A Method for Incorporating VSC-HVDC into the Overall Grid Voltage–Reactive Power Control Task

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Abstract— **This paper presents an approach for incorporating VSC – HVDC embedded in AC networks into the secondary voltage control strategy of the network, in addition to the dynamic voltage support requirements following grid short circuits. The models of the hierarchical two-stage slow and fast-acting controllers have been described in detail and the coordination of the steady state (set-point tracking) part and the component responsible for dynamic voltage support explained. Simulation examples demonstrate that the disturbance as well as the reference tracking components operate without interfering with the operation of one another, and thus confirm the possibility of incorporating VSC HVDC into the overall network var dispatch strategy.**

***Index Terms*--VSC-HVDC modeling; secondary voltage control; voltage support; offshore link; voltage source converter; wind farm.**

I. INTRODUCTION

The rapid increase of renewable energy based power generation and the ongoing implementation of smart grid concepts including the installation of new VSC based HVDC lines is changing the dynamic characteristics of the entire power system in significant ways. Transmission system operators are faced with the task of finding appropriate solutions for the dynamic problems brought about by these changes. The European codes for grid connection define the necessary performance requirements with the cross-border implications of these changes in characteristics in mind. The HVDC connections, for example, should not lead to the degradation of existing levels of system reliability. For national level implementations more detailed concepts have to be developed.

As is well-known, modern power electronic based converters and interfaces come with significantly enhanced control features that traditional power equipment are not capable of [1] . An obvious approach to contend with the changing system dynamic properties mentioned above is therefore designing solutions that exploit these new control capabilities to the fullest extent. One such example is integrating the advanced features provided by VSC HVDC into voltage and reactive power control of the AC network in which the line is embedded. Apart from their application in HVDC, VSC have been in use in large numbers for connection of wind turbine and solar photovoltaic power plants to the grid. Using the converter for UQ control in the AC part of the network is an established practice [2] , [3] , and currently applicable grid codes spell out aspects of the performance requirements. But the requirements in practice are more wide-ranging and multidimensional both in reach and response timeframe. Supporting the network to forestall a voltage collapse following a fault in the network requires a fast reactive current injection. On the other hand, responding to slow changes (set-point tracking) in the load flow calls for a correspondingly slow response affecting a wider geographic area within the grid. In addition to the coordinated realization of these objectives, the controller should also enable a smooth transition between successive steady state operating points and also between steady state and dynamic operating modes in a contingency situation and vice versa.

This paper introduces a scheme, in which the converter control in VSC HVDC stations is incorporated into the hierarchical grid voltage and reactive power (UQ) control strategy. The paper starts with the review of the control approaches for the sending- and receiving-end converters of the HVDC line. This will form the basis for identifying a suitable linkage between the proposed coordinated UQ control with the hierarchical network voltage control. This will be followed by detailed description of the proposed coordinated UQ control and the interface between the converter level and central controllers. The approach will then be demonstrated using a test network with embedded HVDC lines.

II. MODELLING AND CONTROL OF VSC-HVDC

The basic approach for modelling a VSC HVDC line in phasor-type studies is based on the assumption that the two converters, on either end of the HVDC line, can be represented by their respective Thévenin or Norton equivalent circuits.The control system acts on the two voltage sources to provide the prescribed terminal conditions by adjusting the magnitude and phase angle of the source voltage (current). In other words, regardless of the converter topology or complexity, the terminals of the VSC can be considered as voltage (current)

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sources behind the HVDC choke, which are connected to the rest of the network Fig. 1.

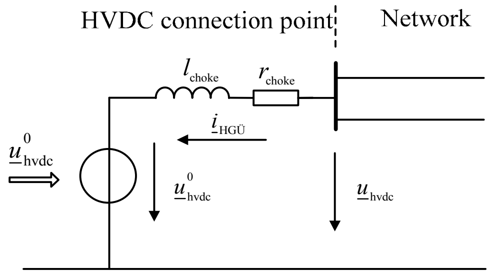

Figure 1. Thevenin equivalent circuit of the converter.

