University of
South-Eastern Norway

www.usn.no

FMH606 Master's Thesis 2018
Electrical Power Engineering

Modeling of a Fault Ride Through in Transmission System with Distributed Hydropower Production

Mulubrhan Teklehaymanot Tewelde

Faculty of Technology, Natural sciences and Maritime Sciences
Campus Porsgrunn

University of South-Eastern Norway

www.usn.no

Course: FMH606 Master's Thesis, 2018

Title: Modeling of a Fault Ride Through in Transmission System with Distributed Hydropower production

Number of pages: 152

Keywords: Power System Stability, Rotor Angle Stability, Transient Analysis, Fault Ride Through Capability

Student:	Mulubrhan Teklehaymanot Tewelde
Supervisor:	Dietmar Winkler
External partner:	Skagerak Kraft
Availability:	Open

Summary:

As part of the development plan for the European Transmission Network, the European Network of Transmission System Operator (ENTSO-E) proposed the creation of a Network code dealing the requirements for the grid connections of generators (NC RfG) which came into effect on May 17th, 2016.

The response to the ENTSO-E network code, the Norwegian Transmission System Operator (TSO) formulated updates to the Norwegian Power System. These updates were based on ENTSO-E requirements for synchronous Power Generating Modules of types B, C and D.

With that in mind, the project for this thesis involved the testing of the Norwegian TSO recommended values on the distribution of hydropower generators based in the Telemark region. The testing was conducted using PowerFactory and OpenIPSL with a simulation of five cases. The simulation cases were designed to test a balanced three-phase short circuit occurring on the 300, 132, 66 and 22 kV sections of the central and regional transmission networks.

Fault simulations on the 300 kV and 132 kV regional distribution networks showed positive results with few exceptions. The 66 kV and 22 kV networks were highlighted as the ones requiring improvement.

This thesis report will present the studies and the simulations conducted along with the results and conclusions drawn from the simulations with the aim of finding an enhanced way forward in the area of power generation and transmission.

Preface

This thesis is the final project of the two-year Master's Program in Electrical Power Engineering at the University of South-Eastern Norway (USN). This task is a continuation of projects that were conducted by myself. The initial thesis was produced in spring of 2016 and the first article for the Ph.D. project was published in January 2018.

Initially, it was assumed that the model from PowerFactory for the case study was a complete model of fully parametrized variables of components from the previous work. The research tasks for the thesis were formulated based on this assumption. Unfortunately, a later review revealed that the components were not fully parametrized which led to extra work and time to find the actual parameters of the network. This delayed the simulation process.

I would like to thank my intern supervisor Assistant Professor Dietmar Winkler for his guidance and support since the commencement of the project. I would also like to thank Professor G.J. Hegglid for helping me in updating of the parameter values during the critical phase of the project. Last but not the least; I would like to thank my classmates for their unwavering support during my time in the Master's Program.

Porsgrunn, May 15th, 2018

Mulubrhan Teklehaymanot Tewelde

Mulubrhan Teklehaymanot Tewelde

Contents

Nomenclature

Symbol	Unit	Description
A_e	-	1st ceiling coefficient
B_e	-	2nd ceiling coefficient
P_a	W	Accelerating power
P_0	MW	Active power at initial operating condition
αp	-	Active power exponent
$ACER$		Agency for the Cooperation of Energy Regulators
θ_m	rad	Angular position of rotor with reference to stationary axis
δ_m	rad	Angular position w.r.t the synchronously rotating reference
ω_m	rad/s	Angular velocity of the rotor, mechanical
R_a	pu	Armature reactance
AVR		Automatic voltage regulator
Z_b	Ω	Base impedance
$CGMES$		Common Grid Model Exchange Specification
R	pu	Conductor resistance
K_a	Pu/pu	controller gain
$V_{r,max}$	pu	Controller Output maximum limit
$V_{r,min}$	pu	Controller Output Minimum limit
T_a	s	Controller time constant
P_{Cu}	kW	Copper losses of transformer winding
D	pu	Damping coefficient
δ	rad	Difference in angle between sending and receiving end voltage
$DIgSILENT$		Digital Simulation Electrical Networks
T_{2d0}, T''_{d0}	s	Direct axis open circuit sub-transient time constant

T_{1d0}, T'_{d0}	s	Direct axis open circuit transient time constant
x_{2d}, x''_d	pu	Direct axis sub-transient reactance
e''_d	pu	Direct axis sub-transient voltage
x_d	pu	Direct axis synchronous reactance
x_{1d}, x'_d	pu	Direct axis transient reactance
e'_d	pu	Direct axis transient voltage
i_d	pu	Direct current of machine
P_e	MW	Electrical power from the generator
P_e	W	Electrical power output from the generator (air gap power)
$ENTSO-E$		European Network of Transmission System Operators for Electricity
$\boldsymbol{EvtShc}$		Event of short circuit
FCT		Fault Clearing Time
t_2	s	Fault end time
X_f	pu	Fault reactance
R_f	pu	Fault resistance
FRT		Fault Ride Through
t_1	s	Fault starting time
K_e	pu/pu	Field circuit integral deviation
T_e	s	Field circuit time constant (Exciter)
$\bar{v}_f$	pu	Field voltage
v_f^*	pu	Field voltage of machine
T_f	s	Filter Time Constant
D_{turb}	pu	Frictional losses factor
$FIKS$		Functional requirements in the power system (in norwegian Funksjonskrav i kraftsystemet)

V_{elm}	pu	Gate Velocity Limit
E_G	kV	Generator internal voltage
T_r	s	Governor Time Constant
HV	kV	High voltage
$HYGOV$		Hydro turbine-governor
L	pu	Inductance
H	s	Inertia constant
V_{inf}	kV	Infinite bus voltage
v_0	pu	Initial measured voltage
g_{Fe}	pu	Iron losses
$z_{s,hv}$,	pu	Leakage impedance on HV
$z_{s,lv}$	pu	Leakage impedance on LV
LV	kV	Low voltage
$LVRT$		Low Voltage Ride Through
U_{rec1}, U_{rec2}	pu	Lower limit of voltage recovery after the clearance of fault at time t_{rec1} and t_{rec2} respectively
b_{μ}	pu	Magnetizing susceptance
G_{max}	pu	Maximum Gate Limit
T_r	s	Measurement delay
T_m	Nm	Mechanical or shaft torque supplied by prime mover
P_m	W	Mechanical power input to the generator
M	s	Mechanical starting time ($M = 2H$)
G_{min}	pu	Minimum Gate Limiter
T_a	Nm	Net accelerating torque
T_e	Nm	Net electrical torque or electromagnetic torque

$NC\ RfG$		Network code on requirements for grid connection of generators
qnl	pu	No Load Flow
$Z_{r,HV}$	Ω	Nominal impedance, HV side of a transformer
$Z_{r,LV}$	Ω	Nominal impedance, LV side of a transformer
R	pu	Permanent Droop of turbine governor
L_l	H/km	Per-unit length line inductance
R_l	Ω/km	Per-unit length line resistance
$PGMs$		Power Generating Modules
$PSAT$		Power System Analysis Toolbox
PSS/E		Power System Simulation for Engineering
$\gamma X, HV_1$	pu	Proportion of transformer short circuit reactance on HV side
$\gamma R, HV_1$	pu	Proportion of transformer short circuit resistance on HV side
T_{aa}	s	Quadrature axis additional leakage time constant
T_{2q0}, T''_{q0}	s	Quadrature axis open circuit sub-transient time constant
x_{2q}, x''_q	pu	Quadrature axis sub-transient reactance
e''_q	pu	Quadrature axis sub-transient voltage
x_q	pu	Quadrature axis synchronous reactance
e'_q	pu	Quadrature axis transient voltage
i_q	pu	Quadrature current of machine
S_n	MVA	Rated apparent power
U_{rh}	kV	Rated voltage on HV side of a transformer
U_{rh}	kV	Rated voltage on LV side of a transformer
S_n	MVA	Rating power
S_r	MVA	Rating power of a transformer

V_n	kV	Rating voltage
x_T	pu	Reactance of transformer
x_L	pu	Reactance of transmission line
Q_0	MVAr	Reactive power at initial operating condition
αq	-	Reactive power exponent
u_{sc}	%	Relative short circuit voltage of transformer
RfG		Requirement for Generators
r_T	pu	Resistance of transformer
r_L	pu	Resistance of transmission line
U_{ret}	pu	Retained voltage at connection point during a fault
E1	pu	Saturation factor 1
Se1	pu	Saturation factor 2
E2	pu	Saturation factor 3
Se2	pu	Saturation factor 4
T_g	s	Servo Time Constant
z_{sc}	pu	Short circuit impedance of transformer
x_{sc}	pu	Short circuit reactance of transformer
r_{sc}	pu	Short circuit resistance of transformer
C	pu	Shunt capacitance
G	pu	Shunt conductance
$g_{L,h}, g_{L,k}$	Pu	Shunt conductance
$b_{L,h}, b_{L,k}$	pu	Shunt susceptance
T_f	s	Stabilization path time constant
K_f	Pu/pu	Stabilizer gain

ω_s	rad/s	Synchronous pulsation ($\omega_s = 2\pi f_n$)
ω_{sm}	rad/s	Synchronous speed of machine
r	pu	Temporary Droop of turbine governor
Ω_b	rad/s	The base synchronous frequency
t_{clear}	s	The instant time fault has been cleared
U_{clear}	pu	The instant voltage fault has been cleared
δ	rad	The machine rotor angle
ω	rad/s	The machine rotor speed
$\bar{V}$	kV	The ratio of operating voltage to the upper/lower voltage limit
t	s	Time
t_{rec1}	s	Time duration associated with U_{rec1}
t_{rec2}	s	Time duration associated with U_{rec1}
t_{rec3}	s	Time duration associated with U_{rec2}
l_t	km	Total length of transmission line
J	Kgm^2	Total moment of inertia generator and turbine
X_T	pu	Total reactance generator, transformer and transmission line
TSO		Transmission System operator
K_G		Turbine governor gain
PN	MW	Turbine Rated Power
V_0	kV	Voltage at initial operating condition
T_W	s	Water Starting Time

1 Introduction

The introduction will present the project objectives and scope of work along with a description of the overall task followed by short introductions to Statnett (the Norwegian power system operator), ENTSO-E (European Network of Transmission System Operators for Electricity), the simulation tools used in this thesis, and the report structure.

1.1 Objectives

This main objective of the study is to create a simulation model of the power distribution network in OpenIPSL and to compare the results obtained via the OpenIPSL simulation against the results produced via the PowerFactory simulation model exhibited in the work of Ph.D. candidate E.M. Edirisinghe [1] which is explained further under section 1.3 (Task description).

The report will provide an analysis of the Fault Ride Through Capability of a power transmission system. The analysis will focus on how the distribution of the hydropower generators enhance system transient stability. During the simulation of transient stability, the impact of short-circuit events on the power transmission system's transient stability will be discussed.

The focus of the report is on the performance of the transmission system, but on the results that are obtained from the PowerFactory and OpenIPSL. These results will help in determining which simulation model provides the best transient stability for the distributed hydropower generators during a test of their Fault Ride Through capability.

1.2 Scope of the Work

The scope of this thesis covered the following areas:

- Grid Code Requirements;
- First Swing Transient Stability study – the study occurred across a period which was equal to the timeline of the first swing.
- Simulation testing against a three-phase fault;
- Selection of 5 fault events including the location of the faults; and
- Analysis of load flow with respect to transient simulation;

This report does not include any mathematical analysis for stability; focus is on the results of the simulation as opposed to processes and calculations.

1.3 Task Description

The task is based on the publication "Transient Stability of Fault Ride Through Capability of a Transmission System of a Distributed Hydropower System" by J.M. Edirisinghe, T. Oyvang, and G.J. Hegglid. This publication describes the Fault Ride Through capability of the power generators in the 132 kV distribution network presented in the Telemark, Norway region.

The purpose of the task is to recreate the Telemark power system presented in Figure 1.1 in Modelica using the OpenIPSL (Open-Instance Power System Library). The results of the simulation will then be compared against the results from PowerFactory simulation [1].

The work packages of the task will include the following;

- Introduction to the theory of Fault Ride Through (FRT) capability;
- Familiarization with the OpenIPSL library [2];
- Analysis of the power system Model (given as reference in PowerFactory simulation tool);
- Staged implementation of the power system;
- Generation of the simulation results based on the faults highlighted in Figure 1.1; and
- Comparison of the PowerFactory simulation results with OpenIPSL

If time allows, the system will be tuned to satisfy the FRT upper limit of 0.25 s

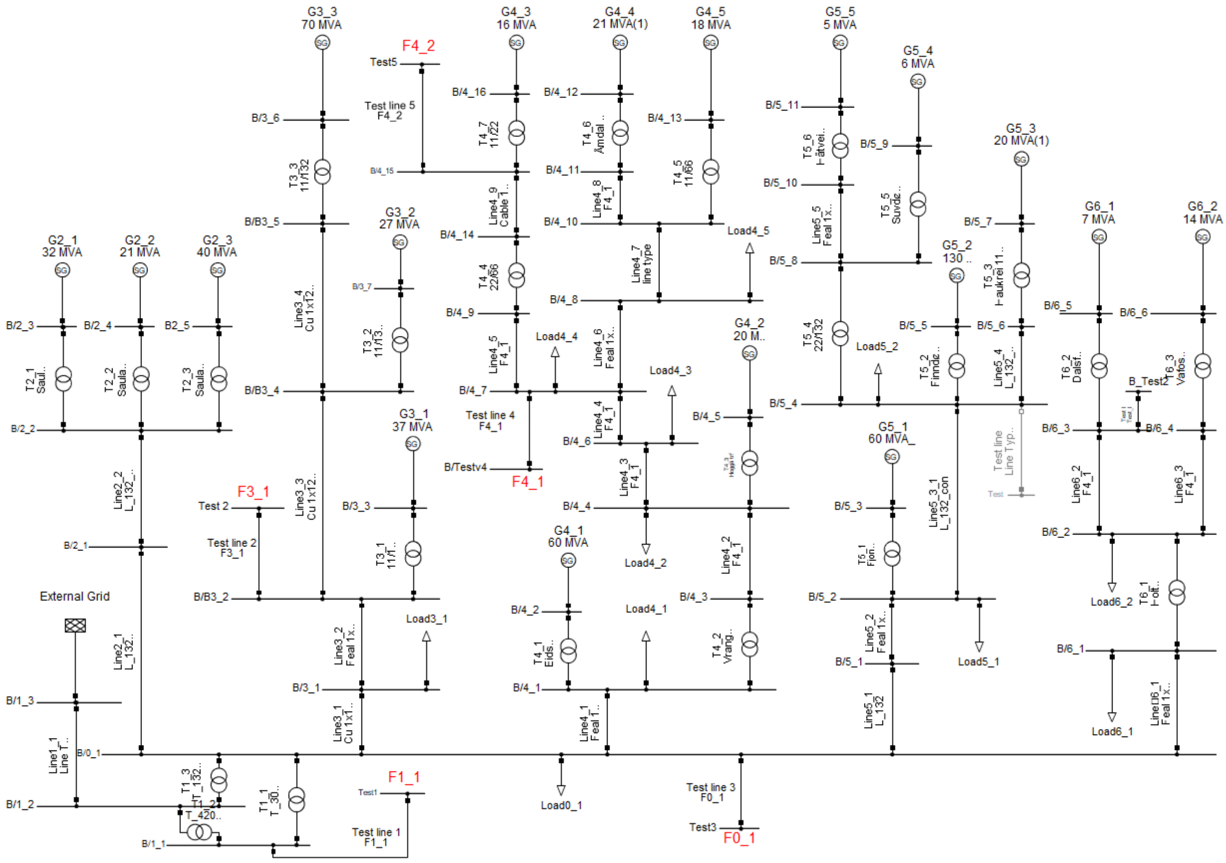


Figure 1.1: Single line diagram of simplified 132 kV Power Distribution System in the Telemark region from PowerFactory [1]

The network in the above figure contains 18 hydropower generators interconnected with each other by 132, 66 and 22 kV transmission lines. Machine sizes range between 1 and 130 MVA and are placed in areas that are far from end users.

1.4 ENTSO-E

The European Network of Transmission System Operators for Electricity (ENTSO-E) was formed in 2009 as part of the liberalization of the electricity and gas markets in the European Union. The ENSTO-E consists of 43 transmission system operators spanning 36 countries across the European Union. The main objective of the ENTSO-E is to provide a platform for seamless cooperation between national transmission system operators in order to implement EU's energy policies and incorporate a higher level of renewable energy integration in to Europe's energy system [3].

ENTSO-E requirements call for members to conduct a cost-benefit analysis for each transmission project to ensure it meets ENTSO-E's environmental and socio-economic criteria. Members are required to report all transmissions activities to the ENTSO-E [3]. Additional information on rules and regulations pertaining to the European and Norwegian power grid including guidance on member requirements are discussed in sections 2.2.1 and 2.2.2 respectively.

1.5 Statnett

Statnett is the operator of the power transmission system for the Norwegian power system. This involves operating about 11,000 km high voltage transmission lines running through 150 stations across Norway. Statnett is also responsible for connections to neighboring countries including Sweden, Finland, Russia, Denmark and the Netherlands [4] and has overall responsibility for developing national guidelines for power generation in Norway.

1.6 Simulation Tools

Two simulation tools (PowerFactory and OpenIPSL) were used to provide simulation for transient stability and Fault Ride Through Capability with the results being compared to each other.

PowerFactory is a tool for electrical power analysis and has been tested by many professional engineers and academic researchers including studies on transient stability conducted by Ph.D. candidates including J.M. Edirisinghe and A.H. Abd [5]. PowerFactory contains a variety of component models that have been classified in compliance with regulatory standards, models and functionality.

OpenIPSL is relatively new and has been utilized less frequently than PowerFactory. OpenIPSL has been tested against PSS/E and PSAT with the results obtained close to the two simulation tools. The OpenIPSL library provides power system components from the PSAT and PSS/E power simulation tools. One of the limitations of OpenIPSL is that it has less available components; but it makes up for that limitation by providing greater flexibility with respect to modifying and rebuilding existing models (such as the PowerFactory model that we are planning to simulate). OpenIPSL can also be used for phasor time domain simulations. However, due to the absence of solvers it cannot be used alone.

1.7 Report Structure

The report structure has been created with the aim of providing the reader with a generic understanding of the concepts presented in the paper followed by an in-depth analysis of the simulations and their results. The following paragraphs will provide the reader a summary of each chapter's content.

Chapter 2 will describe the general theory of Fault Ride Through Capability and the requirements of FRT at the European (ENTSO-E) and national (TSO).

Chapter 3 will describe the theory of Power System Dynamics including its classification. The chapter will also provide insight into Power System Stability including its classification and types of stability such as rotor angle stability and transient stability.

Chapter 4 has been divided into four sections. The first section will describe the simulation tools that were used for the thesis including each tool's advantages and disadvantages along with the methodologies used for the calculations in addition to the parameters that can affect the power distribution network. The second part will introduce the component selection process and the methodologies used to model those components in PowerFactory and OpenIPSL. The third part will present the power system disturbances implemented in this thesis and the final part will introduce the three main steps in transient analysis.

Chapter 5 will present the results of the Pre-fault and post-fault simulations of the network from PowerFactory and OpenIPSL. The parameters used for each simulation will be highlighted with reasoning provided for the selection of said parameters.

Chapter 6 will discuss the results of the simulations from chapter 5.

Chapter 7 will provide the conclusions and recommendations.

2 Fault Ride Through Capability

This chapter will introduce Fault Ride Through Capability (FRT) and highlights the FRT requirements, the ENTSO-E network code requirements, and will outline the new and existing FRT requirements as specified in the functional requirements for the Norwegian Power System (Statnett).

2.1 Introduction

A Fault Ride Through (FRT) capability is the potential of power generators to withstand lower network voltage disturbances and the ability to stay connected for short period of time [6]. A voltage dip in the transmission system can be caused by a short circuit, energizing of the transformers, or a system overload. A disturbance can arise when the power generators are unable to ride through a certain fault along the line. A fault of great severity can cause a major disconnection in power generation and lead to blackouts or system collapse [6].

There are two cases considered when assessing a transmission system's FRT capability, a variation in system load or production, and the actual occurrence of faults and their clearing time. In the first case, variations in the system load or production can cause a stability issue wherein the system has to find a way to compensate for the production shortage. An example of this can be seen in the production of renewable energy wherein the source of production (wind or solar) varies according to wind speed or cloud cover; in such instances, systems need to have the ability of coupling with such production shortages and maintain a stable continuous output [6].

In the second case, a steady increase in power demand brings about new challenges. To increase production, the power transmission system increases its distribution capacity and takes on a higher load. This results in a higher number of faults such as short circuits which affect the output of the system. To mitigate this, the thesis will analyze the case of the three-phase fault and it's clearing time.

Ultimately, a system's FRT capability measures the potential of a power generator to stay connected under abnormal conditions. This potential will depend on the size, design, and control systems of the generator. For the purposes of this thesis, a generator with an integrated Automatic Voltage Regulator (AVR) and a turbine governor will be considered. These control systems will be discussed further in section 4.3.1 - 4.3.4.

2.2 FRT Requirements

The requirements of FRT in a power generation are to keep the generation uninterrupted during a low voltage level condition. Most of the time hydropower generators are located far from the distribution centers; therefore, electricity has to be transported through transmission lines. A grid containing a distribution of hydropower generators is subject to disconnection at low voltage levels; such a disconnection has the potential of causing a chain reaction that can lead to the disruption of other power generators. The overall impact of this disruption may cause the grid voltage to drop to levels low enough to cause a cascading failure of the system [6].

The requirements of FRT are outlined in different standards such as continent, regional, or national. For the purposes of this thesis, the FRT requirements for continental Europe, Nordic and national (Norway) are discussed.

Figure 2.1 explains the voltage-time characteristic for U < 220 kV of time frames in a fault ride through presented by the Statnett reference group meeting no. 5 (RfG) [7]. The numbers 1 - 6 represent the different states where 1 is the pre-fault state and 6 is the postfault state. The blue line represents the lower limit requirement of the phase-phase voltage in pu for the production unit to stay in synchronism [7].

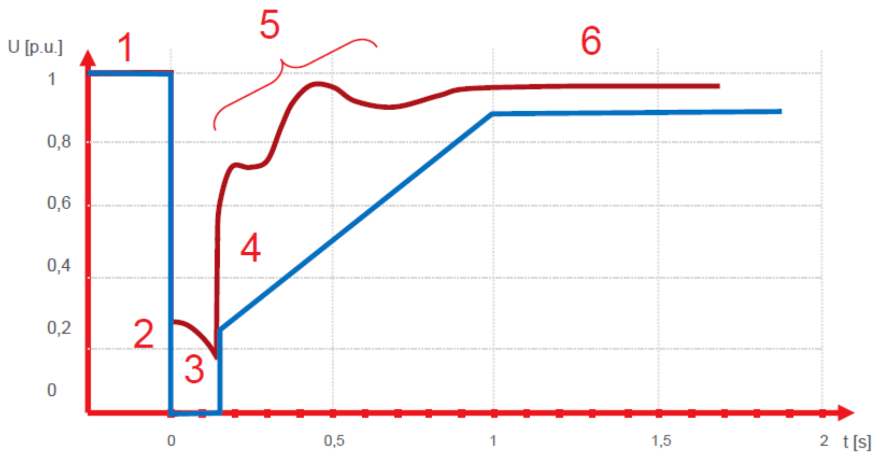


Figure 2.1: Fault Ride Through representation for U > 220 kV with the lower voltage limit (blue) as represented by the reference group meeting at Statnett RfG [7]

Where, 1 represents the normal operation or steady state (t < 0), 2 represents the instant the fault occurs (t = 0), 3 represents the sub-transient loop (t = 0+), 4 represents the fault clearing time (t = 150 ms or t = 400 ms in the case of U < 220 kV), 5 represents the voltage recovery (t = 150 ms+ or 400 ms+) and 6 represents the stationary excitement (t = 150 ms++ or 400 ms++).

2.2.1 ENTSO-E Network Codes

Every year the European Commission proposes some rules and regulations (Network Code) of areas that need further development of network codes for electricity. The main purpose of this Network Code is to increase the compatibility, incorporation and capability of the European electricity market. This is done in partnership with the Agency for the Cooperation of Energy Regulators (ACER) and the ENTSO-E. The proposals for network codes are reviewed further by an Electricity Cross-Border committee of specialists [8].

In the 14 April 2016 publication of the annual network code, the ENTSO-E established a new Network code on the requirement for grid connection of generators (NC RfG); this code came into effect on May 17th, 2016. This Network Code primary applies to new power plants but also applies to existing power plants under some considerations (reference Article 4 ‘Regulatory Aspects’).

> *“Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators”*

Figure 2.2 Describes the FRT profile of PGMs as presented by the ENTSO-E. This is the lower limit of voltage-time requirement at the connection point [3]. Disconnection is allowed if the voltage at the connection point goes below the lower limit profile shown in the figure below.

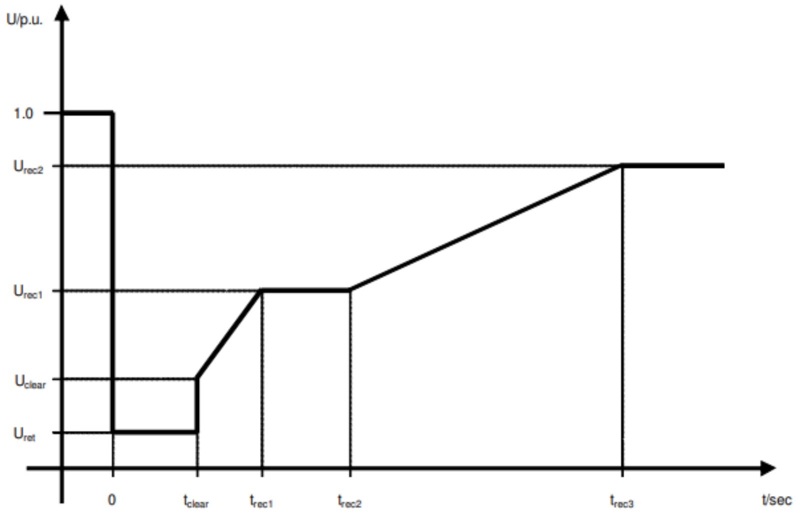


Figure 2.2: FRT requirement of PGMs as presented by the ENTSO-E [3]

Where, U_{ret} is the retained voltage at the connection point during the fault, t_{clear} is the instant when the fault has been cleared, U_{rec1}, U_{rec2}, t_{rec1}, t_{rec2} and t_{rec3} are points of lower limits of voltage after the clearance of the fault.

The NC RfG applies to Power Generating Modules (PGMs), which have a strong effect on the cross-border system performance (Article 5, determination of significance) of the NC RfG. Depending on the type of generator connected to the network (whether the generator is synchronously connected to the grid or not) the requirements of the NC RfG are categorized in to three categories [3]:

- *"Requirements which apply for all Power Generating Modules (PGMs) independent of their connection type"*
- *"Requirements which apply to synchronous Power Generating Modules"*
- *"Requirements for non-synchronously connected Power Generating Modules (Power Park Modules)"*

The requirements which apply to synchronous Power Generating Modules is the case of the area of interest throughout the thesis. The NC RfG categorizes the requirements applicable to PGMs into four generator types, Type A, B, C and D. The categorization is based on the connection point voltage level (HV side of generator transformer) and the maximum capacity of PGMs. The proposals for maximum capacity thresholds for PGMs of type B, C and D for different areas around Europe is given in Table 2.1. The types of generators specified in the NC RfG and their FRT capability requirements are discussed in section 2.2.1.1 - 2.2.1.4 [3].

Table 2.1: Limit for maximum capacity thresholds for types B, C and D PGMs [3]

Synchronous area	Type B [MW]	Type C [MW]	Type D [MW]
Continental Europe	1	50	75
Great Britain	1	50	75
Nordic	**1.5**	**10**	**30**
Ireland and Northern Ireland	0.1	5	10
Baltic	0.5	10	15

2.2.1.1 Type A Generators and Requirements

Type A generating modules are categorized as generators where the connection point is below 110 kV and the maximum capacity is greater than or equal to 0.8 kW. Type A generators are categorized under Power Generating Module. None of the generators from this thesis are type A generators. There are no FRT requirements for Type A Generators [3].

2.2.1.2 Type B Generators and Requirements

Type B generating modules are categorized as generators where the connection point is below 110 kV and the maximum capacity is greater than or equal to the threshold defined by the related TSO but shall not exceed the threshold specified for Type B PGMs (1.5 MW) (see threshold limits for Nordic in Table 2.1. [3]). Please note, none of the generators from this thesis are of Type B generators.

The ENTSO-E upper and lower limits of RfG of fault ride through capability for type B and C synchronous power generating modules is presented in Table 2.2.

Table 2.2: Type B and C FRT capability of synchronous power generating modules [3]

Voltage parameters [pu]		Time parameters [s]	
U_{ret}	0.05 – 0.3	t_{clear}	0.14 – 0.25 (or 0.14 – 0.25 if system protection and secure operation so require)
U_{clear}	0.7 – 0.9	t_{rec1}	t_{clear}
U_{rec1}	U_{clear}	t_{rec2}	t_{rec1} – 0.7
U_{rec2}	0.85 – 0.9 and $\geq U_{clear}$	t_{rec3}	t_{rec2} – 1.5

2.2.1.3 Type C Generators and Requirements

Type C generators are categorized as generators where the connection point is below 110 kV and the maximum operating capacity is greater than or equal to the threshold limit specified by the relevant TSO; the threshold limit cannot be greater than the threshold specified for Type C by the relevant TSO (10 MW) (see threshold limits for Nordic in Table 2.1 [3]).

The requirements of this type are related to stability and highly controllable dynamic response. Type C generators cover a wide range of generators [3]. Type C power generating modules used in this thesis are grouped in Table 2.3.

Table 2.3: Type C generators

Generator	**Sn [MVA]**	**Capacity [MW]**	**Connection point [kV]**
G5_4	6	5	22
G5_5	4	5	22
G6_1	7	6	66

2.2.1.4 Type D Generators and Requirements

According to the NC RfG, type D generators are categorized as generators where the connection point is greater than or equal to 110 kV and maximum capacity is greater than or equal to the threshold limit specified by the relevant TSO (30 MW) [3]. This category contains a sizeable range of generators both in terms of voltage and capacity of generating units. Type D generators have a strong influence on control and operation of the entire system. The generators in this thesis that are under this category are listed in Table 2.4.

Table 2.4: Type D generators (U_n > 110 kV)

Generator	Sn [MVA]	Capacity [MW]	Connection point [kV]
G2_1	32	28	132
G2_2	21	17	132
G2_3	40	34	132
G3_1	37	31	132
G3_2	27	23	132
G3_3	70	63	132
G4_1	60	51	132
G5_1	60	50	132
G5_2	130	117	132
G5_3	20	17	132

Table 2.5: Type D generators (Un < 110 kV)

Generator	Sn [MVA]	Capacity [MW]	Connection point [kV]
G4_2	20	18	66
G4_4	21	18	22
G4_5	18	16	66
G6_2	14	12	66
G4_3	16	15	22

As we can see from the tables above, type D generators have a larger capacity and are linked to generators connected to the central grid. Type D generators are associated to generations with an impact on the control and operation of the whole system.

The ENTSO-E upper and lower limits of RfG of fault ride through capability for type D synchronous power generating modules is presented in Table 2.6.

Table 2.6: Type D FRT capability of synchronous power generating modules [3]

Voltage parameters [pu]		Time parameters [s]	
U_{ret}	0	t_{clear}	0.14 – 0.25 (or 0.14 – 0.25 if system protection and secure operation so require)
U_{clear}	0.25	t_{rec1}	t_{clear} – 0.45
U_{rec1}	0.5 – 0.7	t_{rec2}	t_{rec1} – 0.7
U_{rec2}	0.85 – 0.9	t_{rec3}	t_{rec2} – 1.5

2.2.2 FRT Requirements in FIKS

Functional requirements in the power system (In Norwegian Funksjonskrav i kraftsystemet, FIKS) [9] is a supervisor for the re-establishment and rehabilitation of facilities in the Norwegian power system. This includes both network and production facilities in the regional and central networks. Change in the technical control functions is also part of the functional requirements [9].

The purpose of the FRT requirement is to prevent production facilities from falling out in the event of a normal fault in the network. And further to limit the potential loss of production after more serious disturbances, such as frequency loss in a synchronous area or overload of lines [10]. New requirements for production facilities “Network Code on Requirements for Grid Connection (NC RfG)” applied to all generators and this will affect the FRT requirement available today. However, the existing requirement applies until the new requirement is in place.

In the functional requirements in the power system, chapter 3.2 (Dimensioning/performance in the case of fault) contains the requirements of FRT to the production facilities. This section applies to generators in regional and central networks. The requirements are divided based on two voltage levels: above 220 kV and below 220 kV [9]. Figure 2.3 and Figure 2.4 below are the voltage-time profiles provided in FIKS with respect to the upper limits of FRT capability requirement.

2.2.2.1 Existing FRT Requirements

The lowest voltage limit profile for a production facility that is disconnected after a fault event is presented in Figure 2.3 and Figure 2.4. For at the production facility to stay connected, the voltage must stay on or above the highlighted voltage-time profiles. The discussion of the time frames for fault clearing time, residual voltage under fault and the voltage recovery after fault is discussed under each figure. Further explanation of the figures can be seen in [9]. The summary of the guide to the requirements [10] of fault ride through in FIKS is presented under the Figure 2.3 and Figure 2.4.

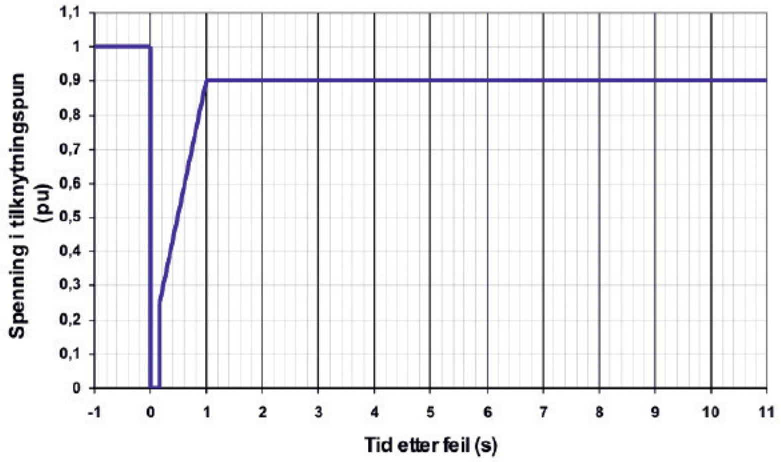


Figure 2.3: Requirements for production facilities connected to network with nominal operating voltage ≥ 220 kV (Figure 3.7-1 in FIKS) [9]

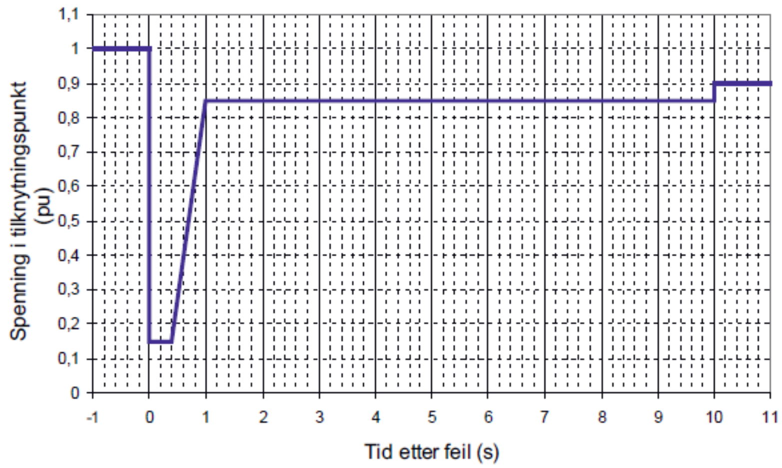


Figure 2.4: Requirements for production facilities connected to networks with nominal operating voltage < 220 (Figure 3.7 – 2 in FIKS) [9]

Fault Clearing Time

The FIKS requirements for operating voltages at or above 220 kV at the connection point call for a normal fault clearing time of short circuit within 100 ms. During a normal fault condition, protective devices are used to clear the fault in the transmission lines with a fault clearing time of 150 ms as specified in FRT requirements for 220 kV or above. This provides a margin of safety to the actual fault clearing time for short-circuits. Similarly, for operating voltages below 220 kV, FIKS sets requirements for normal fault clearing time of short circuits within 400 ms. For transmission lines, short-circuits may be cleared within 700 ms. Therefore, no protected communication is used for transmission lines below 220 kV operating voltage; a time delayed 2nd zone fault clearance is used instead of the protection which is the design requirement for FRT.

Fault Impedance and Residual Voltage

The impedance (distance) of the fault determines the residual voltage at the connection point during the fault. The FRT requirement for residual voltage for both cases mentioned above is as follows.

For operating voltage at or above 220 kV at the connection point, all faults should be cleared successfully without any delays. The design requirement for FRT calls for a residual voltage of 0 % at or near the connection points. Whereas, for operating voltages below 220 kV, a second zone with time delay is incorporated to fulfill the design requirement for the FRT. The impedance to the 2nd zone fault can have a residual voltage of 15 % of rated operating voltage at the connection point.

Voltage Recovery

The main requirement in FIKS regarding the operational voltage is that production facilities should be able to operate continuously at a voltage range of 90 % and 105 % of the normal operating voltage at the connection point. Additionally, FIKS sets requirements with respect to the methodologies that production facilities can use to restore the voltage after fault for both cases mentioned above.

At an operating voltage at or above 220 kV, a quick reconnector is used with a recommended reconnection time of 0.9 s after a single phase to ground fault. The requirement regarding this voltage level is to disconnect production facilities in the event that the operational voltage falls below 90 % of the nominal operating voltage. At an operating voltage below 220 kV, a controlled reconnector is used with a recommended reconnection time delay of 10 s. During this time, the affected system should meet the condition of stability for controlled reconnection as per FRT requirements. Unlike the first case, production facilities can be connected at an operational voltage of 85 % of the nominal value which is used to support the system during the low voltage condition.

2.2.2.2 New FRT Requirements

After the new NC RfG, Statnett published the recommendations regarding FRT for voltage-time profile characteristics based on the power generating module categorization from ENTSO-E. According to the reference meeting RfG number 5 [7], power generating modules of type B and C fall in the same category whereas, power generating modules of type D is further divided in to three categories based on the nominal operating voltage at the connection point and the time used to clear the fault.

For generators to stay connected and deliver power to the system, each generation unit shall as comply with the minimum requirements proposed by Statnett. The recommended values of the FRT requirements with the voltage-time profile is given in the tables Table 2.7 - Table 2.9. The plot is presented together with the FRT capability requirement for synchronous machines from ENTSO-E (Figure 2.5 - Figure 2.7).

Table 2.7: Statnett recommendations for type B, C and D (Un < 110 kV) [7]

Voltage parameters [pu]		**Time parameters [s]**	
U_{ret}	0.3	t_{clear}	0.15
U_{clear}	0.3	t_{rec1}	0.15
U_{rec1}	0.7	t_{rec2}	0.15
U_{rec2}	0.9	t_{rec3}	1

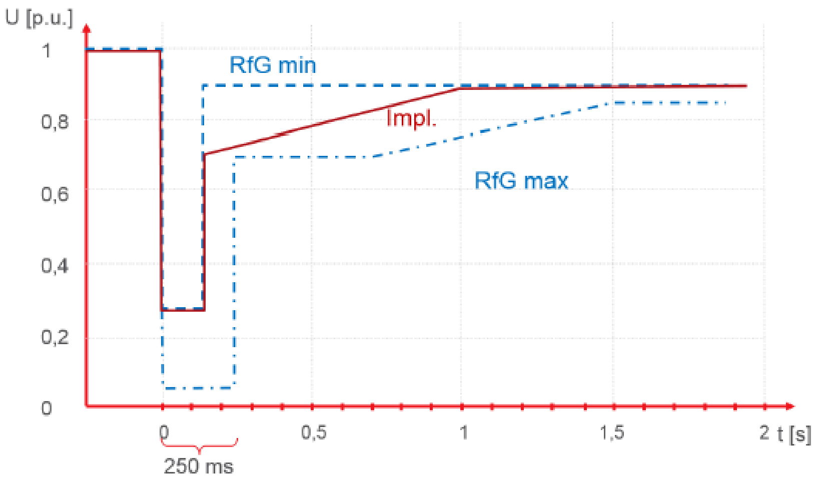


Figure 2.5: FRT requirements for PGMs of type B, C and D, Un < 110 kV [7]

Figure 2.5 represents the voltage-time profile as per FRT capability requirements of the NC RfG vs the recommendations from Statnett. The blue striped lines represent the maximum and minimum limits of the RfG for type B and C PGMs as discussed in Section 2.2.1, Table 2.2 while the red line represents the recommended values from Statnett (Table 2.7) for PGMs of type B, C and D, Un < 110 kV.

Table 2.8: Statnett recommendations for type D, Un > 110 kV (instantaneous disconnection) [7]

Voltage parameters [pu]		**Time parameters [s]**	
U_{ret}	0	t_{clear}	0.15
U_{clear}	0.25	t_{rec1}	(0.36267)
U_{rec1}	0.5	t_{rec2}	(0.36267)
U_{rec2}	0.9	t_{rec3}	1

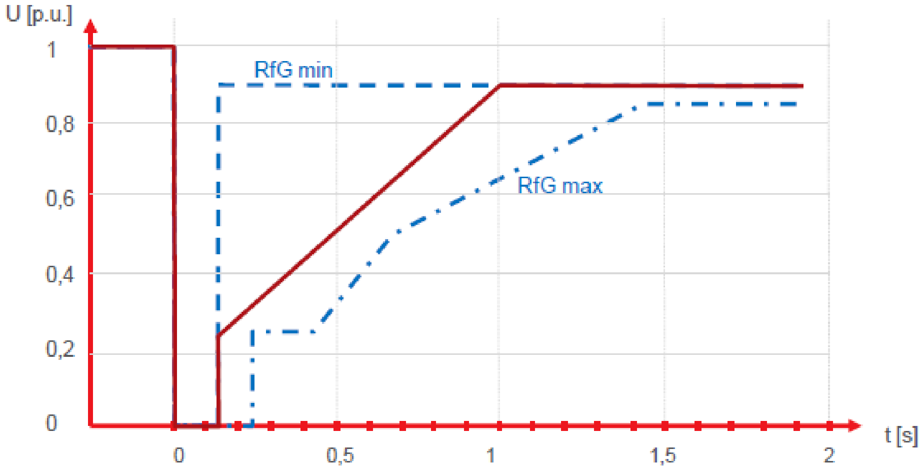


Figure 2.6: Voltage-time profile plot of FRT requirements for PGMs of type D, Un > 110 kV (instantaneous disconnection) [7]

Figure 2.6 represents the voltage-time profile as per FRT capability requirements of the NC RfG vs the recommendations from Statnett. The blue striped lines represent the maximum and minimum limits of the RfG for type D PGMs (Table 2.6) while the red line represents the recommended values from Statnett (Table 2.7) for PGMs of type D, Un < 110 kV with instantaneous disconnection.

Table 2.9: Type D, Un > 110 kV (delayed disconnection) [7]

Voltage parameters [pu]		**Time parameters [s]**	
U_{ret}	0.15	t_{clear}	0.4
U_{clear}	U_{ret}	t_{rec1}	t_{clear}
U_{rec1}	U_{clear}	t_{rec2}	t_{clear}
U_{rec2}	0.9	t_{rec3}	1

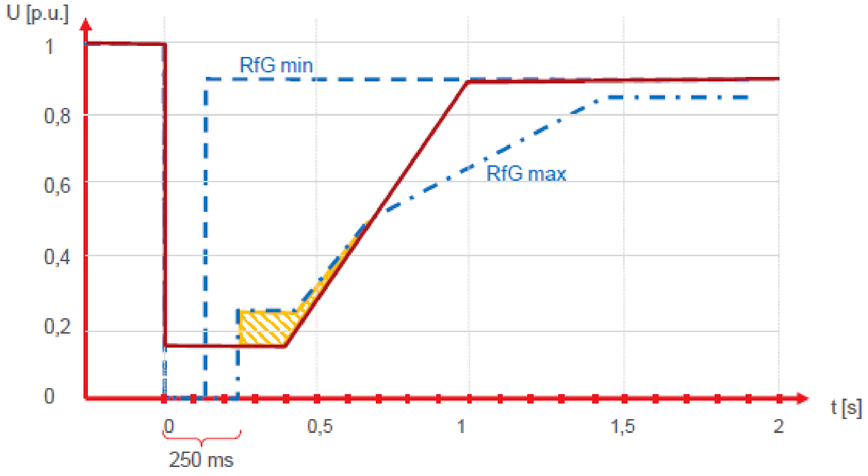


Figure 2.7: Voltage-time profile of FRT requirements for PGMs of type D, Un > 110 kV (delayed disconnection) [7]

Figure 2.7 represents the voltage-time profile as per FRT capability requirements of the NC RfG vs the recommendations from Statnett. The blue striped lines represent the maximum and minimum limits of the RfG for type D PGMs (Table 2.6) while the red line represents the recommended values from Statnett (Table 2.9) for PGMs of type D, Un < 110 kV with delayed disconnection.

3 Power System Stability and Control

This chapter will present an introduction to power system dynamics and its classifications based on their time frames. The chapter will also discuss power system stability and its classifications (including a detailed analysis of the swing equation) in addition to a section on rotor angle stability in which transient stability for the 132-kV simplified Telemark regional network will be discussed (Figure 1.1).

3.1 Introduction

Power System Dynamics

A power system is quite dynamic in nature; it consists of machines that rotate synchronously using their rotating mass. In the event of a disturbance, the power system modified its dynamics by changing its operational point; the nature of the change in dynamics depend on the type and severity of the disturbance.

If the disturbance is major, the system becomes unstable; but if the disturbance is minor to medium, the system has the ability to regain its original state or switch to a new mode of operation. The change in dynamics will be studied in section 3.2 and will be based on a balanced three-phase short circuit occurring on a transmission line near the generator busbars.

Classification of Power System Dynamics

An electrical power system contains electrical components interconnected to form a complex system [11]. From a classification standpoint, transients in electrical power systems are categorized into three-time frames; short-term, mid-term and long-term. Another classification criteria are the physical character of the power system and consists of four categories; wave, electromagnetic, electromechanical and thermodynamic. The character of the power systems based on their time-frames are shown below in Figure 3.1 [11].

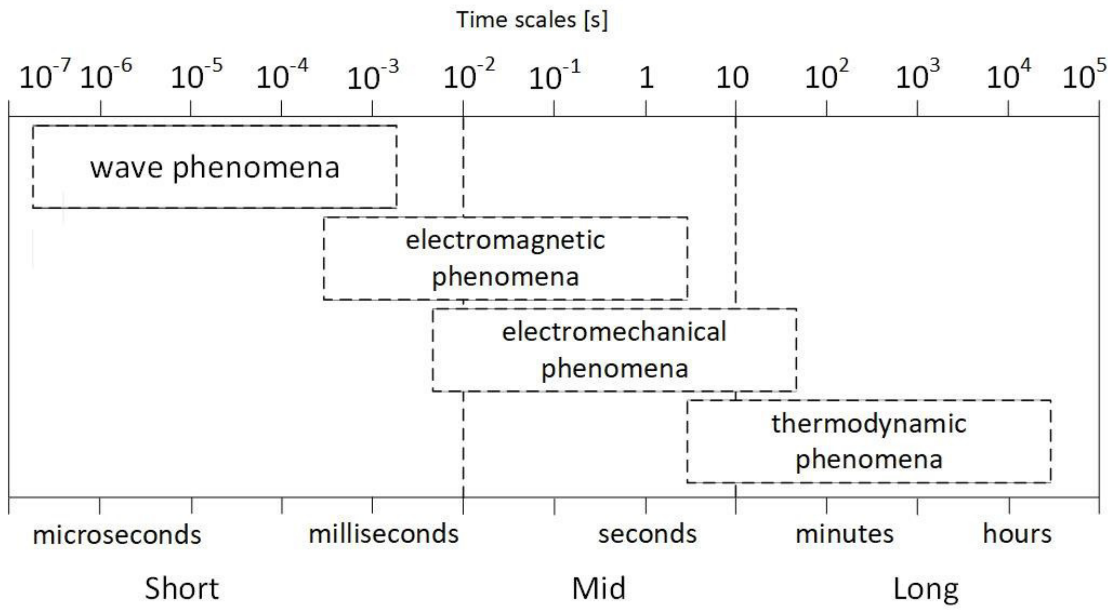


Figure 3.1: Classification of power system dynamics based on physical characteristics [11].

Based on Figure 3.1 short term stability is associated with electromagnetic transients (microseconds) while mid-term stability is associated with electromechanical transients (between 10 s and 100 ms) whereas long-term stability is associated with thermodynamic transients (hours to days). In this thesis, short-term and mid-term, electromechanical transients are the main interest.

3.2 Power System Stability

Power system stability is defined as the ability of a power system to remain in a state of operating equilibrium under normal operating conditions and the ability to regain an acceptable state of operation after being subjected to a planned or non-planned disturbance [12]. The disturbances can vary in size and duration; small disturbances can be in the form of normal variation in load or generation while large disturbances can occur due to faults in the system components or the tripping of transmission lines and in some cases the sudden disconnection of large loads.

The ability of the power system to regain its stability depends on a variety of factors the severity of fault, the machine parameters (mainly the inertia constant), the type of control mechanisms installed in the generation and the type of components present in the system. The Automatic Voltage Regulator and the Turbine Governor are the main components in the system; however, there are cases where a power system stabilizer is added. More models are presented in section 4.3.3 - 4.3.4.

3.2.1 Classification of Stability

As discussed in the previous subchapter, instability of power systems can differ in type, form, size, duration and can be influenced by many factors. Classifying stability is not an easy task therefore [12] have chosen to classify the problem of stability based on the physical nature of instability, the type of devices, the time it takes to regain its stability, the size of the disturbance and the method of calculation. Figure 3.2 shows the three most common groups with their subgroups used to classify stability. As we see from the figure, small disturbance angle stability and transient stability are defined as short-term, while large disturbance voltage stability and small disturbance voltage stability are defined as a short and long-term. In this thesis, the phenomena of rotor angle stability are used in the study of short-term transient stability (electromechanical).

