Applications of Transient Stability Constrained Optimal Power Flow in Systems with High Penetration of Renewable Energy and Storage

by

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ABSTRACT

Transient Stability Constrained Optimal Power Flow (TSCOPF) models emerge as a tool to optimize the operation of power systems ensuring an economic operation, steady state operating constraints, and a transiently stable solution under a set of severe incidents. This dissertation proposes several improved TSCOPF models for modern transmission grids with high renewable generation and storage systems, evaluating them in real electrical power systems.

This thesis advances in a simultaneous discretization TSCOPF formulation that calculates the frequency, the power flow and the voltages at each bus of the system and at each sample time. The model is suitable for the representation of non-synchronous renewable generation equipped with synthetic inertia and voltage regulator controls, energy storage systems and detailed load models.

This work addresses the implementation and test of non-synchronous renewable generation and energy storage system models in the TSCOPF formulation. It is proposed a model to represent non-synchronous renewable generation with reactive power support for voltage dips, synthetic inertia and fault ride-through capability. Moreover, a fast response storage model is implemented in a Multi Contingency (MC)-TSCOPF formulation, calculating its optimal operation for a set of severe incidents in a single optimization problem. This thesis also evaluates the performance of various integration methods and the feasibility of using variable integration time steps in simultaneous discretization TSCOPF formulations.

The proposed formulations are applied to two IEEE test and three real systems: the isolated transmission grid of Tenerife island, the North-West Spanish power system (an area of the Iberian Peninsula System with high penetration of non-synchronous renewable generation), and the Lanzarote-Fuerteventura islands transmission grid (including a Flywheel Energy Storage System in operation). Results show the efficiency of the proposed formulation.

RESUMEN

El problema de flujo de potencia óptimo con restricciones de estabilidad transitoria (TSCOPF, por sus siglas en inglés) es una herramienta útil para optimizar el funcionamiento de los sistemas de transmisión eléctrica, asegurando una operación económica frente a restricciones de operación estática y garantizando la estabilidad transitoria ante un conjunto de incidentes graves en la red. Esta tesis propone varios modelos de TSCOPF para su aplicación a redes de transmisión con almacenamiento y alta penetración de generación renovable.

Esta tesis avanza en una formulación de TSCOPF basada en el método de la integración simultánea, calculando la frecuencia, el flujo de potencia y el voltaje en cada barra del sistema y para cada tiempo de muestreo. El modelo es adecuado para la representación de generación renovable no síncrona equipada con controles de emulación de inercia y regulación de tensión, sistemas de almacenamiento y modelos detallados de cargas.

Este trabajo propone e implementa varios modelos de generación renovable no síncrona y de sistemas de almacenamiento de energía en el TSCOPF. La generación renovable no síncrona incluye la representación de soporte frente a huecos de tensión, inyección de potencia reactiva para regulación de tensión e inercia sintética. Además, se calcula la operación óptima del almacenamiento para un conjunto de incidentes en un mismo problema de optimización con una formulación de múltiples contingencias (MC)-TSCOPF. Esta tesis evalúa también la eficiencia de varios métodos de integración y la viabilidad de utilizar pasos de tiempo de integración variables en el TSCOPF.

Los modelos propuestos se aplican a dos sistemas de prueba IEEE y en tres sistemas reales: la red de transmisión aislada de la isla de Tenerife, el sistema eléctrico del noroeste de España (un área del Sistema de la Península Ibérica con una alta penetración de generación renovable no síncrona) y la red de transmisión de las islas Lanzarote-Fuerteventura (incluyendo un sistema de almacenamiento mediante volante de inercia). Los resultados presentados muestran la eficiencia de la formulación propuesta.

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NOTATION

Abbreviations and Acronyms

AC	Alternating current
COI	Center of Inertia.
DNLP	Discontinuous Nonlinear Programming
ED	Economic dispatch
ESS	Energy Storage System
FESS	Flywheel Energy Storage System
GAMS	General Algebraic Modeling System.
GSO	Glowworm swarm optimization
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
IGBT	Insulated Gate Bipolar Transistor
IPOPT	Interior Point Optimizer
MC	Multi-Contingency
MR	Multiple Responses
MU	Monetary Units
NLP	Nonlinear programming
OPF	Optimal Power Flow.
PCC	Point of Common Coupling
PF	Pre-Fault.
PLL	Phase-Locked Loop
PSO	Particle Swarm Optimization

PSSSE	Power System Simulator for Engineering.
PV	Solar Photovoltaic
RK2	2 nd order Runge-Kutta method.
RK4	4 th order Runge-Kutta method.
ROCOF	Rate of Change of Frequency
SCOPF	Security Constrained Optimal Power Flow.
SIME	Single Machine Equivalent
SR	Single Response
TD	Time Domain.
TEF	Transient Energy Function
TSCOPF	Transient Stability Constrained Optimal Power Flow.
TSO	Transmission System Operator

Indices and sets

i, j	Indices for nodes.
t	Indices for time periods.
c	Indices for contingencies
Ω^B	Set of buses of the power system.
Ω^C	Set of contingencies.
Ω^G	Set of the synchronous generation units.
Ω^{NSG}	Set of the renewable non-synchronous generation units.
Ω^L	Set of loads.
Ω^T	Set of the time periods corresponding to the pre-fault, fault and post fault stages.
Ω^{TD}	Set of the time periods corresponding to the fault and post fault stages.
Ω^{TDELAY}	Set of the time periods corresponding to the delay of the frequency measurement.

Parameters

$A^{\text{CON}}, B^{\text{CON}}, C^{\text{CON}}$	Coefficients of the losses of a power electronic converter.
$A^{\text{FW}}, B^{\text{FW}}$	Coefficients that penalize the operation of a flywheel energy storage system.
$A^{\text{G}}, B^{\text{G}}, C^{\text{G}}$	Fuel cost coefficients of the power plants [€/MWh].
$A^{\text{P}}, B^{\text{P}}, C^{\text{P}}$	Active power coefficients of the ZIP load model.
$A^{\text{RT}}, B^{\text{RT}}, C^{\text{RT}}$	Coefficients of the mechanical losses of a flywheel.
$A^{\text{S}}, B^{\text{S}}$	Excitation system saturation coefficients.
$A^{\text{Q}}, B^{\text{Q}}, C^{\text{Q}}$	Reactive power coefficients of the ZIP load model.
D	Damping coefficient of the power plant [p.u.].
D^{BUS}	Value of the of element (i,j) of the frequency divider formula matrix [p.u.].
$E^{\text{FW},\text{MAX}}$	Upper limit of energy stored on a flywheel energy storage system [p.u.].
$E^{\text{FD},\text{MIN}}, E^{\text{FD},\text{MAX}}$	Limits of the field voltage of the synchronous generator [p.u.].
H	Inertia constant of a synchronous power plant [s].
H^{EMU}	Synthetic inertia constant of a non-synchronous renewable power plant [s].
$I^{\text{L},\text{MAX}}$	Upper limit of the current in lines and transformers. [p.u.].
$I^{\text{PH},\text{MAX}}$	Upper limit of the current in a power electronic converter [p.u.].
J	Flywheel inertia constant [kg.m ²]
$K^{\text{A}}, K^{\text{E}}, K^{\text{F}}$	Gains of the IEEE type 1 excitation system [p.u.].
K^{TG}	Turbine governor gain [p.u.].
$p^{\text{ABS},\text{FW}}, p^{\text{INJ},\text{FW}}$	Limits of the power absorbed or injected by a flywheel energy storage system [p.u.].
$P^{\text{L}}, Q^{\text{L}}$	Active and reactive nominal load [p.u.].
$P^{\text{MIN}}, P^{\text{MAX}}$	Active power limits of a power plant [p.u.].
P^{REF}	Available non-synchronous generation power [p.u.].
P^{FCTL}	Coefficient that defines the power factor of a non-synchronous renewable power plant [p.u.].

$Q^{\text{MIN}}, Q^{\text{MAX}}$	Reactive power limits of a power plant [p.u.].
Q^{REF}	Reactive power injected by a non-synchronous renewable power plant in the steady state operation [p.u.].
R^A	Armature resistance of a synchronous power plant [p.u.].
T^A, T^E, T^F	Time constants of the IEEE type 1 excitation system [s].
$T'^D T'^Q$	Transient time constants of a synchronous power plant [s].
T^{IE}	Synthetic inertia time constant [s].
T^{TG}	Turbine governor time constant [s].
T^{TH}	Parameter that defines the numerical integration method.
V^{CON}	Limit of under-voltage ride through [p.u.].
$V^{\text{MIN}}, V^{\text{MAX}}$	Limits of the bus voltage [p.u.].
$V^{\text{R,MIN}}, V^{\text{R,MAX}}$	Saturation limits of the amplifier of the IEEE type 1 excitation system [p.u.].
X^D, X^Q	Synchronous reactances of the power plant [p.u.].
X'^D, X'^Q	Transient synchronous reactances of the power plant [p.u.].
$Y_{i,j}$	Absolut value of the element (i,j) of the bus admittance matrix [p.u.].
$\Delta p^{\text{MAX,NSG}}, \Delta p^{\text{MIN,NSG}}$	Upper and lower limits of the active power variation of a non-synchronous renewable power plant [p.u.].
Δt	Integration time step [s].
$\Delta \omega^{\text{MAX}}$	Limit of the speed deviation of a synchronous power plant [p.u.].
$\eta^{\text{ABS}}, \eta^{\text{INJ}}$	Efficiency of a synchronous machine of a flywheel energy storage system when it extracts energy from, or injects to the grid [p.u.].
$\theta_{i,j}$	Phase of the element (i,j) of the bus admittance matrix [p.u.].
δ^{MAX}	Limit of the rotor angle deviation of a synchronous power plant [rad].
$\omega^{\text{FW,MAX}}, \omega^{\text{FW,MIN}}$	Upper and lower limits of the speed of a flywheel energy storage system [rad/s].
$\omega^{\text{FW,REF}}$	Steady state speed of a flywheel energy storage system [rad/s].
ω^{REF}	Frequency reference of the grid [rad/s].

Variables

e'^D, e'^Q	Internal transient voltages of the synchronous generator [p.u.].
e^{FD}	Field voltage of the synchronous generator [p.u.].
e^{FW}	Stored energy in a flywheel energy storage system [p.u.].
f^{CON}	Binary variable that is equal to 1 if renewable power plant remains connected, and 0 otherwise.
$f^{CURTAIL}$	Non-synchronous renewable curtailment factor.
f^{LV}	Low voltage correction factor.
i^D, i^Q	Direct and quadrature components of the stator current of a synchronous power plant [p.u.].
i^L	Current between nodes (i,j) [p.u.].
i^{PH}	Current through a power electronic converter [p.u.].
$K^{1D}, K^{2D}, K^{3D}, K^{4D}$	Intermediate variables for the calculation of the transient voltage in the d-axis when using the RK4 method
$p^{ABS,FW}, q^{ABS,FW}$	Active and reactive power absorbed by a flywheel energy storage system [p.u.].
p^E	Electrical power in the rotor of a synchronous generator [p.u.]
p^G, q^G	Active and reactive power output of a synchronous power plant [p.u.].
$p^{INJ,FW}, q^{INJ,FW}$	Active and reactive power injected by a flywheel energy storage system [p.u.].
p^{NSG}, q^{NSG}	Active and reactive power output of a non-synchronous renewable power plant [p.u.].
p^L, q^L	Active and reactive load
$p^{LOSSES,MEC}$	Mechanical losses in a flywheel energy storage system.
$p^{LOSSES,CON}$	Losses in a power electronic converter.
p^M	Mechanical power input of a synchronous power plant [p.u.].
q^{VS}	Reactive power variation during a voltage dip by a non-synchronous renewable power plant [p.u.].
$ROCOF$	Rate of Change of Frequency at bus [p.u.].
v	Bus voltage magnitude [p.u.].

v^R, v^{REF}, r^F	Inputs of the IEEE type 1 excitation system. [p.u.].
v^{RAUX}, v^{RAUX1}	Auxiliary variables of the IEEE type 1 excitation system. [p.u.].
α	Phase of the bus voltage [rad].
Δf	Frequency deviation at bus [p.u.].
Δf^D	Frequency deviation measurement at bus [p.u.].
Δp^M	Turbine governor output of a synchronous power plant [p.u.].
Δp^{NSG}	Active power variation of a non-synchronous renewable power plant [p.u.].
$\Delta \omega$	Speed deviation of a synchronous power plant [rad/s].
$\Delta \omega^{COI}$	Speed deviation of the center of inertia [p.u.].
δ	Rotor angle of a synchronous power plant [rad].
δ^{COI}	Rotor angle of the center of inertia [rad].
ω^{FW}	Flywheel angular velocity [rad/s]

CHAPTER 1

INTRODUCTION

This chapter begins with the context and motivation of the dissertation. The chapter continues with a literature review of power system stability and optimization techniques applied to the operation and planning of power system. Transient Stability Constrained Optimal Power Flow (TSCOPF) is presented, with emphasis on the different approaches that have emerged during the last few years to solve TSCOPF models and present challenges. Then, the general objectives of this dissertation are presented. Finally, the last section outlines the organization of the structure of the thesis.

1.1 Context and motivation

One of the five headline targets of European Commission's Europe 2020 Strategy is the reduction of greenhouse gas emissions and the increase in the share of renewable energy in final energy consumption. This target goes clearly in line with the Spanish Strategy of Science, Technology and Innovation, that counts among its research objectives aimed at societal challenges the development of "Energy, Safety and Safe Sustainable Energy Models" [1].

Renewable energy sources have grown in the European power systems at high speed during the last decade, and today they are at the center of the energy transition [2]. During the last decade, every year they have consistently accounted for the large majority of new electricity-generating capacity, in a scenario in which conventional generation is decommissioned at a higher rate than it is installed.

This growth has been driven by a strong support from European institutions, reflected in the Directive for the Promotion of the Use of Energy from Renewable Sources [3], and

also in national targets such as the Spanish National Action Plan [4]. A recent political agreement reached between the European Commission, the Parliament and the Council on 14 June 2018 sets the binding renewable energy target for the European Union for 2030 at 32%. Spain is one of the countries with a larger share of renewable electrical generation. During 2018, in the Spanish Peninsular System, 19 % of the total production of electrical energy came from wind farms and 3.8% came from photovoltaic systems [5], and this percentages can be much higher during periods of low load and high availability of renewable resources.

1.1.1 Integration of non-synchronous renewable energy in the power system

Many renewable energy sources pose a challenge to traditional ways of operating and controlling the power system. This is due to the variable nature of sources such as wind and solar power, the impossibility of directly storing the energy source (wind and solar radiation) and the fact that the rise of renewable energy sources has been sustained by a rapid development of new technologies. In the case of photovoltaic and wind energy, both on-shore and off-shore, they are transformed into electrical energy in clusters of relatively small units (i.e. solar panels and windmills) that form a power park, and that are connected to the grid via electronic inverters. This has implications on short-circuit currents and on voltage, angle and frequency stability. The dynamics of non-synchronous power parks are very different from conventional synchronous generators, because they lack a rotating mass in synchronism with the voltage at the connection point that reacts to angle and power deviations according to the swing equation.

As a result, during the last two decades the Spanish Transmission System Operator (TSO) and their European counterparts have adapted their methods of operation and their grid codes to integrate the emerging photovoltaic and wind power. One of the first issues to be addressed has been congestions in lines and substations as a result of the liberalization of the electricity market and the need to accommodate non-programmable renewable generation. This is a static problem that has been solved with the help of traditional Optimal Power Flows (OPFs). Another issue early confronted by system operators is the response of non-synchronous generation to voltage dips caused by short-circuits in the transmission system. Today, Spain and many other European countries have published grid codes that require power parks to provide fault ride-through capability together with reactive power support [6].

During the last decade, the dynamic stability of transmission grids with large penetration of non-synchronous generation has emerged as a relevant problem that has led sometimes to wind energy curtailment [7], and that has been addressed following two main approaches. The first approach is to perform off-line dynamic simulations to ensure that the system remains stable after any of a set of reference incidents. If one of the cases is unstable, the original dispatch is modified until a satisfactory result is obtained. Dynamic models of non-synchronous power parks have been incorporated into the libraries of commercial power system simulators. This approach has the advantage of not imposing a limit on the grade of detail of the dynamic modes used in the simulations, but it does not guarantee an optimal use of the resources in the power system. The second option consists in taking into account the stability constraints of the power system during the solution of the optimal power flow, and is sometimes referred to as Transient Stability Constrained Optimal Power Flow (TSCOPF). This approach, which is the one followed in this thesis, has the advantage of calculating the solution that minimizes a certain objective function. Typically, the objective function is the cost of generation, although others can be used, such as deviation from a market solution or greenhouse gas emissions.

Today, the penetration of non-synchronous generation has reached a level in which two new concerns arise from the point of view of its integration in the existing transmission power. The first one is the contribution to primary frequency regulation, and the second one is the reduction of the inertia of the system and its effect on transient and frequency stability [8].

The reduction of the total inertia of the power system is a concern for TSOs because a power imbalance in the system may result in large frequency excursions if the inertia is too low. A significant power imbalance can happen as a result of a loss of load or generation in an insular system or as a result of a split in a large system, as it was the case in the 4 November 2006 incident in Continental Europe [9]. As non-synchronous generation increases and displaces conventional generation, the total inertia of the system decreases. If a part of a split system ends up with too much load, load shedding can be enough to solve the problem, but if a part of a system ends up with too much generation, the fast frequency rise can trigger the tripping of over-frequency protections and lead to frequency instability. As a result, transmission system operators are beginning to demand that power parks modify their control systems to emulate the swing equation of conventional synchronous generators, a solution often referred to as *synthetic inertia* [8].

The new developments regarding frequency control must be addressed in any dynamic study trying to analyse the maximum penetration of non-synchronous generation. Therefore, control systems providing power parks with primary frequency control and synthetic inertia must be included in any realistic simulation or optimization model. In the case of TSCOPF techniques, the inclusion of these practices would provide a tool not only to maximize the penetration of renewable non-synchronous generation, but to explore the possibilities of the new controls by, for example, optimizing parameters such as primary control droop, energy reserve, amount of synthetic inertia, and response time.

1.1.2 Integration of storage in the power system

The transition toward a generation mix with larger shares of non-synchronous renewable generation represents a challenge for traditional forms of operation of transmission grids. Energy Storage Systems (ESS) are recognized as essential devices for the operation of modern power systems in order to increase the renewable generation shares and improve the dynamic stability [10], [11]. ESS devices convert energy from one form (mainly AC electrical energy) to another form to be stored and used when needed. ESS can have several applications for the operation of power systems including: 1) Cover peak-load demands; 2) Support stability in power systems when a contingency occurs; 3) Ensure the power balance when there are variations in generation or demand; 4) Cover remote demand needs; 5) Cover vehicle demand needs; and 6) Provide ancillary services [12].

There is a wide variety of ESS technologies and the selection of the most adequate can depend on several factors such as the desired application, environmental laws, or available resources. For example: Flywheel Energy Storage Systems (FESS) and supercapacitors may be suitable for stability or ancillary purposes due to their high-power capacity and fast response, while thermal energy storage may be adequate to meet peak-load demands because they do have a high capacity to store energy.

Traditionally, pumped-hydroelectric storage has been the most widely used technology in power system operation [13], [14], although its growth is limited by the availability of natural resources and environmental issues. In recent years, other types of storage devices have been put into operation in both large and small networks. Some examples are the two FESSs of 20MW installed by Beacon Power in Stephentown, New York [15] and Hazle Township, Pennsylvania[16]. In Spain, there are some examples of ESS devices in the Canary archipelago. For instance, as a result of the STORE project launched in 2012, Endesa installed a lithium-ion battery of 1 MW on the island of Gran Canaria, a FESS of 0.5 MW in La Gomera, and a supercapacitor of 4 MW on the island of La Palma [17].

Later, the Spanish TSO put into operation a FESS of 1.65MW in the island of Lanzarote[18].

Energy Storage systems will play a fundamental role in modern power systems and, consequently, new tools developed for operation and planning must take into account their effect and include suitable models in their libraries. TSCOPF techniques have not considered EES models yet. The response of these devices can have a significant effect on the results given by these formulations and, therefore, it is essential to explore the implementation of storage devices within TSCOPF models.

1.2 Literature review

This section presents a general literature review of the two fields related to the thesis: power system stability and optimization methods applied to the operation and planning of power systems. Due to the wide variety of topics covered in the thesis, specific literature reviews are presented in the introduction section of each chapter according to the topic addressed.

1.2.1 Power system transient stability

During many decades, several stability definitions and classifications had been presented in the literature, but in 2004, a *joint IEEE/CIGRE Task Force on Stability terms and Definitions* was created with the purpose of creating a common definition and classification of power system stability. Stability in power systems was defined as follows.

“Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact.” [19]

Stability has become a challenge for power system operation since 1920s, with transient stability emerging as the first stability issue. As the number of power plants and interconnections in power system increased other types of stability problems arose, such as voltage or frequency stability. Nowadays, the different stability issues have been classified into rotor angle stability, frequency stability and voltage stability, as shown in Figure 1.1.

Figure 1.1 Classification of power system stability, [19]

Rotor angle stability is defined by the IEEE/CIGRE joint committee as “*the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance*”; voltage stability as “*the ability of a power system to maintain steady state voltage at all buses in the system after being subjected to a disturbance from a given initial operating condition*”; and frequency stability as: “*the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load*”.

Rotor angle stability is subdivided into small-signal (or small-disturbance) stability and transient (or small-disturbance) stability. Small signal stability studies analyze the stability of a system when is subjected to small disturbances. The non-linear equations of the system are linearized to evaluate the stability by analyzing the eigenvalues of the system's state matrix. On the other hand, transient stability refers to “*the ability of the power system to maintain synchronism when subjected to a severe disturbance, such as a fault on transmission facilities, loss of generation or loss of significant amount of load*” [20]. In these cases, the non-linear set of equations that defines the dynamic of the system cannot be linearized because the system faces large excursions of rotor angles.

Transient Stability is an electromechanical phenomenon whose oscillations are due the rotor angle and/or rotor speed deviation of the rotating masses of the power plants when large disturbances occur in a power system. Figure 1.2 shows the different dynamics in a power system with their corresponding time frames. The time scales corresponding to transient stability studies are in the order of a few seconds. Faster electromagnetic phenomena in the grid are neglected in transient stability studies because they do not affect the electromechanical torque in synchronous generators.

Figure 1.2 Time frames of power system dynamics, [21]

The high non-linearity of transient stability phenomena prevents the linearization of the system equations. The most common techniques in transient stability analysis are divided into three groups as follows:

- Time domain simulation: The set of nonlinear dynamic-algebraic equations that models the dynamics of the power system are solved by an explicit or implicit numerical integration method. The solution provides the evolution of variables of a power system over the time of study [22].
- Direct methods: These methods use alternative approaches to avoid the solution of the set of the dynamic-algebraic equations. Methods based on the Lyapunov function and equal-area criterion are among these approaches. Detailed descriptions and examples of applications can be found in [20], [23].
- Hybrid methods: These approaches combine time-domain simulation with direct methods such as the equal-area criterion or Lyapunov function [22], [24]. The well-known Single Machine Equivalent (SIME) approach that uses the equal-area criterion is among these methods [25].