A brief overview of the control system is provided below to identify the access point to influence the operational behavior of VSC-HVDC vis-à-vis the AC grid connected to it.

A. The current control loop

Each VSC station has two degrees of control freedom, of which one is used for reactive power (or voltage) control, while the other is assigned to active power or DC voltage control via the inner current loop. While the control objectives in the outer loop may differ, the inner current control loop is the same for both the sending-end converter (SEC) and receiving-end converter (REC), except the fact that the reference value determination may be different.

The converter control is based on a vector control approach in rotating reference frames aligned with the respective terminal voltages. To perform the transformation into the voltage oriented dq reference frame, in the practical implementation of the control system and also in EMT type simulation environment a Phase-Locked Loop (PLL) for acquiring the voltage phase angle is needed. However, in RMS type simplified simulations the angle can be obtained directly from the simulation results. Nevertheless, even in RMS type simulation, it is recommended to consider the delay caused by the PLL using a first order delay block. Once the transformation into terminal voltage reference is performed active power is proportional to the d-axis and reactive power to the (negative) q-axis component of the converter current, and both can be controlled independently of one another. The control schema is shown in Figure 2. The middle part of the scheme shows the feed-forward part which represents the steady state relationship between internal (behind the choke) and terminal voltages. The main control task is performed by the feed-forward term. However, parameter and measurement uncertainties may result in control errors, which are compensated by the two PI blocks.

The hardware part of the converter is not modelled explicitly in the simulation, and therefore, the controller output voltage represents the voltage source injected into the grid directly.

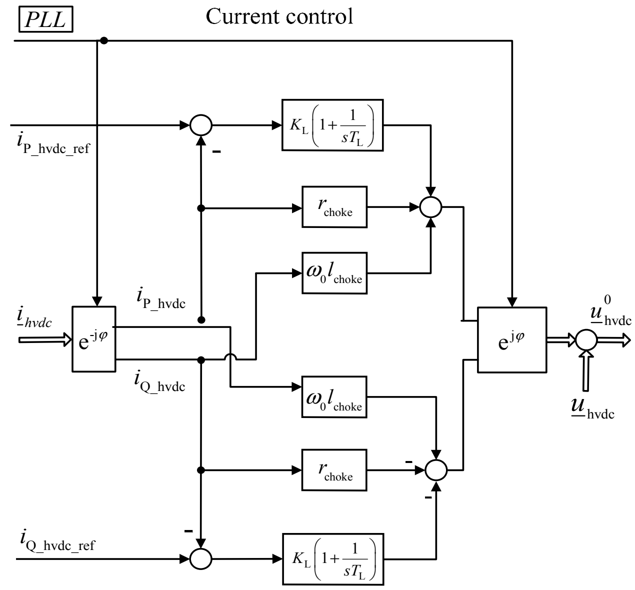

Figure 2. Converter current control.

B. Set-point determination for the current controller

As stated above, the set-points for the active and reactive current are passed on to the current controller from higher level controllers. The active current reference of the SEC is derived from the desired active power to be transmitted through the HVDC line. The task of the REC control is to ensure the transfer of the active power to the AC grid by maintaining the DC voltage level at the prescribed value, with the active current as the control variable. The reactive current control loop on both sides can be used to control the terminal voltage on the AC side and to support the grid voltage during faults.

Figure 3 shows the overall structure of the higher level control system which provides the references for the internal converter current controllers. Since the magnitude of the current is the basis for the converter rating, the available reactive current for voltage control depends also on the active current flow. As a result, the output of the local voltage controller must be maintained within the limits given by the reactive current available at the given operating point. This is achieved by limitation of the active and reactive reference currents. During normal operation the active current has priority, and in case of grid fault ($U < 90\%$), however, the priority is switched to reactive current to provide fast voltage support.

The figure (Figure 3) is augmented by SEC DC-voltage controller. This controller has a backup function in case the REC is unable to limit the DC voltage as a result of the current limit being reached. In such a scenario ($\Delta u_{DC} > 5\%$) SEC-DC voltage controller is activated and reduces the power injected into the network. This additional provision is necessitated by the fact that usually no DC-Link-Chopper is used in HVDC systems embedded completely in the onshore transmission grid, i.e. no offshore link.

