TWO NEW INDICES FOR THE ASSESSMENT OF REGIONAL TRANSMISSION CONNECTION CAPACITIES

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ABSTRACT

TWO NEW INDICES FOR THE ASSESSMENT OF REGIONAL TRANSMISSION CONNECTION CAPACITIES

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Traditionally electrical power industry has been regulated and monopolized. However, since 1980s it has undergone a period of restructuring throughout the world. This privatization procedure has made the planning and operation of the generation, transmission and distribution parts of power system relatively more independent and disconnected. The transmission system planners lost their direct control over plant investments. As a result, planning of the transmission system became more complex than it ever was. This created a need for mechanisms to assess the economics and reliability of transmission expansion planning.

This thesis presents a methodology to determine the maximum amount of new generation that can safely be connected from a region to the transmission system. Two new indices are developed to monitor impact of additional generation in a specific region. The first index examines the effect of additional generation to the transmission system as a whole by taking into account the overloading amount and possibility of each line in the region. The second index identifies the weak points in that region that needs to be strengthened by evaluating the impact of the additional generation on each line separately.

The proposed methodology was applied to Turkish Transmission Network model of 2026 considering four different case studies. These are peak demand and minimum loading scenarios where high and low wind energy investments are considered separately.

Keywords: Transmission System Planning, Transmission Connection Capacity, Security Constrained Load Flow, Congestion Management

ÖZ

İKİ YENİ İNDEKS KULLANILARAK BÖLGESEL İLETİM BAĞLANTI KAPASİTELERİNİN DEĞERLENDİRİLMESİ

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Elektrik endüstrisi geleneksel olarak tekel yapılanmış ve regülasyonlarla düzenlenmiş bir endüstri olmuştur. Bununla birlikte 1980'lerden itibaren dünya çapında bir yeniden yapılanma dönemi geçirmiştir. Bu özelleştirme prosedürü, güç sisteminin üretim, iletim ve dağıtım bölümlerinin planlanması ve çalıştırılmasını nispeten daha bağımsız ve bağlantısız hale getirmiştir. İletim sistemi planlamacıları, tesis yatırımları üzerindeki doğrudan kontrollerini kaybetmiştir. Sonuç olarak, iletim sisteminin planlaması şimdiye kadar olduğundan daha karmaşık hale gelmiştir. Bu durum iletim sistemi planlamasının ekonomisini ve güvenilirliğini değerlendiren mekanizmalara ihtiyaç doğurmuştur.

Bu tezde, bir bölgeden iletim sistemine güvenle bağlanabilecek maksimum yeni üretim miktarını belirlemek için bir metodoloji sunulmuştur. Belirli bir bölgedeki ek üretimin etkisini izlemek için iki yeni endeks geliştirilmiştir. İlk endeks, bölgedeki iletim hatlarının aşırı yüklenme miktarlarını ve olasılıklarını göz önüne alarak ek üretimin iletim sistemine olan etkisini inceler. İkinci endeks, ek üretimin her hatta olan etkisini ayrı ayrı değerlendirerek ilgili bölge için iletim sisteminin güçlendirilmesi gereken zayıf noktalarını belirler.

Önerilen yöntem, 2026 yılı Türk İletim Şebekesi modeline dört farklı senaryo halinde uygulanmıştır. Bu senaryolar, yüksek ve düşük rüzgâr enerjisi yatırımlarının ayrı ayrı düşünüldüğü, en yüksek ve minimum yüklenme senaryolarıdır.

Anahtar Kelimeler: İletim Sistemi Planlaması, İletim Sistemi Bağlantı Kapasitesi, Güvenlik Kısıtlı Yük Akışı, Kısıt Yönetimi

To My Parents

And My Beautiful Sisters

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CHAPTER 1

INTRODUCTION

This chapter begins by giving information about the motivation of the thesis. Then, the scope of the thesis is explained and its contributions are mentioned. Finally, the chapter is concluded by giving an outline and more detailed information on the other chapters of the thesis.

1.1 Motivation

Traditionally power systems were organized in a vertically monopolistic structure. However, in last three decades the power industry has undergone a restructuring period throughout the world. Traditional vertically monopolistic structure has been deregulated and replaced with generation, transmission, distribution and retail companies. The main aim was to introduce competition to generation, distribution and retail companies to reach higher efficiency in electricity production and utilization.

Deregulation in generation and distribution grids entirely changed transmission-planning philosophy. The production, transmission and distribution systems, which were once planned and operated by a single authority, became more independent and disconnected. Furthermore, considering transmission system planners lost their direct control over plant investments, planning and operating transmission systems safely became more complex and important than ever was. Especially the networks with rapid annual growth of electricity consumption are confronted by a challenging planning problem because of the uncertainty of power plant investments. In addition, ability to operate a competitive market mechanism successfully was considered critical for the success of this privatization process. That situation increased the importance of planning and operating transmission system safely since the efficiency of market mechanism is directly related to transmission system adequacy. In case of an inadequate transmission system, local market powers emerge and that results in an inefficient market mechanism.

These developments gave rise to the need for mechanisms that were intended to be used for economic and reliable planning and operation of transmission systems. As a result, many studies were conducted and methods were presented in the literature. Some of these studies aimed to operate transmission system safely without any congestion in the short term, in other words for operational purposes, while others were conducted mostly for planning purposes in the long term. As an example, a limitation mechanism for regional transmission connection capacities is introduced to the Turkish Electricity System in order to ensure the economic and reliable transmission expansion planning. TSO is obliged to calculate regional allowable generation capacity for the next five and ten-year period in order to encourage power plant investments to proper locations and to prevent possible inadequacy of transmission system in the future. However, it has been assessed that there is a need of a study, which examines the impact of the additional generation on transmission system from a holistic view. To fulfill this need, a methodology was developed which enables determination of the maximum amount of new generation that could be reliably connected to transmission system from a region and also enables to assess impact of new generation on this region in general.

Considering that Turkey has a deregulated market mechanism and it is a developing country with a high load grow rate and fast urbanization, the proposed methodology has been applied on the projected Turkish Transmission Network of 2026.

1.2 Scope and Contribution of the Thesis

The focus of this study is to analyze the impact of additional generation on transmission networks of pre-determined regions and to determine bottlenecks of the transmission network in these regions. A methodology was developed to enable transmission system planners to determine the line investments needed to prevent future system inadequacies and to direct the generation investments to the correct zones by observing the impact of additional generation on the pre-determined regions. This approach will serve as a guideline for the planning of investments in the transmission system. Furthermore, generation investors will have the opportunity to evaluate the need for additional generation in the regions they are planning to invest in. In addition, by determining the limits of transmission capacity for each region, it is possible to see how safely the existing transmission system can operate after new generation investments have been made without the need for additional line investments.

In this study, two new indices are proposed and by using them, three different capacities are found for each region. Region based evaluation index (REI) is the first index which is proposed and it is used to determine the impact of additional generation on the region as a whole. Two different capacity values found for each region using this index. First of these capacity values corresponds to the point where line loadings are minimized according to REI. The second one corresponds to the point where the usage of transmission network is maximized without worsening it compare to its initial condition according to REI. Line based evaluation index (LEI) is the second index which is proposed and it is used to monitor each line individually throughout the steps. By following LEI state of a transmission line, it can be observed whether its loading stays within the limits during contingencies or not and whether it benefits from additional generation or not. The remaining capacity value of mentioned three is determined using LEI index and it reflects the point where a line at a specific region overloads at least in one of the possible contingencies defined and it does not benefit from additional generation anymore. The indices are considered together while determining transmission connection capacity of a region and that gives the opportunity to determine impact of additional generation on a region from a holistic view.

Proposed methodology has been applied on the projected Turkish Transmission Network of 2026. The transmission network model has been created by expanding existing topology from current system to 2026 by including planned transmission and generation investments. Substation based demand forecast, generation capacity projection and generation dispatch procedures have been done to obtain a realistic model for year 2026. After that, a security constrained ac-load flow procedure was implemented to each region throughout a step-wise process using PSS-E simulation tool and proposed indices were created. According to created indices, available transmission connection capacities have been determined for each region studied.

Four different scenarios were studied considering Turkish Transmission Network of 2026. Peak demand and minimum loading scenarios were studied with two different wind power dispatches. These are low and expected wind power dispatches. In recent years, interest in renewable energy sources has increased and as a result of this, power generation using renewable sources has increased all over the world. Increasing environmental awareness and desire to reduce dependence on conventional energy sources are the main reasons for this trend. In Turkey, wind energy investments have increased rapidly especially in the last 10 years. It is expected that this increase will continue in the next 10 years and the installed capacity will be nearly doubled. For this reason, it is aimed to observe the effect of increasing wind energy investments on the Turkish Transmission System by taking different wind power dispatch scenarios into account. At low wind power dispatch scenario, the current installed capacity of wind power is assumed to stay as it is while at expected wind power dispatch scenario it is accepted that planned wind power investments will be realized and wind power capacity will be nearly doubled.

1.3 Thesis Outline

The information about the deregulation of power systems, its impact on transmission planning philosophy and literature review about transmission connection capacity assessment studies are given in Chapter 2. The basic concepts of regulation and deregulation, the motivations behind deregulation process, an overview of a deregulated system and a historical background about deregulation process in Turkey are given in the first section of this chapter. Then, how this process influenced the transmission planning is explained in the second section. In the last section of this chapter, a detailed literature review on the transmission connection capacity assessment studies is given.

Chapter 3 focuses on the preliminary work that is done before the main work. In first two sections, modelling and expansion methodology that is followed while creating Turkish Transmission Network model of 2026 is explained. The details about demand and generation forecast procedures are given in the last two sections.

The developed methodology for assessing available transmission connection capacities is explained in first three sections of the Chapter 4. The newly proposed indices and recommended approach for their correct interpretations are emphasized. In the last section of the chapter, proposed type of capacities and classification of regions according to their characteristics are presented.

Information about the determination of the scenarios and their results are presented in first two sections of Chapter 5. The detailed comparison between the results of the scenarios are given in the last section of the chapter. Discussion of the obtained results from the perspective of both transmission system planners and power plant investors are also given in the last section of the chapter.

Chapter 6 concludes the study by giving a summary of work done and evaluating the results of the scenarios in general.

CHAPTER 2

GENERAL BACKGROUND AND LITERATURE REVIEW

This chapter begins with a general review on the concept of deregulation of power systems. Then, it continues by giving information about the impact of deregulation process on transmission planning. Finally, it is concluded with a detailed literature review about the transmission connection capacity assessment studies.

2.1 Deregulation of Power Markets

2.1.1 Basic Concepts of Regulation and Deregulation in Power Industry

Regulation means that *the government has set down laws and rules that put limits on and define how a particular industry or company can operate* [1]. All industries in all countries including most competitive business like auto manufacturing, airlines and banking are regulated to some extent. To be clearer, there are some requirements set by the governments defining what must, can or cannot be done while giving a legal framework to observe the activities in these industries.

Deregulation, on the other hand, offers an opposite kind of approach, as the term suggests. It can be defined as *the removal of regulations or restriction, especially in a particular industry*. Deregulation in power industry can be defined as *restructuring of the rules and economic incentives that government set up to control and drive the electric power industry* [1].

Electrical technology was an untested and skeptical technology when it first appeared. Infrastructure requirements required very large amounts of capital investment.

The government authorities did not want to invest such massive amounts of money in a technology that had not proven itself. However, businesspersons who rely on this technology were ready to meet this funding once they have guaranteed a fair amount of return, because they knew this technology was solid. Thus, the government established an electricity industry by guaranteeing them a local monopoly and a fair amount of return. Therefore, at the dawn of electrical industry, regulation minimized the risk of both governments and investors. Inclusion of government eased the solution of many problems like “right of the way” and it legitimized this technology in the eyes of people that were skeptical in the beginning.

Starting this way, over the years, the electric power industry has been dominated by large utilities that had an overall authority over all activities in their domain of operation. They controlled three distinct components of a power system: generation, transmission and distribution. This kind of utilities are referred as vertically integrated utilities [1-3]. These organizations have functioned as the sole service provider in the area they are responsible for and they were obliged to provide electricity for everyone in this area.

This trend continued until 1980s. From this date on, there have been some radical changes in the electric power industry. Traditionally, electric utilities always preferred large generators comparing to small generator units since the bigger the generator, the more economical was the power produced. Developments in material technology allowed the production of smaller, more robust and less expensive electric machines. In addition, efficiency of small units is considerably improved thanks to technological innovations. Furthermore, computerized control systems are developed which led to control the units from remote distances using less personnel. These changes made possible to build new power plants and produce energy at a lower price. Industrial and commercial users had to ability produce electricity and lower prices than monopoly utilities both for their use or to sell the excess power [1].

2.1.2 Motivations behind Deregulation in Power Industries

There are many reasons that initiated the idea of deregulation in power systems. Some of them can be listed as:

- To be able to meet the fast growth of power demand by attracting various investments to power systems through open access and fair competition in developing countries,
- To reduce government commitment to power industry in terms of severe economic burdens created by power system expansion and intense government functions in organizing the industry,
- To encourage innovation and efficient electricity production through competitions and electricity pricing mechanisms and lowering electricity prices as a result of these,
- To improve customer focus through competitive market structure considering a monopoly utility will not pay much attention for advance customer needs since the regulated environment does not promote to be pro-active,
- To increase managerial efficiency in power industry compared to inefficiency observed in regulated environments,
- To get rid of overstaffing, considering that is usually the condition at regulated electric power industries,
- To be able to meet the increasing environmental demands.

Not all of these reasons have the same priority when developed and developing countries are considered together. Developed countries give priority to efficiency increase, competition in power industry and lowering the electricity prices while developing countries prioritize meeting the fast growth of power demand by attracting various investments to power systems. Developing countries generally found themselves in lack of public resources for further development. Some approaches that encourage investments from companies other than governments such as Build-Operation-Transfer (BOT) etc. are not so popular [2].

2.1.3 An Overview of Deregulated Power Industry

The main characteristic of a competitive structure is that the different tasks are separated from one another and operated in a more practical and profitable way. In order to reduce the total cost in regulated power systems, different tasks (production, transmission, distribution, ancillary services) are coordinated together within responsibility of one large organization. The deregulation process resulted in unbundling of so-called vertically integrated utilities into the utilities tasked with different activities.

Generally, first step in the deregulation process is separation of the transmission activities from generation activities. Since the transmission system has a very large economic scale, privatization is unlikely in practice. Independent of the economic scale it has, it also has a strategic importance and unique role in delivering electricity to the consumer. This unique role gives the transmission operator the ability of overcharging for its services. Thus, it is seen necessary for the transmission system to remain a monopoly under regulations by public authorities. This approach guarantees all producers and consumers to benefit from the system transparently and with reasonable service fees. Parallel to this, steps are taken to create a competitive environment in generation activities through the creation of power pools, provision for direct bilateral transactions or bidding in the spot markets. Therefore, the purpose of deregulation can be expressed as introducing competition in generation and retail services while keeping delivery as regulated monopoly business [1].

The deregulation process brings several new entities to power market structure. These are can be listed as follows: Generator Companies (Gencos), Transmission Companies (Transcos), Distribution Companies (Discos), Retail Energy Service Companies (Rescos) and Independent System Operator (ISO). However, the process of deregulation does not develop in the same way in all countries. There are many variations exist between different countries relating to market structure and scale of deregulation. However, the importance and responsibility of ISO is nearly same in all countries.

ISO is an independent and authorized entity on top of other institutions in power market. It is responsible for keeping system in balance by ensuring that sum of the generation and imports matches the sum of consumptions and exports. As it is name implies, it is not involved in market competition through its own generation or distribution facilities. The ISO also has responsibilities such as operating the system safely and economically, setting transmission tariffs and fees, maintaining service quality and operating the system in an impartial manner. It is expected from ISO to have fairness in its decisions and operations and prevent any kind of favoritism toward some players in the system.

2.1.4 Deregulation Process in Turkey

The Turkish Electricity Authority (TEK) was established in 1970 in view of the necessity of expanding the services related to electricity generation and consumption in Turkey and establishing an institutional structure. TEK was a state-owned monopoly that provided electricity generation, transmission and distribution services.

The Electricity Law issued in 1984 abolished the monopoly status of the TEK. This law allowed private companies to participate in electricity generation, transmission and distribution using the Build-Operate-Transfer (BOT) system. Since then, different approaches have been tried to attract private sector investments in the electrical system. Four different models were used for restructuring to attract private investors, including BOT, Build-Own-Operate (BOO), auto-producer, and the Transfer of Operating Rights (TOOR). While the first three models were used to attract private sector investments for the construction of new power plants, the TOOR model was used to transfer existing generation plants and distribution areas to private sector [4].

TEK was restructured in 1993 in two separate state-owned enterprises as Turkish Electricity Generation and Transmission Corporation (TEAŞ, in native initials) and Turkish Electricity Distribution Corporation (TEDAŞ, in native initials) and in 1994, TEAŞ and TEDAŞ were granted legal entities. In February 2001, Electricity Market Law (No: 4628) was enacted. Turkish Electricity Generation and Transmission

Corporation (TEAŞ, in native initials) was structured as three separate public economic enterprises with the titles of Turkish Electricity Transmission Company (TEİAŞ, in native initials), Electricity Generation Company (EÜAŞ, in native initials) and Turkish Electricity Trade and Contracting Corporation (TETAŞ, in native initials). TEDAŞ, which has been conducting electricity distribution and retailing activities since 1993, was included in the privatization scope and program in 2004 upon the decision on privatization of these services. The regions of distribution were identified again and Turkey was separated into 21 distribution regions. The privatization process of these distribution regions completed at 2010 and power distribution in Turkey became fully privatized. In addition, Electricity Market Regulatory Authority (EPDK, in native initials) was founded at 2001 in order to perform the regulatory and supervisory functions in the market.

In 2013, new Electricity Market Law (No: 6446) was passed with the objective to ensure a financially sound, stable and transparent electricity market that operates in accordance with the provisions of private law in a competitive environment, and an independent regulation and audit in this market for the purpose of electricity supply to the consumers in an efficient, good-quality, sustainable, low-cost and environment-friendly manner. In accordance with this law, transition to day-ahead planning and balancing power market that is based on hourly settlement is arranged with the Electricity Market Balancing and Settlement Regulation while primary and secondary frequency controls are arranged with Ancillary Services Regulation [5-6].

Energy Exchange Istanbul (EPİAŞ, in native initials) was officially established on March 2015 upon the registration processes completed subject to the provisions of the Electricity Market Law (No: 6446) and Turkish Trade Law (No: 6102). The day-to-day market, day ahead market and imbalance delivery activities have passed to EPİAŞ. Balancing power market activities will be carried out as it is until today and will be followed by TEİAŞ. The development of the electricity market in Turkey by years is given in Figure 1.

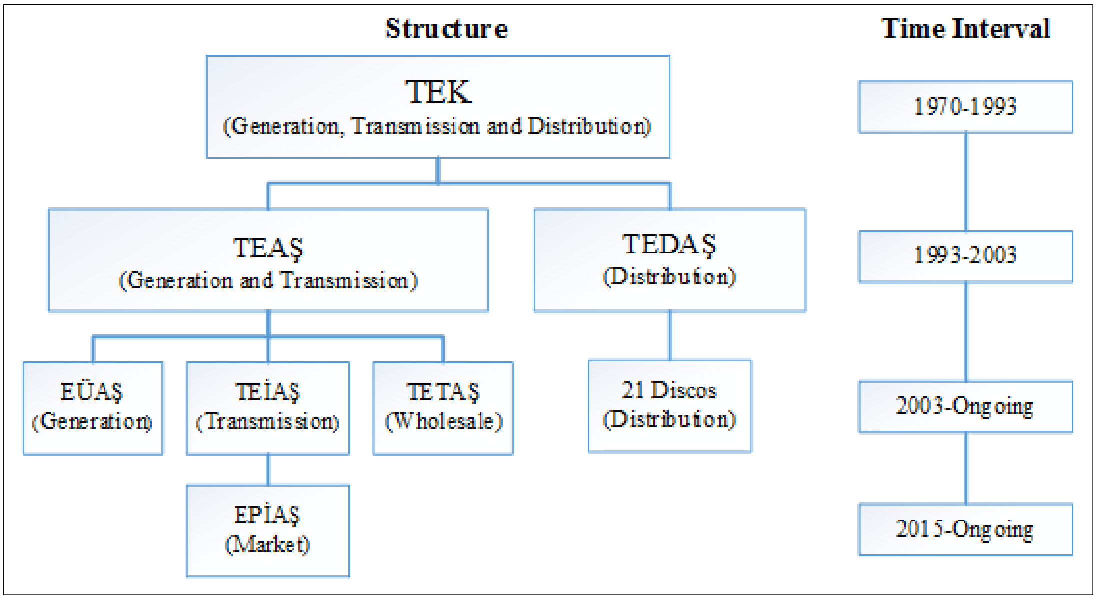

Figure 1. The Development of the Electricity Market of Turkey by Years

2.2 Impact of Deregulation on Transmission System Planning

In the traditional power system planning methodology, generation planning is considered core of the system planning procedure while planning of transmission system is done based on it [7]. During the planning process, system planners have access to all information about the power system and its subcomponents like generation, transmission and distribution. So using this information, the system operator tries to plan system by using the minimum investment cost and keep the system working within the reliable limits. That can be named as least cost planning approach [7].

Market deregulation introduced many new challenges for transmission system planners. With unbundling process taking place, system planners lost their intimate knowledge about where generation will be [8]. In addition, considering the grid construction may lag behind generator installation in developing countries, risk of possible inadequacies of transmission system capacity becomes serious. Because of these inadequacies, the transmission network could get to be dangerously stressed and it could lose its stability in a case of a disturbance. Even a blackout could be the result in case of cascaded faults. In addition, the newly introduced market mechanism alters the dispatch procedures, generation and load patterns. That results in serious changes in power flow patterns and makes the work of transmission planning harder.

The most important challenge for transmission system planners in a deregulated environment is to assure reliable expansion planning by minimizing possible network congestions. System is said to be congested, if the desired amount of generation and consumption forces the transmission system to operate at beyond one or more transfer limit of its elements. Outages of transmission elements (line, transformer etc.) and higher load demands can be considered as short term reasons for network congestion while poor generation and transmission planning can be considered as the long term causes [1-2].

