Synchronous condenser emulator

A Consulting Service Project

P-752511008

Revision 3

14 April 2026

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Revisions	Date	Issue, Modification	Prepared	Checked	Approved

TABLE OF CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

The penetration of converter-based resources (CBR) driven by the integration of renewable energy sources (RES) altered many long-established power system operating concepts and behaviours. One of those concepts is related to the system stability when faced with sudden load changes. The contingency causing the loss of active power load and/or generation leads to unbalance between generation and load that causes all synchronous connected machines to accelerate/decelerate thus producing frequency deviation. Rotating masses of coupled synchronous machines (SM) inherently oppose these changes. How well the system responds to this contingency traditionally depends on the overall kinetic energy stored in the rotating masses. However, by replacing conventional plants with SMs with CBR the amount of kinetic energy that opposes the frequency changes is lost. This can lead to situations where the kinetic energy reserve is not sufficient to successfully contain frequency rate of change and retain stable operation of the system after the contingency. That’s why CBRs implement control schemes that enable them to contribute to the system by modulating power output depending on the grid frequency. This response can be similar to primary frequency control (frequency droop control but faster than the primary frequency control provided by conventional SMs) or response like inertial response of SM. The nature of the response depends on the implemented control scheme. To properly emulate inertial response (usually called synthetic inertia) it is necessary that both amplitude and phase characteristic of the active power modulation due to frequency change follow swing equation response of the rotating masses. When faced with problems related to the loss of overall inertia, system operators have been employing synchronous condensers (SC) as a solution. When SC is installed the lost mechanical inertia is reinstated. This solution has been proven in the past. The drawback is that SCs constitute an additional asset with a large physical footprint and no ability to generate revenue in the electricity market other than in ancillary service market if it exists. GFM technology provides control schemes and responses that are promising when it comes to their ability to emulate inertial response.

This report analyses the effects of the synchronous condenser and GFM technology on grid support during frequency and voltage disturbances and short-circuit levels. The demonstration is performed through EMT simulations using PSCAD.

1. METHODOLOGY

1.1 Reference systems

1.1.1 IEEE 9-bus system

To assess the effects of GFM technology on the frequency stability EMT simulations are performed in PSCAD on a reference system. As a reference system well known and widely used IEEE 9-bus system [1] has been used. Nominal system frequency is 50 Hz.

Figure 1 shows the reference system. The most relevant generator parameters and their active and reactive power loadings are given in Table 1.

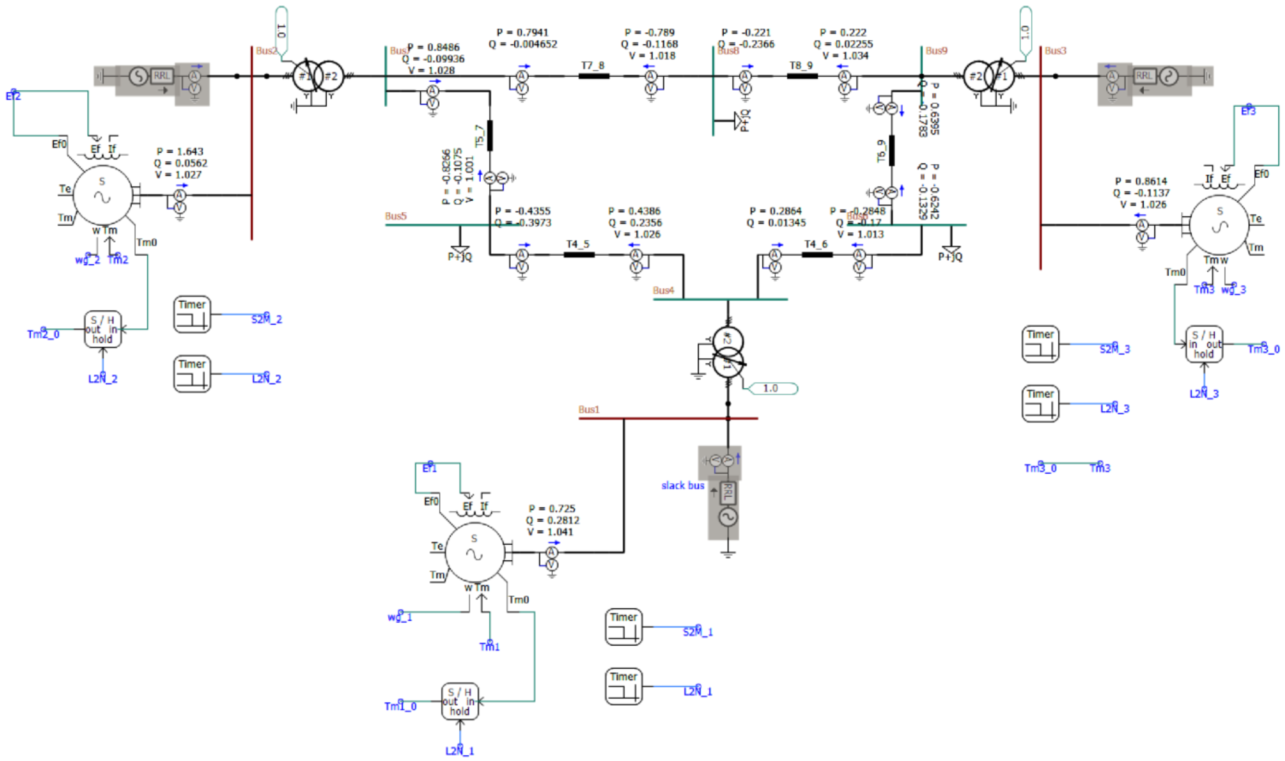

Figure 1 Base case reference system

Type	Name	Sn [MVA]	Un [kV]	$\cos\varphi_n$ [lag]	Ek [MWs]	H [MWs/MVA]	P[1] [pu][2]	P[1] [MW]	Q[1] [pu][2]	Q[1] [Mvar]
HPP[3]	SG1	247.5	16.5	1	2364	9.552	0.725	72.5	0.2812	28.12
SPP[4]	SG2	192	18	0.85	640	3.333	1.643	164.3	0.0562	5.62
SPP	SG3	128	13.8	0.85	301	2.352	0.8614	86.14	-0.1137	-11.37

Table 1 Reference system generator data

As it can be seen from Table 1 overall kinetic energy in the system is quite large 3 305 MWs which corresponds to equivalent weighted system inertia time constant of H = 5.82 MWs/MVA. Systems with such high inertia constants are considered stable.

[1] Load flow results
[2] Base power is 100 MVA
[3] Hydro Power Plant
[4] Steam Power Plant

1.1.2 Two machine equivalent system

Besides IEEE 9-bus systems for assessment of GFM technology on voltage control and short-circuit levels an equivalent two machine system (Figure 2) is also used. Two machine equivalent system is derived from reference IEEE 9 bus system (Figure 1) by finding Thevenin system equivalent at Bus 6.

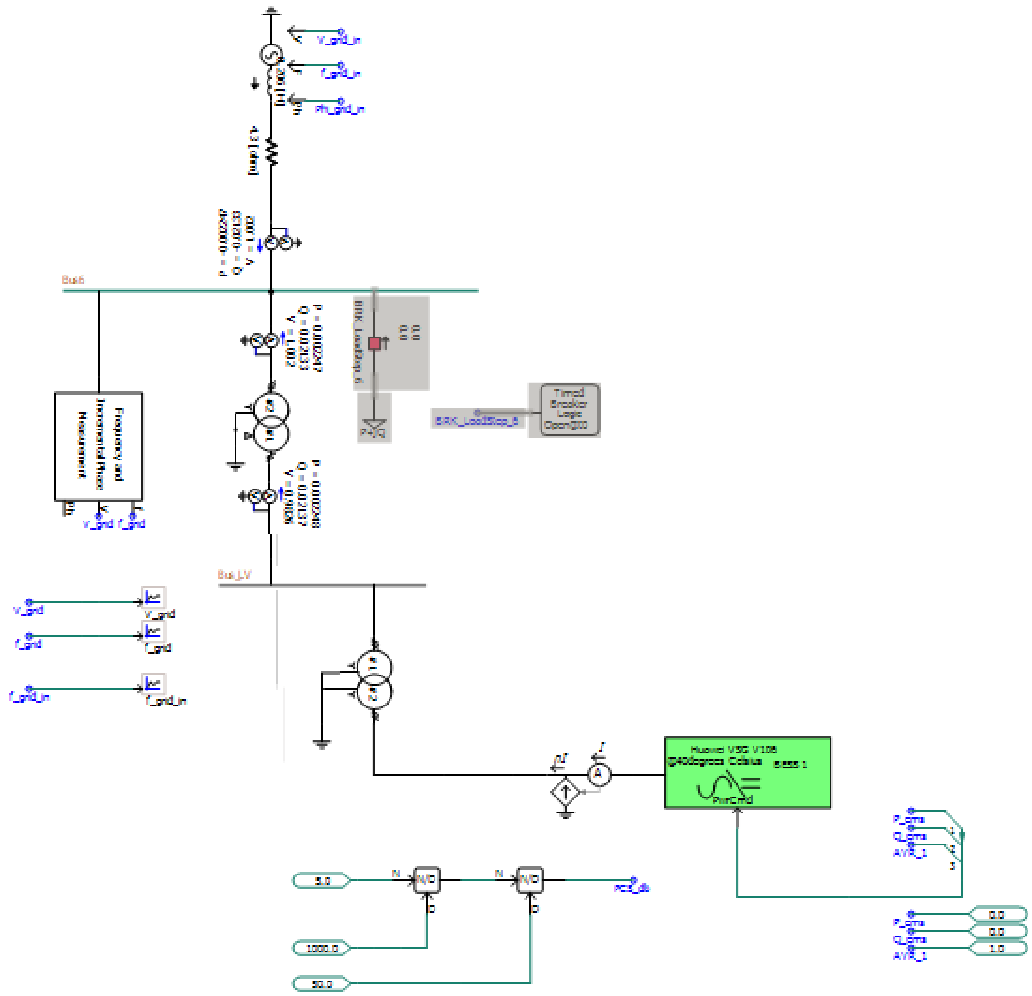

Figure 2 Two machine equivalent system

1.1.2.1 Thevenin equivalent parameters

Voltage of Thevenin equivalent source is equal to the steady state value of voltage at Bus 6 at steady state, and equivalent impedance is determined from short-circuit analysis. Overall grid impedance is determined from short-circuit current value. To determine short-circuit current all generators are modelled as voltage sources with equivalent sub-transient reactances (Figure 3). Equivalent reactance and resistance values are determined from X/R ratio that is determined from the time constant of short-circuit DC component decay constant.

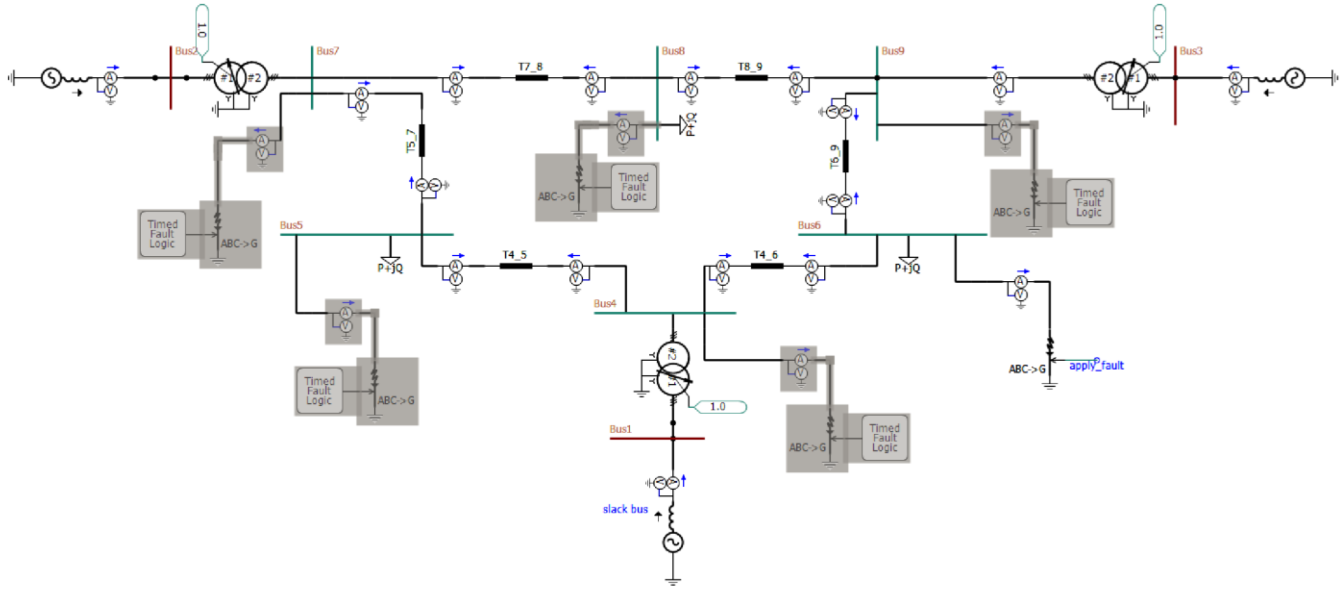

Figure 3 IEEE 9-bus system used for short circuit calculations

To facilitate determination of DC component of short-circuit current, fault is applied when the voltage at phase A is 0. In this way the DC current component is the highest. Implemented custom fault initiation logic based on zero crossing detection is shown in Figure 4. The fault is applied at first zero crossing of Bus 6 line to ground phase A voltage after 1 second from the simulation start has elapsed.

