Risk-Based Framework for Establishing and Visualising Operational Constraints of Power Systems

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Abstract—This paper demonstrates a risk-based framework that can be used to establish operational constraints of power systems. The application of this methodology is illustrated on the areas of small disturbance stability and sub-synchronous resonance (SSR) in order to determine risk levels associated with various operating regions (conditions). By visualizing these risk areas, guidance for planning and operation of the power system can be provided. Furthermore, the way in which these risk areas are affected by various system contingencies, is also investigated to gain understanding of the risk performance of the network. The proposed methods are demonstrated using a meshed power system with capacitor series compensated AC tie lines.

Keywords—dynamic security assessment, probabilistic techniques, risk analysis, small-disturbance stability, SSR, torsional modes.

I. INTRODUCTION

In modern power industries there is a desire to operate systems closer to their limits in order to improve their economics and asset utilization. There is also an increase in the number of renewable energy resource installations and new system loads which introduce intermittency and uncertainty to system operation. Traditional worst-case deterministic approaches can lead to overly cautious operation with assets unnecessarily curtailed during normal conditions to avoid low probability contingency events. Risk analysis can be used to handle the uncertainty inherent in modern power system operation and to consider both the probability and severity of conditions and events to allow systems operators to make greater use of existing system assets.

It is anticipated that modern power systems will be characterized by medium length, or even short, heavily compensated AC transmission lines to maximize bulk power transfer capabilities. For example, in the UK, National Grid (the transmission system operator) has plans to install series compensation on three circuits to improve the transfer capacity between Scotland and the networks of England and Wales [1]. These lines are all approximately 100 km in length or shorter. This development is known to be a potential cause of Sub-Synchronous Resonance (SSR) and so the risk introduced during system operation must be carefully considered.

Small-disturbance stability relates to the ability of a power system to maintain stability following the small variations that naturally and continuously occur in practical power systems. Low frequency inter-area electromechanical oscillations are inherent in all large power systems [2], and in many cases have been exacerbated by the use of high exciter gains to improve the transient recovery of generators [3]. As complex conditions evolve within power systems, it is possible for underlying oscillations to become poorly damped or even unstable which can lead to equipment disconnection and eventual system collapse [4]. Additionally, if SSR is not thoroughly analyzed in compensated power networks, the torsional stresses placed on generator shafts can result in the fatigue and ultimate failure of the generating unit [5].

Small-disturbance stability risk assessment has received limited research effort, though moves towards a greater emphasis on probabilistic techniques are evident in [6]–[9]. The use of probabilistic techniques established in these works is shown to provide a more accurate representation of the variability of the level of angular stability caused by system uncertainties. However a true risk-based approach considering both the probability and severity of system conditions and events is lacking. Furthermore, measures of small-disturbance stability risk have not been used to establish meaningful operational limits which can guide system operation.

Two successive turbine generator shaft failures in 1970 and 1971, caused by subsynchronous resonance, led to intensive research by turbine generator manufacturers, utilities and academics. Studies have been performed to explain the phenomenon, propose actions, protections and countermeasures to avoid future shaft breakdowns and other associated problems. However, the use of probabilistic studies to enable the risk evaluation of subsynchronous resonance is almost entirely unexplored –
the risk assessment was introduced for the first time by the authors in [10] and developed further in [11].

This paper demonstrates the application of a risk-based framework that can be used to establish operational constraints within power systems, building further on the work in [11]. The methodology proposed is applied to the areas of small disturbance stability and SSR in order to determine risk levels for various operating regions. It represents a continuation of the authors’ work in this area by focusing on visualization of risk areas and operational boundaries of the network. It demonstrates the benefits to system planning and operation that a risk-based approach enables. Finally, the effects of contingencies on these risk areas is investigated and discussed with relation to their impact on the operational risk limits.

II. METHODOLOGY

Risk-based approaches to system operation balance the maximization of system asset usage with the avoidance of potentially catastrophic system failures. Risk can be quantified using a variety of means that consider both the probability of an event occurring as well as the severity of that event [12]. As power systems become more stressed and operated closer to their limits, this approach is crucial to ensure system resources are not unnecessarily curtailed to mitigate for extremely rare system contingencies.

