Chapter 1

Managing Risk in Electric Distribution Networks

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Abstract

This book chapter explores existing and emerging flexibility options that can facilitate the integration of large-scale variable renewable energy sources (vRESs) in next-gen electric distribution networks while minimizing their side-effects and associated risks. Nowadays, it is widely accepted that integrating vRESs is highly needed to solve a multitude of global concerns such as meeting an increasing demand for electricity, enhancing energy security, reducing heavy dependence on fossil fuels for energy production and the overall carbon footprint of power production. As a result, the scale of vRES development has been steadily increasing in many electric distribution networks. The favorable agreements of states to curb greenhouse gas emissions and mitigate climate change, along with other technical, socio-economic and structural factors, is expected to further accelerate the integration of renewables in electric distribution networks. Many states are now embarking on ambitious “clean” energy development targets. Distributed generations (DGs) are especially attracting a lot of attention nowadays, and planners and policy makers seem to favor more on a distributed power generation to meet the increasing demand for electricity in the future. And, the role of traditionally centralized power production regime is expected to slowly diminish in future grids. This means that existing electric distribution networks should be readied to effectively handle the increasing penetration of DGs, vRESs in particular, because such systems are not principally designed for this purpose. It is because of all this that regulators often set a maximum RES penetration limit (often in the order of 20%) which is one of the main factors that impede further development of the much-needed vRESs.

The main challenge is posed by the high-level variability as well as partial unpredictability of vRESs which, along with traditional sources of uncertainty, leads to several technical problems and increases operational risk in the system. This is further exacerbated by the increased uncertainty posed by the continuously changing and new forms of energy consumption such as power-to-X and electric vehicles. All these make operation and planning of distribution networks more intricate. Therefore, there is a growing need to transform existing

systems so that they are equipped with adequate flexibility mechanisms (options) that are capable of alleviating the aforementioned challenges and effectively managing inherent technical risk. To this end, the main focus of this chapter is on the optimal management of distribution networks featuring such flexibility options and vRESs. This analysis is supported by numerical results from a standard network system. For this, a reasonably accurate mathematical optimization model is developed, which is based on a linearized AC network model. The results and analysis in this book chapter have policy implications that are important to optimally design ad operate future grids, featuring large-scale variable energy resources. In general, based on the analysis results, distribution networks can go 100% renewable if various flexibility options are adequately deployed and operated in a more efficient manner.

Keywords: Demand Response, Electric Distribution Networks, Energy Storage Systems, Flexibility Options, Mixed Integer Linear Programming, Network Reconfiguration, Stochastic Programing, Variable Renewable Energy Sources.

1.1. Chapter Overview

It is now widely accepted that integrating variable renewable energy sources (vRESs) in electric distribution networks is inevitable to meet a growing demand for electricity, enhance energy security and diminish the heavy dependence on fossil fuels to produce electricity, which are associated with high carbon footprint. Many states are now forging ahead with ambitious vRES integration targets aiming to achieve a substantial reduction of greenhouse gas emissions (GHGs), as in the European Union (EU). Integration of vRES technologies are expected to lead to 80% to 95% GHG emissions by 2050 [1]. One eminent fact about these technologies is that they depend on the availability of primary energy resources such as wind speed and solar irradiation, which are unevenly distributed over a wide geographical area. This means distributed (rather than centralized) development of such resources could be more convenient, efficient and even cost-effective despite the economies-of-scale. The main reason for this is because distributed generations are installed in places closer to demand, which means they are often connected to distribution networks. If this is executed in a well-coordinated manner, vRESs can bring vast benefits to the systems as a whole in terms of improved efficiency, deferred transmission investments, reduced use of fossil fuels for energy production and therefore lower GHG emissions [2]. Hence, distribution networks are expected to accommodate more and more vRESs.

Current trends generally show that the share of vRESs in the overall energy consumption is rapidly increasing in many electric distribution networks globally amid a number of barriers. However, the intermittent nature of such resources means a large-scale integration creates technical problems in the systems. Electric distribution networks are especially experiencing unprecedented challenges due to the increasing penetration level of distributed power generation sources of variable in nature, particularly, wind and solar. In other words, distributed generations (DGs) are attracting a lot of attention from policy makers and planners to meet the increased demand for electricity in the future. There is nowadays a growing trend of adding more new DG capacities than centralized generation capacities. This brings serious concerns to grid operators, though. The partially unpredictable nature of power generation from the key renewable type DGs may endanger the stability and integrity of electric networks as a whole, and at a distribution level in particular. This may also deteriorate the quality of power delivered to consumers.

Because of these concerns, future distribution networks should be prepared to handle the ongoing transformation process of power generation from the traditionally centralized to a more distributed and small power productions. Nonetheless, conventional distribution networks are not designed to manage this, and as a result, regulators often impose a maximum penetration limit which does not help further development of distributed vRESs. But distribution networks are slowly evolving to smart grids, which are adequately equipped with the necessary tools and mechanisms to accommodate large-scale vRESs while minimizing their side-effects mentioned earlier. In this chapter, we explore and discuss the flexibility options that can support the much-needed integration and efficient utilization of large-scale vRESs in the future distribution networks. The assessment also includes managing the negative impacts of vRESs, induced by their high variability and uncertainty, by means of various flexibility options. For this purpose, we perform optimal management of distribution networks via an appropriate mathematical optimization – a stochastic mixed integer linear programing (S-MILP) –for deploy different flexibility options along with vRESs. This chapter aims to address the operation issues that can occur in distribution networks due to the high-level variability and uncertainty of vRESs. The analysis is made from the economic and technical point of view. In particular, this chapter makes an extensive analysis on the impacts of vRESs on the overall performance of the system such as voltage profile, losses, costs, system reliability stability and power quality. In addition, the contributions of different flexibility options in enabling high penetration of vRESs and their wide-range benefits are assessed.

The remainder of this chapter is as follows. The next section presents an overview of the need for increased flexibility in distribution networks. The subsequent section describes the developed mathematical formulation used to carry out the required analysis. This is followed by numerical results and discussions. Finally, the last section summarizes the main findings of this chapter.

1.2. The Need for Flexibility Options in Distribution Networks

Because of the reasons mentioned earlier, an increasing level of DGs is being connected to distribution networks. The fact that these are based on erratic power sources (wind and solar, for example) is creating technical problems in such systems. Grid operators are especially concerned as the conventional means of overseeing the network systems are now becoming insufficient to keep a healthy operation of such systems. The main reason for this boils down to the partially unpredictable nature of these energy resources. In such circumstances, proper management mechanisms need to be put in place so as to seamlessly accommodate large-scale vRES type DGs. This is critical to address a multitude of global concerns, partially described in the previous section.

In general, there is an increased need for flexibility in distribution networks counterbalance the continuous fluctuations in RES power production and even demand [3], [4]. Traditionally, demand-generation balancing is handled by conventional power plants. However, in the presence of high level vRESs, this approach may be prohibitively expensive or even not sufficient to provide the standard balancing service level. Therefore, the existence of vRES in the system decreases the effectiveness of existing flexibility mechanisms compared with the traditional system (without these resources), mainly due to the intermittent nature of renewables. In other words, the system needs a greater level of flexibility to be able to guarantee the system reliability as the variation increases (both in supply and demand). This is one of the key challenges integrating these energy sources. Therefore, new flexibility options are needed to manage the real-time imbalances in demand and power production. This way, the security of electric supply, stability and power quality can be guaranteed.

Flexibility can be defined as the ability electric distribution networks to efficiently manage its own resources in the event of continuous changes in power supply and demand sides. In this regard, voltage and frequency controls are the primary resources to face uncertainty and variability [5], [6]. In addition, another resource in electric distribution network useful for handling the imbalances as a result of unpredictable changes in the system (either from the supply, demand or both sides) is the network's reserve capacity. Nonetheless, flexibility in electric distribution networks can be affected by many factors such as the amount of reserve capacity, the ramp rates of generators, the type of generation, the availability of generation, interconnection with other electric distribution networks, capacity of interconnections, etc. [7]. These are traditional mechanisms to deal with imbalances mainly caused by traditional sources of uncertainty and variability. Conventional power plants can add reserve capacity to the system but the inherent variability and uncertainty of vRESs definitively change the operation of distribution networks. Under these circumstances, it may not be economical for conventional power plants to offer spinning reserves. This would be costly because of a possibly increased use of fossil fuels for providing the huge requirement of spinning reserves [8].

The fact that the energy sector is transforming to a new paradigm with improved energy efficiency and environmentally-friendly technologies to produce energy at reasonably priced tariffs [9] brings both opportunities and challenges. Flexibility options will be highly needed to address those challenges and reap the benefits. The system-wide reliability, efficiency, reduction of GHGs and affordability of energy can be achieved by deploying and coordinating different flexibility options such as energy storage systems (ESSs), switchable capacitor banks (SCBs), demand response (DR) and others. These technologies substantially enhance the flexibility of the system and its ability to continuously maintain a standard service in the face of large fluctuations in the supply and demand [10], [11].

Given the background given above, the question of having adequate renewables to meet the electricity demand requires one to have sufficient flexibility technologies to balance forecasting errors and fluctuations [12]. These flexibility options can be provided by the energy storage medium, electric distribution networks, demand and supply sides as shown in Fig. 1.1. For example, from the network side, the system can dynamically change its topology to adapt to changing operational situations. The more frequent the reconfiguration is, the better the contribution of such a flexibility mechanism will generally be. From the supply side, the traditional flexibility service in the form of spinning reserve provided by conventional generators is one example. Others include curtailment of variable power and reactive power control. On the demand side, some flexibility options are demand response, energy efficiency and electric vehicles.

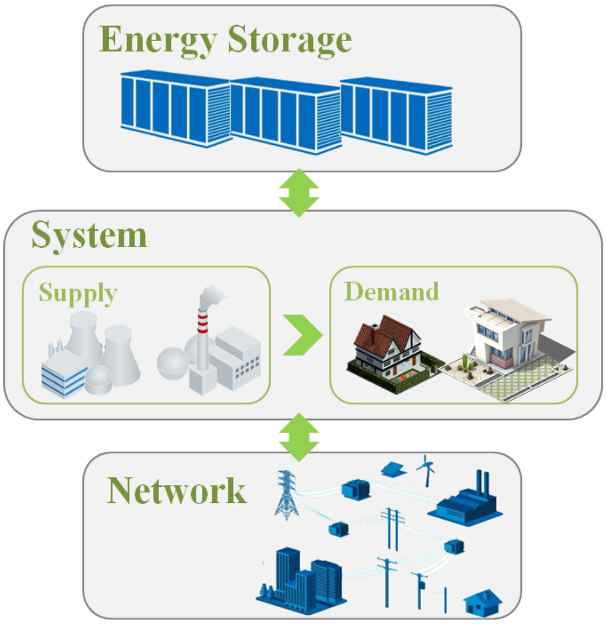


Fig. 1.1. Identifying flexibility options in electric distribution networks

1.2.1 Challenges of Variable Energy Sources Integration

Traditionally, distribution networks are built to serve the peak demand, and fulfill reliability and quality requirements, in a radial structure [13]. The role of distribution operators has so far been mainly to construct, maintain and manage outages of their distribution network assets [13]. However, with advent of new technologies and new consumption forms as well as increasing penetration of DGs, this conventional business model needs to be structurally changed. Under this circumstance, distribution grids are expected to support bi-directional power flows, which is completely different from the way these are designed to. This is increasingly becoming a concern for grid operators as this new role complicates the operation of such grids. As a result, the architecture of distribution networks needs to change to effectively overcome the limitations and address the operators' concerns. The systems need to adopt modern technologies after careful planning and be equipped with necessary tools for their efficient operation. This is important to deal with compounded issues pertaining to the political, social, economic and environmental concerns, as well as meet rising demand for energy and sustainable development goals [14].