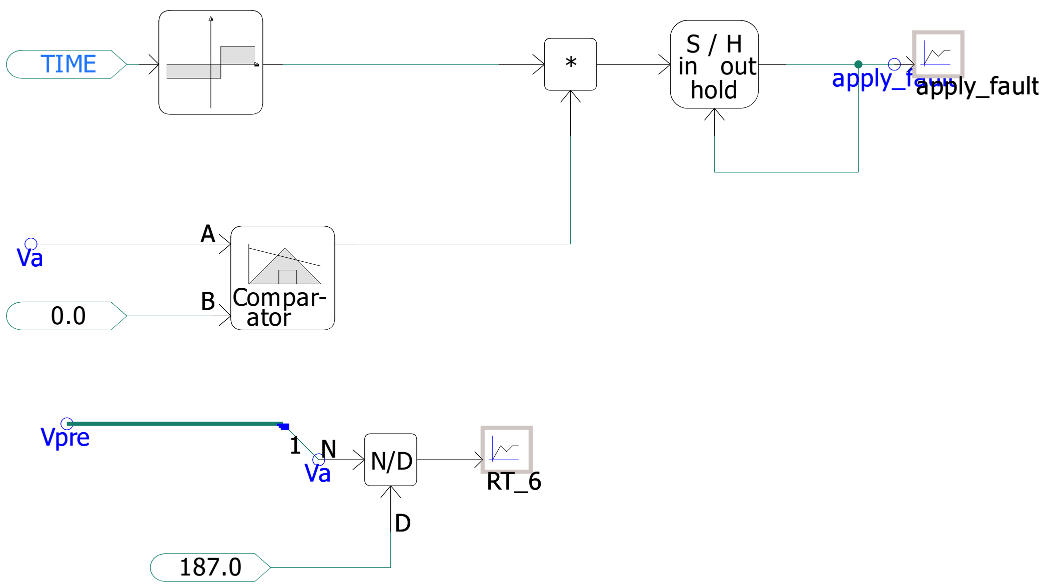

Figure 4 Fault initiation logic

Short-circuit current is given in Figure 5. X/R value is estimated from DC component of short-circuit current and expression for DC short-circuit component

$$i_{DC} = i_{DC}(0)e^{-t/\tau} + C$$

where $\tau = \frac{L}{R} = \frac{1}{2\pi f} X/R$. Time constant is estimated to value of 0.0326 s. This corresponds to X/R ratio value of 10.25.

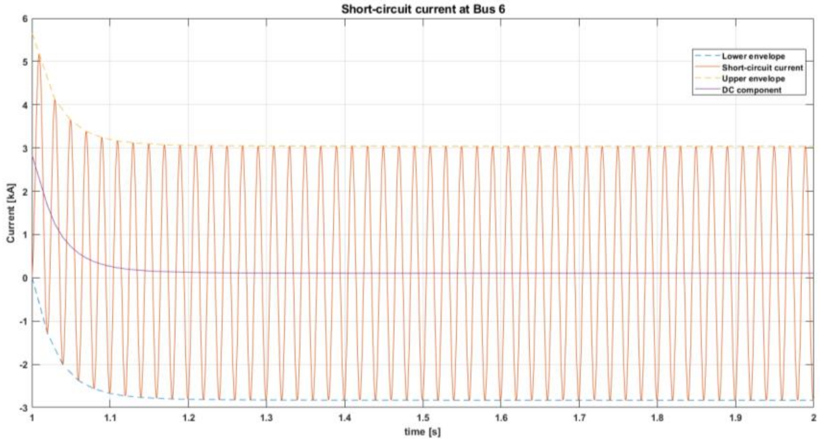

Figure 5 Short-circuit current of phase A with estimated DC component

Grid impedance is calculated from the short circuit value after the DC component has decayed to zero. When this happens RMS value calculated using digital multimeter in PSCAD reaches steady state value (Figure 6). These values are given under the column **Isc_3phase** in Table 2.

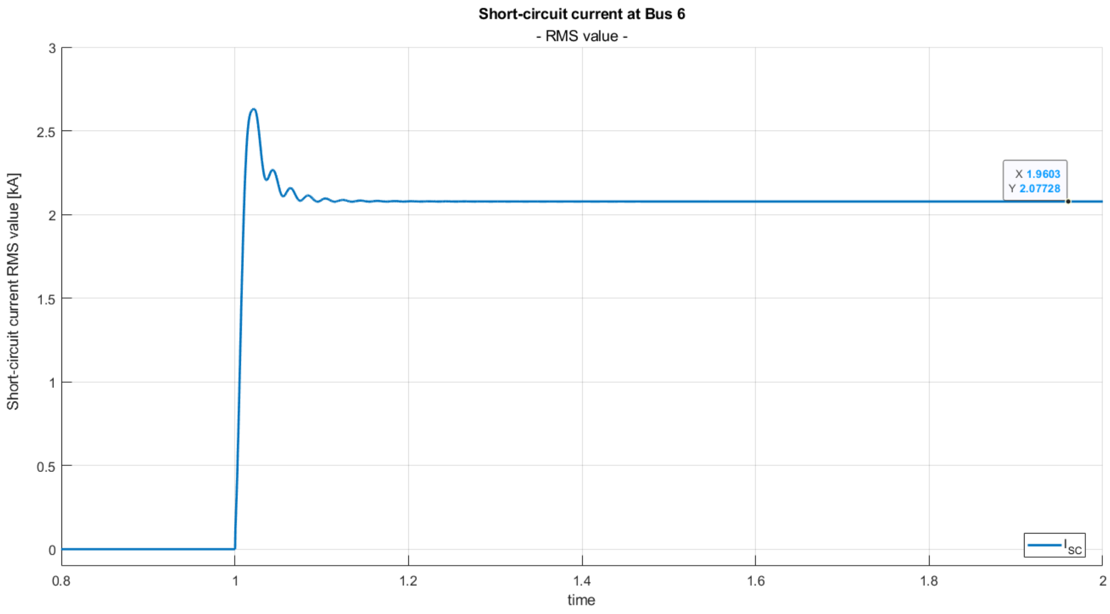

Figure 6 RMS value of short-circuit current at Bus 6

Calculated values of pre fault voltage values, short circuit current values, short circuit powers, and Thevenin equivalent impedances, reactances and resistances as seen from bus 6 for are given in Table 2.

IEEE 9 bus network

- Base case -									
Bus number	Vn [kV]	Vpre_fault* [pu]*	Isc_3phase [kA]	SC [MVA]	Zgrid [Ω]**	X/R	Xgrid [Ω]**	Lgrid [H]**	Rgrid [Ω]**
4	230	1.025	3.087	1261	44.091				
5	230	0.999	2.33	927	56.935				
6	230	1.012	2.077	837	64.701	10.25	64.395	0.206	6.3
7	230	1.026	2.953	1207	46.137				
8	230	1.017	2.435	987	55.461				
9	230	1.032	2.62	1077	52.305				

* taken immediately before short-circuit (t=0.99s) expressed at 230 kV base

** at HV side i.e. 230 kV

Table 2 Equivalent grid parameters and short circuit levels for IEEE 9 bus network

1.2 Modelling of system frequency dynamics

To evaluate how SC and GFM affect frequency stability, both reference IEEE 9-bus system and two machine equivalent include the models of power system frequency control and dynamics.

Reference IEEE 9 bus system (Figure 1) is modified so that SG1 includes an aggregated primary frequency control. Figure 7 shows aggregated primary frequency control model. The model is based on simple droop characteristics. The dynamics of primary frequency control are governed by the parameters of lead-lag filter. Primary frequency control parameters are set according to [2] with added ±5 mHz dead-band. Primary frequency control droop is set to 4%, lead-lag time constants are T1 = 1 s and T2 = 2 s. In performed simulations primary frequency is enabled after the initialization of all the machines has been finished.

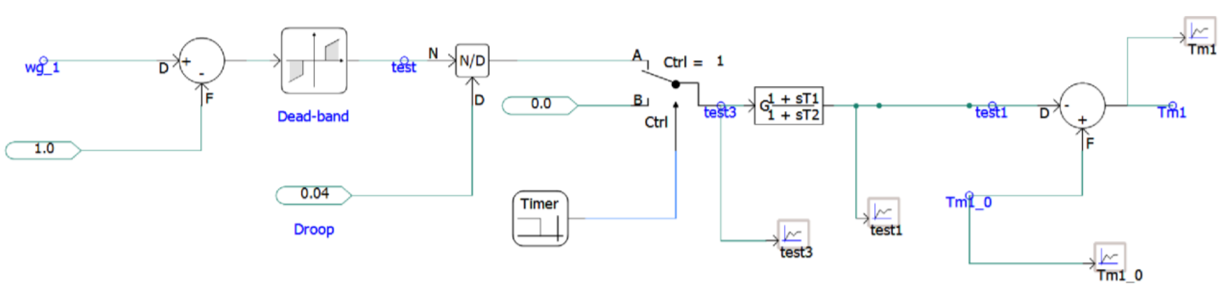

Figure 7 Aggregated primary frequency control mode

In IEEE 9 bus system inherent system frequency dynamics are modelled with each generator's inertia time constant. In the analysis, where reference IEEE 9 bus system is used the share of RES is varied by adjusting the inertia constant of SG1. Two scenarios are considered: the first – base case with strong grid where inertia of SG1 is according to the Table 1; and the second where inertia constant of SG1 is **2.586 MW s/MVA**. In the second – weak system case – overall weighted system inertia is 2.786 MW s/MVA or around 50% of the strong grid case. This has effect on overall system frequency dynamics.

In the case of two machine equivalent system grid frequency dynamics and control are modelled with equivalent inertia and primary frequency control. The overall inertia of equivalent source is set according to the overall kinetic energy of the system (see Table 1) expressed at 100 MVA base i.e. H= 33.05 MWs/MVA. Primary frequency control is modelled in the same way as presented in Figure 7, and with the same parameters as previously stated. Frequency subsystem of equivalent source is given in Figure 8, where **f_grid** and **P6_grid** are frequency and active power measurements taken at the Bus 6 i.e. point of common coupling (PCC) and P0 is initial active power of the equivalent source.

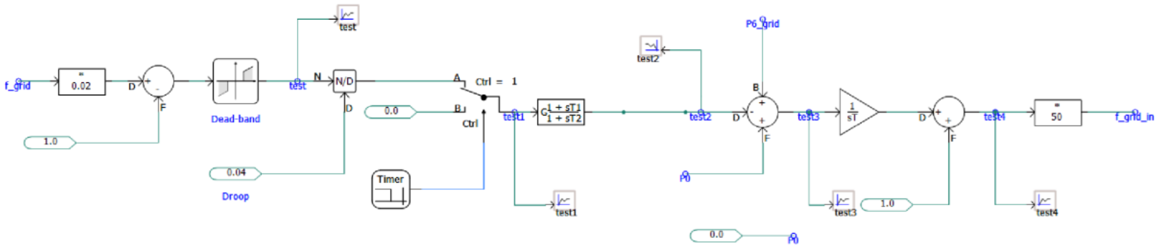

Figure 8 Frequency dynamics subsystem of equivalent source

1.3 Synchronous condenser model

For the performed analysis SC with main parameters given in Table 3 is used. The modelled SC has flywheel which increases machine's inertia.

SC model includes detailed AVR model. AVR is operated in voltage control mode with droop characteristics. SC AVR implements reactive power compensation of voltage reference:

$$U_{ref} = U_{set-point} + k_q Q$$

Values in previous equation are in per unit. Base voltage is equal to generator rated voltage and base power is machine's rated MVA. U_{ref} is the value to which the PI controller regulates the stator voltage, $U_{set-point}$ is entered setpoint value, k_q is reactive power compensation factor and Q is the machine's reactive power output. Reactive power compensation k_q[5] is set so that reactive power contribution of SC and PCS after the analysed voltage step event are equal.

SC is connected to the transmission grid via 140 MVA, 13.8/235 kV/kV transformer with 0.1 pu leakage reactance.

Figure 9 shows reference system model with integrated SC.

[5] $k_q = -0.04$

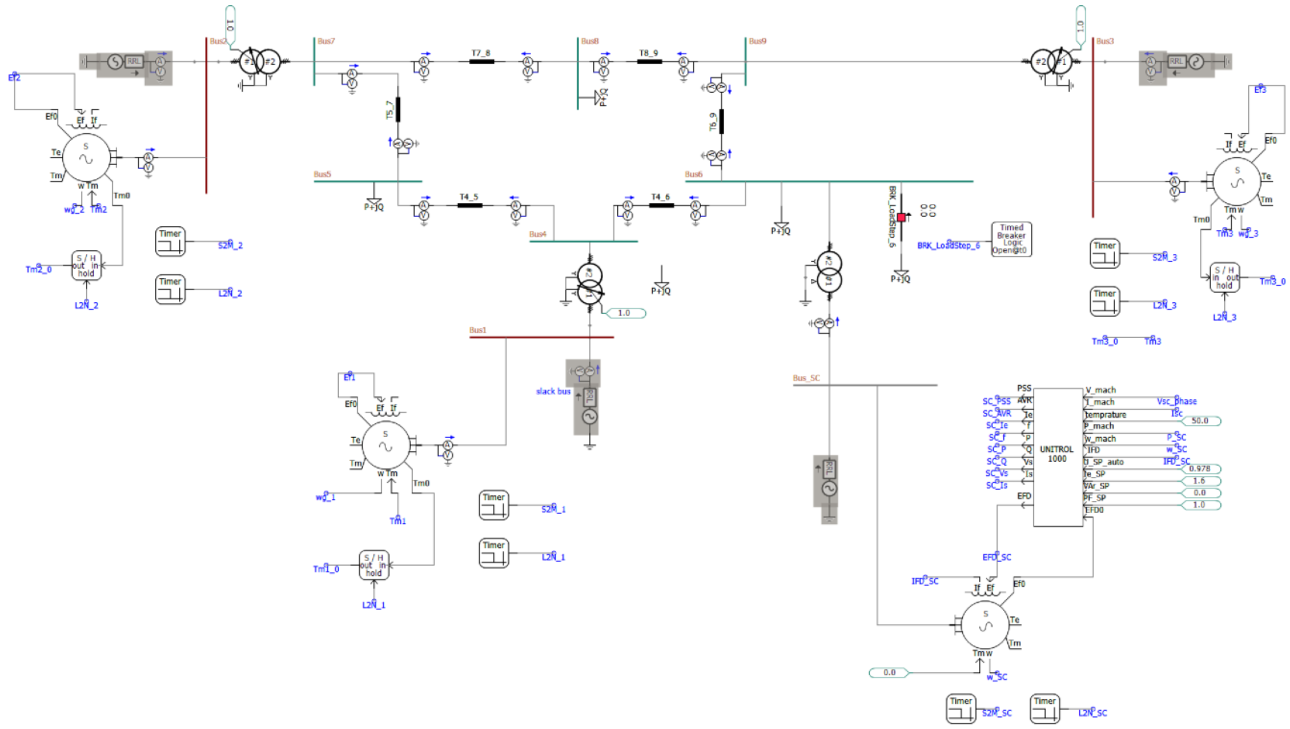

Figure 9 Reference system with integrated synchronous condenser model

Rated apparent power	S_n	67	MVA
Rated terminal voltage	U_n	13.8	kV
Rated frequency	f_{un}	50	Hz
Reactance and resistances			
Armature resistance	Raster	0.002	pu
Potier Reactance	Xp	0.178	pu
Direct axis synchronous reactance	Xd	1.77	pu
Quadrature axis synchronous reactance	Xq	0.662	pu
Direct axis transient reactance – saturated value	Xd’	0.233	pu
Direct axis sub transient reactance – saturated value	Xd”	0.146	pu
Quadrature axis sun transient reactance – saturated value	Xq”	0.219	pu
Air Gap Factor	=XL/Xp	0.597	
Time constants			
Direct axis transient open circuit time constant	T'_{d0}	11.006	s
Direct axis sub-transient open circuit time constant	T''_{d0}	0.047	s
Quadrature axis sub-transient open circuit time constant	T''_{q0}	0.135	s
Combined inertia constant	H	7.02	MW s/MVA
Saturation data			
	U	**Ifd**	
Point 1	0	0.0000	pu
Point 2	**0.25**	**0.2417**	pu
Point 3	0.5	0.4996	pu
Point 4	0.75	0.7767	pu
Point 5	**1**	**1.0924**	pu
Point 6	1.25	1.8330	pu
Point 7	**1.5**	**4.2933**	pu
Point 8	1.75	7.3507	pu

Table 3 Synchronous condenser model data

1.4 Grid forming PCS model

For GFM PCS a black-box model provided by Huawei is used. Model corresponds to Huawei LUNA2000-213KTL-H1. According to [3] the model includes the following functions:

1) DC-DC circuit, DC-AC circuit and filter circuit
2) VSG control
3) DC-DC voltage control
4) Over/Under Voltage, Over/Under Frequency, Over Current Protections and LVRT Curve Protection
5) PWM process module

In the provided PCS model active power modulation due to frequency deviations as well as reactive power modulation due to voltage deviations are implemented. These functions are implemented as droop controls [3].

