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Impact of Inverter-Based Resource Negative-Sequence Current Injection on Transmission System Protection

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Abstract

This report documents the results of analysis performed to investigate the impact of inverter-based resource (IBR) response to unbalanced faults on transmission system protective relay dependability and security. Electromagnetic transient (EMT) simulations were performed to simulate IBR response to these faults using existing manufacturer-developed EMT models for four separate IBRs. The study team was composed of IBR manufacturers, relay manufacturers, transmission providers, reliability coordinators and industry consultants with experience in EMT simulation and system protection. The results indicate that under certain conditions, IBR response can result in protective relay misoperations if current protection practices, which were developed based on conventional power sources, are not adapted to the characteristics of IBRs.

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TABLE OF CONTENTS

1.	Problem Statement and Study Objectives.....	14
1.1.	The Problem.....	14
1.2.	Study Objectives	16
2.	Technical Study Definition	18
2.1.	Use of Electromagnetic Transient Models.....	18
2.2.	Test System	19
2.2.1.	PSCAD System Model.....	21
2.2.2.	Test Scenarios	23
2.2.3.	Inverter-Based Resource (IBR) Models	25
2.3.	Relay Testing	25
2.3.1.	Relays Configuration and Settings.....	25
2.3.2.	Playback of COMTRADE Data.....	26
3.	Results and Analysis	28
3.1.	Observations on Relay Response.....	28
3.2.	Observations on Model Fault Response	31
3.3.	Observations on Transient Overvoltage.....	34
4.	Conclusions.....	38
5.	Recommendations for Further Study	42
	References.....	44
	Further Reading	46
	Appendix A: System Protection Primer.....	48
A1.	Introduction to Symmetrical Components	48
A2.	Use of Symmetrical Components in Unbalanced Fault Analysis	48
A3.	Sequence Component Networks	50
A4.	Introduction to Transmission Line Protection	56
A4.a.	Impedance Protection Elements.....	56
A4.b.	Line Differential Protection Elements	57
A4.c.	Communication-Aided Protection	57
A4.c.i.	Pilot Communication Schemes	58
A4.c.ii.	Differential Protection Communication Schemes	59
A5.	Concepts of Dependability and Security.....	59
A6.	Comparison of IBR and Rotating Machine Fault Response	59
	Appendix B: PSCAD Traces	60

FIGURES

Figure 2-1.	Power System Analysis Tool Application by Time Frame of Interest	18
Figure 2-2.	Four-Bus Test System	20
Figure 2-3.	PSCAD/EMTDC Test System with Automation and Plotting Modules	21
Figure 2-4.	230 kV Transmission Line Model (Frequency Dependent).....	22
Figure 2-5.	34.5 kV Collector System Equivalent.....	22

Figure 2-6. 230 / 0.6 / 34.5 kV POI Transformer	23
Figure 2-7. Example waveforms for AB fault in Scenario 31; secondary voltages (left) and currents (right).....	26
Figure 3-1. Inconsistent phase distance fault direction discrimination during AB fault.	30
Figure 3-2. Inconsistent faulted phase selection during ABG fault.....	32
Figure 3-3. Unfiltered negative-sequence current (blue) and voltage (red) signals during fault. 33	
Figure 3-4. Angles of filtered negative-sequence current (blue) and voltage (red) during AB fault.....	33
Figure 3-5. Bus 4 Voltage, Scenario 1, OEM 3; L-L Fault Applied from 5.0s to 5.1s.....	36
Figure A-5-1. Positive (left) and Negative (right) Phase Sequence.....	48
Figure A-5-2. Power system network with transmission line fault distance m from Bus S	50
Figure A-5-3. Sequence network diagram for an A-phase SLG fault on transmission line	51
Figure A-5-4. Sequence network diagram for a B-phase to C-phase fault on transmission line. 52	
Figure A-5-5. Sequence network diagram for an B-phase to C-phase to ground fault on transmission line.....	53
Figure A-5-6. Sequence network diagram for a 3-Phase fault on transmission line	54
Figure A-5-7. Sequence network diagram for an open pole condition for the system shown in Figure A-2	55
Figure A-5-8. Reach of the instantaneous and the time delayed impedance elements.....	56
Figure A-5-9. Application of line current differential element (87L)	57
Figure A-5-10. Implementation of permissive pilot communication scheme	58
Figure A-5-11. Implementation of blocking pilot communication scheme.....	59

TABLES

Table 2-1. Scenario List (per IBR)	23
Table 3-1. Reduced Scenario List (per IBR)	28
Table 3-2. Relay Results Summary	29
Table 3-3. Overvoltage Results Summary	35

EXECUTIVE SUMMARY

The increasing penetration levels of grid following inverter-based resources (IBRs) connected to the bulk power system (BPS) across North America have raised concern among transmission system protection engineers as to whether their current practices for applying and setting protective relays are still adequate to maintain BPS reliability. These practices were developed in an era when IBR penetration was negligible, and fault current contribution was dominated by synchronous generators. Unlike synchronous machine fault response, which is determined by the physics of the machine and well understood by protection engineers, IBR fault response is determined by the control code implemented within its embedded control systems. There is little consistency in this fault response, particularly in North America, where there are no related industry standards¹.

Under the leadership of Sandia National Laboratories, a team of IBR manufacturers, relay manufacturers, transmission providers, reliability coordinators and industry consultants was assembled to investigate one particular aspect of IBR fault response and its impact on system protection. This aspect was the response of IBR to unbalanced (line-to-line and line-to-ground) faults. The focus of the study team on this particular issue was driven by: 1) the lack of adequate IBR models in commercial short circuit analysis tools, 2) the fact that at least two BPS relay misoperations in North America have been attributed to unexpected IBR unbalanced fault response, and 3) the previously mentioned lack of standardization around this topic.

The primary objective of the study is to provide guidance to practicing transmission system protection engineers on criteria to evaluate whether further analysis of unbalanced fault response is needed in the interconnection study process. To achieve this objective, the study team first characterized the unbalanced fault response from four IBR manufacturers based on electromagnetic transient (EMT) simulations using manufacturer-developed EMT models generated from the actual control code implemented in the hardware. The outputs of these simulations were then provided to two relay manufacturers for playback through transmission line protective relays that were set according to current industry standard practices. The relay manufacturers then analyzed the response of their relays and identified the scenarios in which protection dependability or security was potentially comprised.

The results indicated that, for certain realistic scenarios, the unbalanced fault response of some IBR was inadequate to ensure reliable operation of protection elements using the relay application and setting practices that are currently in place. Additionally, the unbalanced fault response varied so much between IBR manufacturers that simple changes to protection settings would be inadequate to maintain reliability.

The study team recommends standardization of the response of IBRs to unbalanced faults. With protection engineers lacking access to the details of the IBR controls, EMT studies would be necessary for proper evaluation of system protection during interconnection studies. This is currently impractical, because it is a costly and time-consuming process. A standardized IBR

¹ The IEEE P2800 Working Group (<https://standards.ieee.org/project/2800.html>) is currently developing performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems. Response to transmission system faults is one aspect of these criteria.

fault response could simplify the selection of protection schemes and development of relay settings, resulting in decreased risk of mis-operations, and a reduced interconnection study complexity and cost. For these scenarios, protection engineers should consider additional evaluation, or alternative forms of protection to maintain reliability.

NOMENCLATURE

Abbreviation	Explanation
BPS	Bulk Power System (as defined by NERC)
CCVT	Coupling Capacitor Voltage Transformer
COMTRADE	Common Format for Transient Data Exchange (IEEE Standard C37.111)
CT	Current Transformer
DCB	Directional Comparison Blocking
EMT	Electromagnetic Transient
FACTS	Flexible Alternating Current Transmission System
EMTDC	Electromagnetic Transients including DC
F32P	Forward Phase Directional Element
FFOV	Fundamental Frequency Overvoltage
FFT	Fast Fourier Transform
IBR	Inverter-Based Resource
IEEE	Institute for Electrical and Electronics Engineers
I0	Zero-sequence Current
I1	Positive-sequence Current
I2	Negative-sequence Current
MV	Medium Voltage
NERC	North American Electric Reliability Corporation
OEM	Original Equipment Manufacturer
PSCAD	Power System Computer-Aided Design
PV	Photovoltaic
POI	Point of Interconnection (of an IBR with the BPS)
POTT	Permissive Overreaching Transfer Trip
R32P	Reverse Phase Directional Element
SCR	Short Circuit Ratio
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
VDE	Verband der Elektrotechnik, Elektronik und Informationstechnik
VT	Voltage Transformer
Z1P	Zone 1 Phase Distance Element
Z2P	Zone 2 Phase Distance Element
Z3P	Zone 3 Phase Distance Element
Z2G	Zone 2 Ground Distance Element

Abbreviation	Explanation
32GF	Forward Ground (Zero-Sequence) Directional Element
32QF	Forward Negative-Sequence Directional Element
67G	Directional Ground (Zero-Sequence) Overcurrent Element
67Q	Directional Negative-Sequence Overcurrent Element

1. PROBLEM STATEMENT AND STUDY OBJECTIVES

1.1. The Problem

With increasing penetration levels of grid following inverter-based resources (IBRs) connected to the bulk power system (BPS) across North America, engineers responsible for transmission system protection are concerned about how these resources may impact present industry practices for transmission protection systems. Conventional power system protection practices were developed during a period stretching over 100 years where IBR penetration levels were zero (or at least negligible) and fault current contributions were dominated by the response of rotating machines (primarily synchronous generators). The response of a synchronous generator to a fault on the BPS is determined by the physics of the rotating machine. It is well understood by system protection engineers, who employ linear circuit analysis techniques with appropriate machine impedances and time constants relevant to the time period of interest.

The fault response of an IBR, in contrast, is determined by how the inverter control system has been programmed to respond to its terminal conditions. The manner in which the fast-acting controls within the inverter respond to rapidly changing terminal conditions is an engineered feature but not well understood by system protection engineers. In addition, the response from one inverter manufacturer to another manufacturer is not consistent. This is particularly a challenge in North America, where inverter original equipment manufacturers (OEMs) do not have any standardization of expected performance from IBR. Simply put, existing protection practices developed for power systems with low IBR penetration levels may result in inadequate transmission system protection as IBR penetration increases.

The focus of this study was on one aspect of IBR fault response – negative-sequence current injection in the presence of unbalanced (phase-to-phase and phase-to-ground) faults on the BPS near an IBR. The drivers behind the focus on this particular issue include:

- An IBR's positive-sequence current injection during three-phase (symmetrical) faults is better understood. It is somewhat consistent across manufacturers, though current limits vary slightly. Most commercial short circuit software used by transmission system protection engineers have now incorporated current-limited generator models that model IBR response to three-phase faults with sufficient accuracy. Also, positive-sequence phasor-domain dynamic models have existed (both generic and manufacturer-specific) for several years.
- As previously mentioned, there are currently no North American industry standards that govern negative-sequence fault response by IBR, so approaches vary from one manufacturer to the next. Some OEMs inject negative-sequence current, while others do not. For those that do allow for negative-sequence current injection, the lack of an industry standard may mean that the phase angle of the negative-sequence current with respect to the negative-sequence terminal voltage is uncontrolled.

- There are documented cases of relay mis-operations that have been attributed to lack of, or incorrect, negative-sequence current injection from IBR. Two of these cases were on the BC Hydro system [1].
- In high IBR penetration scenarios, a lack of negative-sequence current injection during an unbalanced fault could cause the unfaulted phases to experience temporary or transient overvoltage². This can result in adverse effects on inverter performance during fault events as well as excessive lightning (surge) arrester energy accumulations³. Transient, sub-cycle overvoltage tripping by the IBR is commonly identified as a contributor to the large disturbances analyzed in the Western Interconnection (i.e., the Blue Cut Fire, Canyon 2 Fire, Angeles Forest, and Palmdale Roost disturbances [2, 3, 4]).
- In high IBR penetration scenarios, the use of traditional transmission protection methods may be inadequate to maintain reliability and security. Without further investigation, industry has little guidance as to recommended or necessary modifications to existing protection. Further, inverter manufacturers are seeking guidance as to the appropriate response to grid disturbances so as to provide support to the BPS during these events.

In high IBR penetration scenarios, unexpected fault response could result in transmission line protective relay loss of security due to incorrect impedance/reactance calculations if the relay settings are based on synchronous generator fault response and traditional relay setting practices. Protective relay dependability⁴ and security⁵ can both be degraded. In the first case documented by BC Hydro, a 230 kV ground fault occurred on a transmission line feeding a large wind plant consisting of Type 3 (doubly-fed induction generator) wind turbine generators (WTGs). Ground fault protection at each line terminal consisted of negative-sequence voltage-polarized ground overcurrent elements⁶ in multi-function microprocessor-based relays. The terminal near the wind plant failed to trip due to the negative-sequence forward directional element failing to assert, caused by an unforeseen angular difference between the negative-sequence voltage and current phasors (demonstration of degraded dependability). In the second case, a 138 kV ground fault occurred on a low, short circuit strength portion of the BC Hydro system. The fault location was near a pair of STATCOMs with a combined ± 24 MVar rating. A Zone 1 ground distance relay at the substation hosting the STATCOMs tripped for an out-of-zone fault, a demonstration of degraded security which was attributed to insufficient negative-

² While there are numerous causes of transient overvoltage, the focus of this study was limited to transients resulting from the injection of negative sequence current, or lack thereof, by IBRs during unbalanced faults

³ The service life of a surge arrester is strongly impacted by the accumulated number of operations and the energy dissipated in each operation. More frequent operations hasten end-of-life.

⁴ The ability of the relay to trip for faults within its zone of protection.

⁵ The ability of the relay to remain secure for faults outside its zone of protection.

⁶ An “element” is a specific function implemented in a digital relay’s firmware. The relay’s tripping logic is a Boolean function of the status of these elements.

sequence current injection from the STATCOMs to reliably polarize the ground distance relay⁷ and prevent false tripping.

While an equipment or performance standard for negative-sequence current injection from IBR currently does not exist in North America, it should be noted that this issue has been recently addressed in Germany [5, 6]. VDE Standards AR-N-4120 and AR-N-4130 are the German standards, most recently revised in November 2018, that govern interconnection and operation requirements for the high-voltage (HV) and extra-high-voltage (EHV) transmission networks, respectively. Each require both positive and negative-sequence dynamic reactive current response to unbalanced faults. Note that the specification of reactive current fixes the angles of the positive- and negative-sequence current phasors with respect to the positive- and negative-sequence terminal voltages, addressing the issue of unexpected angular differences between these phasors that BC Hydro pointed to in one of its relay mis-operations. The VDE standard defines that positive and negative-sequence current injection be made in proportion to the change in positive and negative-sequence terminal voltages from their “normal” values (nominal system voltage for the positive-sequence voltage and zero for the negative-sequence voltage). Assessment of whether this particular approach is optimal for the North American BPS is beyond the scope of this study.

1.2. Study Objectives

In developing the scope of work for this study, the authors established that the study should provide the following:

- “Real world” examples of unbalanced fault response by IBR-based generation based on electromagnetic transient (EMT) simulations using inverter OEM-developed EMT models generated from their actual control code.
- Identification of IBR-based power plant interconnection scenarios where transmission system reliability could potentially be compromised by a lack of and/or poorly characterized response to unbalanced faults⁸. These threats to reliability could be in the form of degraded dependability or security of protective relaying schemes or could manifest themselves as failure of the IBR to ride through asymmetrical grid voltage disturbances⁹.

⁷ In this case, the ground distance element was supervised by a negative sequence polarized directional element. If it would have been polarized by a zero sequence directional element, this misoperation likely would not have occurred.

⁸ Balanced faults create a challenge to the security of the relay elements since the voltage collapse is the same whether the fault is right in front of the protective relay or at the end of the line (or even out of the zone). For a fault located on the transmission line adjacent to the line coming from the IBR, a three phase fault would result in a zero voltage at the fault point due to the IBR being a weak source. The voltage measured at the IBR POI would also be zero and so a distance element would calculate the impedance to the fault point to be right at the relaying point. Furthermore, the angular relationship between the fault current and the fault voltages even for a three phase fault is not what is expected, i.e. that the current lags the voltage by the line/source angle. However, relay response to balanced faults is beyond the scope of this study.

⁹ It should be noted that as IBR penetration grows, these issues would not be limited to transmission lines adjacent to IBRs.

- Guidance to practicing transmission system protection engineers on criteria to evaluate whether further analysis of unbalanced fault responses needed in the interconnection study process.
- Background and simulation results that can inform the IEEE P2800 Working Group on the issue, to serve as guidance on potential equipment capability and performance requirements for negative-sequence current injection in response to asymmetrical faults.
- Identification of areas for further research that could not be addressed in the first phase of this project.

The remaining sections of this report provide this technical background, document the results of the EMT simulations, and describe how the EMT simulation results were applied to perform protective relay operations analysis. The report concludes with a list of conclusions and recommendations for further study that are intended to inform the efforts of other industry working groups such as the IEEE P2800 project and the NERC Inverter-Based Resource Performance Task Force (IRPTF).

2. TECHNICAL STUDY DEFINITION

2.1. Use of Electromagnetic Transient Models

Power systems engineers utilize a variety of computer-based simulation tools to analyze the impact of IBRs on the BPS. Selection of the tool to address a particular issue is driven largely by the time frame of interest. As shown in Figure 2-1, these time frames range from steady-state conditions down to sub-cycle transients.

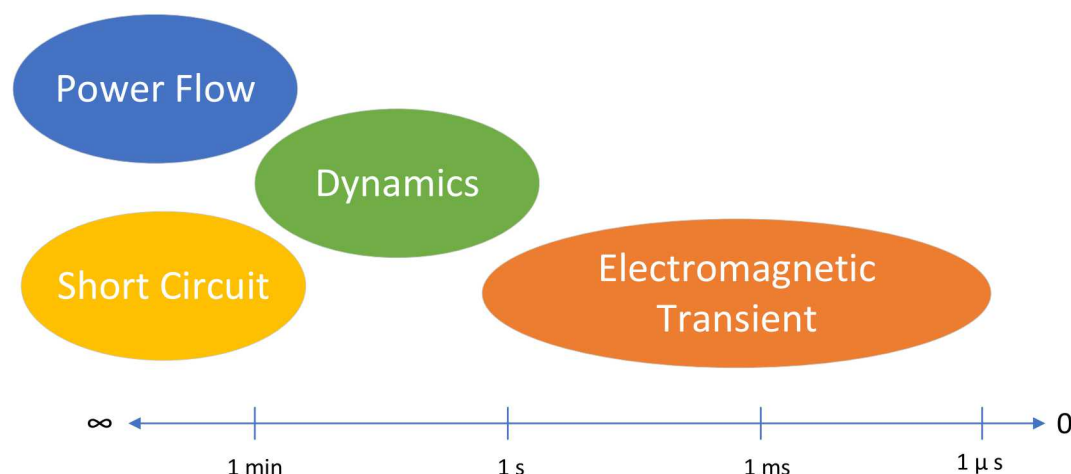


Figure 2-1. Power System Analysis Tool Application by Time Frame of Interest¹⁰

Steady-state analysis is performed with power flow software and is used to assess reliability based on thermal and voltage criteria under some static operating scenario and contingency events. For transmission systems, power flow analysis normally assumes balanced (pure positive-sequence) currents and voltages throughout the power system. IBR and conventional generators are modeled in the same manner. Examples of transmission system power flow analysis tools include Siemens PTI PSS[®]E, GE PSLF, DigSilent, Powertech TSAT, and PowerWorld Simulator.

Short circuit analysis is another form of steady-state analysis but is used to evaluate the voltages and currents in a power system when it is subjected to balanced (three phase) and unbalanced (two phase, single phase-to-ground and two phase-to-ground) short circuits. Examples of transmission system short circuit analysis tools include Siemens PSS[®]CAPE, ETAP, and ASPEN OneLiner. At present, these tools have limited capability for modeling IBR, particularly for unbalanced faults, since there are currently no North American standards that define IBR response to these faults.

Power system dynamic analysis is used to assess reliability of the BPS related to its response to large-signal and small-signal disturbances and the stability of that response. Examples of these disturbances include short circuits, loss of generation, and

¹⁰ While short circuit simulation is done in the pseudo-steady state, actual short circuits could range from a few cycles to a second. Most faults on the bulk transmission system are cleared in 4-10 cycles.

sudden changes in load. The power flow data is supplemented with dynamics data (a representation of the defining differential equations) for generators, generator excitation systems, turbine governors, and FACTS devices, and many other control systems. This dynamics data allows the electromechanical response of the power system in the positive-sequence phasor domain to be simulated. Simulation time steps may be as small as a millisecond but are typically done at $\frac{1}{4}$ or $\frac{1}{2}$ cycle of the power system's fundamental frequency. Much work has been done over past few years by the major software vendors to extend their standard dynamic model libraries to include IBR in the form of generic wind, solar photovoltaic (PV), and energy storage models. These models are now widely used in IBR interconnection studies.

Finally, electromagnetic transient (EMT) analysis is performed when the phenomena of interest cannot be adequately observed through dynamic analysis. Examples of EMT analysis tools include EMTP-RV, ATP, and PSCAD. The algebraic models of power system branches used in dynamic analysis are replaced with their corresponding differential equations in a full three-phase representation, providing high sample frequency point-on-wave outputs. Likewise, generators and associated control equipment are modeled according to their time-domain dynamic equations and with explicit three-phase representation. Simulation time steps are typically in the tens of microsecond range. A benefit of an EMT analysis is the ability to observe the time-domain response of the power system on each phase to either balanced or unbalanced disturbances. EMT simulations are computationally burdensome, and simulation times grow quickly as the size of the EMT model or the simulation period increases. While not widely used today, their relevance to power system reliability studies is growing rapidly as more IBR connect to the BPS.

The scope of the project described in this report clearly called for an explicit three-phase power system representation since the focus was on IBR and relay response to unbalanced faults under high IBR penetration scenarios. Further, sub-cycle transient response during fault application and clearing were of great interest to the working group. For these reasons, EMT analysis was the clear choice for performing these assessments. The time-domain output of an EMT analysis can be exported to a COMTRADE file, an industry standard file format that can be played back via test amplifiers or front-end emulation to observe relay performance. Further, the use of custom user-defined EMT models generated from the actual embedded controller code implemented in four IBR inverters allowed the group to evaluate the effects of a diverse set of OEM approaches to current injection to unbalanced fault events.

2.2. Test System

The studies in this report were conducted using a 4-bus test system developed in the PSCAD/EMTDC program (X4.6.2). This test system is comprised of a 100 MW IBR, three transmission lines, one collector system equivalent, and one three winding POI transformer as shown in Figure 2-2. The nominal transmission voltage is 230 kV and the power delivered to Bus 2 is approximately 150 MW.

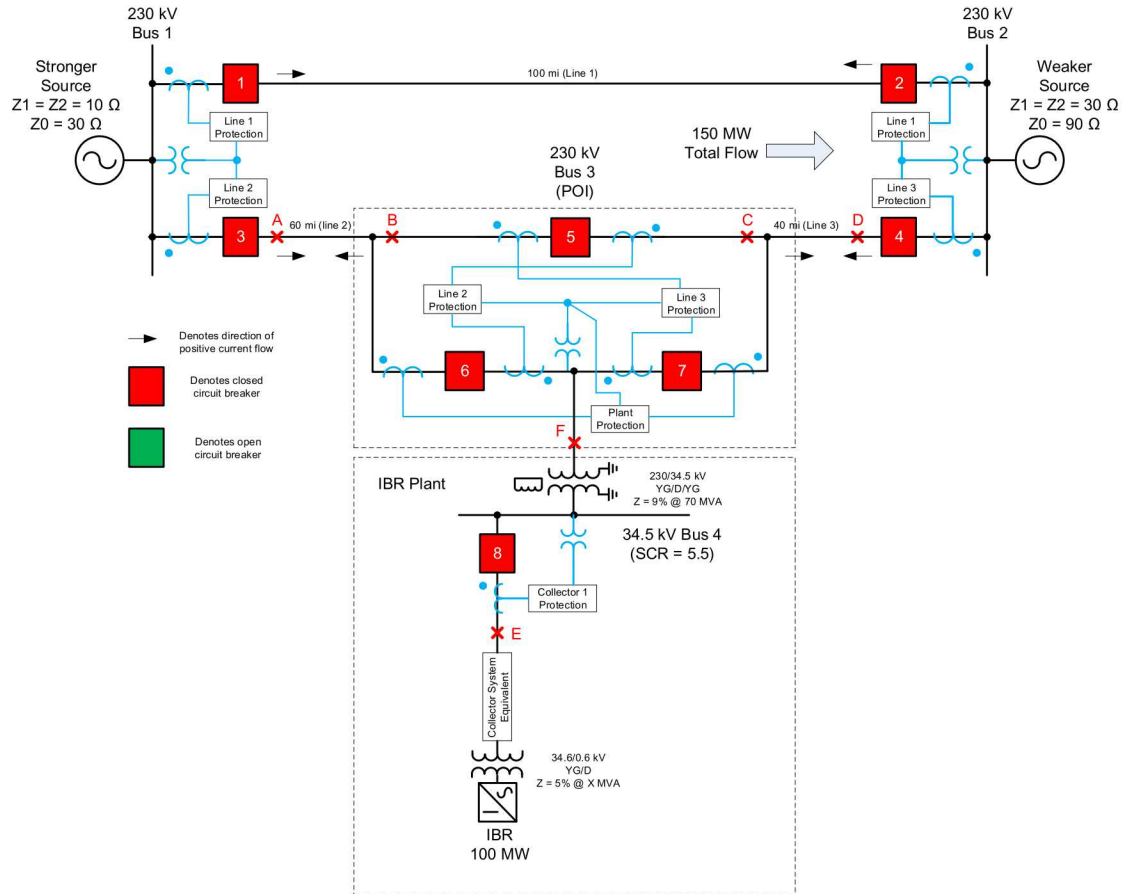


Figure 2-2. Four-Bus Test System

The test system in Figure 2-2 was first built in PSS/E to tune the source impedances at Bus 1 and Bus 2 to have a suitable short circuit ratio¹¹ (SCR) at the IBR medium voltage (MV) bus (Bus 4), and to calculate the source equivalent set points to deliver the expected power. Then the system was brought into PSCAD/EMTDC for the detailed analysis (Figure 2-3).

¹¹ The SCR is the ratio of the short circuit contribution of the BPS to the short circuit contribution of the IBR at a particular POI.

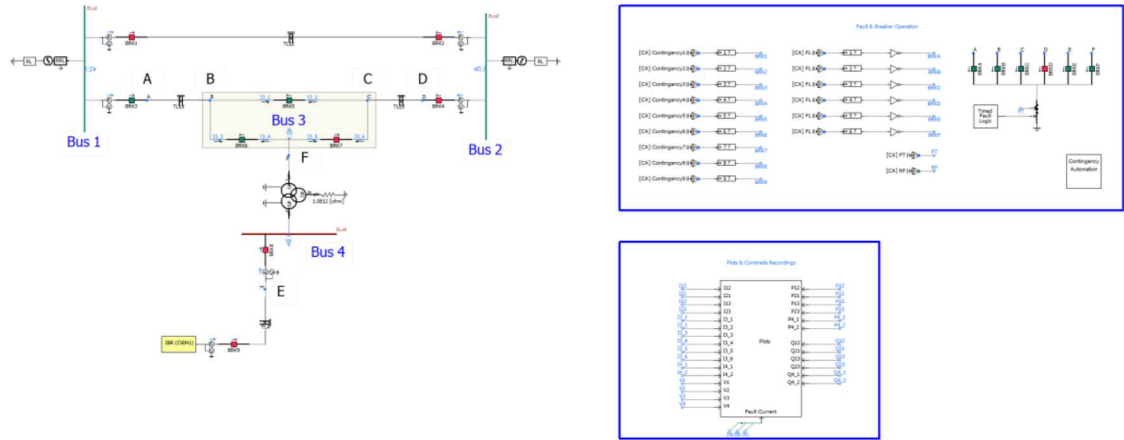


Figure 2-3. PSCAD/EMTDC Test System with Automation and Plotting Modules

The details of the main PSCAD components and the process of automation are discussed in the following sections.

2.2.1. PSCAD System Model

2.2.1.1. Bus 1 and Bus 2 Equivalent Sources

The sources at Bus 1 and Bus 2 are represented by Thevenin equivalents in each symmetrical component set. Bus 1, designated in Figure 2-2, as the “stronger” source, has a 5,290 MVA three-phase short circuit capability. Bus 2, the “weaker” source, has a 1,763 MVA short circuit MVA capability. The equivalent zero-sequence impedance of each source is three times its positive- and negative-sequence impedances.

2.2.1.2. Transmission Lines

All 230 kV transmission lines in the test system used the same tower and conductor model as shown in Figure 2-4. The lengths of each line are given as follows; TL12: 100 miles, TL13: 60 miles and TL23: 40 miles.

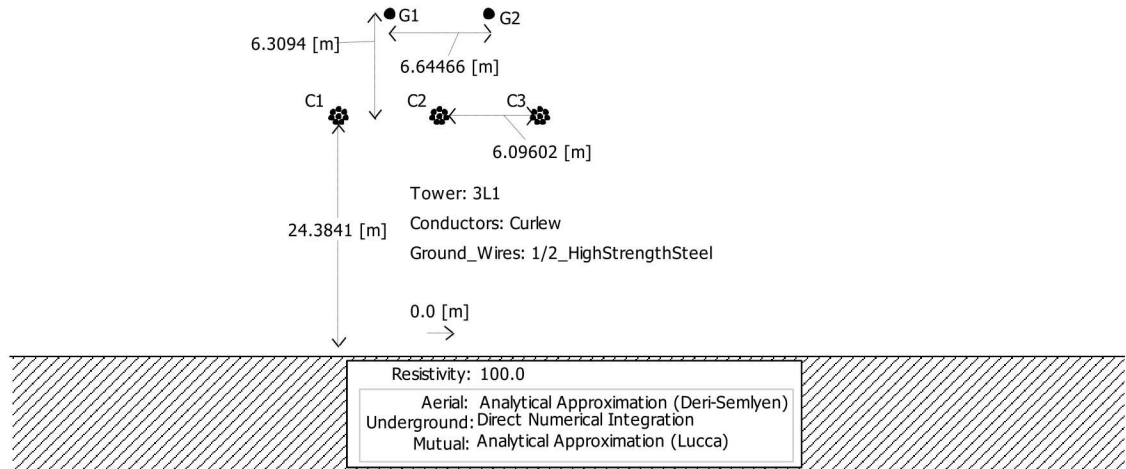


Figure 2-4. 230 kV Transmission Line Model (Frequency Dependent)

2.2.1.3. Collector System Equivalent

A PSCAD Bergeron¹² line model is used to represent the 34.5 kV collector system as shown in Figure 2-5. Note that the resistance (R), reactance (XL), and the susceptance (B) values are for the entire line (i.e., line length is 1 m).

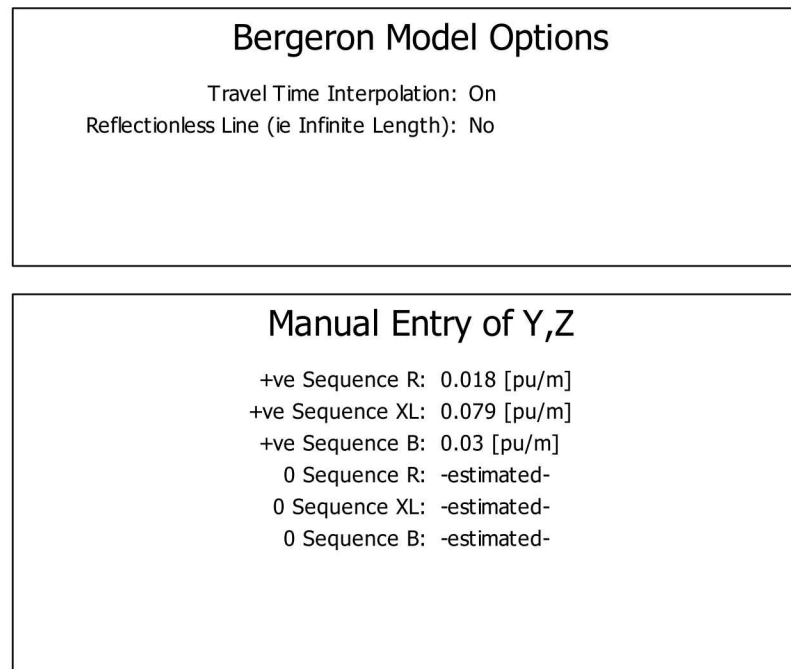


Figure 2-5. 34.5 kV Collector System Equivalent

¹² The Bergeron model represents the line inductances and capacitances in a distributed manner (as opposed to lumped elements used in the “pi” model), but lumps the line resistance with half at the middle of the line and a quarter at each end. It is linear in nature (i.e., not frequency dependent).

2.2.1.4. Transformer

The PSCAD model to represent the 230 / 0.6 / 34.5 kV POI transformer is shown in Figure 2-6. The transformer model neglects magnetizing current and uses generic saturation parameters.

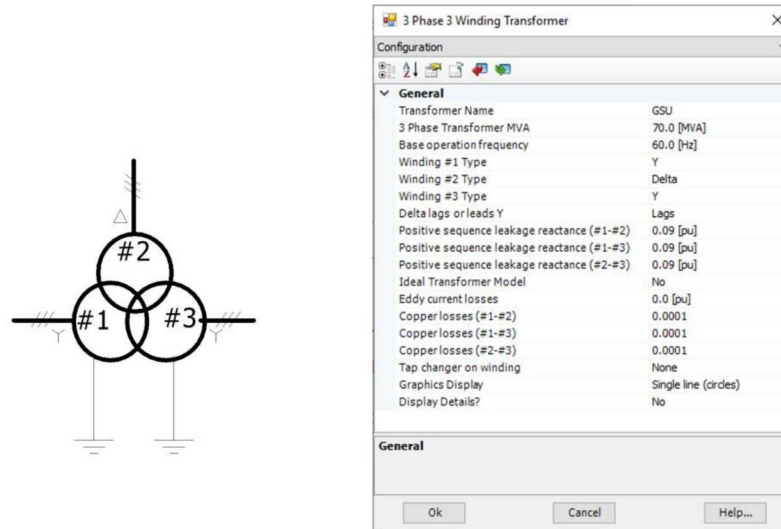


Figure 2-6. 230 / 0.6 / 34.5 kV POI Transformer

2.2.2. Test Scenarios

192 scenarios were created, 48 scenarios for each of the four OEM's IBRs evaluated. The list of scenarios are tabulated in Table 2-1. For each scenario, the fault was applied for 5 cycles (100 ms)¹³, assuming that the relays would clear the fault in this time at both ends of the impacted transmission line. Staggered tripping¹⁴ was not considered in this study.

Table 2-1. Scenario List (per IBR)

Scenario ID	Prior Outage	Fault Location	Fault Type	Fault Resistance (Ω)
1	None	B	LG	0
2	None	B	LG	5
3	None	B	LLG	0
4	None	B	LLG	5
5	None	B	LLLG	0
6	None	B	LLLG	5
7	None	B	LL	0
8	None	B	LL	5

¹³ A five-cycle fault duration is common in HV and EHV applications where the relay response time and circuit breaker clearing time are approximately two and three cycles, respectively.

¹⁴ Staggered tripping is when the breaker(s) at one line terminal open at a different time than that (those) at the remote terminal of the transmission line. Tripping is normally staggered slightly due to different operating times for relay elements and communication delays between line terminals, but those effects were not simulated.

9	None	E	LG	0
10	None	E	LG	5
11	None	E	LLG	0
12	None	E	LLG	5
13	None	E	LLLG	0
14	None	E	LLLG	5
15	None	E	LL	0
16	None	E	LL	5
17	None	F	LG	0
18	None	F	LG	5
19	None	F	LLG	0
20	None	F	LLG	5
21	None	F	LLLG	0
22	None	F	LLLG	5
23	None	F	LL	0
24	None	F	LL	5
25	TL13	D	LG	0
26	TL13	D	LG	5
27	TL13	D	LLG	0
28	TL13	D	LLG	5
29	TL13	D	LLLG	0
30	TL13	D	LLLG	5
31	TL13	D	LL	0
32	TL13	D	LL	5
33	TL12	A	LG	0
34	TL12	A	LG	5
35	TL12	A	LLG	0
36	TL12	A	LLG	5
37	TL12	A	LLLG	0
38	TL12	A	LLLG	5
39	TL12	A	LL	0
40	TL12	A	LL	5
41	TL12	D	LG	0
42	TL12	D	LG	5
43	TL12	D	LLG	0
44	TL12	D	LLG	5
45	TL12	D	LLLG	0
46	TL12	D	LLLG	5
47	TL12	D	LL	0
48	TL12	D	LL	5

For each scenario, all instantaneous currents and voltages in all the bus CTs and VTs were recorded using PSCAD COMTRADE components for further analysis. This is to analyze the relay operation by playing back these recordings on an actual relay. Apart

from COMTRADE recordings, the sequence components of currents and voltages, active and reactive power flows, and fault currents were recorded using PSCAD Fast Fourier Transformation (FFT) component and RMS meters. Note that CT and VT transients were not expected to have a significant impact on the results, therefore they were not simulated. These devices were assumed to be ideal.

2.2.3. Inverter-Based Resource (IBR) Models

Four different IBR models (from different inverter manufacturers) were used for this study (one at a time). Each of these models is an accurate representation of the actual control behavior of the inverters. In this report, these IBR are designated as OEM 1 through 4, and represent a combination of solar PV, Type 3 WTGs, and Type 4 WTGs.

IBR model output currents were scaled to increase the total power output of each plant to 100 MW. The output voltage is maintained at 34.5 kV at 60 Hz. The disturbance is applied after 5.0 seconds, giving enough time for the IBR to come to a steady-state initial condition.

The amount of negative-sequence current that each IBR model would contribute to unbalanced faults was not known in advance of the simulations. But, as will be discussed in Section 3.2 of this report, the negative-sequence current injection varied widely not only between IBRs, but between fault scenarios for the same IBR.

2.3. Relay Testing

The goal of this testing was to estimate the response of the commercially available off-the-shelf relays installed on transmission line connecting IBR to the system to the line fault. Two different manufacturers' protective relays were set per common existing transmission line protection practice with the equivalent settings, and then COMTRADE files from the simulations were played back to actual relays using test sets that provided physical voltage and current inputs.

2.3.1. Relays Configuration and Settings

The protective relays at both terminals of line TL23 were configured as follows:

VTs and CTs: 1000A/5A, 230kV/115V

Phase distance (Mho): $Z1P = 2.57\Omega\angle 83^\circ$, $Z2P = 3.85\Omega\angle 83^\circ$ (pilot scheme), $Z3P$ (reverse) = $1.6\Omega\angle 83^\circ$

Ground distance (Mho): $K0^{15} = 0.661\angle -13.96^\circ$, $Z1P = 2.57\Omega\angle 83^\circ$, $Z2P = 3.85\Omega\angle 83^\circ$, $Z3P$ (reverse) = $1.6\Omega\angle 83^\circ$

¹⁵ K0 is known as the zero sequence compensation factor, and used to compensate for the difference between the phase impedance and the ground impedance for ground distance elements.

Ground directional: $3I_0 = 0.5A$ ($0.1 \times I_n$), $Z_{0F} = -0.30$, $Z_{0R} = 0.30$

Negative-sequence directional: $3I_2 = 0.25A$ ($0.05 \times I_n$), $Z_{2F} = -0.30$, $Z_{2R} = 0.30$

2.3.2. **Playback of COMTRADE Data**

All simulated scenarios were played into the two relay manufacturers' relays. Figure 2-7 depicts sample test scenario currents and voltages for the Phase A to Phase B fault simulated in Scenario 31. During the 100 ms duration of the fault, it was expected that protection from both ends of the line connecting IBR to the BPS will operate and clear the fault. It was assumed that either a step distance or pilot aided scheme operated by distance and ground directional protection would clear the fault.

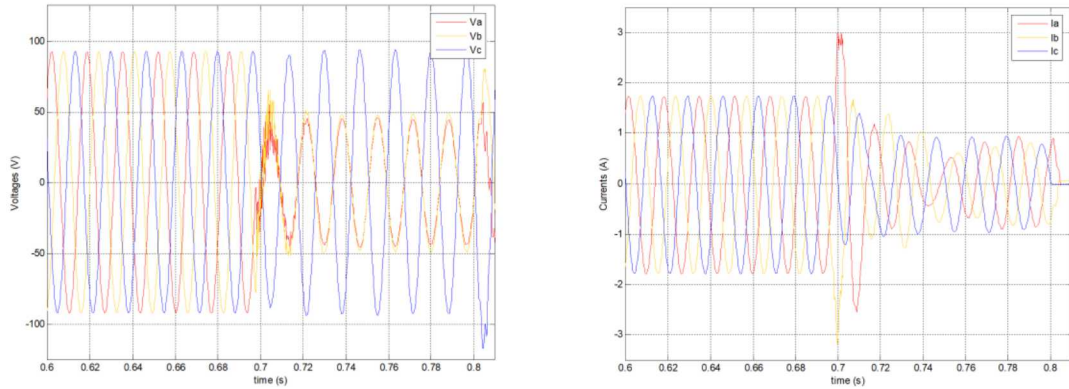


Figure 2-7. Example waveforms for AB fault in Scenario 31; secondary voltages (left) and currents (right)

3. RESULTS AND ANALYSIS

Simulations were conducted with 48 scenarios (for each of 4 IBRs) as listed in Table 2-1 in the previous section. Preliminary analysis of the magnitude and angle of I2 that would be seen by the protective relays in these simulation results indicated that the most challenging scenarios from a protection standpoint were those where the I2 contribution is only from the IBR (i.e., when the I2 contribution from synchronous machines is zero).

A reduced subset of eight simulations was then selected for detailed analysis and COMTRADE play-in to the manufacturer relays, as shown in Table 3-1. This scenario list first includes four simulations where the protective relays see current from both conventional sources (the Thévenin equivalents at Bus 1 and Bus 2 in Figure 2-2) and IBR (Scenarios 1, 3, 5 and 7). These first four scenarios were included for comparison to show the important effect of conventional sources in allowing correct relay operation. The second four simulations were chosen such that the only current seen by the protective relay is produced by IBR (Scenarios 25, 27, 29 and 31).

Table 3-1. Reduced Scenario List (per IBR)

Scenario ID	Initial Test System Lines Out of Service	Fault Location	Fault Type	Fault Resistance (Ω)
1	None	B	LG	0
3	None	B	LLG	0
5	None	B	LLL	0
7	None	B	LL	0
25	TL13	D	LG	0
27	TL13	D	LLG	0
29	TL13	D	LLL	0
31	TL13	D	LL	0

3.1. Observations on Relay Response

The summary of results for reduced scenario list for each IBR is tabulated in Table 3-2. A complete set of PSCAD traces is attached in Appendix B and relevant page numbers can be found in the summary tables.

Table 3-2. Relay Results Summary

Scenario ID	Prior Outage	Fault Location	Fault Type (bolted)	Desired Line Trip	Negative Sequence Current from IBR During		Breakers expected to clear fault	Relay OEM 1			Relay OEM 2			Results Reference In Appendix B
					Min	Max		Line Protected ?	Expected elements operation ?	Notes	Line Protected ?	Expected elements operation ?	Notes	
IBR OEM1														
1	None	B	LG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 61 - 76
3	None	B	LLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 77 - 92
5	None	B	LLLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 93 - 108
7	None	B	LL	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 109 - 124
25	TL13	D	LG	TL23	20	60	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 4	Page 125 - 140
27	TL13	D	LLG	TL23	30	80	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 5	Page 141 - 156
29	TL13	D	LLLG	TL23	0	40	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 6	Page 157 - 172
31	TL13	D	LL	TL23	40	110	BRK4, BRK7	No	No	Note 3	No	No	Note 3	Page 173 - 188
IBR OEM2														
1	None	B	LG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 61 - 76
3	None	B	LLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 77 - 92
5	None	B	LLLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 93 - 108
7	None	B	LL	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 109 - 124
25	TL13	D	LG	TL23	0	20	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 4	Page 125 - 140
27	TL13	D	LLG	TL23	0	50	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 4	Page 141 - 156
29	TL13	D	LLLG	TL23	0	25	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 5	Page 157 - 172
31	TL13	D	LL	TL23	20	50	BRK4, BRK7	Yes	No	Note 3	No	No	Note 3	Page 173 - 188
IBR OEM3														
1	None	B	LG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 61 - 76
3	None	B	LLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 77 - 92
5	None	B	LLLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 93 - 108
7	None	B	LL	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 109 - 124
25	TL13	D	LG	TL23	50	90	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 4	Page 125 - 140
27	TL13	D	LLG	TL23	140	160	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 4	Page 141 - 156
29	TL13	D	LLLG	TL23	0	35	BRK4, BRK7	Yes	No	Note 2	No	No	Note 3	Page 157 - 172
31	TL13	D	LL	TL23	170	200	BRK4, BRK7	Yes	No	Note 3	Yes	No	Note 4	Page 173 - 188
IBR OEM4														
1	None	B	LG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 61 - 76
3	None	B	LLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 77 - 92
5	None	B	LLLG	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 93 - 108
7	None	B	LL	TL13			BRK3, BRK5, BRK6	Yes	Yes	Note 1	Yes	Yes	Note 1	Page 109 - 124
25	TL13	D	LG	TL23	30	35	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 5	Page 125 - 140
27	TL13	D	LLG	TL23	70	75	BRK4, BRK7	Yes	No	Note 2	Yes	No	Note 5	Page 141 - 156
29	TL13	D	LLLG	TL23	0	0	BRK4, BRK7	Yes	No	Note 2	Yes	Yes	Note 1	Page 157 - 172
31	TL13	D	LL	TL23	90	97	BRK4, BRK7	Yes	No	Note 3	Yes	Yes	Note 1	Page 173 - 188

Notes for Table 3-2 are as follows:

- Note 1: Protection will operate correctly and will clear this fault at both line terminals.
- Note 2: At Breaker 7 terminal - ground directional (32GF) element asserted forward which is correct. Therefore, this fault can be cleared by a 67G element. The zone 2 ground distance (Z2G) element also asserted for approximately 1.5 cycles. Alternatively the fault can be cleared by means of a communication-aided scheme (POTT or DCB) that is keyed by the 67G or Z2G elements. At Breaker 4 - all elements operated as expected, also correct faulted phase identification.
- Note 3: At Breaker 7 terminal - The 32GF, 32QF and the F32P elements pickup transiently at the beginning of the fault. What is most concerning about this fault is that the relay declared the fault in the reverse direction, R32P asserted and so did the Zone 3 (Z3P) phase distance element. Even with communication-aided protective relaying, tripping would be delayed or clearing this fault may not have been possible. At Breaker 4 - all elements operated as expected, also correct faulted phase identification. As shown in the Figure 3-1 below, initially reverse-looking Z3P picked up for approximately 4 cycles into the fault and only later 5 cycles into the fault forward-looking Z2P picked up.

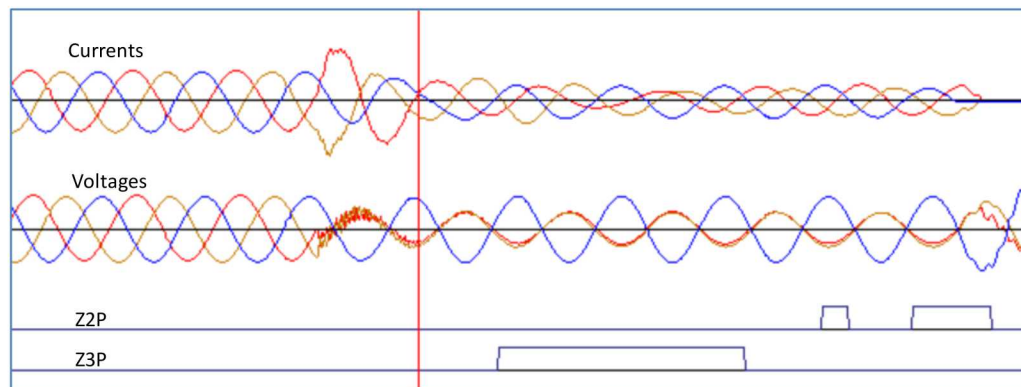


Figure 3-1. Inconsistent phase distance fault direction discrimination during AB fault.

- Note 4: At Breaker 7 terminal - distance operated correctly, but delayed by 1 cycle or more, 67G = FWD as expected, 67Q = No pickup due to low I₂. At Breaker 4 terminal - all protection elements operated as expected. Overall protection would clear the fault without any delay by means of a communication-aided scheme
- Note 5: At Breaker 7 terminal - distance operated correctly, 67G=FWD as expected, 67Q=No pickup due to low I₂. At Breaker 4 terminal – all protection elements operated as expected. Fault would clear without delay, however negative-sequence elements operation is affected.

- Note 6: At Breaker 7 terminal – reverse Z3P picked up initially and Z2P distance delayed (inconsistent directionality), 67G=No pickup, 67Q=No pickup. At Breaker 4 terminal - all protection elements operated as expected. Even with communications aided scheme trip can be significantly delayed or fail to clear fault at all.

3.2. Observations on Model Fault Response

Scenarios 25, 27, 29 and 31 all included pre-fault transmission line outages that resulted in the source behind the relay at the Bus 3 terminal of transmission line TL23 being composed solely of IBRs. In these cases, the protection did not operate as expected. Major observations of the protection's performance at the IBR are listed below:

- Since the IBRs are current-limited devices, the positive-, negative- and zero-sequence voltages at the POI of the IBR (Bus 3) were largely generated by the conventional sources at Bus 1 and Bus 2. The zero-sequence current seen by the relay at the IBR POI was generated by the conventional sources, as well. However, the positive and negative-sequence currents at the IBR end of transmission line TL23 were generated by the IBR.
- Because zero-sequence current and voltage were generated by the transmission grid, zero-sequence directionality was not affected. During faults involving ground, due to 3I0 contribution provided by the step-up transformer at the POI, the ground directional elements in the relays performed as expected.
- The magnitude of the negative-sequence current provided by the IBR varied from manufacturer to manufacturer, but was always significantly lower in magnitude than in a conventional system such as those selected to represent the Thévenin sources at Bus 1 and Bus 2. To detect such low magnitudes of negative-sequence current, the relays have to be set very sensitively, which may jeopardize security of the protection.
- Because the frequency of the negative-sequence voltage and current was not the same, the phase relationship between current and voltage changed continuously. Therefore, the phase relationship between the negative-sequence current and voltage was not useful for the negative-sequence directional elements to make a reliable directional decision.
- Unlike a conventional synchronous generator, it took two or more cycles for the IBRs to respond to the fault condition and adjust their output currents (both positive- and negative-sequence) in response to a fault on the transmission network. This is the typical time interval during a fault when protection elements are expected to operate. In a number of cases, this resulted in delayed protection operation.
- Faulted phase selection is not consistent in a number of cases due to the unpredictable relationships between the I0 and I2 currents. Figure 3-2 below demonstrates that the relay cannot determine the correctly faulted phase during and ABG fault.

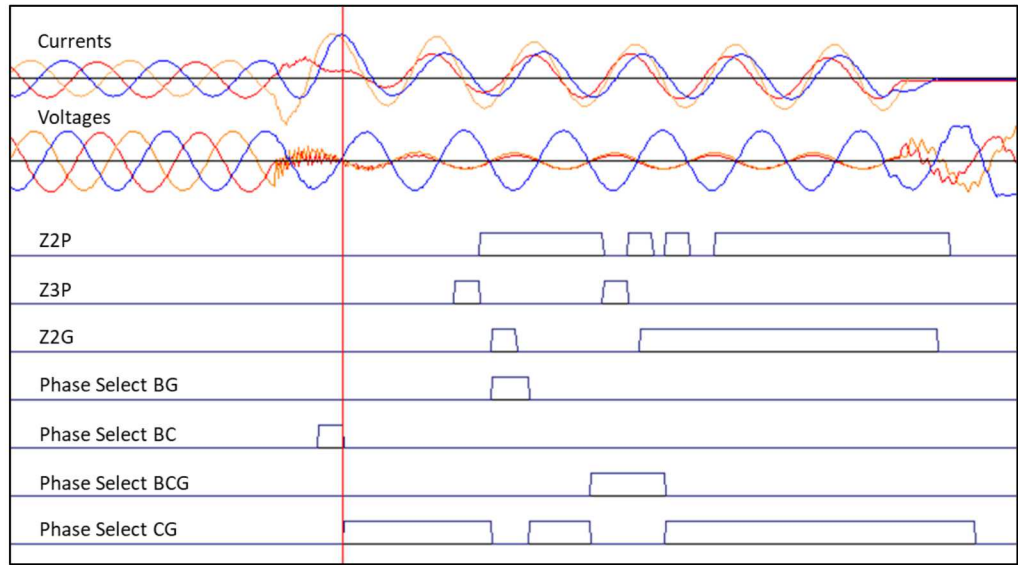


Figure 3-2. Inconsistent faulted phase selection during ABG fault

- It was noticed in a number of cases that the frequency of the positive and negative-sequence currents injected by the IBRs is different from the frequency of their respective terminal voltages. This is because the frequency of the voltage is largely determined by the Bus 1 and/or Bus 2 Thévenin sources and their infinite rotational inertia, while the frequency of the currents is determined by the IBRs. This lack of coherency¹⁶ in the voltage and current results in both security and dependability issues for directional and distance elements. In some cases it even caused reverse directional and distance zone operation for a forward fault. Lack of coherency in the voltage and current signals frequency is illustrated in Figure 3-3 below for the AB fault test case ID 31 with a waveforms shown in the Figure 2-7 above. The frequency of the unfiltered negative-sequence current (blue) is visibly different from the frequency of the unfiltered negative-sequence voltage (red).

¹⁶ Two waves are perfectly coherent if they have a constant phase difference and the same frequency and the same waveform.

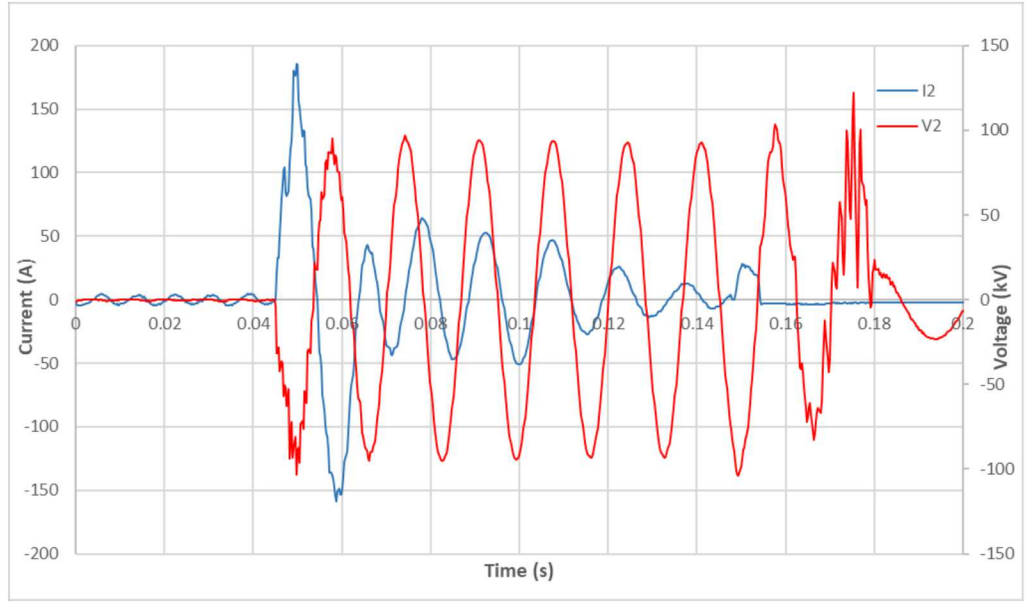


Figure 3-3. Unfiltered negative-sequence current (blue) and voltage (red) signals during fault

- Lack of coherency in voltage and current signals is further illustrated in the Figure 3-4 below, showing measurements by the relay-filtered quantities. It can be noticed that angle of the negative-sequence voltage remains stable through the fault, but angle of the negative-sequence current is continuously changing, causing inconsistent directional discrimination by protection.

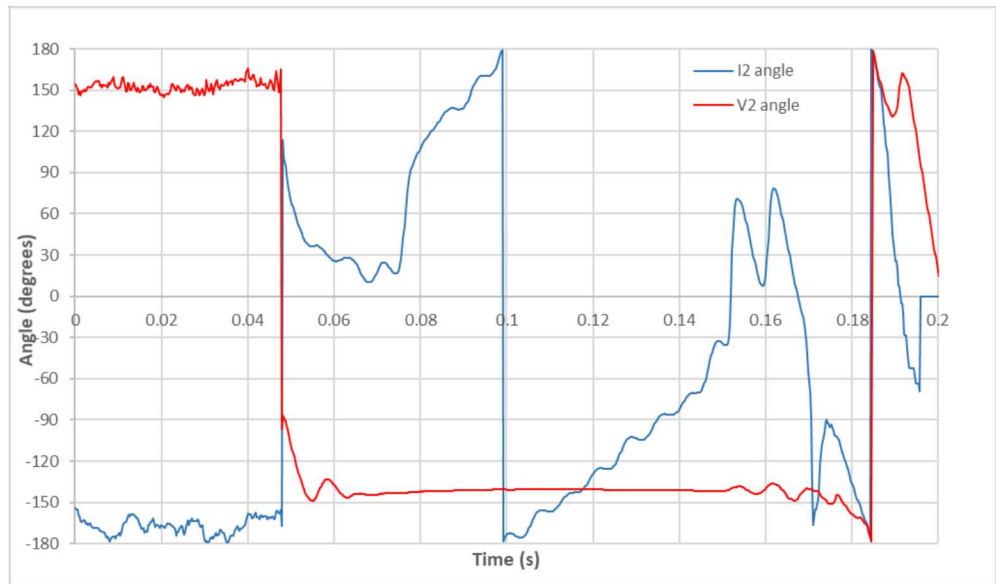


Figure 3-4. Angles of filtered negative-sequence current (blue) and voltage (red) during AB fault

3.3. Observations on Transient Overvoltage

Analyses of recent BES events, such as the Canyon 2 Fire [3], have shown IBR tripping with control indications of ac transient overvoltage (TOV). TOV is a very short term (usually less than one or two cycles) high voltage event which can be influenced by system harmonic impedance, fault type, point-on-wave of fault inception, non-linear effects of transformer saturation and arresters, interaction of IBR current injections with the system, and other factors. In general, the nature of any TOV is highly dependent on the specific parameters of the event and physical equipment involved, and is usually brief in duration.

Some TOV events may be sustained for longer periods. These also may occur for many reasons but are usually driven by harmonic resonances or instabilities. In the case of 60 Hz overvoltages (termed Fundamental Frequency Overvoltages or FFOVs), these may be caused by ordinary network topology changes such as load rejection.

Of particular interest for this study was whether the injection of a purely positive-sequence reactive current (without any negative-sequence contribution) into an unbalanced fault would result in overvoltage on the non-faulted phases. The specific conditions resulting in historical IBR tripping were different from those simulated in the test scenario.¹⁷ Nevertheless, the magnitudes of all instantaneous phase voltages were monitored for all scenarios to determine whether unexpected overvoltage would occur for this or any other reason.

Although overvoltage (using a 1.2 pu threshold for greater than four cycles) was observed in several scenarios, in each scenario it was attributed either to normal post-fault overvoltage due to the constant-current based IBR operating into an open circuit (islanding condition), or to non-fundamental frequency harmonic instabilities and transients specific to the individual inverter EMT models and the simplified test system.

A summary of overvoltage results for the reduced scenario list for each IBR is tabulated in Table 3-3. A complete set of PSCAD traces is attached in Appendix B. While there are several overvoltages that occur in the larger scenario list, the reduced scenario list is representative of the overvoltage types seen generally.

¹⁷ This is because many IBRs on the BPS employ momentary cessation of current injection outside the continuous operating range whereas this study focused on the injection of current during fault events.

Table 3-3. Overvoltage Results Summary

Case	Form an island during post-fault period ?	Over Voltage During Fault Period				Over Voltage During Post-Fault Period			
		OEM1	OEM2	OEM3	OEM4	OEM1	OEM2	OEM3	OEM4
1	No	no	no	Bus 4 ¹	no	no	no	Bus 4 ²	no
3	No	no	no	Bus 4 ¹	no	no	no	Bus 4 ²	No
5	No	no	no	Bus 4 ¹	no	no	no	Bus 4 ²	No
7	No	no	no	Bus 4 ¹	no	no	no	Bus 4 ²	No
25	Yes	no	no	no	no	Bus 4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}
27	Yes	no	no	Bus 3,4 ¹	no	Bus 4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}
29	Yes	no	no	Bus 3,4 ¹	no	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}
31	Yes	no	no	Bus 3,4 ¹	no	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}	Bus 3,4 ^{3,4}

* The threshold for declaring over voltage is assumed as 1.2 pu voltage for a duration of more than 4 cycles

Notes:

- 1 On-fault harmonic instability (mainly unstable for OEM3, but visible in other OEMs as damped harmonics).
- 2 Post-fault damped harmonic instability (removing fault results in harmonics damping, provided system is not islanded).
- 3 Post-fault FFOV (due to load imbalance and constant current inverter characteristic). Normally occurs after system is removed (island), and usually results in tripping. This is normal and expected.
- 4 Post-fault harmonic instability (mainly unstable for OEM3, but visible in other OEMs as damped harmonics).

For the scenarios where IBR is not islanded during the post-fault condition (Scenarios 1, 3, 5 and 7), overvoltages were observed only for OEM3 during fault and post-fault conditions. This is due to on-fault harmonic instability. These overvoltages remain in the system for multiple cycles even after the fault is cleared. The harmonic distortion causing instability in OEM3 is also present in other OEM models, but is only undamped in OEM3.

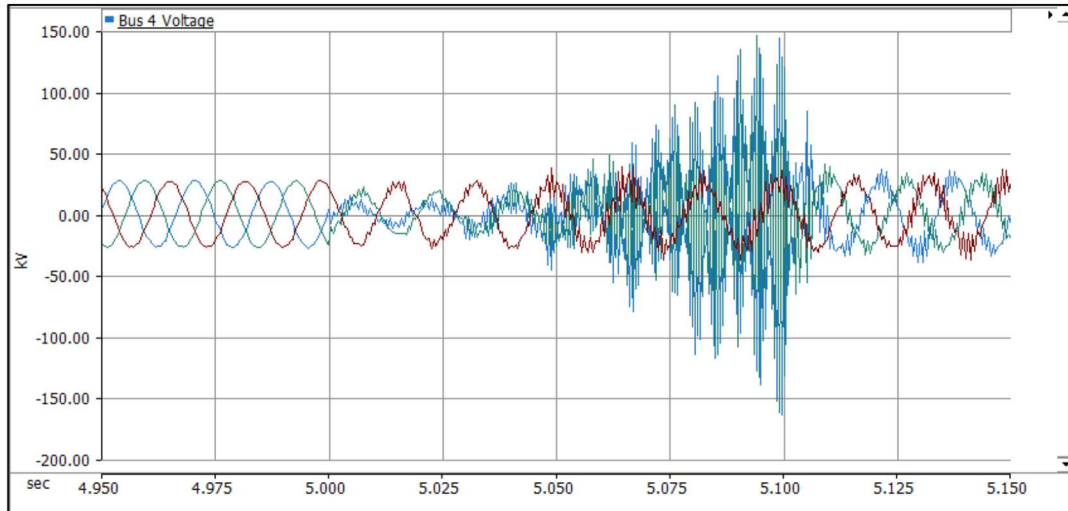


Figure 3-5. Bus 4 Voltage, Scenario 1, OEM 3; L-L Fault Applied from 5.0s to 5.1s

For the scenarios where an IBR is islanded during the post-fault period (Scenarios 25, 27, 29 and 31), high overvoltages were observed for all OEMs after the fault was cleared. This normally occurs in IBRs (which may be considered constant current sources in the transient period) after the plants are left connected into an islanded system, and usually results in the IBR tripping. Overvoltage during and after the fault also occurs in some scenarios due to on-fault harmonic instability.

The question of whether there is potential for overvoltage on the unfaulted phases if there is no negative-sequence current injection was not definitively answered. This type of overvoltage was not observed in the cases studied, but it should be noted that there were several mitigating circumstances with these cases. First, any condition where unfaulted phases were fed purely by IBR also had the other end of these phases connected to a voltage source, which would suppress overvoltages. Additionally, the level of positive-sequence current injection tended to be relatively low and a number of IBR models did not consistently inject positive-sequence reactive current during the fault. Finally, the negative-sequence current was very low, but non-zero in all cases. Consequently, the study was not able to verify whether problematic overvoltages could be present on the unfaulted phases for SLG faults with IBRs injecting only positive-sequence reactive current, nor identify the cause of the overvoltage tripping from the actual grid disturbances. Focused investigation via detailed EMT studies using system-specific IBR and topology should be performed to explore this issue further.

4. CONCLUSIONS

In keeping with the study scope, the conclusions presented in this section relate primarily to the negative-sequence response of the IBRs modeled in the simulations and the impact of that behavior on the responses of the protective relays that were tested using the simulation outputs. Any conclusions based on observations unrelated to negative-sequence fault current response are so noted.

In summary, of the 48 test scenarios studied, eight were deemed worthy of deeper evaluation by the study team. For those eight scenarios (identified in Table 3-1), relay response was tested for each IBR, resulting in total of 32 tests per relay. Of those 32 tests, 16 were problematic in that at least one of the two relays tests experienced unexpected operation of one or more relay elements.

In a synchronous machine-based system, the fault current is determined by the impedance between the source and the fault point. The magnitude and the angular relationship between the fault current and voltage is predictable and can be readily determined. The synchronous machine is represented as a voltage source behind an impedance. Regardless of size, manufacturer, type of energy source, vintage etc., the behavior of synchronous machines to a system fault are very similar. The traditional protection schemes in use today are designed based on this system characteristic.

The response of IBR during a fault condition on the power system is due to the respective control system. The IBR cannot be represented as a voltage source behind an impedance. The magnitude of the fault current is also controlled to not exceed its designed current rating. At present, the fault response of IBRs is not consistent. This lack of consistency applies not only across IBR manufacturers, but across generating technology (PV, Type 3 Wind, Type 4 Wind), as well. Additionally, there are further inconsistencies regarding negative-sequence current injection during unbalanced faults. As such, detailed EMT studies are necessary to understand IBR's fault response and impact to traditional protection schemes. Protection engineers typically do not run EMT studies and requiring one to select protection schemes and respective relay settings is extremely burdensome. An effort should be made to standardize the fault response as much as possible and develop models to represent IBRs in traditional short-circuit analysis programs.

Most IBRs that interconnect to the transmission network employ a main step-up transformer that offers a path for zero-sequence currents for unbalanced faults involving ground. Therefore, in the absence of negative-sequence current injection from IBRs during unbalanced faults, zero-sequence quantities could be used to reliably detect faults, including direction and location. Obviously, proper consideration should be given to relay coordination to maintain security and dependability essential with any protection schemes. For unbalanced faults where ground is not involved, traditional protection schemes have relied on negative-sequence quantities.

The adoption of microprocessor relays has allowed protection engineers to use negative-sequence quantities for unbalanced faults detection with much greater ease than they could with electromechanical relays. Negative-sequence voltages and

currents can now be extracted via digital signal processing techniques instead of employing bulky analog filters. This is particularly important in transmission line protection, where the computation of zero-sequence quantities may be impacted by the presence of strong mutual coupling between transmission lines. In these situations, zero-sequence polarization may be impractical [7]. If IBRs were to inject negative-sequence current with the proper phase relationship with the negative-sequence voltage (leading by ~ 90 degrees), this would ensure consistent and repeatable quantities that can be used by protection engineers during selection of protection schemes and development of relay settings. As such, consideration should be given to require IBRs to inject negative sequence current during unbalanced faults, which not only aids in detection of unbalanced faults where ground is not involved but also offers an alternative when use of zero-sequence quantities can't be deployed securely.

This study used a small test system. Most protection issues are observed for a case when IBR is connected to the BPS via a tie-line, with faults on this tie-line. However, as penetration of IBRs continues to grow, the identified issues may not only be limited to tie-lines connecting IBRs to the grid. At some penetration level, most of the grid may experience these same issues.

IBRs are current limited devices. Even when required to inject negative-sequence current, the magnitude is expected to remain low since the phasor sum of positive-sequence load current, positive-sequence reactive current, and negative-sequence reactive current would be limited to the inverter equipment rating. As such, protection engineers should review and update standard applications and practices and, if necessary, make adjustments to account for fault response from IBRs.

This study confirmed that protective relays using today's phasor-based algorithms cannot always provide secure and dependable protection with current state-of-the-art IBR control schemes. The authors recognize that advancement of new protection technologies will provide improvements to the secure and dependable protection of systems which include IBR. Continued research on advanced protection topics is highly encouraged, although outside the scope of this limited work.

The following are major observations for protection operation:

- Neither the magnitude nor the phase angle of negative-sequence current supplied by IBRs during fault conditions may be adequate to ensure reliable operation of protection elements.
- Negative-sequence current injection varies from manufacturer to manufacturer.
- The frequency of the current signal supplied by IBR during power system faults may not be coherent with the frequency of the voltage signal at the terminals of the IBR.
- Where IBR is connected to the power system through a main step-up transformer that offers a path for zero-sequence currents, zero-sequence based elements provide reliable protection operation for unbalance faults involving ground.

In summary,

1. There is a need to standardize response from IBRs to the line fault because:
 - a. Power engineers don't have access and knowledge of the particular IBR control model and IBR response to the line fault.
 - b. Even if the IBR control model is available, running EMT studies for various short circuit studies is not practical using today's standard computing technology.
 - c. A standardized IBR fault response streamlines selection of protection schemes and development of relay settings.
2. There is a need to require IBRs to inject negative-sequence current and control frequency of the current during unbalanced faults to aid in detection of unbalanced faults, especially ones that do not involve ground. Although some IBRs do inject negative-sequence current into the grid during fault conditions, not all do, nor is the magnitude consistent across OEMs. Injecting negative-sequence current implies a reduction in positive-sequence current such that the total IBR phase current is limited to its rating. Therefore, negative-sequence current injection by IBRs during a fault should ensure that a sufficient amount of positive-sequence current is also injected to aid in system fault recovery and stability. Alternatively, an IBR could, at higher cost, be required to provide higher transient current injection, similar to the subtransient reactance inherent to rotating machines. This study did not address either option.
3. The IBRs are current limited devices, i.e., fault current injection is close to the current rating. As penetration of these resources continues to grow, system fault currents are expected to fall, impact of which on traditional protection schemes is not fully understood at this time and continuing research in this field is necessary.

