SECURITY CONSTRAINED OPTIMAL REDISPATCH MANAGEMENT IN BALANCING MARKETS

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ABSTRACT

SECURITY CONSTRAINED OPTIMAL REDISPATCH MANAGEMENT IN BALANCING MARKETS

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A core function of each Transmission System Operator (TSO) is the procurement of ancillary services in real-time balancing markets, necessary for a stable and reliable operation of the system. In a balancing market, TSO controls the active power generation and manages congestions in the transmission network in the sense of single or multiple elements over-loadings or violations of the N-1 security criterion. Congestion management is achieved by rescheduling generation using mainly operators' experiences. However, TSO has legal obligations to procure ancillary services in accordance to economic, transparent, non-discriminatory procedures.

This thesis aims to develop an algorithm for TSO to decide the optimum redispatch in the sense of economy and security to eliminate transmission bottlenecks. The suggested algorithm considers the bidding strategies of power producers in balancing markets, physical constraints of generators, and transmission constraints. Single cost formulation for multiple generation units can be applied to the problem so that power plants whose generators locate at different voltage levels and virtual power plants of aggregators can be modeled.

The problem is formulated as an optimal power flow to calculate both corrective and preventive actions. To obtain a robust application, state-dependent linearization techniques are applied to network constraints thanks to the nature of the close states of pre- and post-operating points of redispatch actions. Unlike the classical DC OPF formulation, reactive power flows and voltage magnitudes are considered in the optimization. Accuracy-enhancing approaches and strategies to minimize the number of control actions have been developed.

The proposed algorithm is tested with standard test cases and a real large-scale electricity network. Benders Decomposition technique is utilized for solving security-constrained formulation; thus, large-scale optimization problems (such as those with more than 1M variables) can be solved in less than a minute. The developed application is deployed as a decision support system for a large-scale transmission network in real-time operation for a year, and it has been observed to produce more economical redispatches.

Keywords: Security Constrained Optimum Power Flow, Redispatch in Balancing Market, Congestion Management, Network Linearization, Robust Optimization

ÖZ

DENGELEME PİYASALARINDA GÜVENLİK KISITLI OPTİMAL ELEKTRİK ÜRETİM TALİMATI YÖNETİMİ

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Her iletim sistemi işletmecisinin temel fonksiyonu, sistemin kararlı ve güvenilir işletimi için gerekli olan yan hizmetleri gerçek zamanlı dengeleme piyasasından temin etmektedir. Dengeleme piyasasında işletmeci aktif güç üretimini kontrol eder ve iletim sisteminde gerçekleşen bir veya birden fazla ekipmandaki aşırı yüklenme veya N-1 durumunda güvenlik kriterlerinin ihlalini, yani sistem kısıtlarını yönetir. Kısıt yönetimi genellikle işletmecilerin tecrübelerine dayalı olarak üretimin yeniden dağıtımı ile sağlanır. Bununla birlikte işletmecinin yönetmeliklere göre yan hizmetleri ekonomik, şeffaf ve ayrım gözetmeden tedarik etme yükümlülüğü bulunmaktadır.

Bu tez sistem işletmecisi için ekonomi ve güvenlik açısından kısıt durumunu ortadan kaldırmak amacıyla en uygun üretim talimatını belirleyen algoritmanın geliştirilmesini hedeflemektedir. Önerilen algoritma enerji üreticilerinin dengeleme piyasalarındaki teklif stratejilerini, generatörlerin fiziksel limitlerini ve iletim kısıtlarını dikkate alır. Birden fazla üretim birimi için tek maliyeti formülasyonunu uygulayabilerek farklı sistem bağlantı noktalarında generatörlere sahip santrallerin ve toplayıcıların sanal santrallerinin modellenmesini destekler.

Kısıt talimatı belirleme işlemi düzeltici ve önleyici aksiyonları hesaplayabilecek bir optimal güç akış problemi olarak tanımlanmıştır. Sağlam ve hızlı bir uygulama elde etmek amacıyla üretim değişikliklerinin öncesi ve sonrasındaki şebeke koşullarının yakınlıklarını kullanarak şebeke durumuna bağlı linearizasyon tekniği uygulanmıştır. Klasik DC OPF formülasyonlarının aksine reaktif güç akışlarının ve gerilim büyüklüklerinin optimizasyonda dikkate alınması sağlanmıştır. Sonuçların doğruluğunu artıran ve aksiyon sayınını minimumda tutmayı sağlayan stratejiler geliştirilmiştir.

Önerilen algoritma standart test şebekelerinde ve gerçek büyük ölçekli bir elektrik şebekesi ile test edilmiştir. Güvenlik kısıtlarını içeren optimizasyon probleminin çözümünde Benders Decomposition tekniği uygulanmıştır, bu sayede 1M'dan fazla değişkene sahip büyük optimizasyon problemlerinin bir dakikanın altında çözümü sağlanabilmiştir. Geliştirilen uygulama büyük bir elektrik iletim sisteminde gerçek zamanlı işletmede kullanılacak bir karar destek sistemi olarak kullanıma sunulmuştur ve uygulamada geçen bir yıllık süre zarfından işletmede gerçekleştirilen talimat maliyetinin daha altında çözümlerin alınabildiği görülmüştür.

Anahtar Kelimeler: Güvenlik Kısıtlı Optimum Yük Akış, Dengeleme Piyasasında Üretim Talimatı, İletim Sistemi Darboğaz Yönetimi, Şebeke Linearizasyonu, Sağlam Optimizasyon

To my son, the one who gave me the strength in life

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LIST OF ABBREVIATIONS

AC	Alternating Current
ACOPF	Non-linear AC Optimal Power Flow
CM	Congestion Management
DC	Direct Current
DCOPF	Linear DC Optimal Power Flow
DSO	Distribution System Operator
ENTSO-E	European Network of Transmission System Operators for Electricity
GENCO	Generation Company
MCP	Marginal Clearing Price
MILP	Mixed Integer Linear Programming
MO	Market Operator
OPF	Optimal Power Flow
PBUC	Price Based Unit Commitment
PTDF	Power Transfer Distribution Factor
SCOPF	Security Constrained Optimal Power Flow
SCUC	Security Constrained Unit Commitment
TEİAŞ	Turkish Electricity Transmission Company
TSO	Transmission System Operator
UC	Unit Commitment

LIST OF SYMBOLS

Sets

$\mathcal{N}$	Buses
$\mathcal{P}$	Power Plants
$\mathcal{G}$	Generators, G^p generators belongs to the plant p
$\mathcal{L}$	Pieces/Levels of Plant Bid, L^p piece-wise levels belongs to the plant p
$\mathcal{C}$	Contingencies
$\mathcal{R}$	Renewables
$\mathcal{D}$	Loads

Indices

i, j	Bus $\in \mathcal{N}$
p	Power Plant $\in \mathcal{P}$
g	Generator $\in \mathcal{G}$
l	Bid Level, l $\in \mathcal{L}$
c	Contingency $\in \mathcal{C}$
r	Renewable $\in \mathcal{R}$
d	Load $\in \mathcal{D}$

Parameters

g_{ij}	Series Conductance of branch (i,j).
b_{ij}	Series Susceptance of branch (i,j).
G_{ij}	Real part of Y_{ij} in the admittance matrix.

B_{ij} Imaginary part of Y_{ij} in the admittance matrix.

δ_{ij} Angle of Y_{ij} in the admittance matrix.

S_{ij}^{max} Apparent power limit of branch (i,j) for the normal case.

$S_{ij}^{max,c}$ Apparent power limit of branch (i,j) under contingency c.

P_g^{min} Minimum active power limit of generator g.

P_g^{max} Maximum active power limit of generator g.

$P_p^{up,min}$ Minimum generation-up limit of plant p.

$P_p^{up,max}$ Maximum generation-up limit of plant p.

$P_p^{down,min}$ Minimum generation-down limit of plant p.

$P_p^{down,max}$ Maximum generation-down limit of plant p.

$P_{p,l}^{min}$ Minimum redispatch amount of piece of l of plant p.

$P_{p,l}^{max}$ Maximum redispatch amount of piece of l of plant p.

C_p^{min} Minimum redispatch cost of plant p.

C_p^{max} Maximum redispatch cost of plant p.

c_r Cost of renewable curtailment per MW.

c_d Cost of load shedding per MW.

P_r^{max} Maximum limit of renewable curtailment for renewable r.

P_d^{max} Maximum limit of load shedding for load d.

$P_g^{ramp-down}$ Active power ramp-down limit of generator g in 15 minutes.

$P_g^{ramp-up}$ Active power ramp-up limit of generator g in 15 minutes.

$v_{i,0}$ Bus voltage magnitude of bus i in the base case.

$\theta_{i,0}$ Bus voltage angle of bus i in the base case.

$P_{g,0}$ Active power generation of generator g in the base case.

Variables

θ_i Bus voltage angle for the normal case.

θ_i^c Bus voltage angle under contingency case c.

v_i Bus voltage magnitude for the normal case.

v_i^2 Square of bus voltage magnitude for the normal case.

P_{ij} Active power flow of branch (i,j) for the normal case.

P_{ij}^c Active power flow of branch (i,j) under contingency case c.

Q_{ij} Reactive power flow of branch (i,j) for the normal case.

P_{ij}^L Linearized active power loss of branch (i,j).

Q_{ij}^L Linearized reactive power loss of branch (i,j).

P_i Net Active power injection at bus i.

Q_i Net Reactive power injection at bus i.

P_p^R Redispatch amount of plant p.

C_p^R Redispatch cost of plant p.

$C_{p,l}^R$ Redispatch cost of the piece l of plant p.

X_p^{up} Generation up status (on/off) of plant p.

X_p^{down} Generation down status (on/off) of plant p.

$X_{p,l}^{on}$ Status (on/off) of the piece l of plant p.

ϵ_{ij}^+ Penalty factor for losses in branch (i,j).

γ_i^+, γ_i^- Penalty factors for bus i voltage.

$\beta_g^{+,c}$, $\beta_g^{-,c}$ Penalty factors for additional redispatch of generator g at contingency case c.

Decision Variables

P_g^R Redispatch amount of generator g for the normal case.

Q_g Reactive power generation of generator g for the normal case.

$P_g^{R,c}$ Redispatch amount of generator g under contingency case c.

X_g^{on} Status (on/off) of generator g.

P_r^c Renewable curtailment amount of renewable r at contingency case c.

P_d^c Load shedding amount of load d at contingency case c.

CHAPTER 1

INTRODUCTION

Diversified number of actors affect energy transfer in the electricity network, such as generation companies, consumers, regulators, and operators. The impacts of some of these participants are predictable but not determinable, such as consumers and renewable energy sources, and some are manageable, such as conventional power plants. In this business, Electricity Transmission System Operator (TSO) is responsible for the secure, reliable, and economic operation of the electricity grid.

Market Operator (MO) manages and operates the electricity market, where members send bids to buy or sell energy in determined delivery platforms. Its task is to match all buy or sell orders transparently, according to the regulations, and establish a reference price.

Electricity market designs vary from country to county, and the way of power transactions are decisive on power flows in the grid. For example, the majority of market designs aim for the economic operation of the system (i.e., price-based unit commitment) rather than security-constrained unit commitment. This market design may result in security violations in the grid, such as the loading of one or multiple elements, bus voltage deviations, and loss of stability.

In general, a congestion in electricity transmission occurs when the demand for power transfer between two points in the power grid exceeds the available transmission capacity. This can be caused by several factors, including:

1. Limited transmission capacity: The physical limitations of transmission lines, such as their thermal capacities and impedances, can restrict the amount of power that can be transmitted. If the demand for power transfer exceeds these

limits, congestion occurs.

2. Network topology: The layout and interconnections of the power grid can also contribute to congestion. Some areas may have more generation capacity than others, leading to an imbalance in power flow. The power grid may also have bottlenecks or weak points that limit power transfer between regions.

3. Generation dispatch: The way power plants are dispatched to meet the demand can also cause congestion. If power plants in a specific area generate more power than the transmission lines can handle, congestion can occur.

4. Maintenance and outages: Scheduled maintenance or unexpected outages of transmission lines or power plants can reduce the available transmission capacity, leading to congestion.

5. Load growth: As electricity demand increases over time, the existing transmission infrastructure may become insufficient to handle the increased power flow, resulting in congestion.

6. Renewable energy integration: The integration of renewable energy sources, such as wind and solar, can cause congestion due to their intermittent and variable nature. These sources may generate power in areas with limited transmission capacity or during times when the power grid is already congested.

To solve congestion problems, system operators employ various strategies, such as upgrading transmission infrastructure, optimizing generation dispatch, implementing demand-side management programs, and using advanced technologies like Flexible AC Transmission Systems (FACTS) devices to improve the power flow control. Market mechanisms like congestion pricing can also help in managing the congestion by incentivizing generators to produce power in less congested areas.

In a real-time operation, TSO manages transmission congestions via generation rescheduling or load shedding in a balancing market. In this work, an operational assistant is developed to determine the redispatch in accordance with economic, transparent, non-discriminatory procedures for a transmission system operation.

1.1 Motivation and Objectives

Security remains to be the most important aspect of power systems operation [4]. System operators allocate resources to ensure the reliability and stability of the grid. For instance, the cost of the congestion management by redispatch actions of Turkey is presented in Fig. 1.1. An operational optimization in congestion management will create high economic value. Additionally, the installed capacity of the uncontrollable generation (solar, wind, and run-of-river) has increased by 212% from 13750 MW at the end of 2016 to 29170 MW at the end of 2022. The investment trend in renewables is expected to continue in the next ten-year period [5]; thus, the cost of congestion management is expected to increase with increasing volatility in the generation.

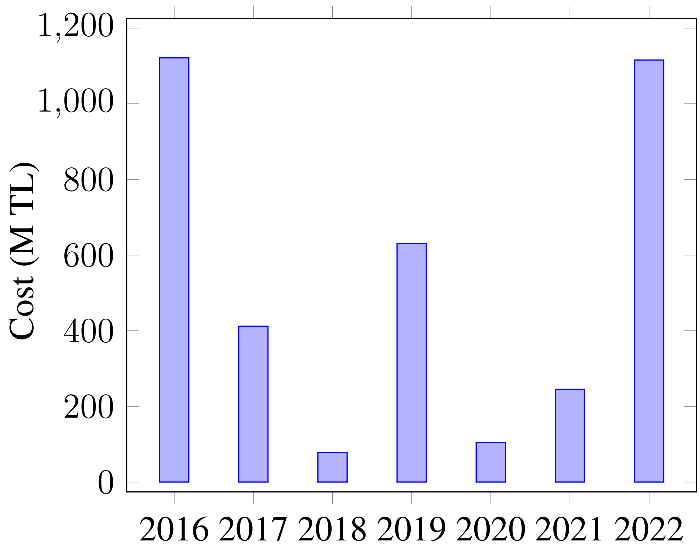


Figure 1.1: Cost of the Congestion Management in Turkey [1]

In this thesis, it is aimed to propose a methodological approach and develop an efficient algorithm to calculate the generation up and down actions to eliminate the congestion within Balancing Markets in an optimal manner. The suggested algorithm is expected to consider both the transmission constraints and the market rules. Furthermore, it is expected to perform the calculations in a real-time system operation; thus, it should be robust. Finally, it is aimed that algorithm is flexible for future instruments such as demand response management and the involvement of aggregator agents.

The developed algorithm is tested on a large-scale electricity network. The transmission system operator of Turkey (TEİAŞ) supported this study and gave the necessary permission and data for the case studies.

1.2 Congestion Management

In a deregulated environment, different methods of accomplishing congestion management have been implemented [6]. Price area congestion control and transaction-based control can be given as example models. For the market models considering transmission conditions in unit commitment (UC) processes, fewer security violations are expected in real-time operation. However, transmission bottlenecks can still be encountered in operation due to the dynamic nature of consumption and renewable generation, any failure in an equipment, or complex security conditions such as stability, which may not be covered in UC.

Moreover, generation scheduling procedures may be free of security constraints since they require complex business processes to integrate between the market and network models, robustness issues, and non-deterministic designs. In this case, TSO has to deal with more corrective control actions in real-time system operation. In most cases, congestion management is based on the experience of operators. Although their decisions are not based on analytical calculations and do not yield optimal solutions, this approach may successfully solve congestion problems. In more systematic approaches, power transfer distribution factors (PTDF) are used to deal with the problem [7]. The PTDF approach presents the relation between bus injections and branch flows so that the operator can decide on rescheduling the generation. However, the solution obtained by this approach may not be the optimum solution and is limited to cases that can be solved by a single action. In most professional cases, the problem is defined as optimal power flow (OPF), and redispatch requirements are obtained from optimization results.

In this part, approaches regarding congestion management (CM) are discussed. CM in power systems can be categorized under two perspectives [8]: cost-free and non-cost-free methods. The method preferences of the US and EU practices are reviewed.

1.2.1 Cost Free Methods

The cost-free methods are tools that TSO may utilize on its own and generally require investments. These methods include adapting network topology (i.e., changing positions of circuit breakers and disconnectors), regulating voltage profiles by transformer tap positions and shunt equipment, and active power control devices such as phase shifting transformers and Flexible AC Transmission System (FACTS) devices.

1.2.1.1 Transmission Switching Method

Cost-free methods are advantageous solutions for economic considerations. However, certain limitations exist, such as decreasing the N-1 security and robustness. The optimal transmission switching (OTS) method aims to change the network topology and power flows to obtain a secure network condition. OTS problem can decide in-service statutes of equipment and bus connectivity optimizing the use of transmission [9]. However, OTS problems contain a large number of variables and probabilities, and it is hard to obtain a feasible and optimal solution in a real-time operation.

In [10], a multi-objective-based CM methodology is proposed using OTS strategies, considering minimizing the total operating cost and maximizing probabilistic reliability as two conflicting objectives. The OTS can increase the economic efficiency of power dispatch with the existing infrastructure. OTS aims to find the most influential lines as candidate lines for disconnection. The proposed optimization problem is solved using the hybrid of evolutionary and stochastic programming approaches.

In [11], transmission switching is introduced in the security-constrained unit commitment problem to reduce operating costs. The problem is decomposed into a unit commitment problem and transmission switching (TS) problem using Benders Decomposition. UC is formulated as the master problem, and each TS is configured as a subproblem. However, the paper states the number of switchable lines is limited. If the number of switchable lines is increased, TS may find better SCUC solutions which could also converge at slower rates. Building the problem with a limited transmission switching case may not get close enough to the optimal point.

Kocuk *et al.* [12] formulate the problem with the full AC power flow model and solves it with mixed-integer second-order cone programming relaxation. Although authors improve this relaxation via several types of strong valid inequalities, practical applications on IEEE 300-bus test cases take 40 minutes of computation time. Therefore, TS methods seem more suitable for operational planning than the real-time management.

1.2.1.2 Flexible AC Transmission Systems Devices

One of the cost-free methods of congestion management is the installation of Flexible AC Transmission Systems (FACTS) devices. FACTS are power electronic based systems that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability. The most common devices are Thyristor Controlled Series Capacitors (TCSC) and Unified Power Flow Controllers (UPFC).

TCSCs are used to control the impedance of transmission lines by inserting a variable series capacitance. This allows for better control of power flow and helps alleviate congestion by redistributing power flows across parallel transmission paths.

UPFCs are the most versatile FACTS devices, capable of controlling both active and reactive power flows in the transmission system. They can simultaneously regulate voltage, line impedance, and phase angle, making them highly effective for managing congestion and improving overall system performance.

The disadvantages of FACTS devices are investment costs and limited availability in transmission systems. In [13], the formulation of FACTS as a control variable in optimal power flow problem is presented.

1.2.2 Non-Cost Free Methods

The non-cost-free methods are generally market-based tools that are related to the market design or give incentives to producers to avoid the dispatch, which leads to overloads.

1.2.2.1 Price Area Method

The price area method is a market-based approach to congestion management. It is widely used in deregulated electricity markets to determine the real-time cost of electricity at different locations within the network. The main idea behind zonal pricing is to reflect the actual cost of delivering electricity to consumers, considering generation costs, transmission losses, and congestion.

In zonal pricing, the power system is divided into multiple zones, each with its own price for electricity. The price in each zone is determined by the marginal cost of supplying an additional unit of electrical energy at that location. In some cases, nodal pricing methods can be implemented.

Generally, power exchange capacities are limited in the price area method. Thus, high amounts of power flows are avoided, and congestion is prevented. There exist studies of the determination of the price areas to obtain the optimal congestion cost. Reference [14] proposes an algorithm to determine bidding areas based on a full nodal pricing simulation that is developed and applied to a model of the European electricity system. Price area congestion management is extensively practiced in Nordic countries.

In Turkey, the regulations allow TSO to build up price areas to minimize congestion. However, it is challenging work to determine these areas since non-optimal decisions can raise market prices. Moreover, if congestions do not have a particular reason, i.e., changes with the time and region, there may be better solutions for CM than price area methods.

1.2.2.2 Uplift Cost Method

The uplift cost method updates the market price by additional costs for certain generators. This method can be called as a capacity mechanism in some applications. The main purpose is to make some generators must-run units to decrease the power transmission in the network. US PJM Capacity Market and Uplift Cost in UK Power Pool are applications of this method. Regional transmission tariff is also a kind of uplift cost method to regulate dispatch in the interest of the grid.

The paper [15] evaluates the uplift cost applications in England and Wales Pool and illustrates how congestion is managed under privatization. However, there are discussions on capacity markets, whether they are the way of the future or the way of the past. It is controversial to give incentives for producers rather than utilize generation redispatch.

Turkey has a capacity mechanism to ensure grid security and reliability. TSO determines the power plants to be given incentives based on the criticality of their grid connection location. If these power plants do not commit to the wholesale power market, they cannot take incentives. So that they adjust their bids to be committed to the generation program. The redispatch cost for certain plants is transferred to the capacity cost in this way. The plant list in the capacity mechanism is updated by TSO of Turkey each month.

1.2.3 Congestion Management Applications

1.2.3.1 CM in United States Electricity Networks

In the United States, electricity congestion management is primarily handled by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). These organizations are responsible for managing electricity transmission across large regions, ensuring efficient and reliable power grid operation.

FERC Orders No. 888 and 889 publish the rules and procedures for the use of the U.S. portions of the transmission systems in the Eastern and Western Interconnections. The practices should be non-discriminatory by TSOs and provide open access to the transmission system for all users.

RTO/ISOs use centralized dispatch procedures driven by competitive offers from generators to sell electricity to purchasers. These procedures account for all transmission constraints to form a marginal price at each point within the transmission system, i.e., the point at which wholesale electricity is either injected into the system by a seller or withdrawn by a purchaser.

Ignoring the effect of transmission losses, when no transmission or generation constraints are restricting economic dispatch and all desirable transactions are occurring, all marginal prices at all points will be identical. If there is a constraint, the marginal prices on the two sides of the constraint will differ. The price difference is an economic measure of the congestion cost [16].

Locational Marginal Pricing (LMP) reflects the real-time cost of delivering electricity to specific locations within the grid. It accounts for generation costs, transmission constraints, and losses. By using LMP, ISOs and RTOs can send price signals to market participants, incentivizing them to adjust their generation or consumption patterns to alleviate congestion. Nodal pricing mechanisms are utilized in the majority of US electricity markets, including PJM, New York, New England, California, Texas, and others.

1.2.3.2 CM in European Electricity Network

In the European Union (EU), regulation 2015/1222 establishes a guideline on capacity allocation and congestion management. The goal is to ensure the efficient and reliable operation of the power grid while addressing transmission constraints that can limit the flow of electricity and lead to higher costs for consumers. Key strategies and tools used for congestion management in the EU include:

- Market Coupling: Market coupling is a mechanism that integrates different national electricity markets to optimize the use of cross-border transmission capacity. It involves the coordination of day-ahead and intraday markets, allowing for the efficient allocation of available transmission capacity and minimizing price differences between interconnected markets.
- Capacity Allocation and Congestion Management (CACM) Guidelines: The CACM guidelines, established by the European Network of Transmission System Operators for Electricity (ENTSO-E), provide a harmonized framework for capacity allocation and congestion management across the EU. The guidelines aim to promote competition, non-discrimination, and transparency in the electricity market while ensuring the efficient use of transmission infrastructure.

- Flow-Based Market Coupling (FBMC): FBMC is an advanced market coupling mechanism that considers the physical flows of electricity on the transmission network when allocating cross-border capacity. By taking into account the actual impact of power flows on the grid, FBMC allows for more efficient use of available transmission capacity and better management of congestion.

- Redispatching and Countertrading: TSOs use redispatching and countertrading measures to manage congestion in real time. Redispatching involves adjusting the output of generators within a control area to alleviate transmission constraints, while countertrading is the process of buying and selling energy across borders to balance power flows and manage congestion.

The FBMC methodology is an important cornerstone of the European Congestion Management Strategy. [17] gives a detailed explanation of the flow-based methodology. In this approach, the network is divided into zones, and power flows are restricted between the zones by Available Transmission Capacity (ATC). In real-time, if any congestion occurs TSOs manage the security with redispatching.

1.3 Electricity Balancing Markets

Electricity is traded in both wholesale and retail markets, which function similarly to other wholesale and retail markets. The wholesale market is where electricity is bought and sold to resellers, who then sell it to consumers. On the other hand, the retail market is where electricity is sold directly to consumers. These markets were established to address rising electricity prices and promote innovation through competition in a free-market environment.

The electricity market models can be generalized as follows:

- Single Buyer Model: This model is used in countries with a centralized approach to electricity procurement. The government or a single entity is responsible for purchasing the electricity from the generators and selling it to the distribution companies.

- Pool-Based Model: This model is used in countries with a decentralized approach to electricity procurement. Generators sell their electricity to a pool, which is then allocated among the distribution companies according to their needs.

- Spot Market Model: This model is used in countries with a competitive electricity market. Generators sell their electricity to distribution companies in a spot market, where prices are determined by supply and demand.

- Bilateral Contract Model: This model is used in countries with a hybrid electricity market. Generators and distribution companies enter into long-term contracts to purchase and sell electricity at predetermined prices.

The architecture of the electrical market model based on wholesale strategy is given in Fig. 1.2.

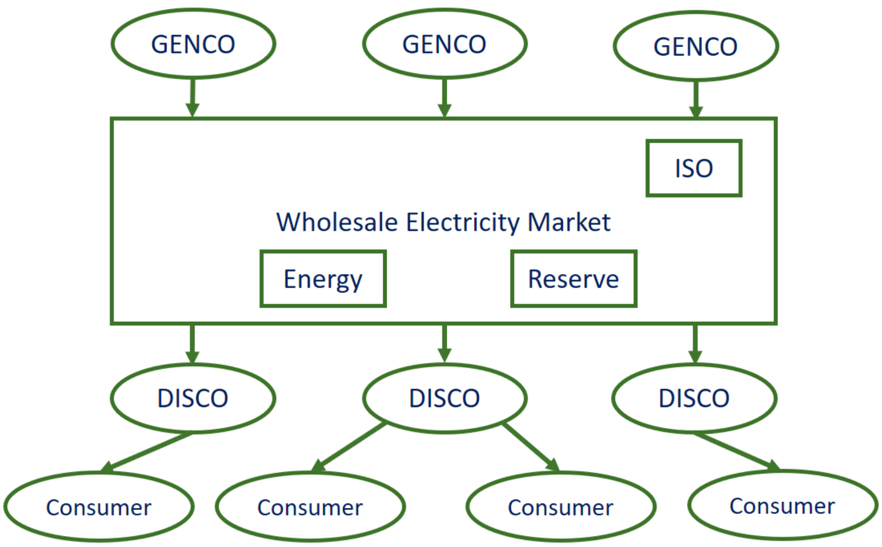


Figure 1.2: Architecture of Electrical Market Model based on Wholesale Strategy

Electricity balancing markets, also known as ancillary services markets, are essential components of modern power systems. They ensure the continuous balance between electricity supply and demand in real-time, maintaining the stability and reliability of the grid. Balancing markets contain products that help system operators handle supply-demand imbalance, security problems, and power quality issues.

Generally, the timeline of Balancing Markets starts 24 hours before the real-time and after the closure of day-ahead market operations. The settlement period varies between 5 minutes to 1 hour. The market participants can offer the redispatch bids until 1 hour before the settlement period. The general framework of electricity markets is given in Figure 1.3.