A. Risk of Small Disturbance Instability

All large power systems exhibit low frequency inter-area electromechanical oscillations [2]. In many networks these oscillations are not problematic, however the use of high generator exciter gains to improve system transient recovery and large power transfers across transmission lines are increasingly exacerbating small-disturbance stability issues [3].

By modeling the operational uncertainties within a power system, the probability density functions (pdfs) for critical mode damping values can be established. These pdfs can subsequently be used to determine the risk of small disturbance instability.

1) Oscillation Severity

The severity of small disturbance stability issues is defined within this work using a purely technical measure – the settling time of power oscillations. This measure can be easily tailored to different power systems based upon acceptable operational and regulatory limits. Further risk analysis based on economic assessment could also be completed for situations when the translation from oscillatory instability to resulting financial impact can be quantified.

The critical mode settling time \( T_s \) is dependent on the tolerance (tol.) and the damping of the critical eigenvalue (\( \sigma_{crit} \)) according to (1). Also shown in (1) is the numerical equation if settling to within a 5% tolerance of the maximum deviation is desired (as in this work, though any other value could be chosen). It is therefore evident \( \sigma_{crit} \) can be used to define bounds for oscillations of various durations. Within this work, limits are set as follows to define oscillations as:

- **Acceptable**: \( T_s \leq 60 \text{ s}, (\sigma_{crit} \leq -0.05) \).
- **Critical**: \( T_s > 60 \text{ s}, (-0.05 < \sigma_{crit} \leq 0) \).
- **Unstable**: oscillations do not settle, \( (\sigma_{crit} > 0) \).

\[
T_s = \frac{\ln(\text{tol.})}{\sigma_{crit}} = \frac{\ln(0.05)}{\sigma_{crit}} = -3.00
\]

(1)

2) Small Disturbance Stability Risk Matrix

Within this work, small disturbance instability risks are quantified using a discrete risk matrix. This approach translates the probability of electromechanical oscillations, and their 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 Fig. 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: acceptable, critical, and unstable. The total system risk level is simply the highest risk level identified for any of the given ranges.

<table>
<thead>
<tr>
<th>Probability</th>
<th>Electromechanical oscillations are:</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>Unstable Low Low Low</td>
</tr>
<tr>
<td>0–1%</td>
<td>Moderate Low Low Low</td>
</tr>
<tr>
<td>1–10%</td>
<td>Severe Moderate Low Low</td>
</tr>
<tr>
<td>10–100%</td>
<td>Severe Severe Low Low</td>
</tr>
</tbody>
</table>

Fig. 1: Risk matrix for analysis of small disturbance stability issues.

B. Risk of SSR

Capacitor series compensation of transmission lines allows higher power transfer, improves the angular and voltage stability of the network and provides dynamic contributions of reactive power. However, series compensation of lines can also cause dynamic instability or transient torque amplification due to sub-synchronous phenomena (referred to collectively as SSR). Dynamic instability results in increasing mechanical torques in the turbine generator shaft section and can lead to shaft fatigue or damage. Transient torque amplification due to SSR produces high amplitude shaft torques following electrical disturbances and leads to shaft fatigue.

The analysis completed within this paper identifies the generators within a system that may be exposed to SSR and quantifies the risks.

1) Mechanical Damping of Torsional Modes

The overall damping of torsional modes is the sum of electrical and mechanical damping. Mechanical damping is always positive but very small in magnitude, caused by friction, wind losses and steam flow around the rotor. Mechanical damping is lowest when a turbine generator is at no-load, and increases with the load. Measured values of the mechanical damping of steam turbine generator
torsional modes are generally in the range of 0.02 s\(^{-1}\) to 0.05 s\(^{-1}\) at no-load and 0.2 s\(^{-1}\) at full-load [13].