There is no optimal approach and the selection of a method depends on the desired application. On the one hand, Direct and Hybrid methods are computationally more efficient to evaluate stability, but they do not provide information on the evolution of the system variables over time. On the other hand, Time-domain simulation methods provide complete information of the dynamics of the system over time. Time-domain simulation techniques represent the trajectories of the synchronous machine variables within a framework of 3-5 seconds (in large power system with dominant inter-area oscillations the representation may be extended up to 15 seconds). For a system to be stable, the rotor angle deviations of the synchronous power plants must lie within a specific range of values. Time-domain simulation has been the approach used in this thesis.

1.2.2 Optimal Power Flow

The optimization applications in power system began with the classic economic dispatch (ED) problem. The ED formulation aims to divide the total demand among the power plants so that the total generation cost of a power system is minimized. The ED takes into account the operational limits of the power plants but not the representation of power lines and transmission capacity limits.

The introduction of new mathematical techniques made it possible the solution of extended formulations and, as a consequence, OPF models emerged in the 1960s due to the introduction of new non-linear programming techniques and powerful computational capacities [26], [27]. Nowadays, OPF formulations have become essential tools for the operation and planning of modern power systems. The OPF problem is formulated as follows:

$$\text{minimize} \quad f(x) \quad (1.1)$$

Subject to:

$$G(x) = 0 \quad (1.2)$$

$$H(x) \leq 0 \quad (1.3)$$

Equation (1.1) is the objective function that typically minimizes the total generation cost, but other objectives functions can be used such as minimizing losses, minimizing greenhouse emissions, minimizing power deviations from a specific dispatch, or maximizing system security [28]. Equation (1.2) represents the equality constraints of the optimization problem that is the set of network equations including the load flow balances

at each node of the system. Equation (1.3) represents the inequality constraints that correspond to the technical operation limits, such as voltage limits in transmission buses, power generation limits in power plants, and capacity limits in lines and transformers.

Later, the OPF formulations were expanded to include operational constraints in both steady state operation and possible post-contingency scenarios. This problem is known as Security Constrained Optimal Power Flow (SCOPF) and ensures the system operates stable in the steady state and in different post-contingency configurations, because it solves in a single optimization problem the base case and several post-contingencies scenarios [29], [30].

Regarding the solution algorithms, Interior Point methods are presented as valid and effective techniques to solve OPF formulations. However, other approaches can be applied such as reduced gradient methods, SIMPLEX, and sequential quadratic programming [27]. Heuristic methods have also been applied to solve OPF models [31].

1.2.3 Transient Stability Constrained Optimal Power Flow

TSCOPF models emerge in the last decade of twentieth century as algorithms to calculate the optimal operation of power systems while maintaining transient stability limits [32], [33]. TSCOPF models combine an OPF formulation with the transient stability assessment of the system to ensure both an economic operation and a transiently stable solution under a set of severe incidents. The inclusion of static and dynamic constraints in a single optimization model becomes a challenge due to the size, non-linear nature, and complexity of power system static and dynamic models. Several approaches have been proposed in the literature to solve TSCOPF formulations that can be classified as: 1) Time domain simulation techniques; 2) Simplification based techniques; and 3) Metaheuristic optimization techniques. An extensive and recent review of techniques to solve TSCOPF formulations is presented in [34], [35]. Each approach presents strengths and drawbacks and, consequently, the selection of a method depends on the desired application. The following subsections describes briefly each of these techniques.

1.2.3.1 Time-domain simulation techniques

Time-domain simulation techniques generally require the use of Non-linear Programming (NLP) approaches to solve the optimization problem. These formulations solve the differential-algebraic equations that model the behavior of the power system using explicit or implicit numerical integration methods. In [34] the variants to solve TSCOPF based on Time-Domain simulation are divided into the following categories:

- Simultaneous discretization [33], [36]–[40]: The differential equations, which represent the dynamics of the system, are discretized and integrated together with the OPF constraints in a single optimization model that is solved as a whole. The complete mathematical representation of the system is preserved. These methods create large optimization models with a high amount of constraints and variables.
- Constraint transcription [41]–[44]: These approaches decouple optimisation algorithms and simulation tools, and the TSCOPF model is solved following an iterative process. The external simulation tool solves the differential-algebraic equations that model the dynamics of the system. Then, a trajectory sensitivity analysis is performed to obtain the gradients and, feed the optimization model that is solved using an NLP solver. This loop iterates until the desired solution is reached.
- Multiple shooting [45]: This approach results as a combination between simultaneous discretization and constraint transcription.

1.2.3.2 Simplification based techniques

These approaches aim to reduce the size and complexity of the optimization problem [46], [47]. To do this, they avoid the solution of the set of differential differential-algebraic equations by using direct or hybrid methods to assess stability. Generally, these studies rely on reduced dynamic models such as the Single-Machine equivalent or Transient Energy Functions (TEFs). They provide a deterministic measure of the stability on the post-fault stage and generally present higher computation efficiency than time domain simulation methods, but they do not provide complete information on the evolution of the system variables over time. It is argued that these methods can only provide rough estimations [48] and have limitations when dealing with complex trajectories

1.2.3.3 Metaheuristic optimization techniques

Computational intelligence techniques solve TSCOPF formulations using heuristic and stochastic techniques. These algorithms present a huge searching capacity but usually present slow convergence and it is argued that obtained solutions can be inaccurate [48]. These methods include 1) Evolutionary algorithms such as evolutionary programming, genetic algorithms, and differential evolution methods [31], [49]; and 2) Swarm-based optimization methods such as Glowworm Swarm Optimization (GSO) or Particle Swarm Optimization (PSO) [50], [51].

1.2.4 Background

This thesis continues with the work developed in the dissertation of Dr. Ignacio Antonio Calle, in which models and applications for simultaneous discretization TSCOPF formulations are proposed and implemented [52].

The dissertation of Dr. Calle proposes a TSCOPF formulation that represents power plants using a transient 4th order d-q axes synchronous generator model equipped with a turbine governor and an excitation system. Electronic inverters modelled as current sources are incorporated to the optimization model to represent a High Voltage Direct Current (HVDC) line. Several practical applications are proposed in this previous work: In [36] a TSCOPF model is used to calculate the maximum loadability of the system and in [39] the effect of different fault clearing times on the cost of generation is analyzed.

1.2.5 Challenges in Transient Stability Constrained Optimal Power Flow formulations

Several approaches have been presented over the last two decades to deal with TSCOPF problems, with their strengths and drawbacks. Research work should still be done in the following directions:

- Application of TSCOPF to real power systems maintaining reasonable computational times and an accurate representation of both the steady-state and the dynamics of the system. TSCOPF is an extensive mathematical problem with a large number of non-linear equations and variables and, at present, it is difficult to apply it to real power systems, since they produce large mathematical models that are difficult to solve.
- Improvement of TSCOPF models for their application to modern power systems with high participation of non-synchronous renewable generation and energy storage. Traditionally, the energy demand in power systems has been covered by large synchronous power plants that have also been responsible for stability. Consequently, TSCOPF studies have only focused on the representation of synchronous power plants to assess stability. Non-synchronous renewable sources are not represented in these studies. The increasing penetration of non-synchronous generation and storage systems in power systems has a considerable impact on the stability and, accordingly, these devices must be modelled in TSCOPF formulations.

- New applications of TSCOPF formulations: TSCOPF is generally proposed as a tool to calculate the dispatch of power systems, but the TSCOPF models can also be applied to other problems. For instance, other objectives functions can be evaluated to optimize the parameters of the controllers implemented in TSCOPF formulations.

1.3 Objectives

The general objective of this thesis is to provide a software tool to optimize the operation of power systems, accommodating high shares of renewable non-synchronous generation in a secure and economic way, and taking into account the new requirements put forward by European Transmission System Operators. These objectives are in line with the challenges outlined in Section 1.2.5. The following specific objectives can be highlighted:

Development and improvement of TSCOPF algorithms:

- Formulation of a simultaneous discretization TSCOPF model that calculates the voltage and frequency at each node of the system and at each discretization time interval. The formulation allows the representation of non-synchronous renewable generation equipped with synthetic inertia and voltage regulator controls, energy storage systems and detailed load models.
- A comparative study of the performance of different numerical integration algorithms in TSCOPF, implementation of a variable integration time step in simultaneous discretization TSCOPF approaches and evaluation of their feasibility. Previous TSCOPF studies generally make use of the trapezoidal rule as an integration method while the performance of other integration methods has not yet been explored.
- Formulation of a model to represent non-synchronous renewable generation in simultaneous discretization TSCOPF studies. The model must be equipped with fault ride-through capability and provide reactive power support during voltage dips following the requirements imposed by the current Spanish grid code.
- Formulation and inclusion of an energy storage system model in a TSCOPF algorithm. Assessment of the effect of the energy storage system on the total generation cost and dynamic stability.

- Implementation of a synthetic inertia control in non-synchronous renewable generation models. Evaluation of the impact of the emulation of inertia on the total generation cost and dynamic stability, studying different parameters configurations for these controllers.
- Formulation of a multi-contingency TSCOPF to include a set of contingencies in a single optimization model. The solution ensures an economic operation and transient stability for the set of severe incidents previously defined by a user.
- The proposed tool must be simple to use, transparent to the user and flexible. It will receive the case data in a standard input format that will make it possible for the user to build and modify the case using PSS/E, the power system simulation tool most used by the Spanish Transmission System Operator and one of the most commonly used worldwide.

Application of the proposed TSCOPF formulations to different real and test case studies.

The proposed formulation is applied to the following networks:

- Tenerife network: The operation of the system in scenarios with high penetration of non-synchronous renewable generation presents a challenge due to the low inertia of the system since it is an isolated system without interconnections. The proposed TSCOPF formulation including the new non-synchronous renewable generation models is used to optimize the operation of the system in future scenarios with high rates of non-synchronous renewable generation, while minimizing operation cost and ensuring stability.
- North West Spanish network: The system is chosen due to both the very high penetration of renewable sources in the region and the international connection with the neighboring country of Portugal. Its operation involves scenarios where the production with renewable sources connected to the network through electronic converters highly exceeds production with conventional generation. The system is suitable for testing the new TSCOPF formulations proposed here, including non-synchronous renewable generation models equipped with synthetic inertia controllers and fault ride-through capability.
- Lanzarote-Fuerteventura power system: The selection of this system is due to the peculiar topology of the network of these islands that is basically linear, isolated and has a FESS installed to improve voltage and frequency stability. The system is

suitable for testing a Multi Contingency (MC)-TSCOPF, including non-synchronous renewable generation models and energy storage system models.

- The algorithm is also tested on both the New England IEEE 39 bus test system and the IEEE-57 bus test system. These cases provide a term of comparison with proposed TSCOPF formulations in other research works.

New applications of TSCOPF formulations:

- Use of a TSCOPF to optimize the operation of systems with very high penetration of non-synchronous renewable generation.
- Application of a TSCOPF formulation to minimize the curtailment of renewable generation in scenarios with high availability of wind and/or solar resources and low demand.
- The TSCOPF formulations are used to evaluate the effect of different control strategies in power parks and storage systems, both on the economic dispatch and stability.
- Application of a TSCOPF formulation to optimize the dynamic response of fast energy storage systems to support stability after different types of incidents in power systems.

1.4 Dissertation outline

The dissertation is organized into six different chapters. The first and the last chapter correspond to the Introduction and Conclusion, while the intermediate chapters correspond to four separate works that can be read independently.

Chapter 2 conducts a comparative study between different implementations to include the dynamic equations of power plants into the optimization problem. The chapter begins with a review of the numerical integration methods applied to simultaneous discretization TSCOPF models. Then, a flexible software framework is presented to facilitate the application of TSCOPF to different power systems. The chapter continues with the evaluation of the effect on the results of different explicit and implicit numerical integration methods as well as the use of different integration time steps. Finally, the use of a variable integration method is presented and implemented as a technique to reduce the size of the optimization problem while maintaining accuracy.

Chapter 3 proposes a TSCOPF formulation that includes a non-synchronous renewable generation model that provide reactive power support for voltage dips and fault ride-through capability. The algorithm is applied to both the IEEE 39 benchmark system and the real system of the island of Tenerife. A practical application of the algorithm is presented to minimize renewable generation curtailment in scenarios with high availability of wind and solar resources and low demand. The chapter concludes with the implementation and evaluation of several solutions to reduce renewable curtailment.

Chapter 4 introduces a new feature of the TSCOPF formulation that calculates the frequency and voltage at all buses of the system. The model includes the representation of non-synchronous generation modules with fault ride-through capability and equipped with a control for inertia emulation. The proposed TSCOPF is applied to the North-West Spanish power system, a region with high percentages of renewable generation. The algorithm calculates the optimal dispatch, minimizing generation cost and ensuring transient stability in scenarios with high wind penetration, as well as in 100% renewable scenarios. Finally, the chapter evaluates the impact on the results of different parameters for synthetic inertia controls.

Chapter 5 presents a multi-contingency TSCOPF formulation to consider simultaneously in a single optimization problem a set of severe incidents. The chapter continues with the presentation of a model to include energy storage systems within TSCOPF formulations. The model is applied to the real power system of the islands of Fuerteventura-Lanzarote where a flywheel energy storage system has been recently put in operation. Then, it is conducted an evaluation of the impact of load modelling in TSCOPF. Finally, the chapter presents a practical application of MC-TSCOPF to calculate the optimal response of a flywheel to support stability in the event of a contingency.

CHAPTER 2

ANALYSIS OF NUMERICAL METHODS TO INCLUDE DYNAMIC CONSTRAINTS IN AN OPTIMAL POWER FLOW MODEL

Transient Stability Constrained Optimal Power Flow (TSCOPF) is a non-linear mathematical programming problem that optimizes the operation of power systems considering steady state and dynamic constraints. TSCOPF models extend OPF models by including the electromechanical oscillations of synchronous machines. One of the main approaches in TSCOPF studies discretizes the differential equations representing the dynamics of the system and includes these equations in the optimization model. This chapter evaluates the impact of different numerical integration methods on the solution of a TSCOPF model, as well as the effect of the integration time step. Specifically, it is studied the effect on the power dispatch, the total generation cost, the calculation of the electromechanical oscillations between machines, the size of the optimization problem and the computational time required to attain the solution.

2.1 Introduction

During the last decade, Transient Stability Constrained Optimal Power Flow models have emerged as a useful tool for the operation and planning of power systems. TSCOPF is an optimization problem that calculates the optimal operating point of electric power systems, considering both static and dynamic constraints. A large number of papers have been recently published on the subject and different approaches have been proposed to deal with the problem [34], [35], [53], [54].

A TSCOPF model based on simultaneous discretization consists of two parts: 1) the equations representing the steady state operation of the power system and its limits of operation; and 2) the representation of the dynamics of the system during one or more incidents, together with the stability limits. Both parts are included in a single optimization model together with the objective function. One major drawback of the simultaneous discretization approach is that the inclusion of the dynamic equations causes a considerable increase in the number of equations and variables. To evaluate the transient stability, it is necessary to represent a period of at least 2-3 seconds. The choice of the integration time step is not straightforward and plays an important role, since small integration time steps lead to a proportional increase in the size of the optimization model, while large steps can introduce significant errors. The use of a variable integration time step can help to reduce the computational effort by applying different time steps at several stages of the simulation, depending on the dominant transient phenomena. Using a variable time step is a relatively common approach in power system dynamic simulations [55], but it has been rarely used in TSCOPF studies.

Regarding the integration method, there are two main approaches to solve the differential-algebraic system of equations that represent the power system: simultaneous-implicit methods and partitioned-explicit methods [56]. On the one hand, partitioned-explicit methods are commonly used in power system transient stability programs because they are conceptually simple and easy to implement. On the other hand, simultaneous-implicit methods are generally preferred in TSCOPF studies because they are numerically more stable when applied to stiff systems. In the case of TSCOPF models the solution of an implicit method is not more complicated than the solution of an explicit one, as all the equations in the optimization model are solved simultaneously. Most previous TSCOPF studies have used the trapezoidal rule to integrate the dynamic equations [33], [34], [46], [57], [58]. However, the impact of the numerical integration algorithm and the corresponding time step has not been fully addressed.

This chapter applies a TSCOPF model that represents the load flow equations at each bus and at each sample time [59]. The dynamics of the system are represented using a 4th order d-q generator model that provides an adequate representation for transient stability studies [60]. The differential equations of the model are discretized using several implicit and explicit integration methods. The Theta method is used to implement three of the most widely used integration procedures for power system simulation: the forward Euler method, the trapezoidal rule, and the backward Euler method [20], [61], [62]. Two Runge-Kutta variants are also implemented separately.

The object of this study is twofold: 1) a comparative study of the performance of different numerical integration methods in the solution of the TSCOPF model; and 2) the implementation of a variable integration time step to reduce the size of the optimization problem and the convergence time. This chapter applies a software framework that reads the network data from standard PSSE files and automatically constructs the optimization model in GAMS language. The study presented here is performed on the IEEE 39 Bus benchmark test system.

The rest of chapter is organized as follows: Section 2.2 describes the optimization problem; Section 2.3 presents the case study and the software framework; Section 2.4 shows the results and discussion; and Section 2.5 concludes the chapter.

2.2 Optimization model

The optimization model of the proposed TSCOPF is described, as follows:

$$\min f(p_{i,0}^G) = \sum_{\forall i \in \Omega^G} (A_i^G (p_{i,0}^G)^2 + B_i^G p_{i,0}^G + C_i^G) \quad (2.1)$$

Subject to:

$$p_{i,t}^G - p_{i,t}^L = v_{i,t} \sum_{j=1}^{j=N} v_{j,t} Y_{i,j} \cos(\alpha_{i,t} - \alpha_{j,t} - \theta_{i,j}), \forall i \in \Omega^B, \forall t \in \Omega^T \quad (2.2)$$

$$q_{i,t}^G - q_{i,t}^L = v_{i,t} \sum_{j=1}^{j=N} v_{j,t} Y_{i,j} \sin(\alpha_{i,t} - \alpha_{j,t} - \theta_{i,j}), \forall i \in \Omega^B, \forall t \in \Omega^T \quad (2.3)$$

$$p_{i,t}^L = P_i^L (A_i^P + B_i^P (v_{i,t} / v_{i,0}) + C_i^P (v_{i,t} / v_{i,0})^2), \forall i \in \Omega^L, \forall t \in \Omega^T \quad (2.4)$$

$$q_{i,t}^L = Q_i^L (A_i^Q + B_i^Q (v_{i,t} / v_{i,0}) + C_i^Q (v_{i,t} / v_{i,0})^2), \forall i \in \Omega^L, \forall t \in \Omega^T \quad (2.5)$$

$$i_{i,j}^{L^2} = Y_{i,j}^2 (v_{i,0} \cos \alpha_{i,0} - v_{j,0} \cos \alpha_{j,0})^2 + Y_{i,j}^2 (v_{i,0} \sin \alpha_{i,0} - v_{j,0} \sin \alpha_{j,0})^2 \forall i, j \in \Omega^B \quad (2.6)$$

$$\alpha_{i,0} = 0 \quad (2.7)$$

$$\begin{aligned} e_{i,t}^{rQ} - e_{i,t-1}^{rQ} &= \frac{\Delta t T^{TH}}{T_i^{rD}} \left[e_i^{rFD} - (X_i^D - X_i^{rD}) i_{i,t-1}^{rD} - e_{i,t-1}^{rQ} \right] \\ &+ \frac{\Delta t (1 - T^{TH})}{T_i^{rD}} \left[e_i^{rFD} - (X_i^D - X_i^{rD}) i_{i,t}^{rD} - e_{i,t}^{rQ} \right] \forall i \in \Omega^G, \forall t \in \Omega^{TD} \end{aligned} \quad (2.8)$$

$$\begin{aligned}
e_{i,t}^D - e_{i,t-1}^D &= \frac{\Delta t T^{\text{TH}}}{T_i^Q} \left[(X_i^Q - X_i^Q) i_{i,t-1}^Q - e_{i,t-1}^D \right] \\
&+ \frac{\Delta t (1 - T^{\text{TH}})}{T_i^Q} \left[(X_i^Q - X_i^Q) i_{i,t}^Q - e_{i,t}^D \right] \forall i \in \Omega^G, \forall t \in \Omega^{\text{TD}}
\end{aligned} \tag{2.9}$$

$$\begin{aligned}
\Delta \omega_{i,t} - \Delta \omega_{i,t-1} &= \frac{\Delta t T^{\text{TH}}}{2H_i} \left[p_i^M - p_{i,t-1}^E - D_i \Delta \omega_{i,t-1} \right] \\
&+ \frac{\Delta t (1 - T^{\text{TH}})}{2H_i} \left[p_i^M - p_{i,t}^E - D_i \Delta \omega_{i,t} \right] \forall i \in \Omega^G, \forall t \in \Omega^{\text{TD}}
\end{aligned} \tag{2.10}$$

$$\delta_{i,t} - \delta_{i,t-1} = \Delta t \omega^{\text{REF}} (T^{\text{TH}} \Delta \omega_{i,t-1} + (1 - T^{\text{TH}}) \Delta \omega_{i,t}), \forall i \in \Omega^G, \forall t \in \Omega^{\text{TD}} \tag{2.11}$$

$$e_{i,0}^D = (X_i^Q - X_i^Q) i_{i,0}^Q, \forall i \in \Omega^G \tag{2.12}$$

$$e_{i,0}^Q = e_i^{\text{FD}} - (X_i^D - X_i^D) i_{i,0}^D, \forall i \in \Omega^G \tag{2.13}$$

$$p_i^M = p_{i,0}^E, \forall i \in \Omega^G \tag{2.14}$$

$$\Delta \omega_{i,0} = 0, \forall i \in \Omega^G \tag{2.15}$$

$$e_{i,t}^D = v_{i,t} \sin(\delta_{i,t} - \alpha_{i,t}) + R_i^A i_{i,t}^D - X_i^Q i_{i,t}^Q, \forall i \in \Omega^G, \forall t \in \Omega^T \tag{2.16}$$

$$e_{i,t}^Q = v_{i,t} \cos(\delta_{i,t} - \alpha_{i,t}) + R_i^A i_{i,t}^Q + X_i^D i_{i,t}^D, \forall i \in \Omega^G, \forall t \in \Omega^T \tag{2.17}$$

$$p_{i,t}^E = e_{i,t}^D i_{i,t}^D + e_{i,t}^Q i_{i,t}^Q, \forall i \in \Omega^G, \forall t \in \Omega^T \tag{2.18}$$

$$p_{i,0}^G = i_{i,0}^D v_{i,0} \sin(\delta_{i,0} - \alpha_{i,0}) + i_{i,0}^Q v_{i,0} \cos(\delta_{i,0} - \alpha_{i,0}), \forall i \in \Omega^G \tag{2.19}$$

$$q_{i,0}^G = i_{i,0}^D v_{i,0} \sin(\delta_{i,0} - \alpha_{i,0}) - i_{i,0}^Q v_{i,0} \cos(\delta_{i,0} - \alpha_{i,0}), \forall i \in \Omega^G \tag{2.20}$$

$$\delta_t^{\text{COI}} = \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \delta_{i,t} \right) / \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \right), \forall t \in \Omega^T \tag{2.21}$$

$$-\delta^{\text{MAX}} \leq \delta_{i,t} - \delta_t^{\text{COI}} \leq \delta^{\text{MAX}}, \forall i \in \Omega^G, \forall t \in \Omega^T \tag{2.22}$$

$$P_i^{\text{MIN}} \leq p_{i,0}^G \leq P_i^{\text{MAX}}, \forall i \in \Omega^G \tag{2.23}$$

$$Q_i^{\text{MIN}} \leq q_{i,0}^G \leq Q_i^{\text{MAX}}, \forall i \in \Omega^G \quad (2.24)$$

$$V_i^{\text{MIN}} \leq v_{i,0} \leq V_i^{\text{MAX}}, \forall i \in \Omega^B \quad (2.25)$$

$$0 \leq i_{i,j}^L \leq I_{i,j}^{\text{MAX}}, \forall i, j \in \Omega^B \quad (2.26)$$

$$\text{EFD}_i^{\text{MIN}} \leq e_i^{\text{FD}} \leq \text{EFD}_i^{\text{MAX}}, \forall i \in \Omega^G \quad (2.27)$$

The objective function (2.1) minimizes the generation cost of the system calculated as a quadratic function. Constraints (2.2) and (2.3) represent the active and reactive power balance at each node of the grid and at each sample time, including the pre-fault, fault and post fault periods. Constraints (2.4) and (2.5) represent the system loads, which are modeled by the standard ZIP load model [20]. Constraints (2.6) determine the current flowing through the power lines at the pre-fault stage. Constraint (2.7) sets the angle reference at the initialization.

