COMILLAS
UNIVERSIDAD PONTIFICIA
ICAI

DOUBLE MASTER'S DEGREE IN INDUSTRIAL ENGINEERING & SMART GRIDS

MASTER THESIS

Analysis and implementation of Optimal Power Flow (OPF) tool for grid operation and planning under different future potential flexibility scenarios- Application to i-DE network.

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Madrid

August 2021

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ANALYSIS AND IMPLEMENTATION OF OPTIMAL POWER FLOW (OPF) TOOL FOR GRID OPERATION AND PLANNING UNDER DIFFERENT FUTURE POTENTIAL FLEXIBILITY SCENARIOS- APPLICATION TO I-DE NETWORK.

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RESUMEN DEL PROYECTO

La optimización de recursos distribuidos (DER) permite una operación más eficiente de la red sin incurrir en gastos de capital (CAPEX). Este proyecto analiza los beneficios tecnoeconómicos derivados de utilizar cambiadores de tomas en carga (OLTCs), dispositivos shunt, generación distribuida (DG) y demanda flexible para optimizar el funcionamiento de una red de distribución real de 20 kV mediante un algoritmo de flujo óptimo de cargas (OPF).

Palabras clave: OLTC, DG, demanda flexible, shunt, OPF, GRD.

1. Introducción

Tradicionalmente, la red de distribución se ha operado de forma radial con una demanda pasiva, donde los flujos de potencia han ido de la alta a la baja tensión. En los últimos años se ha producido un aumento de los agentes distribuidos (DER) como generadores distribuidos (DGs) alimentados por diferentes tecnologías (cogeneración, plantas de renovables…), vehículos eléctricos (EVs) o flexibilidad en demanda.

Estos nuevos recursos de la red de distribución pueden ser un desafio de cara a la operación de la red, aumentando la complejidad para las protecciones y equipos como los cambiadores de tomas en carga (OLTC) debido a la aparición de flujos de potencia inversos. Sin embargo, esta flexibilidad abre la puerta a nuevas oportunidades, al introducir nuevas variables de control que pueden utilizarse para una operación más eficiente de la red, presentandose como alternativas a los gastos de capital.

Este proyecto analiza las nuevas variables de control disponibles en la red de distribución gracias a los cambiadores de tomas en carga (OLTC), elementos shunt, generación distribuida (DG) y demanda flexible, estudiando las posibles aplicaciones y usos de la herramienta del Flujo Óptimo de Cargas (OPF).

Se identifica la información necesaria para parametrizar cada una de estas variables de control en la herramienta OPF del software PSS®E y se evaluan los beneficios tecnoeconómicos derivados del uso de esta herramienta mediante la simulación de diferentes escenarios de flexibilidad en una red de distribución real de 20kV.

El problema de optimización en los sistemas eléctricos aparece cuando dos o más generadores deben satisfacer una demanda determinada. El OPF determina el reparto óptimo de potencia para cada uno de los generadores de tal forma que se minimize el coste total de generación, manteniendo los flujos de potencia del sistema dentro de los límites.

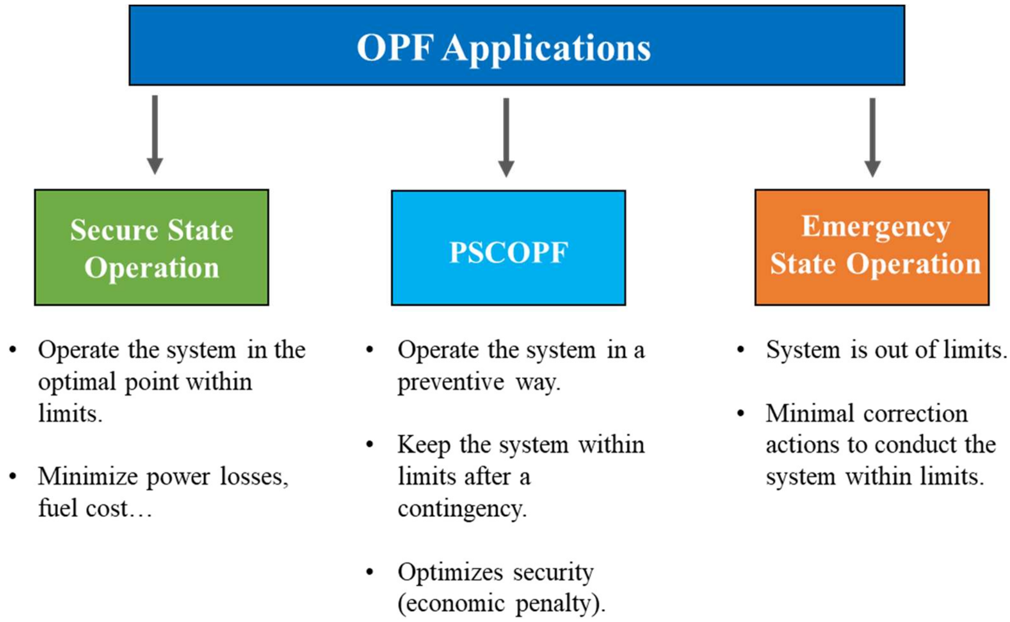

Ilustración 1: Aplicaciones de la herramienta OPF

La Ilustración 1 muestra las principales aplicaciones de la herramienta durante la operación de la red. Se han dividido en tres categorías: operación en estado preventivo (PSCOPF), operación en estado seguro y operación en estado de emergencia. En la actualidad, existe un incentivo económico en la retribución del gestor de la red de distribución (GRD) a minimizar las pérdidas durante la operación y a reducir las interrupciones de los clientes (índices NIEPI y TIEPI). Por esta razón, las aplicaciones del OPF que se estudian en este proyecto están orientadas a la operación en estado seguro, donde se calcula el punto óptimo de operación con mínimas pérdidas y a la operación en estado de emergencia, donde se obtinenen el conjunto de acciones óptimas que llevan el sistema dentro de los límites de operación.

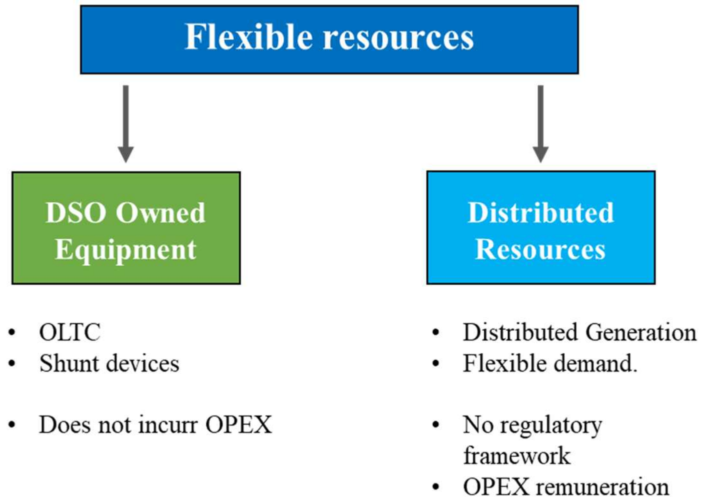

Ilustración 2: Clasificación de los recursos flexibles

Cada uno de los recursos flexibles presentes en la red de distribución tiene variables de control que potencialmente pueden utilizarse en el OPF. Los recursos se han dividido en 2 grupos, como se muestra en la Ilustración 2: equipos propiedad del GRD (cambiadores de tomas en carga y dispositivos shunt) y servicios auxiliares proporcionados por agentes externos (generadores distribuidos y flexibilidad en demanda).

En un escenario futuro, en el que se implemente una ejecución periódica en segundo plano del OPF durante la operación de la red, los equipos propiedad del GRD ya instalados se utilizarán preferentemente para minimizar pérdidas, al ser recursos con un Gastos Operativos (OPEX) casi nulos. La instalación de nuevos equipos tendrá gastos de capital (CAPEX) que deberán considerarse y compararse con los gastos operativos de otros recursos distribuidos ya existentes en la red.

El despacho de potencia activa de los generadores distribuidos y la flexibilidad para reducir la potencia activa de la demanda son alternativas que pueden utilizarse para la gestión de contingencias en la red (operación en estado de emergencia). Cuando una sobrecarga hace disparar una línea, se interrumpe el suministro de todos los clientes conectados a ella. La gestión de las sobrecargas utilizando el OPF puede ayudar a reducir los minutos de energía no servida, un incentivo en la remuneración de DSO.

2. Metodología

Primero, se han modelado y parametrizado las variables de control asociadas a los recursos flexibles. En segundo lugar, se evalúan los beneficios de aplicar un OPF en una red de distribución real de 20kV bajo diferentes escenarios de flexibilidad, comparando los resultados con un escenario base. Finalmente, se realiza un análisis de sensibilidades, determinando para los diferentes escenarios de flexibilidad estudiados, cuáles son los controles más efectivos.

La metodología de las simulaciones realizadas en el proyecto se puede resumir en los siguientes pasos:

1. Los casos base de la red de distribución se obtienen del estimador de estados PSE (herramienta i-DE) y se analizan utilizando el software de flujo de cargas PSS®E, determinando los resultados del escenario inicial.

2. Se definen cada uno de los casos de optimización para los recursos flexibles discutidos en la sección 2 (OLTC, elemento shunt, DGs y demanda flexible) evaluando diferentes funciones objetivo y variables de control disponibles (posición de la toma, conexión del shunt, regulación de potencia activa y reactiva de los generadores distribuidos y reducción de la potencia activa de la demanda).

3. Se obtienen los resultados de las simulaciones OPF y se evalúa el impacto de cada una de las variables de control en el sistema, comparando los resultados con el escenario inicial.

4. Con los resultados obtenidos, se realiza un análisis de sensibilidades, determinando para los diferentes escenarios de flexibilidad, cuáles son los controles más efectivos.

La Tabla 1 describe las funciones objetivo, recursos flexibles y variables de control utilizadas para de cada una de las simulaciones realizadas.

Para los casos de simulación 1 y 2, se utilizan los recursos flexibles propiedad del GRD, controlando la posición de la toma del OLTC y la inyección de reactiva del dispositivo shunt (decisión de conexión) para minimizar las pérdidas en la red.

En el caso de simulación 3, se utiliza la regulación de tensión/reactiva de los generadores distribuidos (DGs), controlando su inyección de potencia reactiva para obtener el perfil de tensiones óptimo que minimiza las pérdidas de la red. Evaluando su sensibilidad respecto la función objetivo y su efecto sobre otras variables eléctricas como las tensiones o flujos de potencia por las lineas.

Actualmente, los generadores son modelados por algunas de las aplicaciones eléctricas de i-DE como cargas negativas PQ que generan potencia activa con un factor de potencia fijo sin ningún tipo de regulación sobre la tensión y la potencia reactiva.

Por último, en el caso de simulación 4, se utiliza la flexibilidad en potencia activa de la generación distribuida y demanda para resolver un caso de operación en estado de emergencia. Obteniendo las acciones correctivas más eficientes económicamente para eliminar una sobrecarga en una línea, según diferentes escenarios de costes para la demanda flexible.

Simulación	Función objetivo	Recurso flexible	Variable de control
Caso 1	*Minimización de pérdidas*	OLTC	• Posición de toma
Caso 2	*Minimización de pérdidas*	Elemento shunt subestación	• Valor óptimo de shunt • Conexión horaria del elemento shunt
Caso 3	*Minimización de pérdidas*	DGs	• Control tension/reactiva de los DGs.
Caso 4	Operación en estado de emergencia (sobrecarga en linea) *Minimización de demanda flexible y coste de combustible*	DG & Flexible demand	• Potencia generada (G1) • Deslastre de carga flexible (residencial e industrial) bajo diferentes escenarios de costes

Tabla 1: Función objetivo, recursos flexibles y variables de control para cada una de las simulaciones realizadas

3. Resultados

La Ilustración 3 muestra la reducción de pérdidas respecto a los escenarios iniciales durante las 24 horas simuladas de los casos de simulación 1 al 3, donde la posición de la toma del OLTC, la conexión horaria del elemento shunt y la potencia reactiva de los generadores distribuidos (DGs) se optimizan respectivamente.

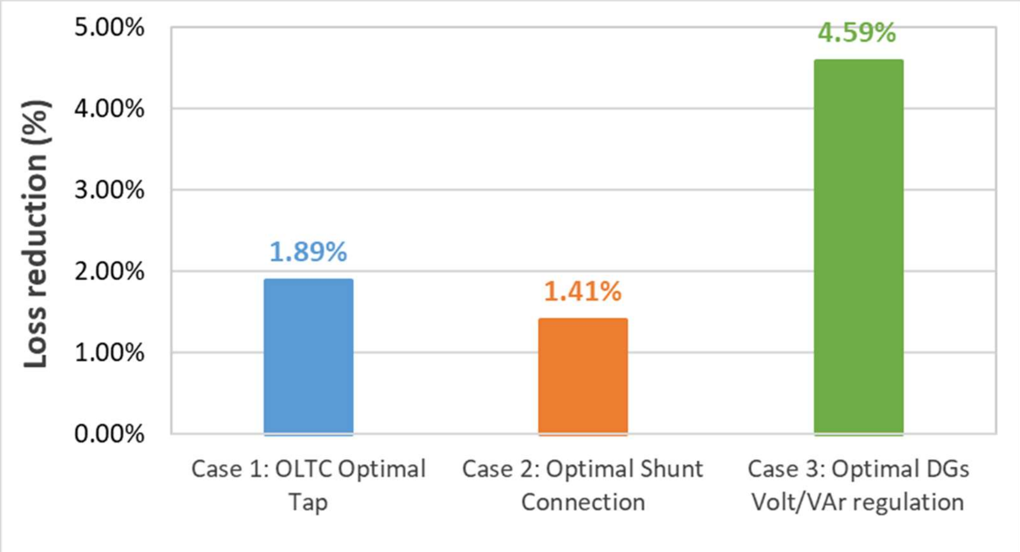

Ilustración 3: Reducción de pérdidas durante 24 horas de los casos 1 al 3

La Tabla 2 expone los resultados del caso de operación en estado de emergencia, según tres escenarios de coste de deslastre de la demanda flexible: alto, medio y bajo. Se muestran cuales son las acciones de control óptimas para cada uno de los escenarios planteados y cuál es el incremento en el coste total del sistema respecto al caso inicial.

Operación en estado de emergencia	Coste marginal generador (€/MWh)	Tipo de carga	Coste (€/MWh)	Flexibilidad utilizada (%)	Incremento en el coste total (€/h)
Escenario de alto coste de deslastre	60	Residential	70	0%	13.6
		Industrial	80	0%	
Escenario de coste medio de deslastre	60	Residential	50	10%	13.3
		Industrial	65	0%	
Escenario de bajo coste deslastre	60	Residential	40	10%	2.5
		Industrial	45	10%	

Tabla 2: Resultados del caso de simulatión 4: Operación en estado de emergencia

4. Conclusiones

Este proyecto estudia los beneficios de utilizar recursos flexibles de la red como son los cambiadores de tomas en carga (OLTCs), elementos shunt, generadores distribuidos (DGs) y cargas flexibles que pueden aportar variables de control (posición de la toma del OLTC, conexión del elemento shunt, regulación de potencia activa y reactiva de los DGs o reducción de la carga de demanda) para optimizar el funcionamiento de la red mediante la aplicación del Flujo Óptimo de Cargas (OPF).

El efecto directo que se observa al minimizar las pérdidas de la red es aumentar el perfil de tensiones mediante el uso de la variable de control disponible: disminución de la toma del OLTC, inyección de potencia reactiva de los elementos shunt o de los generadores distribuidos. Un aumento en la tensión provoca a una reducción en los flujos por las lineas y, por tanto, menores pérdidas.

El OPF ha demostrado ser una herramienta útil para encontrar el punto óptimo de operación con pérdidas mínimas (Ilustración 3). Obteniendo una reducción de pérdidas durante las 24h estudiadas del **1,89%** utilizando la posición de la toma del OLTC, una reducción del **1,41%** al optimizar el horario de conexión del shunt de la subestación y una reducción del **4,59%** al optimizar la regulación tensión/reactiva de los generadores distribuidos. La sensibilidad de los generadores para reducir las pérdidas ha demostrado ser mayor cuanto más aguas abajo de la subestación se encuentran, lo que significa que estos son los recursos más efectivos para minimizar pérdidas mediante la inyección de reactiva.

El OPF ha demostrado ser capaz de resolver situaciones de operación en estado de emergencia utilizando las acciones correctivas más óptimas. Como se muestra en la Tabla 2, se pueden definir diferentes cargas flexibles, con diferentes flexibilidades y costes. Para un escenario con un bajo coste de deslastre, donde el coste de reducir demanda es inferior al coste marginal del generador ditribuido (60 €/MWh), se reduce la potencia de la demanda flexible para resolver la contingencia. Por el contrario, para un escenario de alto coste de de deslastre, se aumenta la potencia inyectada por el generador, causando unos costes mayores.

Es importante definir unos costes para cada uno de los términos de la función objetivo y unos parámetros de configuración tales que conduzcan el OPF a la solución deseada. Al definir unos limites de tipo *'hard limit'* para las tensiones de la red, los términos de barrera que introducen dichos limites en la función objetivo hace que se deba definir un coste de pérdidas mayor que 1000 €/pu para obtener una solución que minimice las pérdidas.

El control óptimo de los recursos flexibles permite una operación de la red más eficiente incurriendo en gastos operativos (OPEX). Bajo este nuevo potencial escenario de flexibilidad en las redes de disribución, se deben evaluar los gastos de capital (CAPEX) que tienen las nuevas instalaciones y compararlos con los gastos operativos que presentan los recursos flexibles ya existentes en la red para tomar las decisiones económicamente más eficientes.

ANALYSIS AND IMPLEMENTATION OF OPTIMAL POWER FLOW (OPF) TOOL FOR GRID OPERATION AND PLANNING UNDER DIFFERENT FUTURE POTENTIAL FLEXIBILITY SCENARIOS- APPLICATION TO I-DE NETWORK.

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Collaborating Entity: i-DE Redes Eléctricas Inteligentes (Grupo Iberdrola).

PROJECT ABSTRACT

Flexible resource optimization enables a more efficient grid operation without incurring capital expenditures. This project analyzes the techno-economic benefits of using OLTC, shunt device, DGs and flexible demand as potential flexible resources to optimize the operation of a real 20kV distribution network using an Optimal Power Flow (OPF).

Keywords: OLTC, DGs, Flexible demand, shunt, OPF, DSO.

1. Introduction

Traditionally, the distribution grid has been operated radially with a passive demand, where power flows go from the HV to the LV. In recent years, there has been an increase of Distributed Energy Resources (DER) such as distributed generators (DGs) powered by different technologies (cogeneration, renewable source…), electric vehicles (EVs) or demand response (DR) available in the distribution level.

These new flexible resources may become a challenge, increasing the complexity in grid operation, and causing issues in the equipment such as protections or transformer's On-Load Tap Changer (OLTC) due to the appearance of reverse power flows. But they offer plenty of opportunities as well, introducing new potential control variables that could lead to a more efficient operation, and cost-efficient alternatives to network investment.

This project analyzes potential control variables in the distribution grid given by the OLTCs, shunt elements, distributed generation and flexible demand resources, that could be used to optimize grid operation with the Optimal Power Flow tool (OPF).

Identifying the information required to parametrize each control variable in the software PSS®E, defining the potential applications and objectives of the OPF tool and evaluating the techno-economic benefits by performing simulations over different flexibility scenarios in a real 20kV distribution network.

The optimality problem appears in power systems when two or more generators must satisfy a given demand. The OPF determines the optimal power dispatch for each generation unit that minimizes total generation costs, keeping power flows within limits.

Illustration 1 provides the main applications given to the OPF tool for power system operation. OPF objectives for grid operation have been divided into three categories: Preventive Security Constrained OPF (PSCOPF), secure state operation and emergency state operation. At present, there is an economic incentive for Distribution System

Operators (DSOs) to minimize power losses during grid operation, as well as reducing customer interruptions (NIEPI and TIEPI). Therefore, the OPF applications studied in this project are focused in the secure state and emergency state operation groups respectively.

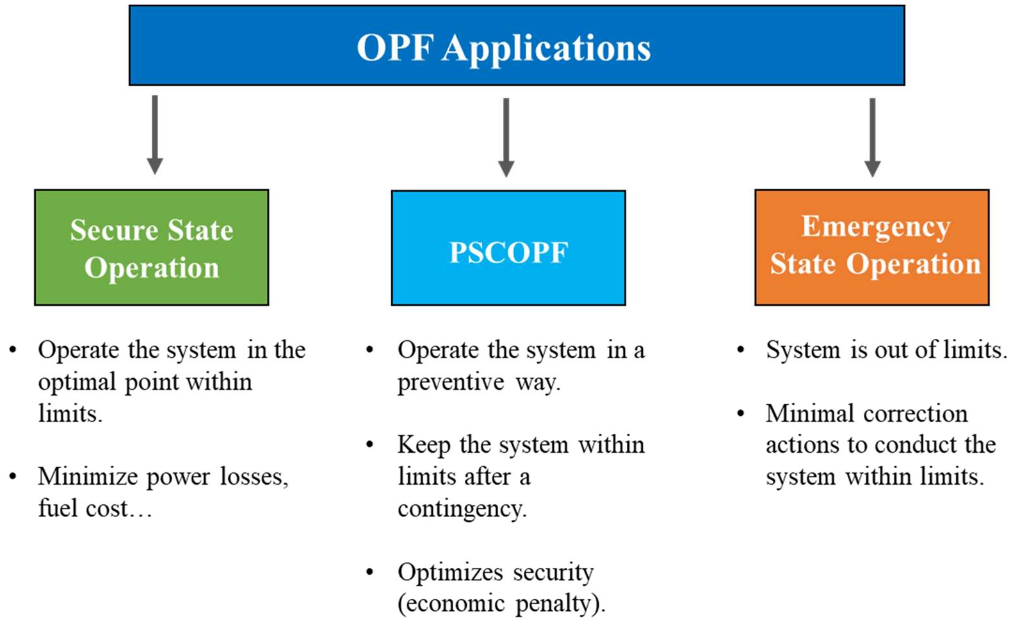

Illustration 1: OPF applications

Every flexible resource in the grid has control variables that could potentially be used in the OPF. Resources have been divided into 2 main groups as shown in Illustration 2: DSO owned equipment (On Load Tap Changers and shunt devices) and ancillary services provided by external agents (Distributed Generators and Demand Response).

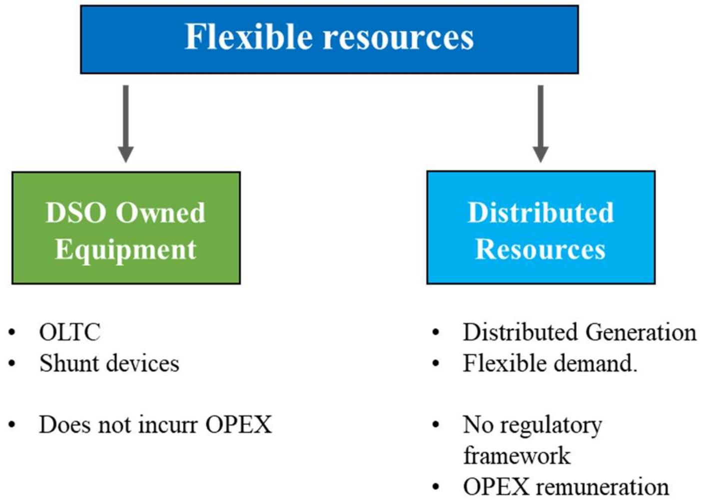

Illustration 2: Flexible resources classification

In a future context where a periodical OPF background execution is implemented during grid operation, DSOs owned equipment already installed will probably be the preferred flexible resource to minimize losses, since it would have almost none Operational

Expenditures (OPEX). However, new installations will have capital expenditures that need to be considered and compared with alternatives such as distributed resources.

Active power dispatch from generators and demand load flexibility could be used for contingency management. An overload can trip a line, leaving all the customers connected to it unenergized. Managing overloads in lines could also help in reducing minutes of non-served energy, which is another incentive in the DSO remuneration.

2. Methodology

First, control variables associated to each flexible resource have been modelled and parametrized. Secondly, benefits of applying an OPF in a real 20kV distribution network under different flexibility scenarios are evaluated and compared with the initial case. Finally, a sensitivity analysis is performed, determining for different flexibility scenarios, which are the most effective controls.

Project simulation's methodology can be resumed in the following steps:

1. Base case scenarios from a real distribution network are obtained from the state estimator PSE (i-DE tool) and analyzed using PSS®E power flow software, determining the base case results.

2. Optimization cases are defined for each of the flexible resources discussed in Section 2 (OLTC, shunt device, DGs and flexible demand) evaluating different objective functions by using their available control variables (tap position, shunt device connection, active and reactive power regulation from DGs and demand load reduction).

3. For the flexibility cases simulated, impacts of using each control variable are evaluated and compared with the initial case scenario results.

4. With results obtained, a sensitivity analysis is performed, determining for different flexibility scenarios, which are the most effective controls.

Chart 1 describes which are the objective functions, flexible resources and control variables used within each of the OPF simulations performed.

Simulation cases 1 and 2 use the DSO owned flexible resources, controlling the OLTCs tap position and shunt device reactive injection (connection schedule) variables respectively for power losses minimization.

Simulation case 3 uses DGs Volt/VAr regulation, controlling their reactive power injection to obtain the optimal voltage profile that minimizes power losses. Evaluating their sensitivity with the objective function and their effect on other electrical variables such as voltages or power flows.

Currently, generators are modelled by some of the i-DE electrical applications as negative fixed PQ loads generating active power at a fixed power factor with no control over the reactive power outputs.

Simulation case 4 uses active power flexibility of demand and DG power dispatch to solve an emergency state operation. Obtaining the most cost-efficient control actions under different load-shedding costs to eliminate an overload in a line.

Simulation	Objective functions	Flexible resources	Control variables
Case 1	Secure state operation *Minimize Losses*	OLTC	• Tap position
Case 2	Secure state operation *Minimize Losses*	Substation shunt device	• Adjustable shunt optimal value • Shunt connection decision
Case 3	Secure state operation *Minimize Losses*	DGs	• Volt/VAr regulation from DGs
Case 4	Emergency state operation (Solve an overload) *Minimize Bus Load* *Minimize Fuel Cost*	DG & Flexible demand	• Power dispatch from G1 • Load shedding from industrial and residential flexible demand under different load-shedding costs

Chart 1: Objective function, flexible resources and control variables used in each of the simulations performed

3. Results

Illustration 3 shows the the 24-hour power loss reductions obtained with respect the initial scenarios considered for simulation cases 1 to 3, where OLTC tap position, shunt device connection schedule and reactive power from DGs are optimized respectively.

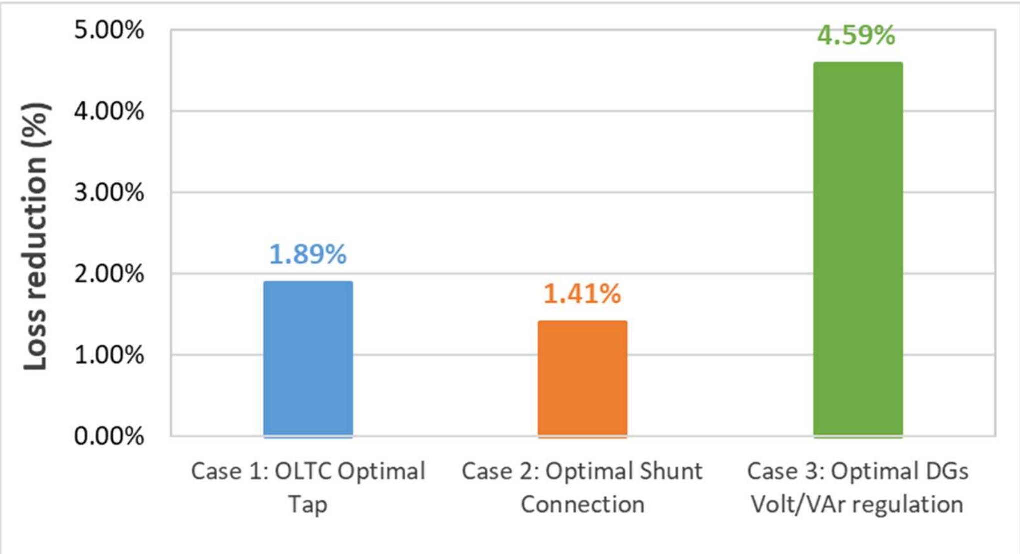

Illustration 3: 24 hour loss reduction for OPF cases 1 to 3

Chart 2 shows the results for the emergency state operation case under different load-shedding cost scenarios. Providing the optimal control actions taken to eliminate an overload in a line and the associated total cost increment with respect the initial case.