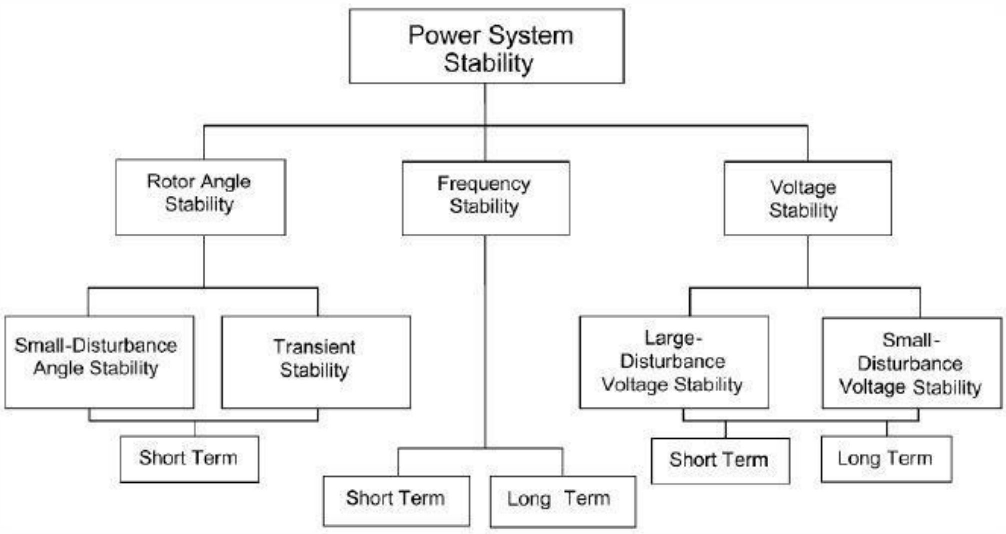


Figure 3.2: Classification of stability [12]

3.2.2 Rotor (Power) Angle Stability

A power system is designed to operate in such a way that it can tolerate certain probable events. Rotor angle stability is defined as the ability of a machine to remain in synchronism when subjected to disturbances [12]. During a disturbance, the rotor speed of one or more synchronous machines connected in the network will vary from the initial values (steady state); as a result, the mechanical power input, as well as the electrical power output, will vary. The variation in mechanical and electrical powers (torque) will result in rotor angle (power angle) difference between the machines. When this happens, the machines are said to be out of synchronism. On the flip side, if the rotor angle variations of machines connected to the network achieve the pre-disturbance state or a new stable position after some time, then the machines are said to be in synchronism [13].

Based on Figure 3.2, rotor angle stability can be classified into two types: small signal stability and transient stability. Small signal stability is the ability of a power system to remain in synchronism after being subjected to small disturbances which occur due to normal variations in load or generation. Transient stability is the ability of a power system to remain in synchronism after being subjected to large disturbances. As the focus of this thesis is to discuss fault ride through capability of generators, transient stability is the type of rotor angle stability that will be discussed.

The synchronous generator is the main power generating component in a power system. To gain un understanding of stability, one requires an understanding of the dynamics of the rotor. A synchronous machine rotor contains two torques which act in opposite directions, the mechanical and electrical torques. The mechanical torque is provided by the prime mover (turbine) and the electrical torque (electromagnetic torque) is developed by the interaction between the magnetic field and rotor currents [12].

Under the normal operating conditions, both electrical and mechanical torques are equal. This means that the rotor of synchronous machine rotates at synchronous speed. However, when a disturbance occurs, the torques differ from each other; this difference is called acceleration torque. The mathematical expression which describes the relative motion of the rotor load angle (δ) with reference to the stator field as a function of time is called the swing equation. The expression of the swing equation as given in [13] is provided by:

The differential form of the swing equation is expressed as follows:

$$J\frac{d^2\theta_m}{dt^2} = T_a = T_m - T_e \tag{3.1}$$

Where, J is the total moment of inertia in Kgm^2, θ_m is the angular displacement of rotor with respect to a stationary axis in mechanical radians and T_a, T_m and T_e are respectively the accelerating, mechanical and electrical torques.

Representing the rotor angular position with respect to synchronously rotating frames gives:

$$\theta_m = \omega_{sm}t + \delta_m \tag{3.2}$$

Where, ω_{sm} is synchronous speed of the machine in mechanical radians/sec and δ_m is the angular position in radians with respect to the synchronously rotating reference frame.

The derivatives of Equation (3.2) with respect to time gives as specified in Equation (3.3), meaning the rotor speed is equal to synchronous speed and some additional torque is added.

$$\frac{d\theta_m}{dt} = \omega_{sm} + \frac{d\delta_m}{dt} \tag{3.3}$$

and taking the second derivative will results in:

$$\frac{d^2\theta_m}{dt^2} = \frac{d^2\delta_m}{dt^2} \tag{3.4}$$

Substituting equation (3.4) which is the rotor acceleration in to the differential equation of the swing equation, Equation (3.1) will give:

$$J\frac{d^2\delta_m}{dt^2} = T_a = T_m - T_e \tag{3.5}$$

In the above-mentioned equations all the terms are torque terms in Nm, but as the interest is in power we introduce the angular velocity term:

$$\omega_m = \frac{d\theta_m}{dt} \tag{3.6}$$

To get the values of torque converted to power multiplying both sides of equation (3.5) by ω_m gives:

$$J\omega_m\frac{d^2\delta_m}{dt^2} = T_m\omega_m = T_m\omega_m - T_e\omega_m \tag{3.7}$$

Equation (3.7) can be written in power form by substituting the terms $T_m\omega_m$, $T_e\omega_m$ and $T_a\omega_m$ with P_m, P_e and P_a.

$$J\omega_m\frac{d^2\delta_m}{dt^2} = P_m - P_e = P_a \tag{3.8}$$

Where the coefficient $J\omega_m$ is the angular momentum of the rotor at synchronous speed, it is denoted **M** and called the inertia constant of the machine. Parameters P_m, P_e and P_a are the mechanical, electrical and accelerating power in MW respectively.

During normal operation, the difference between the angular velocity and the synchronous speed are very small. Further by assuming that the angular and synchronous speed is equal equation (3.8) can be simplified to:

$$\omega_m = \omega_{sm} \tag{3.9}$$

$$M\frac{d^2\delta_m}{dt^2} = P_m - P_e \tag{3.10}$$

M can vary in a wide range depending on the machine size and type. In some cases, the inertia constant is denoted by H and the expression is as follows:

$$H = \frac{stored\ K.E\ in\ megajoule\ at\ synchronous\ speed}{machine\ rating\ in\ MVA}$$

The stored K.E is can be calculated by:

$$K.E = \frac{\frac{1}{2}J\omega_{sm}^2}{S_n} = \frac{\frac{1}{2}M\omega_m}{S_n} \tag{3.11}$$

Where, S_n is the three-phase rating of the machine in MVA.

The relation between the inertia constants M and H can be expresses as:

$$M = \left(\frac{2H}{\omega_m}\right)S_n \tag{3.12}$$

Finally substituting M to Equation (3.10) will give the swing equation expression in pu (assuming machine MVA as a base).

For systems of electrical frequency, the swing equation can further be written as:

$$\frac{H}{\pi f}\frac{d^2\delta}{dt^2} = P_m - P_e \tag{3.13}$$

Where, δ is in electrical radians

Or Equation (3.13) can be written as seen in Equation (3.14) if δ is expressed in electrical degrees instead of electrical radians.

$$\frac{H}{180}\frac{d^2\delta}{dt^2} = P_m - P_e \tag{3.14}$$

The inertia time constant plays a vital role in the stability of a power system. The inertia time constant (H) for the synchronous machine is the total inertia constant of the system (the inertia constant of generator rotor and turbine). The inertia constant explains the time the machine takes to accelerate from rest to a synchronous speed or decelerate from a synchronous speed to a complete stop state if rated power is taken out from it and no mechanical power is supplied into it [12].

3.2.3 Transient Stability

Transient stability is the ability of a power system to maintain synchronous output when subjected to severe disturbances. Major disturbances come about in the form of transmission system faults, large loads changes, impact on power generation or power line switching [12].

The greatest test of a system's transient stability comes in the form of a three-phase short-circuit; during such a disturbance, the system loses its ability to maintain synchronous output which leads to system lapses such as large rotor angle fluctuations, bus voltage violations, and large changes in power flow. In summary, the system becomes transiently unstable [14].

When referring to faults associated transient stability, it is assumed that most issues occur on the transmission lines; however, there may be instances where faults occur on the buses or transformers. The methodology for clearing these faults may involve opening circuit breakers or using high speed reclosers [12]. In most cases, transient stability is managed during the planning phase of the generation and transmission system and a thorough risk assessment [12].

The area of study presented in Figure 1.1 consists of 18 synchronously interconnected hydropower generators operating near the maximum capacity to supply a total load of 569 MW and 118 MVAr connected through a 132, 66 and 22 kV transmission lines.

The three-phase fault is a fundamental disturbance used for simulation purposes in operational and planning studies. In this study, a balanced three-phase fault occur on 300, 132, 66 and 22 kV transmission lines near to busbar as shown in Figure 1.1

At normal operating condition, all the generators are operating at a synchronous speed and frequency of 50 Hz; this can be defined as the balance point between the mechanical power input to the generator and the electrical power output from the generator. This can be expressed as:

$$\frac{d^2\delta}{dt^2} = 0 \rightarrow P_m = P_e$$

$$\frac{d\delta}{dt} = 0 \rightarrow \ \omega = \ \omega_{sm}$$

Rotor angle response to a transient disturbance depends on the size of the disturbance, the three possible scenarios are illustrated below in Figure 3.3. A power system can be considered as a first swing stable if the rotor angles of the machines in the system managed a successive first swing in a finite time (usually in ms) after a disturbance (case 1). If the rotor angles continues to increase until the machines lose synchronism, then this can be classified as first swing stability problem (case 2) [12]. The second case is when the system managed a successive first swing stability but due to the lack of sufficient torque the system becomes unstable because of growing oscillations in the system (case 3). These two cases are studied for the study system presented in Figure 1.1.

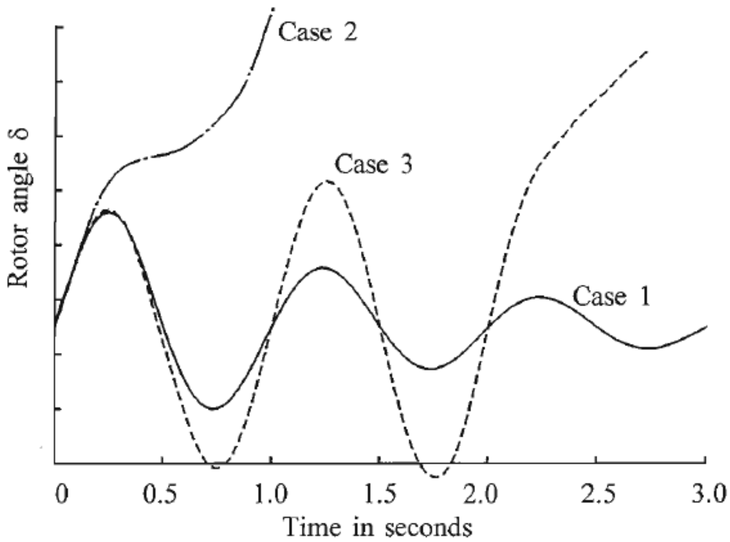


Figure 3.3: Rotor angle response to a transient disturbance [12]

The transient stability analysis will involve the investigation of the response of generators to a defined fault from different areas and the identification of critical clearing time of the generators to a three-phase fault implemented on different nodes. And the effect of AVRs on transient stability.

Representing the entire multi-machine system in detail is quite challenging hence, some important simplification is necessary. The method used in this study is to divide the system in to study systems.

Whenever a disturbance occurs in any one area of the system, the system close to the disturbance is severely affected, and this area is studied under the study system. The system far away from the disturbance is less affected and this is studied under an external system.

Therefore, the system close to the location of the disturbance can be represented in detail and the system far away from the disturbance can be represented by equivalent.

The post-disturbance operation point of the power system can be the same as the pre-disturbance (steady state) operating and can differ depending on the severity of the disturbance. For small disturbances, the new operating point will be the same as the pre-disturbance operating point while for large and severe disturbances the operating point will be different from the pre-disturbance operating. In this thesis the same contingencies are used in all cases, therefore, the severity depends mainly on the fault clearing time of the system. The longer the clearing time, the greater the impact of the fault.

During a transient disturbance, the power transfer in the system is disturbed. Therefore, understanding the system stability limit is very important. The maximum power transfer limit to the system without the system losing stability is known as transient stability limit.

The electric power transferred from a laminated salient pole generator considering a single-machine infinite bus is described using Equation (3.16) [11]. For a salient pole machine $x'_q = x_q$ and $\delta' = \delta$.

$$P_e = \frac{E_G V_{inf}}{X_T} \cdot \sin \delta - \frac{V_s^2}{2} \cdot \frac{x_q - x'_d}{x_q x'_d} \sin 2\delta' \tag{3.15}$$

Equation (3.15) can be further simplified to Equation (3.16) by ignoring the transient saliency, that is assuming $x'_d = x'_q$. This is known us the classical model.

$$P_e = \frac{E_G V_{inf}}{X_T} \cdot \sin \delta \tag{3.16}$$

Where, P_e is the electrical power from output from the generator, E_G is generator internal voltage, V_{inf} is infinite bus voltage, X_T is the total internal reactance of the synchronous machine, transformer and transmission line and δ is the difference in angle between the sending and receiving end voltages in degrees.

The Effect of Automatic Voltage Regulator (AVR) in Transient Stability

The main function of an AVR is to reduce the damping of the rotor swings at the time of the disturbance. When a fault occurs on the generator terminal, the terminal voltage drops dramatically and results in a major voltage error. Large voltage errors (Δv) will force the AVR to increase the field current until the voltage reaches the desired value (v^{ref}) [11]. The type of AVR and the parameters used in this thesis are provided in Section 4.3.3.

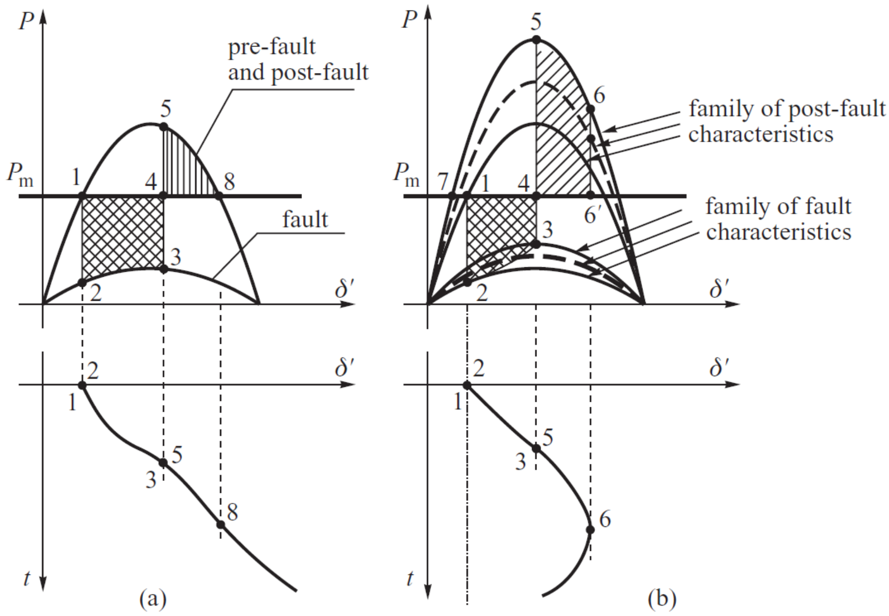


Figure 3.4: Acceleration area and the deceleration when the influence of the voltage regulator is (a) neglected; (b) included [11]

Figure 3.4 presents the operation of a generator with and without an automatic voltage regulator. The generator without an automatic voltage regulator (Figure 3.4 (a)) is seen to go out of step in the first swing. Whereas the generator with an automatic voltage regulator is seen to stay in synchronism. The effect of an automatic voltage regulator will be father discussed in Section (4.3.3).

4 Model Set-Up

This chapter will present the simulation tools that were used in the thesis including dynamic component modeling of the power components in PowerFactory and OpenIPSL. The chapter will also exhibit network component modeling, electrical fault modeling, and transient step-simulation. System components are modeled based on some simplifications and hence an in-depth study is required for comprehensive understanding.

4.1 Simulation tools

4.1.1 PowerFactory

PowerFactory is a computer-supported program owned by DIgSILENT (Digital Simulation and Electrical Network calculation program). It is widely used tool for the analysis of electrical networks for industrial, educational as well as commercial sectors. PowerFactory is used in system planning and operational study of a power system [15].

PowerFactory is designed to handle large and complex networks of both DC and AC models. Some of the calculation commands provided in PowerFactory are load flow analysis, short circuit analysis, stability and EMT simulations, contingency analysis, etc. [16]

The simulation language used in PowerFactory is called DIgSILENT Simulation Language (DSL). Powerfactory DIgSILENT library is a large library grouped into the following groups: Dynamic Models, Equipment Types, Harmonics, Operational Data, Protection devices, Quasi-Dynamic Models, Scripts and Templates. The Dynamic Models provide models of different standards categorized in the following categories; DIgSILENT, ENTSO-E, Macros, PSS/E etc. These dynamic models have a wide range of components for excitation systems. [16]

Standard models in PowerFactory include AVRs, Turbine Governors, PSS, Excitation, Limiters, and Static Compensators. ENTSO-E Dynamic Models include Excitation Models, Governor Models, Power System Stabilizers, and Voltage Compensators.

The Newton-Raphson is an inbuilt solver in PowerFactory. The Newton-Raphson method is used to analyze the networks being simulated in PowerFactory; this method can be utilized for both current equations and classical power equations. For large and complex networks, the power equation recommended, and this is applied in this thesis.

4.1.2 OpenIPSL

OpenIPSL (Open-Instance Power System Library) is an open source library developed by Professor Luigi Vanfretti and his coworkers at the SmarTS Lab (now ALSETLab) research group. It is primarily used for phase domain simulations but cannot be used as a standalone program due to the absence of an associated power flow solver [17]. The load flow calculations can be performed with assistance from other user selected software; for the purpose of this thesis, PowerFactory was used to calculate the power flow.

The OpenIPSL library is a Modelica package used with one of the available Modelica Simulation Environments. In this thesis a licensed Modelica Simulation Environment, Dymola is used. Dymola (Dynamic Modeling Laboratory) is a tool for modelling and simulation of integrated and complex systems used in different applications [18].

The OpenIPSL library provides components from PSAT and PSS\E and components from Simulink and CGMES. Any combination of these tools can be used without any issues. The flexibility to combine components from different tools provides an exciting opportunity for users to model and simulate larger and complex systems and brings a step closer to reality.

The OpenIPSL library has five main divisions (packages): example, electrical, non-electrical, interfaces and types. A short description of the divisions is provided below:

Example: This package contains models of components from the library with instructions on implementation with other components. The models are based on technical literature and are fully parametrized. The models are usable and can be used with minor modifications.

Electrical: This package contains models of components of a power system. They are categorized by types and producer (such as PSAT, Simulink, PSS/E and CGMES). Some of the packages within this module include machines, controls, loads, branches, banks, etc. which are used in the main part of the OpenIPSL library for this thesis.

Non-electrical: This package contains supplementary components to the electrical component package. The packages include Logical, Continuous, Nonlinear and Functions.

Interfaces: This package contains the base models of the pins and generators. These models contain the necessary parameter definitions and equations that can be used as a base model while building larger models. The generators in this thesis are modelled based on these generator base models.

Types: This package contains the parameter definition of Active power in MW, Apparent power in MVA, Reactive power in MVAr and Voltage in kV.

4.2 External Parameter Corrections

External parameter corrections were incorporated into the calculations and schematics mentioned in the above sections. Some changes were made as a result of input from the external partner Professor G.J. Hegglid while other modifications were incorporated for simplification. The parameter and physical corrections are presented in the single line diagram on Figure 1.1. All the parameters for the generators and transformers were changed with new parameters incorporated Appendix B. The Automatic Voltage Regulator (AVR) parameters were updated to reflect the Norwegian Power System Functional requirements in (FIKS). All parameters including their models are provided in Appendix C.

Prior to the external partner corrections, damping coefficients had been calculated based on the oscillations of each individual generator; but for the purposes of the thesis, the damping coefficients were not considered at all. This was due to the fact that the previously calculated values for the generator parameters, the transformers, the loads in the network, and the nature of the oscillations were found to be invalid.

In addition to the external parameter corrections, physical changes were made to the single line diagram Figure 1.1. All the changes have been documented in Appendix D. A slight modification was made to the G2_2 and G2_3 common generator busbars.

For generators connecting the same busbar with different power ratings and mechanical starting time the AVR should be modeled to regulate the common bus voltage via a load compensator.

The issue is circumvented by providing each generator with its own busbar. All the changes have been documented in Appendix D.

4.3 Network Component Modeling

This chapter contains the components for the network shown in Figure 1.1. The main components have been modelled using the parameters used in [1] with modifications on the parameters. The components were modeled based on some simplifications with the aim of producing a transient stability analysis of distributed hydropower generators.

The simplifications had little effect on the results and were made regarding component selection and their parameters as follows:

- Generators were modelled independent of their sizes.
- Automatic voltage regulator (AVR) and turbine governors available in the system are assumed to be the same type and size.
- Turbine governor are implemented only in the PowerFactory model and default parameters are used.
- Only two-winding transformers are used.
- Generators connected to the same busbars were separated to design an independent control system for each machine.

4.3.1 Excitation System

The primary function of an excitation system is as follows: provide direct current to the synchronous machine field winding; controlling the machine terminal voltage; and protecting power system components from exceeding their capability limit. The main requirement of an excitation system is to act as a constant voltage terminal for the synchronous machine field to provide a shield against variations in the field current and to respond to short-term transient disturbance[12].

The main components of an excitation system are as follows: an exciter, regulator (automatic voltage regulator, AVR), terminal voltage transducer, load compensator, generator and power system stabilizer. The function of the controller and the working principle is discussed in section 4.3.3. The block diagram of excitation control system is shown in Figure 4.1

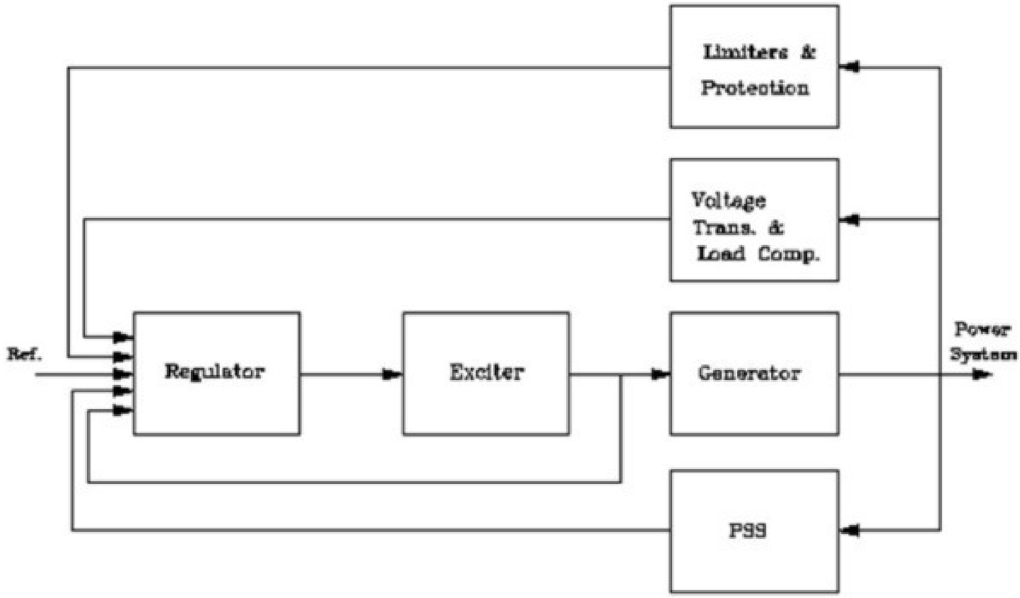


Figure 4.1: Functional block diagram of a synchronous generator excitation system [12]

4.3.2 Generators

Generators are the primary unit for producing power in transmission system. Generators differ in size, type and methods used to generate electricity. Hydropower generators and their control systems are the focus of this thesis due to the fact that the focus is to study transient stability of distributed hydropower generators. The generators available in this study are slow speed (salient pole) hydropower generators.

As highlighted in many references, reactance values of hydropower generators differ according to the type and size of the generator. In this report, the reactance values are recommended by an external partner from Skagerak Kraft, Professor G. J. Hegglid. The input parameters available for the synchronous machines are the short circuit data. The recommended values for the sub-transient, transient and synchronous reactance's are provided in Table 4.1. The remaining generators input data is provided in Appendix B. Further requirements for the generator design is based on the functional requirements in the power system (FIKS). For further generator modeling in PowerFactory and OpenIPSL see Section 4.3.2.1 and 4.3.2.2.

Table 4.1: Generator reactance parameters in pu

Reactance	Range for hydropower generators [pu]	Recommended reactance value [pu]	
		d-axis	q-axis
Sub-transient	0.15 - 0.25	0.22	0.22
Transient	0.2 – 0.3	0.25	0
Synchronous	1.0 – 1.5	1.1	0.682

Table 4.1 provides the normal range for sub-transient, transient as well as synchronous reactance and the recommended values of the direct and quadrature axis. The quadrature axis sub-transient reactance is equal to the direct axis whereas the quadrature axis synchronous reactance is assumed to be 62 % of the direct axis synchronous reactance.

During the RMS simulation the speed deviation of the generators were calculated based on the nominal speed of the generator with no damping coefficients added to either the Turbine shaft friction, damping torque or damping torque coefficient based on power.

4.3.2.1 Generator Modeling in PowerFactory

PowerFactory contains four different types of synchronous machines, the standard model 2.1 and 2.2 (salient and round pole machines respectively), Model 3.3 (detailed generator model), classical (simplified model) and Asynchronous starting model (considering eddy-current effects). In this thesis, the salient pole machine of standard model 2.1 (field and one damper winding in the d-axis and one damper winding in the q-axis) is used [19]. A local controller as constant voltage (PV mode) is used to control the bus voltage where the generator is connected.

Beside the short circuit reactance in Table 4.1, short circuit time constants are used by the PowerFactory model. In the standard model 2.1, the transient reactance x_q' and the time constant t_q' in the q-axis are ignored. The equivalent circuit diagram for the standard model 2.1 (salient pole), represented in dq reference frame is presented in Figure 4.2 and Figure 4.3.

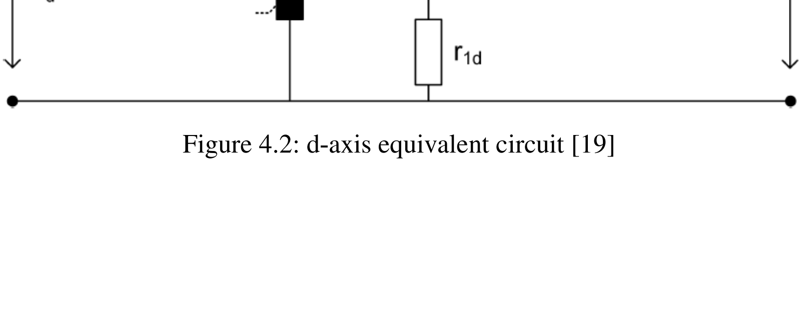


Figure 4.2: d-axis equivalent circuit [19]

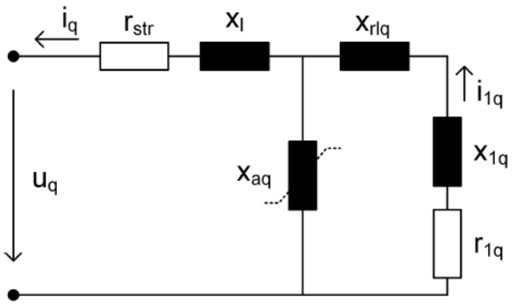


Figure 4.3: q-axis equivalent circuit - salient rotor [19]

The detailed mathematical modeling of standard model 2.1 is given in the DIgSILENT PowerFactory user manual [19].

4.3.2.2 Generator Modeling in OpenIPSL

OpenIPSL provides generator models from both PSS/E and PSAT. In this thesis generators from PSAT are used. OpenIPSL contains different types of machines with different order numbers and types. Order numbers vary from the simplest swing equation (second order) to the model with field saturation (eighth order). Order number to the model explains the type of simplification made to the model.

In this thesis a type 2 of fifth order (Order V-Type 2) model is used. This model is selected to match the salient pole hydropower generator used in PowerFactory (standard model 2.1). This model has 5 state variables ($\delta, \omega, e'_q, e''_q$, and e''_d) and 5 differential equations. The mathematical modeling of this is as follows [20]:

$$\dot{\delta} = \Omega_b(\omega - 1) \tag{4.1}$$

$$\dot{\omega} = (p_m - p_e - D(\omega - 1))/M \tag{4.2}$$

$$\dot{e}'_q = (-f_s(e'_q) - \left(x_d - x'_d - \frac{T''_{d0}}{T'_{d0}}\frac{x''_d}{x'_d}(x_d - x'_d)\right)i_d + \left(1 - \frac{T_{AA}}{T'_{d0}}\right)v_f^*)/T'_{d0} \tag{4.3}$$

$$\dot{e}''_q = (-e''_q + e'_q - \left(x'_d - x''_d + \frac{T''_{d0}}{T'_{d0}}\frac{x''_d}{x'_d}(x_d - x'_d)\right)i_d + \frac{T_{AA}}{T'_{d0}}v_f^*)/T''_{d0} \tag{4.4}$$

$$\dot{e}''_d = \left(-e''_d + (x_q - x''_q)i_q\right)/T''_{q0} \tag{4.5}$$

Where, δ is the machine rotor angle, Ω_b is the base synchronous frequency $[rad/s]$, ω is the machine rotor speed, p_m and p_e are the mechanical power input as well as the electrical power output of the generator respectively, M is the mechanical starting time ($M = 2 \cdot H$), i_q and i_d are the quadrature and direct axis currents respectively, e'_d, e''_d, e'_q, e''_q are the transient and sub-transient voltages in the direct axis and quadrature axis respectively and v_f^* is the field voltage.

The algebraic equations for voltage and current can link as follows:

$$0 = v_q + r_a i_q - e_q'' + x_d'' i_d \tag{4.6}$$

$$0 = v_d + r_a i_d - e_d'' - x_q'' i_q \tag{4.7}$$

Figure 4.4 represents a generator model of Order V Type 2 with an automatic voltage regulator (AVR) and without power system stabilizer. Parameters V_{f0} and V_{ref0} are the field voltage and the reference voltage at the input of the controller respectively, v represents the generator terminal voltage. In this model, there is no turbine but, to provide the mechanical power input (P_m) at the initialization a connection is made from the initial flow (pm0) and the mechanical power input is calculated from speed after the initialization.

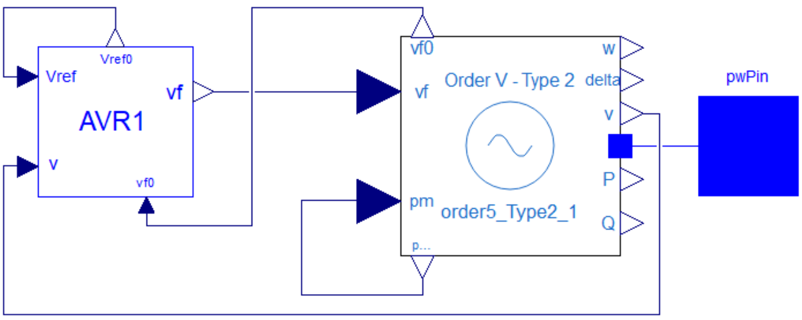


Figure 4.4: Generator and AVR model connection diagram in OpenIPSL

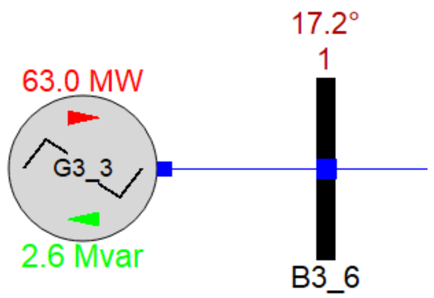


Figure 4.5: Generator G3_3 in normal operation in OpenIPSL

Figure 4.5 shown the connection diagram of generator G3_3 to the busbar B3_6 in a steady state operation. The arrows representing the flow direction, in this case, the generator is levering 63 MW to the system and receiving 2.6 MVAr from the system at voltage magnitude of 1 pu and phase angle of 17.2 degrees.

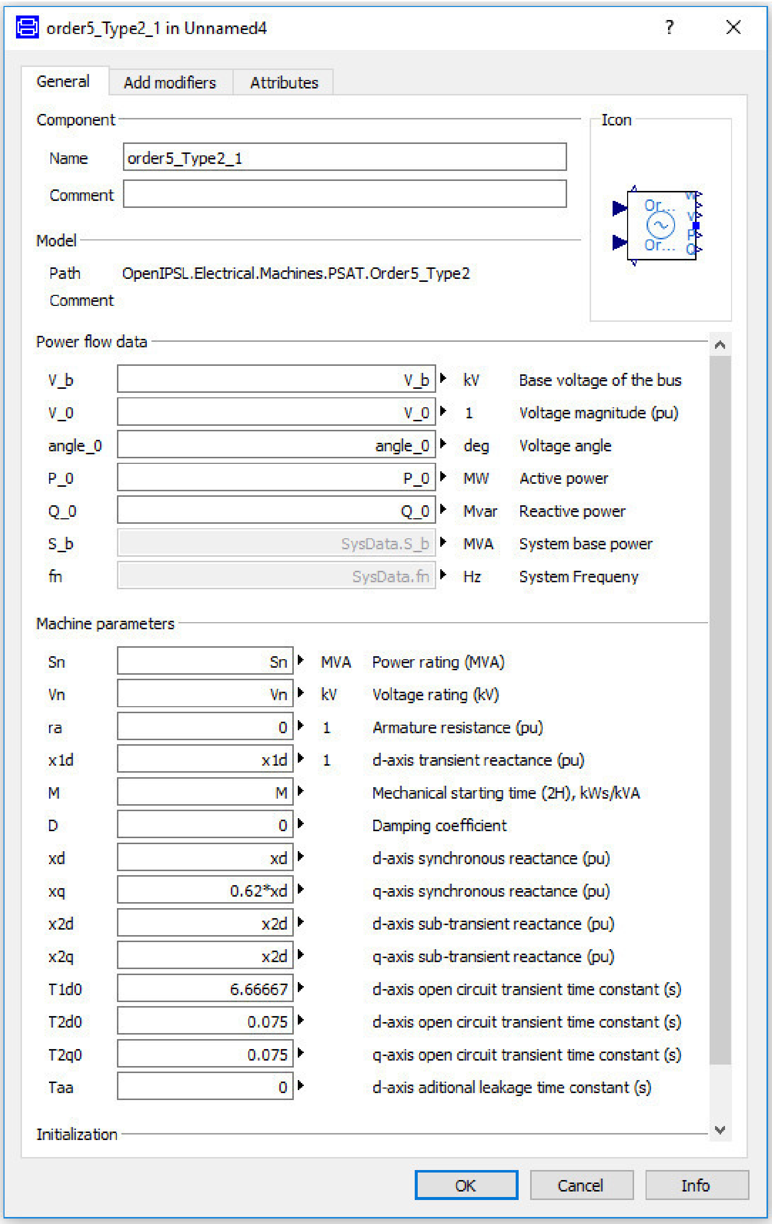


Figure 4.6: Order 5 Type 2 machine parameter and load flow data representation from OpenIPSL

Figure 4.6 shows the parameters of generator model of Order 5 Type 2 shown in Figure 4.4. The power flow data is the machine operating point whereas, the machine parameters are the nominal machine parameters. The parameters which are common to all machines are set as fixed values whereas parameters that differs from machine to machine are propagated to the outer layer of the generator see Figure 4.7 below. All parameters of the machine are in pu of machine base.

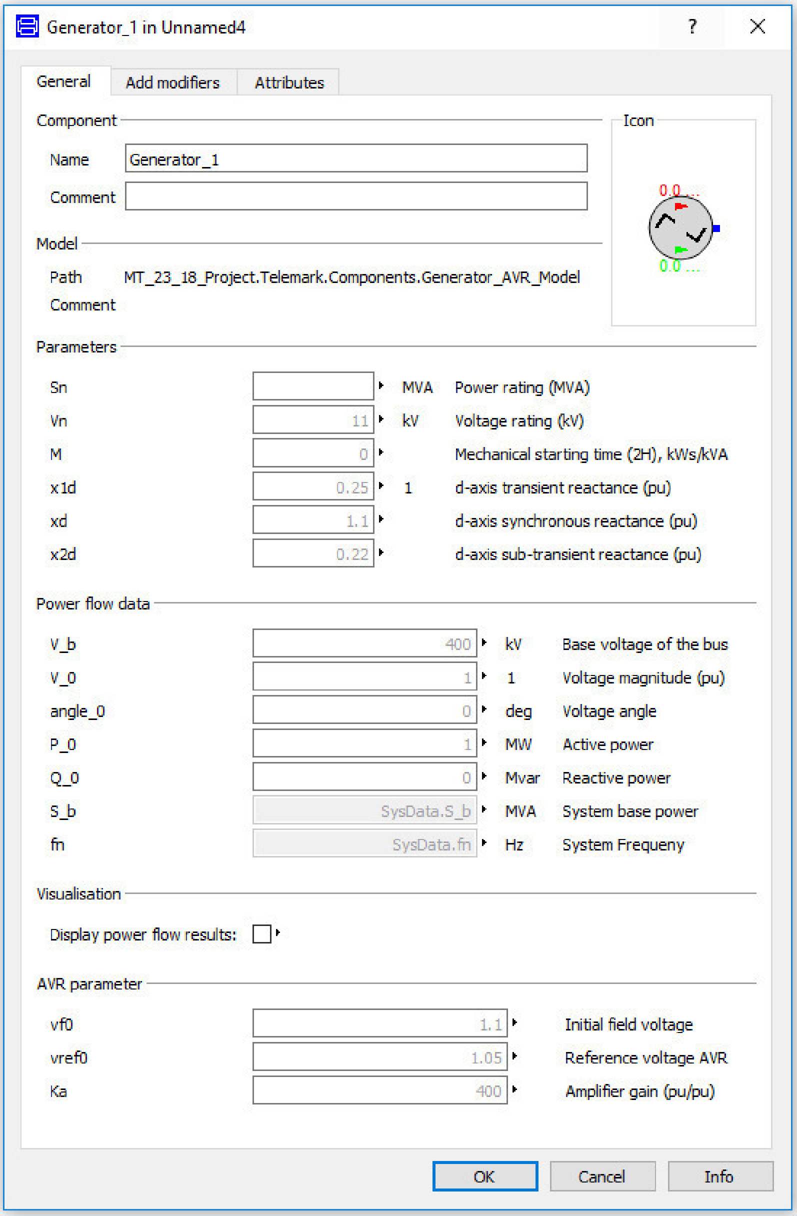


Figure 4.7: Generator model with automatic voltage regulator (AVR) as viewed from the outer layer

Figure 4.7 shows the parameters of the base generator modeled in this thesis (reference to Figure 4.5). The parameter window is divided into three sections, parameters, power flow data and AVR parameter. These parameters differ from generator to generator therefore each machine can be modeled independently.

4.3.3 Automatic Voltage Regulator (AVR)

Automatic voltage regulator (AVR) is the primary voltage regulation of synchronous machines. The AVR regulates the generator terminal voltage which is achieved by controlling the excitation current. By controlling the excitation current, the field current that is supplied to the generator is controlled and as a result, the generator's terminal voltage is controlled [11].

The AVR takes a reference of set point voltage (v^{ref}). The reference voltage should always be close to the generator terminal voltage and in this model, this is designed to be 1.05 pu. The reference voltage determines how much reactive power the generator has to supply. A feedback is used to compare the measured value (generator terminal voltage, v_h) with the desired (reference) value [11]. The error signal is used by the control rectifiers of the excitation system. The block diagram of voltage control system is presented in Figure 4.8 [11].

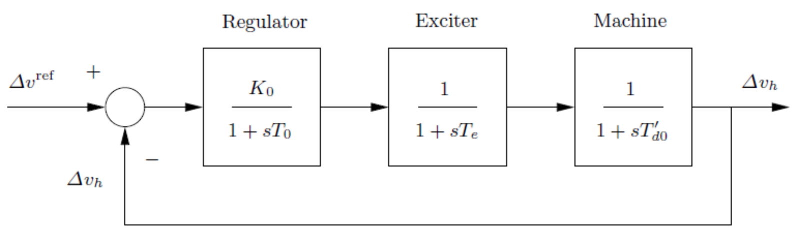


Figure 4.8: Simple representation of primary voltage control [21]

The AVR contains limiters to protect against very high voltages and currents. This is performed by pre-set limiters. The limiters limit the input signal for the amplifier, the field current for the exciter, the field current for the system, the armature current, and the power angle for the generator. Some limiters have built-in time delays to compensate for the thermal time constant due to temperature rise in the winding. A power system stabilizer (PSS) could be added to help dampen power swings in the system but in this thesis, PSS is not considered [11].

To produce a desired voltage regulation a correct combination of parameters of AVR should be chosen. The parameters used to assess the regulation are settling time t_ε, overshoot ε_p and rise time t_r [11].

The type of AVR implemented in this report is IEEE Type 1. This is the simplified version of the IEEE DC1 excitation system. For further modeling of AVR in PowerFactory and OpenIPSL see Section 4.3.3.1 and 4.3.3.2 respectively.

The parameters of the AVR are chosen according to the Norwegian Functional requirements in the power system (FIKS 2012). The requirement is classified into two categories depending on the rated apparent power of the synchronous generators. According to FIKS 2012 synchronous generators above 0.5 MVA need to have voltage regulating equipment while synchronous generators at or above 25 MVA need to have static magnetizing with damping [9]. However, in this thesis no damping is used in the generator model.

The proposed parameters used for system studies of model brushless synchronous machines below 25 MVA and static system of other machines are presented in Table 4.2. Other recommended models of IEEE for system studies are given in Appendix C.

Table 4.2: Automatic voltage regulator parameters used for system studies by IEEE

Parameter	**Unit**	**Variable**	**Value**
Maximum regulator voltage	pu	v_r^{max}	7.3
Minimum regulator voltage	pu	v_r^{min}	-7.3
Regulator gain	pu/pu	K_a	400
Regulator time constant	s	T_a	0.02
Stabilizer gain	pu	K_f	0.03
Stabilizer time constant	s	T_f	1.0
Field circuit integral deviation	s	K_e	1
Field circuit time constant	s	T_e	0.8
Measurement time constant	s	T_r	0
Saturation factor 1	pu	E_{FD1}	4.2
Saturation factor 2 ($S_E[E_{FD1}]$	pu	S_{E1}	0.5
Saturation factor 3 (0.75· E_{FD1})	pu	E_{FD2}	5.6
Saturation factor 4 ($S_E[E_{FD2}]$)	pu	S_{E2}	0.86

4.3.3.1 AVR Modeling in PowerFactory

PowerFactory contains several AVRs classified according to standards, models and types. In this thesis the avr_IEEE1 (1968 IEEE type 1 excitation system) is considered. According to the DIgSILENT PowerFactory user manual [19] this is the most used excitation system; the avr_IEEE1excitation system represents systems with shunt dc exciters and alternator exciters with an uncontrolled shaft-mounted rectifier bridge. The parameters used in this model are provided in Table 4.2.

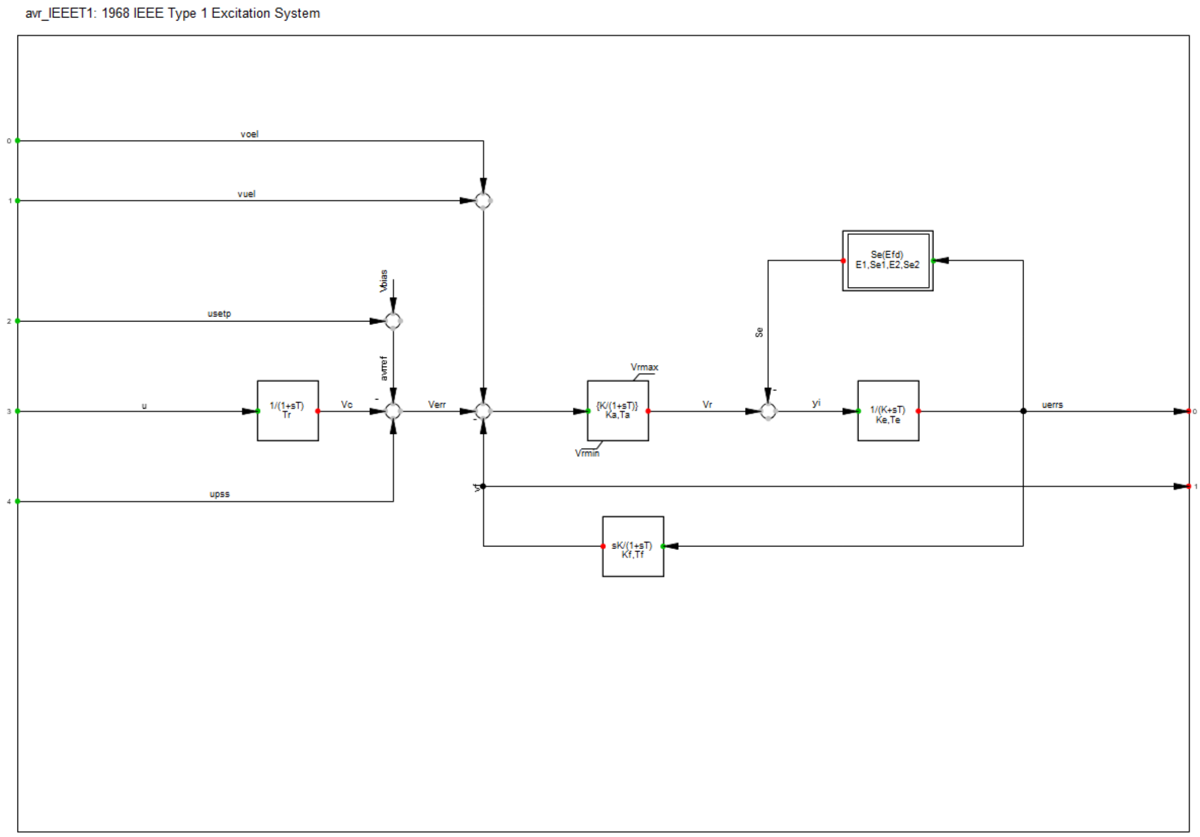


Figure 4.9: Automatic voltage regulator of type IEEET1 from PowerFactory

4.3.3.2 AVR Modeling in OpenIPSL

OpenIPSL provides several excitation systems from both PSAT, Simulink, PSS/E and CGMES (Common Grid Model Exchange Specification). The AVR Type I shown in Figure 4.10 is the simplified version of the standard dc exciter IEEE type I. This selection is made in order to match to the type of AVR used in [1]. The differential algebraic equations which describes the behavior of the AVR can be described using Equations (4.8) - (4.11).

$$\dot{v}_{r1} = (K_a(v^{ref} - v_m - v_{r2} - \frac{K_f}{T_f}\tilde{v}_f) - v_{r1})/T_a \tag{4.8}$$

$$\dot{v}_{r2} = -(\frac{K_f}{T_f}\tilde{v}_f + v_{r2})/T_f \tag{4.9}$$

$$\dot{\tilde{v}}_f = -(\tilde{v}_f\left(K_e + S_e(\tilde{v}_f)\right) - v_{r1})/T_e \tag{4.10}$$

Where the ceiling function S_e is:

$$S_e(\tilde{v}_f) = A_e e^{Be|\tilde{v}_f|} \tag{4.11}$$

The AVR model in OpenIPSL is a little different in the ceiling block from the standard IEEET1 model used in PowerFactory. The coefficients of A_e and B_e are calculated from two measured points of the ceiling function, S_e in this case a 100 % and 75 % of the field voltages provided in Table 4.2 are used [21]. Solving for A_e and B_e need to know the values of S_e^{max} and $S_e^{0.75 \cdot max}$ which corresponds the values of the field voltage v_f^{max} and $0.75 \cdot v_f^{max}$ respectively. Equations (4.12) - (4.14) are used to solve for the values of A_e and B_e.

$$0 = -(1 + S_e^{max})v_f^{max} + v_r^{max} \tag{4.12}$$

$$S_e^{max} = A_e e^{B_e v_f^{max}} \tag{4.13}$$

$$S_e^{0.75 \cdot max} = A_e e^{B_e v_f^{0.75 \cdot max}} \tag{4.14}$$

Where, A_e and B_e are 1st and 2nd ceiling coefficients, K_a is the amplifier gain, K_e is the field circuit integral deviation and, K_f is the stabilizer gain, T_a, T_f, T_e, T_r are the amplifier, stabilizer, field circuit and measurement time constants respectively; v_r^{max} and v_r^{min} are the maximum and minimum regulator voltages respectively and $\bar{v}_f$ is the field voltage.