Figure 10 shows reactive power droop characteristics. Main parameters for reactive power droop control are set under Voltage modulation parameters (Figure 11): Udead(pu), VRC, HVRTQLimit, LVRTQLimit. As defined in [3] reactive power modulation is governed by following equations:

If $U_{inv} > U_N + U_{db}$

$$\Delta U = U_N + U_{db} - U_{inv}$$

$$\Delta Q = max\{VRC \cdot \Delta U, -Q_{LMT}\}$$

$$S_{LMT} = min\{1.5pu, 3I_N U_{inv}\}$$

$$Q_{out} = max\{\Delta Q + Q_{avc}, -S_{LMT}, -1.5pu\}$$

$$P_{LMT} = \sqrt{{S_{LMT}}^2 - {Q_{out}}^2}$$

If $U_{inv} < U_N - U_{db}$

$$\Delta U = U_N - U_{db} - U_{inv}$$

$$\Delta Q = min\{VRC \cdot \Delta U, Q_{LMT}\}$$

$$S_{LMT} = min\{1.5pu, 3I_N U_{inv}\}$$

$$Q_{out} = min\{\Delta Q + Q_{avc}, S_{LMT}, -1.5pu\}$$

$$P_{LMT} = \sqrt{{S_{LMT}}^2 - {Q_{out}}^2}$$

where U_{db} is set by parameter Udead(pu), Q_{LMT} is set by parameters HVRTQLimit, LVRTQLimit, U_N is rated voltage, U_{inv} is voltage measured by PCS and Q_{out} is output reactive power.

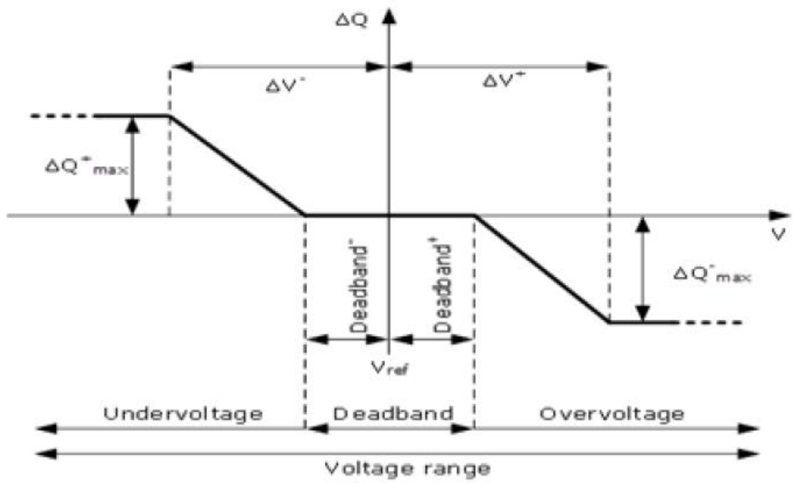

Figure 10 Reactive power droop control

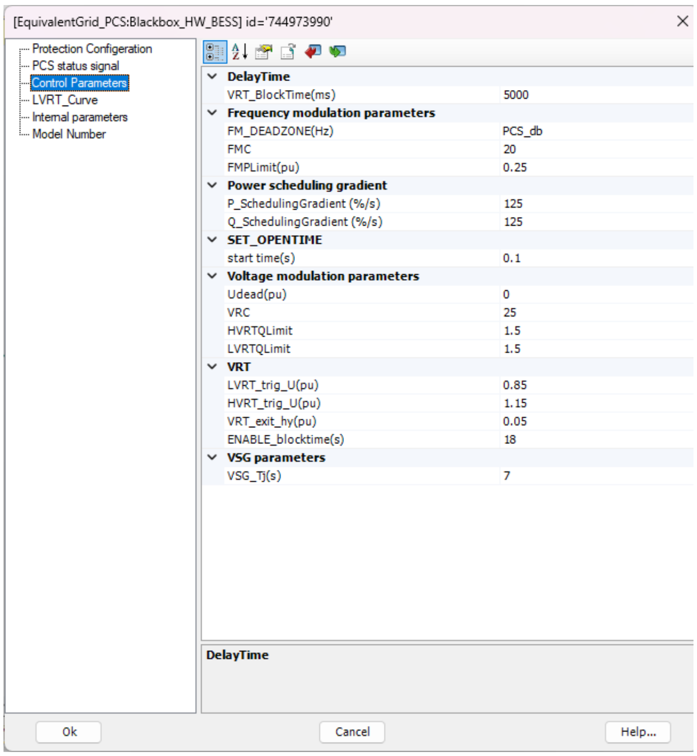

Figure 11 Reactive and active power droop control parameters

Main parameters for active power droop control are set under Frequency modulation parameters (Figure 11): FM_DEADZONE(Hz), FMC and FMPLimit(pu). As defined in [3] active power modulation is governed by following equations:

If $f_{inv} > f_N + f_{db}$

$$\Delta f = f_N + f_{db} - f_{inv}$$

$$P_{freq} = max\{FMC \cdot \Delta f, -FMP_{LMT}\}$$

$$P_1 = P_{freq} + P_{avc}$$

$$P_{out} = max\{min\{P_1, P_{LMT}, 1.25\}, -P_{LMT}, -1.25pu\}$$

If $f_{inv} < f_N - f_{db}$

$$\Delta f = f_N - f_{db} - f_{inv}$$

$$P_{freq} = min\{FMC \cdot \Delta f, FMP_{LMT}\}$$

$$P_1 = P_{freq} + P_{avc}$$

$$P_{out} = min\{max\{P_1, P_{LMT}, 1.25\}, P_{LMT}, 1.25pu\}$$

where $f_{db}$is set by parameter FM_DEADZONE, f_{inv} is frequency measured by PCS and P_{out} is output active power.

Rated power of the module is 106.5 kW, rated voltage is 800 V_{AC} and rated current is 76.8598 I_{AC} [3]. To simulate multiple PCS a current scaling component is used. Scaling factor is set so as to have same MVA between aggregated PCS and SC. Used scaling factor is 637.5. Additionally, an ideal transformer (ratio changer) is employed to adapt the PCS voltage to the transformer low-voltage winding. Transformer for connection to transmission system is the same one as it was used with SC.

Figure 12 shows reference system model with integrated PCS.

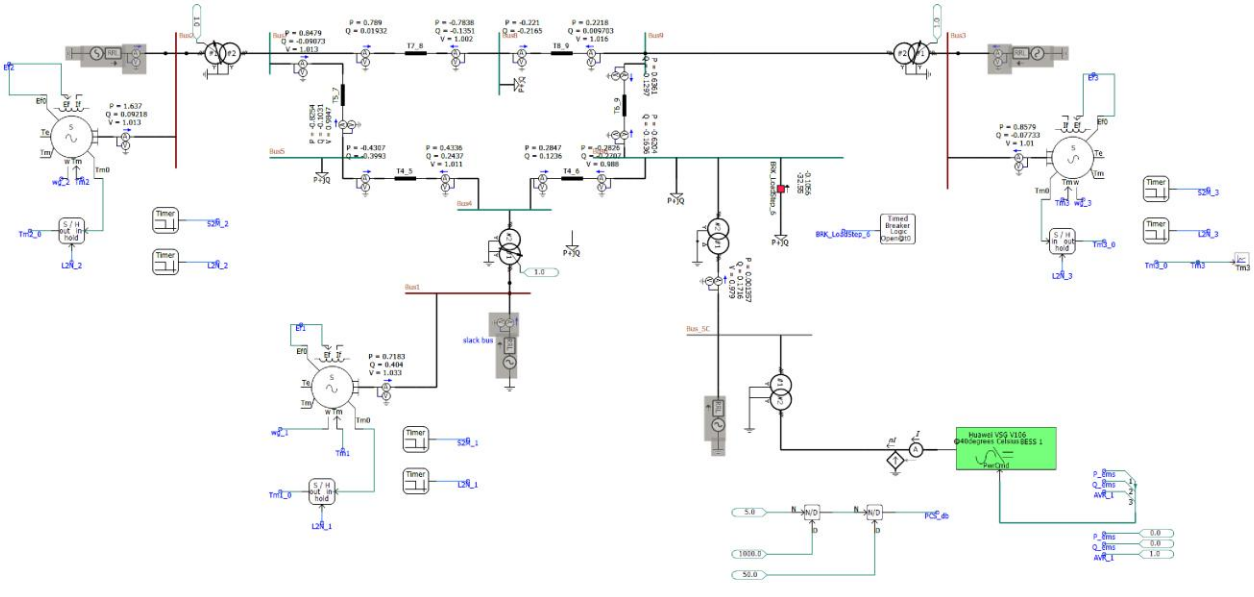

Figure 12 Reference system with integrated PCS model

Besides the case with scaling factor that yields same rated power of SC and PCS analysis shall be performed with the varying scaling factor, so as to have the same frequency nadir for the loss of generation event in the weak grid conditions in both the systems with SC and PCS used for frequency support.

2. FREQUENCY CONTROL

2.1 Loss of generation

To analyse SC and GFM contribution to frequency stability active power disturbance is simulated. Disturbance is simulated as a sudden loss of generation. This is simulated as a step change of the mechanical torque of SG2. 50 MW generation loss is simulated, which is about 15% of overall generation.

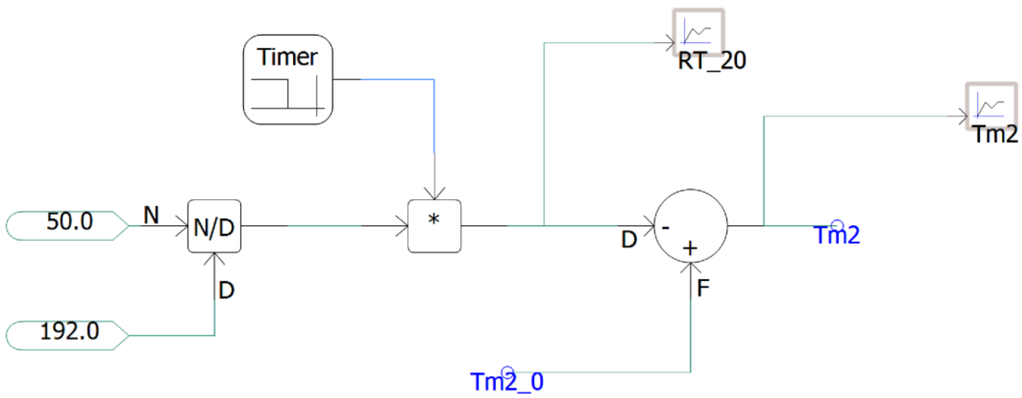

Figure 13 Torque step model

SG1 responds to the frequency deviation due to the aggregated primary frequency control, and torque of SG3 is constant throughout the simulation.

Simulated disturbance causes rapid frequency decrease after the step change of SG2 torque. System inertia opposes this change. The greater the inertia less steep the frequency change, i.e. rate of change of frequency (ROCOF) is lower. At the same time primary frequency control acts to contain the frequency after the disturbance.

To compare the effects of SC and GFM for the same loss of generation ROCOF and frequency nadir value shall be compared as well as overall frequency dynamics during the disturbance.

For loss of generation disturbance an additional analysis is performed. In this analysis the installed PCS capacity that contains the frequency to the same frequency nadir for the same loss of generation event shall be determined.

2.2 Results

2.2.1 Base case

Figure 14 shows change in the mechanical torques of the generators for simulated sudden loss of generation. Responses are as expected:

- Torque of the first generator increases due to the action of primary frequency control
- Torque of the second generator experiences step change at t = 1 s, as simulated
- Torque of the third generator remains the same throughout the simulation

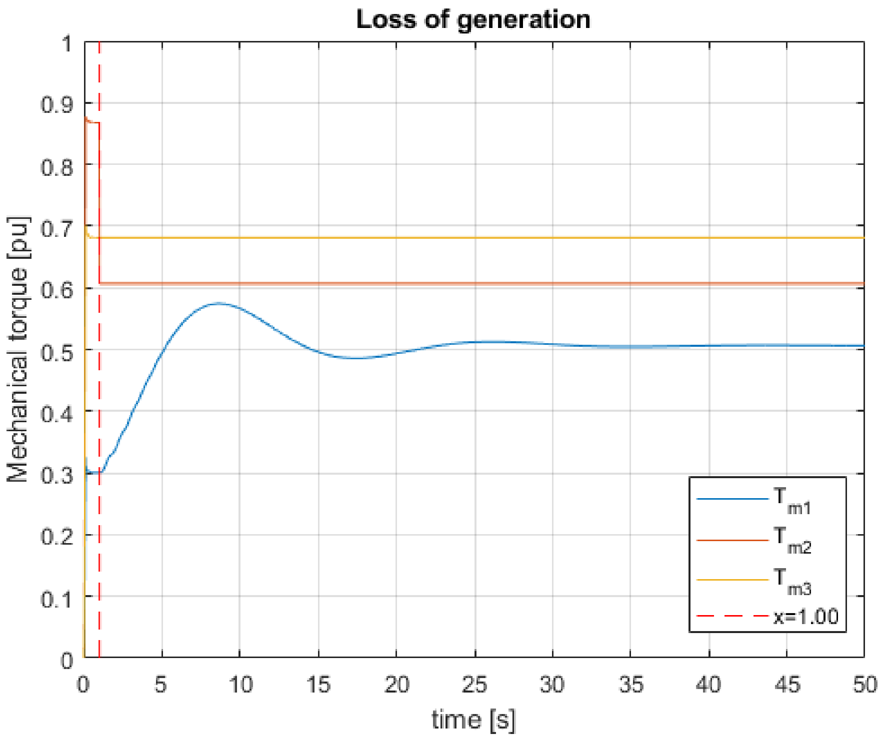

Figure 14 Mechanical torques of the generators

Changes of active power generation are given in Figure 15:

- Active power of first generator increases due to primary frequency response. Comparing steady state output with the pre-disturbance loading given in Table 1 it can be calculated that the power output has increased by about 50 MW
- Active power of the second generator has decreased 50 MW following the application of a step disturbance
- Active power of the third generator remains the same.