Generally, the integration of variable energy sources has several challenges and barriers, which can be categorized as technical, economic, social, political, financial, policy and regulatory aspects [15]–[24]. These are summarized in Fig. 1.2. The technical challenges and barriers are already discussed. There financial markets, such as banks, inventors or capital firms are the main contributors for economic growth; they define the technological trajectories [15]. Because of this, they can provide a fundamental element to any strategy in the direction of a more sustainable future. Understanding the importance, profile and information that an investor needs is critical to formulate renewable energy source (RES) policies and strategies. In this context, it is expected that the challenges with integration of variable energy sources are related with cost benefit scenario, policies and social acceptance analysis as can be seen in Fig. 1.2.

Policies and regulations have unexpected – sometimes counterproductive – effects on integrating RESs. And, it is necessary for policy makers to study the system by modeling the interactions between different parts of the system and different policies adopted in order to accommodate a large-scale integration of vRESs [25]. Although there are very supportive contributions from different nations, we face with a regulatory framework that comprises laws to overall support RESs but there is no long-term planning because the approaches and framework conditions are always changing [26]. As the network requires to build and operate complex systems involving many corporations, this changing conditions does not permit a system to function effectively [26]. Policies for renewable energy integration are being promoted to diffuse renewable energies within electric distribution networks though their effectiveness to accommodate large-scale integration remains subject to uncertainty [27]. For instance, states often try to assist countries that import laws from others and do not adapt the framework to their reality [26]. The lack of planning combined with inappropriate incentives can result in financial problems limiting the progress of companies. Lack of qualified persons combined with the absence of information about markets, operation, planning and potential customers are other barriers to growth of vRESs. The slow rate of decentralized energy systems could be purposely due to fear of losing control with power shifting to new competitors and their pioneering business models [26]. For example, "investment in oil and gas infrastructure and exploration in 2012 was about US$ 650 billion, and on the flip side, investments in vRES development was only US$ 244 billion" [28].

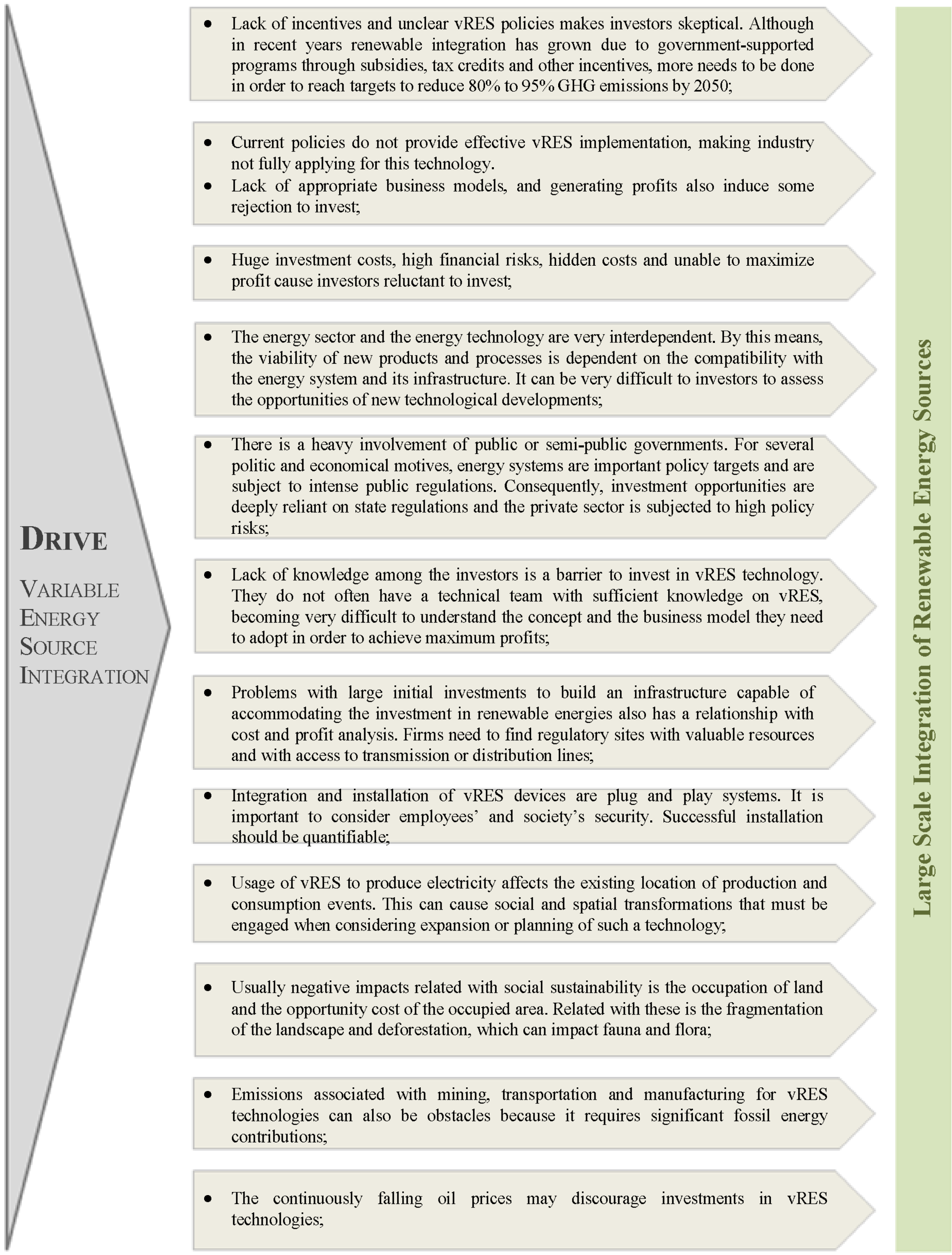


Fig. 1.2. Challenges of integrating vRESs

Among the aforementioned challenges, the technical ones present serious problems in the network systems. In the absence of adequate countering mechanisms, the level of vRES power absorbed by such systems could be insignificant, which hardly help to achieve the targets sets forth by regulators and policy makers. This chapter explores ways to address these issues by means of deploying different flexibility options.

1.2.2 Emerging Energy Consumption Forms

The electric sector is undergoing rapid changes with a paradigm shift in three fronts: generation, network and demand sides. Much has been said in the previous sections of this chapter about the growing changes on the generation side. The demand side is also experiencing rapid transformations. This means that along with the current evolution of the electric sector and society, new forms of consumptions are emerging and other forms are moving from parallel sectors to the energy sector. For example, new and increasing consumption styles include e-mobility (such as electric vehicles), power-to-X (an initiative to convert electricity to other forms of energy), etc. These can be broadly grouped into three categories: the demand response, electric vehicles and power-to-X, as shown in Fig. 1.3. The category of demand response according [29] can be divided into three new sub categories, industry intensive energy demand, demand management in services and households and smart applications. The latter stems from the changes that are being made in the electricity sector by transforming the traditional networks into smart grid, taking advantage of the new communication capabilities that are being integrated into the system. The remaining subcategories arise from the electrification of other sectors such as, the transportation and the heating/cooling sectors [29]. A more detailed approach to each of these categories is made in the subsequent sections, where the main features of the new demand forms are presented together with the challenges associated with each one.

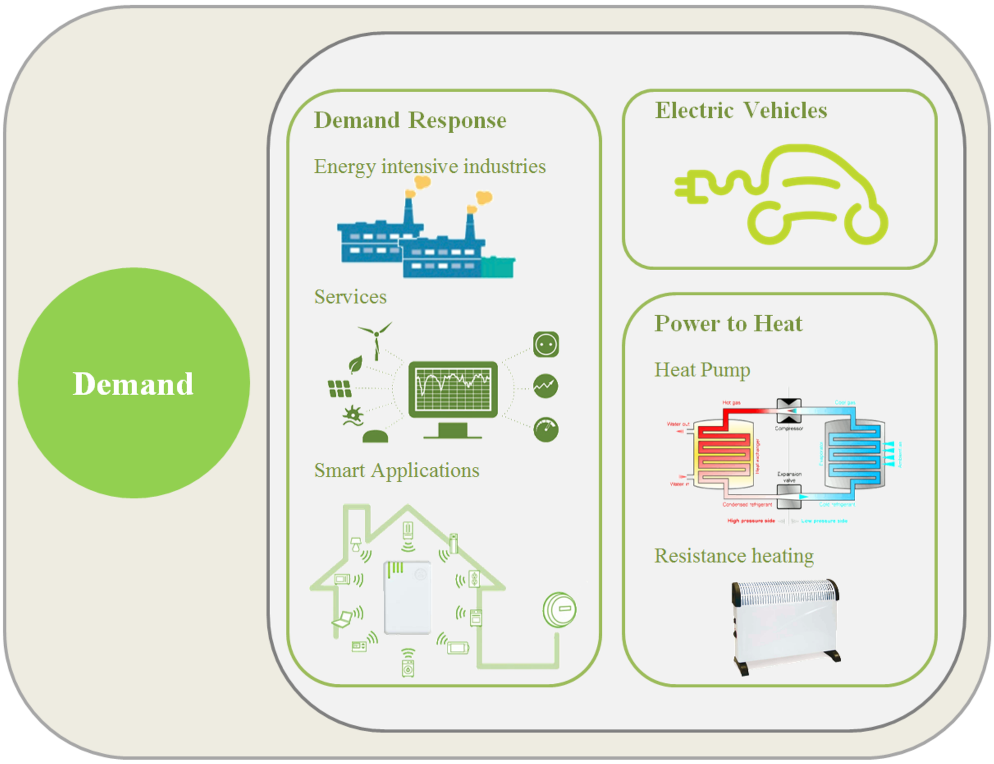


Fig. 1.3. New emerging forms of energy consumption.

1.2.2.1 Demand Management in Industrial Installations

One of the subcategories within the demand is the demand management in industrial facilities. In this subcategory, demand is modeled by the specific industrial process characteristics, and can vary from one type of industry to another type. As a result, the demand is not uniform. However, as already explained before, the energy sector is changing and with the emergence of new concepts related to the smart grids, some ways can be found inside the demand to enhance system stability. Therefore, some types of industries have productive processes that offer a certain level of flexibility, that is, they can change the energy needs of the production process over a given period of time. Some examples of such processes are the ones that include electrolysis (very intensive installations), cement and paper industries, electric boilers, and electric arc furnaces [30]. However, a large number of industries do not have this flexibility.

In the industry, the factors that determine any action are the costs and gains. According to the reports in [29], [30], increasing flexibility at a low cost is generally possible in the cases where the primary process is not disturbed. These costs generally refer to the workers' shifts, the installation of communication and control equipment, and the additional potential storage of intermediate products on-site [31]. Therefore, this subcategory faces significant challenges that are presented in Fig. 1.4.

DEMAND MANAGEMENT BARRIERS IN INDUSTRIAL INSTALLATIONS

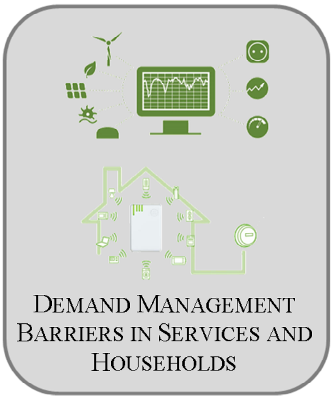
Barrier	Description
Economic	Demand response is dependent on the electricity costs sensitivity and market price signals.
	In most markets, the extra capacity prevents large price spikes.
	In most industrial entities, the high organizational effort is not worthwhile due to the low level savings resulting from the demand shift to hours with lower electricity prices.
Technical	Some of the potential barriers are the product quality loss, shorter periods for production line changes, and the demand structure.
Political	Some markets punish temporary differences in demand, for example, higher rates on the network.

Fig. 1.4. Demand management barriers in industrial installations [29].

1.2.2.2 Small-scale DR: Demand Management in Services and Households

Another subcategory is related to the demand response in commercial and residential sectors, which can be accommodated in the same category because demand management can be applied to transversal processes such as heating and cooling. Including different demand electricity price levels, such as refrigeration timing for refrigerated warehouses, automatic adjustment of demand can be done by refrigerators [29].