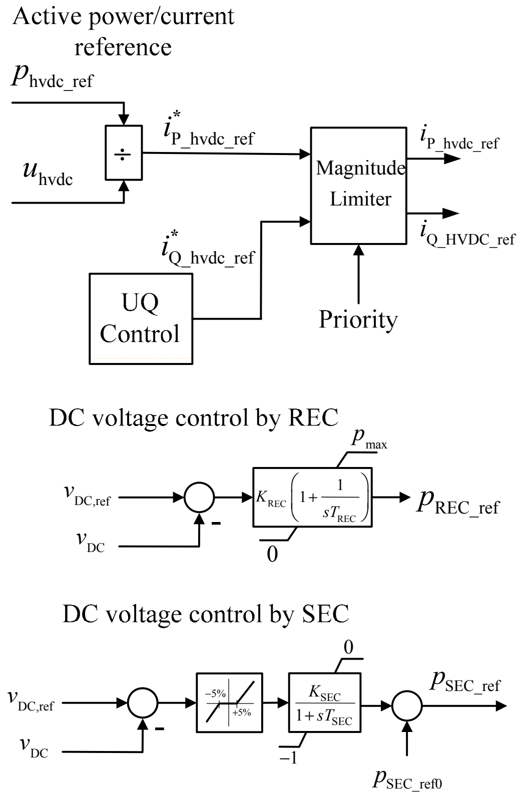

Figure 3. Determination of set-points for the current controller.

A current i_{max} of at least 1.25 p.u. should be possible for a duration not exceeding 500 ms. This overload capability enables, on the one hand, a reliable fault detection by the protection system and makes the voltage support following a fault more effective and sustained on the other. A voltage collapse resulting from severe short-circuit makes the exact determination of the voltage angle by the PLL and thus the targeted injection of reactive power difficult or even impossible. In such cases the reactive current supply for at least 500 ms can be based on the last available frequency and phase angle information. Blocking the inverter after a few milliseconds and as a result stopping the reactive current supply for the full duration of the fault should be avoided as it may affect the correct functioning of the network protection system.

III. INCORPORATION OF HVDC – VSC INTO THE HIERARCHICAL VOLTAGE – REACTIVE POWER CONTROL

Supporting the network to forestall a fault-induced voltage collapse in the network through fast reactive current injection is an established practice in converter control. The scheme proposed in this paper adds another higher layer that responds to voltage fluctuations arising from changes in network power flow configuration. The approach is based on a hierarchical control concept, in which an upper level slow-acting controller is responsible for tracking set-point changes dictated by system-wide exigencies, while a local fast-acting controller responds to major voltage dips where local action is required. In addition to the coordinated realization of these objectives, the controller is designed to ensure a smooth transition between the resulting successive operating points.

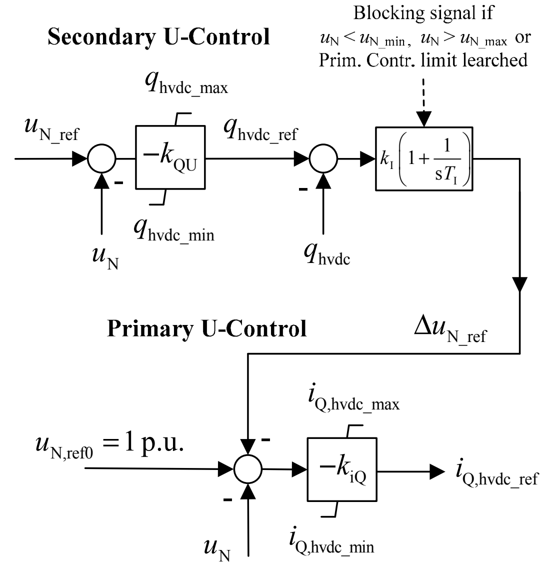

Figure 4. Structure of the hierarchical UQ control.

