Aalto-yliopisto
Aalto-universitetet
Aalto University

Master's Programme in Advanced Energy Solutions

Analysis of Synchronous Condenser Capability of Active Generator Sets in the Non-Frequency Based Ancillary Markets

Indula Amarasinghe

Master's thesis
2025

Aalto-yliopisto
Aalto-universitetet
Aalto University

Author Indula Amarasinghe

Title of thesis Analysis of Synchronous Condenser Capability of Active Generator Sets in the Non- Frequency Based Ancillary Markets

Programme Master's Programme in Advanced Energy Solutions

Major Energy Systems and Markets

Thesis supervisor Prof. Janne Seppänen

Thesis advisor(s) Ville Telatie, MSc and Mustafizur Rahman, MSc

Collaborative partner Wärtsilä Corporation

Date 29.09. 2025 **Number of pages** 77 **Language** English

Abstract

The global power system is undergoing a significant evolution driven by the green energy transition, decentralization, and load-side dynamics. While this transition enables an enhanced resilience and greater energy flexibility, it also introduces significant technical and operational challenges on grid stability issues, system strength, and power quality. To ensure a reliable and secure operation amidst these challenges, system operators must maintain an adequate supply of ancillary services. Among the grid-connected devices capable of delivering such services, synchronous condensers have gained renewed interest due to their ability to provide reactive power, inertia, short circuit strength, and fault ride-through capability.

This thesis studies the prevailing stability challenges in the power system, existing and future non frequency based ancillary markets, and renewed interest on synchronous condensers as a grid connected device to provide non frequency ancillary services, through a detailed literature study The thesis conducts a comprehensive scenario-based simulation analysis on Wärtsilä 20V31SG gas turbine generator sets to quantify its synchronous condenser capability to provide non frequency ancillary services in supporting grid stability under increasing inverter-based resource (IBR) penetration, as its main objective. Analysing the impact of deploying the conventional synchronous machines as synchronous condensers instead of merit order curtailments in high renewable energy injection was also an objective of the thesis.

The analysis is conducted through time domain simulations using DIgSILENT PowerFactory, based on an IEEE 14-bus system scaled to represent a large power network. A base case with 30% IBR penetration was developed and extended to configurations with 50%, 75%, and 96% IBR shares. For each case, dynamic simulations were conducted to assess the performance of the Wärtsilä gensets under different operating modes and disturbance events.

Keywords: Ancillary Services, Synchronous Condensers, Voltage Stability, Reactive Power, Short Circuit Power

Table of contents

Preface and Acknowledgements

As I conclude my master's studies, I would like to express my sincere gratitude to the individuals and institutions who have supported me throughout this journey.

First, I would like to thank Aalto University and all the lecturers under whom I have had the privilege to study. I am grateful for the opportunity to learn and grow. I believe I made the best of it and will continue to put this knowledge to good use. I truly appreciate my thesis supervisor, Prof. Janne Seppänen, for his valuable guidance and constructive feedback throughout the thesis process.

A huge shoutout to Mr. Stefan Schleeh, General Manager, Power Systems at Wärtsilä Corporation, for believing in me and giving me the opportunity to conduct my thesis with Wärtsilä's power system team. The mentorship and technical insights I received from the Power Systems team at Wärtsilä, especially from thesis advisors Mr. Ville Telatie and Mr. Mustafizur Rahman, were instrumental in shaping my thesis.

A special thanks goes to my parents and sister, for cheering me on from miles away. And to my girlfriend, Kalani for being with me through highs and lows, for reminding me of my strengths when I doubted myself, and for inspiring me to strive for greater things.

The scholarship I received from Aalto university truly changed my life in the best possible way. It opened doors to many invaluable opportunities that would've otherwise remained closed. I am deeply grateful for Finland's free education system, for making higher education accessible to students from around the world, including myself.

Tampere, 29 September 2025
Indula Amarasinghe

Symbols and abbreviations

Symbols

˚C	Celsius
Hz	Heartz
V	Volt
%	Percentage of
Z	Impedance
P	Active Power
Var	Volt Ampere
s	Seconds
I	Current
Q	Reactive Power
X	Reactance
C	Capacitance
L	Inductance

Abbreviations

AC	Alternating Current
ACME	Australian Energy Market Commission
AFL	Available Fault Level
AS	Ancillary services
AVR	Automatic Voltage Regulator
BSP	Balance Service Providers
CAGR	Compound Annual Growth Rate
CAISO	California Independent System Operator
DER	Distributed Energy Resources
DFIG	Doubly Fed Induction Generator
DSO	Distribution System Operator
EHV	Extra High Voltage
EPF	Expected Payment Function
FACTS	Flexible Alternating Current Transmission Systems
FCR	Frequency Containment Reserve
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
FRR	Frequency Restoration Reserve
GFL	Grid Following Converter
GFM	Grid Forming Inverter
GVA	Giga Volt Ampere
GW	Giga Watt
HVDC	High Voltage Direct Current

IBR	Inverter Based Resources
IEEE	Institute of Electrical and Electronics Engineers
IGBT	Insulated Gate Bipolar Transistors
IM	Induction Motors
IR	Inertial Response
IRENA	International Renewable Energy Agency
kV	Kilo Volt
LCOE	Levelized Cost of Energy
LVRT	Low Voltage Ride Through
MCP	Market Clearing Price
MVA	Mega Volt Ampere
NYISO	New York Independent System Operator
OLTC	On Load Tap Changer
PAB	Pay as Bid
PCC	Point of Common Coupling
PLL	Phase Locked Loop
PPC	Power Plant Controller
PU	Per Unit
PV	Photovoltaic
REG	Renewable Energy Generator
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
RR	Replacement Reserve
SC	Synchronous Condensers
SCR	Short Circuit Ratio
SSS	Synchro-Self-Synchronising
STATCOM	Static Synchronous Compensator
SVC	Static Voltage Compensator
TCR	Thyristor Controlled Reactor
TSC	Thyristor Switched Capacitor
TSO	Transmission System Operator
TWh	Terawatt Hour
USD	United States Dollar
VRE	Variable Renewable Energy
WECC	Western Electricity Coordinating Council
ZIP	Constant Impedance, Constant Current, Constant Power

1 Introduction

1.1 Background

The global power system is evolving rapidly, fuelled by the ongoing green energy transition, decentralization of the power system, and load-side dynamics. Apart from the opportunities it brings, such as the integration of new energy technologies, greater energy flexibility, and the development of resilient grids, it also introduces a set of technical and operational challenges. Grid stability issues, depleting system strength, and power quality are among the significant concerns. To ensure a reliable and secure operation amidst these challenges, system operators must maintain an adequate supply of ancillary services in the power grid

Among the grid-connected compensation devices that provide ancillary services, synchronous condensers have gained significant interest among system operators due to their inherent characteristics that overpower the existing power electronics-based devices. Besides their historically utilized reactive power contribution, synchronous condensers can provide inertia support, high and rapid overloading during disturbances, and, more importantly, short circuit power during extreme contingencies, making them one of the most versatile Flexible Alternating Current Transmission Systems FACTS devices.

Wärtsilä, as a global leader in power system solutions, has made significant advancements with synchronous condenser technology as a part of its genset portfolio, especially with the hybrid Genset that can work as a generator or synchronous condenser. As a part of this development, this thesis work is implemented to analyse the power system's response in different grid scenarios under the assistance of Wärtsilä gensets capable of providing synchronous condenser features.

1.2 Research Objectives and Scope

The objective of the research is to quantify the synchronous condenser capability of Wärtsilä generator sets to provide reactive power and short circuit power support, when operating as a grid supporting device under different renewable energy penetration levels, operational configurations, and disturbance events.

Having inbuilt synchronous generators, these unit are capable of injecting both active and reactive power to the power system. However, with the growing penetration of renewable energy sources, the active power dispatch from gas turbines is often curtailed by the merit order. Instead of shutting down the entire plant during such periods, this study investigates the feasibility of switching the operating mode from generation to synchronous condenser mode to provide non-frequency based ancillary services, in this case reactive power and short circuit power support.

The scope of the thesis includes performing a dynamic simulation based on IEEE 14 bus system. These simulations aim to assess the impact of reactive power and short circuit power support provided by Wärtsilä gensets operating in synchronous condenser mode during power systems' steady state conditions, load variations and disturbance events under different renewable energy penetration levels.

1.3 Research Method

The research is extensively based on simulations that are performed using the power system analysis software, DIgSILENT PowerFactory. DIgSILENT PowerFactory was chosen as the analysis tool due to its direct compatibility with the existing Wärtsilä generator models. The simulation model was constructed based on IEEE 14 bus system, which is a widely recognized benchmark network and intended to represent a large power system having a capacity of around 10GWs. A base system was first constructed that had 30% Inverter Based Resource (IBR) share which was then extended to different versions with 50%, 75% and 96% IBR share. These IBR penetration levels were selected to represent a progressive transition towards high renewable shares, enabling the assessment of system stability under varying grid conditions. Simulation was performed for all grid versions. Predetermined grid scenarios were applied to quantify the impact of the synchronous condenser capabilities of Wärtsilä gensets, on power system stability improvement.

To construct the simulation model, several types of generators were used. Out of them, gas turbines, wind turbines and solar PV plants were obtained from the already existing models in the software, while custom-developed Wärtsilä 20V31SG gas turbine model has been selected for the simulation representing Wärtsilä generator sets. All other components were sourced directly from the software.

1.4 Thesis Structure

This thesis report consists of four main chapters. First, an introduction was made to the thesis with separate subsections to give the readers an overall understanding of the thesis flow. A comprehensive literature review is then carried out to discuss the theoretical background of the thesis.

The literature review identifies the ongoing challenges due to the changing power system dynamics, the role of ancillary services to mitigate the challenges. It further extends to investigate how non frequency ancillary services can support the power system stability and reliability and the commercial aspect of it. It finally introduces the synchronous condenser as a device to provide non frequency ancillary services to the power system, compare and contrast it with other existing ancillary service providing devices to emphasize the renewed interest for synchronous condensers. Finally, it presents an in-depth theoretical analysis on working principles of the Synchronous Condensers.

The third chapter is dedicated for the research methodology, which includes the configuration of the simulation models, demonstration of control of reactive power by Wärtsila 20V31SG gas turbine's control system and scenario development for the simulation. The fourth chapter involves detailed analysis on the results obtained in the scenario analysis. Fifth and the final chapter discusses about the conclusions of the study, what went right and wrong in the thesis process, and provides suggestions for improvements in future continuation of the thesis.

2 Literature review

2.1 Ongoing transition of the global power system

Growing concerns about the global climate crisis have fuelled a rapid shift in the global energy landscape. As an industry, electricity and heat generation have been substantial greenhouse gas emitters ever since, accounting for 31.8% of the total global greenhouse gas emissions in 2020 [1]. To achieve net zero emissions and limit the global temperature rise to 1.5˚C by the year 2050, decarbonizing efforts in the electricity sector will play a crucial role, since it will not only result in direct emissions but also indirect reduction of emissions from other industries such as transportation and buildings.

These factors, combined with the concerns of depleting fossil fuel resources, accelerated the deployment of renewable energy sources into the global power system. According to IRENA, at the end of 2023, worldwide installed renewable power capacity had amounted to 3865 GW [3], threefolds compared to 2010 levels. The report mentions, apart from hydro that has 33% share of global installed renewable capacity as of 2023, the most dominant renewable energy sources are wind and solar, having a share of 26% and 37%, respectively. Bioenergy, Geothermal and Marine sources take up the rest which is around 4%. Figure 1 shows worldwide cumulative renewable generation capacity change from 2010 to 2023.

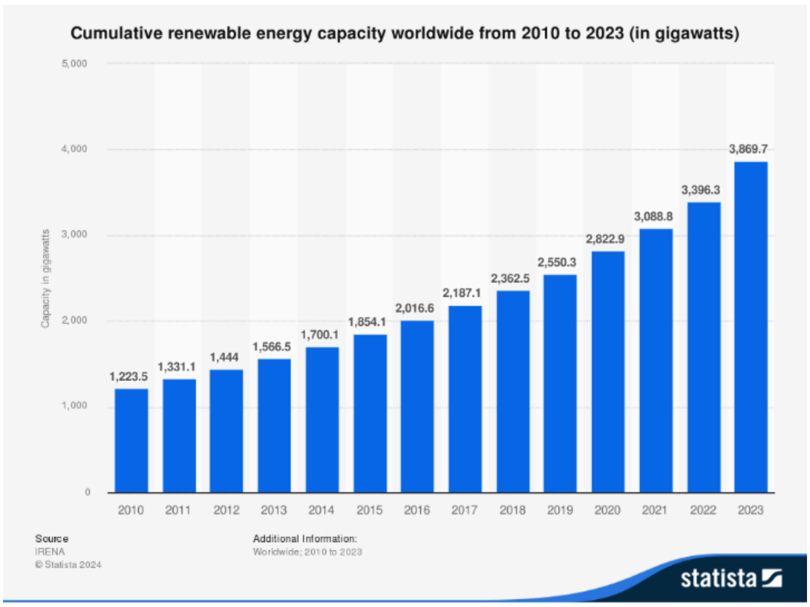


Figure 1: Worldwide cumulative renewable capacity from 2010 to 2023 [2]

Continued growth and technological advancements have further improved the efficiency of renewable sources while reducing the cost of energy. Comparing 2010 levels to 2023, the capacity factor of Solar PV has increased by 14%, and LCOE has decreased by 90% [3]. For onshore wind, the capacity factor increased by 33%, and the LCOE reduced by 70% during the same period [3]. The favourable technical and economic feasibility steadily makes renewables (especially Wind and Solar PV) a promising alternative to conventional energy generation, allowing most countries to increase their renewable energy portfolio and gradually phase out conventional generators.

While renewable integration often takes centre stage in the multi-faceted transition of the global power system, an equally important driver of this transformation is the changing dynamics of the load side. Over the past two decades, global electricity demand has risen from 15,277 TWh in 2000 to 29,471 TWh in 2023 [41]. The global trend towards digitalization has introduced new types of energy-intensive applications such as data centres and cryptocurrency mining [31]. Additionally, load profiles are shifting from traditional static and passive load models such as ZIP (constant impedance, constant current, constant power) to more dynamic models, driven by the increased use of load types, such as drive-controlled induction motors and the growing penetration of distributed energy sources [31].

Similarly, the rise of distributed generation, where power generation takes place on a smaller scale, closer to the load centers, is changing the traditional power system landscape, adding positive and negative effects [42]. Aggregation of Distributed Energy Resources (DERs) is transitioning the traditional power system to a decentralized generation model, enabling consumers to step from passive consumers to prosumers, contributing to both demand and supply in the grid [31].

This paradigm shifts towards a renewable-driven, decentralized power system introduces significant changes to its stability, flexibility, reliability, and controllability.

2.2 Inverter Based Resources (IBRs) in the traditional power grid

The traditional power grid was designed to generate electricity from a few centralized generators [4]. The generators were primarily synchronous machines with a rotational mass and driven by fossil fuel, nuclear, or large-hydro resources [4]. Synchronized with the power system's voltage, frequency, and phase angle, they functioned as voltage sources. Power flow in this system was limited to a single direction, from power plants upstream to the end user downstream, utilizing Alternating Current (AC) transmission to

propagate power through the network. In addition to inertia, these machines premeditatedly provide short circuit strength and adequate reactive power to the power system, ensuring better stability over contingency scenarios.
In contrast, most renewable sources nowadays are connected to the traditional power system through a power electronic converter-based interface. Two primary control strategies employed in converter-based interfaces are Grid Following and Grid Forming converters [5]. Grid synchronization of Grid Following converters is done through a control method called a phase-locked loop (PLL). PLL tracks and follows the existing grid voltage and injects current into the power system, making the converter behave as a controlled current source. Since these converters depend on an already stable grid for voltage and frequency reference without contributing to their regulation, they are referred to as grid-following converters (GFL) [5]. Due to this passive nature of grid-following converters, widespread integration of grid following converter interfaced generation could challenge the power system's resilience against disturbances.

Grid Forming Converters (GFM), developed initially to support the islanded mode of microgrids [59], are making their way to large power systems due to the advantages they can bring. Unlike GFL, which operates as a current source following the grid voltage, GFM acts as a voltage source and does not rely on the grid voltage for synchronization. Rather than focusing on maximizing active power output, the primary objective of GFMs is to regulate frequency and voltage in the grid [59]. GFMs employ several controlling mechanisms to achieve these grid-supporting functions. One widely used approach is droop control, which allows the GFMs to regulate active and reactive power based on voltage and frequency, closely emulating the operation of conventional synchronous generators [60]. Another common method is Virtual Synchronous Machine (VSM) mode that mimics the dynamic behaviour of synchronous generators by providing virtual inertia and damping [60]. However, most GFM technologies are still developing and have yet to make their way to commercial use. Since the future power system will likely be IBR-dominated, switching towards GFM inverter interfaces will mitigate the adverse effects of GFL inverters and provide an additional layer of support for the grid.

2.3 Classification of power system stability

Power system stability refers to the ability of a power system to return to its normal operating conditions after being subjected to a disturbance [6]. In the traditional power system, stability is classified into three categories: rotor angle stability, frequency stability, and voltage stability [6]. However, with the rapid growth of Inverter Based Resources (IBRs) and phasing out of conventional generators, the power system is gradually becoming more dependent on fast-response power electronic interfaces. Considering the influence of these devices, the CIGRE and IEEE Power System Dynamic Performance Committee have jointly introduced two new categories into the power system stability classification: Converter-based stability and Resonance Stability [6].

A power system should be reliable in both normal and contingency situations. In a conventional generator-dominated power system, synchronous generators' operational characteristics and control ensure dynamic stability [6]. This equipment usually responds slowly and operates in the power system time scale's electromagnetic, electromechanical, and thermodynamic regions. As IBRs take over, the system's dynamic behaviour changes due to its fast response characteristics. IBRs can respond almost immediately to changes in the power system, introducing new challenges in stability, control, and protection within the modern power system [6]. In addition, the high dependency of renewable energy on natural phenomena creates another layer of challenges. The following section will mainly focus on the challenges of voltage stability and strength of the power system. However, other stability scenarios are described briefly as well. The classification of power system stability is illustrated in Figure 2.

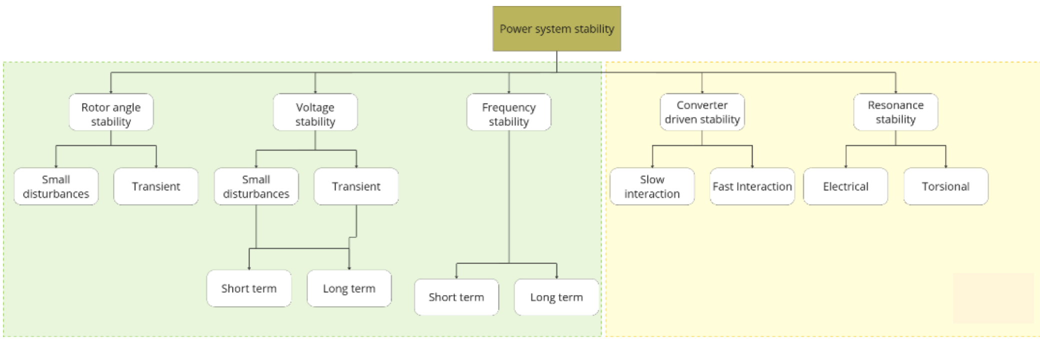


Figure 2: Categorisation of power system stability [6].