One of the main effects of network congestion is that it can result in creating local market powers. In case of power cannot be transferred to a desired region due to the congestion of the transmission system, the generators in that area can increase their profits without having to lower their costs. In this case, it is said that these generators have market power in this area. When inadequate transmission capacity results in some generators to exercise market power in certain locations that leads to market inefficiency [1].

2.3 Literature Review on Transmission Connection Capacity Assessment Studies

The privatization of power systems has made the planning of the transmission system more complex than it ever was. The structure in which generation, transmission and distribution were planned and operated by a single authority has changed. The planning and operation of the system became relatively more independent and disconnected. The transmission system planners lost their direct control over plant investments. Therefore, to be able to plan and operate transmission in economic and reliable way many studies are conducted and methods are presented in literature. These studies can be considered in two different groups. The first group of studies are the congestion management studies that aim to prevent possible congestions in transmission system in short term [9-16]. That kind of studies are being used for more operational purposes. The second group of studies are done to prevent possible inadequacies of the transmission system in the longer term. These studies, also, can be divided into three different groups based on their priorities: the ones which aim to determine maximum amount of new generation that can be connected to transmission system safely [17-19], the ones which try to identify most suitable locations for new generation [20-23] and the ones which intend to maximize utilization of the existing capacities and assets [24-25].

There are three basic methods in the literature for congestion managements and reliable system operation: price area congestion management, available transfer capability based congestion management and optimal power flow (OPF) based congestion management [1]. Price area congested management is used in Nordic region to manage congestions by using area price model and counter trade [9]. Available transfer capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for future commercial activity over and above already committed uses according to North American Electric Reliability Council (NERC) definition [10]. ATC helps to alleviate problem of congestion by giving power transfer capability available in the system for a particular transaction [11]. It is used extensively for operational planning purposes [12-14]. OPF based congestion methods are used to handle congestions by solving OPF problem which can be defined as optimizing the steady state performance of a power system in terms of an objective function while satisfying security constraints [15-16].

The second group of studies aim to prevent possible inadequacies of transmission systems that can happen in the future. In [17], a generation connection capacity assessment is done for future transmission network of South Africa. In this study, new generation is added gradually to supply area until the area’s N-1 limit is reached. In [18], a transmission connection capacity assessment is done for the future transmission network of Turkey. In this study, the capacities of pre-determined regions are found after a step-wise process. While the generation in the selected region is increased gradually, same amount of generation is decreased in rest of the regions to keep generation constant and using N-1 criteria, the capacities are determined. In [19], a method is presented for transmission system capacity assessment to connect new generation using pre-fault (base case) and post fault criteria (N-1 and N-2) that can be used at early stages to identify suitable connection locations. The proposed methodology is applied on English and Wales transmission system. In [20], a method that determines the generation locations that are beneficial to grid by measuring transmission system securities is presented. In this method, the weighted transmission loading relief sensitivities are used to determine the locations for new generation that benefit the grid security. In [21] and [22] generation investments are encouraged to locate pre-determined geographic regions via transmission tariffs while in [23] carbon criteria is used for same purpose. In [24], system loadability quantification is used for assessing the system transmission capacity with respect to system voltage stability. In [25], simple probabilistic planning methods that aim to maximize the use of existing capacities and assets.

The procedures adopted by European Transmission System Operators (ETSO) for determining available transfer capacity are discussed in [26]. Here, the available transfer capacity is calculated using generation increase/decrease within the adjacent TSO networks while in each step security rules are checked. Although this methodology is generally utilized for operational planning purposes, with little modification it can be used for long-term available generation assessment as in [18] providing that a realistic model of future network is available. The adjacent networks can be considered as different regions in the same network. The additional generation can be modelled as generation increase in supply area while same amount of generation decrease is realized in rest of the system and by applying security constrained ac load flow in each step, the available transmission connection capacity for new generation can be determined for each individual region.

In this thesis, a methodology has been developed to determine the maximum amount of generation that can safely be connected to the transmission system in the long term on a regional basis. The proposed methodology was applied to the projected network model of the Turkish Transmission System of 2026 considering four different case studies. Unlike the [19] and [20], in this thesis, additional generation that is predicted to enter a region in the future is evenly distributed throughout the steps to all suitable substations. Generation increase was carried out through artificial units assigned to these substations rather than using existing generators. The aim of this approach is to reflect the unpredictability of future generation investments in terms of resources, size and location. In addition, in [17] and [18], a step-wise procedure is performed to find the additional generation amount that can be connected safely to transmission system. The first step in which the security constrained ac load flow is violated is considered as the reference point for transmission connection capacity value of that region. In this thesis, there are three different capacity values found for each region using two newly proposed indices, named, region based evaluation index (REI) and line based evaluation index (LEI). Two of these capacities are found using REI while the remaining capacity value is determined using LEI. The capacity values found, not only show the weaknesses of the regional transmission system and limits of the new generation connection for that region, but also show the reaction of the region to the increase of generation as a whole. While REI based capacities are more useful to assess the condition of the transmission system in the region as a whole, LEI based capacity is more useful to assess the weaknesses of the transmission system in the region. Furthermore, it shows the maximum generation increase that can be made in that region without any additional investments are needed.

In Turkish electricity market case, Transmission System Operator is obliged to calculate regional allowable transmission connection capacity for the next five and ten year periods to encourage power plant investments to proper locations and to prevent possible inadequacy of the transmission system in the future. This study, while fulfilling this need, implements the proposed methodology on different scenarios. This study has been conducted for four different cases. These are summer peak and spring minimum loading conditions, which are evaluated for two different wind power dispatches, namely, expected and low wind power dispatches. The studied network is the projected Turkish Transmission Network of 2026.

CHAPTER 3

PRELIMINARY WORK

This chapter explains the preliminary work that is done prior to main study. Since an appropriate network model is necessary for the application of proposed methodology, this chapter gives steps of creating this network model. In this thesis, Turkish Transmission Network of 2026 is studied considering different loading conditions and dispatches. Therefore, in first two sections, information is given about modelling the existing Turkish Transmission Network and expanding it to year 2026. Then, in last two sections, procedures of demand forecast, generation capacity projection and generation dispatch are presented.

3.1 Transmission System Modelling

In this thesis, PSS-E software of Siemens Power Technologies International (PTI) is used for simulations. PSS-E is an integrated set of computer programs that handles the power system analysis calculations such as; power flow and related network analysis functions, balanced and unbalanced fault analysis, network equivalent construction and dynamic simulation. This software also allows the user to define and implement processing and reporting functions via the Python programming language. Different Python codes are developed and used during studies that presented in this thesis. Some of these codes have been developed to automate contingencies and load flow analyses in PSS-E while others are used to constructing and updating newly proposed indices.

Simulation data of 2026 Turkish Transmission Network is constructed before conducting studies on the transmission system. That is made by expanding existing system topology from current system data to year 2026. The demand data used in PSS-

E is independent from voltage and current variations. Therefore, it is assumed that same demand is presented in constant MW and MVAR values in any voltage variation. The simulation data includes all transmission lines at 154 kV and 400 kV levels, which are the two main voltage levels, utilized in transmission system of Turkey. Their corresponding grid lengths are roughly 41522 and 20379 km, respectively. Loads are represented as constant PQ load type at the low voltage side of 400 kV / 33 kV and 154 kV / 33 kV transformers. Generators are modelled with the generating busbars and step-up transformers. All large-scale power plants are connected to transmission network including Akkuyu and Sinop NPP. The current system transformer and generator parameters are taken from the real measurements. Moreover, subsequent equipment is characterized with the reasonable parameters, such as 100 MVA 154 kV / 33 kV transformer has 0.12 per unit positive reactance or a generator has 0.25 per unit synchronous reactance.

In analyses, line loadings are calculated in terms of the MVA capability of lines and presented in terms of MVA percentage loadings. PSS-E calculates the power flowing through the lines and then using the necessary equations it presents the MVA loading of that line in percentage. Line ratings are adjusted according to seasonal thermal rating values. In summer peak demand scenario line ratings are adjusted according to summer ratings while in spring minimum loading condition they are adjusted according to spring ratings.

3.2 Transmission System Expansion Methodology

The network data utilized throughout the study is based on existing transmission network topology. Considering Turkey’s fast growing electrical energy demand, significant amount of new generation investments together with the transmission system expansion is needed. Therefore, long term public and private transmission network investments (i.e., transmission substations, transmission lines and power plants etc.) are added to existing topology and system configuration is expanded from existing topology to cover expected investments at 2026.

System expansion methodology was applied as mentioned above and results show that the number of transmission system substations will increase from 1074 to 1323. In addition, transmission system is expected to have installed transformer capacity of 208900 MVA as an increase from 182120 MVA. These values include 400 kV / 154 kV, 400 kV / 33 kV and 154 kV / 33 kV transformers. Finally, 154 kV line length is expected to go up to 47280 km from 41522 km while, 400 kV line length is expected to reach 29940 km from 20379 km.

3.3 Demand Forecast

The first step for the transmission system planning studies is the long-term load demand projection. To be able to make realistic plans and projections related to future, load demand projections must be reliable especially for countries with the high rapid annual growth. Turkey has annual growth of 5 % - 7 % so that demand forecast should be considered as highly important.

In determination of regional transmission capacities study, there is a need of regional demand forecast for each transmission substation considering year 2026. The inputs of the forecast are the monthly peak demands between 1995 and 2016, and the substation peak demands between 2004 and 2016. Turkey’s monthly peak demand forecast have been made in order to obtain the demand forecast on regional basis in the summer peak demand and spring minimum loading hours. Figure 2 shows the sequence followed during the process of the peak demand forecast.

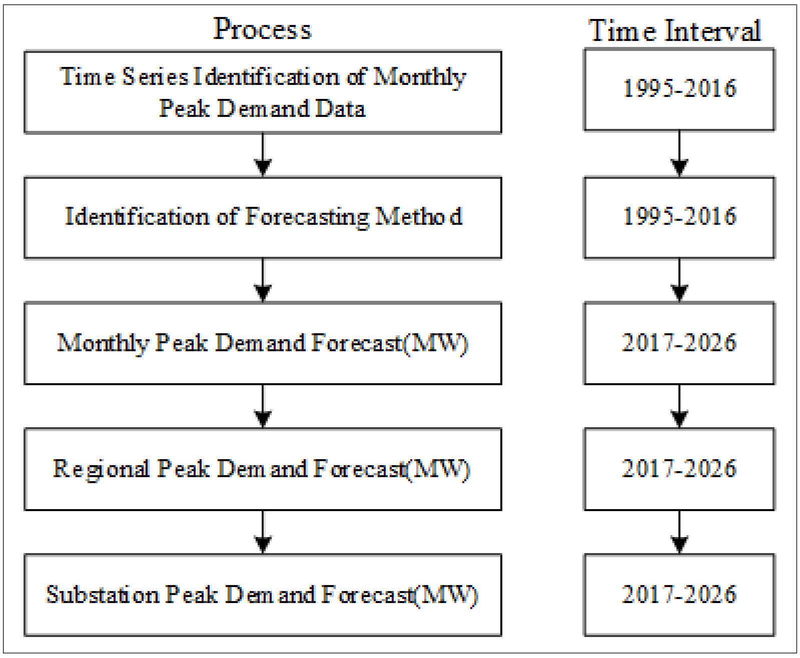

Figure 2. Demand Forecasting Process

Generally, long-term demand forecasting methods can be classified in two broad categories: artificial intelligence based methods and parametric methods [27]. Neural networks, genetic algorithms and fuzzy logic methods can be given as examples to the artificial intelligence based methods. The parametric methods are based on relating load demand to its affecting factors by a suitable mathematical model. Trend analysis, econometrics model and end-use modeling are some of the well-known parametric methods. The summary of these models are given as following:

- **Trend Analysis**

Load forecasting using trend analysis (also referred to as time series or regression analysis) relies solely on the historical load with no consideration of the factors that affected the amount of energy used. In essence, regression models determine a mathematical equation that explains historical usage and extrapolated to future usage using that equation. The major advantage of trend analysis is simplicity. It requires no data beyond the historical observations of the value that is being forecasted. In addition, it is quick and inexpensive. The major disadvantage of the trend models is that they do not account for changes in the economic, climatic, and demographic factors that may change energy use.

- **Econometric models**

Econometric models attempt to quantify the relationship between the parameter that is being forecasted (the output variable) and a number of factors that affect the output variable. These factors are commonly referred to as explanatory variables or drivers. An equation is derived that includes the relationship of each driver to the output. Projections of the values for the drivers are then used to determine the output variable for each forecast period. The major advantages of econometric forecasting are the potential for improved accuracy and the ability to analyze the impact of different factors on output. The major disadvantage of econometric forecasts is that it is difficult to account for factors that will change the future relationship between the drivers and the output variable. In addition, as another disadvantage, it can be hard to find reliable data for drivers.

- **End-use models**

End-use forecasts look at energy use at the individual device level. The consumption of energy is categorized into a number of different activities, which provide a desired service or end use. Examples of these include lighting, refrigeration, space heating, and cooling. End use models start with a catalogue of the existing stock of devices for each end use. This includes the vintage, or age, fuel source, and efficiency of the devices. For each forecast period, the model assumes that some of the existing stock will fail, with failure rates being a function of the vintage of the device. When failure occurs, the device can either be repaired or replaced. Additionally, new devices will be added to the stock as the number of homes and businesses increase. New devices, along with replacement of existing devices, are chosen from the available options. This provides a new "existing" stock to be used for the next forecast period. The forecast is then derived from the energy used by all of the devices in each forecast period. The major advantage of end-use models is the ability to directly capture changes in efficiency. In addition, it is very accurate. Disadvantages of end-use models include being very data-intensive, the potential to miss energy consumption from devices that have yet to be invented or adopted, and the inability to capture changes in customer behavior.

3.3.1 Time Series Identification of Monthly Peak Demand Data

The monthly peak estimates have a significant role in the capacity determination of the transmission system because one of the scenarios studied in this thesis is based on the annual peak demand time. Figure 3 shows the time series plot of Turkey's monthly peak demand data. As can be seen from the figure, there is an increasing trend in Turkish peak demand over the years.

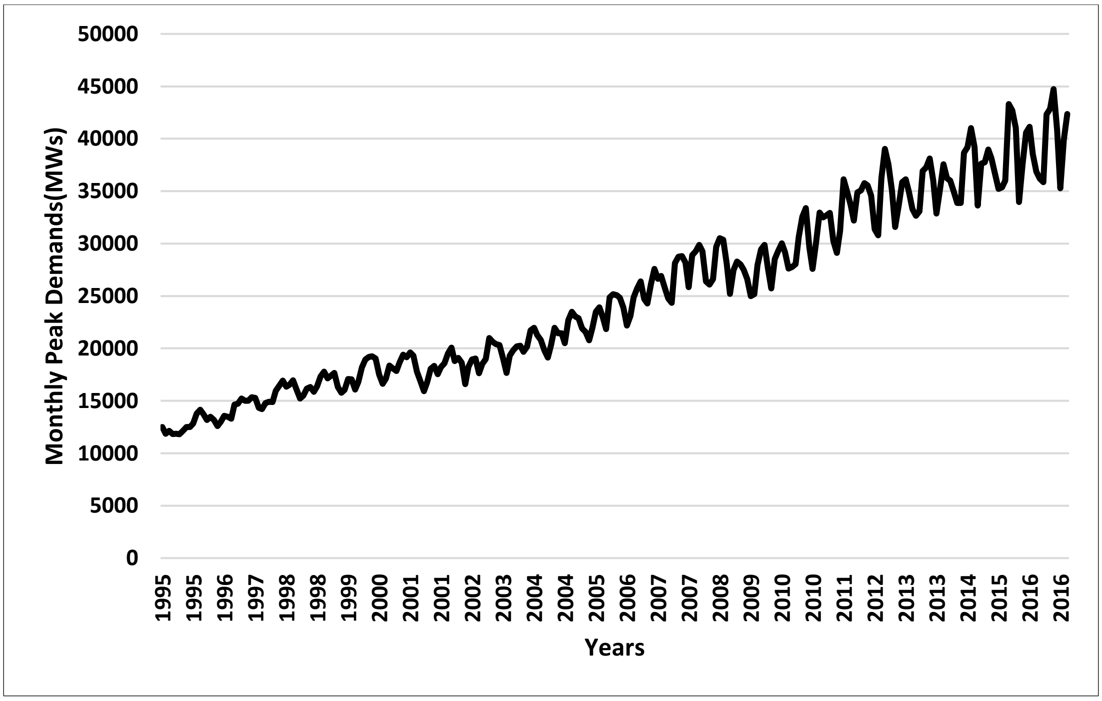

Figure 3. Turkey's Monthly Peak Demand Data

In Figure 4, percent growths of yearly peak demands of Turkey are visualized. Monthly peak demands are directly related to the economic developments. While peak demand of Turkey has grown at a rate higher than 10% in some years, the most important factors that have brought down the trend in the last decade are the recession in 2013 with the economic crises of 2001 and 2009. Turkey's peak demand grew by 5.70% on average from 1995 to 2016.

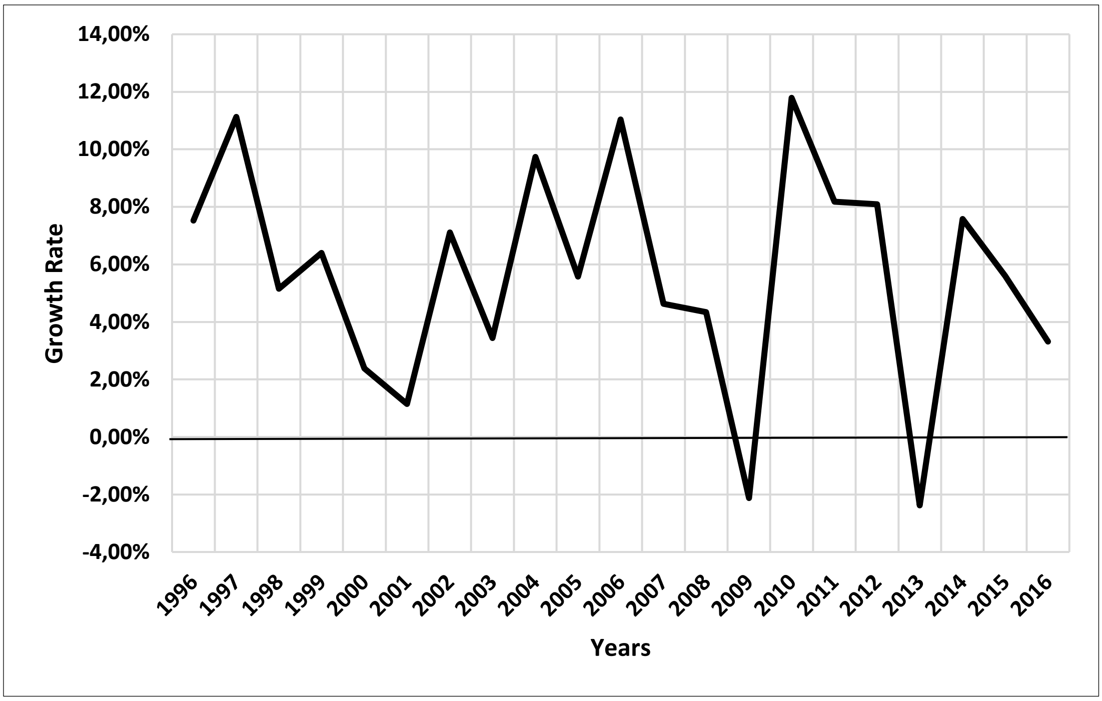

Figure 4. Percent Growth of Yearly Peak Demands of Turkey

3.3.2 Identification of Forecasting Method

Seasonal ARIMA (Seasonal Auto Regressive Integrated Moving Averages) method is used for peak demand forecast in this thesis. It is a trend analysis method. Among all methods mentioned before it is most easy to perform since it is hard to find reliable long-term (10 years) data to implement econometric models or end-use models.

Statistical work is carried out using open source software R [28]. R is preferred in this study since it provides a wide variety of statistical tools (linear and nonlinear modeling, classical statistical tests, time-series analysis, classification, clustering) supported by extensive graphic abilities.

A SARIMA model can be viewed as a "filter" that tries to separate the data from the noise, and the data is then extrapolated into the future to obtain forecasts. The model predicts a value in a response time series as a linear combination of its own past values and past errors (also called shocks or innovations).

Seasonal ARIMA (SARIMA) model can be written as ARIMA (p, d, q) $(P, D, Q)_s$ where

p *is the order of autoregressive part*

P *is the order of seasonal autoregressive part*

q *is the order of moving average part*

Q *is the order of seasonal moving average part*

d *is the degree of first differencing involved*

D *is the degree of seasonal differencing involved*

s *is the number of periods per season*

If $\{Y_t: 1 \leq t \leq n\}$ is defined as the time series to be forecasted, the mathematical expression of the SARIMA model can be written as:

$$(1-B)^d * (1-B^s)^D * Y_t = \mu + \frac{\theta(B)\,\theta_s(B^s)}{\Phi(B)\Phi_s(B^s)} * \alpha_t \tag{3.1}$$

where

t *is the time index*

μ *is the mean term*

α_t *is the random error term.*

B *is the backshift operator, that is,* $BX_t = X_{t-1}$

$\theta(B)$ *is the autoregressive operator, represented as a polynomial in the back shift operator:*

$$\theta(B) = 1 - \theta_1 B - \cdots - \theta_p B^p \tag{3.2}$$

Φ (B) is the moving-average operator, represented as a polynomial in the back shift operator:

$$\Phi(B) = 1 - \Phi_1 B - \cdots - \Phi_q B^q \tag{3.3}$$

θ_s (B^s) is the seasonal autoregressive operator, represented as a polynomial in the back shift operator:

$$\theta_s(B^s) = 1 - \theta_{s,1}(B^s) - \cdots - \theta_{s,P}(B^{sP}) \tag{3.4}$$

Φ_s (B^s) is the seasonal moving-average operator, represented as a polynomial in the back shift operator:

$$\Phi_s(B^s) = 1 - \Phi_{s,1}(B^s) - \cdots - \Phi_{s,Q}(B^{sQ}) \tag{3.5}$$

The basic assumption of the SARIMA model is that the studied time series is stationary. A stationary time series is one whose properties do not depend on the time at which the series is observed. More precisely, if y_t is a stationary time series, then for all s, the distribution of $(y_t , \ldots , y_{t+s})$ does not depend on t.

