



Toward Standards for Dynamics in Electric Energy Systems

Final Project Report

S-55

Power Systems Engineering Research Center

*Empowering Minds to Engineer
the Future Electric Energy System*



Toward Standards for Dynamics in Electric Energy Systems (S-55)

Final Project Report

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Executive Summary

Overall summary

The goal of our research is to define criteria and a systematic method for advancing the current control/automation in power systems for the purpose of guaranteeing transient stabilization during severe, yet anticipated contingencies. This is very important since such criteria/requirements for the dynamical components when interconnecting to the grid do not exist. As such, these dynamical components lack specific control objectives, relevant for the stability and the performance of the large power grid. This situation has many implications since as power grids become more dynamic the stability and the performance of the grid will be greatly challenged. In addition, various types of generators, wind generators, storage and Flexible AC Transmission systems (FACTS) need to have specific objectives which if met, will enable them to assist on maintaining the stability and the performance of the interconnected grid. Based on these distributed stability criteria, the control and automation of each component can be defined accordingly (for meeting those requirements). Today, the current automation used in power systems is linear constant-gain-based AVR controllers that are not designed to meet any specific stability requirements at the component level. Because of this, their contribution to the stability of the large power grid is not clear. These controllers are at best able to guarantee stability and performance in a small neighborhood around the equilibrium point and correspondingly respond in a stable way to small disturbances only. Because of this, the performance of the currently used transient stability controllers, during large severe disturbances, is greatly challenged. Today's power systems are experiencing many dynamical problems ranging from small-signal instabilities, frequency instabilities, voltage instabilities to transient instabilities, sub-synchronous resonance (SSR) and transient instabilities, such as loss of synchronism. Undoubtedly, one of the most critical dynamical problems is loss of synchronism since in the most known wide-spread blackouts transient instabilities were the main cause. In fact, loss of synchronism typically initiates a sequence of cascading events that lead to blackouts.

While the range of dynamical problems that power systems experience at present still has not been significantly affected by the integration of renewables, it is expected that this will change in the near future. The reason is that the integration of renewable energy resources in the US system is still very low. Nonetheless, numerous wind generators and PVs are expected to get connected to the bulk energy system (BES) grid and to produce a significant amount of the total US electricity demand in the near future. Such high integration levels, are going to alter the dynamical behavior of the system during transients. Therefore, transient instabilities will become even more critical and need to be addressed carefully. The only standards related to transient stabilities today are the North American Electric Reliability Corporation (NERC) transmission planning (TPL) standards. These are concerned with the planning of a power system such that at various loading levels and under expected severe contingencies, it remains transiently stable. Such an approach, suffers from several drawbacks. First, it is prone to inefficiencies i.e. to causing operation of power systems far below its real equipment capabilities. Second, it is expensive i.e it results to high costs of transmission expansion to meet the worst-case stability criteria. Third, it does not relate the system-wide transient stability requirement to transparent criteria that various dynamical components,

such as synchronous generators, have to meet. The above points make the need for simple plug-and-play standards for transient stability more pronounced.

Our approach to overcoming these problems fundamentally relies on advanced control and automation to ensure provable/guaranteed transient stability and performance for the assumed known set of contingencies. The first part of the proposed approach is defining stability criteria that different components have to meet, either on their own or as a group. We then relate these distributed stability criteria in light of the system-wide stability. This is important for bridging the gap between system-wide stability guarantees and plug-and-play distributed stability criteria. In this report, we propose design of specifications for components and groups of components so that when these are met the system-level criteria are met. When the components cooperate to meet specified objectives as a group, communication-based control architectures are required to implement the required cooperative schemes. The second part of our approach is based on the introduction of the intelligent Balancing Authorities (iBAs), which are, groups of components that are responsible for meeting a set of stability criteria in a coordinated way. The final part of our approach discusses the development of several novel advanced nonlinear control design methods that can be used by the iBAs to meet their stability criteria.

As a proof-of-concept, we use several test cases to illustrate the effectiveness of our approach. More specifically, we use the IEEE 24-bus RT system to show that with our method the Critical Clearing Time (CCT) of the system, which is the most-common metric for assessing transient stability, is increased for the given set of probable contingencies. In this scenario, nonlinear decentralized controllers are used by the formed iBAs. The performance of iBAs with more advanced cooperative control scheme is assessed using the IEEE 14-bus system and a small 3-bus system. On the IEEE 14-bus system, we show how transient stability and voltage regulation can be achieved using an iBA comprising conventional synchronous generators. At other extreme, the 3-bus system has in addition to two synchronous generators a state-of-the-art wind generator with a fast battery storage. On this system, we show how the wind generator and the synchronous generator can define an iBA and jointly ensure that synchronous generators do not lose synchronism during a given contingency. This is achieved by means of using storage available on the wind generator.

We conclude, more generally, that advanced control-based methods can enable operation of power systems closer to their stability limits. This is because advanced nonlinear control can make an unstable contingency scenarios in closed-loop stable. Therefore, it becomes possible to reduce the need for unnecessary transmission expansions for retaining transient stability during severe contingencies. Instead, the approach offers less expensive cyber solutions to further enhancing stability of critical generators. Notably, new dynamical components such as storage, state-of-the-art wind generators and Flexible AC Transmission Systems (FACTS) can be integrated into power systems at value for improving transient stability of power systems; this fundamentally enhances stability of current systems whose controllers are only governors and AVR of synchronous generators.

Part I: Standards and Protocols for Stable Dynamics in the Electric Power Systems

Part I of this project performed by Carnegie Mellon University (CMU) team concerns difficult questions regarding relations between: (1) the specifications which manufacturers must meet prior to connecting dynamic components (power plants, FACTS) to an electric power grid; (2) NERC standards which require that system operators do not create different types of instabilities during normal and/or contingency conditions; and, (3) standards and protocols which new equipment owners must meet prior to connecting to an electric power grid. These seemingly unrelated problems must be related in order for the electric power systems to work in the future as the grids evolve and are expected to serve supply/demand patterns for which they may have not been designed. Notably, to utilize the potential of new fast controllable technologies, such as FACTS and various fast storage, and to close the loop with synchronized sensors such as PMUs, for purposes of operating the grid more efficiently without experiencing operating problems, it is essential to establish relatively simple enforceable standards for dynamics. In particular, it is necessary to ensure that such standards will lead to provably acceptable dynamic response. Meeting these objectives is a tall order, given that at present only analyses tools exist for assessing off-line whether the system would respond in a dynamically acceptable manner (say, stay transiently stable within pre-specified critical clearing time for the given list of contingencies). This is done for given tuned controllers implemented by the manufacturers. We propose to consider standards which enhance dynamic response by requiring that (groups of) components meet their own standards as recommended in this report.

Having dynamic standards becomes particularly critical in grids with continuous net demand fluctuations. These fluctuations can only be balanced by fast primary controllers and, given lack of market and financial mechanisms to incentivize deployment of fast control and sensing, it is essential to establish technical standards and protocols.

In this report we briefly describe that relations (1)-(3) are currently not aligned, and stress the need to relate them. Two, somewhat different, approaches are proposed to overcome this problem. The first approach requires system operators to play the key role in identifying likely dynamical problems, identify equipment affected and set requirements for enhanced control for this equipment only. The second approach proposes a set of criteria which all (groups of) components must meet in order to connect to the power grid. The system operator only provides solved power flow for normal loading and equipment conditions, the range of likely load deviations and the list of contingencies for which required standards for dynamics must be met. No specific dynamic models information is required by the system operators about any equipment. Each component must either meet the set standards for dynamics by implementing its own local control and/or cooperate with the other components to meet standards for dynamics jointly. The second idea is effectively a generalization of how control authorities (areas) meet frequency regulation specifications today; we note that the AGC standards are being set without knowing characteristics of the power plants in the control area; it is the responsibility of the control area itself to know these characteristics in order to meet the AGC standards. We explain in this report how can this be defined for ensuring acceptable dynamic response more generally. We refer to the control area-like entities (groups of components jointly meeting standards for dynamics) as intelligent Balancing Authorities (iBAs).

As a result of our attempting to generalize AGC standards for frequency regulation by establishing protocols to ensure acceptable dynamic response over wide temporal ranges and during both normal and contingency conditions, we propose how such standards could be set for avoiding most typical dynamical problems. It was pointed out to us during the course of this project that the digital electronics standardization was the key to technology deployment at value. As the electric power industry evolves into more dynamic industry driven by both technological and societal changes it is essential to take a step back and attempt to set relatively simple (or as simple as possible) protocols and standards to enable dynamically acceptable operation of the changing electric power grid operation. The effort at CMU in this project is highly motivated by this situation. It is our recommendation to discuss further the proposed protocols and to make next steps into the direction of relating existing NERC standards to the standards which would lead to provable performance by requiring all (groups) of components connected to the grid to meet them. Assuming that the basic idea is of interest to the industry, further discussions with industry, NERC in particular, will be needed to move forward.

Throughout this report the emphasis has been on a representative critical standard, namely transient stability standard. Illustration of the two approaches to setting quantifiable criteria needed to ensure transient stability within a given critical clearing time for given list of contingencies is provided. We emphasize that by combining a systematic modeling of power system dynamics with model-based control design for nonlinear dynamic systems, the proposed criteria become verifiable and implementable. Illustrative examples are provided showing how the proposed standards can result in transiently acceptable system response. Future steps include generalization of the proposed transient stability standard to the set of standards for acceptable dynamics, ranging across voltage stability, mid-range dynamic response, inter-area dynamic specifications. An important open question concerns protection settings so that they do not over-ride the response set by standards for dynamics. Protection should be a safety mechanism to protect the equipment from damage, and not for managing system-level dynamic response. Special protection schemes are examples of iBAs meeting transient stability standards in a coordinated way. The difference between SPSs and the dynamic standards proposed is that protection disconnects equipment in a coordinated way. It is proposed here to, instead, achieve pre-specified transient stability according to the proposed standard using smart high-gain multi-modal nonlinear control to avoid loss of synchronism, for example. Further work is needed to establish mechanisms for coordinating the proposed dynamic standards with the protection settings in the newly emerging power grids. This is needed to avoid situations in which protection leads to loss of synchronism often experienced during major blackouts.

Part II: Standards for Dynamics in Microgrid-based Future Distribution Systems

The objective of this work done at Texas A&M is to formulate and evaluate standards for dynamics in future distribution systems. With the advance of sensing and communication technologies, we envision a “smarter distribution” system that is comprised of multiple microgrids [1]. Clusters of distributed energy resources and loads, known as “microgrids”, can be managed by local intelligent decision makers and coordinated by the distribution system operator (DSO) to achieve stable and sustainable operation. Interconnected through distribution lines, microgrids exchange power to mitigate renewable resource output fluctuation and balance out the mismatch between local power generation and consumption through aggregation effect. The dynamic performance of such a smart

distribution system heavily depends on the control architecture that manages thousands of heterogeneous resources/consumers at scale.

One of the main challenges of dynamic control architecture for future distribution grid is how to coordinate heterogeneous distributed energy resources (DERs), energy storage systems (ESSs) and controllable loads (CLs) so that the overall system performance is guaranteed. A promising solution would be to break the distribution system down into interconnected clusters [1]. As defined by the U.S. Department of Energy (DOE) [2], such resource and load clusters can be considered as a microgrid if it has a clear electric boundary. This boundary is commonly referred to as “the point of common coupling (PCC)”. In a microgrid, each power generation and/or consumption unit is controlled by its local unit controller (LUC). In addition, all the LUCs are managed by an intelligent microgrid central controller (MGCC). Then one level above, the PCC voltage of each microgrid will be coordinated by the DSO [3]. With such clustered configuration, the computational complexity and communicational burden can be significantly reduced for distribution system operation.

For the coupled operation of microgrids, it is important that proper power sharing achieved among system modules. In current practice of microgrid interface control, algorithms mimicking SG swing equations are commonly adopted to craft synthetic inertia in case that the system frequency is at risk of running into unacceptable level following resource and/or load disturbances. Such frequency droop and inertia emulation methods generate microgrid interface behavior according to the nature of SG swing equations. However, several factors limit their application for future distribution systems: 1) synthetic inertia slows down system transient response; 2) the conflict between frequency regulation requirement and the sensitivity of indicating power imbalance [4]. Taking advantage of synchrophasor measurement technology, VSI output voltage angle can be directly drooped instead of frequency to indicate power imbalance since the voltage angle of microgrid interface VSIs can be set arbitrarily as long as a synchronized angle reference is available. It has been realized that drooping the VSI voltage angle instead of frequency can be a better option for power sharing considering its advantage in transient performance and control flexibility. In angle droop control methods, signals from the global positioning system (GPS) are utilized for angle referencing, which is enabled by intelligent electronic devices (IEDs) with phasor measurement units (PMUs) embedded [4]. In the study system to be investigated in this paper, no physical interface VSI is deployed at each microgrid PCC. A virtual interfacing scheme is designed to control the PCC voltage indirectly through managing the integration VSIs of selected internal distributed generation units with synchrophasor measurement available at their respective connection point (CP).

With future distribution grids configured as microgrid interconnections, a three level hierarchical control framework is proposed to guarantee system-wide small signal and transient stability. At the primary level the model reference control (MRC) is performed, through which each microgrid interface is controlled to track a designed reference model. At the secondary level, a droop management scheme is proposed to adjust the reference model droop gains based on the stability assessment results. At the tertiary level, an AC power flow (ACPF)-based supervisory control strategy is utilized to dispatch the nominal setting to each microgrid central controller (MGCC). With such three-level control framework adopted, theoretical results on system-wide dynamic stability criteria in the sense of Lyapunov are obtained. Minimum information exchange is required

among microgrid modules and the distribution system operator, which is a highly desirable feature in energy management programs for future distribution systems. This theoretical result implies the potential of designing provably stable standards for dynamics for future distribution systems. Future work will continue to develop real-world systems and validate the dynamic performance of such real-world distribution systems.

Part III: Risk Based Transient Instability Criteria for Dynamic Reliability Standards

The objective of this research is to provide an approach for risk-based security assessment (RBSA) to define the dynamic reliability standards in the future electricity grid. Electric power system security assessment is one of the most important requirements for operational and resource planning of the bulk power system. Security assessment ensures safe operation of the power system for all credible contingencies. The traditional deterministic approach for power system planning as per the North American Electric Reliability Corporation (NERC) reliability criterion consists of evaluating operating limits or planning the system to withstand the worst-case scenario. This deterministic approach usually provides a conservative criterion and can result in expensive bulk system expansion plans or conservative operating limits. Electric utilities have to operate much below their maximum capacity due to the security margins imposed on them by the system operating criteria. Furthermore, with increased converter-based renewable penetration into the electric grid the dynamics of the grid are changing. In addition, the variability and intermittency associated with the renewable energy sources introduce uncertainty in the electricity grid. Since, security margins have direct economic impact on the utilities; more clarity is required regarding the basis on which security decisions are made.

RBSA of a power system provides a measure of the security of the power system that combines both the likelihood and the consequence of an event. Risk based methods provide more information on the security of the system at different operating conditions and can provide a basis for making decisions on security margins. A novel approach to estimate the impact of transient stability is presented in this research by modeling several important protection systems within the transient stability analysis. A robust metric to quantify the impact of transient instability event is proposed in the research that incorporates the effort required to stabilize any transiently unstable event. Two different metrics to quantify the impact of transient instability are presented. To simulate the proposed RBSA method, a synthetic test case is developed that represents upstate New York and the province of Ontario. The test case has all the major features of a realistic power system for transient stability simulations and reliability assessment. Exhaustive time domain simulations are performed on a credible list of contingencies for different fault types and location. Simulations are performed for varying system loading conditions and varying converter-interfaced renewable energy injections. Risk of transient instability events are evaluated from accurate impact assessment obtained by modeling the protection system and accurate probabilistic data obtained from the industry. The stochastic nature of converter-interfaced wind energy injection is also modeled into the risk assessment methodology. The variability and intermittency of such renewable generation should be included in the defining the standards for the future electricity grid. The effect of converter-interfaced renewable energy injection on system reliability is investigated using RBSA. The simulations results show that converter-based renewable generation injection helps in improving the transient stability limits. The simulation results show that RBSA can be used effectively in system planning to select security limits. Comparison of RBSA with

deterministic methods show that RBSA not only provides less conservative results, it also illustrates the bases on which such security decisions are made. RBSA is used to identify zones in the electricity grid with reliability issues using equal risk contour plots. Zonal risk assessment can help system planners in identifying key areas within the system that can affect system reliability. RBSA helps in identifying critical aspects of system reliability that is not possible using the deterministic reliability techniques.

Project Publications:

- [1] Y. Zhang, Y.; and L. Xie. "Online dynamic security assessment of microgrids interconnections for future smart distribution," *IEEE Transactions on Power Systems*, vol. 30, no. 6, pp. 3246-3254, November 2015.
- [2] Zhang, Y.; K. Ding, and L. Xie. "Interactive Control of Coupled Microgrids for Guaranteed System-wide Small Signal Stability," *IEEE Transactions on Smart Grids*, vol 7, issue 2, pp. 1088-1096, March 2016.
- [3] Zhang, Y.; and L. Xie. "A Transient Stability Assessment Framework in Power Electronic-interfaced Distribution Systems," *IEEE Transactions on Power Systems*, vol. PP, issue 99, pp. 1-9, February 25, 2016.
- [4] Datta, Sohom; Vijay Vittal. "Operational Risk Metric for Dynamic Security Assessment of Renewable Generation," *IEEE Transactions on Power Systems*, to appear, accepted May 28, 2016, doi: 10.1109/TPWRS.2016.2577500

Student Theses:

- [1] Zhang, Yun. *A Clean Slate Control Framework for Future Distribution Systems*. Ph.D. dissertation, Texas A&M University, College Station, TX, 2015.
- [2] Datta, Sohom. *Risk-based Transient Instability Criteria for Dynamic Reliability Standards in the Future Electricity Grid*, Ph.D. dissertation, Arizona State University, Tempe, AZ, 2016.

Part I

Standards and Protocols for Stable Dynamics in the Electric Power Systems

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The Power Systems Engineering Research Center (PSERC) is a multi-university Center conducting research on challenges facing the electric power industry and educating the next generation of power engineers. More information about PSERC can be found at the Center's website: <http://www.pserc.org>.

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1. Current status of transient stability related standards

1.1 Introduction

1.1.1 Possible dynamical problems in today's and future power systems

Today's power systems experience many dynamical problems. These dynamical problems can be small-signal instabilities, frequency instabilities, voltage instabilities, transient instabilities, sub-synchronous resonance (SSR) and transient instabilities. A question that arises naturally when considering power systems with new dynamical components like storage, FACTS and state-of-the-art wind generators is the following:

Which types of dynamical components contribute to each of those dynamical problems and conversely, which types of components can be used to address each type of these dynamical problems? The following table summarizes common dynamical problems and types of dynamical components that exist in today's power systems.

Table 1-1: Dynamical problems

Types of Components	Dynamical problems						
		Small signal instability	Transient instability	SSR	SSCI	Frequency instability	Voltage Instability
	Synchronous generators	?	?	?	?	?	?
	Wind generators	?	?	?	?	?	?
	Solar plants	?	?	?	?	?	?
	FACTS	?	?	?	?	?	?
	Storage	?	?	?	?	?	?

It is important to emphasize that the above table is not comprehensive since, as new dynamical components are integrated into power systems, new dynamical phenomena will emerge and the existing dynamical phenomena will also be affected at various levels. For instance, state-of-the-art wind turbines are found to cause a new dynamical problem, namely Sub-synchronous Control Interactions (SSCI). This problem is caused because of the interactions of a wind generator converter and a series-compensated AC transmission line at sub-synchronous frequencies. Addressing effectively, existing and new dynamical problems in power systems is an important challenge that awaits effective solutions.

1.2 Problem formulation - Transient stability

Transient stability, is a term specifically devised for power systems term to characterize the condition in which all generators in a given system retain their synchronism after the system is subjected to a large disturbance. Generators losing synchronism with the grid is often the main cause of wide-spread blackouts. To underline how important is to retain transient stability, we consider the mechanism through which transient instabilities can trigger a series of catastrophic

cascading events. Consider the case where in a given power system a contingency such as the disconnection of a transmission line occurs. A disturbance like this can alter line power flows in the vicinity of the fault. Concurrently, the synchronous generators (SG), mostly the ones in close proximity of the fault experience some power imbalance. At this point, consider the rotor speed dynamics of a SG i given by the differential equation below.

$$\dot{\omega}_i = \frac{P_{mi} - P_{ei}}{2H_i} \quad \text{Equation 1-1}$$

In the above differential equation P_{mi} , P_{ei} are the mechanical and the electrical power respectively. The variable H_i is the generator inertia. During a fault, the mechanical power P_{mi} of a SG is not changing much whereas the electrical power P_{ei} is significantly varying. As a result, the rotor speed of generators that experience a power imbalance i.e $P_{mi} \neq P_{ei}$, will not remain constant. In fact, generators will accelerate or decelerate depending on the power imbalance that they experience. Thereby, the critical generators will tend to rotate either faster or slower than the synchronous speed of the grid. If the generators accelerate/decelerate too much they can reach a state where the out-of-step protection will disconnect them from the grid in order to avoid any physical damages to their equipment.

Accordingly, the disconnection of the synchronous generators will lead to severe generation-load imbalance that can cause multiple other generators to accelerate/decelerate and finally getting disconnected from the grid as well. A series of cascading events like these can end up affecting/disconnecting a large portion of the power system.

The latest report [26], regarding the 2003 blackout, pointed out several methods that can be used to minimize the occurrence and the impact of widespread blackouts. Amongst others, it is recommended to consider coordinated emergency control, real time monitoring and control, FACTS and distributed generation. The findings in [26] verify the need for developing advanced-control-based methods for enhancing transient stability in power systems. Here we formulate the problem mathematically and propose possible solutions of this type.

Mathematical formulation of the problem

Transient stability can be put into the context of Lyapunov stability of equilibrium points of dynamical systems. Consider a power system described by the differential equation:

$$\dot{x} = f(x) \quad \text{Equation 1-2}$$

Problem Formulation 1 (Transient stability): We consider a power system that is initially operating in equilibrium when a disturbance occurs. Let the subscripts pr, ps denote the post-fault and pre-fault operating conditions and f the faulted conditions. The disturbance alters the vector field that describes its dynamics i.e $f_{pr} \rightarrow f_f$. After the disturbance ends, the system evolves according to the same pre-fault vector field such that $f_{ps} = f_{pr}$. This system can be compactly described as:

$$\dot{x} = f_{pr}(x) \quad 0 \leq t < t_f \quad \text{Equation 1-3}$$

$$\dot{x} = f_f(x) \quad t_f \leq t < t_{cl} \quad \text{Equation 1-4}$$

$$\dot{x} = f_{ps}(x) \quad t_{cl} \leq t \quad \text{Equation 1-5}$$

The variables t_f and t_{cl} are the time instants at which the fault occurred and cleared respectively. Then, the power system **is transiently stable** if $x(t_{cl}) \in RA_{ps}$ i.e at the time instant that the fault is cleared the state-variables lies inside the Region Of Attraction (RAps) of the equilibrium point of the system described by the post-fault system dynamics. On the other hand, there are two main scenarios that can yield to the power system experiencing a transient instability.

Case 1: The equilibrium point of the post-fault system $x_{e,ps}$ is the same as the pre-fault system $x_{e,pr}$ i.e $x_{e,ps} = x_{e,pr}$, and a disturbance moves the state out of the RA_{pr} at the time the fault is cleared i.e $x(t_{cl}) \notin RA_{pr}$.

Case 2: The equilibrium point of the post-fault system $x_{e,ps}$ is different than the equil.point of the pre-fault system $x_{e,ps} \neq x_{e,pr}$ and a disturbance moves the state out of the RA_{ps} at the time the fault is cleared i.e $x(t_{cl}) \notin RA_{ps}$.

The sets RA_{pr} , RA_{ps} denote the region of attraction of the pre-fault and post-fault systems respectively. From the above formulation it springs that two factors play a key role in maintaining transient stability of a power system. These are, the size of the RA (region of attraction) and the stability property of the equilibrium point e.g. asymptotically stable. In [19], [20], we focused on the case where the equilibrium point of a, the post-fault and pre-fault dynamics is identical; such a case can be for instance when the topology of the power grid remains intact after a disturbance. In that case, maintaining transient stability depends solely on the equilibrium point having a RA large enough for the state to lie inside at the time at which the fault is cleared. When this is true, the state will converge to the equilibrium point asymptotically. In power systems language, the time interval measured from the onset of a fault until the moment that the states exit the RA is called the Critical Clearing Time (CCT). Therefore, guaranteeing transient stability in this context is equivalent to having a CCT large enough or in other words RA large enough, such that for a given set of disturbances, the states lie inside the RA at the moment the fault is cleared.

1.3 Today's approaches for ensuring transient stability

1.3.1 Current component-level criteria for tuning control and automation

Tuning of the generator controllers [6]

The current approach for tuning/designing the AVR excitation controllers of generators can be described as follows. First, the generator is assumed connected to an isolated load that might represent the Thevenin equivalent of the rest of the system (that the generator is going to be connected to), or even assumed to be off-line. Then, the control systems' response is evaluated for this set-up and metrics for large signal and small signal performance are used to assess its performance [6]. Once a desired (with respect to the metrics used) response is observed the control system performance is deemed satisfactory and ready to be applied to the synchronous generator.

Tuning of the out-of-step protection

According to [6], in order to avoid damage of a generator that is experiencing out-of-step conditions as well as to avoid damage of the generator's auxiliary equipment; an out-of-step relay

or out-of-step-protection exists in the generators circuit. The most common type of relay that of mho-element-scheme (apparent impedance) is tuned such that it disconnects/trips the unit as soon as the apparent impedance measured at the HT bus enters a specific characteristic. This characteristic is set such that it captures unstable swing conditions. Nevertheless, the out-of-step-protection tuned in this way is not guaranteed to disconnect only unstable swings since its tuning is based on experience.

1.3.2 Review of NERC TPL reliability standards [29]

Today, as far as the authors are aware, the only system-wide standards related to transient stability are the North American Electric Reliability Corporation (NERC) transmission planning (TPL) standards [29]. The next table provides an overview of some of the requirements/standards that power systems have to meet at the transmission expansion level.

Table 1.2: Overview of requirements/standards

Category	Contingencies	System Stable and both Thermal and Voltage Limits within Applicable Rating	Loss of Demand
A	No contingency	Yes	No
B	Event resulting in the loss of a single element.	Yes	No
C	Event(s) resulting in the loss of two or more (multiple) elements.	Yes	Planned/ Controlled
D	Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	Evaluate for risks and Consequences. - May involve substantial loss of customer Demand and generation in a widespread area or areas. - Portions or all of the interconnected systems may or may not achieve a new, stable operating point. -Evaluation of these events may require joint studies with neighboring systems.	D

According to NERC, for a given set of contingencies that belong to the above specific types, system simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance. The studies need to be conducted using the future expansions accounted for as well.

1.3.3 Review of FAC Standards - System Operating Limits Methodology for the Planning Horizon [30]

These specific standards are mainly concerned with the system operating limits and the methodologies with which they are derived. The goal is the reliable planning of bulk power systems. Nevertheless, the R2 section of these standards documentation (that can be found in [30]) mentions the following.

- In pre-contingency state the bulk power system should retain its transient, dynamic and voltage

stability while operating within voltage and thermal operating limits.

- After any single contingency (type described in TPL standards), the bulk power system should retain its transient, dynamic and voltage stability together while operating within voltage and thermal operating limits.
- After a scenario where multiple contingencies (types described in TPL standards) occur, the bulk power system should retain its transient, dynamic and voltage stability together while operating within voltage and thermal operating limits.

1.3.4 Review of ISO New England Operating Procedure - Transmission Operations [31]

Based on the TPL and FAC standards imposed by NERC, the ISO New England defines its criteria, methods and limits for operating the New England Transmission System. In particular, the Section 2 of the online report in [31] mentions that in Emergency conditions after single or multiple contingencies occur, actions needs to be taken such that:

- Emergency Stability Criteria: contingencies will not cause any instability of any single unit or the system. Additionally, that contingencies do not cause any unacceptable system oscillations and sufficient damping should exist together with good post-transient voltage response.

1.3.5 Summary of current industry practice for ensuring transient stability

The main industry practice for ensuring transient stability during possible disturbances is primarily based on implementing Security Constrained Economic Dispatch (SCED); the line flow limits used are proxy limits obtained by off-line transient stability analyses. Additionally, many ISOs use On-line Dynamic Security Assessment in the implementation/production stage.

Industry practice – Security Constrained Economic Dispatch (SCED)

This practice starts by running contingency analysis for all possible faults in a given system with the Economic /AC OPF dispatch assigned to the various generators. Then, the following steps are executed.

- ❖ If the contingency analysis outcome shows out-of-synchronism conditions then:
 - Alter the dispatch obtained from ED or AC OPF i.e.: re-distribute power loading from critical to not critical gens/transmission lines, using knowledge of the system and re-conduct the contingency analysis.
 - The altered dispatch that guarantees no out-of-step conditions for all contingencies is judged as secure and is the one that is actually going to be implemented.

The above method which is preventive, constitutes today's industry practice against transient instabilities. On the other hand, this current industry practice causes conservative operation of power systems. That is a consequence of the resulted constrained dispatch that is actually implemented in practice and comes as an outcome of the SCED.

1.4 Issues with current practices for ensuring transient stability

Following the above description of the component-level tuning of automation and protection as well as the system-wide NERC, FAC and ISO New England standards, several key points emerge. These points are summarized below as:

1. The tuning of the generators control system is initially conducted under stand-alone conditions without taking the system interconnections into account. We note that, control schemes tuned/designed in a stand-alone setting are not able to have guaranteed performance or provide stability guarantees of the generator sub-system dynamics when the generator is interconnected with the grid. Although generation System Impact Studies (SIS) are conducted to assess whether the interconnection of the generator causes unacceptable system behavior with the Power System Stabilizer (PSS) being tuned together with the system interconnections, no systematic methodologies for doing that exist that are able to guarantee system-wide stability.
2. Tuning of the out-of-step protection as discussed above has the main goal the equipment protection. Nevertheless, although it affects transient stability indirectly by disconnecting the “unstable” generators its tuning/design is not coordinated with the control system design in 1.
3. These NERC standards mentioned above are based on system-wide simulations for assessing unstable conditions, and cannot be directly related to the tuning of the generators system control design and the protection tuning. In particular, the interconnection standards for individual generators do not exist.
4. System-wide transient stability analysis cannot be systematically mapped into criteria/requirements that interconnected components themselves have to comply with.
5. More generally, all NERC, FAC and ISO New England standards require among others the studied power systems to retain voltage transient and dynamic stability they do not specify by whom and how they will accomplish this. Therefore, with the transient stability requirement being generic without any mapping into simple requirements for generators the actual practices of tuning generator controllers and setting their protection greatly vary without no assigned control objectives that if met will ensure transient stability. As a result, the actual practices are not able to provide any formal stability guarantees during large disturbances since the controllers are designed based on linearization approaches whose performance is guaranteed only in a small neighborhood around equilibrium. Nevertheless, transient stability studies that include numerical simulations provide a heuristic approach for assessing stability under different operating conditions.

The above observations lead to the following major issues with today’s reliability standards:

- Current practices do not guarantee stability of components (such as avoiding loss of synchronism) or the stability of the grid (no cascading blackouts) during large disturbances.
- There exists a major disconnection between the system-wide transient stability requirements set on utility operators, on one hand, and the metrics which various dynamical components, synchronous generators in particular, have to meet, on the other hand. This means, that the current utility-level standards do not allocate the responsibility for system performance to the various dynamical components systematically.

- They may lead to conservative operation of a power system far below its real capabilities.
- They may result in high-cost transmission expansions to meet the worst-case stability criteria.
- Notably, they do not consider potential of advanced automation for enhanced system operations before resorting to expensive system expansion solutions for meeting the transient stability requirements.

The implications of these issues are that, although utility-level requirements for ensuring transient stability exist, without transparent and quantifiable criteria for components the control design metrics for their design are hard to implement in practice. As a result there is no guarantee that transient instability, in one form or the other, would be avoided in operations. The real problem we identify is that, there exists a huge gap that needs to be bridged between the general stability requirements and the actual practices.

1.5 Goals/Objectives of this report

Our report aims to achieve several key goal/objectives. Amongst them, to introduce distributed stability criteria that can be met using advanced-control-based approaches rather than conservative-off-line analyses-based approaches. The key goal/objectives of our research can be summarized as:

1. To introduce transient stability criteria/standards based on Lyapunov theory that will enable provable transient stabilization
2. To define intelligent Balancing Authorities (iBAs) as means for meeting those standards
3. To propose heuristic methods for defining critical areas for a given set of contingencies as well as guidance for creating iBAs inside the critical areas boundaries
4. To develop several novel nonlinear control design methods that guarantee transient stabilization and enable the generators to comply with the transient stability criteria/standards provably
5. To evaluate the effectiveness of the proposed approaches via simulations on the IEEE 24-bus RT system, the IEEE 14-bus system and a proof-of-concept 3-bus system

1.6 Structure of this report

In the section above we presented possible dynamical problems in power systems and recalled the transient stability problem formulation. Further, we presented the NERC transient stability-related standards and the current industry practice for ensuring transient stabilization. In what follows, we introduce transient stability criteria/metrics for single or group of components, based on Lyapunov theory, which, if satisfied by all (groups of) components would guarantee no loss of synchronism of the relevant generators. We then recognize that instead of setting requirements on all individual components, it would be effective to allow for collaboration of components to jointly meet the transient stability metrics required. The proposed notion is a generalization of today's balancing authorities which we name intelligent Balancing Authorities (iBAs). These are effectively portfolios of existing and new equipment added to the system which jointly ensure sufficient

response so that iBA requirements are met. We point out that the boundaries of iBAs could be determined either by the utilities or by the owners of equipment. More work is needed to further formalize portfolios design criteria. In this report we only illustrate the role of iBAs in utilizing advanced nonlinear control on the IEEE 24-bus system. Design of iBAs is further illustrated for the IEEE 14-bus system. Potential benefits from aggregating unconventional resources with their control for assisting conventional generators not lose synchronism are discussed by looking at the portfolio of a DFIG-controlled wind generator and conventional generator jointly managing response to a large disturbance within a small 3 bus power system. Finally, we conclude this report and suggest future work.

2. Transient stability criteria and iBAs

2.1 On the importance of guaranteed transient stabilization of critical generators

It is widely accepted in the power systems community that contingencies and faults most of the times initiate a localized dynamic response. We emphasize here that, there exist cases where local disturbances can have a higher impact on remote areas leading to non-localized response. Nevertheless, it is accepted that at most of the times large disturbances cause localized response. That means, when a disturbance occurs, the group of generators that is “closer” to the point of the disturbance, in terms of smaller electrical-distance, are the ones that are going to be affected the most. In fact, one or more generators, which belong to the coherent group of generators that is closer to the fault, are the ones that are likely to lose synchronism with the grid. In addition, the dynamics of these critical generators are going to be highly nonlinear, rendering linear controllers’ inadequate to provide guaranteed performance and stability. On the other hand, advanced nonlinear controllers are able to offer guaranteed stability, having as only drawback the controllers’ increased complexity and, potentially, higher control limit requirements. Granted that, advancing the control/automation of specific targeted critical generators can enable robust power grid operation with respect to a possible set of contingencies. This observation constitutes the basis for our further analysis and work.

2.2 Proposed approach - Improving control system reliability through design specifications

Following the above analysis, we can argue that, today, there exists a disconnection between system-wide performance/stability criteria for large power systems and distributed stability criteria for the various components that are interconnected within these power systems. Motivated by this major observation, and also by the overall concern with innovative control solutions, we adopt the idea of improving control system reliability through careful design specifications. The basic idea comes from the general control design for nonlinear dynamical systems which specifies sufficient conditions for stability of stand-alone dynamical components, which, in turn, ensure that the interconnected system is stable. This problem has been a Holy Grail challenge to many of the best minds in this field and much progress has been achieved. For a detailed survey of these approaches and, in particular, for their relevance for operating future electric energy systems, see [21]. In a nutshell, this literature offers sufficient conditions which must be met by the dynamic components so that the interconnected system is stable. This approach has a potential of answering the difficult question of allocating responsibilities to all components, instead of only requiring balancing authorities to ensure no loss of synchronism. Translated into the standards for dynamics discussion, this would mean the ability to define quantifiable and transparent metrics on all components so that the interconnected system meets the dynamic performance metrics set. Those familiar with control design paradigms quickly find a well-known loophole in this otherwise promising approach which concerns conservativeness of competitive control design. Applying this concept is particularly troublesome in electric power systems because in the past the entire dynamic control has been provided by controlling power plants. All other components, loads and delivery system, have been mainly uncontrolled. We recognize this problem and it is with this in mind that setting the performance metrics on an iBA instead of on all individual components becomes very important. However, we arrive at the proposed approach for ensuring transient stability in steps.

We start first by considering performance metrics required for competitive control of individual power plants. Out of several approaches underlying control design for stable nonlinear dynamic systems, the work carried out in this project draws on Lyapunov approach. The work by Stefanos Baros proposes that each component or a group of components interconnected with the grid guarantees asymptotic stability of its sub-system dynamics. This means that if each component or group of components guarantee this, then the system-wide stability can be inferred. The implications of such an approach are that, the components have to meet their local stability criteria but at the same time by meeting those criteria, the system as a whole is guaranteed to retain its stability. By doing this, the proposed approach inherently bridges the gap between the design of local automation for meeting specific criteria, and the required criteria for system-wide stability and performance. It also captures the interrelation between the local distributed plug-and-play stability criteria and the system-wide criteria. This is because when the former are met the latter are also guaranteed to be met. The theoretical basis behind our approach can be found in standard large-scale system textbooks [27, 28].

The major challenge with meeting specifications for asymptotically stable response of power plants to contingencies is complex. To start with, the dynamic response of power plants to large disturbances is highly nonlinear. Because of this, advanced nonlinear local control is required so that a power plant in closed loop is provably stable within the interconnected system. The basis for the proposed approach rests on the following:

1. The system is guaranteed to be transiently stable for large disturbances due to the stability-under-interconnections property of the sub-systems. Nevertheless, this is not true for any large disturbance. The magnitude of the disturbance that can be sustained by the system without losing stability of the full system depends on the region of attraction of the full system. Because of this, it is necessary to specify the list of contingencies for which the control design is intended, as illustrated in the remainder of this report.
2. The region of attraction of the interconnected system can be enlarged such that for a given set of disturbances the full system can become transiently stable while with the current controllers it could be unstable. This can be explained by the fact that the use of nonlinear controllers increases the region of attraction of the local dynamics making the region of attraction of the whole system larger.
3. The system critical clearing time (CCT) is greatly increased. Therefore, the increased region of attraction implies larger critical clearing time since the duration of a disturbance that can be sustained by the system without losing stability is now longer.

2.3 System-wide stability criteria for guaranteed transient stabilization

Transient stability is concerned with the rotor angle δ_i and the rotor speed ω_i dynamics. The first system-wide criterion for transient stability is to have the rotor angle/speed equilibrium of the full system being asymptotically stable. In other words, to have that:

$$(\delta_{10}, \dots, \delta_{n0}, \omega_{10}, \dots, \omega_{n0})$$

is **asymptotically stable** (for a system with n generators). A sufficient condition that renders the above statement true is to have a system Lyapunov function, more specifically a positive definite function V_{system} for which the following conditions hold:

$$V_{system} = \sum_{i=1}^n V_i > 0 \quad \text{Equation 2-1}$$

$$\dot{V}_{system} = \sum_{i=1}^n \dot{V}_i < 0 \quad \text{Equation 2-2}$$

around the system rotor angle/speed equil. point given above. As can be seen above, V_{system} can be formed from the Lyapunov functions of the individual generators. In general, it is hard to find a Lyapunov function for the full system. Nevertheless, energy-like Lyapunov functions were proposed in the literature long time ago and were used to prove asymptotic stability of the swing dynamics under certain assumptions. It is important to note that, the mere existence of a Lyapunov function for the relevant dynamics does not directly address the transient stability problem. What does so, is to have a region of attraction (ROA) large enough, that, for a given system subjected to a disturbance the generator state-variables remain in this ROA. In the power systems language, to have a critical clearing time (CCT) larger than the duration of the worst disturbance. At this point, we point out an observation that is going to form the basis of our proposed methodology.

Observation 1

The ROA of a full power system is dependent on the ROA of the individual generators that comprise the system. In fact, the ROA of the full system can be given as the cartesian product of the ROA of each generator in the system with n generators.

$$ROA = ROA_1 \times ROA_2 \times \cdots \times ROA_n \quad \text{Equation 2-3}$$

The above observation makes clear that, a way to increase the ROA of the full system is to increase the ROA of each of the generators dynamics. A nonlinear controller for a given generator can definitely achieve that. Placing a nonlinear controller to every single generator in a system is going to be de facto effective but rather too costly to be implemented in a realistic scenario. The localized power systems response to contingencies can be used to simplify this problem and avoid such expensive solutions. Specifically, we can first identify the set of generators that can be characterized as “critical” and are the ones that fine-tune the CCT for a given set of contingencies. Then, we propose stability criteria that the critical generators have to meet and consider several control designs to meet them. As a result, this will improve the ROA of these critical generators and as a consequence increase the CCT of a given system.

