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Assessing the Risk of Small Disturbance Instability in Mixed AC/DC Networks

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Abstract

This paper presents a risk-based Probabilistic Small-disturbance Security Analysis (PSSA) of a mixed AC/DC power system. The proposed approach establishes the probability density functions (*pdfs*) for the critical system modes based on the stochastic variation of operational system uncertainties (such as generation, loading, and HVDC line power flows). From these *pdfs* the probability of unstable operation or poorly damped oscillations in the system is determined. This analysis can be completed for any given loading scenario and level of uncertainty. Furthermore, the approach is utilized to establish risk-based power flow limits to ensure acceptable system performance.

Key Terms

Small-disturbance stability, dynamic security assessment, modal analysis.

Introduction

Power systems are increasingly being operated closer to the boundaries of stability in order to improve the efficiency and economics of their use. Stochastic renewable generation sources are replacing conventional generation, resulting in lower system inertia. Together with new types of system loads, this introduces more uncertain system parameters and operating conditions. It is essential to explore the effects of these uncertainties, and the risks that they introduce with respect to power system stability.

The security assessment of power systems is completed regularly to ensure that expected operating conditions will not endanger the system. These analyses often focus on static system criteria such as line overload, low voltages, or voltage instability margins [1–3]. Although these factors are undoubtedly of concern – especially with increasingly uncertain network parameters and operating conditions driven by markets and renewable generation – Dynamic Security Assessment (DSA) must also be performed to avoid wide-spread problems or even system collapse.

The consequences of transient events are highly dependent on incident-specific uncertainties, such as fault location, fault type, and fault clearing time. As such, much of the work on *transient*-DSA has focused on the fast detection (and suitable restorative control) of transient stability issues following the occurrence of the disturbance [4–6]. These transient instability predictors often use classification techniques and data collected by Supervisory Control And Data Acquisition (SCADA) systems and more and more by Phasor Measurement Units (PMUs) [5], [6].

Small-disturbance stability analysis relates to the ability of the system to maintain stability following the small changes which continuously occur in practical power systems. It is not dependent on the nature of the disturbance and can, therefore, be investigated using a probabilistic risk-based approach considering relevant uncertainties and system contingencies.

Low-frequency oscillations are inherent to large power systems [7] and have become more prevalent as networks have grown larger, seeking greater reliability and economy through interconnection and power transfer with neighboring systems. As complex conditions evolve within power systems, it is possible for these underlying oscillations to become unstable or very poorly damped, potentially leading to equipment disconnection and system collapse. There is growing interest in the identification of (potentially troublesome) oscillatory modes using real-time PMU data and signal identification techniques [8]. Although this work can provide accurate information about the current state of the system and facilitate real-time corrective control, it is not able to predict small-disturbance stability issues associated with future loading scenarios or operational decisions.

In [9], a Small-signal Security Assessment (SSA) tool is presented which uses advanced computational algorithms to complete deterministic studies. The driving forces for its development include potential online application and the determination of operating guidelines to alleviate oscillation damping problems within power systems. With increasing uncertainty, this deterministic approach may fail to accurately represent true system security levels. The development of a probabilistic SSA (or PSSA) will ensure that system risks are correctly quantified.

This paper presents methodology for a risk-based probabilistic small-disturbance security assessment of a large power system incorporating two VSC-HVDC systems and a large embedded wind farm. The uncertainty of the operating conditions is taken into account for forecasted loading scenarios in order to establish the probability of not only instability, but also persistent oscillations. PSSA is also used to establish operational limits to ensure that an acceptable level of system risk is not exceeded.

Methodology

The Probabilistic Small-disturbance Security Assessment (PSSA) is completed by simulating the stochastic variation around forecasted loading scenarios. Although reliable forecasts of aggregated system loading levels may be possible, variations in the loading at individual buses and the output from renewable energy generation are much less predictable and introduce a significant level of uncertainty.

System Uncertainties

The power system consists of a set Γ of uncertain parameters. Within this study, Γ includes the output from generation units, the loading (and load power factor) of system buses, and the power flow through VSC-HVDC systems. Where possible, the stochastic variation of each uncertainty γ can be based on historical data for the power system being studied.