2.3.1 Voltage stability

Voltage stability is referred to as the ability of a power system to maintain an acceptable voltage level, for example within 5% of the nominal voltage [30], across all the buses during both steady-state and contingency situations. Voltage instability can appear as a reduction or rise in voltage at certain buses, especially in systems with heavy loading or reactive power limitations, potentially leading to voltage collapse [10]. Several factors that directly affect the voltage stability of the power system are network strength, the reactive power capability of the generation sources and compensation devices, distance to the reactive power source from the point of interest, and load characteristics [29] [44].

Further, the widespread integration of renewable sources often displaces a significant amount of synchronous generation, and the power system is not compensated for the reactive power that synchronous generators provide. The grid can become unstable without sufficient reactive power resources, potentially leading to voltage collapse and blackouts following a post-fault period [11]. Extended transmission networks must be utilized when most large-scale renewable energy generators are far from load centres. Instabilities can arise in these transmission corridors during a system disturbance due to insufficient reactive power to stabilize voltage [11].

2.3.1.1 Classification of voltage stability

The voltage stability of a power system is mainly categorized into small disturbance stability and transient stability, depending on the severity of the disturbance. Small-disturbance voltage stability refers to the system's ability to maintain voltage within acceptable limits following a minor perturbation, such as an incremental load change. In contrast, transient voltage stability deals with the system's response to sudden, significant disturbances, such as the loss of a generation unit or a short circuit [45]. Voltage stability is further classified into short-term and long-term stability. The dynamics of rapidly responding components such as HVDC systems and inverter-based generation are involved in short-term stability. In contrast, long-term stability is influenced by the operation of slower-responding equipment, including tap-changing transformers, thermostatically controlled loads, and generator current limiters [6].

In a converter-dominated power system, short-term voltage stability is mainly impacted by the reactive power deficiency in the network. Large-scale converter-based generation introduces a low ratio between active power and reactive power, as these systems are primarily designed to maximize active power while consuming reactive power [4][6]. On the demand side, the composition of dynamic loads, typically linked to Induction Motors (IM), often leads to stalling following a failure. This results in delayed voltage recovery, voltage instability, and, in severe cases, rapid voltage collapses. This situation occurs because stalled IMs draw a large starting inrush current, further depressing the voltage and continuing to draw reactive power, preventing the voltage from recovering [37]. Therefore, higher concentrations of such loads can increase the system's vulnerability to short-term voltage stability problems. Especially in weak systems with low short circuit capacity, where the increased consumption of reactive power coupled with the reduced capability of converter-based systems to provide reactive power compensation, creates significant challenges for voltage regulation [4].

2.3.1.2 Voltage stability challenges from distributed generation

The distributed deployment of power generation in modern power systems introduces several complexities, such as power quality challenges, mainly due to the intermittent nature of wind and solar energy [18]. The most common power quality issues introduced by grid-connected renewable energy sources are voltage fluctuation, voltage sag/swell, and harmonic distortion [19]. Voltage fluctuations can lead to voltage sags and swells, where the voltage drops 10-90% from its nominal levels and rises above 10% of nominal levels respectively.

2.3.1.3 Solutions for voltage stability challenges

Ultimately, voltage instability can cause electromechanical power imbalance at synchronous generators, leading to transient instability. Therefore, it is important to maintain reactive power reserves precisely to improve voltage stability in the system. The grid operators (TSOs and DSOs) have taken several measures to address these challenges, such as implementing strict grid codes ensuring acceptable reactive power management from REGs and deploying reactive power supporting devices [11].

2.3.2 Prevailing challenges related to the power system short circuit level

The strength of a power system is a crucial parameter for power system security and focuses on how quickly the system can respond in the phase of unexpected disturbances [12]. Power system strength can be directly related to the extent of voltage change in a power system following a fault or a disturbance [12]. At any given point, the strength of the power system can be quantified using the Available Fault Level (AFL) [13]. The AFL, widely known as the Short Circuit Power, represents the maximum current that could flow through a point during a short circuit fault [14]. Mathematically, the AFL is expressed as [13]:

$$AFL = \frac{E_{\mathrm{g}}^2}{Z_{\mathrm{g}}} \quad \text{--------} \ (1)$$

E_{g}^2 = Voltage seen at the point of interest in the grid
Z_{g} = Equivalent Network Impedance seen at the point of interest in the grid

If the AFL is high, a power system is considered strong, while a lower AFL makes a power system weak [13]. Synchronous generators have been the primary contributor to the fault level in traditional power systems, with an inherent capability of generating a significant short circuit current in the range of 5-8 Per Unit (P.U) of the rated current [4][13]. However, as mentioned above, the broad adoption of converter-based renewable sources is leading to the gradual replacement of synchronous generators, creating a significant adverse effect on the power system's strength [13].

Typically, IBR sources generate short circuit currents in the range of 1.1 -1.5 P.U. of the rated current due to the thermal limitations of the inverters [13]. Due to this limitation, IBR contributes less to the AFL of the power grid than conventional sources, increasing the system's vulnerability to voltage instability and potential collapse following a disturbance [13]. The strength of a power system is further influenced by both the size (rating) of the connected source and their electrical distance from the synchronous generators in the network. Most large IBR sources are located in remote areas, which increases the electrical distance from available synchronous generators. These IBRs do not provide the same level of AFL as synchronous generators, reducing the effectiveness of available synchronous generators and depleting the grid strength [15].

In an IBR-dominated power system context, the short circuit ratio (SCR) is an important parameter for evaluating the IBR's withstandability under low-strength conditions. SCR is defined as the ratio of the AFL at the point of interest to the nominal active power output of the IBR [14].

$$SCR = \frac{AFL_{\mathrm{POI}}}{P_{\mathrm{IBR}}} \quad \text{--------} \ (2)$$

AFL_{POI} = Available Fault Level at the Point of Interest
P_{IBR} = Nominal Active Power Output of the IBR

A higher SCR indicates a stronger system, while lower values suggest otherwise. Typically, if a grid's SCR is lower than 3, it is considered weak [13]. Therefore, most grid-connected inverters require maintaining a minimum SCR ratio for stable operation [14].

2.3.2.1 Fault Ride Through Issues with IBRs

In the event of a severe fault, such as a short circuit, the voltage at the fault location experiences a significant reduction. This voltage dip propagates over an extended area until the fault is cleared [11]. Detecting and disconnecting the faulty component by operating the relevant relays is crucial to protecting grid assets in such incidents. In conventional systems, the high short circuit currents help to detect the faults and limit the voltage imbalances following the faults while staying connected throughout the fault situation [16].

In the aforementioned weak grid scenario in section 2.3.2, where there is widespread penetration of IBRs that do not provide adequate dynamic reactive power and short circuit power in a fault situation, IBR sources tend to disconnect from the grid when they sense a decrease in terminal voltage below the Low Voltage Ride Through (LVRT) thresholds. This disconnection creates serious voltage stability issues in the system and adversely impacts the operation of the remaining generator units [11]. Modern grid code requires IBRs to remain connected during a fault to improve system reliability and resilience, and this is achieved by integrating improved control strategies and auxiliary devices installed and controlled with IBRs [17].

2.3.3 Frequency Stability challenges in the modern power systems

Demand and supply in the power system are in a delicate balance. Having a constant supply of input power, conventional generators could provide constant and reliable power to the system, maintaining frequency, typically at 50 or 60 Hz [7]. The ability of a power system to maintain a steady frequency and restore it quickly following a severe disturbance is referred to as frequency stability [9]. Such disturbances cause imbalances between supply and demand. In situations where the power system cannot correctly balance load and generation after a disturbance, significant frequency deviation can occur in the system which could result in power system instability. Protection systems will activate if the frequency fluctuation exceeds the safe operational limits, causing generator units to trip [7][9].

Inertia within the power system is important for its ability to maintain frequency stability. During severe disturbances, the system's inertial response slows down the Rate of Change of Frequency (RoCoF), preventing the system from being pulled into a cascading failure [7]. Conventional sources naturally provide this inertial response due to having rotating masses whose mechanical speed is synchronized with the grid frequency. In contrast, IBRs rely entirely on electronic components and do not contain any mechanical components or rotating masses. As a result, IBRs, except batteries and STATCOMs with energy storage, do not contribute to the system inertia and are frequently described as 'Zero Inertia' devices. Therefore, their response to disturbances rather than an inertial response depends on their control strategies [7].

The limited inertial response in the system may pose challenges for integrating additional renewable resources due to the rapid control characteristics of IBRs. Under normal operating conditions, IBR's power electronic controllers automatically adjust to meet the supply-demand balance. However, reduced system inertia leads to more significant frequency fluctuations and reduced natural damping. In extreme cases, this can result in the control system of IBRs exceeding their operational limits, potentially leading to automatic shutdowns and equipment damage [4].

2.3.3.1 Solutions for frequency stability challenges

Efforts are being taken to address the challenges of diminishing inertia with the widespread adoption of IBRs. These efforts include utilizing retiring synchronous generators, integrating grid forming inverters (GFM) that can mimic the inertial response behaviour of synchronous generators (virtual synchronous machines), Battery Energy Storage Systems (BESS), and employing wind generators (Type III, Type IV, and Type V) that can provide short term inertia [7]. Additionally, demand response participation in frequency control could improve the frequency nadir, the lowest point the system frequency reaches during a disturbance in a low inertia system [43]. One research [43] shows that it does not significantly contribute to the systems RoCoF. However, necessary measurements should be taken, such as implementing synchronous condensers to maintain an acceptable RoCoF during a disturbance [43].

2.3.4 Rotor angle stability

The ability of a synchronous machine to remain in synchronism and regain synchronism after being subjected to a disturbance is called rotor angle stability [6]. Rotor angle stability is further classified into small signal stability and transient stability [6], where transient stability often relates to a large disturbance such as a short circuit failure [45]. Power system strength and the type of the generator excitation system are factors impacting the system's response to such a disturbance [45]. As the power system weakens, insufficient damping torque results in rotor angle instability, potentially leading to blackouts. A recent example is the blackout in a highly renewable concentrated network in Southern Australia 2016 [57].

2.3.5 Resonance Stability

Resonance in the power system occurs when an energy exchange happens periodically and an oscillatory manner. These oscillations can escalate voltage, current, or torque magnitudes where resonance instability could occur if the magnitudes exceed a certain threshold [6]. Resonance stability is further classified into two categories: electrical resonance and torsional resonance. Issues due to electrical resonance are typically due to the resonance between the electrical characteristics of a generator and a series of compensated lines. In contrast, torsional resonance stability issues occur due to the interaction between a series of compensated lines and the mechanical torsional properties of the generator shaft, making the generator shaft vulnerable to fatigue and potential failures [60].

2.3.6 Converter driven stability

Converter-driven stability was introduced primarily due to the difference in dynamic behaviour between conventional synchronous generators and the converter integrated generators [6]. As mentioned in section 2.2, converter-based generators employ control loops such as PLL that work with faster time responses than conventional generators. When these units operate in a wide range of the power system time scale, they can create unstable oscillations in the power system due to interaction with electromechanical dynamics of rotating machines and transients in the electrical network [6]. Converter-driven stability is further classified into fast interaction and slow interaction, where fast interaction stability deals with the oscillation caused by the interaction of power electronic-based devices such as STATCOM and HVDC with controllers of other grid-connected devices such as synchronous generators and transmission lines. Frequency of oscillations for fast interaction stability range from a few hundred Hz to several kHz, while the range is typically lower than 10 Hz for slow interaction stability [6]. 4HZ oscillation experienced by Texas grid due to the integration of wind is an example of a slow interaction stability [62].

2.4 Ancillary Services

To maintain a secure and reliable grid operation amidst the challenges discussed in Section 2.4, Independent System Operators (TSOs and DSOs) must adopt enhanced flexibility within their networks provided by ancillary services [20]. In general terms, ancillary services refer to the functions beyond active power generation and transmission that are essential to ensure the stability, reliability, and power quality of the power system [21][23]. There is a constant need for ancillary services in a power system under normal and contingency situations. These services must be readily available to handle anything from minor imbalances in the system to a power system black start in the event of a severe system failure. [23].

The Federal Energy Regulatory Commission (FERC), in collaboration with the Interconnected Services Working Group, has identified and defined several types of ancillary service types that include spinning reserves, reactive power supply and voltage control, real power loss replacement, and system black start support [24]. Each type of ancillary service is organized within a hierarchical setup based on their response times, with faster-responding services being considered higher quality. The hierarchical structure allows for the replacement of higher-quality ancillary services with lower-quality ones when necessary [25]. However, with the widespread integration of IBR into the power system, the need for ancillary services with a shorter response time is increasing. Table 1 shows a classification and time scale of different ancillary services that are commonly available.

Table 1: Classification of ancillary services [28][31].

Service Name	Acronym	Time scale of service
Inertial Response	IR	200 milliseconds following the power imbalance event
Fast Frequency Response	FFR	2-10 seconds following the power imbalance event
Frequency Containment Reserve	FCR	Few seconds after power imbalance incident
Frequency Restoration Reserve	FRR	From 30 seconds up to 15 minutes following the power imbalance incident
Replacement Reserve	RR	From 30 seconds up to few hours following the power imbalance incident
Reactive power & Voltage Control	-	Milliseconds to minutes
Fault Ride Through	FRT	Microseconds to less than a second following the power imbalance incident

Black Start Support	-	Microseconds to few days after the blackout incident

Ancillary services (AS) can further be categorized into two main groups according to the authors of [31]. They are Frequency-related AS and non-frequency-related AS. Ancillary services that ensure frequency equilibrium in both steady state and contingency operation are considered frequency-related AS [31]. The aforementioned services in Table 1, including IR, FFR, FCR, FRR, and RR, fall under the frequency related AS category [46]. On the other hand, non-frequency related AS focuses on ensuring voltage stability, providing reactive power compensation, and restoring the power system in the event of a blackout [46]. However, later parts of this section narrow its focus to reactive power and voltage control ancillary services and fast fault current injection within the non-frequency related AS category.

As of 2024, the global ancillary services market value is estimated to be USD 8.67 billion and is expected to grow around USD 16.81 billion by 2032 at an annual growth rate of 8.6% [26]. The growth is primarily driven by integrating variable renewable energy sources and phasing out conventional sources that traditionally supplied ancillary services. These changes in the power grid, coupled with the emerging demand-side dynamics, have increased demand for ancillary services.

2.4.1 Procurement of Ancillary Services

TSOs use two procurement approaches for ancillary services to ensure the availability of the required amount. The first approach is compulsory provision, where generators must provide certain types of ancillary services in order to be connected to the power system. These requirements are defined by the grid codes of the TSO [29]. The mandatory procurement is done at a fixed price or free of charge. As this approach had its drawbacks, such as unnecessary investments, excessive procurement of services, and insufficient motivation for the participants to invest and innovate, a commercial approach was introduced to procure ancillary services [25].

2.4.2 Ancillary Services for Voltage Control

Ancillary services for voltage control aim to achieve the regulation of the voltage level across each node of the network (both transmission and distribution levels) such that voltage is maintained within acceptable limits while ensuring voltage stability in the system [29]. Additionally, voltage control helps to minimize the bottleneck for active power flow in transmission lines and to reduce active power losses [30].

Voltage control is closely linked to reactive power management [29]. Reactive power exists in the power system when the current and voltage waveforms are not in phase. Inductive and capacitive equipment at an AC electrical network's transmission and distribution levels absorb or produce reactive power. The system's loading condition and supply availability directly influences the required reactive power compensation and is also related to voltage control [23]. Therefore, voltage control is achieved by absorbing or injecting reactive power at or near the relevant network nodes [28][29]. However, due to significant reactive losses, reactive power cannot travel long distances through transmission lines. For instance, in a 230kV line operating at full load, reactive power losses are typically five times greater than active power losses [30]. Furthermore, delivering reactive power over long distances reduces the active power capacity of the transmission network. Consequently, reactive power is produced locally by devices installed closer to the nodes where the voltage control ancillary services are required.

Depending on the control strategy, voltage control can be categorized into three groups: steady-state voltage control, dynamic voltage control, and fast reactive current injection [31]. Steady-state control ensures that the voltage profile of the system remains close to the acceptable values during normal operating conditions and after slower disturbances. This type of control is usually done within hours [29]. Dynamic control activates within seconds to minutes to stabilize the system's voltage profile during transient disturbances, such as sudden load changes, faults, or generator outages [29]. Fast reactive current injection refers to a generator's capability of delivering a proportional response to a voltage dip. This ancillary service activates in a dynamic frame within milliseconds. It operates for a few minutes, preventing or limiting the extent of a voltage collapse right after a disturbance, ensuring the dynamic security of the power system [28].

Several devices can provide voltage control ancillary services by absorbing, injecting, or forcing reactive power flow. Dynamic sources such as synchronous generators and synchronous condensers and static sources such as capacitor banks, Static Voltage Compensator (SVC), and Static Synchronous Compensator (STATCOM) are among these devices [29]. These devices are distinguished by different characteristics such as response speed, capital and operating costs, control continuity, and response to system voltage changes [30].

2.4.2.1. Rising challenges for voltage control in the power system

With the increasing penetration of IBR and market-based displacement of conventional sources, the future power system will consist of a higher number of variable renewable sources and a relatively lower number of conventional synchronous resources, fundamentally altering the demand and availability of ancillary services, including voltage control.

Renewable power generation, such as wind and solar, is often located in remote areas with abundant resources. However, as the remaining synchronous units are spread thinly across the power system, the electrical distance between the synchronous voltage sources and the renewable generators is increased, reducing the electromagnetic strength of the system [32]. While the availability of synchronous reactive power in the system is reduced, demand rises for the reactive power at the EHV level due to the increased distance between load centres and the energy supply [33]. This could create challenges in maintaining the voltage profile across the system and restoring voltage in the event of a failure.

Additionally, a significant portion of IBR penetration will occur at the distribution level. A report published by EirGrid in 2010 indicated that more than half of the projected wind power plant connections in Ireland will occur at the distribution level [32]. Having volatile energy sources connected to the distributed network can impact the voltage profile, such as unintended voltage rises and drops.

2.4.2.2. Future demand for voltage control ancillary services

The demand for additional dynamic and steady-state reactive power-supporting mechanisms will increase with the above changes in the power system. This can be provided by connecting dedicated reactive power sources (such as FACTS devices and Synchronous condensers) or allowing VRE sources to participate in reactive power support ancillary services. However, the reactive power provision by VRE sources beyond the grid code requirements can be challenging for several reasons.