Other technology types that are transversal to the two subcategories and with potential in the demand management are the air conditioned, air compression for mechanical use or even scheduling of washing processes in the dwellings. Several small load management programs are currently being installed up to 5kW in several countries using two directions of communication (coming from the integration of smart grids) and the potential of these programs is very large [31]. However, existing IT infrastructures as well as primary device control constraints can present significant challenges. Therefore, demand management can reverse the game in the electricity markets, since this subcategory can also contribute to the creation of flexibility in the network systems, being no longer seen simply as a demand, in terms of flexible demand, by establishing the marginal prices in wholesale electricity markets [32]. The set of challenges pertaining to demand management in commercial and households are summarized in Fig. 1.5.



Barrier Type	
Economic	The need to invest in information infrastructures and telecommunication (IT), and data processing.
	Few price tariffs are available in real time and market prices are not visible at the retail level.
Technical	The lack of communication infrastructure, costumer empowerment in most countries.
Political	Lack of acceptance or support in data security issues, change the paradigm of several different interest parts including the consumer.

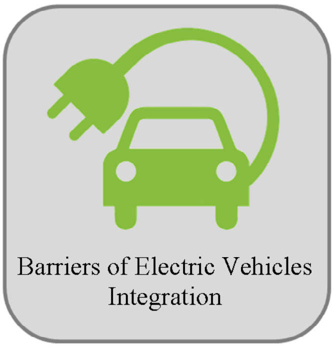
Fig. 1.5. Demand management barriers in services and households.

1.2.2.3 Electric Vehicles (EVs)

Electric vehicles are one of the new energy consumption forms. For mobility purposes, they use energy stored in their EV batteries. The charging process is carried out by connecting the EV to the grid when the vehicle is parked at an EV parking lot [33]. Energy can also be transferred the EV to the electricity grid. This effectively means that EVs can operate in two modes: power source and demand. The demand characteristics in the mobility sector makes the EV fleets be similar to the previous subcategories, as an option not only for demand but also for flexibility in the energy system that can be presented in two fundamental forms [34]:

- G2V (Grid-to-Vehicle mode, where the fleets of EVs are operated as a demand side management option, allowing a shift of load among different times).
- V2G (Vehicle-to-Grid mode, where in addition to charging the batteries of the electric vehicle, EVs could be discharged and feed power back to the grid).

Due to the fact that its primary use is for mobility, the provision of flexibility by EVs is subject to many constraints. In addition, it is highly uncertain supply source. However, several studies show that EVs may be competitive flexibility options [33]–[36] because they are expected to be largely available overnight (home charging). During the day, their availability depends on the charging infrastructures that exist elsewhere (for example, at work). The main advantage of EVs is that they are a parallel development, i.e. their investment comes from the transport sector [36]. EVs have a potential role to serve as a source of balancing and reserve requirements, as well as a solution to solve problems locally [34]. However, EVs face a significant set of challenges that are presented in Fig. 1.6.



Barrier Type	Description
Economic	There are no business models yet.
Technical	Battery technologies (low driving times, high battery costs).
	The size of electric vehicles fleet is still very small. There are inadequate charging infrastructures, control and communication infrastructures.
Political	Lack of acceptance or support in data security issues, change the paradigm of several different interest parts including the consumers.

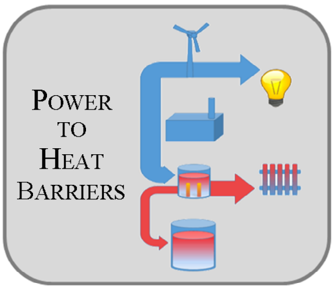
Fig. 1.6. Electric Vehicles main barriers.

1.2.2.4 Power to Heat

Electricity can be used to replace other fuels such as gas or oil for residential heating purposes. One of the possible options is the direct heating in a housing, where the electric current through a resistor converts electrical energy into thermal energy [37]. Moreover, this subcategory has potential at the flexibility level, which can be created by selectively energizing heaters and storing the heat generated for later use. Thermal energy can be stored with relative efficiency in several ways [38], typically including insulated ceramic type containers and hot water tanks. The heat is then released as needed by the end users. Electric heat pump technology is one of the most efficient technologies that convert electricity into heat. The heat pumps efficiently move the stored heat energy from a heat source (e.g. ambient air) to the end use or storage.

Heat pump technology is a part of conditioned air and refrigerators. The principle is the same, but the direction of the heat flow is from outside, the ambient air from the conditioner in cooling applications, whereas in the heating is the inverse [37]. In fact, heat pumps are reversible and can perform as both heating and cooling functions simultaneously in some applications.

The electrification of the heating sector also shifts the demand from the heating sector to the electricity sector, and can add some important flexibility to the system. The combination of thermal storage with electric heating has the potential to increase the flexibility of the electric distribution networks as it builds an optional place to put temporary surges of vRES energy and reduce carbon emissions through the displacement of heat sources out of fossil fuels [12]. Power to Heat also has a set of barriers that are summarized in Fig. 1.7.



Barrier Type	Description
Economic	High electricity cost when supplied by the grid, especially for heating resistors.
Technical	Limited work due to the primary operation (temperature limits), and since the efficiency depends on the ambient air temperature, in addition to being limited to specific periods of the year.
Political	Fees and taxes.

Fig. 1.7. Power to Heat barriers.

1.2.2.5 Power to Gas

Power to Gas is a category commonly found in energy storage but can also be integrated into demand since Power to Gas refers to the storage of chemical energy, namely the use of electric power to create fuels that can be used in conventional power plants. The key fuel is synthetic methane (and hydrogen in some cases). The procedure consists of two steps [39]:

- Electricity is used in electrolysis to divide water into hydrogen and oxygen.
- Hydrogen is combined with carbon to obtain methane.

Methane is the main constituent of natural gas and therefore can be injected into the existing infrastructure of natural gas (network and storage). The high storage capacity in the network could then be used for medium and long term storage purposes.

A first demonstration project at the kW scale was built and operated in Germany, and a 6 MW German plant also started operating in 2013 [40]. The key to chemical storage compared to other technologies is their energy density (kWh/liter) compared to most other technologies as well as the long period of change. The key barrier is low efficiency [41].

The great strength of this category lies in the seasonal storage, probably to be used in the transport sector in the first place. The technology perspective increases with the prospect of relying on 100% of renewable resources, storing the surplus of electric energy in the (central) gas infrastructure when generation from vRES is low [39]. Some of the challenges of the Power to Gas technology can be seen in Fig. 1.8 [29].

Barrier Type	Description
Economic	High cost.
Technical	Low efficiency, an external CO_2 source or extraction of air (which leads to a reduction of efficiency)

Fig. 1.8. Power to Gas barriers

1.2.3 Risk Posed by Increasing Uncertainty and Variability

Variable RESs are not always available when needed. They are subject to high level variability and uncertainty. Variability is related to the natural variation, for instance, of wind or sun to produce energy, meaning that the produced energy can fluctuate in certain quantity over regular time intervals. Uncertainty refers to the partially unpredictable nature of the uncertain parameters. As a result, daily and seasonal effects and limited predictability turns vRESs as highly intermittent generation sources [27]. Hence, as they are intermittent, they are not dispatchable as we cannot have control over the power output. Because of these reasons, in the absence of proper strategies, integration of vRESs can pose significant operational risk, making system voltage and frequency controls very difficult. This is because increasing penetration of vRESs increases fluctuations and creates big and uncertain generation-demand imbalances [42]. This leads to power quality and stability concerns. Grid disturbances, for instance, short-circuit faults can cause voltage sags and frequency variations, sending them both off the standard limits. Generally, increased levels of vRESs may cause more complex and uncertain operation situations [42]. Accordingly, there is a need for proper planning and decision making to face uncertainties for achieving optimal vRES integration [43].

Power quality issues when integrating vRES encompass the following important issues: (1) voltage and frequency oscillations triggered by non-controllable vRESs and by power grid disturbances, and (2) harmonics that are introduced by the electronic converters used in vRESs, that are necessary for adapting fluctuating production with grid requirements [42], [44]. Because of the intermittence of vRESs, one way to control power output is simply by curtailing the power production. Nonetheless, it is not an effective way since the curtailed energy could be stored and used on latter moments, not only for demand supply but also for voltage and frequency control of the power output.

In order to face voltage and frequency problems, utilities have introduced various grid codes for connecting vRESs to electric distribution networks. The regulatory framework of the grid codes are defined by the system operators to outline the duties and rights of all loads and power generation connected to the transmission and distribution networks [45]. Previously, the large-scale integration of vRESs, grid codes did not include regulations for wind and solar systems because the installed generation was very insignificant compared to the traditional generation systems. This situation has been changing in recent years as the level of vRESs integrated in distribution grids is on the rise. Such a massive integration of vRESs creates genuine stability concerns in the system due to the negative impacts of large solar and wind power plants. These concerns are related with voltage and frequency drops in the presence of a fault or high winds, making wind turbines to stall, that can lead to outages [45]. Accordingly, rigorous technical requirements are enforced to protect networks to contrast to these threats. As an example, wind power plants are required to withstand various grid disturbances and contribute to the stability of the system and provide ancillary services.

The technical challenges that vRES introduces to electric distribution networks increases the need for high level flexibility from other parts of the systems and flexibility through interaction with other energy sectors, like heating sector, natural gas and interaction between transportation and distribution networks [25].

1.2.4 The Path towards More Flexible and Smarter Grids

Given the new developments from the demand and supply sides, distribution network systems need to undergo the necessary transition to more flexible and smarter grids. Future grids will be equipped with different types of flexibility options such as energy storage systems (ESSs), reactive power sources such as switchable capacitor banks (SCBs), demand response (DR) and dynamic network reconfiguration (DNR). Moreover, a coordinated deployment and scheduling of flexibility options are needed to optimally manage an increased penetration of vRES in distribution networks. For example, energy storage systems can be added onsite for frequency control and add quick reserve capacity to the system. ESSs can also provide other services. Their fast response means that they can be part of the ancillary services (frequency control) and suited to black-out restart of the system.

The operation principle of ESSs is to store excessive energy during the demand low period that will be utilized in periods of high demand.

Load flexibility options like demand response (DR) can also enhance the integration of vRESs, giving the control of operation of contracted services to a new competitor, named aggregator. From the network side, one example of potential flexibility option is dynamic reconfiguration of the distribution network. Dynamic reconfiguration can play substantial role in improving reliability, increasing RES penetration and minimizing power losses. Switchable capacitor banks can also provide adequate flexibility to the system, enhancing stability and RES integration level.

Flexibility options form important components of electric distribution networks and play important roles in the transformation of current electric distribution networks to smarter grids in the future. Most current systems are based on fossil fuels. Yet, the recent trend of system evolution shows that future grid systems will be based on the efficient accommodation of large scale variable renewable energy sources [32]. The existence of sufficient operational flexibility is a necessary prerequisite for the efficient large-scale integration RES energy in such network systems. Flexibility is not only necessary to mitigate supply variations due to increased uncertainties but also the variations in from demand side due to new and relatively unpredictable energy consumption forms. This is graphically illustrated in Fig. 1.9.

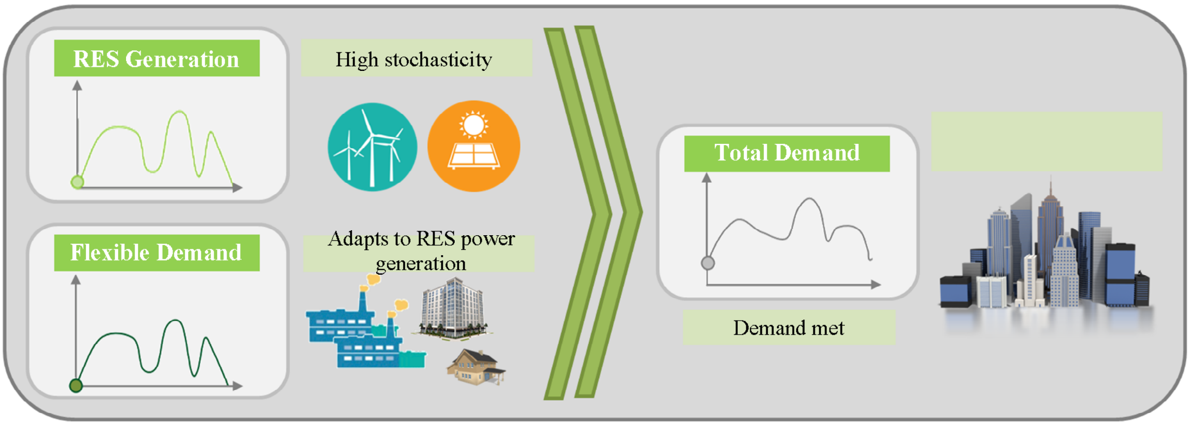


Fig. 1.9. Flexibility options and smart grids.