Figure 5 gives Turkish peak demand data as decomposed to its elements. It is clear that, the peak demand data has an increasing trend and seasonal characteristics. Furthermore, the mean and the variance of the series are not constant and they are increasing.

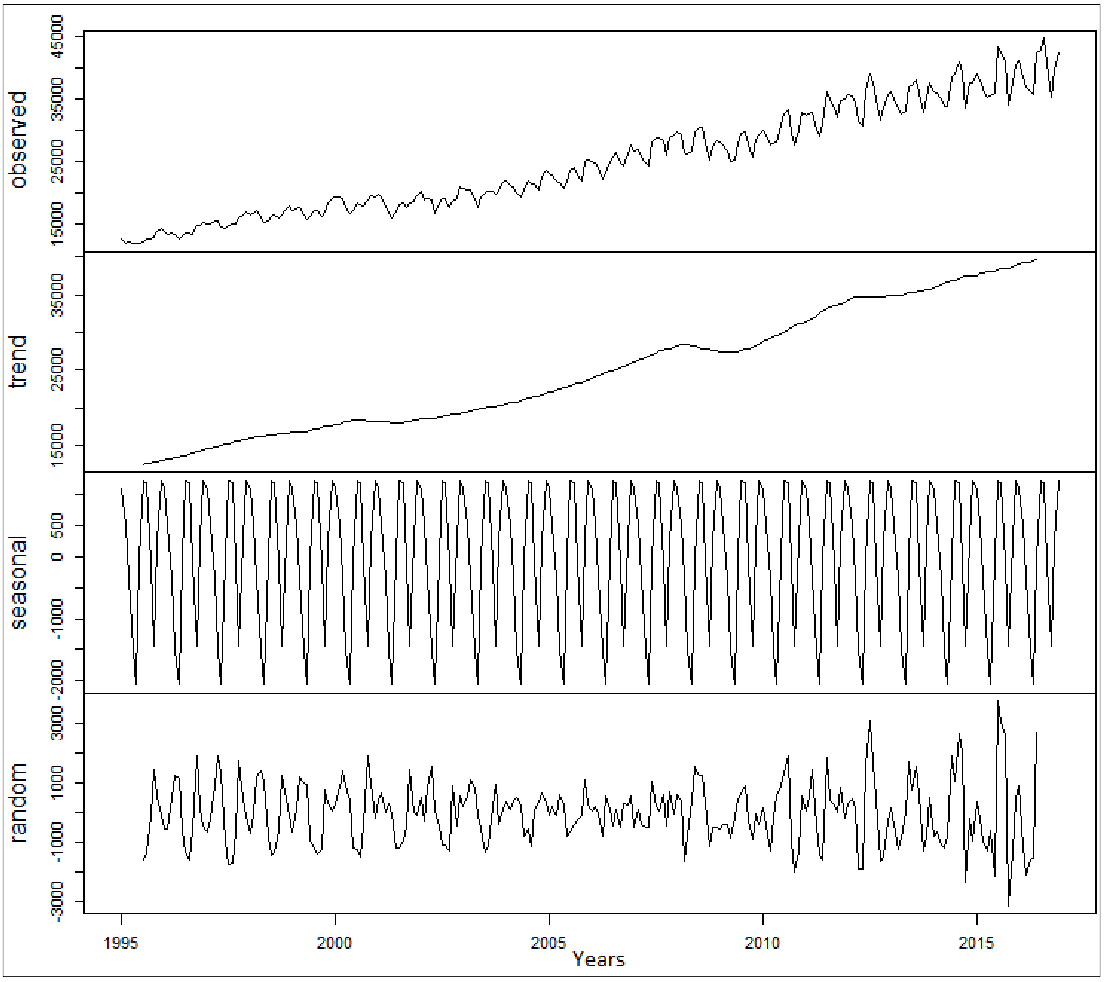

Figure 5. Decomposition of Turkey's Peak Demand Data to Its Elements

So in order to make the data stationary, variance of the data is stabilized first. To stabilize variance and make the data more normal distribution-like, Box–Cox Transformation is applied [29]. The formulation of Box–Cox Transformation is given as:

$$y_i^{\lambda} = \begin{cases} \dfrac{y_i^{\lambda} - 1}{\lambda} & if\ \lambda \neq 0, \\ \ln(y_i) & if\ \lambda = 0, \end{cases} \tag{3.6}$$

where

y_i *is the* i^{th} *element of time series*

λ *is the transformation coefficient.*

The transformation coefficient is found as 0.20 using *BoxCox* function of R software as shown in Figure 6.

```
> BoxCox.lambda(peakdemand, method=c("loglik"), lower=-1, upper=2)
[1] 0.2
```

Figure 6. Determination of Box-Cox Transformation Coefficient

After that, logarithmic transformation is applied with λ = 0.2. Figure 7 shows the distribution of the data before and after transformation. As can be seen from the figure, the data is more like Gaussian-Distribution after the transformation.

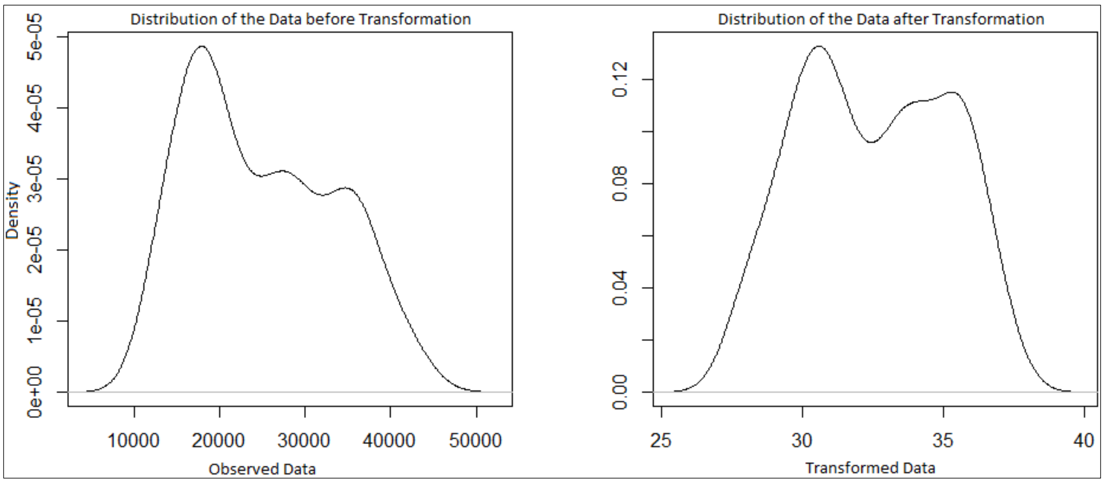

Figure 7. Distribution of the Peak Demand Data Before and After the Transformation

As it can be understood intuitively, a time series with trend and seasonality cannot be stationary since the trend and seasonality will affect the value of the time series at different times. However, to check data stationarity in a mathematical way, KPSS test (Kwiatkowski–Phillips–Schmidt–Shin) will be applied. KPSS test is used for testing a null hypothesis that an observable time series is stationary around a deterministic trend [30].

The results of KPSS test when it is applied to the Turkish peak demand data is presented in Figure 8.

```
> kpss.test(peakdemand,c("Trend"))

        KPSS Test for Trend Stationarity

data:  peakdemand
KPSS Trend = 0.79845, Truncation lag parameter = 3, p-value = 0.01
```

Figure 8. Result of KPSS Test for Raw Turkish Peak Demand Data

From Figure 8, it can be seen that p-value is lesser than usual 5% level (p=0.05) so that the null hypothesis of time-series is being trend stationary is rejected. That result shows clearly that our series is not trend-stationary.

One way to make a time series stationary is computing the differences between consecutive observations, which is known as differencing. While transformations such as logarithms (Box-Cox Transformation) can help to stabilize the variance of a time series, differencing can help stabilize the mean of a time series by removing changes in the level of a time series, and so eliminating trend and seasonality.

Since the peak demand data has seasonal characteristics with period of 12 (yearly-seasonality), seasonal differencing is applied. A seasonal difference is the difference between an observation and the corresponding observation from the previous year. Then, KPSS test is applied to seasonally differenced peak demand data and the results are shown in Figure 9.

```
> kpss.test(seasonally_differenced_peakdemand,c("Trend"))

        KPSS Test for Trend Stationarity

data:  seasonally_differenced_peakdemand
KPSS Trend = 0.10975, Truncation lag parameter = 3, p-value = 0.1
```

Figure 9. Result of KPSS Test for Differenced Turkish Peak Demand Data

As can be seen from Figure 9, the resultant p-value is larger than usual 5% level (p=0.05) so that the null hypothesis of time-series is trend stationary is accepted. That results show that our series is trend-stationary after it was seasonally differenced.

Finally, the peak demand data become stabilized in terms of variance and trend after Box-Cox transformation and seasonal differencing were applied. That makes the peak demand data ready to be used in SARIMA model. To find appropriate *(p, d, q)* and *(P, D, Q)* coefficients of SARIMA model *auto.arima* function of R software is used. This function returns best ARIMA model according to either AIC (Akaike Information Criteria), AICc (Second-order Akaike Information Criteria) or BIC (Bayesian Information Criteria) value. The function conducts a search over possible model within the order constraints provided. Figure 10 shows a snapshot from *auto.arima* process. After the searching process is completed, the resultant model is given in Figure 11.

```
ARIMA(1,0,0)(3,1,0)[12]                      : 65.00054
ARIMA(1,0,0)(3,1,0)[12] with drift           : 31.68501
ARIMA(1,0,0)(3,1,1)[12]                      : 67.0254
ARIMA(1,0,0)(3,1,1)[12] with drift           : 32.14554
ARIMA(1,0,0)(4,1,0)[12]                      : 67.05353
ARIMA(1,0,0)(4,1,0)[12] with drift           : 33.44871
ARIMA(1,0,1)(0,1,0)[12]                      : 70.97334
ARIMA(1,0,1)(0,1,0)[12] with drift           : 63.31166
ARIMA(1,0,1)(0,1,1)[12]                      : Inf
ARIMA(1,0,1)(0,1,1)[12] with drift           : 4.065593
ARIMA(1,0,1)(0,1,2)[12]                      : Inf
ARIMA(1,0,1)(0,1,2)[12] with drift           : 6.15967
ARIMA(1,0,1)(0,1,3)[12]                      : Inf
ARIMA(1,0,1)(0,1,3)[12] with drift           : 7.795288
ARIMA(1,0,1)(1,1,0)[12]                      : 27.34821
ARIMA(1,0,1)(1,1,0)[12] with drift           : 21.69835
ARIMA(1,0,1)(1,1,1)[12]                      : Inf
ARIMA(1,0,1)(1,1,1)[12] with drift           : 6.160341
ARIMA(1,0,1)(1,1,2)[12]                      : Inf
ARIMA(1,0,1)(1,1,2)[12] with drift           : 8.280618
```

Figure 10. Model Searching Process with *auto.arima* Function

```
Series: peakdemand
ARIMA(1,0,1)(0,1,1)[12] with drift
Box Cox transformation: lambda= 0.2

Coefficients:
         ar1      ma1     sma1   drift
      0.9325  -0.5332  -0.5511  0.0343
s.e.  0.0311   0.0761   0.0524  0.0039

sigma^2 estimated as 0.057:  log likelihood=3.09
AIC=3.82   AICc=4.07   BIC=21.47
```

Figure 11. Resultant ARIMA Model

The chosen model can be written as ARIMA ($1, 0, 1$) ($0, 1, 1$) $_{12}$. In order to verify model, autocorrelations of residuals are calculated and presented in Figure 12.

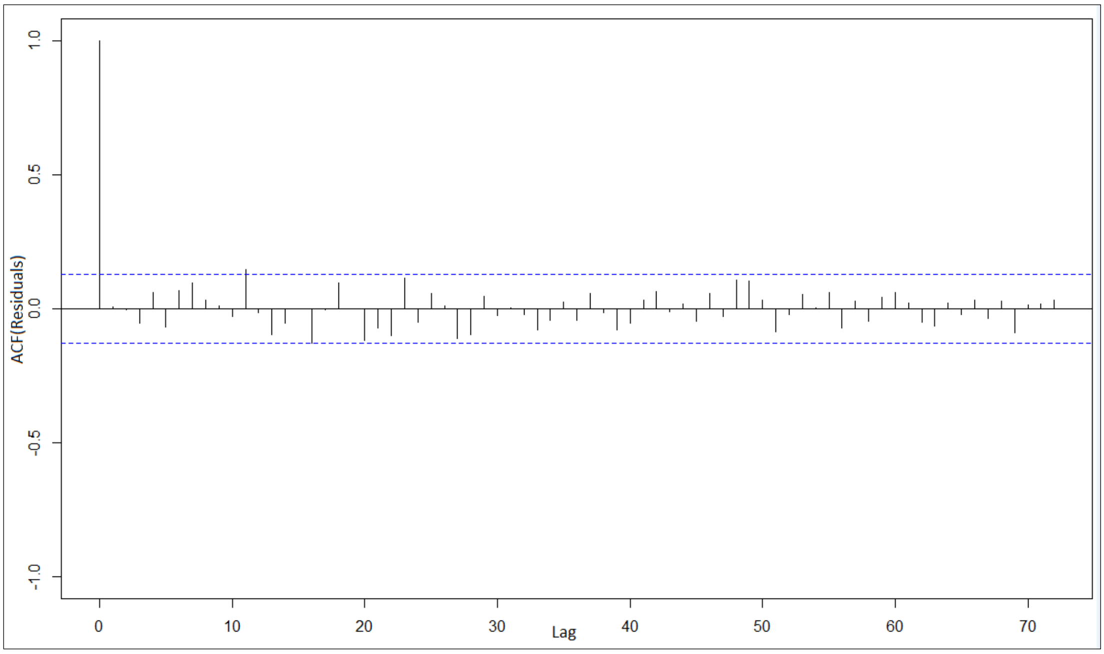

Figure 12. Autocorrelation Function of the Residuals

3.3.3 Peak Demand Forecast

After the formulation is completed, monthly peak demand of the Turkey was forecasted. Spring minimum of the system is statistically half of the minimum monthly peak of the year, considering 2004 - 2016 observed values. Therefore, spring minimum was assumed 50 % of forecasted spring peaks [31]. Table 1 shows the results of the normal scenario. Table 2 shows the summer peak and spring minimum projection bands. The trend lines of the maximum and minimum projection bands are given in Figure 13.

Table 1. Turkey's Monthly Peak Demand Projection (MW)

Year	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Nov.	Oct.	Dec.
2017	42500	40945	39415	38300	38190	42851	45542	46562	43606	37756	41975	44360
2018	44699	43074	41476	40309	40191	45039	47835	48892	45814	39722	44111	46589
2019	46939	45246	43581	42365	42240	47281	50186	51282	48081	41745	46309	48883
2020	49246	47485	45753	44488	44357	49596	52613	53750	50425	43839	48582	51256
2021	51632	49802	48003	46688	46552	51994	55125	56305	52854	46011	50939	53715
2022	54106	52206	50337	48970	48829	54480	57730	58954	55372	48266	53385	56266
2023	56671	54699	52759	51340	51192	57060	60431	61700	57985	50608	55922	58912
2024	59332	57286	55272	53799	53646	59735	63231	64547	60695	53039	58555	61656
2025	62092	59970	57880	56352	56193	62509	66134	67498	63504	55563	61285	64501
2026	64953	62753	60586	59001	58836	65386	69143	70556	66417	58182	64117	67451

Table 2. Projection Bands for Summer Peak and Spring Minimum (MW)

Year	Summer Peak			Spring Minumum		
	Lower	Normal	Upper	Lower	Normal	Upper
2017	44138	46562	49091	18795	19708	20655
2018	45649	48892	52317	19405	20738	22143
2019	47374	51282	55443	20145	21791	23542
2020	49231	53750	58594	20952	22877	24941
2021	51194	56305	61816	21809	24002	26367
2022	53255	58954	65131	22712	25168	27833
2023	55409	61700	68550	23657	26379	29346
2024	57656	64547	72082	24645	27636	30911
2025	59995	67498	75734	25675	28940	32530
2026	62427	70556	79511	26747	30293	34206

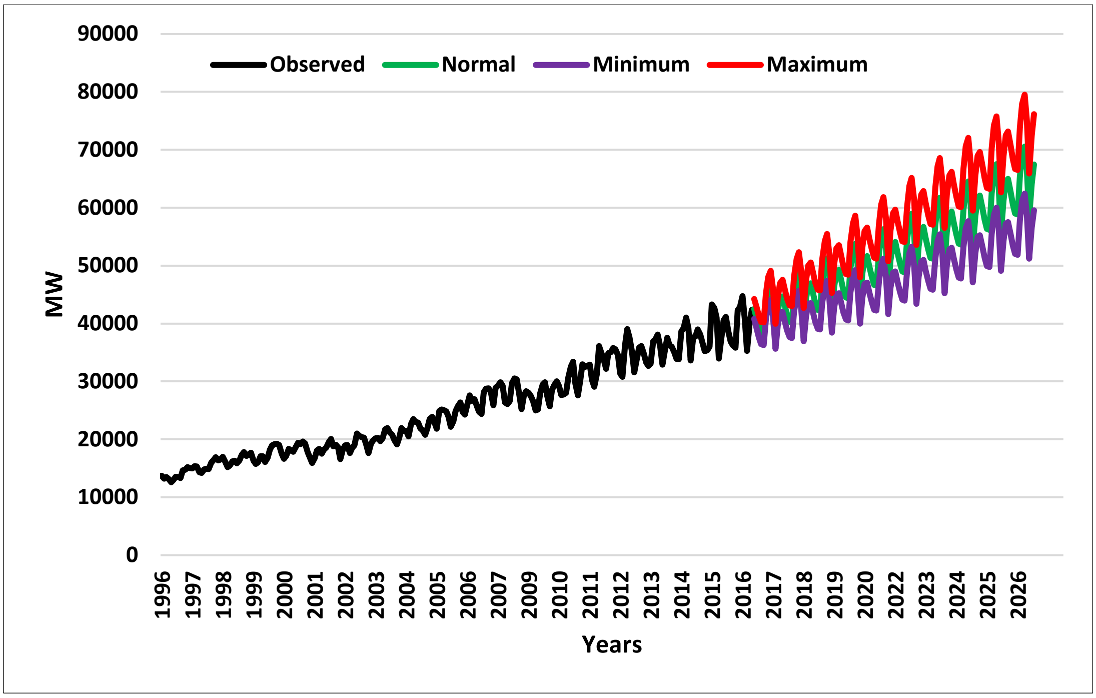

Figure 13. Trend Lines of the Projection Bands of Turkey's Monthly Peak Demand

3.3.4 Regional Peak Demand Forecast

For the Turkish Electricity System, a deductive methodology was used for the regional realization of the demand projection in summer peak and spring minimum loading conditions. After Turkey's summer peak and spring demand projection was realized, regions' contributions to the total demand projection were calculated as the second step.

In order to minimize the negative effects of factors such as load transfer between substations, transfer of part of the load of existing substations to the newly constructed ones and interruptions on projection analysis, the regions are determined as follows:

- The total load of transformer centers in each city was accepted as the total load of that city and the data of 81 cities for 1994-2016 were created.

- Each city, which has more than one percent of the total electricity demand in the last three years' average, was considered as a separate region (major regions).
- For all other cities, the geographical boundaries of the electricity distribution companies to which they depend were considered as a region (minor regions).

By following this procedure, 43 regions were identified, 27 of them being major and 16 of them being minor. The resultant regions are presented in Table 3.

Table 3. Determined Regions for Peak Demand Forecast

1	İstanbul	Major	**16**	Mugla	Major	**31**	Coruh DISCO	Minor
2	İzmir	Major	**17**	Diyarbakir	Major	**32**	Baskent DISCO	Minor
3	Ankara	Major	**18**	K.maras	Major	**33**	Y.irmak DISCO	Minor
4	Bursa	Major	**19**	Denizli	Major	**34**	Aras DISCO	Minor
5	Antalya	Major	**20**	Kayseri	Major	**35**	Firat DISCO	Minor
6	Kocaeli	Major	**21**	Balikesir	Major	**36**	Çamlibel DISCO	Minor
7	Sanliurfa	Major	**22**	Canakkale	Major	**37**	Trakya DISCO	Minor
8	Adana	Major	**23**	Sakarya	Major	**38**	Vangolu DISCO	Minor
9	Konya	Major	**24**	Aydin	Major	**39**	Sakarya DISCO	Minor
10	Tekirdag	Major	**25**	Samsun	Major	**40**	Akdeniz DISCO	Minor
11	Hatay	Major	**26**	Eskisehir	Major	**41**	Akedas DISCO	Minor
12	Gaziantep	Major	**27**	Zonguldak	Major	**42**	Uludag DISCO	Minor
13	Mardin	Major	**28**	OS.gazi DISCO	Minor	**43**	Toroslar DISCO	Minor
14	Manisa	Major	**29**	Meram DISCO	Minor			
15	Mersin	Major	**30**	Dicle DISCO	Minor			

Holt's linear trend method was used to forecast regional peak demands between years 2017-2026. This method is an extended exponential smoothing method, which allows forecasting of data with a trend [32]. Forecasts produced using exponential smoothing methods are weighted averages of past observations with the weights decaying exponentially as the observations get older. In other words, the more recent the observation the higher the associated weight. Holt's linear method can be formulized using three equations: a forecast equation and two smoothing equations (one for the level and one for the trend). These equations are given as:

Forecast equation: $$\hat{y}_{t+h|t} = l_t + h * b_t \tag{3.7}$$

Level equation: $$l_t = \alpha * \hat{y}_t + (1-\alpha) * (l_{t-1} + b_{t-1}) \tag{3.8}$$

Trend equation: $$b_t = \beta * (l_t - l_{t-1}) + (1-\beta) * b_{t-1} \tag{3.9}$$

where:

t	*is the time*
l_t	*is the estimate of the level of the series at time t*
b_t	*is the estimate of the trend of the series at time t*
α	*is the smoothing parameter for trend,* $0 \leq \alpha \leq 1$
β	*is the smoothing parameter for level,* $0 \leq \beta \leq 1$
h	*is the number of step-ahead forecast.*

The forecast function given in (3.7) is not flat but trending. The *h* step ahead forecast is equal to the last estimated level plus h times the last estimated trend value. Hence, the forecasts are a linear function of h. Using this method each regions' demand is forecasted and total demand of the regions is equalized to Turkey's forecasted total demand value.