For instance, wind power plants have a limited power factor range compared to conventional synchronous generators. Typically, wind power plants operate at a lagging/leading power factor of 0.95 P.U. at maximum wind power output. In contrast, conventional generators have a wider range of 0.93 P.U., leading to a 0.85 P.U. lagging power factor at their maximum active power output. This results in a potential reduction of the overall reactive power controllability of the system even with a higher number of wind power plants complying with the grid codes [32]. Participating in ancillary services can also create high opportunity costs for renewable generators, as the revenues from such services could be outweighed by significant losses due to market premiums for the curtailed active power [58]. Unlike synchronous sources, which consist of excitation systems capable of providing constant reactive current during transient disturbances, doubly fed induction generators (DFIGs) commonly used in wind power plants may face difficulties in providing dynamic reactive power during transient instability or voltage collapse due to their limited reactive power capabilities [32].

In the same report by EirGrid [32], an analysis was conducted to measure the impact of the increasing penetration of wind power generation on available reactive power in Ireland and Northern Ireland's power systems. A model was created by aggregating hourly dispatch data from each reactive power-generating unit for both 2010 and 2020 levels. In 2010, the total lagging reactive power in the system ranged from 2500 Mvar to slightly over 5000 Mvar. By 2020, there was a noticeable reduction in the availability of reactive power in the system. Even after considering the reactive power generation at the TSO level wind power plants, the total reactive power availability still could not reach the 2010 levels. This indicates the power system will have less reactive power capability to manage voltage profile and system stability in 2020, with high wind power penetration. Figure 3 shows the reactive power duration curve created in this study to compare the reactive power availability in the 2010 and 2020 scenarios.

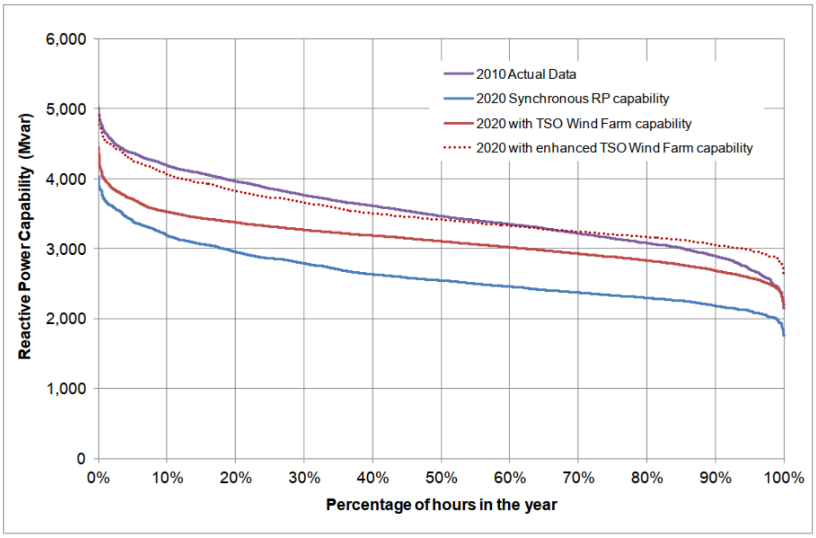


Figure 3: Comparison of reactive power availability in Ireland’s power grid in 2010 and 2020 scenarios [32]

In summary, increasing penetration of variable renewable energy, shifting towards a more decentralized power system, and extending transmission lines due to remote power generation locations will create a growing demand for reactive power in future power systems. It will, therefore, be necessary to adapt different reactive power compensation technologies, such as synchronous condensers and FACTS devices, to manage voltage control and ensure voltage stability rather than relying solely on synchronous or non-synchronous generators. However, grid code will still require VRE systems to provide low-voltage ride-through capability and participate in voltage control operations in steady-state conditions in transmission and distribution levels [32][33].

2.4.3 Ancillary services for fast fault current injection

In power systems, fast fault current, also known as the short circuit current, refers to the current injected by synchronous sources during a transient fault, such as a short circuit fault, aiming to serve multiple critical functions. It enables the network protection system to promptly identify the faults at the initial stage, supports maintaining system voltage during the fault, and restores the voltage after the fault has been cleared [34]. TSOs must ensure the power system can supply a sufficiently large, short circuit current following a fault [33].

The amount of fault current supplied during a fault mostly depends on the reactance of the synchronous machine and the electrical distance to the fault. The short circuit faults happening closer to a connection point (substation or a busbar) could result in a significant voltage drop. In such a situation, the typical fault current response from a synchronous machine occurs in three stages. At the initial fault period, it injects a faster fault current (marked with A in Figure 4), to identify, locate, and activate fast and selective fault clearance by the system protection devices. In the later part of the fault, the machine injects a precise fault current (marked with B in Figure 4) for either voltage retention or frequency stability depending on the size of the synchronous area, where voltage retention is the priority for a wider synchronous area. Once the fault is cleared, the current is injected to restore voltage (marked with C in Figure 4), and active power, aiming to achieve the pre-fault values. If the injected current is reactive, supporting voltage recovery, it is considered a part of the fast fault current injection [35]. During the fault clearance time, these machines may not cause instability or disconnect from the system to ensure continuous support to the grid [33]. Figure 4 shows the usual response of a synchronous machine to a short circuit fault during the three fault periods. The x axis of figure 4 represents time in seconds while the y axis represents the ratio between per unit instantaneous reactive current of the synchronous machine ($I_{Q,MV}$) and per unit rated current of the synchronous machine (I_n).

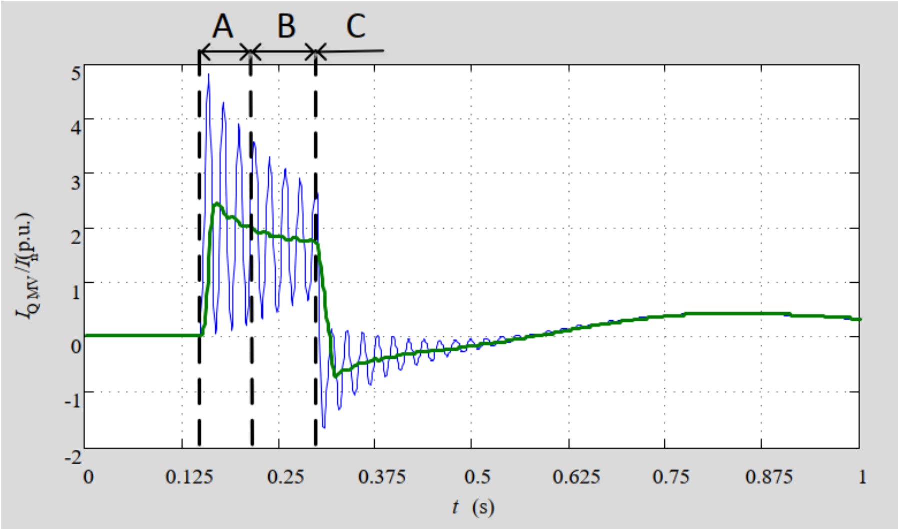


Figure 4: Response of a synchronous machine throughout the fault periods of a short circuit fault.

IBRs, on the other hand, may reduce the fault current contribution due to the thermal limits of the power electronic components they are made of. Unless oversized, IBRs are usually designed to handle a fault current of 1.2 P.U. to 1.5 P.U. (per unit on the plant's MVA base) during a fault condition [37]. Unlike synchronous machines having a higher magnitude of fault current following a fault, the limited fault current contribution of IBR can cause challenges for traditional protection schemes, which largely rely on the high magnitude and inductive nature of fault current and may not provide a reliable operation with the current supplied by IBRs [36]. However, if the local loads of the system do not cause delays or slow voltage recovery following a fault, and the fault clearance does not weaken the local power system, IBRs can effectively inject reactive current without facing stability or synchronization problems [37].

Since the total connected capacity of synchronous generators in the power system is decreasing due to the market-driven displacement, the short circuit capacity provided by the conventional machines will reduce [33]. With the rising levels of IBRs, the available short-circuit capacity in the system will become volatile due to the intermittent nature of renewable sources and will negatively influence the power system's stability and reliability. Therefore, TSOs should carefully consider the IBR performance in the system and take necessary measures, including static and dynamic compensation device integration into the system, to mitigate the potential impacts [37].

2.4.4 Financial models for voltage control ancillary services

Even though reactive power is provided locally, it is TSO's responsibility to procure and manage it within a power system. Apart from the mandatory provision, there are a few other ways of procuring reactive power, which include tariff-based procurement, long-term bilateral contracts, procurement through tenders, and market-based procurement [38]. Depending on the TSO, the method and terms of procurement differ.

Apart from capital investment, operating and opportunity costs are two major cost components related to reactive power supply. Operating costs include the winding losses for generating and absorbing reactive power, and the opportunity cost reflects the lost reactive power generation due to the provision of reactive power [21][30]. The Table 2 consists of procurement methods and related pricing mechanisms of reactive power by TSOs of different countries according to the literature [31],[39], and [29].

Table 2: Different procurement methods used by TSOs for reactive power

Country	Procurement Method	Pricing Mechanism
Great Britain (NG)	i. Mandatory provision ii. Enhanced reactive power through Tender	Regulated price
Ireland	Mandatory service	Regulated price
Germany	i. Mandatory provision ii. Bilateral Contracts	Contracts: Regulated price
Denmark	i. Mandatory provision ii. Bilateral Contracts	Contracts: Regulated price
Sweden	i. Mandatory provision ii. Bilateral Contracts	Contracts: Regulated price
Spain	i. Mandatory provision for conventional generation ii. Via tenders for generators not participating in active power market	-
USA (CAISO)	Mandatory provision	Opportunity cost
USA (PJM, NYISO)	Mandatory provision	i. Capability payment ii. Opportunity cost
Australia	i. Generation mode though tender ii. Synchronous condenser mode through tender	Generation mode: i. Availability cost ii. Opportunity cost iii. Cost for voltage support Synchronous condenser mode: i. Availability cost ii. Cost for voltage support

As of 2024, Reactive power and voltage control takes up to 25% of the global ancillary services market at a market value of USD 2.17 billion and is estimated to grow at an 8.6% CAGR [26]. However, there is no market structure for fast reactive current at present. It is typically a mandatory requirement imposed by grid codes [28]

2.4.4.1 Pay as Bid model for reactive power price settlements

Considering both technical and economic aspects, a discussion of a more competitive reactive power market, especially in countries with deregulated power systems, is proposed by several studies [39][40]. Currently, electricity market prices are determined based on the 'pay at Market Clearing Price (MCP)' framework, where the bids from both electricity sellers and buyers are aggregated to create a demand and supply curve. The intersection point will be the market price. A uniform payment will be made to the generators in the day ahead market. However, when it comes to reactive power, the pay-at-MCP model introduces several drawbacks [40]. Unlike active power, the location of dispatch is important for reactive power. Therefore, if reactive power were produced at a low cost, it would not be favourable if it is far from the point of consumption. Conversely, a high-cost reactive power source close to a heavily loaded bus may require producing reactive power to ensure the system's reliability [40]. Hence, integrating a uniform price across the reactive power market is not economically beneficial. It can further create market power for some reactive power producers. It will eventually result in other participants getting paid an extra fee regardless of the location and effectiveness of their reactive power supply to the system [40].

As a solution, a Pay-as-Bid (PAB) model is proposed, where the participants are paid the price, they bid for the reactive power they provide. This way, only the most expensive generator will be compensated at a higher price. To place the bids under the PAB clearing mechanism, an Expected Payment Function (EPF), has been introduced based on the capability curve of a synchronous generator [40].

Figure 5 shows the capability curve of a synchronous generator. As generally mandated by the most grid codes, the generator should maintain a reactive power provision up to Q_{base}, and the reactive power provided between 0 and Q_{base} is not compensated by TSO. When the generator operates at the point (P_{A}, Q_{base}), it can increase the reactive power generation until it reaches the thermal limits of the field winding without compromising active power. Figure 6 shows the operating point A, where the maximum reactive power (Q_{A}) that the generator can deliver without compromising active power $\mathrm{P_A}$. Therefore, for the increment of reactive power from Q_{base} to Q_{A} a payment is made based on the incurred winding losses. However, suppose the generator further requires increasing the reactive power production, for example, from Q_A to Q_B. In that case, it has to compromise on the active power to avoid any damage from overheating. Therefore, this situation will reduce the active power from P_A to P_B. This will create an additional opportunity cost for the generators due to the loss of active power generation. Hence, the generators should be paid not only for the winding losses but also for the opportunity cost at this stage [39][40].

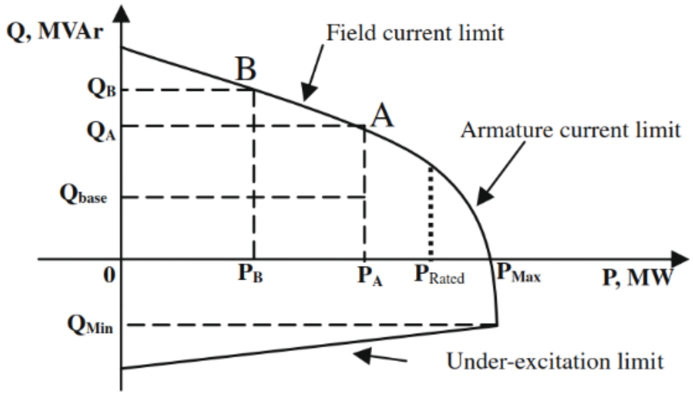


Figure 5: Capability curve of a synchronous generator with different regions of operation for reactive power compensation [39].

The Expected Payment Function (EPF), therefore, includes all the cost components, including the availability of the generators, cost of losses, and opportunity costs, and can be illustrated as shown in Figure 6 as a function of the amount of reactive power production from a generator. EPF can be determined for any operating condition of a synchronous generator. It can also be utilized for synchronous condensers as well. In synchronous condensers, the cost component for opportunity cost would be zero [39]. EPF is mathematically formulated as follows:

$$EPF_i = a_{0,i} + \int_{Q_{min}}^{0} m_{1i}.dQ_i + \int_{Q_{base}}^{Q_A} m_{2i}.dQ_i + \int_{Q_A}^{Q_B} (m_{3i}.Q_i).dQ_i \quad \text{--------} (3)$$

Where $a_{0,i}$, m_{1i} , m_{2i}, m_{3i} are availability cost, operation cost in reactive power absorption mode, operation cost in reactive power generation mode, and lost opportunity cost for the i^{th} generator respectively [39]. Reactive power settlement is then performed to minimize the EPF function, as the objective of the TSO is to minimize the total payment for the reactive power generators [40].

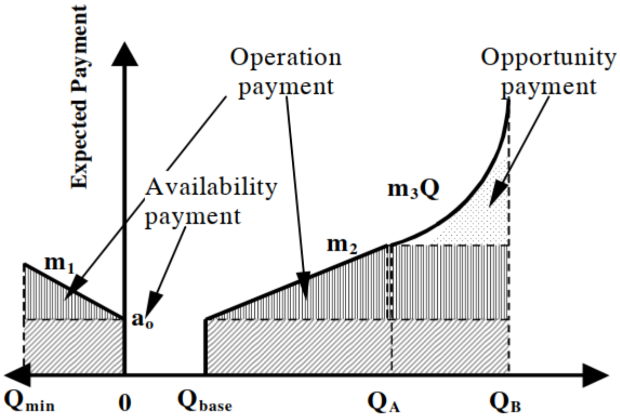


Figure 6: Graphical representation of Expected Payment Function

2.5 Grid connected devices to provide voltage control ancillary services

While the importance of ancillary services to maintain a flexible and reliable power supply was discussed in previous Sections, the different technologies used to provide these services play an important role in enhancing grid stability, improving power quality, and ensuring efficient energy management. Even though this equipment presents in a broad spectrum offering both frequency and non-frequency-based ancillary services, the focus of this chapter will mostly be on a review of the working principles of the power system devices that provide non-frequency-based ancillary services, including STATCOM, SVC, and Synchronous Condensers (SC).

2.5.1 Static Synchronous Compensator (STATCOM)

STATCOM is a shunt-connected compensation device in the Flexible AC Transmission Systems (FACTS) family that utilizes Voltage Source Converters (VSC) for reactive power compensation, dynamic voltage control, and power oscillation damping, ultimately improving the stability of the power system [47][48]. VSC of the STATCOM consists of parallel reverse-blocking diodes and Insulated Gate Bipolar Transistors (IGBTs) in its core [49]. STATCOM is connected to the point of common coupling through a coupling transformer and a reactor, as shown in Figure 7. In Figure 7, $V\angle\theta$ stands for the AC system bus voltage, while $V_c\angle\theta_c$ stands for the STATCOM output voltage. I_c and Q_c represents compensating current and reactive power injected by the STATCOM respectively. jx_T is the STATCOM coupling reactance. V_{dc} and C_{dc} represents DC link voltage and capacitance.

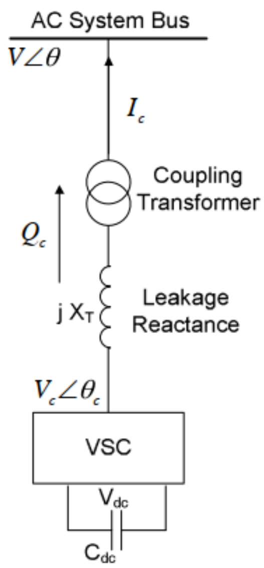


Figure 7: Schematic diagram of a grid connected STATCOM

The STATCOM can be operated in inductive or capacitive modes based on the voltage difference between the grid and the reference [48]. The leading current injected at the PCC by STATCOM supplies reactive power to the grid if a voltage sag is present. Consequently, STATCOM injects a lagging current into the PCC while operating at the inductive state [49]. The advantage of the STATCOM is that it can be fully controlled over its entire output current, even when the system voltage is considerably low [48]. This way, it can provide the maximum reactive power support. This characteristic allows STATCOMs to support to ensure a better LVRT capability as they can still push out maximum reactive current even in low voltage conditions [49]. Further, reactive power generation and absorption from STATCOM are directly proportional to the bus voltage [48], allowing the device to continuously compensate the power system with the right amount of reactive power.

2.5.2 Static Var Compensator (SVC)

The Static Var Compensator (SVC) is also a shunt-connected FACTS device that consists of controllers, including a Thyristor Controlled Reactor (TCR), thyristor-switched capacitor (TSC), and harmonic filters [50]. Even though its response is relatively slower than the STATCOM [51], SVC is capable of dynamic voltage regulation by injecting and absorbing reactive power at the point of common coupling. It is also being used for power factor correction [50]. A schematic diagram of an SVC is shown in Figure 8.

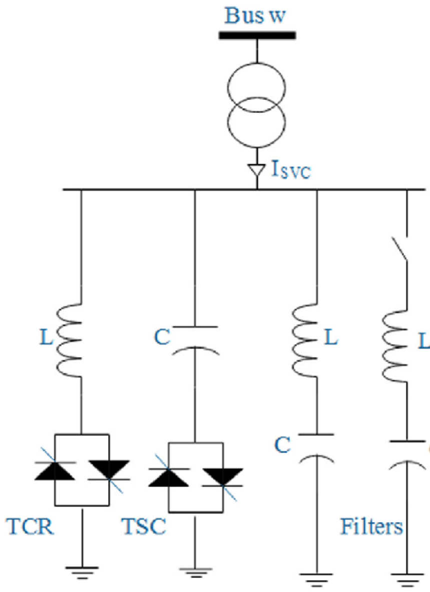


Figure 8: Schematic diagram of a grid connected SVC.