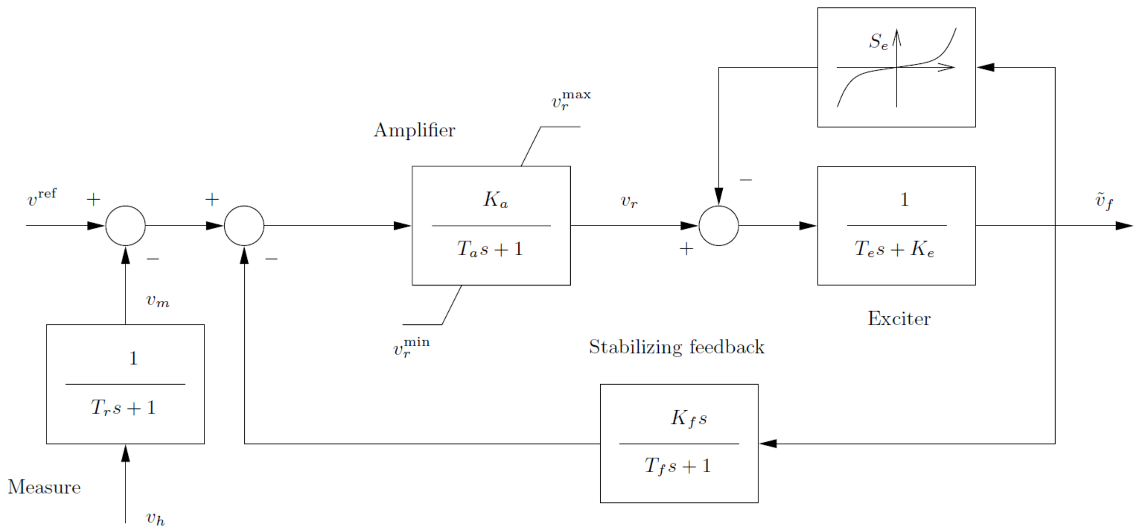


Figure 4.10: Automatic voltage regulator of Type I control diagram [21]

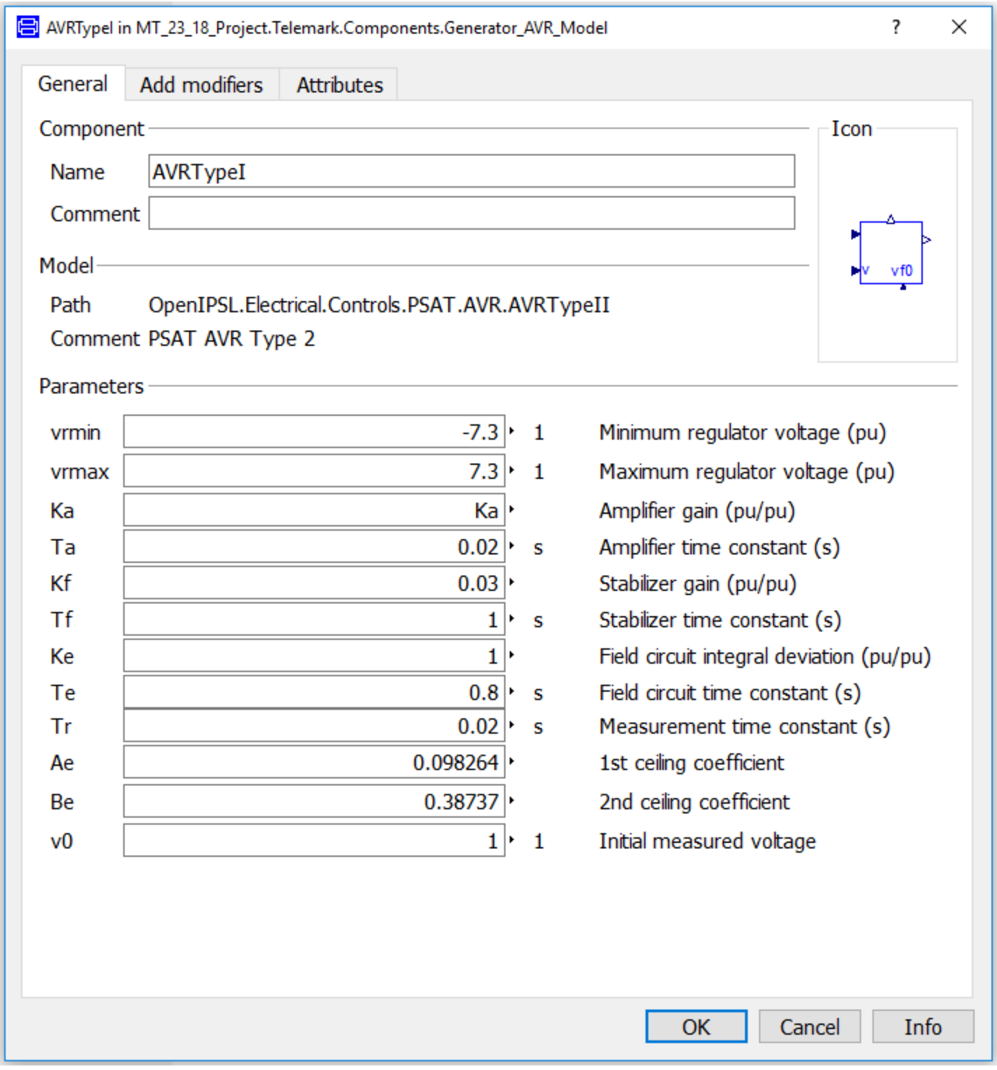


Figure 4.11: Parameters of AVR with calculated values of Ae and Be in OpenIPSL

Figure 4.11 shows the parameters of an AVR Type 1 implemented in OpenIPSL with the parameters from Table 4.2. The values for the parameters of Ae and Be are calculated using the Equations (4.12) - (4.14).

4.3.4 Turbine Governor

The primary purpose of governors is to control the load or speed. There are two types of governors; mechanical-hydraulic and electrical-hydraulic. The mechanical-hydraulic governor uses a watt centrifugal mechanism that incorporates two flyballs as a speed response mechanism [11]. Newer machines have electro-hydraulic governors which were incorporated into this thesis.

In electrical-hydraulic regulators, the turbine rotor speed is measured electronically with high accuracy. The measured speed is compared with the reference speed and the speed error is used to control the speed position [12]. An electro-hydraulic converter amplifies the signal before sending to pilot valve. The block diagram representation of a speed control of a hydraulic generating is shown in Figure 4.12

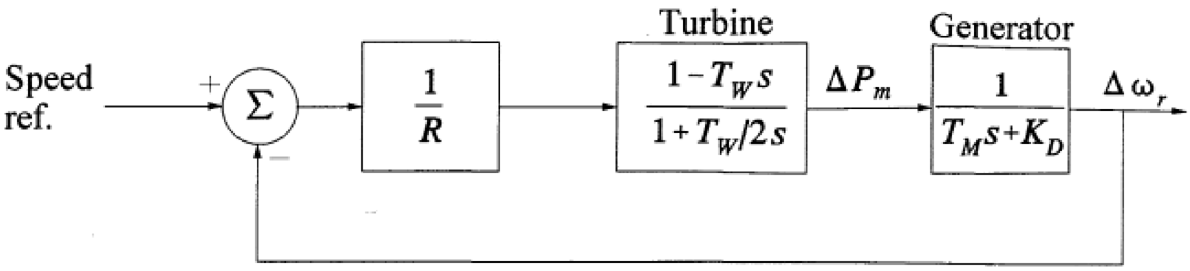


Figure 4.12: Simplified block diagram representation of a speed control [12]

Where, speed ref. is the reference operational speed of the machine, the feedback represents measurement device connected to the generator shaft. The speed governor in this case is represented by pure gain $K_G = {}^{1}/_{R}$. In this thesis a turbine governor of type HYGOV is implemented with the default values from PowerFactory.

4.3.4.1 Turbine Governor Modeling in PowerFactory

Powerfactory offers several turbine governors for steam generators and hydropower generators. In this thesis the PowerFactory model of a HYGOV (hydro turbine-governor) is used. This is a simple hydraulic representation of penstock without a surge tank and no restrictions in the head and tail race [19].

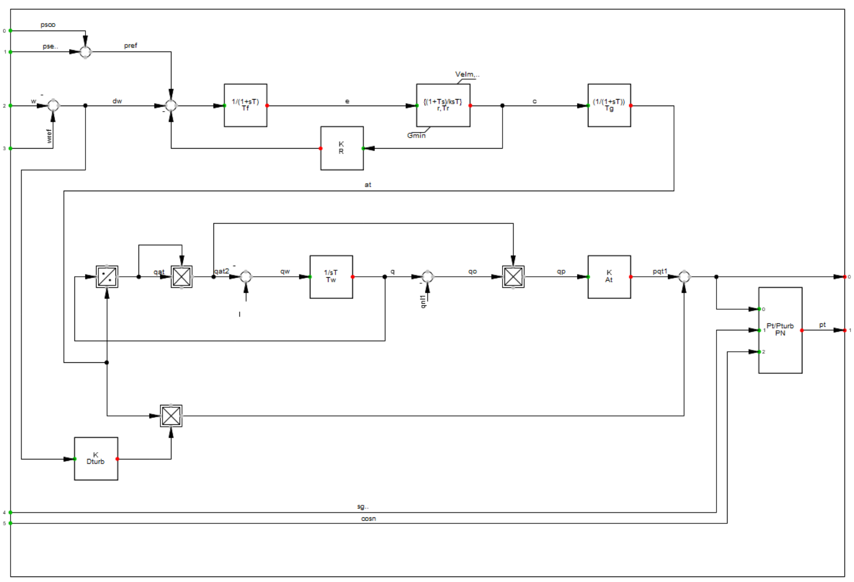


Figure 4.13: HYGOV (Hydro turbine-governor) block diagram

Table 4.3: HYGOV parameter used in PowerFactory

Parameter	unit	Variable	Value
Temporary Droop	pu	r	0.1
Governor Time Constant	s	T_r	10
Filter Time Constant	s	T_f	0.1
Servo Time Constant	s	T_g	0.5
Water Starting Time	s	T_W	1
Turbine Gain	pu	A_t	1
Frictional losses factor	pu	D_{turb}	0.01
No Load Flow	pu	qnl	0.01
Permanent Droop	pu	R	0.04
Turbine Rated Power	MW	PN	0
Minimum Gate Limiter	pu	G_{min}	0
Gate Velocity Limit	pu	V_{elm}	0.15
Maximum Gate Limit	pu	G_{max}	1

Table 4.3 provides the parameters of turbine governor implemented in PowerFactory. These are default parameters from PowerFactory.

4.3.4.2 Turbine Governor Modeling in OpenIPSL

OpenIPSL provides several turbine governors of different types. But in the OpenIPSL model a turbine governor is not implemented; instead an initialization of mechanical input power is fed to the generator. See Figure 4.4 connection from pm0 to pm.

4.3.5 Transmission Line

Transmission lines are used for transferring power from generator to consumer. In most cases, overhead lines are used to minimize the cost. Overhead lines can be characterized by 4 parameters: conductor resistance (R), shunt conductance (G), inductance (L) and shunt capacitance (C) [12].

Depending on the length, overhead transmission lines can be classified in to three categories: short lines (below 80 km), medium-length lines (between 80 - 200 km) and long lines (over 200 km) [12]. In this thesis the length of transmission line ranges from 1 km to 65 km; therefore, short line modeling is used. Short lines have very small shunt capacitance hence they are always represented by their series impedance. The input parameters for the transmission lines are provided in Appendix B.

4.3.5.1 Transmission Line Modeling in PowerFactory

Transmission lines in PowerFactory are modelled either as a lumped parameter (PI equivalent) or as a distributed parameter. The lumped model is used for short length transmission lines whereas the distributed parameter is preferred for long length transmission lines. Definition of data can be done in parameter per unit length or in pu [19]. The equivalent model of the lumper parameter model used in PowerFactory is shown in Figure 4.14.

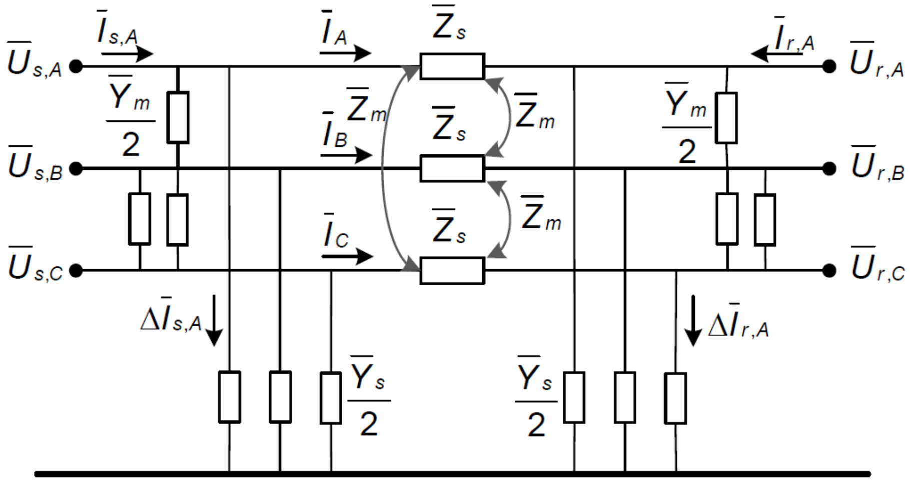


Figure 4.14: Equivalent PI-circuit of lumped parameter without a neutral conductor [19]

The injected voltage and current at the sending and receiving end of the line can be formulated in terms of impedance and admittance matrices.

The voltage drop along the line is given by the impedance matrix in the following form, where A, B and C represents the phases [19].

$$\begin{bmatrix} \bar{U}_{s,A} \\ \bar{U}_{s,B} \\ \bar{U}_{s,C} \end{bmatrix} - \begin{bmatrix} \bar{U}_{r,A} \\ \bar{U}_{r,B} \\ \bar{U}_{r,C} \end{bmatrix} = \begin{bmatrix} \Delta\bar{U}_{A} \\ \Delta\bar{U}_{B} \\ \Delta\bar{U}_{C} \end{bmatrix} = \begin{bmatrix} \bar{Z}_s & \bar{Z}_m & \bar{Z}_m \\ \bar{Z}_m & \bar{Z}_s & \bar{Z}_m \\ \bar{Z}_m & \bar{Z}_m & \bar{Z}_s \end{bmatrix} \cdot \begin{bmatrix} \Delta\,\bar{I}_A \\ \Delta\,\bar{I}_B \\ \Delta\,\bar{I}_C \end{bmatrix} \tag{4.15}$$

The current at the sending and receiving ends of the line can be calculated in terms of the admittance matrix. using equations (4.16) and (4.17) respectively.

$$\begin{bmatrix} \bar{I}_{s,A} \\ \bar{I}_{s,B} \\ \bar{I}_{s,C} \end{bmatrix} = \begin{bmatrix} \Delta\,\bar{I}_{s,A} \\ \Delta\,\bar{I}_{s,B} \\ \Delta\,\bar{I}_{s,C} \end{bmatrix} + \begin{bmatrix} \bar{I}_{A} \\ \bar{I}_{B} \\ \bar{I}_{C} \end{bmatrix} = \frac{1}{2}\begin{bmatrix} \bar{Y}_s & \bar{Y}_m & \bar{Y}_m \\ \bar{Y}_m & \bar{Y}_s & \bar{Y}_m \\ \bar{Y}_m & \bar{Y}_m & \bar{Y}_s \end{bmatrix} \cdot \begin{bmatrix} \bar{U}_{s,A} \\ \bar{U}_{s,B} \\ \bar{U}_{s,C} \end{bmatrix} - \begin{bmatrix} \bar{I}_{A} \\ \bar{I}_{B} \\ \bar{I}_{C} \end{bmatrix} \tag{4.16}$$

$$\begin{bmatrix} \bar{I}_{r,A} \\ \bar{I}_{r,B} \\ \bar{I}_{r,C} \end{bmatrix} = \begin{bmatrix} \Delta\,\bar{I}_{r,A} \\ \Delta\,\bar{I}_{r,B} \\ \Delta\,\bar{I}_{r,C} \end{bmatrix} + \begin{bmatrix} \bar{I}_{A} \\ \bar{I}_{B} \\ \bar{I}_{C} \end{bmatrix} = \frac{1}{2}\begin{bmatrix} \bar{Y}_s & \bar{Y}_m & \bar{Y}_m \\ \bar{Y}_m & \bar{Y}_s & \bar{Y}_m \\ \bar{Y}_m & \bar{Y}_m & \bar{Y}_s \end{bmatrix} \cdot \begin{bmatrix} \bar{U}_{r,A} \\ \bar{U}_{r,B} \\ \bar{U}_{r,C} \end{bmatrix} - \begin{bmatrix} \bar{I}_{A} \\ \bar{I}_{B} \\ \bar{I}_{C} \end{bmatrix} \tag{4.17}$$

Where, the subscripts s and r denote the sending and receiving ends of the line respectively.

Modeling of the lumped parameter model includes the calculation of the impedance (Z) and admittance (Y). See Equation (4.18).

$$\begin{gathered} Z = Z_1' l = (R_1' + j\omega L_1') \cdot l \\ Y = Y_1' l = (G_1' + j\omega C_1') \cdot l \\ G_1' = B_1' \tan\delta_1 \end{gathered} \tag{4.18}$$

4.3.5.2 Transmission Line Modeling in OpenIPSL

All transmission lines in OpenIPSL are modelled using the lumped parameter model. In OpenIPSL, data is defined in absolute value (length = 0), therefore input parameters must amount to the total impedance of the line. The transmission line model in OpenIPSL does not need to specify the rated voltage and current hence maximum values for current, voltage and power can be calculated without any limitation for power flow [21].

In most cases transmission line resistance and reactance values are given in ohm per unit length. However, due to the operation of the OpenIPSL model, the system is based values that were calculated in pu of system base. Line parameters in this thesis are calculated at system base of 100 MVA and their respective base voltages. Detailed line parameters are provided in Appendix B. Equations (4.19) - (4.21) are used to convert total line resistance and reactance to pu.

$$Z_{base} = \frac{V_{base}^2}{S_{base}} \tag{4.19}$$

$$R_{pu} = \frac{R}{Z_{base}} \tag{4.20}$$

$$X_{pu} = \frac{X}{Z_{base}} \tag{4.21}$$

Where, Z_{base} is base impedance, V_{base}^2 is the base voltage for the respective area, S_{base} is the system base (100 MVA), R and X are the total line resistance and reactance respectively and R_{pu} and X_{pu} are the pu values of R and X respectively.

The equivalent circuit diagram, as well as the mathematical representation of a short transmission line π model, is presented below.

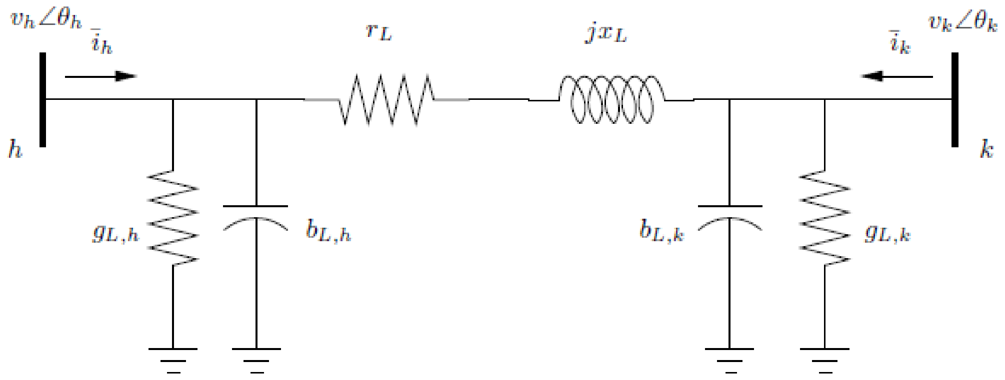


Figure 4.15: Equivalent circuit of short transmission line π model [21]

The injected complex power of the PI model equivalent circuit in Figure 4.15 can be expressed by:

$$\bar{s}_k = \bar{v}_k \cdot \bar{\imath}_k^* \tag{4.22}$$

$$\bar{s}_h = \bar{v}_h \cdot \bar{\imath}_h^* \tag{4.23}$$

Similarly, the injected currents $\bar{\imath}_h^*$ and $\bar{\imath}_k^*$ can be written using the network admittance matrices:

$$\begin{bmatrix} \bar{\imath}_h \\ \bar{\imath}_k \end{bmatrix} = \begin{bmatrix} \bar{y}_L + \bar{y}_{L,h} & -\bar{y}_L \\ -\bar{y}_L & \bar{y}_L + \bar{y}_{L,k} \end{bmatrix} \begin{bmatrix} \bar{v}_h \\ \bar{v}_k \end{bmatrix} \tag{4.24}$$

Inserting the parameters of PI model to the Y-admittance matrix gives:

$$\bar{y}_L = g_L + jb_L = (r_L + jx_L)^{-1}$$
$$\bar{y}_{L,h} = g_{L,h} + jb_{L,h} \tag{4.25}$$
$$\bar{y}_{L,k} = g_{L,k} + jb_{L,k}$$

Finally, the algebraic equations of injected complex powers for sending and receiving end in equation (4.22) and (4.23) can be written as real power (p) and reactive power(q).

$$p_h = v_h^2(g_L + g_{L,h}) - v_h v_k (g_L \cos\theta_{hk} + b_l \sin\theta_{hk}) \tag{4.26}$$

$$q_h = -v_h^2(g_L + g_{L,h}) - v_h v_k (g_L \cos\theta_{hk} - b_l \sin\theta_{hk}) \tag{4.27}$$

$$p_k = v_k^2(g_L + g_{L,k}) - v_h v_k (g_L \cos\theta_{hk} + b_l \sin\theta_{hk}) \tag{4.28}$$

$$q_k = -v_k^2(g_L + g_{L,k}) - v_h v_k (g_L \cos\theta_{hk} + b_l \sin\theta_{hk}) \tag{4.29}$$

Where, $\theta_{hk} = \theta_h - \theta_k$ and with the short transmission line assumption $g_{L,h} \approx g_{L,k} \approx 0$.

Equations (4.26) - (4.29) can be written as a lumped series resistance and reactance.

$$r_L = \frac{R_l l_t}{Z_b} \tag{4.30}$$

$$x_L = \frac{\omega_s L_l l_t}{Z_b} \tag{4.31}$$

Where, $\omega_s = 2\pi f_n$ is the synchronous pulsation in rad/sec, Z_b is the base impedance in ohm, l_t is total line length, L_l and R_l are per-unit length line inductance and reactance respectively whereas r_L and x_L are total resistance and reactance of the line.

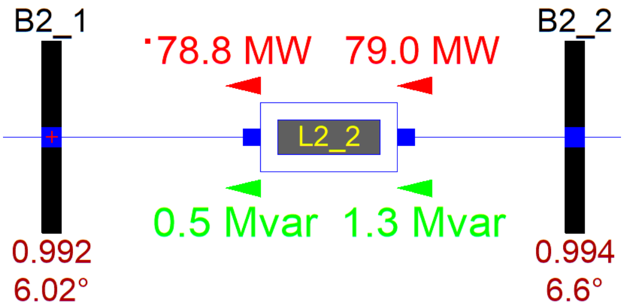


Figure 4.16: Transmission line model in OpenIPSL

Figure 4.16 shows the connection diagram of transmission line L2_2 between busbars B2_1 and B2_2 in a steady state operation. The arrows representing the flow direction, in this case, both the active and reactive powers are flowing from the right to the left at voltage magnitude and phase angle as shown. The difference in power represents the power lose in the transmission line.

4.3.6 Transformer

Transformers are one of the fundamental electrical components of power systems. Transformers transfer electrical energy between two circuits through electromagnetic induction. Different types are used depending on the purpose. Transformers may be used to either step-up, step down or to regulate voltage levels in power system. In this thesis, a two-winding transformer is used to step-up or step down the voltage depending on the area of implementation. For more detailed model representation refer to Section 4.3.6.1 and 4.3.6.2 for PowerFactory and OpenIPSL respectively. The input parameters used in this thesis are attached in Appendix B.

4.3.6.1 Transformer Modeling in PowerFactory

PowerFactory contains a wide range of transformers including 2-winding, 3-winding, 4-winding, autotransformer, booster transformer and step-voltage regulator. The two-winding transformer model in PowerFactory consists of winding resistances and reactance's on both sides and a magnetizing reactance along with a parallel resistance. The simplified equivalent circuit of a three phase two-winding transformer is given in Figure 4.17 [19].

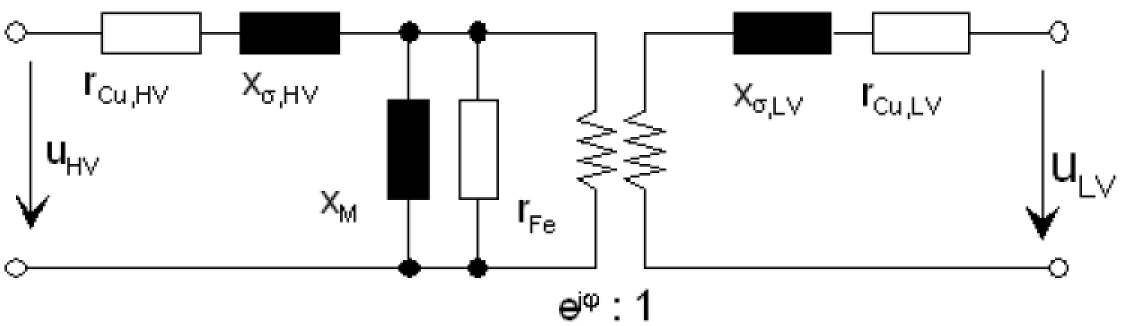


Figure 4.17: Positive sequence equivalent circuit of two-winding transformer

The mathematical model representation of the three-phase two winding transformer as it is represented in the PowerFactory User manual. In this thesis the resistive losses in the windings, iron losses in the core and the magnetizing effect are ignored.

The nominal impedances on the high voltage (HV) and low voltage (LV) sides of the transformer is given by:

$$Z_{r,HV} = \frac{U_{rh}^2}{S_r} \quad (4.32)$$

$$z_{r,LV} = \frac{U_{rl}^2}{S_r} \quad (4.33)$$

Where, $Z_{r,HV}$, U_{rh}, $z_{r,LV}$, U_{rl} are nominal impedance and rated voltage referred to HV and LV sides respectively and S_r is the rated power.

The short circuit impedance, resistance and reactance in per-unit are calculated as follows:

$$Z_{sc} = \frac{U_{sc}}{100} \quad (4.34)$$

$$r_{sc} \frac{{P_{Cu}}/{1000}}{S_r} \quad (4.35)$$

$$x_{sc} = \sqrt{z_{sc}^2 - r_{sc}^2} \quad (4.36)$$

The leakage impedance of HV and LV sides are represented by:

$$z_{s,hv} = (r_{sc} \cdot \gamma R, HV_1) + (x_{sc} \cdot \gamma X, HV_1) \quad (4.37)$$

$$z_{s,lv} = (r_{sc} \cdot (1 - \gamma R, HV_1) + (x_{sc} \cdot (1 - \gamma X, HV_1) \quad (4.38)$$

Where, $z_{s,hv}$ and $z_{s,lv}$ are the leakage impedance on HV and LV respectively, $\gamma R, HV_1$and $\gamma X, HV_1$ are the ratio of transformer short circuit resistance and reactance on HV respectively.

4.3.6.2 Transformer Modeling in OpenIPSL

In OpenIPSL three-phase two-winding transformers are modelled the same way as transmission lines with series resistance (r_T) and reactance (x_T) along with a shunt admittance at the sending end bus to model iron losses (g_{Fe}) and magnetizing susceptance (b_μ). As [21] shows, the error introduced by approximated circuit is acceptable. The following line parameters will be replaced by the corresponding transformer parameters:

$$r_L = r_T \qquad x_L = x_T$$

$$b_{L,h} = b_\mu \qquad g_{L,h} = g_{Fe}$$

$$b_{L,k} = 0 \qquad g_{L,k} = 0$$

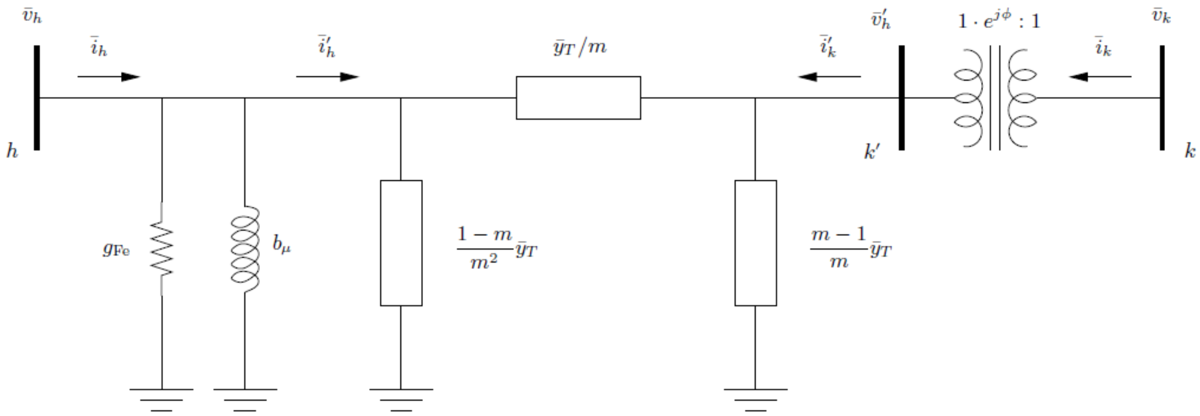


Figure 4.18: Two-winding transformer equivalent circuit [21]

The algebraic equations presented in section 4.3.5.2, Equations (4.26) (4.29) describes the injected active and reactive powers at sending and receiving ends respectively apply for transformer with the corresponding transformer parameters mentioned above.

4.3.7 Power System Loads

Electrical loads are devices that consume electric energy and transform that energy to other forms such as heat, light, work, etc. The electrical loads differ depending on their types and functions. Electrical loads may be resistive, inductive, capacitive or combination of the two or three [22].

Loads in power system can be categorized into static and dynamic loads. Static loads are loads that do not change their characteristics with time (constant impedance) whereas, dynamic loads are time-dependent. Voltage dependent loads are those in which the active and reactive powers are expressed as the function of the bus voltage. In this thesis, a voltage-dependent static load is considered to model the load. Further modeling of the load is provided in section 4.3.7.1 and 4.3.7.2 in PowerFactory and OpenIPSL respectively [12].

4.3.7.1 Load Modeling in PowerFactory

Depending on the selection type PowerFactory supports two different models of loads, general loads and complex loads. The balanced loads (specifying the sum of all phases) and unbalanced loads (only specifying the load per phase) can be modelled differently. The three-phase balanced load model is used in this thesis. The voltage dependency of loads in PowerFactory can be modelled using polynomials as follows:

$$P = P_0\left(aP \cdot \left(\frac{v}{v_0}\right)^{e\_aP} + bP \cdot \left(\frac{v}{v_0}\right)^{e\_bP} + (1 - aP - bP) \cdot \left(\frac{v}{v_0}\right)^{e\_cP}\right) \qquad (4.39)$$

Where

$[1 - aP - bP = cP]$, and v is the busbar voltage in pu

$$Q = Q_0\left(aQ \cdot \left(\frac{v}{v_0}\right)^{e\_aQ} + bQ \cdot \left(\frac{v}{v_0}\right)^{e\_bQ} + (1 - aQ - bQ) \cdot \left(\frac{v}{v_0}\right)^{e\_cQ}\right) \qquad (4.40)$$

Where

$[1 - aQ - bQ = cQ]$, and v is the busbar voltage in pu

Where, the coefficients 0, 1 and 2 are the power, current and impedance respectively, v_0 is the reference voltage at the busbar at which $P = P_0$ and $Q = Q_0$

During load flow calculation, the loads have constant active and reactive power demands. The active and reactive power demands are listed in Appendix B.

The illustration to the three-phase load model (3P –D) used in this thesis is shown in the figure below (Figure 4.19).

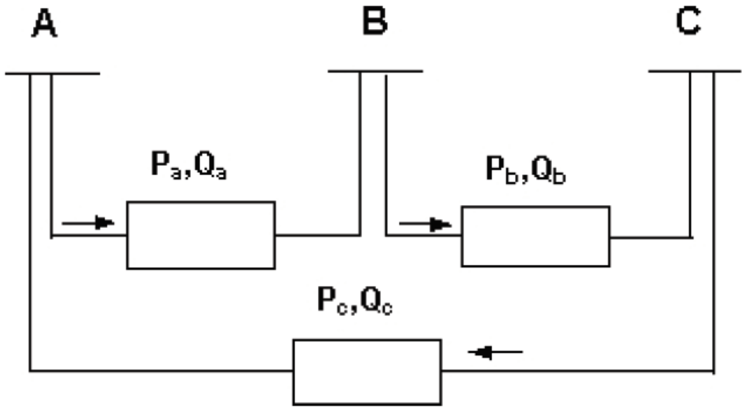


Figure 4.19: Three-phase, Technology 3PH 'D' [19]

4.3.7.2 Load Modeling in OpenIPSL

OpenIPSL provides different types of loads both from PSAT and PSS/E; however, in this thesis, static constant PQ load from PSAT is used. Load PQ is a static load meaning P and Q can be modeled as constant values if voltage is between the specified limits. However, if voltage is not with in the specified limits (voltage violation) PQ loads become constant impedance and P and Q can be modeled differently. Static loads can be voltage or frequency dependent. The voltage dependent modeling is used to model the PQ loads in OpenIPSL [21].

Mathematical representation of PQ loads as P and Q are considered separately. Equation (4.41) and (4.42) represents the active and reactive power in the case where voltage is within the specified limits or at the initialization time.

$$P = P_0 \tag{4.41}$$

$$Q = Q_0 \tag{4.42}$$

An alternative model is presented for the mathematical representation of P and Q in the case of voltage limits outside the specified limits (either above or below) apply Equations (4.43) and (4.44) exhibit this:

$$P = P_0 \cdot (\bar{V})^{\alpha p} \tag{4.43}$$

$$Q = Q_0 \cdot (\bar{V})^{\alpha q} \tag{4.44}$$

Where, P and Q are the active and reactive components of the load when the bus voltage magnitude is V, $\bar{V}$ is described as the ratio of the operating voltage to the upper or lower limit of the voltage levels (V_{max} = 1.2 pu and V_{min} = 0.8 pu), P_0 and Q_0 are the active and reactive powers at the initial operating condition and αp and αq are active and reactive power exponents and can be determined from the PV curves (in this case αp = αq =2).

4.3.8 External Grid

External grids in a simulation programs are used to represent external networks. In most cases it is used to represent networks that contain large power grids and industrial networks. Networks with only their contribution is necessary are always represented by external grid. In this thesis external grid contribution from the transmission network is available with the values provided in Table 4.4.

4.3.8.1 External Grid Modeling PowerFactory

PowerFactory contains an External Grid model (***ElmXnet***) for the representation of external networks. The external grid model includes models for Load Flow, short-circuit, harmonics, and RMS and EMT simulations. For the purpose of this thesis, the RMS and EMT models in addition to the load flow models are used.

The load flow model is used for load flow calculations and can operate as any of the following bus types: PQ bus, PV bus, or SL bus. For the purposes of this thesis, the PV bus is used. The PV bus has implication for active power because the bus voltage is known at the bus. The PV bus feeds in a constant active power (for P > 0) and controls the voltage of the connected busbar [19].

With respect to RMS and EMT simulation modeling of the external grid, a synchronous generator model is used. A simplified version of the model is used wherein the reactance of the model is pre-planned. In terms of the parameters, there are three types that need to be entered into this type of model: the short-circuit min and max power values, the c-factor, and the impedance ratios. Additionally, the frequency bias and acceleration time values need to be incorporated into the RMS and EMT modeling for external grid networks [19].

Table 4.4 contains the input parameters from the network feeder (External Grid). The maximum short-circuit power value is provided by external partner and the minimum short-circuit power is assumed to be 50 % of the maximum.

Table 4.4: Input parameters of the network feeder

Location	$U_n[kV]$	$S''_{k-max}\,[MVA]$	$S''_{k-min}[MVA]$
B1_3	420	14549.23	7274.613

4.3.8.2 External Grid Modeling in OpenIPSL (Infinite Bus)

The voltage magnitude and phase angle of the bus is specified at the time of initialization. The magnitude of the real as well as the imaginary voltages are calculated from the initialization voltage at the bus (V0) and the initialization angle at the bus (angle0). Thus, the real and reactive powers are calculated as a result of voltage and current at the pin.

In OpenIPSL the infinite model construction acts as a reference bus (SL bus). The infinite bus controls the voltage and the angle of the bus to which it is connected. The slack bus has no any limitations in the amount of generations and the primary purpose of the slack bus is to ensure a power balance in the system.

```
  parameter Boolean displayPF=false
  "Display power flow results:" a;
equation
  p.vr = V_0*cos(angle_0*Modelica.Constants.pi/180);
  p.vi = V_0*sin(angle_0*Modelica.Constants.pi/180);
  P = -(p.vr*p.ir + p.vi*p.ii)*S_b;
  Q = -(p.vr*p.ii - p.vi*p.ir)*S_b;
  a
end InfiniteBus;
```

Figure 4.20: Textual modeling of an infinite bus in OpenIPSL

4.4 Electrical Faults

A fault in a power system is an abnormal condition that interrupts the steady state operation of the system. Power system faults vary in size, type, duration and locations. The causes of electrical faults are numerous; they include lightning, animals entering switchgear, breaking of lines due to excessive loading, loss of insulation in component, etc. The most common fault associated with a power system is a short circuit that occurs in both the busbars and transmission lines.

The most frequent faults are a single line to ground faults; however, power system components should be protected from three phase faults (highest possible short circuit) as well. As discussed, the previous sections, three-phase faults are used as the limit for the transient stability of synchronous generators in numerous studies.

For the simulation purpose, three-phase balanced faults are used as events in PowerFactory and OpenIPSL. Further detail of the faults is given in Sections 4.4.1 and 4.4.2. The fault events and their locations used in this report are provided in Table 2.1.

Table 4.5: Fault locations and bus voltage

case	Fault ID	Fault Location	Bus voltage
Case 1	F1_1	B1_1	300
Case 2	F3_1	B3_2	132
Case 3	F0_1	B0_1	132
Case 4	F4_1	B4_7	66
Case 5	F4_2	B4_15	22

Table 4.5 presents information for the fault events presented in Figure 1.1. The fault areas are chosen in a way that tests the different voltage levels i.e. both at 300, 132 kV centrally located in Grenland and out in the 132, 66 and 22 kV voltages to observe the response of the generators to different fault area of different voltage levels.

4.4.1 Fault Modeling in PowerFactory

The short circuit event is one of many events in PowerFactory. This event involves a short-circuit on the busbar terminals or in a specified location on the transmission line. All fault types including three-phase, two-phase or single-phase faults can be specified. To clear the fault another, short-circuit event has to be defined, because PowerFactory does not have the ability to define the fault duration [19].

In this study, a test busbar with a short test line of negligible impedance is installed near the area where the fault will be simulated. During the test, the fault is cleared by opening the circuit-breaker at both ends of the test line without changing the equivalent network impedance of the system.

4.4.2 Fault Modeling in OpenIPSL

One of three events available in OpenIPSL is the short circuit event. Unlike PowerFactory OpenIPSL does not provide much flexibility for choosing the type of fault event. However, it allows us to define the duration of the short circuit. The simulation in this thesis is limited to a three-phase short circuit due to the limitation in OpenIPSL.

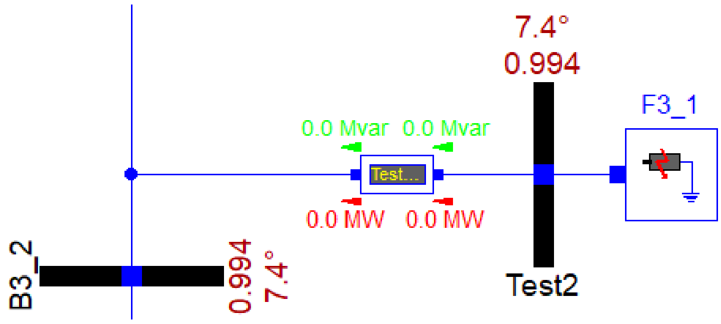


Figure 4.21: Fault representation for case 2 for t < 0 in OpenIPSL

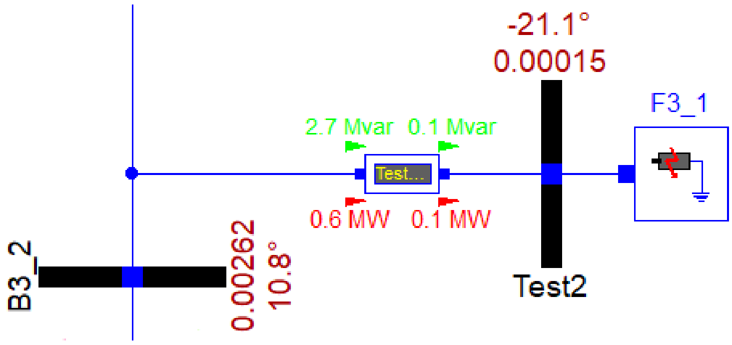


Figure 4.22: Fault representation for case 2 for t > 0 in OpenIPSL

Figure 4.21 and Figure 4.22 represent the pre-fault as well as the post-fault condition of a fault model implemented in OpenIPSL for selected case 2 (F3_1). In this thesis, the three-phase fault model is implemented with a short line length of a negligible impedance connected to a busbar at the end. This transmission line and busbar have nothing to do with the fault, rather it is used as an indication for the flow of current in the transmission line and voltage magnitude with phase angle at the busbar.

A fault definition in OpenIPSL includes the definition of fault resistance (R) and reactance (X) in pu, fault starting time ($t1$) and fault end time ($t2$) in seconds. The fault impedance in this thesis is assumed to be zero, but due to the problem solving for sin (0), a very small impedance is inserted based on the base voltage of the fault location.

The model working principle is based on time intervals $> t1$ and $< t2$. This is a transitory short circuit on a node which sets the voltage to approximately zero during a specified interval of time. During this time the real current at the pin p (p.ir) as well as the imaginary current at the pin p (p.ii) are calculated separately based on the inserted fault resistance and reactance. The textual model of the fault event sees Figure 4.23.

```
  parameter Boolean ground=abs(R) < eps and abs(X) < eps;
equation
  if time < t1 then
    p.ii = 0;
    p.ir = 0;
  elseif time < t2 and ground then
    p.vr = 1E-10;
    // This is to avoid numerical problems
    p.vi = 0;
  elseif time < t2 then
    p.ii = (R*p.vi - X*p.vr)/(X*X + R*R);
    p.ir = (R*p.vr + X*p.vi)/(R*R + X*X);
  else
    p.ii = 0;
    p.ir = 0;
  end if;
  a
end PwFault;
```

Figure 4.23: Textual modeling of a three-phase power fault (pwFault) in OpenIPSL

4.5 RMS Simulation

This simulation is conducted at full capacity which means the generators are working at their maximum production capacity. This assumption is made in order to test the worst-case scenario of the power system. Performing transient simulation involves several steps and differs from one tool to another. In this thesis the following steps are used for the simplicity reason: the initial value calculation (the load flow calculation), event definition, the execution of simulation based on the calculated initial values and the specified event and the simulation result analysis.

4.5.1 Initial Conditions

The first step in a transient simulation analysis is the calculation of the initial conditions. During this step, a load flow calculation is performed to calculate the internal variables and internal operation status of connected generation, controllers and other transient models that can affect the time-domain simulation.

A load flow calculation includes the calculation of bus voltages and power flows in a power system. Calculating voltages and power flows in a power system are fundamental to operational planning as well as development planning. The loaf flow calculation from PowerFactory is provided in Appendix E. Such calculation provides information about the voltage during load disconnections, the limit for reactive power production and the angle between individual voltages. In addition, a load flow calculation provides the active and reactive power in the system, and the loading capacity of power system components. the way load flow calculation is performed is further explained in section 4.5.1.1.

4.5.1.1 Initial Conditions in PowerFactory

In PowerFactory, calculation of initial conditions can be performed using "Calculate initial condition" command. During this point, several parameters such as simulation methods, network representation, step size etc. are defined. Load flow calculations are performed for all power system components based on load parameter specification. The load flow calculation determines the real and reactive power flow for all the network branches and the voltage magnitude and phase for all nodes in a steady state operation [19]. The parameters selected while performing a load flow calculation are as follows:

- AC load flow calculation of a balanced positive sequence in the basic option
- Newton-Raphson (Power Equations) method to solve the non-linear equations of the system

During this initialization process, parameters such as simulation method, network type, step size, and starting times should be defined. For the purpose of this thesis, an RMS simulation of a three-phase balanced positive sequence (ABC) with an option of automatic step size adaption is selected.

In terms of load flow calculations, there are two main areas of simulation: Normal System Conditions and Abnormal system Conditions. With respect to the two areas of simulation the manner of the simulation differs as follows:

For simulation of normal operating system operating conditions, the results of the load flow analysis should be based on a system condition wherein none of the network branch or generator maximums are exceeded in terms of the active and reactive power of all loads. For simulation of abnormal operating system conditions, the assumption regarding the system operating within the scope of its limits is removed. Here the focus is on the system's reactive power wherein generators and their voltage dependencies have to be modeled to their maximum limits. Additionally, the power system simulation analysis should also take into account the load flow calculations for unbalanced power networks [19].

With respect to the Newton-Raphson (Power Equations) method for AC Load Flow Analysis, this method helps in formulating large power transmission systems with heavy loads. To utilize this option, the "Power Equations" formulation is selected [19].

The AC Load Flow calculation for a balanced, positive sequence provides calculations with a single-phase, positive sequence, symmetrical network representation. The AC Load Flow calculation for an unbalanced, three-phase (ABC) sequence provides calculations for a more complex network representation and provides analysis tools for imbalances such as ones introduced by load imbalances or un-transposed lines [19].

4.5.1.2 Initial Value Calculation in OpenIPSL

OpenIPSL cannot be used alone to start the transient simulation. The initial values for load flow should be calculated with the aid of other programs. In this thesis load flow calculations are taken in PowerFactory and used as initial values to start the model. Using the load flow values from PowerFactory a 100 s simulation time is used to get a fine steady state value for transient simulations. The single line diagram In OpenIPSL with the steady state values is provided in Appendix G. These final values at the end of 100 s are used to define the pre-state operation of the power system in OpenIPSL. The steady state operation plots from PowerFactory and OpenIPSL are presented in Section 5.1.

4.5.2 Definition of Events

Events are situations that cause the change in a power system during the simulation process. In this thesis, a balanced three phase short circuit event is used for the transient simulation purposes on the transmission line near to selected busbar as shown in the Figure 1.1. In simulation, a short circuit event is defined as the time from which the fault occurs to the time when the fault is cleared, and a successive reclosing of protective devices are done. The Short circuit events differ in type, location in the power system (distance), duration and their clearing mechanism. Further short circuit event definition in PowerFactory and OpenIPSL are provided in section 4.5.2.1 and 4.5.2.2 respectively.

4.5.2.1 Event Definition in PowerFactory

PowerFactory contains different types of events used for different purposes. For the purposes of this thesis, the event of short-circuit (***EvtShc***) is used during the evaluation of transient simulation. The short circuit event causes a short circuit on the selected busbars at the specified location on the transmission line. In PowerFactory there is no way to define the duration of the fault. So, another short circuit event has to be defined in the same place to clear the fault. In this case a switching event is defined with the same time as the expected clearing time of the fault [19]. PowerFactory allows all types of fault events although in this thesis only a three-phase fault is considered.

The short-circuit event definition in PowerFactory includes the definition of fault execution time, fault type, fault resistance as well as fault reactance in Ohms. In this thesis five short-circuit events of a three-phase fault is assumed to occur at t = 0 s with fault resistance and reactance as provided in Table 5.1 for each case.

The same way as the short-circuit event the switching event (***EvtSwitch***) definition includes the definition of the execution time, the type of action (whether to open or close the CB) and the selection of the phases involved in the switching event. In this thesis fault clearing time of 0.1 – 0.6 s with the action of all breakers to open are selected.

To make the operations mentioned above work the line has to be available for the RMS/EMT simulations. And this can be defined in the Simulation RMS/EMT and check the available box and same time the short circuit location on the line is selected. This location makes an extra node for the calculation of the short-circuit.

4.5.2.2 Event Definition in OpenIPSL

A three-phase balanced short circuit event is used for the transient study. The short circuit event definition includes the definition of a fault resistance in pu (R_f), fault reactance in pu (X_f), fault starting time (t_1) as well as end time (t_2) (fault duration). In OpenIPSL only a balance three-phase fault is available.

Unlike PowerFactory the short-circuit as well as the switching events are defined at the same time and the short-circuit has to be in the busbar and no other specified place on the transmission.

4.5.3 Execution of Simulation

This step includes the transient simulation and data analysis based on the necessary parameter definitions done during the first two steps (initialization and event definition). Depending on the type of simulation tools, there are some parameters to be defined that can directly affect the output results.

4.5.3.1 Execution of Simulation in PowerFactory

In PowerFactory this steep includes several steps from the RMS simulation used by the DIgSILENT PowerFactory. Defining results objects, running transient simulation, creating plots and variable selection are some of the steps. Detail information about the way they performed can be seen in the User Manual [19].

4.5.3.2 Execution of Simulation in OpenIPSL

In OpenIPSL model checking, and simulation setup are the two last steps in making a successful simulation. Model checking performs initial condition verification and model translation. *The code is translated into procedural code that serves to facilitate functions to be called as the software works through each time step* [23]. The message box of selected case (case 1) is shown in Figure 4.24.

The simulation setup contains parameters like start time, stop time, output interval length, integration algorithm, integration step and tolerance. The parameters used in the simulation setup are the same in all cases and the parameter are shown in Figure 4.25.

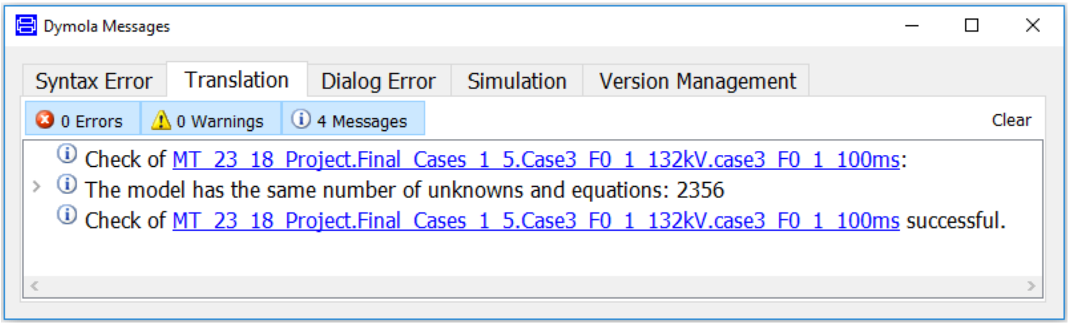


Figure 4.24: Information message after checking from OpenIPSL

As we see from the figure above (Figure 5.43), this is the message for the model (case3_F0_1_100ms). Following a review there no errors or warnings and the number of unknowns matched with the number of equations (2356).

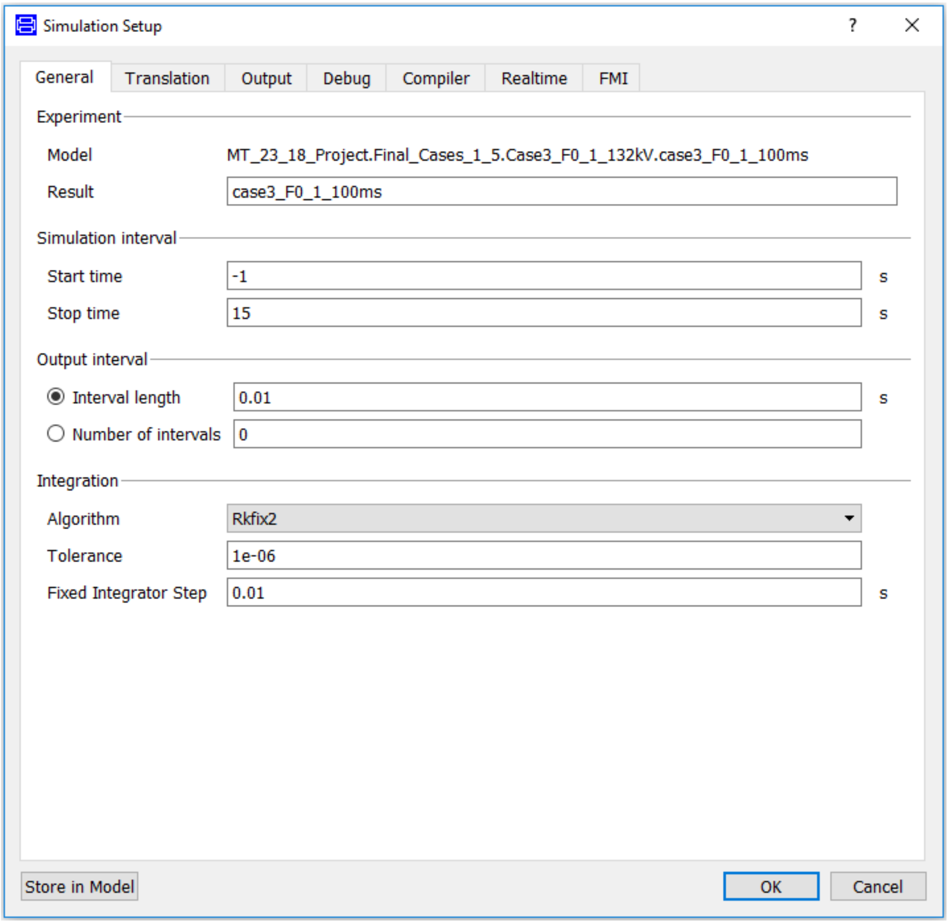


Figure 4.25: Simulation parameters from OpenIPSL

Figure 4.25 provides the simulation setup parameters. Runge Kutta order 2 or 4 is the suitable solver obtained after several tests and in this thesis order 2 (Rkfix2) with time step and tolerance as seen in the figure above is selected.