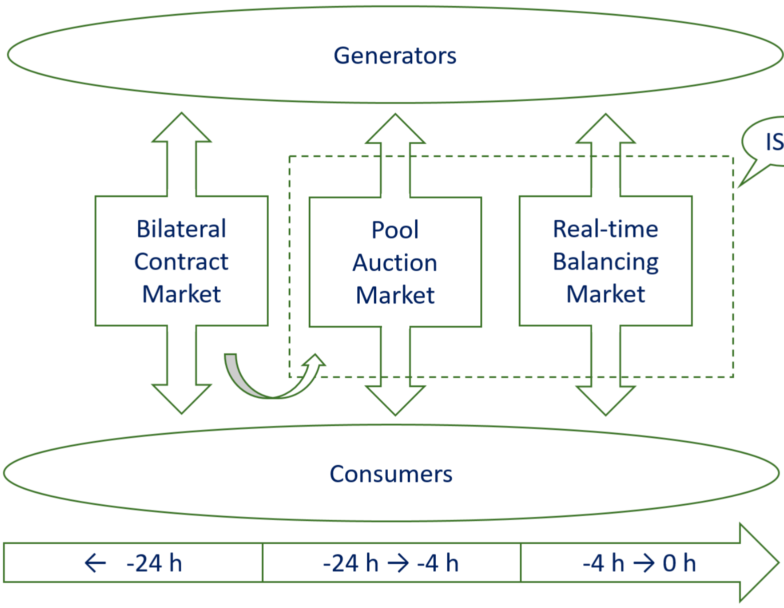


Figure 1.3: General Timeline of Electricity Markets

1.3.1 Overview of Turkish Electricity Market

The organized and physical Wholesale Power Market of Turkey is operated under two entities: TSO (TEİAŞ) and MO (EPİAŞ). EPİAŞ is responsible for the day-ahead and intra-day markets, while TEİAŞ is responsible for balancing and ancillary markets.

Actions in the balancing market are conducted under two objectives: to restore frequency reserve and to eliminate congestion management.

In the balancing market, producers can bid their redispatch offers up to a maximum of 15 price levels in up/down direction. The offers are based on bidding units, which are converted and distributed to physical generators using the market model - network model integration tool. The rules for the balancing market are stated in the Balancing and Settlement Regulation of the Energy Market Regulatory Authority. The developed module in this thesis considers all the related constraints of the Regulation.

1.4 Overview of Turkish Electricity System

The unbundled structure of the Turkish Electricity System has liberalized generation and retail services and regulated transmission and distribution services (Fig. 1.4). Energy Market Regulation Agency (EPDK) is the authority that will oversee the electric power markets, including setting tariffs, issuing licenses, and assuring competition. In this section, the general setup of the system is introduced.

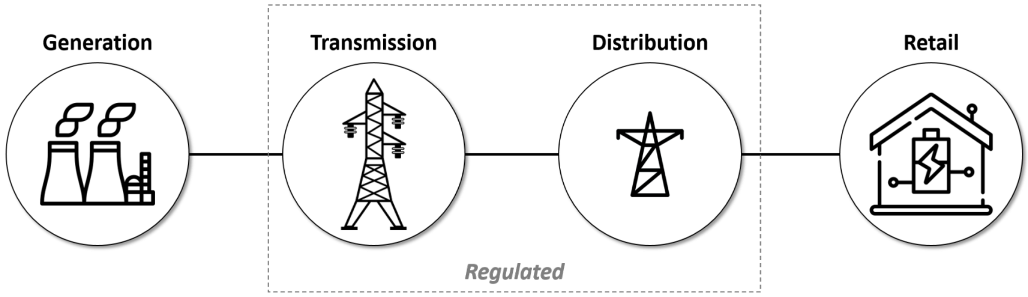


Figure 1.4: Electrical Energy Procurement Chain in Turkey

1.4.1 Electricity Generation

Power generation can be classified by different aspects such as controllability, intermittency, or by carbon emissions. A prevalent distinction involves categorizing power generation into two groups: renewable energy sources like wind, solar, hydro, and biomass and depletable resources such as coal, gas, or uranium. The technology mix of the installed capacity (total 103,9 GW) and the actual generation (total 328,7 TWh) in Turkey in 2022 is presented in Fig. 1.5. About 54% of the installed capacity in Turkey is renewable power, while about 41% of the generation comes from these sources.

Ownership of the power plants is divided into four main categories: state-owned generation company (EÜAŞ), private electric generation companies, power plants subject to TOOR, and unlicensed power plants (mainly PV rooftop installations). The share

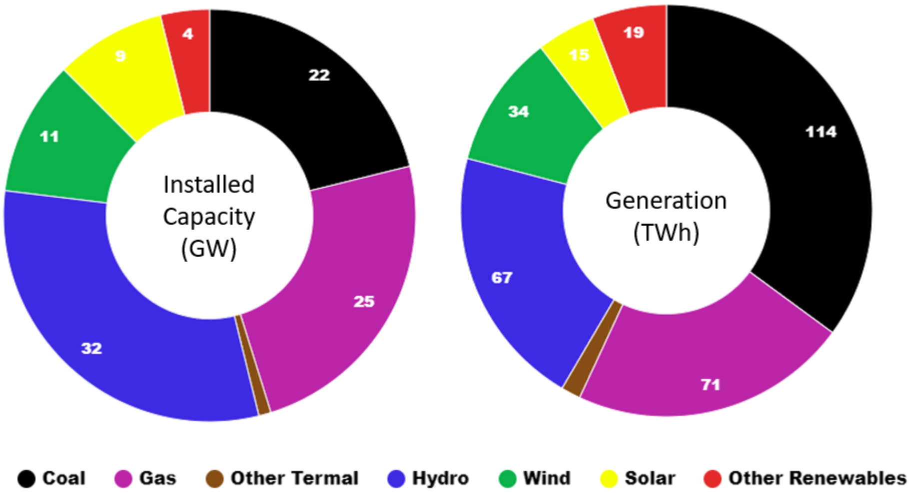


Figure 1.5: Generation and Installed Capacity in Turkey 2022 [2]

of private generation has grown in the last ten years. The ratio of private investments in Turkey's total installed capacity is 80% by the end of 2022 [2].

The electricity generation in Turkey is unevenly distributed for conventional and intermittent (i.e., Wind PP and Solar PP) resources. The conventional generation is dominated by coal and gas-fuelled thermal power plants concentrated in South Marmara and South West Anatolia regions. In last decade, the installed capacity of non-renewable generation has increased by 2.84% annually. However, the installed capacity of the South Anatolia region is expected to be boosted with the first nuclear power plant (4.800 MW Akkuyu NPP) in Turkey in 2024.

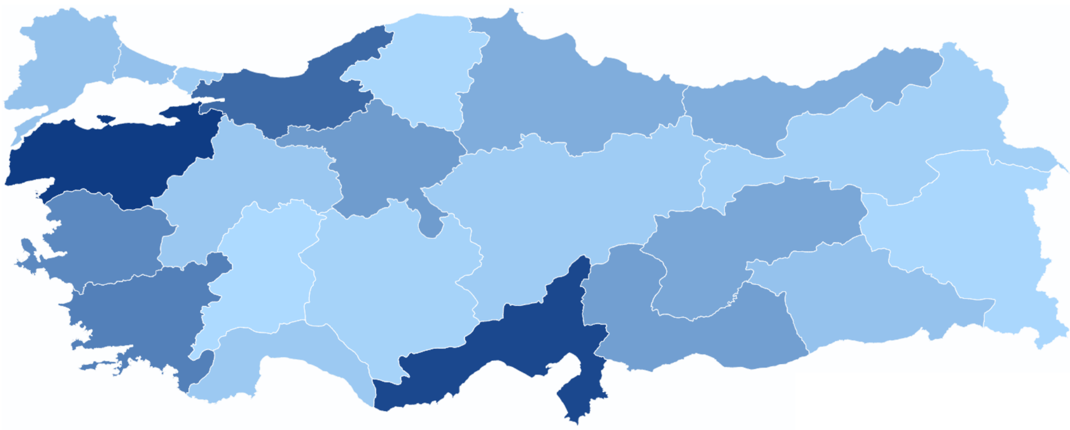


Figure 1.6: Distribution of the Conventional Generation by Regions [2]

The wind power plants in the country are located mainly in the Aegean region, and solar power plants are located in Central Anatolia. In the last ten years, the installed capacity of renewable generation has increased by 9.18% annually. Compared with non-renewable investments, it is seen that the share of the pie is rapidly changing in favor of renewable energy sources.

The distribution of the intermittent resources is shown in Fig. 1.7. Both pictures give insight reason for transmission bottlenecks in the South Marmara region.

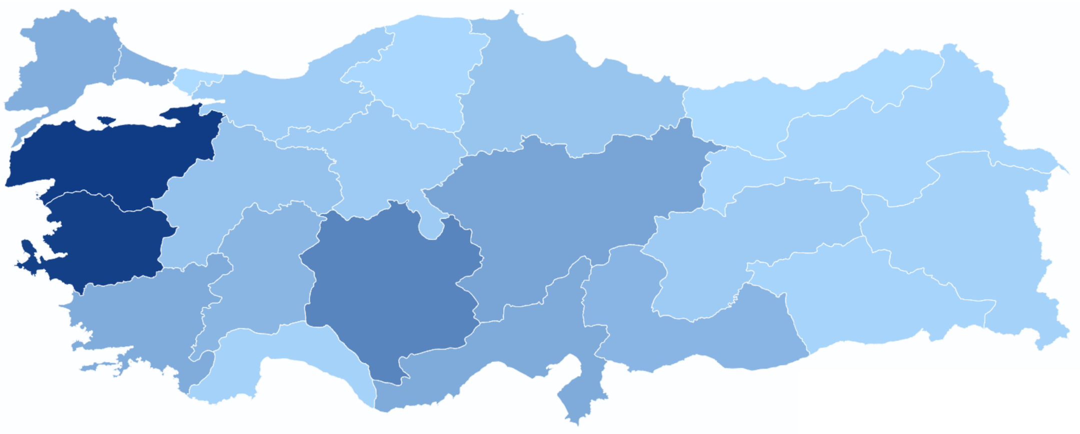


Figure 1.7: Distribution of the Renewable Generation by Regions [2]

1.4.2 Electricity Transmission

The transmission grid of Turkey is quite a large electricity network for its geographical scale and the number of infrastructure. The grid consists of 400 and 154 kV nominal voltages. The voltages under 36 kV are considered as the distribution network. The network is operated by a single state-owned TSO, TEİAŞ, which is a regulated natural monopoly.

The transmission system operates at a frequency of 50 Hz and is synchronously operated with the European Network of Transmission System Operators (ENTSO-E) since 2010. TEİAŞ has been an observer member of ENTSO-E since 2016 and actively pursues its full membership. Asynchronous interconnections exist with Georgia and Iran via DC-B2B connection, with Azerbaijan, Iraq, and Syria via isolated operations.

TEİAŞ is responsible for the secure operation of the network, including the operation of preventive emergency measures such as redispatch, the procurement of ancillary services, maintenance of grid components, and transmission planning.

National Energy Plan of Turkey [5] predicts 2.1 MW of storage investment to increase the flexibility of the grid. Moreover, the regulations of demand-side management encourage large consumers to participate in the Balancing Market. The new consumer actors in the market are expected to contribute to congestion management in the near future.

1.4.3 Electricity Distribution

The distribution grid of Turkey is operated by 21 Distribution System Operators (DSOs). Through the distribution system, DSOs serve 47 million customer points [3]. Distribution companies are privately operated and regulated by Energy Market Regulatory Authority (EMRA).

26% of renewable power plants are connected to the distribution grid with a regulated feed-in tariff. The integration of renewable generation presents a significant challenge for DSOs. One of the critical issues is the management of reversed power flows from lower voltage to higher voltage grid levels. This can occur when distributed energy resources (DERs) such as solar panels or wind turbines generate more power than is consumed locally, resulting in excess power being fed back into the grid.

To manage these reversed power flows, DSOs must ensure that the voltage and frequency of the grid remain within acceptable limits. This requires careful monitoring and control of the distribution network and the implementation of advanced technologies such as smart inverters and energy storage systems.

DSOs are not responsible for congestion management since they do not have a role in the Balancing Market.

1.4.4 Electricity Consumption and Retail

Electrical energy consumption in Turkey has been increasing with an average of 4.7% annually in the last 20 years. Maximum peak demand is measured as 56.3 GW in August 2021. The gross consumption and peak demand trend of Turkey is shown in Fig. 1.8.

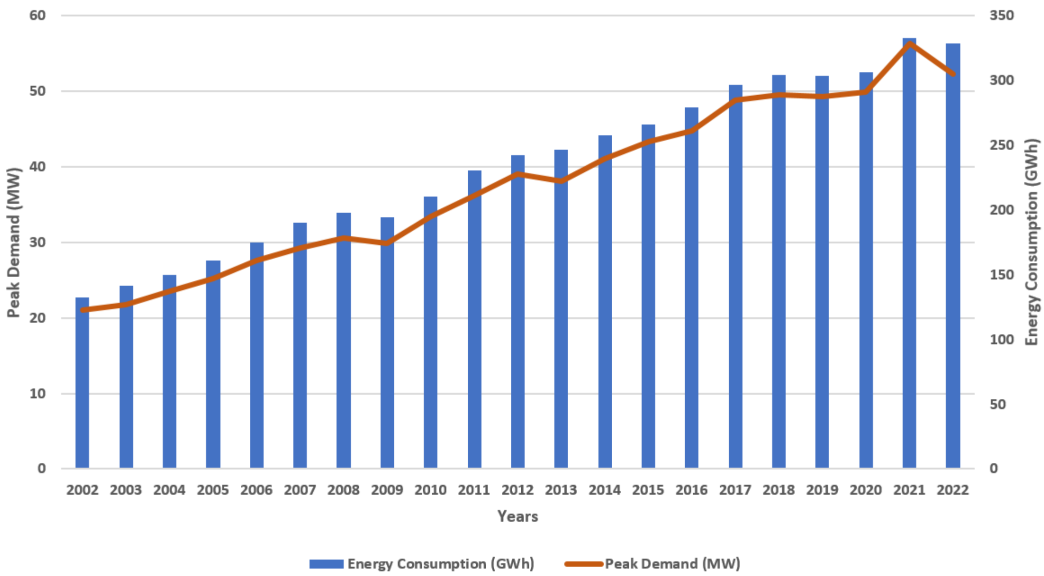


Figure 1.8: Energy Consumption and Peak Demand in Turkey [2]

Historically, electricity consumption is doubled every 15 years, resulting in a considerable amount of transmission investments. If the realization of investments lags behind economic development, the transmission system can be in a stressful condition facing congestion.

The electricity retail sector in Turkey has evolved significantly over the past two decades, with the establishment of EMRA and the enactment of the Electricity Market Law in 2001. These reforms aimed to create a competitive market structure, allowing private companies to enter the generation, distribution, and retail sectors.

In the liberalized market, retail companies are responsible for selling electricity to end consumers. These companies can either be affiliated with distribution companies or operate independently. Retail companies purchase electricity from the wholesale market or directly from generators and sell it to consumers at competitive prices.

As part of the liberalization process, consumers with a certain level of annual electricity consumption are allowed to choose their electricity supplier. This threshold has been gradually reduced over the years, enabling more consumers to participate in the competitive market. Now, about 60% of the consumers are eligible consumers, which means they have the rights of contracting retail agreements [3]. For non-eligible consumers, the retail tariffs are regulated by EMRA. The electricity consumption by sectors is given in Fig. 1.9.

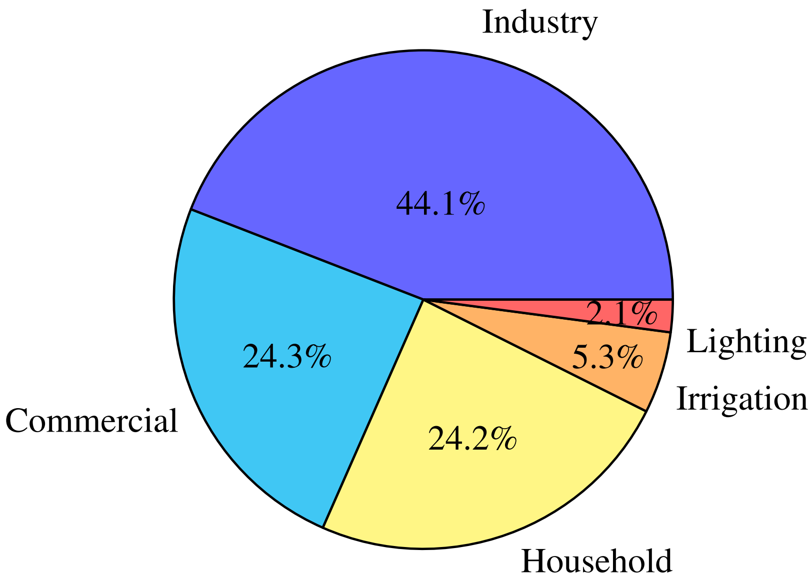


Figure 1.9: Distribution of Consumers by Sectors in 2021 in Turkey [3]

Consumers have not bid in the Balancing Market and participate in congestion management yet. However, new regulations on aggregators are expected to facilitate and encourage consumers into market mechanisms. Thus, the increase in the number of actors in the Balancing Market will facilitate the system operator's network management. Similar to the generation, electricity consumption in Turkey is unevenly distributed across the country. Fig. 1.10 shows the distribution of energy consumption among geographic regions. The consumption is mainly concentrated in Istanbul, Izmir, and East Mediterranean region. The large amount of power transfer between the North and South Marmara region is one of the challenging parts of the transmission network.

Figure 1.10: Distribution of the Consumption by Regions [2]

CHAPTER 2

GENERAL BACKGROUND

2.1 Literature Survey on OPF

After the first formulation of the OPF problem in the 1970s, numerous solution techniques have been proposed [18]. In OPF methods with an AC network model, original power flow equations are considered in the optimization problem. Nonlinear optimization methods (i.e., Successive Linear Programming, Interior Point Method) are used to solve the problem due to the non-convex and non-linear nature of the problem.

Some methods linearize network models to approximate ones, also called DC-OPF models. They assume voltage angle differences of neighboring buses are close to zero, and voltage magnitudes are close to nominal values. This approach reduces the computational complexity, and guarantees the convergence; however, the accuracy of the solution is sacrificed. There are also various metaheuristic methods suggested for OPF based on machine learning techniques (i.e., Genetic Algorithm, Particle Swarm Optimization) to overcome this complex problem [19].

An OPF formulation has several features to meet the requirements of the power industry. These can be listed as:

- **High computational speed**: Speed is the key requirement for OPF in practical implementation, especially in real-time applications and large-scale networks. Moreover, to overcome the complex requirements of security-constrained OPF, an efficient OPF algorithm is a must.
- **Reliability of solution**: An OPF algorithm should be able to present a solution even for stressed network conditions reliably.

- **Robustness of solution**: OPF solutions must be insensitive to starting points of variables, and must be stable against the system operating conditions.
- **Flexibility**: An OPF algorithm should respond to the requirements of regulations and the special operating principles.
- **Cover security constraints**: An OPF algorithm that considers security constraints in optimization has a significant advantage for system security.
- **Integer variable**: A transmission system has discrete control variables such as switch status or tap positions, OPF algorithms should consider these integer variables.
- **Low computational requirements**: There is always a hardware limit of servers dedicated to run OPF algorithms. It is a desirable feature to have low computational requirements in terms of memory and processor.
- **Integrability**: An OPF algorithm must be suitable for incorporation into more complex control processes, such as energy management systems.

It is a very challenging task to include all the stated features into a single algorithm; therefore, OPF algorithms are considered as state of art applications.

There is always a trade-off between the speed of the solution, risk of convergence, and accuracy of results. Throughout the thesis process, different OPF models are surveyed and compared. Comprehensive surveys are conducted for the efforts to formulate and solve OPF algorithms [20, 21]. The most suitable OPF formulation is determined and developed to meet the time and convergence requirements of system operators in real-time operation. Notable works on OPF are presented in this section.

2.1.1 OPF Methods with AC Network Model

The nonlinearity and nonconvexity of the AC-OPF problem are caused by the power flow Equations (2.1) and (2.2). For OPF methods with the strict AC network model, general-purpose solution algorithms for nonlinear programming (NLP) problems can be applied, including the Newton method [22], quadratic programming (QP) methods, Successive Linear Programming, and Interior Point Methods.

$$P_{ij} = g_{ij}\left(v_i^2 - v_i v_j cos\theta_{ij}\right) - b_{ij} v_i v_j sin\theta_{ij} \tag{2.1}$$

$$Q_{ij} = -b_{ij}\left(v_i^2 - v_i v_j cos\theta_{ij}\right) - g_{ij} v_i v_j sin\theta_{ij} \tag{2.2}$$

NLP algorithms deal with problems containing non-linear objectives and/or constraints. Successive Linear Programming (SLP) approach is a practiced method for OPF problems [23–25]. SLP, also known as Sequential Linear Programming, is a series of linear approximations implemented to a non-linear optimization problem. The original NLP is reduced to an LP using a linear approximation of the objective function and constraints about an initial estimate of the optimal solution. The obtained LP is then solved, a new linearization is performed for the new solution point, and the process iterates until convergence.

In SLP as applied to OPF, an optimal solution is obtained by iterating between conventional power flow and linearized LP subproblems. Specifically, at each iteration, the linearization is performed by generating a 1st order Taylor series expansion about the solution of a conventional power flow. SLP is desirable for OPF because it retains the speed of LP but approaches the accuracy of NLP methods. In addition, SLP can guarantee improvement in the objective function at every iteration. However, because the linear program is constructed around a current operating point, these methods find local optima only. In addition, the linearization process can lead to oscillation as the algorithm approaches the optimum, or to slow convergence and even divergence in the case of highly nonlinear objective functions.

In the context of SLP utilized for OPF, an optimal solution is achieved through a cycle of traditional power flow and linearized Linear Programming (LP) sub-problems. Specifically, each cycle involves a linearization process, which is carried out by creating a first-order Taylor series expansion centered around the solution of a standard power flow. SLP is favored for OPF as it maintains the speed of LP while nearing the precision of NLP methods. Moreover, SLP can assure enhancement in the objective function with each cycle. However, as the linear program is built around a current operational point, these methods find only the local optimum. Furthermore, the linearization process can result in oscillation as the algorithm nears the optimum, or cause slow convergence and even divergence in instances of highly nonlinear objective functions.

Castillo *et al.* [26] present an SLP approach to solve the AC-OPF by applying first-order Taylor series expansions to construct local subproblems, and then apply a combination of outer approximation and constraint reduction techniques. Authors iteratively co-optimize real and reactive power dispatch and enable the system operator more optimal control over system resources. However, the current limitation of the proposed work is that for non-convex problems, there are no known theoretical convergence results to the global optimum for SLP algorithms. In another work, the author [27] decomposes the UC problem into a tighter outer approximation subproblem and an inner approximation subproblem, where the former leads to a better lower bound than the outer approximation (OA) method, and the latter provides a better upper which offers a theoretical guarantee of convergence to the global optimum in a finite number of iterations. Regardless, for non-convex MINLPs such as the UC with AC network constraints, the OA method is considered as a heuristic method.

One of the conventional methods of solving nonlinear OPF problems is the interior point method. In [28], the improved quadratic interior point method is used to solve the problem with a variety of objective functions, including economic dispatch, reactive power (VAR) planning, and loss minimization. The paper [29] analyses the ability of three interior-point based algorithms: the pure primal-dual, the predictor-corrector, and the multiple centrality corrections to solve OPF problems.

There are also Stochastic Optimization (SO) methods implemented on OPF and UC. [30] reviews the works that have contributed to the modeling and computational aspects of stochastic optimization-based UC.

Actually, it is very difficult for TSOs to apply these algorithms in clearing markets or DAMs or real-time scheduling, as long as their computational convergence cannot be guaranteed, although it has the advantage of introducing the voltage constraints into its formulation through exact modeling. In [31], the computational issues of market-based optimal power flow are discussed through the introduction of new OPF formulations and algorithms.

2.1.2 Metaheuristic Methods for OPF

The modern heuristic optimization algorithms represent a group of intelligent algorithms that either make analog of the natural evolution process based on Darwinian principles or mimic a certain natural phenomenon in searching for an optimal solution. They have been successfully applied to a wide range of power system optimization problems where non-differentiable regions exist and the global solution is extremely difficult to be determined.

The non-deterministic optimization methods are random search algorithms that aim to overcome the problem of the weak global search capabilities of the deterministic algorithms. There are numerous metaheuristic techniques such as Ant Colony Optimization, Artificial Neural Networks, Chaos Optimization Algorithms, Tabu Search, etc. The most popularly used heuristic optimization algorithms in solving OPF problems are introduced briefly as follows.

Genetic algorithm (GA) is one of the most popular and famous approaches in evolutionary computation. Founded on the mechanism of natural genetics and Darwinian principles of evolution and natural selection, this novel algorithm showed strong capabilities and advantages for solving a wide range of problems. Kumar and Mohan [32] used GAs to solve the unit commitment problem with transmission constraints. The authors compared their results with those obtained using lambda iteration techniques for economic dispatch and concluded that their GA reduces the power losses.

GA can be considered as a population-based approach, the search process of which is conducted by means of transforming a set of points (individuals) to another set of points in the search space. Authors in [33] present an enhanced genetic algorithm for the solution of the OPF with both continuous and discrete control variables.

Particle swarm optimization (PSO) is one of the most important swarm intelligence paradigms. The PSO uses a simple mechanism that mimics swarm behavior in birds flocking and fish schooling to guide the particles to search for a globally optimal solution. As PSO is easy to implement, it has rapidly progressed in recent years and with many successful applications in solving real-world optimization problems. [34] proposes an algorithm based on PSO, which minimizes the deviations of rescheduled values of generator power outputs from scheduled levels.

Reference [35] develops a learning-augmented method for solving AC OPF, which integrates both power network equations and machine learning (ML) to yield near-optimal solutions.

Though each methodology has its own philosophy, the fundamental idea unifying all the specified meta-heuristics is the systematic exploration of the search space using a heuristic improvement scheme. Meta-heuristics are able to escape local optimum and converge to a global optimum solution. However, these methods generally require high computational resources. In many cases, a computation time barrier may be encountered for real-time applications; therefore, there are fewer commercial implementations with respect to deterministic or linear programming methods.

2.1.3 OPF Methods with Linearized Network Model

OPF methods with linearized network models intend to linearize the power flow equations (2.1) and (2.2) and facilitate the linear formulation of the OPF model following a DC approach. OPF methods with linearized network models are preferred by system operators because of their desirable computational performance. The simplex method is the most robust optimization method for linear problems. Another advantage of the linear optimization model is its transparency. The influencing factors in the OPF model are linearly coupled.

The theory of the DC models is based on the following conclusions for well-designed and properly operated electricity networks:

- Bus voltage angles of the neighboring busses are "close", i.e., $\theta_i - \theta_j \approx 0$.
- Bus voltage magnitudes are close to their nominal values, i.e., $v_i \approx 1$ pu.
- Branch susceptances are many times greater than branch conductances.

The basic foundation of DC model theory is summarized in [36]. The DC approximation methods are widely used by system operators to solve the OPF problems in electrical markets, thanks to their low computational burden and the convergence can be guaranteed. The DC-OPF problem is a convex problem and for this reason, it can be easily solved. However, the DC-OPF lacks the accuracy of the solution because the reactive power flows are not considered, and the voltages are set at their rated value. The drawback of DC-OPF is that the voltage constraints are not considered in the classical linearized algorithms.

However, there are studies advancing the DC models. These studies aim the increase the accuracy of linearization and try to consider the voltage and reactive power effects. The approaches can be categorized under two groups: state-dependent linearization and state-independent linearization. Yang *et al.* [37] presents a state-independent linear power flow model with an accurate estimation of voltage magnitude, and [38] uses line outage distribution factors of a linearized AC model for economic dispatch problem.

A new method is introduced in [39] that considers reactive power flows for cold start models. Finally, a novel state-dependent linear power flow model (for hot-start models) is proposed by Yang *et al.* [40]. This state-dependent approach is applied to the redispatch problem in our study, and the undefined initial condition is embodied by the base case network operating conditions of the congested case. The "Linearized AC OPF" in the developed algorithm considers bus voltage magnitudes and branch reactive power flows; therefore, a higher approximation to branch loadings is obtained.

2.2 Literature Survey on Security Constraints Formulation

A power system is called secure if the system can withstand any credible contingency without serious consequences [41]. System operators can take preventive actions in real-time operations for the sake of security. Therefore, the developed algorithm is extended with security constraints.

Power flow equations in contingency cases can introduce an excessive amount of variables and constraints to the optimization problem. In order to keep the robustness of the algorithm, the Benders Decomposition (BD) technique is applied in the solution procedure. Benders Decomposition is a frequently used technique in SCOPF problems for large-scale networks.