2.5.3 Synchronous Condenser (SC)

A synchronous condenser (SC) is a machine synchronized with the power system but operating idle without a prime mover and any load connected to the drive end. Like a synchronous generator, the SC can supply or absorb reactive power by changing the excitation state to over or under-excitation via varying its field excitation current. Since the SC consists of a rotational mass, and due to the electromagnetic coupling, it is inherently capable of providing inertia to the power system [52]. During a fault condition such as a short circuit, SC acts as a voltage source, and its impedance varies with the time throughout the characteristic periods of the fault: sub-transient, transient, and steady state [53].

Due to these capabilities, SC has historically been adopted by the conventional power system as a device that can provide inertia, dynamic regulation, and enhanced system strength.

2.5.3.1 Renewed Interest in Synchronous Condensers

As the future power system will rely more on non-dispatchable renewable sources, it will be crucial to address the stability challenges arising as the grid becoming weaker with the high penetration of IBRs and other dynamics. Therefore, supporting mechanisms for frequency regulation, dynamic voltage support and short circuit power support will play a crucial role in ensuring the flexibility, stability and reliability of the power system.

Although plenty of devices have been developed to provide these services, as described in the previous section, SCs have gained significant attention from TSOs in recent years due to several inherent characteristics that make SCs superior to other devices such as STATCOMs and SVCs [54]. Unlike power electronic-based devices, which are often designed to provide a single AS (e.g., frequency regulation or reactive power support), SCs simultaneously deliver multiple capabilities. Apart from reactive power compensation, inertia support, and short circuit current contribution, synchronous condensers bring several key advantages, including the fault ride-through capability, which allows them to remain operational during short-term faults, supporting grid resilience, rapid overloading capability, which makes the SC reliable during unexpected grid disturbances, ability to deliver controllable continuous reactive power, and high short term overloading capability while having a relatively low power consumption [4].

SCs can also be customized to meet specific requirements of power system operators such as adding flywheels to the main shaft to increase rotational inertia. These customizations enable operators to optimize the performance of the synchronous condenser for specific grid conditions [4]. Furthermore, one significant benefit is that existing synchronous generators can be converted to SCs if the generator locations are suitable for effectively delivering ancillary services [4]. Utilizing existing infrastructure creates a significant cost benefit on capital investments for operators providing ancillary services. It provides a medium-term solution for the longer delivery time of new SCs due to rapidly increased demand [4][55]. The table 3 presents a performance comparison of SC with STATCOM and SVC.

Table 3: Performance comparison of SC, SVC, and Grid Following (GFL) STATCOM [4]

Solution	VAR Provision	Dynamic VAR Provision	Overload capability	Short Circuit support	Inertia Support
SVC	Weak	Yes	Very Limited	Limited	Very Limited
GFL STATCOM	Strong	Yes	Very Limited	Limited	Very Limited
SC	Strong	Yes	Very High	Very High	Very High

Consequently, this versatility makes SCs a highly effective and reliable solution for modern power systems, especially for the widespread integration of IBRs. As an example, the largest TSO in Australia, Transgrid, is planning to add four synchronous condensers to improve the system strength by the end of 2025. By 2032-33, a total of 29 synchronous condensers are planned to be included in the grid operated by Transgrid to address the grid challenges arising with the IBR integration [55], making it a prime example of the importance of SCs in the future power system.

2.5.3.2 Hybrid Compensation System with Synchronous Condenser

Hybrid compensation systems refer to configurations that combine different technologies, typically synchronous condensers with power electronic-based devices to enhance grid stability and flexibility [56]. A recent hype in hybrid synchronous condensers involves generator models driven by gas turbines that contain a clutch mechanism between the generator and the turbine. This arrangement enables the system to transition between SC operation and power generation mode [55]. When active power is not required from the generator, the clutch allows it to decouple from the turbine, allowing the generator to function as a synchronous condenser to provide necessary ancillary services. This way, the generator can be effectively utilized even when active power is not required. Otherwise, the generator would be completely shut down. The same clutch system allows the generator to reengage into generation mode when active power is required. The Figure 9 shows a block diagram of how a gas turbine is connected with the synchronous generator through a clutch system that allows the generator to seamlessly switch between the generation and synchronous condenser modes.

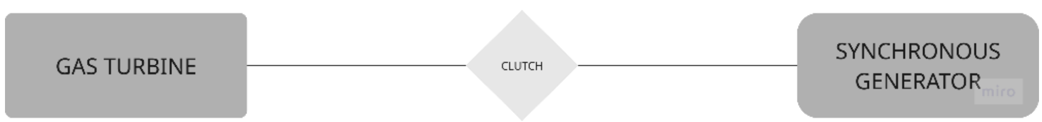


Figure 9: Block diagram of a gas turbine and a synchronous generator connected through a clutch system [55]

2.6 Operating Principles of the Synchronous Condenser

The following Section will focus on two key design and operational parameters of the Synchronous Condensers. It will explain how they contribute to dynamic voltage control by generating and absorbing reactive power and contribute to the system's strength by providing short-circuit power. Being a synchronous machine, the operating principle of a synchronous condenser is similar to other synchronous machines, such as synchronous generators and motors [45].

A three-phase synchronous machine consists of two fundamental components: the armature and the rotor. The rotor windings carry DC, producing a rotating magnetic field inducing voltage in the armature windings. The following equation can determine the induced EMF (Electromotive Force) at the stator winding.

$$\mathrm{E.M.F} = 4.44\ K_c K_d K_f N f \varphi \ \text{ volts/phase} \quad \text{--------}\ (4)$$

Where K_c, K_d, K_f stand for coil span factor, distribution factor and form factor respectively. N represents the number of turns per phase, f represents the frequency in Hz, and φ represents the air gap flux in Wb. According to the above equation, for a particular synchronous machine operating in steady state, the only variable impacts the EMF is the airgap flux, thus closely relates to the reactive power generation. The airgap flux can be represented as a vector sum of the flux produced by the rotating field (φ_f) and the armature flux (φ_s) where the rotating field's flux is imposed by the DC excitation current and load angle. In contrast the armature flux is created by the AC current flowing through stator winding and system power factor [4].

$$\overrightarrow{\varphi_r} = \overrightarrow{\varphi_s} + \overrightarrow{\varphi_f} \quad \text{--------}\ (5)$$

2.6.1 Reactive power generation and absorption by synchronous condenser

In a synchronous machine, control of airgap flux is directly related to its ability to generate and absorb reactive power. The interaction between rotating field flux and armature flux governs this phenomenon. When the synchronous machine is connected to a system with inductive loads, the stator winding current lags the voltage waveform. The lagging current causes the armature flux $\overrightarrow{\varphi_s}$ to oppose the rotating field flux $\overrightarrow{\varphi_f}$ and weakens the air gap flux in the machine $\overrightarrow{\varphi_r}$, leading to a decrease in the induced EMF and terminal voltage. To boost the airgap flux and maintain the terminal voltage, the DC excitation current supplied to the rotor is increased. The increased excitation current enhances $\overrightarrow{\varphi_f}$, compensating for the demagnetizing effect from armature reaction. As a result of this over excitation state, the machine operates with a leading power factor, generating reactive power and supplying it to the power system, thereby maintaining the grid voltage levels and compensating the voltage drops caused by inductive loads [4].

In contrast, when the synchronous machine is connected to an electrical system with capacitive loads, the stator winding current leads the voltage waveform. The leading current causes the armature flux $\overrightarrow{\varphi_s}$ to align the rotating field flux $\overrightarrow{\varphi_f}$ and further strengthen the air gap flux $\overrightarrow{\varphi_r}$ in the machine, leading to an increase in the induced EMF and terminal voltage. To prevent the terminal voltage from rising too high, the DC excitation current supplied to the rotor is reduced. The reduced excitation current lowers the rotating field flux, thereby reducing the airgap flux and the terminal voltage. As a result of this under excitation state, the machine operates with a lagging power factor, absorbing reactive power from the power system. This function helps maintain the grid voltage levels and manage the excessive voltage rises [4].

The amount of reactive power the synchronous machine can provide is typically determined by the thermal limits of the excitation system [4] and reflected by the capability curve. Reactive power control can be achieved through Automatic Voltage Regulators (AVRs) which act on field current of the rotor [55].

2.6.2 Short circuit power support by synchronous condenser

Reducing overall Thevenin equivalent impedance is crucial to enhance the short circuit level of a power system. In practice, the equivalent source impedance decreases when multiple synchronous machines operate in parallel, since their internal reactance combine. Besides the steady-state equivalent circuit, synchronous machines introduce additional reactance (if minor resistance is ignored) during sub-transient and transient levels of the short circuit fault timeline. This additional reactance are parallel and reduce the machine's overall reactance during the transient and sub-transient levels [4]. Figure 10 shows the reactance arrangement of a synchronous machine during steady state, transient, and sub-transient states, respectively. X_a, X_f ,X_{dw} ,X_l Represents armature reactance, field winding reactance, damper winding reactance and leakage flux reactance, respectively.

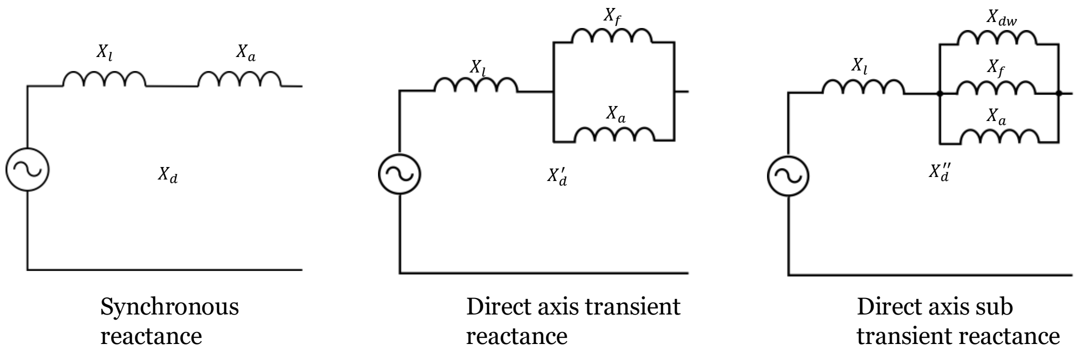


Figure 10: Circuit model for synchronous machines during different fault periods [4]

For instance, the specific reactance X_{dw} introduced at the sub transient stage is due to the damper winding leakage inductance on the d-axis. Within the first few hundred milliseconds following a short circuit fault, this reactance significantly reduces the overall impedance, resulting in a sub-transient fault current typically 5-8 times greater than the machine's rated current [4]. This mechanism is a key contributing factor that enables synchronous condensers to achieve Fault Ride Through (FRT), enhancing short circuit level and maintaining system voltage during disturbances, thereby supporting the ongoing power system dynamics.

3 Research materials and methods

The primary objective of this research is to quantify the synchronous condenser capability of Wärtsilä generator sets in providing reactive power and short-circuit power support when operating as grid-supporting devices under different renewable energy penetration levels and disturbance events. For the simulation purposes Wärtsilä 20V31SG gas engine generator set was chosen.

The simulation is analysed from the power system's perspective and is conducted in two main stages. Initially, a base model is developed based on the IEEE 14 bus system to establish a benchmark for system behaviour. A series of scenario- based simulations was then conducted to evaluate the performance of the generator set operating in synchronous condenser mode under varying levels of IBR penetration, ranging from 30% to 96%. The scenarios were defined specifically to examine how the unit supports grid stability in critical conditions particularly in terms of reactive power injection, absorption and short circuit power support. The following sections outline the research materials, simulation tools and methodologies employed throughout in this study.

3.1 DIgSILENT PowerFactory Simulations

As the simulation involved a complex and dynamic power system, a comprehensive software platform was necessary to ensure the accuracy of modelling and analysis. For this purpose, DIgSILENT PowerFactory was selected. PowerFactory is a computer-aided design and simulation tool, specifically used in the field of electrical engineering for analysing power transmission, distribution an industrial power systems. The acronym 'DIgSILENT' stands for 'DIgital SImuLation and Electrical NeTwork calculation program'. The software combines analytical tools in electrical domain visualization enabling in-depth analysis of power systems and its controls.

DIgSILENT PowerFactory includes a range of functionalities, including load flow analysis, contingency analysis, short-circuit calculations, transient stability analysis, protection coordination, and RMS/EMT analysis. It further consists of inbuilt electrical component models. Within this study, base model of the IEEE 14 bus system, key power system components such as synchronous generators, renewable energy sources, system loads, busbars and transmission lines were obtained from these inbuilt models. The model for Wärtsilä 20V31SG gas engine generator set was custom built in DIgSILENT PowerFactory environment and was available for direct application for the simulation purposes. All the simulations were carried out in RMS mode.

3.2 Configuration of IEEE 14 Bus system Model

The general model of the IEEE 14 bus system represents the simplified version of American power grid as of 1962, consisting of 14 buses, 5 generators and 11 loads [61]. Figure 11 shows the general version of an IEEE 14 bus system. However, necessary modifications were made to the IEEE 14 bus system model which was configured in this thesis.

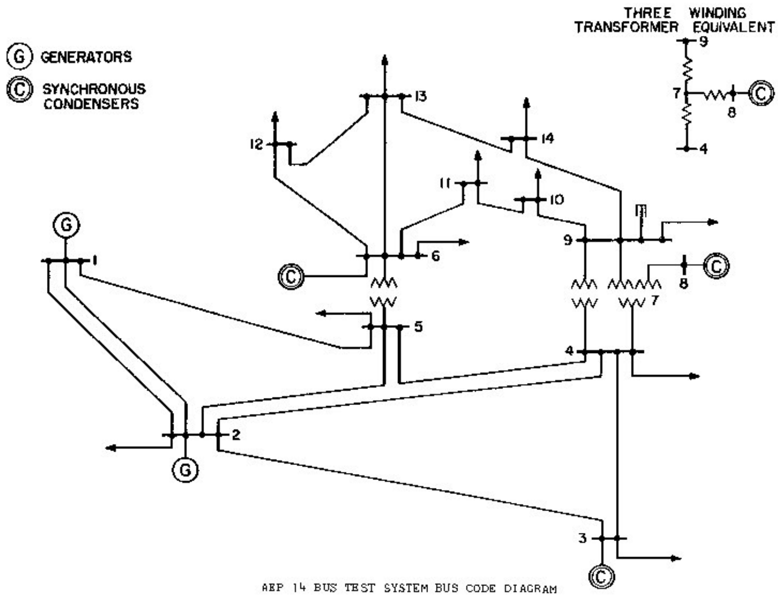


Figure 11: Single line diagram of IEEE 14 Bus system [61]

The simulated power system represents a 10 GW scale power grid operating at 50Hz frequency. The generation mix consists of four types of generators: 47MVA gas turbines, 2MVA WECC Generation 4 wind turbines, Wärtsilä 20V31SG balancers, and 110MVA WECC large-scale solar PV models. Out of these, the Wärtsilä 20V31SG plant was explicitly modelled, and the other models were prebuilt components of the simulation software. The Gas turbine and Wärtsilä 20V31SG plant operated at a power factor 0.8, while the IBR models were configured to operate at a power factor of 0.95. To represent the system loads, a general load model was utilized with a lagging power factor of 0.95. Overall load demand of the system was set to 9.6 GW. The Table 4 describes the distribution of system load demand.

Table 4: Load characteristics of the power system model

Bus Number	Load	
	Real Power (MW)	Reactive Power (Mvar)
2	740	243.2
3	800	262.9
4	850	279.4
5	730	239.9
6	740	243.2
7	900	295.8
9	850	279.4
10	820	269.5
11	780	256.4
12	850	279.4
13	840	276.1
14	730	239.9

The default voltage of busbar terminals was set to 220kV to accommodate the higher capacity of individual power plants. Since the system represents a transmission network, the default two-winding transformers connecting buses 5-6 and 4-9, as well as the three-winding transformer connecting buses 7, 8, and 9, were removed from IEEE 14 bus model. Instead, the buses were connected with transmission lines to maintain a uniform 220kV voltage across the system. For each busbar, a steady state voltage limit of $\pm$10% was assigned. Out of the 14 buses, bus 5, 7, 10, 11, and 13 were PQ buses (Active and Reactive power magnitudes are specified) while the rest of the buses were PV buses (Active power and voltage magnitudes are specified).

All 14 busbars were connected to overhead transmission lines with a rated voltage of 220kV and a rated current of 2kA. As the system represents a large power system at the scale of a country, the line distances were selected accordingly. The Table 5 shows the selected line distances along with the positive sequence resistance, positive sequence reactance and positive sequence capacitive susceptance for each transmission line segment.

Table 5: Line characteristics of the power system model

Line		Line Length (km)	R (Ohm/km)	X (Ohm/km)	B (µS/km)
From bus	To bus				
1	2	100	0.030	0.31	4.0
1	5	125	0.022	0.30	4.2
2	3	150	0.024	0.33	3.9
2	4	75	0.018	0.26	3.2
2	5	75	0.025	0.34	3.5

Line		Line Length (km)	R (Ohm/km)	X (Ohm/km)	B (μS/km)
From bus	To bus				
3	4	50	0.030	0.31	4.0
4	5	50	0.024	0.33	3.9
4	7	75	0.018	0.26	3.2
4	9	150	0.022	0.30	4.2
5	6	75	0.025	0.34	3.5
6	11	60	0.020	0.28	3.8
6	12	60	0.024	0.33	3.9
6	13	150	0.030	0.31	4.0
7	8	75	0.022	0.30	4.2
7	9	100	0.018	0.26	3.2
9	10	80	0.025	0.34	3.5
9	14	140	0.020	0.28	3.8
10	11	75	0.024	0.33	3.9
12	13	90	0.030	0.31	4.0
13	14	110	0.025	0.34	3.5

The nominal terminal voltage of all conventional generators in the model is 11kV. Renewable generators have a nominal terminal voltage of 690V. The generators connect to the transmission network through two winding, OLTC (On Load Tap Changer) step up transformers with YNd1 vector groups. Considering 80% loading for a transformer, different transformer capacities were defined where gas turbines use 62MVA transformers, renewable generators use 400MVA transformers, while Wärtsilä plants use 21MVA transformers. Tap setting of all transformers range from -8 to +8 steps with 1.25% change in the voltage between two steps.

3.3 Control of reactive power in a Synchronous Generator

The control of reactive power of a Synchronous Generator is explained in this section, referring to the control system of Wärtsilä 20V31SG gas turbine generator set. The machine controls the reactive power generation and absorption through a sophisticated control system consisting of ABB UNITROL 1000 Automatic Voltage Regulator (AVR) system. Figure 13 demonstrates the complete surface control diagram for the generator set.

