DYNAMIC MODEL ACCEPTANCE GUIDELINE

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AEMO has prepared this Guideline to explain how to assess accuracy and robustness of computer models used for power system analysis.

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Glossary

Term	Definition
AEMO	Australian energy market operator
AVR	Automatic voltage regulator
DSA	Dynamic security assessment
EMT	Electromagnetic transient
HVDC	High voltage direct current
LVRT	Low voltage ride through
NSP	Network service provider
OEL	Over excitation limiter
OPDMS	Operations and planning data management system
PCC	Point of common coupling
PI	Proportional integral
PSS	Power system stabiliser
PSS®E	Power system simulator for engineering
RMS	Root mean square
SCR	Short circuit ratio
STATCOM	Static compensator
SVC	Static Var Compensator
TCR	Thyristor controlled reactor
TSC	Thyristor switched capacitor
UEL	Under excitation limiter

1 PURPOSE OF DOCUMENT

This document explains the process for carrying out dynamic model acceptance tests (MAT) for RMS type models. Model acceptance tests are necessary to provide confidence the model is usable, numerically robust and represents the plant under all expected operating conditions. The model must comply with the Power System Model Guidelines and is expected to be accurate enough to enable AEMO to assess the commissioning process and any impacts on system security. The objective of the acceptance tests in this document is to determine the robustness of the model for defined test conditions. The tests do not provide any assessment of compliance for performance or access standards for specific connection points. Successful acceptance testing does not guarantee that models submitted for a particular connection project will meet the applicable compliance requirements.[1]

This document presents a systematic test suite and the key criteria for dynamic model acceptance, including simulation case studies which the dynamic models will undergo for acceptance.

All models will be stored in AEMO's Operations and Planning Data Management System (OPDMS) for planning, operations and automated dynamic security assessment (DSA), and other applications.

The MAT submission should include all associated study files (case and output files) and a report summarising key results of the tests undertaken, AEMO may provide a Python script to assist proponents with completing a Model Acceptance Test,. Enquiries regarding the script can be sent to connections@aemo.com.au

2 RELATED POLICIES AND PROCEDURES

This document is not intended to replace AEMO's existing Power System Model Guidelines.[2] In addition to the acceptance testing set out in this document, dynamic models provided for generator connections must meet all requirements in the Power System Model Guidelines.

3 MODEL ACCEPTANCE PRINCIPLES

3.1 Scope

3.1.1 Scope of tests

The scope of this Guideline covers each primary plant item for which dynamic models have been provided independently. This includes:

- For synchronous generating units, models of:
    - Excitation system (AVR, exciter, PSS and limiters), using a generic (or specific, if provided) synchronous generator model.
    - Governor system, using a generic (or specific, if provided) synchronous generator and exciter model.
- For variable generation technologies such as wind and solar farms, models of:
    - Aggregated equivalent wind turbine model including central park level controller.

[1] AEMO or the relevant network service provider may have specific requirements for an individual connection.

[2] AEMO. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Power_Systems_Model_Guidelines_PUBLISHED.pdf

- For dynamic reactive support plant such as SVC and STATCOM, models of:
    - Main and auxiliary control systems (e.g., power oscillation damping), with a generic large (nearly infinite) generating system representing the source power system.
- For high voltage direct current (HVDC) links:
    - If intended as interconnectors, the DC link model with a generic large (nearly infinite) generating system connected at one end.
    - If intended as embedded DC links with generating systems connected to one or both ends the DC link model with generic (or specific, if provided) model of the generating system(s) at one end or both ends (if applicable).
    - If intended to interface islanded networks, e.g., DC-connected wind farms, the DC link model with a specific model of the wind farm.

For plant commonly used in combination with other plant (e.g., specific wind turbine models and dynamic reactive support devices), similar model testing can be used to assess potential model interactions.

For plant with several control or operation modes, the model acceptance will encompass all modes. Included in this category are:

- Central park level controller for wind and solar farms, which can provide multiple control functions such as voltage control, frequency control, power factor control.
- Generating units with a changeover function between the star and delta connection modes for various power output levels.

3.1.2 Model type

The model acceptance testing discussed in this document primarily applies to positive sequence RMS type dynamic models developed in line with AEMO's preferred simulation platforms as discussed in:

https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Power_Systems_Model_Guidelines_PUBLISHED.pdf

3.1.3 Power system study applications

This model acceptance testing guideline does not assess the model with respect to the following:

- Unbalanced disturbances.
- Power quality including harmonics, flicker, and voltage unbalance.
- Temporary and transient overvoltages.
- Control instability.
- Sub-synchronous interaction.

3.2 Model documentation and structure

Proponents need to submit the following items as part of a model assessment submission. It is expected that all documentation provided will be consistent.

- Encrypted model in PSS®E.
- Corresponding model source codes.

- Corresponding transfer function block diagrams complying with the Power System Model Guidelines.
- Instructions on how the model should be set up and used.
- Validation report comparing the model's fault ride-through performance with the measurements for power electronic connected generation technologies.