The PSSA is completed by determining the *pdfs* for the critical system modes given the modeled uncertainty using small-disturbance linearization-based studies. Once the modal *pdfs* are produced, the probability of instability, and also of persistent oscillations can be assessed. Settling times for the oscillations can be estimated from the values of mode *damping* (eigenvalue real part σ) calculated during small-disturbance studies.

Quantifying Risk

The risk that a power system is exposed to is related to the probability of an event occurring, and the subsequent severity and consequences of the event [1], [3]. Simulation of the stochastic uncertainties based on their given distributions facilitates the calculation of the probabilities of given modal damping. To assess the severity, a number of measures could be utilized. Economic risk analysis is particularly valuable as it allows various system risks to be readily compared. However when looking at complex system phenomena such as small-disturbance rotor angle instability, apportioning the economic impact of a catastrophic event to various system controls and schemes is extremely difficult.

Within this work, severity is quantified using a technical measure – the length of time taken for system oscillations to settle. This measure can easily be used by different systems operators who can set the bounds on what is considered acceptable based on the specific system they control, and the regulations under which they operate.

Oscillation Settling Times. Assuming a standard second-order system response (as described by an oscillatory mode $\lambda = \sigma \pm j\omega$), the settling time T_S for the oscillations is dependent on the tolerance (*tol.*) and damping according to (1). Also, shown in (1) is the final numerical equation if the time taken to settle to within a 5% tolerance of the maximum deviation is required.

$$T_S = \frac{\ln(tol.)}{\sigma} = \frac{\ln(0.05)}{\sigma} = \frac{-3.00}{\sigma} \qquad (1)$$

Using (1), a set of bounds for modal damping σ can be established relating to various settling times. A damping value of –0.15 relates to a settling time of 20 s, and when damping is $\sigma = -0.05$, the settling time is $T_S = 60$ s. The instability boundary is at $\sigma = 0$.

Risk Matrix. Within this study, a discrete risk matrix has been defined in order to translate *probability* and *severity* into a system risk level. A three-tiered structure where risk is defined as *Low*, *Moderate*, and *Severe* has been developed and is presented as Table 1. The probability ranges presented within this risk matrix have been selected to represent frequencies of events with reasonable granularity. Such probabilities should be modified by system operators to accurately represent tolerable operating behavior in specific power systems.

A risk level will be determined for each range of oscillation settling times: *unstable*, *>60 s*, *20–60 s*, and *<20 s*. The total system risk level is simply the highest risk level identified for any of the given ranges.

The use of a risk matrix such as this allows fast translation of detailed results to a representative risk level based on predetermined criteria. Clearly, this risk matrix (Table 1) is purely illustrative and would need to be designed based on the levels of electromechanical oscillations permissible within a given power system.