In [42], an effective AC corrective/preventive contingency dispatch over a 24-h period is formulated as security-constrained unit commitment (SCUC) problem and the hourly scheduling of generating units is obtained by Benders Decomposition technique.

Benders Decomposition can be applied to stochastic optimization problems, for example Wang [43] *et al.* constitute intermittency and volatility of wind power generation as subproblems of Benders. If the redispatch fails to mitigate violations, Benders cuts are created and added to the master problem to revise the commitment solution.

The optimization problems for large scale networks with multiple time horizon can be still exhausting work for BD. In these cases, attempts to simplify the problem such as reducing the dependency of subproblems [44] or a combination of Benders decomposition type algorithm with the outer approximation technique [45] are done. Moreover, contingency filtering techniques [46] can be applied to create a credible list of contingencies, thus problem size can be reduced.

Security constrained redispatch problem stands at more advantage position comparing to the unit commitment problems since the subproblems are not depend on each other with time-limit constraints. In security constrained redispatch problem, subproblems are only interact with master problem, thus BD provides a robust solution opportunity. Therefore, BD technique is utilized in this thesis and the details are provided in Chapter 4.

CHAPTER 3

OVERVIEW OF THE ALGORITHM

The optimum redispatch algorithm is designed as a software application to operate in the control center of a TSO. In this Chapter, the architecture of the Economic Redispatch Algorithm that is developed and implemented in this study is presented.

Economic Redispatch Module is designed to operate and control the network state and conduct the redispatch actions if necessary. Initially, this algorithm obtains the network model data and performs pre-processing. Then it calculates network states by performing a load flow (LF) analysis. Network states predicate voltage violations and overloadings in branches. If there is no congestion observed, the system presents LF analysis results. If there is, redispatch candidates are obtained from Balancing Market. Generation up/down costs are based on the bids of generation companies. OPF problem is finally carried out to obtain the most economical solution for eliminating congestion. If the optimization problem is solved successfully, new power flows are calculated after redispatch. The workflow diagram is summarized in Fig. 3.1.

Throughout the thesis, three terms are used to distinguish each other;

- **Base Case** is the grid condition before the optimization, whether it is congested or not. The parameters $P_{g,0}$ or $v_{i,0}$ are calculated or measured values from the base case.
- **Normal Case** represents the grid condition (v_i or θ_i) after the redispatch optimization.
- **Contingency Case** is the n-1 state of the electricity network (θ_i^c or $P_g^{R,c}$) after any single branch outage c occurs.

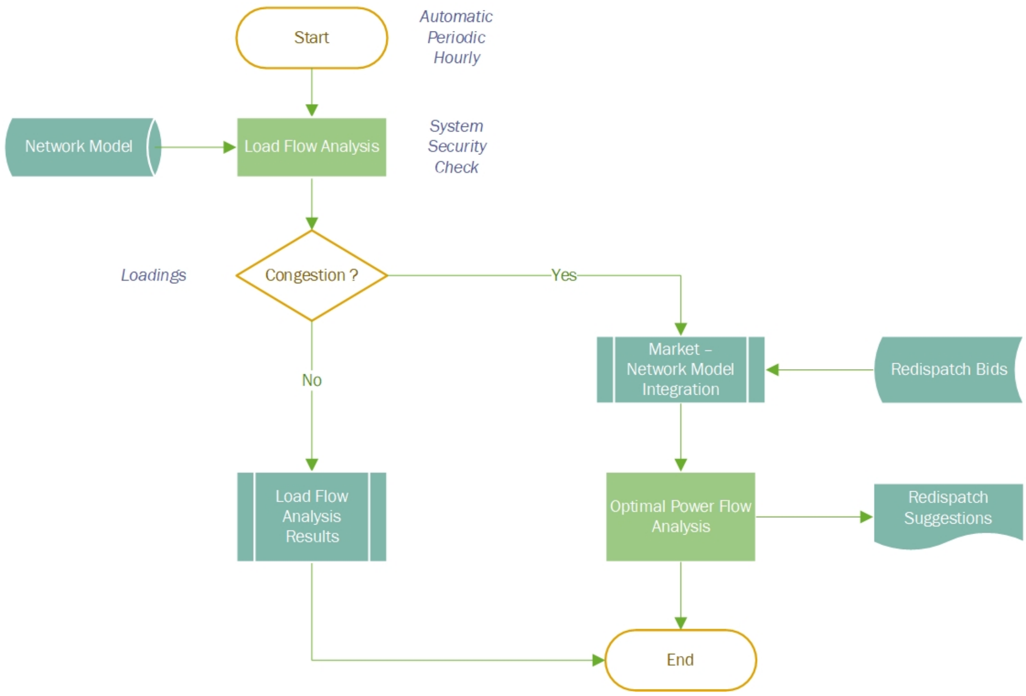


Figure 3.1: Workflow of the Economic Redispatch Module

3.1 Optimal Power Flow Criteria

The economic redispatch algorithm runs with a predefined setting list and can be managed by this parameter configuration. In the settings, these parameters take part:

- **Method**. Defines the calculation technique by the algorithm. Options:
  - DC OPF
  - AC Linearized OPF (Cold Start)
  - AC Linearized OPF (Warm Start)

  Default value: AC Linearized OPF (Warm Start).
- **Slack Bus**. Defines the bus code of the slack bus where the slack generator is connected.
- **Voltage Limit for 400 kV Network**. Options:
  - Critical Operational Limit: 1.05 pu - 0.93 pu
  - Normal Operational Limit: 1.03 pu - 0.97 pu

  - Custom Operational Limit: Limits defined by TSO for each bus

  Default value: Normal Operational Limit.

- **Voltage Limit for 154 kV Network**. Options:
  - Critical Operational Limit: 1.10 pu - 0.90 pu
  - Normal Operational Limit: 1.05 pu - 0.95 pu
  - Custom Operational Limit: Limits defined by TSO for each bus

  Default value: Critical Operational Limit.

- **Flow Limit for 400 kV Transmission Lines**. Options:
  - Thermal Limit
  - Operational Limit: Limits defined by TSO for each line
  - None: No limits

  Default value: Operational Limit.

- **Flow Limit for 154 kV Transmission Lines**. Options:
  - Thermal Limit
  - Operational Limit: Limits defined by TSO for each line
  - None: No limits

  Default value: None.

- **Flow Limit for 400/154 kV Transformers**. Options:
  - Thermal Limit
  - None: No limits

  Default value: Thermal Limit.

- **Decision Variables**. Multiple selection options:
  - Generator Active Power Generation
  - Generator Reactive Power Generation
  - Load Shedding in Contingency Cases

- Renewable Curtailment in Contingency Cases
- Additional Generator Active Power Generation in Contingency Cases

Default value: Generator Active Power Generation.

OPF-solving criteria are configurable by a system administrator, and the algorithm is tested by various setting configurations.

3.2 Network Model

The second input of the algorithm is the network model. The network model consists of buses, transmission lines, transformers, generators, loads, shunt equipment, and their electrical characteristics. The model also contains measurements and the topological state of the grid.

The network model can be supplied with IEEE Case Data Format, and then it is converted to a defined network model convention. In application, network data is supplied from the network model database of TSO. If required, Common Information Model (CIM) is an applicable format for the network data in the future.

In real-time operation, a snapshot of the grid is provided. However, intra-day forecast models can be used as input for the algorithm. Thus, forecast congestion and redispatch results can be obtained.

The scope of the network is limited to the transmission network (i.e., > 36kV). If any medium or low voltage equipment exists in the network data, they are reflected to the transmission coupling point and then eliminated. So that size of the network data is optimized.

Finally, topology processing algorithms are performed on the network data, such as the elimination of out-of-service equipment and merging parallel buses to minimize the network matrix.

3.3 Load Flow Analysis

Redispatch planning starts with the calculation of load flows. A fully coupled Newton-Raphson algorithm with a high convergence rate is developed to obtain the network states. The network states are used to calculate the branch flows and to detect if any congestion occurs. Additionally, network states are used to linearize the network, as stated in the problem formulation. The base case results are presented to the operators if no congestion is detected.

The load flow calculation routine starts with the construction of the network admittance matrix using the network model. According to the initial conditions in the analysis criteria, bus voltage magnitudes and angles are created as variables. Then the bus control modes (PV, PQ, SL) are determined.

The full Jacobian matrix and the bus injection array are created. Sparse matrix data storage methods are utilized. A mismatch array is obtained with sparse matrix calculation techniques. With the obtained new variables, bus mismatch values are updated.

When the maximum mismatch value is observed under the limit specified in the analysis criteria, the iteration is terminated, and the flow values are calculated. If it is not below the limit, the loop is repeated until it exceeds the maximum iteration limit. The workflow of the developed load flow algorithm is given in Fig. 3.2.

In this section, the steps of the load flow calculation algorithm are detailed.

3.3.1 Load Flow Analysis Criteria

The operation of the load flow analysis is defined with a setting preference. The settings contain the following options.

- **Method**. Defines the calculation technique by the algorithm. Options:
  - DC Load Flow
  - AC Full Newton Raphson

  Default value: AC Full Newton Raphson.

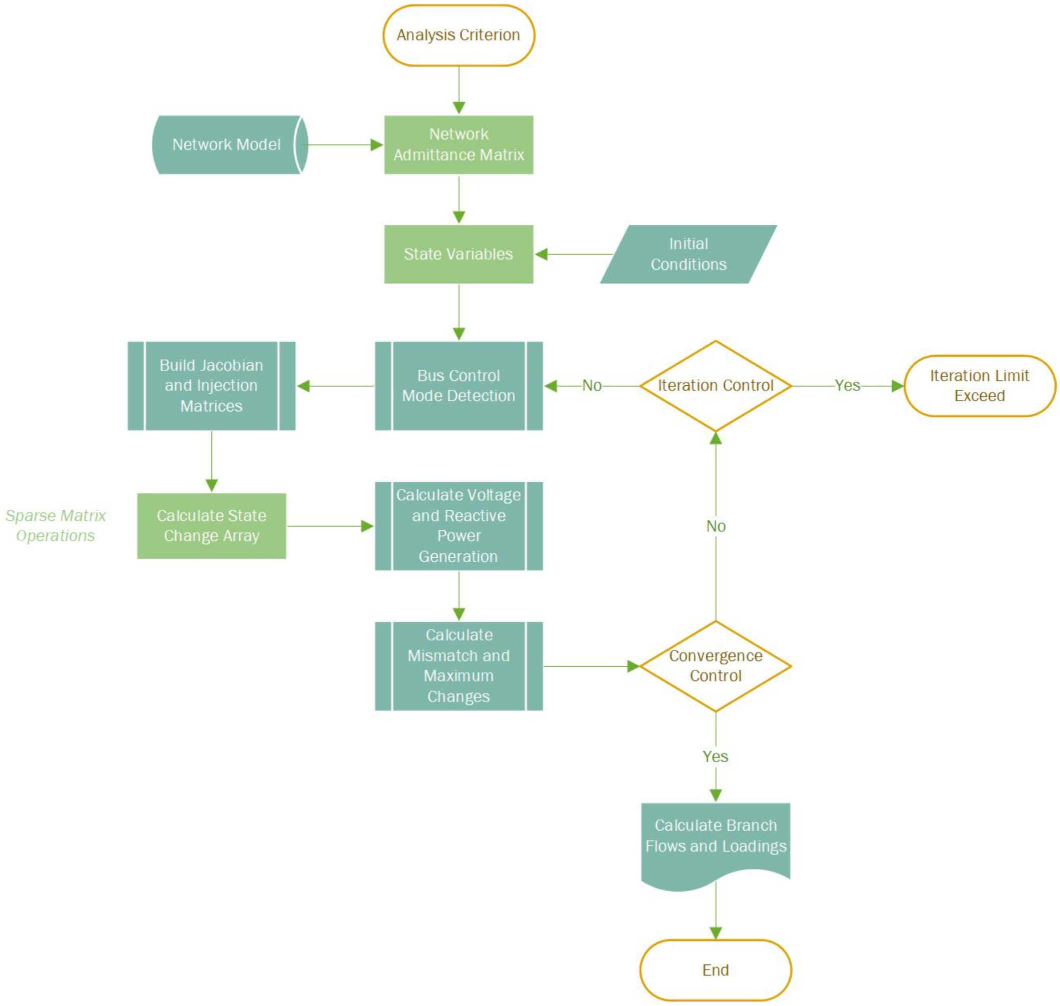


Figure 3.2: Workflow of the Load Flow Analysis

- **Initialization**. Defines the initial values of bus voltages and angles. Options:
  - Flat Start
  - Cold Start
  - Warm Start
  - DC Based

  Default value: Cold Start.

- **Slack Bus**. Defines the bus code of the slack bus where the slack generator is connected.

- **Active Power Dispatch**. Defines how the difference between generation and consumption (including losses) will be balanced. Options:

- Slack Generator
- Distributed by loads.

Default value: Distributed by loads.

- **Acceleration Factor (ACCN)**. Defines the update of variables between iterations. Options: (0,2]. Default value: 1.
- **Largest Mismatch in MW & MVAr (TOLN)**. Defines the maximum value of power sum in a bus at the successful solution. Options: (0.001,2]. Default value: 0.1.
- **Maximum Iteration Number (ITMXN)**. Defines the maximum number of iterations while trying to find convergence. The calculations that reach the maximum iteration number are labeled as "iteration limit exceeded". Options: (>0). Default value: 15.
- **Largest change in bus voltage (DVLIM)**. Defines the maximum limit of voltage correction in an iteration. It provides stability in calculation cycles. Options: (0.01, 1). Default value: 0.99.
- **Largest voltage change threshold (BLOWUP)**. Used for determination of instability of a calculation with controlling the largest value of bus voltage change in an iteration. The calculation is labeled as blown up if the specified value is exceeded. Options: (>0). Default value: 5.0.
- **Controlled bus Q mismatch convergence tolerance (VCTOLQ)**. Defines the maximum value of the reactive power mismatch for a voltage-controlled bus. Options: (>0). Default value: 0.1.
- **Controlled bus voltage error convergence tolerance (VCTOLV)**. Defines tolerance between calculated voltage and target voltage for voltage-controlled buses. Options: (>0). Default value: 0.0001.
- **Apply VAR Limits**. Defines the iteration number to force voltage-controlled generators inside reactive power limits. Options:
  - 1: Immediately

– x: Start at Iteration x

– Maximum Iteration Number + 1: Ignore

Default value: 2.

3.3.2 Network Admittance Matrix

In the second step, the network admittance matrix is created. The network admittance matrix is obtained with the calculation of admittance values between neighboring buses. The network admittance matrix consists of impedance objects of lines, transformers and series capacitors, and shunt equipment.

Transmission lines contribute to the matrix with the following:

$$\begin{aligned} Y(i,i) = Y(j,j) &= Series\ Admittance(i,j) + Shunt\ Admittance(i,i) \\ Y(i,j) = Y(j,i) &= -Series\ Admittance(i,j) \end{aligned} \tag{3.1}$$

where

$$\begin{aligned} Series\ Admittance(i,j) &= \frac{1}{Resistance(pu) + jReactance(pu)} \\ Shunt\ Admittance(i,i) &= j\frac{Susceptance(pu)}{2} \end{aligned} \tag{3.2}$$

Transformers contribute to the matrix with the following:

$$\begin{aligned} Y(i,i) &= Series\ Admittance(i,j) + Shunt\ Admittance(i,i) \\ Y(i,j) = Y(j,i) &= Series\ Admittance(i,j) \\ Y(j,j) &= Series\ Admittance(j,j) \end{aligned} \tag{3.3}$$

where

$$\begin{aligned} Series\ Admittance(i,i) &= y_{ij}^{'} \\ Series\ Admittance(i,j) &= y_{ij}^{'} * (-t) \\ Series\ Admittance(j,j) &= y_{ij}^{'} * t^2 \\ Shunt\ Admittance(i,i) &= y_{ii}^{'} \end{aligned} \tag{3.4}$$

$$
\begin{aligned}
&y_{ii}^{'}\ (Corrected\ Series\ Admittance) = y_{ij} * f\\
&y_{ii}^{'}\ (Corrected\ Shunt\ Admittance) = y_{ii}/f\\
&t\ (Tap\ Change\ Ratio) = \frac{V_{OperationalPri.WindingVol.}}{V_{Pri.WindingNom.BusVol.}} / \frac{V_{OperationalSec.WindingVol.}}{V_{Sec.WindingNom.BusVol.}}\\
&f\ (Impedance\ Correction\ Factor) = \frac{S_{base}}{S_{equipment}} * \frac{V^2_{OperationalWindingVol.}}{V^2_{BusNominalVol.}}
\end{aligned}
\tag{3.5}
$$

Series capacitors contribute to the matrix with the following:

$$
\begin{aligned}
Y(i,i) = Y(j,j) &= Series\ Admittance(i,j)\\
Y(i,j) = Y(j,i) &= -Series\ Admittance(i,j)
\end{aligned}
\tag{3.6}
$$

where

$$
Series\ Admittance(i,j) = j\frac{1}{Reactance(pu)} \tag{3.7}
$$

Shunt equipment contributes to the matrix with the following:

$$
Y(i,i) = Shunt\ Admittance(i,i) \tag{3.8}
$$

where

$$
\begin{aligned}
&Shunt\ Admittance(i,i) = -\frac{1}{Q^c(pu)}\\
&Q^c(Corrected\ R.\ Power) := Operational\ R.\ Power \times \frac{V^2_{BusNom.Vol.}}{V^2_{EquipmentNom.Vol.}} \times (-1)^{**}\\
&^{**}\ if\ equipment\ type\ is\ capacitor.
\end{aligned}
\tag{3.9}
$$

In general, i refers to the from bus index, and j refers to the end bus index.

3.3.3 Problem Variables

In load flow analysis, the main calculation parameters are bus voltage magnitude ($|V_i|$) and bus voltage angle (θ_i). Branch flows are calculated from these values. In addition, the reactive power generation of the voltage-controlled generators is calculated.

In the third step, the main variables are initialized with the initialization criteria of load flow analysis. These values can be;

- **Flat Start**: $|V_i| = 1$ pu, $\theta_i = 0$ rad are taken.
- **Cold Start**: $|V_i| = V_i^m$ pu, $\theta_i = 0$ rad are taken. V_i^m is the voltage measurements of the grid.
- **Warm Start**: $|V_i| = V_i^s$ pu, $\theta_i = \theta_i^s$ rad are taken. V_i^s corresponds to predefined voltage magnitude, and θ_i^s is predefined voltage angles. This option refers to starting from the previous calculation's final conditions.
- **DC Based**: $|V_i| = V_i^m$ pu, $\theta_i = \theta_i^c$ rad are taken. V_i^m is the voltage measurements of the grid, and θ_i^c is the result of the bus voltage angle of DC Load Flow calculation.

3.3.4 Bus Control Modes

In the fourth step, bus control modes are determined. These modes are;

- **SL**: A bus is called the Slack Bus with the preference in the analysis criteria.
- **PV**: A bus, its voltage is regulated. For a bus to be PV bus, at least one of the voltage controllers must target the bus, the control mode of this voltage controller must be voltage control, and the reactive power produced by the units of this controller must be within the reactive power capability. In addition, the direction of the reactive power limit should be coherent with the target bus voltage and the calculated bus voltage.
- **PQ**: All other buses are labeled as PQ buses.

For generators whose voltage controller is in voltage control mode, if the generated reactive power is not within the limits, the voltage control mode of the generator is corrected as PQ, and the generated reactive power value is equalized to the limit.

3.3.5 Jacobian Matrix

In the fifth step, the Jacobian matrix is created. The Jacobian matrix consists of differential active and reactive power values to the bus voltage and angle. The Jacobian matrix assumes a coupled relation between PQ and $V\theta$. The structure of the Jacobian matrix is given in equation 3.10.

$$\begin{bmatrix} \frac{\partial P_2}{\partial \theta_2} & \cdots & \frac{\partial P_2}{\partial \theta_n} & & |V_2|\frac{\partial P_2}{\partial |V_2|} & \cdots & |V_N|\frac{\partial P_2}{\partial |V_N|} \\ \vdots & H & \vdots & \cdots & \vdots & N & \vdots \\ \frac{\partial P_N}{\partial \theta_2} & \cdots & \frac{\partial P_N}{\partial \theta_n} & & |V_2|\frac{\partial P_N}{\partial |V_2|} & \cdots & |V_N|\frac{\partial P_N}{\partial |V_N|} \\ & \vdots & & \ddots & & \vdots & \\ \frac{\partial Q_2}{\partial \theta_2} & \cdots & \frac{\partial Q_2}{\partial \theta_n} & & |V_2|\frac{\partial Q_2}{\partial |V_2|} & \cdots & |V_N|\frac{\partial Q_2}{\partial |V_N|} \\ \vdots & M & \vdots & \cdots & \vdots & L & \vdots \\ \frac{\partial Q_N}{\partial \theta_2} & \cdots & \frac{\partial Q_N}{\partial \theta_n} & & |V_2|\frac{\partial Q_N}{\partial |V_2|} & \cdots & |V_N|\frac{\partial Q_N}{\partial |V_N|} \end{bmatrix} \begin{bmatrix} \Delta\theta_2 \\ \vdots \\ \Delta\theta_N \\ \cdots \\ \frac{\Delta|V_2|}{|V_2|} \\ \vdots \\ \frac{\Delta|V_N|}{|V_N|} \end{bmatrix} = \begin{bmatrix} \Delta P_2 \\ \vdots \\ \Delta P_N \\ \cdots \\ \Delta Q_2 \\ \vdots \\ \Delta Q_N \end{bmatrix} \tag{3.10}$$

The entries of Jacobian matrix, H, M, N and L are given as;

$$H_{ij} = \frac{\partial P_i}{\partial \theta_j} = -|Y_{ij}V_iV_j|\sin(\delta_{ij} + \theta_j - \theta_i) \tag{3.11}$$

$$H_{ii} = \frac{\partial P_i}{\partial \theta_i} = -Q_i - |V_i|^2 B_{ii} \tag{3.12}$$

$$N_{ij} = |V_j|\frac{\partial P_i}{\partial |V_j|} = -\frac{\partial Q_i}{\partial \theta_j} \tag{3.13}$$

$$N_{ii} = |V_i|\frac{\partial P_i}{\partial |V_i|} = \frac{\partial Q_i}{\partial \theta_i} + 2|V_i|^2 G_{ii} \tag{3.14}$$

$$M_{ij} = \frac{\partial Q_i}{\partial \theta_j} = -|Y_{ij}V_iV_j|\cos(\delta_{ij} + \theta_j - \theta_i) \tag{3.15}$$

$$M_{ii} = \frac{\partial Q_i}{\partial \theta_i} = P_i - |V_i|^2 G_{ii} \tag{3.16}$$

$$L_{ij} = |V_j|\frac{\partial Q_i}{\partial |V_j|} = +\frac{\partial P_i}{\partial \theta_j} \tag{3.17}$$

$$L_{ii} = |V_i|\frac{\partial Q_i}{\partial |V_i|} = -\frac{\partial P_i}{\partial \theta_i} - 2|V_i|^2 B_{ii} \tag{3.18}$$

The Jacobian matrix is recalculated in each iteration with most recent values of bus voltages and angles. Bus control modes are determined in each iteration with controlling whether the reactive power generation of voltage controlled generators are at limits or not. The dimensions and content of the Jacobian matrix may change in every iteration with bus control modes.

3.3.6 Injection Array

In the sixth step, power injection and mismatch arrays are calculated. The equations used in the algorithm are given in Eq. 3.19 and 3.20.

$$P_i = \sum_{n=1}^{N} |Y_{in} V_i V_n| \cos(\delta_{in} + \theta_n - \theta_i) \tag{3.19}$$

$$Q_i = -\sum_{n=1}^{N} |Y_{in} V_i V_n| \sin(\delta_{in} + \theta_n - \theta_i) \tag{3.20}$$

where Y_{ij} is the entry of network admittance matrix, δ_{ij} is the angle of Y_{ij}, θ_n is voltage angle of bus n.

The mismatch array is calculated by the difference between scheduled and calculated powers. ΔP_i is for PV or PQ buses, while ΔQ_i is for only PQ buses.

$$\Delta P_i = P_{i,sch} - P_{i,calc} \tag{3.21}$$

$$\Delta Q_i = Q_{i,sch} - Q_{i,calc} \tag{3.22}$$

3.3.7 Change Matrix

In the seventh step, the change matrix (or delta array) is calculated by using Jacobian and Mismatch matrices. Sparse matrix techniques are utilized in the solution of Equation 3.23.

$$\begin{bmatrix} H & N \\ M & L \end{bmatrix} \begin{bmatrix} \Delta\theta \\ \frac{\Delta|V|}{|V|} \end{bmatrix} = \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \tag{3.23}$$

Using the $\Delta\theta$ and $\frac{\Delta|V|}{|V|}$ vectors, bus voltage variables are updated as in Equation 3.24 and 3.25. k refers to the iteration index.

$$\theta_i^{(k+1)} = \theta_i^{(k)} + \Delta\theta_i^{(k)} \tag{3.24}$$

$$|V_i|^{(k+1)} = |V_i|^{(k)} + \left(1 + \frac{\Delta|V_i|^{(k)}}{|V_i|^{(k)}}\right) \tag{3.25}$$

In the eighth step, reactive power injection values are calculated for PV buses. Then, reactive power is distributed to the generators linearly based on their active power generation. Special cases, such as different power factors of the same power plant and synchronous compensator operating modes, are considered in this distribution.

3.3.8 Convergence Check

In the ninth step, the following criteria are checked.

- Bus voltage change does not exceed the threshold BLOWUP (blown-up)
- Bus angle change does not exceed the threshold BLOWUP (blown-up)
- Active power mismatch does not exceed the tolerance TOLN (unconverged)
- Reactive power mismatch of a PQ bus does not exceed the tolerance VCTOLQ (unconverged)
- Reactive power mismatch of a PV bus does not exceed the tolerance VCTOLV (unconverged)
- Regulated bus voltage does not exceed the target voltage by the threshold (unconverged)

If the conditions are met, the load flow solution is stated as successful, and the algorithm moves to the tenth step. If a blown-up condition is detected, the algorithm is terminated. If an unconverged condition is detected, the iteration number is checked with the iteration limit (ITMXN). If the iteration has reached the upper limit, the calculation is terminated with the iteration limit exceeded status; otherwise, the algorithm goes to the fourth step.

3.3.9 Calculation of Flow Variables

If the load flow calculation is ended successfully with convergence, power flows, loadings, and branch losses are calculated. The branch flow equations for active power and reactive power are given in 3.26 and 3.27.

$$P_{ij} = |V_i^2|(g_{si} + g_{ij}) - |V_i||V_j|(g_{ij}\cos\theta_{ij} + b_{ij}\sin\theta_{ij}) \quad (3.26)$$

$$Q_{ij} = -|V_i^2|(b_{si} + b_{ij}) - |V_i||V_j|(g_{ij}\sin\theta_{ij} - b_{ij}\cos\theta_{ij}) \quad (3.27)$$

For transmission lines, y_{ij} = g_{ij} + j b_{ij} refers to the series admittance of the branch between bus i and j. b_{si} refers to the half of the shunt susceptance between bus i and j.

For transformers,

$y_{ij} = g_{ij} + jb_{ij} = y_{ij}^{'} * t$

y_{ii} = g_{si} + j b_{si} = $y_{ij}^{'} * (1 - t) + y_{ii}^{'}$

y_{jj} = g_{sj} + j b_{sj} = $y_{ij}^{'} * (t - 1) * t$

where $y_{ij}^{'}$ refers to the corrected series admittance, $y_{ii}^{'}$ corrected shunt admittance, t refers to the tap change factor.

The developed load flow calculation algorithm is tested with a real network data on more than 1000 hours of different operational scenarios. A successful convergence performance is obtained. The results of bus voltages and angles and branch flows are compared with the results of a conventional power system analysis software. It was observed that there was a one-to-one agreement in the results.

3.4 Definition of Congestion

A successful solution of load flow calculation is a prerequisite for the economic redispatch algorithm. If the LF solution is not converged, the redispatch algorithm is terminated. Otherwise, the detection of the contingency process is executed.

The security of a power system is having an operation condition that will result in no load is interrupted and no equipment is damaged. The security of the grid is violated (i.e., congestion occurs) if any of the following conditions are experienced:

- Violations of power flow limits in branch elements

- Violations of voltage limits in buses
- Violations in stability conditions
  - Small-signal stability
  - Transient stability
  - Voltage stability

In addition to specified conditions, a system in a secure operating state can sustain one or several *contingencies*, such as a transmission line going down or a generator unexpectedly going off-line, and continue to function without interruption. This is called the security-constrained operation of the system.