In the absence of better data, it is assumed in this work that the mechanical damping \(\sigma_m\) varies linearly with generator electrical power output \(P_e\). No-load and full-load mechanical damping values are taken from [14] and assumed to be 0.045 rad s\(^{-1}\) and 0.2 rad s\(^{-1}\) respectively. Therefore, the relationship between \(\sigma_m\) and \(P_e\) is given by (2), where \(P_e^{\text{full-load}}\) is the full-load electrical power output of the generator.

\[
\sigma_m = 0.045 + (0.2 - 0.045)P_e/P_e^{\text{full-load}} \quad (2)
\]

2) Negative Electrical Damping of Torsional Modes

Series compensated transmission lines introduce negative electrical damping (\(\Delta \sigma_e\)) in torsional modes. A torsional mode becomes unstable when its net damping (\(\sigma_{\text{net}} = \sigma_m + \Delta \sigma_e\)) is negative. The electrical damping introduced in a torsional mode of frequency \(f_n\) in a 50 Hz system is given by (3) which is derived in [15]. The results from (3) are correlated with station tests in [16].

\[
\Delta \sigma_e = \frac{50-f_n}{8f_n H_n} \left( \frac{R_{\text{sup}}}{R_{\text{sub}} + X_{\text{sub}}} \right) - \frac{50+f_n}{8f_n H_n} \left( \frac{R_{\text{sup}}}{R_{\text{sub}} + X_{\text{sub}}} \right) \quad (3)
\]

In (3), \(f_n\) is the mechanical modal frequency, \(H_n\) is the equivalent per unit stored energy for a pure modal oscillation, \(R_{\text{sub}}\) and \(X_{\text{sub}}\) are the sub-synchronous resistance and reactance at frequency \(50-f_n\), and \(R_{\text{sup}}\) and \(X_{\text{sup}}\) are the super-synchronous resistance and reactance at frequency \(50+f_n\). Modal inertia \(H_n\) is calculated from the knowledge of mode shapes and masses of turbine section using (4). In (4), \(v_i\) is the velocity of the \(k^{\text{th}}\) mass, \(v_g\) is the velocity of the generator (equal to one), \((WR)_i\) is the inertia of \(k^{\text{th}}\) mass, and \(m\) is number of masses.

\[
H_n = \sum_{k=1}^{n} 1.73 \times 10^{-6} (WR^2)_i \left( v_i/v_g \right)^2 \quad (4)
\]

3) SSR Risk Matrix

The SSR risk level is dependent upon the net damping \(\sigma_{\text{net}}\) of the critical torsional mode. The pdf for \(\sigma_{\text{net}}\) can be easily derived from the pdf of generator output \(P_e\) and the negative electrical damping introduced using (2)–(4). Limits to decompose the \(\sigma_{\text{net}}\) pdf are selected to represent cases when net damping is:

- **Normal**: \(\sigma_{\text{net}} \geq 0.045\).
- **Critical**: \(0 \leq \sigma_{\text{net}} < 0.045\).
- **Unstable**: \(\sigma_{\text{net}} < 0\).

A three-tiered risk classification is used as with the quantification of small disturbance instability risk, shown in Fig. 2. Again, as with the assessment of small disturbance stability risks, these limits and the probabilities used in the risk matrix can be modified by system operators to accurately represent tolerable operating behavior in specific power systems.

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**Torsional mode net damping is:**

<table>
<thead>
<tr>
<th>Probability</th>
<th>Unstable</th>
<th>Critical</th>
<th>Normal</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>Low</td>
<td>Low</td>
<td>Normal</td>
</tr>
<tr>
<td>0–1%</td>
<td>Moderate</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>1–100%</td>
<td>Severe</td>
<td>Moderate</td>
<td>Low</td>
</tr>
</tbody>
</table>

![Fig. 2: Risk matrix for analysis of SSR risk.](image)

**C. Establishing Risk-based Operational Constraints**

Power systems are carefully operated to ensure that limits imposed to safeguard the network and its assets are not exceeded. These restrictions are typically established through deterministic analysis of worst-case scenarios. The use of a probabilistic risk-based approach will allow greater system utilization.

Any search function can be used to find limits which represent the boundaries between different risk levels for varying system conditions. Within this work, a **bisection** iterative process is used to determine the risk-based limits on inter-area power transfer. These limits are established for varying levels of capacitive series compensation in order to plot the risk areas of power system operation. Both small disturbance stability and SSR risks are considered. Furthermore, by investigating outage contingencies for critical system assets the effects on the system operation risk areas can be evaluated and discussed.

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**III. TEST SYSTEM**

The methods described within this paper are illustrated using the 16 machine, 68 bus reduced order representation of the New England Test System and the New York Power System (NETS & NYPS) [17]. The network (including additional series compensation on some AC tie lines) is shown in Fig. 3. System analysis and simulations are performed using MATLAB/Simulink and DIgSILENT PowerFactory.