Power plants are modeled by the 4th order d-q transient synchronous generator model that provides an accurate representation for TSCOPF studies [47], [56]. The differential equations of the model represented in (2.28)-(2.31) are discretized by using the generalized Theta method in (2.32)-(2.33) resulting in constraints (2.8)-(2.11). Thereby, the forward Euler method, the trapezoidal Rule and the backward Euler method are selected by adjusting the theta value (T^{TH}) to 1, $\frac{1}{2}$ and 0, respectively [61]. Constraints (2.12)-(2.15) determine the initial values of the transient stability variables, that result from equating to zero the differential equations in (2.28)-(2.31).

Constraints (2.16) and (2.17) relate the internal variables of power plants to variables of the grid, and constraints (2.18) determine the electric power in the rotor of the synchronous machine at each sample time t . Constraints (2.19) and (2.20) calculate the direct and quadrature currents by power plants. Constraints (2.21) determine the angle deviation of the center of inertia (COI) at each sample time. On the other hand, constraints (2.22) limit the maximum rotor angle deviation of each power plant at each sample time to ensure transient stability. Constraints (2.23) and (2.24) limit active and reactive power outputs by power plants, respectively. Finally, constraints (2.25) limit the voltages at each node of the grid, constraints (2.26) are the operation limits of power lines, and constraints (2.27) limit the field voltages at each power plant.

$$\begin{bmatrix} e^{i^{\text{FD}}} - (X^{\text{D}} - X^{\text{D}})i^{\text{D}} - e^{i^{\text{Q}}} \end{bmatrix} \quad (2.28)$$

$$\begin{bmatrix} (X^{\text{Q}} - X^{\text{Q}})i^{\text{Q}} - e^{i^{\text{D}}} \end{bmatrix} \quad (2.29)$$

$$\Delta \omega \begin{bmatrix} p^{\text{M}} - p^{\text{E}} - D\Delta\omega \end{bmatrix} \quad (2.30)$$

$$\begin{bmatrix} \end{bmatrix} \quad (2.31)$$

$$\begin{bmatrix} \end{bmatrix} \quad (2.32)$$

$$y_{t+1} = y_t + \Delta t [T^{\text{TH}} f(t, y_t) + (1 - T^{\text{TH}}) f(t_{t+1}, y_{t+1})] \quad (2.33)$$

2.3 Case of study and implementation

The study is applied to the IEEE 39 Bus New England benchmark test system, represented in Figure 2.1. The system data can be found in [63].

The optimization problem proposed here is implemented using the software framework shown in Figure 2.2. Firstly, a program in Python reads the data corresponding to the network, power plants and loads from standard PSSE files. Then, it constructs automatically the TSCOPF model, as follows: 1) It calculates the admittance matrices for the pre-fault, fault and post fault stages taking into account the information about the contingency and the switching operations; 2) It defines the set of power plants, buses, loads and parameters of the system using the data from the PSSE file; and 3) It writes the optimization model using (2.1)-(2.27). Finally, the file is fed into GAMS [64], that compiles it and subsequently solves it using the library IPOPT. IPOPT solves large scale non-linear optimization problems using a prime-dual interior point method [65], [66]. The proposed approach facilitates the application of the optimization model to different electric power systems and allows the user to easily modify the network topology, the load, the contingencies and the optimization solver.

Figure 2.1 New England bus test system and the fault locations corresponding to the study in Section 2.4.

Figure 2.2 Software implementation for TSCOPF.

Two different contingencies have been analyzed, as shown in Figure 2.1:

- A three-phase short-circuit occurs in the transmission line connecting buses 15 and 16—adjacent to bus 16. The fault is cleared by opening the circuit breakers at the two ends of this line after 300 ms.
- A three-phase short-circuit occurs in the transmission line connecting buses 3 and 4—adjacent to bus 3. The fault is cleared by opening the circuit breakers at the two ends of this line after 300 ms.

These faults have been selected because they pose a considerable risk to transient stability due, on the one hand, to their location in the bulk of the transmission system and, on the other hand, to the fact that the loss of the line after the clearance of the fault significantly weakens the system. As a result, in all the studied cases the rotor angle deviation at one or more synchronous generators reaches its limits (see Figure 2.10. for an example), which means that the dynamic constraints play a significant role because they affect the optimal dispatch. In other words, the solution provided by a classical OPF is not transiently stable and the TSCOPF modifies the dispatch to ensure that the solution is stable. Thus, in the studied cases the production cost of the dispatch provided by the TSCOPF is always higher than the cost of the dispatch provided by a classical OPF.

The simulations in this chapter have been performed using the IPOPT library on a personal computer equipped with a 3.40 GHz processor. The results obtained by a version of the proposed TSCOPF model that implemented a trapezoidal rule have been verified using dynamic simulations in PSSE [39].

2.4 Results and discussion

2.4.1 Comparison between numerical integration methods

This section presents the influence of different integration methods on the solution of the TSCOPF model. Figure 2.3 shows the optimal production cost (i.e. the value of the objective function) calculated by the solution of the TSCOPF model when a short-circuit at bus 16. The different values correspond to the three discretization methods implemented and several integration time steps. The study considers a time-horizon representation of 2 seconds after the fault.

It can be seen from Figure 2.3 that all three methods provide the same result when the integration step is small enough, while large integration steps produce different results depending on the integration method. To provide a term of comparison, a typical time step

Figure 2.3 TSCOPF result obtained using different numerical integration methods and integration time steps.

used in commercial power system simulators is one half of a cycle, this is 0.0083 s at 60 Hz and 0.01 s at 50 Hz. As can be seen, the forward Euler method is the least affected by the choice of integration step and the one that provides the most accurate solution in terms of the objective function. The largest errors are obtained with the backward Euler method, while the trapezoidal rule (the most commonly used method in TSCOPF studies) is localized between the two variants of the Euler method.

The results in Figure 2.3 may be explained by the trajectories of the rotor speed deviations given by the solution of the TSCOPF model when using each method. Figure 2.4. shows the speed deviation of the power plant at bus 34 using two integration time steps, 0.002 and 0.02 s. It can be seen in Figure 2.4 a) that when the integration step is small the trajectories are similar. Thus, as the integration step approaches zero, a common solution is reached by the three methods. This common solution is taken as the reference solution in Figure 2.4.b), which shows the electromechanical oscillations obtained with a larger integration time step by the three implemented methods. Figure 2.4 b) is quite revealing because it shows that the solution obtained by the backward Euler method is significantly damped compared to the reference solution. The oscillation obtained using the trapezoidal rule is also damped, but to a lesser degree. As a result, the solutions provided by the backward Euler method and the trapezoidal rule are more stable than the reference solution and their operating costs are lower, as shown in Figure 2.3. On the other hand, it can be seen that the forward Euler method heightens the electromechanical oscillations with respect to the reference solution, which implies a more conservative solution. These results are consistent with those described in [67], where different integration methods are applied to a classical mechanical problem, and in [21], [62], where different integration methods are applied to a power system using the toolbox for power system analysis PSAT.

Figure 2.4 Rotor speed deviation at the generator at bus 34 when a short circuit at bus 16. a) with a integration time step of 0.002 s b) with a integration time step of 0.02 s.

Figure 2.5 shows the trajectories corresponding to a short circuit at bus number 3. The results are qualitatively similar to those in Figure 2.4, described above. Again, as the integration time step increases the solutions provided by the backward Euler method and the trapezoidal rule are damped compared to the reference solution, as opposed to the forward Euler method.

It is well known that, contrary to the forward Euler method, the backward Euler method and the trapezoidal rule are A-stable. This makes both methods well suited for numerical integration of stiff systems in general, and power system in particular [20], [21]. Thus, it is remarkable that integration methods that are numerically stable can produce dispatches that are transiently unstable in the real world because they tend to damp electromechanical oscillations with respect to the real trajectories for long integration time steps.

Regarding the numerical convergence of the solution, it must be observed that it has not been possible to obtain solutions of the TSCOPF model with the forward Euler method and time steps longer than 0.05 s. Figure 2.6 shows the rotor speed deviation at the synchronous generator connected to bus 34 when a short circuit is applied at bus 16 and the integration step is 0.05 s. It can be seen that the trajectory obtained by the forward Euler method differs

Figure 2.5 Rotor speed deviation at the generator at bus 30 when a short circuit at bus 3. a) with a integration time step of 0.002 s b) with a integration time step of 0.02 s

largely from those of the other two methods and the reference solution. This can be explained by the poor numerical stability of the forward Euler method.

Figure 2.6 Rotor speed deviation at the generator at bus 34 when a short circuit at bus 16 and a integration time step of 0.05 s.

Regarding the computation time, Table 2.1 presents the convergence times for the three cases of study in Figure 2.3. It can be seen that the computation time increases rapidly as the integration step decreases. For example, as the integration step is divided by 10 from 0.01 to 0.001, the computation time is multiplied by 34 (forward Euler), by 44 (trapezoidal rule) and by 39 (backward Euler). The reason is that reducing the integration step increases

the number of equality constraints in the optimization model. When large integration steps are used the convergence times are similar in the three methods. As the integration step decreases, and although the results vary depending on the specific case, it is observed that the optimization model applying the trapezoidal rule is solved with the shortest computational time. It is remarkable that the increase in computation time is not proportional to the number of equations or variables, as can be seen in the rows showing Time/Equations and Time/Variables. According to the results in this section it can be concluded that in terms of accuracy and calculation times, an integration time step of 0.01–0.02 s seems to be the optimal choice.

Table 2.1 Time of convergence of the TSCOPF for the studied numerical integration methods and different integration time steps.

Δt	0.0005	0.001	0.002	0.003	0.005	0.01	0.02	0.05
Equations	680,071	340,071	170,071	113,291	68,071	34,071	17,071	6871
Variables	600,030	300,030	150,030	60,030	30,030	15,030	9930	6030
Forward Euler								
Time (s)	4211	796	394	188	157.6	23.48	9.95	2.84
Time/Equations	6.2×10^{-3}	2.3×10^{-3}	2.3×10^{-3}	1.7×10^{-3}	2.3×10^{-3}	7×10^{-4}	6×10^{-4}	4×10^{-4}
Time/Variables	7×10^{-3}	2.7×10^{-3}	2.6×10^{-3}	1.9×10^{-3}	2.6×10^{-3}	8×10^{-4}	7×10^{-4}	5×10^{-4}
Trapezoidal Rule								
Time (s)	3799	774	184	176	69.3	17.7	7.85	2.83
Time/Equations	5.6×10^{-3}	2.3×10^{-3}	1.1×10^{-3}	1.6×10^{-3}	1×10^{-3}	5×10^{-4}	4.6×10^{-4}	4×10^{-4}
Time/Variables	6.3×10^{-3}	2.6×10^{-3}	1.2×10^{-3}	1.8×10^{-3}	1.2×10^{-3}	5.9×10^{-4}	5.2×10^{-4}	4.7×10^{-4}
Backward Euler								
Time (s)	5739	1055	537	289	116	18	7.97	2.94
Time/Equations (s)	8.4×10^{-3}	3.1×10^{-3}	3.2×10^{-3}	2.6×10^{-3}	1.7×10^{-3}	5.3×10^{-4}	4.7×10^{-4}	4.3×10^{-4}
Time/Variables (s)	9.6×10^{-3}	3.5×10^{-3}	3.6×10^{-3}	2.9×10^{-3}	1.9×10^{-3}	6×10^{-4}	5.3×10^{-4}	4.9×10^{-4}

2.4.2 Simulation of other disturbances

This section shows the results of applying the TSCOPF algorithm to other types of contingencies using the different integration methods presented in Section 2.4.1. Three different types of contingencies are studied: 1) the power outage of a generator; 2) the loss of a load; and 3) the loss of a line. Three of the most severe cases are presented here:

Figure 2.7 Rotor speed deviation of generators. a) Generators 37 and 38 when a power outage of generator connected to bus 30. b) Generators 34 and 36 when the loss of the load connected to bus 20. c) Generators 30 and 31 when the loss of line 2–3

- The power outage of power plant connected to bus 30 which is injecting 800 MW to the grid
- The loss of the load connected to bus 20 which is the largest of the system and consumes 680 MW.

- The loss of the line connecting buses 2 and 3.

In contrast to the three-phase short-circuits presented previously these contingencies are not critical, which means that the operational costs given by the TSCOPF is the same obtained with an OPF. Figure 2.7 illustrates the speed deviation of different power plants when the described contingencies occur.

Figure 2.7.a shows the rotor speed deviation of power plants connected to buses 37 and 38 after a sudden disconnection of the power plant connected to bus 30. It can be observed how the speed of the machines decreases as they assume the generation of the disconnected power plant. It is remarkable how the curves obtained using the different integration methods follow the same tendency as those presented in Section 2.4.1. The forward Euler method presents the most conservative solution because it maintains the size of the oscillations. On the other hand, the trapezoidal rule and, to a higher degree, the backward Euler method damp the oscillations with respect to the reference solution.

Figure 2.7.b shows the rotor speed deviation of power plants connected to buses 34 and 36 when the load connected to bus 20 is shed. In this scenario, the rotor speed of synchronous machines increases as they transform the demand of the disconnected load into kinetic energy. Again, the result of the curves obtained by the different integration methods follows the same tendency. Finally, Figure 2.7.c shows the rotor speed deviation of power plants connected to buses 30 and 31 when the line connecting buses 2 and 3 is lost. Similar conclusions can be obtained here with respect to the different integration methods.

2.4.3 Generalized Theta Method

The Theta method represents alternatively the forward Euler method, when $\Theta = 1$, the Trapezoidal Rule, when $\Theta = 0.5$, and the backward Euler method, when $\Theta = 0$ [61]. The generalized Theta method makes it possible to extend the range of application of this notation by assigning to Theta any other number between 0 and 1 in equations (2.8)-(2.11).

Figure 2.8 shows the generation costs obtained when different values of Theta are used in the case of a short circuit at bus 16 and various time steps. A similar result is obtained with all the Theta values for short integration time steps. However, as the integration step increases, the result obtained for the same case increases as the Theta value grows. These results are consistent with those shown in the previous section: the forward Euler method provides a more conservative solution, and therefore a slightly higher generation cost. As

shown in Figure 2.8, the relation between the value of Theta and the generation cost when the generalized Theta method is applied is essentially linear.

Figure 2.8 Results of the TSCOPF depending on the value of Theta when a short circuit is applied at bus 16

Figure 2.9 shows the computation time needed to solve the cases in Figure 2.8. Similar convergence times are obtained using large integration time steps since the size of the optimization problem is small. However, it can be observed that the computation time tends to increase with Theta = 0 and with Theta = 1 when the time step is short. These are the cases corresponding to the forward and backward Euler methods, which are the cases in which the state variables appear at just one discretization point in the discretized differential equations (2.8)-(2.11). According to Figure 2.9, when the computation time is an issue it is advisable to avoid these methods.

Figure 2.9 Computation time depending on the value of Theta when a short circuit is applied at bus 16

2.4.4 Comparison with RK2 and RK4 Runge-Kutta methods

This section analyzes the performance of the second and fourth order Runge-Kutta methods (RK2 and RK4). These methods are rarely used in TSCOPF studies because implicit methods are usually preferred due to their numerical stability. The interest of Runge-Kutta methods lies in that they are widely used to solve differential-algebraic equation systems in general, and power system dynamic models in transient stability software programs, in particular.

The implementation of the RK2 and RK4 methods involves the introduction of several intermediate variables and constraints to represent the differential equations (2 constraints per differential equation in the case of RK2 and 4 in the case of RK4). This has the unwanted effect of increasing the already large size of the optimization model, which is one of the main drawbacks of TSCOPF studies in real systems applications.

The 4th order d-q generator model is represented by four differential equations [56]. Constraints (2.34)-(2.38) result from the application of the RK4 method to the differential equation that calculates the transient voltage in the d-axis and serve as an example of the implementation of the RK4 method in the optimization model. Therefore, constraints (2.34)-(2.38) replace constraints (2.9) in the original optimization model (2.1)-(2.27). As can be seen, five different constraints and four intermediate variables (k^{1D} , k^{2D} , k^{3D} and k^{4D}) must be added for each differential equation. Similarly, constraints (2.8), (2.10) and (2.11) must be substituted with the corresponding RK4. In the case of implementing the RK2 method, each differential equation requires 3 equations and 2 intermediate variables in the optimization model.

$$e_{i,t}^{1D} - e_{i,t-1}^{1D} = \frac{\Delta t}{6} \left[K_{i,t-1}^{1D} + 2K_{i,t-1}^{2D} + 2K_{i,t-1}^{3D} + K_{i,t-1}^{4D} \right], \forall i \in \Omega^G, \forall t \in \Omega^{TD} \quad (2.34)$$

$$K_{i,t-1}^{1D} = \frac{1}{T_i^{1Q}} \left[(X_i^Q - X_i^{1Q}) i_{i,t-1}^Q - e_{i,t-1}^{1D} \right], \forall i \in \Omega^G, \forall t \in \Omega^{TD} \quad (2.35)$$

$$K_{i,t-1}^{2D} = \frac{1}{T_i^{1Q}} \left[(X_i^Q - X_i^{1Q}) i_{i,t-1}^Q - (e_{i,t-1}^{1D} + \frac{\Delta t K_{i,t-1}^{1D}}{2}) \right], \forall i \in \Omega^G, \forall t \in \Omega^{TD} \quad (2.36)$$

$$K_{i,t-1}^{3D} = \frac{1}{T_i^{1Q}} \left[(X_i^Q - X_i^{1Q}) i_{i,t-1}^Q - (e_{i,t-1}^{1D} + \frac{\Delta t K_{i,t-1}^{2D}}{2}) \right], \forall i \in \Omega^G, \forall t \in \Omega^{TD} \quad (2.37)$$

$$K_{i,t-1}^{4D} = \frac{1}{T_i^Q} \left[(X_i^Q - X_i^{*Q}) i_{i,t-1}^Q - (e_{i,t-1}^{1D} + \Delta t K_{i,t-1}^{3D}) \right], \forall i \in \Omega^G, \forall t \in \Omega^{TD} \quad (2.38)$$

Table 2.2 shows the results obtained when applying the different algorithms to a short circuit at bus 16 and an integration time step of 0.002 s. It can be seen that the size of the model in terms of number of variables and number of constraints increases significantly with the order of the Runge-Kutta method. The computational time needed to solve the model increases too, although the number of iterations remains relatively small.

Table 2.2 Comparison of the common methods used in TSCOPF with the Runge Kutta methods

Method	Forward Euler	Trapezoidal Rule	BackwardEuler	Runge Kutta 2	Runge Kutta 4
Number of variables	150,030	150,030	150,030	459,950	619,870
Number of constraints	170,071	170,071	170,071	499,991	659911
Number of iterations	50	49	56	55	54
CPU time (s)	404	347	451	1,463	1,438

In the studied cases, it has not been possible to solve the models using the Runge-Kutta algorithms with integration time steps larger than 0.005 s or shorter than 0.0005 s. On the one hand, the size of the optimization model prevents the use of small integration time steps. On the other hand, numerical convergence issues prevent the use of large integration time steps. It can be concluded that in the studied cases the combined effect of the size of the model and numerical stability narrows the applicability of the Runge-Kutta methods to a point that can make them unfeasible for TSCOPF studies.

2.4.5 Effect of a variable integration time step

This section proposes the use of a variable integration step to reduce convergence times. The implementation is carried out as follows: 1) A short time step is applied during the first second, to account for the severe transients produced during the fault and after the clearance of the fault; and 2) from that moment on a larger integration step is applied.

Table 3.3 shows the results obtained with and without a variable time step when a short-circuit is applied at bus 3. The first case uses a fixed time integration step of 0.005 s. The second case applies an integration time step of 0.005 s during the first second, and a step of 0.01 s from then on. It can be seen in Table 3.3 that the application of a variable

Table 2.3 Results of TSCOPF considering fixed and variable integration time step

Size	Fixed step		Variable step		$\Delta\text{Size. (\%)}$
Equations	68,071		51,071		-24.97
Variables	60,030		45,030		-24.99
Method	Cost(€)	Conv. (s)	Cost(€)	Conv. (s)	$\Delta\text{TConv. (\%)}$
F. Euler	43,993	157.708	43,960	32.359	-79.48
T. rule	43,942	69.289	43,942	29.033	-58.10
B. Euler	43,893	116.569	43,925	29.947	-74.31

integration time step reduces the size of the optimization problem, the number of equations is decreased by 24.97%, and the number of variables by 24.99%. However, the impact on the computation time is more significant, reducing it by 79.48% with the forward Euler method, by 58.10% with the trapezoidal rule, and by 74.31% with the backward Euler method. The high impact on the reduction in terms of convergence times is due to the large nonlinearity between the computation time and the step size, as shown in Table 2.1.

Figure 2.10 Rotor angles as provided by the solution of the TSCOPF when a short circuit at bus 16: a) using a fixed integration time step b) using a variable integration time step.