Model documentation and structure will be reviewed, and several main attributes will be assessed:

- The transfer function block diagram must include all functional controllers and physical plant that materially affects the performance of the model.[3]
- The model must meet the accuracy requirements specified in the AEMO Power System Model Guidelines.
- The models of the controllers and items of plant must be easily identifiable.
- The model parameter values must reflect typical values appropriate for the actual equipment installed. The block diagram must show all model parameters and their values.
- The use of black-box type representation is not acceptable.
- The interconnection of the different functional controllers and the items of plant must be clearly shown.
- Control systems with several discrete states or logic elements may be provided in flow chart format if a block diagram format is not suitable.
- Model parameter values that are intended to be (or can be) externally adjusted (i.e., those explicitly in PSS®E dynamic data file) must be clearly identified in the model block diagram.
- The model block diagram and flow charts (if applicable) must represent the corresponding model source code.[4]
- The model inputs and outputs shown in the transfer function block diagram representation should match those indicated in the model datasheet tables.
- The state variables shown in the transfer function block diagram representation should match those indicated in the model datasheet tables.
- Model documentation and transfer function block diagram representation should be provided at the level of detail required for AEMO and network service providers to derive the corresponding linear small-signal model of the equipment.
- Dynamic data must be provided as 'per unit' quantities on the machine MVA base.
- The maximum duration of the dynamic simulation run for which the model accuracy is proven should be clearly mentioned.
- For wind-up, and anti-wind-up proportional integral (PI) controllers details of the controller—including any potential dead-band and saturation—must be shown in the transfer function block diagram representation.

[3] Included in this category are the central park level controllers that schedule active and reactive power across the wind and solar farms.

[4] It is also expected that the functional block diagrams provided with the Power System Design and Setting Data Sheets for a specific generating system connection will match these diagrams, although the parameter values might differ to reflect particular connection point performance requirements.

- For variable generation technologies (such as wind turbines and solar panels) the following parameters must be accessible in the main software interface for online monitoring and possible changes during the simulation:
    - Active power at LV terminals.
    - Reactive power at LV terminals.
    - Active current at LV terminals.
    - Reactive current at LV terminals.
    - RMS voltage at LV terminals.
    - Applicable set-points including:
        - Active power set-point.
        - Frequency set-point.
        - Voltage set-point.
        - Reactive power set-point.
        - Power factor set-point.
    - Fault ride-through activation/deactivation.
    - Reactive current injection during the fault.
    - Additional requirements for wind turbines[5]:
        - Pitch angle.
        - Wind speed.
        - Generator rotor speed.
        - Mechanical torque/power.
        - Aerodynamic torque/power.
- The minimum design value of the short circuit ratio (SCR)[6] for variable generation technologies, HVDC links, and dynamic reactive support plant must be documented. As the model will be assessed independent of specific connection projects, the SCR must be defined at the equipment terminals rather than the point of common coupling (PCC). Vendors must provision detailed EMT-type models when seeking assessment of the model for a short circuit ratio of less than three.
- The recommended range of the following dynamic simulation parameters should be stated in the model documentation.
    - Numerical integration time step. Where models use an internal integration time step for some of its faster acting controllers this should be clearly highlighted.
    - Tolerance for network solution.
    - Acceleration factor for network solution.
    - Frequency filter (filter time constant).

[6] SCR is a measure of the strength of the network to which the equipment is connected. This is defined as the ratio of the short circuit capacity of the grid at the point of common coupling (PCC) in MVA to the nominal power at the PCC in MW.

- For wind and solar farms the model aggregation methodology proposed must be clearly specified.
    - The aggregation method should not restrict access to the wind turbine terminals (LV side of the turbine transformer).
    - The use of full feeder representation for one or more feeders is not considered good industry practice due to accompanying computational burden. It should not be used if possible.
- Currently, AEMO accepts the source code formats FORTRAN and FLEX. Source codes written in other formats (such as C/C++) may be assessed on a case-by-case basis.
- The model must be written and prepared using good electricity industry practice and good model writing practices for the relevant software. For PSS®E, this would include:
    - Execution of the DOCU command should show all model states, outputs and constants that are observable/adjustable externally. The output format of these commands should be consistent with the format of dynamic data.
    - Execution of dynamic data documentation commands should not result in model crashing.
    - Using models which include calls into either of the CONEC or CONET subroutines is not acceptable. In PSS®E this approach would require users to make a fresh compilation every time the network configuration changes, so a dedicated FORTRAN compiler is needed for each user.
    - Using identical names should be avoided for models of similar structure where the number of one of the CONs, ICONs, VARs, or STATES is different between the two models.
    - The model should comprise a single executable file for each physical plant. Use of auxiliary or linking files is discouraged.

3.3 Model initialisation

- The derivative of all state variables should be less than 0.0001 during initialisation.
- Models should be initialised successfully for the entire intended plant operating range. In other words, the model operating range should be consistent with the actual equipment design in particular with respect to the following:
    - The entire range of active power.
    - The entire range of reactive power/power factor (including limits of reactive power generation and consumption).

3.4 Acceptance criteria during dynamic simulation

Dynamic models provided should have the following characteristics:

- Voltage, frequency, active and reactive power should remain constant for dynamic simulation runs with no disturbance.
- Should not interfere with the operation of other dynamic models.
- Should be numerically robust for dynamic simulation runs of several minutes.

- The numerical integration time step should be kept under 20–25% of the shortest time constant in the process being simulated. For acceptable numerical integration time steps please refer to section 4.3 of AEMO's Power System Model Guidelines.
- Time constants smaller than the minimum acceptable numerical integration time step should be avoided.
- Model outputs in terms of the voltage, frequency, active and reactive power should be reasonably constant and consistent when doubling and halving the recommended time step.
- Should be numerically stable for a wide range of grid SCR and grid and fault X/R ratio.
- Should be numerically stable for unity, lagging and leading power factors.
- When the simulated response exhibits unusual performance characteristics several seconds after removal of the disturbance, provision of off-site test results for identical equipment is necessary to demonstrate that the actual equipment will perform the same way.
- Models are expected to work for a range of the dynamic simulation parameters rather than for specific settings.
- To avoid excessive simulation burden when integrating those models into AEMO OPDMS and DSA tools the minimum permissible values of the numerical integration time step and acceleration factors are 1 ms and 0.2 ms respectively. The frequency filter time constant should be set to four times the integration time step.