3.3.5 Substation Based Peak Demand Forecast

After regional demand forecasts were done, substation based demand forecasts were realized. Substations' demand was forecasted using Holt's method. After estimating each substation's demand separately, the estimates of the substations in a region were equalized to the general estimate of that region. Flow-chart of the followed methodology during whole process of demand forecasting is given in Figure 14.

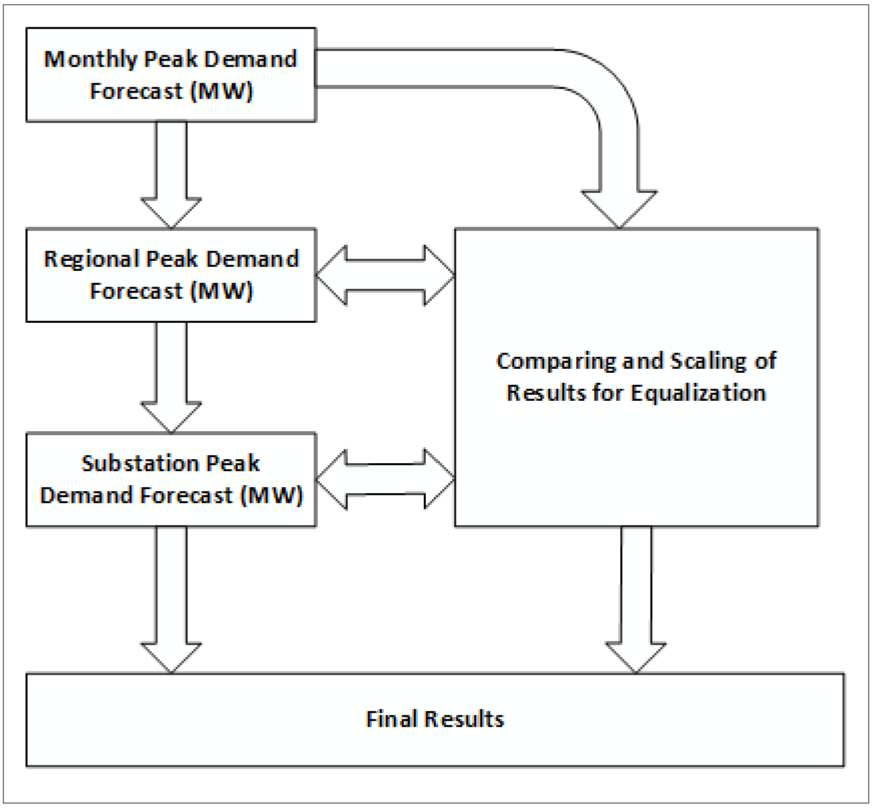

Figure 14. Flowchart of the Demand Forecasting Process

3.4 Generation Forecast

3.4.1 Installed Capacity Projection between 2016-2026

The public authority, between 1970 and 2000, determined the power plant investments of Turkey. During this period, Turkish Electricity Authority (TEK) planned the long-term investments with the long-term demand forecast. However, starting from 2000, because of the large-scale privatization of the generation and distribution parts of the power system, the planning of the generation has become more and more dependent on market conditions. Generation investments have started to be realized by the independent generation companies. In the past, TEK was determinant at installed capacity projections since it was determining the commissioning dates of power plant projects. However, after deregulation process have taken place, this procedure changed radically. With the Electric Market Law in 2001, companies are obliged to take licenses from Electricity Market Regulatory Authority (EPDK, in native initials) before realizing their projects. Determinations of connections to the high voltage is up to Turkish Electricity Transmission Company (TEİAŞ, in native initials). For this reasons, installed capacity projections were performed using databases of TEİAŞ and EPDK.

By the end of 2016, Turkey had a total installed capacity of 78.4 GW. The total number of power plants was 2.131 of which 1129 were licensed and 1102 were unlicensed. It is expected for Turkey to have total installed capacity of 120.4 GW by the year of 2026. Table 4 shows the installed capacity at the end of 2016 and the estimated capacities in 2026 based on their resources.

Table 4. Installed and Projected Capacities (MW)

Power Plant Type	***Capacities in 2016***	***Projected Capacities in 2026***
Lignite Fueled (Thermic)	9860	12898
Imp. Coal Fueled (Thermic)	7896	16461
Natural Gas Fueled (Thermic)	25478	28935
Geothermal Power Plant	821	1655
Fuel Oil Fueled (Thermic)	755	560
Biomass Fueled (Thermic)	484	608
Nuclear Power Plant (Thermic)	0	8160
Hydroelectric Power Plant	26678	36981
Wind Power Plant	5784	11193
Solar Power	690	2960
Total	78446	120411

3.4.2 Generation Dispatch

As last step for creating the appropriate network data of 2026, a unit commitment procedure followed by generation dispatch was realized. In Turkey, the unit commitment process is carried out with a market mechanism which legally defined by the Electricity Market Law (No. 6446). "Day-Ahead Balancing" and "Real Time Balancing" constitute the balancing activities. Dispatch of the system is mainly determined in day ahead balancing which is executed in Day Ahead Market for the following day. After purchase and sale offers are given, these are matched and at the intersection point of supply and demand curves market price occurs which reflects real value of the electricity.

The prices are practically defined by the units with the highest cost, which are natural gas thermic power plants (NGTPP) in case of Turkish market, in general. In this study, unit commitment process was realized assuming units are going to enter generation list starting with the lowest cost units and continues until highest cost units. However, there is an exemption of this procedure, since some generation facilities are exempted from balancing procedure according to Law on the Utilization of the Renewable Energy Sources (No. 5346). These are the electricity generation facilities, which use renewable sources such as wind energy, solar energy, geothermal energy and river type hydroelectricity. These units were accepted as the first units entering the generation list. Then, before conventional units were committed according to their cost and generation statistics, nuclear power plants entered the list since they were considered as must-run type of units. Finally, conventional (dam type) hydro power plants (HPP), lignite fueled TPPs, imported coal & asphaltite fueled TPPs, natural gas fueled TPPs and fuel oil fueled TPPs entered the list. Figure 15 shows the dispatching procedure.

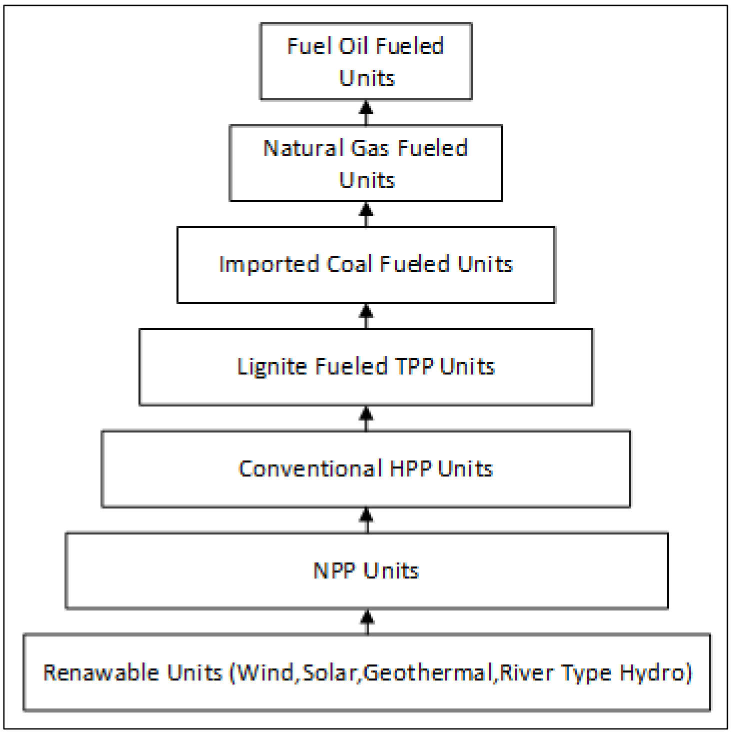

Figure 15. Generation Dispatch Procedure

It is necessary to determine the utilization factors of the generation according to primary sources before dispatching procedure is completed. That is done in *Transmission System Master Plan Study Generation Forecast Report (2017-2026)* of TUBITAK MAM EE [33]. Results taken from this study are used in this thesis. Table 5 shows the used utilization factors for summer peak and spring minimum conditions. In this study, hydroelectric power plants are evaluated considering four different water basins as shown in Figure 16. These are listed as:

- Region I: Sakarya, West Black Sea, Kizilirmak and Yesilirmak Water Basins
- Region II: East Black Sea, Coruh and Aras Water Basins
- Region III: Euphrates - Tigris and Van Water Basins
- Region IV: Middle & East Mediterranean, Seyhan and Ceyhan Water Basins

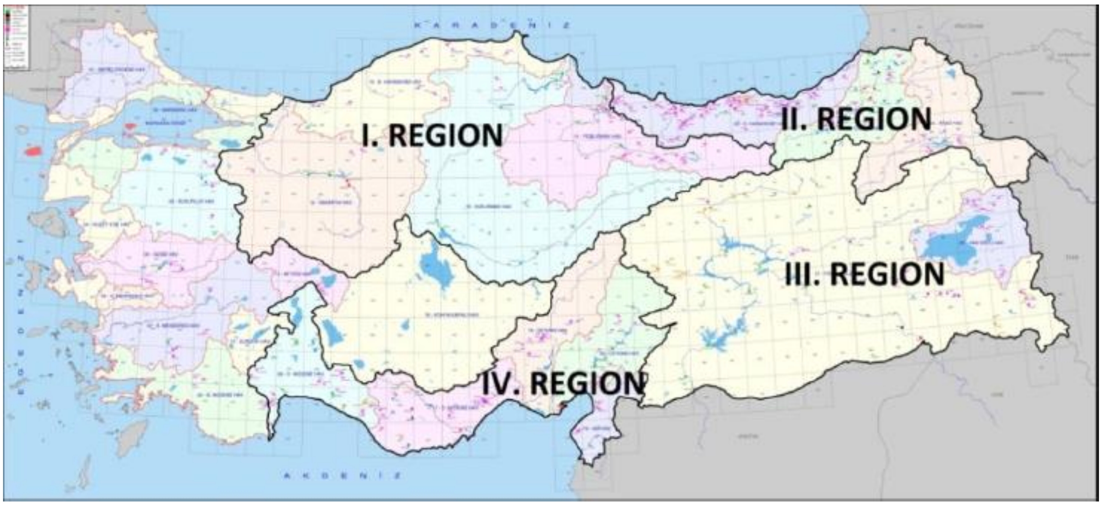

Figure 16. Water Basin Regions

Table 5. Utilization Factors for Summer Peak and Spring Minimum Conditions

Power Plant Types	***Summer Peak***			***Spring Minimum***		
	Lower	***Normal***	***Upper***	***Lower***	***Normal***	***Upper***
ROR HPP Region I	19%	33%	47%	6%	31%	51%
ROR HPP Region II	22%	31%	45%	8%	45%	77%
ROR HPP Region III	31%	40%	60%	13%	49%	69%
ROR HPP Region IV	20%	24%	31%	9%	56%	79%
DAM HPP Region I	51%	64%	75%	7%	13%	22%
DAM HPP Region II	40%	51%	64%	3%	66%	89%
DAM HPP Region III	56%	68%	81%	4%	20%	30%
DAM HPP Region IV	55%	61%	68%	18%	27%	35%
Lignite Fueled TPP	47%	56%	65%	31%	37%	41%
Imp Coal Fueled TPP	86%	90%	95%	47%	53%	61%
Fuel oil fueled TPP	0%	0%	0%	0%	0%	0%
Nuclear Power Plants	0%	100%	100%	0%	100%	100%
Geothermal PPs	60%	72%	88%	66%	85%	91%
Biomass PPs	44%	51%	60%	44%	49%	55%
Wind Power Plants	27%	43%	56%	13%	23%	35%

CHAPTER 4

PROPOSED METHODOLOGY FOR CAPACITY ASSESSMENT

In this chapter, the proposed methodology is divided into sub-parts and detailed information is provided for each part. Firstly, information is given about determination of regions. Then, assignment of artificial generation units is explained. Finally, generation shifting algorithm and proposed indices are presented and proposed type of capacities are defined.

4.1 Determination of Regions

Region identification is the first step in determination of transmission connection capacities. These regions can be determined considering many different criterions such as:

- Geographic borders of cities
- Geographic borders of distribution companies
- Borders of Load Dispatch Centers determined by TSO
- Borders determined by special purposes etc.

In this thesis, since the scenarios studied were based on the Turkish Transmission System, the regions were selected as the regions of the Turkish Distribution System. The reasons behind using distribution region concept is that the borders of regions are definite in terms of electrical connection and practical for generation investment evaluations. Turkish Distribution System is privatized and managed by 21 distribution companies. Figure 17 shows geographic borders of the distribution companies.

The borders of distribution companies were evaluated as areas subject to capacity calculations, with the exception of Istanbul province. Istanbul has been divided into two separate distribution regions due to the fact that more than 15 percent of national consumption is carried out by itself and due to its special geographical location. In this study, the city is accepted as one region. As a result, the study was conducted for 20 regions instead of 21.

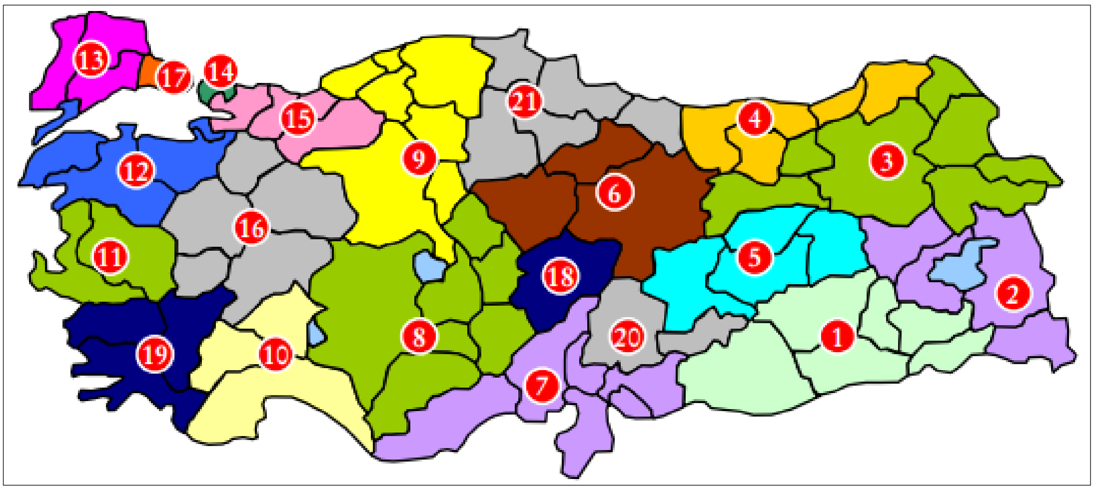

Figure 17. Geographic Borders of the Distribution Companies in Turkey

4.2 Assignment of Artificial Generation Units

In order to determine a region's transmission connection capacity, the generation in that specific region should be alterable while power demand of the whole system is kept constant. The generation increase in a specific region is achieved through artificial units that are connected to suitable substations.

TSO is responsible for maintaining safe and sufficient grid connection. Therefore, this study assumes that any artificial generation to be connected to the grid model is safely planned and sufficient number of connections are to be realized to relieve and balance regions' transmission. Generation investments can be done in all physically suitable locations since generation industry is deregulated. Based on this perspective, artificial generating units are distributed throughout the suitable substations, which are the ones not operating at rated capacity or not located at a town-center. Artificial units are assigned to each high voltage bus at these substations. Thanks to this approach, probabilistic nature of generation investments is modelled. Furthermore, both the process automatization (automatic increase / decrease of generation during capacity calculations) and balanced distribution of generation can be achieved with the utilization of this approach.

Any plant that is planned to be connected to the grid should satisfy regulations implied by grid code. Considering also the requirements stated in grid code, artificial generating unit transformer requirements and reactive power capabilities are adjusted. Automatization codes are developed utilizing Python libraries in order to ease the process.

In this study, 87 substations are excluded since they found to be unsuitable. Figure 18 shows unsuitable bus stations on Turkey map. Figure 19 shows unsuitable places in Istanbul region. The artificial units were assigned to the 400 and 154 kV busbars of the substations suitable for investment, as 1 unit per bus. When generation is desired to be increased in a region, these artificial generation units were used to achieve this purpose. It is important to remember that artificial units were only assigned to the region which its transmission connection capacity is wanted to be found and they are used only to increase generation in that region. The generation decrease in other regions were achieved through existing generators in proportion to their already committed dispatches.

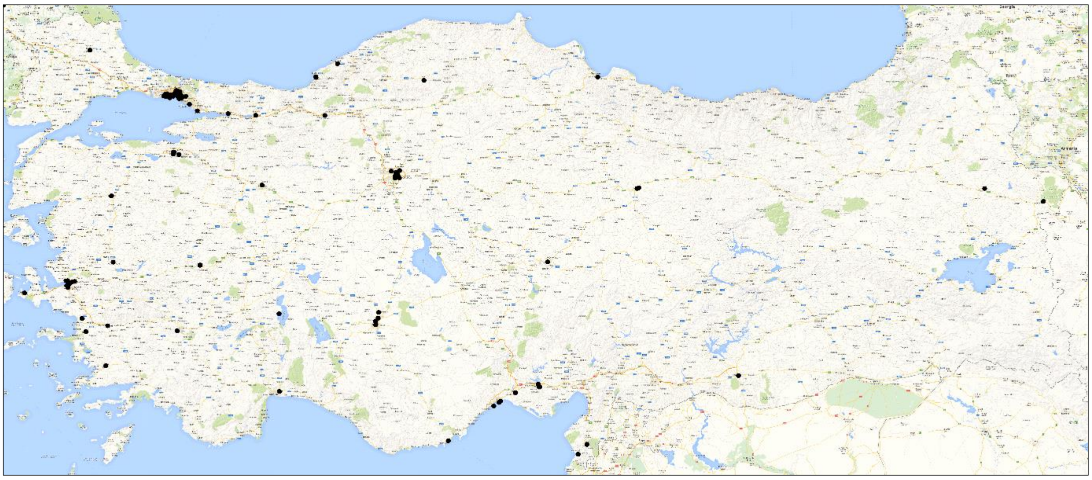

Figure 18. Unsuitable Substations for the Artificial Unit Assignment in Turkey

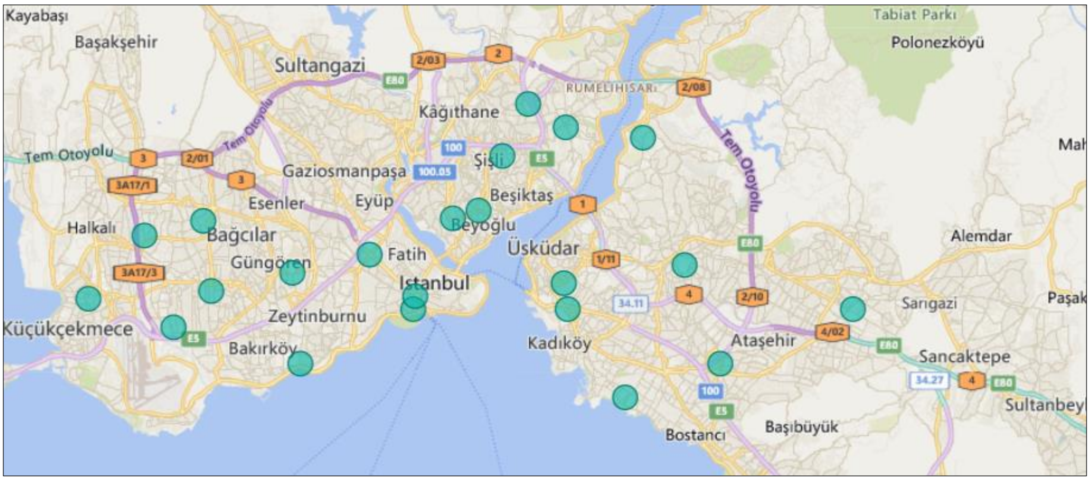

Figure 19. Unsuitable Substations in Istanbul for the Artificial Unit Assignment

4.3 Generation Shifting and Forming Indices

In order to determine a region’s transmission connection capacity, the generation of that region is increased gradually while an equivalent decrease of generation is made for rest of the system to maintain supply – demand balance of the system. This generation shift is made step-wise.

For generation increase / decrease operations, there are mainly three ways in the literature [26, 34]. These are given as;

- **Proportional increase / decrease:** *The factor which distributes the generation increase/decrease in a given control area over the different generators in this area could be the ratio of base case schedule of each generator to the total of internal generation scheduled and involved in the shift.*

  If this method is to be used in this study, it has to be used with a little modification. Because the increase in generation is done through artificially assigned units, rather than by existing generators, the increase in generation must be equally divided between these units, since it is not known which resources or conditions they represent. The corresponding generation decrease should be made relative to the committed dispatches of the existing generators.

- **Increase / decrease according to previously observed behaviors of generators:** *The factor which distributes the generation increase/decrease in a given control area could take into account the usual response pattern of generation to different system loads.*

  If this method is preferred in this study, it is necessary to classify the artificial units to be assigned according to their resources and prepare a dispatch plan considering the units that use same resources in the region. On the other hand, the decrease in generation must be planned according to existing generators and their generation patterns.