2.4 Stability criteria for single or group of components

2.4.1 Single component stability criterion

Following the above analysis, we argue that with the proper control design a single component or group of components can guarantee that their rotor angle/speed dynamics are *asymptotically stable*. To do that, consider that for a single component we can define a **candidate control Lyapunov function** (CLF) $V_i = f_i(\delta_i, \omega_i)$ for which it holds:

$$V_i > 0 \quad \forall (\delta_i, \omega_i) \in \mathcal{D}_i \setminus (\delta_{i0}, \omega_{i0}) \quad \text{Equation 2-4}$$

Then, we can use the controller for the generator to guarantee that:

$$\dot{V}_i < 0 \quad \forall (\delta_i, \omega_i) \in \mathcal{D}_i \setminus (\delta_{i0}, \omega_{i0}) \quad \text{Equation 2-5}$$

The derivative of the above Lyapunov function is computed along the trajectories of the interconnected system, with the swing dynamics having their nonlinear form. That, guarantees the validity of the controller and its performance for large deviations around the equilibrium point. An example of a CLF that can be used is for example a quadratic function of the form:

$$V_i = \frac{1}{2}(\delta_i - \delta_{i0})^2 + \frac{1}{2}(\omega_i - \omega_{i0})^2 \quad \text{Equation 2-6}$$

2.4.2 Single component stability criterion

We can extend the idea of constructing a CLF for a single component into constructing a CLF for a group of components. For instance, for a group of two components, namely component **i** and **j**, we can find a similar function V_{ij} , e.g the sum of V_i and V_j , for which we have:

$$V_{ij} = V_i + V_j > 0 \quad \text{Equation 2-7}$$

Then, we can design the controllers of this group of components in such a way that their CLF becomes negative definite, i.e

$$\dot{V}_{ij} = \dot{V}_i + \dot{V}_j < 0 \quad \text{Equation 2-8}$$

Around the rotor speed/angle equilibrium point of the group of two generators given below.

$$(\delta_{i0}, \delta_{j0}, \omega_{i0}, \omega_{j0})$$

The basic advantage of achieving asymptotic stability as a group is that the control potential of the various components that constitute the group can be used effectively, without having to resort to expensive control for each component independently. This rather simple idea provides the basis for major innovation on the control design methods for today's and future power systems.

Additionally, since the group stability metric can be used to design group controllers, it indirectly provides a way of assessing the tradeoffs between complex decentralized controllers and communication-based controllers. Also, it gives freedom on how to exploit the control capability of any given group as long as the group meets its stability criterion collaboratively. Of course, the above idea can be extended for a larger group of components.

2.5 Recommended control design approaches to meet the distributed stability metrics

In order to meet the above criteria, each dynamical component or group of components (iBAs) have to design their automation appropriately. More specifically, to guarantee stability of their sub-systems under interconnections the components or group of components can design their controllers using the approaches described next:

1. Using known bounds on their interactions variables, they can design robust controllers to guarantee stability of their local dynamics.
2. Or, if local measurements of the interaction variables are available (e.g via PMUs) they can design control schemes that cancel their interactions with the rest of the grid and guarantee stability of their local dynamics.

We emphasize that, the control designs in 2 would be continuous and not discrete. Furthermore, the controllers do not need to know the exact contingency as long as they are able to drive the dynamics to a valid operating point. Thus, the control logic is not dependent on the specific contingency since the controllers guarantee cancelling of the interactions using the power output variable and its derivative. That means, when a contingency occurs, the controller would guarantee stability by cancelling its effect through cancellation of the power output variations or its derivative. As long as these variables can be measured or observed the controller can guarantee its properties. Now, the contingency's effect on the controller comes only to the operating point that the controller drives the system dynamics. With the controller being able to drive the system to valid operating point this interdependency also disappears.

Both approaches enable the components to retain stability of their local dynamics within the interconnected grid. A control approach belonging to category 2 is analyzed in this report. Specifically, we explore an application of nonlinear feedback linearizing excitation controllers that cancel the interactions of each generator with the grid and stabilizing its local dynamics provably. Physically, this is achieved by regulating the DC field voltage in response to signals from the rotor angle and speed of the generator such that the output voltage of the generator is “balancing out” the effect that the rest of the grid has on the local power output of the generator. By doing that, it “cancels out” the effect of the neighbors into the local dynamics and is able to stabilize the local dynamics.

2.6 Generalization of the stability criteria for other dynamical problems

Although we analyzed the required stability criteria for transient stability, similar criteria can be derived for all the dynamical problems explained in Table 1-1. We note that, the proposed transient stability criteria will also guarantee no small-signal instabilities. The reason is that with the proposed criteria stabilization of the generator rotor angle/speed dynamics is guaranteed during

large disturbances. Therefore, since small-signal instabilities are concerned with the generator rotor angle/speed dynamics for small-magnitude disturbances, meeting the transient stability criteria will also guarantee small-signal stability. We describe a methodology to derive the criteria for the other dynamical problems as well. For example, criteria that will guarantee that SSR is avoided can be derived by employing a more detailed model of the generator turbine dynamics. Then, a desired equilibrium point as in the transient stability case needs to be assigned. Around this equilibrium point we can design a candidate control Lyapunov function $V_{SSR,i}$ and we can design the generator controllers to guarantee that $\dot{V}_{SSR,i} < 0$ is met. When that holds, with the relevant dynamics we can ensure that all the relevant dynamics reach their equilibrium point eliminating any SSR.

2.7 Quality of Response (QoR) problem and related standards

We have discussed so far in this report stability criteria that are sufficient for guaranteeing transient stability as well as small signal stability. These criteria are very important for ensuring that rotor/speed dynamics do not become unstable in response to given list of contingencies. However, in electric power systems it is also necessary to ensure specific Quality of Response (QoR) in response to disturbances. This means that while we may be able to guarantee sufficiently large ROA for the system to remain in synchronism, the approach described so far does not provide any bounds on rate of response to the disturbances. Consider that, when a contingency happens in a given power system its dynamic effects will propagate through the system. The faster the generators compensate power imbalances seen, the smaller system-wide effects of the disturbance will be. This can be explained as when the power imbalance of each generator is eliminated and the synchronous speed is reached, the rotor angle is also going to reach a steady-state equilibrium. Recall that, the rotor angle dynamics is a means by which a disturbance propagates through the system. As a result, ensuring QoR in this case, is going to have a direct impact on how far a disturbance propagated through the system.

2.7.1 Quality of response (QoR) standards

Having described the significance of QoR we can now formulate the problem mathematically. Since transient stability has to do primarily with power imbalances, we propose that a meaningful QoR criterion would be to ensure that for any generator the rate of change of power output imbalance $\Delta P_{ei} = P_{mi} - P_{ei}$ is bounded below.

$$|\Delta \dot{P}_{ei}| > \varepsilon \quad \text{Equation 2-9}$$

To establish a connection of the above statement with the previous sections remember that in the previous sections we showed that a generator should ensure that a candidate Lyapunov function $V_i = (\omega_i - \omega_{i0})^2$ is becoming negative definite or $\dot{V}_i = -k(\omega_i - \omega_{i0})^2$ where k is some control design. To ensure that a generator has to make sure that:

$$\dot{\omega}_i = -k(\omega_i - \omega_{i0}) \quad \text{Equation 2-10}$$

But since we have also that:

$$\dot{\omega}_i = \frac{\Delta P_{ei}}{2H_i} \quad \text{Equation 2-11}$$

we can rewrite the power imbalance dynamics as:

$$\Delta \dot{P}_{ei} = \frac{-k \Delta P_{ei}}{2H_i} \quad \text{Equation 2-12}$$

which leads to the following solution for the power imbalance :

$$\Delta P_{ei} = \Delta P_{ei} e^{\frac{-k}{2H_i} t} \quad \text{Equation 2-13}$$

That means, by tuning the gain **k** accordingly we can control how fast the generator “covers its imbalance”. From equation 2-12, we can see that by having some bounds on the ΔP_{ei} we can derive the necessary value of the gains **k** such that the rate of change $|\Delta \dot{P}_{ei}|$ meets the lower bound ε as well. That means, after the disturbance is eliminated, the generator will “cover” its imbalance with rate of change greater than ε .

Note that the choice of Lyapunov function is independent from the level of modeling detail in specific dynamic components and their primary controllers. This makes it possible to design many different types of controllers.

While further work is needed to relate protection and stability standards proposed, the basic idea would be to also set an upper limit on the rate of change of electrical power so that the equipment does not get damaged. The information about this limit must be provided by the manufacturers themselves. Of course, this upper limit depends on the time over which the standards must be met. It will be different for different phenomena relevant for industry standards.

2.8 Intelligent Balancing Authorities as means for meeting the stability criteria

In the previous sections we showed how a single or group of components can define an appropriate CLF and guarantee asymptotic stability of their rotor angle/speed dynamics using their controllers. At this point, we propose the following definition.

***Intelligent Balancing Authority (iBA)** is a single or group of components (portfolios of components) that guarantees nonlinear transient stabilization of their generator members (thereby they meet the stability criterion) via appropriate control design. They are designed assuming given list of disturbances and ranges of operating conditions.*

Shown here are possible iBAs on a simple 3 bus system comprising two conventional generators, wind generator with power electronically controlled storage and a thyristor controlled series capacitor (TCSC) controlling line flow. It is shown that, instead of setting transient stability requirements on each component prior to allowing it to connect to the grid, portfolios of highly diverse components can be formed to save on individual control requirements. Notably, transient stabilization metric can be met by a combined control of generator at bus 1 and power electronically controlled wind generator. This is a nice example of how an unconventional

intermittent resource can help increase critical clearing time without setting additional stress on conventional generator's governor control or when its exciter reaches saturation. Similarly, a conventional generator located at bus 2 in combination with TCSC jointly meet transient stability metric.

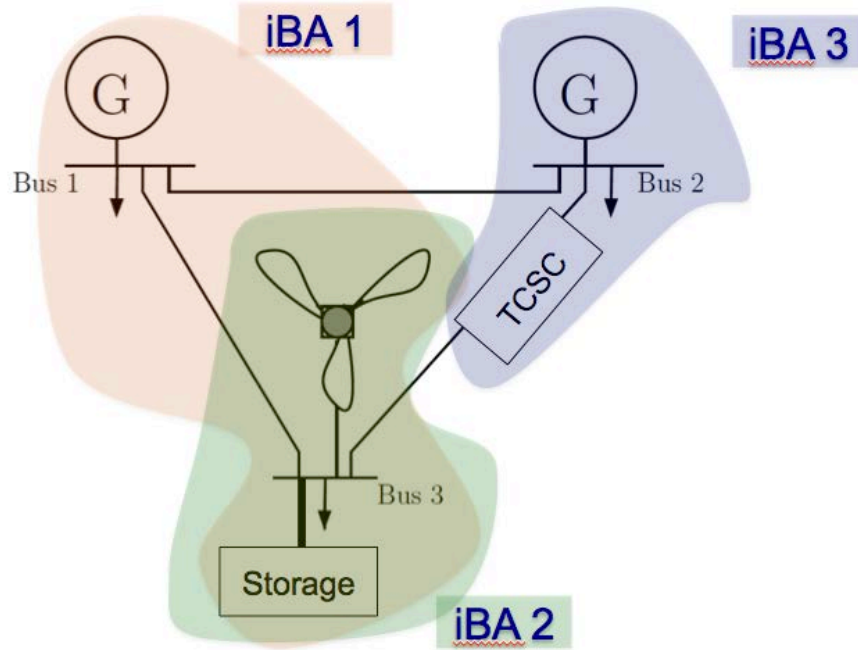


Figure 2-1: Examples of possible iBAs on a 3-bus system

It is important, however, to observe in this simple power system that all components must belong to an iBA, each of which being responsible for meeting transient stability metric. If this is not the case, no guaranteed stability of the interconnected grid is achievable.

However, in order to take advantage of these new opportunities, it is essential to develop protocols and methods for creating iBAs. Note that the effects of the three portfolios for the 3 bus system are not overlapping. This can be achieved either by creating boundaries so that the iBAs are weakly connected during contingencies of interest, or by designing iBA controllers so that the effects of neighboring iBAs are cancelled out. The trade-off between these two different criteria for forming iBAs are system dependent.

In what follows we consider two qualitatively different methods for forming boundaries of iBAs. The first is a top-down approach by the utility responsible for ensuring that transient stability of the system as a whole is met. The second approach is a bottom-up approach based on the requirement that each component must ensure that it is transiently stable with respect to the list of contingencies of interest; it can do so by either having sufficient control itself or by joining an iBA. The first approach generally considers grouping of generators with the existing controllers. The second approach is particularly intriguing as it gives incentives to the components to explore several options. Some of these require simple expensive fast storage, and the others may require

more complicated communications-based coordination with other components, all together resulting in more efficient and less costly ways of meeting the criteria.

2.9 Method to identify the critical generators

A possible heuristic algorithm for defining critical generators area of a given system and a given set of contingencies can be found in [16]. In short, a transient stability analysis is done to simulate interconnected system response to a specific contingency of interest, and generators are found which have significant response to this disturbance. Areas comprising generators connected to these critical generators form an iBA relevant for this contingency. This is illustrated next using small IEEE test systems.

3. Illustration of top-down formation of iBAs using the IEEE 24-bus reliability test system (RTS)

We illustrate here the result of the heuristic method for finding the critical generators and creating iBAs by the system (utility) operator in a top-down manner.

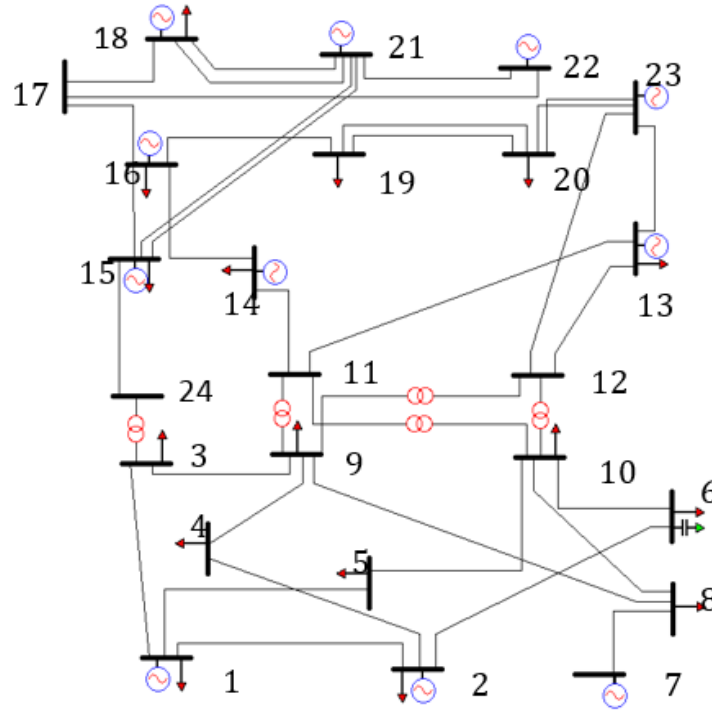


Figure 3-1: IEEE 24-bus RTS

3.1 Contingency scenario

For the IEEE 24-bus RTS we consider the following contingency.

Table 3-1: Contingency on IEEE RTS 24 Bus System

CONTINGENCY CONSIDERED ON THE IEEE RTS 24 BUS SYSTEM	
CONTINGENCY (CATEGORY B)	DURATION (secs)
Tripping of generator 1 after 3-phase fault on its terminal bus	0.17

As mentioned earlier, the iBAs are contingency dependent. Here a single contingency of a generator connected to bus 1 tripping is considered. We emphasize that the generator is assumed to be reconnected with the grid after 0.17 seconds.

3.2 Identification of the critical area on the IEEE 24-bus RTS

We conducted simulations on the IEEE 24-bus system under two different loading scenarios and for the contingency described above. The following graph shows the maximum power output deviations of the 11 generators.

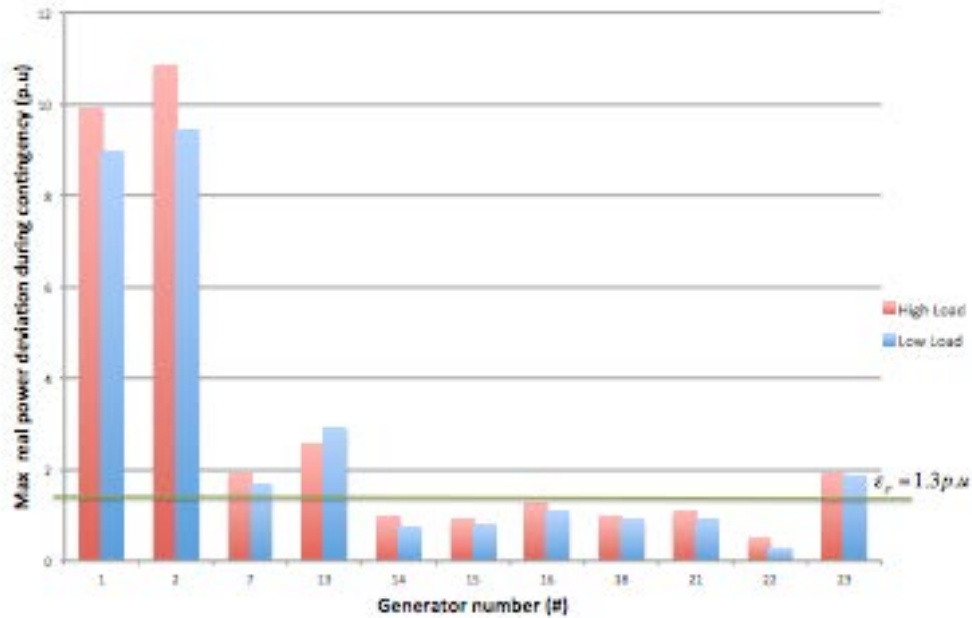


Figure 3-2: Maximum power output deviations during high/ low load scenarios and under the cont. of Table 3-1

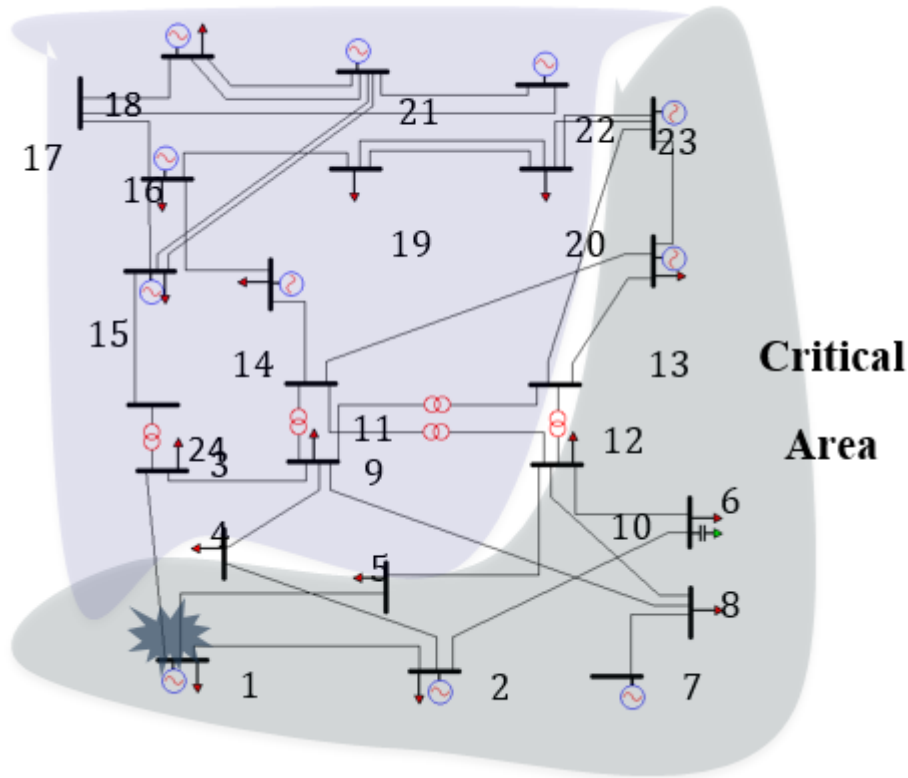


Figure 3-3: Critical area identification for fault at gen.1

3.3 iBA formation: non-cooperative scenario

Next, we consider a scenario during which the critical generators decide not to cooperate. In this case, each generator in the critical area defines an iBA on its own. As a result, the decentralized controller for each generator that is described below needs to decouple the dynamics of each generator with the rest of the grid. Nevertheless, it is different than any approach that assumes decomposition of the system into single-machine equivalents in the following aspects. Single machine equivalents presume approximation of the rest of the system and therefore any controller designed based on these single-machine equivalents cannot provide provable performance when used in the full dynamical system. In our case below, the controller decouples the local dynamical model from the rest of the grid, by cancelling its exact, meaning no approximations are assumed here for the rest of the grid, interactions. On the contrary such a scheme, provides provable performance since it is based on exact representation of the full system dynamics. (since the dynamical interactions are exact). The controller that is considered here, although is based on the idea of cancelling the interactions with the grid, did not exhibit any fighting with the same controller, placed even in neighboring buses. That means there were no conflicting objectives for the controllers.

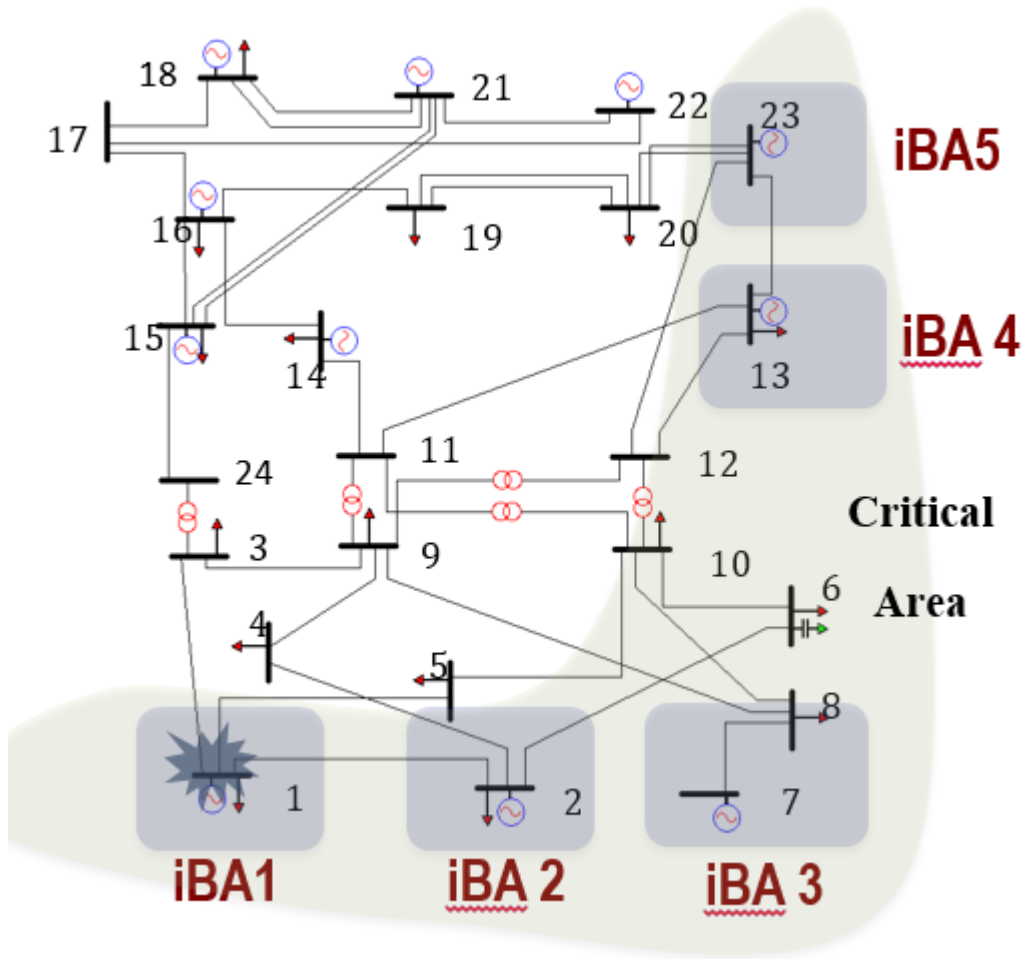


Figure 3-4: iBA formations on the critical area

3.4 iBA control: feedback linearizing exciter

We briefly describe the idea behind the feedback linearizing excitation controller. In general, a feedback linearizing controller (FBLC) can invert the nonlinearity of a given nonlinear system and can make it behave as a linear system in closed-loop. Then, a linear input can be easily designed to ensure that the linear system possesses an asymptotically stable equilibrium point. In this work, we use feedback linearizing excitation control (FBLC) and we assume that each generator is modeled with the one-axis model presented in previous sections. The states of each generator are $e_{q,i}'$, δ_i , ω_i and are described by the corresponding nonlinear dynamics. Using the FBLC, this nonlinear system can take the form of the following linearizing system.

Comment: The basic idea of this type of nonlinear controller is that we can transform the dynamical model in a new form where it would be easier to cancel the nonlinearities of the system. In our particular case, the initial dynamical model is given by the states $e_{q,i}'$, δ_i , ω_i . The new state space, in which it is easier to cancel the nonlinearities, can be described in terms of the states δ_i , ω_i , $\dot{\omega}_i$ where the rotor speed acceleration takes the place of the state $e_{q,i}'$. It can be described as:

$$\dot{z}_i = A_i z_i + B_i v_i \quad \text{Equation 3-1}$$

where the new state-vector becomes:

$$z_i = [\delta_i \ \omega_i \ \dot{\omega}_i]^T \quad \text{Equation 3-2}$$

And v_i is the input of the linearized system that can be designed to ensure that the system has an asymp. stable equilibrium point. In this case, we would also have from Lyapunov theory that:

$$\exists P_i \text{ such that } V_i = z_i^T P_i z_i \quad \text{Equation 3-3}$$

is a Lyapunov function. From the above we can see, that the rotor angle/speed equal point becomes asymptotically $(\delta_{i0}, \omega_{i0})$ stable for the nonlinear swing dynamics. Therefore, each generator meets its stability criterion alone using the above controller.

3.5 Simulation results & discussion

The feedback linearizing excitation controllers derived above were applied on the IEEE RTS 24-bus system. The simulation results below depict the dynamic response of the system under the contingency of Table 3-1.

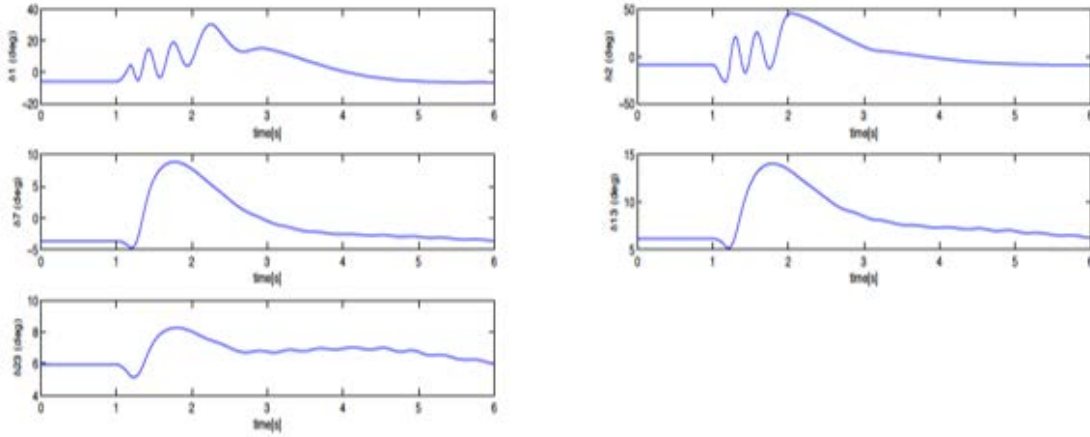


Figure 3-5: Rotor angle response of gens 1,2,7,13,23 under the low-load scenario

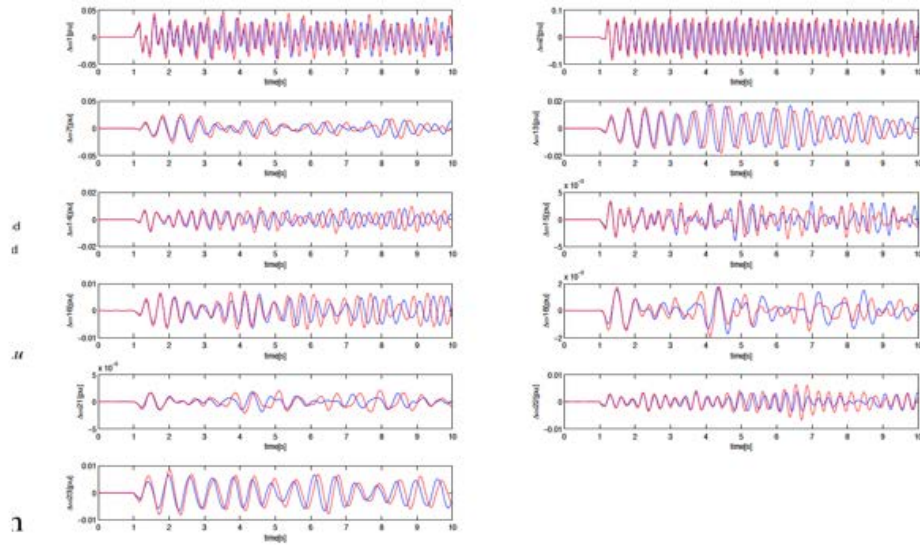


Figure 3-6: Frequency response without iBA for different loading conditions

blue: low loading scenario

red: high loading scenario

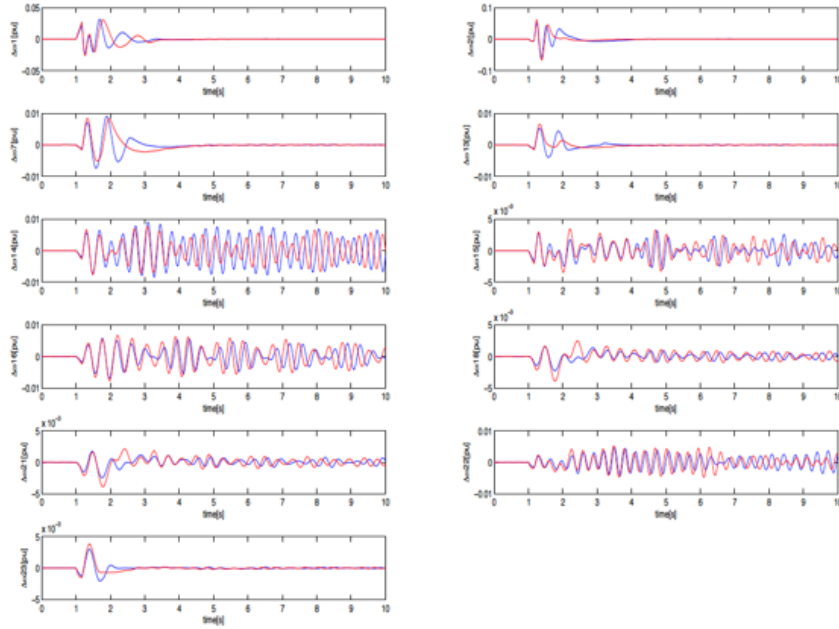


Figure 3-7: Frequency response with iBA for different loading conditions

blue: low loading scenario

red: high loading scenario

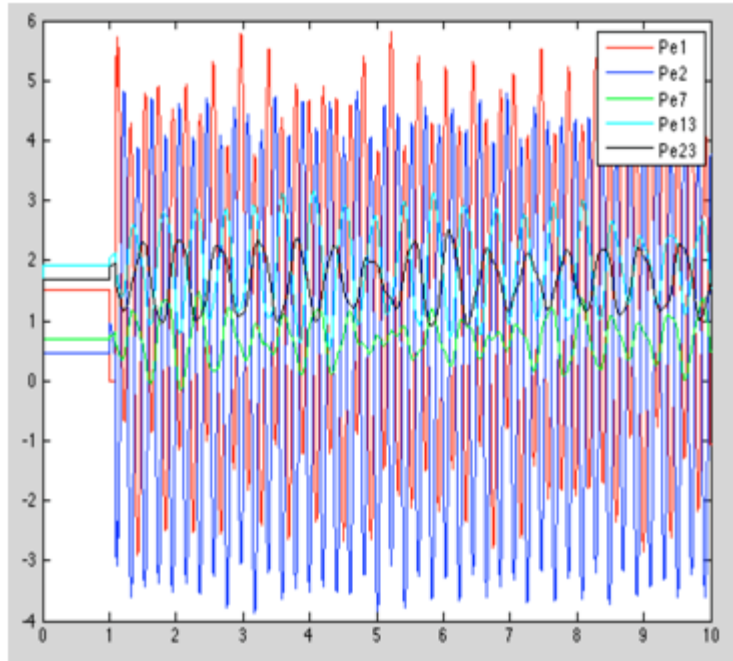


Figure 3-8: Power output response of gens 1,2,7,13,23 without iBAs

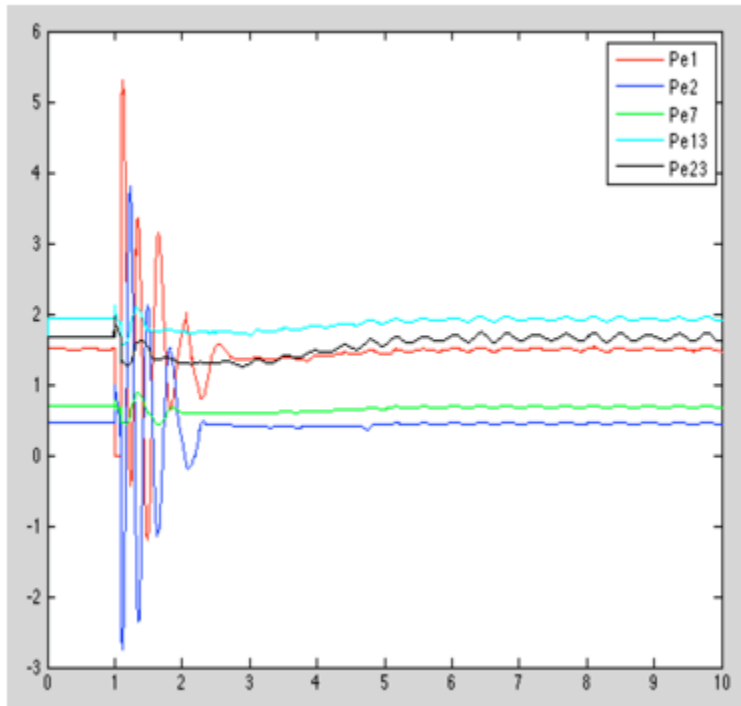


Figure 3-9: Power output response of gens 1,2,7,13,23 with iBAs

Table 3-2: Critical Clearing Time

CRITICAL CLEARING TIME WITH AND WITHOUT iBA (LOW LOAD SCENARIO)	
SCENARIOS STUDIED	t_{CCT} (secs)
Without iBAs- AVR _s	0.36
With iBAs- FBLCs/fast valving	0.47

3.6 Discussion on the results

From the above results several conclusions can be made. The first, is that the rotor angle and power response of the critical generators with the introduction of the iBAs and the advanced control, becomes very damped. That is in contrast with the power output response without iBAs but with AVR exciters, which is very oscillatory. This means that the critical generators rapidly synchronize with the grid without propagating oscillations throughout the system. The most important improvement with the iBAs is the CCT increase that went from 0.36s to 0.47s. This evidences the enhanced transient stabilization that is achieved with the advanced automation/control used by the iBAs.

4. iBA on the IEEE 14-bus system

4.1 Coordinated nonlinear control of a generator and a STATCOM/Battery storage system for transient stability and voltage regulation

In this section we illustrate the idea of iBAs on the IEEE 14-bus system. More specifically, we define an iBA to be a module, comprised of a synchronous generator and a STATCOM/Battery storage system. The iBA control objectives are transient stabilization of the synchronous generator and terminal voltage regulation. The reason for defining a coordinated control scheme and a corresponding iBA is that the synchronous generators exciter cannot achieve transient stability and voltage regulation simultaneously. Many researchers pointed out this observation and the explanation is given as follows. Transient stability is achieved when the rotor angle/speed dynamics are controlled. On the other hand, when the exciter is controlled in such a way that it regulates the voltage to the equilibrium rapidly it loses the capability to control the rotor speed/angle dynamics. In other words, when the goal is to control the rotor speed/angle dynamics the voltage has to be a free variable for the exciter and it will settle to an equilibrium that is an outcome of the rotor angle/speed dynamics equilibrium.

Based on the above analysis, in this section we develop a nonlinear coordinated controller for an iBA comprising of battery storage and generator excitation, which jointly guarantee terminal voltage regulation and transient stabilization of the generator. Such controller is designed to meet the transient stability criteria/metric proposed. The proposed controller is based on a new state transformation which enables the derivation of a Multi-Input Multi-Output (MIMO) feedback-linearizing controller. First, we define the state-space transformation that maps the original state-space into a new state-space which has all state-variables relevant for achieving transient stability and voltage regulation. Then, we design the coordinated controller for the energy storage and the generator excitation based on this transformation and MIMO feedback linearization theory. We illustrate the performance of this controller by simulating closed-loop dynamics of the IEEE 14-bus power system.

4.2 Modeling of a synchronous generator

Each generator is modelled as a voltage behind the transient reactance. The center of inertia is also used as a reference for the generator rotor angle. The dynamic model of a generator can be represented by the next dynamic equations (*one axis model*) given in [11]:

$$\dot{\delta} = \omega_s(\omega - \omega_0) \quad \text{Equation 4-1}$$

$$\dot{\omega} = \frac{(P_m - P_e - D(\omega - \omega_0))}{2H} \quad \text{Equation 4-2}$$

$$\dot{E}'_q = \frac{(E_{fd} - E'_q - (x_d - x'_d)i_d)}{T'_{d0}} \quad \text{Equation 4-3}$$

$$P_e = E_q' i_q \quad \text{Equation 4-4}$$

Variable P_e represents the electrical power output of the generator and P_m the mechanical power. The rotor angle and the generator speed are given by δ and ω respectively. E_q' is the voltage behind the transient reactance. The variables that represent the coupling of the generator model with the rest of the grid are the currents i_d , i_q . The generator damping is given by the variable D . The excitation voltage input is E_{fd} . The constants H , ω_s , T_{d0}' represent the inertia constant, the synchronous speed $2\pi 60$ r/s and the transient time constant of the field circuit respectively.

4.3 Load Modeling

The loads are represented as constant impedances and eliminated using Kron's reduction. Therefore, the internal representation of the studied system is obtained where only the generator dynamics described by equations (4.1)-(4.3) and the storage dynamics described by (4.5), (4.6) are present.

4.4 Modeling of a STATCOM integrated with a Battery Energy Storage System

According to [12] the dynamic model for a STATCOM integrated with a battery energy storage can be written in the network reference frame D-Q:

$$\dot{i}_{Ds} = \omega_s \left(\frac{-R_s}{L_s} i_{Ds} + \omega_0 i_{Qs} + \frac{u_\alpha - V_{sD}}{L_s} \right) \quad \text{Equation 4-5}$$

$$u_\alpha = k V_{dc} \cos(\alpha + \theta)$$

$$\dot{i}_{Qs} = \omega_s \left(\frac{-R_s}{L_s} i_{Qs} - \omega_0 i_{Ds} + \frac{u_\beta - V_{sQ}}{L_s} \right) \quad \text{Equation 4-6}$$

$$(\alpha + \theta), u_\beta = k V_{dc} \sin(\alpha + \theta) \quad \omega_0 = 1 \text{ .u}$$

Note that, since energy storage is connected on the DC side of the STATCOM, the capacitor voltage V_{dc} is held constant. For this reason the dynamics of the V_{dc} voltage are not included in the above model. In order to transform the above model in a form that will enable decoupled P-Q control we use the next equation:

$$\begin{pmatrix} i_{Ps} \\ i_{Rs} \end{pmatrix} = \begin{pmatrix} \cos(\theta) & \sin(\theta) \\ -\sin(\theta) & \cos(\theta) \end{pmatrix} \begin{pmatrix} i_{Ds} \\ i_{Qs} \end{pmatrix} \quad \text{Equation 4-7}$$

Where i_{Ps} is the active current which is in phase with the terminal voltage and i_{Rs} is the reactive current which lags the terminal voltage by 90° . Angle θ is the terminal voltage angle with respect to the D axis. We use the transformation to recast the STATCOM-BESS model into the following form which is more convenient for control design.

$$\dot{i}_{P_s} = \omega_s \left(\frac{-R_s}{L_s} i_{P_s} + \left(\omega_0 + \frac{d\theta}{dt} \right) i_{R_s} + \frac{u'_\alpha - V_s}{L_s} \right) \quad \text{Equation 4-8}$$

$$\dot{i}_{R_s} = \omega_s \left(\frac{-R_s}{L_s} i_{R_s} - \left(\omega_0 + \frac{d\theta}{dt} \right) i_{P_s} + \frac{u'_\beta}{L_s} \right) \quad \text{Equation 4-9}$$

The variables R_s and L_s represent the STATCOM transformer losses whereas $u'_\alpha = k V_{dc} \cos(\alpha)$, $u'_\beta = k V_{dc} \sin(\alpha)$ the control inputs for the transformed system. The magnitude k and the angle α can be obtained by the following equations:

$$k = \frac{\sqrt{u'^2_\alpha + u'^2_\beta}}{V_{dc}} \quad \alpha = \cos^{-1} \left(\frac{u'_\alpha}{k V_{dc}} \right) \quad \text{Equation 4-10}$$

4.5 Problem Formulation - Transient stability and voltage regulation

Synchronization of a generator with the grid can be achieved by stabilization of its speed to the synchronous speed. In that case, the acceleration of the generator should also be regulated to zero. All things considered, the control objectives for transient stabilization of a generator can be summarized by the following two equations:

$$\lim_{t \rightarrow \infty} \|\omega(t) - \omega_0\| = 0 \quad \text{Equation 4-11}$$

$$\lim_{t \rightarrow \infty} \|\dot{\omega}(t)\| = 0 \quad \text{Equation 4-12}$$

In order to achieve voltage regulation at the terminal bus of a generator the voltage should be asymptotically regulated to an acceptable equilibrium value. The pre-fault voltage equilibrium point is used as a desirable equilibrium point. By considering this, the control objective for voltage regulation can be described by:

$$\lim_{t \rightarrow \infty} \|V_s(t) - V_{s0}\| = 0 \quad \text{Equation 4-13}$$

Asymptotic regulation of the above variables to their equilibrium can be achieved by reformulating the system dynamic equations such that all the relevant variables for transient stabilization and voltage regulation are becoming state variables. A nonlinear stabilizing controller for the transformed system implicitly realizes the above objectives. Practically, it is important that the controller also keeps the speed and voltage between reasonable upper and lower limits to avoid triggering of the protection.