4 MODEL ACCEPTANCE TESTS

The model acceptances tests that need to be carried out are outlined in Tables 1 and 2.

As examples, the test circuits used for variable generation and synchronous generation technologies are shown in Figure 1(a) and Figure 1(b) respectively.

Test set-up for acceptance testing of HVDC links and dynamic reactive support plant can be established by referring to Section 2.1 of this document.

In Figure 1(a) and 1(b) the network slack bus is an infinite bus where the voltage magnitude and voltage angle are determined by an ideal voltage source being the reference node and balancing node. The unit and substation transformer voltages provided are example values and can vary according to the nominal values of the particular equipment.

Note that it is a common practice to connect the power plant (e.g., wind farms) via two parallel connected substation transformers. The substation transformer impedance shown in Figure 1(a) therefore represents two parallel connected transformers.

As indicated by equation (1), with the application of a network fault the remaining voltage, U_{dip} can be calculated as a function of fault impedance Z_f, system impedance Z_s, and source voltage V_s.

Equation (1) $$U_{dip} = V_s \cdot \frac{Z_f}{d \cdot Z_s + Z_f}$$

where d is a variable which allows varying fault distance with respect to the generating unit

Note that U_{dip} as the remaining voltage that appears when zero in-feed is provided by the generating unit for which the model is being tested.

Rearranging (1) and assuming V_s equal to 1 pu the fault impedance can be calculated as:

Equation (2) $$Z_f = d \cdot Z_s \cdot \frac{U_{dip}}{1 - U_{dip}}$$

Equation (2) implies that the fault impedance can be determined as a function of the predefined residual voltage at the fault location.

4.1 Case studies for both wind farms and synchronous generators

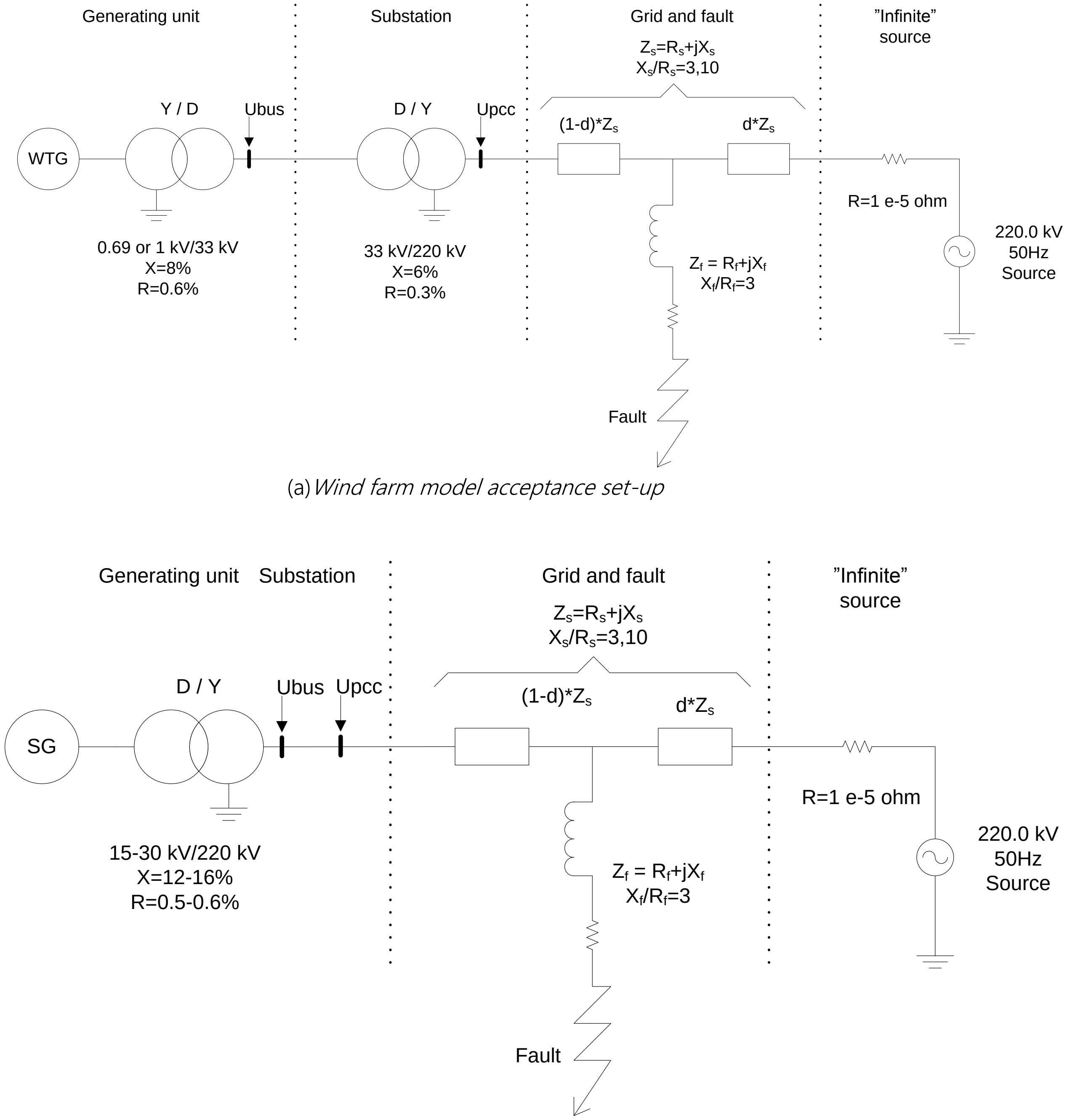
In summary, the general model acceptance tests required can be summarised as follows:

- Fault disturbance tests with three-phase-to-ground fault scenarios considering various factors such as:
  - Fault duration.
  - Voltage dip.
  - Grid SCR.
  - Grid X/R ratio.
  - Pre-fault active power at the PCC.
  - Pre-fault reactive power at the PCC.
  - Fault X/R ratio.
- Non-fault disturbance tests:
  - Step response test on machine active power set-point as shown in Figure 2.
  - Step response test on machine reactive power set-point as shown in Figure 3.
  - Step response test on grid voltage magnitude.
  - Rate of change of grid frequency test as shown in Figure 4. (Note that for all cases the grid frequency is increased to 52 Hz and restored to 50 Hz again).
  - Step response test on grid voltage angle equal to ±20°.