- **Increase / decrease according to a well-known merit order:** *The increase / decrease of generation shall be applied according to merit order.*

If this method is implemented in this study, then it is necessary to list the assigned units in a merit order. Generation increase should be made based on this merit order. Similarly, generation decrease is made among existing generators in other regions by following a pre-determined list.

When these methods are compared, it can be seen that the third method is a primitive method and is more suitable for smaller networks comparing to Turkey's electricity network. When the second method is considered, it can be seen that it is necessary to estimate the sources and working patterns of the assigned artificial units in order to model the generation increase in a region. However, in this study, the increase in generation of a region is modeled through the artificial units assigned to all suitable substations at that region and the aim was to model the probabilistic nature of the future generation investments in terms of their resources, size and location. Therefore, this second method is also not preferred.

In this study, proportional increase / decrease method is used, as it is the most common practice in capacity assessments. Increase / decrease step size is determined as 100 MW. In each step, 100 MW increase is divided equally between artificial generation units. At the same time, the existing generation units in other regions shared 100 MW decrease in proportion to their committed dispatches. If any of the existing generators falls below the range of efficient operation during this process, it is taken out of the service and its generation is distributed to the remaining generators of the same substation, as long as they operate using the same resource. If these generators reach their maximum generation capacity after this procedure, the remaining generation is transferred to the generators in the nearest substation provided that they operate with the same source as these generators. Then, AC load flow calculations are executed and proposed indices are calculated. Each step ends after indices are updated. While REI is a single value calculated for a region in each step, LEI is a state of discrete function, which is determined for each line in the region.

4.3.1 Region Based Evaluation Index

Region Based Evaluation Index (REI) is evaluated based on N-1 contingency analysis and updated at each step once. During each step, lines of that region are made out of service one by one. After each contingency AC load flow calculations are executed and line loadings are determined. Loading higher than hundred percent of the line rating is considered as overloading. Then, for each line in the region, overloading possibility (OP) is calculated as:

$$OP_{i,l} = \frac{NOIC_{i,l}}{NOTPC} \tag{4.1}$$

where

OP	*is the overloading possibility of line - l at step - i,*
NOIC	*is the number of contingencies that line - l overloads at step - i,*
NOTPC	*is the number of all possible contingencies for that region.*

OP takes values in range of [0, 1] where 0 means the selected line overloads at no contingency and 1 means that it overloads at every possible contingency.

After each contingency, maximum loading amount (MLA) of each line is calculated as:

$$MLA_{i,l} = \max(\frac{LL_{i,l,c}}{100}) \tag{4.2}$$

where

MLA	*is the maximum loading amount of line - l among all possible contingencies of step - i,*
LL	*is the loading of line - l in percentage during contingency - c of step - i.*

MLA takes values in range of [0, 2] where 0 means the selected line's loading is zero and 2 means its loading is 200 percent. LL is limited to 200 percent.

Then a scaling factor (SF) for each line is calculated as:

$$SF_{i,l} = 1 + OP_{i,l} * (MLA_{i,l} - 1) \tag{4.3}$$

where

SF *is the scaling factor of line - l at step - i.*

SF is designated to be in range of [1, 2]. For a line that has OP of 0, SF would become 1 which is multiplicative identity. However, for a line that has OP of 1 and MLA of 2, SF would become 2. This condition implies that, for ongoing step, this line is overloading in each one of the possible contingencies for that region and at least in one of those contingencies it overloads up to 200 percent.

Finally, to evaluate REI at a specific step, all line loadings are squared and scaled with scaling factor and then added up as:

$$REI_i = \sum_{l=1}^{n} SF_{i,l} * \left(MLA_{i,l}\right)^2 \tag{4.4}$$

where

n *is the number of the lines at the region.*

There are two goals for choosing a formulation like (4.4) when creating this index. The first one is to increase the weight of the overloaded lines comparing the lines that do not overload. That is done by squaring MLA value in (4.4). Thanks to this, it is assured that effect of overloading lines on REI is increased while effect of other lines, which are loaded within the limits, are decreased. The second goal is to arrange weights of overloading lines according to not only their maximum loading amounts (MLAs) but also by considering their overloading possibilities (OPs). That is achieved with introducing the scaling factor (SF) to equation (4.4).

The main reason behind using a line's MLA while calculating its SF value is that suppressing the exaggerated impact of its OP in proportion to its MLA. Consider that a line is loaded just under the loading limit in many contingencies during a step. In the next step, line loading may exceed the limit slightly in various contingencies. As a result, OP will increase significantly while MLA remains nearly unchanged. A line with high OP but relatively low MLA tells us that this line can overload in many contingencies however, its overloading is recoverable in a case of a contingency by taking necessary actions (load shedding etc.). That is because, its overload amount is not by far over the limits. However, a line with high MLA, independent of its OP value, can cause irreversible damage in case of a contingency like a cascading failure resulting in a blackout as happened in Turkey on 31st March 2015 [35]. By introducing (MLA-1) in (4.3), it is assured for an overloading line that unless it has a high MLA, the effect of OP will be limited.

A numerical example shall be given to show how computation process of REI affects the numerical result. During this example, calculation of an overloading line's contribution to REI will be illustrated. The region that is going to be inspected in the example has NOTPC=10, so that, there are ten lines that will be included in N-1 analysis in each step. At the beginning, two different SF calculations are performed for three consecutive steps and results are given in Table 6.

- **SF_1 Calculation:** This value is determined by omitting (MLA-1) from (4.3).

- **SF_2 Calculation:** This value is determined according to (4.3), as it is given.

Table 6. Calculation of Different SF Values of a Line

Step	***NOIC***	***OP***	***MLA***	***SF_1***	***SF_2***
1	1	0.1	1.2	1+0.1=1.1	1+0.1*0.2=1.02
2	5	0.5	1.25	1+0.5=1.5	1+0.5*0.25=1.125
3	10	1	1.3	1+1=2	1+(10/10)*0.3=1.3

Then, three different REI values are calculated using different SF values and results are given in Table 7. Results from Table 7 are visualized at Figure 20. MOA (maximum overloading amount) label is used instead of (MLA-1) in order to see impact of the MOA and OP separately at explicit mathematical formulations.

- **REI without SF:** This value is determined by omitting SF from (4.4). The mathematical formulation of REI becomes as:

$$(REI\ without\ SF)_{i,l} = 1 + 2MOA_{i,l} + MOA_{i,l}{}^{2} \tag{4.5}$$

- **REI with SF_1:** This value is determined according to (4.4), using SF_1. The mathematical formulation of REI becomes as:

$$(REI\ with\ SF_1)_{i,l} = 1 + 2MOA_{i,l} * \left(1 + OP_{i,l}\right) + MOA_{i,l}{}^{2} * \left(1 + OP_{i,l}\right) + OP_{i,l} \tag{4.6}$$

- **REI with SF_2:** This value is determined according to (4.4), using SF_2. The mathematical formulation of REI becomes:

$$(REI\ with\ SF_2)_{i,l} = 1 + MOA_{i,l} * \left(2 + OP_{i,l}\right) + MOA_{i,l}{}^{2} * \left(1 + 2OP_{i,l}\right) + MOA_{i,l}{}^{3} * OP_{i,l} \tag{4.7}$$

Table 7. Calculation of REI Using Different SF Values

Step	*REI without SF*	*REI with SF_1*	*REI with SF_2*
1	1.2^2=1.44	1.1*1.2^2=1.58	1.02*1.2^2=1.47
2	1.25^2=1.56	1.5*1.25^2=2.34	1.125*1.25^2=1.76
3	1.3^2=1.69	2*1.3^2=3.38	1.3*1.3^2=2.20

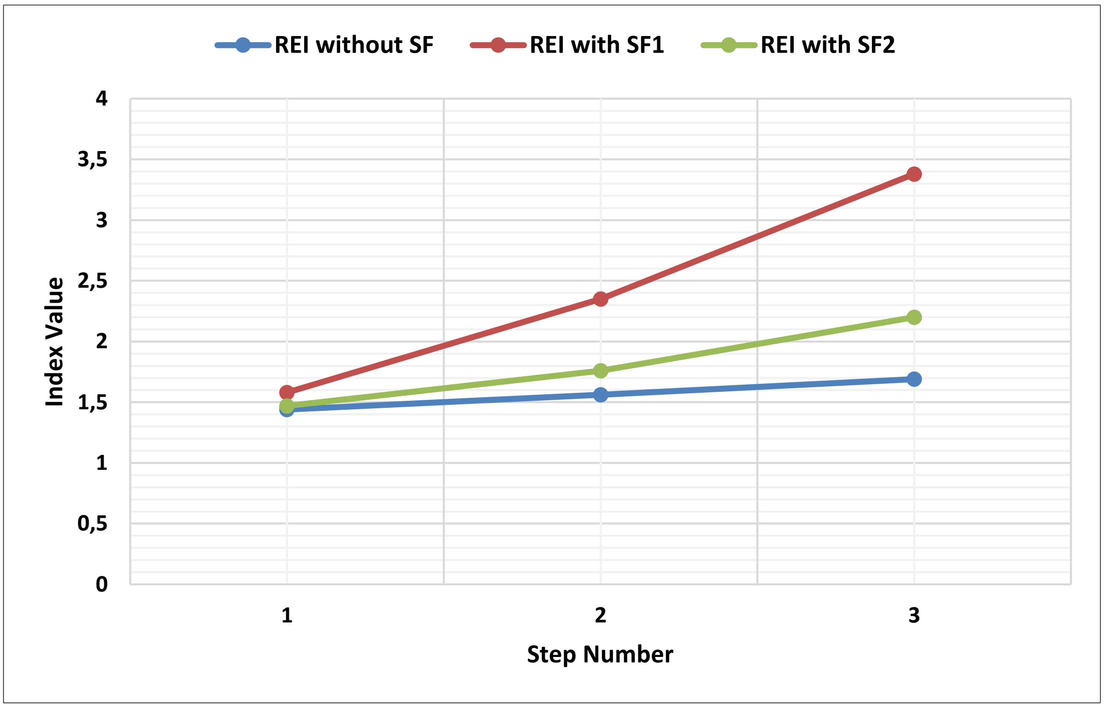

Figure 20. A Line's Contribution to REI with Different SF Values

The resultant REI values can be evaluated as:

- **REI without SF:** Omitting SF from (4.4) results in limited difference of REI in spite of the increase in NOIC from 1 to 10 and increase in MLA from 1.2 to 1.3. That is expected since there is no OP element in the formulation (4.5).

- **REI with SF_1:** Using SF_1 in calculation of (4.4) leads to drastic increase in REI values. That is because OP increases rapidly from 0.1 to 1, as does SF_1. However, it is clear that MLA increases only from 1.2 to 1.3, which means increase in OP does not exactly requires an increase in MLA. This kind of drastic increase of REI value could be acceptable if not only OP but also MLA increased considerably. That kind of behavior is expected, since there is an OP factor independent from MLA in (4.6).

- **REI with SF_2:** Using SF_2 in calculation of (4.4) results in more reasonable REI values comparing to former ones. Since impact of increase in OP is balanced by including (MLA-1) in (4.3), the resultant REI values do not show a divergent character as they were in *REI with SF_1*. Furthermore, REI values increases more rapidly than *REI without SF* values as they reflect impact of OP in (4.3). When (4.7) is examined carefully, it can be seen that unlike (4.6) there is no OP factor independent form MLA.

4.3.2 Line Based Evaluation Index

Line Based Evaluation Index (LEI) is evaluated based on N-1 contingency analysis and it is updated at each step once for each line in the region. It is formed using two flags. The first flag shows whether line loading is within the line limits, while second flag shows whether this line benefits from increased generation at that region.

To determine LEI, at each step lines of that region are made out of service one by one. After each contingency AC load flow calculations are executed and line loadings are determined. Loading higher than hundred percent of the line rating is considered as overloading. Then maximum loading happened for a line among these contingencies is accepted as definitive loading value (DLV) for that line and this value is stored. During each step, this value is firstly compared to thermal rating of the line that defines maximum allowable loading value for that line. If line overloads first flag becomes 1, if it is not then it remains 0. Afterwards, it is compared with the DLV from the previous step and related flag becomes 0 or 1 based on a decrease or increase, respectively.

From different combinations of these two flags, it can be seen that, LEI could be at four different state as shown in Table 8.

Table 8. Possible States of LEI

State	***LEI***	***Line Loading***	***Comparison to previous value***
1	[0, 0]	Within limits	Better
2	[0, 1]	Within limits	Worse
3	[1, 0]	Overload	Better
4	[1, 1]	Overload	Worse

At base case, all lines in the region starts with the first state which is [0, 0]. That indicates the lines are operating at normal state at the beginning. After each step, the DLV value of a line is compared to its thermal rating and to its DLV value from previous step. First state, which is [0, 0], is the most desirable state for a line since it indicates that there is no overloading in that line and its DLV decreased compared to previous step. Second state, which is [0, 1], shows that the line is still operating within the limits however its DLV increased compared to previous step. Third state, which is [1, 0], indicates that the line is overloaded in at least one of the contingencies at that step but its DLV decreased compared to previous step. Final and fourth state, which is [1, 1], shows that the line is overloaded in at least one of the contingencies during that step and its DLV increased compared the its value at the previous step. Obviously, last state is the most undesirable state for a line.

4.3.3 Interpretation of Indices

This section explains interpretation of the proposed indices for capacity assessment. The indices are considered together while determining capacity of a region. It must be remembered that while REI gives a general idea concerning the impact of additional generation to the line loadings in the region, LEI monitors each line's loading individually throughout all steps.

4.3.3.1 Interpretation of REI

REI is unitless and is calculated once per step. Since its value is directly related to the number of lines in the region, its value itself does not have any direct meaning. A meaningful interpretation is only possible after multiple steps are conducted and resultant REI values are evaluated together. REI is used to observe the impact of additional generation on the region's line loadings as a whole, such that the high loadings on a single line may not affect value of REI significantly.

REI exhibits two different behaviors for different regions. The first behavior is the non-decreasing characteristic shown in Figure 21. As can be seen from the figure, starting from the first step the index value is increasing. Such a pattern may correspond to different cases. The first one is that a region, which has more generation than consumption, transfers extra power to neighboring regions. As a result, additional generation increases line loadings in this region further. Especially tie lines are affected. In the second case, unlike the first, the power consumption in the region may be greater than or equal to the generation. If customers with high power demand are concentrated in a small part of a region, it is expected that the line loadings in this part will be positively affected from the additional generation. However, for the line loadings at the other parts of the region the opposite may be true. As a result, the impact of additional generation on the region as a whole could be negative. In addition, independent of generation-consumption ratio, additional generation may change load flow in a way that REI might start increasing from the very beginning.

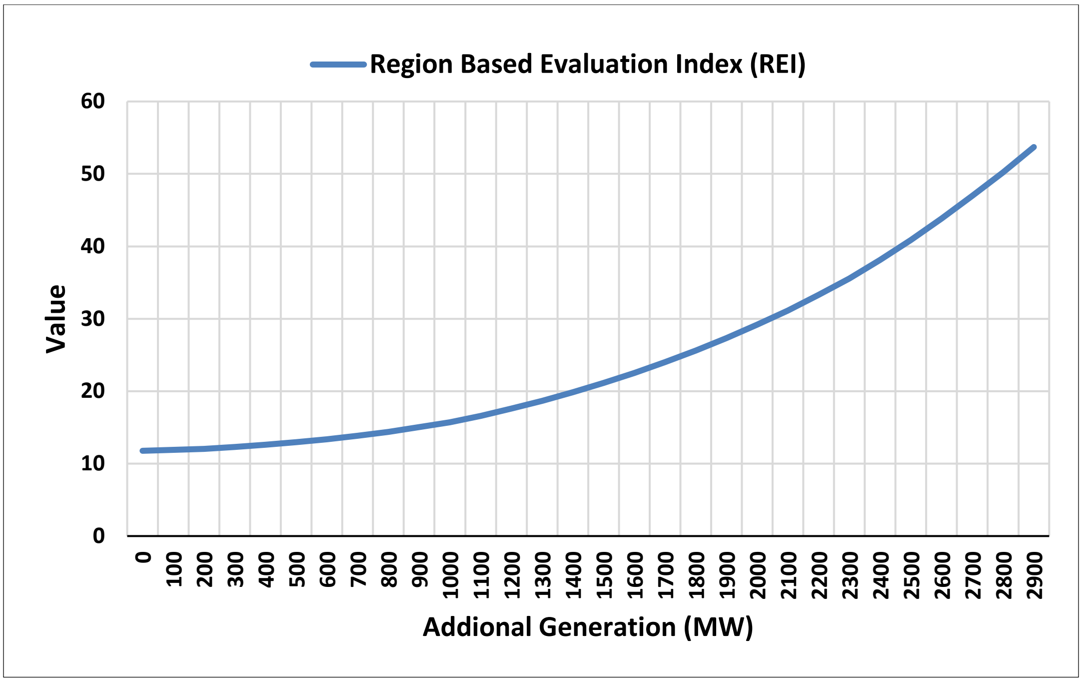

Figure 21. REI with Non-Decreasing Characteristics

Non-decreasing REI characteristic does not necessarily mean that the region is not fit for additional generation. Although additional generation seems to be unfavorable for the lines at regions with this type of REI characteristics, all line loadings might be within the limits up to some point. From investor point of view unless a line is overloaded and threatening system security, additional generation should be allowable. However, from TSO point of view, the additional generation could be more beneficial if it was in the more power demanding regions so that it would relieve transmission system by reducing losses.

The second characteristic behavior of REI is visualized in Figure 22. In this case, the region benefits from additional generation up to a point, which labeled as *minimum-REI point* on Figure 22. Up to that point, most of the line loadings are seemed to be decreasing. It is very important to realize that all line loadings in that region do not necessarily decrease. It is very important to realize that all line loadings in that region do not necessarily decrease. There could be lines with increased loadings but it is clear that their impact is limited compared to the ones with decreased loadings. After that point up to *initial equivalence point* where index value comes close to its initial value, the value of index increases. That indicates line loadings start to increase once more. Again, the pattern followed in that interval does not necessarily imply an increase at all line loadings.

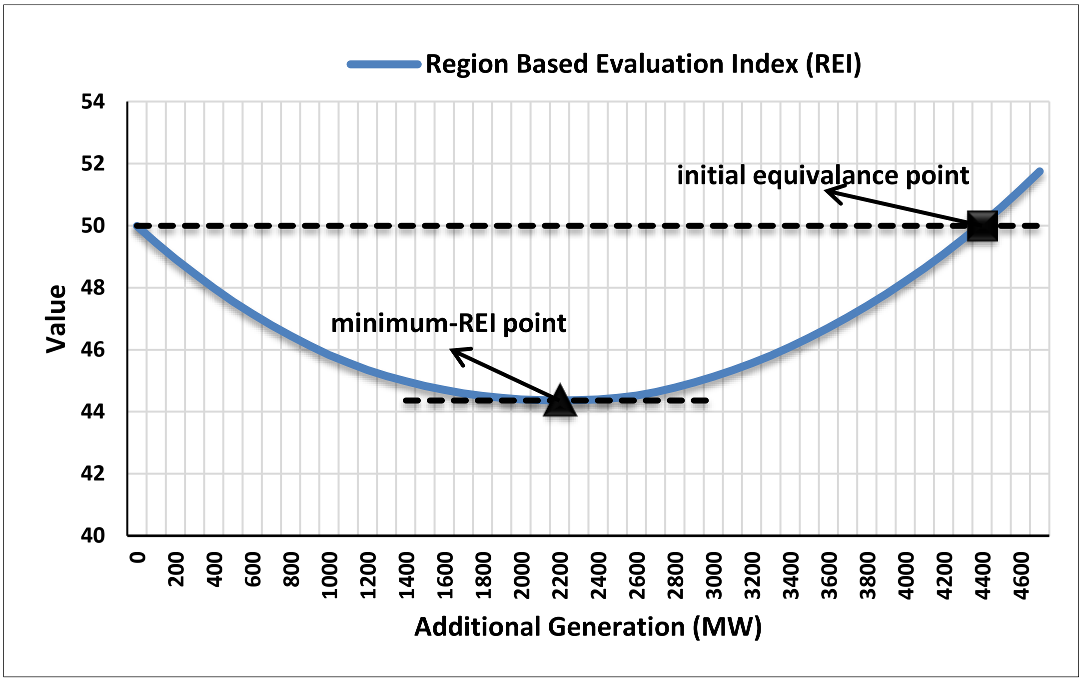

Figure 22. REI with Curved Characteristics

This behavior of the REI is generally observed in power demanding regions where additional generation directly supplies some of the loads in these regions. As a result, power transfer to those regions from neighboring regions through the tie lines decreases hence loadings of these lines relieve.

4.3.3.2 Interpretation of LEI

As mentioned before, REI does not give explicit information about individual line loadings at the region. REI might be decreasing while some lines are dangerously overloading or vice versa. Therefore, to be able to monitor each line individually throughout the steps LEI is developed. By monitoring LEI of a line, it can be observed whether its loading stays within the limits during contingencies and if it benefits from additional generation or not.

A numerical example is provided in Table 9 to clarify how LEI works. Line 1 is starting within loading limits and benefits from additional generation, so its loading decreases throughout the all five steps. On the other hand, even though line 2 starts within the limits, it is affected negatively from additional generation yet its loading stays within the limits. Line 3 starts similar to line 2, however, after 3rd step it starts to overload. Line 3 type lines should be considered as bottlenecks of the system and transmission system investments should be planned considering those lines primarily. Line 4 starts with the overloads, however, it benefits from additional generation and its DLV decreases as can be understood from the second flag of the index. Finally, line 5 starts over the limits but after the 4th step, its loading remains within the limits.

Thanks to LEI, all lines can be observed individually and bottlenecks of a region can be determined. The lines that reaches the 4th state, should be considered as first candidates for investment since they limit a region's additional transmission connection capacity.