UNITROL 1000 AVR is the primary component responsible for directly adjusting the reactive power of the generator by controlling the excitation current supplied to the field winding of the synchronous generator, which is represented as GEN W2 in the diagram in Figure 13. When the excitation is increased, the generator operates in an overexcited mode, injecting reactive power into the Point of Common Coupling (PCC). On the contrary, reducing excitation brings the machine into an under excited state, enabling it to absorb reactive power from the power system.

According to the block diagram in Figure 13, the UNITROL 1000 excitation system receives several real-time measurement data from GEN W2, such as per unit terminal voltage of the generator (U_gen_pu), field current (Ifd_pu) , and reference signals such as reference voltage (U_ref) and reactive power setpoint (Qsetpoint) through the PPC (Power Plant Controller) interface. UNITROL then compares the reference values to the actual measured values to calculate an error. This error is then processed through a set of internal control algorithms involving PID controllers to determine the appropriate value for the field voltage E_{fd} to apply to the generator's rotor. Depending on the UNITROL output E_{fd} , the rotor's magnetic field is changed, thereby influencing the generator terminal voltage and reactive power flow.

3.3.1 Converting Wärtsilä 20V31SG gas turbine generator into a Synchronous Condenser

The simulation stage will assess the non-frequency ancillary service contribution in three distinct operational stages of Wärtsilä 20V31SG generator set. One of the operational cases is majority of the Wärtsilä plant models are acting fully in synchronous condenser mode. In normal operating conditions, the plants are operating in synchronous generator mode while partially contributing to reactive power compensation. Therefore, for the machine to enter fully into synchronous condenser mode, it has to be decoupled from its prime mover via a clutch system implemented between the synchronous generator and the gas turbine.

In PowerFactory simulation environment, this conversion was achieved by modifying specific control parameters in the generator model block. In the configuration window, the generator type was changed to synchronous condenser. In generator control system, UNIC, Fuel Control, Engine and Coupling blocks were set as 'Out of Service' to ensure that the generator is no longer connected to mechanical power input. Additionally, the generators intended to operate as synchronous condensers, were removed from the Power Frequency Controller as the machines aren't supposed to inject active power to the power system. Once these modifications were implemented, the Wärtsilä 20V31SG plants were fully transitioned into synchronous condenser mode, entirely providing reactive power compensation to the system. Figure 12 illustrates Wärtsilä 20V31SG plants operating as synchronous generators compared to their operation as synchronous condensers.

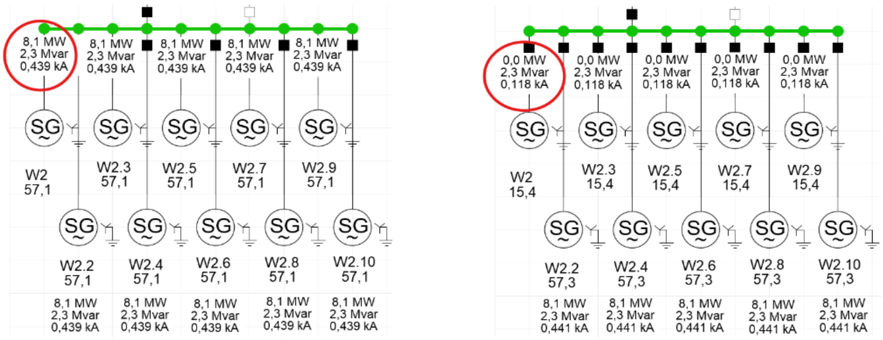


Figure 12: Synchronous generator operation vs Synchronous Condenser operation of Wärtsilä plants

3.4 Configuration of Simulation Base Model

The base system is configured with the load and line characteristics described in Section 3.2 and considering a 30% share of IBR resources in the generation mix. The total installed capacity for the base system was 15.5 GVA comprising 228 units of 47 MVA gas turbines, 20 units of Wärtsilä 20V31SG plants, 1000 units of 2 MVA type 4 wind turbine units and 24: 110 MVA solar PV plants. The base system was intended to showcase present-day power system taking 30% renewable penetration level as a norm.

Considering the scale of the system and the number of generation units included, it was difficult to connect all the generators as single units to the network model. Therefore, to reduce the system complexity, ‘parallel machines’ function was used. Parallel machines function is a feature in PowerFactory that allows the simulation of two or more identical machines operating in parallel, using a single power plant model. When parallel machines are assigned to a power plant model, the software internally scales the total impedance, MVA rating, and inertia constants accordingly. However, controllers of the customized model of Wärtsilä 20V31SG plant did not support the parallel machine’s function and had to be connected to the generator terminal as separate machines. Figure 14 illustrates the constructed IEEE 14 bus base system.

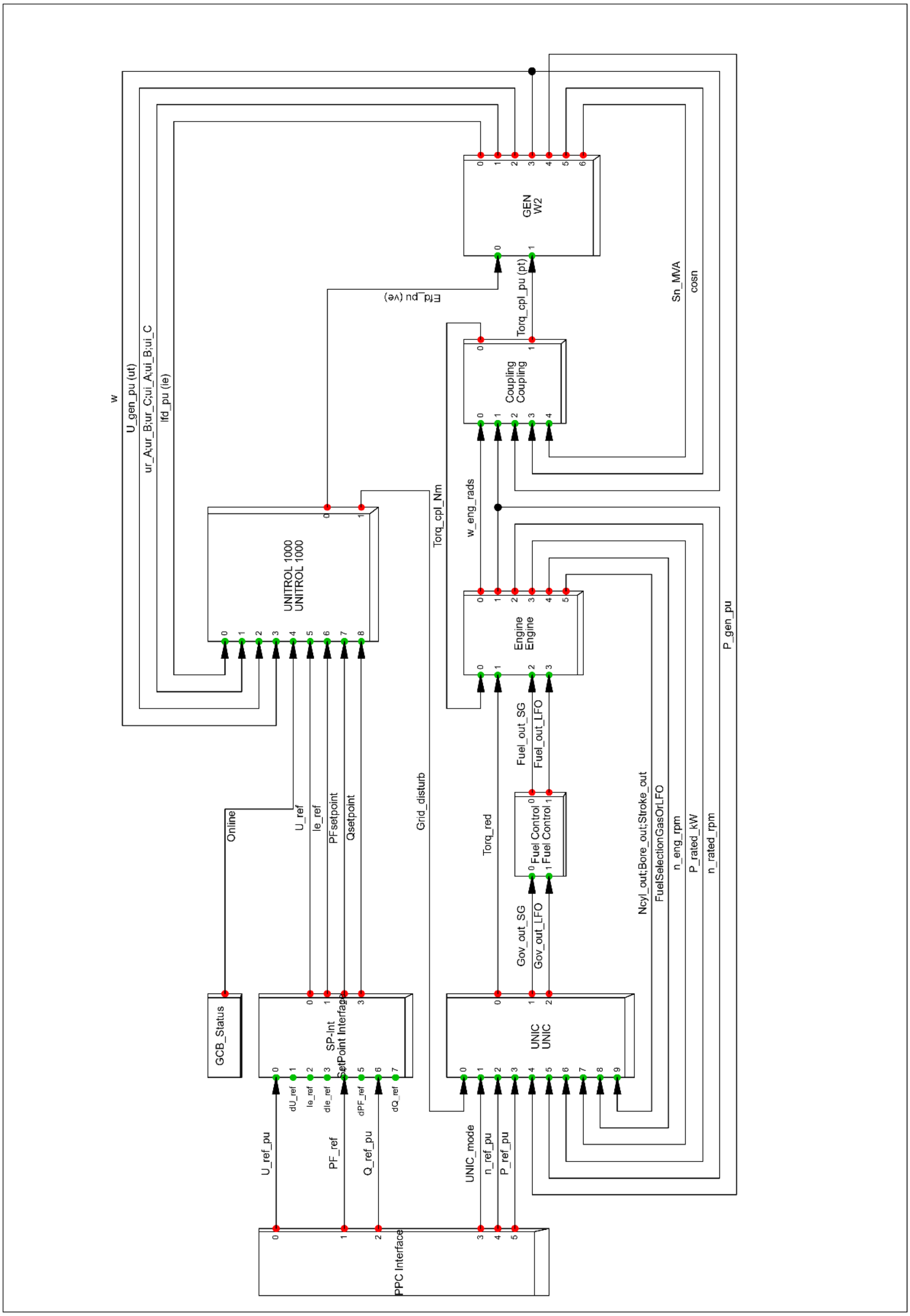


Figure 13: Control diagram of Wärtsilä 20V31SG Balancer.

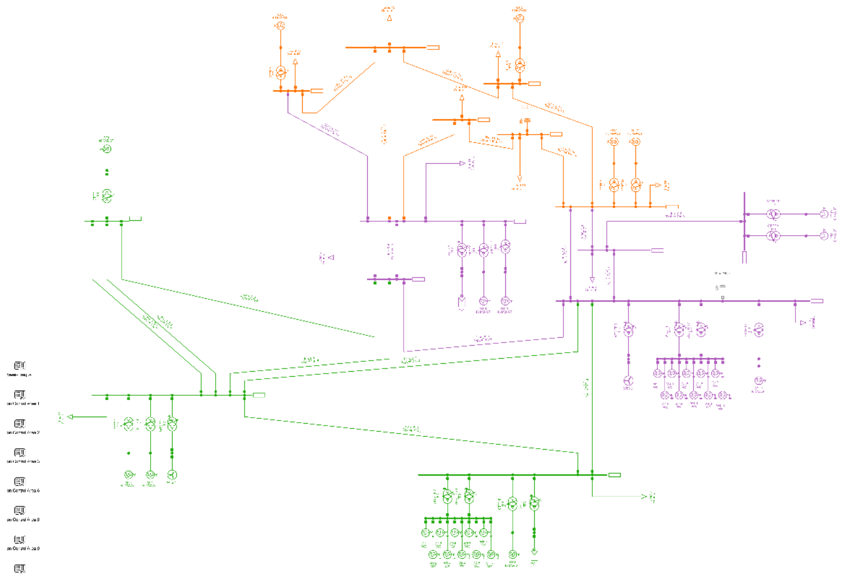


Figure 14: Configured base system for simulations

3.4.1 Control of frequency and reactive power in the system

In PowerFactory, two types of controllers are employed to dynamically adjust the active power output, frequency, and reactive power. They are Power Frequency controller and Station Controller. Power Frequency controllers are designed to maintain the stability of the simulated power grid by regulating the electrical power and frequency. Since the frequency is a global parameter throughout the power grid, only one controller is required to achieve the power-frequency regulation in the system. In contrast, more than one station controller is required to achieve the voltage control throughout the system due to the location sensitivity of reactive power.

3.4.1.1 Configuration of Power Frequency Controller

Once the generators are connected to their respective busbars, the power frequency controller was implemented using the graphical tools available within PowerFactory's project interface. All the generators, including the renewable sources, were then linked to the controller. Several parameters including control mode, busbar for frequency measurement, and active power distribution modes needed to be considered during the configuration phase of the Power Frequency Controller. For this study, the control mode was selected as Frequency Control, which directly responds to frequency deviations in the system by adjusting the active power output of the generators. Busbar 2 was set as the measurement bus bar, while the Individual Active Power option was selected for active power distribution. The reason for selecting the Individual Active Power option is to ensure that intended percentage power output criteria are met for IBR sources in different stages of the simulation.

3.4.1.2 Configuration of Station Controller

Considering the longer distance between busbars in the system, and the location sensitivity of reactive power distribution, it was decided to implement a dedicated station controller for each generation busbar to regulate the voltage locally. Once the generators were assigned to the station controller, key parameters were adjusted in the load flow section, of the station controller configuration menu. Specifically, the controlled node was set as the local busbar for each controller, as the goal was to regulate the voltage at the PCC.

When there is more than one power plant connected to the busbar, each capable of controlling busbar voltage, it becomes essential to coordinate their reactive power contributions to avoid undesirable interactions. To achieve this, droop control was enabled in each station control. This ensures coordinated reactive power sharing among the generators. If all voltage regulating units attempt to control busbar voltage independently without a presence of droop control, they may act against each other. This may potentially result in oscillatory or conflicting reactive power injections. Consequently, droop control introduces a linear voltage-reactive power characteristic, ensuring each unit adjusts their reactive power contribution proportionally to the reference voltage deviation.

3.5 Configuration of Power System Models with Varying IBR Shares

Several changes have been made to the base model to derive the systems having IBR penetration of 50%, 75%, and 96%. Total number of grid-connected 46 MVA gas turbines in the base case were 228 units. It was reduced by 30% in the 50% IBR share model and completely retired in the 96% IBR share model. The number of Wärtsilä gas turbine plants was increased as the IBR share increased, to ensure impactful and measurable grid support is provided. In the 96% IBR share scenario, the only grid connected conventional generator was the Wärtsilä 20V31SG gas turbine generator. However, in this scenario, the same number of 46 MVA gas turbines used in the 75% scenario were kept as backup, as battery energy supply systems were not considered in these simulations. Furthermore, to ensure sufficient reactive power is available throughout the system, few Static Var Systems, each with 100 MVAr capacity were implemented on busbars 4, 7, 8, and 10. The Annexure 1 provides a comprehensive description of the generation mix in each power system model variant constructed with 30% IBR penetration to 96% IBR penetration. Images of the constructed power system models are demonstrated in Annexure 2.

3.6 Disturbance types and methods

To evaluate the dynamic behaviour of the constructed power systems with the reactive power and short-circuit power support from the Wärtsilä 20V31SG machines, several disturbance events were introduced. These disturbance scenarios included a three-phase-to-earth fault, switching incident involving a large load and switching event involving a large renewable source. All events were applied at busbar 3; a generation node hosting a large solar PV plant, a significantly large load, and a gas turbine plant.

The disturbance events were configured using Power Factory's time domain simulation event setup environment, which provides dedicated event objects for modelling system perturbations. As an example, the switching event for the large load was modelled using the 'Switch Event' object in the simulation event setup, which enabled precise opening and closing of the load's breaker switch during time domain simulation. Execution time field was used to define the moment at which the switching event triggers once the RMS simulation starts running.

3.7 Structure of the Simulation

The simulation was structured to have three main stages. Initially, a load flow analysis was conducted for the base system as well as for the systems with different levels of IBR penetration. Following this step, an N-1 contingency analysis was performed to assess the system's resilience against single element outages.

Once the systems are satisfied with contingency and power flow analysis for a stable system, a dV/dQ sensitivity analysis was conducted on the selected bus to assess the impact of the Wärtsilä 20V31SG plant for local voltage control. The motivation behind the sensitivity analysis was the practical modelling constraint explained in Section 3.4. Since the Wärtsila 20V31SG plant model did not support parallel machine function, the plants had to be connected to the grid as individual machines. This creates a significant complexity to the simulation configurations if higher plant capacities are considered. Therefore, the overall capacity of Wärtsilä plants had to be kept relatively smaller compared to the rest of the energy sources and loads in the system. Therefore, it was crucial to conduct a dV/dQ sensitivity analysis to evaluate whether the reactive power contribution from Wärtsilä 20V31SG plants were sufficiently impactful at the considered busbar.

If the sensitivity analysis confirms that Wärtsilä 20V31SG plants demonstrate a significant sensitivity to the deviations in busbar voltage, then the study proceeds into the scenario based dynamic analysis. The scenario analysis was structured into three distinct operational cases. First, the generators operate under normal conditions in active power generation mode, allowing their natural reactive power contribution to be evaluated during disturbances. The second operational scenario considers the partial curtailment of Wärtsilä 20V31SG plants following merit-order dispatch due to high IBR penetration. The final operational scenario considers a grid support focused operation of Wärtsilä plants during high IBR penetration. Instead of curtailing the plants as in the previous scenario, the units here are not shut down entirely; Instead, they are switched fully into synchronous condenser mode using the clutch system. Once switched, the units disengage with the active power path while retaining reactive power capabilities. This scenario enables the evaluation of the potential benefit of repurposing the conventional generators (In this case, the Wärtsilä 20V31SG plants) as grid supporting units in non-frequency ancillary markets instead of idling them in high IBR penetrating situations in the power system.

The Annexure 3 lists down the set of simulations performed according to the operational and disturbance scenarios described above. All the simulations were performed in RMS Mode in PowerFactory.

4 Results and Analysis

The results were generated following the simulation structure mentioned in Section 3.9 through DIgSILENT PowerFactory software.

4.1 Load flow and N-1 Contingency analysis under different renewable energy shares

Load flow calculation was executed starting from the base case and extending through the power system models with different IBR share. The method used for load flow calculation was the Newton-Raphson method. The primary purpose of this analysis was to verify that the system remains within it's operational limits under steady state conditions. Parameters such as busbar voltage profiles, generator loading, and reactive power compensation were evaluated during the analysis.

As the IBR share increased in the system and conventional generators, typically responsible for providing local reactive power were displaced, additional compensation modes were introduced for the busbars that are further away from the generator buses. System loads were unchanged in all grid variants. Table 6 presents a summary of the load flow analysis across all power system models variants.

Table 6: Load Flow Analysis Results for the created power system models.

Scenario	Minimum Bus Voltage (P.U)	Maximum Bus Voltage (P.U)	Total Reactive Power Compensation (MVAr)	Additional Compensation (MVAr)	Maximum Loading (%)
Base case	0,981	1,017	3098,1	517,2	77,8
IBR 50%	0,985	1,015	2726	515,6	77
IBR 75%	0,985	1,015	2983	515,1	78
IBR 96%	0,980	1,02	2584	996	78,7

According to the results summary in Table 6, all four power system variants satisfy the set voltage limits of 0.9 P. U. – 1.10 P. U. The total reactive power compensation is supplied collectively by conventional generators with a power factor of 0.8, IBRs with a power factor of 0.95, and on load tap changing transformers as well. As the share of IBRs increases in the power system, the total reactive power availability in the system decreases, even though the active power levels remain unchanged. When the system moves from 75% to 96% IBR penetration, capacity of the Static Var Systems (SVS) deployed to counteract the deficit in reactive power, had to be nearly doubled. Due to the sufficient reactive power compensation from primary and secondary sources, the system loading remains well below 80% during the steady-state operation despite shifts in the IBR share. Figure 15 shows the visual evidence of thermal loading of the IBR 75% system during the load flow analysis. The colour green indicates the system is well within the thermal loading limits. If the system is getting overloaded, the colour deviates towards red.