5. RECOMMENDATIONS FOR FURTHER STUDY

In the process of executing this study, the study team identified a number of issues that warrant further study. Those include:

1. *Staggered Tripping*: In Section 2.2.2, it was noted that staggered tripping of breakers at each line terminal was not simulated. A more rigorous representation of breaker operation could impact relay response since it impacts the IBR penetration in the source behind the relay.
2. *Mutually Coupled Transmission Circuits*: Section 4 and [7] discuss the impact of mutual coupling between transmission circuits on zero-sequence quantities during ground faults. An investigation could be done into how much IBR (% penetration, for example) can exist within the source behind a relay before switching from zero-sequence to negative-sequence ground fault detection is warranted.
3. *Single-Pole Tripping and Reclosing*: Many EHV transmission lines employ single-pole tripping and reclosing to improve transient stability following ground faults. The extent to which IBRs impact the ability of the line relays to properly discriminate the faulted phase and their response to the momentary open-pole condition is of interest.
4. *Unbalanced Series Faults*: Relay response to unbalanced series faults (e.g., open conductors) was not considered in this study.
5. *Additional Out-of-Section Faults*: Placing faults on Line 1 in Figure 2-2 would allow evaluation of the security of the relays protecting Line 2 and Line 3 when they become radial with the IBR supplying the fault currents.
6. *Series Compensated Transmission Circuits*: The protection of series-compensated transmission lines is challenging since the line reactance varies during fault conditions due to the operation of the capacitor bypass devices. While relay manufacturers have developed solutions to overcome these challenges, it is unknown how these solution may be impacted by increasing IBR penetration levels.

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APPENDIX A: SYSTEM PROTECTION PRIMER

A1. Introduction to Symmetrical Components

Symmetrical components are a tool used by power system engineers in analyzing balanced and unbalanced conditions (such as shunt and series faults) within a power system. Charles Fortescue proposed a method whereby a system of N unbalanced (non-symmetrical) phasors can be represented by a linear combination of N balanced (symmetrical) phasors. This method of expressing a set of unsymmetrical phasors by a linear combination of symmetrical phasors has become known as symmetrical components by power engineers.

In three phase power systems, the coupled phase components (in the A, B and C phase domain) can be represented by a linear combination of decoupled, symmetrical components known as the positive-, negative- and zero-sequence components. Sequence components are commonly used by protection engineers in analyzing power system faults or non-symmetrical system conditions.

A2. Use of Symmetrical Components in Unbalanced Fault Analysis

As mentioned in the introduction symmetrical components are used to analyze power system unbalance conditions, such as shunt or series faults. In this section we will review the basic shunt faults, such as a single line to ground fault (SLG), a line-to-line-to-ground fault (LLG), a line-to-line fault (LL) a three-phase fault (LLL) and the most common series fault which is the single pole open condition (SPO).

To convert a set of generally unbalanced phasors (X_A, X_B, X_C) to a set of balanced phasors (X_0, X_1, X_2) Fortescue proposed the following method;

$$\begin{pmatrix} X_{0,A} \\ X_{1,A} \\ X_{2,A} \end{pmatrix} = \frac{1}{3} \begin{pmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{pmatrix} \begin{pmatrix} X_A \\ X_B \\ X_C \end{pmatrix} \quad [1]$$

Where:

$a = 1\angle 120^\circ$ if the phase rotation is “ABC” see Figure 3.1(a)

$a = 1\angle -120^\circ$ if the phase rotation is “ACB” see Figure 3.1(b)

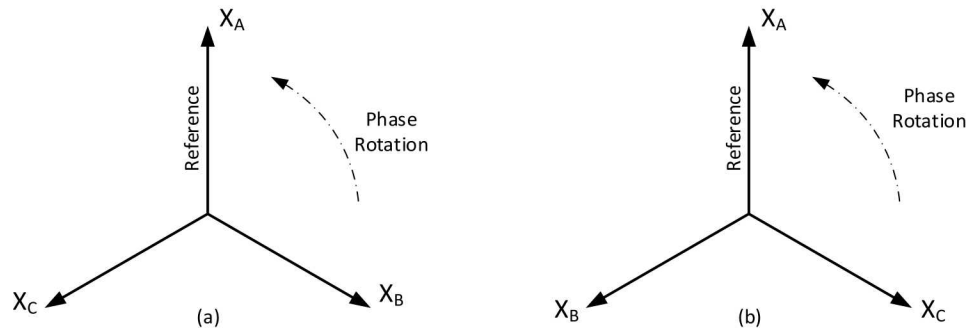


Figure A-5-1. Positive (left) and Negative (right) Phase Sequence

Equation [1] calculates the sequence quantities using the “A-phase” as the reference hence the subscript “A” in the equation.

The “B” phase can also be used as reference, this is done by rotating the indices of (X_A , X_B and X_C) as follows;

$$\begin{pmatrix} X_{0B} \\ X_{1B} \\ X_{2B} \end{pmatrix} = \frac{1}{3} \begin{pmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{pmatrix} \begin{pmatrix} X_B \\ X_C \\ X_A \end{pmatrix} \quad [2]$$

(note the phase rotation stays the same)

And similarly, we can use the “C” phase as the reference again by rotating the indices

$$\begin{pmatrix} X_{0C} \\ X_{1C} \\ X_{2C} \end{pmatrix} = \frac{1}{3} \begin{pmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{pmatrix} \begin{pmatrix} X_C \\ X_A \\ X_B \end{pmatrix} \quad [3]$$

Observing equation [1],[2],[3] we can make the following statements with respect to the X_{0A} , X_{0B} and the X_{0C} quantities in the different reference frames;

$$X_{0A} = X_{0B} = X_{0C}$$

The X_0 quantities are the same in all three reference frames and therefore X_0 is called the **zero-sequence** component. If we now observe X_{1A} , X_{1B} and X_{1C} we can make the following observation;

$$X_{1B} = a^{-1} X_{1A}; X_{1C} = a^{-1} X_{1B}$$

The X_1 components follow the phase sequence of the power system, they rotate in the same direction as the power system. Therefore, The X_1 components are called the **positive-sequence** components. And for the X_{2A} , X_{2B} and the X_{2C} we can make the following observation;

$$X_{2B} = a^{-2} X_{2A}; X_{2C} = a^{-2} X_{2B}$$

The X_1 components follow the phase sequence opposite to that of the power system, they rotate in the opposite direction to the power system. Therefore, The X_2 components are called the **negative-sequence** components.

It is typical to use the A phase as reference when analyzing an “A-phase” single line to ground (SLG) fault or a “BC” line-to-line (LL) fault or a “BCG” line-to-line-to-ground (LLG) fault. Similarly, the B phase is used for reference when analyzing a “B-phase” single line-to-ground fault or an “AC” line-to-line fault or a “ACG” Line-to-line-to-ground fault. The logic for using the C-phase as reference is similar as for using the A or B phase as reference. However,

it has become customary for power system engineers to use the “A-phase” as reference when analyzing faults or non-symmetrical conditions. Therefore, in most literature the equation to transform a set of non-symmetrical phasors to a set of balanced set of phasors is given by equation [4]. (*Note that the A subscript is dropped*)

$$\begin{pmatrix} X_0 \\ X_1 \\ X_2 \end{pmatrix} = \frac{1}{3} \begin{pmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{pmatrix} \begin{pmatrix} X_A \\ X_B \\ X_C \end{pmatrix} = [A] \begin{pmatrix} X_A \\ X_B \\ X_C \end{pmatrix} \quad [4]$$

The “A” matrix in equation 4 is known as the sequence transformation matrix. To convert sequence components back to phase components we use the following equation [5]

$$\begin{pmatrix} X_A \\ X_B \\ X_C \end{pmatrix} = \begin{pmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{pmatrix} \begin{pmatrix} X_0 \\ X_1 \\ X_2 \end{pmatrix} = [A]^{-1} \begin{pmatrix} X_0 \\ X_1 \\ X_2 \end{pmatrix} \quad [5]$$

So, we use equation [4] to decompose phase components into their sequence components and we use equation [5] to reconstruct the phase components from the sequence components.

A3. Sequence Component Networks

Power system engineers typically decompose faults on the power system into sequence diagrams so that they can analyze a fault or calculate the fault currents and voltages that are generated by different faults within the power system. In this section we will use a simple power system network, as is shown in Figure A-2, with a fault located on the transmission line between Bus S and Bus T a distance “m” from Bus S. To give the reader an insight into sequence components and how they are derived we will draw the sequence diagrams that are used to calculate the sequence currents and voltages for the different fault types within this simple power system and comment on the results.

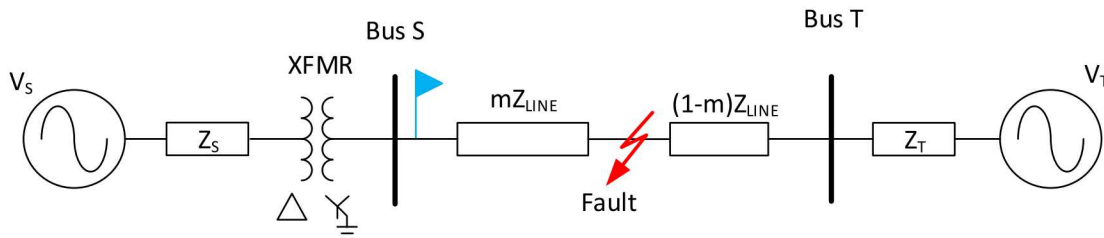


Figure A-5-2. Power system network with transmission line fault distance m from Bus S

For an A-phase SLG fault the sequence network diagram looks as shown in Figure A-3;

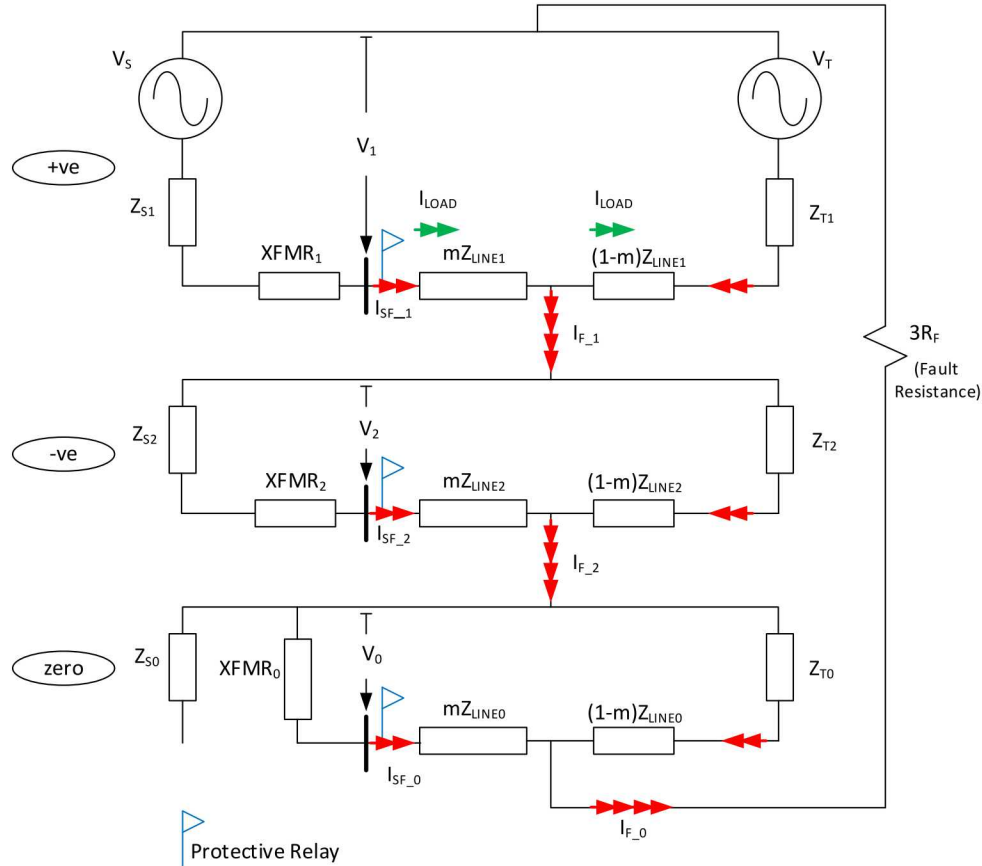


Figure A-5-3. Sequence network diagram for an A-phase SLG fault on transmission line

Examining Figure A-3, we can see that for an A-phase SLG fault, we can draw the following statements;

- The sequence fault currents; I_{F_1} , I_{F_2} and I_{F_0} are equal in magnitude and in phase with one another. (Note: That for a B-phase or C-phase SLG the sequence fault currents are still of equal magnitude with one another but are no longer in phase with one another, the angular relationship between the negative- and zero-sequence currents can be used to identify the faulted phase in a power system)
- The sequence currents measured at the relay location (Bus S) not only include the fault currents contributed by the source at S (I_{SF_0} , I_{SF_1} , I_{SF_2}) but, also includes the load current (I_{LOAD}). The load current is one of the factors that attributes to the sequence currents measured by the protective relay not being of equal magnitude or being in phase with one another.
- The negative- and zero-sequence fault current contribution from the sources always flow towards the fault point (This is the reason for using negative- or zero-sequence direction elements to determine the direction of a fault.)

For a BC LL fault the sequence network is as shown in Figure A-4.

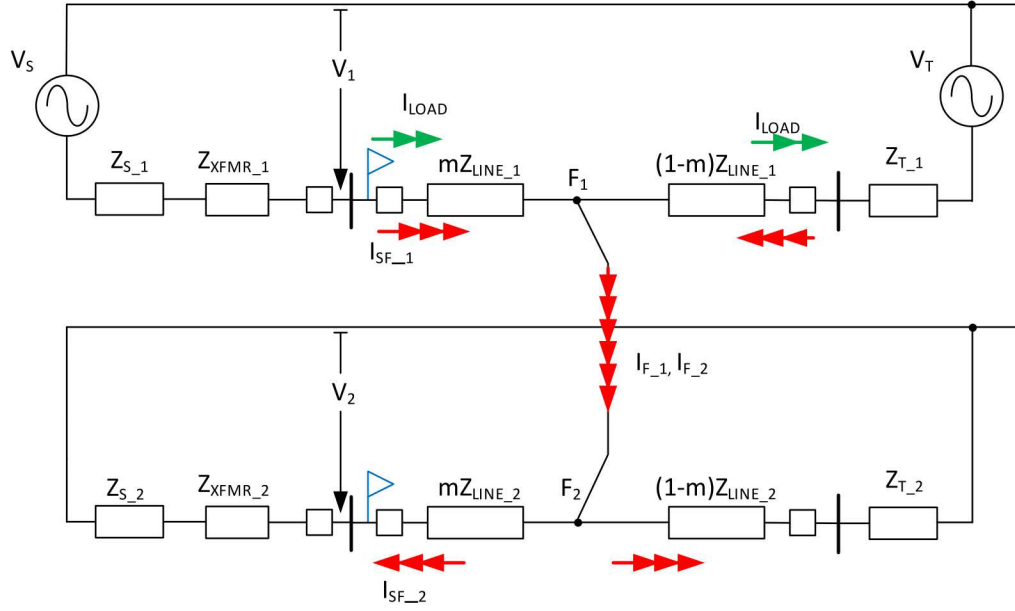


Figure A-5-4. Sequence network diagram for a B-phase to C-phase fault on transmission line

Examining Figure A-4, we can see that for an BC LL fault, we can make the following Statements;

- The positive-sequence fault current (I_{F_1}) and negative-sequence fault current (I_{F_2}) are of equal magnitude and of opposite polarity (i.e. $I_{F_1} = -I_{F_2}$).
- At the fault point the positive- and negative-sequence voltages are equal in magnitude and phase.

For a BCG, LLG fault the sequence network is as shown in Figure A-5.

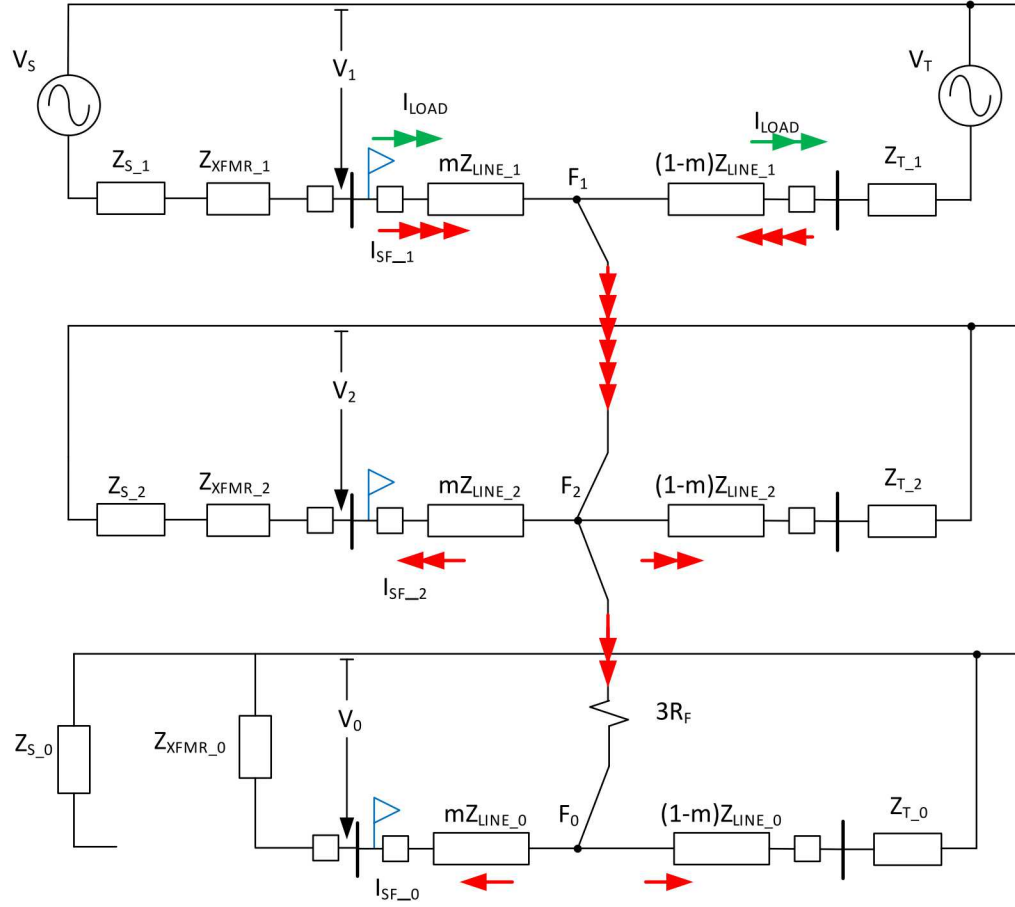


Figure A-5-5. Sequence network diagram for an B-phase to C-phase to ground fault on transmission line

Examining Figure A-5, we can see that for an BCG, LLG fault, we can make the following Statements;

- The positive-sequence (I_{F_1}) is equal to the negative of the sum of negative-sequence fault current (I_{F_2}) and the zero-sequence fault current (I_{F_0}), i.e.

$$I_{F_1} = -(I_{F_2} + I_{F_0})$$
- At the fault point the positive-, negative- and zero-sequence voltages are all equal to zero, if $R_F=0$.

For a 3-Phase, LLL fault the sequence network is as shown in Figure A-6.

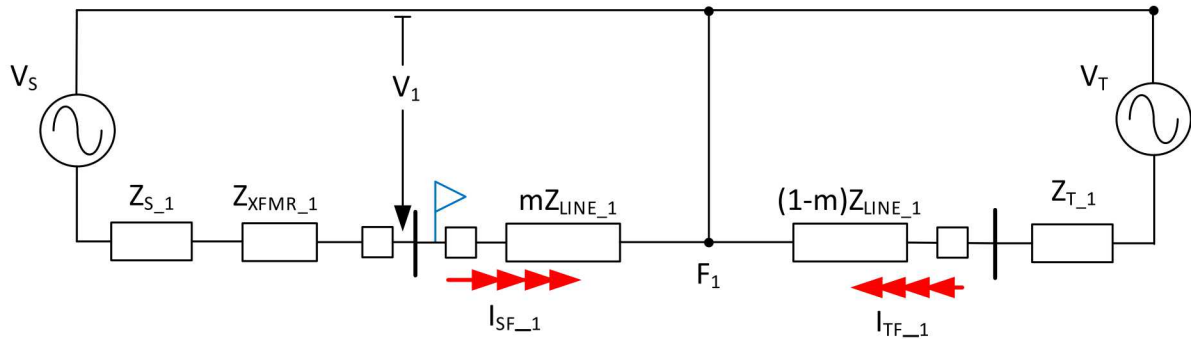


Figure A-5-6. Sequence network diagram for a 3-Phase fault on transmission line

Examining Figure A-6, we can see that for a 3-Phase fault we can make the following statements;

- The network is composed of only positive-sequence components.
- The current supplied by the sources only consists of positive-sequence fault currents (I_{SF_1} and I_{TF_1}) and no load current. (A three-phase short basically shorts out each sources)
- This type of fault is known as a symmetrical fault since the three phase currents are equal in magnitude and displaced from one another by 120°
- The only difference between a three-phase short circuit and load is the magnitude of the positive-sequence current and the phase angle between the phase voltage and current. Typically, load current is far less than short circuit current.

The above are all shunt faults. The only series fault we will consider for this report is the open phase fault. An open phase fault occurs when one breaker pole is open, or a conductor breaks, etc. The sequence diagram for an open pole condition is as shown in Figure A-7 since we are ignoring the shunt components of the transmission line the location of where the conductor is broken does not influence the sequence diagram.

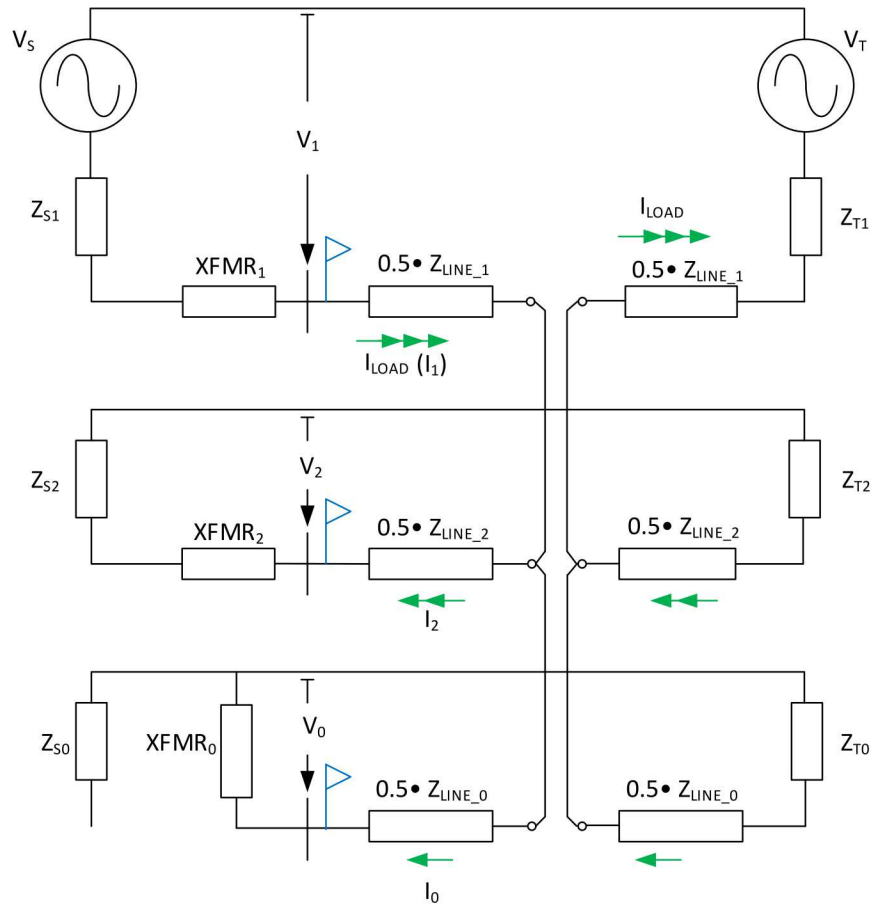


Figure A-5-7. Sequence network diagram for an open pole condition for the system shown in Figure A-2

Examining Figure A-7, we can make the following statement;

- The positive-sequence current (load current) is equal to the negative of the sum of the of negative- and zero-sequence current measured by the protection relay. (This is very similar to an LLG fault when there is no load).
- The magnitude of the load current determines the magnitude of the negative- and zero-sequence current.

A4. Introduction to Transmission Line Protection

In its basic/simplest form transmission line protection is comprised of either one or both of the following two elements;

- Impedance (or distance) protection element (21)
- Line current differential protection element (87L).

Most transmission lines on the BPS are protected using the above two methods. The following section will give the reader an overview of these two elements.

A4.a. Impedance Protection Elements

In its simplest form an impedance element measures the impedance from its location to the fault point. If the measured impedance falls within the set reach of the element, i.e. the measured impedance is less than the set reach of the impedance element, the element asserts its output. Since the exact impedance of a transmission line is not precisely known and to account for instrument transformer inaccuracies and the inaccuracy of the measurement element of the impedance element, the set reach of the instantaneous impedance element is lower than the actual impedance of the transmission line. Typically, the set reach of the instantaneous impedance element is set to 80% of the line impedance, so that the element does not operate for a fault outside of the protected line. Because the set reach for the instantaneous impedance element is set below the impedance of the transmission line this element is also known as an *underreaching element* (i.e. it does not cover the entire line). Therefore, to provide protection for the entire line a second time delayed impedance element is required with a reach setting of no less than 120% of the line impedance. The second impedance element overlaps with the instantaneous impedance element of the adjacent feeder and to give the instantaneous impedance element of the adjacent line an opportunity to clear a fault in the adjacent line first the second impedance element is time delayed by typically about 330 ms-400 ms. Since the set reach of the second impedance element is set greater than the impedance of the transmission line this impedance element is also known as an *overreaching element*. Figure A-8 is a simple sketch showing the reach of the instantaneous and the time delayed impedance elements.

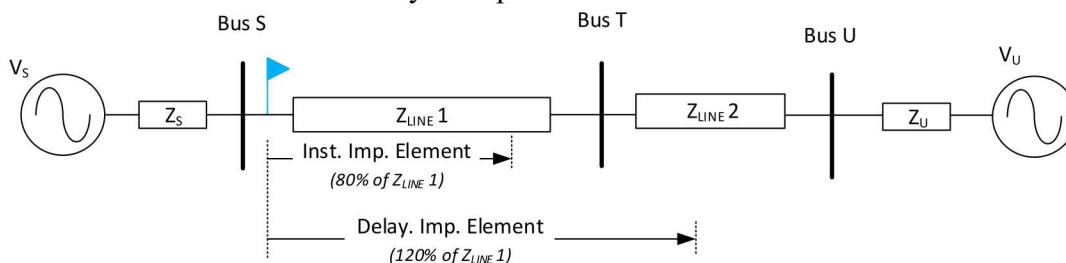


Figure A-5-8. Reach of the instantaneous and the time delayed impedance elements

As can be seen from the above approach the proposed solution has one major drawback that is that not all faults are cleared without an intentional time delay. Faults within the first 80% of the line are cleared instantaneously (without any intentional delay) and faults in the remaining 20% of the line are cleared after an intentional delay. It may be acceptable in some cases but not

most, to accelerate tripping for faults in the remaining 20% of the transmission lines where communication schemes are employed.

A4.b. Line Differential Protection Elements

The basic principle of line current differential protection (87L) is that the current flowing into a transmission line is equal to the current flowing out of the transmission line under non faulted condition when one ignore the lines charging current, i.e. $I_{IN} = I_{OUT}$. Stated differently in a healthy (non-faulted) transmission line, the net current flow in the transmission line is equal to zero. However, to provide current differential protection, each relay at each of the transmission line terminals needs the current information from the other (remote) transmission line terminals in order to calculate the net current flow in the transmission line. For each current differential element to have access to each remote line terminal's current, a high fidelity, low latency, lower jitter communication medium is required between the relays at each line terminal.

The current differential element aligns all the current data from all the line terminal (s) then calculates the total net current (or differential) in the transmission line. For an N-terminal transmission line the differential current is calculated as follows;

$$I_{DIFF} = |I_1 + I_2 + I_3 + I_4 + \dots I_N| \quad [6]$$

If the differential current (IDIFF) is above a threshold, the element declares a fault condition and initiates a trip. Figure A-9 is a sketch of a simple application of a line current differential element.

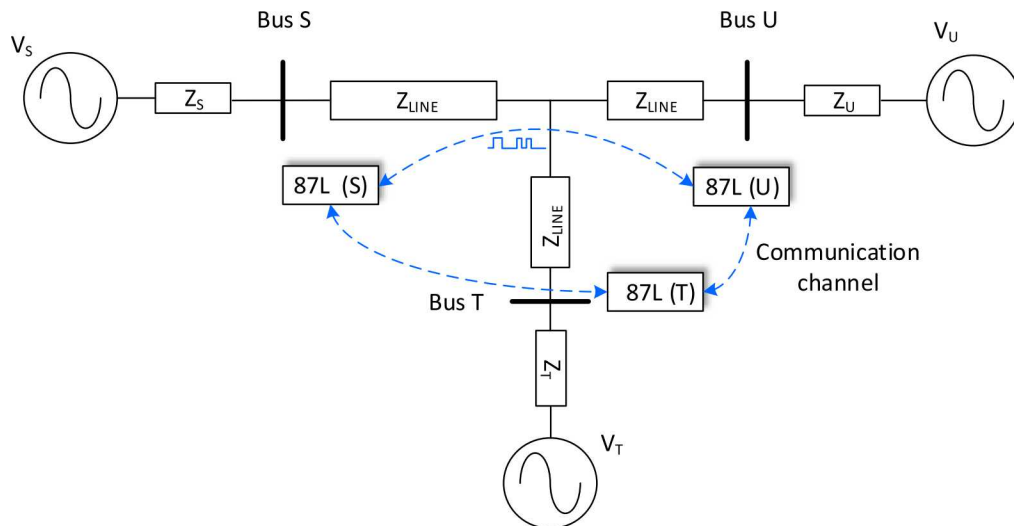


Figure A-5-9. Application of line current differential element (87L)

A4.c. Communication-Aided Protection

There are two main types of communication-aided protection schemes these being;

- Pilot communication schemes
- Line current differential schemes (discussed in section 3.3.2)

The main difference between the two types of communication schemes has to do with the bandwidth requirements. In general the pilot-based communication schemes do not require as high of a bandwidth as the line current differential schemes nor do latency and jitter play as important of a role.

A4.c.i. Pilot Communication Schemes

Pilot-based communication schemes operate in conjunction with impedance protection elements to facilitate rapid tripping for faults not covered by the instantaneous impedance protection element. Pilot communication schemes can be broken up into two main categories namely;

- Permissive schemes: requires a communication signal from the remote terminal to accelerate tripping of the overreaching element. For example, assume that the transmission line experiences a fault 90 % from the local terminal. At the local terminal the fault will be detected by the overreaching distance element. At the remote terminal the fault will be detected by both the underreaching distance element (*instantaneous element*) and the overreaching distance element. At the remote terminal the overreaching distance element will send a signal to the local relay that it sees the fault within its reach. At the local terminal, the permissive scheme will see that the overreaching element is asserted, and it received a signal from the remote terminal. The scheme now knows that the fault is within the protected transmission line and therefore issues a trip signal. (*The remote terminal gave the local terminal permission to trip*). Figure A-10 illustrates the basic principle of a POTT scheme.

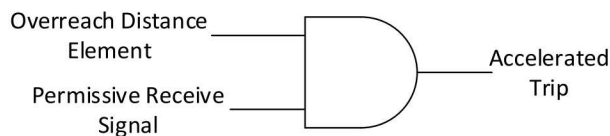


Figure A-5-10. Implementation of permissive pilot communication scheme

- Blocking schemes: requires a communication signal from the remote terminal to block accelerated tripping of an overreaching element after a short time delay. For this scheme to work, the relays at all the line terminals have to have impedance elements set to detect faults behind the relay, i.e. in the reverse direction. If one of the terminals detects a fault in the reverse direction it will send a blocking signal to the other relay terminals. For example, assume the same scenario as the permissive scheme, fault 90% from the local terminal. At the local relay terminal, the overreaching distance element will detect the fault and start a timer (open a window). At the remote terminal both the underreaching and overreaching elements will detect the fault but since the reverse distance element did not assert, no blocking signal is sent to the local relay. At the local relay after the preset time delay (*set long*

enough for the remote block signal to arrive), the scheme issues an accelerated trip. Figure A-11 illustrates the basic principle of a blocking scheme.

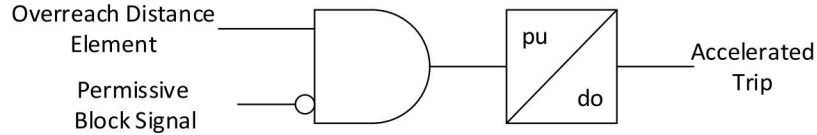


Figure A-5-11. Implementation of blocking pilot communication scheme

A4.c.ii. Differential Protection Communication Schemes

As mentioned in section A4.b, line current differential requires the current differential element to have access to all the currents at all the line terminals. Therefore, line current differential requires a high fidelity, low latency, low jitter communication channel.

A5. Concepts of Dependability and Security

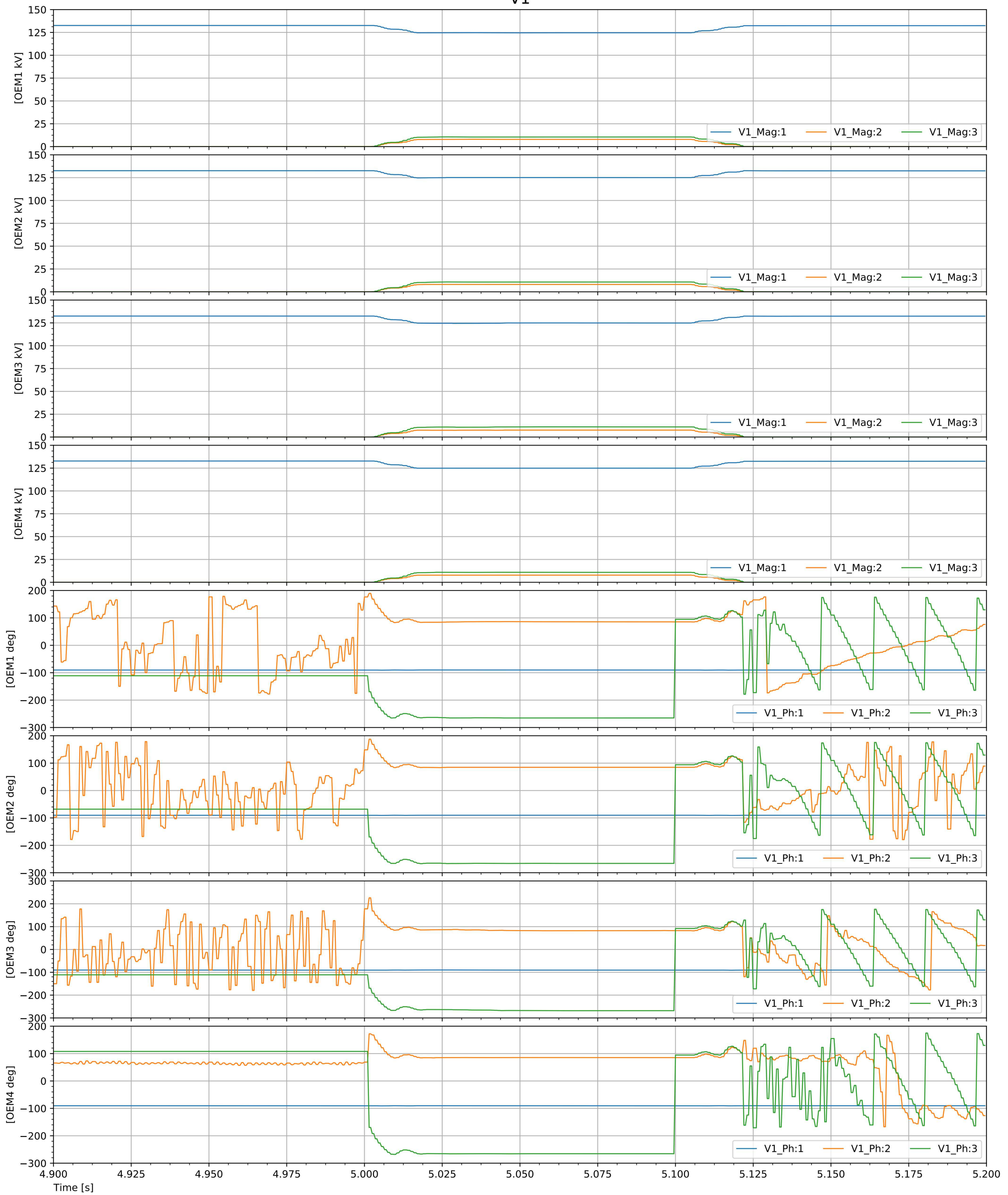
Dependability and security go hand in hand when it comes to protection systems. We define an element as being dependable if it detects every event (fault) within its zone of protection and takes the correct action. The definition of security is that an element remains stable (does not operate) for any event (fault) outside of its protective zone. From the definition of dependability and security we can now understand that a protection element must be both dependable and secure. It must operate when required (for all faults within its protective zone) and remain stable for any faults outside of its protective zone.

A6. Comparison of IBR and Rotating Machine Fault Response

From the test results to date, we can state that if the source behind the protective relay is predominantly made up from IBR, we can consider this as a weak positive- and negative-sequence source, but a strong zero-sequence source (more correctly a sink). The strength of the zero-sequence source is in no way attributable to the IBR but is a result of the Wye/Delta/Wye transformer at the point of interconnection (POI). The results also show that protective elements that rely on positive- and zero-sequence currents (both in magnitude and phase) may not be dependable nor secure, whereas protective elements that use zero-sequence elements maintain their dependability and security.

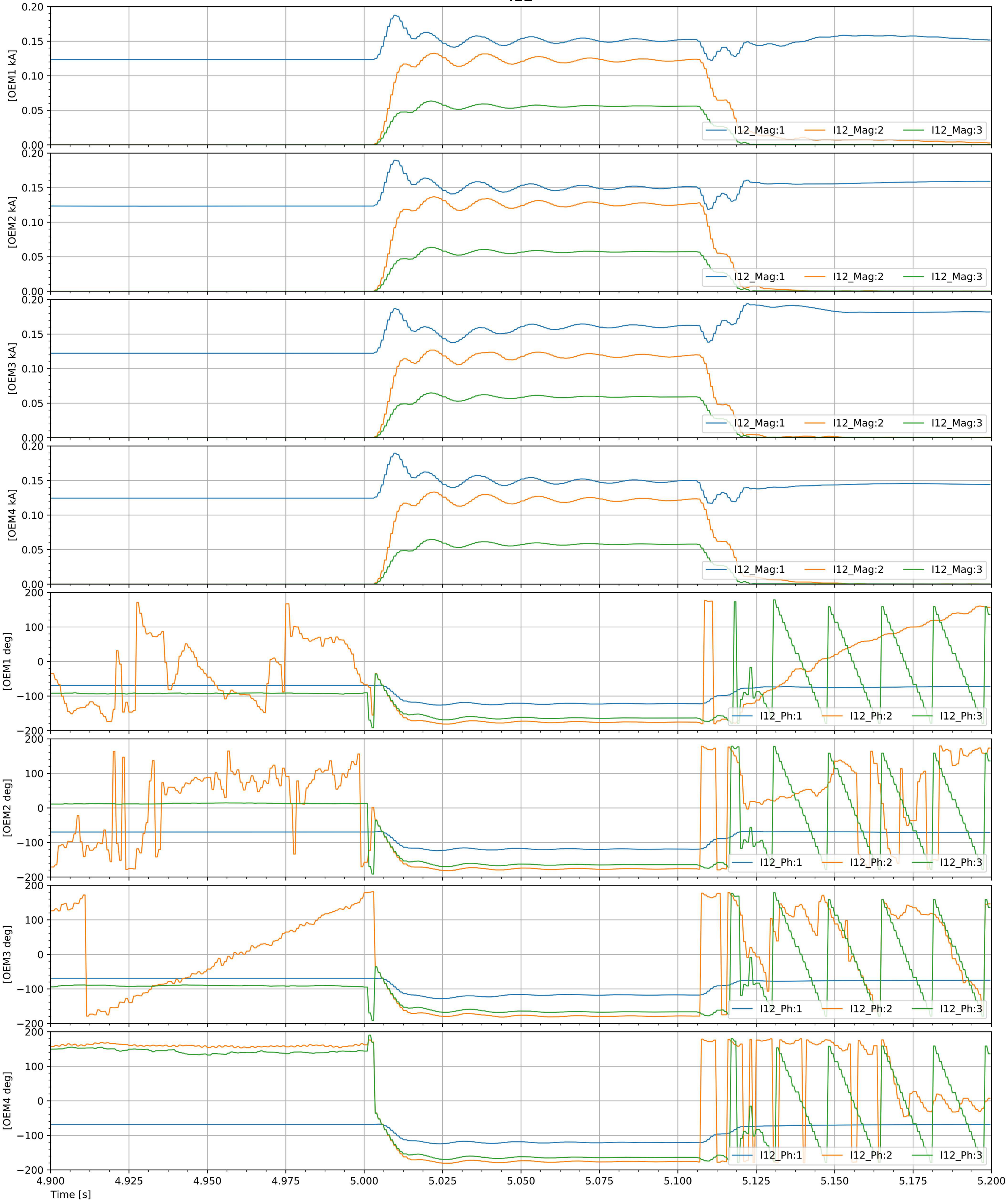
APPENDIX B: PSCAD TRACES

V1



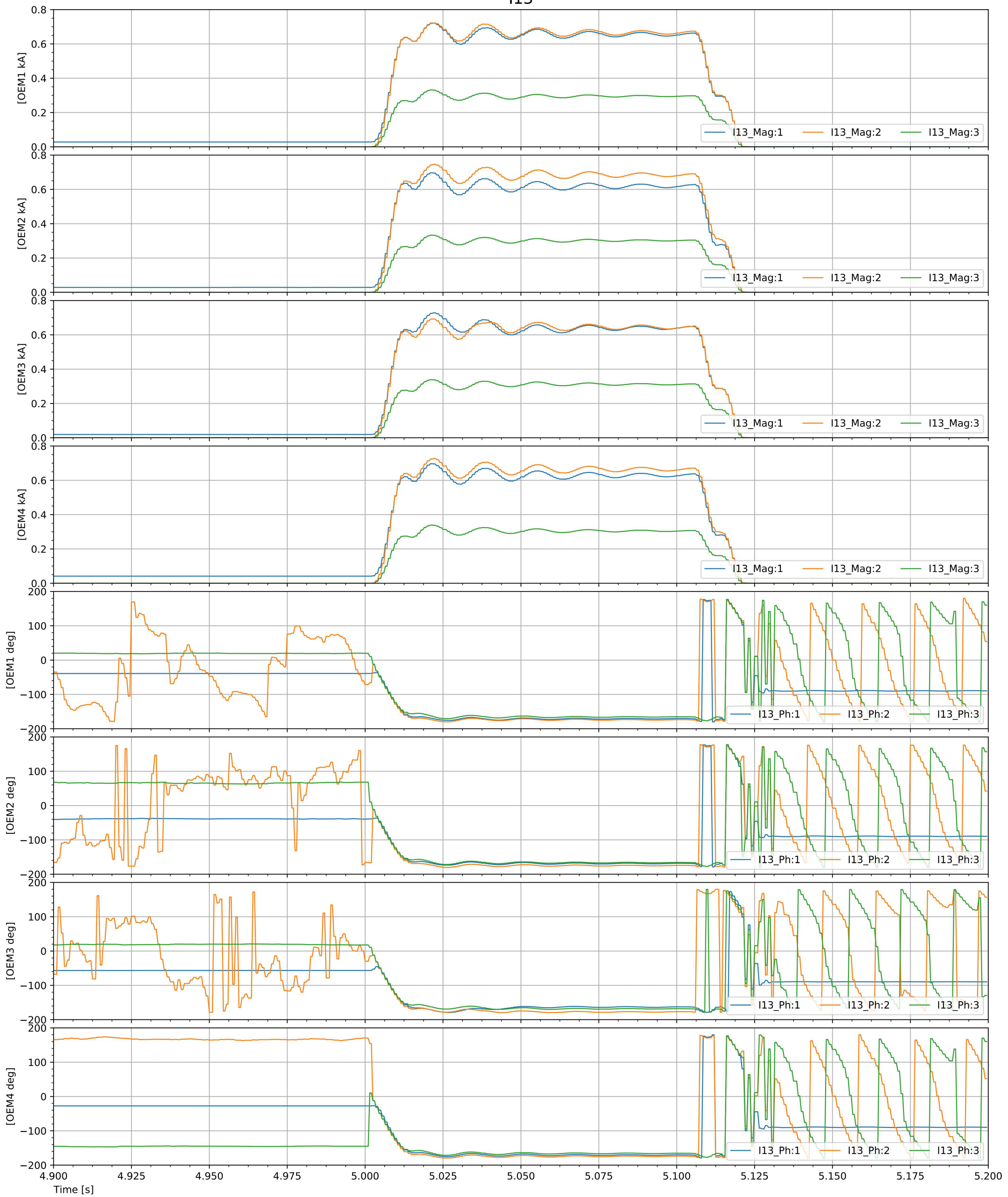
Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms

I12



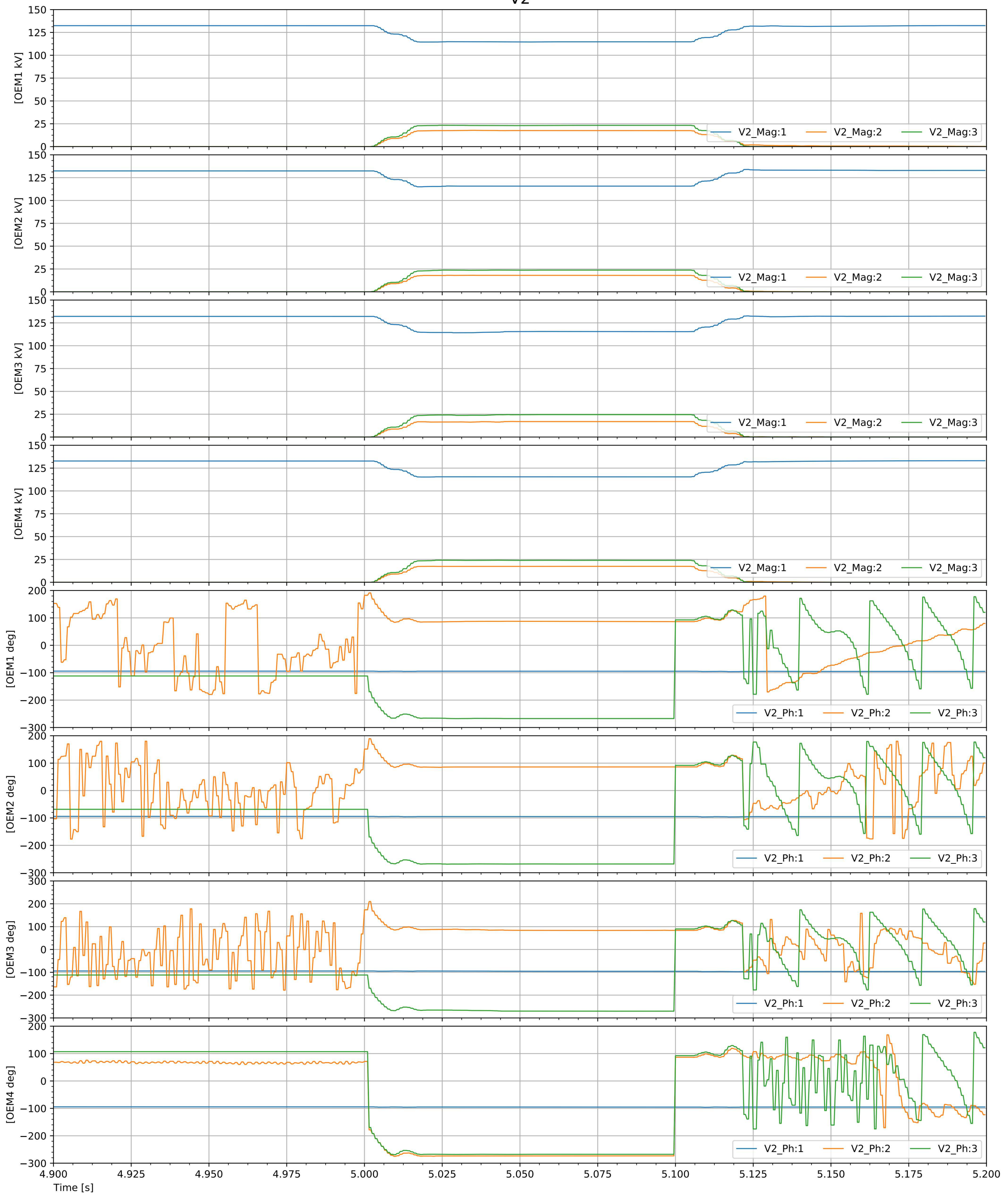
Network Configuration: System Intact
Fault Location: B
Fault Type: AG
Fault Resistance: 0.001 ohms

I13



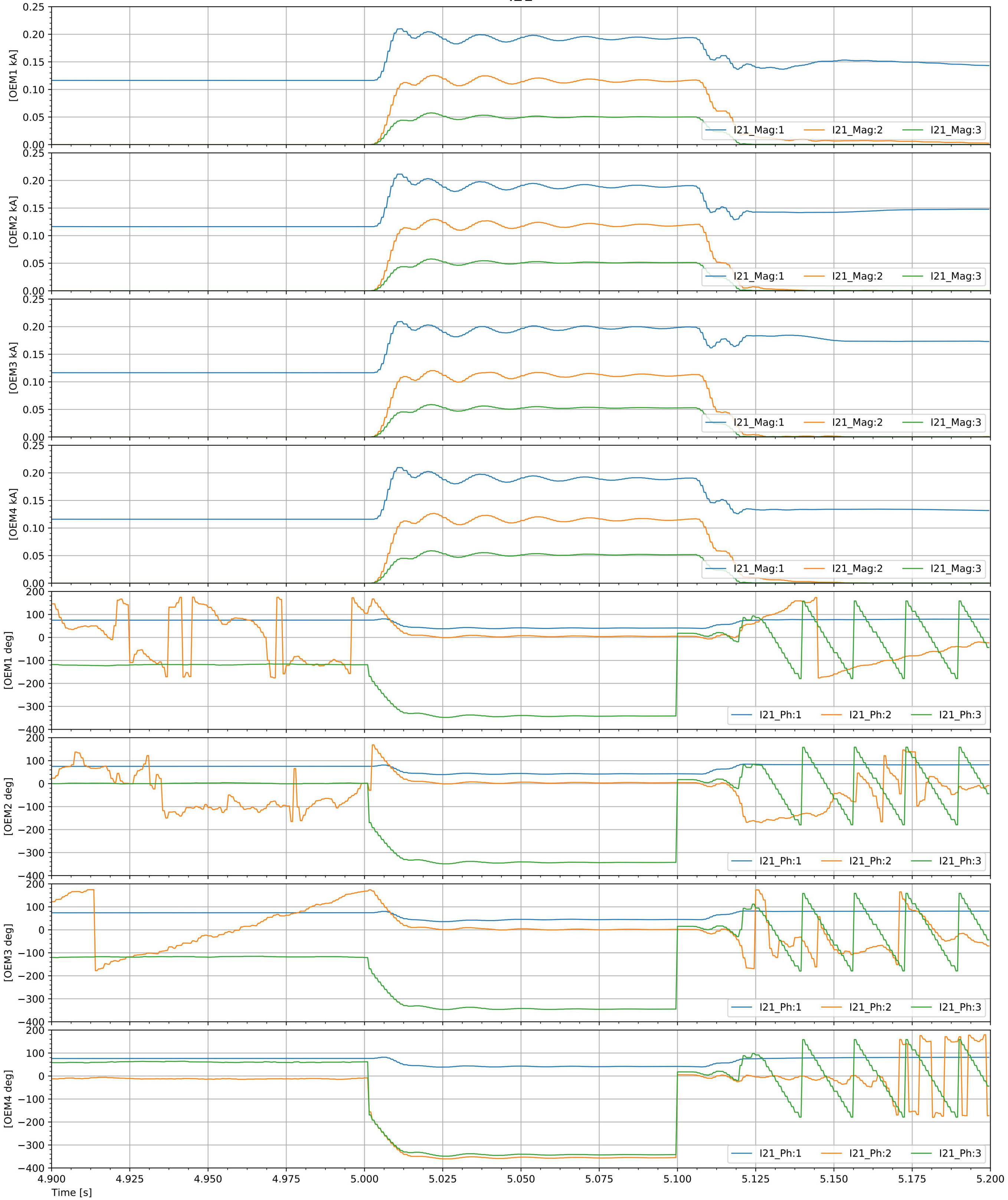
Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms

V2



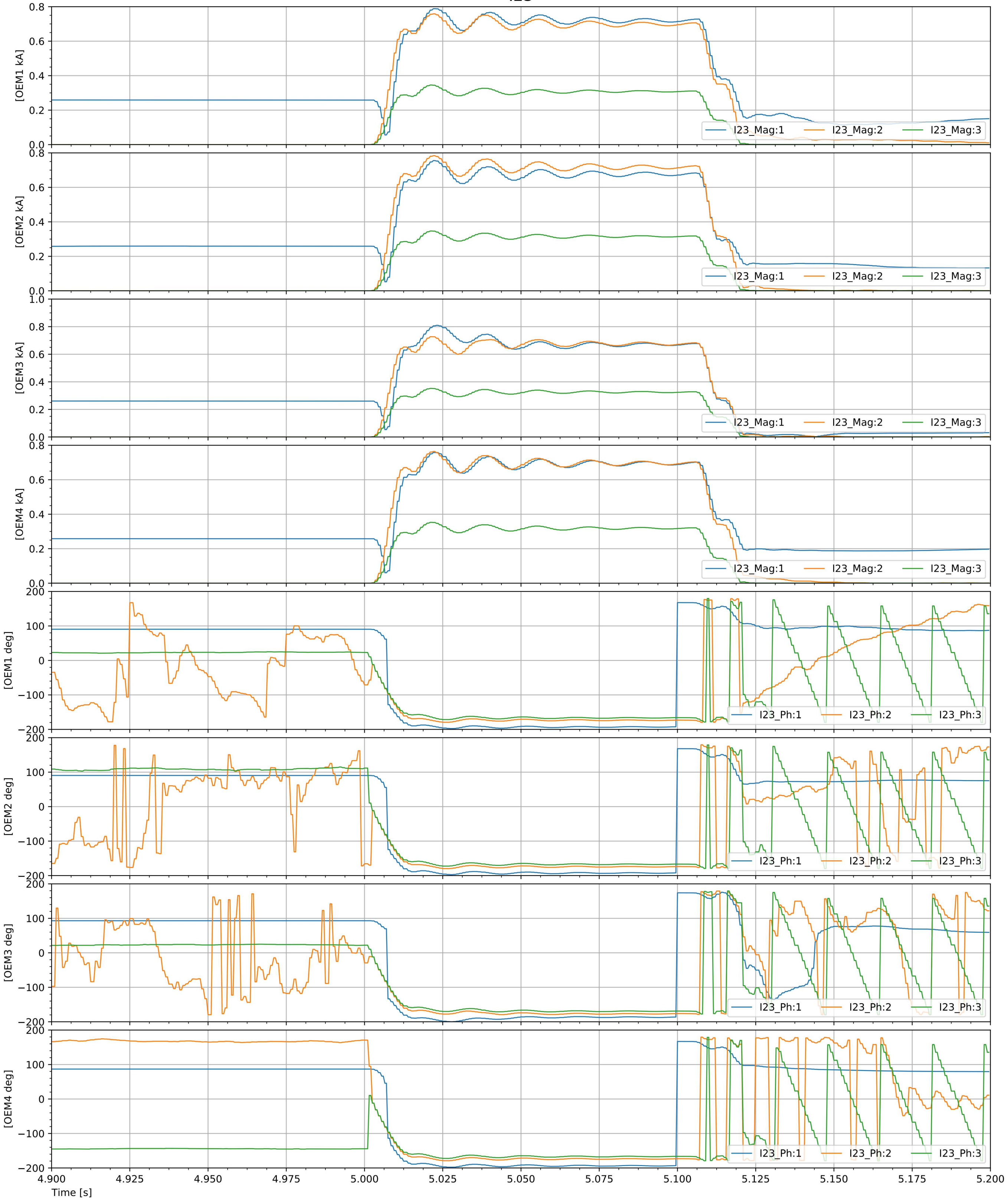
Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms

I21



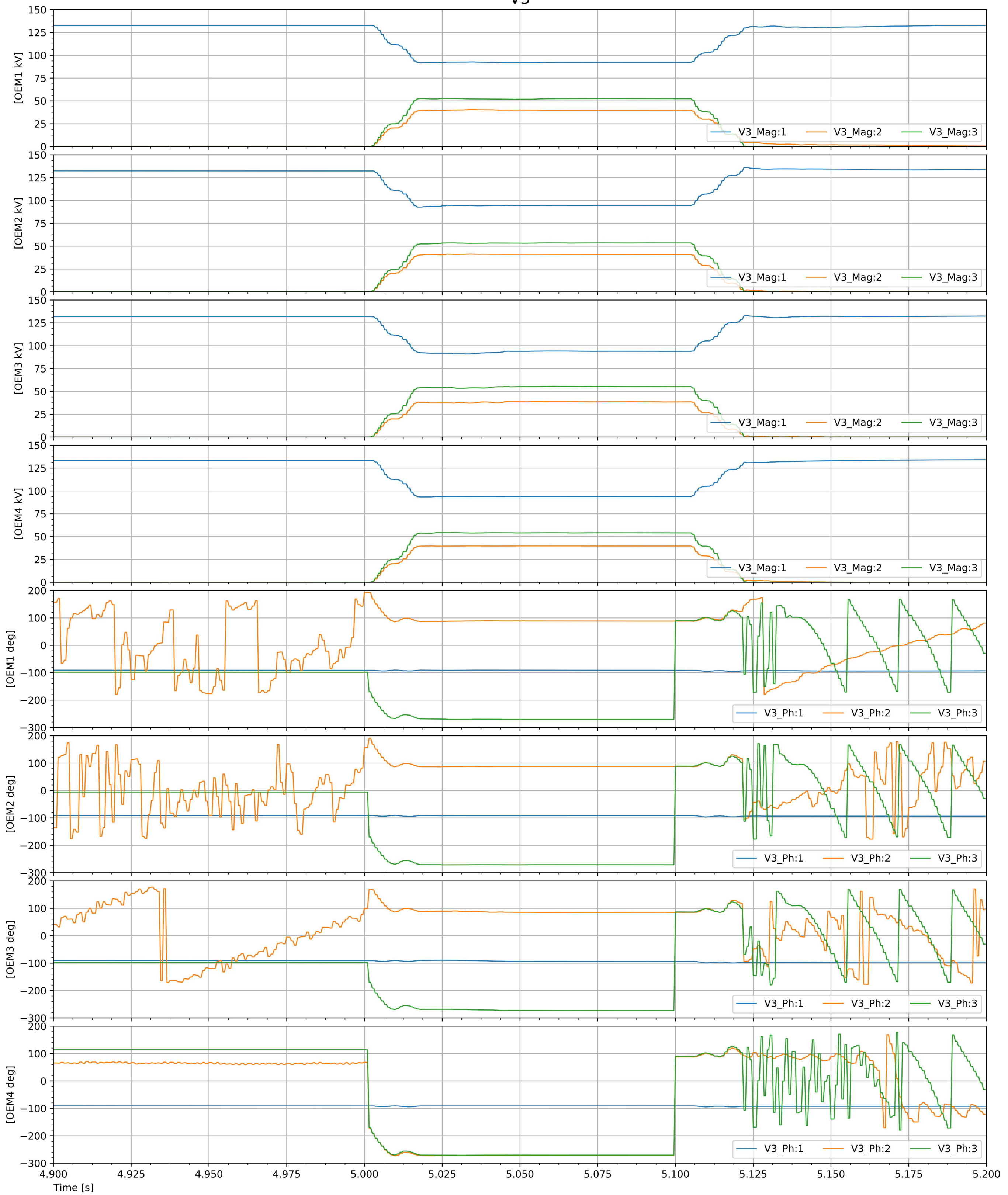
Network Configuration: System Intact
Fault Location: B
Fault Type: AG
Fault Resistance: 0.001 ohms

I23

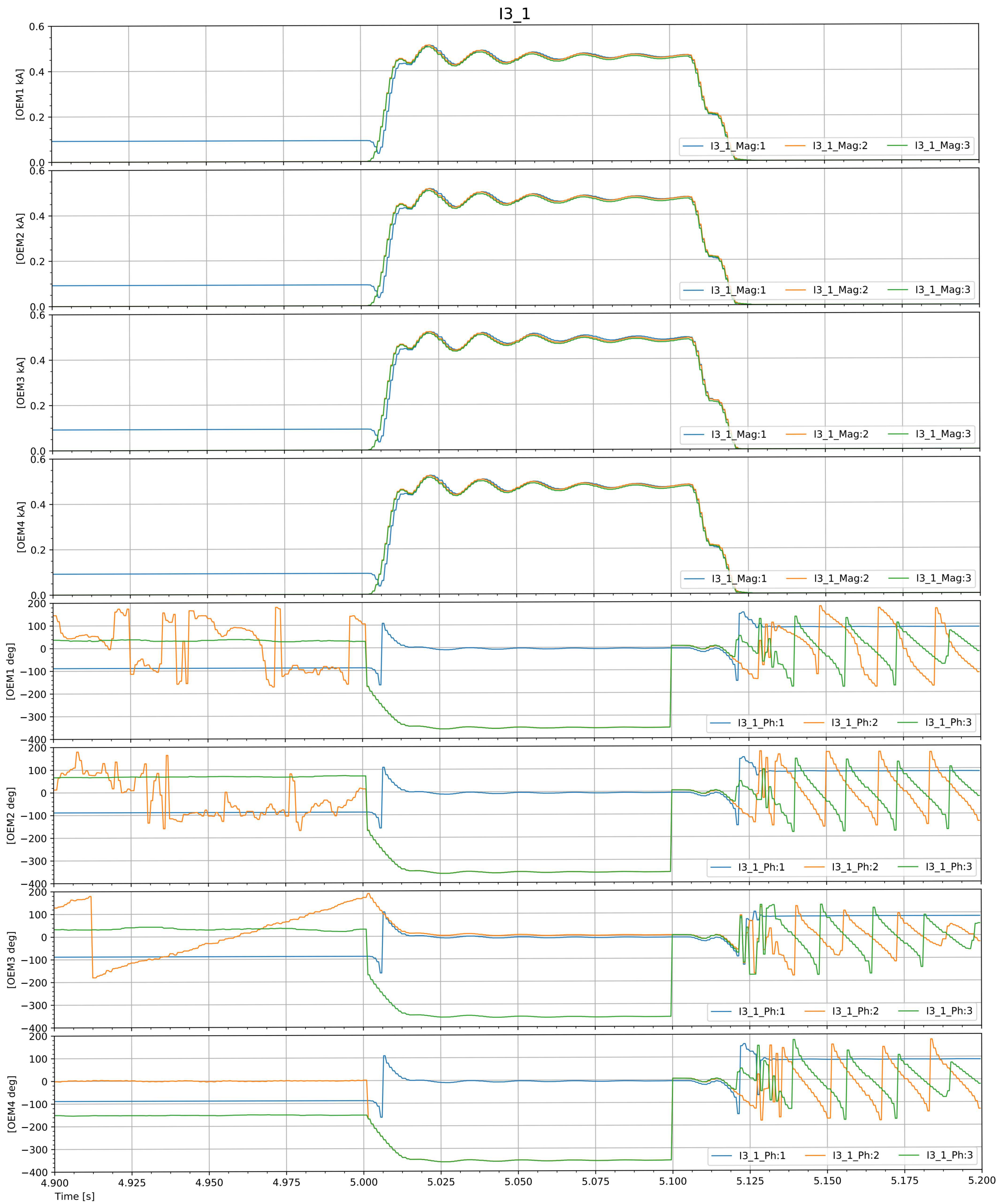


Network Configuration: System Intact
Fault Location: B
Fault Type: AG
Fault Resistance: 0.001 ohms

V3

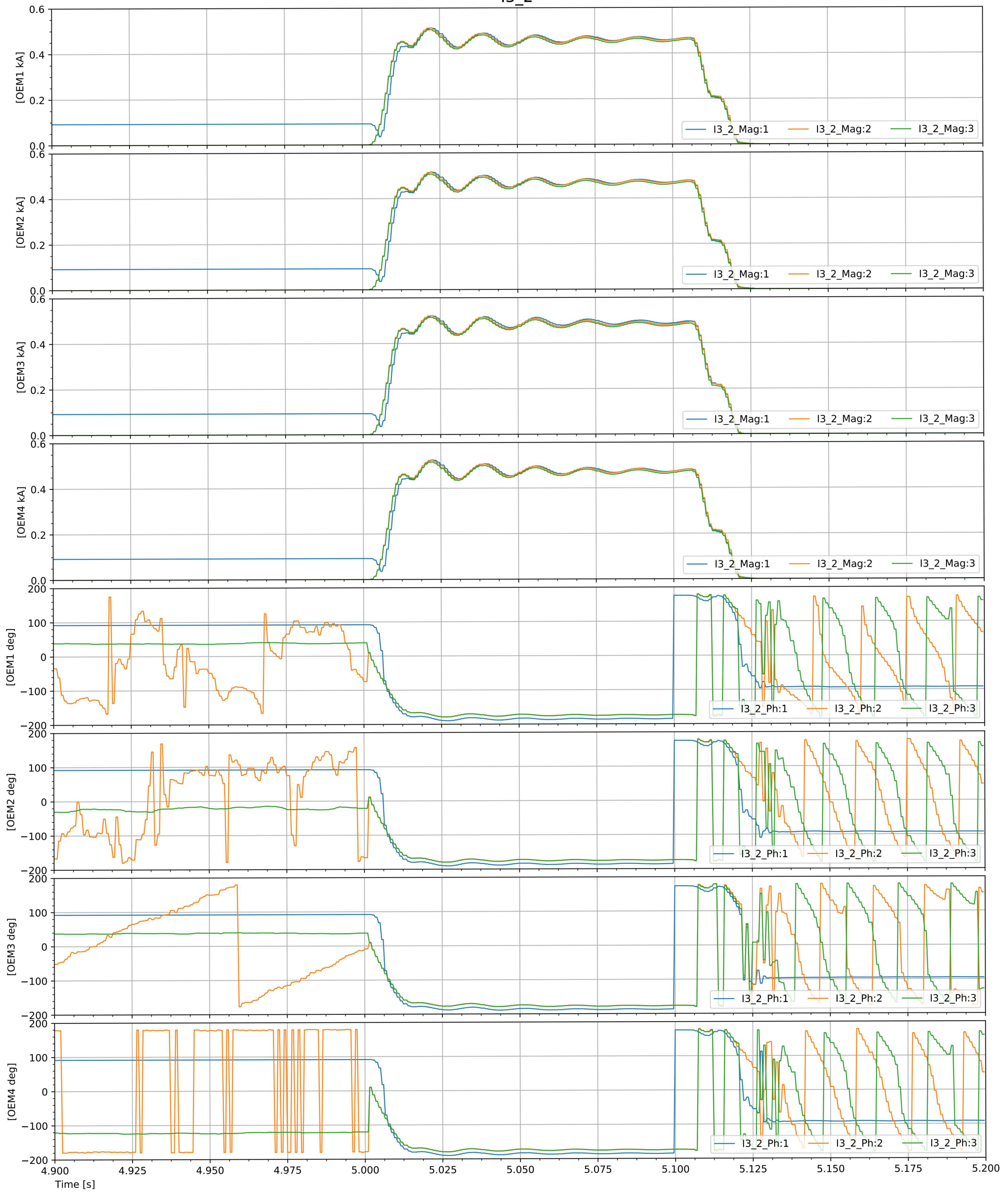


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms

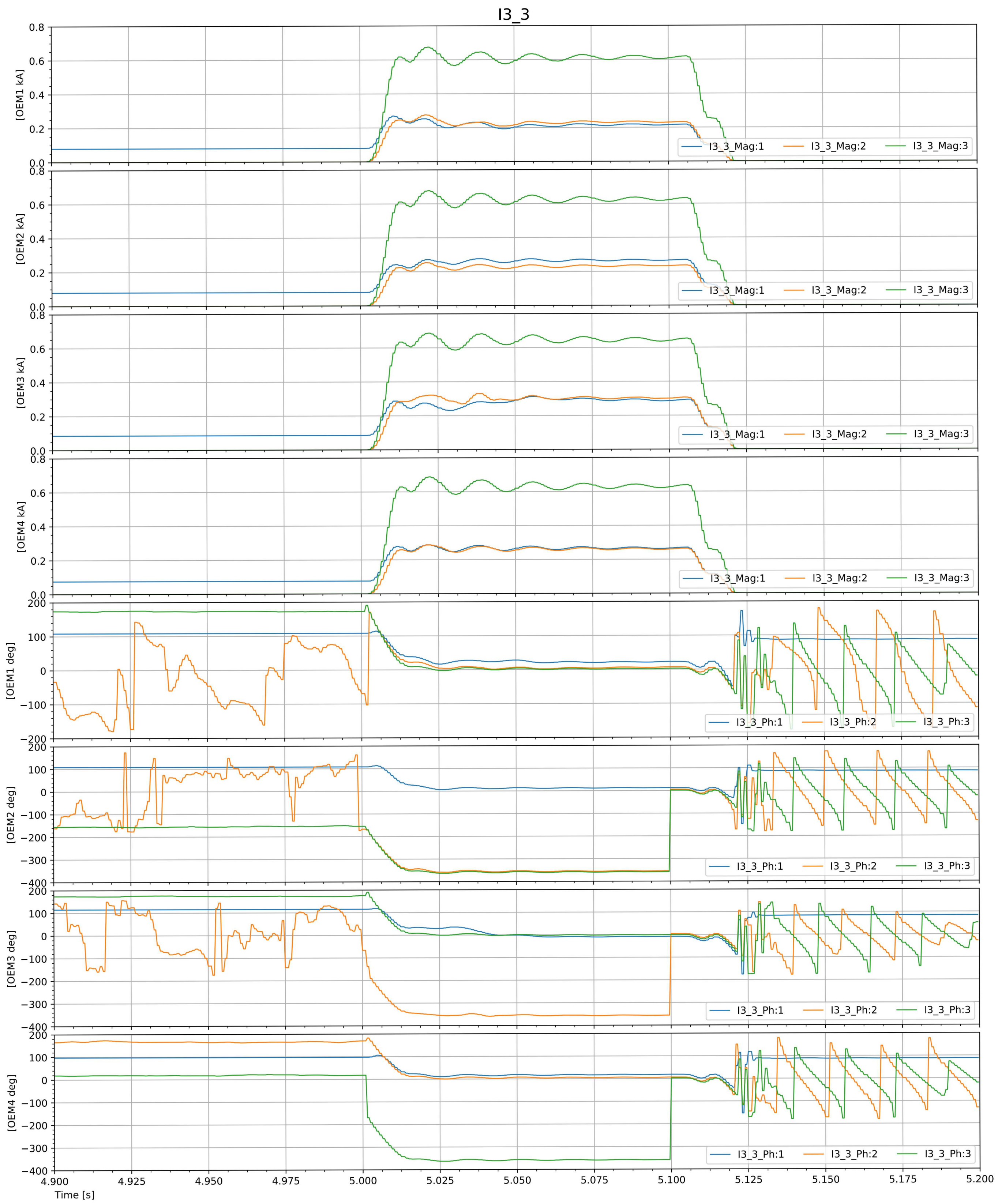


Network Configuration: System Intact
Fault Location: B
Fault Type: AG
Fault Resistance: 0.001 ohms

