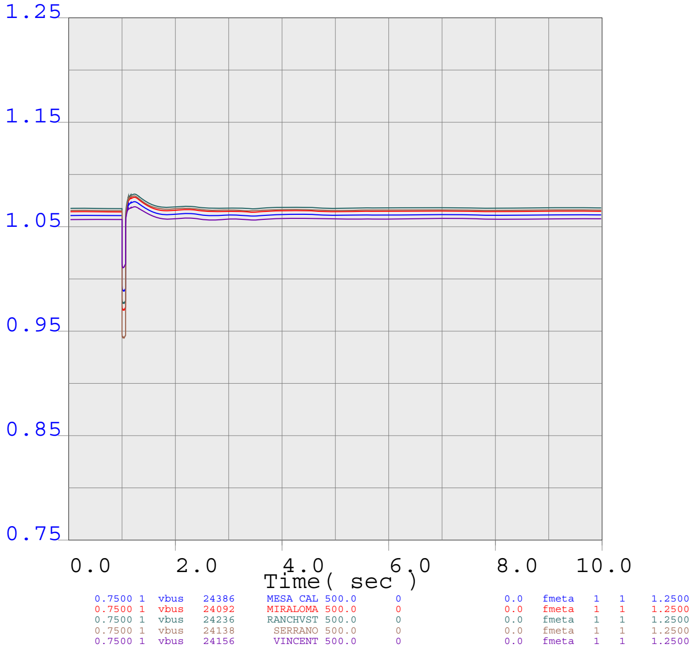
line_1252
Line REDONDO 230.0 to LITEHIPE 230.0 Circuit 1
1 MW dispatch Case

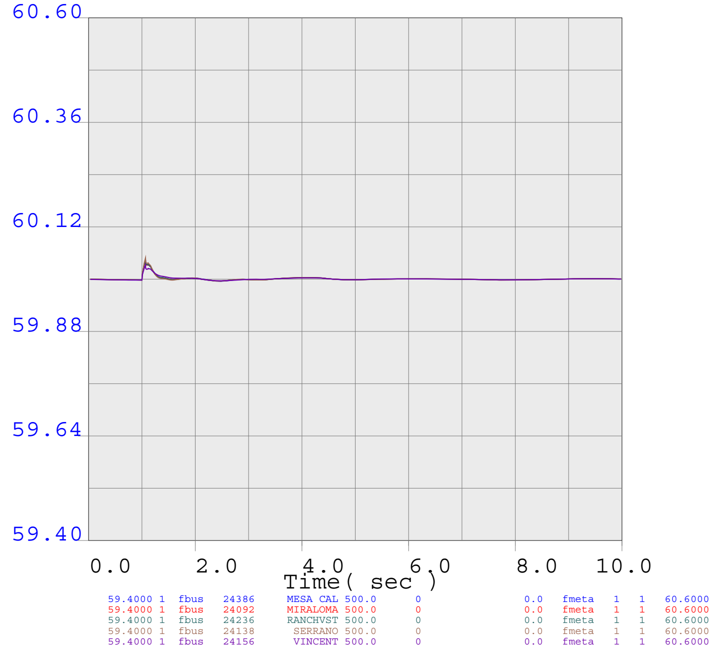
qc9p-line_1252.chf

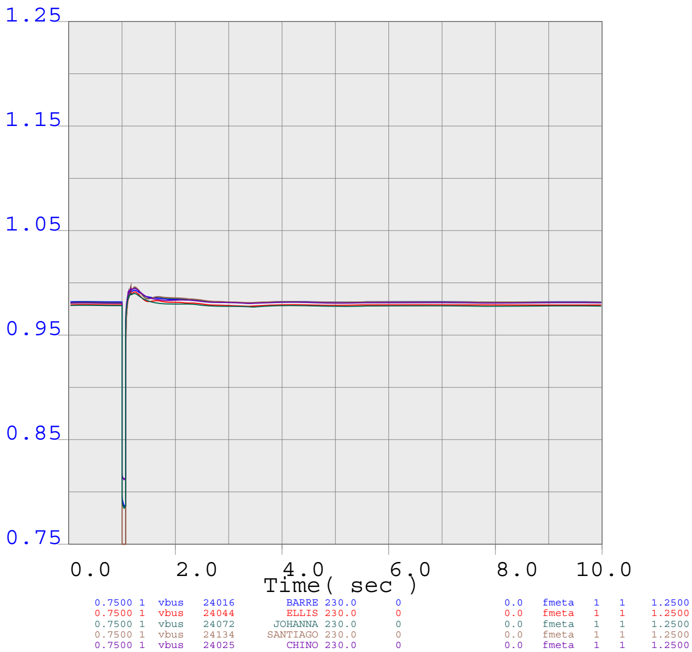
C:\DYTOOLS

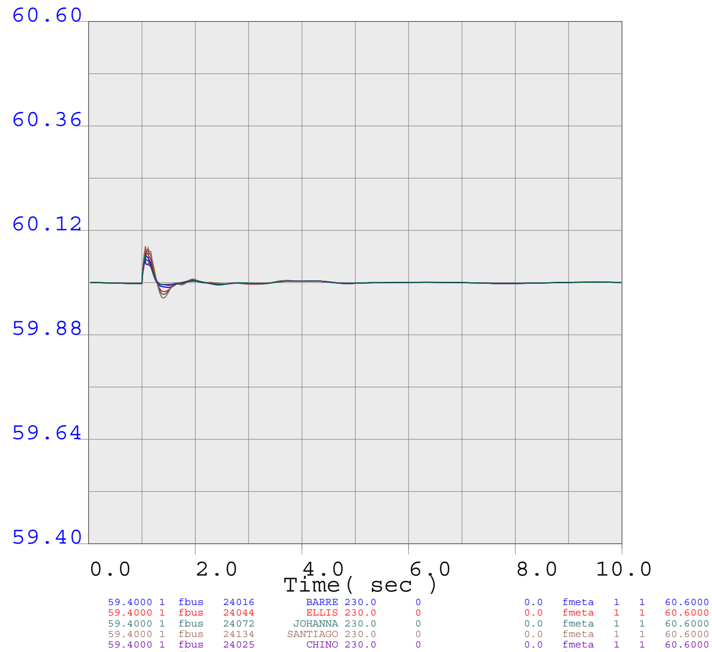
Thu Oct 20 09:01:56 2016

METRO









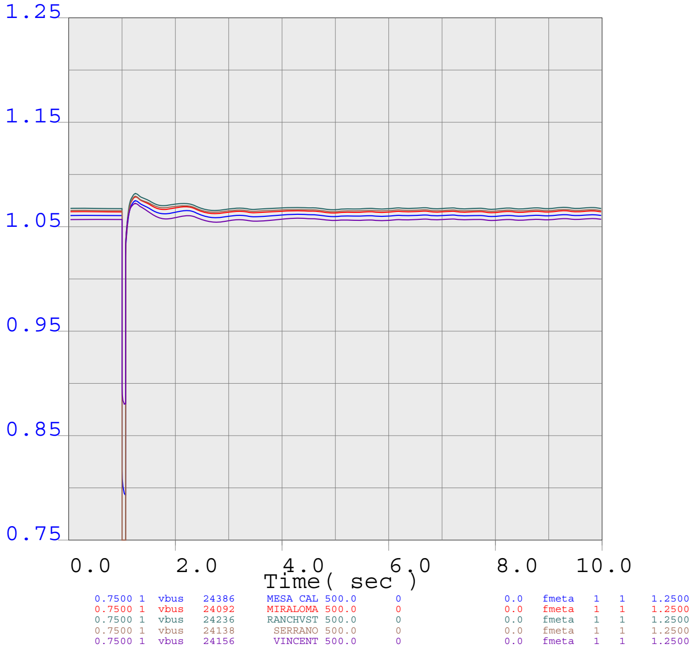
line_1253
Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1
1 MW dispatch Case

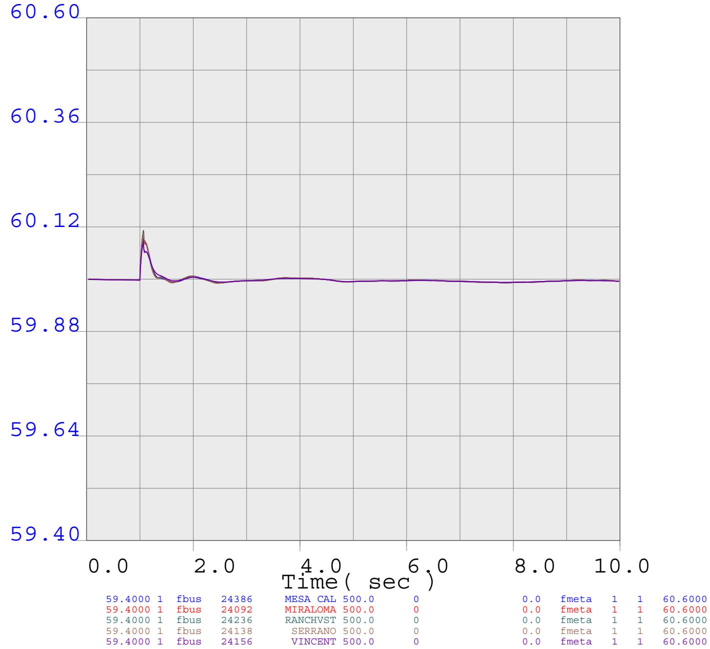
qc9p-line_1253.chf

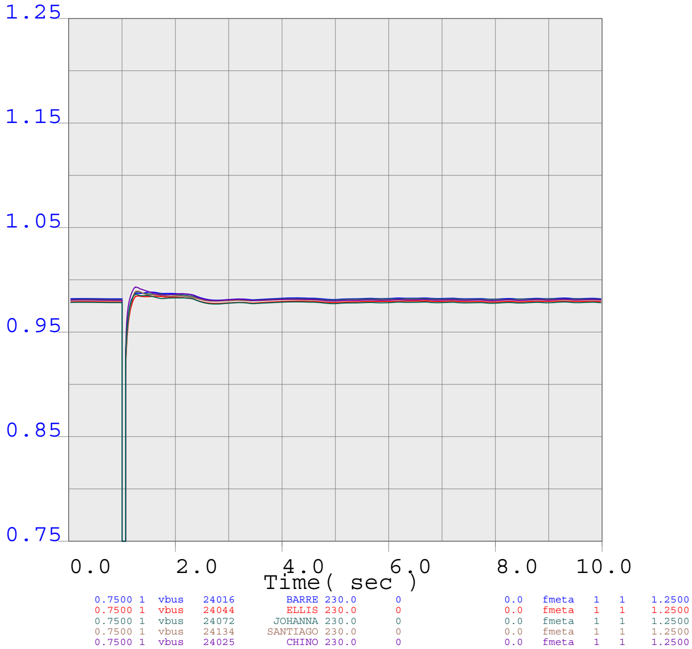
C:\DYTOOLS

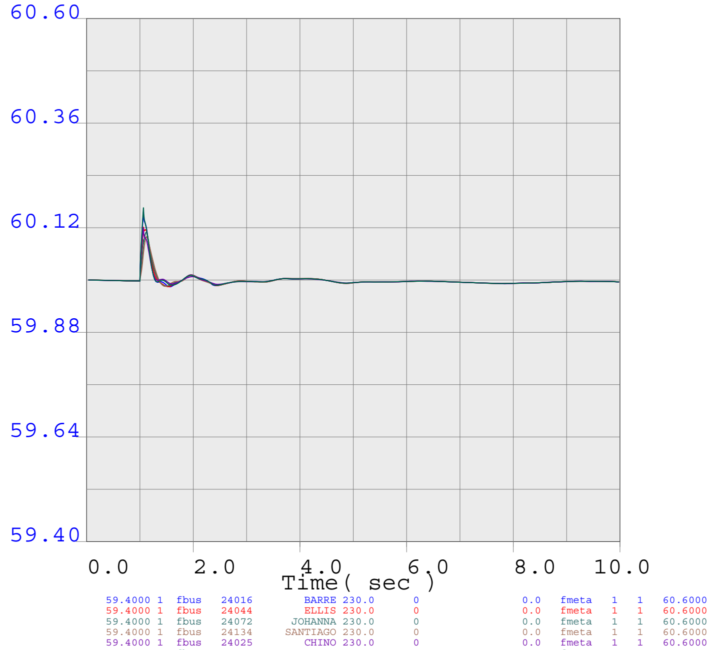
Thu Oct 20 09:01:58 2016

METRO









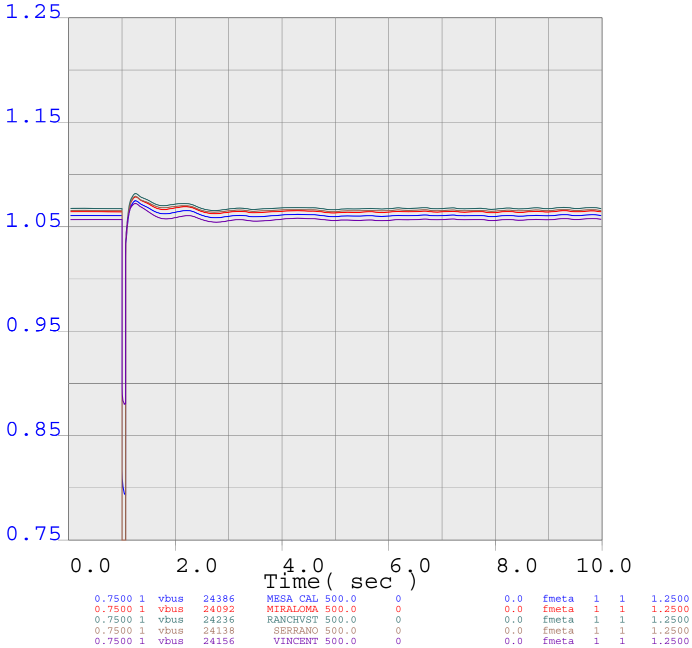
line_1254
Line SERRANO 230.0 to VILLA PK 230.0 Circuit 1
1 MW dispatch Case

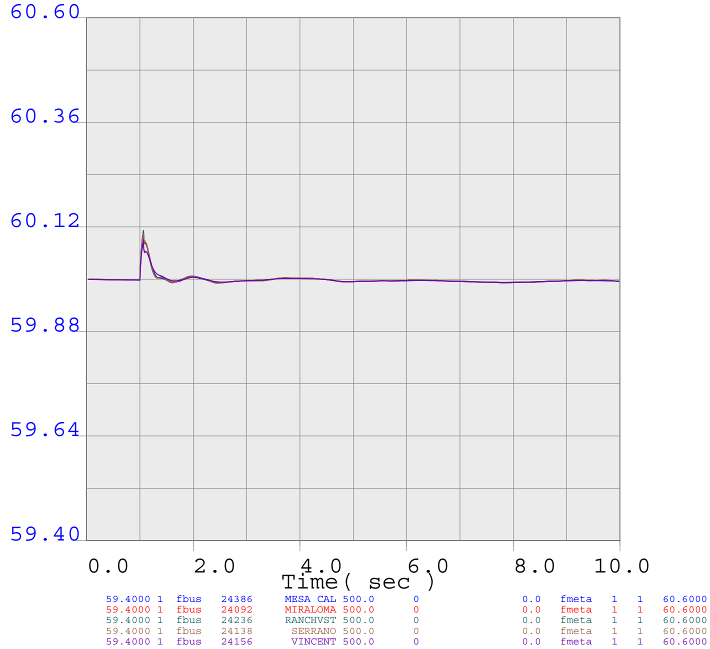
qc9p-line_1254.chf

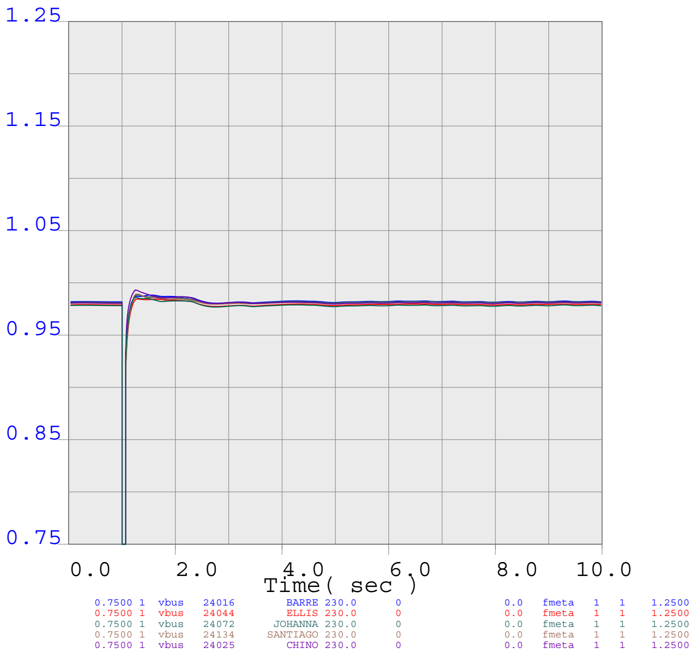
C:\DYTOOLS

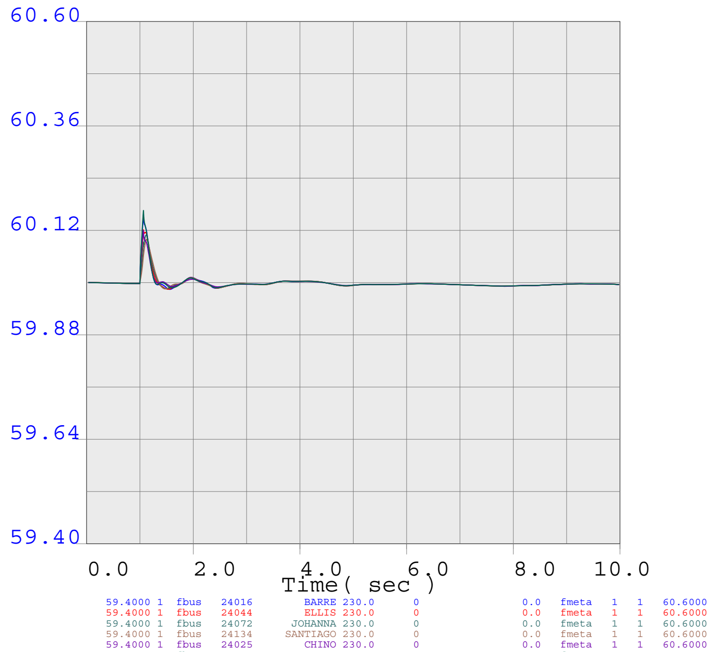
Thu Oct 20 09:02:00 2016

METRO









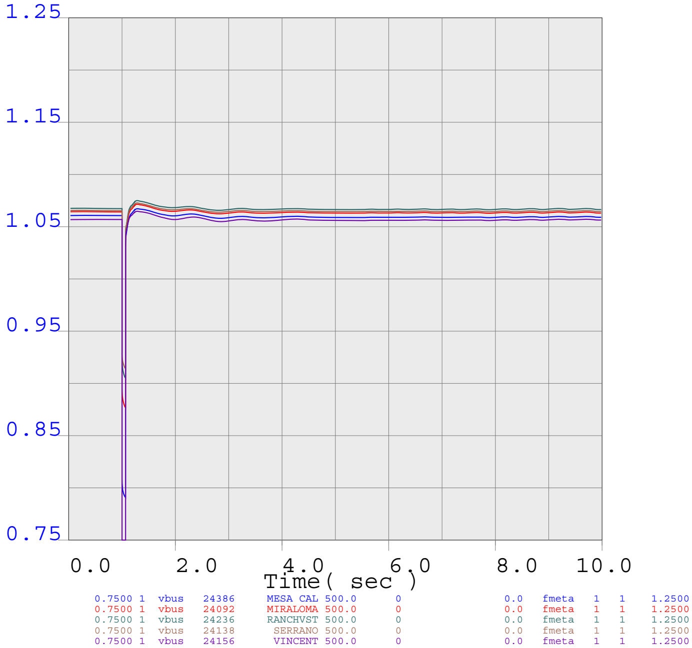
line_1255
Line SERRANO 230.0 to VILLA PK 230.0 Circuit 2
1 MW dispatch Case

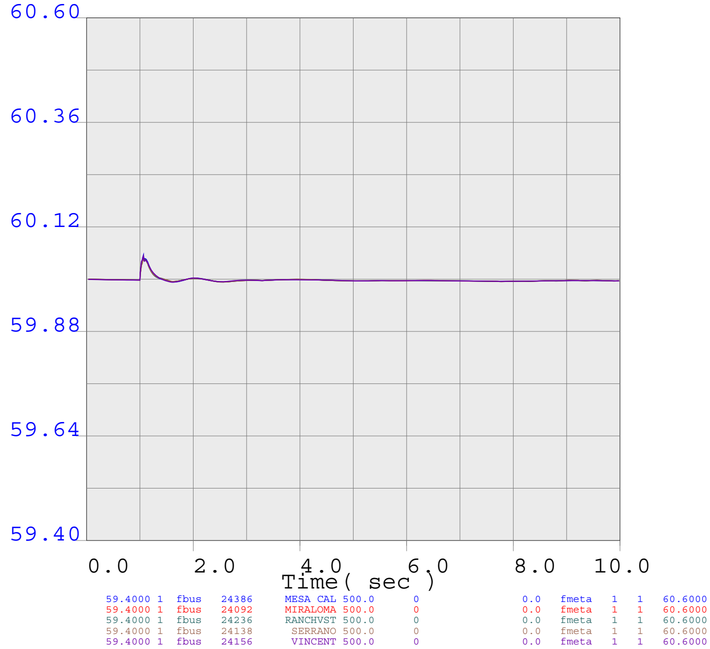
qc9p-line_1255.chf

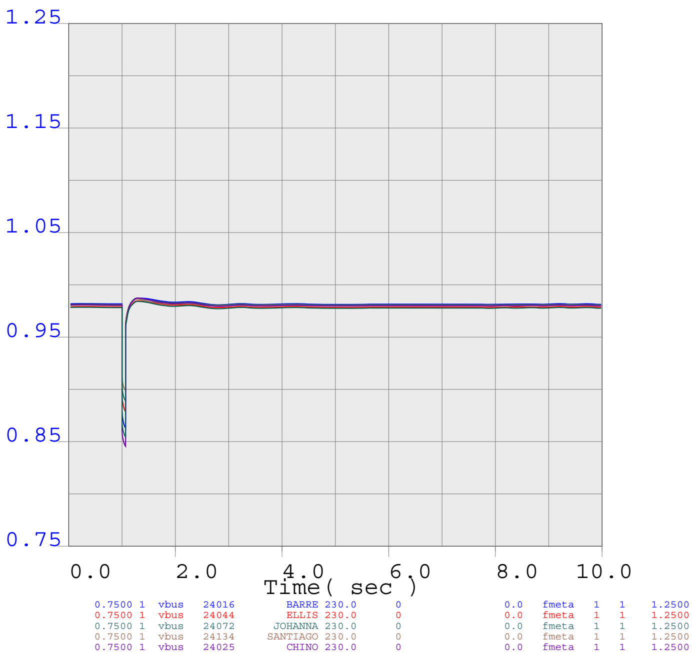
C:\DYTOOLS

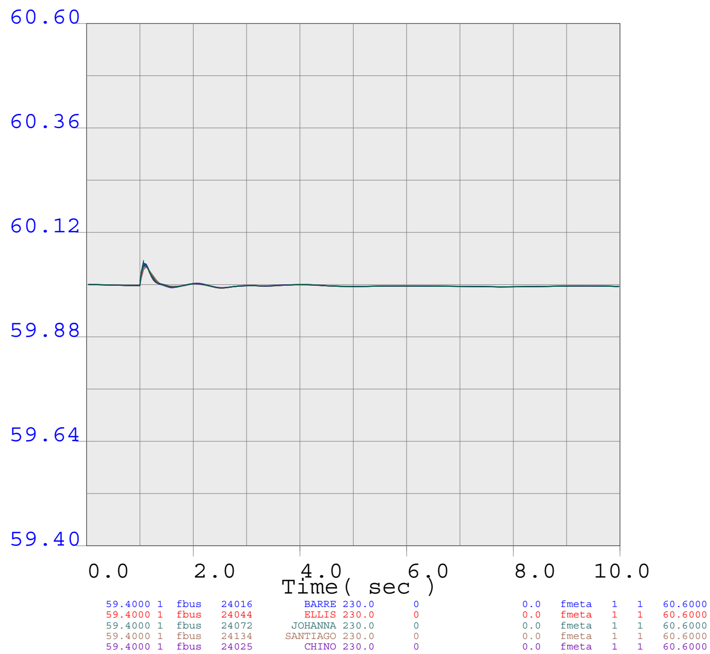
Thu Oct 20 09:02:02 2016

METRO









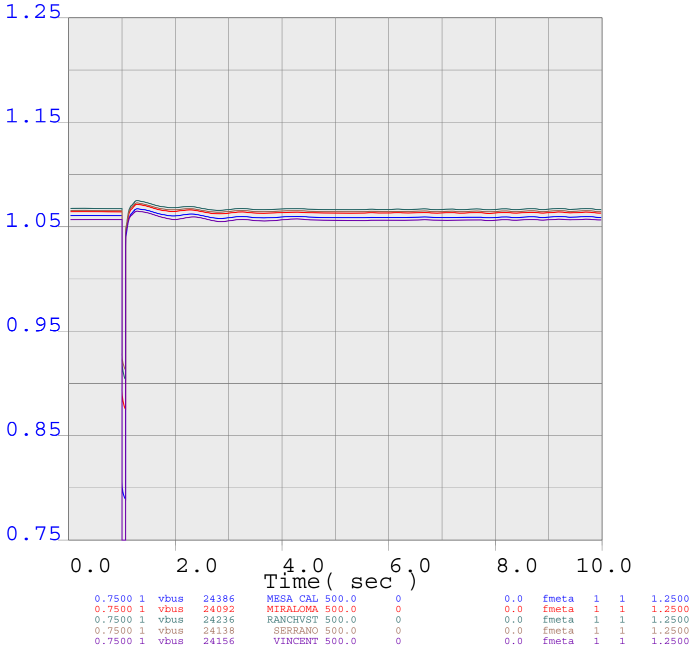
line_1256
Line VINCENT 230.0 to RIOHONDO 230.0 Circuit 1
1 MW dispatch Case

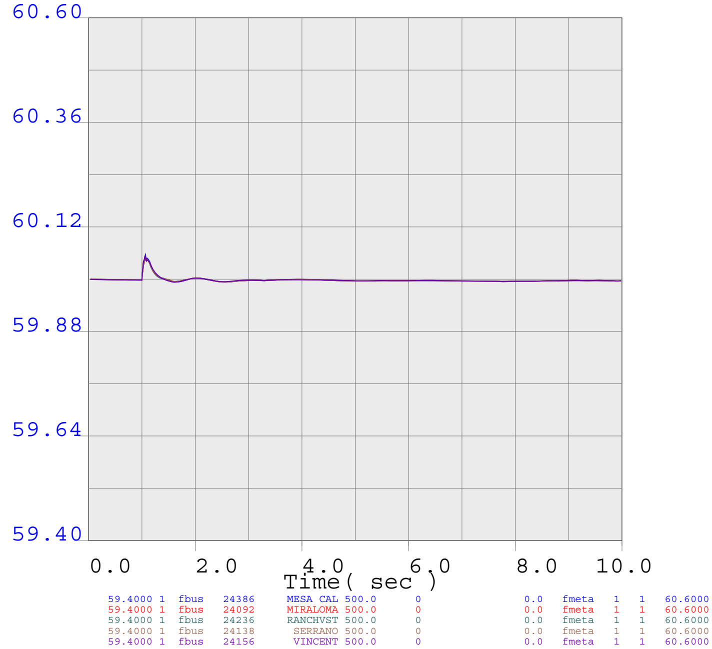
qc9p-line_1256.chf

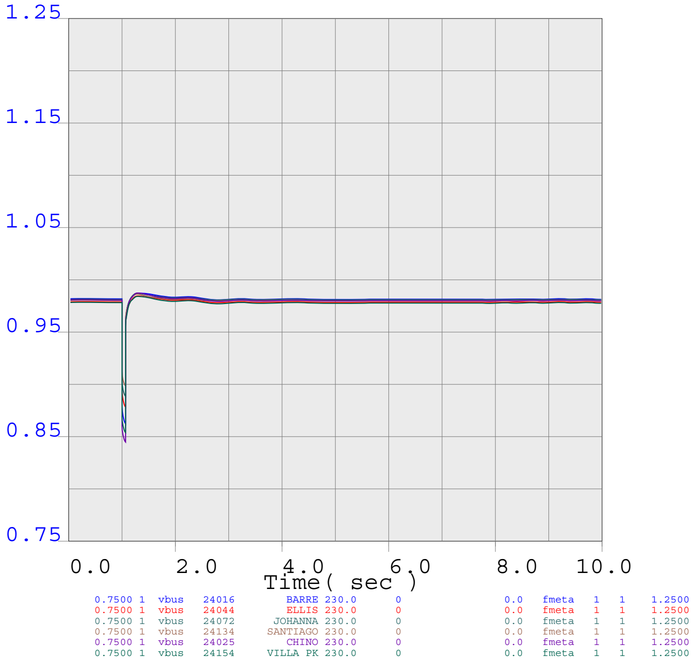
C:\DYTOOLS

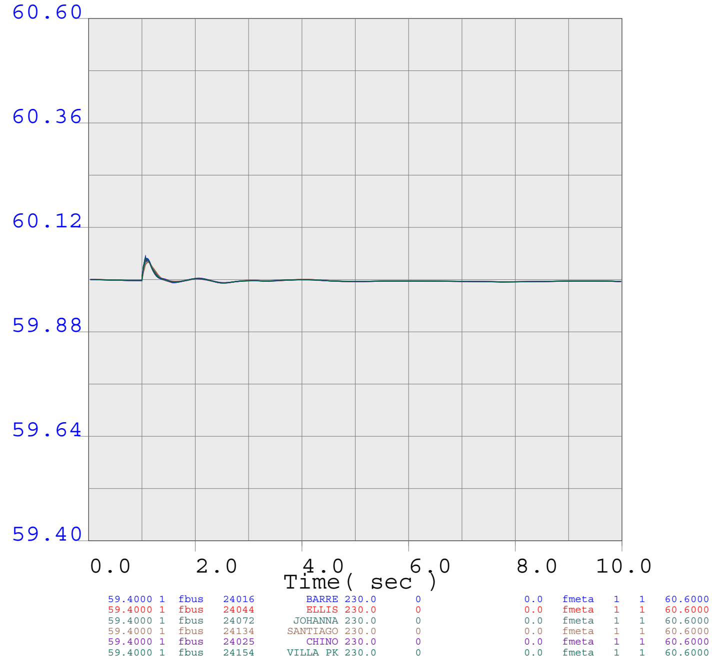
Thu Oct 20 09:02:04 2016

METRO









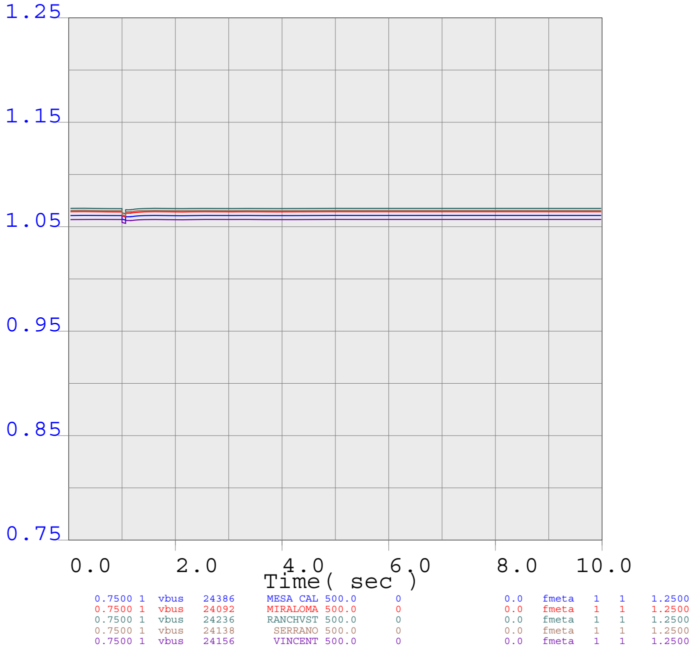
line_1257
Line VINCENT 230.0 to RIOHONDO 230.0 Circuit 2
1 MW dispatch Case

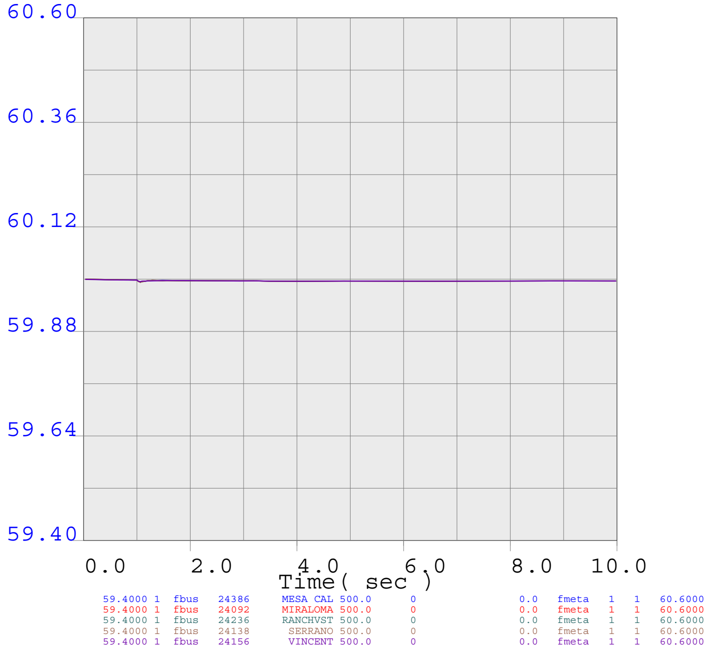
qc9p-line_1257.chf

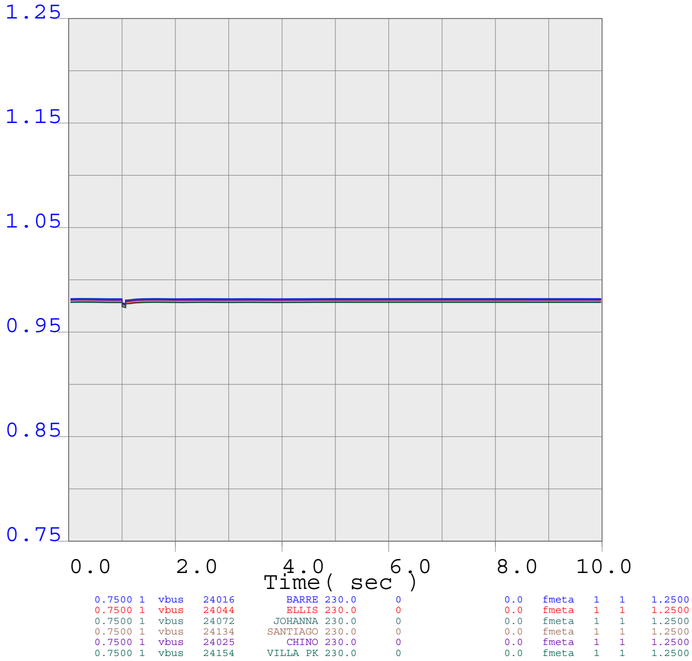
C:\DYTOOLS

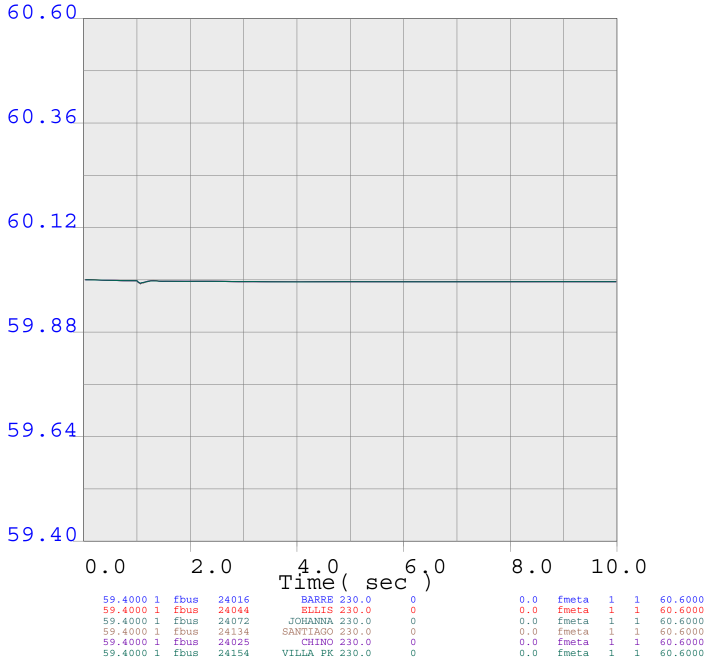
Thu Oct 20 09:02:06 2016

METRO









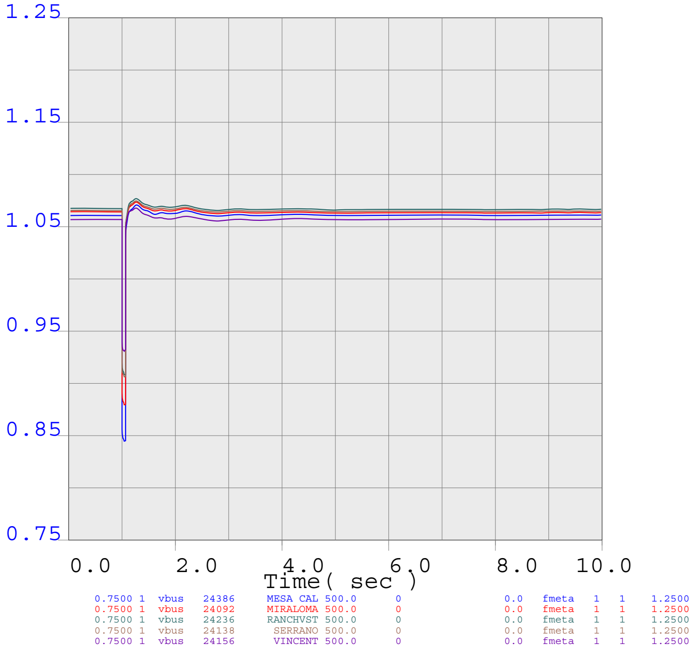
line_1259
Line VINCENT 230.0 to VINCNT2 230.0 Circuit BT
1 MW dispatch Case

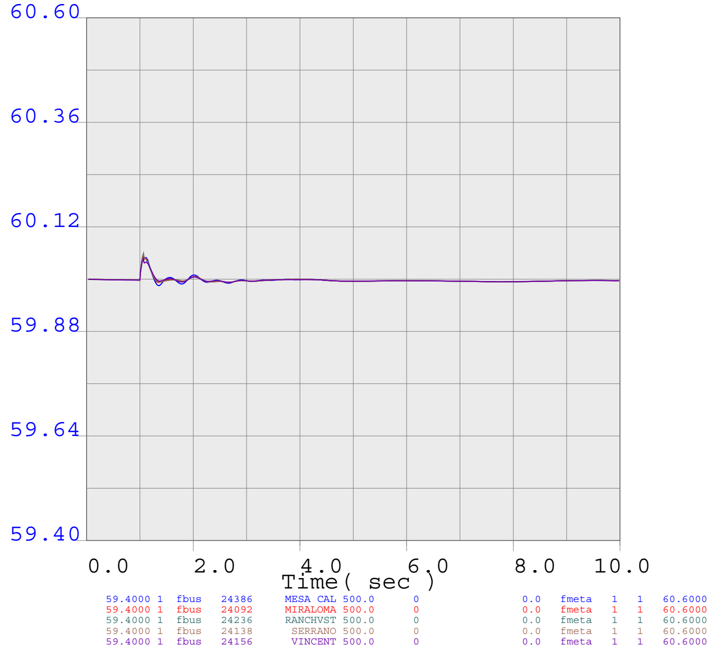
qc9p-line_1259.chf

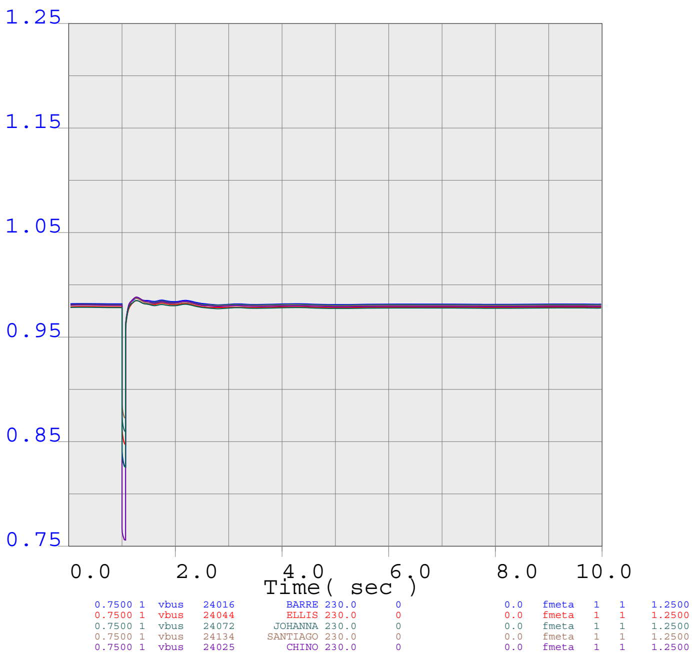
C:\DYTOOLS

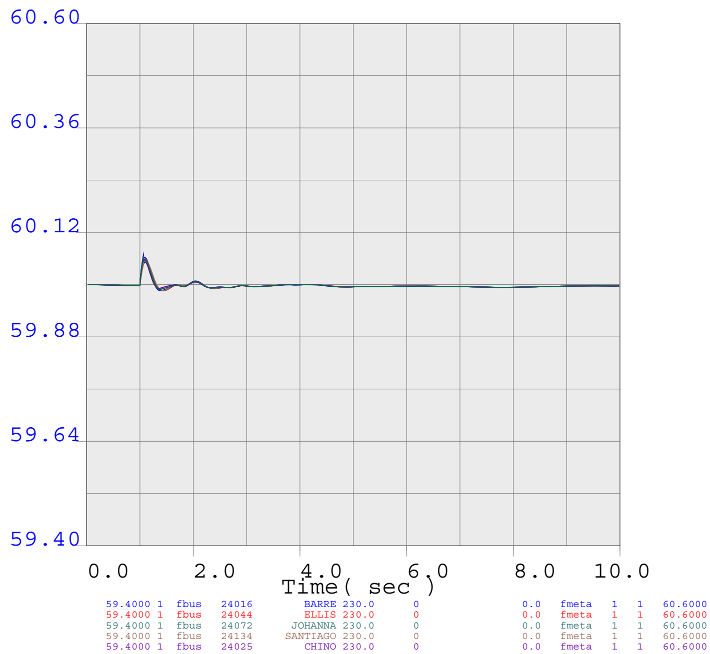
Thu Oct 20 09:02:08 2016

METRO









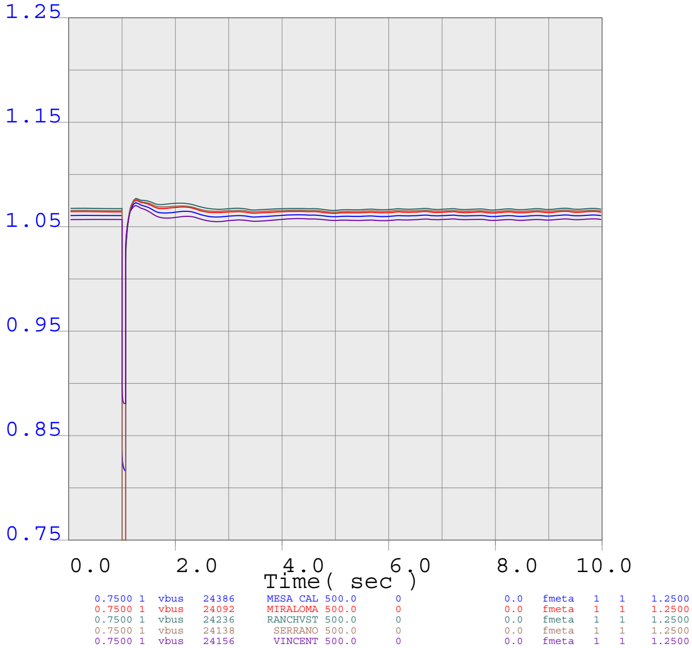
line_1261
Line WALNUTE 230.0 to WALNUTW 230.0 Circuit 1
1 MW dispatch Case

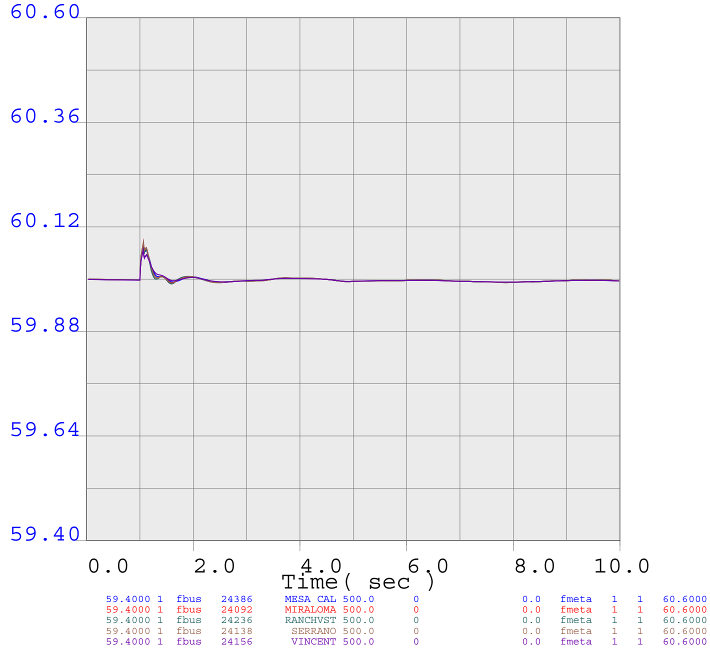
qc9p-line_1261.chf

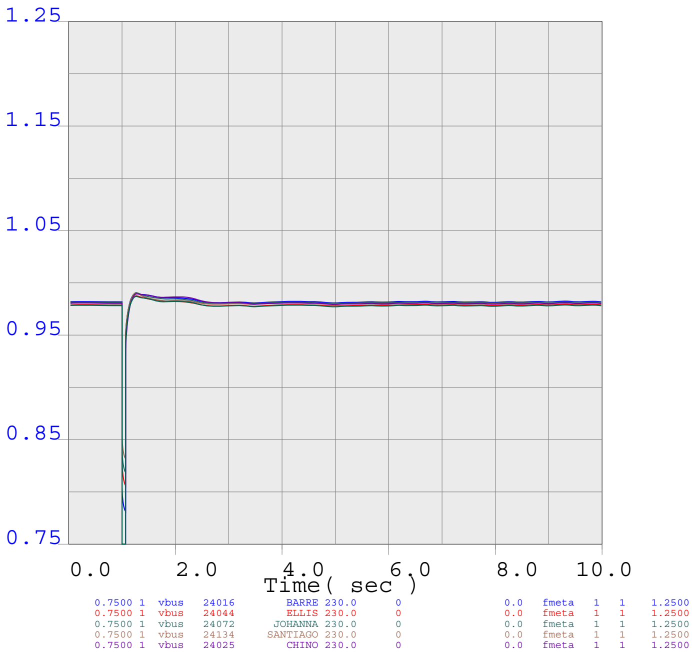
C:\DYTOOLS

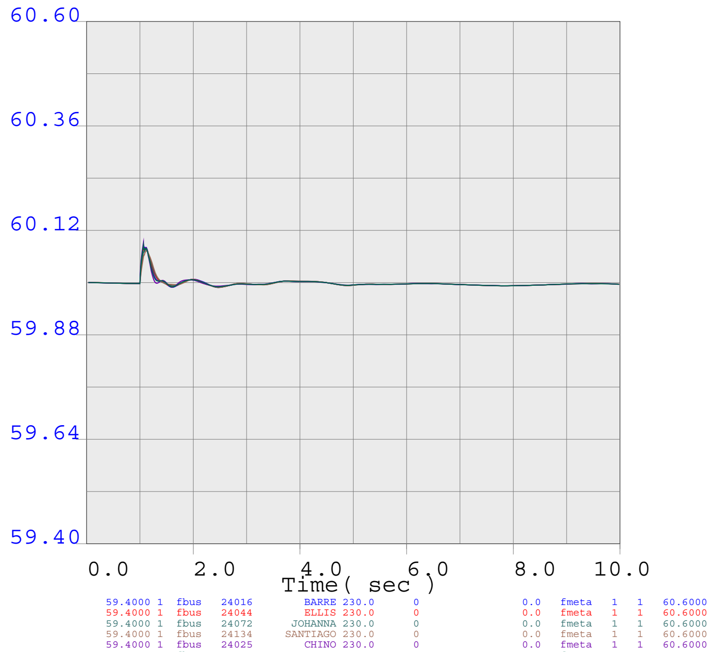
Thu Oct 20 09:02:10 2016

METRO









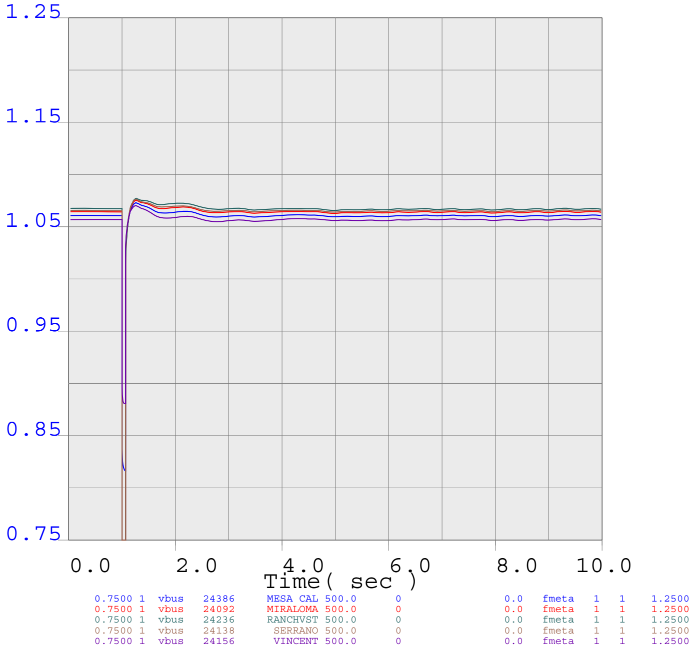
line_1262
Line RANCHVST 230.0 to PADUA 230.0 Circuit 1
1 MW dispatch Case

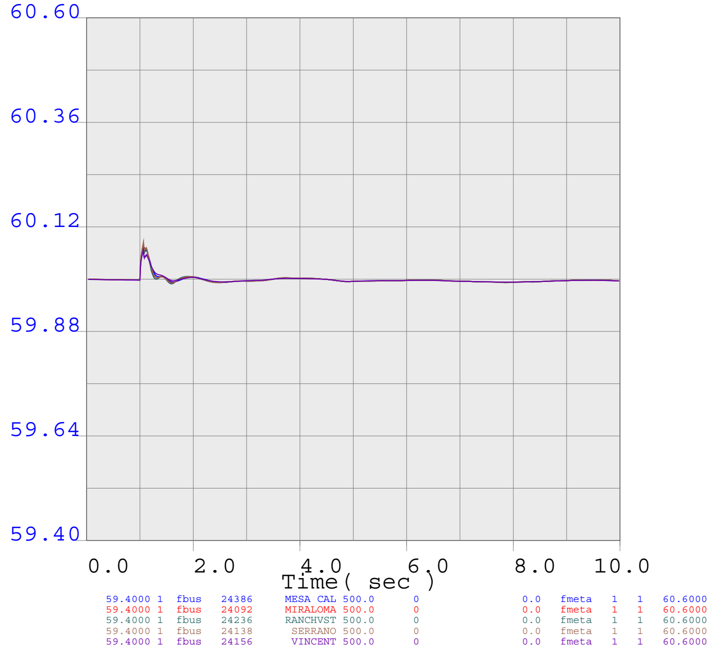
qc9p-line_1262.chf

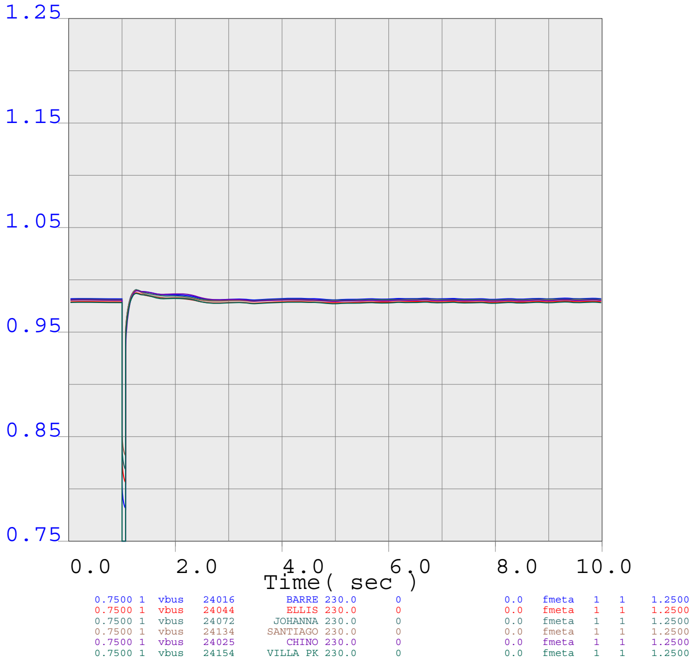
C:\DYTOOLS

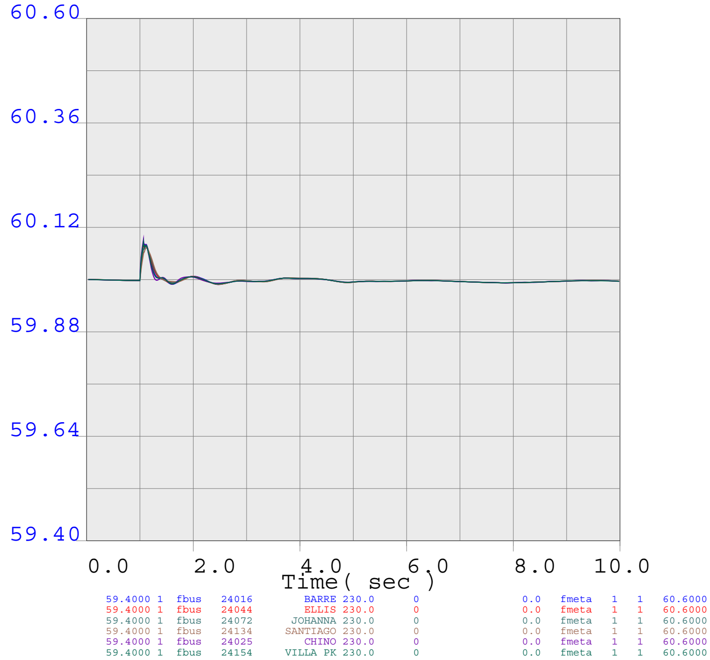
Thu Oct 20 09:02:12 2016

METRO









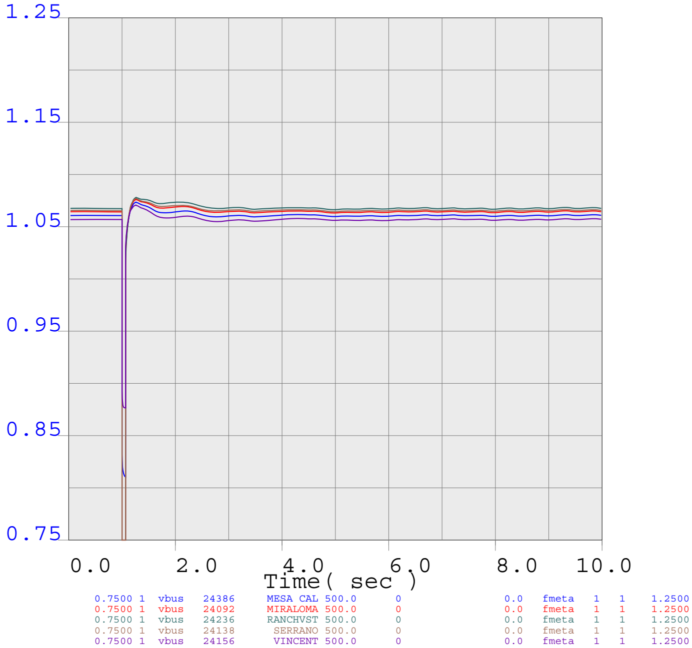
line_1263
Line RANCHVST 230.0 to PADUA 230.0 Circuit 2
1 MW dispatch Case

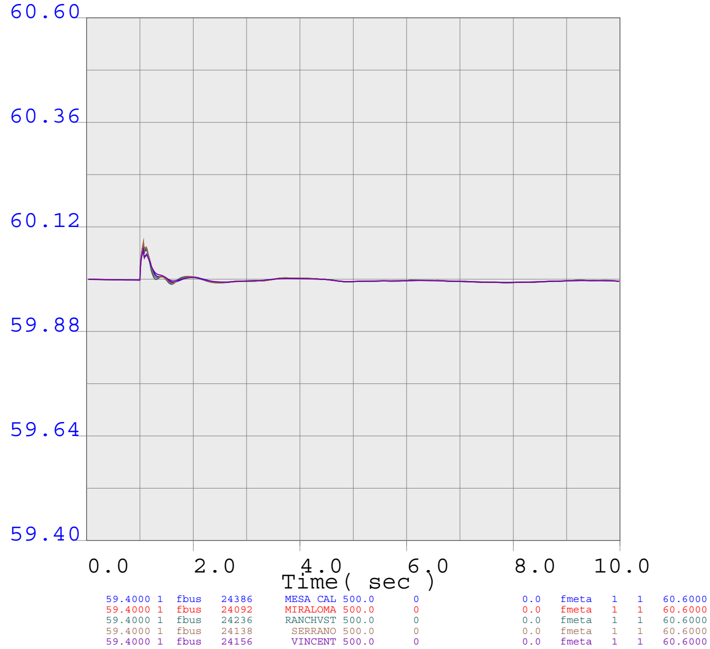
qc9p-line_1263.chf

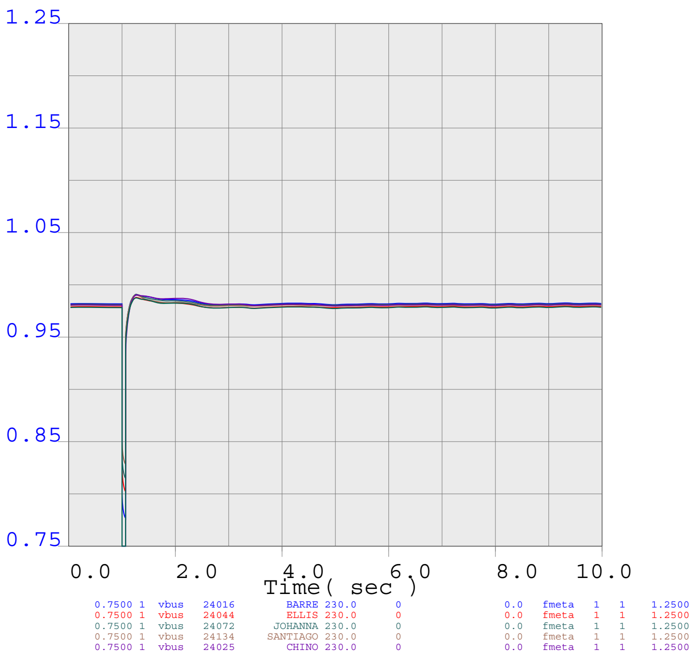
C:\DYTOOLS

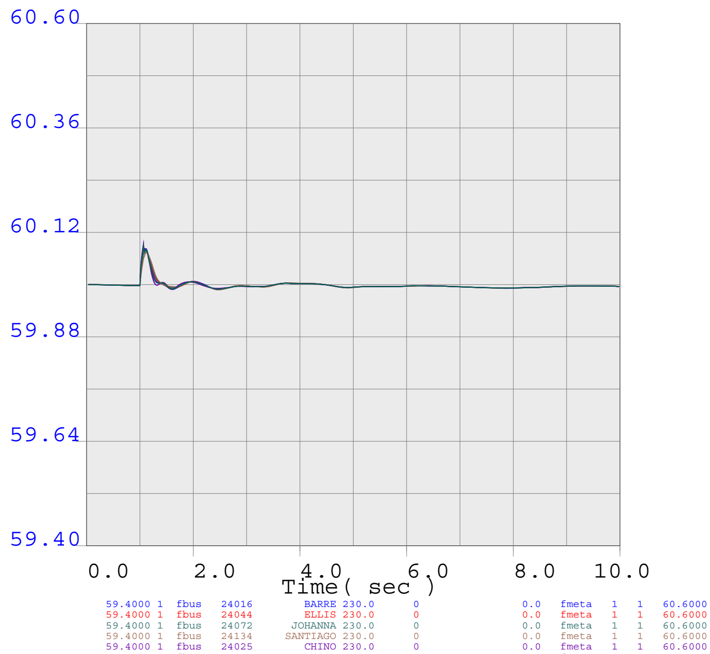
Thu Oct 20 09:02:14 2016

METRO









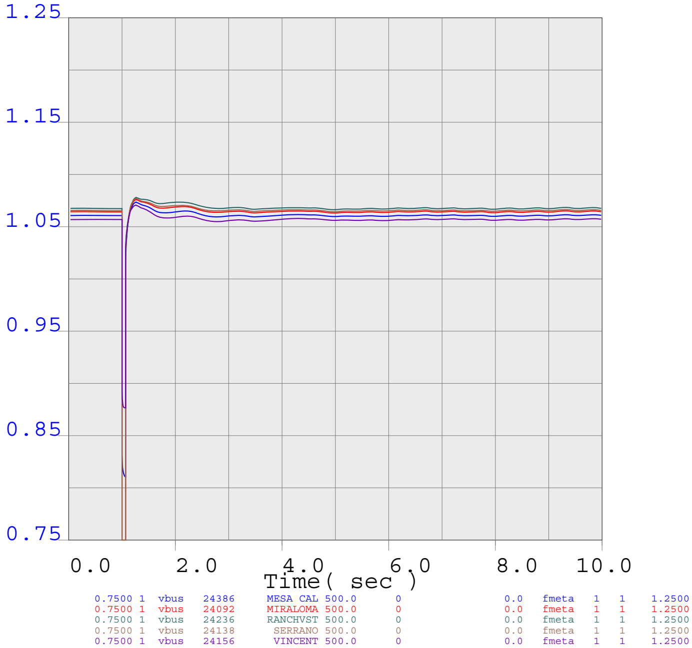
line_1264
Line RANCHVST 230.0 to MIRALOME 230.0 Circuit 1
1 MW dispatch Case

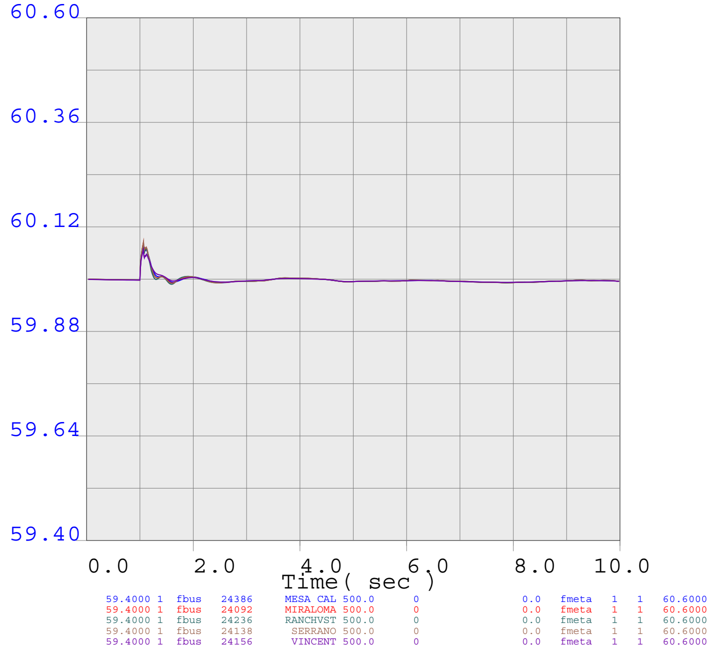
qc9p-line_1264.chf

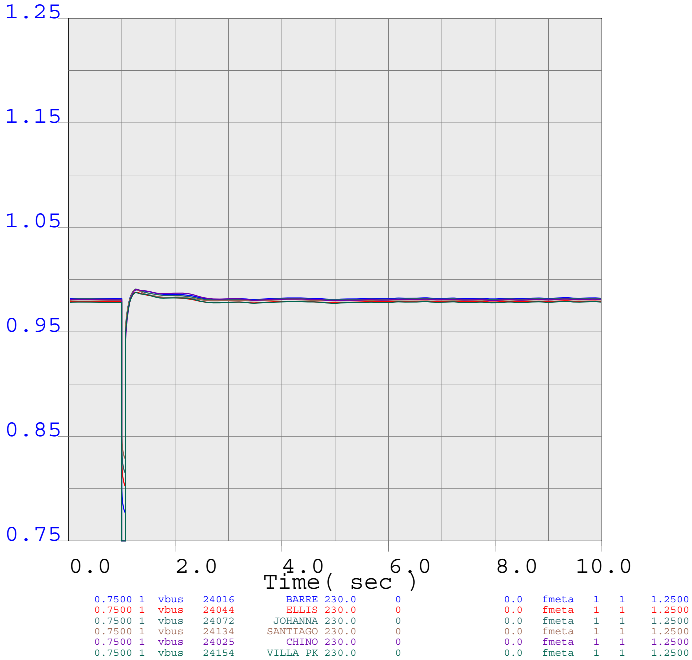
C:\DYTOOLS

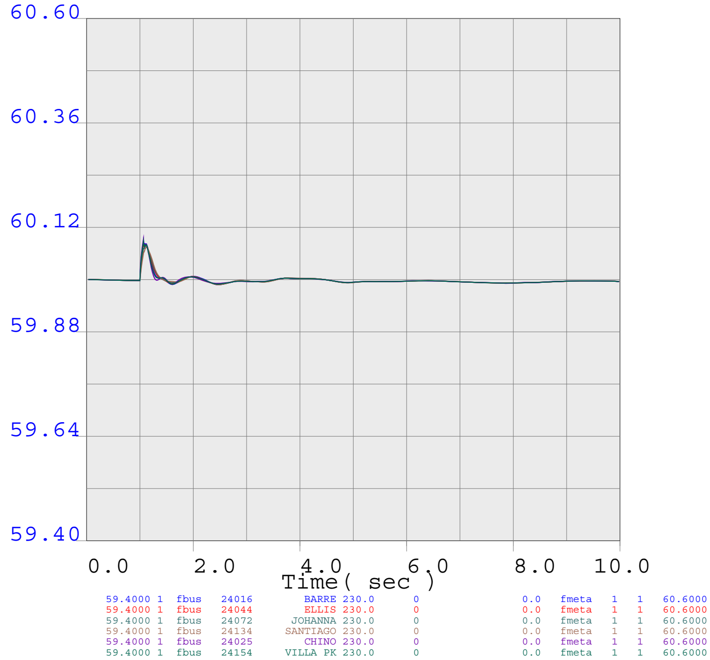
Thu Oct 20 09:02:16 2016

METRO









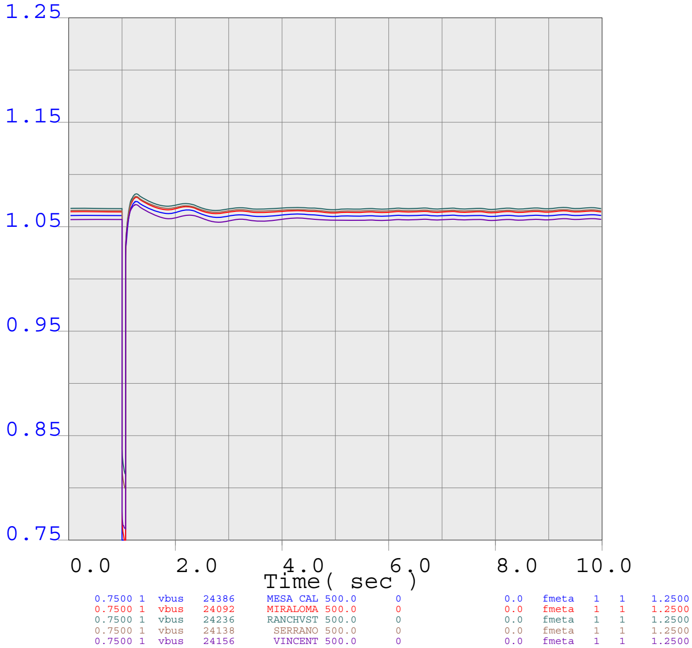
line_1265
Line RANCHVST 230.0 to MIRALOME 230.0 Circuit 2
1 MW dispatch Case

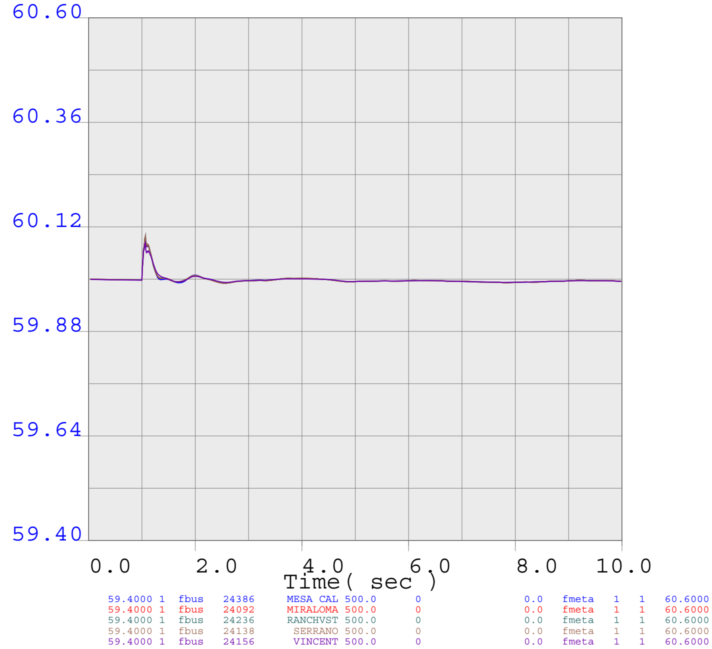
qc9p-line_1265.chf

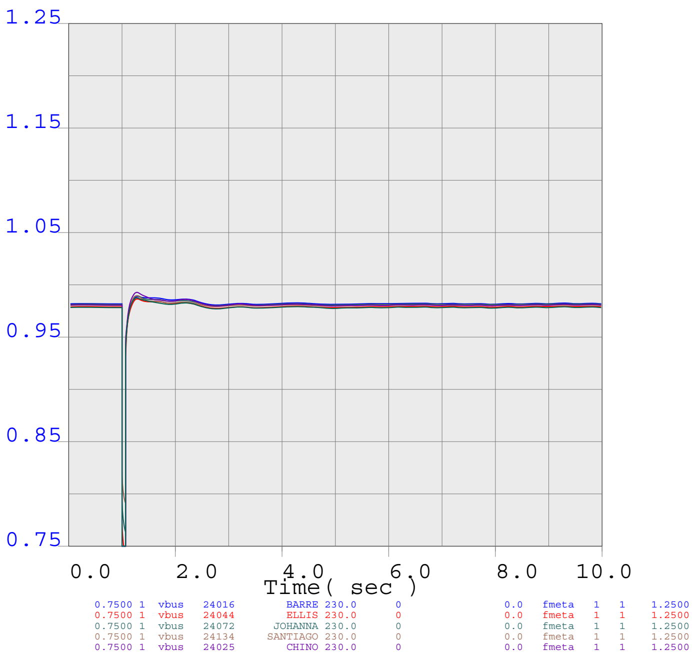
C:\DYTOOLS

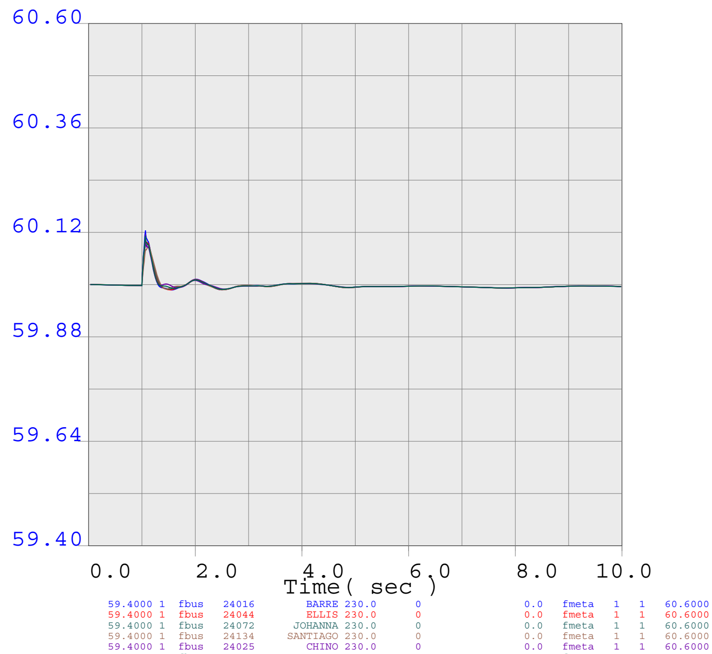
Thu Oct 20 09:02:18 2016

METRO









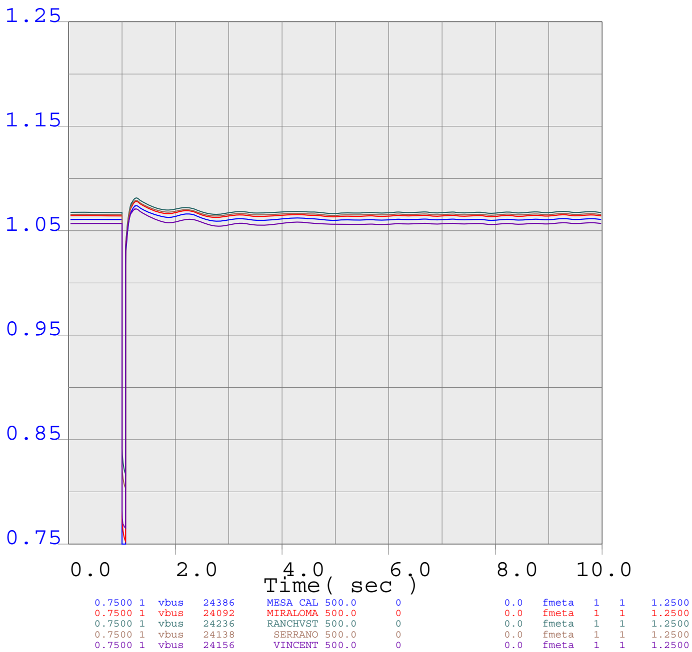
line_1266
Line MESACALS 230.0 to LAGUBELL 230.0 Circuit 2
1 MW dispatch Case

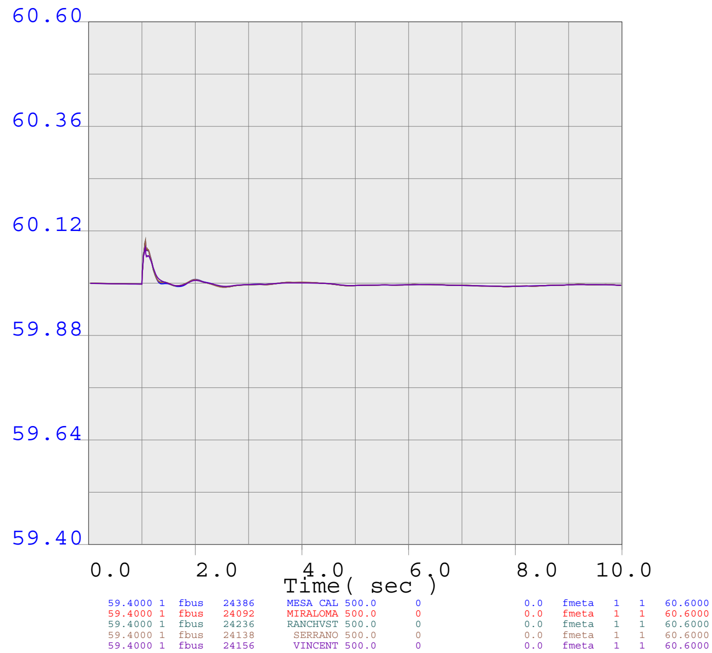
qc9p-line_1266.chf

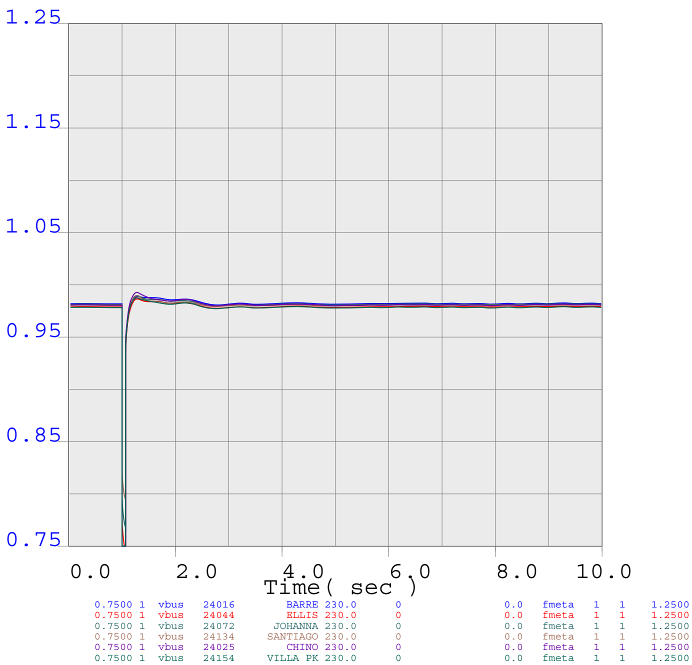
C:\DYTOOLS

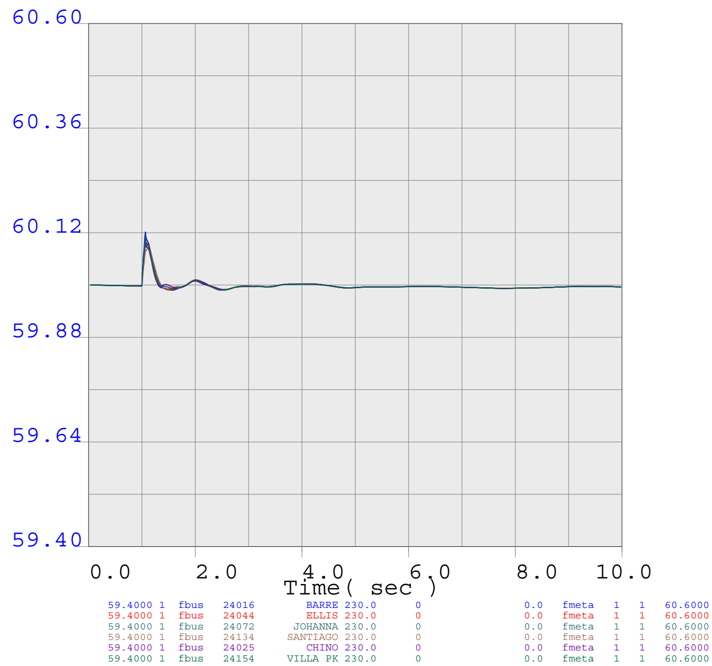
Thu Oct 20 09:02:20 2016

METRO









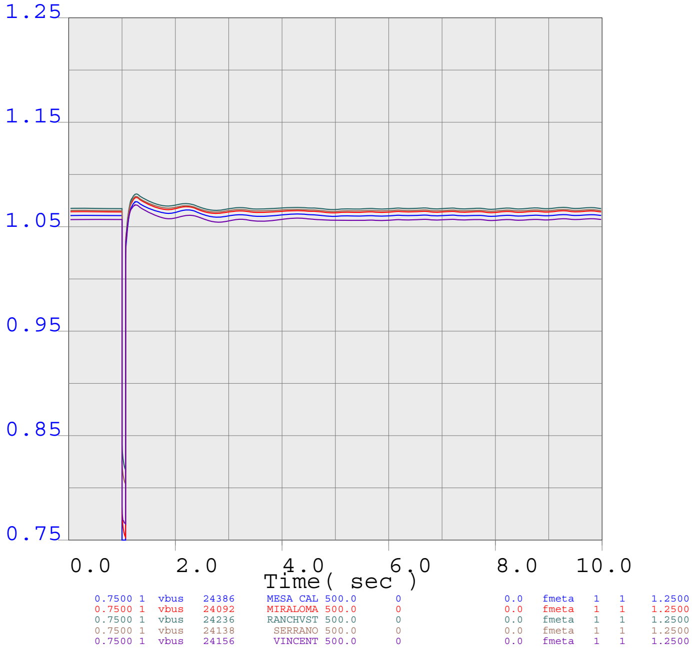
line_1267
Line MESACALS 230.0 to RIOHONDO 230.0 Circuit 1
1 MW dispatch Case

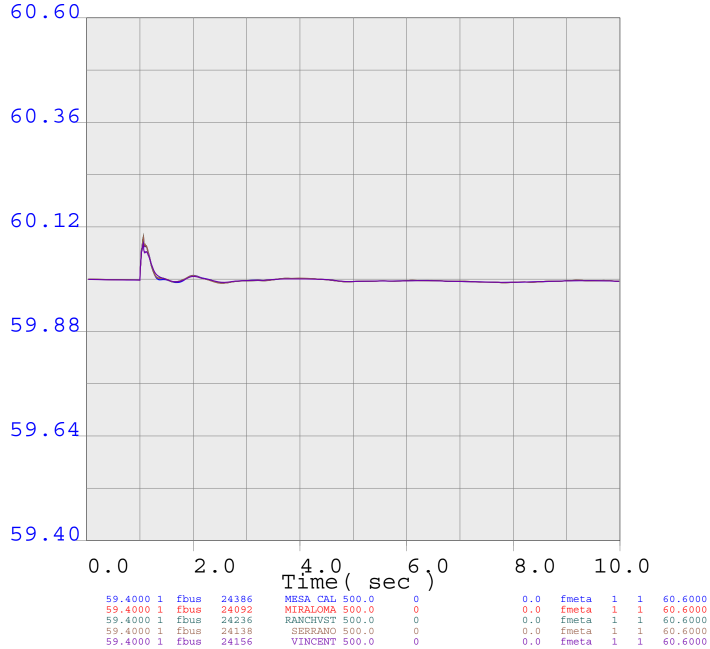
qc9p-line_1267.chf

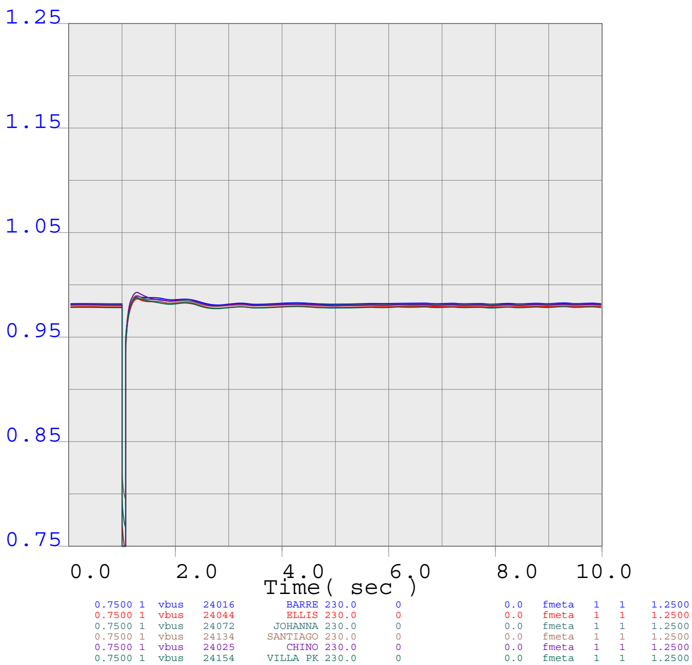
C:\DYTOOLS

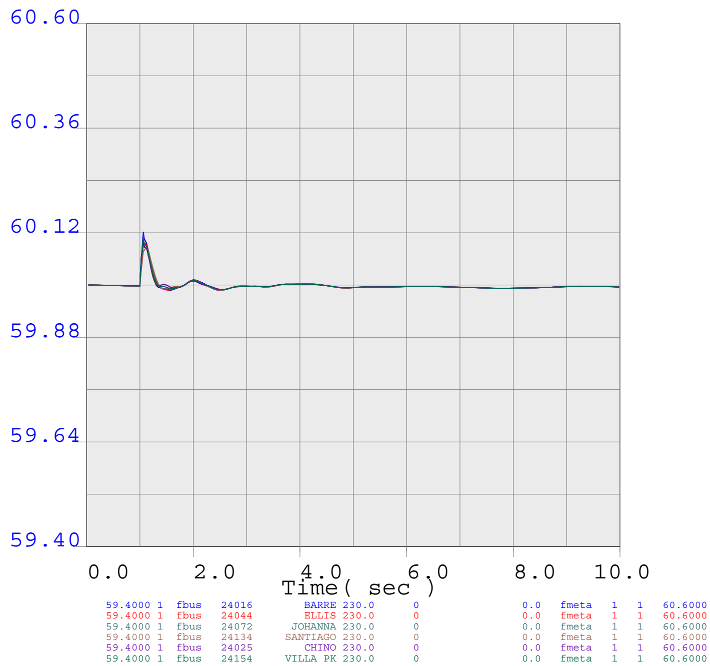
Thu Oct 20 09:02:22 2016

METRO









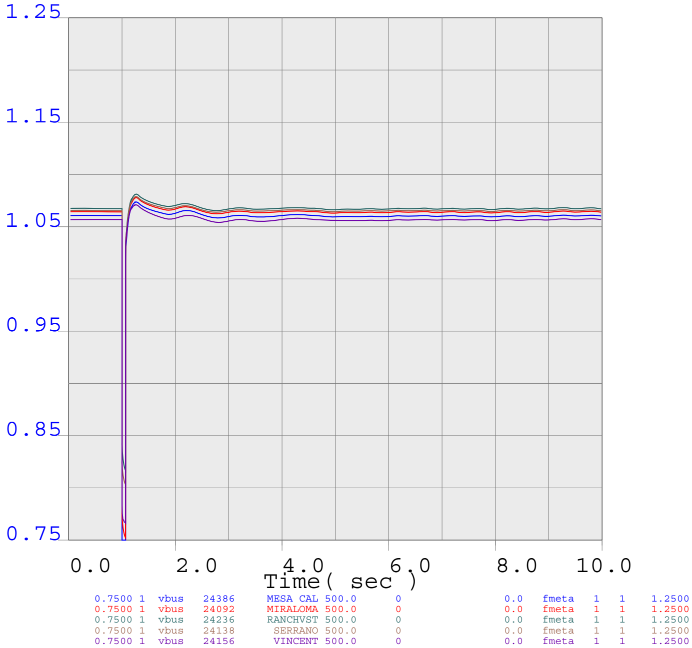
line_1268
Line MESACALS 230.0 to RIOHONDO 230.0 Circuit 2
1 MW dispatch Case

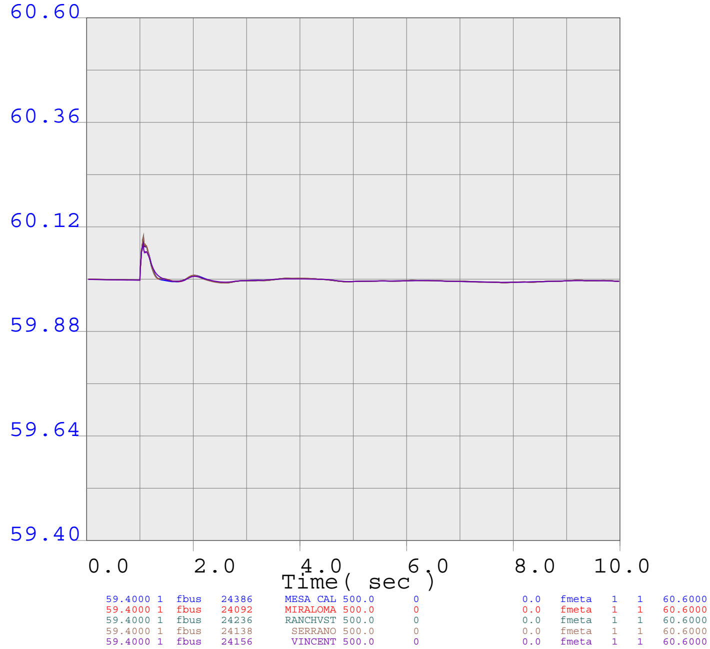
qc9p-line_1268.chf

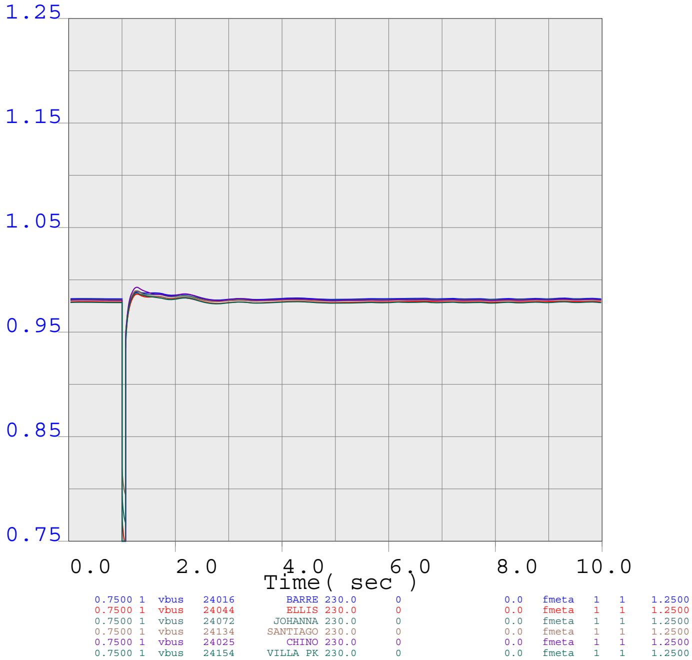
C:\DYTOOLS

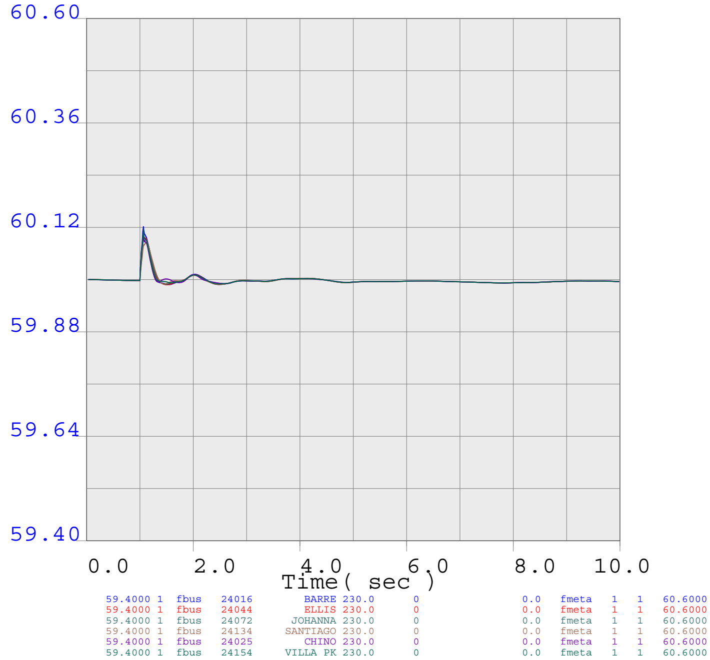
Thu Oct 20 09:02:24 2016

METRO









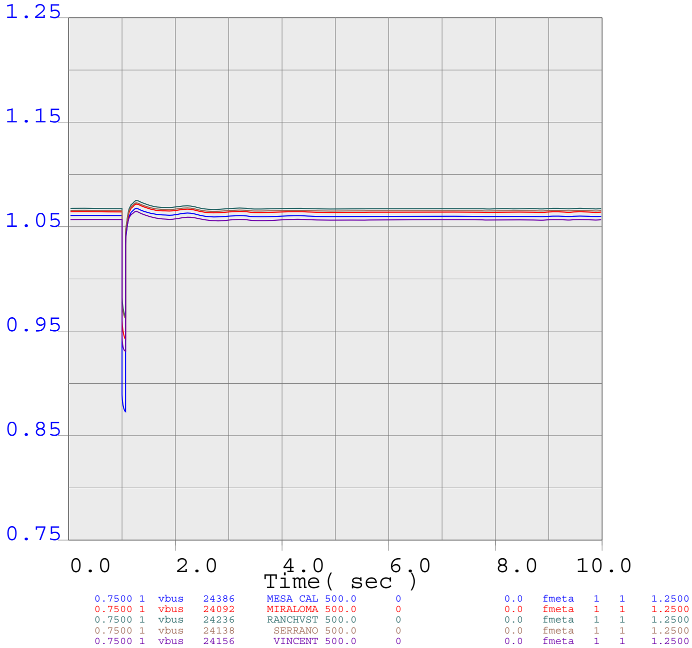
line_1269
Line MESACALS 230.0 to WALNUTW 230.0 Circuit 1
1 MW dispatch Case

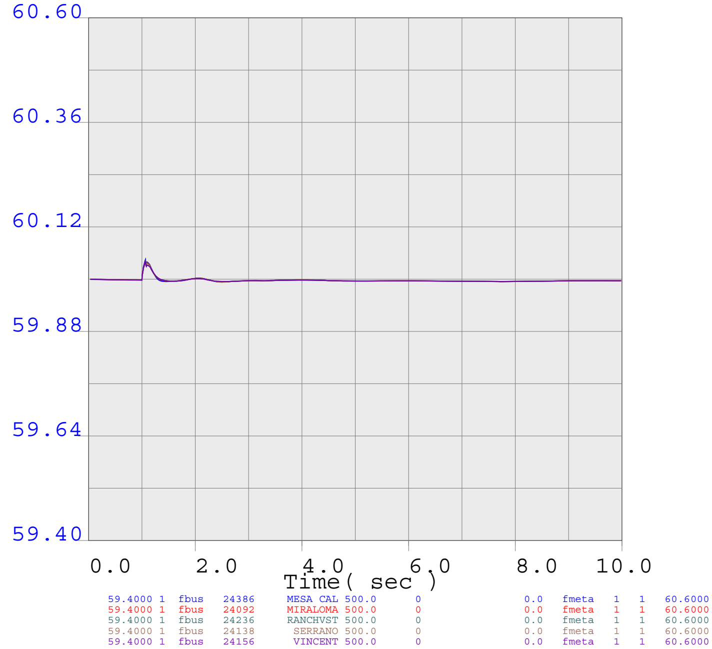
qc9p-line_1269.chf

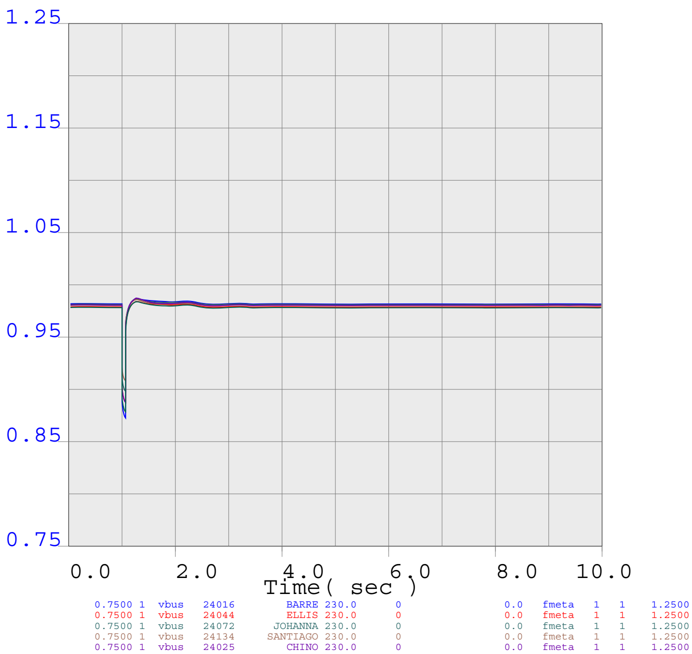
C:\DYTOOLS

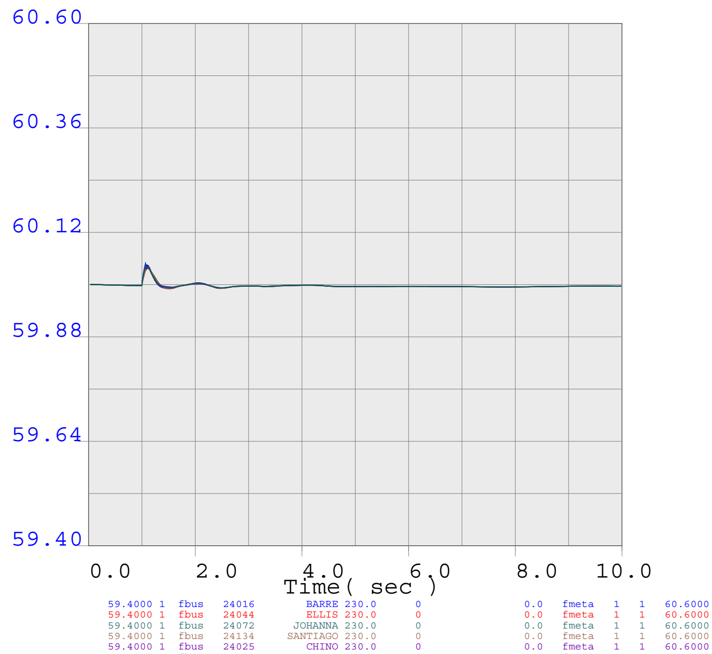
Thu Oct 20 09:02:26 2016

METRO









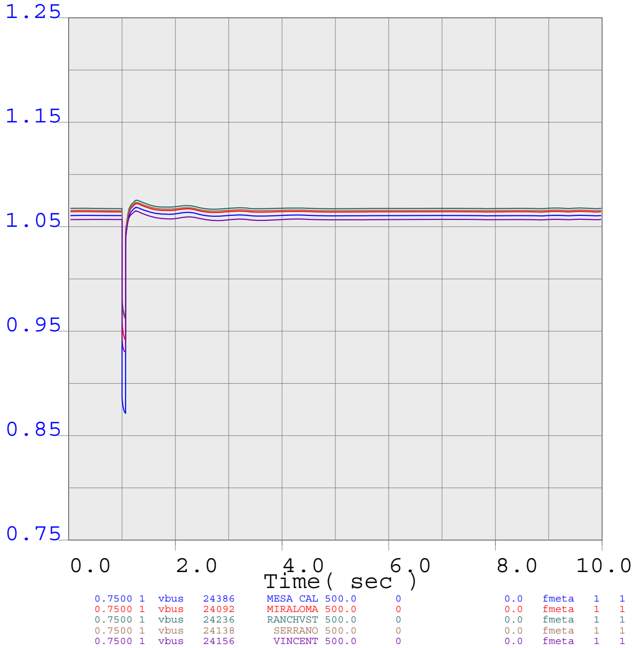
line_1270
Line GOODRICH 230.0 to GOULD 230.0 Circuit 1
1 MW dispatch Case