The plotting channels used depend on the equipment, but as a minimum the following quantities will be plotted for all equipment at their terminals and POC:

- Active power.
- Reactive power.
- Active current.
- Reactive current.
- Magnitude of terminal voltage.
- Phase angle of terminal voltage.
- Grid frequency.

Additional plotting channels may be used for assessment of each specific type of equipment.



(a) *Wind farm model acceptance set-up*

(b) Synchronous generator model acceptance set-up

Figure 1 Test circuit for model acceptance testing

Table 1 Large disturbance test cases

Note: The table below assumes SCR values of 3 and 5 and X/R values of 3 and 10. In the event the SCR and X/R values are expected to be lower at the generating systems connection point then the SCR and X/R values for system normal and the most severe N-1 credible contingency should be used.

Item	Fault Duration (s)	Residual voltage (pu)	Short-circuit ratio	Grid X/R ratio	Active power (pu)	Time step (ms)	Acceleration factor	Reactive power (pu)
Voltage dip test cases								
1	0.12	0	5	3	1.0	2	1.0	0.0
2	0.12	0	5	3	1.0	2	1.0	0.3
3	0.12	0	5	3	1.0	2	1.0	-0.3
4	0.12	0	3	3	1.0	2	1.0	0.0
5	0.12	0	3	3	1.0	2	1.0	0.3
6	0.12	0	3	3	1.0	2	1.0	-0.3
7	0.12	0	5	3	0.05	2	1.0	0.0
8	0.12	0	5	3	0.05	2	1.0	0.3
9	0.12	0	5	3	0.05	2	1.0	-0.3
10	0.12	0	3	3	0.05	2	1.0	0.0
11	0.12	0	3	3	0.05	2	1.0	0.3
12	0.12	0	3	3	0.05	2	1.0	-0.3
13	0.12	0	5	10	1.0	2	1.0	0.0
14	0.12	0	5	10	1.0	2	1.0	0.3
15	0.12	0	5	10	1.0	2	1.0	-0.3
16	0.12	0	3	10	1.0	2	1.0	0.0
17	0.12	0	3	10	1.0	2	1.0	0.3
18	0.12	0	3	10	1.0	2	1.0	-0.3
19	0.12	0	3	3	1.0	1	1.0	0.0
20	0.12	0	3	3	1.0	1	1.0	0.3
21	0.12	0	3	3	1.0	1	1.0	-0.3

22	0.12	0	3	3	0.05	1	1.0	0.0
23	0.12	0	3	3	0.05	1	1.0	0.3
24	0.12	0	3	3	0.05	1	1.0	-0.3
25	0.12	0	3	3	1.0	2	0.3	0.0
26	0.12	0	3	3	1.0	2	0.3	0.3
27	0.12	0	3	3	1.0	2	0.3	-0.3
28	0.12	0	3	3	0.05	2	0.3	0.0
29	0.12	0	3	3	0.05	2	0.3	0.3
30	0.12	0	3	3	0.05	2	0.3	-0.3
31	0.5	0.7	5	3	1.0	2	1.0	0.0
32	0.5	0.7	5	3	1.0	2	1.0	0.3
33	0.5	0.7	5	3	1.0	2	1.0	-0.3
34	0.5	0.7	3	3	1.0	2	1.0	0.0
35	0.5	0.7	3	3	1.0	2	1.0	0.3
36	0.5	0.7	3	3	1.0	2	1.0	-0.3
37	0.5	0.7	5	3	0.05	2	1.0	0.0
38	0.5	0.7	5	3	0.05	2	1.0	0.3
39	0.5	0.7	5	3	0.05	2	1.0	-0.3
40	0.5	0.7	3	3	0.05	2	1.0	0.0
41	0.5	0.7	3	3	0.05	2	1.0	0.3
42	0.5	0.7	3	3	0.05	2	1.0	-0.3
43	0.5	0.7	5	10	1.0	2	1.0	0.0
44	0.5	0.7	5	10	1.0	2	1.0	0.3
45	0.5	0.7	5	10	1.0	2	1.0	-0.3
46	0.5	0.7	3	10	1.0	2	1.0	0.0
47	0.5	0.7	3	10	1.0	2	1.0	0.3

48	0.5	0.7	3	10	1.0	2	1.0	-0.3
49	0.5	0.7	3	3	1.0	1	1.0	0.0
50	0.5	0.7	3	3	1.0	1	1.0	0.3
51	0.5	0.7	3	3	1.0	1	1.0	-0.3
52	0.5	0.7	3	3	0.05	1	1.0	0.0
53	0.5	0.7	3	3	0.05	1	1.0	0.3
54	0.5	0.7	3	3	0.05	1	1.0	-0.3
55	0.5	0.7	3	3	1.0	2	0.3	0.0
56	0.5	0.7	3	3	1.0	2	0.3	0.3
57	0.5	0.7	3	3	1.0	2	0.3	-0.3
58	0.5	0.7	3	3	0.05	2	0.3	0.0
59	0.5	0.7	3	3	0.05	2	0.3	0.3
60	0.5	0.7	3	3	0.05	2	0.3	-0.3