As expected in new steady state first generator that has primary frequency control enabled makes up for lost generation.

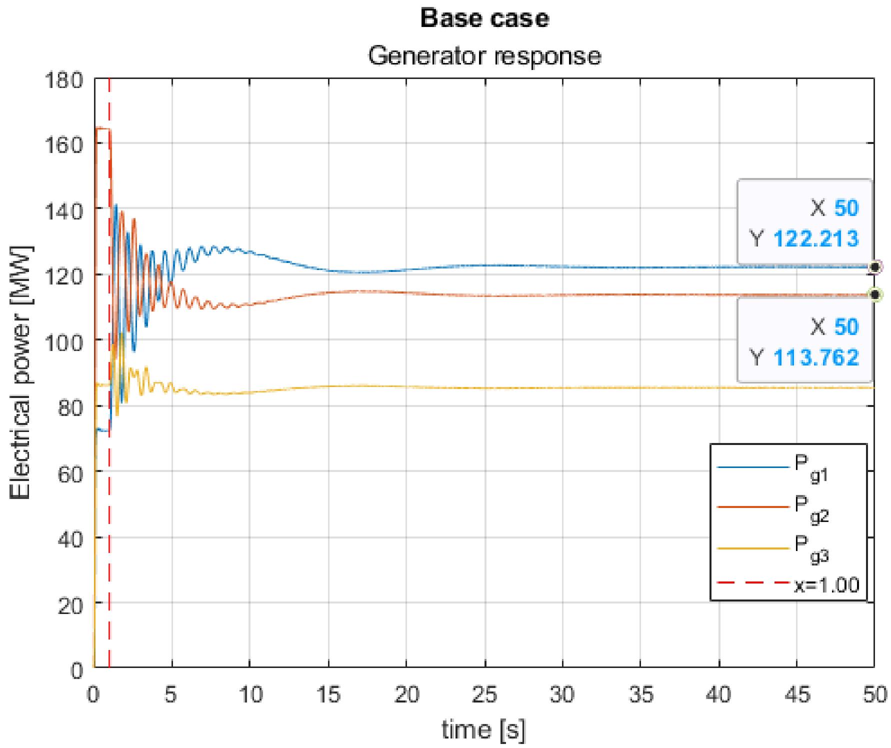

Figure 15 Base case – Power output of the generators

Disturbances are the same for both strong and weak network conditions. However, frequency change dynamics are not the same (Figure 16).

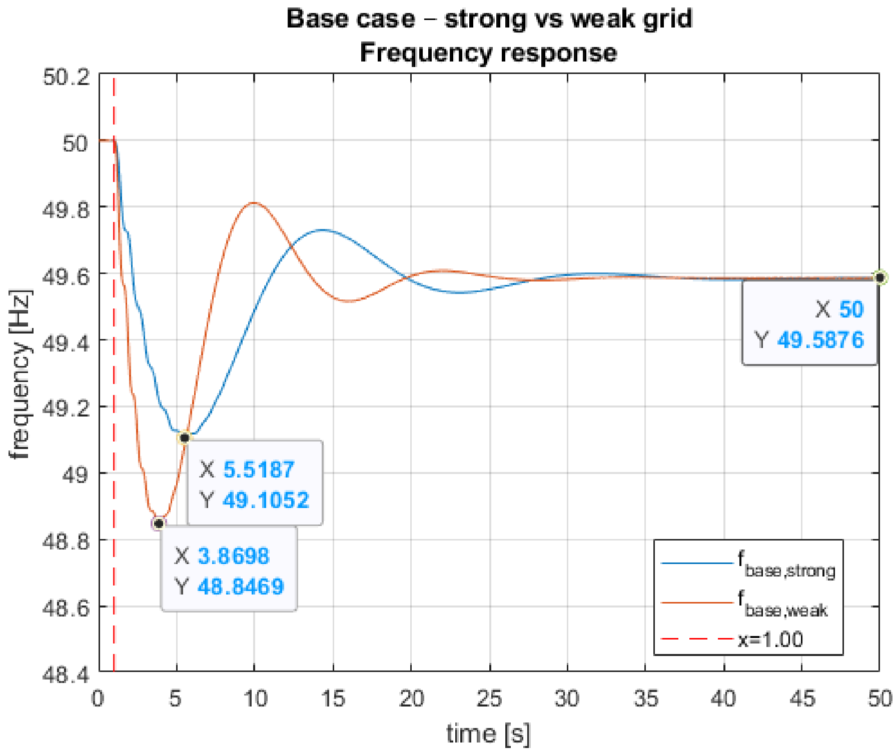

Figure 16 Base case – Frequency changes

2.2.2 Reference system with synchronous condenser

For reference system with SC connected two disturbances are simulated as previously explained.

Simulated torque change of the generators is the same as for the base case (Figure 14). Figure 17 shows generator active power responses.

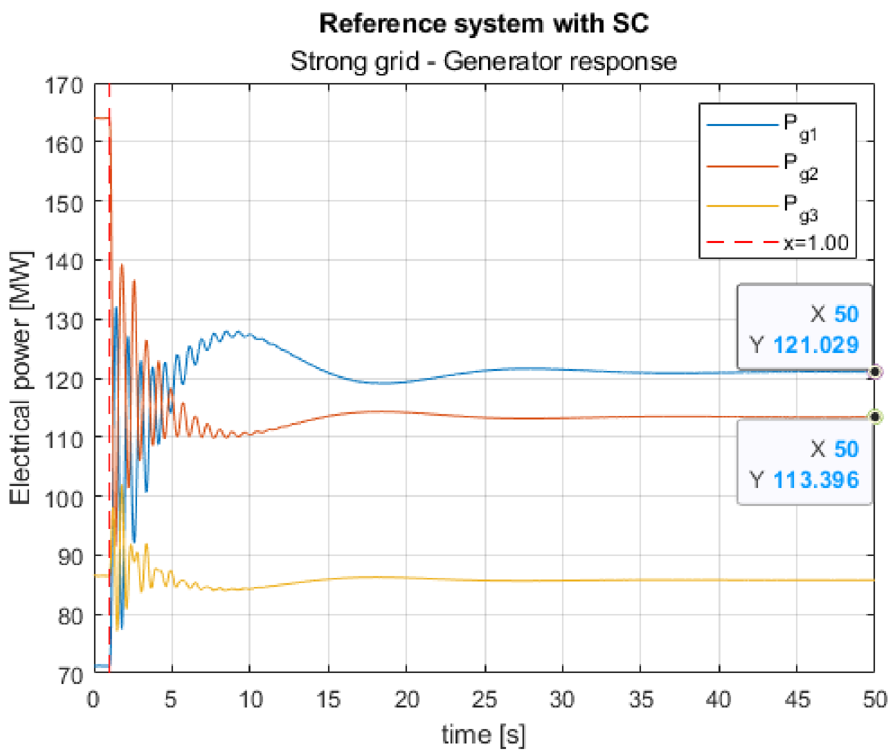

Figure 17 Reference system + SC – Power output of the generators

Figure 18 shows SC inertial response to loss of generation, and Figure 19 shows system frequency change for the reference system with connected SC, for both strong and weak system conditions.

Figure 18 shows that the SC inertial response to loss of generation is slightly different for strong and weak system conditions. From Figure 19 it can be seen that in the case of strong system conditions frequency nadir is 49.1576 Hz and for the weak system conditions frequency nadir is 48.9573 Hz. Steady state frequency difference is the same in both cases and equal to 415 mHz.

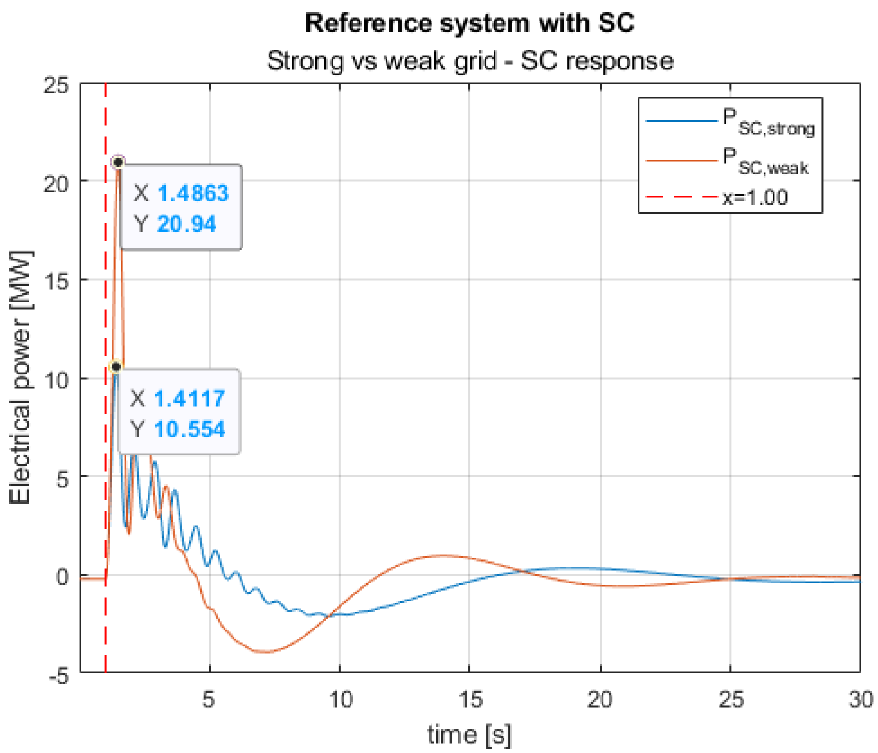

Figure 18 Reference system + SC – SC responses

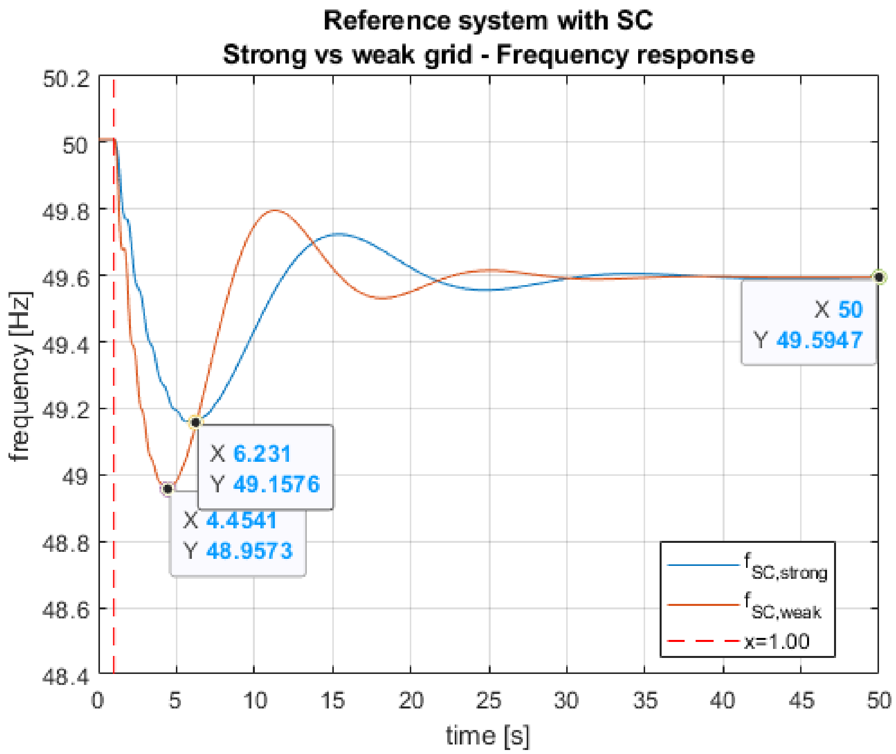

Figure 19 Reference system + SC – Frequency changes

2.2.3 Reference system with grid forming PCS

2.2.3.1 Active power disturbance – Equal installed capacity

Simulated torque change of the generators is the same as for the base case (Figure 14). Figure 20 shows generator active power responses.

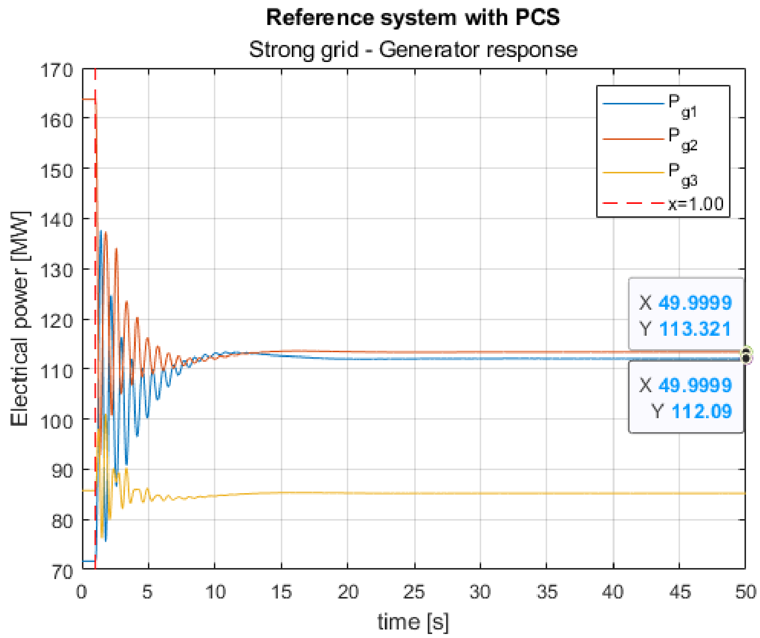

Figure 20 Reference system + PCS – Power output of the generators

Figure 21 shows PCS response to loss of generation, and Figure 22 shows frequency change for the reference system with connected PCS, for both strong and weak system conditions.