In this thesis, stability constraints are not considered in optimal power flow analysis.

If an overload in branch elements is calculated in the base case after LF analysis, the network state is considered as congested. The next process, redispatch modeling and OPF, is started. Otherwise, the algorithm is terminated with "No congestion is detected in the base case conditions". The branch monitoring list can be managed by TSO such as ignoring the overload in a specific line or adapting the loading limit with dynamic conditions.

If only a violation of the voltage limits is observed in the base case condition, the OPF procedure does not executed. The voltage problem in the network is not necessarily solved with the active power redispatch technique. TSO generally corrects voltage profile with shunt capacitor or reactor switching, regulation transformer tap positions, or adapting voltage settings of power plants.

3.5 Redispatch Cost Modelling

For a market-based OPF modeling, the costs should be based on the bidding strategies of producers in the Balancing Market. The redispatch cost modeling process has three main steps:

1. Obtaining the market data

2. Integrating the market data to the physical network data

3. Validating and converting the bids to the redispatch costs

In this section, the details of the redispatch cost modelling are given.

Economic Redispatch Module obtains the bids from the Balancing Power Market of TEİAŞ. The producers who bid in the Balancing Market constitute the redispatch candidates, i.e., not all generators are candidates for the optimization problem. However, the solution of the problem can be infeasible in certain congested cases. In such cases, the problem is reconstructed with more general decision variables: all generators are assigned as a redispatch candidate. The legal basis of this approach is the network regulations authorize TSO to take necessary actions to secure the grid.

In the real-time operation of the algorithm, redispatch bids for the reference time period are queried. If the bid list is found to be empty, the algorithm is terminated with a "There exists no redispatch candidate" error message. This rare case is due to a communication error.

The properties of the obtained market bids are;

- Based on the unit of settlement, this can be a single generator or multiple generators.
- Bids are valid for a single hour, there is no block offer concept.
- Bids are maximum +/- 15 steps (pieces) in generation up and down direction.
- Bids in MW unit.

In the next step, the integration of the market model to the physical model procedure is executed. A map between the unit of settlement and generators is used in the optimization problem. A unit of settlement can refer to one or more generators in the grid. The redispatch amount vs. redispatch cost formulation is associated with the summation of the redispatch amount of the related generators.

The generation unit-based formulation is expected to model the aggregators in electricity markets. An aggregator is a new type of energy service provider that can manage the electricity generation (or consumption) of a group of power plants. An aggregator is expected to bid a single offer for generators scattered at different locations in the grid. The suggested formulation supports the modeling of these new market players and offers solutions to TSO in congestion management.

Then, bids are validated and corrected if necessary. Initially, if a generation-up cost is less than the market clearing price (MCP), the cost is equalized to MCP. Or, if a generation-down cost is greater than MCP, the cost is equalized to MCP. A typical structure of a bid in the Balancing Market is given in Fig. 3.3.

$$Generation\ Up\ Cost \geq Market\ Clearing\ Price$$

$$Generation\ Down\ Cost \leq Market\ Clearing\ Price$$

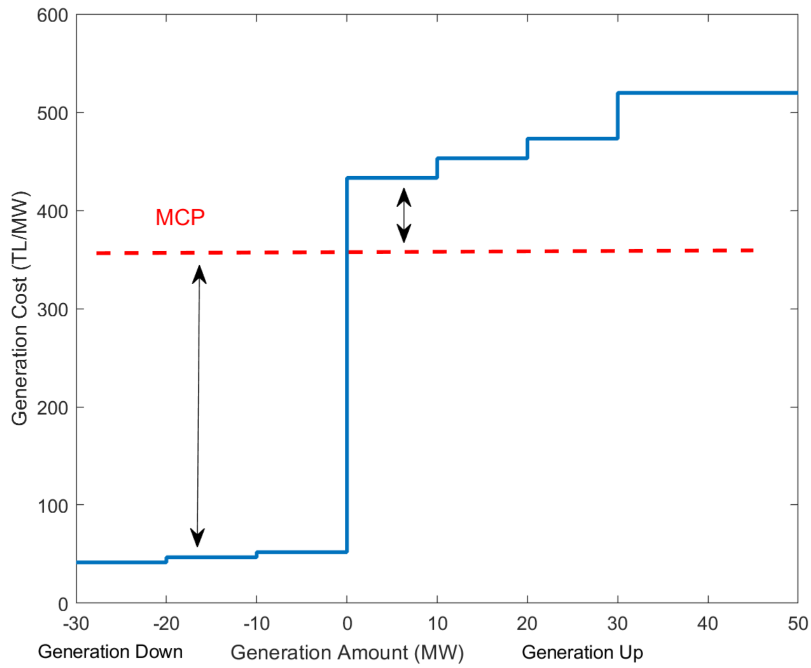


Figure 3.3: A Typical Generation Bid in the Market

The redispatch cost is represented as a piece-wise linear function and formulated as the difference between the generation cost and MCP. Thus, readjusting the base case generation in either direction reflects an operational cost. Since the objective function of the problem is to obtain a secure network condition with a minimum cost, the minimum number of redispatch actions is tried to obtain.

$$Redispatch\ Up\ Cost = Generation\ Up\ Cost - MCP$$

$$Redispatch\ Down\ Cost = MCP - Generation\ Down\ Cost$$

With this method, a typical bid submitted as in Fig. 3.3 is rearranged as in Fig. 3.4. Thus, keeping a generation as in the base case becomes costless and changing generation in both direction generates redispatch costs.

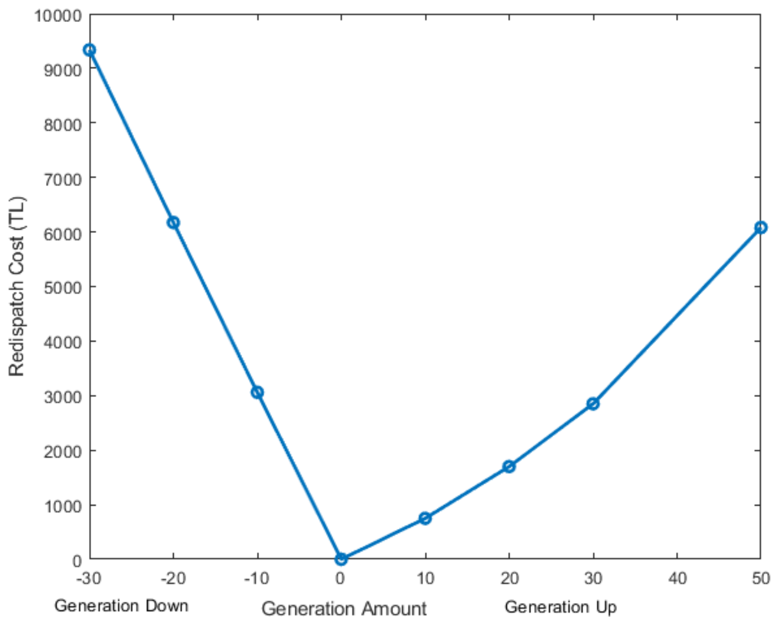


Figure 3.4: A Calculated Redispatch of a Power Plant

In the next step, the limits of the redispatch are validated. If the total redispatch up limit is greater than the active power reserve, the upper limit is readjusted. If the total redispatch down limit exceeds the active power generation, the down limit is readjusted as in Fig. 3.5.

$$Redispatch\ Up\ Amount \leq Maximum\ Active\ Power - Active\ Power\ Generation$$

$$Redispatch\ Down\ Amount \leq Active\ Power\ Generation$$

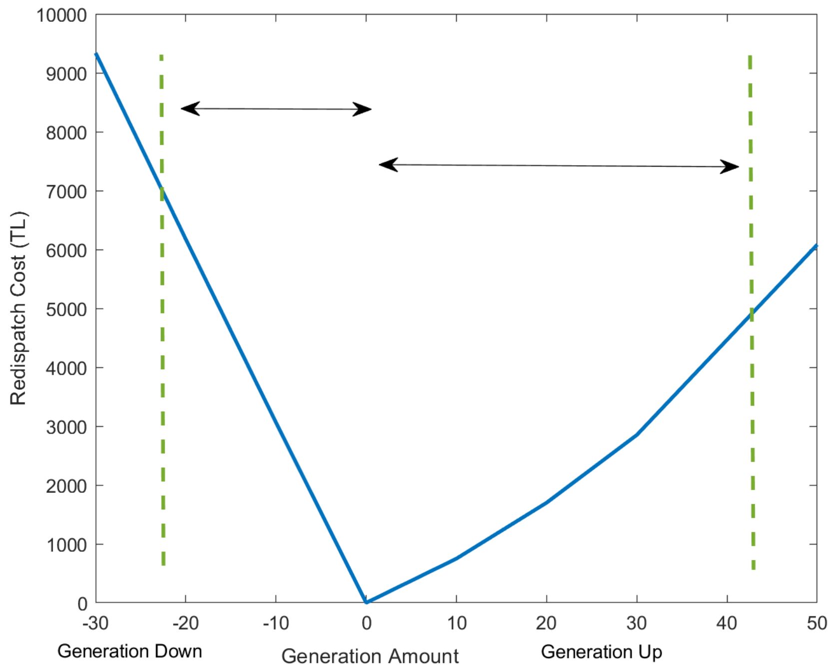


Figure 3.5: A Converted Redispatch Cost in the Problem

The cases which a feasible solution of the optimization problem is not found is called emergency cases. In such cases, the generators, who do not commit to the Balancing Market, are assigned as decision variables. For that generators, the cost of the generation up is defined as the highest generation up cost in the network in the reference hour.

Similarly, the cost of the generation down is defined as the highest generation down cost in the network. This approach ensures that power plants not participating in the market are not given redispatch orders as much as possible.

A rare but a possible risk in the cost formulation may result due to the generation costs that are close to the marginal clearing price since their redispatch costs are near zero. In this condition, the solution may try to redispatch generation more generously and increase the number of redispatch actions. To prevent this probability, the base additional cost (when the redispatch of a generator is non-zero) is considered a deterrent measure.

3.6 Optimal Power Flow Analysis

After the redispatch decision variables are prepared, the optimum power flow calculation is performed. The optimal power flow problem contains power flow constraints in the normal case and contingency cases. The problem formulation and the state of art approach for the robust solution of the problem are given in depth in Chapter 4.

3.7 Definition of Contingency

Security of supply in the power system requires that the robustness of the network can be satisfied with endurance against contingencies. This robustness depends on the redundancy of the grid and security limits. Traditionally, the "N-1" contingency analysis has been used to control the security margin of the network. This methodology requires the definition or listing of the contingency events.

The contingency events are mainly referred to events of equipment being out-of-service. Three types of contingency event are considered in the formulation:

- **Normal (N-1) Contingencies**: This type of contingency contains a single element. Elements are generally one of the transmission lines or auto-transformers.
- **Normal (N-k) Contingencies**: This type of contingency contains more than one elements. This contingency category refers to network elements that will be out of service in a single fault event. These elements are usually protected by a single relaying schema. The transmission lines connected with a junction point are an example of this contingency list.
- **Exceptional Contingencies**: This type of contingency contains more than one elements. These contingencies contains independent equipment and defined by the TSO for critical security considerations.

In the study, for the Standard Test Case applications, only normal (N-1) contingency events are listed for security formulations. All transmission lines are assigned as out-of-service event.

For the Real Test Case applications, three types of contingency events are included in the contingency list. The contingency list is limited with extra high voltage network (i.e., 400 kV).

After the formation of the contingency list, contingency filtering processes are executed. Initial check is that a contingency is valid only if contingency elements do not partition the network. A bridge is illustrated in Fig. 3.6.

In Graph Theory, this condition is called "bridge", and defined as an edge in an undirected connected graph is a bridge if removing it disconnects the graph. In order to detect this elements, a bridge detection algorithm is implemented. Depth-first search (DFS) is an algorithm for traversing or searching tree or graph data structures. The algorithm starts at the root node (selecting some arbitrary node as the root node in the case of a graph) and explores as far as possible along each branch before backtracking. Contingency listing is filtered if a branch element is a bridge accordingly.

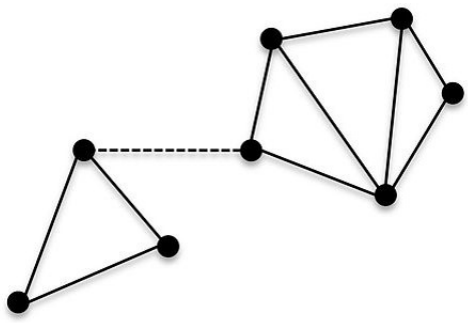


Figure 3.6: Visualization of a Bridge Element in a Graph

For a large-scale network, the number of possible contingencies is high. The high number of contingencies increases the size of the optimization problem and the duration of the solution. Various techniques have been developed to limit the problem size to obtain a subset of the set of credible contingencies ([47]). These methods involve screening and direct ranking of the contingency cases. Screening involves the fast approximate power-flow simulation of each contingency case. By monitoring the appropriate post-contingent quantities (flows, voltages), the case's severity can be quantified directly in some heuristic manner for ranking purposes. A severity measure is often a single number, the Severity or Performance Index.

In security formulations, a contingency screening technique is not implemented; all eligible contingencies are considered in the formulation. Instead, the speed performance-increasing techniques are applied. Nonetheless, for a faster solution to the problem, a contingency filtering technique can be implemented and added to the solution algorithm. The security formulation in the algorithm is presented in Chapter 4 in detail.

3.8 Specifications of the Developed Software

The developed algorithm is designed as a software system and environment to be deployed as an energy management system of a TSO in real time operation. The server architecture of the system is presented in Fig. 3.7. The servers are operated in a virtualized environment. The system components can be listed as following:

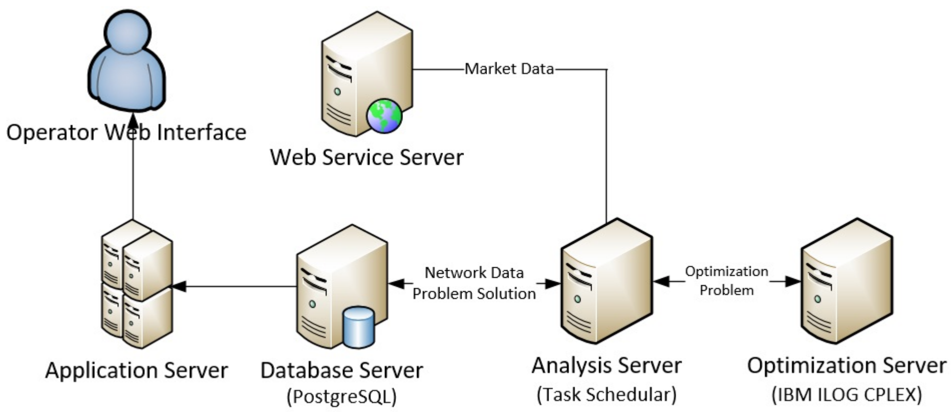


Figure 3.7: Server Architecture of the Developed System

- **Analysis Server**: The main server that operate the simulation process. It has a task scheduler feature that help to run the algorithm periodically and automatically in a specific manner. The server can obtain the network model from the database server, run the load flow calculation, and obtain the market data through the web service server. It can build the optimization problem, and obtain a solution via optimization server. When the process is done, the server send the solution and messages to the database server.
- **Optimization Server**: The optimization server contains the optimization solver application. It is the server where CPLEX installation is located. In principle,

the optimization application can solve any CPLEX mathematical problem independent of OPF. In this way, it is aimed to take part in solving other optimization problems in the future.

- **Web Service Servers**: The web service servers contain the client side of RestFUL APIs to obtain the data from market systems. It has access rights to integrated systems.
- **Database Servers**: Database servers are responsible for storing DBMS (PostgreSQL) and database itself. Its main role is supplying the network data for analysis server and supplying the problem solution for the application servers.
- **Application Servers**: Application servers host and run the server side of the user application. They take the data and solution of the congestion problem and present them to the operators. The web application also provide the setting management of the algorithm and manually trigger the run of the algorithm by TSO.

The software is developed fully in Java language, and is independent of the operation system.

3.9 The Developed System in Real Operation

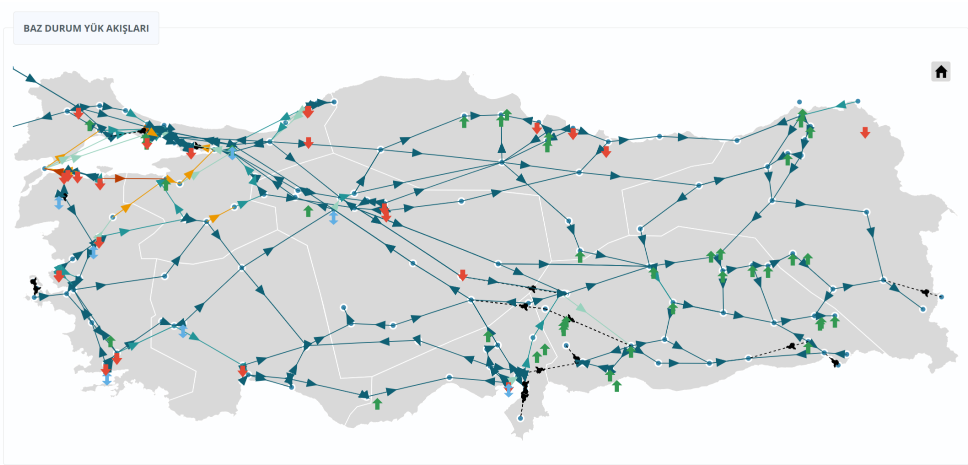
The developed algorithm is deployed as a software system to TSO of Turkey, and integrated into the Energy Management System. The system operators access the operation and results of the algorithm via web interfaces. Operators monitor congestions in the base case and the final operating condition and then report the suggested redispatch orders.

The outputs of the developed software can be listed as follows.

- The state of the calculation after termination:
  - Load flow calculation is unsuccessful
  - Optimum power flow calculation is unsuccessful

  - Optimum power flow calculation is successful
  - No redispatch bid regarding to the reference hour is found
  - Marginal clearing price regarding to the reference hour is found
  - There is no congestion in the base case condition

- The list of congestion, and overloads in transmission lines, are listed if any.
- The total redispatch cost (the result of the objective function without penalties)
- The list of suggested redispatch actions in the base case
- The list of suggested additional redispatch actions in a contingency case
- The redispatch candidate list (power plants bid to the Balancing Market)
- The load shedding candidates and results in a contingency if necessary
- The renewable curtailment candidates and results in a contingency if necessary
- The contingency list considered in the optimization
- Bus voltage and branch flow calculations in the base case. Fig. 3.8 shows the power flows on transmission lines in the form of a map and data table. The users can monitor the redispatch candidates on the same map. When the cursor hover the icons on the map, the detailed information (names, magnitudes etc.) is given.
- Bus voltage and branch flow calculations in the normal case (after redispatch). Fig. 3.9 shows the power flows on transmission lines as a map and data table. The users can monitor the redispatch suggestions on the same map. When the cursor hovers over the icons on the map, detailed information is given.
- The relaxed constraints if the optimization problem is infeasible and solved with a relaxation. This list indicates there is nonsatisfying conditions, such as a line power flow could not be decreased below the rating.
- The list of messages (errors, warnings, data validation violations) generated during the execution of the algorithm.



BAZ DURUM, 400kV HAT AKIŞLARI

HAT ID	HAT ADI	BAŞLANGIÇ GÖRÜNÜR GÜÇ (MVA)	BAŞLANGIÇ AKTİF GÜÇ (MW)	BAŞLANGIÇ AKIM AKIŞ (A)	BİTİŞ GÖRÜNÜR GÜÇ (MVA)	BİTİŞ AKTİF GÜÇ (MW)	BİTİŞ AKIM AKIŞ (A)	KAPASİTE (MVA)	YÜKLENME (%)	KAYIP (MW)
3996	400kV GELİBOLU - BEKİRLİ TES - II EİH	932,7	-930,8	1347	939,9	937,0	1340	1040	89,7	6,24
3995	400kV GELİBOLU - BEKİRLİ TES - I EİH	931,0	-929,1	1344	938,3	935,3	1338	1040	89,6	6,23
2204	400kV BURSA DGKÇ - BANDIRMA DGKÇ EİH	1248,0	-1230,8	1784	1255,2	1255,1	1793	1500	82,8	24,30
4875	400kV İKİTELLİ - DELİKLİKAYA EİH	1282,9	-1270,1	1845	1281,6	1272,1	1846	1700	75,3	2,10
4151	400kV TÜRKGÜCÜ - GELİBOLU EİH	1171,0	-1161,4	1697	1179,0	1178,2	1702	1700	69,4	16,81
2197	400kV BURSA SANAYİ - KÖYLÜKÖY EİH	693,5	-690,0	991	701,0	700,4	998	1000	69,1	10,39
3207	400kV DAVUTPAŞA - İKİTELLİ EİH	672,6	-672,5	967	680,6	673,0	979	1040	65,2	0,50
3296	400kV SEYİTÖMER TES - ESKİŞEHİR3 EİH	658,0	650,1	929	655,3	-645,5	921	1000	64,4	4,56

Figure 3.8: Presentation of Base Case Calculations

To present results to operators, web-based graphical user interfaces are developed. Fig. 3.10 is a display from the congestion management module. Users can query results by submitting date and time. The results of the operation of the algorithm can be viewed both for the real-time condition and historical outputs. The operators can also trigger the run of the algorithm manually in case needed through the web page.

FİNAL DURUM YÜK AKIŞLARI

FİNAL DURUM, 400kV HAT AKIŞLARI

HAT ID ⇅	HAT ADI ⇅	BAŞLANGIÇ GÖRÜNÜR GÜÇ (MVA) ⇅	BAŞLANGIÇ AKTİF GÜÇ (MW) ⇅	BAŞLANGIÇ AKIM AKIŞ (A) ⇅	BİTİŞ GÖRÜNÜR GÜÇ (MVA) ⇅	BİTİŞ AKTİF GÜÇ (MW) ⇅	BİTİŞ AKIM AKIŞ (A) ⇅	KAPASİTE (MVA) ⇅	YÜKLENME (%) ⇅	KAYIP (MW) ⇅
2204	400kV BURSA DGKÇ - BANDIRMA DGKÇ EİH	1169,8	-1141,2	1674	1164,7	1162,7	1691	1500	78,1	21,50
3996	400kV GELİBOLU - BEKİRLİ TES - II EİH	759,0	-757,2	1096	762,3	761,3	1090	1040	73,0	4,13
3995	400kV GELİBOLU - BEKİRLİ TES - I EİH	757,6	-755,8	1094	761,0	759,9	1088	1040	72,9	4,12
4875	400kV İKİTELLİ - DELİKLİKAYA EİH	1176,6	-1169,5	1691	1176,3	1171,2	1693	1700	69,0	1,76
4491	400kV İSTANBUL F.OİL DGKÇ (B) - YENİBOSNA EİH	624,9	623,9	896	642,0	-623,3	923	1040	61,5	0,56
3207	400kV DAVUTPAŞA - İKİTELLİ EİH	629,5	-627,3	906	629,0	627,8	904	1040	60,3	0,43
2197	400kV BURSA SANAYİ - KÖYLÜKÖY EİH	593,5	-592,1	848	600,4	599,7	854	1000	59,2	7,60
3837	400kV BÖLÜCEK - ZETES2 EİH	1027,1	-1025,5	1443	1030,9	1030,8	1445	1700	58,9	5,30
4151	400kV TÜRKGÜCÜ - GELİBOLU EİH	971,8	-967,1	1407	978,7	978,7	1413	1700	57,6	11,57

Figure 3.9: Presentation of Final Case Results

KISIT TALİMATI ANALİZİ

TARİH: * 06.02.2023 SAAT: * 13:00 ANALİZ: * 27.06.2023 22:43:06 Göster Hesapla

Genel Bilgiler

ANALİZ ID:	10013
ANALİZ ZAMANI:	06.02.2023 13:00
ÇÖZÜM:	Optimum yük akışı başarılı.
HESAPLAYAN KULLANICI:	SİNAN EREN
HESAPLANMA ZAMANI:	27.06.2023 22:43

TALİMAT ÖNERİSİ

ENERJİ TANIMLAMA KODU	UEVÇB ADI	BARA	YÖN	MİKTAR (MW)
40W000000000980K	İST.DGAZ-A BLOK(C)	400 B-1	YAL	420
40W000000000923W	İST.DGAZ- A BLOK(A)	154 B-2	YAL	280
40W000003205381G	ADAPAZARI DGKÇS	400 B-1	YAL	267
40W000003204385D	ESENYURT DGKÇ SANTRALI	154 B-1	YAL	148
40W0000000038744	DELTA DGKÇS	154 B-1	YAL	19
40W0000032055251	GEBZE DGKÇS_-2	400 B-1	YAL	10
40W0000032007305	ÇAN-2 TES	400 B-2	YAT	-20

Figure 3.10: Web Page Display for Economic Redispatch Module

Finally, a web page for setting management is developed, illustrated in Fig. 3.11. Authorized staff can define parameters such as minimum size in the magnitude of a redispatch, and penalty costs. In this way, against the different operational conditions, multiple control alternatives can be generated.

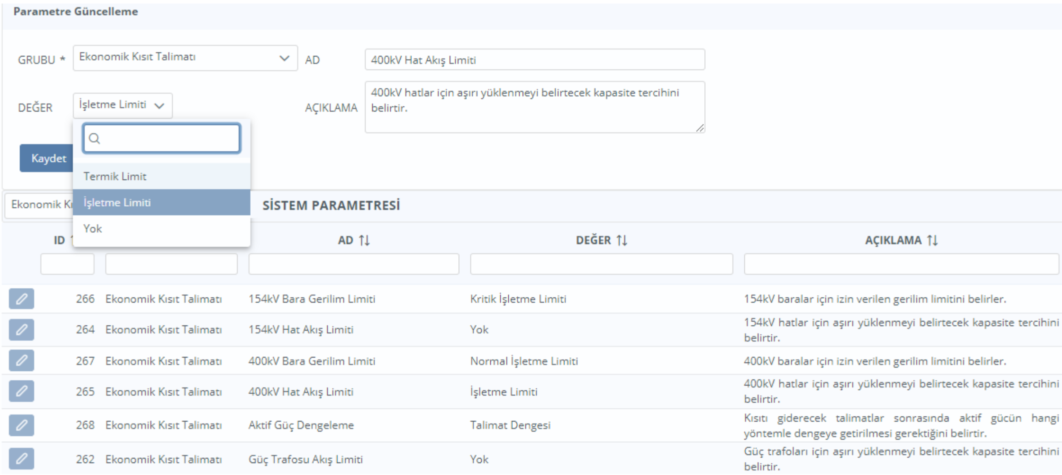


Figure 3.11: Parameter Management Interface

CHAPTER 4

PROPOSED METHOD

4.1 Mathematical Model

4.1.1 Objective Function and Generation Constraints

The problem's main objective function is the minimization of the total redispatch cost (4.1). Redispatch cost is calculated based on the piece-wise linear function of generation up/down bids; this formulation introduces integer variables into the problem. There are also penalty terms in the objective function, such as bus voltage magnitude deviation from base case results, since voltage adaptations require many control actions that are not easily applicable in real-time operation.

$$min \sum_{p \subset P} C_p^R + \sum \varepsilon \tag{4.1}$$

where p is the power plant index of plant set P, C_p^R is the redispatch cost, which is a piece-wise linear function of redispatch magnitude P_p^R (4.2). ε is the general expression of penalty terms which will be explained in detail in the following sections.

$$C_p^R = f(P_p^R) \tag{4.2}$$

The cost function f(.) in the problem is determined by the bids of GENCOs in the Balancing Market. The general structure of a bid is given in Figure 4.1. The general rules of the bids are:

- Generation cost should be increasing with the generation amount
- The costs for the generation up should be greater than the market price

- The costs for the generation down should be less than the market price
- There exists a limit of price segments in generation cost (for example, limits for the test case are 15 in the upward direction and 15 in the downward direction)
- Maximum redispatch magnitude for a plant is limited by the plant capacity minus the scheduled generation
- Minimum redispatch magnitude for a plant is limited to the scheduled generation

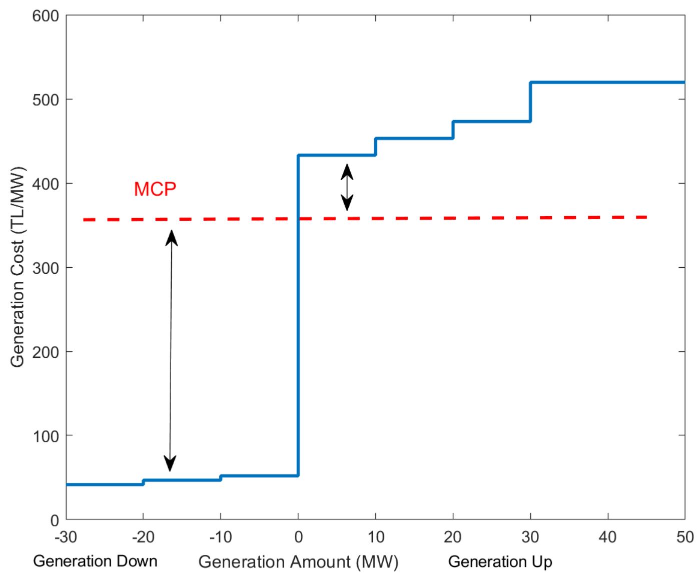


Figure 4.1: A Generation Cost Bid in the Market

The market price for the Standard Test Case, which is defined in Chapter 5, is calculated from the unit commitment solution. The most expensive generation is taken as a reference for the market price. The details of the test case data are given in Section 5.1. Day-ahead market clearing price (MCP) is used for the market price in the Real Test Case, which is 1400-bus transmission network of Turkey.