Regarding the accuracy of the results, Figure 2.10 compares the rotor angle deviation of all the synchronous generators when using the trapezoidal rule with fixed (Figure 2.10.a) and variable (Figure 2.10.b) integration time steps as described above. The generators reach the transient stability limit at approximately 0.6 s after the fault, before shifting to the longer time step. As it can be seen, the results are almost identical. The same can be said from Figure 2.11 that shows the rotor speed deviation of all synchronous generators when using a fixed and a variable integration time step.

These results show that the use of a variable integration step in the TSCOPF model achieves a considerable reduction in computation times while maintaining the accuracy of the results. The results obtained for other contingencies have been qualitatively similar to those presented here.

Figure 2.11 Rotor speed deviation as provided by the solution of the TSCOPF when a short circuit at bus 16: a) using a fixed integration time step b) using a variable integration time step

2.5 Conclusions

The performance of several numerical integration methods in a transient stability constrained optimal power flow based on simultaneous discretization has been analyzed.

The trapezoidal rule, the backward Euler method and the forward Euler method have been found to be practical alternatives, with these differences:

- In terms of convergence, there are no problems in the studied cases with time steps up to 0.03 s. However, the forward Euler method provides results that differ significantly from the reference solution when the integration time step is larger than 0.03 s and fails to converge if larger integration steps are used. As expected, the numerical stability of the forward Euler method is known to be poor compared to implicit integration methods. Although the forward Euler method is viable in the studied case, in other cases numerical stability could be a problem depending on the stiffness of the set of differential-algebraic equations representing the dynamics of the power system.
- In terms of the numerical solution, it has been found that the backward Euler method and, in less degree, the trapezoidal rule, tend to damp the electromechanical oscillations. This effect increases with the length of the integration time step and can lead to dispatches that produce unstable cases in the real world. Operators assessing the stability of a system should be aware of this effect, and perhaps compensate it by introducing a security margin in the dynamic constraints of the optimization model.
- In terms of the speed of convergence, the trapezoidal rule has been found to be the fastest method.

In sum, all three methods have been found to be viable and an integration time step length of 0.01 s has provided accurate solutions and reasonable convergence times. Although in the studied cases the trapezoidal rule represents a good compromise between numerical stability, convergence speed and accuracy of the solution, the forward Euler method provides more conservative results. It is therefore advisable to keep the Theta formulation in the optimization model to be able to explore both methods depending on the specific case they are applied to.

Finally, the use of a variable integration time step has proven to be a valid technique to reduce the number of equations and variables of the optimization model and, substantially, convergence times. Reductions of up to almost 80% have been obtained and no problems of convergence or errors in the solution have been observed using adequate variable integration steps.

CHAPTER 3

OPTIMAL CURTAILMENT OF NON-SYNCHRONOUS RENEWABLE GENERATION IN THE ISLAND OF TENERIFE CONSIDERING TRANSIENT STABILITY CONSTRAINTS

The increasing penetration of non-synchronous, renewable energy in modern power systems displaces synchronous generation and affects transient stability. This is just one of the factors that has led to preventive curtailment of renewable energy sources in an increasing number of electrical grids. Transient stability constrained optimal power flow techniques provide a tool to optimize the dispatch of power systems while ensuring a secure operation. This chapter proposes a transient stability-constrained OPF model that includes non-synchronous generation with fault ride-through capability and reactive support during voltage dips. The model is applied it to the IEEE 39 Bus benchmark test case and to the power system of the Spanish island of Tenerife and solved using the open-source library IPOPT that implements a primal-dual interior point algorithm. The solution of the model makes it possible to optimize the dispatch of conventional plants and the curtailment of non-synchronous generation, as well as to explore methods to reduce generation cost. Fault ride-through capability, synchronous inertia and fault clearing times are identified as useful tools to reduce the curtailment of non-synchronous generation, especially during periods of low load and high availability of renewable energy sources.

3.1 Introduction

Probably, over the last two decades, increasing numbers of non-synchronous wind and solar photovoltaic (PV) stations have been connected to many power systems, following a trend that is likely to continue given the international commitment to fighting climate change. These power stations are very different in nature from the conventional synchronous generation that has dominated the development of power systems over the course of the 20th century. The difficulties of integrating these technologies have led to preventive curtailment of renewable generation in several systems over the last decade [7], [68]. One of the key factors is that non-synchronous generation is connected to the electrical grid through electronic converters. This affects the inertia of the system and the electromechanical oscillations between synchronous generators after a severe fault [69]. As a result, transient stability is one of the reasons why transmission system operators limit the amount of non-synchronous renewable generation [70]–[72].

The island of Tenerife belongs to the Spanish Canary Islands archipelago, located west of Morocco on the north-west African coast. Non-synchronous generation is expected to grow significantly on the island over the next decade due to the high potential of the island for wind [73] and PV [74] generation, and a strong institutional support [75]. The integration of this new generation within the existing system poses challenges similar to those in other islands with high penetration of renewable energy sources [76], [77]. Among these challenges is the need to ensure transient stability and maintain cost-effective operation, limiting non-dispatchable generation if necessary. Optimal Power Flow (OPF) methods that include transient stability constraints, often referred to as Transient Stability-Constrained Optimal Power Flow (TSCOPF) methods, have emerged since the late 1990s to address this problem [48]. Given the size and complexity of TSCOPF optimization models, the necessary trade-off between model detail and computational time has produced a number of different approaches [34]. Numerical methods that incorporate the discretized differential equations defining the dynamics of the power system into the formulation of the OPF [33], [58] have several advantages, such as being able to robustly handle unstable systems with different constraints [34]. However, they produce large models with a number of variables and equality constraints that is impractical for large or medium-size systems. To reduce computational time, methods based on simplified models such as SIME [78], [79] provide rough estimations and have limitations dealing with complex trajectories, but are generally fast and robust. Other authors reach a compromise between accuracy and computational time by decoupling optimization algorithms and simulation tools [45], or by

using detailed models in combination with meta-heuristic searching algorithms [31], [48], [80]. The relatively small size of the Tenerife power system makes it suitable for an optimization model that directly incorporates the discretized differential equations. This chapter proposes a TSCOPF model based on a simultaneous discretization approach that includes non-synchronous generation, and calculates the optimal curtailment of non-dispatchable plants based on static and dynamic constraints. The dynamic constraints ensure that the power system remains transiently stable after a series of pre-determined faults. The main contributions are the inclusion of non-synchronous generators with fault ride-through capability and voltage support in the optimization model; the treatment of non-dispatchable generation in the pre-fault stage as a variable to optimize the curtailment of renewable energy; and the application of the proposed model to explore several alternatives to reduce the generation cost on the island of Tenerife.

3.2 Optimization model

The optimization model consists of an objective function that represents the generation cost, a set of equality constraints that model the power system during the pre-fault, fault and post-fault stages, and a series of inequality constraints that represent the static and dynamic limits that ensure a secure operation. If more than one contingency is considered, then there is an independent set of equations for the fault and post-fault stages of each contingency. The pre-fault stage includes also the inequality constraints common in standard OPF models [26], such as limits on bus voltages, branch currents and production of power plants.

The cost function (2.1) is a quadratic function that includes all the synchronous generation in the pre-fault stage, although other options such as combinations of linear or exponential functions could also be used. Power produced by non-synchronous generators is not included in the cost function because it is supposed to come from non-dispatchable, renewable sources. Table 3.1 summarizes the constraints in the optimization model. Those constraints that are not common to other OPF and TSCOPF [33] models are detailed in the following sections.

3.2.1 Network and load modeling

The power system during the pre-fault, fault and post-fault stages is modelled by the following equations representing the power balance at bus i and at time step t :

Table 3.1 Summary of the constraints of the optimization problem.

Equality constraints		PF	TD
Network and load modeling	Power flow equations (3.1)-(3.2)	X	X
	Angle reference (2.7)	X	
	Load equations (3.3)-(3.4)	X	X
	Low voltages correction factor (3.5)		
	Currents in branches and transformers (2.6)	X	
Inequality constraints		PF	TD
	Voltage limits at buses(2.25)	X	
	Active and reactive power generation limits (2.23)-(2.24)	X	
	Maximum currents through branches and transformers (2.26)	X	
Equality constraints		PF	TD
Conventional power plant model	Discretized differential equations of power plants (2.8)-(2.11)		X
	Initialization of the differential equations(2.12)-(2.15)	X	
	Power plant static equations (2.16)-(2.20)	X	X
Inequality constraints		PF	TD
	Field voltage limits(2.27)	X	X
Equality constraints		PF	TD
Non-synchronous power plant model	Active power equations (3.6)	X	X
	Reactive power equations (3.7)	X	X
	Voltage support equations (3.8)		X
Equality constraints		PF	TD
Stability Limits	Rotor angles center of inertia(3.9)	X	X
	Speed deviation center of inertia(3.11)	X	X
Inequality constraints		PF	TD
	Rotor angle and speed deviation limits (3.10),(3.12)	X	X

$$p_{i,t}^G + f_{i,t}^{LV} p_{i,t}^{NSG} - f_{i,t}^{LV} p_{i,t}^L = v_{i,t} \sum_{j=1}^{j=N} v_{j,t} Y_{i,j} \cos(\alpha_{i,t} - \alpha_{j,t} - \theta_{i,j}), \forall i \in \Omega^B, \forall t \in \Omega^T \quad (3.1)$$

$$q_{i,t}^G + f_{i,t}^{LV} q_{i,t}^{NSG} - f_{i,t}^{LV} q_{i,t}^L = v_{i,t} \sum_{j=1}^{j=N} v_{j,t} Y_{i,j} \sin(\alpha_{i,t} - \alpha_{j,t} - \theta_{i,j}), \forall i \in \Omega^B, \forall t \in \Omega^T \quad (3.2)$$

where $p_{i,t}^G$, $q_{i,t}^G$, $p_{i,t}^{NSG}$ and $q_{i,t}^{NSG}$ are the active and reactive power produced by synchronous and non-synchronous generators, respectively; $v_{i,t} \angle \alpha_{i,t}$ is the complex voltage; and $Y_{i,j} \angle \theta_{i,j}$ is the (i,j) term of the bus admittance matrix. When $t = 0$ equations (3.1) and (3.2) represent the pre-fault stage and the pre-fault admittance matrix is used. When $t > 0$, depending on the time step, $Y_{i,j} \angle \theta_{i,t}$ is the admittance matrix that represents the grid under fault or post-fault conditions. Unlike other TSCOPF models that use a reduced admittance matrix at the fault and post-fault stages [38], here the complete bus admittance matrix is used. This makes it possible to calculate bus voltages at all time steps and therefore to represent non-linear loads and non-synchronous generation.

Loads are represented by the standard ZIP model [20], which uses a quadratic function of the voltage to model the load as a combination of constant impedance, constant current and constant power

$$p_{i,t}^L = P_i^L (A_i^P + B_i^P (v_{i,t} / v_{i,0}) + C_i^P (v_{i,t} / v_{i,0})^2), \forall i \in \Omega^L, \forall t \in \Omega^T \quad (3.3)$$

$$q_{i,t}^L = Q_i^L (A_i^Q + B_i^Q (v_{i,t} / v_{i,0}) + C_i^Q (v_{i,t} / v_{i,0})^2), \forall i \in \Omega^L, \forall t \in \Omega^T \quad (3.4)$$

Very low voltages are handled by means of low-voltage correction factor $f_{i,t}^{LV}$, which has a value of 1 at normal voltages and decreases quadratically towards zero when the magnitude of the voltage is lower than 0.2 p.u.:

$$f_{i,t}^{LV} = \min \left\{ \left(\frac{v_{i,t}}{0.2} \right)^2, 1 \right\}, \forall i \in \Omega^B, \forall t \in \Omega^T \quad (3.5)$$

The introduction of a low-voltage correction factor is a standard practice in transient stability simulations [81] to achieve numerical stability during severe faults.

3.2.2 Conventional power plant model

Synchronous generators are represented by the well-known, fourth order transient generator model [56]. The state variables of the model are the flux linkages in the d and q axis of a reference frame linked to the rotor, the rotor speed and the rotor angle. The differential equations that define the generator model are discretized over the fault and post-fault stages using the trapezoidal rule, and incorporated to the optimization model as equality constraints. Table 3.1 summarizes the different constraints that model conventional generation whose equations are presented in Chapter 2.

3.2.3 Non-synchronous renewable power plant model

This chapter includes non-synchronous generators in the optimization model to account for renewable energy connected to the grid through electronic converters. This category includes PV stations and variable speed windmills, either with doubly-fed induction generators or with synchronous generators connected to the grid via back-to-back electronic converters [82]. Fixed-speed windmills, that represent a small and declining proportion of new wind turbines, utilize induction generators and are not included in this category. It is a standard practice to neglect the dynamic of electronic converters in transient stability studies because they are very fast in comparison with the time scale of electromechanical oscillations. As a result, converters are modelled as current sources

instead of voltage sources [83]. This is the approach followed in the proposed model, where non-synchronous generators are defined by their production of active and reactive power. Fault ride-through requirements of non-synchronous power stations are critical to the stability of the system, and are therefore taken into account. Grid codes regarding regulation during faults refer mainly to two points: conditions under which the generating unit can be disconnected, and provision of reactive current during voltage dips [84]. Here requirements based on the Spanish Grid Code [6] are applied: non-synchronous plants disconnect if the voltage at the connection point falls below 20% of the nominal value, and reactive current during voltage dips increase linearly with the voltage decrease until it reaches 90% of the nominal current when voltage is 0.5 p.u., as shown in Figure 3.1.

Figure 3.1 Reactive power requirement for voltage support.

Power provided by non-synchronous plants depends primarily on the active and reactive power references P_i^{REF} and Q_i^{REF} , and is modelled as:

$$p_{i,t}^{\text{NSG}} = f_{i,t}^{\text{CON}} f_i^{\text{CURTAIL}} P_i^{\text{REF}}, \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{T}} \quad (3.6)$$

$$q_{i,t}^{\text{NSG}} = f_{i,t}^{\text{CON}} (Q_i^{\text{REF}} + q_{i,t}^{\text{VS}}), \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{T}} \quad (3.7)$$

Reference P_i^{REF} depends on the available renewable energy resource, such as wind or solar radiation. Reactive power Q_i^{REF} depends on the control strategy under normal conditions, which can be reactive power control, power factor control, or voltage control. Binary factor $f_{i,t}^{\text{CON}}$ in equations (3.6) and (3.7) is equal to one in the pre-fault stage. During the fault and post-fault stages, $f_{i,t}^{\text{CON}}$ is 1 if the power plant remains connected, and 0 if it is disconnected. Factor $q_{i,t}^{\text{VS}}$ in equation (3.7) represents the reactive current injected into the grid to support the voltage, and is calculated according to Figure 3.1 as shown in equation (3.8).

$$q_{i,t}^{\text{VS}} = v_{i,t} \min \left\{ 0.9, \frac{0.9}{0.5} (1 - v_{i,t}) \right\}, \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{T}} \quad (3.8)$$

Active power curtailment applied to each non-synchronous power plant is represented by term f_i^{CURTAIL} , which can have any value between 0 and 1.

3.2.4 Stability limits

Two different dynamic constraints are applied to ensure the stability of the system. Firstly, a common Center Of Inertia (COI) angle δ_t^{COI} is calculated, based on the synchronous generator rotor angles $\delta_{i,t}$ and inertia constants H_i , as shown in (3.9).

$$\delta_t^{\text{COI}} = \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \delta_{i,t} \right) / \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \right), \forall t \in \Omega^{\text{T}} \quad (3.9)$$

and the deviation of the rotor angles with respect to the COI angle is limited in all synchronous generators:

$$-\delta^{\text{MAX}} \leq \delta_{i,t} - \delta_t^{\text{COI}} \leq \delta^{\text{MAX}}, \forall i \in \Omega^{\text{G}}, \forall t \in \Omega^{\text{T}} \quad (3.10)$$

Secondly, a constraint is imposed on the frequency after the fault because frequency stability is an important issue on the island of Tenerife because of its small inertia. A common COI speed is calculated, based on the synchronous generator rotor speeds $\Delta\omega_{i,t}$ and inertia constants H_i , as:

$$\Delta\omega_t^{\text{COI}} = \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \Delta\omega_{i,t} \right) / \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \right), \forall t \in \Omega^{\text{T}} \quad (3.11)$$

and the deviation of the COI speed from the reference value is limited in constraints (3.12).

$$-\Delta\omega^{\text{MAX}} \leq \Delta\omega_{i,t} - \Delta\omega_t^{\text{COI}} \leq \Delta\omega^{\text{MAX}}, \forall i \in \Omega^{\text{G}}, \forall t \in \Omega^{\text{T}} \quad (3.12)$$

3.2.5 Implementation of the model

The model is programmed in the algebraic modelling language GAMS and defined as a nonlinear programming model with discontinuities (DNLP). It is solved using IPOPT, an open source library for large nonlinear models based on a primal-dual interior point method [85]. Figure 2.2 shows the flowchart of the implementation framework. To facilitate the process of writing and modifying the model, a Python program is developed that reads all

relevant data from a standard PSSE file and writes the GAMS model. This makes it possible to read the input data directly from the PSSE files routinely maintained by the Transmission System Operator.

3.3 Application to the IEEE 39 Bus Test System

The proposed optimization model is applied to a modified version of the IEEE 39 Bus Test System [86] that includes 10 non-synchronous power plants. The aims of this case are to show an application of the model and to evaluate its performance. Figure 3.2 shows all non-synchronous generators and the location of the fault, which is a direct 3-phase short circuit at bus 16 cleared after 300 ms by the disconnection of line 15–16. A GAMS model corresponding to this case is provided as a separate file in [87].

Figure 3.2 IEEE 39 Bus Test System with 10 non-sync plants.

The total load in the system is 6149.5 MW. The power plant at bus 39 represents a neighboring system that exports 1000 MW. Generators at buses 30 and 33 are base load power plants that produce 800 MW each; the rest of the synchronous generators are totally dispatchable. Non-synchronous power plants have a nominal power of 600 MW, and the availability of the renewable source is such that they can produce a maximum of 450 MW each (75% of the nominal power). This implies that some non-synchronous generation has

to be curtailed, since the load (6145.9 MW) is smaller than the base load generation (1600 MW) plus the imports (1000 MW) plus the available non-synchronous, renewable generation ($450 \times 10 = 4500$ MW). The first column in Table 3.2 shows the results of the conventional OPF model obtained when the dynamic constraints are removed. The second column shows the results of the proposed model when a homogeneous curtailment is applied, which means that all non-synchronous power plants are curtailed in the same proportion. This is achieved by using a unique f_i^{CURTAIL} for all non-synchronous power plants in equation (3.6). The third column shows the solution of the model when a selective curtailment is applied, this is when the curtailment of each non-synchronous plant is calculated independently.

Table 3.2. Solution of the optimization model

Concept	OPF	Proposed Model Homogeneous Curtailment	Proposed Model Selective Curtailment
Cost (M.U.)	227,382	308,902	247,767
Cost increase (%)	-	35.8	9.0
Sync. generation (MW)	2600.0	4048.0	3224.7
Non-sync. generation (MW)	3698.6	2273.4	2980.4
Non-sync curtailment (MW)	801.3	2226.6	1519.6
Non-sync curtailment (%)	17.8	50.5	33.8

It can be seen that the application of the dynamic constraints increases both non-synchronous energy curtailment and generation cost. The additional cost can be seen as the price to pay to ensure that the system is stable after the fault. The increase in cost is significantly lower in the case of selective curtailment compared to homogeneous curtailment (9.0% compared to 35.8%), because different non-synchronous plants have different effects on transient stability depending on their location in the system. Figure 3.3 shows the renewable energy curtailed at each non-synchronous power station when a selective and a homogeneous curtailment is applied.

Figure 3.3 Non-synchronous generation curtailment.

Figure 3.4 shows the rotor angles as provided by the solution of the optimization model in the case of the selective curtailment. It can be seen that all rotor angles remain within the limits, with the rotor angle of two synchronous generators reaching the limit at the point marked as A in Figure 3.4.

Figure 3.4 Solution of the optimization model: rotor angles.

Table 3.3 shows various parameters related to the performance of the solver. The memory and CPU time usage have been obtained on a personal computer with an AMD 1.35 GHz processor.

Table 3.3 Performance of the Ipopt solver

Concept	Value
Number of variables	15,238
Number of equality constraints	15,209
Number of inequality constraints	1660
Number of Iterations	117
Memory usage (MB)	414
CPU time in IPOPT (s)	80
CPU time in NLP function evaluations (s)	31

3.4 Application to the Tenerife Power System

Figure 3.5 represents a model of the Tenerife power system including several wind and PV power stations that account for renewable generation expected to be installed in the near future. The transmission network includes a 220 kV grid that covers the most

populated areas and a 66 kV ring around the island. Most lines are double circuits, so the loss of one circuit does not necessarily disconnects the substations at both ends of the line.

Figure 3.5 Tenerife Power System.

The peak load of the system is 580 MW and the off-peak load is 360 MW. Most generation is concentrated on the south-east coast of the island, around the substations of Granadilla and Candelaria. Table 3.4 shows all power stations in the system. Coal stations Candelaria, with 180MW, and Granadilla I, with 178 MW, provide a minimum base load generation. Combined cycle power plant Granadilla II contains several groups that can provide up to 300 MW. A smaller 50 MW, coal-fired power plant is connected on the west coast, at Chio substation. Non-synchronous generation corresponds to a number of wind farms and PV plans. Wind generation is concentrated on the south and east of the island, while solar generation is located on the south and at Realejos substation on the north. Part

Table 3.4 Power stations in the Tenerife power system.

Bus	Type	Rated power (MW)
Candelaria	Coal	180
Granadilla I	Coal	178
Granadilla II	Gas	300
Chio	Coal	50
Dique del este	Wind	100
Poris W	Wind	50
Poris PV	PV	50
Granadilla W	Wind	50
Granadilla PV	PV	50
Vallitos	Wind	100
Realejos	PV	100

of this renewable generation is already in place, such as some wind farms and PV generation at Granadilla and Poris. The rest corresponds to power plants that are expected to be installed in a few years. The total renewable energy capacity is 500 MW, slightly lower than the peak load

Three 3-phase short circuits have been identified as major contingencies and included in the analysis. The resulting multi-contingency optimization model contains short circuits at Candelaria in one of the Candelaria—Buenos Aires lines; at Granadilla in one of the Granadilla—Candelaria lines; and at Guajara in the Guajara—Tacoronte line. Each fault is cleared by the disconnection of the affected line after 150 ms.

3.4.1 Base case

Figure 3.6 shows the power dispatch at peak hour provided by the solution of the optimization model against the availability of renewable energy. It can be seen that all non-synchronous generation can be dispatched up to a production of 60% of the installed capacity. From this point on, the dynamic constraints of the optimization model impose a certain curtailment on the production of renewable energy.

Figure 3.6 Active power at peak case.

Figure 3.7 shows a similar graphic obtained at off-peak hour. The curtailment of non-synchronous generation is larger than in the peak load case and because the system cannot accommodate so much renewable energy production.

Figure 3.7 Active power at off-peak case.