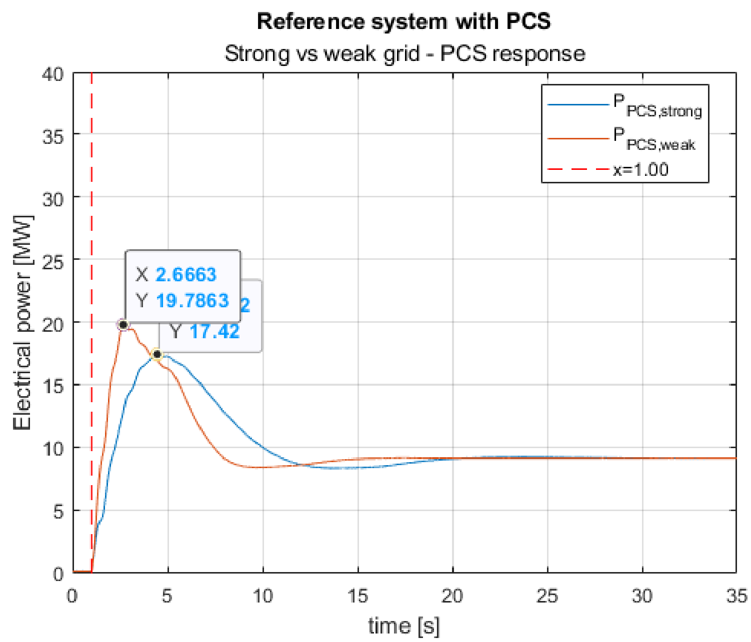

Figure 21 Reference system + PCS – PCS responses

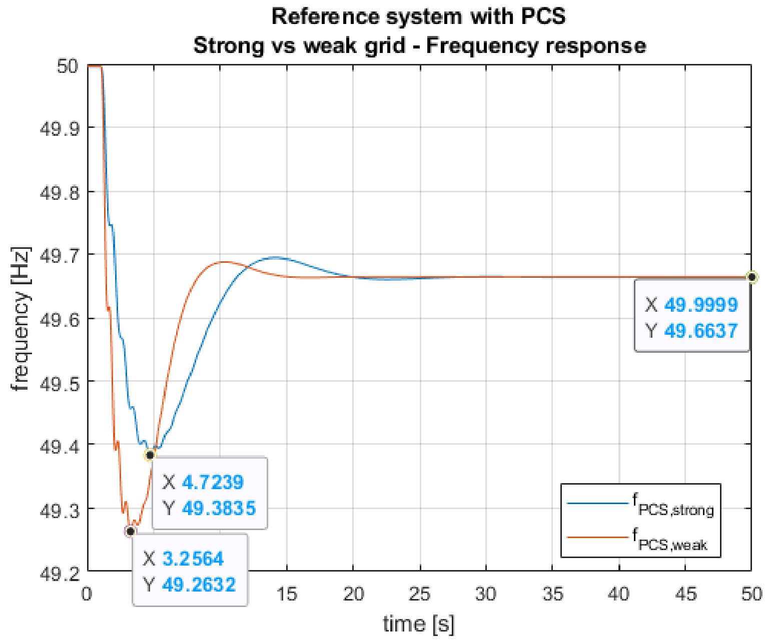

Figure 22 Reference system + PCS – Frequency changes

2.2.3.2 Active power disturbance – Equal frequency nadir

In this analysis the simulated torque change of the generators is the same as shown in Figure 14 and Figure 20. For this analysis scaling factor of PCS is set to 150. The scaling factor is chosen so that the PCS contains the frequency to same frequency nadir as SC (see Figure 23). The analysis is performed for weak system conditions, as this is the more critical case.

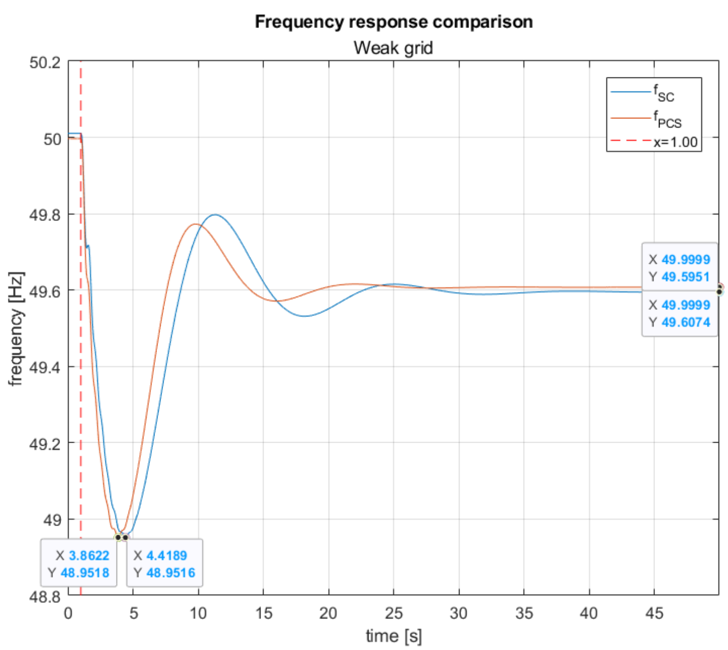

Figure 23 Frequency response of reference system +SC and reference system + PCS

Figure 24 shows comparison between SC and PCS response to loss of generation in the case where the scaling factor is set to 150

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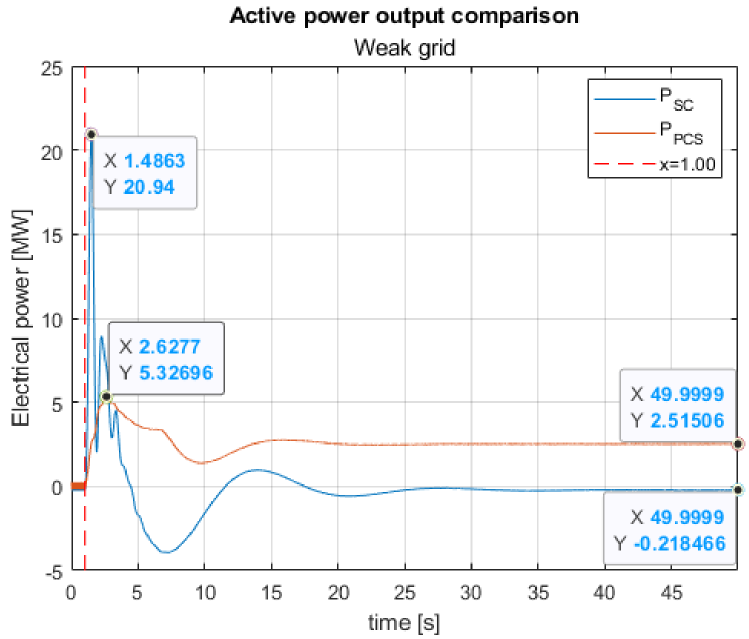

Figure 24 Power response of SC and PCS for same loss of generation disturbance and same frequency nadir

2.3 Results comparison

In the base case new steady state frequency after loss of generation is 412 mHz lower than initial value and it is the same for both strong and weak system cases. For base case and reference system with connected SC new steady state frequency values are basically the same. The result is as expected since the SC provides inertial response at the expense of accumulated kinetic energy. SC active power before disturbance and at new steady state is 0, therefore aggregated primary frequency control is the only control mechanism containing frequency after the loss of generation.

In the case of reference system with PCS of equivalent power rating as SC, frequency steady state after loss of generation is different than in other cases. New steady state frequency after the loss of generation is 49.66 Hz. This is a 70 mHz increase compared to other cases. The reason for this is that the PCS provides fast frequency primary control as well as synthetic inertia (i.e. active power output of PCS is modulated due to frequency deviation from nominal value and due to the frequency change gradient). Effect of primary frequency control is such that after the disturbance PCS doesn't continue to operate at 0 MW (see Figure 21). Following the loss of generation, the PCS outputs 11 MW, thereby additionally contributing to overall frequency containment. This is the same in both strong and weak system conditions.

From Figure 18 and Figure 21 it can be observed that maximum active power response of SC and PCS differ significantly. While maximum SC active power increase peaks at around 1.4 MW (for both strong and weak system conditions), PCS provides 19.7 MW and 17.4 MW in the case of weak and strong system conditions respectfully.

Figure 10 shows frequency changes for base case strong and weak system conditions. In the case of strong system conditions frequency nadir is 49.1052 Hz and for the weak system conditions frequency nadir is 48.8469 Hz. As expected in all analysed scenarios, ROCOF is greater in the case of the weak system conditions.

Figure 19 shows frequency changes for reference system with connected SC for strong and weak system conditions. In the case of system with SC connected and strong system conditions frequency nadir is 49.1576 Hz and for the weak system conditions frequency nadir is 48.9573 Hz.

Figure 22 shows frequency changes for reference system with connected PCS of equivalent power rating for strong and weak system conditions. In the case of system with PCS connected and strong system conditions frequency nadir is 49.3835 Hz and for the weak system conditions frequency nadir is 49.2632 Hz. PCS has improved frequency nadir significantly. While SC provides around 5% and 9% nadir decrease in strong and weak conditions respectfully, PCS with equivalent power rating provides improvements of 31.5% and 36.4%.

The results are summarized in Table 4 and Table 5.

Figure 25 ÷ Figure 28 show frequency comparison between different analysed scenarios. Frequency nadir improvements are evident with similar initial ROCOF.

IEEE 9 bus network

- Strong system -					
Case	Sn	f_{nadir}	f_1	max(Δf)	Δf
	[MVA]	[Hz]	[Hz]	[mHz]	[mHz]
Base case	N/A	49.105	49.588	895	412
Base case + SC	67	49.158	49.595	842	405
Base case +PCS	67	49.384	49.664	616	336

Table 4 Comparison of frequency comparison between base case, base case + SC and base case + PCS - Strong system conditions –

IEEE 9 bus network

- Weak system -					
Case	Sn	f_{nadir}	f_1	max(Δf)	Δf
	[MVA]	[Hz]	[Hz]	[mHz]	[mHz]
Base case	N/A	48.847	49.588	1153	412
Base case + SC	67	48.957	49.595	1043	405
Base case + PCS	67	49.263	49.664	737	336

Table 5 Comparison of frequency comparison between base case, base case + SC and base case + PCS - Weak system conditions -