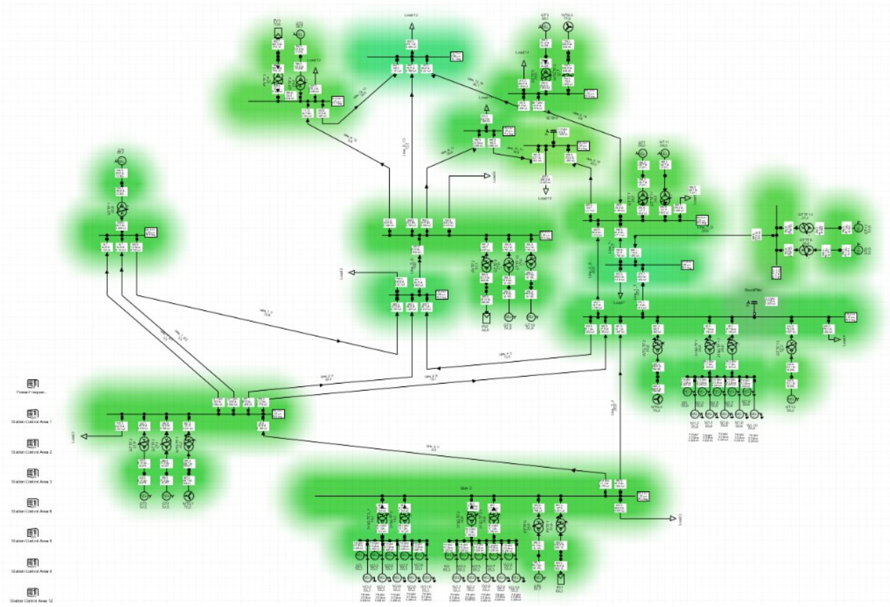


Figure 15: Heat map indicating thermal loading of 75% IBR share power system during the load flow calculation.

4.1.1 n-1 contingency analysis

The N-1 contingency analysis was conducted across all four system variants to assess the operational security under realistic stress conditions. Every possible contingent scenario, including loss of a generator, transmission line, and busbar was considered for the analysis. The voltage profiles of the busbars and the thermal loading of the system components, including power transformers and generators were also measured. Table 7 summarises the results obtained during the contingency analysis.

Table 7: N-1 Contingency Analysis Results

Scenario	Maximum Post contingency voltage drops (P.U)	Number of Buses <0,9 P.U post contingency voltage	Maximum Generator Loading (%)
Base case	0,0540	0	91,2
IBR 50%	0,0369	0	94
IBR 75%	0,0700	1	112,4
IBR 96%	0,1680	6	115,9

The results highlight a significant impact on voltage stability and generator loading as the IBR share increases in the system. In both 30% and 50% IBR share scenarios, there was no significant voltage drop following a contingency, and no buses fell below 0.9 P. U. for post-contingency voltage. Generator loading was also below 95% in these two scenarios. However, as the IBR share rises to 96%, the maximum post contingency voltage drops in the system increases by 67%, and 6 buses are violating 0.9 P. U. margin. Maximum generator loading after a contingency also increases up to 115.9%. These results suggest that the power system becomes increasingly sensitive to single element outages due to the depletion of dynamic reactive power support from conventional resources as the IBR share increases.

4.2 Evaluation of reactive power potential by dV/dQ Analysis

Prior to conducting the scenario-based simulation, it was crucial to determine the effectiveness of the Wärtsilä 20V31SG generator sets connected to the busbar selected for the study. For this purpose, busbar 3 was selected. As discussed in Chapter 3.7, a voltage sensitivity analysis was performed using the dV/dQ approach to quantify the localized influence of reactive power injection on voltage magnitude. The dV/dQ calculation provides a linearized matrix of how responsive the voltage at a particular bus is to the incremental reactive power injection.

The figure 16 shows the results of the dV/dQ sensitivity analysis, plotted against the four IBR share variants considered in the study. The values indicate the sensitivity to 1 Mvar reactive power injection from the three generators connected to the busbar 3: the Wärtsilä 20V31SG unit, the gas turbine unit and the solar PV unit. As the IBR penetration increases, it can be seen that the sensitivity of the Wärtsilä plant becomes more effective as the IBR share rises from 30% to 96%. However, the PV plant consistently shows the highest sensitivity, peaking at −5.33E−05 P.U./Mvar in the 96% case, suggesting high voltage vulnerability in inverter-dominated systems.

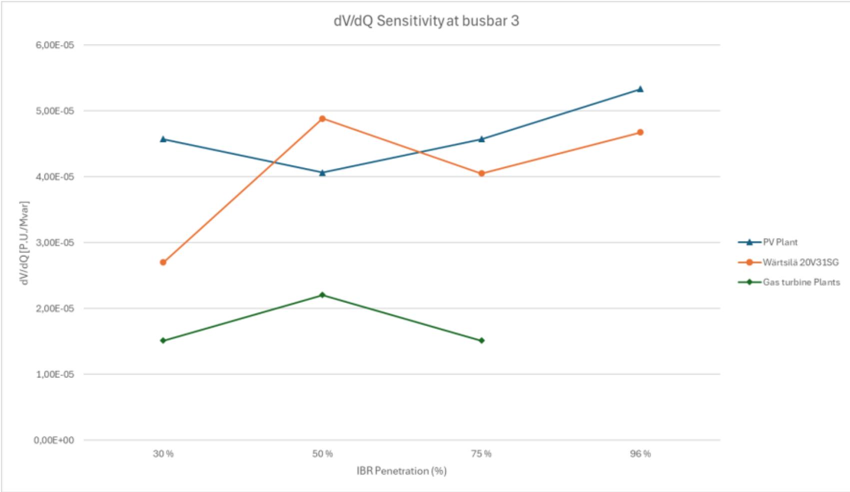


Figure 16: dV/dQ Sensitivity at Busbar 3 vs IBR share in the power system

It can also be seen that the absolute values of the sensitivities are relatively small. This may have been caused due to closer electrical distance of busbar 3 to the large generators and low network impedance around busbar 3. Overall, the sensitivity analysis considers a linear approach in the system. However, to evaluate the power system's behaviour in nonlinear interactions and to better quantify the reactive power compensation from Wärtsilä plants under varying operating conditions, conducting a dynamic analysis would be essential.

4.3 Overview of Simulation Scenarios

Busbar 3 of all the constructed models were tested against the pre-defined scenarios, including three-phase-to-earth short-circuit fault, a sudden load switching event and a renewable energy plant switching event. Time duration for each simulation scenario was 30 seconds. In the load switching scenario, the breakers of the load were tripped at the 3rd second and closed again at the 12th second. Three-phase-to-earth short circuit scenario lasted for 150ms, starting from the 3rd second. Meanwhile, the PV plant connected to busbar 3 was tripped at the 3rd second and switched back at the 10th second of the simulation. Graphs related to the voltage behaviour of bus bar 3 and reactive power compensation of Wärtsilä 20V31SG gas turbine generators were obtained as results of the simulation.

Table 8: Simulation summary

Disturbance Type	Simulation Status											
	IBR 30%			IBR 50%			IBR 75%			IBR 96%		
	Normal Operation	Capacity Curtailment	SynCon mode	Normal Operation	Capacity Curtailment	SynCon mode	Normal Operation	Capacity Curtailment	SynCon mode	Normal Operation	Capacity Curtailment	SynCon mode
Three Phase to Earth Fault	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Collapse	Collapse	Collapse
PV Plant Switching	Stable	Stable	Stable	Stable	Collapse	Collapse	Stable	Stable	Stable	Collapse	Collapse	Collapse
Large Load switching	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Collapse	Collapse	Collapse

As shown in Table 8 above, the system can maintain stability during the disturbances up to 75% of IBR presence in the power system in majority of the scenarios. Beyond this point, the system tends to collapse immediately after the disturbance is triggered. The primary reason for this is that, due to the reduced share of conventional operation, the power system fails to maintain sufficient voltage support at busbar 3. This initiates a cascading effect throughout the power system resulting in subsequent generators to trip and ultimately leading to systemwide instability. Furthermore, the reactive power compensation from Wärtsilä plants becomes negligible under high IBR penetration, primarily due to their relatively smaller capacity compared to overall loads and IBR capacity. Although the SVSs are deployed to support voltage regulation in the system, they also appear to be inadequate in resisting rapid voltage fluctuations.

4.4 Scenario 1: Load Switching

4.4.1 Voltage response during load disconnection and reconnection

Figure 24 demonstrates the busbar 3 voltage profile during the load switching event of the base model. Once the load is disconnected from the busbar, a sudden voltage spike can be observed, reaching up to approximately 225.8 kV. This voltage transient appears due to the sudden reduction in reactive power demand in the busbar following the load disconnection. The spike is then followed by a high-frequency damped oscillation until the voltage is partially stabilized around 222 kV, until the load is reconnected at the 12th second. A sudden voltage dip occurs as the load reconnects, dropping the busbar voltage below 218 kV. However, due to the adequate reactive power support and damping capability of the system, the voltage recovers and converges smoothly towards pre fault voltage levels.

As the IBR penetration increases in the system, busbar 3 voltage profile exhibits deeper voltage spikes, dips and slow recovery due to the reduced availability of synchronous inertia and short-circuit strength. In Figure 17, the voltages show a slight overshoot above 220 kV level after the load is reconnected, which then followed by damping oscillations. In contrast, at 50% and 75% IBR cases, the voltage remains below the nominal voltage levels converging slowly and without an overshoot.

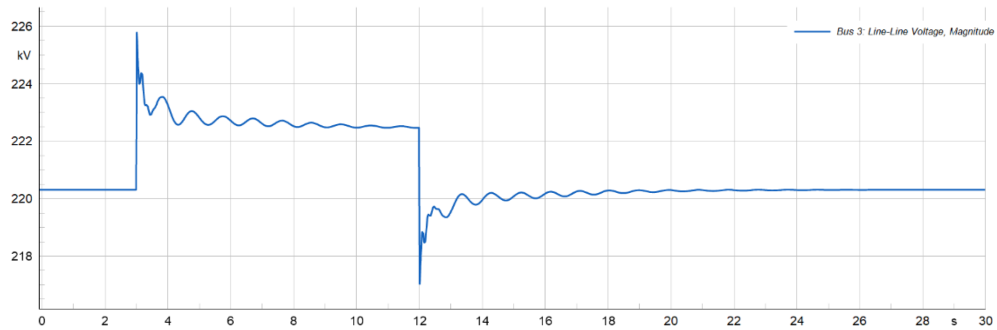
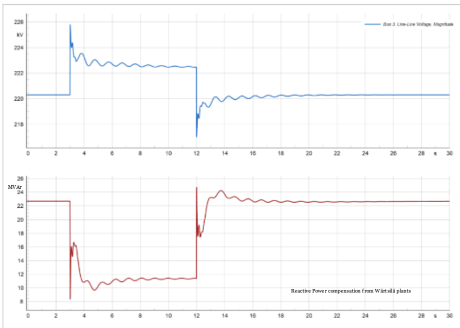


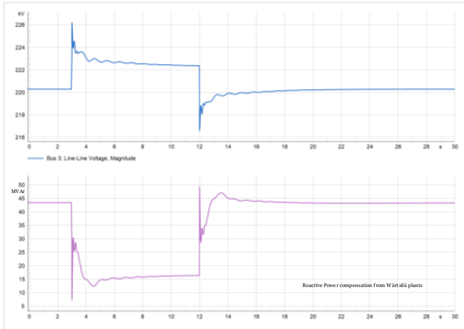
Figure 17: Busbar 3 voltage profile during the load switch event

4.4.2 Reactive Power behaviour of Wartsila Power plant units

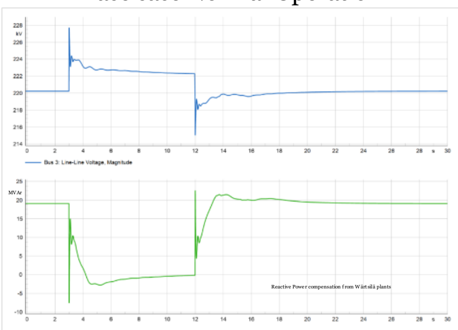
Even though the reactive power support in busbar 3 is mainly provided by a larger conventional and IBR plant, Wärtsilä power plants play an important role in voltage stabilization, especially under increased penetration of IBRs. Across all the study scenarios analysed, Wärtsilä power plants dynamically adapt the reactive power compensation depending on its operational mode and the IBR share of the power system. This behaviour is illustrated in Figure 18.



Base case Normal Operation



50% IBR case SC Operation



75% IBR case Curtailed Operation

Figure 18: Dynamic reactive power compensation behaviour of Wärtsilä Plants during load switch event under different IBR levels and operation cases.

In base case, where system inertia and fault levels are relatively high, Wärtsilä plants do not make a significant contribution for the voltage regulation. As the IBR share rises to 50% and 75%, the size of Wärtsila Plants is doubled, in order to enhance the reactive power support amidst the declining presence of synchronous machines in the system. In these scenarios, the plant's role becomes more visible, especially when the plants are fully operating in synchronous condenser mode. This reactive power behaviour is summarized in Figure 19, considering the peak reactive power injection from Wärtsilä plants across three IBR shares under all operation modes.

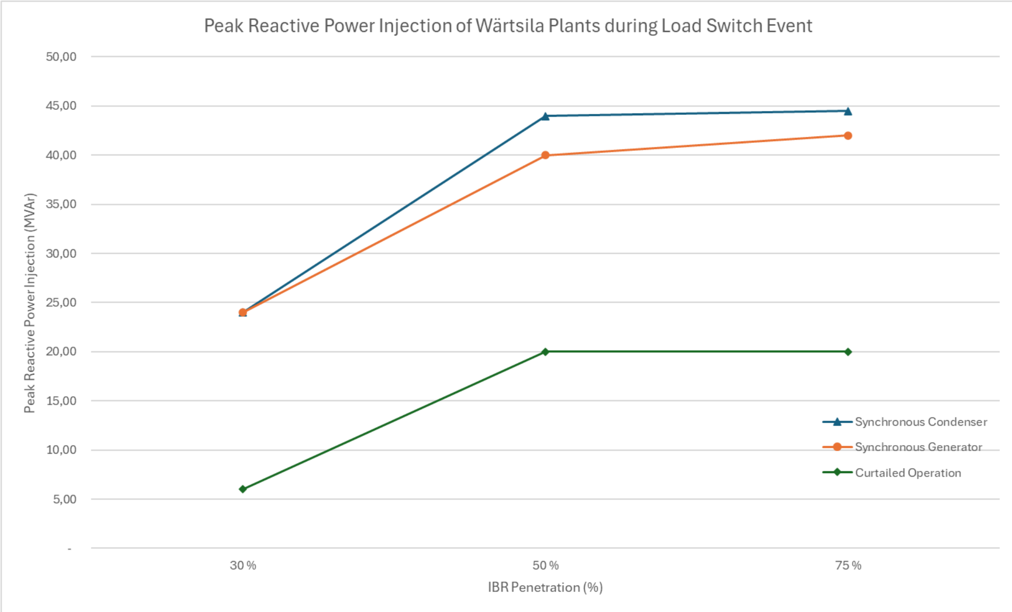


Figure 19: Change in Peak reactive power injection of Wärtsilä plants under different IBR shares and operation cases.

As shown in Figure 19, a clear reduction in reactive power contribution can be observed in the scenarios where the Wärtsilä plants are curtailed due to high IBR penetration. In 50% and 75% cases, there's an increase in the peak reactive power injection when a set of plants is operating fully as synchronous condensers compared to the normal operation. However, this improvement remains modest as the reactive power is distributed through a station controller in both cases. Regardless of whether the machines are operating as a generator or a synchronous condenser, the station controller dynamically distributes the reactive power requirement across all the available machines, without maximizing the reactive power support from individual machines.

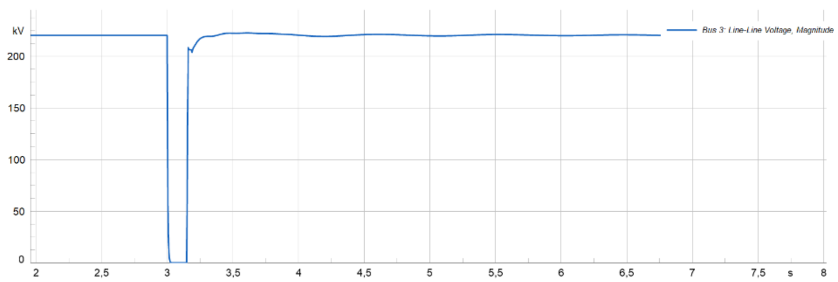
In 96% IBR case, the system fails to remain stability following the disturbance, and the busbar voltage collapses rapidly, triggering a cascading effect in the system. As the only available conventional reactive power source, Wärtsilä power plant units inject a large reactive power transient up to 480 MVAr soon after the disturbance. However, the rate of voltage change exceeds the reactive power capability of the power plants, and the amount of reactive power is further limited due to the relatively smaller size of the power plant.

4.5 Scenario 2: Three Phase to Earth Fault

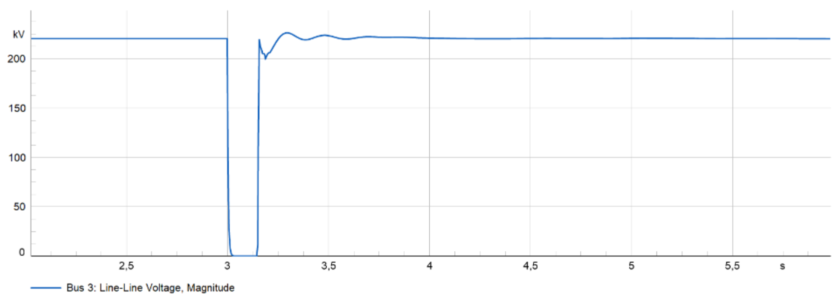
4.5.1 Voltage response during load Three Phase to Earth fault

The three-phase-to-earth fault is the most severe disturbance type simulated in this analysis. As illustrated in Figure 20, when the fault is triggered at t = 3s, the busbar 3 voltage experiences a drastic collapse to nearly 0 kV from its nominal state of 220 kV. The voltage remains close to zero during the entire fault period and once the fault is cleared after 150ms, it recovers sharply and exhibits a slight overshoot (in base case) and settles close to the pre-fault voltage level within a few seconds.

However, as the IBR share rises, the post-fault voltage recovery becomes relatively unstable. At 75% IBR share the post fault voltage overshoot becomes more visible, and more pronounced transient can be observed. In 96% IBR scenario, the system fails to maintain voltage stability following the short circuit failure. As illustrated in Figure 23, the voltage at busbar 3 recovers only partially and remains significantly depressed, indicating the weakened damping and LVRT capability of the high IBR systems.



Busbar 3 Voltage profile during short circuit fault in base case



Busbar 3 Voltage profile during short circuit fault in 75% IBR case

Figure 20: Voltage profiles of the base and IBR 75% systems during short circuit fault.

4.5.2 Reactive Power behaviour of Wartsila Power plant units

In the base case scenario, it can be noticed that the system strength is sufficient to withstand the fault. The system exhibits well-damped, prompt post-fault voltage recovery across all operating modes of Wärtsilä plants. As illustrated in the Figure 21, the voltage at busbar 3 returns to its nominal pre-fault limit within 2 to 3 seconds after the fault is cleared. The Wärtsilä plants contribute to this voltage recovery by a rapid reactive power injection during the fault, which is close to 160 MVAr in either synchronous generator or synchronous condenser operating modes. Even though the reactive power injection during fault drops close to 63 MVAr when set of generators are curtailed in Wärtsilä plant, the power system strength and the reactive power contribution from other connected power plants remain adequate to support voltage recovery. The reactive power absorption during the fault clearing remains around 60 MVAr in all the operating modes.