5 Simulation Results

This chapter presents the pre-fault and post fault simulation results obtained from the Powerfactory and OpenIPSL simulations. The results will be presented based on the study technique defined in section 5.2.

Some notations were used in this section. All generators in the same area were denoted as GX_ where G represents the generators and X represents the numbers 1 - 5 which denote the number of generators. For example, G2_ can represent generators G2_1, G2_2 and G2_3. Another notation is the abbreviation for fault clearing time, denoted as (FRT).

5.1 Pre-fault Condition

The pre-fault condition of a power system is the condition of the system before the presence of disturbance (t < 0). In the pre/fault condition, it is assumed that the power system is operating fault free and without any changes in load and production for a specified period of time (steady-state operation). This means that all the synchronous generators are operating at nominal speed with the specified system voltage range between 0.9 – 1.05 pu.

The initialization values used in OpenIPSL are the same as the ones used in PowerFactory. These values define the steady-state operation for both the PowerFactory and OpenIPSL models. The parameters used in the post-fault analysis will be presented in their pre-fault state in this section. The variables of interest are rotor angle (delta), active power (P), the reactive power (Q), speed, the terminal voltage, and the high voltage side of generator transformer.

5.1.1 PowerFactory

The pre-fault operation in PowerFactory will be presented below in Figure 5.1 and Figure 5.2, using selected generators G3_. The rotor angles of all the generators as well as active power, rotor speed and terminal voltage of the selected generators G3_ are provided below.

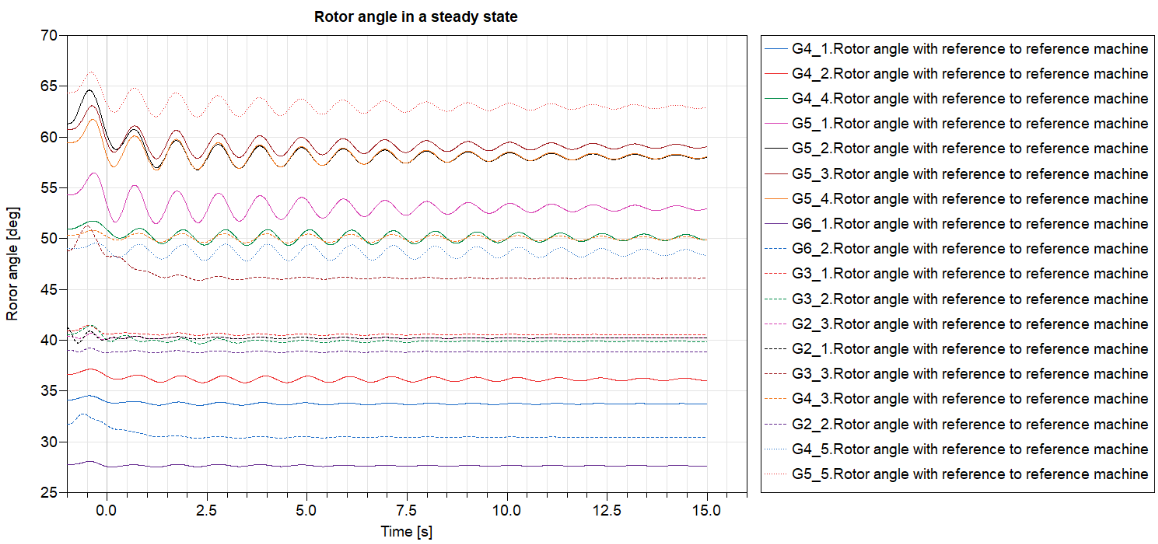


Figure 5.1: Rotor angle representation of all generators in a pre-fault condition from PowerFactory

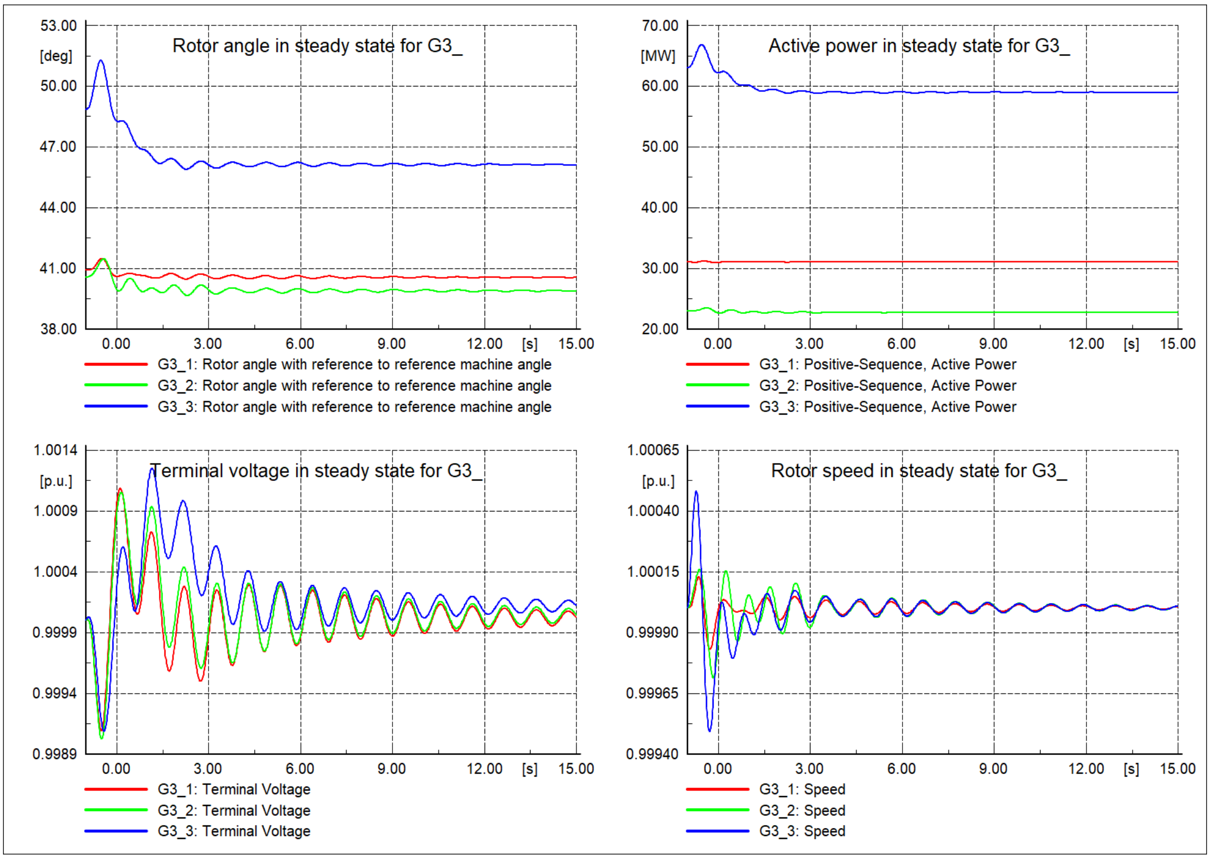


Figure 5.2: Steady state operation of selected generators G3_ from PowerFactory

Figure 5.1 and Figure 5.2 represents the rotor angle of all the generators in a pre-fault condition and the steady state operation of the selected generators from Powerfactory. The rotor angle oscillates in the beginning but during the first 20 s, the system reaches a fine steady state. During the transient stability test, all the simulations in PowerFactory were started at t = -20 and the fault event was planned to occur at t = 0. This gave enough time for the system to reach a fine steady state (pre-fault) for the start of the simulations which is equivalent to those presented in Figure 5.3 and Figure 5.4 from OpenIPSL.

5.1.2 OpenIPSL

The pre-fault operation in OpenIPSL will be presented below in Figure 5.3 and Figure 5.4. The rotor angle of all the generators as well as active power and rotor speed of the selected generators G3 are provided below.

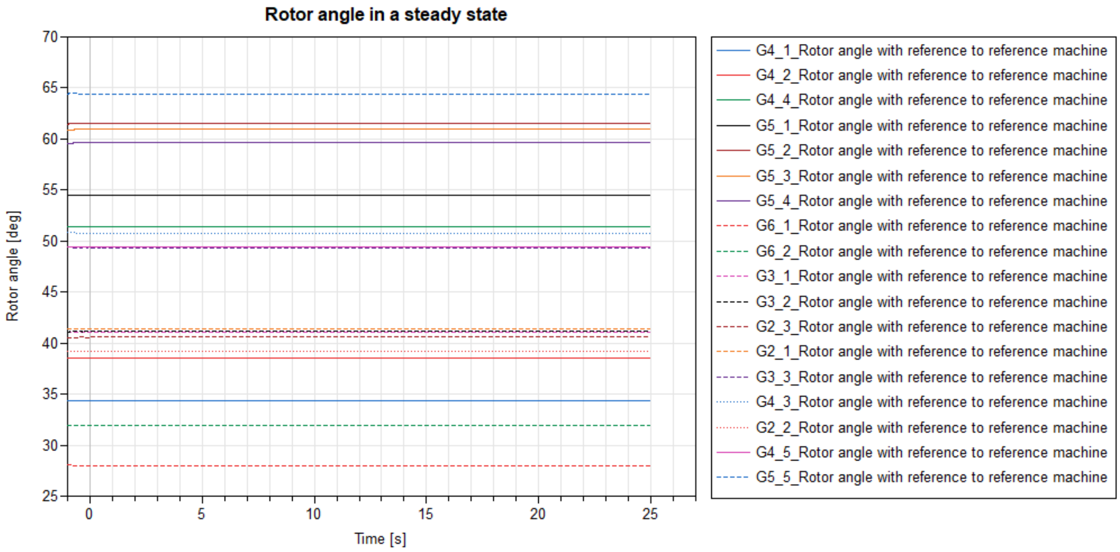


Figure 5.3: Rotor angle representation of all generators in a pre-fault condition in OpenIPSL

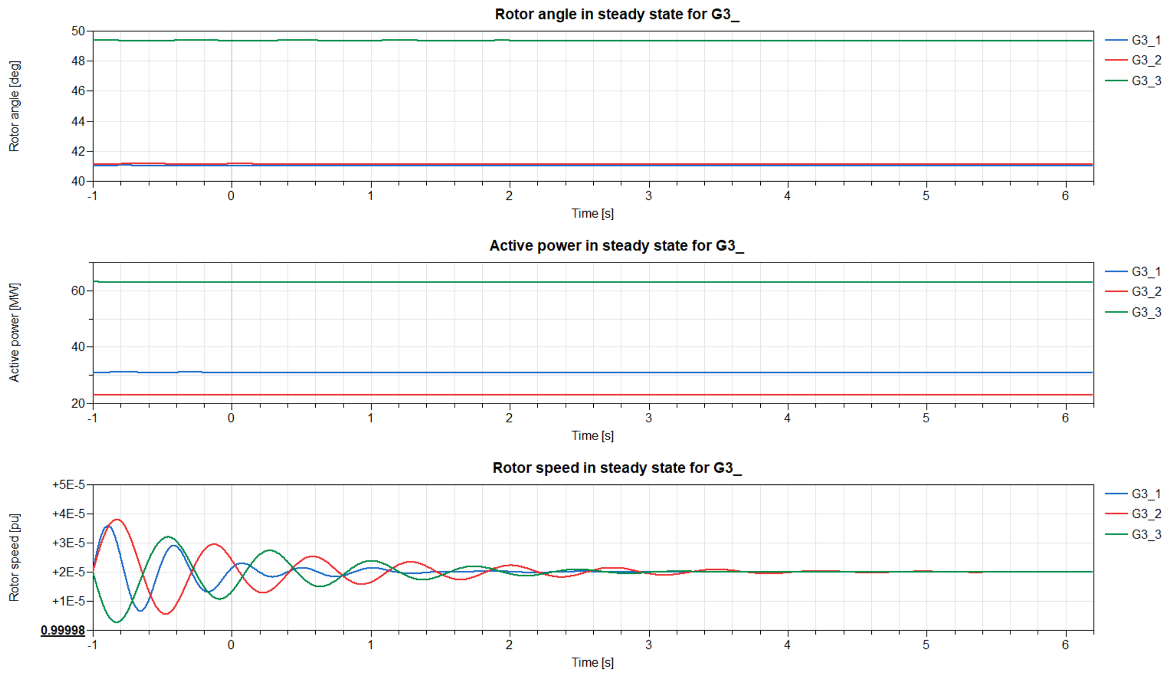


Figure 5.4: Steady state operation of selected generators G3_ from OpenIPSL

Figure 5.4 represents the rotor angle in degrees, positive sequence active power in MW and rotor speed in pu of selected generators G3_ in a steady state operation. Note that the rotor speed has a maximum range of +5E-5.

5.2 Post Fault Condition

The post-fault condition of a power system is the time when the fault occurs (t = 0) to the final state (t >> 0). The area of a study presented in Figure 1.1 is divided into 7 isolated areas according to their geographical locations (the connection points in the 132-kV main station). However, for the study purpose, the system is further categorized into two study systems according to the way the fault influences the system. The generators that are close to the fault area or directly affected by the fault will be studied under the one study system while generators that are further from the fault area will be studied under another external system.

In this section, simulation results from PowerFactory and OpenIPSL will be presented based on the study systems for each of the cases identified in Section 4.4. The simulations will start at t = -1 and a fault will be assumed to occur at t = 0 s with a simulation time over 10 s which will be used in all cases to cover the maximum possible transients.

In Powerfactory the simulation results were obtained using RMS simulation of balanced, positive sequence of adoption step size 0.01 s and maximum step size of 0.1 s. A balanced three-phase short circuit was aimed at the test lines near the target busbar or station. The fault was cleared by opening the circuit-breakers at both ends of the faulty line (test line) simultaneously at the specified fault clearing time.

In OpenIPSL the simulation results were obtained using a second order Runge-Kutta, Rkfix2 (One-step solver) of fixed time step 0.01 s. Greater accuracy could have been achieved using a smaller time step but due to longer simulation times for the smaller time step, this was an acceptable accuracy. A balanced three-phase short circuit was aimed directly at the target busbar or station.

A fault impedance is required in OpenIPSL in order to perform a successful simulation. The size of the fault impedance varies from case to case. Even though smaller fault impedance is acceptable in most cases however, there are cases where large fault impedance is required. A fault resistance (R_f) and reactance (X_f) values are specified in Table 5.1 and are used in Powerfactory and OpenIPSL. The fault impedance has a huge impact in reducing the short-circuit current during the fault period thereby reducing the severity of the fault. The main objective in this thesis is to assess the stability response for high severity of the faults. The primary purpose is to simulate the highest possible short-circuit currents which can be achieved without a fault impedance (bolted faults).

For the purpose of this study, the fault impedance is implemented in two different ways depending on the size of the fault impedance required in OpenIPSL. The two cases are as follows:

- Requirement of a very small fault impedance – Range 1E-05 – 1E-03 pu
- Requirement of a very large fault impedance – Range 1E-02 pu and above

For the first case, equal sized fault impedance is used in OpenIPSL and PowerFactory with the aim to comparing the output results independent of the input parameters. For the second case, no fault impedance is used in PowerFactory.

There will be 5 sub cases with respect to the simulations. Cases 1, 2 and 5 will be simulated with fault impedance in both OpenIPSL and Powerfactory whereas cases 3 and 4 will be simulated with the minimum fault impedance required in OpenIPSL and no fault impedance in PowerFactory.

During the post-fault analysis, the simulation results will be presented based on the study systems classification. In the study system, variables will be plotted together for PowerFactory and OpenIPSL and in the External system, either variables of PowerFactory or OpenIPSL or both will be provided. At the end, FRT capability of generators from PowerFactory and OpenIPSL with different fault clearing times will be determined and the results will be presented in Appendix F. And the FRT plots will be provided at the end for each case.

Table 2.1 provides the fault impedance used in PowerFactory and OpenIPSL for the cases 1 - 5 defined in Section 4.4, Table 4.5 are as follows:

Table 5.1: Fault impedance used in PowerFactory and OpenIPSL

case	Voltage around the fault area [kV]	Base Impedance [Ω]	PowerFactory		OpenIPSL	
			R_f [Ω]	X_f [Ω]	R_f [pu]	X_f [pu]
Case 1	300	900	1E-06	1E-06	9E-04	9E-04
Case 2	132	174.24	1E-05	1E-05	1.7E-03	1.7E-03
Case 3	132	174.24	0	0	5.5E-03	1E-06
Case 4	66	43.56	0	0	1E-01	1E-05
Case 5	22	4.84	4.8E-06	4.8E-06	1E-06	1E-06

5.2.1 Result Fault Case 1 (F1_1)

The first case assumes a fault occurring on the 300-kV side of a (420/300 kV) transmission grid transformer busbar B1_1. This is a central transmission network with the contribution of a three-phase maximum short-circuit power as specified in Table 4.4 which is equivalent to a maximum short circuit current of approximately 20 kA. The simulation results from Powerfactory will provide a higher result due to the contribution from the External Grid.

The function of the infinite bus in OpenIPSL is to control the voltage and the angle of the bus to which it is connected. The infinite bus is only applied during the load flow and does not represent any external network.

The way the generators respond to the fault F1_1 will be provided below in sections 5.2.1.1 and 5.2.1.2 for the study system and external system respectively.

The FRT capability results of a 132, 66 and 22 kV generator units subjected to F1_1 are provided in Appendix F. The FRT plot for the different fault clearing time is shown in Figure 5.14.

5.2.1.1 Case 1 Study System

This is the system where the transmission grid is connected to the main 132 kV station (B0_1). All the generators are connected to the main 132 kV station through a transmission line; in this case the fault will influence all the generators in the system and primary the generators which are in the areas where there is no load or very low load. Generators G2_ and G5_ are among the first generators to lose synchronism.

To study the contribution of the external grid in Powerfactory and compare to the infinite bus in OpenIPSL, the generators G2_ are selected as study generators. The rotor angle, the active power response as well as the voltage of the faulted busbar from PowerFactory and OpenIPSL are plotted together for fault clearing time of 0.2 s.

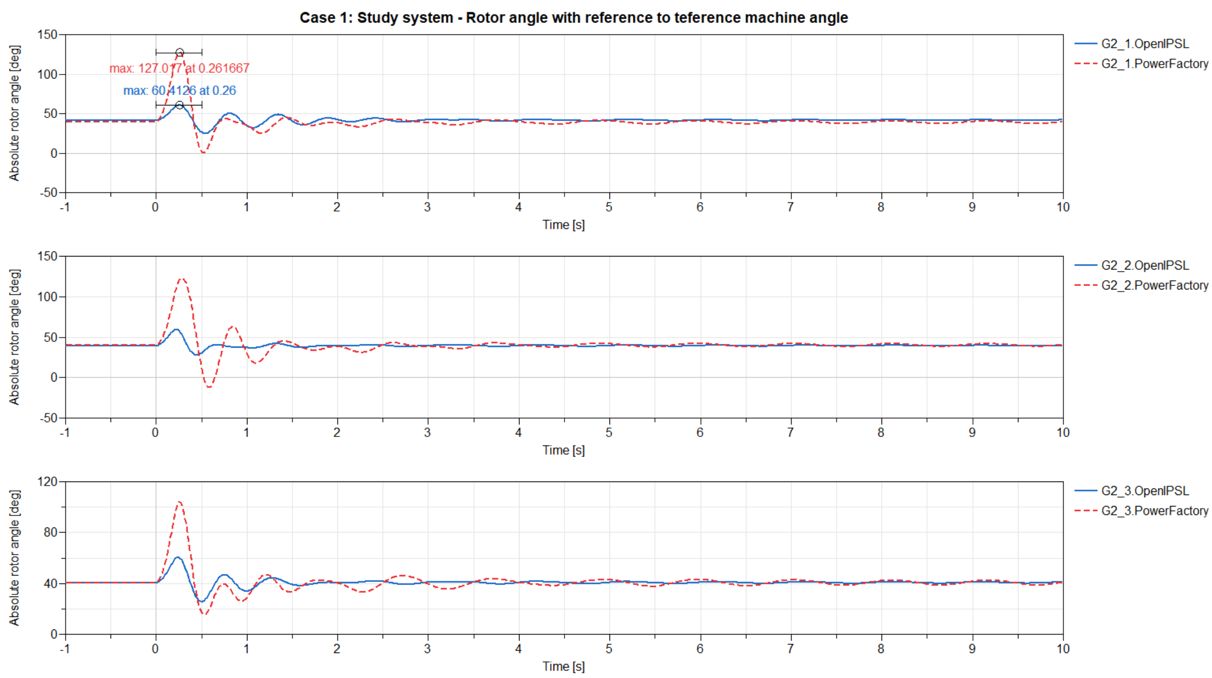


Figure 5.5: Case 1: Study system - Rotor angle with reference to reference machine angle in deg in the event of 0.2 s fault clearing time for OpenIPSL (blue) and PowerFactory (red)

Figure 5.5 represents the rotor angle response in degrees of generators G2_ with a fault clearing time of 0.2 s with (PowerFactory) and without (OpenIPSL) the contribution from the external grid. The solid blue line represents the simulation results from OpenIPSL whereas the dashed red line represents the simulation results from PowerFactory. As seen in figure above, the rotor angle reaches its maximum angle at approximately the same time (t = 0.26 s) for both Powerfactory and OpenIPSL. However, due to the contribution from the external grid, the rotor angle from Powerfactory can be observed to reach approximately double the angle from OpenIPSL.

Beside the difference in the amplitude of the rotor angles, both simulation tools seemed to react in the same way as expected and reached an acceptable stable operating point at approximately the same time.

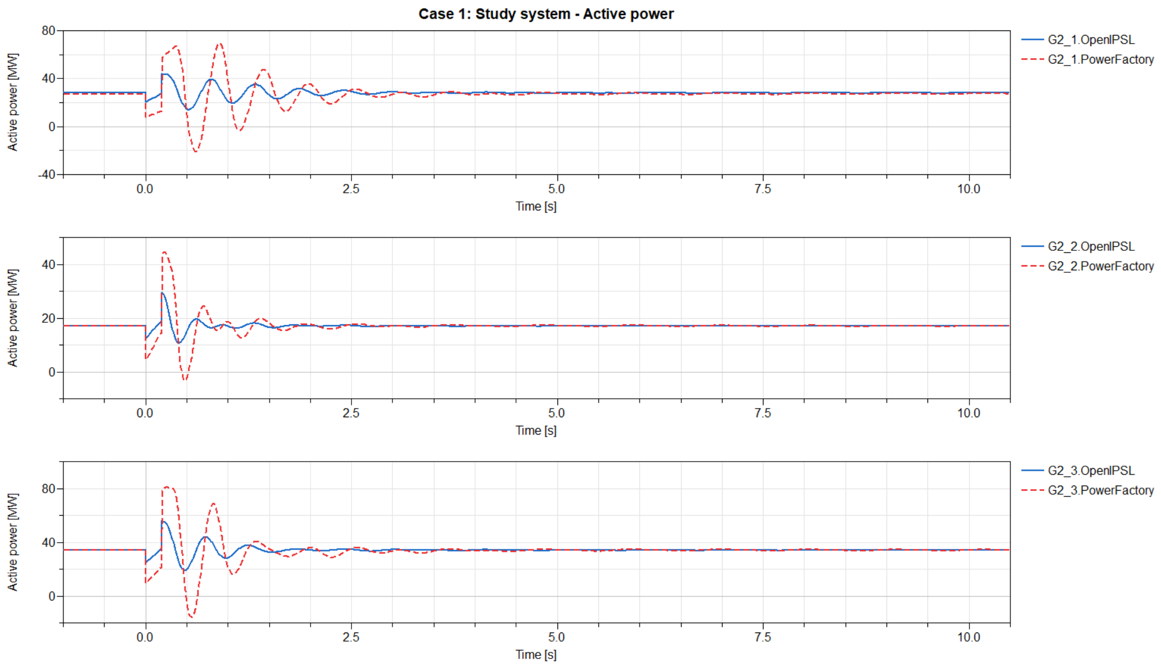


Figure 5.6: Case 1: Study system - Active power in MW in the event of 0.2 s FCT

Figure 5.6 represents the active power response in MW from Powerfactory as well as OpenIPSL for the generators G2_ shown in Figure 5.5.

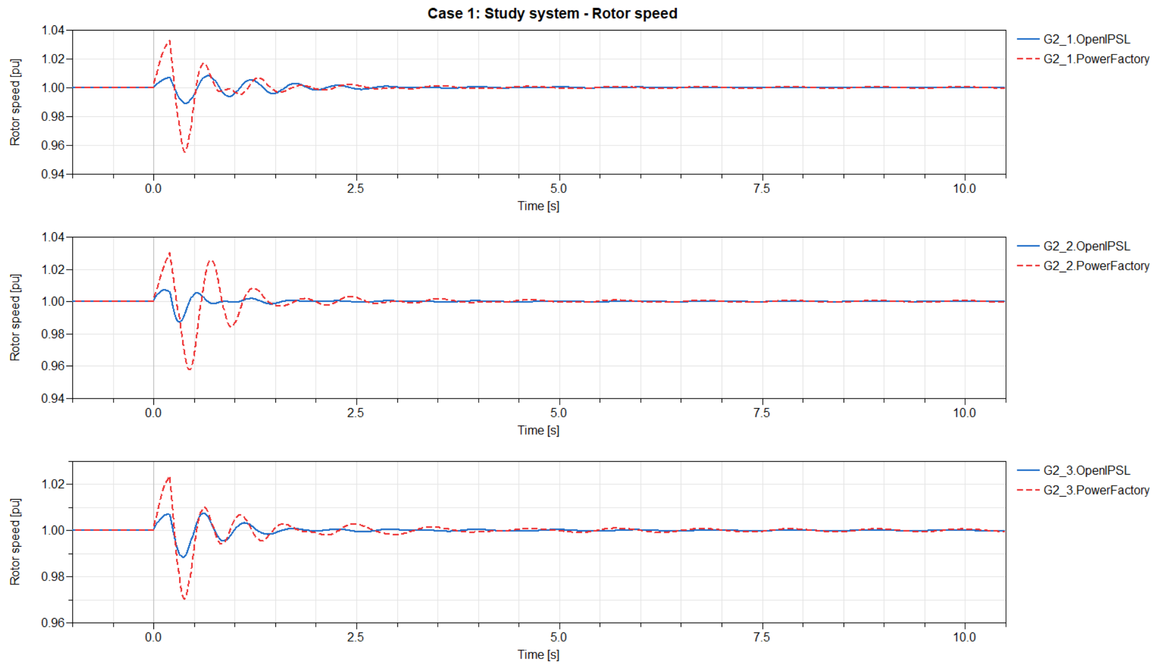


Figure 5.7: Case 1: Study system - Rotor speed in pu in the event of 0.2 s FCT

Figure 5.7 presents the rotor speed in pu of the generators G2_ in the event of 0.2 s fault clearing time. Again, both PowerFactory and OpenIPSL show great similarity on the rotor speed response.

5.2.1.2 Case 1 External System

The external system, in this case, will include the study of the entire system including the way they respond to the fault specified in this case. For case 1, the plot from PowerFactory will be presented.

For a fault clearing time of 0.1 and 0.2 s, all the generators stay in synchronism; but from 0.3 s onwards, the generators start going out of step (pole slip) and at 0.4 s none of the generators were in synchronism. Detailed information about the generators that exhibited successive synchronism is provided in Appendix F. The rotor angle, active power and the rotor speed will be presented below for the last two fault clearing times before all generators went out of step (0.2 and 0.3 s).

Results from PowerFactory (F1_1)

The simulation results of rotor angle, active power and rotor speed from PowerFactory in the event of 0.2 and 0.3 s will be presented below.

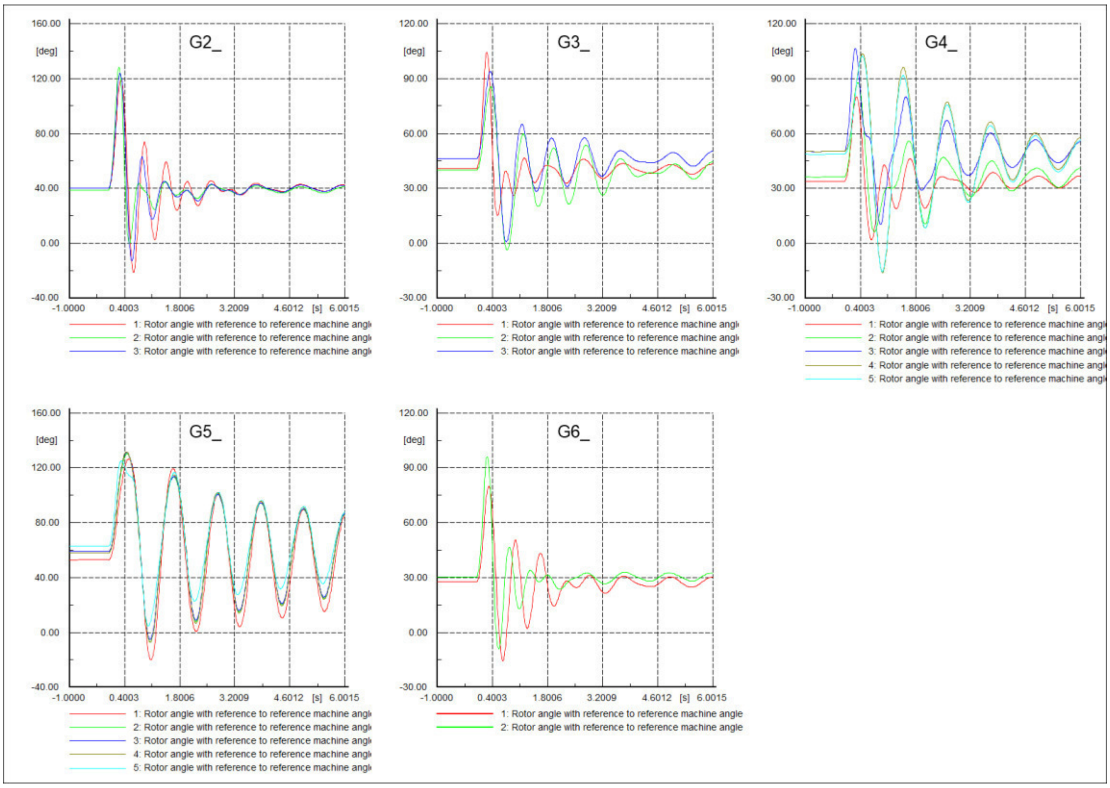


Figure 5.8: Case 1: External system - Rotor angle response in the event of 0.2 s FCT

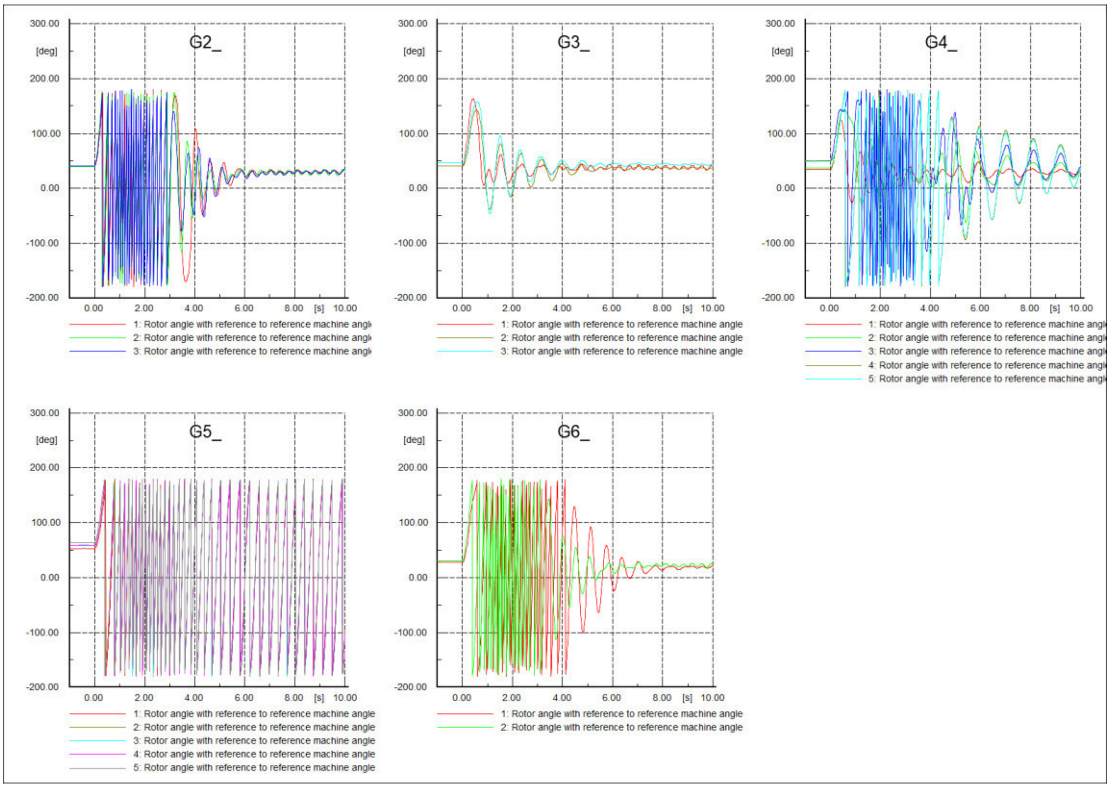


Figure 5.9: Case 1: External system - Rotor angle response in the event of 0.3 s FCT

Figure 5.8 and Figure 5.9 provides the rotor angle response from PowerFactory for fault clearing time 0.2 and 0.3 s respectively.

In the event of fault clearing time 0.2 s (Figure 5.8), it can be observed that the generators stayed in synchronism. During the first swing, all the generators oscillated in the same way, but some generators were observed to oscillate further, especially generators G5_ and part of generators G4_.

For fault clearing time 0.3 s (Figure 5.9) a very large part of the generators was seen going out of step except for generators G3_ and part of generators G4_. This was the last time a generator withstood the fault and stay connected.

The way the generators responded to the fault (F1_1) was similar to each other except for generators in the area of G5_.

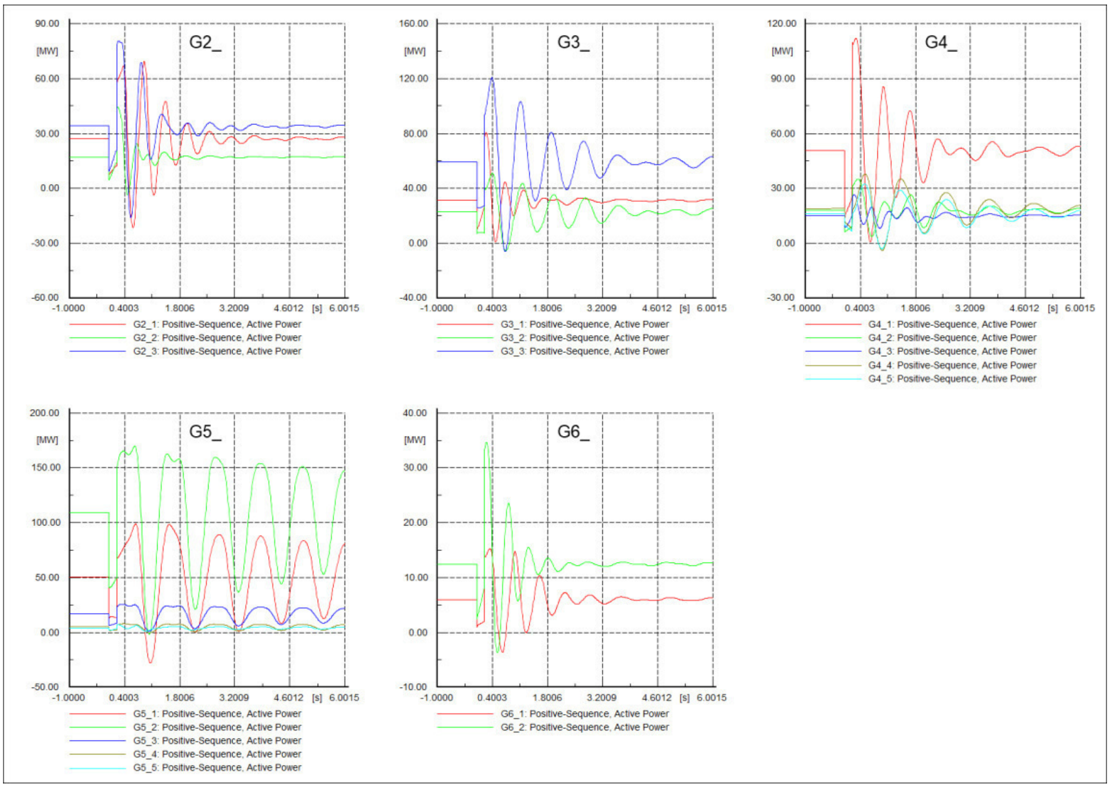


Figure 5.10: Case 1: External system - Active power response in the event of 0.2 s FCT

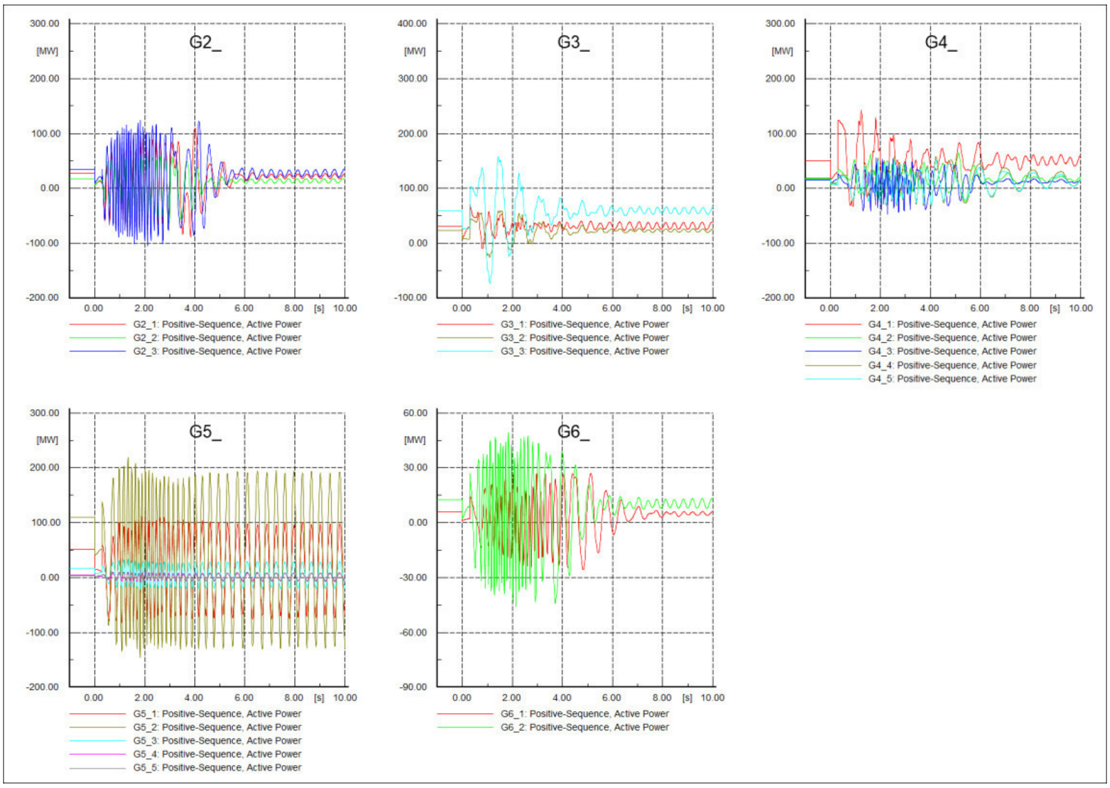


Figure 5.11: Case 1: External system - Active power response in the event of fault clearing time 0.3 s

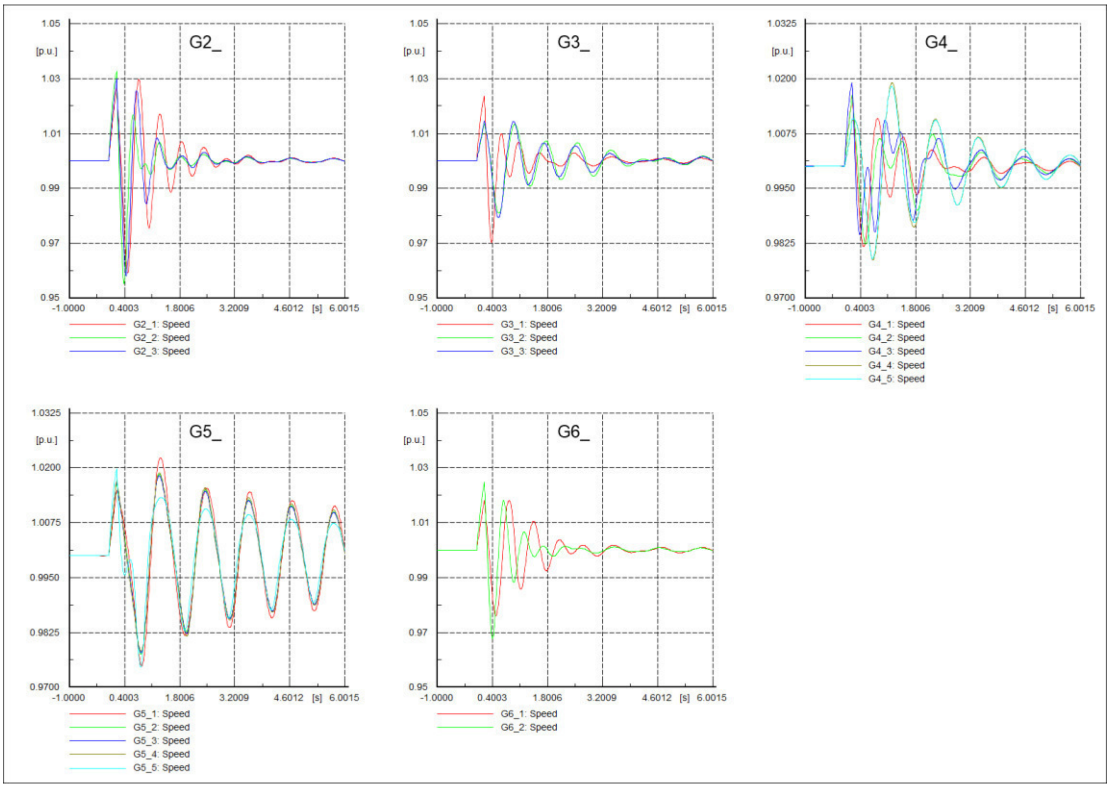


Figure 5.12: Case 1: External system – Rotor speed in the event of 0.2 s fault clearing time

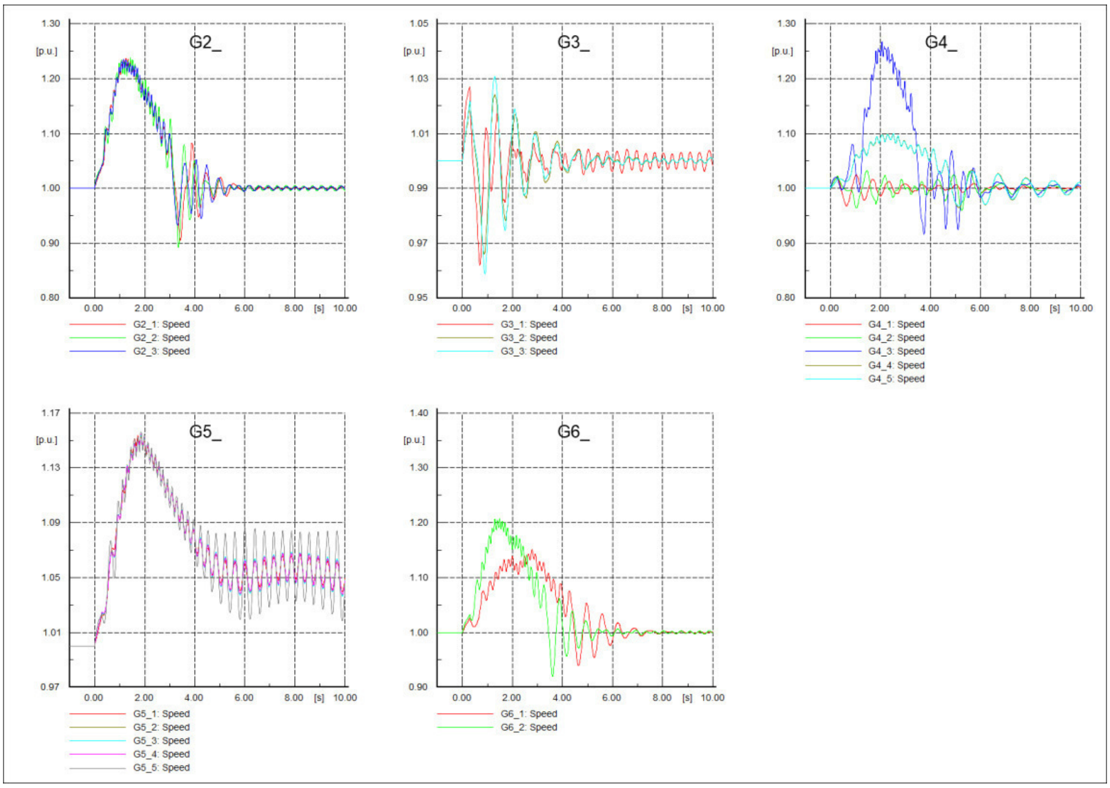


Figure 5.13: Case 1: External system - Rotor speed in the event of 0.3 s fault clearing time

Figure 5.12 and Figure 5.13 represent the rotor speed of the generators in the entire system subjected to the fault F1_1 for fault clearing time 0.2 and 0.3 s respectively.

In the event of fault clearing time 0.2 s (Figure 5.12), the generators got interrupted from a nominal speed of 1 pu and most of the generators were seen to swing in the same way. Even though the generators managed to come to a stable operation afterwards, the way they come to that point differed from generator to generator. Generators with lower mechanical starting time were the generators with higher rotor speed registered but at the same time they were observed to arrive faster to the nominal speed before other generators in the same area.

In the event of fault clearing time 0.3 s (Figure 5.13), most part of the generators were seen to reach a higher speed and as a result lost synchronism.

The FRT capability performance of the generators from PowerFactory and OpenIPSL for the case 1 of clearing time from 0.1 – 0.6 s is presented below in Figure 5.14.

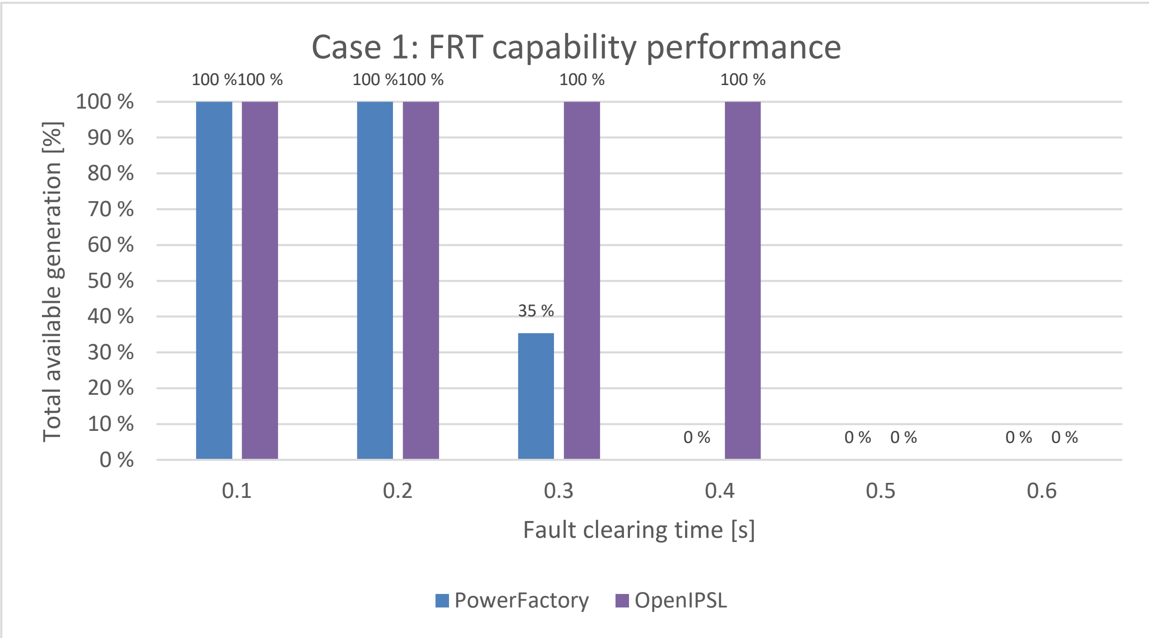


Figure 5.14: FRT capability performance for case 1 of fault clearing time 0-1 – 0.6 s

Figure 5.14 presents the plot of total available generation after the system is subjected to the fault F1_1 of fault clearing time 0.1 – 0.6 s. The results differ from each other and this is due to the contribution from the external network.

Powerfactory showed no generators are available for fault clearing time of 0.4 s and above. The OpenIPSL simulation failed for fault clearing time 0.5 s and above, therefore no data could be recorded for fault clearing time 0.5 and 0.6 s.

5.2.2 Result Fault Case 2 (F3_1)

The second case assumes a balanced three-phase short circuit aimed to occur in the 132-kV test line 2 near busbar B3_2 as shown in the Figure 1.1 denoted as F3_1. A small fault resistance and reactance of 1E-05 pu is used ($Z_{base} = 174.24\ \Omega$) in OpenIPSL and in PowerFactory. The fault impedance was so small to the point where the effect was negligible.

The way the generators respond to the fault F3_1 will be provided below in Sections 5.2.2.1 and 5.2.2.2 for the study system and external system respectively.

The FRT capability results of the 132, 66 and 22 kV generator units subjected to F3_1 are provided in Appendix F. The FRT plot for the different fault clearing time is shown in Figure 5.25.

5.2.2.1 Case 2 Study System

For case 2 the study system will include the generators in the area close to the fault F3_1. This is an area of 3 synchronous generators G3_1, G3_2 and G3_3 supplying a load of 10 MW and 4 MVAr near them. The generators are located about 0, 5 and 47 km from the fault location and connected to each other through 132-kV overhead line. The line further connects to the main 132-kV station through a 21 km long overhead line.

The rotor angle, active power, rotor speed and busbar voltage response of the generators in the study system are plotted in figures below for both PowerFactory and OpenIPSL.