Therefore, future power grids need to become smarter, allowing multi-directional power flows, and allowing consumers to no longer have a passive role instead to play an active role in the electricity markets [11], [46], [47, p. 21]. Intelligent infrastructures are being developed both at the distribution and transmission levels. Intelligent network projects are being generalized around the world, where budgets have kept on increasing almost exponentially from 2006 [12].

However, the development of smart grids faces a significant set of challenges. In particular, standardization of communication and operational protocols, which will play a key role in future networks, is yet an ongoing process. Energy consumption optimization should be based on near-real time, which requires well-developed communication framework to facilitate the active interactions between producers and consumers. In order to select these communications individually, standardized protocols already exist. However, these are limited to a single domain [48]. With regard to the introduction of smart grids, one of the key tasks in the near future is the establishment of an interactive bidirectional communication system from the generation to the final consumer.

Having smart grids in perspective, the main ways to introduce flexibility into the electric distribution networks are through the introduction of fast markets, flexible generation (e.g. gas and water), demand side management, energy storage systems and interconnections. The smart grids in combination with all other forms of flexibility options mentioned previously will considerably increase the flexibility of the system, overcome congestion in the network systems, either by changing flexible loads from peak periods to periods with less congestion, or through the control of the network power flow due to the integration of large-scale renewables in the near future, among others. This leads to the creation of a more flexible and manageable network. However, the costs and benefits associated with the development of smart grids and network flexibility have direct and indirect effects, as can be seen in the scheme of Fig. 1.10.

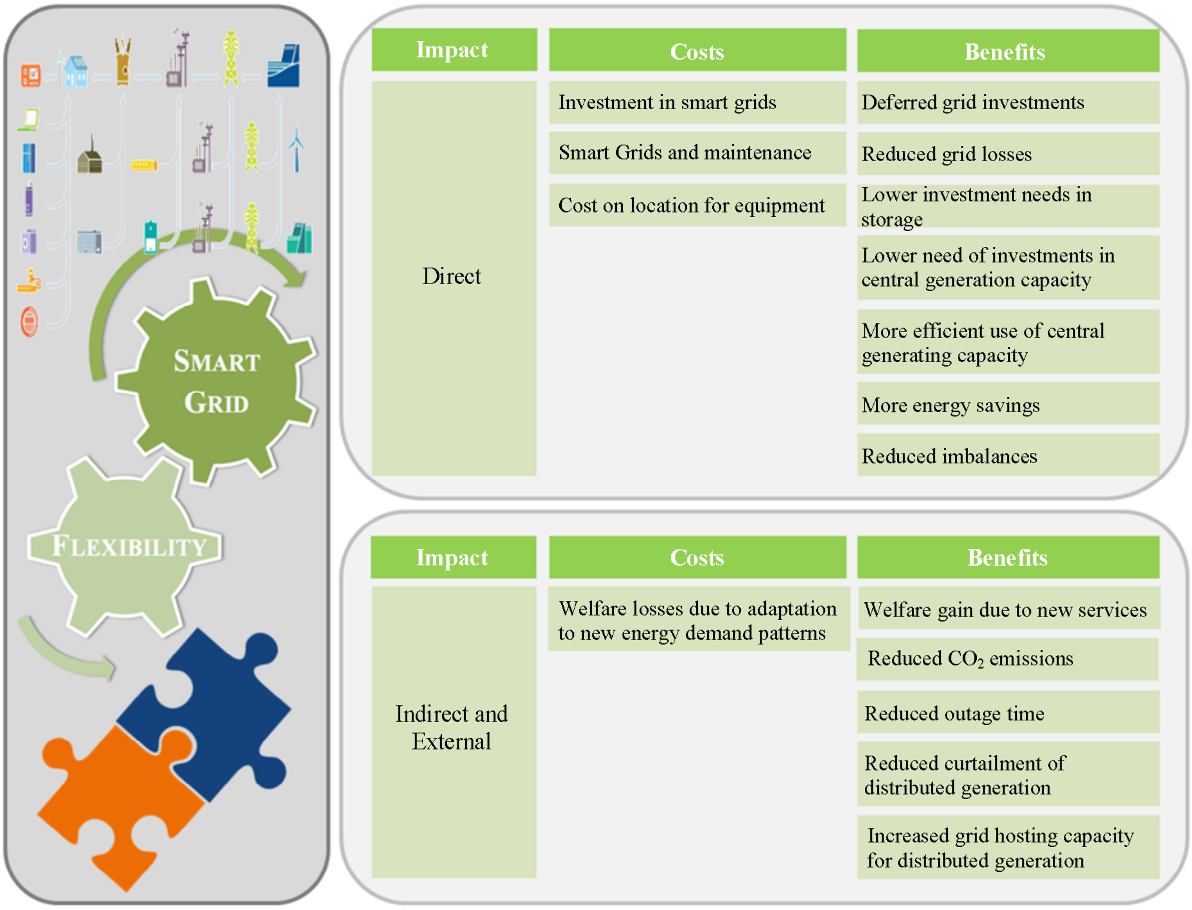


Fig. 1.10. Comparison of potential costs and benefits of developing smart grids and flexibility.

With regard to integrated solutions for low carbon emissions, Smart Grids will be a key element in the implementation of modern technologies. The need for flexibility resulting from the integration of renewable energies, demand and contingencies can be met in different ways, including through flexible generation, response to demand, energy storage and interconnections of the electric distribution networks. All this makes it a key component for the emergence of Smart Grids.

1.3. Managing Distribution Networks Featuring Large-scale Variable Energy Sources

1.3.1 General Problem Description

This chapter develops an optimization model for carrying out detailed analysis of optimally operating distribution network systems featuring large-scale intermittent power sources with the help of various flexibility mechanisms. These mechanisms include dynamic network reconfiguration, energy storage systems, reactive power sources and demand response. A coordinated use of these technologies should lead to increased benefits in distribution network systems such as reduced costs, increased utilization of renewables and others.

The uncertainty inherent to the problem addressed in this chapter is handled by means of stochastic programming. In order to ensure solution exactness and enhance problem tractability, the entire problem is formulated as a stochastic mixed integer linear programming (MILP) optimization model. The accuracy of the analysis is guaranteed because this chapter proposes a model that employs a linearized AC power flow model, which strikes the right balance between accuracy and computational requirement.

1.3.2 Algebraic Formulation

Objective Function

The objective of the formulated DNR problem is to minimize the sum of relevant cost terms, namely, costs of switching, expected costs of operation, unserved power and emissions in the system. This is given as:

$$Minimize\ TC = TSC + TEC + TENSC + TEmiC \tag{1.1}$$

where TC refers to the expected total cost in the system.

The first term in (1.1), TSC, is related to the switching costs as a result of dynamic network reconfigurations. A switching cost is incurred when the status of a given feeder changes from 0 (open) to 1 (closed) or 1 (closed) to 0 (open). This leads to the absolute value of difference in successive switching variables. In order to linearly represent such a module, two non-negative auxiliary variables $x_{l,h}^{+}$ and $x_{l,h}^{-}$ are introduced. Thus, TSC can be expressed as a function of the sum of these variables:

$$TSC = \sum_{k \in \Omega^k} \sum_{h \in \Omega^h} SW_k * \left(x_{k,h}^{+} + x_{k,h}^{-}\right) \tag{1.2}$$

where

$$u_{k,h} - u_{k,h-1} = y_{k,h}^{+} - y_{k,h}^{-};\ y_{k,h}^{+} \geq 0;\ y_{k,h}^{-} \geq 0 \tag{1.3}$$

$$u_{k,0} = 1;\ \forall k \in \Omega^1\ and\ u_{k,0} = 0;\ \forall k \in \Omega^0 \tag{1.4}$$

It should be noted that Ω^1 and Ω^0refer to the sets of normally closed feeders and tie lines (which are normally opened), respectively. However, the status of any of these feeders can change during the course of the day depending on the optimality of the dynamic network reconfiguration.

The second term in (1.1), *TEC*, represents the expected costs of producing power using DGs, operating energy storage systems (ESSs) and importing power from upstream, which is given as in (1.5).

$$TEC = EC^{DG} + EC^{ES} + EC^{SS} \tag{1.5}$$

Each term in (1.5) is calculated as:

$$EC^{DG} = \sum_{s\in\Omega^s} \rho_s \sum_{h\in\Omega^h} \sum_{g\in\Omega^g} OC_g P^{DG}_{g,i,s,h} \tag{1.6}$$

$$EC^{ES} = \sum_{s\in\Omega^s} \rho_s \sum_{h\in\Omega^h} \sum_{es\in\Omega^{es}} \lambda^{es} P^{dch}_{es,i,s,h} \tag{1.7}$$

$$EC^{SS} = \sum_{s\in\Omega^s} \rho_s \sum_{h\in\Omega^h} \sum_{\varsigma\in\Omega^\varsigma} \lambda^{\varsigma}_{h} P^{SS}_{\varsigma,s,h} \tag{1.8}$$

The third term, *TENSC*, captures the expected cost of load shedding. This is calculated as the sum of the costs of unserved active and reactive power as:

$$TENSC = \sum_{s\in\Omega^s} \rho_s \sum_{h\in\Omega^h} \sum_{n\in\Omega^n} (\upsilon^P_{s,h} P^{NS}_{i,s,h} + \upsilon^Q_{s,h} Q^{NS}_{i,s,h}) \tag{1.9}$$

where $\upsilon^{P}_{s,h}$ and $\upsilon^{Q}_{s,h}$ are penalty parameters corresponding to active and reactive power demand curtailment. These parameters should be sufficiently large to avoid undesirably high unserved power.

The last term, *TEmiC*, accounts for the expected cost of emissions as a result of generating power using DGs and importing power through the substation as in (10).

$$TEmiC = EmiC^{DG} + EmiC^{SS} \tag{1.10}$$

Each of the terms in (1.10) are determined by:

$$EmiC^{DG} = \sum_{s\in\Omega^s} \rho_s \sum_{h\in\Omega^h} \sum_{g\in\Omega^g} \sum_{n\in\Omega^n} \lambda^{CO_2} ER^{DG}_g P^{DG}_{g,i,s,h} \tag{1.11}$$

$$EmiC^{SS} = \sum_{s\in\Omega^s} \rho_s \sum_{h\in\Omega^h} \sum_{\varsigma\in\Omega^\varsigma} \sum_{n\in\Omega^n} \lambda^{CO_2} ER^{SS}_{\varsigma} P^{SS}_{\varsigma,s,h} \tag{1.12}$$

Constraints

There are a number of technical and economic constraints that need to be respected all the time to ensure a healthy operation of distribution networks. Kirchhoff's current law states that the sum of all incoming flows to a node should be always equal to the sum of all outgoing flows at any given time. This constraint applies to both active (1.13) and reactive (1.14) power flows, and should be respected all the time:

$$\sum_{g\epsilon\Omega^g} P^{DG}_{g,i,s,h} + \sum_{es\epsilon\Omega^{es}} \left(P^{dch}_{es,i,s,h} - P^{ch}_{es,i,s,h}\right) + P^{SS}_{\varsigma,s,h} + P^{NS}_{i,s,h} + \sum_{in,l\epsilon\Omega^l} P_{l,s,h} - \sum_{out,l\epsilon\Omega^l} P_{l,s,h} = PD^{i}_{s,h} + \sum_{in,l\epsilon\Omega^l} \frac{1}{2} PL_{l,s,h} + \sum_{out,l\epsilon\Omega^l} \frac{1}{2} PL_{l,s,h} \;;\forall\varsigma\epsilon\Omega^{\varsigma};\ \forall\varsigma\epsilon i;\ l\epsilon i \tag{1.13}$$

$$\sum_{g\epsilon\Omega^g} Q^{DG}_{g,i,s,h} + Q^{c}_{c,i,s,h} + Q^{SS}_{\varsigma,s,h} + Q^{NS}_{i,s,h} + \sum_{in,l\epsilon\Omega^l} Q_{l,s,h} - \sum_{out,l\epsilon\Omega^l} Q_{l,s,h} = QD^{i}_{s,h} + \sum_{in,l\epsilon\Omega^l} \frac{1}{2} QL_{l,s,h} + \sum_{out,l\epsilon\Omega^l} \frac{1}{2} QL_{l,s,h} \;;\forall\varsigma\epsilon\Omega^{\varsigma};\ \forall\varsigma\epsilon i;\ l\epsilon i \tag{1.14}$$

As can be seen in (1.13), incoming flows include the active power injected by DGs, inward active power flows in associated feeders, power discharged from ESSs and the amount of power imported (if the bus under consideration is a substation). On the other hand, outgoing flows encompass demand, losses (which are treated here as fictitious loads), outward flows in feeders and charged amount of ESSs.