A. *Secondary (upper level) controller*

This controller can be implemented as a voltage, power factor or reactive power controller. In case the reactive power or power factor control options are used the reference values are directly passed on to the PI controller downstream. For implementation as a voltage controller, the reactive power reference is determined on the basis of a predefined and adjustable voltage versus reactive power functional relationship (droop characteristics). In this characteristic, a voltage value ($u = u_{\mathrm{Netz,ref}}$) is determined for which no reactive power injection is required. This value can be determined by the dispatcher on the basis of, for example, optimum power flow computation and may be updated at regular intervals. The resulting reactive power reference is then passed on to the adjoining PI controller with small or even zero proportional constant. The time constant is chosen in such a way that reactive power injection by the converter precedes and forestalls possible transformer tap movement, but not too fast in order to avoid undesirable interaction with other controllers downstream. Apart from the fact that there is no operational need for a fast transition between any two successive steady state operating points, a faster transition would possibly excite transient phenomena or cause undesired interaction between other controllers or the synchronous machines. The slow reactive power adjustment also permits the deployment of reactive power sources as per pre-specified reactive power deployment plan. Depending on the level of active power flow, reactive power provision using the HVDC line might be the most preferred among the available reactive power generation equipment. It is also recommended that the controllers exhibit an integral (I) behavior so that the control error becomes zero, in addition to the slow tracking of the set-point command from the dispatcher.

It makes operationally sense to implement the automatic adjustment of Q according to a defined and adjustable functional relationship with the voltage. A linear relationship represented by the proportional gain k_{QU} is proposed in this paper.

The proportional gain, i.e. the slope of the linear Q vs. U relationship, can be determined as:

$$k_{\mathrm{QU}} = \frac{\Delta q_{\mathrm{hvdc}}}{\Delta u_{\mathrm{N}}} \qquad (1)$$

For example, if the nominal power factor at rated power is equal to 0.95 the available reactive power for control is approximately 0.33 p.u.. Assuming this power is to be activated upon a voltage deviation of ±5%, the resulting proportional gain would be:

$$k_{\mathrm{QU}} = \frac{\Delta q_{\mathrm{hvdc}}}{\Delta u_{\mathrm{N}}} = \frac{0.333}{0.05} = 6.66 \text{ p.u.} \qquad (2)$$

Theoretically the slope can be varied as the power flow in the network changes. But this seems to be impractical and the operational advantages vis-à-vis the effort required for its implementation is not justifiable. When the reactive power limit (depending on active power) is exceeded the var limit can correspondingly be adjusted.

The reactive power reference (q_{ref}) may be set by the dispatcher depending on the actual load flow configuration in the network and the corresponding optimum power flow (OPF) results. Accordingly, this setting needs to be updated at regular intervals, say, every 15 minutes.

Once the required reactive power $q_{\mathrm{hvdc\_ref}}$ is determined by the OPF at the HVDC terminal, it follows for $u_{\mathrm{N\_,ref}}$:

$$u_{\mathrm{N\_ref}} = -\frac{q_{\mathrm{hvdc\_ref}}}{k_{\mathrm{QU}}} + u_{\mathrm{N}} \qquad (3)$$

The voltage u_{N} represents the desired voltage (corresponding to actual load flow and the resulting OPF). It should be emphasized again that the voltage $u_{\mathrm{N\_ref}}$ does not represent any desired target voltage to be brought about by the reactive power output, but is merely the voltage value at which no reactive power injection by the HVDC is required.

Reactive power limits $q_{\mathrm{hvdc\_,max}}$ and $q_{\mathrm{hvdc\_min}}$ represent steady state continuous values, which normally are functions of the operating point and other influencing factors such as active power, voltage, frequency, rating of the converter, etc. For choosing optimum limits the operational chart of the converter in form of a P – Q diagram considering the above-mentioned and other influencing factors is necessary.