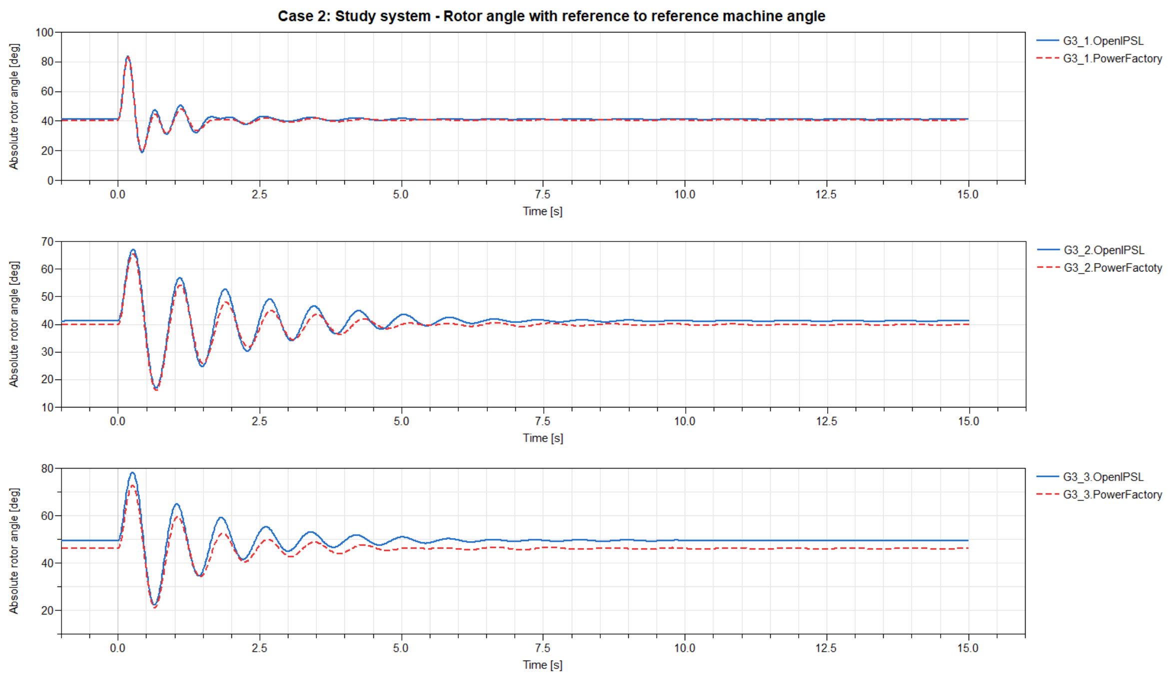


Figure 5.15: Case 2: Study system – Rotor angle with reference to reference machine angle in degrees in the event of 0.1 s FCT for OpenIPSL and PowerFactory

Figure 5.15 represents the rotor angle response in degrees of the generators G3_ with a fault clearing time of 0.1 s. The way the generators responded to the fault from PowerFactory and OpenIPSL match for the generators G3_1 and G3_2 but the result for G3_3 appeared to offset by approximately 3 degrees throughout. This can be due to slight difference in phase angle voltage at the initialization.

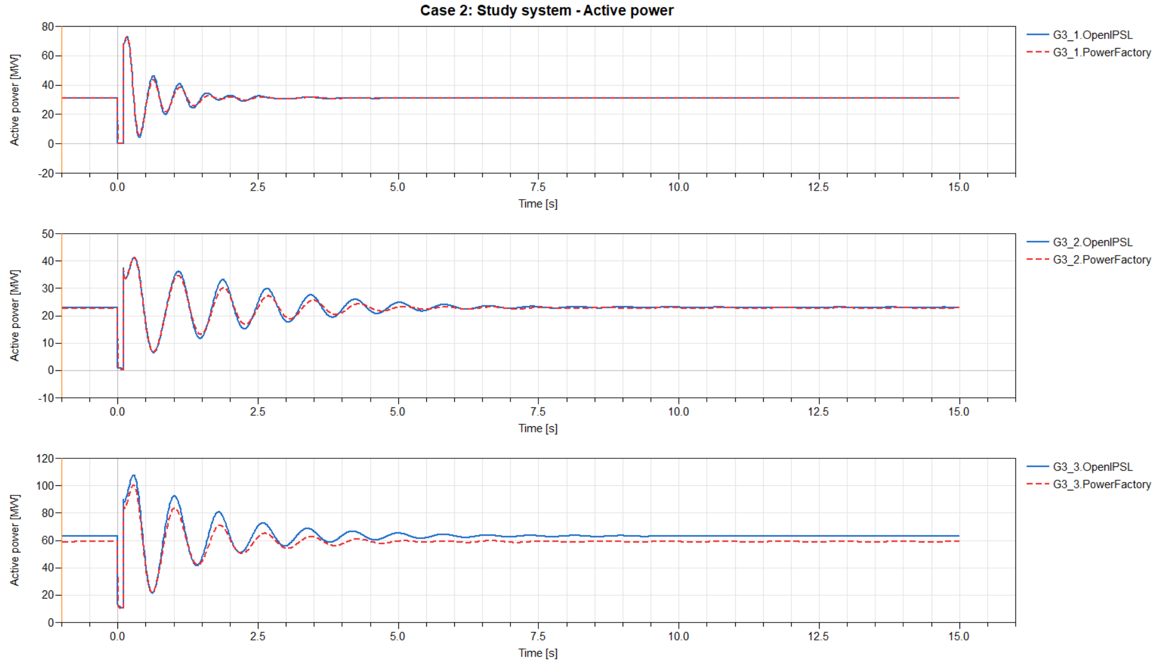


Figure 5.16: Case 2: Study system – Active power in MW in the event of 0.1 s fault clearing time

Figure 5.16 represents the active power response of the generator's rotor angles from Figure 5.15. Due the similarity in rotor angle response, active power response is the same as well.

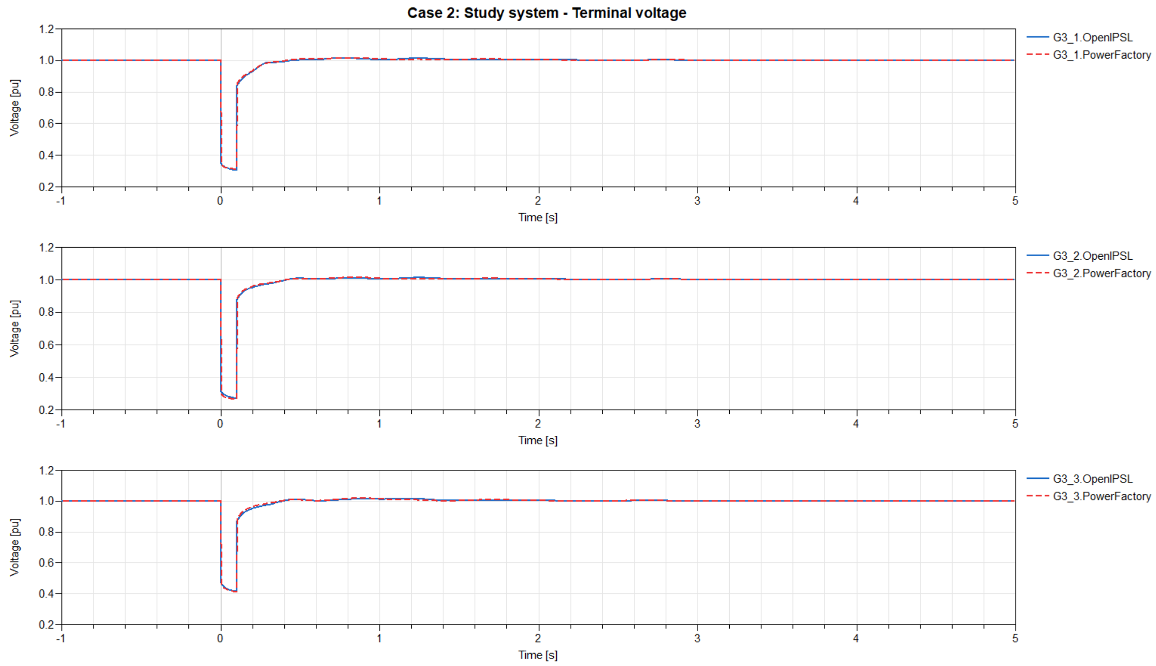


Figure 5.17: Case 2: Study system – Terminal voltage in pu in in the event of 0.1 s FCT

Figure 5.17 shows the terminal voltage of generators which rotor angle presented in Figure 5.15. The way PowerFactory and OpenIPSL responded in the terminal voltage is identical. And this clarifies the AVR response is the same from both models.

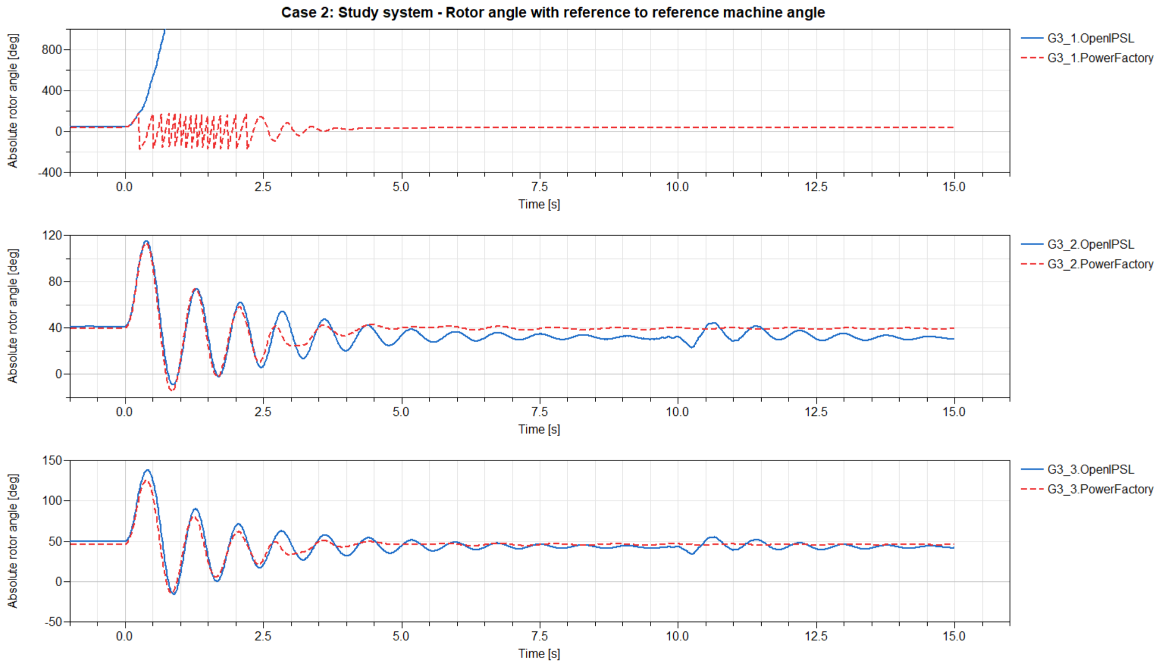


Figure 5.18: Case 2: Study system - Rotor angle response in the event of FCT of 0.2 s

Figure 5.18 shows the rotor angle response in degrees of the generators G3_ with a fault clearing time of 0.2 s. Generator G3_1 is seen facing a first swing instability and this was the only generator out of step with generators G3_2 and G3_3 marginally in synchronism as the rotor angles with both generators observed reaching over 100 degrees. Both PowerFactory and OpenIPSL shows great similarity once again for larger fault clearing times. Note that the range used in the first plot (plot for G3_1) was smaller than the actual angle reached during the15 s simulation time.

5.2.2.2 Case 2 External System

The external system, in this case, included the study of the entire system including the way it responded to the fault specified in this case. For case 2, the plot from PowerFactory will be presented again for all generators and a selected generator group of G6_ from OpenIPSL.

For a fault clearing time of 0.1 s, all the generators stayed in synchronism; but from 0.2 s onwards, the generators start going out of step (pole slip) and at 0.3 s all G3_ generators went out of step. None of the generators went out of step than the generators in the study system and this applied for both Powerfactory and OpenIPSL.

Detailed information about the generators that exhibited successive synchronism is provided in Appendix F The rotor angle, active power and the rotor speed will be presented below for the event of FCT of 0.2 and 0.6 s.

Results from PowerFactory (F3_1)

The simulation results of rotor angle, active power and rotor speed from PowerFactory in the event of 0.2 s will be presented below.

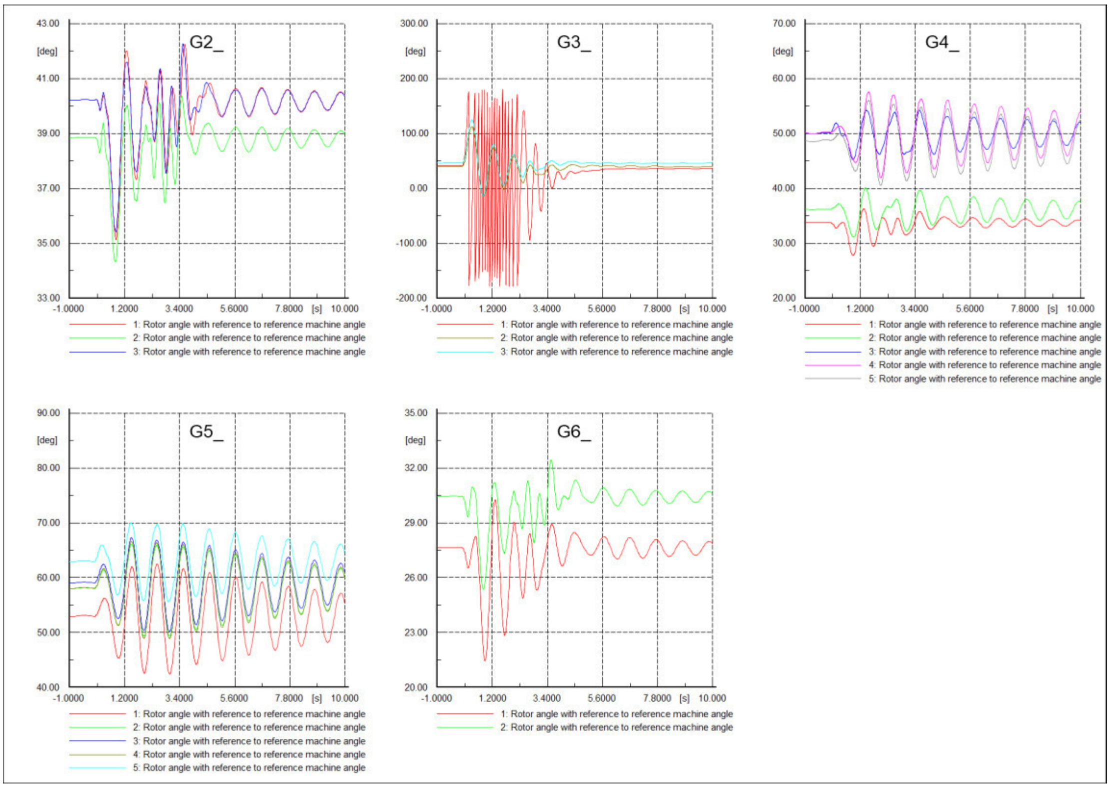


Figure 5.19: Case 2: External system - Rotor angle response in the event of 0.2 s FCT

Figure 5.19 presents the rotor angle response of entire system generators in the event of 0.2 s FCT. The generators out side the study system showed minor disturbance during the first second but generator from the generation group of G5_ are seen to oscillate further. Note that the vertical range scale is smaller.

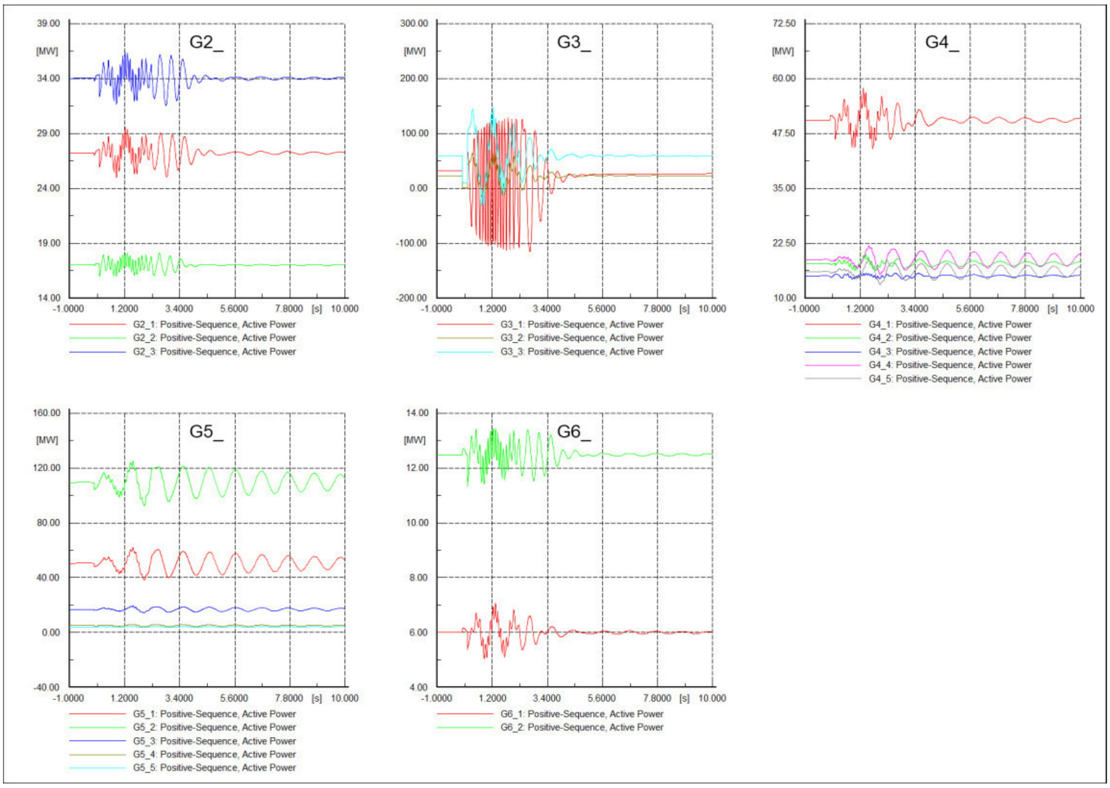


Figure 5.20: Case 2: External system - Active power response in the event of FCT of 0.2 s

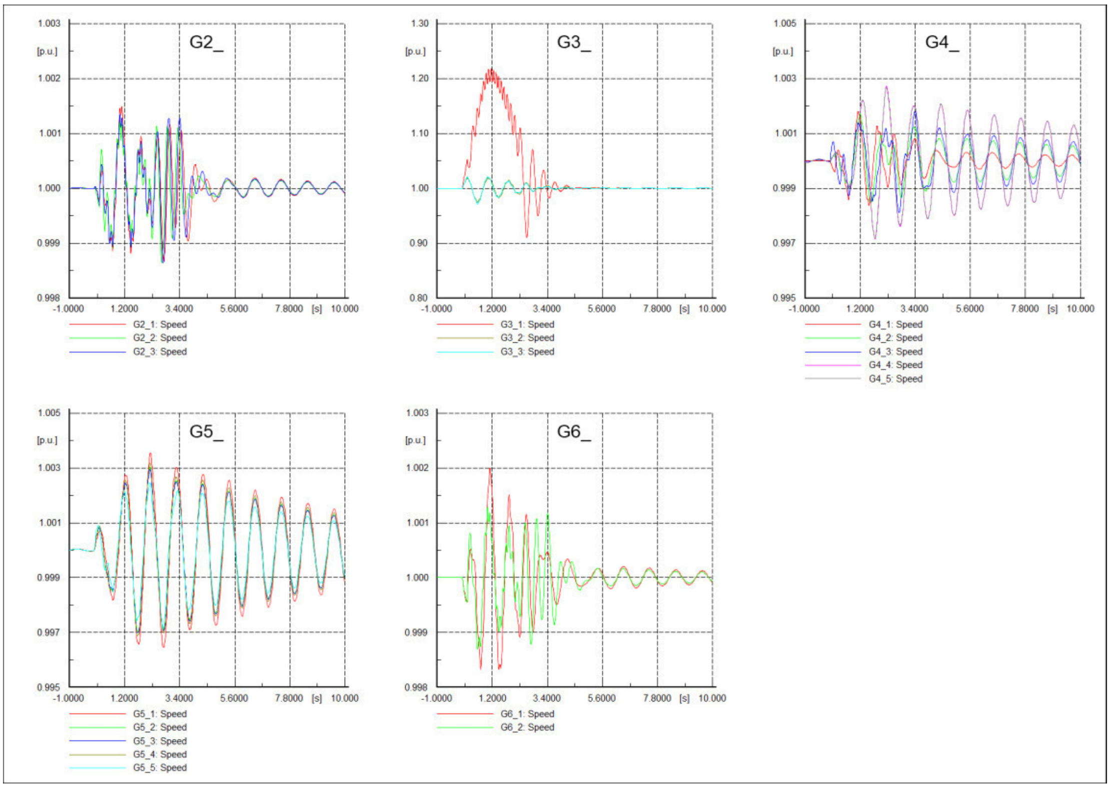


Figure 5.21: Case 2: External system – Rotor peed in the event of 0.2 s FCT

Figure 5.19 - Figure 5.21 represent the rotor angle in degrees, active power in MW and rotor speed in pu of all the generators in the event of 0.2 s FCT.

The rotor angles of the generators in the system were observed to react in the same way. Note that the vertical range scale differs from one generator group to another. As a result, it can be seen more clearly from the rotor speed plot that the generators in the same area oscillated in the same manner except a few generators from G4_. This may be due to the difference in mechanical starting time.

Results from OpenIPSL (F3_1)

To see the response of the external system from OpenIPSL, generators G6_ were selected for further study. The rotor angle response, rotor speed and the connection point voltage were plotted for PowerFactory and OpenIPSL.

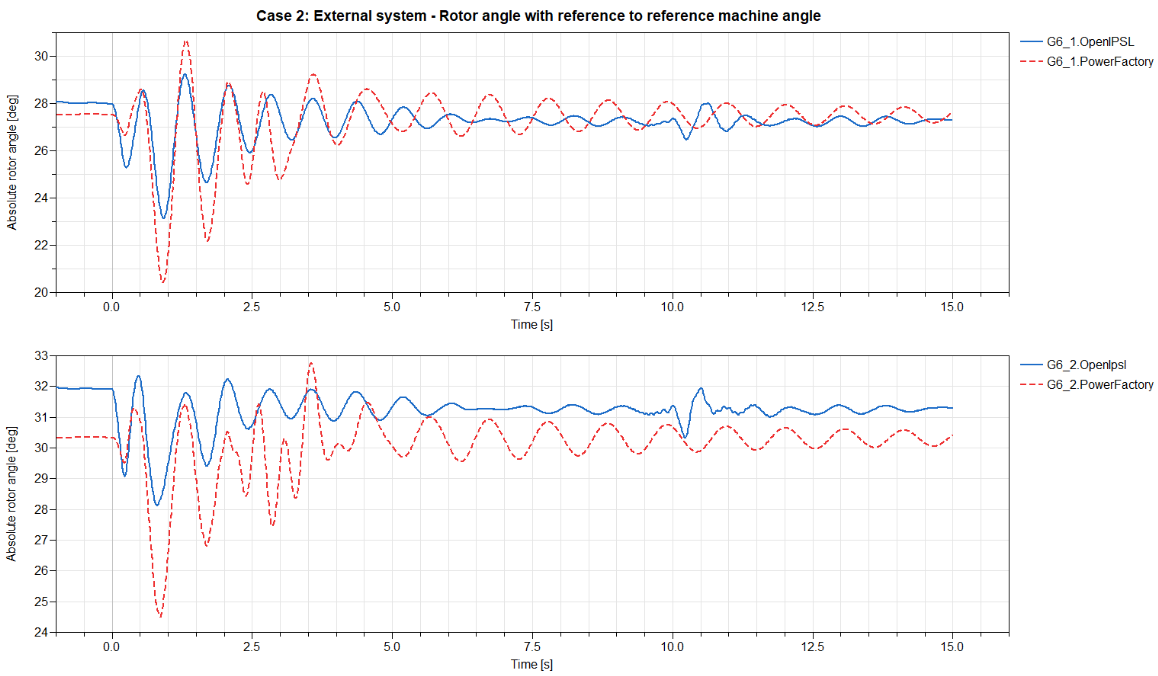


Figure 5.22: Case 2: External system - Rotor angle with reference to reference machine angle in degrees in the event of 0.2 s FCT

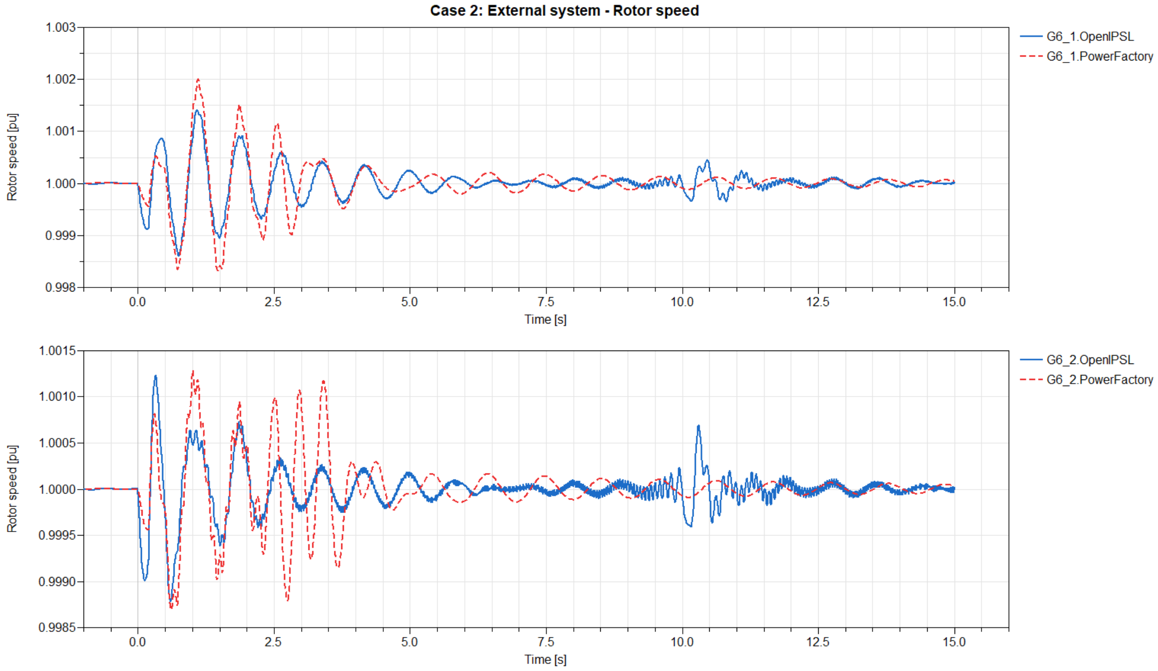


Figure 5.23: Case 2: External system - Rotor speed in pu in the event of 0.2 s FCT

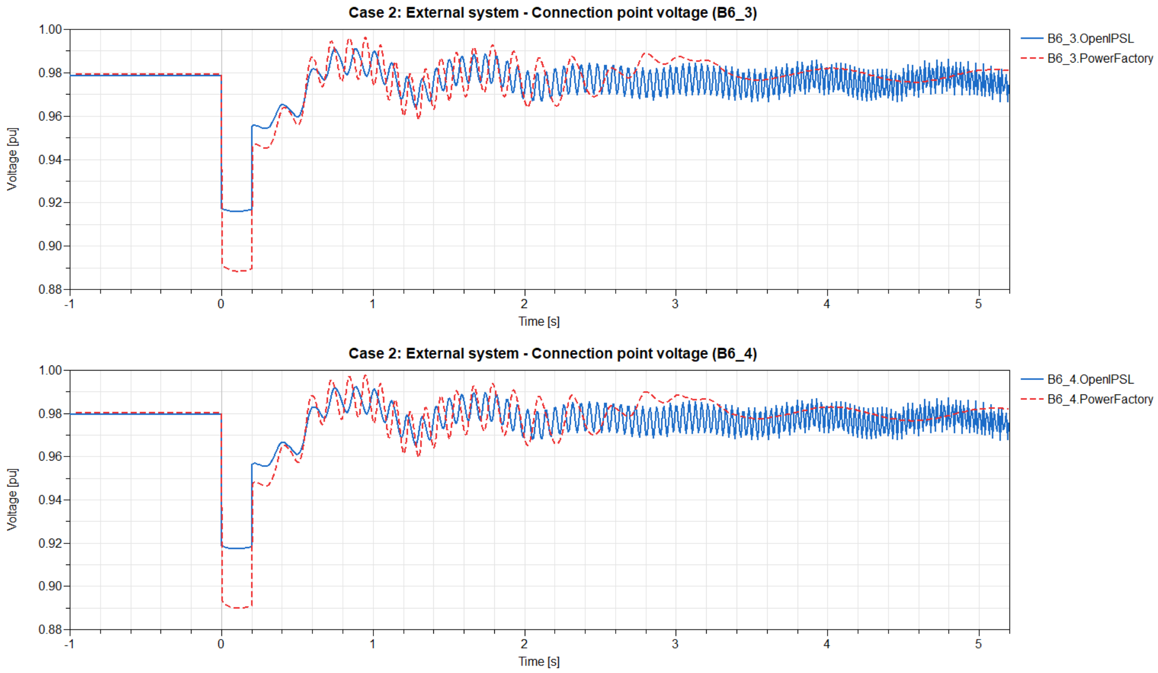


Figure 5.24: Case 2: External system - Connection point voltage in pu in the event of 0.2 s FCT

Figure 5.22 - Figure 5.24 present the rotor angle, rotor speed and the connection point voltage of generators G6_1 and G6_2. These were the selected generators from a group of external system generators. The results for the rotor angle were observed to offset by approximately 0.5

and 1.5 degrees for generator G6_1 and G6_2 due to the slight difference in phase angle at the time of initialization. The rotor angle response was very close for generator G2_1, but for generator G6_2, the rotor angle can be seen to oscillate a little more. As a result, the rotor speed (Figure 5.23) increased aggressively to correct the rotor angle. During this time the voltage at the connection point was seen to fluctuate (Figure 5.24), red dashed line.

Figure 5.25 presents the FRT capability performance of the generators from PowerFactory and OpenIPSL for the case 2 of clearing time from 0.1 – 0.6 s

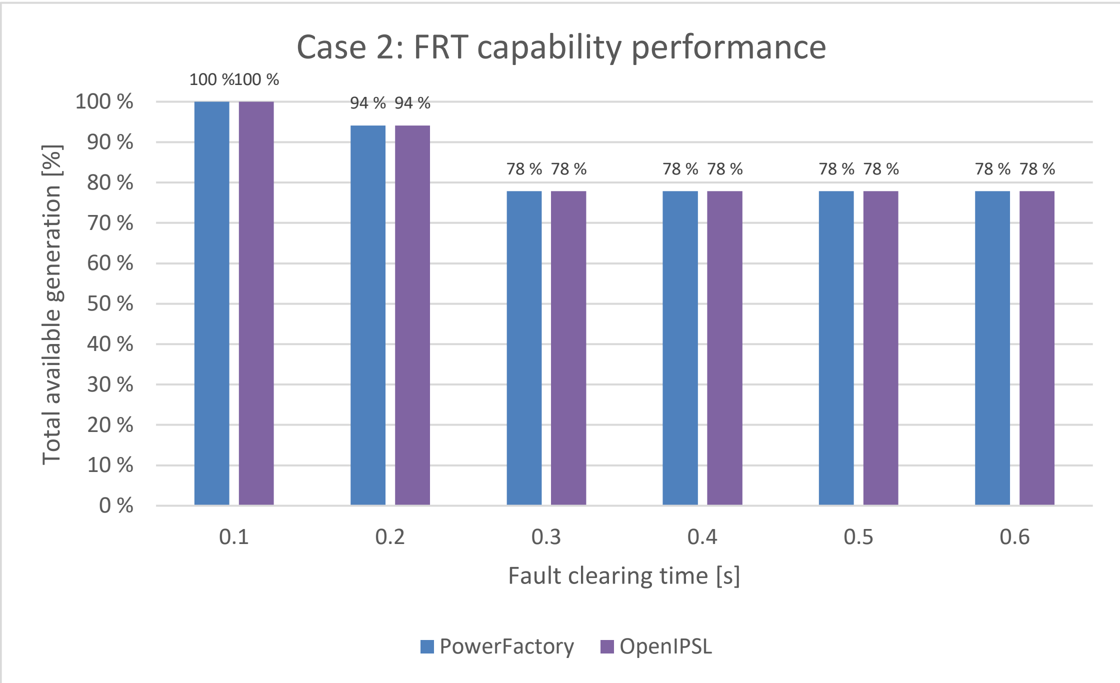


Figure 5.25: FRT capability performance for case 2 of fault clearing time 0.1 – 0.6 s

Figure 5.25 shows the plot of total production managed by the generators after the system is subjected to the fault specified for case 2 with a fault clearing time of 0.1 – 0.6 s. The same initialization parameters are used for both PowerFactory and OpenIPSL. The results obtained were identical in both PowerFactory and OpenIPSL for all fault clearing times.

5.2.3 Result Fault Case 3 (F0_1)

This is the main 132 kV station which has a large influence on the load flow for the entire system from different areas. In this case a balanced three-phase short circuit is assumed to occur on test line 3 near the main 132 kV station as shown in Figure 1.1 denoted as F0_1.

The fault impedance is quite large, and the effect cannot be neglected. Using this on the simulation has a potential to affect the severity of the short circuit during the fault. As the primary purpose is to produce a simulation based on a balanced three-phase of zero fault impedance, this will be the hindrance to see the maximum possible short circuit current.

As mentioned in the introduction part of this chapter, two different initializations will be provided for this case. PowerFactory will be simulated with zero fault impedance whereas OpenIPSL will be simulated with the fault impedance specified in Table 5.1.

The simulation results from OpenIPSL failed at t = 0.305 during the simulation of fault clearing time 0.4 s. This has the same effect for the next 2 test points, therefore no data is recorded from Open IPSL at these points.

The FRT capability results of a 132, 66 and 22 kV generator units subjected to F0_1 is provided in Appendix F. And the FRT plot for the different fault clearing time is shown in Figure 5.32.

5.2.3.1 Case 3 Study System

A fault occurring on the main station will affect the load flow of the entire system. Primary the generators located in a distributed areas or generators which are in areas where there is no load or very low load will be affected. The generators associated with the study system for this case will be generators G2_ (generators with no load close to the production) and generators G5_ (generators with low load to supply near to the production).

The area around generators G2_ is selected as study system for this case. This is an area of 3 synchronous generators each connected to a 132 kV generator transformer which are further connected to a common bus (B2_2). The generators are located approximately 71 km from the fault location (B0_1) and the total production from those generators are supplied to the main station.

The plots of rotor angle, active power, rotor speed in the event of 0.1 and 0.2 s fault clearing time will be provided for PowerFactory and OpenIPSL together in this section.

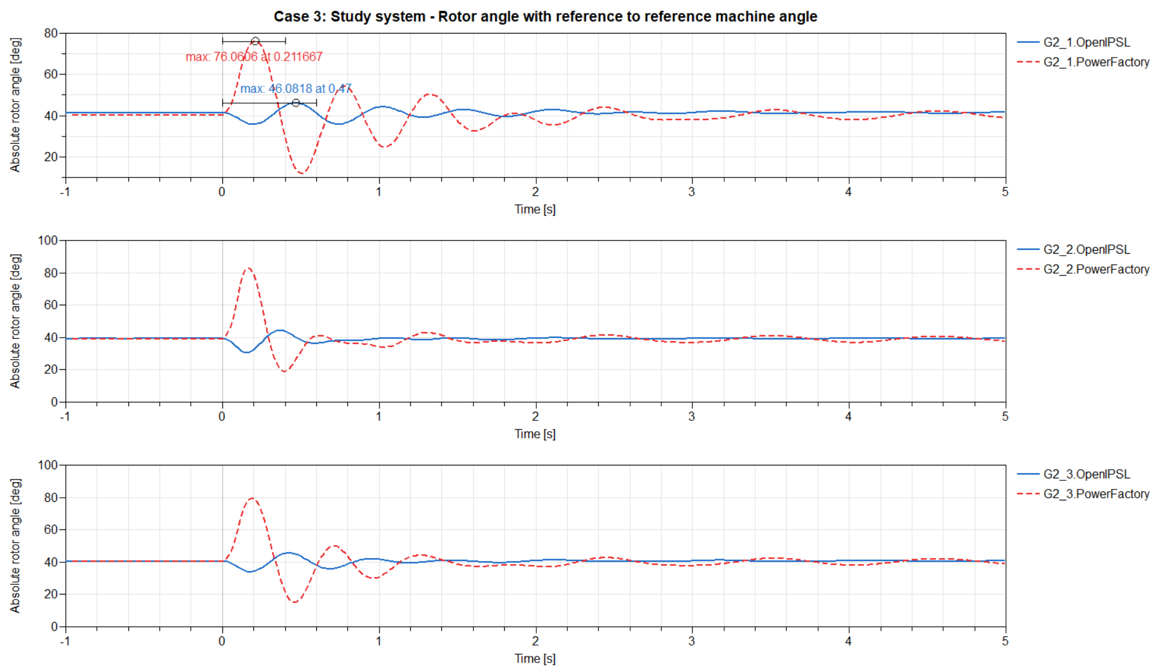


Figure 5.26: Case 3: Study system - Rotor angle in the event of 0.1 s FCT

Figure 5.26 represents the rotor angle response of generators G2_ to the fault F0_1 in the event of 0.1 s fault clearing time. The effect of fault impedance can be observed to reduce the amplitude of the rotor angle and divert the nature of rotor angle response to fault. Beside the difference in the amplitude of the rotor angles and the way they first reacted at t = 0, both simulation tools had the same pre-fault conditions and reached the same stable point.

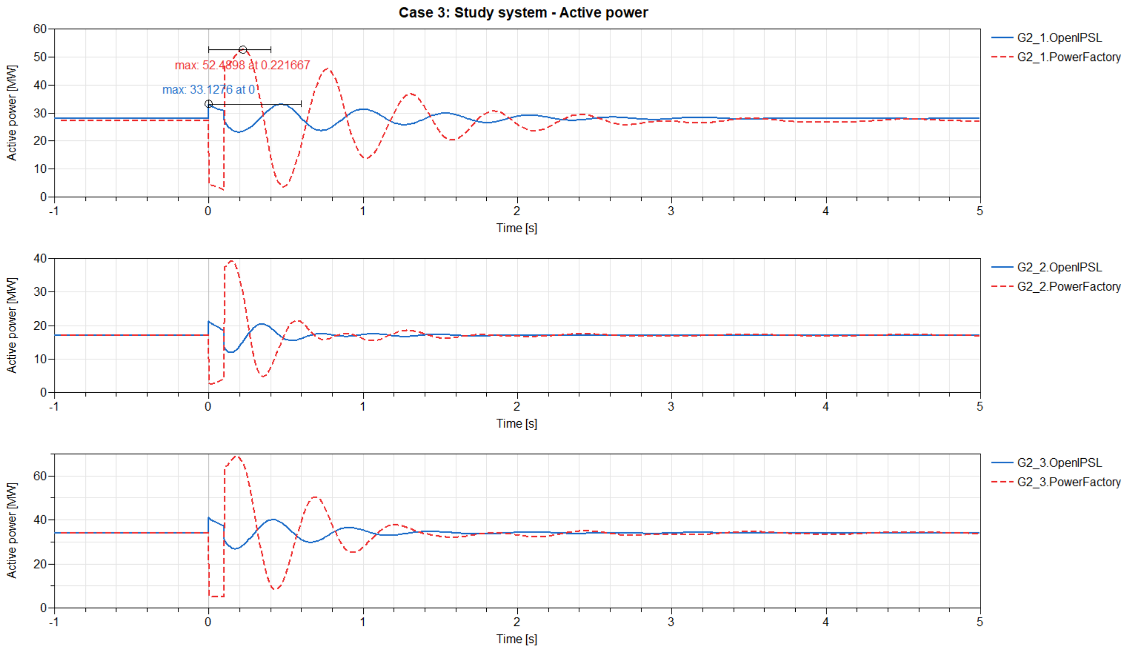


Figure 5.27: Case 3: Study system - Active power in MW in the event of 0.1 s FCT

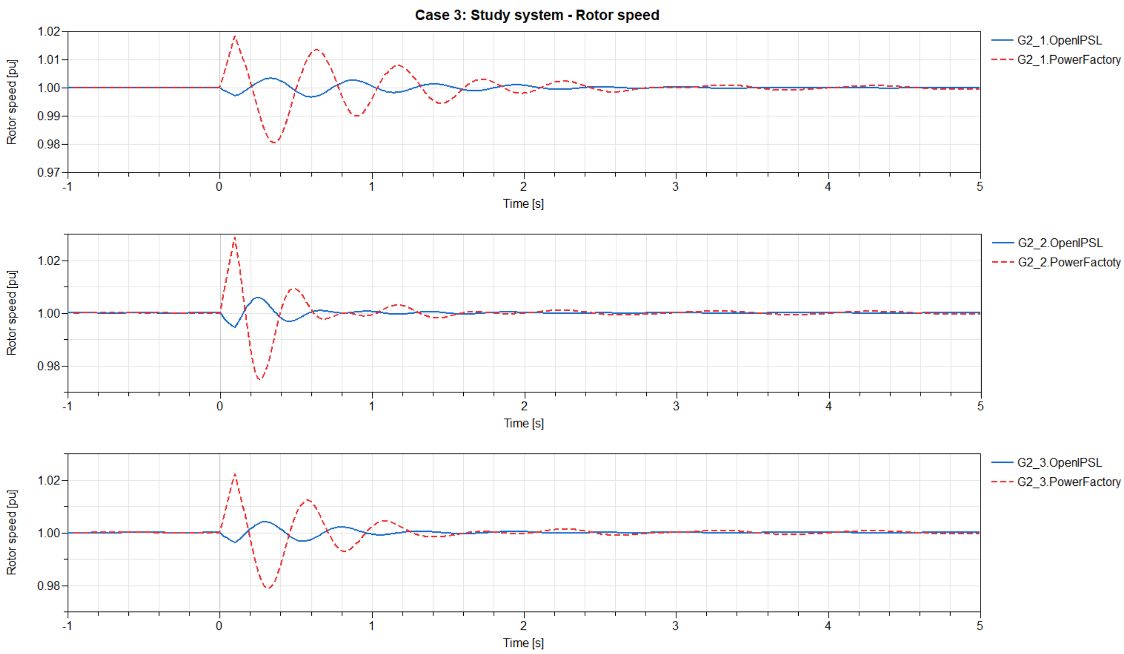


Figure 5.28: Case 3: Study system - Rotor speed in the event of 0.1 s FCT

Figure 5.26 - Figure 5.28 provide the rotor angle, active power and the rotor speed of generators G2_ of fault clearing time 0.1 s from OpenIPSL and PowerFactory with fault impedance in OpenIPSL and no fault impedance in PowerFactory.

5.2.3.2 Case 3 External System

The external system for the case 3 will be the study of the way the generators in the system respond to the fault F0_1 with comparison to the study system generators. Again, plots from PowerFactory will be presented for all generators.

Results from PowerFactory (F0_1)

The simulation results of rotor angle, active power and rotor speed from PowerFactory in the event of 0.2 s will be presented below.

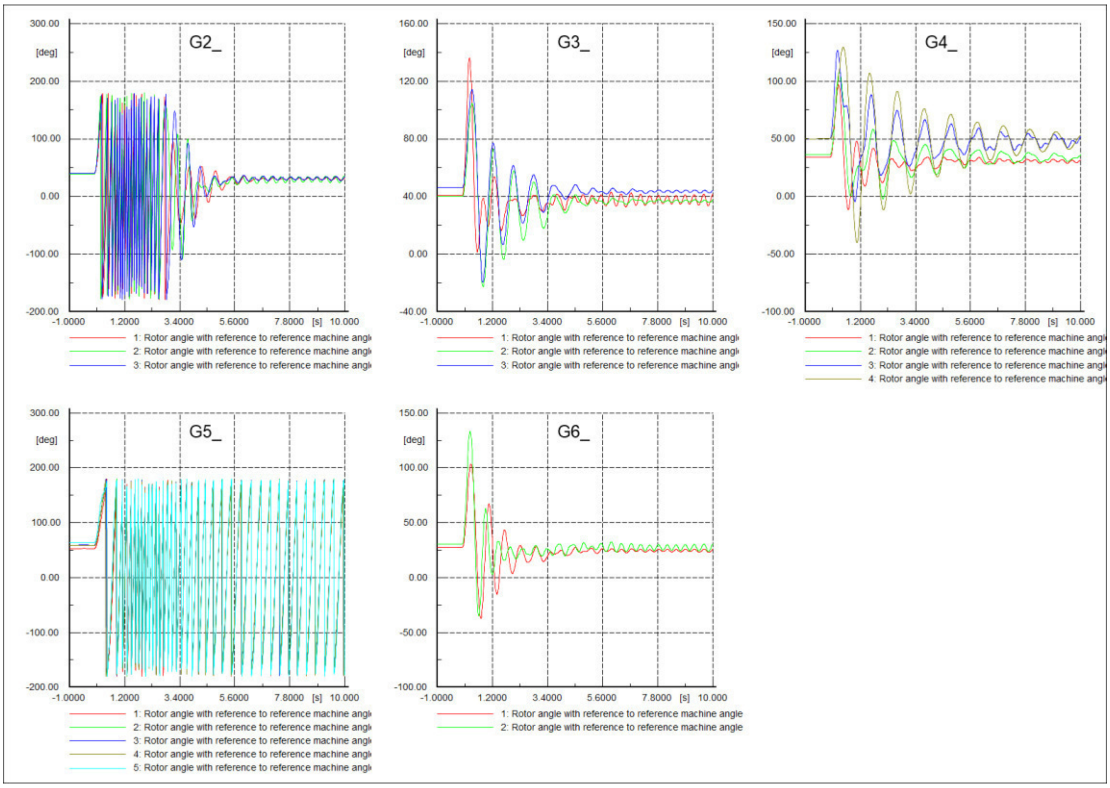


Figure 5.29: External system - Rotor angle in the event of 0.2 s FCT

Figure 5.29 presents the rotor angle response of all the generators in the event of 0.2 s FCT. The generators located in the same area are plotted within the same plot. As mentioned in the study system, generators which supplied most of their production to the main station affects first. As seen from the figure above generators G2_ and G5_ went out of step early in the event of o.2 s FCT. The rest generators are observed to reach rotor angles of over 110 degrees. This is the last time a generator is seen in synchronism for this case.

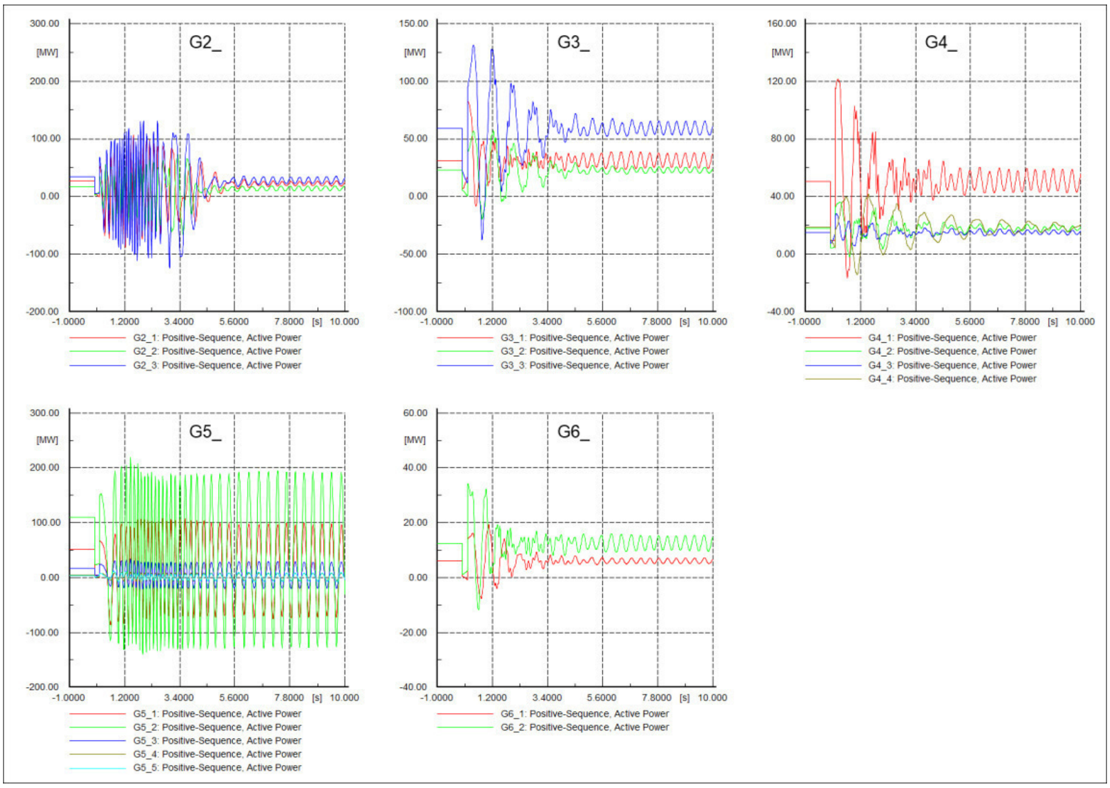


Figure 5.30: Case 3: External system - Active power in the event of 0.2 s FCT

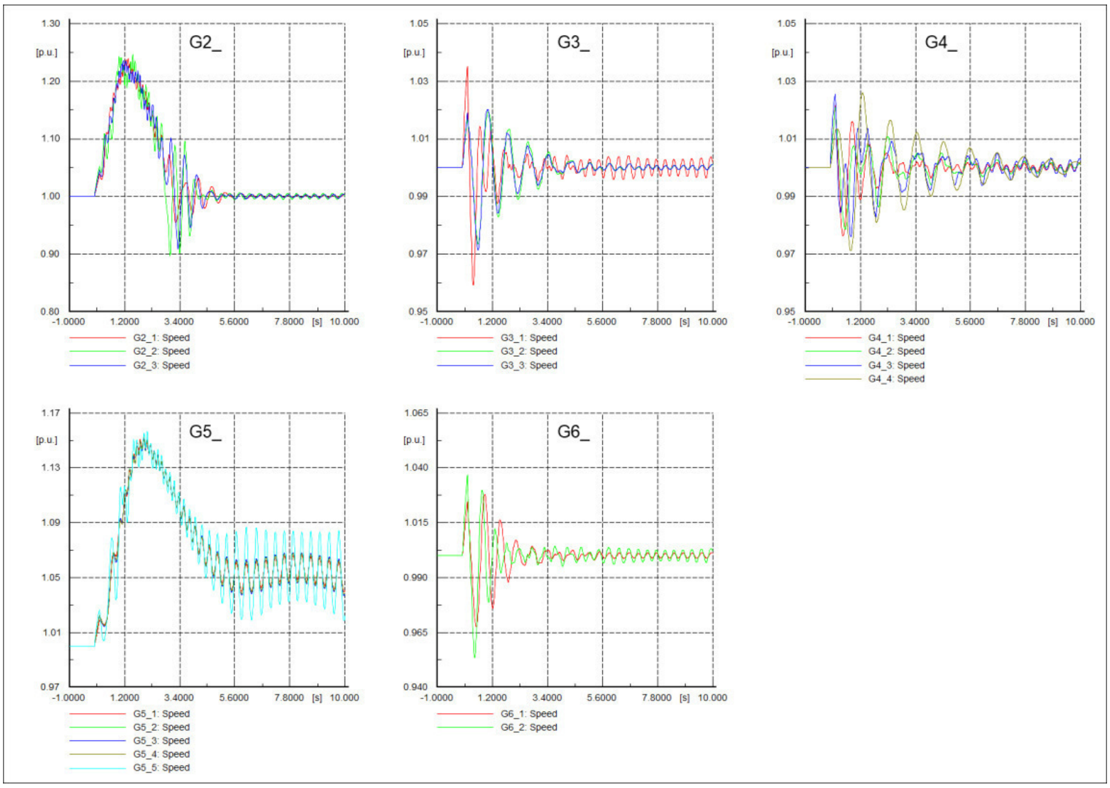


Figure 5.31: Case 3: External system - Rotor speed in the event of 0.2 s FCT

Figure 5.32 presents the FRT capability performance of the generators from PowerFactory and OpenIPSL for case 2 of fault clearing time from 0.1 – 0.6 s.