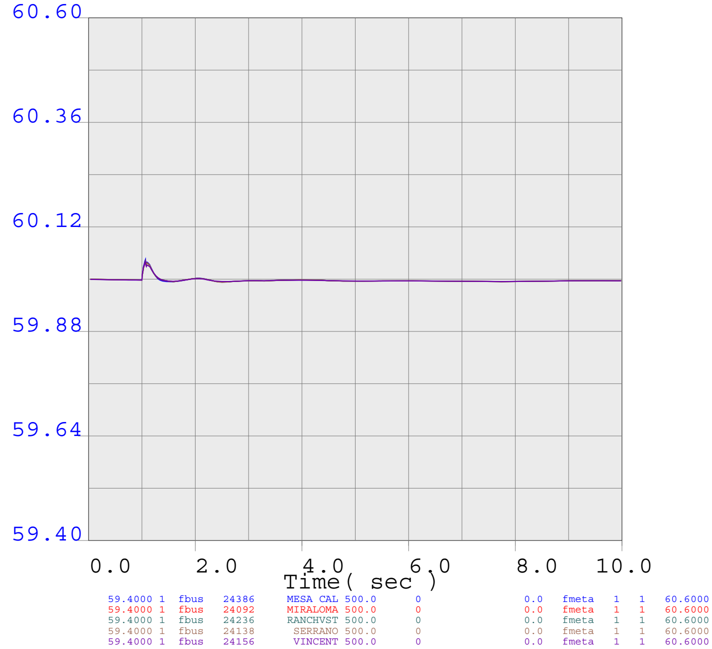
qc9p-line_1270.chf

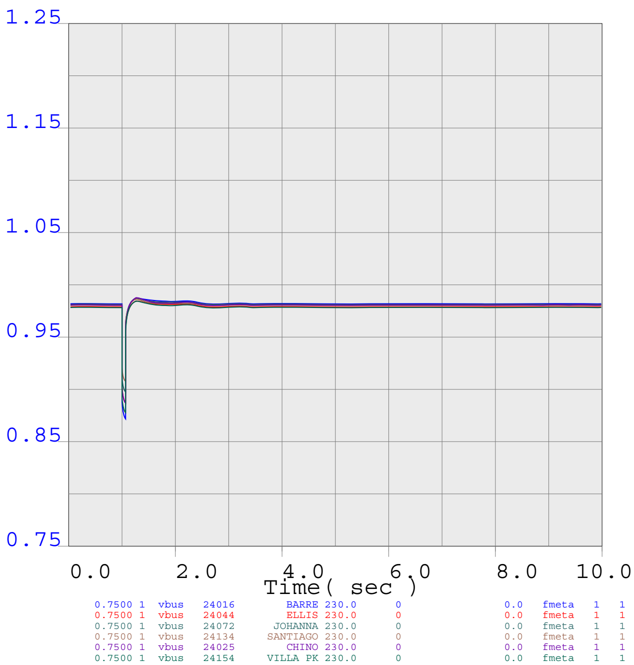
C:\DYTOOLS

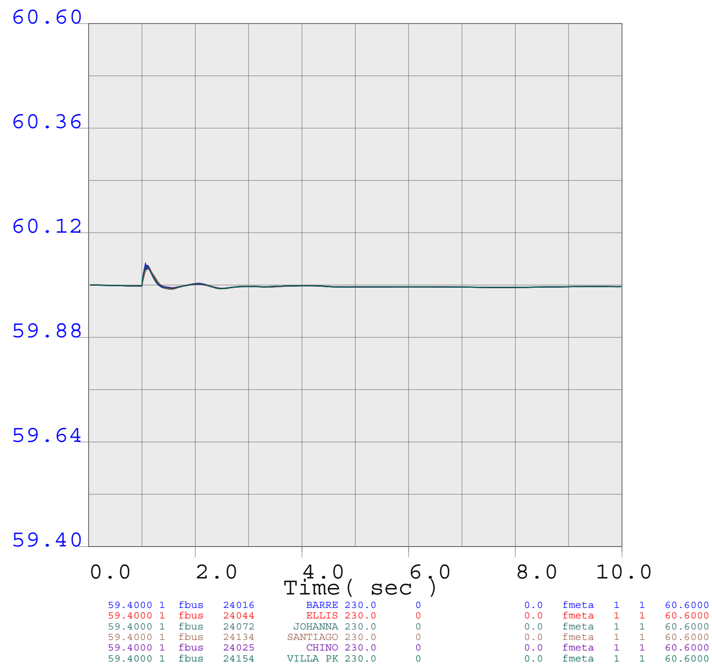
Thu Oct 20 09:02:28 2016

METRO









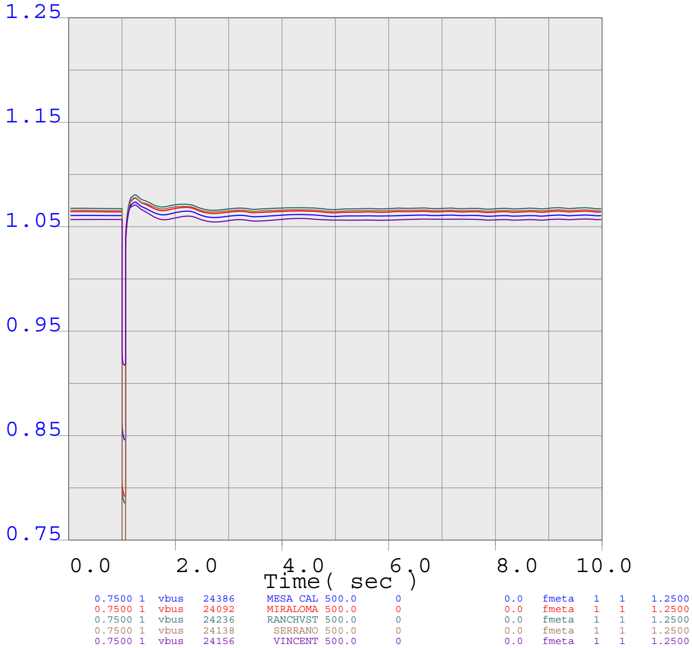
line_1271
Line GOODRICH 230.0 to MESA CAL 230.0 Circuit 1
1 MW dispatch Case

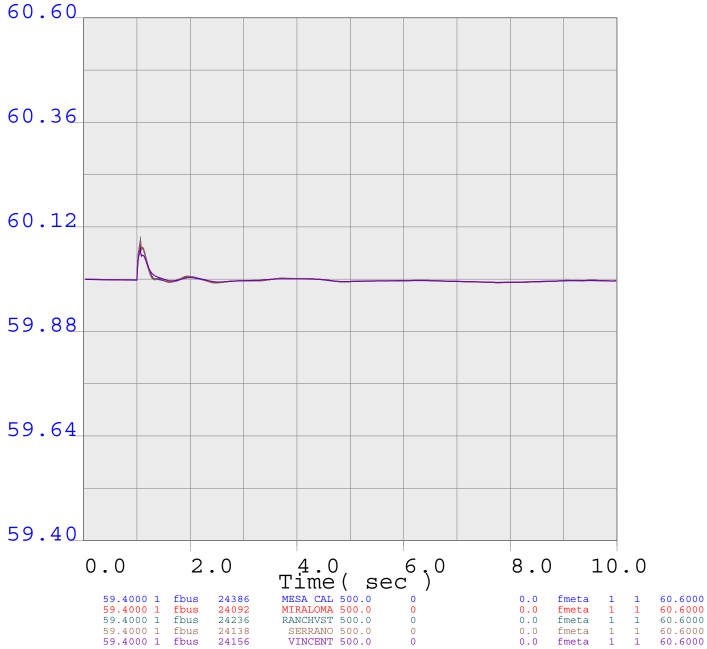
qc9p-line_1271.chf

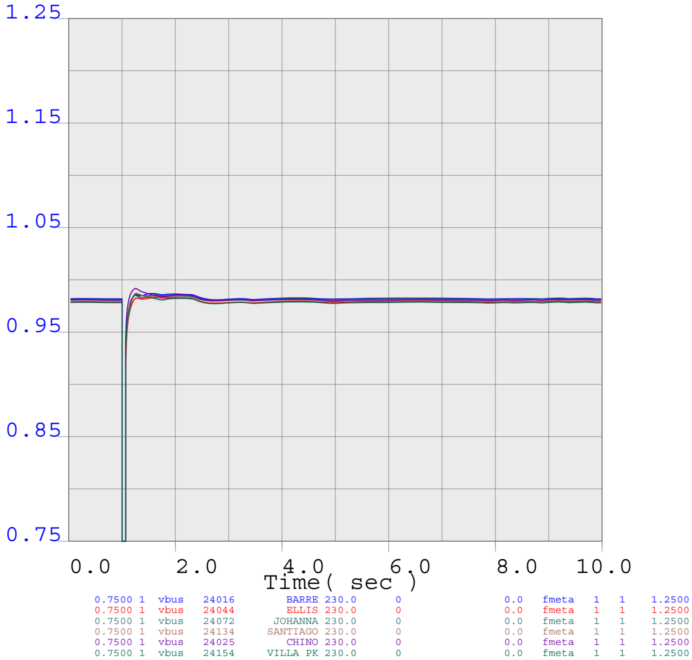
C:\DYTOOLS

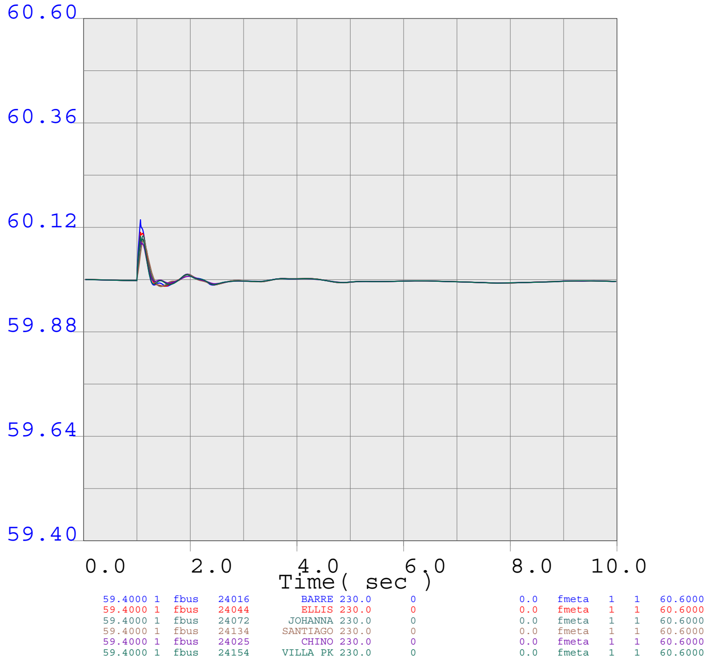
Thu Oct 20 09:02:30 2016

METRO









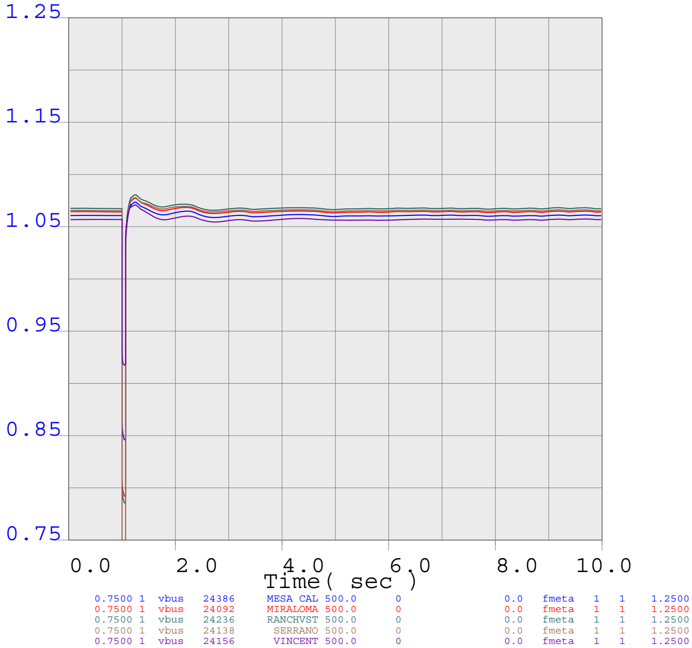
line_1272
Line LEWIS 230.0 to SERRANO 230.0 Circuit 1
1 MW dispatch Case

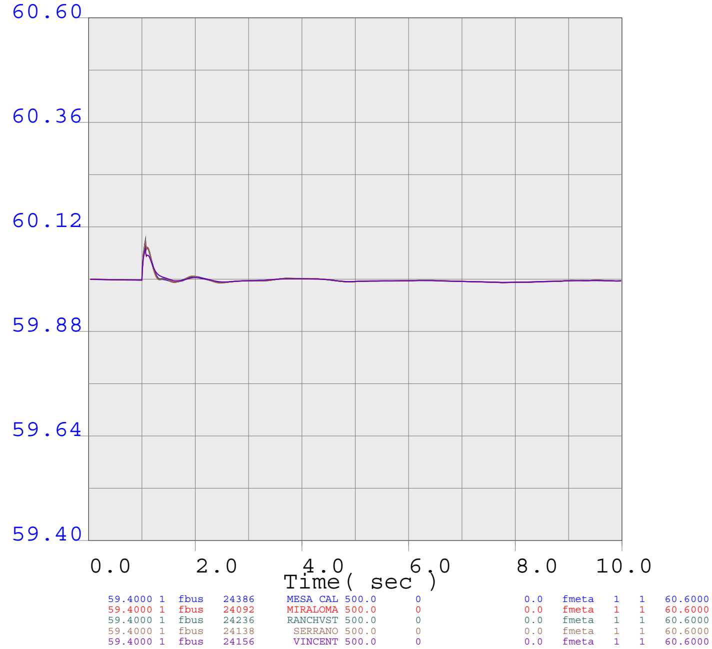
qc9p-line_1272.chf

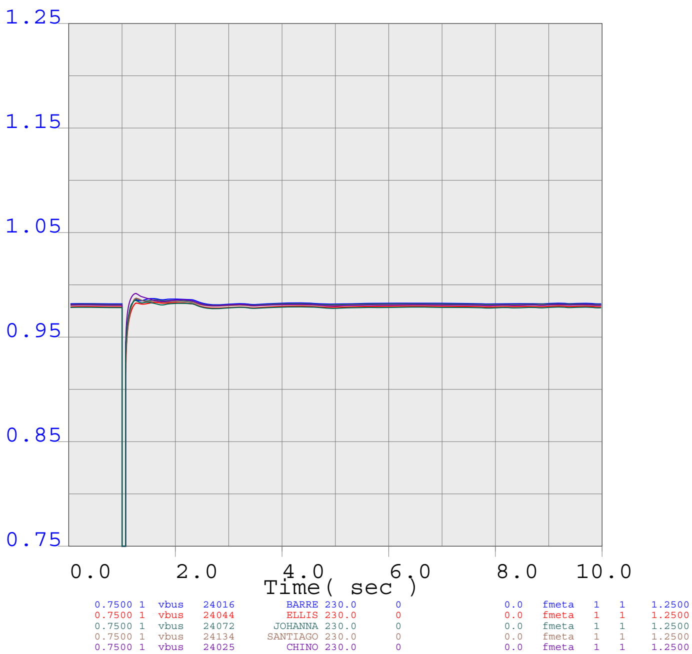
C:\DYTOOLS

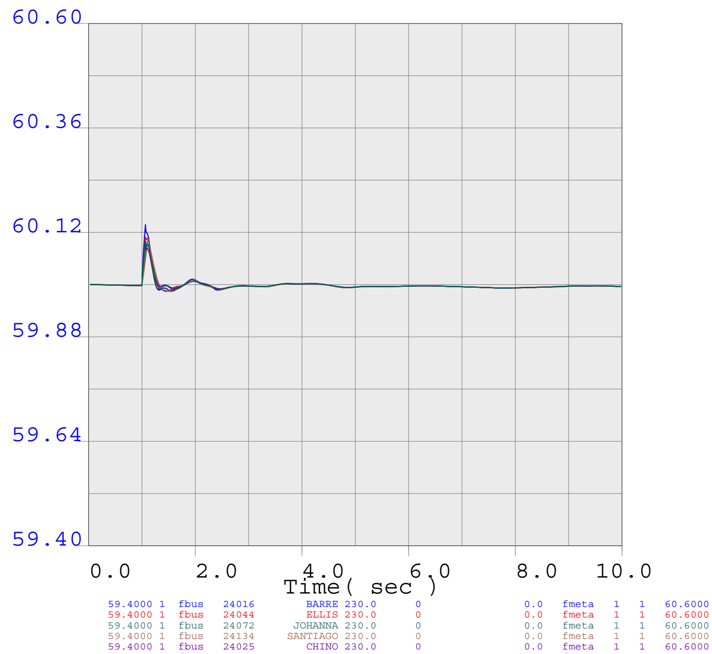
Thu Oct 20 09:02:32 2016

METRO









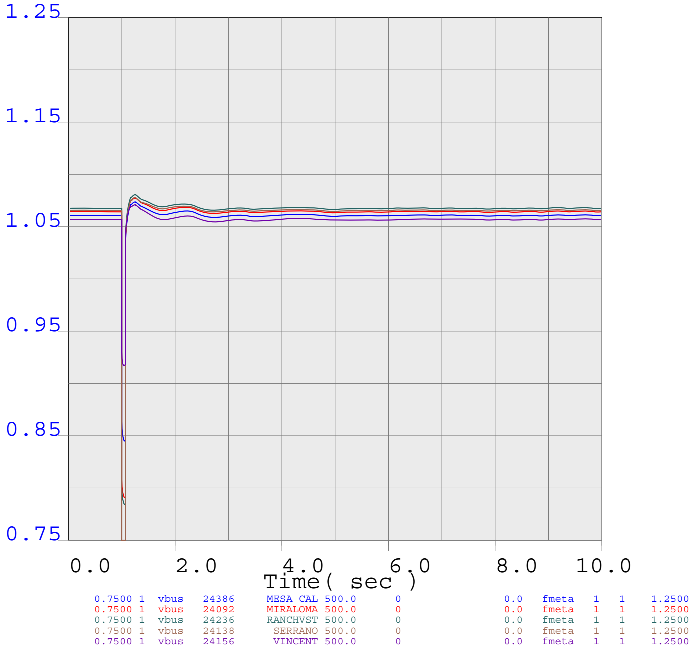
line_1273
Line LEWIS 230.0 to SERRANO 230.0 Circuit 2
1 MW dispatch Case

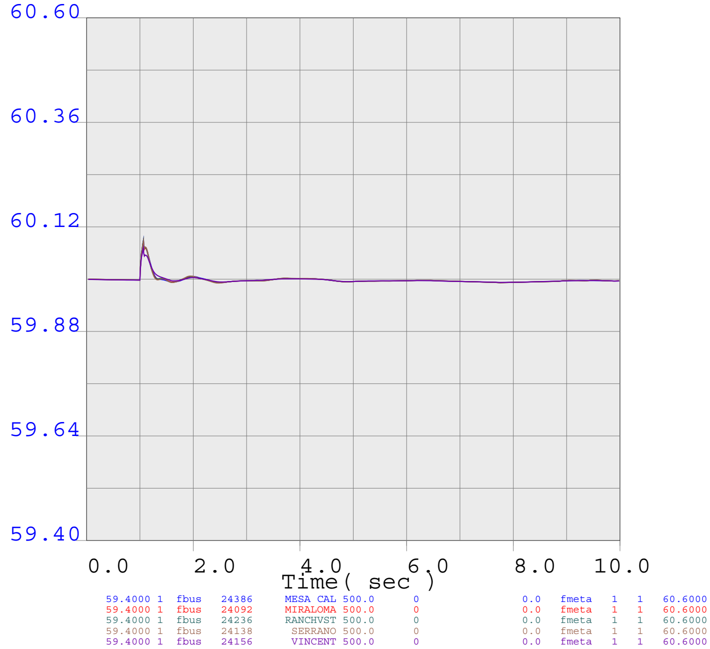
qc9p-line_1273.chf

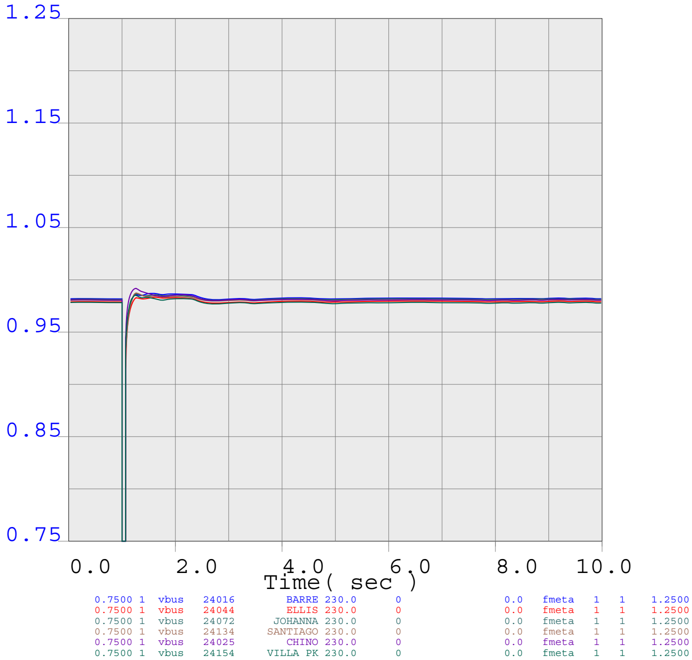
C:\DYTOOLS

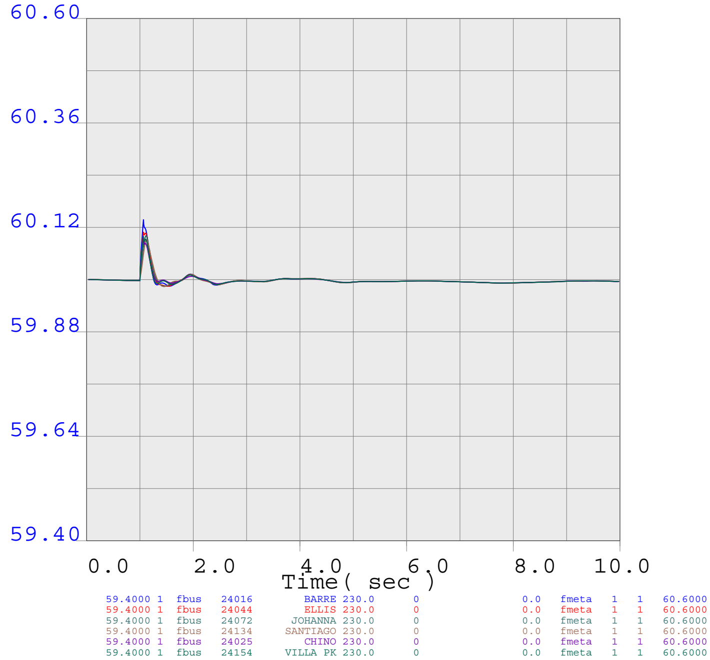
Thu Oct 20 09:02:34 2016

METRO





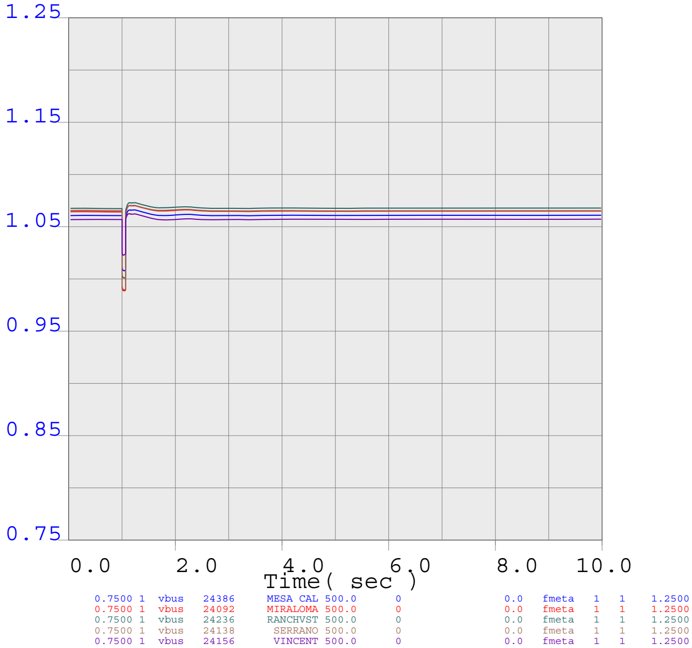


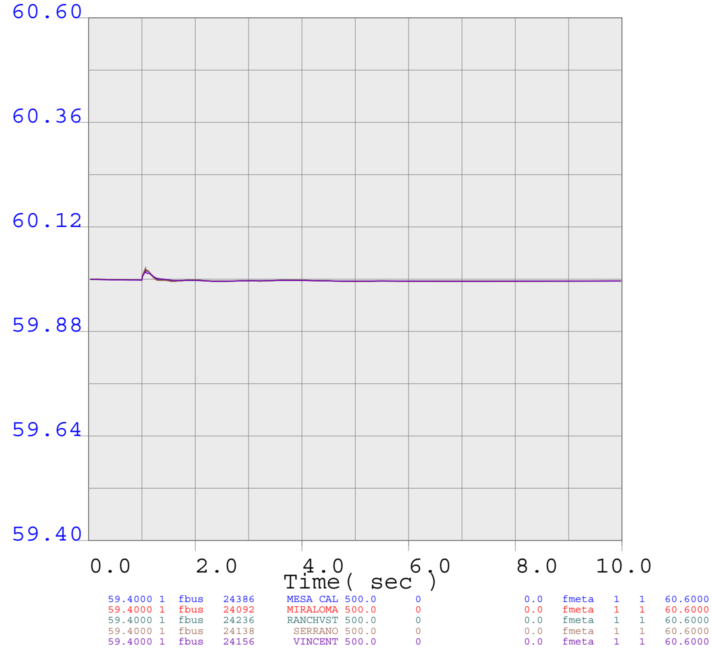


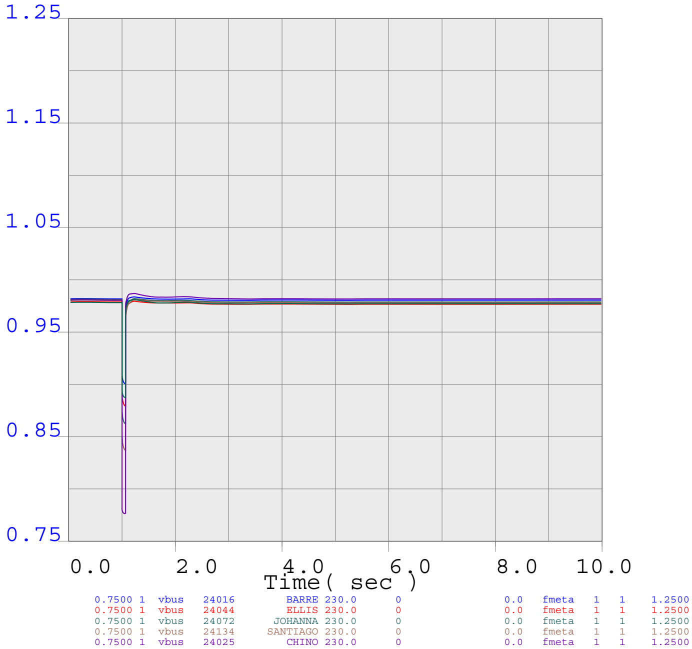
line_1274
Line LEWIS 230.0 to VILLA PK 230.0 Circuit 1
1 MW dispatch Case

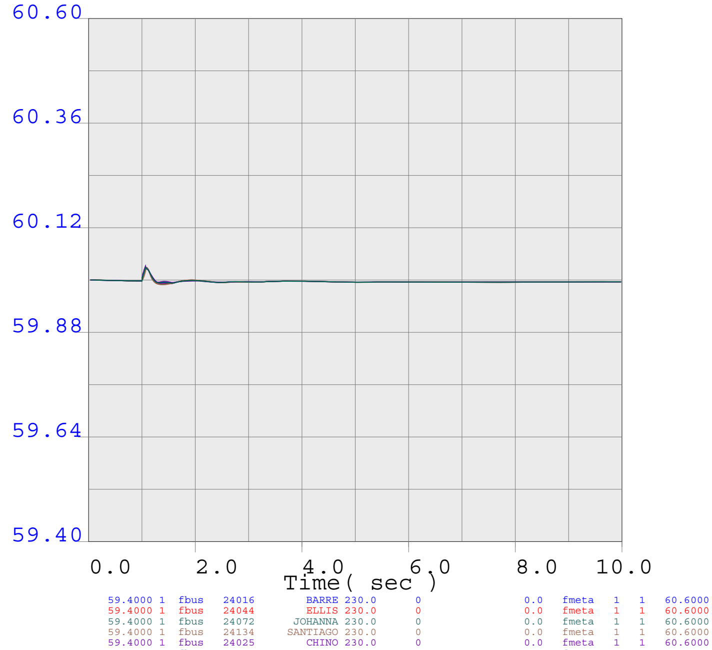
	qc9p-line_1274.chf	C:\DYTOOLS Thu Oct 20 09:02:36 2016

METRO









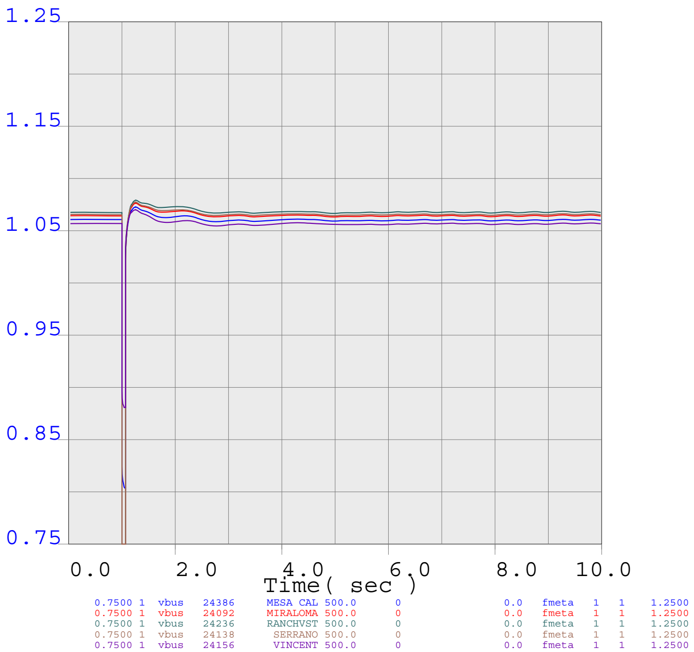
line_1275
Line VIEJO 230.0 to CHINO 230.0 Circuit 1
1 MW dispatch Case

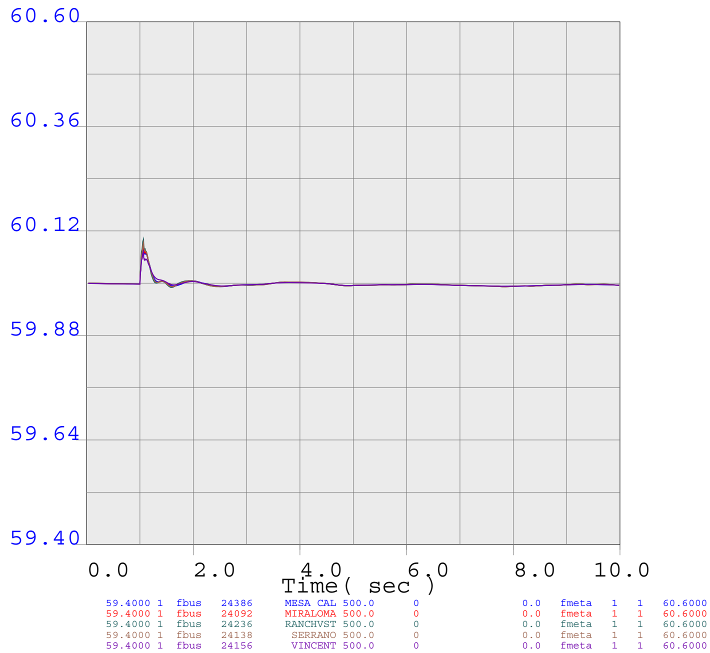
qc9p-line_1275.chf

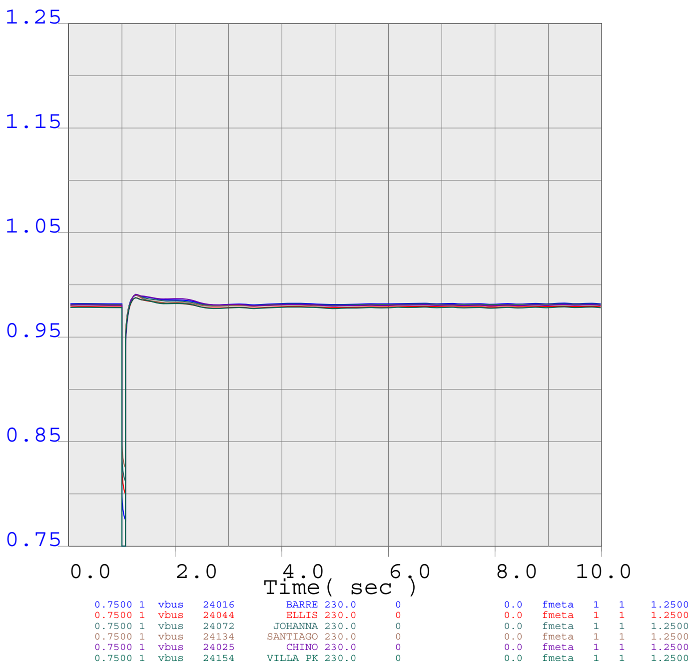
C:\DYTOOLS

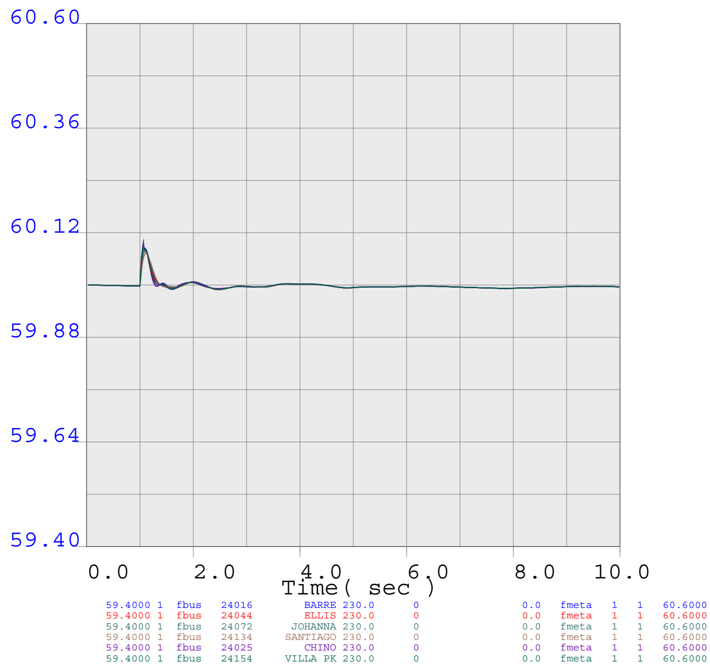
Thu Oct 20 09:02:38 2016

METRO









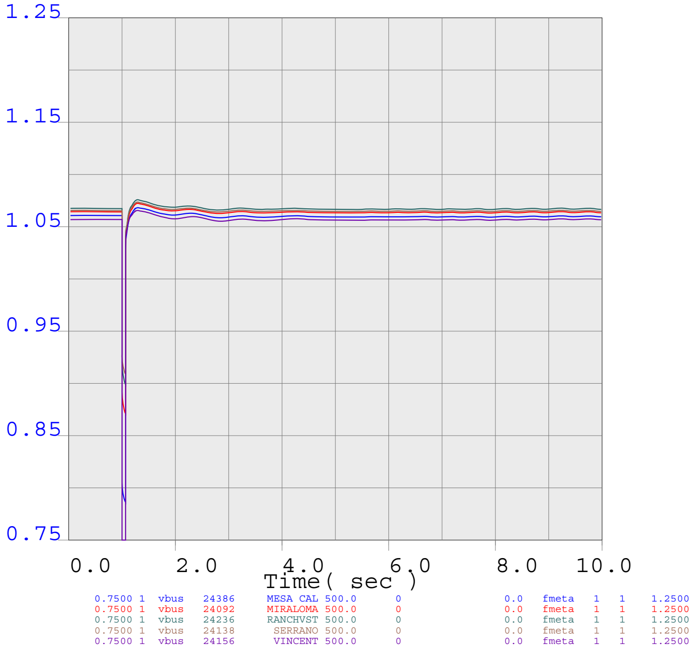
line_1276
Line MIRALOME 230.0 to OLINDA 230.0 Circuit 1
1 MW dispatch Case

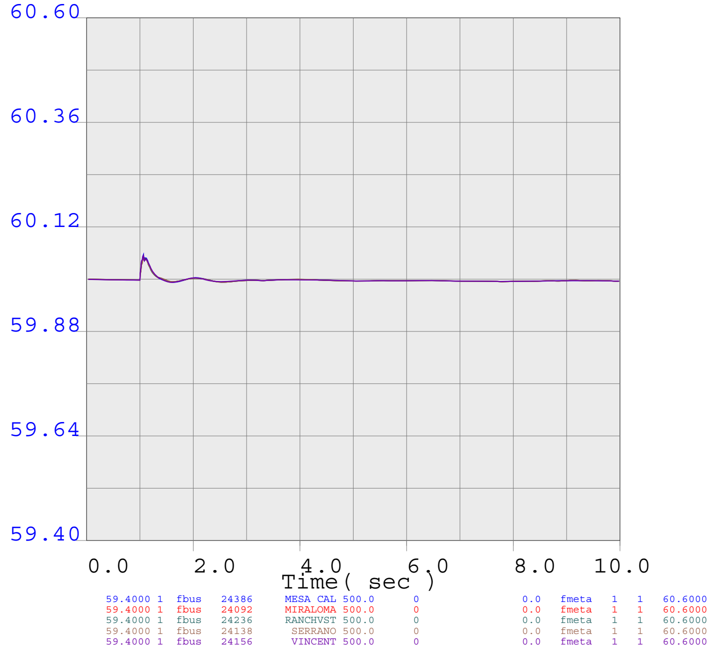
qc9p-line_1276.chf

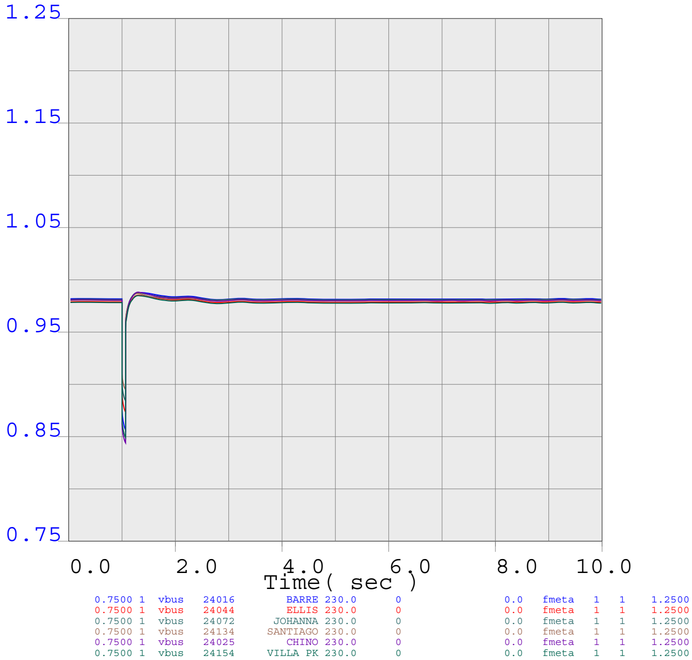
C:\DYTOOLS

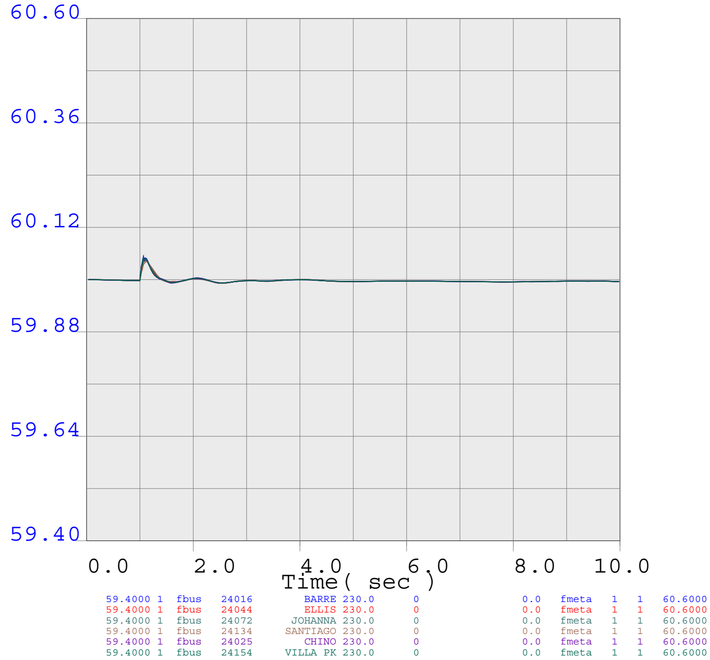
Thu Oct 20 09:02:40 2016

METRO









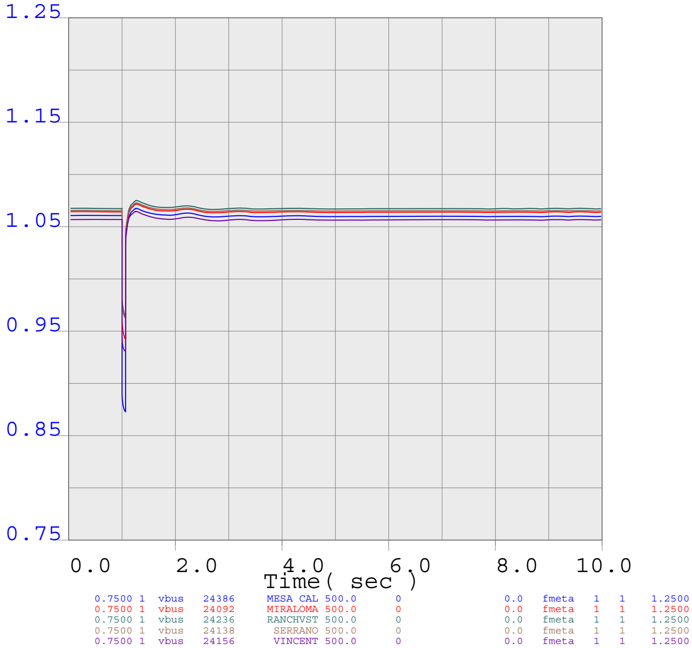
line_1277
Line VINCNT2 230.0 to MESA CAL 230.0 Circuit 1
1 MW dispatch Case

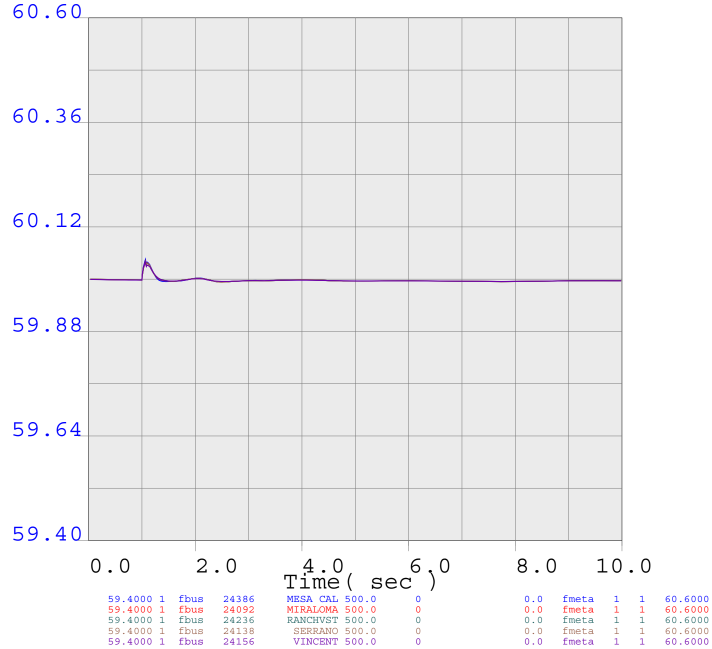
qc9p-line_1277.chf

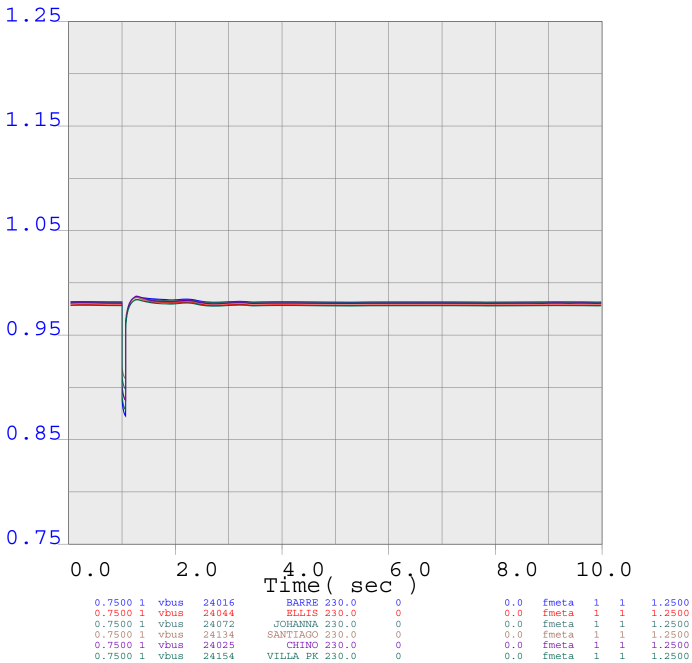
C:\DYTOOLS

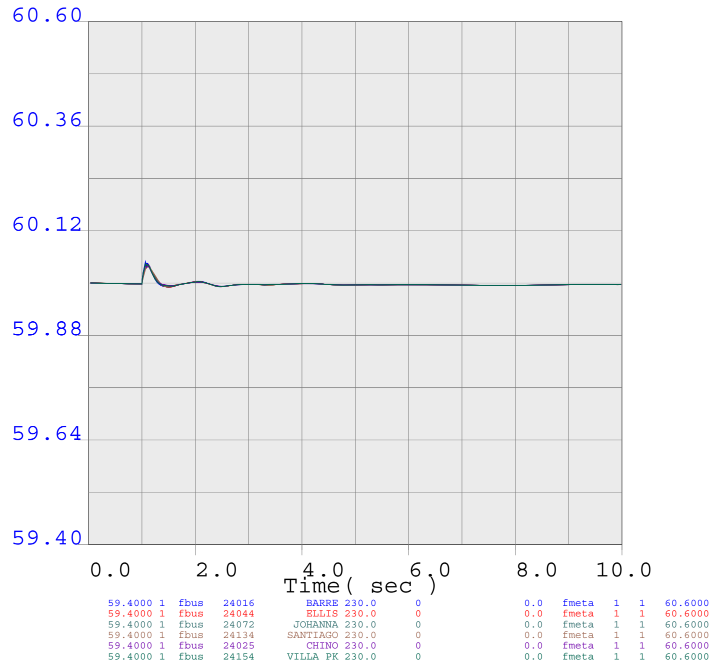
Thu Oct 20 09:02:42 2016

METRO









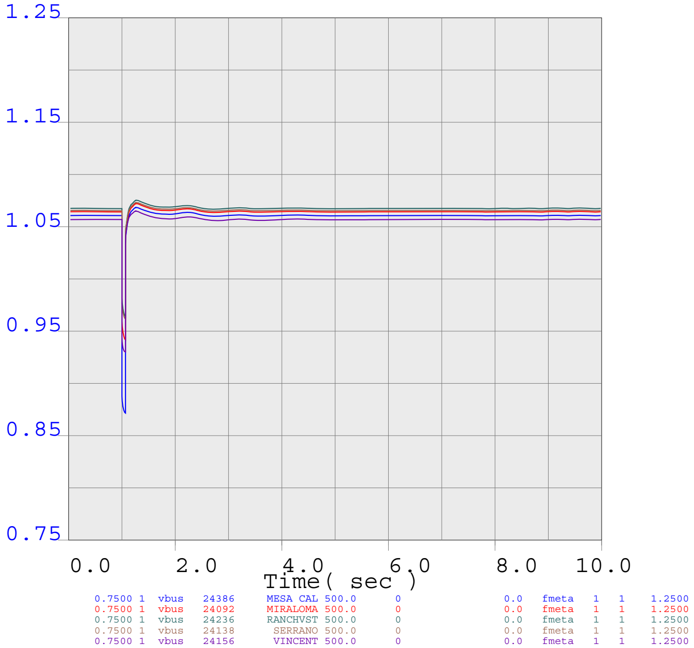
line_1279
Line GOODRICH 230.0 to GOULD 230.0 Circuit 1
1 MW dispatch Case

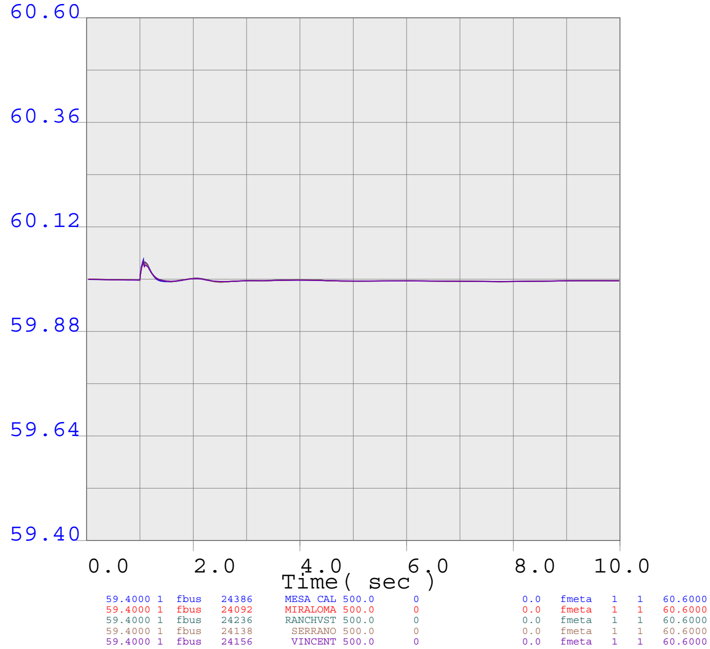
qc9p-line_1279.chf

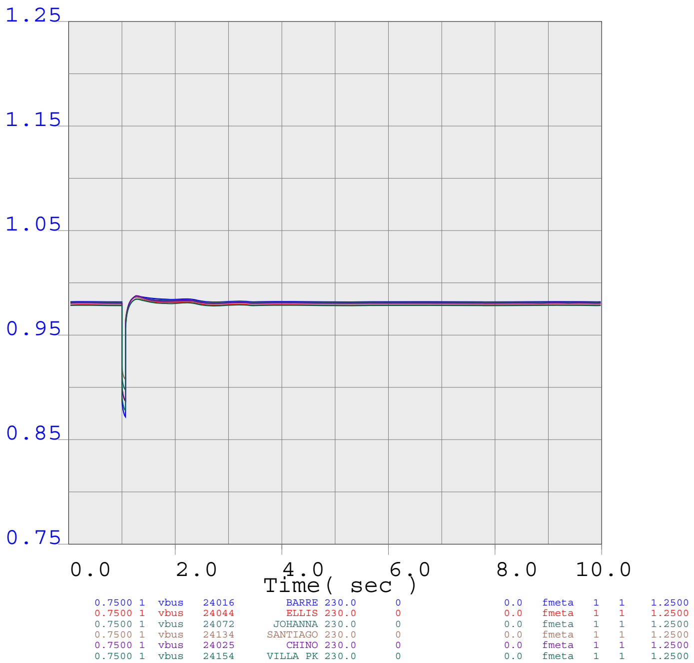
C:\DYTOOLS

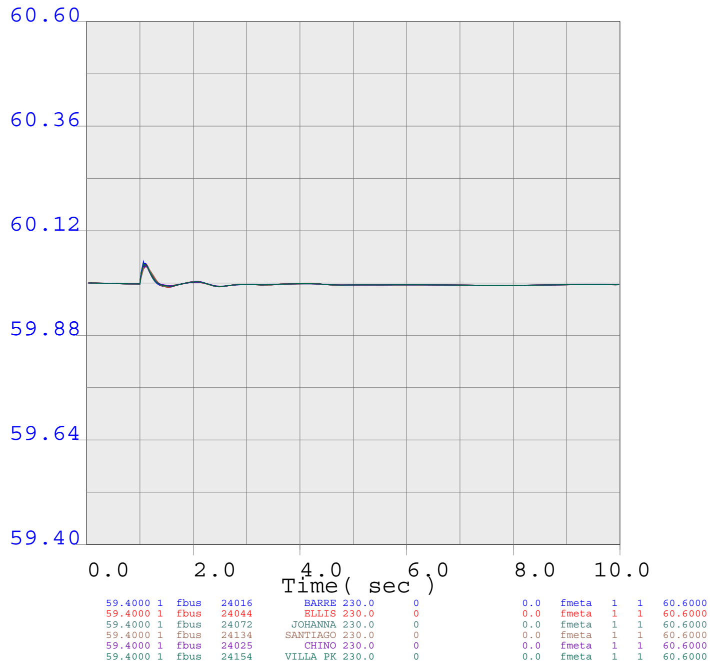
Thu Oct 20 09:02:44 2016

METRO









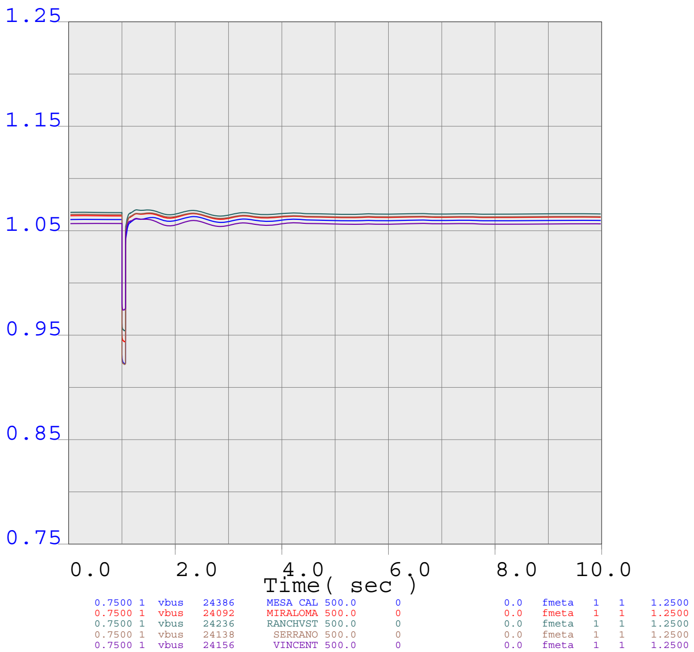
line_1280
Line GOODRICH 230.0 to MESA CAL 230.0 Circuit 1
1 MW dispatch Case

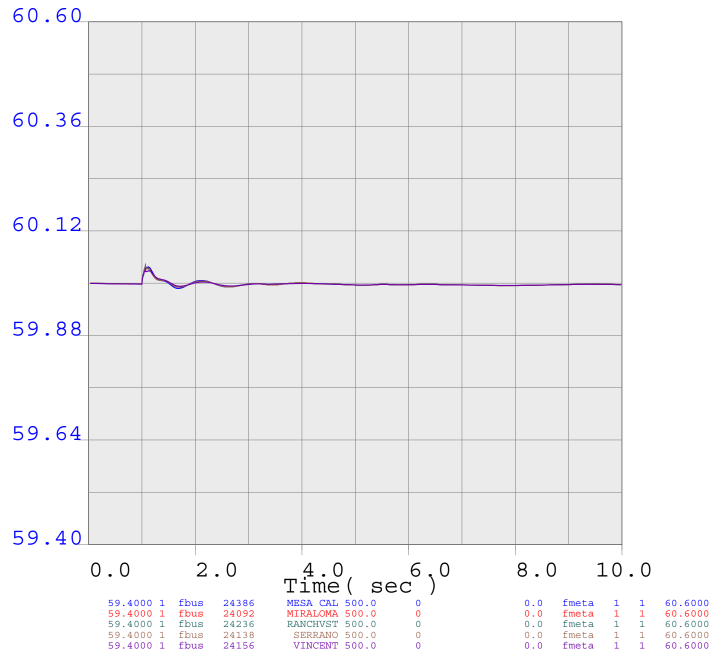
qc9p-line_1280.chf

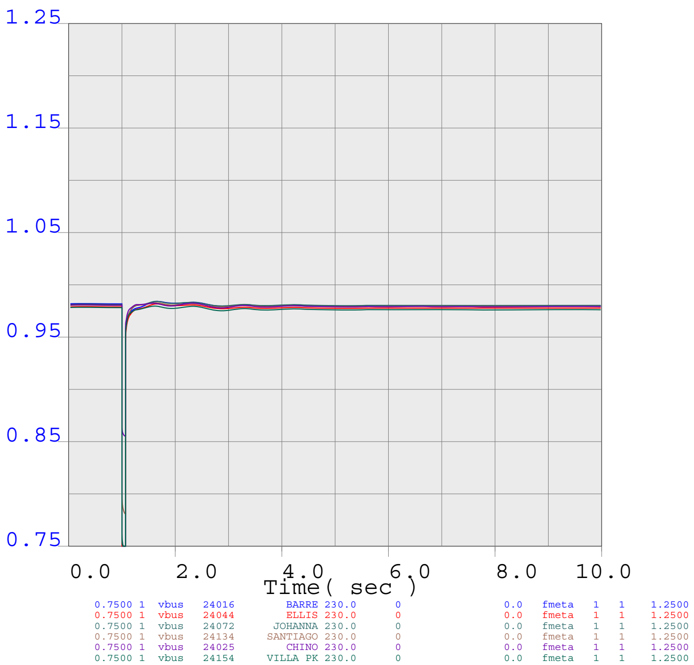
C:\DYTOOLS

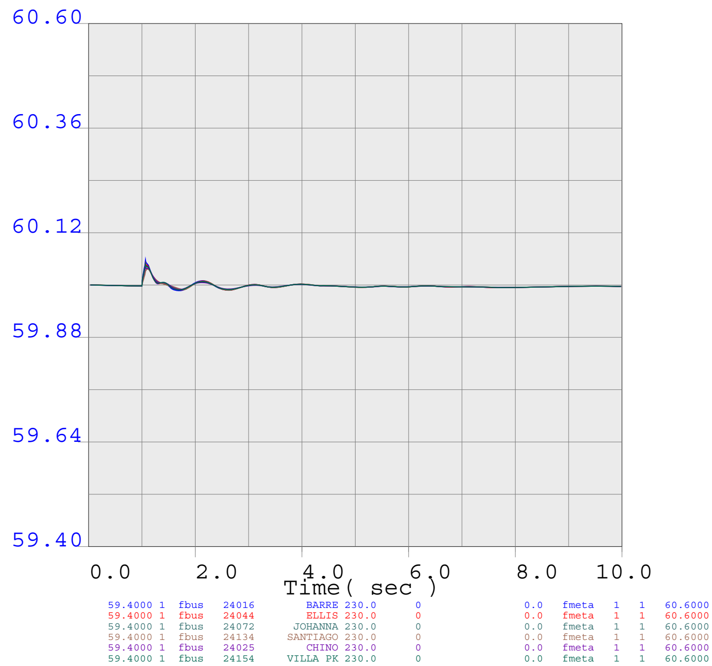
Thu Oct 20 09:02:46 2016

METRO









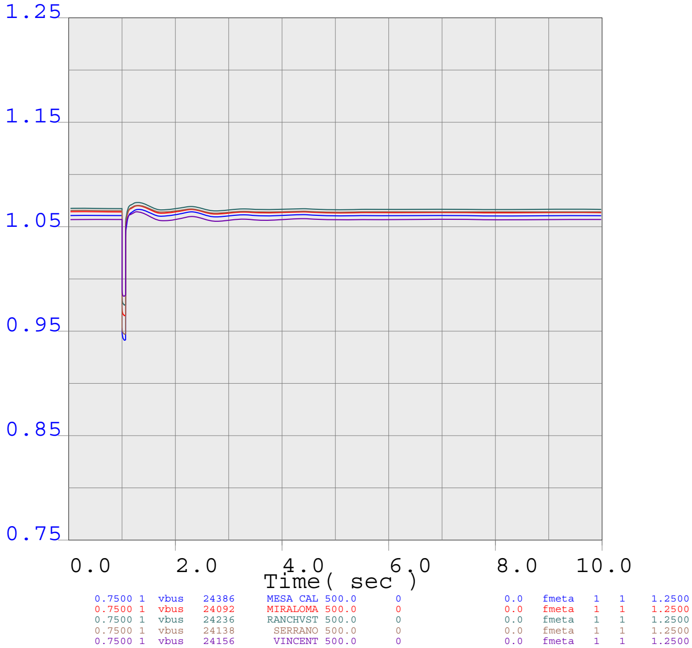
line_1281
Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1
1 MW dispatch Case

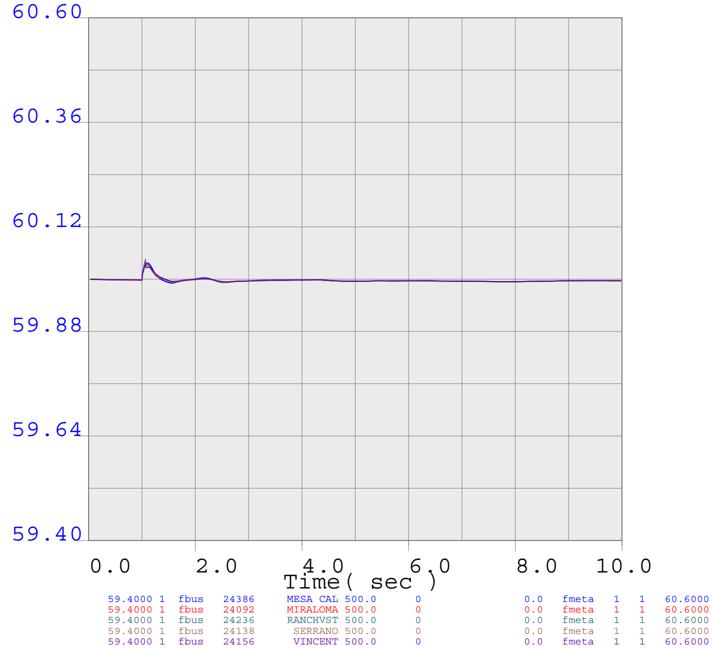
qc9p-line_1281.chf

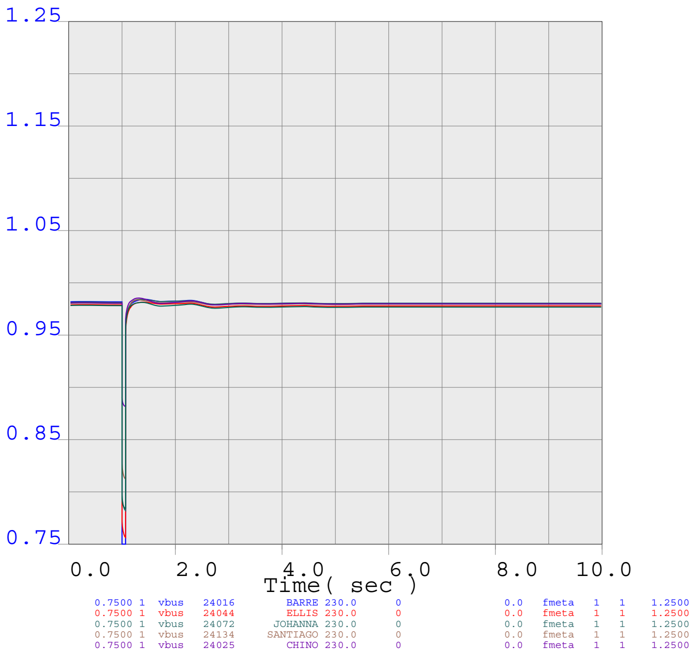
C:\DYTOOLS

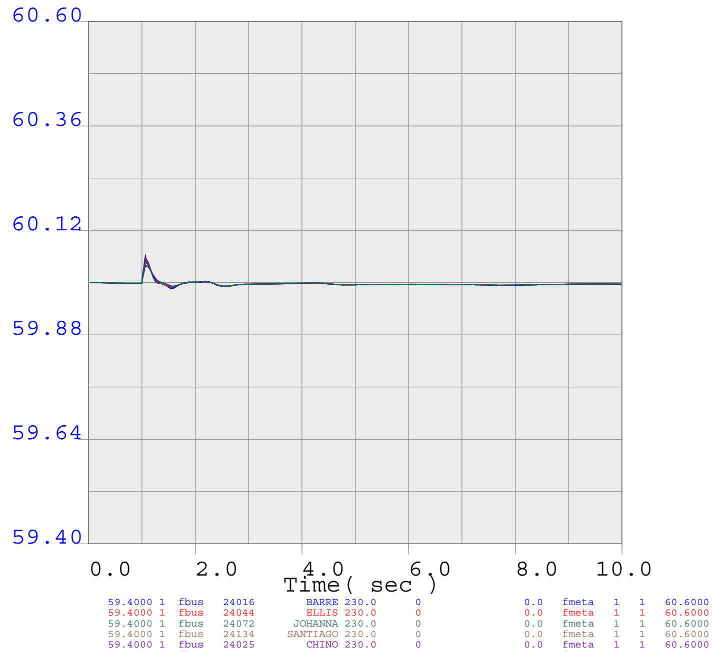
Thu Oct 20 09:02:48 2016

METRO









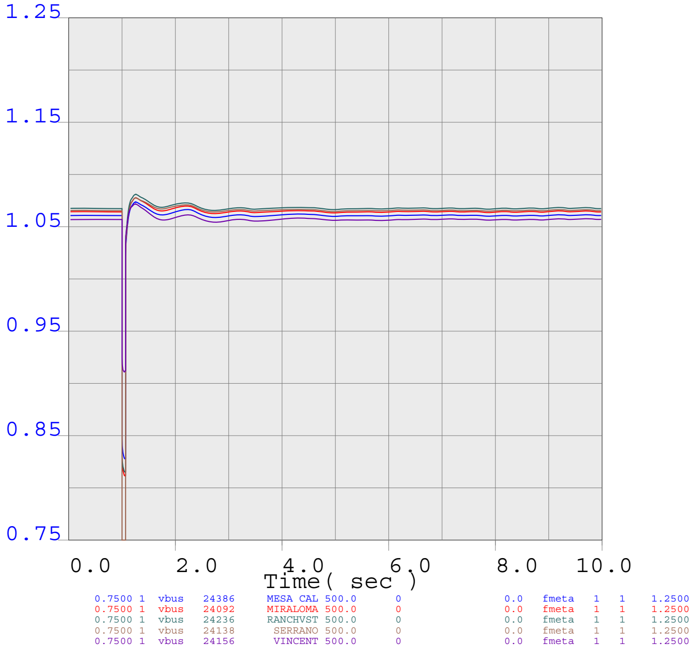
line_1282
Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2
1 MW dispatch Case

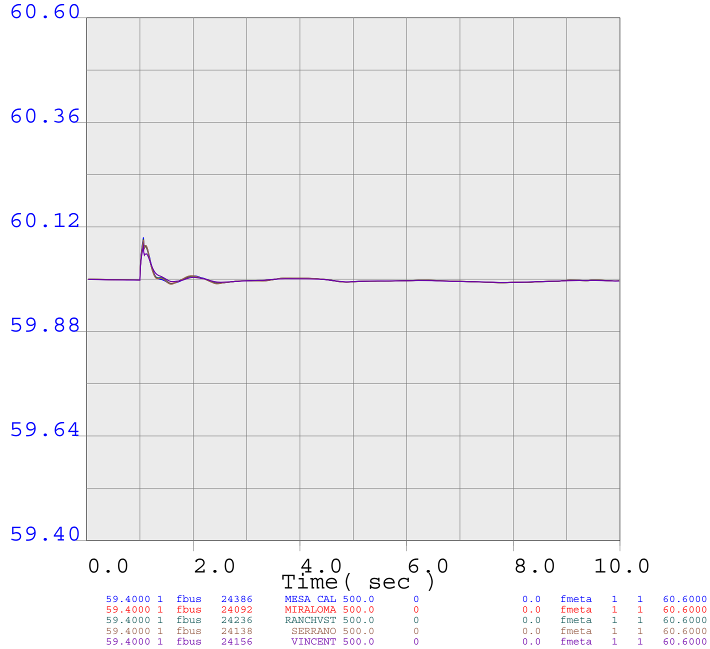
qc9p-line_1282.chf

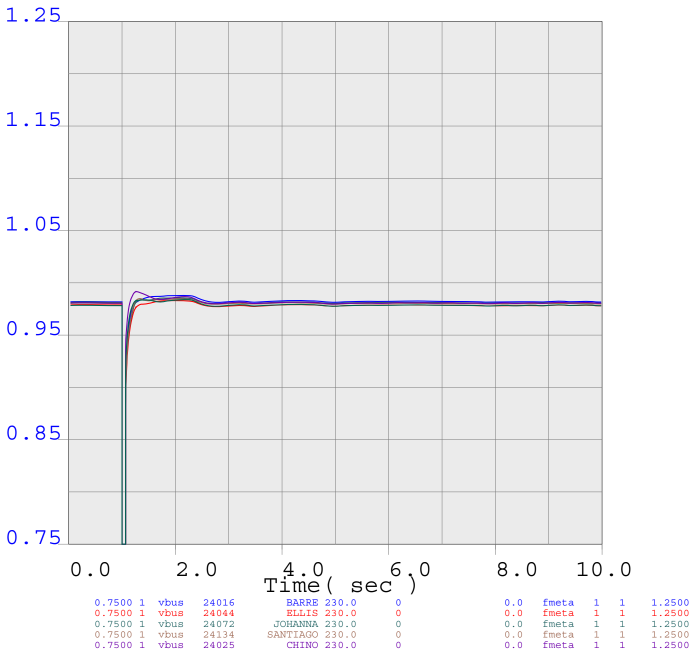
C:\DYTOOLS

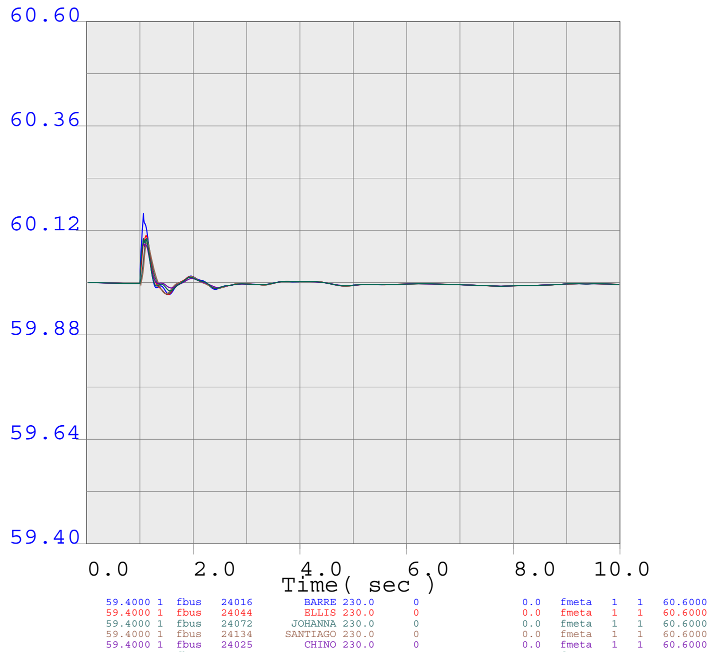
Thu Oct 20 09:02:50 2016

METRO









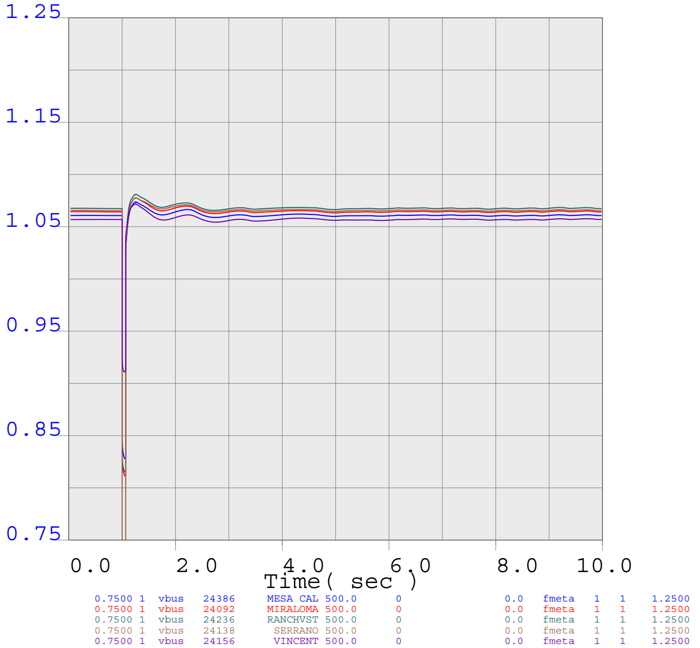
line_1283
Line BARRE 230.0 to ELLIS 230.0 Circuit 1
1 MW dispatch Case

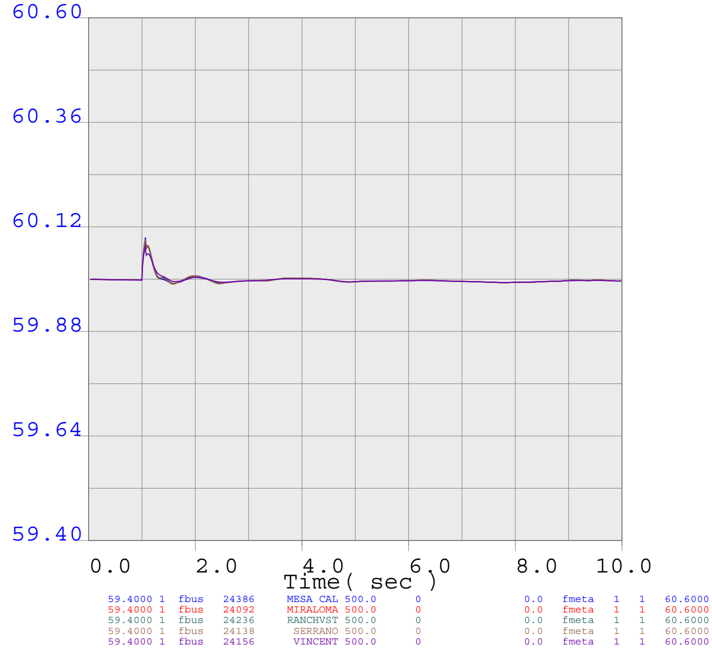
qc9p-line_1283.chf

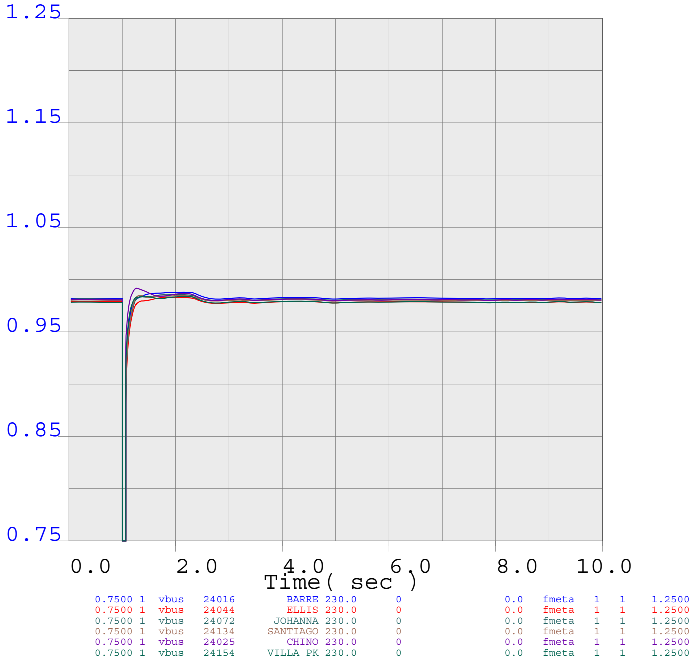
C:\DYTOOLS

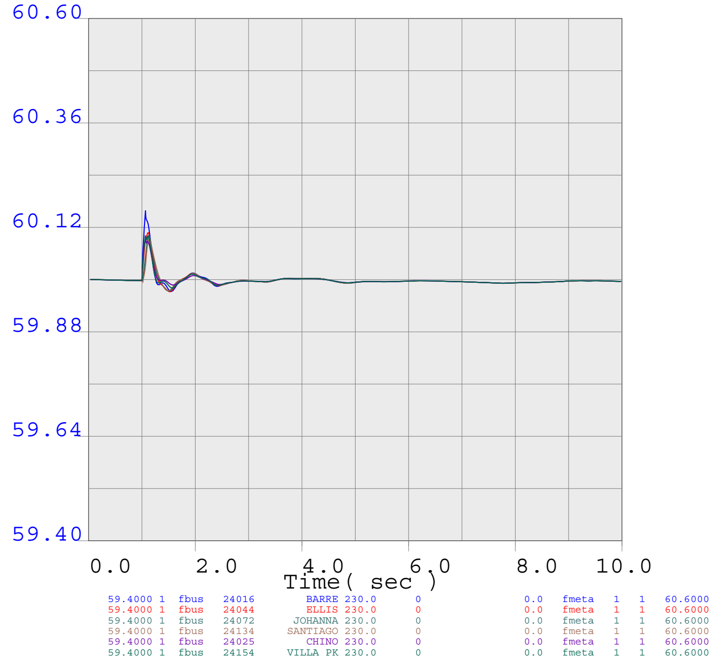
Thu Oct 20 09:02:53 2016

METRO









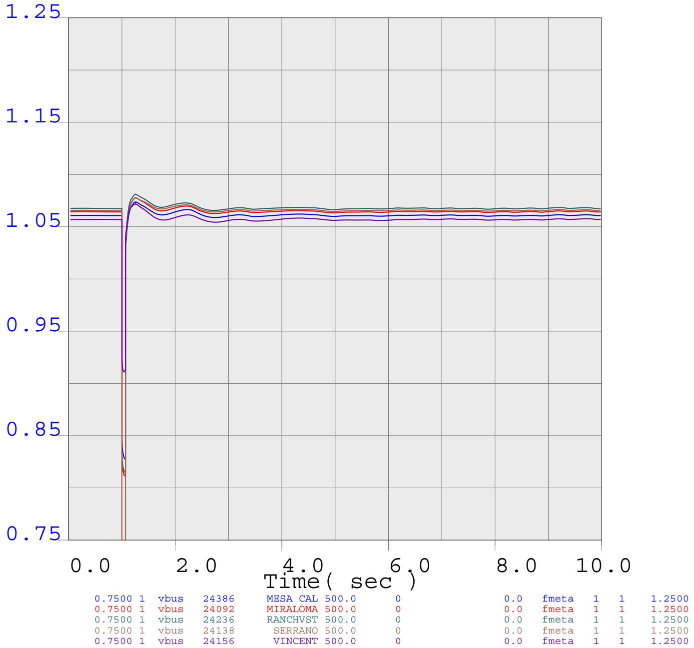
line_1284
Line BARRE 230.0 to ELLIS 230.0 Circuit 2
1 MW dispatch Case

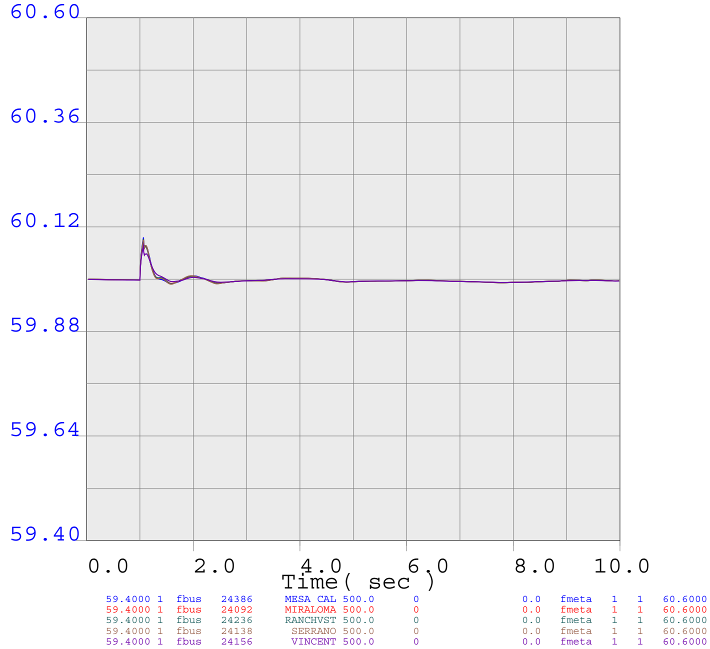
qc9p-line_1284.chf

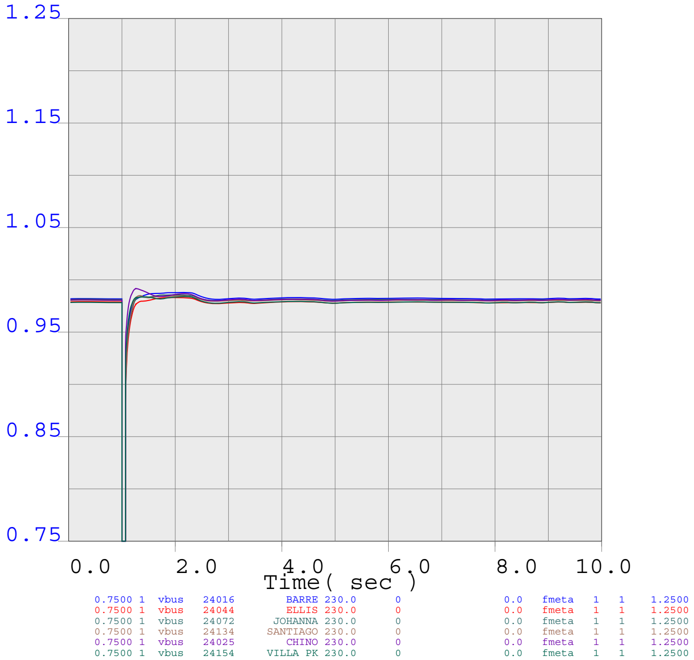
C:\DYTOOLS

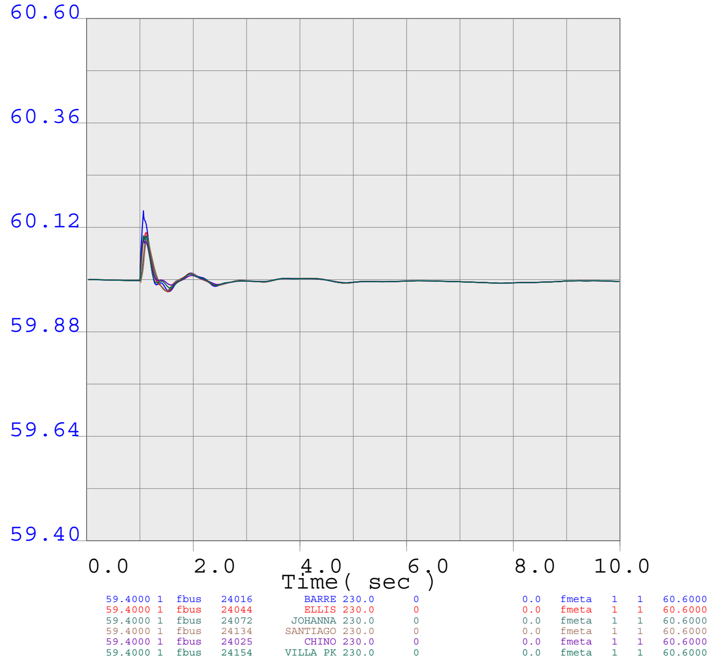
Thu Oct 20 09:02:55 2016

METRO









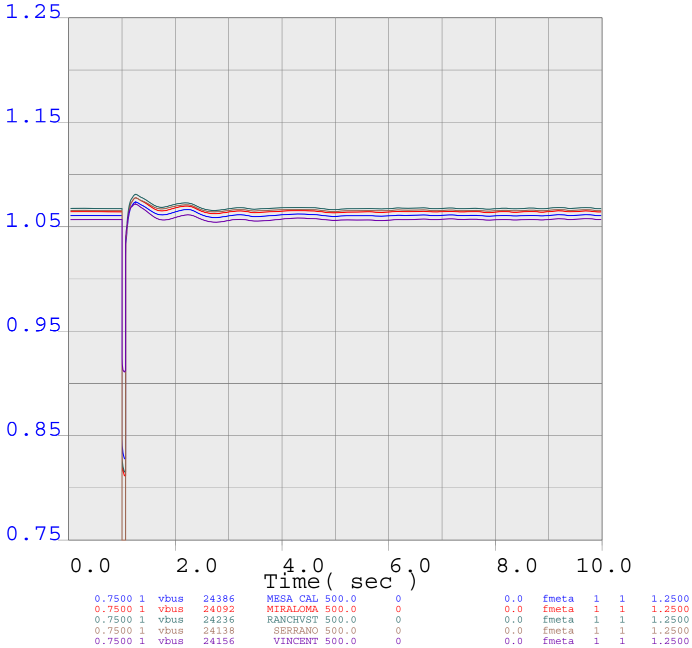
line_1285
Line BARRE 230.0 to ELLIS 230.0 Circuit 3
1 MW dispatch Case

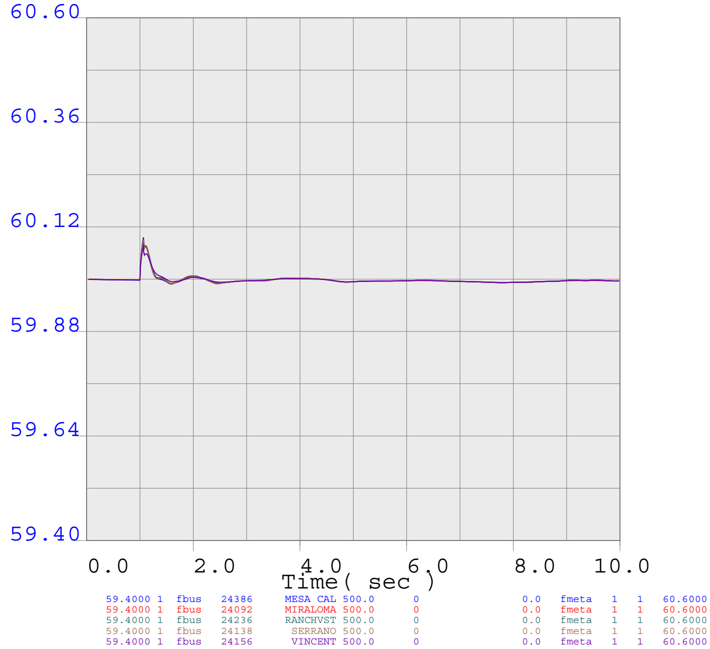
qc9p-line_1285.chf

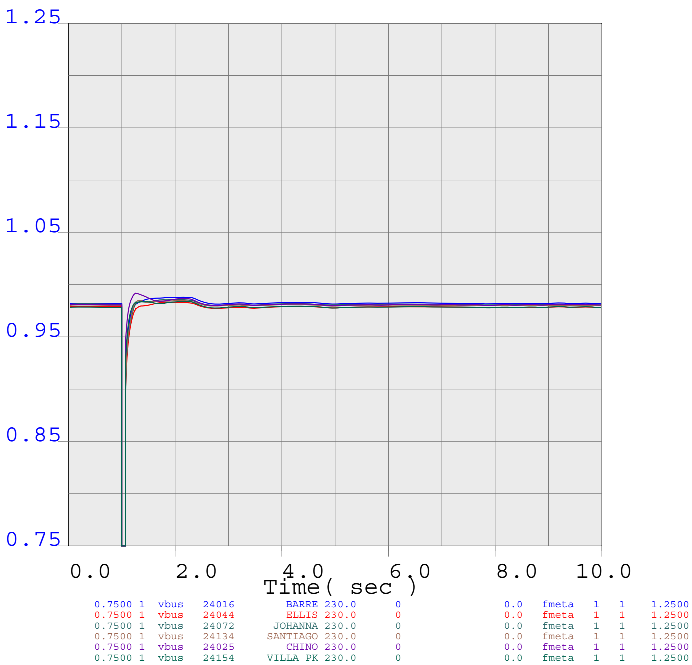
C:\DYTOOLS

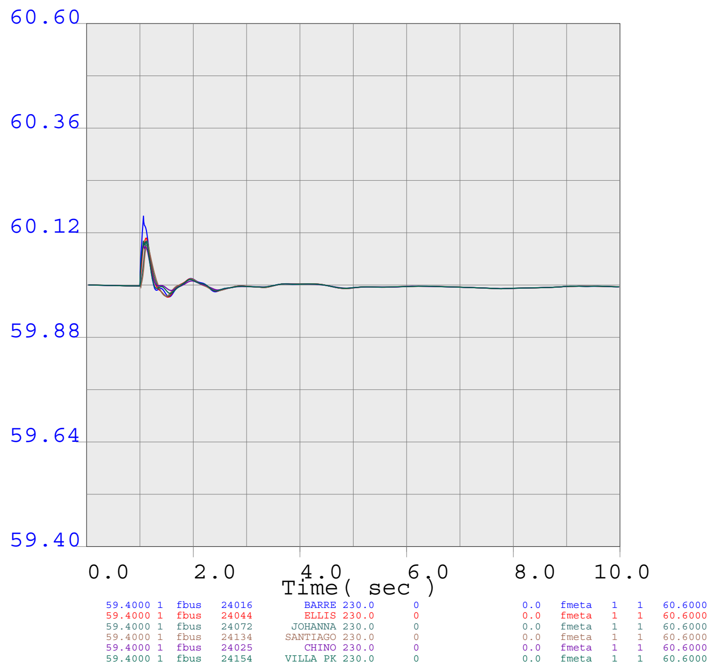
Thu Oct 20 09:02:57 2016

METRO









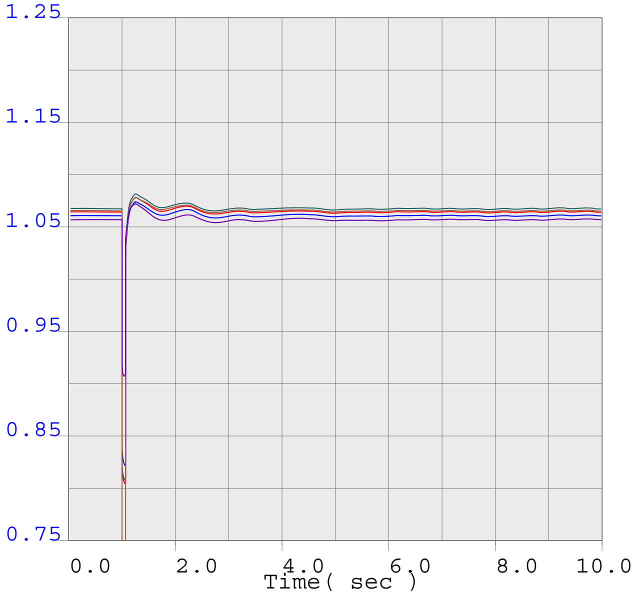
line_1286
Line BARRE 230.0 to ELLIS 230.0 Circuit 4
1 MW dispatch Case

qc9p-line_1286.chf

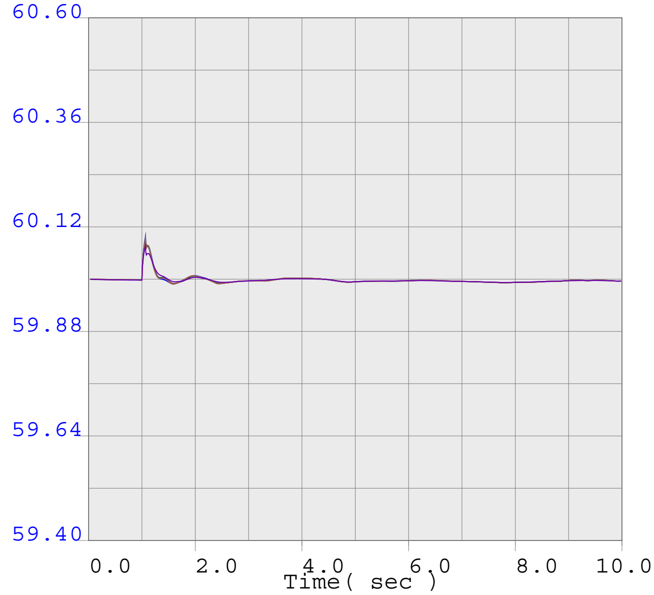
C:\DYTOOLS

Thu Oct 20 09:02:59 2016

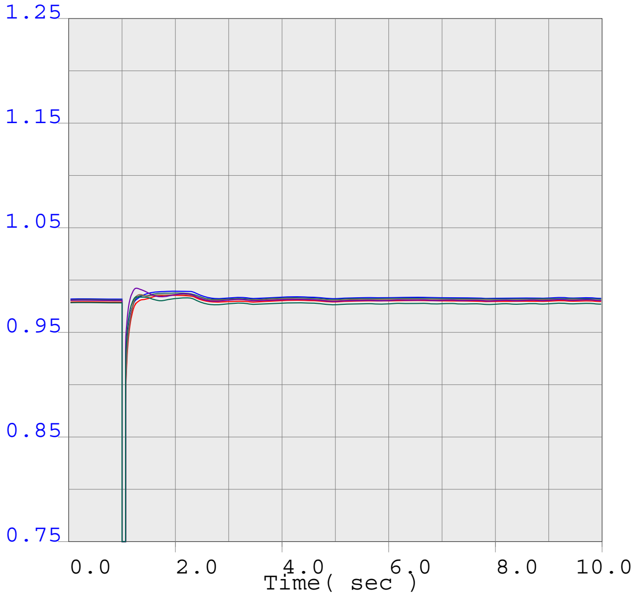
METRO



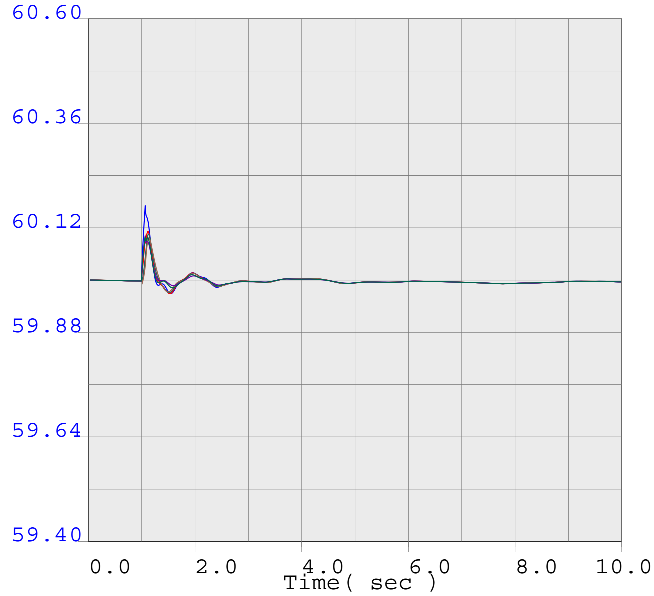
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