Figure 3.8 shows the optimal distribution of the curtailment between non-synchronous power plants when the load is lowest and the availability of renewable resources is highest.

Figure 3.8 Non-synchronous generation curtailment.

A similar study has been performed calculating the optimal solution for different load factors and availability of renewable energy. Studied load factors range from 0.4 to 1 p.u., where load factor 1 corresponds to peak load, and availability of renewable energy ranges from 0.2 to 0.8 p.u. Figure 3.9 shows that the curtailment of non-synchronous generation is larger when the load is low and the availability of renewable energy is large. Figure 3.10 shows the total generation cost. It can be seen that the generation cost tends to decrease when the availability of renewable energy increases but this reduction ceases when non-synchronous generation cannot be fully dispatched, either when there is a high availability of renewable energy or when the load is small. Figure 3.9 and Figure 3.10 correlate in the

sense that curtailment of non-synchronous generation depicted in Figure 3.9 results in a halt in the decrease of generation cost in Figure 3.10. To make the most of non-synchronous generation during periods of large availability of renewable sources, appropriate measures should be adopted in the system.

Figure 3.9 Curtailment.

Figure 3.10 Cost.

3.4.2 Actions to reduce the curtailment of renewable energy

Several actions have been evaluated to reduce the curtailment of non-synchronous generation, according to the results obtained in the previous section. The actions studied are:

1. Reduce the fault clearing time of protection systems from 150 ms to 120 ms.
2. Provide non-synchronous generators with full fault ride-through capability. This means that all non-synchronous generators remain connected after the fault, regardless of the depth of the voltage dip.
3. Increase the inertia of the system. There are several options to perform this action, such as emulating in the control system of non-synchronous generation, using synchronous condensers, and increasing the inertia constant in the synchronous generator. As a first approach, the inertia of synchronous generators has been increased by a 25%.
4. Connect a STATCOM to improve transient stability. A 50 Mvar STATCOM at Granadilla substation is modelled by including an extra term to account for the STATCOM reactive power in equation (3.2).

Figure 3.11 shows the reduction in generation cost obtained with each strategy with respect to the base case. It can be seen that this reduction occurs when the availability of renewable energy is larger, which is when non-synchronous curtailment is larger in the base case. It can be seen in Figure 3.11.b that the provision of full fault ride-through capability provides the largest reduction in cost. This can be explained because the sudden disconnection of non-synchronous generation displaces the equilibrium point of the system and can therefore worsen the electromechanical oscillations of synchronous generations, and because the loss of non-synchronous generation decreases the frequency of the system. Addition of inertia to the system in Figure 3.11.c also makes it possible to reduce non-synchronous curtailment and total generation cost. This is congruent with the fact that large inertia constants improve both transient and frequency stability, but it must be noted that system inertia affects other aspects of the operation of power system such as primary control that must also be taken into account. The installation of faster automatic circuit breakers that are able to clear the fault in 120 ms reduces the cost too as shows Figure 3.11.a, although on a lower scale. Finally, the effect of a 50 Mvar STATCOM shown in Figure 3.11.d is relatively small compared to the rest of the solutions.

Figure 3.11 Reduction in cost using several strategies.

3.5 Discussion

The application of the optimization model proposed in Section 3.3 to the IEEE 39 Bus test case demonstrates its performance on a standard case. It illustrates also, in Figure 3.4, how non-synchronous generation can affect transient stability: the optimal solution curtails non-synchronous generation despite the fact that its cost is zero, because it is necessary to maintain the rotor angles of synchronous generators within their limits.

It is difficult to find terms of comparison for the performance of the solution, because most previous works tested on the IEEE 39 Bus system use a simpler, 2nd order classical synchronous generator model [31], [46], [88], [89]. The proposed method applies a 4rd order, transient synchronous generator model that increases the number of variables and equations but represents the dynamics of the machine with more accuracy [90]. Compared to the method proposed in [39] which also uses a 4rd order synchronous generator model, the proposed method calculates the voltage at every bus and at every sample time. This makes it possible to represent non-synchronous power stations and nonlinear, ZIP load

models, but comes at the prize of increasing the number of variables by 80% and the number of constraints by 64%. Nevertheless, the size of the model is suitable for application to isolated systems such as the Tenerife System studied in this chapter, although its application to large power systems would be problematic unless they are previously reduced.

No problems of convergence have been observed during the application of the method, neither to the IEEE 39 Bus system nor to the Tenerife system. It is worth noting that the calculation of all voltages at every sample time makes it possible to apply the voltage correction term defined by term $f_{i,t}^{LV}$ in equation (3.5) during deep voltage dips. This term ensures numerical stability when representing severe faults that are not compatible with the references of active power in loads and non-synchronous generators. The results show a significant improvement if selective curtailment is applied as opposed to homogeneous curtailment, although homogeneous curtailment may be easier to implement for reasons of market organization.

The application of the proposed model to the Tenerife system makes it possible to calculate the optimal curtailment of non-synchronous generators (Figure 3.9), and to quantify the increase in cost associated with it (Figure 3.10). This is calculated in the chapter taking the load and the availability of non-synchronous generation as independent variables. Largest curtailments and increases in cost are obtained during periods of small load and large availability of renewable energy resources, as expected. Further analysis can match these data with historical records of load and availability of renewable resources to estimate costs over long periods of time, which will probably benefit from the usual correlation between load and availability of solar energy.

Several techniques have been explored to reduce curtailment of non-synchronous generation. Results are summarized in Figure 3.11, that shows how a substantial improvement can be obtained if non-synchronous power stations are provided with full ride-through capability. This can be explained as a consequence of the small inertia in the Tenerife power system. The small inertia makes it prone to large deviations of rotor speeds after a severe fault, which worsen if part of the non-synchronous generation trips off. This explains also how an increase in the inertia of the system provides a reduction in the curtailment of non-synchronous generation. Here the inertia of synchronous generators is directly increased, which must be seen as a preliminary study because there are some other options such as connecting synchronous condensers or emulating inertia in non-synchronous plants. Some benefits can be obtained from a reduction in fault clearing times,

a solution that would require to invest in faster circuit breakers. The connection of a 50 Mvar STATCOM at Granadilla substation produces a slightly lower improvement. This may be due to the fact that STATCOMs are effective when damping electromechanical oscillations between synchronous generators, but have a limited effect on frequency stability. Nevertheless, a more detailed study of the effect of a STATCOM should evaluate the effect of different sizes, control systems, and connection points.

It can be concluded from the studied system that the connection of non-synchronous generation will impact on transient and frequency stability to the point of forcing the curtailment of renewable generation in certain cases. Specific measures such as improving voltage dip-ride through capability, reducing fault clearing times, providing real or synthetic inertia and using a FACTS can reduce the curtailment of non-synchronous generation and restrict it to cases with very low load and high availability of renewable energy sources.

CHAPTER 4

STABILITY IMPROVEMENT OF TRANSMISSION GRIDS WITH HIGH PENETRATION OF RENEWABLE ENERGY USING TSCOPF AND INERTIA EMULATION

This chapter proposes a Transient Stability Constrained Optimal Power Flow (TSCOPF) formulation that models non-synchronous renewable generation equipped with synthetic inertia. The proposed optimization problem calculates the optimal operating point of the system, accommodating high shares of non-synchronous renewable generation while ensuring transient stability in the event of critical incidents. Synthetic inertia controllers are used to improve the dynamic stability of the system in cases of very high penetration of renewable generation. The TSCOPF model is applied to the North-West Spanish system, a network with a high penetration of wind energy that causes a reduction in the total system inertia. The results of the study show that 1) synthetic inertia in renewable power plants can be used to reduce electromechanical oscillations after a severe contingency, reducing the cost of ensuring transient stability; 2) using synthetic inertia the system becomes more stable when conventional generation is decommissioned following de-carbonization and renewable promotion policies; and 3) the proposed model can be used to optimize the parameters of the synthetic inertia control.

4.1 Introduction

The transition towards a 100% renewable electric power system implies the replacement of conventional synchronous power plants with non-synchronous renewable generation, reducing the inertia of the system and affecting transient stability. This new scenario must however maintain adequate indices of stability, reliability, and security of the system. Therefore, one of the main challenges faced by current and future power grid operators is to minimize the impact on security of non-synchronous generation. To optimize the operation of energy systems, TSCOPF emerges as an effective tool to calculate the optimal operation point of power systems while maintaining a secure operation.

TSCOPF is a non-linear optimization problem that includes in the same structure the static representation of the system in normal operation and the dynamic simulation of the system during and after a contingency. The solution of a TSCOPF ensures 1) an economic and secure steady state operation of the power system; and 2) that the system remains stable in the event of one or several critical contingencies. During the last few years various approaches have been proposed to address this problem. References [34], [35], [53], [48] review the different approaches and their contributions in detail.

Previous TSCOPF studies consider essentially the dynamic representation of conventional generation to evaluate stability but not the dynamic response of renewable energy sources connected through electronic power converters. However, the continued growth of the penetration of this kind of renewable sources increases their impact on stability and, consequently, it becomes essential to include them on this type of studies.

Traditionally, the inertial response of energy systems is given by large synchronous power plants, as they contain a large rotating mass directly connected to the system. Non-synchronous renewable sources do not provide inertia since they decouple the grid from the electrical generator via electronic interfaces [91]. Consequently, scenarios with high shares of non-synchronous renewable sources reduce the total inertia, which can make the system more unstable under critical contingencies. Thus, there is a growing number of studies that propose that non-synchronous power plants should emulate inertia to improve the dynamic stability [8], [92], [93]. To provide inertia to the system, one typical approach is that virtual inertia controllers modify the active power output proportionally to the derivative of the network frequency or Rate Of Change of Frequency (ROCOF) at the connection point [94], [95].

The object of this study is the North West Spanish power system, around the region of Galicia. Due to its location, it has become optimal for the installation of wind and hydro power plants. Currently its operation involves scenarios where the production with renewable sources connected to the network through electronic converters exceeds production with conventional generation. In the next future non-synchronous generation will increase its share in the system due to de-carbonization and renewable promotion policies. The main contributions of this chapter are:

- A simultaneous discretization TSCOPF algorithm that calculates the frequency and voltages at each bus of the system and at each sample time. This formulation allows the representation of non-synchronous renewable energy sources and/or energy storage systems whose controls act in accordance with the frequency and voltage measurements at their Point of Common Coupling (PCC).
- A model to represent the control of inverters of non-synchronous renewable energy sources to provide synthetic inertia in TSCOPF.
- An evaluation of the impact of different control strategies for inertia emulation on the power dispatch and the total generation cost using TSCOPF.

The rest of the chapter is organized as follows: Section 4.2 describes the optimization model; Section 4.3 describes the case study; Section 4.4 shows and discusses the results; and Section 4.5 concludes the chapter.

4.2 Optimization model

The optimization model proposed here is composed of 1) the objective function (4.1) that minimizes the total generation cost of the system and 2) the set of equality and inequality constraints that is summarized in Table 4.1. The set of equality and inequality constraints models both the steady state and the dynamic behavior of a system when is subjected to a severe contingency. Some of these equations are presented in previous chapters and some of them are new and introduced in following sections. The solution of this problem provides the most economic operation point of a system maintaining, on the one hand, upper and lower generation constraints, voltage limits at each bus of the system

$$\min f(p_{i,0}^G) = \sum_{\forall i \in \Omega^G} (A_i^G (p_{i,0}^G)^2 + B_i^G p_{i,0}^G + C_i^G) \quad (4.1)$$

Table 4.1 Summary of the constraints of the optimization problem.

Component	Equality Constraints	Inequality Constraints
Network and loads	Power flow equations. Eqs.: (4.2)-(4.3) Load equations. Eqs.: (4.4)-(4.5). Currents in branches and transformers. Eq.: (2.6)	Voltage limits at buses, limits on power generation, and maximum currents through branches and transformers. Eqs.: (2.23)-(2.26)
Conventional generation	Discretized differential equations of power plants. Eqs.: (2.8)-(2.15) Power plant static equations. Eqs.: (2.16)(2.20)	Field voltage limits. Eq.: (2.27)
Frequency calculation	Frequency divider formula. Eq.: (4.6) Delay due to the frequency measurement. Eq.: (4.18)-(4.19)	
Non-synchronous generation	Active/reactive power generation. Eqs.: (4.7)-(4.8) Fault ride through capability. Eq.: (4.9) Synthetic inertia control and calculation of ROCOF. Eq.: (4.12)-(4.17)	
Stability limits	Calculation of the COI angle. Eq.: (4.20)	Maximum deviation of rotor angles with respect to the COI angle. Eq.: (4.21)

and transmission restrictions in power lines and, on the other hand, ensuring transient stability in the event of a critical incident.

4.2.1 Network and load modeling

The power balance at each bus i and at each sample time t is modeled by the following equations:

$$p_{i,t}^G + f_{i,t}^{LV} p_{i,t}^{NSG} - f_{i,t}^{LV} p_{i,t}^L = v_{i,t} \sum_{j=1}^{j=N} v_{j,t} Y_{i,j} \cos(\alpha_{i,t} - \alpha_{j,t} - \theta_{i,j}), \forall i \in \Omega^B, \forall t \in \Omega^T \quad (4.2)$$

$$q_{i,t}^G + f_{i,t}^{LV} q_{i,t}^{NSG} - f_{i,t}^{LV} q_{i,t}^L = v_{i,t} \sum_{j=1}^{j=N} v_{j,t} Y_{i,j} \sin(\alpha_{i,t} - \alpha_{j,t} - \theta_{i,j}), \forall i \in \Omega^B, \forall t \in \Omega^T \quad (4.3)$$

where terms $p_{i,t}^G$ and $q_{i,t}^G$ represent the active and reactive power injected by a synchronous conventional power plant, and $p_{i,t}^{NSG}$ and $q_{i,t}^{NSG}$ the active and reactive power injected by a non-conventional power plant. Variables $v_{i,t}$ and $v_{j,t}$ are the absolute values of the voltage at bus i or j , while variables $\alpha_{i,t}$ and $\alpha_{j,t}$ represent the angle of the complex voltage at bus i or j . Parameters $Y_{i,j}$ and $\theta_{i,j}$ are the real and the imaginary part of the term of the bus admittance matrix in the (i, j) position, respectively. Terms $p_{i,t}^L$ and $q_{i,t}^L$ are the system loads,

represented by the ZIP load model that is composed of a constant power, a constant current, and a constant impedance component:

$$p_{i,t}^L = P_i^L (A_i^P + B_i^P (v_{i,t} / v_{i,0}) + C_i^P (v_{i,t} / v_{i,0})^2), \forall i \in \Omega^L, \forall t \in \Omega^T \quad (4.4)$$

$$q_{i,t}^L = Q_i^L (A_i^Q + B_i^Q (v_{i,t} / v_{i,0}) + C_i^Q (v_{i,t} / v_{i,0})^2), \forall i \in \Omega^L, \forall t \in \Omega^T \quad (4.5)$$

4.2.2 Calculation of the frequency at the nodes of the system

The calculation of the frequency at all buses of the system is required to model non-synchronous renewable generation, energy storage systems or loads whose controls or values depend on the frequency at their connection point. Traditionally, two approaches have been used for the calculation of the frequency. On the one hand, the calculation of the frequency of the Center of Inertia (COI) through the speed of the synchronous power plants. While the COI is simple to implement, it is not useful to represent local oscillations and consequently not adequate to define controls based on frequency measurements. On the other hand, the use of a phase-locked loop (PLL) to measure the derivative of the bus voltage angle has been demonstrated as a valid technique to measure local oscillations. However, the complexity to implement the PLL in optimization problems, as well as their well-known numerical issues, make it inappropriate for its implementation on simultaneous discretization TSCOPF approaches [96].

The frequency divider formula has been recently shown as a simple and reliable approach to estimate the frequency at all buses of the system [97] and has been successfully implemented in this work. Equation (4.6) presents the frequency divider formula that calculates the frequency deviation at each bus of the system and each sample time, using the synchronous power plants speed deviation and the matrix of parameters $D_{i,j}^{BUS}$. The speed deviation is given by equation (2.10), and the matrix $D_{i,j}^{BUS}$ is calculated using the network admittances and the synchronous machine internal impedances, as explained in [97].

$$\Delta f_{i,t} = \sum_{\forall j \in \Omega^G} D_{i,j}^{BUS} \Delta \omega_{j,t}, \forall i \in \Omega^B, \forall t \in \Omega^T \quad (4.6)$$

4.2.3 Modeling of non-conventional renewable power plants

Renewable sources connected to the grid through electronic converters are increasingly used in modern power systems and must therefore be properly accounted for in TSCOPF

models. This section proposes a non-conventional renewable power plant model (4.7)-(4.9), together with its controllers (4.12)-(4.17), that is adequate for the representation of this kind of sources in simultaneous discretization TSCOPF problems. The proposed model is suitable for both variable speed windmills and/or PV sources.

Equations (4.7) and (4.8) represent the active and reactive power injected to the grid by a non-synchronous renewable power plant at each sample time:

$$p_{i,t}^{\text{NSG}} = f_i^{\text{CON}} (P_i^{\text{REF}} + \Delta p_{i,t}^{\text{NSG}}) \frac{v_{i,t}}{v_{i,0}}, \forall i \in \Omega^{\text{NSG}} \forall t \in \Omega^{\text{TD}} \quad (4.7)$$

$$q_{i,t}^{\text{NSG}} = f_i^{\text{CON}} Q_i^{\text{REF}} \frac{v_{i,t}}{v_{i,0}}, \forall i \in \Omega^{\text{NSG}} \forall t \in \Omega^{\text{TD}} \quad (4.8)$$

These power plants are represented as a controlled current source since the response time of the power electronics and their controllers is short compared to the time scale of the transient stability studies [83]. Parameters P_i^{REF} and Q_i^{REF} represent the scheduled active and reactive power injected by the renewable module during steady state operation. Variable $\Delta p_{i,t}^{\text{NSG}}$ represents the dynamic response of the active power given by a controller during the time domain. Finally, variable f_i^{CON} is calculated in equation (4.9) and models the fault ride through capability of renewable sources, which disconnect the power plant when the voltage dip at the point of common coupling exceeds the low voltage limits given by the corresponding grid code [6]. In the pre-fault stage, variable f_i^{CON} takes always the value 1.

$$f_i^{\text{CON}} = \begin{cases} 1 & \text{if } v_{i,t} \geq V^{\text{CON}}, \forall i \in \Omega^{\text{NSG}} \forall t \in \Omega^{\text{TD}} \\ 0 & \text{if } v_{i,t} < V^{\text{CON}}, \forall i \in \Omega^{\text{NSG}} \forall t \in \Omega^{\text{TD}} \end{cases} \quad (4.9)$$

This work evaluates the impact of a synthetic inertia control on transient stability. The modelled control follows the ROCOF at the point of common coupling and modifies the active power set point using Equation (4.10). The controller is a control loop added in the power converter that creates an active power control signal following a similar version of the inertia emulation regulator proposed in [94], [95]. The ROCOF is calculated using Equation (4.11) at each bus and at each sample time using the frequency deviation as calculated by Equation (4.6).

$$\frac{d\Delta p_i^{\text{NSG}}}{dt} = -\frac{1}{T_i^{\text{IE}}} (2\omega^{\text{REF}} H_i^{\text{EMU}} \text{ROCOF}_i + \Delta p_i^{\text{NSG}}) \quad (4.10)$$

$$\frac{d\Delta f_i}{dt} = ROCOF_i \quad (4.11)$$

To include differential equations (4.10) and (4.11) in the optimization problem they are discretized using the trapezoidal rule, which results in equations (4.12) and (4.15) respectively. Constraints (4.13) and (4.14) are the upper and lower limits of the active power variation. Finally, constraints (4.16) and (4.17) results from equaling to zero equations (4.10) and (4.11) and initializing variables Δp_i^{NSG} and $ROCOF_i$ in the pre-fault stage.

$$\begin{aligned} \Delta p_{i,t}^{\text{NSG}} \left(1 + \Delta t / 2T_i^{\text{IE}}\right) - \Delta p_{i,t-1}^{\text{NSG}} \left(1 - \Delta t / 2T_i^{\text{IE}}\right) \\ = -\left(2\omega^{\text{REF}} H_i^{\text{EMU}} \Delta t / 2T_i^{\text{IE}}\right) \left(ROCOF_{i,t} + ROCOF_{i,t-1}\right), \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{TD}} \end{aligned} \quad (4.12)$$

$$\Delta p_{i,t}^{\text{NSG}} = \min[\Delta p_{i,t}^{\text{NSG}}, \Delta P_i^{\text{MAX,NSG}}] \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{TD}} \quad (4.13)$$

$$\Delta p_{i,t}^{\text{NSG}} = \max[\Delta p_{i,t}^{\text{NSG}}, \Delta P_i^{\text{MIN,NSG}}] \forall i \in \Omega^{\text{NSG}} \forall t \in \Omega^{\text{TD}} \quad (4.14)$$

$$\Delta f_{i,t}^{\text{D}} - \Delta f_{i,t-1}^{\text{D}} = 0.5\Delta t(ROCOF_{i,t} + ROCOF_{i,t-1}), \forall i \in \Omega^{\text{NSG}} \forall t \in \Omega^{\text{TD}} \quad (4.15)$$

$$\Delta p_{i,0}^{\text{NSG}} = 0, \forall i \in \Omega^{\text{NSG}} \quad (4.16)$$

$$ROCOF_{i,0} = 0, \forall i \in \Omega^{\text{NSG}} \quad (4.17)$$

The delay due to the frequency measurement and the phase-locked loop can cause considerable variations in the response of the inertia controller and must therefore be properly accounted for [94]. This study models this delay using constraints (4.18) and (4.19).

$$\Delta f_{i,t}^{\text{D}} = \Delta f_{i,t-\text{DELAY}} \forall i \in \Omega^{\text{NSG}} \forall t \notin \Omega^{\text{TDELAY}} \quad (4.18)$$

$$\Delta f_{i,t}^{\text{D}} = 0, \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{TDELAY}} \quad (4.19)$$

4.2.4 Modeling of conventional power plants and neighboring power systems

Synchronous power plants are modeled using the well-known 4th order d-q synchronous generator model [56], whose equations are presented in Table 4.1.

Neighboring power systems are crucial to enhance inertia and stability, and consequently, to be able to increase the shares of non-conventional renewable generation in a secure way. In the optimization problem, the neighboring system is reduced to one equivalent bus with a constant power load and a synchronous generator with an inertia equal to the aggregated inertia of the whole system. The load minus the generation in the equivalent bus is the power exported by the studied system, which can take a positive or negative value depending on the direction of the power flow.