4.6 Derivation of the iBA-based coordinated excitation and STATCOM/BES controller

The full derivation of the coordinated control scheme can be found in [20].

4.7 Simulation Results

4.7.1 Scenarios

Our proposed controller is applied on the modified IEEE 14 bus system depicted in Fig.4-1. The performance of the controller is evaluated under two contingency scenarios.

Case 1: A three phase short-circuit at bus 2 for 150 ms

Case 2: A three phase short-circuit at the middle of line 1-2 for 150 ms

A STATCOM-BESS is added at bus 1 and our proposed controller coordinated the actions of the excitation and the STATCOM-BESS. The rotor angle responses and the terminal voltage responses of all generators during the two considered scenarios are shown in Fig.4-2 and Fig.4-3. In the same Figures the excitation input of generator 1 and the STATCOM-BESS inputs are also shown. As benchmark controllers for comparison a high-gain excitation controller for generator 1 and a simplified controller for the storage were used. For the storage controller the inputs are given by $u_{\alpha}' = V_s$ and $u_{\beta}' = 0$.

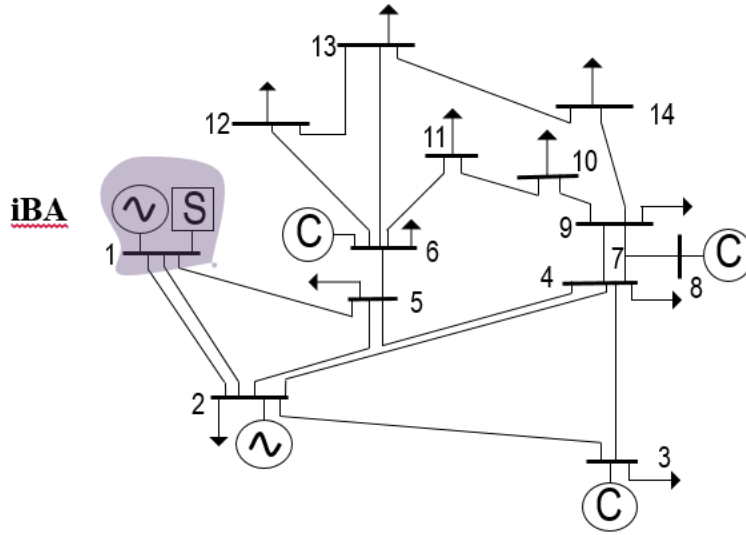


Figure 4-1: Modified IEEE 14 bus system with iBA at bus 1

4.7.2 Evaluation Results

It can be seen from the results in Fig.4-2 and Fig.4-3 that our proposed coordinated controller asymptotically stabilized the angle/speed and the terminal voltage to their equilibrium values. These objectives are very important aspects of power system operation and control.

During the Case 1 scenario it can be observed from the results in Fig.4-2 that the damping of rotor angle oscillations is significantly improved with the proposed controller. Similarly, the voltage is asymptotically regulated to the equilibrium value almost immediately after the fault without any oscillations. On the other hand, with the high-gain excitation controller operating in the AVR

mode, oscillations were present in the rotor angle response. From Fig.4-2 it can be seen that with the benchmark controller the voltage response was also very oscillatory. The STATCOM-BESS did not contribute significantly in the asymptotic stabilization of the rotor angle/speed and the voltage. From Fig.4-2 a key observation can be made. The excitation input of generator 1 saturated significantly during these dynamics as a result of the high gain on the exciter.

During the Case 2 scenario it can be seen from Fig.4-3 that the rotor angle and terminal voltage at bus 1 are stabilized rapidly. With the high-gain AVR controller, oscillations were present in both responses. Similarly, in this fault scenario the generator 1 exciter input saturated significantly. From the results in Fig.4-2 and Fig.4-3 it can be concluded that the proposed controller can enhance the capability of a generator to retain its synchronism with the grid. At the same time, it can regulate the terminal voltage to the equilibrium point.

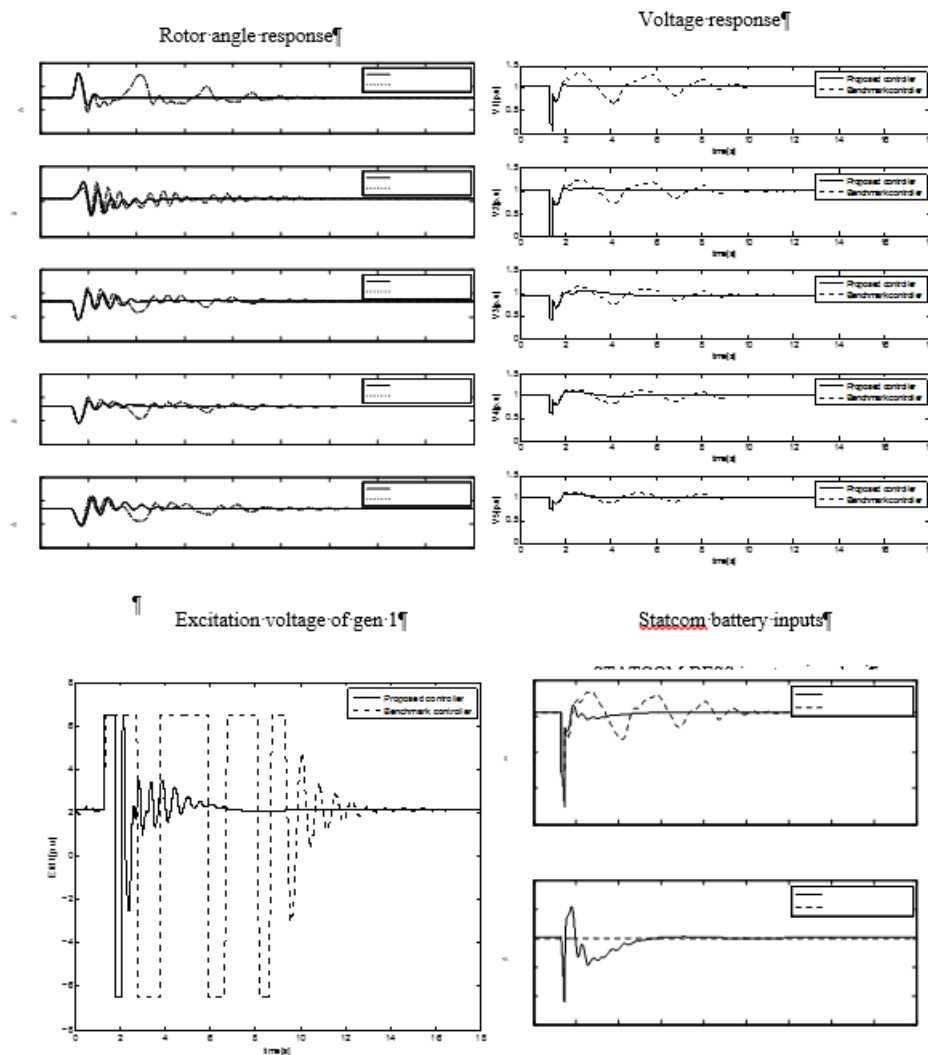


Figure 4-2: System response with the proposed and with the benchmark controller under the Case 1 scenario

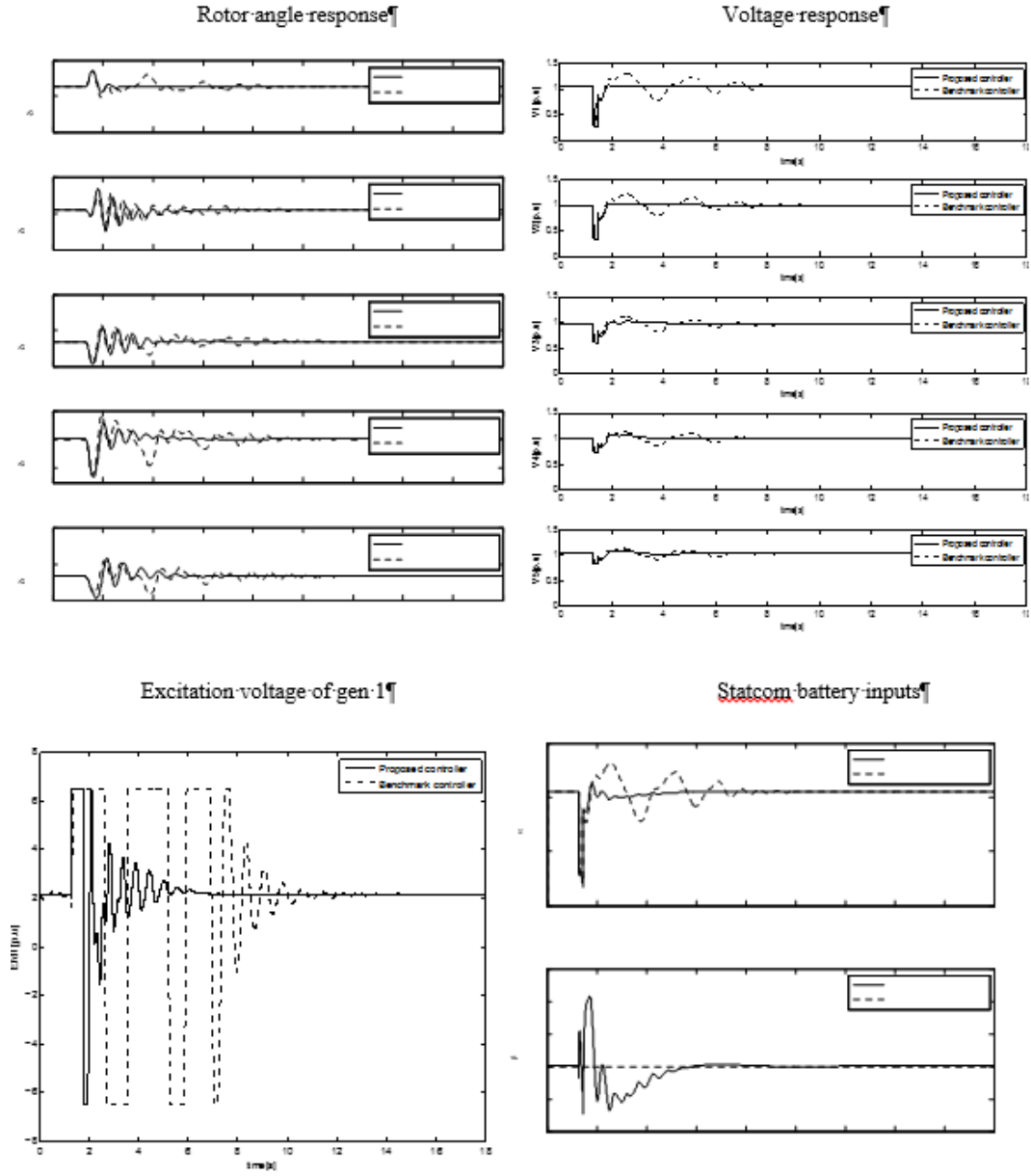


Figure 4-3: System response with the proposed and with the benchmark controller under the Case 2

5. iBA on a proof-of-concept - 3-bus system

5.1 Nonlinear control of a DFIG with energy storage for transient stabilization of a neighboring synchronous generator

To further illustrate the idea of intelligent Balancing Authorities (iBAs), we study the proof-of-concept 3-bus system, shown in Fig.5-1. We consider the following setting:

- The synchronous generator 2 is found critical for losing synchronism with the grid.
- The local controller of generator 2 is a typical exciter operating in the AVR mode. Thereby, it cannot guarantee transient stabilization.

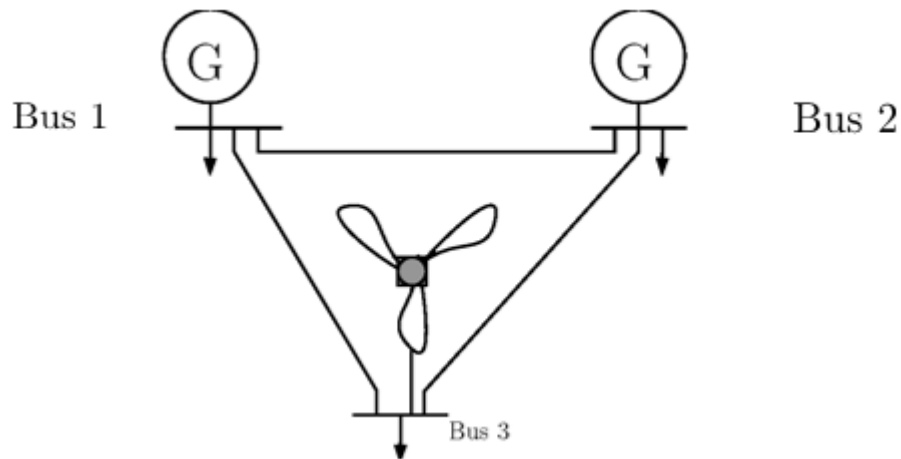


Figure 5-1: 3-bus system

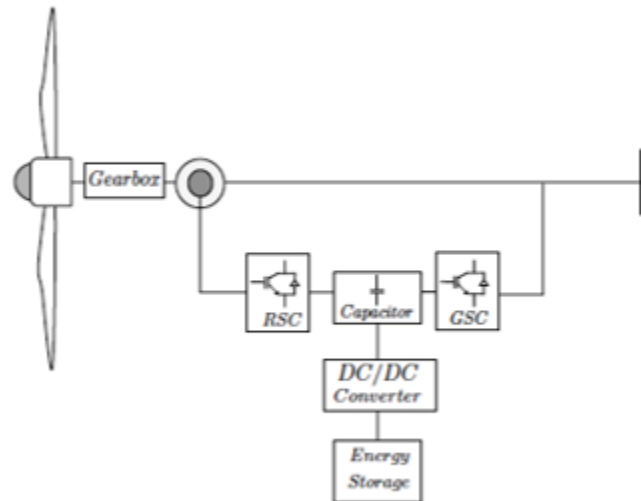


Figure 5-2: Wind DFIG with storage at bus 3

In this section, we aim to address the following key questions:

Question 1

Can we use the energy stored, into the DFIG scheme, to robustly guarantee the synchronism of generator 2 with the grid, after a fault?

Question 2

Independently, can we achieve maximum power point tracking (MPPT) from the wind turbine through control of the RSC?

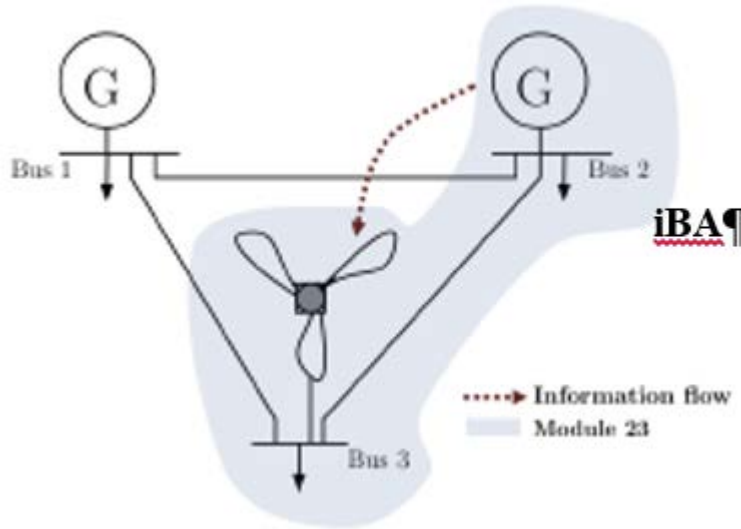


Figure 5-3: Formation of an iBA-module 23: wind DFIG/storage 3 and synchronous gen. 2

5.2 iBA-based control design for transients stabilization of generator 2

For the control design we define a candidate Robust Control Lyapunov Function (RCLF) for the module (ij) that will guarantee between others meeting the transient stability criteria. Note that, a module ij is comprised with a SG i and WG j.

$$\begin{aligned} \mathcal{V}_{ij,1} &= \frac{1}{2}(\delta_i - \delta_{i0})^2 + \frac{1}{2}(\omega_i - \omega_{i0})^2 \\ \mathcal{E}_{ij,2} &= \frac{1}{2}(E_{k,j} - E_{k,jopt})^2 \\ \mathcal{E}_{ij,3} &= \frac{1}{2}(E_{dc,j} - E_{dc,j0})^2 \end{aligned}$$

where δ_i , ω_i are the rotor angle and speed of generator i and $E_{k,j}$ and $E_{dc,j}$ are the kinetic energy on the shaft of the WG j and the stored energy on the capacitor between the two converters of the WG j.

From above, observe that when the RCLF $\mathcal{V}_{ij,1} \rightarrow 0$, iBA ij achieves:

- **MPPT from WG j**
- **Transient stabilization of generator i**

5.3 Design of the RSC controller

The RSC controller is designed such that the following hold:

- $\dot{\mathcal{E}}_{ij,2} < 0, \forall E_{k,j} \in \mathcal{D}_2 \setminus E_{k,jopt}$
- This implies, as $t \rightarrow \infty$
 $\Rightarrow \mathcal{E}_{ij,2} \rightarrow 0 \Rightarrow E_{k,j} \rightarrow E_{k,jopt} \Rightarrow$
 $\omega_{r,j} \rightarrow \omega_{r,jopt}$ (MPPT).

where the next figure provides some insight on how this controller acts:

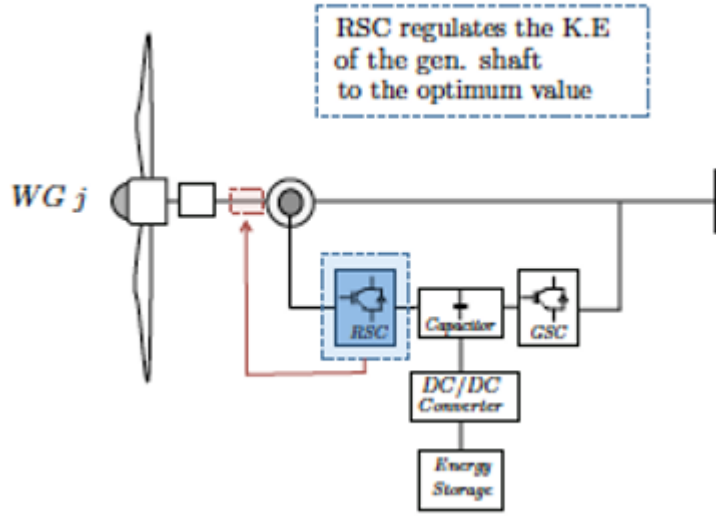


Figure 5-4: Action of the RSC controller

Intuitively, the RSC controller regulates the KE on the shaft of the WG such that it extracts maximum power from the wind.

5.4 Design of the GSC controller

The GSC controller is designed such that the following hold:

- transient stabilization of generator i is guaranteed
- $\dot{\mathcal{V}}_{ij,1} < 0, \forall (\delta_i, \omega_i) \in \mathcal{D}_1 \setminus \{\delta_{i0}, \omega_{i0}\}$
- As $t \rightarrow \infty \Rightarrow \mathcal{V}_{ij,1} \rightarrow 0 \Rightarrow \delta_i \rightarrow \delta_{i0}, \omega_i \rightarrow \omega_{i0}$.

The GSC controller acts as shown on the next figure.

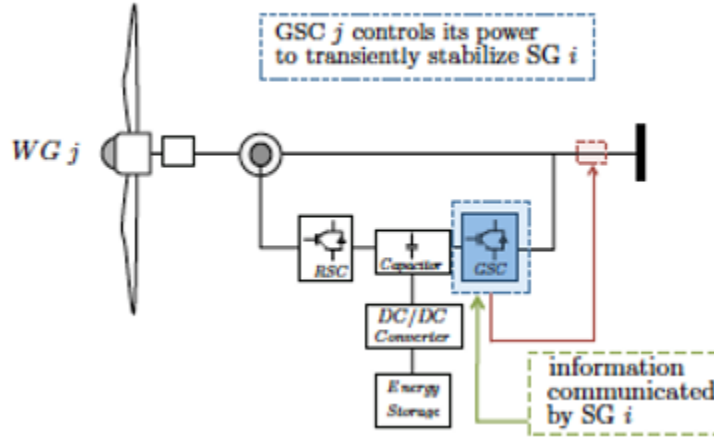


Figure 5-5: Action of the GSC controller

The GSC controller of the WG j is the one that is ensuring that the neighboring generator i retains its synchronism with the grid. The way it achieves that is by regulating its power output using feedback signals from the rotor speed and angle of the SG i . Next, we are going to design the storage controller to provide the power required by the GSC to stabilize the neighboring generator.

5.5 Design of the Storage Controller

The storage controller of the WG j is designed such that:

- the storage compensates the power imbalance on the capacitor, created by the GSC, i.e generates the power required for stabiliz.
- stabilizes the energy potential of the cap. i.e $\dot{\mathcal{E}}_{ij,3} < 0, \forall E_{dc,j} \in \mathcal{D}_3 \setminus E_{dc,j0}$
- As $t \rightarrow \infty \Rightarrow \mathcal{E}_{ij,3} \rightarrow 0 \Rightarrow E_{dc,j} \rightarrow E_{dc,j0}$.

The storage controller acts as shown on the next figure.

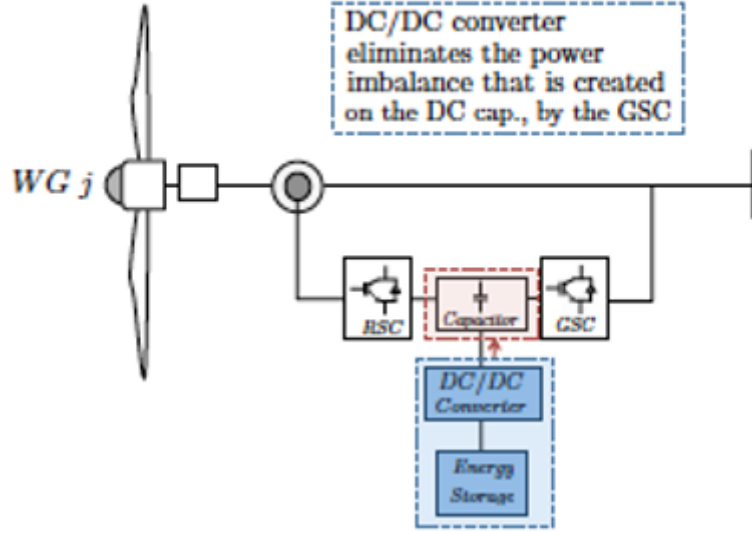


Figure 5-6: Action of the storage controller

The storage controller stabilizes the energy potential on the capacitor between the two converters. By doing that, it essentially provides the power required by the GSC controller to stabilize the nearby SG i . To realize why this is true, consider that the GSC controller is causing an imbalance on the capacitor whenever it tries to regulate its power output to stabilize the SG i . Moreover, since the storage controller stabilizes the capacitor energy potential, it eliminates the power imbalance on the capacitor. Therefore, it provides needed by the GSC.

5.6 Performance evaluation at the 3-bus system

5.6.1 Transient stabilization of generator 2

To evaluate the performance of the proposed control scheme on transiently stabilizing the neighboring generator we considered the following contingency scenario.

Contingency scenario 1

- Initially, the system is at the equilibrium.
- At $t=1.1s$ the mech. power of generator 2 changes from $P_{m2}=P_{m20}$ to $P_{m2}=0.1P_{m20}$
- At $t=1.25s$ the mechanical power becomes $P_{m2}=P_{m20}$

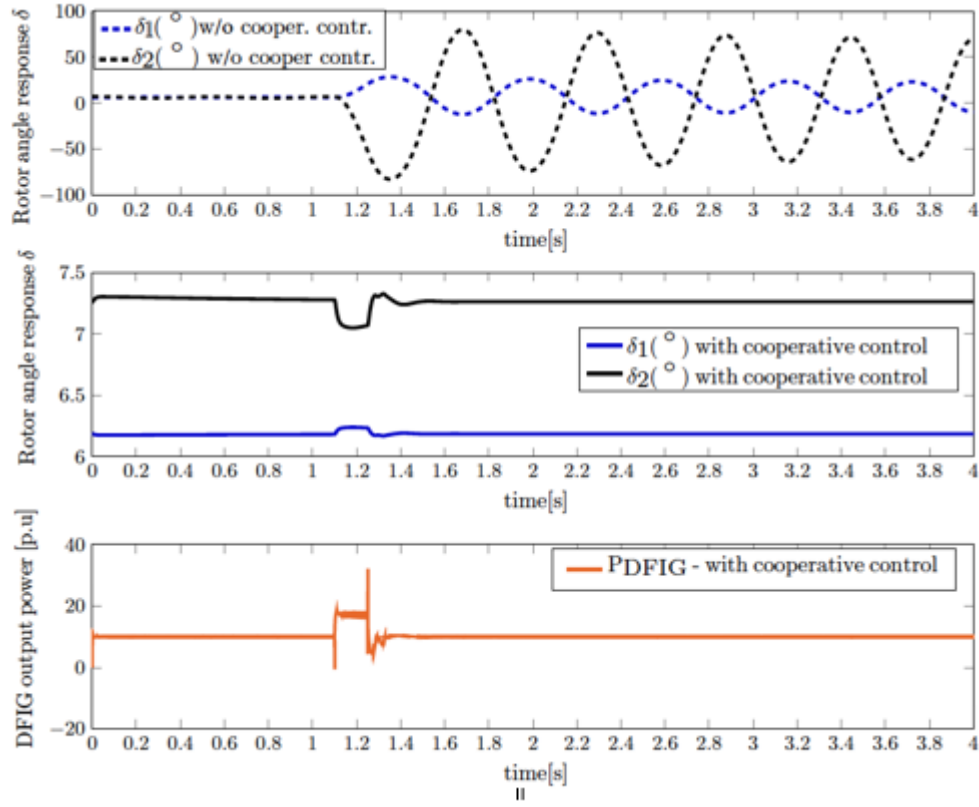


Figure 5-7: Rotor angle response of SG with (middle graph) and without (upper graph) cooperative control and power output of DFIG (PDFIG) (lower graph)

Discussion on the results:

The rotor angle response of generator 2 is more damped and the first swing has lower magnitude when compared with the response without cooperative control. It is therefore evident that the proposed control scheme achieves enhanced transient stabilization of gen. 2.

5.6.2 Maximum power point tracking of wind generator 3

To evaluate the maximum power point tracking performance, we consider the wind-speed scenario shown in the next figure.

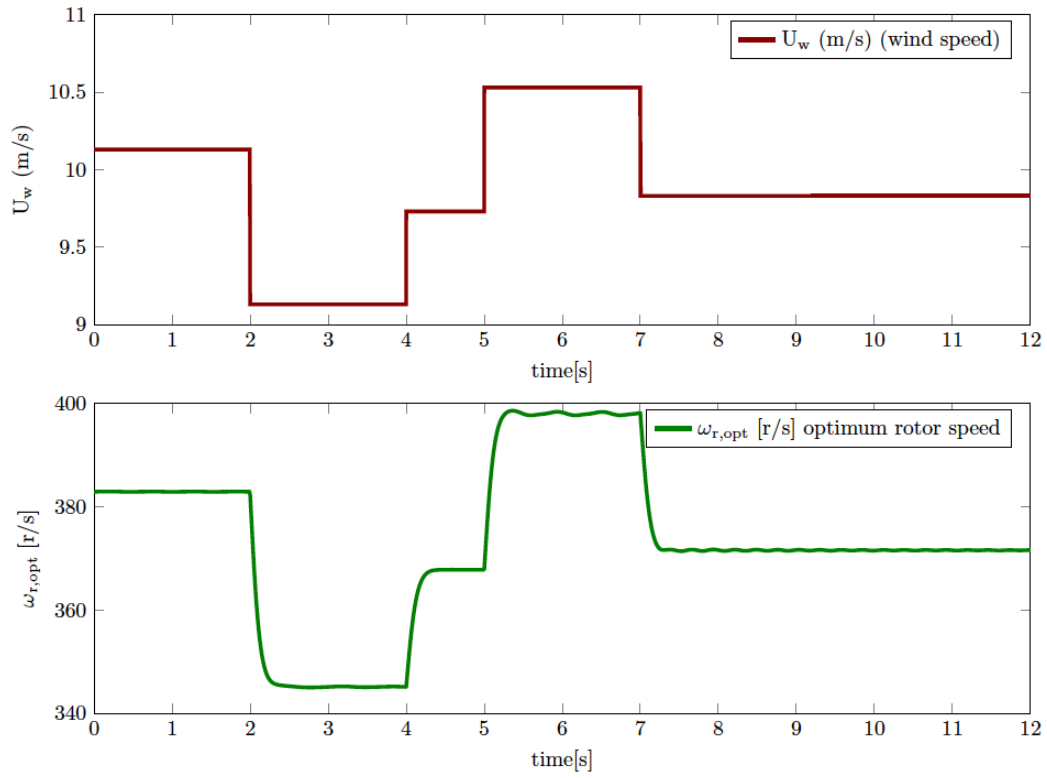


Figure 5-8: Wind speed (U_w) scenario (upper graph) and rotor speed response (lower graph)

Discussion on the results:

The tracking response of the rotor speed is rapid, damped and without oscillations. Thereby, MPPT is achieved for varying off-nominal wind-speed conditions.

6. Concluding remarks

In this work, we first introduced some distributed stability criteria based on the concepts of control Lyapunov functions (CLFs). Then we imposed as a responsibility of critical (for a given set of contingencies) generators to meet those criteria either alone or as by coordinating with neighboring components and forming iBAs. We formally introduced the concept of intelligent Balancing Authorities (iBAs), and applied it on the critical areas. Then, we showed several control design approaches that were used by the iBAs to guarantee transient stabilization and meet those stability criteria. Using the fact that contingencies in power systems usually cause a localized dynamic response we proposed some heuristic method of identifying the critical area for a given set of contingencies. We tested and evaluated our methodology on a proof-of-concept 3-bus system, on the IEEE 14-bus system and the IEEE 24-bus RT system. The results verified the effectiveness of our method.

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Part II

Standards for Dynamics in Microgrid-based Future Distribution Systems (S-55)

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Glossary

AC	Alternating current
ACPF	AC power flow
CL	Critical load
CP	Connection point
DER	Distributed energy resource
DOE	U.S. Department of Energy
DSA	Dynamic security assessment
DSO	Distributed system operator
ESS	Energy storage system
GPS	Global positioning system
IED	intelligent electronic device
LUC	Local unit controller
MGCC	Microgrid central controller
MRAC	Model reference adaptive control
MRC	Model reference control
PCC	Point of common coupling
PE	Power electronic
PMU	Phasor measurement unit
SG	Synchronous generator
SMIB	Single machine infinite bus
SOC	State of charge
TB	Tie-branch
VSI	Voltage source inverter
μ G	Microgrid

1. Introduction

1.1 Background

This research is motivated by the emerging need of design, control and management solutions to future distribution systems. Today's electric infrastructure is comprised of a complex system of power generation, transmission networks and distribution systems. Electricity is generated by large power plants located near available resource such as hydro in the mountains, thermal plants by a river or remote areas to minimize pollution exposure to urban areas. The transmission systems are the vital link between power production and usage responsible for delivering power from remote location of power generation to the commonly populated areas where power is demanded. The distribution systems are responsible for carrying power from the high voltage transmission systems to individual customers [5].

In current industrial practice, distribution systems are mostly passive, less reliable with little intelligence compared with transmission systems [1]. However, technology advancement, environmental concern and economic incentives proliferate the integration of distributed energy resources (DER) [6]. With high penetration level of DER and the related smart grid technologies that in development, future distribution systems will be as active as today's transmission systems. Operating principle used for current distribution grids will not be suitable for the smart and active future distribution systems. Thus novel system architecture and corresponding control and stability assessment frameworks are of urgent need to realize the envisioned smart grid concept. Smart distribution can be realized through real-time dispatch of a dynamical set of DER operation points; however, with a high penetration level, timely management of a large and time variant number of setting points can be an overwhelming task [1].

Considering the heterogeneous physical nature and consequent dynamic diversity of DER units, a promising management strategy for DER-based smart distribution is to package DER and associated loads into clusters, which are typically referred to as microgrids. If the system can be configured as an interconnection of microgrids, the number of control points managed by system coordinator will be reduced significantly [1]. As in the microgrid architecture only a single point of connection, known as the point of common coupling (PCC), need to be controlled by the system operator for interconnection level management [7].

1.2 State-of-the-art: Distributed Generation

Unlike highly centralized traditional power generation systems, distributed energy resources can be considered as small-scale power generation units supplying all or a portion of their local loads, and may be capable of injecting power into the utility grid if local power surplus presents. DER technologies can be largely divided into renewable and nonrenewable depending on their prime movers [5]. Fig. 1.1 shows the mainstream types of DER technologies implemented in current industrial practice [8]. As a collection of technologies with different performance characteristics, the DER family includes various types of units with heterogeneous profiles. With high level of DER integrated, the net load profiles could be significantly altered, either increasing or reducing

peaks [12]. Combining and clustering DERs at the distribution level, known as microgrid implementation, is considered a promising solution to future smart distribution systems [26].

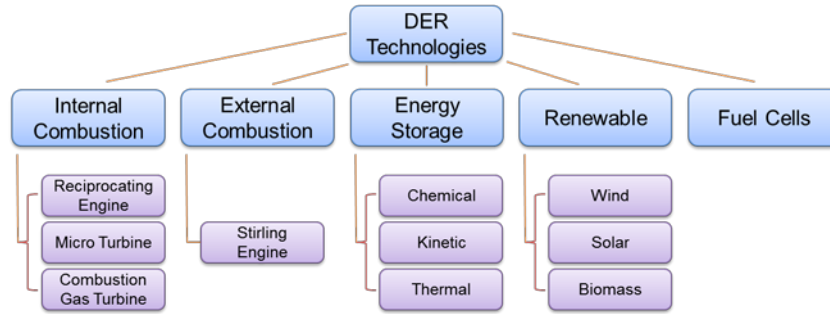


Figure 1.1: Mainstream types of DER technologies

1.3 State-of-the-Art: Microgrid Analysis and Control

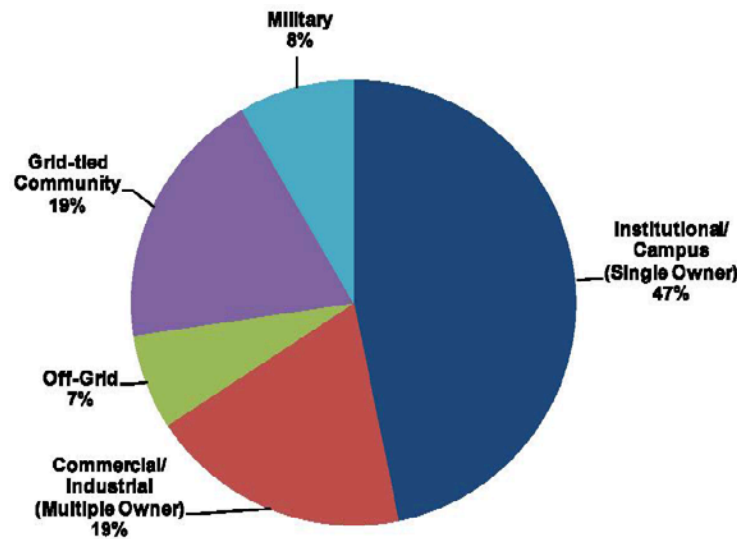


Figure 1.2: Market sector revenue breakdown, North America 2015

Great efforts are made to study microgrid and construct test beds all over the world. In current practice, microgrids are mostly divided into three categories: 1) remote microgrids, 2) facility microgrids and 3) utility microgrids. The remote microgrids are mostly located in distant areas where the utility grid is inaccessible, and do not have the grid-connected operation mode. Facility microgrids are typically integrated at the medium voltage level and have little impact on utility grids. Facility microgrids are mainly formulated in North America specifically for industrial or institutional application where technology is matured. Utility microgrids are generally integrated at high voltage level and have massive impact on utility power systems.

Such applications are mainly found in Japan, Europe and China where renewable energy is rapidly developing [16]. By 2015, a total capacity of over 3.1 GW is identified worldwide for microgrid

applications. North America will capture 74% of a total \$7.8 billion market value. The market sector revenue breaks down for North America in 2015 is shown in Fig. 1.2 [18].

1.4 Challenges for Systematic Control of Coupling Operated Microgrids

The control and operation problems of individual microgrid have been studied extensively, e.g. topology formulation, power management strategy, islanding and resynchronizing operation, etc. [1], [9], [10]. For stability studies, small signal stability of microgrids was investigated in [11], which proposes an adaptive droop controller ensuring relative stability at different loading conditions. In [12], a stability assessment approach is proposed for parallel-connected inverters to examine the system (microgrid) stability in a decentralized manner. However, it remains an open area of research for the coupling operation of microgrids at the interconnection level. High penetration of intermittent energy resources could have significant effect on the dynamic behaviors of microgrids. Excessive interaction of microgrids could result in power swings and losing synchronized coupling even if all microgrids are individually stabilized. A systematic stability analysis could provide key insights for the distribution system operator to assess effectively system-wide dynamic security of microgrid interconnections.

In large-scale system theory, a well-established method for stability analysis of interconnected systems is to utilize properties of individual subsystems in conjunction with the interconnection structure to obtain sufficient conditions for asymptotic stability in the large [13], [14]. Numerous stability analysis algorithms and results for interconnected systems had been tailored and applied to conventional power systems, e.g. [15], [16]. However, several unique features differ interconnected microgrids from conventional power systems.

- Energy resources are commonly integrated through power electronic (PE) converters decoupling their physical inertia from the grid.
- The (external) behavior of microgrids will be primarily determined by the control scheme of their interfaces.
- Microgrids are generally integrated at the distribution level, where lines cannot be considered lossless.
- Commonly, intelligent electronic devices (IEDs) with synchrophasor capability are equipped at the PCC to realize seamless transition between grid-connected and islanded modes.
- Modeling and control framework capable of handling meshed networks might be desirable with an eye to their potential for loss reduction and better support of DER integration [17].

Clearly, these unique features advocate a fresh control framework customized for the coupling operation of microgrids in future smart distribution systems.

1.5 Architecture of Future Distribution Systems

Two types of distribution system configuration exist in today's practice: radial or network [19]. Arranged like a tree, a radial distribution system involves just one power source for a cluster of

clients as shown in Fig. 1.3. It is the least complex and most inexpensive distribution grid to build; however, any failure in the power line will result in a blackout due to the single source configuration. A network distribution system has multiple sources of supply operated in a coupling manner, which provides great opportunities for coupled microgrids application, shown in Fig. 1.4, and adds a huge advantage in terms of reliability [20].