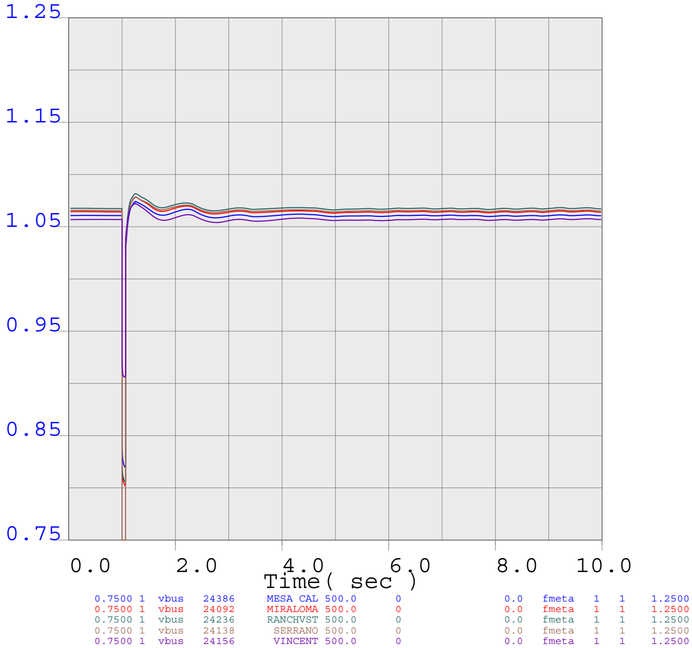
line_1287
Line BARRE 230.0 to VILLA PK 230.0 Circuit 1
1 MW dispatch Case

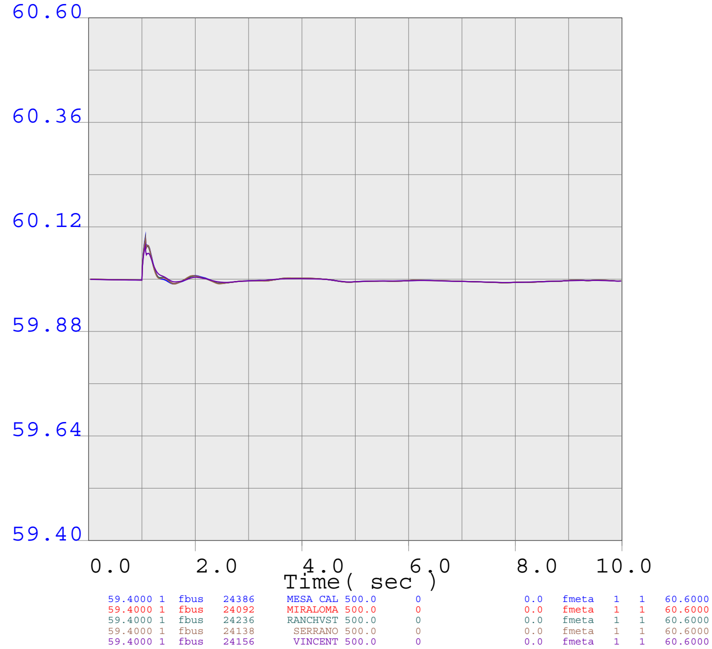
qc9p-line_1287.chf

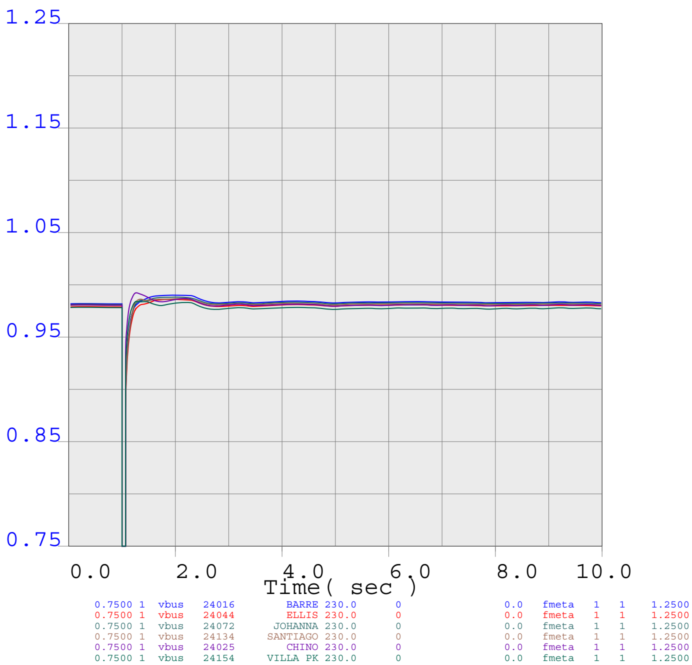
C:\DYTOOLS

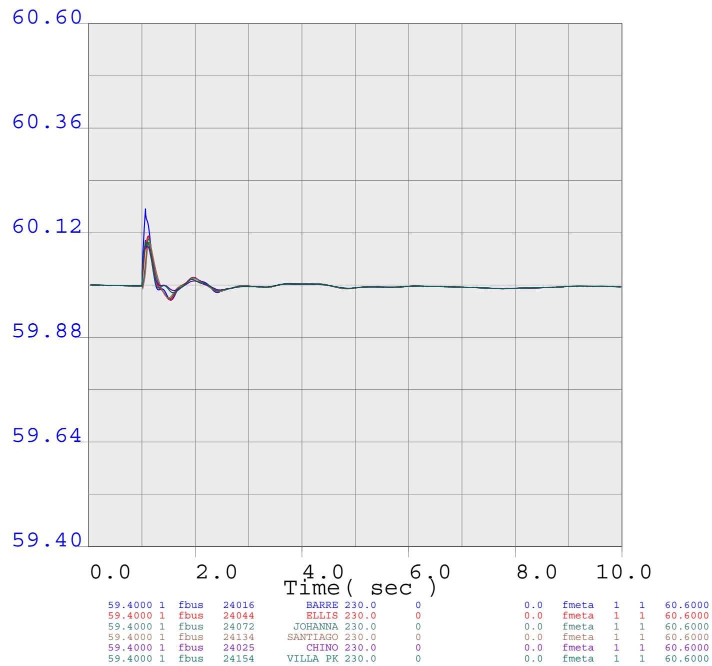
Thu Oct 20 09:03:01 2016

METRO









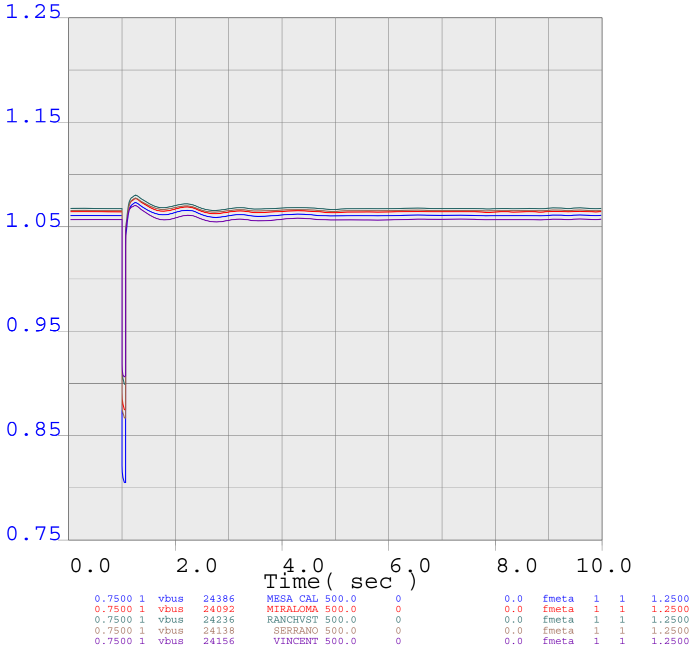
line_1288
Line BARRE 230.0 to LEWIS 230.0 Circuit 1
1 MW dispatch Case

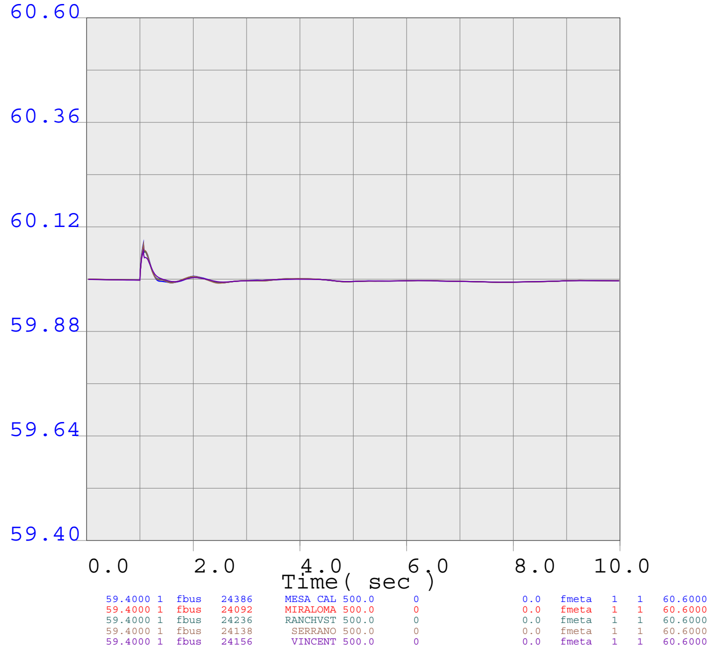
qc9p-line_1288.chf

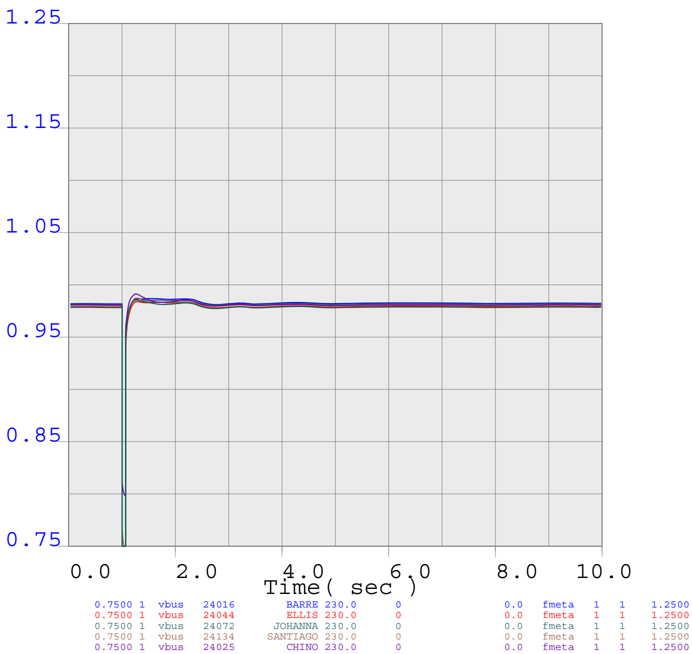
C:\DYTOOLS

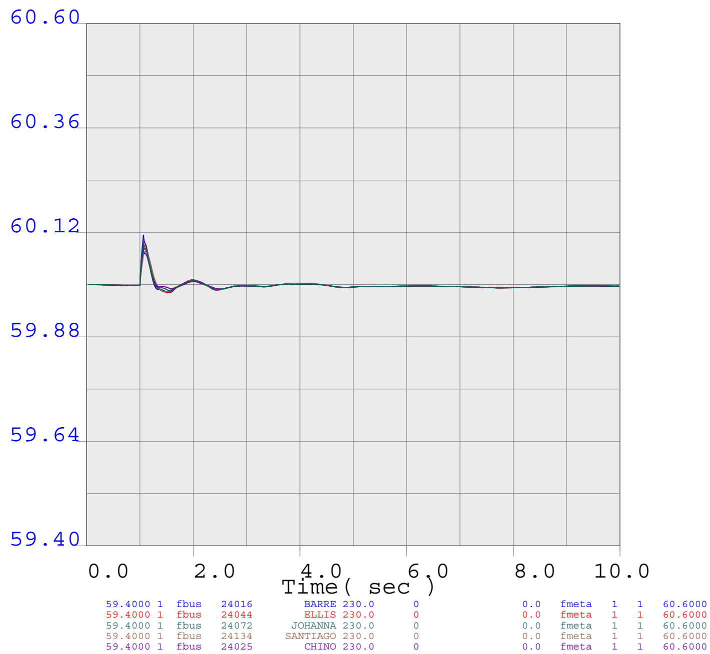
Thu Oct 20 09:03:03 2016

METRO









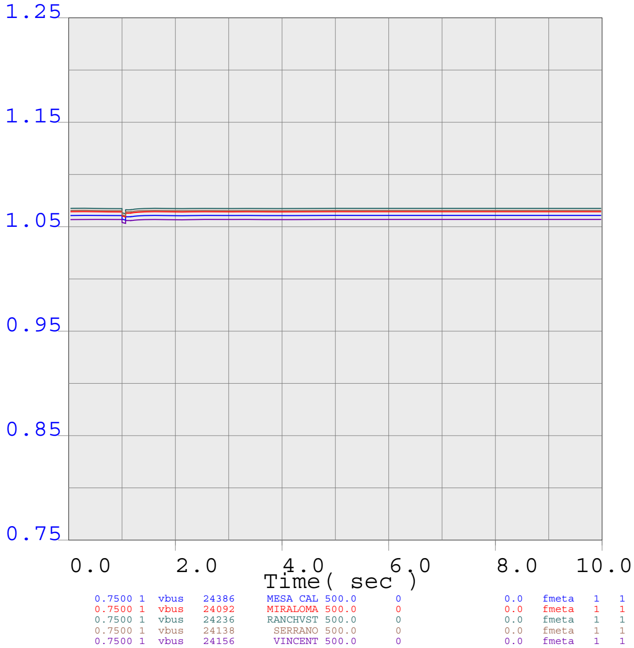
line_1289
Line DELAMO 230.0 to BARRE 230.0 Circuit 1
1 MW dispatch Case

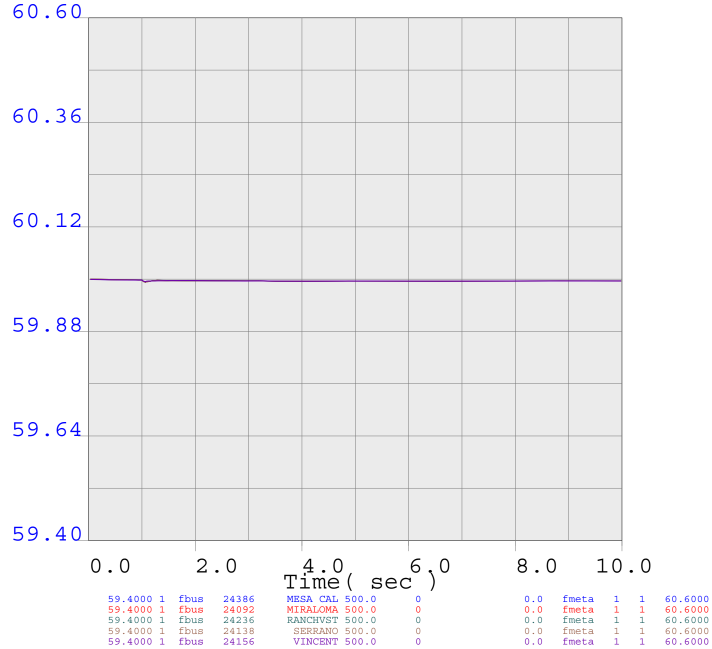
qc9p-line_1289.chf

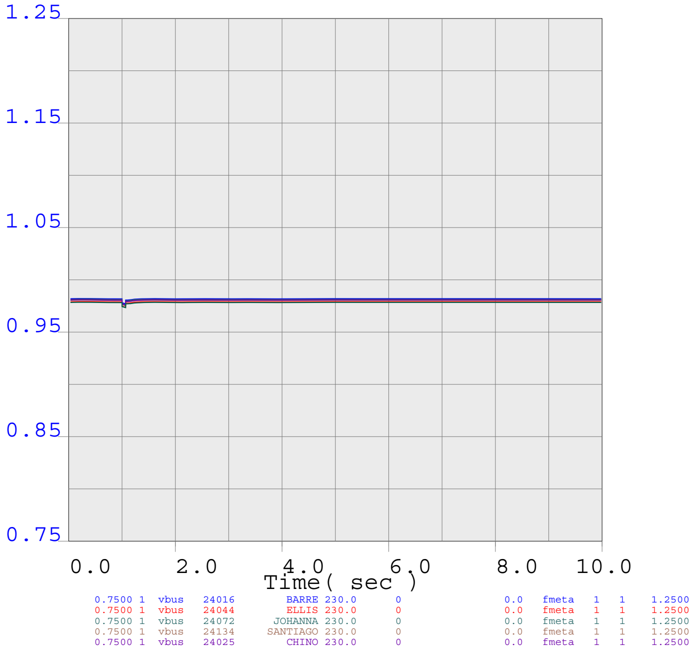
C:\DYTOOLS

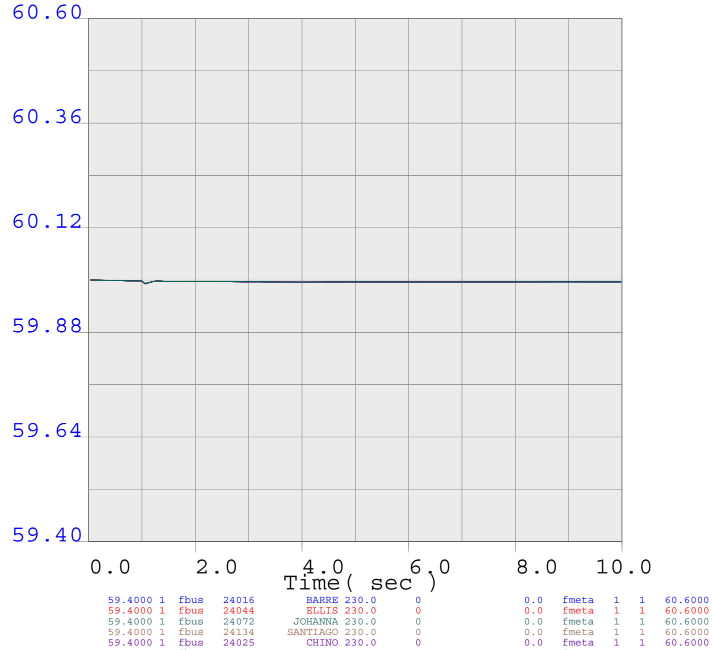
Thu Oct 20 09:03:05 2016

METRO









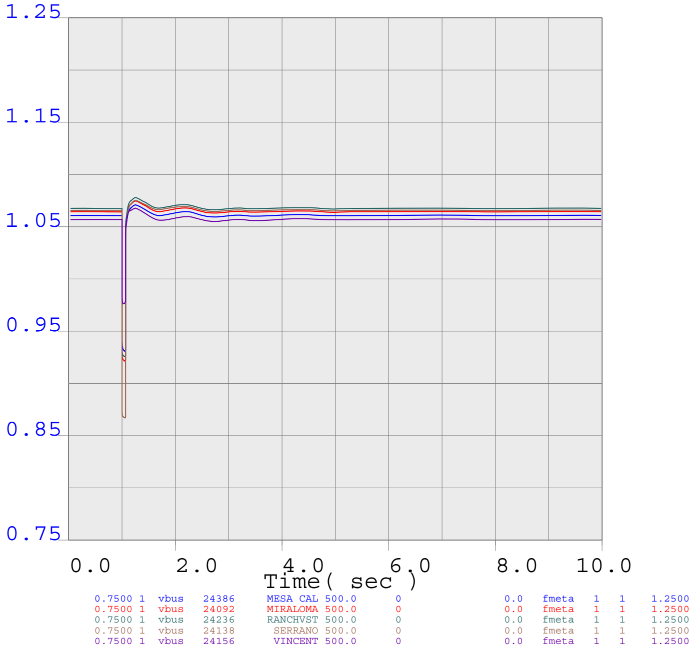
line_1290
Line DELAMO 230.0 to ELLIS 230.0 Circuit 1
1 MW dispatch Case

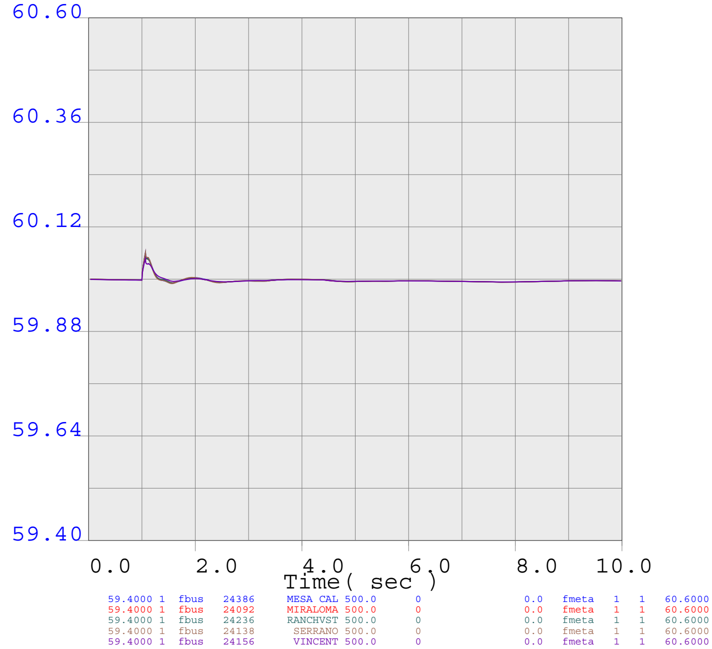
qc9p-line_1290.chf

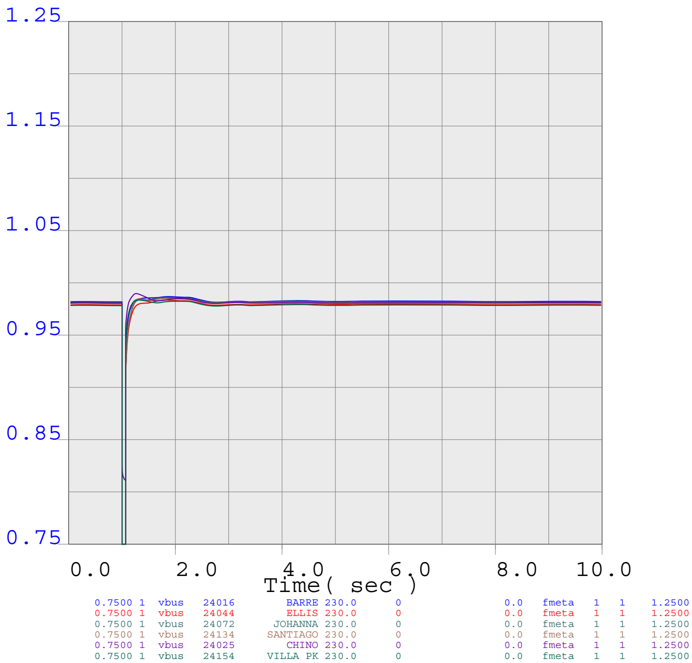
C:\DYTOOLS

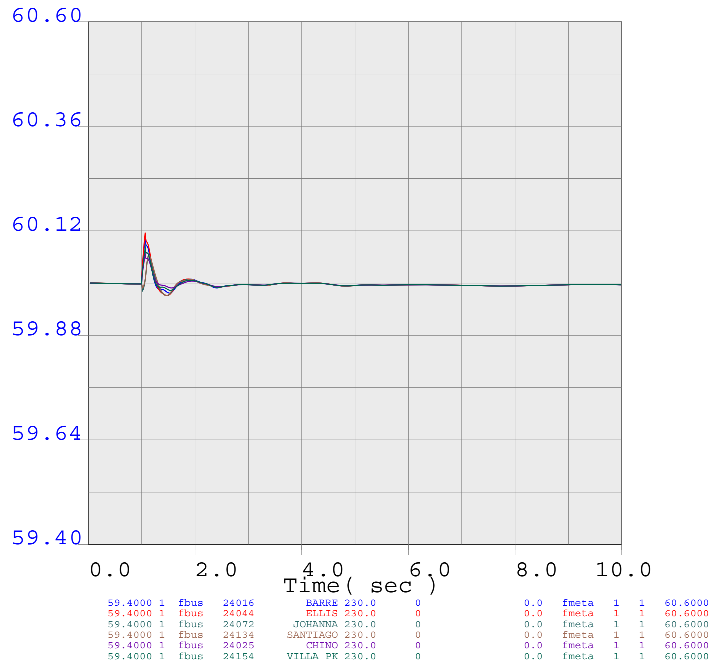
Thu Oct 20 09:03:07 2016

METRO









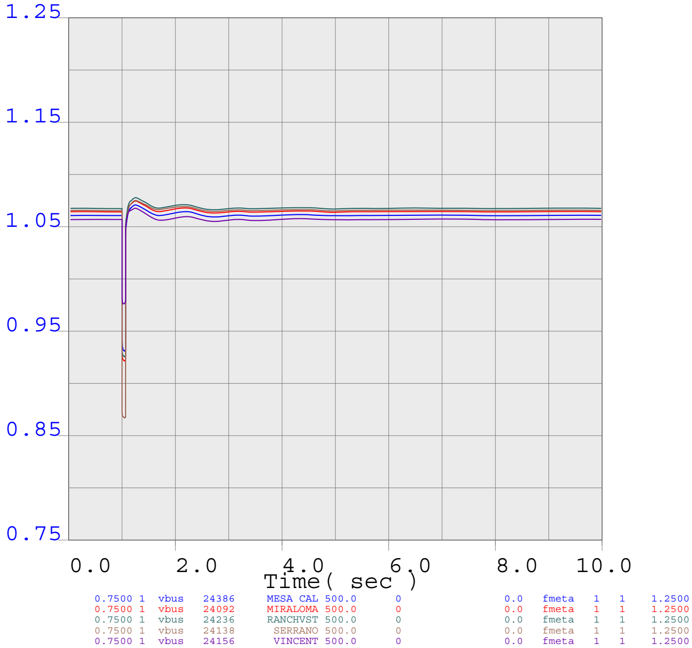
line_1291
Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 1
1 MW dispatch Case

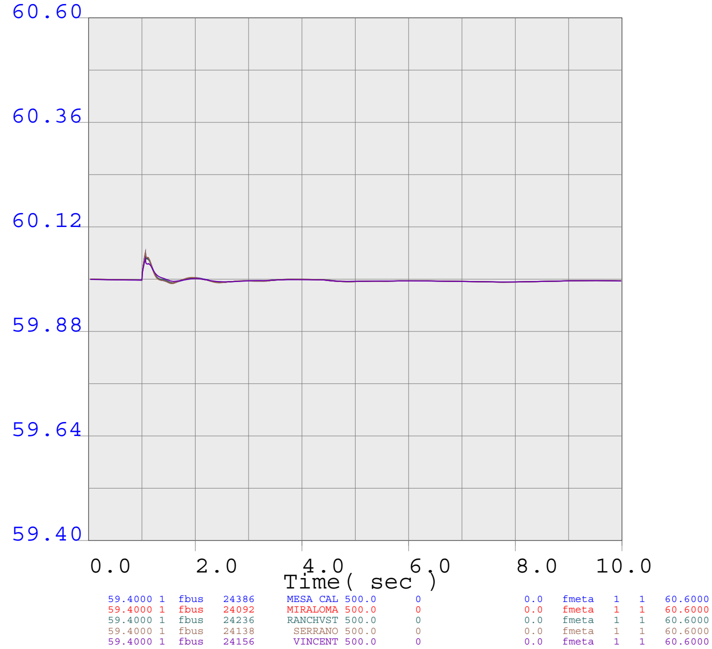
qc9p-line_1291.chf

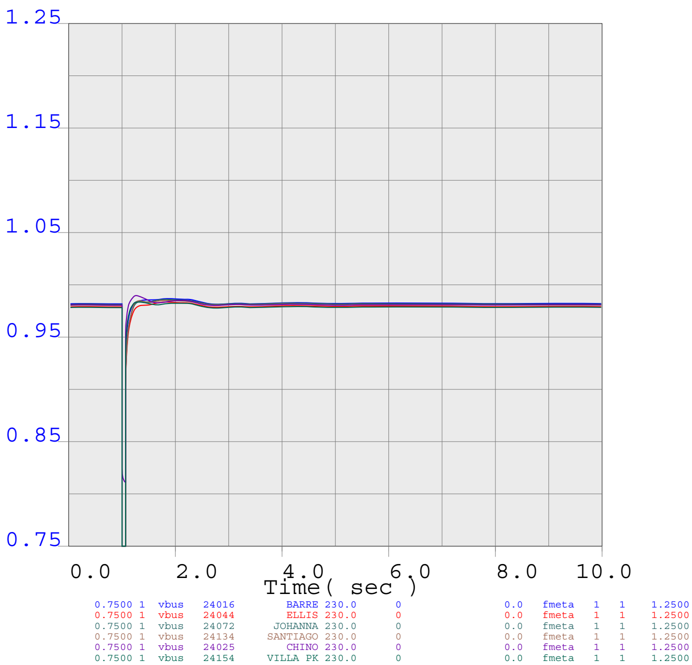
C:\DYTOOLS

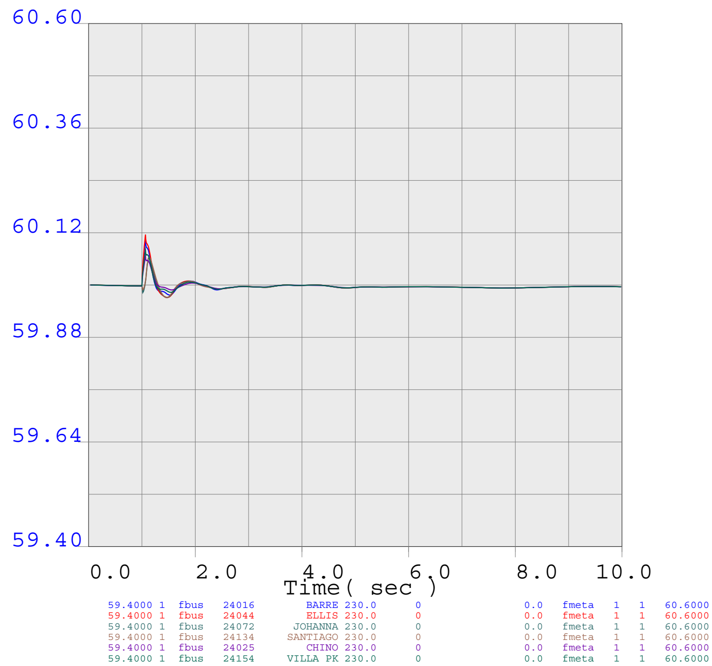
Thu Oct 20 09:03:09 2016

METRO









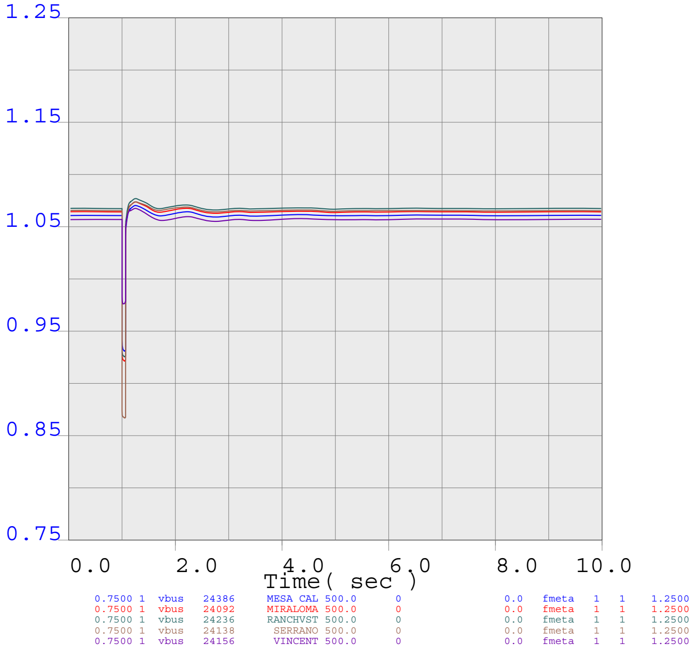
line_1292
Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 3
1 MW dispatch Case

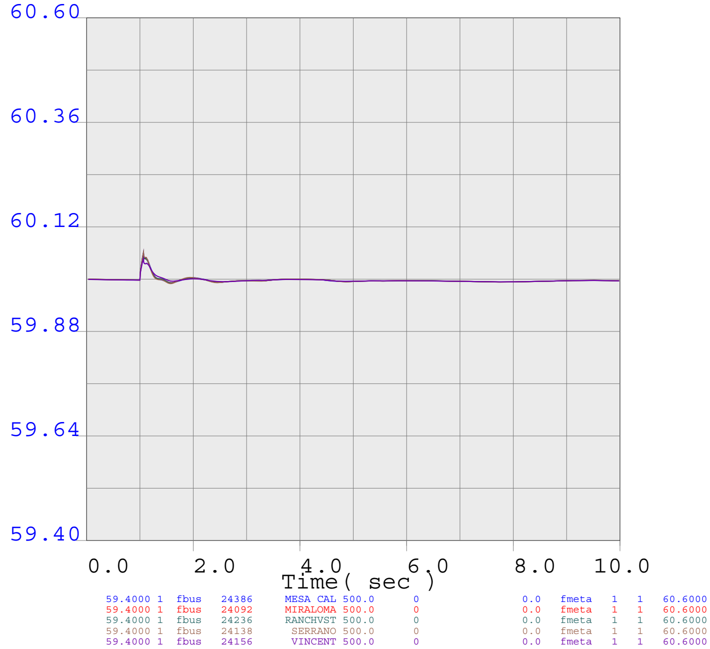
qc9p-line_1292.chf

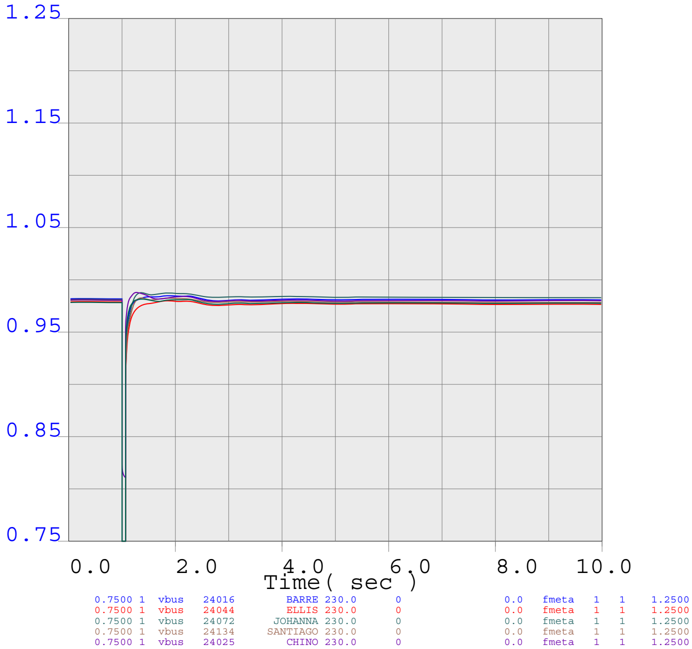
C:\DYTOOLS

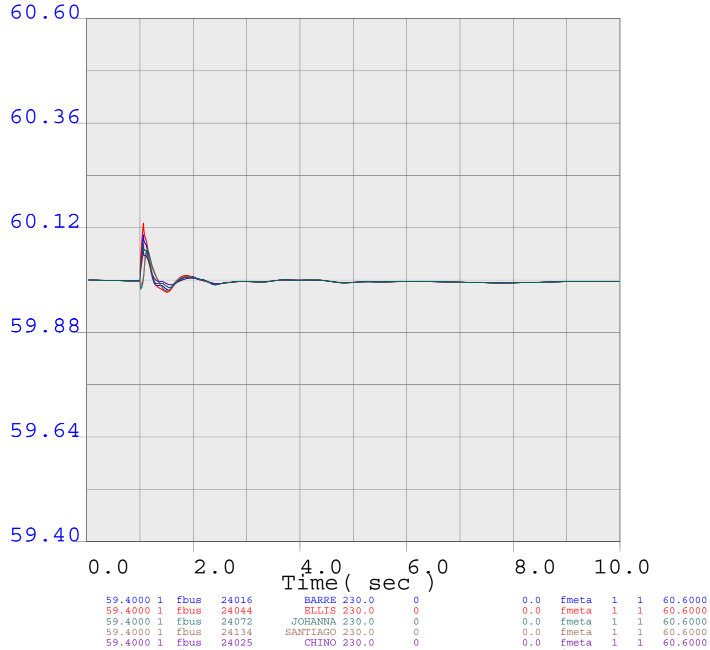
Thu Oct 20 09:03:11 2016

METRO









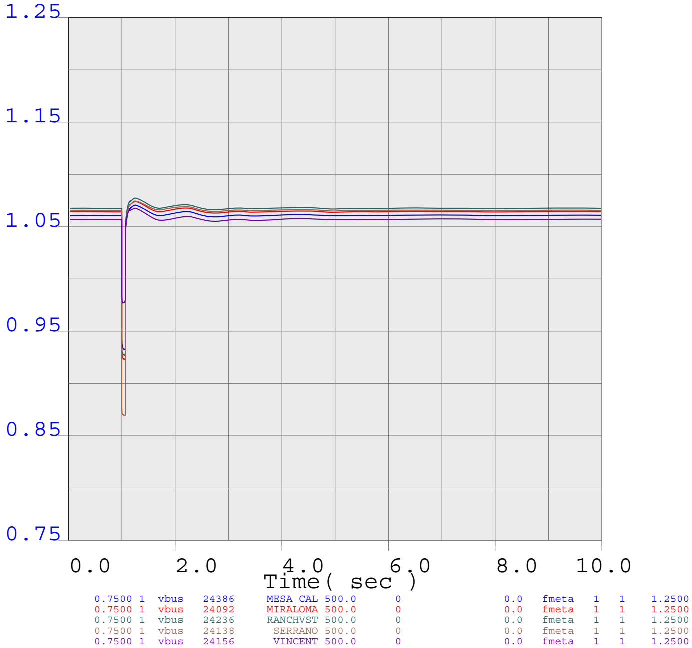
line_1293
Line ELLIS 230.0 to JOHANNA 230.0 Circuit 1
1 MW dispatch Case

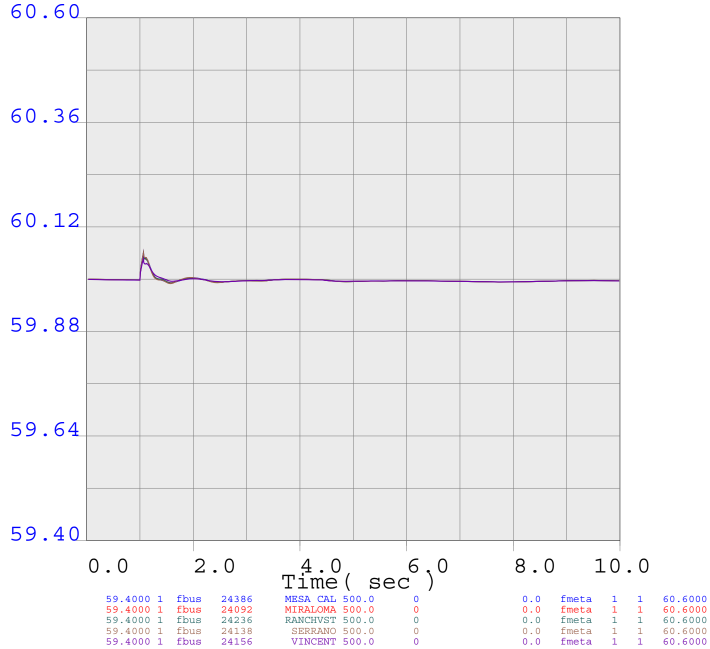
qc9p-line_1293.chf

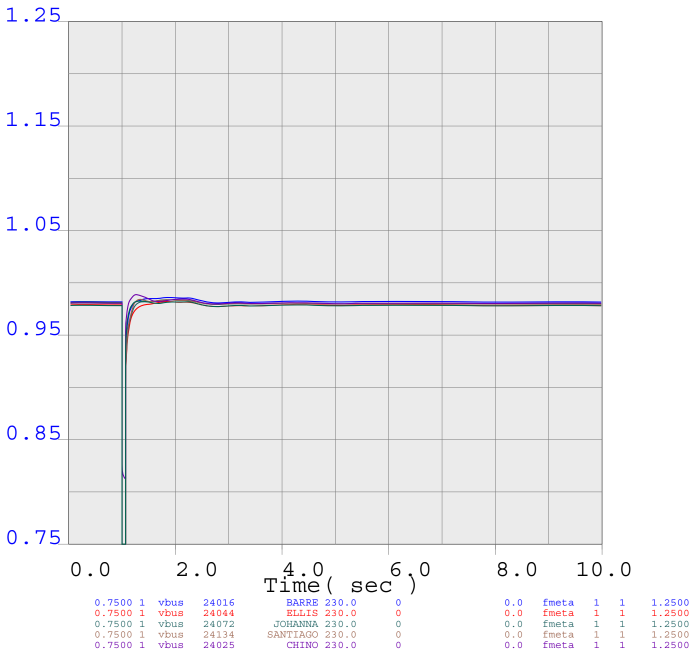
C:\DYTOOLS

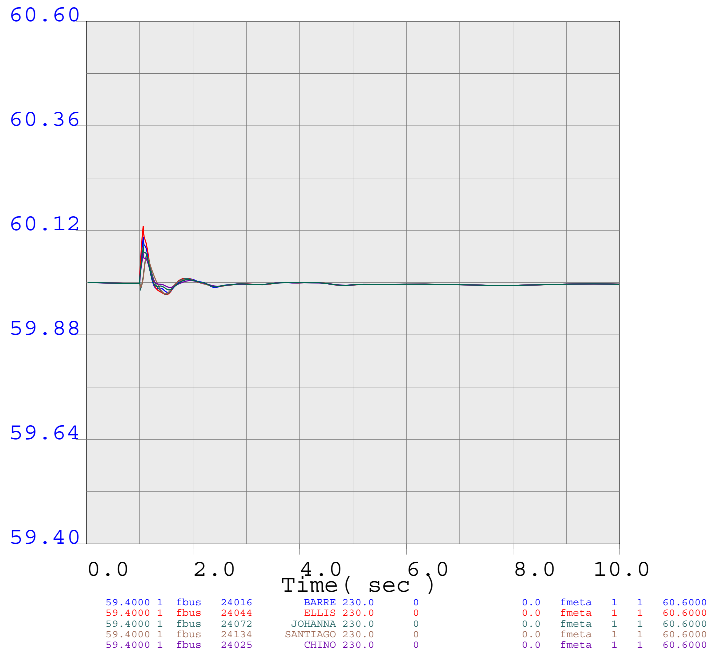
Thu Oct 20 09:03:13 2016

METRO









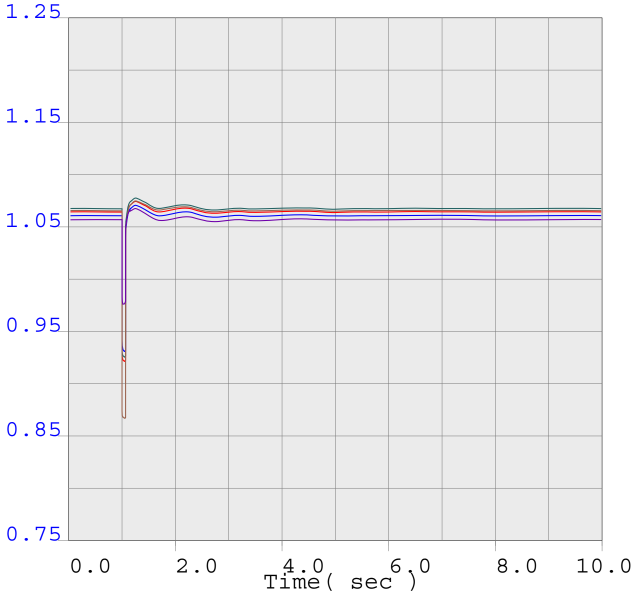
line_1294
Line ELLIS 230.0 to SANTIAGO 230.0 Circuit 1
1 MW dispatch Case

qc9p-line_1294.chf

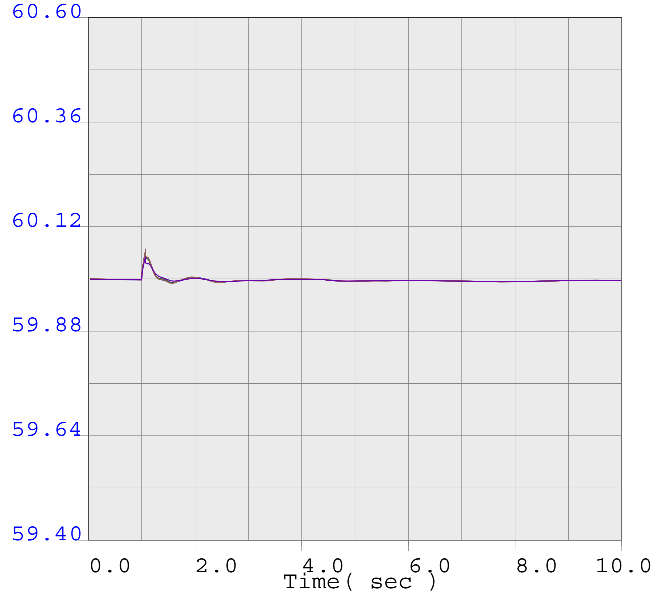
C:\DYTOOLS

Thu Oct 20 09:03:15 2016

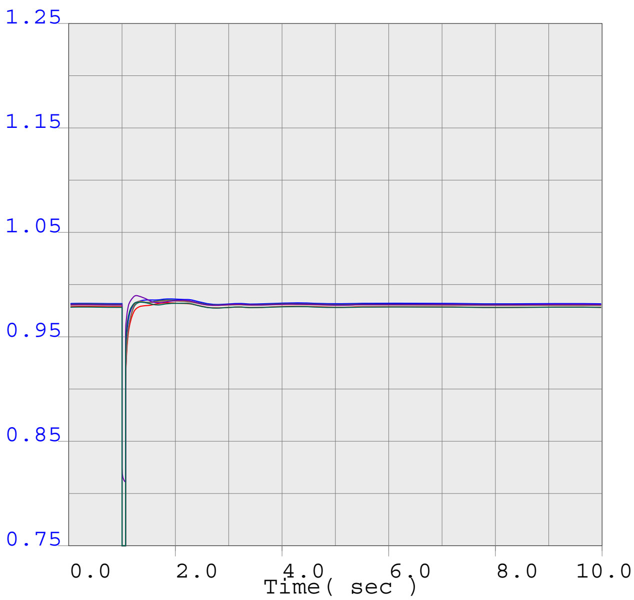
METRO



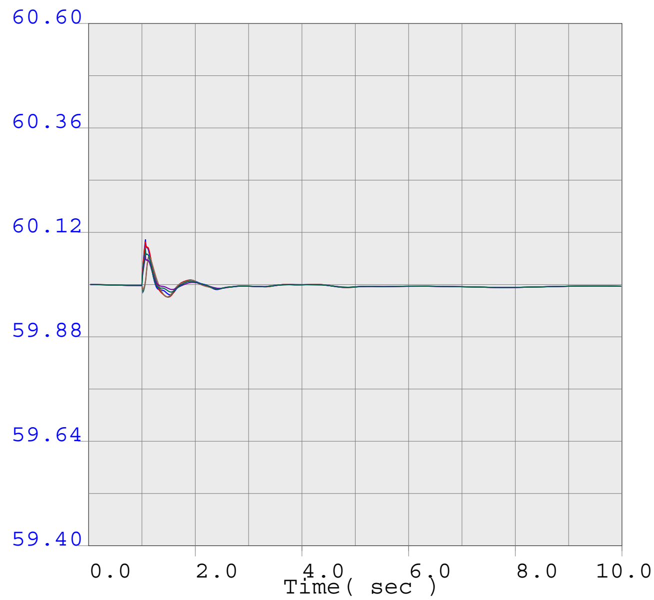
0.7500	1	vbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	60.6000

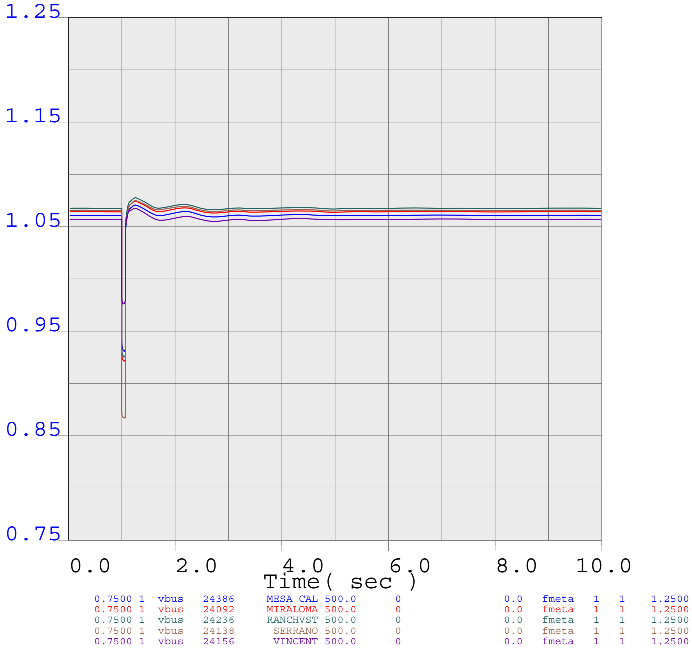
line_1295
Line ELLIS 230.0 to HUNTBCH1 230.0 Circuit 2
1 MW dispatch Case

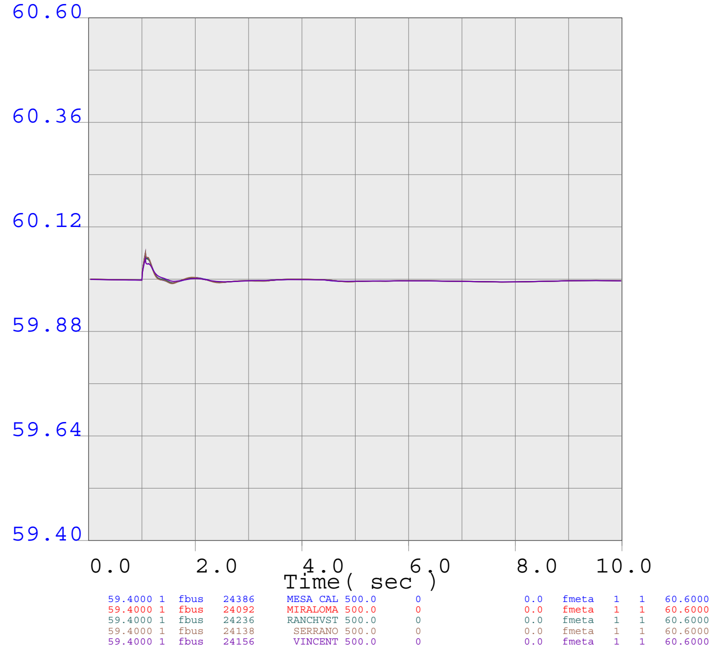
qc9p-line_1295.chf

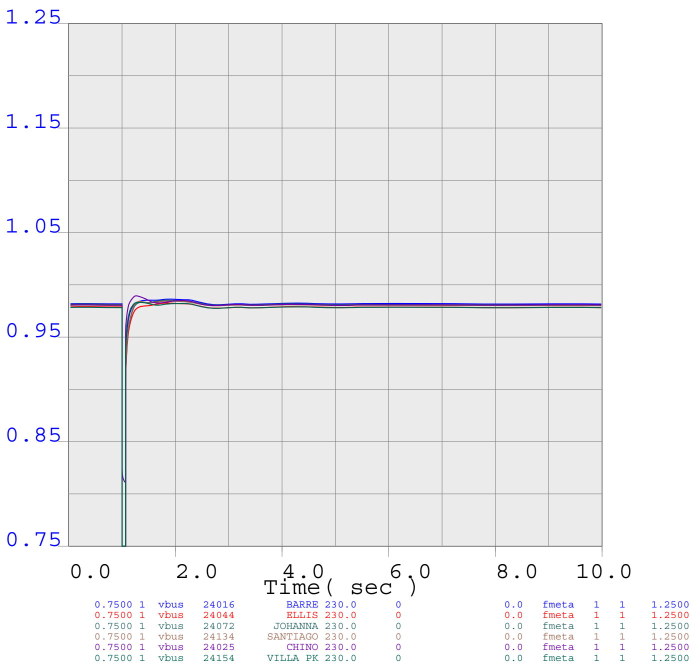
C:\DYTOOLS

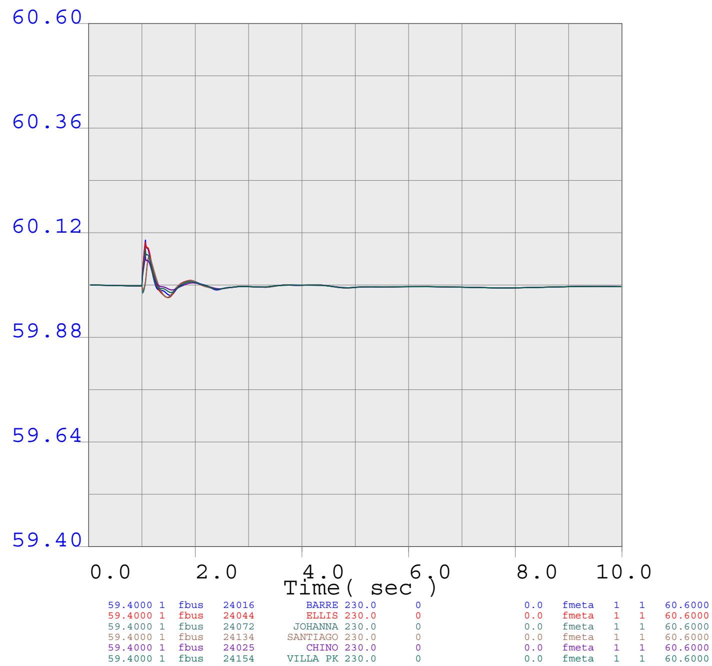
Thu Oct 20 09:03:17 2016

METRO









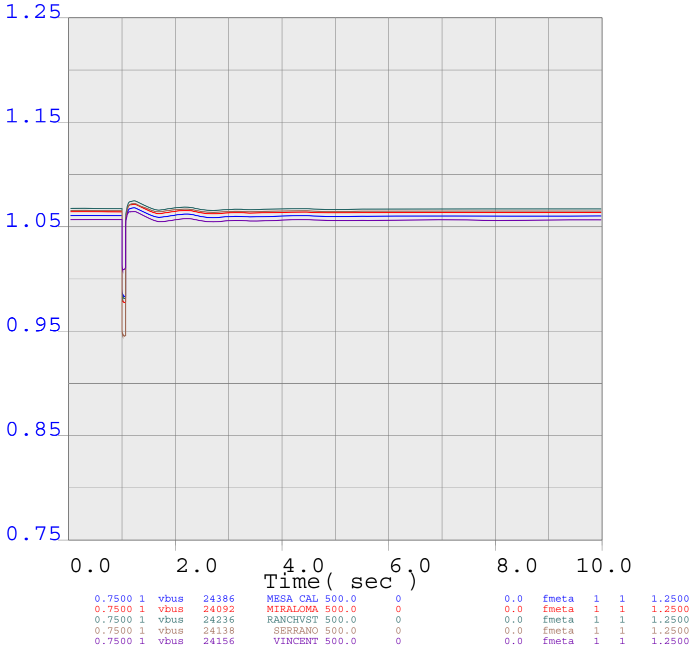
line_1296
Line ELLIS 230.0 to HUNTBCH1 230.0 Circuit 4
1 MW dispatch Case

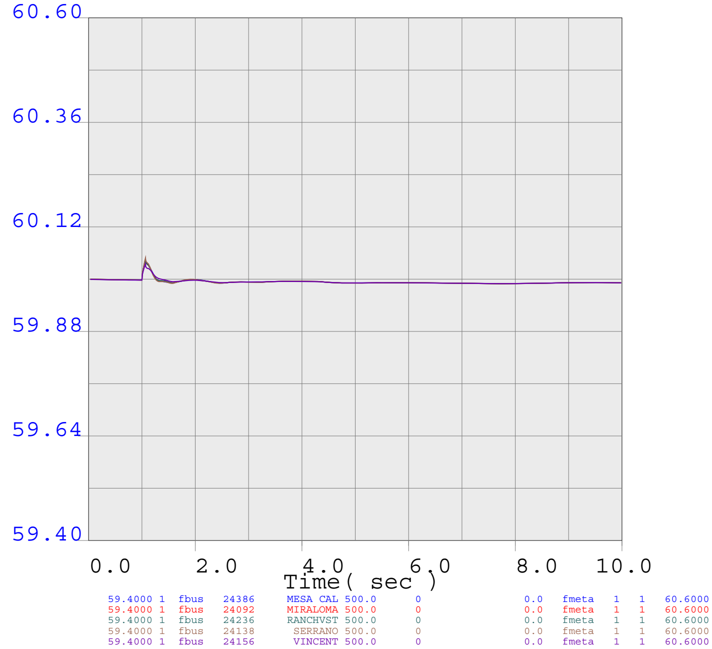
qc9p-line_1296.chf

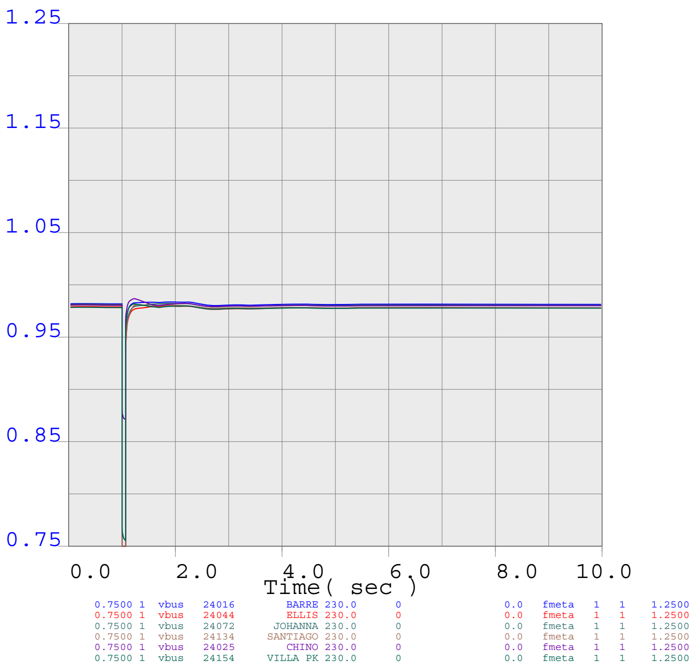
C:\DYTOOLS

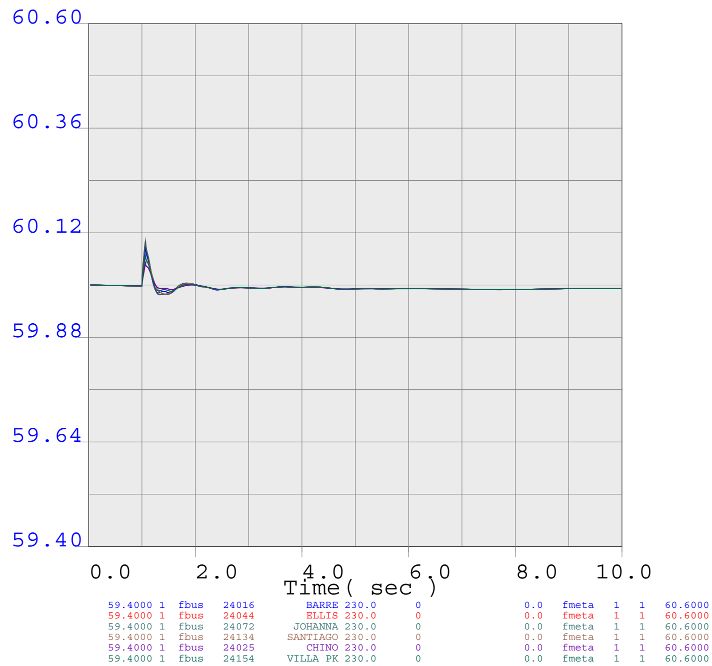
Thu Oct 20 09:03:19 2016

METRO









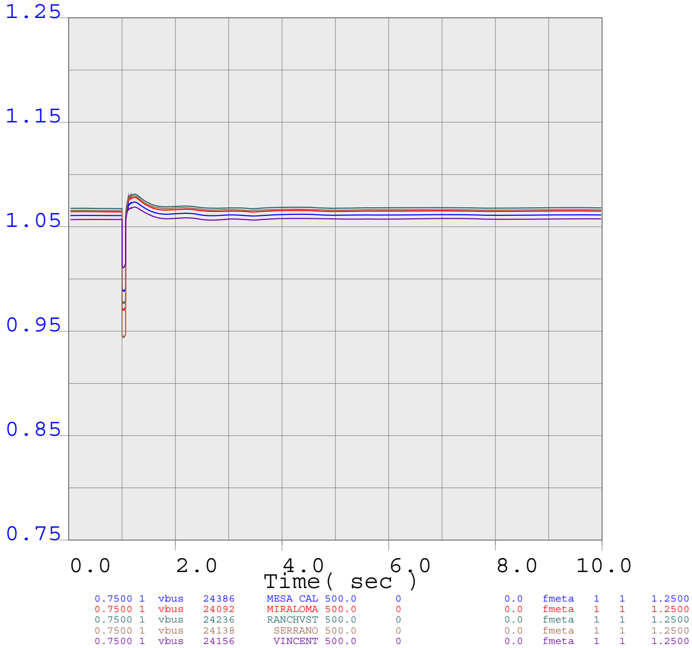
line_1297
Line JOHANNA 230.0 to SANTIAGO 230.0 Circuit 1
1 MW dispatch Case

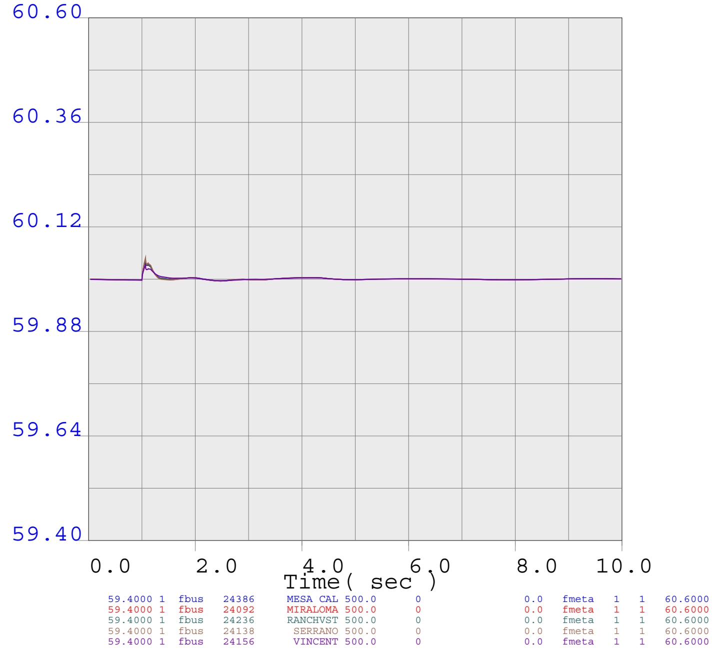
qc9p-line_1297.chf

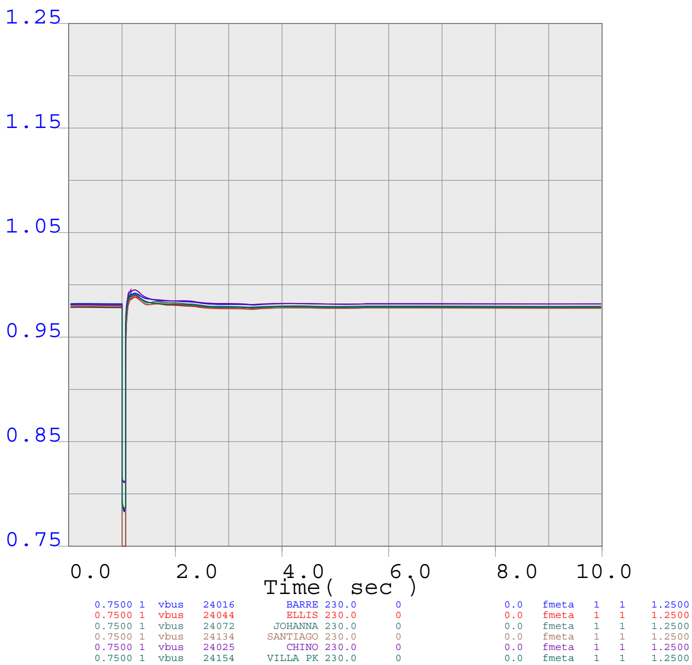
C:\DYTOOLS

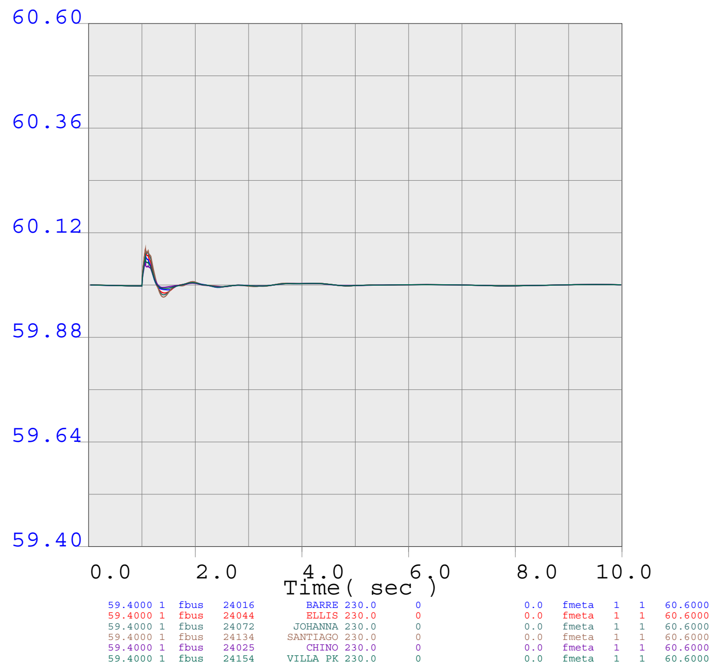
Thu Oct 20 09:03:21 2016

METRO









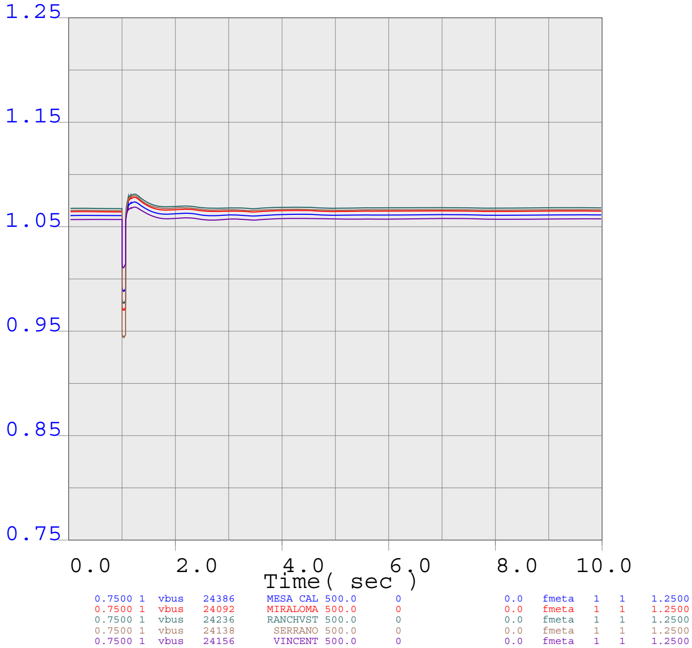
line_1298
Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 1
1 MW dispatch Case

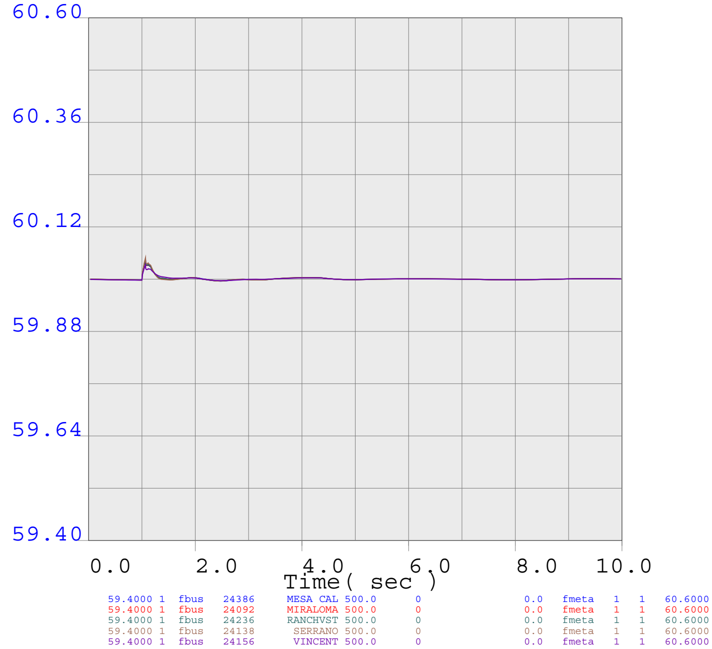
qc9p-line_1298.chf

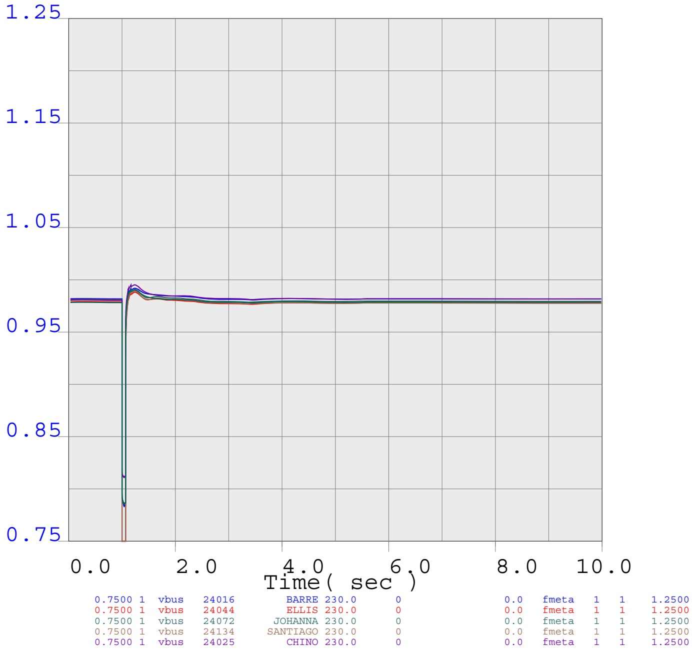
C:\DYTOOLS

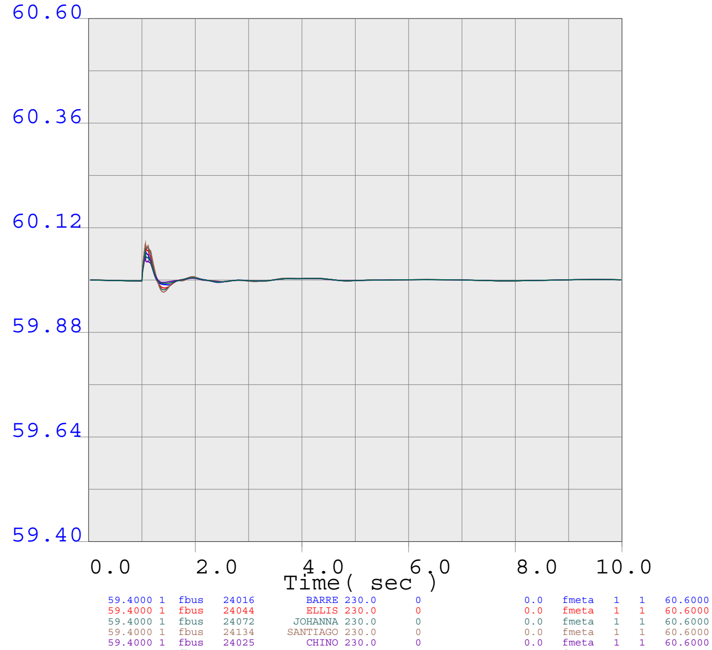
Thu Oct 20 09:03:23 2016

METRO









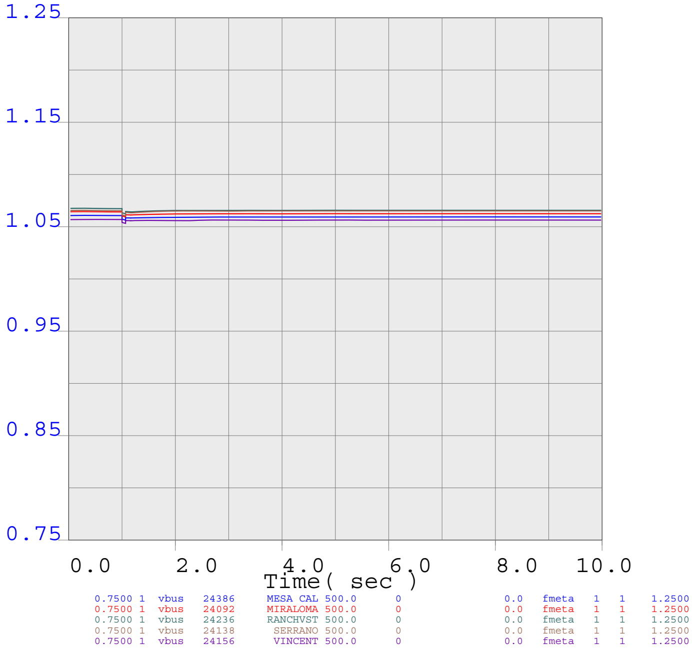
line_1299
Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 2
1 MW dispatch Case

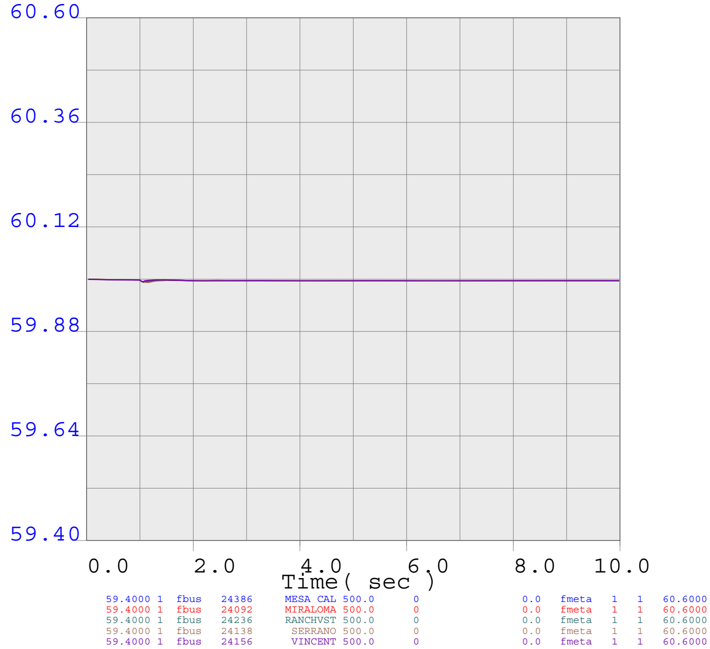
qc9p-line_1299.chf

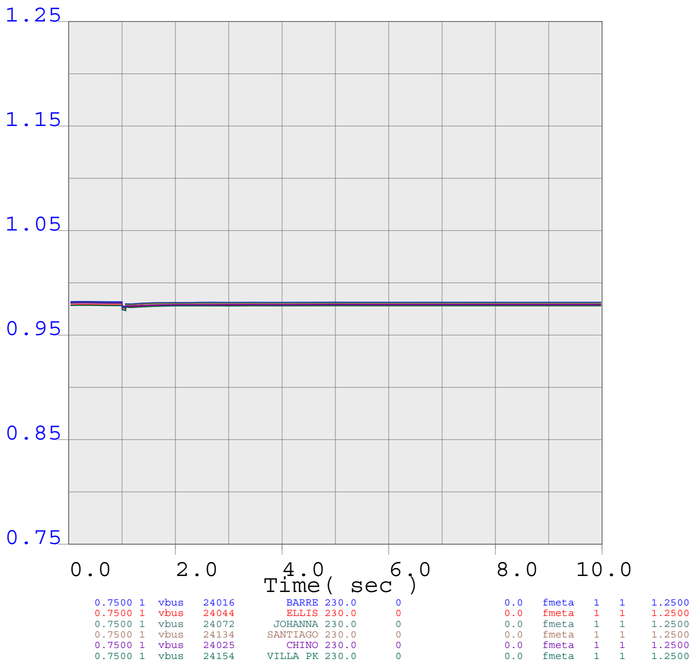
C:\DYTOOLS

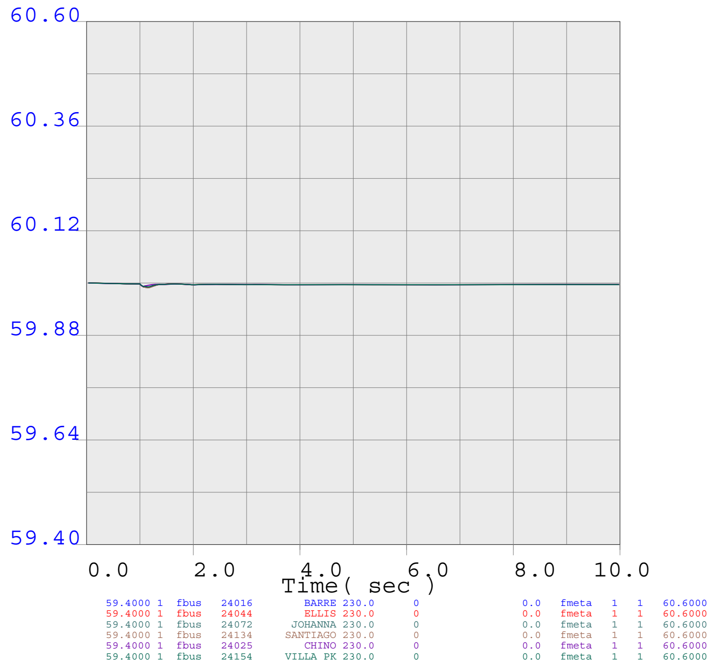
Thu Oct 20 09:03:25 2016

METRO





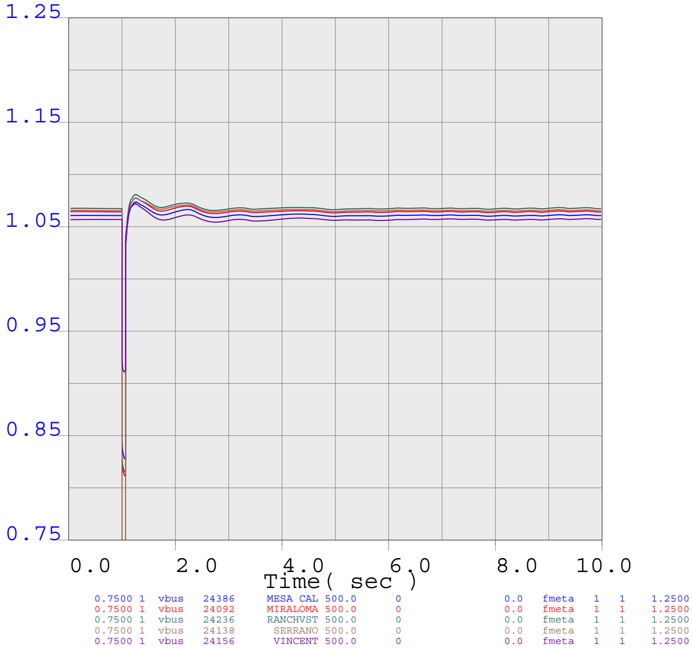


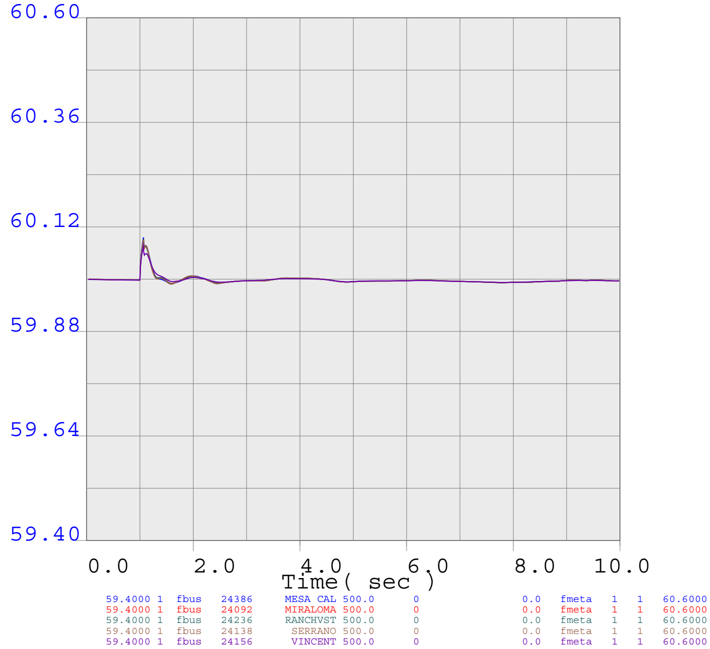


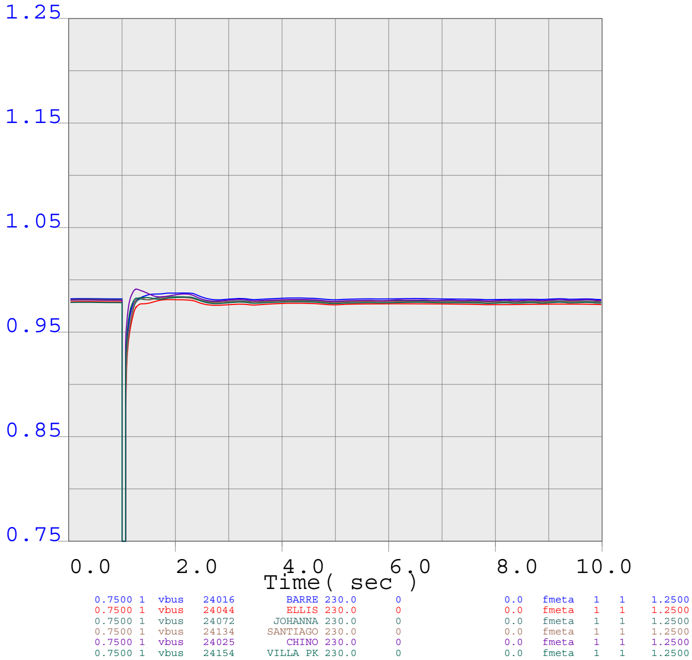
line_7101
Line MIRALOMA 500.0 to SERRANO 500.0 Circuit 1 & Line MIRALOMA 500.0 to SERRANO
1 MW dispatch Case

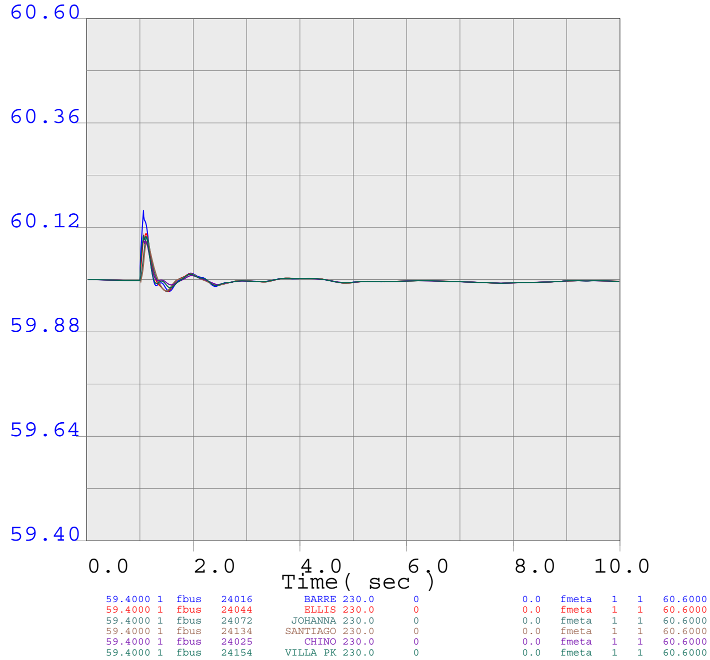
	qc9p-line_7101.chf	C:\DYTOOLS Thu Oct 20 09:03:27 2016

METRO









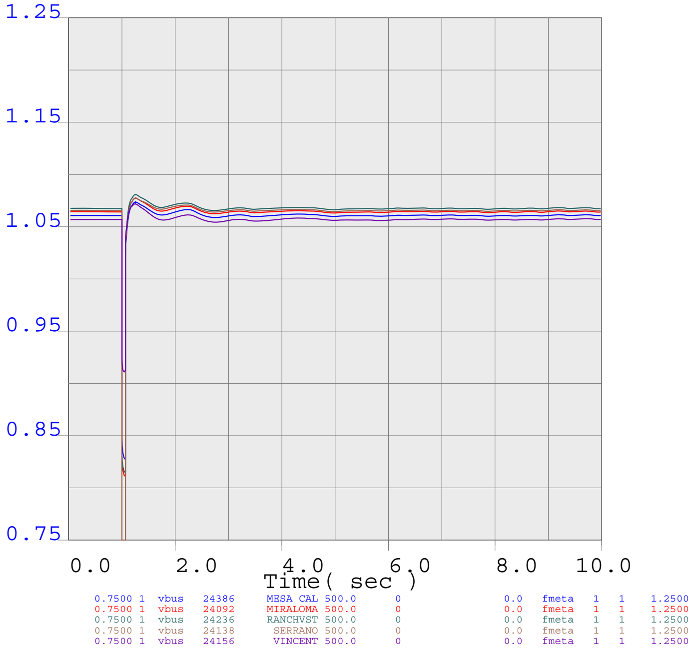
line_7102
Line BARRE 230.0 to ELLIS 230.0 Circuit 1 & Line BARRE 230.0 to ELLIS 230.0 Cir

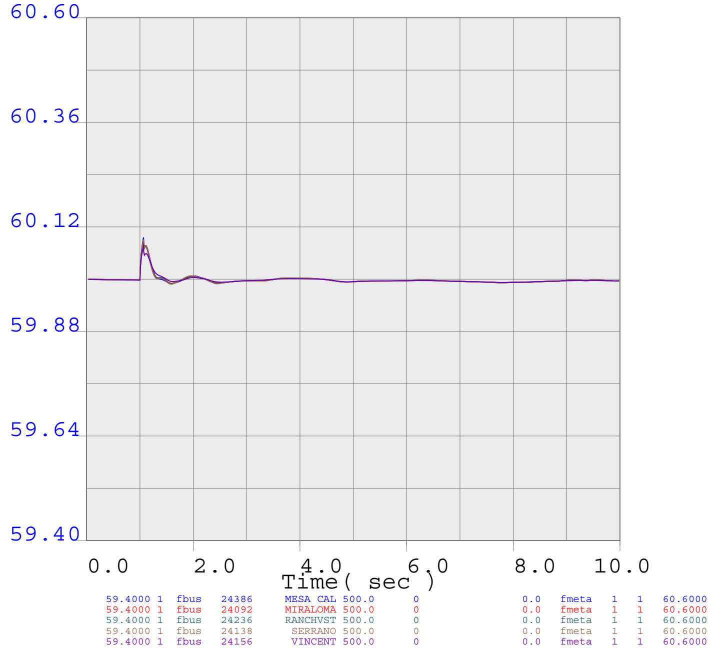
qc9p-line_7102.chf

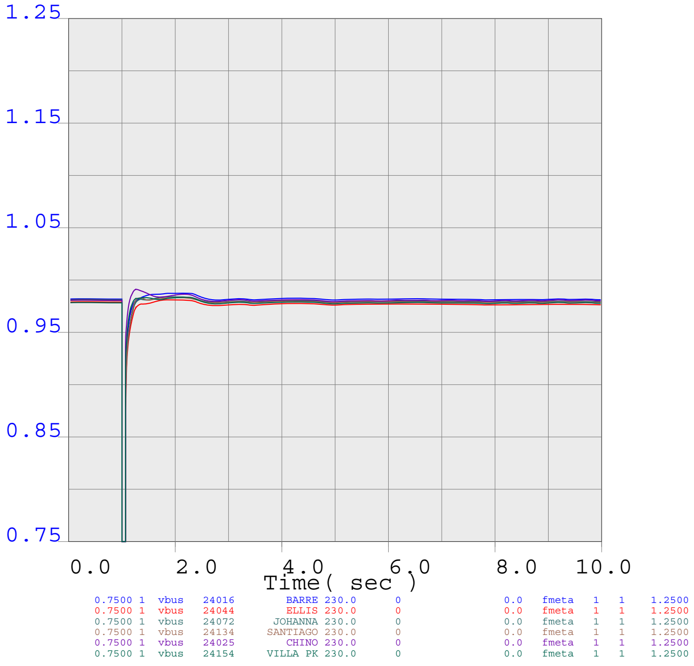
C:\DYTOOLS

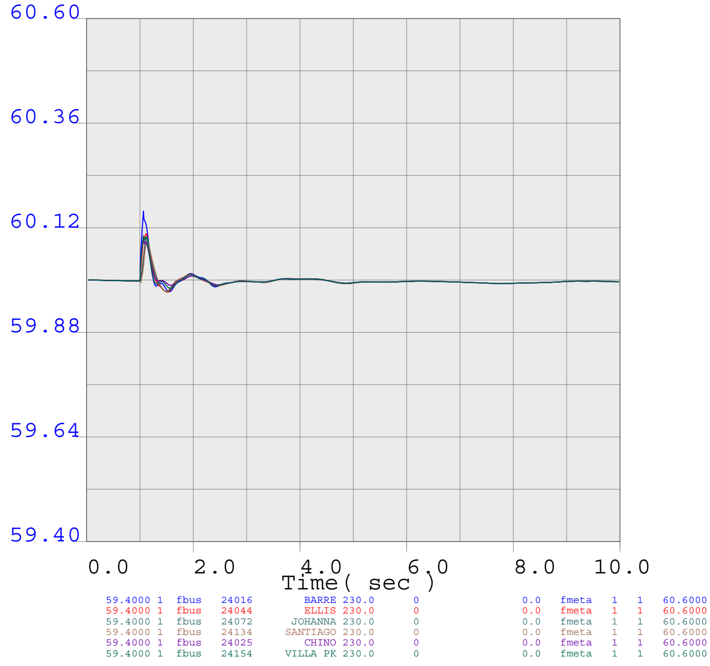
Thu Oct 20 09:03:29 2016

METRO









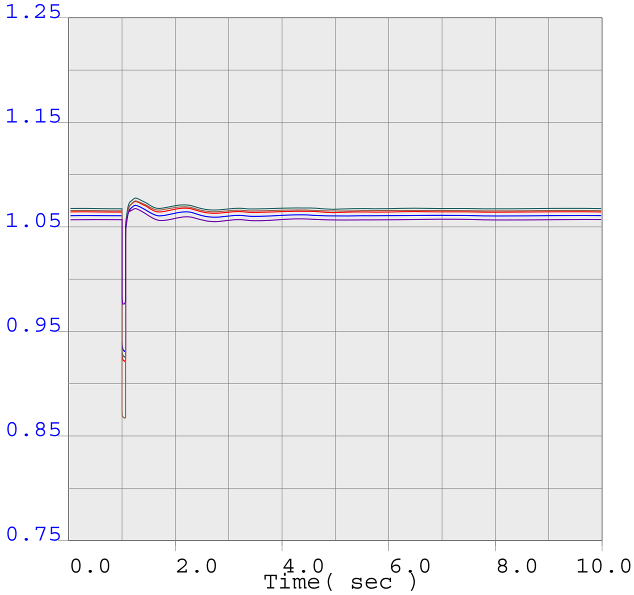
line_7103
Line BARRE 230.0 to ELLIS 230.0 Circuit 3 & Line BARRE 230.0 to ELLIS 230.0 Cir

qc9p-line_7103.chf

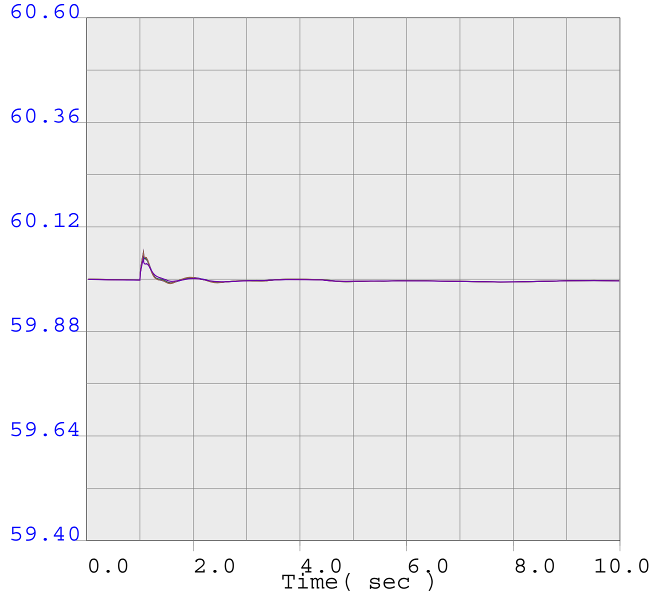
C:\DYTOOLS

Thu Oct 20 09:03:31 2016

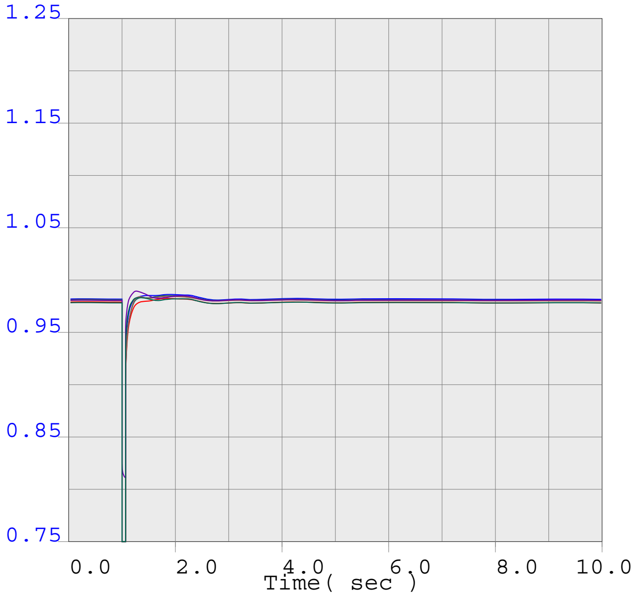
METRO



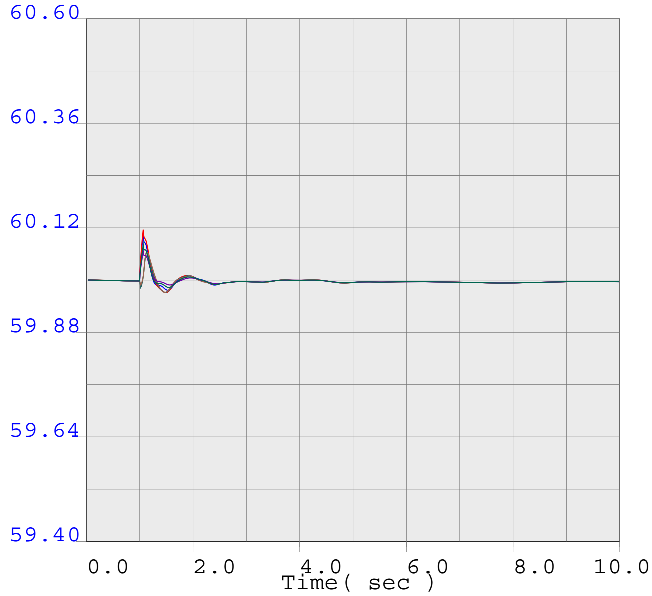
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