Emergency state operation	Generator marginal cost (€/MWh)	Load Type	Cost (€/MWh)	Load Flexibility use (%)	Total cost increment (€/h)
High load-shedding cost scenario	60	Residential	70	0%	13.6
		Industrial	80	0%	
Medium load-shedding cost scenario	60	Residential	50	10%	13.3
		Industrial	65	0%	
Low load-shedding cost scenario	60	Residential	40	10%	2.5
		Industrial	45	10%	

Chart 2: Case 4 simulation results (emergency state operation)

4. Conclusions

This project analyzes the benefits of using OLTC, shunt device, DGs and flexible demand as potential flexible resources and their available control variables (OLTC tap position, shunt element connection, active and reactive power regulation from DGs and demand load reduction) to optimize grid operation using an OPF.

The direct effect observed when minimizing losses is an increase in the network's voltage profile by using the associated control variable: decreasing OLTC tap position or injecting reactive power into the network with resources such as shunt devices or DGs. A rise in voltages leads to a reduction in branch currents and therefore power losses.

The OPF has proven to be a useful tool for finding the optimal operational point with minimal losses (Illustration 3). Obtaining a 24h losses reduction of **1.89%** by managing the tap position of the OLTC, a reduction of **1.41%** when optimizing the substation's capacitor bank connection schedule, and a total reduction of **4.59%** when using the reactive power regulation from DGs. DGs sensitivity for reducing power losses is higher for more downstream locations from the primary substation, meaning that these are the most effective resources to minimize power losses when injecting reactive power.

The OPF has proven to be capable of solving emergency state situations by providing the optimal corrective control actions in terms of cost-efficiency for the flexible resources available. As shown in Chart 2 different flexible loads may be defined in the OPF, with different quantities and costs. For a low load-shedding cost scenario, below the generator's marginal fuel cost (60 €/MWh), demand flexibility is used to solve the contingency. For a high load-shedding cost scenario, above the generator's marginal fuel cost, demand flexibility is not used, incurring higher costs.

It is important to define coherent cost/weights for the objective terms and limit configuration parameters to conduct the optimal solution in the desired direction. When hard limits are defined for inequality constraints, appropriate values for the objective terms costs and final barrier coefficients. When applying hard limits to the bus voltages, a losses cost coefficient greater than 1000 €/pu must be applied to minimize the power losses

Flexible resources optimal control allows a more efficient grid operation at the cost of operational expenditures (OPEX). Under this new potential flexibility scenario, during the planning and operation of the distribution grid capital expenditures (CAPEX) for new installations must be evaluated and compared with the operational costs of existent grid flexible resources to obtain the most cost-efficient alternatives.

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1 Introduction

By its nature, the distribution of electricity constitutes a regulated activity as it is not economically optimal to have competition and duplicate network assets. Distribution System Operators (DSOs) are responsible for the planning, construction, operation and maintenance of network assets and infrastructure.

Power networks can be classified according to their nominal voltage level; in Spain, they are: very high voltage networks (400, 220, 132kV), high voltage networks (66, 45, 30kV) medium voltage networks (20, 15, 13, 12, 6.6kV are some typical values) and low voltage networks (<1kV) feeding commercial and residential consumers [1].

In Spain, very high voltage networks are owned and operated by the Transport System Operator (TSO), Red Eléctrica de España (REE) [2]. DSOs typically own HV, MV and LV networks and some 132kV subtransmission networks as well as substations connecting to the transport network, HV/MV primary substations, and MV/LV secondary substations. Generators and consumers will be connected to different voltage levels depending on their size.

The distribution network operation is the activity of managing power flows and bus voltages, by controlling DSO owned equipment such as substation transformer's On-Load Tap Changers (OLTCs), shunt element connection or circuit breaker operation to ensure that certain security of supply and quality are provided at the consumer's connection point.

Traditionally, the distribution grid has been operated radially with a passive demand, where power flows go from the HV to the LV. In recent years, there has been an increase of Distributed Energy Resources (DER) such as distributed generators (DGs) powered by different technologies (cogeneration, renewable source…), electric vehicles (EVs) or demand response (DR) available in the distribution level.

These new flexible resources may become a challenge, increasing the complexity in grid operation, and causing issues in the equipment such as protections or OLTC transformers due to the appearance of reverse flows. But they offer plenty of opportunities as well, introducing new potential control variables that could lead to a more efficient operation, and cost-efficient alternatives to network investment.

Therefore, it is a crucial moment for innovating and preparing DSO electrical applications to face the operative challenges that pose this new environment while being able to take advantage of the opportunities.

This project analyzes possible applications and implementation requirements of an Optimal Power Flow (OPF) tool for grid operation under different potential flexibility scenarios that could appear in the near future.

As it was done in [3], different flexible resources and control variables will be studied and modelized using the Optimal Power Flow in software PSS®E [4], as well as the state estimation tool PSE developed by i-DE. Under different scenarios of interest, benefits observed in applying the OPF tool are discussed, as well as its effects on grid variables such as voltages and power flows.

1.1 DSO economic regulation

As distribution constitutes a regulated activity, not opened to a competitive environment, DSOs economic retribution must be established by a regulator. In the absence of a market, economic regulation must be defined with enough incentives for the DSO to be able to obtain a profit according to their performance while minimizing the total cost on the final consumer, so they do not pay an extra cost for the service.

In Spain, the regulator is CNMC (Comisión Nacional de los Mercados y Competencia) [5]. This agent oversees the distribution companies activity and investment plans to define their retribution. It also establishes an income limitation to fix a top limit in the customer tariffs during each regulatory period.

Economic retribution is defined to incentivize the DSO to invest in network assets, as long as they are cost-efficient, so it does not incur an extra cost to the final consumer. It balances the quality of service offered and reduction in power losses with investment in network assets, to avoid non-economically efficient investments.

Therefore, under every regulatory period, the DSO's income will depend on investment plans, quality of service and security of supply offered. The new potential control variables appearing in the distribution grid, open the possibility of a more efficient operation by using the flexibility of these resources. This new paradigm will enable cost-efficient alternatives to network investment, reducing consumer final tariff and increasing the importance of the DSO role in operating the distribution grid optimally.

At present, according to [5], there is an economic incentive for the DSO to minimize power losses during grid operation, as well as reducing customer interruptions (NIEPI and TIEPI). Therefore, the OPF applications studied in this project are focused on minimizing power losses and optimally solving an emergency state operation.

1.2 Current electrical applications

The deployment of smart meters and automation equipment throughout the distribution network has enabled new remote control and supervision capabilities that did not exist in the past. This transition towards a smart grid is a necessary step for integrating the new flexible resources and be prepared for the upcoming scenario.

A robust data infrastructure at the distribution level increases the visibility and is necessary for running power flow calculations at lower voltage levels. The power flow is a non-linear problem used during the operation of the grid for determining the state of every network variable at a certain moment. Knowing the load and generation power injections at every bus, voltages and angles are calculated so the electrical equations are met, and the state of the network is obtained.

The power flow tool can be used for contingency analysis, to evaluate the effect of using different control actions, voltages and power flows or some unserved customers when a sudden change in the topology of the grid occurs [1].

Currently, field data acquisition is performed by the SCADA system. This data includes measurements such as active power, reactive power, bus voltage and current. As seen before, the power flow only uses as inputs the power injections at every bus to determine the actual state of the network. The state estimator tool was developed to take advantage of every measurement available.

The state estimator uses every field measurement collected by the SCADA system to determine the most probable state of the network that fulfils the electrical equations. It detects wrong measurements and substitutes them with more probable estimations to minimize the absolute error between measurements and estimated values [6].

It requires more measurements that the conventional power flow, being perfect for scenarios with measurement's redundancy. It is able to work with uncertainty, providing an estimation for buses where measurements are not available. The more measurements it has, the more robust and reliable the estimation will be. The enhaced visibility in distribution grids, has made the state estimator an essential supervision tool for these networks.

The state estimator tool enables the DSO to have a reliable picture of the state of the network at every moment. It is the basis of every power flow analysis, as it obtains reliable power measurements at every system bus. The implementation of an Optimal Power Flow engine depends on the accuracy of the state estimator. Therefore, a robust state estimator is required.

Nowadays, optimization algorithms are not very commonly used during the operation of the grid. DSO current electrical applications are based on the data field acquisition by the SCADA system, which may also have remote control capability in case it is a SCADA-DMS system, and state estimation and power flow engines.

During grid operation, OLTCs can be managed using an automatic regulation (based on setpoints) as explained in Section 2.1, and capacitor banks operated in an open-loop according to a pre-defined schedule. Both controls may be operated manually at any moment by the grid operator. The implementation of an Optimal Power Flow tool facilitates the supervision of these variables while considering the whole state of the network, providing the optimal control action that minimizes the objective function, while keeping the system within limits [7]. The OPF may have different applications, as it is described in Section 3.1. With enough experience and confidence in the results, the OPF offers the possibility of introducing close loop solutions for grid operation.

Reliable power flow cases from a real 20kV distribution network, have been obtained using the state estimator tool developed by i-DE (PSE) and executed in the Optimal Power Flow tool in PSS®E software [4].

1.3 Project objectives

The objectives that this project will cover are the following:

- Identification and modelling of potential flexible sources in the distribution grid. OLTC, shunt element, distributed generation and flexible demand will be studied and modelized, analyzing their potential flexibility and how they could be used for grid operation.

- Identification of the information required to parametrize each control variable from flexible sources. Every control variable under study will be parametrized using

PSS®E software to identify the data requirements for the future industrialization of the OPF tool.

- Analysis of potential applications of the Optimal Power Flow tool for grid planning and operation and their interest of a DSO

- Evaluation of the techno-economic benefits observed in terms of technical losses reductions, voltages and power flows of using the OPF algorithm by performing simulations of different scenarios in a real distribution network.

1.4 Distribution grid under study

The distribution grid under study is shown in Figure 1.1, a more detailed Single Line Diagram is shown in Annex B (Page 74). It is a MV 20kV network owned and operated by i-DE, with a total of 247 buses and a high penetration of industrial loads and distributed generators (G1 to G10), most of them cogeneration from the industry.

The grid is a radially operated network where the terminal nodes represent MV/LV secondary substations showing the aggregated load downstream. The secondary substations, also known as distribution transformers can be owned by the client or by the DSO (i-DE), every big industrial consumer has its own distribution transformer. These two types of owners have been defined for every bus within PSS®E.

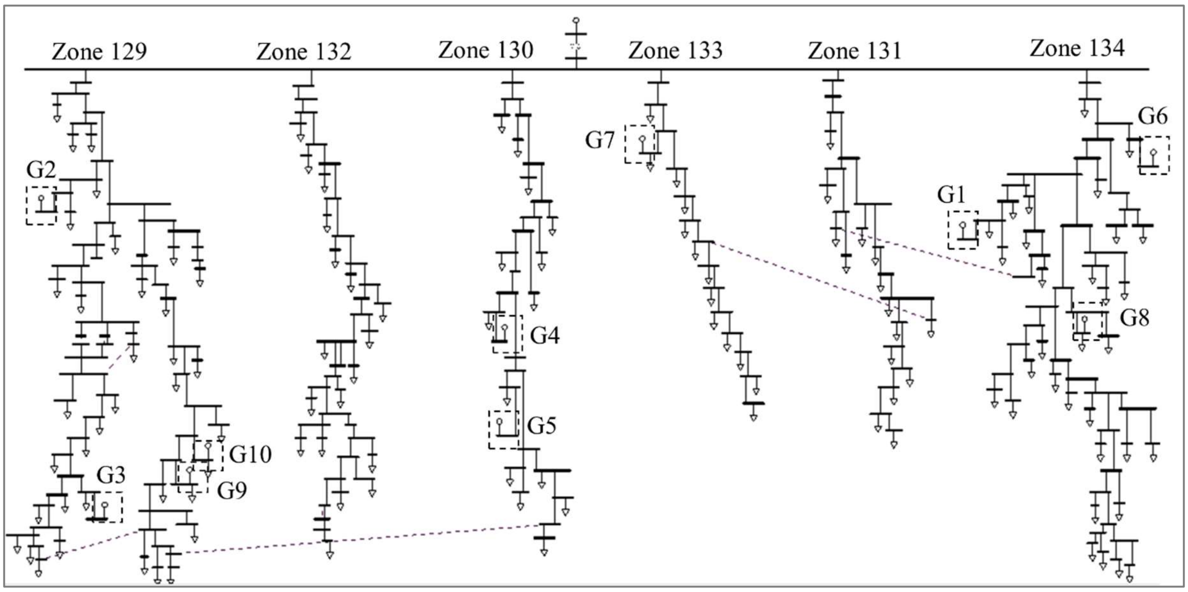


Figure 1.1: Network diagram

The network is connected to the 66kV grid through a 66kV/20kV primary substation. The substation transformer has an OLTC at the primary winding, which regulates the voltage at the secondary side as explained in 2.1. The primary side of the transformer (66kV) has been considered as the slack bus, with a fixed voltage and reference angle.

The 10 distributed generators characteristics are shown in Table 1.1. Five of them are heat & power cogeneration (CHP) governed by a Gas Turbine (G.T.). The synchronous machine model from PSS®E has been used to model and parametrize the reactive capability limits for these generators as shown in Sections 2.3.1 and 3.4.3.

Generator G2 is a wind generation plant, modelled as an inverter-connected plant (Section 2.3.2). The rest of the generators are small-scale PV plants located downstream of the MV/LV secondary substations. Only the big generators (> 1 MW) are used as flexible resources in this study. The rest of the small generators are modelled as fixed power factor PQ nodes. Generators considered as flexible resources in the following simulations are green colored in Table 1.1.

Every switchbay in the substation busbar has been assigned to a zone number within PSS®E. This facilitates posterior studies and data interpretation. As shown in Figure 1.1, Zones 132 and 131 have no distributed generation. It is discussed in section 5.2 how the absence of distributed generation causes a higher power flow in these lines, lower voltages, and therefore higher losses.

Generators	$P_{Nom.}$	Generation Tech.	Zone
G1	1.14 MW	CHP (G.T.)	134
G2	17.91 MW	Wind	129
G3	17.91 MW	CHP (G.T.)	129
G4	3.8 MW	CHP (G.T.)	130
G5	4.28 MW	CHP (G.T.)	130
G6	17.76 MW	CHP (G.T.)	134
G7	0.02 MW	PV	133
G8	0.01 MW	PV	134
G9	0.096 MW	PV	129
G10	0.032 MW	PV	129

Table 1.1: Distributed Generators in the MV grid

One of the main motivations for applying an OPF to support grid operation is to take decisions over the available controls in response to the actual state of the network variables. Its main advantage over the classical approach is that decisions made over the control variables such as the connection of a shunt element or the tap position movement of the OLTC are taken according to the actual state of the network.

As demand load varies depending on the substation, month, day and hour studied, 24 hours of a representative day at the substation is studied. Evaluating the benefits of applying the OPF considering the initial results obtained for the real operation during that day.

To find this representative day, the demand curve was studied through the whole year, selecting first a representative sample week and then a representative day within it. The year 2020 was discarded due to the Covid-19 pandemic. Therefore, measurements of active and reactive power through the primary substation transformer were analyzed during 2019.

October 2019 was selected as it is a time of the year that is not too cold nor too warm and may enable to obtain representative results. Active power flowing through the substation from HV to MV is represented in Figure 1.2, for the first week of October 2019.

Tuesday, October 1st was selected as the day under study, as it represents a general load pattern on the substation demand curve, with not the highest nor the lowest load. This day load pattern measured at the substation is represented in Figure 1.3.

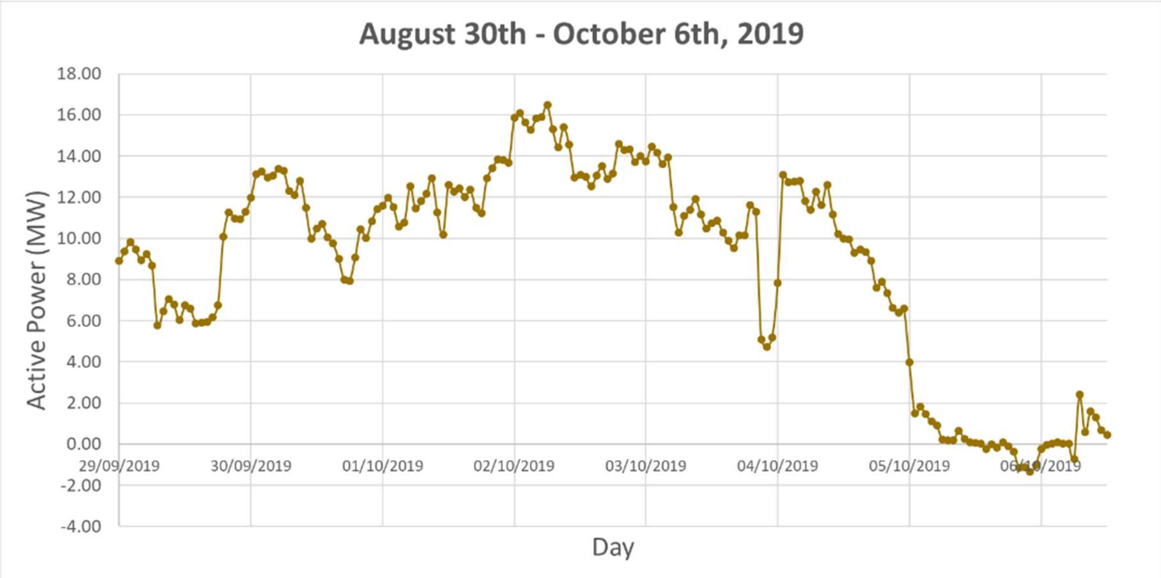


Figure 1.2: August 30th - October 1st week, demand load curve at the substation

As shown in Figure 1.2, the high penetration of industrial loads and generation creates a huge difference between the power demanded from the grid on weekdays and weekends, when the industry reduces its demand, causing negative reverse power flows on weekends from the 20kV level to the 66kV level.

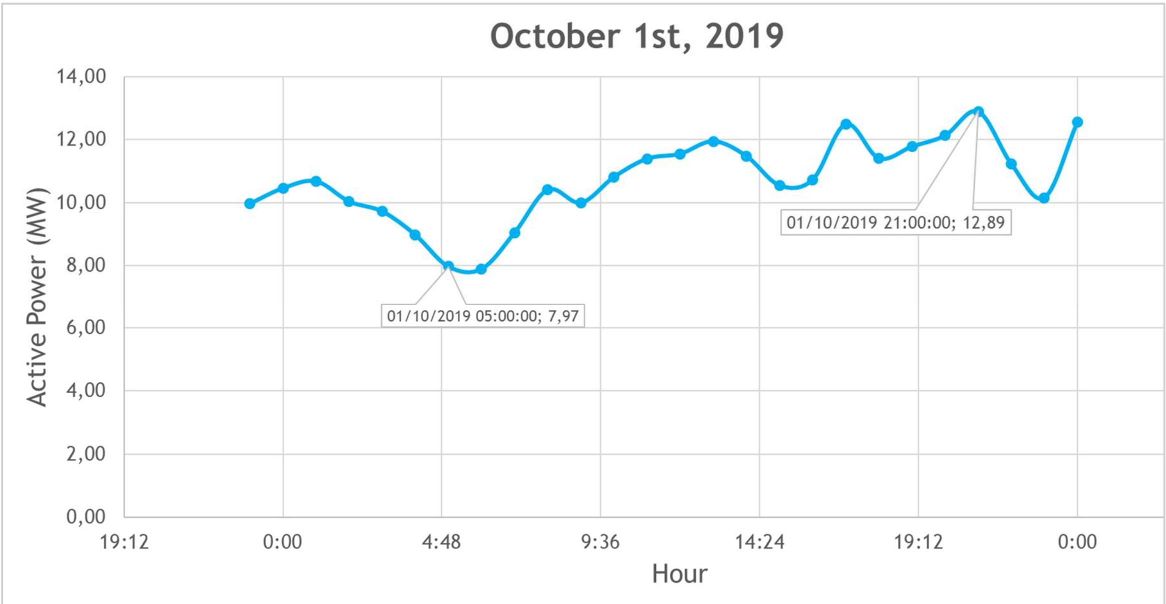


Figure 1.3: October 1st, demand load curve at the substation

From Figure 1.3, it can be stated that the valley hour for active power demand in the substation is between 5:00 and 6:00 in the morning and the peak hour is between 20:00 and 21:00.

There are unexpected peaks of demand during the night hours, (Tuesday, October 1st at 1:00, Figure 1.3) caused by the industrial consumers. These kinds of unexpected events are the main reason for applying an OPF which considers the actual state of the network rather than using a generalized pattern that could not suit perfectly for every location.

2 Flexible resources modelling

Every flexible resource in the grid has control variables that could potentially be used in the OPF. Resources have been divided into 2 main groups: DSO owned equipment (On Load Tap Changers and shunt devices) and ancillary services provided by external agents (Distributed Generators and Demand Response).

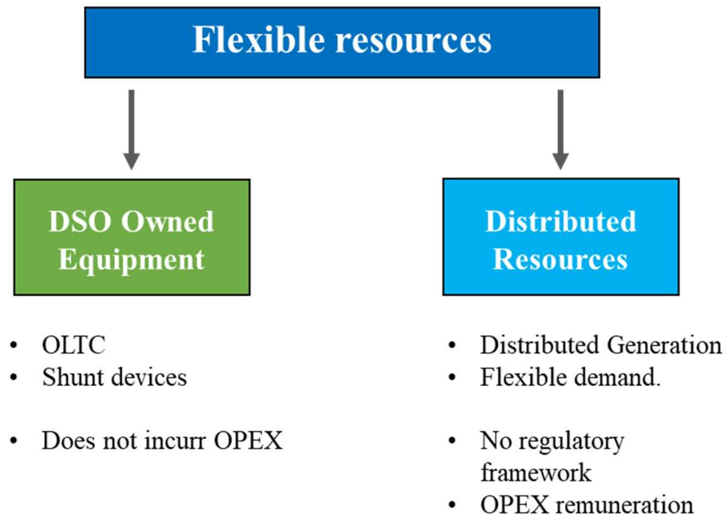


Figure 2.1: Flexible resources classification

In a future context where a periodical OPF background execution is implemented during grid operation, DSOs owned equipment already installed will probably be the preferred flexible resource to minimize losses, since it would have almost none Operational Expenditures (OPEX), these devices will be used to optimize losses. However, new installations will have capital expenditures that need to be considered and compared with alternatives such as distributed resources.

Active power dispatch from generators and demand load flexibility could be used for contingency management. An overload can trip a line, leaving all the customers connected to it unenergized. Managing overloads in lines could also help in reducing minutes of non-served energy, which is another incentive in the DSO remuneration.

These flexibilities offer the opportunity of deferral in network assets investments, such as building new transformers and lines. Reducing the power flows through the lines by managing the active power of demand and generation, substitutes the traditional investment in CAPEX (Capital Expenditures) with OPEX (Operational Expenditures) to remunerate the flexible agents. Enabling the DSO to find the most cost-efficient solutions.

The first demand flexibility auctions have been performed in Spain in 2020 under the procedure specified in IET/2013/2013 [8]. Within this mechanism, the Transmission System Operator (Red Eléctrica de España) can reduce the active power of demand participating in the auction a maximum number of hours per month and year, in exchange of remuneration.

On the other hand, distributed generators could provide reactive power and voltage regulation (Volt/VAr control) in exchange for remuneration as studied in [9].

However, there is not a current regulatory framework to define the cooperation and remuneration mechanisms between the DSO and the flexibility of these distributed resources.

Control variables can be classified depending on their dynamic response [9], [10]. It has been assumed for this project that every control can respond fast enough to change its value between the hours studied. For studies where the time scale considered is below the hour, the dynamic time response of the control should be considered.

2.1 On-Load Tap changer (OLTC)

Typically, primary substation transformers are equipped with on-load tap changers being able to modify their transformation ratio without de-energizing the transformer. Providing a control variable during operation to regulate voltages downstream.

Currently, tap-changers are managed in two ways, from the control centre: the operator changes the tap position through a command, or using a setpoint (voltage or tap position) which is managed by the traaunsformer regulator unit at field to maintain the controlled voltage as close as possible to a reference value [11].

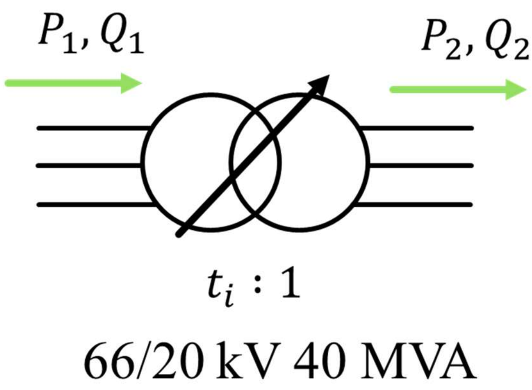


Figure 2.2: Primary substation transformer with OLTC

Figure 2.2 represents the 40 MVA, 66/20 kV substation transformer studied. The OLTC is placed on the primary winding (66kV) with 19 tap positions, regulating the secondary voltage (20kV). The tap position is represented as t_i, where $i = 0$ at the central position and has 9 positions on top and 9 positions below.

	Tap position	Ratio (pu)
t_9	Tap +9	1.008
t_0	Tap 0	0.916
t_{-9}	Tap -9	0.825

Table 2.1: Tap positions OLTC

Table 2.1 shows the tap position configuration for the OLTC. Tap ratios are presented in pu, taking as bases 66kV and 20kV for the primary and secondary winding respectively.

The transformer nominal voltage values are 65kV/21.5kV. As the transformer's nominal voltage ratio is different from the grid nominal ratio 66kV/20kV, at the nominal tap position $i = 0$, the tap ratio is different to 1 pu. Equation (2.1) shows how the central tap position is calculated using the grid voltage bases and the nominal voltage values of the transformer.

$$t_0 = \frac{65kV}{66kV} \cdot \frac{20kV}{21.5kV} = 0.916 \tag{2.1}$$

The OPF will be used to control the tap position such that the voltage limit constraints in all buses are met and active power losses minimized. The primary winding voltage has been selected as the slack bus, and during the OPF solution, it has been fixed to its initial value, assuming an infinite bus to represent the 66kV network.

2.2 Shunt devices

Shunt reactances and capacitor banks show a dynamic constraint which makes them unable to react close to the real-time voltage control [9], [10]. However, as the time scale for the control variables in this project is hours, it has been assumed that the connection and disconnection of the shunt is possible at every hour without any dynamic constraint.

There are two types of bus shunt devices:

- *Fixed value shunt devices* consisting of a single block shunt reactance or capacitor which can be fully connected to inject all its nominal power $Q_{sh.}$ or fully disconnected.

- *Switched shunt devices* with several reactance or capacitor blocks in parallel, which can be connected or disconnected in steps to modify the reactive power injection $Q_{sh.}$ offering more flexibility on their control.

Figure 2.3 represents a shunt device model and sign criterion, connected to a determined bus i.

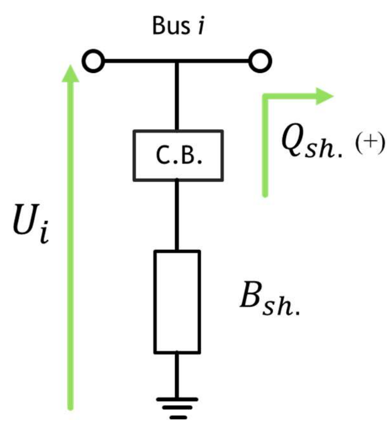


Figure 2.3: Shunt device model

The capacitor bank has a positive nominal reactive power $Q_{sh.} > 0$ (injection) and a positive susceptance $B_{sh.} > 0$. The reactance has a negative nominal reactive power $Q_{sh.} < 0$ (absorption) and a negative susceptance $B_{sh.} < 0$.