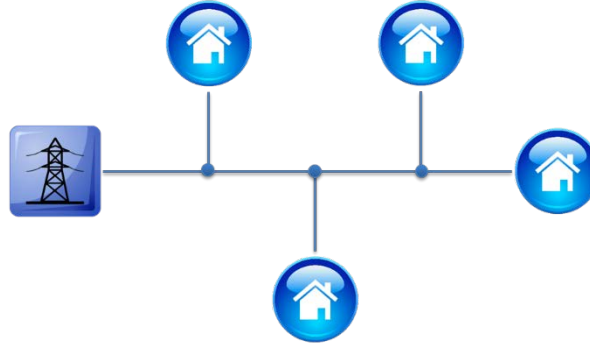


Figure 1.3: Diagram of a radial distribution system

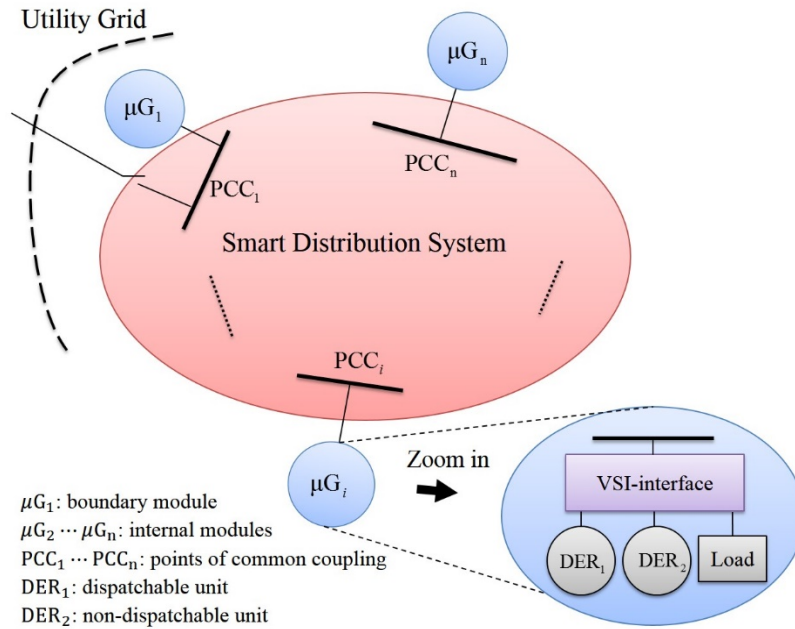


Figure 1.4: Diagram of a microgrid-based distribution system

In order to integrate successfully large amount of DERs, many technical challenges must be overcome to guarantee system stability and sustainability and at the meantime ensure that the potential benefits of DERs are fully harnessed [21].

A promising solution is to configure the distribution system as coupling operated microgrids interfaced through power electronic-based interfaces, shown in Fig. 1.4 [3]. Defined as an energy resource and load cluster, each microgrid packages closely located DER units, energy storage systems and loads at the point of common coupling (PCC) such that the uncontrollable or semi-controllable units (renewable and loads) can be partnered with controllable units (fuel-based

sources) and storage. Each power generation and/or consumption unit is controlled by its local unit controller (LUC), and all the LUCs are managed by an intelligent microgrid central controller (MGCC). Then at the upper level, the distribution system operator (DSO) only needs to coordinate each microgrid interface and distributes the task of controlling individual DER units to each microgrid central controller (MGCC) as shown in Fig. 1.5.

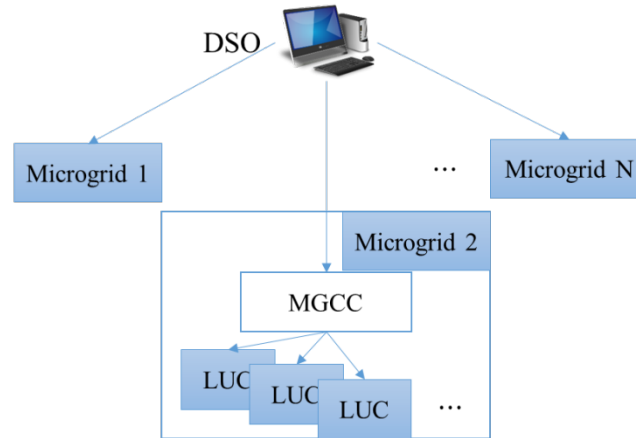


Figure 1.5: Organizational architecture for future distribution systems

Such system architecture is similar to the large transmission level multi-machine systems [23], whereas different system interfaces are adopted. Generally, synchronous generators (SGs) are utilized as interfaces for large multi-machine power systems while voltage source inverters (VSI) are widely used as power electronic (PE) interfaces for DER or microgrid considering their advantage in power conversion efficiency and their more compact and economical installation compared with current source inverters [23]. With the VSI-based interfaces, the physical inertia on the resource side will be decoupled from the grid side. Thus, the interaction behaviors among coupling operated microgrids will be determined primarily by the VSI interface control functions [24].

2. Interface Control Strategy for Coupled Microgrids

In current practice of microgrid interface control, algorithms mimicking SG swing equations are commonly used to craft synthetic inertia in case that the system frequency is at risk of running into unacceptable level following resource and/or load disturbances [25]. Such algorithms are frequency droop methods utilizing the frequency deviation signal as power balance indicator due to the nature of SG swing equations. Nevertheless, several factors limit their application for future distribution systems.

- Synthetic inertia slows down system transient response.
- The conflict between frequency regulation requirement and the sensitivity of indicating power imbalance [26].

The frequency regulation constraint limits the allowable range of the droop gains, angle droop methods are emerging that droop the VSI output voltage angle instead of frequency to indicate power imbalance [27], [28], [26]. For the angle droop control methods signals from the global positioning system (GPS) are required for angle referencing, which is enabled by intelligent electronic devices (IEDs) with phasor measurement units (PMUs) embedded. It has been realized that better system transient performance could be expected with angle droop method [29].

2.1 Angle Droop Control for VSI Interfaces

Concerning the interfacing of microgrids to the distribution system, it is important that proper power sharing achieved among coupling operated microgrids. Droop-based methods are highly desirable due to their minimal communication requirement as the distribution systems can be complex and span over large areas [29]. Motivated by SG operation principle, frequency droop method is mostly adopted using local frequency signals (real power balance indicator) as feedback to control respective interface output. Depending on the stiffness of the power-frequency curve, the steady state frequency will change with the time varying power production and consumption mismatch. It is widely known that in order to achieve stable operation, the alternating current (AC) frequency must be held within tight tolerance bounds. Such high requirement of frequency regulation limits the allowable range of frequency droop gain, which in turn, may lead to chattering during frequent load change or renewable resource fluctuation [28]. If all the microgrids are interfaced through VSIs as shown in Fig. 1.4, the output voltage angle of each interface can be set arbitrarily as long as a synchronized angle reference is available [3]. Thus drooping the VSI voltage angle instead of frequency can be a better option for power sharing considering its advantage in transient performance and control flexibility [3], [28], and [30].

In the proposed system configuration, shown in Fig.1.4, each microgrid is connected to the system at the point of common coupling (PCC) through a VSI interface equipped with PMU-functional IEDs. Angle and voltage droop control is utilized for autonomous real and reactive power sharing among interconnected microgrids. Corresponding interface control function for the i th microgrid is given as follows.

$$\tau_{\delta_i} \dot{\delta}_i + \delta_i - \delta_i^* = \sigma_{\delta_i} (P_{l_i}^* - P_{l_i}), \quad (2.1)$$

$$\tau_{V_i} \dot{V}_i + V_i - V_i^* = \sigma_{V_i} (Q_{I_i}^* - Q_{I_i}), \quad (2.2)$$

where δ_i , V_i are the PCC voltage and magnitude. $P_{I_i}^*$, $Q_{I_i}^*$ are the nominal real and reactive power injections. P_{I_i} , Q_{I_i} are the actual real and reactive power injections. τ_{δ_i} , τ_{V_i} are angle and voltage tracking time constants. σ_{δ_i} , σ_{V_i} are the angle and voltage droop gains that represent the sensitivity of indicating real and reactive power imbalance, respectively.

The nominal real and reactive power injections P_{I_i} , Q_{I_i} are dispatched by the DSO solving an AC power flow problem and remain constant during a dispatch interval, e.g. 15 minutes. The actual real and reactive power injections are determined by the following power angle relationship.

$$P_{I_i} = V_i^2 G_{ii} + \sum_{k=1, k \neq i}^n V_i V_k Y_{ik} \sin(\delta_{ik} + \frac{\pi}{2} - \theta_{ik}), \quad (2.3)$$

$$Q_{I_i} = -V_i^2 B_{ii} + \sum_{k=1, k \neq i}^n V_i V_k Y_{ik} \sin(\delta_{ik} - \theta_{ik}), \quad (2.4)$$

where G_{ii} is the self-conductance, B_{ii} is the self-susceptance. Y_{ik} , θ_{ik} are the modulus and phase angle of the transfer admittance between the i th and the k th microgrid.

For a n -microgrid system, the equilibrium states of interest are the solutions of (2.1), (2.2), (2.3) and (2.4) with $\dot{\delta}_i = 0$, $\dot{V}_i = 0$, $P_{I_i} = P_{I_i}^*$ and $Q_{I_i} = Q_{I_i}^*$, $i = 1 \dots n$. The nominal power injections satisfy the following power flow equations.

$$P_{I_i}^* = V_i^{*2} G_{ii} + \sum_{k=1, k \neq i}^n V_i V_k Y_{ik} \sin(\delta_{ik}^* + \frac{\pi}{2} - \theta_{ik}), \quad (2.5)$$

$$Q_{I_i}^* = -V_i^{*2} B_{ii} + \sum_{k=1, k \neq i}^n V_i V_k Y_{ik} \sin(\delta_{ik}^* - \theta_{ik}), \quad (2.6)$$

Different from the commonly used frequency droop methods, the proposed interface control scheme is implemented with integrators. For the $P - \delta$ subsystem, the frequency domain representation corresponding to (2.1) is

$$\Delta \delta_i(s) = -\frac{\sigma_{\delta_i}}{\tau_{\delta_i} s + 1} \Delta P_{I_i}(s). \quad (2.7)$$

For a constant ΔP_{I_i} , we have the following relationship [31].

$$\Delta \omega_i(0) = -\frac{\sigma_{\delta_i}}{\tau_{\delta_i}} \Delta P_{I_i}, \Delta \omega_i(\infty) = 0, \Delta \delta_i(\infty) = -\sigma_{\delta_i} \Delta P_{I_i}, \quad (2.8)$$

in which, $\Delta \omega_i \triangleq \Delta \delta_i$ is the frequency deviation from the static base frequency (e.g. 60 Hz).

Thus right after a sustaining disturbance, the proposed scheme will behave like the widely used frequency droop control with the droop gain $\sigma_{\omega} = \frac{\sigma_{\delta}}{\tau_{\delta}}$. When approaching steady state as time goes on, it will behave as the angle droop control used in [26]. In addition, it should be noted that with the proposed scheme the frequency deviation converges to zero at the steady state, a feature highly desirable for operating coupled microgrids.

2.2 Distributed Control of Multiple VSIs for Virtual Interfacing

If no interface VSI is deployed at the microgrid PCC, virtual interfacing can be realized by managing the integration VSI of each internal DER unit. Fig. 2.1 shows the diagram of a microgrid with n DER units integrated. The PCC voltage is not directly controlled by an interface VSI although synchrophasor measurement is available.

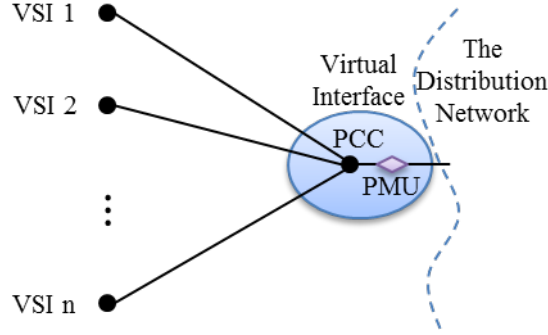


Figure 2.1: Diagram of a microgrid virtual interface with n integration VSIs

Assuming a virtual interface VSI deployed at the PCC of microgrid i , a droop-based control function can be adopted so that the microgrid interface dynamics represented by (2.1) and (2.2).

By definition, each microgrid acts as a single controllable entity for the interconnection level analysis, of which the dynamics is determined by the control strategy of a virtual interface [2], [3]. With the above control strategy, the voltage angle and magnitude of the virtual interface at the PCC of microgrid i can be obtained as $\delta_i^{if} = \delta_i$, $V_i^{if} = V_i$.

The PCC voltage $V_i^{if} \angle \delta_i^{if}$ cannot be generated directly if there is no interface VSI deployed; however, it can be managed indirectly by controlling the integration VSIs of selected DER units in a distributed manner. Assuming the PCC voltage is three-phase balanced, the d-q equivalent circuit can be utilized to simplify the analysis. Aligning the d-axis with the PCC voltage $V_i^{if} \angle \delta_i^{if}$, shown in Fig. 2.2, the d-axis and q-axis current injections to the network can be calculated as follows.

$$I_{d_i} = \frac{P_{I_i}}{V_{if_i}}, I_{q_i} = -\frac{Q_{I_i}}{V_{if_i}}. \quad (2.9)$$

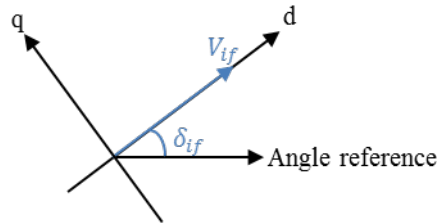


Figure 2.2: The d-q axis alignment

For the integration VSI of DER k , let its d-q axis currents be

$$I_{d_k} = c_{d_k} I_{d_i}, I_{q_k} = c_{q_k} I_{q_i}, \quad (2.10)$$

where c_{d_k}, c_{q_k} are the participation factors of VSI k , $k = 1 \cdots m$, for the d and q axis current injection to the network, which are assigned by the MGCC according to the following condition.

$$\sum_{k=1}^m c_{d_k} = 1, \sum_{k=1}^m c_{q_k} = 1. \quad (2.11)$$

Note the line impedance from VSI k to the PCC of microgrid i as $z_k = R_k + jX_k$, we have

$$V_{d_k} = V_{if_i} + R_k I_{d_k} - X_k I_{q_k}, V_{q_k} = R_k I_{q_k} + X_k I_{d_k}. \quad (2.12)$$

The corresponding voltage setting point for VSI k can be obtained as follows.

$$V_k^{ref} = |V_{d_k} + jV_{q_k}|, \delta_k^{ref} = \delta_{if_i} + \tan^{-1}(\frac{V_{q_k}}{V_{d_k}}). \quad (2.13)$$

2.3 Interfacing with Multiple Physical Connection Points

In current practice of microgrid integration, a single VSI inverter is deployed at the point of common coupling (PCC) as the power electronic interface; however, in the future microgrid-based smart distribution systems, the power rating of each microgrid module could be much larger. For a large utility size microgrid, it is desirable that it can be integrated with the network at multiple physical connection points (CPs). As by definition, a microgrid acts as a single controllable entity to simplify the interconnection level control implementation. Thus, the voltage profile for all the connection points determined by the interface control strategy should be consistent.

Fig. 2.3 shows the one-line diagram of a three-microgrid system. Each microgrid is integrated with the network at two distant CPs. For microgrid i , the phase angle and voltage magnitude at each CP can be obtained as

$$\tau_{\delta_i} \dot{\delta}_{if} + \delta_{if} - \delta_i^* = \sigma_{\delta_i} (P_{I_1}^* - P_{if_1}^1 - P_{if_1}^2), \quad (2.14)$$

$$\tau_{V_i} \dot{V}_{if} + V_{if} - V_i^* = \sigma_{V_i} (Q_{I_1}^* - Q_{if_1}^1 - Q_{if_1}^2), \quad (2.15)$$

$$\delta_{if_1}^1 = \delta_{if_1}^2 = \delta_{if}, V_{if_1}^1 = V_{if_1}^2 = V_{if}. \quad (2.16)$$

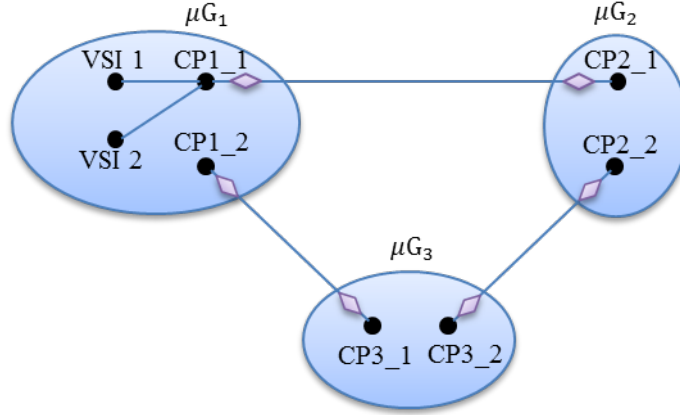


Figure 2.3: Virtual interfacing for a three-microgrid system

In order to determine the setting point of VSI 1 and VSI 2, the d and q axis injection from CP1_1 into the network need to be calculated as

$$I_d = \frac{P_{if1}^1}{V_{if1}^1}, I_q = -\frac{Q_{if1}^1}{V_{if1}^1}. \quad (2.17)$$

Assume the d and q axis current are equally distributed between VSI 1 and VSI 2, the their d and q axis current will be

$$I_{d1} = I_{d2} = 0.5I_d, I_{q1} = I_{q2} = 0.5I_q. \quad (2.18)$$

The corresponding d and q axis voltage will be

$$V_{d1} = V_{if1}^1 + R_1 I_{d1} - X_1 I_{q1}, V_{q1} = R_1 I_{q1} + X_1 I_{d1}, \quad (2.19)$$

$$V_{d2} = V_{if1}^1 + R_2 I_{d2} - X_2 I_{q2}, V_{q2} = R_2 I_{q2} + X_2 I_{d2}. \quad (2.20)$$

In addition, the voltage reference of each VSI can be obtained as

$$V_1^{ref} = |V_{d1} + jV_{q1}|, \delta_1^{ref} = \delta_{if1}^1 + \tan^{-1} \left(\frac{V_{q1}}{V_{d1}} \right), \quad (2.21)$$

$$V_2^{ref} = |V_{d2} + jV_{q2}|, \delta_2^{ref} = \delta_{if1}^1 + \tan^{-1} \left(\frac{V_{q2}}{V_{d2}} \right). \quad (2.22)$$

3. Hierarchical Control Framework for Future Distribution Systems

The control and operation problems of individual microgrid have been studied extensively, e.g. topology formulation, power management strategy, islanding and resynchronizing operation, etc. [1], [9], [10]. For stability studies, small signal stability of microgrids was investigated in [11], which proposes an adaptive droop controller ensuring relative stability at different loading conditions. In [32], system (microgrid) stability is investigated for parallel-connected inverters. However, it remains an open area of research for the coupling operation of microgrids at the interconnection level. High penetration of intermittent energy resources could have significant effect on the dynamic behaviors of microgrids. Excessive interaction of microgrids could result in power swings and losing synchronism even if all microgrids are individually stabilized.

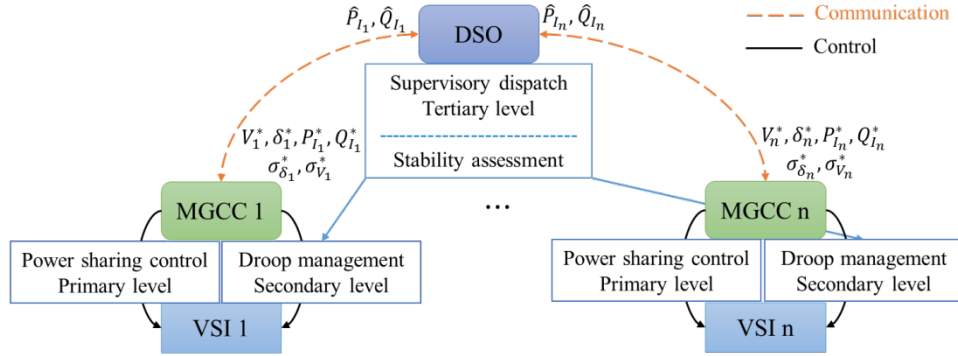


Figure 3.1: The interactive control framework for future distribution systems

Assuming voltage source inverters (VSIs) are readily deployed as interfaces, a hierarchical control framework [45], [46] is proposed for future distribution systems to guarantee system-wide stability, in which three control levels are defined as shown in Fig. 3.1. A model reference control (MRC)-based scheme is adopted for primary level power sharing, through which the interface inverter of each microgrid is controlled to track a designed reference model. At the secondary level, an interactive droop management scheme is proposed to manage the reference model droop gains based on derived system stability criteria. At the tertiary level, an AC power flow (ACPF)-based supervisory control strategy is utilized to 1) dispatch the nominal setting to each microgrid central controller (MGCC) for the primary level reference tracking, and 2) broadcast an interaction coefficient to each MGCC so that the droop gains can be managed to guarantee system-wide stability.

3.1 Primary Level Power Sharing Control

With angle and voltage droop-based interface control strategy adopted, the interface dynamics of each microgrid can be represented by the plant model (2.1) and (2.2) with the real and reactive power injections tracking the nominal values

$$P_I^* = P_G + P_R - P_L, \quad (3.1)$$

$$Q_I^* = Q_G + Q_R - Q_L, \quad (3.2)$$

where P_G, Q_G are the total real and reactive power generated in the microgrid. P_R, Q_R correspond to the total real and reactive regulation power, which can be controlled for model reference tracking. P_L, Q_L are the total real and reactive power consumption.

The objective is to choose an appropriate control law such that all signals in the closed-loop plant are bounded and the states δ, V track the reference model states δ_r, V_r given by

$$\tau_{\delta_r} \dot{\delta}_r + \delta_r - \delta^* = \sigma_{\delta_r} (P_I^* - P_I), \quad (3.3)$$

$$\tau_{V_r} \dot{V}_r + V_r - V^* = \sigma_{V_r} (Q_I^* - Q_I), \quad (3.4)$$

where $\tau_{\delta_r}, \tau_{V_r}$ are the designed time constants for tracking voltage angle and magnitude, respectively, which range from several to tens of seconds for smoothing out fast disturbance. $\sigma_{\delta_r}, \sigma_{V_r}$ are the P - δ and Q - V droop characteristics determined by the secondary level control scheme.

In order to track the reference model (3.3) and (3.4), we propose the following control law

$$P_R = -k_P^* (\delta - \delta^*) + l_P^* (P_I^* - P_I) - P_G + P_L + P_I, \quad (3.5)$$

$$Q_R = -k_Q^* (V - V^*) + l_Q^* (Q_I^* - Q_I) - Q_G + Q_L + Q_I, \quad (3.6)$$

where $k_P^*, l_P^*, k_Q^*, l_Q^*$ are the control parameters to be calculated.

The corresponding close-loop dynamical model can be obtained as follows.

$$\frac{\tau_{\delta}}{1 + \sigma_{\delta} k_P^*} \dot{\delta} + \delta - \delta^* = \frac{\sigma_{\delta} l_P^*}{1 + \sigma_{\delta} k_P^*} (P_I^* - P_I), \quad (3.7)$$

$$\frac{\tau_V}{1 + \sigma_V k_Q^*} \dot{V} + V - V^* = \frac{\sigma_V l_Q^*}{1 + \sigma_V k_Q^*} (Q_I^* - Q_I). \quad (3.8)$$

If the plant model parameters were known, by matching (3.7) and (3.8) with (3.3) and (3.4), the control parameters can be calculated as follows.

$$k_P^* = \frac{\tau_{\delta} - \tau_{\delta_r}}{\tau_{\delta_r} \sigma_{\delta}}, l_P^* = \frac{\tau_{\delta} \sigma_{\delta_r}}{\tau_{\delta_r} \sigma_{\delta}}, \quad (3.9)$$

$$k_Q^* = \frac{\tau_V - \tau_{V_r}}{\tau_{V_r} \sigma_V}, l_P^* = \frac{\tau_V \sigma_{V_r}}{\tau_{V_r} \sigma_V}, \quad (3.10)$$

The above matching approach guarantees that the close-loop plant states converge to the reference model exponentially fast for any bounded signal [33]

$$r(t) = [P_I^*(t) - P_I(t), Q_I^*(t) - Q_I(t)]^T. \quad (3.11)$$

Depending on how the VSI control is implemented, the up to date plant model parameters might be unknown to the MGCC. An adaptive law can be implemented with on-line estimates of the

plant model parameters. Then, the corresponding direct or indirect model reference adaptive control (MRAC) schemes can be utilized for the aforementioned control objective [33].

The key idea of the proposed MRC-based scheme is to reshape the interface characteristics according to a designed reference model through managing available regulation power. We will show in the following that how the reference model can be determined at the secondary level to guarantee system-wide stability.

3.2 Secondary Level Droop Management for Guaranteed System-wide Stability

In order to integrate successfully large amount of DERs, many technical challenges must be overcome to guarantee system stability and sustainability and at the meantime ensure that the potential benefits of DERs are fully harnessed [21]. Transient stability is considered a fundamental and important problem in power system design and operation [34]. It had been shown that conventional power system interfaced through SGs are generally not asymptotically stable in the large [35]. There are often multiple equilibrium solutions due to two essential factors:

- The second order SG swing equation,
- The sinusoidal power angle relationship.

For a PMU and PE-enabled future distributed system with angle droop controlled interfaces, it will be shown that asymptotically stable in the large may be achieved with conservative droop gain design. On the other hand, if voltage phase angle of all interfaces can be contained in a limited range, conservativeness in droop gain design can be significantly reduced.

In this section, a transient stability assessment framework is proposed for future distribution systems, which can be implemented online to guarantee system-wide operation stability. Sufficient condition for system transient stability is derived for based on Lyapunov direct method. The Lyapunov function proving transient stability is obtained by solving the LMIs formulated based on the multi-variable Popov criterion. As a general numerical method, the proposed transient stability assessment procedure is well suited for automatic computation and can be integrated into the droop management procedure at the secondary control level to guarantee system transient stability.

For a n-microgrid distribution system, the local stability properties of the equilibrium solution $\delta_i^*, V_i^*, P_{Li}^*, Q_{Li}^*, i = 1 \dots n$, can be derived from linearizing (2.1), (2.2), (2.3) and (2.4) around the equilibrium solution. The corresponding small signal (SS) model of the n-microgrid system can be formulated as follows.

$$\dot{x} = A^s x + B^s u, \quad (3.12)$$

$$u = Jx, \quad (3.13)$$

where

$$x = [x_1^T \dots x_n^T]^T, u = [u_1^T \dots u_n^T]^T, \quad (3.14)$$

in which

$$x_i = [\Delta\delta_i, \Delta V_i]^T, u_i = [\Delta P_{l_i}, \Delta Q_{l_i}]^T, \quad (3.15)$$

and

$$A^s = \text{diag}(A_i^s), B^s = \text{diag}(B_i^s), i = 1 \dots n, \quad (3.16)$$

where

$$A_i^s = \begin{bmatrix} -\frac{1}{\tau_{\delta_i}} & 0 \\ 0 & -\frac{1}{\tau_{V_i}} \end{bmatrix}, B_i^s = \begin{bmatrix} -\frac{\sigma_{\delta_i}}{\tau_{\delta_i}} & 0 \\ 0 & -\frac{\sigma_{V_i}}{\tau_{V_i}} \end{bmatrix}, \quad (3.17)$$

The extended Jacobian matrix is formulated as follows.

$$J = \begin{bmatrix} \frac{\partial u_1}{\partial x_1} & \dots & \frac{\partial u_1}{\partial x_n} \\ \vdots & \ddots & \vdots \\ \frac{\partial u_n}{\partial x_1} & \dots & \frac{\partial u_n}{\partial x_n} \end{bmatrix}, \quad (3.18)$$

3.2.1 Criteria of Small-signal Stability for Multi-microgrid Systems

For reliable operation of coupling operated microgrids, stability conditions need to be derived to ensure system dynamic security subject to small disturbances. It has been pointed out in [40] that instability may be resulted from three scenarios in DER-based distribution systems:

- Oversensitive response of DERs to local disturbances.
- Interaction of electrically connected unstable DERs.
- Interaction of electrically connected stable DERs.

For the coupling operation of microgrids, the first two instability scenarios are relatively easy to track and stabilize locally by module agents. The key idea is that the intelligent microgrid agents will appropriately manage the controllable distributed generators and/or storages, responsive (non-critical) loads, etc., to support local generation and ensure local stability. However, the last scenario can only be assessed in a systematic manner. Focusing on the third scenario, here we will derive assessment criteria for system-wide small-signal stability.

Since the small signal model (3.12), (3.13) is linear and time invariant, it suffices to consider the eigenvalues of the matrix

$$A_{cl}^s = A^s + B^s J. \quad (3.19)$$

Small signal stability of the system equilibrium can be concluded if all the eigenvalues of A_{cl}^s have negative real parts.

With high penetration level of DERs, a large number of interconnected microgrids may need to be managed in real time to realize smart distribution. Computing eigenvalues of a large-scale system matrix is not a trivial task, thus the corresponding assessment could be challenging for on-line applications.

Here instead, we consider the well-known Lyapunov theorem [41]: the system (3.12), (3.13) is stable if and only if there exists a positive-definite matrix P such that

Criterion 1:

$$A_{cl}^s P + P A_{cl}^s < 0. \quad (3.20)$$

which can be formulated as a convex optimization problem involving LMIs [42]. Actually, this convex feasibility problem can be solved by interior-point algorithms [43].

For the coupling operation of a large number of microgrids, it would be desirable to perform on-line assessment of system-wide small-signal stability in a distributed manner. As a natural generalization of Lyapunov theory for open systems, the dissipative system theory is very useful for analysing interconnected systems [42], [44]. Accordingly the following procedures can be performed:

- Given that the interfacing control strategy ensures module local stability, dissipative dynamic equivalents (singular-perturbed model) are obtained for all microgrid modules.
- Based on the module equivalents, their storage functions can be constructed as Lyapunov function candidates.
- Each module agent assess system stability with a distributed criterion derived based on an upper bound of the module interaction strength.
- System-wide stability may be concluded by collecting the assessment results from module agents.

For a general minimal finite dimensional linear system (FDLS) represented by state space matrices A, B, C, D , the dissipativeness can be evaluated from the LMIs in (3.21). According to Theorem 3 of [44], the minimal FDLS is dissipative with respect to the supply rate $w = \langle u, y \rangle$ if and only if (3.21) has a solution. With solution Q the function $\frac{1}{2} \langle x, Qx \rangle$ defines a quadratic storage function. Here $\langle x, y \rangle$ stands for the inner product of vector x and y .

$$\begin{bmatrix} A^T Q + QA & QB - C^T \\ B^T Q - C & -D - D^T \end{bmatrix} \leq 0, \quad Q = Q^T \geq 0. \quad (3.21)$$

Since the model (3.12), (3.13) is strictly proper as $D_i = D_i^T = 0$, the LMIs in (3.21) reduces to the following

$$A_i^T Q_i + Q_i A_i \leq 0, Q_i B_i = I, Q_i = Q_i^T > 0. \quad (3.22)$$

Hence, module i is dissipative with respect to $\langle u_i, y_i \rangle$ if the interface control strategy generates positive angle feedback gain and voltage droop gain, since

$$Q_i = Q_i^T = B_i^{-1} = \begin{bmatrix} \frac{\tau_{\delta_i}}{\sigma_{\delta_i}} & 0 \\ 0 & \frac{\tau_{v_i}}{\sigma_{v_i}} \end{bmatrix} > 0, \quad A_i^T Q_i + Q_i A_i = -2 \begin{bmatrix} \frac{1}{\sigma_{\delta_i}} & 0 \\ 0 & \frac{1}{\sigma_{v_i}} \end{bmatrix} < 0. \quad (3.23)$$

Formulate the storage matrix for the system model (3.12), (3.13) as

$$Q = B^{-1} = \text{diag}(Q_i), \quad (3.24)$$

For the simplicity of representation, we omit the superscript s in system matrices of model (3.12), (3.13).

With all modules dissipative, Q is positive definite. Consider the time derivative of the storage function

$$S(x) = \frac{1}{2} \langle x, Qx \rangle, \quad (3.25)$$

we have

$$\dot{S}(x) = \frac{1}{2} (\dot{x}^T Qx + x^T Q \dot{x}) = x^T (AQ - \frac{J^T + J}{2})x. \quad (3.26)$$

Obviously, $S(x)$ is a Lyapunov function if $M^{C1} = AQ - \frac{J^T + J}{2}$ is negative definite. Noticing that $F = -\frac{J^T + J}{2}$ is a Hermitian matrix with real entries, its Rayleigh quotient is bounded by its eigenvalues according to Theorem 8.1.4 in [41]:

$$\lambda_{\min} = \min R_F(x), \lambda_{\max} = \max R_F(x), \quad (3.27)$$

where $R_F(x) = \frac{\langle Fx, x \rangle}{\langle x, x \rangle}$. $\lambda_{\min}, \lambda_{\max}$ correspond to the smallest and largest eigenvalue of F . Here $\lambda_{\max}$ is defined as the interaction coefficient indicating the upper bound of overall module coupling strength for a specific system operation condition.

Then following (3.26), we have

$$\dot{S}(x) = x^T AQx + x^T Fx \leq x^T AQx + \lambda_{\max} x^T x = \sum_{i=1}^N x_i^T (A_i Q_i + \lambda_{\max} I) x_i, \quad (3.28)$$

Accordingly, the distributed stability criterion is formulated as follows.

Criterion 2:

If a) the interconnected system (3.12), (3.13) have all modules exhibit positive inertia and damping coefficients, and b) the assessment matrices $M_i^{C2} = A_i Q_i + \lambda_{\max} I, i = 1 \dots n$ are all negative definite, then the system is asymptotically stable.

This is a distributed criterion in the sense that it only requires each microgrid module to check their internal stability property. The assessment can be performed by each agent checking its angle droop gain and voltage droop gain since

$$A_i Q_i + \lambda_{max} I = \begin{bmatrix} -\frac{1}{\sigma_{\delta_i}} + \lambda_{max} & 0 \\ 0 & -\frac{1}{\sigma_{V_i}} + \lambda_{max} \end{bmatrix} < 0. \quad (3.29)$$

The only piece of information need to be broadcast by the system coordinator is the interaction coefficient λ_{max} defined in (3.27). It can be obtained through calculating the extended Jacobian matrix defined in (3.18) based on real time operation condition.

3.2.2 Criterion of Transient Stability for Multi-microgrid Systems [46]

Small signal stability only suggests that the system solutions tend to the equilibrium of interest for initial conditions sufficiently close to it. However, it is important not only to establish the local stability properties of the equilibrium solution, but also to study the transient stability properties when the system experiences large disturbances.

In practical situations, the voltage regulation behavior is generally much slower than the transient phenomena, which are of interest in transient stability studies [35]. If for each microgrid interface, τ_{V_i} is much larger than τ_{δ_i} by design, the PCC voltage can then be assumed constant during the transient period, i.e. $V_i = V_i^*$. The transient stability problem can be significantly simplified.

Note $z_i = \delta_i - \delta_i^*$, $i = 1 \dots n$, and let m_i be the number of branches connected to the i th microgrid. Then from (2.1), (2.3) and (2.5) we have,

$$\tau_{\delta_i} \dot{z}_i + z_i = -\sigma_{\delta_i} \sum_{j=1}^{m_i} e_j \phi_j(y_j), \quad (3.30)$$

$$\phi_j(y_j) = \sin(y_j + y_j^0) - \sin(y_j^0), \quad (3.31)$$

where $e_j = V_i^* V_k^* Y_{ik}$, $y_j = z_i - z_k = \delta_{ik} - \delta_{ik}^*$, and $y_j^0 = \delta_{ik}^* + \frac{\pi}{2} - \theta_{ik}$.

Formulate the incidence matrix H and the connectivity matrix C such that the n -microgrid system with states $z = [z_1 \dots z_n]^T$ and output $y = [y_1 \dots y_n]^T$ can be represented as follows.

$$\dot{z} = Az + B\phi(y), \quad (3.32)$$

$$y = Cz, \quad (3.33)$$

where $A = \text{diag}(-\frac{1}{\tau_{\delta_i}})$, $D = \text{diag}(-\frac{\sigma_{\delta_i}}{\tau_{\delta_i}})$, $i = 1 \dots n$. $E = \text{diag}(e_j)$, $j = 1 \dots m$. $B = DHE$. The system nonlinearities $\phi(y) = [\phi_1(y_1) \dots \phi_m(y_m)]^T$. It should be noted that here $m = \sum_{i=1}^n m_i$ equals to twice the total number of system branches.

The n-microgrid system represented by (3.22) and (3.23) is a multi-variable Lur'e system with time invariant sector-bounded memoryless nonlinearities. From (3.21) we see that the functions $\phi_j(y_j)$ satisfy the $[-1, 1]$ sector condition

$$-y_j^2 \leq y_j \phi_j(y_j) \leq y_j^2, j = 1 \dots m, \quad (3.34)$$

For all $y_j \in R$.

In order to prove stability of the system (3.22) and (3.23) with nonlinearity sector conditions given in (3.34), a loop transformation procedure can be performed [36]. Define

$$\bar{\phi}_j(y_j) = \frac{1}{\beta_j - \alpha_j} (\phi_j(y_j) - \alpha_j y_j), \quad (3.35)$$

where the sector lower bound $\alpha_j = -1$ and the sector upper bound $\beta_j = 1$ for all $j = 1 \dots m$.

Obviously $0 \leq \bar{\phi}_j(y_j) \leq y_j^2$ for all $y_j \in R$. Let $\Lambda = \text{diag}(\alpha_j)$ and $\Gamma = \text{diag}(\beta_j - \alpha_j)$, so that $\bar{\phi}(y) = \Gamma^{-1}(\phi(y) - \Lambda y)$. Substitute $\phi(y) = \Gamma \bar{\phi}(y) + \Lambda y$ into (3.22), we have

$$\dot{z} = \bar{A}z + \bar{B}\bar{\phi}(y), \quad (3.36)$$

$$y = \bar{C}z, \quad (3.37)$$

where $\bar{A} = A + B\Lambda C$, $\bar{B} = B\Gamma$ and $\bar{C} = C$.

Now the nonlinearities are contained within $[0, 1]$ sectors

$$0 \leq y_j \bar{\phi}_j(y_j) \leq y_j^2, j = 1 \dots m, \quad (3.38)$$

or, equivalently,

$$\bar{\phi}_j(y_j)(\bar{\phi}_j(y_j) - y_j \bar{\phi}_j(y_j)) \leq 0, j = 1 \dots m, \quad (3.39)$$

for all $y_j \in R$.

To prove stability of the n-microgrid system represented by (3.26) and (3.27), consider the Lyapunov function of the form

$$V(z) = z^T P z + 2 \sum_{j=1}^m \lambda_j \int_0^{\bar{C}_j z} \bar{\phi}_j(y_j) dy_j, \quad (3.40)$$

where $\bar{C}_j$ denotes the i th row of $\bar{C}$.

According to the Lyapunov theorem, seek P and $\lambda_j, j = 1 \dots m$, such that

$$\frac{dV(z)}{dt} < 0, \quad (3.41)$$

for all nonzero z satisfying (3.26), (3.27) and (3.28).

The S-procedure [36] can be utilized to derive sufficient condition for (3.31):

The LMI in $P > 0$, $\Lambda = \text{diag}(\lambda_j) \leq 0$ and $T = \text{diag}(\tau_j)$, $j = 1 \dots m$,

$$\begin{bmatrix} \bar{A}^T P + P \bar{A} & P \bar{B} + \bar{A}^T \bar{C}^T \Lambda + \bar{C}^T T \\ \bar{B}^T P + \Lambda \bar{C} \bar{A}^T + T \bar{C} & \Lambda \bar{C} \bar{B} + \bar{B}^T \bar{C}^T \Lambda - 2T \end{bmatrix} < 0, \quad (3.42)$$

hold.

The above stability condition is actually LMI version of the Kalman Yakubovich-Popov conditions corresponding to the multi-variable Popov criterion [37]. The system will be asymptotically stable (a.s.) in the large if the LMIs given in (4.19) are feasible. However, this global stability criterion will require the angle droop gains σ_{δ_i} , $i = 1 \dots n$, to be sufficiently small, which may result in over-conservative design of interface control with limited droop-based power sharing capability. Such conservativeness can be significantly reduced with the following procedure:

- Step 1: consider the sectors $\phi_j(y_j) \in [-1, 1]$, $j = 1 \dots m$.
- Step 2: transform the sectors to $[0, 1]$ according to (3.26) and (3.27).
- Step 3: solve the LMIs formulated in (3.32).
- Step 4: if (3.32) is feasible the system (3.22), (3.23) is a.s. in the large, else go to Step 5.
- Step 5: take the upper half of the sectors and perform Step 2.
- Step 6: perform Step 3.
- Step 7: if (3.32) is feasible regional stability can be concluded and go to Step 6, otherwise go to Step 5.
- Step 6: calculate guaranteed stability region according to the sector condition specified in Step 5.
- Step 7: if the initial condition z_0 falls into the stability region, the system (3.22), (3.23) will be transient stable and $z_0 \rightarrow 0$ at steady state, otherwise droop management will be requested for smaller angle droop gains.

The above procedure is integrated into the stability assessment framework, as shown in Fig. 3.2.