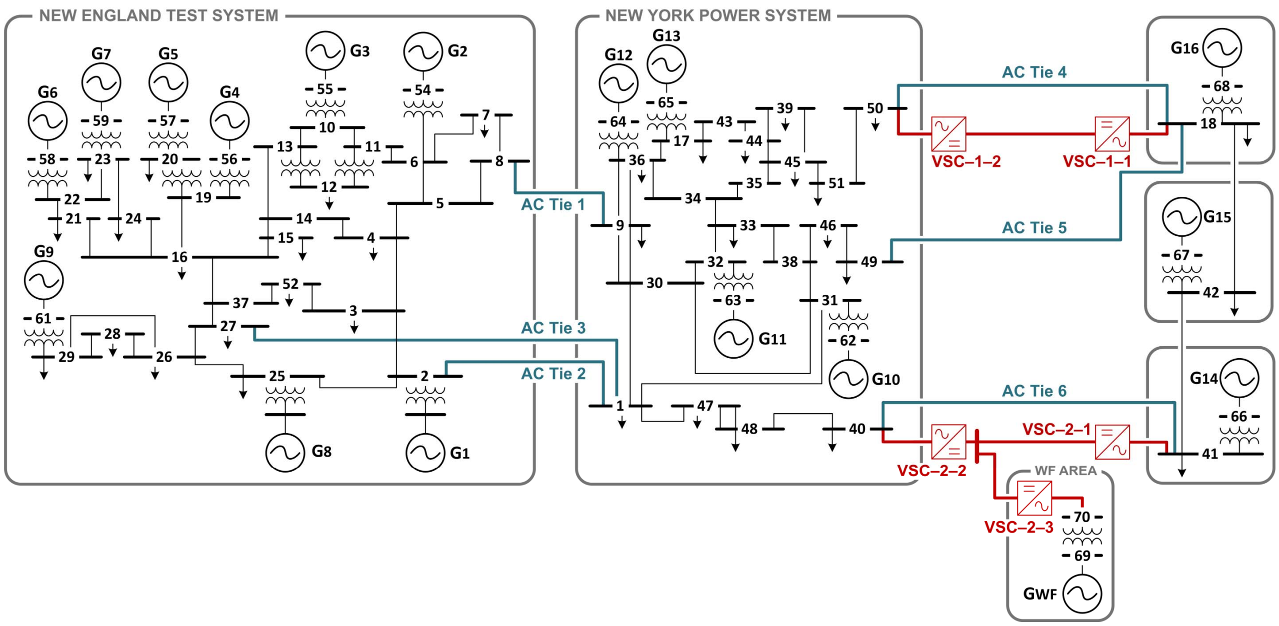


Fig. 1: NETS & NYPS network including one point-to-point VSC-HVDC line and a three-terminal VSC-MTDC grid incorporating a 500 MW wind farm.

Table 1: Risk matrix for analysis of probabilistic small-disturbance security assessment (PSSA) results.

		Settling Time of Oscillations			
		Unstable	**>60 s**	**20–60 s**	**<20 s**
Probability	**0%**	Low	Low	Low	Low
	0–1%	Moderate	Low	Low	Low
	1–5%	Severe	Moderate	Low	Low
	5–20%	Severe	Moderate	Low	Low
	20–50%	Severe	Severe	Moderate	Low
	50–100%	Severe	Severe	Moderate	Low

Test System

The risk-based PSSA has been tested using a modified version of the New England Test System and New York Power System (NETS & NYPS) shown in Fig. 1. System analysis and simulations are all performed within the MATLAB/Simulink environment making use of modified MATPOWER [10] functions to perform initial load flows.

AC System Details

Generators G1–8 are under slow DC excitation (IEEE-DC1A) only, whilst G9 is equipped with a fast acting static exciter (IEEE-ST1A) and a Power System Stabiliser (PSS). The remaining generators (G10–16) are under constant manual excitation. All generators are represented by full sixth order models. Loads are modeled as constant impedance. Full system details, generator and exciter parameters are given in [11] with PSS settings for G9 taken from [12].

The generator G10 within the NYPS area of the test network has been de-rated from its standard nominal power output of 500 MW to 250 MW. The dynamic parameter values for G10 have been scaled accordingly.

VSC-HVDC System Details

Two VSC-HVDC systems have been introduced into the test network in order to support power flow through the most heavily loaded AC ties: *line 18–50* and *line 40–41*. Each converter station is modeled as an injection of active and reactive power [13]. As these studies are concerned with electromechanical oscillations with typical frequencies of 0.2–2.5 Hz, the fast dynamics associated with semiconductor device switching operations can be neglected [13]. Converter station controllers are included as described in [14] and DC lines are modeled as presented in [15].

The first system (*VSC–1*) is a point-to-point VSC-HVDC line connected in parallel with *line 18–50*. The converter connected to bus 18 (*VSC–1–1*) regulates the DC voltage. The converter connected at bus 50 (*VSC–1–2*) controls active power injected into the AC systems from the VSC-HVDC line. At both converters, reactive power injection is regulated at zero.

The second system (*VSC–2*) is a multi-terminal HVDC (MTDC) grid consisting of three converter stations. *VSC–2–1*, connected to bus 41, acts as a slack converter and regulates the DC voltage. *VSC–2–2* is connected to bus 40 and controls the active power injected into the AC system by the VSC-MTDC system. The third converter (*VSC–2–3*) is connected to a large wind farm. Active power injected into the MTDC system is determined by the output of this wind farm, and reactive power is supplied as required to support the renewable generation.