Table 2 Small disturbance test cases

Section	Event	SCR	Grid X/R ratio	Active power (pu)	Time step (ms)	Acceleration factor	Reactive power (pu)
Small-disturbance test cases							
1	Pref step as per Fig.2	5	10	1.0	2	1.0	0.0
2	Pref step as per Fig.2	5	10	1.0	2	1.0	0.3
3	Pref step as per Fig.2	5	10	1.0	2	1.0	-0.3
4	Pref step as per Fig.2	3	10	1.0	2	1.0	0.0
5	Pref step as per Fig.2	3	10	1.0	2	1.0	0.3
6	Pref step as per Fig.2	3	10	1.0	2	1.0	-0.3
7	Pref step as per Fig.2	3	10	1.0	1	1.0	0.0
8	Pref step as per Fig.2	3	10	1.0	1	1.0	0.3
9	Pref step as per Fig.2	3	10	1.0	1	1.0	-0.3
10	Pref step as per Fig.2	3	10	1.0	2	0.3	0.0
11	Pref step as per Fig.2	3	10	1.0	2	0.3	0.3
12	Pref step as per Fig.2	3	10	1.0	2	0.3	-0.3

13	Pref step as per Fig.2	5	3	1.0	1	1.0	0.0
14	Pref step as per Fig.2	5	3	1.0	1	1.0	0.3
15	Pref step as per Fig.2	5	3	1.0	1	1.0	-0.3
16	Pref step as per Fig.2	5	3	1.0	2	0.3	0.0
17	Pref step as per Fig.2	5	3	1.0	2	0.3	0.3
18	Pref step as per Fig.2	5	3	1.0	2	0.3	-0.3
19	Qref step as per Fig.3	5	10	1.0	2	1.0	0.0
20	Qref step as per Fig.3	3	10	1.0	2	1.0	0.0
21	Qref step as per Fig.3	5	10	0.05	2	1.0	0.0
22	Qref step as per Fig.3	3	10	0.05	2	1.0	0.0
23	Qref step as per Fig.3	3	10	1.0	1	1.0	0.0
24	Qref step as per Fig.3	3	10	0.05	1	1.0	0.0
25	Qref step as per Fig.3	3	10	1.0	1	0.3	0.0
26	Qref step as per Fig.3	3	10	0.05	1	0.3	0.0
27	Qref step as per Fig.3	5	3	1.0	1	1.0	0.0
28	Qref step as per Fig.3	3	3	0.05	1	1.0	0.0
29	Qref step as per Fig.3	5	3	1.0	1	0.3	0.0
30	Qref step as per Fig.3	3	3	0.05	1	0.3	0.0
31	Voltage step as per Fig.4	5	10	1.0	2	1.0	0.0
32	Voltage step as per Fig.4	3	10	1.0	2	1.0	0.0
33	Voltage step as per Fig.4	5	10	0.05	2	1.0	0.0
34	Voltage step as per Fig.4	3	10	0.05	2	1.0	0.0
35	Voltage step as per Fig.4	3	10	1.0	1	1.0	0.0
36	Voltage step as per Fig.4	3	10	0.05	1	1.0	0.0
37	Voltage step as per Fig.4	3	10	1.0	1	0.3	0.0
38	Voltage step as per Fig.4	3	10	0.05	1	0.3	0.0
39	Voltage step as per Fig.4	5	3	1.0	1	1.0	0.0
40	Voltage step as per Fig.4	3	3	1.0	1	1.0	0.0
41	Voltage step as per Fig.4	5	3	1.0	1	0.3	0.0
42	Voltage step as per Fig.4	3	3	1.0	1	0.3	0.0
43	Grid frequency ramp up/down: ±2 Hz/s	3	3	1.0	1	0.3	0.0
44	Grid frequency ramp up/down: ±2 Hz/s	5	3	1.0	1	0.3	0.0
45	Grid frequency ramp up/down: ±2 Hz/s	5	3	1.0	1	1.0	0.0
46	Grid frequency ramp up/down: ±2 Hz/s	5	10	1.0	1	1.0	0.0

47	Grid frequency ramp up/down: ±4 Hz/s	3	3	1.0	1	0.3	0.0
48	Grid frequency ramp up/down: ±4 Hz/s	5	3	1.0	1	0.3	0.0
49	Grid frequency ramp up/down: ±4 Hz/s	5	3	1.0	1	1.0	0.0
50	Grid frequency ramp up/down: ±4 Hz/s	5	10	1.0	1	1.0	0.0
51	Grid frequency ramp up/down: ±4 Hz/s	5	3	1.0	2	1.0	0.0
52	Grid frequency ramp up/down: ±4 Hz/s	5	3	1.0	2	1.0	0.0
53	Grid voltage angle change equal to ±20°	3	3	1.0	1	0.3	0.0
54	Grid voltage angle change equal to ±20°	5	3	1.0	1	0.3	0.0
55	Grid voltage angle change equal to ±20°	5	3	1.0	1	1.0	0.0
56	Grid voltage angle change equal to ±20°	5	10	1.0	1	1.0	0.0
57	Grid voltage angle change equal to ±20°	5	3	1.0	1	2.0	0.0
58	Grid voltage angle change equal to ±20°	5	10	1.0	1	2.0	0.0
59	Grid voltage angle change equal to ±20°	3	3	0.05	1	1.0	0.0
60	Grid voltage angle change equal to ±20°	5	3	0.05	1	1.0	0.0