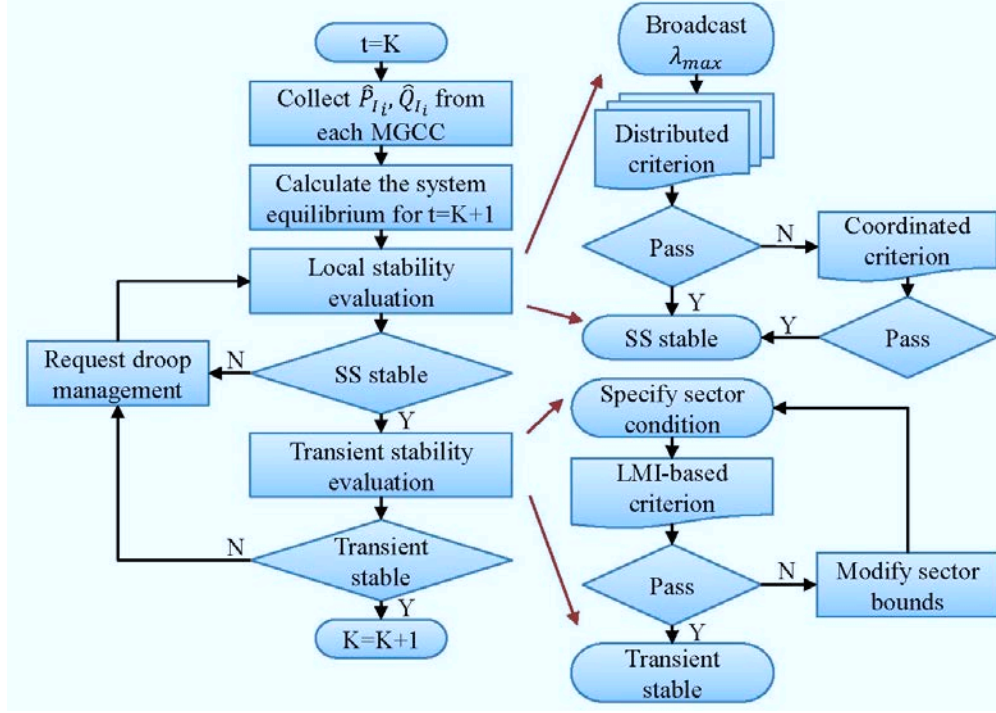


Figure 3.2: Stability assessment framework

3.3 Tertiary Level Supervisory Control for Microgrid Dispatch

As the highest level of control for multi-microgrid systems, tertiary control is responsible for coordinating the operation of all on-line microgrids [21]. The main purpose is to mitigate the DER output variation and balance out the long-term mismatch between power production and consumption through aggregation effect, i.e. power exchange among interconnected microgrids. For a reliable, secure and economical operation, the reference setting of each microgrid interface can be managed by the DSO with a supervisory control scheme.

Assume effective power sharing is achieved with the primary level control and system-wide stability guaranteed with the droop management performed at the secondary level. Since commonly, the distribution lines have comparative resistance and reactance, an ACPF problem is formulated to generate the reference setting for each microgrid. The procedure starts with each microgrid forecasting its total local real and reactive power injection $\bar{P}_i^*, \bar{Q}_i^*$ for an operation interval defined by the DSO. It should be noted that if used as the main regulation resource, the ESS of each microgrid might keep on injection or absorbing real power due to the droop-based method employed. Thus, the amount of real power generation or consumption of the ESS needs to be included in the forecasting of power injection based on its state of charge (SOC).

In the ACPF problem formulation, the PCC of the microgrid connected with the external system is designated as the swing bus; PCCs of all the other microgrids will be considered as P - Q buses at the beginning. If the physical limits of V_t is hit for some buses, they will be treated as P - V buses instead.

The ACPF solution $o_e = [\delta_i^*, V_i^*, P_{I_i}^*, Q_{I_i}^*]^T, i = 1 \dots n$, will be sent to each MGCC for the primary level reference tracking and the secondary level droop management, respectively. It should be noted that the time-frame resolution of droop management could be designed differently from the microgrid setting point dispatch resolution. For instance, droop gains for each microgrid may can be managed with a finer resolution for better support of fast variation resources. However, if frequent change of droop gains is not allowed, conservative values can be designed based on the contingency scenarios.

4. Numerical Examples

4.1 Angle droop-based Interface Control Strategy and Virtual Interfacing Scheme

With the proposed angle droop control for real power sharing, better transient performance can be expected compared with the frequency droop-based approaches and strategies emulating synchronous generator behaviour. In conventional power systems, it is well known that local mode oscillations, one generator swings against the rest of the system, are resulted from the second order angle dynamics of the SG swing equations. The corresponding impact is localized to the generator and the line connecting it to the grid. The rest of the system is normally modelled as a constant voltage whose frequency is assumed to remain constant, known as the single machine infinite bus (SMIB) model. On the other hand, the proposed strategy results in a first order angle dynamics without causing such local oscillation.

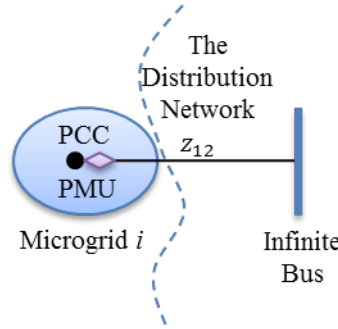


Figure 4.1: One microgrid infinite bus system

Fig. 3.3 shows the diagram of a SMIB system, in which a microgrid is connected to an infinite bus through a distribution line with impedance $Z_{12} = 1.5042 + j1.3554\Omega$. With the power and voltage base chosen as $V_{base} = 4.16 \text{ kV}$, $S_{base} = 1 \text{ MV}$ we have the per unit line impedance $z_{12} = 0.0869 + j0.0783$. Assume the infinite bus voltage $V_{inf} \angle \delta_{inf} = 1 \angle 0^\circ \text{ p.u.}$ and the PCC voltage magnitude of microgrid i is fixed at 1 p.u. , the PCC voltage phase angle and real power injection transient responses from the initial condition, $V_i \angle \delta_i = 1 \angle 0^\circ \text{ p.u.}$ and $P_{I_i} = 0 \text{ p.u.}$, to the equilibrium point $V_i \angle \delta_i = 1 \angle 30^\circ \text{ p.u.}$ and $P_{I_i} = 3.71 \text{ p.u.}$, are evaluated through time domain simulation.

Table 4.1: Interface control parameters

Parameter	J_i	D_i	τ_{δ_i}	σ_{δ_i}
Value (p.u.)	10	2	5	0.5

Note: J_i is the synthetic inertia and D_i is the damping coefficient in the SG emulation method.

Two interface control strategies are compared with control parameters given in Table 4.1, one emulating synchronous generator behaviour, known as the synthetic inertia method [8]. The other adopting angle droop control as introduced in this paper. Fig. 3.4 shows the trajectories of the PCC voltage angle and real power injection of microgrid i . It can be seen that the local oscillation mode

presents with the synthetic inertia method but not with the angle droop control, through which better transient performance can be expected.

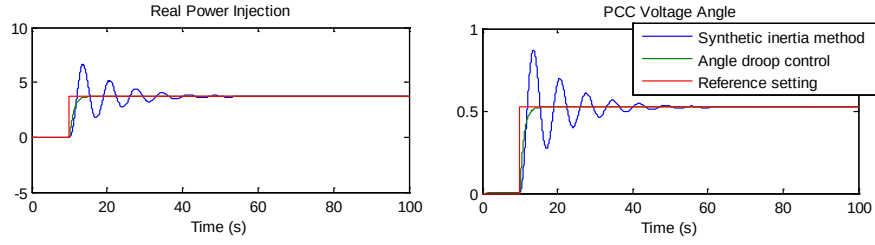


Figure 4.2: Trajectory comparison of PCC voltage and real power injection

For the scenario that no physical interface VSI is deployed at the microgrid PCC, diagram shown in Fig. 3.5, the proposed virtual interfacing scheme is adopted managing three DER integration VSIs in a distributed manner. Assume the participation factors for the three VSI $c_{d1} = c_{q1} = c_{d2} = c_{q2} = 0.25$ and $c_{d3} = c_{q3} = 0.5$ with electrical distance $z_{VSI1} = 0.5 + j0.5$, $z_{VSI2} = 0.5 + j1.0$ and $z_{VSI3} = 1.0 + j0.5$, all in per unit. Fig. 3.6 shows the voltage reference setting for the three integration VSIs so that the PCC voltage profile with angle droop control as shown in Fig. 3.4 can be achieved.

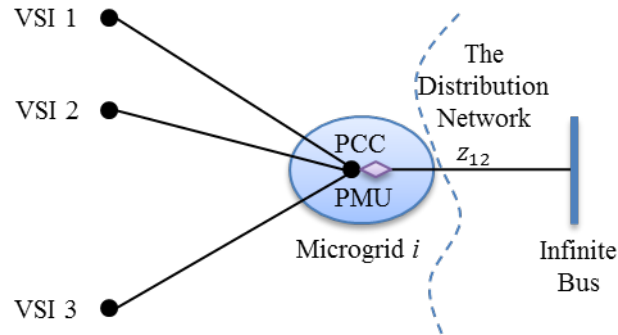


Figure 4.3: Virtual interfacing with DER integration VSIs

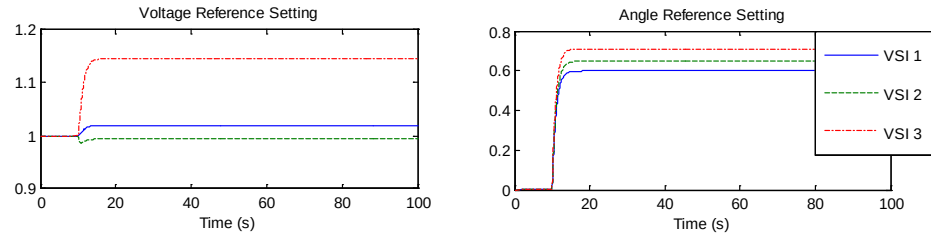


Figure 4.4: Integration VSI reference setting for micro-grid virtual interfacing

4.2 Stability Criteria and Dynamic Security Assessment of Multi-microgrid Systems

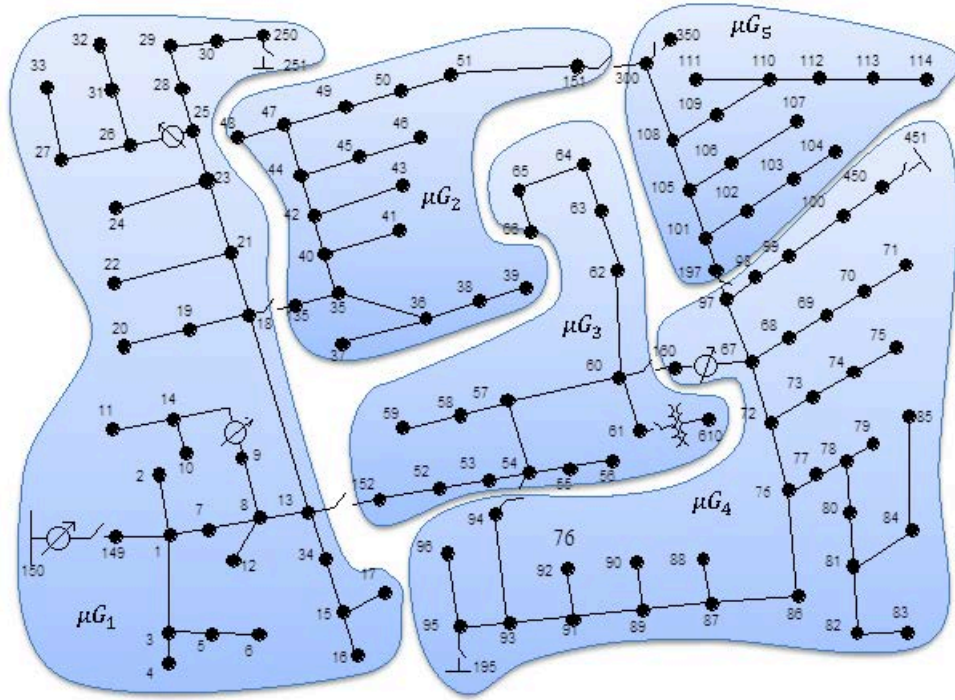


Figure 4.5: Diagram of study system based on IEEE 123-bus test feeder

In this section, we consider a study system designed based on the IEEE 123-node test feeder [38], shown in Fig. 4.5, with some modifications to allow for microgrid application. In current practice, radial distribution systems are more preferred than loop systems by distribution engineers because 1) simple and inexpensive protection schemes can be utilized; 2) fast isolation of faulted section [39]. However, radial distribution systems can have such advantages only if power flows in one direction. In multi-microgrid systems, power exchange among interconnected modules will be dependent on the operating condition of both module at that time. Thus, bi-directional power flow need to be considered. As will be shown in our case study, loop system configurations could be more desirable for multi-microgrid application over the radial ones mainly due to two of their benefits:

- More balanced power flow (with reduced power loss and better-regulated voltage profile).
- More secure (allowing for more aggressive droop characteristics for load sharing among interconnected microgrids).

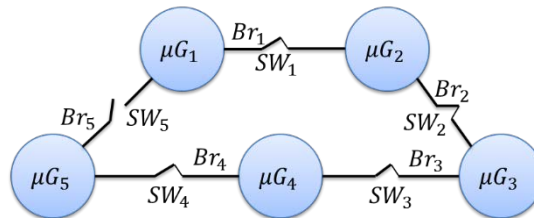


Figure 4.6: Diagram of a 5-microgrid radial system

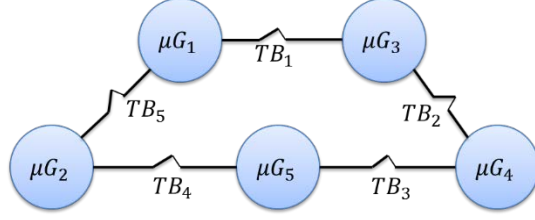


Figure 4.7: Diagram of a 5-microgrid loop system

Here we will demonstrate our modelling and DSA framework for both radial and loop system configurations. A 5-microgrid radial system is configured with the default tie-switch status, shown in Fig. 4.6. In addition, a loop system is configured by closing all the tie-switches as shown in Fig. 4.7. Here line parameters of the tie-branches are given in Table. 4.2. Aggregated generation and load profiles for each module are given in Table. 4.3.

Table 4.2: Inter-module line parameters

Br No.	1	2	3	4	5
R (Ω)	0.11	0.16	0.05	0.16	0.03
X (Ω)	0.08	0.15	0.03	0.15	0.02

Table 4.3: Module generation and load profiles

Module	μG_1	μG_2	μG_3	μG_4	μG_5
P_G (kW)	-	600	400	500	800
Q_G (kVar)	-	200	100	400	700
P_L (kW)	920	230	450	270	1530
Q_L (kVar)	470	110	200	120	750

Start with Case A, shown in Fig. 4.6, in which 5 microgrids are connected through a radial network. At a specific operation point with the generation and load profiles given in Table 4.3, PCC voltage profile of each microgrid can be obtained through an AC power flow program, shown in Table 4.4. In this case, real power loss for load sharing is 9 kW. Here we choose the power base $S_B = 10$ kW and voltage base $V_B = 4.16$ kV. Then the interaction coefficient defined in (3.27) can be calculated as $\lambda_{\max} = 0.5671$.

Table 4.4: PCC voltage profile of each microgrid – Case A

PCC	μG_1	μG_2	μG_3	μG_4	μG_5
V (p. u.)	1.000	1.000	0.996	0.995	0.987
δ (rad)	0.000	-0.128	-0.472	-0.559	-0.903

Table 4.5: PCC voltage profile of each microgrid – Case B

PCC	μG_1	μG_2	μG_3	μG_4	μG_5
V (p. u.)	1.000	1.003	1.002	1.003	0.999
δ (rad)	0.000	0.043	0.007	-0.014	-0.045

Now consider Case B, shown in Fig. 4.7, in which all tie-switches are closed. Then a loop 5-microgrid system is configured. With the same generation and load profiles as the base case, corresponding PCC profile of each microgrid is obtained as in Table 4.5. In this case, the real power loss for load sharing reduces to 2 kW, and $\lambda_{\max} = 0.1424$.

Obviously, with the loop configuration, both the real power loss and the interaction coefficient for the system are significantly reduced, by 78% and 75%, respectively. According to the analysis in Chapter 4, smaller $\lambda_{\max}$ indicates less damping requirement for module interfaces. Thus more aggressive droop characteristics can be designed for inter-microgrid load sharing, which could be beneficial to support DER integration.

Following the procedure introduced in Section 3.2.1., the system-wide stability can be assessed with a two-level assessment framework. Here three sets of interface parameters, shown in Table 4.6, are considered for both the radial and the loop network configuration Case A and B. The system-wide stability is assessed with both the coordinated Criterion 1 and distributed Criterion 2, with results given in Table 4.7. For a specific operation point, the assessment procedure starts with module agents evaluating system stability with Criterion 2. If satisfied (Case B, Set 1 and 2), system-wide stability can be concluded. However, if Criterion 2 is not satisfied (Case A, Set 1, 2 and 3; Case B, Set 3), the system coordinator will need to evaluate system-wide stability with Criterion 1. If satisfied, the operation point considered is asymptotically stable (Case A, Set 2; Case B, Set 3); otherwise, instability can be concluded (Case A, Set 1 and 3), which requires module agents to modify their control characteristics.

Table 4.6: Interface parameter sets of each module

Set	Parameter	μG_1	μG_2	μG_3	μG_4	μG_5
1	J_δ	8.00	12.00	12.00	9.00	12.00
	D_δ	0.29	0.32	0.33	0.29	0.40
	J_V	5.00	2.50	6.25	4.00	4.00
	D_V	0.31	0.25	0.31	0.20	0.25
2	J_δ	8.00	12.00	12.00	9.00	12.00
	D_δ	0.47	0.52	0.55	0.47	0.62
	J_V	10.00	5.00	12.50	8.00	8.00
	D_V	0.63	0.50	0.63	0.40	0.50
3	J_δ	8.00	12.00	12.00	9.00	12.00
	D_δ	1.76	1.60	1.85	1.76	1.90
	J_V	8.60	8.10	8.00	7.65	7.82

	D_V	1.67	1.59	1.54	1.47	1.52
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Table 4.7: System-wide small-signal stability assessment result

Configuration	Parameter	$\max R_e(\lambda_i)$	Criterion 1	Criterion 2
Case A	Set 1	0.0231	Unstable	N/A
	Set 2	-0.0189	Stable	N/A
	Set 3	0.1071	Unstable	N/A
Case B	Set 1	-0.0308	Stable	Stable
	Set 2	-0.0497	Stable	Stable
	Set 3	-0.0214	Stable	N/A

4.3 Hierarchical Control Framework

In this section, the feasibility of the proposed interactive control framework is numerically tested for the study system designed based on IEEE 123-bus test feeder, shown in Fig. 4.5. Configured as a microgrid-based distribution system, five microgrids are interconnected in a loop through tie-branches (TBs), with line parameters given in Table 4.8.

Table 4.8: Inter-module line parameters

Br No.	1	2	3	4	5
R (Ω)	1.0300	1.4680	1.5042	1.4512	1.2030
X (Ω)	0.7400	1.1150	1.3554	1.3083	1.1034

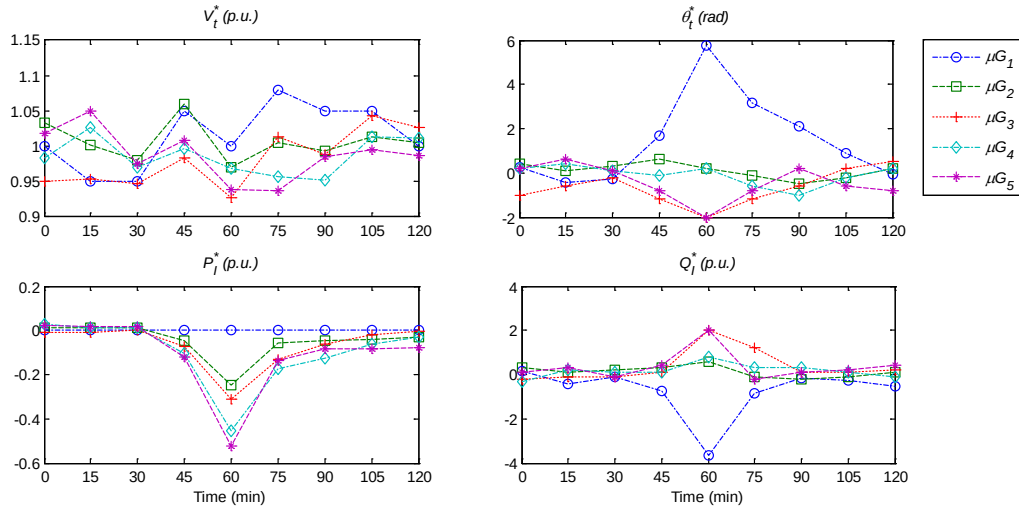


Figure 4.8: Reference setting of each micro-grid

With the ACPF problem formulated in Section 3.3 solved every 15 minutes, the reference setting for each micro-grid can be obtained, as presented in Fig. 4.8. Corresponding to each system operation point, the interaction coefficient $\lambda_{\max}$ defined in (3.27) can be calculated, as plotted in Fig. 4.9. In Fig. 4.8, per unit representation (p.u.) are used for voltage magnitude, real and reactive power injections, while radian measure is used for voltage phase angle. The voltage and power bases are $V_B = 4.16$ kV, $S_B = 1$ MW, respectively.

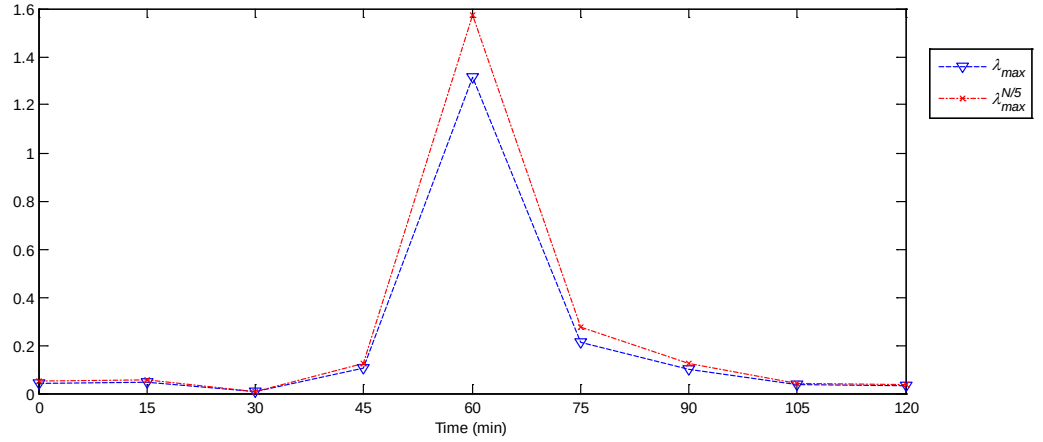


Figure 4.9: Variation of the system interaction coefficient

The interaction coefficient shows the network stressfulness at a specified operation point. It can be seen from Fig. 4.8, and Fig. 4.9 that the higher utilization of the tie-branches for power exchange the larger interaction coefficient will the system have. For the operation point at 30 min, the largest real power branch flow is $F_{2-1} = 0.31$ MW from $\mu G2$ to $\mu G1$ through TB5. The corresponding interaction coefficient $\lambda_{max}(15) = 0.008$. For the operation point at 60 min, the largest real power branch flow is $F_{1-3} = 3.58$ MW from $\mu G1$ to $\mu G3$ through TB1. The corresponding interaction coefficient $\lambda_{max}(60) = 1.316$. Apparently, the system interaction coefficient at 60 min is much larger than that at 30 min with significantly higher utilization of the network for power exchange.

In order to study the impact of angle and voltage droop gains on system-wide small-signal stability, first consider the scenario that no real time droop management is performed. Each microgrid interface VSI has its droop gain designed a priori without considering system operation condition. Assume the plant model parameters are uniformly designed for each microgrid interface, as given in Table 4.9. Time domain simulation is performed the obtained system model for the operation point at 60 min, as presented in Table 4.9 (worst-case scenario). With the initial condition, $\Delta V_{t_i} = 0.10$ p.u., $\Delta \delta_{t_i} = 0.05$ rad, $i = 1 \dots 5$, the system state response for the first 30 seconds is shown in Fig. 4.10, from which we see that the system is unstable as the state trajectories do not converge to their reference values.

Table 4.8: Interface plant model parameters

Parameter	τ_δ	σ_δ	τ_v	σ_v
Value	8.0	2.0	4.0	2.0

Table 4.9: System operation condition at $t = 60$ min

State	μG_1	μG_2	μG_3	μG_4	μG_5
V_t^* (p.u.)	1.0000	0.9698	0.9267	0.9695	0.9392
δ_t^* (rad)	0	-0.2478	-0.3130	-0.4540	-0.5252
P_l^* (p.u.)	5.7563	0.2000	-2.0000	0.2000	-2.0000
Q_l^* (p.u.)	-3.6458	0.6000	2.0000	0.8000	2.0000

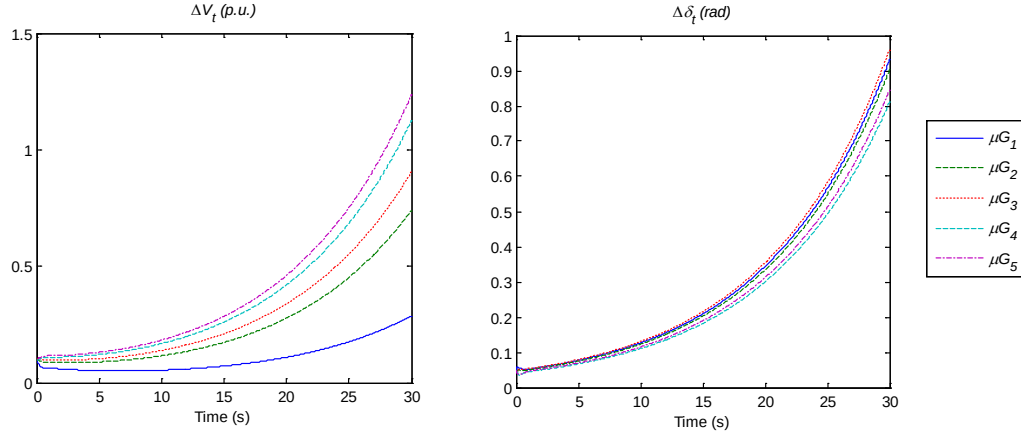


Figure 4.10: System state trajectories without droop management

Now consider the scenario that real time droop gains of each microgrid interface are managed interactively with the DSO. Assume for each module, it is required that the PCC voltage phase angle and magnitude regulated within $\pm 5^\circ$ from their reference values, respectively. According to the Criterion 2 in (3.2.1), the regulation capacity of each microgrid needs to be configured satisfying

$$P_{R_i}^{up} = P_{R_i}^{dn} > 0.0873 \lambda_{max}, Q_{R_i}^{up} = Q_{R_i}^{dn} > 0.05 \lambda_{max}. \quad (4.1)$$

For the operation point at 60 min, given in Table 4.9, the system interaction coefficient λ_{max} (60) = 1.316. Then without loss of generality, assume the regulation capacity is uniformly configured for each microgrid as

$$P_{R_i}^{up} = P_{R_i}^{dn} = 0.16 \text{ (p.u.)}, Q_{R_i}^{up} = Q_{R_i}^{dn} = 0.08 \text{ (p.u.)}. \quad (4.2)$$

Choosing a 10% margin, the droop gains of each microgrid can be determined accordingly

$$\sigma_{\delta_r} = 0.49, \sigma_{V_r} = 0.56. \quad (4.3)$$

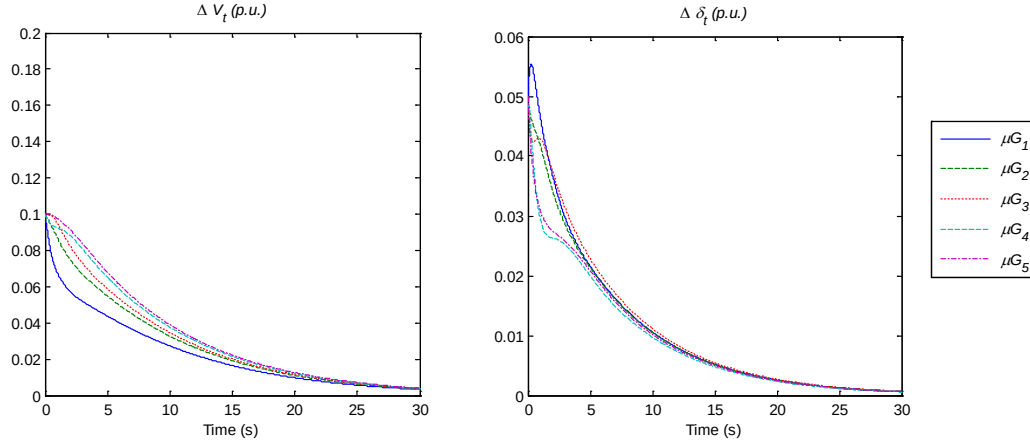


Figure 4.11: System state trajectories with interactive droop management

Assuming successful reference tracking is achieved with the MRC-based primary level control, the designed droop gains $\sigma_{\delta_r}, \sigma_{V_r}$ are used instead of the plant droop gains $\sigma_{\delta}, \sigma_V$ to represent microgrid interface dynamics. Keep the time constants unchanged $\tau_{\delta_r} = \tau_{\delta} = 8.0$, $\tau_{V_r} = \tau_V = 4.0$, and consider the same system operation point at 60 min with the same initial condition specified above, the system state trajectories are obtained, shown in Fig. 4.11. It can be observed that the system is asymptotically stable as the state trajectories converge to their reference values at the steady state.

4.4 Transient Stability Assessment

In this section, the transient stability of the study system, diagram shown in Fig. 4.7 with line parameters given in Table 4.8, will be evaluated. The transition to be considered is from the initial condition o^K to the equilibrium operation point o^{K+1} of the next dispatch interval, given in Table 4.10.

Table 4.10: Transition between two consecutive operation points

PCC	μG_1	μG_2	μG_3	μG_4	μG_5
$V^{*K}(\text{p.u.})$	1.00	1.00	1.00	1.00	1.00
$\delta^{*K}(\text{rad})$	0.00	-0.38	-0.24	0.34	0.77
$V^{*K+1}(\text{p.u.})$	1.05	0.95	1.00	1.05	0.95
$\delta^{*K+1}(\text{rad})$	0.00	-0.17	0.03	-0.18	-0.40

The local stability of o^{K+1} can be evaluated with the small-signal model (3.12), (3.13) formulated in Section 3.2. Three study cases are studied, of which the interface control parameters for each case are given in Table 4.11. The system eigenvalues for each study case are plotted in Fig. 4.12.

Table 4.11: Interface control parameters

Case	Parameter	μG_1	μG_2	μG_3	μG_4	μG_5
A	τ_δ	1.20	1.00	0.80	1.00	1.20
	σ_δ	2%	2%	2%	2%	2%
	τ_V	12.0	10.0	16.0	10.0	12.0
	σ_V	2%	2%	2%	2%	2%
B	τ_δ	1.20	1.00	0.80	1.00	1.20
	σ_δ	15%	15%	15%	15%	20%
	τ_V	12.0	10.0	16.0	10.0	12.0
	σ_V	2%	2%	2%	2%	2%
C	τ_δ	1.20	1.00	0.80	1.00	1.20
	σ_δ	120%	150%	100%	120%	150%
	τ_V	12.0	10.0	16.0	10.0	12.0
	σ_V	2%	2%	2%	2%	2%

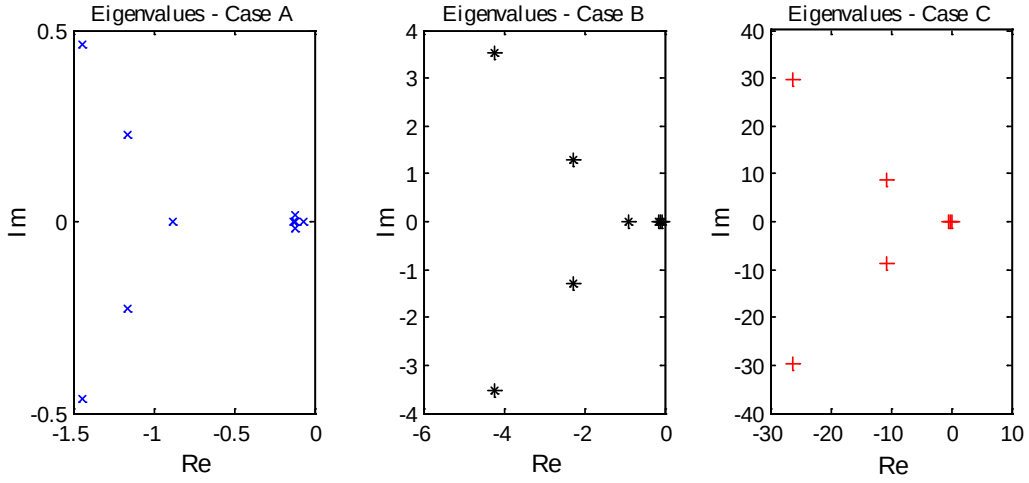


Figure 4.12: Eigenvalues for small signal system model

Now that the system operation point o^{K+1} is small-signal stable for Case A and B, their transient stability from the initial condition o^K to the intermediate point o^{K+} can be evaluated, results given in Table 4.12.

Table 4.12: Stability assessment result

Stability	Case A	Case B	Case C
o^{K+1} (small-signal)	Stable	Stable	Unstable
o^K to o^{K+} (transient)	Globally stable	Regionally stable	-

For Case A, the LMIs formulated in (3.42) are feasible with the sector condition $\phi_j(y_j) \in [-1,1], j = 1 \dots 10$, thus global stability can be concluded. For Case B, feasible solution of (3.42) cannot be obtained with the above sector condition, whereas regional stability can be established with sector condition $\phi_j(y_j) \in [0,1], j = 1 \dots 10$. The stability region is given in Table 4.13.

Table 4.13: Regional stability region

Bound	$x_1 - x_2$	$x_1 - x_3$	$x_2 - x_5$	$x_3 - x_4$	$x_4 - x_5$
Upper bound (rad)	1.14	1.30	1.07	1.06	0.95
Lower bound (rad)	-1.82	-1.19	-1.87	-1.87	-1.72

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Part III

Risk Based Transient Instability Criteria for Dynamic Reliability Standards

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Glossary

A	variable that denotes type of fault. Three phase to ground fault, two phase to ground fault, phase-to-phase fault and one phase to ground fault are represented by the indices 1, 2, 3 and 4 respectively
$C_{original}$	(\$/MWh) original cost of generation
$C_{replacement}$	(\$/MWh) replacement generator cost
C_{load}	(\$/MW) large penalty due to customer load interruption
CD	the centerline distance of the OOS characteristic circle in pu on system MVA base
CDF	cumulative distribution function
DFIG	doubly fed induction generator
DT	the diameter of the OOS characteristic circle in pu on system MVA base ($DT > 0$)
E_i	“N-1” contingency event due to occurrence of the fault F_i
EUL	Expected Unserved Load
f_n	frequency of occurrence of each fault type
F_i	event of occurrence of a fault on the i^{th} circuit
GE	General Electric
GENROU	round rotor generator model
h	outage duration in hours
i	variable to denote a particular circuit
Im	impact
Im_i	the impact of transient instability for the i^{th} contingency
Im_{gen}	the impact due to the replacement cost of generators being tripped
Im_{load}	the impact due to customer load interruptions
k	variable to denote the particular fault location
K	transient instability event
L	# of segments in a circuit
LLG	two-phase to ground fault
LLL	three-phase to ground fault
LL	line-to-line fault
M	the total number of WTGs in the plant
n	variable to denote the particular type of fault
N_c	total number of critical circuits considered in the evaluation
OOS	out-of-step
$P_{loadshed}$	total amount of load shed
P_g	generator MW tripped

Pr	probability
PSAT	power flow and short circuit analysis tool
PSLF	GE PSLF software
P_{WTG}	probability of WTG generation output at a certain percentage
RBSA	risk based security assessment
SLG	single line to ground fault
SPS	special protection system
TSAT	transient security assessment tool
TSI	transient stability index
UFLS	under frequency load shedding
WTG	wind turbine generator
GEWTG	generator/converter model
EWTGFC	electrical control model
WNDTGE	mechanical control (wind turbine) model
X	pre-contingency operating point
Z_{ef}	effective fault impedance representation for stability studies
Z_{neg}	negative sequence impedance
Z_0	zero sequence impedance
λ_i	fault rate in outages/hour
δ_{max}	maximum angle separation between any two generators at the same time in the post-fault response
η	angular margin based transient stability index
θ	the centerline angle of the OOS characteristic circle in degree ($-180 \leq \theta \leq 180$)
w	the percentage of rated capacity of renewable generation that is operational

1. Introduction

1.1 Background

Power systems are regularly subjected to unanticipated and unavoidable events due to faults, disturbances, human errors and equipment failures. Such disturbances can cause overloads, voltage collapse or transient instability and can lead to widespread outages due to cascading failures. To maintain system reliability and security, system operators and planners perform analysis to make crucial operation and planning decisions that will guarantee safe operation of the power system following such faults/failures. The current practice within the power industry is the usage of deterministic methods with significant safety margins to cover for all potential uncertainties. Hence, with deterministic criteria for system security, power systems typically operate with a large security margin.

Power systems have shifted from a regulated system to a competitive and uncertain market environment where market prices for energy are defined by demand and supply. Deterministic security margins compel utilities to operate at levels much lower than their capability. This has led utilities to face more pressure to operate at lower security margins due to the economic imperatives in the power markets. Electric utilities require transparent and quantitative metrics to complement the security margins imposed on them. Hence, to operate the power system beyond the deterministic security margin, refined techniques are required in the planning stages to assess the security of the power system. Additionally, with increased penetration of converter-based renewable energy into the electricity grid, the overall dynamics of the system is changing. In the future with very high renewable penetration, it is imperative that the uncertainty (associated with variability and intermittency) and dynamics of such renewable generation is incorporated into the reliability standards.

The reliability requirement for operation and planning of the North-American Bulk Electric System (BES) is defined by the NERC Reliability Standards. The NERC transmission reliability standards [1] provide the requirements to develop a BES that will operate reliably over a wide range of operating conditions and probable contingencies within the planning horizon. The criteria requirement the NERC standards are deterministic and do not include any information about probabilities associated with the fault occurrence. Typically, these deterministic criteria provide safe but conservative as defined in limits to system operating conditions. The most crucial security criteria are the “ $N-1$ ” security criteria that ensure safe operation of the power system following a failure of a single element of the system where N is the total number of system components. The deterministic “ $N-1$ ” security criterion are obtained by determining the ability of the system to remain stable following the worst case contingency from a credible list of contingencies. The operating condition, for which a system is secure for the worst case “ $N-1$ ” contingency, is said to be “ $N-1$ ” secure. “ $N-2$ ” security of a system is assessed in a similar way, although the probability of the simultaneous outage of two components is low if they are mutually exclusive.

1.2 Problem statement and rationale

The deterministic security criteria estimation is intuitive and straightforward to implement, but does not provide sufficient information on the actual risk of the violation of the criteria. With present changes in the electric power industry due to deregulation as well as renewable energy integration, utilities are compelled to operate very close to the deterministic security margins. These deterministic margins fail to provide the actual risk of operating at that particular operating point. With the deterministic security criteria, an operating condition is considered as insecure if any operating constraints are violated. The extent of the violation is not considered in the deterministic approach and hence the system is either at risk or at no risk at all.

On the other hand, if the reliability standards are based on both the probability as well as the economic impact of the contingencies, then it provides a clearer picture of the extent of violation of constraints for a given operating condition. A ‘risk’ based index encompasses both the likelihood and consequence of an event and can relax the operating limits imposed by the deterministic approach. There is a fundamental difference between the deterministic approach and the risk based approach for security assessment. The deterministic approach develops security limits based on the worst case contingency while a risk based security decision is determined by comparing the risk of all contingencies from a credible contingency list. Hence, the risk based approach for security assessment can provide more information about the security margins obtained and can also quantify the bases on which security decisions are made. The risk of an event represents the expected cost due to possible insecurity problems measured by the economic consequence of an uncertainty weighted by its probability of occurrence [2]. Hence, with risk assessment system reliability and economics can be merged into a single metric. The most formidable problem of risk assessment is the quantification of the economic impact or consequence due to a power system disturbance.

1.3 Objectives

The overall objective of this report is to define new reliability standards for the dynamics of the power system based on risk-based criteria instead of traditional deterministic criteria. The work done in this research has the following objectives:

- To obtain a realistic dynamic model of a power system test case with sufficient renewable penetration in the form of wind turbine generators (WTGs)
- To obtain a method for accurate impact assessment of a transient instability event by modeling of specific protection systems in transient stability analysis
- To obtain the overall risk of transient instability on the system as well as the risk of transient instability for all credible contingencies
- Incorporate the stochastic model for renewable energy sources in reliability assessment
- To perform risk based security assessment for the future electricity grid with very high renewable penetration
- To obtain system security limits for transient instability based on risk assessment
- To compare deterministic security limits with risk based security limits.

1.4 Report organization

The report is organized as follows. Chapter 2 presents a detailed literature review of the existing work done in this area. Chapter 3 presents effect of converter-based renewable generation on the system transient stability. Chapter 4 presents the mathematical background for the risk assessment procedure and the derivation of the expressions for probability and impact of transient instability. Chapter 5 discusses the WTG models used in the simulations and the modeling of the protection system for impact assessment. Chapter 6 illustrates the risk assessment procedure in detail for a test system. Chapter 7 presents the simulation results along with discussions.

2. Literature review

In this section, the previous work on probabilistic and risk based methods for system security assessment is discussed.

A significant amount of literature is available on probabilistic transient instability assessment. Anderson and Bose in [3] proposed a method for obtaining probabilistic transient stability assessment by using distribution functions based on location, fault type and sequence. Anderson, Bose and Timko in [4] demonstrated the use of Monte Carlo simulations in the computation of probabilistic measures for the transient stability problem. Billinton, Carvalho and Kuruganty, in [5], demonstrated approximate methods for evaluating probabilistic transient instability and identifying critical stability areas for system planning. In [6-7], Billinton and Kuruganty developed an approach for obtaining a stability index for individual lines as well as for the overall system for different fault types. The effect of clearing times and reclosing times were also investigated for critical lines. In [8], Billinton and Kuruganty proposed the use of stochastic models of the protection system in probabilistic transient stability assessment by considering the probability density functions of the protection system components. Aboreshaid, Billinton, and Firuzabad, in [9], described the use of the bisection method in evaluating probabilistic transient stability.