Power flows in any feeder should also be governed by Kirchhoff's voltage law. This is enforced by including linearized power flow equations, derived by considering two practical assumptions. The first assumption is related to bus voltage magnitudes, which is expected to be close to the nominal value V_{nom} in electric distribution networks. The second one is related to the voltage angle difference θ_k, which is often very small due to practical reasons. The second assumption leads to the trigonometric approximations $\sin\theta_k \approx \theta_k$ and $\cos\theta_k \approx 1$. Given these simplifying assumptions, the well-known AC power flow equations (which are naturally complex nonlinear and non-convex functions of voltage magnitude and angles) can be linearly represented. The linearized active and reactive flows in a line are given by the disjunctive inequalities in (1.15) and (1.16), respectively.

$$\left|P_{k,s,h} - \left(V_{nom}\left(\Delta V_{i,s,h} - \Delta V_{j,s,h}\right)g_k - V^2_{nom} b_k \theta_{k,s,h}\right)\right| \le MP_k(1 - u_{k,h}) \tag{1.15}$$

$$\left|Q_{k,s,h} - \left(-V_{nom}\left(\Delta V_{i,s,h} - \Delta V_{j,s,h}\right)b_k - V^2_{nom} g_k \theta_{k,s,h}\right)\right| \le MQ_k(1 - u_{k,h}) \tag{1.16}$$

where $\Delta V^{min} \le \Delta V_{i,s,h} \le \Delta V^{max}$.

Moreover, power flows in each line should not exceed the maximum transfer capacity, which is enforced by:

$$P^2_{k,s,h} + Q^2_{k,s,h} \le u_{k,h}(S^{max}_k)^2 \tag{1.17}$$

The following constraints are related to the active (1.18) and reactive (1.19) power losses in line k.

$$PL_{k,s,h} = R_k \left(P^2_{k,s,h} + Q^2_{k,s,h}\right) / V^2_{nom} \tag{1.18}$$

$$QL_{k,s,h} = X_k \left(P^2_{k,s,h} + Q^2_{k,s,h}\right) / V^2_{nom} \tag{1.19}$$

Note that the quadratic flows in (1.17)—(1.19) are linearized using a piecewise linearization approach, which is widely used in the literature.

Constraints (1.20)—(1.25) represent the energy storage model employed in this chapter. The amount of power charged and discharged are limited as in (1.20) and (1.21). Constraint (1.22) ensures that charging and discharging operations do not happen at the same time. The constraint related to the state of charge is given by (1.23). The storage level should always be within the permissible range (1.24). Equation (1.25) sets the initial storage level, and makes sure the storage level at the end of the time period is equal to the initial level. For sake of simplicity, both η_{es}^{dch} and η_{es}^{ch} are often set equal.

$$0 \le P_{es,i,s,h}^{ch} \le I_{es,i,s,h}^{ch} P_{es,i,h}^{ch,max} \tag{1.20}$$

$$0 \le P_{es,i,s,h}^{dch} \le I_{es,i,s,h}^{dch} P_{es,i}^{ch,max} \tag{1.21}$$

$$I_{es,i,s,h}^{ch} + I_{es,i,s,h}^{dch} \le 1 \tag{1.22}$$

$$E_{es,i,s,h} = E_{es,i,s,h-1} + \eta_{es}^{ch} P_{es,i,s,h}^{ch} - P_{es,i,s,h}^{dch} / \eta_{es}^{dch} \tag{1.23}$$

$$E_{es,i}^{min} \le E_{es,i,s,h} \le E_{es,i}^{max} \tag{1.24}$$

$$E_{es,i,s,h0} = \mu_{es} E_{es,i}^{max}; \;\; E_{es,i,s,h24} = \mu_{es} E_{es,i}^{max} \tag{1.25}$$

Equations (1.26) and (1.27) impose the active and reactive power limits of DGs, respectively.

$$P_{g,i,s,h}^{DG,min} \le P_{g,i,s,h}^{DG} \le P_{g,i,s,h}^{DG,max} \tag{1.26}$$

$$-\tan\left(\cos^{-1}(pf_g)\right) P_{g,i,s,h}^{DG} \le Q_{g,i,s,h}^{DG} \le \tan\left(\cos^{-1}(pf_g)\right) P_{g,i,s,h}^{DG} \tag{1.27}$$

The reactive power supplied by switchable capacitor banks (SCBs) is limited by inequality (1.28):

$$0 \le Q_{c,i,s,h}^{c} \le x_{c,i,h}\, Q_c^0 \tag{1.28}$$

where Q_c^0 is the minimum deployable unit of a capacitor bank.

For stability reasons, the reactive power at the substation is subject to lower and upper bounds as:

$$-\tan\left(\cos^{-1}(pf_{ss})\right) P_{\varsigma,s,h}^{SS} \le Q_{\varsigma,s,h}^{SS} \le \tan\left(\cos^{-1}(pf_{ss})\right) P_{\varsigma,s,h}^{SS} \tag{1.29}$$

In order to account for demand response, the following constraints corresponding to the responsive active and reactive power demand are added:

$$PD_{s,h}^{i} = PD_{s,h}^{i,0}\left(1 + \sum_{h'} \xi_{h,h'} \left(\frac{\lambda_{s,h'} - \lambda_s^{flat}}{\lambda_s^{flat}}\right)\right) \tag{1.30}$$

$$QD_{s,h}^{i} = QD_{s,h}^{i,0}\left(1 + \sum_{h'} \xi_{h,h'} \left(\frac{\lambda_{s,h'} - \lambda_{s}^{flat}}{\lambda_{s}^{flat}}\right)\right) \tag{1.31}$$

$$\lambda_{s}^{flat} = \frac{\sum_{h} \lambda_{s,h}^{\varsigma}}{24} \tag{1.32}$$

where $PD_{s,h}^{i,0}$ and $QD_{s,h}^{i,0}$ are the active and reactive power loads before demand response. Note that, for the sake of simplicity, the flat price is assumed to be equal to the average electricity price of the day as in (1.32).

Electric distribution networks are normally operated in a radial configuration. Hence, in addition to the aforementioned ones, the radiality constraints in [16] are included in the model developed here. It should be also noted that, in (1.15) and (1.16), the angle difference $\theta_{l,s,h}$ is defined as $\theta_{k,s,h} = \theta_{i,s,h} - \theta_{j,s,h}$ where i and j correspond to the same line k.

1.4. Case Study, Results and Discussions

1.4.1. Input Data and Assumptions

A standard IEEE 41-bus test system, whose single-line diagram is shown in Fig. 1.11, is employed here to perform the required technical and economic analysis. The total active and reactive power demand of this system are 4.635 MW and 3.25 MVAr, respectively. The nominal voltage of the system is 12.66 kV. Further details and information of this test system can be found in [49], [50].

The optimal locations and sizes of various distributed energy resources such as wind and solar type DGs, ESSs and SCBs in [50] are considered in this chapter. The only exception is at bus 14, where, instead of the optimal DG size (3 MW) reported in [50], a 2 MW DG is considered throughout this analysis. To make this chapter self-contained, the input data with regards to reactive power sources, DGs and ESSs are presented in Tables 1.1, 1.2 and 1.3 [50]. Fig. 1.11 also clearly shows the locations of the considered DGs and ESSs. In addition, the following considerations are made when carrying out the simulations:

- The operational analysis spans over a 24-hour period, with the possibility of hourly network reconfiguration.
- The maximum allowable deviation of the nodal voltage at each node is set to ±5% of the nominal value (12.66 kV).
- For all simulations, the substation serves as the reference node, whose voltage magnitude and angle are set equal to the nominal value and 0, respectively.
- The power factor at the substation is set equal to 0.8, and this is held constant throughout the analysis. The power factor of all DG types is considered to be 0.95.
- The emission rate at the substation is arbitrarily set to 0.4 $\mathrm{tCO_2e/MWh}$ while those of solar and wind type DGs are assumed to be 0.0584 and 0.0276 $\mathrm{tCO_2e/MWh}$, respectively.
- The price of emissions is considered to be 7 $€/\mathrm{tCO_2e}$.
- The tariffs of solar and wind power generation are set equal to 40 and 20 $€/\mathrm{MWh}$, respectively.

- Both charging and discharging efficiency of ESSs is 90%.
- The variable cost of operating ESSs is considered as 5 €/MWh.
- The cost of load shedding is 3000 €/MW, and any unserved reactive power is also penalized by the same amount.
- All feeders (including tie-lines) have a maximum transfer capacity of 6.986 MVA, which needs to be respected.
- All big-M parameters are set equal to 20, which is sufficiently large for the considered system.
- The number of partitions considered for linearizing quadratic terms in (1.17)—(1.19) is 5, which is set according to the findings in [51].
- The switching cost parameter is set to 10 €/switching.
- All self-elasticity parameters are set equal to -0.2 while the effect of cross-elasticities is not accounted for in this chapter. This means that cross-elasticity parameters are all considered to be zero.

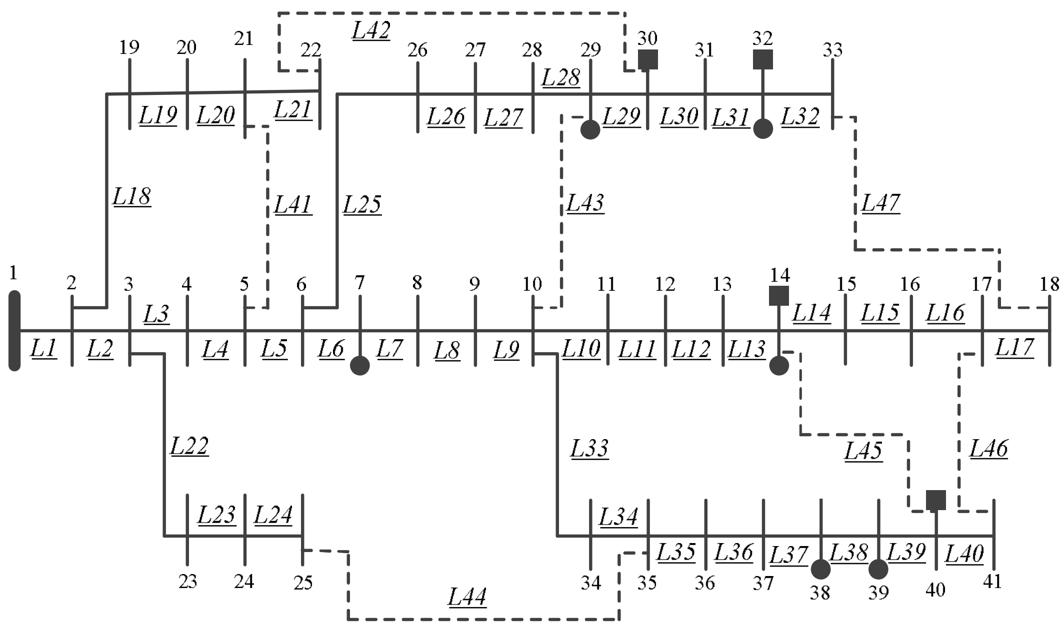


Fig. 1.11. IEEE 41-bus distribution network with new tie-lines (square and circle dots represent the locations of ESSs and DGs, respectively)

Table 1.1. Location and Size of Capacitor Banks

Location (Bus)	Size [MVAr]
7	0.9
14	1.3
24	0.1
25	0.3
29	0.3
30	1
31	0.2
32	0.5
37	0.1
38	2
39	0.1
40	0.6

Table 1.2. Location and Size of DGs

vRES Type	Location (Bus)	Size [MW]
PV	32	1
PV	38	1
Wind	7	1
Wind	14	2
Wind	29	1
Wind	32	1
Wind	38	1
Wind	39	1

Table 1.3. Location and Size of ESSs

Location (Bus)	Size [MW]
14	2
30	1
32	1
40	1

In addition, for the sake of brevity, the energy intensities of solar and wind power sources is considered to be uniform throughout the system nodes. This means that the power generation profiles of solar and wind type DGs are the same in all the nodes where these resources are connected to. Moreover, it is assumed that the energy consumption patterns at all load nodes follow the same trend.