	Capacitor Bank	Reactance
Reactive power ($Q_{sh.}$)	> 0	< 0
Susceptance ($B_{sh.}$)	> 0	< 0

Table 2.2: Shunt device sign criterion

The real reactive power injection of the shunt device is slightly different from their rated power, as the real bus voltage differs from the nominal voltage of 1pu.:

$$Q_{real}(MVAr) = \frac{Q_{sh.}(MVAr)}{V_{nom}(pu)^2} \cdot V_{real}(pu)^2 = Q_{sh.}(MVAr) \cdot V_{real}(pu)^2 \tag{2.2}$$

At present, most of the shunt devices owned by i-DE are fixed value capacitor banks placed at the substation busbars, following a pre-determined schedule for their connection and disconnection. The installation of switched step devices is being considered, offering more flexibility in their control for reducing power losses.

Currently, the connection of capacitor banks is made during demand peak hours where grid voltages are lower. This fixed schedule is independent of the status of the network.

As stated before, the demand profile depends a lot on the location and topology of the grid, peak hours are different depending on the substation studied. Making this fixed schedule approach, not the optimal one for every substation.

The OPF will find which is the optimal connection and disconnection schedule for the shunt device that minimizes power losses. This study aims to provide a sense of how the OPF could decide in during the operation of the grid, considering the actual load and status of the network variables, which is the optimal connection period of the capacitor bank.

As there is not a capacitor bank in the actual network studied (Figure 1.1), a modified base case including a shunt device has been created in section 5.3. For this initial case, the fixed shunt scheduling has been considered from 7:00h to 13:00h and 18:00h to 21:00h.

Capacitor banks are able to regulate voltage by injecting reactive power directly on their bus. The OLTC however, is not a local control as it affects the reactive power flow from the 66kV level to 20kV level. For this reason, in general, shunt control may be preferred over the OLTC control when both are available.

2.3 Distributed Generation (DG)

Due to the development of renewable technologies such as wind and solar energy and non-renewable sources such as cogeneration in the industry, the connection of distributed generation (DG) has grown very fast in the distribution networks for the last decade.

DGs offer an opportunity for Active Network Management (ANM), but they also pose a challenge for system operation creating voltage deviations, reverse power flows or increasing power losses if not managed rationally. Several articles have studied the impact on the power losses and voltage profile of the distributed generation and how the rational control of these resources in coordination with the actual status of the grid can enhance efficiency [3], [12].

Currently, generators are modelled by some of the i-DE electrical applications as negative fixed PQ loads generating active power at a fixed power factor with no control over the active or reactive power outputs. This project studies different uses of flexibility from the DGs during the operation of the grid, evaluating their effect on bus voltages, line flows and power losses.

According to the T.E.D./749/2020 [13], the six generators used for this study (G1-G6), whose connection point is below 110kV and maximum capacity between 5 MW and 50 MW, are classified as Type C modules, establishing for this class a certain mandatory reactive power capability.

Currently, the voltage/reactive power service regulatory framework and remuneration mechanisms are under discussion [9]. It has been assumed a regulatory framework where flexibility services from these generators can be used by the DSO in exchange of remuneration.

Reactive power control of DG can be used for voltage regulation, congestion management and as has been done in Section 5.4 for minimizing technical losses. Article [14] shows the active and reactive capability limits for the most common DG technologies: PV plants, Wind plants, Small Hydro Plants and CHP. DG units are divided into synchronous generators, induction generators (directly connected or through a converter) and power electronic inverters.

The two technologies present at the grid under study are CHP and wind. The generator models defined below can be utilized for every synchronous machine and inverter-connected plant.

2.3.1 Synchronous machine model (CHP)

The model presented in this section will be valid for every generation technology using a synchronous generator connected to the power network.

Big CHP generators are typically governed by gas turbines. The steam cycle uses the residual heat from the industrial process to generate electricity in a turbine. These turbines are synchronous generators connected directly to the grid. The control of reactive power is done by the excitation system.

Figure 2.4 represents the permanent regime model for the synchronous machine used by PSS®E for the OPF problem, showing the sign criterion (positive P and Q for generation). The impedance x_d is the synchronous reactance and the generation losses have not been considered.

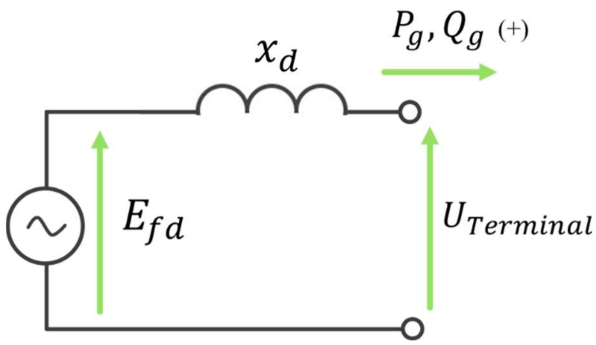


Figure 2.4: Permanent regime model synchronous machine

The working modes, absorbing and injecting reactive power, for a synchronous generator ($P_g \geq 0$) are represented in Figure 2.5. The positive sign criterion for the angles is shown in the figure.

The angle δ, represents the phase displacement measured from the terminal voltage $U_{Terminal}$ to the excitation voltage E_{fd}. It determines the sign of the active power of the machine. For the case of a synchronous generator $\delta \geq 0$ always because $P_g \geq 0$.

The angle ρ is defined as the current phase delay with respect to the voltage. Therefore, the positive sign criterion is the opposite as before, measuring ρ from the voltage phasor to the current phasor.

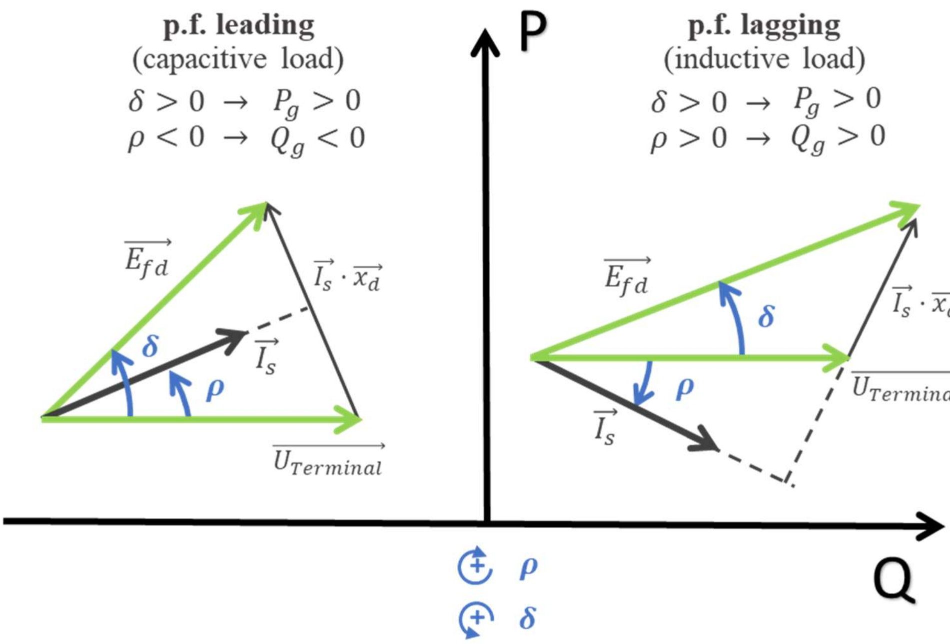


Figure 2.5: Working modes of a synchronous machine

The reactive power absorption or generation is determined by ρ. When $\delta < 0$, the current is ahead of the voltage in phase, and it is equivalent to supplying a capacitive load, therefore the generator is absorbing reactive power and $Q_g < 0$. Similarly, when $\delta > 0$, the generator is injecting reactive power and $Q_g > 0$.

The active and reactive power limits for synchronous generators are shown in Figure 2.6. As exposed in [1], the most important restrictions are:

- *The maximum stator current:* I_{S_max} is the stator thermal limit of 1pu. It determines the maximum apparent power output at the machine terminals S_{max}.

$$S_{max} = I_{S\_max} \cdot U_{Terminal} \tag{2.3}$$

  - Limiting the power output at any operational point:

$$S_g(t) = \sqrt{P_g(t)^2 + Q_g(t)^2} \leq S_{max} \tag{2.4}$$

  - Where $P_g(t)$ and $Q_g(t)$ are the active and reactive power generated at the terminal connection point (Figure 2.4) at any time.

  - Using pu units and the nominal terminal voltage (1 pu), it represents is a radius 1 circumference centered at zero.

$$s_g(t) = \sqrt{p_g(t)^2 + q_g(t)^2} \leq 1\, pu \tag{2.5}$$

- *The active power limits:* P_{max} the maximum power that can be generated and P_{min} the minimum viable power which is settled to 0. Both restrictions represent horizontal lines in the PQ diagram.

$$\begin{gathered} P_g(t) \leq P_{max} \\ P_g(t) \geq P_{min} \end{gathered} \tag{2.6}$$

- *The maximum excitation voltage:* E_{fd_max} limited by the rotor thermal limit and the maximum insulation voltage. It is determined in the nominal point of operation (P1 in Figure 2.6).

  - Power balance at the excitation system is:

$$P_g(t)^2 + \left(Q_g(t) + \frac{U(t)^2}{X_d}\right)^2 = \frac{E_{fd}(t)^2 \cdot U(t)^2}{{X_d}^2} \tag{2.7}$$

  - Using pu units, at the nominal point the active power is p_{max}, the voltage and stator current are 1 pu and the maximum excitation voltage e_{fd_max} can be calculated as:

$$\begin{gathered} {p_{max}}^2 + \left(q_{nom} + \frac{1^2}{x_d}\right)^2 = \frac{{e_{fd\_max}}^2 \cdot 1^2}{{x_d}^2} \\ e_{fd\_max} = \sqrt{{x_d}^2 \cdot \left({p_{max}}^2 + \left(q_{nom} + \frac{1}{x_d}\right)^2\right)} \end{gathered} \tag{2.8}$$

- At any operational point, the maximum excitation voltage restriction is:

$$p_g(t)^2 + \left(q_g(t) + \frac{u(t)^2}{x_d}\right)^2 \leq \frac{{e_{fd\_max}}^2 \cdot u(t)^2}{{x_d}^2} \tag{2.9}$$

- Representing a circumference in the PQ diagram of radius $\frac{e_{fd\_max} \cdot u(t)}{x_d}$ centered at $-\frac{u(t)^2}{x_d}$.

- *The minimum excitation voltage:* E_{fd_min} is determined by the maximum reactive power absorption Q_{min} at a power factor of 1 ($P_g = 0$).

  - From the power balance equation at the excitation system (2.7). Using pu units, e_{fd_min} can be calculated as:

$$\left(q_{min} + \frac{1^2}{x_d}\right)^2 = \frac{{e_{fd\_min}}^2 \cdot 1^2}{{x_d}^2}$$

$$e_{fd\_min} = x_d \cdot \left(q_{min} + \frac{1}{x_d}\right) \tag{2.10}$$

$$e_{fd\_min} = x_d \cdot q_{min} + 1$$

$$\boldsymbol{e_{fd\_min} = 1 - x_d \cdot |q_{min}|}$$

  - At any operational point, the minimum excitation voltage restriction is:

$$p_g(t)^2 + \left(q_g(t) + \frac{u(t)^2}{x_d}\right)^2 \geq \frac{{e_{fd\_min}}^2 \cdot u(t)^2}{{x_d}^2} \tag{2.11}$$

  - This limit has not been represented in Figure 2.6, considering a Q_{min} of 0. When Q_{min} is different from 0 it represents a circumference of radius $\frac{e_{fd\_min} \cdot u(t)}{x_d}$ centered at $-\frac{u(t)^2}{x_d}$.

- *The maximum stability limit:* δ_{max} can be fixed depending on the stability of the specific machine considered; The angle δ has a maximum stability limit of 90º [1].

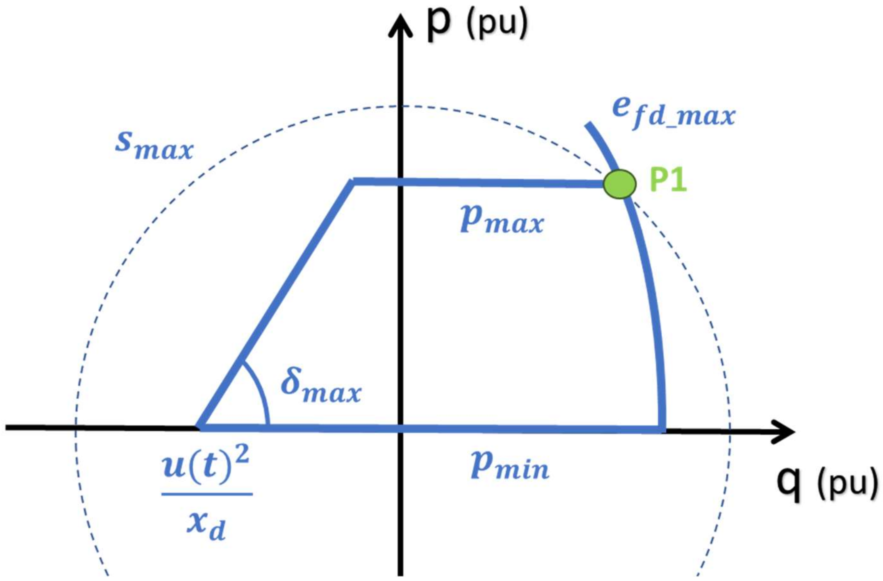


Figure 2.6: Synchronous Generator (CHP) PQ Diagram in pu

2.3.2 Inverter connected model (wind farm)

It is assumed that the wind farm under study is a full-converter synchronous generator as shown in Figure 2.7, where the converter is connected directly to the machine stator. The model presented in this section will be valid for every renewable source such as PV plants connected to the grid through a power inverter.

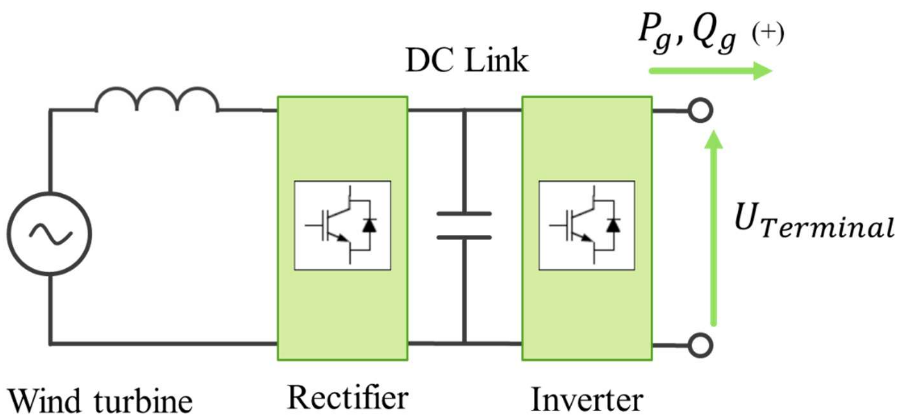


Figure 2.7: Full-converter synchronous machine

For the modelling of the PQ capability limits of other wind farm technologies, such as Doubly-Fed Induction Generators (DFIG) see [14].

As demonstrated in [12], any plant connected to the grid through an inverter can manage independently the active and reactive power as long as it operates under the power converter operational limits. For any renewable plant where the active power is fixed, the reactive power capability of the unit is determined by the following inverter limits:

- *The maximum inverter current:* I_{max} the inverter's maximum current transfer constrains the power output of the unit. The maximum apparent power at the unit terminals S_{max}, is determined by I_{max} and the terminal voltage.

$$S_{max} = I_{max} \cdot U_{Terminal} \tag{2.12}$$

- *The active power limits:* P_{max} the maximum power that can be generated and P_{min} the minimum viable power (which has been settled to 0).

$$\begin{gathered} P_g(t) \leq P_{max} \\ P_g(t) \geq P_{min} \end{gathered} \tag{2.13}$$

- *The reactive power limits:* Q_{max} and Q_{min} are determined at any operational point by the active power output P_g, the terminal voltage $U_{Terminal}$ and the maximum current of the inverter I_{max}.
  - Considering any operational point in time where the active power is $P_g(t)$ (between P_{max} and P_{min}). The reactive power limit curves $Q_{min}(t)$, $Q_{max}(t)$ can be defined as:

$$\begin{gathered} |Q_{limit}|(t) = \sqrt{{S_{max}}^2 - P_g(t)^2} \\ Q_{min}(t) = -Q_{limit}(t) \\ Q_{max}(t) = Q_{limit}(t) \\ Q_{min}(t) \leq Q_g(t) \leq Q_{max}(t) \end{gathered} \tag{2.14}$$

Figure 2.8 represents the above limits in pu units. As demonstrated in (2.14), these limits are dependent on $p_g(t)$ and therefore they are defined between 0 and p_{max}. The reactive power limit curves are shown in a solid green line.

Even though the power converter control can regulate its reactive power output within these limits in a time scale of milliseconds. It is common to define the reactive capability limits as shown in the dashed blue line [14], [12]. For the simulations in this study, the full reactive power limits have been employed, assuming the power inverter control can work under those limits.

Usually the apparent power of the power inverter (equivalent to the stator current I_{max}) is dimensioned with some oversizing concerning the maximum active power limit P_{max}, to have some reactive capability when $P_g(t) = P_{max}$. It is common to have an oversizing of 20%. Which implies a $p_{max} = 0.8\,pu$ in machine pu base. This value has been considered for the parametrization of the wind farm. An operational point is represented in orange. Showing a $P_g(t)$ within P_{max} and P_{min} limits and the reactive power limits for that point.

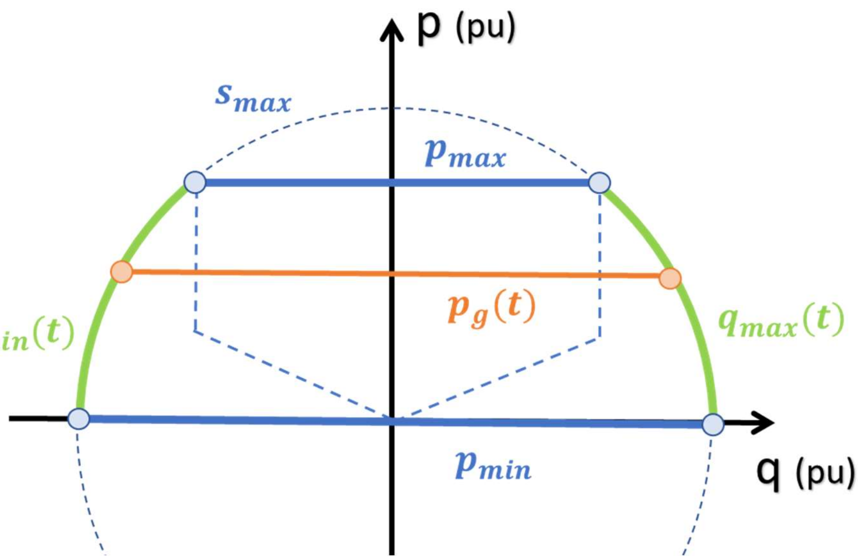


Figure 2.8: Inverter PQ limits in pu. Total reactive capability (green). Typically used PQ capability (dashed blue line). Operational point (orange).

2.4 Flexible demand

Figure 2.9 represents the equivalent model for the secondary substation downstream aggregated load at certain bus *i*, showing the sign criterion used (positive P and Q for consumption).

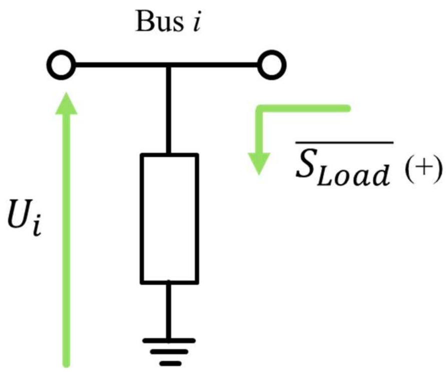


Figure 2.9: Equivalent aggregated load model

IET/2013/2013 [8] defines the demand interruptibility service for the Spanish power sector. Two demand flexibility products as well as their remuneration mechanism are defined within it. This service is defined for reducing demand load and it is managed by the System Operator.

The demand flexibility service described is defined for reducing discrete power steps for big consumers connected to the HV network. It defines 5 MW blocks for 240 hours/year with a maximum of 40 hours per month, and 40 MW blocks for 360 hours/year with a maximum of 60 hours per month. The flexibility provider will reduce its power when the System Operator requires it, according to the products defined.

The assignation mechanism is done through an auction process, where the System Operator defines the total amount of power flexibility to be awarded according to the grid requirements.

The System Operator may use demand active power reduction according to a security criterion, as a tool to solve emergencies and a cost-efficiency criterion, when it represents a cheaper control variable than the rest of the controls available.

Although this service is not yet available at the distribution level, this project studies the potential application of demand flexibility for optimal contingency management, also known as emergency state operation (3.1.3).

Two types of flexible loads with different costs and participation share have been considered in this project, industrial and residential loads, depending on the ownership of the secondary substations.

Load Type	Sec. Sbs. Owner
Residential load	DSO (i-DE)
Industrial load	Client

Table 2.3: Types of flexible loads considered

Different prices, as well as quantities, have been assigned to industrial and residential loads depending on their flexibility as it is discussed in section 3.4.4. The flexibility cost assigned to each load will determine whether it is a cost-efficient solution and the amount of demand flexibility used.

3 The Optimal Power Flow

The optimality problem appears in power systems when two or more generators must satisfy a given demand. The Optimal Power Flow determines the optimal power dispatch for each generation unit that minimizes total generation costs, keeping power flows within limits [1].

A formal formulation is presented in (3.1), the OPF determines the value of the control variables, which optimizes the objective function while satisfying the equality and inequality constraints

$$\begin{array}{ll} Min./Max. & f(x,u) \\ Subject\ to & h(x,u)=0 \\ & g(x,u)\geq 0 \end{array} \tag{3.1}$$

Where:

- $f(x,u)$ *is the objective function:* composed of one or more objective terms whose values are optimized in the problem. Section 3.1 classifies the different objective functions available and their interest for a DSO.

- u *is the set of control variables* whose value is modified by the OPF to obtain an optimal and feasible solution. This set of variables may include:

    - OLTC Tap position t_i
    - Shunt device reactive power output $Q_{sh.}$
    - V_i bus voltages of PV modelled Distributed Generators (regulating voltage)
    - P_g active power generation of DGs participating in a power dispatch
    - P_L flexible load from demand (load adjustment)

- *x is the set of dependent variables* whose value is determined by the OPF solution. This set includes:

    - Q_g reactive power of DGs participating in voltage regulation (PV node)
    - V_i bus voltages at every PQ bus in the system
    - P_{slack} slack bus active power (exchange with the 66kV grid)
    - S_{ij} Branch flows between buses

- $h(x,u)$ *are the equality constraints of the problem*, they include the conventional non-linear power flow equations. There are $2 \cdot N_{Buses}$ nodal equations of active and reactive power at every bus i.

$$S_{Gi}-S_{Li}=\sum_{j=1}^{N_{Buses}} S_{ij} \qquad \forall i \in N_{Buses} \tag{3.2}$$

Being:

- N_{Buses} is the total number of buses
- S_{Gi} is the net complex power from the generators connected to bus i
- S_{Li} is the net complex power from the loads connected to bus i
- S_{ij} is the complex power flow through each branch between bus i and bus j.

The slack bus angle is settled to 0 as it is the reference bus. The slack bus voltage has been fixed to its initial value in the base case representing the 66 kV grid as an infinite power bus (Section 2.1).

$$|V_{Slack}| = V_{initial}$$
$$\theta_{Slack} = 0 \tag{3.3}$$

- $g(x,u)$ *are the inequality constraints* consisting of all the limits imposed to the dependent and control variables, which will be allowed to vary within an admissible range. Different limit treatment is given to the different variables depending on their flexibility (Section 3.2.1).

In the conventional power flow, the mismatch for the set of non-linear power flow equations at every bus (3.2) is calculated at every iteration until a solution is below the maximum tolerance. When a variable limit is violated, a new convergent solution must be found to saturate that variable. This may be a slow process.

In contrast to the previous approach, the Optimal Power Flow considers the full power flow equations and automatically changes the value of the control variables to find a feasible and optimal solution with all the system variables within limits. The objective function is defined as a combination of weighted functions and variable constraints to be met. The Optimal Power Flow requires much less user intervention than the conventional power flow [15].

Variables, constraints and objective functions which have been considered of interest for a DSO, their parametrization and modelling in the PSS®E software are analyzed in the following sections.

3.1 Applications of the OPF

There are several objective functions $f(x,u)$ exposed in literature and within PSS®E software [15]. As shown in Figure 3.1, OPF objectives for grid operation have been divided into three categories: Preventive Security Constrained OPF (PSCOPF), secure state operation and emergency state operation [1]. Each of these objectives is described within this section.

Different objective terms can be combined within the problem's objective function, including several objectives together. The weights assigned to each term determine the final solution obtained and the control actions taken to reach it.

The OPF in PSS®E introduces penalty barrier terms in the objective function coming from constraints with hard limits imposed (see Section 3.2.1). Hard limit barrier terms penalize the excursions of the variable from the central value of its range.

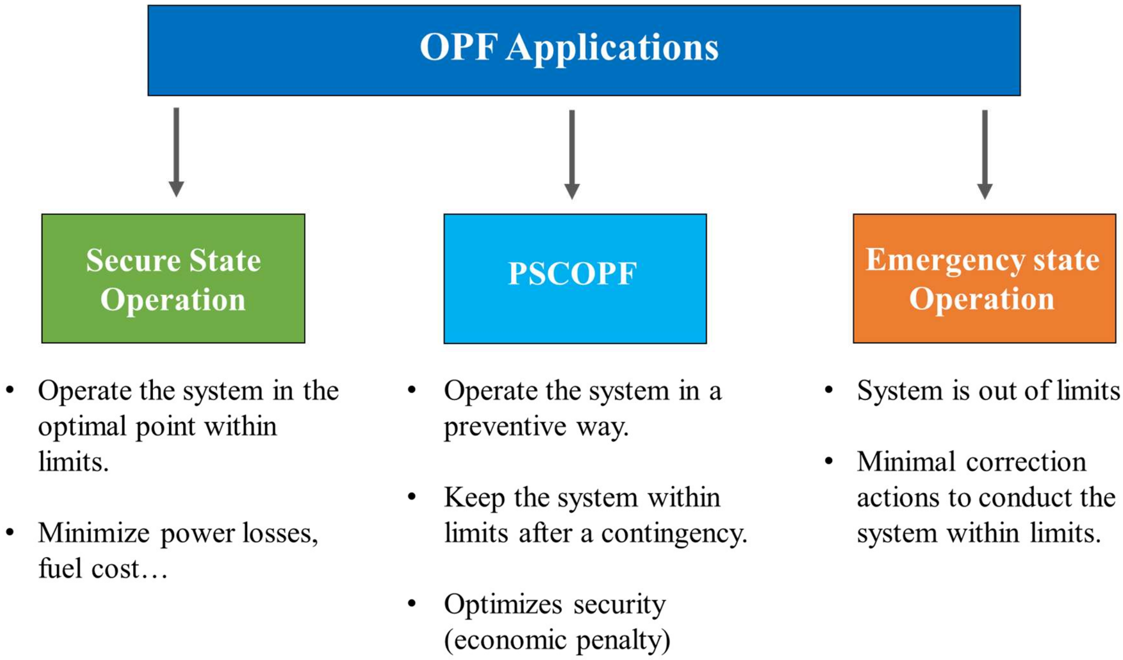


Figure 3.1: OPF Typical applications

3.1.1 Preventive Security Constrained OPF (PSCOPF)

The first application of the OPF is to operate the system in a preventive method, introducing security constraints to keep the system variables within limits even after a contingency has occurred. Operating the system in a preventive way incurs an economic cost.

From a base case and a set of contingency cases defined, all the control variables are optimized such that no post-contingency adjustments are needed and therefore no operator intervention is required.

It is important to notice, that the PSCOPF moves the system away from the optimal point of operation, causing an economic cost. Therefore, this approach should only be taken for applications where security is prioritized over economic costs [1].

3.1.2 Secure state operation

This application seeks to operate the system at the optimal point and with all the variables within limits. The OPF in PSS®E includes several objective functions, being the most used in literature:

- *Optimal Power Dispatch (Minimize Fuel Cost):* assigns the optimal generation that minimizes the total fuel costs and power losses. This application is very common in the transmission system, but not so common for distribution systems. An example of this OPF application for a distribution system is shown in [3].