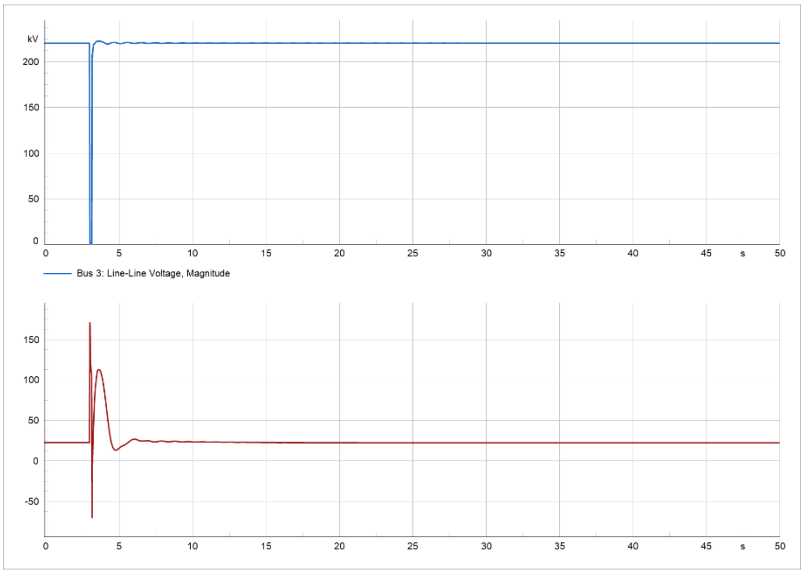


Figure 21: Reactive power compensation of Wärtsilä plants during short circuit fault at base case.

As the IBR share rises in the system, few notable changes can be observed. At 50% IBR penetration level, the reactive power injection from Wärtsilä power plant at synchronous generator mode outperforms the reactive power injection at synchronous condenser mode. Consequently, the trend reverses at the 75% IBR penetration level, where the synchronous condenser mode contributes to slightly higher reactive power injection than the synchronous generator mode. The potential reason for this difference is due to the excitation dynamics and the station controller behaviour during each scenario.

Unlike the base system, which has a higher short-circuit strength, the 50% IBR model experiences reduced strength, resulting in a sharper voltage dip during the fault, that demands a rapid surge of reactive power. This triggers a more aggressive response from the excitation system. In this instance, the synchronous generator has an advantage, as the mechanical torque and active power output helps to maintain a certain level of terminal voltage. Thus, it allows the Automatic Voltage Regulator (AVR) to increase the excitation current without immediately reaching the field current limit. In contrast, machines operating in synchronous condenser mode lacks the mechanical torque and active power generation, leading to a more significant drop in terminal voltage during the fault, which limits the amount of reactive power injected before reaching the field current limit.

The system becomes increasingly weaker as it reaches 75% IBR penetration level, due to the reduced short-circuit capacity resulting from greater IBR dominance. When a short-circuit fault occurs in such system, a significant stress is imposed on the synchronous machines when they are operating in synchronous generator mode, as the system simultaneously demands for larger amount of reactive power and active power. This compound electrical loading drags the machine closer to its thermal and field current limits, thereby limiting the reactive power injection capability. However, when the machine is functioning as a synchronous condenser, it operates without active power constraints, allowing the AVR to fully utilize the machine's capability to inject reactive power to the system. Figure 22 illustrates the peak reactive power compensation of Wärtsilä power plants in each operating mode as the IBR level increases in the system.

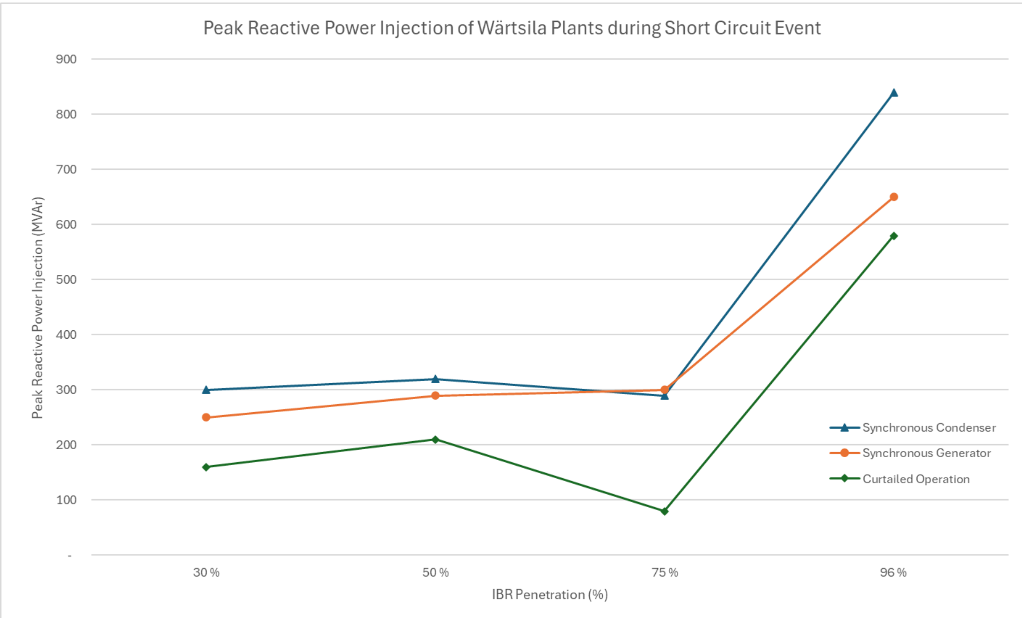


Figure 22: Peak reactive power injection of Wärtsilä plants during short circuit fault across different IBR share systems

At 96% IBR scenario, as demonstrated in Figure 23, the system fails to withstand the severe impact from the three-phase to earth fault, despite the reactive power contribution from Wärtsilä plants across all operational modes. The Main reason for this behaviour could be the relatively smaller size of the Wärtsilä plants, which are the only conventional energy source in this scenario. The lack of other forms of grid-supporting mechanisms such as STATCOMs, SVCs, and Capacitor Banks, may have further enhanced the system's vulnerability to extreme fault conditions.

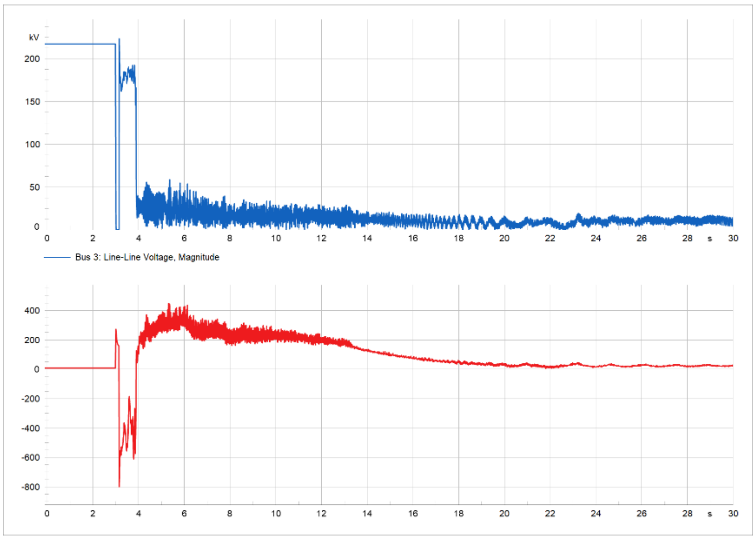


Figure 23: Reactive power compensation of Wärtsilä plants during short circuit fault at 96% IBR case.

4.6 Scenario 3: IBR plant switching

4.6.1 Voltage response during load disconnection and reconnection

The switching event of the large-scale solar PV plant connected to busbar 3 occurred, starting at t= 3 s, where the plant was disconnected, and at t= 10 s the plant was connected back to the system. The disconnection and reconnection happened automatically via breaker operations in the simulation. Even though the voltage dip during disconnection was negligible in most cases, the reconnection of the plant resulted in a huge voltage spike, which exceeded 2000 kV margin. In over 50% of the analysed scenarios, the voltage returns to its nominal levels after few high-frequency oscillations. However, considering the Basic Insulation Level (BIL) for lightning impulse withstand capability of a 220 kV system which is around 1050 kV [62], this voltage behaviour is unrealistic across all the scenarios examined. In an actual system, such a large voltage spike would result in protective tripping as the voltage exceeds the safety margins. The likely cause for these excessive spikes is the sudden reconnection of the PV plant in full scale in the simulation. Figure 24 shows the above explained voltage profile of busbar 3 in 75% IBR scenario.

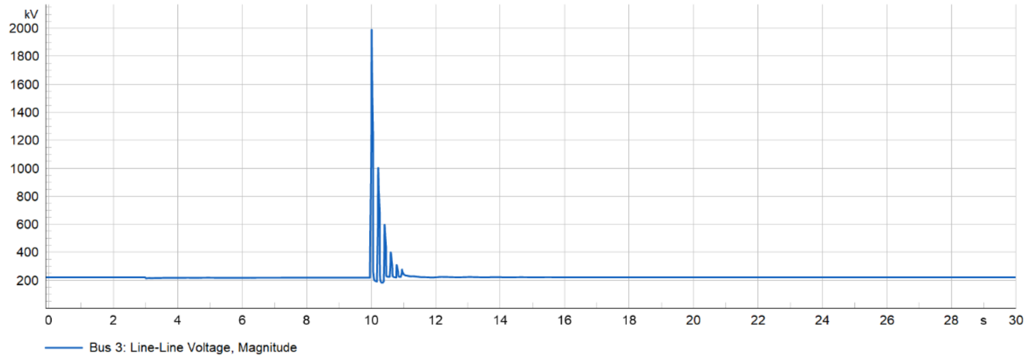


Figure 24: Busbar 3 voltage profile during large PV plant switch at 75% IBR case.

4.6.2 Reactive Power behaviour of Wartsila Power plant units

In response to the extreme voltage transient resulting from the PV plant switching, particularly during the reconnection of the PV plant, Wärtsilä machines absorbs a large amount of reactive power from the system to stabilize the voltage. However, the reactive power response way exceeds the physical limits of Wärtsilä plants, with one instance absorbing over -100,000 MVAr, whereas the typical response limits should be around -300 MVAr according to the plant's properties. The reason for the Wärtsilä plants to exhibit such extreme values is likely that the simulation model lacks the required protection, thermal limits, field and stator winding current limitations, which allows the AVR to demand ultimate reactive power compensation from the machines during extremely large voltage excursions.

5 Conclusion

The primary objective of this thesis was to quantify the synchronous condenser capability of Wärtsilä generator sets for reactive power and short circuit power support when operating under different renewable energy penetration levels and disturbance events. Evaluation of potential benefit of repurposing the conventional generators (In this case the Wärtsilä 20V31SG plants) as grid-supporting units, particularly synchronous condensers, in non-frequency ancillary markets, instead of idling them in high IBR penetrating situations in the power system, was also an objective.

To meet these thesis objectives, a comprehensive literature study was conducted, followed by a scenario-based analysis. The scenario analysis was conducted based on an IEEE 14 bus system, which was customized to represent a large-scale power system. Three disturbance situations were analysed across different power system configurations with increasing IBR shares, up to 96%. Reactive power compensation in Wärtsilä plants were evaluated considering three operational modes: Synchronous generator, synchronous condenser and partially curtailed.

In both the load switching and three-phase fault scenarios, the system's ability to maintain stable voltage declined as the IBR share increased, particularly beyond 75%. Under these conditions, the reactive power response of the Wärtsilä plant helped to mitigate voltage instability. Among the three operating modes, the synchronous condenser mode generally provided the most favourable dynamic response. However, the overall difference in performance between SC mode and the other modes was moderate rather than significant in most scenarios. This can be attributed to the relatively small size of the Wärtsilä plant in proportion to the total system capacity, which limited its ability to influence bulk system voltage regardless of operating mode. Moreover, during normal generator operation, active power output provided additional voltage support via internal torque and terminal voltage regulation, which in some cases reduced the distinction between operating modes.

In contrast, the PV plant switching scenario produced responses that were deviated from realistic figures. While the disconnection of the PV plant generally caused negligible voltage deviation, the reconnection at t =10 s resulted in extreme voltage spikes, in some cases exceeding 2000 kV, and highly abnormal reactive power absorption, reaching values above 100,000 MVAR. These outputs are far beyond the physical operating thresholds of a 220 kV system and a 300 - 400 MVA synchronous machine and therefore do not represent feasible system behaviour. The results highlight the importance of implementing control boundaries and realistic switching strategies when assessing synchronous generator performance under high-IBR conditions.

5.1 Limitations of the simulation model

Several limitations were identified during the modelling phase of the thesis, which affected the simulation model and significantly impacted the results. Since the Wärtsilä plant model's control system did not support parallel machine function, the Wärtsilä plant's size had to be reduced compared to the overall power system. This limitation was identified midway through the simulation process, at which point it was not feasible to redesign the entire model or scale the system accordingly. As a result, the simulations were carried out at the best possible plant scale, which may have underrepresented the potential influence of synchronous support from Wärtsilä plants under realistic multi-unit configurations.

It was further observed that the simulation model did not include critical control constraints such as field current limiters, overexcitation limiters, or stator current protection. This allowed the AVR to command unrealistic levels of reactive power under high voltage transients. Therefore, the simulated values exceeded technical and thermal limits that would normally trigger protective actions or restrict generator response in an actual system.

5.2 Further Research

To improve the overall simulations accuracy and to better evaluate the impact of Wärtsilä plants, further work should be carried out by addressing the limitations in the simulation model mentioned in Section 5.1. To address the mismatch in the scale between the power system and Wärtsilä plants, two approached can be suggested: Further developments of the Wärtsilä 20V31SG gas turbine generator model enabling a single simulation block to support parallel machine integration or downscaling the entire model to match the existing integrated capacity of Wärtsilä plant models. Enabling protection schemes would further enhance the accurate representation of real-world scenarios.

In addition, incorporating other forms of grid supporting technologies to system, especially at high IBR levels would be essential to establish adequate reactive power supply during critical disturbance situations. Devices such as STATCOMs, SVCs, and battery energy storage systems can provide fast dynamic reactive power and inertia, working along with Wärtsilä plants to support local voltage regulation in low inertia systems. Integrating such devices in the model would offer a more comprehensive view of system wide voltage stability and allow for a realistic evaluation in high IBR grid environments.

References

[1] H. Ritchie, M. Roser, and P. Rosado, "Emissions by sector: where do greenhouse gases come from?," Our World in Data, 2024. [Online]. Available: https://ourworldindata.org/emissions-by-sector

[2] Statista, "Global cumulative renewable capacity installed 2010-2023," Statista, Jul. 11, 2024. [Online]. Available: https://www.statista.com/statistics/1094331/global-renewable-capacity-cumulative/

[3] IRENA, "Renewable power generation costs in 2023," Sep. 01, 2024. [Online]. Available: https://www.irena.org/Publications/2024/Sep/Renewable-Power-Generation-Costs-in-2023

[4] D.K. Chaturvedi et al., Guide on the Assessment, Specification and Design of Synchronous Condenser for Power System with Predominance of Low or Zero Inertia Generators, CIGRE Technical Brochure 885, Nov. 2022, ISBN: 978-2-85873-590-7.

[5] J. C. Martínez et al., “Stability Assessment in Power Systems with High Penetration of Converter-based Generation,” 2022 IEEE International Conference on Environment and Electrical Engineering and 2022 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&Amp;CPS Europe), pp. 1–6, Jun. 2023, doi: 10.1109/eeeic/icpseurope57605.2023.10194891.

[6] N. Hatziargyriou et al., “Definition and Classification of Power System Stability – Revisited & Extended,” IEEE Transactions on Power Systems, vol. 36, no. 4, pp. 3271–3281, Dec. 2020, doi: 10.1109/tpwrs.2020.3041774.

[7] B. Kroposki et al., “Achieving a 100% Renewable Grid: Operating Electric Power Systems with Extremely High Levels of Variable Renewable Energy,” IEEE Power and Energy Magazine, vol. 15, no. 2, pp. 61–73, Mar. 2017, doi: 10.1109/mpe.2016.2637122.

[8] M. Mladenova, D. Stoilov and R. Stanev, "Challenges and Effects of High Penetration of Variable Renewable Energy Resources: Insights for the Bulgarian Power Market," 2023 15th Electrical Engineering Faculty Conference (BulEF), Varna, Bulgaria, 2023, pp. 1-7, doi: 10.1109/BulEF59783.2023.10406255.

[9] P. Kundur et al., “Definition and Classification of Power System Stability IEEE/CIGRE Joint Task Force on Stability Terms and Definitions,” IEEE Transactions on Power Systems, vol. 19, no. 3, pp. 1387–1401, Aug. 2004, doi: 10.1109/tpwrs.2004.825981.

[10] R. Aljarrah, G. Semreen, A. Rawashdeh, J. Abu-Hamad and M. Al-Omary, "Impact of Increased PV Penetration on Steady State Voltage Stability," 2023 2nd International Engineering Conference on Electrical, Energy, and Artificial Intelligence (EICEEAI), Zarqa, Jordan, 2023, pp. 1-6, doi: 10.1109/EICEEAI60672.2023.10590151.

[11] M. N. I. Sarkar, L. G. Meegahapola, and M. Datta, “Reactive power management in renewable rich power Grids: A review of Grid-Codes, renewable generators, support devices, control strategies and optimization algorithms,” IEEE Access, vol. 6, pp. 41458–41489, Jan. 2018, doi: 10.1109/access.2018.2838563.

[12] L. Liyanarachchi, N. Hosseinzadeh, A. Gargoom, and E. M. Farahani, “A new index for the assessment of power system strength considering reactive power injection and interaction of inverter based resources,” Sustainable Energy Technologies and Assessments, vol. 60, p. 103460, Oct. 2023, doi: 10.1016/j.seta.2023.103460.

[13] M. I. Saleem, S. Saha, U. Izhar, and L.-M. Ang, “Integration challenges of inverter based renewable energy sources in weak grids,” 2022 IEEE Industry Applications Society Annual Meeting (IAS), pp. 1–18, Oct. 2022, doi: 10.1109/ias54023.2022.9939753.

[14] CIGRE, “Innovation in the power systems industry,” CIGRE Science & Engineering, vol. 20, Feb. 2021, [Online]. Available: https://www.e-cigre.org/publications/detail/cse020-cse-020.html

[15] S. Achilles et al., “Integrating InverterBased Resources into Low Short Circuit Strength Systems.” North American Electric Reliability Corporation, Atlanta, Dec. 2017

[16] L. Yan, C. Yongning, T. Haiyan, T. Xinshou, Z. Zhankui and J. Jianqing, "Common Focus and New Requirement on Technical Standards of Renewable Energy Grid Integration," 2019 Chinese Automation Congress (CAC), Hangzhou, China, 2019, pp. 3719-3723, doi: 10.1109/CAC48633.2019.8996943.

[17] M. S. Alam, F. S. Al-Ismail, A. Salem and M. A. Abido, "High-Level Penetration of Renewable Energy Sources Into Grid Utility: Challenges and

Solutions," in IEEE Access, vol. 8, pp. 190277-190299, 2020, doi: 10.1109/ACCESS.2020.3031481.