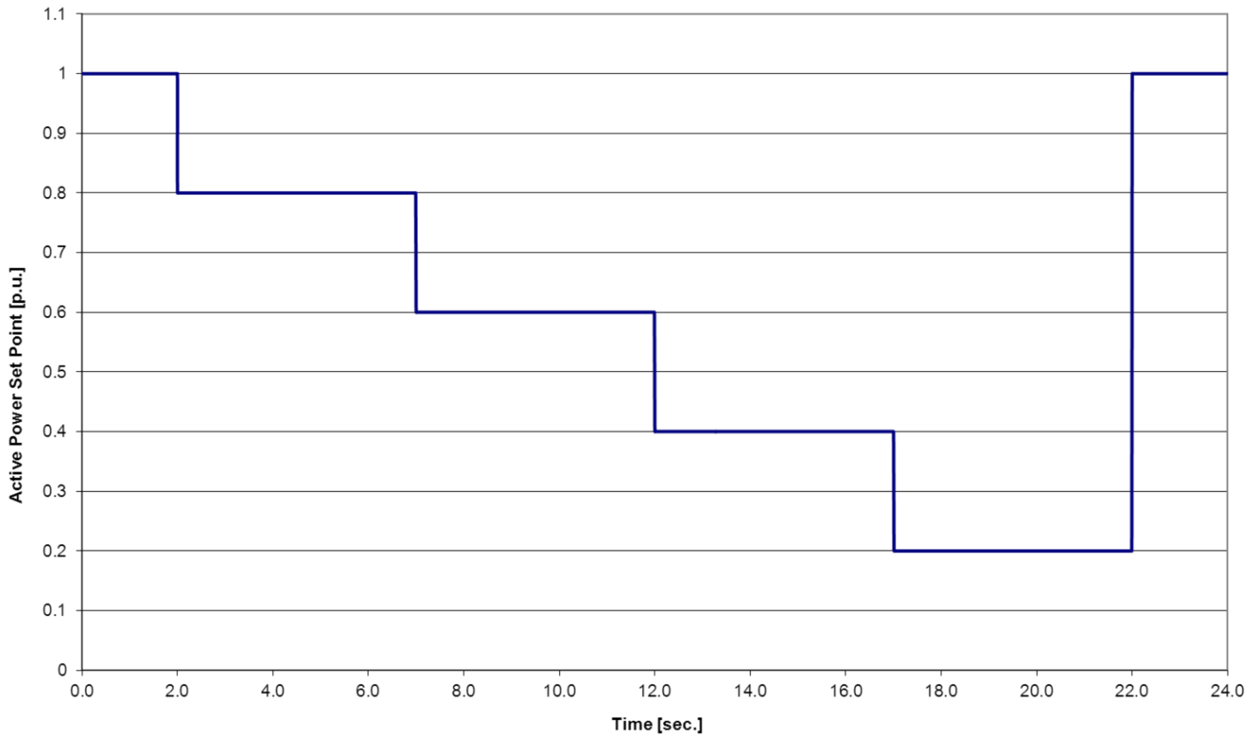


Figure 2 Active power set point step response test

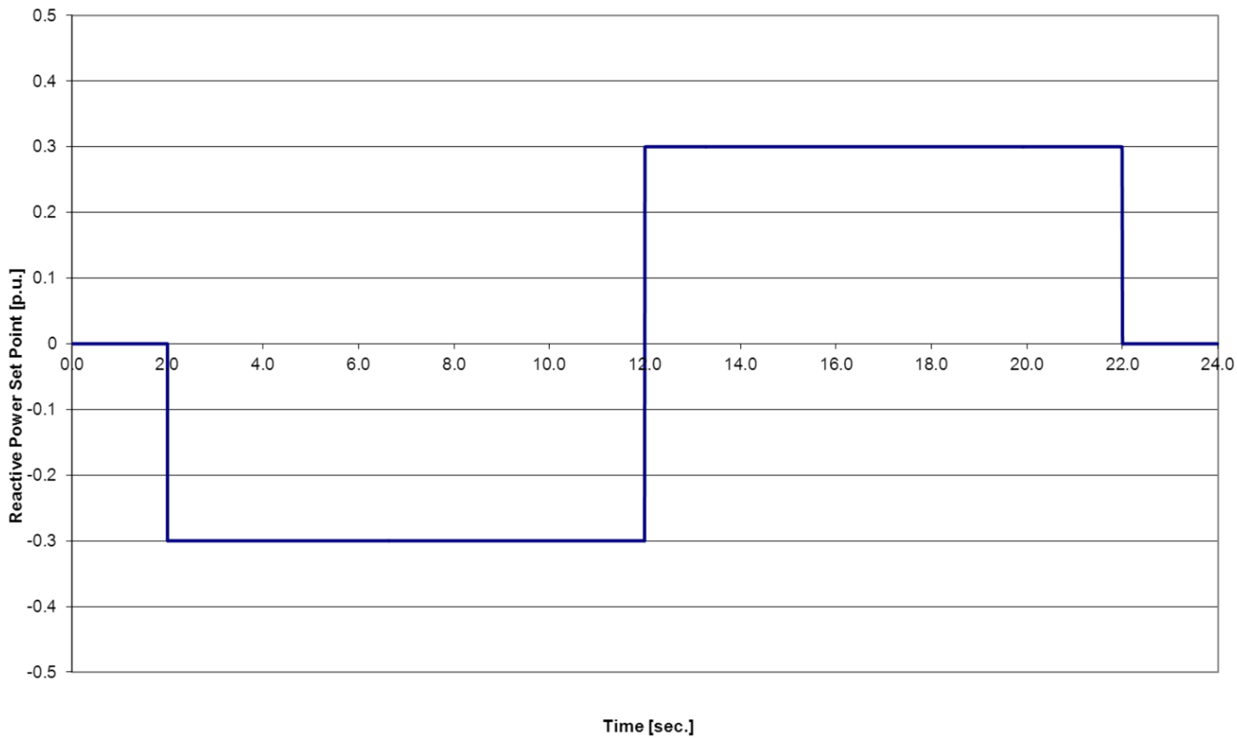


Figure 3 Reactive power set point step response test

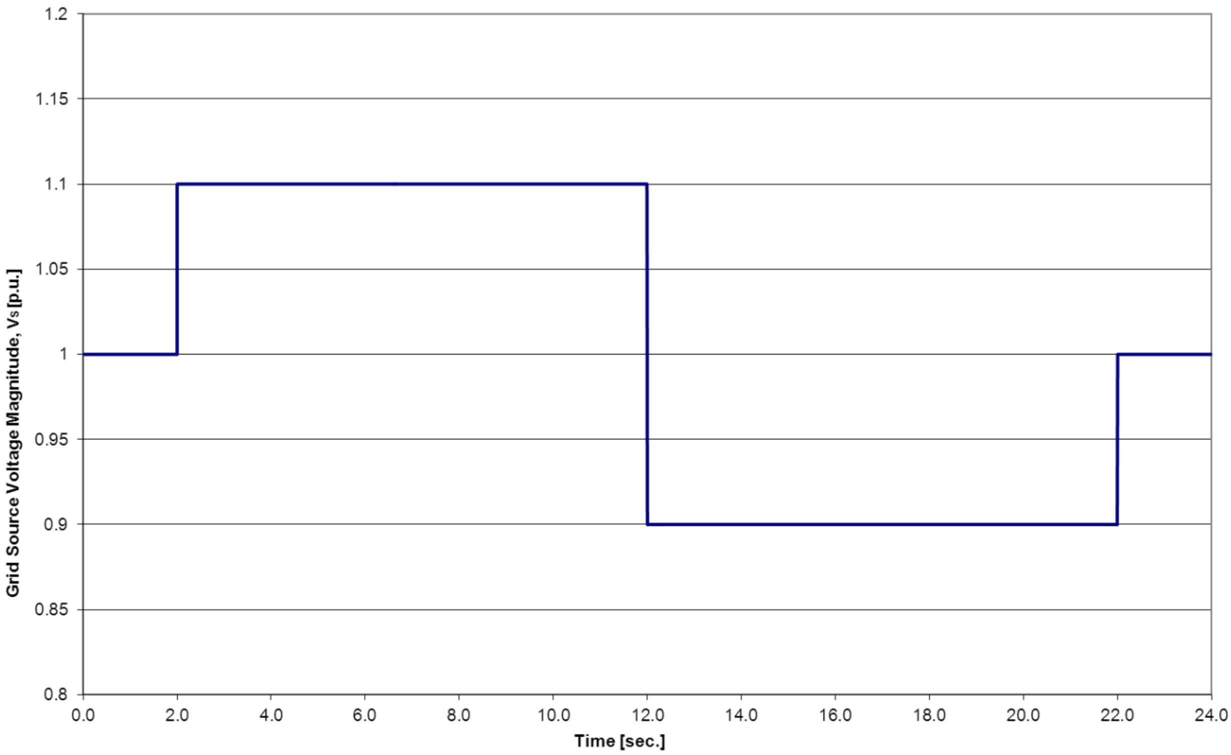


Figure 4 Voltage set point step response test and grid voltage disturbance test

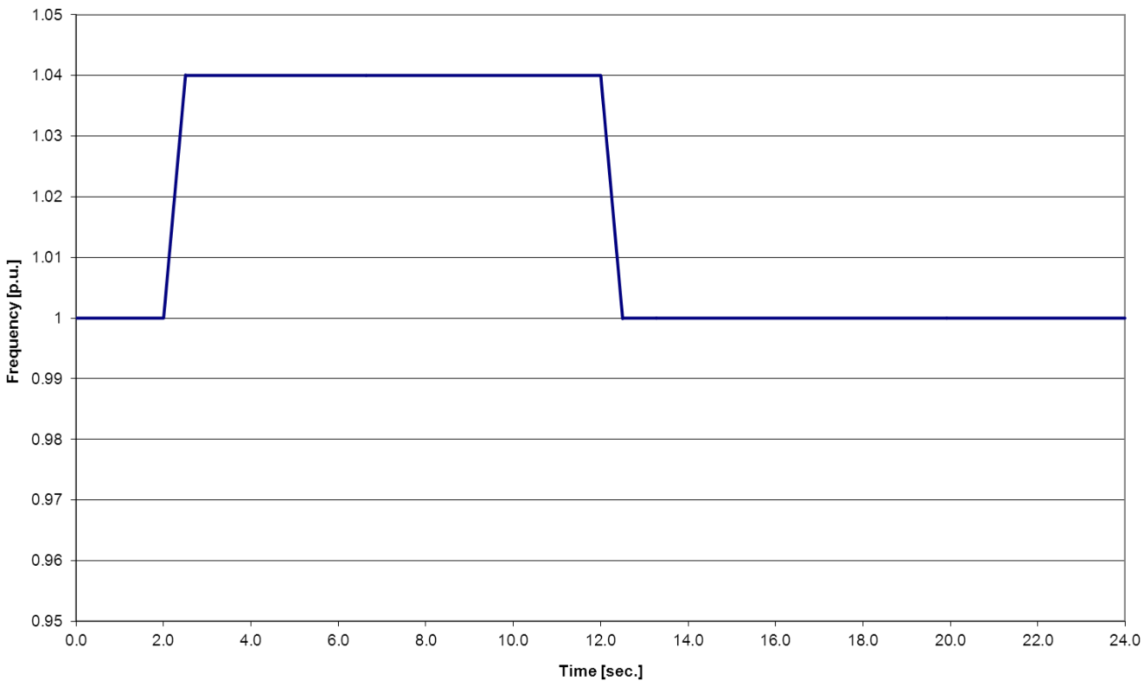


Figure 5 Rate of change of frequency test

4.2 Additional case studies for variable generation technologies with low voltage ride-through function

- For wind turbines with low voltage ride-through (LVRT) control (assuming the voltage threshold for activation of the LVRT control is k%), apply voltage step responses of (k+1)%, and (k-1) to ensure correct operation of the control without any oscillatory behaviour.