Then the incremental generation costs are converted to redispatch costs as the costs move away from the market price. The absolute difference between the generation cost and the market price is calculated for this purpose as shown in Figure 4.2.

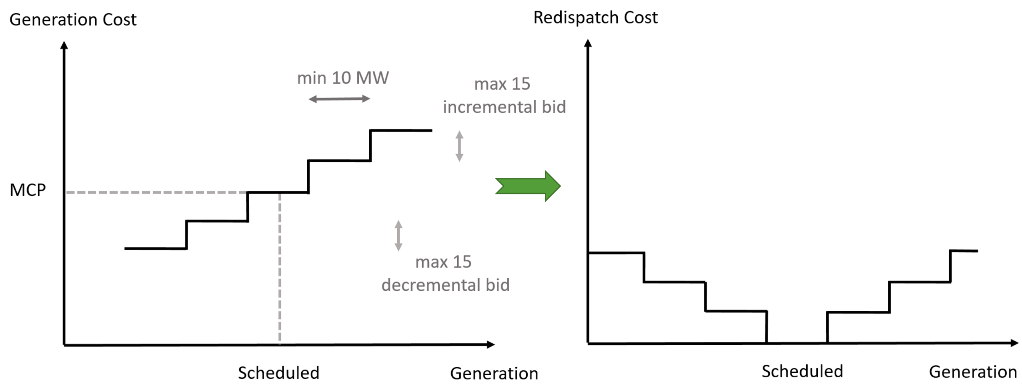


Figure 4.2: Generation Cost Bid to Redispatch Cost Bid

Each power plant has a maximum limit for generation up ($P_p^{up,max}$). This value refers to the available generation capacity minus the existing production. And a minimum limit exists for generation down ($P_p^{down,min}$). This value generally refers to the existing production of that plant. However, for some generation types, such as nuclear power plants, this value can be the minimum active power limit of generators since the plant shutdown is not a flexible option.

Finally, each redispatch order should have a minimum limit in both directions ($P_p^{up,min}$ and $P_p^{down,min}$). This constraint satisfies the elimination of insignificant redispatch suggestions for optimization and limits the number of the redispatch action in the sense of number of plants. These plant constraints are represented in the algorithm as in Eq. 4.3, where X_p^{down} and X_p^{down} refers to whether there exists a generation up/down condition in a particular plant.

$$P_p^{down,min} \times X_p^{down} + P_p^{up,min} \times X_p^{up} \leq P_p^R \leq P_p^{down,max} \times X_p^{down} + P_p^{up,max} \times X_p^{up} \tag{4.3}$$

Generation up/down conditions cannot exist together for the same power plant, represented as a constraint as in Eq. 4.4.

$$X_p^{down} + X_p^{up} \leq 1 \tag{4.4}$$

Bids of the GENCOs in Balancing Markets are usually piece-wise linear functions of redispatch amounts. The cost of the redispatch changes with the redispatch amount. The linear piece l of a bid of plant p is called the active bid by integer variable $X_{p,l}^{on}$.

$X_{p,l}^{on}$ is equal to 1, showing the price is formulated as the linear equation represented by the piece l. Active power redispatch amount is bounded with the start and end points of the bid function as formulated in Eq. 4.5.

$$\sum_{l \subset L^p} P_{p,l}^{min} \times X_{p,l}^{on} \leq P_p^R \leq \sum_{l \subset L^p} P_{p,l}^{max} \times X_{p,l}^{on} \tag{4.5}$$

Linear cost function at p, l is equal to $C_{p,l}^R = a_{p,l} \times P_p^R + b_{p,l}$ where $a_{p,l}$ and $b_{p,l}$ are derived from ($P_{p,l}^{max}$, $C_{p,l}^{max}$) and ($P_{p,l}^{min}$, $C_{p,l}^{min}$), as given in Figure 4.3.

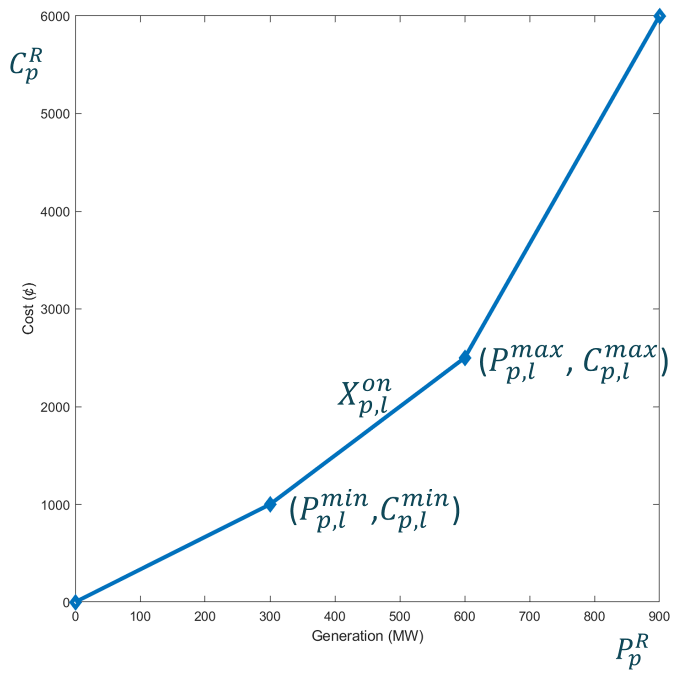


Figure 4.3: Formulation of Redispatch Cost

The redispatch cost of a plant is represented as in Eq. (4.6).

$$C_p^{min}(1 - X_{p,l}^{on}) \leq C_p^R - C_{p,l}^R \leq C_p^{max}(1 - X_{p,l}^{on}) \tag{4.6}$$

Redispatch of a power plant p is the sum of the redispatch values of generators that belongs to the power plant p (4.7). In Balancing Markets, generally, the bids are offered for a plant; however, the effects of power injections is originated from generators. In some cases, the location of generators belonging to the same power plant may have different connection points in the grid. Generators connected to different voltage levels in a substation can be given as an example.

$$P_p^R = \sum_{g \subset G^p} P_g^R \tag{4.7}$$

Modeling redispatch values of generators in the optimization ensures to cover the generator constraints. The minimum and maximum active power limits of generators are represented as in Eq. 4.8 where X_g^{on} is the on/off status of a generator. The redispatch actions may start up or shut down a generator through this constraint.

$$P_g^{min} \times X_g^{on} \leq P_{g,0} + P_g^R \leq P_g^{max} \times X_g^{on} \tag{4.8}$$

The power balance is satisfied with Eq. 4.9, thus suggested corrective actions do not disturb the frequency reserves.

$$\sum_{p \subset P} P_p^R = 0 \tag{4.9}$$

4.1.2 Power Flow Constraints as Corrective Actions

The transmission constraints, such as voltage limits and branch flow limits, are represented as power flow equations in the optimization. The active and reactive power flow equations on a branch are given in (4.10) and (4.11). These equations are nonlinear and non-convex by nature. The solution of the power flow equations in its original form is challenging and requires considerable computational burden.

$$P_{ij} = g_{ij}\left(v_i^2 - v_i v_j cos\theta_{ij}\right) - b_{ij} v_i v_j sin\theta_{ij} \tag{4.10}$$

$$Q_{ij} = -b_{ij}\left(v_i^2 - v_i v_j cos\theta_{ij}\right) - g_{ij} v_i v_j sin\theta_{ij} \tag{4.11}$$

Nodal active and reactive power balance equations are given in (4.12) and (4.13).

$$P_i + \sum_{g \in i} P_g^R = \sum_{(i,j) \in \mathcal{K}} P_{ij} + \left(\sum_{j=1}^{N} G_{ij}\right) v_i^2 \tag{4.12}$$

$$Q_i + \sum_{g \in i} Q_g = \sum_{(i,j) \in \mathcal{K}} Q_{ij} + \left(\sum_{j=1}^{N} -B_{ij}\right) v_i^2 \tag{4.13}$$

P_{ij} / Q_{ij} represent active/reactive power flows from bus i to bus j; P_i / Q_i represent active/reactive power injections at bus i; G_{ij} / B_{ij} are real / imaginary parts of Y_{ij}

in the bus admittance matrix; g_{ij} / b_{ij} are conductance / susceptance of branch (i, j); finally v_i / θ_i are voltage magnitude / angle at bus i.

These equations constitute a non-linear and a non-convex problem. In order to transform this problem into a linear problem, linearization techniques are utilized. Second-order Taylor series expansions of sine and cosine functions are applied (Eqs. 4.14 - 4.15), assuming θ_{ij} is generally low.

$$sin\theta_{ij} \approx \theta_{ij} \tag{4.14}$$

$$cos\theta_{ij} \approx 1 - \frac{\theta_{ij}^2}{2} \tag{4.15}$$

To decouple v and θ, voltage magnitudes are assumed to be close to 1 p.u. (Eqs. 4.16 - 4.17).

$$v_i v_j \theta_{ij} \approx \theta_{ij} \tag{4.16}$$

$$v_i v_j \theta_{ij}^2 \approx \theta_{ij}^2 \tag{4.17}$$

By substituting (4.16) and (4.17) into (4.10) and (4.11), the following equations are obtained:

$$P_{ij} = g_{ij}\left(v_i^2 - v_i v_j\right) - b_{ij}\theta_{ij} + \frac{1}{2}g_{ij}\theta_{ij}^2 \tag{4.18}$$

$$Q_{ij} = -b_{ij}\left(v_i^2 - v_i v_j\right) - g_{ij}\theta_{ij} + \frac{1}{2}(-b_{ij})\theta_{ij}^2 \tag{4.19}$$

Regarding v^2 as an independent variable, a mathematical transformation for nonlinear voltage magnitude term is used ($v_{ij} = v_i - v_j$):

$$v_i^2 - v_i v_j = v_i^2 - \left(\frac{v_i^2 + v_j^2}{2} - \frac{v_{ij}^2}{2}\right) = \frac{v_i^2 - v_j^2}{2} + \frac{v_{ij}^2}{2} \tag{4.20}$$

Without sacrificing the accuracy, the nonlinear term $v_i v_j$ is transformed into a linear term and a quadratic term by (4.20). By substituting (4.20) into (4.18) and (4.19), the linearized network model with Q and v is obtained:

$$P_{ij}^A = g_{ij}\left(\frac{v_i^2 - v_i^2}{2}\right) - b_{ij}\theta_{ij} + P_{ij}^L \tag{4.21}$$

$$Q_{ij}^A = -b_{ij}\left(\frac{v_i^2 - v_i^2}{2}\right) - g_{ij}\theta_{ij} + Q_{ij}^L \tag{4.22}$$

where

$$P_{ij}^L = \frac{1}{2}g_{ij}\left(\theta_{ij}^2 + v_{ij}^2\right) \tag{4.23}$$

$$Q_{ij}^L = \frac{1}{2}(-b_{ij})\left(\theta_{ij}^2 + v_{ij}^2\right) \tag{4.24}$$

Problem still constitutes non-convex behaviour due to θ_{ij}^2 and v_{ij}^2 terms. These terms are linearized using first-order Taylor series expansion (Eqs. 4.25 - 4.26) around the operating point of base case load flow conditions ($\theta_{i,0}$, $v_{i,0}$).

$$\theta_{ij}^2 \approx 2\theta_{ij,0}\theta_{ij} - \theta_{ij,0}^2 \tag{4.25}$$

$$v_{ij}^2 \approx 2\frac{v_{i,0} - v_{j,0}}{v_{i,0} + v_{j,0}}\left(v_i^2 - v_j^2\right) - \left(v_{i,0} - v_{j,0}\right)^2 \tag{4.26}$$

When θ_i and v_i^2 are chosen as independent variables, the problem becomes a linear optimization problem, as given in Eqs. (4.27) and (4.28). In the implementation, the original approach stated in [40] is adhered.

$$P_{ij}^L \approx g_{ij}\theta_{ij,0}\theta_{ij} - \frac{1}{2}g_{ij}\theta_{ij,0}^2 + g_{ij}\frac{v_{i,0} - v_{j,0}}{v_{i,0} + v_{j,0}}(v_i^2 - v_j^2) - \frac{1}{2}g_{ij}(v_{i,0} - v_{j,0})^2 \tag{4.27}$$

$$Q_{ij}^L \approx -b_{ij}\theta_{ij,0}\theta_{ij} + \frac{1}{2}b_{ij}\theta_{ij,0}^2 - b_{ij}\frac{v_{i,0} - v_{j,0}}{v_{i,0} + v_{j,0}}(v_i^2 - v_j^2) + \frac{1}{2}b_{ij}(v_{i,0} - v_{j,0})^2 \tag{4.28}$$

The other constraints of this problem are voltage and angle limits. And also, there exist branch power flow limits which are quadratic inequalities based on active and reactive power flows as shown in Eq. 4.29.

$$P_{ij}^2 + Q_{ij}^2 \leq (S_{ij}^{max})^2 \tag{4.29}$$

Branch flow limits are quadratic inequalities that constitute Mixed Integer Quadratically Constrained Linear Programming. In order to eliminate the quadratic relation and improve solution speed, branch capacities are represented by 12 linear equations (Figure 4.4).

$$Q_{ij} - m_\alpha P_{ij} \leq S_{ij}^{max} n_\alpha \qquad \forall\alpha \in 0, 30, \ldots, 150 \tag{4.30}$$

$$Q_{ij} - m_\alpha P_{ij} \geq S_{ij}^{max} n_\alpha \qquad \forall\alpha \in 180, 210, \ldots, 330 \tag{4.31}$$

where m_α and n_α are calculated for each piece of α.

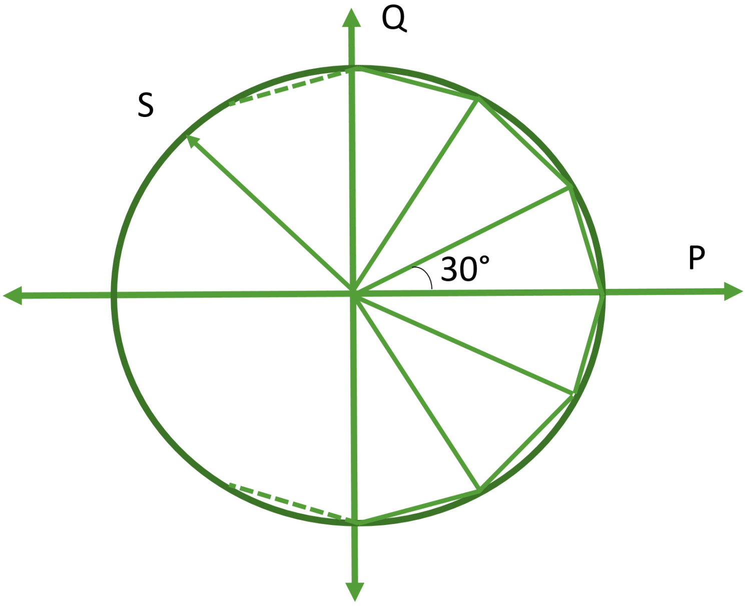


Figure 4.4: Linearization of Branch Capacity

The coefficients of the branch flow limiting constraints in Eqs. (4.30) and (4.31) are given in Table 4.1. The losses are expressed by a linear function, which can be positive or negative. However, the actual network losses should always be positive. To avoid the negative values of P^L_{ij}, the following constraint is added:

$$P^L_{ij} + \epsilon^+_{ij} \geq 0 \tag{4.32}$$

The penalty factor for ϵ^+_{ij} is added to the objective function.

The voltage magnitudes are variables in the network. However, congestion is expected to be eliminated by redispatch actions rather than the voltage scheduling of the network since it is not practically applicable in the real-time operation. Therefore, the following constraint is added:

$$v_i^2 + \gamma_i^+ - \gamma_i^- = v_{i,0}^2 \tag{4.33}$$

The penalty factors for γ_i^+ and γ_i^- are added to the objective function.

The implementation of penalty factor for voltage deviations from the base case is a contribution to the state-dependent linearization of optimal power flow for redispatch application. The penalty factor tries to keep the voltage values unchanged; thus, the

Table 4.1: Coefficients of branch flow limits after linearization

Angle (α)	m_α	n_α
0	-3.7321	3.7321
30	-1.0000	1.3660
60	-0.2679	1.0000
90	0.2679	1.0000
120	1.0000	1.3660
150	3.7321	3.7321
180	-3.7321	-3.7321
210	-1.0000	-1.3660
240	-0.2679	-1.0000
270	0.2679	-1.0000
300	1.0000	-1.3660
330	3.7321	-3.7321

linearization assumptions are satisfied as much as possible, and the accuracy of the results is increased.

4.1.3 Objective Function and Generation Constraints in Contingency Cases

The redispatch actions can be categorized under two groups as shown in Fig. 4.5. Redispatch actions for eliminating the congestion in the normal state are called corrective control. On the other side, redispatch actions for eliminating the congestion in contingency case are called preventive actions.

Security-constrained optimal power flow (SCOPF) is the extension of a standard optimal power flow. Contingency states are included in the optimization problem formulation. Thus, system constraint violations, such as those related to transmission lines and voltage constraints, can be avoided in both normal and contingency states.

Security constraints increase the number of variables and equations in the problem formulation considerably. Each contingency case introduces its own power flow

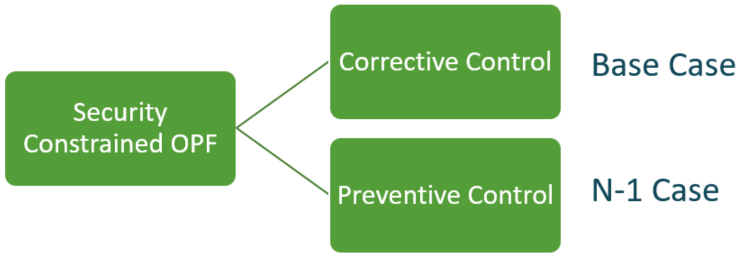


Figure 4.5: Corrective and Preventive Control

condition (i.e., θ_i and P_{ij}). These contingency state variables are specified with a contingency index c as used in θ_i^c or P_{ij}^c. Large networks having a high number of contingency cases constitute large optimization problems and create a significant computational burden preventing the efficient solution.

In problem formulation, corrective control actions and preventive control actions are loosely coupled to minimize the objective function. There are redispatch decision variables for normal case condition and contingency case separately. The redispatch amount of a generator (P_g^R) in the normal case is also valid for a contingency case. And there may exist an additional redispatch amount of the generator ($P_g^{R,c}$) in a contingency case.

The reason behind the additional redispatch amount due to a contingency is a probabilistic situation that may not happen. Preventive actions applied to the normal case is costly in the system operation. However, the additional actions should be in the region of the reachable state from the normal operation. This condition is satisfied by Eq. (4.34).

The ramp limits of the generators are active power change capabilities in 15 min. Any grid equipment is expected to withstand overloading conditions within a short time period. If a contingency requires significant redispatch action, which cannot be satisfied under ramp limits, the redispatch actions in the normal case is adapted in the optimization.

$$P_g^{ramp-down} \leq P_g^{R,c} \leq P_g^{ramp-up} \tag{4.34}$$

For contingency constraints, the additional redispatch actions should not violate the active power limits of the generators, satisfied with Eq. (4.35).

$$P_g^{min} \times X_g^{on} \leq P_{g,0} + P_g^R + P_g^{R,c} \leq P_g^{max} \times X_g^{on} \tag{4.35}$$

The additional redispatch action in a plant should not exceed the limits of generation up and down bid limits as in Eq. (4.3).

$$P_p^{down,min} \leq P_p^R + P_p^{R,c} \leq P_p^{up,max} \tag{4.36}$$

The power balance in a contingency is sustained with Eq. (4.37).

$$\sum_{p \subset P} P_p^{R,c} = 0 \tag{4.37}$$

A contingency case may be a stressed state of the grid resulting in a congestion. In some cases, the congestion may not be corrected via redispatch actions; thus, a feasible solution cannot be obtained. In order to obtain a feasible solution for all SCOPF solutions, the feasible region is increased by considering new decision variables of renewable curtailment and load shedding in contingency cases.

Renewable resources like wind, solar, and run-off-river hydros generally do not bid in the Balancing Market. If there are no storage capabilities, they cannot increase their generation. However, in need of system operating conditions, TSO has the right to apply renewable curtailment. Therefore, each renewable generation connected to the transmission grid is formulated as a variable in the optimization formulation. Renewable curtailment can be different for each contingency and limited to the generation in the base case, as shown in Eq. (4.38).

$$0 \leq P_r^c \leq P_r^{max} = P_{r,0} \tag{4.38}$$

In some cases, congested regions in the transmission network may not have close-by or effective generators (renewable or conventional). The bottlenecks cannot be simply eliminated by redispatch actions. In order to obtain feasible solutions for that situation, the load shedding option is included in the optimization formulation. Each (positive) load is a load-shedding candidate for the problem. Load shedding can be different for each contingency and limited to the consumption in the base case, represented with Eq. (4.39).

$$0 \leq P_d^c \leq P_d^{max} = P_{d,0} \tag{4.39}$$

Renewable curtailment and load shedding can help to obtain a feasible solution in security constraints; however, they are not desirable control actions. Thus, the objective function of the optimization is extended by the penalty costs of these preventive actions, as in Eq. (4.40). In simulations that will be presented in the following chapter, the cost of renewable curtailment is taken as three times of MCP. The cost of load shedding is taken as ten times of MCP.

$$min \sum_{p \subset \mathcal{P}} C_p^R + \sum \varepsilon + c_r \times \sum_{r \subset \mathcal{R}} P_r^c + c_d \times \sum_{d \subset \mathcal{D}} P_d^c \tag{4.40}$$

The additional generation in a contingency is not reflected as a cost function in the objective function to avoid an increase in computational complexity. However, the amount of the additional generation would like to be minimized and listed as a possible additional action list for operators. Therefore, penalty variables of non-positive $\beta_g^{+,c}$ and $\beta_g^{-,c}$ are created to bound $P_g^{R,c}$, as in Eq. (4.41).

$$P_g^{R,c} + \beta_g^{+,c} + \beta_g^{-,c} = 0 \tag{4.41}$$

The penalty factor for $\beta_g^{+,c}$ and $\beta_g^{-,c}$ are added to the objective function in the contingency formulation.

4.1.4 Power Flow Constraints as Preventive Actions

The power load flow equations are formulated in contingency cases as a linearized DC load flow model. In Figure 4.6, a branch element with electrical variables is shown.

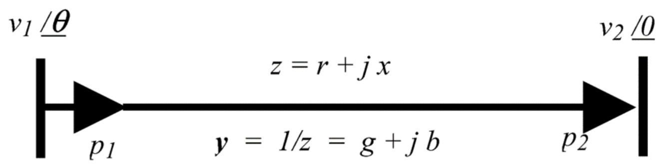


Figure 4.6: Power Flow through a Branch Element

A DC power flow derivation reduces the exact branch MW flow via a sequence of approximations. Initially, active power loss on a branch is neglected as in Eq. (4.42).

$$loss \approx 0 \rightarrow p_1 = p_2 = p = -v_1 v_2 b \sin\theta \tag{4.42}$$

Assuming the difference of bus voltage angles of the neighboring buses is small so that sine function is approximated to angle value as given in Eq. (4.43).

$$\sin\theta \approx \theta \rightarrow p = -v_1 v_2 b\theta \tag{4.43}$$

Assuming the bus voltages are close to their nominal values, the power flow equation becomes as in Eq. (4.44).

$$v_1, v_2 \approx 1 \rightarrow p = -b\theta \tag{4.44}$$

Finally, the resistance of the branch elements can be neglected assuming x » r, as given in Eq. (4.45).

$$-b \approx \frac{1}{x} \rightarrow p = \frac{\theta}{x} \tag{4.45}$$

In congestion management, the redispatch is applied to the given initial network state. And it is expected to have the final state of the grid (i.e., bus voltages and angles) close to the initial state.

In the proposed algorithm, in order to increase the accuracy of branch flow equations in contingency cases, only the assumptions of (4.43) are done. The branch losses calculated from the load flow algorithm are distributed to the branch connection busses equally as injections (Figure 4.7). The green branches represent high accuracy in branch flows (i.e., less then 3 MW) by the DC solution compared to the AC solution. As branch colors turns red, the difference in results may reach up to 30 MW.

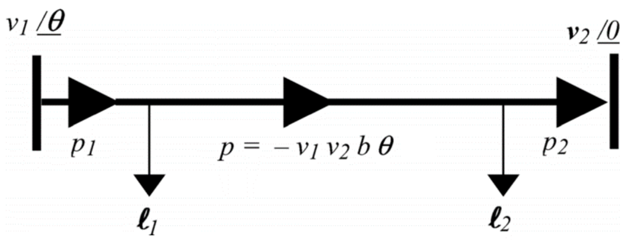


Figure 4.7: Linearized Branch Power Flow

The utilized active power flow equation in the algorithm is given in (4.46).

$$P_{ij}^{c} = -v_i v_j b_{ij} \theta_{ij}^{c} \tag{4.46}$$

This approach increases the accuracy of power flows in contingency formulation considerably. In Figure 4.8, the comparison of active power results between the AC load flow calculation in Eq. (4.10) and the classical DC load flow calculation in Eq. (4.45) is presented.

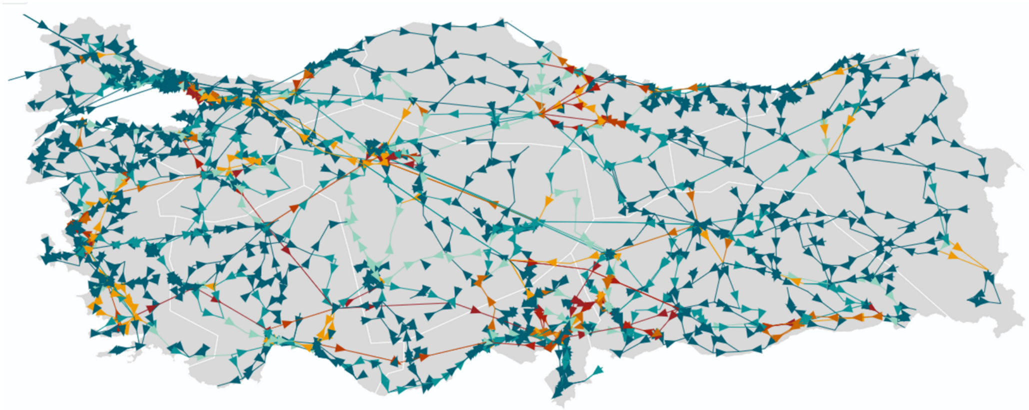


Figure 4.8: Comparison of Results for AC – Classical DC Load Flow Solution

The comparison of results of active power flows between the AC load flow calculation (4.46) and the revised load flow calculation is illustrated in Fig. 4.9. The proposed formulation improves the accuracy of solutions for branch flows considerably in contingency formulation. It was observed from green branches that the calculation difference due to linearization was reduced under 3 MW in almost all lines.