**A. AC System Description**

Generators G1–8 use slow DC excitation (IEEE-DC1A), G9 is equipped with a fast acting static exciter (IEEE-ST1A) and power system stabilizer (PSS), and the remaining generators G10–16 are under manual excitation as in [17]. All generators are represented by full sixth order models. System loads are modeled as constant impedance. Full system details, generator and exciter parameters are given in [17] with PSS settings for G9 taken from [3]. Additionally, series capacitor compensation has been added to AC Ties 1 and 2 (the major infeeds from NETS to NYPS) to support increased power transfer.

An optimal power flow solution (minimizing generation cost) is used within this work to more accurately generate representative system operating points. Voltages are constrained within 0.9–1.1 pu, except generator buses for G14–16 which are set at 1.0 pu. Additional constraints are placed on the NYPS infeeds from G14 and G16 to represent thermal limits equal to 800, 400, and 600 MVA for AC Ties 4–6 respectively. Generator cost data, and active and reactive power limits are provided in [11].
Mechanical data for the turbine generator is taken from the first benchmark model for SSR studies [18] and scaled appropriately to match the generator size and inertia.

IV. APPLICATION & RESULTS

The proposed methodologies have been demonstrated on the test system outlined in order to assess system risks, establish operational constraints, and investigate the effects of specific system contingencies.

A. System Uncertainties

The risk-based limits are determined by considering the stochastic uncertainty surrounding forecast loading scenarios. The correlation of different load types is also considered with loads categorized as residential or industrial based on their nominal power factors (values greater than 0.9 are classed as residential). The correlation coefficients \( \rho \) between different loads are as in [19] with \( \rho = 0.8 \) between residential loads, \( \rho = 0.4 \) between industrial loads, and \( \rho = 0.2 \) between residential and industrial loads. All loads are normally distributed with nominal mean values and standard deviation (s.d.) of 1.67% (5% at 3\( \sigma \)). Load power factors are non-correlated with s.d. of 1.67%. Practically, historical data should be utilized wherever possible to most accurately represent the true variation.

Increases in the forecast power flow from the NETS area to the NYPS area are considered by increasing the loading values within the NYPS region. This is completed by using an equal percentage rise on the nominal loading values for each NYPS bus. Due to the system constraints present on generators and AC Ties 4–6, this additional demand is met almost entirely by the NETS area.

B. Small Disturbance Risk Assessment

Small disturbance stability risk-based inter-area power flow limits between NETS and NYPS are set through iteratively determining the pdf of the critical mode damping. A total of 5000 data points are used to generate the pdf for each forecast loading scenario.

The \( \sigma_{\text{crit}} \) pdf for the nominal loading scenario as given in [17] with no series compensation installed is shown in Fig. 4. The critical electromechanical mode for this test system is the lowest frequency mode with a frequency of approximately 0.4 Hz. Also shown in Fig. 4 are the probabilities for the various \( \sigma_{\text{crit}} \) ranges previously outlined. Evaluation of the risk matrix shown in Fig. 1 reveals a system risk level of moderate for this scenario when NETS→NYPS power flow is equal to 1074 MW.

1) Finding Risk Boundaries

The boundaries between different system risk levels (both Severe–Moderate and Moderate–Low) are to be determined for varying levels of series compensation of AC Ties 1 and 2. These boundaries are defined in terms of forecast inter-area power flow from NETS→NYPS (to a resolution of 1 MW) and are determined through variation in NYPS forecast loading.

This iterative process is shown for the Severe–Moderate risk boundary for the case with no series compensation installed in Fig. 5. A final power flow limit of 1162 MW is established. This iterative process is completed to find both Severe–Moderate and Moderate–Low risk boundaries for all considered compensation levels in order to produce the results detailed in Table 1.
a greater amount of power from NETS to NYPS without experiencing a greater risk of SD stability issues.

It can be seen in Table 1 that the Moderate–Low risk boundary is undefined for low levels of series compensation (30% or lower). This is because it is not possible to operate the network at a Low risk level, even when the NETS→NYPS forecast power flow is reduced below the value required to fulfill nominal loading. The calculated risk boundary values of Table 1 can be used to plot the risk regions of operation.