- *Minimize Power Losses:* assuming the active power from generators has already been dispatched, this application finds the optimal voltage profile within limits that minimizes the active power losses. This is a very interesting application for the DSOs, as it automatically manages the utility assets (OLTCs and shunt devices) and other voltage control resources such as Volt/VAr regulation from DG [12], to minimize power losses, which is an incentive in the DSO remuneration (Section 1.1).

$$f_{PLoss}(x,u) = C_{PLoss} \cdot \sum_{i=1}^{N_{branch}} P_{Loss\_i} \tag{3.4}$$

The active power loss term added to the objective function is shown in (3.4). Where C_{PLoss} is the weighted cost in €/pu (MWh) applied to the power losses in the objective function. The losses at every branch are added together and weighted using the cost coefficient.

3.1.3 Emergency state operation

The last application is for determining the minimum number of corrective actions that conducts the system from an emergency state, out of limits, to a secure state, within limits.

A typical application of interest for the DSO is to use the optimal combination of available controls in the grid to eliminate an overload in a line. If different costs are associated to different control variables, the final solution finds the corrective actions required, minimizing the economic cost associated with them.

If an overloaded line trips, it will leave all the costumers downstream unserved, incurring economic penalizations to the DSO. This overload can be eliminated by using the OPF most cost-efficient control variables, bringing the system to a secure state.

Penalties and costs can be a useful tool for minimizing the number of control actions taken to solve an emergency state operation and to establish control priorities.

3.2 OPF Solution

Several techniques have been applied in the literature for solving this non-linear constrained optimization problem. As shown in [1], linear programming, quadratic programming, newton's method, and interior point method are the most common approaches.

PSS®E solves the non-linear programming problem by using the Kuhn-Tucker formulation [15]. Building the Lagrange function and solving the KT optimality condition from the Hessian and Jacobian matrices.

$$L(x,u,\lambda) = f(x,u) + \sum_{i=1}^{N} \lambda_i \cdot h_i(x,u) \tag{3.5}$$

Where:

- x is the set of control variables
- u is the set of dependent variables
- λ is the set of linear Lagrange multiplier variables
- $f(x,u)$ is the objective function
- $h(x,u)$ are the equality constraints including the $2 \cdot N_{Buses}$ nodal power flow equations for the active and reactive power injections at every bus i

The results obtained are the value of x and u at the optimal point and the set of Lagrange multiplier variables λ. As the λ coefficients are added in the Lagrange function multiplying each equality constraint $h(x,u)$, there is one Lagrange multiplier for every row element in the Jacobian matrix.

At the optimal point, λ_i determines the sensitivity of the objective function to a change in any of the constraints $h_i(x,u)$. For the power flow equations, it gives a sense of how much the objective function would vary if one more unit of active or reactive power is injected at bus i.

3.2.1 Limit treatment for inequality constraints $g(x,u)$

Inequality constraints limit treatment is one of the most complex aspects of the OPF. As described in [15], PSS®E software has different ways to treat inequality limits and penalize variable's excursions.

- *Soft limits* introduce penalization terms in the objective function. These limits are defined for the infeasible region and their penalization is determined by the cost assigned. Two types of limits may be defined:
  - *Soft quadratic limits* introduce a quadratic penalty term for any deviation of the variable from the middle point of the interval.
  - *Soft linear limits* introduce a linear penalty term only when the variable is out of the limits defined.
- *Hard limits* introduce a logarithmic barrier term $B(x)$ in the Lagrange Function (3.6). These terms are solved by using the Interior Point Method technique [1] - [15], to find an optimal solution to the combined objective $f(x) + B(x)$ within the feasible region.

$$L'(x,u,\lambda) = f(x,u) + B(x) + \sum_{i=1}^{N} \lambda_i \cdot h_i(x,u) \tag{3.6}$$

Where:

$$B(x) = -(10^{\mu}) \sum_{i=1}^{N_{HL}} \left[log\left(x_i - x_{i\_min}\right) + log\left(x_{i\_max} - x_i\right) \right]$$

Being:

- $B(x)$ the barrier terms
- μ the barrier coefficient
- N_{HL} the number of variables with hard limit constraints
- x_i the constrained variable
- x_{i_max} and x_{i_min} the constraint limits

- *Reporting limits* do not introduce any penalty or constraint in the problem. These restrictions are not considered by the OPF solution, but they are reported at the end if any of these constraints have been violated.

Barrier limits are asymptotic, and not defined for the infeasible region, forcing the variable to be within limits. Any infeasibility in the variable leads to a divergent solution. To find the minimum of the objective function $f(x)$, the barrier term $B(x)$ is decreased accordingly, by reducing the μ barrier coefficient from an initial value to a final one until the optimal solution is found. The barrier parameter μ works like a weight in the objective function, and therefore, it may influence the optimal solution found.

The objective term $f(x)$ can be decomposed in the sum of all the combined objectives desired with their assigned weights C_i: $f(x) + B(x) = \sum C_i \cdot f_i(x) + B(x)$. It is very important to set appropriate values for the objective term's weights C_i as their magnitude compared to the final μ barrier coefficient determines which term has a higher importance in the solution.

Hard barriers tend to provide an optimal solution in the middle point of the interval to minimize the value of $B(x)$. Therefore, very small objective costs C_i selected, may lead to an undesired result as the optimal solution will give more importance to the barrier term. When hard barriers are used, appropriate objective function term costs C_i must be selected, so the OPF provides the desired solution.

Section 5.1.1 shows how these parameters and costs were selected to obtain the desired solution.

Hard barriers are applied to every discrete control variable such as OLTC tap positions or switched shunt device steps to represent their physical limitations.

3.2.2 Variable sensitivities

The sensitivity values of the variables with the objective function have the same concept as the Lagrange multiplier. PSS®E provides sensitivity for every column variable in the Jacobian matrix (dependent x and control variables u). The value of the sensitivity for a variable x_i is calculated as (3.7) and it determines the change in the objective function when there is an increase or decrease of one unit in the variable's value. This is a very useful tool, to evaluate which are the most effective controls to optimize the objective function.

$$s_i = \frac{\Delta f(x,u)}{\Delta x_i} \tag{3.7}$$

- A positive (negative) sensitivity means that an increase of one unit in the variable's value leads to an increase (decrease) of the sensitivity value in the objective function.
- At the optimal point of a variable, its sensitivity is zero. A sensitivity that is different from zero means that the variable is constrained.
- If a variable is constrained, the sensitivity determines the value for moving that constrain one unit forward. How much is willing to pay the DSO for an extra unit of that variable.
- The sensitivity values of the fixed control variables determine which are the most effective controls for optimizing the objective function.

3.3 Data Files

This section describes the data file management to run the Optimal Power Flow within PSS®E software.

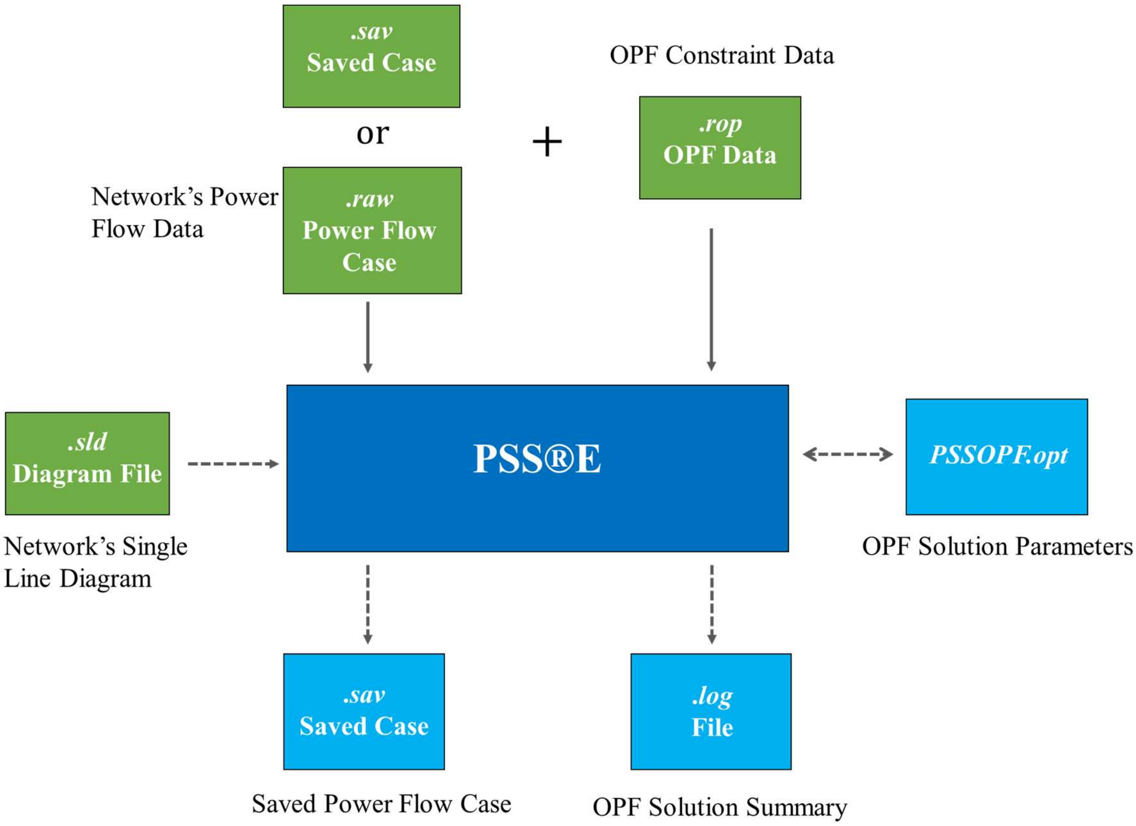


Figure 3.2: Data Files used by the OPF in PSS®E

- *Power Flow Case Data File*

  This file is required as it contains all the information that defines the electrical network: areas, zones and owners, and every element present within it: buses, branches, loads, generators, transformers. It is the file used in the conventional power flow.

  A *.raw* data file can be created using a text editor. This file has been used for the 24h simulation. However, it can be substituted by a *.sav* file created by PSS®E from a previously saved power flow case. The *.raw* data must be written with a specific structure, as described in [15].

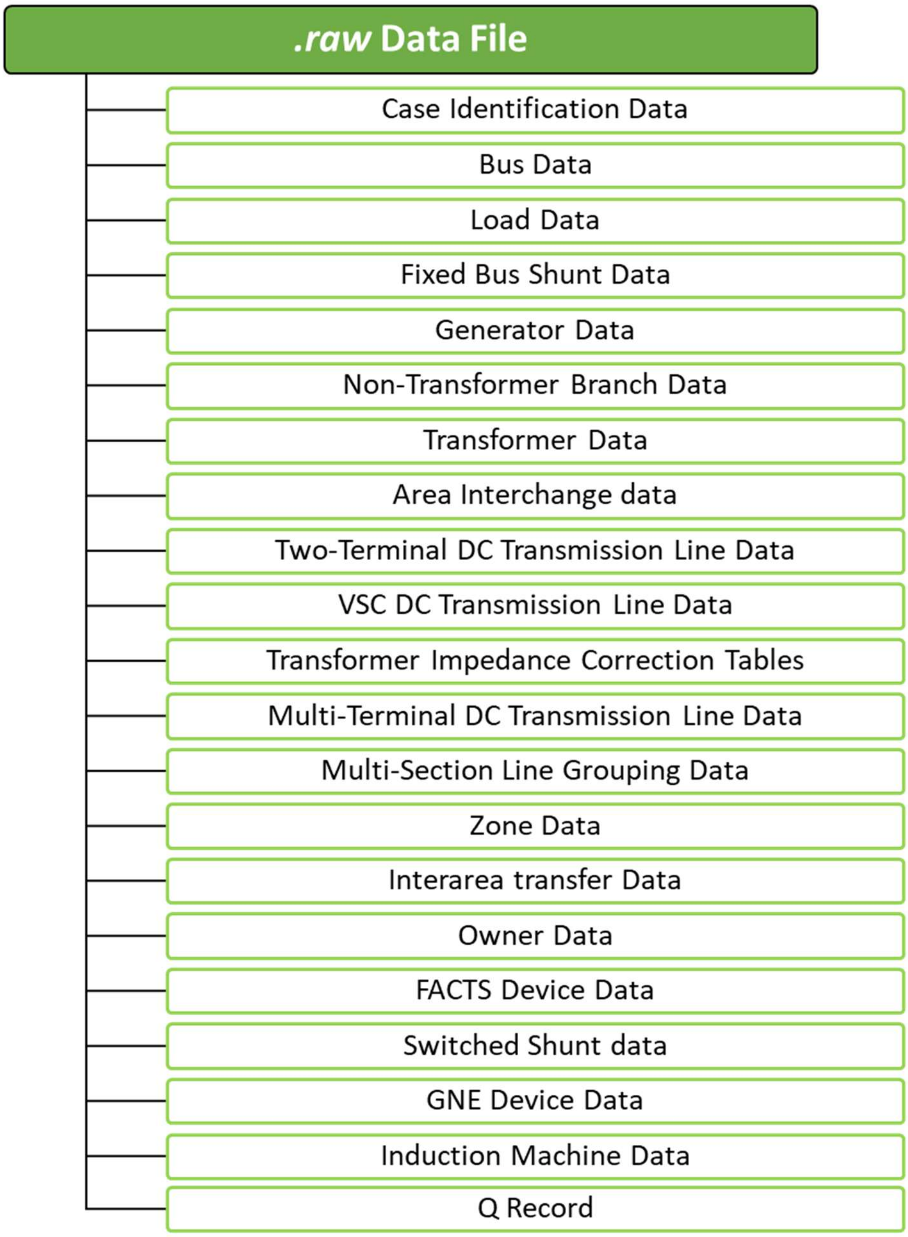


Figure 3.3: *.raw* Data File structure [15]

- *Optimal Power Flow Data File*

  Once the power flow *.raw* case has been imported, the *.rop* file is required. It contains constraints and control data of the elements present in the simulation case. This file can be opened and modified using a text editor.

  It can be automatically created by the PSS®E or an already existing *.rop* file can be opened. The data records must be introduced in the specific order shown in Figure 3.4 [15].

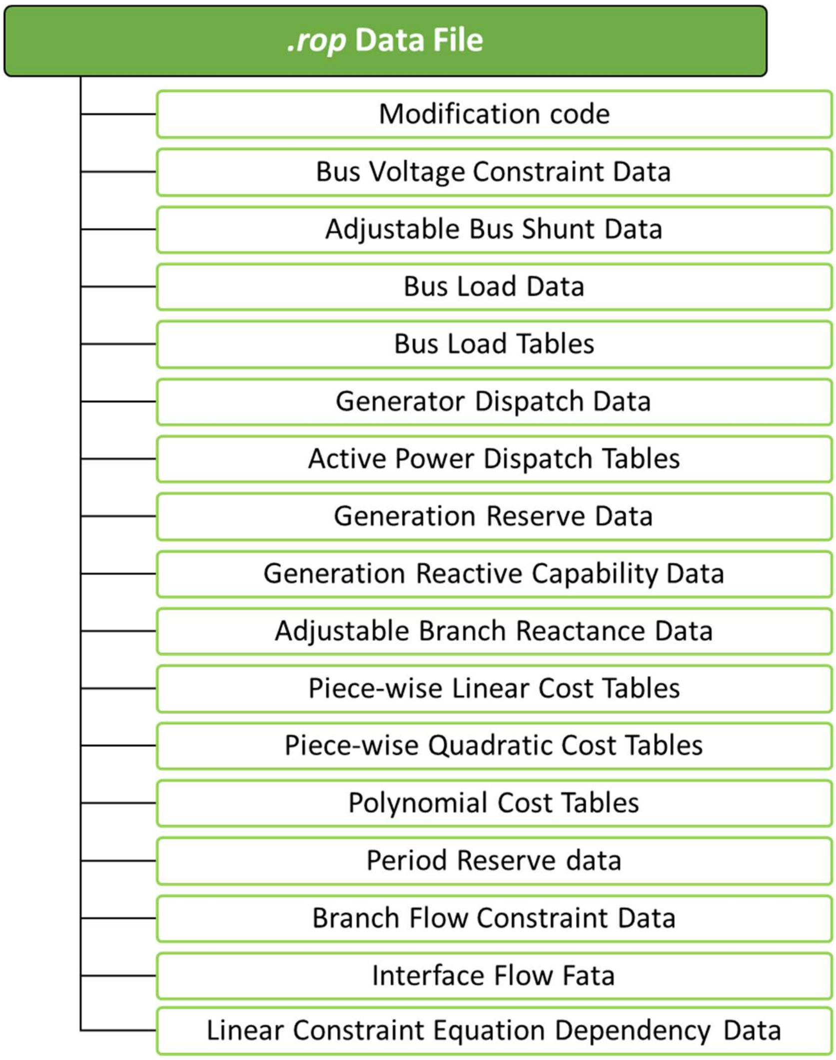


Figure 3.4: *.rop* Data File structure [15]

The *.rop* file does not contain information about solution parameters, objectives and tolerances. This must be specified for each working case, and default settings can be saved in the *PSSOPF.opt* file.

- *Parameter Settings File (PSSOPF.opt)*

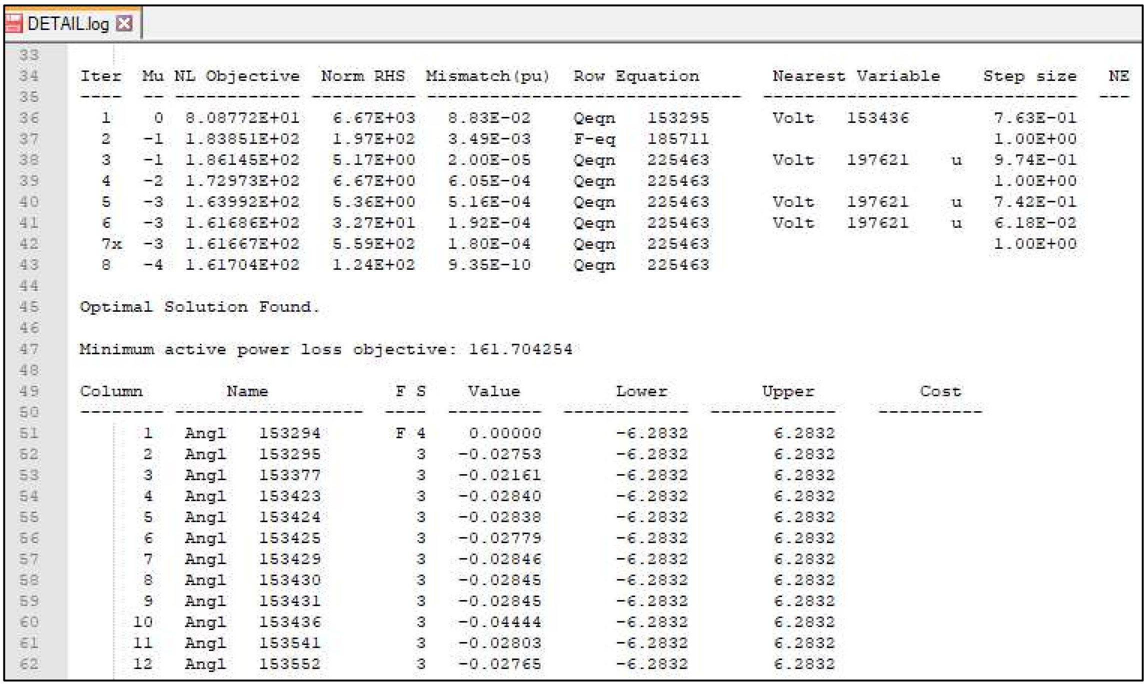
  The *PSSOPF.opt* can be used to save the current OPF solution parameters window as the default ones. When a new case is imported, PSS®E finds if a *PSSOPF.opt* exists in the current directory, and if it does, it sets it as the default parameter settings.

- *Single-Line Diagram*

  The *.sld* diagram file can be created within PSS®E from a *.raw* case or opened from an already existing file. It can be helpful as it displays the power flow results graphically. Figure 1.1 shows the *.sld* diagram created for this case (shown in more detail in Annex B).

- *OPF Optimization Log File (.log)*

  It is an output text file created by PSS®E containing very useful information about the OPF solution, such as the objective's function value, network's variables values, limits and sensitivities, and the equality constraint's LaGrange multipliers.



```
DETAIL.log

Iter  Mu NL Objective   Norm RHS   Mismatch(pu)   Row Equation        Nearest Variable         Step size   NE
----  -- ------------ ---------- ------------------------------   -----------------------------  ---
   1   0  8.08772E+01   6.67E+03   8.83E-02    Qeqn   153295      Volt   153436          7.63E-01
   2  -1  1.83851E+02   1.97E+02   3.49E-03    F-eq   185711                             1.00E+00
   3  -1  1.86145E+02   5.17E+00   2.00E-05    Qeqn   225463      Volt   197621     u    9.74E-01
   4  -2  1.72973E+02   6.67E+00   6.05E-04    Qeqn   225463                             1.00E+00
   5  -3  1.63992E+02   5.36E+00   5.16E-04    Qeqn   225463      Volt   197621     u    7.42E-01
   6  -3  1.61686E+02   3.27E+01   1.92E-04    Qeqn   225463      Volt   197621     u    6.18E-02
  7x  -3  1.61667E+02   5.59E+02   1.80E-04    Qeqn   225463                             1.00E+00
   8  -4  1.61704E+02   1.24E+02   9.35E-10    Qeqn   225463

Optimal Solution Found.

Minimum active power loss objective: 161.704254

Column         Name            F S     Value          Lower          Upper          Cost
-------- ------------------   ----   ---------   ------------   ------------    ----------
      1   Angl    153294       F 4     0.00000        -6.2832         6.2832
      2   Angl    153295         3    -0.02753        -6.2832         6.2832
      3   Angl    153377         3    -0.02161        -6.2832         6.2832
      4   Angl    153423         3    -0.02840        -6.2832         6.2832
      5   Angl    153424         3    -0.02838        -6.2832         6.2832
      6   Angl    153425         3    -0.02779        -6.2832         6.2832
      7   Angl    153429         3    -0.02846        -6.2832         6.2832
      8   Angl    153430         3    -0.02845        -6.2832         6.2832
      9   Angl    153431         3    -0.02845        -6.2832         6.2832
     10   Angl    153436         3    -0.04444        -6.2832         6.2832
     11   Angl    153541         3    -0.02803        -6.2832         6.2832
     12   Angl    153552         3    -0.02765        -6.2832         6.2832
```

Figure 3.5: *.log* File Example

3.4 Flexible resources parametrization

This section describes the parametrization of each of the flexible resource models studied in Section 2. This parametrization has been done in the software PSS®E.

As it will be exposed, some parameters used by the OPF are directly obtained from the *.raw* power flow data file. These files are obtained from the already existent i-DE databases and electrical applications.

Other parameters which must be defined in the *.rop* OPF Data File are not currently available in the existent i-DE databases and electrical applications. This section shows the parameters required to model each flexible resource, determining the information needs to industrialize the OPF tool in the future.

3.4.1 On-Load Tap Changer (OLTC)

Transformer data is recorded in the .raw power flow data file (Figure 3.3) using the parameters in the order described in [15], not requiring any additional information for its parametrization in the model.

The OPF allocates a control variable to the tap ratio for every transformer defined in the *.raw* file, within the optimized area and with a non-zero winding ratio. The transformers' tap ratio within a non-optimized area are fixed to their initial value.

The physical limits for this control variable are the maximum turn ratio R_{max} and the minimum R_{min} defined in the *.raw* File. As described in Section 3.2.1, these limits are treated as hard barriers.

Table 3.1 describes the three possible ways to configure the tap position optimization, with the OLTC modelling employed in this project underlined.

Model	Configuration	Tap Optimization
OLTC Fixed Tap Ratio (Not optimized)	• *Fix transformer tap ratio* setting at OPF Solution Parameters.	• Tap is fixed to its initial value (not a control variable).
OLTC Discrete Optimization	• *Round transformer tap ratio* setting at OPF Solution Parameters.	• An optimal solution is found (in the feasible region), and the tap ratio is rounded to the nearest discrete step t_i. • Not robust performance shown (divergency).
<u>OLTC Continuous Optimization</u>	• No settings selected. • Posterior required discretization (ensuring an optimal and feasible solution).	• The optimal continuous tap position between R_{max} and R_{min} is found.

Table 3.1: Optimization models for the OLTC

Using the discrete tap optimization, the OPF finds first an optimal solution with the tap in continuous mode, discretizing afterwards to the closest discrete tap. However, due to the simulations performed (voltages with hard barriers and losses minimization), this setting usually leads to divergent solutions, as the discretized tap leads to voltages in the infeasible area.

To solve this matter, tap positions have been treated as continuous for the execution of the OPF in PSS®E and discretized afterwards to the closest upwards discrete step that ensures a feasible and optimal solution for the simulations performed (the same solution is suggested in [1]).

3.4.2 Shunt devices

Three modelling alternatives are available to define the bus shunt device parametrization: fixed, adjustable and switched shunts.

3.4.2.1 Fixed shunt model

The fixed shunt device does not represent a control variable in the OPF problem. The user must define whether this device is in service or not. Fixed shunt data is recorded in the *.raw* power flow data file (Figure 3.6).

```
0 / END OF LOAD DATA, BEGIN FIXED SHUNT DATA
225463,'1 ',1,     0.000,     3.000
0 / END OF FIXED SHUNT DATA, BEGIN GENERATOR DATA
```

Figure 3.6: 3 MVAr Fixed shunt data record in the *.raw* File

When it is in service, the entire susceptance value is connected (2.2). When defined as out of service, it is not considered in the power flow solution.

The fixed shunt device by itself does not represent a control variable in the OPF problem. This model has been used in combination with the adjustable shunt model to optimize the connection schedule of a shunt device in 5.3.3.

3.4.2.2 Optimal adjustable fixed shunt

The optimal adjustable fixed shunt value represents a control variable in the OPF problem. For a selected bus in the optimized area, the OPF returns the optimal fixed bus shunt susceptance value B_{sh_opt} that minimizes the optimal function.

The *Minimize Adjustable Bus Shunts* setting must be defined in the OPF solution parameters configuration. For the adjustable shunt model defined in the substation busbar, the objective term introduced is:

$$f_{Adj_{Sh}}\left(B_{sh_{opt}}\right) = B_{sh_{opt}} \cdot C_{sh_{opt}} \qquad (3.8)$$
$$B_{sh\_opt\_min} \leq B_{sh_{opt}} \leq B_{sh\_opt\_max}$$

Being:

- B_{sh_opt} the optimal fixed shunt susceptance value (control variable)
- $B_{sh\_opt\_max}$ and $B_{sh\_opt\_min}$ are the maximum and minimum limits defined
- $C_{sh_{opt}}$ the cost/weight assigned to the shunt value in €/MVAr.

The data records for the adjustable shunt value are written in the *.rop* data file. Table 3.2 shows the parametrization entered to model the adjustable shunt in PSS®E for the case shown in section 5.3.

Model	$B_{sh\_opt\_min}$ (MVAr)	$B_{sh\_opt\_max}$ (MVAr)	$C_{sh_{opt}}$ (€/MVAr)
Adjustable shunt	0	100	0

Table 3.2: Adjustable shunt parametrization

If the *Minimize Adjustable Bus Shunts* is selected, the optimal shunt value B_{sh_opt} is updated in the *.raw* data file. If a fixed shunt already exists at the specified bus, its susceptance value $B_{sh.}$ Is updated with the optimal one B_{sh_opt}, otherwise, a new fixed shunt is created.

The cost $C_{sh_{opt}}$ determines the weight of the adjustable shunt term (3.8) in the objective function. As in this study, only one shunt device has been analyzed, and its optimal value is desired, this cost has been settled to zero.

3.4.2.3 Switched shunt model

A control variable is defined for every switched shunt device present in the *.raw* power flow data file (Figure 3.3). Where most important parameters are:

- The number of shunt blocks ($0 \leq N_B \leq 8$), up to 8 blocks either of reactance, capacitance or both can be defined.

- The number of steps within each block ($0 \leq N_S \leq 9$), up to 9 susceptance steps can be defined for each of the N_B shunt blocks.
- The nominal susceptance increment B_{sh_i} in each of the N_S steps of the N_B blocks.

Switched shunts within a non-optimized area are fixed to their initial value. As well as the OLTC, switched shunt susceptance limits are treated as hard barriers non defined for the infeasible area. As well as the OLTC, three settings are available: fixed, continuous optimization and discrete optimization (Table 3.3).