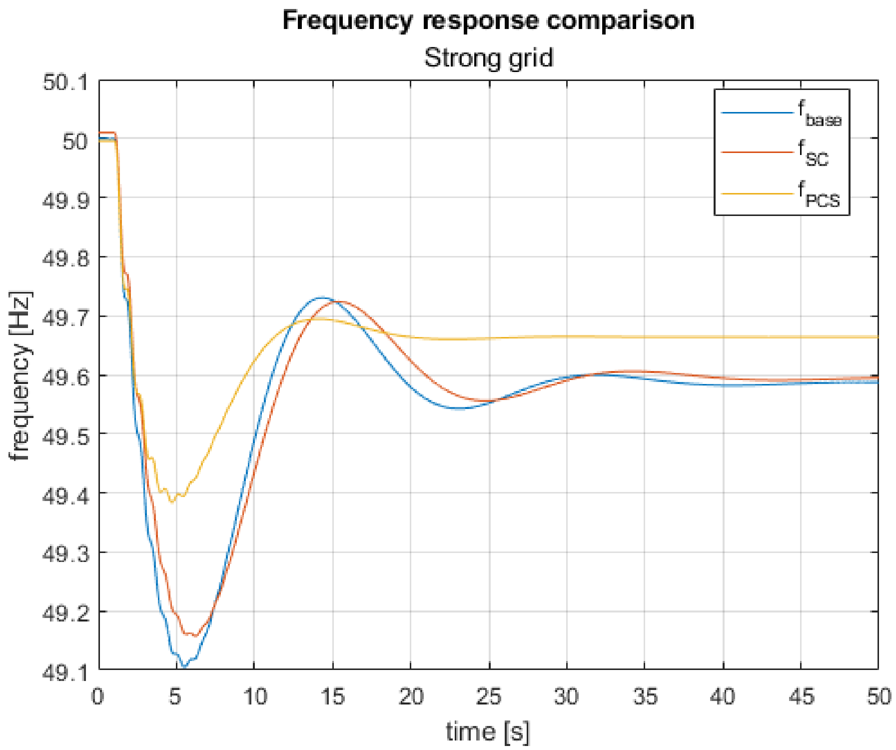

Figure 25 Frequency response comparison – Strong system conditions

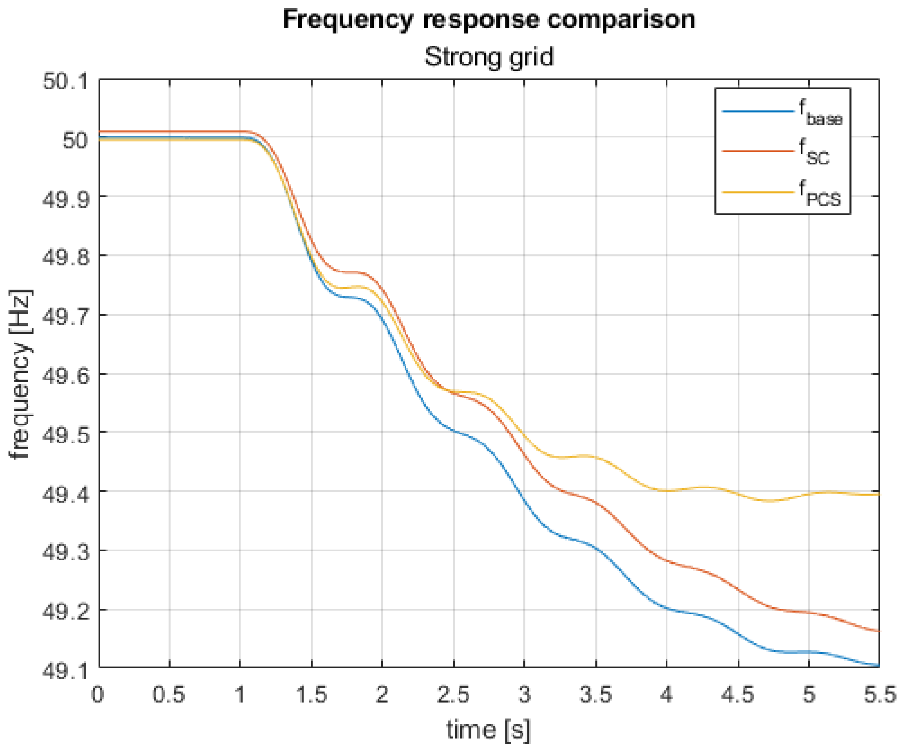

Figure 26 Initial frequency response comparison – Strong system conditions

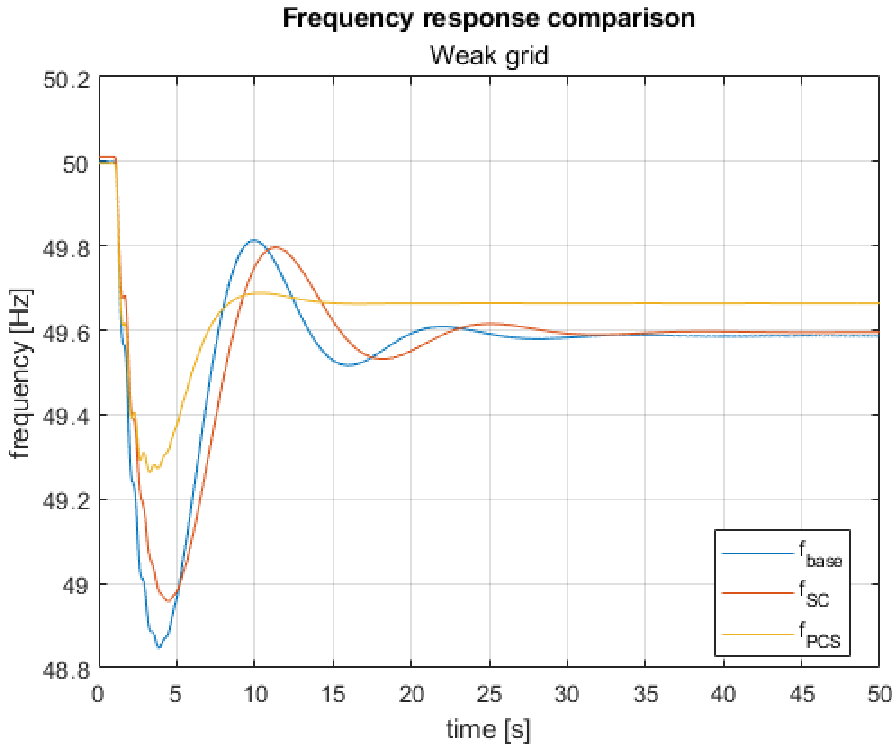

Figure 27 Frequency response comparison – Weak system conditions

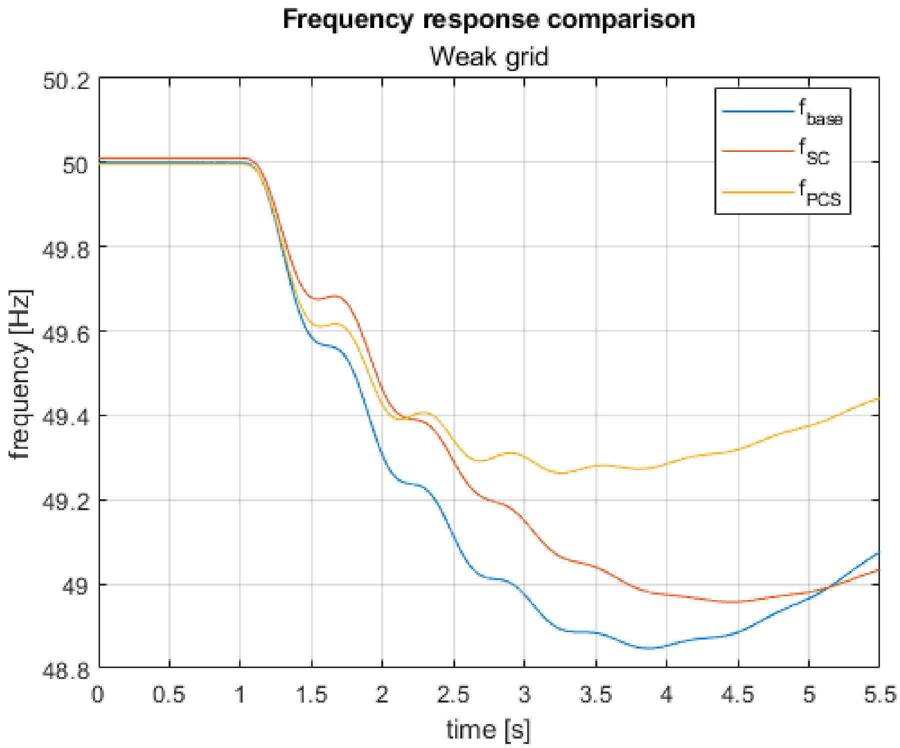

Figure 28 Initial frequency response comparison – Weak system conditions

Regarding frequency nadir PCS scaling factor of 150 contains frequency to the same frequency nadir as does the SC, for the 50 MW loss of generation in the weak grid conditions. PCS installed capacity is 106.5 kW, so this scaling factor is equivalent to around 16 MW rated capacity of the PCSs. As given in Table 3 SC installed capacity is 67MVA. **It can be concluded that the installed PCS capacity that is 4.2 times smaller or about 24% of the rated SC capacity provides equal support to the reference system when it comes to the frequency nadir containment.** As noted, PCS provides both primary frequency control and synthetic inertia. However, with lowered scaling the primary frequency control contribution of PCS is much smaller than the support of the SG1 that provides aggregated primary frequency control (Figure 29). PCS contributes to overall activated primary frequency with about 2.52 MW (or about 5% of overall activated primary reserve). This can be also seen in the frequency response (Figure 23) since the steady state frequency of the new steady state after the loss of generation differs by only 12 mHz.

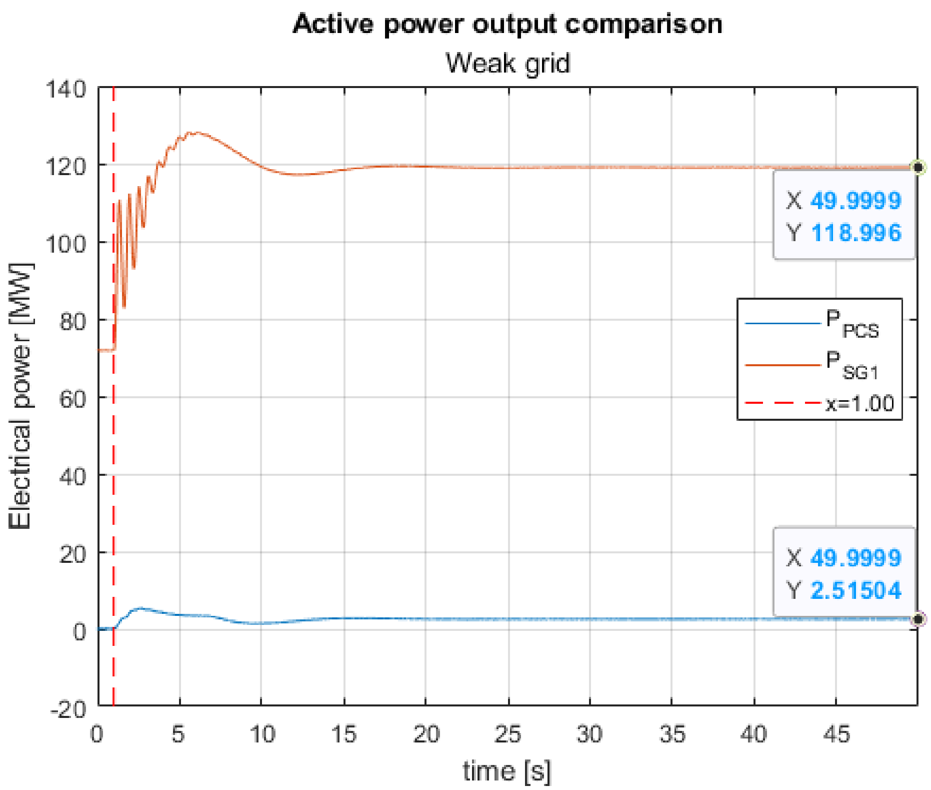

Figure 29 Aggregated primary frequency support and PCS response comparison – Weak system conditions (PCS scaling factor 150)

3. REACTIVE POWER/VOLTAGE CONTROL

3.1.1 Voltage control

To analyse SC and GFM contribution to voltage control, a connection of reactive load is simulated. This analysis is performed on full IEEE 9-bus reference system (Figure 1) and two machine equivalent (Figure 2). In the analysis 10 Mvar pure reactive load is connected to Bus 6[6], 50 s after the simulation start.

Besides additional reactive load analysis, in order to compare SC and GFM voltage control, voltage step change of equivalent Thevenin generator of two machine equivalent (Figure 2) is also simulated. For this analysis 5% voltage step decrease of Thevenin equivalent 50 s after the simulation start is simulated.

To compare SC and GFM responses, voltage profiles during the disturbances and reactive power responses are compared.

3.2 Results comparison

3.2.1 Reactive load disturbance

3.2.1.1 IEEE 9-Bus reference system

Reactive load disturbance is simulated as a connection of additional 10 Mvar pure reactive load to Bus 6

Figure 30 shows voltage change of Bus 6 and Figure 31 shows reactive power response of SC, for the connection of additional 10 Mvar load to Bus 6.

Figure 32 shows voltage change of Bus 6 and Figure 33 shows reactive power response of PCS, for the connection of additional 10 Mvar load to Bus 6.

In the case of reference system with connected SC minimum voltage after disturbance is 0.96 pu (Figure 30), while in the case of reference system with connected PCS minimum voltage after disturbance is 0.986 pu (Figure 33). In the case of reference system with PCS steady state voltage is 0.988 pu and in the case of reference system with SC steady state voltage after the disturbance is 0.974 pu. In both cases the voltage drop is the same, but as it can be seen from Figure 30 and Figure 33 that voltage recovery is much faster in the case of system with connected PCS.

SC and PCS reactive power output after load connection are around 18 Mvar, but from Figure 31 and Figure 33 it can be seen that reactive power response of PCS is much faster.