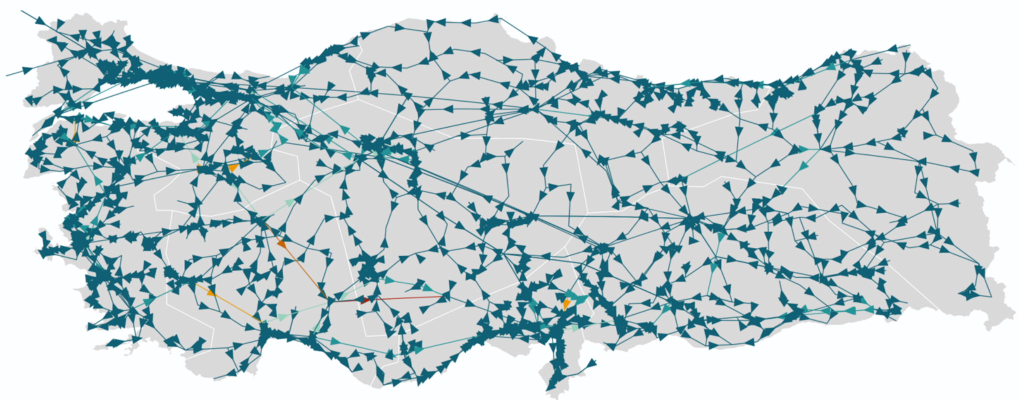


Figure 4.9: Comparison of Results for AC – Implemented DC Load Flow Solution

In the contingency formulation, branch limits are taken as the emergency rating as in (4.47). α value in Eq. (4.48) is taken as 1.1 in simulations performed in this study.

The emergency rating maintains the low cost of preventive actions.

$$-S_{ij}^{max,c} \leq P_{ij}^{c} \leq S_{ij}^{max,c} \tag{4.47}$$

$$S_{ij}^{max,c} = \alpha \times S_{ij}^{max} \tag{4.48}$$

Finally, the bus active power injection equality, including the additional redispatch, renewable curtailment, and load shedding, is given in Eq. (4.49).

$$\sum P_{ij}^{c} + \sum_{r \in i} P_{r}^{c} + \sum_{d \in i} P_{d}^{c} = \sum_{g \in i} P_{g}^{R} + \sum_{g \in i} P_{g}^{R,c} + P_{i} \tag{4.49}$$

4.2 Solution Methodology

The stated problem formulation constitutes a Mixed Integer Linear Programming problem. To solve the problem efficiently, the IBM ILO CPLEX software package is utilized. CPLEX Optimizer has a modeling layer called Concert that provides interfaces to Java language. The problem is built in the Analysis Server environment; then, it is sent to the developed Optimization Server application, which has installed CPLEX software.

CPLEX as an optimization solver is preferred for its certain advantages:

- Solves all sizes of optimization models like linear programming and mixed integer programming
- Provides advantageous speed performance in problem-solving
- Implements Benders Decomposition algorithm
- Provides relaxation option for infeasible problems so that the root cause of the unresolved congestions can be presented to operators
- Supports multiple model development languages and tools

4.2.1 Benders Decomposition

Optimization problems having a large number of variables and constraints require a considerable amount of time to reach to the solution. The generalization of Bender's approach to an optimization problem reduces the problem to a set of ordinary linear problems and divides the problem into smaller ones to obtain faster calculation.

The strategy behind Benders' decomposition can be summarized as divide-and-conquer. That is, in Benders decomposition, the variables of the original problem are divided into two subsets so that a first-stage master problem is solved over the first set of variables, and the values for the second set of variables are determined in a second-stage subproblem for a given first-stage solution.

If the subproblem determines that the fixed first-stage decisions are infeasible, then so-called Benders cuts are generated and added to the master problem, which is then re-solved until no cuts can be generated. The outline of the decomposition methodology is given in Fig. 4.10.

For the security-constrained OPF problem, the normal case power flow equations and redispatch cost variables of the objective function are constituted as the master problem. Each contingency case is formulated as a subproblem.

The master problem can be expressed as follows;

$$\begin{aligned} min\ c(x_0) \\ s.t.\ \ a_0(x_0) \geq b_0 \end{aligned}$$

where x_0 represents operating decisions (corrective controls) and the constraint $a_0(x_0) \geq b_0$ represents all system operating constraints

Suppose we have a list of M possible contingencies. Each contingency (with an index of i) introduces new operating constraints:

$$a_i(x_0) \geq b_i\ for\ all\ i = 1, 2, ..., M.$$

This leads to the implementation of preventive control actions on the system and, thus a higher level of system security.

The relation of a subproblem with the master problem is the redispatch amount in the base condition. Each subproblem has its own variables (bus voltage angles, branch flows) and its own constraints (bus injections, branch capacity inequalities). The

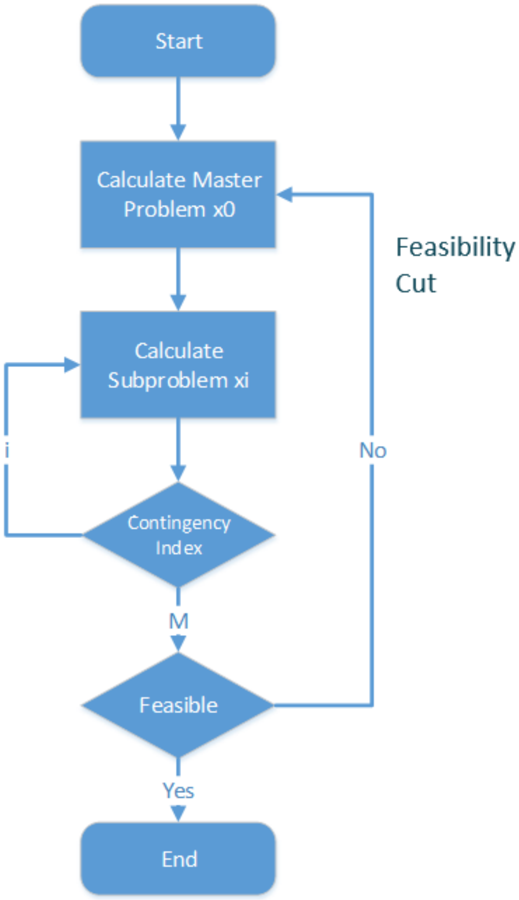


Figure 4.10: Outline of Decomposition Methodology

subproblems are not connected to each other (as in the unit commitment problem), which makes it a best case for Benders Decomposition. Fig. 4.11 shows the Benders Decomposition of the OPF problem.

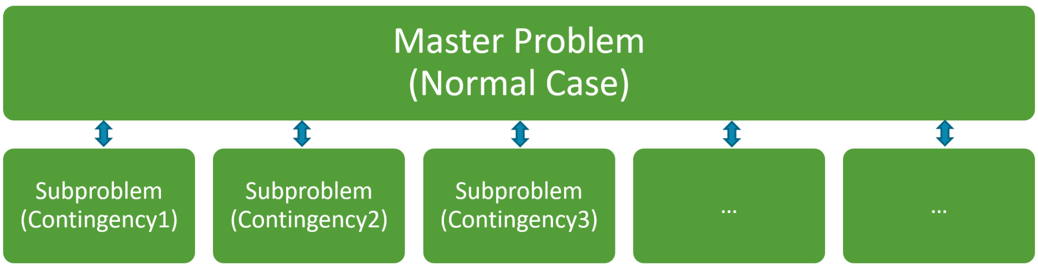


Figure 4.11: Benders Decomposition of the Problem

Benders Decomposition is utilized by built-in feature of CPLEX Optimization Solver.

The variables and constraints are manually *annotated* with a contingency index for each subproblem. Although CPLEX has built-in automatic decomposition, it is observed that the automatic decomposition of CPLEX is not efficient as the manually decomposed problem.

In the tests, Benders Decomposition increased the solution performance

- x 3 times in Standard Test Case (i.e., in IEEE 118-bus network)
- x 5 times in Real Test Case (i.e., in 1400-bus network)

which helps to solve problems with more than 1 million variables in a limited and acceptable duration. In the next Chapter, the numerical studies for different network cases are presented.

CHAPTER 5

CASE STUDIES

The case studies are conducted on two network data. The first one is IEEE 118-Bus Test Network and is called the "Standard Test Case". The second one is the 1400-Bus Transmission Network of Turkey and is called the "Real Test Case" in the following sections.

5.1 Standard Test Case: IEEE 118-Bus System

The initial data is obtained from The Library of IEEE PES Power Grid Benchmarks, which is adapted for Benchmarks for the Optimal Power Flow Problems [48]. There exist 59 test cases, such as IEEE Power Flow Test Cases, RTE Test Cases, and Polish Test Cases, to perform OPF algorithms. A routine is developed to utilize all test cases for the OPF; the necessary data read and conversion algorithms are built up.

This section presents the results of the IEEE 118 Bus Case. The network data is given in Appendix A. The single-line diagram of the network is shown in Figure 5.1. The network contains 54 generators, some of them operate as synchronous generators. Synchronous generators have zero active power limit; therefore, they do not participate in congestion management. And the grid has 186 branches. Bus 2 is assigned as the slack bus. The original network condition has 3258 MW of generation and 4242 MW of demand (not in steady state condition); therefore, load flow calculation does not converge.

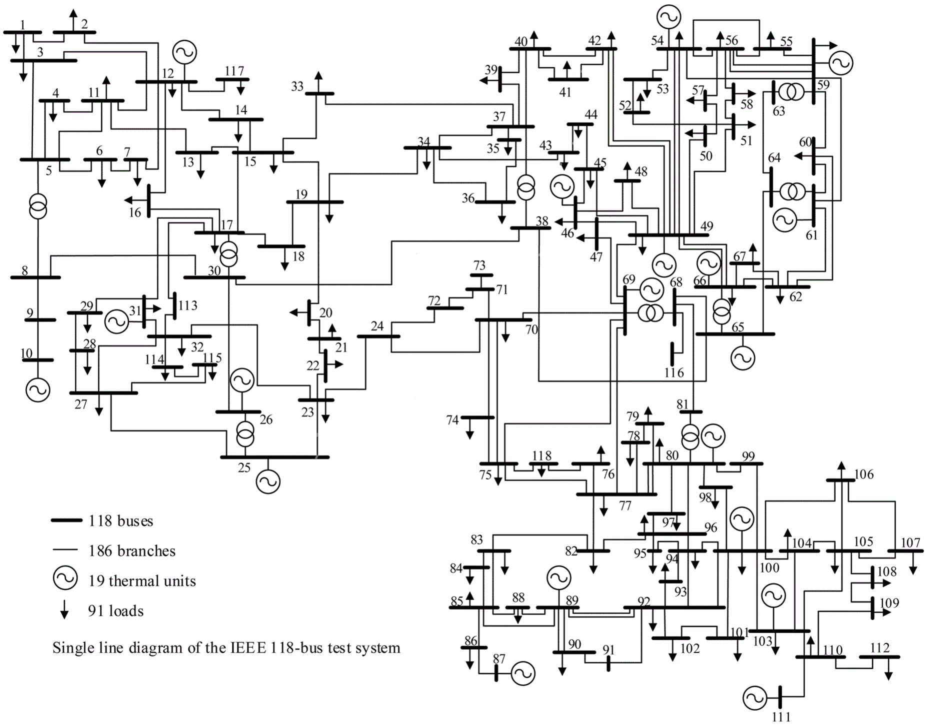


Figure 5.1: Single Line Diagram of IEEE 118 Bus Network

Initially, the unit commitment algorithm without transmission constraints is applied, and economic dispatch results are implemented as the base case condition. The result of the dispatch is given in Table 5.1. The most economical generator is at Bus 100, and the most expensive one is at Bus 12. The marginal clearing price is defined by the generator at Bus 69.

The load flow calculation algorithm is performed after the economic dispatch results are implemented in the case data. Three transmission lines are overloaded in the base case. Therefore, the test case is eligible for the redispatch problem without any data modification. Figure 5.2 presents the results of the load flow for the base case condition. The dispatched generators are in blue, and the congested lines are in red.

The list of the congested lines is given in Table 5.2. No critical voltage violation is observed in the base case. All bus voltages are greater than 0.90 pu and less than 1.10 pu.

Table 5.1: Results of the economic dispatch on the standard test case

Bus Number	Generation (MW)
10	505
26	485
46	20
49	223
59	308
61	195
69	707
80	509
89	637
100	653

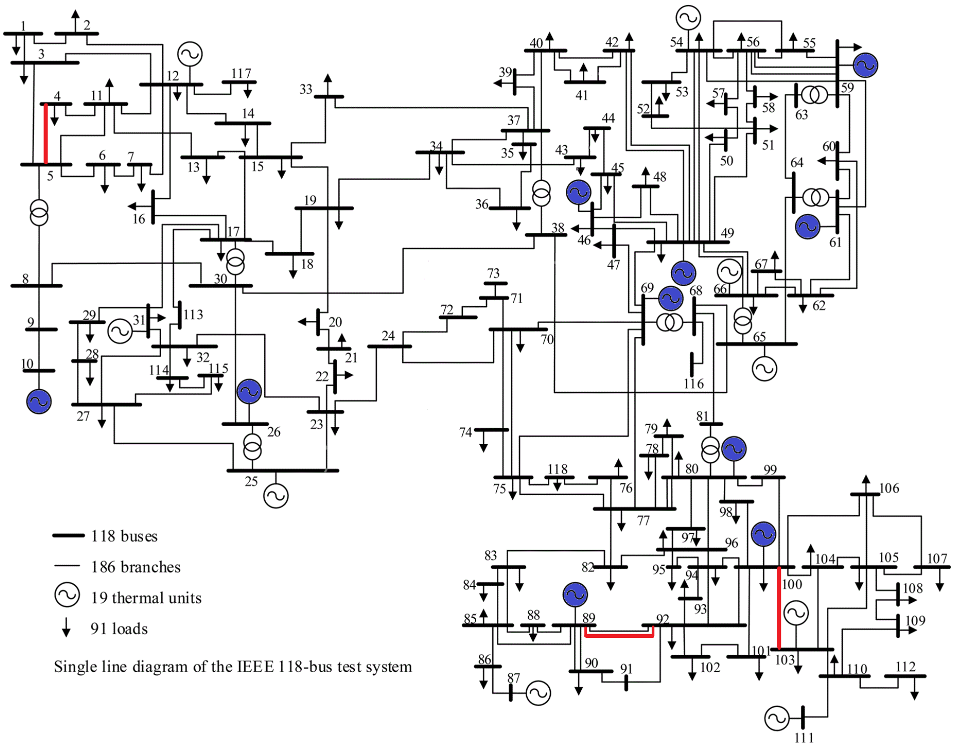


Figure 5.2: IEEE 118 Bus Network in Base Case

Table 5.2: Congested lines on the standard test case

Line	Power Flow (MVA)	Loading (%)
89-92	190.05	102
100-103	170.71	113
4-5	207.71	118

5.1.1 OPF Results

The voltage settings of the generators are not properly configured in the original data. The voltage controllers are set to 1 pu, resulting in non-optimal reactive power flows in the base case conditions. The bus voltages obtained from the load flow calculation are given in Fig. 5.3. As seen, 18% of the bus voltages are below 0.95 pu. Therefore, the optimal power flow algorithm is performed with the decision variables of generator active power generation and generator reactive power generation options. The default options of the OPF is stated in Chapter 3.1.

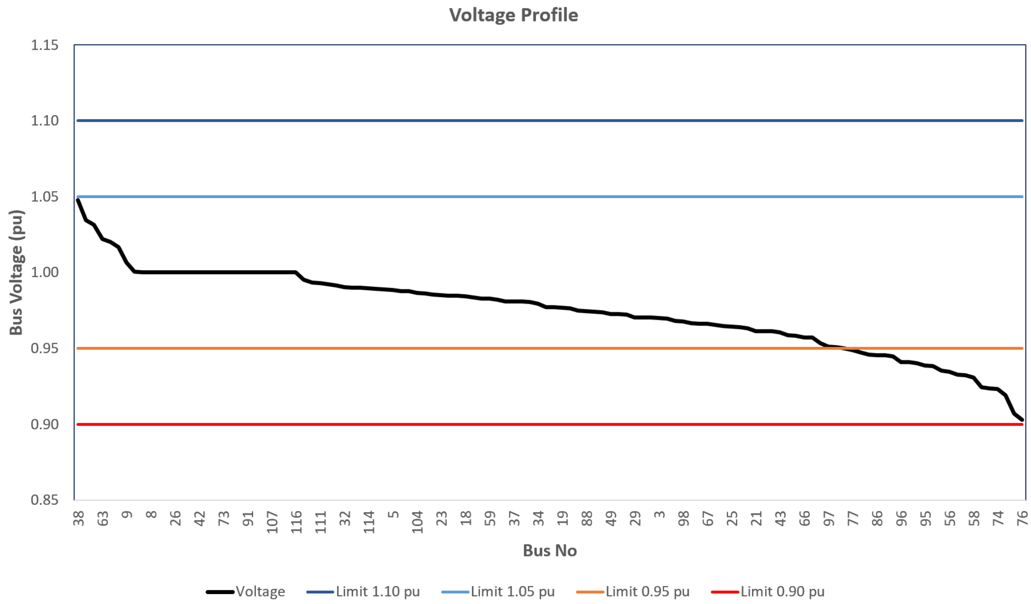


Figure 5.3: IEEE 118 Bus Network, Bus Voltages in the Base Case

AC Linearized OPF without security constraints is solved on the standard test case. The problem formulation contains 77 integer variables, 1878 numeric variables, and 5186 constraints.

The developed algorithm increases the generation at Bus 103 by 21.87 MW to eliminate the congestion and decreases the generation of Bus 69 by 21.87 MW to balance the power injections. In Fig. 5.4, the generator, which takes the generation up order, is shown in green; the other one is shown in red.

The overload in Branch 4-5 is eliminated by the reactive power regulation. In the base case, reactive power flow in Branch 4-5 is calculated as 170 MVAr; in the final case flow is decreased to 120 MVAr. The active power flow in the branch is kept constant; however, the reschedule in reactive power generation is eliminated the overload in Branch 4-5.

The solution of the problem takes 0.16 seconds. Experiments were run on a computer with an Intel(R) i7-10700 CPU processor @ 2.90 GHz using 32 GB of RAM, running Windows 10 version 21H2.

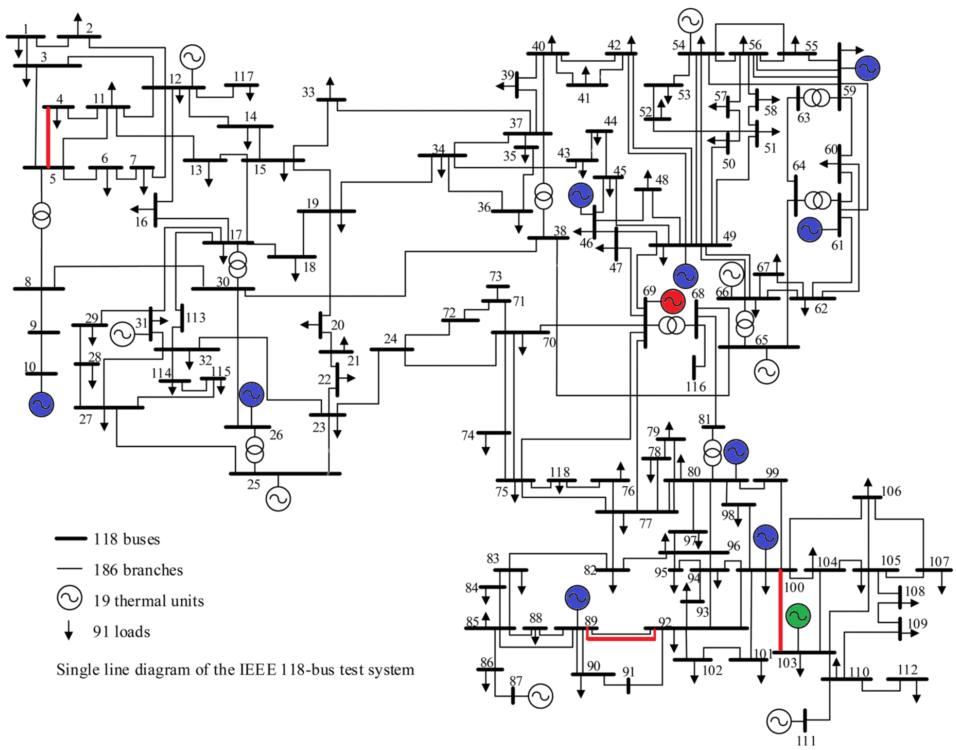


Figure 5.4: OPF Results of IEEE 118 Bus Network, with Reactive Power Regulation

However, in a real operation, the bus voltage settings are normally configured properly to avoid unnecessary reactive flows in branches and minimize network loss. Therefore, the reactive power generation of the generators in the problem is expected to be (nearly) fixed. This assumption also decreases the number of control actions since the adaptation of the voltage setting requires an order to the power plants.

Congestions are generally solved by active power management. In the next case, only the active power of the generators is set as decision variables and OPF is calculated. The results are given in Fig. 5.5. In this case, the number of the redispatched generator is increased as expected (Table 5.3). The cost of the redispatch is calculated as 5348 \$. For the rest of the results in the standard test case, the reactive power generation of the generators is not taken as a control variable.

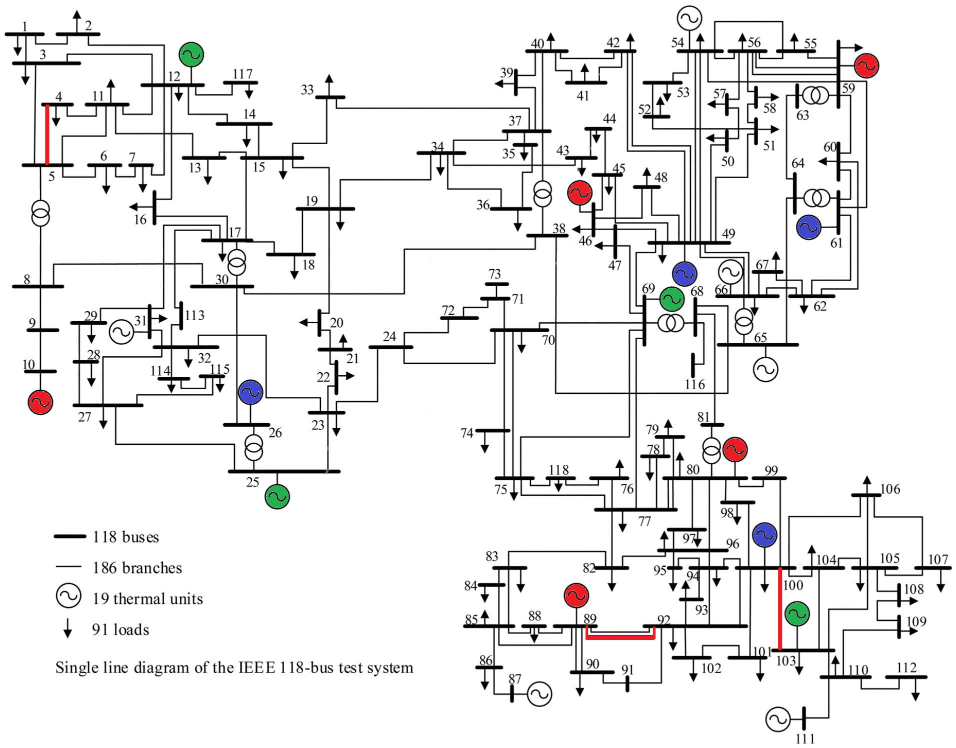


Figure 5.5: OPF Results of IEEE 118 Bus Network, without Reactive Power Scheduling

Table 5.3: Results of the redispatch without reactive power regulation

Bus Number	Redispatch (MW)
10	-222
12	44
25	83
46	-20
59	-11
69	453
80	-334
89	-22
103	29

5.1.2 SCOPF Results of Single Contingency

The corrective control actions for the standard test case are reported in the previous section. After the implementation of the actions to the case data, a contingency analysis is performed to check if the network is 'secure'. As an example, the outage of Branch 26-30 causes new branch loadings, as given in Table 5.4. That means corrective actions are not sufficient to obtain a secure operation point. A single contingency example is presented to evaluate the results of the algorithm easily.

Table 5.4: Congested lines after contingency on Branch 26-30

Line	Power Flow (MVA)	Loading (%)
38-65	340.25	116
23-25	318.68	178
25-27	256.49	150
23-32	167.29	109

Security Constrained OPF is formulated with two alternatives:

- Approach I: Post-contingency actions are isolated from corrective controls unless the generator ramp limits enable to reach post-contingency states in 15 minutes. This approach produces two separate sets of redispatch actions; corrective actions regarding the normal case and the other set of additional corrective controls for each contingency case. The additional redispatch actions are not applied in operation unless the contingency occurs.

In the first case, SCOPF Approach I is performed. The optimization problem contains 77 integer variables, 2348 numeric variables, and 6410 constraints. The solution of the problem takes 0.37 seconds. The corrective control actions do not change from the OPF results. The additional redispatch actions are calculated as in Table 5.5.

Table 5.5: Results of the additional redispatch after the outage of Branch 26-30

Bus Number	Redispatch (MW)
10	19
12	41
25	-77
26	-125
46	20
54	7
80	16
87	10
89	18
103	70

- Approach II: Post-contingency actions are reflected into corrective actions so that the final case operating state is secure to any contingency without additional control actions

The second approach obviously increases the cost of congestion management. This operational preference can be configured by TSO. In practice, if the contingency list comprises all the possible contingencies, Approach I is preferred. If the contingency list contains only limited critical events, TSO may choose the Approach II in order to have a secure network state. Approach II is the default value in the setting configuration.

When SCOPF Approach II is performed, the optimization problem contains 77 integer variables, 2272 numeric variables, and 6238 constraints. The solution of the problem takes 0.37 seconds. The preventive control actions are observed in the redispatch calculation. The solution results are given in Table 5.6. The value of the objective function is 14013 \$. The number/size of the redispatch order is higher than the solution of OPF without security constraints, as expected.

Table 5.6: Results of redispatch considering the contingency

Bus Number	Redispatch (MW)
10	-171
12	85
26	-66
31	17
54	53
59	-308
61	-133
66	399
69	475
80	-400
87	10
89	-27
103	66

The new redispatch suggestion eliminates all the congestions in the base case and contingency cases except the outage of Branch 25-27. The outage of Branch 25-27 requires load shedding at Bus 2 of 19 MW and at Bus 103 of 22 MW.

5.1.3 SCOPF Results of Multiple Contingencies

Security-constrained AC Linearized OPF formulation for the standard test case contains 168 contingency cases. The problem contains 77 integer variables, 80,838 numeric variables, and 213,824 constraints.

The solution of the problem takes only 6.6 seconds. If the Benders Decomposition technique is not implemented, the duration of the solution takes 13.3 seconds.

It has been seen that a solution can be found without the need for load shedding in contingencies; however, additional redispatch is expected. The value of the objective function (i.e., the redispatch cost) is increased from 5347$ to 5421$. The redispatch in the normal case is slightly adapted for security concerns. The redispatch difference between the OPF solution and SCOPF solution is given in Table 5.7.

Table 5.7: Comparison of results between OPF and SCOPF formulation

Bus Number	OPF Redispatch (MW)	SCOPF Redispatch (MW)	Difference (MW)
10	-222	-221	-
12	44	44	-
25	83	90	+7
46	-20	-20	-
59	-11	No Redispatch	+11
69	453	417	-36
80	-334	-315	+19
89	-22	-38	-16
103	29	42	+13

The difference between OPF and SCOPF simulations is due to the generator ramp limits in 15 minutes. For the standard test data, the ramp limits for coal and oil fuelled thermal plants are taken as maximum active power / 8 in 15 minutes. The ramp limits for gas fuelled thermal plants are taken as maximum active power / 2 in 15 minutes. The difference in results imply that in some contingencies, additional redispatch orders cannot bet met due to ramp limits.

In 18 contingency cases, additional redispatches are calculated. For example, contingency on Branch 65-68 is expected to create 521 MW of additional redispatch, it can be called the worst contingency in terms of amount of redispatch requirement.

5.2 Real Test Case: 1400-Bus Transmission System of Turkey

Tests on a large-scale network are also conducted on the electricity transmission network of Turkey, shown in Fig. 5.6. The developed system was later installed and operated as a decision support system of the TSO of Turkey.