In [10], Wu, Tsai, and Yu presented an approach to evaluate the distribution of the probability of instability. In [11], Hsu, Yun-Yih, and Chang used conditional probabilities in the evaluation of probabilistic transient instability.

In [2, 12-15], risk based security assessment of power systems is presented for operations and planning. In [12], McCalley, Fouad, Vittal, Irizarry-Rivera, Agrawal, and Farmer presented a risk based security index for determining operating limits in stability limited power systems. In [13], Acker, McCalley, Vittal, and Pecas Lopes presented a risk based transient stability assessment procedure. The impact assessment was obtained through offline simulation with underfrequency relays by estimating the cost of load shedding. Generators going out-of-step were also considered in the impact estimation. Ming, McCalley, Vittal, and Tayyib, in [14], discussed the online evaluation of risk indices for security assessment. The EPRI report [2] by McCalley, Vittal, Dai, Fu, Irizarry-Rivera, Acker, Wan and Zhao provided a detailed discussion on risk based security assessment for different aspects of power system performance. The report described the concepts and algorithms developed in building a decision-making framework for computing the risk associated with power system disturbances. The report discussed the risk assessment procedure for line overload, transformer overload, voltage instability, voltage limit violations, transient instability and special protection systems. In [16], Fu Zhao, McCalley, Vittal, and Abi-Samra presented a risk based security assessment for special protection systems.

Dissanayaka, Annakkage, Jayasekara, and Bagen, in [17], presented a linearized technique to determine a risk-based index for dynamic security. Abapour and Haghifam, in [18], presented a method for on-line assessment of risk of transient instability. In [19], Faried, Billinton, and Aboreshaid incorporated wind farms in the evaluation of the probabilistic transient stability of power system using a stochastic two-mass model of the WTG. Vaahedi, W. Li, Chia and Dommel, in [20], presented the results of the probabilistic transient stability assessment on a large scale system of B. C. Hydro and showed that deterministic criteria produce conservative results and also

that the deterministic criteria do not always correspond to the worst case scenario. In [21], Maruejouis, Sermanson, Lee, and Zhang discussed the probabilistic reliability assessment using risk indices for overloads, voltage violations, voltage stability and load loss events. In [22], Kirschen, Jayaweera, Nedic, and Allan demonstrated the use of a probabilistic indicator based on ‘expected energy not served’ to estimate the level of system stress and its inverse - security. They suggested the use of the indicator in conjunction with deterministic criteria for the system operation decisions.

In [23], Kirschen and Jayaweera compared the differences between risk based and deterministic security assessment methods and illustrated the benefits of risk based security assessment over traditional deterministic approaches.

2.1 Summary

The majority of the literature on probabilistic and risk based security assessment methods emphasize the benefit of the probabilistic methods over deterministic methods for security assessment.

The present NERC reliability standards [1] for transmission planning are based on deterministic methods, but in [24] NERC mentions the need of probabilistic security standards for long term planning to enhance resource adequacy metrics. With the recent trends in increased renewable penetration, stable operation of the power system will be dependent on proper security assessment by system planners. The literature survey presented above also shows that in previous work the impact assessment is simplistic and is not evaluated for all fault types and fault locations.

3. Effect of converter-based renewable generation on system transient stability

The United States electricity grid has witnessed increased deployment of renewable energy in recent years. In 2013, around 523 million MW-hours of energy produced in United States were from renewable energy sources [41]. The major drivers for the increased renewable generation are reduced cost of electricity production and the state-level renewable energy portfolio standards. The majority of the renewable energy penetration is in the form of utility scale solar PV panels and type-4 wind turbine generators. The increased penetration of converter-based generation can have significant effect on the transient stability of a power system. Most of the research works [42-45] in this area have mainly focused on small signal stability analysis as well as transient stability analysis aspects on test systems with increased renewable penetration. The studies show that increased renewable penetration can have both beneficial and detrimental effects on the system stability. Due to the changed dynamics of the system, it is essential that the reliability standards for transmission planning should be re-evaluated. In this research, a probabilistic risk based methods for determining reliability standards is proposed. It is shown that the proposed standard can be more effective in system planning and provide more information on the system security limits.

3.1 Single machine infinite bus (SMIB) test case

In order to illustrate the differences between the dynamics of a conventional generator and full convertor-based wind generation a SMIB test case is generated. The single line diagram of the test case is provided in Figure 3.1. The SMIB model consists of a 500MW generator at bus #1 connected to 230 kV transmission line through a generator transformer. There is a local constant impedance load of 100 MW at bus #2. Two 230 kV transmission lines are present between bus #2 and bus #3. Bus #3 in the SMIB case is modeled as the infinite bus with a detailed generator model and a constant impedance load of 500MW. To maintain the generation-load balance, the swing bus generates 100 MW to feed the load. Hence, for normal operation the tie line flow is 400 MW.

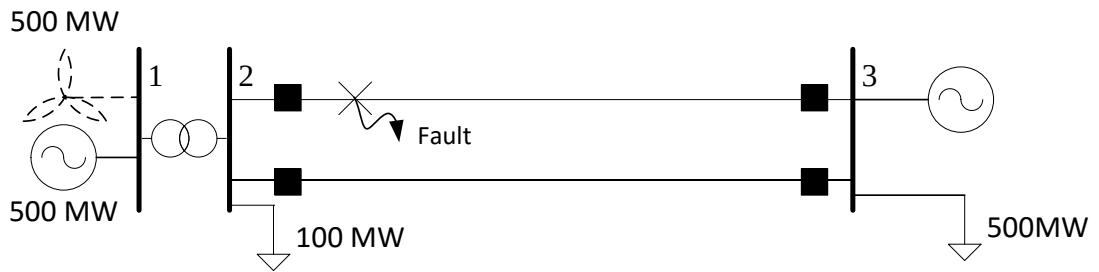


Figure 3.1: SMIB test case

3.2 SMIB simulation and results

The SMIB case is modeled in GE PSLF software and two cases are considered. In the first case, the generator at bus #1 is a conventional thermal generator modeled as GENROU with exciter model as EXST1 and governor model as TGOV1. In the second case, the generator at bus #1 is modeled as full-converter type-4 wind turbine generator (models: GEWTG, EWTGFC and

WNDTGE). A three-phase to ground fault is considered in one of the transmission lines connecting bus #2 and bus #3 near bus #2 at time $t = 1$ second. The fault is cleared after 5 cycles by opening the faulted line between bus #2 and bus #3. For this particular study, the time domain simulation is performed for different line impedance values between bus #2 and bus #3 to simulate varying electrical distances between the generator and the load. Figure 3.2 and Figure 3.3 provide the simulation results for both the cases. The figures show the time domain simulation of the electrical power generated at the generator bus #1 and infinite bus (bus #3) following the three phase fault. From Figure 3.2, it can be observed that as the line reactance is increased to 0.12 pu, the system becomes transiently unstable. On the other hand, it can be observed from when the generator at bus #1 is modeled as type-4 WTG, the system stays stable even when the line reactance is increased to 0.15 pu. In addition, it can be observed by comparing the two figures that the oscillations in the type-4 WTG are negligible compared to the synchronous generator following the three-phase to ground fault near the generator terminal.

3.3 Summary

Type-4 WTGs are connected to the grid by power converters. In this research, the type IV WTGs are modeled with voltage regulation control at the point of interconnection. The overall dynamics of the WTG is significantly different from that of synchronous generators as is evident from the simulation results. With increased penetration of renewable energy into the electricity grid, the overall system dynamics and transient behavior of the grid is changing. Therefore, there is a necessity to modify the current dynamic reliability standards for system planning such that the future electricity grids operate at most economical and reliable operating conditions. In the following chapter, the mathematical formulation of the RBSA is discussed in detail.

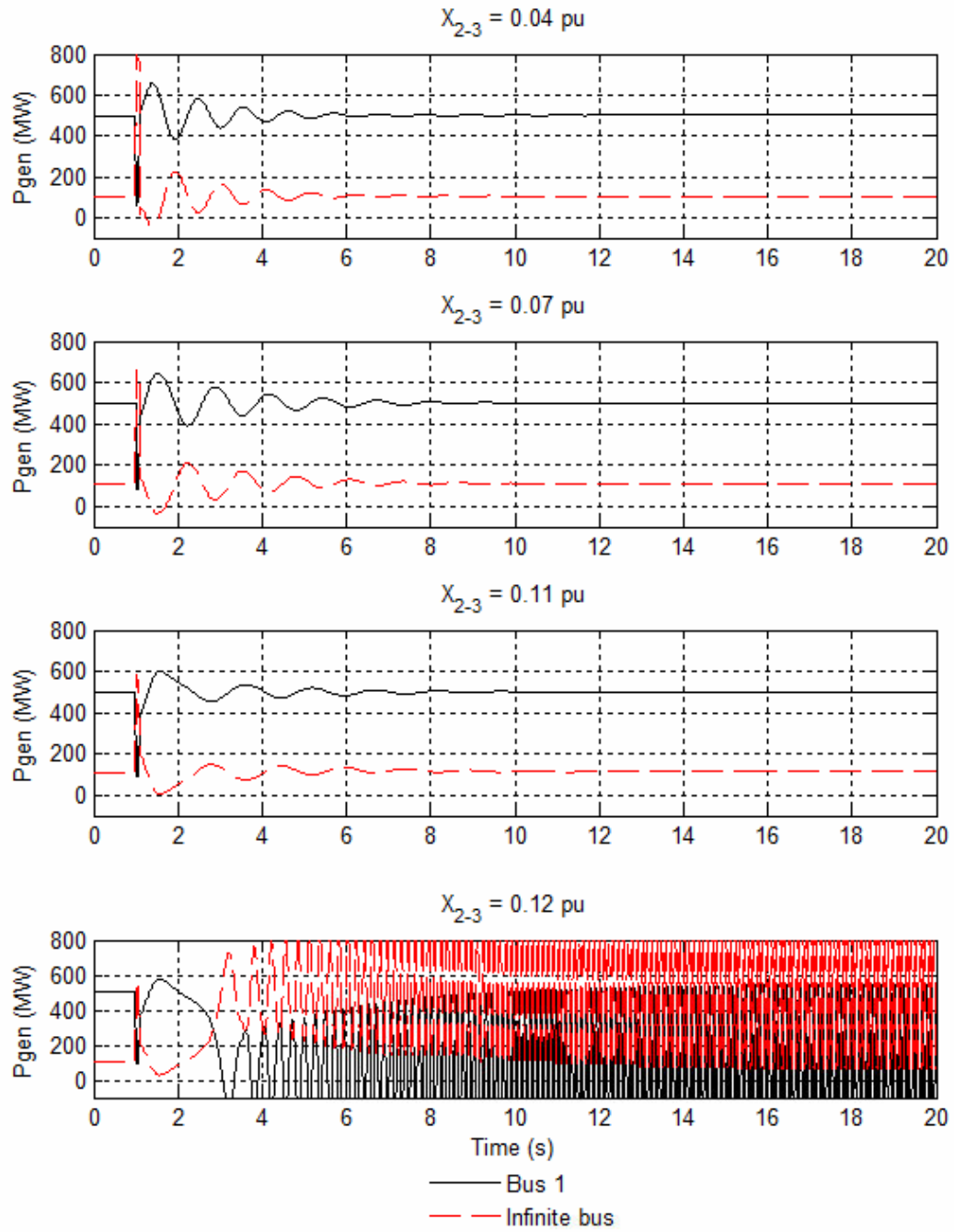


Figure 3.2: Transient stability with conventional synchronous generator

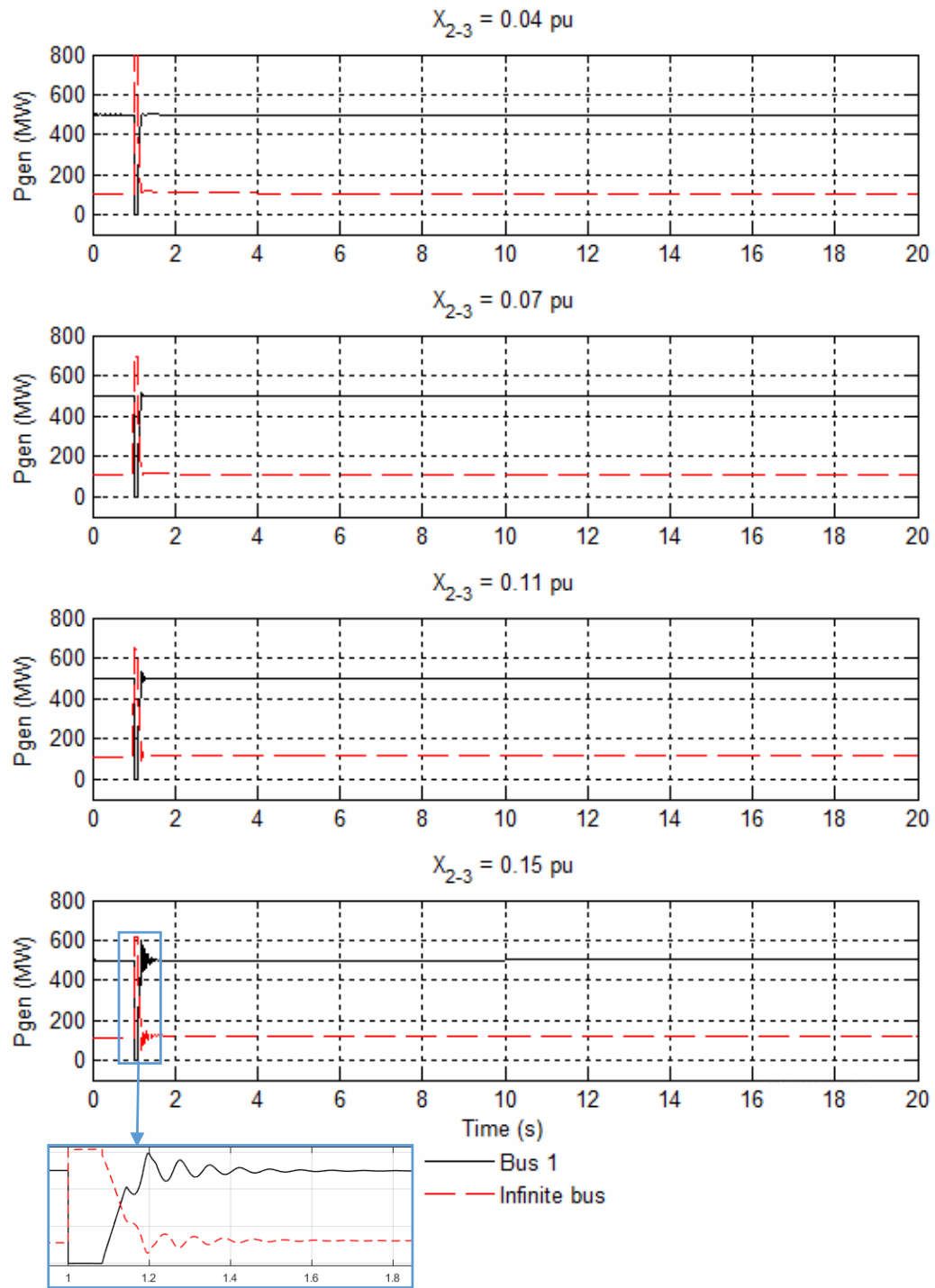


Figure 3.3: Transient stability with asynchronous type-4 WTG

4. Risk-based transient stability assessment

In this chapter, the theory behind risk based security assessment (RBSA) of the transient instability problem is discussed. Risk is defined as the product of the probability of an occurrence of an event and the consequence of that particular event. The computed risk is equivalent to the expected cost of a transient instability event. The computed risk is useful in making system security decisions related to stability performance. The evaluation of the risk of transient instability is computationally intensive due to repetitive time domain simulations involved. In the following section, the mathematical expressions required to assess the transient instability risk is discussed.

4.1 Risk evaluation

The two main components of risk evaluation is the probability of occurrence of an event and the impact/consequence of that event [2, 13]. The following notations will be used in this report for the mathematical representation of the risk of transient instability:

F_i : event of occurrence of a fault on the i^{th} circuit

A : variable that denotes type of fault. Three phase to ground fault, two phase to ground fault, phase-to-phase fault and one phase to ground fault are represented by the indices 1, 2, 3 and 4 respectively

N_c : total number of critical circuits considered in the evaluation

E_i : “N-1” contingency event due to occurrence of the fault F_i

X : pre-contingency operating point

K : transient instability event due to one or more generators losing synchronism

Pr : probability

Im : impact.

The risk due to a transient instability event K over the next time period at the pre-contingency operating point X due to all possible N -1 contingencies is evaluated as

$$\begin{aligned} Risk(K | X) &= Pr(K | X)Im(K | X) \\ &= \sum_{i=1}^{N_c} Pr(K \cap E_i | X)Im(K \cap E_i | X). \end{aligned} \tag{4.1}$$

4.2 Probability of transient instability

It is assumed that following a fault F_i the circuit is disconnected due to correct circuit breaker operation and fault is cleared after a fixed interval of time based on the voltage level at which the fault occurs. This event E_i is transiently unstable if one or more generators lose synchronism. Since the different types of faults ($A = 1, 2, 3, 4$) are mutually exclusive and exhaustive events, the following expression can be obtained:

$$\begin{aligned} K \cap E_i &= K \cap E_i \cap ((A=1) \cup (A=2) \cup (A=3) \cup (A=4)) \\ &= (K \cap E_i \cap (A=1)) \cup (K \cap E_i \cap (A=2)) \cup (K \cap E_i \cap (A=3)) \cup (K \cap E_i \cap (A=4)). \end{aligned} \quad (4.2)$$

Hence, the probability of transient instability can be expressed as

$$Pr(K \cap E_i | X) = \sum_{n=1}^4 Pr(K \cap E_i \cap (A=n) | X). \quad (4.3)$$

The notation X for the operating condition is dropped in the following expressions due to simplicity of notation.

$$\begin{aligned} Pr(K \cap E_i) &= \sum_{n=1}^4 Pr(K \cap E_i \cap (A=n)) \\ &= \sum_{n=1}^4 Pr(E_i) Pr((A=n) | E_i) Pr(K | E_i \cap (A=n)). \end{aligned} \quad (4.4)$$

In addition, the probability of occurrence of a fault at different line locations is assumed to follow a uniform distribution; hence, the likelihood of occurrence of a fault on any part of the circuit is equal throughout the circuit. Hence, (4.4) can be re-written as follows:

$$Pr(K \cap E_i) = \sum_{k=1}^L \sum_{n=1}^4 Pr(E_{ik}) Pr((A=n) | E_i) Pr(K | E_i \cap (A=n)) \quad (4.5)$$

where $Pr(E_{ik})$ is the probability of occurrence of a fault on the k^{th} section of the of the i^{th} circuit with L segments. From (4.5), it can be observed that there are three parts in the probability expression. In the following subsections, the detailed analysis of the probability expression in (4.5) is discussed.

4.2.1 Fault occurrence

The first part, $Pr(E_i)$ is the probability of occurrence of the considered $N-1$ contingency. Each line has a fault rate that can be obtained from historical data. It is assumed that the occurrence of a fault on the i^{th} circuit is a homogeneous Poisson process [2, 13]. Given the failure rate λ_i (faults/hour) of the i^{th} circuit, the fault probability of the i^{th} circuit is given as:

$$\begin{aligned} Pr(F_i) &= 1 - e^{-\lambda_i} \\ i &= 1, \dots, N_c. \end{aligned} \quad (4.6)$$

The occurrence of faults on different circuits are mutually independent of each other, hence the following expression can be derived,

$$\begin{aligned} Pr(E_i) &= Pr(\overline{F}_1 \cap \overline{F}_2 \cap \dots \cap \overline{F}_{i-1} \cap F_i \cap \overline{F}_{i+1} \cap \dots \cap \overline{F}_{N_c}) \\ &= Pr(F_i) \prod_{j \neq i} Pr(\overline{F}_j) \\ &= (1 - e^{-\lambda_i}) e^{-\sum_{j \neq i} \lambda_j}. \end{aligned} \quad (4.7)$$

4.2.2 Fault location

To account for the influence of fault location on the probability of transient instability, a discrete uniform distribution is assumed. Since, very few historical data are available on the locations of the faults on the lines, assuming that all locations of faults along the line have equal probability of occurrence is a good engineering assumption. If appropriate historical information is available on fault locations on a circuit the information can be used without loss of generality. In this research work, a uniform distribution is assumed for the fault location. Considering, each line has L segments, the probability of occurrence of the fault on the k^{th} section of the of the i^{th} circuit for the next unit time is given by

$$Pr(E_{ik}) = \frac{(1 - e^{-\lambda_i}) e^{-\sum_{j \neq i} \lambda_j}}{L}. \quad (4.8)$$

4.2.3 Fault type

The second expression $Pr((A = n) | E_i)$ in (4.5) denotes the probability of occurrence of a specific type of fault. Table 4.1 shows the different fault types with decreasing order of severity: three phase to ground fault (LLL), two phase-to-ground fault (LLG), line-to-line fault (LL) and single line-to-ground fault (SLG). In stability studies, the negative sequence and zero sequence voltages and currents are usually not of interest but their effects on faults are represented by equivalent impedance as seen from the point of fault. Depending on the type of fault, an effective impedance (Z_{ef}), measured in terms of negative sequence impedance (Z_{neg}) and zero sequence impedance (Z_0), is inserted in the positive sequence network as shown in Figure 4.1. Table 4.1 shows the effective fault impedances for different fault types for stability studies [25]. From historical data, the frequency f_n of occurrence of each type of fault can be obtained for the individual circuits. For each fault type, the probability expression is given by

$$Pr((A = n) | E_i) = \frac{f_n}{\sum_{j=1}^4 f_j} \quad n = 1, 2, 3, 4. \quad (4.9)$$

Table 4.1: Fault representation in transient stability studies

n	Fault type	Effective Impedance (Z_{ef})
1	LLL	0
2	LLG	$\frac{Z_0 \cdot Z_{neg}}{Z_0 + Z_{neg}}$
3	LL	Z_{neg}
4	SLG	$Z_{neg} + Z_0$

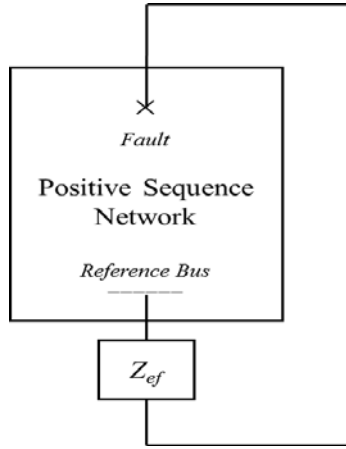


Figure 4.1: Fault representation in transient stability studies

4.2.4 Probability of transient instability

The third expression $Pr(K | E_i \cap (A = n))$ in (4.5) denotes the probability of transient instability of an event. The value of the expression is one if the system is unstable and zero if stable. The angle margin based transient instability index is used to distinguish between stable and unstable system. The angle based stability margin is discussed in detail in Chapter 6.

4.3 Stochastic modeling of wind power generation

The reliability of the power system is significantly impacted by the intermittent nature of any renewable energy injected to the grid especially the wind energy sources. The industry wide deterministic reliability standards fail to incorporate the uncertainty associated with the wind power generation in operation and planning studies. With the adoption of renewable portfolio standards, large numbers of renewable energy sources are being added to the electricity grid. Hence, the variability and the intermittency of such sources should be modeled into the reliability standards for system planning. The current deterministic standards used in system planning consider stability consider only the worst-case scenario and do not incorporate the stochastic nature

of the wind energy sources. In [46], the authors present the need of probabilistic wind energy modeling in reliability assessment. In this research, to incorporate the stochastic nature of the wind energy an additional probability expression is introduced in (4.5). The expression for the probability of transient stability incorporating the stochastic wind generation model is

$$Pr(K \cap E_i) = \sum_{k=1}^L \sum_{n=1}^4 \sum_{w=0}^{100} Pr(E_{ik}) Pr((A=n) | E_i) Pr(P_{WTG}) Pr(K | E_i \cap (A=n)). \quad (4.10)$$

In (4.10), $Pr(P_{WTG})$ is the probability of wind generation output and w is the percentage of the installed wind capacity operational. The probability of wind generation output can be evaluated from a fitted cumulative distribution function (CDF). Figure 4.2 shows a typical fitted CDF of wind power output. The CDF can be obtained from historical data as well as forecasted wind power output. In this research, the CDF is evaluated from historical data of a typical wind energy farm.

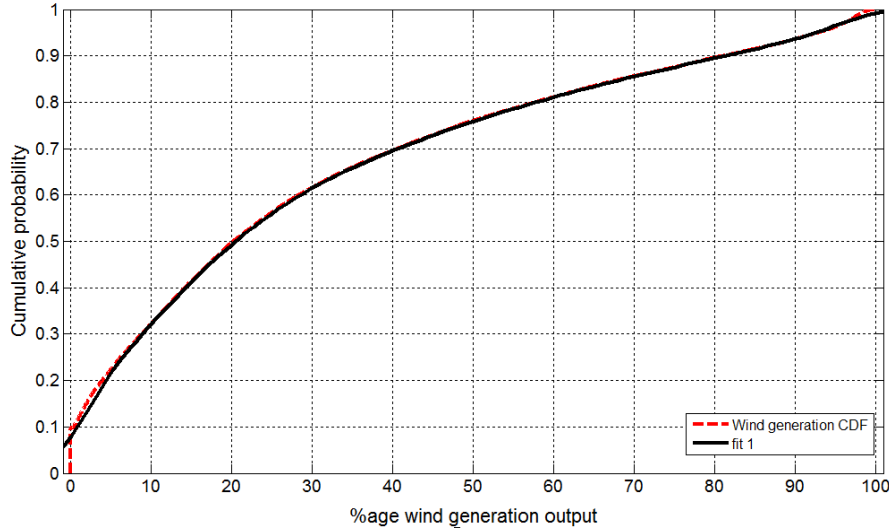


Figure 4.2: Fitted wind power output CDF

4.4 Impact assessment of transient instability

The quantification of the impact/consequence of the transient instability is one of the most formidable problems in RBSA. In this report, a novel procedure for determining the impact of transient instability is suggested. In this research, the protection system is modeled with out-of-step tripping for both transmission lines and generators, over-frequency/under-frequency/under-voltage and over-voltage generator tripping and under-frequency load shedding. Based on the simulation results, the total MW load shed and total generator MW tripped is used in estimating the impact of the transient instability event. In this research, two methods have been analyzed for quantifying the impact of a transient instability event. The first method gives an economic perspective of the effort required to stabilize an unstable event while the other looks into how much load has to be dropped following a transient instability event. The two impact assessment methods are explained in the next sub-section.

4.4.1 Impact assessment: Method 1

The economic impact of transient instability can be represented as follows:

$$Im_i = \sum_{k=1}^L \sum_{n=1}^4 Im_{gen} + \sum_{k=1}^L \sum_{n=1}^4 Im_{load} \quad (4.11)$$

where Im_i is the impact of transient instability for the i^{th} contingency. Im_{gen} is the impact due to the replacement cost of generators being tripped and Im_{load} is the impact due to customer load interruptions. Assuming that original cost of generation is $C_{original}$ (\$/MWh), replacement generator cost is given by $C_{replacement}$ (\$/MWh), generator MW tripped is P_g and outage time is h hours, the expression for the loss of revenue due to generator tripping is given by [2, 13]

$$Im_{gen} = (C_{replacement} - C_{original}) P_g h. \quad (4.12)$$

Due to tripping of generators, certain areas in the system can become generation deficit due to loss of critical lines and generators losing synchronism. To protect the system from frequency instability, under-frequency load shedding relays progressively remove the loads if the frequency drops below unacceptable values. The economic impact due to customer load interruption is estimated by the product of total load shed in MW and a large penalty factor due to load interruption in \$/MW. The impact due to customer load interruption is given by [2, 13]

$$Im_{load} = C_{load} P_{loadshed} \quad (4.13)$$

where C_{load} (\$/MW) is a large penalty due to customer load interruption, $P_{loadshed}$ is the total load shed. The modeling of the protection system for the impact assessment is discussed in detail in chapter 5.

4.4.2 Impact assessment: Method 2

The system wide effect of a transient instability event can be quantified as expected unserved load (EUL) in MW/hour. This quantity can be easily calculated and unlike the first method is not dependent on generation and load prices, which are difficult to obtain in the planning stages.

4.5 Summary

In this chapter, the mathematical expressions for transient instability risk estimation have been discussed. The probability of the occurrence of a transient instability event and its impact estimation methods are discussed in detail. Typical values of the different parameters for risk estimation are provided in Chapter 7. In the following chapter, the modeling of wind turbine generators and the protection system are discussed.

5. Modeling of wind turbine generators and protection system

5.1 Modeling of wind turbine generators

The dynamic behavior of the WTG is significantly different from the conventional synchronous generators. Hence, the dynamic performance of the power system changes due to ever-increasing penetration of renewable generation in the form of WTGs. In this research work, WTGs are modeled as type-4 [26-29] since it is the most widely used WTG technology worldwide. Type-4 WTG models have been developed to simulate the performance of wind turbines employing generators connected to the grid via power converters. Accurate WTG models are developed and maintained by the turbine manufacturers but those models are not publicly disclosed by them. This has led to the use of generic WTG models, which can capture the properties of most type-4 WTGs [26-29]. The modeling of WTG for time domain simulations mainly consists of two parts:

- Power flow model for WTG
- Dynamic model for WTG.

5.1.1 Power flow model for WTG

A wind plant for grid studies is modeled with a local grid collecting the output of individual WTGs at a single point of interconnection to the grid [26]. The multiple identical WTGs can be approximated to be in parallel to form a single equivalent machine behind an equivalent reactance. The power flow model of a wind plant is shown in Figure 5.1. The model consists of a single WTG with a unit transformer of M times the MVA rating of each individual WTG, where M is the total number of WTGs in the plant. For the power flow study, the wind farm is modeled as a conventional generator (PV bus). The generator real power output (P_{gen}), maximum reactive power output (Q_{max}) and minimum reactive power output (Q_{min}) are set at M times the individual WTG unit capabilities. Typical collector system voltages are at distribution levels – 12.5 kV or 34.5 kV for 60 Hz application. The substation transformer ratings are dependent on the total number of WTGs in the plant with typical impedance of 10%. In this research work, WTGS are modeled as GE 1.5 MW WTG and the typical parameters are provided in Table 5.1.

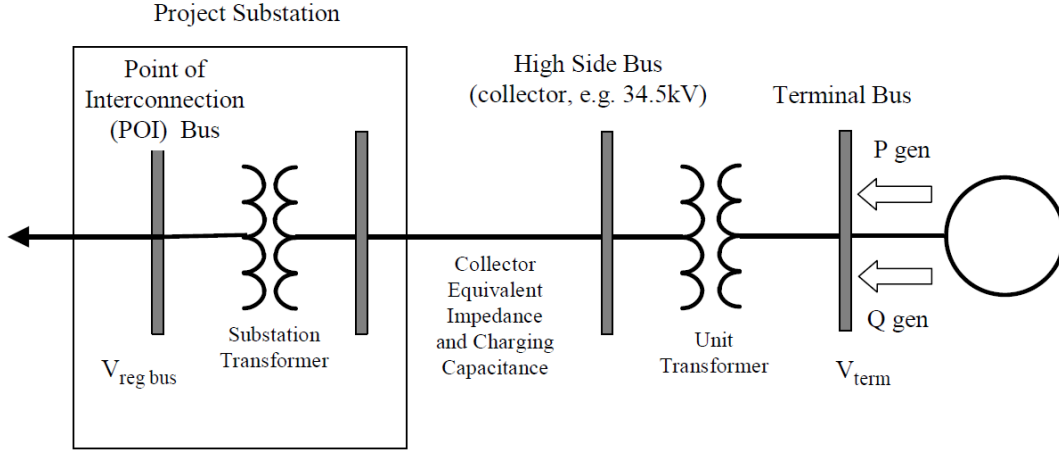


Figure 5.1: Simplified power flow model of a wind power plant, [26]

Table 5.1: GE 1.5 MW WTG power flow parameters, [26]

Generator Rating	1.67 MVA
P_{max}	1.5 MW
P_{min}	0.07MW
Q_{max}	0.726 MVA _r
Q_{min}	-0.726 MVA _r
Terminal voltage (60 Hz)	690V / 575 V
Unit transformer rating	1.75MVA
Unit transformer Z	5.75 %
Unit transformer X/R	7.5

5.1.2 Dynamic model for type-4 WTG

The power flow solution provides the initial conditions for the dynamic model. The WTG dynamic model can be divided into four functional blocks as shown in Figure 5.2. The PSLF dynamic models for type-4 WTG are as follows [30]:

- GEWTG: generator/converter model
- EWTGFC: electrical control model
- WNDTGE: wind turbine and turbine control model.

The generator/converter model injects real and reactive current into the network following commands from the other control blocks. The model also includes low voltage power logic that is used to limit the real current command during and immediately following sustained faults [26]. The electrical control model includes reactive power control and voltage regulation.

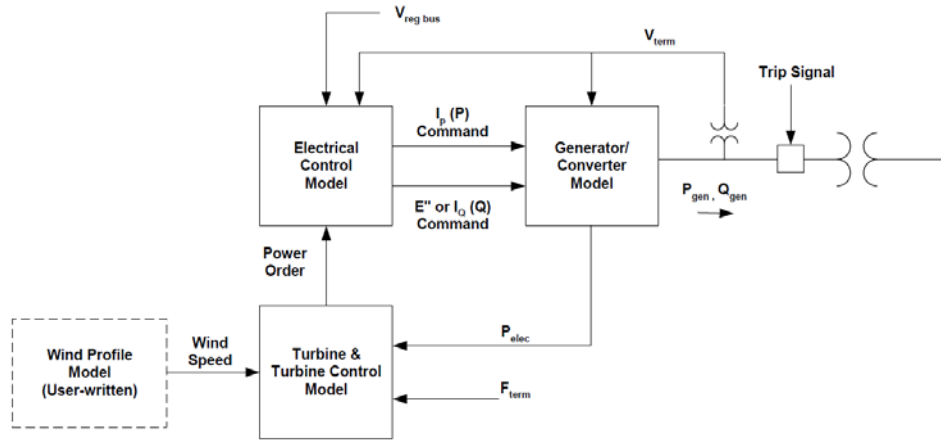


Figure 5.2: GE WTG dynamic model overall structure [26]

5.1.3 GEWTG: generator/converter model

The WT3G model is an equivalent of the generator and the full converter providing the interface between the network and the WTG. This model contains no mechanical state variables. All flux dynamics are eliminated in the model to account for the fast response to the electrical commands from the electrical control model through the converter. The model is represented both by reactive and active current commands from the electrical control model [26]. The full converter WTG generator/converter model is shown in Figure 5.3.

5.1.4 EWTGFC: electrical control model

This model controls the active power and reactive power to be injected into the network based on the inputs from the turbine model (P_{ord}) and from the supervisory VAR controller (Q_{ord}) [26]. The model includes additional functions like dynamic braking resistor and converter current limit. The objective of the dynamic braking resistor is to minimize the WTG response to large system disturbances. The objective of the current order limit is to check and prevent the real and reactive power injections from exceeding the converter maximum capability. Real or reactive power can be prioritized by selecting a user-specified flag. The PSLF electrical control model is shown in Figure 5.4.

5.1.5 WNDTGE: wind turbine and turbine control model

This model represents the simplified mechanical dynamics of the wind turbine along with relevant control models.

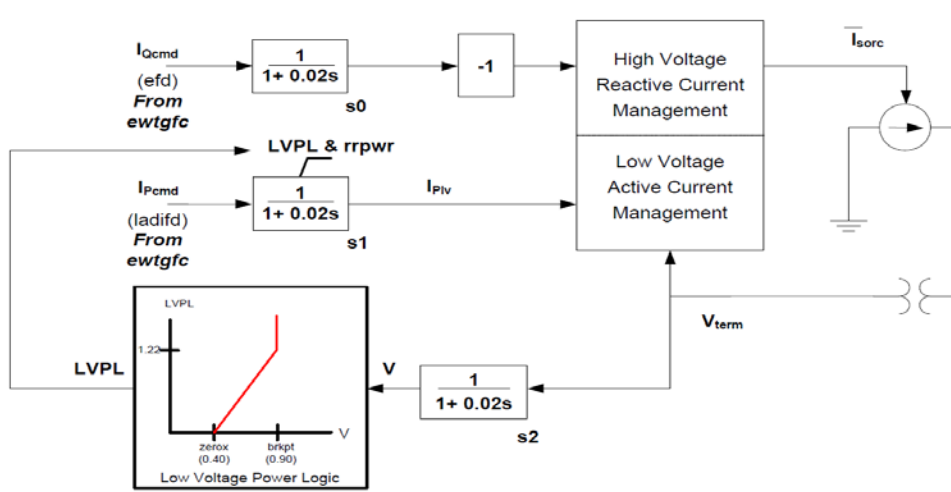


Figure 5.3: Full-converter WTG generator/converter model [26]

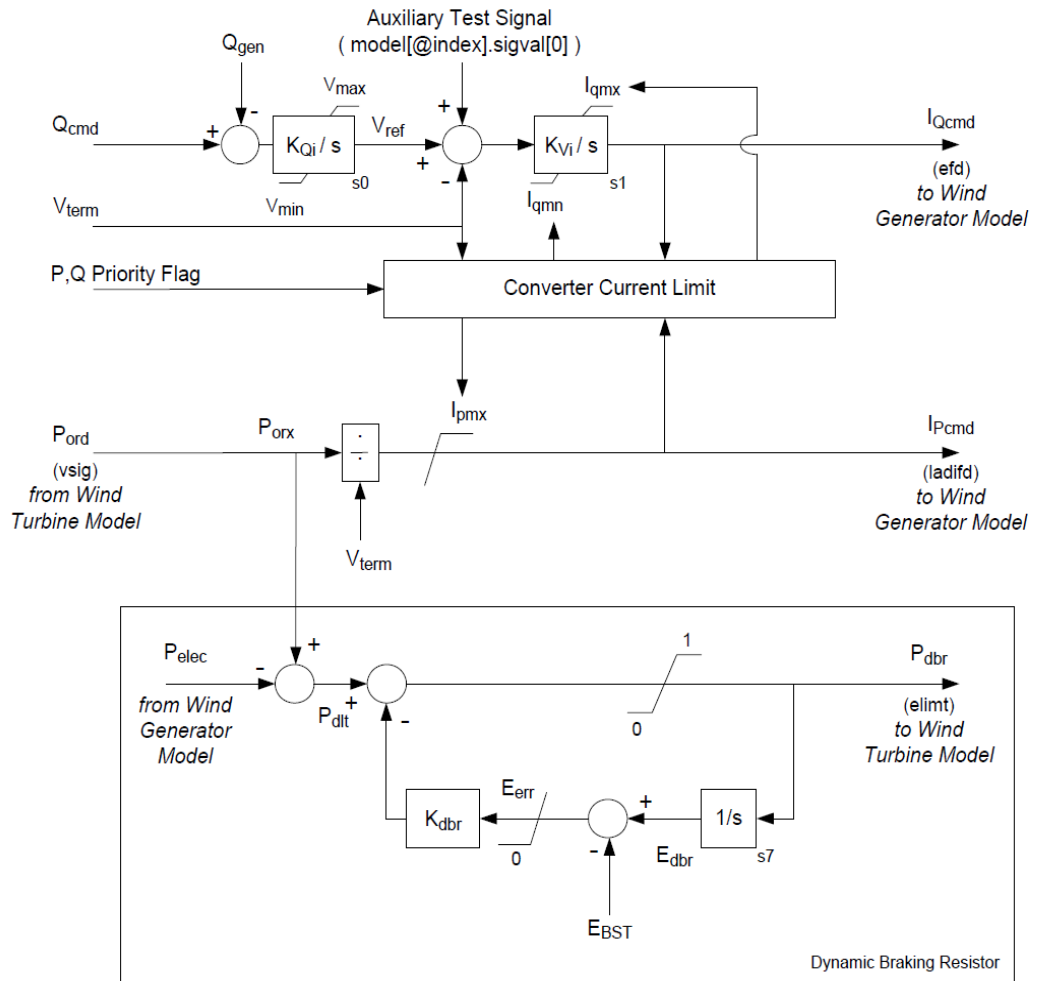


Figure 5.4: Full-converter WTG electrical control model [26]

5.2 Modeling of protection system

The aim of modeling the protection systems in this research work is to quantify the impact of the transient instability event. The protection systems are modeled such that following a contingency the system should be transiently stable. In order to stabilize the system, three types of protection systems are modeled in this work:

- a. Out-of-step (OOS) protection scheme for both lines and generators
- b. Under-frequency load shedding
- c. Over/under-frequency and over/under-voltage generator tripping.

5.2.1 OOS protection modeling

The philosophy behind out-of-step protection is simple and straightforward: protect the power system during unstable power swings and avoid tripping of any equipment during stable power swings. When two areas of a power system or two interconnected systems lose synchronism, the areas must be separated quickly and in a controlled manner to avoid system blackout and damage to costly equipment. Controlled tripping of power system equipment will prevent widespread loss of load and maintain maximum service continuity.