The discrete optimization for the switched shunt device does not provide a robust alternative, as it usually leads to a non-convergent solution with voltages in the infeasible area.

For this reason, it is recommended to use the continuous optimization of the shunt device, which provides the optimal shunt value within limits that minimizes the objective function, discretizing afterwards to the closest downwards shunt step value, ensuring an optimal and feasible solution with voltages within the feasible area.

The continuous treatment of the switched shunt element is equivalent to the optimal adjustable fixed shunt model case (Section 3.4.2.2) with zero cost $C_{sh_{opt}} = 0$.

3.4.2.4 Bus shunt parametrization

A summary of the modelling alternatives is shown in Table 3.3, with the bus shunt modelling employed underlined.

The combination of a fixed shunt model with the adjustable shunt optimization is preferred over the switched shunt modelling, as it has been shown more robust and flexible modelling.

In both cases, external logic is required to discretize the shunt value after a solution is found, to ensure a feasible and optimal solution.

As commented, when the cost $C_{sh_{opt}} = 0$, the adjustable shunt optimization leads to the same solution as the switched shunt continuous optimization, offering the potential of penalizing the use of the shunt element with a cost $C_{sh_{opt}}$ different from zero.

<table>
<tr><th colspan="2">Model</th><th>Configuration</th><th>Shunt optimization</th></tr>
<tr><td colspan="2">Fixed shunt (No control variable)</td><td>• In the service setting defined by the user in the .raw power flow data file.</td><td>• Not a control variable.</td></tr>
<tr><td rowspan="3">SWITCHED SHUNT</td><td>Fixed setting (Not optimized)</td><td>• Fix switched shunts setting at OPF Solution Parameters.</td><td>• The shunt is fixed to its initial value (not a control variable).</td></tr>
<tr><td>Discrete Optimization</td><td>• Round switched shunt vars setting at OPF Solution Parameters.</td><td>• An optimal continuous solution is found (in the feasible region), and then the shunt value is rounded to the nearest discrete step.
• Not robust performance shown (divergency).</td></tr>
<tr><td>Continuous Optimization</td><td>• No settings selected.
• Posterior discretization is required.</td><td>• The optimal continuous shunt value within limits is found.
• Equivalent to the Optimal Adjustable fixed shunt model with $C_{sh\_opt\_i} = 0$</td></tr>
<tr><td colspan="2"><u>Optimal Adjustable Fixed Shunt</u></td><td>• Minimize Adjustable Bus Shunts setting.
• .rop File required parameters: bus, shunt limits and cost.
• Posterior discretization is required.</td><td>• Optimal fixed shunt value B_{sh_opt} within limits at the specified bus.
• Used in combination with the Fixed shunt data record
• Cost assignment allows potential control priority ($C_{sh\_opt\_i}$).
• Parameters used in Table 3.2</td></tr>
</table>

Table 3.3: Summary of the modelling alternatives for a bus shunt device

3.4.3 Distributed Generation (DG)

The generator's power flow data is recorded in the .raw data file as described in [15]. Figure 3.7 shows some of the generator's characteristics defined for the reactive power simulation (5.4).

The first row represents the primary substation transformer limited by the 40 MVA rating. G1 to G6 are the generators which are going to be used for the reactive power regulation case (PV node generators).

A nominal power factor of 0.8 has been considered for all of them. G2 represents the wind farm and G7 to G10 the small solar PV plants which are going to be treated as fixed PQ nodes.

	Bus Number	Zone Num	VSched (pu)	In Service	PGen (MW)	PMax (MW)	PMin (MW)	QGen (Mvar)	QMax (Mvar)	QMin (Mvar)	Mbase (MVA)
ST	153294	61	0,9981	☑	13,9230	40,0000	-40,0000	7,5760	40,0000	-40,0000	40,00
G1	153431	134	1,0335	☑	0,1120	1,1370	0,0000	0,0000	0,0000	0,0000	1,42
G2	153560	129	1,0360	☑	6,5880	17,9110	0,0000	0,0000	21,3970	-21,3970	22,39
G3	154880	129	1,0347	☑	4,0020	17,9110	0,0000	0,0000	0,0000	0,0000	22,39
G4	154893	130	1,0320	☑	1,4100	3,8000	0,0000	0,0000	0,0000	0,0000	4,75
G5	154894	130	1,0270	☑	1,6390	4,2750	0,0000	0,0000	0,0000	0,0000	5,34
G6	154899	134	1,0349	☑	6,9170	17,7630	0,0000	0,0000	0,0000	0,0000	22,20
G7	286052	133	1,0380	☑	0,0000	0,0200	0,0000	0,0000	0,0000	0,0000	0,02
G8	286059	134	1,0335	☑	0,0000	0,0100	0,0000	0,0000	0,0000	0,0000	0,01
G9	286077	129	1,0303	☑	0,0000	0,0960	0,0000	0,0000	0,0000	0,0000	0,10
G10	286080	129	1,0305	☑	0,0000	0,0320	0,0000	0,0000	0,0000	0,0000	0,03

Figure 3.7: Machine parameters used at hour 20:00h in PSS®E Network data

3.4.3.1 Reactive power output limits

In the conventional power flow, generators may be treated as PV or PQ nodes depending on whether they regulate their bus voltage or not:

- PV nodes determine the active power injection and a fixed bus voltage. Regulating their scheduled voltage by injecting or absorbing reactive power (V/var control [12]). When any of their reactive power limits are saturated, they become PQ nodes. A PV node in Figure 3.7 would be G2.

- PQ nodes are constant power buses (actual treatment of every DG in the network), which determine active and reactive power injections and do not regulate their bus voltage. As shown in Figure 3.7, PQ node generators are defined by setting the reactive power limits equal to the reactive power output (at 0 for this case)

The OPF includes further functionalities in the control of optimized generators. PV node generators are optimized controlling their schedule voltage within limits defined, to minimize the objective function. Generators G1 to G6 have been treated as optimized generators with a PV node for the OPF solution.

For the inverter connected plants, it is possible to define their reactive capability limits in two possible ways, by using the *wind machine* option in PSS®E which enables to define of a power factor limit (WPF), or by defining the maximum and minimum Q_{max} and Q_{min} limits.

- The wind farm limits have been parametrized as explained in section 2.3.2, with a nominal power factor of $0.8\,pu$. Q_{max} and Q_{min} are calculated for every hour depending on the active power generation $P_g(t)$ as done in (2.14). For the example in Figure 3.7, reactive power limits of G2 have been calculated as:

$$Q_{max} = \sqrt{{S_{max}}^2 - {P_g}^2} = \sqrt{22.4^2 - 6.6^2} = 21.4\ MVar$$
$$Q_{min} = -\,Q_{max} \tag{3.9}$$

For modelling synchronous generators, a more sophisticated PQ diagram has been employed as explained in 2.3.1. The *.rop* data file parameters required to define the generator's reactive capability are shown in Table 3.4.

When the reactive capability model is enabled in the OPF data, the reactive generation limits defined in the conventional power flow shown in Figure 3.7 are not considered (for this reason they are set to zero).

- Generators G1, G3, G4, G5 and G6 representing the cogeneration plants are parametrized using the *reactive capability limits* model working as PV node generators, providing V/var control within their PQ diagram operational limits.

- Synchronous reactance, stator limit current, leading and lagging power factor and maximum reactive absorption at zero power factor are obtained from typical gas turbine parameters.

- Excitation limits can be calculated from the parameters defined as:

$$e_{fd\_min} = 1 - x_d \cdot |q_{min}| = 0.28 \text{ pu}$$

from (2.10)

$$e_{fd\_max} = \sqrt{{x_d}^2 \cdot \left({p_{max}}^2 + \left(q_{nom} + \frac{1}{x_d}\right)^2\right)} = \sqrt{1.8^2 \cdot \left(0.8^2 + \left(0.6 + \frac{1}{1.8}\right)^2\right)} = 2.53 \text{ pu}$$

from (2.8)

- Where p_{max} and q_{nom} are obtained at the nominal operating point with a defined lagging power factor of 0.8.

- Finally, the maximum leading power factor determines the maximum delta angle restriction δ_{max}.

- For calculating reactive output sensitivities, as it is done in section 5.4, its value must be calculated as:

    - *Initial solution OPF reactive output sensitivities*, as initially, in the base case every generator is treated as a non-regulating PQ node with a restriction of zero reactive power output. Their reactive power sensitivities can be calculated from the Q_g variable sensitivity. Showing the change in the objective function value if the reactive output limit is moved away in one unit.

    - *Final OPF reactive output sensitivities* must be obtained depending on the generator's model:

        - For G2, as it is treated as an optimized PV node generator, with defined Q_g limits in the network data file. Its reactive output sensitivity can be obtained from the Q_g variable sensitivity as before. If this variable is within limits, output sensitivity is zero. In case this variable is bounded by the maximum or minimum limit, the sensitivity value represents the 'cost' of relaxing that restriction one unit.

- For G1, G3, G4, G5, G6, modelled with the *reactive capability model,* the aforementioned method cannot be used as the Q_g limits from the network data file are neglected within this configuration. Reactive output sensitivities must be calculated from the e_{fd} and I_s sensitivity values. In case one of these variables is bounded in the final OPF solution, it will have a sensitivity greater than zero.

Generator	Parametrization
G1, G3, G4, G5, G6	• CHP • PQ Diagram: Figure 2.6 • *Reactive capability* parameters (OPF Data) ○ Synchronous reactance $x_d = 1.8$ pu ○ Stator limit current $I_{S\_max} = 1$ pu ○ Nominal lagging p.f.: 0.8 ○ Nominal leading p.f.: 1 ○ Max. reactive absorption $Q_{abs\_max} = 0.4$ pu
G2	• Wind • PQ Diagram: Figure 2.8 • Reactive power limits at every hour *t* (Network Data) ○ $Q_{max} = \sqrt{{S_{max}}^2 - P_g(t)^2}$ ○ $Q_{min} = -Q_{max}$

Table 3.4: Distributed generators reactive limits parametrization

3.4.3.2 Active power dispatch

Active power generation can be defined as a control variable by introducing a fuel cost function for the generators whose active power will be dispatched.

Two fuel cost curves have been defined for the simulation in the case presented in section 5.5. First, the slack bus active power represents the power coming from the HV network through the substation, assuming a marginal cost of 40 €/MWh for all the power demanded from the grid. A linear cost curve has been assumed for generator G1.

The *Minimize Fuel Cost* option must be selected for dispatching the active power generation of the generators participating optimally, minimizing the total fuel cost incurred.

3.4.4 Flexible demand

For the flexible load model, which has been defined for two flexible load types, industrial and residential, as commented in 2.4, the objective term introduced is:

$$f_{Adj_{Load}}(\alpha_{res}, \alpha_{ind}) = (1-\alpha_{res}) \cdot C_{res} \cdot P_{res} + (1-\alpha_{ind}) \cdot C_{ind} \cdot P_{ind}$$
$$\alpha_{res\_min} \leq \alpha_{res} \leq \alpha_{res\_max} \tag{3.10}$$
$$\alpha_{ind\_min} \leq \alpha_{ind} \leq \alpha_{ind\_max}$$

Being:

- α_{res} and α_{ind} the optimal load multiplier for the residential and industrial flexible demand.
- α_{res_max}, α_{res_min}, α_{ind_max} and α_{ind_min} represent the maximum and minimum flexibility limits for the residential and industrial demand.
- C_{res} and C_{ind} the cost assigned to each of the flexible loads in €/pu (MWh).
- P_{res} and P_{ind} the total initial residential and industrial active power demand.

Selecting the *Minimize Adjustable Bus Load,* the optimal load multiplier for each of the flexible loads defined is obtained. Therefore, demand has been treated as a continuous variable for the simulation performed. If a posterior discretization is desired, it may be done after the continuous OPF solution as in the OLTC case.

Data records for the adjustable loads are written in the *.rop* data file. Table 3.5 shows the parametrization used in section 5.5 for each of the flexible loads defined. Different costs have been applied to the flexible demand to simulate different flexibility scenarios and obtain the most cost-efficient solution in each of them.

Load Type	α_{min}	α_{max}	Cost (€/pu)
Residential Load	0.9	1	Case 4.1: 7000 Case 4.2: 5000 Case 4.3: 4000
Industrial Load	0.8	1	Case 4.1: 8000 Case 4.2: 6500 Case 4.3: 4500

Table 3.5: Flexible demand parametrization

A maximum load multiplier of 1 has been considered, representing the load shedding scenario to solve an overload in a line. Higher load flexibility with greater load-shedding costs has been assigned to the industrial loads.

3.5 Network limits

Bus voltage and branch flow limit treatment must be defined in the *.rop* data file. As discussed in Section 3.2.1, these constraints can be defined as hard or soft limits depending on the degree of relaxation desired.

3.5.1 Bus voltages

By regulation, Distribution System Operators must operate the grid to maintain supply voltages within some limits ensuring a secure and reliable supply. Voltages out of limits could damage grid assets and cause instabilities. According to the European standard

EN50160 [16], the supply voltage range in distribution grids should be between 0.9 and 1.1 of the nominal voltage of the grid.

The Spanish regulation for the activities of transport, distribution and supply of electricity accepts a narrower limit range. The RD 1634/2006 from December 29th [17] imposes a maximum variation limit at the final consumer's supply voltage of 7%.

A maximum variation limit of 7% at the grid under study is considered at every bus. As it is a 20kV medium voltage (MV) distribution grid, the load buses represent MV/LV secondary substations showing the aggregated load in the LV level. Therefore, the 7% limit is conservative enough to meet the requirements at the LV supply point.

As it is shown in the simulations performed (section 5), the natural effect of minimizing power losses is to increase bus voltages, to force voltages to be within the 7% limits, hard limits are defined. Due to the barrier terms introduced, coherent solution parameters and costs must be found (Section 5.1.1).

The bus voltage limit parametrization in PSS®E is defined in the *.rop* data file. Table 3.6 describes the data fields required to define these constraints.

Bus	Limit configuration
Slack Bus	• Secondary of the primary substation transformer. • Maximum and minimum hard limits are defined to its initial value. • Fixed voltage during OPF solution.
Network Buses	• Hard limit type. • 7% maximum and minimum limit. • Soft penalty coefficient only used for soft limits (Section 3.2.1)

Table 3.6: Bus Voltage Limits Parametrization (*.rop* data file)

As explained in 2.1, the primary winding voltage has been defined as the slack bus, fixing to its initial value, assuming an infinite bus to represent the 66kV network. To do so, maximum and minimum hard limits have been settled to its initial value

3.5.2 Branch flows

Branch flows' constraints can be automatically defined in the *.rop* data file obtained from the power flow data model. Branch flows are defined within the *.raw* data file with three ratings:

- *Rate A:* representing the minimum rating in MVA between Rate A and Rate B.
- *Rate B:* representing the summer rating in MVA.
- *Rate C:* representing the winter rating in MVA, typically a higher capacity than in summer.

All the branches in an area can be automatically initialized in the OPF Data structure, selecting one of the Rating limits presented above and specifying the limit type and soft limit coefficient if applicable. The branch limit parametrization configured for the simulations is described in Table 3.7.

Branches	Limit configuration
All branches within .raw File	• Rate A. As the day selected is in October, the most restrictive limit is considered. • Reporting type limit, no penalty is applied. Overloads in the solution are reported. • ZIL overload reports discarded.

Table 3.7: Bus Voltage Limits Parametrization (*.rop* data file)

Zero Impedance Lines (ZILs) are short segments, breakers or switches connecting two buses, whose limits are not considered in the power flow solution. There are two possible ways of modelling short segments:

- *THRSHZ threshold*, every line with a zero resistance and a reactance below the threshold, is considered as a ZIL. During the power flow solution buses between the ZIL are considered as the same bus, excluding ZILs. After a solution, ZIL is not considered in the Limit Checking reports.

- *Bypass Check*: short segments with a non-zero resistance or whose impedance is defined above the THRSHZ are considered in the power flow solution. But as their ratings are settled to zero, after a solution, these branches are bypassed by the power flow Limit Checking reports.

The second approach is considered to model short segments. However, when initializing the OPF branch flow limits, all of these zero-rating branches are automatically initialized causing a zero-flow restriction. In this case, as reporting limits were defined, it does not affect the optimal solution. However, for other limit types, this would affect the optimal solution, and these restrictions should be eliminated.

4 Methodology

First, control variables associated to each flexible resource have been modelled and parametrized. Secondly, benefits of applying an OPF in a real 20kV distribution network under different flexibility scenarios are evaluated and compared with the initial case. Finally, a sensitivity analysis is performed, determining for different flexibility scenarios, which are the most effective controls.

The project's methodology can be resumed in the following steps:

1. Base case scenarios from a real distribution network are obtained from the state estimator PSE and analyzed using PSS®E power flow software, determining the base case results.

2. Optimization cases are defined for each of the flexible resources discussed in Section 2 (OLTC, shunt device, DGs and flexible demand) evaluating different objective functions by using their available control variables (tap position, shunt device connection, active and reactive power regulation from DGs and demand load reduction) parametrized as explained in Section 3.4.

3. For the flexibility cases simulated (Table 4.1), impacts of using each control variable are evaluated and compared with the initial case scenario results.

4. With results obtained, a sensitivity analysis is performed, determining for different flexibility scenarios, which are the most effective controls.

Section 4.1 explains the optimization simulations performed, as well as the control variables and objective functions used. Section 4.2 provides a step-by-step description of the OPF simulation models.

4.1 Simulations performed

Table 4.1 represents the simulations performed within this project for each of the flexible resources discussed. Showing for each case of study, the objective function defined and the flexible resource's control variables used. Flexible resources models are exposed in Section 2 and their parametrization in Section 3.4.

Simulation cases 1 and 2 use the DSO owned flexible resources, controlling the OLTCs tap position and shunt device reactive injection (connection schedule) variables respectively for power losses minimization.

Simulation case 3 uses DGs Volt/VAr regulation, controlling their reactive power injection to obtain the optimal voltage profile that minimizes power losses. Evaluating their sensitivity with the objective function and their effect on other electrical variables such as voltages or power flows.

Finally, an emergency state operation is simulated, where the most cost-efficient control actions from flexible demand load reduction and DG active power dispatch are used to solve an overload in a line. Different costs are applied to the flexible load to investigate its effect on the solution and determine which is the most cost-efficient control in each case.

Simulation	Objective functions	Flexible resources	Control variables
Case 1	Secure state operation *Minimize Losses*	OLTC	• Tap position
Case 2	Secure state operation *Minimize Losses*	Substation shunt device	• Adjustable shunt optimal value • Shunt connection decision
Case 3	Secure state operation *Minimize Losses*	DGs	• Volt/VAr regulation from DGs
Case 4	Emergency state operation (Solve an overload using the most cost-efficient controls) *Minimize Bus Load* *Minimize Fuel Cost*	DG & Flexible demand	• Power dispatch from G1 • Load shedding from industrial and residential flexible demand in Zones 131 & 134 under different load-shedding costs

Table 4.1: Objective function, flexible resources and control variables used in each of the simulations performed

4.2 Simulation steps

As exposed in Section 1.2, the implementation of a periodical OPF background execution during grid operation depends on a reliable supervision, control and data acquisition tool (SCADA) and a robust state estimator (PSE) that builds the power flow data cases.

For cases 1, 2 and 3 that require a 24h simulation, a Python script has been created to automatically run in PSS®E each of the 24 cases and saves the optimization results obtained. The steps and data file management for the 24h losses minimization cases (cases 1, 2 and 3) performed in this project are shown in Figure 4.1.

- First, for every hour of the day selected (October 1st, 2019), PSE runs the state estimation importing every field measurement available in the database for the day, hour, and substation selected. Generating for each of the 24 hours a *'.raw'* power flow case that is exported in PSS®E version 33.

- Before analyzing the 24-hour simulations, valley and peak hours are studied, using different control variables obtaining coherent configuration parameters for each simulation (Section 5.1.1).

- The Python script *'F_RAW_OPF_T2.py'* initializes the *'.rop'* Optimal Power Flow data file for each of the 24 cases introducing constraint limits and control variable parameters according to each simulation performed as shown in Section 3.

- Finally, another python script *'F_OPF.py'* solves the base case power flow and Optimal Power Flow using the desired control variables and OPF solution parameters.

Saving the output variables for both cases which are written in a '*.txt*' file for its posterior analysis in Excel.

Python scripts *'F_RAW_OPF_T2.py'* and *'F_OPF.py'* use the python API functions available in [18].

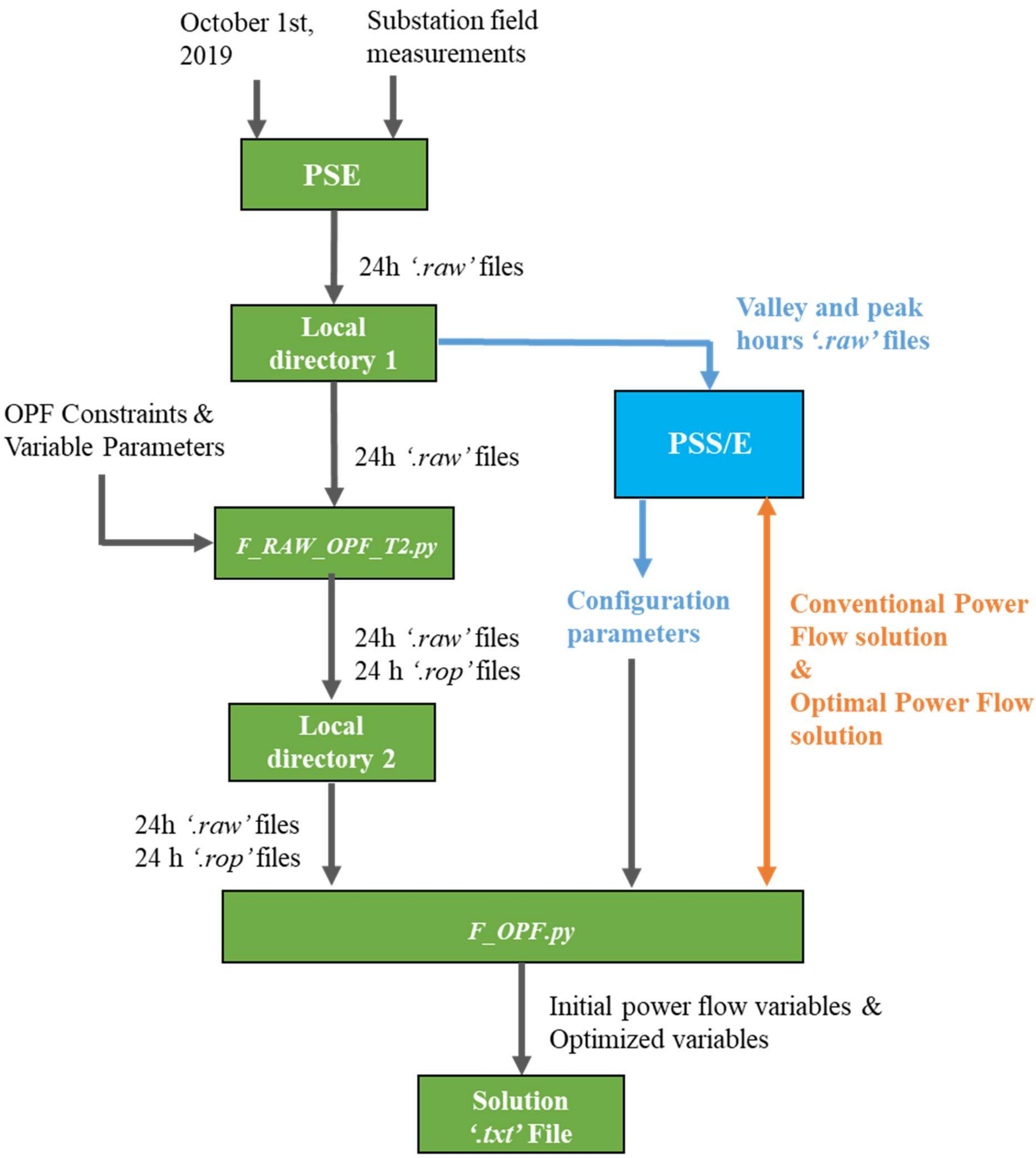


Figure 4.1: File Management

The emergency state operation (Case 4) is not defined for a 24-hour simulation, only one hour is simulated. Therefore, the OPF in PSS®E is used directly to evaluate the optimal corrective control actions to solve a contingency at a certain hour.

For this case, an initial emergency case scenario is created from the valley hour base case (5:00h), and the most cost-efficient control is evaluated under the different flexible demand cost scenarios shown in Table 3.5.

5 Results analysis

This section describes the base case simulation scenario, solution configuration parameters used, and results obtained in each simulation case.

5.1 Base case

The 24h power flow cases obtained from the state estimator (PSE) are used as the base case benchmark to evaluate the results obtained within each OPF simulation. Initial power losses, bus voltages and branch power flows are obtained from the base case power flow solution.

As commented before, there is not a capacitor bank connected in the primary substation busbar in the grid under study (Figure 1.1), for this reason, the base case has been modified in Section 5.3.1 for Case 2 simulation.

As stated in Section 2.1, the OLTC tap position from the primary substation transformer, is currently modified by the transformer regulator unit to maintain the secondary voltage as close as possible to the reference value fixed by the operator. Figure 5.1 shows the tap position movement in the base case scenario during the 24 hours studied. Being the position zero, the neutral tap (Table 2.1).

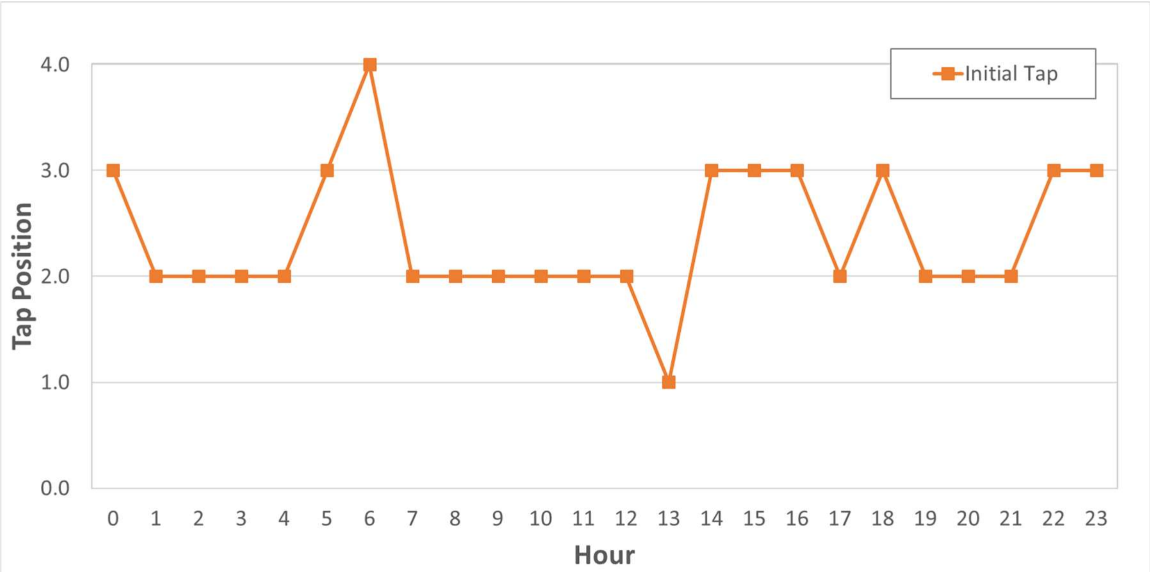


Figure 5.1: 24h base case transformer tap position

Table 5.3 orange chart, shows the base case solution outputs in terms of power losses, tap positions, branch overload checks and maximum bus voltage at the network for every hour studied. As explained in Section 3.5, bus voltages are defined with 7% hard limits and branch flows with report limits. Before starting with the OPF solution, it must be checked that every bus voltage in the base case is within the 7% limits and no overloads exist to ensure that the scenario corresponds to a secure state operation.

Power losses reduction at any period i has been calculated as:

$$Losses\ reduction_{\ period\ i}\ (\%) = \frac{P_{Loss\_i}^{Base\ Case} - P_{Loss\_i}^{OPF}}{P_{Loss\_i}^{Base\ Case}} \cdot 100 \tag{5.1}$$

Where $P_{Loss\_i}^{Base\ Case}$ are the base case active power losses at period i, and $P_{Loss\_i}^{OPF}$ are the OPF solution power losses at period i.