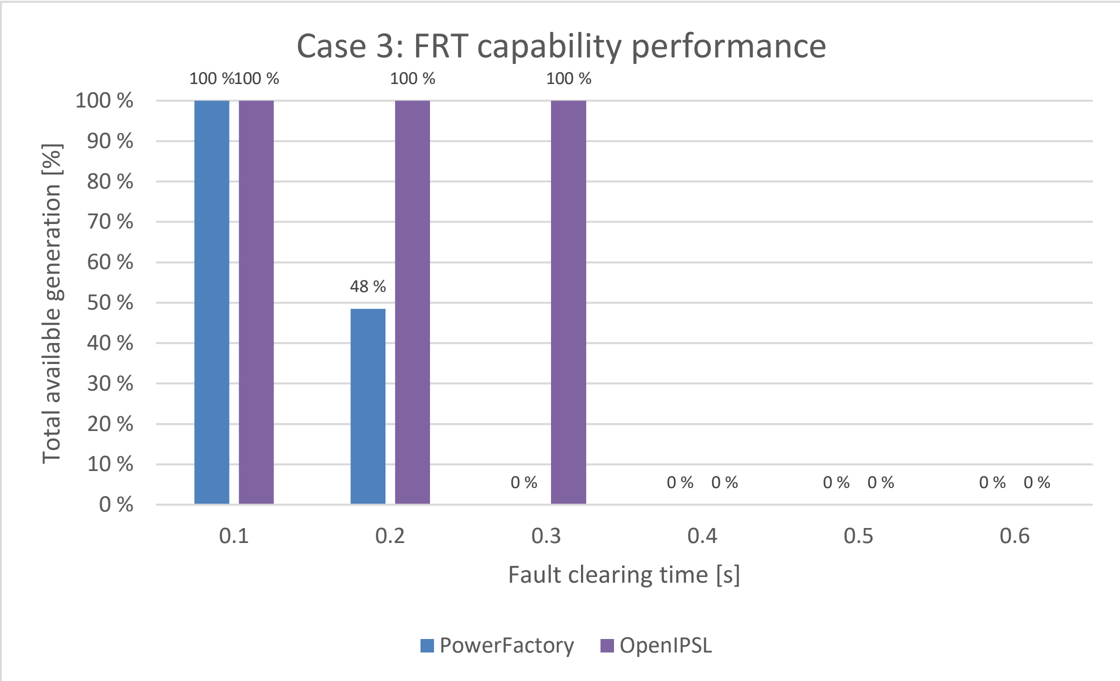


Figure 5.32: FRT capability performance for case 3 of fault clearing time 0.1 – 0.6 s

Figure 5.32 presents the plot of total available generation after the system is subjected to the fault F0_1 with a fault clearing time 0.1 – 0.6 s. The results from PowerFactory and OpenIPSL show huge variance, and this is because of the fault impedance inserted in OpenIPSL.

In the event of 0.2 s FCT, PowerFactory simulation showed only 35% of the total production and no generators available for the fault clearing time of 0.3 s and above. The OpenIPSL simulation failed for fault clearing time of 0.4 s and above, therefore no data could be recorded for the remaining fault clearing times.

5.2.4 Result Fault Case 4 (F4_1)

This is a 66 kV regional distribution network where a balanced three-phase short circuit is assumed to occur on test line 4 near busbar B4_7 as shown in the Figure 1.1 denoted as F4_1. The area around the fault contains several transmission lines of 132, 66 and 22 kV connecting 5 generators, generator transformers and load centers. The combination of different voltages and loads corresponding to these voltages will increase the complexity of the system. During the simulation. OpenIPSL will be simulated with the fault impedance specified in Table 5.1 whereas, PowerFactory will be simulated with no fault impedance. The main objective in this case is to observe the effect of fault impedance.

The way the generators respond to the fault F4_1 are provided below in Sections 5.2.4.1 and 5.2.4.2 for the study system and the external system respectively.

The FRT capability results of a 132, 66 and 22 kV generator units subjected to F4_1 are provided in Appendix F. The FRT plot for the different fault clearing time is shown in Figure 5.39.

5.2.4.1 Case 4 Study System

For case 4 the study system will be the generators that are in the area close to the fault F4_1 which includes generators G4_. During the fault simulation, the network will be split in to 9 isolated areas at the fault point namely the generators above the fault point (G4_3, G4_4 and G4_5) and generators below the fault point (G4_1 and G4_2). Generators which are above the fault will face the biggest problems. Generators located above the fault as well as generator G4_1 are chosen in this study system.

The rotor angle, active power, rotor speed and connection point voltage response of the generators in the study system in the event of 0.6 s FCT are plotted together for PowerFactory and OpenIPSL in the figures below.

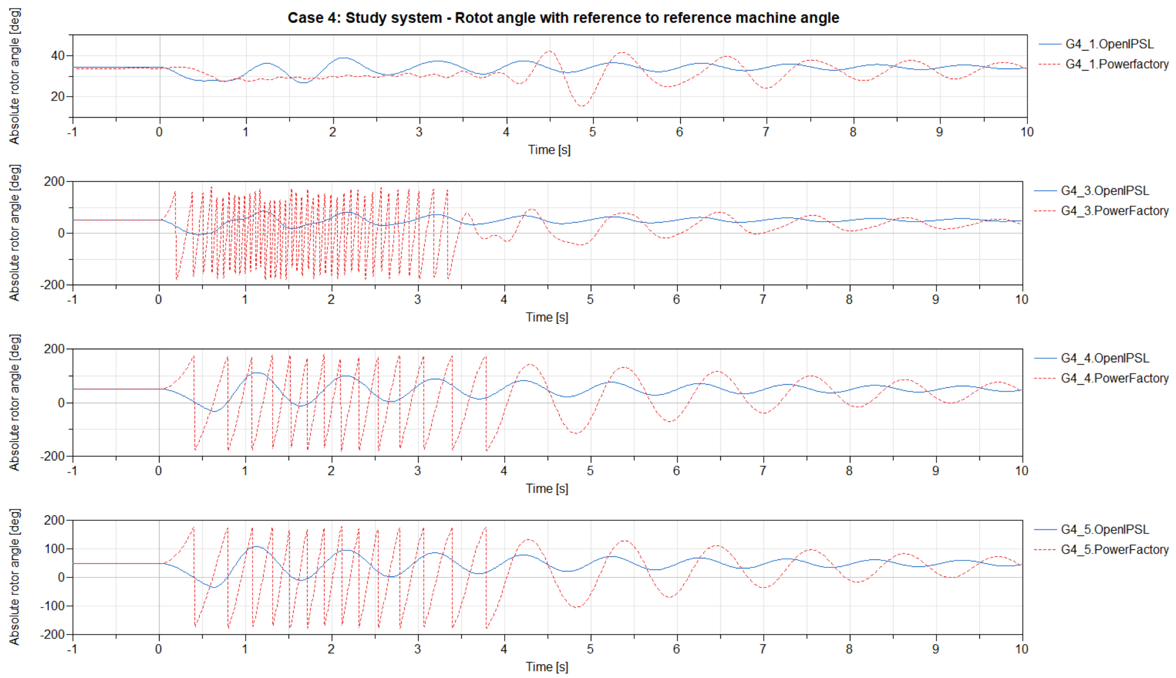


Figure 5.33: Case 4: Study system - Rotor angle with reference to reference machine angle in the event of 0.6 s FCT

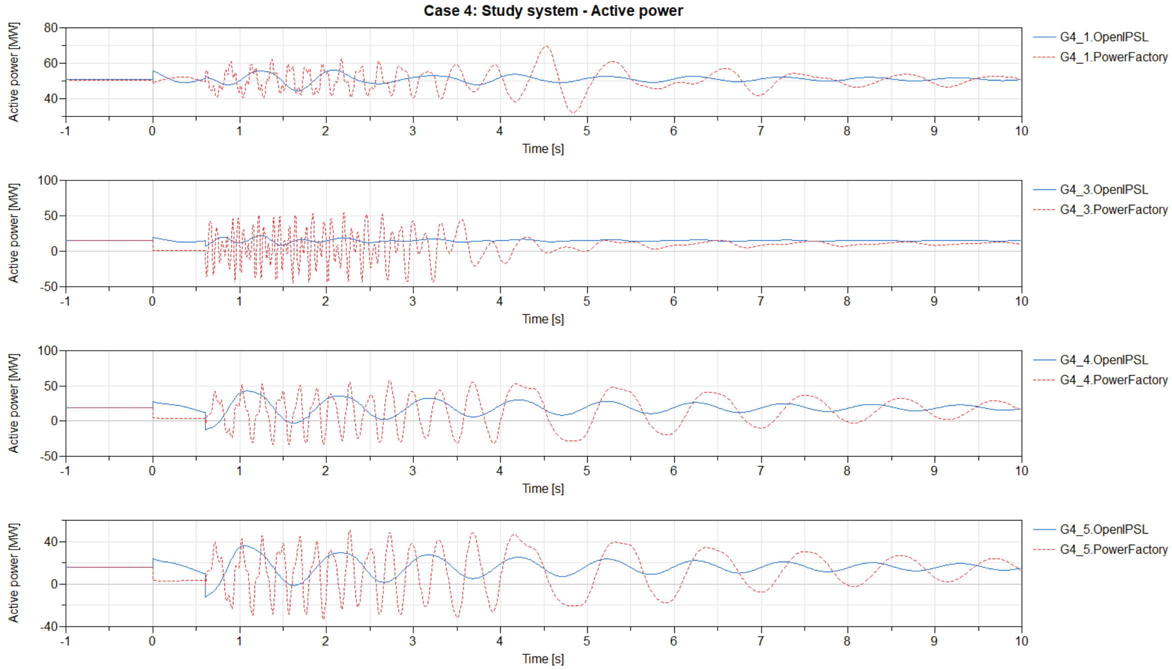


Figure 5.34: Case 4: Study system - Active power in the event of 0.6 s FCT

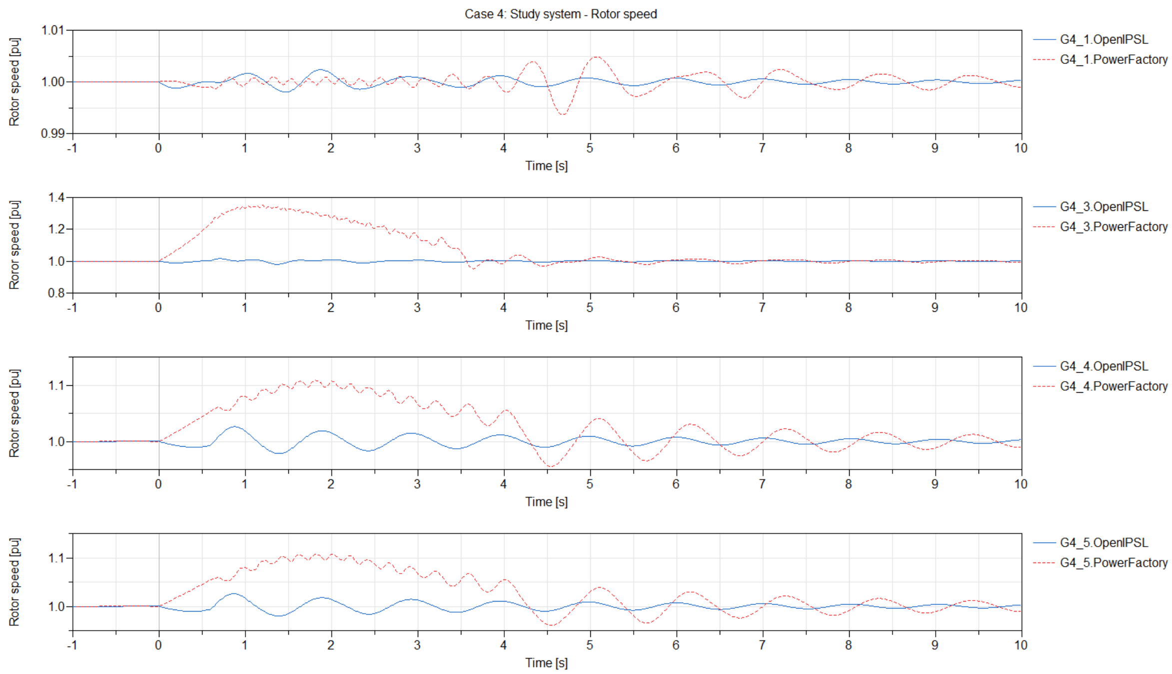


Figure 5.35: Case4: Study system - Rotor speed in the event of 0.6 s FCT

Figure 5.33 - Figure 5.35 represent the rotor angle, active power and rotor speed in the event of 0.6 s FCT of the study system generators. The simulation is based on different initializations for PowerFactory and OpenIPSL, as a result the output is observed to be as expected.

5.2.4.2 Case 4 External System

The external system in this case will include the study of the entire system to the way they respond to the fault F4_1. The plots of the rotor angle, active power and the rotor speed of the entire system from PowerFactory will be presented in figures below.

Results from PowerFactory (F4_1)

The plot of the rotor angle, active power and rotor speed of the entire system in the event of 0.6 s FCT are shown in the figures below.

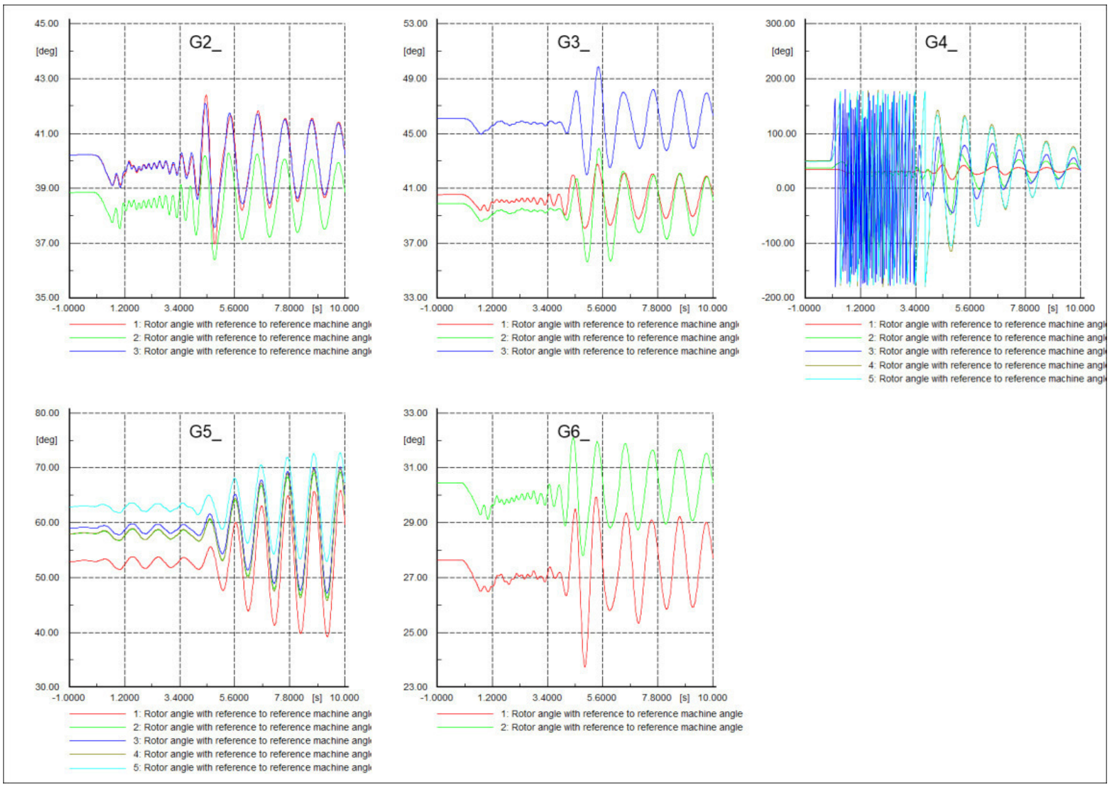


Figure 5.36: Case 4: External system - Rotor angle with reference to reference machine angle in the event of 0.6 s FCT

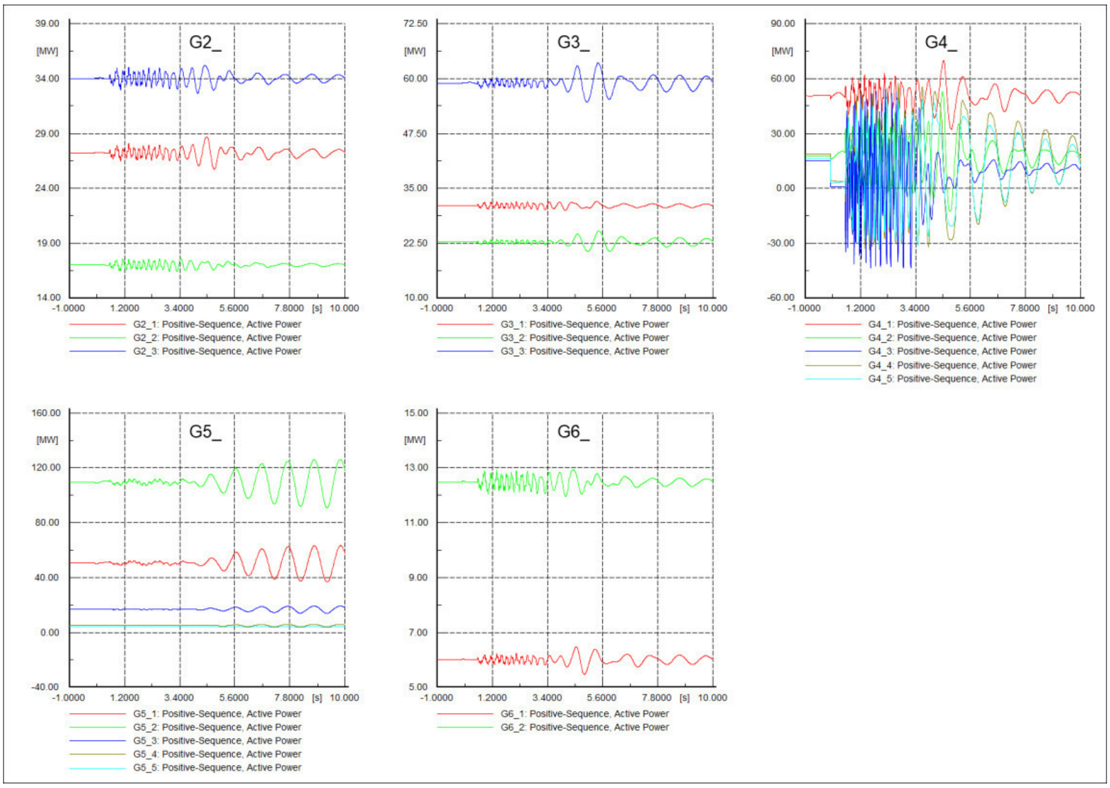


Figure 5.37: Case 4: External system - Active power in the event of 0.6 s fault clearing time

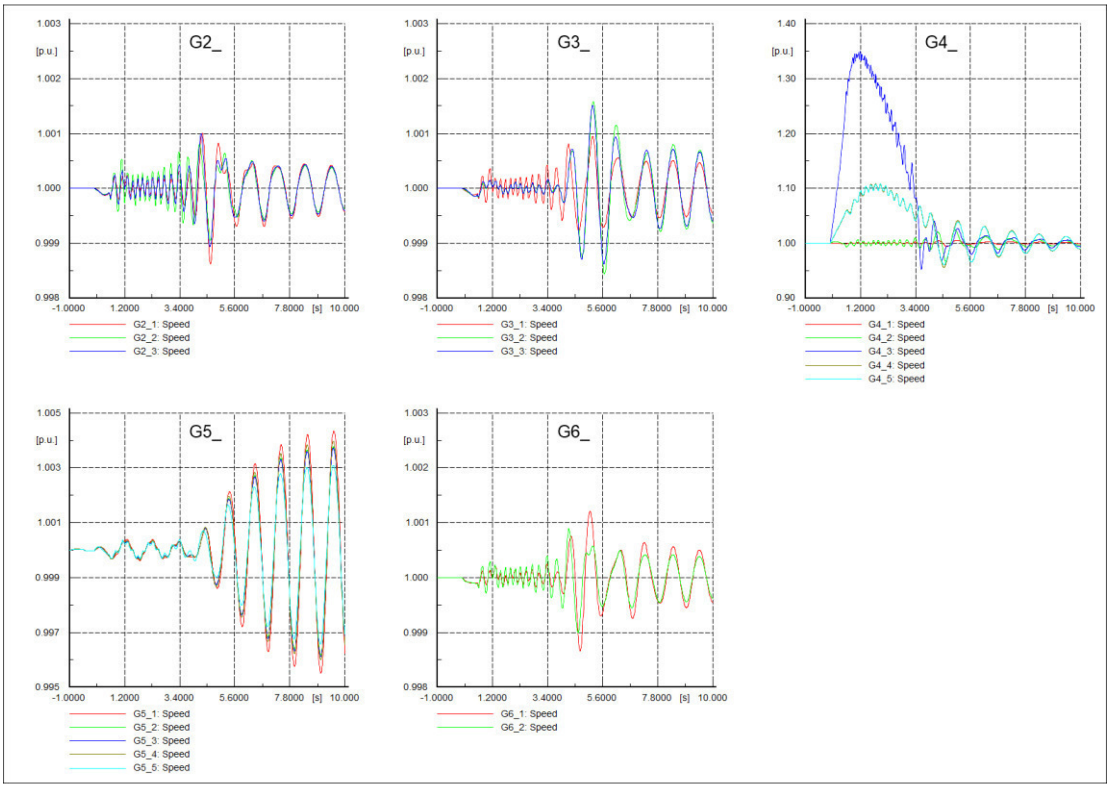


Figure 5.38: Case 4: External system - Rotor speed in the event of 0.6 s fault clearing time

Figure 5.36 - Figure 5.38 provide the rotor angle, active power and rotor speed response of the entire system subjected to F4_1 in the event of 0.6 s FCT. For a fault clearing time of 0.2 s only generator G4_3 was out of step; but at a fault clearing time of 0.3 s generators G4_4 and G4_5 joined generator G4_3 but generators G4_1 and G4_2 stayed in synchronism with no sign of any major disturbance.

Figure 5.39 presents the FRT capability performance of the generators from PowerFactory and OpenIPSL for the case 2 of clearing time from 0.1 – 0.6 s.

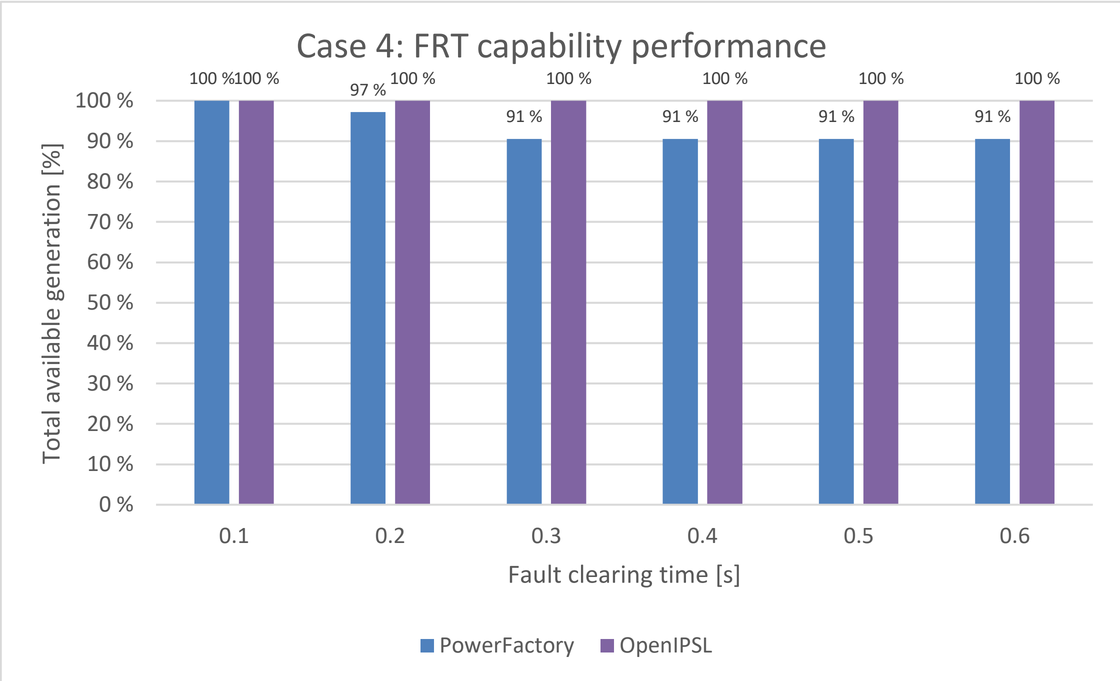


Figure 5.39: FRT capability performance for case 4 of fault clearing time 0.1 - 0.6 s

Figure 5.39 presents the plot of total production managed by the generators after the system is subjected to the fault F4_1 of fault clearing time 0.1 – 0.6 s. Different initialization is used during the simulation. PowerFactory is simulated with no fault impedance and OpenIPSL with fault impedance.

The simulation results from OpenIPSL showed that no single generator lost its synchronism for all fault clearing times. Whereas PowerFactory shows only 1 generator out of step in the event of 0.2 s FCT and 3 generators for FCT 0.3 s and above.

5.2.5 Result Fault Case 5 (F4_2)

This is a local distribution network of 22 kV. This is the last case where a balanced three-phase short circuit F4_2 was targeted on the 22 kV test line 5 of negligible impedance near the busbar B4_15 as shown in Figure 1.1 denoted as F4_2. A small fault resistance and reactance of 1E-06 pu is inserted ($Z_{base} = 4.84\ \Omega$) in OpenIPSL and in PowerFactory. The fault impedance was so small that the effect was negligible.

The way the generators respond to the fault F4_2 are provided below in sections 5.2.5.1 and 5.2.5.2 for the study system and external system respectively.

The FRT capability results of the 132, 66 and 22 kV generator units subjected to F4_2 are provided in Appendix F. The FRT plot for the different fault clearing time is shown in Figure 5.50.

5.2.5.1 Case 5 Study System

The study system for case 5 will include generators which are in the area close to the fault F4_2. During the fault the grid will split in to 9 isolated area (with a node at the fault point). The generators above the fault point (G4_3) and generators below the fault point (G4_5, G4_4 G4_2 and G4_1). Generator G3_ will face the biggest problem since there is no delivery point.

The generators located in the area G4_ are associated with this fault and generator G4_3 is primary affected. The rotor angle, active power, rotor speed and the terminal voltage of the generator G4_3 will be provided in Figure 5.40 and Figure 5.41. The rotor angle response of the generator G4_2 in this study case are plotted below in Figure 5.43.

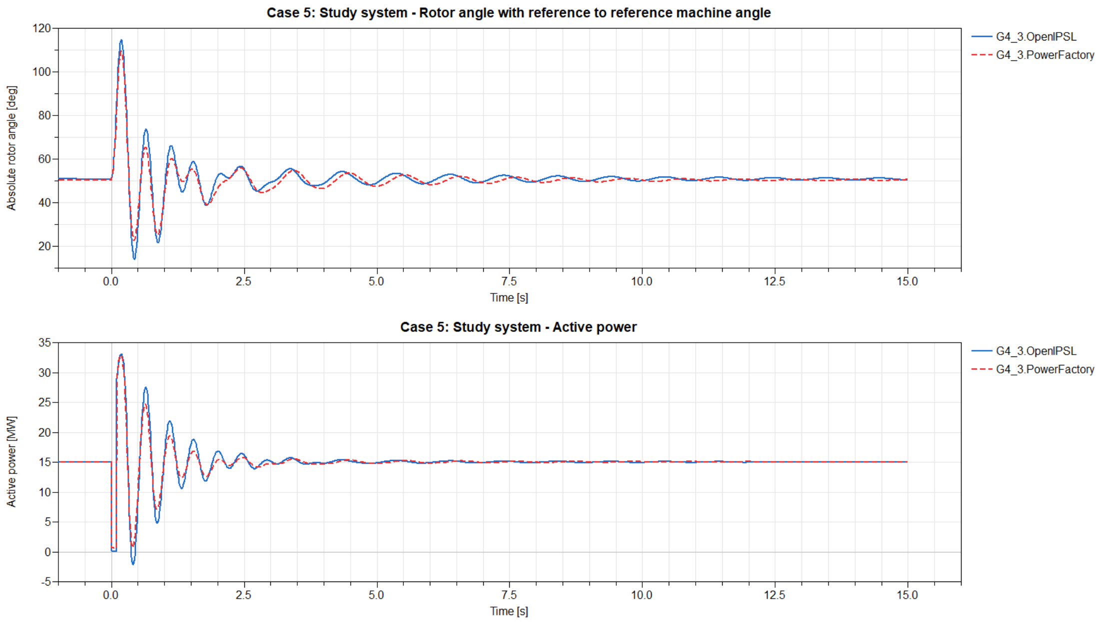


Figure 5.40: Case 5: Study system rotor angle (top) and active power (bottom) for generator G4_3 in the event of 0.1 s FCT

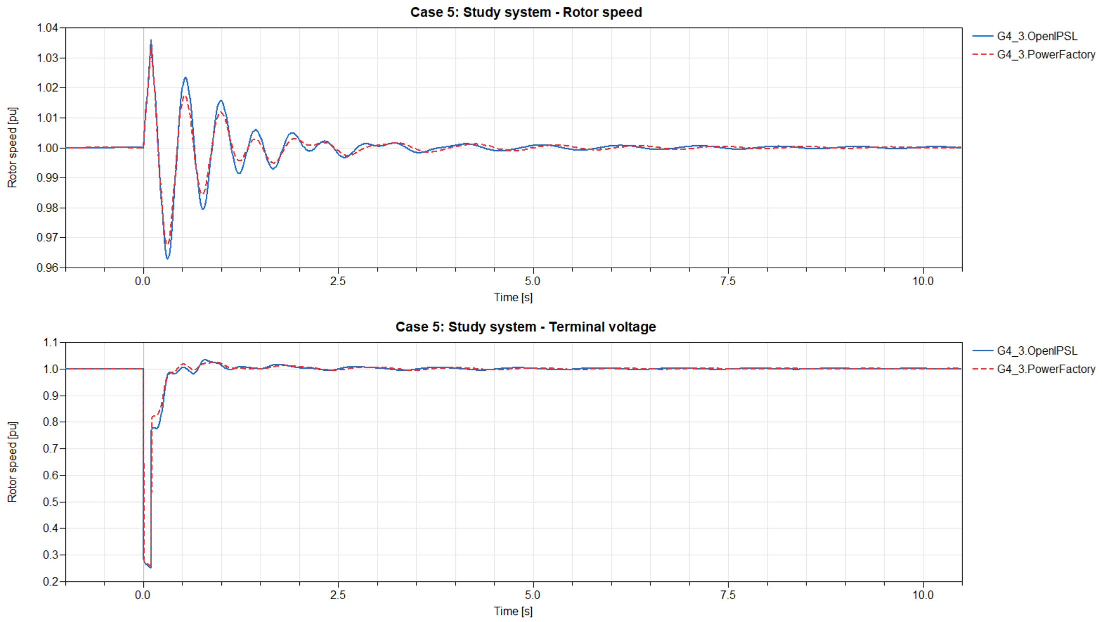


Figure 5.41: Case 5: Study system - Rotor speed (top) and terminal voltage (bottom) of generator G4_3 in the event of 0.1 s FCT

Figure 5.40 - Figure 5.41 provide the rotor angle, active power, rotor speed and terminal voltage of generator G4_3 from PowerFactory and OpenIPSL in the event of 0.1 s FCT. PowerFactory and OpenIPSL are seen to respond in the same way. This was the last time the generator stayed in synchronism.

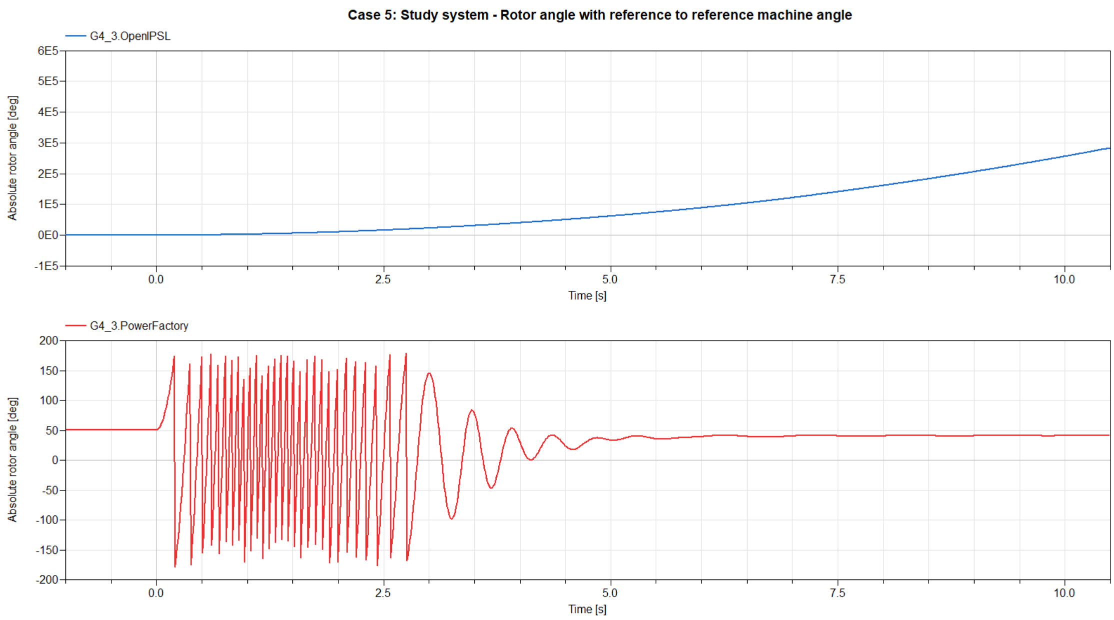


Figure 5.42: Case 5: Study system - Rotor angle of G4_3 OpenIPSL (top) PowerFactory (bottom) in the event of 0.2 s FCT

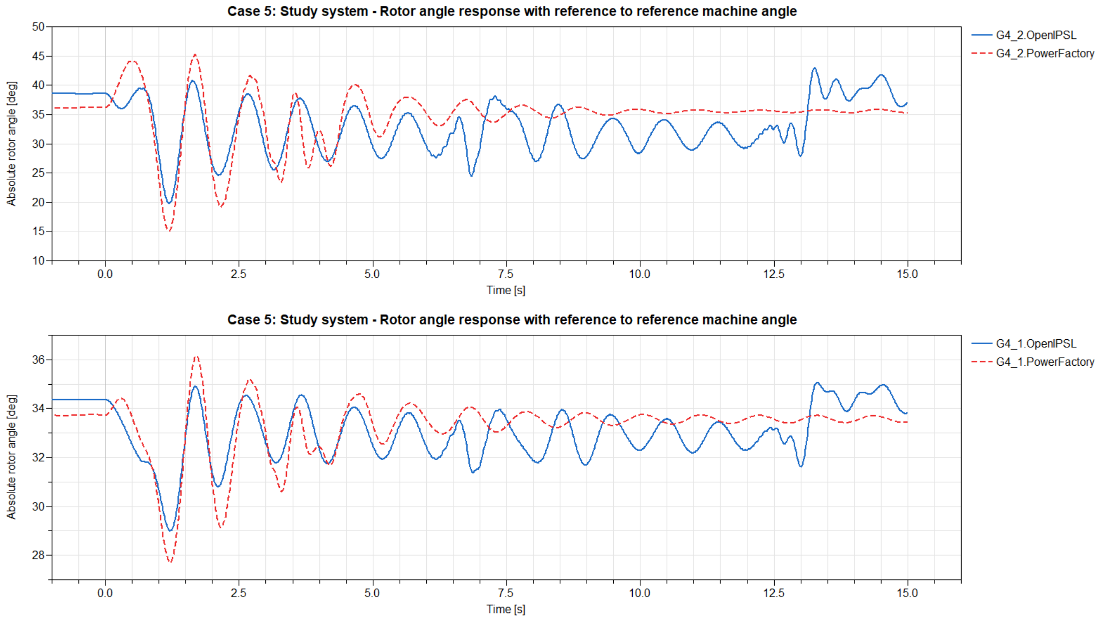


Figure 5.43: Case 5: Study system - Rotor angle response in the event of 0.6 s FCT

Figure 5.43 shows the rotor angle response of the selected generators from the study system. Generators G4_1 and G4_2 were the least affected generators because of their location in relation to the fault. Generator G4_3 was affected the most and faced a first swing instability early in the event of 0.2 s fault clearing time (see Figure 5.42 above). All the generators stayed connected and did not seem to get affected much including in the event of 0.6 s FCT (Figure 5.43).

5.2.5.2 Case 5 External System

The external system in this case will be the study of the area around the fault, but in somehow which stayed in synchronism. For case 5, again the plot from PowerFactory will be presented for all the generators. The results of selected generator G4_2 will be plotted from both PowerFactory and OpenIPSL.

Result from PowerFactory (F4_2)

In the figures below the plots of the rotor angle, active power and rotor speed in the event of 0.1 and 0.6 s FCT will be presented for the entire system grouped according to the generation area.

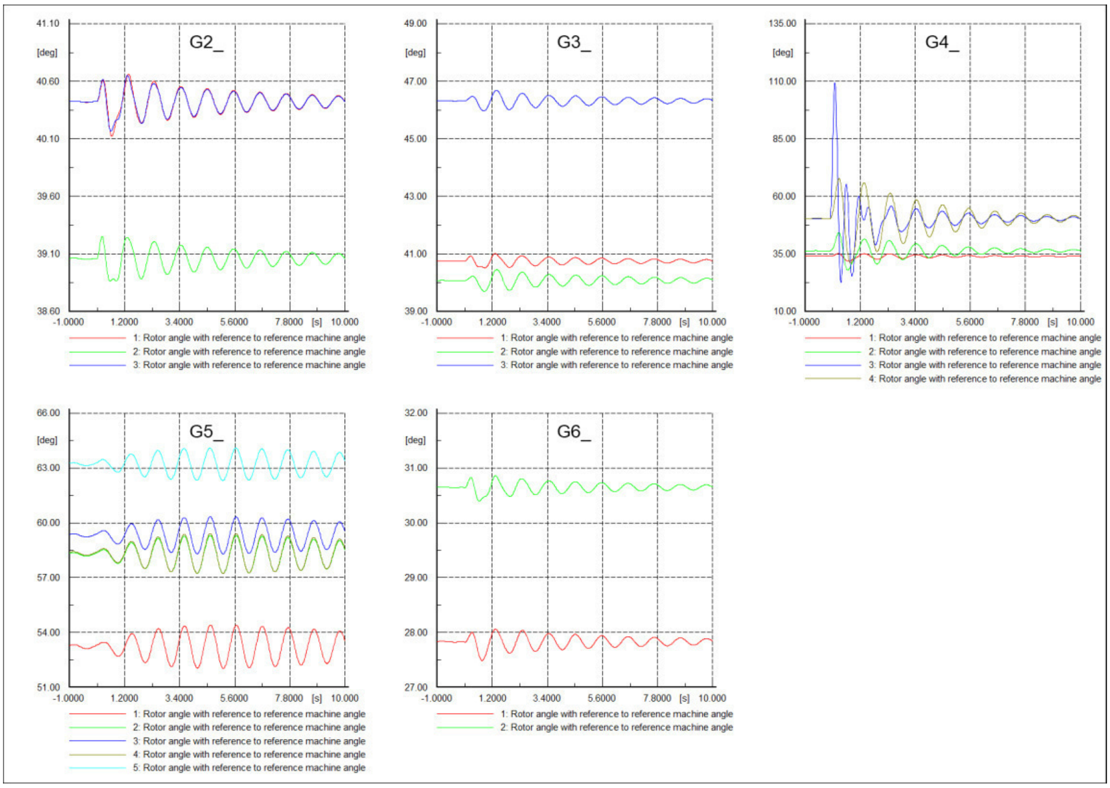


Figure 5.44: Case 5: External system - Rotor angle response in the event of 0.1 s fault clearing time

Figure 5.44 shows the rotor angle response of entire system generators in the event of 0.1 s FCT. All the generators remain in synchronism however, the generator which the fault is located (G4_3) is seen reaching a rotor angle close to 100 degrees. This was the last time generator g4_3 is seen in synchronism.

This has very little effect for the rest of the system as the fault is limited only in the distribution network.

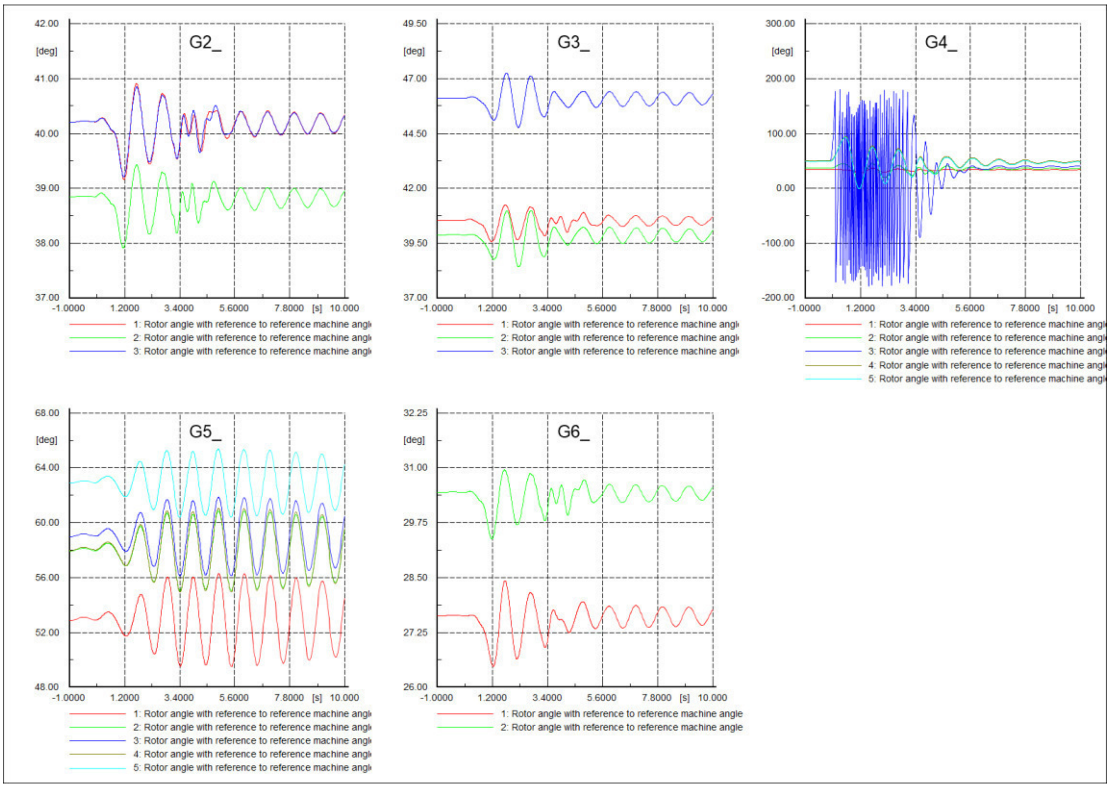


Figure 5.45: Case 5: External system - Rotor angle response in the event of 0.6 s FCT

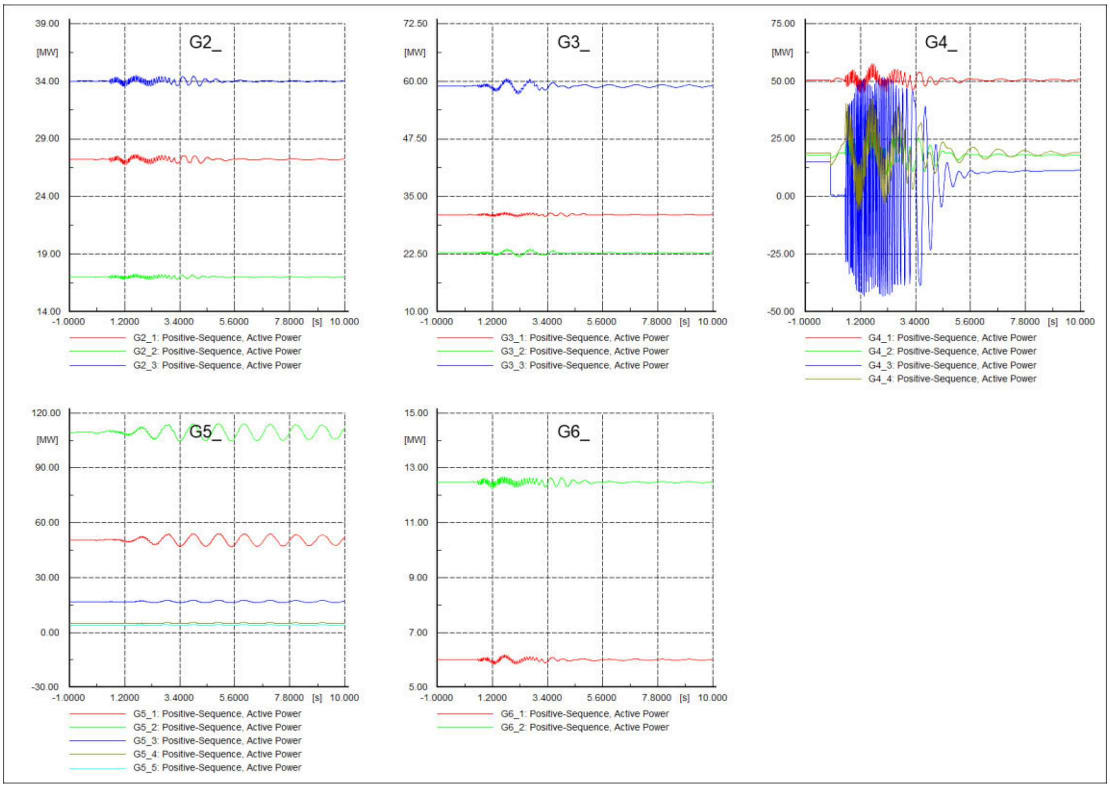


Figure 5.46: Case 5: External system - Active power response in the event of 0.6 s FCT

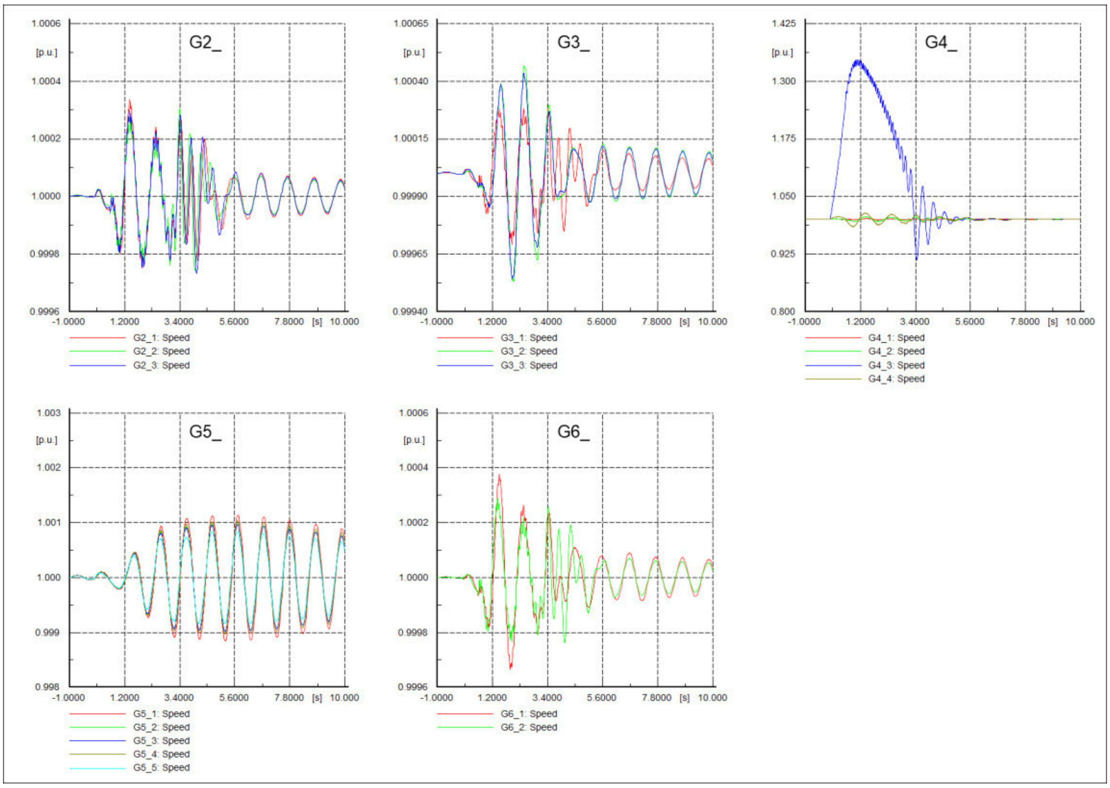


Figure 5.47:Case 5: External system – Rotor speed in the event of 0.6 s FCT

Figure 5.45 **-** Figure 5.47 provides the rotor angle, active power and rotor speed in the event of 0.6 s FCT. Again, for longer FCT all the generators are seen in synchronism except generator G4_3. As observed from the rotor speed (Figure 5.47) the generators in the same area are seen to swing in the same manner except for generators in the generation area G4_.

Result from OpenIPSL (F4_2)

As the generators in the generation area G4_ stayed in synchronism in the event of longer fault clearing time with a fault occurring in the area, it was interesting to see how they responded to the fault. For the purpose of this study generators G4_ were selected for further review with the results from Powerfactory. The plots for the rotor angle, active power and rotor speed are provided in the figures below.