Table 9. An Illustrative Region for LEI

Step	***Line 1***	***Line 2***	***Line 3***	***Line 4***	***Line 5***
1	[0,0]	[0,1]	[0,1]	[1,0]	[1,0]
2	[0,0]	[0,1]	[0,1]	[1,0]	[1,0]
3	[0,0]	[0,1]	**[1,1]**	[1,0]	[1,0]
4	[0,0]	[0,1]	**[1,1]**	[1,0]	[0,0]
5	[0,0]	[0,1]	**[1,1]**	[1,0]	[0,0]

To sum up, REI aims to indicate how feasible a region is in terms of generation investments while LEI aims to determine the bottlenecks and limits of the considered region in terms of transmission connection capacity increase.

4.4 Proposed Types of Capacities

The flowchart of the proposed methodology is given in Figure 23. That methodology is applied to each region individually. For each region, three different capacity values are determined. These are listed as:

- **REI Optimal Capacity:** This value is determined using *minimum-REI point* on REI index. It corresponds to the capacity value that minimizes the line loadings according to REI for that region (*minimum-REI point* in Figure 22).

- **REI Equivalence Capacity:** This value is determined using *initial equivalence point* on REI index. It corresponds to the capacity value that maximizes the use of the transmission system according to REI without worsening compared to the initial state (*initial equivalence point* in Figure 22).

- **LEI Capacity:** This value is determined by observing each lines' LEI state and looking for the ones that reach to 4th state. Whenever one of the lines' state becomes 4th, it is accepted as a break point for that region since it means there is a transmission line that dangerously overloaded and its loading does not benefit from additional generation. For example, considering the hypothetical region given at the Table 9, Line 3's LEI goes to 4th state right after the 3rd step. Considering each step corresponds to 100 MW additional generation, LEI capacity for that region would be 300 MWs.

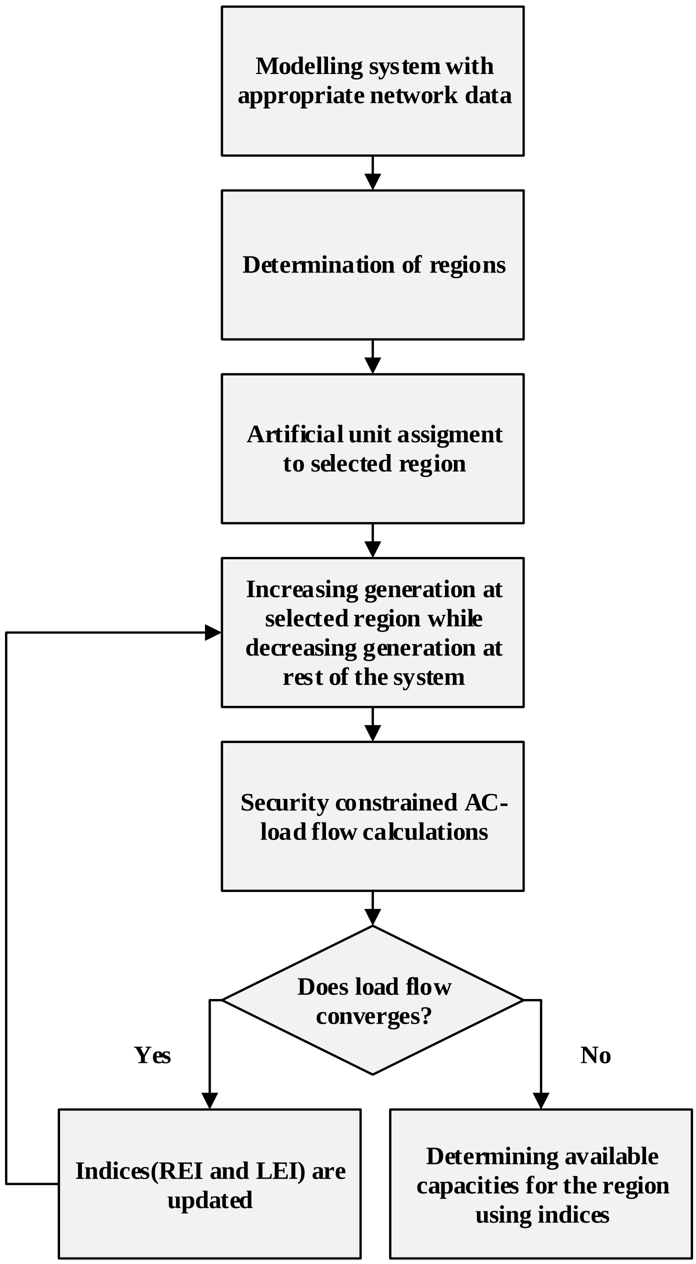

Figure 23. Flowchart of the Proposed Methodology

There are three inequalities that these capacity values always have to ensure by definition. These equations are given as:

$$LEI\ Capacity \geq 0 \tag{4.8}$$

$$REI\ Optimal\ Capacity \geq 0 \tag{4.9}$$

$$\begin{cases} REI\ Equivalence\ Capacity > REI\ Optimal\ Capacity; \\ \quad if\ REI\ Optimal\ Capacity > 0, \\ REI\ Equivalence\ Capacity = REI\ Optimal\ Capacity; \\ \quad if\ REI\ Optimal\ Capacity = 0 \end{cases} \tag{4.10}$$

There are three special cases observed when different combinations of these three capacities are taken into consideration. These are:

- Cases with no available capacity increase:
    - LEI Capacity = REI Equivalence Capacity = REI Optimal Capacity =0

  Zero LEI capacity means that starting from the first step, there are some lines that are dangerously overloaded and they do not benefit from additional generation. Zero REI-related capacities mean that considered region does not benefit from additional generation as a whole. So without additional investments realized to strengthened transmission system in these regions, it is not recommended to let extra generation to come into service.

- LEI-limited cases:
    - REI Equivalence Capacity > REI Optimal Capacity > LEI Capacity
    - LEI Capacity≥0

  Regions that shows this type of characteristics benefit from additional generation up to *minimum-REI point*. However, to be able to reach that point or *initial equivalence point* given in Figure 22, some transmission lines should be replaced or invested. Considering a special case of this type of regions where LEI Capacity is zero, additional investments must be realized to strengthened transmission system before letting any additional generation to come into service.

Generally, regions of this type are power-demanding regions where additional generation directly supplies some of the loads in the region. As a result, power transfer to those regions from neighboring regions through the tie lines decreases hence loadings of these lines relieves.

- REI-limited cases:
    - LEI Capacity > REI Equivalence Capacity > REI Optimal Capacity ≠0
    - LEI Capacity > REI Equivalence Capacity = REI Optimal Capacity =0

In this type of regions, additional generation may be beneficial up to a certain point depending on REI Optimal Capacity and REI Equivalence Capacity, as well as the impact can be negative starting from the beginning in case of REI based capacities are zero. Any of these situations does not necessarily mean these regions are not fit for additional generation. While, in general, additional generation seemed to be unfavorable for the lines at these regions, all line loadings seem to be within the limits up to value of LEI Capacity.

Regions that shows this type of characteristics are usually regions with generation surplus. So as expected, additional generation are transferred to neighboring regions through tie lines and as a result, line loadings increase. This kind of situation have a negative impact on REI based capacities. However, considering LEI capacity stays higher than REI based capacities, it can be concluded that there is not specifically congested line in the region that demands investment before value of LEI capacity. It can be said that, although these type of regions are not power demanding regions, technically there is no obstacle for additional generation.

A similar type of characteristic can also be seen when there is no generation surplus and generation and consumption are more balanced. This happens when power-demanding centers are concentrated in a specific part of a region. In this case, the lines in that part of the region benefit from additional generation while the rest of them are affected negatively and region, in general, is affected negatively. That results in decrease at REI based capacities. However, considering LEI capacity is higher than REI based capacities there is no obstacle for additional generation up to point determined by value of LEI capacity.

CHAPTER 5

APPLICATION AND RESULTS

This chapter gives information on application of proposed methodology to the Turkish Transmission Network of 2026. Firstly, an explanation is given about determination of the cases that is studied in this thesis. Following that, results of these case studies are illustrated. The chapter is concluded with the discussion and comparison of the results.

5.1 Determination of the Scenarios

In order to maintain a safe and stable operation for a transmission system during all loading conditions, capacity calculations should consider extreme operation points for the grid. These are peak demand (summer) and minimum loading (spring) conditions for Turkish Electricity Network. The former one is not only the peak demand condition but also thermal ratings of electrical equipment are at their lowest during summer season which makes this scenario one of the extreme operation points. To understand the importance of the latter scenario, extra information is required about Turkish Electricity Network. Turkey has mainly hydro power plants in its east and south-east regions while it has thermal power plants at its central and western regions. Two nuclear power plants (Akkuyu, Sinop) are considered to come into service in northern and southern parts of the country by the 2026. In addition, most power demanding cities are located at the western and the north-western regions of the country. When climate conditions of Turkey are considered, during spring season, power dispatch is becoming mainly hydro-power based and the result is the increasing distance between generation and consumption bases. That situation results in load flows mainly at long east-west corridors and it forces the system in terms of reactive compounds and angle stability problems. The greatest blackout occurred in Turkish Electricity Network was at 31st March 2015 and it happened under these very extreme conditions [35]. The long transmission distance and the out of service of all the series capacitors resulted in a high east to west transfer impedance and the system was not compliant with dynamic security criterion (N-1) anymore [35]. The tripping on overload of the line with the highest load initiated angular instability and consequently system separation. That is why minimum demand (spring) condition is considered as another extreme point of operation.

Each of these two scenarios has been studied in two separate case studies. These case studies were prepared by considering different wind energy dispatches. That was done in order to observe the impact of the wind energy investments on the available transmission connection capacities considering geographical distribution of wind energy and its increasing share in country's power generation. Turkey already has more than 6 GW of wind power by the end of 2016 [36]. This figure has increased rapidly in the last ten years with the incentives given for power generation using renewable energy resources. Figure 24 shows development of installed wind power in Turkey.

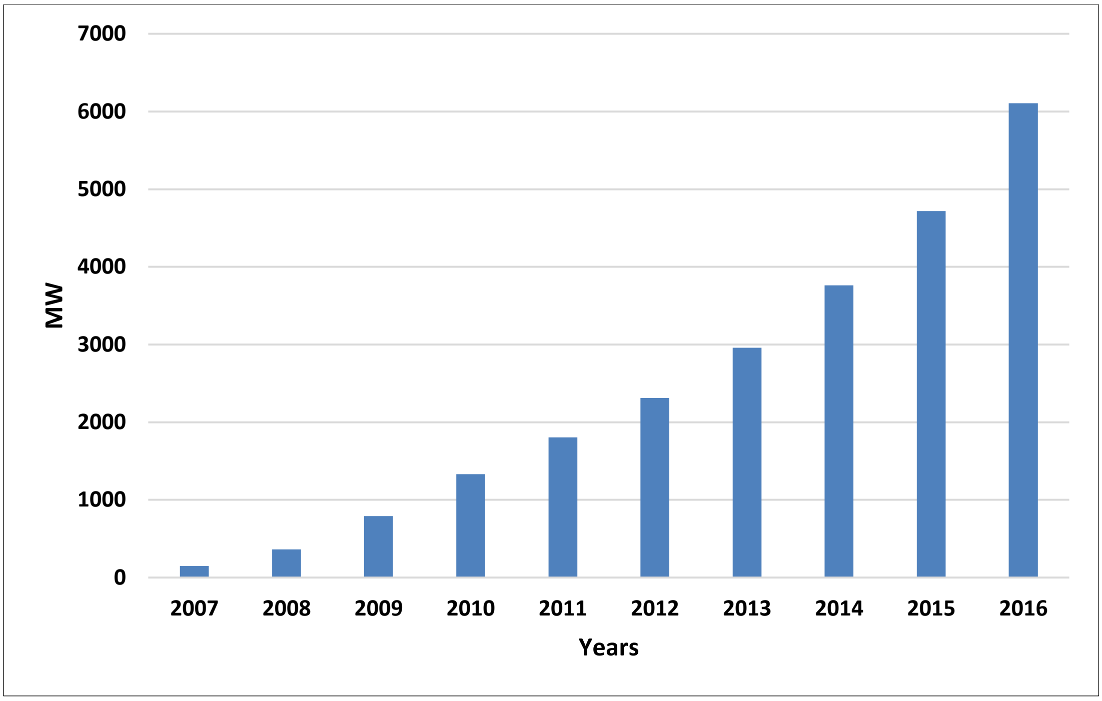

Figure 24. Development of the Installed Wind Power in Turkey

Wind power investments continue to increase rapidly. As of 2016, there are more than 250 licensed wind farm projects [37]. When these power plant investments are realized, it is expected that the total installed capacity will reach 11.2 GW, nearly doubling the existing installed capacity. Expected installed wind power capacities are given in Table 10 while Figure 25 shows their distribution in percentage, based on distribution companies.

Table 10. Expected Regional Installed Wind Capacities (MW)

City	*Projected Capacity*	*City*	*Projected Capacity*
IZMIR	1738	***SAKARYA***	120
BALIKESIR	1466	***ZONGULDAK***	120
CANAKKALE	876	***K.MARAS***	118
MANISA	639	***AMASYA***	117
ISTANBUL	624	***YALOVA***	116
HATAY	505	***GAZIANTEP***	86
AYDIN	463	***BOLU***	80
KIRKLARELI	422	***DENIZLI***	66
BURSA	368	***ISPARTA***	60
AFYON	324	***KARAMAN***	57
KOCAELI	294	***USAK***	54
KAYSERI	272	***VAN***	50
KONYA	260	***BINGOL***	50
MUGLA	259	***SAMSUN***	48
OSMANIYE	235	***ANKARA***	45
SIVAS	187	***ESKISEHIR***	39
EDIRNE	186	***TRABZON***	30
TEKIRDAG	178	***ADIYAMAN***	25
MERSIN	174	***ORDU***	10
BILECIK	170	***MALATYA***	10
KIRSEHIR	150	***KARABUK***	5
TOKAT	128	***SINOP***	4

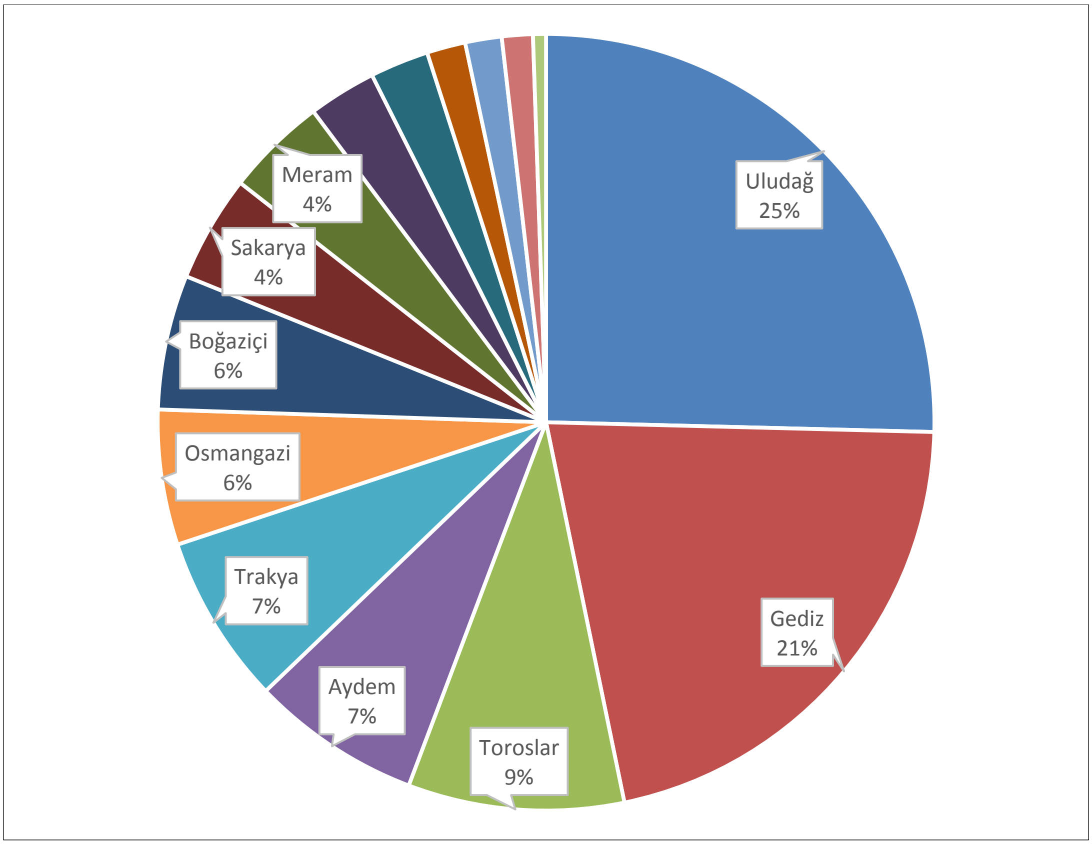

Figure 25. Distribution of the Expected Wind Capacities based on Discos

The first case study is based on the assumption of installed wind power capacity will stay as 6 GW, in other words, no other wind power plant investments will be realized. The generation dispatch was done according to 6 GW of installed wind power while the resulted generation deficit was completed using thermal and hydro power plants in proportion to their already committed dispatches. The second case study is based on the assumption of the expected wind power plant investment will be realized and installed wind power capacity will reach to 11.2 GW. The generation dispatch was done according to 11.2 GW of installed wind power capacity.

To sum up, four different cases are studied in this thesis. These cases can be listed as:

- Peak Demand Condition with Low Wind Power Dispatch,

- Peak Demand Condition with Expected Wind Power Dispatch,
- Minimum Loading Condition with Low Wind Power Dispatch,
- Minimum Loading Condition with Expected Wind Power Dispatch.

5.2 Results of the Scenarios

5.2.1 Peak Demand Condition with Low Wind Power Dispatch

The results of the peak demand condition with low wind power dispatch are visualized in Figure 26. The tabulated results are presented in Table 11.

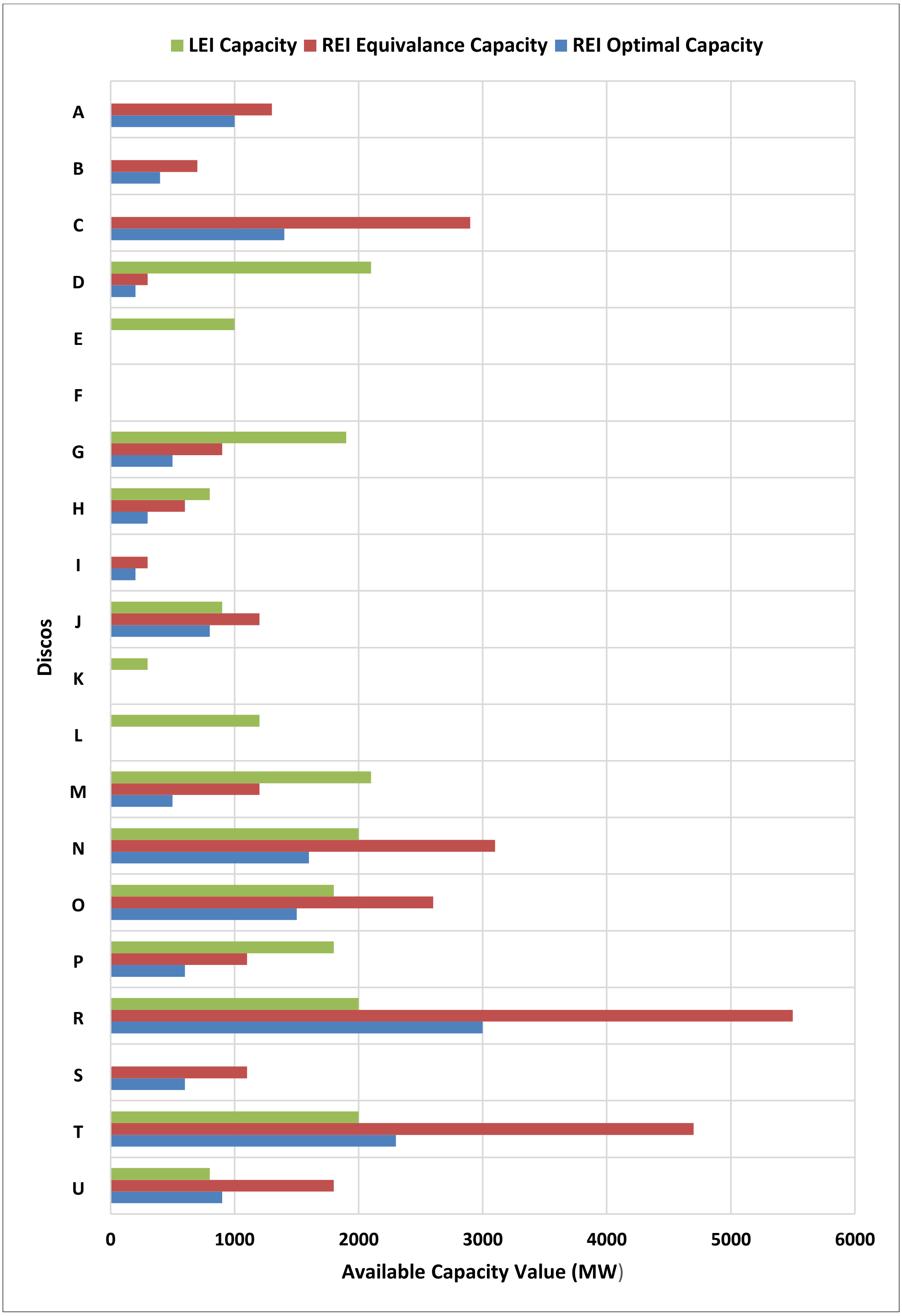

Figure 26. Results for Peak Demand Condition with Low Wind Power Dispatch

Table 11. Results for Peak Demand Condition with Low Wind Power Dispatch (MW)

Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	1000	1300	0
Disco B	400	700	0
Disco C	1400	2900	0
Disco D	200	300	2100
Disco E	0	0	1000
Disco F	0	0	0
Disco G	500	900	1900
Disco H	300	600	800
Disco I	200	300	0
Disco J	800	1200	900
Disco K	0	0	300
Disco L	0	0	1200
Disco M	500	1200	2100
Disco N	1600	3100	2000
Disco O	1500	2600	1800
Disco P	600	1100	1800
Disco R	3000	5500	2000
Disco S	600	1100	0
Disco T	2300	4700	2000
Disco U	900	1800	800
Sum	**15800**	**29300**	**20700**

5.2.2 Peak Demand Condition with Expected Wind Power Dispatch

The results of the peak demand condition with expected wind power dispatch are visualized in Figure 27. The tabulated results are presented in Table 12.