4.3 Additional case studies for synchronous generators

4.3.1 Excitation system limiters

- To test any limiter, control, or protection (such as under- and over-excitation limiters) in synchronous machines, adjust the operating conditions such that these controls can be activated. The following case studies are generally used to demonstrate correct operation of the limiters.
- **Case study 1**

  On-load Vref step responses over the capability of the plant at three load levels: minimum load, full load and one or more loading levels between:

  - 5% step in Vref starting from within the UEL and not operating into another limiter.
  - 5% step in Vref starting from within the generator's capability curve. The final settling value should be just within the UEL and should not enter into any limiter, including the UEL.
  - 5% step in Vref starting from within the OEL and not operating into another limiter.
  - 5% step in Vref starting from within the generator's capability curve. The final settling value should be just within the OEL and should not enter into any limiter, including the OEL.

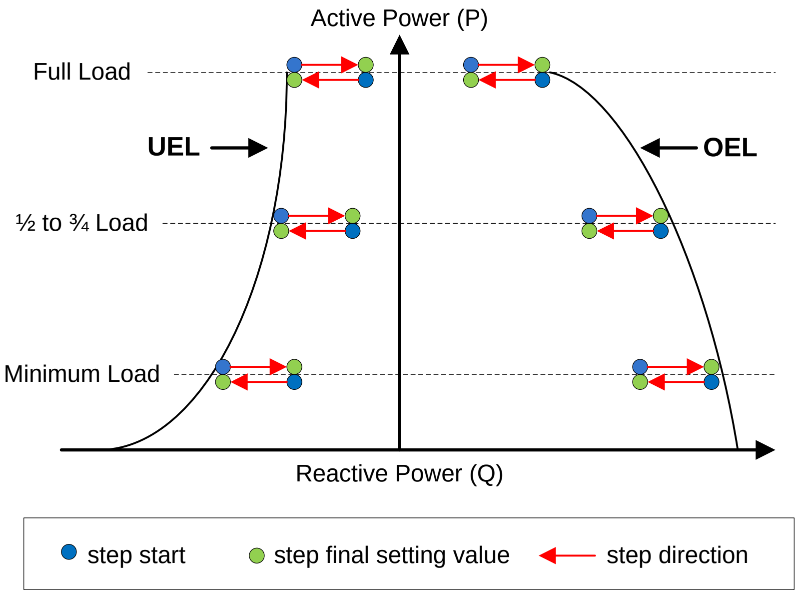


Figure 6 - Step response simulations without limiter operation

- **Case study 2**

  On load Vref step responses into excitation limiters over the capability of the plant at three load levels: minimum load, full load and one or more loading levels between. Step responses should be determined at each loading level for (see Figure 7):

  - 5% step in Vref, into the UEL.
  - 5% step in Vref, into the OEL.

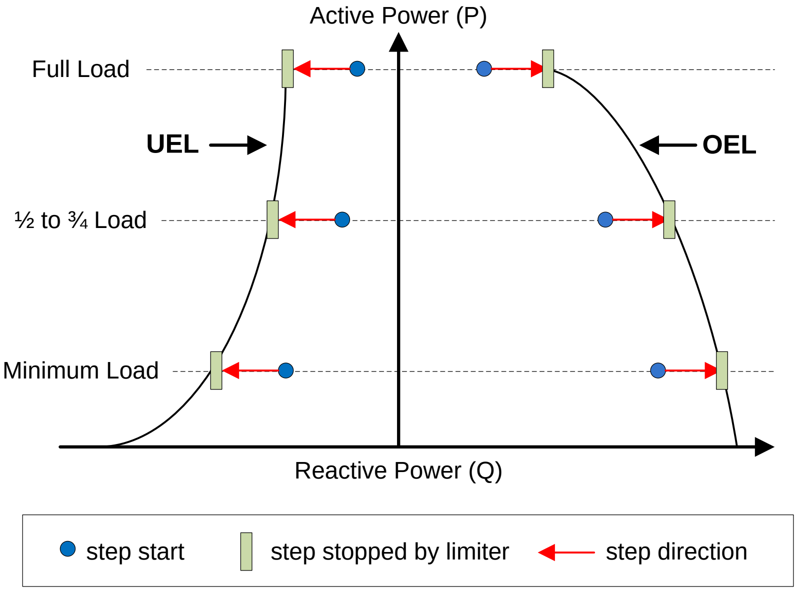


Figure 7 - Step response simulations into UEL and OEL

4.3.2 Governor

- To ensure there is no adverse interaction between the governor and PSS, the following case study is carried out
  - For operation at full load and unity power factor compare PSS performance for each governor operating mode, and with the governor switched out of service (constant mechanical power applied to the synchronous generator model). It is expected the governor does not materially change the overall performance.

4.4 Additional case studies for dynamic reactive support plant

- Similar tests specified in Section 6.3.1 are carried out; the only difference is that the device does not transfer any active power. The tests are not therefore repeated at various active power levels.
- When mode changes are involved within the operating range of the device, e.g., changeover from thyristor switched capacitor (TSC) mode to thyristor controlled reactor (TCR) for static var compensators (SVCs), the model acceptance testing will be carried out in the vicinity of the changeover point to confirm correct operation when changeover occurs.

4.5 Additional case studies for HVDC links

- Similar tests specified in section 6.3.1 are carried out.