Wind Farm System Details

A large 500 MW wind farm in connected to the test network through the *VSC–2* MTDC system, as shown in Fig. 1. For the PSSA performed within this study it has been assumed that the power output from the wind farm will be constant during each individual investigated operating point (at which the system is linearized and small-disturbance analysis is completed).

The converter to which the wind farm is connected (*VSC–2–3*) operates using *frequency–AC voltage* control. It has been assumed that the converter is able to maintain a constant AC voltage such that all power produced by the wind farm is transferred to the VSC-MTDC system. This assumption is valid as long as the DC voltage does not deviate considerably. This is an acceptable simplification as the work presented is focused on the small-disturbance rotor angle stability of the mixed AC/DC system, and not on the fast transient performance of the VSC-HVDC systems.

Nominal System Performance

Small-disturbance analysis has been completed for the system as described at the nominal operating point given in [11]. The wind farm power output is 500 MW and active power injection into the AC network from *VSC–1–2* and *VSC–2–2* is 500 MW and 700 MW respectively. This reveals that the test system displays four poorly damped low frequency electromechanical oscillations as detailed in Table 2. All other electromechanical modes are adequately damped.

Table 2: Low frequency mode details for the test system at the nominal operating point.

Mode	Eigenvalue $\lambda = \sigma \pm j\omega$	Damping Factor *(%)* $\zeta = -\sigma / \sqrt{\sigma^2 + \omega^2}$	Frequency *(Hz)* $f = \omega / 2\pi$
Mode 1	–0.137±*j*2.567	5.31	0.409
Mode 2	–0.126±*j*3.191	3.96	0.508
Mode 3	–0.160±*j*3.906	4.10	0.622
Mode 4	–0.242±*j*4.986	4.87	0.791

Application of Probabilistic Small-disturbance Security Assessment

Within this paper, a number of studies are presented to demonstrate the different benefits of completing a probabilistic small-disturbance security assessment. The analysis is completed for two forecasted loading scenarios – evaluating the risk of small-disturbance stability issues based on the stochastic variation around the given operating conditions. The PSSA is also used to establish a probabilistic risk-based limit on power flow between two areas of the network. By pre-determining the risk of persistent or unstable oscillations within the network, it is possible to avoid risky scenarios during system operation.

Risk during Forecasted Loading Scenarios

Two forecasted loading scenarios are considered for the modified NETS & NYPS test network. Both situations consist of an increase in load within the NYPS region and standard nominal loading for the remainder of the network. This increased demand is met by the generators in the NETS area, resulting in increased power flows through the NETS→NYPS tie lines (AC Ties 1, 2 and 3).

The considered scenarios are selected as a *5% increase*, and a *6% increase* in NYPS loading – relative to the nominal base case given in [11]. These loading scenarios represent future stressed operating conditions and have been selected to highlight the difference that a small increase (from *5%* to *6%*) can have on the risk of stability issues within power systems. Table 3 details the active power flow through each inter-area AC tie for each of these loading conditions. Also shown is the percentage difference compared to the *base* loading. It is clear that the increase in loading is met from the NETS region and the power flows through AC ties 4–6 (from regions G14 and G16) are largely unaffected.

Table 3: AC tie line power flows for increased NYPS loading when supplied from NETS generators.

AC Tie		Active Power Flow Through AC Ties *(MW)*				
		Base	***5% increase***		***6% increase***	
1	**8–9**	425	616	+45%	654	+54%
2	**2–1**	260	444	+71%	480	+85%
3	**27–1**	25	56	+124%	63	+152%
4	**18–50**	759	780	+3%	784	+3%
5	**18–49**	323	315	–2%	313	–3%
6	**41–40**	310	296	–5%	294	–5%

Variation in System Operating Conditions. For each of the given scenarios, generation is modeled as stochastic with normal distribution with a small standard deviation of 5% at $3\sigma_\gamma$. Active power load demand and load power factors at each bus are normally distributed, again with standard deviation of 5% at $3\sigma_\gamma$.

VSC-HVDC power injection values are modeled as uniformly distributed around the given nominal values of 500 MW for VSC–1–2 and 700 MW for VSC–2–2. The uniform distribution is set as ±150 MW at each node. Historical data should be used where possible to inform the selection of distributions for stochastic variables. For this study, in the absence of practical data, a uniform variation represents plausible VSC-HVDC power flow variations around the nominal power transfer.