In order to account for the uncertainty pertaining to demand, wind and solar power outputs, six different scenarios are considered for each uncertain parameter, as shown in Figs. 1.12 through 1.14. As can be seen in these figures, each scenario represents possible hourly realizations of the uncertain parameter over the 24-hour period. The individual scenarios are obtained by clustering a larger number of scenarios (30 in this case). These scenarios are then combined to form a new set of 216 (6^3) scenarios that are considered in the analysis.

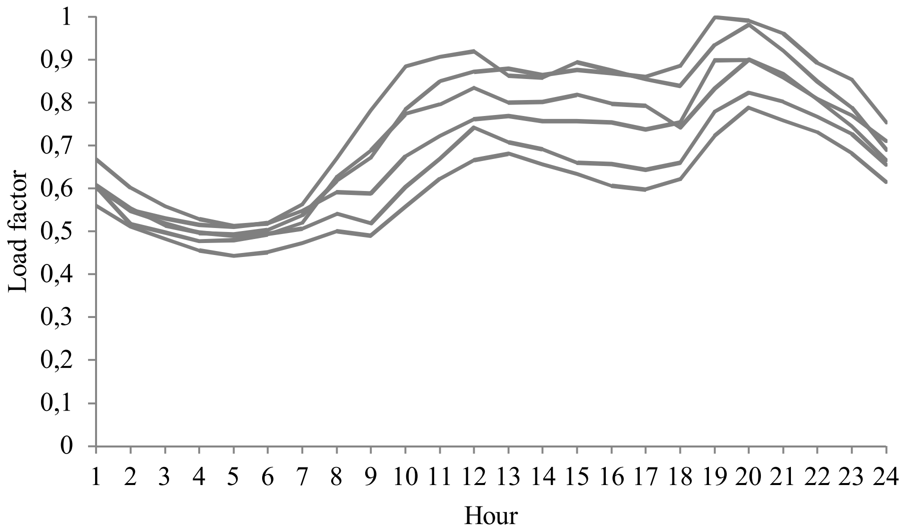


Fig. 1.12. Considered demand scenarios

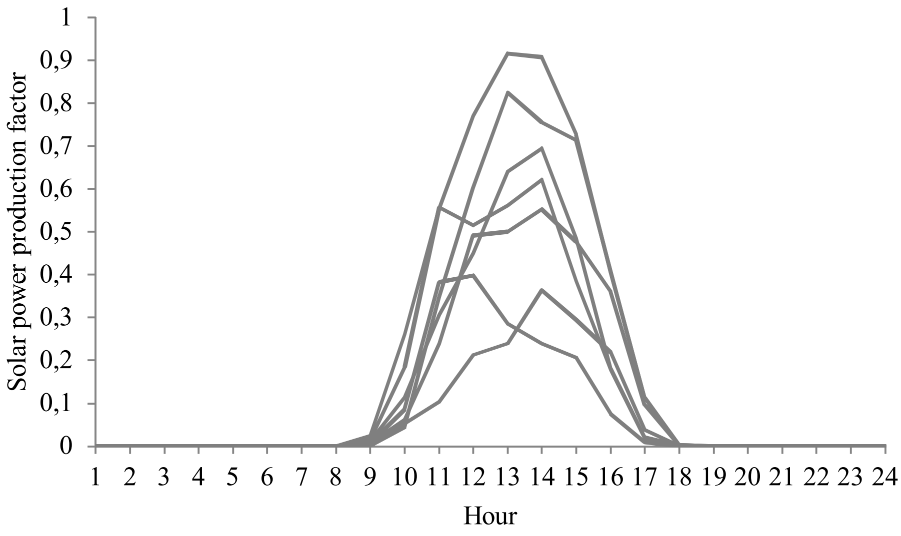


Fig. 1.13. Considered solar PV power output scenarios

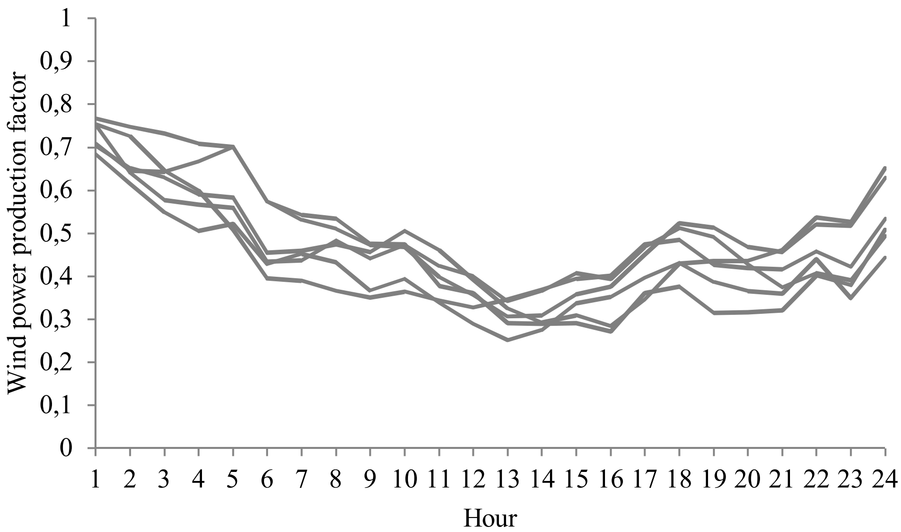


Fig. 1.14. Considered wind power output scenarios

Electricity prices are assumed to follow a similar trend as demand, varying between 107 $€/MWh$ during peak and 30 $€/MWh$ during shallow hours. This is depicted in Fig. 1.15.

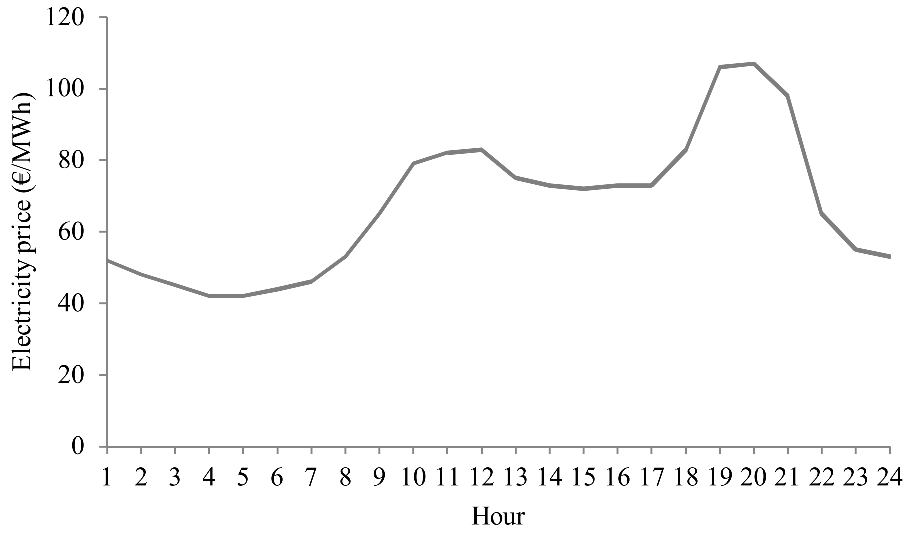


Fig. 1.15. Dynamic electricity price

The potential of DR in the provision of flexibility for integrating vRESs is assessed by considering different self-elasticity values. Fig. 1.16 demonstrates the impact of DR in the hourly consumption profile. In the results section, we shall present analysis results for self-elasticities of -0.2.

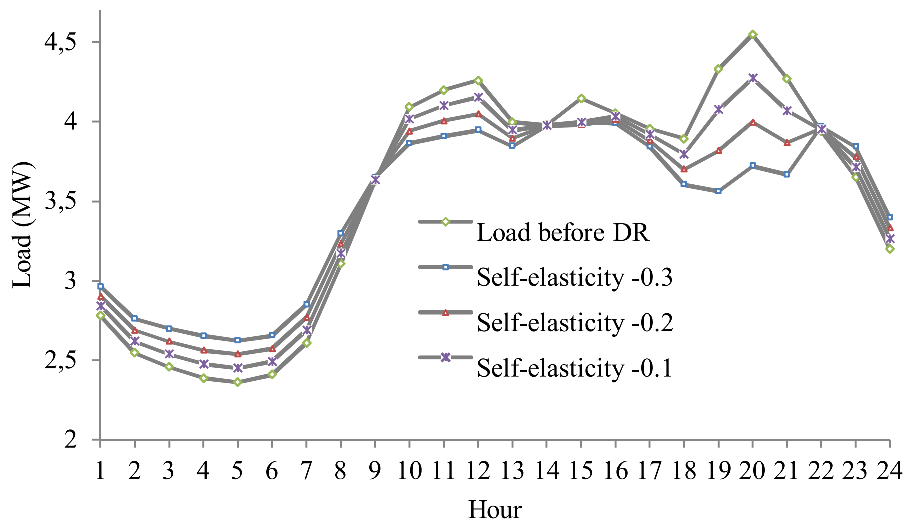


Fig. 1.16. Flexibility via demand response

1.4.2. Numerical Results and Discussions

To ease the aforementioned analysis work, a total of six cases are considered here. Table 4 summarizes the distinctive features of each case. As can be observed in this table, all cases except the first case have two things in common – dynamic network reconfiguration (DNR) and DG integration but differ in other aspects as clearly shown in Table 1.4.

The first case is related to the "do-nothing" scenario, where no distributed energy resource is connected and the entire load is met by importing power via the substation at bus 1. And, this is referred to as the "Base case". The second one considers DG integration with dynamic network reconfiguration, and is hereinafter referred to as "Only DNR". Note that DNR deals with the possibility of optimally changing the statuses of feeders (on an hourly basis) depending on the operational situation in the system. This case helps to understand the possible contribution of DNR in terms of enhancing system flexibility, and thereby increasing vRES utilization level. In addition to DNR, the third case considers switchable capacitor banks as a means of flexibility option. From now onwards, we shall refer this as the "Plus SCBs" case. The fourth and the fifth cases are similar in that both consider the flexibility options provided by DNR, SCBs and ESSs. The only difference between these two cases is that the former does not have DR integrated as an additional flexibility mechanism. These cases are denoted as "Plus SCBs & ESSs" and "Full flex", respectively. The last case only considers the flexibility options: DNR, SCBs and DR, and we shall denote this by "Plus SCBs & DR". Note that lower bound of nodal voltage is relaxed in the base case to avoid infeasibility. This is due to the fact that the original system is poorly compensated. And, under this circumstance, it is not technically possible to meet the high reactive power requirement in this system while simultaneously imposing the voltage limits. For comparison purposes, the average voltage deviation at each bus is presented in Fig. 1.17. This also displays the minimum and maximum average values corresponding to different operational situations. We can observe that most of the voltages fall outside the permissible range, particularly at the nodes located far away from the substation. The lowest voltage deviation occurs at bus 41, which can reach 18% in some operational situations.