OOS detection is based on the principle that the power swing is an electromechanical transient process has a longer time constant than that for faults and the positive sequence apparent impedance changes slowly during the power swing than during a fault. The fundamental technique to distinguish a fault from an OOS condition is to observe the rate of change of apparent impedance. There are two broad functionalities of OOS protection [32]:

- OOS tripping
- OOS blocking.

OOS tripping is used to distinguish between stable and unstable power swing and initiate pre-determined network sectionalizing or islanding. The OOS blocking function is used to distinguish between faults and power swings to avoid faulty operation of distance relays during the power swing. In this work, only the OOS tripping function is implemented for impact assessment of transient instability. A simple impedance based OOS tripping relay is considered with concentric circle characteristics as shown in Figure 5.5.

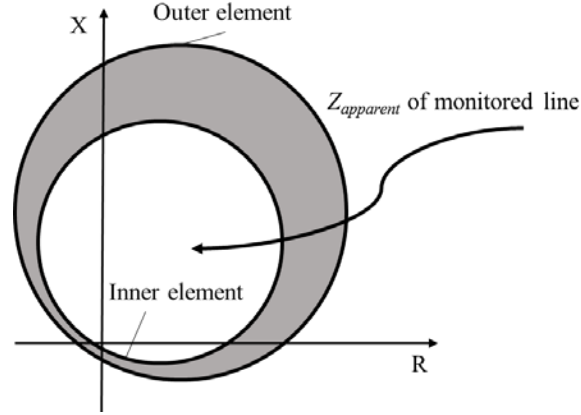


Figure 5.5: Concentric circle based OOS trip relay model

This relay has two elements an inner element and an outer element. The apparent impedance $Z_{apparent}$ of the monitored line is checked against these two elements. If $Z_{apparent}$ stays in the outer element for a specified time and then enters the inner element, a power swing is detected and a tripping signal is initiated. The block diagram of the OOS relay setting for a line connecting bus P and bus Q is shown in Figure 5.6.

RAPP+jXAPP is the apparent impedance Z of a monitored line # P - Q . The inner and outer element characteristics must be set according to the OOS relay settings. The model assumes that the inner element is entirely within the outer element. The output of these blocks has logical value: zero if the input ($Z_{apparent}$) is out of their circles or one if $Z_{apparent}$ is inside their circles. The OOS relay trips the line # P - Q and transfer trips lines # R - S and # T - U if the following conditions are met: $Z_{apparent}$ is in the outer element (but not in the inner element) for at least 3 cycles, and then $Z_{apparent}$ enters the inner element. The apparent impedance plots for stable and unstable swings for the line # P - Q are shown in Figure 5.7 (a) and 5.7 (b) respectively. In addition, the inner and outer concentric circles as per the implementation are shown in Figure 5.8. These figures correspond to actual implementations in the test system.

The circular OOS characteristic function is defined by the parameters DT , CD and angle θ as illustrated in the Figure 5.8, where DT is the diameter of the circle in pu on system MVA base ($DT > 0$), CD is the centerline distance in pu on the system MVA base and the angle θ is the centerline angle in degrees ($-180 \leq \theta \leq 180$).

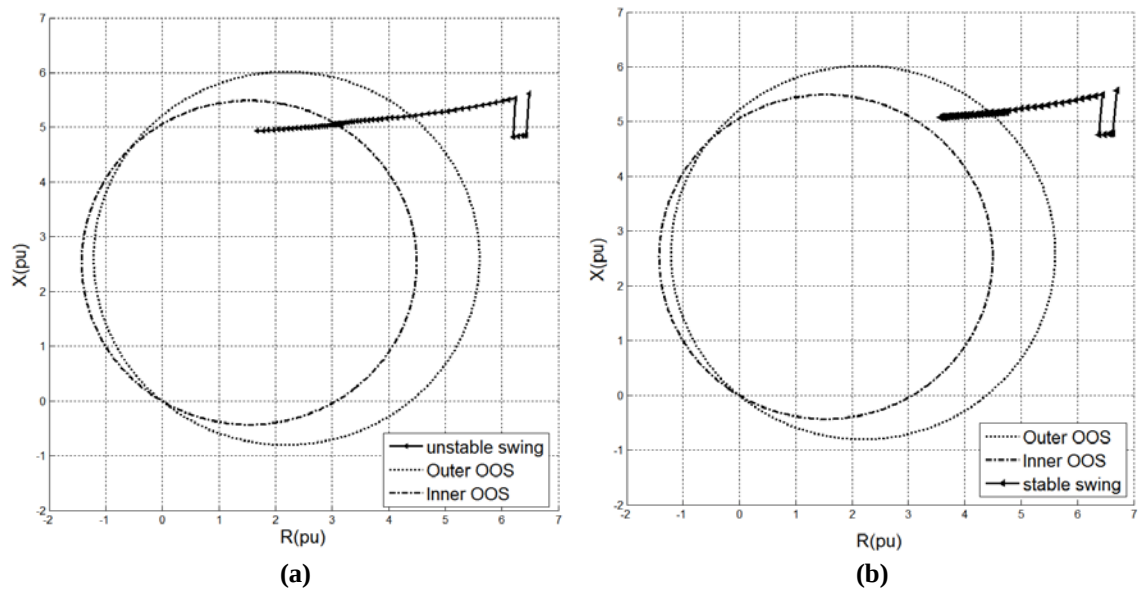
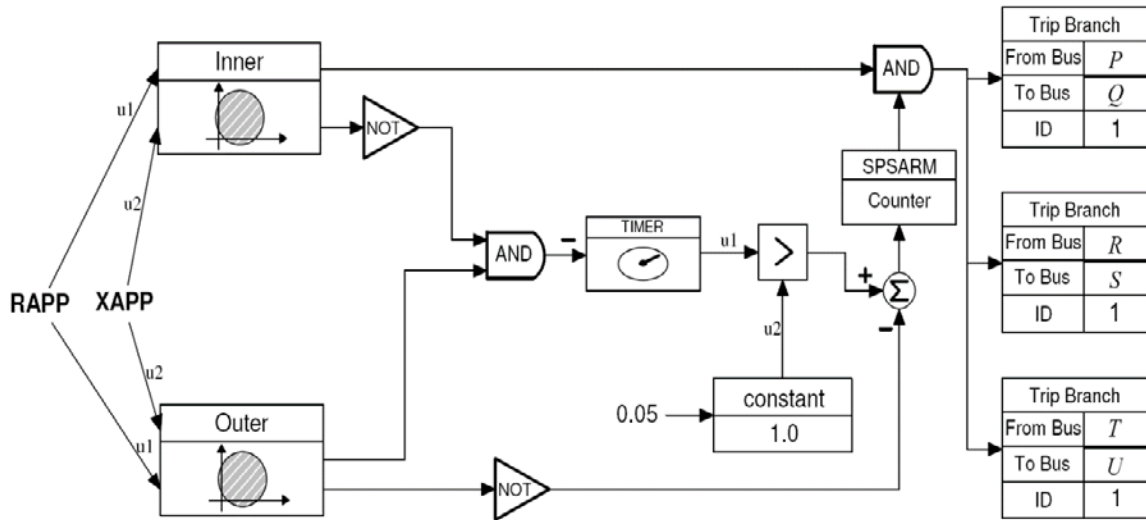


Figure 5.7: Apparent impedance during stable and unstable power swings

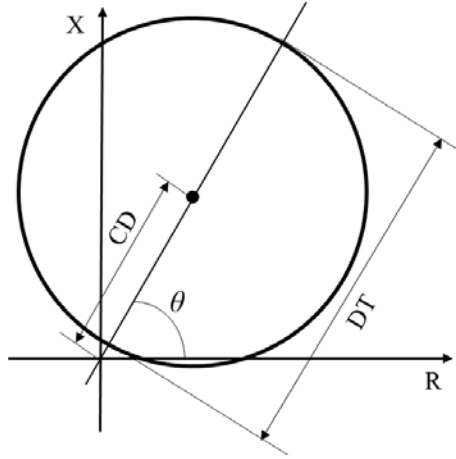


Figure 5.8: Circular OOS characteristic function

5.2.2 Under-frequency load shedding (UFLS)

The primary requirement of UFLS is to trip excess load to obtain generation-load balance following a disturbance that results in tripping of lines and/or generators causing that area generation deficit [33]. Since generator turbines cannot operate at low frequencies (56-58 Hz), it is necessary to maintain frequency near the nominal frequency (60 Hz). Slow changes in load can be compensated by the system by governor action if generators have available spinning reserve and equilibrium can be reached. However, during transient outages, the excess load is fed by the available kinetic energy of the rotating machines and frequency starts dropping. The only way to stabilize the system under such conditions is progressively shedding the load of pre-determined load centers at certain frequency thresholds.

The NERC reliability standard [34] for the Eastern Interconnection provides the required guidelines for automatic under-frequency load shedding. Table 5.2 shows the UFLS criteria for the Eastern Interconnection for utilities with net peak loads greater than 100 MW.

Table 5.2: UFLS attributes for with net peak load greater than 100MW

Frequency Threshold (Hz)	Total Nominal Operating Time (sec)	Load Shed at Stage (%)	Cumulative Load Shed (%)
59.5	0.30	6.5-7.5	6.5-7.5
59.3	0.30	6.5-7.5	13.5-14.5
59.1	0.30	6.5-7.5	20.5-21.5
58.8	0.30	6.5-7.5	27.5-28.5

5.2.3 Over/under-frequency and over/under-voltage generator tripping

Over-frequency and under-frequency generator tripping is required to maintain generation-load balance [33]. If any area is load deficit, the generators start speeding up. The generator turbines

are designed to operate near nominal frequency and operation at off-nominal frequency can damage the turbine blades. To protect the costly turbine generators, the NERC reliability criteria for UFLS [34] also provide guidelines for over-frequency and under-frequency generator tripping. Figure 5.9 shows the generator over-frequency and under-frequency performance characteristics and trip modeling criteria. In this work, the generators modeled with over-frequency and under-frequency relays are tripped if the over-frequency threshold of 61.8 Hz is violated or the under-frequency threshold of 57.8 Hz is violated.

Generators are designed to operate at a continuous minimum terminal voltage of 0.95 pu of its rated voltage, while delivering power at rated voltage and frequency. Under-voltage can reduce stability limit, excessive reactive power import and malfunctioning of voltage sensitive equipment. In this research, if the generator terminal voltage reduces to 0.90 pu for 1.0 sec, then the generator is tripped. Generator overvoltage protection, on the other hand, is required to prevent insulation breakdown due to sustained terminal overvoltage. The generator insulation is capable of operating at continuous overvoltage of 1.05 pu of its rated voltage. In this research, if the generator terminal voltage increases to 1.15 pu for 0.5 sec, the generators are tripped.

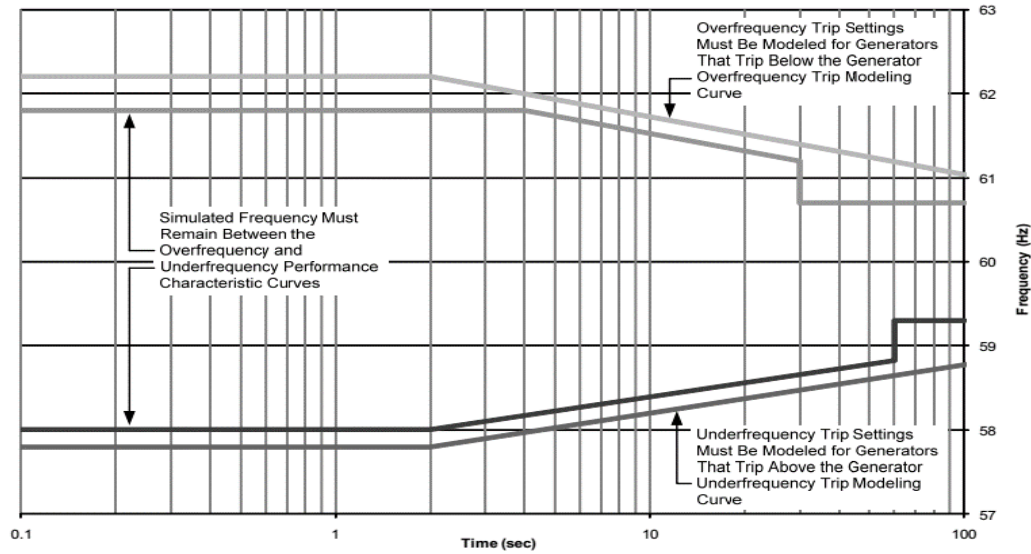


Figure 5.9: Design performance and modeling curves for over and under frequency generator trip [34]

5.3 Summary

In this chapter, the mathematical modeling of WTGs and protection systems required for risk based transient instability assessment are discussed. The details of the protection models used in this work and locations of the WTGs that are added to the test system are provided in the following chapter.

6. Methodology

The research encompasses the evaluation of risk indices of transient instability for security assessment. The study is conducted using analytical tools from the GE PSLF software. The simulations are automated using EPCL [39] based scripting available in the PSLF package. The flow chart of the overall procedure to evaluate risk based transient instability is provided in Figure 6.1. The automated EPCL scripts export transient stability simulation results into data files. Another MATLAB program is used to read the data files for risk assessment and generation of plots and graphs.

The solution obtained from the power flow provides the initial conditions for the time domain simulations. RBSA for transient instability requires a large number of time domain simulations to determine whether the system is transiently stable or not. Transient instability is usually assessed by observing the relative rotor angle plots of the generators. The risk assessment requires the transient stability assessment has to be automated. Hence, transient stability is assessed using the transient stability index (TSI). Section 6.1 provides details of the angle margin based TSI used in this work.

6.1 Automated transient stability assessment

For risk based transient stability assessment, the determination whether a fault type A at the k^{th} line location is transiently stable or unstable is required. In this research work, a TSI is used for evaluating whether a time domain simulation is stable or not. The TSI used in this work is calculated based on the angle margin algorithm. The expression for the TSI is [31]

$$\eta = \frac{360 - \delta_{\max}}{360 + \delta_{\max}} \times 100, \text{ where } -100 < \eta < 100 \quad (6.1)$$

where $\delta_{\max}$ is the maximum angle separation between any two generators at the same time in the post-fault response. Hence, $\eta > 0$ signifies a stable condition and $\eta < 0$ signifies an unstable condition. For a small value of $\delta_{\max}$, η becomes close to 100 and for a large value of $\delta_{\max}$, η becomes close to -100. This TSI is used in the evaluation of the probability of transient stability in risk assessment.

6.2 RBSA procedure

For each operating condition, the power flow is initially solved. A set of credible contingencies are selected for voltage level greater than 100kV. For each credible contingency, exhaustive positive sequence time domain simulations are performed for different fault types (LLL, LLG, LL, and SLG) and at different fault locations (near bus, far bus and center) for lines and at two ends of all transformers. The protection system is modeled such that for all credible contingencies the system remains stable. The impact of a fault is determined by the effort in tripping generators and loads to maintain stability. The generator tripping and load shedding data for the contingency is used to evaluate the impact of transient instability. For each contingency, the risk is evaluated for different operating conditions. The simulations are performed at different system loading levels

and with varying wind generation output at each loading level. Using realistic statistical data from the Canadian Electricity Authority [38], the probabilities of transient instability are calculated. The overall risk of the system with all contingencies taken into account is also evaluated for different operating conditions. The uncertainty of the injected wind power is also incorporated into the risk calculation using a simple stochastic model of the wind generation output. Equal risk contours are plotted to illustrate the effect of system loading and renewable generation on system risk and hence on system reliability.

6.3 System description

A synthetic test system is generated to perform the risk based transient stability assessment. The synthetic system is generated to represent the realistic test system comprising of Ontario and upstate New York. The test system consists of all the major features of a realistic power system for transient stability and reliability studies for system planning. The single line diagram of the test system is shown in Figure 6.2. The system consists of 11 conventional synchronous generators with detailed generator, governor and exciter models. The total installed capacity of conventional generation (17,000 MW). Renewable generation in the form of type-4 WTG is added at different locations within the test system with installed capacity of 1,680 MW. The description of all the generators in the system is provided in Table 6.1. The test system is divided into 5 distinct zones to illustrate the risk based transient stability assessment method. The risk is evaluated for each zone separately which can help in identifying the highest risk and lowest risk zones.

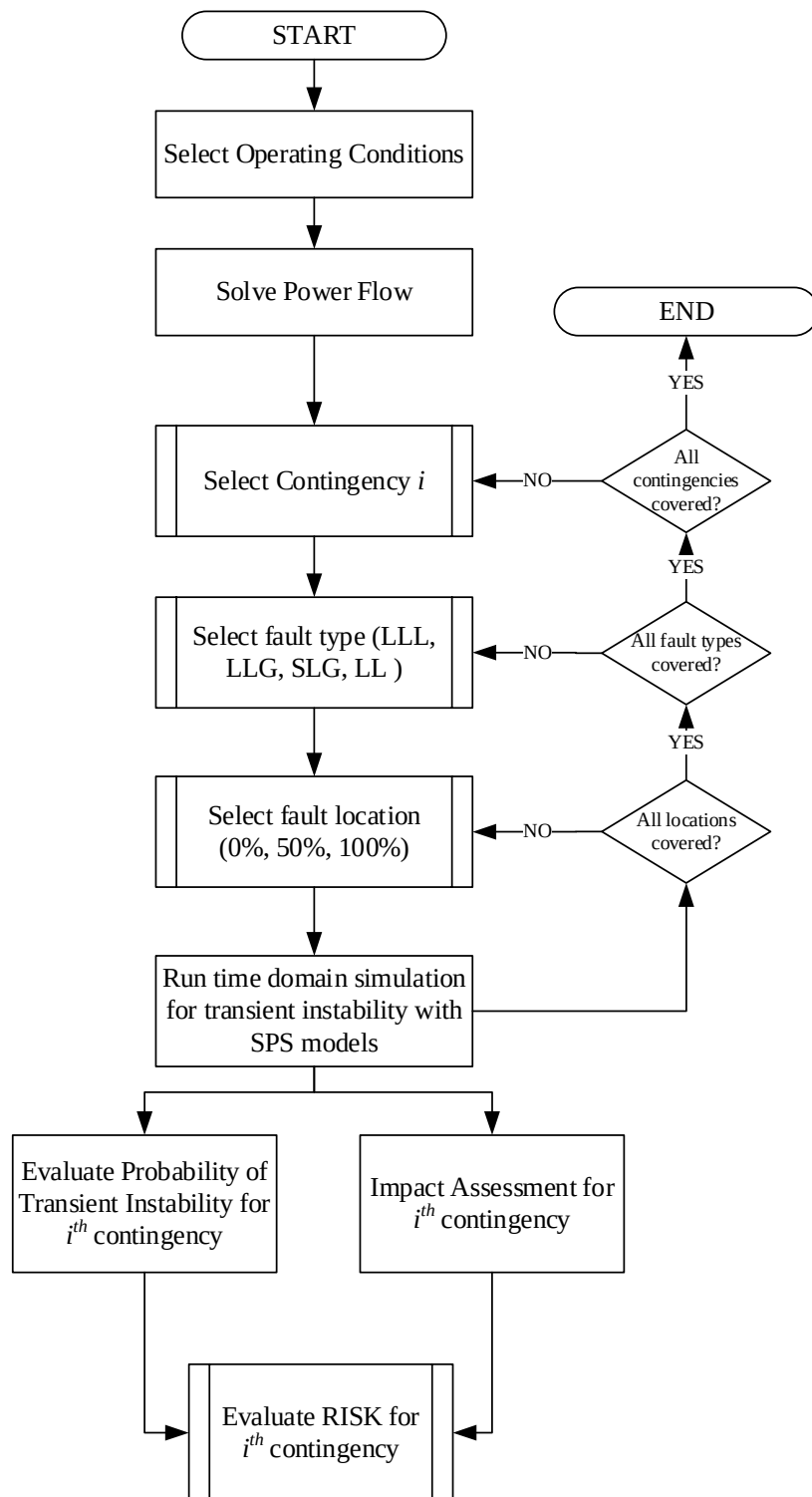


Figure 6.1: Flow chart for risk based transient instability assessment

Table 6.1: Details of the installed generators in the test system

Bus	Generator type	Capacity (MW)	PSLF models	Bus	Generator type	Capacity (MW)	PSLF models
1	hydro	2000	genrou, exst1, hygov	8	WTG type-4	300	gewtg, ewtgfc, wndtge
2	hydro	2000	genrou, exst1, hygov	28	WTG type-4	150	gewtg, ewtgfc, wndtge
4	coal	1000	genrou, exst1, tgov1	29	WTG type-4	150	gewtg, ewtgfc, wndtge
5	coal	1000	genrou, exst1, tgov1	30	WTG type-4	150	gewtg, ewtgfc, wndtge
7	gas turbine	1000	genrou, exst1, ggov1	31	WTG type-4	150	gewtg, ewtgfc, wndtge
11	gas turbine	500	genrou, exst1, ggov1	32	WTG type-4	150	gewtg, ewtgfc, wndtge
14	nuclear	2000	genrou, exst1, tgov1	33	WTG type-4	105	gewtg, ewtgfc, wndtge
20	coal	1500	genrou, exst1, tgov1	34	WTG type-4	200	gewtg, ewtgfc, wndtge
22	coal	2000	genrou, exst1, tgov1	35	WTG type-4	200	gewtg, ewtgfc, wndtge
24	coal	4000	genrou, exst1, tgov1	36	WTG type-4	105	gewtg, ewtgfc, wndtge
26	coal	1000	genrou, exst1, tgov1				
TOTAL		17,000		TOTAL		1,680	

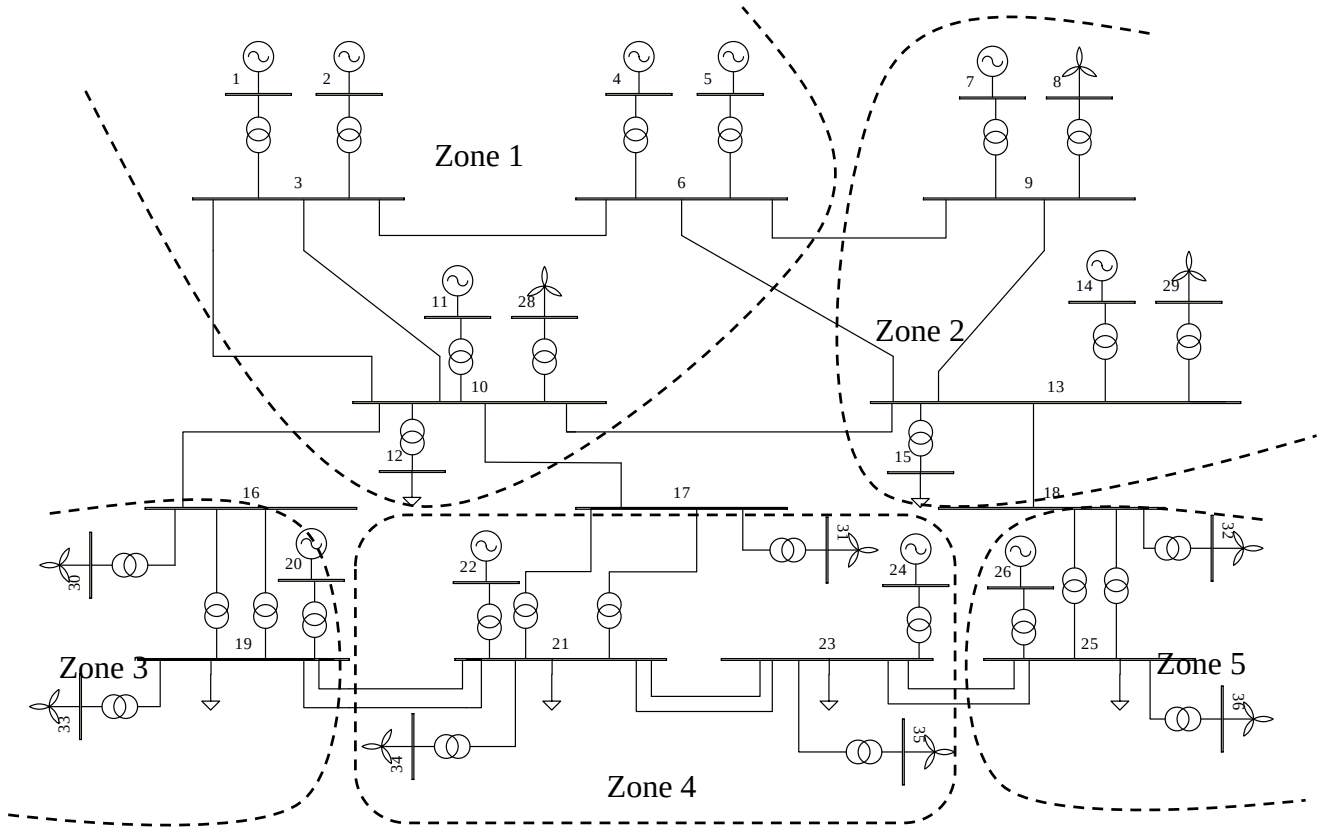


Figure 6.2: Synthetic test system for RBSA

Table 6.2: Test system summary

Buses	36 + 20 additional buses for WTG POI
Generators	11 (synchronous) + 10 WTG farm
Lines	30
Total synchronous Generation	17,000 MW installed capacity
Wind Generation	1,680 MW installed capacity (10 wind farms)

6.4 Summary

In this chapter, the overall procedure for risk based transient stability assessment is presented along with the detailed explanation of the test system. In the following chapter, the detailed simulation results are provided.

7. Results and discussion

This chapter provides the detailed simulation results of RBSA for transient instability. The test is performed on the test system as described in the previous chapter.

7.1 Operating conditions

The base case operating condition is provided in the previous section. The base case of the test system is “N-1” stable for all credible contingencies. To generate the set of different operating conditions the system loading is varied from the base case loading. Considering 100% loading as the base case loading, the system loading is increased in steps of 5% until 185% above the base case. The generators are dispatched in accordance with each load scenario. For each loading scenario, the wind generation injected into the system is also varied from 0% to 100% in steps of 10%. Hence, we obtain a grid of scenarios to perform the simulations. As the wind power injection is increased, the conventional synchronous generators are rescheduled to produce less to maintain the generation-load balance.

Steady state conditions are non-existent in a realistic system and power systems constantly undergo changes. In this work, the same contingency is simulated for different pre-contingency operating conditions. Since, RBSA is intended for system planning – considering different stages of the transient is not necessary.

7.2 Credible contingency selection

The preliminary set of contingency is selected by finding all transmission line and transformers above 100 kV. This preliminary contingency list is used to run the worst-case faults (3 phase-to-ground fault on the terminal buses) at the highest operating condition possible (185% loading above the base case). Those contingencies that are transiently unstable for the worst-case test mentioned above are considered as credible contingencies. This worst-case test led to 19 overall contingencies (14 transmission line contingencies and 5 transformer contingencies) which are used for the risk assessment procedure. The contingency list is provided in Table A and Table B of the Appendix. Further, in the RBSA procedure for varying loading conditions –three-phase faults are first considered near the terminal buses, if these three-phase faults trigger generator tripping/load shedding, only then other fault types are considered. These filters are already implemented in the RBSA and helps in reducing the computational burden by not simulating cases, which do not cause transient instability problems. Further simplifications are also possible to incorporate in the RBSA methodology, for example, the bisection method based approach can be used to minimize the risk calculation for all possible loading levels.

7.3 Parameters used in risk assessment

In this section, the detailed list of parameters used for the risk assessment on the test system is provided.

7.3.1 Fault rates of transmission lines

The fault rates for different lines are required to evaluate the probability of transient instability as shown in (4.7). The Canadian Electricity Authority 2012 Annual report [38] provides transmission system reliability statistical data. The transmission line statistics for line-related transient forced outages data provides the frequency of outage of transmission lines for different voltage levels in number per 100 mile-annum. For transformers, the fault rates are available as per the voltage ratings as shown in Table 7.1. The fault rates of the transmission lines in outages/hour are evaluated based on the line lengths. Table A and Table B in the Appendix provide the fault rates of the selected transmission lines and transformers respectively.

Table 7.1: Transient forced outage statistical data

Transmission lines		Transformers	
Voltage classification	Frequency (number / 100 mile-annum)	Voltage classification	Frequency (number / annum)
100 kV	1.3573	100-199 kV	0.1143
220 kV	0.7548	500-599 kV	0.1364
500 kV	1.8535		

7.3.2 Probability of fault types

The fault type probabilities assumed for the risk assessment discussed in this work is given in Table 7.2. These values are usually obtained from historical data. The SLG fault has the highest probability of occurrence while the three-phase fault is the least probable.

Table 7.2: Fault type probabilities

<i>n</i>	Fault type	Fault Probability (%)
1	LLL	6.2
2	LLG	10.0
3	LL	8.8
4	SLG	75

7.3.3 Fault location probability

A discrete uniform distribution is adopted in the risk assessment procedure where each of the 14 lines is divided into 2 segments. Hence, three line fault locations exist – 0.1%, 50% and 99.9%. The severity of the fault diminishes towards the center of the line and the faults near the terminal buses (0.1% and 99.9% location) are the most severe. Equal probability of occurrence of the fault throughout the line is considered. If data for the frequency of fault occurrence for different line locations are available, it can be easily incorporated into the probability calculations.

7.3.4 Fault clearing time

It is assumed that following any fault the circuit breakers open and clear the fault in 5 cycles. A fixed clearing time of 5 cycles is considered for all contingencies. Based on the operating voltage level of the line considered, the fault clearing time can be changed without any loss of generality. In this research, the simulations are performed in GE PSLF for four different fault types at different locations with 5 cycles fault clearance. Although, PSLF does not provide stuck breaker simulation out-of-the box, it can be modeled by clearing the furthest bus at a nominal clearing time of 5 cycles while delaying the fault clearance in the near bus to 10-16 cycles and initiating adjacent breakers to operate. Since, the proposed RBSA method incorporates modeling of the protection system to evaluate the impact, any type of contingency that can be simulated in time domain simulation can be analyzed using the RBSA and its impact can be assessed through the tripping of generation/load.

Also, for contingencies resulting in cascading events where the loss of transient stability occurs during the cascade but not directly caused by an initial short circuit, the RBSA method can be used if the protection system is modeled such that cascading events can be simulated in time domain simulation. Some, initial short circuits can trigger cascading failures which are observed in the simulations. Such cases were included in the RBSA. In such cases, the length of the time domain simulation is increased for the system to settle to a new operating condition.

7.3.5 Wind generation stochastic model

To incorporate the stochastic model of wind power generation, a probability density curve of a typical wind power plant is obtained from historical data. In this research, a typical wind farm data from Australian Energy Market Operator (AEMO) is used to obtain the probability density curve and cumulative density curve. The cumulative density curve is fitted to get the CDF for wind power generation as shown in Figure 4.2 in chapter 4.

7.3.6 Impact assessment parameters

For each particular fault, the impact of transient instability is obtained based on the SPS action report obtained from the time domain simulations. The impact (Method I) is assessed based on the generator tripping and load shedding information. The impact of each contingency for a particular fault type and fault location is calculated as in (4.10-4.12). Table 6.3 shows the different parameters used for impact estimation. The parameters are in line with previous works on RBSA for transient instability [2, 13] and the Ontario Power Authority website [40]. To evaluate the impact by Method 2, no additional parameters are required.

Table 7.3: Impact assessment parameters

Generator outage duration h	10 hours
$C_{replacement}$ –cost of replacement generation	85 \$/MWh
$C_{original}$ – original cost of generation	60 \$/MWh
C_{load} – penalty due to load interruption	1000 \$/MW

7.4 Deterministic transient instability criteria

The deterministic “N-1” security criterion is assessed by evaluating the worst-case contingency. The worst-case contingency for the test system is obtained by progressively increasing the loading of the system from base case and running time domain simulations for all credible contingencies for the three-phase faults near the terminal buses (0.1% and 99.9% location). When the system becomes “N-1” transiently unstable, the particular contingency, which makes the system unstable is defined as the worst-case contingency. The highest system loading at which the system is “N-1” stable is defined as the deterministic security limit. For the test system, the limiting operating condition occurs at a loading level 33.0 % above the base case due to contingency#1 –three-phase fault near bus #6, cleared by opening line # 3–6 after 5 cycles. Figures 7.1 and 7.2 show the rotor angle plots for all the 11 generators for contingency #1 at the limiting loading cases. The generators at bus #4 and bus #5 lose synchronism and system becomes unstable at a load 34% above base case. Hence, the deterministic “N-1” security margin of the system for transiently instability is 33.0% above the base case loading.

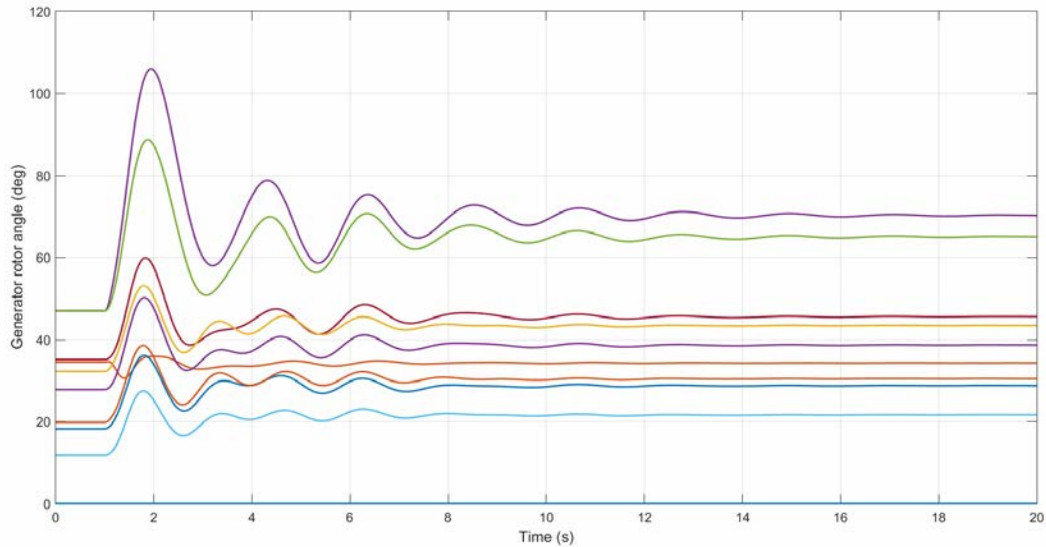


Figure 7.1: Relative rotor angles of the generators for a loading 33.0% above the base case

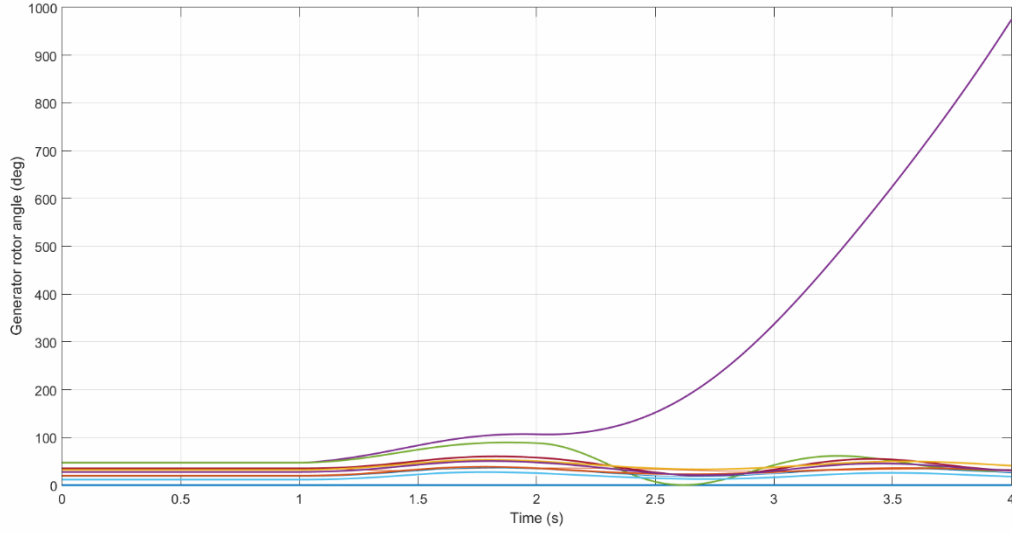


Figure 7.2: Relative rotor angles of the generators for a loading 34.0% above the base case

7.5 Risk based security assessment for transient instability

This section illustrates the detailed results of the risk based security assessment for transient instability. The exhaustive time domain simulations provide a measure of risk for two varying operating parameters – system loading above base case and amount of renewable injection. Figure 7.3 and Figure 7.4 shows the mesh plot of system overall risk with percentage loading above base case in the x-axis, MW renewable generation in the y-axis and the risk is the z-axis. In Figure 7.3, the risk is estimated using in \$/hour as per Method I and in Figure 7.4, the risk is estimated in expected unserved load (EUL) in MW/hour as per Method 2. It can be observed that both Figure 7.3 and Figure 7.4 have similar characteristics and any method can be used for risk estimation. In order to maintain consistency, all risk values are expressed in \$/hour as per Method I henceforth in the report.

From Figure 7.3, it can be seen that the risk increases sharply when the system is loaded 150% above base case. In addition, it can be observed that higher the renewable power injection; lower is the system risk due to transient instability. The results show that converter-based generation has significant effect on the system risk and hence on the system reliability. In the next sub-section, equal risk contours are plotted to mark safe operation region.

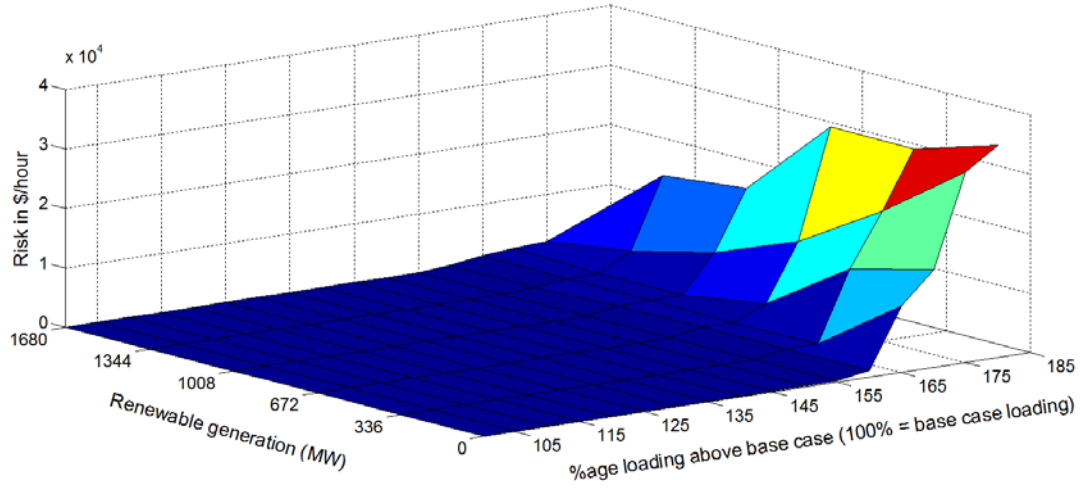


Figure 7.3: Overall risk of the system in \$/hour for varying load and wind power injection

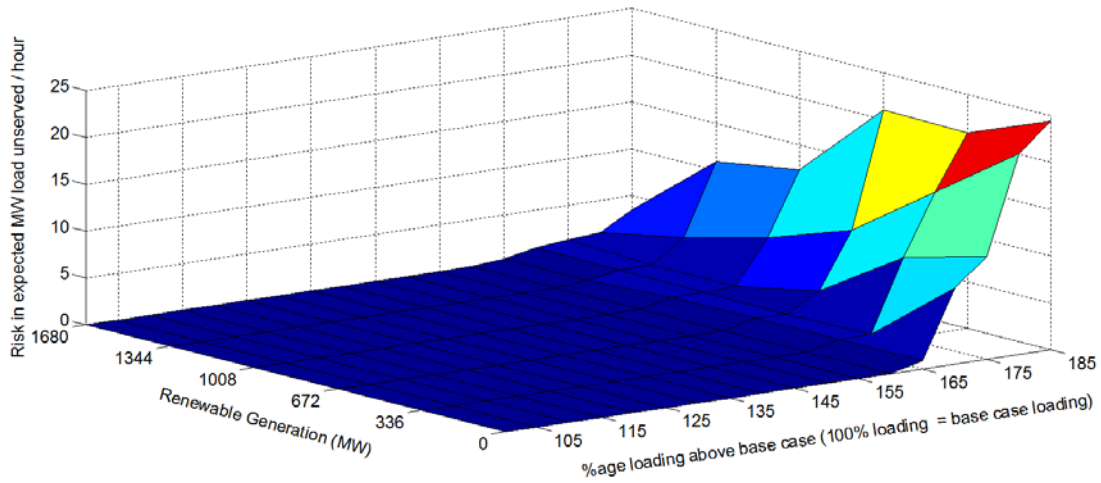


Figure 7.4: Overall risk of the system in EUL in MW/hour for varying load and wind power injection

7.5.1 Equal risk contours

Figure 7.5 shows the equal risk contours for varying system loading and varying wind power injection. The safe operating region can be easily identified from the equal risk plot. It can be seen in the figure that the equal risk contours have a positive slope indicating that converter based generation can enhance the system transient instability. The type-4 full converter WTGs have faster dynamics compared to conventional synchronous generators and can help in improving the transient stability limits. It can be inferred that probabilistic risk based methods for transient stability can provide useful and critical information on system reliability that is not possible in traditional deterministic methods.