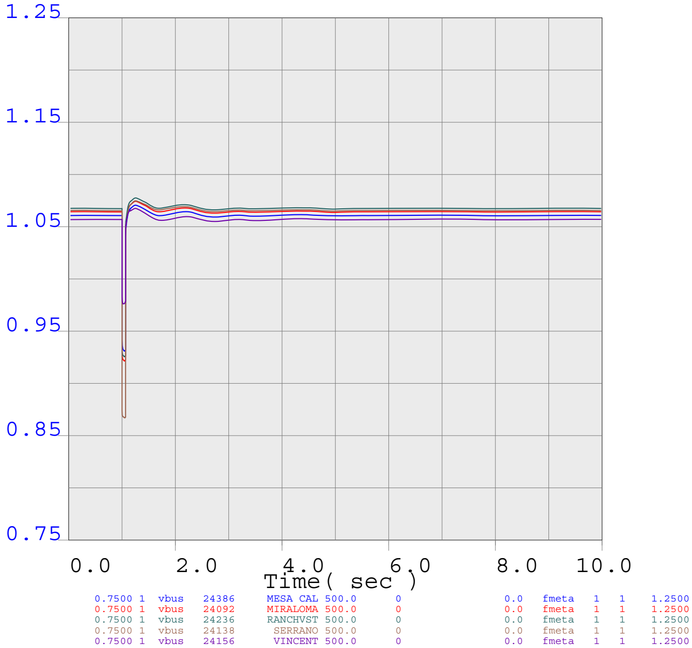
line_7104
Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 1 & Line ELLIS 230.0 to HUNTBCH1 230

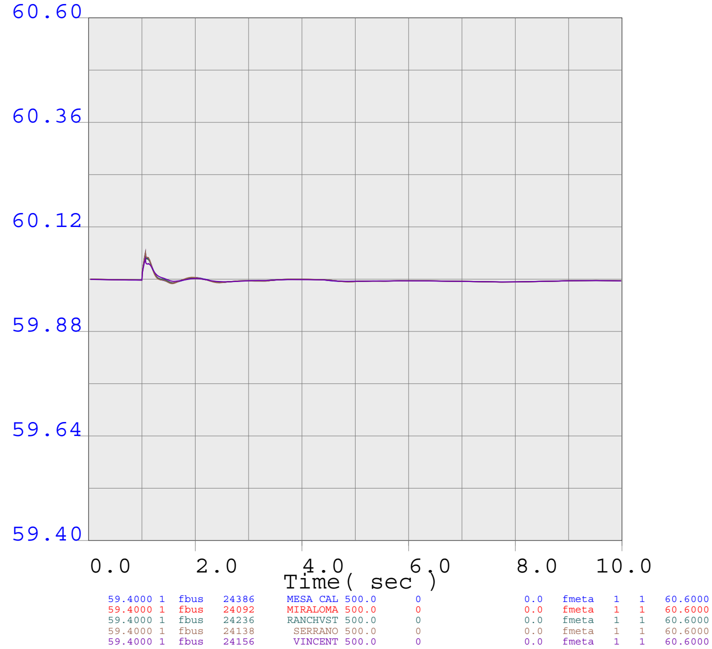
qc9p-line_7104.chf

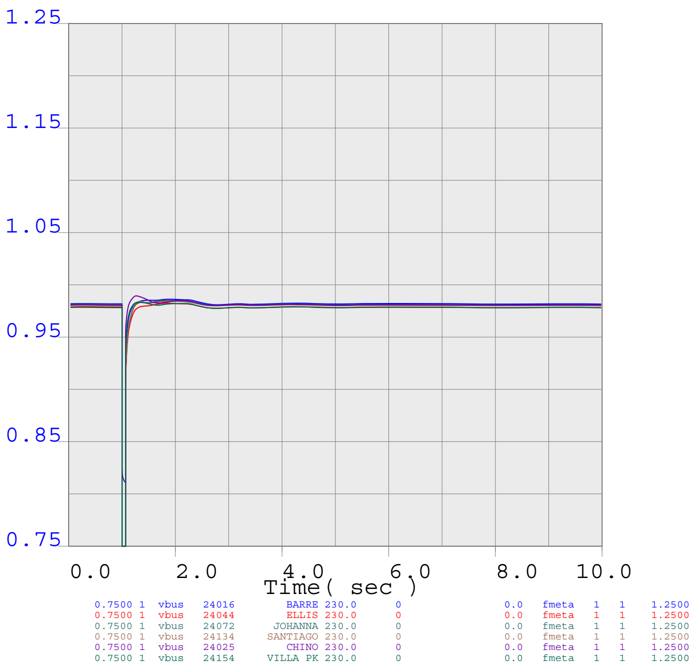
C:\DYTOOLS

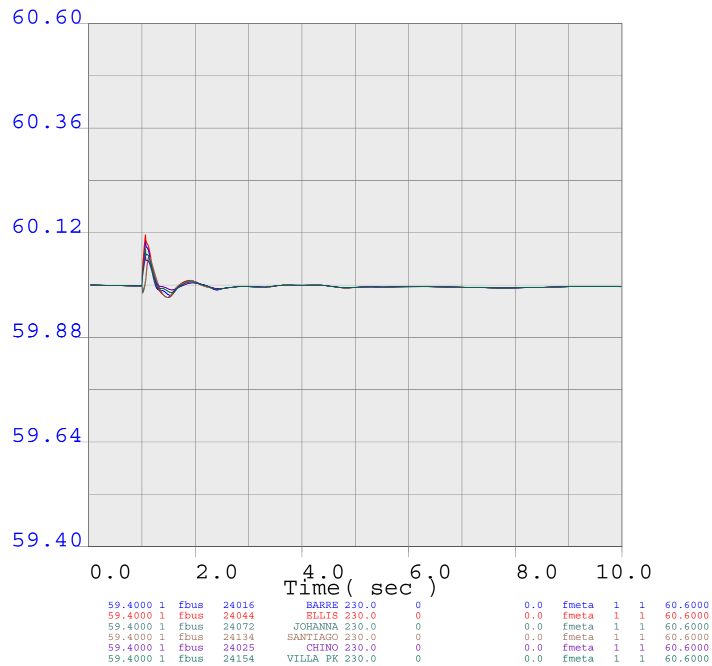
Thu Oct 20 09:03:33 2016

METRO









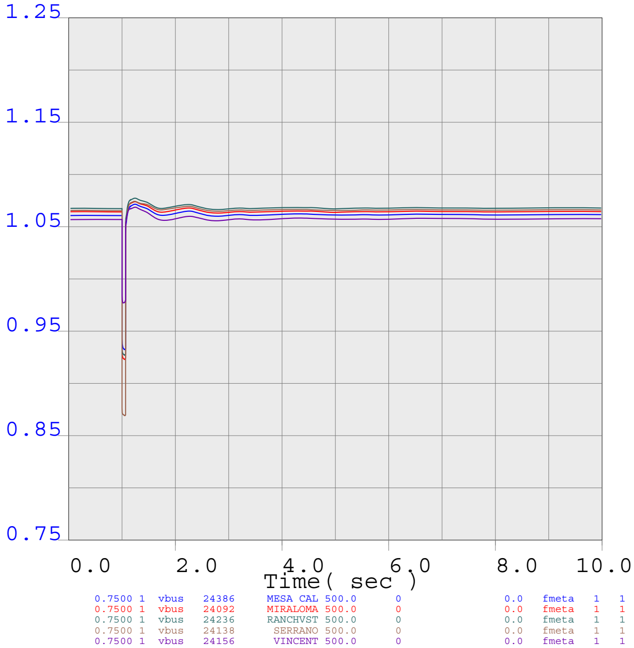
line_7105
Line ELLIS 230.0 to HUNTGBCH 230.0 Circuit 3 & Line ELLIS 230.0 to HUNTBCH1 230

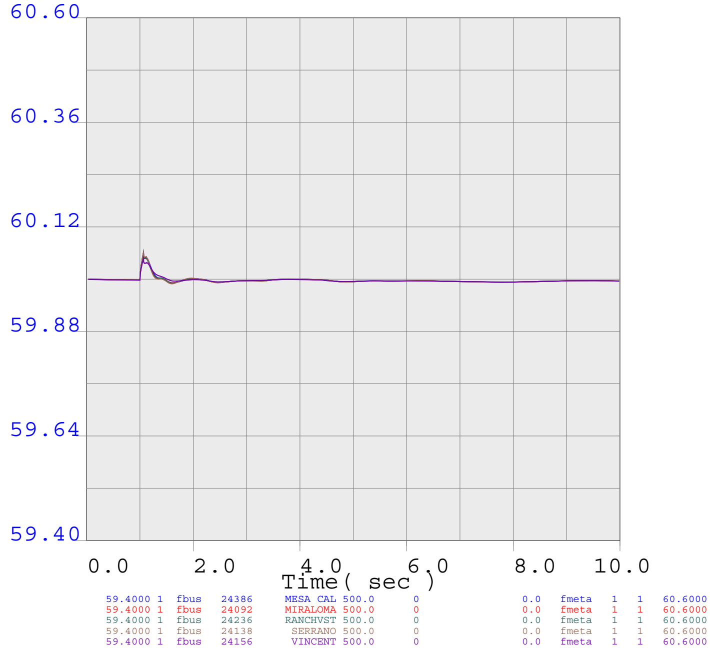
qc9p-line_7105.chf

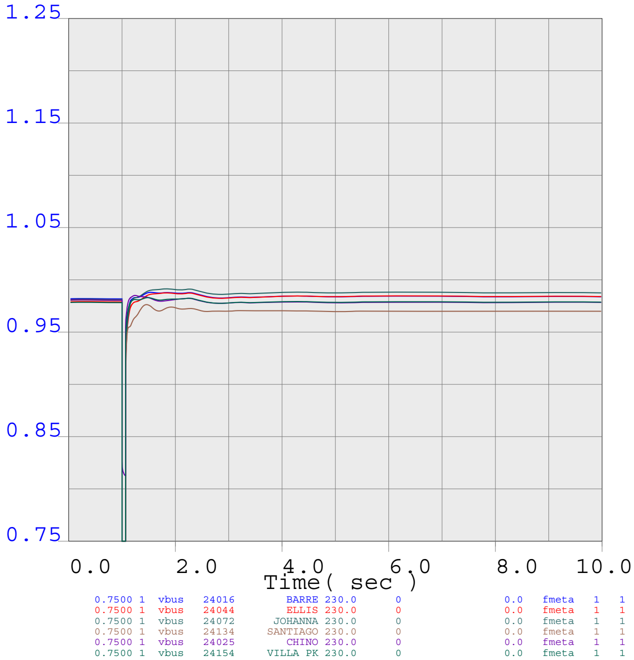
C:\DYTOOLS

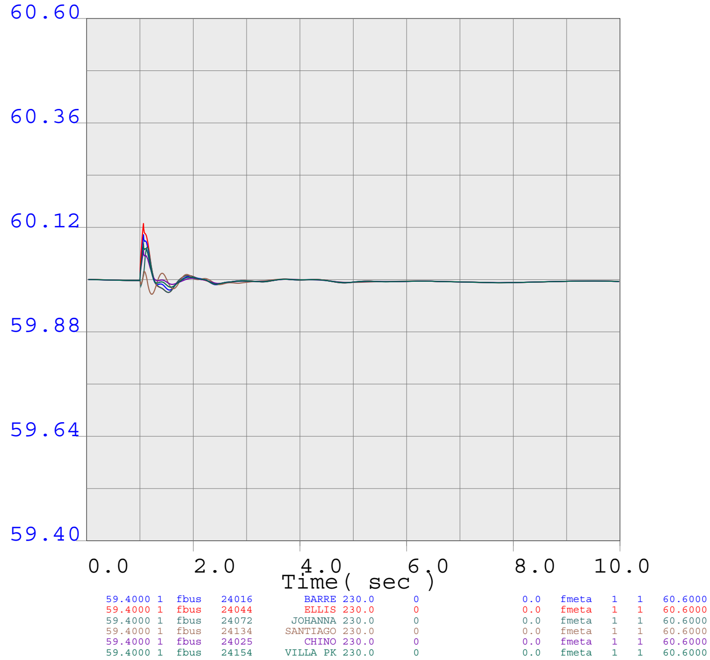
Thu Oct 20 09:03:35 2016

METRO









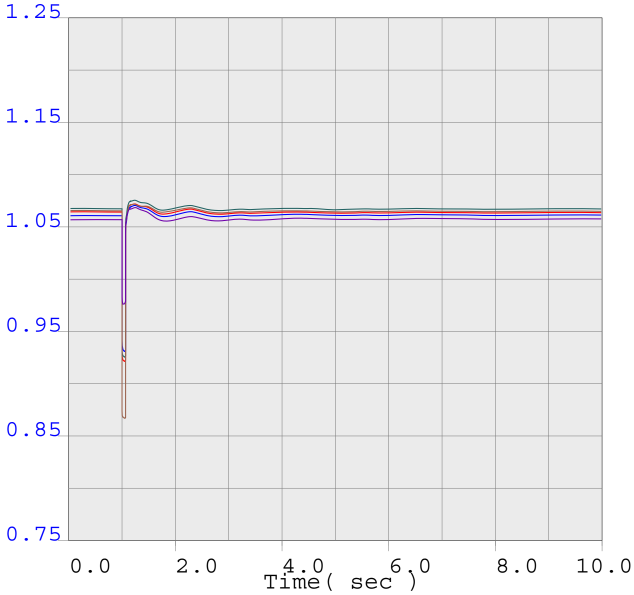
line_7106
Line ELLIS 230.0 to SANTIAGO 230.0 Circuit 1 & Line JOHANNA 230.0 to SANTIAGO 2

qc9p-line_7106.chf

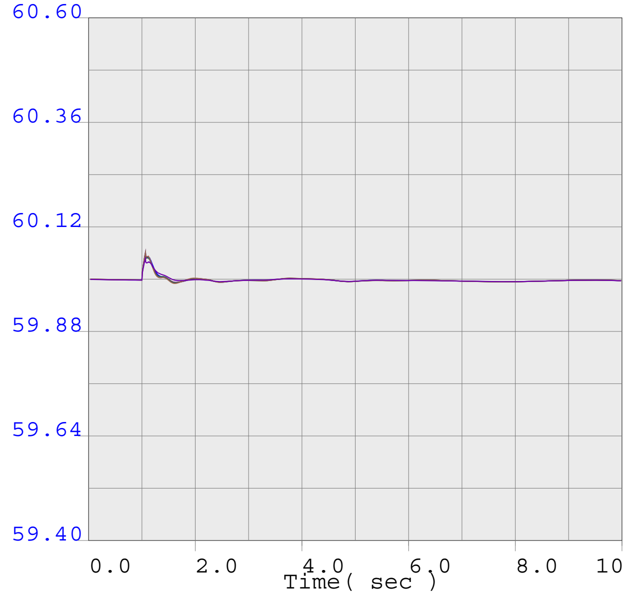
C:\DYTOOLS

Thu Oct 20 09:03:37 2016

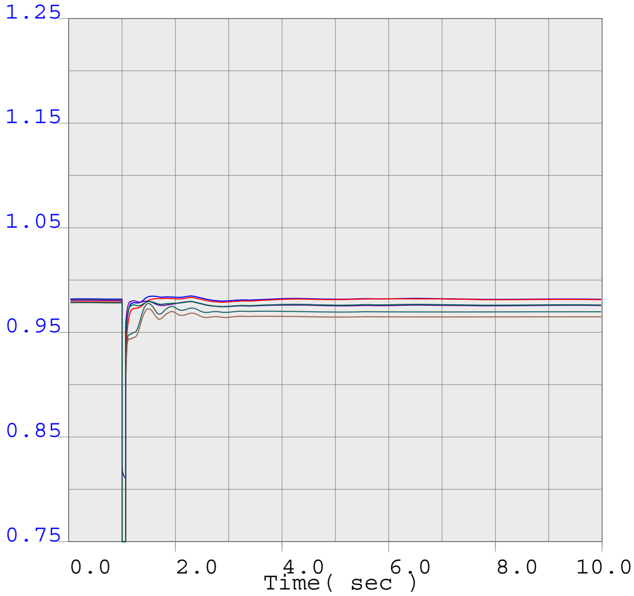
METRO



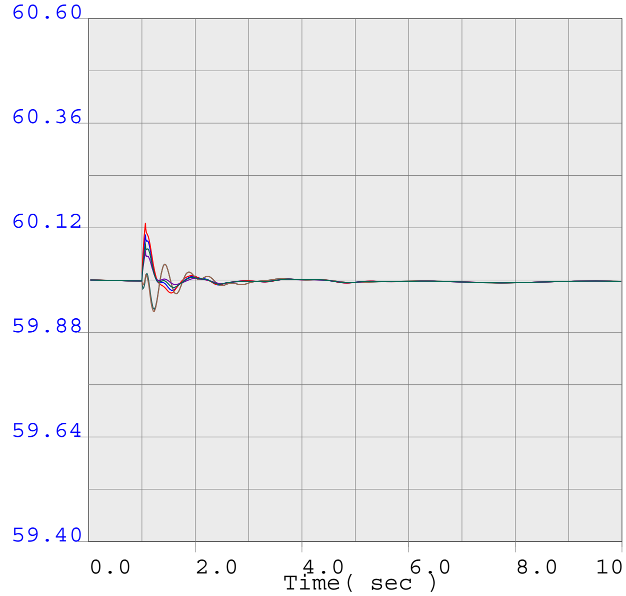
0.7500	1	vbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	60.6000

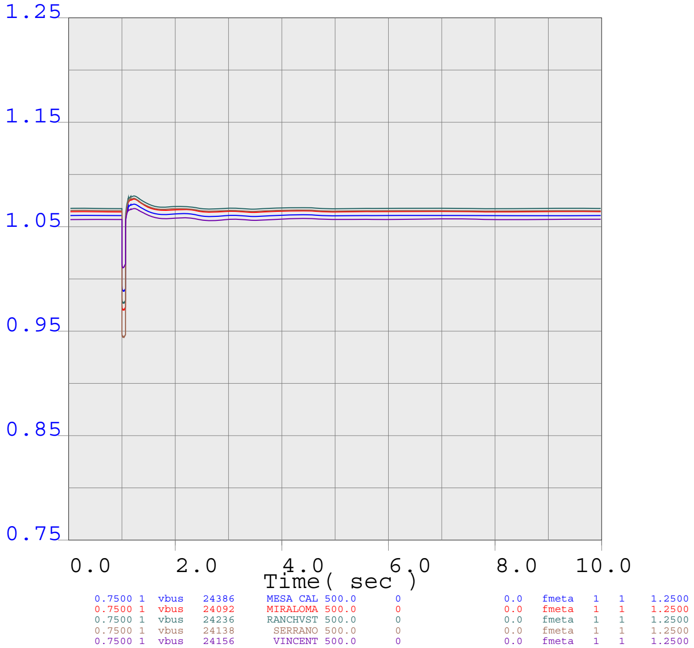
line_7107
Line ELLIS 230.0 to JOHANNA 230.0 Circuit 1 & Line ELLIS 230.0 to SANTIAGO 230.

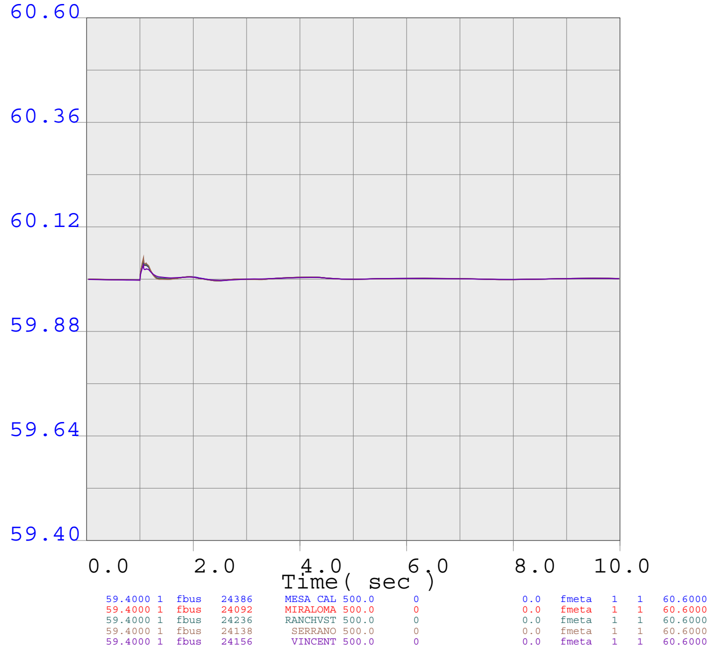
qc9p-line_7107.chf

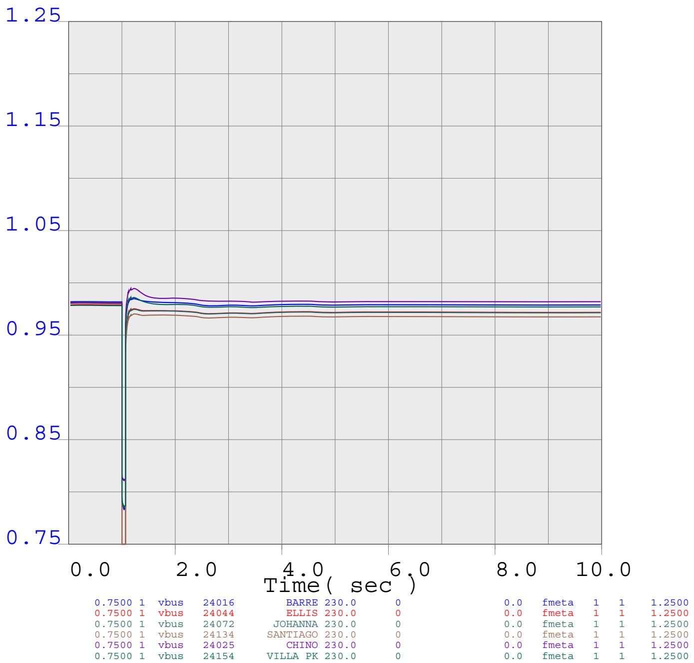
C:\DYTOOLS

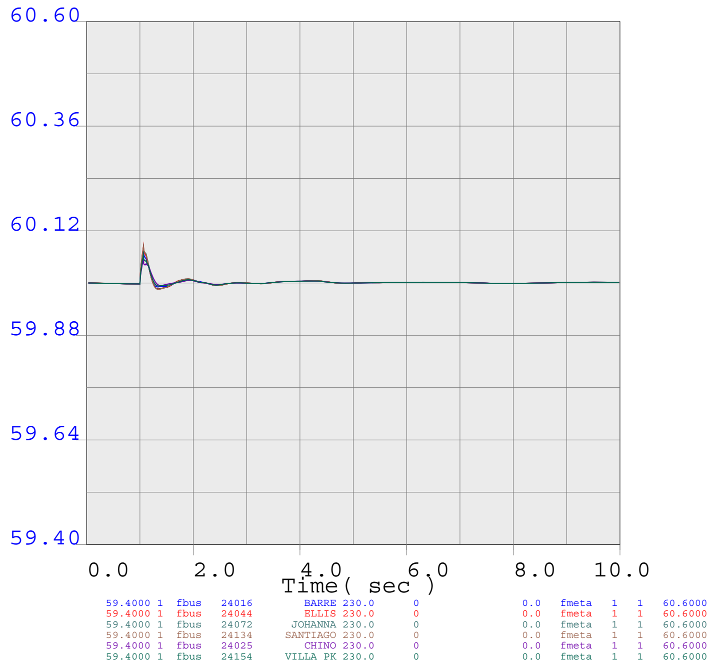
Thu Oct 20 09:03:39 2016

METRO









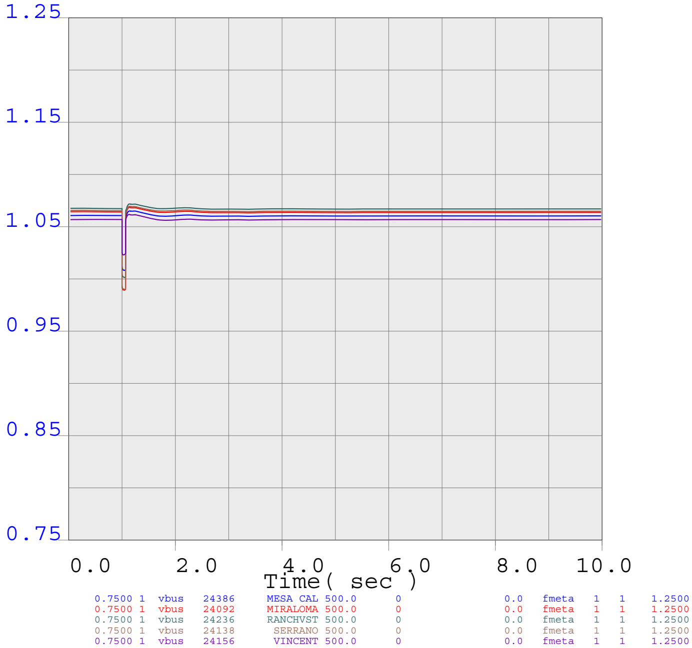
line_7108
Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SANTIA

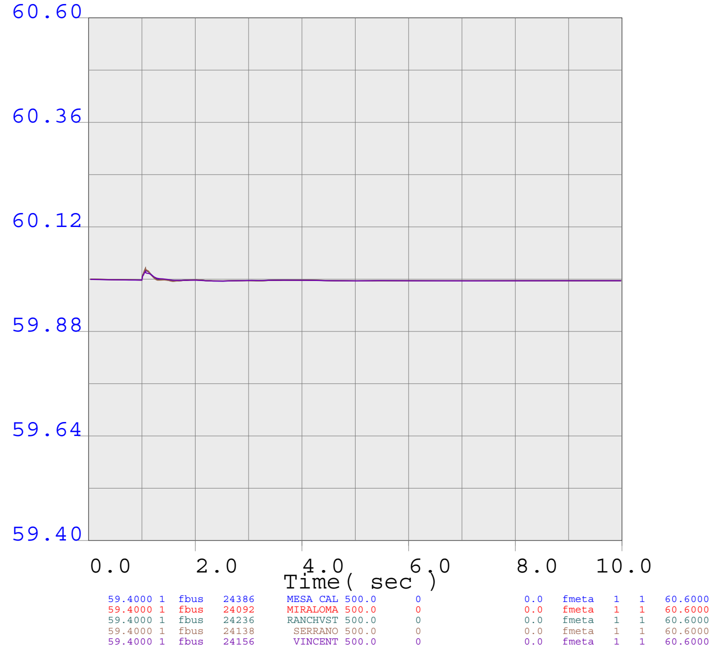
qc9p-line_7108.chf

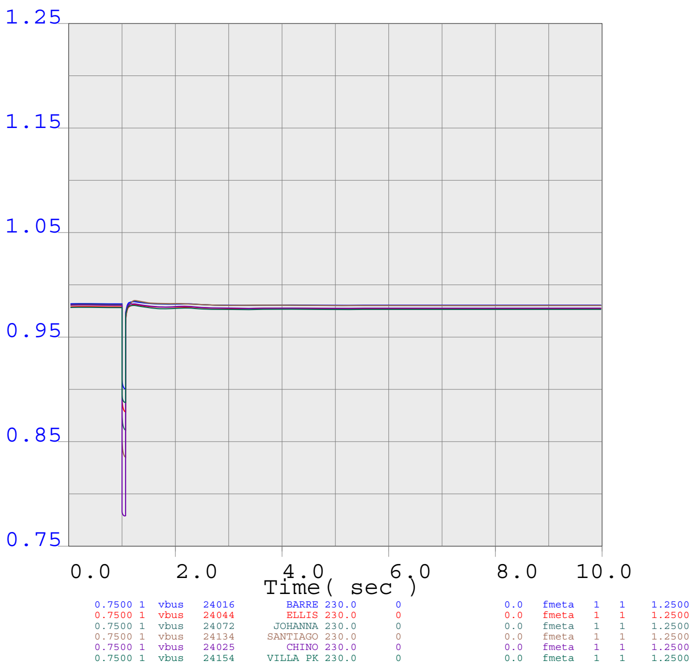
C:\DYTOOLS

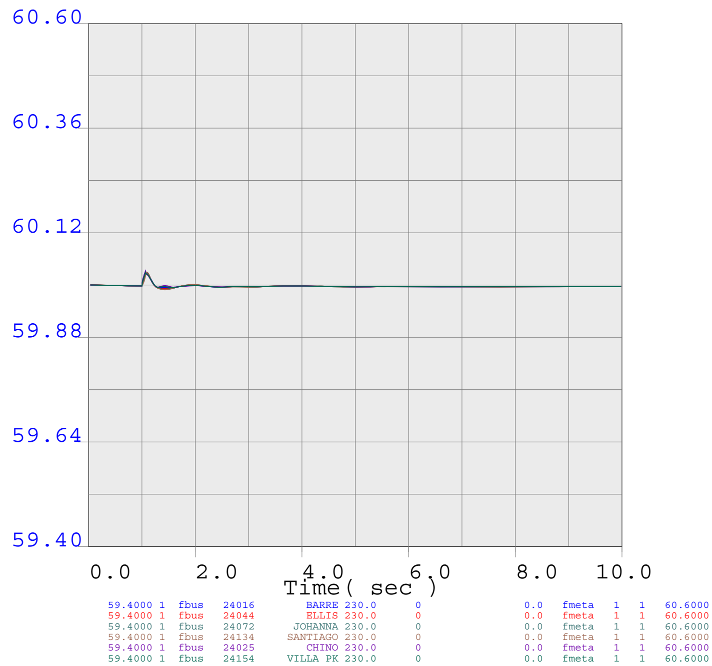
Thu Oct 20 09:03:41 2016

METRO









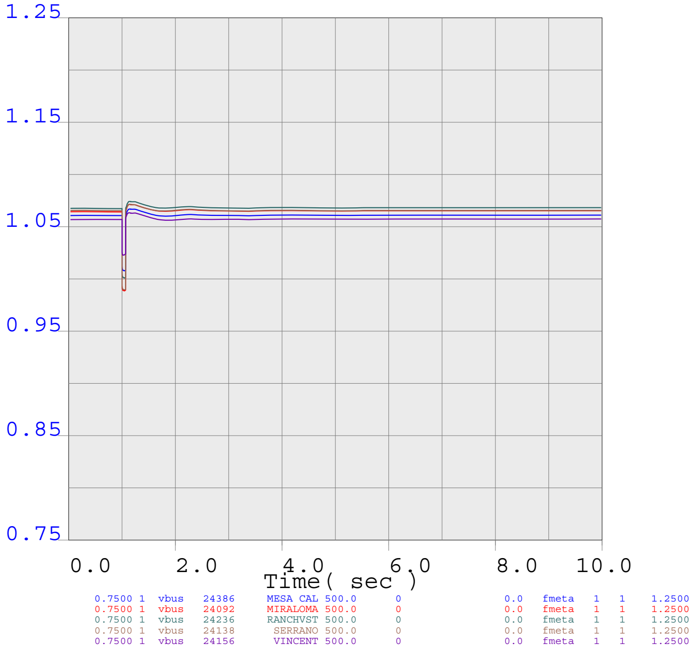
line_7109
Line VIEJO 230.0 to S.ONOFRE 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 2

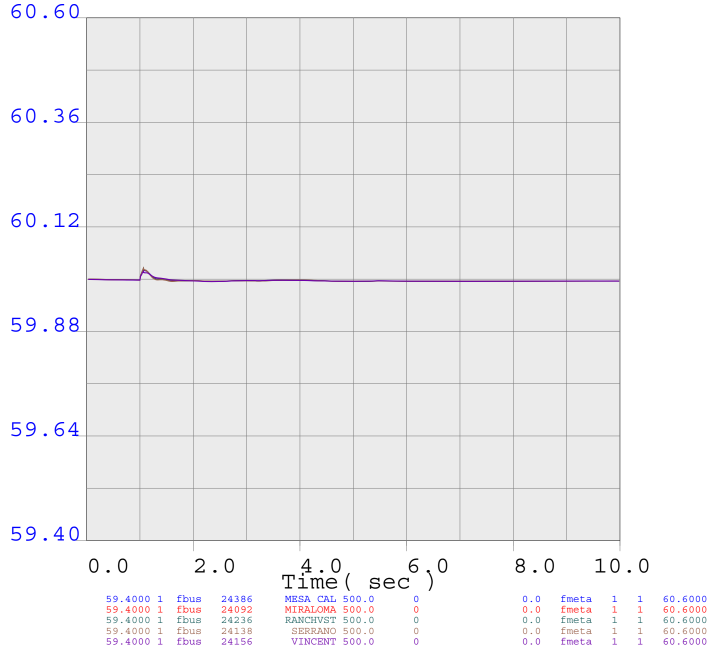
qc9p-line_7109.chf

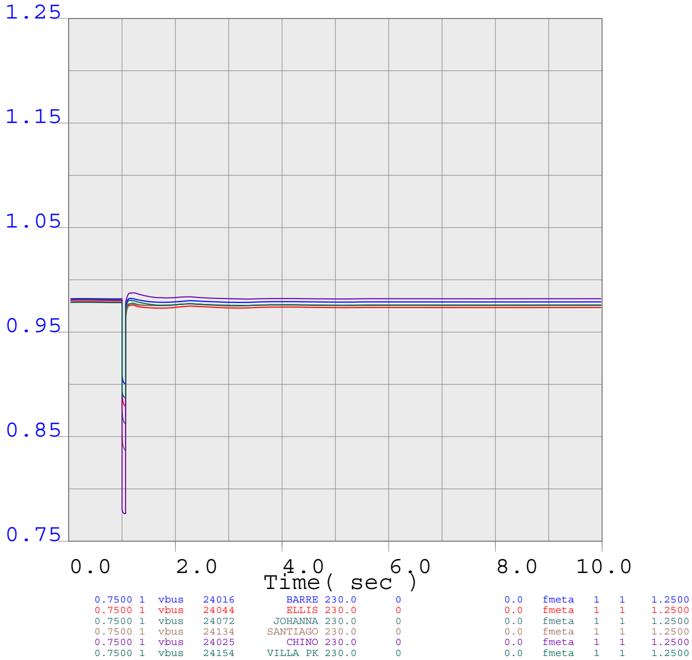
C:\DYTOOLS

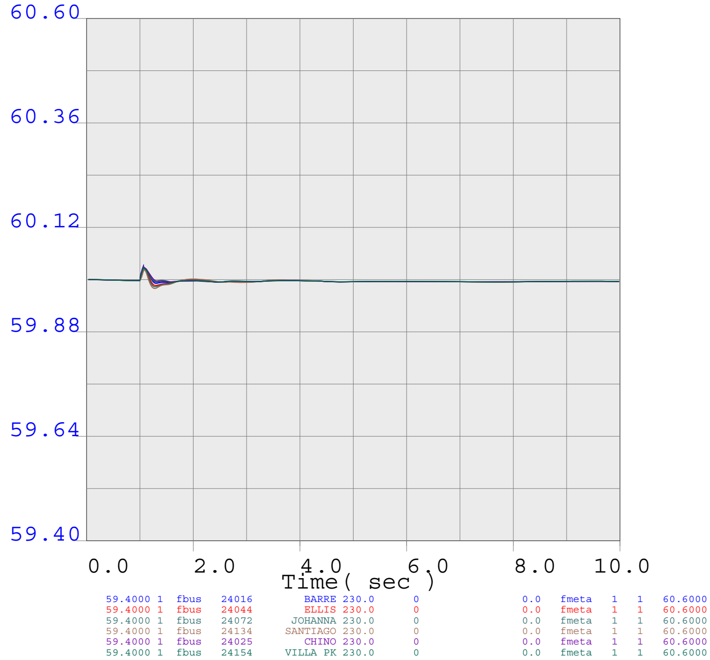
Thu Oct 20 09:03:43 2016

METRO









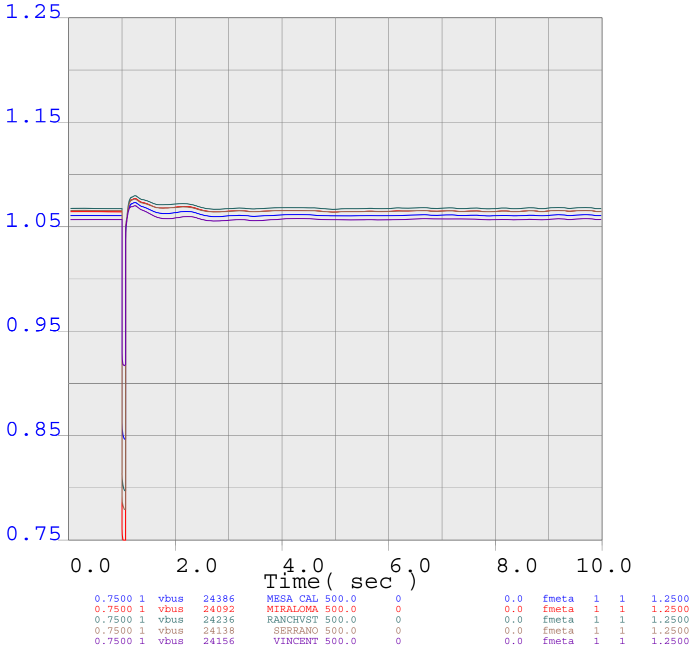
line_7110
Line VIEJO 230.0 to CHINO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 230.

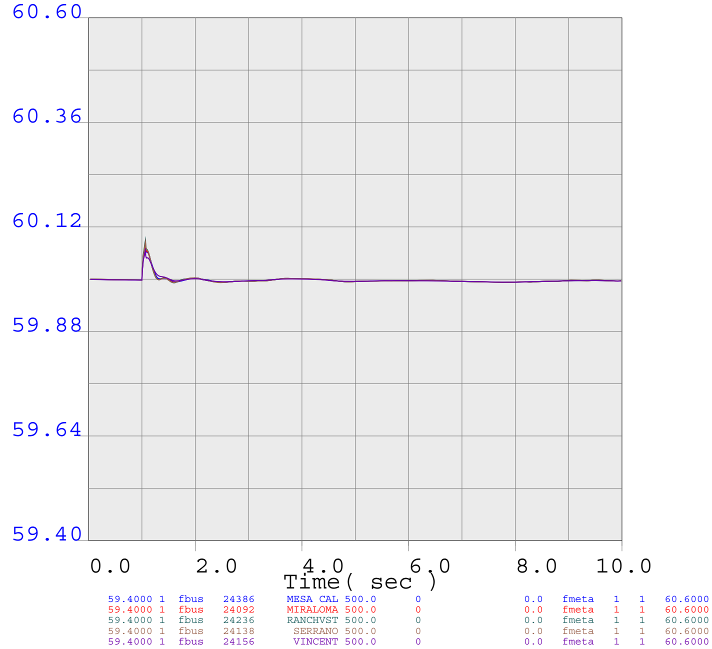
qc9p-line_7110.chf

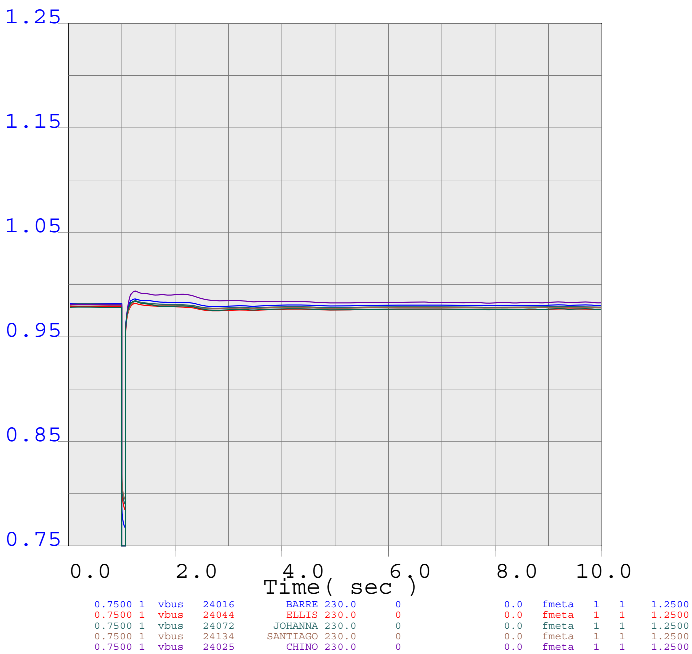
C:\DYTOOLS

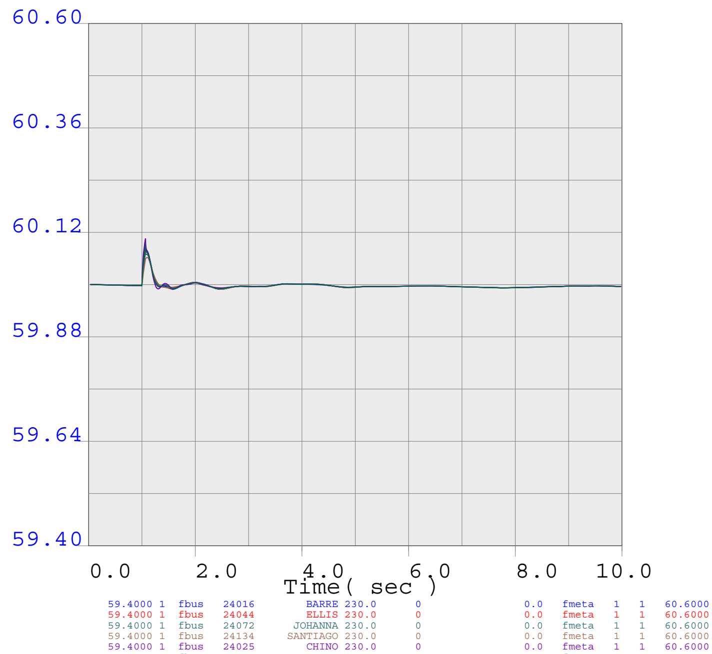
Thu Oct 20 09:03:45 2016

METRO









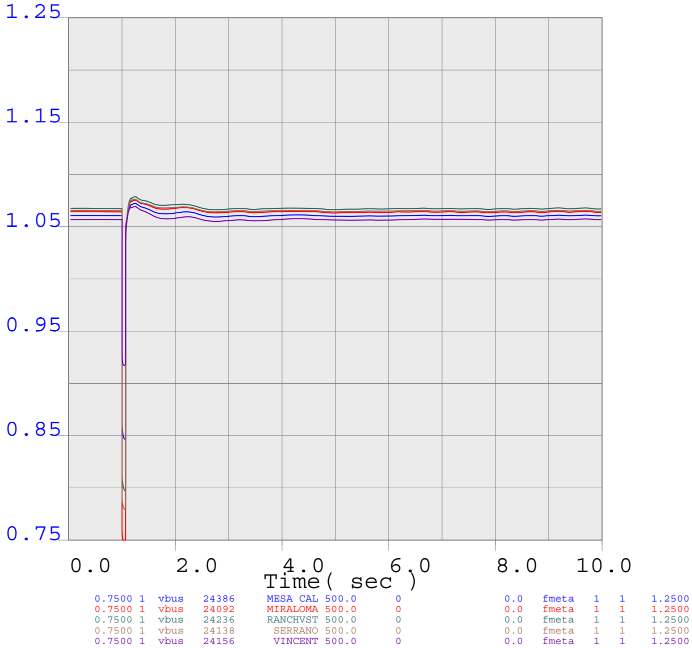
line_7111
Line CHINO 230.0 to SERRANO 230.0 Circuit 1 & Line VIEJO 230.0 to CHINO 230.0 C

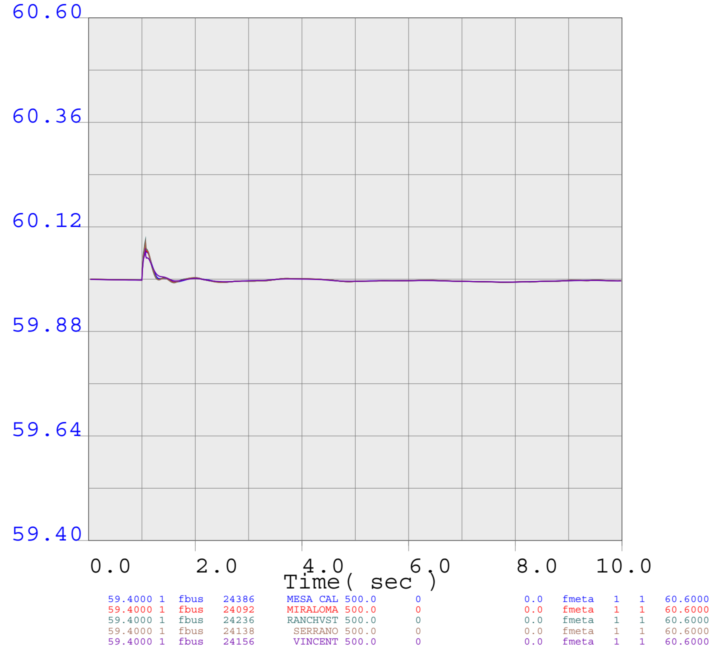
qc9p-line_7111.chf

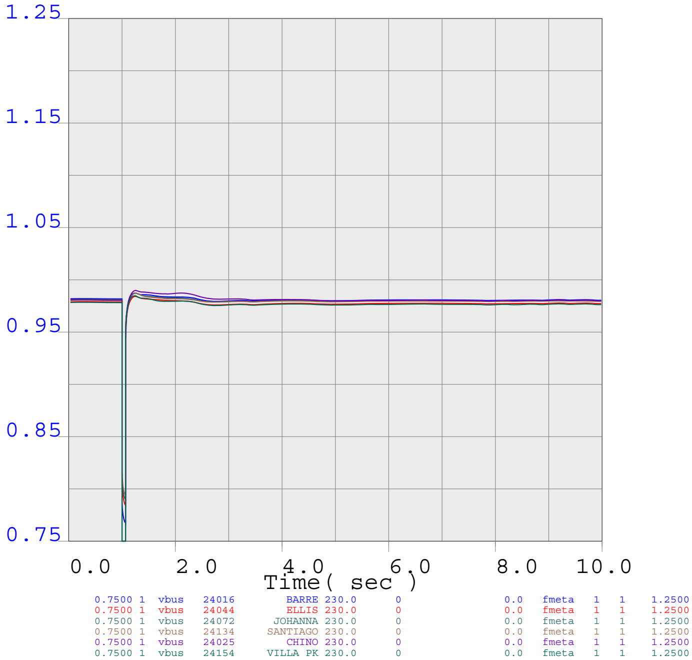
C:\DYTOOLS

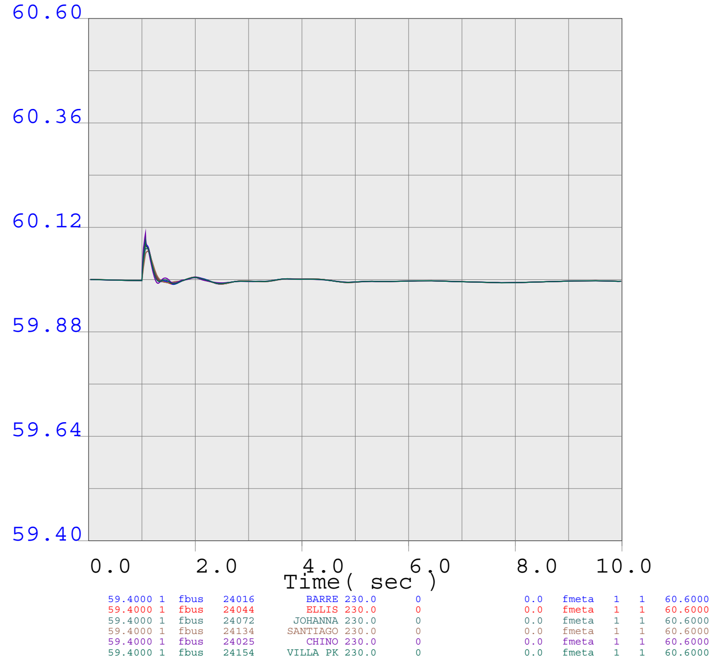
Thu Oct 20 09:03:48 2016

METRO









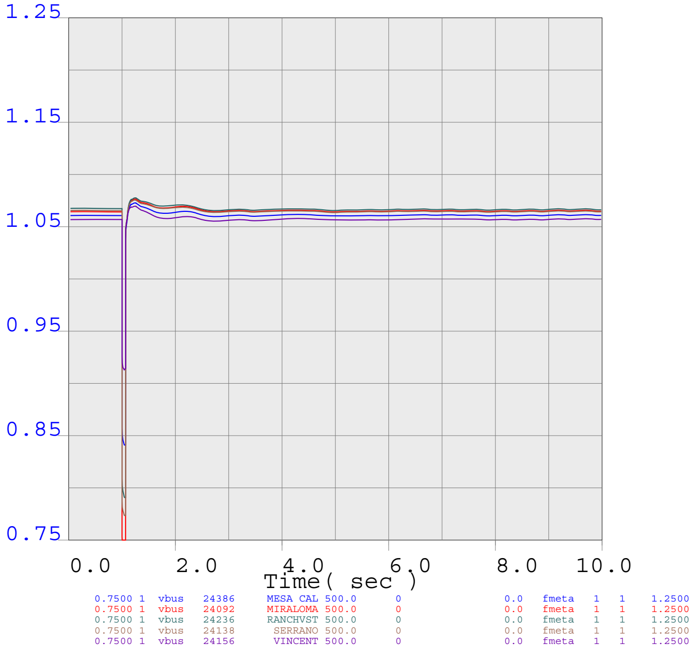
line_7112
Line CHINO 230.0 to SERRANO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 23

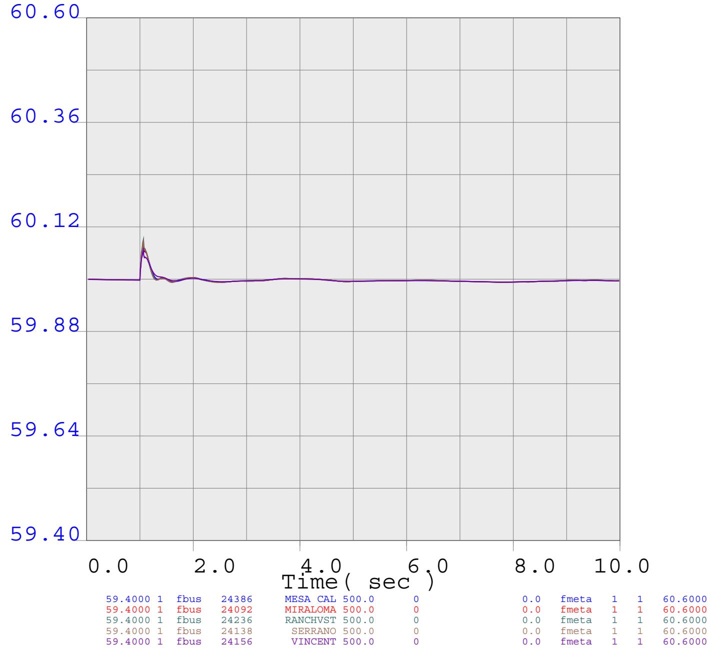
qc9p-line_7112.chf

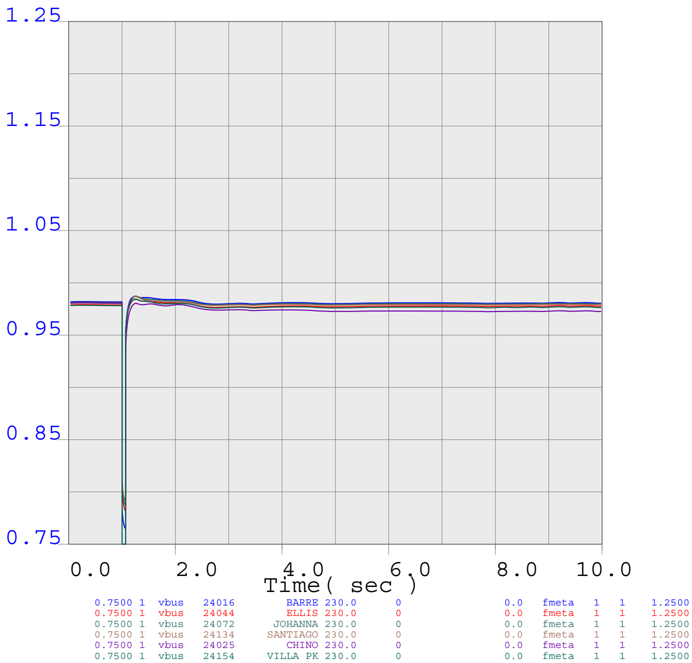
C:\DYTOOLS

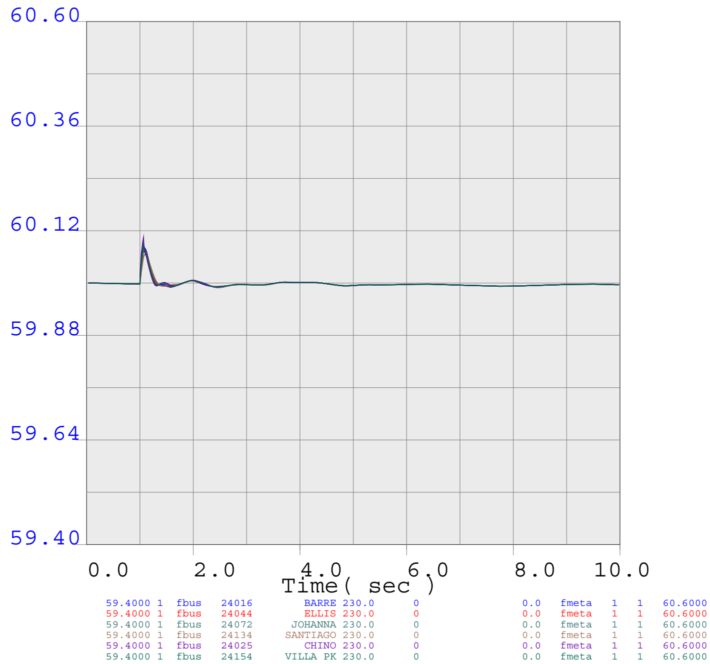
Thu Oct 20 09:03:50 2016

METRO









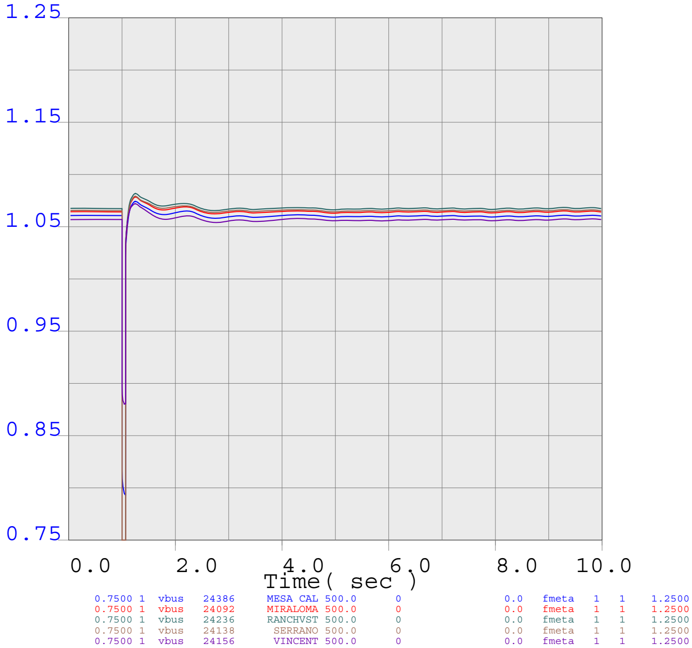
line_7114
Line CHINO 230.0 to MIRALOMW 230.0 Circuit 1 & Line CHINO 230.0 to MIRALOMW 230

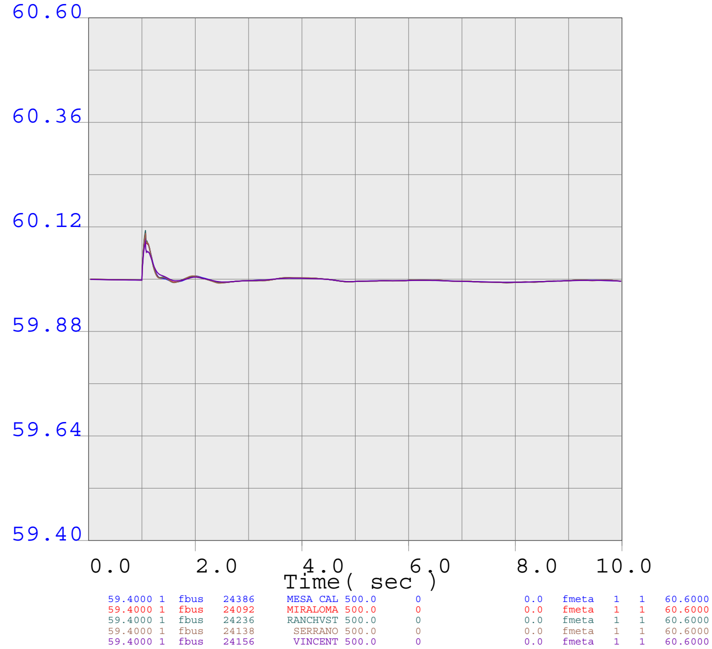
qc9p-line_7114.chf

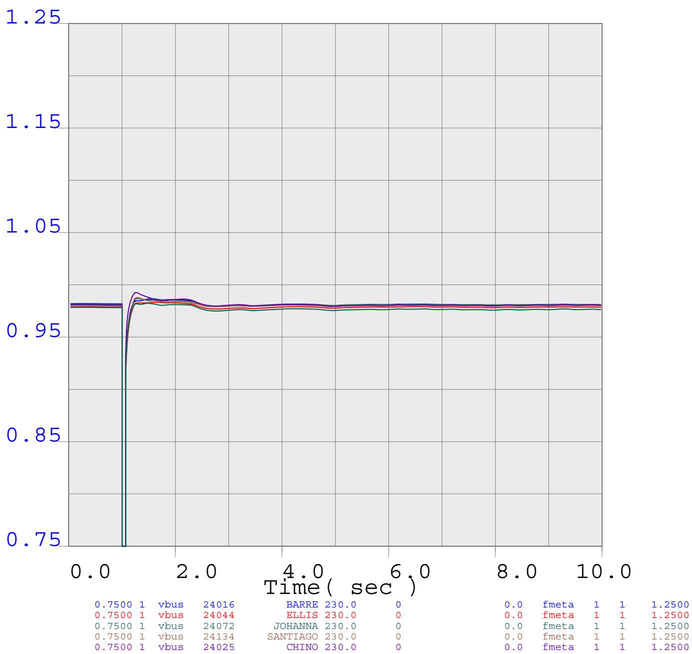
C:\DYTOOLS

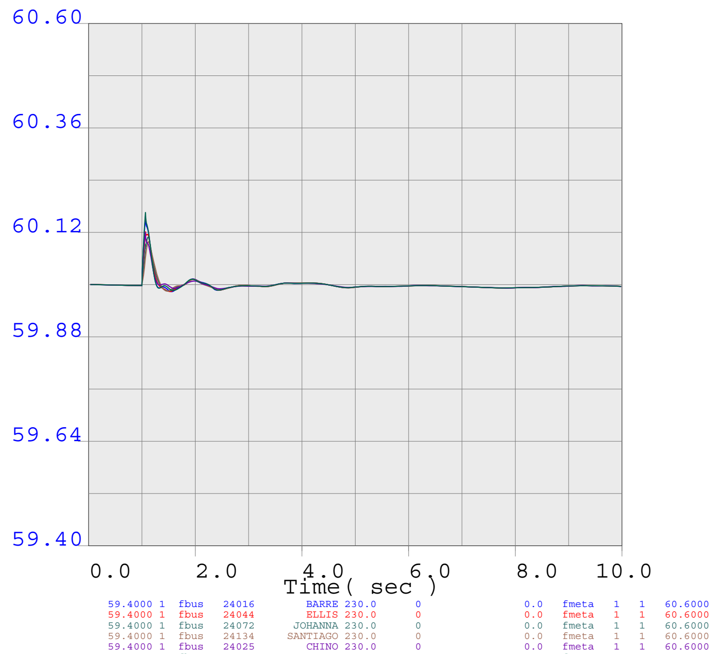
Thu Oct 20 09:03:52 2016

METRO









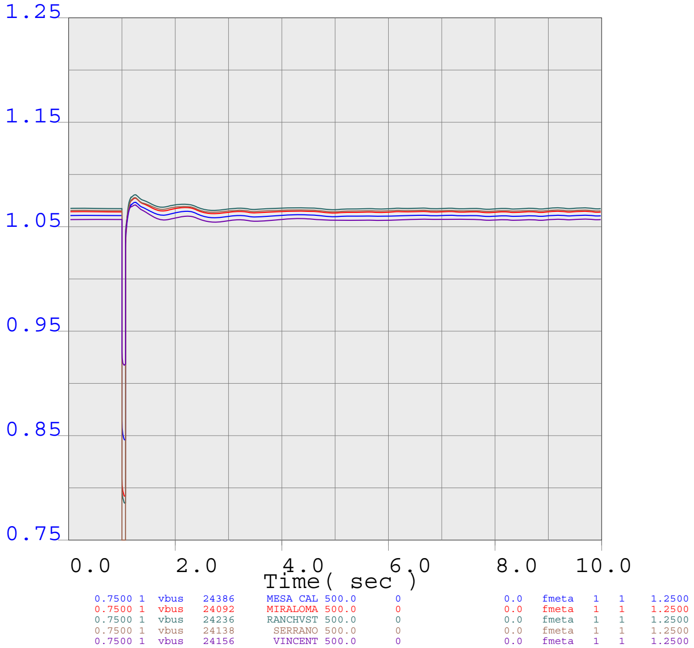
line_7115
Line SERRANO 230.0 to VILLA PK 230.0 Circuit 1 & Line SERRANO 230.0 to VILLA PK
1 MW dispatch Case

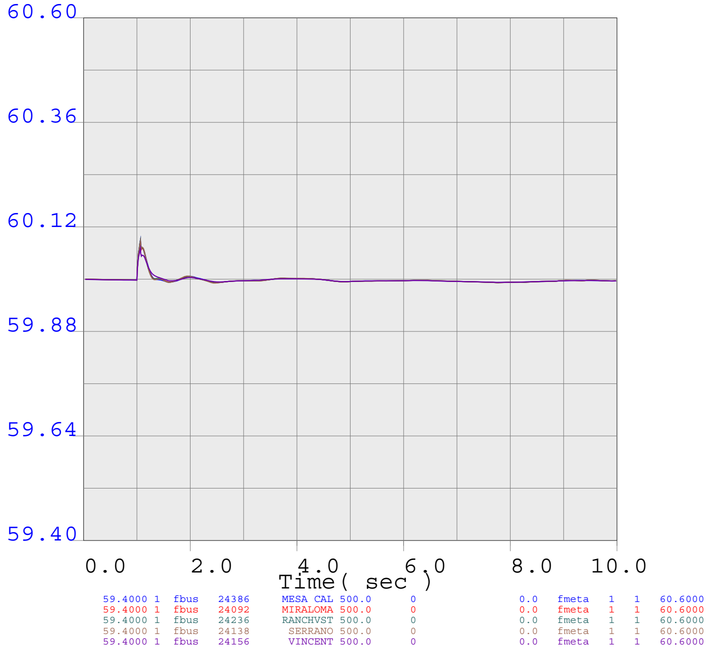
qc9p-line_7115.chf

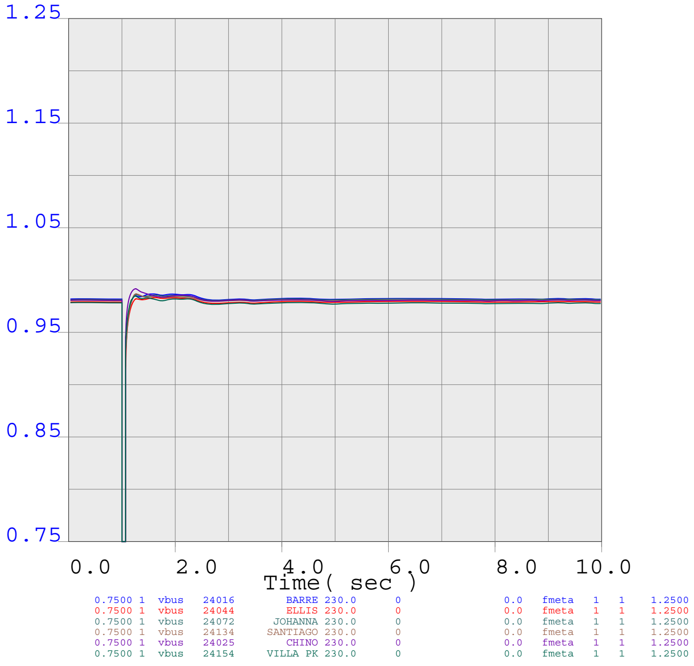
C:\DYTOOLS

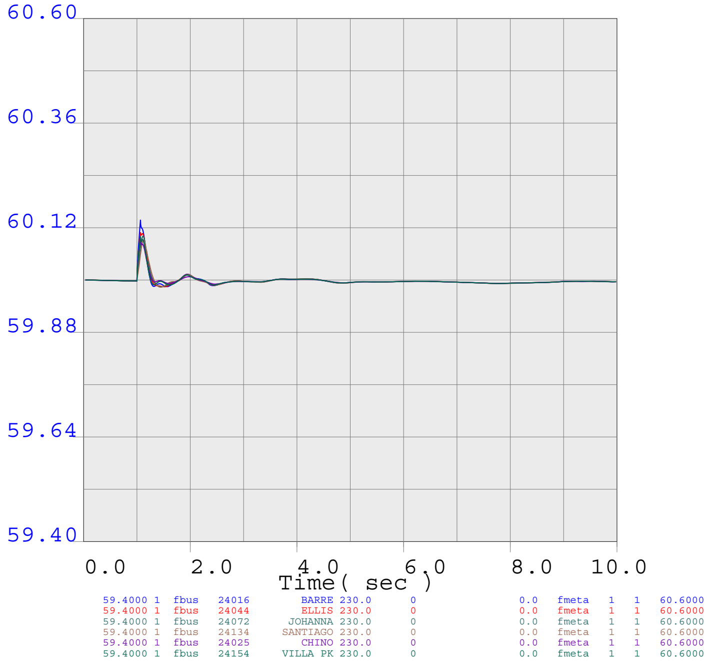
Thu Oct 20 09:03:54 2016

METRO









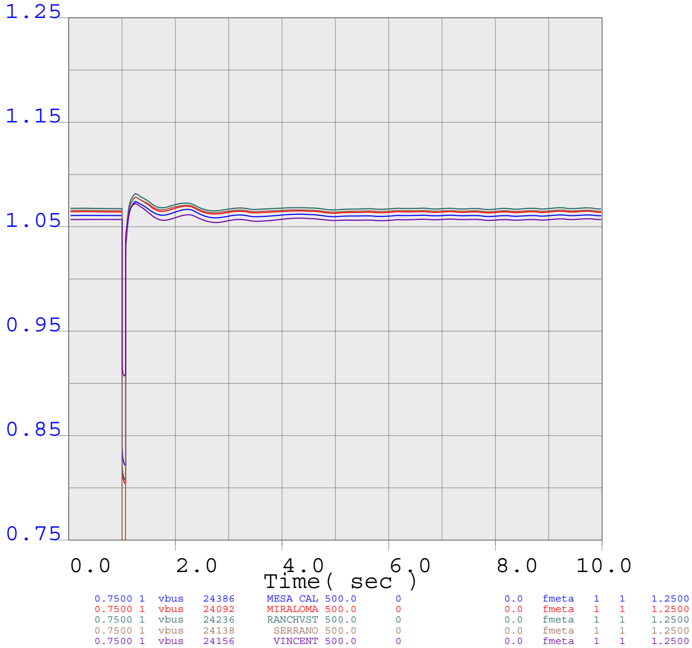
line_7116
Line LEWIS 230.0 to SERRANO 230.0 Circuit 1 & Line LEWIS 230.0 to SERRANO 230.0
1 MW dispatch Case

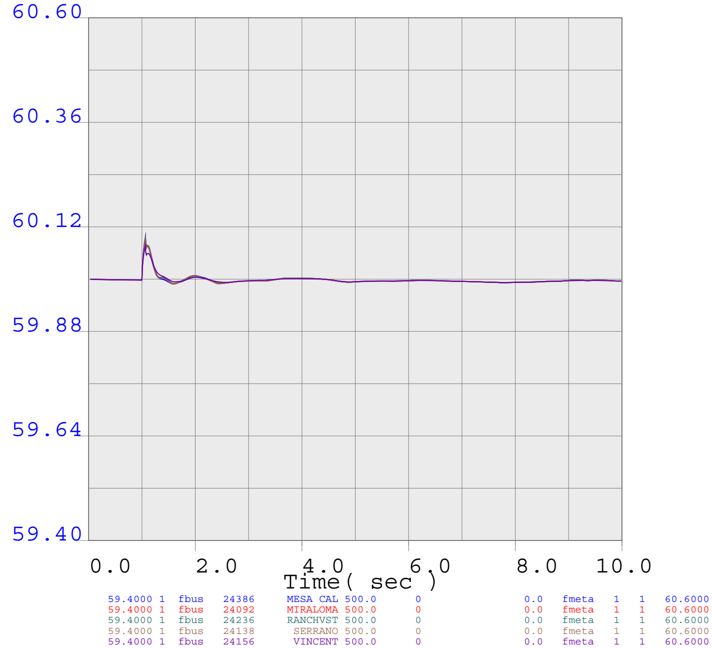
qc9p-line_7116.chf

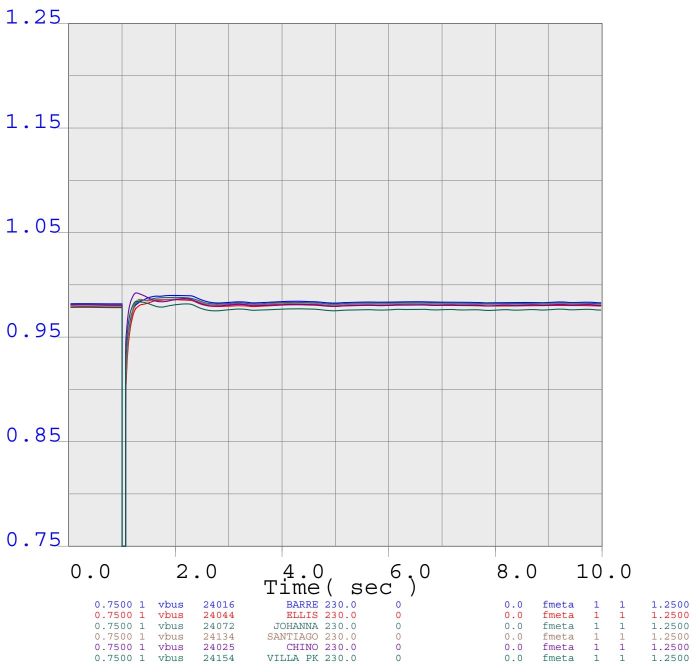
C:\DYTOOLS

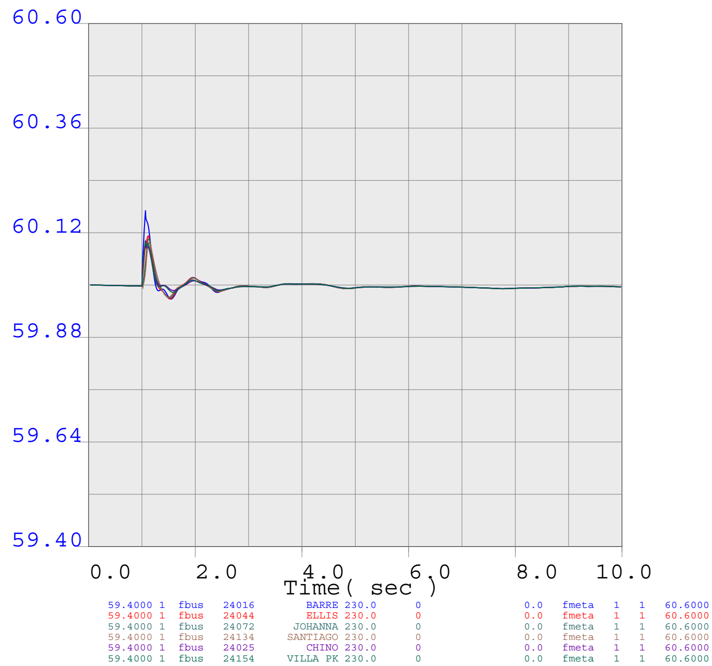
Thu Oct 20 09:03:55 2016

METRO





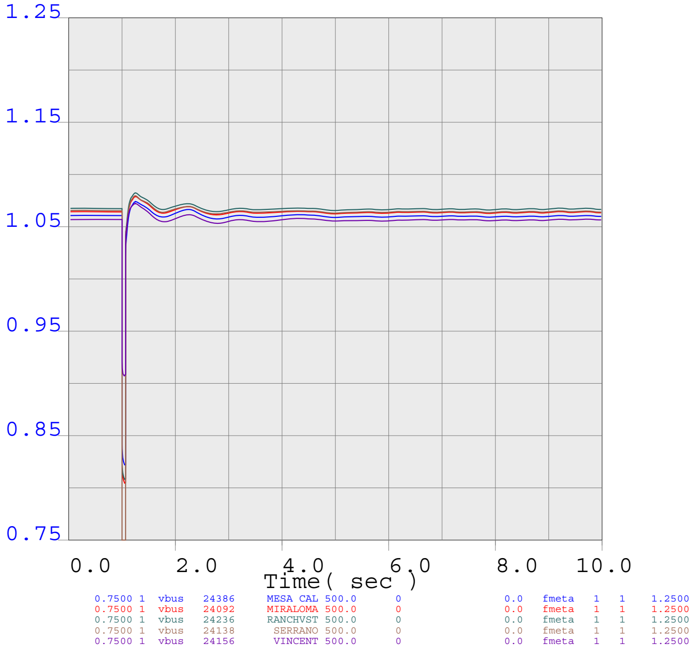


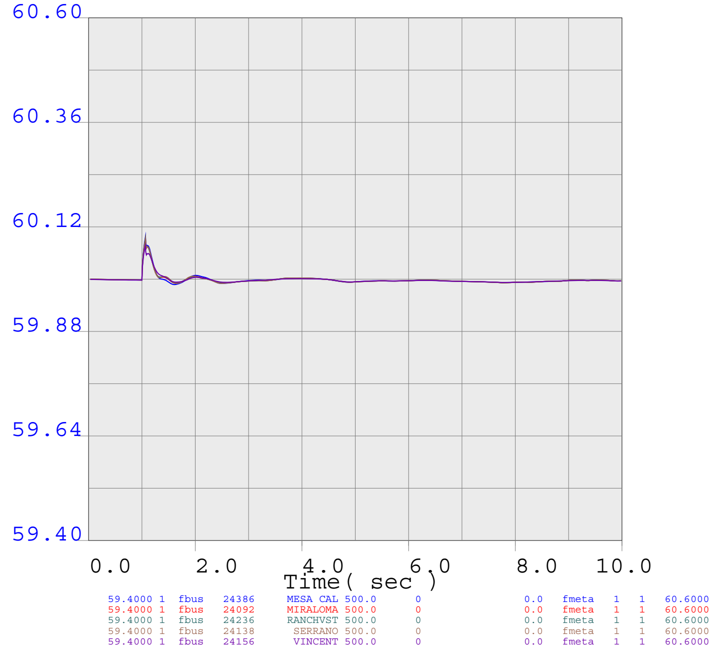


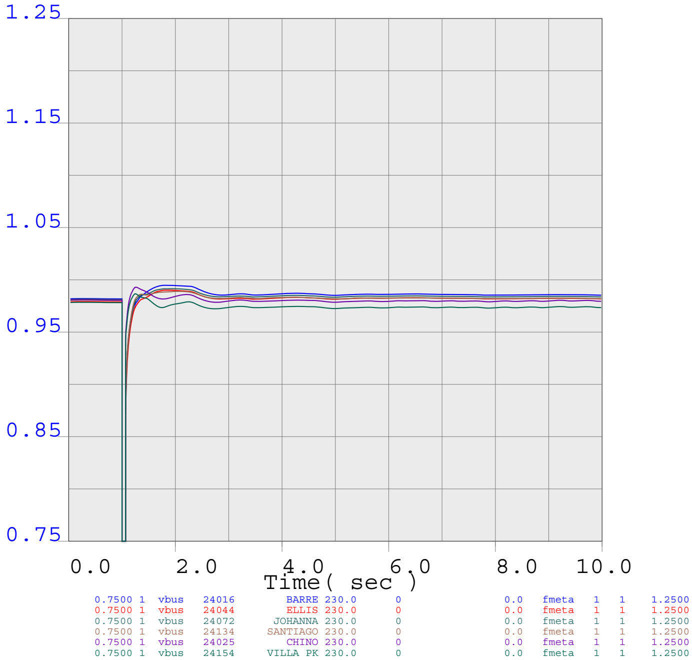
line_7117
Line BARRE 230.0 to VILLA PK 230.0 Circuit 1 & Line LEWIS 230.0 to VILLA PK 230

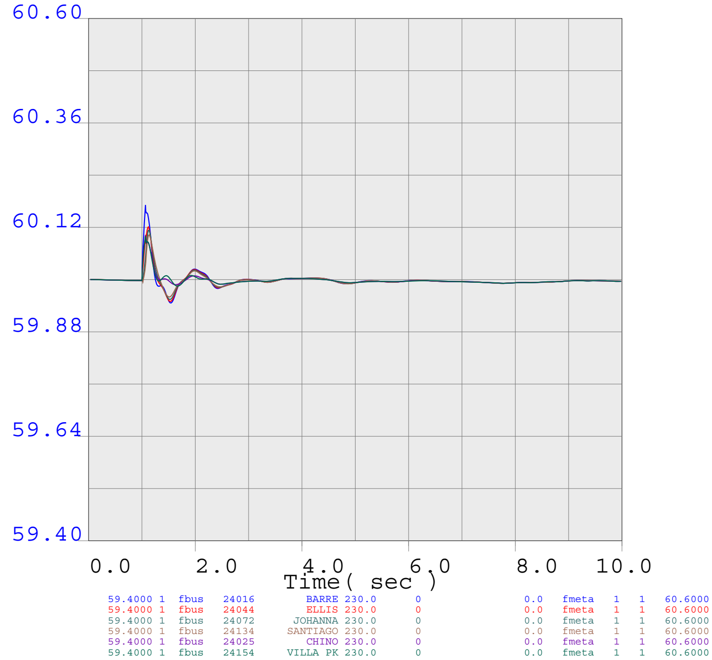
	qc9p-line_7117.chf	C:\DYTOOLS Thu Oct 20 09:03:57 2016

METRO







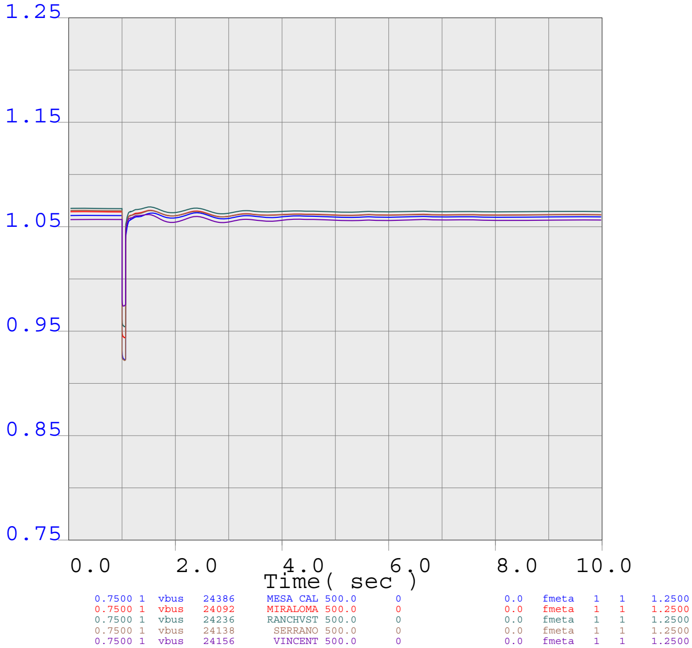


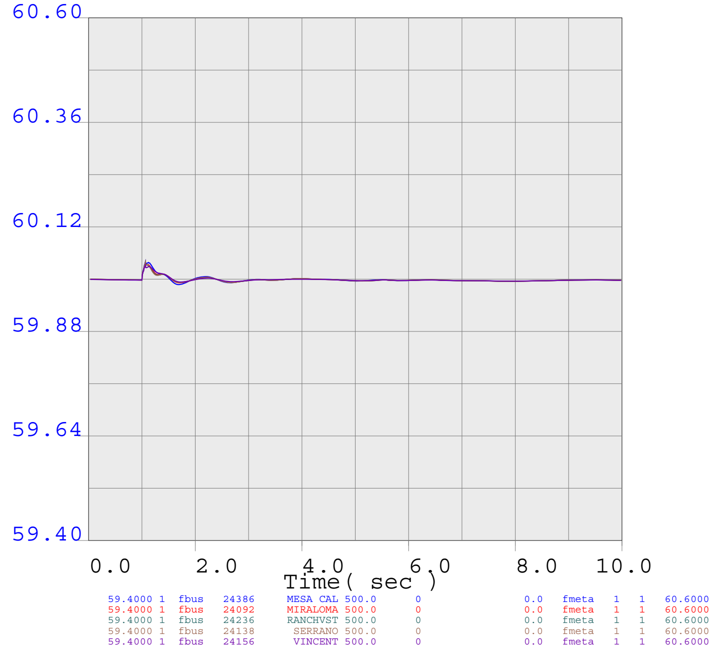
line_7118

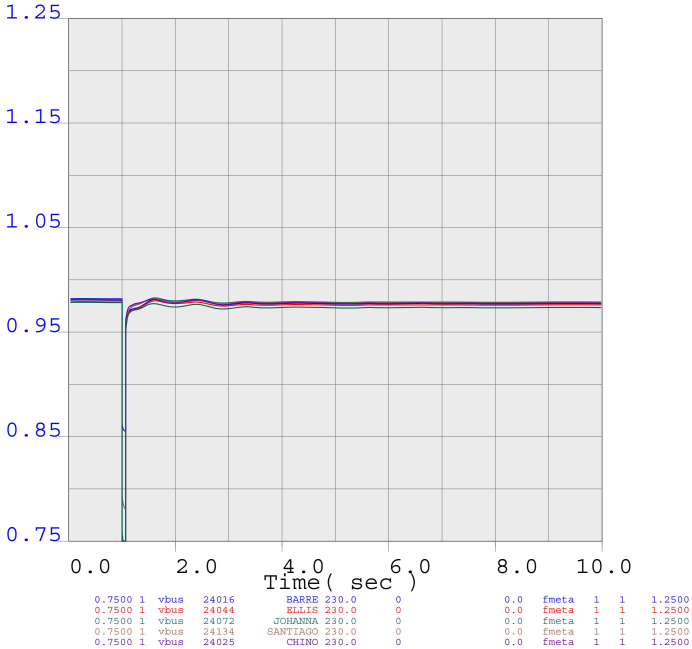
Line BARRE 230.0 to VILLA PK 230.0 Circuit 1 & Line BARRE 230.0 to LEWIS 230.0

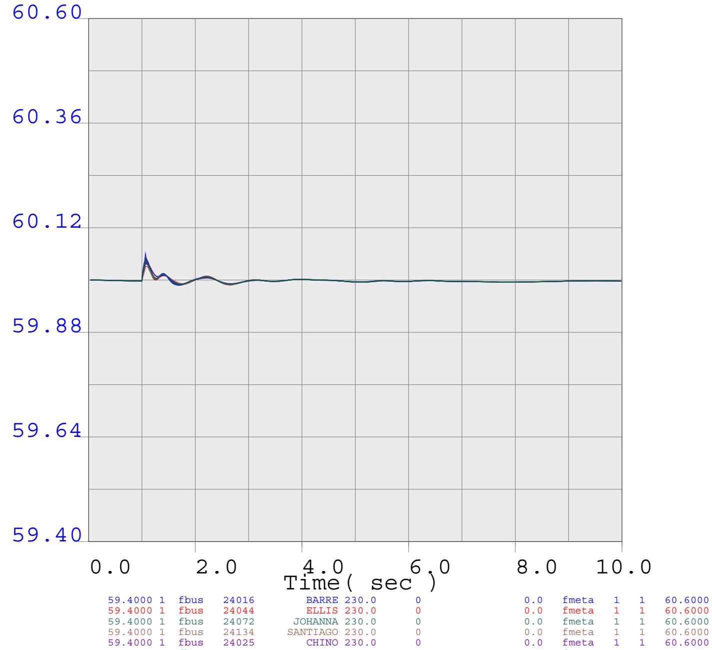
	qc9p-line_7118.chf	C:\DYTOOLS Thu Oct 20 09:04:00 2016

METRO









line_7119

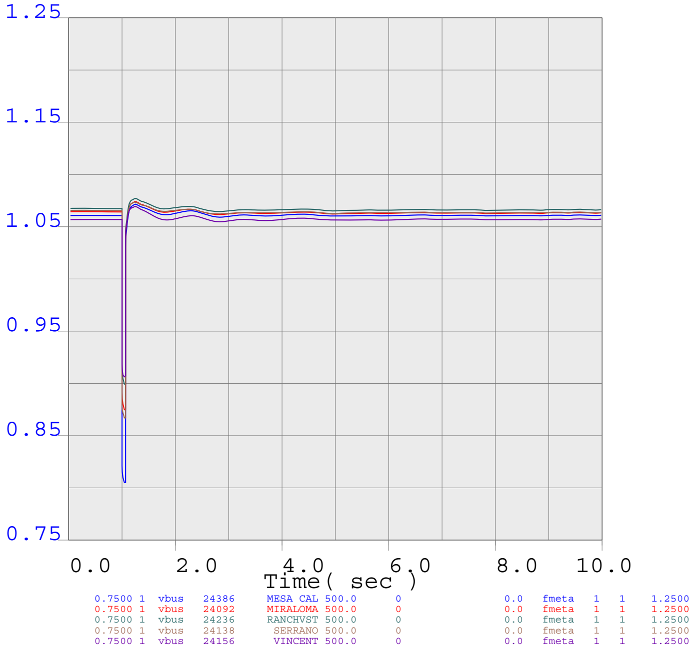
Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1 & Line ALMITOSW 230.0 to BARRE 230

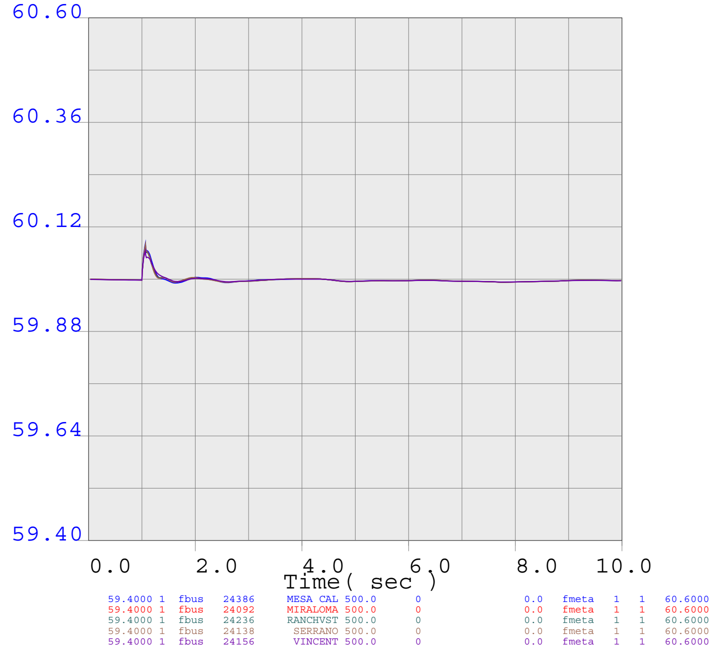
qc9p-line_7119.chf

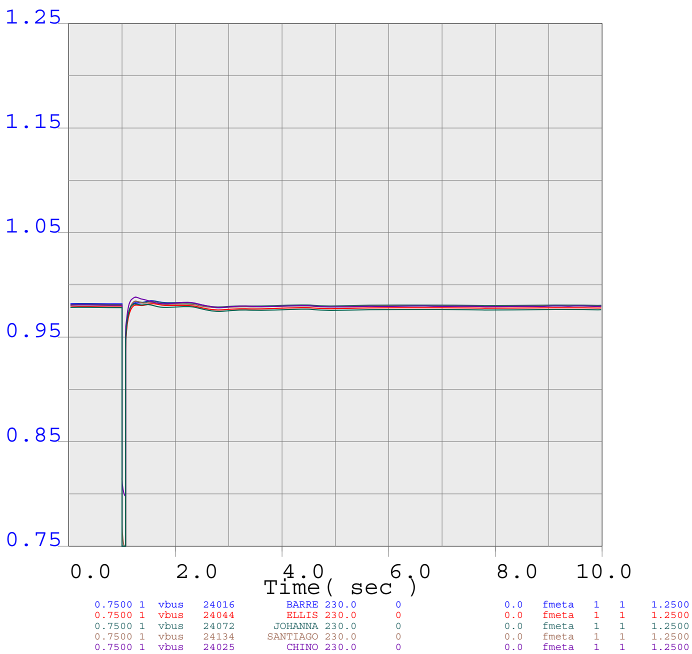
C:\DYTOOLS

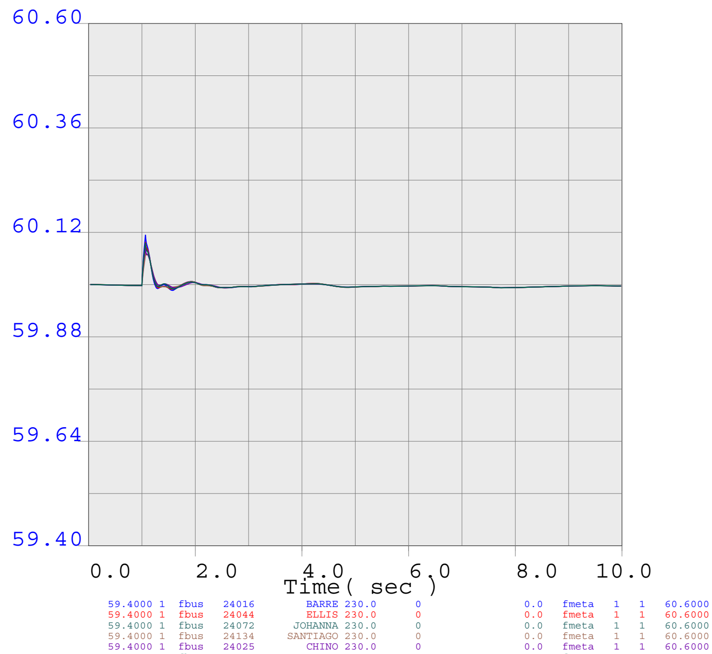
Thu Oct 20 09:04:02 2016

METRO









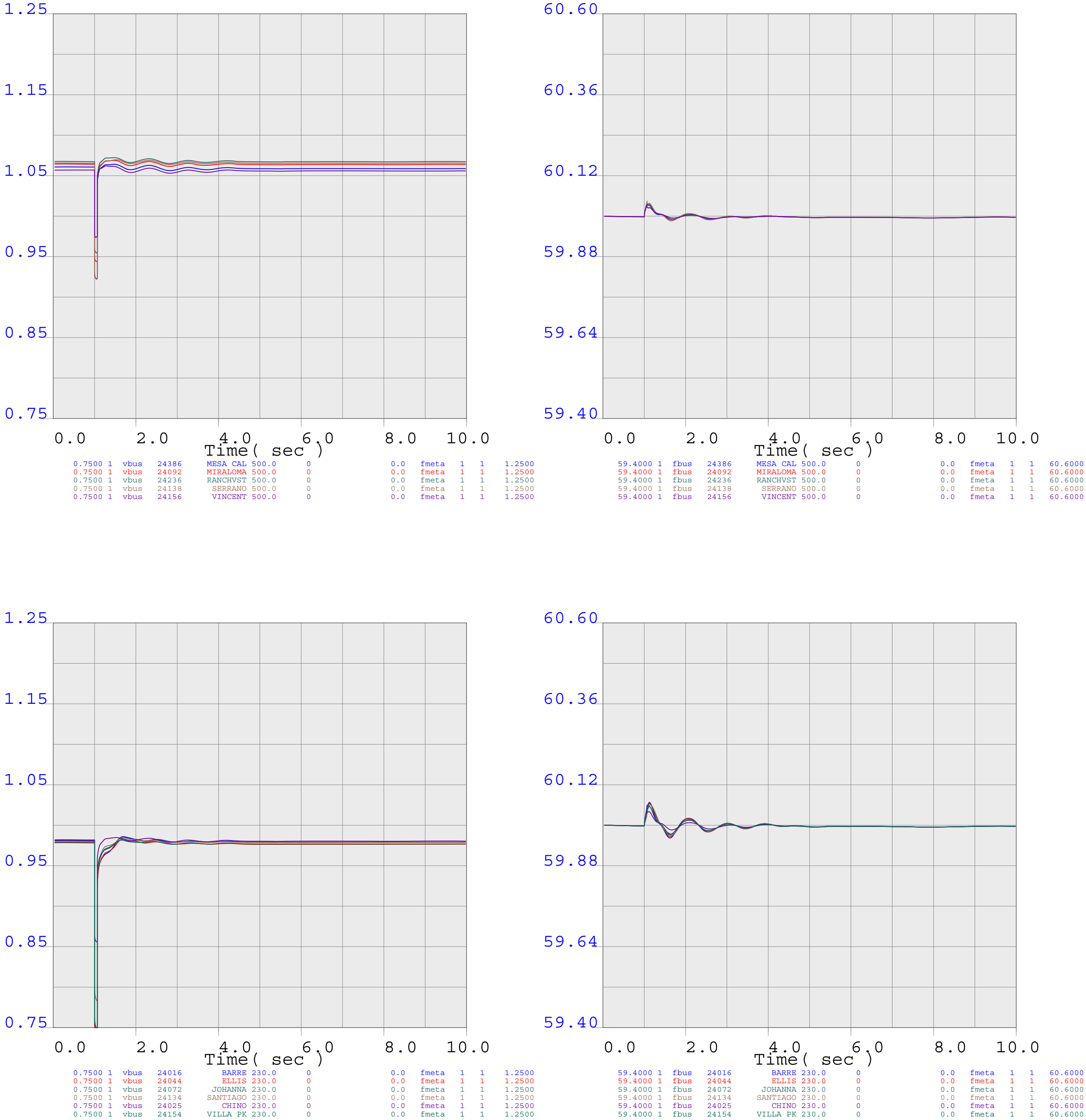
line_7120
Line DELAMO 230.0 to BARRE 230.0 Circuit 1 & Line ALMITOSW 230.0 to BARRE 230.0
1 MW dispatch Case

qc9p-line_7120.chf

C:\DYTOOLS

Thu Oct 20 09:04:04 2016

METRO



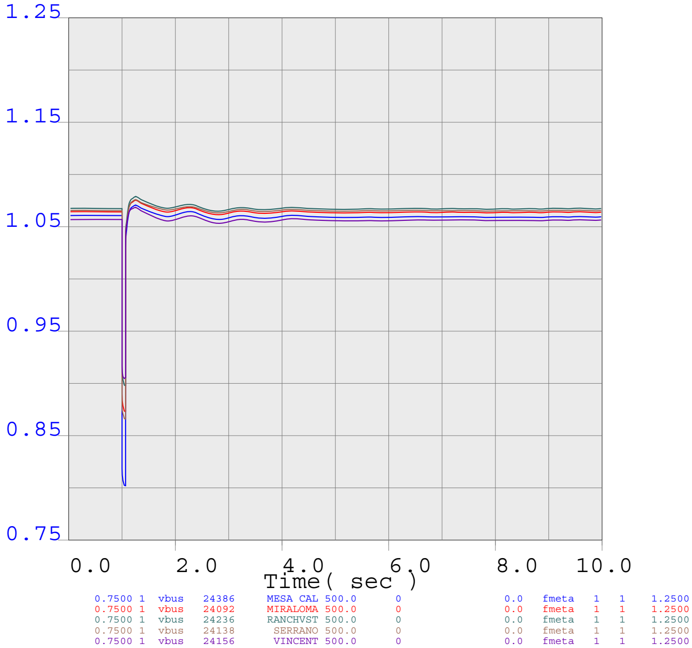
line_7121
Line ALMITOSE 230.0 to CENTER S 230.0 Circuit 1 & Line ALMITOSW 230.0 to LITEHI