4.2.5 Stability criteria

Transient stability is ensured in the optimization problem by means of constraints (4.20) and (4.21). Constraints (4.20) calculate the rotor speed deviation of the Center of Inertia (COI) of the system, while constraints (4.21) limit the maximum rotor angle deviation of a synchronous power plant with respect to the rotor angle of the COI. This ensures that all synchronous power plant maintain synchronism when a critical incident occurs.

$$\delta_t^{\text{COI}} = \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \delta_{i,t} \right) / \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \right), \forall t \in \Omega^{\text{T}} \quad (4.20)$$

$$-\delta^{\text{MAX}} \leq \delta_{i,t} - \delta_t^{\text{COI}} \leq \delta^{\text{MAX}}, \forall i \in \Omega^{\text{G}}, \forall t \in \Omega^{\text{T}} \quad (4.21)$$

4.3 Description of the study case and implementation

This study is carried out in the North-West Spanish power system, a transmission grid that is interconnected to the Spanish system to the east and the Portuguese system to the south, and that borders the Atlantic Ocean to the west and the Cantabrian Sea to the north along 1,500 km of coastline. Its geographical location puts it in direct contact with the Atlantic Ocean, being one of the points of the Iberian Peninsula where the Atlantic winds hit with more force. Due to its strategic location, the system has become an optimal area for the installation of non-synchronous wind power plants.

Figure 4.1 shows the transmission system and the main power plants and loads in the region. Generation is mainly provided by six conventional power plants and eight non-conventional renewable generation power plants with a total maximum capacity of 3300 MW and 3174 MW, respectively. Regular winds from the ocean provide a relatively steady production of wind power [98].

Figure 4.1 North west spanish power system

The following set of critical incidents have been included in the optimization problem:

- A three-phase short-circuit in a transmission line connecting buses 5 and 6 - adjacent to bus 5. The fault is cleared after 300 ms.
- A three-phase short-circuit in the transmission line connecting buses 6 and 5 - adjacent to bus 6. The fault is cleared after 300 ms.

These incidents are chosen because they pose a considerable risk to transient stability due, on the one hand, to their location in the bulk of the transmission system, and on the other hand, to its proximity to the main synchronous power plants. Rotor angle deviation limits are reached at one or more synchronous generators in all the studied cases, affecting the optimal dispatch. This means that the solution given by a classical OPF is not transiently stable under the studied contingencies and the TSCOPF modifies the power dispatch to provide a stable solution. Consequently, the total generation cost provided by a TSCOPF is always higher than the cost of the dispatch provided by a classical OPF.

The optimization problem is solved using the prime-dual interior point library IPOPT in GAMS language and an automatic implementation is carried out using the software framework explained in Section 2.3. All simulations are performed using a personal

computer based on Intel Core (TM) i7-2600 CPU 3.4 GHz, 16 GB RAM with Windows 10-64-bit operating system.

4.4 Results and discussion

4.4.1 Effect of non-synchronous generation on the transient stability.

This section presents different case studies with high non-synchronous renewable generation that covers most of the demand of the system. The objective is to evaluate the effect of the substitution of synchronous power plants with non-synchronous generation on the dispatch and on the total cost of generation. Different scenarios towards an objective of a 100% renewable system are evaluated:

- Case study 1: Current situation in which all synchronous power plants are available.
- Case study 2: The thermal power plants, which are the most polluted are disconnected.
- Case study 3: The thermal power plants as well as the combined cycle power plants are disconnected, achieving a 100% renewable scenario in the region.

Table 4.2 shows the results of the synchronous power plants for the three case studies together with their data for a scenario in which the available non-synchronous renewable resource is 2221.8 MW (over 70% of the installed nominal capacity) and supplies 86.7% of the demand. All available non-synchronous renewable generation is systematically dispatched. Results are obtained using: a) a classical OPF without dynamic constraints; b) a TSCOPF considering the most critical contingency in the system, which is a three phase short-circuit in line 5-6 adjacent to bus 5; and c) a TSCOPF in which non-synchronous renewable power plants are equipped with a control for inertia emulation, considering again the same critical contingency.

It can be seen in Table 4.2 that in the first case study, as a result of a classical OPF, only plant G11 is dispatched because it is the most economical. Application of the TSCOPF model, which takes into account the stability limits, indicates that the result given by the OPF is not stable under the considered contingency. The TSCOPF increases the total generation cost in 1220 M.U. with respect to the OPF because the algorithm assigns power to more expensive power plants to ensure stability. In the case TSCOPF-EMU, when non-

Table 4.2 Results of the dispatch for synchronous power plants under the three case studies.

Power plant data								
Technology	Coal	Coal	Gas	Gas	Hydro	Hydro	Cost (M.U.)	Δ Cost (M.U.)
Marginal cost (M.U./MWh)	29	38	51	63	72	98		
Nominal power (MW)	450	1400	350	700	400	200		
Minimum power (MW)	112.5	350	35	70	0	0		
Power plant	G5 (MW)	G9 (MW)	G11 (MW)	G10 (MW)	G4 (MW)	G12 (MW)		
Case study 1. All synchronous generation available								
OPF	327.4	ND ¹	ND ¹	ND ¹	ND ¹	ND ¹	9495	-
TSCOPF	274.3	ND ¹	54.2	ND ¹	ND ¹	ND ¹	10715	1220
TSCOPF EMU	277.8	ND ¹	50.4	ND ¹	ND ¹	ND ¹	10628	1133
Case study 2. Without coal								
OPF	NA ²	NA ²	327.4	ND ¹	ND ¹	ND ¹	16697	-
TSCOPF	NA ²	NA ²	117.2	ND ¹	212.7	ND ¹	19202	2505
TSCOPF EMU	NA ²	NA ²	208.7	119.7	ND ¹	ND ¹	18185	1488
Case study 3. 100 % renewable								
OPF	NA ²	NA ²	NA ²	NA ²	327.4	ND ¹	23572	-
TSCOPF	NA ²	NA ²	NA ²	NA ²	202.8	125.7	26920	3348
TSCOPF EMU	NA ²	NA ²	NA ²	NA ²	241.8	85.7	25810	2238

1. ND: Not dispatched

2. NA: Not applicable

synchronous renewable generation is equipped with inertia emulation, the system is more stable under the contingency and the total generation cost is reduced to 1133 M.U. over the cost given by the OPF.

Regarding the results in the second case study, the OPF solution dispatches all the synchronous generation to the combined cycle plant connected to bus 11, which is the most economical. The application of the TSCOPF model increases the total generation cost in 2505 M.U. Similarly to the previous case, the introduction of the synthetic inertia reduces the total generation cost to 1488 M.U. over the cost given by the OPF.

The third case study presents a 100% renewable scenario, in which hydro generation provides the only synchronous generation in the area. Again, when using a classical OPF, all synchronous generation is dispatched to the most economic power plant, in this case to Hydro G4. The application of a TSCOPF shifts 125.7 MW to the most expensive power plant to achieve a stable case under the considered contingency, increasing the total generation costs in 3348 M.U. Once again, when renewable generation provides synthetic inertia the case is more stable, and the total generation cost is reduced.

Figure 4.2 and Figure 4.3 show the differences in the response of hydro machines obtained as a result of a TSCOPF in the third case study. Figure 4.2 shows the rotor angles of hydro power plants when non-synchronous renewable power plants provide/do not provide synthetic inertia. Figure 4.3 shows the rotor speed deviation of hydro power plants in the same scenarios. It can be seen, both in Figure 4.2 and Figure 4.3, that rotor angle and rotor speed oscillations are reduced when renewable power plants provide synthetic inertia. This results in a more stable situation and, consequently, a more economic operation as shown in Table 4.2.

Figure 4.2 Rotor angles of the synchronous power plants for a 100% renewable case without inertia emulation (NO EMU) and with inertia emulation (EMU).

Figure 4.3 Rotor speed deviation of the synchronous power plants for a 100% renewable case without inertia emulation (NO EMU) and with inertia emulation (EMU).

Figure 4.4 corresponds to the third case study in which power plants are equipped with inertia emulation, and shows the active power injected by the non-synchronous renewable plant connected to bus number 6 together with the frequency at this bus as calculated by the frequency divider. It can be seen that during the voltage dip due to the short-circuit the plant reduces its output power. Once the fault is cleared, the plant modifies its active output power following the ROCOF as imposed by equations (4.12)-(4.15) to damp the

electromechanical oscillations of the system. Figure 4.5 shows the active power injected by the wind farm connected to bus 22, which is the closest to the short-circuit, together with the frequency at this bus. It can be seen how power plant G22 is disconnected due to the effect of constraint (4.9) since the voltage dip exceeds the fault ride-through limit.

Figure 4.4 Active generation and frequency at bus 6. Left axis: Active power of the non-synchronous renewable plant connected to the bus considering inertia emulation. Right axis: Frequency.

Figure 4.5 Active generation and frequency at bus 22. Left axis: Active power of the non-synchronous renewable plant connected to the bus considering inertia emulation. Right axis: Frequency.

4.4.2 Impact of wind penetration and optimal controllers in 100% renewable scenarios

This section analyses the results for different scenarios with high available renewable resources, different contingencies, and different synthetic inertia controllers when the generation is 100% renewable. Some control parameters of synthetic inertia within

renewable modules are selected to assess how they impact on the results of the TSCOPF, as follows: a) (NO-EMU) Non-synchronous renewable plants do not provide synthetic inertia; b) (EMU $\pm 10\%$) Non-synchronous renewable plants provide synthetic inertia and their active power output variation is limited to $\pm 10\%$ of their nominal power. The critical contingencies exposed in Section 4.3 are evaluated for the following scenarios of renewable resources:

- Scenario 1: The available non-synchronous renewable resource is 2221.8 MW (over 70% of the installed nominal capacity) and supplies 86.7% of the demand.
- Scenario 2: The available non-synchronous renewable resource is 2301 MW (over 72.5% of the installed nominal capacity) and supplies 90% of the demand.
- Scenario 3: The available non-synchronous renewable resource is 2364 MW (over 74.5% of the installed nominal capacity) and supplies 92.5% of the demand.

Table 4.3 presents the results in all the studied cases using a TSCOPF that includes steady state and transient stability limits. The results are compared with those obtained using a classic OPF.

Table 4.3 shows that the result provided by a classical OPF in all the scenarios assigns all synchronous generation to power plant G4, which is the most economic. OPF solutions are modified and the generation cost increases when the TSCOPF is applied. This means that the results provided by the classical OPF are unstable under the considered incidents. Table 4.3 shows also that, when the renewable generation provides synthetic inertia, the system becomes more stable under the considered contingencies reducing the generation cost in all the studied cases

Figure 4.6 shows the increment of the generation cost provided by the TSCOPF over the OPF when a short-circuit is applied at bus 5 depending on the penetration of non-synchronous generation and the range of control of the synthetic inertia. It can be seen that the generation cost of the dispatch provided by the TSCOPF increases as non-synchronous generation in the system replaces synchronous power plants. It can also be seen that, as the limits of maximum active power variation for the inertia emulation control become larger, the system becomes more stable reducing total generation cost. The largest cost reduction is achieved when using a limit of $\pm 5\%$ in equations (4.13)-(4.14) for the maximum variation of active power, while the impact of considering greater variations is not so remarkable in terms of reduction of generation costs.

Table 4.3 Results of the dispatch for synchronous power plants under the three case studies.

Algorithm	Strategy	G4 (MW)	G12 (MW)	Cost (M.U.)	ΔCost (%)
Scenario 1 86.9% % penetration of non-synchronous renewable penetration					
OPF	NA ¹	327.4	ND ¹	23,572.8	-
TSCOPF-SC5	NO EMU	202.8	125.7	26,920.2	14.2
	EMU ±10%	241.8	85.7	25,808.2	9.48
TSCOPF-SC6	NO EMU	224	104.5	26,369	11.86
	EMU ±10%	269.3	58.2	25,093	6.44
Scenario 2 90 % penetration of non-synchronous renewable penetration					
OPF	NA ²	299.2	ND ¹	21,542.4	-
TSCOPF-SC5	NO EMU	173.8	126.5	24,910.6	15.64
	EMU ±10%	241.9	57.4	23,042	6.96
TSCOPF-SC6	NO EMU	255.2	44.5	21,542.4	5.54
	EMU ±10%	270.1	29.2	22,308.8	3.56
Scenario 3 92.5 % penetration of non-synchronous renewable penetration					
OPF	NA ²	184.9	ND ¹	13,312.8	-
TSCOPF-SC5	NO EMU	50.5	134.5	16,817	26.32
	EMU ±10%	184.6	0.4	13,330.4	0.1322
TSCOPF-SC6	NO EMU	183.2	1.8	13,366.8	0.41
	EMU ±10%	183.5	1.4	13,349.2	0.27

ND: Not dispatched

NA: Not applicable

SC5: Short-circuit at bus 5

SC6: Short-circuit at bus 6

Figure 4.6 Cost increment over the results of an OPF for different scenarios of available renewable resources and parameters of synthetic inertia when a short-circuit is applied at bus 5.

From this section it can be concluded that synthetic inertia is helpful in maintaining stability in systems with high shares of non-synchronous renewable penetration and TSCOPF becomes an effective tool to calculate the optimal power dispatch in these scenarios.

4.5 Conclusions

This chapter proposes a TSCOPF model based on the simultaneous discretization method that calculates frequency and voltages in all buses and in all sample times. The model makes it possible to represent non-synchronous renewable generation and/or storage systems whose controls act as a function of frequency and voltage at their point of connection. The model includes a control for synthetic inertia in non-synchronous renewable generation. The following conclusions are drawn:

- The proposed optimization algorithm is adequate for the calculation of the optimal operation of system with high shares of non-synchronous renewable generation maintaining economic and secure operation limits.
- The use of a control for inertia emulation in non-synchronous power plants improves transient stability when a critical incident occurs and reduces the total generation cost of the system provided by a TSCOPF.
- The proposed tool can be efficiently used to adjust the parameters of the synthetic inertia controllers of non-synchronous power plants.

4.6 Appendix

Table 4.4 Nominal power of non-synchronous renewable power plants

Wind power plants	
Bus-Name	Nominal Power (MW)
6-As Pontes	514
8-Boimente	1068
13-Mazaricos	525
14-Carba	447
17-Tambre	115
19-Pazos B.	175
21-Albarellos	163
22-Sidegasa	167
Total power 3174 MW	

Table 4.5 Inertia and damping coefficients of synchronous power plants

Power plant	H (s)	D
G1 (Spain)	1650	660
G2 (Portugal)	550	220.3
G4 (Hydro)	11	4.40
G5 (Coal)	30.63	9.9
G9 (Coal)	77	30.8
G10 (Gas)	38.5	15.4
G11 (Gas)	21.505	7.7
G12 (Hydro)	11	4.4

CHAPTER 5

OPTIMIZATION OF THE OPERATION OF A FLYWHEEL TO SUPPORT STABILITY AND REDUCE GENERATION COSTS USING A MULTI-CONTINGENCY TSCOPF

Multi-Contingency Transient Stability Constrained Optimal Power Flow (MC-TSCOPF) models optimize the economic dispatch of power systems while ensuring their stability after a series of reference incidents. This chapter proposes a MC-TSCOPF model that represents the power balance at each node of the system and at each sample time. The proposed model includes non-linear loads, synchronous generators, a windfarm, and a Flywheel Energy Storage system (FESS). The model is written on GAMS and solved using a standard Interior Point algorithm. This study focuses on the Fuerteventura-Lanzarote insular grid in Spain, where stability problems and load shedding cause high additional costs due to the low inertia of the system. A FESS has been recently installed in the system to improve its stability, taking advantage of its high-power capacity and rapid response. The proposed TSCOPF model has been applied to optimize the operation of the FESS to support stability in the event of a contingency. The results of the study show that 1) a proper model of non-linear loads is essential in TSCOPF studies; 2) the proposed MC-TSCOPF provides a tool for minimizing the generation costs while ensuring transient and frequency stability; and 3) it is possible to further reduce the generation costs by using the proposed model to calculate an optimal dynamic response of the FESS.

5.1 Introduction

Ensuring stability and reducing generation costs are essential issues in modern power systems. TSCOPF models have emerged over the last decade as a tool to combine the economic and secure operation requirements. The TSCOPF studies include a time-domain representation of the system dynamics in the optimization problem to account for the effects that dynamic constraints have on the optimal operation.

During the last few years various approaches have been proposed to address TSCOPF [34], [35], [53], [48]. On the one hand, evolutionary algorithm methods that use stochastic optimization algorithms [50], [99], [88] and direct methods that rely on simplified models [46], [47] have been applied to reduce the size and complexity of the problem in large power systems. Other approaches have recently included the uncertainty of the renewable generation for transient stability assessment using probabilistic techniques [100], [101]. On the other hand, simultaneous discretization methods, which discretize the differential equations representing the dynamics of the system and include them in the optimization model as algebraic equations, have been applied to smaller systems [33], [36], [38], [39].

Simultaneous discretization methods have the advantages of including the dynamics of all the synchronous machines and using standard nonlinear programming solvers, but they are difficult to apply to large. The two main problems associated with the simultaneous discretization TSCOPF studies is the large number of restrictions and variables and the high nonlinearity of the electromechanical oscillations between synchronous generators. The size of the model has been reduced in previous studies by representing the grid and the loads as a linear circuit and applying the Kron reduction method [33], [36], [38], [39]. This approach has the disadvantage of representing loads as constant impedances. It is also a common practice to represent synchronous generators by using the classical model instead of a standard dynamic model in the dq-axes reference frame [33], [36], [38].

The object of this study is the insular power system of Fuerteventura-Lanzarote in Spain. The small size and low inertia of the system, which contains two conventional power plants and a wind farm, make it prone to transient and frequency stability problems. Flywheel Energy Storage Systems (FESS) have received growing interest in practical studies as a tool for increasing the stability, especially in small and isolated power systems where stability and frequency problems are major concerns. High power capacity, short access time, high efficiency, and small environmental impact make flywheels suitable for this purpose [102]. A FESS has been installed in the island of Lanzarote. This device has

proven to be a useful resource to improve the frequency stability in small systems [10], [103], [104]. However, the calculation of its optimal response to a contingency has not been clearly determined in the literature.

This chapter proposes a novel Multi-Contingency TSCOPF (MC-TSCOPF) model based on the simultaneous discretization method. The aim of the study is to minimize the generation costs while ensuring stability. Instead of representing the grid as a linear passive circuit, the proposed model represents the active and reactive power injected at each node and at each sample time as independent variables. Therefore, this approach allows modelling loads as standard ZIP models instead of assuming constant impedances. Furthermore, it enables the integration of variable-speed wind farms and FESSs, represented as devices that inject power according to their control systems and independent of the magnitude of the voltage at the connection point. In the study, the synchronous generators are represented by the transient, 4th-order generator model, that provides an accurate representation for transient stability studies as stated in [47], [60].

The main contributions of this chapter are as follows:

- A simultaneous discretization MC-TSCOPF model that includes non-linear loads and combines frequency and transient stability constraints.
- The integration of a FESS model into the TSCOPF problem.
- The optimization of the dynamic response of the FESS to reduce generation costs while ensuring both frequency and transient stability.

The optimization algorithm is applied to a real system in the Canary archipelago (Spain), where a FESS has been put in operation. The method proposed here is used to optimize the generation costs while ensuring stability in the event of any critical contingency. The results are compared with those obtained with the conventional operation of the FESS.

The rest of chapter is organized as follows: Section 5.2 describes the proposed MC-TSCOPF model, including the FESS; Section 5.3 describes the case study; Section 5.4 shows and discusses the results obtained when solving the proposed MC-TSCOPF; and Section 5.5 concludes the chapter.

5.2 Description of the model

The TSCOPF models based on simultaneous discretization are composed of two parts: the steady-state and the time-domain period. The steady-state or pre-fault stage corresponds to the normal operation of the system, and the time-domain period simulates the behavior of the system during and after a contingency. The time-domain period is subdivided into fault and post-fault stages. All periods are included as equality and inequality constraints and solved in the same optimization problem. This section gives a complete account of the steady-state and time-domain equations of the proposed MC-TSCOPF model, organized according to the parts and components that compose the power system.

5.2.1 Grid model

The power balance at each bus and at each sample time is represented by the following general equations:

$$\begin{aligned} i_{c,i,t}^D v_{c,i,t} \sin(\delta_{c,i,t} - \alpha_{c,i,t}) + i_{c,i,t}^Q v_{c,i,t} \cos(\delta_{c,i,t} - \alpha_{c,i,t}) + p_{c,i,t}^{\text{INJ,FW}} - p_{c,i,t}^{\text{ABS,FW}} + p_{c,i,t}^{\text{NSG}} - p_{c,i,t}^L \\ = v_{c,i,t} \sum_{j=1}^{j=N} v_{c,j,t} Y_{c,i,j} \cos(\alpha_{c,i,t} - \alpha_{c,j,t} - \theta_{c,i,j}), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^T \end{aligned} \quad (5.1)$$

$$\begin{aligned} i_{c,i,t}^D v_{c,i,t} \cos(\delta_{c,i,t} - \alpha_{c,i,t}) - i_{c,i,t}^Q v_{c,i,t} \sin(\delta_{c,i,t} - \alpha_{c,i,t}) + q_{c,i,t}^{\text{INJ,FW}} - q_{c,i,t}^{\text{ABS,FW}} + q_{c,i,t}^{\text{NSG}} - q_{c,i,t}^L \\ = v_{c,i,t} \sum_{j=1}^{j=N} v_{c,j,t} Y_{c,i,j} \sin(\alpha_{c,i,t} - \alpha_{c,j,t} - \theta_{c,i,j}), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^T \end{aligned} \quad (5.2)$$

The first two terms in (5.1) and (5.2) represent the power injected by a synchronous generator, if connected to the bus. The terms $p_{c,i,t}^{\text{INJ,FW}}$, $p_{c,i,t}^{\text{ABS,FW}}$, $q_{c,i,t}^{\text{INJ,FW}}$ and $q_{c,i,t}^{\text{ABS,FW}}$ represent the power injected or absorbed by any FESS connected to the bus. The power injected by a wind farm is modelled by $p_{c,i,t}^{\text{NSG}}$ and $q_{c,i,t}^{\text{NSG}}$, respectively. The terms $p_{c,i,t}^L$ and $q_{c,i,t}^L$ represent the loads consisting of a constant power, a constant current, and a constant impedance component (ZIP model) as shown in (5.3) and (5.4).

$$p_{c,i,t}^L = P_i^L (A_i^P + B_i^P (v_{c,i,t} / v_{i,0}) + C_i^P (v_{c,i,t} / v_{i,0})^2), \forall c \in \Omega^C, \forall i \in \Omega^L, \forall t \in \Omega^T \quad (5.3)$$

$$q_{c,i,t}^L = Q_i^L (A_i^Q + B_i^Q (v_{c,i,t} / v_{i,0}) + C_i^Q (v_{c,i,t} / v_{i,0})^2), \forall c \in \Omega^C, \forall i \in \Omega^L, \forall t \in \Omega^T \quad (5.4)$$

Constraints (5.5) calculate the current in lines and transformers. The limits of active and reactive generation of the power plants, current limits in lines and transformers, and voltage magnitude limits are restricted by inequality constraints (5.6)-(5.9), respectively.

$$i_{i,j}^{L^2} = Y_{i,j}^2 (v_{i,0} \cos \alpha_{c,i,0} - v_{j,0} \cos \alpha_{j,0})^2 + Y_{i,j}^2 (v_{i,0} \sin \alpha_{c,i,0} - v_{j,0} \sin \alpha_{j,0})^2 \forall i, j \in \Omega^B \quad (5.5)$$

$$P_i^{\min} \leq p_i^G \leq P_i^{\max}, \forall i \in \Omega^G \quad (5.6)$$

$$Q_i^{\min} \leq q_i^G \leq Q_i^{\max}, \forall i \in \Omega^G \quad (5.7)$$

$$0 \leq i_{i,j}^L \leq I_{i,j}^{\max}, \forall i, j \in \Omega^B \quad (5.8)$$

$$V_i^{\min} \leq v_{i,0} \leq V_i^{\max}, \forall i \in \Omega^B \quad (5.9)$$

Equations (5.1)-(5.4) are included both in the steady-state stage and in each interval of the time-domain period. Constraints (5.5)-(5.9) are only present in the steady-state stage.