Figure 7.6 shows the equal risk contours for each zone separately. From Figure 7.6 it can be seen that Zone 1 is the lowest risk zone while Zone 4 is the highest risk zone. In the test system, Zone 1 is a generation rich zone while Zone 4 is generation deficit region and obtains most of its power through critical tie lines. Hence, any contingency on the critical tie lines will cause significant transient stability problems in the region and affect the reliability. The zonal risk contours can help system planners identify critical zones within the system easily and set the reliability criteria. Safe operating limits for a particular zone can be easily identified using this risk assessment technique. The equal risk contours can provide clear information on the bases on which security decisions are made.

The zonal risk contours also show that converter based renewable generation helps improving the transient stability limit. The positive slope of the equal risk contours in all five zones indicate that converter-based generation can help in improving the overall system reliability to transient stability events.

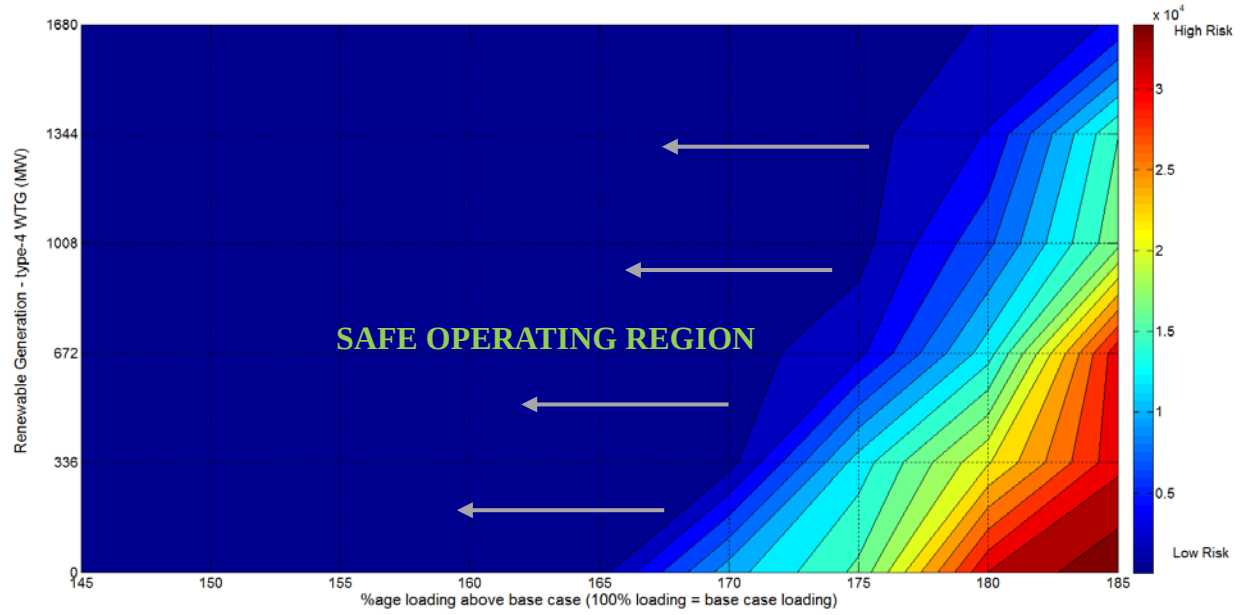


Figure 7.5: System wide equal risk contours

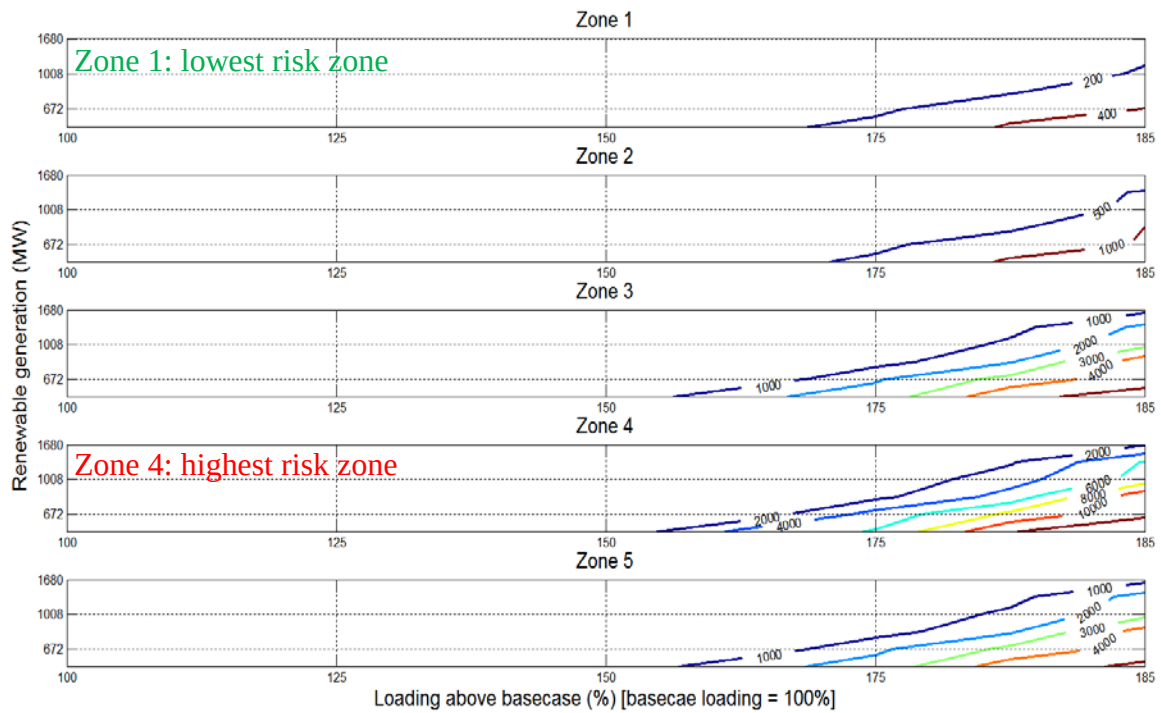


Figure 7.6: Zonal equal risk contours

7.5.2 Risk estimation using stochastic wind generation model

In this section, the risk estimation using the stochastic wind generation model is presented. Wind energy like most other renewable generation sources is uncertain in nature. In traditional

deterministic reliability assessment, the variability and the intermittency of the wind power generation is not modeled. In the future electricity grid with high penetration of renewable energy, the stochastic nature of such renewable energy sources should be incorporated in the reliability assessment studies. Figure 7.7 shows the transient instability risk assessment at different wind generation levels and the risk estimated using the stochastic wind generation model. It can be seen that the risk estimation at different wind generation levels convolve into the risk estimated using the stochastic wind generation model. The stochastic model can provide an estimate of the overall system risk when exact forecast of wind generation is not available. Risk estimation using the stochastic model can be used in cases where renewable generation is highly uncertain. It can also be used in the planning stages where correct forecasted renewable generation levels are not available. Figure 7.8 shows the zonal risk estimation using the stochastic wind generation model.

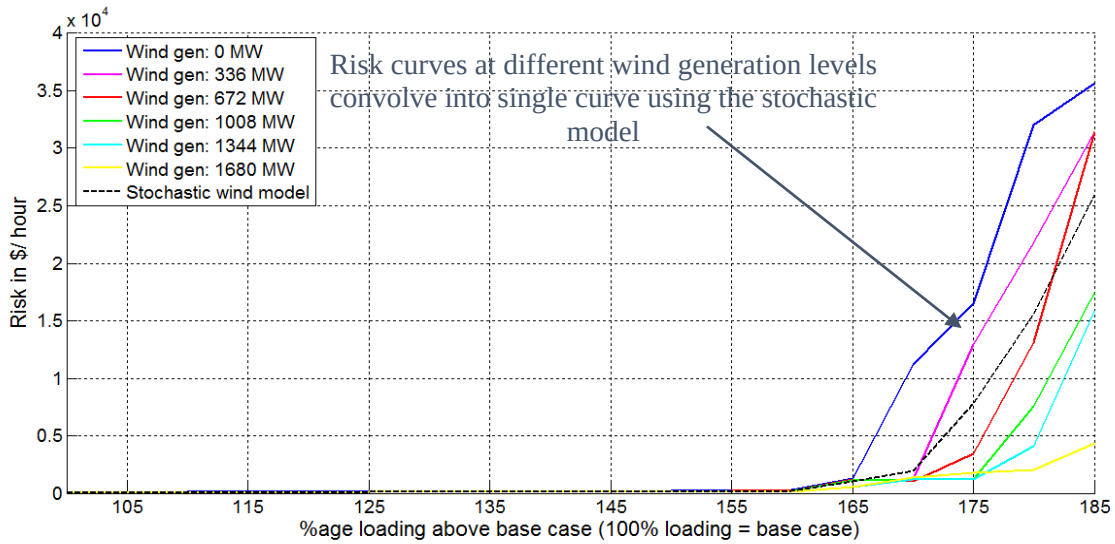


Figure 7.7: Risk estimation using stochastic wind generation model

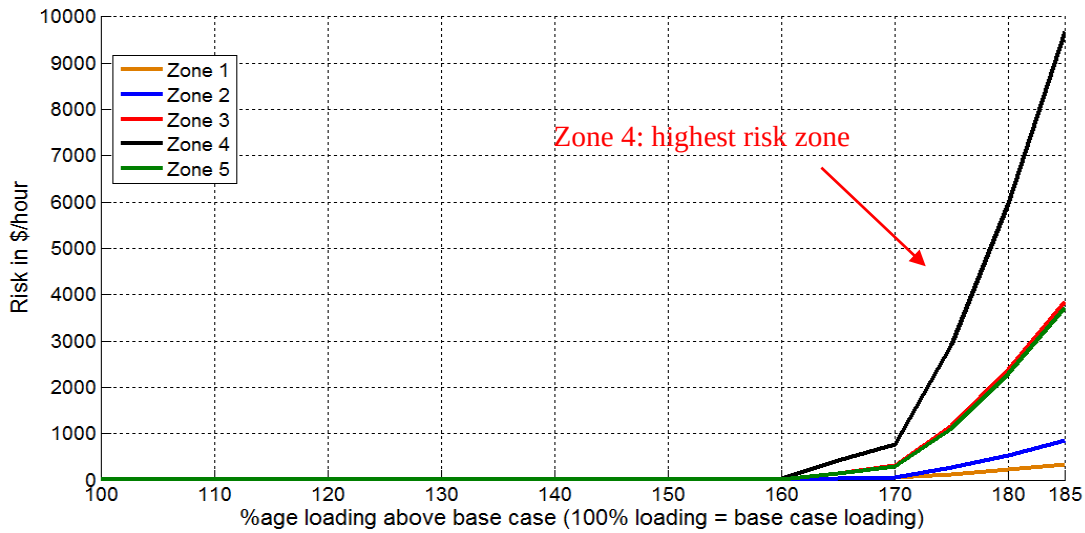


Figure 7.8: Zonal risk using stochastic wind generation model

7.5.3 Comparison of risk-based and deterministic security assessment

In this section, the deterministic approach for dynamic security is compared with the proposed risk-based approach. Figure 7.9 shows the risk estimated using stochastic wind generation model for the individual contingencies. The worst-case contingency as per the deterministic criteria and the contingency with highest overall risk are indicated in the figure. It can be observed that the risk increases rapidly after a particular loading condition. High risk of a particular contingency can be due to either high probability of fault occurrence or due to high impact. The highest risk contingency is estimated by the particular contingency with the largest mean value of risk. This research work proposes to establish “ $N-1$ ” security criteria for transient instability based on the highest risk contingency. From the simulation results, the highest risk contingency is Contingency #6 (fault on line #9-13). The risk based transient instability security margin for a three-phase fault on line #9-13 near bus #9 is at a loading condition 60.0% above the base case loading. Figure 7.10 and Figure 7.11 show the rotor angle plots for three-phase fault on line #9-13 near bus #9 at the limiting operating conditions. Figure 7.10 shows the stable rotor angle plots at 60.0% above base case loading while Figure 7.11 shows the unstable rotor angle plots at 61.0% above base case loading.

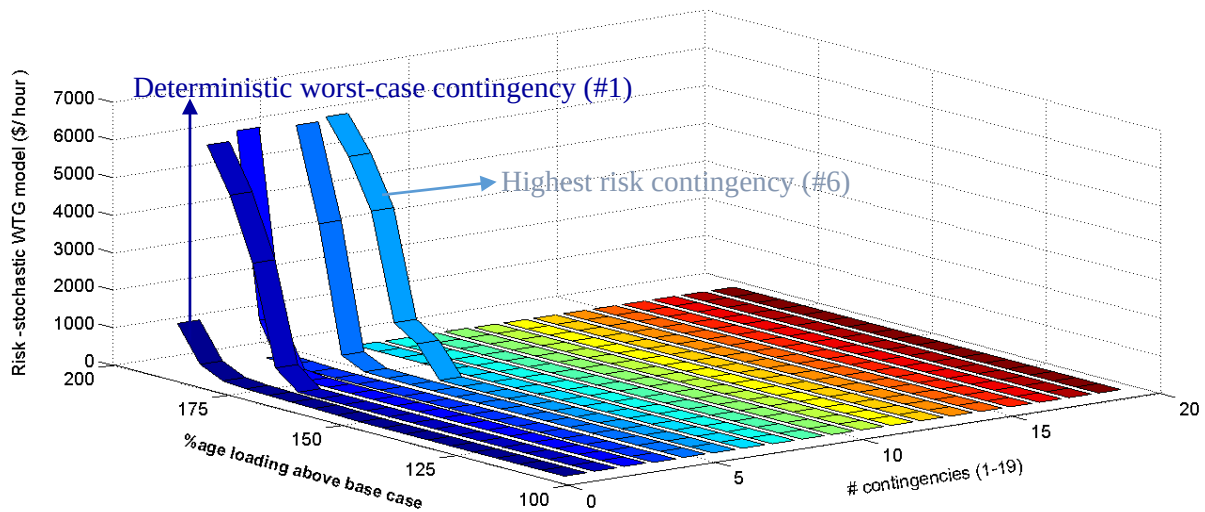


Figure 7.9: Risk using stochastic wind generation model for individual contingencies

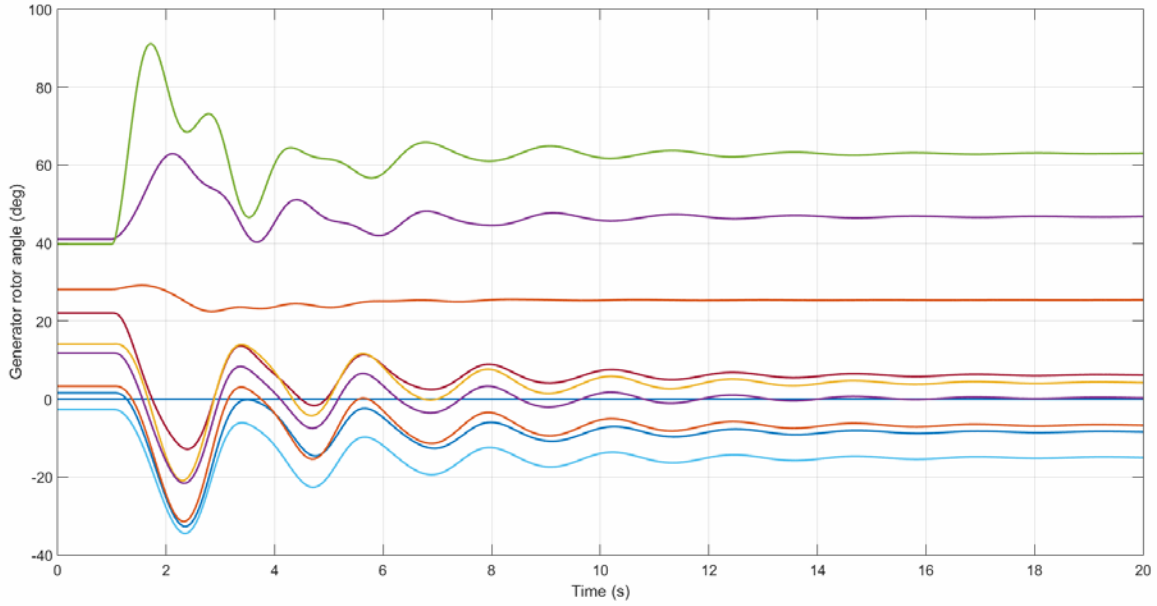


Figure 7.10: Relative rotor angle plot for three phase fault on line #9-13 near bus #9 at loading of 60.0% above base case (Contingency #6)

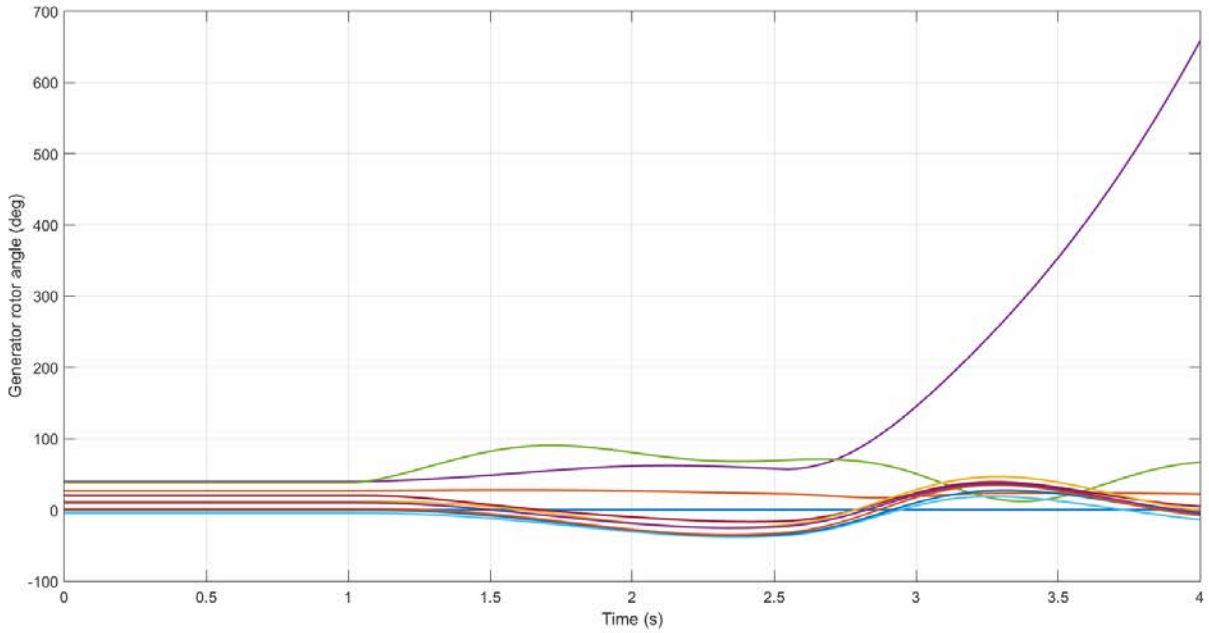


Figure 7.11: Relative rotor angle plot for three phase fault on line #9-13 near bus #9 at loading of 61.0% above base case (Contingency #6)

The operation of the protection system of the highest risk contingency risk contingency at the limiting operating condition (165 % base case and 0 MW renewable injection) is tabulated in Table 7.4. It can be seen that 1183.2 MW of generation is tripped and 1182.2 MW of load is tripped to maintain stability. Table 7.5 shows the operation of the protection system for the deterministic worst-case contingency at the limiting operating condition (135% base case loading and 0 MW

renewable injection). It can be observed that only 986.6 MW of generation is tripped but no load has been shed. The governors of the other generators are able to increase the mechanical power input to stabilize the system and load shedding is not required. Hence, the impact of the deterministic worst-case contingency is less on the system for a transient stability event. In addition, from Appendix Table A it can be observed that the fault rate of the worst-case line is lower than the highest risk contingency line. In this case, both the probability of occurrence of fault and impact of transient stability has an effect on the risk estimate.

Table 7.4: Protection system operated for highest risk contingency
Contingency #6, fault on line #9-13) at 165% base case loading

Gen bus	time (s)	Protection operated	MW tripped	Total tripped (MW)
4	2.488	under-voltage (gp1)	591.6	1183.2
5	2.488	under-voltage (gp1)	591.6	
Load bus	time(s)	Protection operated	MW shed	Total shed (MW)
19	5.384	under-freq (stage 1 LSDT1)	268.5	1182.2
21	5.376	under-freq (stage 1 LSDT1)	259.8	
23	5.288	under-freq (stage 1 LSDT1)	394.1	
25	5.388	under-freq (stage 1 LSDT1)	259.8	

Table 7.5: Protection system operated for deterministic worst-case contingency
(Contingency #1, fault on line #3-6) at 135% base case loading

Gen bus	time (s)	Protection operated	MW tripped	Total tripped (MW)
4	2.088	under-voltage (gp1)	484.3	968.6
5	2.088	under-voltage (gp1)	484.3	
Load bus	time(s)	Protection operated	MW shed	Total shed (MW)
-	-	-	-	-

Figure 7.12 shows the “N-1” security margins for deterministic and risk based transient instability assessment for transient stability. The deterministic approach gives conservative results which results in lower security limits. On the other hand, risk based security assessment provides higher operating limits based on both the likelihood as well as the consequence of instability. It can also be observed that the overall risk of the system is very low at both the risk based security limit and deterministic security limits. The comparison shows how risk based security criterion provides non-conservative security limits and does provide relevant information about the actual risk of operating at that limit.

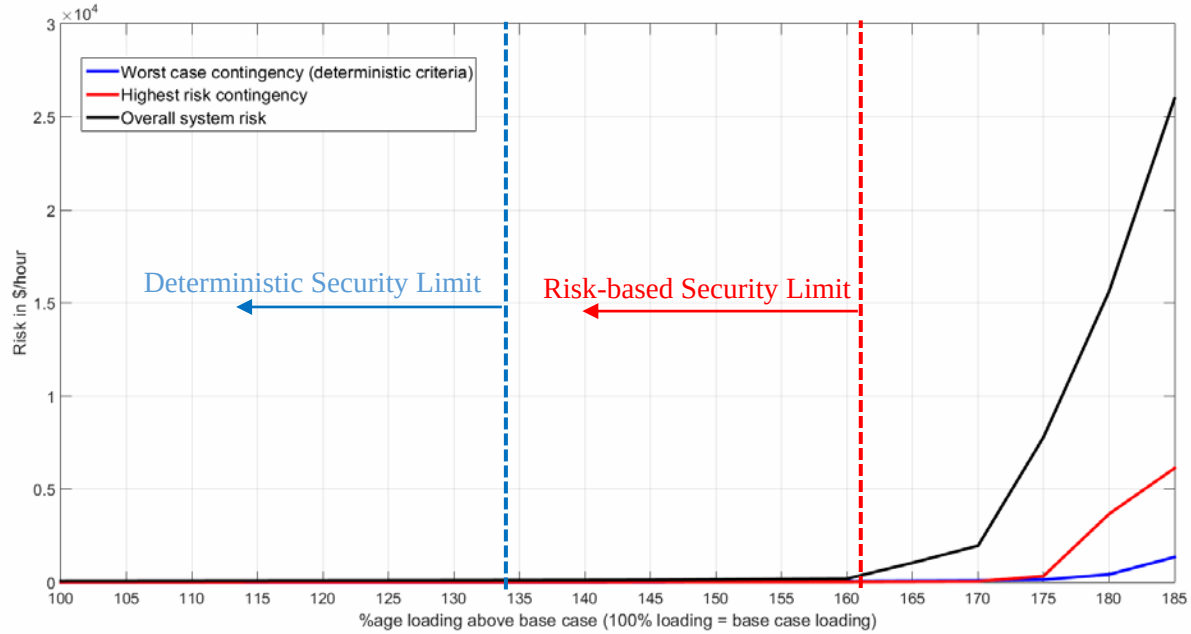


Figure 7.12: Comparison of deterministic and risk-based operating limit

7.6 RBSA for future grid with very high renewable penetration

In this experiment, the synchronous generators present in the test system are gradually replaced by converter-based renewable generation (type-4 WTG). Total generation capacity is not changed in the system. The MVA rating of the generators are adjusted according to the percentage of converter based generation. The renewable penetration is varied from 0% to 80% in steps of 20%. Figure 7.13 shows the system overall risk for varying renewable penetration and at four different loading levels. It can be seen that with higher renewable penetration the risk on the system due to the transient stability event is reduced. Hence, with respect to system dynamics and transient stability, high converter-based generation is beneficial for the system considered. The variability and intermittency of such generation sources have not been considered in this study. Figure 7.14 shows the zonal equal risk contours for the test system with very high renewable penetration.

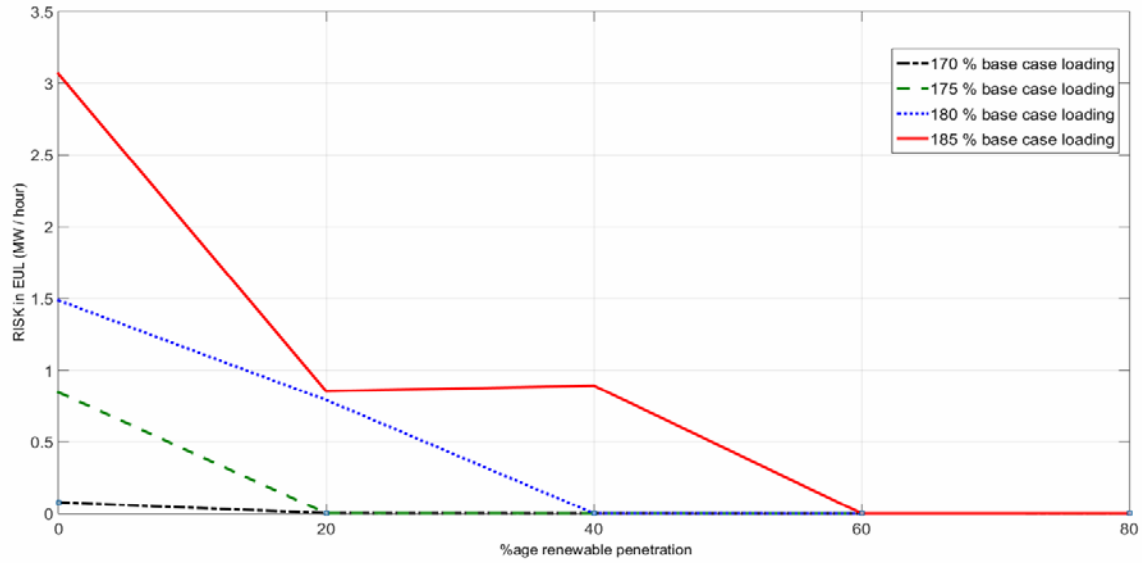


Figure 7.13: Risk estimation for the test system with very high renewable penetration

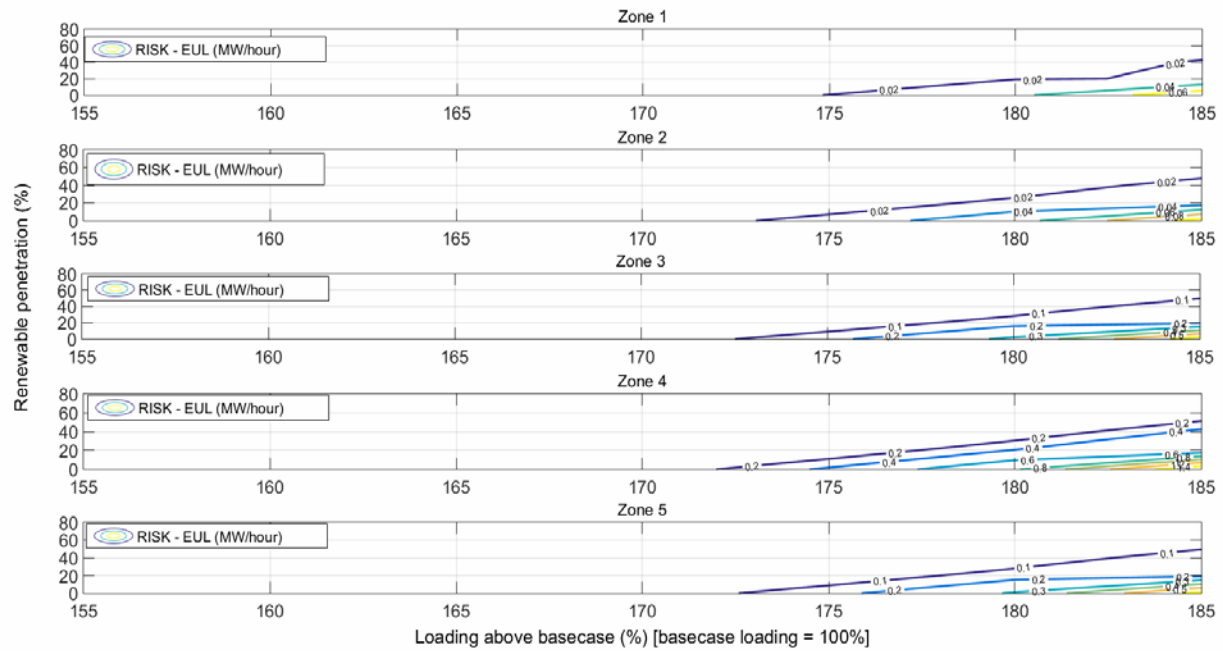


Figure 7.14: Zonal risk for the test system with very high renewable penetration

7.7 Conclusion

The traditional deterministic “ $N-1$ ” criterion provides conservative limits and provides inadequate information about the probability of occurrence of the worst-case contingency to make crucial operational decisions. The risk-based method, on the other hand helps in quantification of the

security criteria, providing an actual risk of a contingency on system security. The utilities as well as system operators have a transparent basis on which security limit decision is made.

The RBSA can be used in defining new standards for transient stability of the system. The risk of operating the power system should be evaluated to rank the credible contingencies. Standards should be formulated such that the highest risk contingency is accounted in the decision making process for security assessment instead of the traditional worst-case contingency. Current NERC reliability standards are deterministic and do not incorporate any probabilistic methods. As a first step, RBSA can be compared with the current deterministic standards while making security decisions. RBSA helps in ranking contingencies based on the operating conditions.

Identifying a risk threshold can be critical for a system and is not straight-forward. For the system to be reliable it has to operate at very low risk and ideally the system should operate at zero risk. Selecting the risk threshold will require some detailed analyses on the high risk contingencies that contribute most to the risk estimates. The risk threshold will vary from system to system. One approach may be to select a risk value as the initial threshold and then through detailed analyses of all the critical high risk contingencies decide whether to increase or decrease the threshold. A few iterations of this technique can be used to set a risk threshold for a system or a particular contingency.

RBSA is used to estimate both overall system risk and risk of individual contingencies. The overall system risk is measured by summing the risk of all the credible contingencies and not by the highest/high risk contingencies. RBSA helps in identifying the high risk contingencies that can affect the system reliability. System planners can perform detailed analyses on the high risk contingencies to make critical security decisions.

The effect of renewable penetration on system reliability can be investigated using RBSA. The equal risk contours can be used by system planners to determine secure operating regions. Zonal risk assessment can help system planners in identifying key areas within the system that can affect system reliability.

Impact of transient instability can be assessed either by a cost based metric or by expected unserved MW load, the latter being easy to estimate. In systems where risk indices estimated from cost based metrics are difficult to compare, the risk indices estimated using expected unserved load can be used. The impact estimated using method 2 can provide more insight into such systems. Also, it has been shown that overall profile of the risk indices estimated by the two different metrics is similar.

From the simulation results, it can be seen that converter-based generation helps in reducing the risk due to transient instability due to its faster control and dynamics compared to synchronous generators. The uncertainty of such renewable generation can be modeled into risk estimation using stochastic modeling. In this research, the type IV WTGs are modeled with voltage regulation control at the point of interconnection. A detailed study with the different control modes of WTG in the SMIB case will be performed in the future work. Type IV WTGs do not have any inherent inertial response. Synthetic inertia based on system frequency is not available in the generic WTG models in the commercially available packages. In this research, addition of WTG results in the

relaxation of the rotor angles in the conventional generators and hence improves transient stability limits.

In this research, varying operating conditions are selected by varying load and generation schedule. RBSA can be performed for different seasons separately based on equipment outage and generation schedules. For example, for summer and winter months all possible loading conditions (seasonal load curve) and generation schedules/outages can be considered.

The risk-based security assessment has a high computational burden due to the large number of time domain simulations involved. However, the disadvantage due to the added computational burden is compensated by the extended operating limits provided by this method. The computational burden is reduced by using different checks and filters to avoid time domain simulations for stable cases.

The computational burden of RBSA is very high to make it suitable for operations. However, if suitable machine learning algorithms/ANN models are developed to map the system operating conditions to risk estimates, then RBSA can be used in operations as a tool to identify critical contingencies that might affect the system reliability.

In this research, the main focus is towards risk assessment for the transient stability problem. Small signal stability and transient voltage stability phenomenon can be assessed using risk based methods. In such cases, however, the impact can be assessed by linear/non-linear severity functions of modal damping (for small signal stability) and voltage profile (for transient voltage problems).

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9. Appendix A: Fault Rates

Table A.1: Fault rates of the selected contingencies (transmission lines)

Cont #	From Bus	To Bus	Ckt	kV	length	fault rate
1	3	6	1	500	250	0.000529
2	3	10	1	500	300	0.000634
3	3	10	2	500	400	0.000846
4	6	9	1	500	250	0.000529
5	6	13	1	500	400	0.000846
6	9	13	1	500	300	0.000634
7	10	13	1	500	250	0.000529
8	10	16	1	500	100	0.000211
9	10	17	1	500	100	0.000211
10	13	18	1	500	100	0.000211
11	16	17	1	500	100	0.000211
12	19	21	1	110	20	3.1E-05
13	21	23	1	110	20	3.1E-05
14	23	25	1	110	20	3.1E-05

Table A.2: Fault rates of the selected contingencies (transformers)

Cont #	From Bus	To Bus	Id	From kV	To kV	fault rate
15	10	12	1	500	110	0.000529
16	13	15	1	500	110	0.000634
17	16	19	1	110	500	0.000846
18	17	21	1	110	500	0.000529
19	18	25	1	110	500	0.000846

10. Appendix B: CPU time metrics

The CPU metrics for the proposed method is provided in Table VI where the total number of time domain simulations performed for risk estimation is. The metrics are based on the performance on a 64-bit Intel(R) Core(TM) i7 quad-core 3.4 GHz CPU with 16 GB RAM.

Table B.1 CPU time metrics

Time domain simulation	time /simulation	total time
	2.5 s	$2.5 \times \psi$ s
Post-processing risk estimation		34.652 s

11. Appendix C: Test system (T1) data -- power flow data

The power flow per unit data are on 100 MVA system base. Bus 1 is defined as the slack bus. The power flow data provided is for the base case loading with high wind generation case.

Table C.1 Transmission line data

From	To	kV	Ckt	R (pu)	X(pu)	B(pu)
3	6	500	1	0.0019	0.0426	3.9
3	10	500	1	0.002	0.064	5.89
3	10	500	2	0.003	0.085	7.85
6	9	500	1	0.0019	0.0426	3.9
6	13	500	1	0.003	0.085	7.85
9	13	500	1	0.002	0.064	5.89
10	13	500	1	0.0019	0.0426	3.9
10	16	500	1	0.001	0.02	1.95
10	17	500	1	0.001	0.02	1.95
13	18	500	1	0.001	0.02	1.95
13	18	500	2	0.001	0.02	1.95
16	17	500	1	0.001	0.02	1.95
19	21	110	1	0.0022	0.02	0.011
19	21	110	2	0.0022	0.02	0.011
21	23	110	1	0.0022	0.02	0.011
21	23	110	2	0.0022	0.02	0.011
21	23	110	3	0.0022	0.02	0.011
23	25	110	1	0.0022	0.02	0.011
23	25	110	2	0.0022	0.02	0.011
23	25	110	3	0.0022	0.02	0.011

Table C.2 Transformer data

Transformer type	R(pu)	X(pu)
Generator transformers	0.0012	0.12
Substation transformers	0.0006	0.06
WTG POI unit transformers	0.001	0.1

Table C.3 Generator data

Bus	Name	kV	Pgen	Qmax	Qmin	MVA	Pmax	Pmin
1	Gen1	22	29.6	750	-600	2200	2000	0
2	Gen2	22	280	325	-250	1200	1000	0
4	Gen11	22	280	325	-250	1200	1000	0
5	Gen12	22	280	325	-250	1200	1000	0
7	Gen9	22	280	325	-250	1200	1000	0
11	Gen3	22	120	175	-95	600	500	0
14	Gen7	22	800	850	-750	2400	2000	0
20	Gen4	22	600	500	-400	1800	1500	0
22	Gen5	22	800	1000	-800	2400	2000	0
24	Gen6	22	2050	1500	-1200	4500	4000	0
26	Gen8	22	450	360	-280	1200	1000	0
8	WTG8	0.69	300	145	-145	334	300	14
28	WTG28	0.69	150	72.5	-72.5	167	150	7
29	WTG29	0.69	150	72.5	-72.5	167	150	7
30	WTG30	0.69	150	72.5	-72.5	167	150	7
31	WTG31	0.69	150	72.5	-72.5	167	150	7
32	WTG32	0.69	150	72.5	-72.5	167	150	7
33	WTG33	0.69	105	50	-50	117	105	5
34	WTG34	0.69	210	100	-100	234	210	10
35	WTG35	0.69	210	100	-100	234	210	10
36	WTG36	0.69	105	50	-50	117	105	5

*Pgen, Pmax and Pmin are in MW, Qmax and Qmin are in MVAR

Table C.4 Load data

Bus	Name	kV	Pload (MW)	Qload (MVAR)
12	ACBus12	110	183.75	52.5
15	ACBus15	110	262.5	127.05
19	ACBus19	110	1627.5	406.88
21	ACBus21	110	1575	393.75
23	ACBus23	110	2388.75	735
25	ACBus25	110	1575	393.75

Table C.5 Shunt data

Bus	Name	kV	G(pu)	B (pu)
3	ACBus3	500	0	-7.848
6	ACBus6	500	0	-7.213
9	ACBus9	500	0	-3.514
10	ACBus10	500	0	-9.749
12	ACBus12	110	0	0.572
13	ACBus13	500	0	-8.881
15	ACBus15	110	0	1.331
19	ACBus19	110	0	3.212
21	ACBus21	110	0	2.841
23	ACBus23	110	0	8.353
25	ACBus25	110	0	3.457

12. Appendix D: Test system (T1) data -- dynamic data

The WTG data used in this paper is the default data provided in the GE PSLF user manual [39] for the GE generic WTG models -- GEWTG, EWTGFC and WNDTGE. The synchronous machine governor models are listed in Table D.1. Default governor model parameters are used as provided in the GE PSLF user manual [39]. The generator per unit dynamic data is on the corresponding machine MVA base.

Table D.1 Synchronous machine inertia constant and governor models

Bus	Name	H (s)	Governor model
1	Gen1	5.91	HYGOV
2	Gen2	5.91	HYGOV
4	Gen11	9.7	TGOV1
5	Gen12	9.7	TGOV1
7	Gen9	6	GGOV1
11	Gen3	9.7	GGOV1
14	Gen7	9.7	TGOV1
20	Gen4	6	TGOV1
22	Gen5	14	TGOV1
24	Gen6	14	TGOV1
26	Gen8	8	TGOV1

Table D.2 Synchronous generator dynamic data -- GENROU

Tpdo	7	D-axis transient rotor time constant, s
Tppdo	0.025	D-axis sub-transient rotor time constant, s
Tpqo	0.75	Q-axis transient rotor time constant, s
Tppqo	0.05	Q-axis sub-transient rotor time constant, s
D	0	Damping factor, pu
Ld	2.2	D-axis synchronous reactance, pu
Lq	2.1	Q-axis synchronous reactance, pu
Lpd	0.22	D-axis transient reactance, pu
Lpq	0.416	Q-axis transient reactance, pu
Lppd	0.2	D-axis sub-transient reactance, pu
Ll	0.147	Stator leakage reactance, pu
S1	0.109	Saturation factor at 1 pu flux
S12	0.3	Saturation factor at 1.2 pu flux
Ra	0	Stator resistance, pu
Rcomp	0	Compounding resistance for voltage control, pu
Xcomp	-0.07	Compounding reactance for voltage control, pu

Table D.3 Exciter data -- EXST1

Tr	0	Filter time constant, s
Vimax	0.1	Maximum error, pu
Vimin	-0.1	Minimum error, pu
Tc	1	Lead time constant, s
Tb	10	Lag time constant, s
Ka	100	Gain, pu
Ta	0.02	Time constant, s
Vrmax	5	Maximum controller output, pu
Vrmin	-5	Minimum controller output, pu
Kc	0.05	Excitation system regulation factor, pu
Kf	0	Rate feedback gain
Tf	1	Rate feedback time constant, s
Tc1	1	Lead time constant, s
Tb1	1	Lag time constant, s
Vamax	5	Maximum control element output, pu
Vamin	-5	Minimum control element output, pu
Xe	0.04	Excitation xfmr effective reactance, pu
Ilr	2.8	Maximum field current, pu
Klr	5	Gain on field current limit