Table 1.4. Details of the cases considered in the analysis

	Features					
Cases	DNR	DGs	SCBs	ESSs	DR	Voltage limits
Base case	No	No	No	No	No	Not imposed
Only DNR	Yes	Yes	No	No	No	Imposed
Plus SCBs	Yes	Yes	Yes	No	No	Imposed
Plus SCBs & ESSs	Yes	Yes	Yes	Yes	No	Imposed
Full flex	Yes	Yes	Yes	Yes	Yes	Imposed
Plus SCBs & DR	Yes	Yes	Yes	No	Yes	Imposed

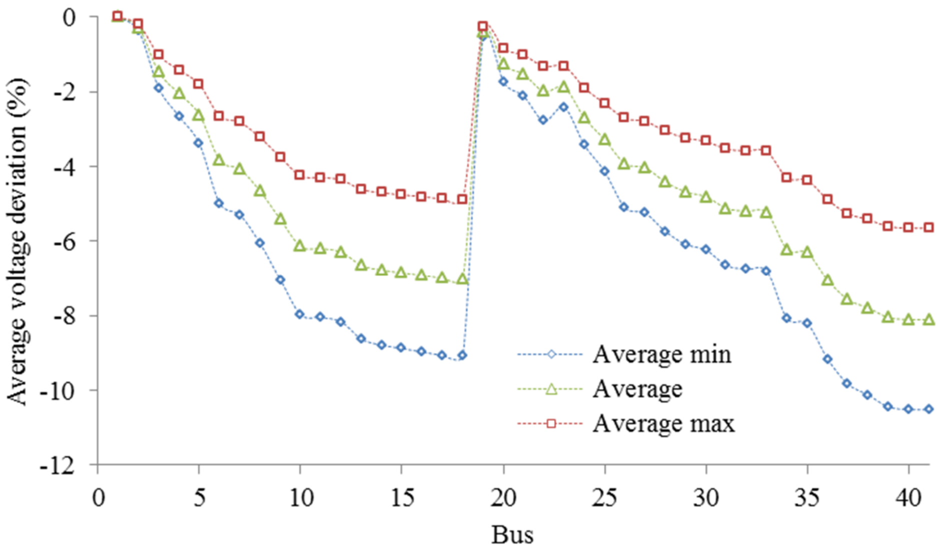


Fig. 1.17. Average voltage deviation profiles with no flexibility options (base case)

Table 1.5 compares the objective function values and average losses corresponding to the different cases considered in the analysis. Compared to the base case, we can see that there are substantial improvements in the values of the designated function and variables. In the "Only DNR" case, for example, the total cost is reduced by about 9% and average losses by 24%. However, the vRES penetration level in this particular case (which stands at 12.2%) is not significant; solar PV and wind type DG utilization levels are only 0.4% and 11.8%, respectively. The wind and solar PV power sources are not being utilized because of technical constraints mainly related to the voltage limits. Since the system is not well-compensated, more power needs to be imported to support the high reactive power requirement in the system. Injecting more active power from the DGs, without proper compensation, would otherwise lead to voltage hikes which is not acceptable. Fig. 1.18 shows the energy mix in the "Only DNR" case. Based on these results, it seems DNR alone may not contribute enough to enahce vRES penetration level in electric distribution networks. However, this may be case-dependent. Moreover, some of the assumptions made in this chapter may not reflect the real potential of DNR as a key flexibility option. For example, the assumptions on the uniform patterns of electricity consumptions and vRES power outputs may not encourage more frequent reconfigurations of the network so as to adapt to varying operational situations.

Table 1.5. Total expected costs and average losses for the considered cases

		Average losses (MW/h)		
Cases	Total cost (€)	Active	Reactive	Voltage limits
Base case	6036.281	0.275	0.201	Not imposed
Only DNR	5512.385	0.208	0.158	Imposed
Plus SCBs	2677.782	0.073	0.058	Imposed
Plus SCBs & ESSs	2229.248	0.096	0.075	Imposed
Full flex	**2151.926**	0.093	0.073	Imposed
Plus SCBs & DR	2522.484	**0.072**	**0.057**	Imposed

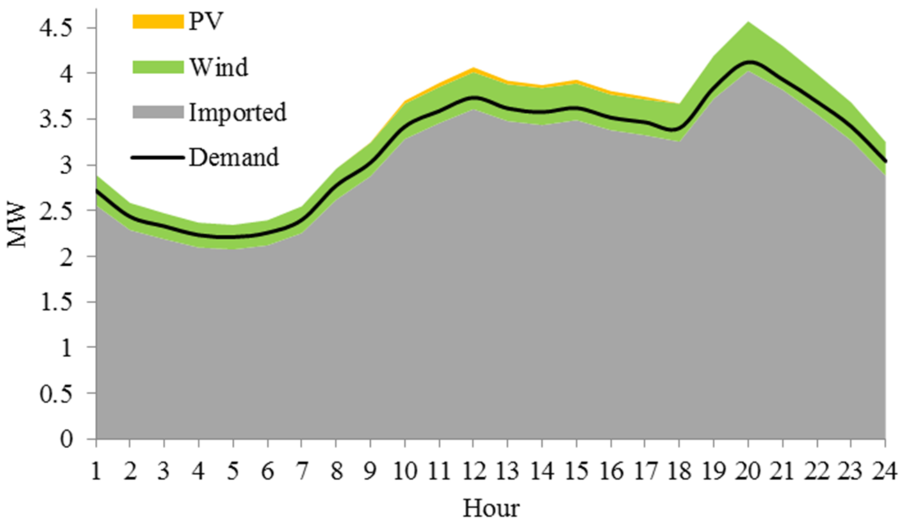


Fig. 1.18. Aggregate energy mix in the system in the “Only DNR” case

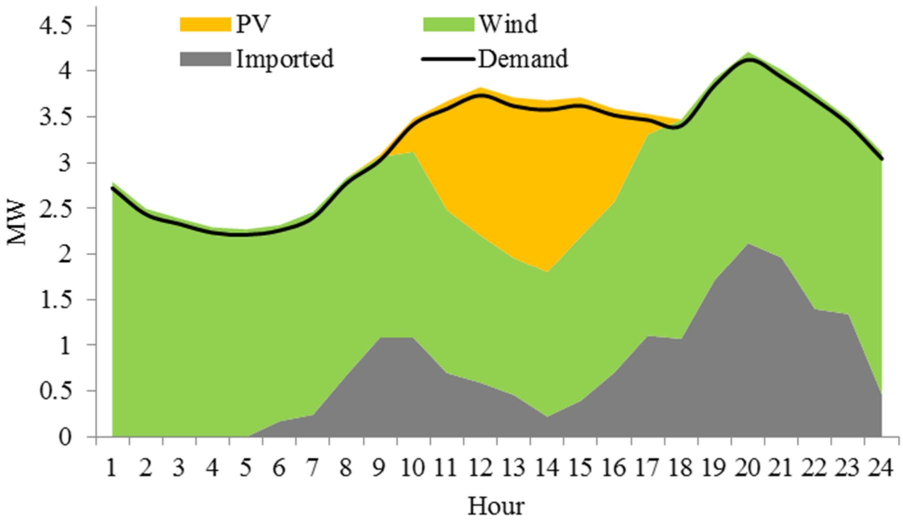


Fig. 1.19. Aggregate energy mix in the system corresponding to the "Plus SCBs" case

In the case of "Plus SCBs", the results in Table 1.5 show that the reduction in total cost and losses is simply dramatic, and so is the level of vRES penetration. Compared to the base case, costs are slashed by about 56% while the reduction of losses amounts to more than 73%. In this case, solar PV and wind cover about 12.6% and 66.8% of the aggregate demand in the system over the whole day. The energy-mix corresponding to this case is depicted in Fig. 1.19. As we can see, there are hours where the system operates in island mode (see the first four hours). This mean the demand in these hours is fully met by locally produced renewable power. Generally, the results here reveal the substantial benefits of SCBs in enabling a large-scale penetration of variable energy resources. In other words, a properly compensated distribution network can manage the technical risk posed by the intermittent nature of such resources.

As can be observed in Table 1.5, the overall cost is further reduced in the "Plus SCBs & ESSs" case by 63% in comparison to that of the base case. However, losses are slightly higher in this case than in the "Plus SCBs" one. This is mainly because of the fact that some feeders carry more power to charge/discharge the ESSs as opposed to the "Plus SCBs" case. It should be noted that the losses are yet substantially lower than that of the base case by 65%. The presence of ESSs in the "Plus SCBs & ESSs" case further increases the flexibility of the system, and allows a more efficient utilization of the "cleaner" DG power. This is can be seen in Fig. 1.20. One interesting observation in this figure is that the system operates autonomously during peak hours by releasing the cheaper energy stored in the ESSs during valley and off-peak hours. Here, solar and wind power contribute 14.3% and 72.2% to the total energy consumption during the whole period. This means the total penetration level of vRESs reaches 86.5%, which is very high by any standard.

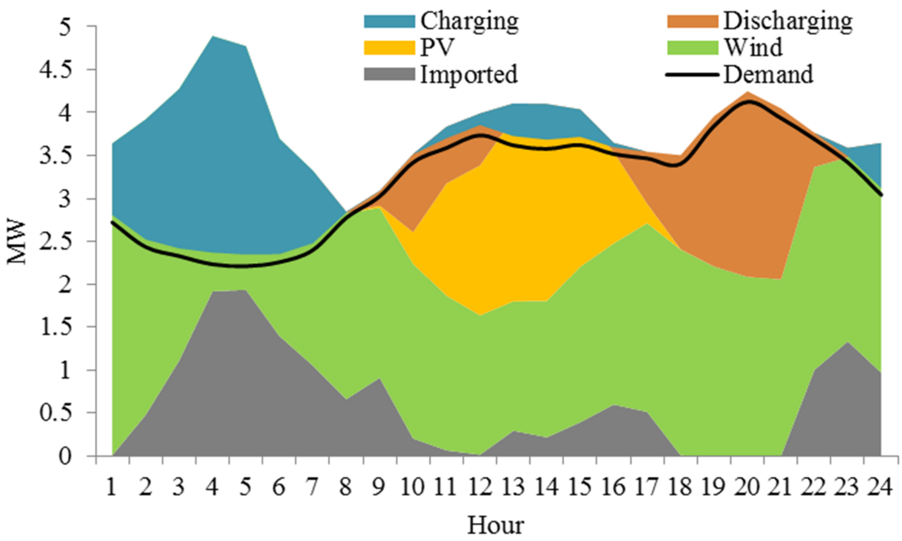


Fig. 1.20. Aggregate energy mix corresponding to the “Plus SCBs & ESSs” case

The results in Table 1.5 also demonstrate that the introduction of DR, as in the “SCBs & DR” case, improves the flexibility of the system, and leads to the lowest losses (with an approximately 74% reduction in comparison to the base case). This is because of the relatively reduced amount of flows in the feeders especially during peak hours. Likewise, the total cost here is reduced by about 58%. This is higher by 2% than that of the “Plus SCBs” case. The aggregate energy mix corresponding to the “SCBs & DR” case is shown in Fig. 1.21. The shares of wind and solar PV power production over the whole period are 12.4% and 67.9%, respectively, which brings the total vRES penetration level to 80.3%. Because of the absence of a storage medium, this value is lower than the 86.5% share in the “Plus SCBs & ESSs” case.