I3_2

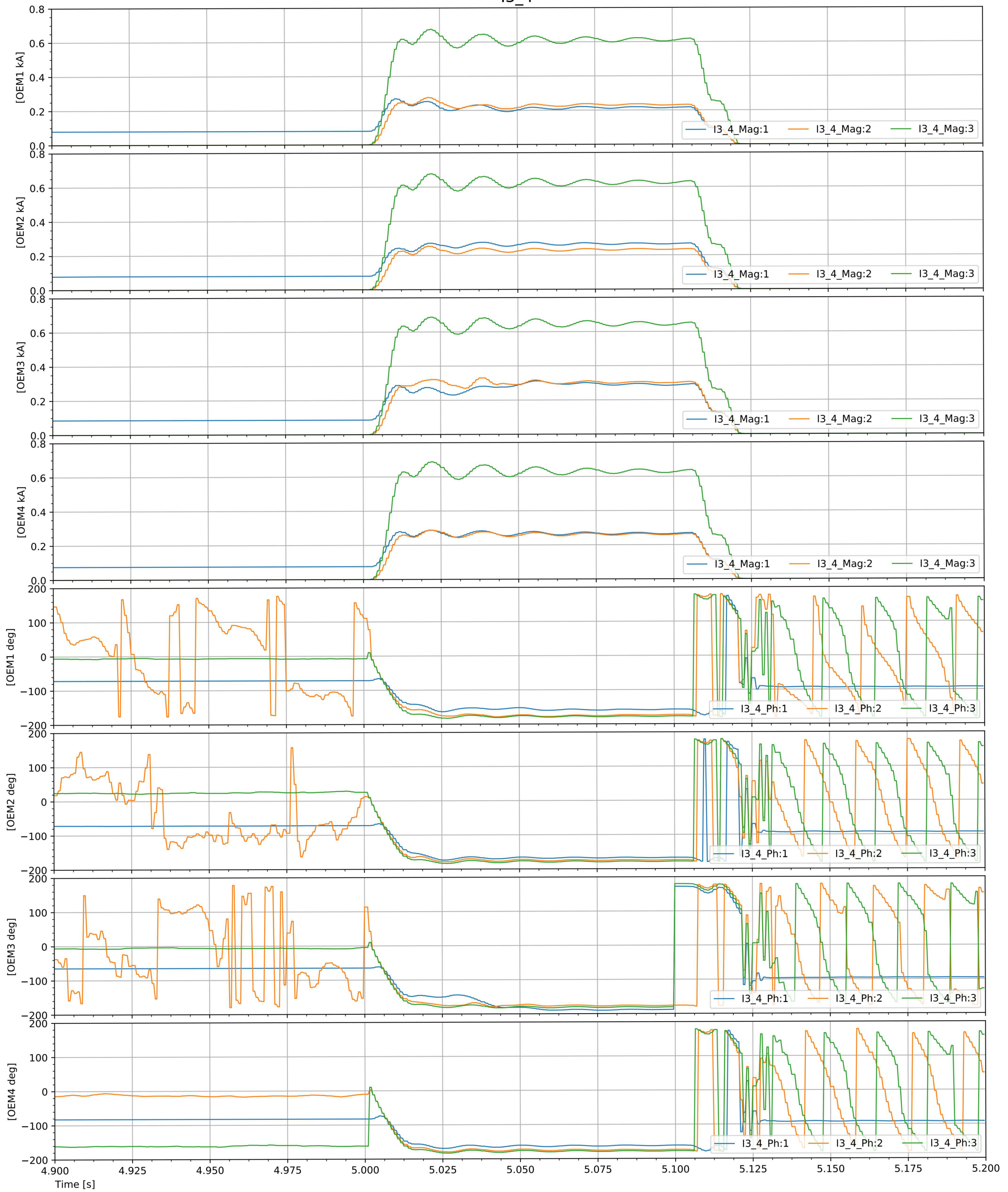


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms

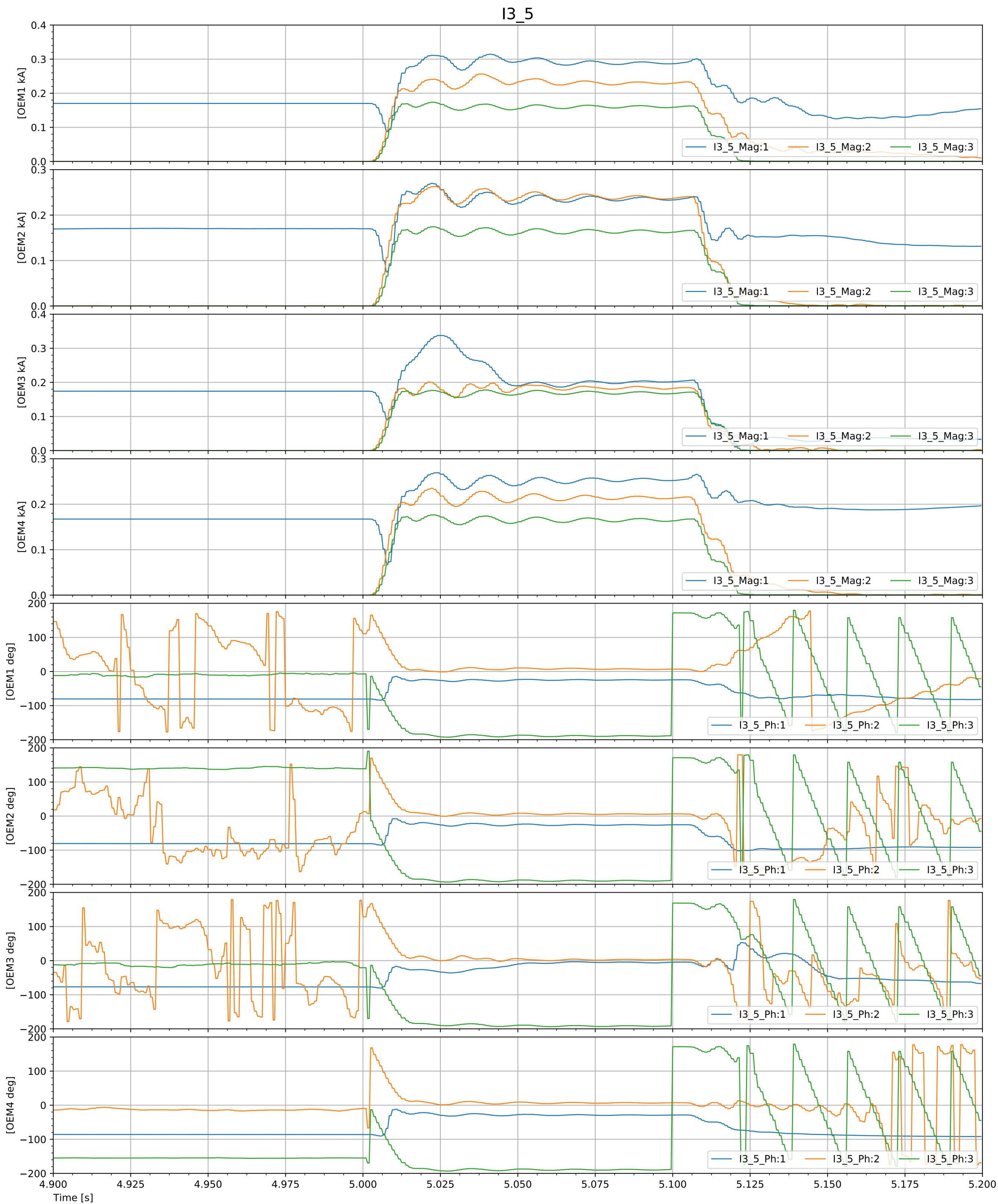


Network Configuration: System Intact
Fault Location: B
Fault Type: AG
Fault Resistance: 0.001 ohms

I3_4

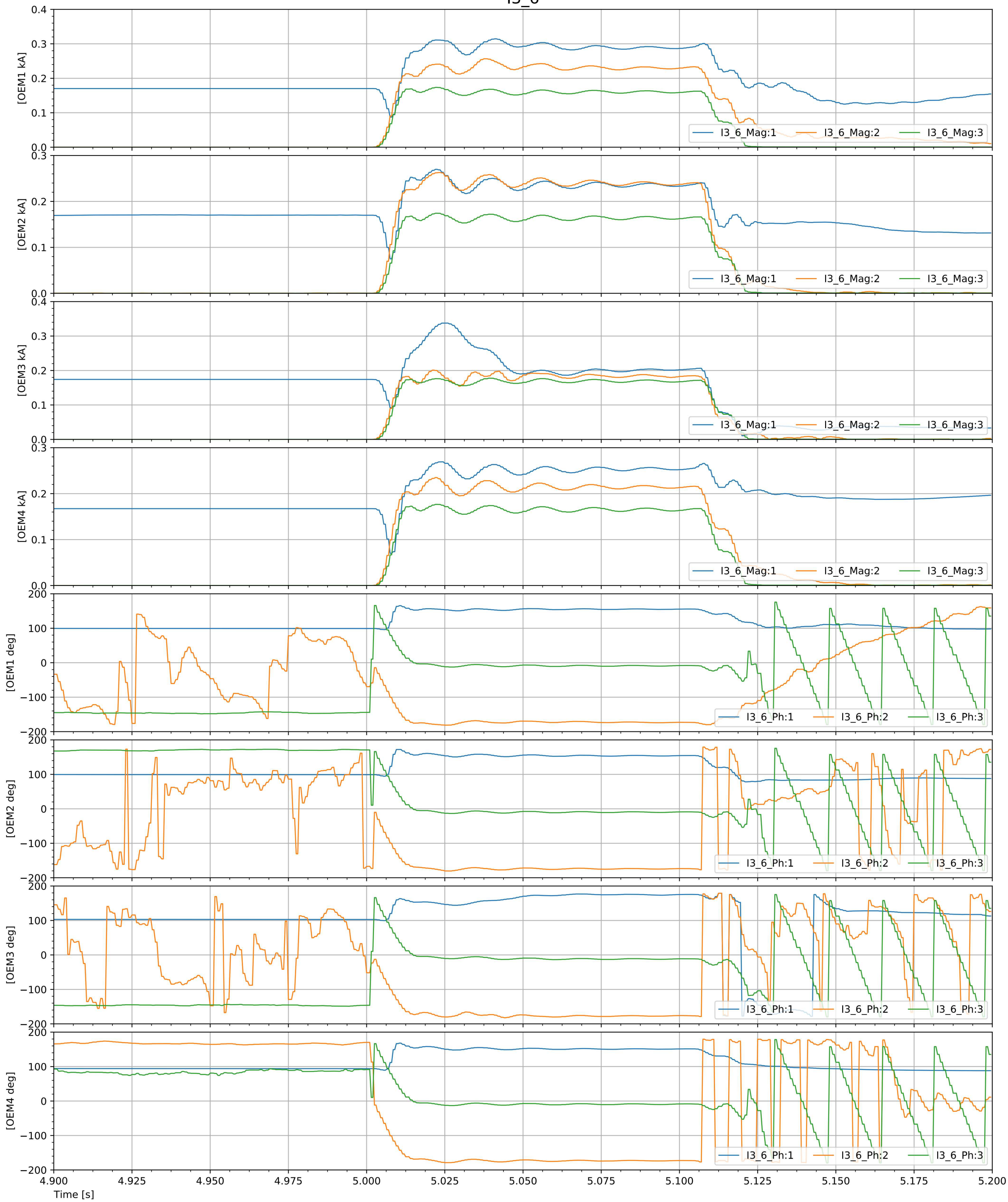


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms



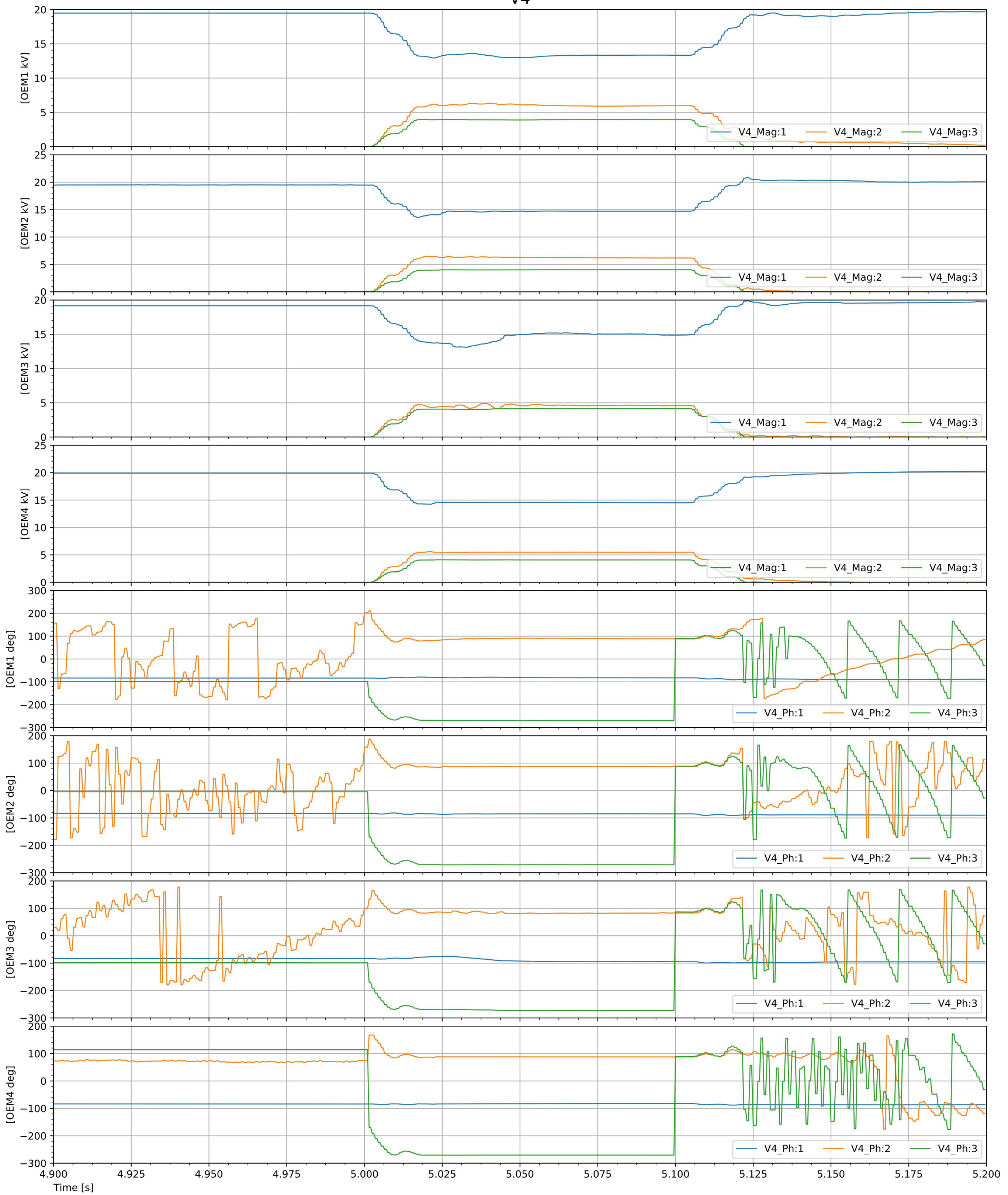
Network Configuration: System Intact
Fault Location: B
Fault Type: AG
Fault Resistance: 0.001 ohms

I3_6



Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms

V4

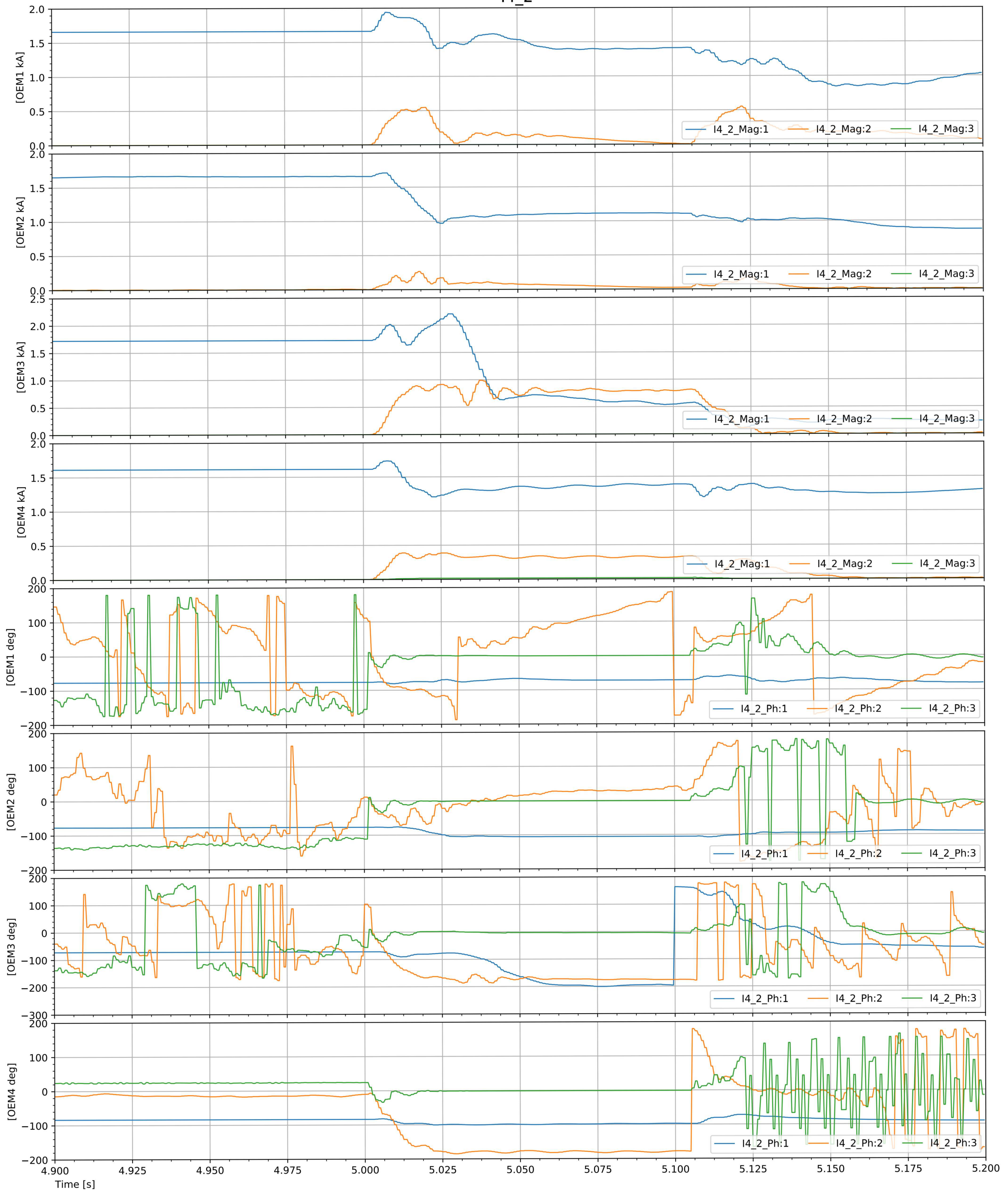


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms



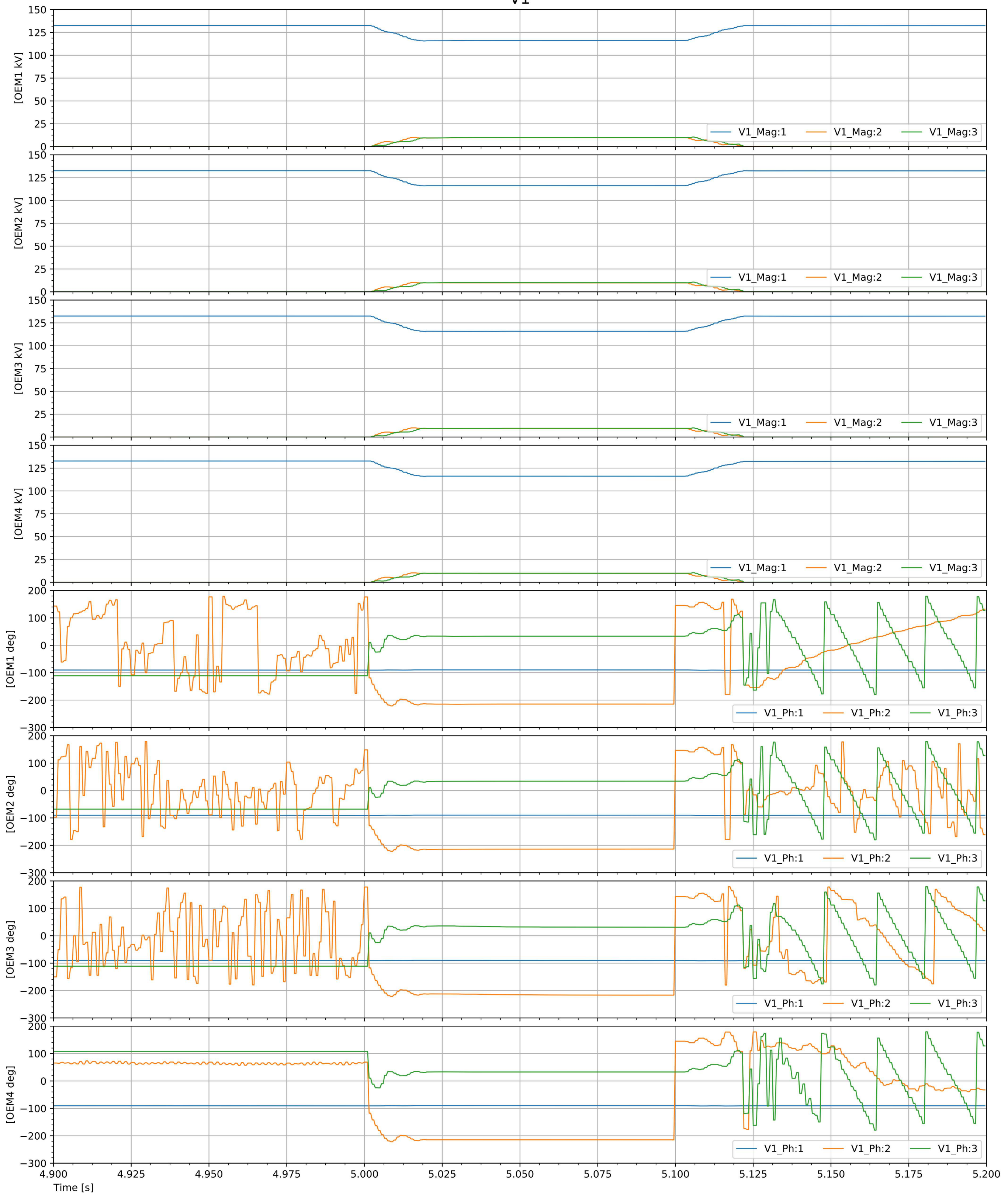
Network Configuration: System Intact
Fault Location: B
Fault Type: AG
Fault Resistance: 0.001 ohms

I4_2

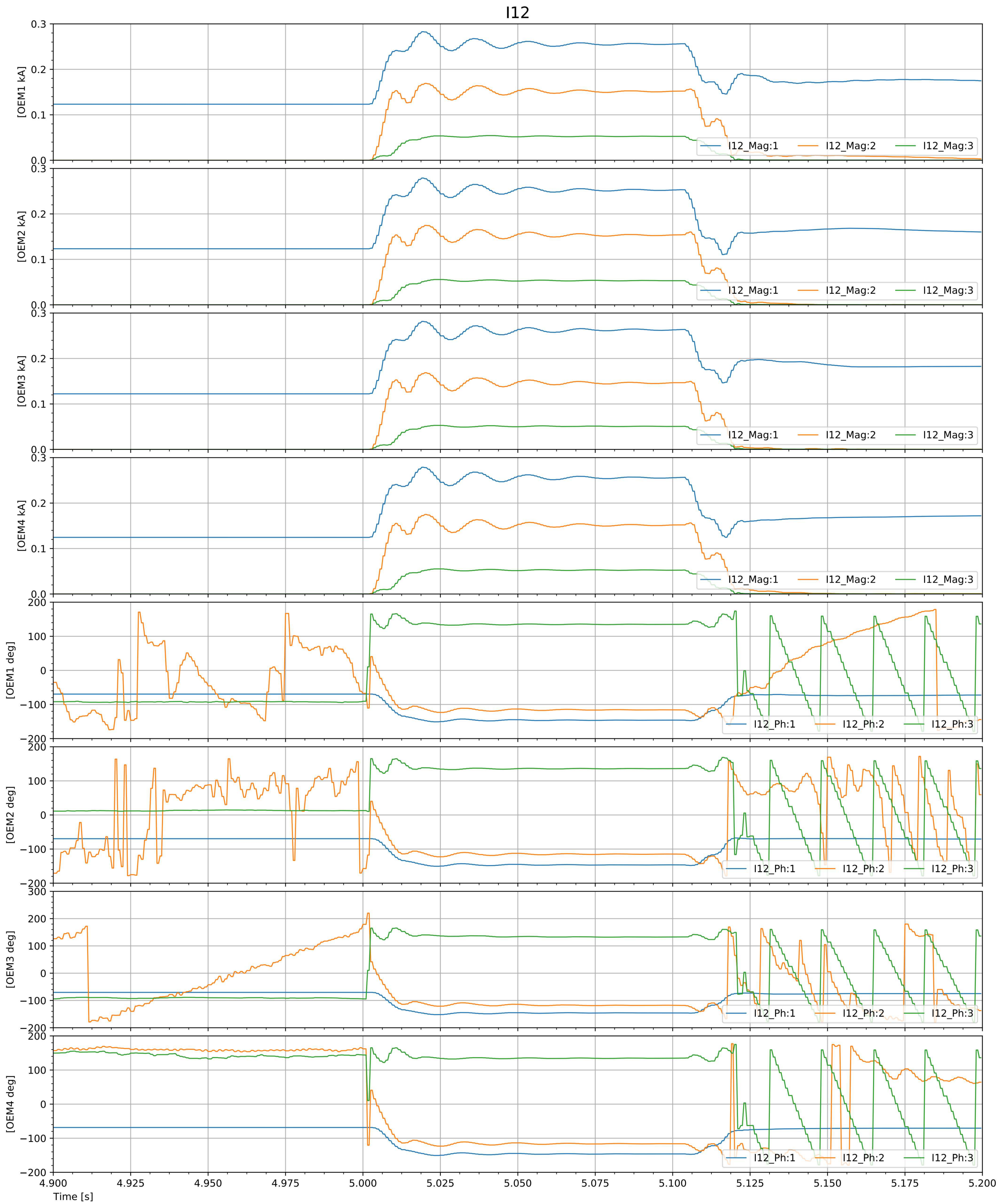


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AG
 Fault Resistance: 0.001 ohms

V1

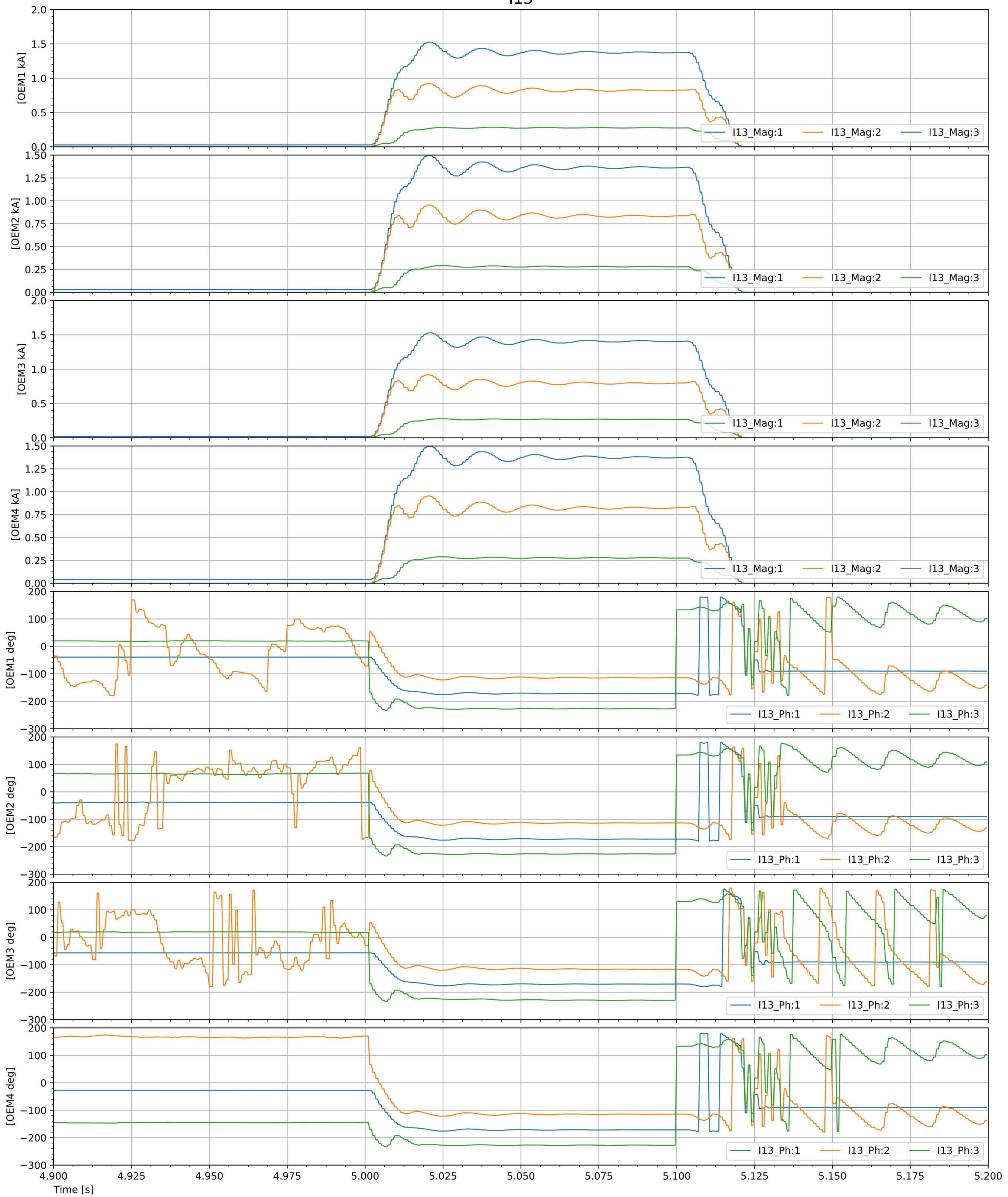


Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms



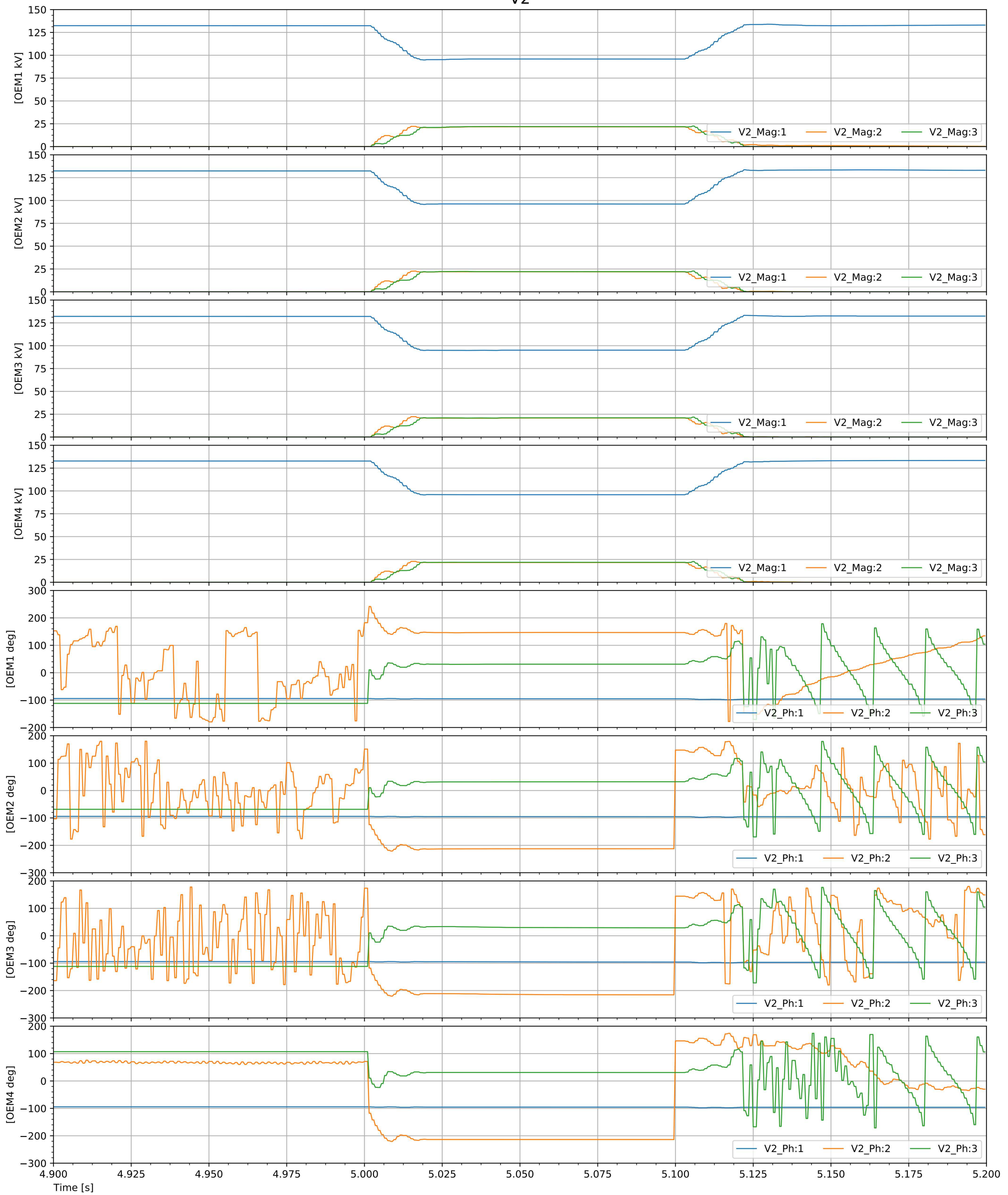
Network Configuration: System Intact
Fault Location: B
Fault Type: ABG
Fault Resistance: 0.001 ohms

I13



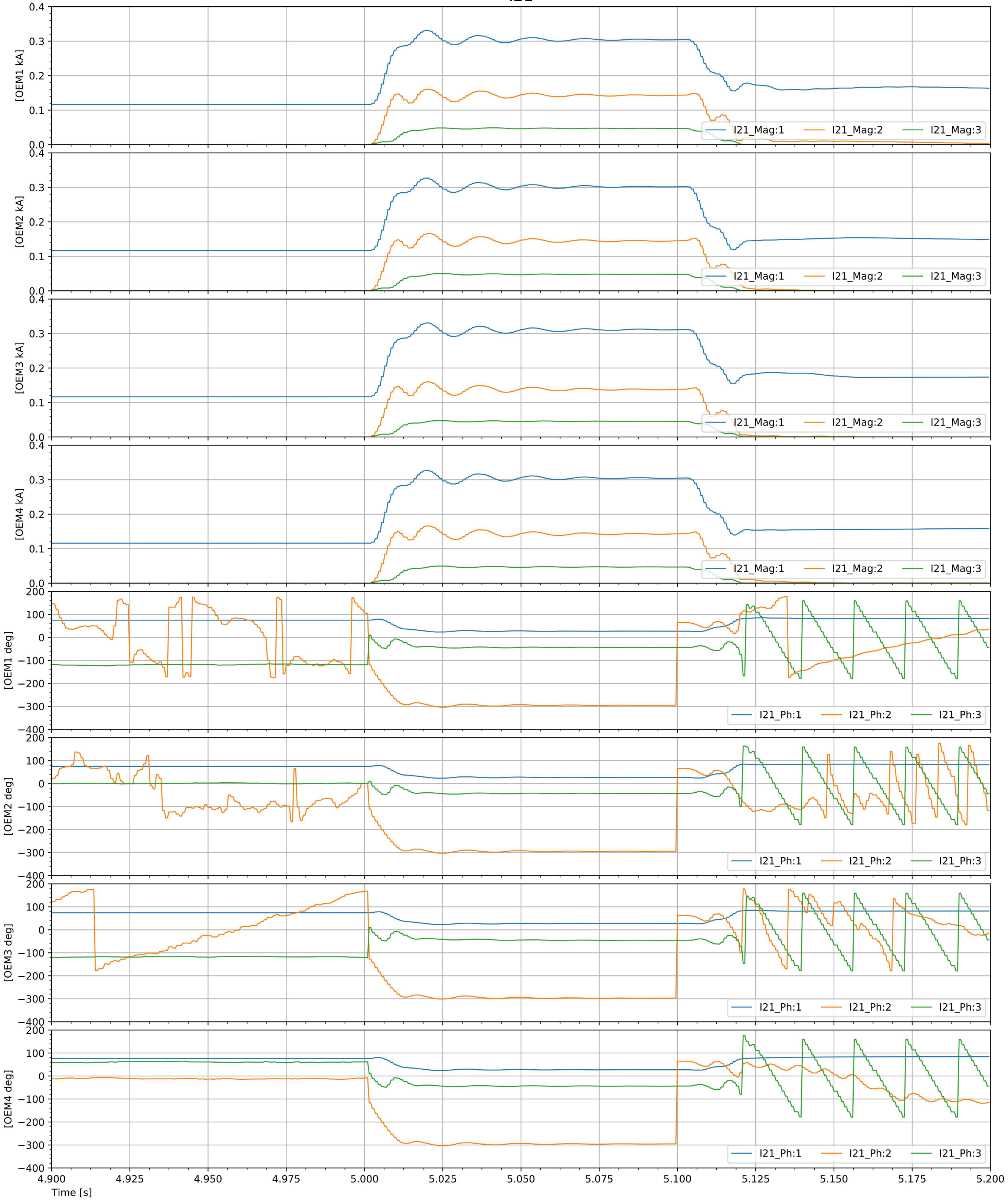
Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

V2



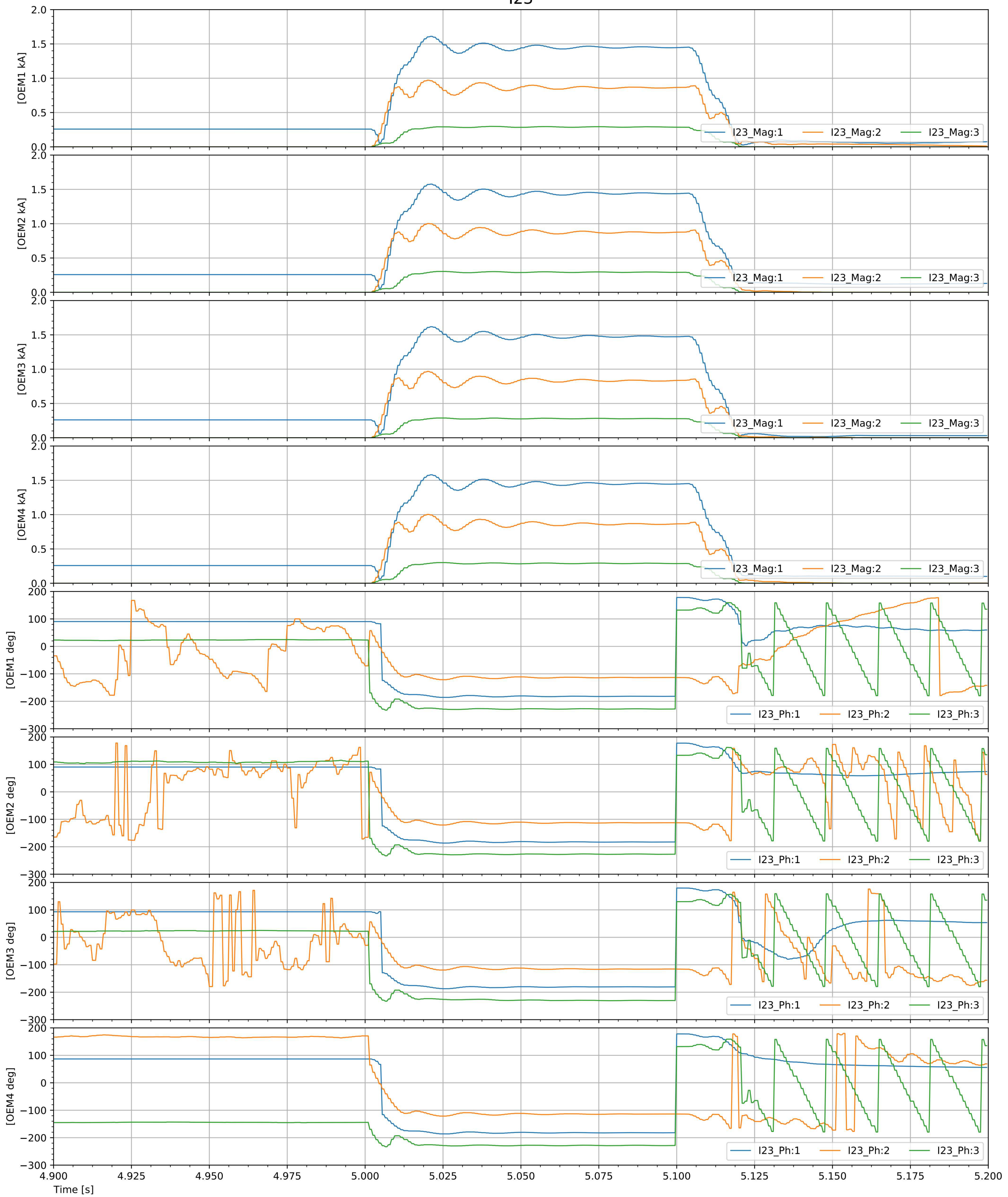
Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

I21



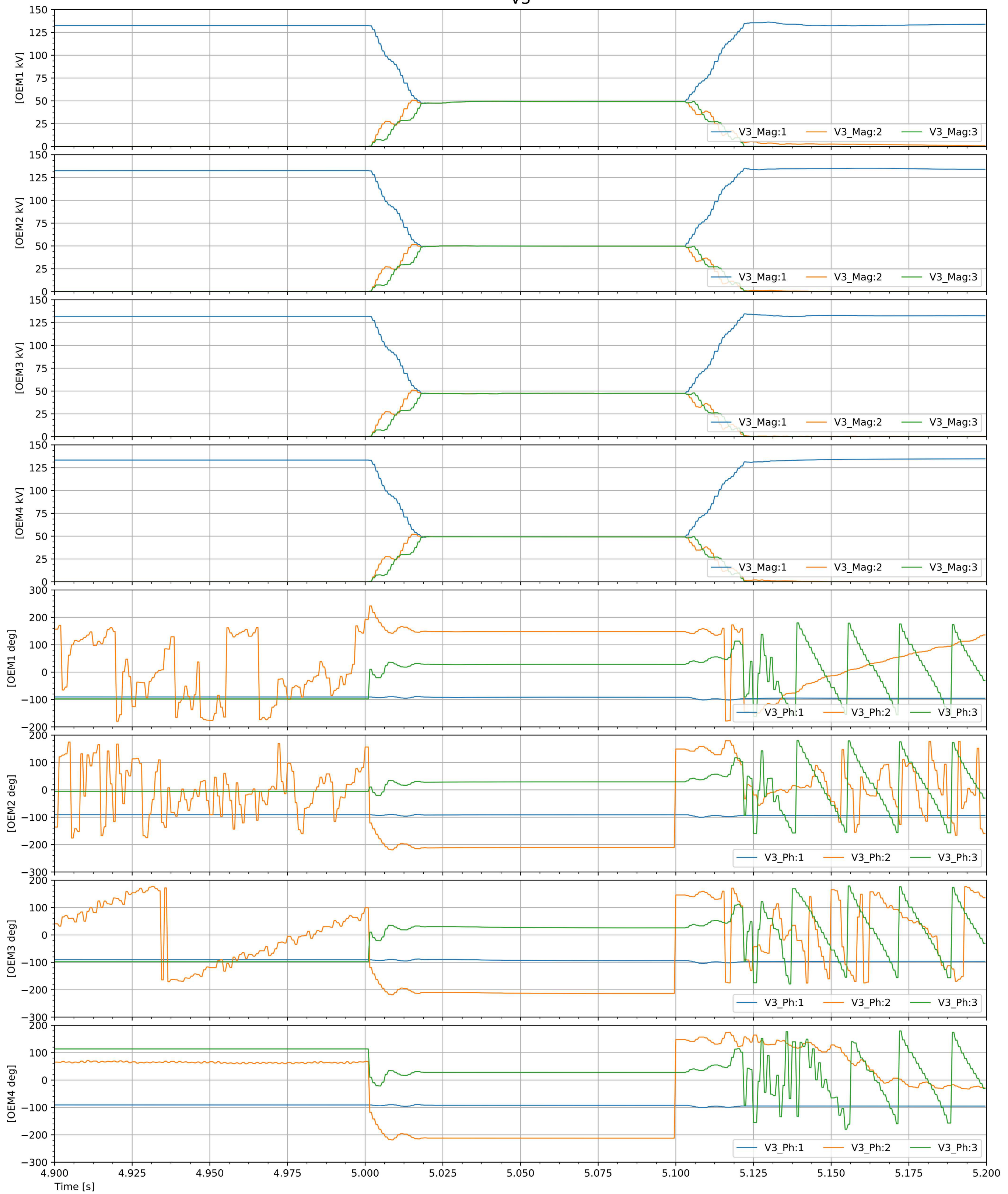
Network Configuration: System Intact
Fault Location: B
Fault Type: ABG
Fault Resistance: 0.001 ohms

I23

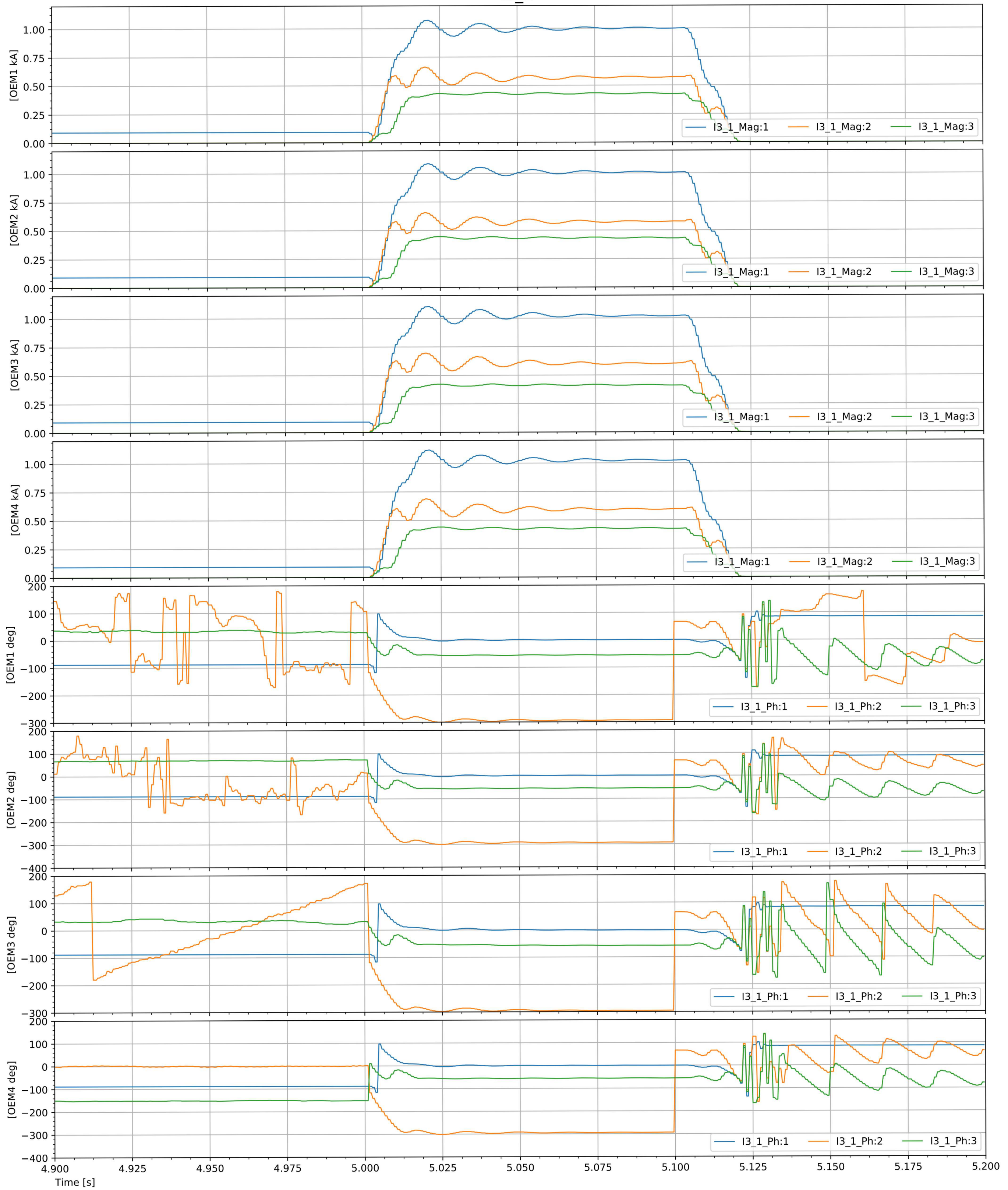


Network Configuration: System Intact
Fault Location: B
Fault Type: ABG
Fault Resistance: 0.001 ohms

V3



I3_1

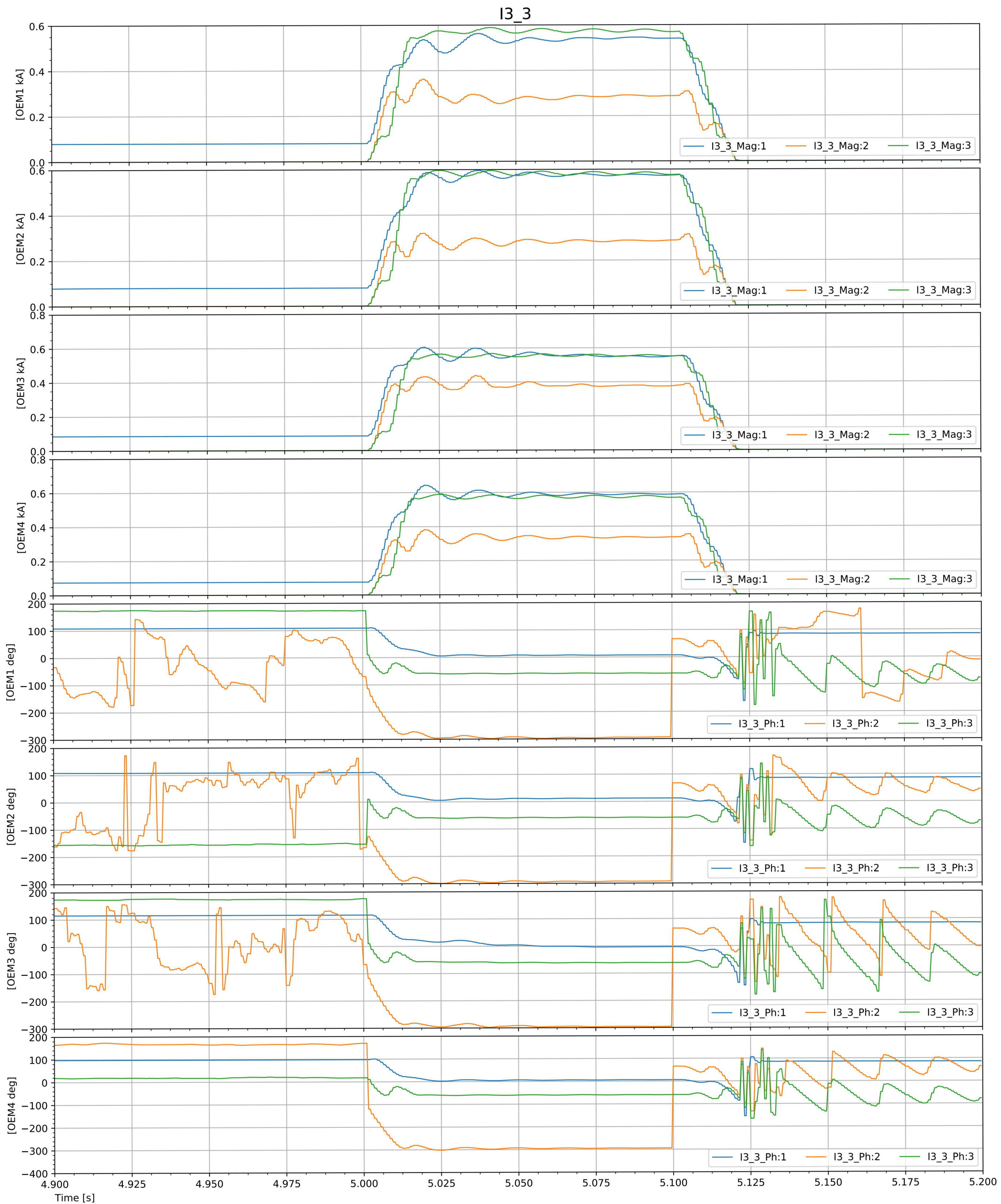


Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

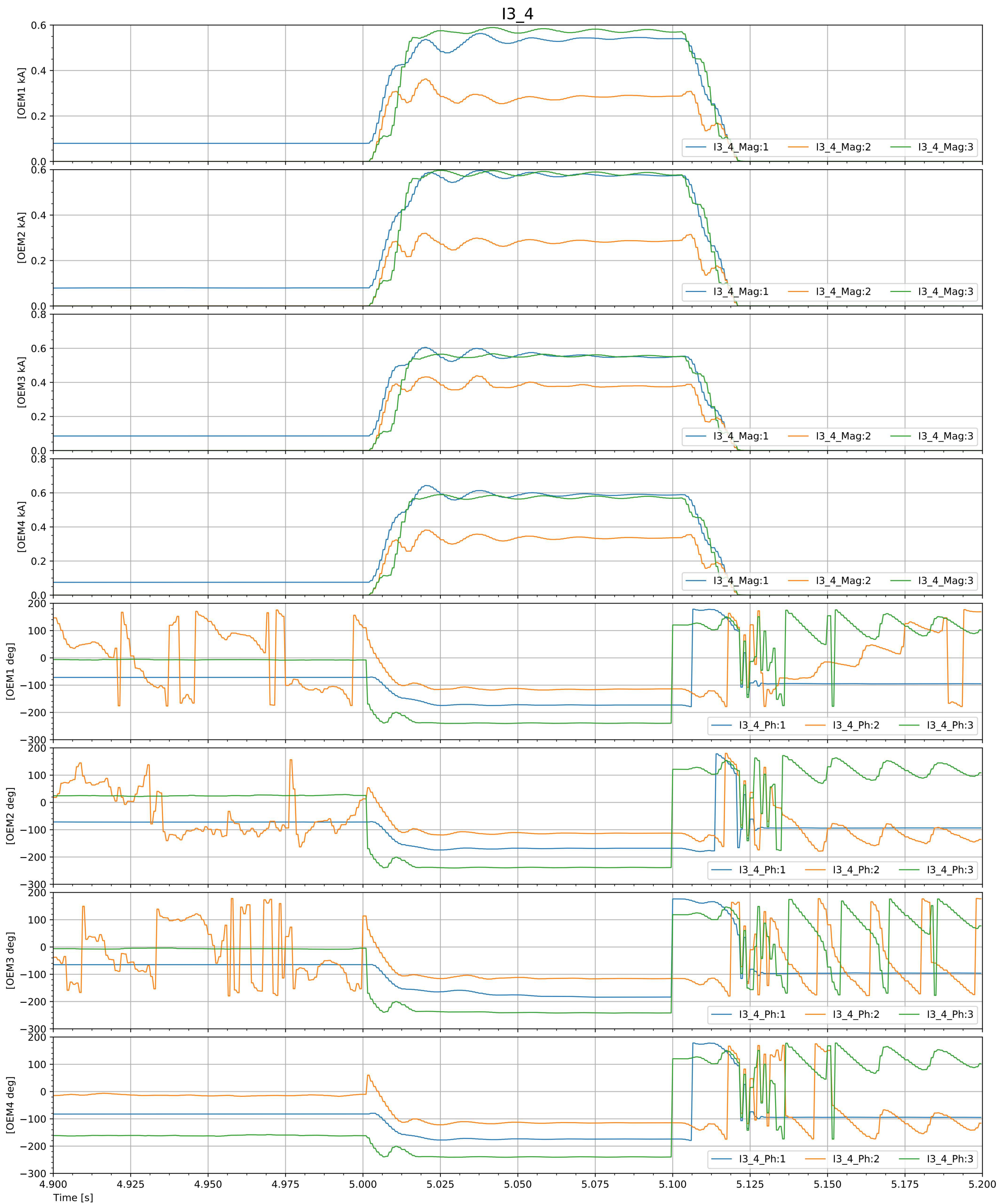
I3_2



Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

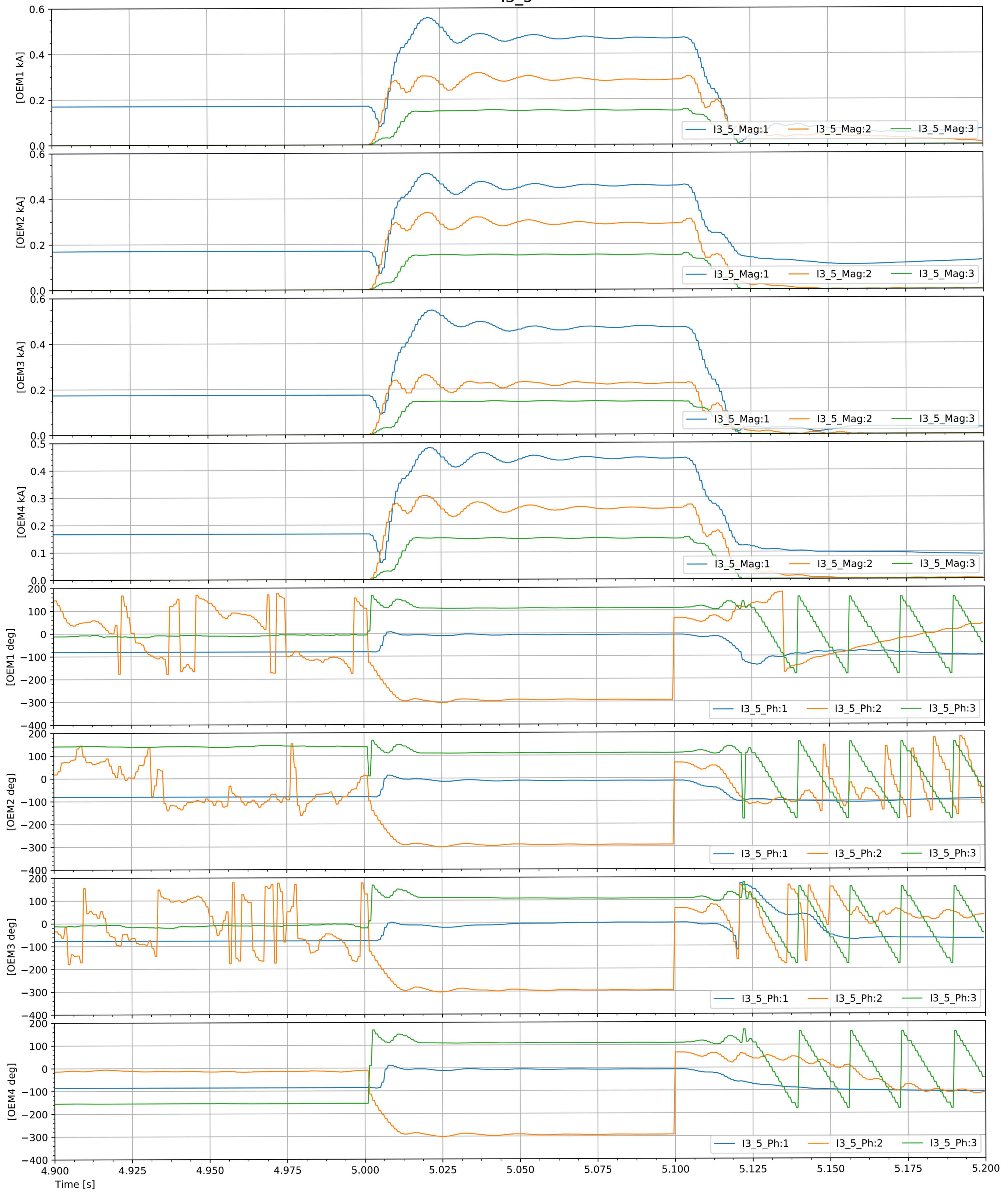


Network Configuration: System Intact
Fault Location: B
Fault Type: ABG
Fault Resistance: 0.001 ohms

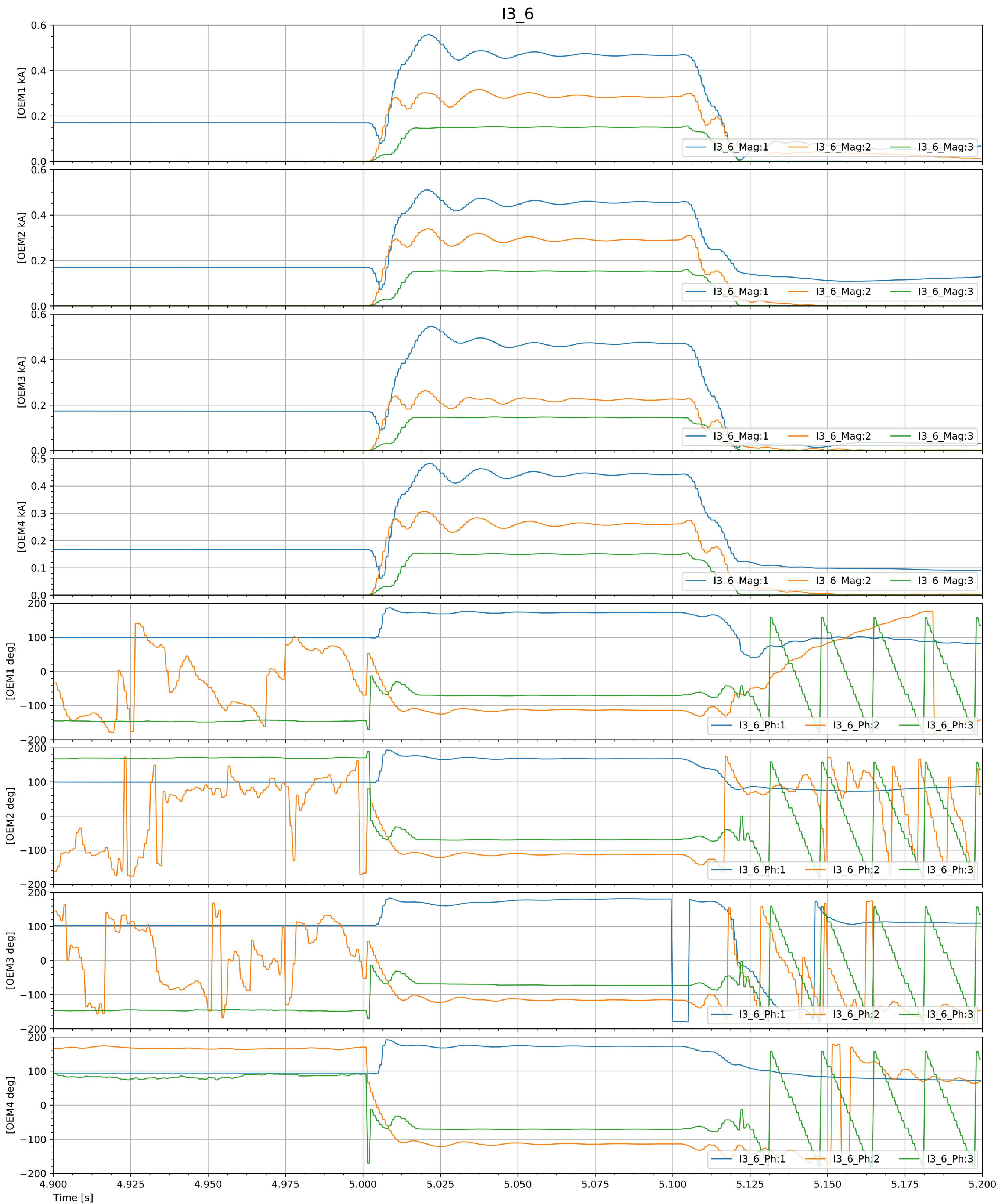


Network Configuration: System Intact
Fault Location: B
Fault Type: ABG
Fault Resistance: 0.001 ohms

I3_5

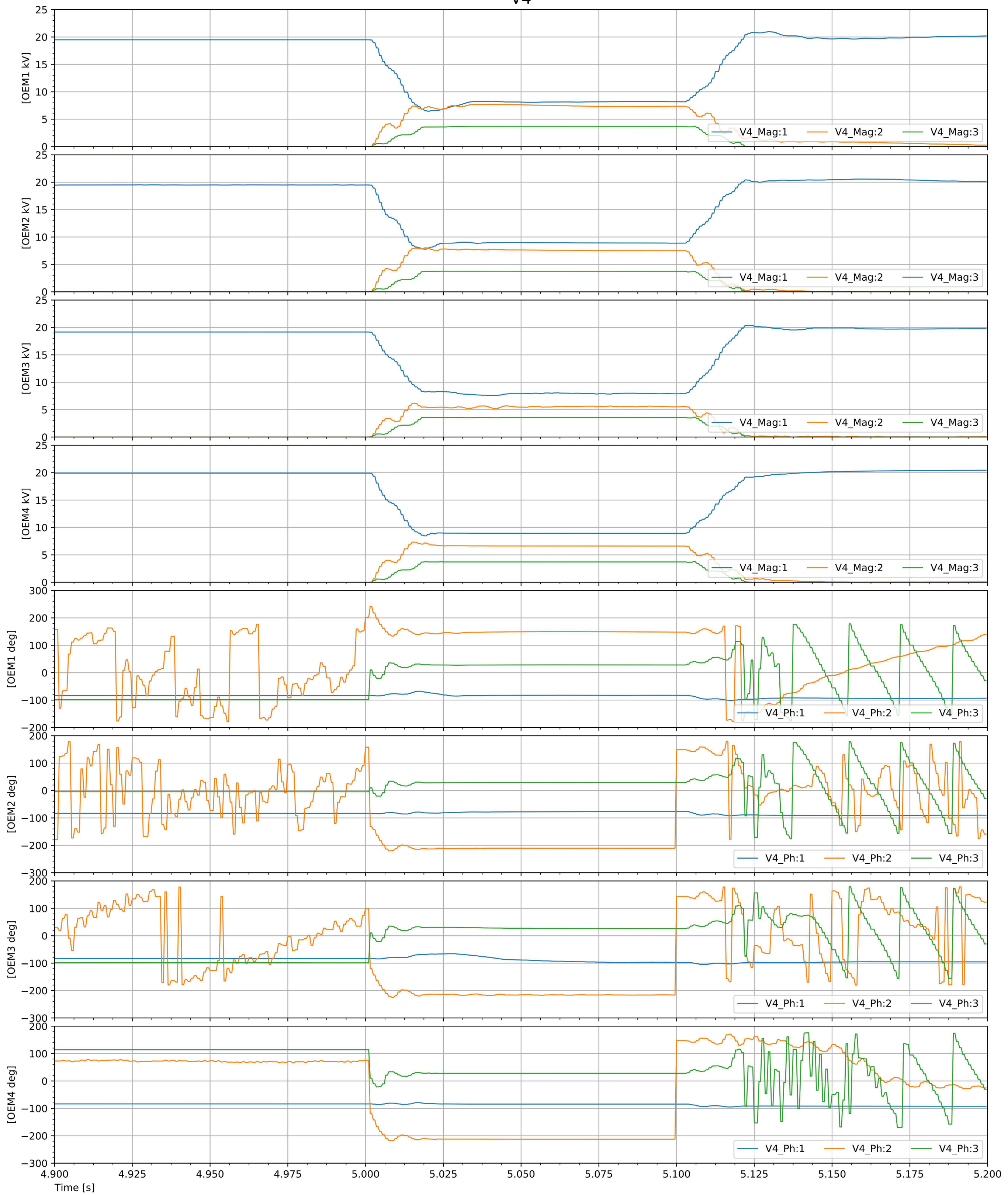


Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

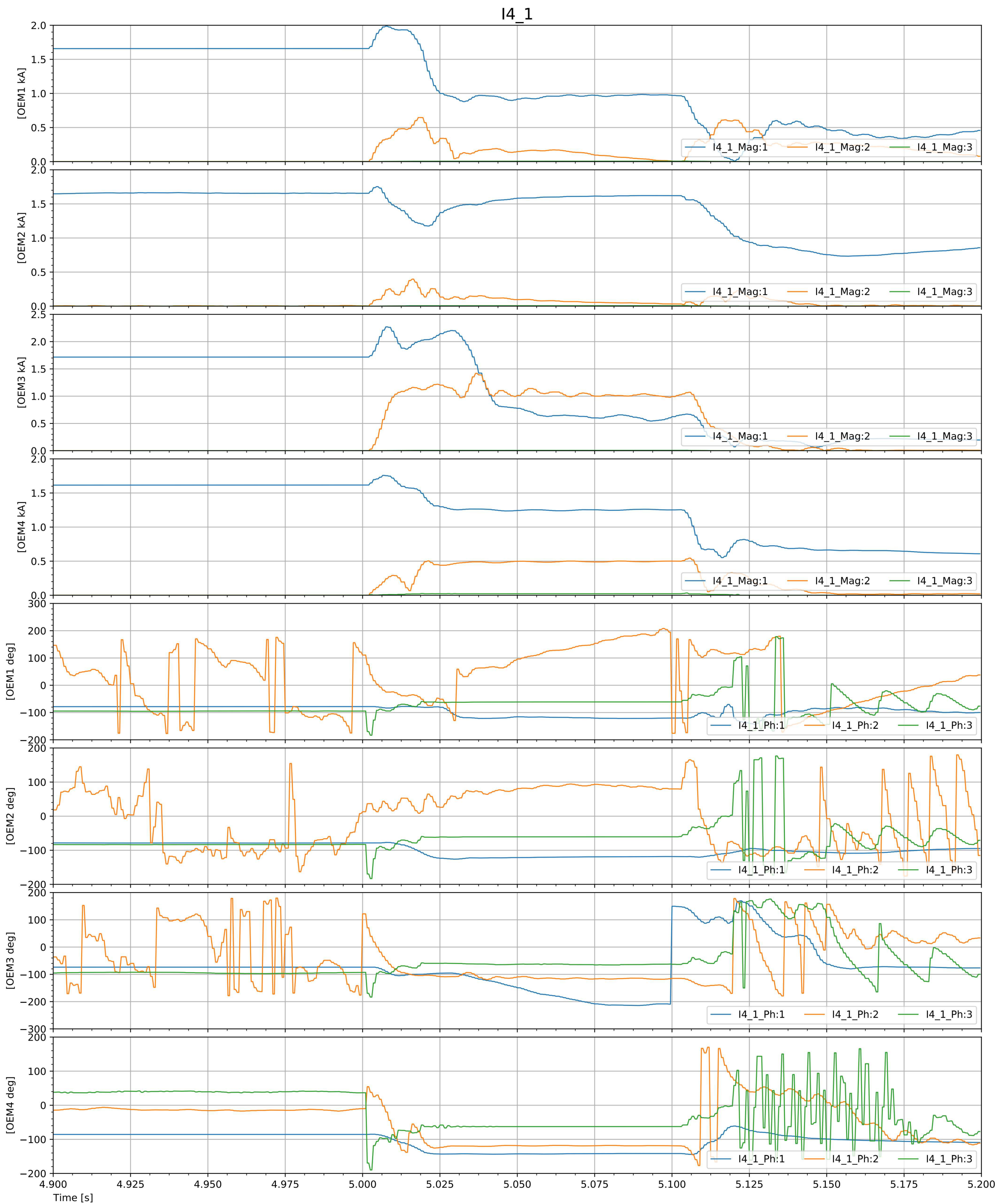


Network Configuration: System Intact
Fault Location: B
Fault Type: ABG
Fault Resistance: 0.001 ohms