As stated above, the main controller has a PI characteristic. The proportional term can be small or even zero. The controller receives the reactive power reference value $q_{\mathrm{hvdc\_ref}}$ as input. The time constant T_{I} is to be chosen in such a way that reactive power injection by the converter precedes and forestalls possible transformer tap change as stated above. Reasonable values for the time constant lie in the range T_{I} = 5 – 30 s. A value towards the higher end of the range tends to stabilize, while lower values may excite oscillations and cause interactions with other controllers. The lower level local voltage controllers can be assumed to act without time delay.

The (slow acting PI) controller is to be deactivated when the current limit of the converter is reached. Also, during periods of deep voltage sags or significant peaks a signal should be sent to deactivate the controller. The possible range may be a value outside ±10% of the rated value. During this period only the local primary controllers (to be discussed next) should remain active and deal with the voltage dip by injecting the appropriate reactive current. An example of such a scenario is a short circuit event. During this short period the output of the secondary controller remains almost constant due to the large integral time constant and the blocking signal if necessary.

B. Primary (local) controller

The primary fast acting converter level voltage controller should have a static proportional gain. The simplest implementation is represented by a proportional controller and receives the output of the secondary controller as an input signal. This block is primarily responsible for grid voltage support during large sudden voltage drops due to grid faults. The response of the primary controller must be fast (less than 30 ms rise time) and should have significant effect on the proper operation of the digital protection relays. This block is primarily responsible for grid voltage support during faults. Voltage boosting response by the controller must be based on locally sensed inputs and should not depend on remote quantities involving a communication channel. In terms of the controller characteristic, a proportional controller is more suited. The proportional gain of the local voltage controller can be determined as:

$$k_{\mathrm{iQ}} = \frac{\Delta i_{\mathrm{Q\_hvdc}}}{\Delta u_{\mathrm{N}}} \qquad (4)$$

The values may range from 2 – 10 p.u. A value of 2.0, for example, implies that a 50 % voltage deviation calls for 1 p.u. reactive current injection. This value, i.e. 2 p.u., is used as the default setting for wind turbines. Studies in [4] have shown that the natural physical response of conventional synchronous machines corresponds with the gain of approx. 4 p.u.

It is also possible to use a PD type controller in place of a simple proportional one. The transfer function in this case would be:

$$F(s) = k_{\mathrm{iQ}} \frac{1 + sT_{\mathrm{D}}}{1 + sT_{\mathrm{V}}} \qquad (5)$$

The time constants T_{D} and T_{V} can be obtained on the basis of a controller design procedure or tuned simply by trial and error. It is possible to conceive an even more complex controller. However, in steady state the controller should exhibit a proportional characteristic in steady state corresponding to gain k_{iQ}.

It seems to be operationally expedient to focus the fast primary control on the positive sequence voltage only (instead of implementing a more complex controller involving negative sequence) as any sustained positive sequence voltage dips may cause induction machines to stall and may adversely affect the operation of other voltage sensitive devices.

IV. TEST SYSTEM AND SIMULATION RESULTS

For the conceptual validation and testing the functionality of the control approach a test network shown in Figure 5 has been used. The network is composed of three areas interconnected by AC overhead lines, of which one link is replaced by a VSC HVDC lines in parallel to two 380-kV AC overhead lines. The network contains in all sixteen synchronous machines of different types. All controllers of the conventional synchronous machines have been included. The software package PSD (Power System Dynamics) developed at University Duisburg-Essen was used as a simulation tool.

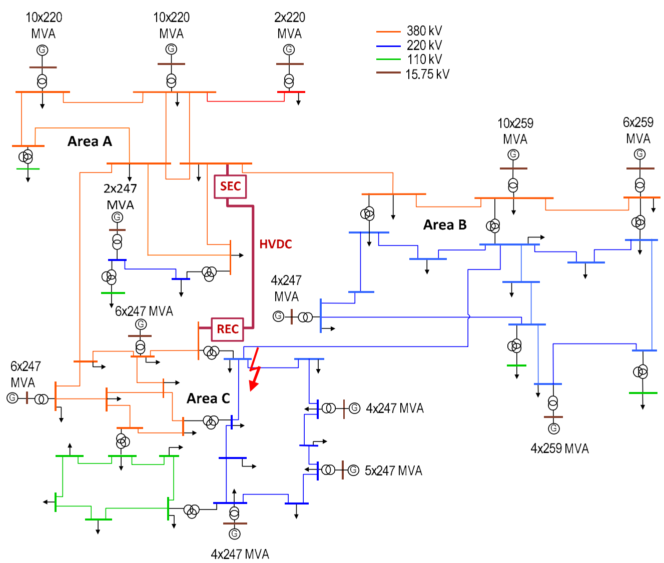

Figure 5. Test network.