C. SSR Risk Assessment

The risks of SSR are also evaluated to determine whether high levels of compensation will have adverse effects on the turbine generator shafts.

1) Negative Electrical Damping

SSR risks are evaluated by first calculating the negative electrical damping introduced at all compensation levels. Therefore, the sub– and super–synchronous network resistances and reactances must be determined. This is completed using the frequency scan method based on the determination of the network impedance seen from the generator neutral in the frequency range of interest [16].

Shown in Fig. 6 are the network reactance curves in the frequency domain as seen by the worst affected generator (G2) for increasing levels of series compensation (10–70%). The presence of the dips in these plots at electrical frequencies near (within ±3Hz [16]) the 50 Hz complement of torsional frequencies indicates that negative damping may be introduced and that there may therefore be a risk of SSR.

![Fig. 6: Network reactance seen from G2 neutral for 10–70% series compensation levels (in 10% steps).](image)

Final values of negative damping are evaluated using (3) for all torsional modes and all generators within the system. This is completed for each compensation level considered (0–70% in 10% steps). Table 2 presents the negative damping values introduced for the worst affected torsional mode of the most affected generator (G2).

It should be noted that the negative damping introduced is dependent not only on the size of the variation in network impedance, but also on the frequency at which this variation occurs and its proximity to the 50 Hz complement of a torsional mode frequency. This explains the generally increasing values of negative damping seen as the compensation level rises. It also accounts for the fluctuations seen in Table 2 at 30% and at 50% compensation as the dips in the network reactance curves of

![Fig. 7: Operational risk visualisation with all lines in service.](image)

Table 2: Negative damping introduced for G2 with different capacitive series compensation levels.

<table>
<thead>
<tr>
<th>Compensation Level</th>
<th>Negative damping (−Δσ) for G2</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>0</td>
</tr>
<tr>
<td>10%</td>
<td>0.019</td>
</tr>
<tr>
<td>20%</td>
<td>0.045</td>
</tr>
<tr>
<td>30%</td>
<td>0.020</td>
</tr>
<tr>
<td>40%</td>
<td>0.087</td>
</tr>
<tr>
<td>50%</td>
<td>0.026</td>
</tr>
<tr>
<td>60%</td>
<td>0.176</td>
</tr>
<tr>
<td>70%</td>
<td>0.348</td>
</tr>
</tbody>
</table>

2) SSR Risk Boundaries

The risk of SSR is quantified using the risk matrix presented as Fig. 2. Risk boundaries have been calculated as for the small-disturbance assessment. This has been completed by varying the forecast loading point and determining the variation in the output of the most affected generator (G2). This variation is transformed using (2) to provide the pdf of the torsional mode mechanical damping. The calculated value of negative electrical damping introduced (from Table 2) is then subtracted to provide the pdf of net damping which is used during the risk assessment.

The SSR risk boundaries have not been tabulated as they are essentially determined by the level of compensation alone. The negative damping introduced for differing compensation levels is such that variations in mechanical damping (caused by differing load forecasts) are not substantial enough to change the SSR risk.

D. Visualising Operational Risk Areas

The previously established risk boundaries can be plotted to produce the operational risk areas for various system conditions. Fig. 7 illustrates the resulting operational risk areas for the power system with all lines in service.

Both SD and SSR risk boundaries are shown and labeled within the figure. Only moderate and severe boundaries regions are labeled and shaded to minimize figure notations. Note that no moderate SSR risk region is identified – the negative damping introduced is such that the risk level jumps directly from low to severe as the
compensation level is increased from 50% to 60%. It can be seen that only a small operational area exists where the system risk level for this particular test system is low (non shaded area in Fig. 7).

Fig. 7 shows how operating at various inter-area power transfer levels, or installing different levels of series compensation, will affect the risk of small-disturbance stability issues and of SSR. Such a plot would be valuable during network planning to identify necessary reinforcements and the risks associated with various forecast operating conditions. The ability of the method to incorporate uncertainties surrounding system operation and display the results as readily usable risk plots is novel and valuable.

E. Effect of Contingencies

The use of risk area plots also facilitates fast comparison of the effects of outage contingencies on the risk associated with various operating scenarios. To demonstrate this, two outage contingency situations are considered:

(i) with Line A (shown in Fig. 3) removed from service, and

(ii) with Line A and Line B removed from service.