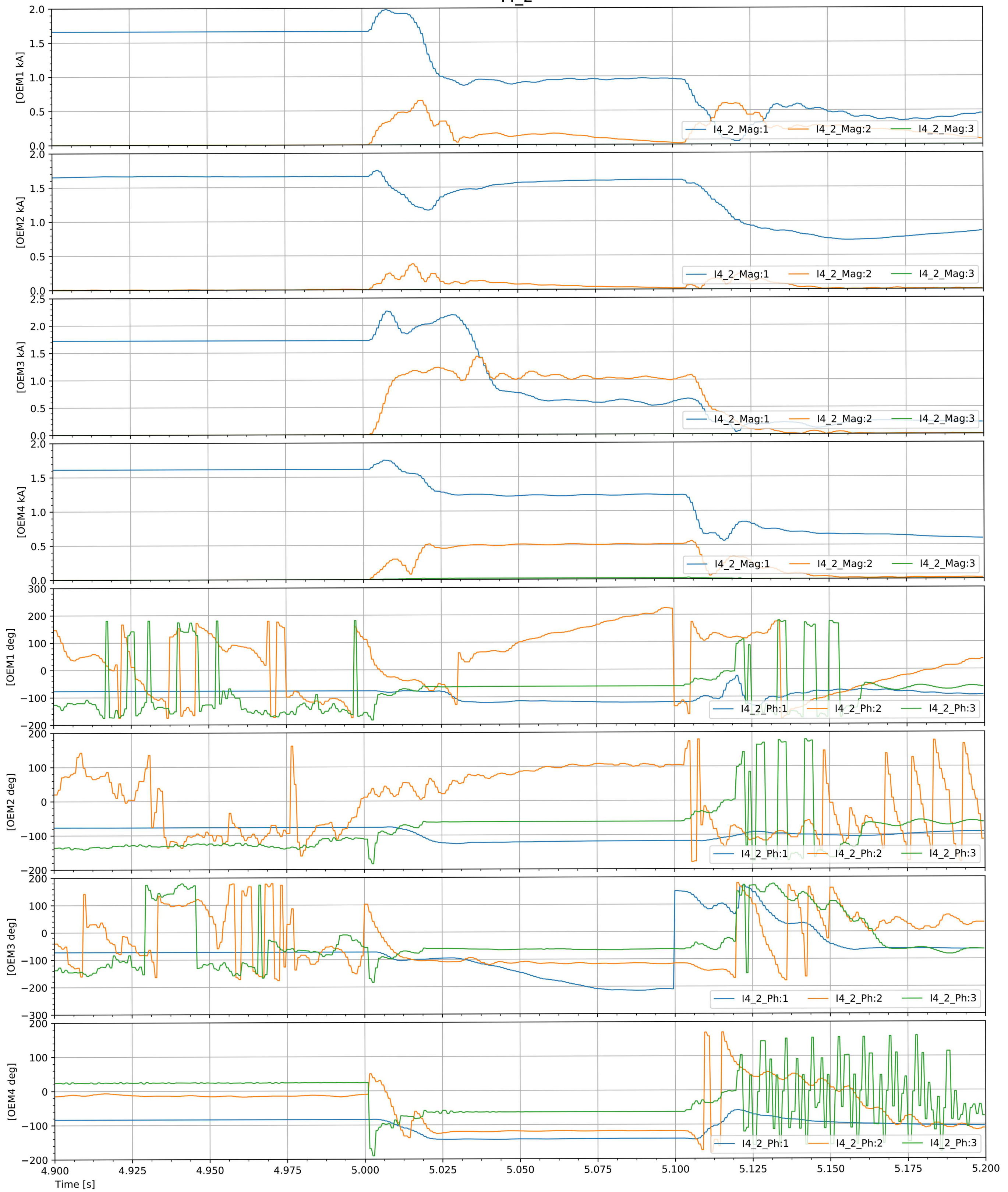
V4



Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

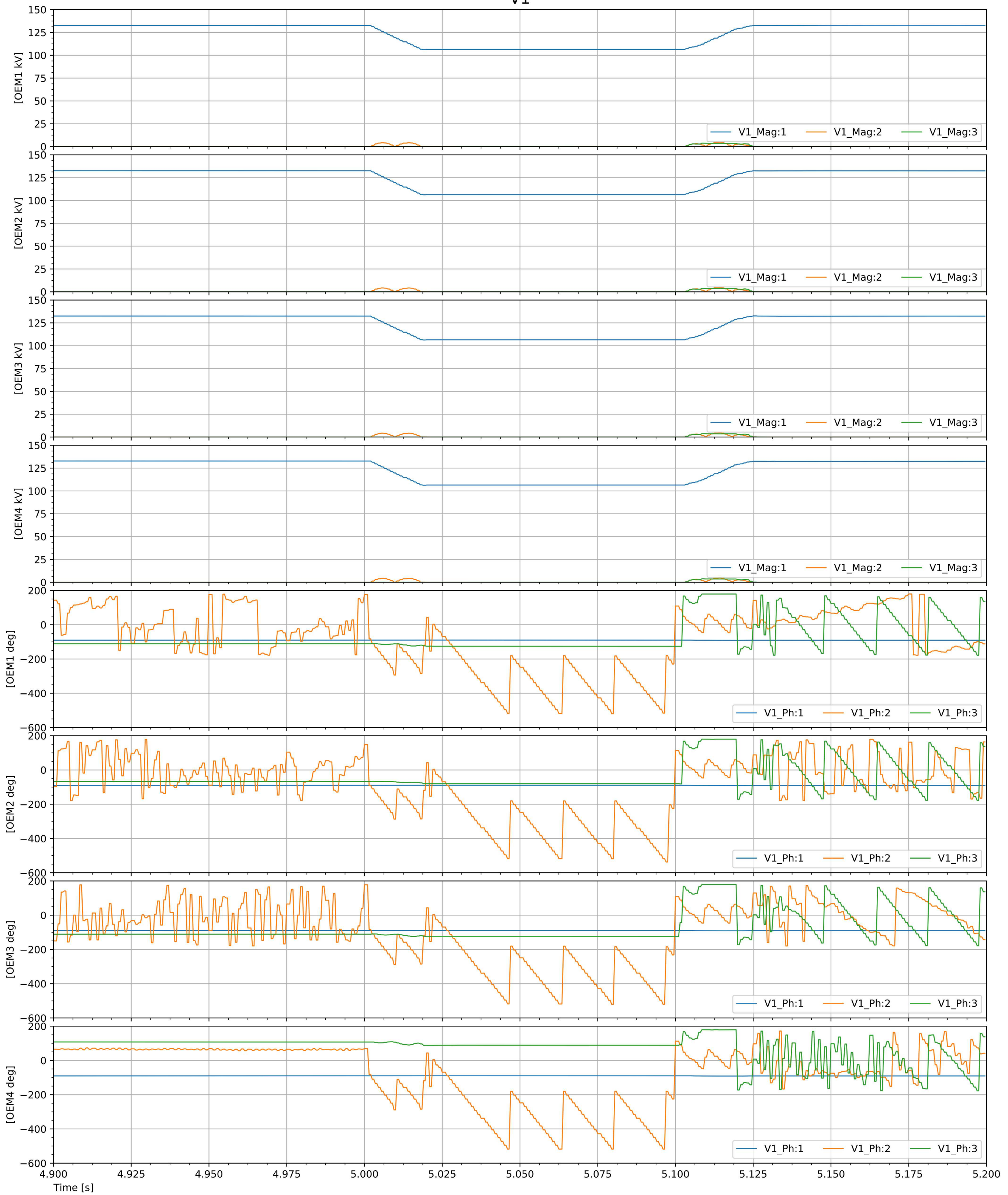


I4_2



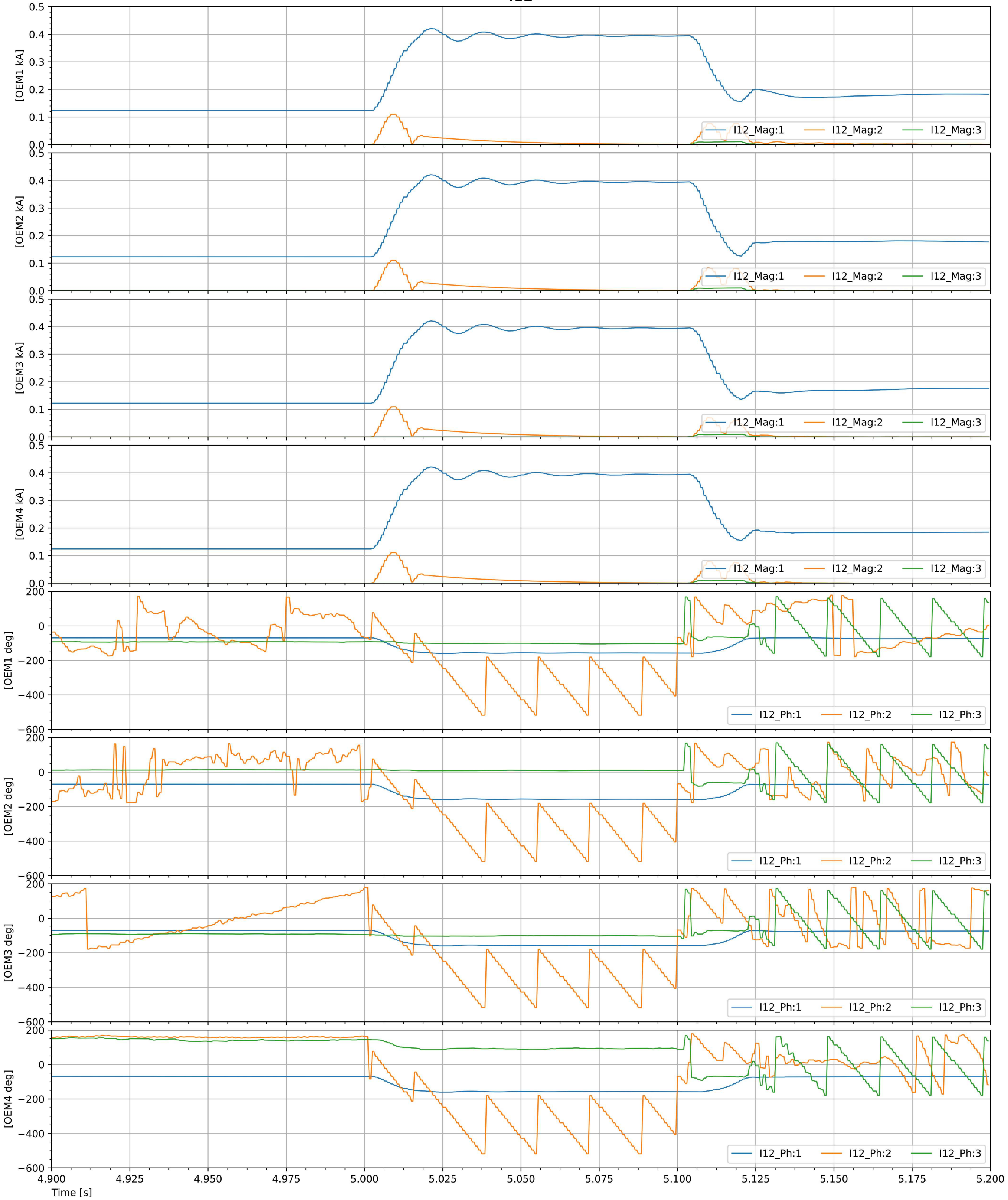
Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

V1

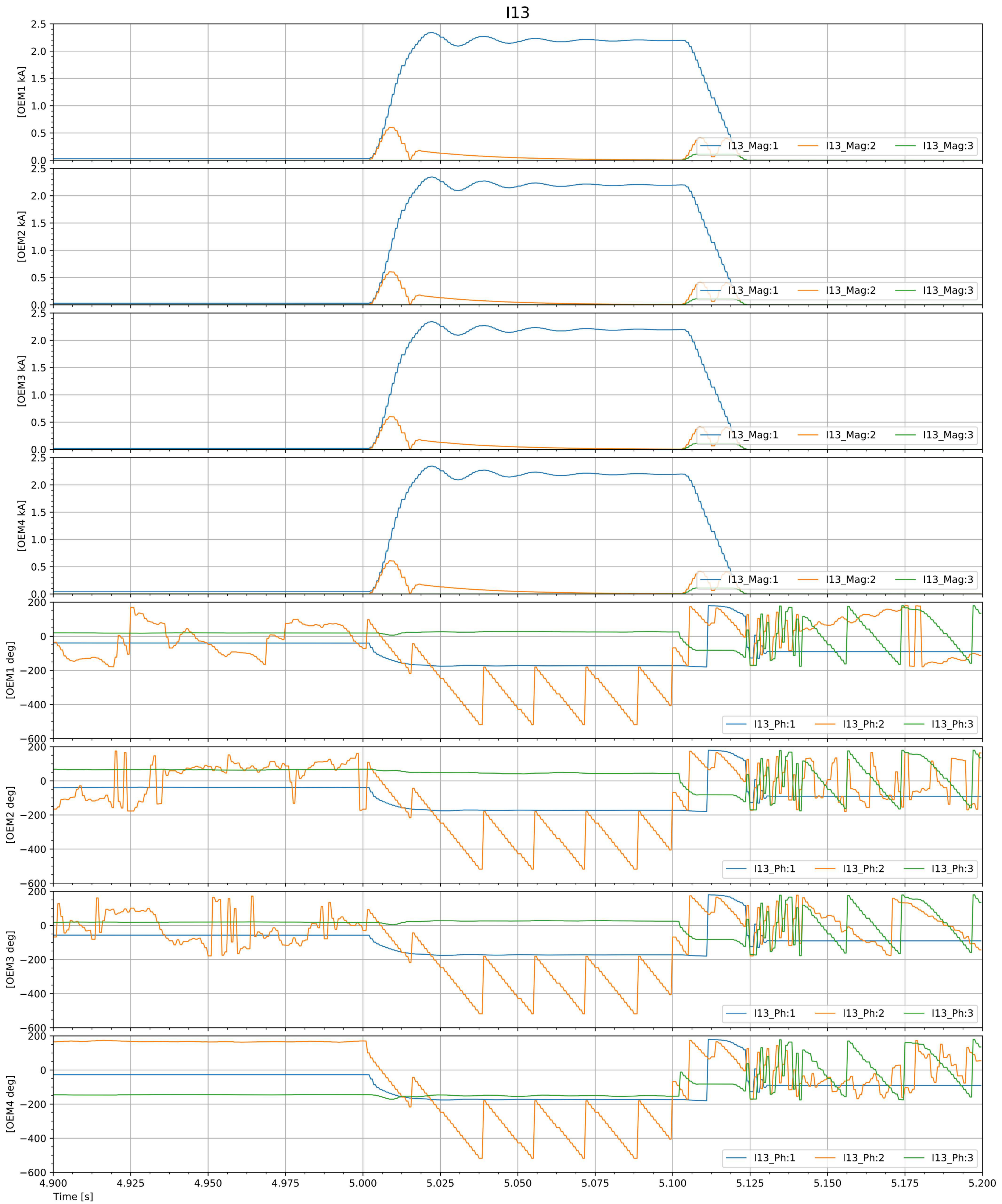


Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

I12

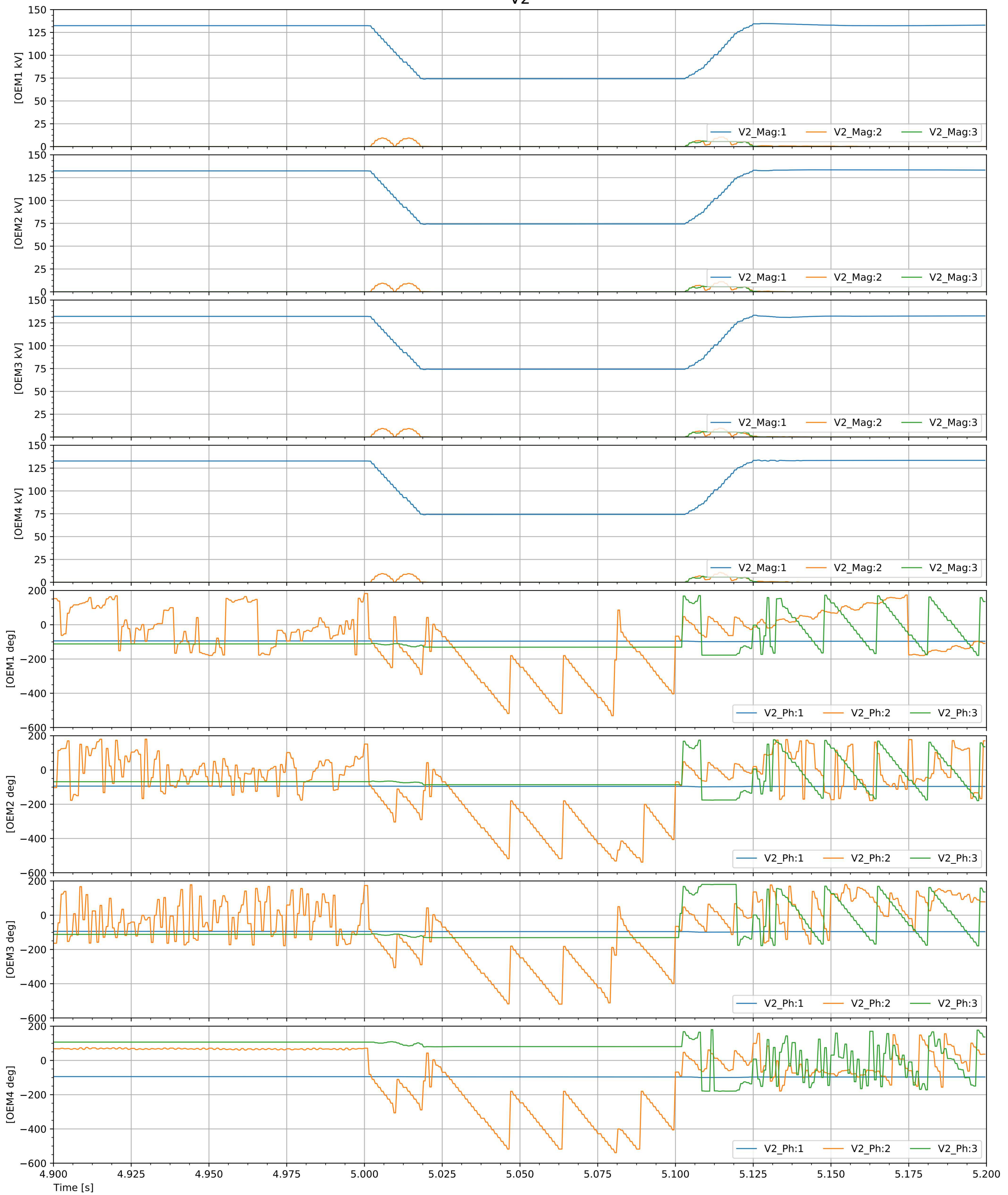


Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms



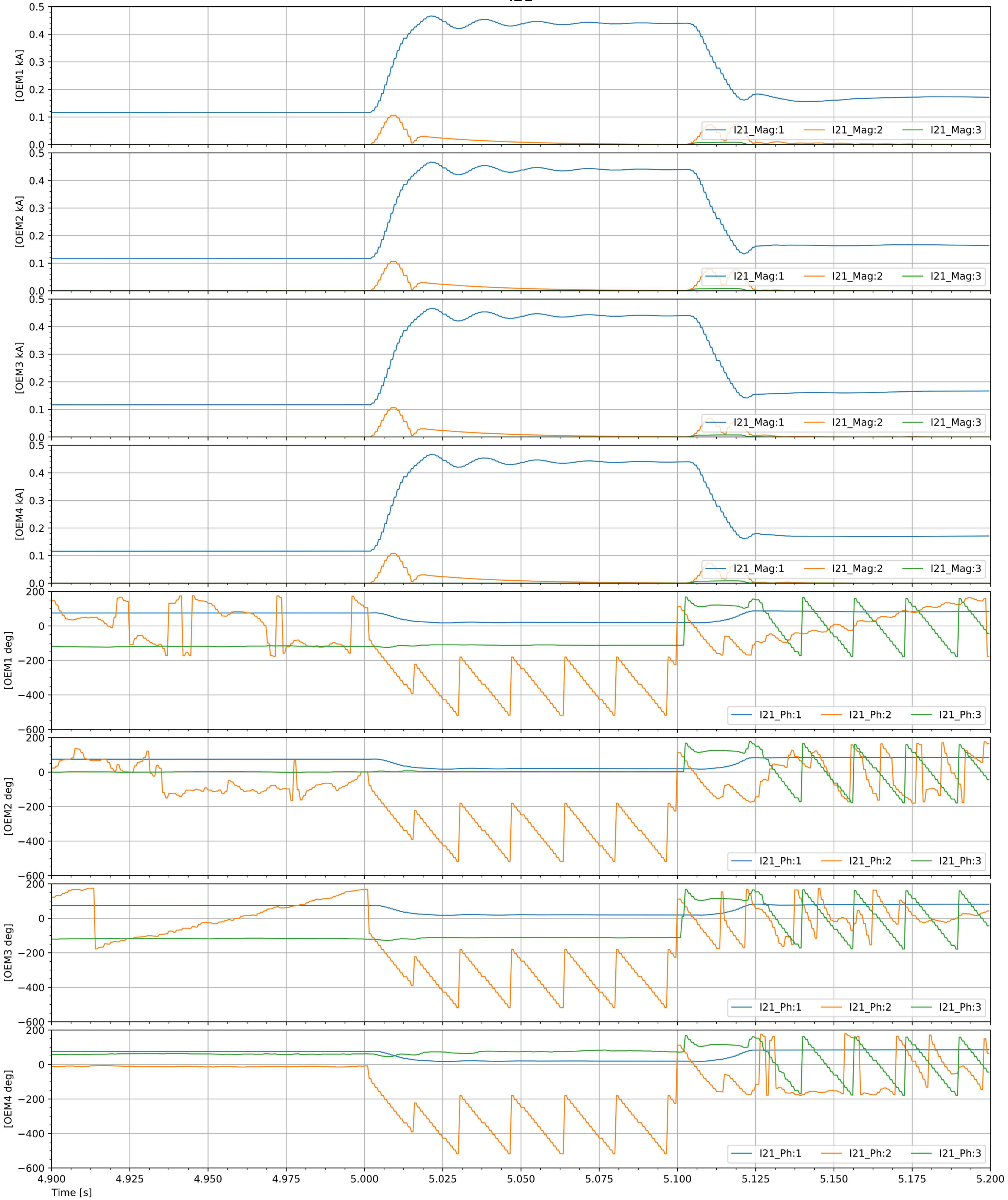
Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms

V2

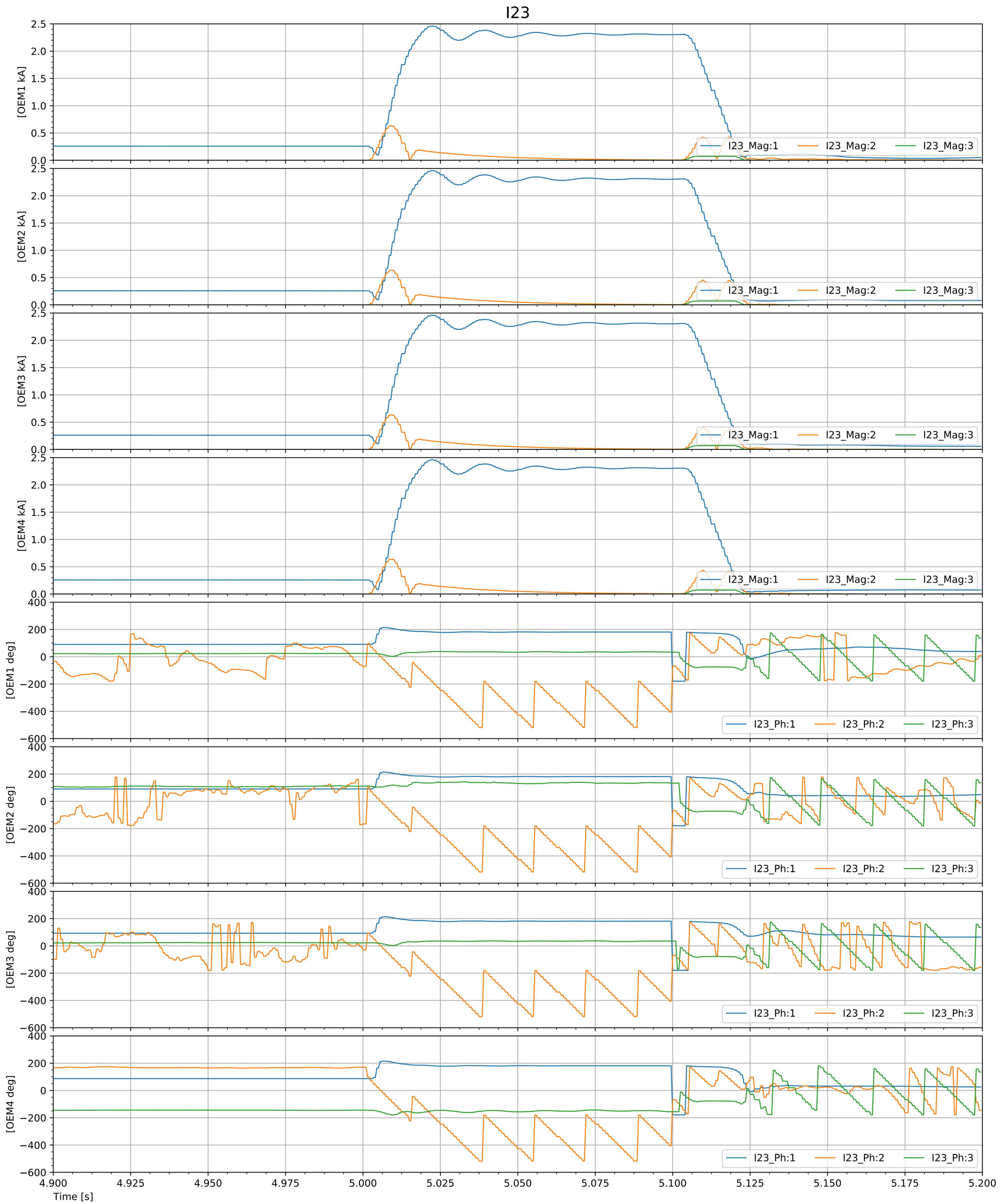


Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

I21

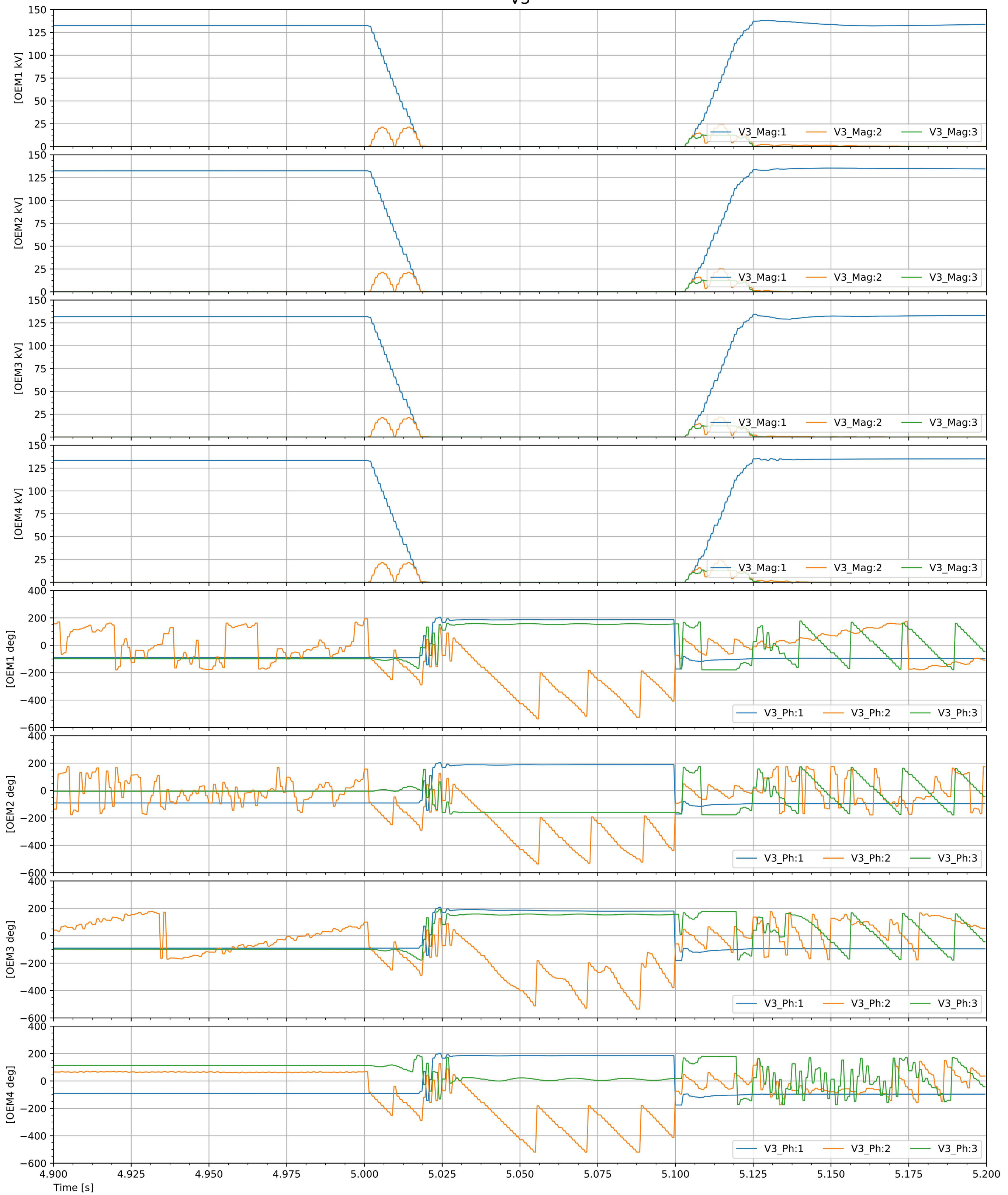


Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms

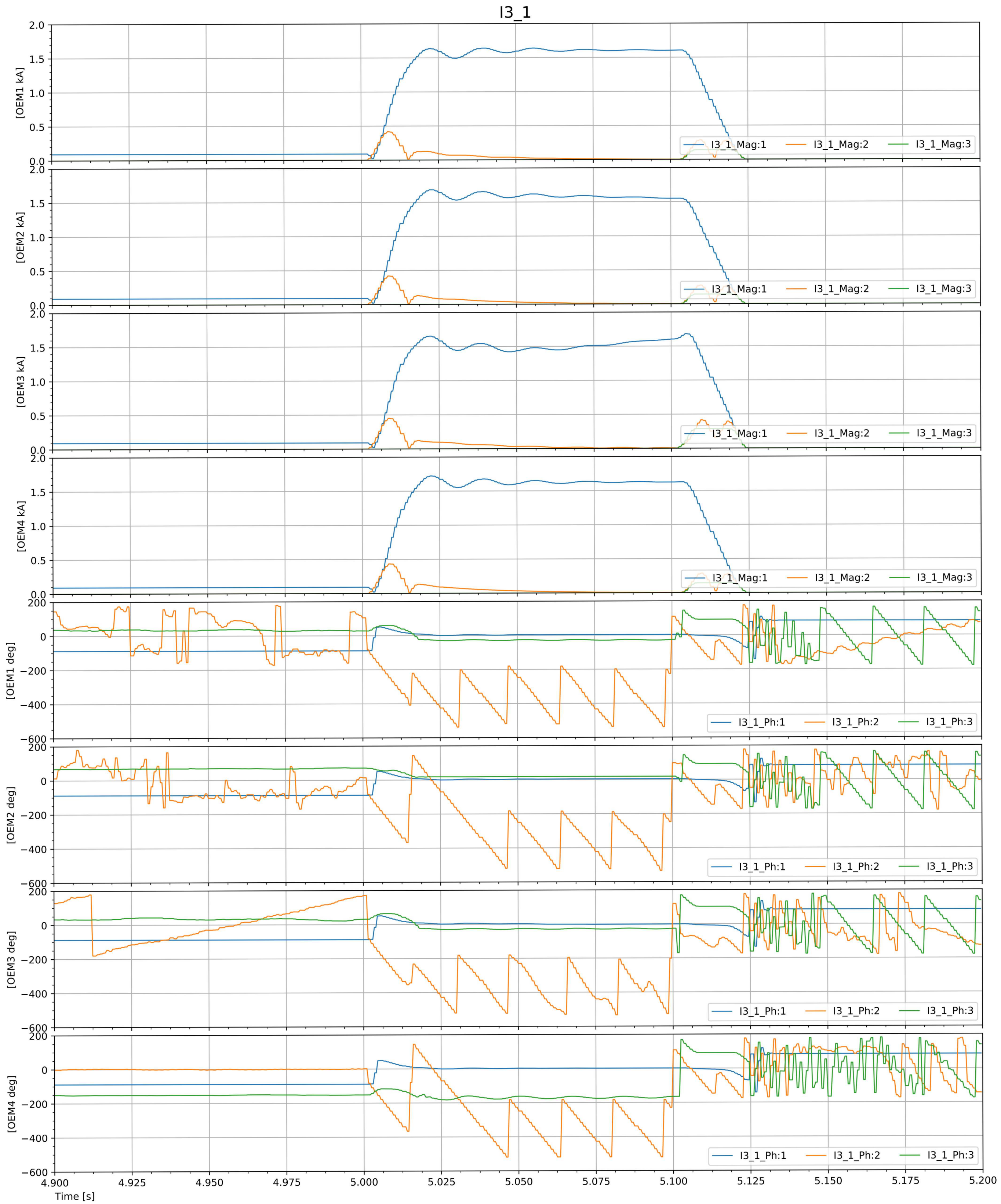


Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms

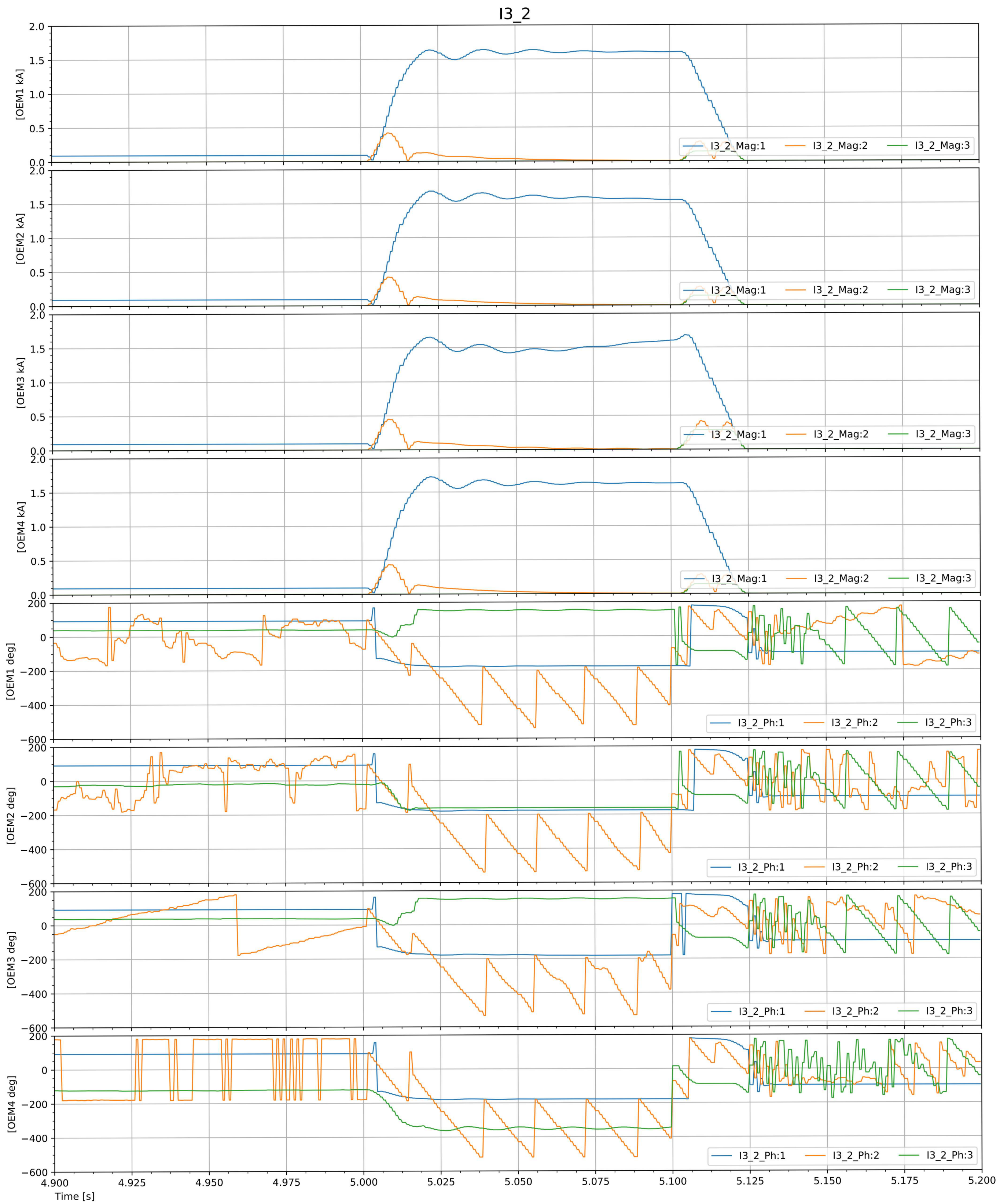
V3



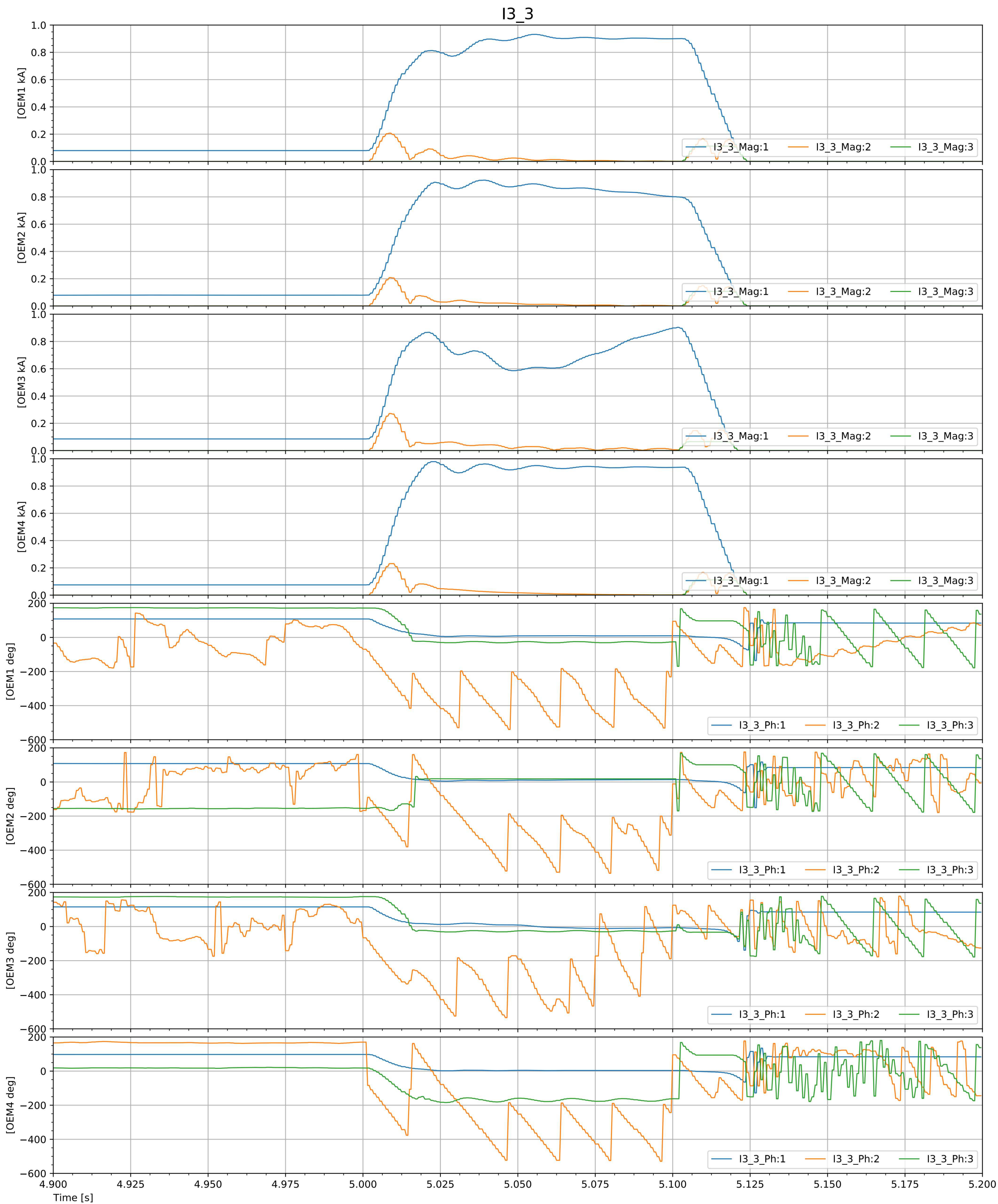
Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms



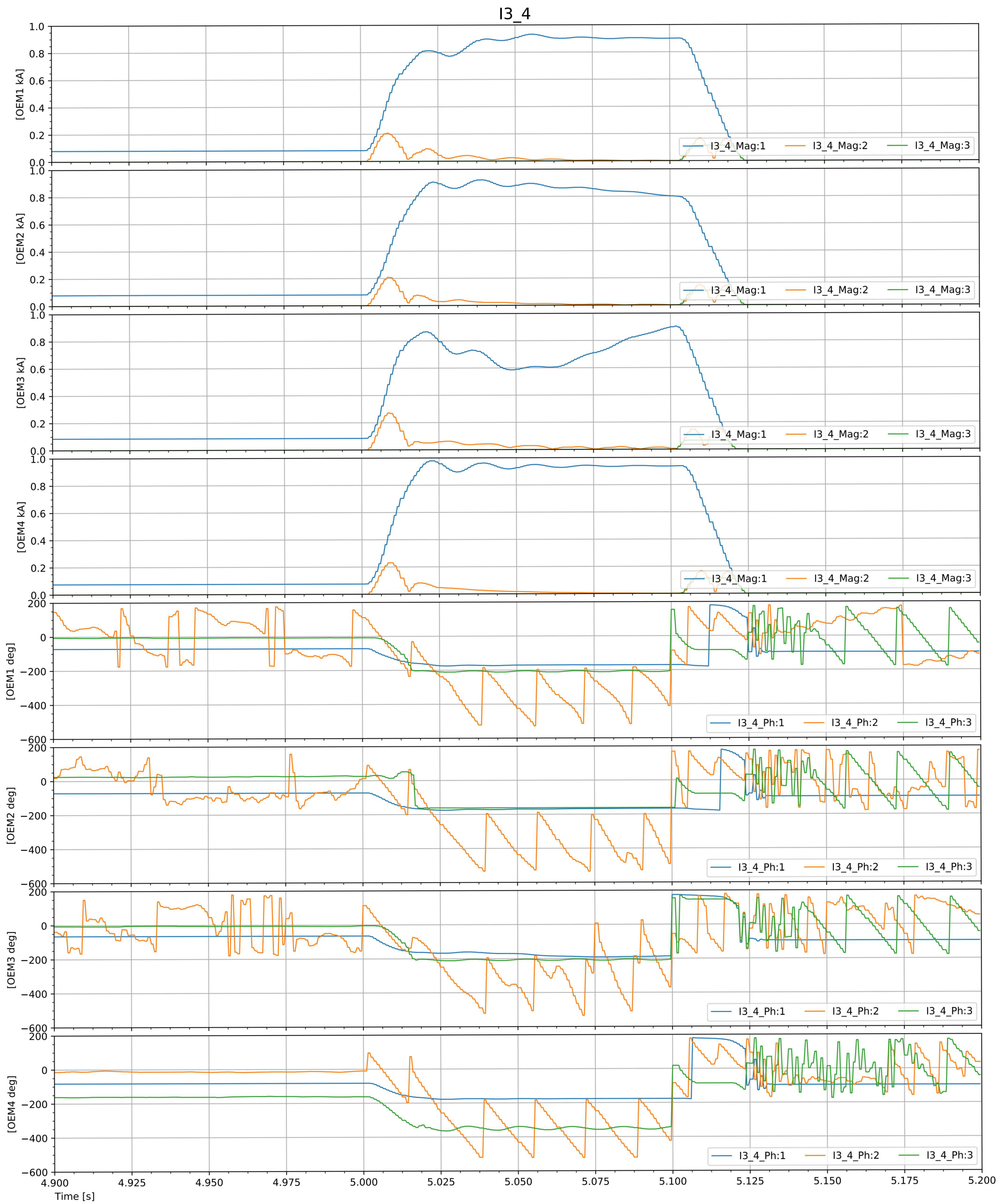
Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms



Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms

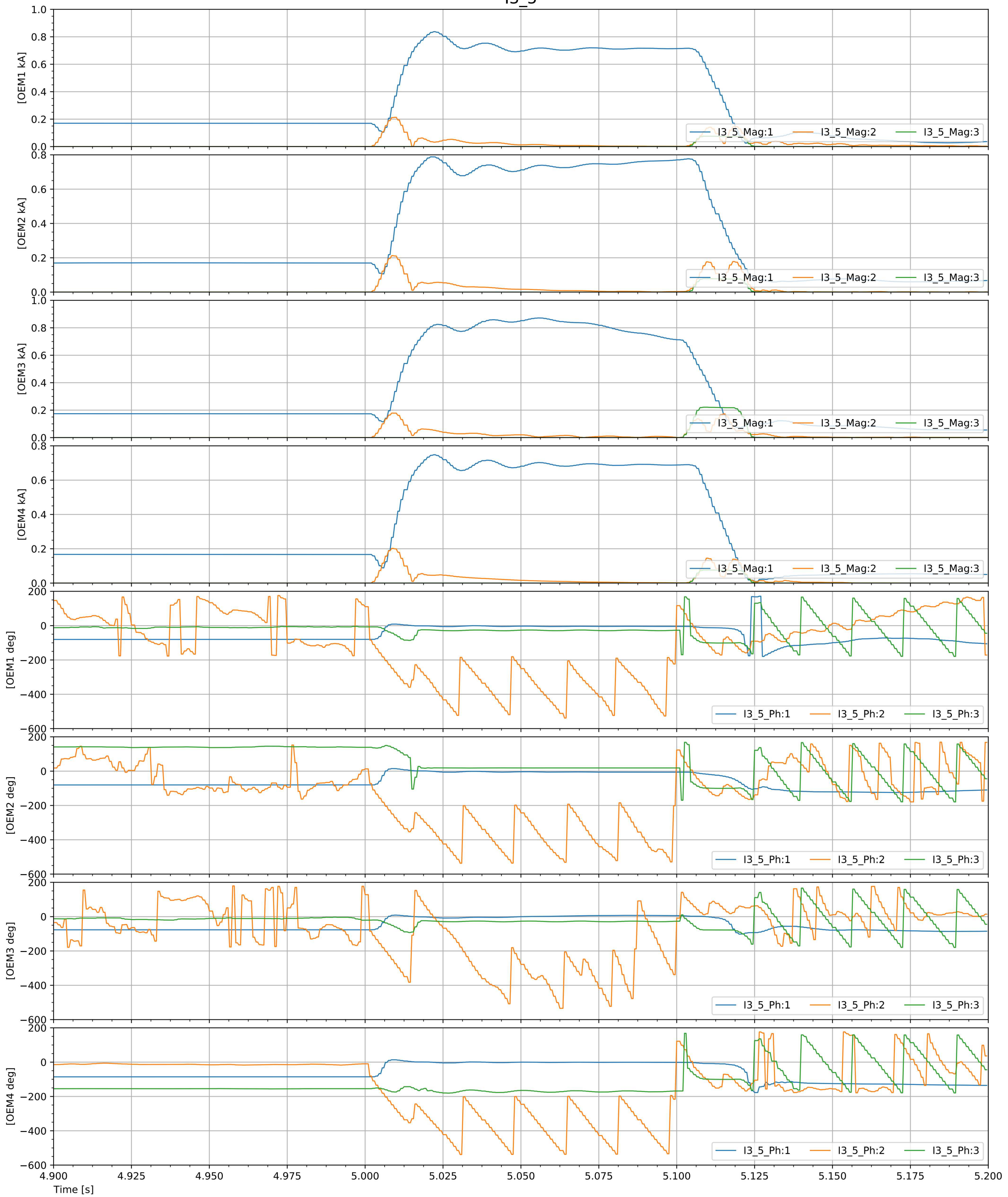


Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms



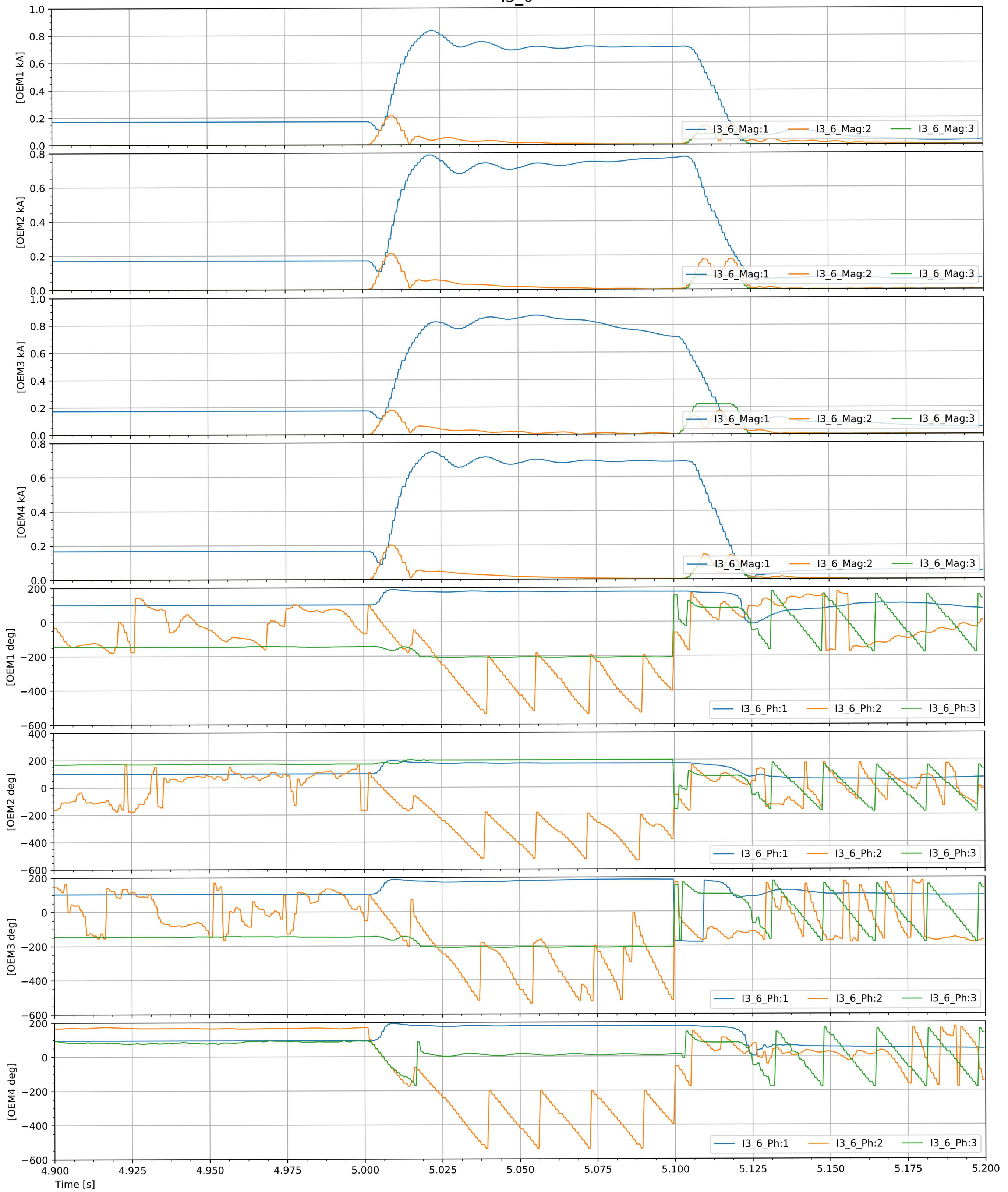
Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms

I3_5



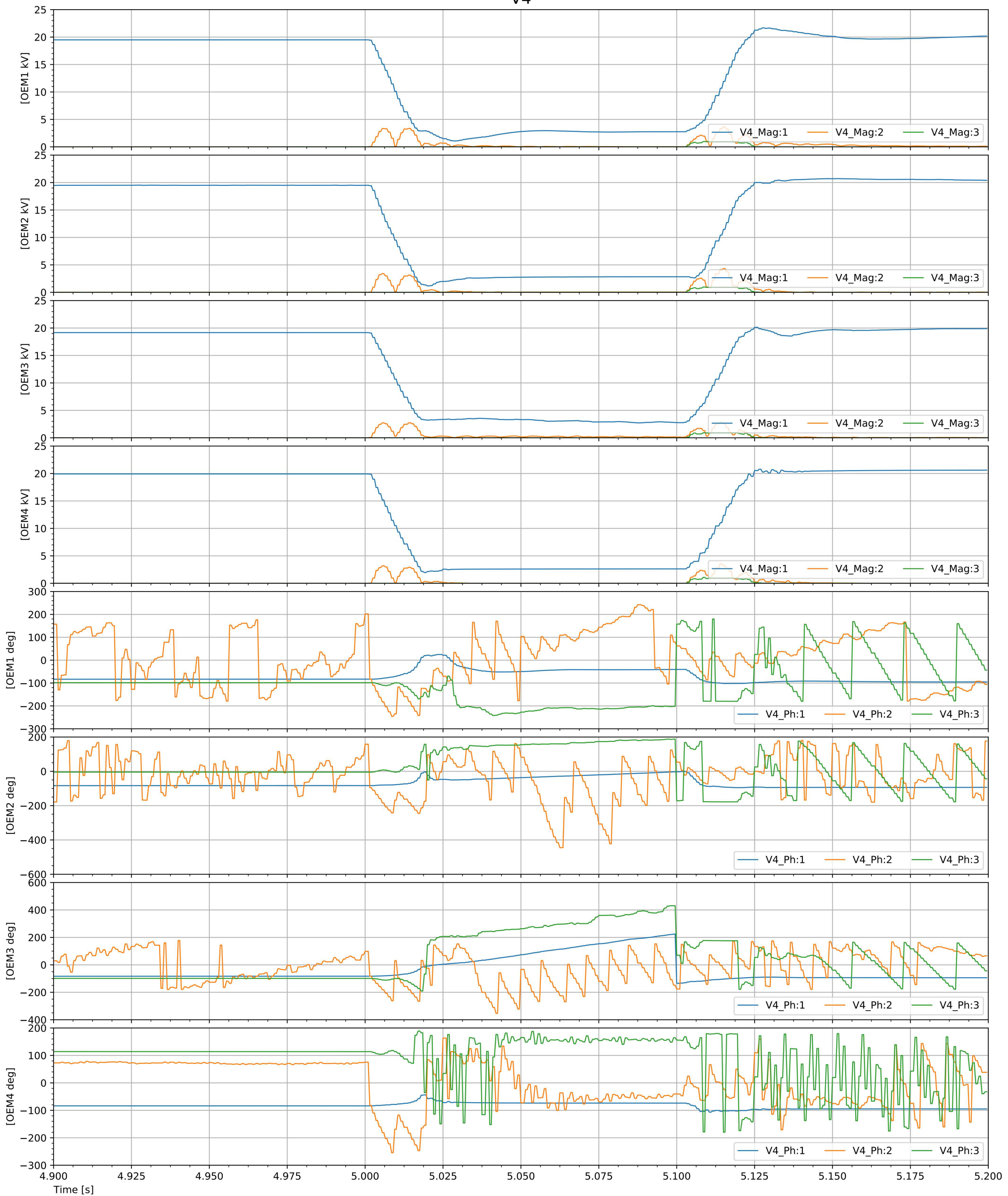
Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

I3_6

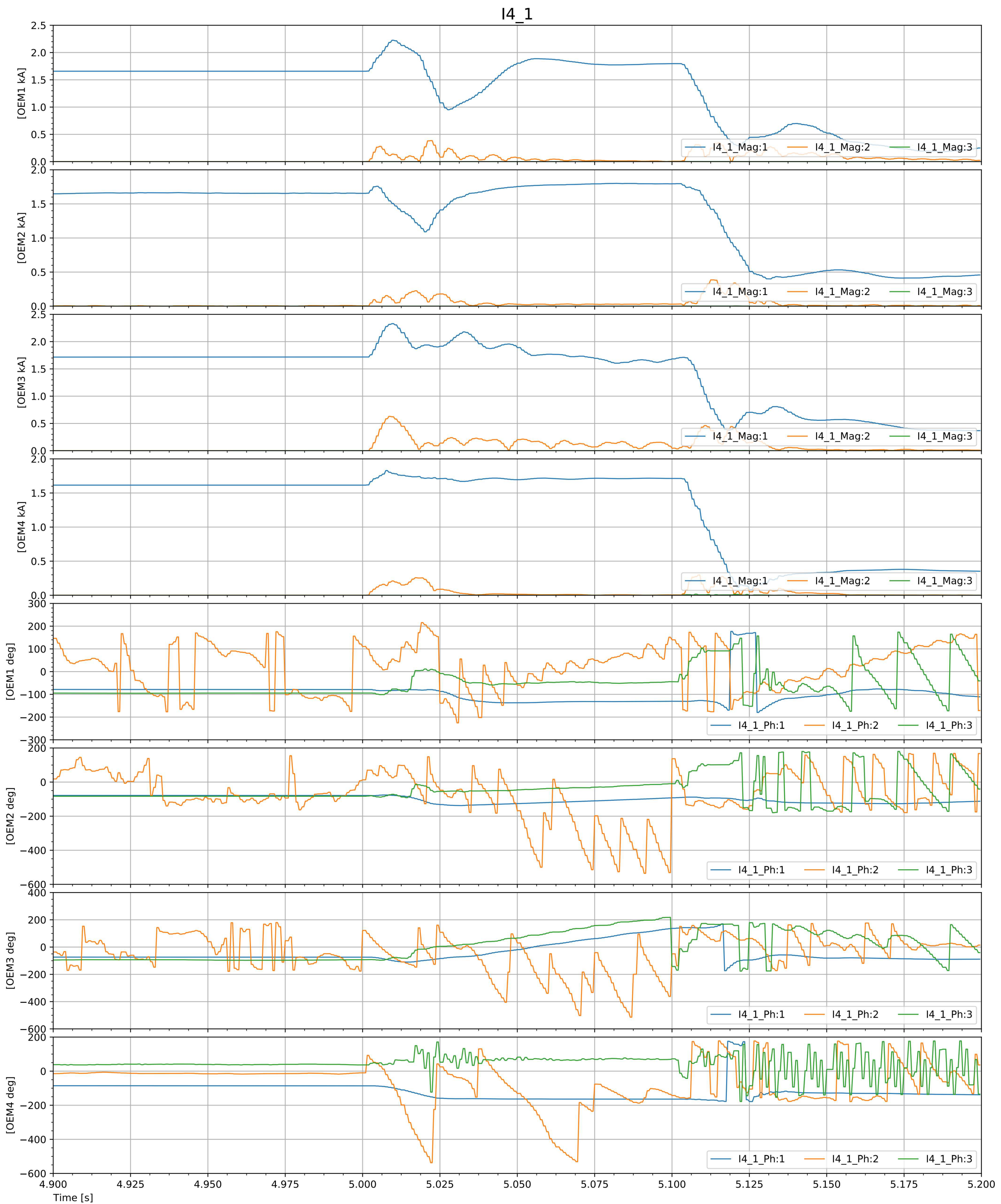


Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

V4

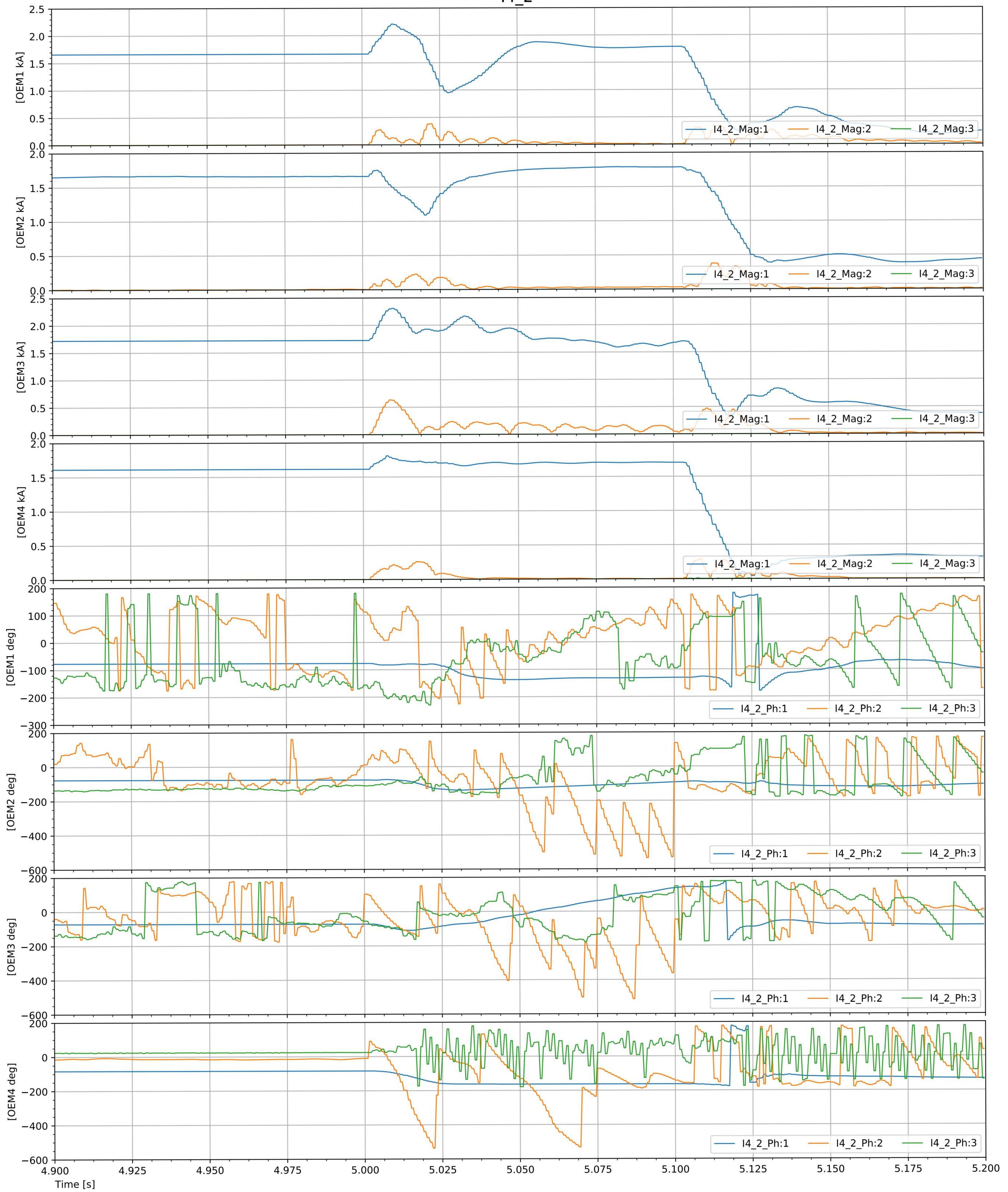


Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms



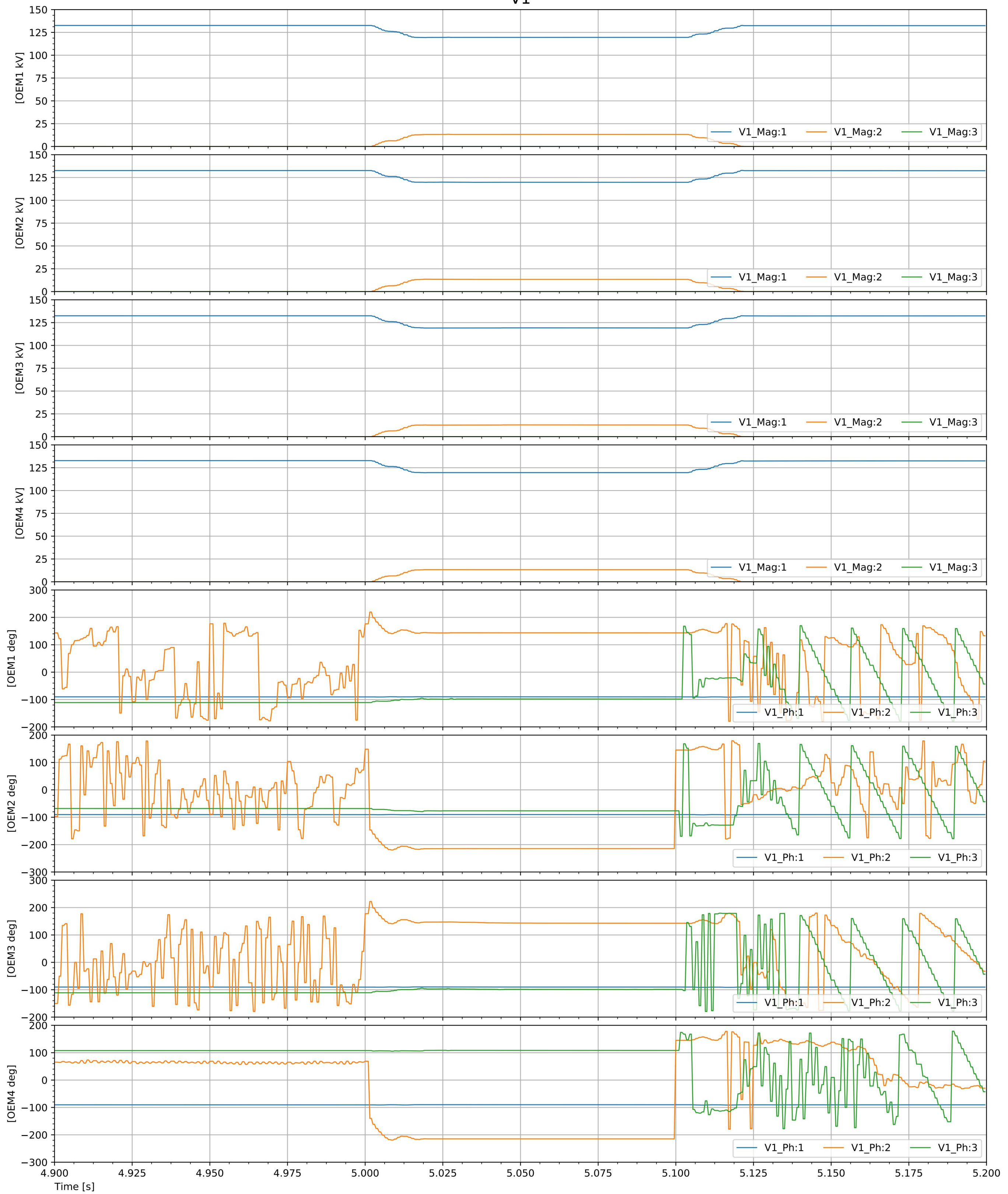
Network Configuration: System Intact
Fault Location: B
Fault Type: ABCG
Fault Resistance: 0.001 ohms

I4_2



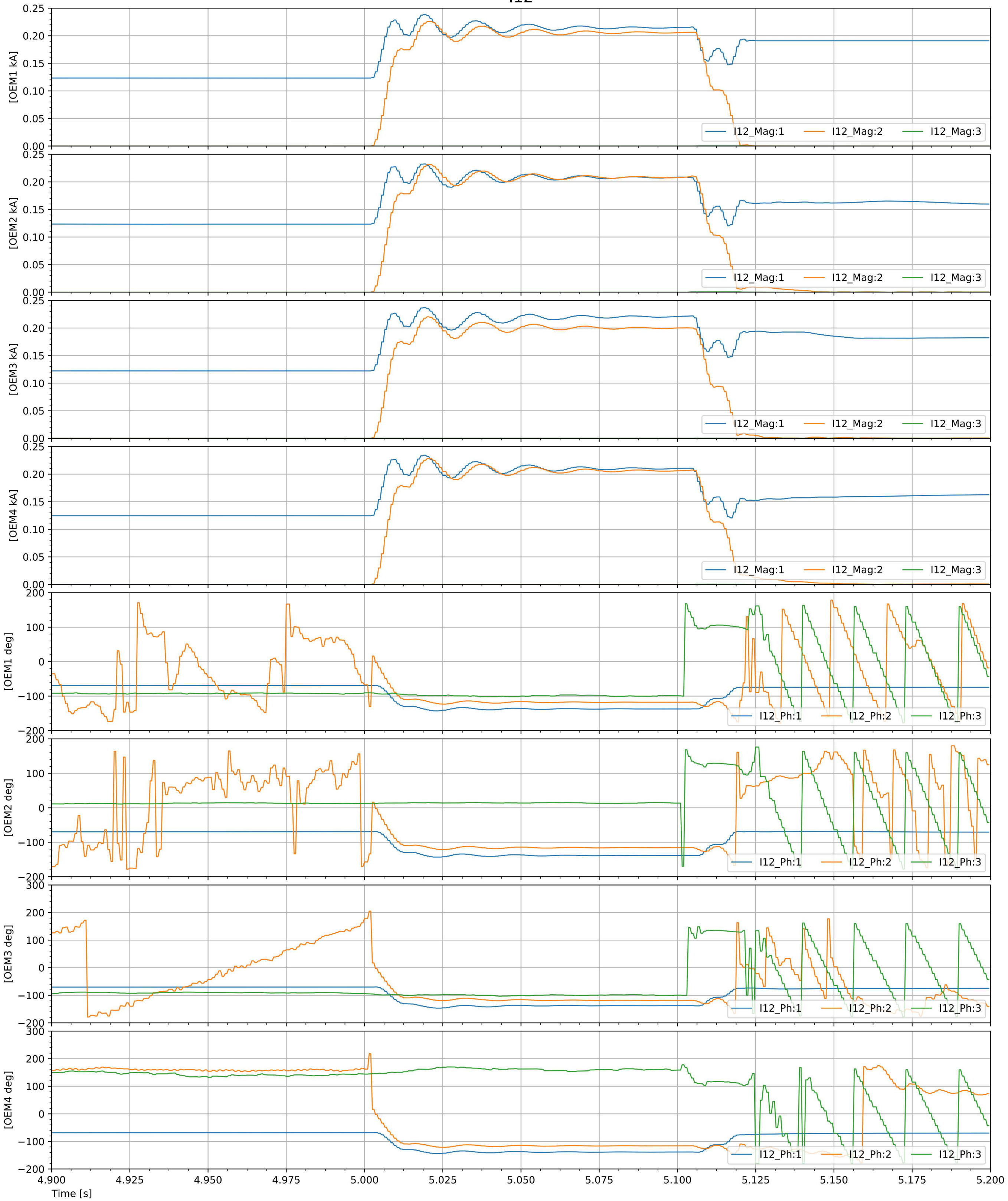
Network Configuration: System Intact
 Fault Location: B
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