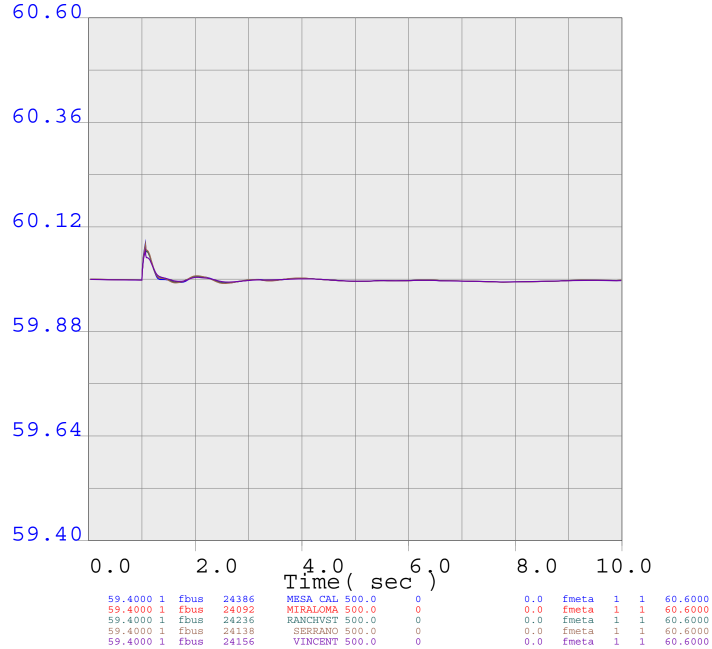
qc9p-line_7121.chf

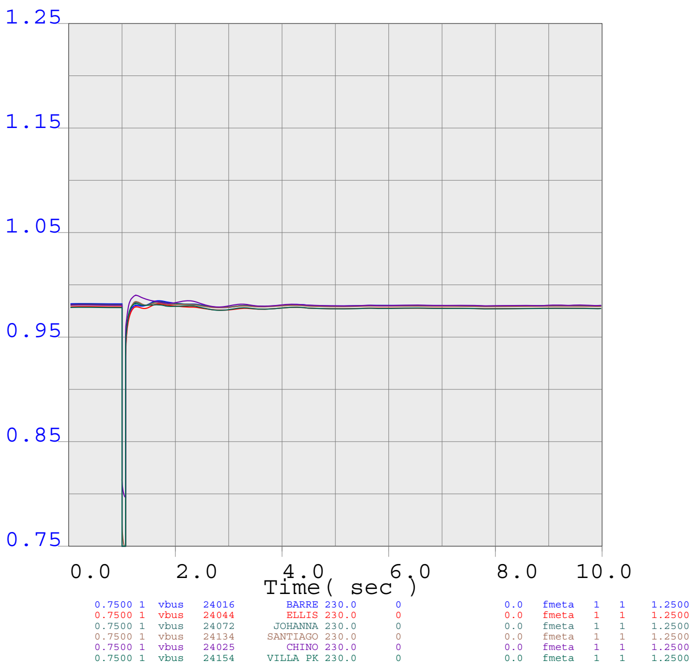
C:\DYTOOLS

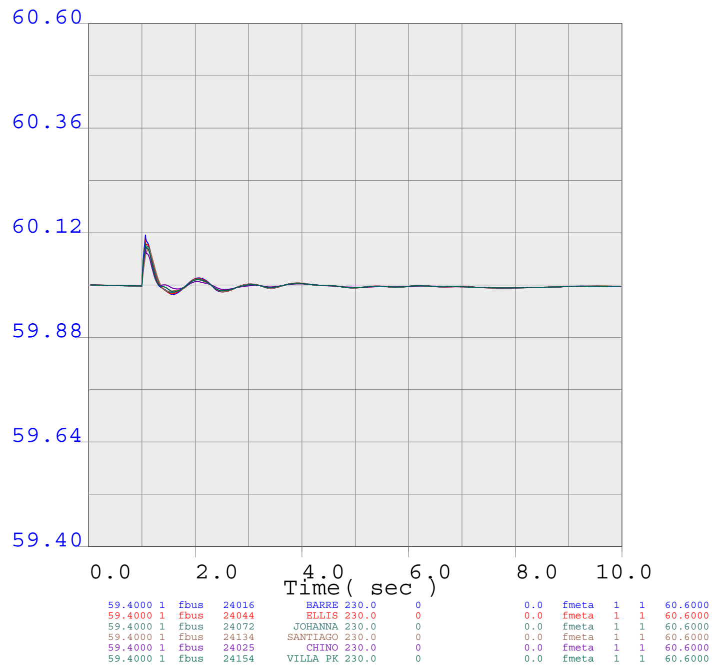
Thu Oct 20 09:04:06 2016

METRO









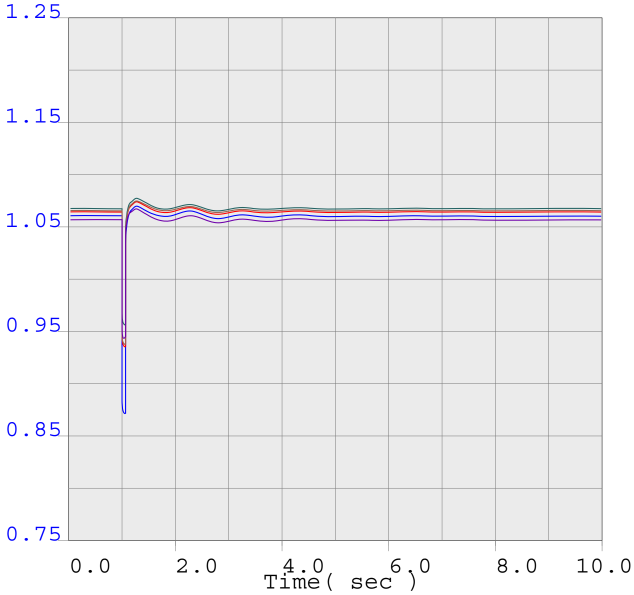
line_7122
Line DELAMO 230.0 to CENTER S 230.0 Circuit 1 & Line ALMITOSE 230.0 to CENTER S
1 MW dispatch Case

qc9p-line_7122.chf

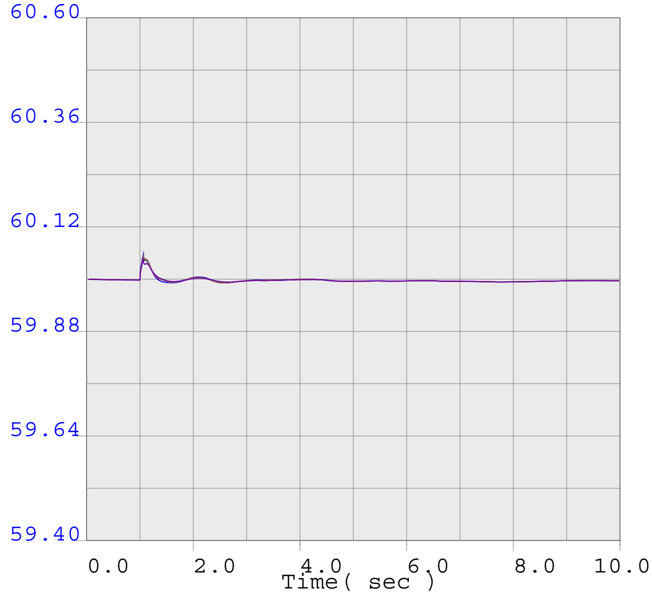
C:\DYTOOLS

Thu Oct 20 09:04:08 2016

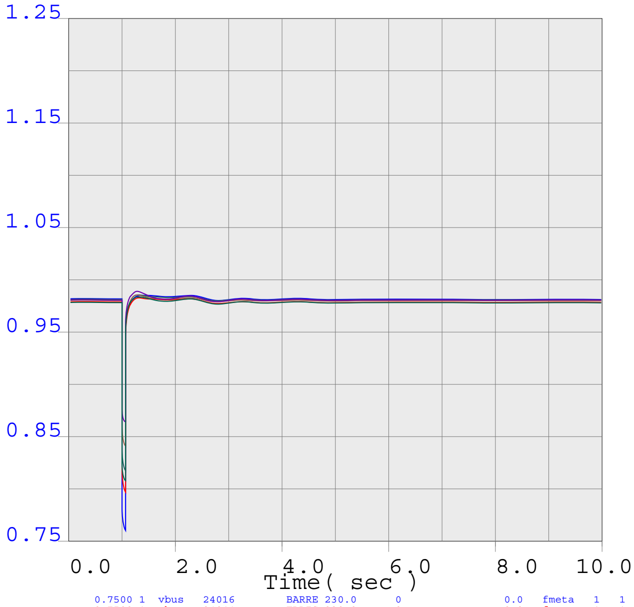
METRO



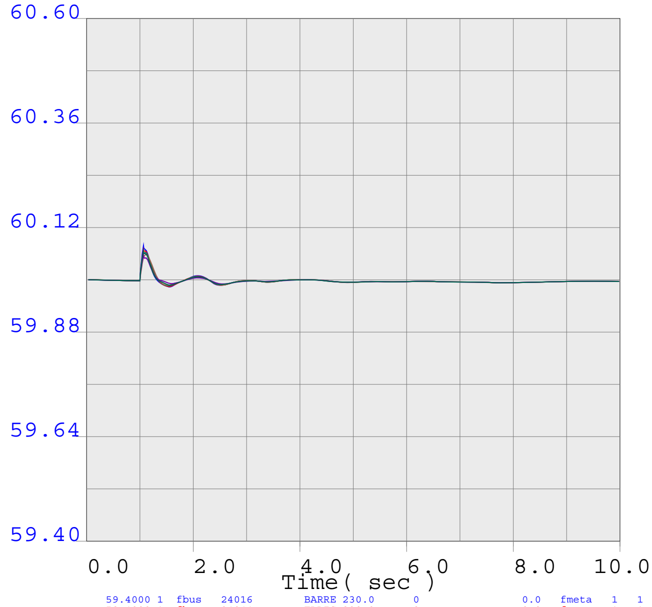
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

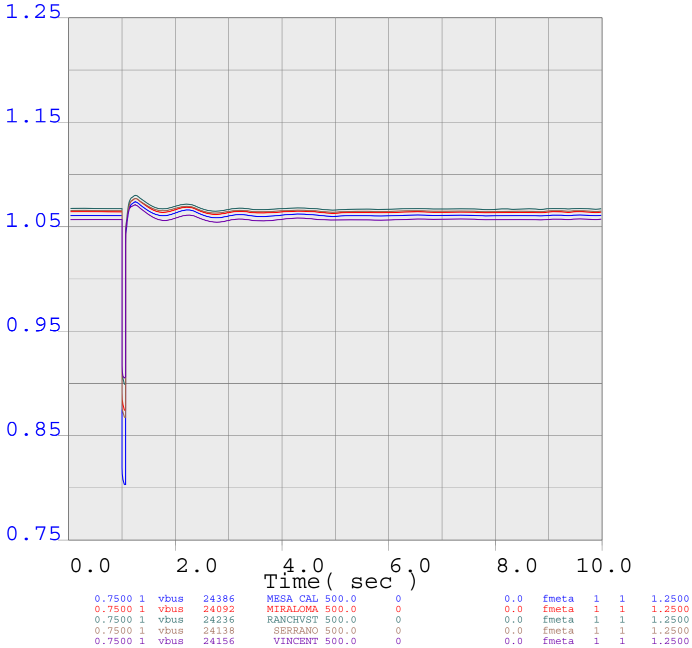
line_7123
Line HINSON 230.0 to DELAMO 230.0 Circuit 1 & Line ALMITOSW 230.0 to LITEHIPE 2

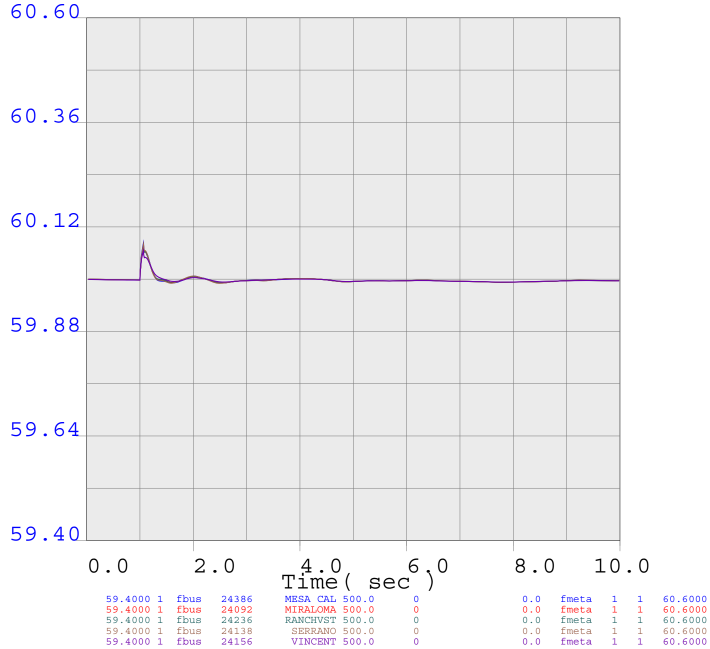
qc9p-line_7123.chf

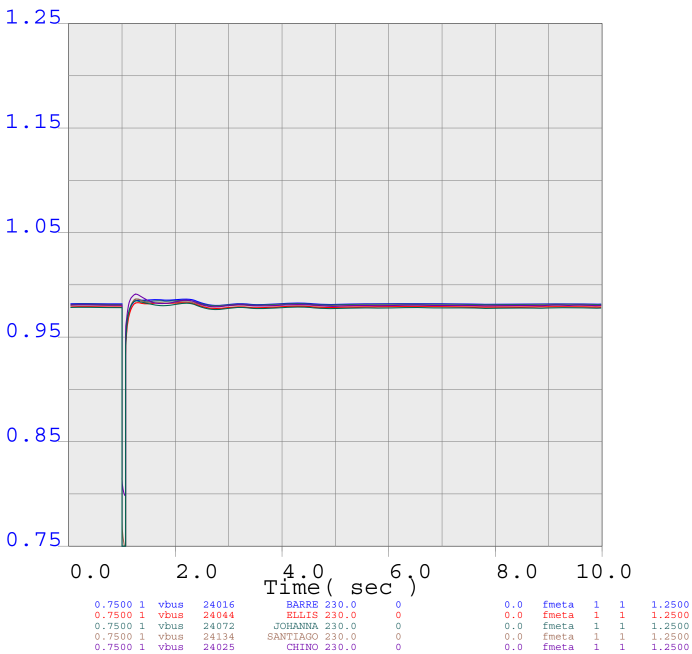
C:\DYTOOLS

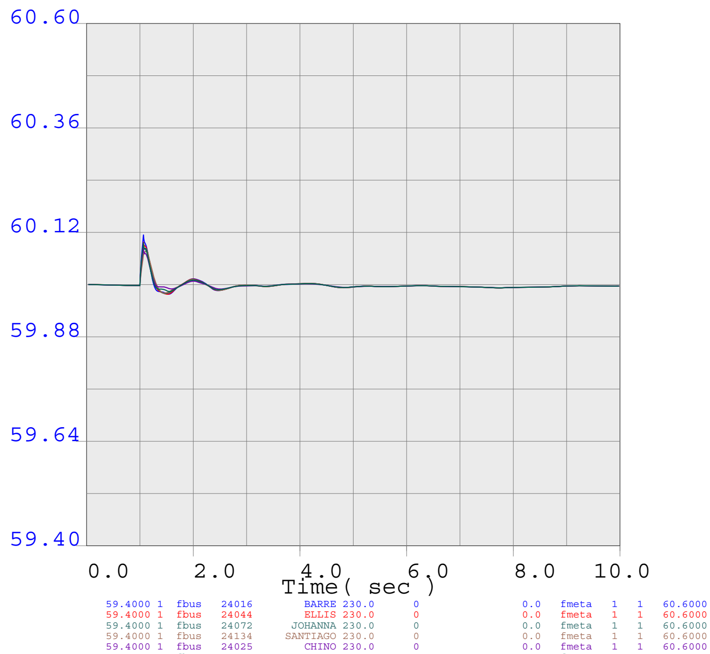
Thu Oct 20 09:04:10 2016

METRO









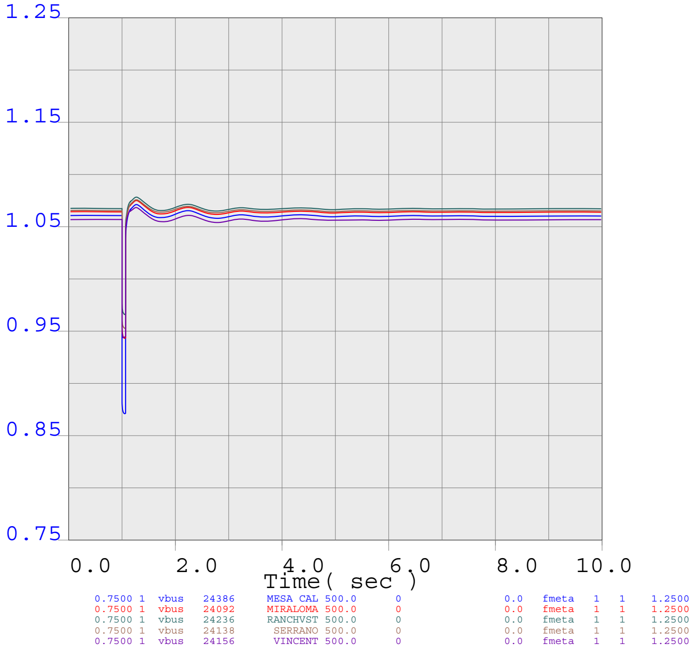
line_7124
Line DELAMO 230.0 to LAGUBELL 230.0 Circuit 1 & Line LITEHIPE 230.0 to MESA CAL
1 MW dispatch Case

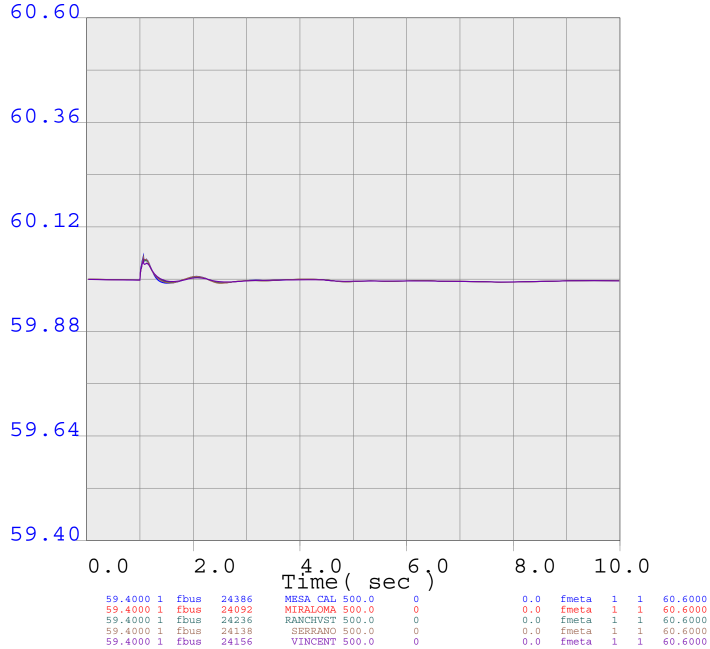
qc9p-line_7124.chf

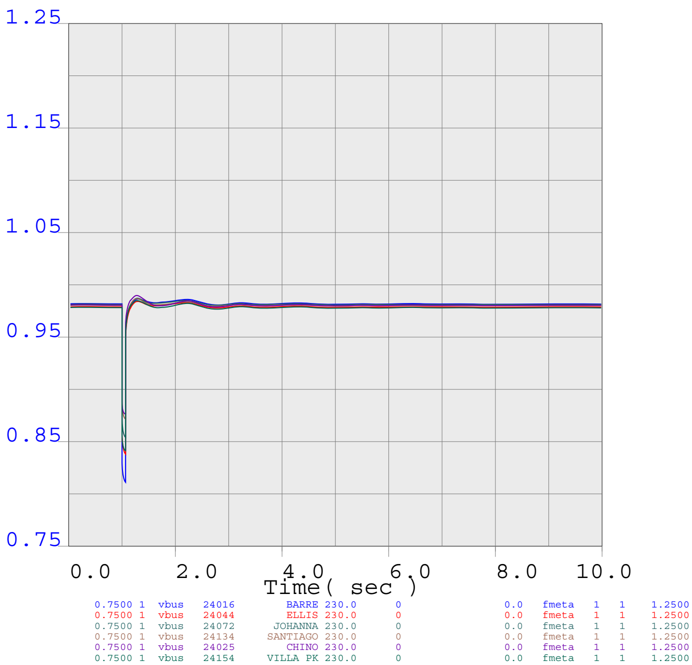
C:\DYTOOLS

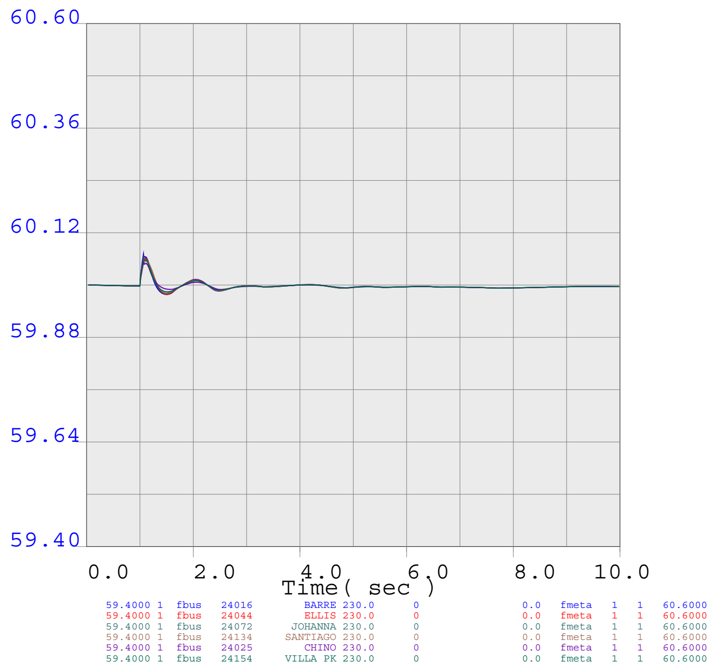
Thu Oct 20 09:04:12 2016

METRO









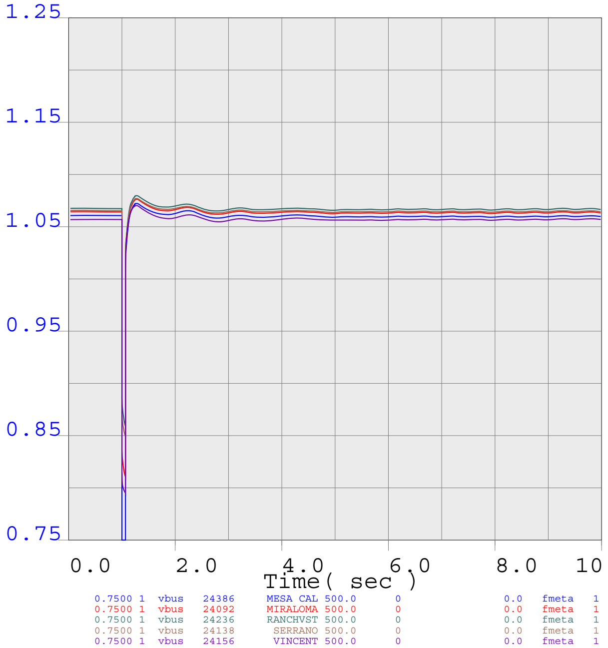
line_7125
Line LA FRESA 230.0 to LAGUBELL 230.0 Circuit 1 & Line MESA CAL 230.0 to REDOND

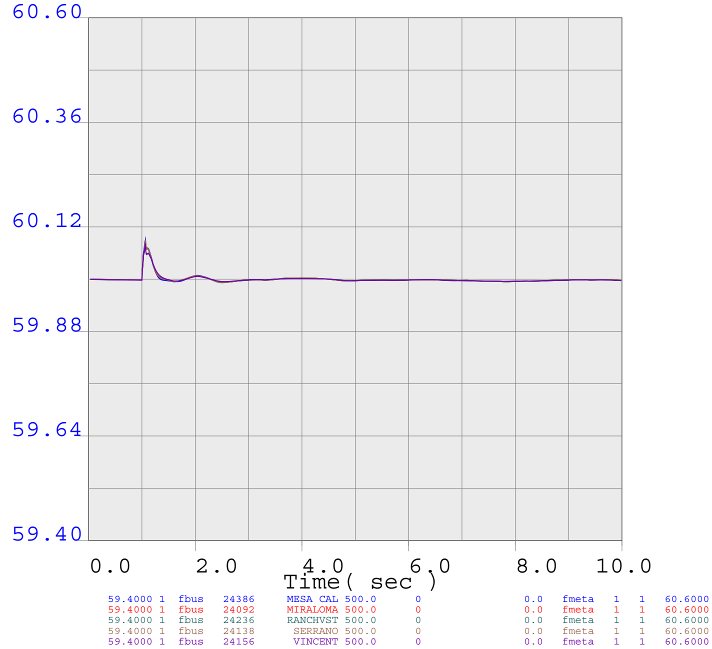
qc9p-line_7125.chf

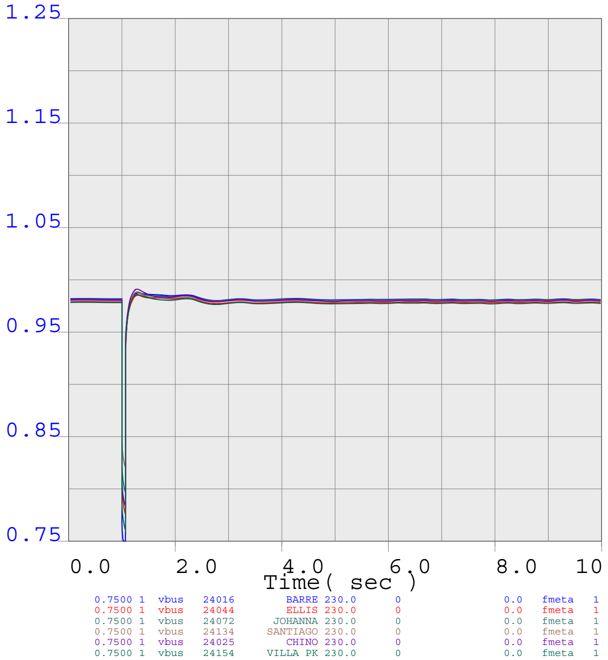
C:\DYTOOLS

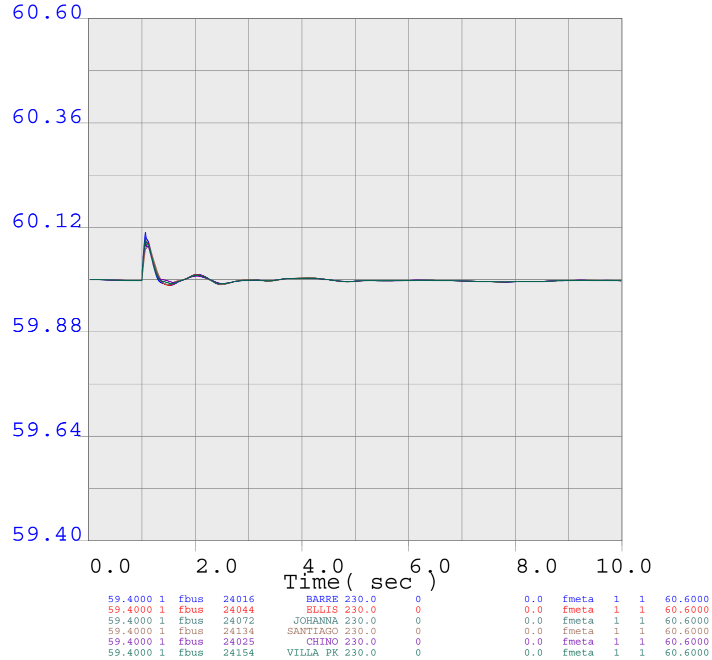
Thu Oct 20 09:04:14 2016

METRO









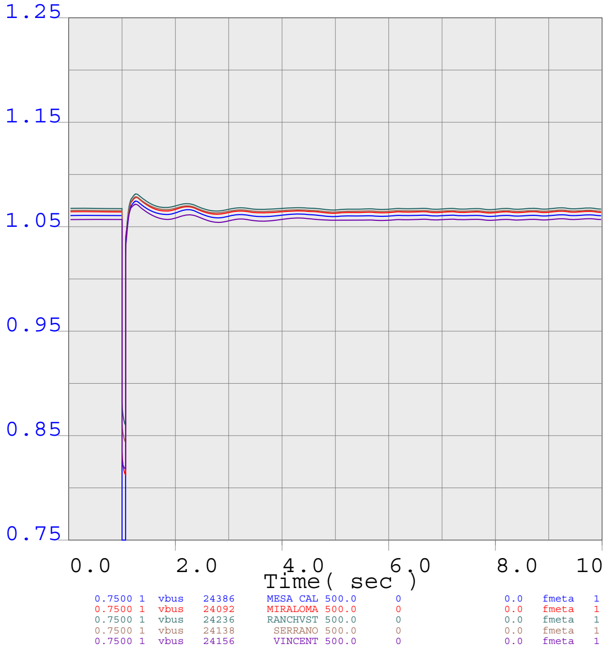
line_7126
Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1 & Line LAGUBELL 230.0 to MESA CA

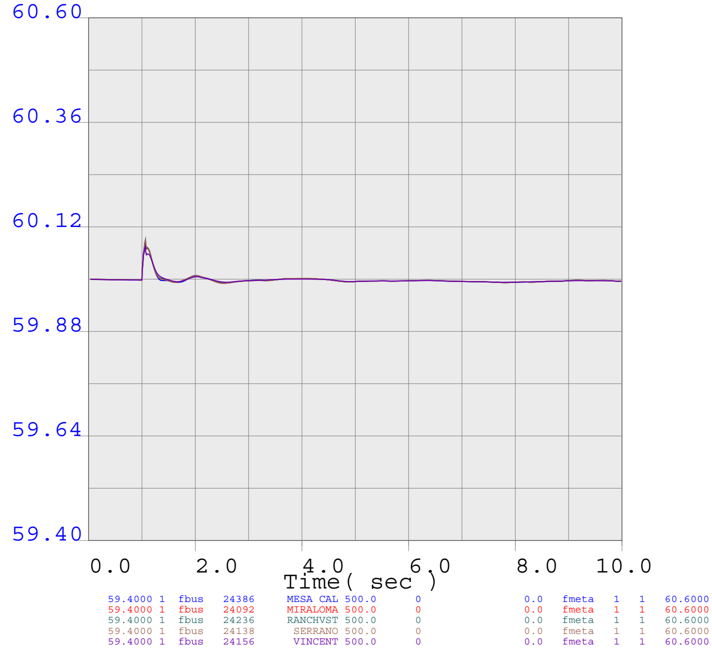
qc9p-line_7126.chf

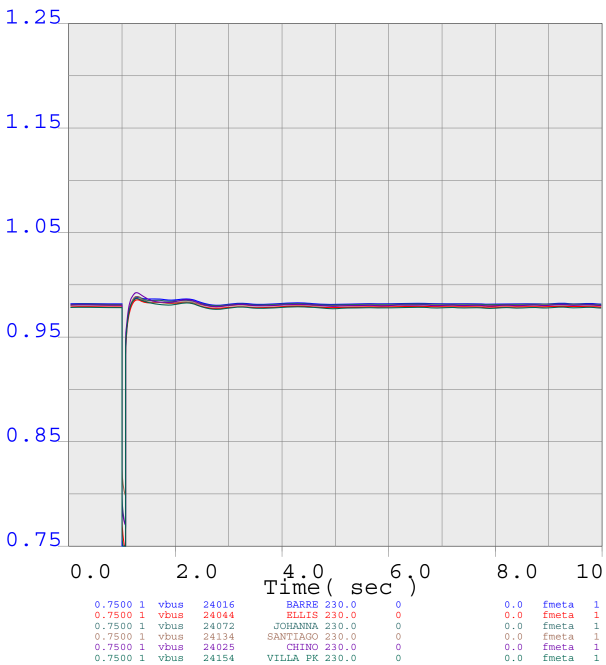
C:\DYTOOLS

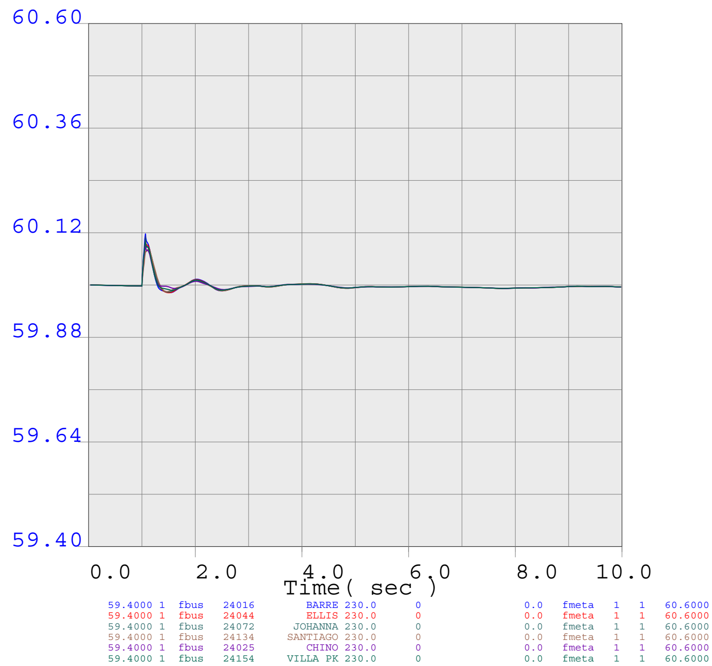
Thu Oct 20 09:04:16 2016

METRO









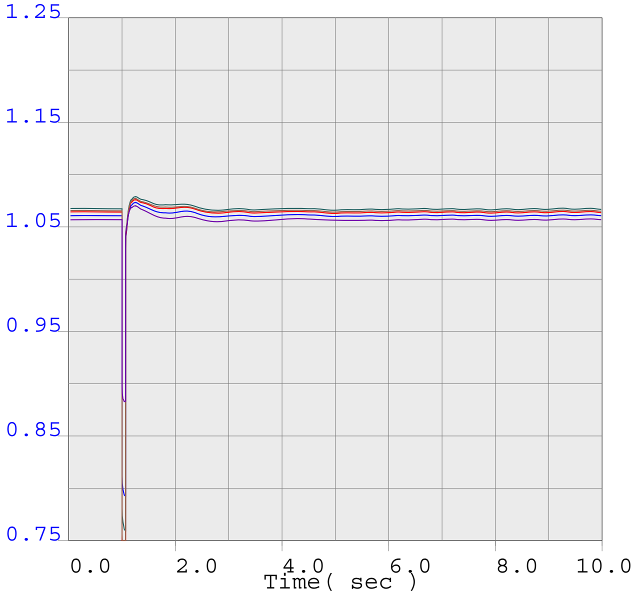
line_7127
Line LAGUBELL 230.0 to MESACALS 230.0 Circuit 2 & Line LITEHIPE 230.0 to MESA C

qc9p-line_7127.chf

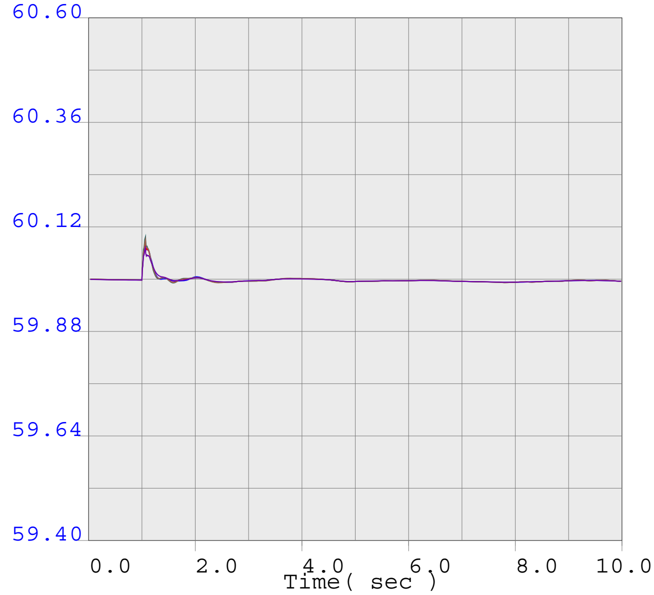
C:\DYTOOLS

Thu Oct 20 09:04:18 2016

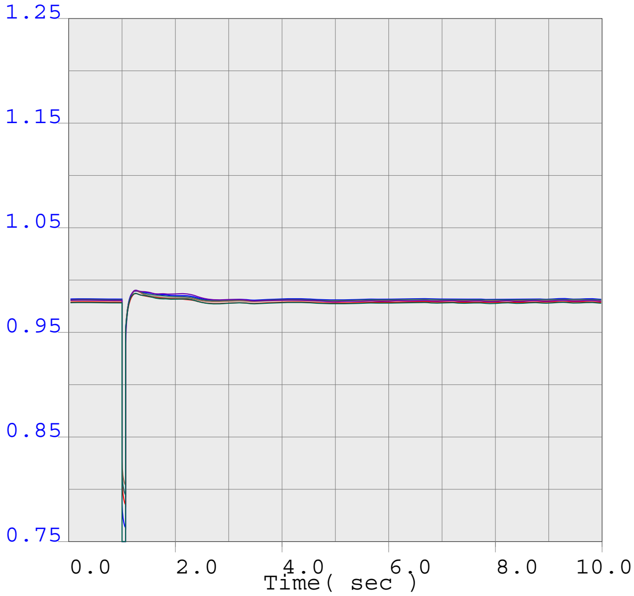
METRO



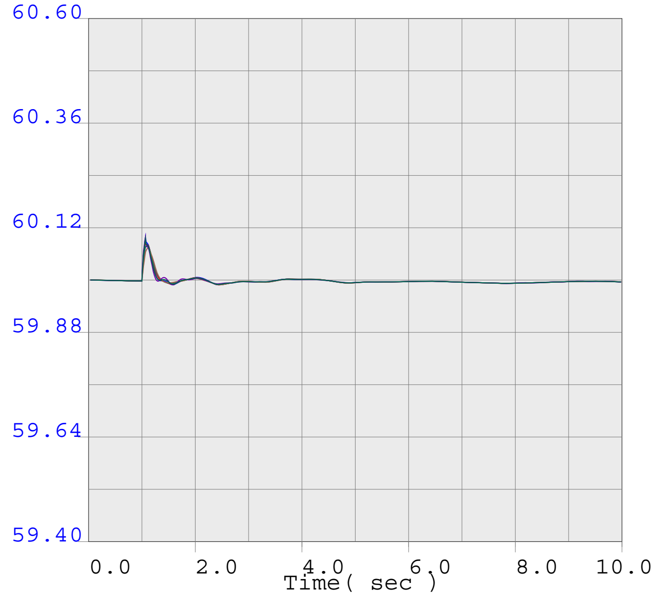
0.7500	1	vbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO 500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT 500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO 230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK 230.0	0	0.0	fmeta	1	1	60.6000

line_7131

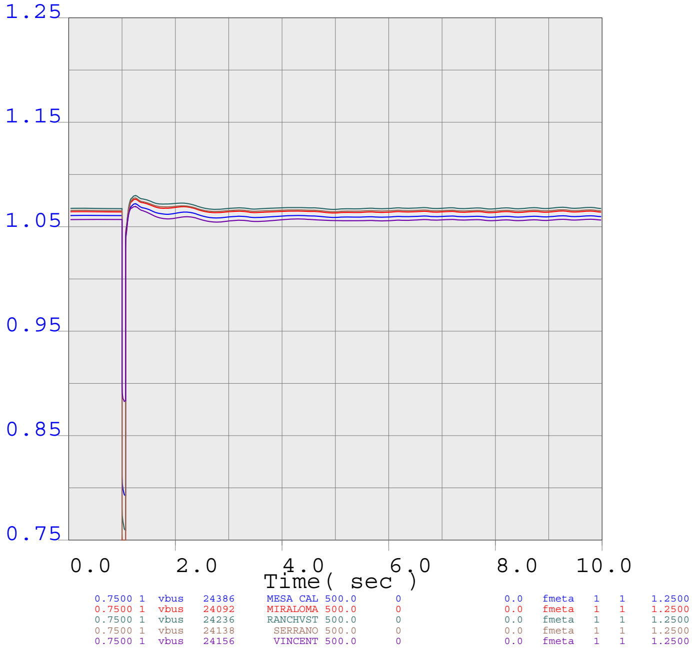
Line MIRALOMW 230.0 to WALNUT 230.0 Circuit 1 & Line OLINDA 230.0 to WALNUT 230

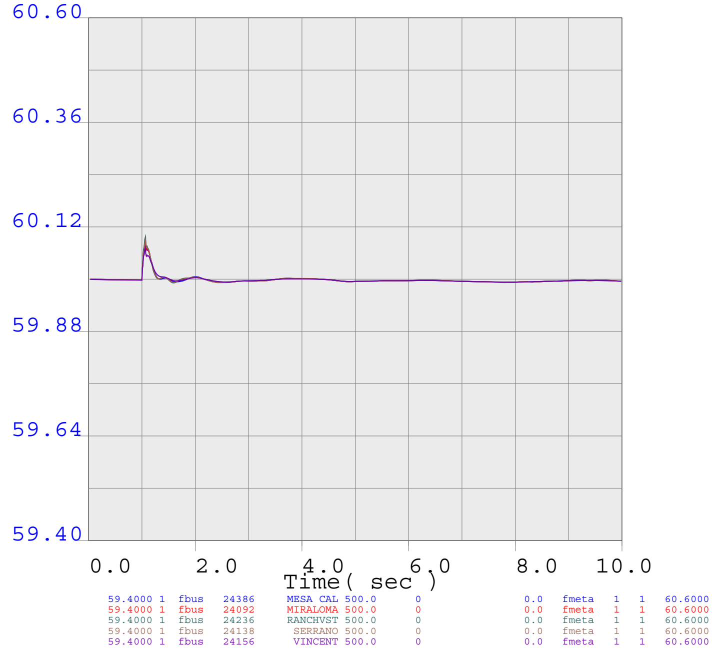
qc9p-line_7131.chf

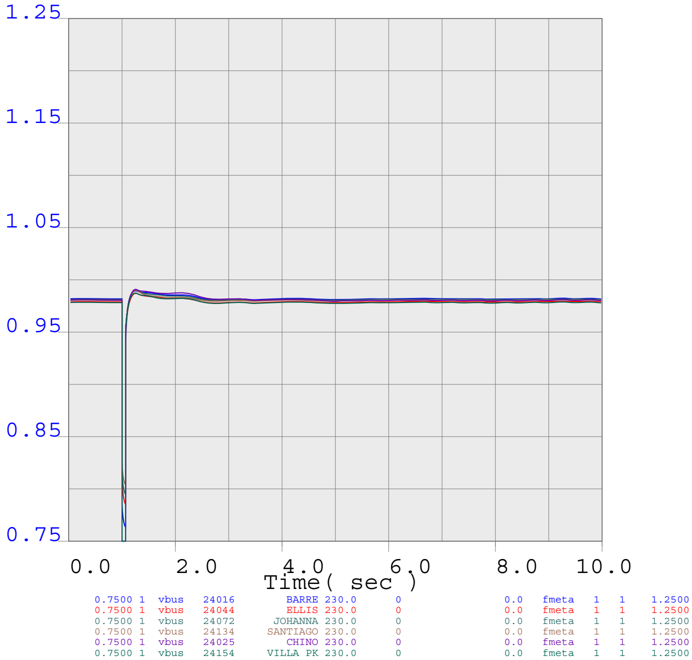
C:\DYTOOLS

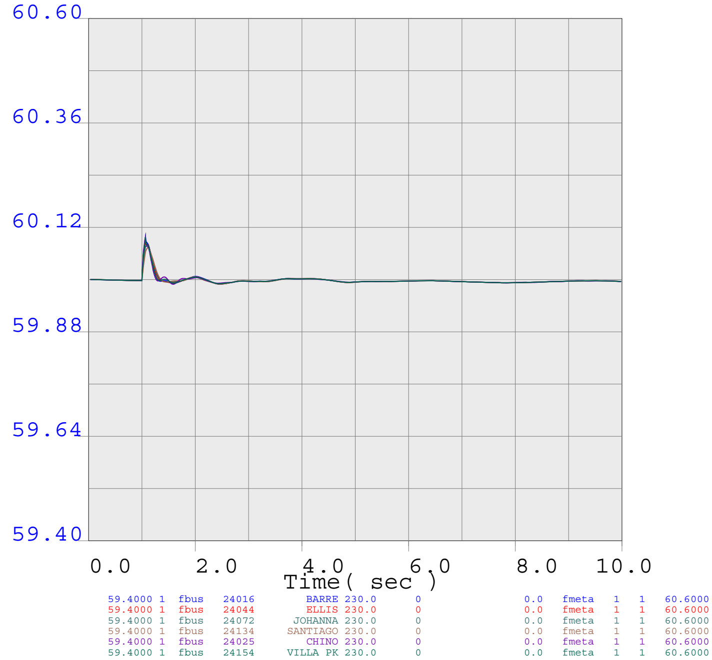
Thu Oct 20 09:04:20 2016

METRO









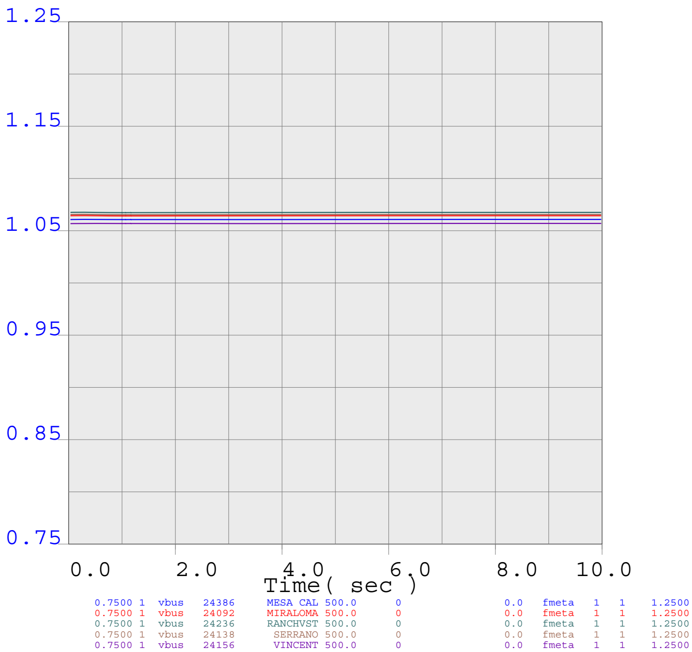
line_7133
Line MIRALOMW 230.0 to WALNUT 230.0 Circuit 1 & Line MIRALOME 230.0 to OLINDA 2

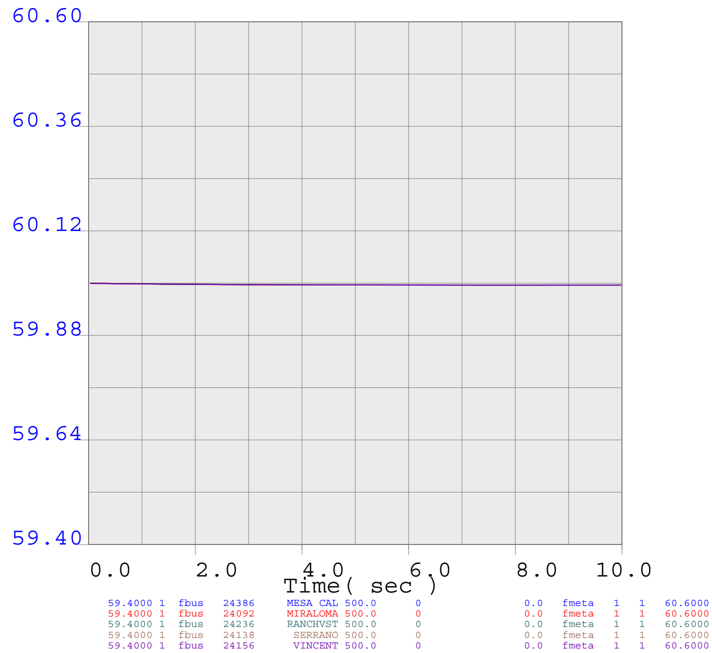
qc9p-line_7133.chf

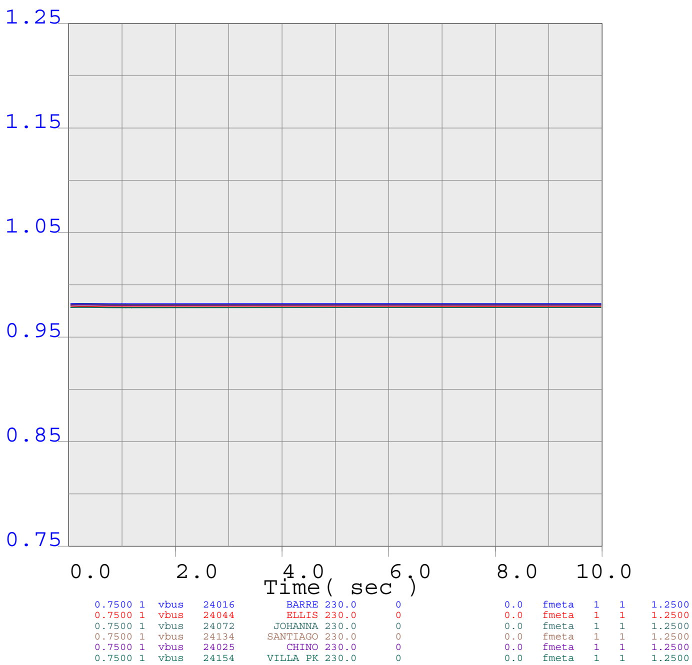
C:\DYTOOLS

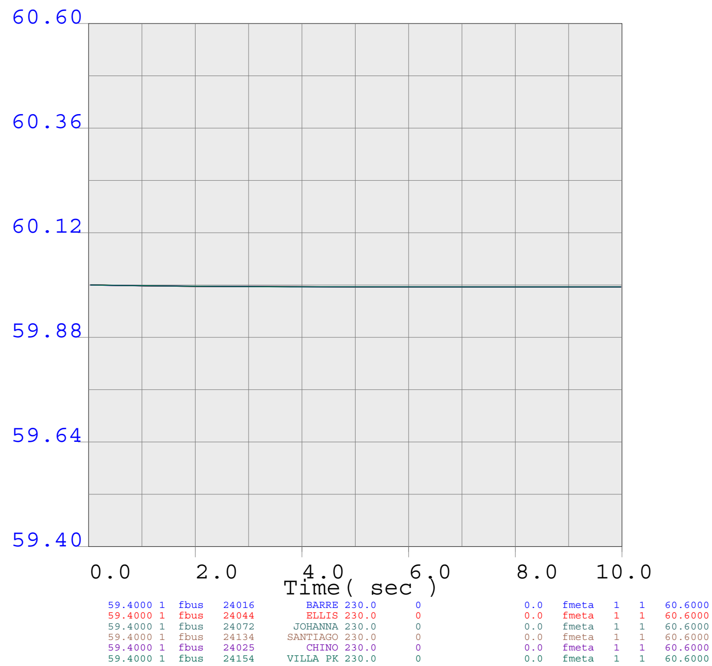
Thu Oct 20 09:04:22 2016

METRO









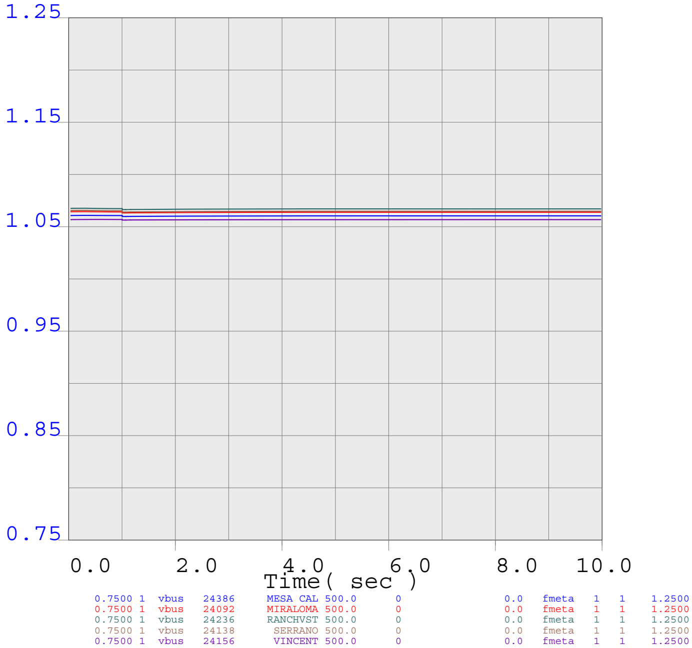
lshunt
EAST TS 500.00
1 MW dispatch Case

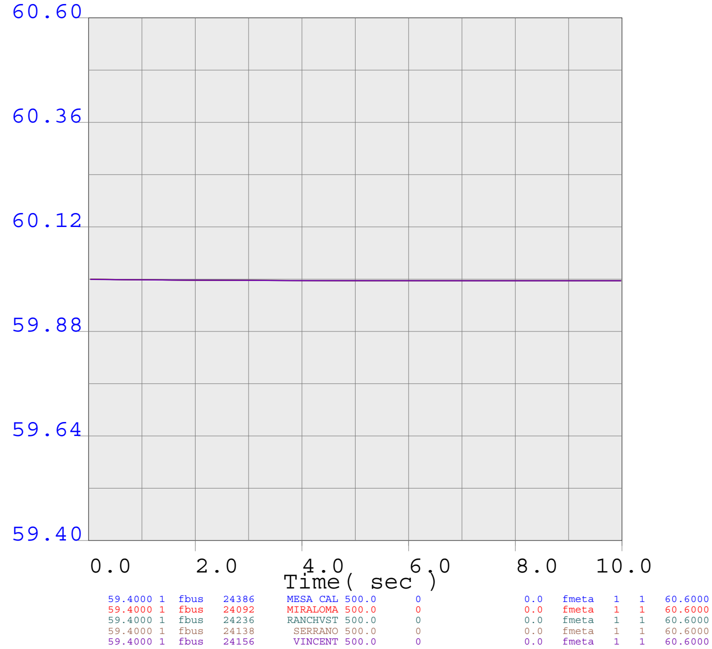
qc9p-lshunt.chf

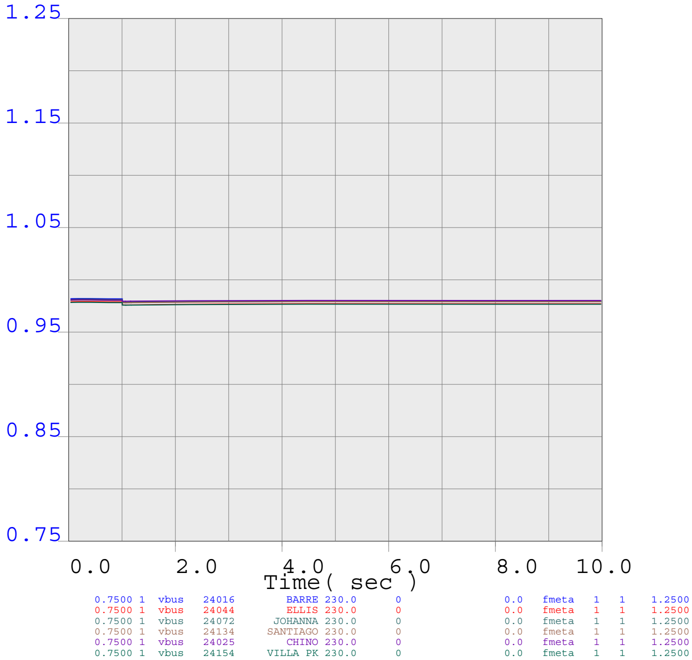
C:\DYTOOLS

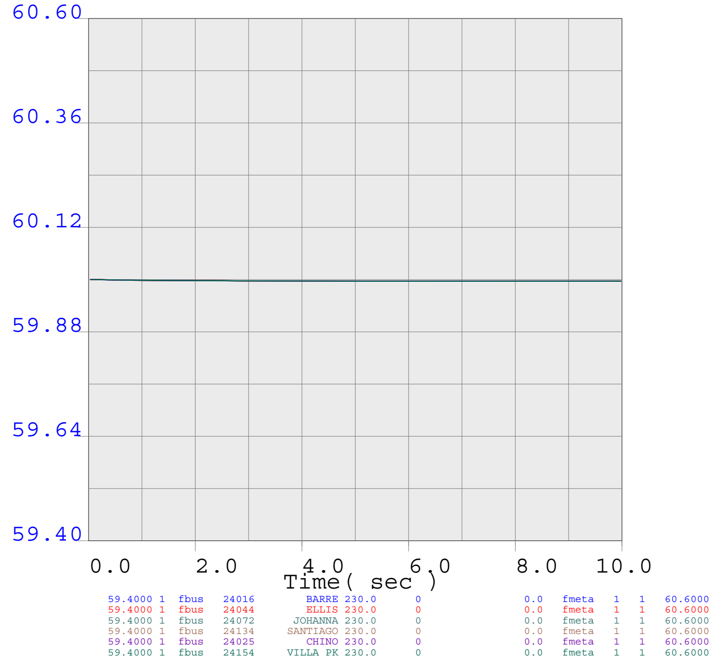
Thu Oct 20 09:04:24 2016

METRO









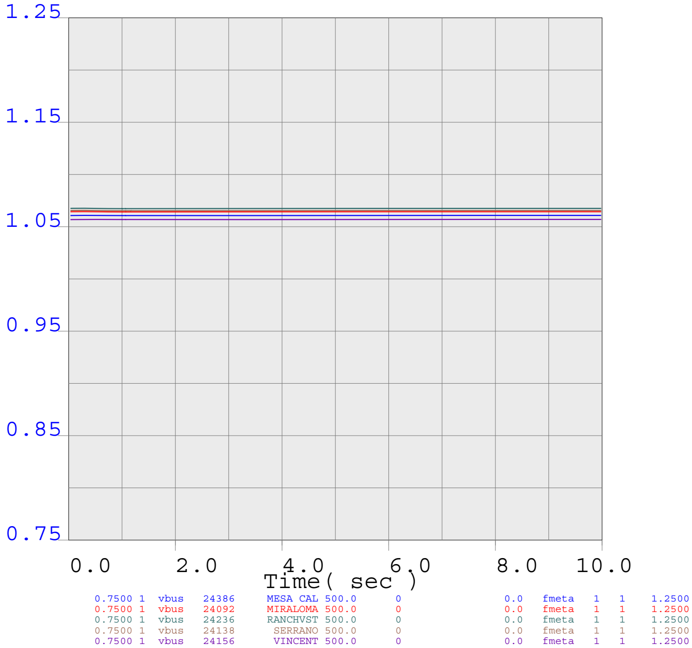
svd_1402
SVD BARRE 230.00
1 MW dispatch Case

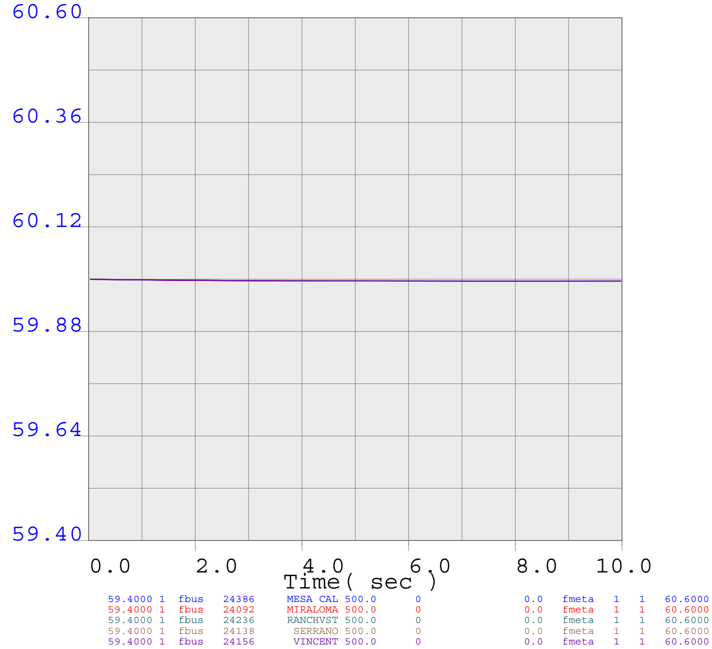
qc9p-svd_1402.chf

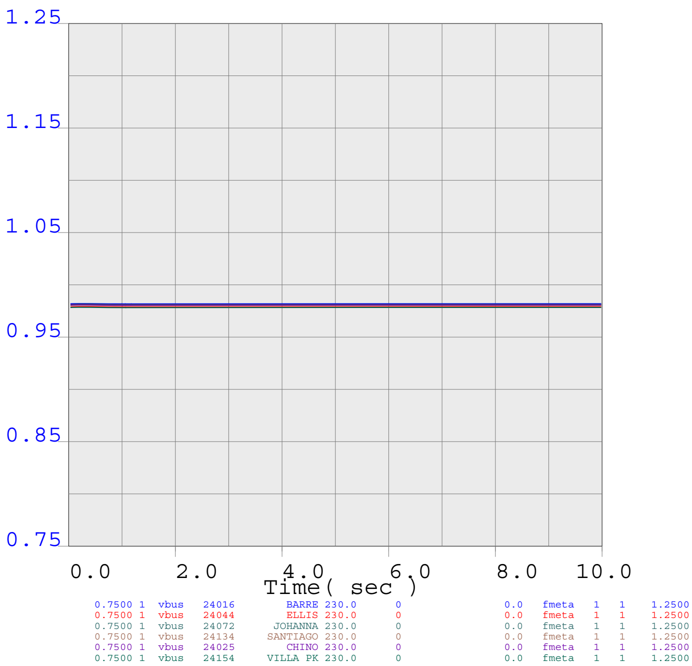
C:\DYTOOLS

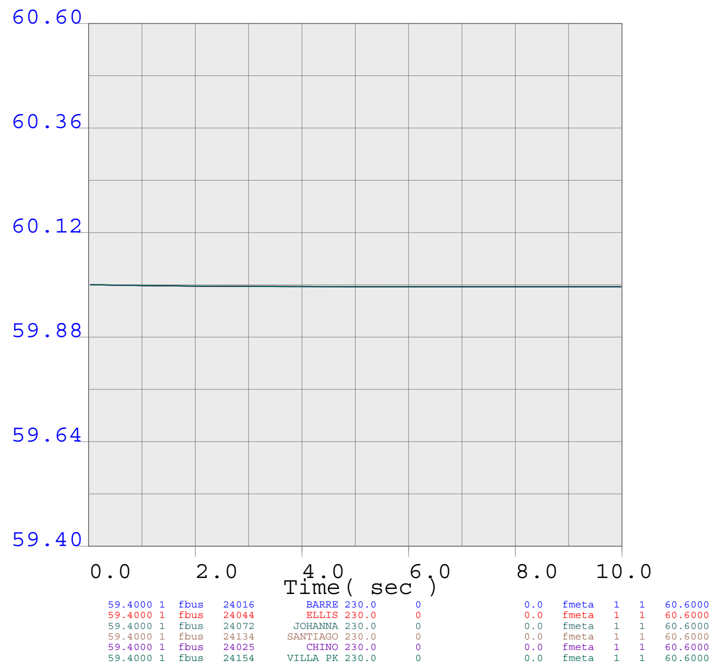
Thu Oct 20 09:04:26 2016

METRO









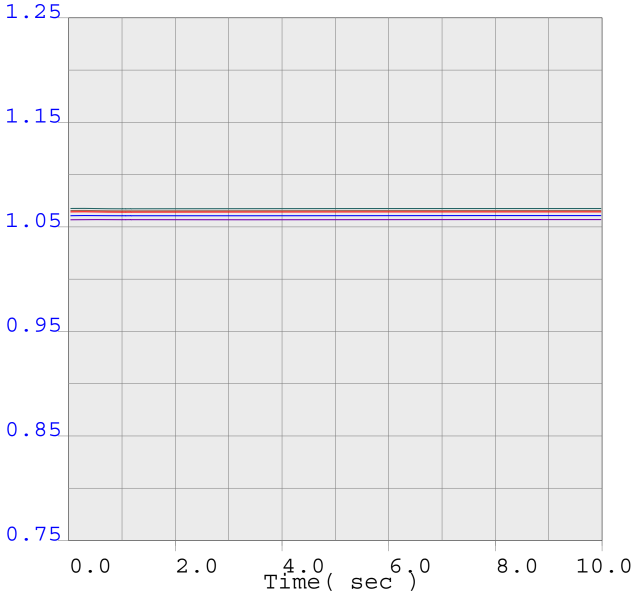
svd_1403
SVD CHINO 230.00
1 MW dispatch Case

qc9p-svd_1403.chf

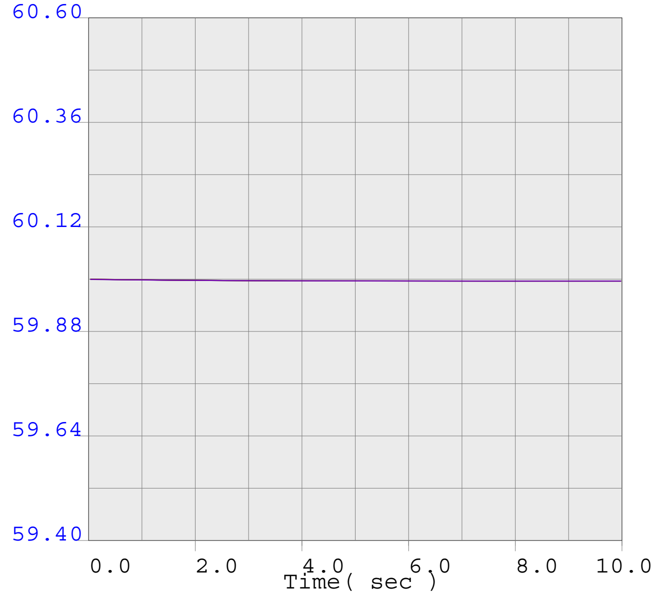
C:\DYTOOLS

Thu Oct 20 09:04:28 2016

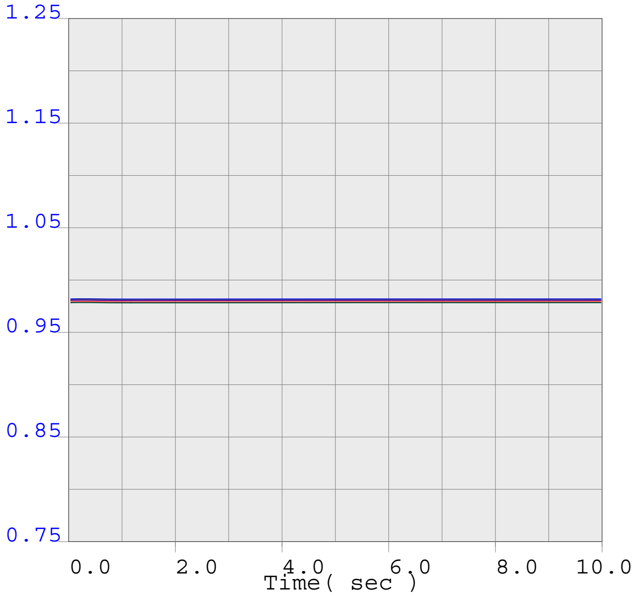
METRO



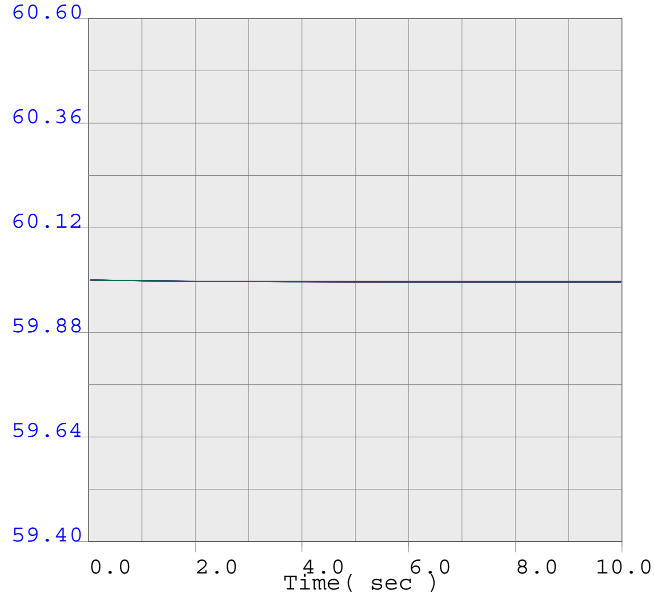

```
0.7500 1  vbus   24386    MESA CAL 500.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24092    MIRALOMA 500.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24236    RANCHVST 500.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24138     SERRANO 500.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24156     VINCENT 500.0      0          0.0   fmeta  1  1   1.2500
```




```
59.4000 1  fbus   24386    MESA CAL 500.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24092    MIRALOMA 500.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24236    RANCHVST 500.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24138     SERRANO 500.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24156     VINCENT 500.0      0          0.0   fmeta  1  1   60.6000
```




```
0.7500 1  vbus   24016       BARRE 230.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24044       ELLIS 230.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24072     JOHANNA 230.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24134    SANTIAGO 230.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24025       CHINO 230.0      0          0.0   fmeta  1  1   1.2500
0.7500 1  vbus   24154    VILLA PK 230.0      0          0.0   fmeta  1  1   1.2500
```




```
59.4000 1  fbus   24016       BARRE 230.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24044       ELLIS 230.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24072     JOHANNA 230.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24134    SANTIAGO 230.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24025       CHINO 230.0      0          0.0   fmeta  1  1   60.6000
59.4000 1  fbus   24154    VILLA PK 230.0      0          0.0   fmeta  1  1   60.6000
```

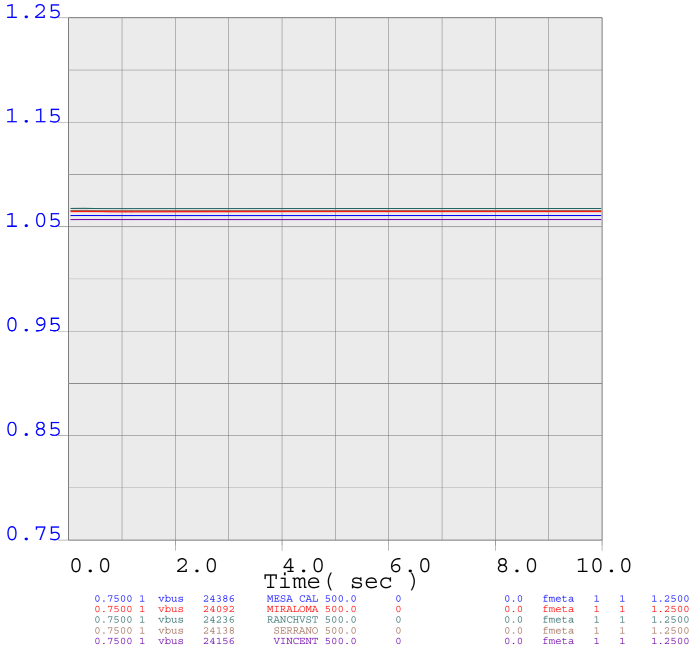
svd_1404
SVD EL NIDO 230.00
1 MW dispatch Case

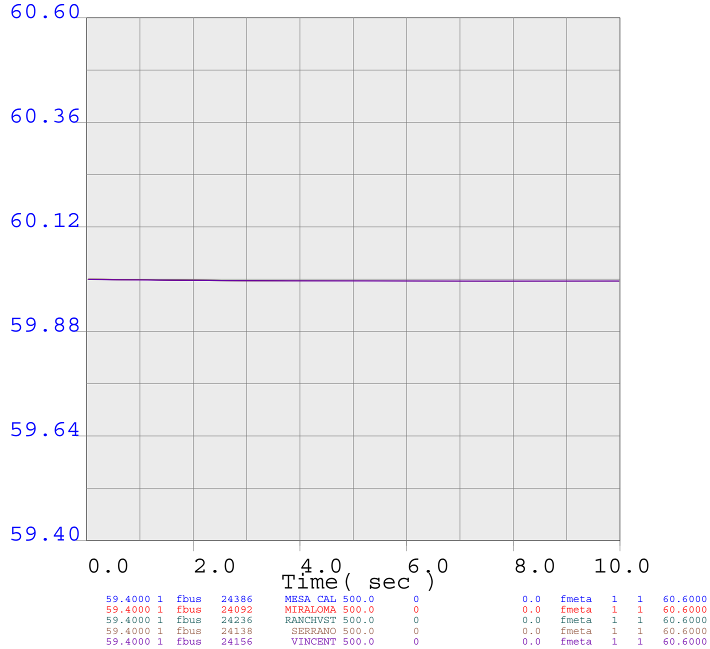
qc9p-svd_1404.chf

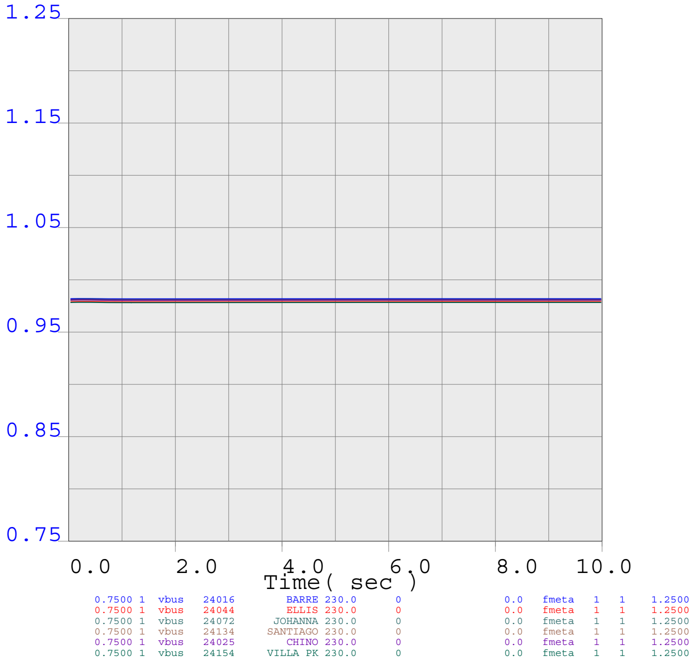
C:\DYTOOLS

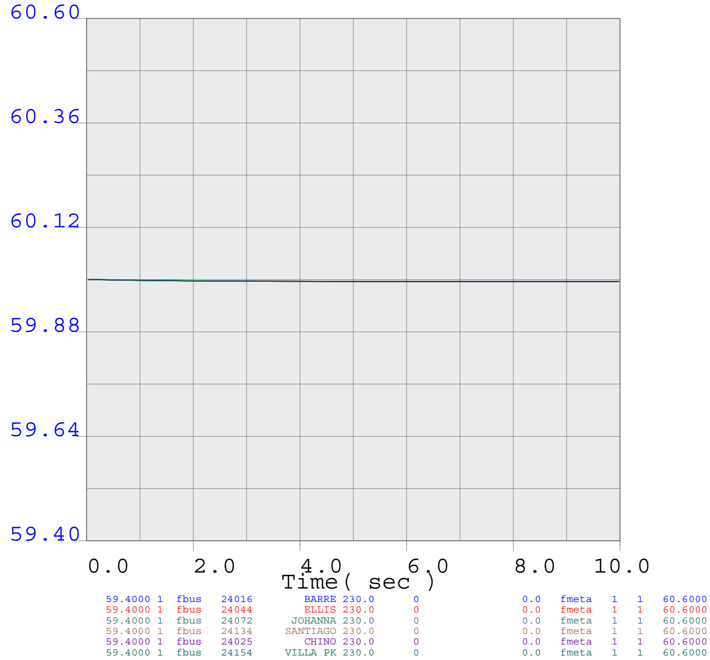
Thu Oct 20 09:04:30 2016

METRO









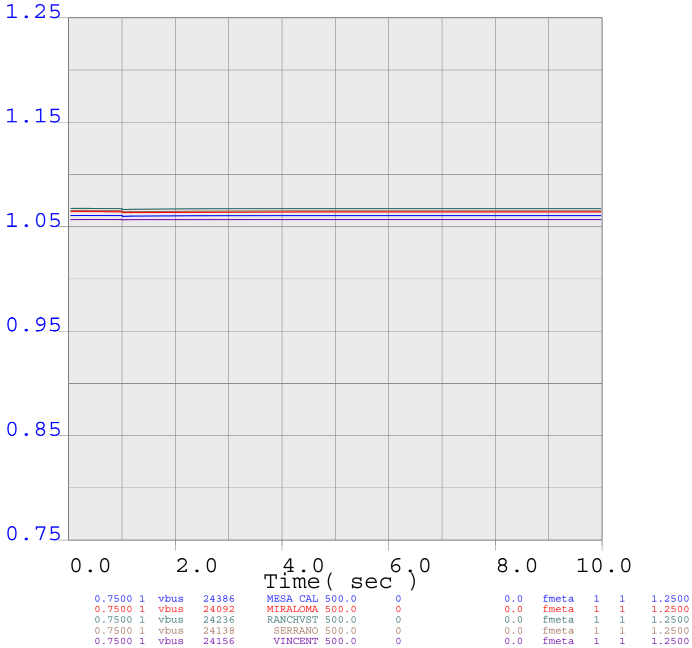
svd_1405
SVD GOULD 230.00
1 MW dispatch Case

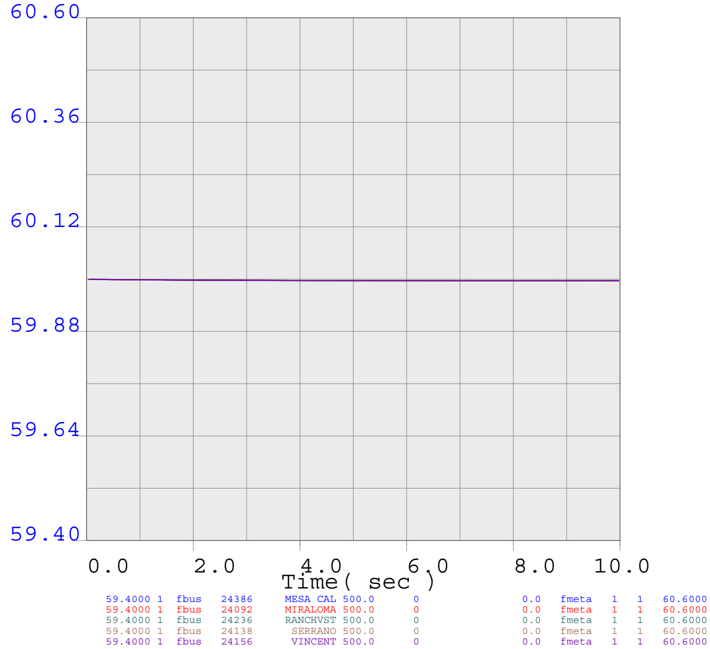
qc9p-svd_1405.chf

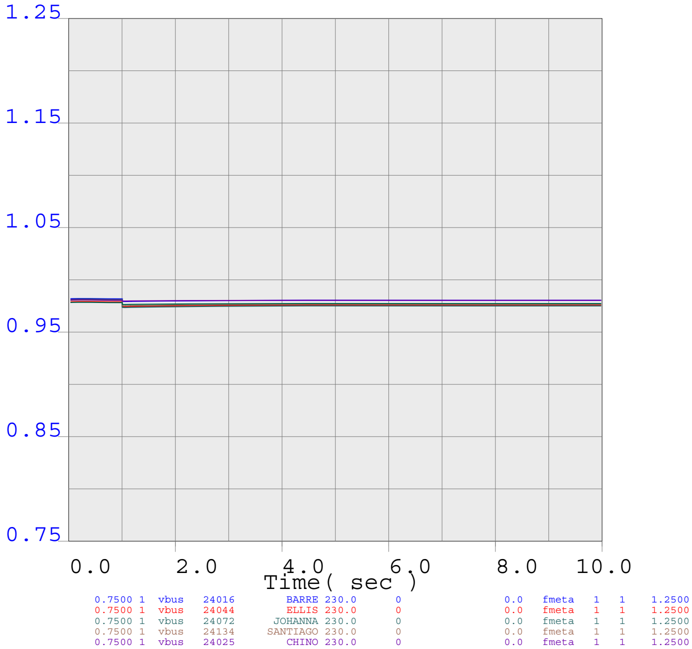
C:\DYTOOLS

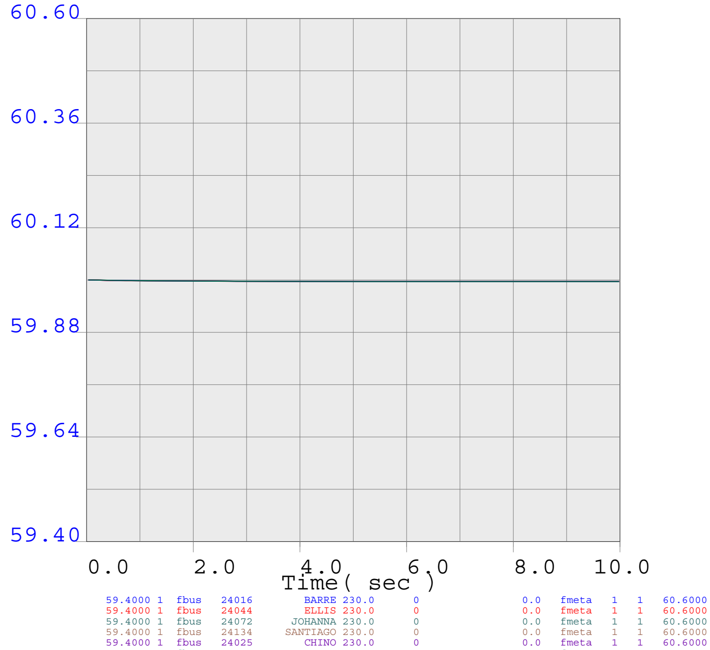
Thu Oct 20 09:04:32 2016

METRO









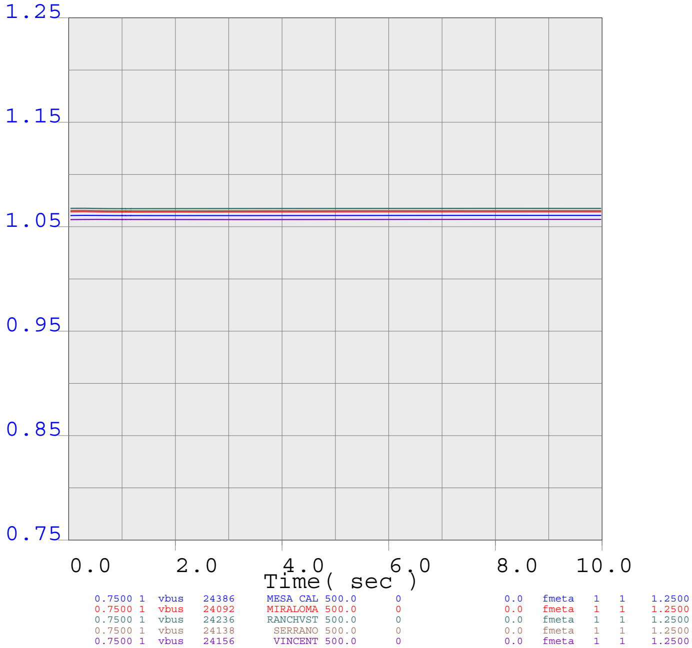
svd_1406
SVD JOHANNA 230.00
1 MW dispatch Case

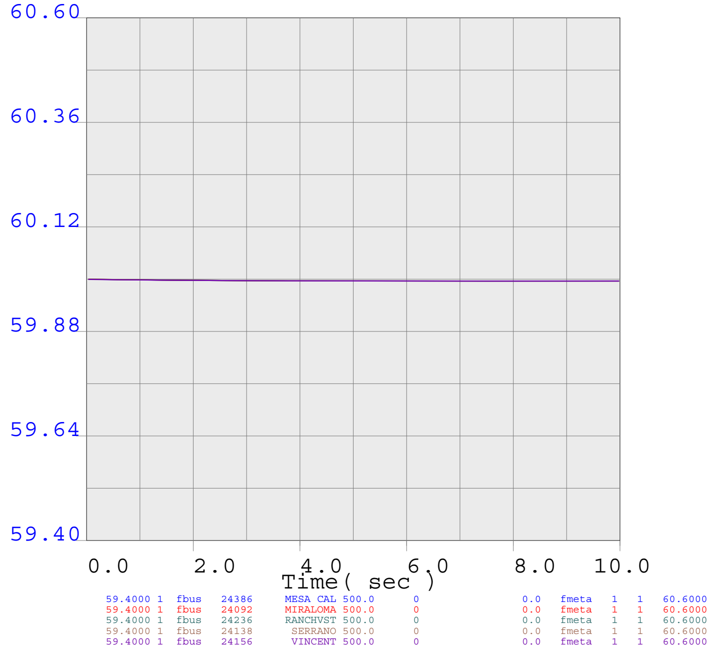
qc9p-svd_1406.chf

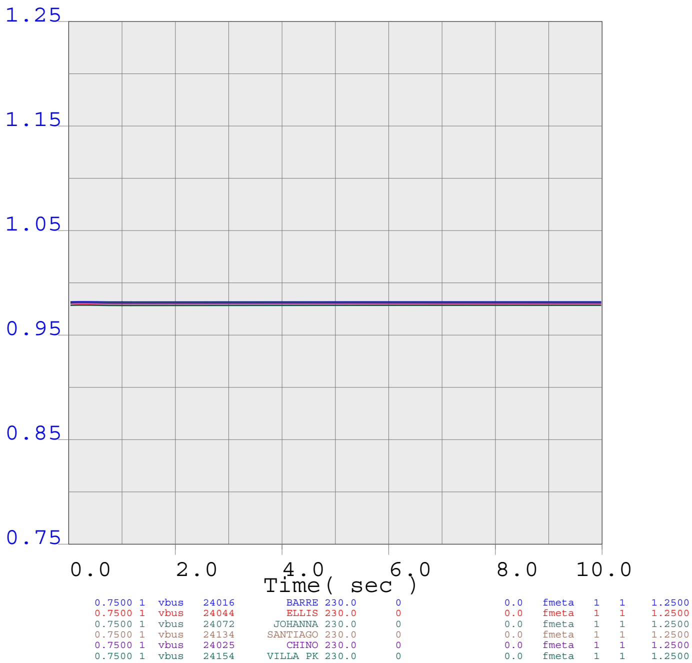
C:\DYTOOLS

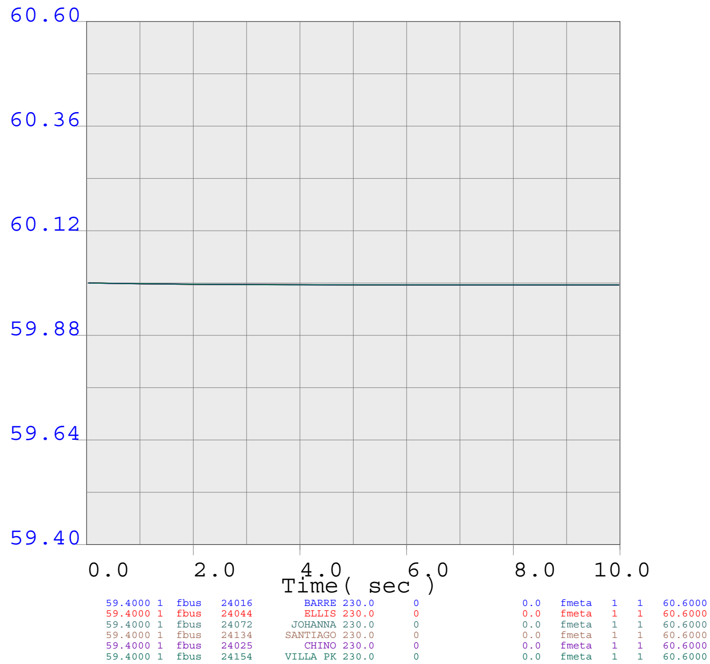
Thu Oct 20 09:04:34 2016

METRO









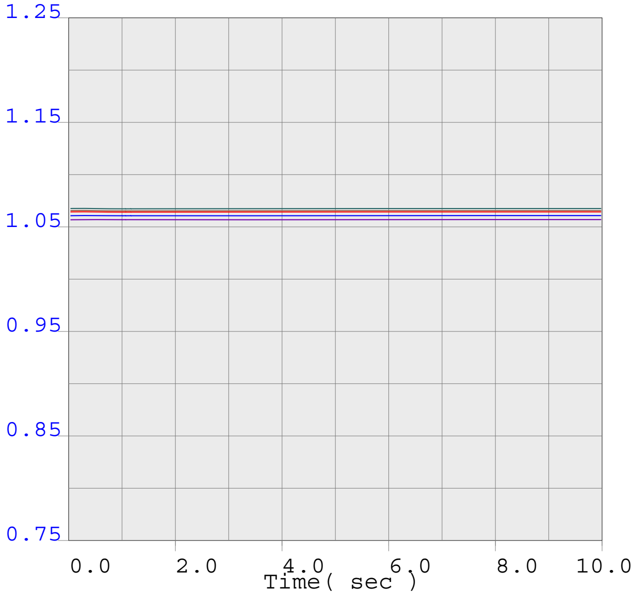
svd_1407
SVD LA FRESA 230.00
1 MW dispatch Case

qc9p-svd_1407.chf

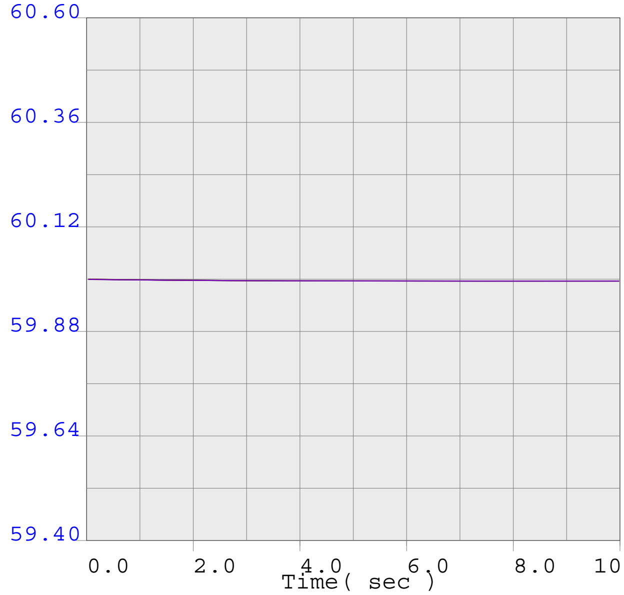
C:\DYTOOLS

Thu Oct 20 09:04:36 2016

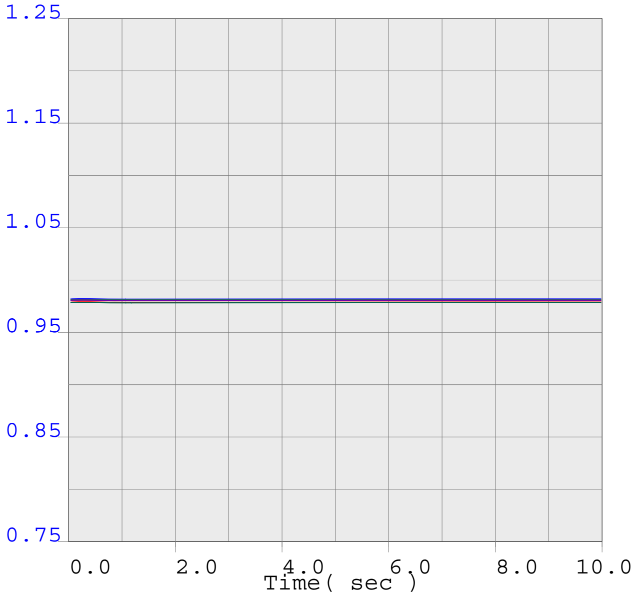
METRO



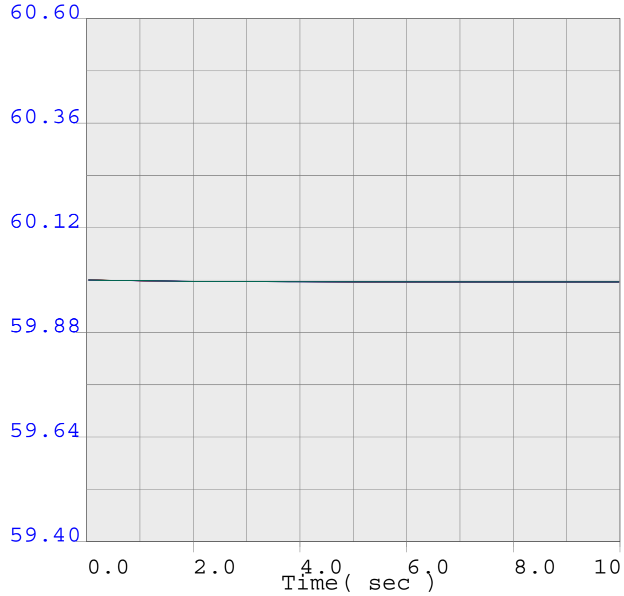
0.7500 1 vbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24386 MESA CAL 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24092 MIRALOMA 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24236 RANCHVST 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24138 SERRANO 500.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24156 VINCENT 500.0 0 0.0 fmeta 1 1 60.6000



0.7500 1 vbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 1.2500
0.7500 1 vbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 1.2500



59.4000 1 fbus 24016 BARRE 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24044 ELLIS 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24072 JOHANNA 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24134 SANTIAGO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24025 CHINO 230.0 0 0.0 fmeta 1 1 60.6000
59.4000 1 fbus 24154 VILLA PK 230.0 0 0.0 fmeta 1 1 60.6000

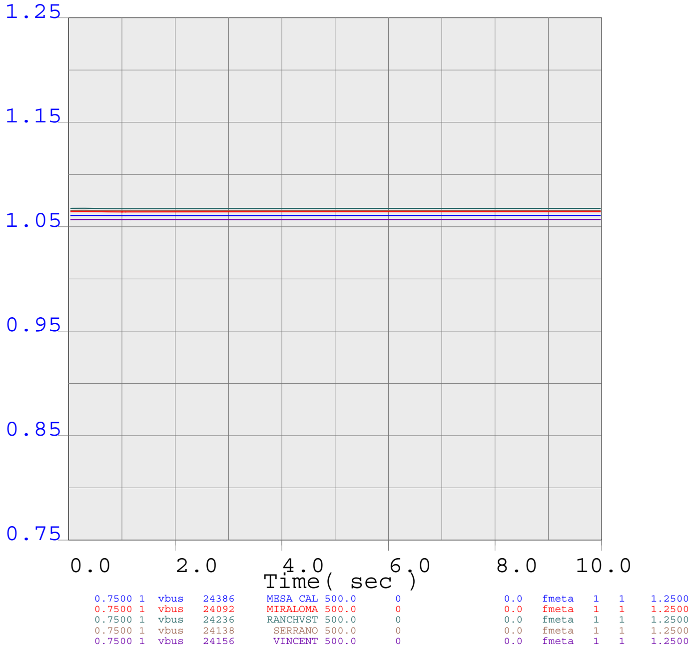
svd_1408
SVD LAGUBELL 230.00
1 MW dispatch Case