5.1.1 Model configuration parameters

Before doing any of the 24 hour simulations, coherent solution parameters must be determined. Table 5.1 shows the solution parameters used, to obtain those parameters, sample cases of the valley and peak hours were analyzed for the control variables used in the losses minimization objective: OLTC tap position, adjustable shunt device value and reactive power regulation from DGs. Building a matrix (Table 5.2) using different power losses costs, to define the coefficients that lead to the desired outcome and provide robust convergent solutions, to use them in the 24 hour simulations.

The rest of the solution configuration parameters available have been left at the default values.

Setting	Configuration
S_{Base} (MVA)	100
Active power loss cost C_{PLoss} (€/pu)	10000 (100 €/MWh)
Initial barrier coefficient $\mu_{initial}$	1 (0)
Final barrier coefficient μ_{final}	0.00001 (-5)
Minimum barrier step length	0.00001

Table 5.1: OPF solution parameters used

- Firstly, the μ barrier coefficients have been settled to the value that showed the best performance in terms of convergence and value of the optimal solution. As voltages are defined as hard barriers, the final μ coefficient affects the optimal solution found.

- The final barrier coefficient μ_{final}, is settled at the minimum possible value (-5). With this configuration, the final optimal solution will be as close as possible to the barrier asymptotic limits. Minimal power losses are reached when the bus voltages are equal to the upper limit, which constraints the optimal solution.

- The hard barriers defined for every bus voltage introduce a significantly high barrier term in the objective (section 3.2.1). A matrix with different costs was built to find an appropriate value for the cost parameter. Table 5.2 shows an example of the cost matrix built for the optimal adjustable shunt value.

- For costs below 10 €/pu, the optimal shunt is a reactance. The voltage barrier terms have a higher weight in the objective, reaching a solution where the main objective is to reduce voltages rather than losses, obtaining a voltage profile as close as possible to the middle point of its limits, minimizing the barrier terms which leads to an increase in the power losses.

- For costs above 100 €/pu, the loss coefficient has a higher weight than the barrier terms in the objective function, leading to the desired objective of losses reduction. The optimal solution in terms of power losses is obtained with costs higher than 1000 €/pu in this case.

C_{PLoss} (€/pu)	Optimal shunt value (MVA)	Losses reduction (%)	
1	-10.6	-21.3%	**Optimizes Voltage Profile**
10	-6.8	-12.0%	
100	0.8	1.0%	**Optimizes Power Losses**
1000	3.7	3.6%	
10000	3.7	3.6%	
100000	3.7	3.6%	

Table 5.2: Cost matrix for the optimal adjustable shunt value at peak hour (5 AM)

- A cost matrix such as the one shown above was built for every control variable. Finding a cost of 10000 €/pu (100 €/MWh) that provides the optimal solution which minimizes power losses for every case.

5.2 Case 1: OLTC optimization

Figure 5.2 shows the results of the losses minimization problem using the OLTC tap position as a control variable. As described in section 3.4.1, tap positions have been treated as a continuous variable during the execution of the OPF. Meaning that the OPF solution will provide the optimal transformation ratio without considering the real discrete steps restriction of the OLTC. This value will be discretized afterwards by using an external logic to obtain a feasible and optimal tap position for the OLTC.

Table 5.3 shows the results in a chart, including for every hour the tap position, power losses, maximum voltage observed at the network and maximum loading factor observed, also reporting the number of overloads present at the network.

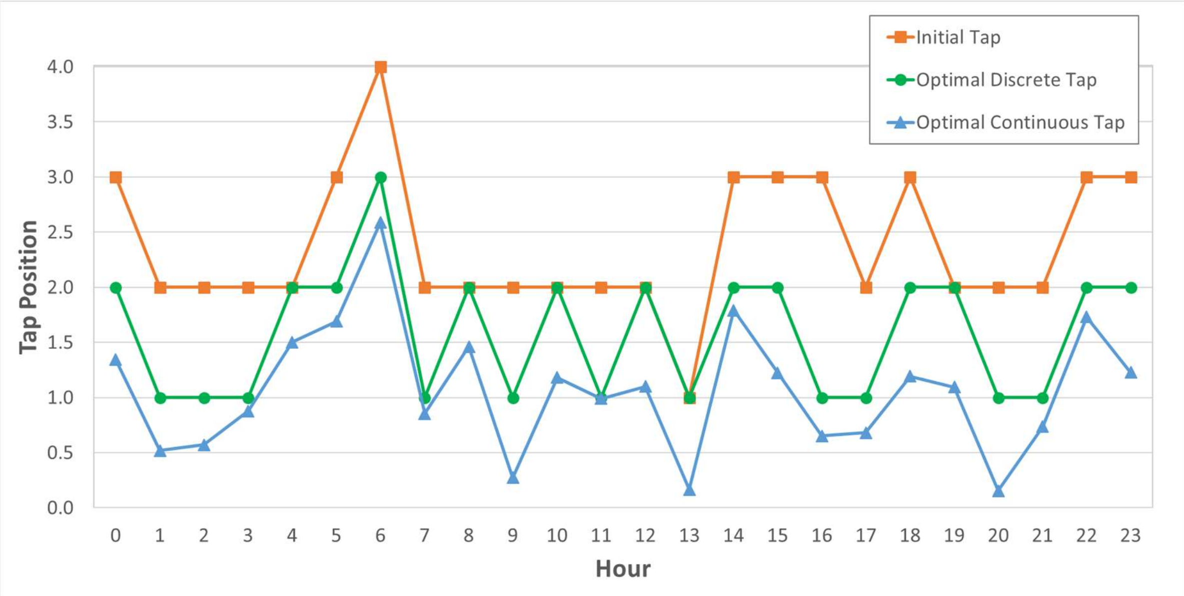


Figure 5.2: 24h transformer tap position optimization

The direct effect observed when minimizing losses is that transformer's tap ratio (tap position) is reduced. This causes the secondary voltage to increase, rising the voltage profile of the network, which leads to a reduction in branch currents and therefore power losses. As shown in Table 5.3, the maximum load for the initial case at every hour is reduced when the tap position is optimized, due to the voltage rise.

As the tap ratio is treated as a continuous variable, the OPF decreases the transformation ratio until the 7% upper limit voltage of any of the busses is reached. Table 5.3 shows how the optimal continuous tap position is bounded by the 1.07 bus voltages at every hour (maximum network bus voltage shown in red), increasing this voltage limit would allow the tap ratio to keep decreasing, reducing consequently power losses.

In other words, the optimal continuous tap represents a top limit in losses reduction but it does not represent a real tap position in the OLTC. It shows the optimal transformer ratio that would lead to minimal losses inside the feasible area.

Base Case	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Tap position	3	2	2	2	2	3	4	2	2	2	2	2	2	1	3	3	3	2	3	2	2	2	3	3
Losses (MW)	0.18	0.18	0.17	0.17	0.17	0.17	0.16	0.24	0.24	0.24	0.24	0.22	0.23	0.25	0.24	0.23	0.23	0.22	0.22	0.21	0.25	0.24	0.19	0.17
Max. Voltage (pu)	1.050	1.052	1.053	1.057	1.064	1.055	1.054	1.056	1.064	1.049	1.060	1.058	1.059	1.060	1.056	1.049	1.042	1.054	1.048	1.059	1.048	1.055	1.055	1.049
Max. Load (%)	88%	87%	87%	84%	85%	87%	85%	87%	84%	85%	85%	87%	86%	89%	86%	90%	86%	85%	91%	87%	93%	89%	86%	86%
Overloads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Continuous Opt.	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Tap position	1.3	0.5	0.6	0.9	1.5	1.7	2.6	0.9	1.5	0.3	1.2	1.0	1.1	0.2	1.8	1.2	0.7	0.7	1.2	1.1	0.2	0.7	1.7	1.2
Losses (MW)	0.18	0.17	0.17	0.16	0.17	0.16	0.16	0.23	0.24	0.23	0.23	0.21	0.23	0.25	0.23	0.22	0.22	0.22	0.21	0.21	0.24	0.23	0.18	0.17
Max. Voltage (pu)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07
Max. Load (%)	87%	85%	85%	83%	84%	85%	83%	86%	84%	84%	84%	86%	85%	88%	85%	88%	84%	84%	89%	86%	91%	88%	85%	84%
Overloads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Discrete Opt.	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Tap position	2	1	1	1	2	2	3	1	2	1	2	1	2	1	2	2	1	1	2	2	1	1	2	2
Losses (MW)	0.18	0.17	0.17	0.16	0.17	0.16	0.16	0.23	0.24	0.23	0.24	0.21	0.23	0.25	0.23	0.23	0.22	0.22	0.21	0.21	0.24	0.23	0.18	0.17
Loss reduction (%	2.4%	2.4%	2.4%	2.4%	0.1%	2.4%	2.3%	2.4%	0.1%	2.4%	0.1%	2.5%	0.1%	0.1%	2.4%	2.4%	4.7%	2.4%	2.4%	0.1%	2.4%	2.4%	2.4%	2.4%
Max. Voltage (pu)	1.062	1.064	1.065	1.069	1.064	1.066	1.065	1.068	1.064	1.061	1.060	1.07	1.059	1.060	1.067	1.061	1.066	1.066	1.060	1.059	1.060	1.067	1.067	1.061
Max. Load (%)	87%	86%	86%	83%	85%	86%	84%	86%	84%	84%	85%	86%	86%	89%	85%	89%	84%	84%	90%	87%	92%	88%	85%	85%
Overloads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

24h Loss reduction
1.89%

Table 5.3: OLTC optimal solution output for the 24 hours studied

To ensure a feasible and optimal solution, the discrete optimal tap is obtained by rounding the optimal continuous tap to the nearest upper discrete step, making sure the solution is feasible, with voltages below or equal to the 7% voltage limit and optimal, because it is as close as possible to the optimal continuous tap ratio. For the 24 hours analyzed, a total **losses reduction of 1.89%** over the base case has been obtained by using the **discrete optimal taps**.

Figure 5.3: Active power losses reduction

Power losses reduction in MW for every hour of using the optimal discrete tap are shown in Figure 5.3. The most significant reduction appears at 16:00h where the tap is reduced in two positions with respect the initial case (Table 5.3).

Figure 5.4 show the network voltage profile for the initial case and the discrete and continuous optimizations for the peak hour case (20:00h). For this hour, the initial tap position is 2 and the optimal continuous tap recommended by the OPF is 0.2. Which is rounded afterwards to the next upper discrete value 1, obtaining the optimal discrete tap.

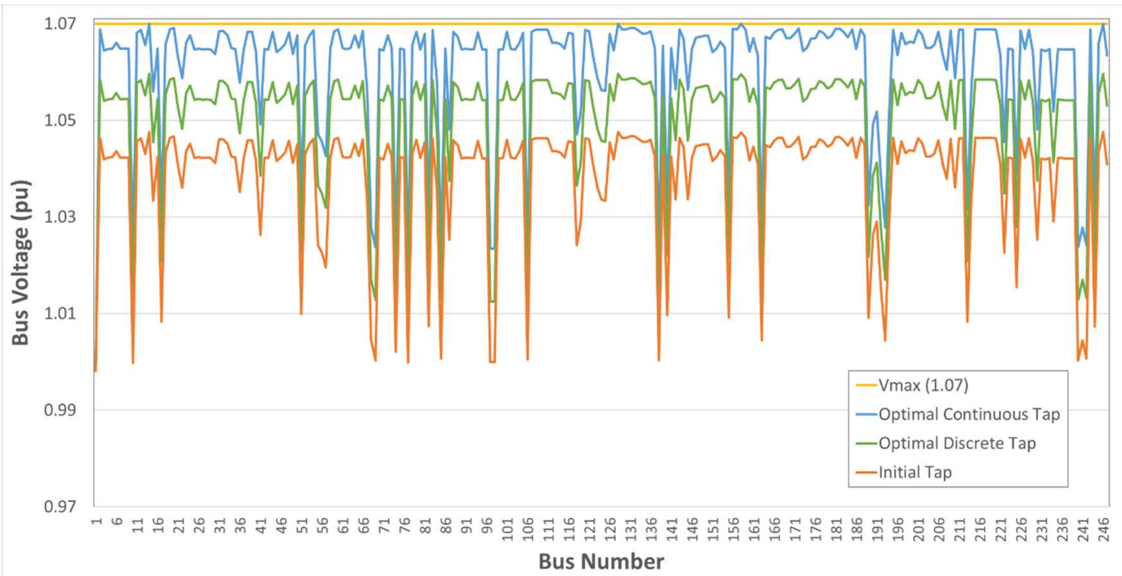


Figure 5.4: Peak hour (20:00h) voltage profile depending on tap position

As shown in Figure 5.4, the optimal continuous transformer tap solution of 0.2, is constrained by several bus voltage's upper 7% limit. When discretizing to tap 1, network voltages are reduced, leading to a lower voltage profile.

From the results obtained, the network voltage profile seems to decrease proportionally with the OLTC tap position. A higher difference between the continuous and the discrete tap value implies a higher margin between the network voltages and the upper 7% limit.

On the other hand, a continuous tap value too close to its next discrete step, leads to a more optimal discrete tap in terms of losses, but with a high voltage profile. This occurs at 11 AM, as shown in Figure 5.5.

At 11 AM, the continuous tap position obtained is 0.99, very close to the discrete optimal tap of 1. Therefore, voltage network profiles obtained for both cases are equal (Figure 5.5) and constrained by the 7% upper limit. Obtaining a high voltage profile for the optimal discrete tap.

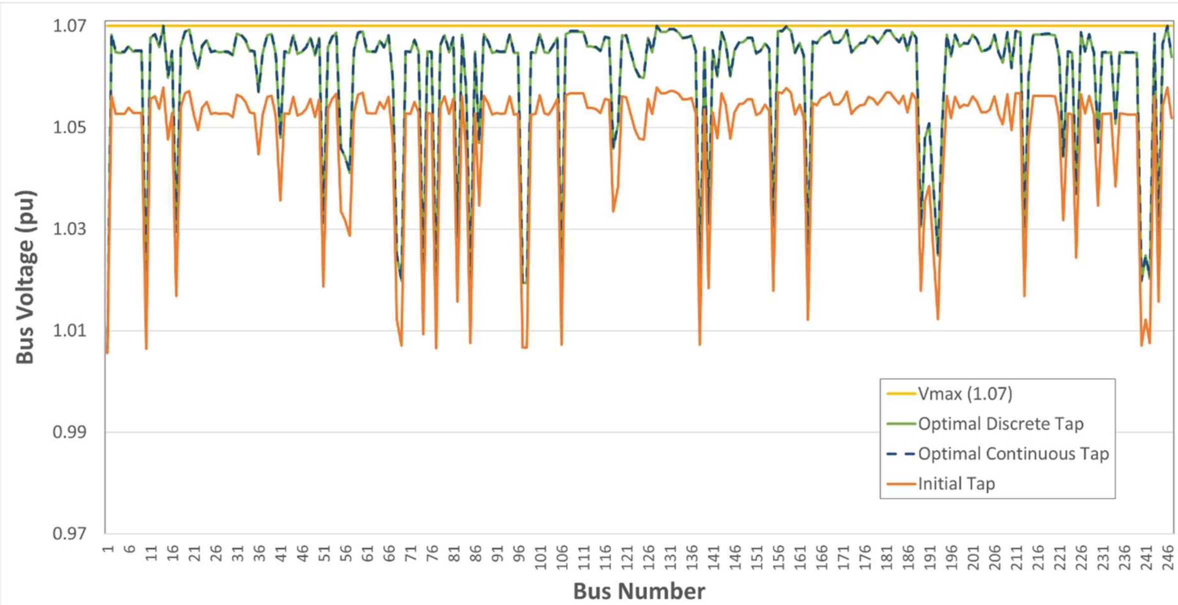


Figure 5.5: 11:00h voltage profile depending on tap position

When it is not desired to operate the grid too close to the upper voltage limit, a good solution could be implementing a security margin in the tap discretization process. If some margin is considered between the continuous tap value and the discrete one, the optimal discrete tap would be 2 instead of 1 for this case, reducing the voltage profile in the network.

Figure 5.6 to Figure 5.8 show a bus voltage color map for the peak hour at 8 PM and the different tap positions. As commented before, it can be seen how the voltage profile in the network increases when the tap position is optimized, being the optimal continuous tap bounded by the upper 7% voltage constraint.

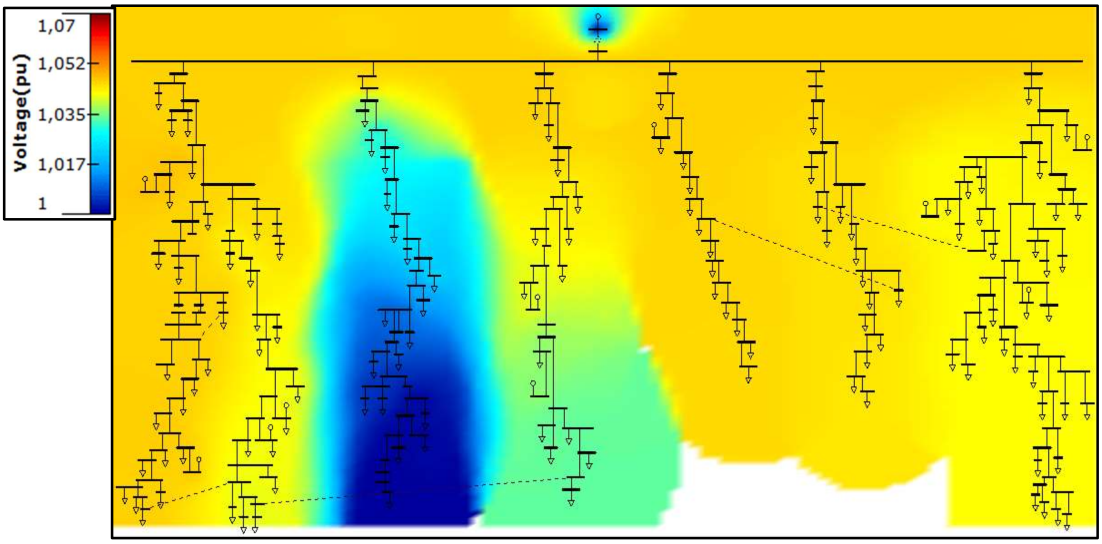


Figure 5.6: Voltage color map for initial tap at peak hour (20:00h)

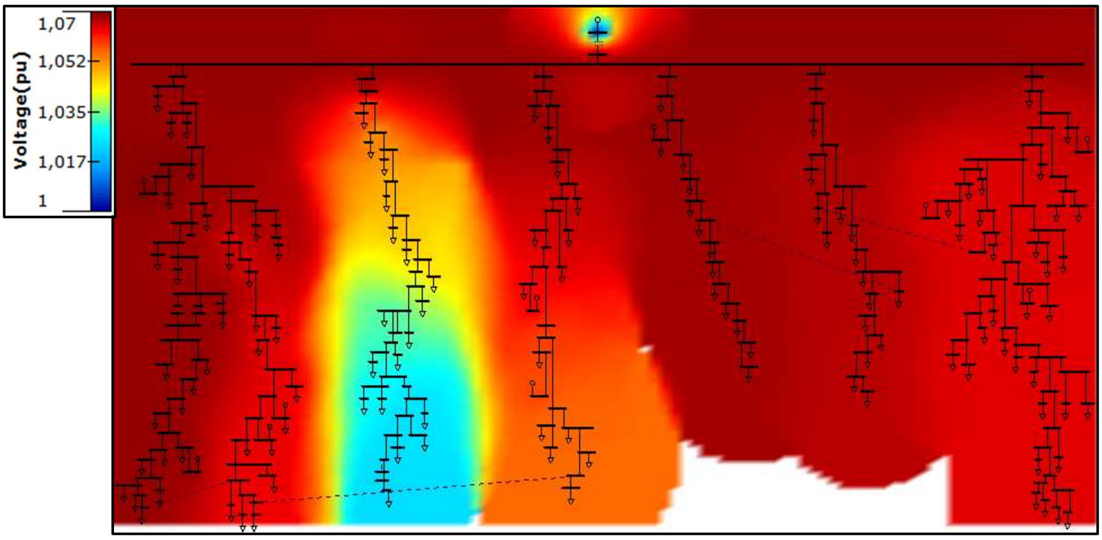


Figure 5.7: Voltage color map for optimal continuous tap at peak hour (20:00h)

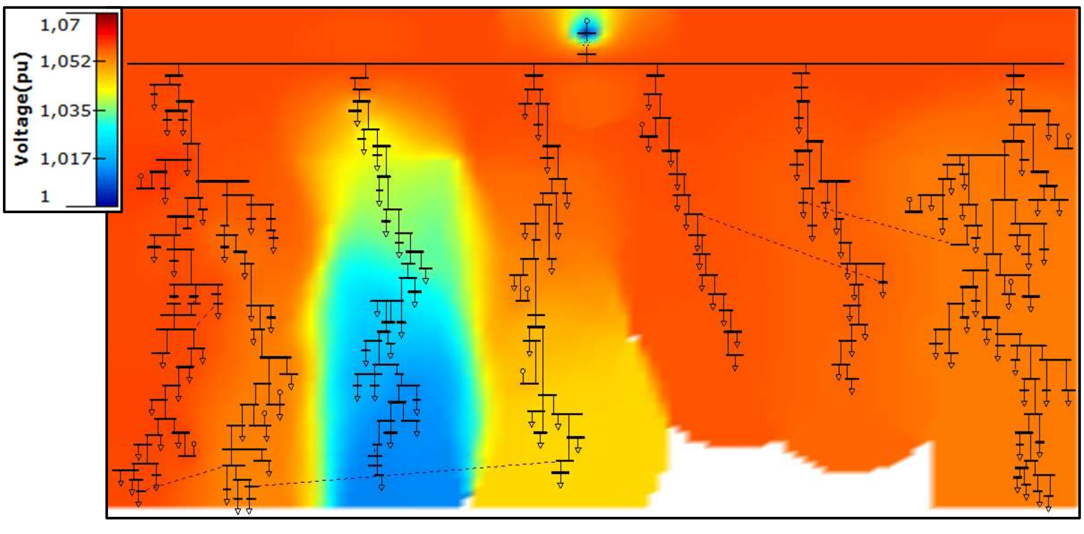


Figure 5.8: Voltage color map for optimal discrete tap at peak hour (20:00h)

It can be seen from the figures above, how Zone 132 presents a lower voltage profile than the rest of the network (blue zone). This voltage difference can be noticed in Figure 5.9 where the power losses are aggregated per zone, showing the greatest losses at Zone 132.

This voltage difference cannot be fixed by using the OLTC or the shunt device at the substation busbars, as these devices increase all network's bus voltages at the same time. A distributed resource could be placed at Zone 132 to regulate its voltage.

The voltage sink is caused by the lack of Distributed Generation in Zone 132. Demand flexibility or connection of distributed generation at this zone could be a good solution for regulating the zone's voltage independently, and therefore reducing its losses.

AREA 74 [ALCORA T2] TOTALS BY ZONE

	X---GENERATION--X		X-TO LOAD + GNE-X		X--TO BUS SHUNT-X		X--TO IND MACS--X		X-TO LINE SHUNT-X		CHARGING	X---TO LOSSES---X	
ZONE X-- NAME --X	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MVAR	MW	MVAR
61 SIN LINEA	13.9	5.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
129 S73L	10.6	0.0	9.0	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0
130 S72L	3.0	0.0	8.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
131 S71L	0.0	0.0	1.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
132 S67L	0.0	0.0	3.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
133 S66L	0.0	0.0	1.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
134 S65L	7.0	0.0	10.8	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
AREA 74 TOTALS:	34.6	5.3	34.3	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.2	0.9

Figure 5.9: Aggregated losses per zone for the peak hour 20:00h

5.3 Case 2: Shunt connection optimization

5.3.1 Fixed shunt base case

As stated before, the 20kV real network studied does not have a fixed shunt connected to the primary substation busbar. Therefore, to perform this simulation, first, a coherent base case for the initial connection of the shunt element must be obtained.

As explained in 2.2, most of the shunt devices owned by i-DE nowadays are capacitor banks of different ratings.

The fixed shunt shows the same effect as the tap changer control on the bus voltages, but instead of regulating the voltage directly, it injects reactive power in the substation busbar, rising the voltage profile and minimizing losses. The connection of this devices may be done manually or following a pre-scheduled pattern according to the expected peak load hours (when grid voltages are lower).

For the shunt connection base case, the peak load hours for the pre-scheduled shunt connection has been considered from 7:00h to 13:00h and 18:00h to 21:00h, similarly as it would be done in real life.

A coherent MVA size for the shunt device must be found. A very large capacitor would bring bus voltages out of limits when connected and a very small capacitor may not be representative.

The Adjustable Shunt Model (3.4.2.2) at the substation busbar, has been run for every hour in the initial base case, leaving the OLTC regulation as in the base case (Figure 5.1). The adjustable shunt can be inductive or capacitive, however as it has been parametrized to minimize losses, the direct effect is to increase the voltages in the network to decrease power losses. For this reason, at every hour, the optimal shunt is capacitive.

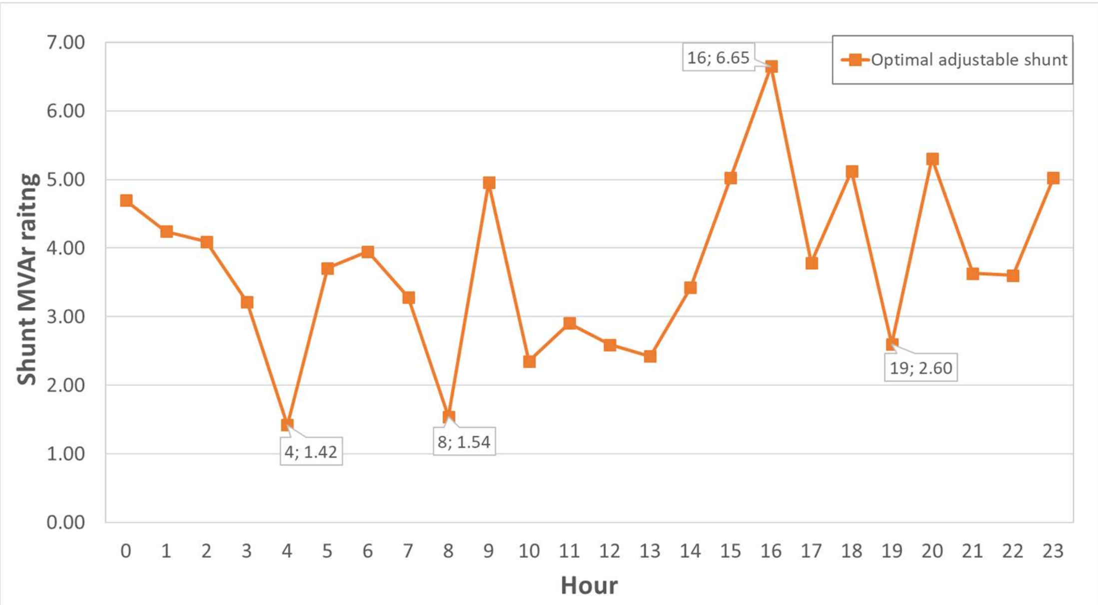


Figure 5.10: Optimal adjustable shunt size from the base case

With the *minimize power losses* and *minimize adjustable shunt* objectives, the OPF provides the maximum (optimal) capacitor bank size, that minimizes losses in the feasible region (within bus voltage limits), meaning that it is bounded by the upper voltage limit of 7%. In other words, Figure 5.10 provides the maximum MVA rating for a capacitor bank connected to the substation busbar at every hour of the base case (5.1).The optimal substation MVA shunt element obtained for the 24 hours analyzed (Figure 5.10) leads to a **total losses reduction of 3.68%.**

There are 2 issues observed in this base case. Firstly, the initial tap regulation makes it difficult to evaluate the real improvements of optimizing the shunt connection schedule. And secondly, as the OLTC regulation is programmed to maintain the secondary voltage within a reference value, without considering the connection of a capacitor bank, it shows very low admissible values for the capacitor ratings within the defined schedule peak hours. Typical real values for i-DE capacitor banks are between 4 and 10 MVAr.

To solve these matters, new 24h base cases, fixing the transformer tap position in 3 have been created (Figure 5.11). Then the optimally adjustable shunt has been run for these base cases, to find a more realistic scenario.