V1



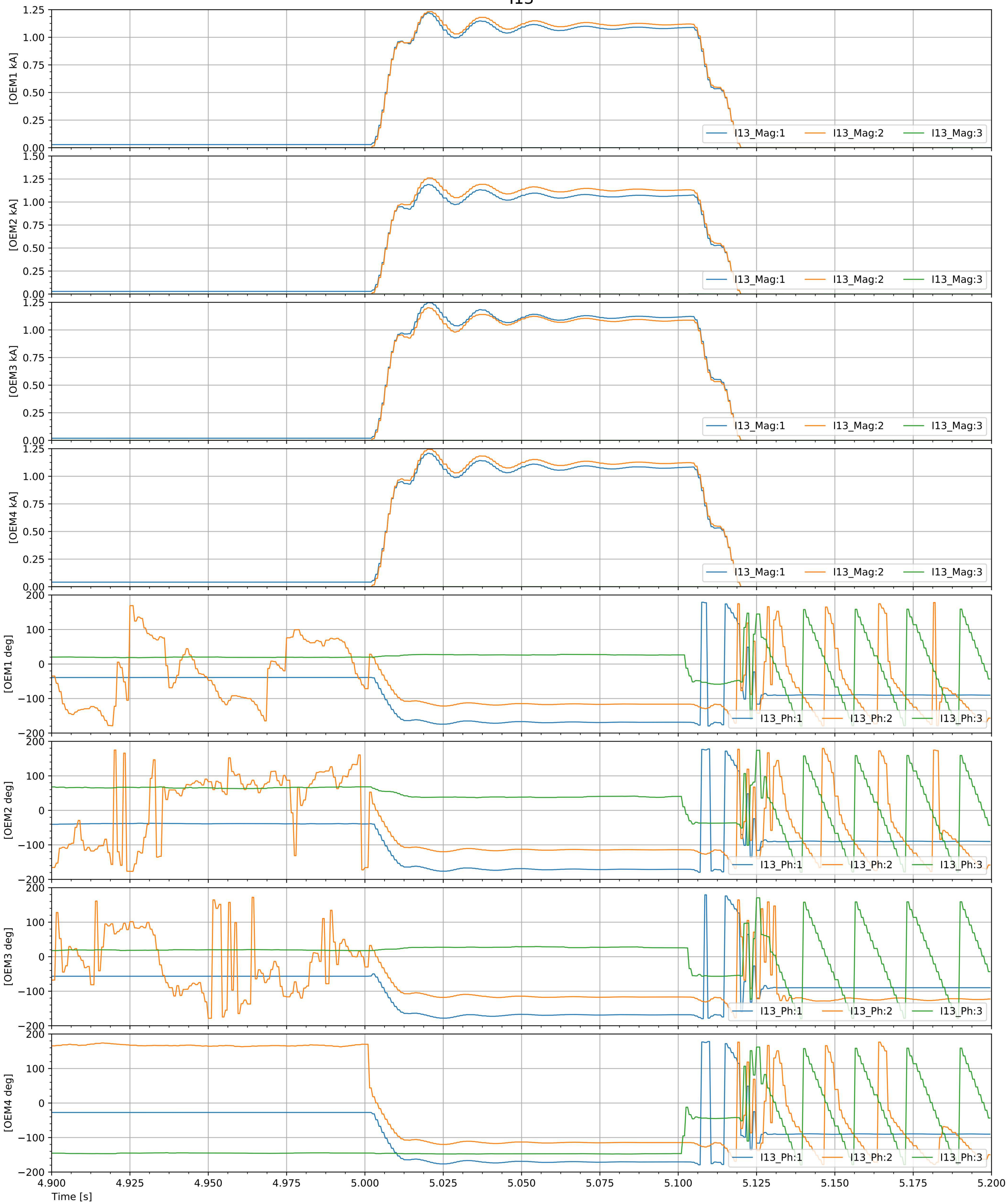
Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms

I12



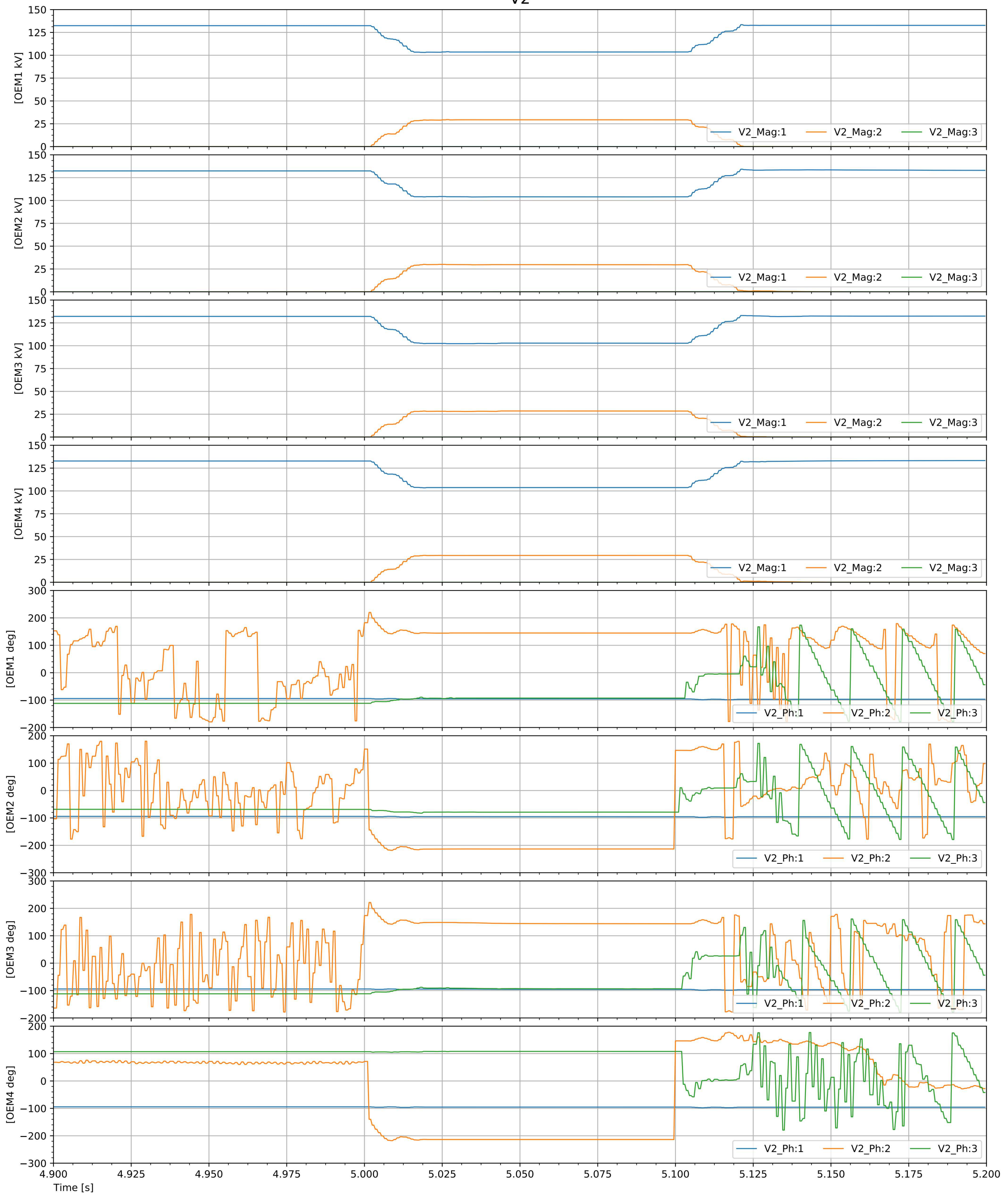
Network Configuration: System Intact
Fault Location: B
Fault Type: AB
Fault Resistance: 0.001 ohms

I13

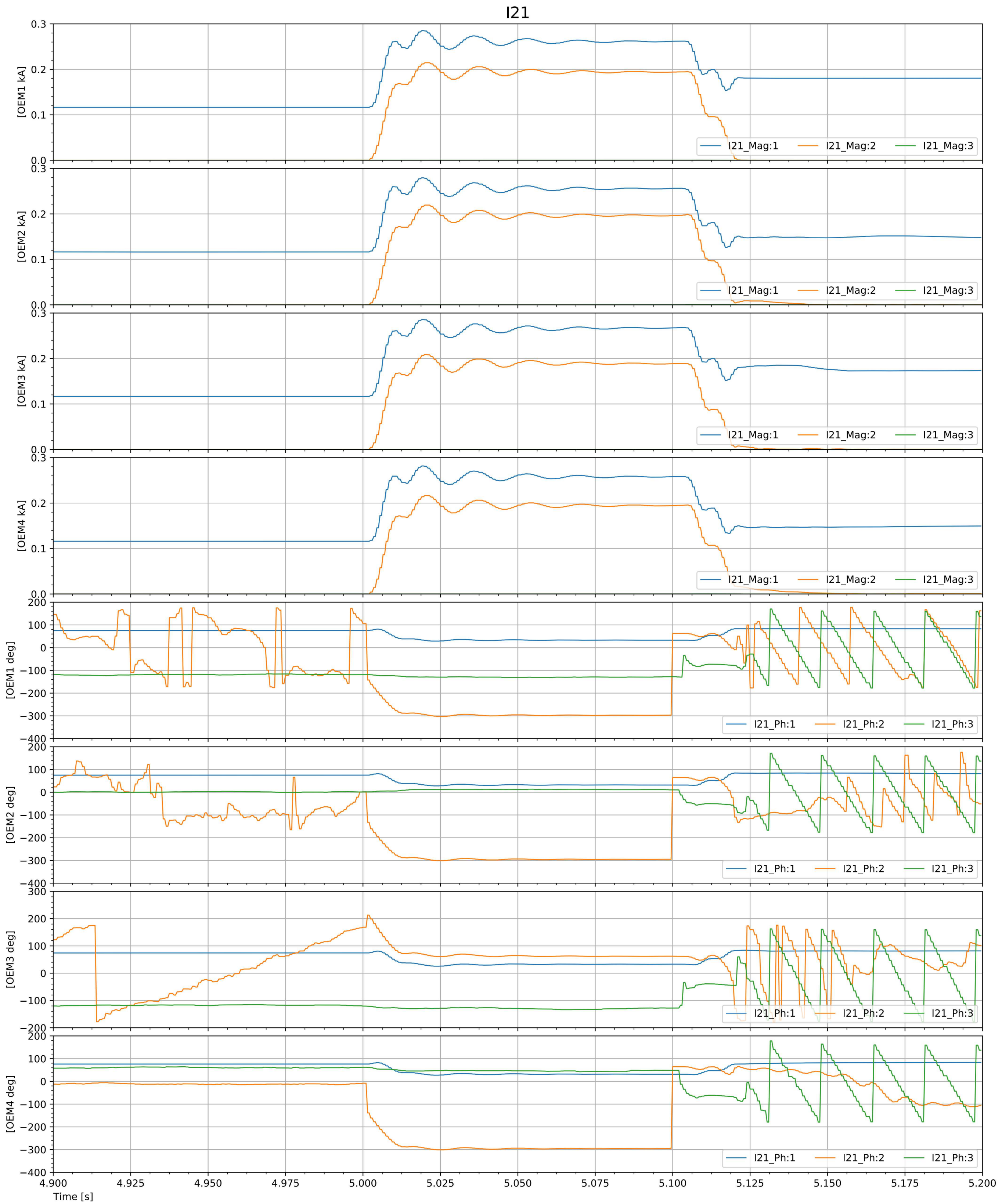


Network Configuration: System Intact
Fault Location: B
Fault Type: AB
Fault Resistance: 0.001 ohms

V2

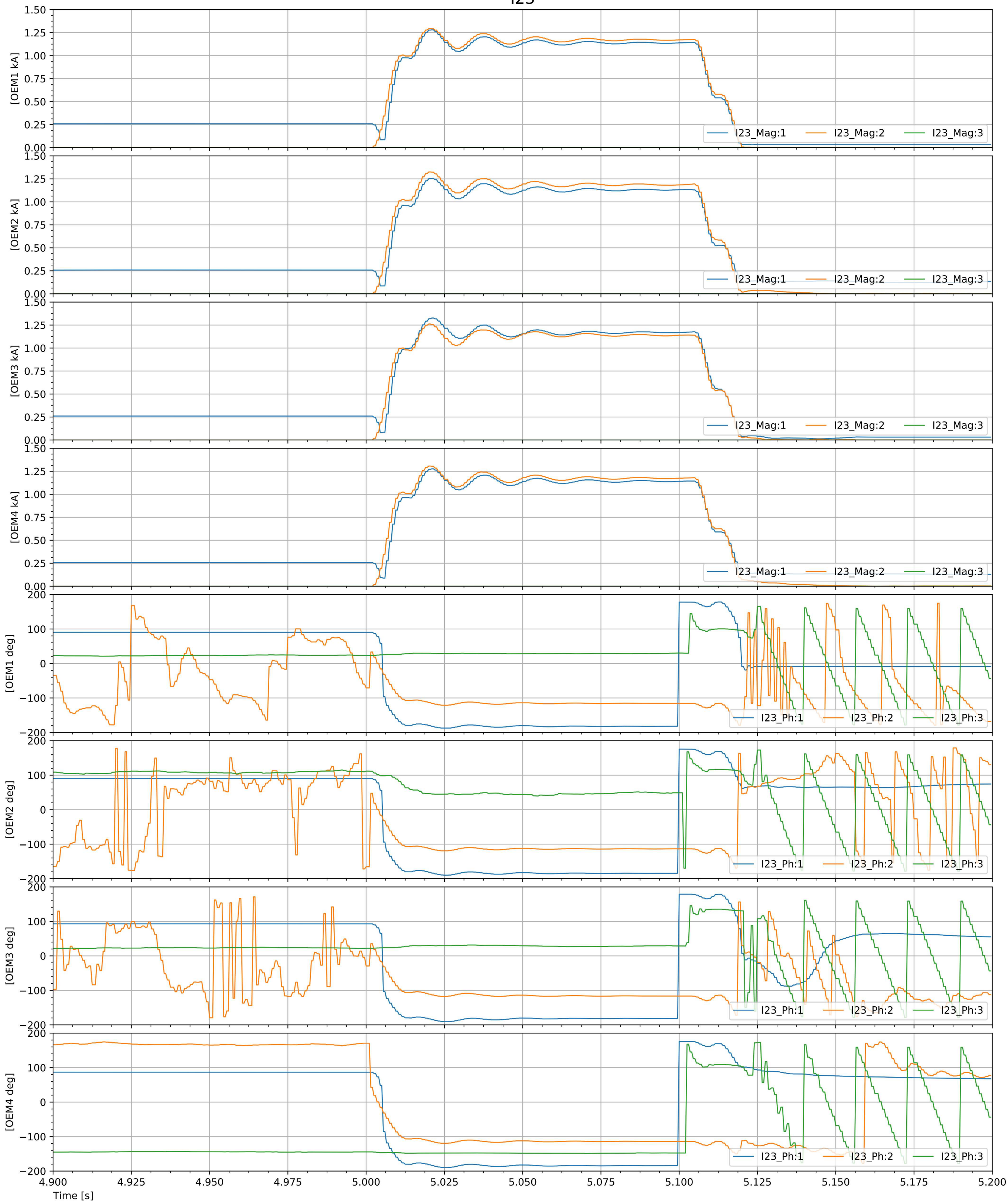


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms



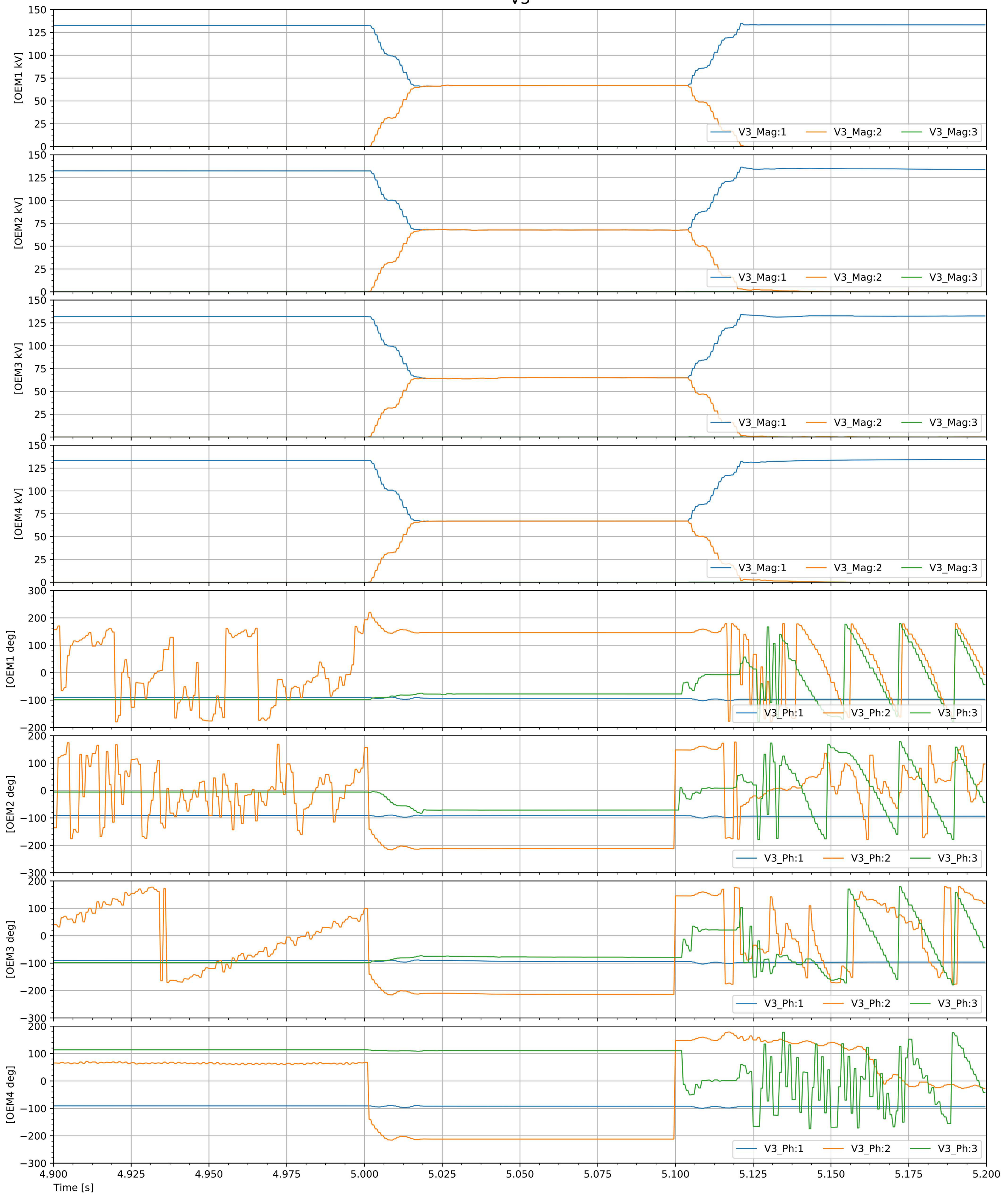
Network Configuration: System Intact
Fault Location: B
Fault Type: AB
Fault Resistance: 0.001 ohms

I23

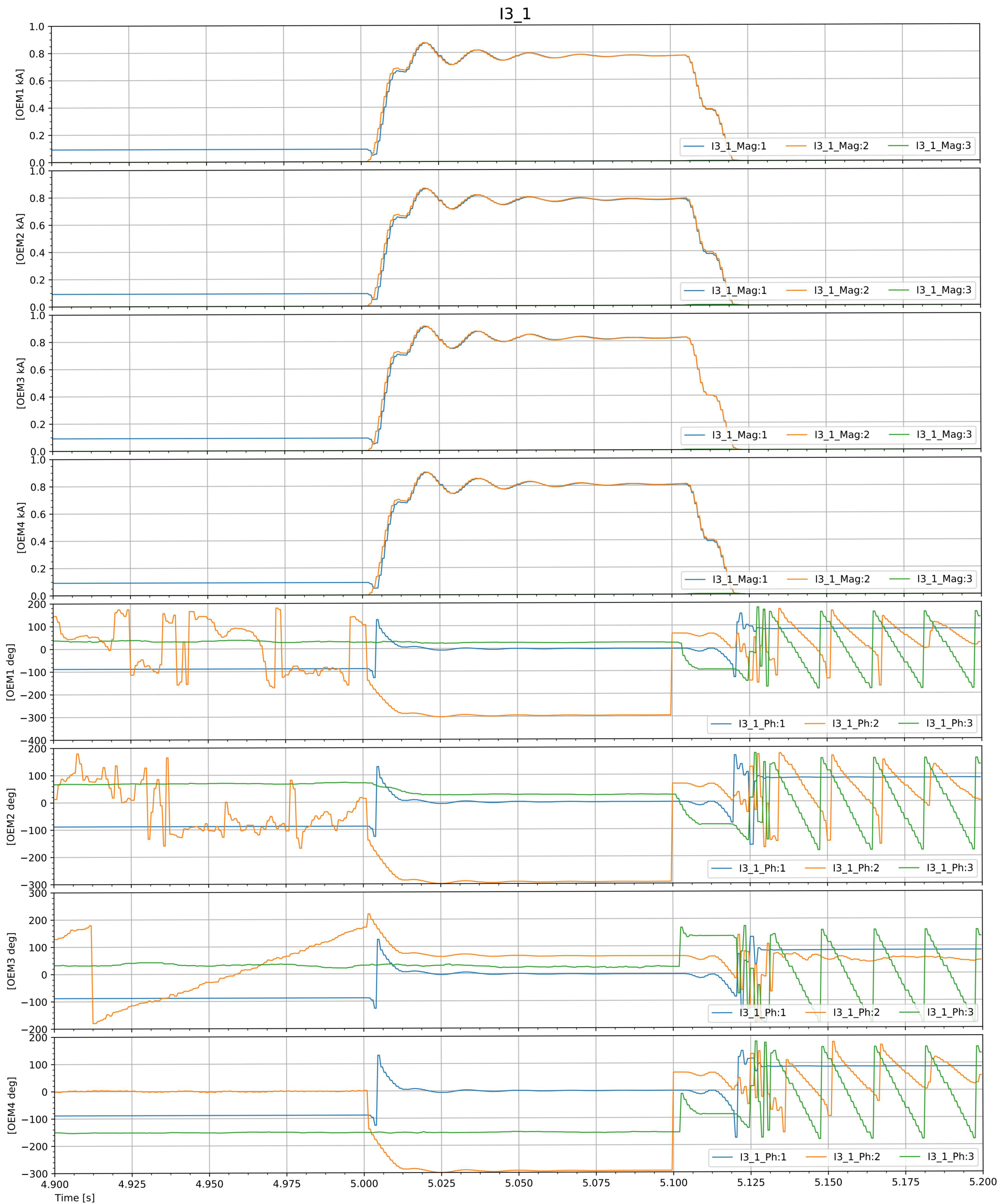


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms

V3

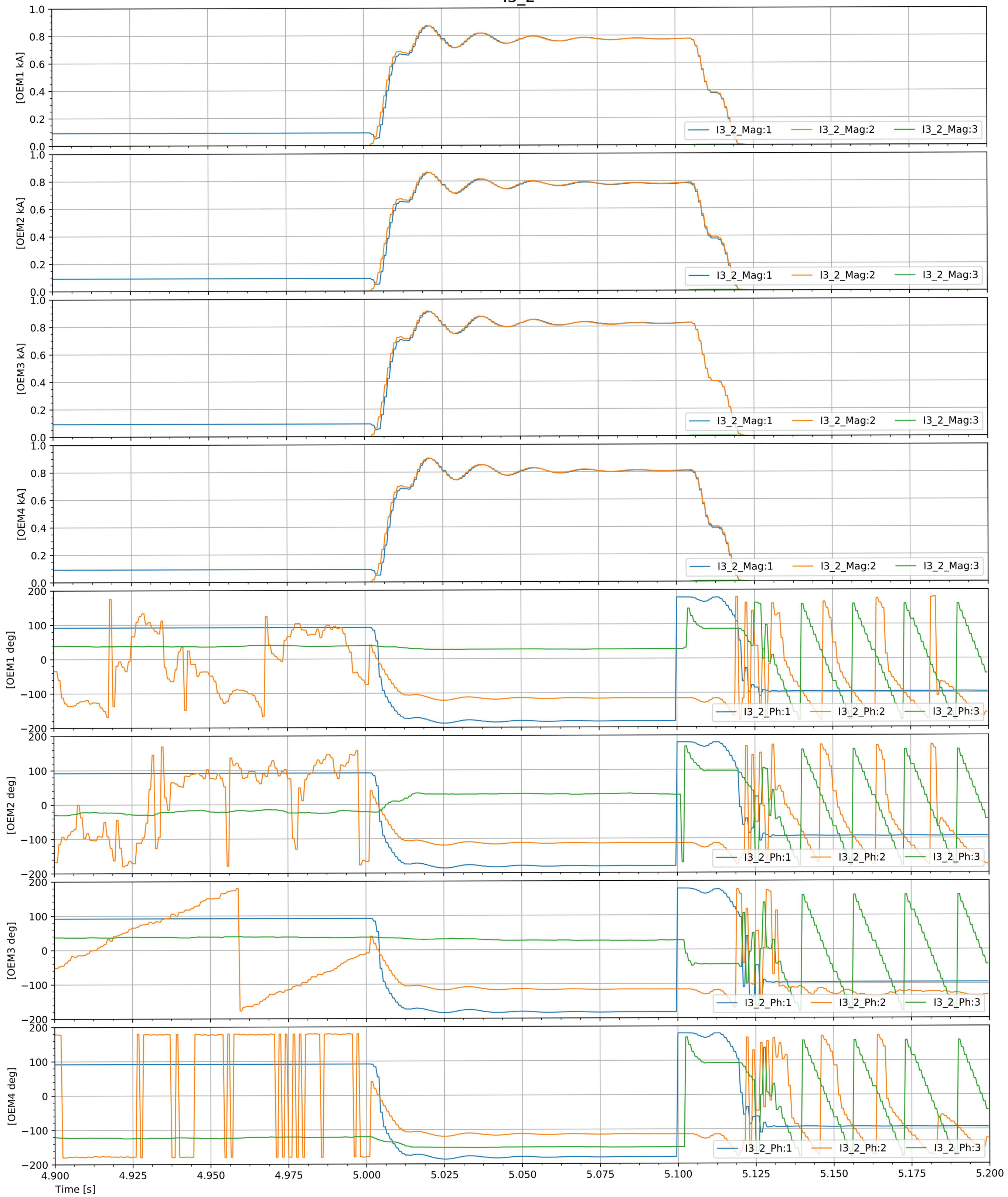


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms

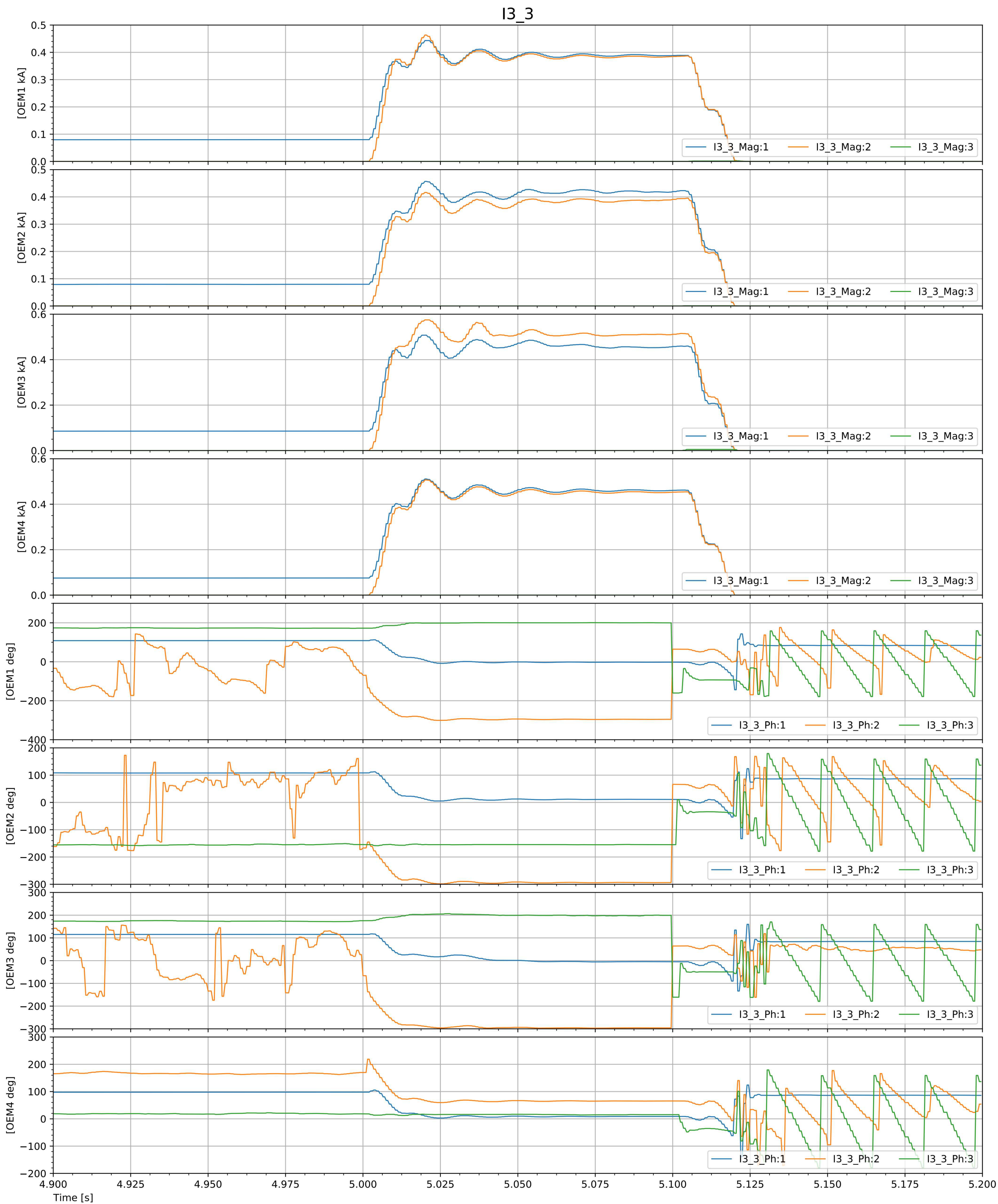


Network Configuration: System Intact
Fault Location: B
Fault Type: AB
Fault Resistance: 0.001 ohms

I3_2

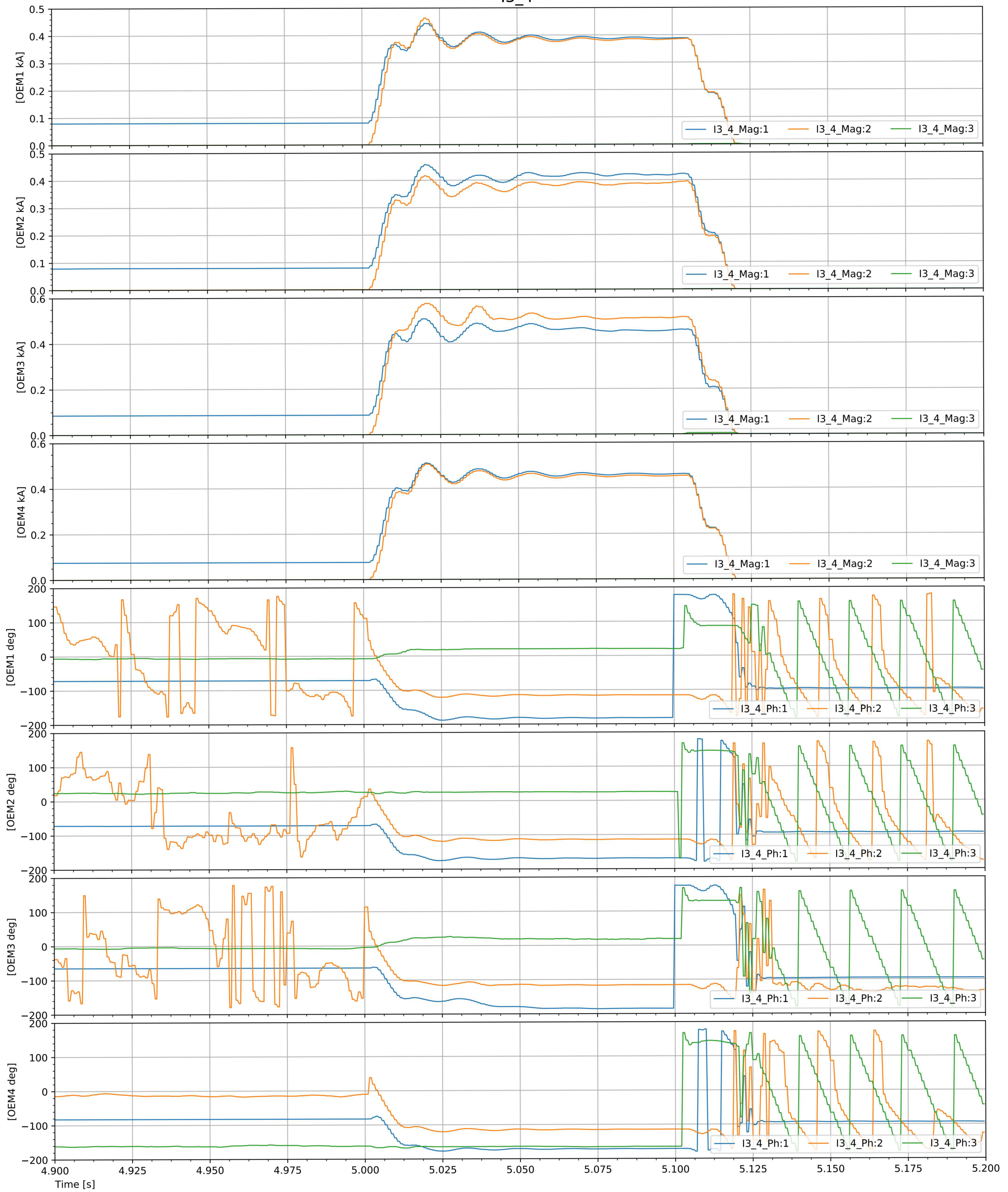


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms



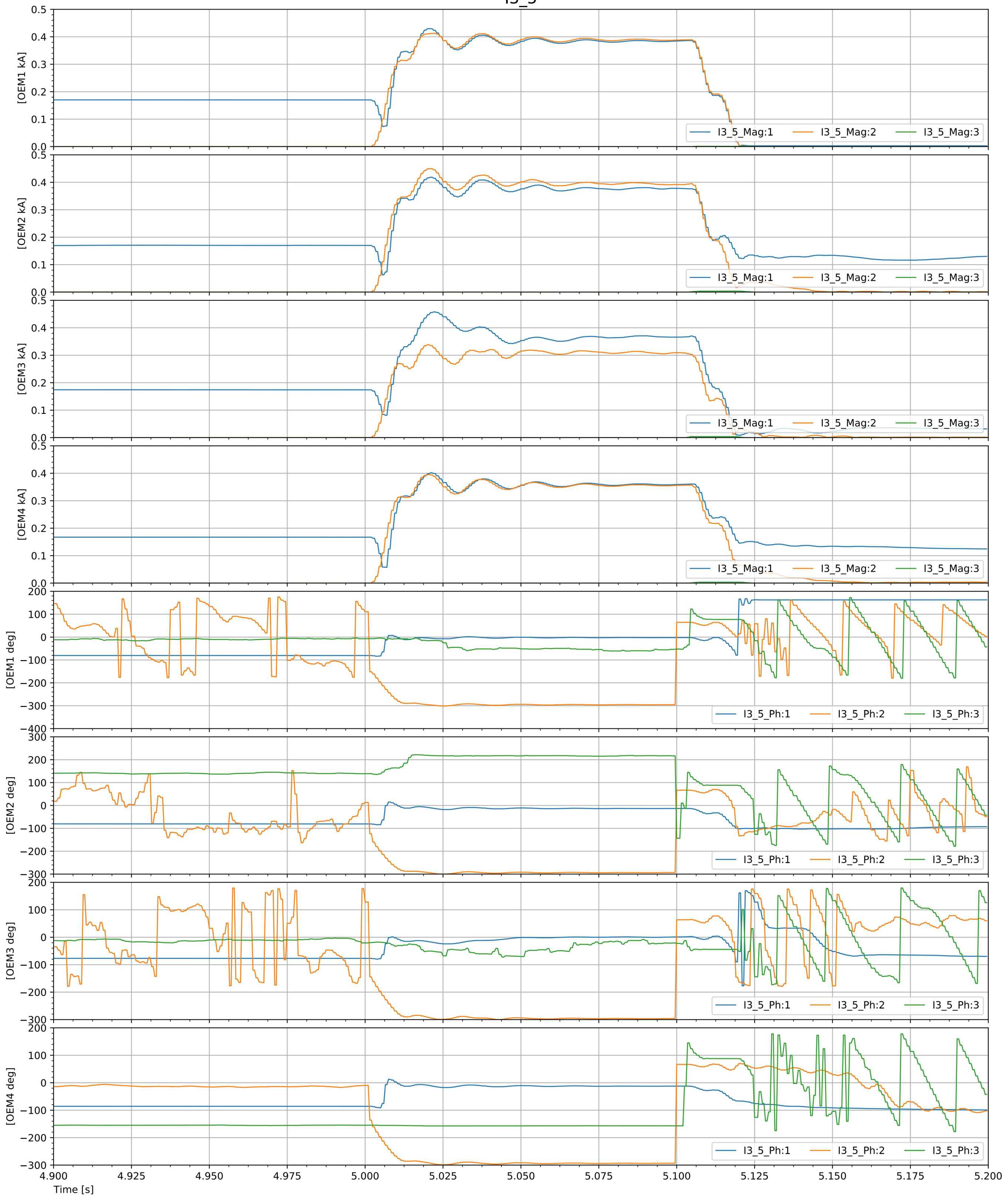
Network Configuration: System Intact
Fault Location: B
Fault Type: AB
Fault Resistance: 0.001 ohms

I3_4



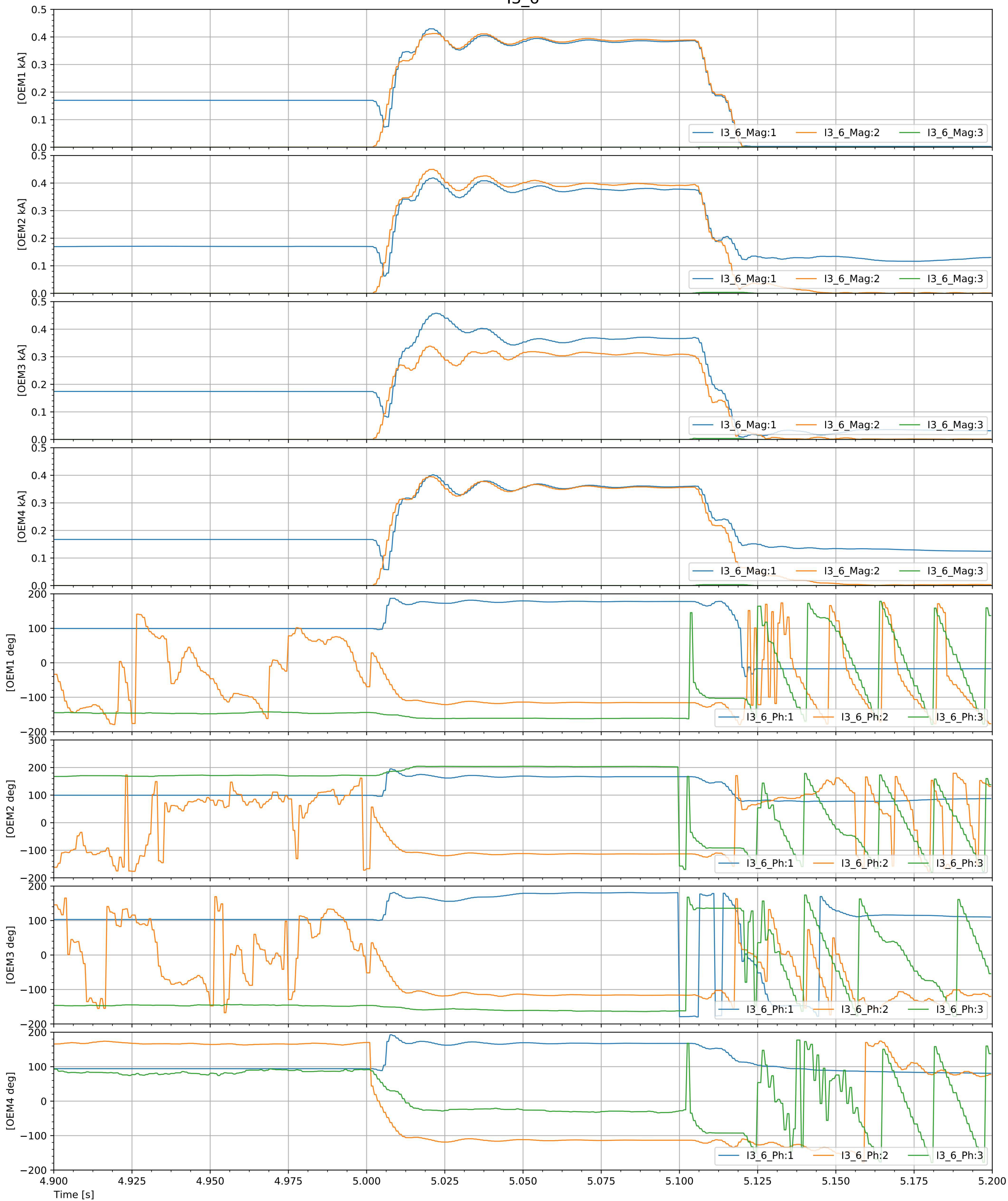
Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms

I3_5



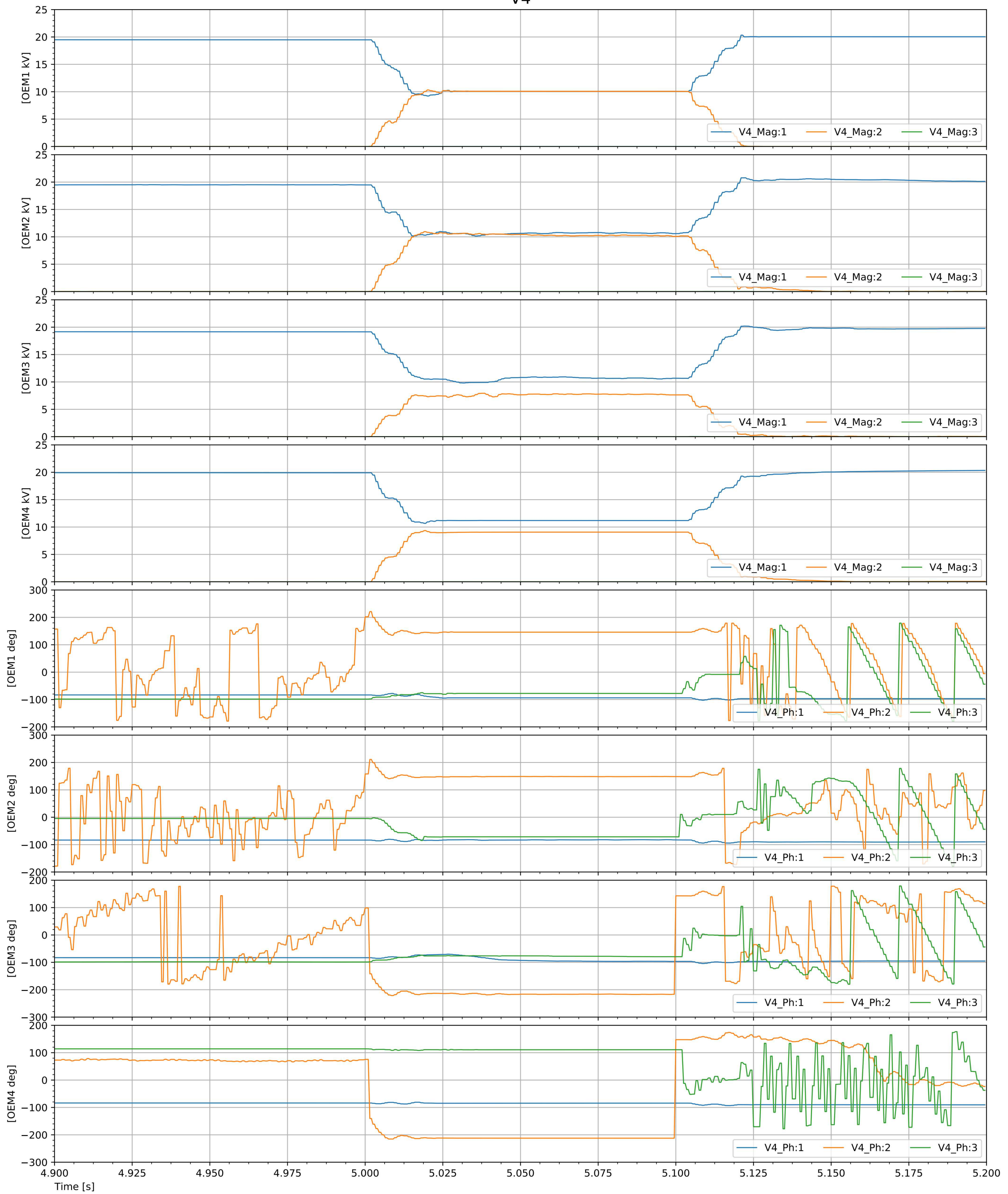
Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms

I3_6

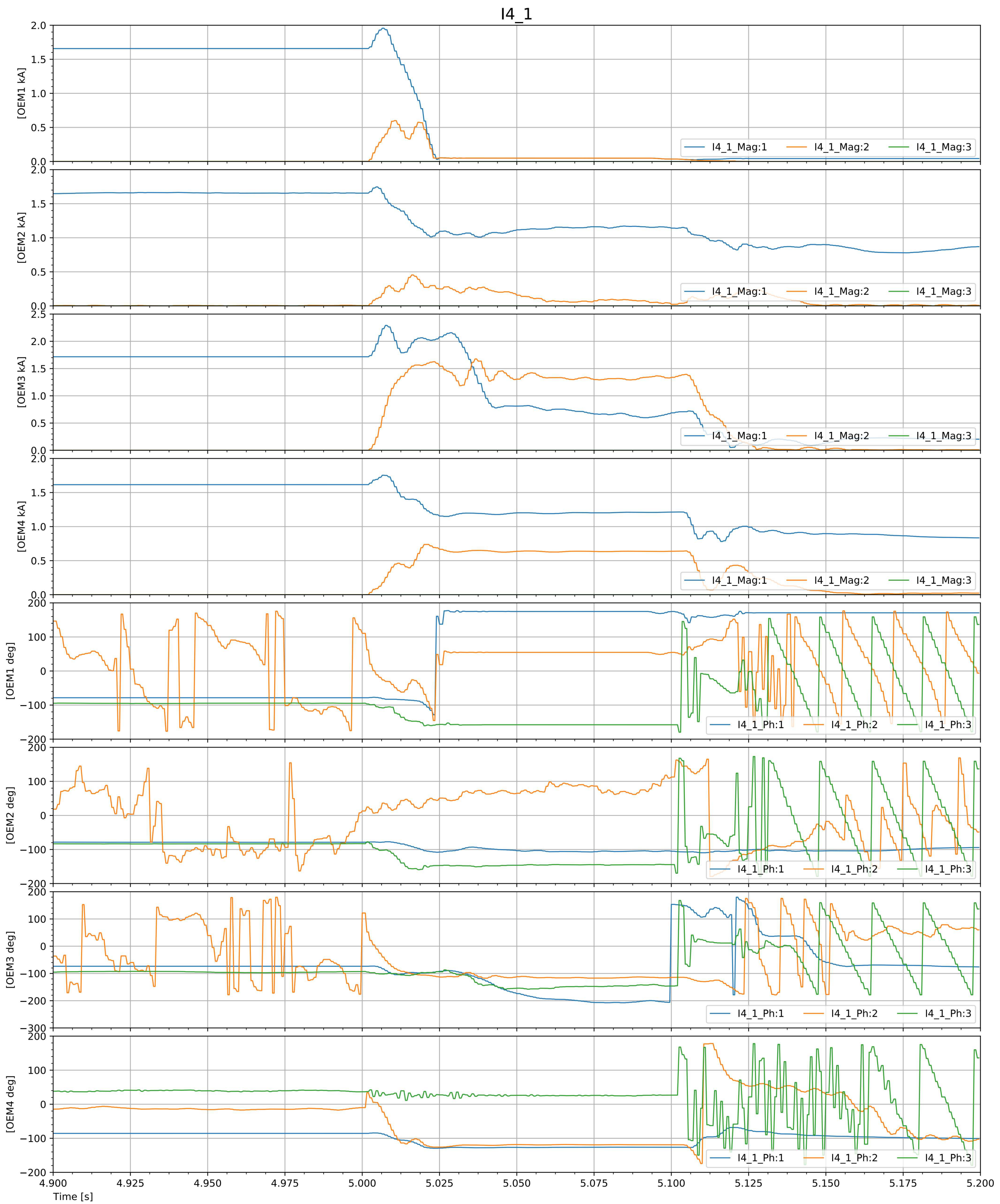


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms

V4

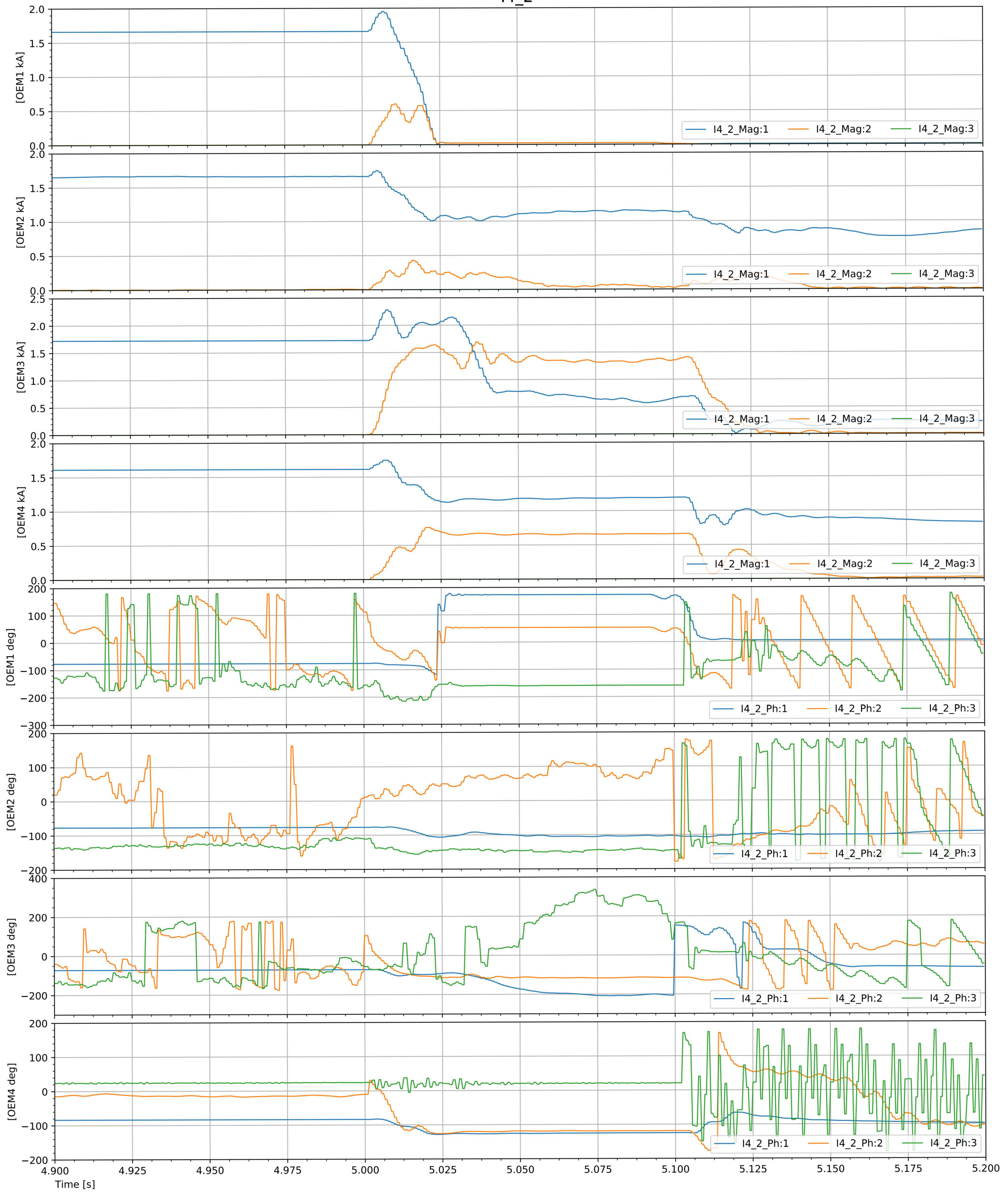


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms



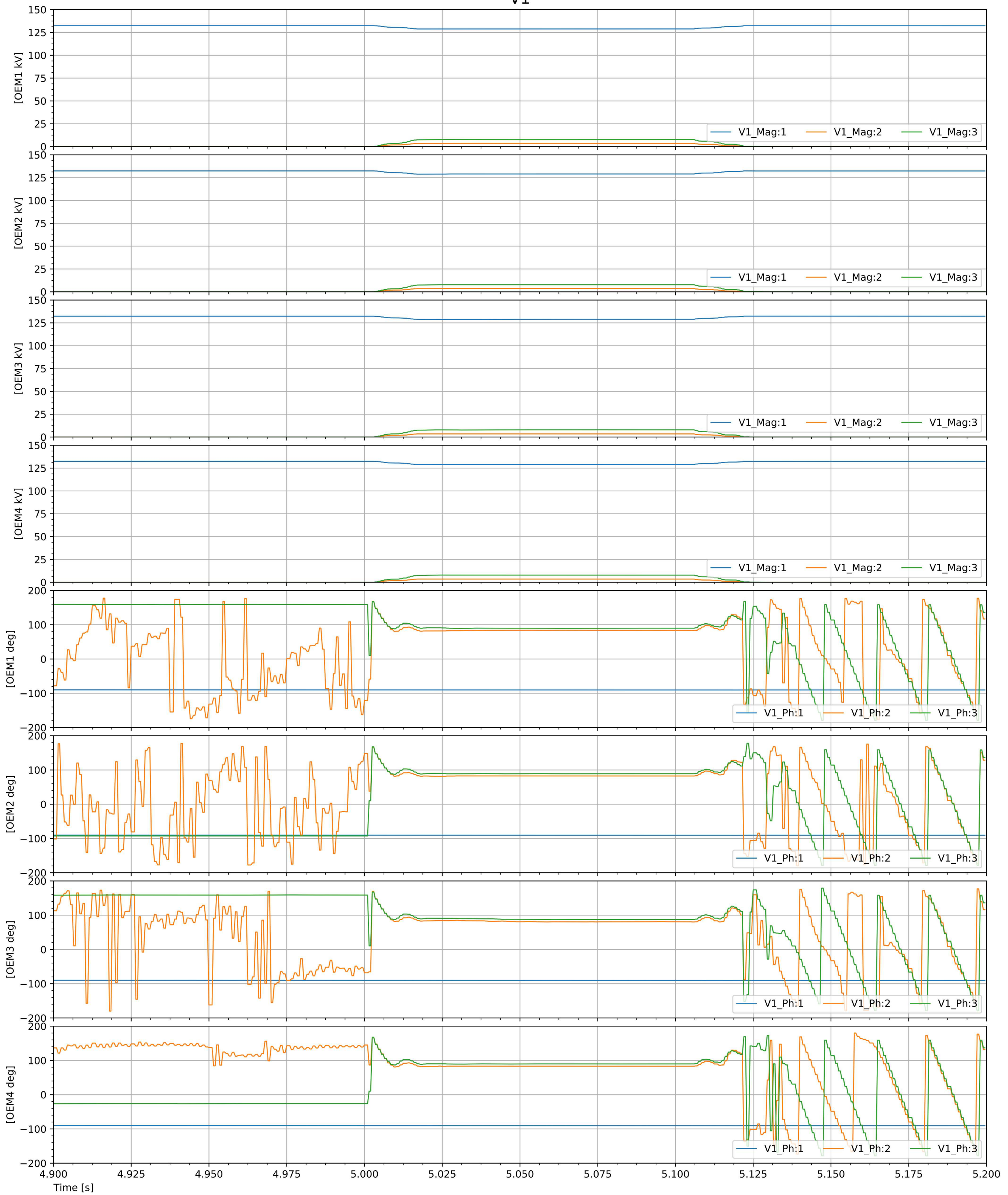
Network Configuration: System Intact
Fault Location: B
Fault Type: AB
Fault Resistance: 0.001 ohms

I4_2

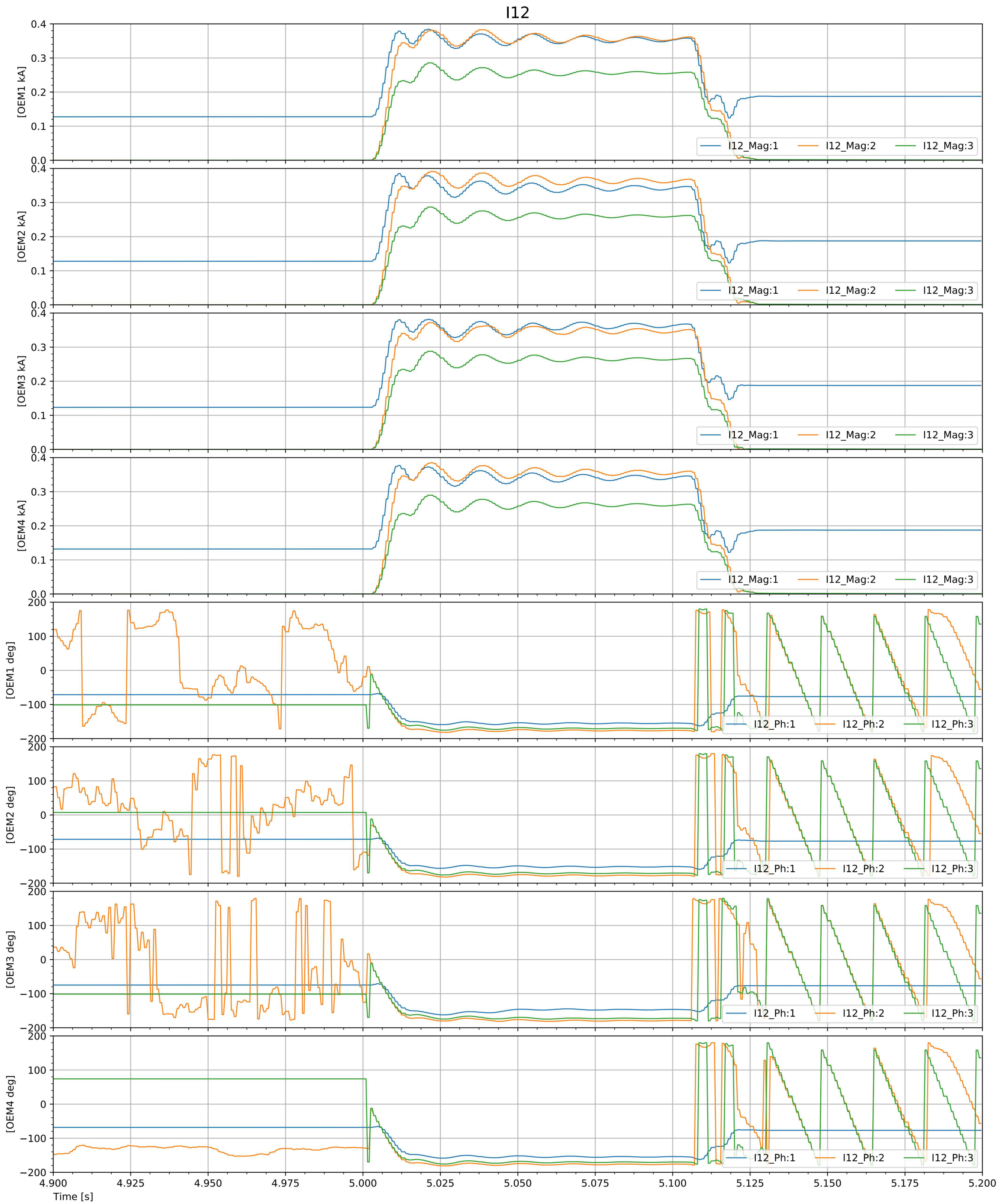


Network Configuration: System Intact
 Fault Location: B
 Fault Type: AB
 Fault Resistance: 0.001 ohms

V1

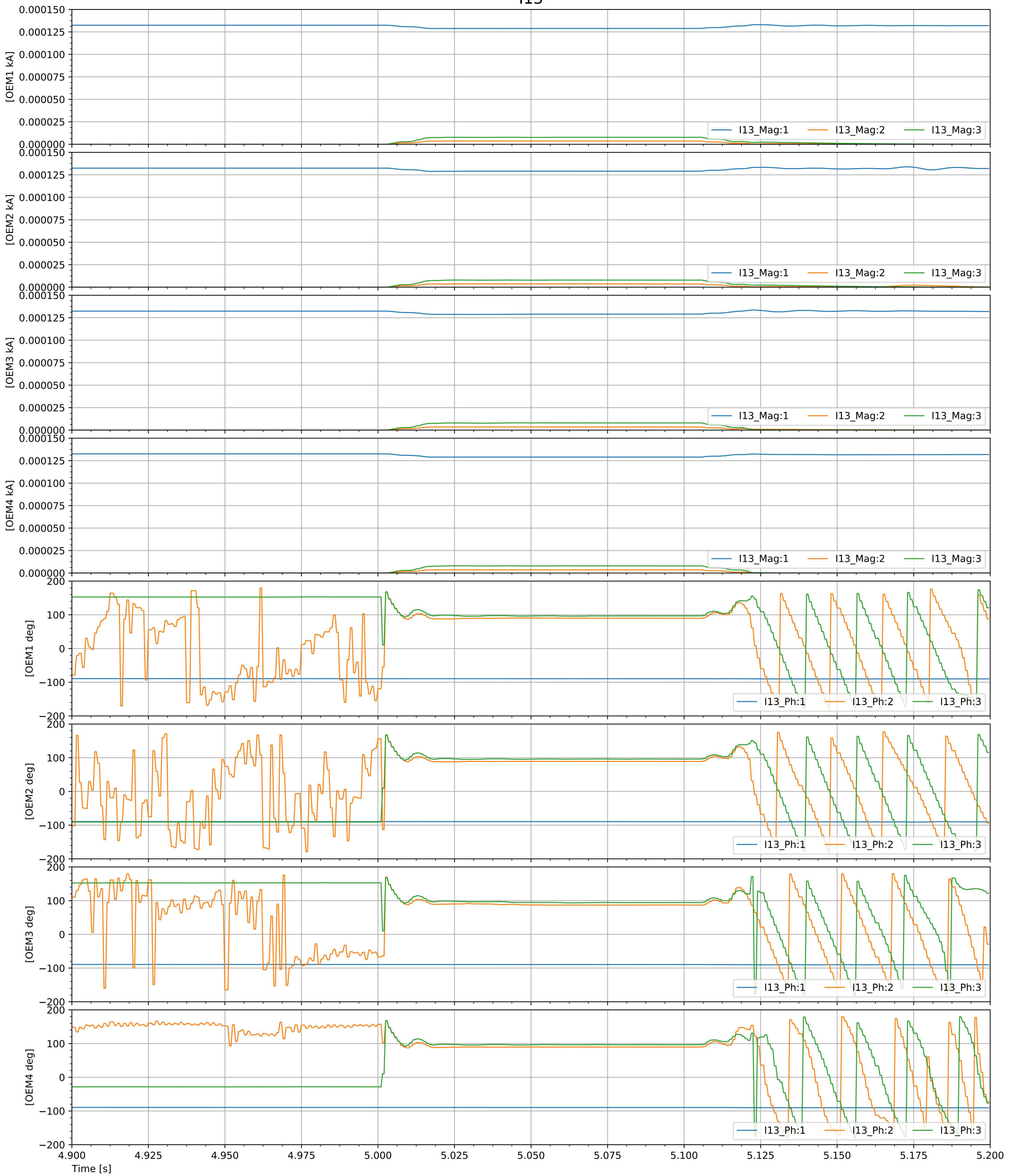


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms



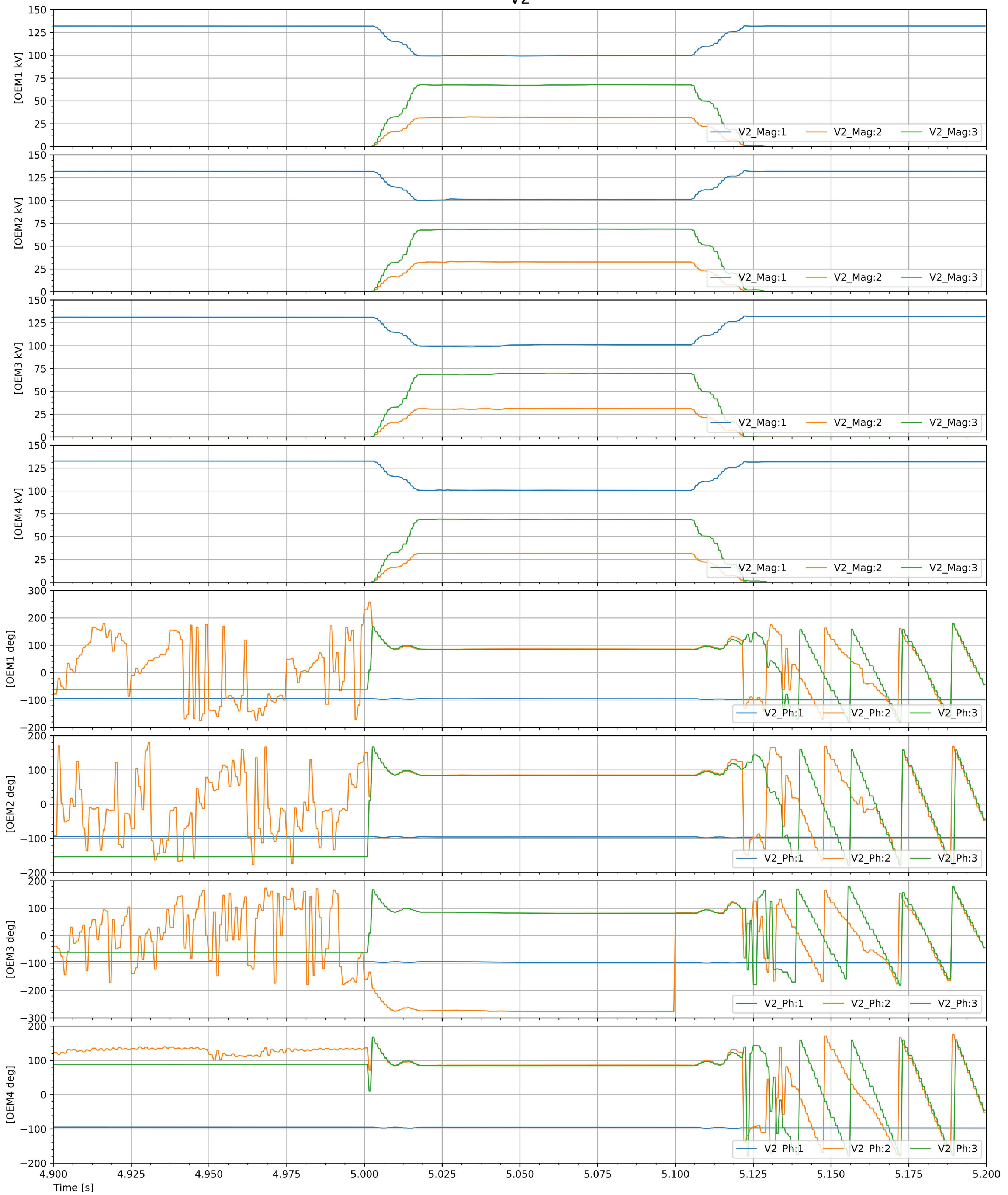
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