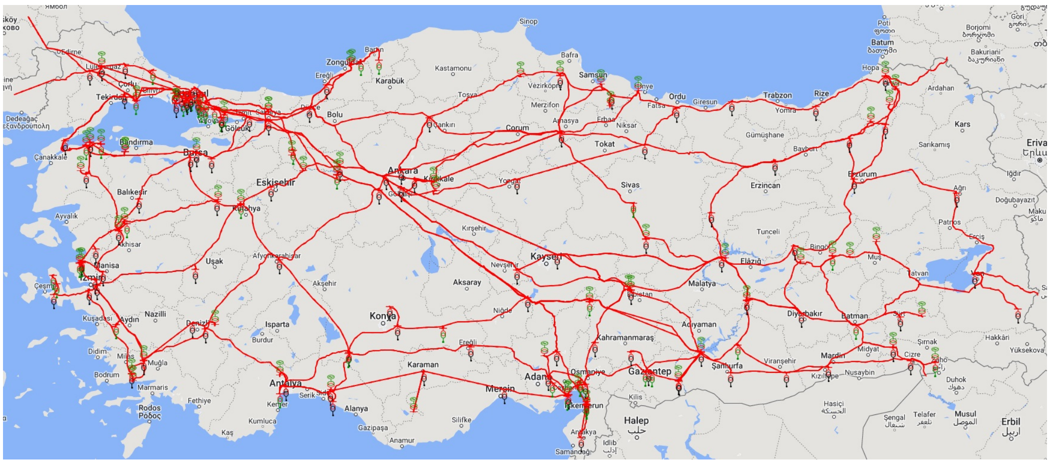


Figure 5.6: 400 kV Electricity Network of Turkey

The required grid data is obtained from the existing Dispatcher Information System (YTBS, abbreviated from Yük Tevzi Bilgi Sistemi) of TSO. YTBS is an Energy Management System (EMS) developed for TEİAŞ in order to meet the requirement of system monitoring and analysis facilities [49]. The system has a network modeling component to construct a mathematical model of the grid for the EMS applications.

Network information comprises more than 1400 substations, 2200 transmission lines, 2700 transformers, and 1800 power plants of a little more than 100 GW installed capacity. The system has integrations with the measurement systems (SCADA RTU, Power Quality Monitoring System [50], and Automatic Metering Systems) and contains the topological information to construct the necessary network matrices required in different analysis.

Only the high voltage ($\geq$ 36 kV) network is considered in the optimization. After parallel bus aggregation, there are around 1400 active buses dependent of topology. The number of integer variables without security constraints changes between 500 and 1000. The number of elements in the optimization problem is given in Table 5.8. The number of power plants refers to power plants connected to the transmission grid, and the number of generators refers to conventional generators connected to the transmission grid. The generators in the distribution grid are excluded from the congestion management.

Table 5.8: General information on the grid

Number of Substations	1350
Number of Buses	1400
Number of Transmission Lines	2200
Length of Transmission Lines	72,000 km
Number of Transformers	350
Number of Power Plants	600
Number of Generators	1200

It should be clarified here that the congestion scenarios in this section do not necessarily represent real events or congestions. In order to observe the performance of the algorithm, the base case condition may be modified, and the names of the lines/substations/power plants/costs may be obscured for the sake of data privacy.

The test cases presented in this section is chosen from the historical congested cases in the last year. Two regions, South Marmara and South West Anatolia, have occasionally experienced transmission bottlenecks due to limited transmission capacity and high energy generation in the regions. In some cases, TSO has applied redispatch actions to secure network against any possible outages. Therefore, these scenarios are considered to be suitable for validating the results of the algorithm.

5.2.1 Case I: South Marmara Congestion Scenario with OPF

The Southern Region of the Marmara Sea is close to the high-consumption area of Istanbul and hosts quite a lot of large-scale thermal power plants (Fig. 5.7). 400 kV transmission line corridor is symbolically shown with red lines. The total installed capacity of those plants exceeds 5000 MW. The list of the major plants in the region is given in Table 5.9.

The power plants in the region have high efficiency and capacity factors. Thus, the generation coincidence factor is high and transmission bottlenecks can be faced occasionally. Europe side of Turkish electricity network has connections to the European network. A contingency event that may lead to a generation loss in the region may trigger to Special Protection System installed on ENTSO-E interconnection. Therefore, TSO would like to ensure the grid security against outages.

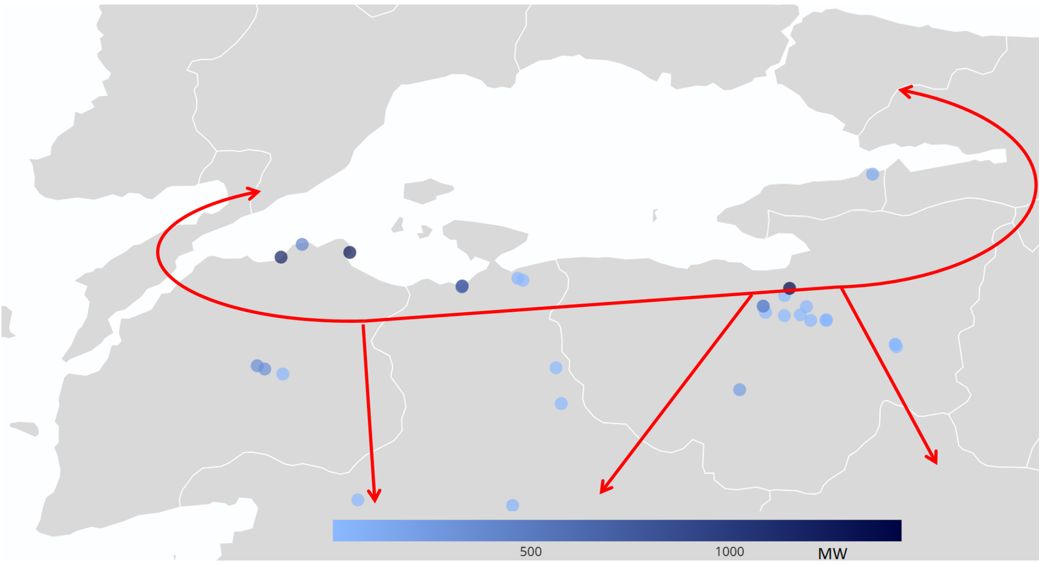


Figure 5.7: Locations of Large Thermal Plants in South Marmara Region

Table 5.9: Large thermal plants in South Marmara Region

Power Plant	Production Type	Installed Capacity (MW)
Cenal TPP	Coal	1320
Bekirli TPP	Coal	1200
Bandırma I NGCCPP	Natural Gas	930
Bandırma II NGCCPP	Natural Gas	607
İçdaş Biga TPP	Coal	405
Çan I TES	Lignite	320
Çan II TES	Lignite	330

Case I is a winter operation condition, and the system demand is at 38000 MW. In this case, the sum of generation of the stated power plants exceeds 4800 MW, and 400 kV BURSA DGKÇ - BURSA SANAYİ transmission line is loaded with 113%. The line has an operational flow limit of 1000 MVA and power flow is calculated as 1132 MVA. Power flows and loadings are shown in Fig. 5.8, the transmission bottleneck is marked with red circle. Red arrows in the figure are redispatch down candidates; green arrows are redispatch up candidates; light blue arrows are candidates for both sides.

The operating data for the simulation of this case belongs to February 16,2023 at 23:00. The OPF problem without security formulation is performed for Case I. The optimization problem consists of 432 integer variables, 23963 numeric variables, and 39848 constraints. The solution of the problem takes 30 seconds.

The redispatch suggestions are given in Table 5.10. The size of the redispatch is 939 MW, and there exists a balancing redispatch. Most of the redispatched generators have generation costs close to the electricity price; that is they have minimum redispatch cost. Although the congestion is resulted from the thermal generation in the region, only 120 MW of local redispatch down is suggested. This is due to the high cost of redispatch down bids of regional plants.

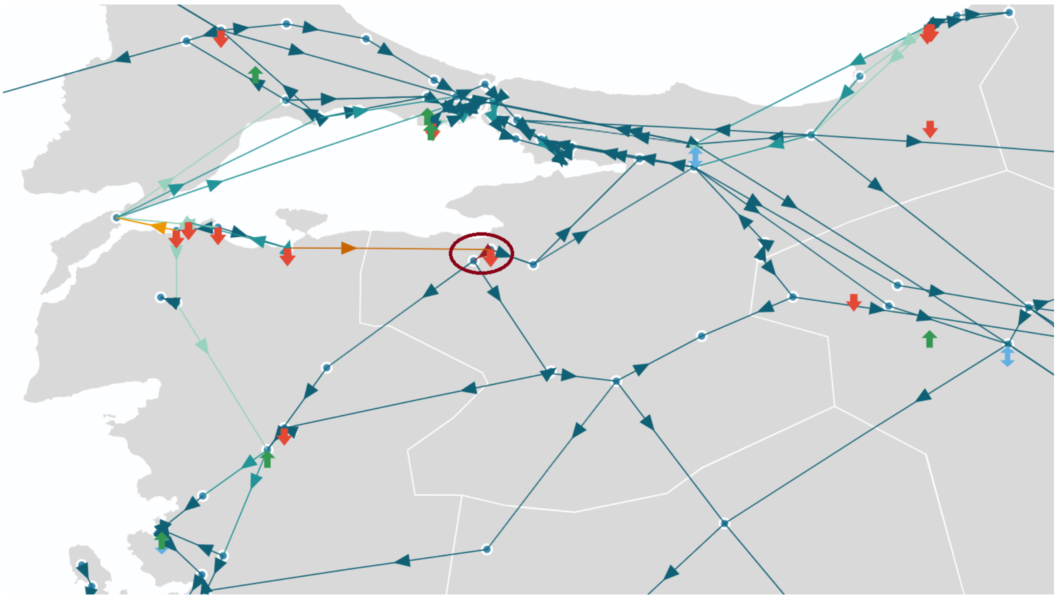


Figure 5.8: Base Case Condition of South Marmara Congestion Scenario, Case I

The locations of the redispatch suggestions are shown in Fig. 5.9. The generation up orders are shown as green arrows and down orders are shown as red arrows.

Table 5.10: OPF results of Case I, redispatch suggestions

Power Plant	Redispatch (MW)
Borçka HPP	-284
Cengiz NGPP	-275
Deriner HPP	-180
Cenal TPP GR-2	-120
Muratlı HPP	-61
Hamitabat NGPP GR-20	-19
Garzan HPP	17
Erzin NGPP	177
İzmir NGPP GR-1	203
İzmir NGPP GR-2	542

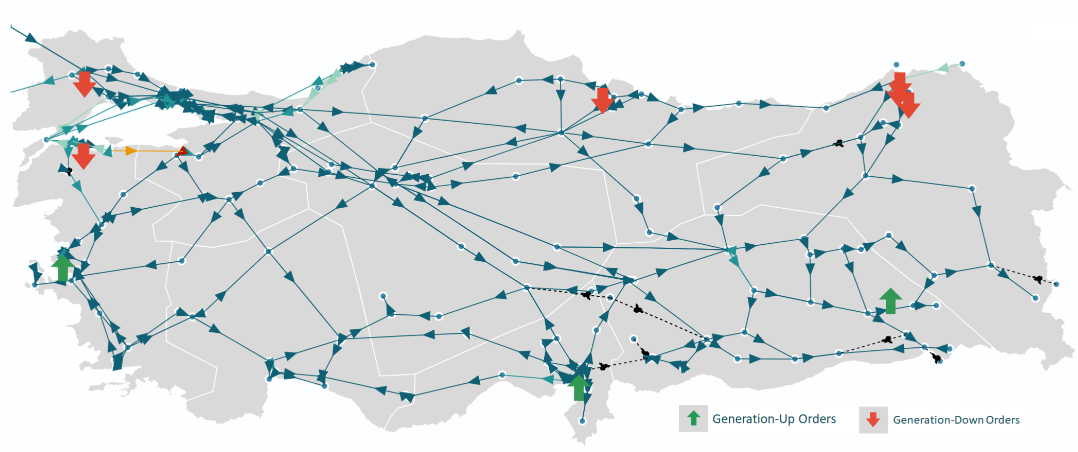


Figure 5.9: OPF Results of Case I, Redispatch Locations

5.2.2 Case II: South Marmara Congestion Scenario with SCOPF

Case II is a winter operation condition on 06.02.2023 at 13:00, and the total system demand is 40700 MW. No congestion is observed in the base case; however, operators had given a generation down order of 2200 MW in the South Marmara region. The most loaded lines in the region are 400 kV GELİBOLU - BEKİRLİ TES - I & II TL with 90% and 400 kV BURSA DGKÇ - BANDIRMA DGKÇ TL with 83%, and both of them is below the loading limits. The thermal power plants in the region generate 4800 MW. The base case power flows are shown in Fig. 5.10.

Figure 5.10: Base Case Condition of South Marmara Congestion Scenario, Case II

In contingency analysis, only the n-1 outages of transmission lines in the region are taken into account. The results of the contingency analysis show that there are overloads in branches due to some outages in the region. Therefore, the OPF problem is formulated with security constraints related to the outages of these lines. The contingency list is defined with 22 transmission lines of 400 kV in the region. Since the operators made precautions of 2200 MW of generation-down orders before a contingency event, the additional redispatch in the contingency option is disabled. The problem contains 540 integer variables, 127,340 numeric variables, and 240,952 constraints. The solution of the problem takes 90 seconds.

The calculated redispatch actions suggested by the algorithm are listed in Table 5.11. The total sum of generation down requirement is 1144 MW, which is 40% less in magnitude than the operator decisions. The calculated redispatch cost is also 85% less than the cost based on the the operator decisions. The locations of the redispatch suggestion are shown in Fig. 5.11. The generation-down actions are for large thermal plants in the North Aegean region. The generation-up actions are mainly in the İstanbul region to decrease the power flows in transmission corridors.

Figure 5.11: OPF Results of Case II, Redispatch Locations

Table 5.11: OPF results of Case II, redispatch suggestions

Power Plant	Redispatch (MW)
İstanbul NGPP (C)	420
İstanbul NGPP (A)	280
Adapazarı NGPP	267
Esenyurt NGPP	148
Delta NGPP	19
Gebze NGPP	10
Çan2 TPP	-20
Bandırma II NGPP	-58
Soma TPP	-70
İçdaş Biga	-217
Bekirli TPP	-221
İzmir NGPP GR-2	-279
İzmir NGPP GR-1	-279

Default settings for penalty cost of load shedding and renewable curtailment are relatively high with respect to redispatch of conventional generators. Therefore, the algorithm generally eliminates congestion with redispatch. To test these control decisions, the penalty costs are assigned equally and lower than the redispatch cost. Case II is performed with new settings, and the results are given in Table 5.12. The locations of these actions are shown in Fig. 5.12. The circles represent renewable curtailment, and triangles represent load shedding.

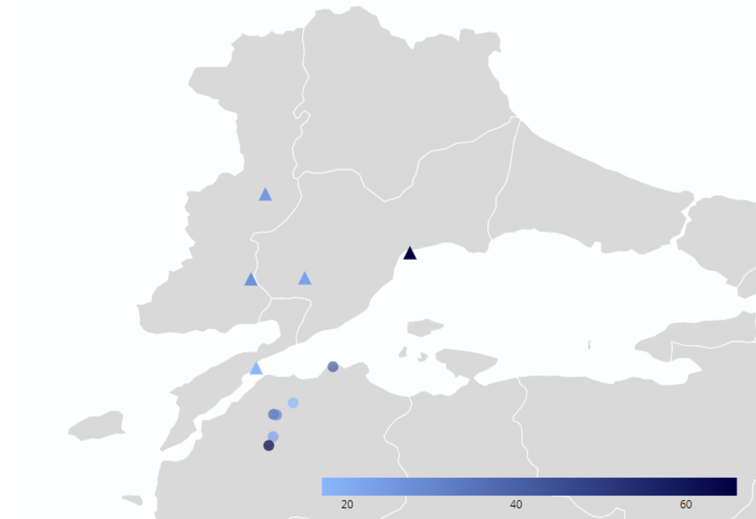


Figure 5.12: OPF Results of Case II, Locations of Alternative Control Actions

Table 5.12: OPF results of Case II, alternative control actions

Action	Location	Amount (MW)
Renewable Curtailment	Saros WPP	96
Renewable Curtailment	Biga WPP	59
Renewable Curtailment	Koru WPP	53
Renewable Curtailment	Yeniköy WPP	42
Renewable Curtailment	Kocalar WPP	30
Renewable Curtailment	Gelibolu WPP	22
Load Shedding	Tekirdağ	66
Load Shedding	Keşan	27
Load Shedding	Uzunköprü	25
Load Shedding	Malkara	23
Load Shedding	Gelibolu	17

5.2.3 Case III, South West Anatolia Congestion Scenario using OPF

Case III is a summer night operating condition on 27.07.2022 at 03:00 and the total system demand is at 38000 MW. The South West Anatolia region (Muğla city) contains three coal power plants, total installed capacity of 1725 MW. In Case III, three power plants have a generation of 900 MW, and there is also wind power generation at 154 kV voltage level. The region and thermal power plants is shown in Fig. 5.13.

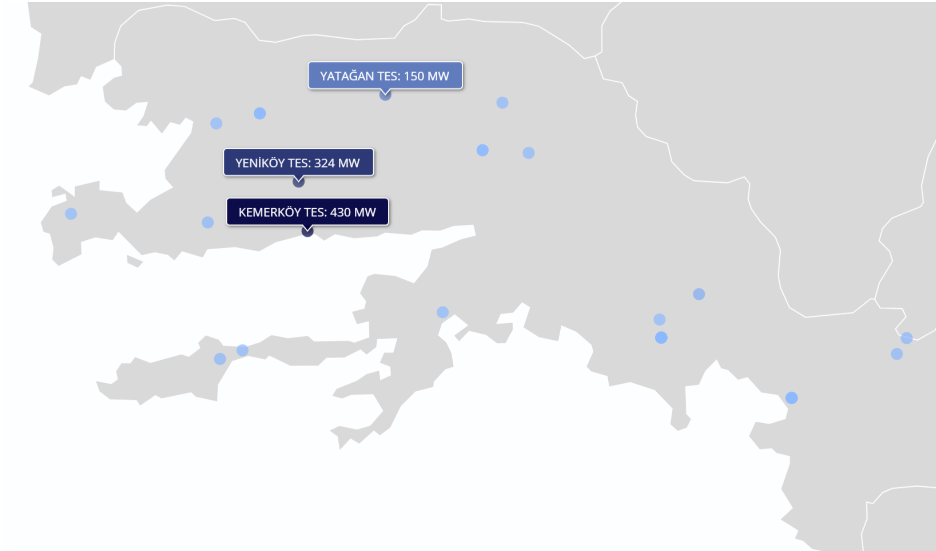


Figure 5.13: Base Case Generation of South West Anatolia Congestion Scenario

Initially, the load flow calculation is performed. The base case conditions result in an overload of 400 kV YATAĞAN TES - DENİZLİ4 transmission line with 122%. The line has an operational capacity of 1000 MVA and power flow is calculated as 1188 MVA. The power flows in the base case and redispatch candidates are given in Fig. 5.14. The loaded line is marked with a red circle. The power flows are mainly outward from the Aegean region.

The problem for this case is formulated as an OPF problem without security constraints. The optimization problem has 515 integer variables, 23,793 numeric variables, and 40,031 constraints. The problem is feasible and the solution takes 60 seconds.

Figure 5.14: Base Case Condition of South Marmara Congestion Scenario

The redispatch suggestions are shown in Fig. 5.15. The generation-down actions are shown in red, while up actions are in green. The redispatch suggestions are listed in Table 5.13. TSO operators had solved overload problems with mainly generation down orders of three regional TPPs. However, their generation-down bids are costly. On the other hand, the algorithm suggests half of the given redispatch action in the region and tries to eliminate the problem with other redispatch actions. The calculated redispatch cost is 45% is less than the operational redispatch actions. So that, more economical solution is obtained.

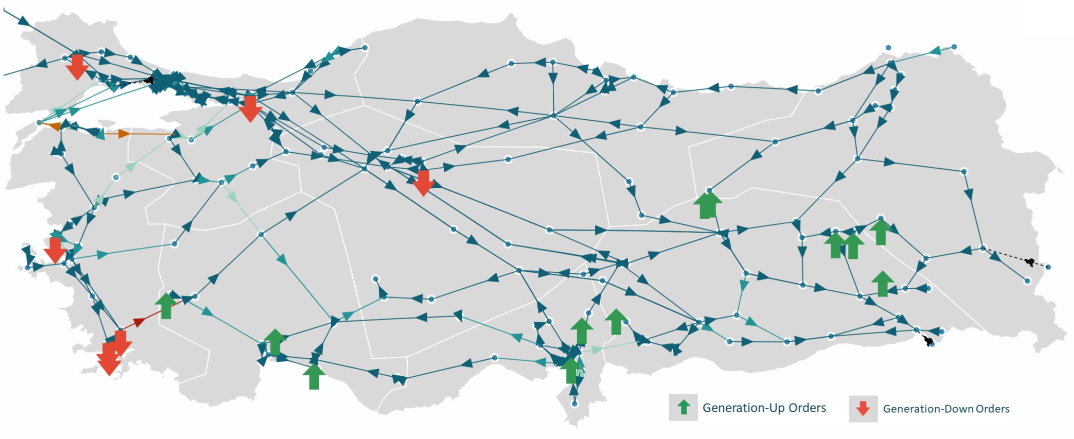


Figure 5.15: OPF Results of Case III, Redispatch Locations

Table 5.13: OPF results of Case III, redispatch suggestions

Power Plant	Redispatch (MW)
AGE NGPP	205
Yukarı Kaleköy HPP	180
Aşağı Kaleköy HPP	140
Erzin NGPP	110
Alpaslan II HPP	87
Bağıştaş I HPP	83
Menzelet HPP	29
Andırın HPP	20
Manavgat HPP	20
Bağıştaş II HPP	16
Karacaören HPP	16
Garzan HPP	10
Yatağan II TPP	-29
Kemerköy TPP GR-2	-33
Kemerköy TPP GR-1	-40
Gebze NGPP	-43
Adapazarı NGPP	-59
Hamitabat NGPP GR-20	-63
Gebze NGPP	-63
Yeniköy TPP	-90
Aliağa NGPP	-214
İç Anadolu NGPP	-283

5.2.4 Case IV, South West Anatolia Congestion Scenario using SCOPF

In the fourth case, a congestion case in South West Anatolia is handled with security constraints. Case IV is a different operational case than Case III, but it also has an overloading line in the base case. Case IV represents the operational scenario on 06.09.2022 at 04:00, and the total system load is 33800 MW. 400 kV YATAĞAN TES - DENİZLİ4 TL is loaded 134%, 1306 MVA. The base case power flows and redispatch candidates are shown in Fig. 5.16.

Figure 5.16: Base Case Condition of South Marmara Congestion Scenario

The security constraints are created with the possibility of outage of one of the nine 400 kV transmission lines in the region. Lines considered in the contingency list are;

- 400 kV Kemerköy TPP - Yatağan TPP TL
- 400 kV Kemerköy TPP - Yeniköy TPP TL
- 400 kV Işıklar - Germencik TL
- 400 kV Yatağan TPP - Germencik TL
- 400 kV Yatağan TPP - Denizli4 TL
- 400 kV Uzundere - Germencik TL
- 400 kV Yeniköy TPP - Germencik TL
- 400 kV IŞIKLAR - Yatağan TPP TL

- 400 kV Yatağan TPP - Yeniköy TPP TL

The SCOPF problem, implemented for this case, contains 417 integer variables, 70,068 numeric variables, and 132,036 constraints. The solution of the optimization problem takes 45 seconds. The redispatch suggestions obtained from the algorithm are given in Table 5.14, also shown on the map in Fig. 5.17.

Table 5.14: OPF results of Case VI, redispatch suggestions

Power Plant	Redispatch (MW)
Antalya NGPP	535
AGE NGPP	205
Kavşak Bendi HPP	119
Köprü HPP	76
Alpaslan II HPP	55
Menge HPP	42
Kangal TPP	30
Şanlıurfa NGPP	30
Feke II HPP	29
Menzelet HPP	27
Manavgat HPP	10
Kuşaklı HPP	10
Kemerköy TPP GR-1	-54
Kemerköy TPP GR-2	-54
Soma Kolin TPP	-86
Yeniköy TPP	-90
Bursa NGPP	-222
Cenal TPP GR-2	-330
Cenal TPP GR-1	-331

Figure 5.17: OPF Results of Case IV, Redispatch Locations

5.2.5 Case V, Complete Contingency Covered SCOPF

In this case, the time performance of the algorithm is tested against a large number of contingencies. The complete set of 400 kV transmission lines is determined as the contingency list. The number of contingencies in this case is 270. The optimization problem contains 572 integer variables, 1,365,678 numeric variables, and 2,720,211 constraints.

The solution of the problem takes approximately 6 minutes. If the Benders Decomposition technique does not implemented, the duration of the solution takes more than 30 minutes. Even for the extra large problems, the developed algorithm can end up with a solution.

The developed algorithm is deployed as a software system to TSO of Turkey, and integrated into the Energy Management System. The system has been in the process of monitoring and evaluating the results since May 2022. The system is currently used in the load dispatch room as a supporting tool. Based on the results of numerous simulations using the actual data, the redispatch cost proposed by the algorithm is 30% less in average than the actual cost of redispatches decided by operators.

CHAPTER 6

CONCLUSIONS

Transmission System Operators occasionally face the congestion problem in real-time operation due to the lack of preventive market designs and the uncontrollable nature of some generations and consumption. In the case of violation of the system security, TSO tries to change the system states at minimum cost with the necessary actions in the Balancing Market. Redispatch is the most effective act on Balancing Markets for congestion management.

Activities in Balancing Markets have significant economic volume. Any contribution to the search for optimality and small increases in dispatch efficiency can yield millions of dollars per year in cost savings. Therefore, this thesis proposes a robust and efficient algorithm to calculate optimal redispatch actions to eliminate transmission bottlenecks.

The congestion management problem is defined as an optimal power flow problem, and an algorithm is developed to determine the necessary control actions. A comprehensive framework is established to obtain the most economical solution for congestion management. The proposed methodology is created in accordance with the existing network regulations and market rules and enhanced with features for the sake of applicability in operation.

Throughout the research process, different OPF models are surveyed and compared. The most suitable OPF formulation is determined and developed to meet the time and convergence requirements of system operators in real-time operation. Non-linear OPF models require high computational complexity and do not guarantee convergence. Heuristic search-based OPF solution techniques simplify computations; however, they can be stuck in the time barrier in real-time operations, especially when security constraints are considered. Therefore, an improved linearized network model is developed.

The proposed algorithm is robust and convergence-guaranteed. Network constraints are linearized with state-dependent linearization techniques. The initial states of the grid are calculated by the developed load flow calculation algorithm. Unlike the classical DC OPF formulization, the AC Linearized OPF considers reactive power flows and bus voltage magnitudes; thus, more precise branch loadings are obtained. In numerical examples, even in the cases when the grid is in stressed condition, such as poor voltage profile or wide voltage angles of neighboring buses, the results are remarkable in accuracy compared with the AC solution.

Furthermore, accuracy-enhancing approaches have been developed and implemented based on the close states of pre- and post- operating points of the redispatch problem. Binding constraints between bus voltage magnitude variables and base case conditions are introduced into the problem so that higher accuracy in linearization is obtained. The reactive power generation is introduced as a decision variable to increase the convergence, yet limited in a particular range for two reasons; to keep the network state close to the linearization point and to reduce the number of control actions regarding voltage regulation.

Congestion management is achieved with complying the rules of balancing markets. Generation companies generally bid in the market with a piecewise linear cost function. The cost formulation introduces integer variables into the problem. In this thesis, single cost bid for multiple generation unit is formulated. Thus, plants with generators connected to the grid at different voltage levels and aggregators can be formulated accordingly. Both plant and generator constraints are considered in the problem formulation. By this means, minimum and maximum power generation limits of generators are satisfied.

The redispatch problem is extended to the security constraints such as an outage of network equipment. In order to obtain a feasible solution, renewable curtailment, and load-shedding options are included as decision variables for contingency cases. Preventive actions are loosely coupled to the corrective actions by formulating additional redispatch actions in contingency. Thus, security constraints are implemented cost-effectively, increasing the solution's performance.

With the inclusion of security constraints for large-scale networks, the problem can reach a high number of variables and constraints. In order to solve the optimization problem efficiently and fast, the Benders Decomposition technique is utilized. The base case problem is stated as the master problem, and each contingency is evaluated as a sub-problem.

The utilization of Benders Decomposition approach has increased the solution performance considerably and made the algorithm practicable even for large problems. In the tests of the 1400-bus network having 270 contingency cases, and with 1.3 million variables and 2.7 million constraints can be solved in about 6 minutes in the PC environment. With the selective contingencies (i.e., contingency screening), the duration of the solution decreases to under 1 minute for the same test case.

The developed algorithm covers all the intermediate steps to operate in real networks. In order to monitor the robustness and performance of the algorithm, the system is deployed for TSO of Turkey (TEİAŞ). The congestion management system has been operating on an hourly basis for the 1400-bus high-voltage transmission grid for almost one year. The results of the optimization algorithm are considered successful and very useful by the system operators.