Generation from the wind farm (GWF) is determined by the wind speed v. For these studies, wind speed is a random variable following a Weibull distribution, as described by (2).

In (2), k is the *shape parameter* and φ is the *scale parameter* (commonly signified by λ but called φ here to avoid confusion). In this study, values for these parameters were sourced from [16] with $k = 2.2$ and $\varphi = 11.1$. The wind farm consists of 100 Areva M5000 5 MW turbines [17]. The total power produced is calculated by selecting a wind speed from the given distribution, determining a single turbine's output according to its power curve, and then finally scaling the individual turbine output to the capacity of the whole wind farm (neglecting wake effects).

$$f(v) = \begin{cases} \frac{k}{\varphi}\left(\frac{v}{\varphi}\right)^{k-1} e^{-(v/\varphi)^k} & v \geq 0, \\ 0 & v < 0. \end{cases} \tag{2}$$

5% Increase Case. The spread of Modes 1–4 seen following 5000 Monte Carlo simulations is shown in Fig. 2. Also shown on this figure are the boundaries for the settling times of oscillations as calculated using (1). It can be seen that Mode 4 is well damped in all cases with oscillations settling in less than 20 s. From Fig. 2, it can also be seen that the oscillations associated with Modes 2 and 3 will settle in 20–60 s. Mode 1, the lowest frequency electromechanical oscillation, is the critical mode within the system, and will persist for longer than 60 s for many of the considered operating conditions. Furthermore, it can be seen that in some circumstances, Mode 1 becomes unstable.

The *pdf* for the damping (eigenvalue real part σ) of the critical Mode 1 is shown in Fig. 3 using a kernel density estimate [18]. Also shown in this figure are the probability of oscillations lasting 20–60 s, over 60 s, and the probabilities of small-disturbance instability: $P(20-60)$, $P(>60)$, and $P(unst.)$ respectively. Additionally, the resulting risk levels for the various oscillation length ranges from Table 1 are shown.

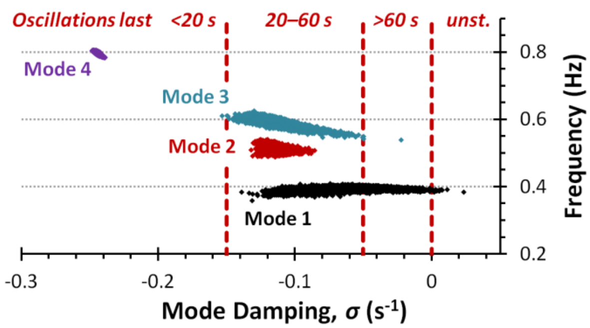
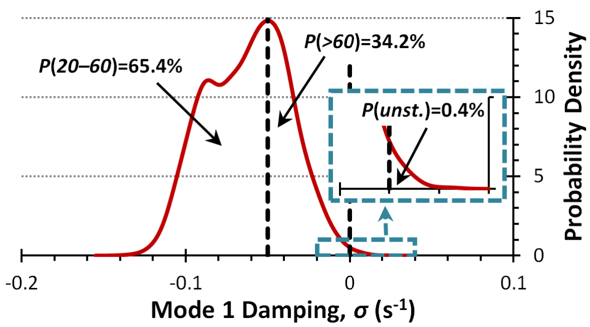


Fig. 2: Modal spread of Modes 1–4 for the 5% increase case due to stochastic variation in operating conditions.

Fig. 3 can be interpreted and converted into risk levels by comparing the probability of oscillations of varying lengths with the threshold probabilities in the risk matrix (Table 1). The 65.4% probability of 20–60 s oscillations relates to a *moderate* risk, as does the 0.4% probability of instability. However, the 34.2% probability of persistent oscillations lasting longer than 60 s represents a *severe* risk. The overall probabilistic small-disturbance security risk for this loading scenario is therefore *severe* and mitigating solutions should be sought.