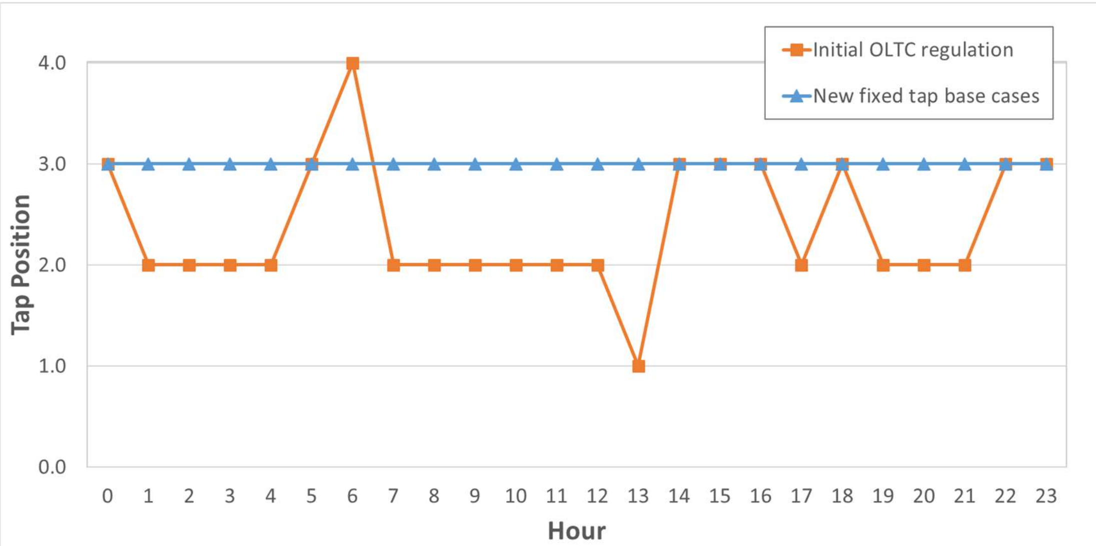


Figure 5.11: New base cases created for shunt connection optimization

Figure 5.12 shows the optimal shunt size for the new base cases with OLTC fixed at position 3. A fixed shunt of 4 MVA is used to evaluate the initial scenario schedule connection from 7:00 to 13:00 and 18:00 to 21:00, comparing it with the optimal one obtained with the OPF.

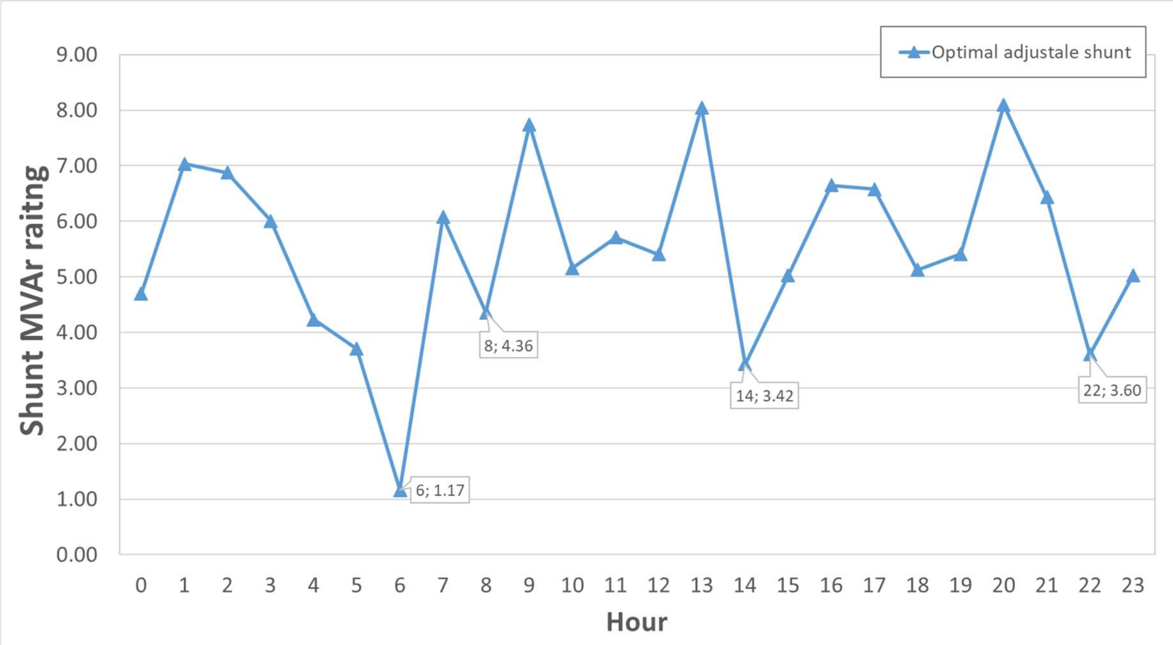


Figure 5.12: Optimal adjustable shunt with fixed tap at position 3

5.3.2 Fixed schedule shunt connection

The 4 MVA capacitor bank is connected initially from 7:00 to 13:00 and from 18:00 to 21:00, representing the base case scenario for evaluating losses, voltages and power flows.

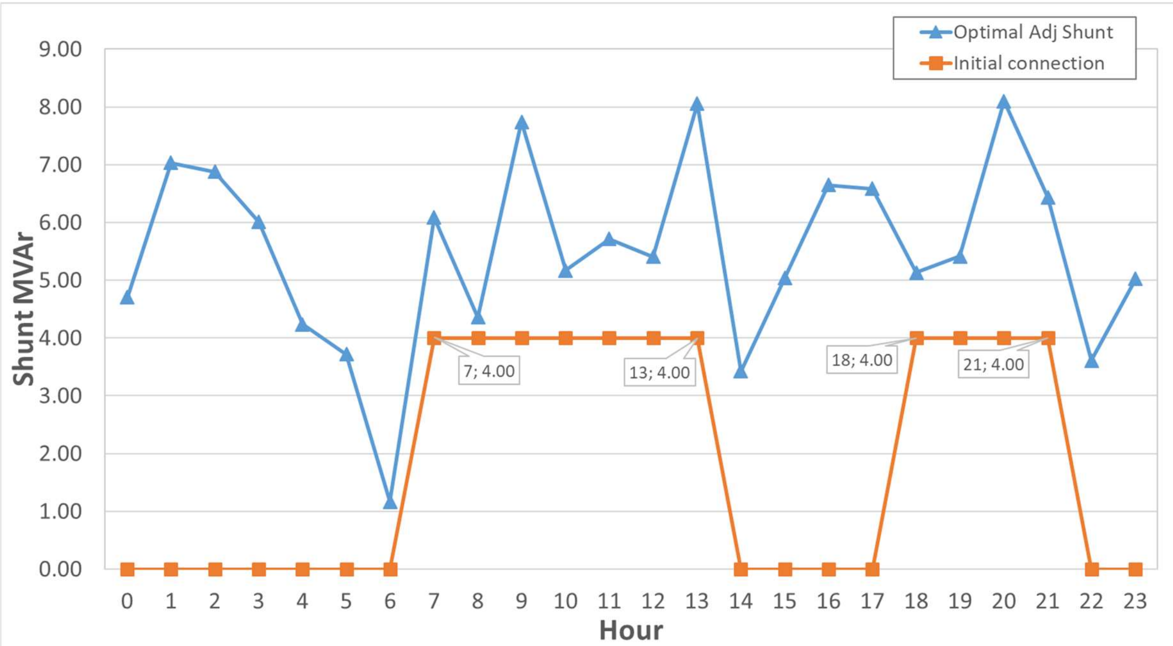


Figure 5.13: Pre-scheduled shunt connection

Table 5.3 shows the results of using the shunt device connection as a control variable for power losses optimization, including for every hour for the initial and optimal shunt connection cases: shunt connection, power losses, maximum network voltage and maximum branch loading factor, reporting as well the number of overloads at the network.

5.3.3 Optimal fixed shunt connection

Figure 5.14 shows the resulting optimal connection schedule for the 4 MVA shunt device. As described in section 3.4.2.4, the adjustable shunt optimization has been used in combination with a fixed shunt model representing the 4 MVA device.

For the simulation performed, the OPF adjustable shunt value provides two main hints:

- The maximum capacitor that can be placed in the bus selected without exceeding the voltage hard limits (optimal feasible solution).
- The maximum losses reduction is available when placing the optimal shunt value in the bus selected, without exceeding voltages (represents a top limit for losses reduction).

Therefore, the adjustable shunt value at every hour is used to make the connection decision for the 4 MVA shunt device, obtaining the optimal connection scheduling. The OPF provides the optimal adjustable shunt value for every hour and an external logic is added to decide the connection of the fixed shunt:

- When the adjustable shunt value is greater or equal to 4 MVA, the fixed shunt device is set *in service*. Otherwise, it is not connected.
- After the connection decision has been taken, a new power flow case is solved, connecting or not the fixed shunt according to this decision, obtaining the optimal connection scenario for every hour.

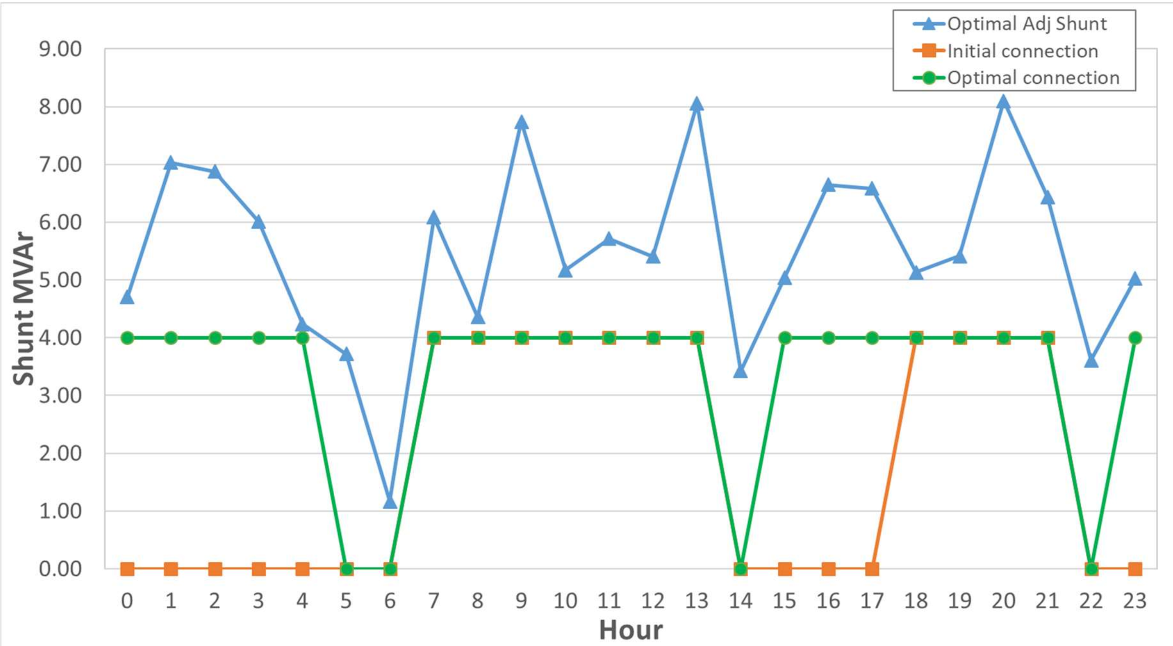


Figure 5.14: Optimal shunt connection

As it can be observed, the resultant connection pattern includes hours from 23:00 to 4:00 and from 15:00 to 17:00, which initially were not considered as peak hours. Connecting the 4 MVAr shunt device during those hours leads to lower power losses (Figure 5.15).

Initial connection	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Shunt connected (MVAr)	0	0	0	0	0	0	0	4	4	4	4	4	4	4	0	0	0	0	4	4	4	4	0	0
Losses (MW)	0.18	0.18	0.18	0.17	0.18	0.17	0.16	0.23	0.23	0.24	0.23	0.22	0.23	0.26	0.24	0.23	0.23	0.23	0.21	0.21	0.25	0.23	0.19	0.17
Max. Voltage (pu)	1.050	1.040	1.041	1.045	1.052	1.055	1.065	1.061	1.069	1.054	1.065	1.063	1.064	1.053	1.056	1.049	1.042	1.042	1.065	1.064	1.052	1.060	1.055	1.049
Max. Load (%)	88%	88%	88%	85%	86%	87%	84%	86%	84%	85%	85%	86%	85%	89%	86%	90%	86%	86%	90%	87%	93%	89%	86%	86%
Overloads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Optimal connection	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Shunt connected (MVAr)	4	4	4	4	4	0	0	4	4	4	4	4	4	4	0	4	4	4	4	4	4	4	0	4
Losses (MW)	0.18	0.17	0.17	0.17	0.17	0.17	0.16	0.23	0.23	0.24	0.23	0.21	0.23	0.26	0.24	0.22	0.22	0.22	0.21	0.21	0.25	0.23	0.19	0.17
Loss reduction (%)	4%	4%	4%	4%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%	4%	4%	0%	0%	0%	0%	0%	4%
Max. Voltage (pu)	1.067	1.057	1.058	1.061	1.069	1.055	1.065	1.061	1.068	1.054	1.065	1.063	1.064	1.053	1.056	1.066	1.059	1.059	1.065	1.064	1.052	1.060	1.055	1.066
Max. Load (%)	87%	86%	86%	84%	84%	87%	84%	86%	84%	85%	85%	86%	85%	89%	86%	88%	85%	85%	89%	87%	93%	89%	86%	85%
Overloads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

24h Loss reduction
1.41%

Table 5.4: Shunt connection optimal solution output for the 24 hours studied

For the 24 hours analyzed, a total **losses reduction of 1.41%** is achieved by **optimizing the shunt connection schedule** considering the real state of the system rather than using a peak-hour pre-defined schedule.

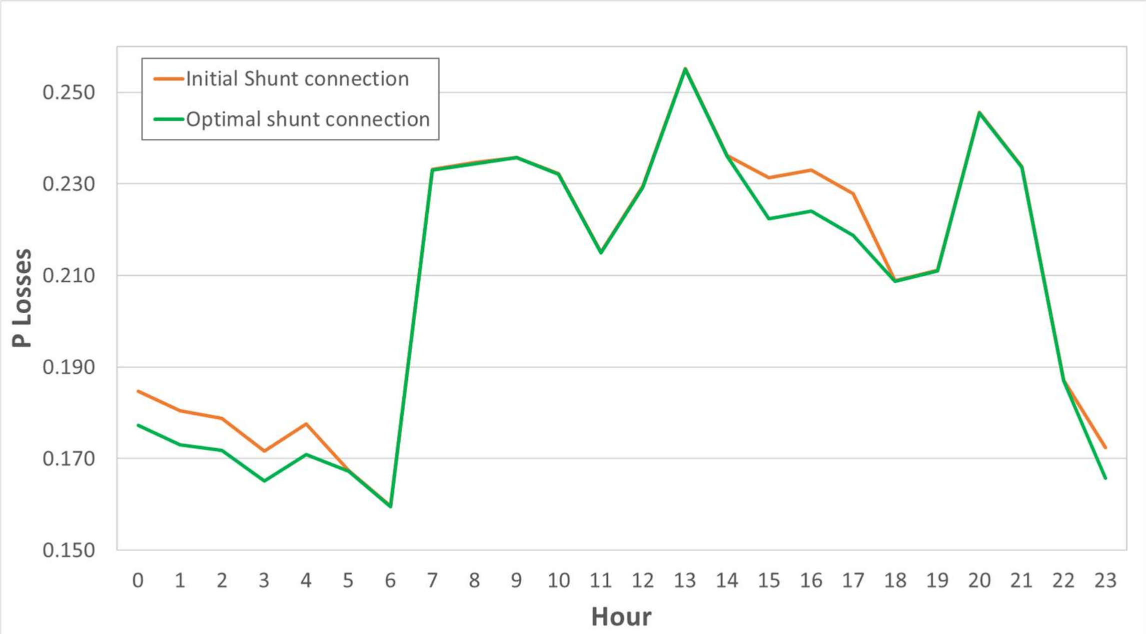


Figure 5.15: Power losses reduction with OPF optimal connection

In Table 5.4 optimal connection chart, shunt connection values are green coloured for the hours where the shunt device was not initially connected. For these hours, the OPF connects the 4MVAr shunt, obtaining a reduction of 4% in power losses with respect the base case. This is achieved by injecting reactive power in the substation busbar, leading to an increase in the maximum network bus voltage (shown in red) and a reduction of the maximum branch power flow (shown in green). Figure 5.16 shows how the connection of the shunt element affects the network bus voltage profile (very similar to the OLTC case)

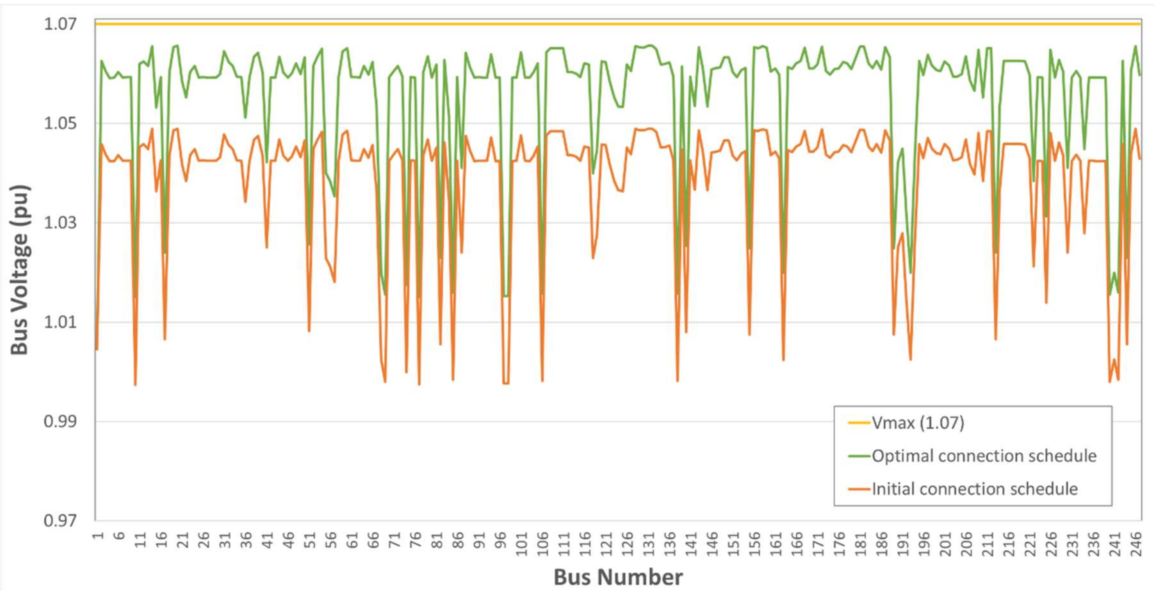


Figure 5.16: 15:00h voltage profile with initial and optimal connection schedules

5.4 Case 3: Generator's reactive power optimization

For this scenario, the initial 24h base case described in 5.1 voltage profile is optimized to minimize losses, controlling the reactive power service regulation provided by generators G1 to G6.

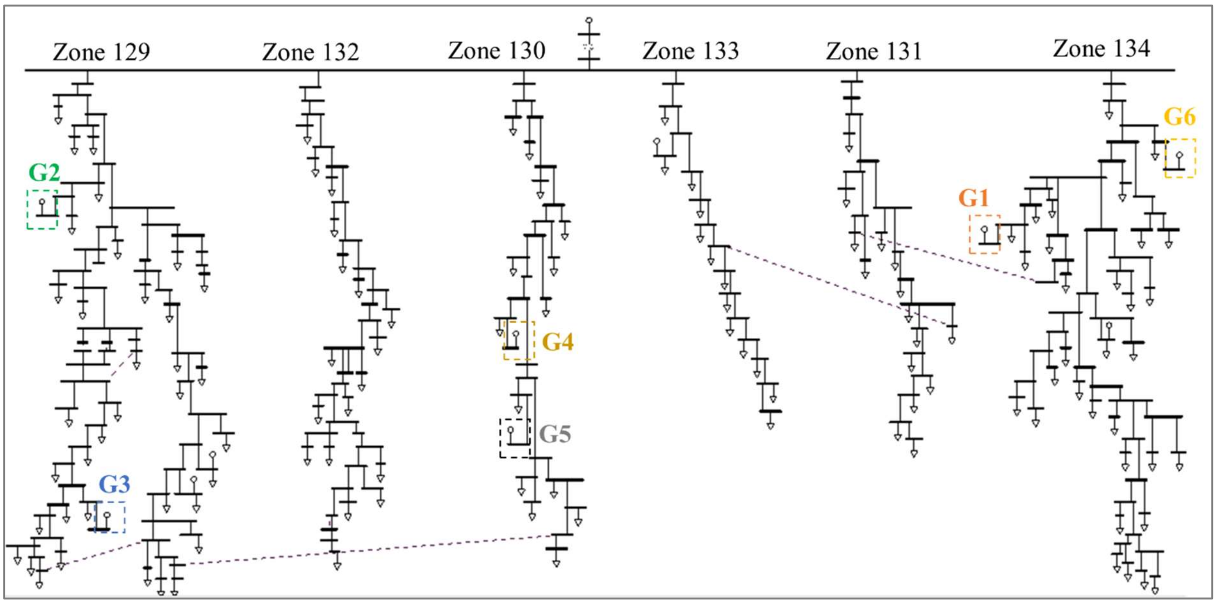


Figure 5.17: DG's providing reactive power regulation

Now the OLTC does not represent a control resource, tap position is managed by the automatic regulation as it is done in the real network for the day selected (Figure 5.1).

Initial sensitivities, losses, voltages, and branch flows are evaluated for the base case and compared with the optimal OPF solution using Volt/VAr control.

Generator	Technology	S_{Base} (MVA)	$cos(\varphi_{Nom})$	P_{Max} (MW)
G1	CHP	1.4	0.8	1.14
G2	Wind	22.4	0.8	17.91
G3	CHP	22.4	0.8	17.91
G4	CHP	4.8	0.8	3.8
G5	CHP	5.3	0.8	4.28
G6	CHP	22.2	0.8	17.76

Table 5.5: G1 to G6 distributed generators characteristics

In the base case solution, every generator is treated as a PQ node with a unity power factor (reactive power limits are settled to zero as explained in 3.4.3). G1 to G6 are only generating the active power represented in Figure 5.18. This active power does not represent a control during the OPF solution, only reactive power output is managed.

As shown in Figure 5.18, wind plant G2 has a greater active power variability due to its renewable nature.

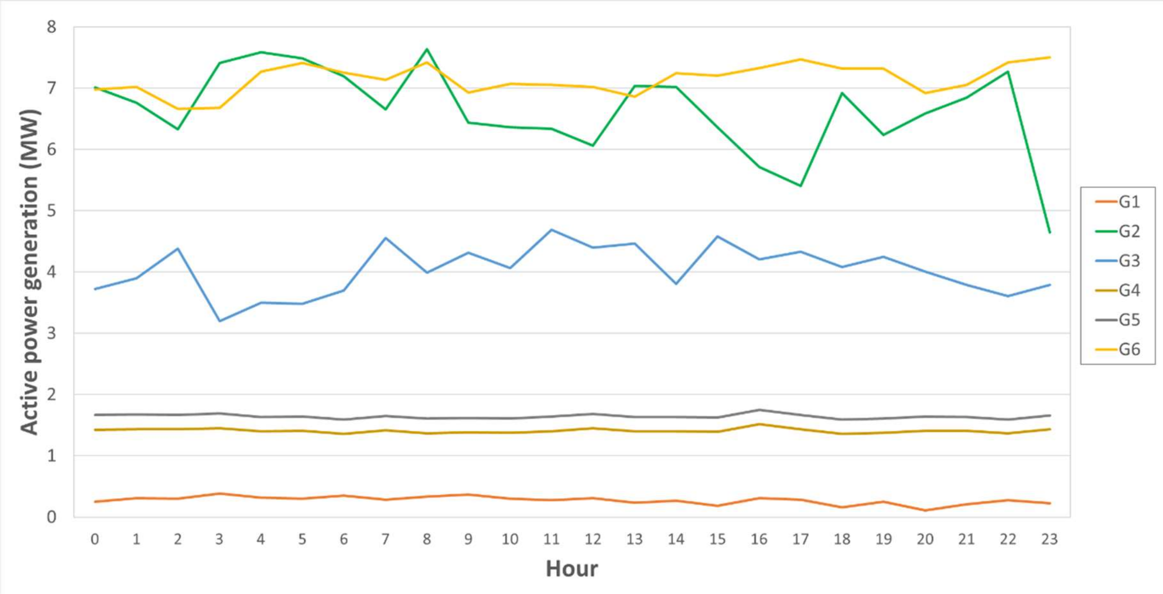


Figure 5.18: DG's active power generation for the 24 hours selected

As commented in section 3.4.3, distributed generators are treated initially as PQ nodes with a fixed power factor (in this case with a reactive power restriction of zero). Figure 5.19 shows every generator's initial reactive power sensitivity with respect to the losses minimization objective in €/pu, for the base case using a 100 €/MWh losses cost.

These sensitivities are negative for every hour, representing the expected reduction in € in the objective function, when an extra pu unit in the reactive power limitation is relaxed. As explained in 3.4.3.1, initial sensitivities are calculated for the Q_g variable.

It can be noticed from Figure 5.19 and location of DGs in Figure 5.17, how at every zone, DGs located more downstream show a higher sensitivity in absolute value at every hour. In zone 129, G3 has a greater sensitivity than G2, in zone 130, G5 has more sensitivity than G4 and the same happens in zone 134 with G1 and G6. Meaning that these are the most effective generators in each of the ones for losses reduction as they inject reactive power in more optimal locations. G2 and G3 in Zone 129 are the most effective generators to reduce losses at every hour.

Final sensitivities are calculated from the Q_g variable for G2 and from the e_{fd} and I_s variables for G1, G3, G4, G5, G6 modelled with the *reactive capability model.* Final reactive output sensitivities obtained at the optimal solution for every hour and generator are zero, meaning that an optimal solution has been found where generator's reactive power is not bounded by their PQ curve constraints.

At the optimal solution obtained, the problem is bounded at every hour by the 7% bus voltage upper limit rather than from generator's reactive output constraint.

In other words, every generator is able to provide at every hour, the optimal reactive power amount that leads to minimal losses within the 7% voltage limit. Therefore, sensitivity to keep reducing power losses is not on the generators but on the 7% upper voltage limit. An increase in this voltage constraint would allow higher reactive injection and a higher losses reduction.

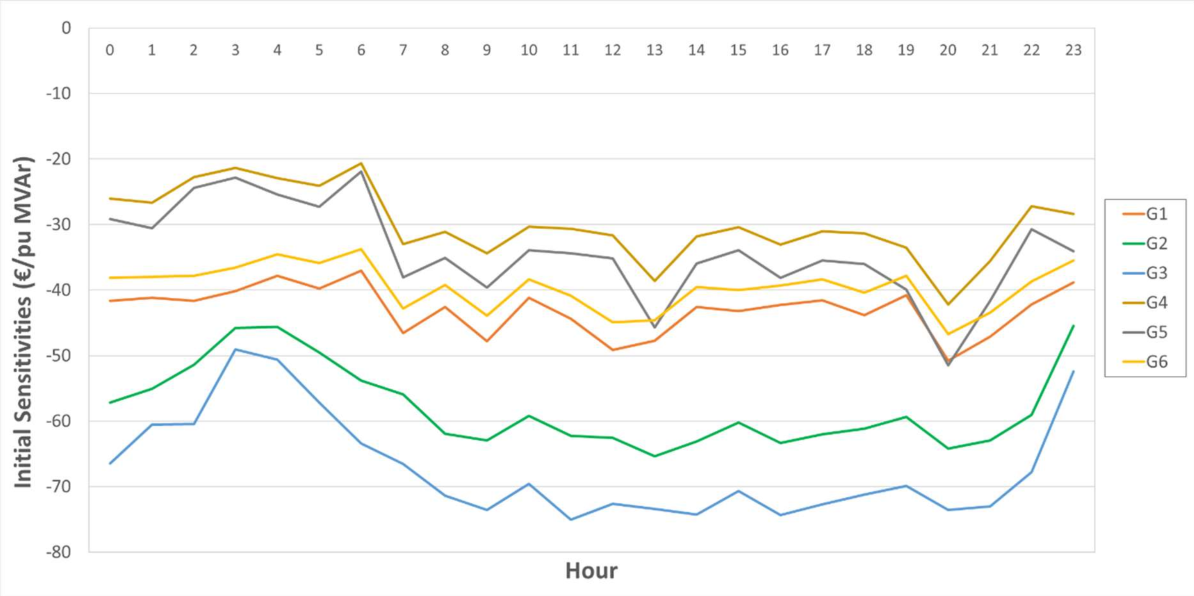


Figure 5.19: Initial DG reactive power sensitivity for a 100 €/MWh losses cost

Branch flows are effectively reduced at every hour by using the reactive injection of distributed generators. It has been checked that no overflows occur. A **total power losses reduction of 4.59%** has been obtained for the 24h studied by using the optimal reactive power service from distributed generators.