In conclusion, congestion management is one of the critical tasks of the electricity system operation and requires a complicated business process. This thesis presents a methodological approach to determine the generation up/down orders within a balancing market in order to eliminate transmission bottlenecks. The redispatch calculations conducted for historical congested cases occurred in Turkish high voltage electricity network indicate that the developed approach makes it possible to obtain more economical operational results. In this way, the redispatch decisions based on operators decreases, the transparency in the system operation increases. With the developed algorithm, considerable economic gains will be achieved.

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APPENDIX A

IEEE 118-BUS NETWORK DATA

IEEE 118 Bus test case data is obtained from The Library of IEEE PES Power Grid Benchmarks, which is adapted for Benchmarks for the Optimal Power Flow Problems, v21.07.

Bus Data are given in Table A.1 which contains following information:

- **bus**: Bus Number
- **type**: Bus type. 1: PQ bus, 2: PV bus, 3: reference bus, 4: isolated bus
- **Pd**: Real power demand (MW)
- **Qd**: Reactive power demand (MVAr)
- **Gs**: Shunt conductance (MW demanded at V = 1.0 p.u.)
- **Bs**: Shunt susceptance (MVAr injected at V = 1.0 p.u.)
- **baseKV**: Base voltage (kV)
- **Vmax**: Maximum voltage magnitude (p.u.)
- **Vmin**: Minimum voltage magnitude (p.u.)

Table A.1: IEEE 118 test case, bus data

bus	type	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin
1	2	51	27	0	0	138	1.06	0.94
2	1	20	9	0	0	138	1.06	0.94

3	1	39	10	0	0	138	1.06	0.94
4	2	39	12	0	0	138	1.06	0.94
5	1	0	0	0	-40	138	1.06	0.94
6	2	52	22	0	0	138	1.06	0.94
7	1	19	2	0	0	138	1.06	0.94
8	2	28	0	0	0	345	1.06	0.94
9	1	0	0	0	0	345	1.06	0.94
10	2	0	0	0	0	345	1.06	0.94
11	1	70	23	0	0	138	1.06	0.94
12	2	47	10	0	0	138	1.06	0.94
13	1	34	16	0	0	138	1.06	0.94
14	1	14	1	0	0	138	1.06	0.94
15	2	90	30	0	0	138	1.06	0.94
16	1	25	10	0	0	138	1.06	0.94
17	1	11	3	0	0	138	1.06	0.94
18	2	60	34	0	0	138	1.06	0.94
19	2	45	25	0	0	138	1.06	0.94
20	1	18	3	0	0	138	1.06	0.94
21	1	14	8	0	0	138	1.06	0.94
22	1	10	5	0	0	138	1.06	0.94
23	1	7	3	0	0	138	1.06	0.94
24	2	13	0	0	0	138	1.06	0.94
25	2	0	0	0	0	138	1.06	0.94
26	2	0	0	0	0	345	1.06	0.94
27	2	71	13	0	0	138	1.06	0.94
28	1	17	7	0	0	138	1.06	0.94
29	1	24	4	0	0	138	1.06	0.94
30	1	0	0	0	0	345	1.06	0.94
31	2	43	27	0	0	138	1.06	0.94
32	2	59	23	0	0	138	1.06	0.94
33	1	23	9	0	0	138	1.06	0.94

34	2	59	26	0	14	138	1.06	0.94
35	1	33	9	0	0	138	1.06	0.94
36	2	31	17	0	0	138	1.06	0.94
37	1	0	0	0	-25	138	1.06	0.94
38	1	0	0	0	0	345	1.06	0.94
39	1	27	11	0	0	138	1.06	0.94
40	2	66	23	0	0	138	1.06	0.94
41	1	37	10	0	0	138	1.06	0.94
42	2	96	23	0	0	138	1.06	0.94
43	1	18	7	0	0	138	1.06	0.94
44	1	16	8	0	10	138	1.06	0.94
45	1	53	22	0	10	138	1.06	0.94
46	2	28	10	0	10	138	1.06	0.94
47	1	34	0	0	0	138	1.06	0.94
48	1	20	11	0	15	138	1.06	0.94
49	2	87	30	0	0	138	1.06	0.94
50	1	17	4	0	0	138	1.06	0.94
51	1	17	8	0	0	138	1.06	0.94
52	1	18	5	0	0	138	1.06	0.94
53	1	23	11	0	0	138	1.06	0.94
54	2	113	32	0	0	138	1.06	0.94
55	2	63	22	0	0	138	1.06	0.94
56	2	84	18	0	0	138	1.06	0.94
57	1	12	3	0	0	138	1.06	0.94
58	1	12	3	0	0	138	1.06	0.94
59	2	277	113	0	0	138	1.06	0.94
60	1	78	3	0	0	138	1.06	0.94
61	2	0	0	0	0	138	1.06	0.94
62	2	77	14	0	0	138	1.06	0.94
63	1	0	0	0	0	345	1.06	0.94
64	1	0	0	0	0	345	1.06	0.94

65	2	0	0	0	0	345	1.06	0.94
66	2	39	18	0	0	138	1.06	0.94
67	1	28	7	0	0	138	1.06	0.94
68	1	0	0	0	0	345	1.06	0.94
69	3	0	0	0	0	138	1.06	0.94
70	2	66	20	0	0	138	1.06	0.94
71	1	0	0	0	0	138	1.06	0.94
72	2	12	0	0	0	138	1.06	0.94
73	2	6	0	0	0	138	1.06	0.94
74	2	68	27	0	12	138	1.06	0.94
75	1	47	11	0	0	138	1.06	0.94
76	2	68	36	0	0	138	1.06	0.94
77	2	61	28	0	0	138	1.06	0.94
78	1	71	26	0	0	138	1.06	0.94
79	1	39	32	0	20	138	1.06	0.94
80	2	130	26	0	0	138	1.06	0.94
81	1	0	0	0	0	345	1.06	0.94
82	1	54	27	0	20	138	1.06	0.94
83	1	20	10	0	10	138	1.06	0.94
84	1	11	7	0	0	138	1.06	0.94
85	2	24	15	0	0	138	1.06	0.94
86	1	21	10	0	0	138	1.06	0.94
87	2	0	0	0	0	161	1.06	0.94
88	1	48	10	0	0	138	1.06	0.94
89	2	0	0	0	0	138	1.06	0.94
90	2	163	42	0	0	138	1.06	0.94
91	2	10	0	0	0	138	1.06	0.94
92	2	65	10	0	0	138	1.06	0.94
93	1	12	7	0	0	138	1.06	0.94
94	1	30	16	0	0	138	1.06	0.94
95	1	42	31	0	0	138	1.06	0.94

96	1	38	15	0	0	138	1.06	0.94
97	1	15	9	0	0	138	1.06	0.94
98	1	34	8	0	0	138	1.06	0.94
99	2	42	0	0	0	138	1.06	0.94
100	2	37	18	0	0	138	1.06	0.94
101	1	22	15	0	0	138	1.06	0.94
102	1	5	3	0	0	138	1.06	0.94
103	2	23	16	0	0	138	1.06	0.94
104	2	38	25	0	0	138	1.06	0.94
105	2	31	26	0	20	138	1.06	0.94
106	1	43	16	0	0	138	1.06	0.94
107	2	50	12	0	6	138	1.06	0.94
108	1	2	1	0	0	138	1.06	0.94
109	1	8	3	0	0	138	1.06	0.94
110	2	39	30	0	6	138	1.06	0.94
111	2	0	0	0	0	138	1.06	0.94
112	2	68	13	0	0	138	1.06	0.94
113	2	6	0	0	0	138	1.06	0.94
114	1	8	3	0	0	138	1.06	0.94
115	1	22	7	0	0	138	1.06	0.94
116	2	184	0	0	0	138	1.06	0.94
117	1	20	8	0	0	138	1.06	0.94
118	1	33	15	0	0	138	1.06	0.94

Generator Data is given in Table A.2 and contains following information:

- **bus**: Bus Number
- **Pg**: Real power output (MW)
- **Qg**: Reactive power output (MVAr)
- **Qmax**: Maximum reactive power output (MVAr)

- **Qmin**: Minimum reactive power output (MVAr)
- **Vg**: Voltage magnitude setpoint (p.u.)
- **Pmax**: Maximum real power output (MW)
- **Pmin**: Minimum real power output (MW)
- **cost**: Linear generation cost coefficient ($/MW)

Table A.2: IEEE 118 test case, generator data

bus	Pg	Qg	Qmax	Qmin	Vg	Pmax	Pmin	cost
1	0	5	15	-5	1	0	0	0
4	0	0	300	-300	1	0	0	0
6	0	18.5	50	-13	1	0	0	0
8	0	0	300	-300	1	0	0	0
10	252.5	26.5	200	-147	1	505	0	24.98342
12	42.5	4	43	-35	1	85	0	124.5816
15	0	10	30	-10	1	0	0	0
18	0	17	50	-16	1	0	0	0
19	0	8	24	-8	1	0	0	0
24	0	0	300	-300	1	0	0	0
25	110.5	32	111	-47	1	221	0	28.94832
26	242.5	0	243	-243	1	485	0	22.22098
27	0	0	300	-300	1	0	0	0
31	8.5	0	9	-9	1	17	0	25.99398
32	0	14	42	-14	1	0	0	0
34	0	8	24	-8	1	0	0	0
36	0	8	24	-8	1	0	0	0
40	0	0	300	-300	1	0	0	0
42	0	0	300	-300	1	0	0	0
46	10	0	10	-10	1	20	0	24.20231
49	111.5	13.5	112	-85	1	223	0	16.67394

54	26.5	0	27	-27	1	53	0	27.27734
55	0	7.5	23	-8	1	0	0	0
56	0	3.5	15	-8	1	0	0	0
59	154	47	154	-60	1	308	0	24.86187
61	97.5	0	98	-98	1	195	0	16.05604
62	0	0	20	-20	1	0	0	0
65	220.5	66.5	200	-67	1	441	0	34.78178
66	392	66.5	200	-67	1	784	0	32.66878
69	591	0	300	-300	1	1182	0	25.75844
70	0	11	32	-10	1	0	0	0
72	0	0	100	-100	1	0	0	0
73	0	0	100	-100	1	0	0	0
74	0	1.5	9	-6	1	0	0	0
76	0	7.5	23	-8	1	0	0	0
77	0	25	70	-20	1	0	0	0
80	254.5	45	255	-165	1	509	0	24.60077
85	0	7.5	23	-8	1	0	0	0
87	5	0	5	-5	1	10	0	34.07263
89	318.5	45	300	-210	1	637	0	24.6051
90	0	0	300	-300	1	0	0	0
91	0	0	100	-100	1	0	0	0
92	0	3	9	-3	1	0	0	0
99	0	0	100	-100	1	0	0	0
100	326.5	52.5	155	-50	1	653	0	12.61217
103	54	12.5	40	-15	1	108	0	28.64947
104	0	7.5	23	-8	1	0	0	0
105	0	7.5	23	-8	1	0	0	0
107	0	0	200	-200	1	0	0	0
110	0	7.5	23	-8	1	0	0	0
111	39.5	0	40	-40	1	79	0	35.0434
112	0	450	1000	-100	1	0	0	0

113	0	50	200	-100	1	0	0	0
116	0	0	1000	-1000	1	0	0	0

Transmission line and transformer data is given in Table A.3 and contains following information:

- **fbus**: From bus number
- **tbus**: To bus number
- **r**: Resistance (p.u.)
- **x**: Reactance (p.u.)
- **b**: Total line charging susceptance (p.u.)
- **rating**: MVA rating
- **ratio**: Transformer off nominal turns ratio (= 0 for lines)

Table A.3: IEEE 118 test case, branch data

fbus	tbus	r	x	b	rating	ratio
1	2	0.0303	0.0999	0.0254	151	0
1	3	0.0129	0.0424	0.01082	151	0
4	5	0.00176	0.00798	0.0021	176	0
3	5	0.0241	0.108	0.0284	175	0
5	6	0.0119	0.054	0.01426	176	0
6	7	0.00459	0.0208	0.0055	176	0
8	9	0.00244	0.0305	1.162	711	0
8	5	0	0.0267	0	1099	0.985
9	10	0.00258	0.0322	1.23	710	0
4	11	0.0209	0.0688	0.01748	151	0
5	11	0.0203	0.0682	0.01738	152	0
11	12	0.00595	0.0196	0.00502	151	0

2	12	0.0187	0.0616	0.01572	151	0
3	12	0.0484	0.16	0.0406	151	0
7	12	0.00862	0.034	0.00874	164	0
11	13	0.02225	0.0731	0.01876	151	0
12	14	0.0215	0.0707	0.01816	151	0
13	15	0.0744	0.2444	0.06268	115	0
14	15	0.0595	0.195	0.0502	144	0
12	16	0.0212	0.0834	0.0214	164	0
15	17	0.0132	0.0437	0.0444	151	0
16	17	0.0454	0.1801	0.0466	158	0
17	18	0.0123	0.0505	0.01298	167	0
18	19	0.01119	0.0493	0.01142	173	0
19	20	0.0252	0.117	0.0298	178	0
15	19	0.012	0.0394	0.0101	151	0
20	21	0.0183	0.0849	0.0216	177	0
21	22	0.0209	0.097	0.0246	178	0
22	23	0.0342	0.159	0.0404	178	0
23	24	0.0135	0.0492	0.0498	158	0
23	25	0.0156	0.08	0.0864	186	0
26	25	0	0.0382	0	768	0.96
25	27	0.0318	0.163	0.1764	177	0
27	28	0.01913	0.0855	0.0216	174	0
28	29	0.0237	0.0943	0.0238	165	0
30	17	0	0.0388	0	756	0.96
8	30	0.00431	0.0504	0.514	580	0
26	30	0.00799	0.086	0.908	340	0
17	31	0.0474	0.1563	0.0399	151	0
29	31	0.0108	0.0331	0.0083	146	0
23	32	0.0317	0.1153	0.1173	158	0
31	32	0.0298	0.0985	0.0251	151	0
27	32	0.0229	0.0755	0.01926	151	0

15	33	0.038	0.1244	0.03194	150	0
19	34	0.0752	0.247	0.0632	114	0
35	36	0.00224	0.0102	0.00268	176	0
35	37	0.011	0.0497	0.01318	175	0
33	37	0.0415	0.142	0.0366	154	0
34	36	0.00871	0.0268	0.00568	146	0
34	37	0.00256	0.0094	0.00984	159	0
38	37	0	0.0375	0	783	0.935
37	39	0.0321	0.106	0.027	151	0
37	40	0.0593	0.168	0.042	140	0
30	38	0.00464	0.054	0.422	542	0
39	40	0.0184	0.0605	0.01552	151	0
40	41	0.0145	0.0487	0.01222	152	0
40	42	0.0555	0.183	0.0466	151	0
41	42	0.041	0.135	0.0344	151	0
43	44	0.0608	0.2454	0.06068	117	0
34	43	0.0413	0.1681	0.04226	167	0
44	45	0.0224	0.0901	0.0224	166	0
45	46	0.04	0.1356	0.0332	153	0
46	47	0.038	0.127	0.0316	152	0
46	48	0.0601	0.189	0.0472	148	0
47	49	0.0191	0.0625	0.01604	150	0
42	49	0.0715	0.323	0.086	89	0
42	49	0.0715	0.323	0.086	89	0
45	49	0.0684	0.186	0.0444	138	0
48	49	0.0179	0.0505	0.01258	140	0
49	50	0.0267	0.0752	0.01874	140	0
49	51	0.0486	0.137	0.0342	140	0
51	52	0.0203	0.0588	0.01396	142	0
52	53	0.0405	0.1635	0.04058	166	0
53	54	0.0263	0.122	0.031	177	0

49	54	0.073	0.289	0.0738	99	0
49	54	0.0869	0.291	0.073	97	0
54	55	0.0169	0.0707	0.0202	169	0
54	56	0.00275	0.00955	0.00732	155	0
55	56	0.00488	0.0151	0.00374	146	0
56	57	0.0343	0.0966	0.0242	140	0
50	57	0.0474	0.134	0.0332	140	0
56	58	0.0343	0.0966	0.0242	140	0
51	58	0.0255	0.0719	0.01788	140	0
54	59	0.0503	0.2293	0.0598	125	0
56	59	0.0825	0.251	0.0569	112	0
56	59	0.0803	0.239	0.0536	117	0
55	59	0.04739	0.2158	0.05646	133	0
59	60	0.0317	0.145	0.0376	176	0
59	61	0.0328	0.15	0.0388	176	0
60	61	0.00264	0.0135	0.01456	186	0
60	62	0.0123	0.0561	0.01468	176	0
61	62	0.00824	0.0376	0.0098	176	0
63	59	0	0.0386	0	760	0.96
63	64	0.00172	0.02	0.216	687	0
64	61	0	0.0268	0	1095	0.985
38	65	0.00901	0.0986	1.046	297	0
64	65	0.00269	0.0302	0.38	675	0
49	66	0.018	0.0919	0.0248	186	0
49	66	0.018	0.0919	0.0248	186	0
62	66	0.0482	0.218	0.0578	132	0
62	67	0.0258	0.117	0.031	176	0
65	66	0	0.037	0	793	0.935
66	67	0.0224	0.1015	0.02682	176	0
65	68	0.00138	0.016	0.638	686	0
47	69	0.0844	0.2778	0.07092	102	0

49	69	0.0985	0.324	0.0828	87	0
68	69	0	0.037	0	793	0.935
69	70	0.03	0.127	0.122	170	0
24	70	0.00221	0.4115	0.10198	72	0
70	71	0.00882	0.0355	0.00878	166	0
24	72	0.0488	0.196	0.0488	146	0
71	72	0.0446	0.18	0.04444	159	0
71	73	0.00866	0.0454	0.01178	188	0
70	74	0.0401	0.1323	0.03368	151	0
70	75	0.0428	0.141	0.036	151	0
69	75	0.0405	0.122	0.124	145	0
74	75	0.0123	0.0406	0.01034	151	0
76	77	0.0444	0.148	0.0368	152	0
69	77	0.0309	0.101	0.1038	150	0
75	77	0.0601	0.1999	0.04978	141	0
77	78	0.00376	0.0124	0.01264	151	0
78	79	0.00546	0.0244	0.00648	174	0
77	80	0.017	0.0485	0.0472	141	0
77	80	0.0294	0.105	0.0228	157	0
79	80	0.0156	0.0704	0.0187	175	0
68	81	0.00175	0.0202	0.808	684	0
81	80	0	0.037	0	793	0.935
77	82	0.0298	0.0853	0.08174	141	0
82	83	0.0112	0.03665	0.03796	150	0
83	84	0.0625	0.132	0.0258	122	0
83	85	0.043	0.148	0.0348	154	0
84	85	0.0302	0.0641	0.01234	122	0
85	86	0.035	0.123	0.0276	156	0
86	87	0.02828	0.2074	0.0445	141	1
85	88	0.02	0.102	0.0276	186	0
85	89	0.0239	0.173	0.047	168	0

88	89	0.0139	0.0712	0.01934	186	0
89	90	0.0518	0.188	0.0528	151	0
89	90	0.0238	0.0997	0.106	169	0
90	91	0.0254	0.0836	0.0214	151	0
89	92	0.0099	0.0505	0.0548	186	0
89	92	0.0393	0.1581	0.0414	166	0
91	92	0.0387	0.1272	0.03268	151	0
92	93	0.0258	0.0848	0.0218	151	0
92	94	0.0481	0.158	0.0406	151	0
93	94	0.0223	0.0732	0.01876	151	0
94	95	0.0132	0.0434	0.0111	151	0
80	96	0.0356	0.182	0.0494	159	0
82	96	0.0162	0.053	0.0544	150	0
94	96	0.0269	0.0869	0.023	149	0
80	97	0.0183	0.0934	0.0254	186	0
80	98	0.0238	0.108	0.0286	176	0
80	99	0.0454	0.206	0.0546	140	0
92	100	0.0648	0.295	0.0472	98	0
94	100	0.0178	0.058	0.0604	150	0
95	96	0.0171	0.0547	0.01474	149	0
96	97	0.0173	0.0885	0.024	186	0
98	100	0.0397	0.179	0.0476	160	0
99	100	0.018	0.0813	0.0216	175	0
100	101	0.0277	0.1262	0.0328	176	0
92	102	0.0123	0.0559	0.01464	176	0
101	102	0.0246	0.112	0.0294	176	0
100	103	0.016	0.0525	0.0536	151	0
100	104	0.0451	0.204	0.0541	141	0
103	104	0.0466	0.1584	0.0407	153	0
103	105	0.0535	0.1625	0.0408	145	0
100	106	0.0605	0.229	0.062	124	0

104	105	0.00994	0.0378	0.00986	161	0
105	106	0.014	0.0547	0.01434	164	0
105	107	0.053	0.183	0.0472	154	0
105	108	0.0261	0.0703	0.01844	137	0
106	107	0.053	0.183	0.0472	154	0
108	109	0.0105	0.0288	0.0076	138	0
103	110	0.03906	0.1813	0.0461	159	0
109	110	0.0278	0.0762	0.0202	138	0
110	111	0.022	0.0755	0.02	154	0
110	112	0.0247	0.064	0.062	135	0
17	113	0.00913	0.0301	0.00768	151	0
32	113	0.0615	0.203	0.0518	139	0
32	114	0.0135	0.0612	0.01628	176	0
27	115	0.0164	0.0741	0.01972	175	0
114	115	0.0023	0.0104	0.00276	175	0
68	116	0.00034	0.00405	0.164	7218	1
12	117	0.0329	0.14	0.0358	170	0
75	118	0.0145	0.0481	0.01198	151	0
76	118	0.0164	0.0544	0.01356	151	0

CURRICULUM VITAE

PERSONAL INFORMATION

Surname, Name: Eren, Sinan
Nationality: Turkish (TC)
Date and Place of Birth: 23 August 1988, İstanbul
Marital Status: Married
Research Interests: Power system modelling, power system security, energy management systems, forecasting, optimization, big data in energy

EDUCATION

Degree	Institution	Year of Graduation
Ph.D.	METU Electrical and Electronics Engineering	2023
M.S.	METU Electrical and Electronics Engineering	2014
B.S.	METU Electrical and Electronics Engineering	2011
High School	Fahrettin Kerim Gökay Anadolu High School	2006

Master Thesis Title: Transmission System Security Study for Akkuyu Nuclear Power Plant
Content: 4 x 1200 MW Akkuyu Nuclear Power Plant will be the first NPP project constructed in Turkey between 2020 and 2023. The scope of the thesis is to ensure the planned network connection satisfies security regulations and determine investment requirements if necessary. The thesis provides preliminary studies about expansion plans of transmission and generation systems, regional long-term demand forecast, dispatch scenario forecast; static analyses on load flow, contingency calculations; transient analyses on fault calculations.
Advisor: Prof. Dr. Ali Nezih Güven

FOREIGN LANGUAGES

Turkish (Native)
English (Advanced)
German (Elementary)

PROFESSIONAL EXPERIENCE

Year	**Place**	**Enrollment**
12 Years	TÜBİTAK MRC Energy Technologies	Chief Researcher/Team Leader

PROJECTS

2019 – Now: **Chief Researcher**

- **Dispatcher Information System Upgrade Project 3** [2022 - 2024]: I managed the project and acted as the product owner. The project is about extending the network model with new elements, new tools for transformer investment planning, grid security analysis, data informatics, and developing new energy management modules such as grid loss forecast and dynamic line rating calculation.
- **Load Dispatcher Technical Consultancy Project** [2020 - 2023]: I worked on developing energy management system modules as a work package manager. My responsibilities are to develop and implement a redispatch management module, solar power generation forecast tool, and SCADA measurement data integration framework.
- **Protection Tools Development Project** [2019 - 2021]: I worked on the project as a work package leader. The project is about the Turkish Electricity Transmission Network protection system analysis, relay modeling, relay setting monitoring, and developing software tools for protection system operation.

2015 - 2019: **Senior Researcher**

- **Dispatcher Information System Upgrade Project 2** [2017 - 2020]: I worked on the project as a project manager, designer, and software developer. The system is advancing for properties regarding network monitoring, reporting, forecasting, and energy management applications.

2011 - 2015: **Researcher**.

- **Transmission System Framework Project** [2013 - 2016]: I worked on the project as a software/database designer and power system engineer. The developed software system has properties on data acquisition of hourly load flow measurements from transmission substations and power plants, topological data acquisition from Regional and National Load Dispatch Centers, web-based current and historical data reporting, transmission system modeling, and energy management system applications such as load flows, contingencies, congestion forecasts.

- **General Technical Support Project** [2013 - 2016]: I worked on studies about developing new regional load forecast methods for electricity transmission grid, developing new analysis methods for master planning studies, designing a database for transmission planning, advanced studies (nuclear and large scale power plant connections, special load analysis, transient analysis, etc.), tariff studies, regulation revisions and power system analyses based on computer simulations.

- **TEİAŞ Transmission Network Expansion Project** [2011 - 2012]: I worked on studies about current status analysis of the electricity transmission system, performing static and dynamic analysis for investment planning, contingency analyses, substation-based load forecast, determination of congestions and investment requirements, construction of 5-10 year ahead load flow scenarios, determination of transmission system usage tariffs.

PUBLICATIONS

Journal Articles

1. S. Eren, D. Küçük, C. Ünlüer, M. Demircioğlu, Y. Yanık, Y. Arslan, B. Özsoy, A. H. Güverçinci, İ. Elma, Ö. Tanıdır, Y. C. Ölmez, S. Sönmez, “A ubiquitous Web-based dispatcher information system for effective monitoring and analysis of the electricity transmission grid”, *International Journal of Electrical Power & Energy Systems*, Volume 86, March 2017, Pages 93-103.

International Conference Publications

1. S. Eren, A. N. Güven, “Optimized Congestion Management in Balancing Markets for Electricity Transmission System Operator”, *Operations Research Proceedings 2022. OR 2022. Lecture Notes in Operations Research.* Springer, Cham.

2. Y. Arslan, A. Ş. Dilbaz, S. Ertekin, P. Karagoz, A. Birturk, S. Eren, D. Küçük. (2018) Short-Term Electricity Consumption Forecast Using Datasets of Various Granularities. In: Woon W., Aung Z., Catalina Feliú A., Madnick S. (eds) *Data Analytics for Renewable Energy Integration. Technologies, Systems and Society. DARE 2018. Lecture Notes in Computer Science*, vol 11325. Springer, Cham

3. Y. Arslan, D. Küçük, S. Eren, A. Birturk. (2018) Clustering River Basins Using Time-Series Data Mining on Hydroelectric Energy Generation. In: Woon W., Aung Z., Catalina Feliú A., Madnick S. (eds) *Data Analytics for Renewable Energy Integration. Technologies, Systems and Society. DARE 2018. Lecture Notes in Computer Science*, vol 11325. Springer, Cham

4. Y. Arslan, A. Birturk and S. Eren, "Basin Clustering of Turkey by Use of Monthly Stream-Flow Data," *2015 IEEE 14th International Conference on Machine Learning and Applications (ICMLA)*, Miami, FL, USA, 2015, pp. 1169-1174.

5. S. Eren, D. Küçük, C. Ünlüer, M. Demircioğlu, Y. Arslan and S. Sönmez, "A Web-based dispatcher information system for electricity transmission grid monitoring and analysis," *2015 9th International Conference on Electrical and Electronics Engineering (ELECO)*, Bursa, 2015, pp. 986-990.

6. A. H. Güverçinci, S. Eren, Y. Yanık and Ö. Tanıdır, "Determination of regional transmission connection capacities in a deregulated environment," *2015 9th International Conference on Electrical and Electronics Engineering (ELECO)*, Bursa, 2015, pp. 555-558.

7. M. E. Cebeci, S. Eren, O. B. Tor and N. Güven, "Transmission and substation expansion planning using Mixed Integer Programming," *North American Power Symposium (NAPS)*, 2011, Boston, MA, 2011, pp. 1-5.

COMPUTER AND PROGRAMMING KNOWLEDGE

Power System Analysis Softwares: DIgSILENT PowerFactory, Siemens PTI PSS/E
Programs: MATLAB, IBM ILOG CPLEX Optimization Studio, Microsoft Office
Programming Languages: Java, Python, R Statistics, Javascript, HTML
Software Development: Eclipse IDE, JavaServer Faces, PrimeFaces, Apache Tomcat, Apache Subversion, Apache Maven, Jenkins
Database Management Systems: PostgreSQL, Microsoft SQL

AWARDS - ACHIEVEMENTS

TÜBİTAK Marmara Research Center, Best Research Group Award of 2015