5.2.2 Power plant model

Equations (5.10)-(5.18) represent the well-known, 4th-order transient synchronous generator model (2.18)-(2.21), whose state variables are the d-q components of the internal voltage, the rotor speed deviation and the rotor angular deviation. Equations (5.10)-(5.13) are the result of applying the trapezoidal rule to discretize the differential equations of the model, and equations (5.14)-(5.17) define the initial values of the state variables. Equation (5.18) limits the field voltage in the pre-fault stage.

$$\begin{aligned} e_{c,i,t}^{iD} (1 + \Delta t / 2T_i^{iQ}) - e_{c,i,t-1}^{iD} (1 - \Delta t / 2T_i^{iQ}) \\ = (\Delta t / 2T_i^{iQ}) (X_i^Q - X_i^{iQ}) (i_{c,i,t}^{iQ} + i_{c,i,t-1}^{iQ}), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{TD} \end{aligned} \quad (5.10)$$

$$\begin{aligned} e_{c,i,t}^Q (1 + \Delta t / 2T_i^{iD}) - e_{c,i,t-1}^Q (1 - \Delta t / 2T_i^{iD}) \\ = (\Delta t / 2T_i^{iD}) [e_{c,i,t}^{FD} + e_{c,i,t-1}^{FD} - (X_i^D - X_i^{iD}) (i_{c,i,t}^D + i_{c,i,t-1}^D)], \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{TD} \end{aligned} \quad (5.11)$$

$$\begin{aligned} \Delta \omega_{c,i,t} (1 + D_i \Delta t / 4H_i) - \Delta \omega_{c,i,t-1} (1 - D_i \Delta t / 4H_i) \\ = (\Delta t / 4H_i) (2p_i^M + \Delta p_{c,i,t}^M + \Delta p_{b,i,t-1}^M - p_{c,i,t}^E - p_{c,i,t-1}^E), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{TD} \end{aligned} \quad (5.12)$$

$$\delta_{c,i,t} = \delta_{c,i,t-1} + (\Delta t / 2) \omega^{\text{REF}} (\Delta \omega_{c,i,t} + \Delta \omega_{c,i,t-1}), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{TD} \quad (5.13)$$

$$e_{i,0}^{iD} = (X_i^Q - X_i^{iQ}) i_{i,0}^{iQ}, \forall i \in \Omega^G \quad (5.14)$$

$$e_{c,i,0}^Q = e_{c,i,0}^{FD} - (X_i^D - X_i^{iD}) i_{i,0}^D, \forall i \in \Omega^G \quad (5.15)$$

$$p_i^M = p_{i,0}^E, \forall i \in \Omega^G \quad (5.16)$$

$$\Delta \omega_{i,0} = 0, \forall i \in \Omega^G \quad (5.17)$$

$$\text{EFD}_i^{\text{MIN}} \leq e_i^{\text{FD}} \leq \text{EFD}_i^{\text{MAX}}, \forall i \in \Omega^G \quad (5.18)$$

Equation (5.19) calculates the active power output of the synchronous machines and equations (5.20)-(5.21) relate the internal variables of the synchronous machine with the variables in the generation bus, at each time step of the time-domain period. Equations (5.22)-(5.23) calculate the active and reactive power produced by the power plants in the steady-state stage.

$$p_{c,i,t}^E = e_{c,i,t}^{\text{ID}} i_{c,i,t}^{\text{D}} + e_{c,i,t}^{\text{IQ}} i_{c,i,t}^{\text{Q}}, \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^T \quad (5.19)$$

$$e_{c,i,t}^{\text{ID}} = v_{c,i,t} \sin(\delta_{c,i,t} - \alpha_{c,i,t}) + R_i^{\text{A}} i_{c,i,t}^{\text{D}} - X_i^{\text{Q}} i_{c,i,t}^{\text{Q}}, \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^T \quad (5.20)$$

$$e_{c,i,t}^{\text{IQ}} = v_{c,i,t} \cos(\delta_{c,i,t} - \alpha_{c,i,t}) + R_i^{\text{A}} i_{c,i,t}^{\text{Q}} + X_i^{\text{D}} i_{c,i,t}^{\text{D}}, \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^T \quad (5.21)$$

$$p_i^G = i_{i,0}^{\text{D}} v_{i,0} \sin(\delta_{i,0} - \alpha_{i,0}) + i_{i,0}^{\text{Q}} v_{i,0} \cos(\delta_{i,0} - \alpha_{i,0}), \forall i \in \Omega^G \quad (5.22)$$

$$q_i^G = i_{i,0}^{\text{D}} v_{i,0} \cos(\delta_{i,0} - \alpha_{i,0}) - i_{i,0}^{\text{Q}} v_{i,0} \sin(\delta_{i,0} - \alpha_{i,0}), \forall i \in \Omega^G \quad (5.23)$$

Equations (5.24)-(5.31) represent the excitation system in each time step of the time-domain period, modelled as an IEEE Type 1 exciter [56]. Equations (5.24), (5.25) and (5.28) result from the discretization of the corresponding differential equations, and equations (5.26) and (5.27) represent the saturation of the amplifier in the excitation system. Equations (5.29)-(5.31) define the initial values of the state variables.

$$e_{c,i,t}^{\text{FD}} \left(1 + (K_i^{\text{E}} \Delta t / 2T_i^{\text{E}}) \right) - e_{c,i,t-1}^{\text{FD}} \left(1 - (K_i^{\text{E}} \Delta t / 2T_i^{\text{E}}) \right) = \Delta t (v_{c,i,t}^{\text{R}} + v_{c,i,t-1}^{\text{R}}) / 2T_i^{\text{E}} - ((e_{c,i,t}^{\text{FD}} A_i^{\text{S}} e_{c,i,t}^{\text{B}} e_{c,i,t}^{\text{FD}} + e_{c,i,t-1}^{\text{FD}} A_i^{\text{S}} e_{c,i,t-1}^{\text{B}} e_{c,i,t-1}^{\text{FD}}) \Delta t) / 2T_i^{\text{E}}, \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{\text{TD}} \quad (5.24)$$

$$(v_{c,i,t}^{\text{RAUX}} / K_i^{\text{A}}) (2T_i^{\text{A}} / \Delta t + 1) - (v_{c,i,t-1}^{\text{R}} / K_i^{\text{A}}) (2T_i^{\text{A}} / \Delta t - 1) - r_{c,i,t}^{\text{F}} + r_{c,i,t-1}^{\text{F}} = (K_i^{\text{F}} / T_i^{\text{F}}) (e_{c,i,t}^{\text{FD}} + e_{c,i,t-1}^{\text{FD}}) + (v_{c,i,t} + v_{c,i,t-1}) - 2v_i^{\text{REF}}, \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{\text{TD}} \quad (5.25)$$

$$v_{c,i,t}^{\text{RAUX1}} = \max(v_i^{\text{R,MIN}}, v_{c,i,t}^{\text{RAUX}}), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{\text{TD}} \quad (5.26)$$

$$v_{c,i,t}^R = \min(V_i^{R,MAX}, v_{c,i,t}^{RAUX1}), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{TD} \quad (5.27)$$

$$\begin{aligned} r_{c,i,t}^F (1 + \Delta t / 2T_i^F) - r_{c,i,t-1}^F (1 - (\Delta t / 2T_i^F)) \\ = (\Delta t K_i^F / (T_i^F)^2) (e_{c,i,t}^{FD} + e_{c,i,t-1}^{FD}), \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{TD} \end{aligned} \quad (5.28)$$

$$v_{i,0}^R = (K_i^E + A_i^S e^{B_i^S e_{i,0}^{FD}}) e_{i,0}^{FD}, \forall i \in \Omega^G \quad (5.29)$$

$$v_{i,0}^R = K_i^A (r_{i,0}^F - (K_i^F / T_i^F) e_{i,0}^{FD} + v_i^{REF} - v_{i,0}), \forall i \in \Omega^G \quad (5.30)$$

$$r_{i,0}^F = - (K_i^F / T_i^F) e_{i,0}^{FD}, \forall i \in \Omega^G \quad (5.31)$$

Finally, the turbine governor is represented by constraints (5.32) and (5.33) as a first-order control loop [39].

$$\begin{aligned} \Delta p_{c,i,t}^M (1 + \Delta t / 2T_i^{TG}) - \Delta p_{c,i,t-1}^M (1 - \Delta t / 2T_i^{TG}) \\ + (\Delta t / 2T_i^{TG}) (\Delta \omega_{c,i,t} + \Delta \omega_{c,i,t-1}) = 0, \forall c \in \Omega^C, \forall i \in \Omega^G, \forall t \in \Omega^{TD} \end{aligned} \quad (5.32)$$

$$\Delta p_{i,0}^M = 0, \forall i \in \Omega^G \quad (5.33)$$

Equations (5.14)-(5.18), (5.22)-(5.23), (5.29)-(5.31) and (5.33) are included in the pre-fault stage and initialize the dynamic algebraic equations of the power plant. Equations (5.10)-(5.13), (5.24)-(5.28) and (5.32) are the dynamic equations represented in the time-domain period. Auxiliary equations (5.19)-(5.21) are included both in the steady-state stage and in each interval of the time-domain period.

5.2.3 FESS model

Energy Storage Systems are increasingly used in power systems to increase the penetration of renewable energies and improve the dynamic stability [10]. In particular, FESS have received growing interest as a tool to improve transient and frequency stability [103], [105] because of their high power capacity and fast response. A FESS consists of a rotating mass or flywheel where energy is stored mechanically as kinetic energy. An integrated synchronous machine converts the energy from mechanical into electrical or vice versa, thus enabling the exchange of power between the flywheel and the power system [106]. Back-to-back IGBT converters act as an interface between the FESS and the grid, allowing the spinning mass to rotate at a variable speed [107], Figure 5.1.

Figure 5.1 FESS connected to the grid

A FESS is a device capable of exchanging active and reactive power independently, since it is connected to the network through electronic power converters. The main control strategies for FESS are: 1) Improvement of frequency and transient stability by means of injecting or absorbing active power to/from the network; and 2) Voltage support by means of reactive power control. As the objective of this work is the improvement of transient and frequency stability, the value of the reactive power is set to zero.

The Fuerteventura-Lanzarote power system includes a FESS [108] that is primarily used to stabilize the frequency. Given that the time response of the FESS is small compared to the time scale of the transient stability studies, the FESS is represented in the TSCOPF model as a source of active power. Equation (5.34) represents the relation between the stored energy in the FESS ($e_{c,t}^{FW}$), the power injected to the grid ($p_{c,t-1}^{INJ,FW}$), the power absorbed from the grid ($p_{c,t-1}^{ABS,FW}$), and the losses ($p_{c,t-1}^{LOSSES,MEC}$) and ($p_{c,t-1}^{LOSSES,CON}$). Parameters (η^{INJ}) and (η^{ABS}) represent the efficiency of the synchronous machine as it injects energy to, or extracts energy from the grid. Mechanical losses ($p_{c,t}^{LOSSES,MEC}$) are defined in (5.35) as a combination of axial rotating and windage losses [109]. Equation (5.36) represents the losses in the electronic converters ($p_{c,t}^{LOSSES,CON}$), modelled as a function of the magnitude of the current through the IGBT converters [110], [111]. When FESS internal losses can be neglected, parameters (A^{RT} , B^{RT} and, C^{RT}) in (5.35) and (A^{CON} , B^{CON} , and C^{CON}) in (5.36) can be considered zero.

$$e_{c,t}^{FW} = e_{c,t-1}^{FW} + \Delta t \left[p_{c,t-1}^{ABS,FW} \eta^{ABS} - p_{c,t-1}^{INJ,FW} / \eta^{INJ} - p_{c,t-1}^{LOSSES,MEC} - p_{c,t-1}^{LOSSES,IGBT} \right], \forall c \in \Omega^C, \forall t \in \Omega^{TD} \quad (5.34)$$

$$p_{c,t}^{LOSSES,MEC} = A^{RT} \omega_{c,t}^{FW} + B^{RT} (\omega_{c,t}^{FW})^2 + C^{RT} (\omega_{c,t}^{FW})^3, \forall c \in \Omega^C, \forall t \in \Omega^T \quad (5.35)$$

$$p_{c,t}^{LOSSES,IGBT} = A^{CON} + B^{CON} i_{c,t}^{PH} + C^{CON} (i_{c,t}^{PH})^2, \forall c \in \Omega^C, \forall t \in \Omega^T \quad (5.36)$$

Equations (5.37) and (5.38) calculate the speed of the rotating mass and the magnitude of the current through the electronic converters, respectively. Limits on the FESS power and stored energy at each sample time are represented in (5.39), (5.40) and (5.41), respectively. Constraint (5.42) is the limit on the current through the electronic converters. Equations (5.37)-(5.42) are included in each time step of the time-domain period. Finally, constraint (5.43) specifies the initial amount of stored energy in the FESS, here, 80% of its maximum capacity, and the power provided by the FESS in the steady state stage is initialized in (5.44).

$$(\omega_{c,t}^{\text{FW}})^2 = 2(e_{c,t}^{\text{FW}})^2 / J^{\text{FW}} + (\omega^{\text{FW,MIN}})^2, \forall c \in \Omega^{\text{C}}, \forall t \in \Omega^{\text{T}} \quad (5.37)$$

$$i_{c,t}^{\text{PH}} = (p_{c,t}^{\text{ABS,FW}} + p_{c,t}^{\text{INJ,FW}}) / (\sqrt{3}v_{c,6,t}), \forall c \in \Omega^{\text{C}}, \forall t \in \Omega^{\text{T}} \quad (5.38)$$

$$0 \leq p_{c,t}^{\text{ABS,FW}} \leq P^{\text{ABS,FW}} \forall c \in \Omega^{\text{C}}, \forall t \in \Omega^{\text{T}} \quad (5.39)$$

$$0 \leq p_{c,t}^{\text{INJ,FW}} \leq P^{\text{INJ,FW}}, \forall c \in \Omega^{\text{C}}, \forall t \in \Omega^{\text{T}} \quad (5.40)$$

$$\omega^{\text{FW,MIN}} \leq \omega_{c,t}^{\text{FW}} \leq \omega^{\text{FW,MAX}}, \forall c \in \Omega^{\text{C}}, \forall t \in \Omega^{\text{T}} \quad (5.41)$$

$$0 \leq i_{c,t}^{\text{PH}} \leq I^{\text{PH,MAX}}, \forall c \in \Omega^{\text{C}}, \forall t \in \Omega^{\text{T}} \quad (5.42)$$

$$e_{c,0}^{\text{ABS,FW}} = 0.8E^{\text{FW,MAX}}, \forall c \in \Omega^{\text{C}} \quad (5.43)$$

$$\{p_{c,0}^{\text{ABS,FW}}, p_{c,0}^{\text{INJ,FW}}\} = \{0; 0\} \forall c \in \Omega^{\text{C}} \quad (5.44)$$

5.2.4 Wind farm model

The variable speed wind farm is modelled as a constant power source with a constant power factor. Fault ride-through requirements for wind farms published in the Spanish national grid code by the Transmission System Operator [6] are applied. Therefore, the wind farm is disconnected when a voltage dip at the wind farm connection point exceeds the low voltage ride-through limits.

$$p_{c,i,t}^{\text{NSG}} = f_{c,i,t}^{\text{CON}} P_i^{\text{REF}}, \forall c \in \Omega^{\text{C}}, \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{T}} \quad (5.45)$$

$$q_{c,i,t}^{\text{NSG}} = f_{c,i,t}^{\text{CON}} Q_i^{\text{REF}}, \forall c \in \Omega^{\text{C}}, \forall i \in \Omega^{\text{NSG}}, \forall t \in \Omega^{\text{T}} \quad (5.46)$$

$$\text{PF}^{\text{CTL}} = P_i^{\text{REF}} / Q_i^{\text{REF}}, \forall i \in \Omega^{\text{NSG}} \quad (5.47)$$

$$f_{c,i,0}^{\text{CON}} = 0; \forall c \in \Omega^{\text{C}}, \forall i \in \Omega^{\text{NSG}} \quad (5.48)$$

Equations (5.45) and (5.46) calculate the active and reactive power injected to the grid at each sample time t , respectively. The parameter P_i^{REF} represent the available wind resource. Equation (5.47) calculates the reactive power Q_i^{REF} that depends on the control strategy, in this case power factor control. The binary variable $f_{c,i,t}^{\text{CON}}$ defines whether the plant is connected or disconnected. During the pre-fault stage, the plant is connected and therefore takes the value of 1, as shown in (5.48). During the fault and post-fault stages, if the voltage is lower than a certain limit then the windfarm is disconnected and $f_{c,i,t}^{\text{CON}}$ becomes zero.

5.2.5 Transient and frequency stability criteria

Transient and frequency stability dynamic constraints are both important in the Fuerteventura-Lanzarote power system. The transient stability constraint is modelled as a limit on the deviation of the rotor angles of the synchronous machines with respect to the center of inertia (COI), as defined in (5.49) and (5.50). The frequency stability criterion is implemented as a limit on the rotor speed of the synchronous generators, as shown in (5.51).

$$\delta_{c,t}^{\text{COI}} = \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \delta_{c,i,t} \right) / \left(\sum_{\forall i \in \Omega^{\text{SG}}} H_i \right), \forall c \in \Omega^{\text{C}}, \forall t \in \Omega^{\text{T}} \quad (5.49)$$

$$-\delta^{\text{MAX}} \leq \delta_{c,i,t} - \delta_{c,t}^{\text{COI}} \leq \delta^{\text{MAX}}, \forall c \in \Omega^{\text{C}}, \forall i \in \Omega^{\text{G}}, \forall t \in \Omega^{\text{T}} \quad (5.50)$$

$$-\Delta\omega^{\text{MAX}} \leq \Delta\omega_{c,i,t} \leq \Delta\omega^{\text{MAX}}, \forall c \in \Omega^{\text{C}}, \forall i \in \Omega^{\text{G}}, \forall t \in \Omega^{\text{T}} \quad (5.51)$$

5.2.6 Objective function

The objective function is:

$$\begin{aligned} \min f(p_i^{\text{G}}, \omega_{c,t}^{\text{FW}}, p_{c,t}^{\text{ABS,FW}}) = & \sum_{\forall i \in \Omega^{\text{G}}} (A_i^{\text{G}} (p_i^{\text{G}})^2 + B_i^{\text{G}} p_i^{\text{G}} + C_i^{\text{G}}) \\ & + \sum_{\forall c \in \Omega^{\text{C}}} \sum_{\forall i \in \Omega^{\text{TD}}} [A^{\text{FW}} (\omega_{c,t}^{\text{FW}} - \omega^{\text{FW,REF}}) + B^{\text{FW}} p_{c,t}^{\text{ABS,FW}}] \end{aligned} \quad (5.52)$$

The first term in (5.52) represents the generation cost as a quadratic function of the power produced by the conventional power plants. The second term in (5.52) is introduced to ensure that the solution of the TSCOPF model produces a smooth dynamic response of the FESS. The minimization of the mean squared error of the FESS speed with respect to the reference speed has the effect of rapidly restoring the FESS speed to the specified steady state value. This readies the FESS to act in case of another contingency. Finally, the power absorbed by the FESS is slightly penalized by B^{FW} to ensure a unique solution of $p_{c,t}^{ABS,FW}$ and $p_{c,t}^{INJ,FW}$. The parameters A^{FW} and B^{FW} are purposely small, to ensure that the second term in (5.52) is significantly smaller than the first term and has a negligible effect on the final value of the objective function.

5.2.7 Multi-contingency formulation

The proposed MC-TSCOPF as described in (5.1)-(5.52) can model a single contingency or the set of critical incidents that system operators often identify that may result in a loss of stability. The MC-TSCOPF model is built by keeping the equations that correspond to the pre-fault stage, and repeating equations of the time domain representation, once for every incident. Equations which represent the dynamic response of the FESS, can be kept unique to model a single response of the FESS to all incidents or repeated for every contingency to model a different response of the FESS to each incident. Both alternatives are discussed in Section 5.4.

5.2.8 Software implementation.

The proposed model is implemented in a software framework that automatically builds and solves it. A Python program reads the parameters of the power system from a standard PSSE file, together with information about the contingencies and the stability limits, and writes the complete model in the GAMS language. The model is then fed into GAMS and solved using the interior point algorithm IPOPT. This approach facilitates the application of the TSCOPF model to different cases and solvers. The procedure is described in detail in Section 2.3. The accuracy of the model has been verified using time-domain simulations with PSSE.

5.3 Study case

The Spanish islands of Lanzarote and Fuerteventura in the Canary archipelago, are located in the Atlantic Ocean off the coast of Northern Africa. Figure 5.2 shows the 66 kV

transmission system, which includes a submerged AC cable between the islands. The topology of the system is mostly linear, apart from a single mesh in the northern area, where most of the load is located.

Figure 5.2 Lanzarote-Fuerteventura power system

Generation is provided by two power plants connected to buses 1 and 2 in the North and Centre of the system, with maximum capacities 187 and 159 MW, respectively, and by a 12 MW wind farm in the South. Regular winds from the Atlantic Ocean provide a relatively steady production of wind power. The fuel cost coefficients of power plants G1 and G2 are considered linear with values of 20 and 50 €/MWh, respectively. The operation cost of the wind generation is considered 10 €/MWh. In the present study, all parameters are considered known. When uncertainties in loads, wind power generation, generation costs and equipment availability are considered in the system [100], [101], the proposed optimization problem can be applied to the most probable values of the parameters, following Monte Carlo or other approaches.

A 1.65 MW FESS is currently connected to bus 6, which is close to generator G1 and to the main urban area in the system. Given the plans to increase the capacity of the FESS in the near future due to the positive effects of its actuation in several real cases, a 5 MW FESS is modelled in the study. A set of reference incidents that can result in the loss of transient and/or frequency stability are specified based on the experience and knowledge of the system. These reference incidents are 1) a direct three-phase short-circuit at bus 5, cleared by a back/up protection after 300 ms; 2) a direct three-phase short-circuit at bus 8,

cleared by a back/up protection after 300 ms; 3) a loss of the largest load, which is the load connected to bus 6; and 4) a loss of the wind farm.