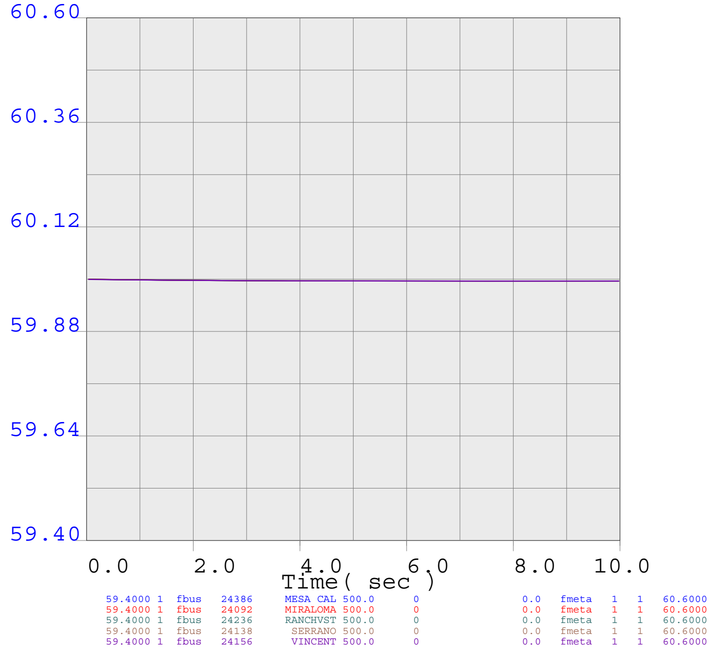
qc9p-svd_1408.chf

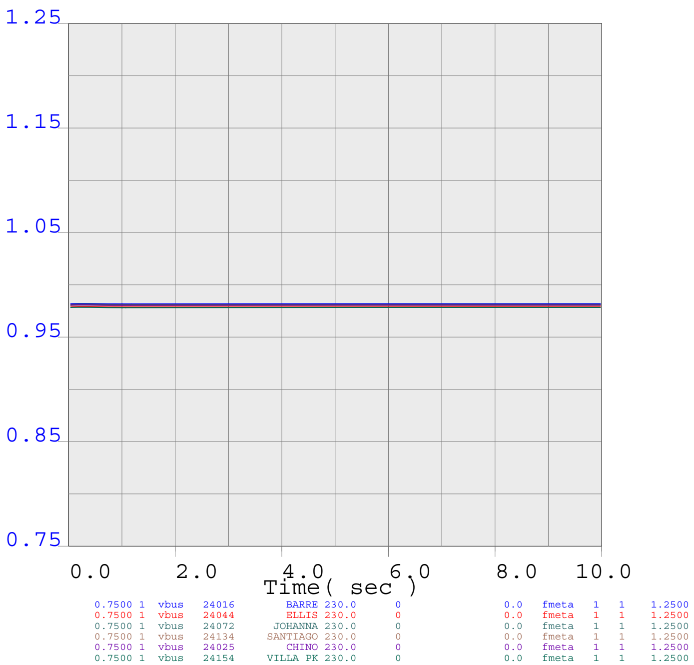
C:\DYTOOLS

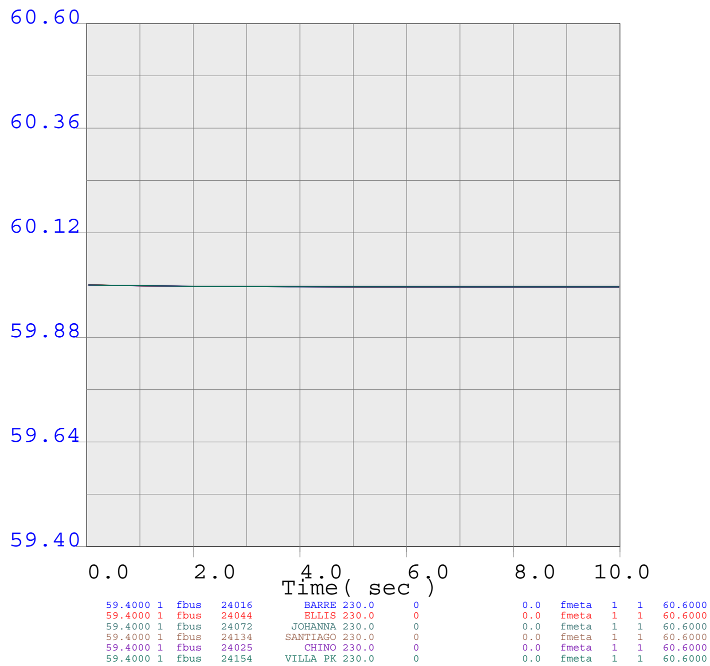
Thu Oct 20 09:04:38 2016

METRO









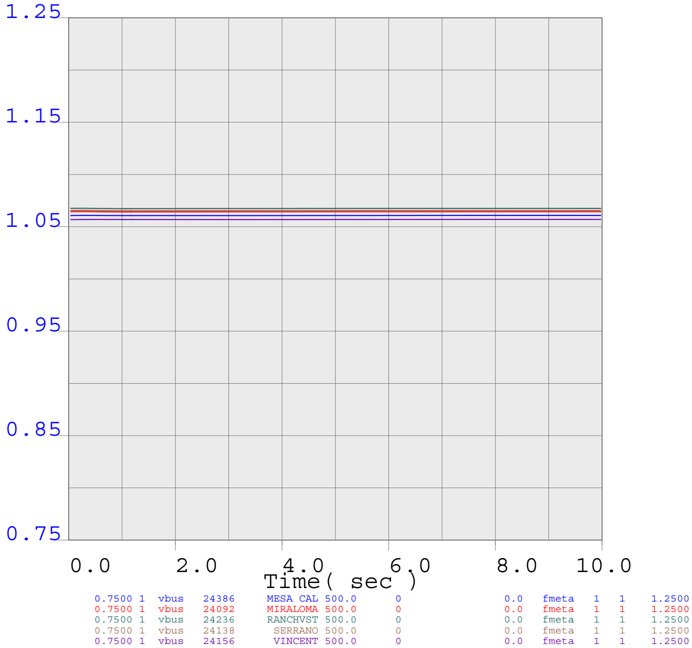
svd_1409
SVD LCIENEGA 230.00
1 MW dispatch Case

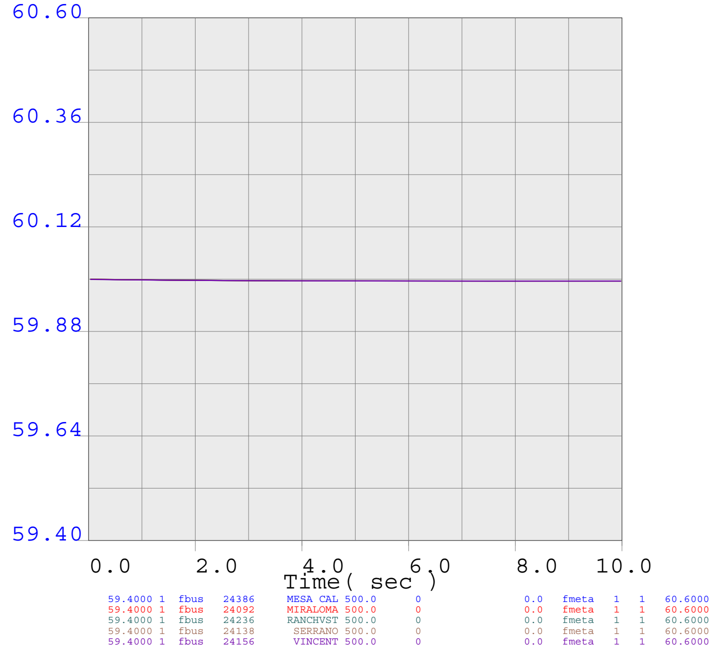
qc9p-svd_1409.chf

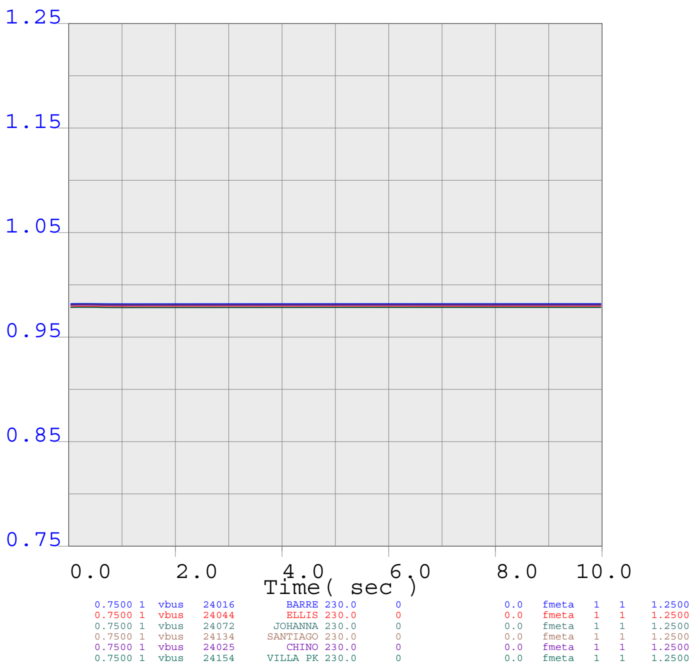
C:\DYTOOLS

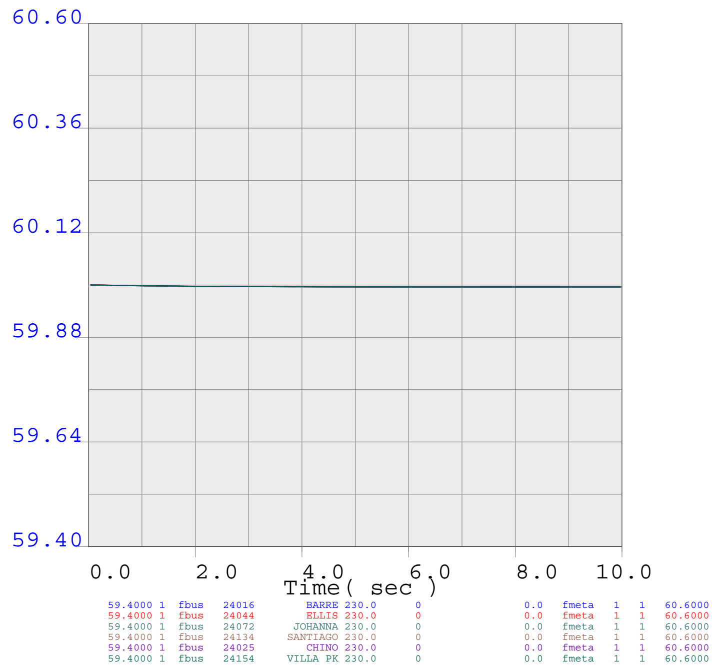
Thu Oct 20 09:04:40 2016

METRO









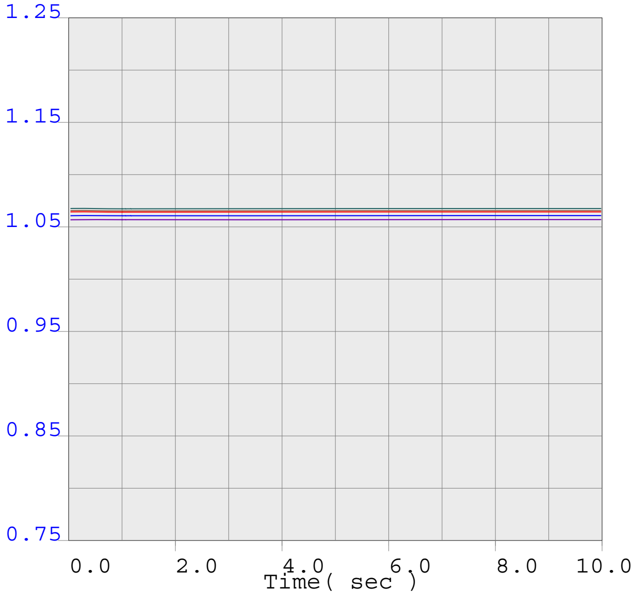
svd_1410
SVD MIRALOMA 500.00
1 MW dispatch Case

qc9p-svd_1410.chf

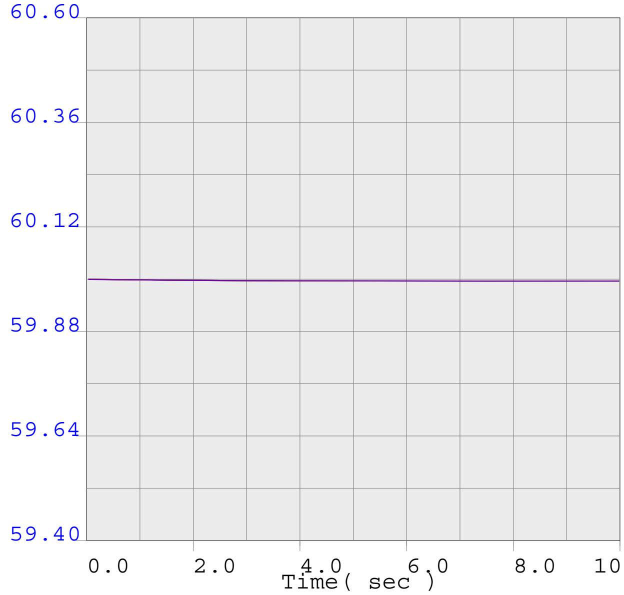
C:\DYTOOLS

Thu Oct 20 09:04:42 2016

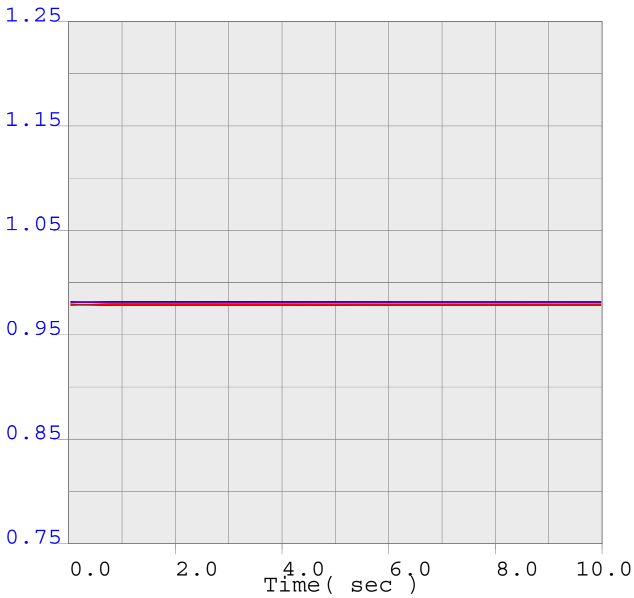
METRO



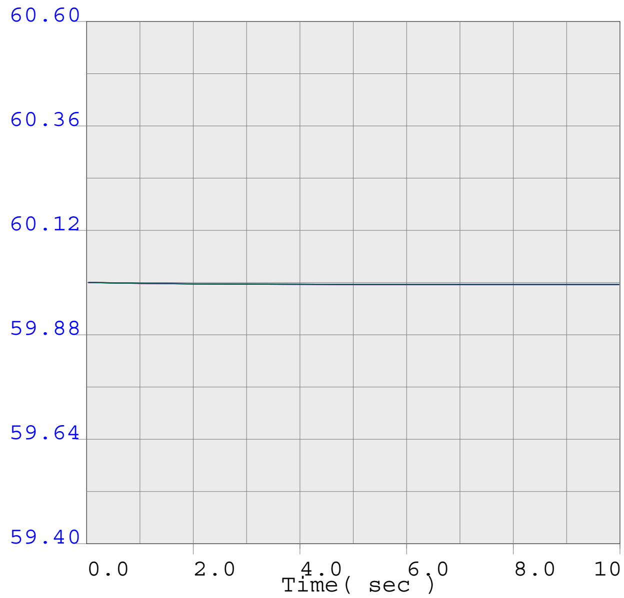
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

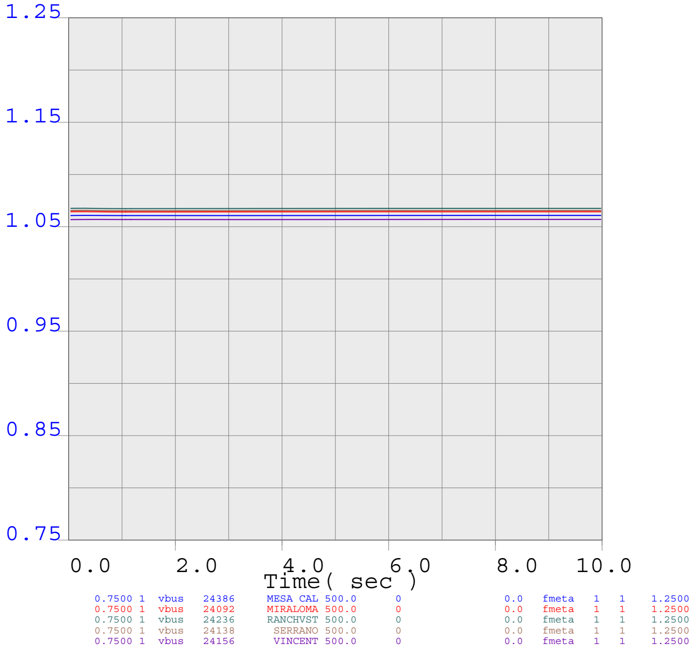
svd_1411
SVD MIRALOME 230.00
1 MW dispatch Case

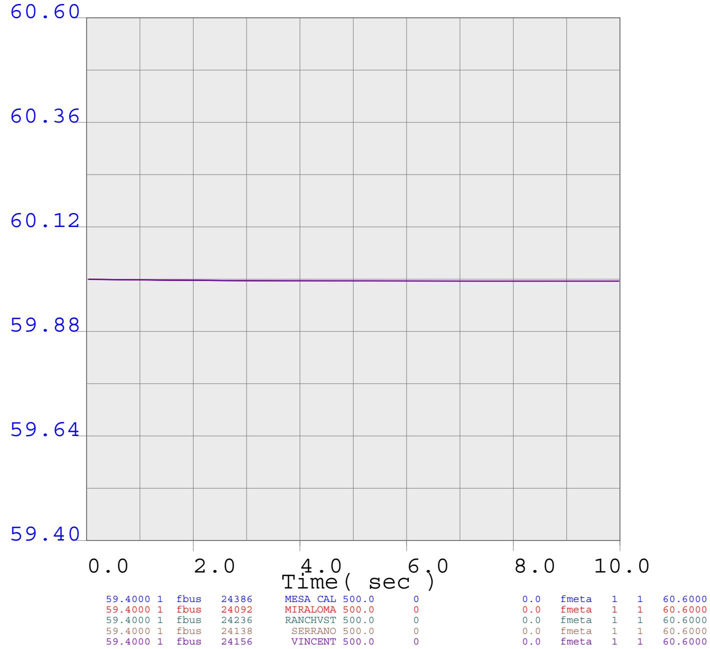
qc9p-svd_1411.chf

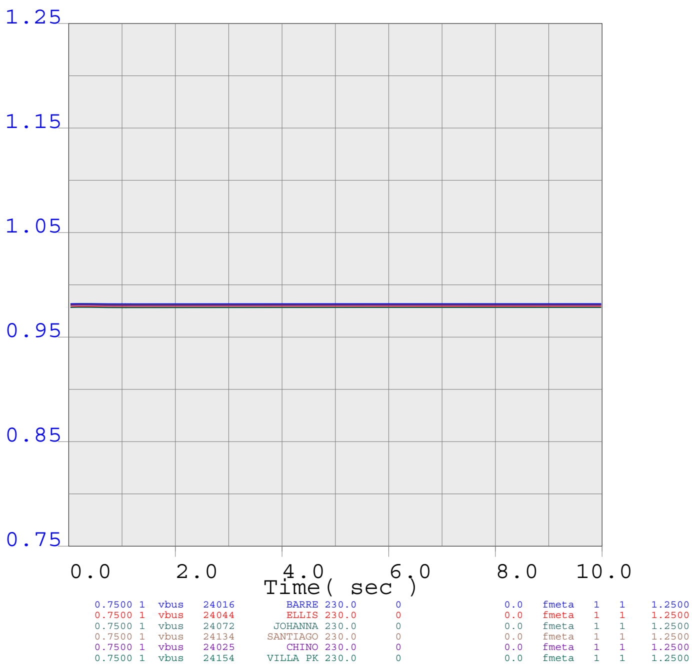
C:\DYTOOLS

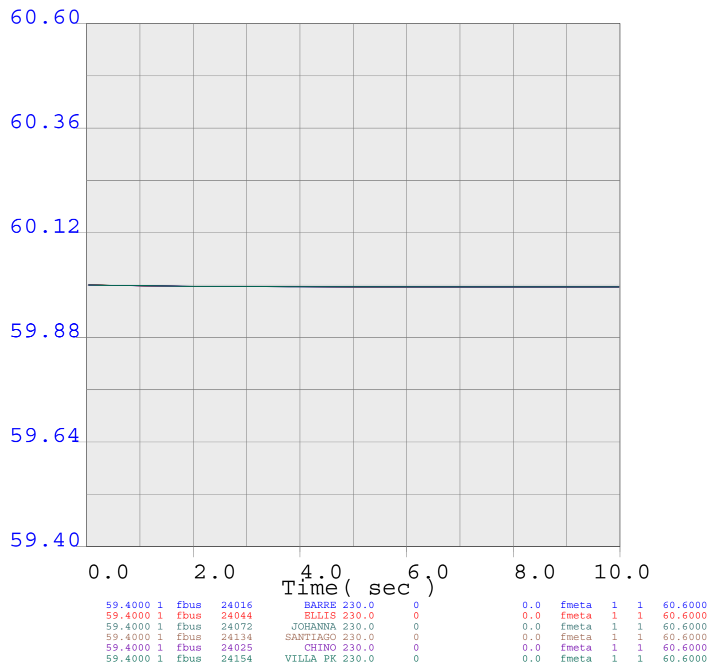
Thu Oct 20 09:04:44 2016

METRO









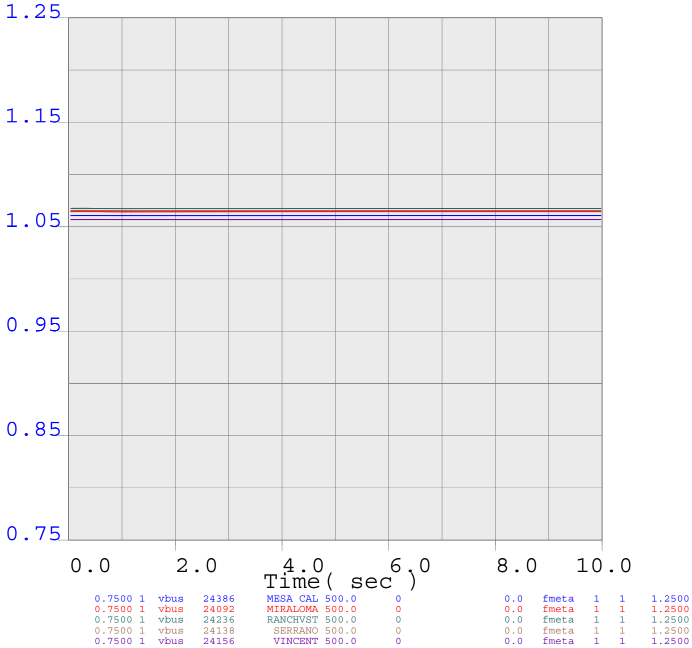
svd_1412
SVD MIRALOMW 230.00
1 MW dispatch Case

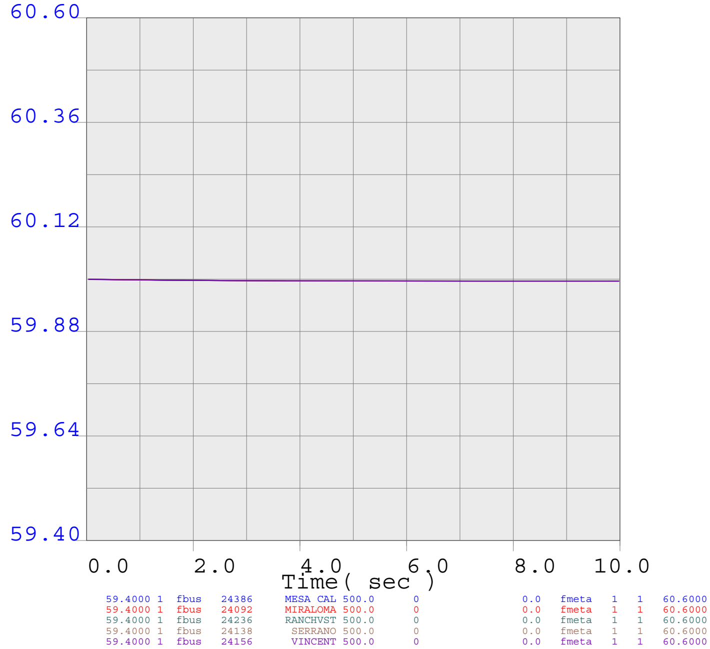
qc9p-svd_1412.chf

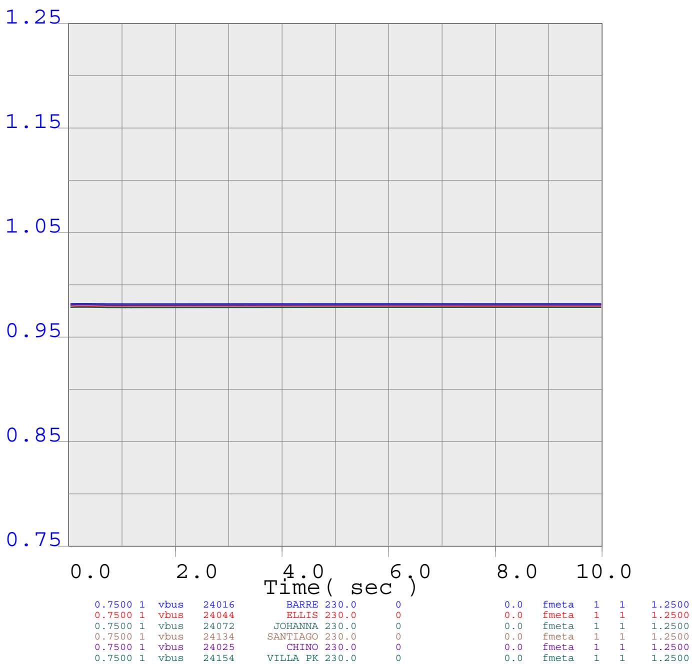
C:\DYTOOLS

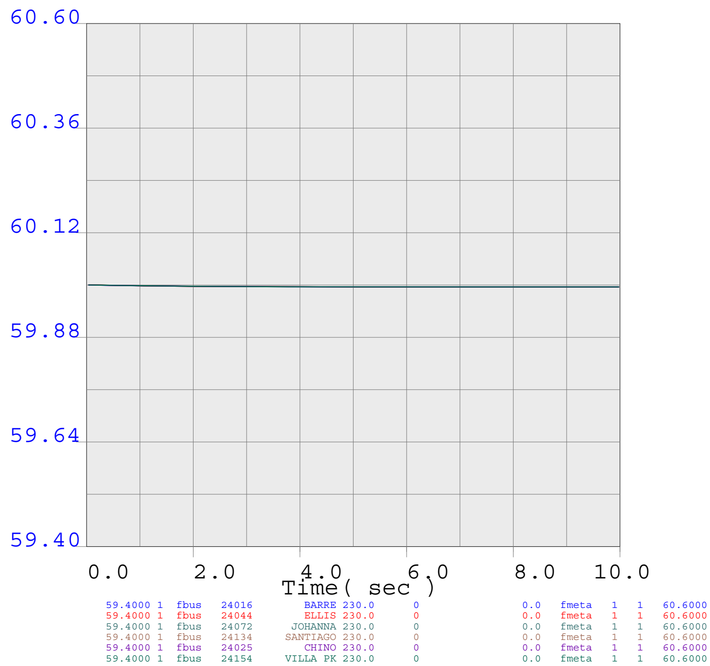
Thu Oct 20 09:04:47 2016

METRO









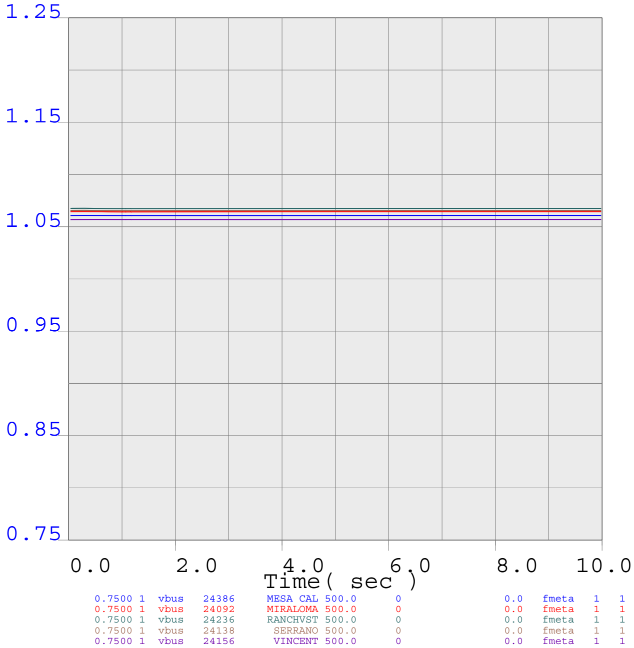
svd_1413
SVD OLINDA 230.00
1 MW dispatch Case

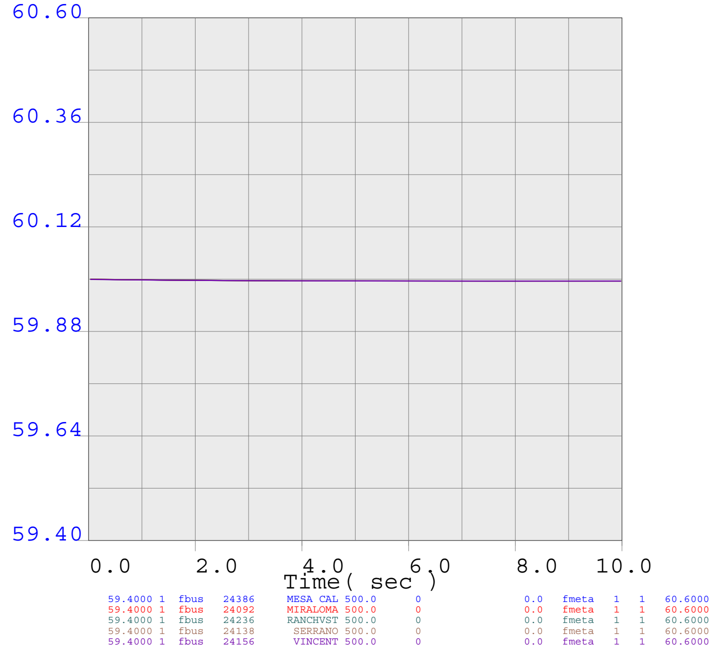
qc9p-svd_1413.chf

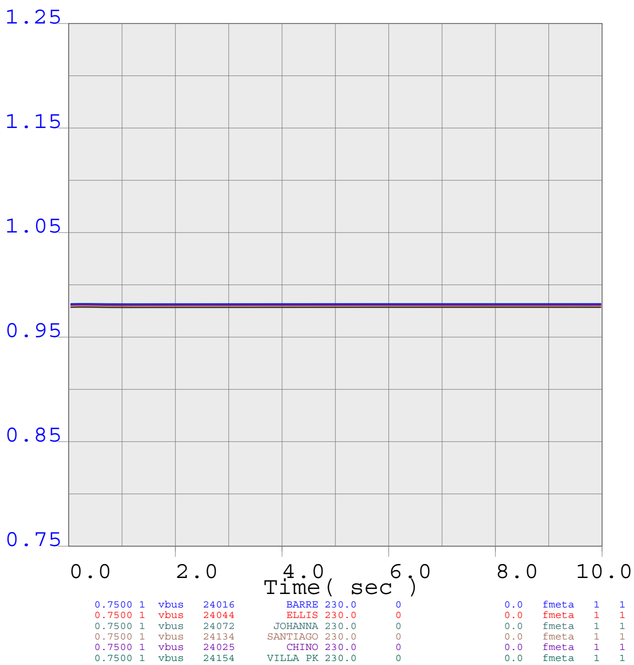
C:\DYTOOLS

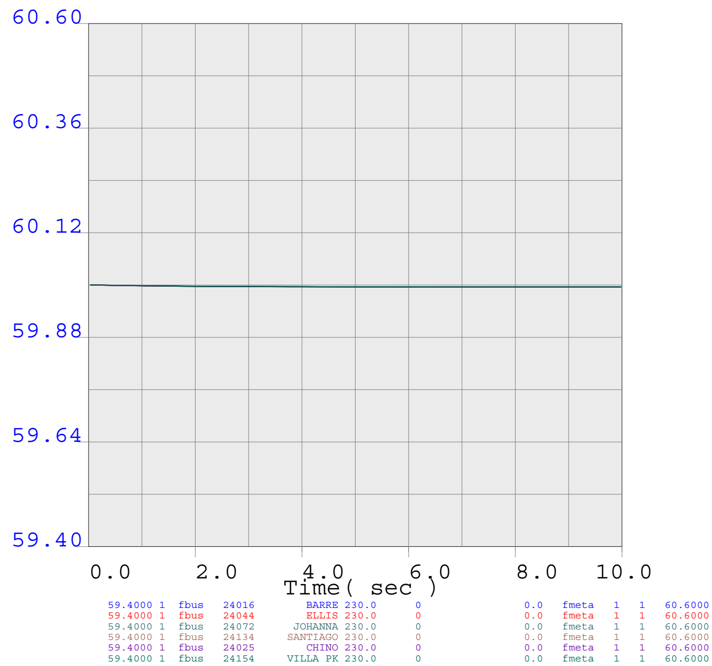
Thu Oct 20 09:04:49 2016

METRO









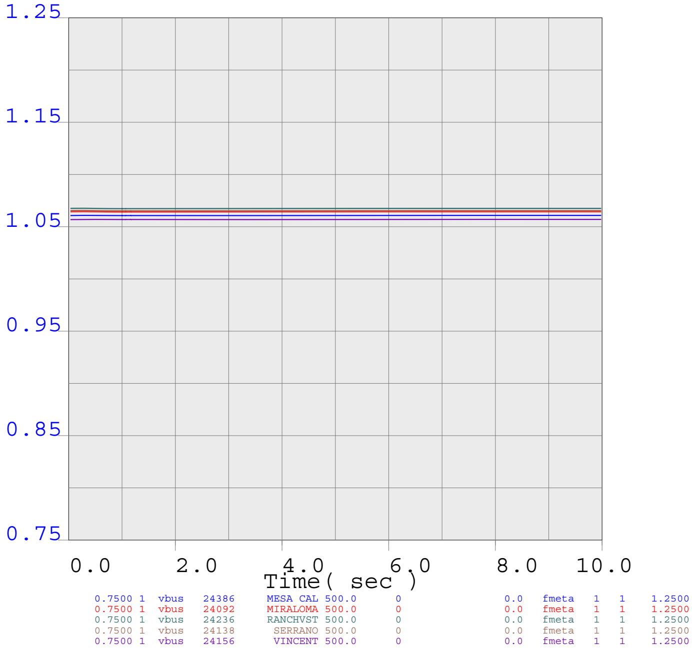
svd_1414
SVD PADUA 230.00
1 MW dispatch Case

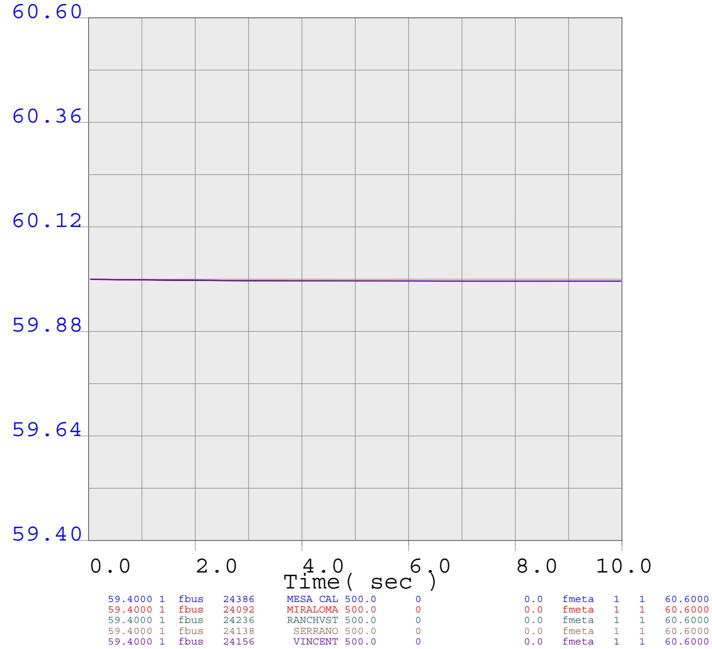
qc9p-svd_1414.chf

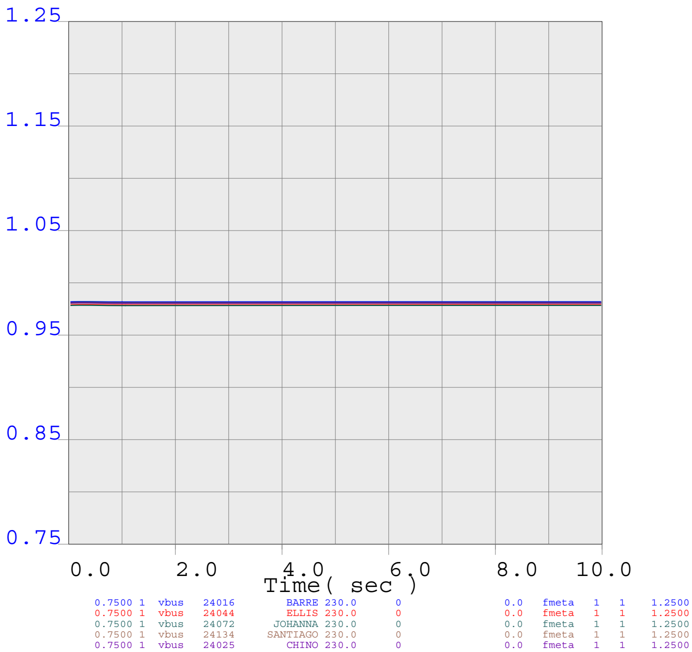
C:\DYTOOLS

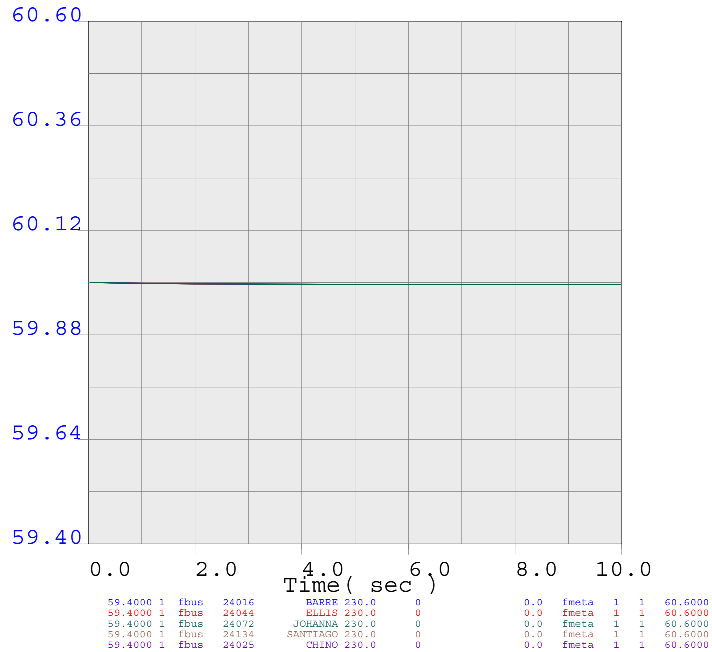
Thu Oct 20 09:04:51 2016

METRO









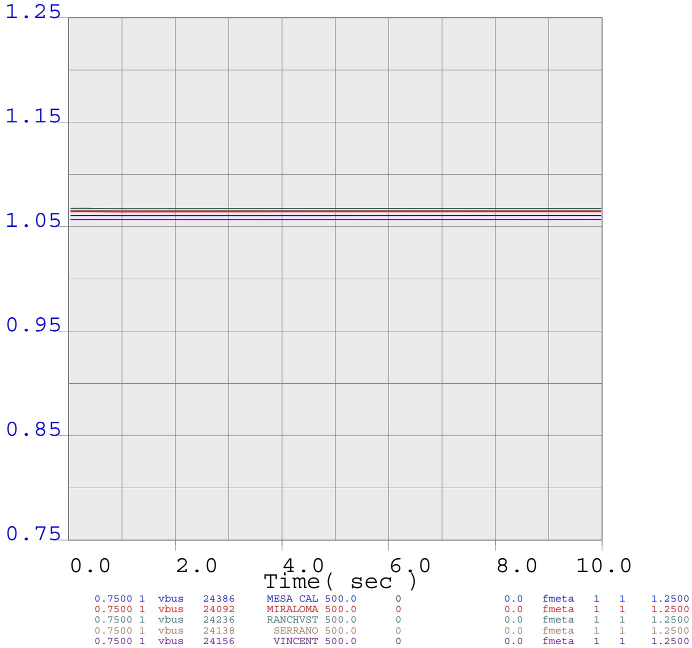
svd_1415
SVD RIOHONDO 230.00
1 MW dispatch Case

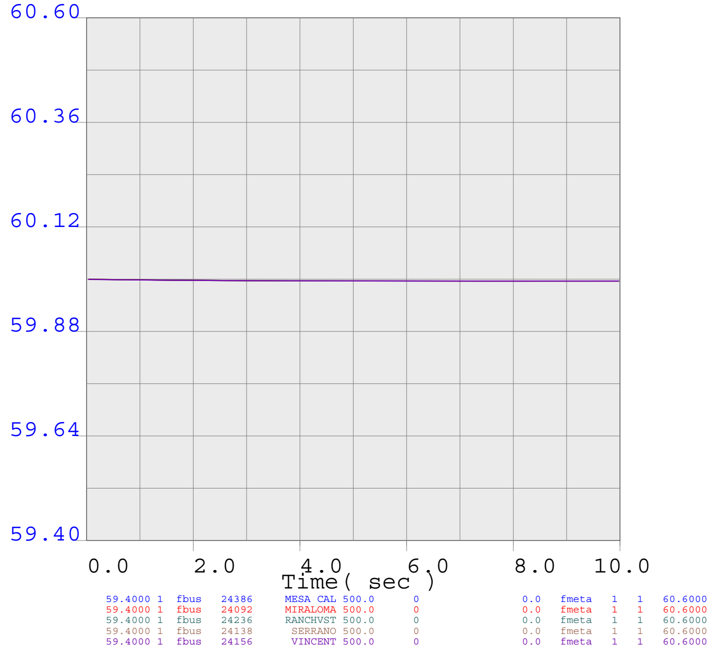
qc9p-svd_1415.chf

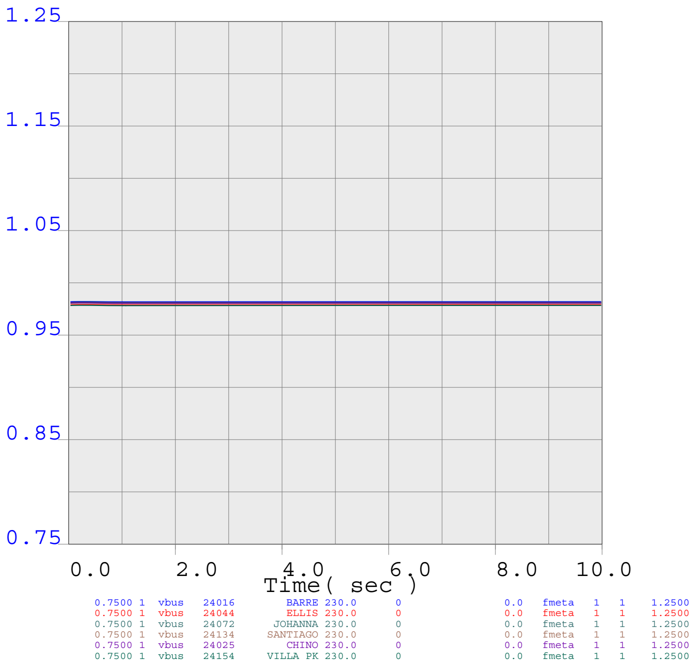
C:\DYTOOLS

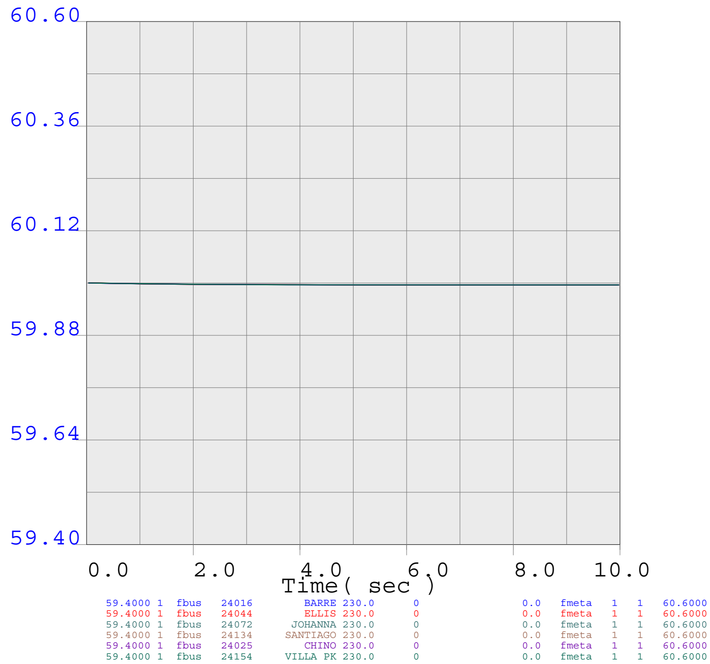
Thu Oct 20 09:04:53 2016

METRO









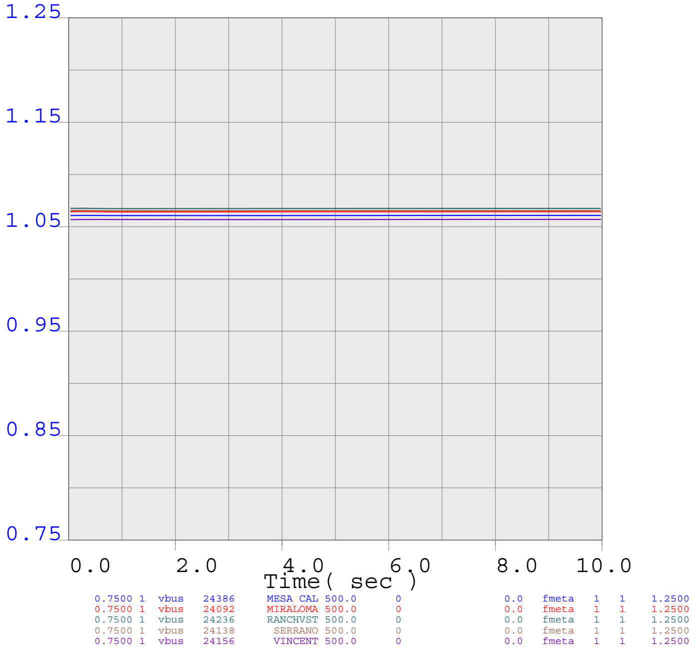
svd_1416
SVD SANTIAGO 230.00
1 MW dispatch Case

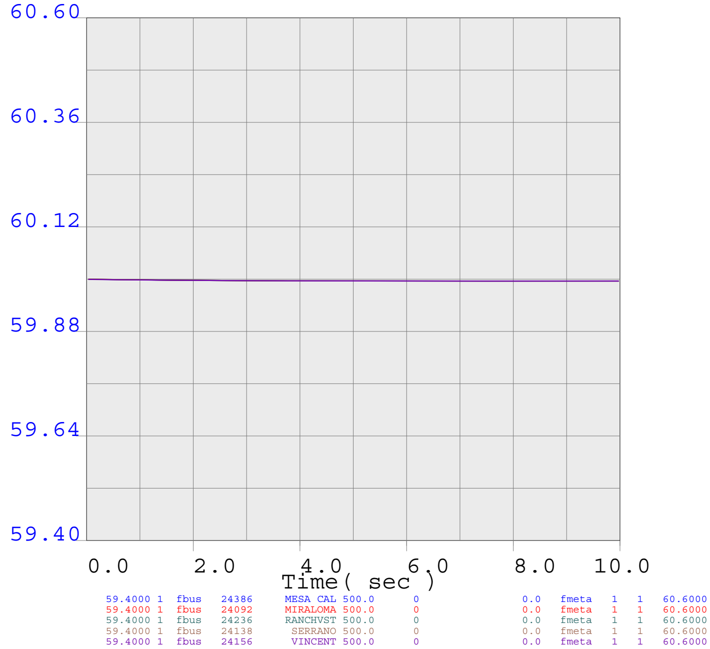
qc9p-svd_1416.chf

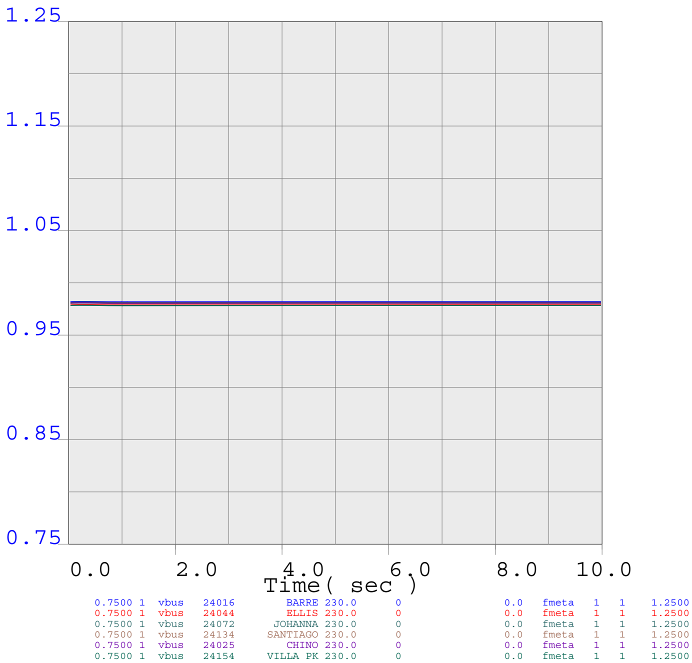
C:\DYTOOLS

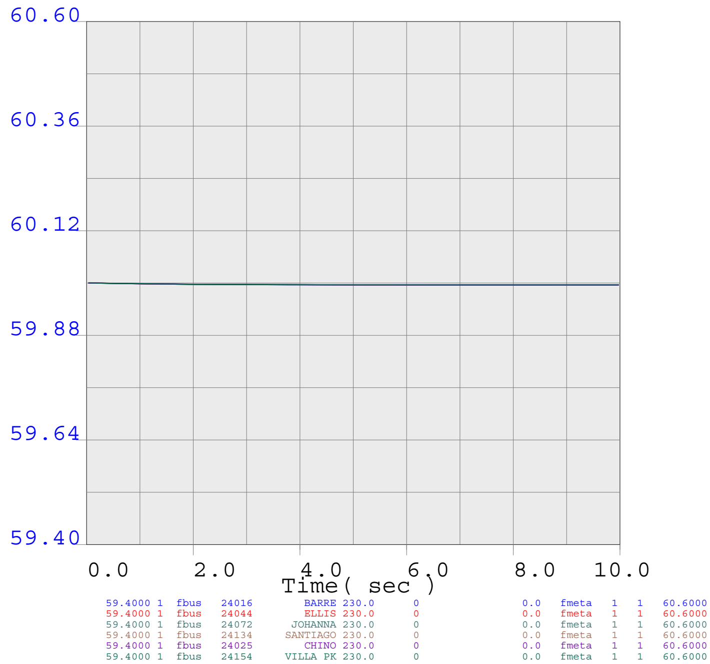
Thu Oct 20 09:04:57 2016

METRO









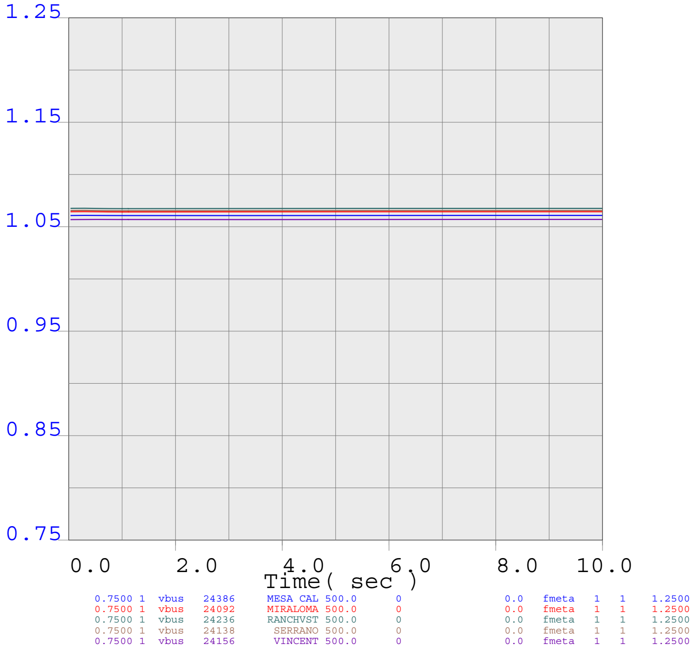
svd_1417
SVD VIEJO 230.00
1 MW dispatch Case

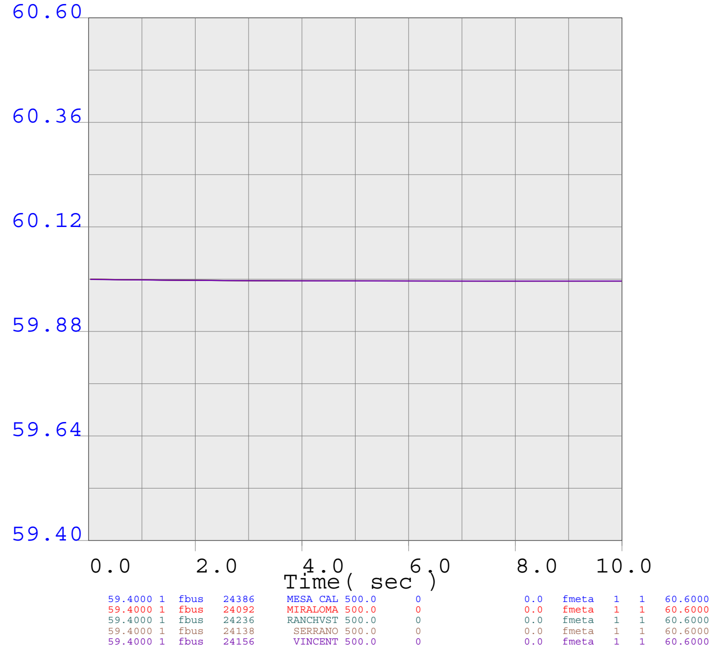
qc9p-svd_1417.chf

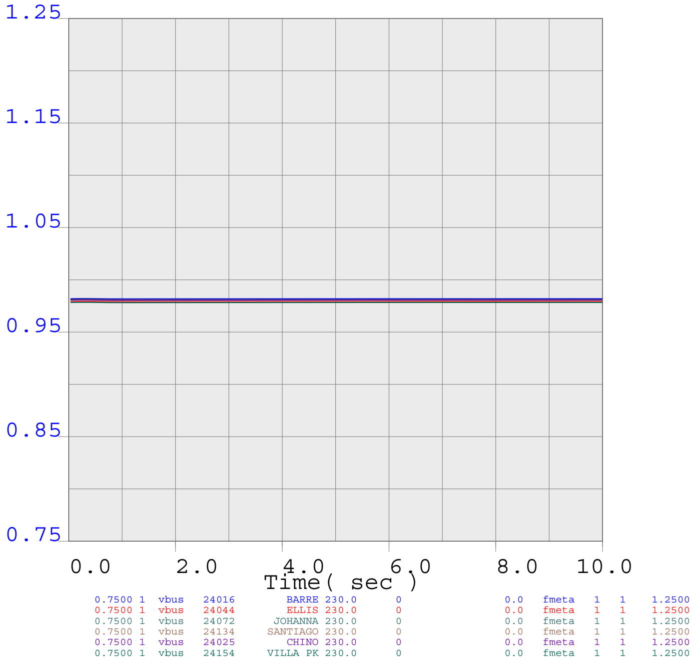
C:\DYTOOLS

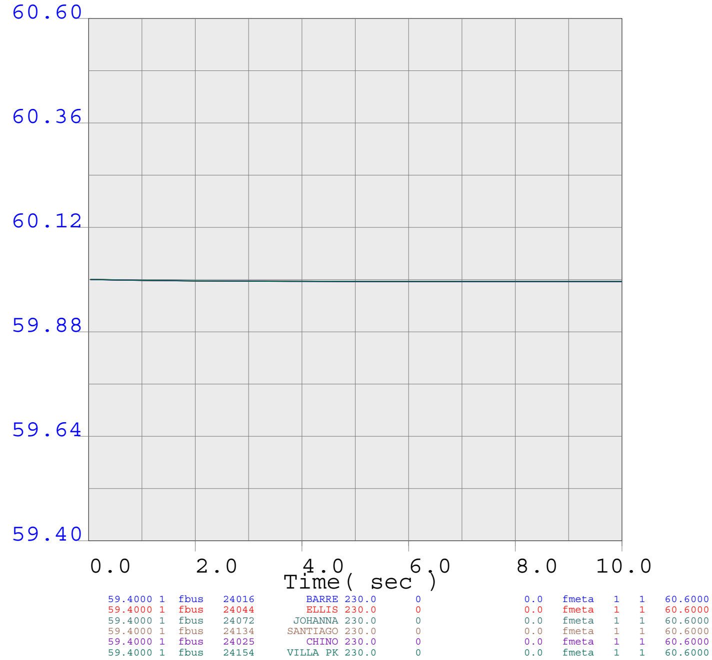
Thu Oct 20 09:04:59 2016

METRO









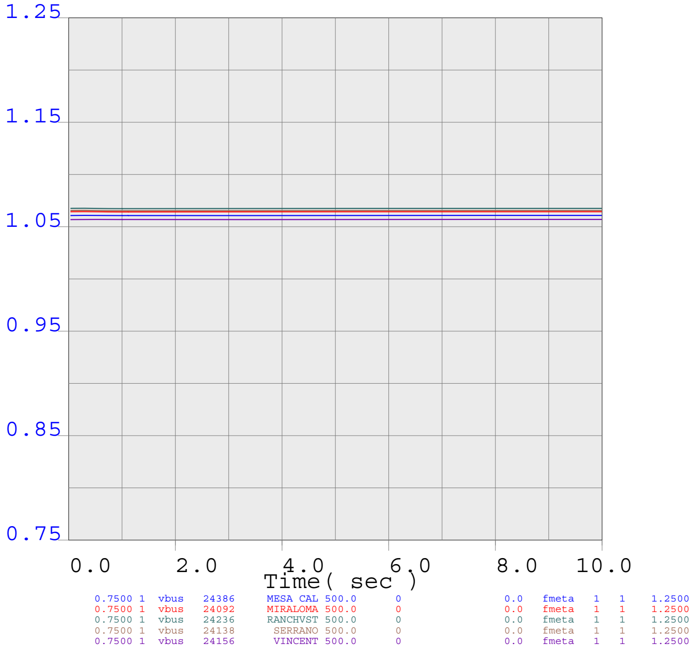
svd_1418
SVD VILLA PK 230.00
1 MW dispatch Case

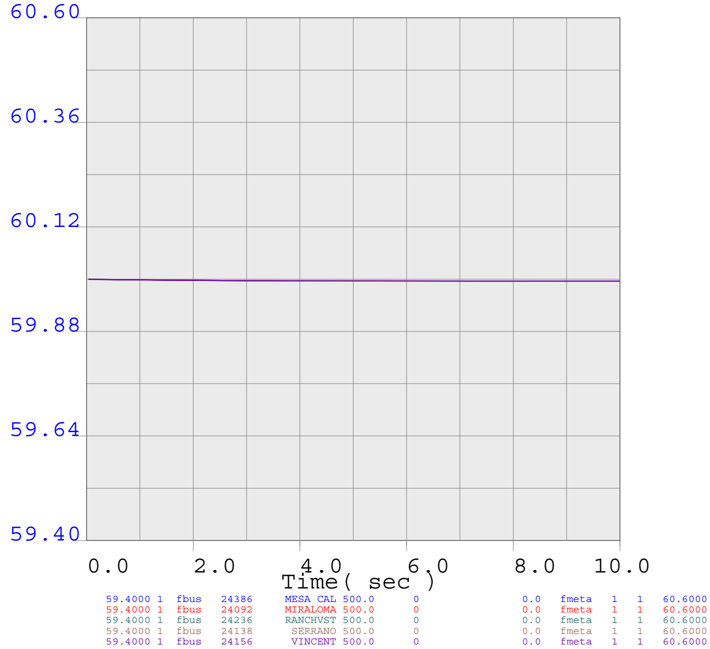
qc9p-svd_1418.chf

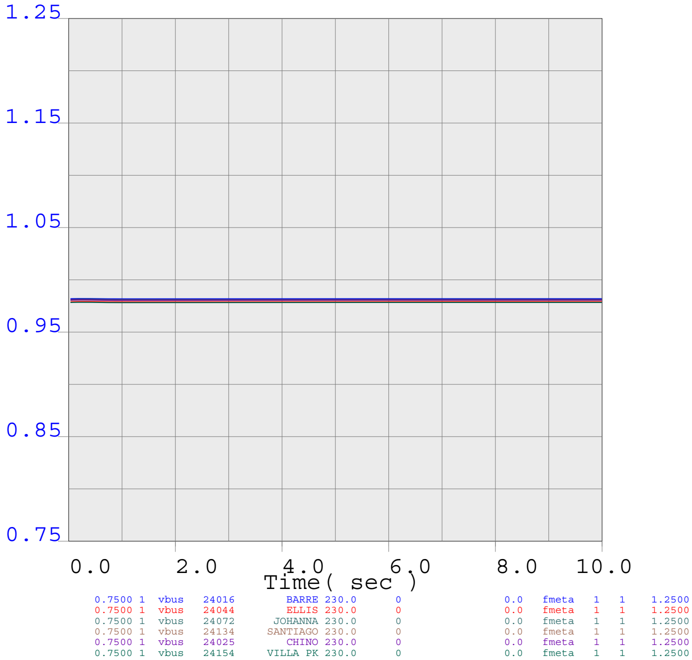
C:\DYTOOLS

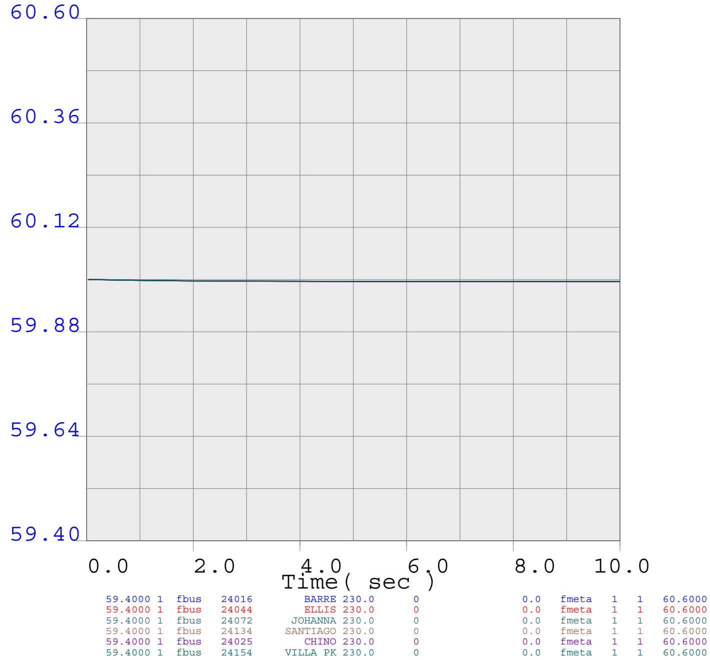
Thu Oct 20 09:05:01 2016

METRO









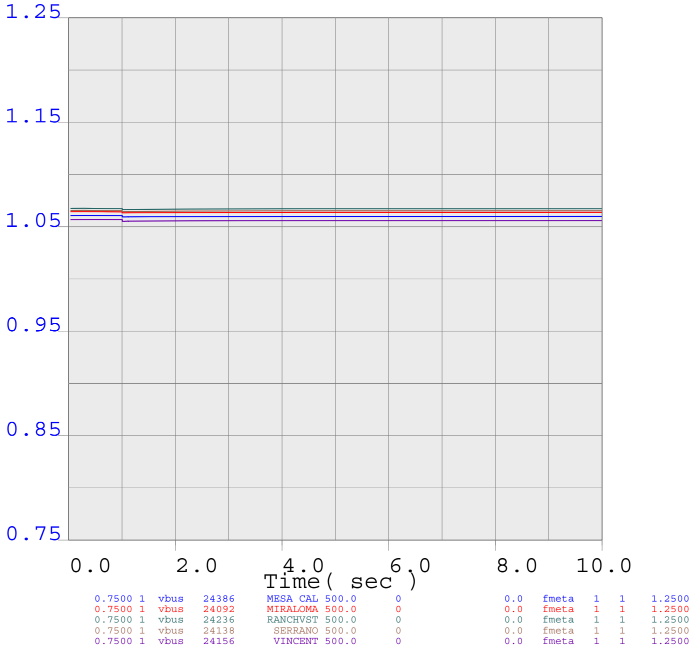
svd_1419
SVD VINCENT 500.00
1 MW dispatch Case

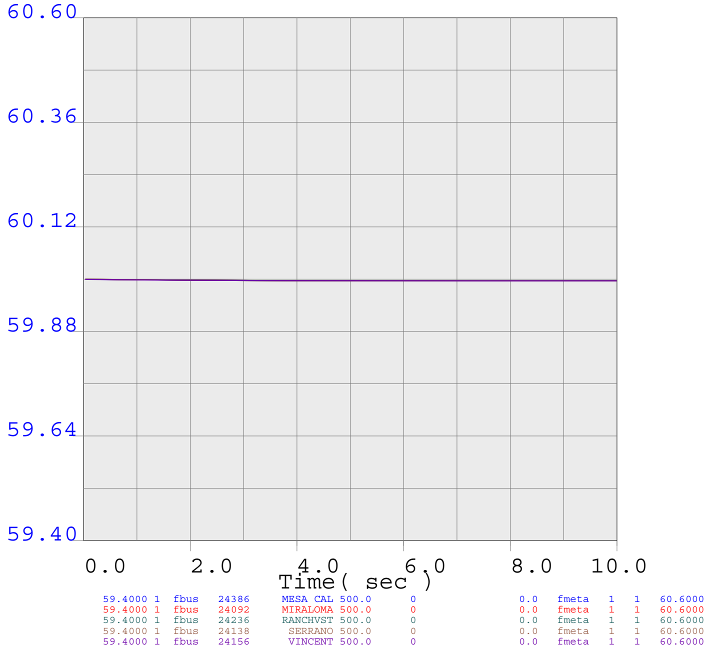
qc9p-svd_1419.chf

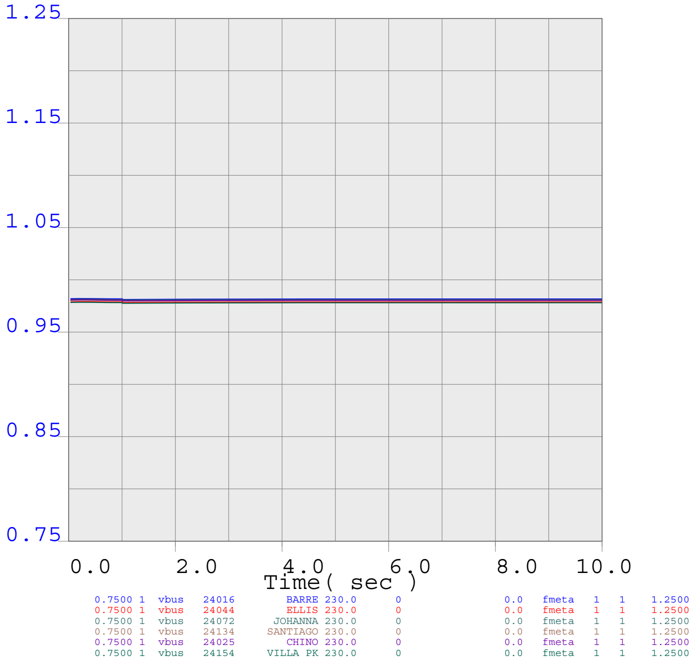
C:\DYTOOLS

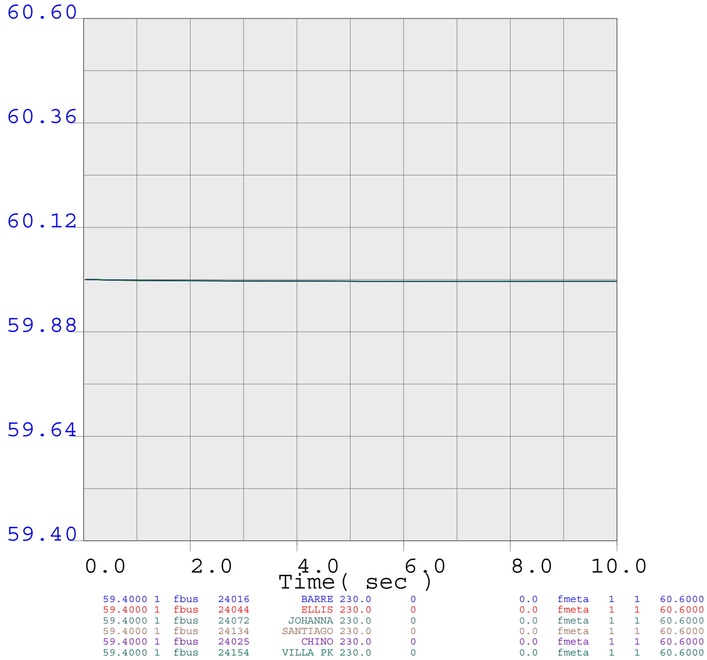
Thu Oct 20 09:05:03 2016

METRO









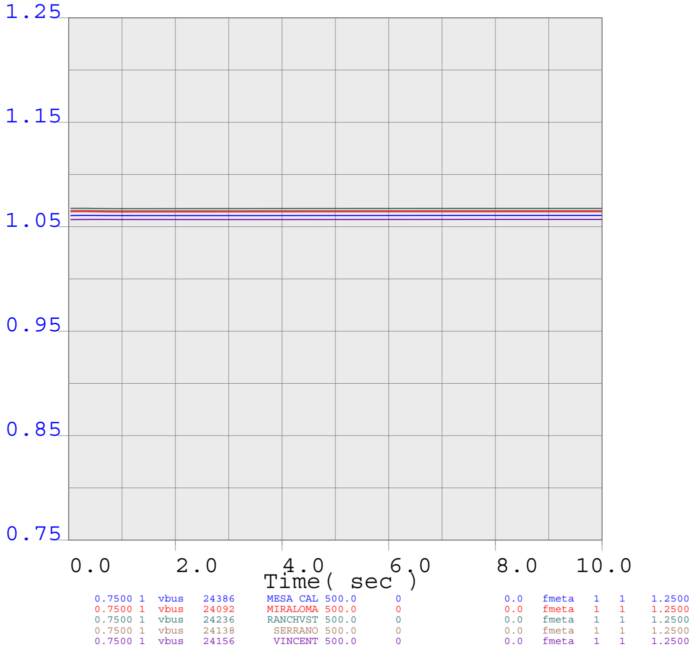
svd_1420
SVD VINCENT 230.00
1 MW dispatch Case

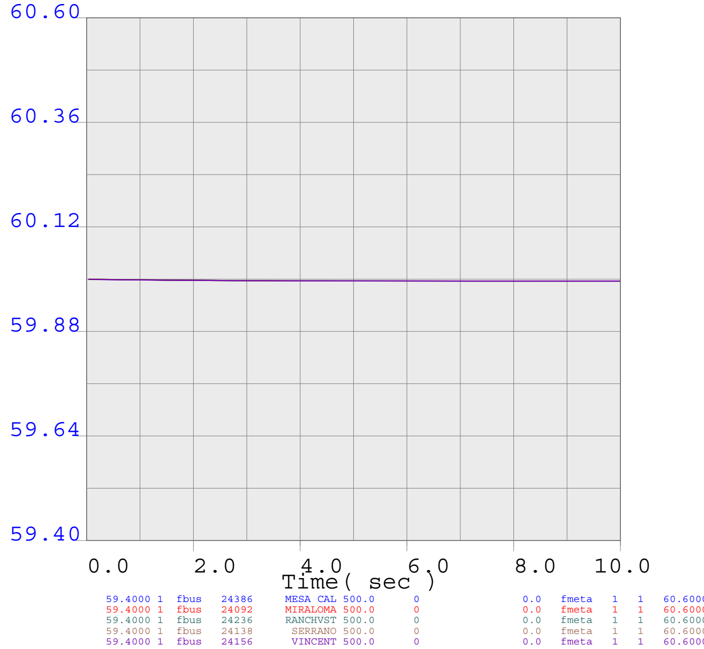
qc9p-svd_1420.chf

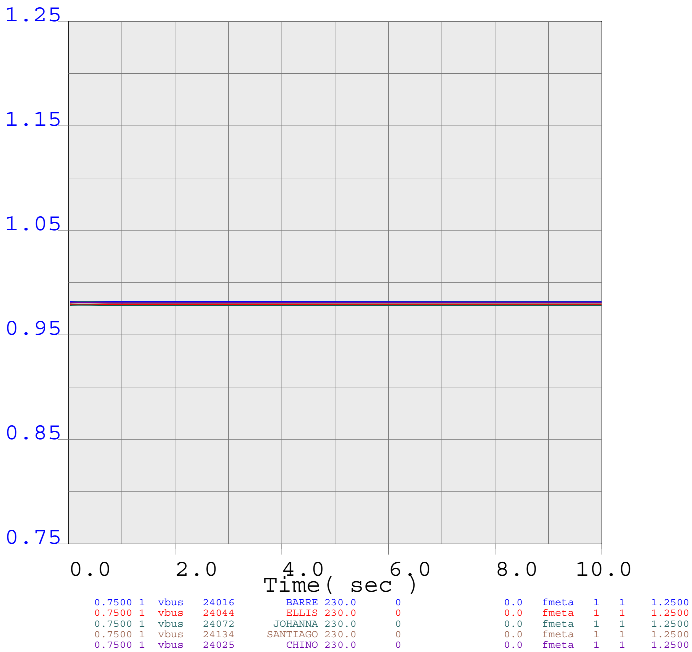
C:\DYTOOLS

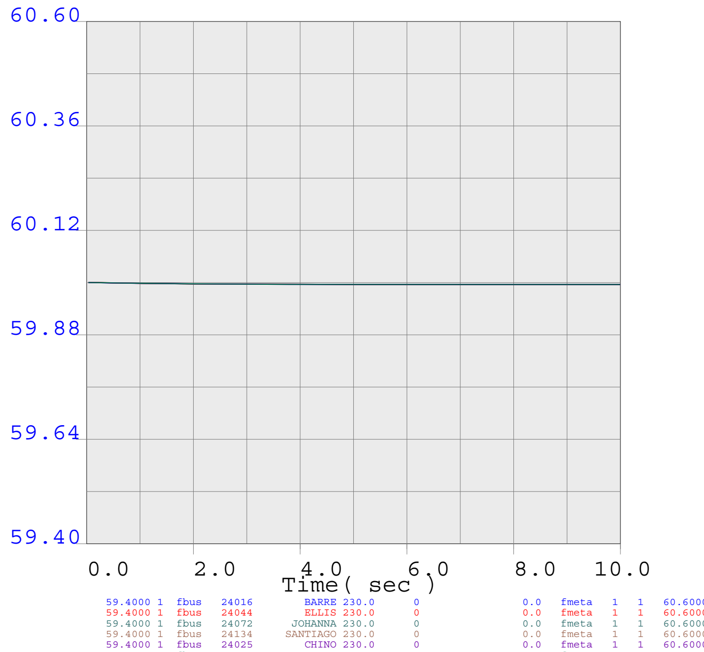
Thu Oct 20 09:05:05 2016

METRO



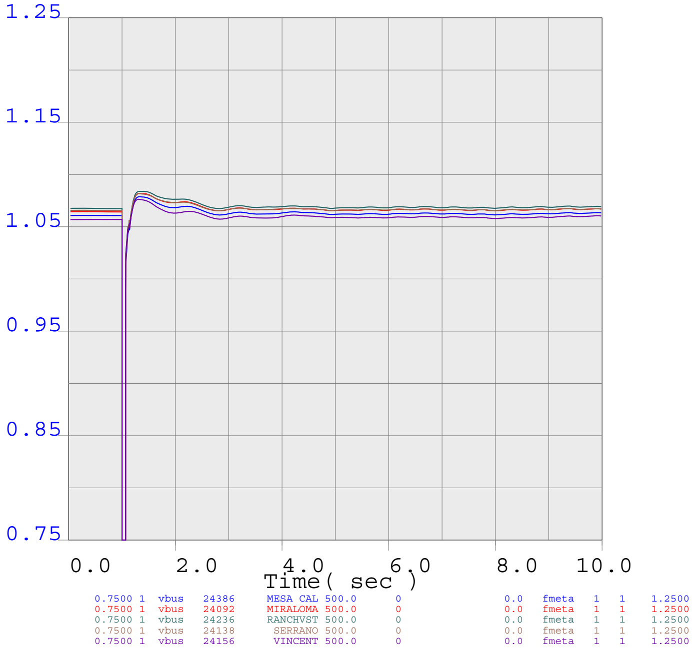


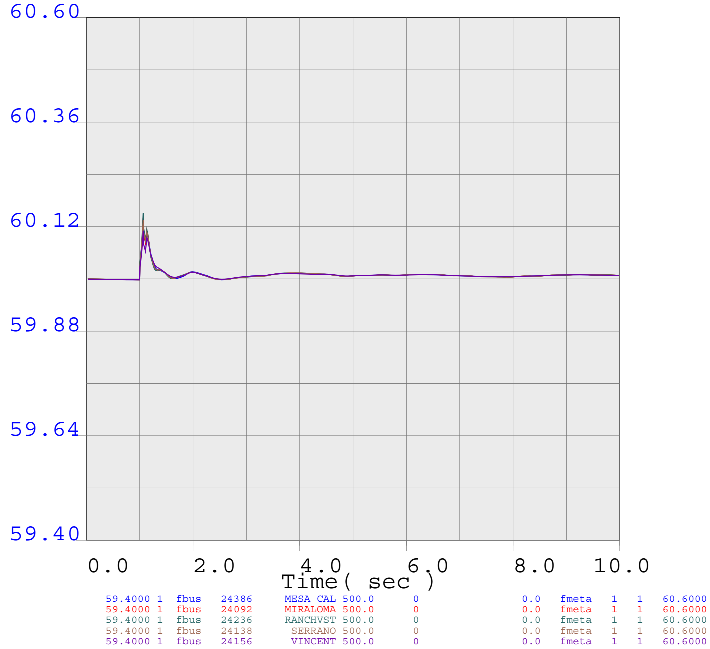


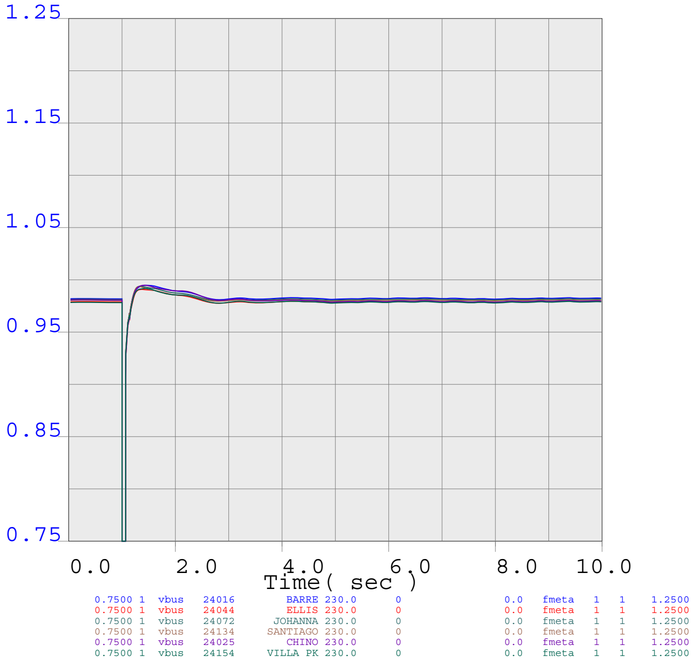


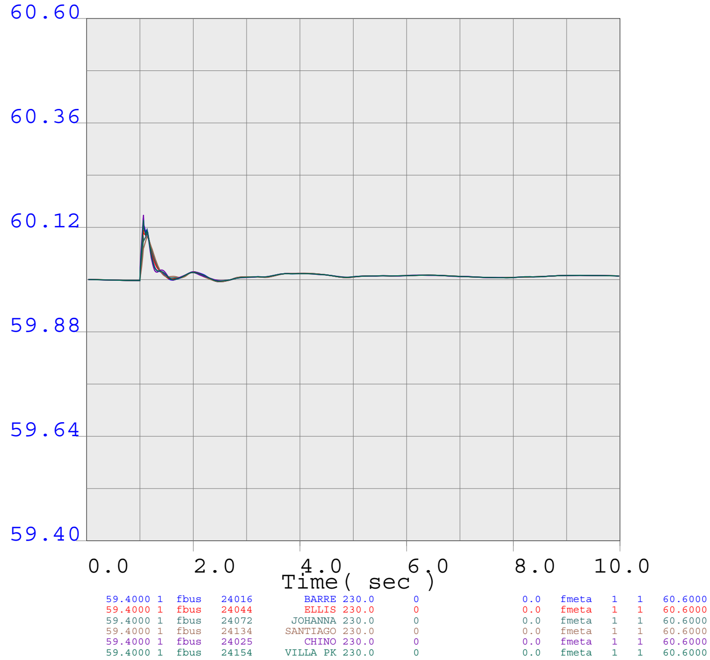
svd_1421
SVD WALNUTW 230.00
1 MW dispatch Case

METRO









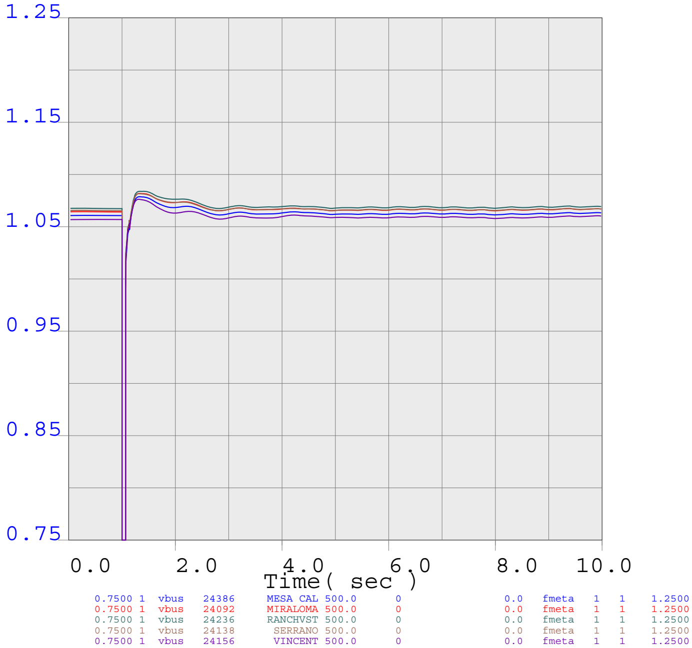
tran_1301
Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 1MIRLOM1T 13.80
1 MW dispatch Case

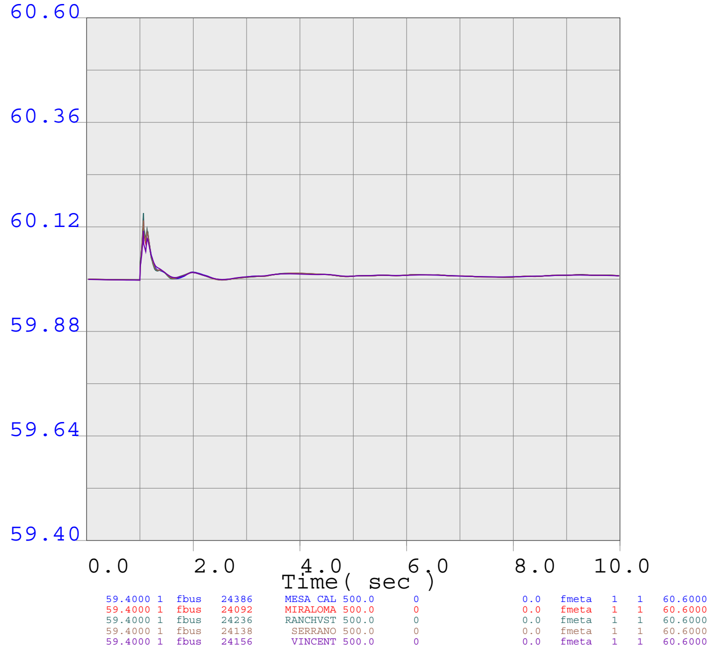
qc9p-tran_1301.chf

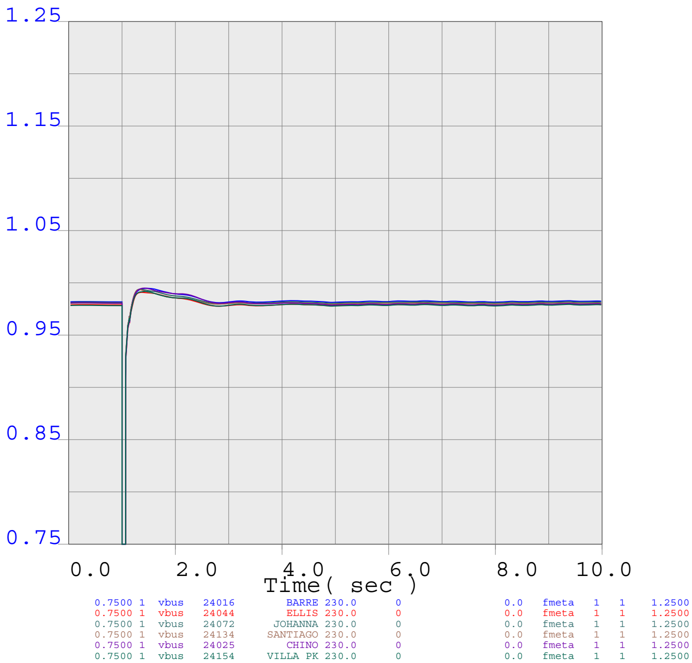
C:\DYTOOLS

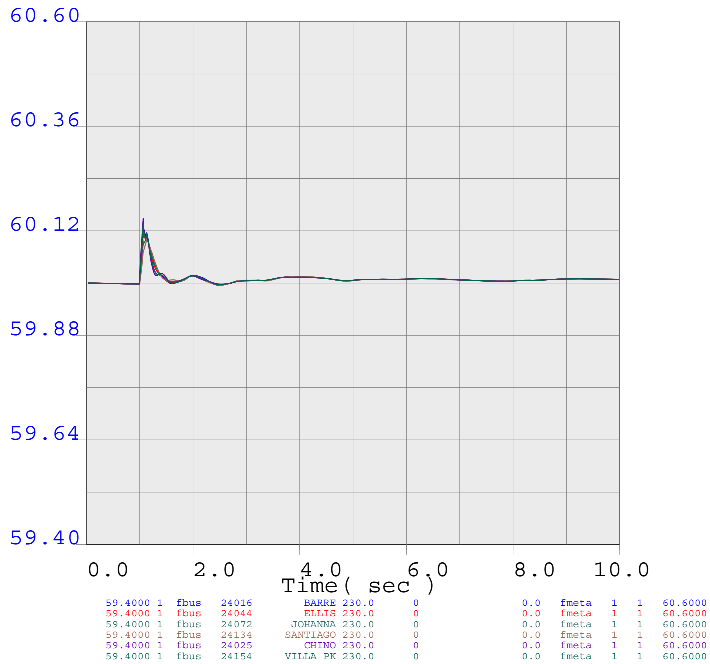
Thu Oct 20 09:05:09 2016

METRO









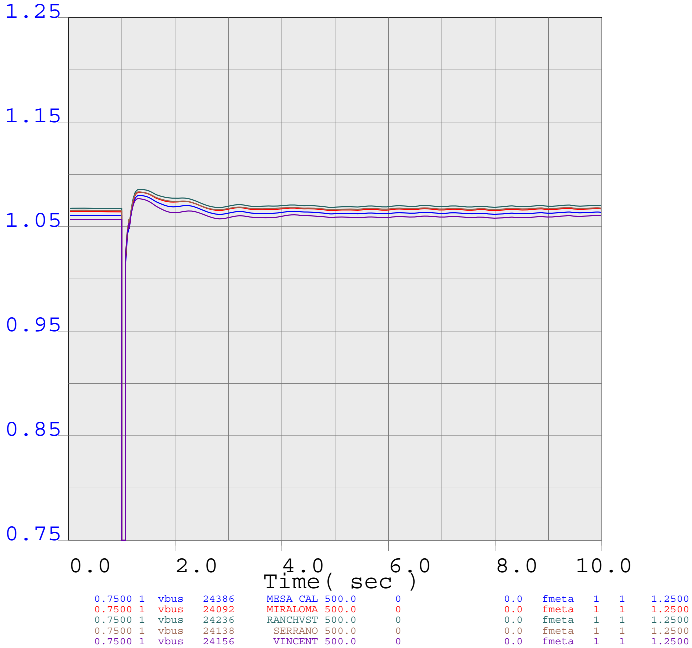
tran_1302
Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 2MIRLOM2T 13.80
1 MW dispatch Case

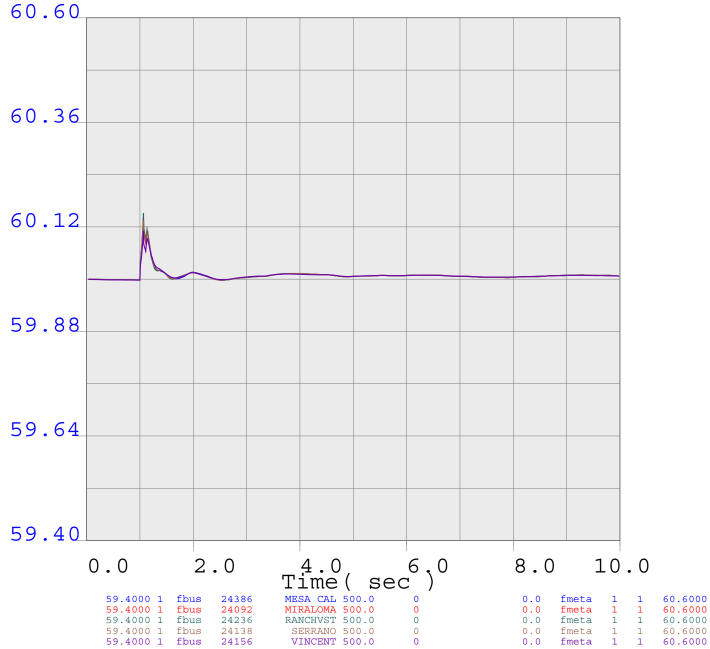
qc9p-tran_1302.chf

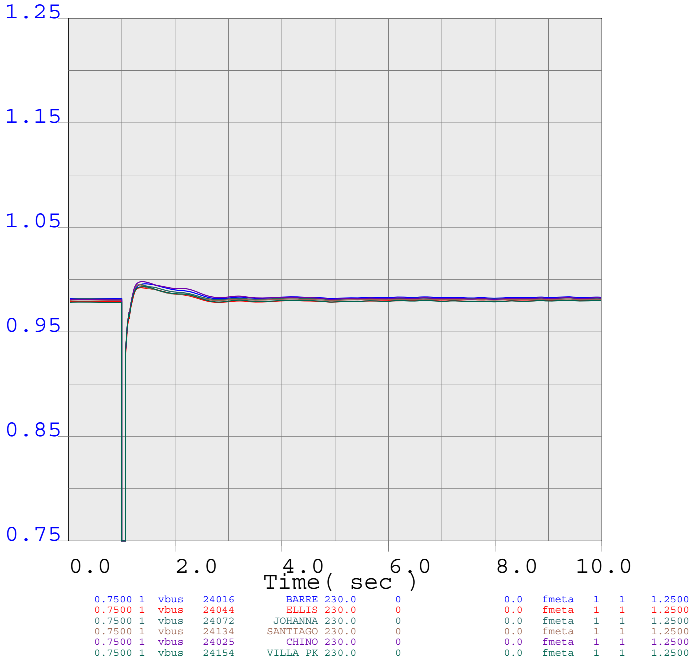
C:\DYTOOLS

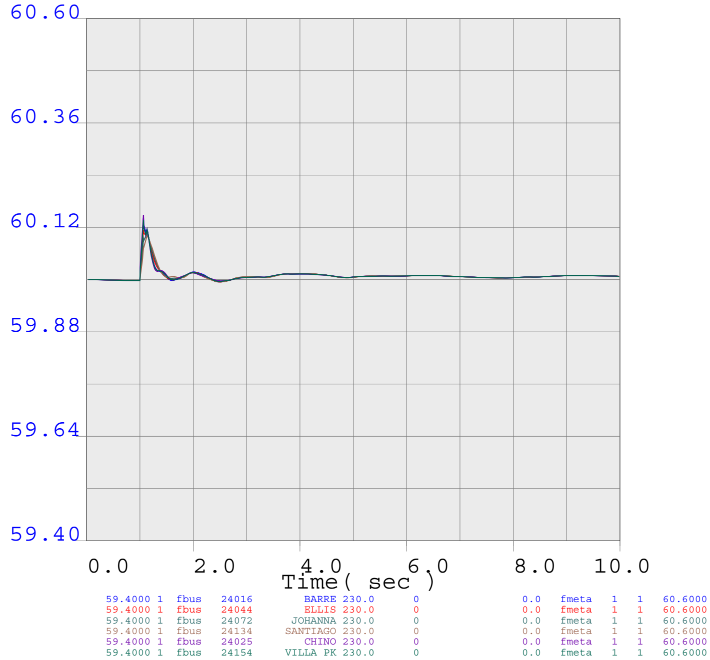
Thu Oct 20 09:05:11 2016

METRO









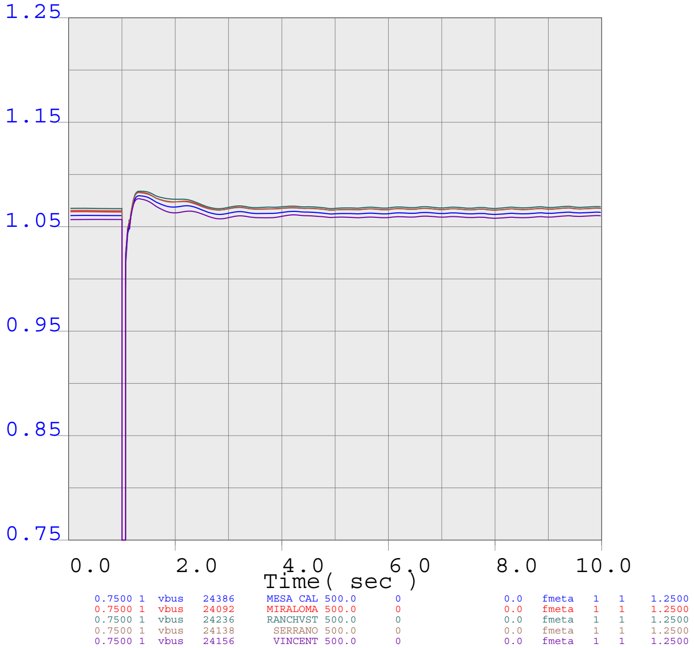
tran_1303
Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 3MIRLOM3T 13.80
1 MW dispatch Case

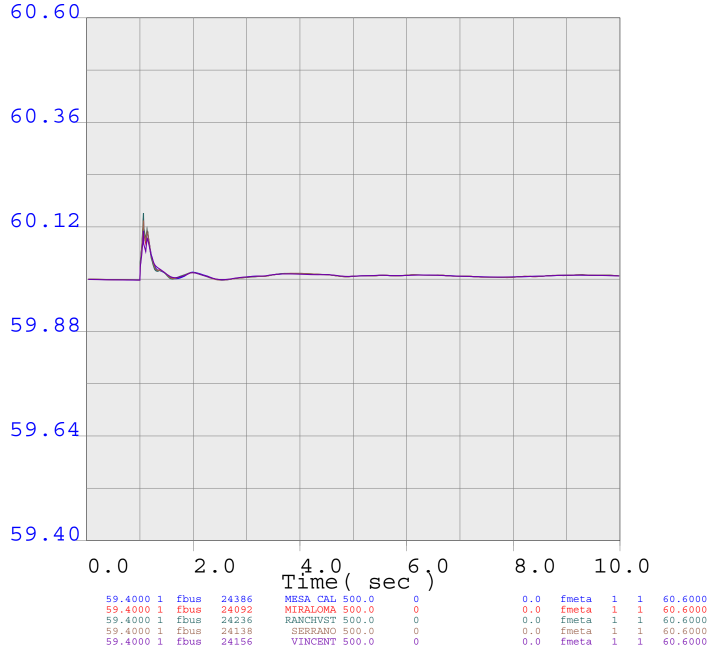
qc9p-tran_1303.chf

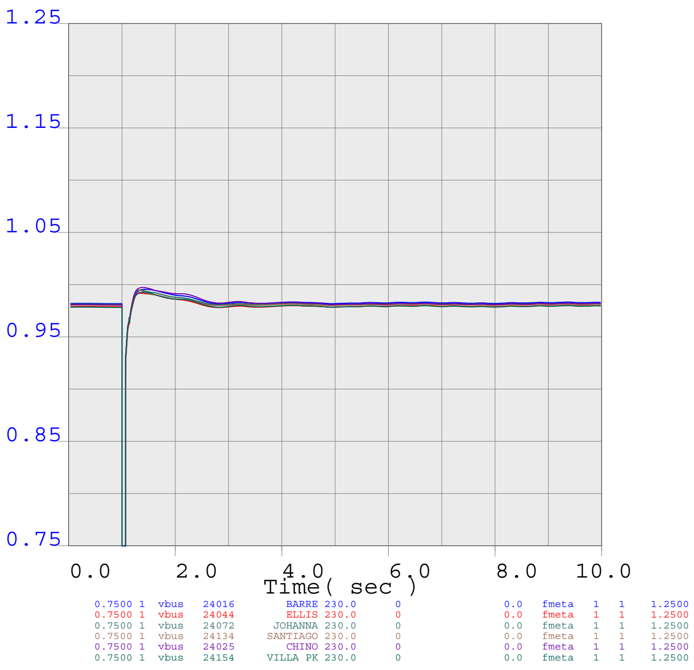
C:\DYTOOLS

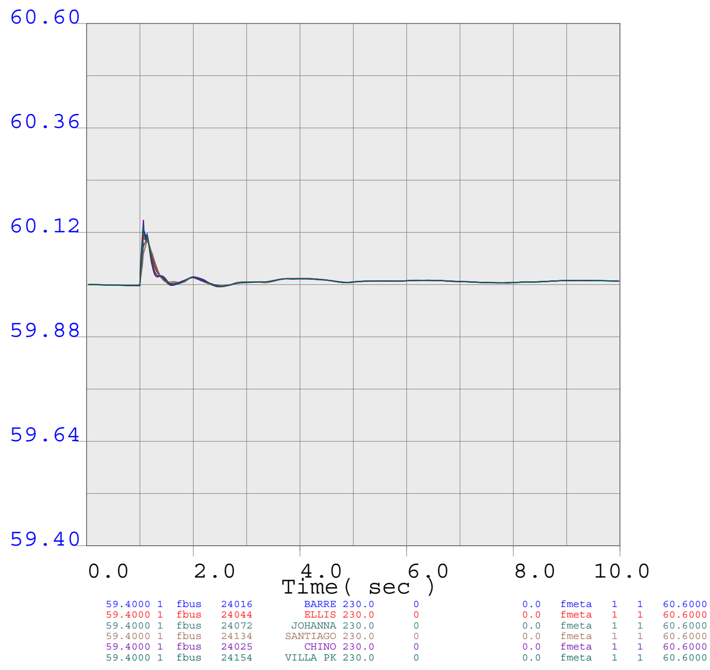
Thu Oct 20 09:05:13 2016

METRO









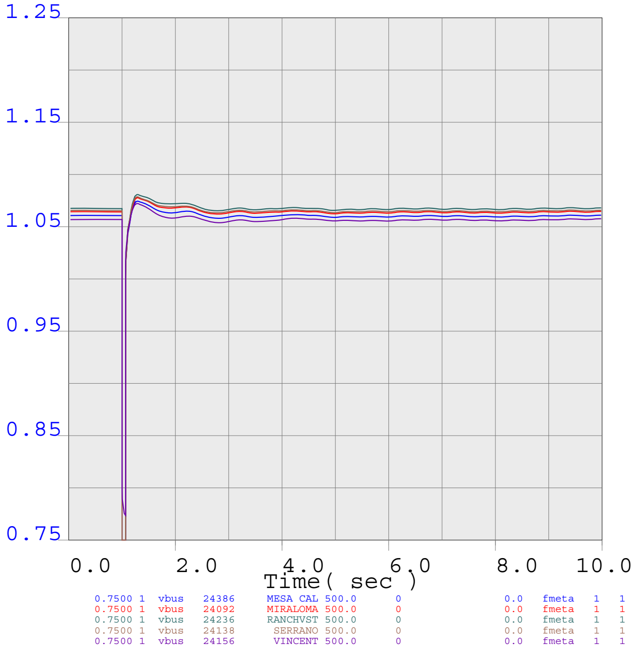
tran_1304
Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 4MIRLOM4T 13.80
1 MW dispatch Case