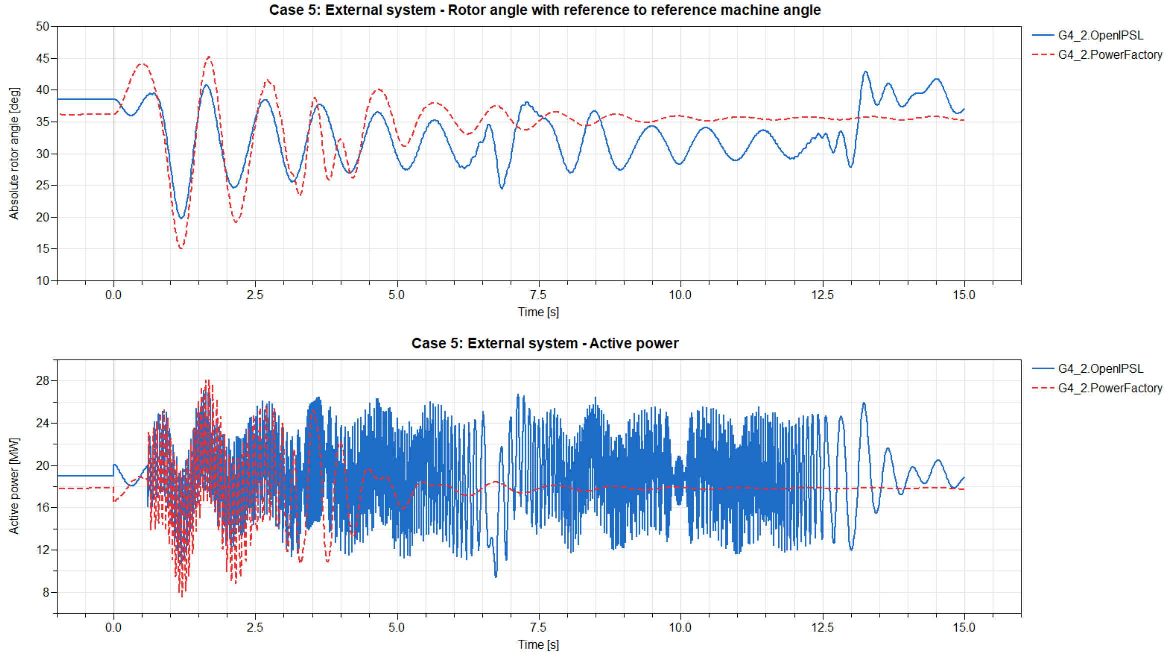


Figure 5.48: Case 5: External system Rotor angle (top) and Active power (bottom) in the event of 0.6 s FCT

Figure 5.48 provides the rotor angle and active power of generator G4_2 from OpenIPSL and PowerFactory in the event of 0.6 s FCT. The way the generator rotor angle responded during the first swing for the cases of PowerFactory and OpenIPSL is opposite. The generator in PowerFactory is seen to increase in rotor angle because of decreasing active power.

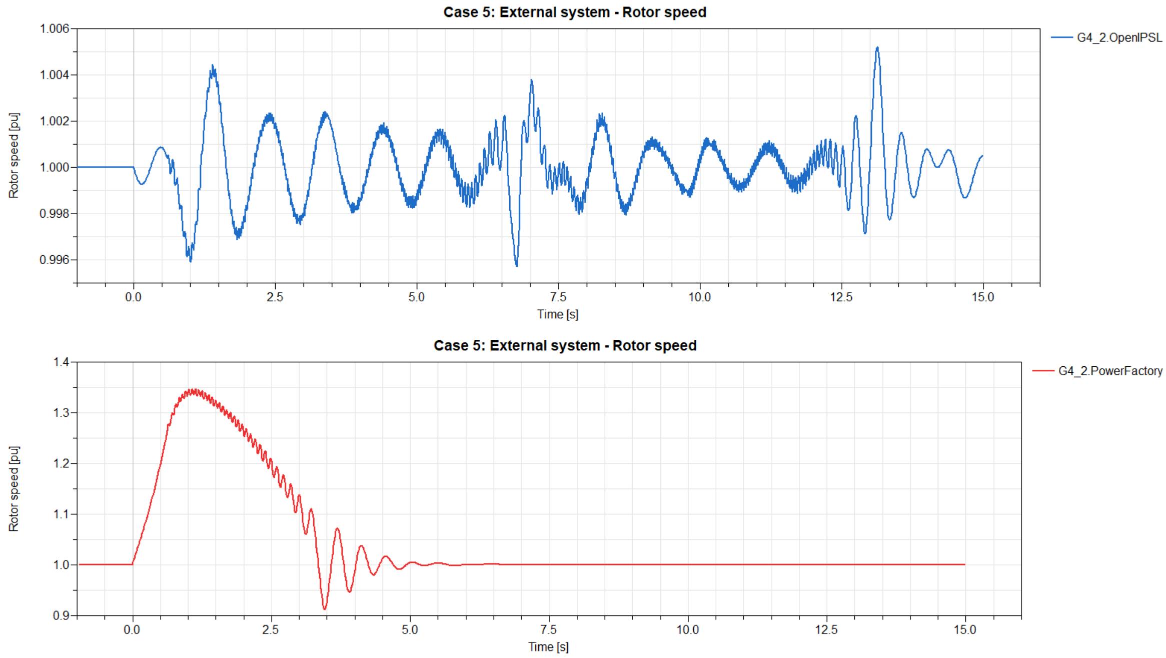


Figure 5.49: Case 5: Rotor speed from OpenIPSL (top) and PowerFactory (bottom) in the event of 0.6 s FCT

Figure 5.49 presents the rotor speed of generator G4_2 in the event of 0.6 s FCT. The way the rotor speed responded is very different. OpenIPSL (top) fluctuated a lot but kept the rotor speed under 1.005 pu. In the PowerFactory its seen less fluctuations but the rotor speed is seen to reach over 1.3 pu. This is due to the way automatic voltage regulators (AVR) is modeled. The only difference between the AVR models is the way the ceiling block is modeled, and this determines field voltage.

Figure 5.50 presents the FRT capability performance of the generators from PowerFactory and OpenIPSL for the case 2 of clearing time from 0.1 – 0.6 s.

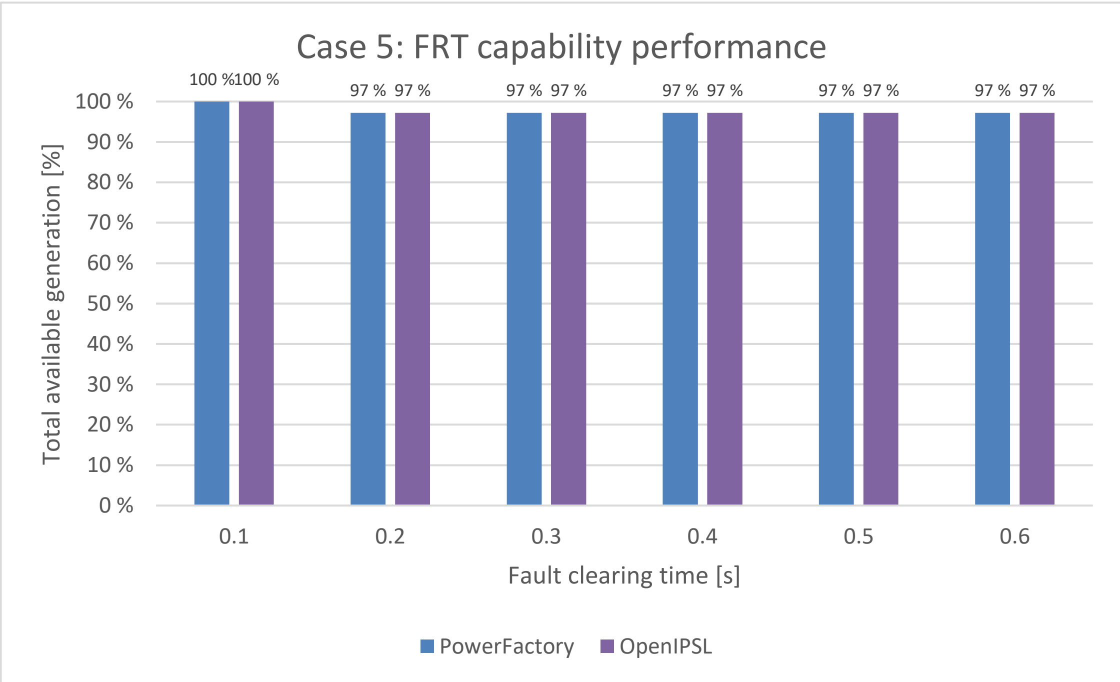


Figure 5.50: FRT capability performance for case 5 of fault clearing time 0.1 - 0.6 s

Figure 5.50 presents the plot of total available production of fault clearing time 0.1 – 0.6 s in percent after the system is subjected to the fault specified for case 5. The same result is obtained from both PowerFactory and OpenIPSL.

5.3 Fault Ride Through (FRT) Capability Test

The RMS/EMT simulation toolbar in PowerFactory contains a tool called "Edit Simulation Scan" (***ScnFr***t) for the analysis of FRT capability. This can be done either for the whole system or user specified generator, terminal, transformer, transmission line or external grid. The Fault ride through can be defined according to the voltage-time characteristic described in the guidelines. Either the upper or lower limit can be defined as well as the type of variable (voltage is used in this case).

To make the operation mentioned above work the Simulation Scan has to be Activated during the calculation of the initial conditions. This can be done under Simulation Scan.

In this thesis three Modules of fault ride through are defined (Figure 5.54) according to Table 2.7 – Table 2.9. These modules are defined according to the Norwegian transmission system operator (TSO) recommendations and the voltage-time profile from PowerFactory is provided in figures below.

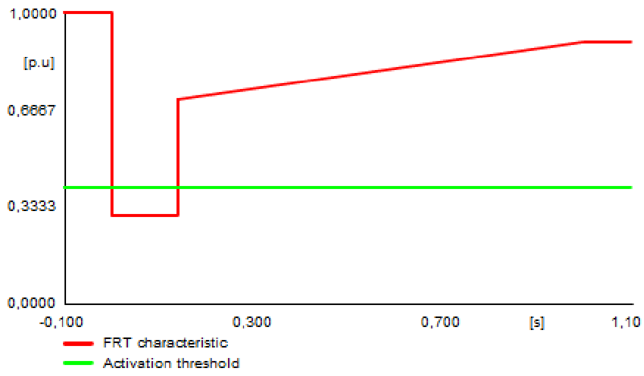


Figure 5.51: FRT characteristic for Type B, C and D, Un <110 kV PGMs

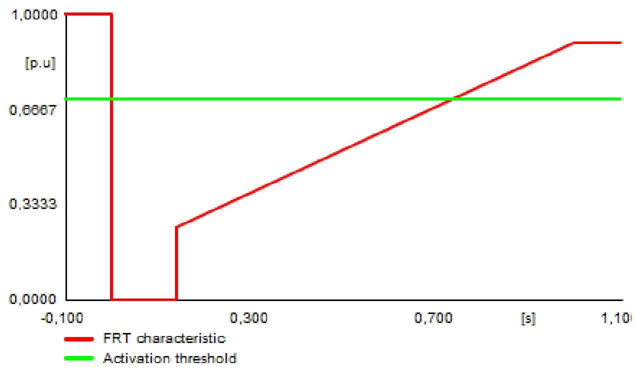


Figure 5.52: FRT characteristic for Type D, Un >110 kV PGMs (instantaneous disconnection)

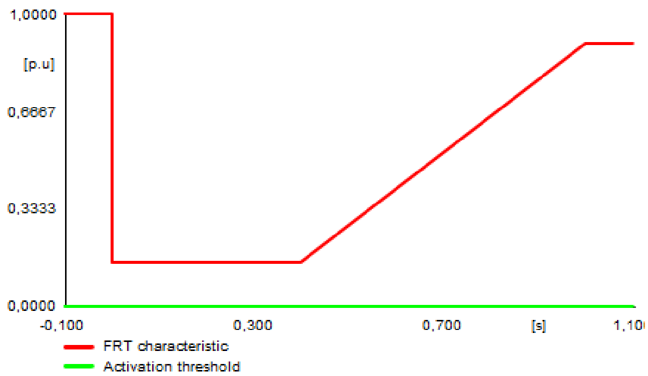


Figure 5.53: FRT characteristic for Type D, Un <110 kV PGMs (delayed disconnection)

Figure 5.51 - Figure 5.53 presents the voltage-time profile of the FRT requirements set by the Norwegian TSO.

In addition to testing the generators' availability and the total production available after a specific FCT, the entire system was scanned using the RMS simulation scan function. During the simulation, the terminal voltage to the connection point at which the generator is connected is used as a class name. The terminal voltage output was scanned against the FRT characteristic as shown in Figure 5.51 - Figure 5.53 above. The results of the voltages and the time at which the voltage was present was displayed in the output window.

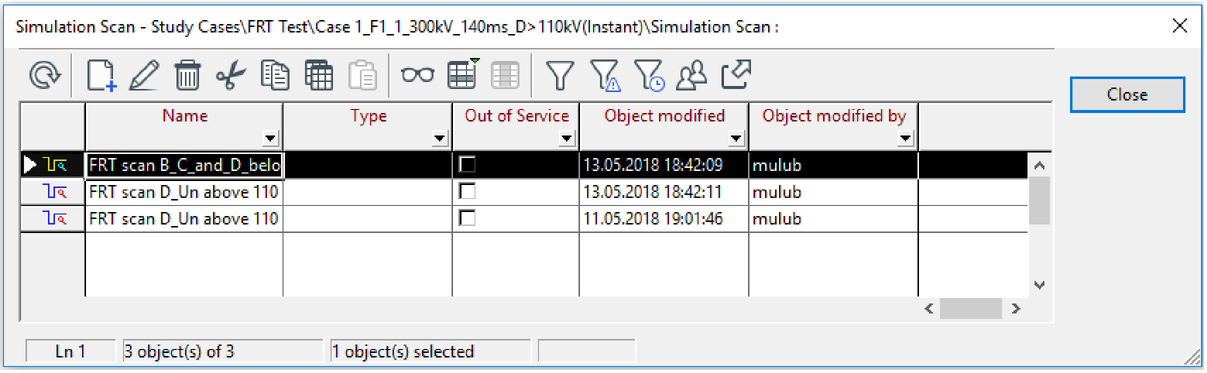


Figure 5.54: Simulation scan implementation in PowerFactory

An FRT scan was applied to the system using the FRT characteristics mentioned above. The results for each case are as follows:

Case 1

The requirement regarding fault clearings time in a central transmission network is 100 ms. The results from the FRT scan was:

- Type B, C and D, $U_n < 110\ kV$: There were a total of 7 generators involved in this scan. Most of the generators managed a voltage above the voltage-time characteristic as presented in Figure 5.51 except generator G5_4.
- Type $U_n > 110\ kV$(instantaneous disconnection): There were a total of 10 generators that fell under this category and only three generators from the generation area G5_ recorded a voltage below the lower limit of voltage-time characteristic defined in Figure 5.52.
- Type $D, U_n > 110\ kV$(delayed disconnection): Same as the above case (instantaneous disconnection) 10 generators were involved in this scan, but all recorded a voltage below the lower limit of the voltage-time characteristics defined in Figure 5.53.

Case 2

This was a 132 kV regional distribution network. The requirement regarding a fault clearing times in this case is 100 ms. A simulation scan was applied to the whole system and the simulation results were:

- Type B, C and D, $U_n < 110\ kV$: All the generators managed a voltage above the voltage-time characteristic presented in Figure 5.51.
- Type $U_n > 110\ kV$(instantaneous disconnection): During this scan all the generators managed a voltage above the lower limit of voltage-time characteristic described in Figure 5.52.
- Type $D, U_n > 110\ kV$(delayed disconnection): same as the above case 10 generators were involved in this scan, but all recorded a voltage below the lower limit of the voltage-time characteristics defined in Figure 5.53.

Case 3

This is the main station of 132 kV regional distribution network.

- Type B, C and D, $U_n < 110\ kV$: most of the generators managed a voltage above the voltage-time characteristic presented in Figure 5.51 except generators G6_1 and G6_2.
- Type $U_n > 110\ kV$(instantaneous disconnection): Majority of the generators managed voltage above the voltage-time characteristic presented in Figure 5.52 except generators G5_1, G5_2 and G5_3.
- Type $D, U_n > 110\ kV$(delayed disconnection): same as the above case 10 generators were involved in this scan, but all recorded a voltage below the lower limit of the voltage-time characteristics defined in Figure 5.53.

Case 4

The FRT scan result for the 66 kV regional distribution network was as follows:

- Type B, C and D, $U_n < 110\ kV$: There were a total of 7 generators involved in this scan. Generators G4_3, G4_4 and G4_5 registered voltage time characteristic below the lower limit presented in Figure 5.51
- $U_n > 110\ kV$(instantaneous disconnection): There were a total of 10 generators that fell under this category and all recorded a voltage above the lower limit of voltage-time characteristic defined in Figure 5.52.
- Type $D, U_n > 110\ kV$(delayed disconnection): Same as the above case (instantaneous disconnection) 10 generators were involved in this scan, but all recorded a voltage below the lower limit of the voltage-time characteristics defined in Figure 5.53.

Case 5

The FRT scan for the 22 kV, local distribution network was as follows:

- Type B, C and D, $U_n < 110\ kV$: There were a total of 7 generators involved in this scan. Most of the generators managed a voltage above the voltage-time characteristic as presented in Figure 5.51 except generator G4_3.
- $U_n > 110\ kV$(instantaneous disconnection): There were a total of 10 generators that fell under this category and all recorded a voltage above the lower limit of voltage-time characteristic defined in Figure 5.52.
- Type $D, U_n > 110\ kV$(delayed disconnection): Same as the above case (instantaneous disconnection) 10 generators were involved in this scan, but all recorded a voltage below the lower limit of the voltage-time characteristics defined in Figure 5.53.

6 Discussion

This thesis involved several stability tests of different voltage areas of the regional power system presented in Fig. 1.1. The whole study was based on the assumption of a balanced three-phase short circuit occurring on a transmission line near the busbar targets 132, 66 and 22 kV with fault clearings ranging from 0.1 – 0.6 s. the simulation tests were performed using PowerFactory and OpenIPSL.

6.1 OpenIPSL Shortcomings

The purpose of this thesis was to simulate the power model in OpenIPSL and to utilize the same parameters in order to model the system in PowerFactory. However, OpenIPSL exhibited some limitations during the simulation attempts specially for a three-phase bolted fault. Due to the shortcoming of OpenIPSL, the thesis had to implement fault in the simplifications to overcome this. The implementation of fault impedance was not part of the original plan for the thesis study but to overcome this first obstacle provided the author of the thesis an opportunity to apply an innovative approach to counteract the challenges.

6.2 The Simulation Study

The study was performed using five cases implemented in two major ways. The two methodologies for the simulation execution were as follows:

- Simulations where small fault impedance was used – Range 1E.06 to 1E-03 pu
- Simulation where large fault impedance was used –Range 1E-02 pu and above

The five simulation cases were characterized as follows:

- Case 1: Equalized fault impedance in OpenIPSL and PowerFactory
- Case 2: Equalized fault impedance in OpenIPSL and PowerFactory
- Case 3: Minimum fault impedance in OpenIPSL, no fault impedance in PowerFactory
- Case 4: Minimum fault impedance in OpenIPSL, no fault impedance in PowerFactory
- Equalized fault impedance in OpenIPSL and PowerFactory

The five study cases were implemented via three different methodologies:

- The first methodology was applied to case 1; due to the external network not being available in OpenIPSL, the contribution from the external grid created a major effect when the system was subjected to fault F1_1. Because of this reason the case become its own methodology.
- The second methodology was applied to case 2 and 5; in these cases, the same fault impedance initialization values were utilized. These cases were used to evaluate the simulation capabilities of OpenIPSL against PowerFactory. The evaluation criteria were based on the FRT capability and the response of the system generators to the simulations.
- The third methodology was applied to case 3 and 4. In these cases, different fault impedance initialization values were used for PowerFactory and OpenIPSL.

The main take away from all these simulations was the observation of a weakness in OpenIPSL mainly the inability to accurately simulate three-phase bolted faults.

6.3 Challenges Faced During the Study

At the beginning of this thesis study, no contributions from the external grid were considered. Instead, it was assumed that the external grid was used as a PV bus during the load flow analysis. Consequently, this contribution was ignored during the modeling of the OpenIPSL model. However, during the final week of the project, a conversation with the project external partner, Professor G.J. Hegglid from Skagerak, revealed that the actual contribution from the external grid was higher than initially anticipated and therefore could not be ignored.

It was found that this oversight had the potential to create a difference in the final results due to the short circuit power. Upon further review, it was found that a limitation in the finished models from the OpenIPSL; based on the time that it would take to create an acceptable model that corresponded with the external model, it is left out for the contributions from the external grid in the OpenIPSL model.

6.4 Simulation Findings

There were four findings that came out of the simulation study. They were:

1. A fault that occurs in the 300 kV central transmission network and central in Grenland (132 kV main station) are those which were highly affected and impacted the entire system. as opposed to the fault occurring out in the 66 and 22 kV regional and local distribution networks. This was observed in the simulation of cases 1 and 5 in the event of 0.3 s FCT. The results from Powerfactory showed that in the event of 0.3 s FCT, only 35 % of the system managed to stay in synchronism. For case 3 none of the generators managed to stay in synchronism. Whereas for case 5 97% of the system managed to stay in synchronism.
2. The point at which the generator go out of synchronism is directly related to the generator's position in relation to the fault location. The closer the generator to the fault is, the quicker it goes out of step.
3. When a fault occurred outside the main station in the 66 kV regional or 22 KV local distribution networks the system was divided into two parts namely the upper and lower parts of the fault. The area over the fault had limited power flow whereas the area under the fault was connected to the rest of the power system and the power continued to keep flowing barring a minor disturbance. The observations for case 4 and 5 with a fault clearing time of 0.6 s were as follows:
   - For case 4 the simulation in OpenIPSL was performed with some fault impedance and as a result all the generator were observed to stay in synchronism. For PowerFactory, the observations for this case 4 and 5(Figure 5.36) the generators above the fault area (G4_3, G4_4 and G4_5) with those generators going out of step. The generators below the fault area and close to the fault location (G4_2) were in synchronism with a minor disturbance whereas the generators located farther from the fault area did not show any sign of disturbance.
   - For case 5 (Figure 5.45) had a similar situation happened with generator G4_3 in the upper part of the fault wherein the generators located in the upper part of the fault went out of step whereas the rest of the generators stayed in operation barring a minor disturbance.

4. A fault occurring in the connection point between the central transmission network (300 kV) and in the regional distribution network of 132 kV main station (center in Grenland) is highly severe. These affects the entire system and primary distributed generators located in remote areas where their production is fully or mostly supplied to the main station. These were observed in cases 1 and 3 in the event of 0.2 s with generators from the generation area of G2_ and G5_ were seen to go out of step first In the PowerFactory simulation (shown in Figure 5.29) for case 3 in the event of 0.2 s FCT. The generators in the generator area of G2_ and G5_ ended up a 100 % out of step. As an additional analysis, the load was increased in generation area G5_ (Load5_2) from 4 MW to 80 MW; the results of the rotor angle response are shown in the Figure 6.1 below.

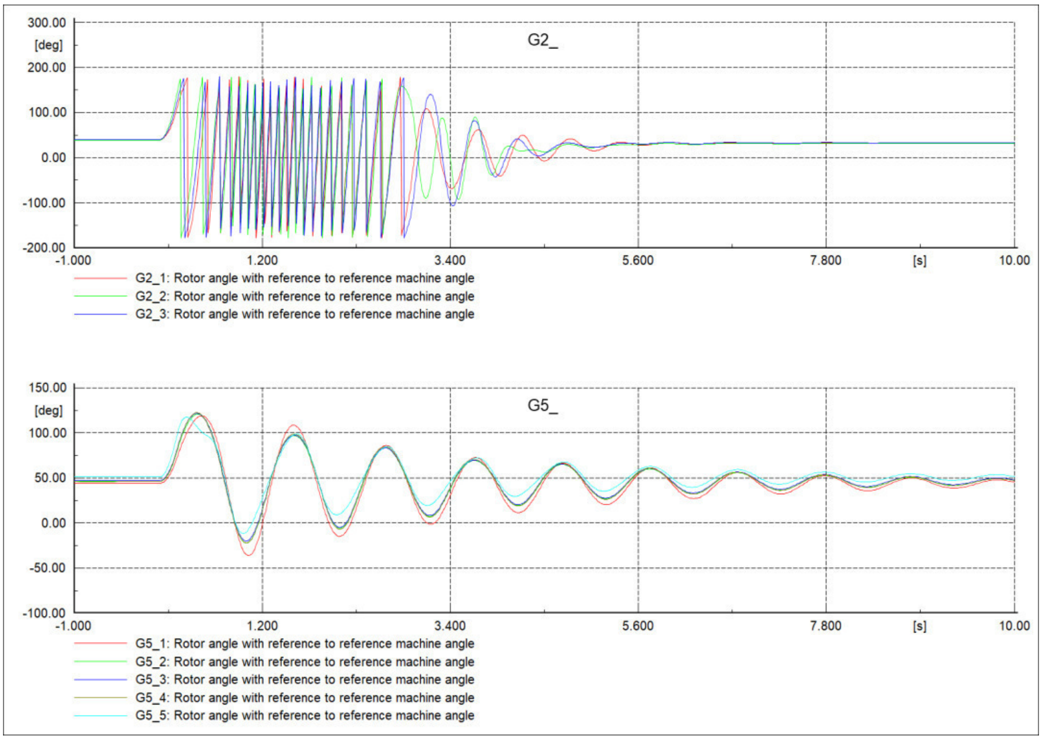


Figure 6.1: Distributed generators G2_ and G5_ with modified load5_2 subjected to F0_1 in the event of 0.2 s fault clearing time

Figure 6.1 above shows the plot of the generators from generation area G2_ and G5_ with a modified load (load5_2) located near production area G5_. The results show that generators from area G2_ continued to be out of step whereas the generations from area G5_the stayed in synchronism on an FCT event of 0.2 s.

7 Conclusion

The system was checked against the new NC RfG proposals as per the TSO (Statnett). The system has been scanned based on the applicable fault area. The system was scanned against

1. Requirement for type B, C and D, Un > 110 kV
2. Requirements for type D Un > 110 kV (instantaneous disconnection)
3. Requirement for type D Un > 110 kV (delayed disconnection)

The 300 kV central transmission network and the 132 kV of regional distribution network at and outside the main station showed a voltage-time profile for instantaneous disconnection above the recommended requirements the only generators that were the exception were from generation area G5_ that registered readings slightly below the recommended requirements.

On the other side, the 66 kV regional distribution network and 22kV local distribution network registered a low voltage at several points in generation area G4_ for cases 1, 4 and 5. Due to time limitations, I was unable to test the type of modifications that would have been needed on the controllers side to improve the voltage levels.

The results of the simulation cases for both OpenIPSL and PowerFactory showed remarkable similarities. The overall conclusion that was drawn from the thesis study was that OpenIPSL can be used for a three-phase electromechanical transient simulation supported by a power flow analysis program.

References

[1] J. M. Edirisinghe V.P., T. Øyvang, and G. J. Hegglid, “Transient stability of fault ride through capability of a transmission system of a distributed hydropower system,” 2017, pp. 355–359.

[2] L. Vanfretti, T. Rabuzin, M. Baudette, and M. Murad, “iTesla Power Systems Library (iPSL): A Modelica library for phasor time-domain simulations,” *SoftwareX*, vol. 5, pp. 84–88, 2016.

[3] “ENTSO-E - European Network of Transmission System Operators,” *ENTSO-E — European Network of Transmission System Operators*. [Online]. Available: https://www.entsoe.eu/Pages/default.aspx. [Accessed: 22-Feb-2018].

[4] Statnett, “Statnett - Fremtiden er elektrisk,” *statnett*. [Online]. Available: http://www.statnett.no/. [Accessed: 05-Mar-2018].

[5] Abdalla Habib Abd, “Transient stability and Fault Ride Through (FRT) Capability of Hydropower units in Norwegian regional power networks,” University College of Southeast Norway, Porsgrunn, 2016.

[6] “Low Voltage Ride Through | Infospaze - Sharing Wisdom by Community.” [Online]. Available: http://infospaze.com/Low_voltage_ride_through. [Accessed: 22-Feb-2018].

[7] Statnett, “Referansegruppemøte RfG nr. 5,” 29. 03-2017.

[8] “Electricity network codes and guidelines - Energy - European Commission,” *Energy*. [Online]. Available: /energy/en/topics/wholesale-market/electricity-network-codes. [Accessed: 27-Feb-2018].

[9] Statnett, “Funksjonskrav i kraftsystemet (FIKS 2012).” [Online]. Available: http://www.statnett.no/Global/Drift%20og%20Marked/Systemansvaret/Funksjonskrav%20i%20kraftsystemet%202012.pdf. [Accessed: 22-Feb-2018].

[10] Statnett, “Veileder til krav i FIKS om Fault-ride-through egenskaper for produksjonsanlegg.” Statnett, 29-Mar-2017.

[11] Jan Machowski, W. Bialek, and R. B. James, *POWER SYSTEM DYNAMICS, Stability and Control*, Second Edition. 2008.

[12] P. Kundur, *Power System Stability and Control*. New York: McGraw-Hill, 1994.

[13] NPTEL, “Module 6 Power system stability.” [Online]. Available: https://nptel.ac.in/courses/108107028/module6/lecture1/lecture1. [Accessed: 24-Feb-2018].

[14] B.M. Weedy, B.J. Cory, N. Jenkins, J.B. Ekanayake, and G. Strbac, *Electric Power Systems, 5th Edition by Weedy*, Fifth edition. United Kingdom, 2012.

[15] Dr. Francisco M. Gonzalez-Longnatt, “DIgSILENT PowerFactory: Website of DigSILENT Tutorials developed by Dr. Francisco M. Gonzalez-Longatt.” [Online]. Available: http://www.fglongatt.org/OLD/Tutorial_DigSilent_EN.html. [Accessed: 13-May-2018].

[16] F. M. Gonzalez-Longatt and J. Luis Rueda, *Powerfactory Applications for Power System Analysis*. Cham, SWITZERLAND: Springer, 2014.

[17] *ipsl: The iTesla Power System Library is a Modelica library developed as part of the iTesla project. The library contains a set of power system component models for phasor time domain simulations*. iTesla, 2017.

[18] "Dymola - Dassault Systèmes®." [Online]. Available: https://www.3ds.com/products-services/catia/products/dymola/. [Accessed: 03-May-2018].

[19] DigSILENT, "DigSILENT PowerFactory 2018 UserManual." Gomaringen, Germany, Dec-2017.

[20] Federico Milano, "Power System Analysis Toolbox (PSAT)." .

[21] M. Federico, *Power-System-Modelling-and-Scripting*. New York: Springer Science & Business Media, 2010.

[22] "Electrical Load," *Circuit Globe*, 20-Mar-2017. [Online]. Available: https://circuitglobe.com/electrical-load.html. [Accessed: 25-Mar-2018].

[23] "Introduction to the model translation and symbolic processing," *Claytex*, 21-Nov-2017. .

Appendices

University College
of Southeast Norway

Faculty of Technology, Natural Sciences and Maritime Sciences, Campus Porsgrunn

FMH606 Master's Thesis

<u>Title</u>: Modelling of a Fault Ride Through in Transmission System with Distributed Hydropower production

<u>USN supervisor</u>: Dietmar Winkler

<u>External partner</u>: Skagerak

<u>Task background</u>:

The topic is based on a the publication «Transient Stability of Fault Ride Through Capability of a Transmission System of a Distributed Hydropower System» by Edirisinghe et al [1]
This publication describes the Fault Ride Through (FRT) capability of generators of a part of the 132 V high voltage power network in Norway using a simplified power system simulator model. The organization, "European network of transmissionsystem operators for electricity" (ENTSO-e) is introducing a network code for the Transmission System Operators (TSO) in Europe where the upper limit of the FRT requirement for 132 kV system is 0.25 s. However, according to the Norwegian network code, this limit is 0.40 s. The generators in the Norwegian power system are located in a distributed network and most of these are hydropower generators. The simulation results show that the structure of the Nordic power system enhances the system stability. The dynamic model of the power network is developed by using DigSILENT PowerFactory simulation tool.

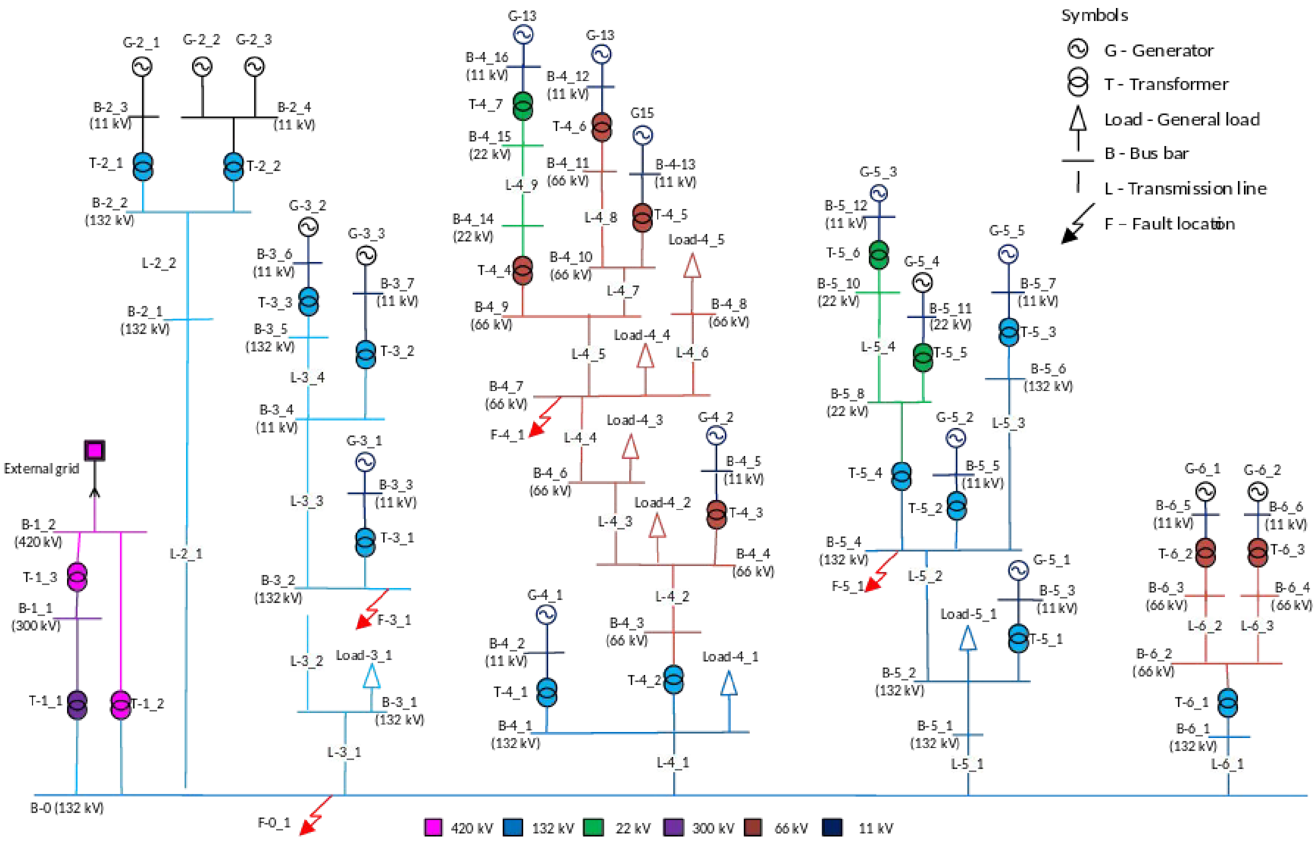


Figure 1: Simplified power system for a part of 132 kV regional power network, Norway

Address: Kjølnes ring 56, NO-3918 Porsgrunn, Norway. **Phone:** 35 57 50 00. **Fax:** 35 55 75 47.

Task description:

The task is to model model the power system in Modelica using the OpenIPSL power systems library. The system should then be simulated and the results compared with the results from [1].

Typical work packages will include:

- Familiarise yourself with the theory of Fault Ride Through capability
- Familiarise yourself with the OpenIPSL library [2]
- Investigate the power system to model (given as reference in PowerFactory)
- Implement the power system in stages
- Generate simulation results of the faults as mentioned in [1]
- Compare with existing results from PowerFactory

Optional, if time allows, the system shall be tuned in order to satisfy the upper limit of FRT of 0.25 s if necessary.

[1] J. M. Edirisinghe V.P., T. Øyvang, and G. J. Hegglid, “Transient stability of fault ride through capability of a transmission system of a distributed hydropower system,” 2017, pp. 355–359.

[2] L. Vanfretti, T. Rabuzin, M. Baudette, and M. Murad, “iTesla Power Systems Library (iPSL): A Modelica library for phasor time-domain simulations,” *SoftwareX*, vol. 5, pp. 84–88, 2016.

Student category: EPE students

Practical arrangements:

Signatures:

Student (date and signature):

Supervisor (date and signature):

Appendix B

Power System Input Parameters

B.1 Generators

Generators are classified according to their connection point (HV side of generator transformer). The three different voltage levels of connection points 132, 66 and 22 kV are listen in tables below. The reactance given are in pu of machine base. All the generators have a terminal voltage of 11 kV and nominal frequency of 50 Hz.

B.1.1 132 kV Generator Unit Parameter

Table 2: 132 kV Generator units input data (reactance's based on machine base)

				Reactance [pu]				**Time constant [s]**		
Gen.	**Sn [MVA]**	**Cos φ**	**M [s]**	x_d	x_q	x'_d	x''_d, x''_q	τ'_{d0}	τ'_{2d0}	τ'_{2d0}
G2_1	32	0.86	4	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G2_2	21	0.86	2.3	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G2_3	40	0.86	3.2	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G3_1	37	0.86	3.2	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G3_2	27	0.85	8.2	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G3_3	70	0.85	6.4	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G4_1	60	0.85	6.4	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G5_1	60	0.85	8.2	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G5_2	130	0.85	6.0	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G5_3	20	0.85	5.6	1.1	0.682	0.25	0.22	5.2	0.062	0.325

B.1.2 66kV Generator Unit Parameters

Table 3: 66 kV Generator units input data (reactance's based on machine base)

				Reactance [pu]				Time constant [s]		
Gen.	**Sn [MVA]**	**Cos φ**	**M [s]**	x_d	x_q	x'_d	x''_d, x''_q	τ'_{d0}	τ'_{2d0}	τ'_{2d0}
G4_2	20	0.9	4	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G4_4	21	0.9	2.6	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G4_5	18	0.9	5.8	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G6_1	7	0.9	7.0	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G6_2	14	0.9	4.2	1.1	0.682	0.25	0.22	5.2	0.062	0.325

B.1.3 22 kV Generator Unit Parameter

Table 4: 22 kV PGMs input data (reactance's based on machine base)

				Reactance [pu]				Time constant [s]		
Gen.	**Sn [MVA]**	**Cos φ**	**M [s]**	x_d	x_q	x'_d	x''_d, x''_q	τ'_{d0}	τ'_{2d0}	τ'_{2d0}
G4_3	16	0.95	4	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G5_4	6	0.9	2.6	1.1	0.682	0.25	0.22	5.2	0.062	0.325
G5_5	5	0.9	5.8	1.1	0.682	0.25	0.22	5.2	0.062	0.325

B.2 Two-winding transformers

Transformers used in this thesis are all two-winding transformers as provided in table below where reactance is given in pu of machine base.

Appendices

Table 5: Two-winding transformer parameters (reactance's based on machine base)

Transformer	**From Bus**	**To Bus**	V_1 **[kV]**	V_2 **[kV]**	S_n **[MVA**	**X [pu]**
T1_1	B1_1	B0_1	300	132	500	0.11
T1_2	B1_2	B0_1	420	132	1000	0.045
T1_3	B1_2	B1_1	420	300	600	0.11
T2_1	B2_2	B2_3	11	132	32	0.11
T2_2	B2_2	B2_4	11	132	60	0.11
T2_3	B2_2	B2_5	11	132	40	0.11
T3_1	B3_2	B3_3	11	132	37	0.11
T3_2	B3_4	B3_7	11	132	35	0.11
T3_3	B3_5	B3_6	11	132	70	0.11
T4_1	B4_1	B4_2	11	132	60	0.11
T4_2	B4_1	B4_3	132	66	60	0.11
T4_3	B4_4	B4_5	11	66	20	0.10
T4_4	B4_9	B4_14	22	66	30	0.10
T4_5	B4_10	B4_13	11	66	18	0.10
T4_6	B4_11	B4_12	11	66	21	0.10
T4_7	B4_15	B4_16	11	22	20	0.10
T5_1	B5_2	B5_3	11	132	60	0.11
T5_2	B5_4	B5_5	11	132	130	0.11
T5_3	B5_6	B5_7	11	132	20	0.11
T5_4	B5_4	B5_8	22	132	25	0.11
T5_5	B5_8	B5_9	11	22	6	0.08
T5_6	B5_10	B5_11	11	22	5	0.07
T6_1	B6_2	B0_1	66	132	40	0.11
T6_2	B6_3	B6_5	11	66	10	0.08
T6_3	B6_4	B6_6	11	66	16	0.08

B.3 Load

The power system loads from the study system are presented in Table 6.

Table 6: System loads

Load /location	Load Type	V [kV]	P [MW]	Q [MVAr]
Load3_1	PQ	132	10	4
Load4_1	PQ	66	22	6
Load4_2	PQ	66	5	1
Load4_3	PQ	66	20	5
Load4_4	PQ	66	12	5
Load4_5	PQ	66	8	2
Load5_1	PQ	132	8	2
Load5_2	PQ	132	4	0
Load6_1	PQ	132	30	10
Load6_2	PQ	66	10	3
Load0_1 (132 kV)	PQ	132	440	80

B.4 External Grid

Table 7: External grid input from PowerFactory

Location	$U_n[kV]$	$S''_{k-max}\,[MVA]$	$S''_{k-min}[MVA]$
B1_3	420	14549.23	7274.613

B.5 Transmission Line

The parameters of transmission lines are given in ohm per unit length, however, due to the input parameters in OpenIPSL are in pu of system base, the parameters of resistance and reactance presented in this section are in pu of system base 100 MVA and base voltage at respective area. The base impedance of the 420, 132, 66 and 22 kV is given under each section.

B.5.1 132 kV Transmission Line Parameters

Table 8: 132 kV transmission line parameters where R and X are resistance and reactance of the line in pu of 100 MVA system base (1 pu = 174.24 Ω)

Line ID	**Line Type**	**From Bus**	**To Bus**	**Len. [km]**	**R [pu]**	**X [pu]**	
L2_1	FeAl 1x253	B2_1	B0_1	65	0.026113	0.138028	OHL
L2_2	FeAl 1x253	B2_2	B2_1	6	0.002410	0.012741	Cable
L3_1	Cu 1x 120	B3_1	B0_1	21.4	0.018423	0.047899	OHL
L3_2	FeAl 1x150 26/7	B3_2	B3_1	30.2	0.020799	0.065863	OHL
L3_3	Cu 1x120	B3_4	B3_2	5	0.004304	0.011191	OHL
L3_4	Cu 1x120	B3_5	B3_4	41.8	0.035985	0.093560	OHL
L4_1	FeAl 1x120 26/7	B4_1	B0_1	31.1	0.026773	0.069611	OHL
L5_1	FeAl 1x253	B5_1	B0_1	31.9	0.012816	0.067740	OHL
L5_2	FeAl 1x253	B5_2	B5_1	64.3	0.025832	0.136541	OHL
L5_3	FeAl 1x253	B5_4	B5_2	22	0.008838	0.046717	OHL
L5_4	FeAl 1x253	B5_6	B5_4	33.9	0.013619	0.071987	OHL
L6_1	FeAl 1x150 26/7	B6_1	B0_1	26.8	0.018457	0.058448	OHL

B.5.2 66 kV Transmission Line Parameters

Table 9: 66 kV transmission line parameters where R and X are resistance and reactance of the line in pu of 100 MVA system base (1 pu = 43.56 Ω)

Line ID	Type	From Bus	To Bus	Len. [km]	R [pu]	X[pu]	
L4_2	FeAl 1x120 26/7-66	B4_4	B4_3	13.6	0.046832	0.121763	OHL
L4_3	FeAl 1x120 26/7-66	B4_6	B4_4	8.9	0.030647	0.079683	OHL
L4_4	FeAl 1x120 26/7-66	B4_7	B4_6	28.6	0.098485	0.256060	OHL
L4_5	FeAl 1x120 26/7-66	B4_9	B4_7	7.5	0.025826	0.067149	OHL
L4_6	FeAl 1x50-66	B4_8	B4_7	1	0.008265	0.009642	OHL
L4_7	FeAl 1x120 26/7-66	B4_10	B4_9	19.1	0.065771	0.171005	OHL
L4_8	FeAl 1x120 26/7-66	B4_11	B4_10	7.2	0.024793	0.064463	OHL
L6_2	FeAl 1x120 26/7-66	B6_3	B6_2	5.2	0.017906	0.046556	OHL
L6_3	FeAl 1x120 26/7-66	B6_4	B6_2	4.3	0.014807	0.038498	OHL

B.5.3 22 kV Transmission Line Parameters

Table 10: 22 kV transmission line parameters where R and X are resistance and reactance of the line in pu of 100 MVA system base (1 pu = 4.84 Ω)

Line ID	Type	From Bus	To Bus	Len. [km]	R [pu]	X[pu]	
L4_9	NA2XS(F)2Y-AI 1x400 RM	B4_15	B4_14	7.5	0.015496	0.263429	Cable
L5_5	FeAl 1x95-22	B5_6	B5_4	15	0.588843	1.208677	OHL

B.5.4 420 kV Transmission Line Parameter

Table 11: 420 kV transmission line parameter where R and X are resistance and reactance of the line in pu of system base 100 MVA (1 pu = 1764 Ω)

Line ID	**Type**	**From Bus**	**To Bus**	**Len. [km]**	**R [pu]**	**X[pu]**	
L1_1	Cu 1x 120	B1_3	B1_2	1	0.0000567	0.000170	Cable

Appendix C

IEEE Exciter Systems

Ieee exiter systems.

Ref: Ieee recommended practice for exitation system models for power system stability studies.

Magnetiseringssystemer avhengig av ytelse.

- For drift av vannkraftaggregater kan børsteslitasje og tilgrising av maskinene med en blanding av kullstøv fra børstene og oljedamp fra lager være et betydelig problem. Derfor kan en ut fra rent driftsteknisk hold ønske at alle aggregater utføres med såkalt børsteløse magnetiseringssystemer som fjerner problemet med kullstøv o.a.
- Ifølge FIKS 2012 skal alle aggregater med ytelse fra og med 25 MVA være utstyrt med statiske magnetiseringssystemer og dempetilsats. Disse systemene vil ha børster mot sleperinger; trafo of likeretter er 'statiske' og feltstrømmen (DC) overføres til maskinens rotor over børster og sleperinger. 100 MVA maskin kan ha nominell feltstrøm omkring 1000 A. Disse statiske systemene gir dynamiske egenskaper gode nok for bruk av dempetilsats / power system stabilizer.
- For maskiner <25 MVA kan en benytte børsteløs teknologi. De aller fleste kommersielle systemer kan ikke gi tilstrekkelige dynamiske egenskaper for dempetilsats. Det er utvikling på gang for å oppnå tilsvarende egenskaper som statiske systemer. Disse vil da kunne 'flytte' grensa for børsteløse systemer opp mot f.eks. 100 – 150 MVA. Slike systemer er ennå ikke fullt ut akseptert i det norske vannkraftbransjen.
- I det følgende er det foreslått modell for børsteløst system for maskiner lavere enn 25 MVA og statisk system for øvrige maskiner.

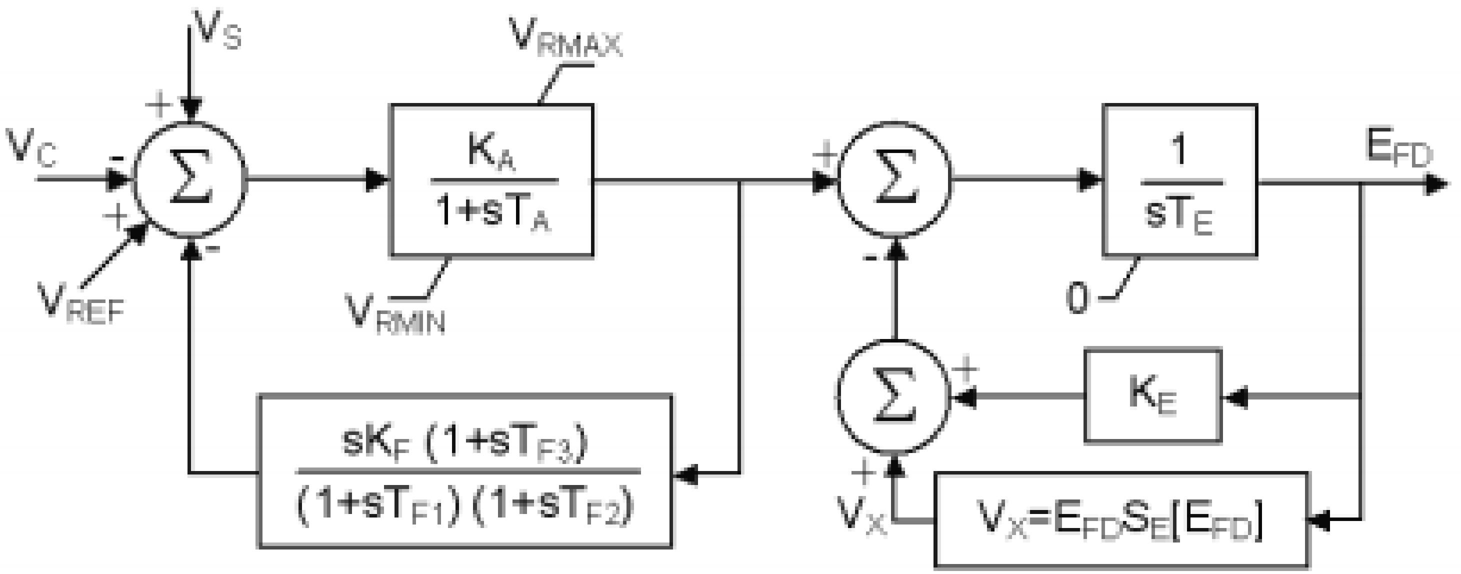


Figure 6-5—Type AC5A—Simplified rotating rectifier excitation system representa-

Modell for børsteløs magnetisering. Maskiner <25 MVA.