I13

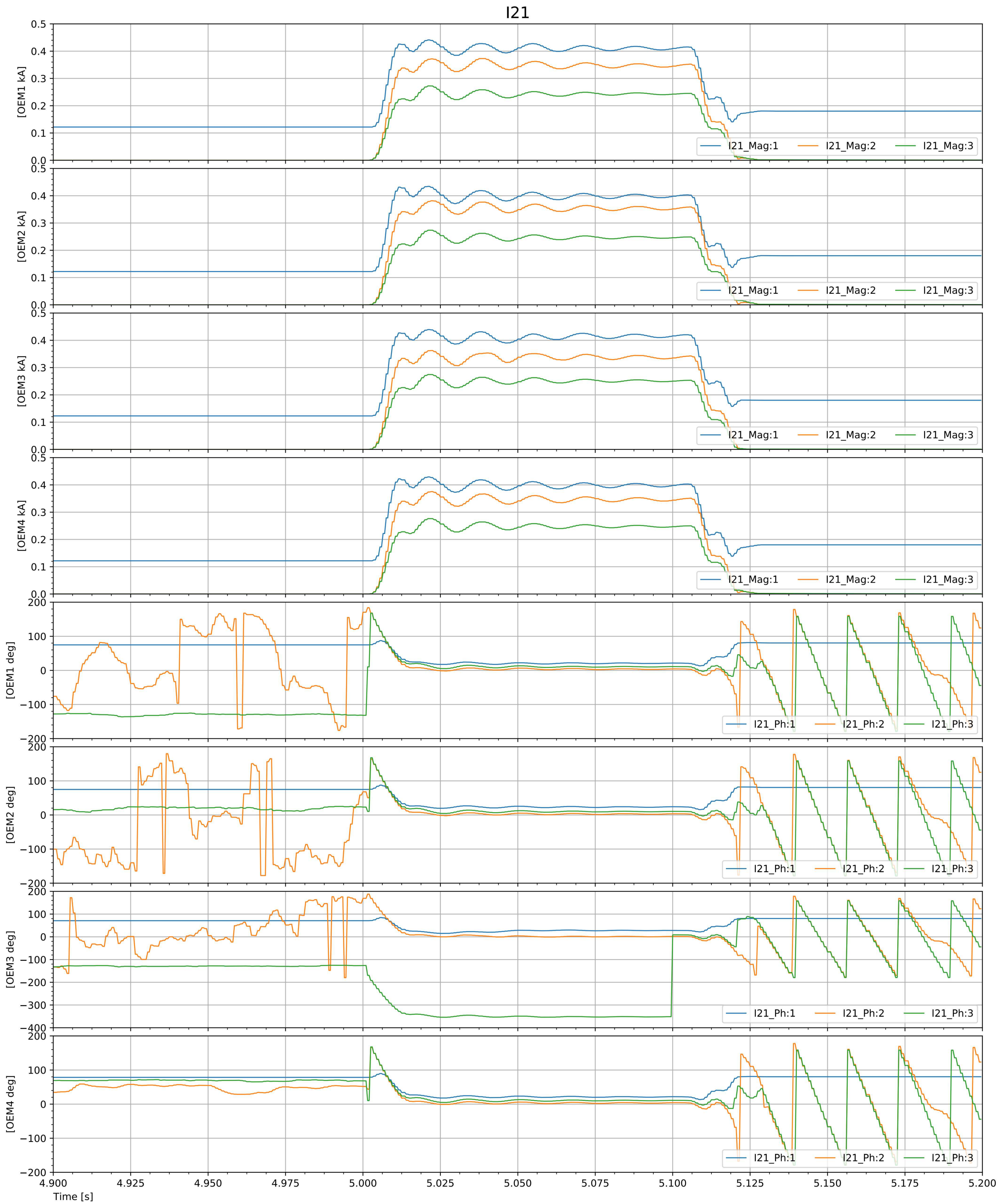


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

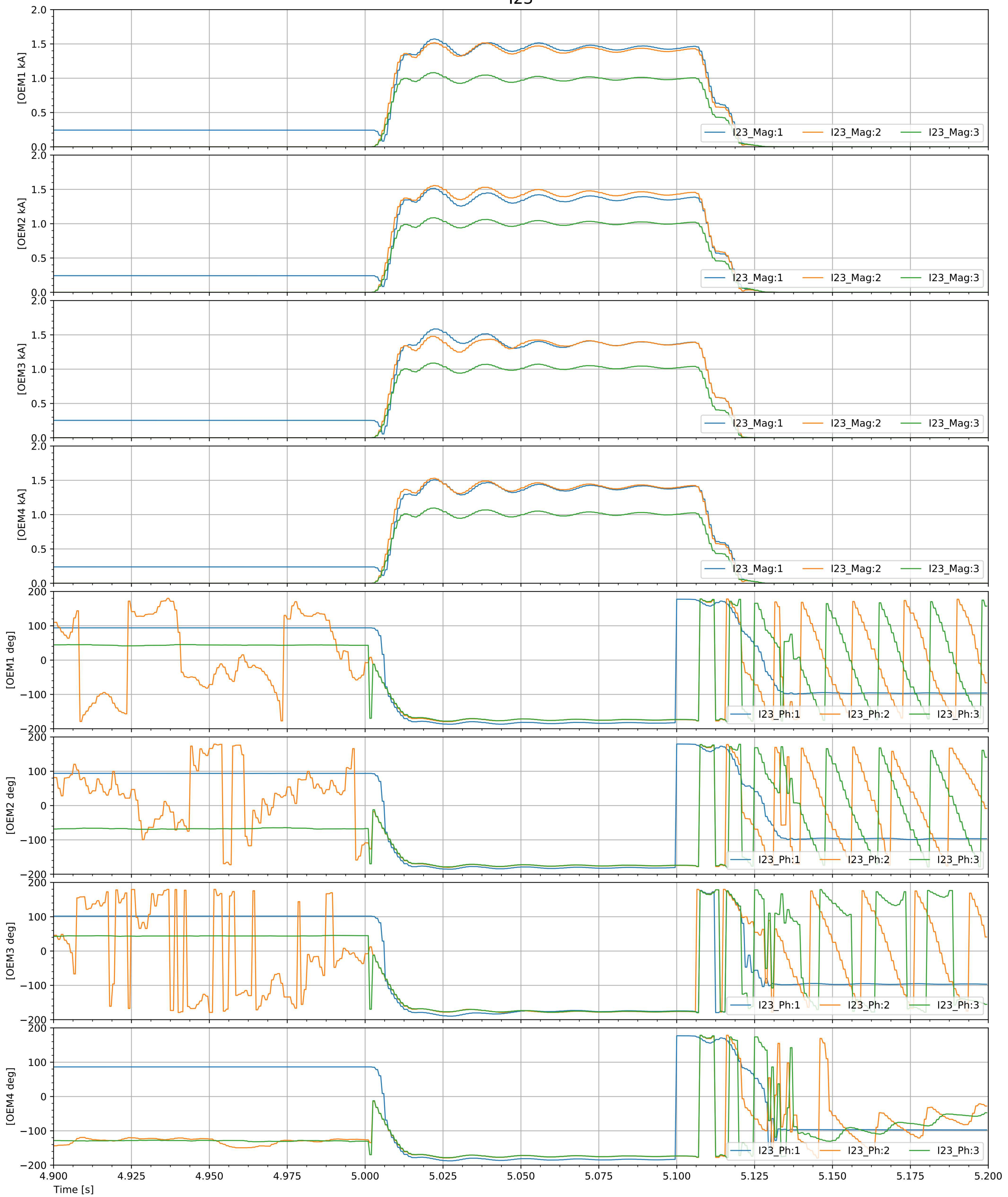
V2



Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms

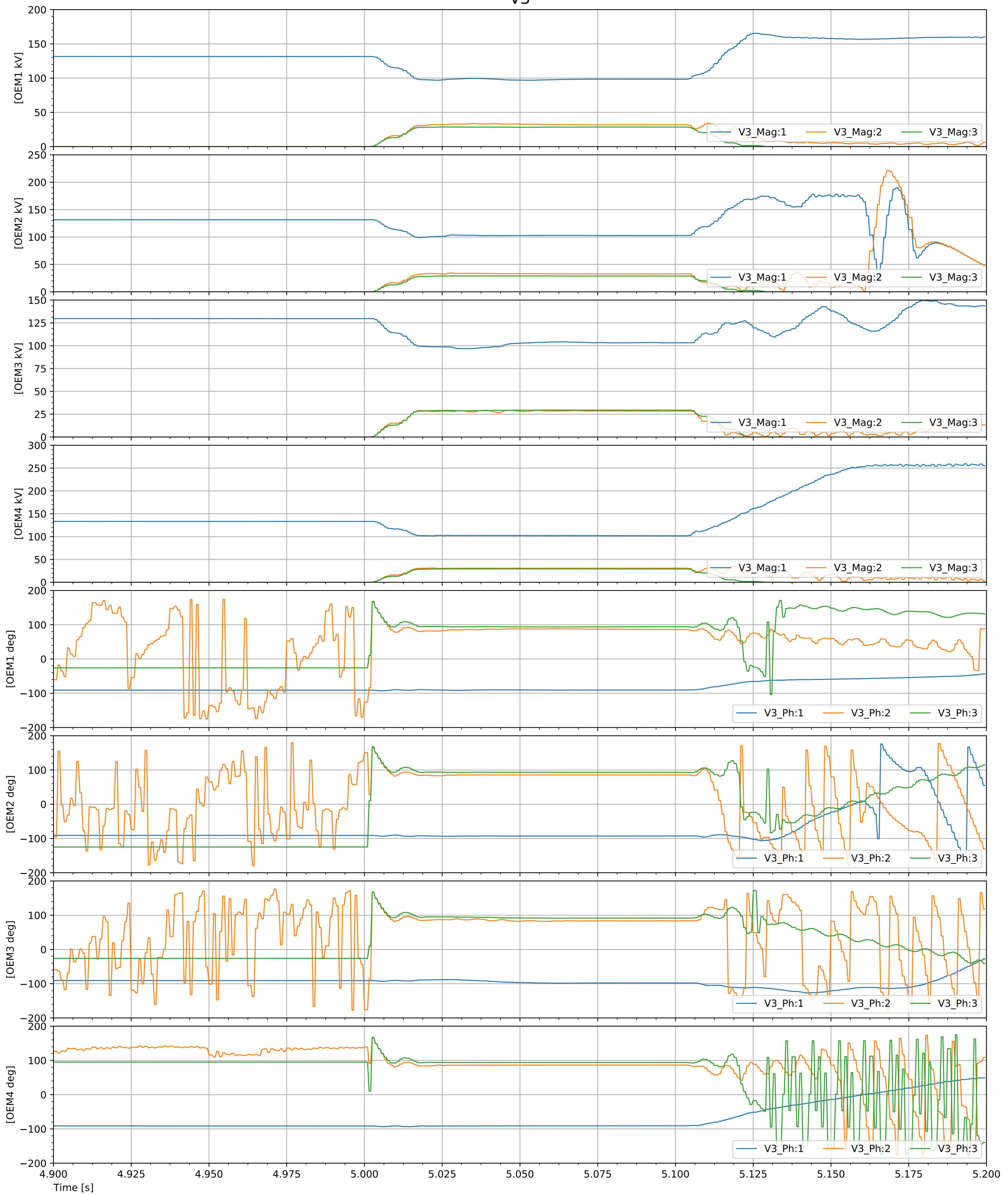


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

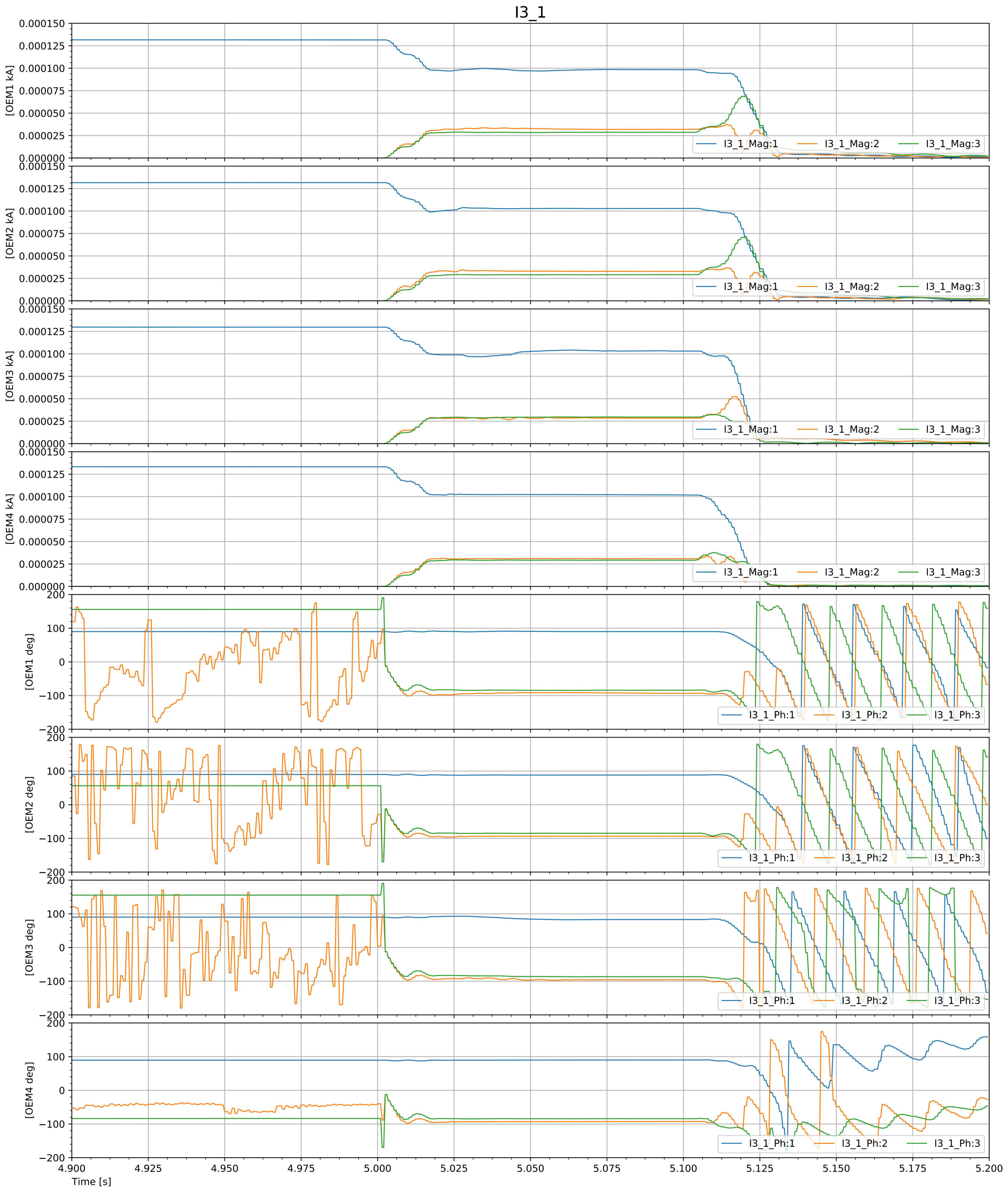


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

V3

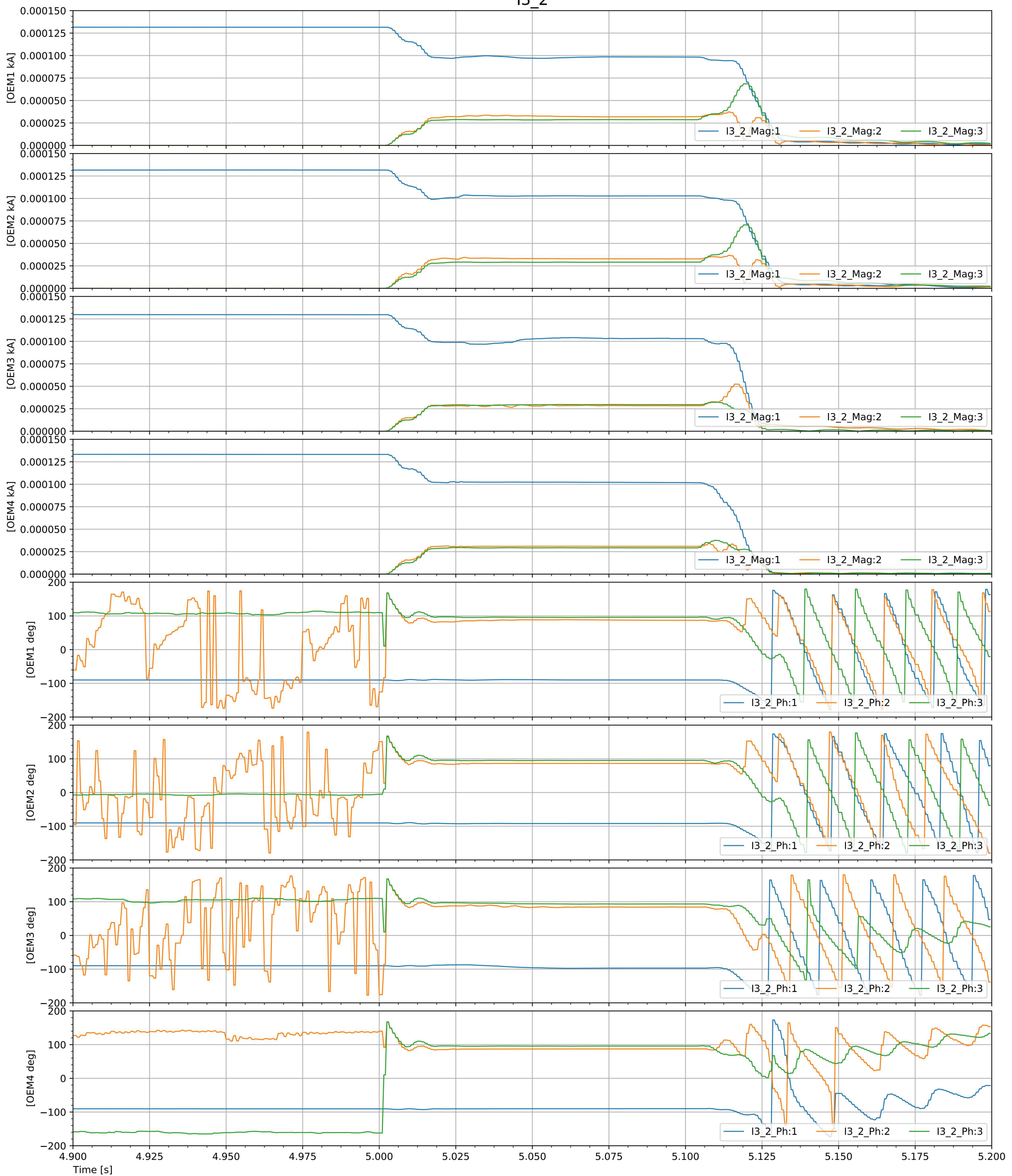


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms



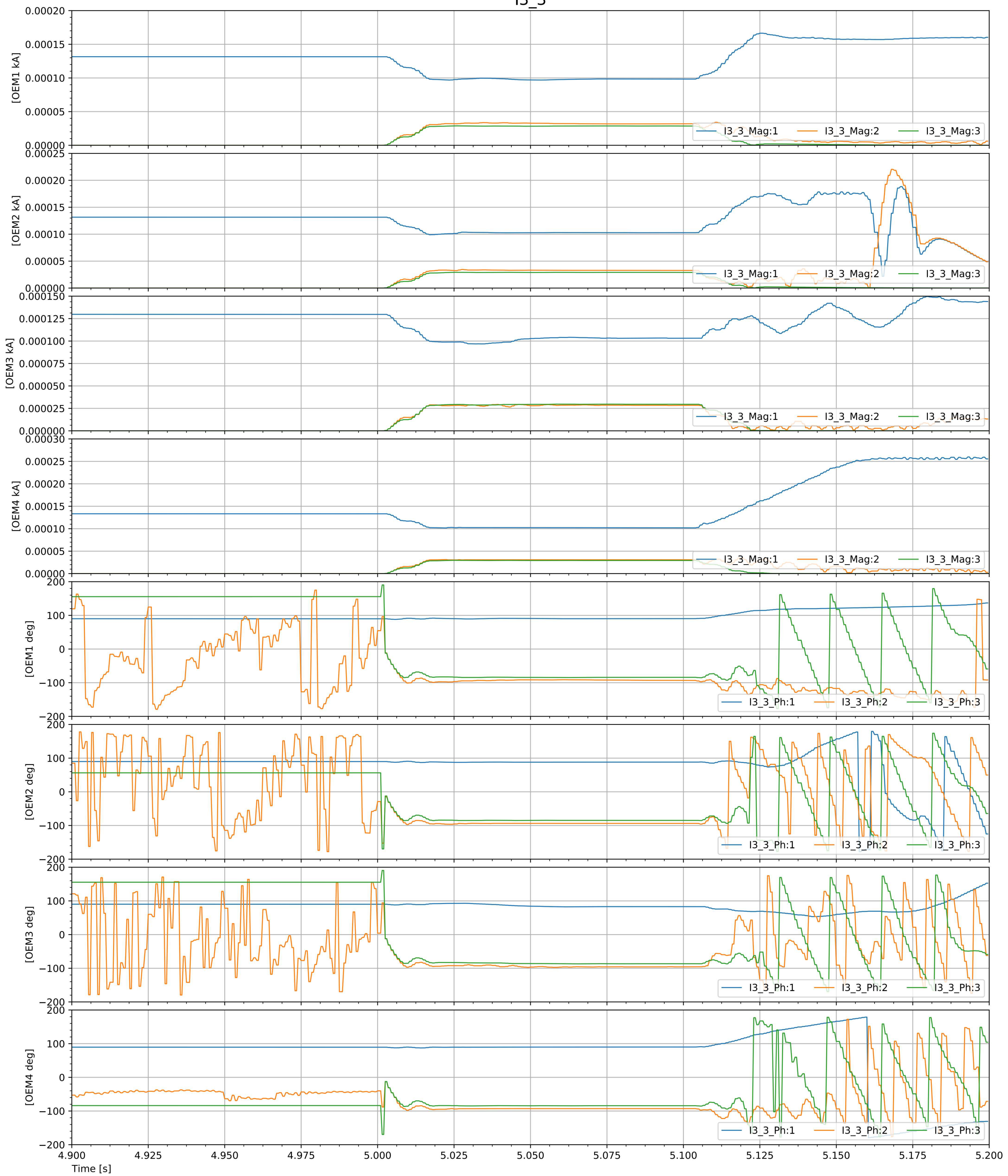
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

I3_2



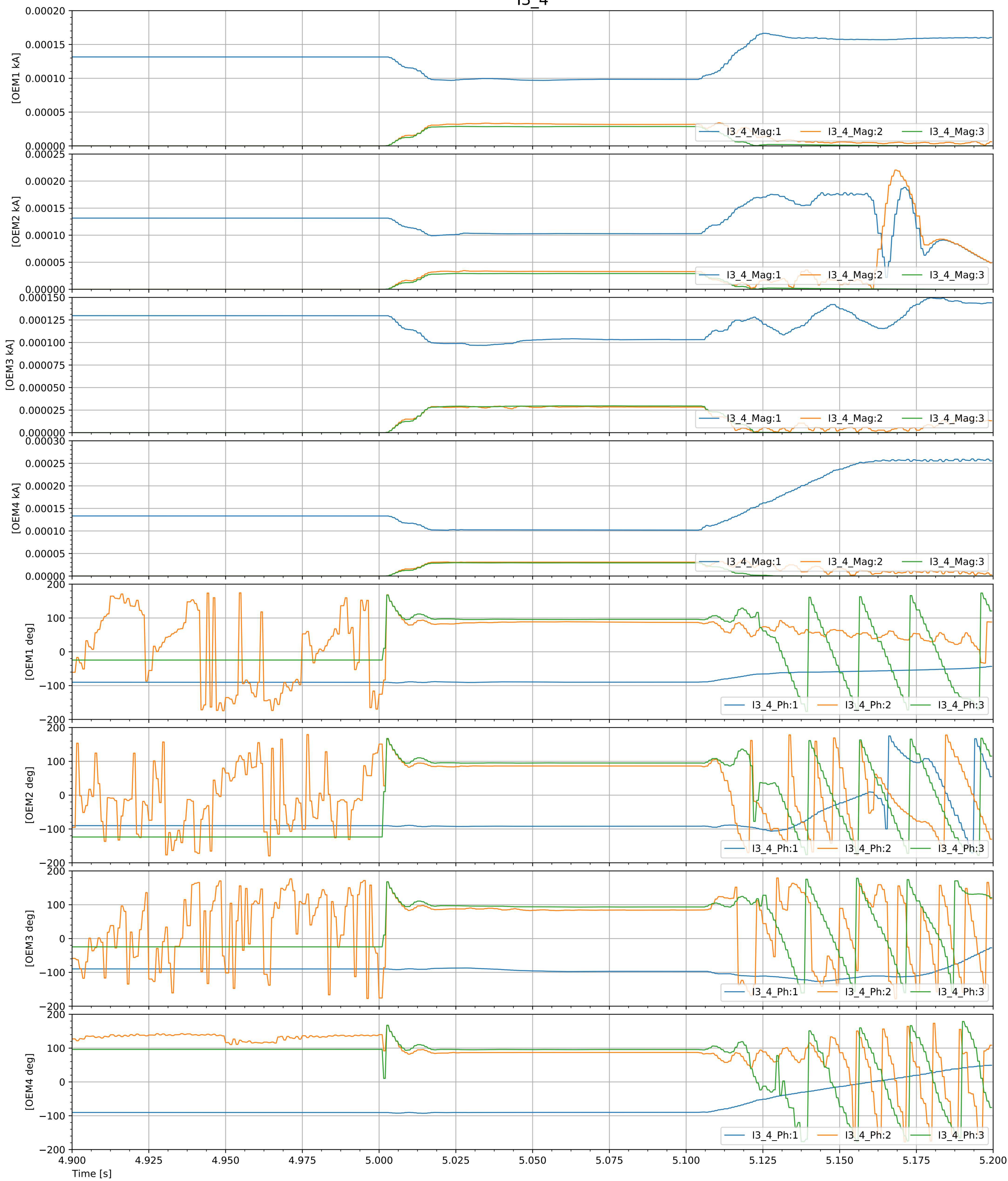
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms

I3_3

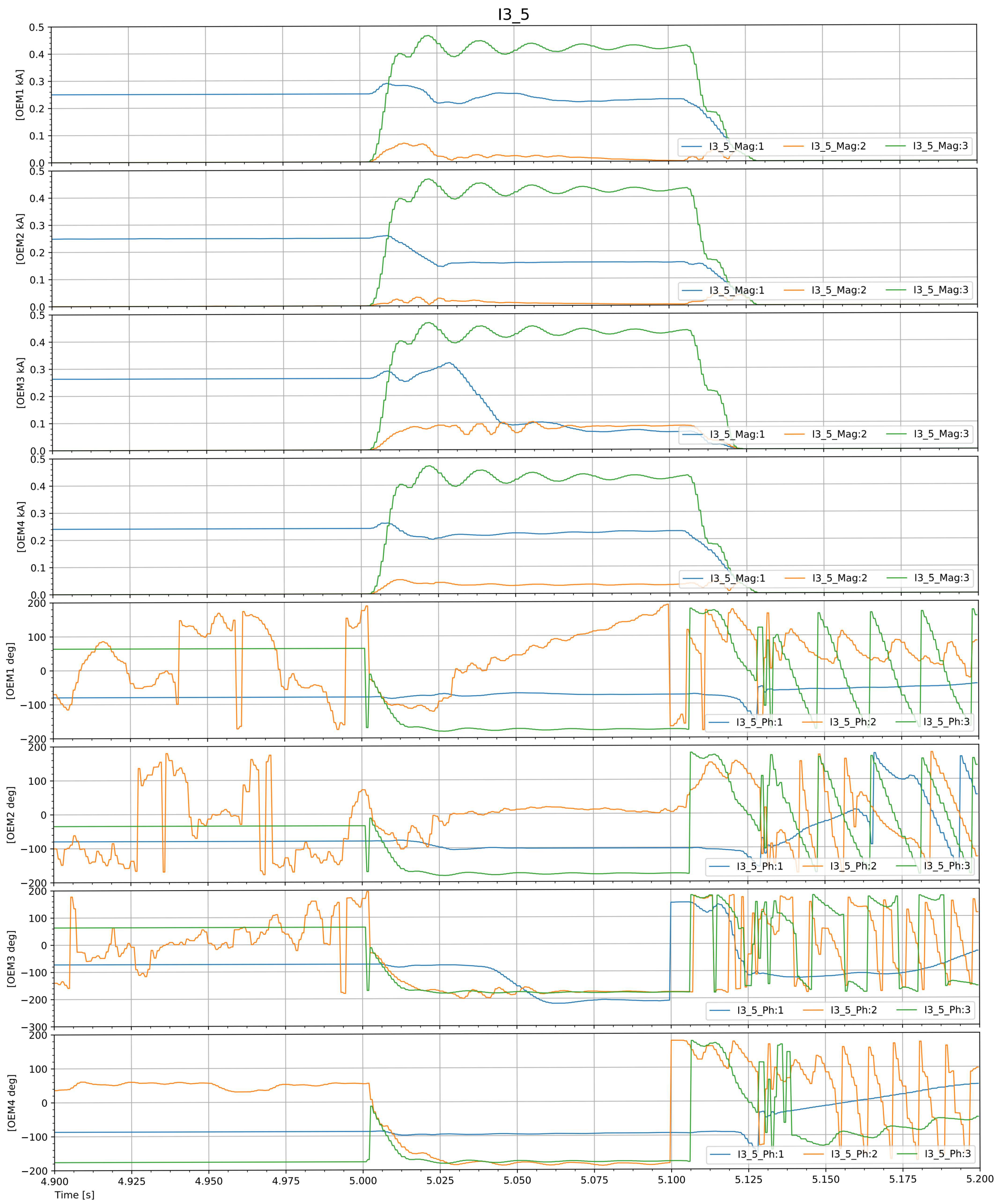


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms

I3_4



Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms

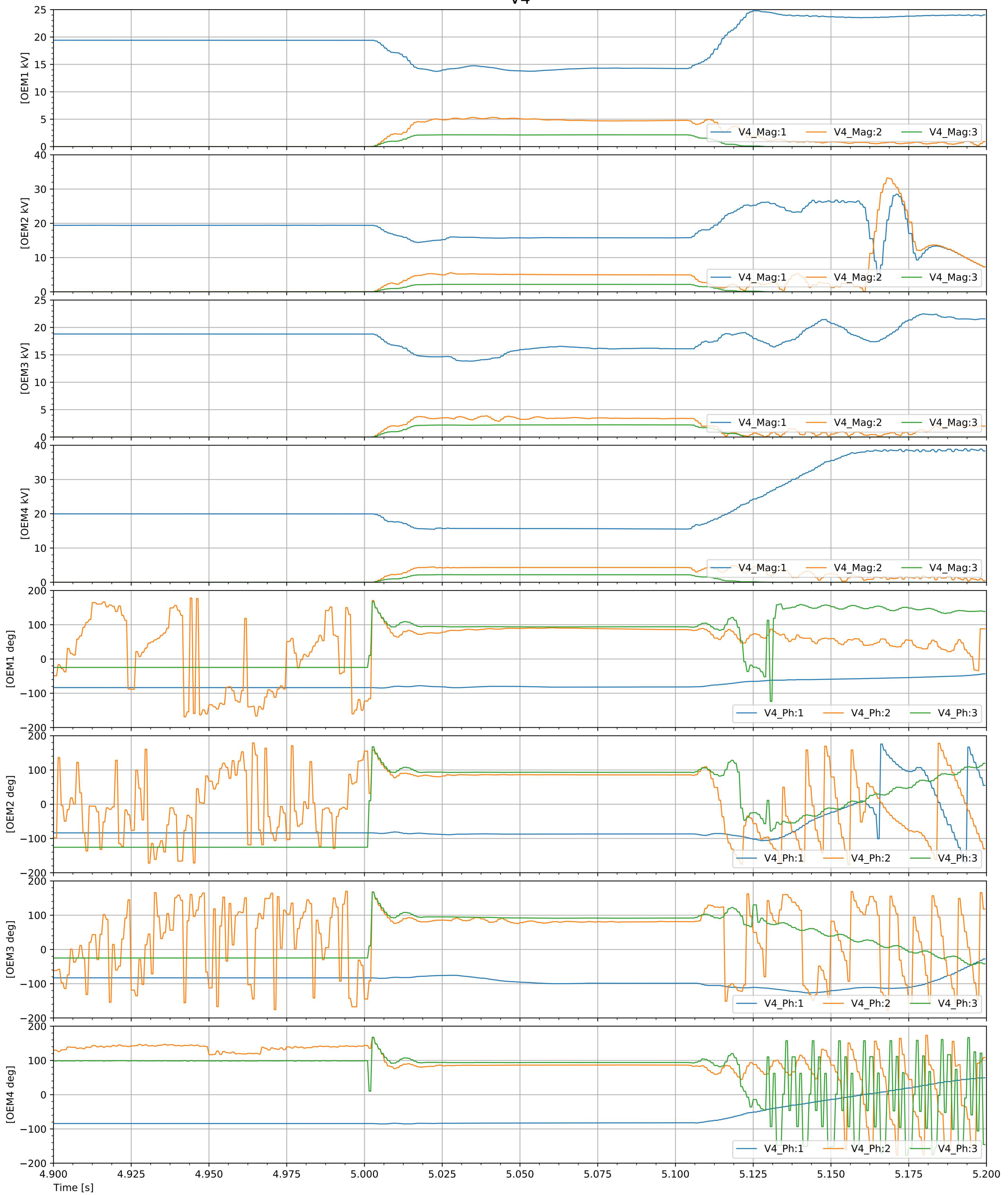


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

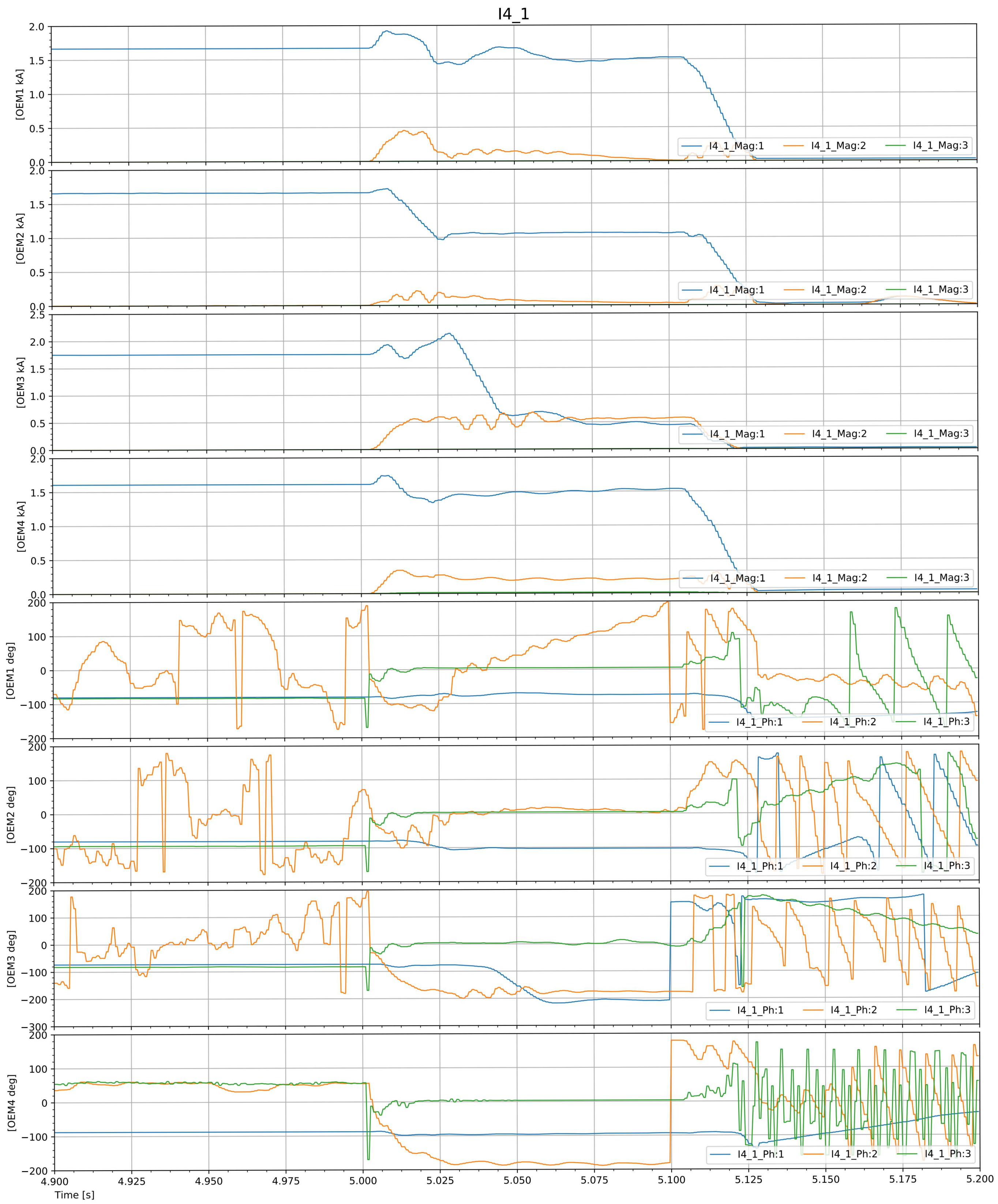


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

V4

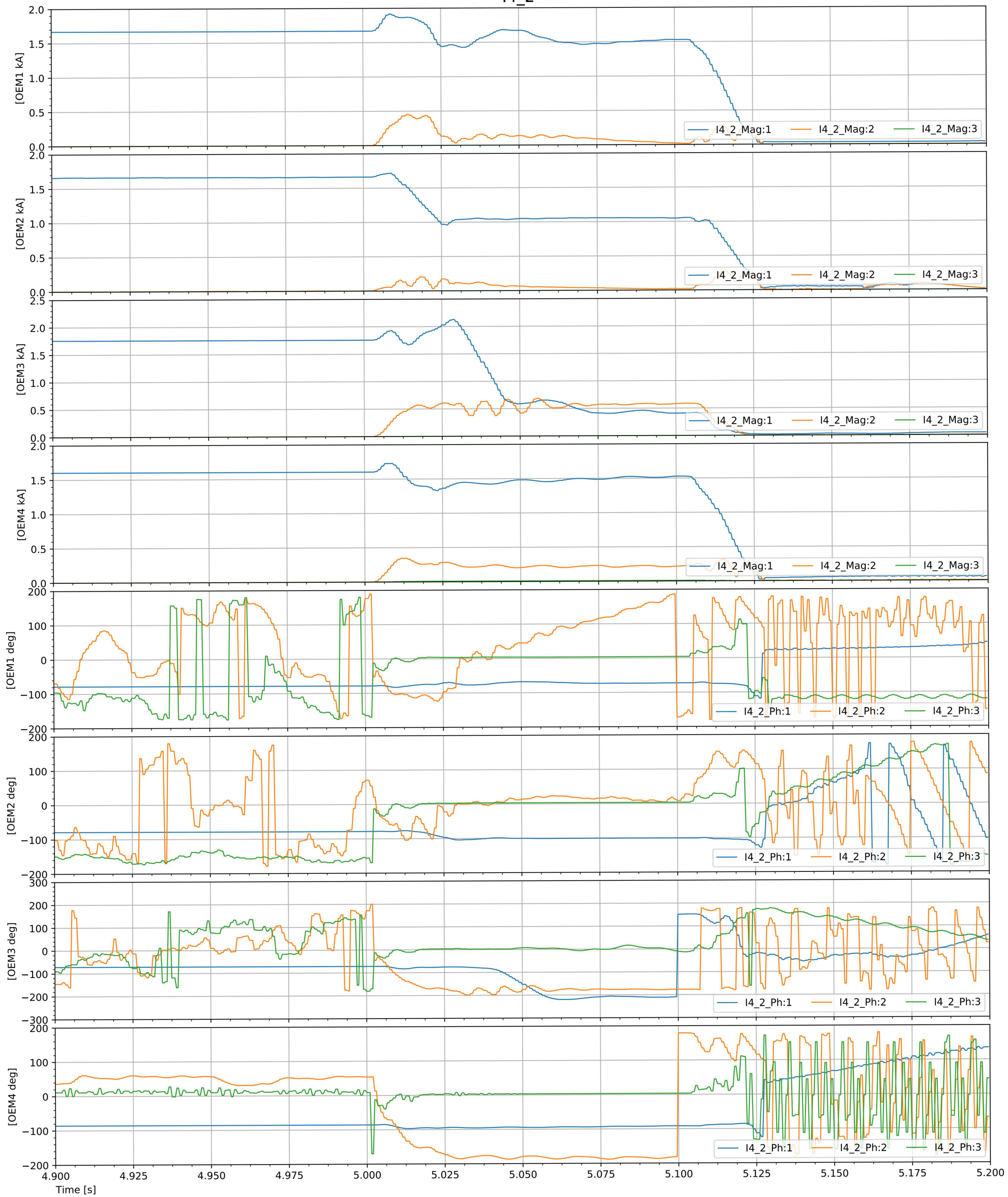


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms



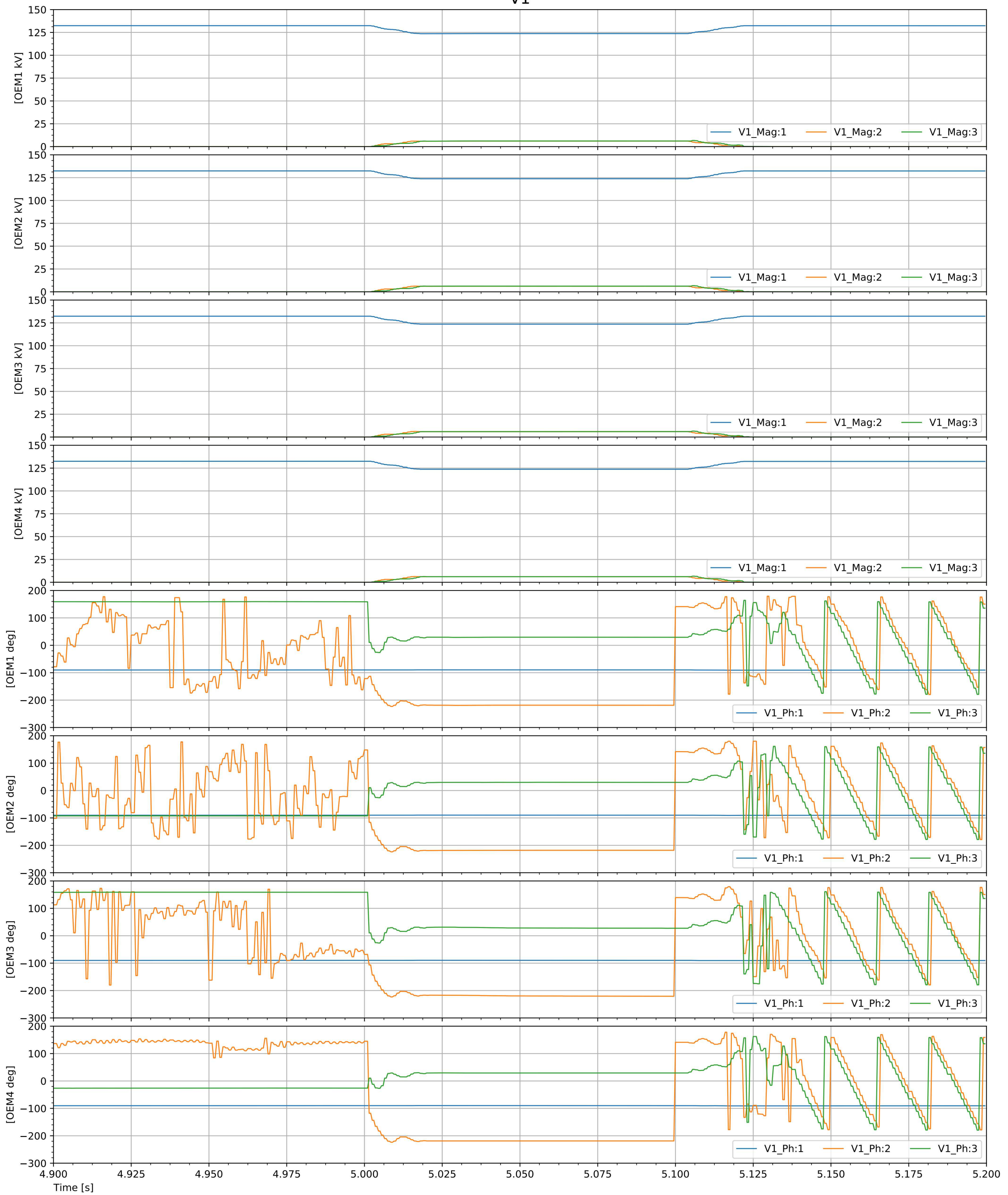
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AG
Fault Resistance: 0.001 ohms

I4_2



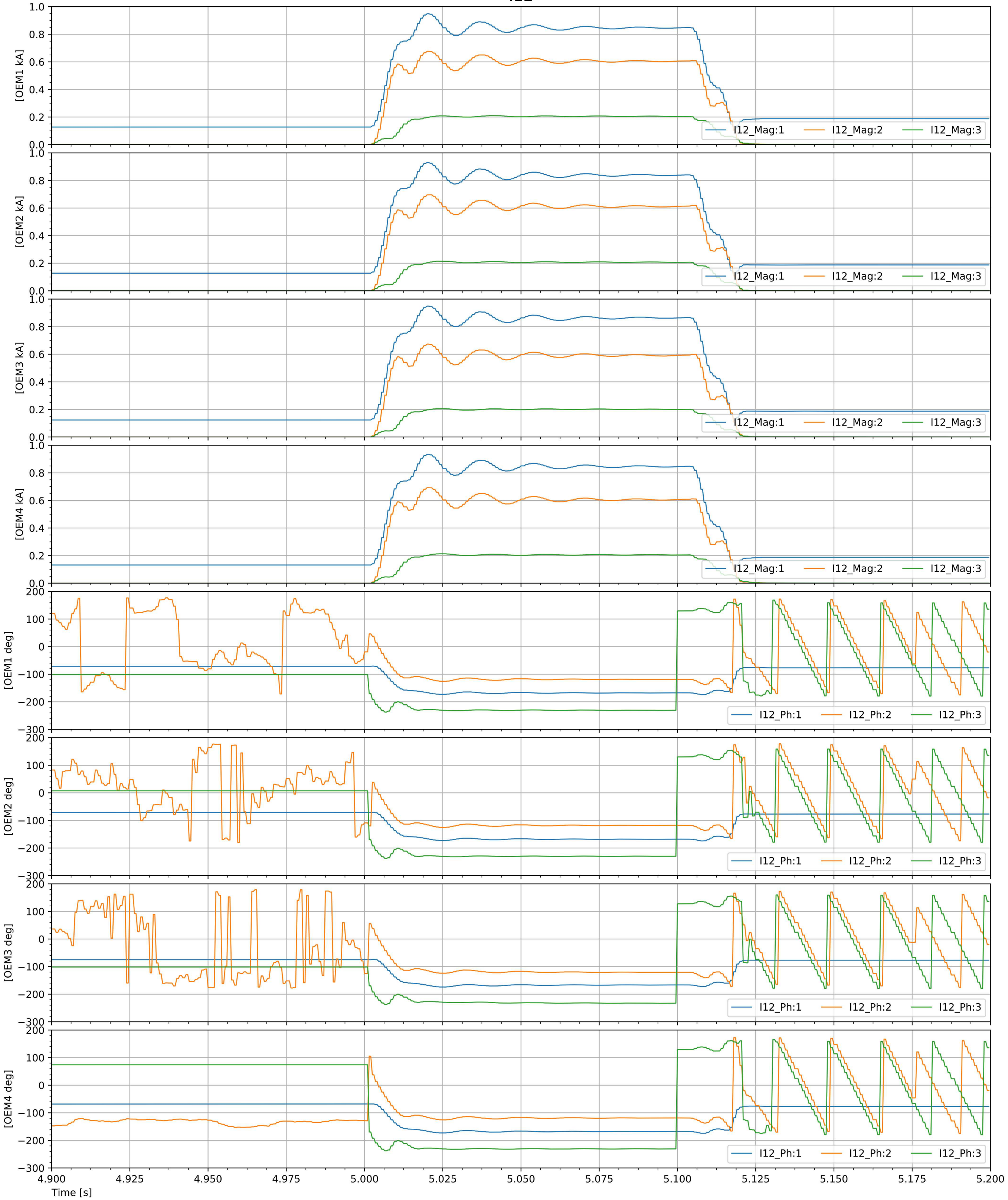
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AG
 Fault Resistance: 0.001 ohms

V1



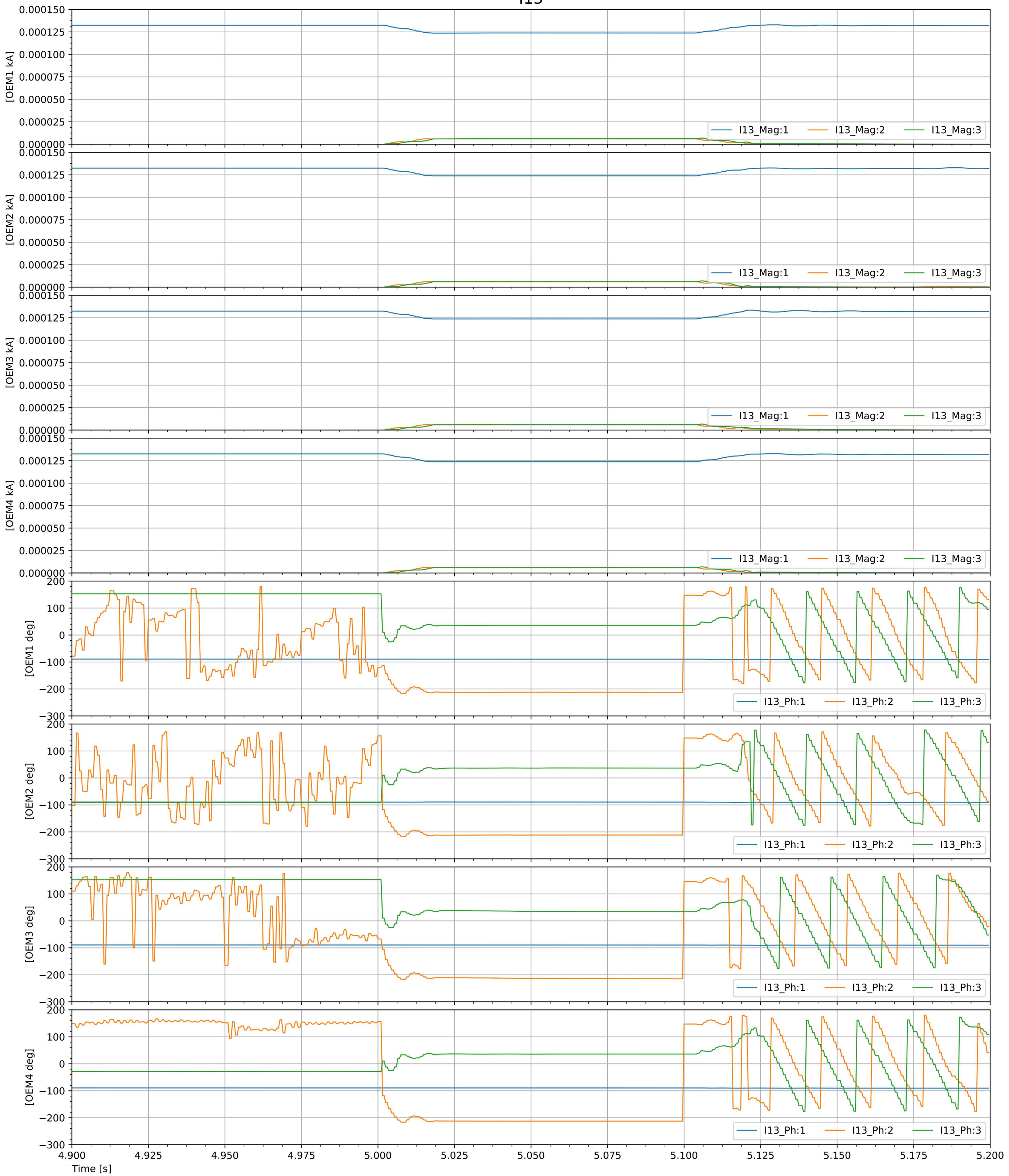
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

I12



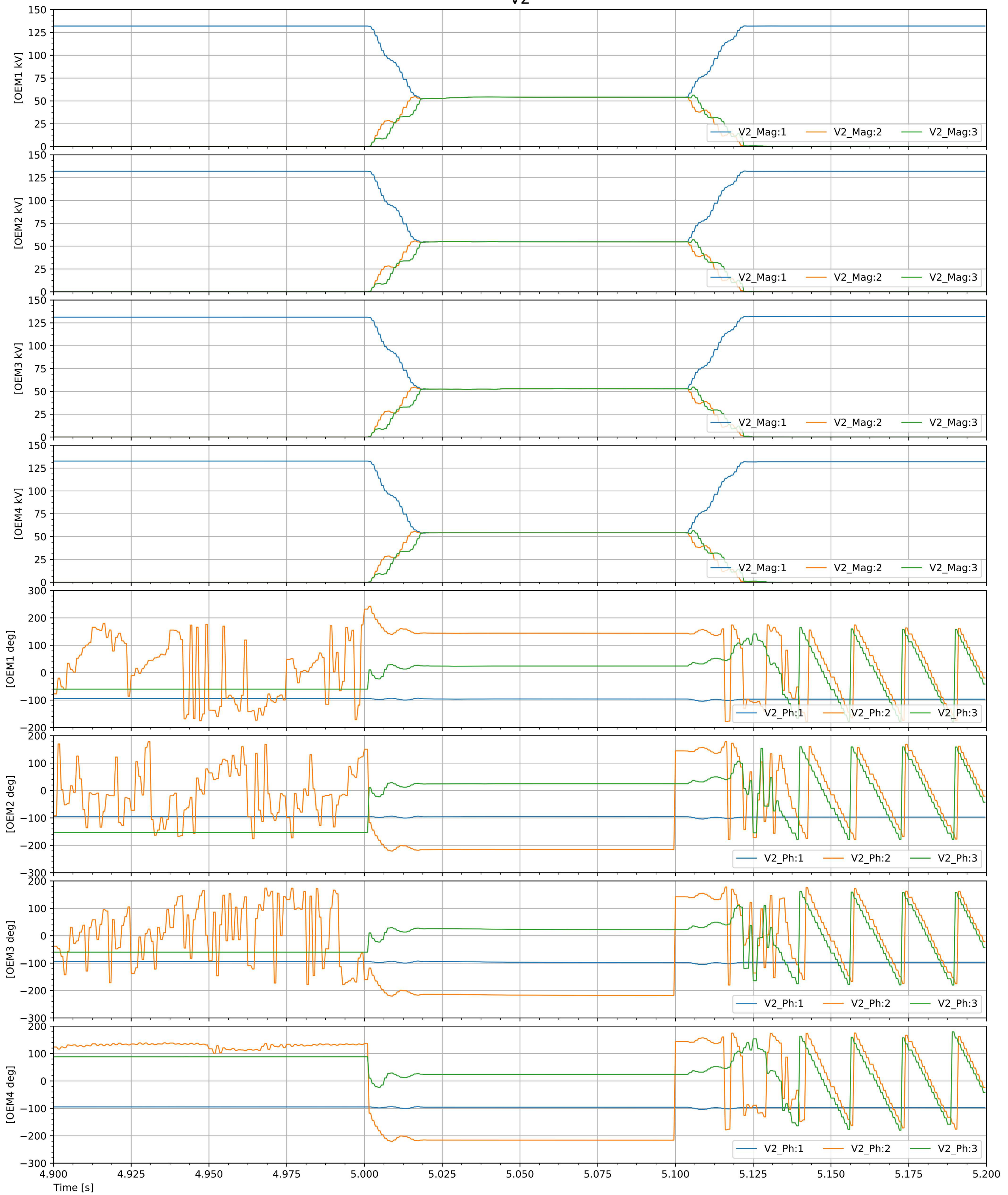
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABG
Fault Resistance: 0.001 ohms

I13

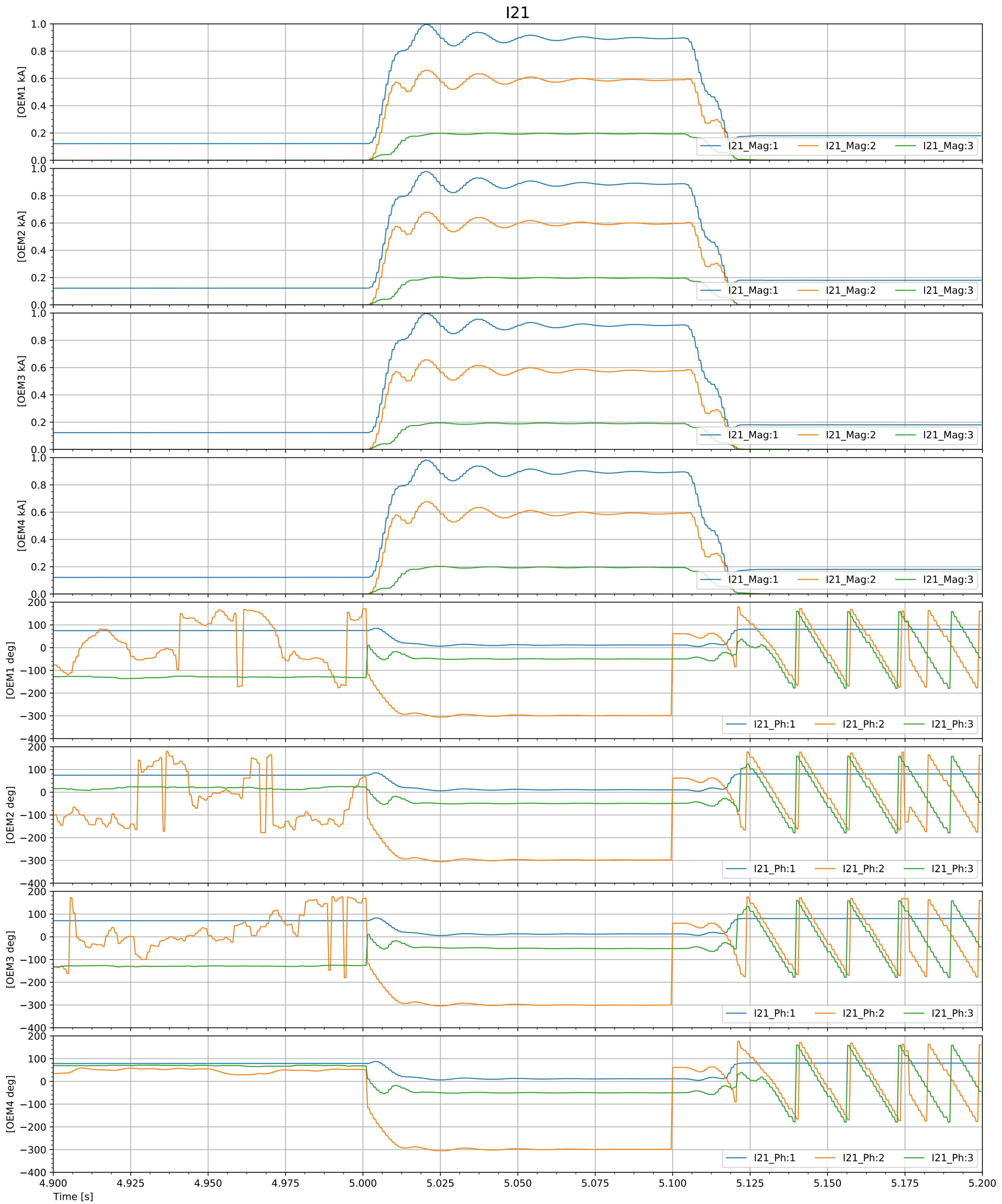


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABG
Fault Resistance: 0.001 ohms

V2

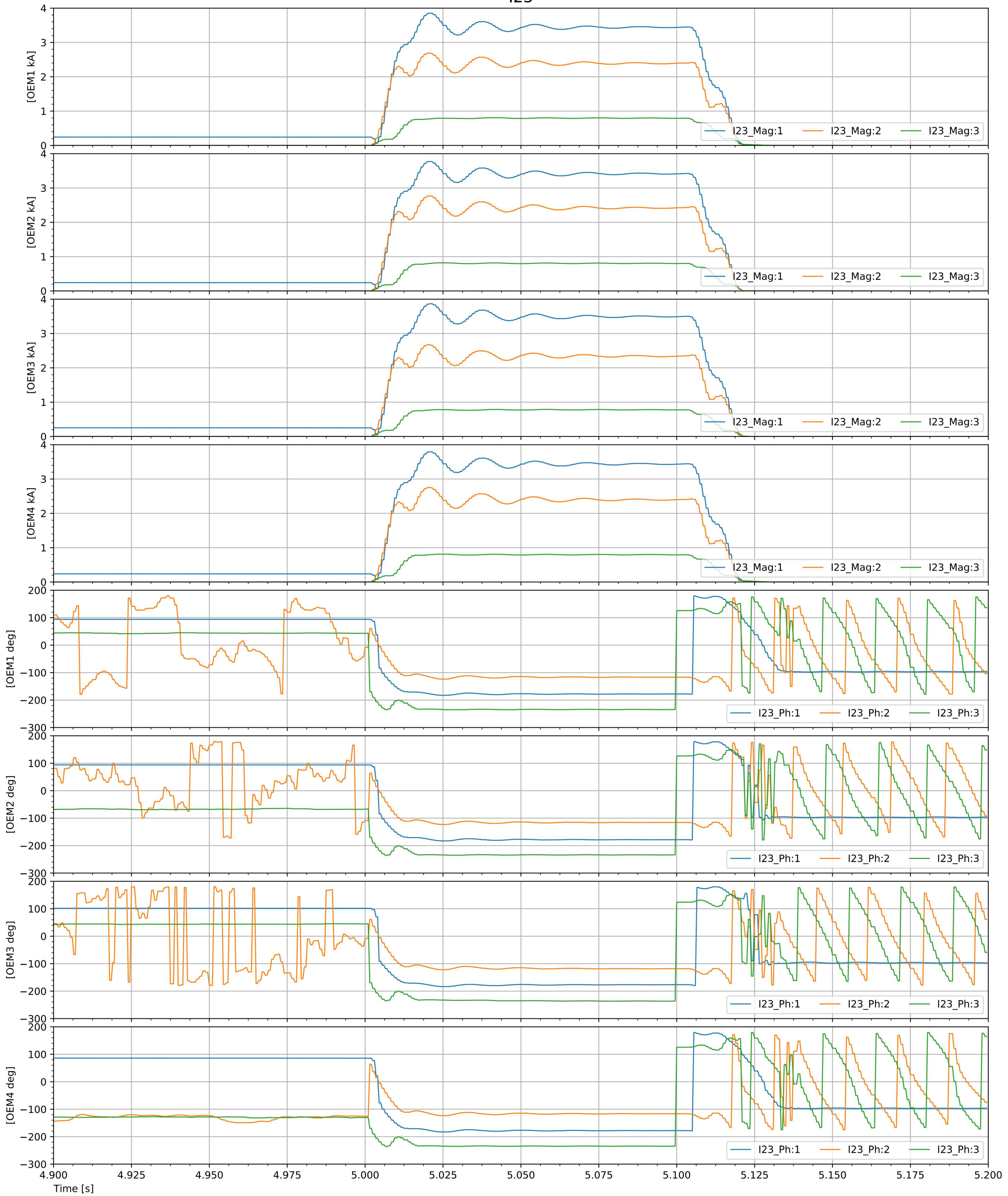


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms



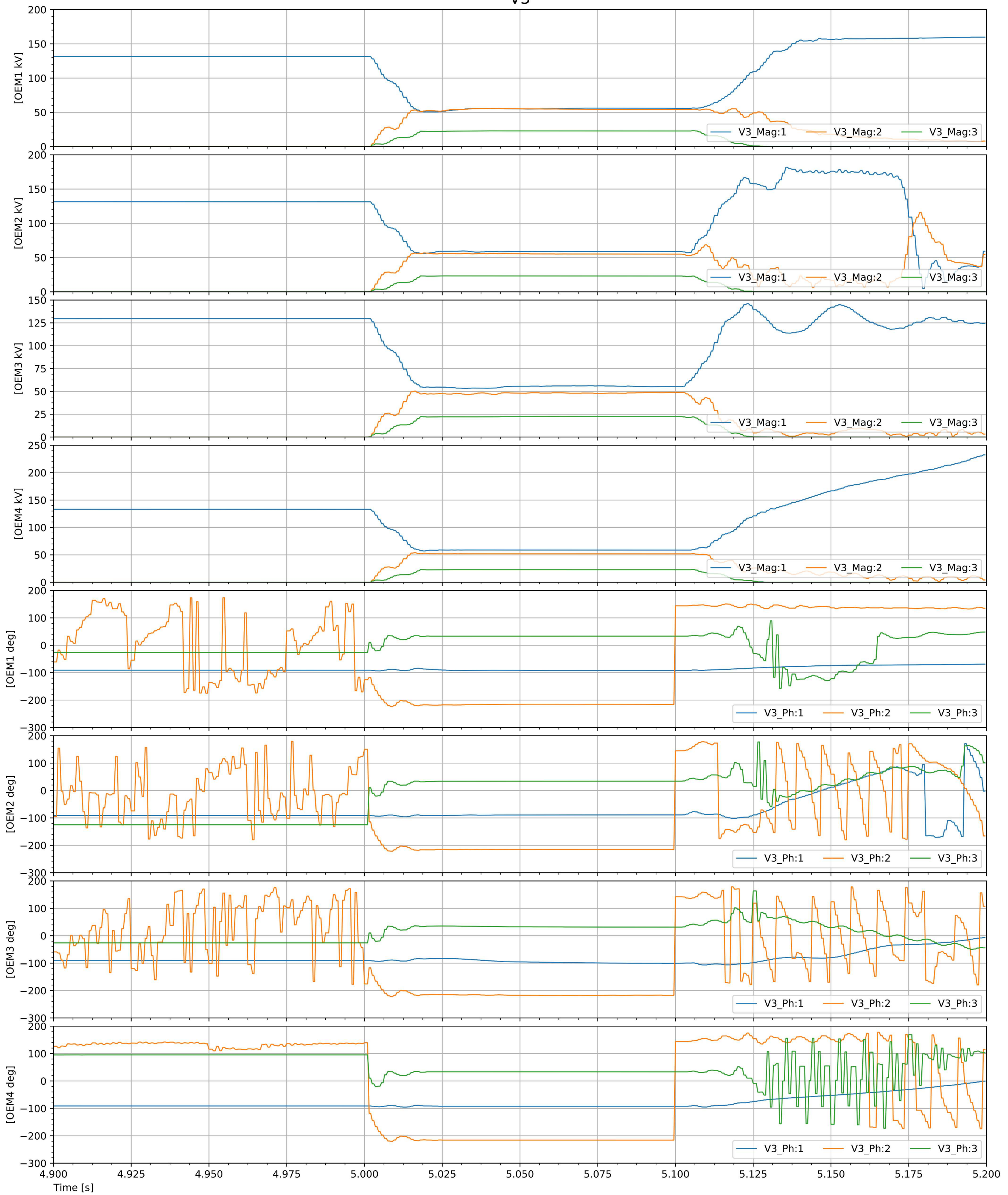
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABG
Fault Resistance: 0.001 ohms