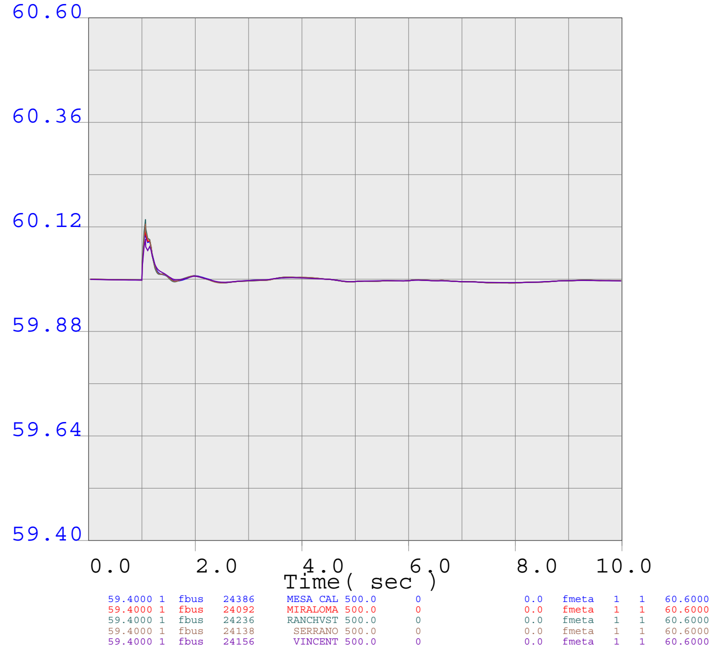
qc9p-tran_1304.chf

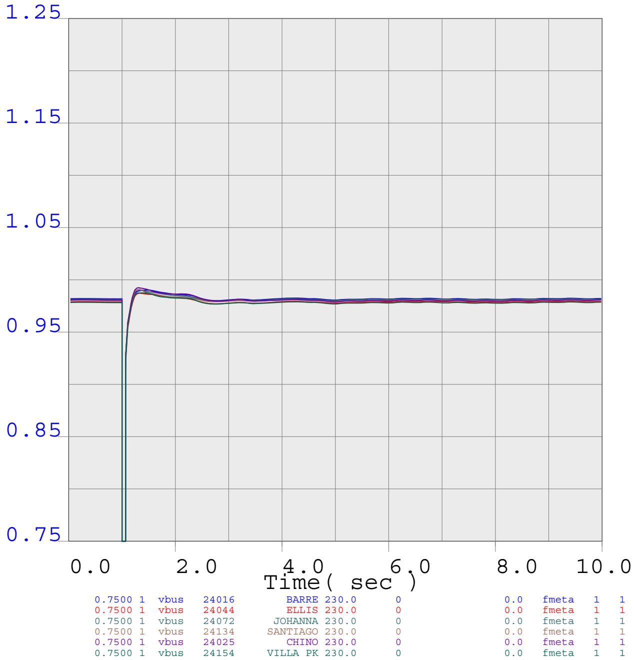
C:\DYTOOLS

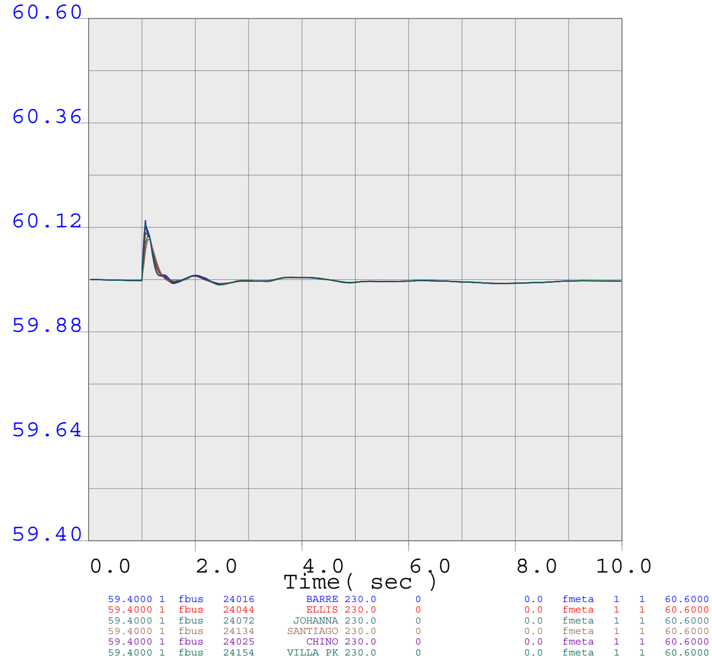
Thu Oct 20 09:05:15 2016

METRO









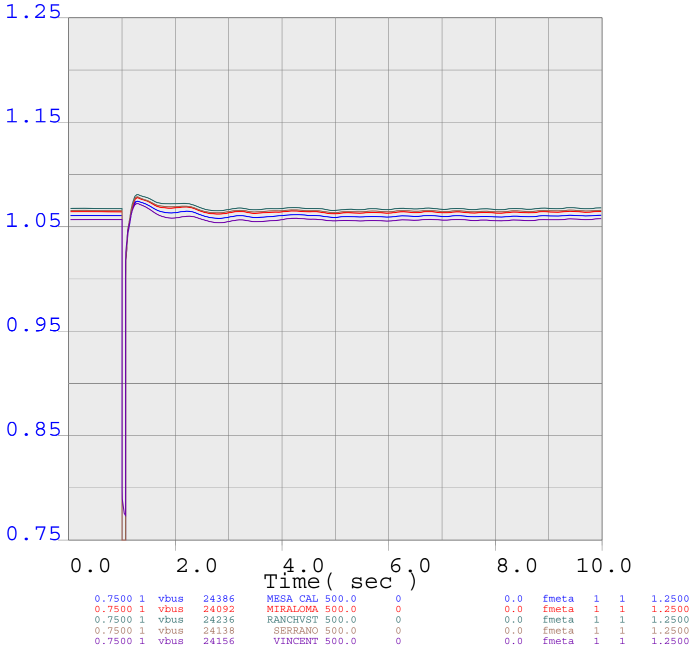
tran_1305
Tran SERRANO 500.00 to SERRANO 230.00 Circuit 1SERRAN1T 13.80
1 MW dispatch Case

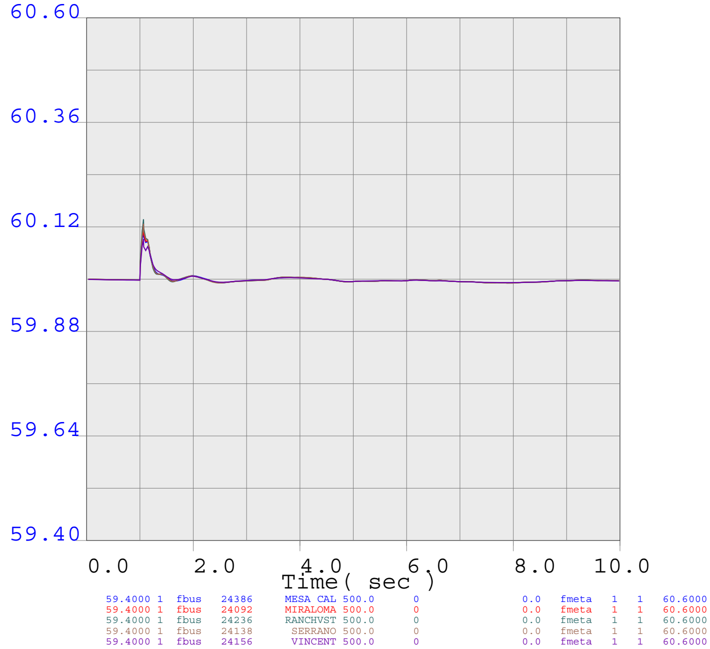
qc9p-tran_1305.chf

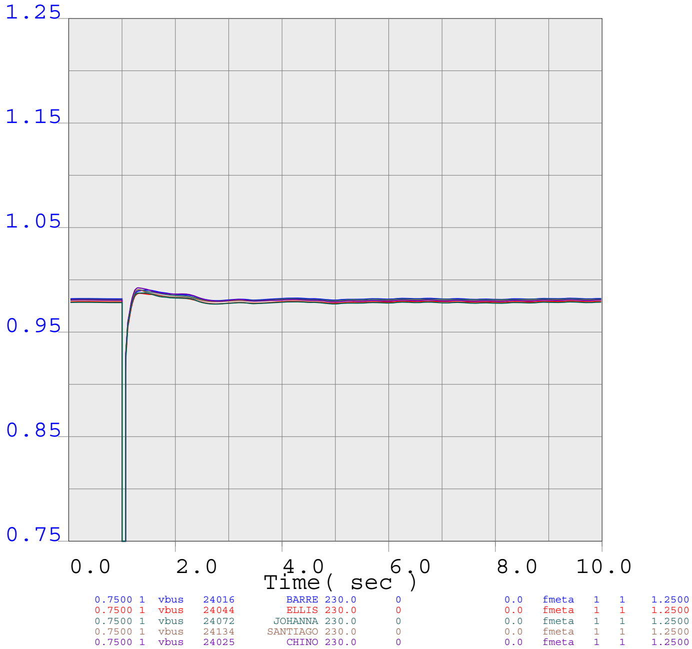
C:\DYTOOLS

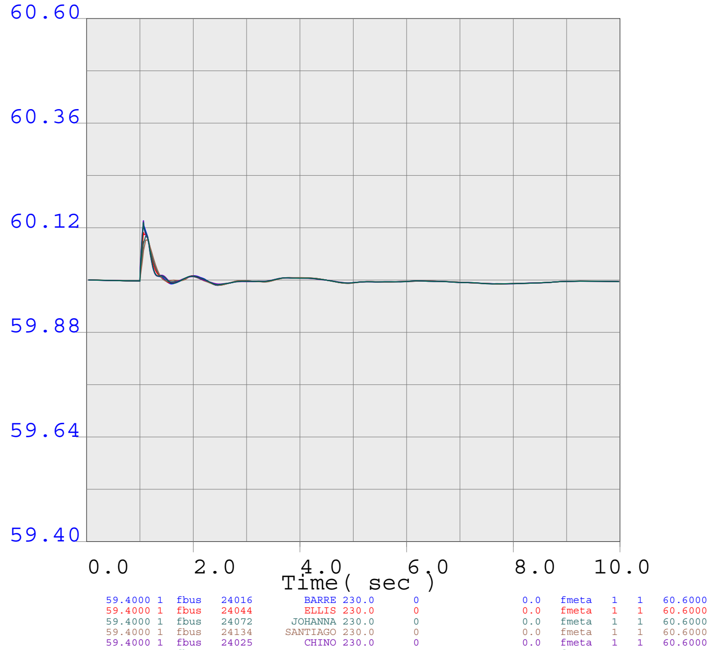
Thu Oct 20 09:05:17 2016

METRO









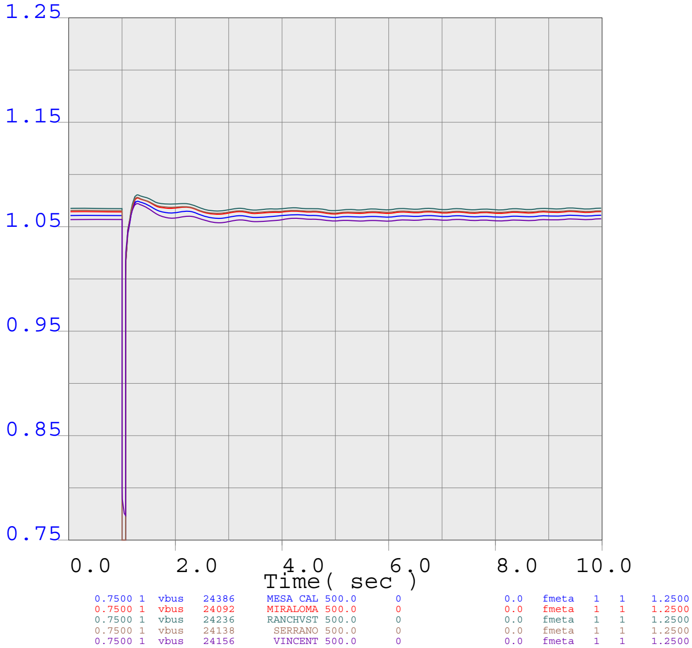
tran_1306
Tran SERRANO 500.00 to SERRANO 230.00 Circuit 2SERRAN2T 13.80
1 MW dispatch Case

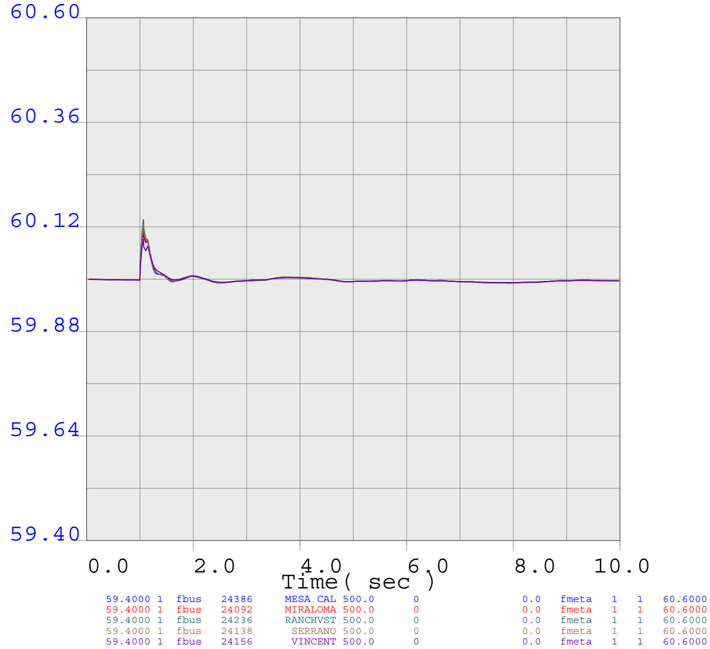
qc9p-tran_1306.chf

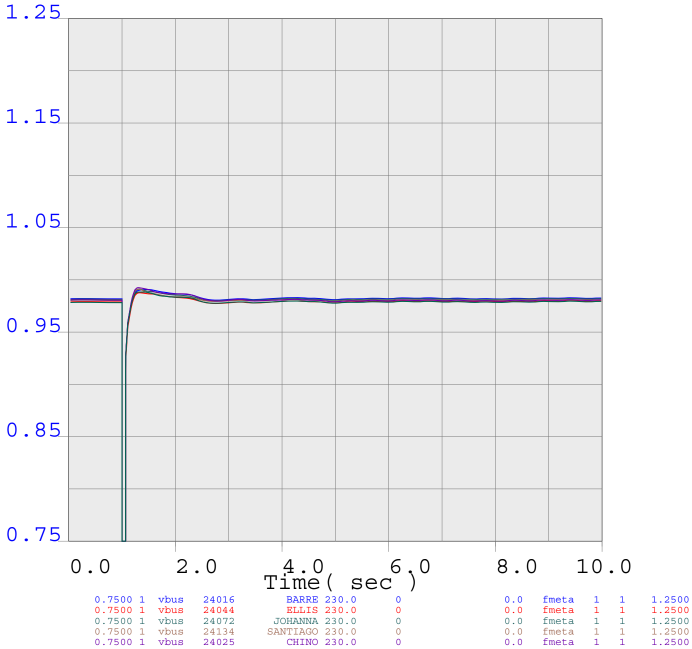
C:\DYTOOLS

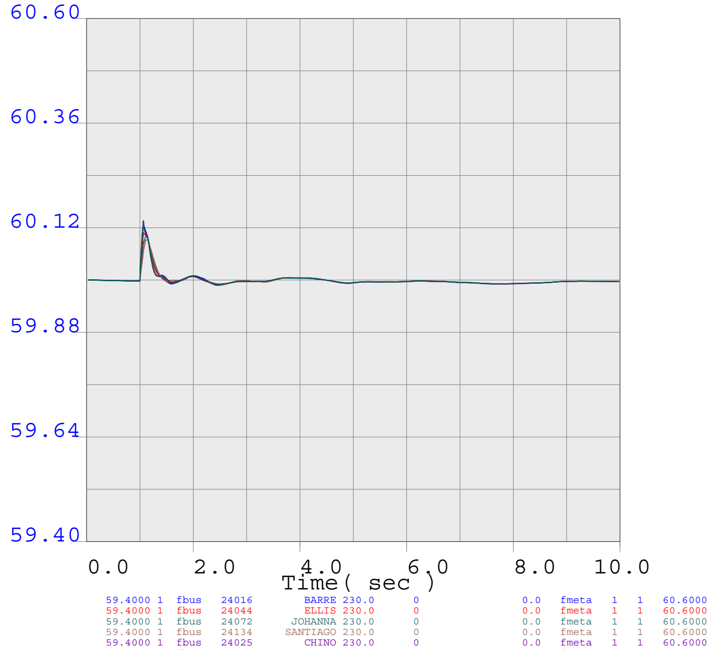
Thu Oct 20 09:05:19 2016

METRO









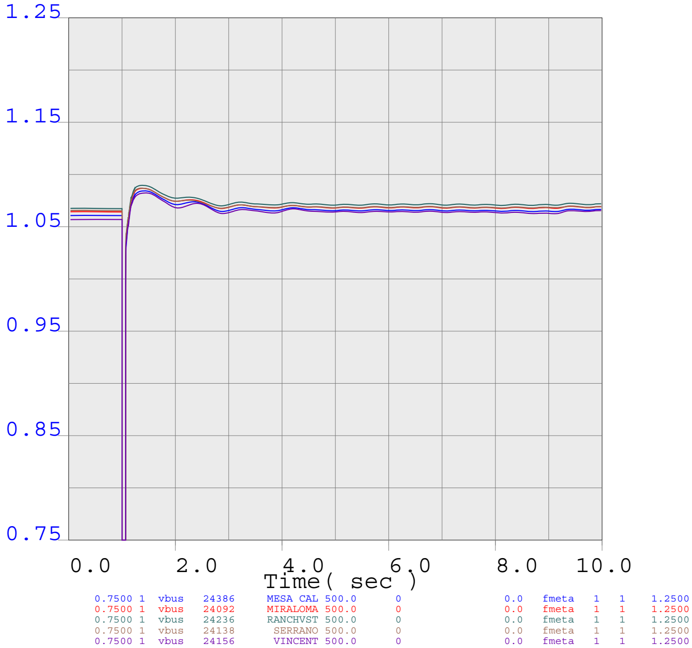
tran_1307
Tran SERRANO 500.00 to SERRANO 230.00 Circuit 3 0.00
1 MW dispatch Case

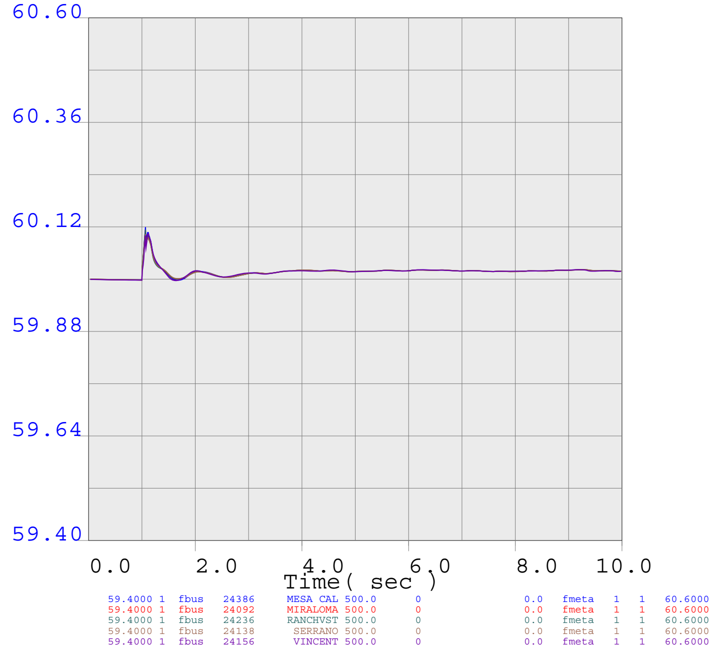
qc9p-tran_1307.chf

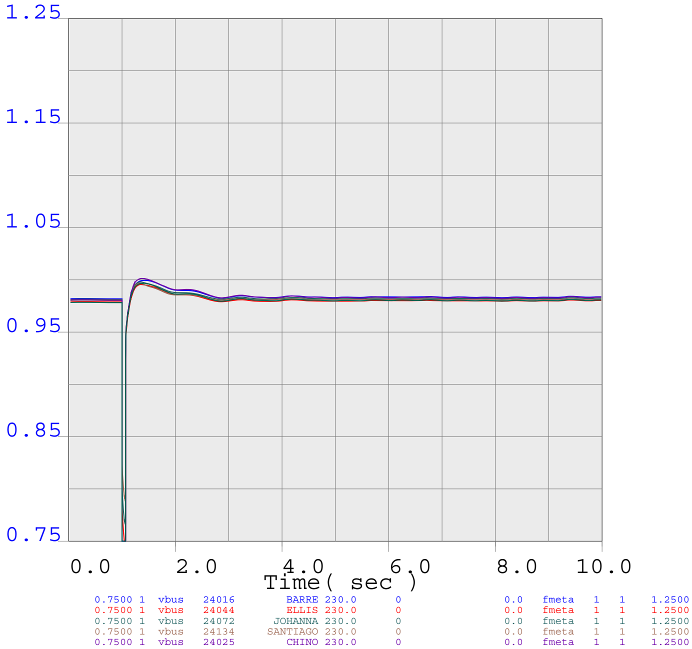
C:\DYTOOLS

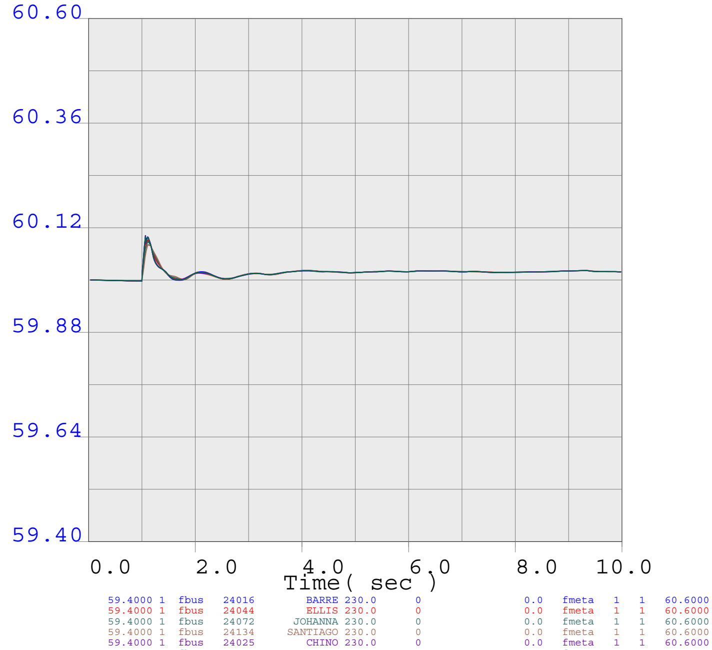
Thu Oct 20 09:05:21 2016

METRO





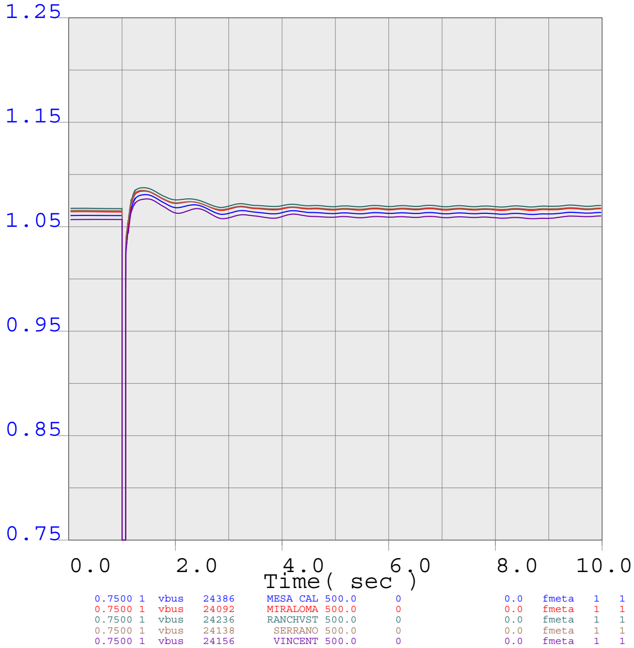


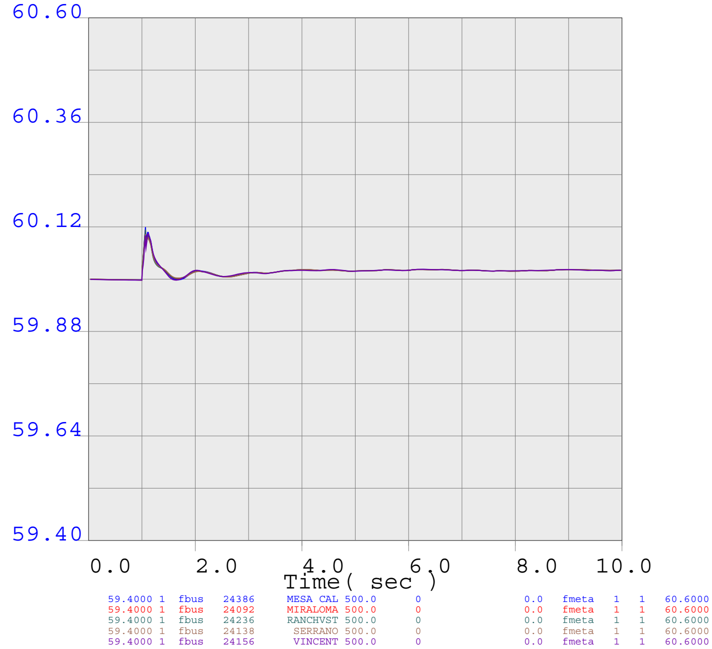


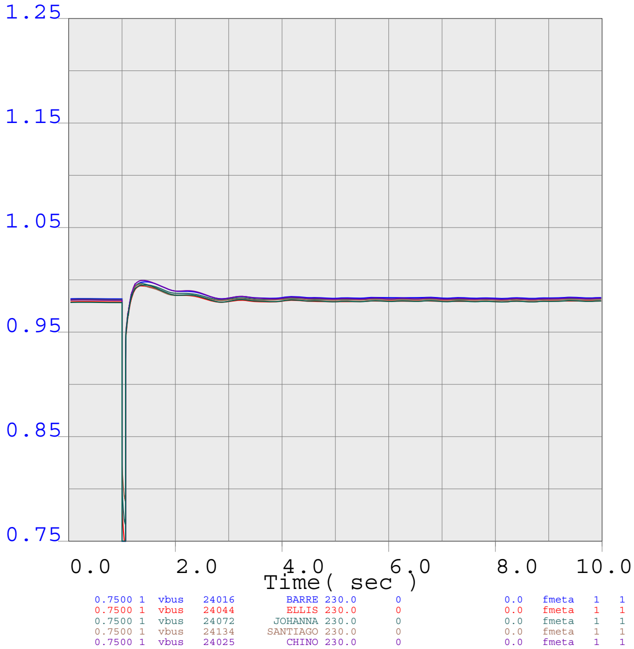
tran_1308
Tran VINCENT 500.00 to VINCENT 230.00 Circuit 2VINCEN2T 13.80
1 MW dispatch Case

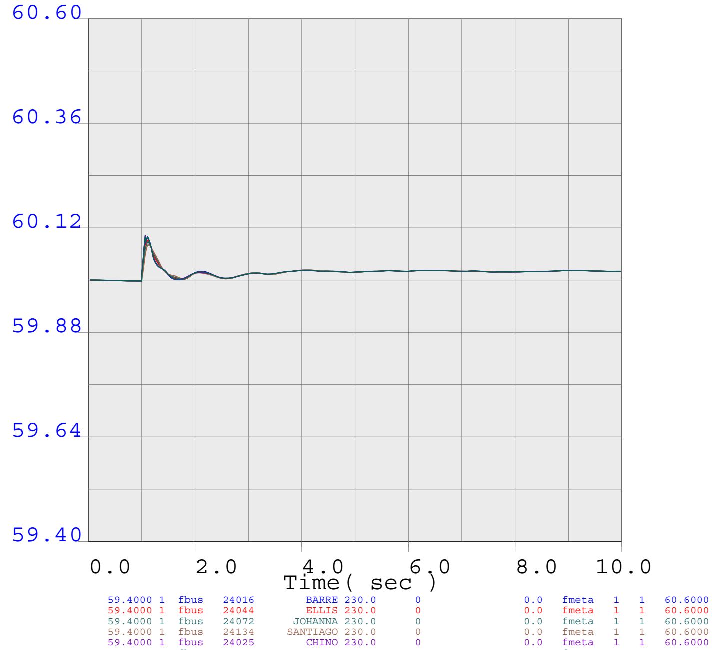
	qc9p-tran_1308.chf	C:\DYTOOLS Thu Oct 20 09:05:24 2016

METRO









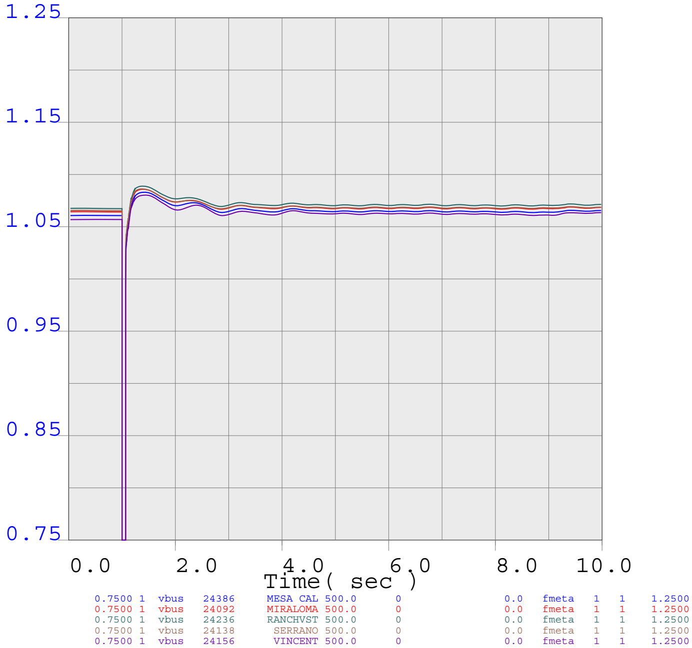
tran_1309
Tran VINCENT 500.00 to VINCENT 230.00 Circuit 3 0.00
1 MW dispatch Case

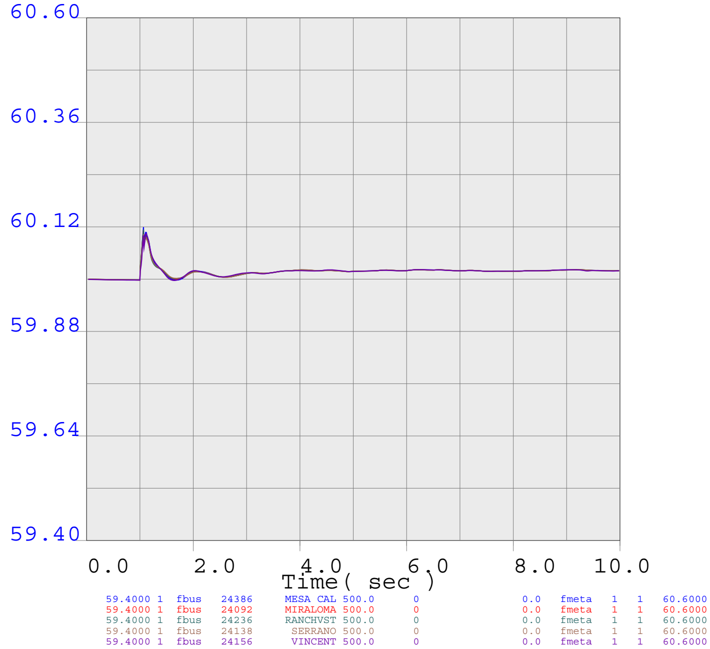
qc9p-tran_1309.chf

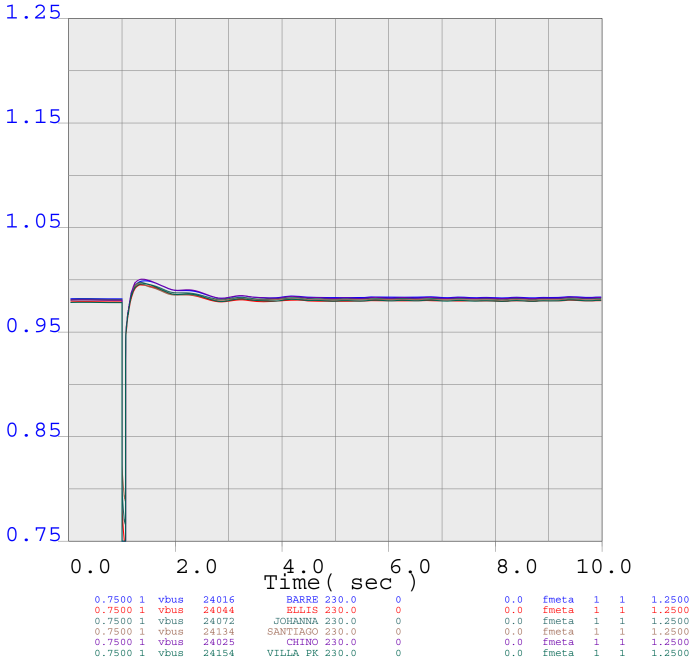
C:\DYTOOLS

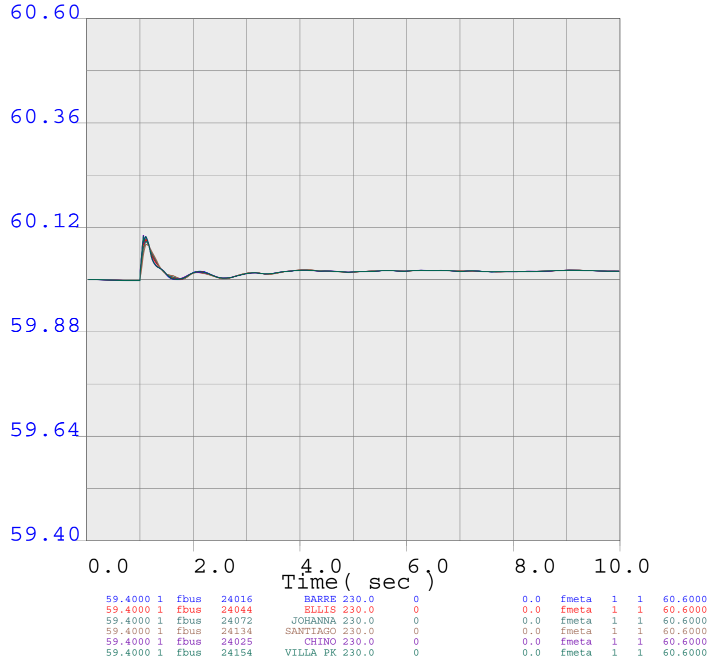
Thu Oct 20 09:05:26 2016

METRO









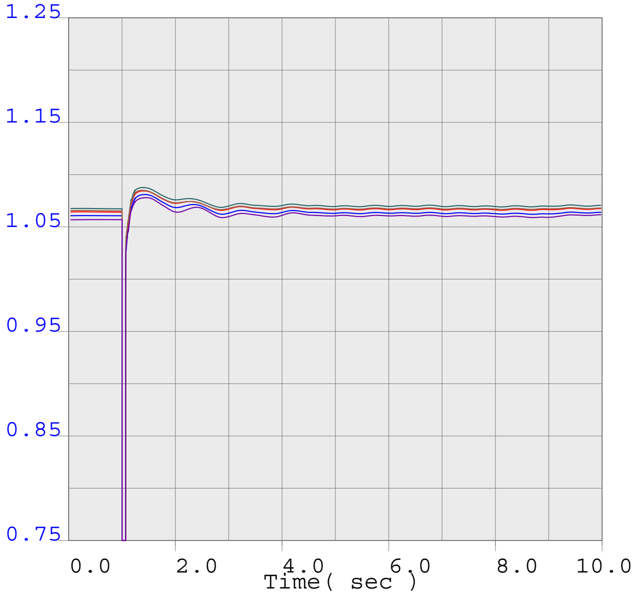
tran_1310
Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 1VINCEN1T 13.80
1 MW dispatch Case

qc9p-tran_1310.chf

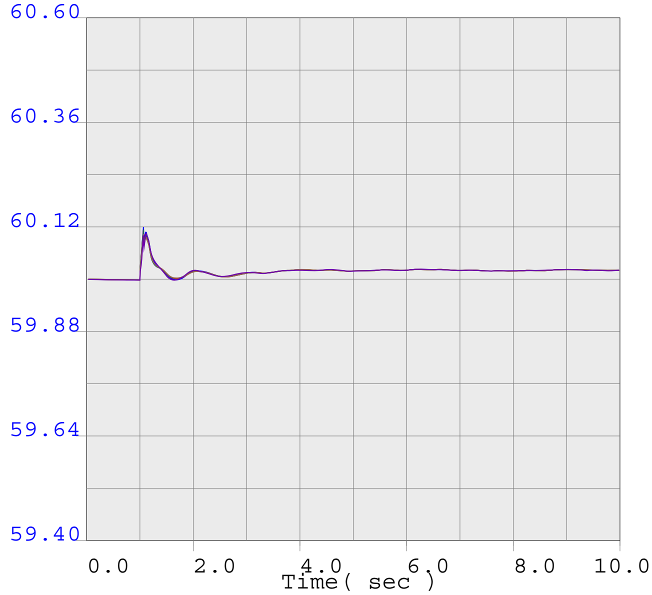
C:\DYTOOLS

Thu Oct 20 09:05:28 2016

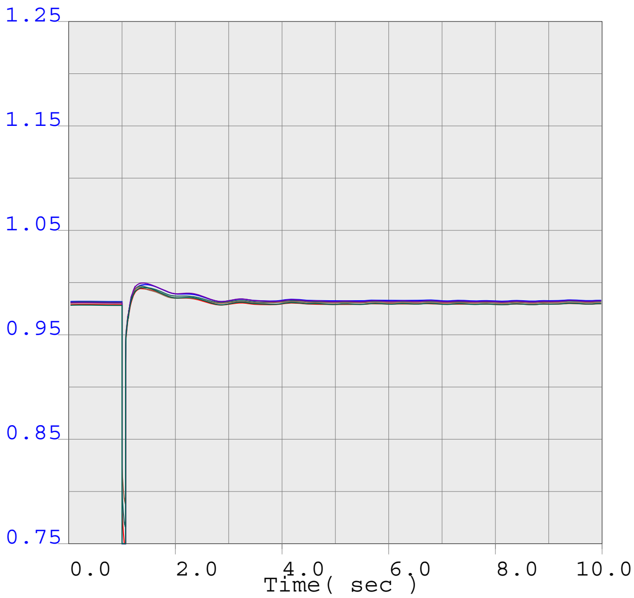
METRO



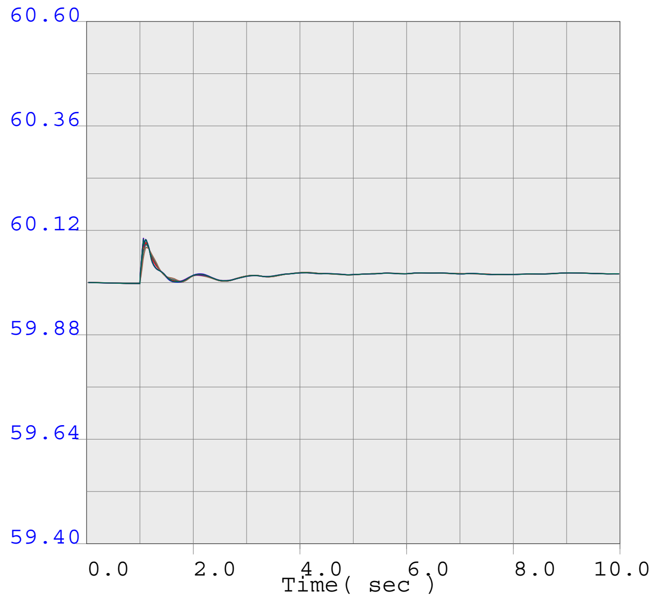
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

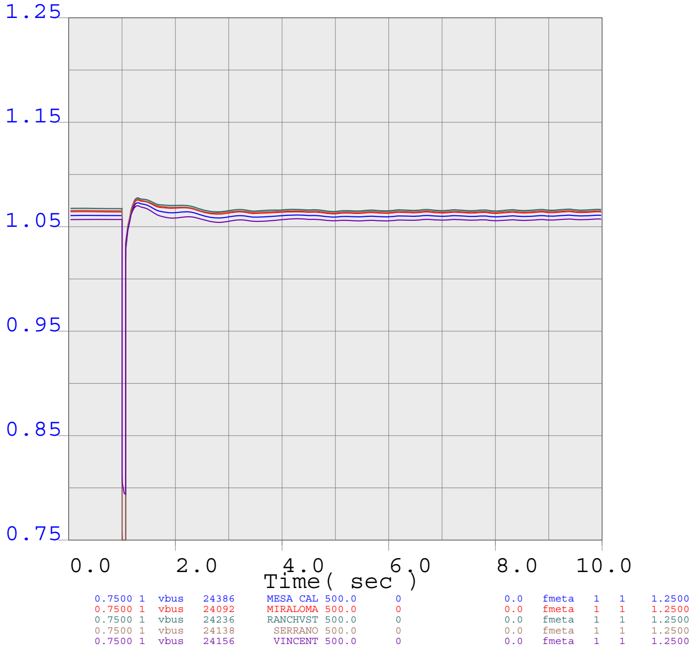
tran_1311
Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 4VINCEN4T 13.80
1 MW dispatch Case

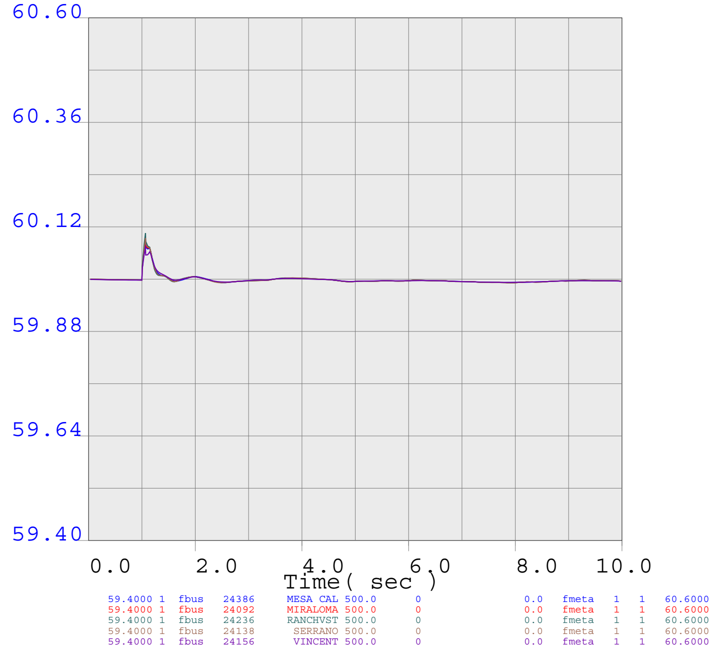
qc9p-tran_1311.chf

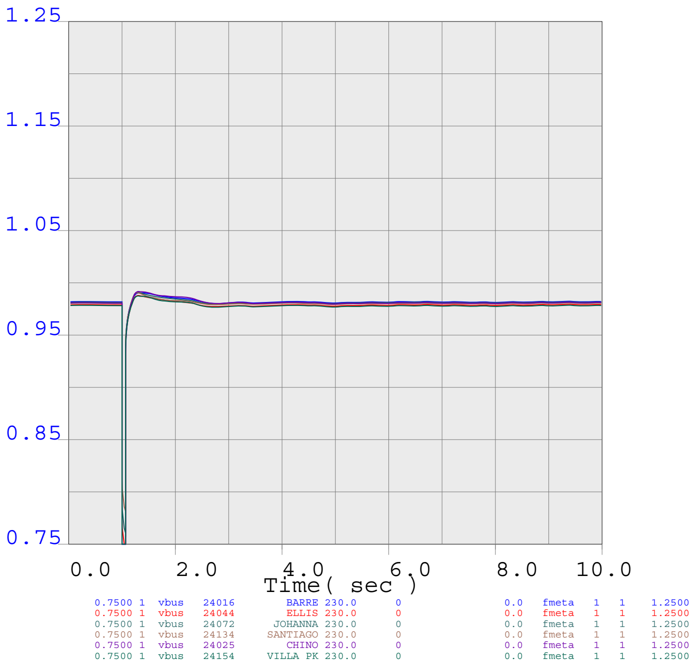
C:\DYTOOLS

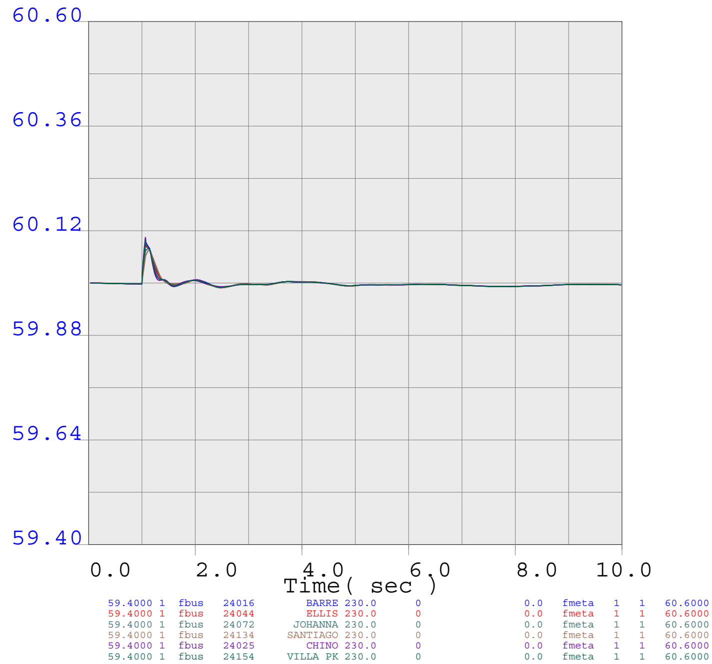
Thu Oct 20 09:05:30 2016

METRO









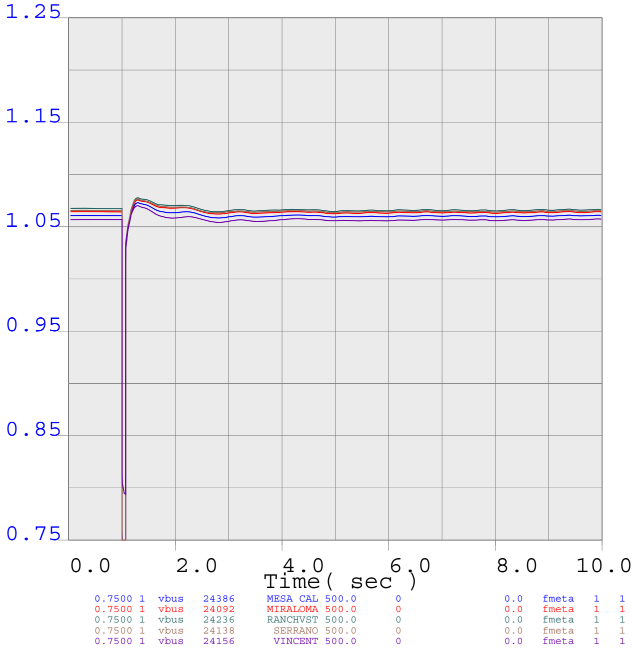
tran_1312
Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 3RCHVST3T 13.80
1 MW dispatch Case

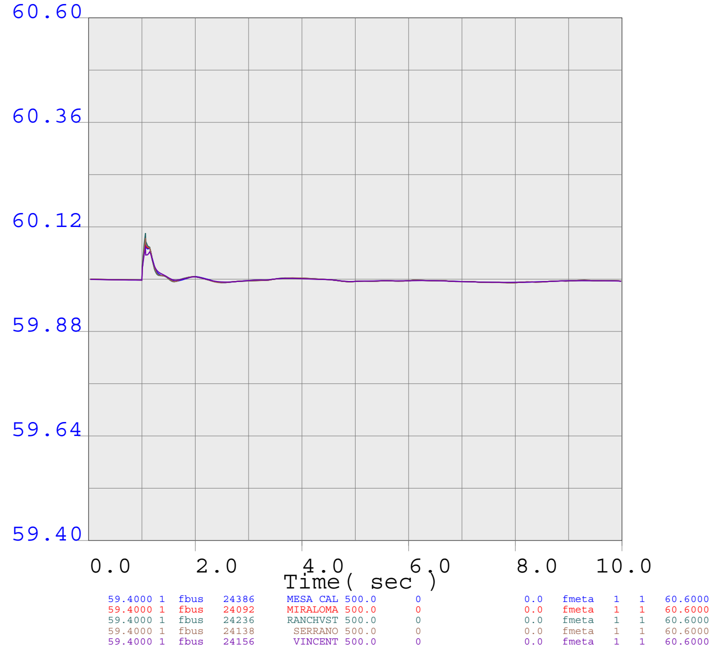
qc9p-tran_1312.chf

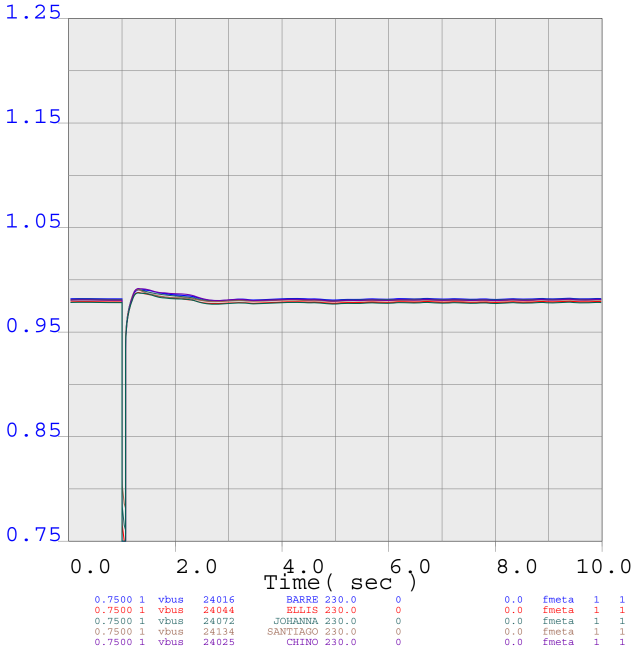
C:\DYTOOLS

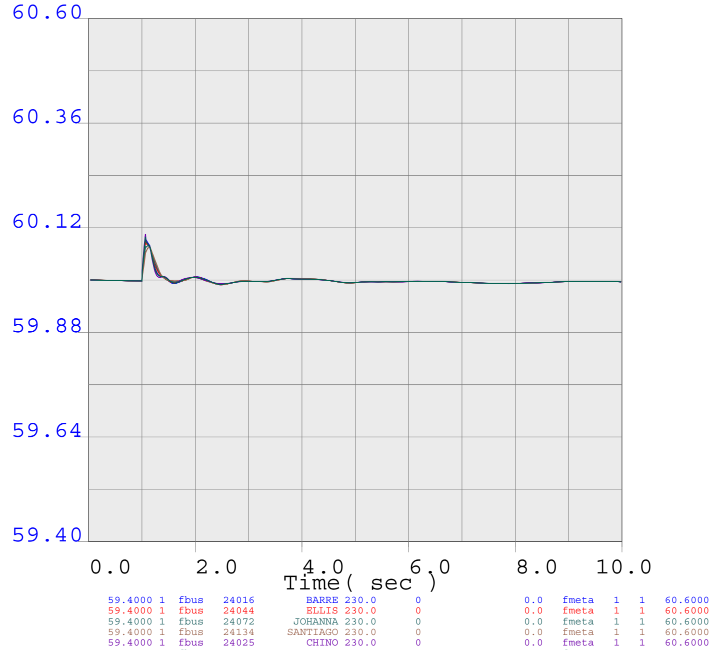
Thu Oct 20 09:05:31 2016

METRO









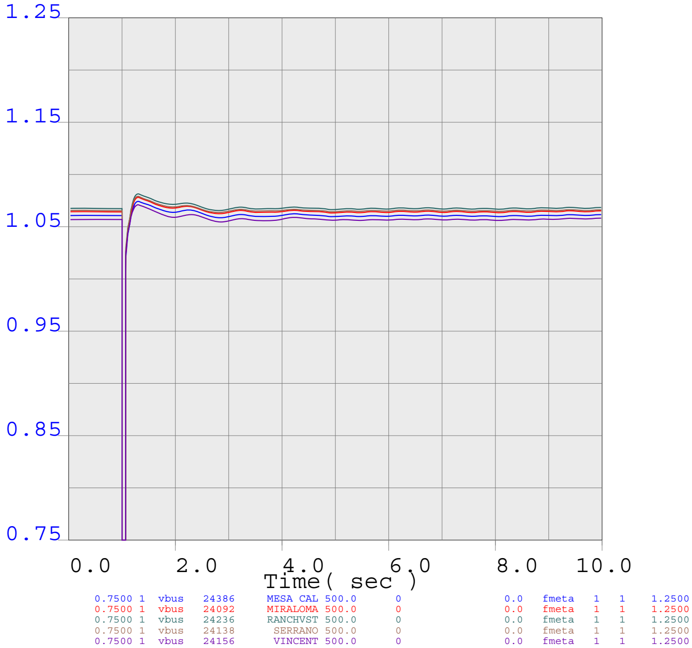
tran_1313
Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 4RCHVST4T 13.80
1 MW dispatch Case

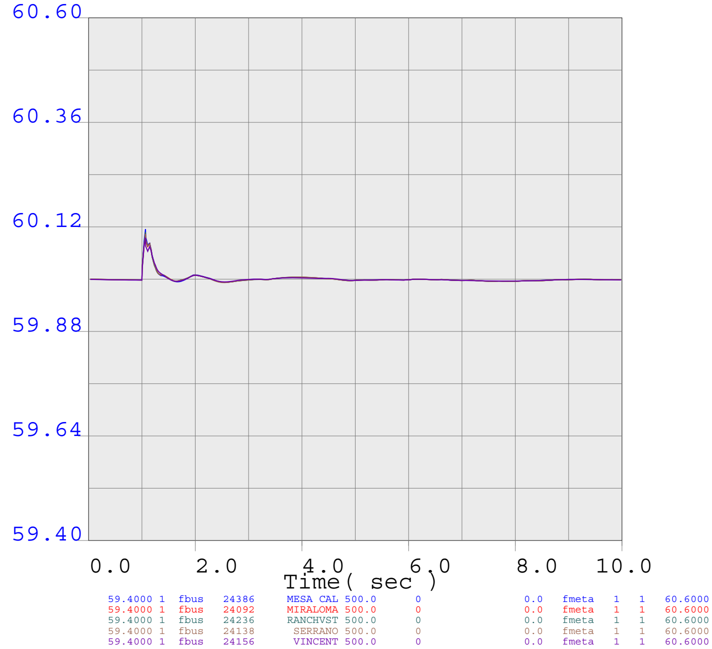
qc9p-tran_1313.chf

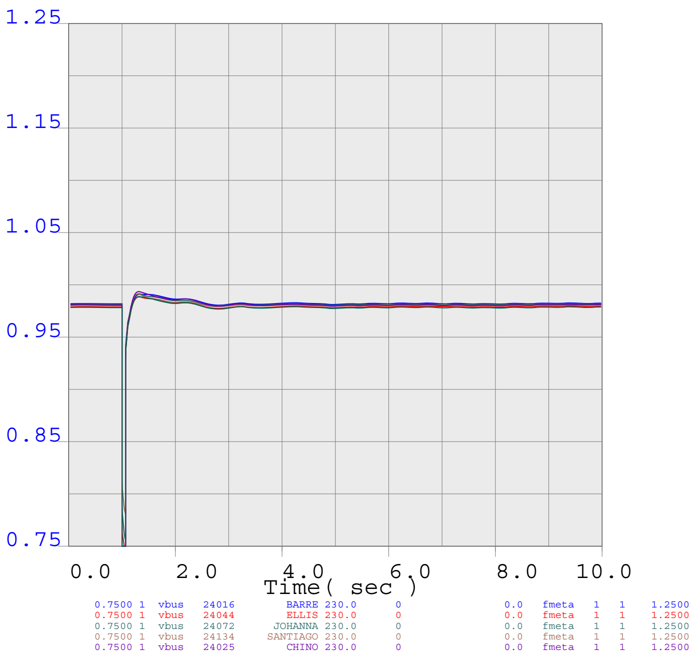
C:\DYTOOLS

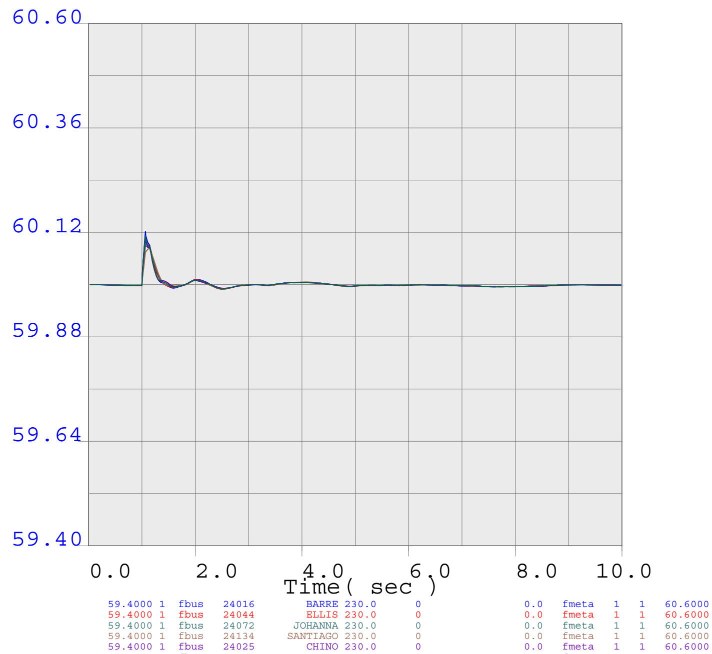
Thu Oct 20 09:05:33 2016

METRO









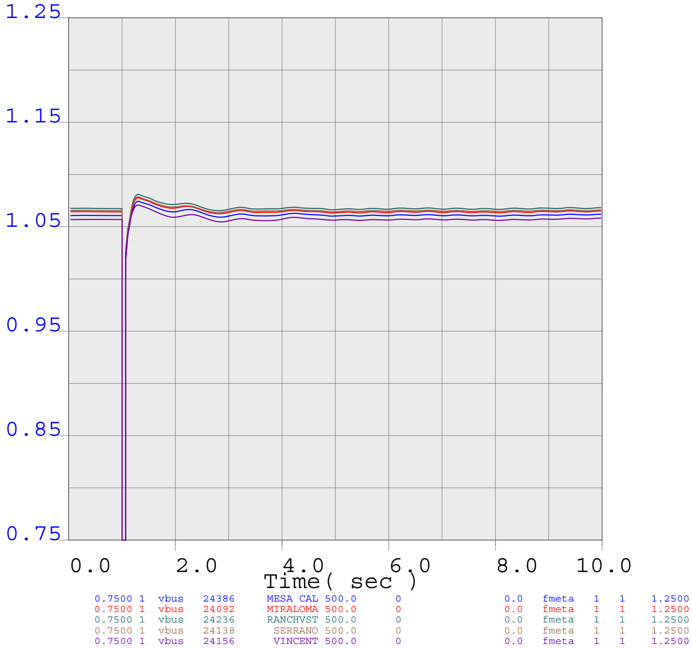
tran_1314
Tran MESA CAL 500.00 to MESA CAL 230.00 Circuit 2MESA2T 13.80
1 MW dispatch Case

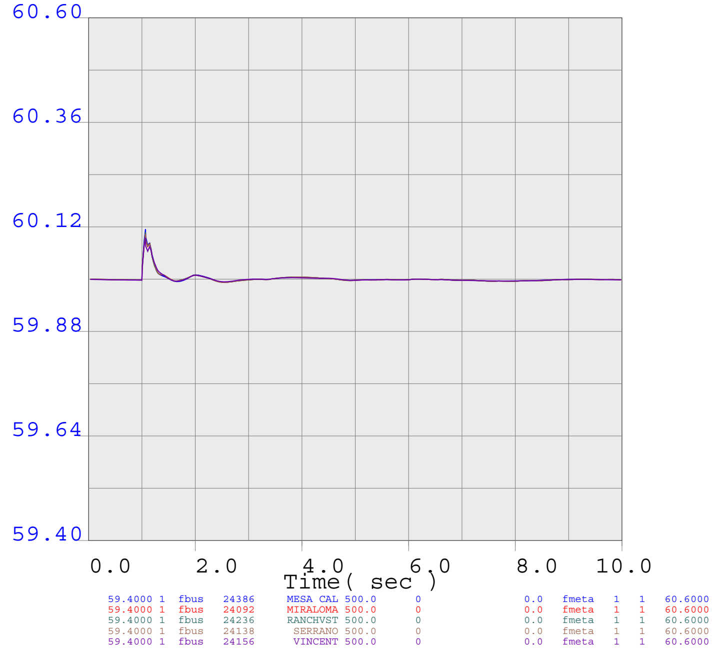
qc9p-tran_1314.chf

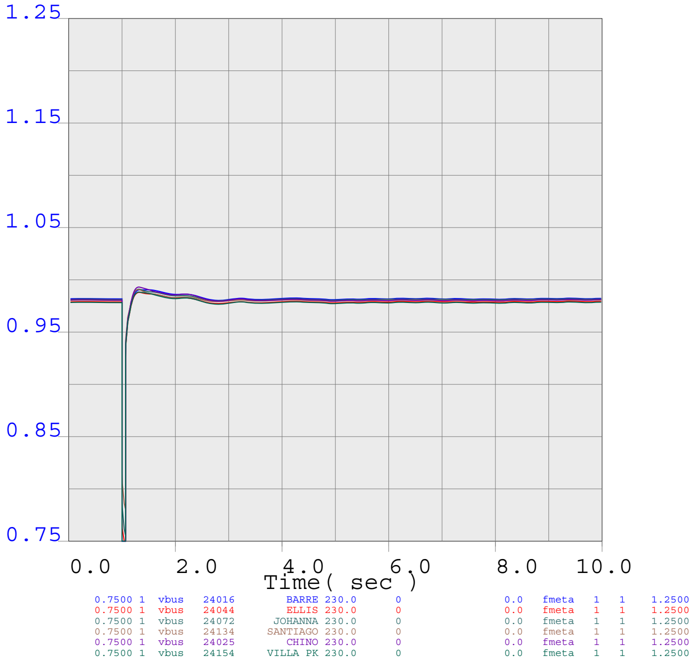
C:\DYTOOLS

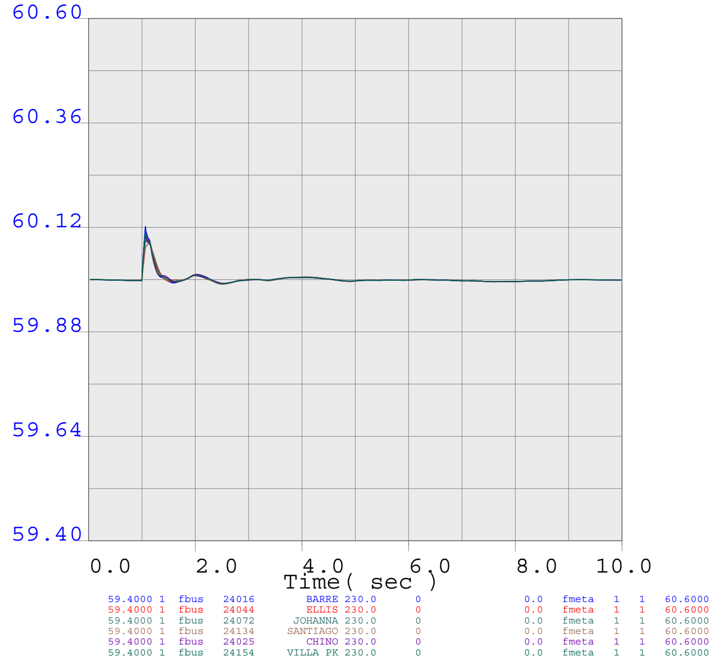
Thu Oct 20 09:05:36 2016

METRO









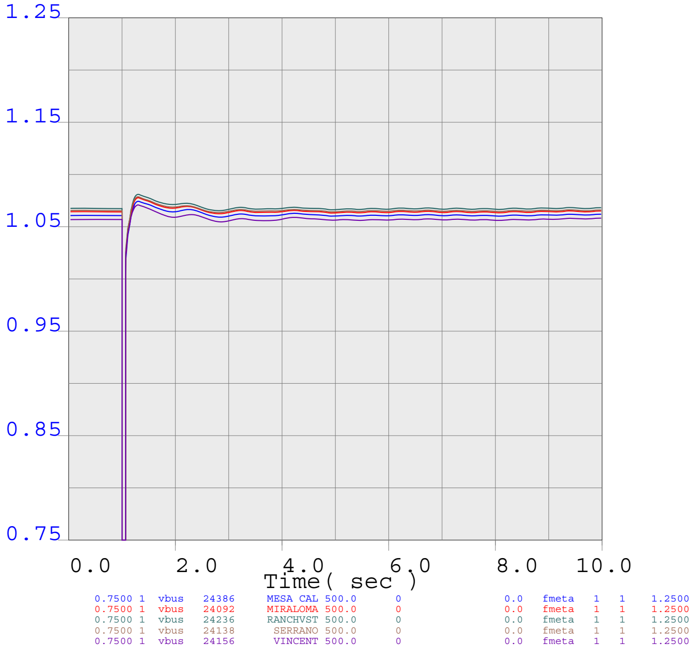
tran_1315
Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 3MESA3T 13.80
1 MW dispatch Case

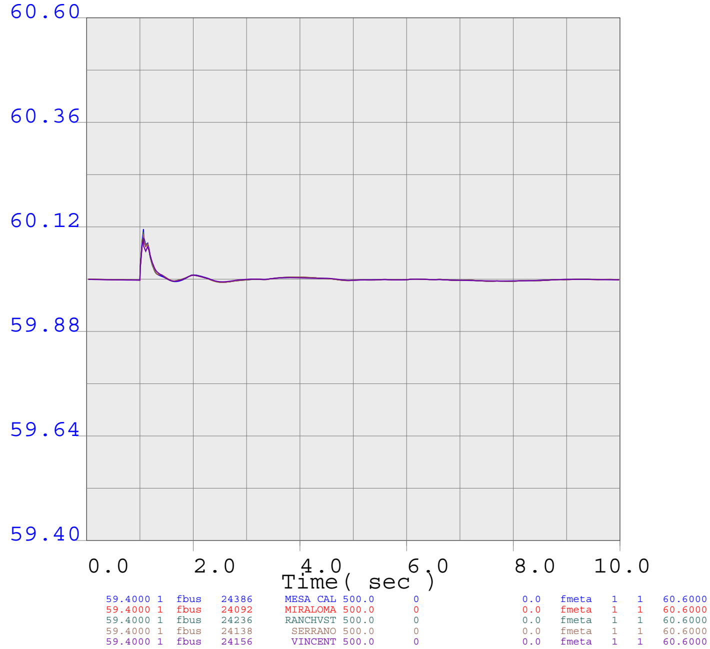
qc9p-tran_1315.chf

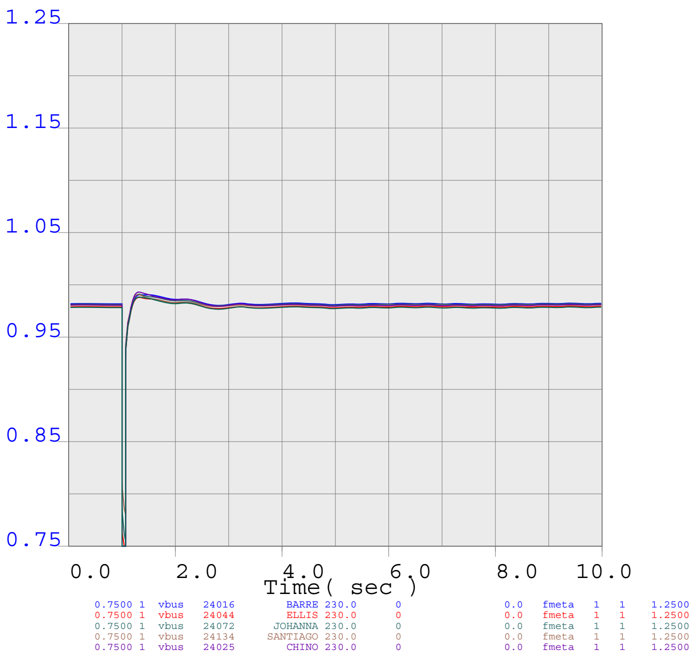
C:\DYTOOLS

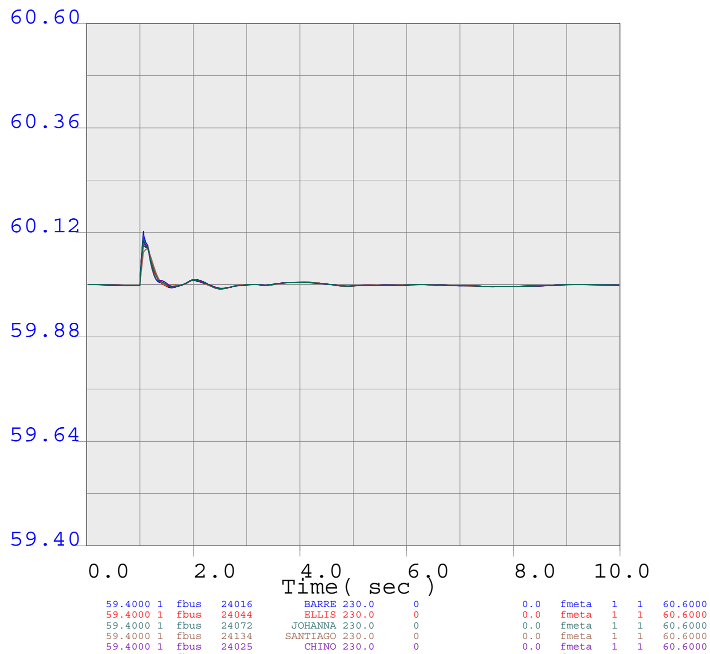
Thu Oct 20 09:05:38 2016

METRO









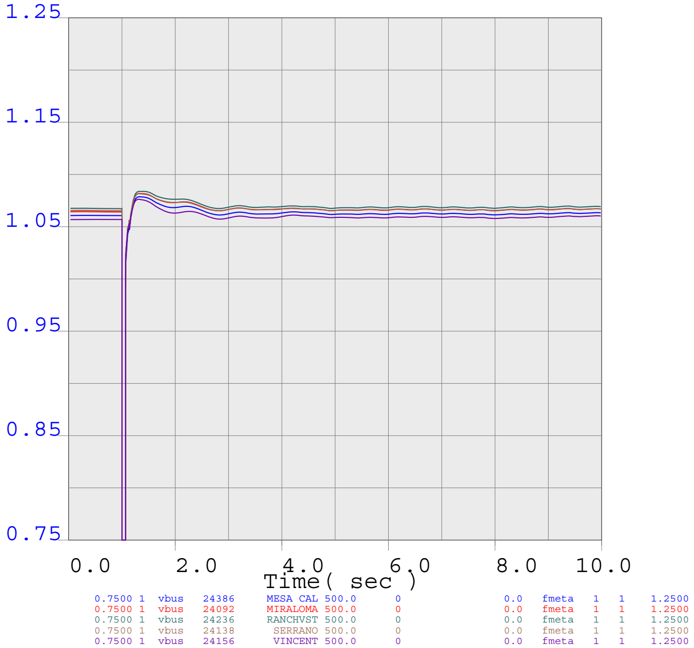
tran_1316
Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 4MESA4T 13.80
1 MW dispatch Case

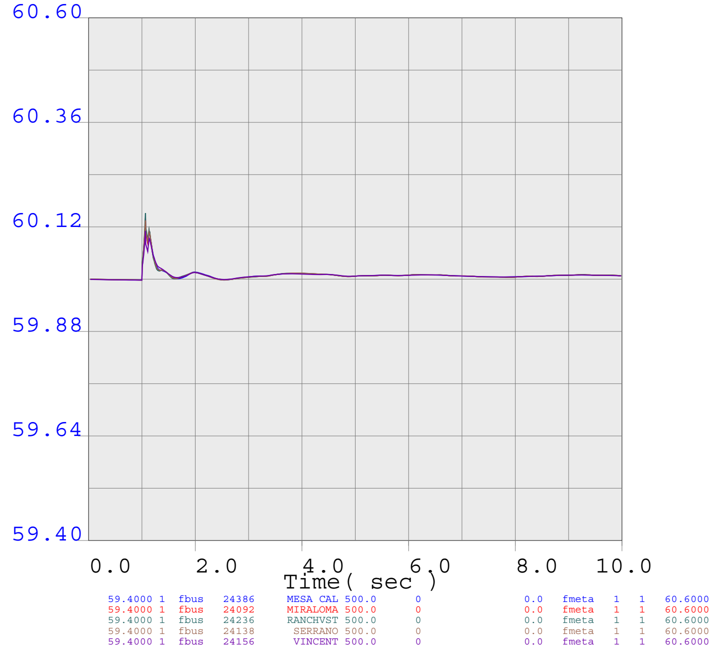
qc9p-tran_1316.chf

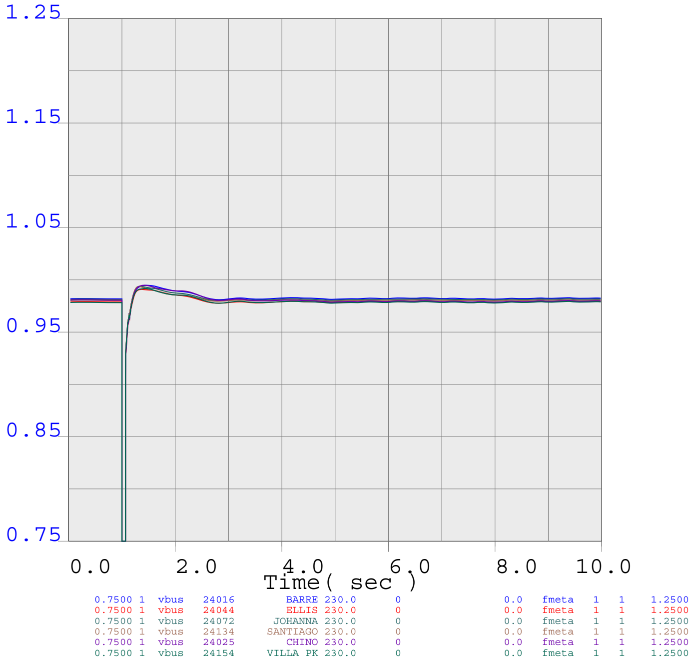
C:\DYTOOLS

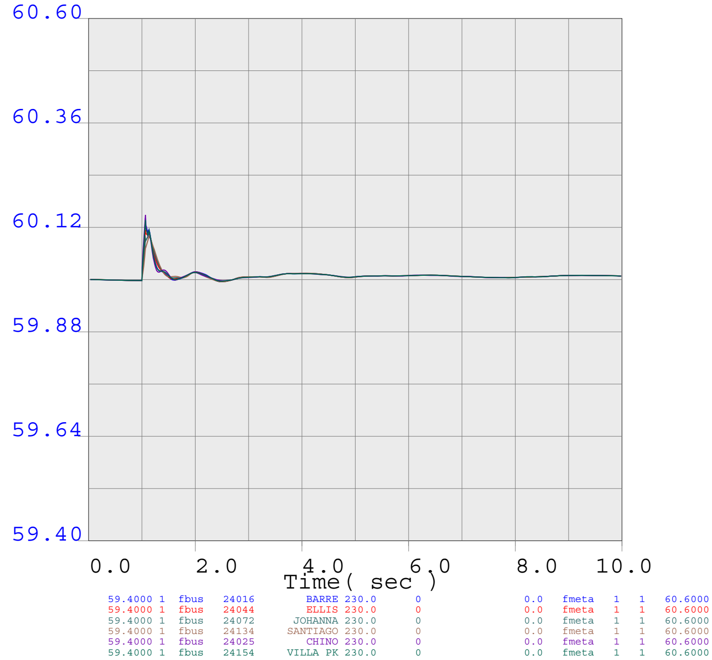
Thu Oct 20 09:05:40 2016

METRO









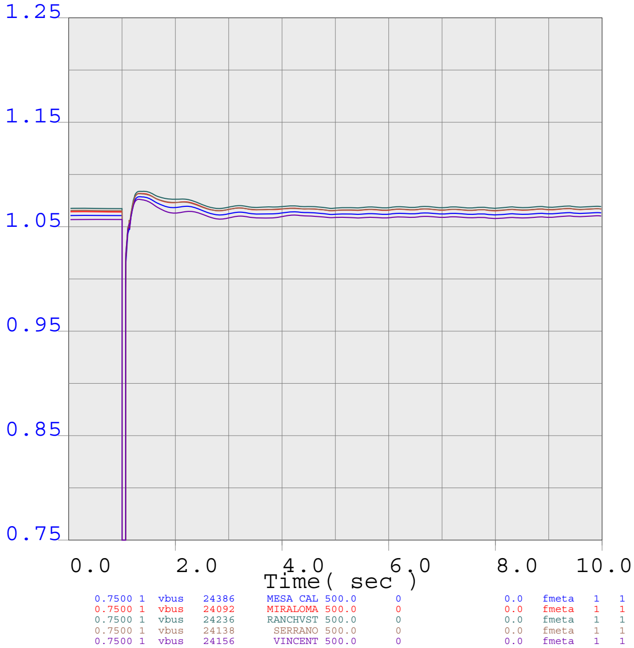
tran_1317
Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 1MIRLOM1T 13.80
1 MW dispatch Case

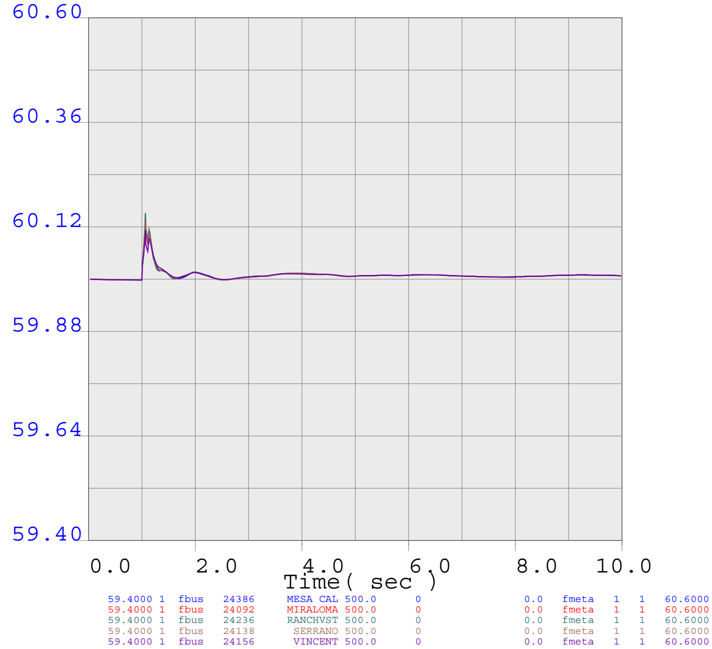
qc9p-tran_1317.chf

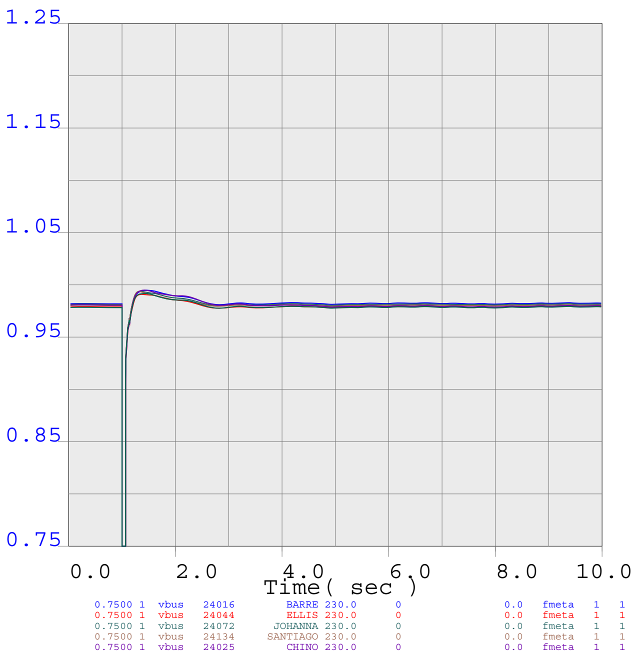
C:\DYTOOLS

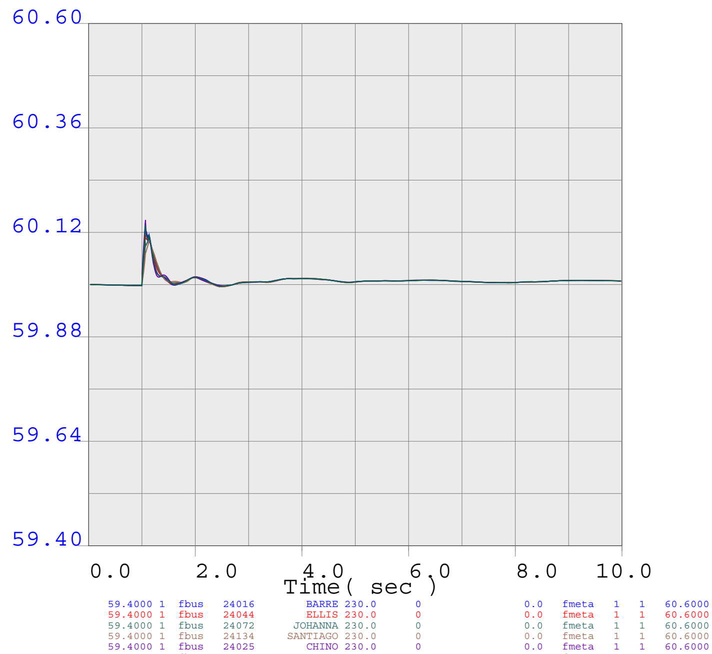
Thu Oct 20 09:05:42 2016

METRO









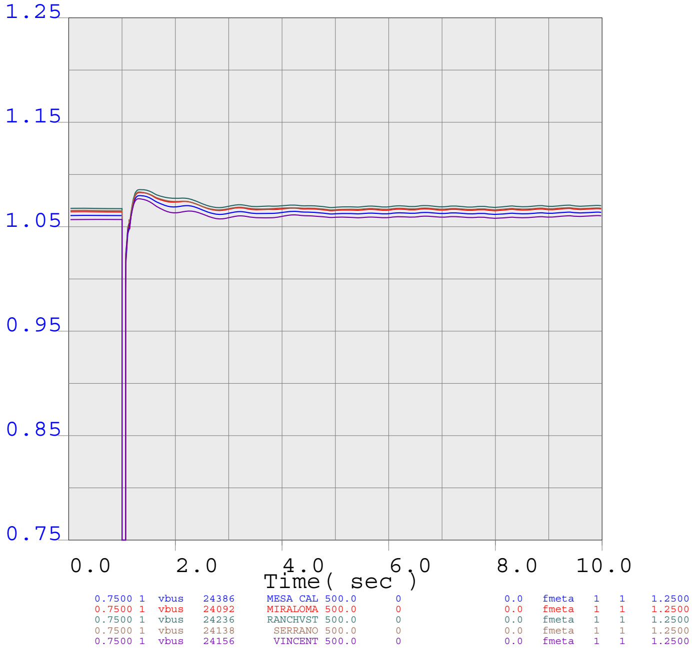
tran_1318
Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 2MIRLOM2T 13.80
1 MW dispatch Case

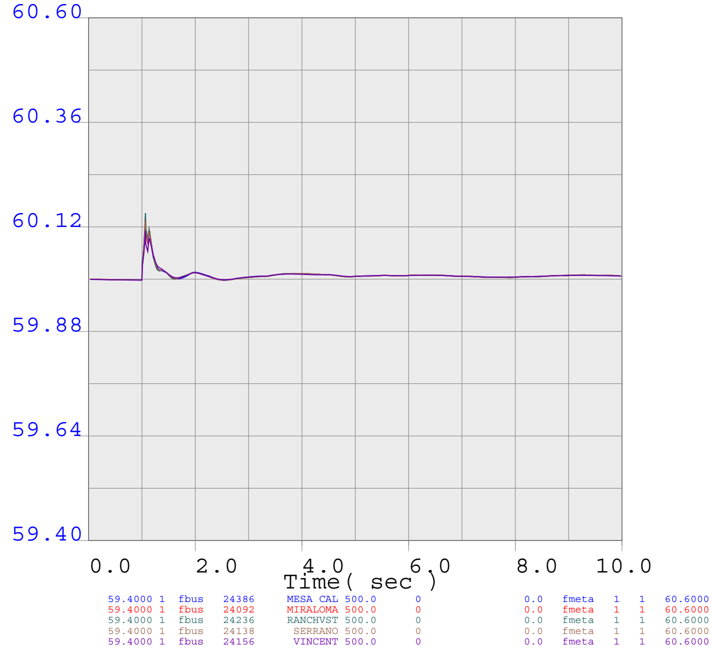
qc9p-tran_1318.chf

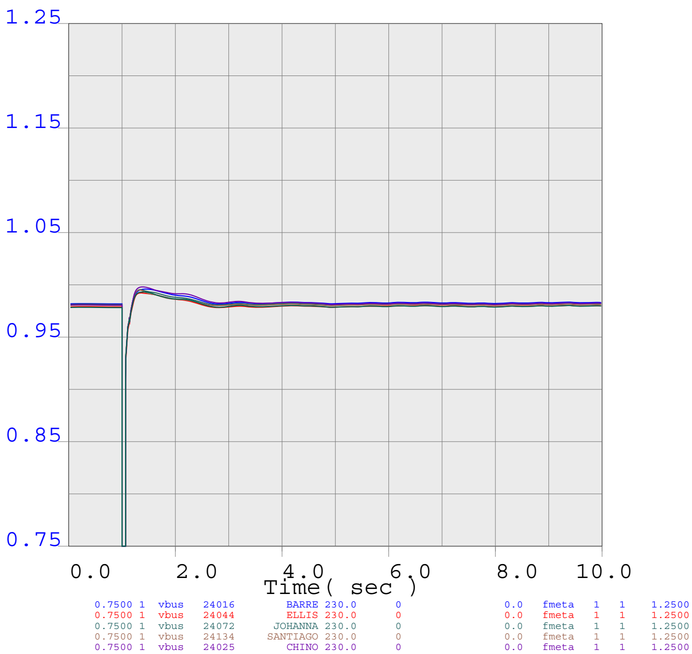
C:\DYTOOLS

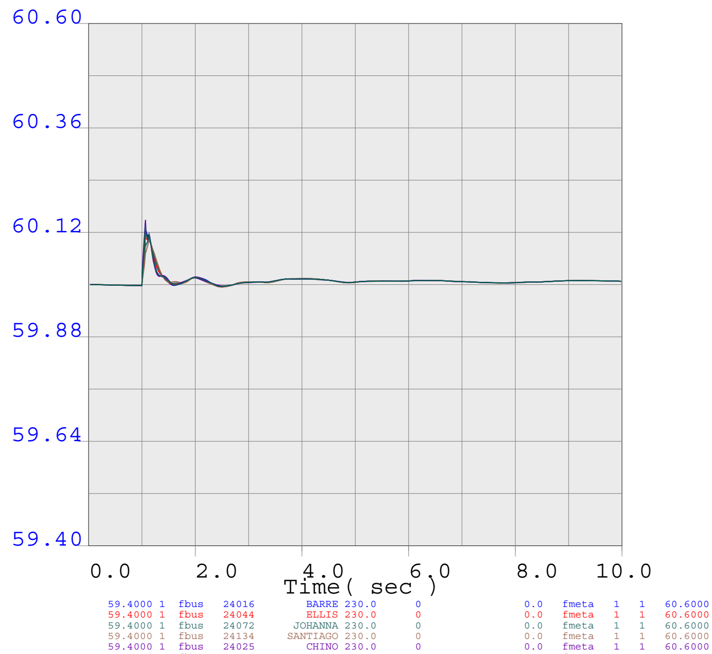
Thu Oct 20 09:05:44 2016

METRO









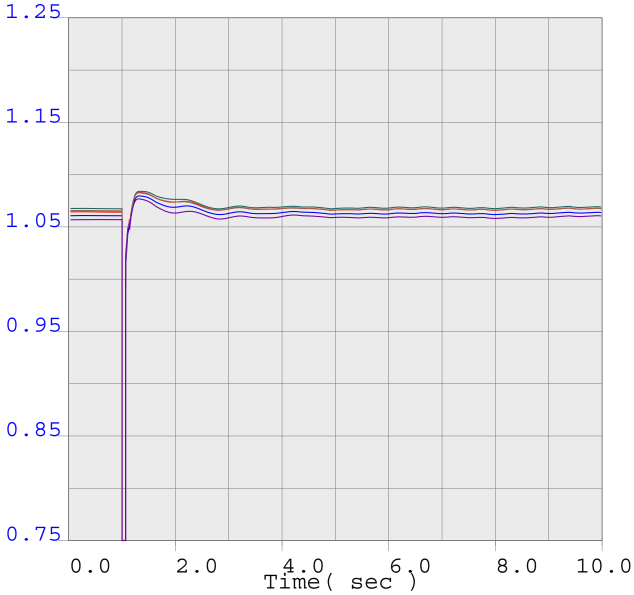
tran_1319
Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 3MIRLOM3T 13.80
1 MW dispatch Case

qc9p-tran_1319.chf

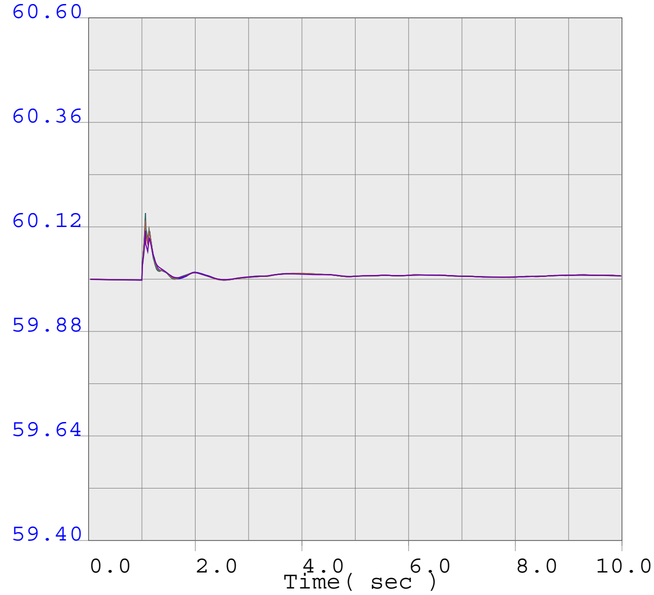
C:\DYTOOLS

Thu Oct 20 09:05:46 2016

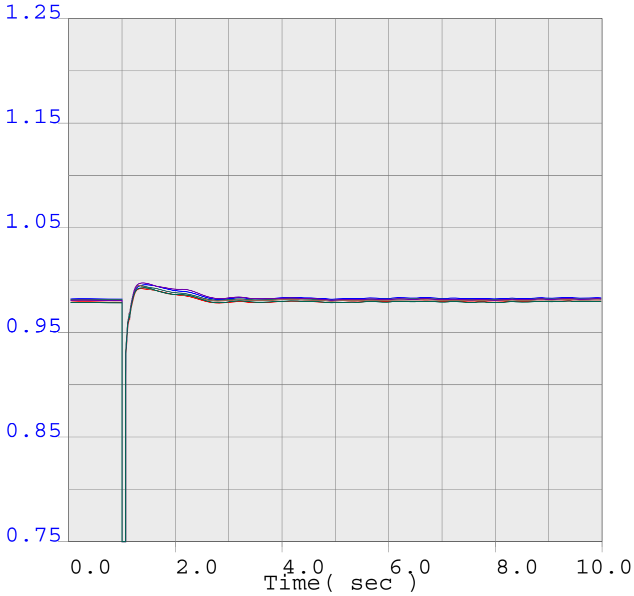
METRO



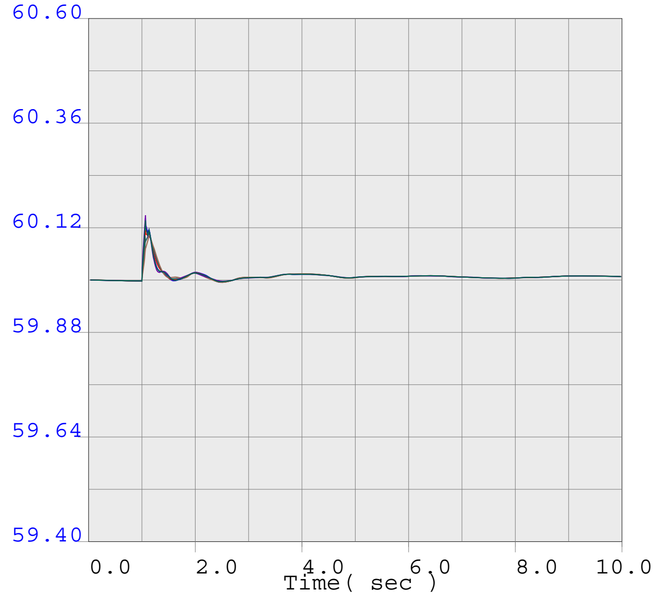
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