H.9 Sample data for a Type AC5A excitation system

Terminal voltage transducer: $T_R = 0; R_C = 0; X_C = 0$

$K_A = 400$	$K_E = 1.0$	$K_F = 0.03$
$T_A = 0.02$	$S_E[E_{FD1}] = 0.86$	$T_{F1} = 1.0$
$V_{RMAX} = 7.3$	$E_{FD1} = 5.6$	$T_{F2} = T_{F3} = 0$
$V_{RMIN} = -7.3$	$S_E[E_{FD2}] = 0.5$	
$T_E = 0.8$	$E_{FD2} = 0.75 \times E_{FD1}$	

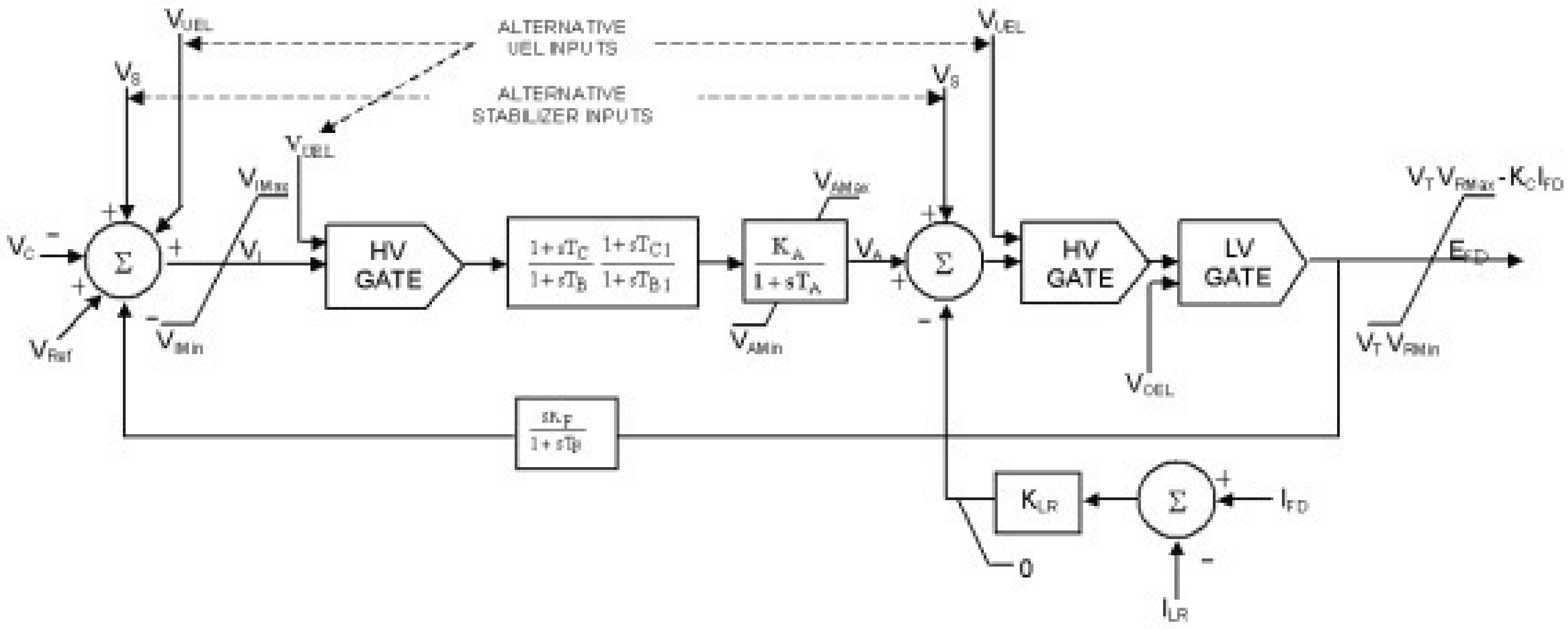


Figure 7-1—Type ST1A—Potential-source, controlled-rectifier exciter

Statisk magnetisering uten PSS.
PSS påvirker dempeforholdene, dvs. hvor lenge en pendling varer etter
En forstyrrelse før den dør ut. Liten påvirkning på første vinkelutsving.
Modellen kan derfor benyttes uten PSS.

Terminal voltage transducer: $T_R = 0.02$; $R_C = 0$; $X_C = 0$

Exciter

$K_A = 210.0$	$T_{B1} = 0$	$K_F = 0$
$T_A = 0$	$V_{RMAX} = 6.43$	$T_F = 0$ (not used)
$T_C = 1.0$	$V_{RMIN} = -6.0$	$K_{LR} = 4.54$
$T_B = 1.0$	$K_C = 0.038$	$I_{LR} = 4.4$
$T_{C1} = 0$	V_{IMAX}, V_{IMIN} (not represented)	

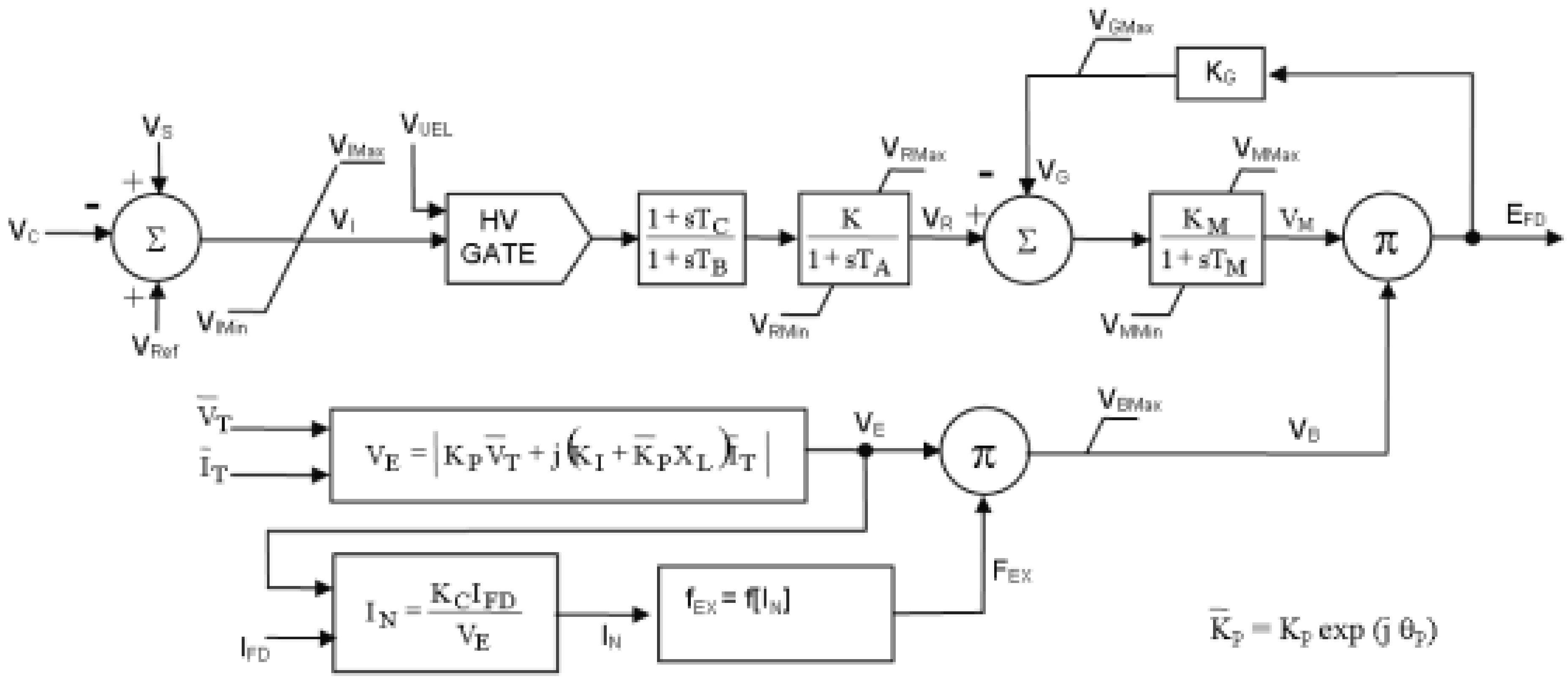


Figure 7-3—Type ST3A—Potential- or compound-source controlled-rectifier exciter with field voltage control loop

Modell for statisk magnetisering hvor en har tilpasset parametre
Slik at PSS (PSS1A) er tilpasset 'optimalt'. Kan benyttes dersom
En ønsker denne funksjonaliteten.

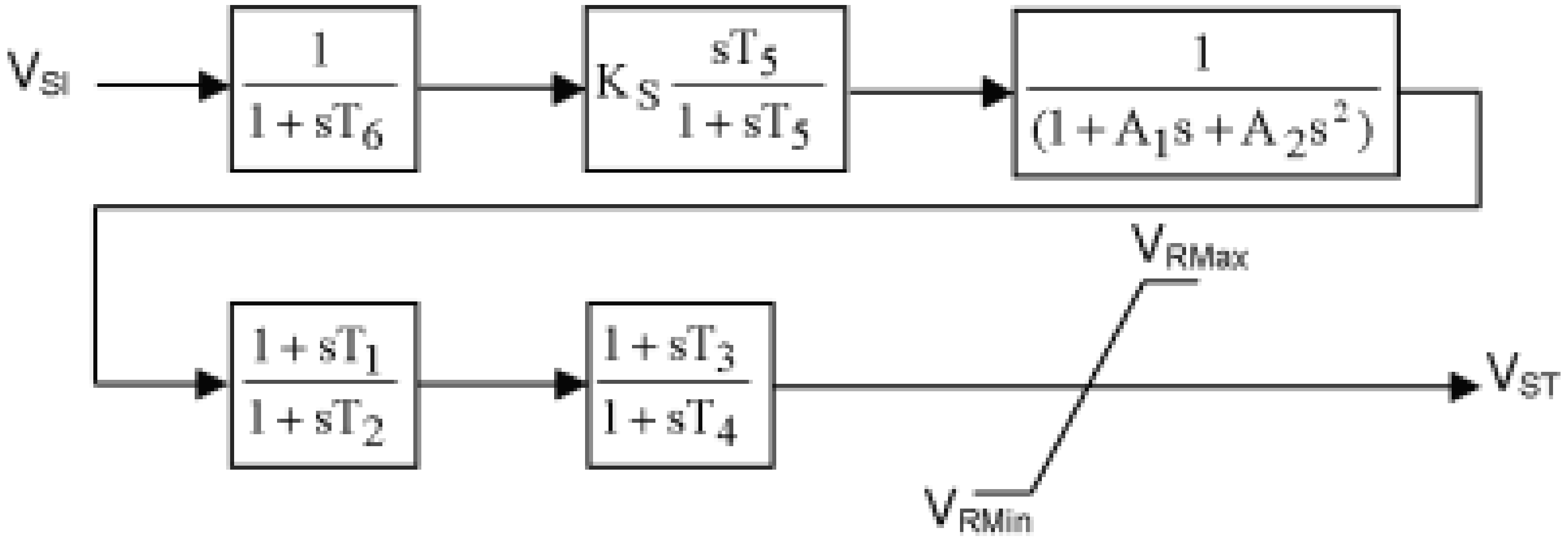


Figure 8-1—Type PSS1A—Single-input PSS

H.15 Sample data for a Type ST3A excitation system

Data set 1: Potential source

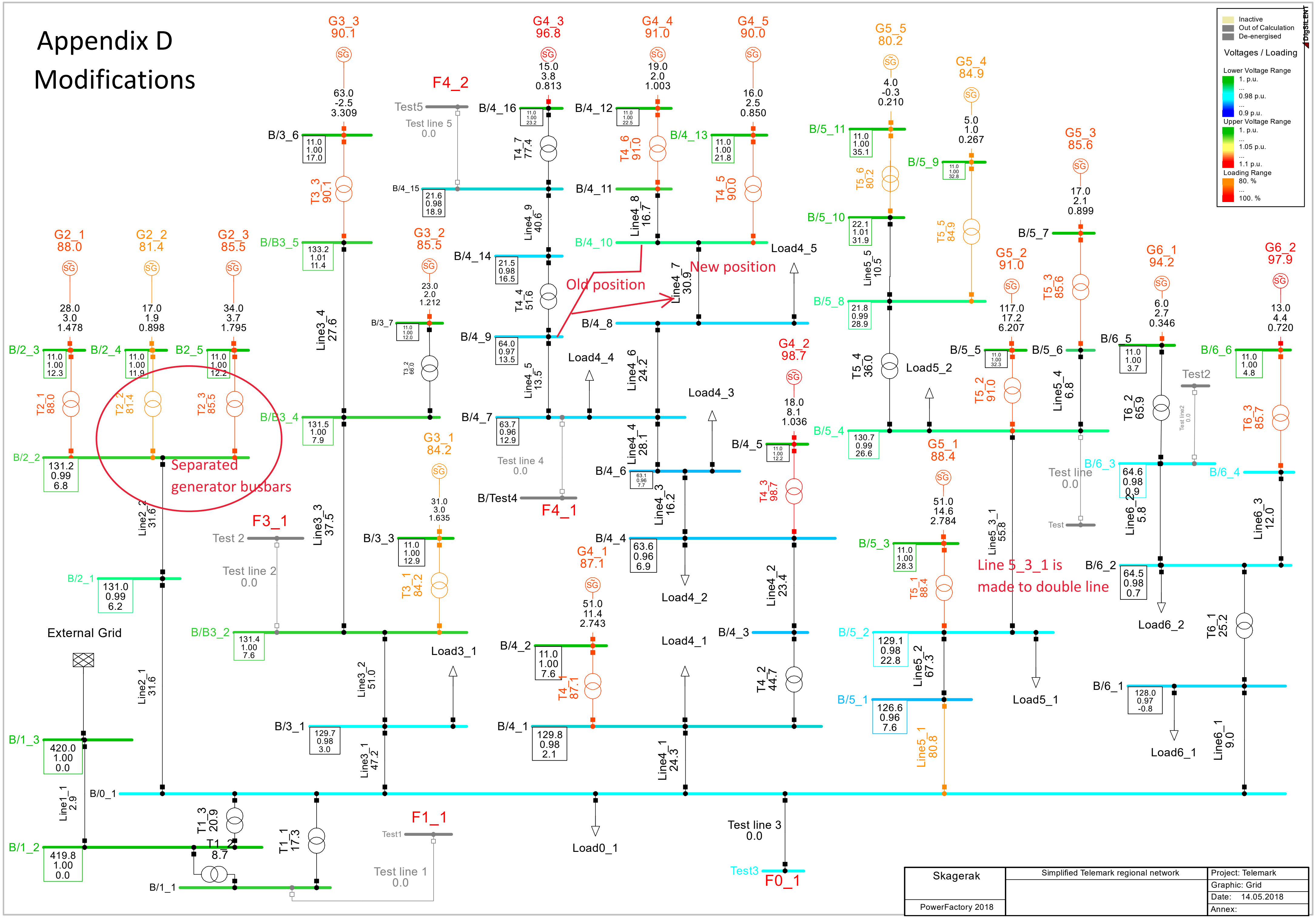
Exciter		
$T_A = 0$	$V_{I\,MIN} = -0.2$	$K_G = 1.0$
$T_R = 0$	$V_{M\,MAX} = 1.0$	$K_M = 7.93$
$T_M = 0.4$[a]	$V_{M\,MIN} = 0$	$K_A = 200$
$T_B = 10.0$	$V_{R\,MAX} = 10.0$	$K_P = 6.15$
$T_C = 1.0$	$V_{R\,MIN} = -10.0$	$\theta_P = 0^o$
$X_L = 0.081$	$V_{G\,MAX} = 5.8$	$K_I = 0$
$V_{I\,MAX} = 0.2$	$E_{FD\,MAX} = 6.9$	$K_C = 0.20$

[a] T_M may be increased to 1.0 s for most studies to permit longer computing time increments, up to 0.02 s.

Stabilizer	Type PSS1A (Input signal: speed or frequency)	
$A_1 = 0.061$	$T_3 = 0.3$	$V_{STMAX} = 0.05$
$A_2 = 0.0017$	$T_4 = 0.03$	$V_{STMIN} = -0.05$
$T_1 = 0.3$	$T_5 = 10$	
$T_2 = 0.03$	$K_S = 5$	

Appendix D

Modifications



Appendix E

Results of Load Flow from PowerFactory

		DIgSILENT PowerFactory 2018	Project:
			Date: 15.05.2018

Load Flow Calculation			Busbars/Terminals
AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic tap adjustment of transformers	No	Max. Acceptable Load Flow Error for	
Consider reactive power limits	No	Nodes	1.00 kVA
		Model Equations	0.10 %

Grid: Grid	System Stage: Grid	Study Case: Steady state representatio	Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
B(1)										
2_4	11.00	1.00	11.00	11.91						
Cub_1	/Sym	G2_2			17.00	1.87	0.99	0.90	81.44	Typ: PV
Cub_1	/Tr2	T2_2			17.00	1.87	0.99	0.90	81.44	Tap: 0.00 Min: 0 Max: 0
B(10)										
3_7	11.00	1.00	11.00	12.02						
Cub_1	/Sym	G3_2			23.00	1.98	1.00	1.21	85.50	Typ: PV
Cub_1	/Tr2	T3_2			23.00	1.98	1.00	1.21	65.96	Tap: 0.00 Min: 0 Max: 0
B(11)										
B3_5	132.00	1.01	133.17	11.41						
Cub_1	/Lne	Line3_4			63.00	-8.77	0.99	0.28	27.58	Pv: 1430.53 kW cLod: -0.00 Mvar L: 41.80 km
Cub_1	/Tr2	T3_3			-63.00	8.77	-0.99	0.28	90.07	Tap: 0.00 Min: 0 Max: 0
B(12)										
3_6	11.00	1.00	11.00	17.04						
Cub_1	/Sym	G3_3			63.00	-2.52	1.00	3.31	90.07	Typ: PV
Cub_1	/Tr2	T3_3			63.00	-2.52	1.00	3.31	90.07	Tap: 0.00 Min: 0 Max: 0
B(13)										
4_1	132.00	0.98	129.82	2.14						
Cub_1	/Lod	Load4_1			21.28	5.80	0.96	0.10		Pl0: 22.00 MW Ql0: 6.00 Mvar
Cub_1	/Lne	Line4_1			53.63	-10.46	0.98	0.24	24.30	Pv: 826.59 kW cLod: -0.00 Mvar L: 31.10 km
Cub_1	/Tr2	T4_1			-51.00	-6.44	-0.99	0.23	87.11	Tap: 0.00 Min: 0 Max: 0
Cub_1	/Tr2	T4_2			-23.91	11.10	-0.91	0.12	44.68	Tap: 0.00 Min: 0 Max: 0

Grid: Grid	System Stage: Grid	Study Case: Steady state representatio	Annex: / 2

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
B(14)										
4_2	11.00	1.00	11.00	7.59						
Cub_1	/Sym	G4_1			51.00	11.45	0.98	2.74	87.11	Typ: PV
Cub_1	/Tr2	T4_1			51.00	11.45	0.98	2.74	87.11	Tap: 0.00 Min: 0 Max: 0
B(15)										
4_3	66.00	0.96	63.61	4.79						
Cub_1	/Lne	Line4_2			-23.91	9.78	-0.93	0.23	23.45	Pv: 336.50 kW cLod: -0.00 Mvar L: 13.60 km
Cub_1	/Tr2	T4_2			23.91	-9.78	0.93	0.23	44.68	Tap: 0.00 Min: 0 Max: 0
B(16)										
4_4	66.00	0.96	63.61	6.87						
Cub_1	/Lod	Load4_2			4.64	0.93	0.98	0.04		Pl0: 5.00 MW Ql0: 1.00 Mvar
Cub_1	/Lne	Line4_2			24.25	-8.90	0.94	0.23	23.45	Pv: 336.50 kW cLod: -0.00 Mvar L: 13.60 km
Cub_1	/Lne	Line4_3			-10.89	14.13	-0.61	0.16	16.19	Pv: 105.01 kW cLod: -0.00 Mvar L: 8.90 km
Cub_1	/Tr2	T4_3			-18.00	-6.15	-0.95	0.17	98.69	Tap: 0.00 Min: 0 Max: 0
B(17)										
4_6	66.00	0.96	63.07	7.68						
Cub_1	/Lod	Load4_3			18.26	4.57	0.97	0.17		Pl0: 20.00 MW Ql0: 5.00 Mvar
Cub_1	/Lne	Line4_3			11.00	-13.85	0.62	0.16	16.19	Pv: 105.01 kW cLod: -0.00 Mvar L: 8.90 km
Cub_1	/Lne	Line4_4			-29.26	9.29	-0.95	0.28	28.10	Pv: 1016.50 kW cLod: -0.00 Mvar L: 28.60 km
B(18)										
4_7	66.00	0.96	63.68	12.91						
Cub_1	/Lod	Load4_4			11.17	4.65	0.92	0.11		Pl0: 12.00 MW Ql0: 5.00 Mvar
Cub_1	/Lne	Line4_4			30.28	-6.65	0.98	0.28	28.10	Pv: 1016.50 kW cLod: -0.00 Mvar L: 28.60 km
Cub_1	/Lne	Line4_5			-14.90	-1.04	-1.00	0.14	13.54	Pv: 61.89 kW cLod: -0.00 Mvar L: 7.50 km
Cub_1	/Lne	Line4_6			-26.55	3.03	-0.99	0.24	24.23	Pv: 63.38 kW cLod: -0.00 Mvar L: 1.00 km
Cub_1	/Lne	Test line 4			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.10 km
B(19)										
4_8	66.00	0.97	63.81	13.08						
Cub_1	/Lod	Load4_5			7.48	1.87	0.97	0.07		Pl0: 8.00 MW Ql0: 2.00 Mvar
Cub_1	/Lne	Line4_6			26.61	-2.96	0.99	0.24	24.23	Pv: 63.38 kW cLod: -0.00 Mvar L: 1.00 km
Cub_1	/Lne	Line4_7			-34.09	1.09	-1.00	0.31	30.86	Pv: 818.52 kW cLod: -0.00 Mvar L: 19.10 km

			rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data					
B(2)																	
2_2			132.00	0.99	131.23	6.77											
Cub_1	/Lne	Line2_2					79.00	1.15	1.00	0.35	31.60	Pv:	152.23 kW	cLod:	-0.00 Mvar	L:	6.00 km
Cub_1	/Tr2	T2_1					-28.00	-0.32	-1.00	0.12	88.02	Tap:	0.00	Min:	0	Max:	0
Cub_1	/Tr2	T2_2					-17.00	-0.34	-1.00	0.07	81.44	Tap:	0.00	Min:	0	Max:	0
Cub_1	/Tr2	T2_3					-34.00	-0.49	-1.00	0.15	85.50	Tap:	0.00	Min:	0	Max:	0
B(20)																	
4_9			66.00	0.97	64.00	13.50											
Cub_1	/Lne	Line4_5					14.96	1.20	1.00	0.14	13.54	Pv:	61.89 kW	cLod:	-0.00 Mvar	L:	7.50 km
Cub_1	/Tr2	T4_4					-14.96	-1.20	-1.00	0.14	51.60	Tap:	0.00	Min:	0	Max:	0
B(21)																	
4_10			66.00	0.99	65.34	16.62											
Cub_1	/Lne	Line4_7					34.91	1.04	1.00	0.31	30.86	Pv:	818.52 kW	cLod:	-0.00 Mvar	L:	19.10 km
Cub_1	/Lne	Line4_8					-18.91	0.02	-1.00	0.17	16.71	Pv:	90.45 kW	cLod:	-0.00 Mvar	L:	7.20 km
Cub_1	/Tr2	T4_5					-16.00	-1.06	-1.00	0.14	89.98	Tap:	0.00	Min:	0	Max:	0
B(22)																	
4_14			22.00	0.98	21.45	16.53											
Cub_1	/Lne	Line4_9					-14.96	-2.00	-0.99	0.41	40.63	Pv:	37.14 kW	cLod:	-0.00 Mvar	L:	7.50 km
Cub_1	/Tr2	T4_4					14.96	2.00	0.99	0.41	51.60	Tap:	0.00	Min:	0	Max:	0
B(23)																	
4_15			22.00	0.98	21.64	18.86											
Cub_1	/Lne	Line4_9					15.00	2.63	0.98	0.41	40.63	Pv:	37.14 kW	cLod:	-0.00 Mvar	L:	7.50 km
Cub_1	/Lne	Test line 5					0.00	0.00	1.00	0.00	0.00	Pv:	0.00 kW	cLod:	-0.00 Mvar	L:	0.10 km
Cub_1	/Tr2	T4_7					-15.00	-2.63	-0.98	0.41	77.40	Tap:	0.00	Min:	0	Max:	0
B(24)																	
4_16			11.00	1.00	11.00	23.24											
Cub_1	/Sym	G4_3					15.00	3.83	0.97	0.81	96.75	Typ:	PV				
Cub_1	/Tr2	T4_7					15.00	3.83	0.97	0.81	77.40	Tap:	0.00	Min:	0	Max:	0
B(25)																	
4_12			11.00	1.00	11.00	22.54											
Cub_1	/Sym	G4_4					19.00	1.96	0.99	1.00	90.95	Typ:	PV				
Cub_1	/Tr2	T4_6					19.00	1.96	0.99	1.00	90.95	Tap:	0.00	Min:	0	Max:	0

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
B(26)										
4_13	11.00	1.00	11.00	21.77						
Cub_1	/Sym	G4_5			16.00	2.52	0.99	0.85	89.98	Typ: PV
Cub_1	/Tr2	T4_5			16.00	2.52	0.99	0.85	89.98	Tap: 0.00 Min: 0 Max: 0
B(27)										
4_11	66.00	0.99	65.66	17.32						
Cub_1	/Lne	Line4_8			19.00	0.22	1.00	0.17	16.71	Pv: 90.45 kW cLod: -0.00 Mvar L: 7.20 km
Cub_1	/Tr2	T4_6			-19.00	-0.22	-1.00	0.17	90.95	Tap: 0.00 Min: 0 Max: 0
B(28)										
4_5	11.00	1.00	11.00	12.23						
Cub_1	/Sym	G4_2			18.00	8.10	0.91	1.04	98.69	Typ: PV
Cub_1	/Tr2	T4_3			18.00	8.10	0.91	1.04	98.69	Tap: 0.00 Min: 0 Max: 0
B(29)										
5_1	132.00	0.96	126.56	7.61						
Cub_1	/Lne	Line5_1			171.74	-43.14	0.97	0.81	80.78	Pv: 4371.39 kW cLod: -0.00 Mvar L: 31.90 km
Cub_1	/Lne	Line5_2			-171.74	43.14	-0.97	0.81	67.32	Pv: 8811.31 kW cLod: -0.00 Mvar L: 64.30 km
B(3)										
2_1	132.00	0.99	130.97	6.18						
Cub_1	/Lne	Line2_1			78.85	0.34	1.00	0.35	31.60	Pv: 1649.15 kW cLod: -0.00 Mvar L: 65.00 km
L	/Lne	Line2_2			-78.85	-0.34	-1.00	0.35	31.60	Pv: 152.23 kW cLod: -0.00 Mvar L: 6.00 km
B(30)										
5_2	132.00	0.98	129.07	22.80						
Cub_1	/Lod	Load5_1			7.65	1.91	0.97	0.04		Pl0: 8.00 MW Ql0: 2.00 Mvar
Cub_1	/Lne	Line5_2			180.55	3.44	1.00	0.81	67.32	Pv: 8811.31 kW cLod: -0.00 Mvar L: 64.30 km
Cub_1	/Lne	Line5_3_1			-137.20	4.06	-1.00	0.61	55.82	Pv: 1741.72 kW cLod: -0.00 Mvar L: 22.00 km
Cub_1	/Tr2	T5_1			-51.00	-9.41	-0.98	0.23	88.40	Tap: 0.00 Min: 0 Max: 0
B(31)										
5_3	11.00	1.00	11.00	28.28						
Cub_1	/Sym	G5_1			51.00	14.57	0.96	2.78	88.40	Typ: PV
Cub_1	/Tr2	T5_1			51.00	14.57	0.96	2.78	88.40	Tap: 0.00 Min: 0 Max: 0

Grid: Grid	System Stage: Grid	Study Case: Steady state representatio	Annex: / 5

			rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
B(32)												
5_4			132.00	0.99	130.74	26.61						
Cub_1	/Lod	Load5_2					3.92	0.00	1.00	0.02		Pl0: 4.00 MW Ql0: 0.00 Mvar
Cub_1	/Lne	Line5_3_1					138.94	5.15	1.00	0.61	55.82	Pv: 1741.72 kW cLod: -0.00 Mvar L: 22.00 km
Cub_1	/Lne	Line5_4					-16.96	-0.25	-1.00	0.07	6.81	Pv: 39.94 kW cLod: -0.00 Mvar L: 33.90 km
Cub_1	/Lne	Test line					0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.10 km
Cub_1	/Tr2	T5_2					-117.00	-5.33	-1.00	0.52	90.96	Tap: 0.00 Min: 0 Max: 0
Cub_1	/Tr2	T5_4					-8.91	0.43	-1.00	0.04	36.01	Tap: 0.00 Min: 0 Max: 0
B(33)												
5_6			132.00	0.99	131.08	27.32						
Cub_1	/Lne	Line5_4					17.00	0.46	1.00	0.07	6.81	Pv: 39.94 kW cLod: -0.00 Mvar L: 33.90 km
Cub_1	/Tr2	T5_3					-17.00	-0.46	-1.00	0.07	85.63	Tap: 0.00 Min: 0 Max: 0
B(34)												
5_7			11.00	1.00	11.00	32.72						
Cub_1	/Sym	G5_3					17.00	2.07	0.99	0.90	85.63	Typ: PV
Cub_1	/Tr2	T5_3					17.00	2.07	0.99	0.90	85.63	Tap: 0.00 Min: 0 Max: 0
B(35)												
5_5			11.00	1.00	11.00	32.35						
Cub_1	/Sym	G5_2					117.00	17.16	0.99	6.21	90.96	Typ: PV
Cub_1	/Tr2	T5_2					117.00	17.16	0.99	6.21	90.96	Tap: 0.00 Min: 0 Max: 0
B(36)												
5_8			22.00	0.99	21.77	28.90						
Cub_1	/Lne	Line5_5					-3.91	0.69	-0.98	0.11	10.52	Pv: 94.66 kW cLod: -0.00 Mvar L: 15.00 km
Cub_1	/Tr2	T5_4					8.91	-0.07	1.00	0.24	36.01	Tap: 0.00 Min: 0 Max: 0
Cub_1	/Tr2	T5_5					-5.00	-0.62	-0.99	0.13	84.88	Tap: 0.00 Min: 0 Max: 0
B(37)												
5_10			22.00	1.01	22.12	31.86						
Cub_1	/Lne	Line5_5					4.00	-0.50	0.99	0.11	10.52	Pv: 94.66 kW cLod: -0.00 Mvar L: 15.00 km
Cub_1	/Tr2	T5_6					-4.00	0.50	-0.99	0.11	80.19	Tap: 0.00 Min: 0 Max: 0
B(38)												
5_9			11.00	1.00	11.00	32.77						
Cub_1	/Sym	G5_4					5.00	0.97	0.98	0.27	84.88	Typ: PV
Cub_1	/Tr2	T5_5					5.00	0.97	0.98	0.27	84.88	Tap: 0.00 Min: 0 Max: 0

Grid: Grid	System Stage: Grid	Study Case: Steady state representatio	Annex: / 6

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
B(39)										
5_11	11.00	1.00	11.00	35.05						
Cub_1	/Sym	G5_5			4.00	-0.28	1.00	0.21	80.19	Typ: PV
Cub_1	/Tr2	T5_6			4.00	-0.28	1.00	0.21	80.19	Tap: 0.00 Min: 0 Max: 0
B(4)										
1_3	420.00	1.00	420.00	0.00						
Cub_1	/Xnet	External Grid			40.82	207.70	0.19	0.29		Sk": 14549.23 MVA
Cub_1	/Lne	Line1_1			40.82	207.70	0.19	0.29	2.91	Pv: 25.40 kW cLod: -0.00 Mvar L: 1.00 km
B(40)										
6_1	132.00	0.97	127.96	-0.84						
Cub_1	/Lod	Load6_1			28.19	9.40	0.95	0.13		Pl0: 30.00 MW Ql0: 10.00 Mvar
Cub_1	/Lne	Line 6_1			-18.77	-6.82	-0.94	0.09	9.01	Pv: 78.37 kW cLod: 0.00 Mvar L: 26.80 km
Cub_1	/Tr2	T6_1			-9.42	-2.57	-0.96	0.04	25.18	Tap: 0.00 Min: 0 Max: 0
B(41)										
6_2	66.00	0.98	64.49	0.72						
Cub_1	/Lod	Load6_2			9.55	2.86	0.96	0.09		Pl0: 10.00 MW Ql0: 3.00 Mvar
Cub_1	/Lne	Line6_2			-5.99	-2.37	-0.93	0.06	5.77	Pv: 7.79 kW cLod: -0.00 Mvar L: 5.20 km
Cub_1	/Lne	Line6_3			-12.97	-3.35	-0.97	0.12	11.99	Pv: 27.84 kW cLod: -0.00 Mvar L: 4.30 km
Cub_1	/Tr2	T6_1			9.42	2.85	0.96	0.09	25.18	Tap: 0.00 Min: 0 Max: 0
B(42)										
6_3	66.00	0.98	64.63	0.86						
Cub_1	/Lne	Line6_2			6.00	2.39	0.93	0.06	5.77	Pv: 7.79 kW cLod: -0.00 Mvar L: 5.20 km
Cub_1	/Lne	Test line2			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 1.00 km
Cub_1	/Tr2	T6_2			-6.00	-2.39	-0.93	0.06	65.95	Tap: 0.00 Min: 0 Max: 0
B(43)										
6_4	66.00	0.98	64.70	0.99						
Cub_1	/Lne	Line6_3			13.00	3.42	0.97	0.12	11.99	Pv: 27.84 kW cLod: -0.00 Mvar L: 4.30 km
Cub_1	/Tr2	T6_3			-13.00	-3.42	-0.97	0.12	85.70	Tap: 0.00 Min: 0 Max: 0
B(44)										
3_1	132.00	0.98	129.70	2.97						
Cub_1	/Lod	Load3_1			9.65	3.86	0.93	0.05		Pl0: 10.00 MW Ql0: 4.00 Mvar
Cub_1	/Lne	Line3_1			102.93	-25.27	0.97	0.47	47.18	Pv: 2143.45 kW cLod: -0.00 Mvar L: 21.40 km
Cub_1	/Lne	Line3_2			-112.58	21.41	-0.98	0.51	51.01	Pv: 2829.30 kW cLod: -0.00 Mvar L: 30.20 km

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
B(45)										
6_6	11.00	1.00	11.00	4.79						
Cub_1	/Sym	G6_2			13.00	4.36	0.95	0.72	97.94	Typ: PV
Cub_1	/Tr2	T6_3			13.00	4.36	0.95	0.72	85.70	Tap: 0.00 Min: 0 Max: 0
B(46)										
6_5	11.00	1.00	11.00	3.67						
Cub_1	/Sym	G6_1			6.00	2.74	0.91	0.35	94.21	Typ: PV
Cub_1	/Tr2	T6_2			6.00	2.74	0.91	0.35	65.95	Tap: 0.00 Min: 0 Max: 0
B(47)										
1_1	300.00	1.00	298.74	-0.04						
Cub_1	/Lne	Test line 1			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.10 km
Cub_1	/Tr2	T1_1			16.68	84.56	0.19	0.17	17.31	Tap: 0.00 Min: 0 Max: 0
Cub_1	/Tr2	T1_2			-16.68	-84.56	-0.19	0.17	8.66	Tap: 0.00 Min: 0 Max: 0
B(48)										
Test4	66.00	0.00	0.00	0.00						
Cub_1	/Lne	Test line 4			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.10 km
B(5)										
1_2	420.00	1.00	419.84	0.00						
Cub_1	/Lne	Line1_1			-40.79	-207.62	-0.19	0.29	2.91	Pv: 25.40 kW cLod: -0.00 Mvar L: 1.00 km
Cub_1	/Tr2	T1_2			16.68	84.90	0.19	0.12	8.66	Tap: 0.00 Min: 0 Max: 0
Cub_1	/Tr2	T1_3			24.11	122.72	0.19	0.17	20.85	Tap: 0.00 Min: 0 Max: 0
B(6)										
0_1	132.00	0.98	128.98	-0.26						
Cub_1	/Lod	Load0_1			420.10	76.38	0.98	1.91		Pl0: 440.00 MW Ql0: 80.00 Mvar
Cub_1	/Lne	Line 6_1			18.85	7.07	0.94	0.09	9.01	Pv: 78.37 kW cLod: 0.00 Mvar L: 26.80 km
Cub_1	/Lne	Line2_1			-77.20	8.37	-0.99	0.35	31.60	Pv: 1649.15 kW cLod: -0.00 Mvar L: 65.00 km
Cub_1	/Lne	Line3_1			-100.78	30.84	-0.96	0.47	47.18	Pv: 2143.45 kW cLod: -0.00 Mvar L: 21.40 km
Cub_1	/Lne	Line4_1			-52.81	12.61	-0.97	0.24	24.30	Pv: 826.59 kW cLod: -0.00 Mvar L: 31.10 km
Cub_1	/Lne	Line5_1			-167.37	67.49	-0.93	0.81	80.78	Pv: 4371.39 kW cLod: -0.00 Mvar L: 31.90 km
Cub_1	/Lne	Test line 3			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: 0.00 Mvar L: 0.10 km
Cub_1	/Tr2	T1_1			-16.68	-82.92	-0.20	0.38	17.31	Tap: 0.00 Min: 0 Max: 0
Cub_1	/Tr2	T1_3			-24.11	-119.85	-0.20	0.55	20.85	Tap: 0.00 Min: 0 Max: 0

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
B(7)										
3_3	11.00	1.00	11.00	12.89						
Cub_1	/Sym	G3_1			31.00	3.03	1.00	1.63	84.18	Typ: PV
Cub_1	/Tr2	T3_1			31.00	3.03	1.00	1.63	84.18	Tap: 0.00 Min: 0 Max: 0
B(8)										
B3_2	132.00	1.00	131.38	7.58						
Cub_1	/Lne	Line3_2			115.41	-12.45	0.99	0.51	51.01	Pv: 2829.30 kW cLod: -0.00 Mvar L: 30.20 km
Cub_1	/Lne	Line3_3			-84.41	12.59	-0.99	0.38	37.51	Pv: 158.26 kW cLod: -0.00 Mvar L: 2.50 km
Cub_1	/Lne	Test line 2			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.00 km
Cub_1	/Tr2	T3_1			-31.00	-0.15	-1.00	0.14	84.18	Tap: 0.00 Min: 0 Max: 0
B(9)										
B3_4	132.00	1.00	131.52	7.86						
Cub_1	/Lne	Line3_3			84.57	-12.18	0.99	0.38	37.51	Pv: 158.26 kW cLod: -0.00 Mvar L: 2.50 km
Cub_1	/Lne	Line3_4			-61.57	12.49	-0.98	0.28	27.58	Pv: 1430.53 kW cLod: -0.00 Mvar L: 41.80 km
Cub_1	/Tr2	T3_2			-23.00	-0.31	-1.00	0.10	65.96	Tap: 0.00 Min: 0 Max: 0
B										
2_3	11.00	1.00	11.00	12.32						
Cub_1	/Sym	G2_1			28.00	3.05	0.99	1.48	88.02	Typ: PV
Cub_1	/Tr2	T2_1			28.00	3.05	0.99	1.48	88.02	Tap: 0.00 Min: 0 Max: 0
B2_5										
	11.00	1.00	11.00	12.16						
Cub_2	/Sym	G2_3			34.00	3.71	0.99	1.80	85.50	Typ: PV
Cub_1	/Tr2	T2_3			34.00	3.71	0.99	1.80	85.50	Tap: 0.00 Min: 0 Max: 0
Test										
	132.00	0.00	0.00	0.00						
Cub_1	/Lne	Test line			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.10 km
Test 2										
	132.00	0.00	0.00	0.00						
Cub_1	/Lne	Test line 2			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.00 km
Test1										
	300.00	0.00	0.00	0.00						
Cub_1	/Lne	Test line 1			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.10 km

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
Test2	66.00	0.00	0.00	0.00						
Cub_1	/Lne	Test line2			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 1.00 km
Test3	132.00	0.98	128.98	-0.26						
Cub_1	/Lne	Test line 3			-0.00	0.00	-1.00	0.00	0.00	Pv: 0.00 kW cLod: 0.00 Mvar L: 0.10 km
Test5	22.00	0.00	0.00	0.00						
Cub_1	/Lne	Test line 5			0.00	0.00	1.00	0.00	0.00	Pv: 0.00 kW cLod: -0.00 Mvar L: 0.10 km

Appendix F

FRT Capability Results

Case 1

Table 12: Case 1 FRT Capability Results in the event of 0.1 - 0.6 fault clearing time

		PowerFactory							**OpenIPSL**					
132 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
Generator	**P[MW]**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
G2_1	28	1	1	0	0	0	0		1	1	1	1	-	-
G2_2	17	1	1	0	0	0	0		1	1	1	1	-	-
G2_3	34	1	1	0	0	0	0		1	1	1	1	-	-
G3_1	31	1	1	1	0	0	0		1	1	1	1	-	-
G3_2	23	1	1	1	0	0	0		1	1	1	1	-	-
G3_3	63	1	1	1	0	0	0		1	1	1	1	-	-
G4_1	51	1	1	1	0	0	0		1	1	1	1	-	-
G5_1	50	1	1	0	0	0	0		1	1	1	1	-	-
G5_2	117	1	1	0	0	0	0		1	1	1	1	-	-
G5_3	17	1	1	0	0	0	0		1	1	1	1	-	-
Tot [MW]	431	431	431	51	0	0	0		431	431	431	431	0	0
Tot [%]	100%	100%	100%	12%	0%	0%	0%		100%	100%	100%	100%	0%	0%
66 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_2	19	1	1	1	0	0	0		1	1	1	1	-	-
G4_4	19	1	1	0	0	0	0		1	1	1	1	-	-
G4_5	16	1	1	0	0	0	0		1	1	1	1	-	-
G6_1	6	1	1	0	0	0	0		1	1	1	1	-	-
G6_2	13	1	1	0	0	0	0		1	1	1	1	-	-
Tot [MW]	73	73	73	19	0	0	0		73	73	73	73	0	0
Tot [%]	100%	100%	100%	26%	0%	0%	0%		100%	100%	100%	100%	0%	0%
22 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_3	15	1	1	0	0	0	0		1	1	1	1	-	-
G5_4	5	1	1	0	0	0	0		1	1	1	1	-	-
G5_5	4	1	1	0	0	0	0		1	1	1	1	-	-
Tot [MW]	24	24	24	0	0	0	0		24	24	24	24	0	0
Tot [%]	100%	100%	100%	0%	0%	0%	0%		100%	100%	100%	100%	0%	0%
		0.1	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
Tot [MW]	528	528	528	187	0	0	0		528	528	528	528	0	0
Tot [%]	100%	100%	100%	35%	0%	0%	0%		100%	100%	0%	0%	0%	0%

Case 2

Table 13: FRT Capability Result in the event of 0.1 – 0-6 s fault clearing time

		PowerFactory							**OpenIPSL**					
132 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
Generator	**P[MW]**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
G2_1	28	1	1	1	1	1	1		1	1	1	1	1	1
G2_2	17	1	1	1	1	1	1		1	1	1	1	1	1
G2_3	34	1	1	1	1	1	1		1	1	1	1	1	1
G3_1	31	1	0	0	0	0	0		1	0	0	0	0	0
G3_2	23	1	1	0	0	0	0		1	1	0	0	0	0
G3_3	63	1	1	0	0	0	0		1	1	0	0	0	0
G4_1	51	1	1	1	1	1	1		1	1	1	1	1	1
G5_1	50	1	1	1	1	1	1		1	1	1	1	1	1
G5_2	117	1	1	1	1	1	1		1	1	1	1	1	1
G5_3	17	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	431	431	400	314	314	314	314		431	400	314	314	314	314
Tot [%]	100%	100%	93%	73%	73%	73%	73%		100%	93%	73%	73%	73%	73%
66 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_2	19	1	1	1	1	1	1		1	1	1	1	1	1
G4_4	19	1	1	1	1	1	1		1	1	1	1	1	1
G4_5	16	1	1	1	1	1	1		1	1	1	1	1	1
G6_1	6	1	1	1	1	1	1		1	1	1	1	1	1
G6_2	13	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	73	73	73	73	73	73	73		73	73	73	73	73	73
Tot [%]	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%	100%	100%
22 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_3	15	1	1	1	1	1	1		1	1	1	1	1	1
G5_4	5	1	1	1	1	1	1		1	1	1	1	1	1
G5_5	4	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	24	24	24	24	24	24	24		24	24	24	24	24	24
Tot [%]	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%	100%	100%
		0.1	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
Tot [MW]	528	528	497	411	411	411	411		528	497	411	411	411	411
Tot [%]	100%	100%	94%	78%	78%	78%	78%		100%	94%	78%	78%	78%	78%

	In synchronism		Out of step	-	Test Failed

Case 3

Table 14: FRT Capability Result in the event of 0.1 - 0.6 s fault clearing time

		PowerFactory							OpenIPSL					
132 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
Generator	**P [MW]**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
G2_1	28	1	0	0	0	0	0		1	1	1	-	-	-
G2_2	17	1	0	0	0	0	0		1	1	1	-	-	-
G2_3	34	1	0	0	0	0	0		1	1	1	-	-	-
G3_1	31	1	1	0	0	0	0		1	1	1	-	-	-
G3_2	23	1	1	0	0	0	0		1	1	1	-	-	-
G3_3	63	1	1	0	0	0	0		1	1	1	-	-	-
G4_1	51	1	1	0	0	0	0		1	1	1	-	-	-
G5_1	50	1	0	0	0	0	0		1	1	1	-	-	-
G5_2	117	1	0	0	0	0	0		1	1	1		--	-
G5_3	17	1	0	0	0	0	0		1	1	1	-	-	-
Tot [MW]	431	431	168	0	0	0	0		431	431	431	0	0	0
Tot [%]	100%	100%	39%	0%	0%	0%	0%		100%	100%	100%	0%	0%	0%
66 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_2	19	1	1	0	0	0	0		1	1	1	-	-	-
G4_4	19	1	1	0	0	0	0		1	1	1	-	-	-
G4_5	16	1	1	0	0	0	0		1	1	1	-	-	-
G6_1	6	1	1	0	0	0	0		1	1	1	-	-	-
G6_2	13	1	1	0	0	0	0		1	1	1	-	-	-
Tot [MW]	73	73	73	0	0	0	0		73	73	73	0	0	0
Tot [%]	100%	100%	100%	0%	0%	0%	0%		100%	100%	0%	0%	0%	0%
22 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_3	15	1	1	0	0	0	0		1	1	1	-	-	-
G5_4	5	1	0	0	0	0	0		1	1	1	-	-	--
G5_5	4	1	0	0	0	0	0		1	1	1	-	-	-
Tot [MW]	24	24	15	0	0	0	0		24	24	24	0	0	0
Tot [%]	100%	100%	63%	0%	0%	0%	0%		100%	100%	0%	0%	0%	0%
		0.1	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
Tot [MW]	528	528	256	0	0	0	0		528	528	528	0	0	0
Tot [%]	100%	100%	48%	0%	0%	0%	0%		100%	100%	100%	0%	0%	0%

	In synchronism		Out of step	-	Test Failed

Case 4

Table 15: FRT Capability Result in the event of 0.1 - 0.6 fault clearing time

		PowerFactory							**OpenIPSL**					
132 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
Generator	**P [MW]**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
G2_1	28	1	1	1	1	1	1		1	1	1	1	1	1
G2_2	17	1	1	1	1	1	1		1	1	1	1	1	1
G2_3	34	1	1	1	1	1	1		1	1	1	1	1	1
G3_1	31	1	1	1	1	1	1		1	1	1	1	1	1
G3_2	23	1	1	1	1	1	1		1	1	1	1	1	1
G3_3	63	1	1	1	1	1	1		1	1	1	1	1	1
G4_1	51	1	1	1	1	1	1		1	1	1	1	1	1
G5_1	50	1	1	1	1	1	1		1	1	1	1	1	1
G5_2	117	1	1	1	1	1	1		1	1	1	1	1	1
G5_3	17	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	431	431	431	431	431	431	431		431	431	431	431	431	431
Tot [%]	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%	100%	100%
66 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_2	19	1	1	1	1	1	1		1	1	1	1	1	1
G4_4	19	1	1	0	0	0	0		1	1	1	1	1	1
G4_5	16	1	1	0	0	0	0		1	1	1	1	1	1
G6_1	6	1	1	1	1	1	1		1	1	1	1	1	1
G6_2	13	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	73	73	73	38	38	38	38		73	73	73	73	73	73
Total [%]	100%	100%	100%	52%	52%	52%	52%		100%	100%	100%	100%	100%	100%
22 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_3	15	1	0	0	0	0	0		1	1	1	1	1	1
G5_4	5	1	1	1	1	1	1		1	1	1	1	1	1
G5_5	4	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	24	24	9	9	9	9	9		24	24	24	24	24	24
Tot [%]	100%	100%	38%	38%	38%	38%	38%		100%	100%	100%	100%	100%	100%
		0.1	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
Tot [MW]	528	528	513	478	478	478	478		528	528	528	528	528	528
Tot [%]	100%	100%	97%	91%	91%	91%	91%		100%	100%	100%	100%	100%	100%

	In synchronism		Out of step	-	Test Failed

Case 5

Table 16: Case 5 FRT Capability Result in the event of 0.1 - 0.6 s fault clearing time

		PowerFactory							**OpenIPSL**					
132 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
Generator	**P [MW]**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
G2_1	28	1	1	1	1	1	1		1	1	1	1	1	1
G2_2	17	1	1	1	1	1	1		1	1	1	1	1	1
G2_3	34	1	1	1	1	1	1		1	1	1	1	1	1
G3_1	31	1	1	1	1	1	1		1	1	1	1	1	1
G3_2	23	1	1	1	1	1	1		1	1	1	1	1	1
G3_3	63	1	1	1	1	1	1		1	1	1	1	1	1
G4_1	51	1	1	1	1	1	1		1	1	1	1	1	1
G5_1	50	1	1	1	1	1	1		1	1	1	1	1	1
G5_2	117	1	1	1	1	1	1		1	1	1	1	1	1
G5_3	17	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	431	431	431	431	431	431	431		431	431	431	431	431	431
Tot [%]	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%	100%	100%
66 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_2	19	1	1	1	1	1	1		1	1	1	1	1	1
G4_4	19	1	1	1	1	1	1		1	1	1	1	1	1
G4_5	16	1	1	1	1	1	1		1	1	1	1	1	1
G6_1	6	1	1	1	1	1	1		1	1	1	1	1	1
G6_2	13	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	73	73	73	73	73	73	73		73	73	73	73	73	73
Tot [%]	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%	100%	100%
22 kV generators		**Fault clearing time [s]**							**Fault clearing time [s]**					
G4_3	15	1	0	0	0	0	0		1	0	0	0	0	0
G5_4	5	1	1	1	1	1	1		1	1	1	1	1	1
G5_5	4	1	1	1	1	1	1		1	1	1	1	1	1
Tot [MW]	24	24	9	9	9	9	9		24	9	9	9	9	9
Tot [%]	100%	100%	38%	38%	38%	38%	38%		100%	38%	38%	38%	38%	38%
		0.1	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**		**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**
Tot [MW]	528	528	513	478	478	478	478		528	528	528	528	528	528
Tot [%]	100%	100%	97%	91%	91%	91%	91%		100%	100%	100%	100%	100%	100%

	In synchronism		Out of step	-	Test Failed

Appendix G
Single Line Diagram in OpenIPSL