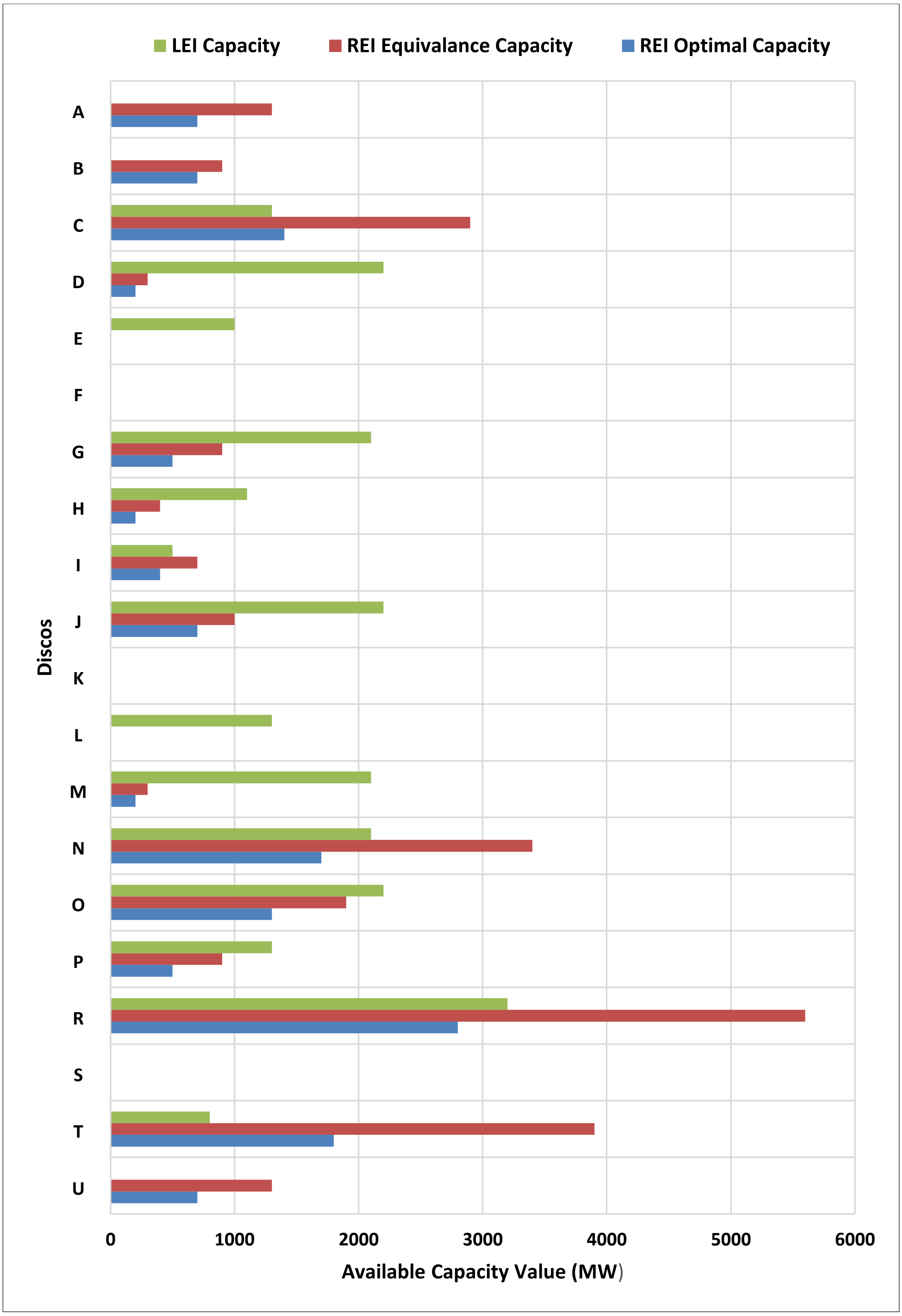

Figure 27. Results for Peak Demand Condition with Expected Wind Power Dispatch

Table 12. Results for Peak Demand Condition with Expected Wind Power Dispatch (MW)

Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	700	1300	0
Disco B	700	900	0
Disco C	1400	2900	1300
Disco D	200	300	2200
Disco E	0	0	1000
Disco F	0	0	0
Disco G	500	900	2100
Disco H	200	400	1100
Disco I	400	700	500
Disco J	700	1000	2200
Disco K	0	0	0
Disco L	0	0	1300
Disco M	200	300	2100
Disco N	1700	3400	2100
Disco O	1300	1900	2200
Disco P	500	900	1300
Disco R	2800	5600	3200
Disco S	0	0	0
Disco T	1800	3900	800
Disco U	700	1300	0
Sum	**13800**	**25700**	**23400**

5.2.3 Minimum Loading Condition with Low Wind Power Dispatch

The results of the minimum loading condition with low wind power dispatch are visualized in Figure 28. The tabulated results are presented in Table 13.

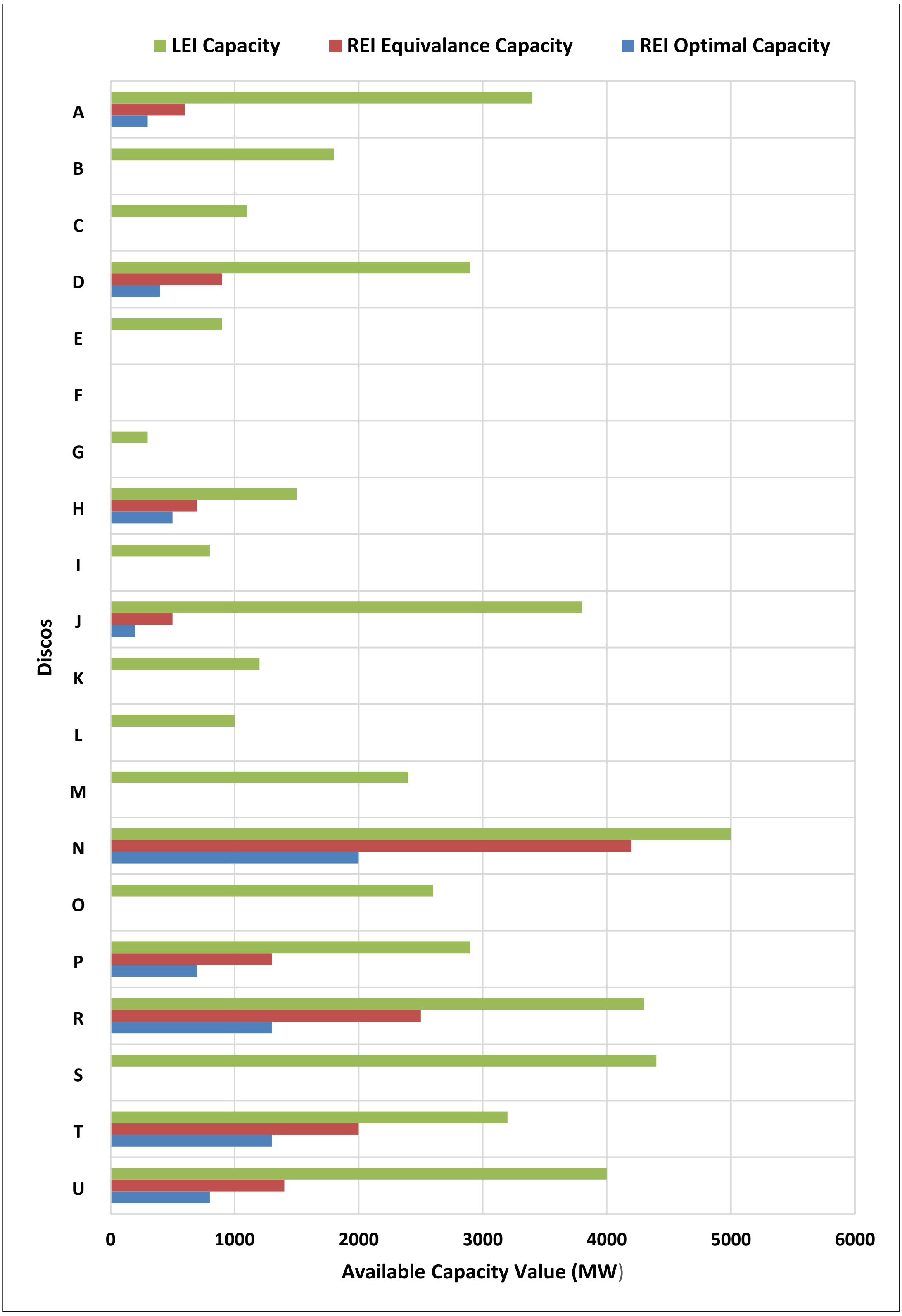

Figure 28. Results for Minimum Loading Condition with Low Wind Power Dispatch

Table 13. Results for Minimum Loading Condition with Low Wind Power Dispatch (MW)

Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	300	600	3400
Disco B	0	0	1800
Disco C	0	0	1100
Disco D	400	900	2900
Disco E	0	0	900
Disco F	0	0	0
Disco G	0	0	300
Disco H	500	700	1500
Disco I	0	0	800
Disco J	200	500	3800
Disco K	0	0	1200
Disco L	0	0	1000
Disco M	0	0	2400
Disco N	2000	4200	5000
Disco O	0	0	2600
Disco P	700	1300	2900
Disco R	1300	2500	4300
Disco S	0	0	4400
Disco T	1300	2000	3200
Disco U	800	1400	4000
Sum	**7500**	**14100**	**47500**

5.2.4 Minimum Loading Condition with Expected Wind Power Dispatch

The results of the minimum loading condition with expected wind power dispatch are visualized in Figure 29. The tabulated results are presented in Table 14.

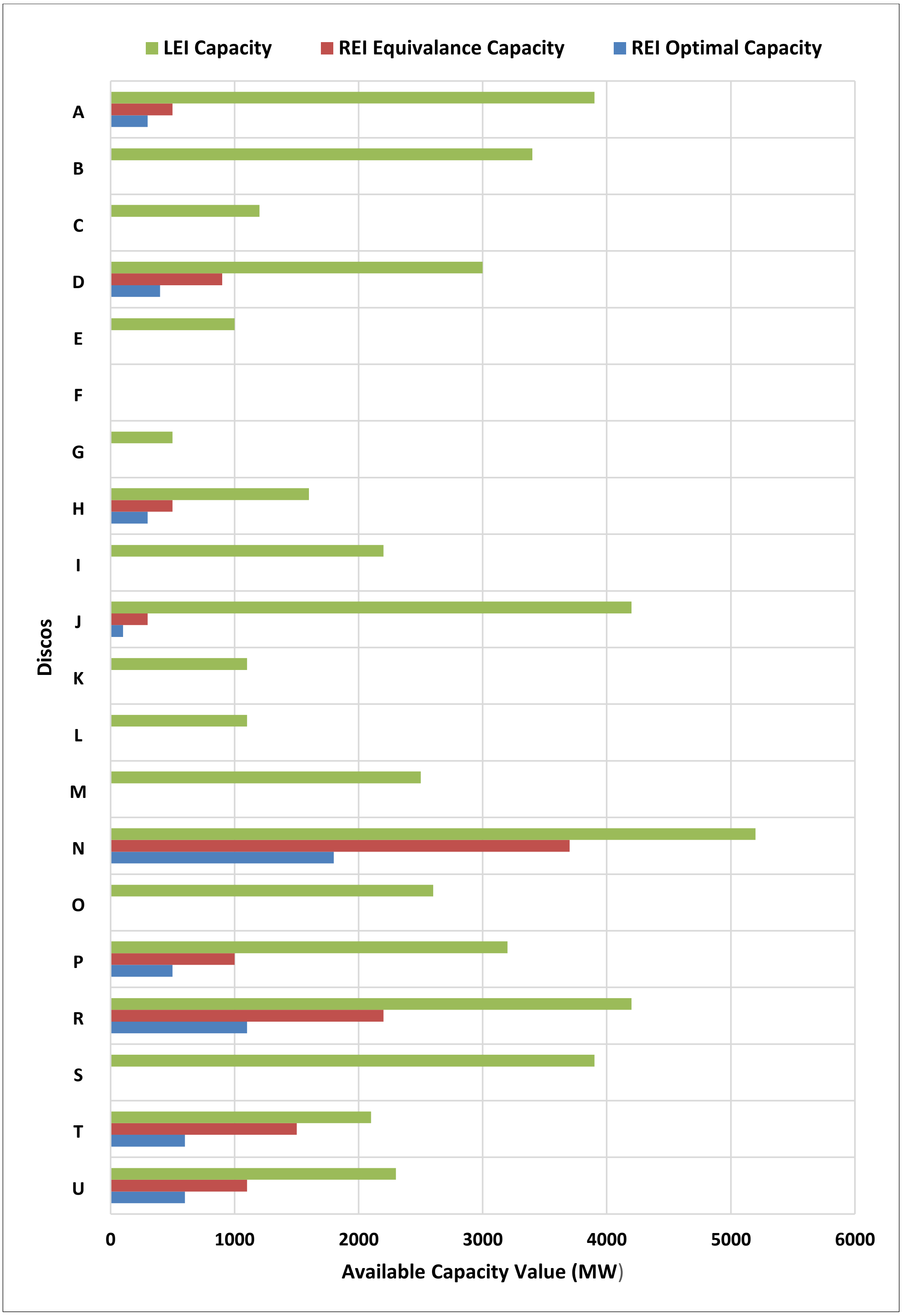

Figure 29. Results for Minimum Loading Condition with Expected Wind Power Dispatch

Table 14. Results for Minimum Loading Condition with Expected Wind Power Dispatch (MW)

Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	300	500	3900
Disco B	0	0	3400
Disco C	0	0	1200
Disco D	400	900	3000
Disco E	0	0	1000
Disco F	0	0	0
Disco G	0	0	500
Disco H	300	500	1600
Disco I	0	0	2200
Disco J	100	300	4200
Disco K	0	0	1100
Disco L	0	0	1100
Disco M	0	0	2500
Disco N	1800	3700	5200
Disco O	0	0	2600
Disco P	500	1000	3200
Disco R	1100	2200	4200
Disco S	0	0	3900
Disco T	600	1500	2100
Disco U	600	1100	2300
Sum	**5700**	**11700**	**49200**

5.3 Discussion and Comparison of the Results

5.3.1 Comparison of the Scenarios with Different Wind Power Dispatches

Differences between different wind power dispatch scenarios for peak demand and minimum loading conditions are found by subtracting capacities found for low wind power dispatch from the ones found for expected wind power dispatch. These differences are visualized in Figure 30 and Figure 31 while tabulated results are given in Table 15 and Table 16.

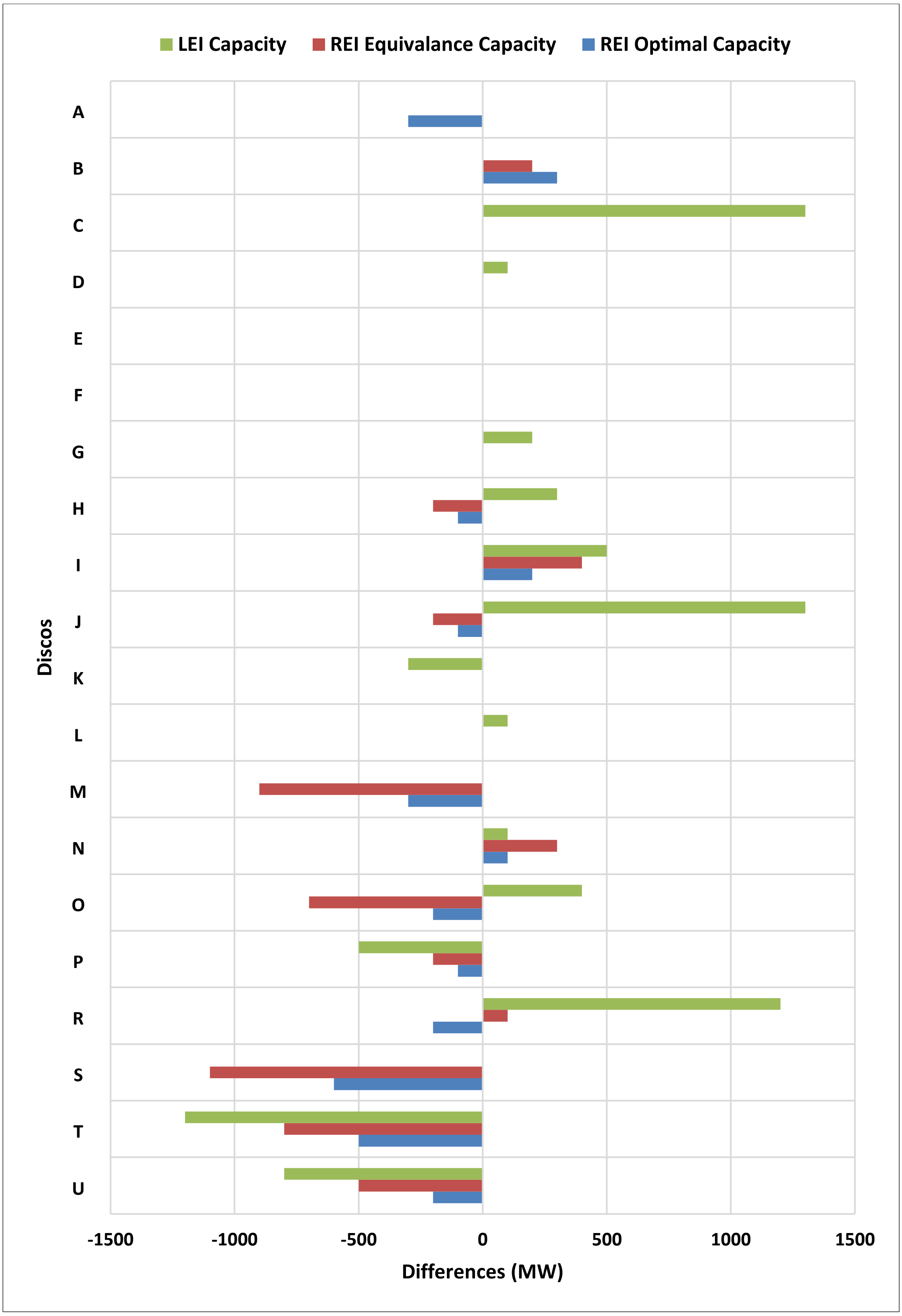

Figure 30. Differences at Peak Demand Condition for Different Wind Power Dispatches (Expected-Low)

Table 15. Differences at Peak Demand Condition for Different Wind Power Dispatches (MW)

	(Expected-Low)		
Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	-300	0	0
Disco B	300	200	0
Disco C	0	0	1300
Disco D	0	0	100
Disco E	0	0	0
Disco F	0	0	0
Disco G	0	0	200
Disco H	-100	-200	300
Disco I	200	400	500
Disco J	-100	-200	1300
Disco K	0	0	-300
Disco L	0	0	100
Disco M	-300	-900	0
Disco N	100	300	100
Disco O	-200	-700	400
Disco P	-100	-200	-500
Disco R	-200	100	1200
Disco S	-600	-1100	0
Disco T	-500	-800	-1200
Disco U	-200	-500	-800
Sum	**-2000**	**-3600**	**2700**

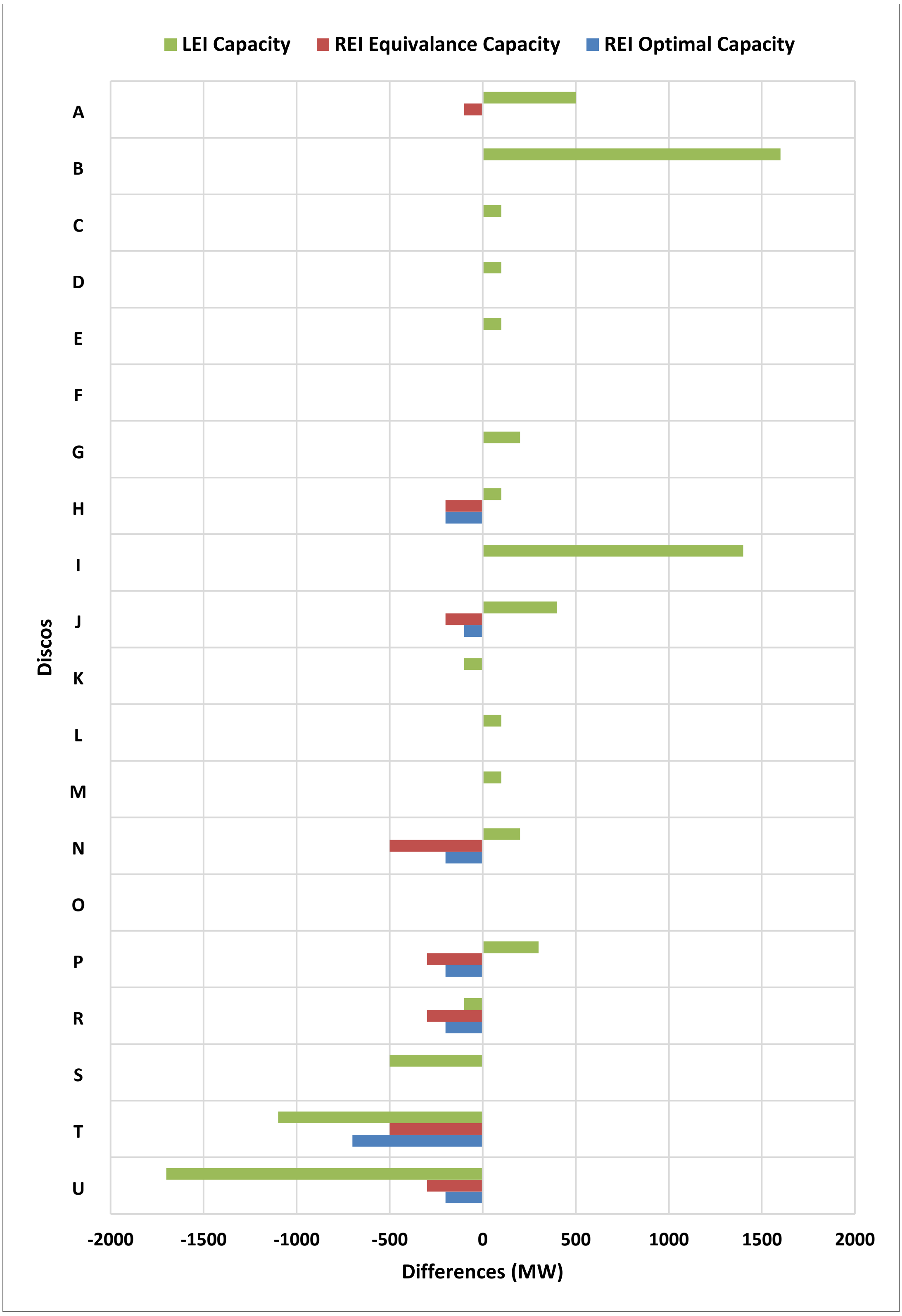

Figure 31. Differences at Minimum Loading Condition for Different Wind Power Dispatches (Expected-Low)

Table 16. Differences at Minimum Loading Condition for Different Wind Power Dispatches (MW)

	(Expected-Low)		
Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	0	-100	500
Disco B	0	0	1600
Disco C	0	0	100
Disco D	0	0	100
Disco E	0	0	100
Disco F	0	0	0
Disco G	0	0	200
Disco H	-200	-200	100
Disco I	0	0	1400
Disco J	-100	-200	400
Disco K	0	0	-100
Disco L	0	0	100
Disco M	0	0	100
Disco N	-200	-500	200
Disco O	0	0	0
Disco P	-200	-300	300
Disco R	-200	-300	-100
Disco S	0	0	-500
Disco T	-700	-500	-1100
Disco U	-200	-300	-1700
Sum	**-1800**	**-2400**	**1700**

5.3.2 Comparison of the Scenarios with Different Loading Conditions

Differences between different loading conditions for expected and low wind power dispatches are found by subtracting capacities found for peak demand conditions from the ones found for minimum loading conditions. These differences are visualized in Figure 32 and Figure 33 while the tabulated results are given in Table 17 and Table 18.