I23

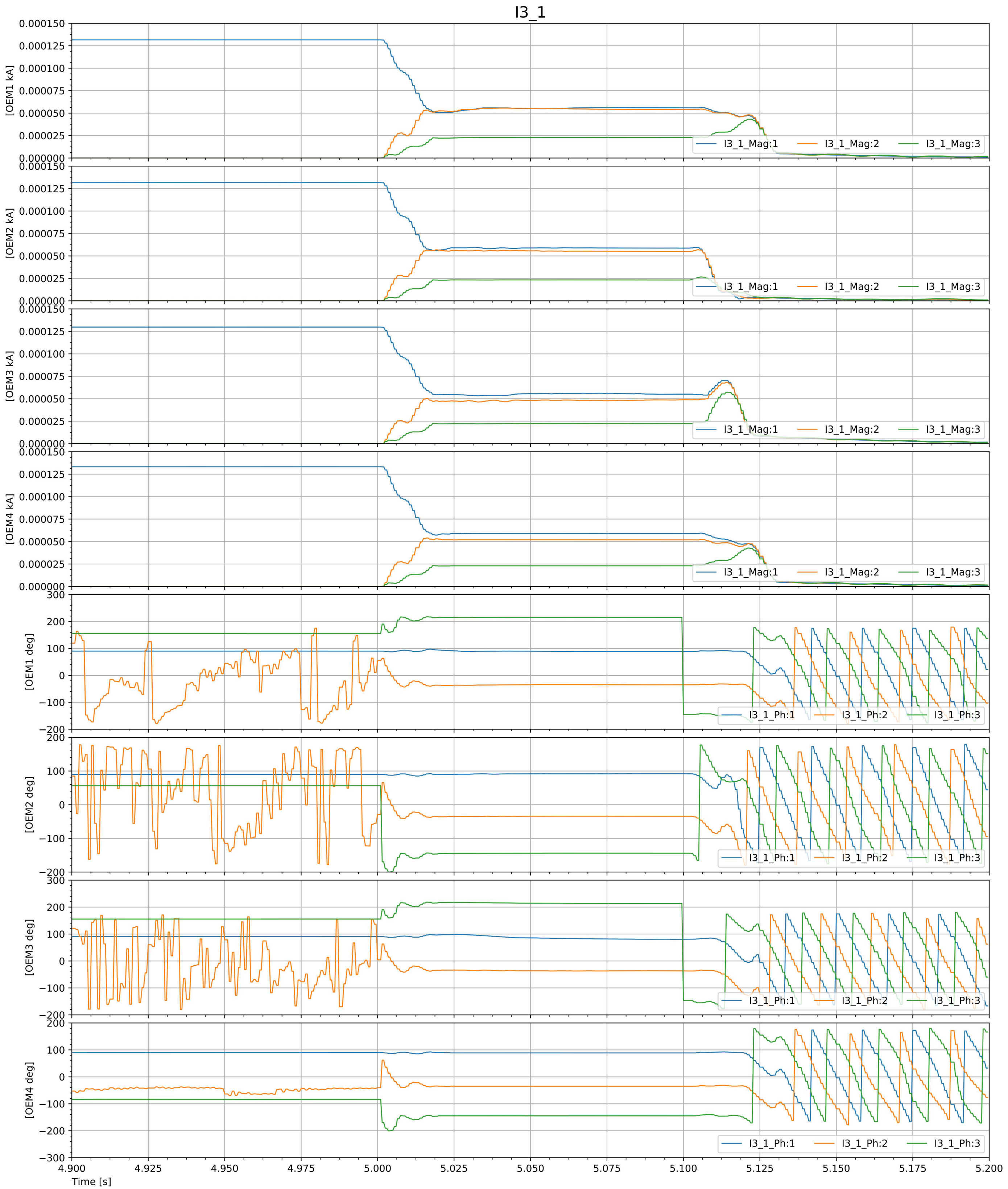


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

V3

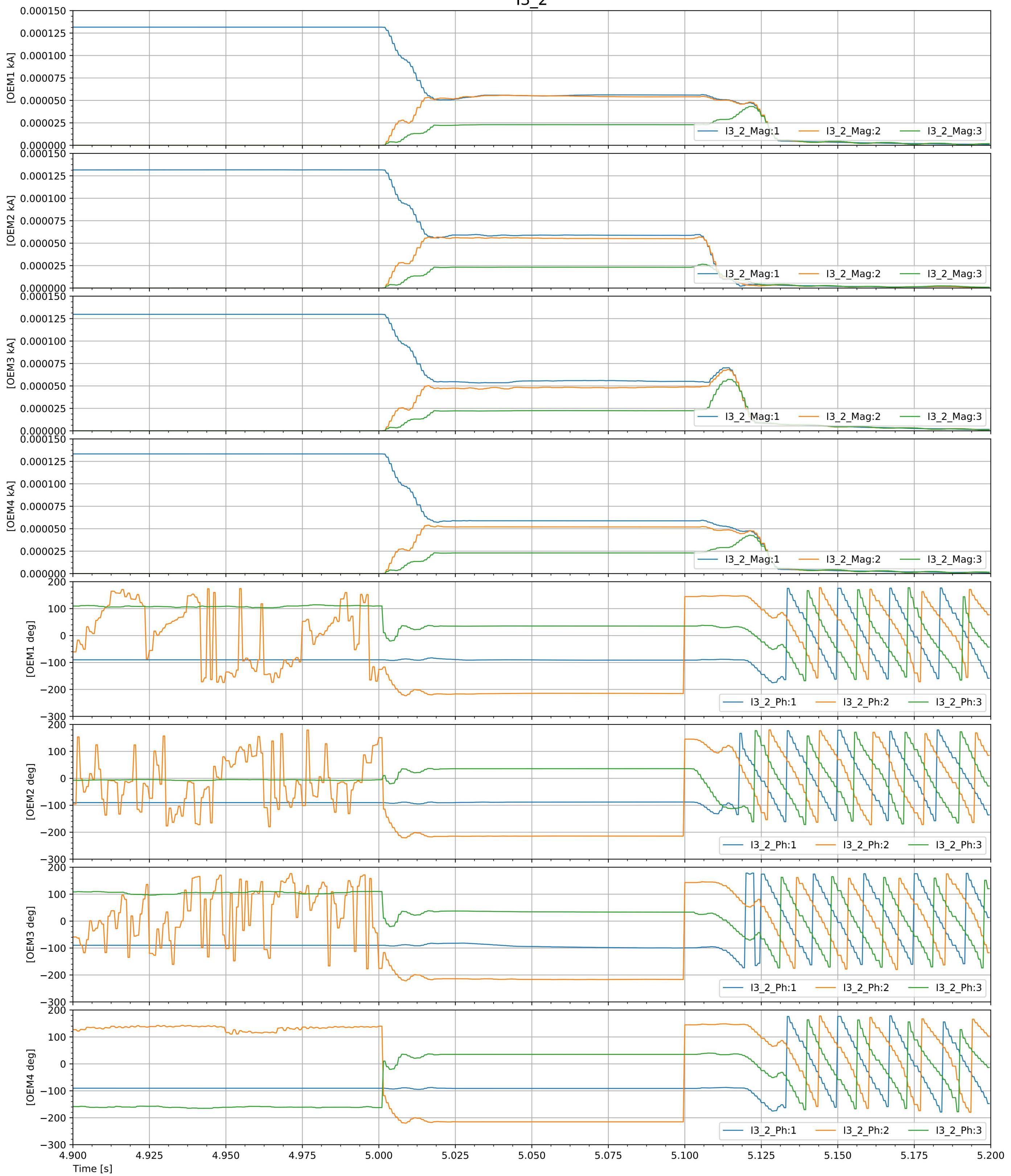


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms



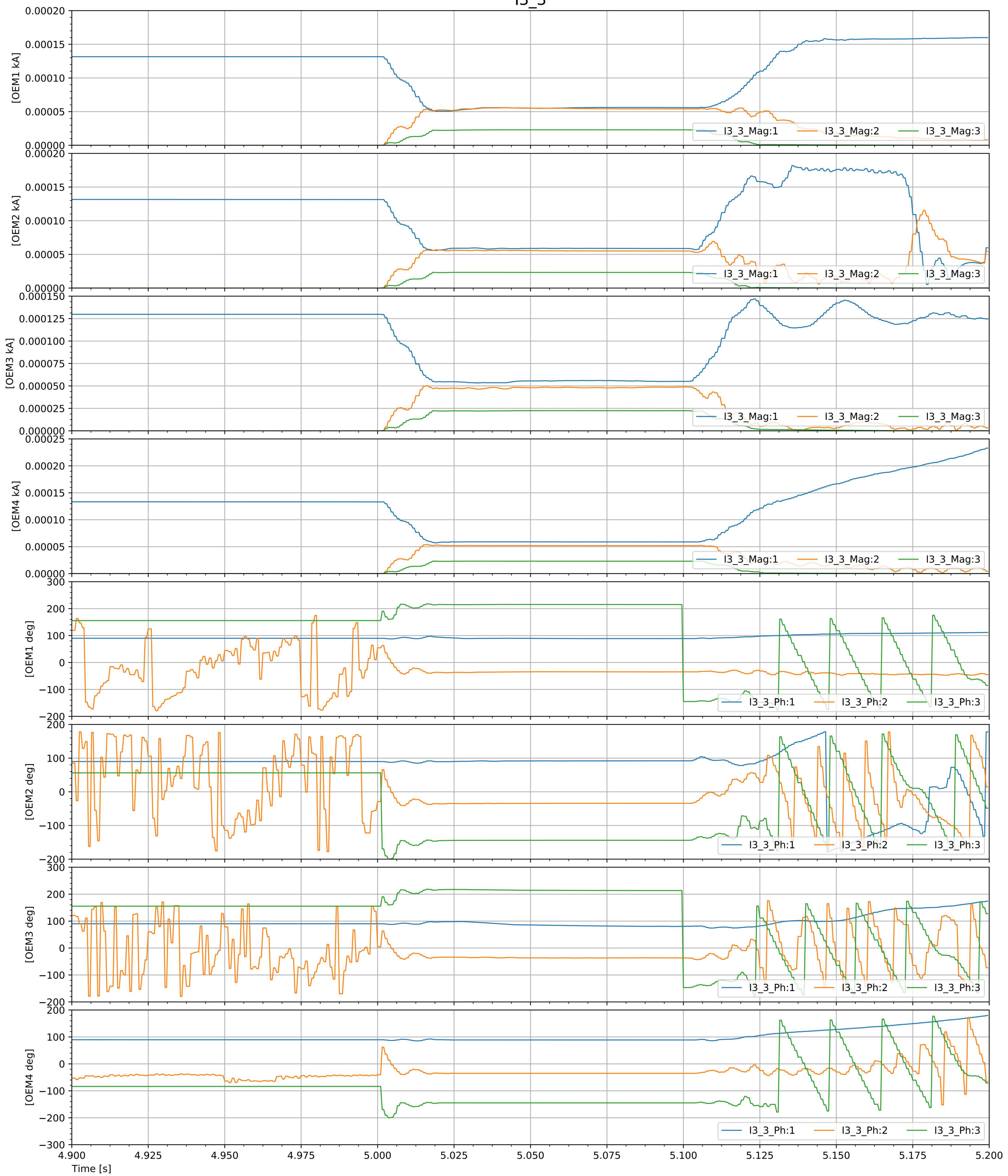
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABG
Fault Resistance: 0.001 ohms

I3_2



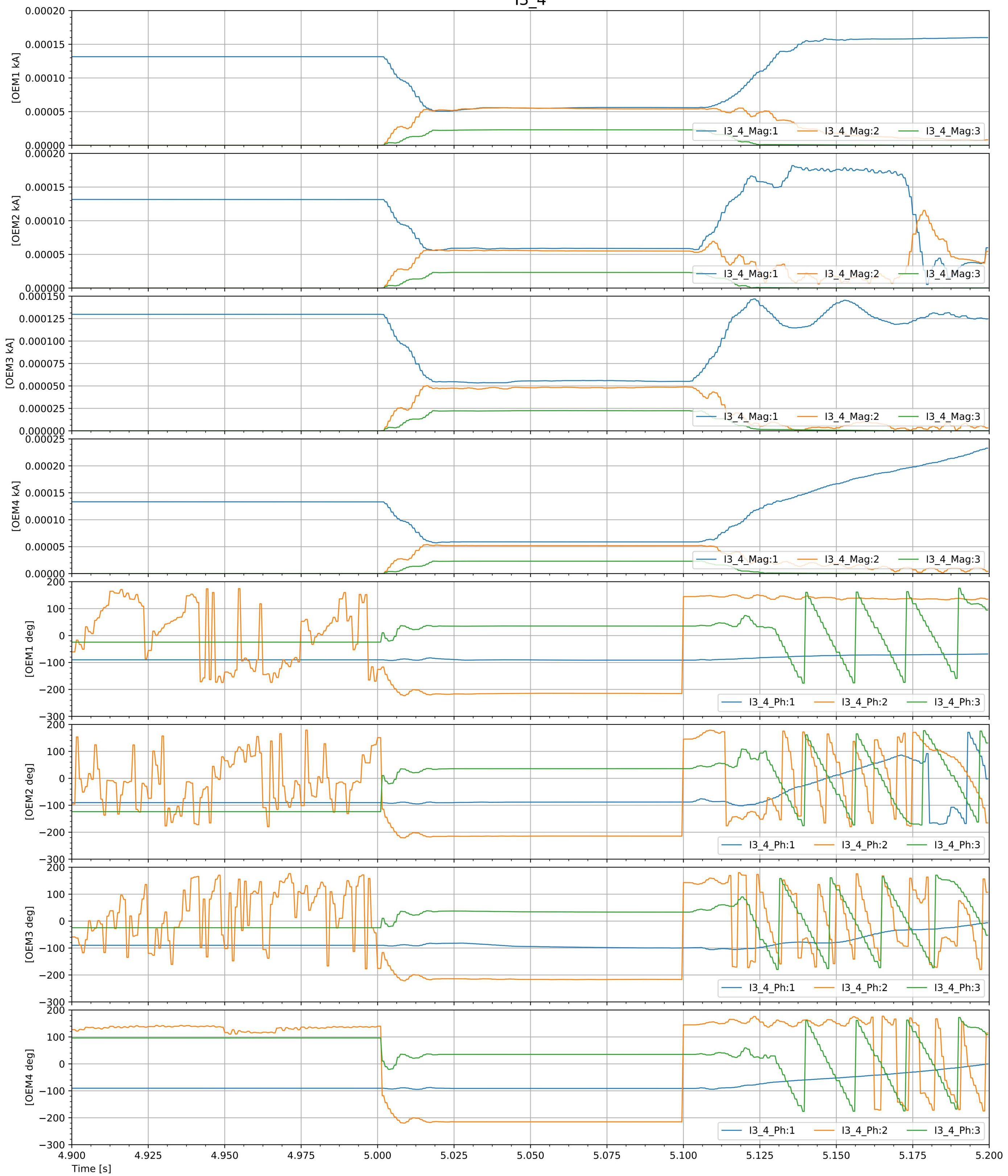
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

I3_3

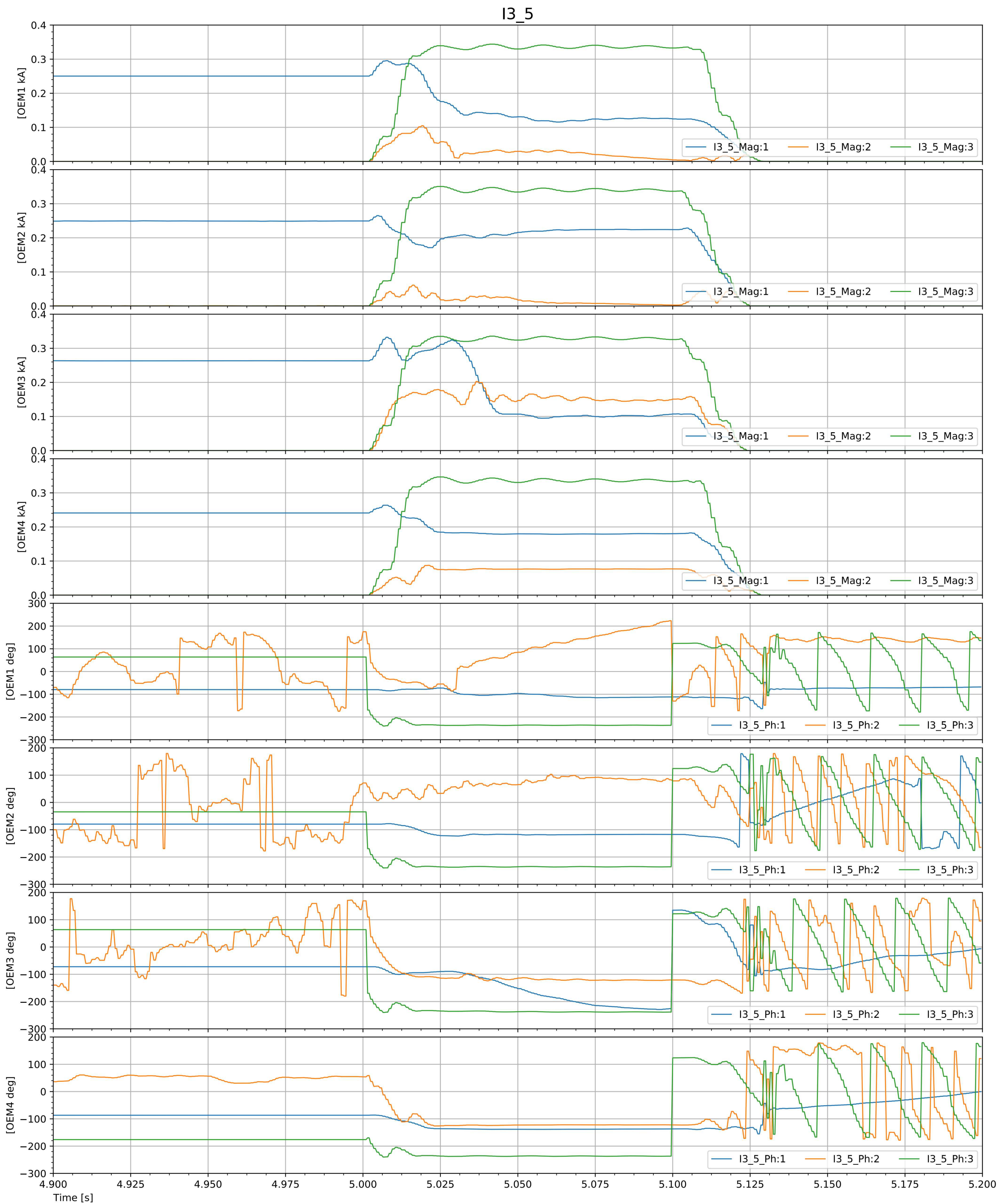


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

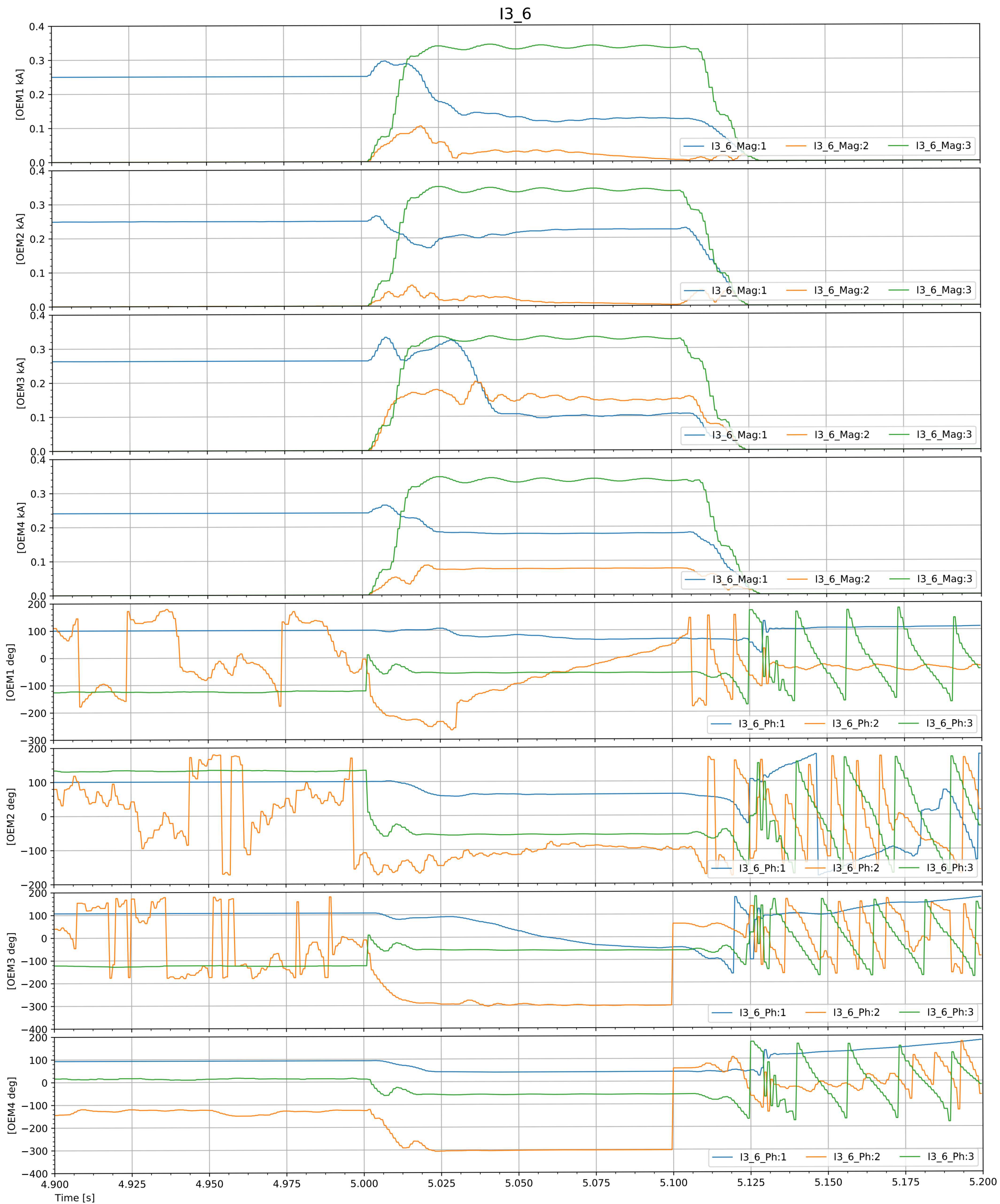
I3_4



Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

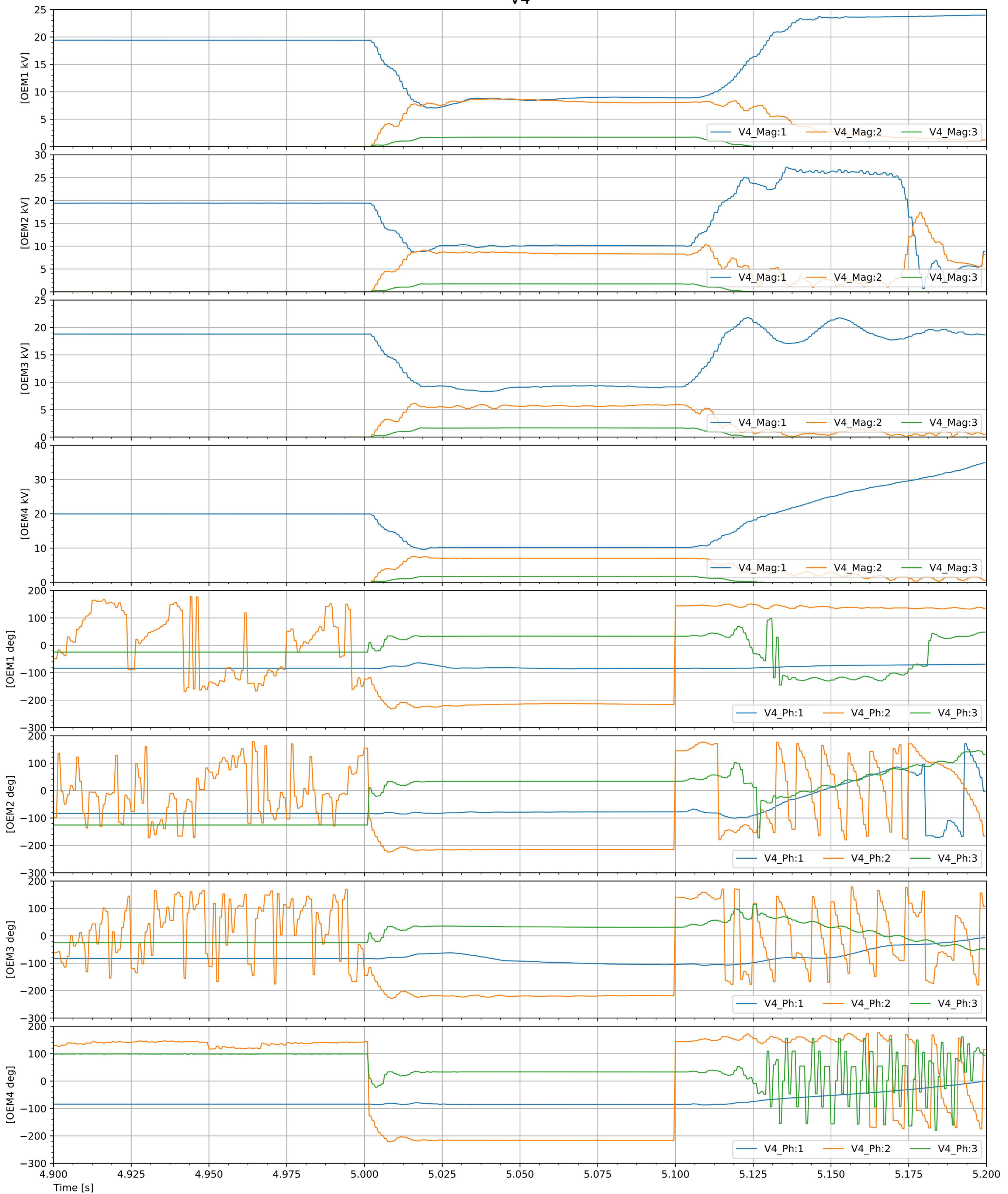


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABG
Fault Resistance: 0.001 ohms

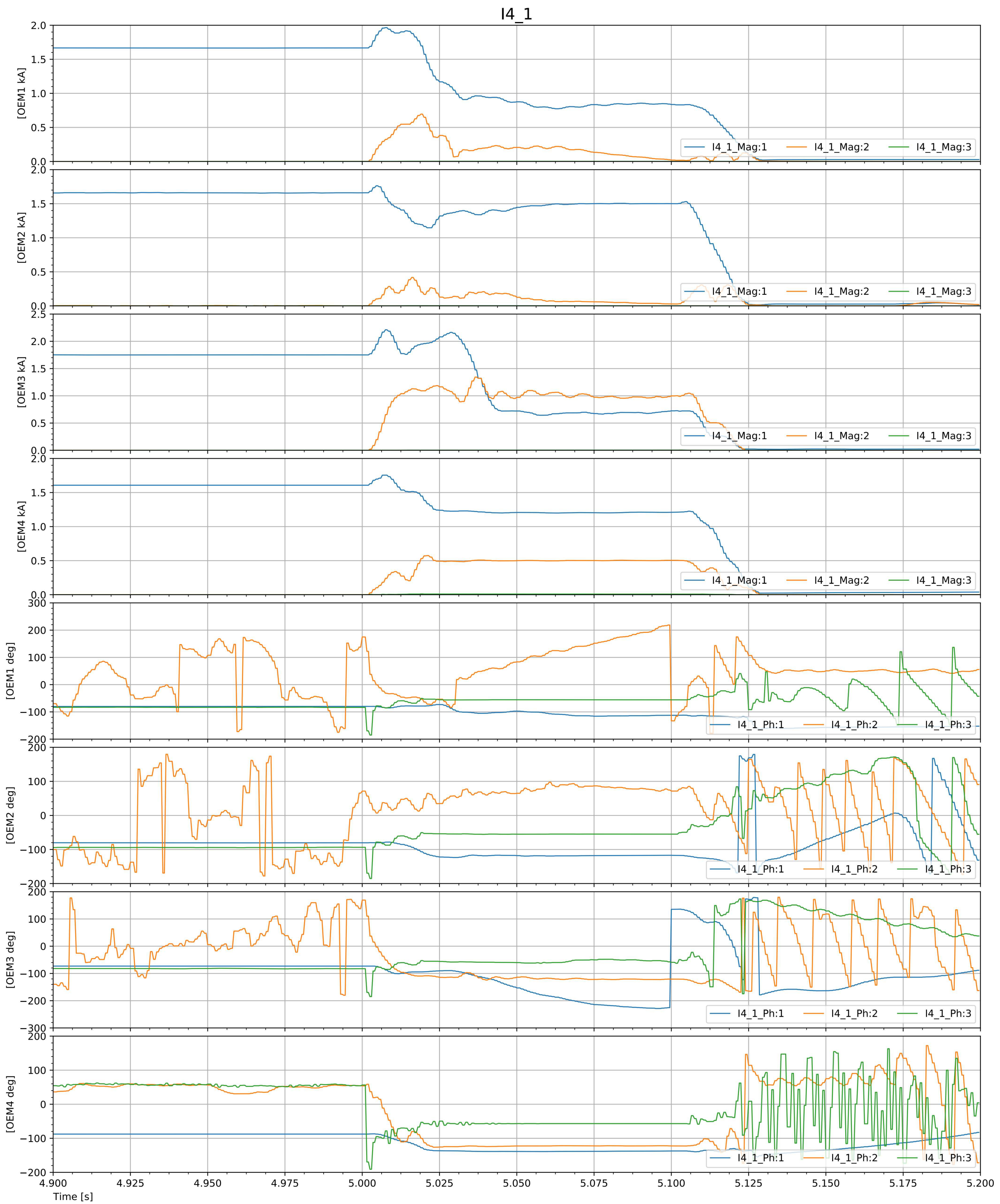


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABG
Fault Resistance: 0.001 ohms

V4



Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms



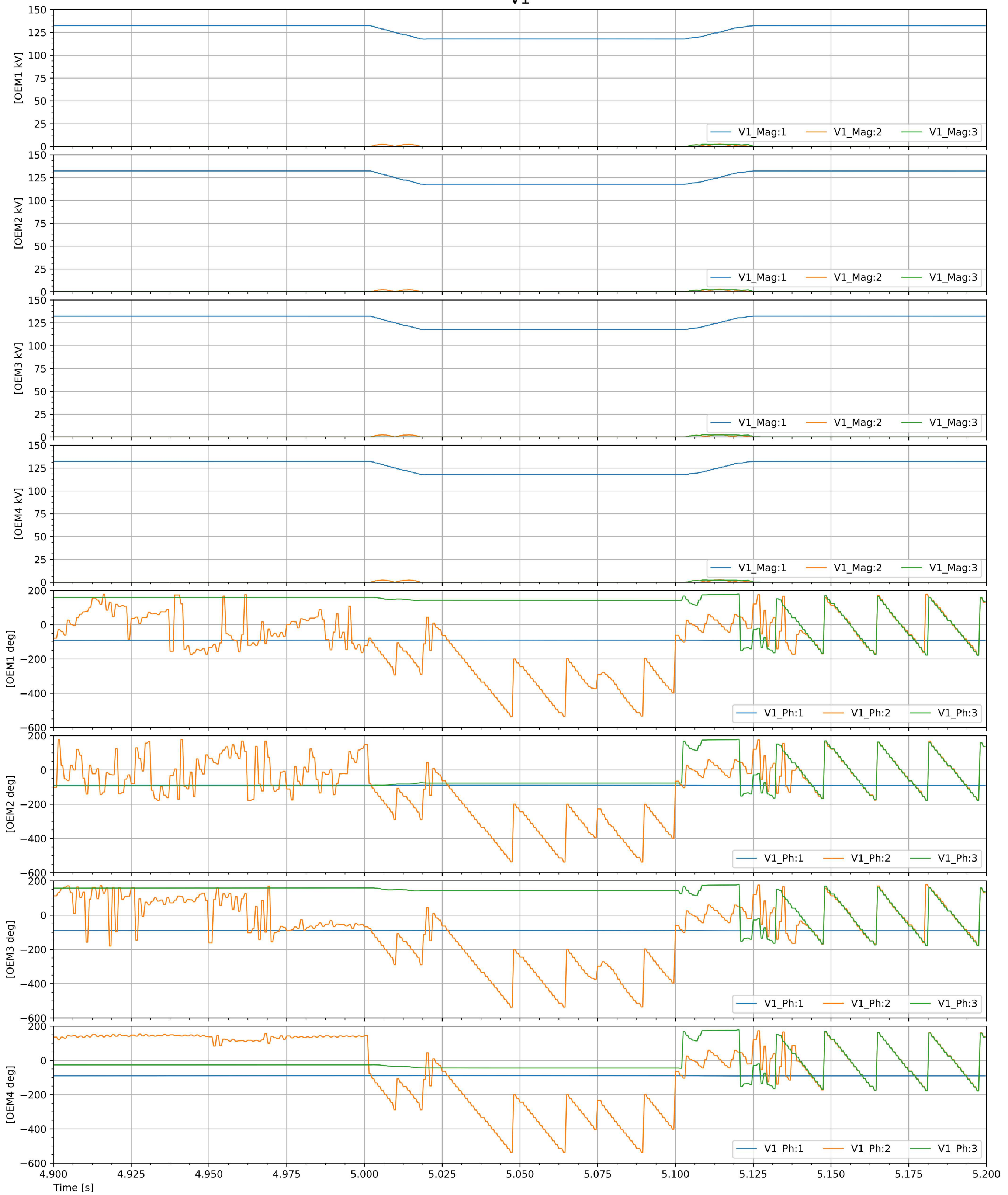
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABG
Fault Resistance: 0.001 ohms

I4_2



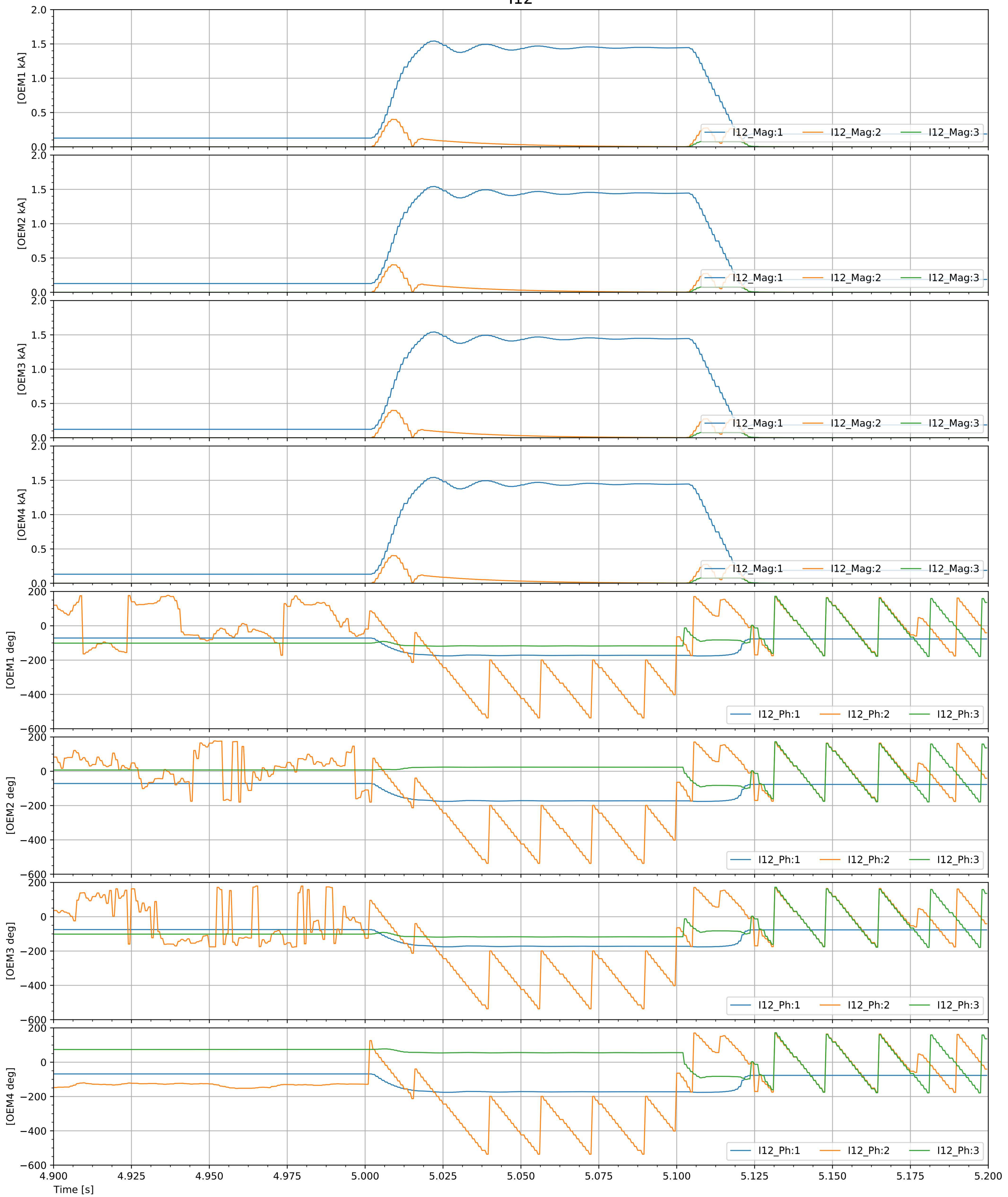
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABG
 Fault Resistance: 0.001 ohms

V1



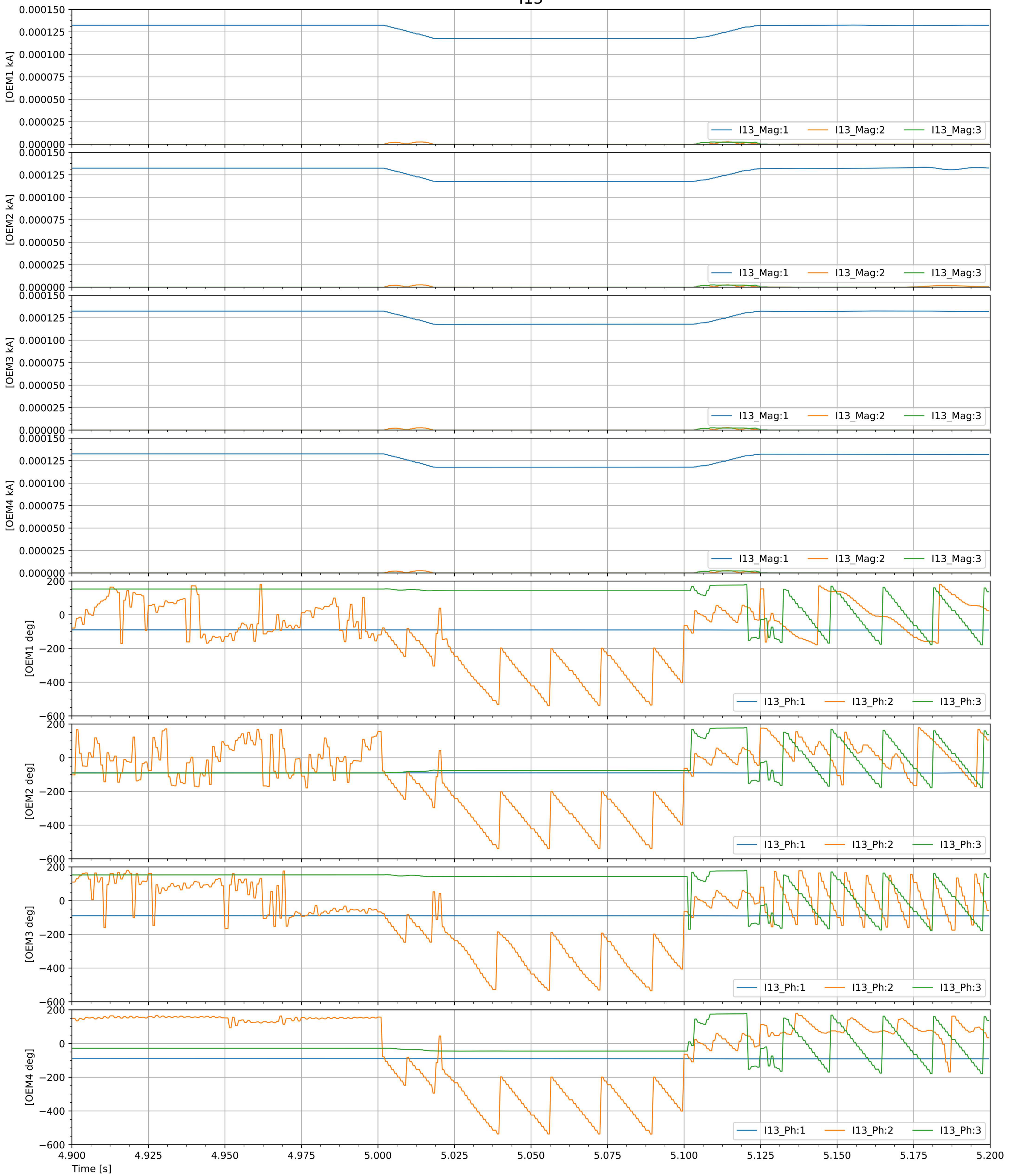
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

I12



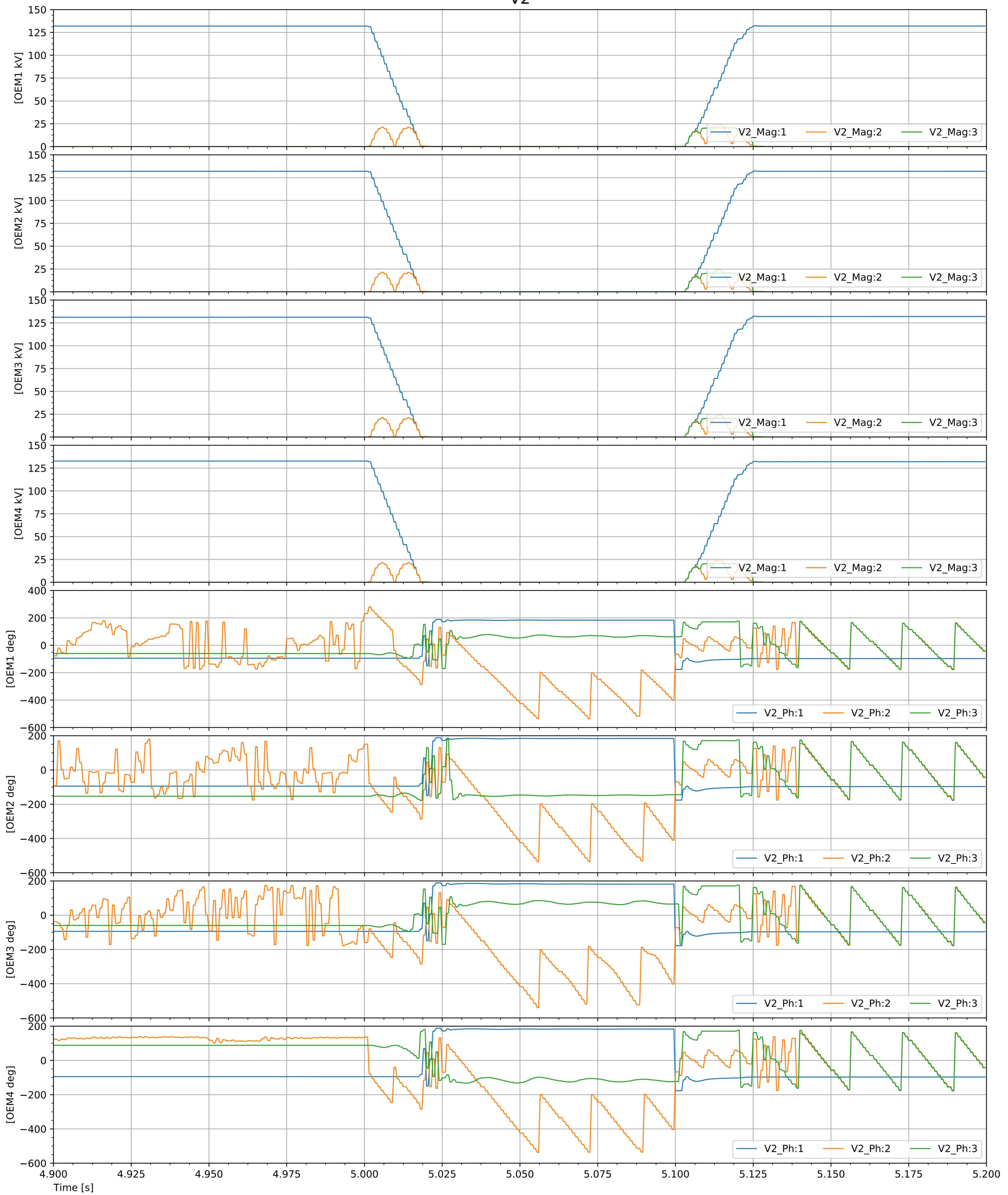
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABCG
Fault Resistance: 0.001 ohms

I13



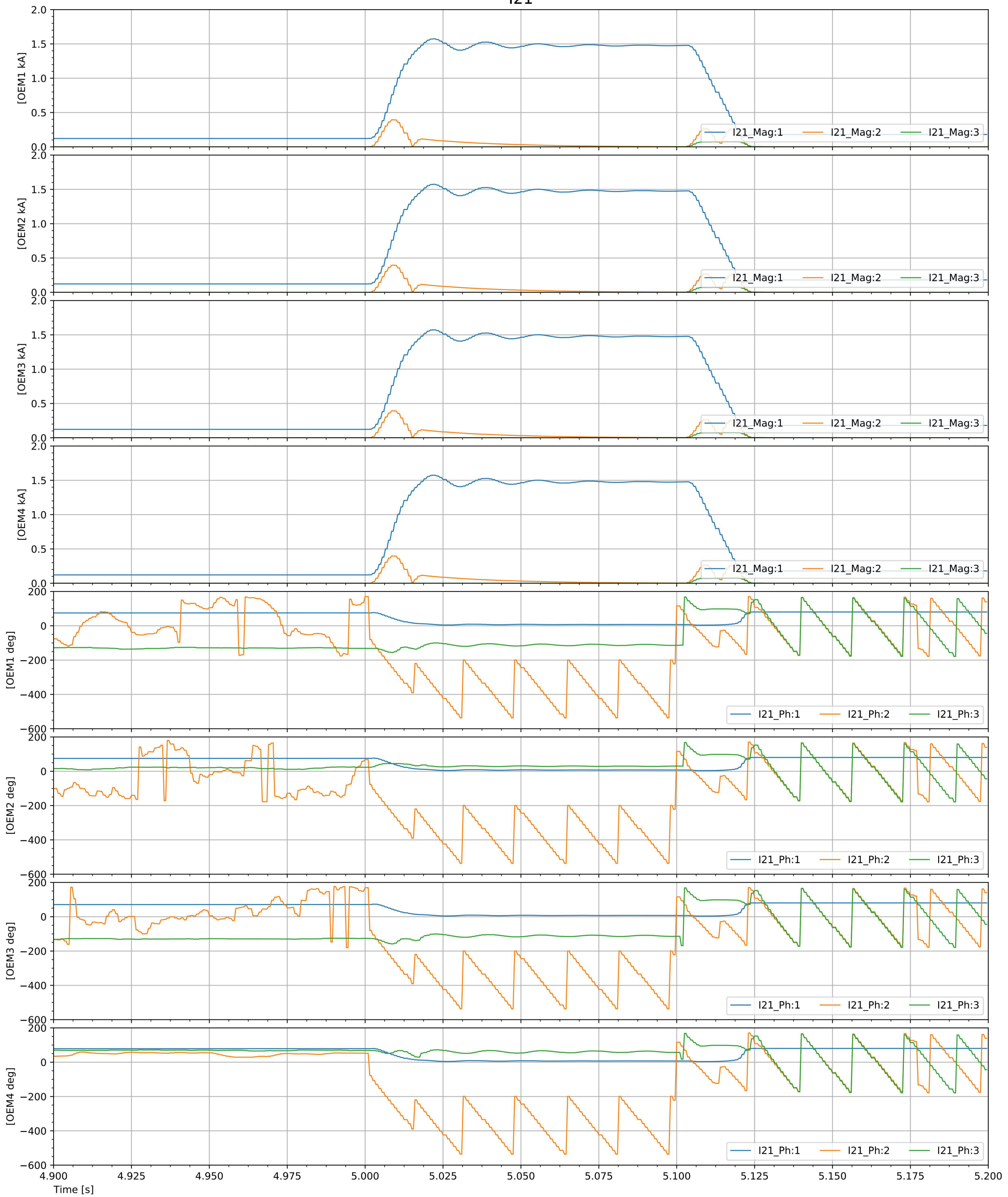
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABCG
Fault Resistance: 0.001 ohms

V2



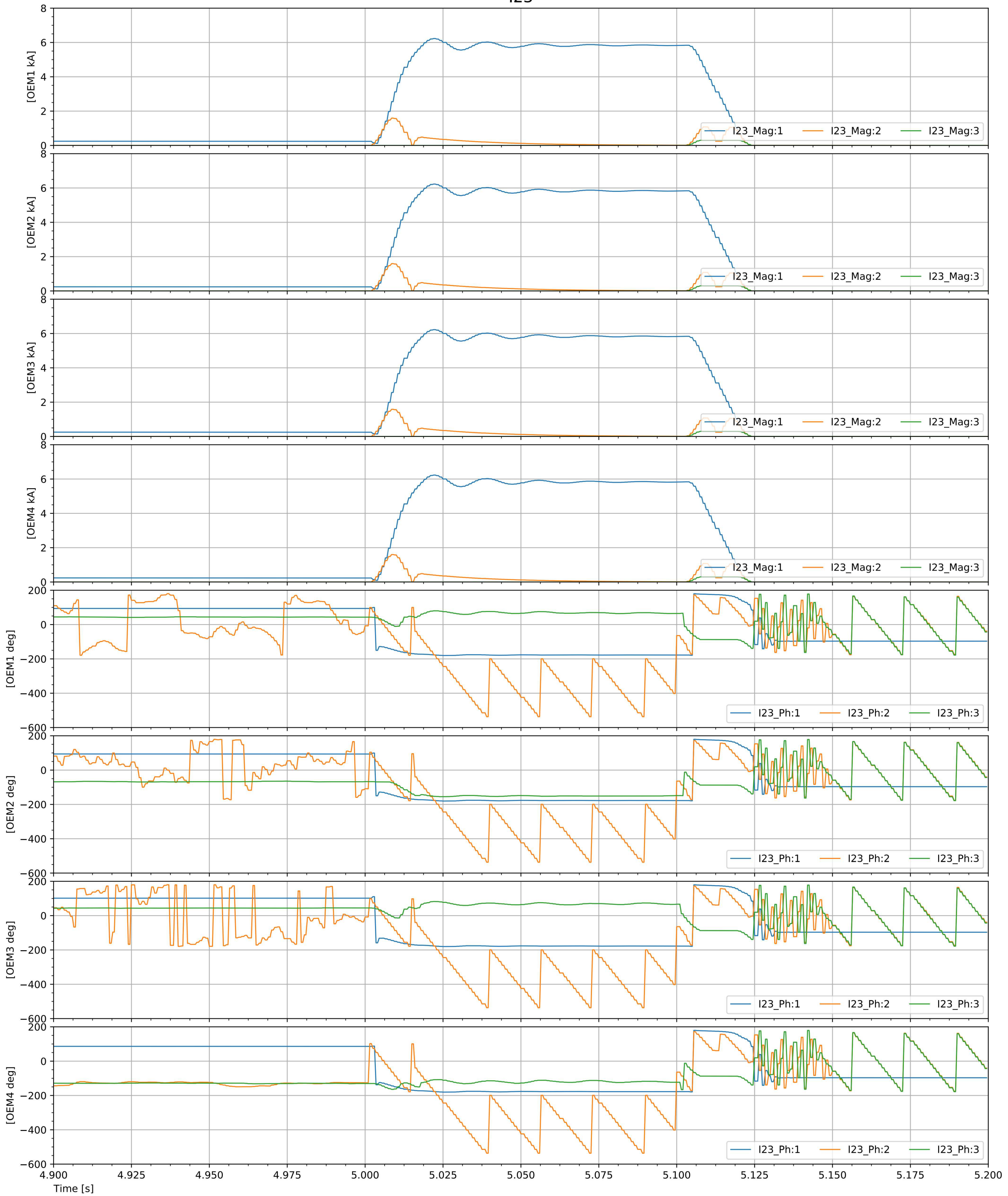
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

I21



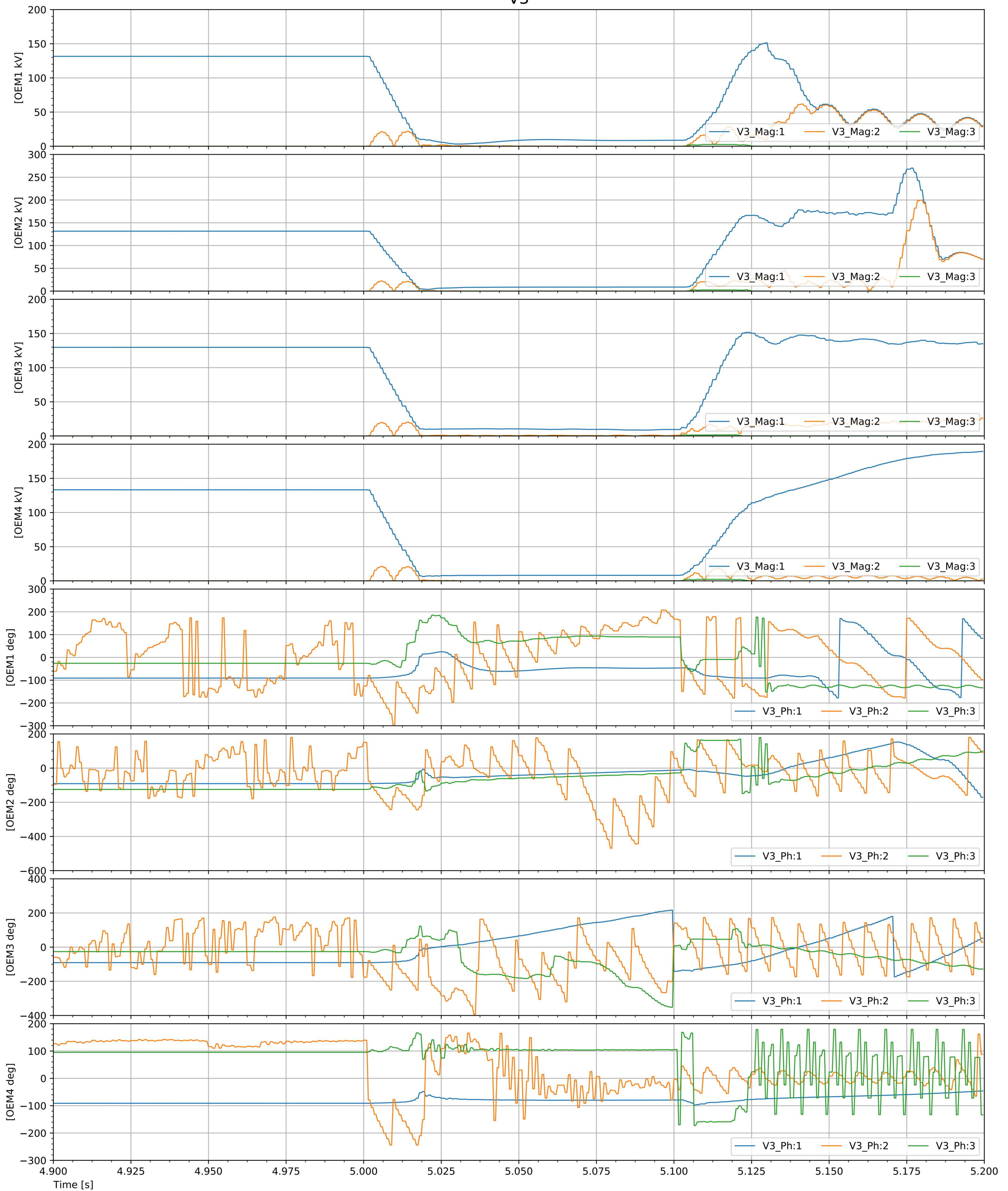
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABCG
Fault Resistance: 0.001 ohms

I23

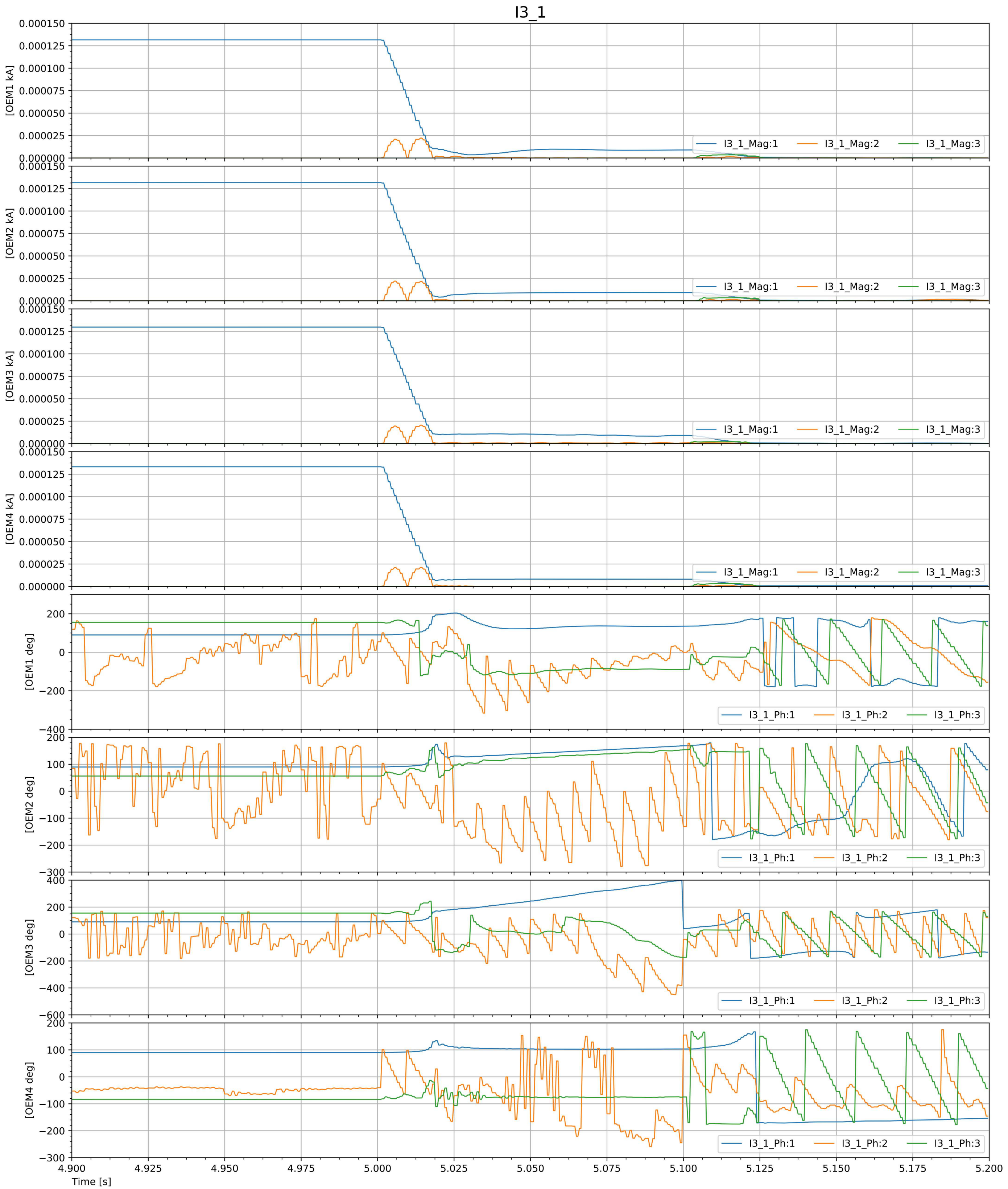


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

V3

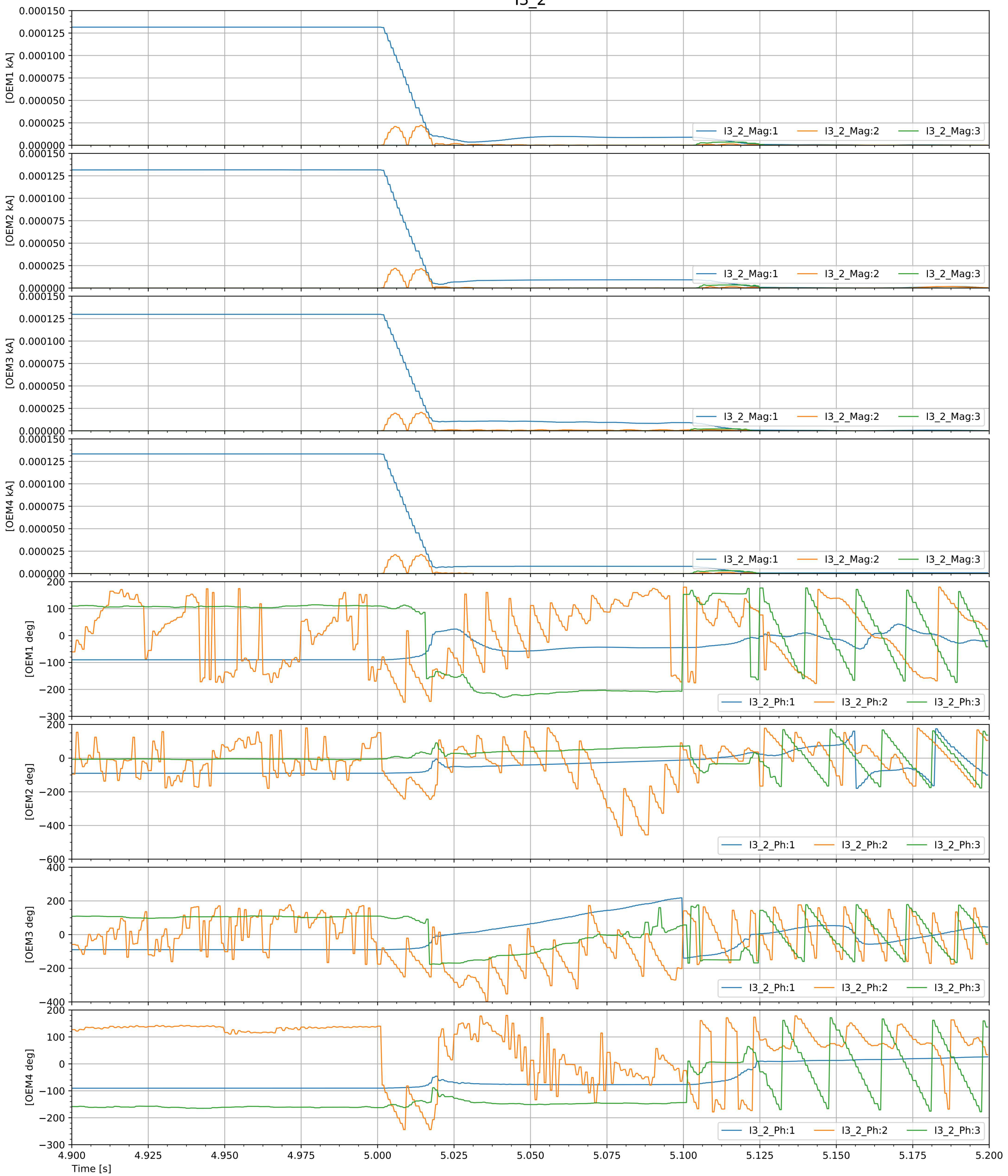


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms



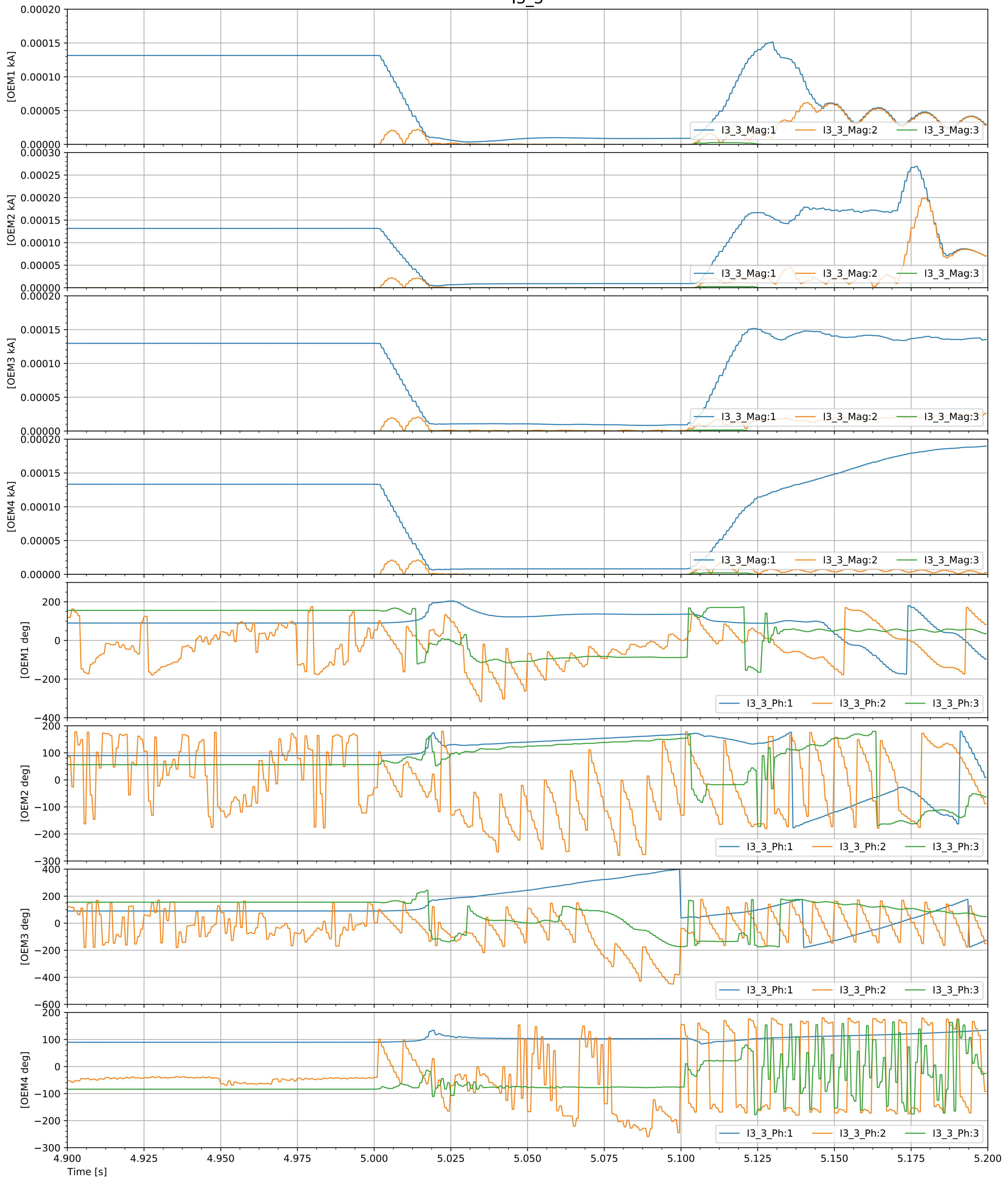
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABCG
Fault Resistance: 0.001 ohms

I3_2



Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

I3_3

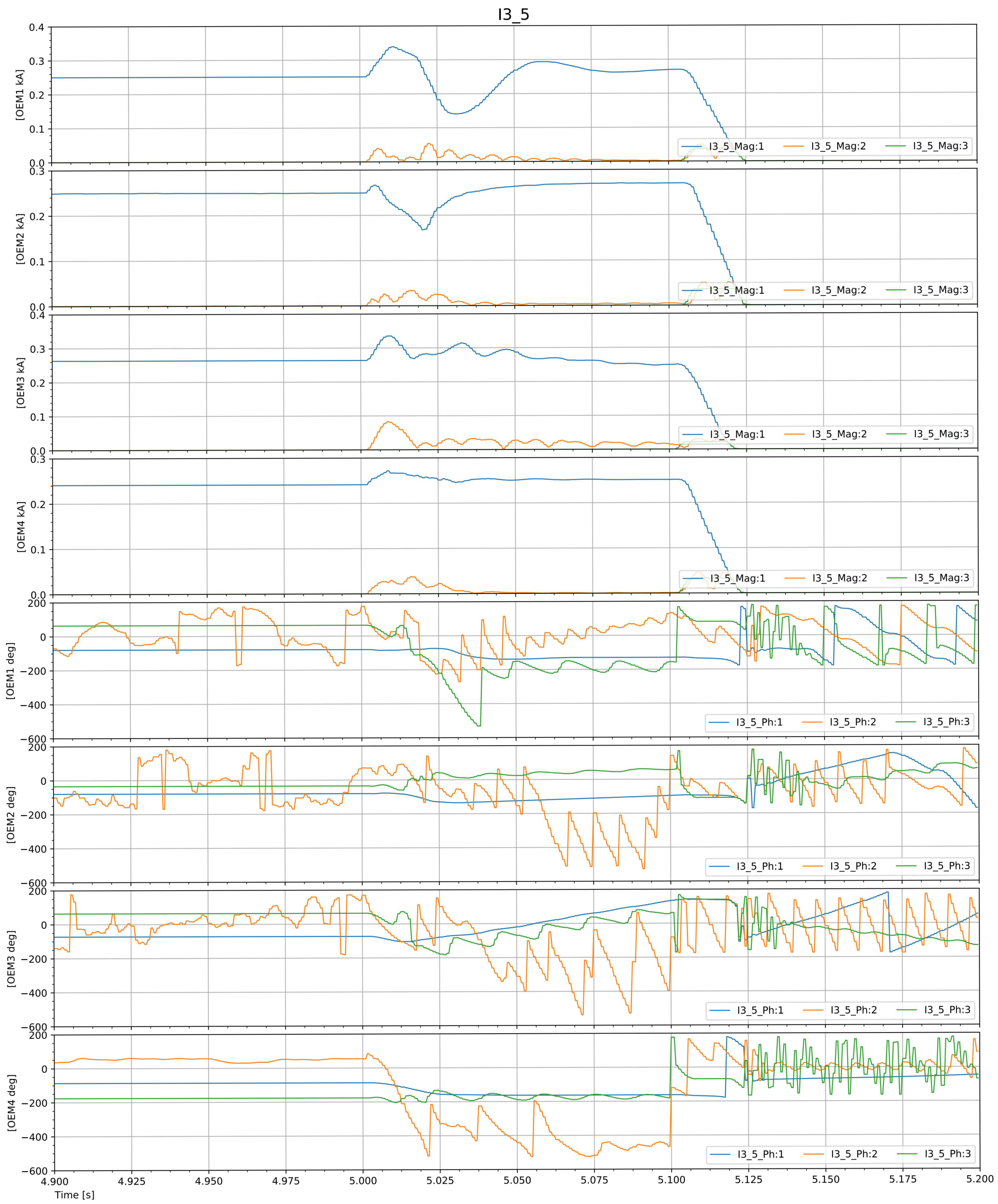


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

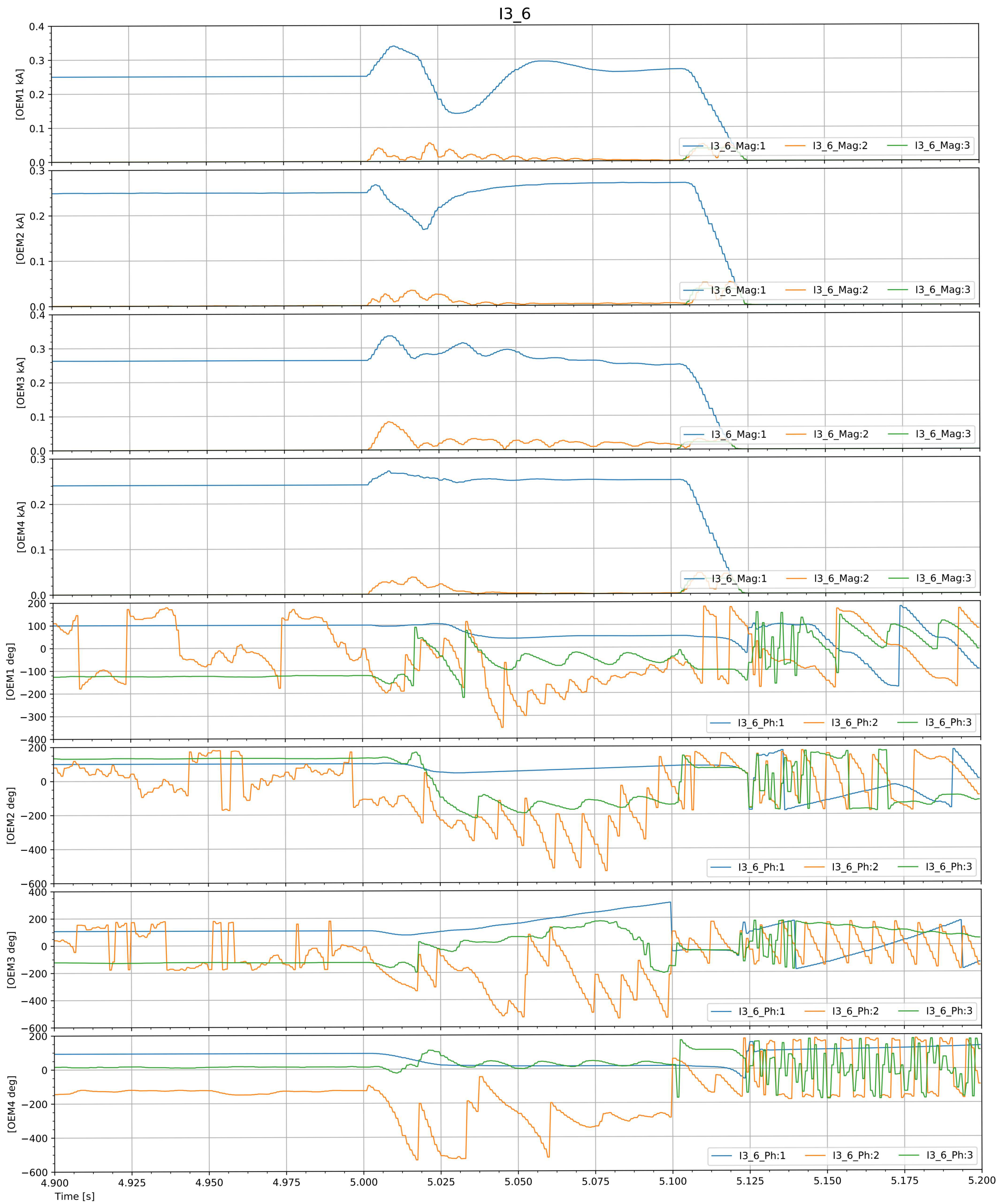
I3_4



Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

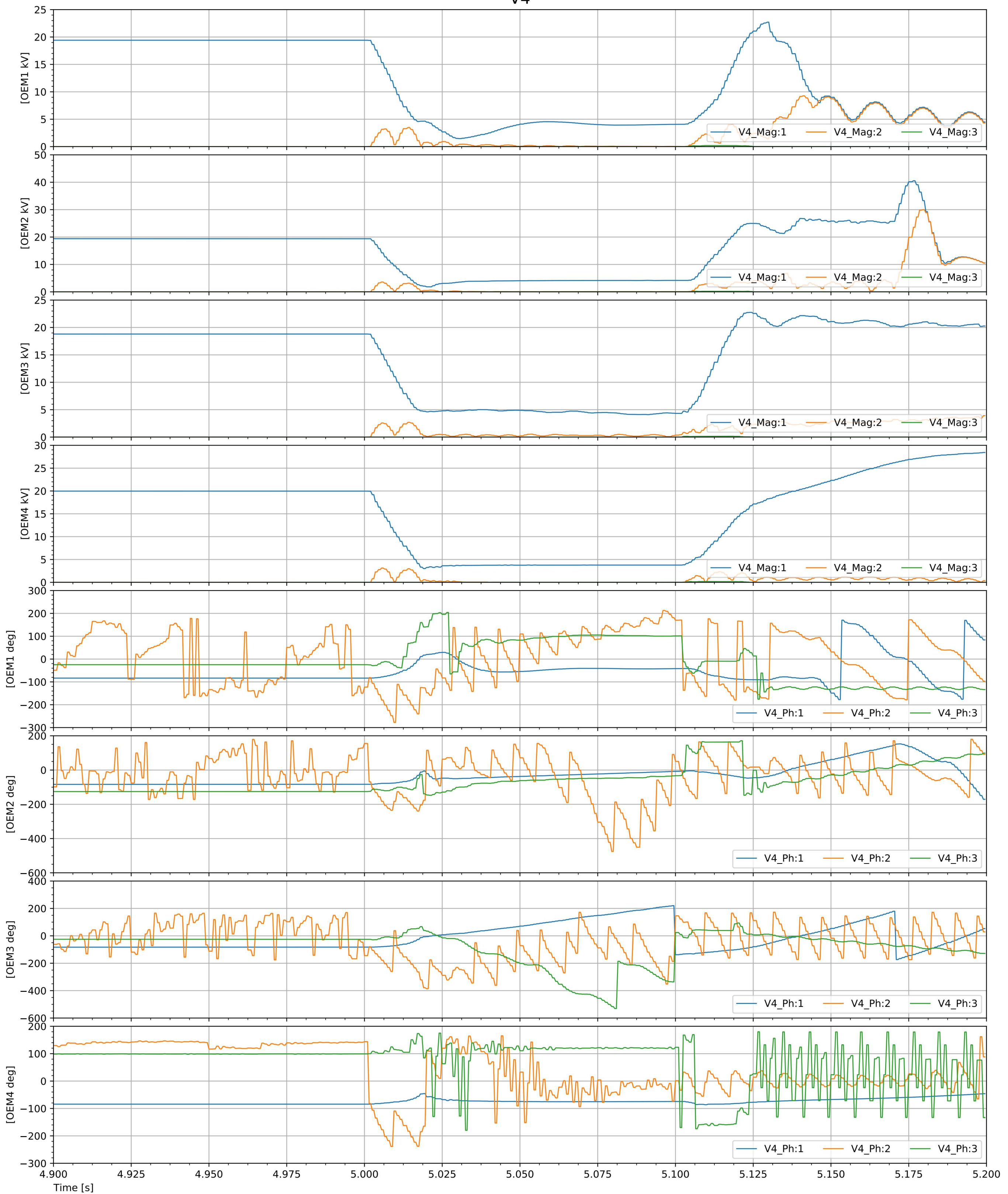


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABCG
Fault Resistance: 0.001 ohms