As stated before, this simulation using the DG reactive flexibility leads to an optimal solution within the allowed feasible region (only bounded by voltage 7% limits) representing a top limit in losses reduction for the day and network under study.

Figure 5.20: Power losses reduction with Volt/VAr regulation

The global effect of using the reactive power from distributed generators is similar to connecting a shunt element that injects or absorbs the optimal amount of reactive power. As it can be seen in Figure 5.21, the total optimal amount of reactive power provided by the DG has a similar shape to the optimal adjustable shunt chart for the initial base case scenario shown in Figure 5.10.

Comparing both charts, DG's prove to be more efficient than the substation adjustable shunt in reducing losses. Using DG's reactive flexibility, resulting in a fewer amount of reactive power required and lower power losses at the optimal point than using the substation optimal shunt size element.

As the DG's inject reactive power in a distributed way downstream, it results to be a more optimal location for reducing power losses than injecting reactive power upstream in the substation (higher sensitivity is achieved downstream).

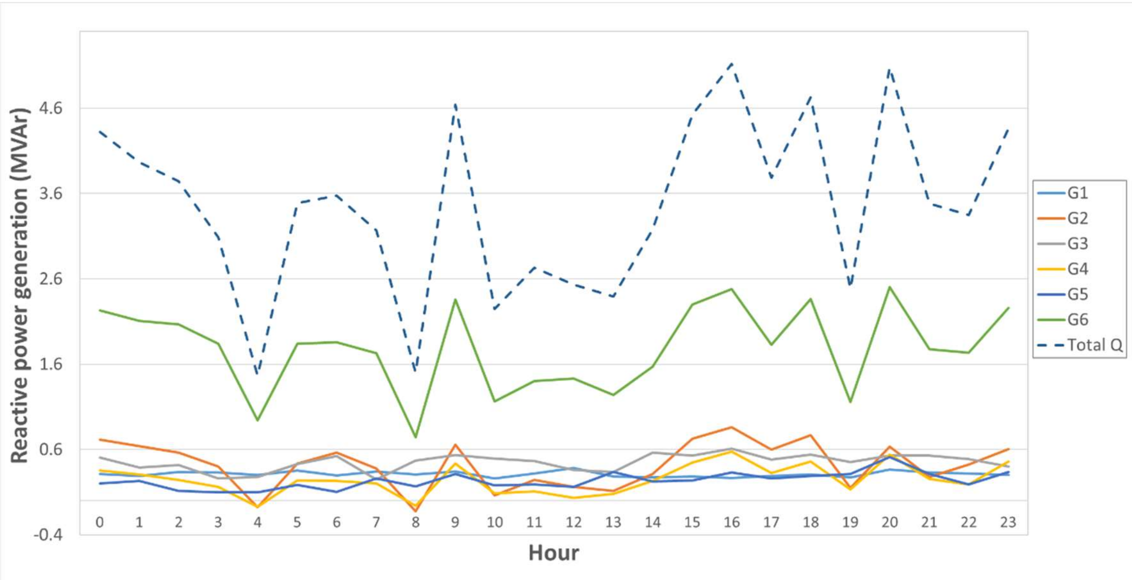


Figure 5.21: Final DG reactive power output

Base Case	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Tap position	3	2	2	2	2	3	4	2	2	2	2	2	2	1	3	3	3	2	3	2	2	2	3	3
Losses (MW)	0.18	0.18	0.17	0.17	0.17	0.17	0.16	0.24	0.24	0.24	0.24	0.22	0.23	0.25	0.24	0.23	0.23	0.22	0.22	0.21	0.25	0.24	0.19	0.17
Max. Voltage (pu)	1.050	1.052	1.053	1.057	1.064	1.055	1.054	1.056	1.064	1.049	1.060	1.058	1.059	1.060	1.056	1.049	1.042	1.054	1.048	1.059	1.048	1.055	1.055	1.049
Max. Load (%)	88%	87%	87%	84%	85%	87%	85%	87%	84%	85%	85%	87%	86%	89%	86%	90%	86%	85%	91%	87%	93%	89%	86%	86%
Overloads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G1 Sensitivity (€/pu MVAr)	-42	-41	-42	-40	-38	-40	-37	-47	-43	-48	-41	-44	-49	-48	-43	-43	-42	-42	-44	-41	-51	-47	-42	-39
G2 Sensitivity (€/pu MVAr)	-57	-55	-51	-46	-46	-49	-54	-56	-62	-63	-59	-62	-63	-65	-63	-60	-63	-62	-61	-59	-64	-63	-59	-45
G3 Sensitivity (€/pu MVAr)	-66	-61	-60	-49	-51	-57	-63	-67	-71	-74	-70	-75	-73	-73	-74	-71	-74	-73	-71	-70	-74	-73	-68	-52
G4 Sensitivity (€/pu MVAr)	-26	-27	-23	-21	-23	-24	-21	-33	-31	-34	-30	-31	-32	-39	-32	-30	-33	-31	-31	-33	-42	-36	-27	-28
G5 Sensitivity (€/pu MVAr)	-29	-31	-24	-23	-25	-27	-22	-38	-35	-40	-34	-34	-35	-46	-36	-34	-38	-35	-36	-40	-51	-42	-31	-34
G6 Sensitivity (€/pu MVAr)	-38	-38	-38	-37	-35	-36	-34	-43	-39	-44	-38	-41	-45	-45	-40	-40	-39	-38	-40	-38	-47	-43	-39	-35

Volt/Var optimal point	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Losses (MW)	0.17	0.17	0.17	0.16	0.17	0.16	0.15	0.23	0.23	0.23	0.23	0.21	0.22	0.24	0.23	0.22	0.22	0.21	0.21	0.21	0.24	0.23	0.18	0.16
Loss reduction (%)	6%	5%	5%	4%	3%	5%	5%	4%	3%	5%	3%	4%	4%	4%	4%	5%	5%	5%	5%	4%	6%	5%	5%	5%
Max. Voltage (pu)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07
Max. Load (%)	86%	85%	85%	82%	84%	85%	83%	85%	83%	83%	84%	85%	84%	87%	85%	88%	84%	84%	89%	86%	90%	87%	84%	84%
Overloads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
QG1 (MVAr)	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3
QG2 (MVAr)	0.7	0.6	0.6	0.4	-0.1	0.4	0.6	0.4	-0.1	0.7	0.1	0.2	0.2	0.1	0.3	0.7	0.9	0.6	0.8	0.2	0.6	0.3	0.4	0.6
QG3 (MVAr)	0.5	0.4	0.4	0.3	0.3	0.4	0.5	0.3	0.5	0.5	0.5	0.5	0.4	0.3	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.4
QG4 (MVAr)	0.4	0.3	0.2	0.2	-0.1	0.2	0.2	0.2	-0.1	0.4	0.1	0.1	0.0	0.1	0.2	0.4	0.6	0.3	0.5	0.1	0.5	0.3	0.2	0.5
QG5 (MVAr)	0.2	0.2	0.1	0.1	0.1	0.2	0.1	0.3	0.2	0.3	0.2	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.5	0.3	0.2	0.3
QG6 (MVAr)	2.2	2.1	2.1	1.8	0.9	1.8	1.9	1.7	0.7	2.4	1.2	1.4	1.4	1.2	1.6	2.3	2.5	1.8	2.4	1.2	2.5	1.8	1.7	2.3
Total QG (MVAr)	4.3	4.0	3.7	3.1	1.5	3.5	3.6	3.2	1.5	4.6	2.2	2.7	2.5	2.4	3.2	4.5	5.1	3.8	4.7	2.5	5.1	3.5	3.3	4.4

24h Loss reduction
4.59%

Table 5.6: Volt/Var regulation optimal solution for the 24 hours studied

5.5 Case 4: Emergency state operation

The valley scenario at 5:00h has been selected as the base case to create an emergency state operation.

An overload in Zone 134 has been created by opening one of the lines in Zone 131 (red box in Figure 5.22) and re-connecting its downstream consumers to Zone 134 by closing the line inside the green box.

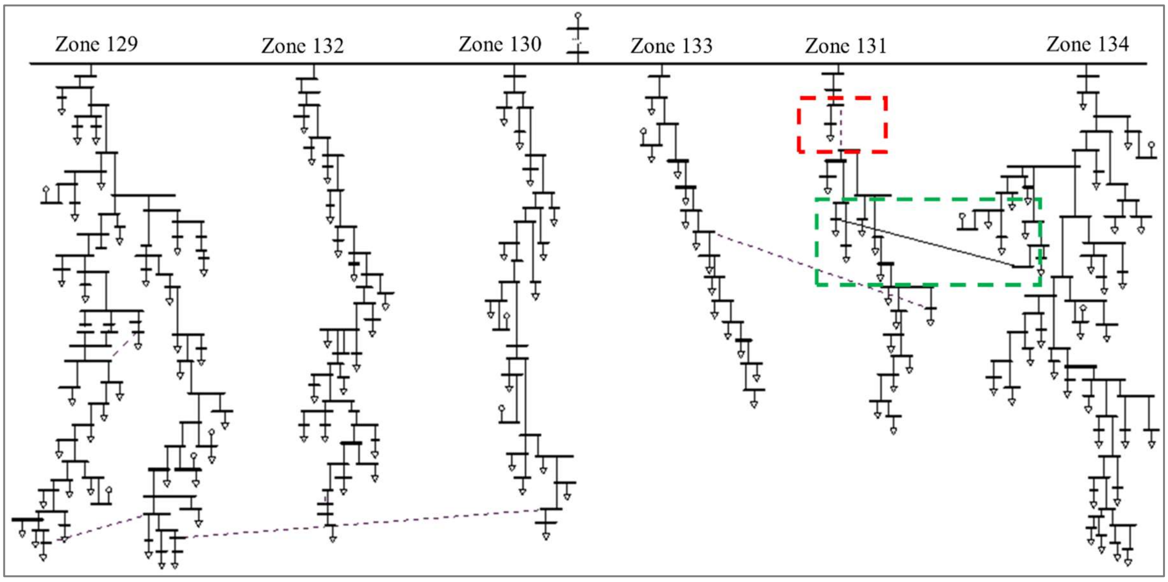


Figure 5.22: Emergency state operation scenario

After running the conventional power flow solution with the scenario shown in Figure 5.22, an **overload in Zone 134 of 105%** appears. A trip in the overloaded line could cause a service interruption to every consumer in Zones 134 and 131. This represents an emergency state operation, where the system is out of limits and corrective actions must be taken to bring it back into limits.

Figure 5.23 shows the branch loadings in % of their rating. Most of the branches have a loading lower than 75%, the overloaded line in Zone 134 can be noticed in red color, showing a loading higher than 100%.

To solve the contingency, the overloaded line limit type has been changed from *Reporting* to *Hard limit*. Enforcing the final solution to be within limits.

Firstly, active power flexibility is used for solving the contingency. Only generator G1 will be participating, as it is the only one downstream of the overloaded line big enough to have an impact on the solution.

For the active power dispatch of G1, both fuel curve costs for the slack bus and G1 must be defined. The slack bus assumes the power variation of G1.

As shown in Figure 5.18, the G1 power generation of G1 at 5:00h is 0.3 MW, below its nominal power, 1.137 MW (Table 5.5). G1 output power remains almost constant for the 24h studied.

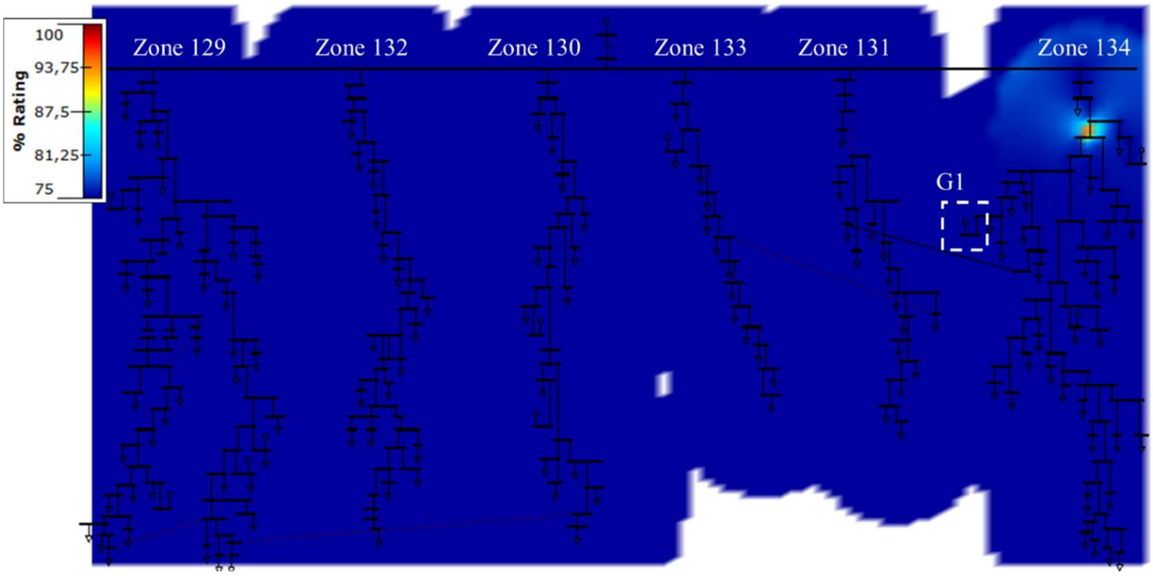


Figure 5.23: Branch flows loadings after reconnecting Zone 131 consumers to Zone 134

A marginal network cost of 40 €/MWh has been considered. Keeping this marginal cost constant for any power variations, considering that the system could assume the total 1.14 MW nominal power variation of G1 at a constant marginal cost of 40 €/MWh.

G1 real cost curve depends on its industrial cogeneration process. For simplicity, it is assumed that the marginal cost for generating from 0 to 0.3 MW is equal to the system's marginal cost of 40 €/MWh and increasing from 0.3 MW to 1.14 MW would imply a constant marginal cost of 60 €/MWh as represented in Figure 5.24.

This way, fuel cost curves are coherent with the initial scenario dispatch, where system marginal cost is 40 €/MWh and G1 is generating 0.3 MW and increasing G1 output above 0.3 MW would incur an extra cost of 20 €/MWh for importing this extra power from the network at a marginal cost of 40 €/MWh.

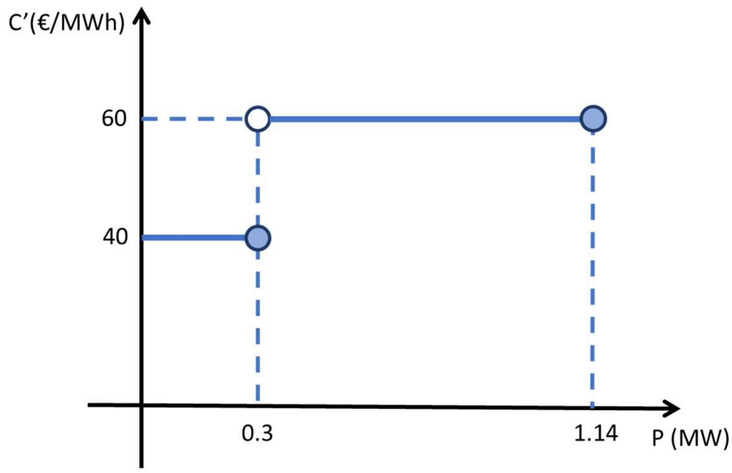


Figure 5.24: G1 marginal cost curve considered

Table 5.7 shows the OPF optimal solution to the emergency state scenario by using G1 active power dispatch. In order to solve the overload, the OPF increases G1 power generation by 0.68 MW at an extra marginal cost of 20 €/MWh, obtaining a total extra cost of 13.6 €/h concerning the initial dispatch.

Valley 5:00h	Initial overloaded case	OPF solution
P_{Slack} (MW)	8.3	7.6
P_{G1} (MW)	0.3	0.98
Max. branch loading	105%	95.4%
	Total cost increment	13.6 €/h

Table 5.7: Optimal solution using G1 and slack bus power dispatch

Therefore, the overload is solved at the cost of increasing the marginal cost at Zones 131 and 134. Supplying power to consumers in Zones 131 and 134 is more expensive due to the overload constraint and the cost of increasing G1 output's power.

Next, demand load flexibility is added as another control variable (demand active power reduction). Loads from Zones 131 and 134 are parametrized as explained in Section 3.4.4. Distinguishing between industrial demand with up to 20% in load reduction flexibility and residential demand with up to 10% in load reduction flexibility (Table 3.5).

For demand response, three different flexibility scenarios with different load-shedding costs are evaluated. The OPF is used to analyze which is the most cost-efficient control to solve the contingency.

5.5.1 Case 4.1: High load-shedding cost scenario

Table 5.8 shows the costs employed under the high-cost flexible demand scenario. These costs have been defined above the marginal cost of G1.

Load Type	Maximum Flexibility	Cost (€/pu)	Cost (€/MWh)
Residential (Zones 131+134)	10%	7000	70
Industrial (Zones 131+134)	20%	8000	80

Table 5.8: Case 4.1 flexible demand costs

For high demand flexibility prices, the OPF does not use demand active power reduction as a control variable, increasing as in the previous case the output power generation of G1.

The marginal cost of increasing G1 power is lower than the marginal cost of demand and therefore the optimal solution is the same as presented in Table 5.7.

Table 5.9 includes the demand load multiplier, which as commented, is kept at 1.

Valley 5:00h	Initial overloaded case	OPF solution
P_{Slack} (MW)	8.3	7.6
P_{G1} (MW)	0.3	0.98
Residential load multiplier α	1	1
Industrial load multiplier α	1	1
Max. branch loading	105%	95.4%
	Total cost increment	13.6 €/h

Table 5.9: Optimal solution using G1 and slack bus power dispatch and flexible demand with costs in Table 5.8

5.5.2 Case 4.2: Medium load-shedding cost scenario

Now an intermediate-cost demand flexibility scenario is proposed in Table 5.10, with residential flexibility at a lower marginal cost than G1.

Load Type	Maximum Flexibility	Cost (€/pu)	Cost (€/MWh)
Residential (Zones 131+134)	10%	5000	50
Industrial (Zones 131+134)	20%	6500	65

Table 5.10: Case 4.2 flexible demand costs

As expected, the OPF uses all of the residential flexibility and none of the industrial load power flexibility which is more expensive than using generator G1.

The final system cost is slightly smaller than before as 0.03 MW is being reduced from residential demand at a price of 50 €/MWh instead of being generated by G1 at 60 €/MWh. Obtaining a cost reduction of 0.3 €/h with respect to the previous case.

Valley 5:00h	Initial overloaded case	OPF solution
P_{Slack} (MW)	8.3	7.6
P_{G1} (MW)	0.3	0.95
Residential load multiplier α	1	0.9
Industrial load multiplier α	1	1
Max. branch loading	105%	95.5%
	Total cost increment	13.3 €/h

Table 5.11: Optimal solution using G1 and slack bus power dispatch and flexible demand with costs in Table 5.10

5.5.3 Case 4.3: Low load-shedding cost scenario

Finally, a low-cost demand flexibility scenario is considered in Table 5.12 with flexible demand costs below G1 marginal cost.

Load Type	Potential Flexibility	Cost (€/pu)	Cost (€/MWh)
Residential (Zones 131+134)	10%	4000	40
Industrial (Zones 131+134)	20%	4500	45

Table 5.12: Case 4.3 flexible demand costs

G1 dispatch is kept constant in this case as using flexibility from both industrial and residential loads leads to a cheaper solution.

The reduction in 1 MW of power coming from the slack bus is assumed by a reduction of 10% in the residential load and a reduction of 9.9% in the industrial load. Leading to an increment in the total system cost of 2.5 €/h from the initial case caused by the extra cost of 5 €/MWh from industrial demand response to system marginal cost.

Valley 5:00h	Initial overloaded case	OPF solution
P_{Slack} (MW)	8.3	7.3
P_{G1} (MW)	0.3	0.3
Residential load multiplier α	1	0.9
Industrial load multiplier α	1	0.91
Max. branch loading	105%	95.3%
	Total cost increment	2.5 €/h

Table 5.13: Optimal solution using G1 and slack bus power dispatch and flexible demand with costs in Table 5.12

As proven in this section, the OPF can solve an emergency state situation by using the most cost-effective resources, minimizing total system costs.

The costs defined for each of the control variables provided by the flexible resources determine the optimal control actions taken. As shown above, whenever the flexible load price is lower than the marginal generation cost, load shedding is preferred as a preferable solution.

6 Conclusions

Flexible resource optimization enables a more efficient grid operation without incurring capital expenditures. This project analyzed the benefits of using OLTC, shunt device, DGs and flexible demand as potential flexible resources to optimize grid operation using an OPF.

First, control variables associated to these resources (OLTC tap position, shunt device connection, active and reative power regulation from DG and demand load reduction) have been modelled and parametrized. Secondly, benefits of applying an OPF in a real 20kV distribution network under different flexibility scenarios are evaluated and compared with the initial case. Finally, a sensitivity analysis is performed, determining for different flexibility scenarios, which are the most effective controls.

The main conclusions and outcomes obtained throughout this project are summarized in this section.

- When different objective terms are combined within the problem's objective function in an OPF, coherent cost/weights must be defined to conduct the optimal solution in the desired direction. When optimizing the shunt device connection, a zero-cost for the optimal adjustable shunt has been applied to obtain the optimal shunt value that leads to the minimal power losses.

- Inequality constraints limit treatment is one of the most complex aspects of an OPF. Hard limits introduce barrier terms in the objective function and it is very important to set appropriate values for the objective terms costs and final barrier coefficients to reach the desired solution. When applying hard limits to the bus voltages, a losses cost coefficient greater than 1000 €/pu must be applied to minimize the power losses.

- Branch flows with reporting type limit do not affect the solution, but short segments defined as zero-rating branches, are automatically initialized by the OPF in PSS®E, introducing constraints with a zero-flow restriction.

- A positive (negative) sensitivity means that an increase of one unit in the variable's value leads to an increase (decrease) of the sensitivity value in the objective function. At the optimal point of a variable, its sensitivity is zero. Sensitivity is different from zero means that the variable is constrained. A greater sensitivity implies a higher potential effect on the objective.

- In a future context where a periodical OPF background execution is implemented during grid operation, DSOs owned equipment will probably be the preferred control to minimize losses, since it would have almost none Operational Expenditures (OPEX). However, new installations will have capital expenditures that need to be considered and compared with alternatives such as distributed resources

- The OLTC and shunt element dynamic response must be considered when the OPF is applied to a time scale shorter than the hour.

- The direct effect observed when minimizing losses is an increase in the network's voltage profile by using the associated control variable: decreasing OLTC tap position or injecting reactive power into the network with resources such as shunt devices or DGs. A rise in voltages leads to a reduction in branch currents and therefore power losses.

- Zones with low penetration of distributed generation or a high load show the lowest voltage profile and highest losses, being the optimal locations for introducing a distributed generation.

- Due to the hard limits imposed on voltages, the discrete tap optimization usually leads to divergent solutions. Tap positions are treated as continuous for the execution of the OPF in PSS®E and discretized afterwards with external logic.

- Network voltage profile seems to increase proportionally with a reduction in the OLTC tap position. The optimal continuous tap represents a top limit in losses reduction bounded by the bus voltage upper limits. When the continuous and discrete tap values are too close, it leads to lower losses, but also a very high voltage profile. A good solution to avoid very high voltages could be implementing a security margin in the tap discretization process.

- Optimizing the tap position of the OLTC has led to a total 24-hour **losses reduction of 1.89%** with respect to the current approach of using voltage setpoints (fixed by the operators) managed by the automatic regulation acting on the transforme tap changer. The OPF has proven to be the correct tool to plan the OLTC tap position optimally while keeping every variable within feasible limits. In the future, when more experience is acquired, the OPF could provide the optimal voltage setpoint to the transformer regulator unit.

- The combination of a fixed shunt model with the adjustable shunt optimization is preferred over the switched shunt modelling. The continuous treatment of the switched shunt element is equivalent to the optimal adjustable fixed shunt model case with a zero cost.

- The OPF adjustable shunt model provides two main hints, the maximum capacitor that can be placed in the bus without exceeding the voltage hard limits and the maximum losses reduction available (top limit).

- For the 24 hours analyzed, a total **losses reduction of 1.41%** is achieved by optimizing the shunt connection schedule considering the real state of the system rather than using a peak-hour pre-defined schedule.

- For the inverter connected wind farm, maximum and minimum reactive limits have been calculated for every hour. For modelling the synchronous generators (cogeneration plants) reactive capability PQ diagram has been used, defining its parameters in the *.rop* data file.

- The DGs that are located more downstream from the primary substation, show a higher sensitivity to reduce power losses, meaning that these are the most effective generators to minimize power losses by injecting reactive power.

- Final reactive output sensitivities obtained at the optimal solution for every hour and generator are zero, meaning that at the optimal solution, every generator is able to provide the optimal reactive power amount that leads to minimal losses within the 7% voltage limit and it is not limited by its PQ curve constraints. Therefore, sensitivity to keep reducing power losses is not on the generators but on the 7% upper voltage limit.

- A total power **losses reduction of 4.59%** has been obtained for the 24h studied by using the optimal reactive power regulation from distributed generators. DG's have proven to be the most efficient control due to their more optimal location.

- Different flexible loads may be defined in the OPF, with different quantities and costs. The OPF proves to be capable to provide the optimal corrective control actions to solve an emergency state following a cost-efficiency criterion. For a low load-shedding cost scenario, below the generator's marginal fuel cost (60 €/MWh), demand flexibility is used to solve the contingency. For a high load-shedding cost scenario, above the generator's marginal fuel cost, demand flexibility is not used, incurring in higher costs.

- Flexible resources optimal control allows a more efficient grid operation at the cost of operational expenditures (OPEX). Under this new potential flexibility scenario, during the planning and operation of the distribution grid capital expenditures (CAPEX) for new installations must be evaluated and compared with the operational costs of existent grid flexible resources to obtain the most cost-efficient alternatives.

6.1 Future work

Future work should consider the following topics:

- Complete the flexible resource modelling with other equipment such as Electric Vehicles (EVs) or Battery Energy Storage Systems (BESS).

- Take into account distributed generation losses in the optimization model (only grid losses were minimized within this project from the point of view of a DSO).

- Investigate the combination of control variables together within the same optimization problem studying features such as control priority.

- Analyze the Optimal Feeder Reconfiguration tool within PSS®E, which also includes the option of grid reconfiguration as a flexible solution.

- Consider CAPEX costs for all different flexibility solutions.

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ANNEX A

Alignment with sustainable development goals (SDGs)

The project described in this report is aligned with sustainable development goals, specifically with objectives seven, nine and thirteen [19].

Objective 7: Ensure access to affordable, reliable, sustainable and modern energy for all

The increase in distributed generation and electric vehicles to accomplish the 2030 horizon has changed the distribution grid operation paradigm. These resources represent an opportunity, to make a more efficient use of energy, minimizing power losses in the grid.

Under the DSO point of view, it is of great importance to be prepared for 2030 horizon, where renewable distributed generators and flexible demand will be common in the distribution networks.

Objective 9: Build resilient infrastructure, promote inclusive and sustainable industrialization and foster innovation

The implementation of an OPF for grid operation, promotes innovation and technological progress, it will enable to do a better use of the networks assets and distributed resources. As discussed in the project, it the implementation of an OPF tool offers the possibility to take at any moment the most cost-efficient alternative.

Objective 13: Climate action

De-carbonization of the power sector can be accelerated by making a more efficient use of resources and energy. This project proposes a solution to improve the efficiency of current network operation.

ANNEX B: Single Line Diagram