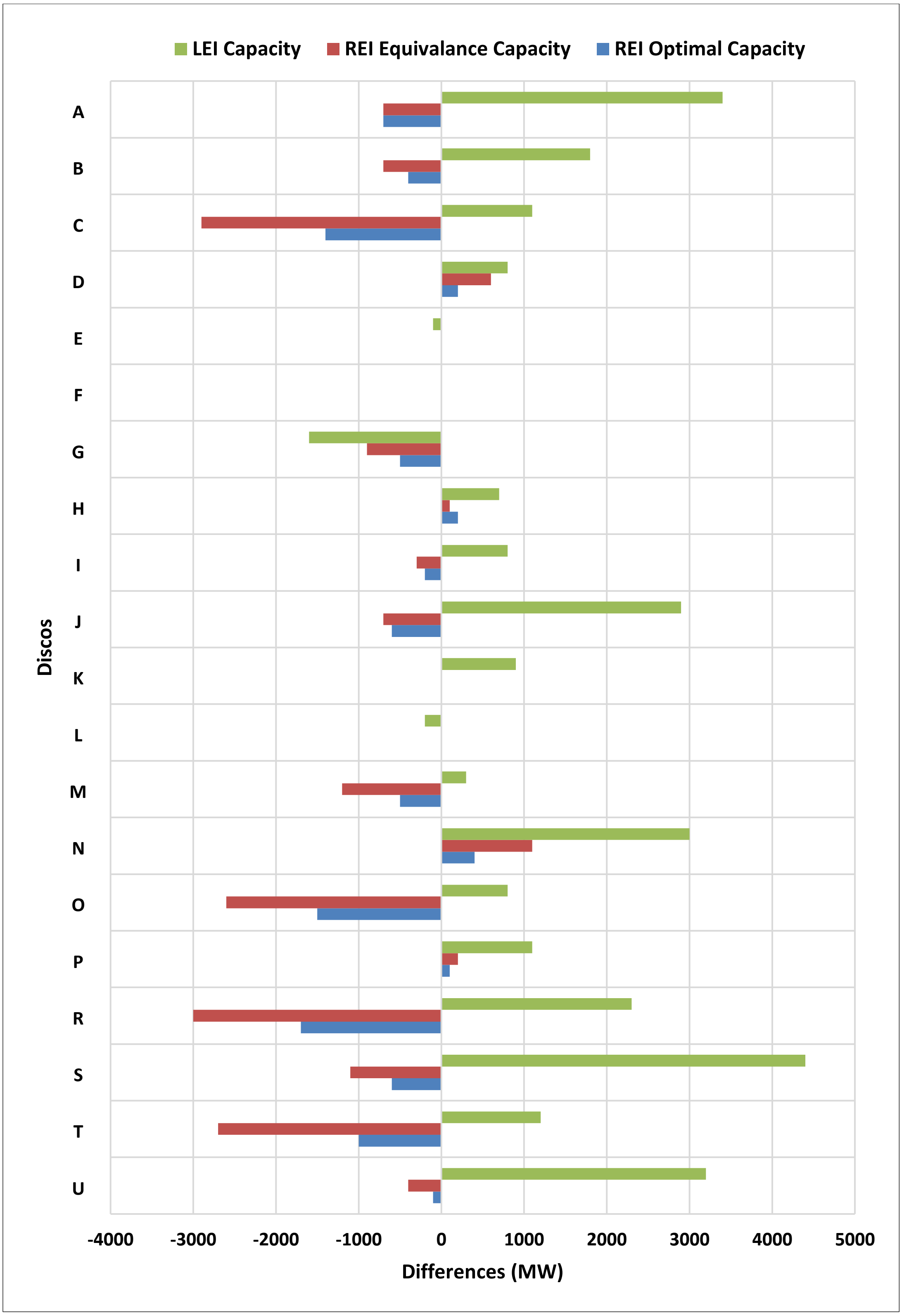

Figure 32. Differences at Low Wind Power Dispatch for Different Loading Conditions (Minimum Loading-Peak Demand)

Table 17. Differences at Low Wind Power Dispatch for Different Loading Conditions (MW)

	(Minimum Loading-Peak Demand)		
Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	-700	-700	3400
Disco B	-400	-700	1800
Disco C	-1400	-2900	1100
Disco D	200	600	800
Disco E	0	0	-100
Disco F	0	0	0
Disco G	-500	-900	-1600
Disco H	200	100	700
Disco I	-200	-300	800
Disco J	-600	-700	2900
Disco K	0	0	900
Disco L	0	0	-200
Disco M	-500	-1200	300
Disco N	400	1100	3000
Disco O	-1500	-2600	800
Disco P	100	200	1100
Disco R	-1700	-3000	2300
Disco S	-600	-1100	4400
Disco T	-1000	-2700	1200
Disco U	-100	-400	3200
Sum	**-8300**	**-15200**	**26800**

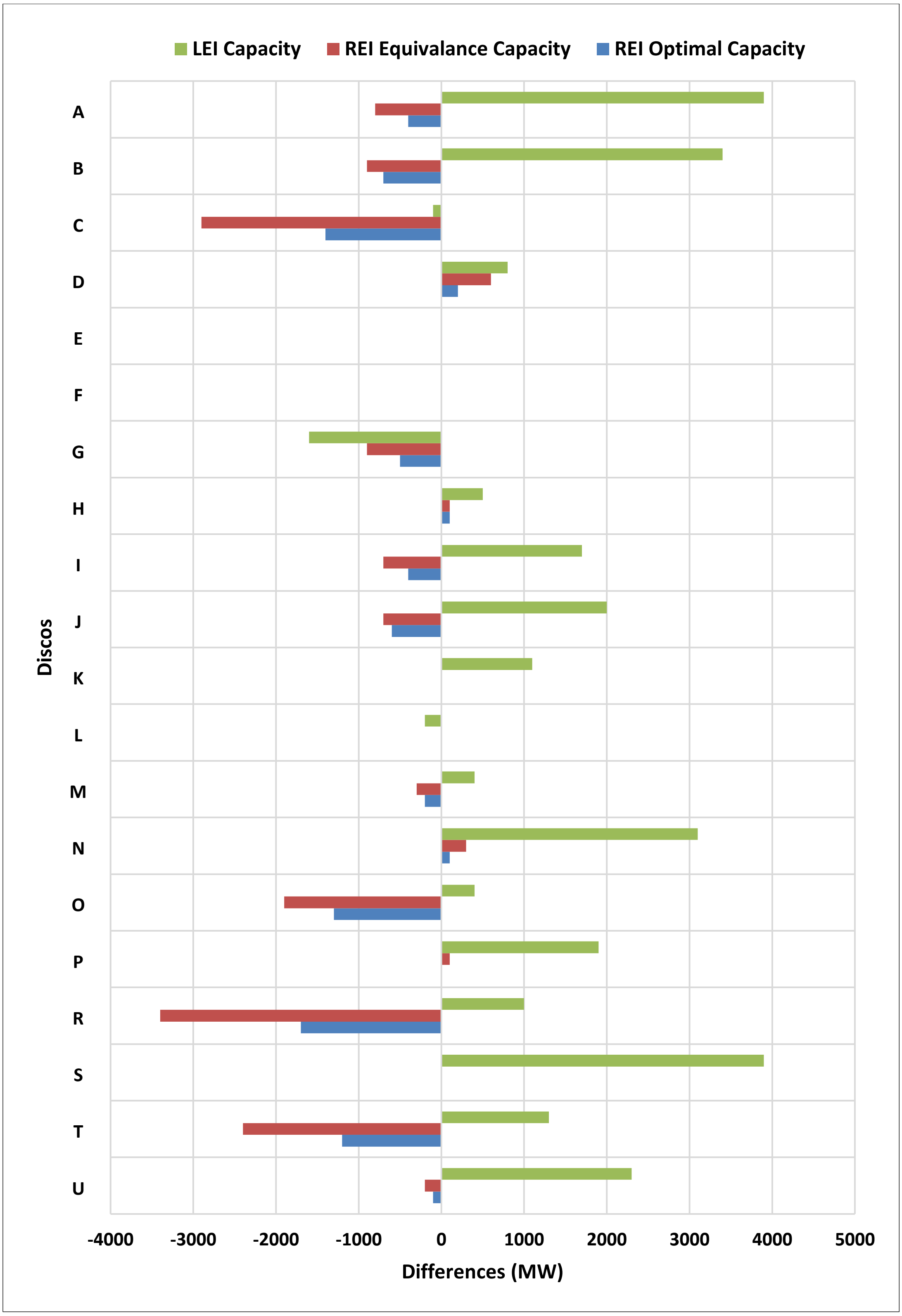

Figure 33. Differences at Expected Wind Power Dispatch for Different Loading Conditions (Minimum Loading-Peak Demand)

Table 18. Differences at Expected Wind Power Dispatch for Different Loading Conditions (MW)

	(Minimum Loading-Peak Demand)		
Regions	***REI Optimal Capacity***	***REI Equivalence Capacity***	***LEI Capacity***
Disco A	-400	-800	3900
Disco B	-700	-900	3400
Disco C	-1400	-2900	-100
Disco D	200	600	800
Disco E	0	0	0
Disco F	0	0	0
Disco G	-500	-900	-1600
Disco H	100	100	500
Disco I	-400	-700	1700
Disco J	-600	-700	2000
Disco K	0	0	1100
Disco L	0	0	-200
Disco M	-200	-300	400
Disco N	100	300	3100
Disco O	-1300	-1900	400
Disco P	0	100	1900
Disco R	-1700	-3400	1000
Disco S	0	0	3900
Disco T	-1200	-2400	1300
Disco U	-100	-200	2300
Sum	**-8100**	**-14000**	**25800**

5.3.3 Discussion of the Scenarios and Comments on the Results

- Comparative results of the different wind dispatch scenarios under same loading conditions are provided at Table 15 and Table 16. From these results it can be seen that sum of REI based capacities decreased while sum of LEI based capacities increased in case of expected wind power plant investments are realized. This is a result of geographical distribution of wind energy investments in the country. As given in the Figure 25, the general distribution of wind investments are mainly concentrated in the northwestern, western and southern regions of the country (Uludag, Gediz, Toroslar, Aydem, Trakya, Osmangazi, Bogazici and Sakarya Discos). These regions are also the regions with highest power consumption in the country. When wind power dispatch is increased in these regions, distance between power generation and consumption centers decreases. This reduces the power flow in long east-west corridors that in result influences the LEI related capacities in inner, northern and eastern regions of the country positively. In addition, REI related capacities in the regions where wind power investments are concentrated in decrease as it is expected since a portion of available transmission connection capacities of these regions are used by additional wind power generation. As can be seen from Table 15, at peak demand condition, sum of REI related capacities decreased 2000 MW and 3600 MW, respectively while LEI capacities increased 2700 MW. On the other hand, the results are very similar when results for minimum loading conditions at Table 16 are inspected. LEI capacities increased 1700 MW while sum of REI related capacities decreased 1800 MW and 2400 MW, respectively.

- Comparative results of the different loading condition scenarios under same wind power dispatches are provided at Table 17 and Table 18. It can be seen that sum of REI based capacities decreased while sum of LEI based capacities increased considerably in the minimum loading condition. The underlying reason for this result is that the thermal ratings of the transmission lines are much higher at spring when minimum loading condition happens. In addition, as can be predicted, the line loadings are mostly lower compare to peak demand condition. The considerable decrease in sum of REI related capacities is an indication that shows there is no need for extra generation under minimum loading conditions. However, this general situation does not apply to all regions. The Coruh region, symbolized as Disco G in this study, is an example of regions that do not fit to the general situation. There are many run of river (ROR) and dam type hydroelectric power plants installed in this area. This region is in second water basin as defined in Figure 16. As can be seen from Table 5, at spring minimum condition, utilization factors of ROR and dam type hydroelectricity in this region are at their highest. Therefore, generation in the region is increasing considerably at the spring minimum condition. Parallel to this, all of the capacities in this region showed a downward change as can be seen from Table 18. LEI capacity of the region decreased 1600 MW while REI related capacities decreased 500 MW and 900 MW, respectively. It should be noted that the thermal ratings of the transmission lines in the spring months are much higher comparing with summer months and in spite of this fact capacity values decreased. Looking at Table 18, there are three other regions that show similar characteristics with Coruh region. Discos C, F and L were identified to be stressed most at minimum loading conditions. That was reasoned, basically, from changed load flow patterns and power dispatch conditions at the spring season. This demonstrates the importance of examining both peak demand (summer) and minimum loading (spring) conditions in countries where load flow patterns change seasonally, such as in Turkey. Transmission system planners should consider the loading characteristics of the spring season as the determinant scenario when deciding on the investments to be made in these regions. For the rest of the regions peak demand conditions were found to be determinant.

- A determinant scenario for each region was determined by comparing the peak demand and minimum loading scenarios and the capacity values found in that scenario were accepted as the final capacity values for that region. The LEI-based capacity was taken into consideration in the selection of the determinant scenario for each region. Peak demand and minimum loading at expected wind power dispatch scenarios are compared in terms of LEI capacities while determinant scenarios for each region is determined. The scenario in which the lowest LEI capacity found for a region was accepted as determinant scenario. The expected wind power dispatch scenario was accepted as base case scenario while low wind power dispatch scenarios were studied to see the impact of increasing wind generation, only. When all analyzed regions are considered, the peak demand conditions found to be determinant for 16 region, while the minimum loading conditions happened to be determinant for 3 regions. For one region, both scenarios gave the same results. The recommended capacity values and determinant scenarios are presented in Table 19.

Table 19. Recommended Capacity Values of Regions (MW)

	REI Optimal Capacity	REI Equivalence Capacity	LEI Capacity	Determinant Scenario
Disco A	700	1300	0	Peak Demand
Disco B	700	900	0	Peak Demand
Disco C	0	0	1200	Min. Loading
Disco D	200	300	2200	Peak Demand
Disco E	0	0	1000	Peak Demand
Disco F	0	0	0	Both
Disco G	0	0	500	Min. Loading
Disco H	200	400	1100	Peak Demand
Disco I	400	700	500	Peak Demand
Disco J	700	1000	2200	Peak Demand
Disco K	0	0	0	Peak Demand
Disco L	0	0	1100	Min. Loading
Disco M	200	300	2100	Peak Demand
Disco N	1700	3400	2100	Peak Demand
Disco O	1300	1900	2200	Peak Demand
Disco P	500	900	1300	Peak Demand
Disco R	2800	5600	3200	Peak Demand
Disco S	0	0	0	Peak Demand
Disco T	1800	3900	800	Peak Demand
Disco U	700	1300	0	Peak Demand
Sum	**11900**	**21900**	**21500**	-

- Discos A, B, F, K, S and U have found to have zero LEI Capacity. Priority should be given to these regions when the transmission system investments are planned. Any additional generation that will come to these regions without strengthening necessary transmission lines could result in congestions in long term and jeopardize the system security. Discos A, B, T and U should be taken into consideration primarily since these regions are LEI-limited regions and benefits from additional generation up to some point as they have non-zero REI related capacities. After the transmission systems of these regions have been strengthened by investing into required transmission lines, it is estimated that future generation investments will have a positive impact in terms of the minimizing the transmission losses.

- Discos R, T, N and O has found to have highest REI related capacity values. These regions are most power demanding regions and power plant investments that are going to come to these regions would be most beneficial for Turkish Transmission System in terms of loss minimization and avoiding long east-west transmission corridors.

- The sum of the capacities is found to be 11900 MW, 21900 MW and 21500 MW for REI Optimal Capacity, REI Equivalence Capacity and LEI Capacity, respectively. It can be concluded that 21500 MW of additional generation can come into service without resulting in any inadequacy of transmission system assuming no additional investment will be realized. However, in LEI-limited cases, REI related capacities are higher than LEI related capacity. That indicates without additional line investments are realized at these regions power plants investments should be limited even though they are beneficial for the line loadings in general. That should be done to prevent a possible congestion in transmission system.

CHAPTER 6

CONCLUSION

In this thesis, a new methodology has been developed to determine regional transmission connection capacities based on two new indices, namely REI and LEI. The proposed method consists of three main parts. The first part is the identification of the regions those transmission connection capacities are wanted to be assessed. Second part is the assignment of artificial generation units to a selected region to enable modelling and controlling future generation. The final part is monitoring the line loadings at the region during N-1 contingencies by increasing the generation through artificial units in the region while total generation of the country is kept constant. This phase is a step-wise process, in which the two recommended index values are updated in each step. Finally, the impact of the additional generation to the regions and to the transmission lines is observed using these indices.

Region Based Evaluation Index (REI) is the first index that is proposed and it is used to observe impact of additional generation on region as a whole. Two capacity values, named, REI Optimal Capacity and REI Equivalence Capacity are defined using REI. The first one is the value that corresponds the optimum value of additional generation for that region. That is the point where REI hits its minimum. The latter value gives the amount of additional generation that can come into service without worsening initial line loadings of the region according to REI. That is the point where REI becomes equal to its initial value after followed a concave shape.

Line Based Evaluation Index (LEI) is the second index that is proposed and it is used to observe line loadings of the region individually in contrast to REI which is used to observe impact of additional generation on region as a whole. LEI is a discrete function of four states. States have two flags and each one gives information about different aspects of a line's loading. The first flag has the information of whether line overloads or not, while second flag compares line's max loading between current and previous steps. By monitoring this index, it can be understood whether a line is loaded within limits and if it benefits from additional generation or not. LEI Capacity is defined using LEI state of the lines. It gives the point where at least one of the lines in the region overloads at one or more of the analyzed contingencies while at the same time it does not benefit from additional generation.

Using these two indices, impact of additional generation to a region can be observed in a correct and complete way. REI indicates how feasible a region is in terms of generation investments while LEI points out the bottlenecks and limitations of the considered region in terms of transmission connection capacity increase. By considering the different combinations of offered capacity values regions can be classified according to their correspondence to additional generation. The results show that some regions are more prone to additional generation connection while some regions are unavailable due to the risk of transmission congestion. Region based capacities (REI Optimal Capacity and REI Equivalence Capacity) are valuable especially for the transmission system planners since these capacity values give an idea of where additional generation could be more beneficial. Therefore by taking into account this information, the power plant investments could be encouraged (via incentives, transmission tariffs etc.) at regions with high REI capacities. Line based capacity (LEI Capacity) is equally important both for transmission system planners and power plant investors since it defines the technical limit for additional generation and gives information about the congested lines of the network. It becomes a guide for transmission network planning studies as it gives the bottlenecks of the network.

The developed methodology was applied to projected Turkish Network model of 2026 considering four different case studies. These were peak demand and minimum loading conditions with expected and low wind power dispatches. Twenty regions were determined according to distribution companies' borders and developed methodology was applied to each of them. Three different capacity values (REI Optimal Capacity, REI Equivalence Capacity, and LEI Capacity) were found for each region. Based on LEI capacities found at different loading conditions at expected wind power dispatch, a determinant scenario is identified for each region. These determinant scenarios are the ones that should be taken into account when regions are assessed both in terms of transmission capacity values and in terms of required transmission line investments.

The examination of the minimum loading conditions besides the peak loading conditions proved to be important because the determining scenario for four of the regions studied was found to be the minimum loadings conditions. It is recommended for transmission system planners to plan related line investments for these regions based on the line loading characteristics of the spring season.

It was seen that when the expected wind energy investments were assumed realized and generation dispatch was made according to that assumption, the sum of the LEI capacities increased. As a result, it can be concluded that wind energy investments are beneficial to the transmission system of Turkey in terms of LEI capacities, as they concentrate in regions with high power requirements or regions close to those ones.

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