[18] X. Liang, "Emerging Power Quality Challenges Due to Integration of Renewable Energy Sources," IEEE Transactions on Industry Applications, vol. 53, no. 2, pp. 855-866, March-April 2017, doi: 10.1109/TIA.2016.2626253.

[19] I. S. Rafiqi and A. H. Bhat, "Role of UPQC In Addressing Power Quality Issues in the Power Grid Connected with Renewable Energy Sources," 2022 1st International Conference on Sustainable Technology for Power and Energy Systems (STPES), SRINAGAR, India, 2022, pp. 1-4, doi: 10.1109/STPES54845.2022.10006596.

[20] H. Khajeh and H. Laaksonen, "Potential ancillary service markets for future power systems," 2022 18th International Conference on the European Energy Market (EEM), Sep. 2022, doi: 10.1109/eem54602.2022.9921133.

[21] E. Hirst and B. Kirby, Electric-Power Ancillary Services. Oak Ridge, TN, USA: Oak Ridge National Laboratory, 1996. [Online]. Available: https://www.consultkirby.com/files/con426_Ancillary_Services.pdf

[22] S. Glismann, "Ancillary Services Acquisition Model: Considering market interactions in policy design," Applied Energy, vol. 304, p. 117697, Sep. 2021, doi: 10.1016/j.apenergy.2021.117697.

[23] L. Idoko, O. Anaya-Lara, and D. Campos-Gaona, "Voltage control ancillary services for low voltage distributed generation," International Journal of Smart Grid and Clean Energy, vol. 7, no. 1, pp. 98–108, Jan. 2018, doi: 10.12720/sgce.7.2.98-108.

[24] E. Hirst and B. Kirby, "Creating Competitive Markets for Ancillary Services," Oak Ridge National Laboratory, Oak Ridge, TN, USA, ORNL/CON-448, Oct. 1997. [Online]. Available: https://www.consultkirby.com/files/con448.pdf

[25] A. Motamedi and M. Fotuhi-Firuzabad, "Ancillary service markets," Large Engineering Systems Conference on Power Engineering, vol. 19, pp. 316–320, Oct. 2007, doi: 10.1109/lescpe.2007.4437400.

[26] Business Research Insights, "Electricity Ancillary Services Market Share, Forecast, 2032," Business Research Insights, Jan. 13, 2025. [Online]. Available: https://www.businessresearchinsights.com/market-reports/electricity-ancillary-services-market-103075

[27] T. Brijs, C. De Jonghe, B. F. Hobbs, and R. Belmans, “Interactions between the design of short-term electricity markets in the CWE region and power system flexibility,” Applied Energy, vol. 195, pp. 36–51, Mar. 2017, doi: 10.1016/j.apenergy.2017.03.026.

[28] J. Ehnberg, O. Lennerhag, E. Hillberg, A. Perez, A. Mutule, and I. Zikmanis, “Categorisation of ancillary services for providers,” Latvian Journal of Physics and Technical Sciences, vol. 56, no. 1, pp. 3–20, Feb. 2019, doi: 10.2478/lpts-2019-0001.

[29] H. Holttinen, J. Kiviluoma, N. Cutululis, A. Gubina, A. Keane, and F. Van Julle, “Ancillary services: technical specifications, system needs and costs: REserviceS Deliverable D2.2,” 2012. [Online]. Available: http://www.reservices-project.eu/wp-content/uploads/D2.2_REserviceS_Ancillary-Services.pdf.

[30] B. Kirby and E. Hirst, Ancillary Service Details: Voltage Control, Oak Ridge National Laboratory, Oak Ridge, TN, USA, Dec. 1997. [Online]. Available: https://www.consultkirby.com/files/con453_Voltage_Control.pdf

[31] L. Viola, S. Mohammadi, D. Dotta, M. R. Hesamzadeh, R. Baldick, and D. Flynn, “Ancillary services in power system transition toward a 100% non-fossil future: Market design challenges in the United States and Europe,” Electric Power Systems Research, vol. 236, p. 110885, Jul. 2024, doi: 10.1016/j.epsr.2024.110885.

[32] EirGrid and SONI, "DS3: System Services Consultation – New Products and Contractual Arrangements," Jun. 8, 2012. [Online]. Available: https://bit.ly/4aAVCR7

[33] Deutsche Energie-Agentur (dena), dena Ancillary Services Study 2030, Berlin, Germany, 2014. [Online]. Available: https://bit.ly/3EhHK1T

[34] A. Johnson, "Fast Fault Current Injection," National Grid – Technical Policy, presented at the HVDC Workgroup Meeting, [Online]. Available: https://www.neso.energy/document/12341/download.

[35] ENTSO-E, Fault Current Contribution from PPMs & HVDC, Mar. 29, 2017. [Online]. Available: https://eepublicdownloads.entsoe.eu/clean-documents/Network%20codes%20documents/NC%20RfG/161116_IGD_Fault%20Current%20Contribution%20from%20PPMs%20%20HVDC_for%20consultation_for%20publication.pdf

[36] M. Nagpal et al., "Impact of Inverter Based Resources on Utility Transmission System Protection," IEEE Power System Relaying and Control Committee, Report of Working Group C32, 2020. [Online]. Available: https://www.pes-psrc.org/kb/report/109.pdf.

[37] P. Mitra, L. Sundaresh, and D. Ramasubramanian, "Stability of inverter-based resource (IBR) dominated systems with different types of local loads," vol. 28, pp. 1, Mar. 18, 2023. Available: bit.ly/4hdmcCk

[38] M. G. Ippolito, F. Massaro, G. Pecoraro, and E. R. Sanseverino, "Economical evaluations of reactive power supply as an ancillary service offered by distributors," IEEE Power Engineering Society General Meeting, 2004., vol. 2, p. 5 pp., Jan. 2006, doi: 10.1109/pes.2006.1709428.

[39] D. Jay and K. S. Swarup, "A comprehensive survey on reactive power ancillary service markets," Renewable and Sustainable Energy Reviews, vol. 144, p. 110967, Mar. 2021, doi: 10.1016/j.rser.2021.110967.

[40] N. Amjady, A. Rabiee, and H. A. Shayanfar, "Pay-as-bid based reactive power market," Energy Conversion and Management, vol. 51, no. 2, pp. 376–381, Nov. 2009, doi: 10.1016/j.enconman.2009.10.012.

[41] Ember, "Global Electricity Review 2024 | Ember," Ember, Dec. 06, 2024. https://bit.ly/4gk75Wp

[42] Zhe Wang, Jingru Li, Weihong Yang and Zinan Shi, "Impact of Distributed Generation on the power supply reliability," IEEE PES Innovative Smart Grid Technologies, Tianjin, 2012, pp. 1-5, doi: 10.1109/ISGT-Asia.2012.6303172.

[43] R. da Cunha Afonso and J. A. Peças Lopes, "Assessment of Demand Response Impact on the Frequency Stability of Low-Inertia Power Systems," 2023 IEEE Belgrade PowerTech, Belgrade, Serbia, 2023, pp. 1-6, doi: 10.1109/PowerTech55446.2023.10202714.

[44] H. W. K. M. Amarasekara, L. Meegahapola, A. P. Agalgaonkar and S. Perera, "Impact of renewable power integration on VQ stability margin," 2013 Australasian Universities Power Engineering Conference (AUPEC), Hobart, TAS, Australia, 2013, pp. 1-6, doi: 10.1109/AUPEC.2013.6725356.

[45] P. S. Kundur and O. P. Malik, Power System Stability and Control, 2nd ed. New York: McGraw-Hill Education, 2022. [Online]. Available: https://www.accessengineeringlibrary.com/content/book/9781260473544

[46] G. Rancilio, A. Rossi, D. Falabretti, A. Galliani, and M. Merlo, “Ancillary services markets in europe: Evolution and regulatory trade-offs,” Renewable and Sustainable Energy Reviews, vol. 154, p. 111850, Nov. 2021, doi: 10.1016/j.rser.2021.111850.

[47] A. Adamczyk, R. Teodorescu, R. N. Mukerjee and P. Rodriguez, "Overview of FACTS devices for wind power plants directly connected to the transmission network," 2010 IEEE International Symposium on Industrial Electronics, Bari, Italy, 2010, pp. 3742-3748, doi: 10.1109/ISIE.2010.5637987.

[48] A. P. Jayam and B. H. Chowdhury, "Improving the dynamic performance of wind farms with STATCOM," 2009 IEEE/PES Power Systems Conference and Exposition, Seattle, WA, USA, 2009, pp. 1-8, doi: 10.1109/PSCE.2009.4840201.

[49] M. A. Mostafa, E. A. El-Hay, and M. M. Elkholy, “An overview and case study of recent low voltage ride through methods for wind energy conversion system,” Renewable and Sustainable Energy Reviews, vol. 183, p. 113521, Jul. 2023, doi: 10.1016/j.rser.2023.113521.

[50] A. A. Ahmad and R. Sirjani, “Optimal placement and sizing of multi-type FACTS devices in power systems using metaheuristic optimisation techniques: An updated review,” Ain Shams Engineering Journal, vol. 11, no. 3, pp. 611–628, Dec. 2019, doi: 10.1016/j.asej.2019.10.013.

[51] B. H. Alajrash, M. Salem, M. Swadi, T. Senjyu, M. Kamarol, and S. Motahhir, “A comprehensive review of FACTS devices in modern power systems: Addressing power quality, optimal placement, and stability with renewable energy penetration,” Energy Reports, vol. 11, pp. 5350–5371, May 2024, doi: 10.1016/j.egyr.2024.05.011.

[52] H. T. Nguyen, C. Guerriero, G. Yang, C. J. Boltonand, T. Rahman and P. H. Jensen, "Talega SynCon - Power Grid Support for Renewable-based Systems," 2019 SoutheastCon, Huntsville, AL, USA, 2019, pp. 1-6, doi: 10.1109/SoutheastCon42311.2019.9020538.

[53] J. Jia, G. Yang, A. H. Nielsen and V. Gevorgian, "Investigation on the Combined Effect of VSC-Based Sources and Synchronous Condensers Under Grid Unbalanced Faults," in IEEE Transactions on Power Delivery, vol. 34, no. 5, pp. 1898-1908, Oct. 2019, doi: 10.1109/TPWRD.2019.2914342.

[54] S. Ghimire, K. Vatta Kkuni, E. D. Guest, K. H. Jensen and G. Yang, "Impact of Synchronous Condensers on Small-Signal Stability of Offshore Wind

Power Plants," in IEEE Access, vol. 12, pp. 168018-168029, 2024, doi: 10.1109/ACCESS.2024.3497669.

[55] DIgSILENT Pacific Pty Ltd, "Repurposing Existing Generators as Synchronous Condensers," Australian Renewable Energy Agency (ARENA), Report No. 3971-ETR-01, Version 1.52, Jun. 22, 2023. [Online]. Available: https://arena.gov.au/assets/2023/06/repurposing-existing-generators-as-synchronous-condensers-report.pdf.

[56] M. Nuhic, K. V. Kkuni, G. Yang, and J. Ramachandran, "Comparative study of hybrid synchronous condenser incorporating battery energy storage system for ancillary service provision," in Proc. 19th Wind Integration Workshop, Energynautics GmbH, 2020. [Online]. Available:https://orbit.dtu.dk/en/publications/comparative-study-of-hybrid-synchronous-condenser-incorporating-b

[57] R. Yan, N. -A. -Masood, T. Kumar Saha, F. Bai and H. Gu, "The Anatomy of the 2016 South Australia Blackout: A Catastrophic Event in a High Renewable Network," in IEEE Transactions on Power Systems, vol. 33, no. 5, pp. 5374-5388, Sept. 2018, doi: 10.1109/TPWRS.2018.2820150.

[58] V. D. W. Adriaan et al., "Design of ancillary service markets and products: Challenges and recommendations for EU renewable power systems: Deliverable D3.3," Jun. 01, 2021. http://hdl.handle.net/10400.9/3710

[59] D. B. Rathnayake et al., "Grid Forming Inverter Modeling, Control, and Applications," in IEEE Access, vol. 9, pp. 114781-114807, 2021, doi: 10.1109/ACCESS.2021.3104617.

[60] P. Unruh, M. Nuschke, P. Strauß, and F. Welck, "Overview on Grid-Forming Inverter Control Methods," Energies, vol. 13, no. 10, p. 2589, 2020, doi: 10.3390/en13102589

[61] Power Systems Test Case Archive, "14 Bus Power Flow Test Case." University of Washington, Seattle. Available: http://labs.ece.uw.edu/pstca/pf14/pg_tca14bus.htm.

[62] L. Fan and Z. Miao, "Wind in Weak Grids: 4 Hz or 30 Hz Oscillations?," IEEE Transactions on Power Systems, vol. 33, no. 5, pp. 5803–5804, Sept. 2018, doi: 10.1109/TPWRS.2018.2852947

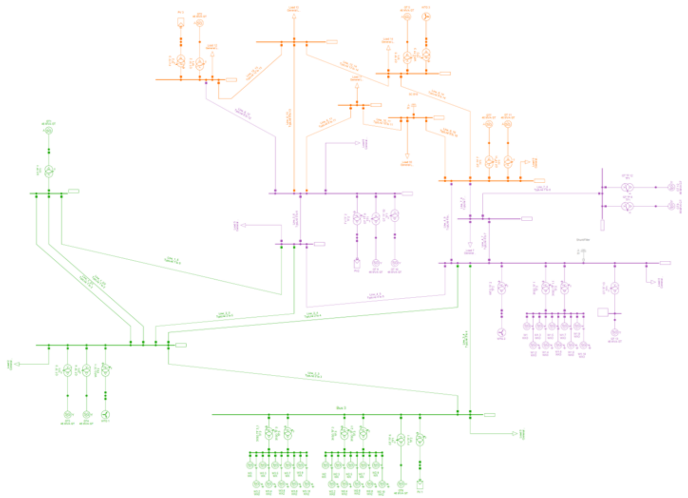
6 Annexures

Annexure 1: Generation Mix in constructed power systems with different IBR shares

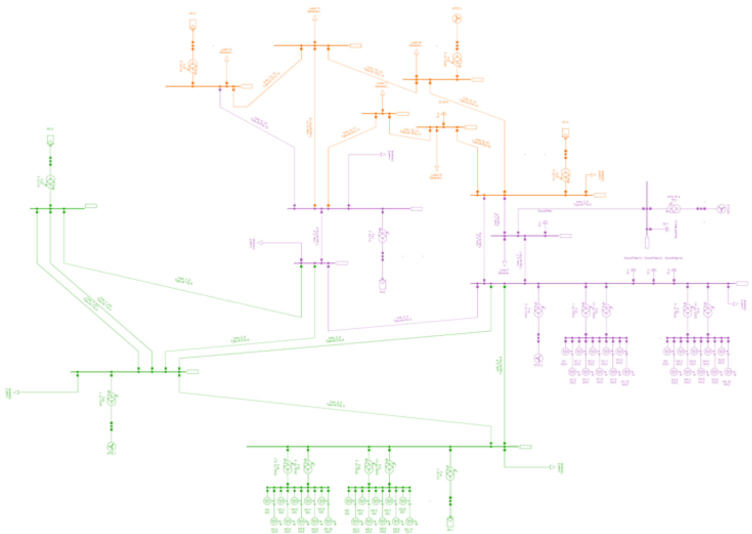
Generator	Unit Capacity (MVA)	Power factor	Number of parallel units															
			IBR 30%				IBR 50%				IBR 75%				IBR 96%			
			U	S	P	Q	U	S	P	Q	U	S	P	Q	U	S	P	Q
G1	46	0,8	20	931	745	559	12	559	447	335	2	93,1	74,5	55,9				
G2	46	0,8	20	931	745	559	12	559	447	335	12	559	447	335				
G3	46	0,8	20	931	745	559	14	652	521	391	14	652	521	391				
G4	46	0,8	18	838	670	503	12	559	447	335	12	559	447	335				
G5	46	0,8	18	838	670	503	12	559	447	335	10	466	372	279				
G6	46	0,8	18	838	670	503	12	559	447	335	10	466	372	279				
G7	46	0,8	18	838	670	503	12	559	447	335	7	326	261	196				
G8	46	0,8	18	838	670	503	12	559	447	335	4	186	149	112				
G9	46	0,8	18	838	670	503	12	559	447	335	4	186	149	112				
G10	46	0,8	15	698	559	419	12	559	447	335	4	186	149	112				
G11	46	0,8	15	698	559	419	12	559	447	335	4	186	149	112				
G12	46	0,8	15	698	559	419	12	559	447	335	4	186	149	112				
G13	46	0,8	15	698	559	419	14	652	521	391	4	186	149	112				
W1	14,7	0,8	10	147	118	88,2	10	147	118	88,2	10	147	118	88,2	10	147	118	88,2
W2	14,7	0,8	10	147	118	88,2	10	147	118	88,2	10	147	118	88,2	10	147	118	88,2
W3	14,7	0,8					10	147	118	88,2	10	147	118	88,2	10	147	118	88,2
W4	14,7	0,8													10	147	118	88,2
WTG1	2	0,95	500	1000	950	312	600	1200	1140	375	832	1664	1581	520	832	1664	1581	520
WTG2	2	0,95	500	1000	950	312	600	1200	1140	375	832	1664	1581	520	832	1664	1581	520
WTG3	2	0,95					400	800	760	250	693	1386	1317	433	693	1386	1317	433
WTG4	2	0,95													570	1140	1083	356
PV 1	110	0,95	12	1320	1254	412	14	1540	1463	481	19	2090	1986	653	19	2090	1986	653
PV 2	110	0,95	12	1320	1254	412	14	1540	1463	481	19	2090	1986	653	19	2090	1986	653
PV 3	110	0,95					12	1320	1254	412	17	1870	1777	584	17	1870	1777	584
PV 4	110	0,95													15	1650	1568	515
PV 5	110	0,95													15	1650	1568	515

U - Number of units
S - Apparent Power
P - Active Power
Q - Reactive Power

Annexure 2: Figures illustrating the constructed power systems from IBR 50% to 96%



Simulation model arrangement in 50% and 75% IBR scenarios.



Simulation model arrangement in 96% IBR scenarios.

Annexure 3: List of simulations performed at busbar 3 across all the constructed power system models.

Case	Total IBR share	Wärtsilä Genset operation mode	Disturbance type	Analyzed location	Analyzed Parameters
1	30 %	Synchronous Generator Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Capacity Curtailment	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Synchronous Condenser Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
2	50 %	Synchronous Generator Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Capacity Curtailment	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Synchronous Condenser Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants

3	75 %	Synchronous Generator Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Capacity Curtailment	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Synchronous Condenser Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
4	96 %	Synchronous Generator Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Capacity Curtailment	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants
		Synchronous Condenser Mode	1.Three-phase to earth fault 2.Load switching 3.PV Plant Switching	Busbar 3	• Voltage Profile of the Busbar (kV) • Reactive power injection from Wärtsilä plants • Reactive power injection from individual Wärtsilä Plants