[6] This is the weakest node of IEEE 9-bus reference system

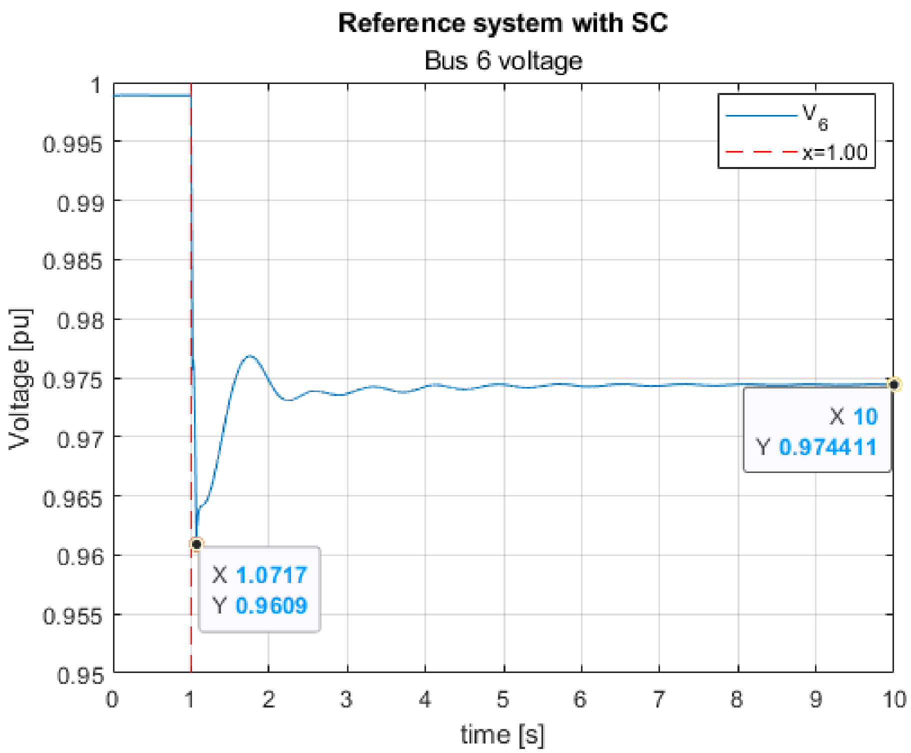

Figure 30 Reference system + SC – Voltage change

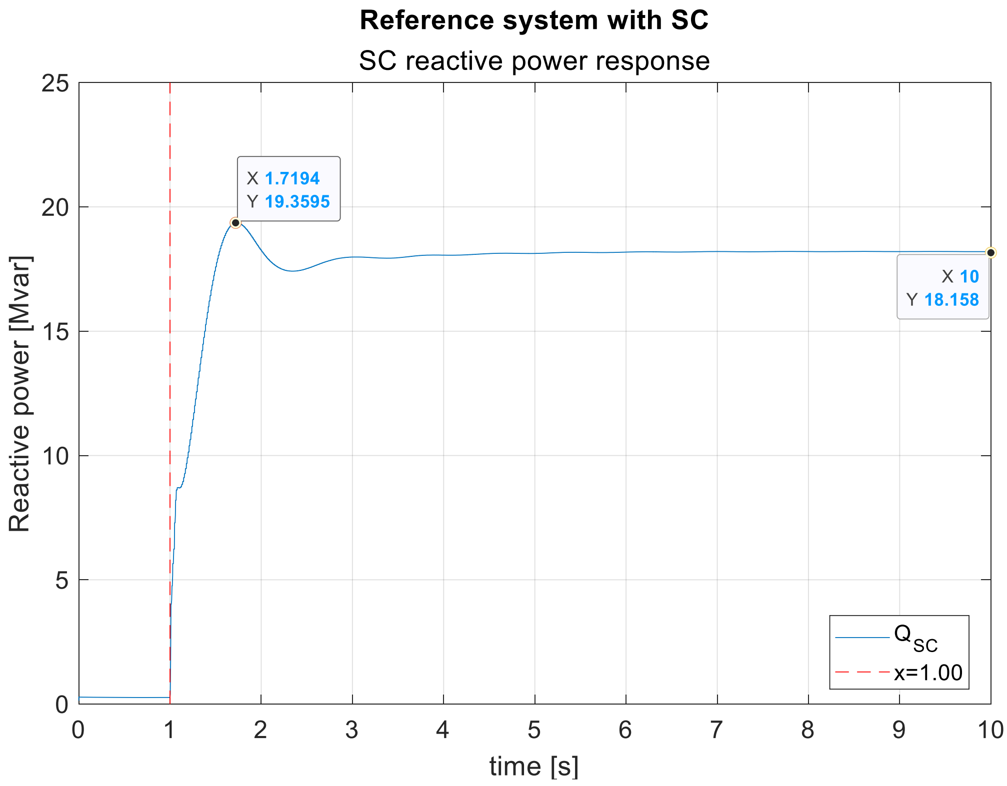

Figure 31 Reference system + SC – SC reactive power response

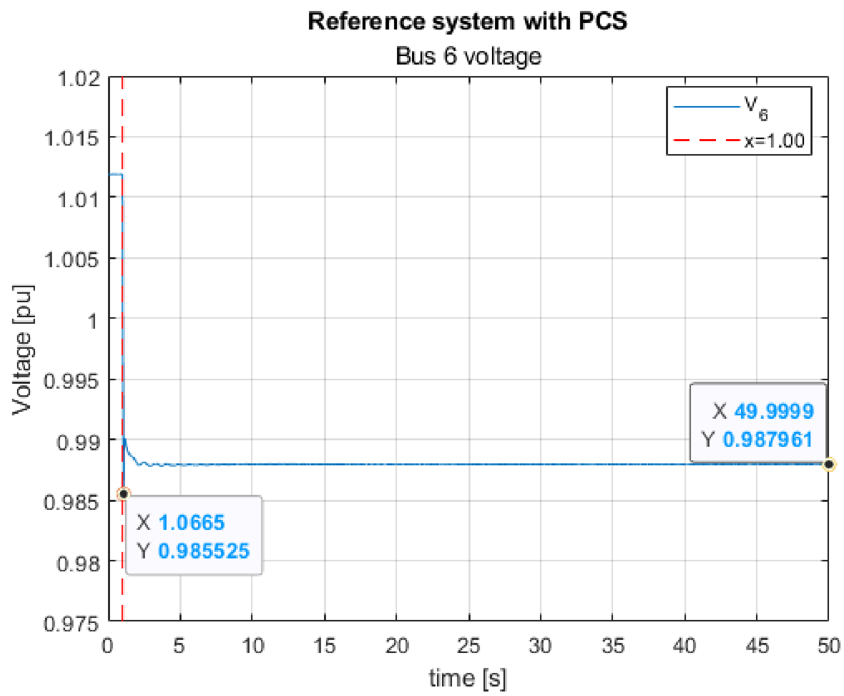

Figure 32 Reference system + PCS – Voltage change

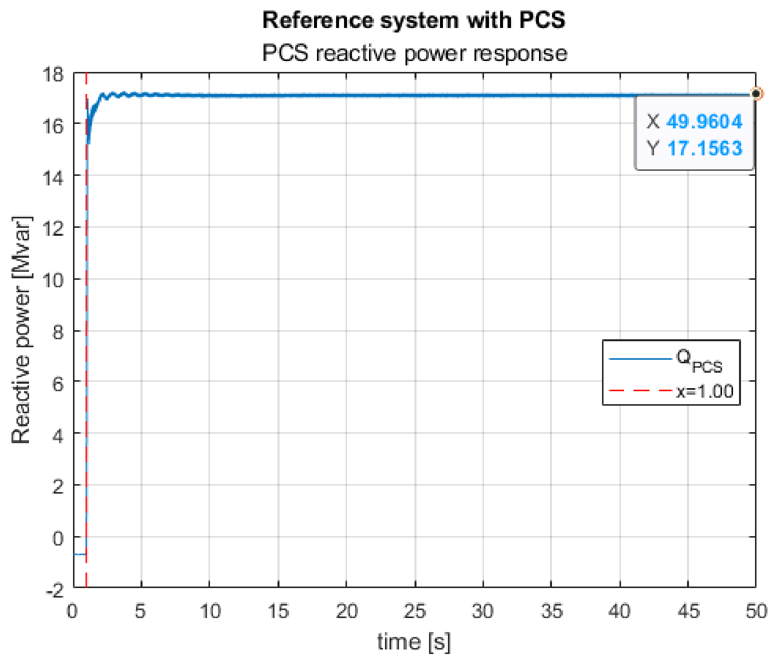

Figure 33 Reference system + PCS – PCS reactive power response

3.2.1.2 Two machine equivalent system

Figure 34 shows voltage profile at Bus 6 of two machine system after the step increase of reactive load. Figure 35 shows close-up of voltage profile at Bus 6 of two machine system 1.5 s after the step increase of reactive load. Figure 36 shows reactive power contributions of SC and PCS after the connection of reactive load at Bus 6. Figure 36 shows filtered reactive power contributions of SC and PCS during the after the connection of reactive load at Bus 6

Before the event voltage at the point of connection was close to Thevenin equivalent voltage and there were no significant active nor reactive power flows. For the analysed event (connection of 10 Mvar pure reactive load) maximum voltage dip is 0.974 pu when voltage support is provided by SC and 0.986 pu when voltage support is provided by the PCS (see Figure 35). From Figure 34 and Figure 35 it can be seen that the voltage recovery after the initial drop is significantly quicker in a system with PCS.

Regarding reactive power outputs as previously stated voltage regulation parameters are set in a way that guarantees equal steady state responses. From Figure 36 it can be seen that maximum reactive power of PCS is higher compared to SC response (around 17 Mvar compared to 15 Mvar respectively). Steady state reactive power contribution after the event as shown in Figure 36 is also the same (around 14 Mvar), however reactive power response of PCS is much faster than SC response.

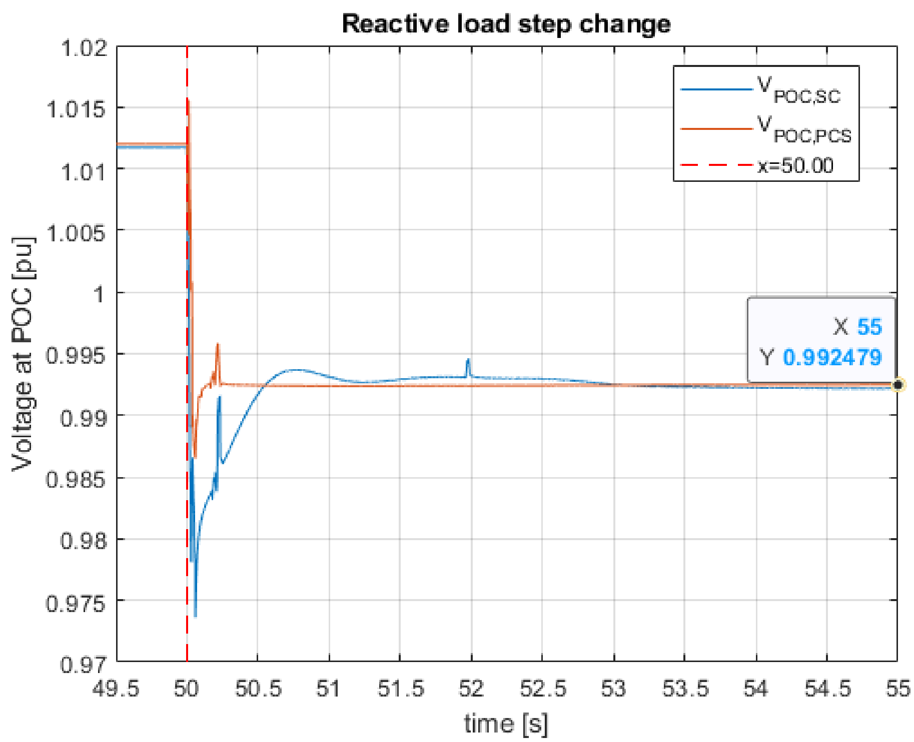

Figure 34 Voltage profile at the point of connection during reactive load step increase – Two machine equivalent –

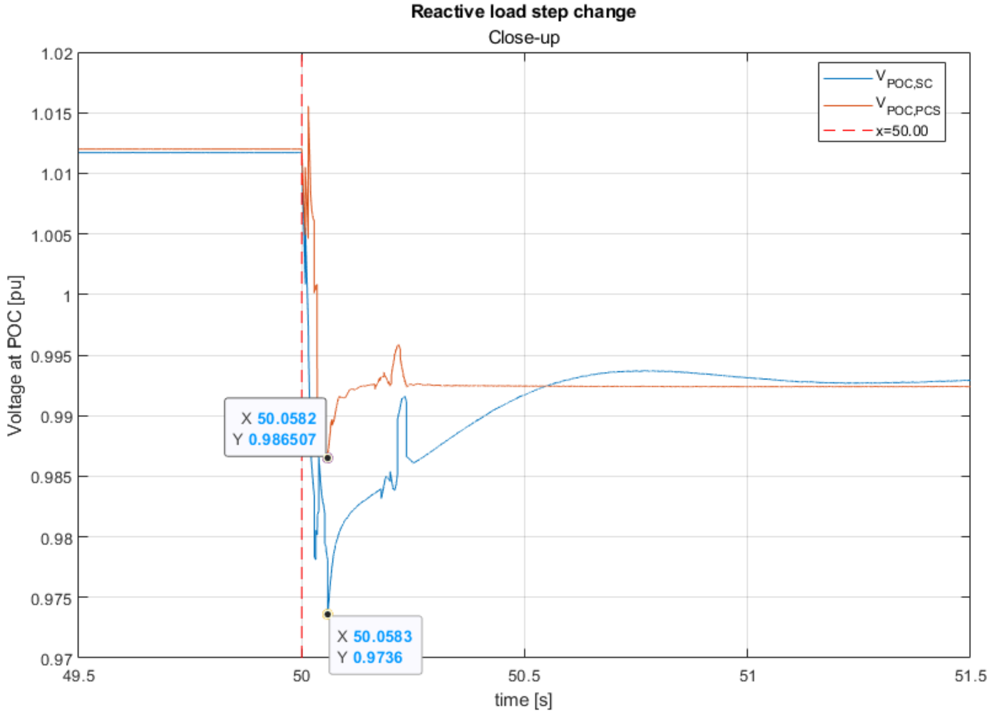

Figure 35 Close-up of voltage profile at the point of connection during reactive load step increase – Two machine equivalent –

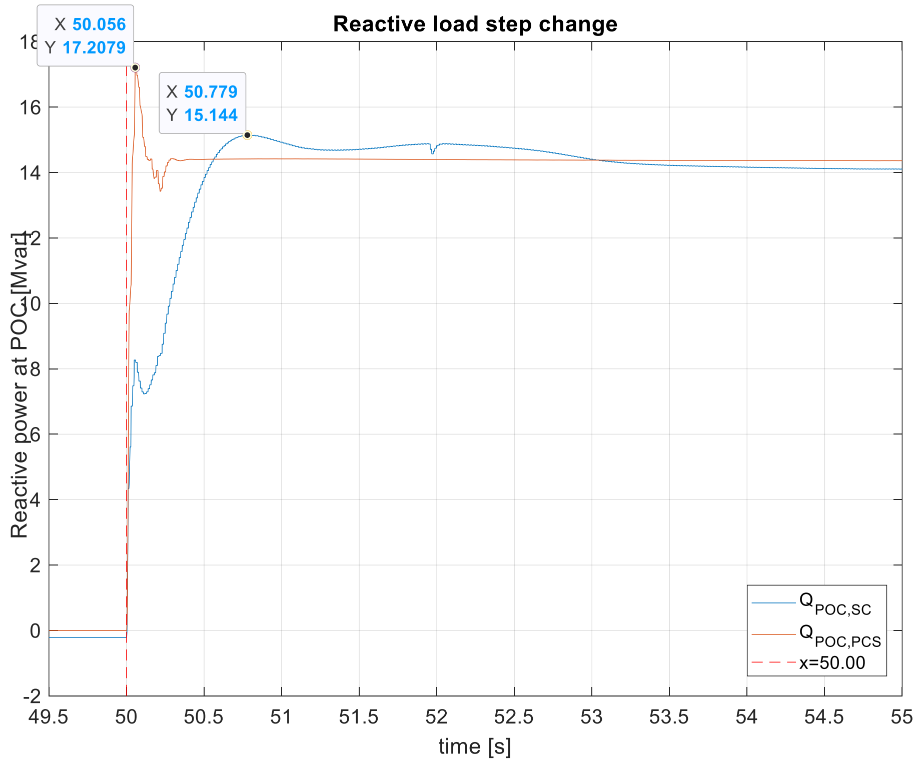

Figure 36 Reactive power contribution to connection of pure reactive load – Two machine equivalent –

3.2.2 Voltage step change

As previously stated, SC and PCS response to step voltage change is simulated using two machine equivalent system (Figure 2).

Figure 37 shows voltage profile on Bus 6 of two machine system after the step decrease of equivalent voltage source. Figure 38 shows reactive power contributions of SC and PCS after the step change of voltage source voltage

Before the event voltage at the point of connection was close to Thevenin equivalent voltage and there were no significant active nor reactive power flows. For the analysed event (voltage source step change) minimum voltage dip is 0.976 pu when voltage support is provided by SC. When the voltage support is provided by PCS there is no voltage dip, i.e. voltage asymptoticly goes to steady state value of 0.986 pu (see Figure 37). From Figure 37 it can be concluded that the new steady state voltage is reached much sooner when the voltage support is provided by PCS.

Regarding reactive power outputs as previously stated voltage regulation parameters are set in a way that guarantees equal steady state response. From Figure 38 it can be seen that steady state reactive power is practically the same for both SC and PCS (around 19 Mvar). However if we look at the dynamics of the reactive power change after the step voltage change it can be seen that reactive power response of PCS is much quicker.