A. Disturbance control behavior

For the investigation of the dynamic response of the fast primary voltage controller, a three-phase short-circuit of 150 ms duration was introduced as shown in Figure 5. The variations of terminal voltage, reactive and active power as well as changes in active power output of the synchronous machines are shown in Figure 6. The fault reduces the voltage at the AC bus connected to REC to approximately 0.4 p.u., whereas the effect on the SEC is much smaller due to the location of the short circuit.

Both controllers inject reactive power during fault in response to the voltage fluctuation (Figure 6, second plot). To be able to supply the reactive current required by the voltage control, active power transmission is temporarily reduced during the fault. The synchronous machines experience typical electromechanical oscillations after the fault. The HVDC terminals on the other hand return quickly to the reference value once the fault is cleared.

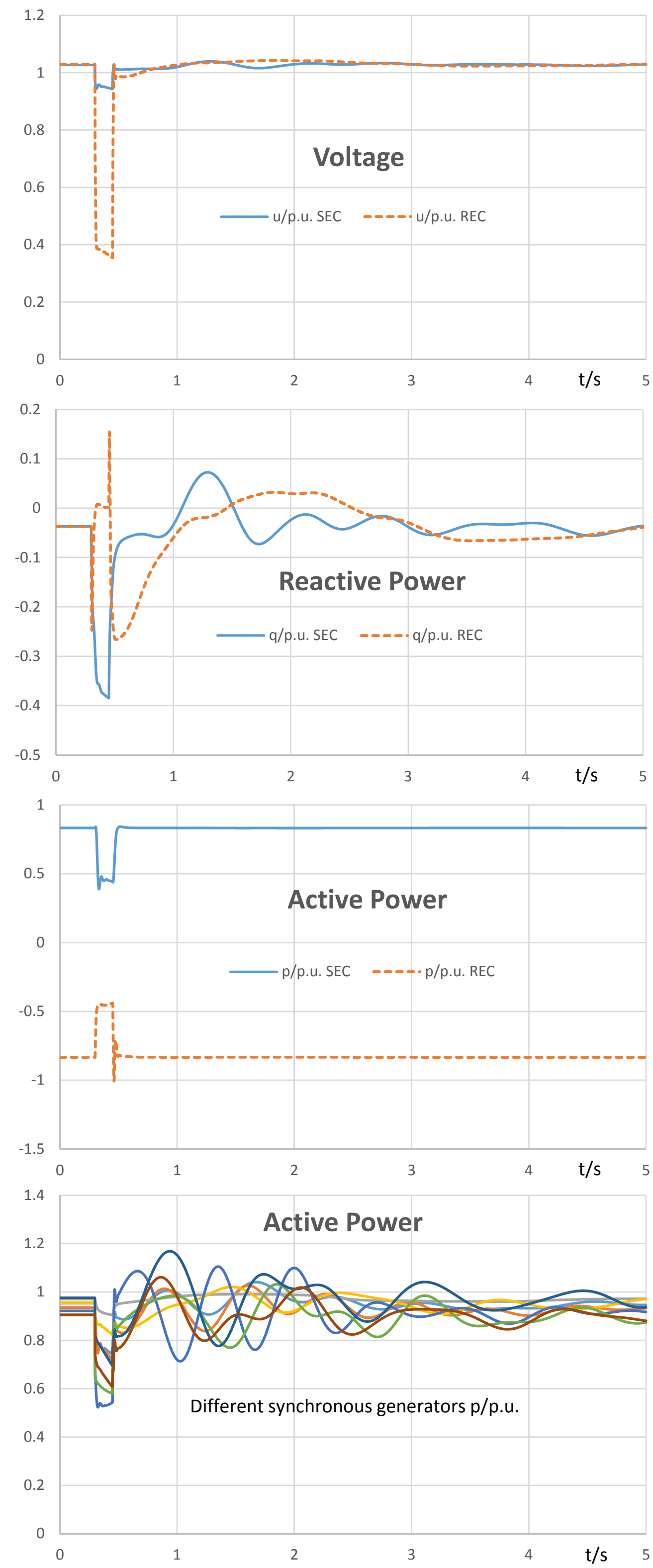

Figure 6. Disturbance response.

B. Set-point tracking behavior

It will be recalled that (cf. Figure 4) Δu_{ref} is the supplementary signal added to the voltage controller. Recall that the voltage at which no additional reactive power needs to be injected is defined as $u_{\mathrm{N\_ref}}$ and the actual voltage at the controlled bus is u_{N}.

To demonstrate the workings of the controller in terms of responding to steady state set-point changes, the following sequence of events has been set in motion at the SEC of HVDC:

- set $\Delta u_{\mathrm{ref}} = -6\%$ at approx. at t = 15 s
- set $\Delta u_{\mathrm{ref}} = +12\%$ at approx. at = 35 s
- set $\Delta u_{\mathrm{ref}} = -6\%$ at approx. at = 65 s
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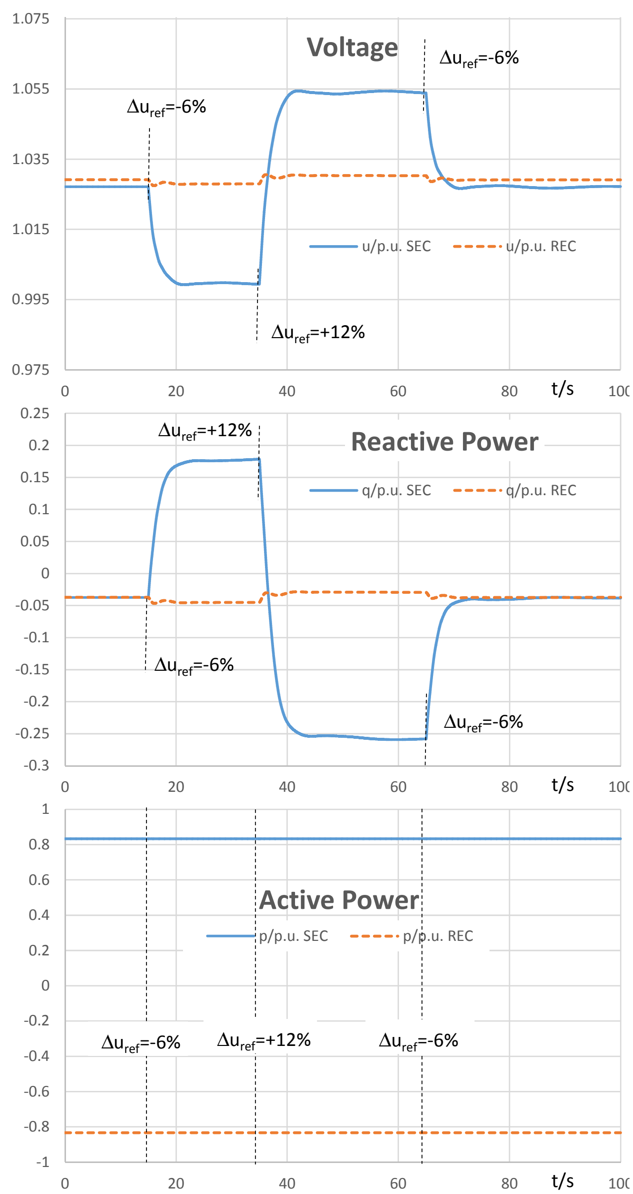

Figure 7. Set-point tracking – HVDC.