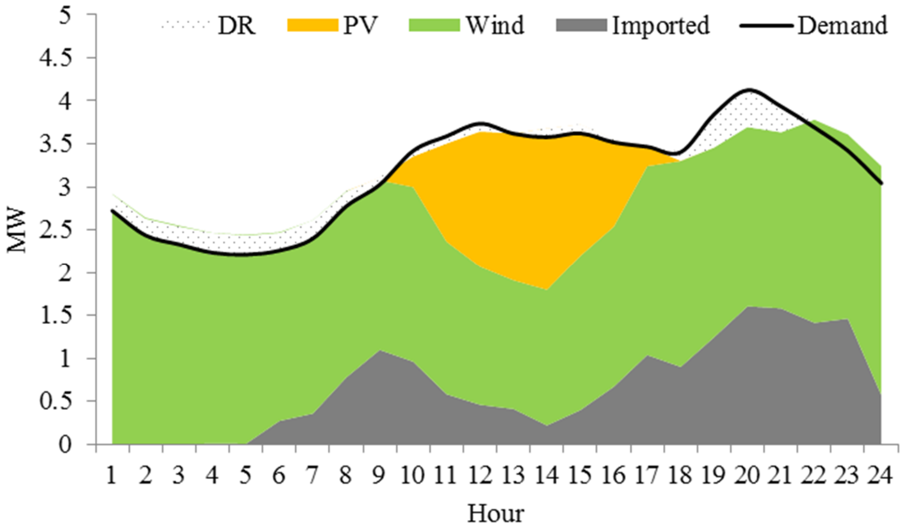


Fig. 1.21. Aggregate energy mix corresponding to the “SCBs & DR” case

As mentioned earlier, the "Full flex" case jointly deploys all four technologies that are capable of providing flexibility to the system: DNR, SCBs, ESSs and DR. As expected, this case leads to the lowest overall cost in the system (i.e. about 64% lower than that of the base case). As can be seen in Table 1.5, the benefit in terms of losses reduction is also evident even though this is slightly higher than that of the "Plus SCBs & DR" due to the same reasons as before. Because of the increased system flexibility in the "Full flex" case, the amount of imported energy is significantly lower than that of any other case. The total share of vRES power production reaches 86.6% (see Fig. 1.22). Wind and solar PV type DGs each contribute 14.4 and 72.2%, respectively.

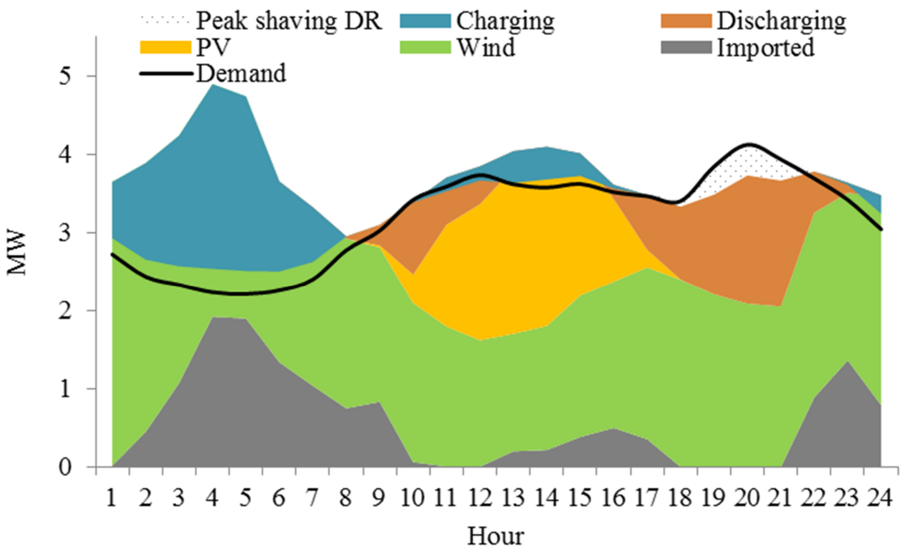


Fig. 1.22. Aggregate energy mix corresponding to the "Full flex" case

So far, the analysis has been in terms of cost, energy mix and losses. Obviously, these are all relevant factors. However, it is also important to analyze the performance of the system from the technical point of view. To this end, the voltage profile is a good indicator. Ideally, voltage deviations in all nodes are desired to be close to the nominal value. But the nodal voltages often vary within certain permissible range (which in our case is 1 ± 5% of the nominal voltage). Fig. 1.23 shows average deviations of voltages at every node in the system for all the cases considered in this chapter. This figure clearly shows that the introduction of flexibility mechanisms dramatically improve the voltage profile within the system. This is very critical to maintain the healthy operation of such a system. The "Only DNR" case alone keeps the voltages within the allowable range. For the remaining cases, the average voltage deviations for most of the nodes are practically insignificant, averaging at about 1%.

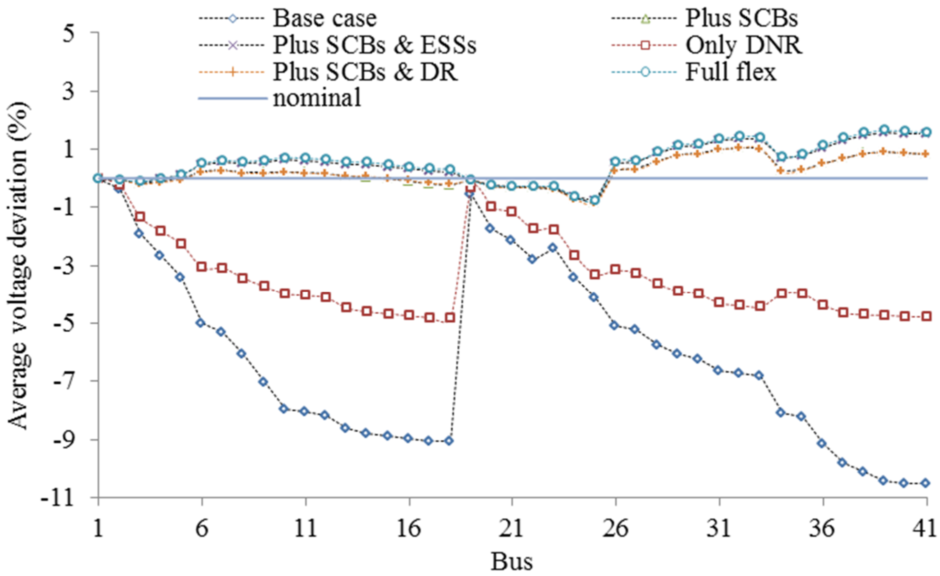


Fig. 1.23. Comparison of average voltage profiles for the different cases

The benefits of all flexibility options considered in this chapter are evident with significant impact in achieving minimization of total costs of operation in the distribution networks. Analysis of jointly or separated operation of ESSs, capacitor banks, vRES and switching substantially improved voltage profiles. Operation of distribution networks with DR show the capability that this technology can have in the utilization of ESSs, making it a more valuable solution during operation, with less impact on total costs, increasing its utilization.

1.5. Conclusions

This chapter has provided an overview of the technical challenges of integrating intermittent power sources (wind and solar in particular) in electric distribution networks. Due to growing concerns on climate change, energy security and other associated issues, integration of such resources cannot be postponed or overlooked, instead, carried out in tandem with enabling technologies. To this end, various flexibility options such as demand response, switchable reactive power sources and energy storage systems are explored to ensure effective utilization of large quantities of wind and solar power. Therefore, the main focus of this chapter is on the optimal management of distribution networks featuring such flexibility options and variable renewables. To support this analysis, this chapter introduces a stochastic MILP operational model. The stochastic model is formulated based on a linearized AC network model, which captures the physical characteristics of the system in a reasonably accurate manner. The optimization model minimizes the sum of relevant cost terms while satisfying a number of techno-economic constraints.

The analysis is supported by numerical results from a standard IEEE 41-bus network system. According to the numerical results, the deployment of any flexibility option considered here results in a more efficient utilization of wind and solar power integrated in the system. In particular, as high as 86.6% penetration level of such resources has been possible in the case study without negatively affecting the stability and integrity of the system as well as the quality of power delivered to the consumers. Moreover, costs and losses are substantially reduced. Generally, the overall system performance especially the voltage profile is improved dramatically. The results and analysis in this book chapter have policy implications that are important to optimally design ad operate future grids, featuring large-scale variable energy resources. As a general conclusion, the results in this chapter highlight the possibility of distribution networks going 100% renewable provided that various flexibility options are adequately deployed and operated in a more efficient and coordinated manner.

Appendix–1.A

1.A.1. Sets/Indices

$\mathrm{c}/\Omega^{\mathrm{c}}$	Index/set of capacitor banks
$\mathrm{es}/\Omega^{\mathrm{es}}$	Index/set energy storages
$\mathrm{i}/\Omega^{\mathrm{i}}$	Index/set of buses
$\mathrm{g}/\Omega^{\mathrm{g}}/\Omega^{\mathrm{DG}}$	Index/set of generators/DGs
$\mathrm{k}/\Omega^{\mathrm{k}}$	Index/set of branches
$\mathrm{h}', \mathrm{h}/\Omega^{\mathrm{h}}$	Index/set of hourly snapshots
$\mathrm{s}/\Omega^{\mathrm{s}}$	Index/set of scenarios
$\varsigma/\Omega^{\varsigma}$	Index/set of substations

1.A.2. Parameters

SC_k	Cost of switching of branch k (€ per single switching)
$E_{es,i}^{min}, E_{es,i}^{max}$	Energy storage limits (MWh)
$ER_g, ER_{\varsigma}^{SS}$	Emission rates of DGs, and energy purchased, respectively (tCO_2e/MWh)
g_k, b_k, S_k^{max}	Conductance, susceptance and flow limit of branch k ($\Omega, \Omega,$ MVA)
MP_k, MQ_k	Big-M parameters associated to active and reactive power flows through branch k
$OC_{g,i,s,h}$	Operation cost of unit energy production by DGs (€/MWh)
N_i, N_{ς}	Number of buses and substations, respectively
$P_{es,i}^{ch,max}, P_{es,i}^{dch,max}$	Charging and discharging power limits of storage system (MW)
V_{nom}	Nominal voltage (kV)
Z_k	Impedance of branch k (Ω)

$\lambda_{s,h}^{CO_2e}$	Price of emissions (€/tCO_2e)
$\lambda_{s,h}^{\varsigma}$	Price of electricity purchased upstream (€/MWh)
$\overline{\lambda_s^{\varsigma}}$	Average price of electricity purchased upstream (€/MWh)
$\lambda_{es,i,s,h}^{dch}$	Cost of energy discharged from storage system (€/MWh)
$\eta_{es}^{ch}, \eta_{es}^{dch}$	Charging and discharging efficiency (%)
ρ_s, π_w	Probability of hourly scenario s and weight (in hours) of hourly snapshot group h
$\upsilon_{s,h}$	Penalty for unserved power (€/MW)
$\xi_{h,h'}$	Elasticity of electricity demand

1.A.3. Variables

$PD_{s,h}^i, QD_{s,h}^i$	Active and reactive power demand at node *i* (MW, MVAr)
$E_{es,i,s,h}$	Reservoir level of ESS (MWh)
$I_{es,i,s,h}^{dch}, I_{es,i,s,h}^{ch}$	Discharging/charging indicator variables
$P_{g,i,s,h}, Q_{g,i,s,h}$	Active and reactive power produced by DGs (MW)
$P_{\varsigma,s,h}^{SS}, Q_{\varsigma,s,h}^{SS}$	Active and reactive power imported from grid (MW)
P_k, Q_k, θ_k	Active and reactive power flows, and voltage angle difference of link k (MW, MVAr, radians)
PL_k, QL_k	Active and reactive power losses (MW, MVAr)
$PL_{\varsigma,s,h}, QL_{\varsigma,s,h}$	Active and reactive power losses at substation ς (MW, MVAr)
$P_{es,i,s,h}^{dch}, P_{es,i,s,h}^{ch}$	Discharged/charged power (MW)
$P_{i,s,h}^{NS}$	Unserved power at node *i* (MW)
$Q_{i,s,h}^{c}$	Reactive power produced by capacitor bank at node i (MVAr)
$Q_{i,s,h}^{NS}$	Unserved power at node *i* (MW)
V_i, V_j	Voltage magnitudes at nodes *i* and *j* (kV)
$u_{k,h}$	Utilization variables of existing lines
$x_{c,h}$	Integer variable of switchable capacitor banks

θ_i, θ_j Voltage angles at node *i* and *j* (radians)

$\lambda_{s,h'}$ Real-time price of electricity (€/MWh)

1.A.4. Functions (all units are in M€)

EC_h^{SS} Expected cost of energy purchased from upstream

EC_h^{DG} Expected cost of energy purchased from DG

EC_h^{ES} Expected cost of energy purchased from energy storage

$ENSC_h$ Expected cost of unserved power

$EmiC_h^{DG}$ Expected emission cost of DG power production

$EmiC_h^{SS}$ Expected emission cost of purchased power

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