For each of these contingencies, the procedure to establish risk-based operational limits has been completed. Full results relating to both small-disturbance stability based risk limits and SSR negative damping are not tabulated for brevity. The final risk areas for these outage scenarios are illustrated in Fig. 8 and Fig. 9.

![Fig. 8: Operational risk visualisation with Line A out of service.](image)

These figures illustrate how the risks associated with the power system evolve when contingency situations arise, and highlight potentially unexpected behavior. When Line A or Line A and Line B are out of service, the increased system stress means that operating with a low risk of small-disturbance stability issues is no longer possible – no matter what level of series compensation is considered. It is also evident (see Fig. 9) that with less than 20% series compensation, operating at a moderate SD risk level is hard to achieve without significantly reducing the inter-area power flow (to less than 400MW) between NETS and NYPS.

Focussing more closely on SSR, Fig. 8 shows that a moderate SSR risk boundary has been introduced once Line A is taken out of service (compare with Fig. 7). This arises due to a slight decrease in the negative damping introduced at the 60% compensation level – the different network topology changes the frequency dependent system reactance. Perhaps more surprising and non-intuitive is the introduction of a new severe SSR risk level at lower levels of series compensation for the more extreme \(n=2\) contingency with both Line A and Line B out of service (see Fig. 9). The network reactance curve for generator G2 has been derived for this contingency scenario (with both lines out of service) for a compensation level of 30% and is shown in Fig. 10, alongside the original curve with all lines in service (previously shown in Fig. 6).

It is evident that that disconnection of lines A and B has a significant effect on the system reactance as seen by G2. It can be observed that this simultaneous outage of Lines A and B gives rise to an electrical resonant frequency (at which the reactance becomes zero) when there is 30% series compensation. Furthermore, this electrical resonant frequency is very close to the 50 Hz complement of a torsional mode of 29.45 Hz. The presence of an electrical resonant frequency within a ±1 Hz range around the 50 Hz complement of any torsional mode results in a large value of conductance, \(R_{\text{sub}}/\left(R_{\text{sub}}^2 + X_{\text{sub}}^2\right)\), in (3). This conductance is directly proportional to the negative damping introduced in the torsional modes. Therefore, the SSR risk is increased for this case. The range of ±1 Hz around the torsional mode complement frequencies is used to consider the uncertainty in torsional mode frequencies.

![Fig. 9: Operational risk visualisation with Line A and Line B out of service.](image)

It should be noted though that the negative damping is not only affected by the conductance. Inspection of (3) reveals that the negative damping introduced in any torsional mode is also inversely proportional to the modal...
inertia of the torsional mode ($H_t$). Change in the compensation level varies the frequency of the electrical resonance (or reactance curve dip) seen by the generator and hence also varies the interacting torsional mode. Therefore, the SSR risk is complex and determined as a combination of many factors. This explains why the SSR risk seen when lines A and B are out of service moves from severe to moderate and then again to severe as the level of compensation increases. Fig. 9 clearly illustrates the complex nature of this issue, and also that for this contingency there are very few regions on the plot where the either the SD or the SSR risk levels are not severe.

V. CONCLUSIONS

This paper has demonstrated the application of a risk-based framework to establish power system operational constraints. The methodology has been applied to both small disturbance stability and subsynchronous resonance issues and accounts for the uncertainty inherent in the operation of modern power systems. Risks are quantified using risk matrices which are easily understood and can be easily customized to incorporate differences in specific systems and the regulations under which they are operated.

In addition to establishing the risk boundaries for small disturbance stability and SSR, these boundaries have been visualized as risk area plots. This facilitates quick identification of the level of risk associated with particular system operating conditions. By producing risk area plots for system contingency situations, the evolution of risk within the network can be traced and assessed. The risk plots for the test system studied here have identified some potentially unexpected risk characteristics, demonstrating the complexity of assessing and quantifying risk in uncertain power systems.

Future work within this area of stability-based risk assessment includes refinement of measures of severity. Of particular importance is an assessment of the potential financial loss associated with these risks in order to compare and incorporate different risk factors. It is also of interest to establish how the risk evolves within complex power systems as forecast events and conditions arise, and whether assessment of the risks can be used to guide (close to) real-time system operation.

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