Figure 7 and Figure 8 summarize the resulting changes in some of the variables of interest following the set-point change commands. The voltage at the controlled AC bus follows the prescribed set-point changes listed above (Figure 7, upper plot). Also, the changes in the reactive power follow a similar pattern. As can be seen in Figure 7, the voltage set-point changes have no cross-coupling effect on the active power as it remains constant (lower plot, Figure 7). In other words, the active and reactive power control channels are almost completely decoupled.

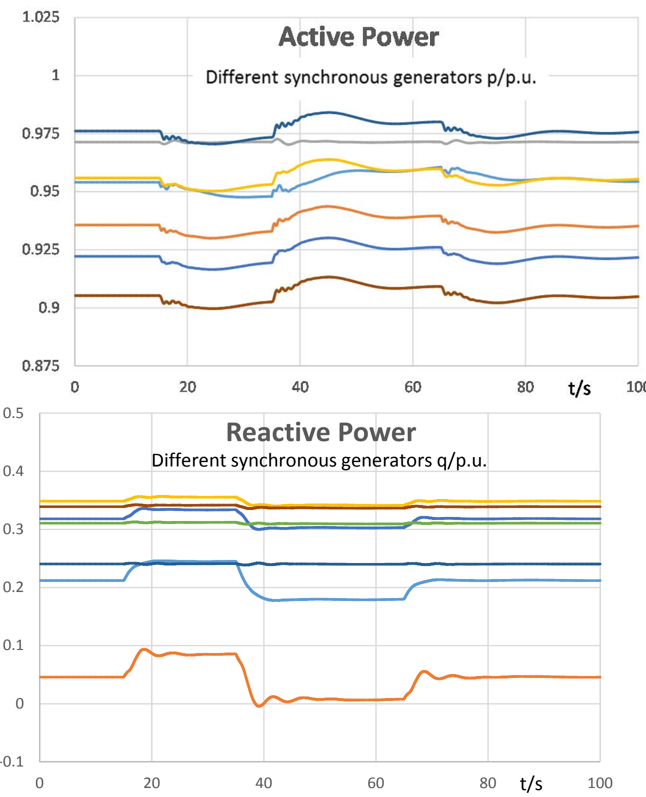

Figure 8. Effect on synchronous generators.

The response of the synchronous machines to the set-point changes is shown in Figure 8. The voltage set-point changes at the terminals of the HVDC influence the active and reactive power outputs the synchronous machines as can be seen in the plots. This is because the load is modeled as a constant impedance load. The loads change as the voltages at network buses change. In response to the load change the primary controller of the synchronous machines adjust the output power in response to the changed voltage profile in the network. The voltage controllers of the synchronous machines change the reactive power output to maintain the voltage set values amid changes in voltage profile in the network.

The figures shown above demonstrate the workability of the basic idea, namely the possibility of incorporating the HVDC line into the overall voltage control and optimum reactive power dispatch strategy of the entire network without impairing the fault ride through capability. In other words, the

VSC HVDC stations can be integrated into the secondary voltage control strategy of the entire network.

V. Conclusion

This paper introduces a hierarchical control concept for integrating the advanced features of VSC HVDC for voltage and reactive power control of the AC network in which the line is embedded. The approach is based on the analysis of the fundamental control requirements in steady state and under contingency situations. Fault ride-through capability and fast reactive power injection to support network voltage belong to the category of dynamic requirements, whereas steady state operational requirements such as set-point tracking involve slow changes. The proposed control approach enables the coordinated realization of these distinct objectives, and guarantees a smooth transition between successive steady state operating points and also between steady state and dynamic operating modes in a contingency situation. The steady state UQ control exhibits a droop characteristic and does not include any dead-band or discontinuity.

The simulation results using a test network that includes an embedded VSC HVDC line demonstrate the feasibility of the basic idea, namely the possibility of incorporating the HVDC line into the overall voltage control and optimum reactive power dispatch strategy of the entire network, in addition to the full implementation of fault ride-through and the dynamic voltage support requirements at the converter level.

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