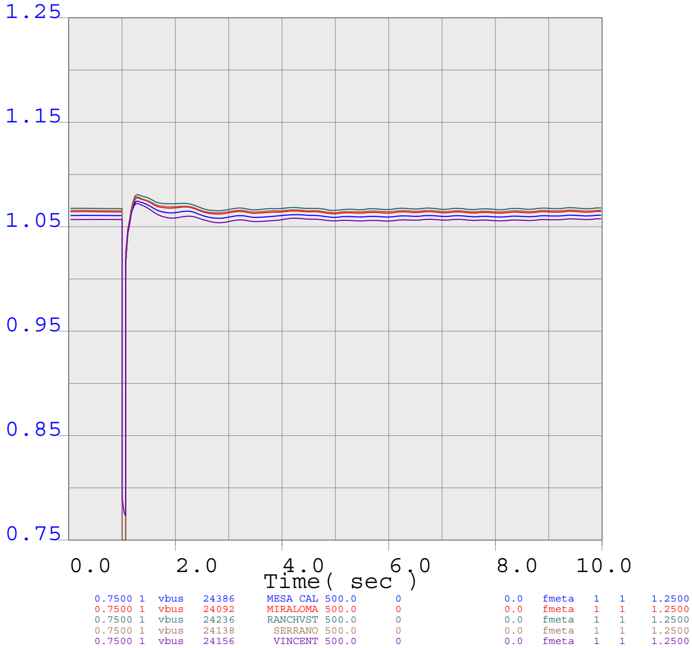
tran_1320
Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 4MIRLOM4T 13.80
1 MW dispatch Case

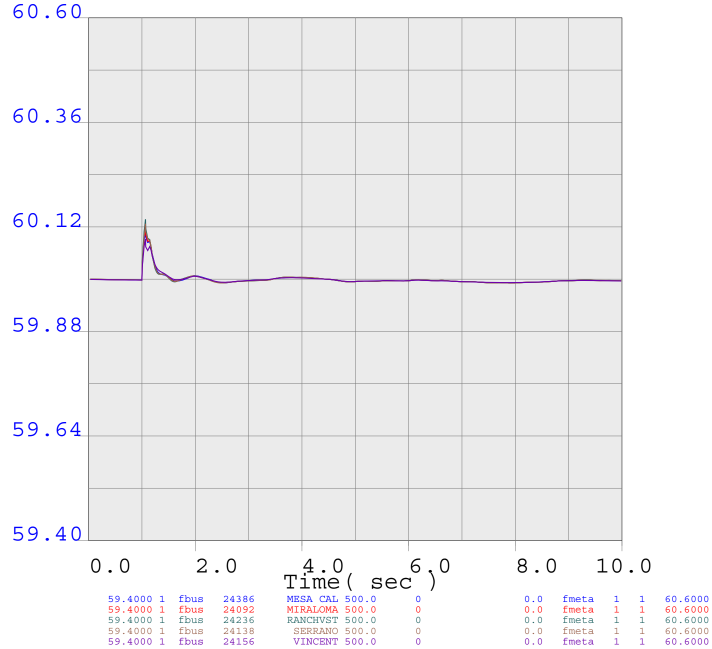
qc9p-tran_1320.chf

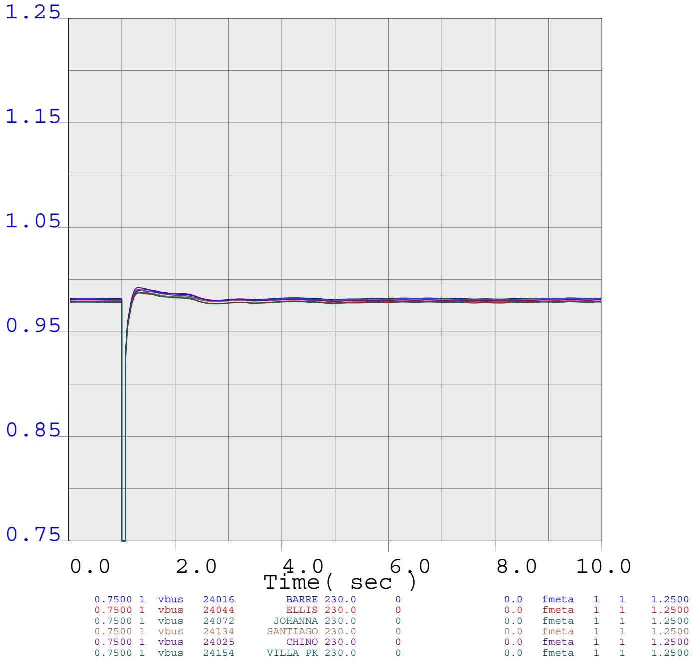
C:\DYTOOLS

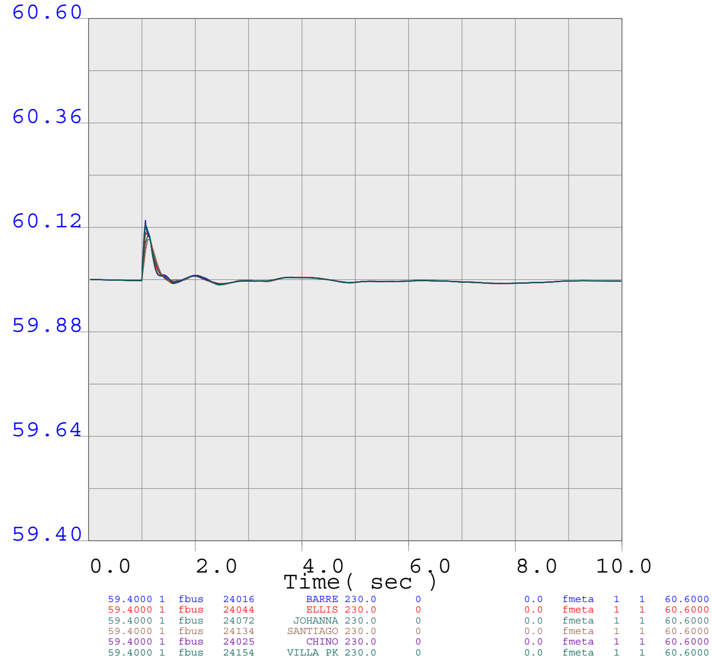
Thu Oct 20 09:05:48 2016

METRO









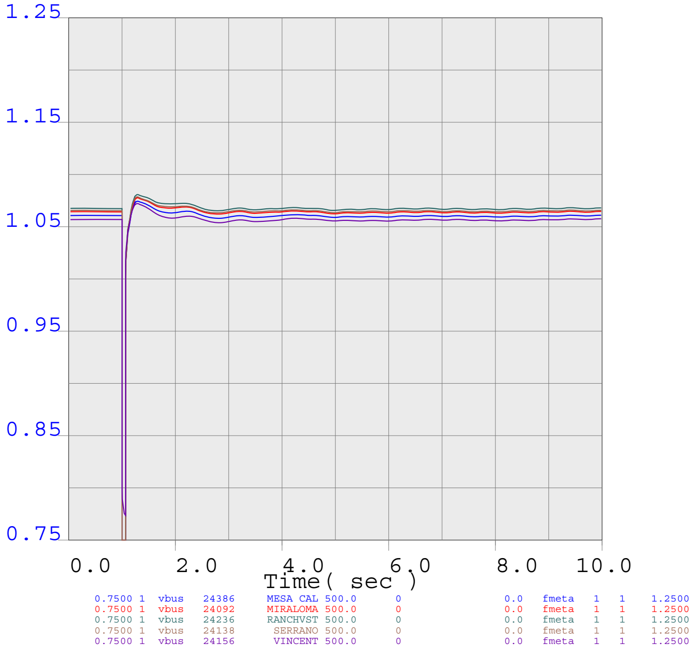
tran_1321
Tran SERRANO 500.00 to SERRANO 230.00 Circuit 1SERRAN1T 13.80
1 MW dispatch Case

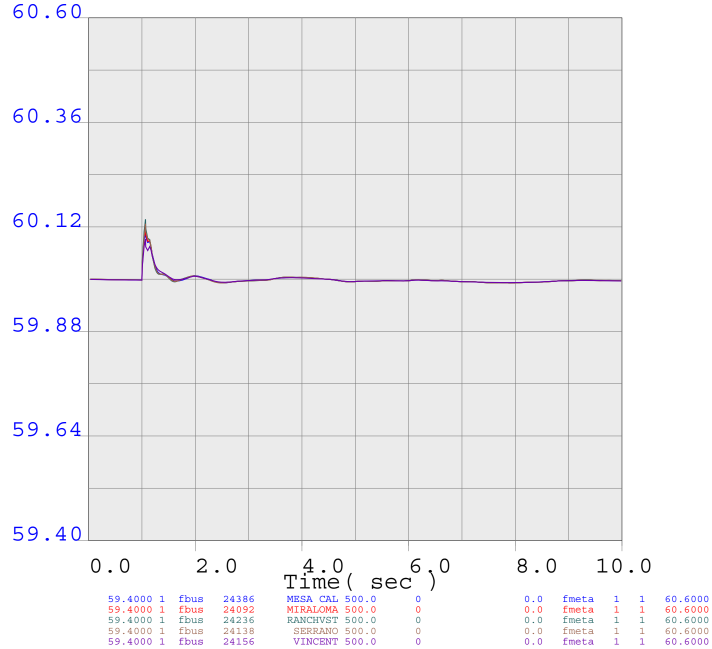
qc9p-tran_1321.chf

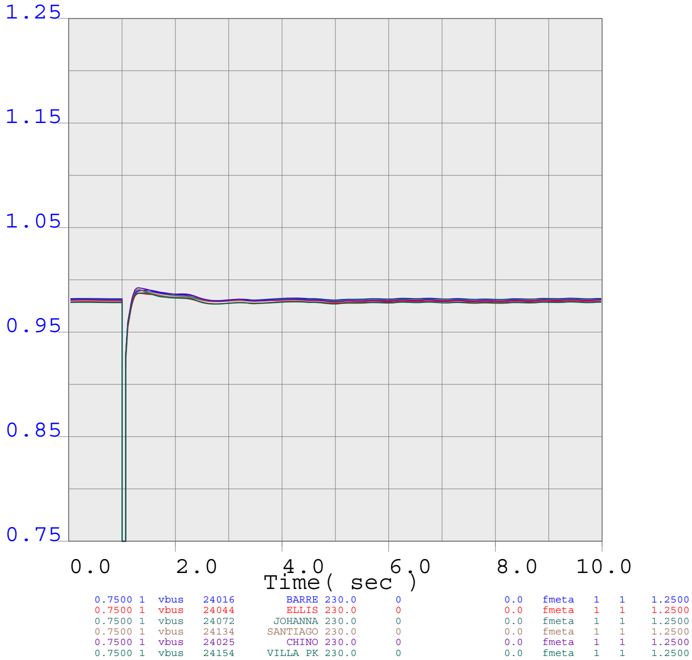
C:\DYTOOLS

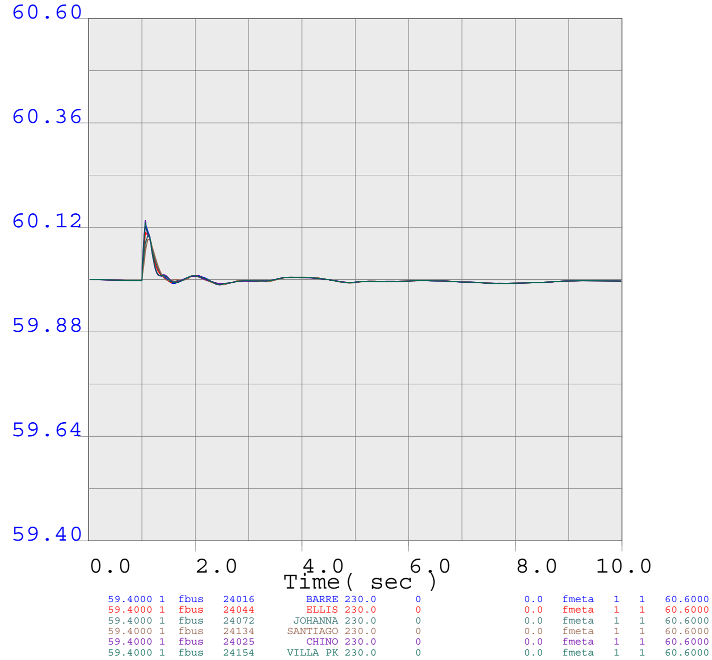
Thu Oct 20 09:05:50 2016

METRO





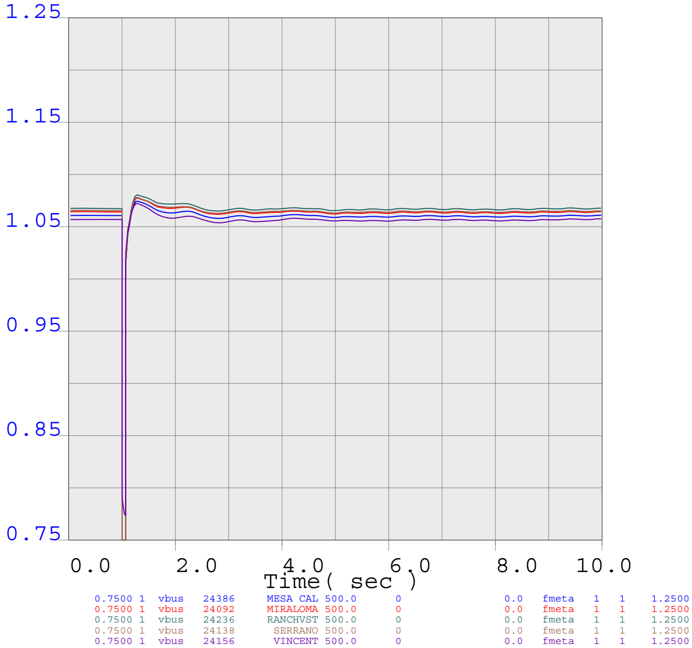


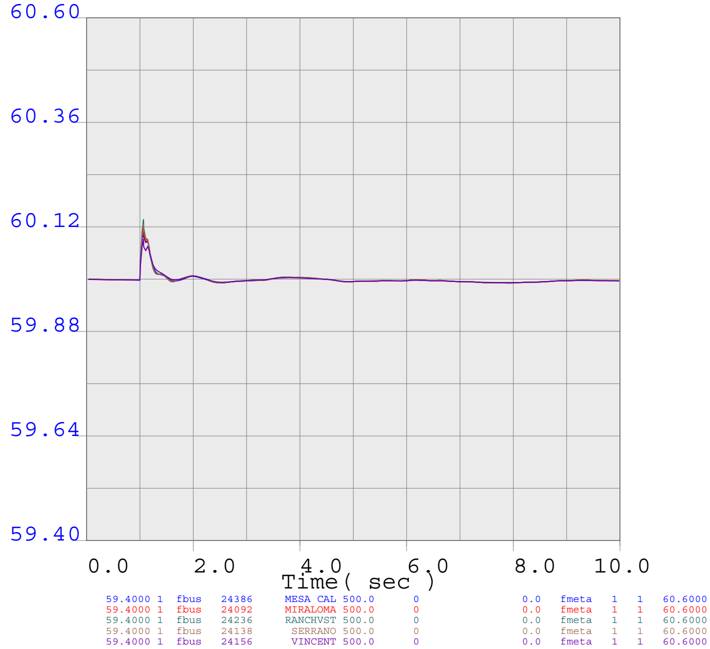


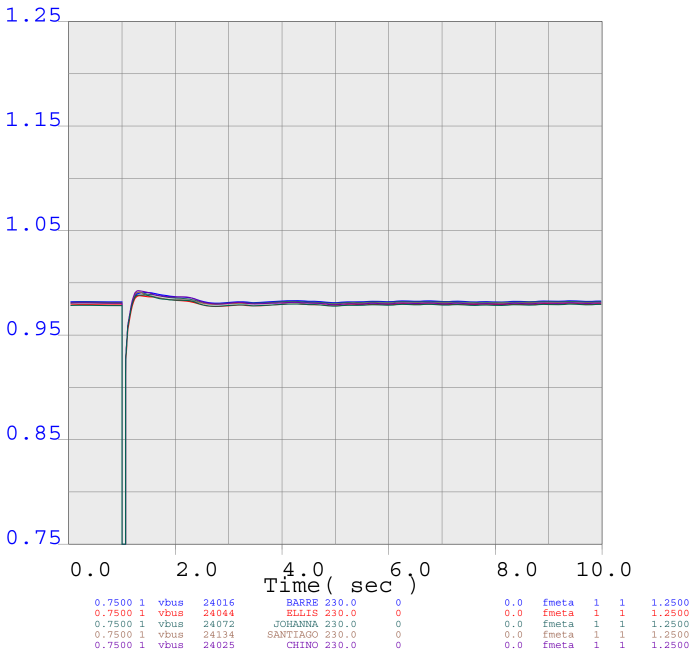
tran_1322
Tran SERRANO 500.00 to SERRANO 230.00 Circuit 2SERRAN2T 13.80
1 MW dispatch Case

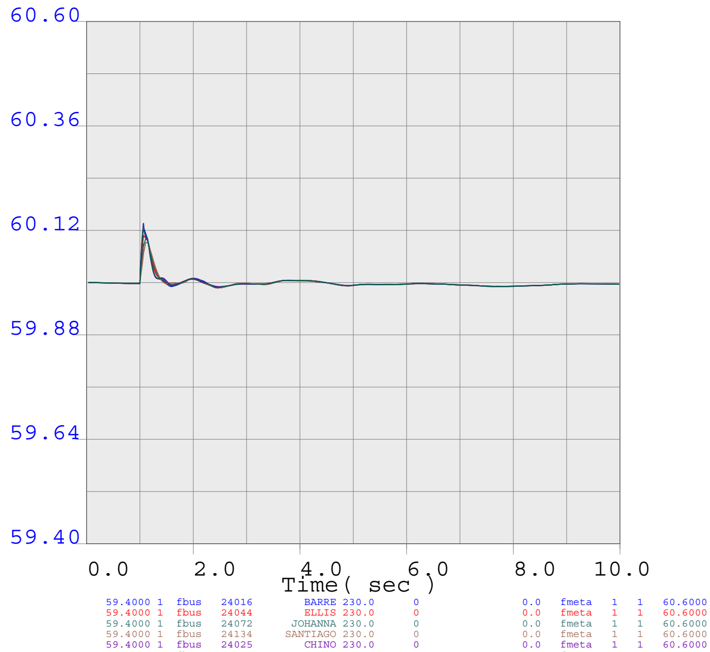
	qc9p-tran_1322.chf	C:\DYTOOLS Thu Oct 20 09:05:53 2016

METRO









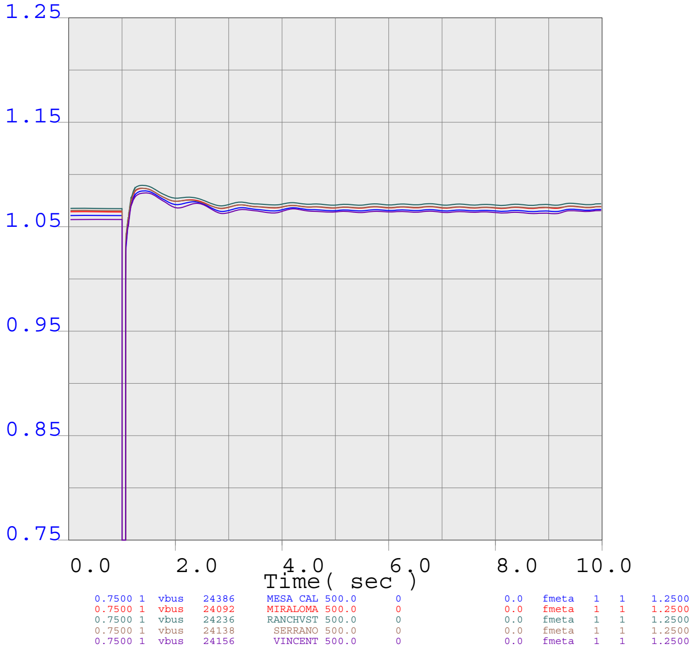
tran_1323
Tran SERRANO 500.00 to SERRANO 230.00 Circuit 3 0.00
1 MW dispatch Case

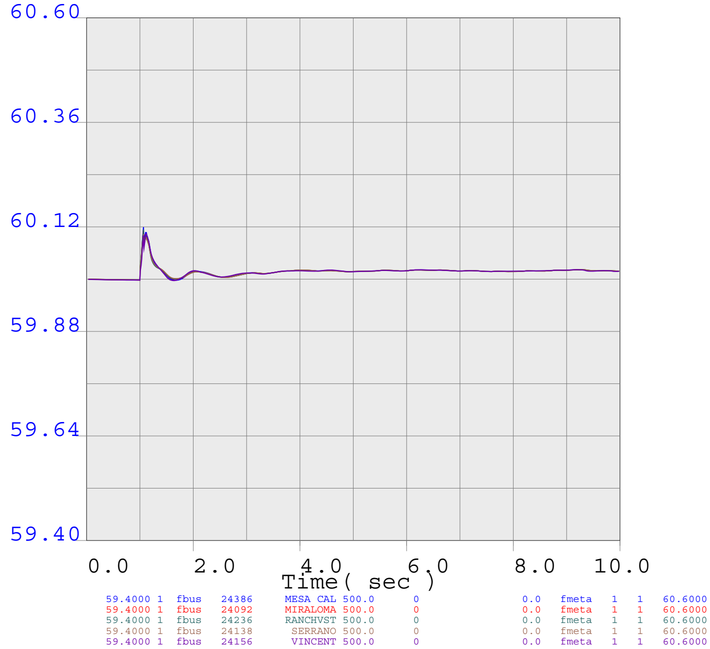
qc9p-tran_1323.chf

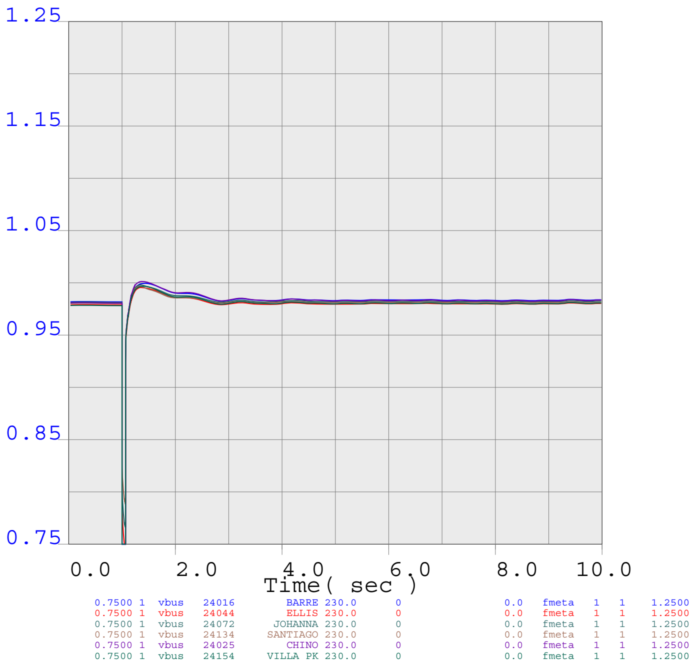
C:\DYTOOLS

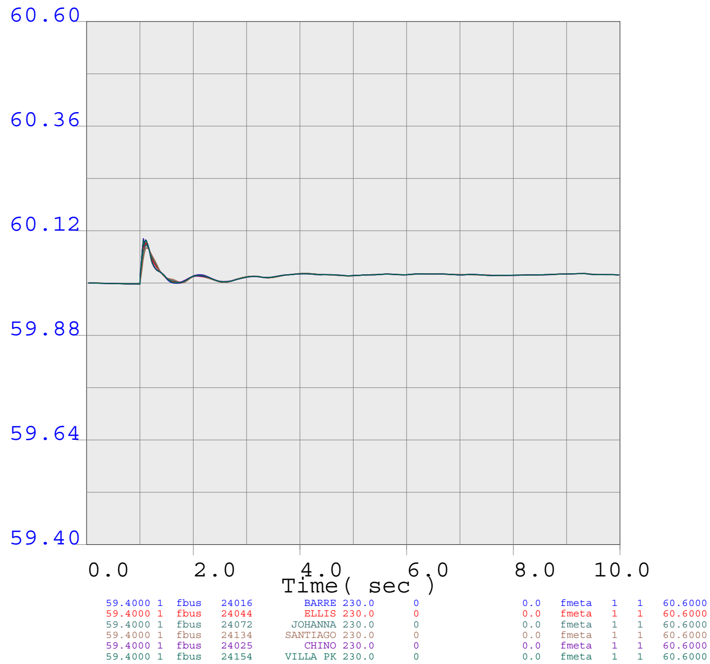
Thu Oct 20 09:05:55 2016

METRO









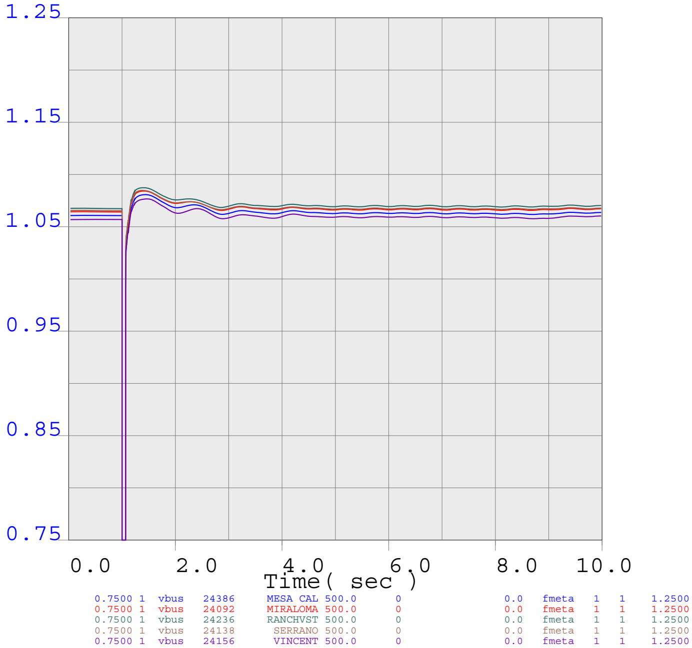
tran_1324
Tran VINCENT 500.00 to VINCENT 230.00 Circuit 2VINCEN2T 13.80
1 MW dispatch Case

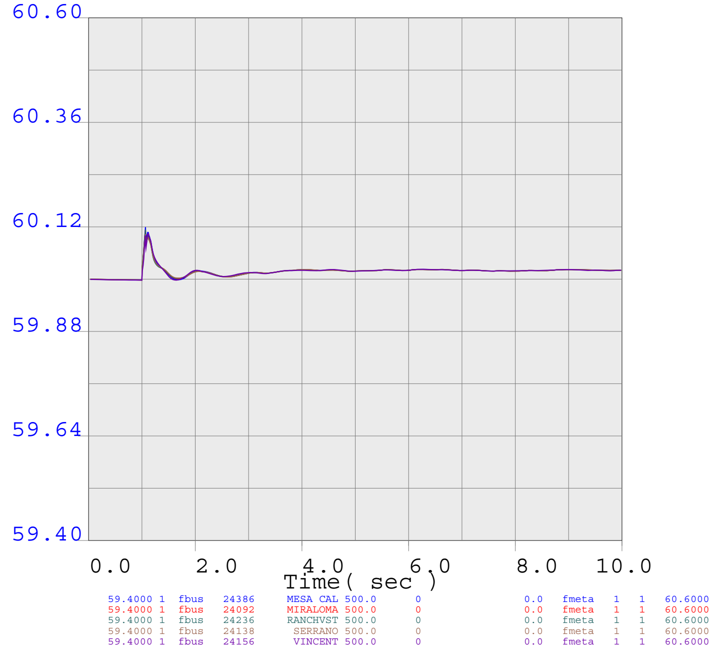
qc9p-tran_1324.chf

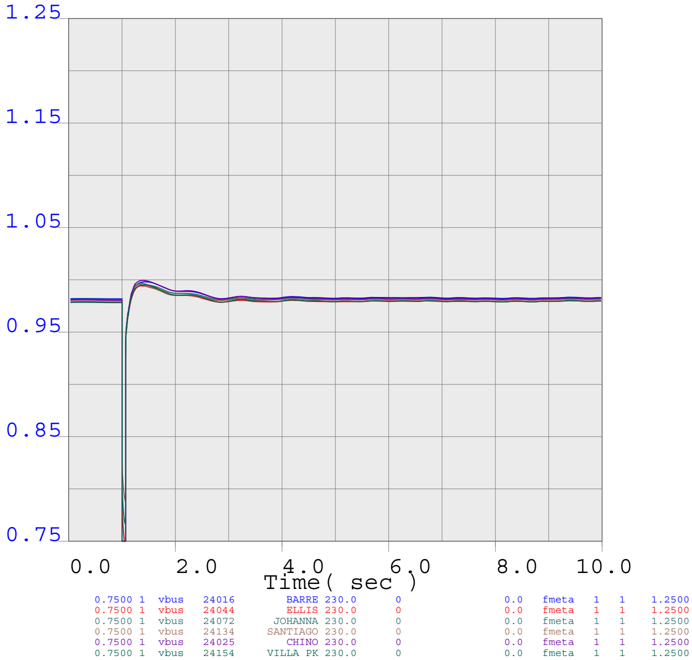
C:\DYTOOLS

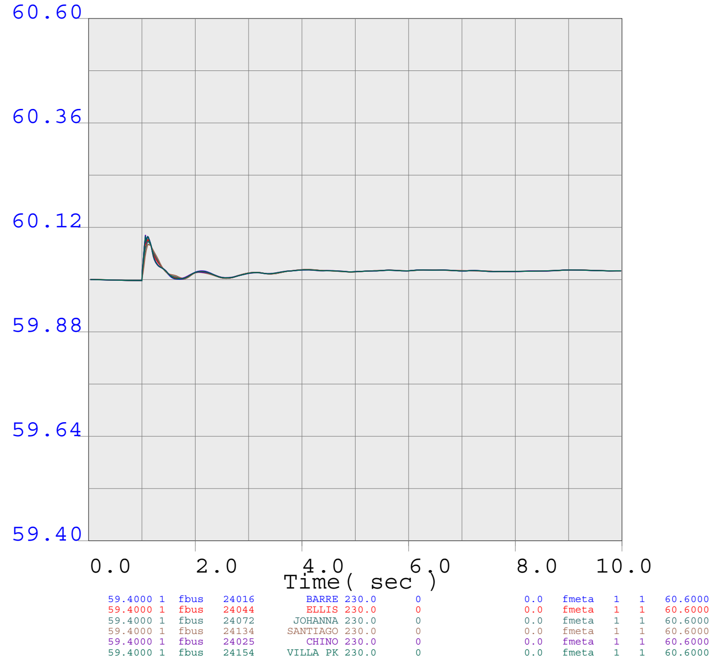
Thu Oct 20 09:05:57 2016

METRO









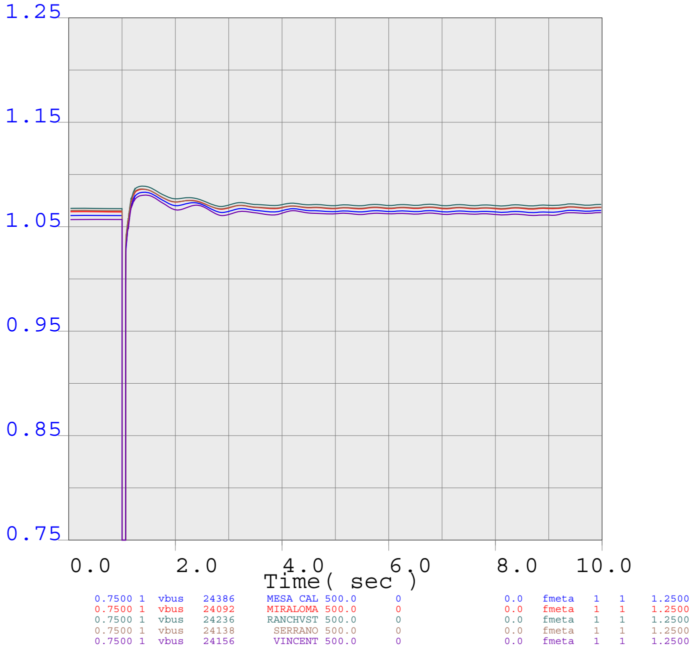
tran_1325
Tran VINCENT 500.00 to VINCENT 230.00 Circuit 3 0.00
1 MW dispatch Case

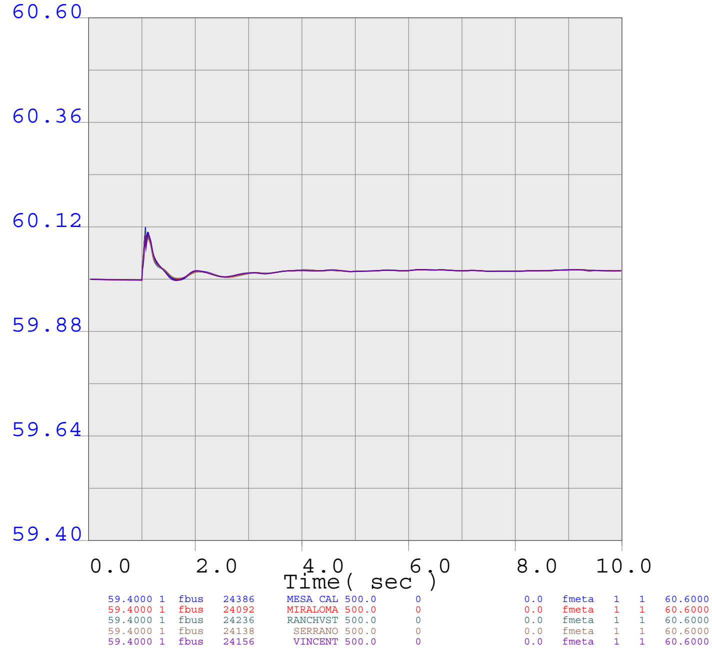
qc9p-tran_1325.chf

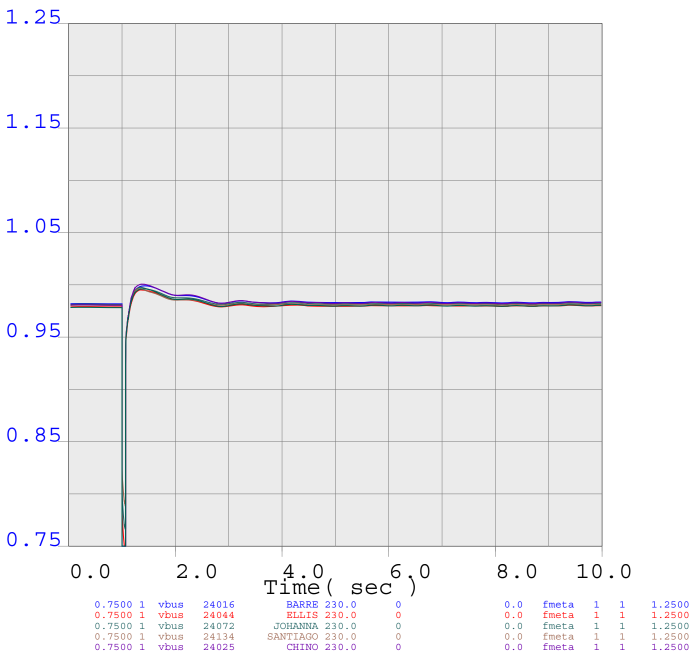
C:\DYTOOLS

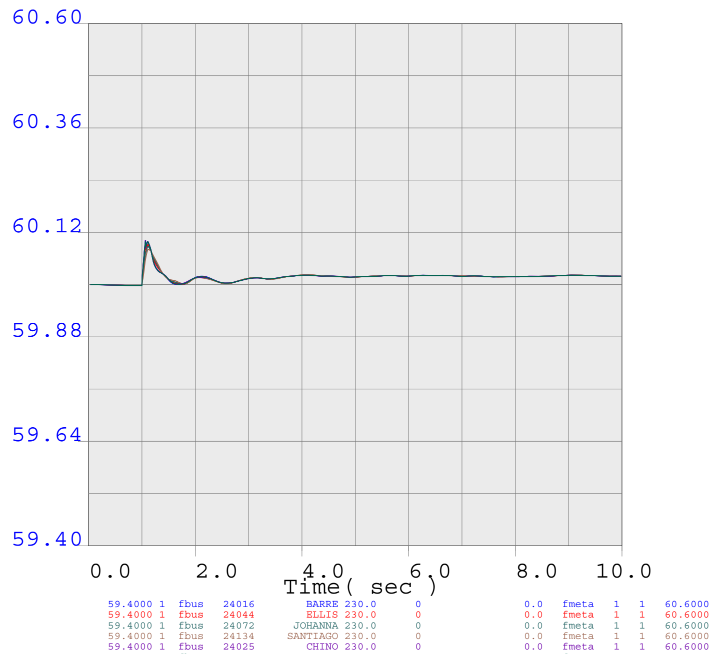
Thu Oct 20 09:05:59 2016

METRO









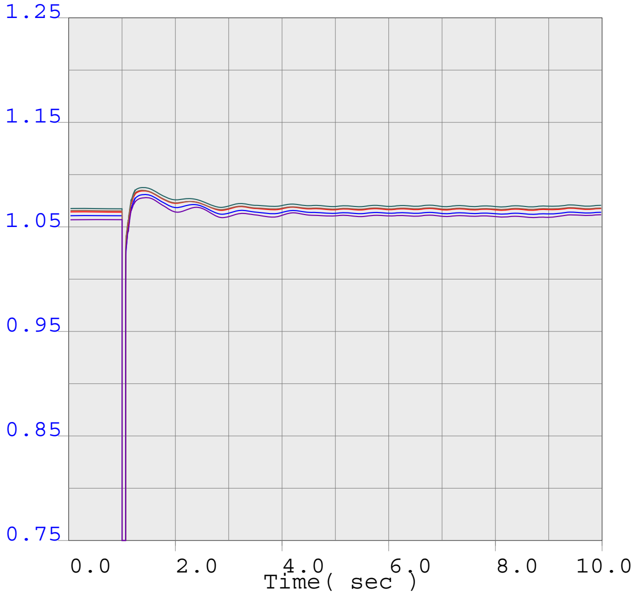
tran_1326
Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 1VINCEN1T 13.80
1 MW dispatch Case

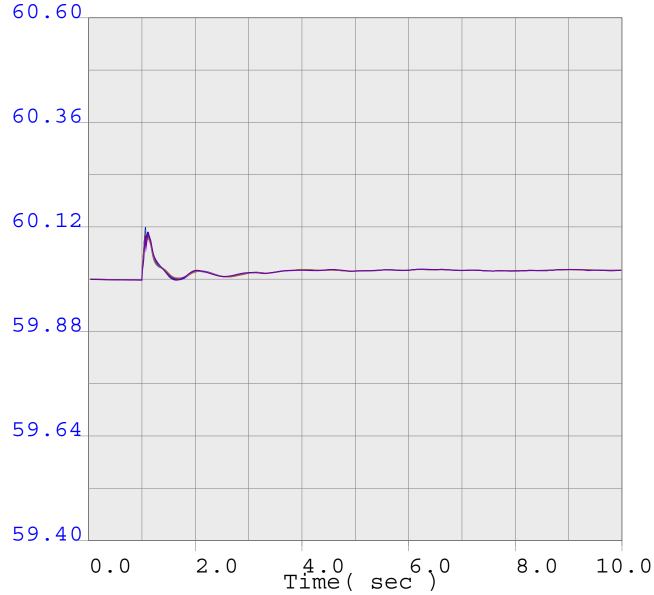
qc9p-tran_1326.chf

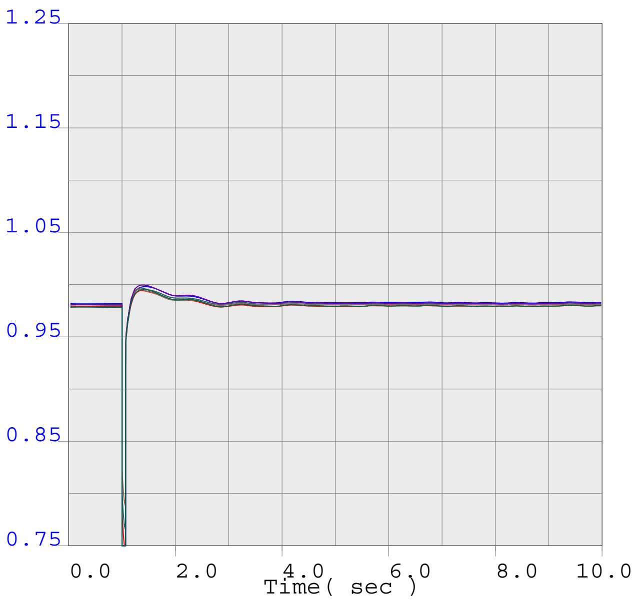
C:\DYTOOLS

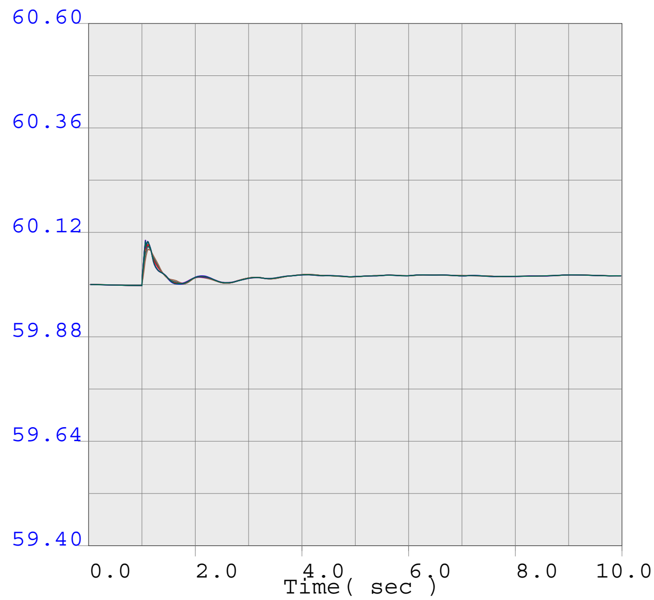
Thu Oct 20 09:06:01 2016

METRO









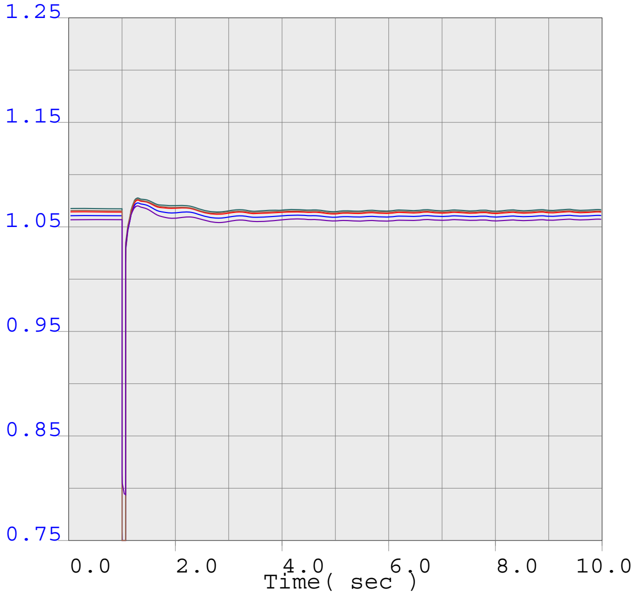
tran_1327
Tran VINCENT 500.00 to VINCNT2 230.00 Circuit 4VINCEN4T 13.80
1 MW dispatch Case

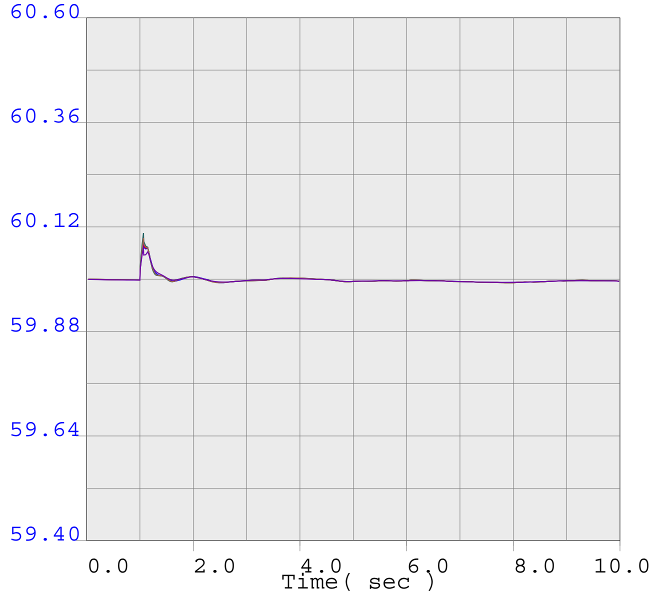
qc9p-tran_1327.chf

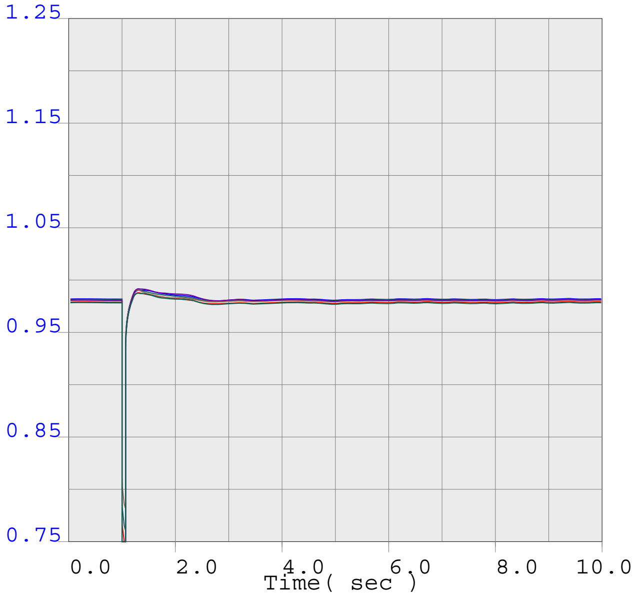
C:\DYTOOLS

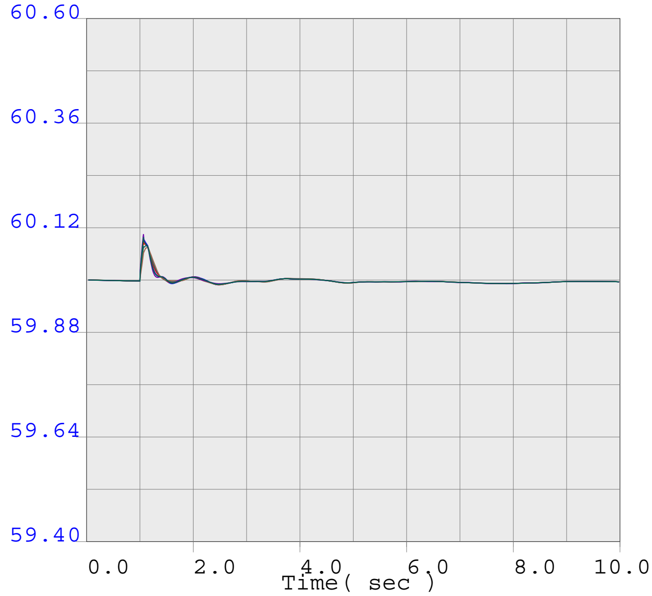
Thu Oct 20 09:06:03 2016

METRO









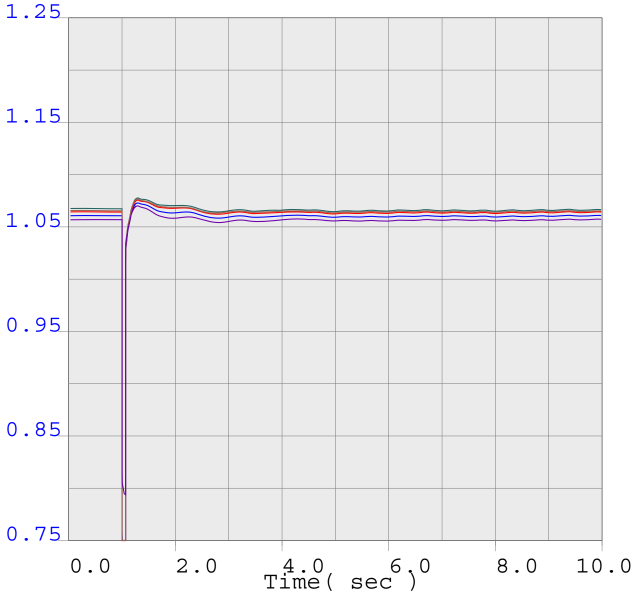
tran_1328
Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 3RCHVST3T 13.80
1 MW dispatch Case

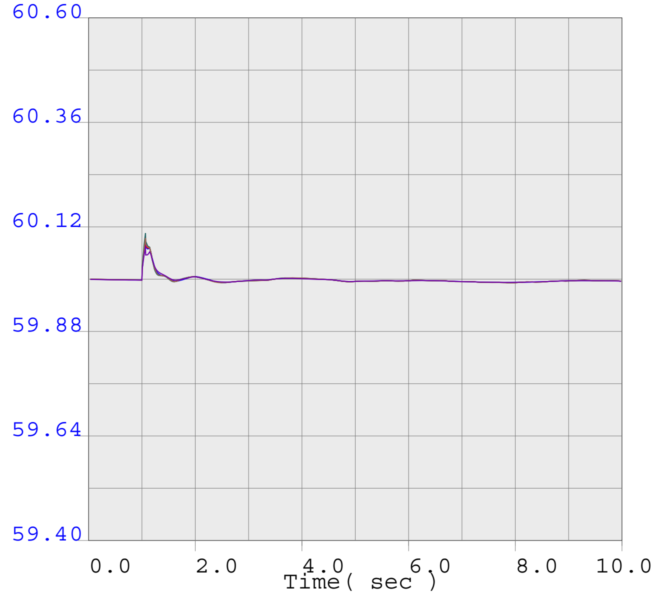
qc9p-tran_1328.chf

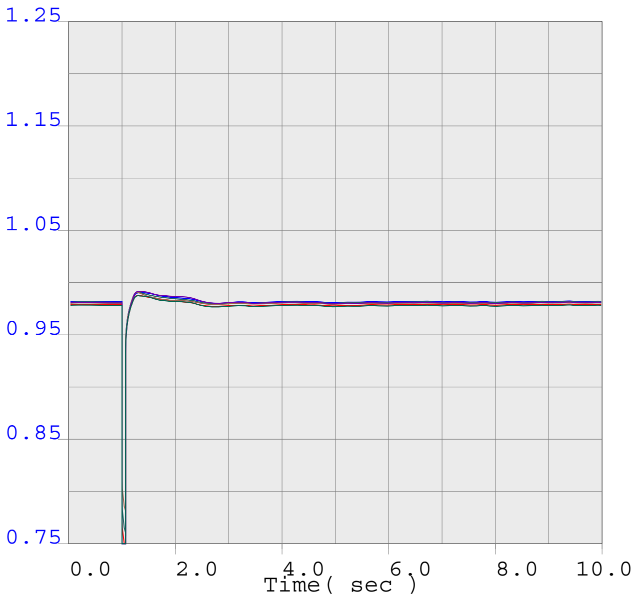
C:\DYTOOLS

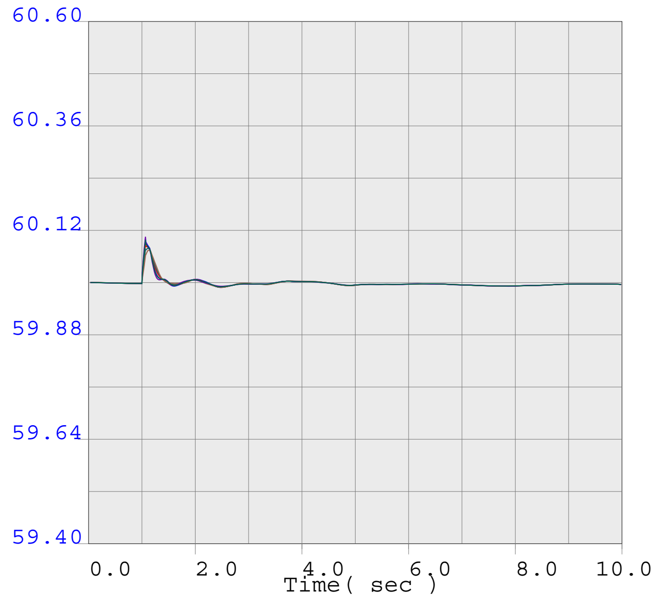
Thu Oct 20 09:06:05 2016

METRO





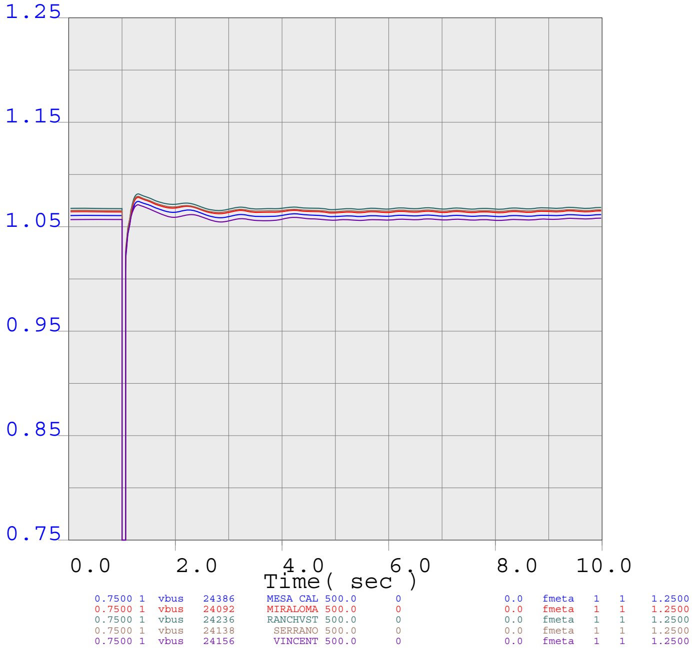


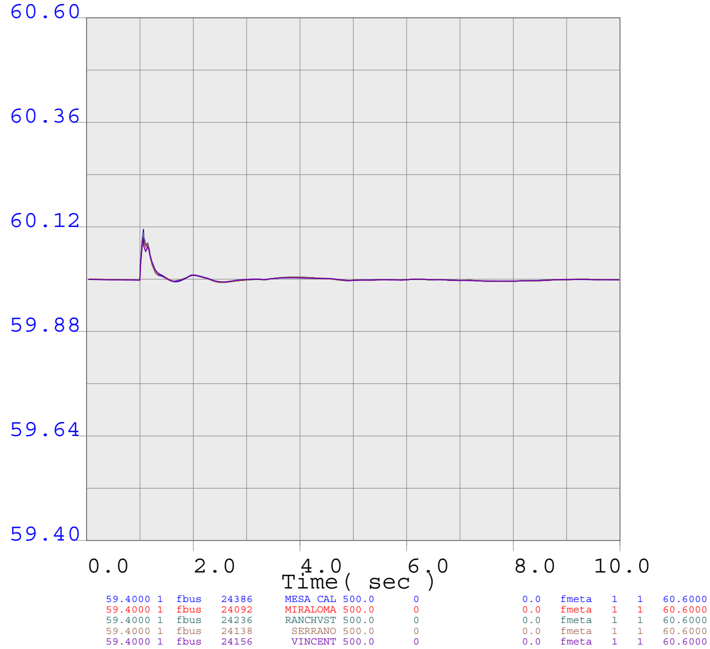


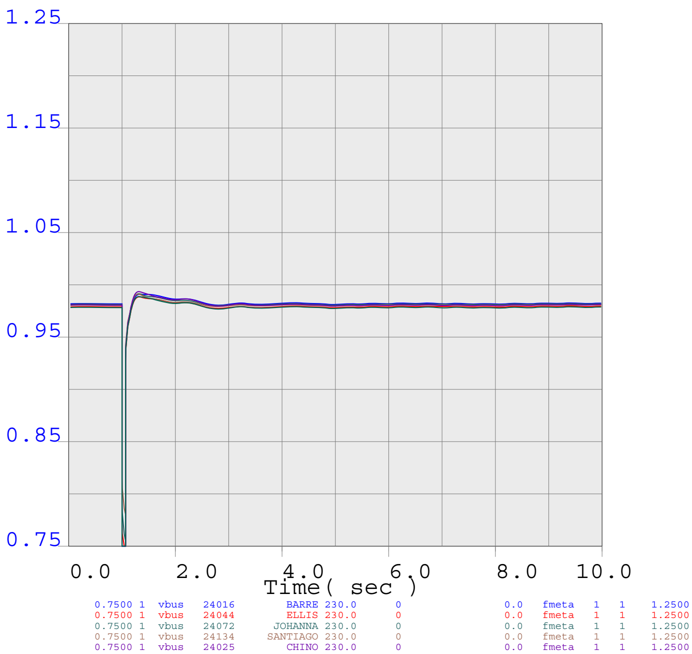
tran_1329
Tran RANCHVST 500.00 to RANCHVST 230.00 Circuit 4RCHVST4T 13.80
1 MW dispatch Case

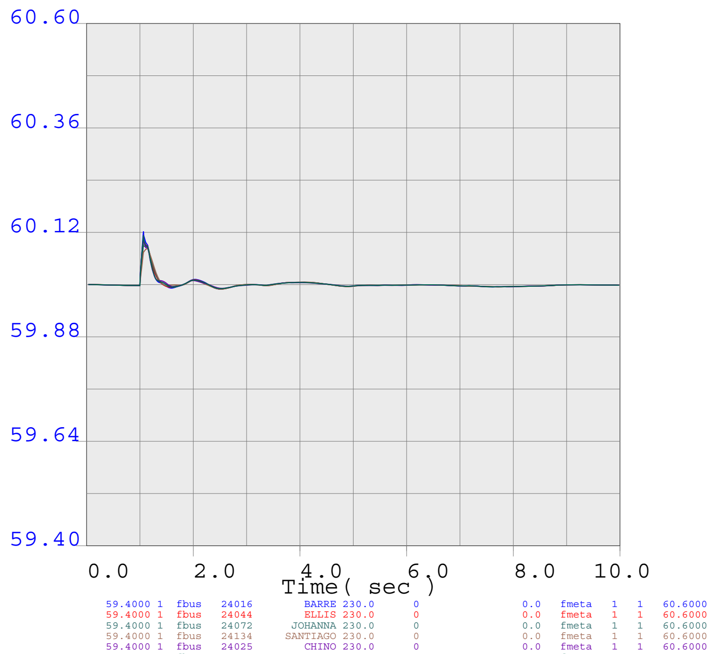
	qc9p-tran_1329.chf	C:\DYTOOLS Thu Oct 20 09:06:07 2016

METRO









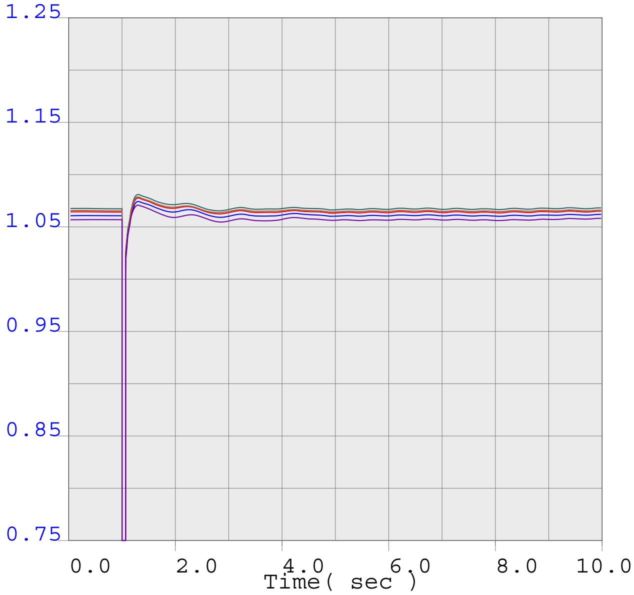
tran_1330
Tran MESA CAL 500.00 to MESA CAL 230.00 Circuit 2MESA2T 13.80
1 MW dispatch Case

qc9p-tran_1330.chf

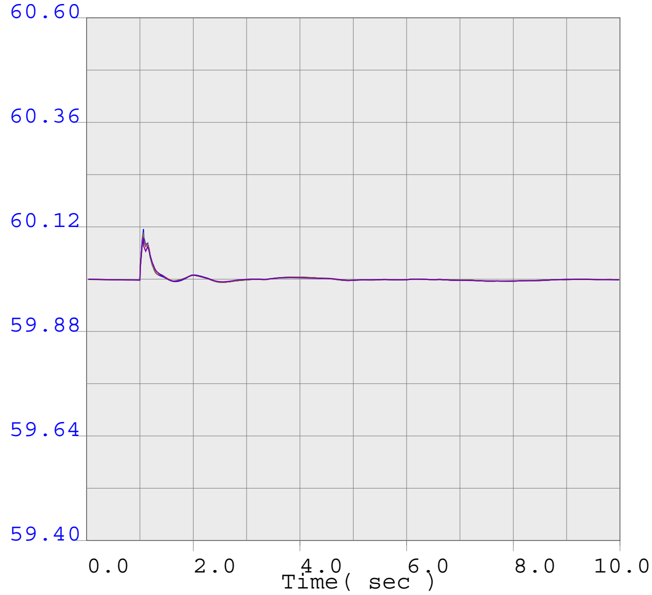
C:\DYTOOLS

Thu Oct 20 09:06:09 2016

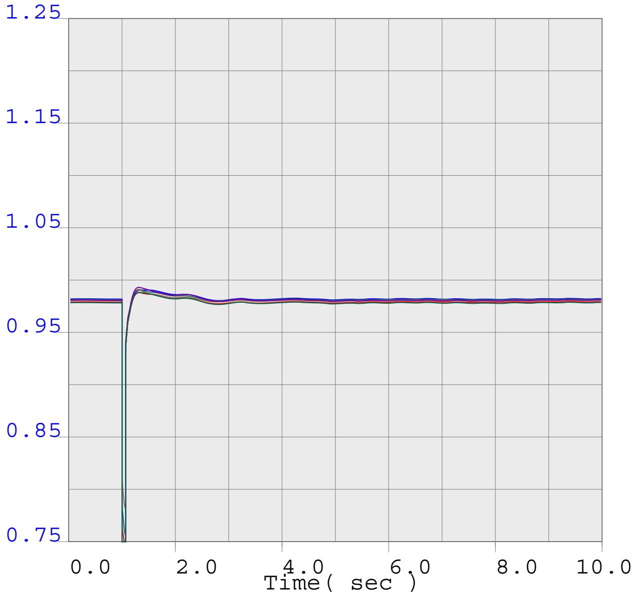
METRO



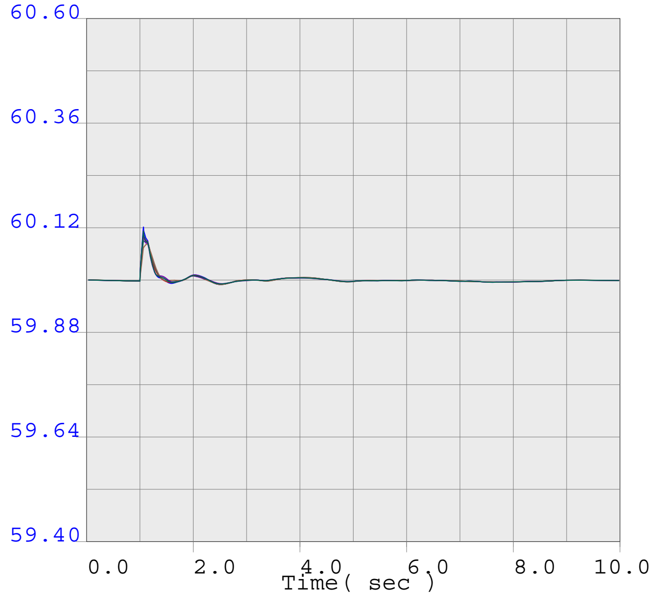
0.7500	1	vbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24386	MESA CAL	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24092	MIRALOMA	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24236	RANCHVST	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24138	SERRANO	500.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24156	VINCENT	500.0	0	0.0	fmeta	1	1	60.6000



0.7500	1	vbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	1.2500
0.7500	1	vbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	1.2500



59.4000	1	fbus	24016	BARRE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24044	ELLIS	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24072	JOHANNA	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24134	SANTIAGO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24025	CHINO	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	24154	VILLA PK	230.0	0	0.0	fmeta	1	1	60.6000

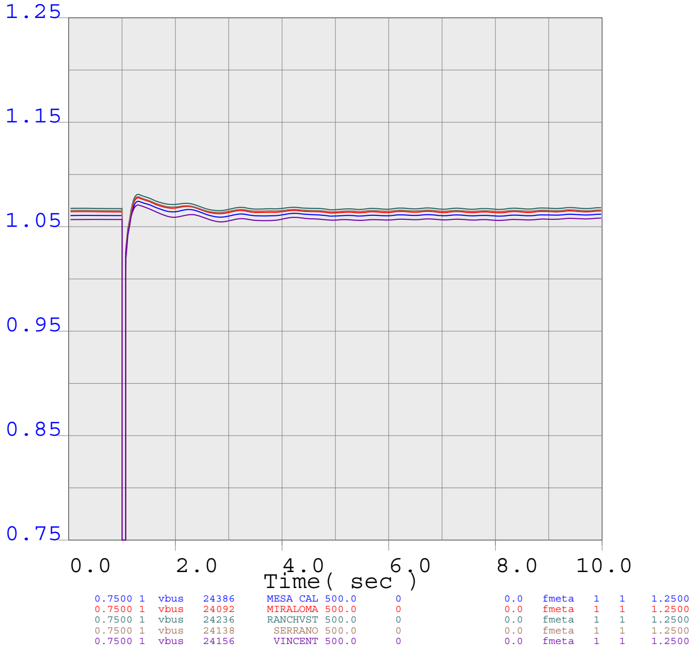
tran_1331
Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 3MESA3T 13.80
1 MW dispatch Case

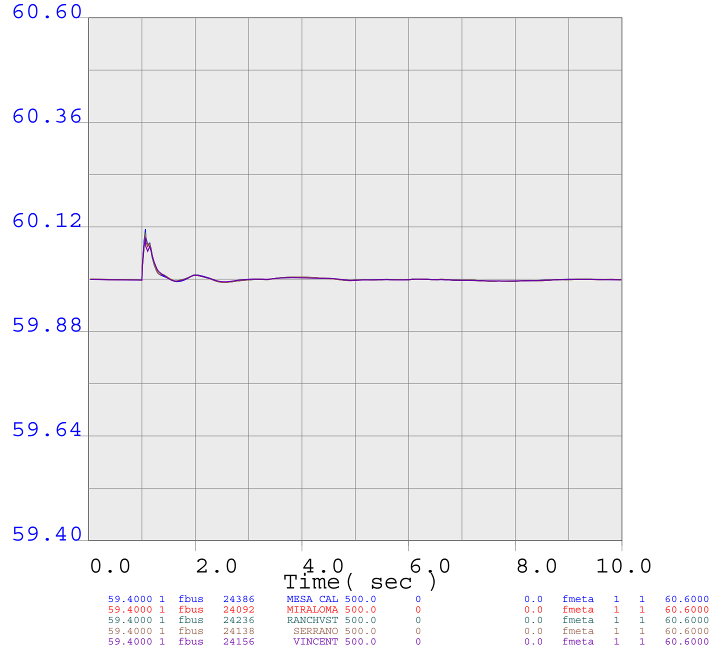
qc9p-tran_1331.chf

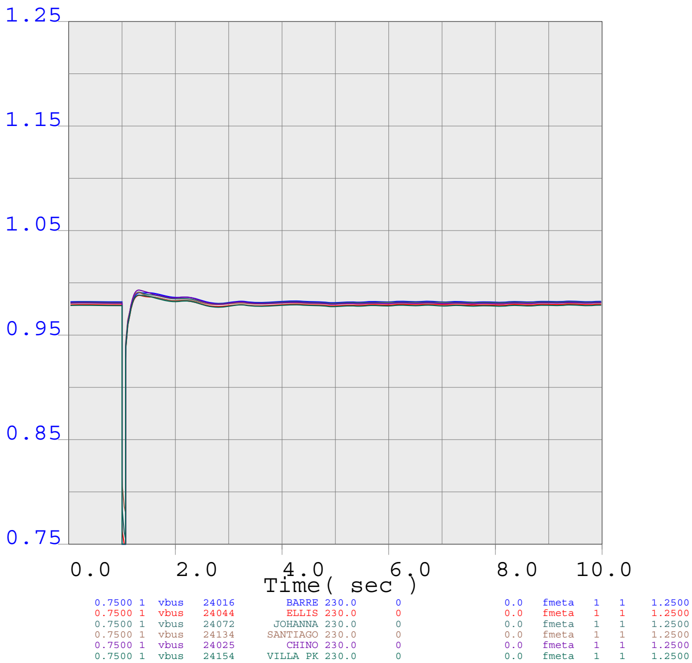
C:\DYTOOLS

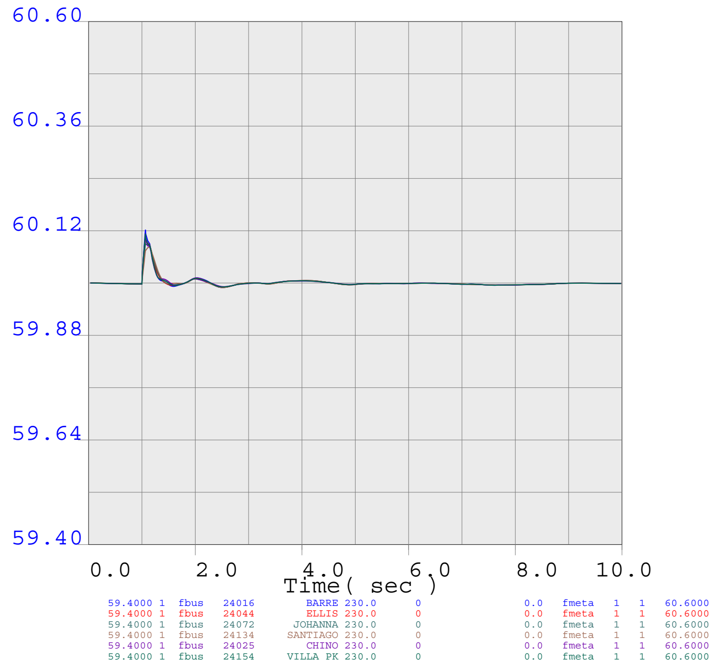
Thu Oct 20 09:06:12 2016

METRO









tran_1332
Tran MESA CAL 500.00 to MESACALS 230.00 Circuit 4MESA4T 13.80
1 MW dispatch Case

qc9p-tran_1332.chf

C:\DYTOOLS

Thu Oct 20 09:06:13 2016

QUEUE CLUSTER 9 PHASE I

Appendix H – Short Circuit Duty Calculation Study Results

Table H.1: Three – Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	22.3	38.5	22.8	41.5	3.0
Colorado River	525	23.8	27.0	23.9	27.3	0.3
Eldorado	525	13.2	57.2	13.5	62.8	5.6
Lugo	525	19.3	53.8	18.4	59.4	5.6
Mesa	525	24.1	29.0	23.3	34.9	5.9
Mira Loma	525	22.9	41.5	22.6	43.5	2.0
Red Bluff	525	22.4	24.3	22.6	24.7	0.4
Serrano	525	24.3	36.1	24.2	37.0	0.9
Valley A	525	25.2	25.9	25.2	26.1	0.2
Valley B	525	25.2	25.9	25.2	26.1	0.2
Vincent	525	19.8	51.1	20.1	56.2	5.1
Whirlwind	525	22.5	35.9	23.1	39.2	3.3
Alamitos B	230	14.1	29.1	14.0	29.3	0.2
Antelope	230	27.4	43.4	28.0	44.8	1.4
Barre	230	20.7	63.2	20.9	64.8	1.6
Calcite	230	13.7	9.9	15.3	16.1	6.2
Center	230	14.4	42.4	14.4	43.1	0.7
Chino	230	15.9	52.2	15.8	53.0	0.8
Colorado River	230	37.3	44.5	37.5	45.0	0.5
Del Amo	230	15.9	47.9	15.8	48.5	0.6
Devers	230	25.2	50.3	25.6	51.9	1.6
El Casco	230	18.4	17.7	18.4	18.2	0.5
Eldorado	230	17.3	58.4	17.4	59.5	1.1
Eldorado_2	230	16.7	28.9	25.9	44.9	16.0
Ellis	230	16.5	45.3	16.4	46.0	0.7
Etiwanda	230	26.6	60.7	26.5	61.6	0.9
Highwind	230	21.3	16.6	22.0	18.4	1.8
Huntington Beach A	230	15.8	39.1	15.8	39.5	0.4
Huntington Beach B	230	15.8	39.1	15.8	39.5	0.4
Ivanpah	230	19.9	12.8	21.2	14.1	1.3
Kramer	230	16.0	20.2	18.3	35.4	15.2
Laguna Bell	230	16.8	55.6	16.9	56.7	1.1
Lewis	230	20.6	52.2	20.6	53.1	0.9
Lighthipe	230	16.7	42.8	16.7	42.9	0.1
Lugo	230	28.9	42.7	27.1	45.7	3.0
Mandalay	230	13.2	17.0	13.6	18.3	1.3
Mesa_2	230	18.7	59.7	19.2	62.6	2.9
Mira Loma A	230	19.7	55.2	19.7	56.1	0.9
Mira Loma B	230	21.9	61.8	21.8	62.9	1.1
Moorpark	230	19.9	35.6	19.6	36.5	0.9
Ormond Beach	230	32.0	31.8	31.5	32.2	0.4
Pardee	230	15.5	59.9	15.4	61.2	1.3
Pastoria	230	13.4	31.1	13.4	31.7	0.6
Primm	230	19.0	12.3	20.3	13.6	1.3
Rancho Vista	230	26.5	61.9	26.5	62.8	0.9

Red Bluff	230	41.8	30.1	41.6	31.1	1.0
Rio Hondo	230	15.8	33.1	15.8	33.7	0.6
San Bernardino	230	24.8	41.8	24.6	42.3	0.5
Sandlot	230	16.9	13.1	15.7	16.6	3.5
Santa Clara	230	12.3	22.7	13.2	25.5	2.8
Santiago	230	17.4	31.8	17.5	32.1	0.3
Serrano	230	25.7	62.7	25.8	63.8	1.1
Sylmar (SCE)	230	15.2	62.7	15.2	64.2	1.5
Victor	230	18.3	34.0	16.9	36.2	2.2
Villa Park	230	24.0	54.1	24.0	55.0	0.9
Vista	230	20.5	49.7	20.4	50.2	0.5
Devers	115	43.7	28.5	44.1	28.6	0.1
Ivanpah	115	27.5	18.2	28.6	18.7	0.5
Kramer	115	13.8	25.0	17.9	26.4	1.4
Terrawind	115	15.9	23.0	15.9	23.1	0.1
Victor	115	23.0	25.0	22.7	25.6	0.6
Antelope	66	30.9	37.5	29.6	40.3	2.8
Apollo	66	11.7	9.3	10.9	12.6	3.3
Barre C	66	52.5	14.9	55.8	21.7	6.8
Barre C	66	60.9	14.9	55.8	21.7	6.8
Bolsa	66	9.0	8.5	9.3	12.1	3.6
Cabrillo	66	12.3	20.1	12.1	20.7	0.6
Cal Cement	66	18.4	19.7	18.3	19.9	0.2
Camden	66	12.7	20.5	12.6	21.1	0.6
Chestnut	66	13.6	19.9	13.6	20.6	0.7
Columbine	66	5.7	9.2	5.7	9.3	0.1
Del Sur	66	8.9	21.9	8.5	22.9	1.0
Delano	66	5.3	11.2	5.3	11.4	0.2
Earlimart	66	5.0	7.8	5.0	7.9	0.1
Fairview	66	13.5	22.5	13.3	23.2	0.7
Goleta	66	15.9	16.2	16.0	16.4	0.2
Great Lakes	66	2.9	6.2	2.9	6.3	0.1
Growers	66	9.1	12.2	9.2	12.5	0.3
Johanna	66	38.8	29.1	39.8	30.3	1.2
Mariposa	66	5.0	8.7	5.0	8.8	0.1
Moorpark_A	66	47.9	22.1	48.1	22.4	0.3
OASIS	66	5.8	10.4	5.7	10.6	0.2
Oceanview	66	7.2	8.0	6.7	10.5	2.5
Poplar	66	2.7	4.0	2.9	4.3	0.3
Quartz Hill	66	9.7	19.0	9.4	19.7	0.7
Rector	66	12.0	21.7	12.2	22.1	0.4
Ritter Ranch	66	7.5	12.3	7.3	12.7	0.4
Rosamond	66	3.7	8.8	3.7	9.2	0.4
Santa Clara	66	16.0	36.3	16.9	37.5	1.2
Shawnee	66	16.6	10.8	14.6	14.6	3.8
Team	66	9.5	8.3	8.4	10.6	2.3
Terra Bella	66	2.8	4.3	2.9	4.5	0.2
Trask	66	20.8	12.0	17.4	16.6	4.6

Vestal	66	13.7	21.1	14.8	22.2	1.1
VillaPark A	66	43.9	33.6	44.1	33.8	0.2
VillaPark B	66	43.9	33.6	44.1	33.8	0.2
Wheatland	66	4.7	7.5	4.7	7.6	0.1
Windhub66_A	66	48.6	26.8	49.2	27.1	0.3
Windhub66_B	66	48.6	26.8	49.2	27.1	0.3

Table H.2: Single – Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	18.0	32.7	17.7	34.9	2.2
Eldorado	525	10.8	45.8	11.4	52.0	6.2
Lugo	525	10.6	39.7	11.5	43.8	4.1
Mesa	525	12.8	24.9	12.4	29.2	4.3
Mira Loma	525	10.1	35.3	9.9	36.5	1.2
Red Bluff	525	15.0	22.0	15.1	22.2	0.2
Serrano	525	12.2	31.1	12.1	31.5	0.4
Valley A	525	13.6	25.8	13.5	26.0	0.2
Valley B	525	13.6	25.8	13.5	26.0	0.2
Vincent	525	13.9	40.8	14.3	46.0	5.2
Whirlwind	525	17.4	32.4	18.3	36.6	4.2
Antelope	230	26.4	48.4	26.8	49.7	1.3
Barre	230	13.2	48.1	13.2	48.8	0.7
Calcite	230	13.4	10.4	13.8	16.0	5.6
Colorado River	230	23.1	51.8	23.2	52.3	0.5
Cool Water	230	26.0	12.7	21.9	19.8	7.1
Del Amo	230	10.7	43.3	10.7	43.7	0.4
Devers	230	21.9	53.0	22.4	56.1	3.1
El Casco	230	12.6	12.6	14.0	14.5	1.9
Eldorado	230	15.7	54.3	16.0	55.6	1.3
Eldorado_2	230	17.9	31.0	24.7	49.9	18.9
Ellis	230	16.9	39.7	16.9	40.1	0.4
Etiwanda	230	18.5	61.3	18.4	62.0	0.7
Highwind	230	9.7	10.7	15.2	15.8	5.1
Huntington Beach A	230	18.7	33.6	18.7	33.8	0.2
Huntington Beach B	230	18.7	33.6	18.7	33.8	0.2
Ivanpah	230	12.1	12.9	12.1	13.8	0.9
Kramer	230	11.3	19.3	17.2	38.4	19.1
Lewis	230	14.9	46.9	14.9	47.3	0.4
Lugo	230	18.2	43.1	18.2	45.7	2.6
Mandalay	230	16.3	15.7	16.3	16.5	0.8
Mesa	230	13.1	50.3	14.1	51.4	1.1
Mesa_2	230	11.3	60.2	11.8	63.1	2.9
Mira Loma A	230	11.9	55.4	11.9	56.1	0.7
Mira Loma B	230	9.6	55.6	9.5	56.2	0.6
Moorpark	230	23.8	30.3	23.6	30.8	0.5
Pardee	230	14.3	45.4	14.2	45.9	0.5
Pastoria	230	14.4	32.8	14.4	33.7	0.9
Primm	230	12.7	12.7	12.7	13.7	1.0
Rancho Vista	230	18.3	63.2	18.2	63.9	0.7
Red Bluff	230	29.9	35.5	29.7	36.4	0.9
San Bernardino	230	24.4	41.7	24.1	42.1	0.4
Sandlot	230	10.4	12.5	10.4	15.6	3.1
Santa Clara	230	14.6	21.7	14.7	24.6	2.9
Santiago	230	17.5	32.1	17.5	32.3	0.2

Serrano	230	17.8	63.4	17.7	64.2	0.8
Sylmar (SCE)	230	12.5	68.4	12.5	69.6	1.2
Victor	230	6.5	27.1	6.3	28.3	1.2
Villa Park	230	16.7	46.5	16.7	46.9	0.4
Vincent A	230	17.0	67.5	17.4	68.5	1.0
Vincent B	230	17.0	67.5	17.4	68.5	1.0
Vista	230	16.0	44.6	15.9	44.9	0.3
Windhub_B	230	40.5	35.0	39.5	38.7	3.7
Cool Water	115	10.3	9.5	12.2	12.7	3.2
Devers	115	36.6	32.4	37.2	32.6	0.2
Ivanpah	115	23.5	20.9	24.1	21.4	0.5
Kramer	115	13.3	25.6	17.2	28.0	2.4
Terawind	115	12.0	21.1	15.9	23.1	2.0
Victor	115	17.8	27.9	17.6	28.4	0.5
Antelope	66	23.1	23.9	21.7	25.5	1.6
Apollo	66	10.2	7.8	9.4	9.9	2.1
Barre C	66	39.8	15.6	32.2	23.2	7.6
Barre C	66	39.8	15.6	34.8	24.2	8.6
Bolsa	66	9.4	8.3	9.8	11.5	3.2
Cabrillo	66	10.0	11.5	9.3	12.8	1.3
Camden	66	8.6	11.9	8.7	13.4	1.5
Chestnut	66	9.6	10.9	11.0	13.9	3.0
Fairview	66	12.3	13.6	11.6	15.4	1.8
Great Lakes	66	4.1	3.4	4.1	3.8	0.4
Growers	66	10.7	10.8	10.8	11.0	0.2
Johanna	66	29.5	19.2	29.3	23.0	3.8
Moorpark_A	66	38.0	21.0	37.9	21.4	0.4
Oceanview	66	6.9	6.5	6.4	7.9	1.4
Poplar	66	3.9	3.5	3.6	3.9	0.4
Rector	66	13.1	22.5	13.2	22.8	0.3
Santa Clara	66	16.2	25.5	16.6	25.9	0.4
Shawnee	66	12.7	9.1	11.0	11.7	2.6
Team	66	7.8	6.5	7.0	7.8	1.3
Terra Bella	66	3.8	3.7	3.7	4.5	0.8
Trask	66	16.6	11.4	13.5	15.3	3.9
Vestal	66	13.0	16.5	13.2	17.0	0.5
Windhub66_A	66	24.9	20.5	24.9	20.7	0.2
Windhub66_B	66	24.9	20.5	24.9	20.7	0.2

QUEUE CLUSTER 9 PHASE I

Appendix K - Environmental Evaluation, Permitting, and Licensing

Appendix K
Environmental Evaluation and Permitting/Licensing Requirements for Generation Interconnection Projects
Prepared by ES/RP&A/Law/MPO on October 10, 2013
Updated by ES on July 7, 2016

The Interconnection Customer may be required to complete environmental impact studies and obtain permits for the construction, operation, and maintenance of the Generating Facility and Interconnection Customer's Interconnection Facilities. Such activities would be the responsibility of the Interconnection Customer.

SCE may also be required to complete environmental studies and obtain permits/licenses for the construction, operation, and maintenance of its facilities, including its Interconnection Facilities and Upgrades. SCE implements procedures to ensure compliance with all applicable federal and state laws and regulations. Depending on the project, SCE's activities may be subject to the jurisdiction of several agencies, such as the California Public Utilities Commission (CPUC), California Department of Fish and Wildlife, U.S. Fish and Wildlife Service, State Water Resources Control Board or Regional Water Quality Control Board, U.S. Army Corps of Engineers, California Coastal Commission, Bureau of Land Management, and U.S. Forest Service.

As both SCE and the Interconnection Customer may be subject to similar requirements for performing environmental studies, it may be beneficial to combine portions of the environmental study processes. For this reason, SCE incorporated assumptions into this Cluster Study that the Interconnection Customer would include SCE's Interconnection Facilities, Distribution Upgrades, and certain Network Upgrades within the scope of its environmental study reports, submitted to the lead agency permitting the Generating Facility and the Interconnection Customer's Interconnection Facilities. However, close coordination with SCE during the study process would be needed to ensure the final study/report/product meets SCE environmental requirements.

I. CPUC Licensing Requirements Pursuant to General Order 131-D

As an electric public utility, SCE is regulated by the CPUC. The CPUC's General Order 131-D (GO 131-D) sets forth rules related to the planning and construction of electric generation, transmission, power, and distribution line facilities and substations located in California. The CPUC issued GO 131-D to be responsive to: the California Environmental Quality Act (CEQA); the need for public notice and the opportunity for affected parties to be heard by the Commission; and the obligations of the utilities to serve their customers in a timely and efficient manner.

Section III of GO 131-D specifies the type of authorization required for the construction of electric facilities to be constructed by electric public utilities subject to the CPUC's jurisdiction. The requirements for a Certificate of Public Convenience and Necessity (CPCN) apply to the construction of major electric transmission line facilities designed for immediate or eventual operation at 200 kV or more (Section III.A). The requirements for a Permit to Construct (PTC) apply to the construction of electric power line facilities designed for immediate or eventual operation at a voltage between 50 kV and 200 kV, or new or upgraded substations with high side voltage equal to or exceeding 50 kV (Section III.B). Sections III.A and III.B.1 provide exemptions from CPUC CPCN and PTC requirements when certain conditions exist. An application for a CPCN or PTC must include a Proponent's Environmental Assessment (PEA) or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and the CPUC's Rules of Practice and Procedure for the CPUC's review (Section IX). CEQA requires that the CPUC consider the environmental consequences before acting upon or approving a project for which SCE has filed an application for a PTC or CPCN; accordingly, construction cannot begin on such projects until the CPUC Commissioners issue a Decision to approve the project and certify the final CEQA document issued by the CPUC.

Generally, SCE takes approximately 18 to 24 months to assemble a CPCN or PTC application, the majority of which time is attributed to developing the PEA and performing related environmental surveys. The CPUC review of such applications may take an additional18 to 48 months depending on the specific issues.

For a copy of GO 131-D, please go to:

http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

A more detailed discussion of PTC and CPCN requirements and certain exemptions from such requirements are provided below:

A. Certificate of Public Convenience and Necessity (CPCN)

Section III.A of GO 131-D requires electric public utilities to obtain a CPCN from the CPUC for the construction of major electric transmission line facilities that are designed for immediate or eventual operation at 200 kV or more except for the following[1]:

- the replacement of existing power line facilities or supporting structures with equivalent facilities or structures,
- the minor relocation of existing power line facilities,
- the conversion of existing overhead lines to underground, or

[1] Note, unlike PTC exemptions discussed later in this document, which are enumerated with specific exemption classifications (e.g., Exemption f), GO 131-D does not enumerate CPCN exemptions in the same manner. Instead, CPCN exemptions are discussed in a lengthy sentence in Section III.A in which the GO states that CPCNs are required "except for" the situations discussed in the bullets above. SCE has bulletized these CPCN exemption references for the purposes of providing clarity in this document.

- the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.

1. "Expedited" CPCN[2]

Unlike the rules for PTCs described later in this document, there is no provision in GO 131-D that exempts from CPCN requirements major electric transmission facilities over 200 kV that have undergone environmental review pursuant to CEQA as part of a larger project. Accordingly, if major electric line facilities have already undergone environmental review pursuant to CEQA by the lead agency that permitted the Generating Facility and the Interconnection Customer's Interconnection Facilities, SCE would proceed under an "expedited" CPCN application by attaching the final CEQA document in lieu of a PEA. Based on past experience, SCE anticipates that an "expedited" CPCN typically may take from six to nine months for the CPUC to process.

B. Permit to Construct (PTC)

Section III.B of GO 131-D requires electric public utilities to obtain a PTC from the CPUC for the construction of electric power line facilities which are designed for immediate or eventual operation at any voltage between 50 kV and 200 kV, or new or upgraded substations with high side voltage equal to or exceeding 50 kV unless one of the listed exemptions under Section III.B.1 (exemptions a through h) applies. Note, though, that exemptions a through h shall not apply when any of the conditions specified in CEQA Guidelines §15300.2 regarding exceptions to categorical exemptions exist (Section III.B.2).

1. PTC Exemptions

Section III.B.1 of GO 131-D discusses the conditions under which certain projects may proceed exempt from PTC requirements. These include:

Exemption b[3].: The replacement of existing power line facilities or supporting structures with equivalent facilities or structures,

Exemption c.: The minor relocation of existing power line facilities up to 2,000 feet in length, or the intersetting of additional support structures between existing support structures,

---

[2] Note, the word "expedited" is not a defined term in GO 131-D. SCE uses this term when it files a CPCN (or PTC) application and anticipates that the CPUC will not be required to undergo separate CEQA review, and accordingly assumes the schedule for the CPUC's review may be "expedited" due the fact the CPUC would likely not have to conduct CEQA review of the application.

[3] PTC Exemption a. is no longer in use; it was a "grandfather" exemption used when GO 131-D was implemented in the mid-1990s to provide an exemption for projects that had an in-service date of January 1, 1996.

Exemption d.: The conversion of existing overhead lines to underground,

Exemption e.: The placing of new or additional conductors, insulators, or their accessories on supporting structures already built,

Exemption f.: Power lines or substations to be relocated or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (Environmental Impact Report (ElR) or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation,

Exemption g.: Power line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility easement; or in a utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, state, or local agencies for which a final Negative Declaration or EIR finds no significant unavoidable environmental impacts,

Exemption h.: The construction of projects that are statutorily or categorically exempt pursuant CEQA.

2. PTC Exemption f

As noted above, exemption f of GO 131-D (Section III.B.1.f), in particular, exempts the need for a PTC for power lines or substations to be relocated or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document finds no significant unavoidable environmental impacts caused by the proposed line or substation.

SCE may be eligible to use exemption f after the Interconnection Customer's lead agency approves a final CEQA document that finds no significant unavoidable environmental impacts caused by SCE's proposed scope of work. While, in some cases, other exemptions discussed above may be applicable, Exemption f is often the likely or preferred exemption to use when there is a larger project driving the SCE scope of work.

To use exemption f, SCE would follow certain noticing requirements, including filing an informational advice letter with the CPUC, posting a notice on-site and off-site at the project location, advertising once a week for two weeks successively in a local newspaper at least 45 days prior to construction, and providing notice to the director for each county or city in which the project would be located and the executive director of the California Energy Commission. As part of an agreement with the CPUC Energy Division, SCE would informally provide a copy of the final CEQA document to the CPUC Energy Division for reference when the advice letter is pending before the CPUC.

The CPUC rules for advice letters consider an advice letter to be in effect on the 30th calendar day after the filing date. Typically, SCE may proceed with construction 45 days after noticing and posting unless a protest is filed and/or the CPUC suspends the advice letter. If a protest is filed with the CPUC, the protestant must address whether SCE has properly claimed the exemption. SCE would have five business days to respond to the protest, and the CPUC would typically take a minimum of 30 days to review the protest and SCE's response. The CPUC would either dismiss the protest or require SCE to file an application for a PTC. Note that SCE would have no control over the time it takes the CPUC to respond when protests arise.

3. "Expedited" PTC[4]

For power lines or substations that have undergone environmental review pursuant to CEQA as part of a larger project but do not qualify for exemption f (final CEQA document finds significant unavoidable environmental impacts caused by the proposed line or substation), SCE may be able to file for an "expedited" PTC by attaching the larger project's final CEQA document to its application in lieu of a PEA. The schedule for the CPUC's review of such an "expedited PTC" could depend on many factors, including issues not resolved in the larger project's CEQA document and/or whether the CPUC would need to issue a Statement of Overriding Considerations. Although SCE assumes such review would not take as long as a "regular" PTC application, a schedule estimate would need to be provided on a case-by-case basis after consultation with the CPUC.

If construction does not qualify for an expedited PTC or an exemption to a PTC, SCE would likely be required to file a PTC application with a PEA. As discussed earlier in this document with respect to the timing for CPCN applications, SCE would typically take 18 – 24 months to develop the PTC application and PEA, and the CPUC's review of the PTC may take 18 – 48 months as the CPUC would need to conduct its own environmental review pursuant to CEQA by issuing an Initial Study and Negative Declaration/Mitigated Negative Declaration or Environmental Impact Report.

C. Projects on Federal Land

If an Interconnection Customer is seeking approvals for the Generating Facility and Interconnection Customer's Interconnection Facilities from only a federal agency and

[4] *ibid*

not from a state agency, the federal lead agency would generally prepare an environmental document pursuant to the National Environmental Policy Act (NEPA). Note that the provisions of GO 131-D do not allow for the use of exemption f, expedited PTC, or expedited CPCN when the environmental review is conducted only pursuant to NEPA and not to CEQA requirements. SCE may consult with the CPUC on a case-by-case basis to determine whether the CPUC would allow for the project to proceed exempt from CPUC permitting requirements or would expedite the PTC/CPCN application process if SCE were to submit the final NEPA document in lieu of a PEA.

D. Projects Not Subject to CPUC GO 131-D Permitting

Section III.C of GO 131-D does not require issuance of a CPCN or PTC from the CPUC for the construction of electric distribution (under 50 kV) line facilities, or substations with a high side voltage under 50 kV, or substation modification projects which increase the voltage of an existing substation to the voltage for which the substation has been previously rated within the existing substation boundaries. Note, though, that the construction of facilities under 50 kV may affect and require work on facilities over 50 kV.

In cases where permits are not required from the CPUC, SCE may be required to obtain permits from other regulatory agencies. For additional information, please see section III below (Permitting Requirements by Resource Agencies).

II. CPUC Approval Requirements Pursuant to Section 851

Since SCE is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other requirements, this code provision requires SCE to obtain CPUC approval of transfers of SCE property, including leases and rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application or advice letter can take several months, and requires compliance with CEQA. SCE recommends that Section 851 issues be identified as early as possible so that the necessary application or advice letter can be prepared and processed. As with GO 131-D compliance, SCE recommends that the project proponent include an analysis of any environmental impacts resulting from transfers of SCE property that may be subject to Section 851 in the lead agency’s CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

III. Permitting Requirements by Resource Agencies

For both projects that are subject to and projects that are not subject to CPUC permitting, SCE must ensure that requirements of all applicable environmental laws and regulations are addressed, necessary environmental surveys and studies are performed, and all required state and federal environmental permits are applied for and secured from various resource agencies before commencement of construction activities. Resource agencies such as California Department of Fish and Wildlife, U.S. Fish and Wildlife Service, State Water Resources Control

Board or Regional Water Quality Control Board, U.S. Army Corps of Engineers, California Coastal Commission, and U.S. Forest Service are required to comply with CEQA or NEPA, as applicable, when issuing permits. Therefore, in order to secure permits from such agencies, SCE's work may require environmental surveys/studies/reports even if no license is required from the CPUC.

Although the necessity for environmental permits is oftentimes unknown during the initial stages of project development, it is recommended and assumed as part of this Cluster Study that the Interconnection Customer would combine SCE's scope of work as part of its environmental study process.

A. CEQA/NEPA Documentation

When the Interconnection Customer incorporates SCE's scope of work into its environmental study reports, the Interconnection Customer must closely coordinate with SCE during the environmental review process to ensure that SCE's scope of work is being adequately described, and to ensure that environmental studies are being performed to industry standard. If the resulting environmental documents do not adequately describe SCE's scope of work or do not adequately analyze the environmental impacts caused by SCE's scope of work, SCE and/or the permitting agencies may not be able to rely on such documents and additional environmental documents may need to be prepared, resulting in delays to the project schedule.

B. Permit Applications

Applications for permits from resource agencies (i.e., Streambed Alteration Agreements or Incidental Take Permits) shall be submitted by SCE for all SCE project components. Therefore, SCE (not the Interconnection Customer) shall be the permit holder for all such permits. It is SCE's experience that securing such permits may take from six to 12 months, depending on the permit type, from the time complete permit applications are submitted by SCE to the resource agencies for agencies to process. More complex permitting, such as Endangered Species Act Section 10 Habitat Conservation Plans and Bald and Golden Eagle Protection Act permitting, are more laborious and may require more than a year—in some cases, multiple years—to perform surveys and prepare plans to adequately address agency requirements.

IV. Recommendations

For the reasons stated above, it is recommended and assumed as part of this Cluster Study that the Interconnection Customer would identity and include all of SCE's Interconnection Facilities, Distribution Upgrades, and certain Network Upgrades (including facilities agreed upon by all parties and permitted by the tariff to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental study reports submitted to the lead agency permitting the Generating Facility and the Interconnection Customer's Interconnection

Facilities (e.g., California Energy Commission, Bureau of Land Management, city, county, or other applicable local, state or federal permitting agency).

It is also recommended and assumed as part of this Cluster Study that such lead agency(ies) would review the potential environmental impacts associated with SCE's scope of work in any environmental document prepared. Doing so may enable SCE to proceed "exempt" from CPUC permitting requirements or under an "expedited" PTC or CPCN. SCE may also be required to obtain other authorizations for its Interconnection Facilities and Upgrades. However, depending on certain circumstances, the CPUC may still require SCE to undergo a standard PTC or CPCN for the facilities associated with the Interconnection Customer's Generating Facility. Hence, SCE's facilities needed for the project interconnection could require an additional four to six years, or more, to develop the application and secure CPUC approval.