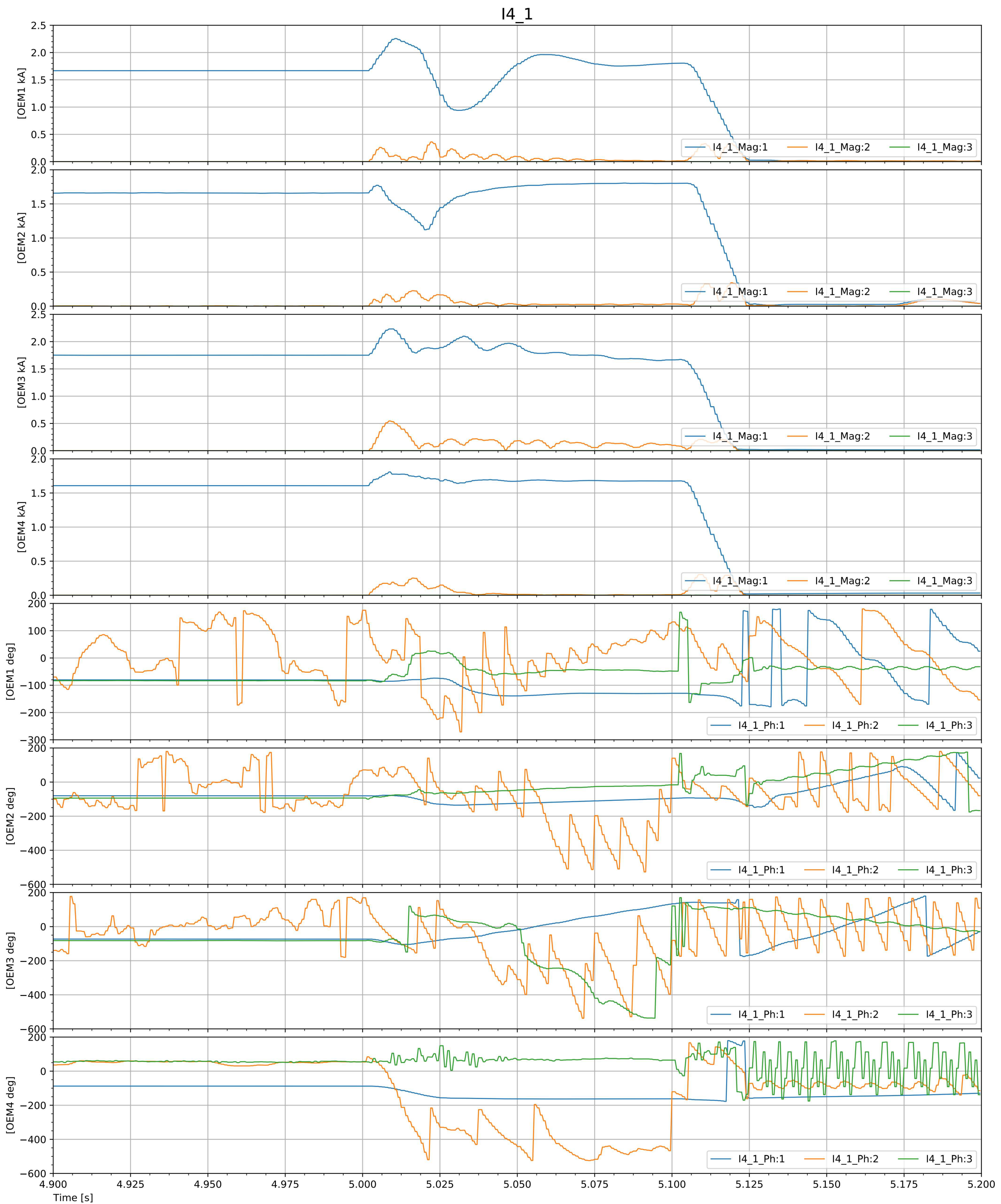


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABCG
Fault Resistance: 0.001 ohms

V4

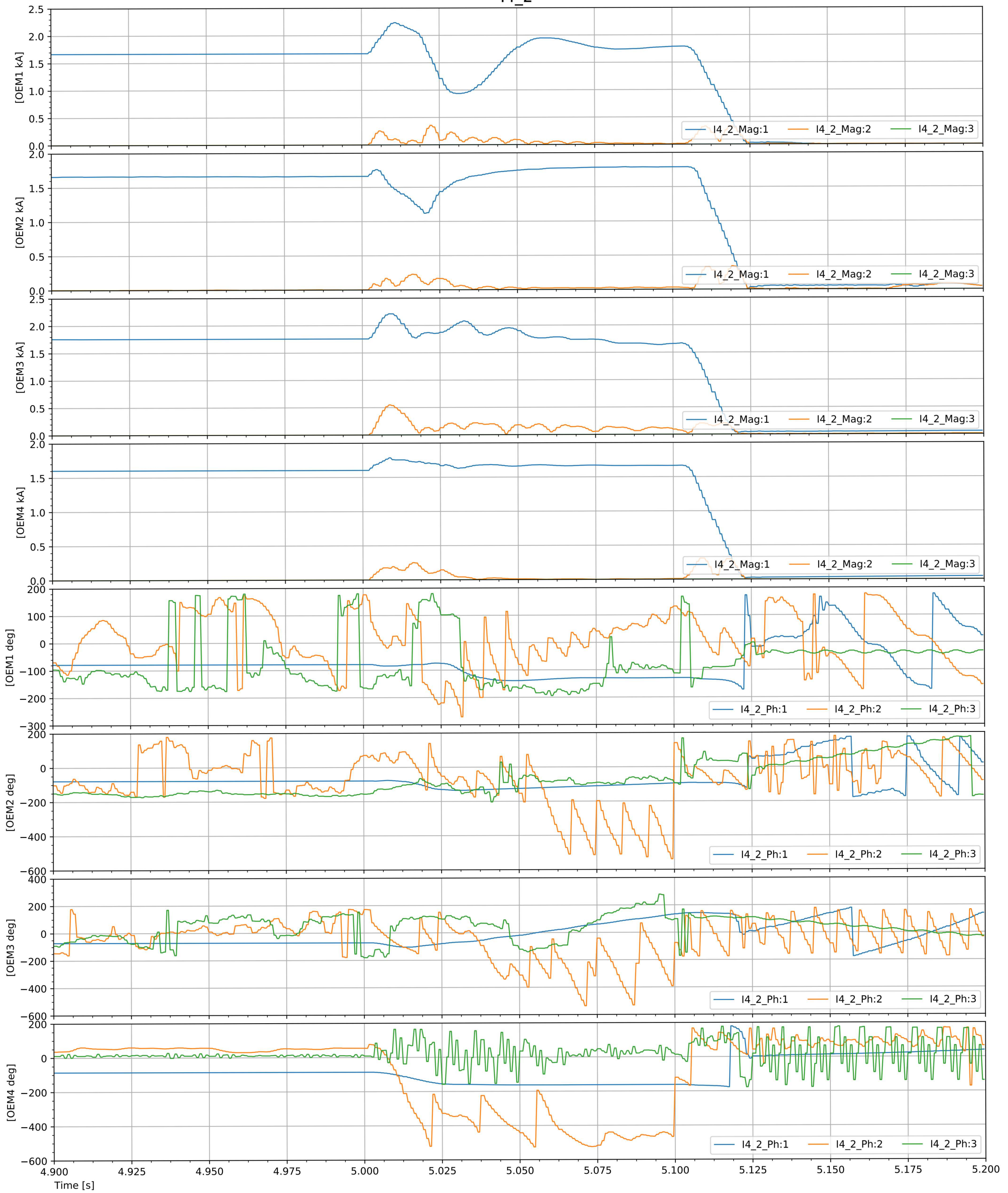


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms



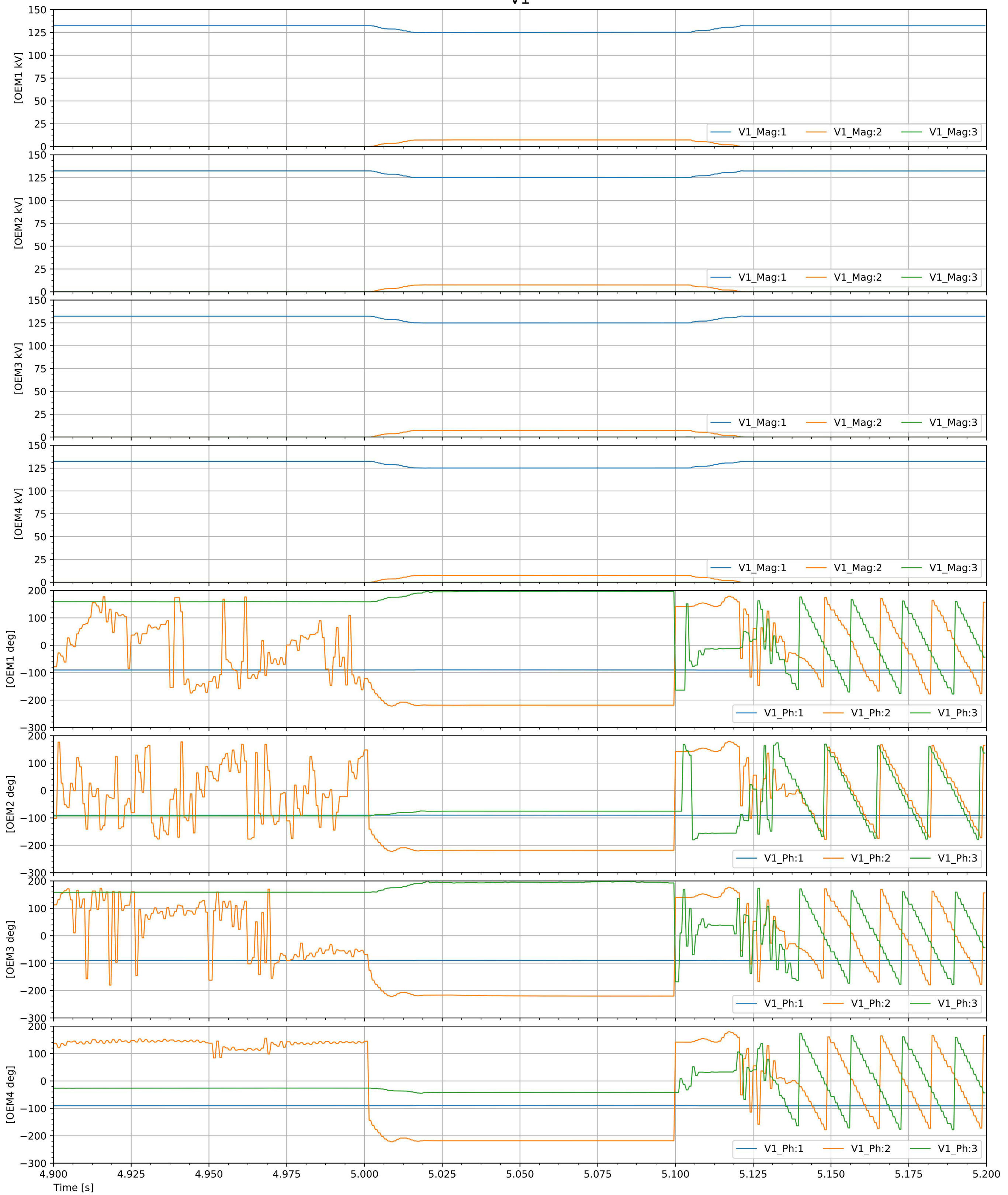
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: ABCG
Fault Resistance: 0.001 ohms

I4_2



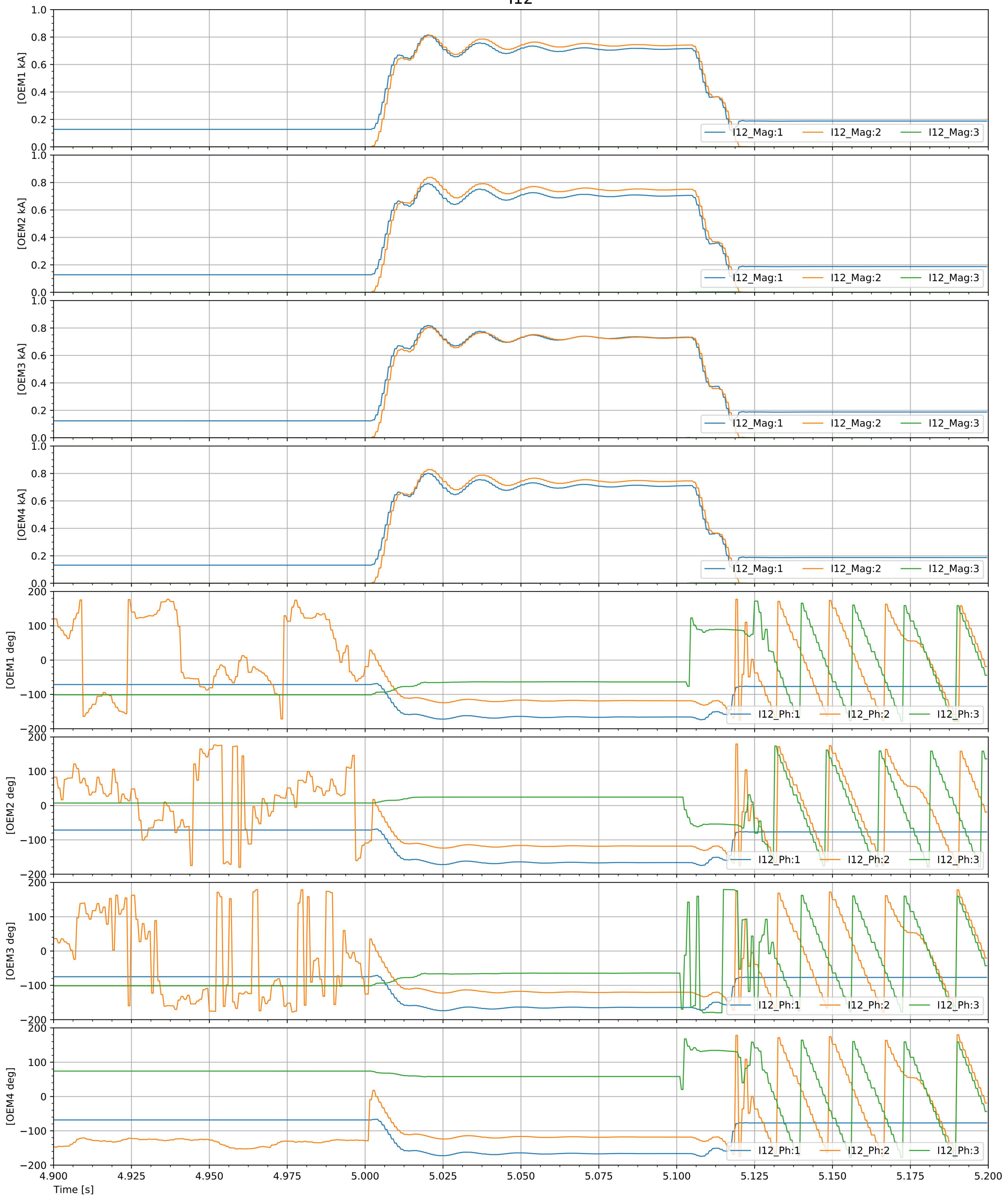
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: ABCG
 Fault Resistance: 0.001 ohms

V1



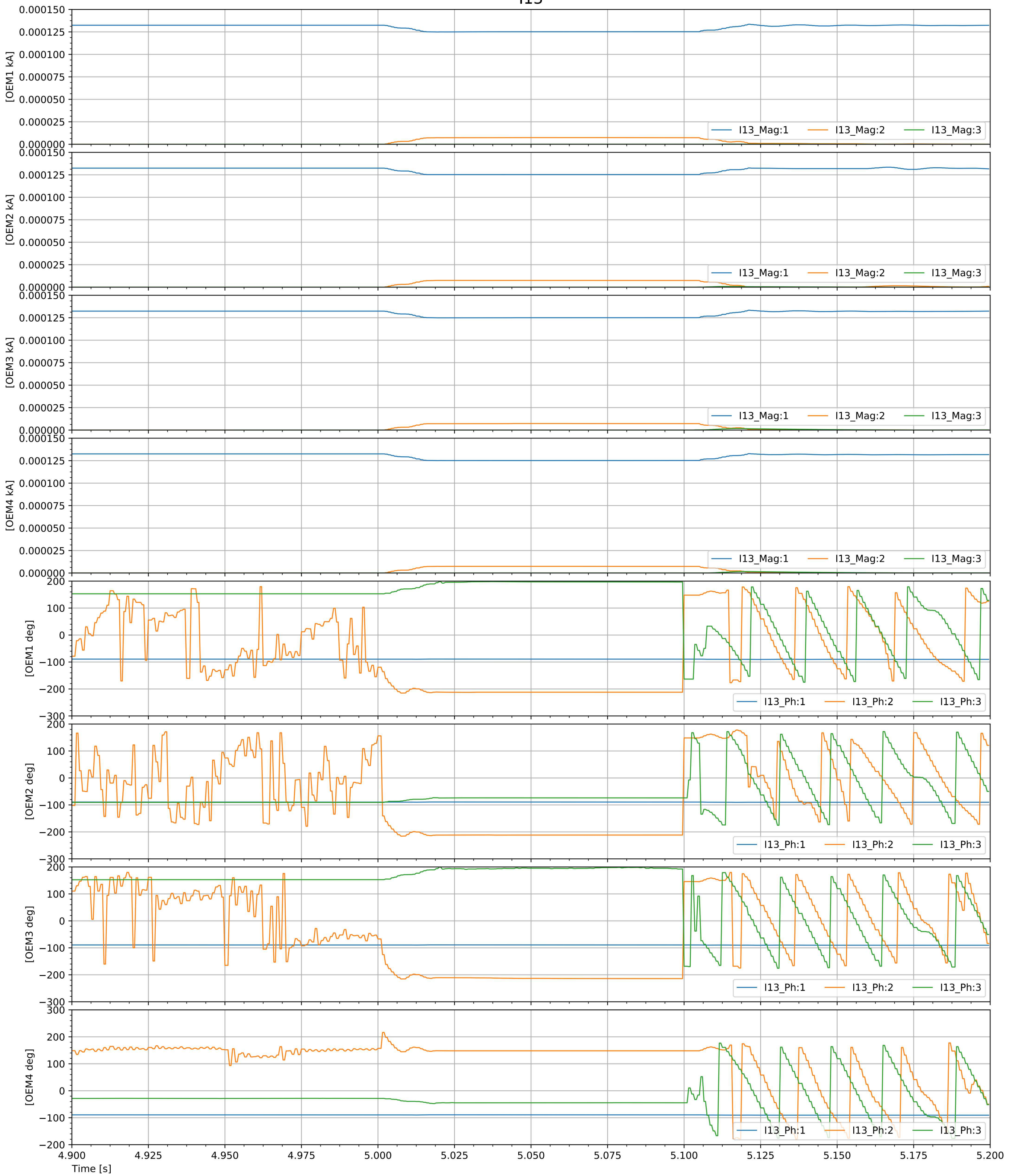
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AB
 Fault Resistance: 0.001 ohms

I12



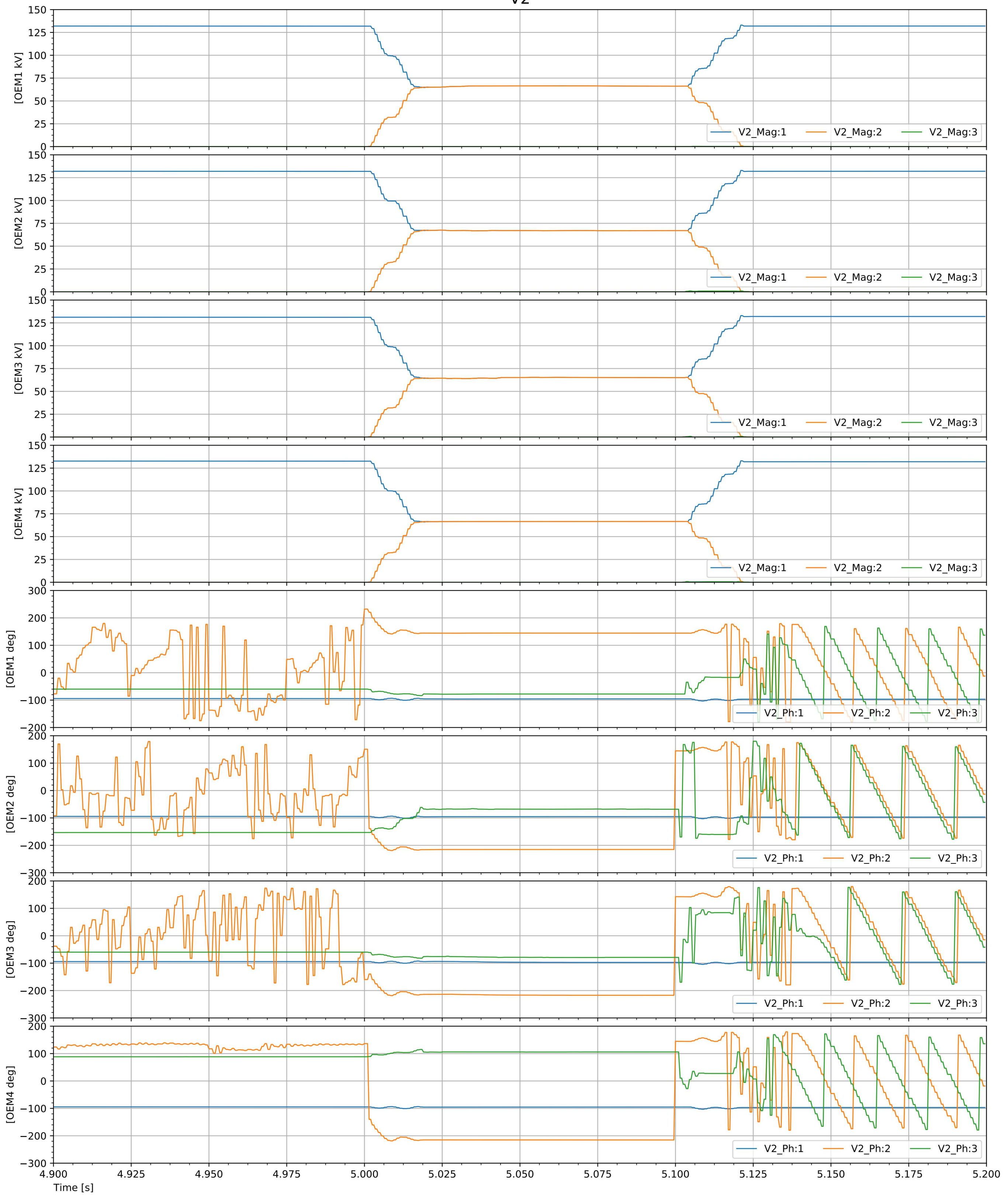
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

I13



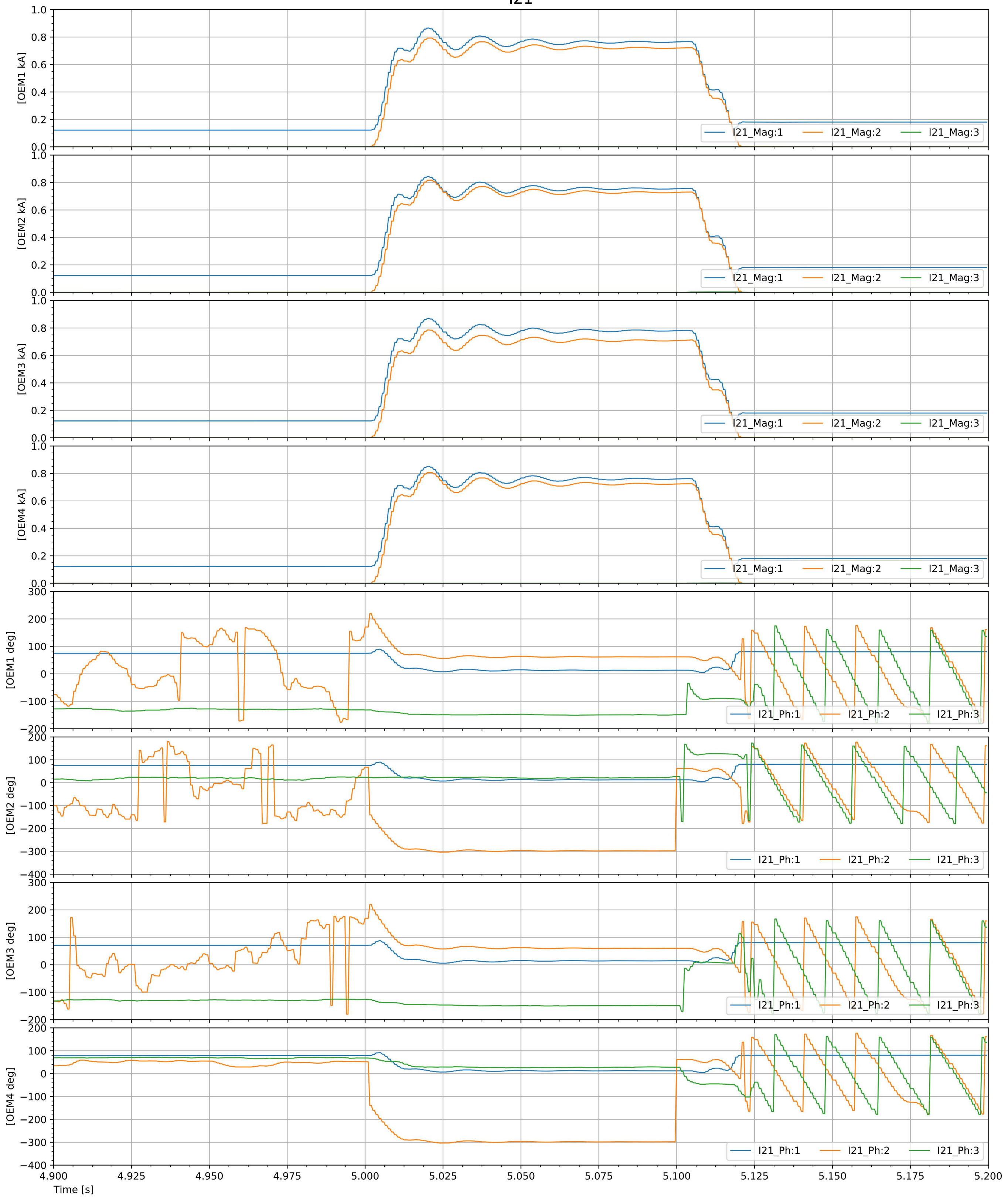
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

V2



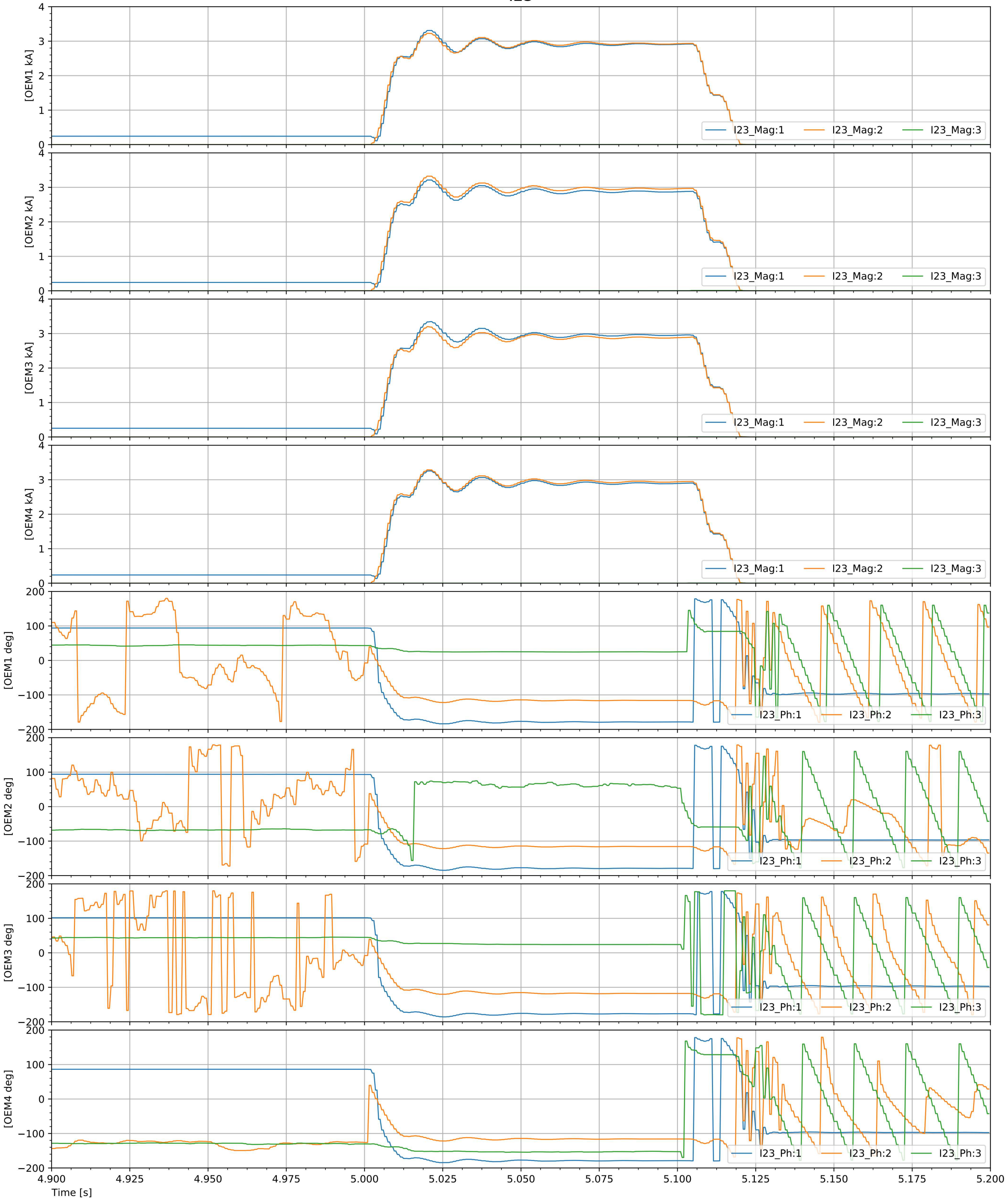
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AB
 Fault Resistance: 0.001 ohms

I21



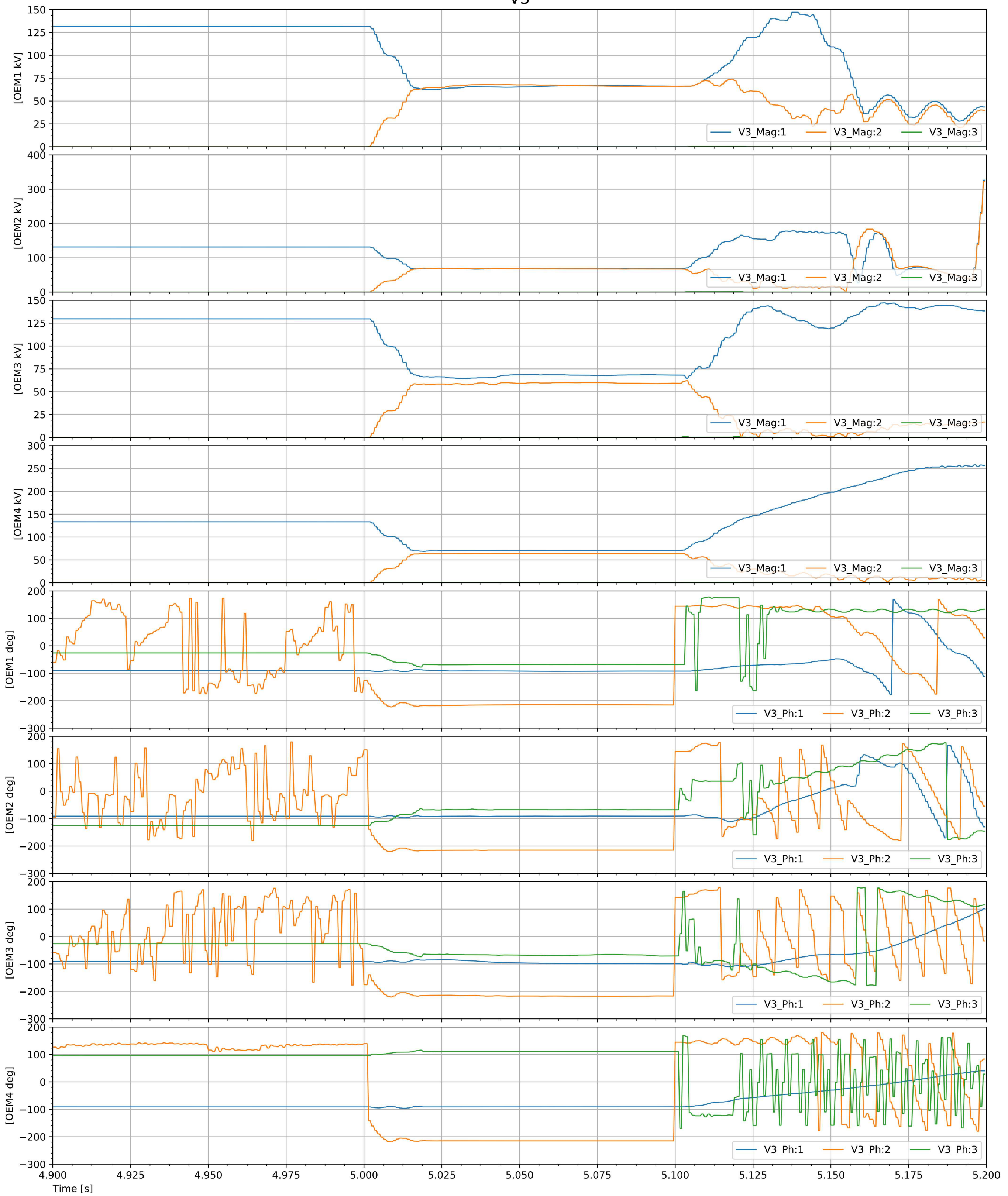
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

I23

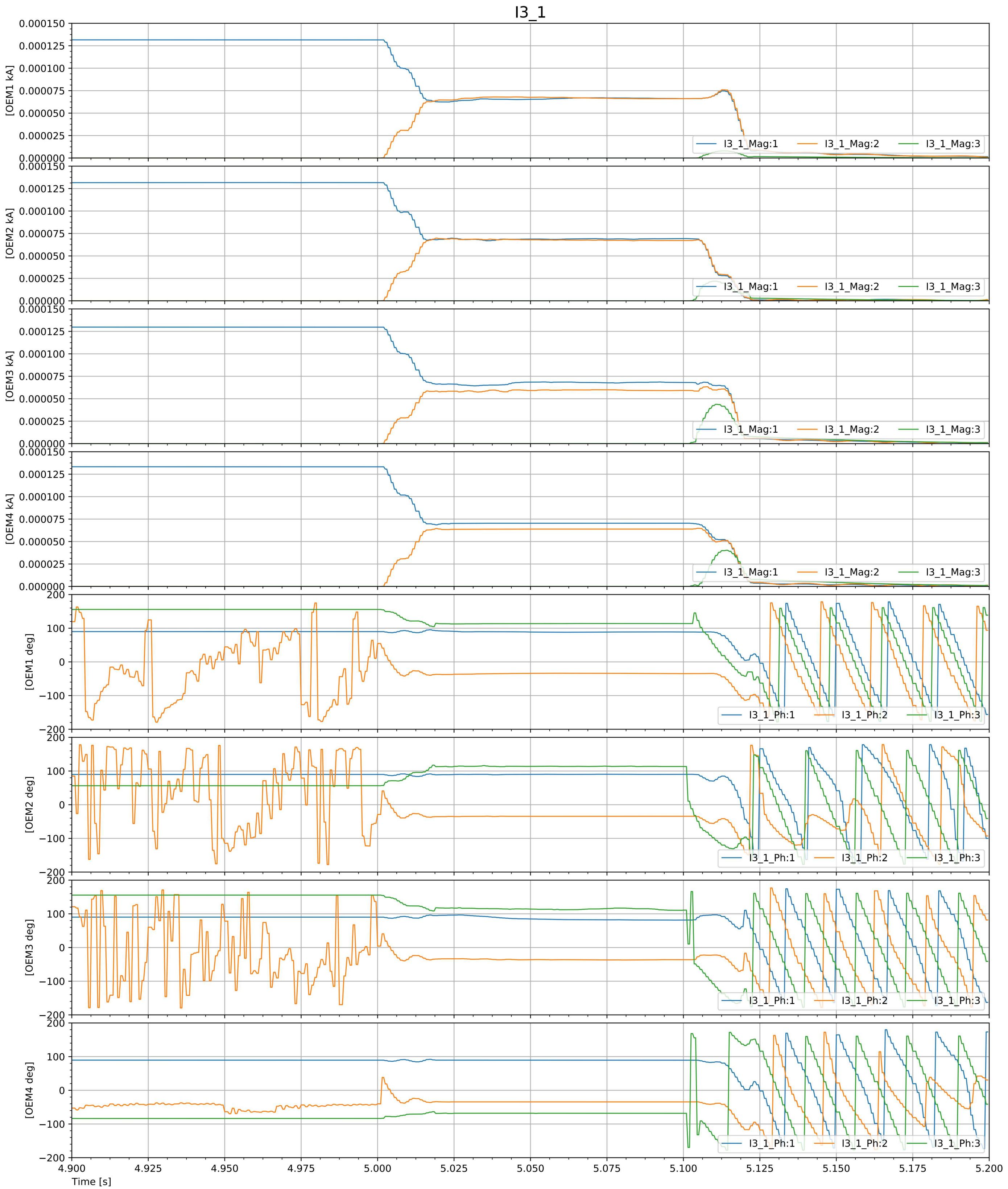


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

V3

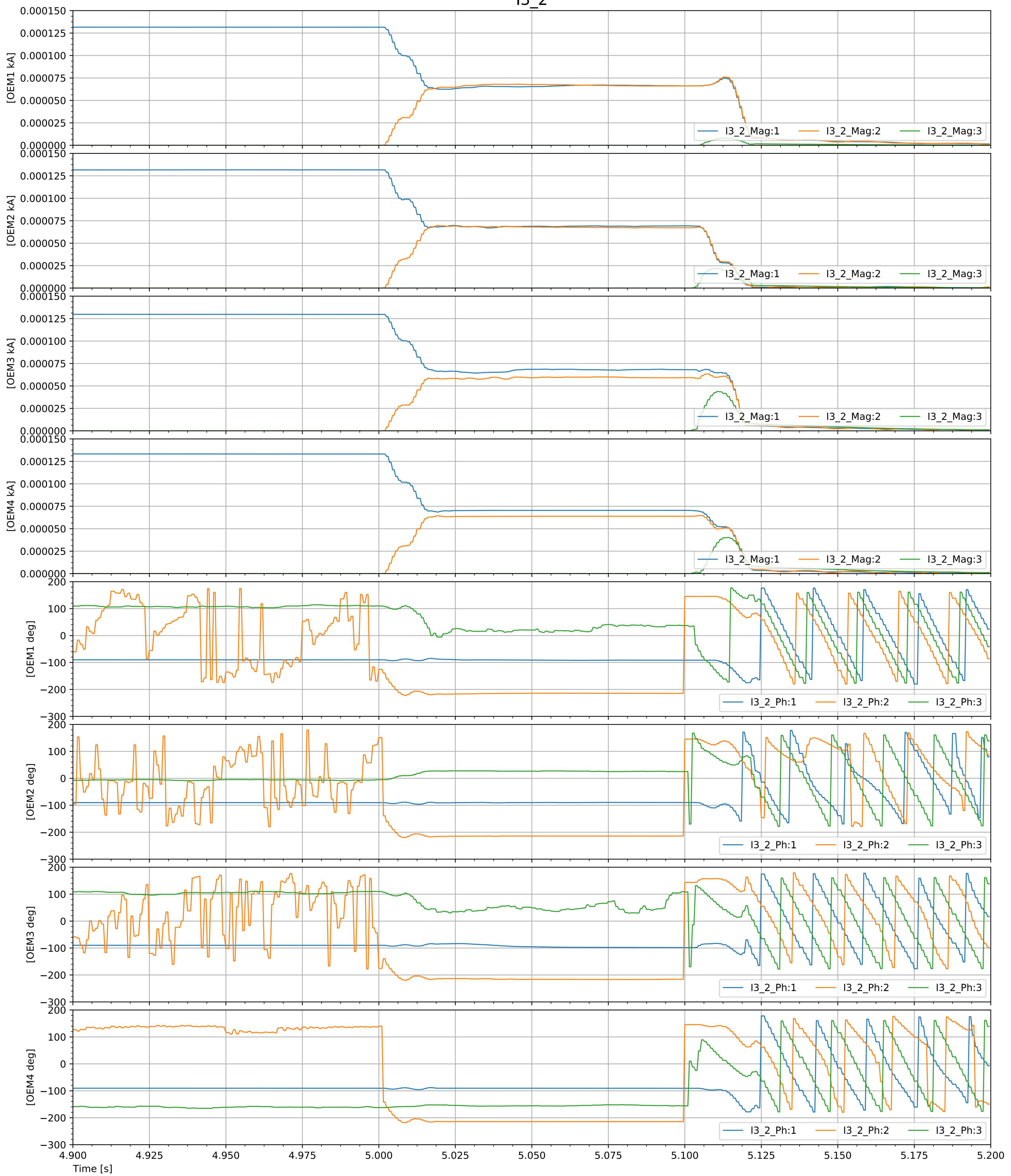


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AB
 Fault Resistance: 0.001 ohms



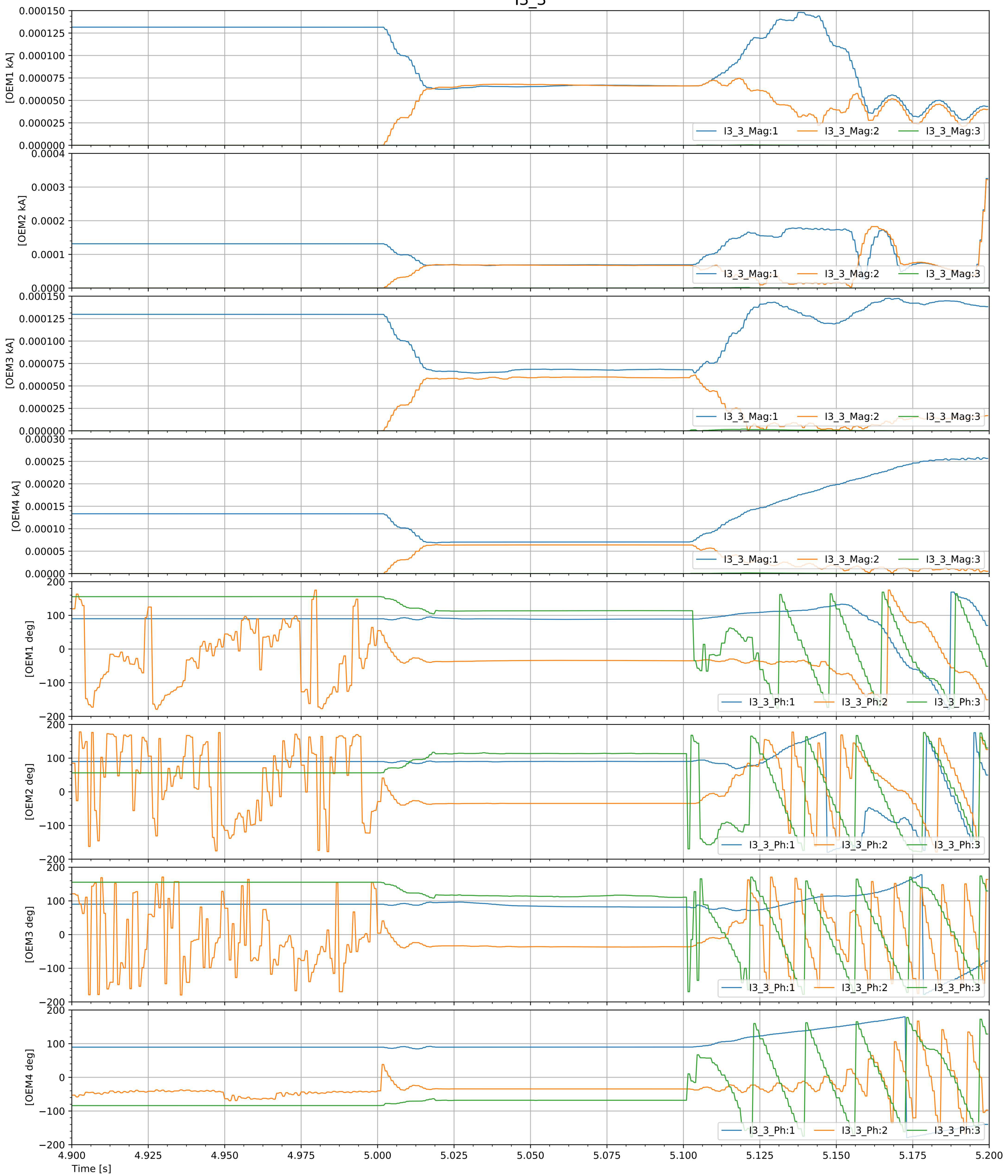
Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

I3_2



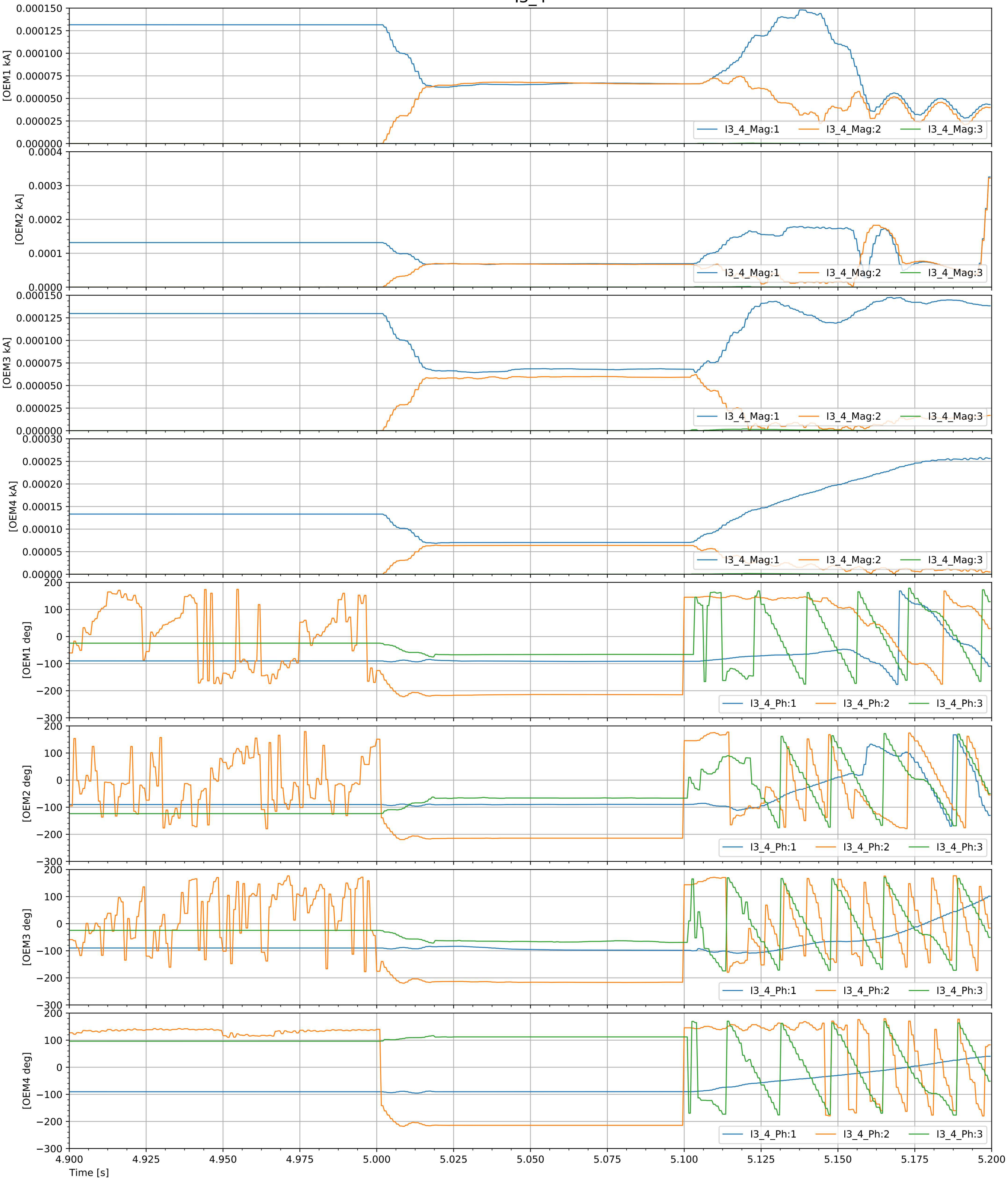
Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AB
 Fault Resistance: 0.001 ohms

I3_3

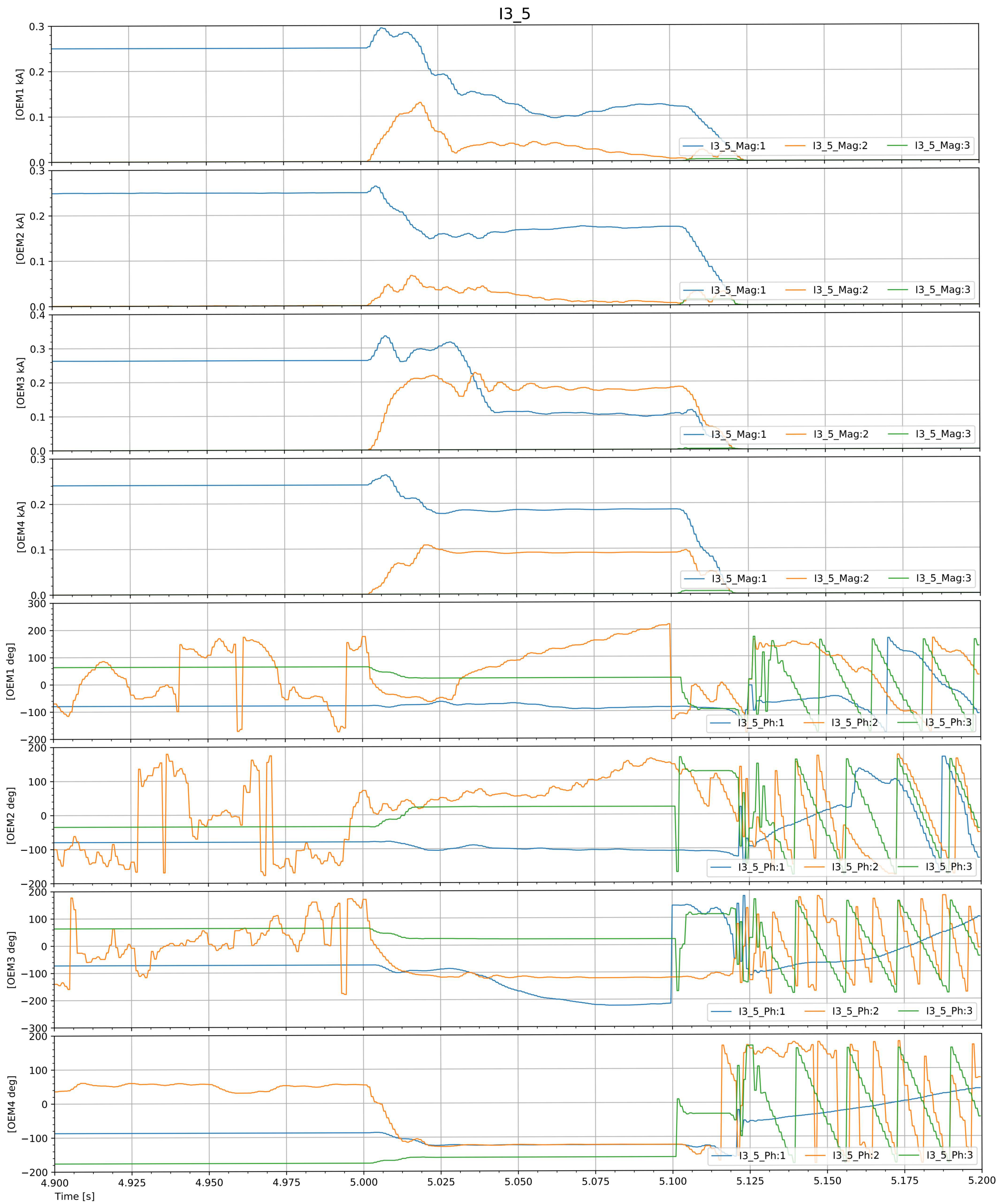


Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AB
 Fault Resistance: 0.001 ohms

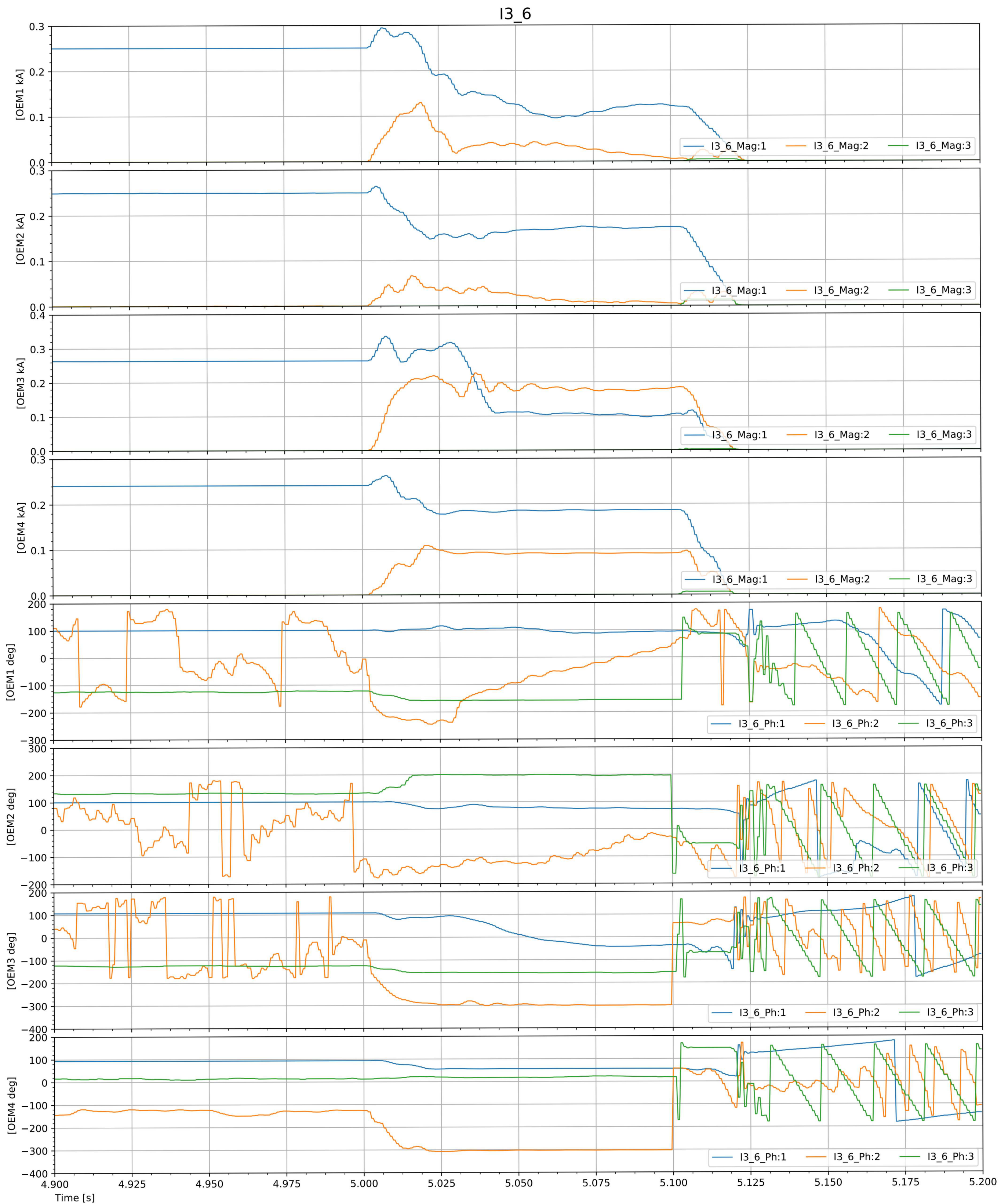
I3_4



Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

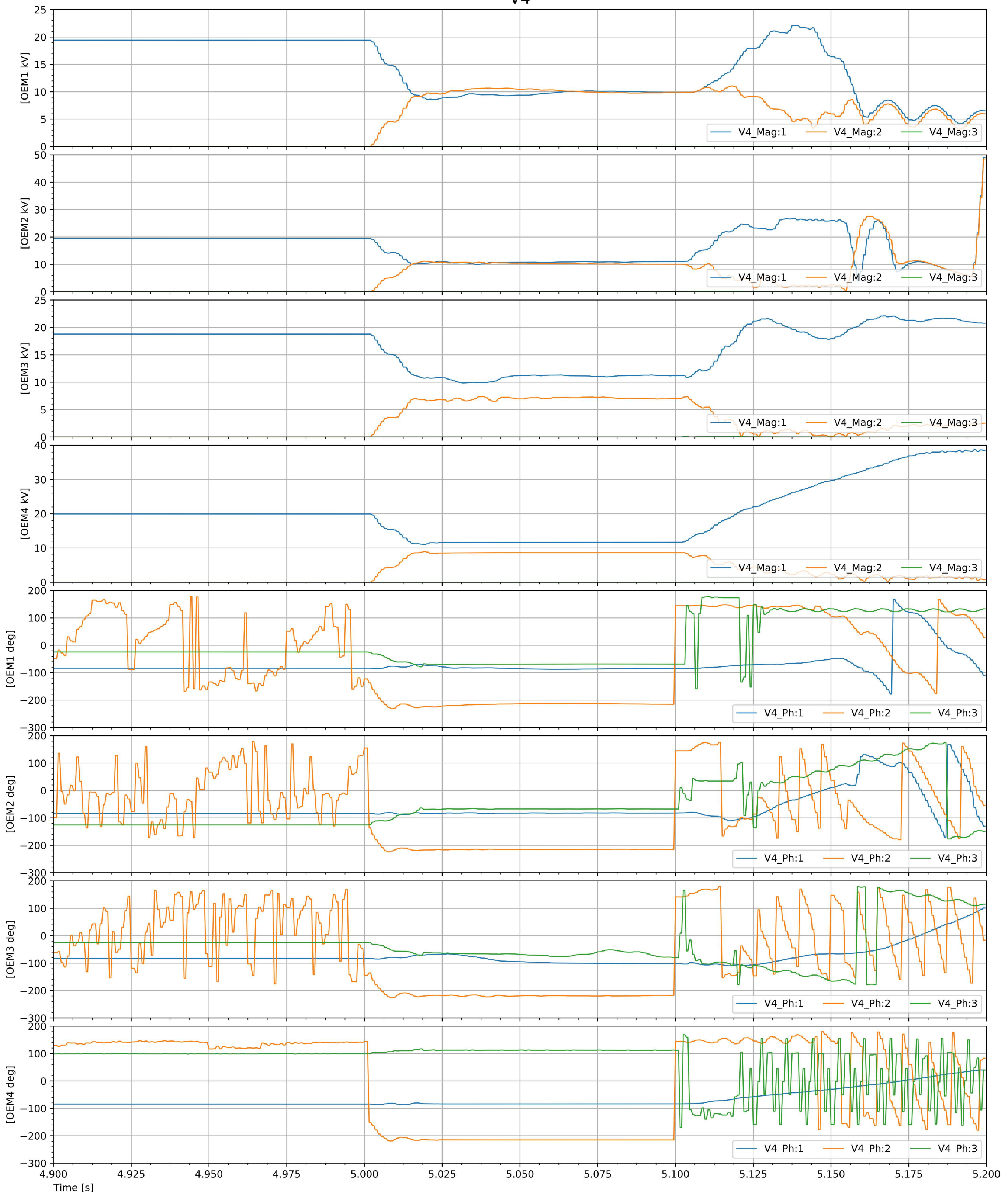


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

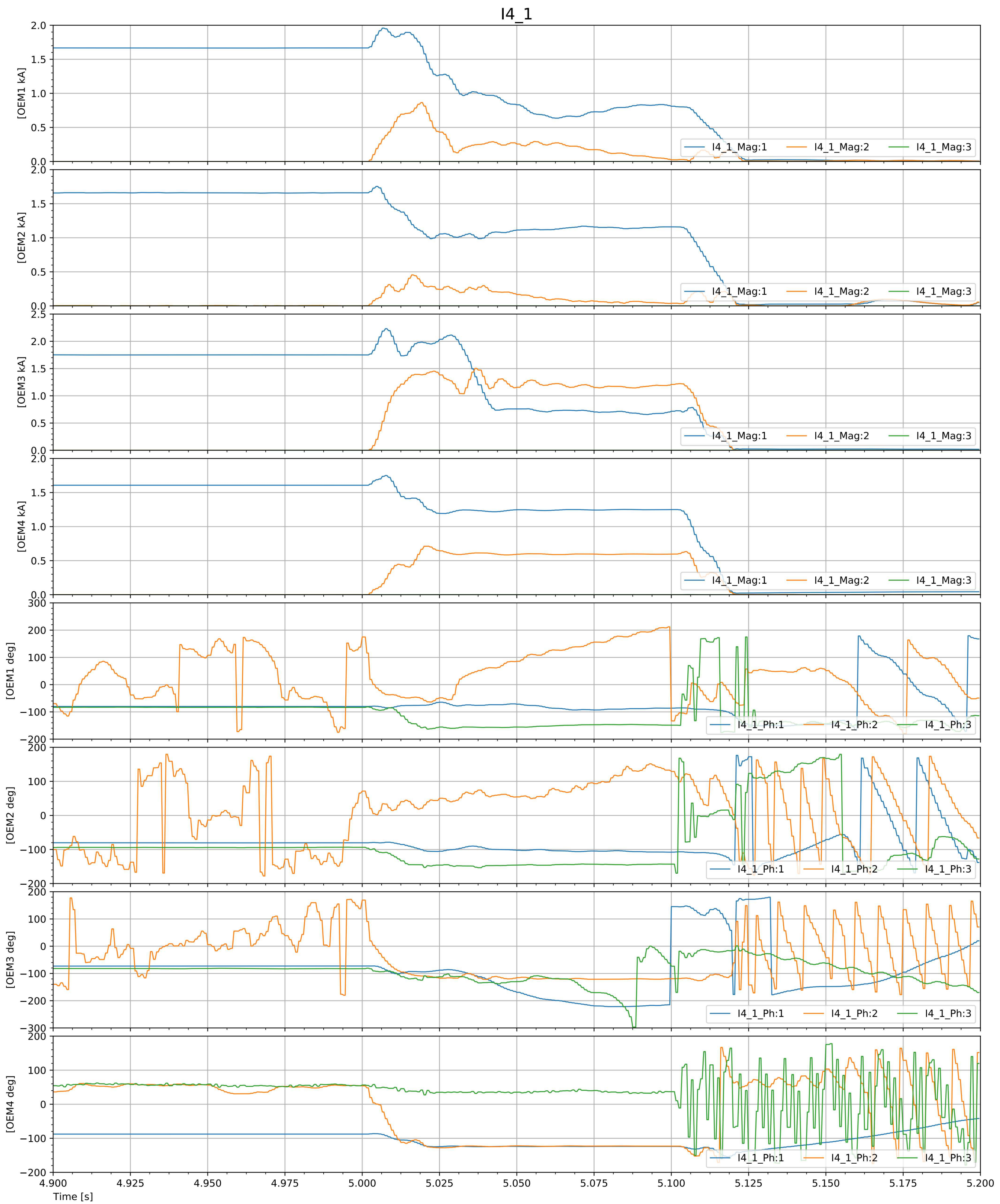


Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

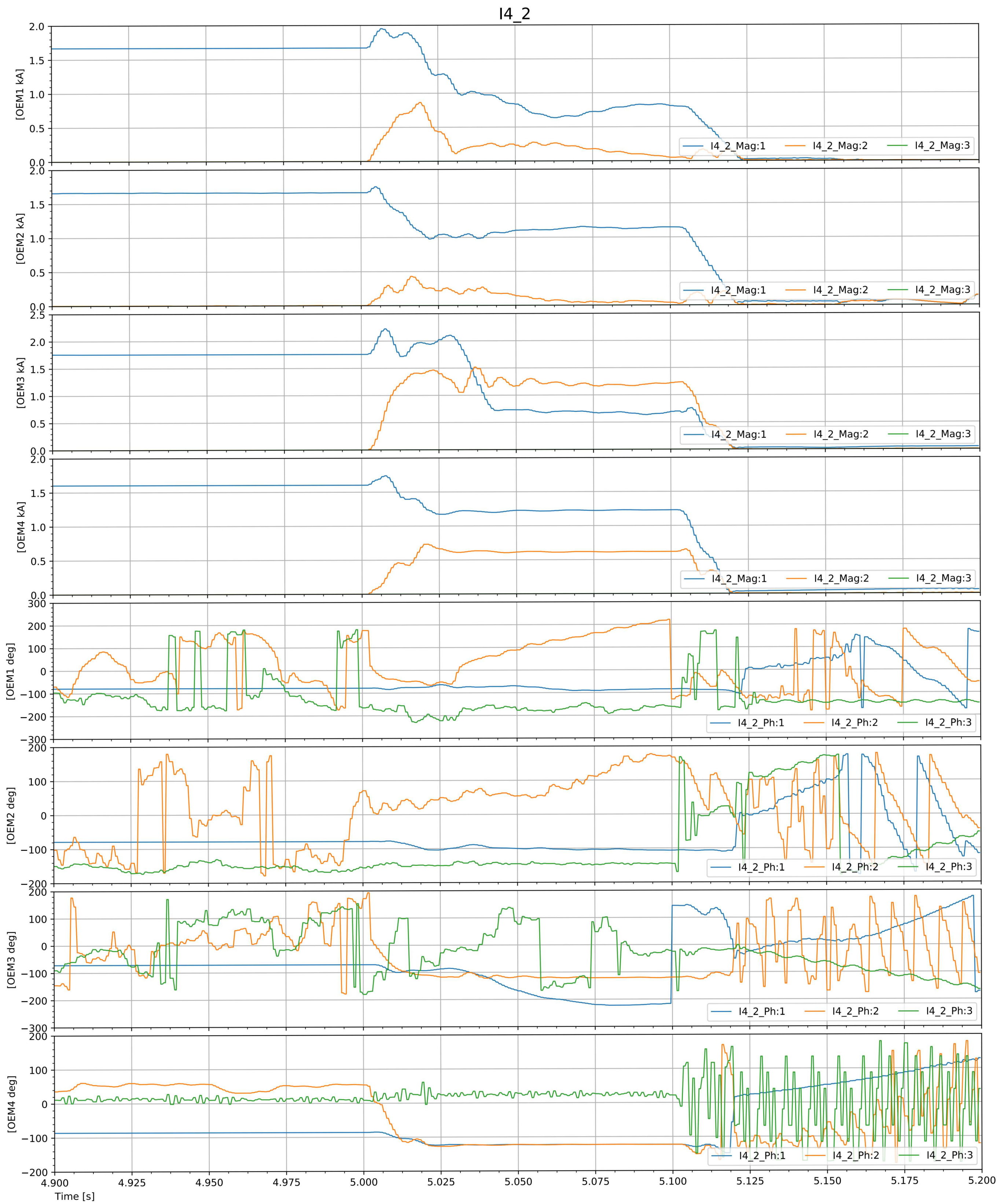
V4



Network Configuration: N-1 (TL13 prior outage)
 Fault Location: D
 Fault Type: AB
 Fault Resistance: 0.001 ohms



Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms



Network Configuration: N-1 (TL13 prior outage)
Fault Location: D
Fault Type: AB
Fault Resistance: 0.001 ohms

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