5.4 Results and discussion

5.4.1 Effect of load modeling on the results of the TSCOPF

Load modelling has a substantial impact on the results of the transient stability simulations and must therefore be properly accounted for in the TSCOPF models. ZIP load models, which calculate the load as a quadratic function of the voltage, are a standard in power system dynamic simulations [20], [112]. However, the common practice in TSCOPF studies that include all dynamic equations in the optimization model has been to represent loads as constant impedances to reduce the number of equations [113]. The proposed TSCOPF model represents the injected power at each bus as an independent variable at every sample time, thus making it possible to introduce the ZIP loads in (5.1) and (5.2).

Figure 5.3 Effect of the load model on the TSCOPF solution. a) Constant impedance load model and b) ZIP load model

To evaluate the effects that load modelling has on the TSCOPF, the same fault has been studied using a linear load model and a ZIP model consisting of a 40% constant impedance, 30% constant current and 30% constant power. The studied fault is the short-circuit at bus 5, which is the most severe of the reference incidents listed in Section 5.3.

The TSCOPF using the ZIP load model results in a generation cost of 6476 €, that is 190 € (3%) more expensive than the dispatch obtained using the linear load model. Figure 5.3 shows the bus voltages as provided by both load models. The ZIP load model produces larger oscillations and results in a more conservative dispatch. It can be concluded that the non-linear nature of loads must be preserved in order to ensure that the solution is transiently stable.

5.4.2 Optimal FESS response to support transient stability

The usual actions performed by FESSs to stabilize the frequency in small power systems are to inject active power when the frequency decreases and to consume active power when the frequency increases [103], [104]. The selection of a FESS strategy to support transient stability is not as straightforward because it depends on several factors, such as the location of the flywheel within the system, the operating point, and the type and location of the fault. The integration of the FESS model into the TSCOPF, as defined by equations (5.34)-(5.44), makes it possible to optimize the dynamic response of the flywheel and thereby minimize the generation costs while ensuring transient stability.

Figure 5.4 shows the results provided by the TSCOPF when the transient stability constraints are applied. On the one hand, Figure 5.4.a shows the rotor angles of the generators, together with the stored energy in the FESS. On the other hand, Figure 5.4.b shows the power delivered to the system by the conventional power plants, together with the power exchanged between the FESS and the network. The case corresponds to a short-circuit at bus 5, cleared by a backup protection after 300 ms. The rotor angles are constrained within the COI angle $\pm 60^\circ$ by (5.50), but the frequency constraints in (5.51) are not applied. It can be seen in Figure 5.4.a that both generators reach the maximum angle deviation limits, approximately 0.5 s, after the fault. During the fault, generator G1 cannot deliver power to the system and accelerates, whereas generator G2 continues delivering power, as shown in Figure 5.4.b. The FESS reacts by injecting power to accelerate the system and reduce the angle deviation between G1 and G2. Once the fault is cleared, the FESS consumes power to decelerate generator G1, to which it is electrically near, thereby reducing its oscillation with respect to generator G2.

Figure 5.4 TSCOPF model with transient stability constraints: a) Rotor angle of generators and energy stored in the FESS; b) Power output of generators and FESS

It can be seen in Figure 5.4.a that the energy stored in the FESS returns to its initial value once there is no action required from the flywheel to stabilize the system. This is due to the component of the objective function that is linked to the speed deviation.

It is remarkable that the FESS initially injects power as the frequency is rising, which is contrary to the typical response of FESS controls to support frequency stability. Conventional frequency FESS controls in this particular case are contrary to the optimal behavior and can have a destabilizing effect.

5.4.3 Optimal FESS response to support transient and frequency stability

Frequency stability is a concerning issue in island power systems because the relatively small inertia makes it difficult to maintain the frequency within acceptable limits after severe losses of generation or load. Fig. 5 shows the results obtained when the frequency constraint (5.51) is included in the model and the frequency deviation is constrained between -0.02 p.u. (49 Hz) and 0.04 p.u. (52 Hz). The minimum frequency is set to 49 Hz

because it is the value at which the under-frequency load shedding scheme begins. The fault is the same as in the previous case: a short-circuit at bus 5 cleared after 300 ms.

Figure 5.5.a shows that generator G1, which is close to the fault, accelerates quickly during the short-circuit because the active power that the synchronous generator cannot inject into the system is transformed into kinetic energy. Once the fault is cleared, generators G1 and G2 oscillate but retain their synchronism. The solution of the optimization model transfers some generation from G1 to G2 to ensure that the angular deviation between the generator remains within the limits. It can be seen that the lower limit is nearly reached by G2 approximately at time ($t = 0.5$ s). The energy stored in the FESS varies as the FESS injects and consumes power, but remains always within the limits.

Figure 5.5.b shows the rotor speeds of the synchronous machines, together with the power exchanged between the FESS and the network. Here it can be seen again the acceleration of G1 during the fault, and the oscillations between G1 and G2 once the fault is cleared. The solution of the optimization model modulates the power injected by the FESS to maintain the speed of G1 and G2 over the limits. It can be seen that generator G2 reaches the lower limit at, approximately, time ($t = 2.2$ s).

Figure 5.5 TSCOPF model with transient stability and frequency constraints: a) Rotor angle of generators and energy stored in the FESS; b) Speed deviation of generators and power output of FESS

Overall, the pattern of the power injected by the FESS, shown in Figure 5.5.b, is more complex than in the previous case, and responds to two combined effects. On the one hand, positive and negative injections alternate during the first 1.5 seconds to damp the electromechanical oscillations between the generators. On the other hand, a net positive amount of energy is injected before the minimum frequency limit is reached to reduce the frequency drop. Once there is no action of the FESS required to recover the system, the FESS absorbs energy to return to its initial state due to the component linked to the deviation of the speed in the objective function. It is remarkable that the rapid response of the controls of the FESS makes it possible to combine a response with positive and negative exchanges of active power, as shown in Figure 5.5.b, damping the electromechanical oscillations between synchronous generators and leading the system to a more stable operation.

5.4.4 Economic assessment

This section analyses the economic cost of ensuring that the system remains stable and no load is shed after any of the reference incidents. Three cases are considered: a) without the flywheel energy storage system (NO FESS); b) with a conventional control in which the flywheel injects or absorbs fixed values of power following frequency deviations, as described in [103] and [104] (C-FESS); and c) optimizing the dynamic response of the flywheel with the proposed TSCOPF (O-FESS). The results are compared with a classical OPF without dynamic constraints.

The solution for a classical OPF results in a generation cost of 5549 €, with G1 generating 157.8 MW and G2 generating 45.5 MW, as shown in the first row of Table 5.1. The remaining rows correspond to the critical reference incidents defined in Section 5.3. Total cost includes the variable operation costs of wind generation [114]. Both the rotor angle constraints and the frequency constraints are included in the model. It can be seen in Table 5.1 that the largest cost is reached in the case of a short-circuit at bus 5, which is a consequence of bus 5 being in proximity to G1, the largest and most economical plant. Application of the TSCOPF model shows that the total generation cost increases with respect to the OPF by 16.7% (927 €) when there is no FESS, and by 15.3% (850 €) when the FESS is connected, and a conventional control is applied. The optimized control of the FESS makes it possible to further reduce the cost to 6166 €, only 13.3% (737 €) above the cost of the solution provided by the OPF.

Table 5.1 Results of TSCOPF considering one incident at a time

	FESS control	G1 (MW)	G2 (MW)	Cost (€)	Δ Cost (%)
OPF	Do not apply	157.8	45.5	5549	0
	NO FESS	106.4	84.6	6476	16.7
SC at bus 5	C-FESS	108.8	82.1	6399	15.3
	O-FESS	112.5	78.3	6286	13.3
	NO FESS	144.6	52.1	5619	1.3
SC at bus 8	C-FESS	145.8	51.4	5608	1.1
	O-FESS	146.1	51.3	5604	1.0
Loss of load	NO FESS	169.5	43.2	5669	2.2
	C & O-FESS	157.8	45.5	5549	0
Loss of WF	All cases	157.8	45.5	5549	0

The results obtained when a short-circuit is applied at bus 8 are qualitatively similar, although the introduction of the dynamic constraints results in lower costs because the incident is less critical. The total cost increases with respect to the OPF by 1.3% (70 €) when there is no FESS, by 1.1% (59 €) when the FESS is connected and a conventional control is applied, and by 1.01% (55 €) when the control of the FESS is optimized.

The dynamic constraints after the loss of load incident cause an incremental increase of 2.2% for the cost when there is no FESS, but this cost is eliminated when the FESS is connected and either a conventional or optimized control is applied. Finally, the dynamic constraints do not increase the cost after the disconnection of the wind farm, which can be explained by the relatively small size of the wind farm that does not compromise the stability of the system.

The proposed TSCOPF is also evaluated in a modified IEEE 57 Bus Test System [63] that includes wind power generation and a FESS. The size and location of the wind farms can be found in Table 5.7. The FESS is located at bus number 15, near to the main generation area. Table 5.2 presents the solution of the TSCOPF model when a short-circuit is applied at bus number 1. Three cases of study are evaluated: a) without flywheel (NO FESS); b) considering the optimal response of a flywheel of 10 MW (O-FESS 10 MW); and c) considering the optimal response of a flywheel of 20 MW (O-FESS 20 MW).

The results in Table 5.2 show that the response of the FESS tends to reduce the generation costs because it improves the stability to the system, making it possible to shift generation to power plants that are more economical. The effect is more pronounced as the size of the FESS increases.

Table 5.2 Results of TSCOPF on the dispatch of the IEEE 57 Bus Test System.

	G1 (MW)	G2 (MW)	G3 (MW)	G4 (MW)	G5 (MW)	G6 (MW)	G7 (MW)	Cost (M.U.)
NO FESS	226.5	239.5	500	11.6	20.7	20.8	39	33820
O-FESS 10 MW	226.9	240.7	500	10.9	19.9	21	38.8	33791
O-FESS 20 MW	227	242.1	500	10.6	19	20.9	38.7	33764

5.4.5 Economic assessment considering multiple contingencies

The optimal operation of the FESS corresponding to one contingency can aggravate the effect of another contingency. The MC-TSCOPF model makes it possible to calculate the most economical operation point that ensures a stable operation and avoids load shedding after any of the reference incidents. The MC-TSCOPF is applied to the power system of Fuerteventura-Lanzarote. The results of the MC-TSCOPF, which includes all critical contingencies in Table 5.1, are presented in Table 5.3. The first row corresponds to a case that does not include the FESS. In this case, the dynamic constraints increase the generation cost by 21.2% with respect to the OPF.

The second row represents a case in which the FESS is connected but its dynamic response is not optimized. Here, the cost is improved with respect to the previous case. The third row corresponds to a case that applies a single common FESS response (SR) to every incident. It is noted that the implementation of this method requires that the FESS control system detects that an incident has occurred in the grid. The cost is further improved with respect to the previous cases.

The final case considers multiple FESS responses (MR), which means that there is a different response for each incident. The implementation of this strategy requires that the FESS control system be aware of the type of incident that has occurred. The resulting generation cost is slightly lower than in the case of the SR.

Table 5.3 Results of MC-TSCOPF including all reference incidents

	G1 (MW)	G2 (MW)	Cost (€)	ΔCost (%)
MC-TSCOPF	101.7	91.5	6726	21.2
MC-TSCOPF + C-FESS	105.1	86	6524	17.6
MC-TSCOPF + O-FESS SR	111.7	79.3	6317	13.8
MC-TSCOPF + O-FESS MR	112.5	78.3	6286	13.3

5.5 Conclusions

A simultaneous discretization MC-TSCOPF model that facilitates the inclusion of renewable generation, an energy storage system, and non-linear loads is formulated. The

application of the proposed MC-TSCOPF model to the Fuerteventura-Lanzarote island system provides the opportunity to calculate an optimal dispatch that ensures the system remains stable and no loads are shed after any one of a set of predefined reference incidents.

The integration of a FESS model in the MC-TSCOPF problem can be used to optimize the dynamic response of the flywheel to support transient and frequency stability. Ensuring the stability in electric power systems presents additional costs because in some cases it entails to shift generation to power plants that are more expensive. The inclusion of the FESS dynamic response in the MC-TSCOPF model allows the generation costs to be reduced while ensuring stability after any of the reference incidents. It is found that the optimal response of the flywheel after a short-circuit may be contrary to the response of conventional FESS controls.

5.6 Appendix

Table 5.4 Parameters of lines and transformers of the Fuerteventura-Lanzarote power system

Branch	R [p.u.]	X [p.u.]	B [p.u.]
1-5	0	0.02	0
2-10	0	0.02	0
4-5	0.0473	0.1515	0.0050
4-6	0.0929	0.2975	0.0098
5-6	0.0506	0.1619	0.0053
6-7	0.0895	0.2865	0.0051
7-8	0.0151	0.0323	0.0578
8-9	0.0202	0.0648	0.0021
9-10	0.1331	0.4260	0.0141
10-11	0.1687	0.5399	0.0179
3-11	0.1365	0.4370	0.0145

Table 5.5 Parameters of power plants and controls of the Fuerteventura Lanzarote power system

K^A	400	$V^{R,MIN}$	-7.3 p.u.	H	3 s
K^F	0.03	$V^{R,MAX}$	7.3 p.u.	D	2
K^E	1	A^S	0.09826	R^A	0 p.u.
T^A	0.02 s	B^S	0.5527	X^D, X^Q	1.5 p.u.
T^F	1 s	K^{TG}	50	X'^D, X'^Q	0.3 p.u.
T^E	0.8 s	T^{TG}	3 s	T'^D, T'^Q	6; 1 s

Table 5.6 FESS parameters

$\omega^{FW,MIN}$	30	$\omega^{FW,MAX}$	60	J	1333.33
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Table 5.7 Wind power generation data from the IEEE 57 modified Bus Test System

Units	Location (buses)	P_{WF} (MW)	Q_{WF} (Mvar)	Total Generation (MW)/(Mvar)
5	7, 21, 24, 34, 37	50	10	250/50

CHAPTER 6

CONCLUSION

TSCOPF is a practical and useful tool to provide an economic operation of power systems while maintaining steady state secure limits and ensuring transient stability. TSCOPF extends classical OPF models by including the dynamic representation of the response of the system under one or more incidents to provide a transiently stable solution. Among the several approaches proposed in the literature to address this problem, this work chooses the simultaneous discretization method because it allows the user to represent separately each individual synchronous or non-synchronous renewable power plant.

Traditionally transient and frequency stability have been determined by the dynamic response of large synchronous power plants, as they contain a large rotating mass directly connected to the system. Non-synchronous renewable sources do not provide inertia, since they decouple the grid from electrical generator via electronic interfaces [91]. Modern and future power systems studies involve scenarios with high shares of non-synchronous renewable sources, reducing the total inertia of the system and making the system more unstable under critical contingencies. As a consequence, TSCOPF algorithms must improve their renewable models to make them useful in new scenarios in which non-synchronous renewable generation and energy storage systems displace synchronous generation and play a crucial role in the operation and stability of the system.

This thesis addresses the inclusion of non-synchronous sources in TSCOPF models, as well as the evaluation of the effect of different control strategies on the results. The proposed models are applied to scenarios with high shares of non-synchronous renewable generation. Energy storage system models are included in the TSCOPF, integrated and optimized to improve stability.

As different scenarios and TSCOPF models may require different numerical approaches, this thesis also studies the application of some of the most used integration methods as an alternative to the trapezoidal rule. Several implicit and explicit numerical integration methods are implemented and their performance in TSCOPF studies is evaluated.

6.1 Contributions

The main contributions of this thesis are:

- A new simultaneous discretization TSCOPF formulation that calculates the frequency, the power flow and the voltages at each bus of the system and at each sample time. This formulation allows the user to represent controllers that receive the frequency and the voltage at the Point of Common Coupling as input variables. The model is suitable for the representation of non-synchronous renewable generation equipped with synthetic inertia and voltage regulator controls, energy storage systems and detailed load models. All these improvements have been implemented and tested in the thesis.
- The formulation and application of a multi-contingency TSCOPF to the operation of an island power system. As the optimal solution for one contingency could be detrimental to the stability of another contingency, more than one critical contingency must be simultaneously evaluated to calculate the stable operation. Multi-contingency TSCOPFs are challenging because they require a large number of equality and inequality constraints.
- A comparative study of the performance of different explicit and implicit numerical integration methods in TSCOPF models. This study can help future research works in the field of TSCOPF to choose a proper integration method, depending on the accuracy and computational performance desired.
- The application of a variable integration time step to reduce the computational size of simultaneous discretization TSCOPF formulations while maintaining the accuracy of the results and reducing computational times. Although, the use of a variable integration time step is a common practice in simulation, to the best of our knowledge, it had not been proposed yet in optimization.

- The implementation of a model to represent non-synchronous renewable generation in simultaneous discretization TSCOPF formulations. The model includes 1) the representation of controllers to provide reactive power support for voltage dips following the current Spanish grid code; 2) the representation of fault ride-through capability following the Spanish grid code; and 3) a controller to provide synthetic inertia.
- The evaluation of the impact of synthetic inertia on the optimal dispatch is evaluated using the proposed TSCOPF model. Implementation of different parameters of the synthetic inertia control and evaluation of the effect on the results.
- The inclusion of energy storage systems in the formulation of the TSCOPF. An analysis of fast response storage systems is performed, evaluating their effects on the total generation cost and stability. Transient and frequency stability in the event of critical incidents in the power system are considered. The optimal response is compared with the current response of real energy storage systems.
- Application of a TSCOPF model to the power systems of both Tenerife and Lanzarote-Fuerteventura, where stability problems are a major issue due to the low inertia. The algorithm is also used to calculate the optimal operation of the North-West Spanish power system, an area with very high shares of non-synchronous renewable generation and an international interconnection.
- The research conducted in this thesis has resulted in four journal papers, three of them already published in different JCR-indexed journals and another still in revision steps. One more paper has been presented and published at a relevant international conference.

6.2 Conclusions

The following conclusions have been found:

1. The proposed TSCOPF formulations are useful to provide the optimal operation of real energy systems with high shares of non-synchronous renewable generation and storage. The application of the proposed TSCOPF formulation to the island systems of Fuerteventura-Lanzarote and Tenerife, and to the North-West Spanish system does not pose notable convergence issues; the solution is reached in few

seconds using a mid-range personal computer. Since there is usually more than one contingency that can endanger stability, a MC-TSCOPF has been implemented taking into account a set of reference incidents. The solution of the MC-TSCOPF is reached in few minutes, as the size of the optimization problem proportionally increases with the number of incidents.

2. Given the non-linear nature of the optimization problem, it is not possible to ensure an optimal solution (as is the case of standard OPF models). However, the coherence of the results over a large range of cases makes the authors think that the solver is actually reaching the global optimal solution.
3. Regarding numerical integration methods, the theta method is an adequate, robust, and flexible integration technique to include the differential equations that represent the dynamics of power plants within TSCOPF. The Theta method allows the user to apply several integration methods without changing the mathematical formulation, particularly the forward Euler method, the backward Euler and the trapezoidal rule. This helps the user to select which one of them is more suitable for their specific problem.
4. In terms of the speed of convergence, the trapezoidal rule and the intermediate variants of the Theta method provide the fastest solutions, while the forward and backward Euler methods requires longer computation times. The fastest methods correspond to those in which the state variables appear twice in each discretized differential equation.
5. In terms of numerical solution, the trapezoidal rule, which is the most used method in TSCOPF, and the backward Euler method, in a higher degree, tend to damp the electromechanical oscillations over the real trajectories. This effect increases with the integration time step. Operators assessing the stability of a system should be aware of this effect, and perhaps compensate it by introducing a security margin in the dynamic constraints of the optimization model.
6. When the computational time is an issue, it is recommended to use a variable integration time step to reduce the size of the optimization problem and convergence times while maintaining the accuracy of the results. It is remarkable that the computational time is reduced rapidly as the size of the optimization problem decreases. To maintain accuracy, it is advisable to keep a short integration time step during the first second of the time domain representation, in which the

largest electromechanical oscillations occur and the transient stability limits are reached, and to use a larger integration time step from that moment on.

7. The non-linear nature of loads must be preserved in order to ensure that the solution of a TSCOPF algorithm is transiently stable, and engineers should be aware of this effect when modeling loads as a constant impedance. While this work makes use of a more detailed non-linear load model, most of previous TSCOPF studies represent loads as a constant impedance to include them into the admittance matrix in order to reduce the size of the optimization problem using Kron reduction. It has been found that, the solution of TSCOPF algorithms when using a constant impedance load model can provide unstable solutions since the simulated electromechanical oscillations are more stable than real trajectories.
8. The solution of a TSCOPF generally increases the cost given by a classic OPF algorithm, since the result shifts generation to more expensive power plants to ensure transient stability. Synthetic inertia in non-renewable generation can improve the stability of the system when the system faces a severe incident, reducing both the rotor angle and speed deviations of synchronous power. The representation of fast response energy storage systems within the TSCOPF improves the transient stability of the power system by damping the electromechanical oscillations between synchronous generators. Both solutions reduce the total generation costs provided by the TSCOPF solution.
9. TSCOPF formulations can be used to find the optimal parameters of inertia emulation controls, such as the amount of synthetic inertia or the maximum increments in the active power, to improve stability and reduce the total generation cost. The delay due to the frequency measurement devices has a considerable effect on the response of synthetic inertia controls and must be properly considered in TSCOPF studies.
10. It is possible to use a TSCOPF to calculate the optimal dynamic response of an energy storage system to improve the dynamic stability after different types of incidents. It has been observed that, in some cases, the optimal response is contrary to the response of conventional FESS controls.
11. Integrating high shares of non-synchronous renewable generation can lead to scenarios that require to cut renewable generation because of security issues. In this thesis, the TSCOPF model is presented as an effective and practical tool to

optimize renewable generation curtailment in scenarios with high availability of renewable resources. The following techniques have proven valid to reduce the curtailment of renewable generation: 1) The reduction of fault clearing time of protection systems; 2) Fault ride-through capability in non-synchronous renewable generation; 3) The increase of the inertia of the system, equipping non-synchronous renewable generation with synthetic inertia; and 4) The use of Flexible AC Transmission Systems (FACTS).

6.3 Future works

This last section suggests research directions to continue the work performed in this thesis that are listed above:

- To perform a comparative implementation of different load models and evaluation of their impact on TSCOPF results. The use of the frequency divider formula together with the representation of load flow equations at each bus and at each sample time allows the implementation of detailed load models that depends on the frequency and voltage in the connection bus.
- Expanding the model to consider larger power systems.
- Application of multi-step numerical integration methods to discretize the differential equations.
- Implementation of a primary frequency regulator in non-synchronous renewable generation and evaluation of its effect on the results.
- To perform a comparative implementation of different types of fast response energy storage systems and evaluation of their effects on the solution of the TSCOPF.
- Evaluation of the impact of different location and size of energy storage systems on the solution of the TSCOPF.
- Application of the proposed tool to the operation of real systems in collaboration with the System Operator.

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