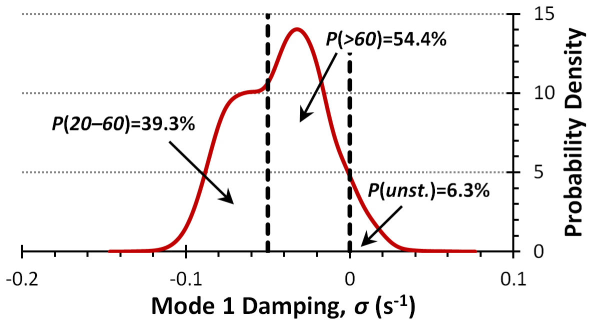


	Settling Time of Oscillations			
	Unstable	>60 s	20–60 s	<20 s
Risk	Moderate	Severe	Moderate	Low

Fig. 3: *Pdf* for critical Mode 1 damping values and resulting risk levels for the *5% increase* scenario.

6% Increase Case. Increasing the loading within the NYPS area by 6% results in the *pdf* of the damping of Mode 1 shown in Fig. 4. This loading condition can be seen to display *severe* risk of not only oscillations longer than 60 s, but also of instability (6.3%). It is evident that the small-disturbance security risk is rising as the active power transfer between the NETS and NYPS regions is increased.

Both of the example loading scenarios presented above display unacceptable *severe* risk of small-disturbance stability problems. In a practical system, completion of the PSSA as shown would highlight this fact and alert operators about the need for mitigation techniques.



	Settling Time of Oscillations			
	Unstable	**>60 s**	**20–60 s**	**<20 s**
Risk	Severe	Severe	Moderate	Low

Fig. 4: *Pdf* for critical Mode 1 damping values and resulting risk levels for the *6% increase* scenario.

A possible mitigation solution is to use Power Oscillation Damping (POD) controllers which can be installed on generators, FACTS devices, or HVDC systems. Such controllers utilize local or global signals and modulate power injection accordingly to damp persistent oscillations.

A further mitigation technique is to limit the power flow from NETS→NYPS to ensure that an acceptable level of risk is not exceeded. This requires identification of the small-disturbance security risk-based power flow limit.

Risk-based Power Flow Limit

The power flow limit can be calculated by iteratively varying the power flow from the NETS area to the NYPS area until the boundary of acceptable risk is identified. Within this study, it is assumed that a *moderate* risk determined using Table 1 is acceptable – whereas *severe* risk is not.

Each operating scenario (around which stochastic variation occurs) is calculated using a uniform increase across all loads within the NYPS region. This increase is supplied by the generators in the NETS area as before. Other options for modeling load increase, change in operating scenarios, are equally possible without any loss of generality.

A simple *divide and conquer* iterative process is used within this study with the following steps:

1. Initial bounds are set based on conditions which are known to display acceptable risk (*base* loading) and unacceptable risk (*5% increase*).
2. The midpoint is selected as the test condition for which a PSSA is completed, using 5000 simulations to ensure accuracy.
3. The *pdf* of the critical Mode 1 is produced and probabilities for oscillations of varying length (as defined by the risk matrix) are determined.
4. From the calculated probabilities, the overall risk level for the test condition is determined. The appropriate bound (for acceptable, or unacceptable, risk) is updated as the given test condition.
5. Steps 2–4 are repeated until the limit in terms of NETS→NYPS active power flow is determined to a resolution of 1 MW.

This process was completed for the test system. It was found that the persistent oscillations lasting longer than 60 s were most likely to present a *severe* risk and therefore $P(>60)$ needed reducing to a *moderate* risk level. From the risk matrix (Table 1), it can be seen that the limit on acceptable (*moderate*) risk is $P(>60) < 20\%$.