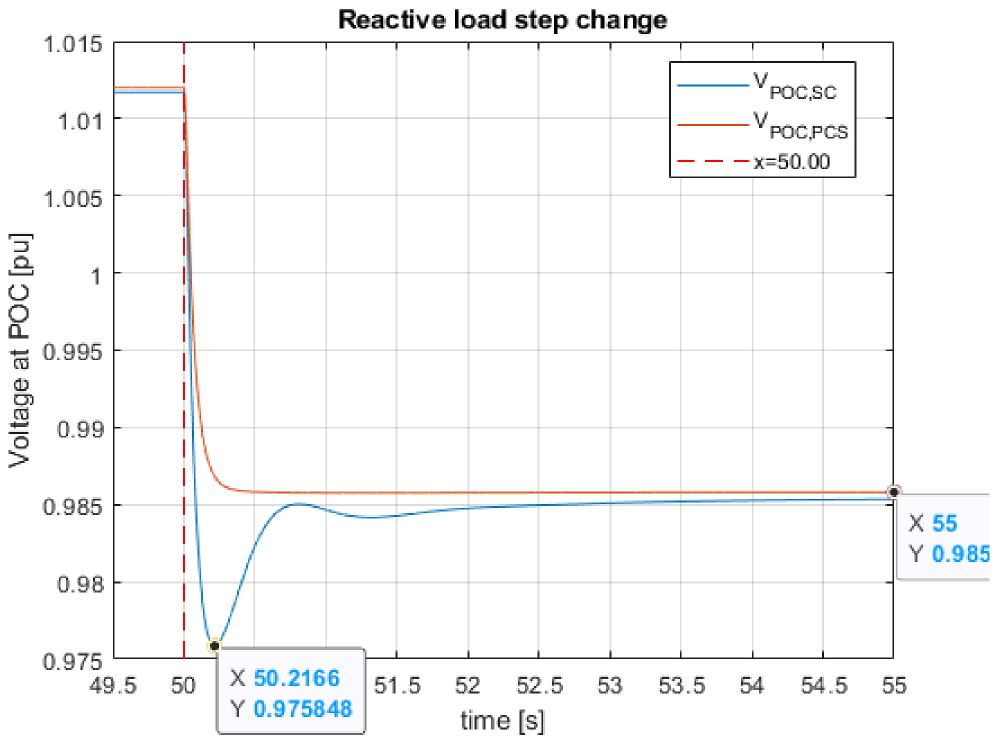

Figure 37 Voltage profile at the point of connection during equivalent source voltage step change – Two machine equivalent –

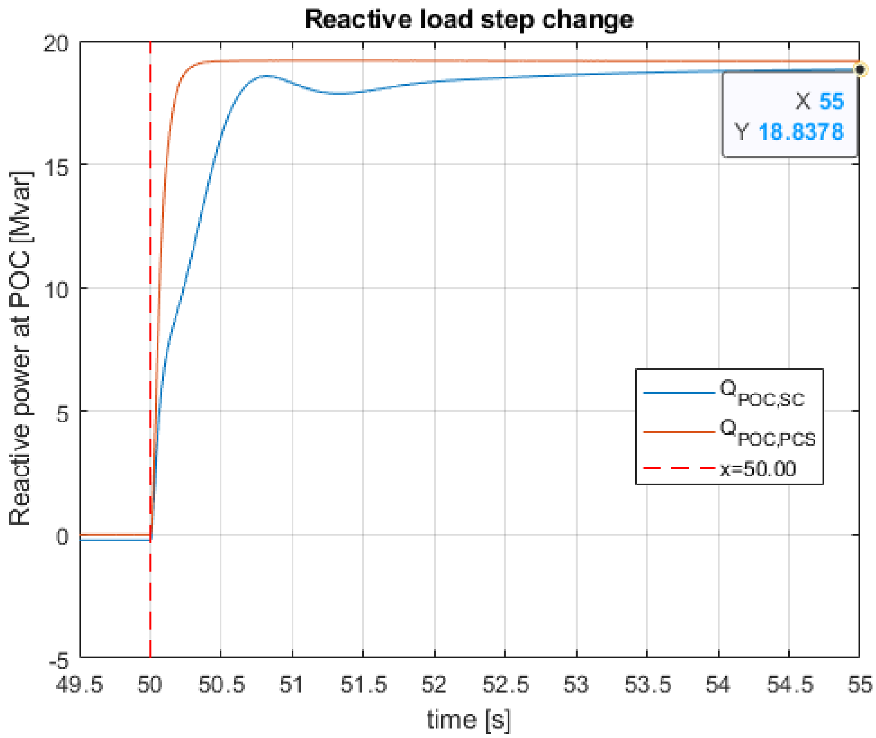

Figure 38 Reactive power response during equivalent source voltage step change – Two machine equivalent –

4. SHORT-CIRCUIT

4.1.1 Short circuit contribution and impact on SCR

To analyse SC and PCS with GFM capability contribution to short circuit a three-phase short circuit at point of connection (Bus 6) in two machine equivalent (see Figure 2) system is simulated. The short circuit is cleared after 150 ms.

To compare the effects of SC and GFM short circuit current contribution shall be compared.

Calculated short circuit currents shall be used to calculate SC and PCS impact on overall SCR values of the IEEE 9-bus reference system. This shall be done by placing current source at Bus 6 of IEEE 9-bus reference system shown in Figure 3. For each HV bus value of short-circuit after the addition of SC and PCS shall be calculated.

4.2 Results comparison

4.2.1 Short circuit contribution

Figure 39 shows short circuit contribution of SC and PCS measured at HV side of step-up transformer. Figure 40 shows short circuit contribution of SC and PCS measured at LV side of step-up transformer. Values in Figure 40 are normalized according to rated values calculated at step up transformer LV side:

- $I_{SC,base} = \frac{67}{\sqrt{3}\,13.8} = 2.8\ kA\ @UT\ LV$
- $I_{PCS,base} = \frac{76.8598}{1\,000} \cdot 637.5 \cdot \frac{0.8}{13.8} = 2.84\ kA\ @UT\ LV.$

where 76.8598 A is inverter nominal output current, UT is the main PCS grid connection transformer (235/13.8 kV/kV) and 637.5 is the current multiplier factor. Even though contribution from PCS to short circuit is lower than SC, analysed PCS exhibits high current overload capability of 3 pu.

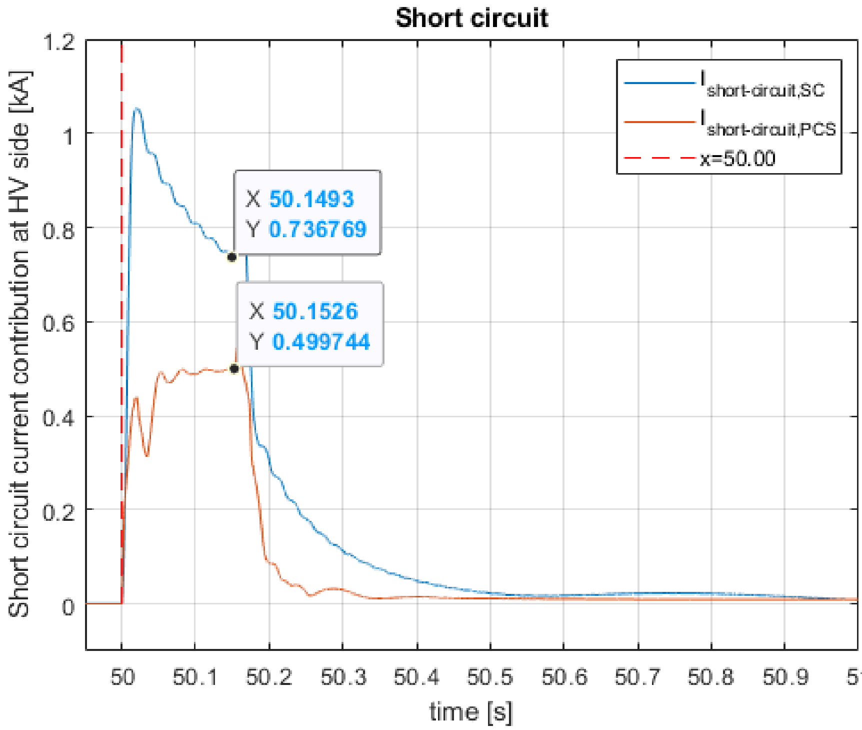

Figure 39 Short-circuit contribution to three-phase short-circuit at POC measured at transformer HV – Two machine equivalent –

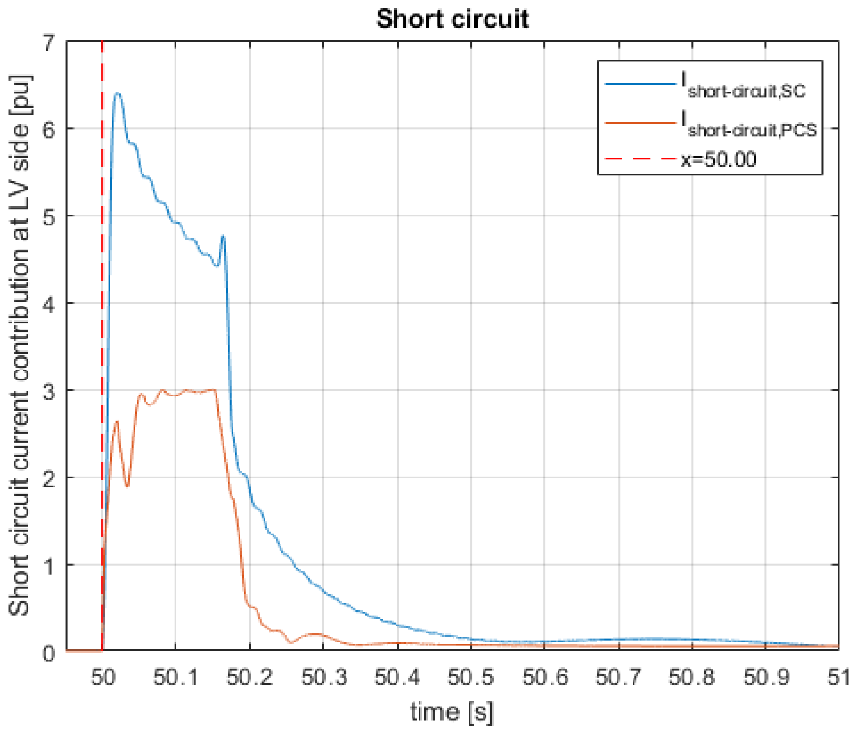

Figure 40 Short-circuit contribution to three-phase short-circuit at POC measured at transformer LV – Two machine equivalent –

4.2.2 Impact of SC and PCS on SCR

Impact of SC and PCS on overall grid strength is evaluated by introducing current source at Bus 6 (Figure 3) and calculating short circuit levels at HV nodes of the grid. Value of current source current is 0.737 kA when effect of SC is analysed and value of 0.5 kA is used when effect of PCS is analysed. Fault levels and short circuit power are given in Table 6.

IEEE 9 bus network

- Comparison -								
Bus number	Vn	Vpre_fault*	Isc_3phase			Short Circuit Power		
			Base	SC	PCS	Base	SC	PCS
	[kV]	[pu]*	[kA]	[kA]	[kA]	[MVA]	[MVA]	[MVA]
4	230	1.025	3.087	3.25	3.187	1261	1327	1301
5	230	0.999	2.33	2.447	2.403	927	974	956
7	230	1.026	2.953	3.065	3.026	1207	1253	1237
8	230	1.017	2.435	2.539	2.502	987	1029	1014
9	230	1.032	2.62	2.755	2.705	1077	1133	1112

* taken immediately before short-circuit (t=0.99s) expressed at 230 kV base

** at HV side i.e. 230 kV

Table 6 Comparison of short circuit currents and power for the base IEEE 9 bus network and network with connected SC or PCS

If we assume common criteria for grid strength of SCR=3 we can calculate amount of RES that can be connected at HV buses. Results are given in Table 7.

IEEE 9 bus network

- Comparison -				
Bus number	SCR	Pmax		
		Base	By adding SC	By adding PCS
		[MW]	[MW]	[MW]
4	3	420	442	434
5	3	309	325	319
7	3	402	418	412
8	3	329	343	338
9	3	359	378	371

Table 7 Comparison of possible RES connection with SCR=3 criteria

Improvements in terms of ratio between value of RES that could be connected in the case and when SC or PCS is connected to the grid are shown in Table 8. The results given in Table 8 show that when SC is connected to the grid around 5% more RES capacity could be integrated than in base case, while maintaining the same SCR of the reference system. On the other hand, if PCS with GFM is connected around 3% more RES capacity could be integrated than in base case, while maintaining the same SCR of the reference system. If amount of RES is kept the same than the SCR of reference system would improve by around 5% when SC is connected, and 3% when PCS with GFM is connected compared to the base case.

IEEE 9 bus network

- Improvements -		
Bus number	SC → Base	PCS → Base
4	1.053	1.032
5	1.050	1.031
7	1.038	1.025
8	1.043	1.028
9	1.052	1.032

Table 8 Possible improvements in installed capacities

5. CONCLUSIONS

The report compares SC and PCS response to: active and reactive power disturbances, voltage disturbance at the POC, short circuit contribution and impact on the overall system strength. Two different scenarios regarding overall system inertial strength are considered. Results show that PCS contributes significantly to frequency stability. When PCS is scaled so that apparent powers of PCS and SC are the same, and the inertia time constants are set to same values PCS provides better results regarding frequency containment i.e. frequency nadir and new steady state frequency. This is partly due to the fact that PCS besides inertial response provides primary frequency control. On the other hand, PCS installed capacity has to be much lower in order to provide same frequency support to the system compared to SC. For the analysed reference system and loss of generation contingency GFM with 15.975 MW installed capacity would replace SC with 67 MVA rated capacity. If we would to scale the results, we would get that 100 MVA of SC could be replaced with 24 MW of PCS. In the performed analysis it is considered that the frequency support is equal if the same frequency nadir is achieved for the simulated loss of generation event. In the case where SC and PCS provide the same frequency support (i.e. for the frequency is contained to the same value), PCS activates primary frequency reserve that is small compared to overall activated reserve. Results show that the PCS improves frequency during active power disturbance and that the effect is more pronounced in the weak system conditions. Weak system conditions correspond to the situation where overall installed capacity is the same but conventional power plants with SMs are replaced with CBR not providing inertia. ROCOF results are similar.

Regarding reactive power disturbance PCS shows quicker response than SC when it comes to both voltage drop containment, voltage recovery and reactive power response.

Regarding short circuit even though the SC outperforms PCS in terms of possible current overload analysed PCS can provide significant short-circuit contribution. Analysed PCS can be overloaded with 3 times rated current. Regarding impact on overall grid strength for the analysed reference system (IEEE 9 bus) the SCR could be improved about 3% with addition of 67 MW of PCS. Putting it in a context of the examined reference system, if the analysed PCS with 67 MW installed capacity is connected to a bus with average short circuit power of 1100 MVA an increase of around 33 MVA in short-circuit level can be gained. The other way to look at this is in the amount of new RES that could be connected without lowering the SCR=3 criteria. The results indicate that by connecting analysed Huawei PCS in the considered reference system for each 5 MW of installed PCS you can integrate additional 1 MW RES not capable of contributing to system SCR and still maintain the same SCR level.

The results presented in this report show that PCS with GFM technology can contribute to frequency and voltage stability of the system that is comparable and better than the response of the SC. Regarding short circuit contribution, the analysed PCS provides 3 times rated current for 3 phase short circuit at the connection point. These are very good results when it comes to the CBRs. Other advantage of PCS is that it is a part of an existing RES power plant or BESS. This means that profitability of solution that contributes to the system operation is not only related to the ancillary service market as it is the case for SC. PCS solution can produce revenue from both electricity and ancillary service markets. Therefore, PCS with GFM technology can be a solution that is more viable for both investors and system operators.

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