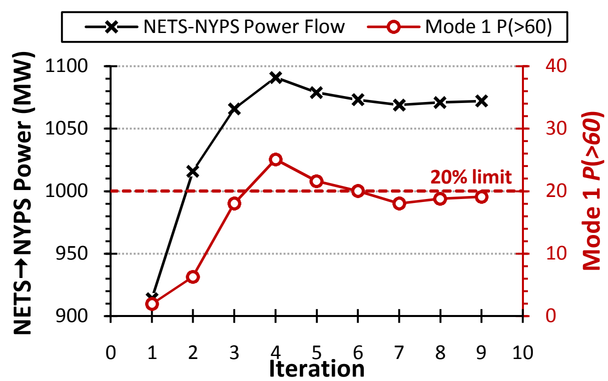
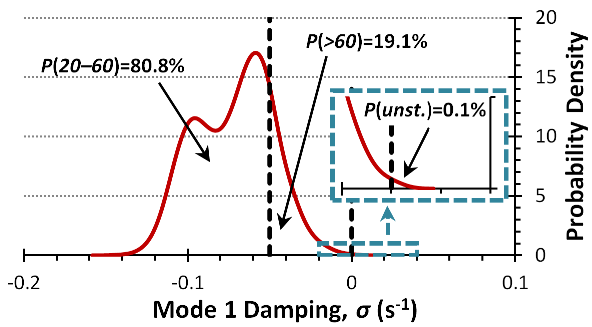


Fig. 5: Iterative process to identify the small-disturbance stability risk-based limit on NETS→NYPS power flow.

Fig. 5 displays the results of the process described above where it is evident that the risk-based power flow limit is determined after nine iterations. A limit on NETS→NYPS power flow of 1072 MW ensures that the overall system small-signal security risk does not exceed *moderate*. This is equivalent to an increase in NYPS loading of 4.443%. Also shown in Fig. 5 is the evolution of $P(>60)$ for each iteration of the process. It is clearly evident that the final solution provided maintains $P(>60)$ value below 20%, and therefore a *moderate* system risk level.

The *pdf* for damping of Mode 1 for this *power flow limit* scenario is presented in Fig. 6. It is clear that the overall system level of risk is *moderate*, and that the previously seen *severe* risks are no longer present. The use of a probabilistic risk-based approach towards establishing this stability limit allows greater system utilization as the likelihood of events are also taken into account – not only their severity. Therefore the system operation is not limited to prevent the small probability of instability that is seen (0.1%) as this is tolerably low.



	Settling Time of Oscillations			
	Unstable	>60 s	20–60 s	<20 s
Risk	Moderate	Moderate	Moderate	Low

Fig. 6: *Pdf* for critical Mode 1 damping values and resulting risk levels for the *power flow limit* scenario.

It should be noted that this process required nine iterations, each using 5000 simulations. Therefore a total of 45,000 simulations were needed in order to establish this power flow limit, requiring extensive computational resources.

Conclusions

The proposed risk-based probabilistic small-disturbance security assessment represents a novel application of uncertainty analysis for power system stability studies. It has been shown that the coupling of probabilistic studies and risk matrices can provide guidance to systems operators about the potential for problematic oscillatory system conditions. The PSSA was also used with an iterative approach in order to establish a risk-based bound on power flow in order to keep the system risk level within acceptable limits.

This methodology can be extended further in order to allow online applications. Efficient sampling methods or analytical techniques could significantly reduce the computational requirements so that the risks associated with system contingencies or control room decisions can be assessed. Furthermore, it is possible to use continuous severity functions rather than discrete matrices which allow for improved quantification of the level of risk for various conditions. These must, however, be carefully designed to ensure that they accurately represent the system operator's perceived risk level.

Appendix

VSC-HVDC Systems & Controller Data

All data provided is based on a 100 MW HVDC base (with $V_{DC}^{base} = 500$ kV). All converter stations cause active power flow losses of 1%.

Controller parameters for *VSC–1* and *VSC–2*:

$$K_P^{Vdc} = 20,\ K_I^{Vdc} = 200,\ K_I^{P} = 50,\ K_I^{Q} = 20$$

VSC–1 converter capacitance (nodes 1–2) *(pu)*:

$$C_{DC}^{VSC-1} = \{0.0375, 0.0375\}$$

VSC–1 line data *(pu)*:

$$R_{DC}^{VSC-1} = 0.003,\ L_{DC}^{VSC-1} = 0.6\times10^{-4}.$$

VSC–2 converter capacitance (nodes 1–3) *(pu)*:

$$C_{DC}^{VSC-2} = \{0.1250, 0.1875, 0.0625\}$$

VSC–2 line data *(pu)*:

Line	From	To	R_{DC}^{VSC-2} *(pu)*	L_{DC}^{VSC-2} *(pu)*
1	1	2	0.01	2.0×10^{-4}
2	2	3	0.005	1.0×10^{-4}

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