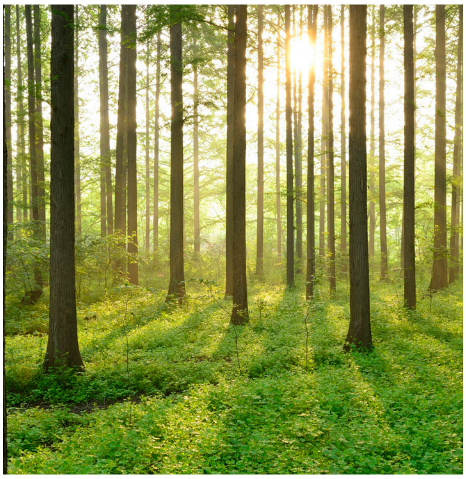
ECONOMIC REGULATION IN POWER DISTRIBUTION

REPORT 2017:362



SMARTA ELNÄT – SMART GRID

Energiforsk

Economic Regulation in Power Distribution

Economic Regulation Impact on Electricity Distribution Network Investment Considering Distributed Generation

YALIN HUANG

ISBN 978-91-7673-362-2 |

Energiforsk AB | Phone: 08-677 25 30 | E-mail: kontakt@energiforsk.se | www.energiforsk.se

Foreword

In the future, more distributed generation will be connected to distribution and regional electrical networks. One of the EU's climate goals for 2020 is that 20% of EU electricity consumption will come from renewable electricity that mostly is from distributed generation. A lot of the investment in renewable electricity production in Sweden will probably be in the wind, because the Energy Agency proposed a planning target of 30 TWh of wind power by the year 2020. Given the network owners technical requirements, power generators independently decide which investments should be implemented and where to connect the distributed generation to distribution and regional network. The network owners must enable connection of distributed generation and also meet the requirements of power quality and reliability at a reasonable cost. An uncertainty is connected with the distributed generation. How will it affect the network companies network planning?

This project analyze how the distributed generation affects the reliability and the consequences of power outages.

Yalin Huang from the Royal Institute of Technology has been the project manager for the project. She has worked together with Lennart Söder who is professor in Electric Power Systems at KTH.

Many thanks to the program board for good initiative and support. The program Board consisted of the following persons:

- Jenny Paulinder, Gothenburg Energy (Chairman)
- Lars Enarsson, Ellevio
- Jonas Alterbäck, Svk
- Hans Andersson, Vattenfall Distribution
- Kenny Granath, Mälarenergi Electric Networks
- Par-Erik Petrusson, Jämtkraft
- Magnus Brodin, Skellefteå Kraft Electric Networks
- Ola Löfgren, FIE
- Anders Richert, Elsäkerhetsverket
- Carl Johan Wallnerström, the Inspectorate
- Susanne Olausson, Energy Research Institute (Program)

The following companies have been involved as stakeholders in the project. A big thanks to all the companies for their valuable contributions.

- Ellevio AB
- Swedish power grids,
- Vattenfall Distribution AB
- Energy AB Gothenburg,
- Ellinorr AB
- Jämtkraft AB,
- Mälarenergi Electricity Networks Ltd.,
- Skellefteå Kraft AB Electric Networks,
- AB PiteEnergi,

- Energigas Sweden,
- Jönköping Energy Networks AB
- Boras Elnät AB
- Industrial Electric Power Engineering Society, FIE

Stockholm, January 2017

Susanne Olausson
Energy Research Institute of Sweden AB
Research Area Networks, Wind and Solar electricity

Summary

One of EU's actions against climate change is to meet 20% of energy consumption from renewable resources by the year 2020 when the project was started. Now this target has increased to at least 27% by the year 2030. In addition, given that the renewable resources are becoming more economical to generate electricity from and that these resources are distributed geographically, more and more distributed generation (DG) is connected to power distribution. The increasing share of DG in the electricity networks implies re-distribution of costs and benefits among distribution system operators (DSOs), customers and DG owners. How the costs and benefits will be allocated among them depends on the established economic regulation.

The established economic regulation regulates the DSOs' revenue and performances. The time when the DSOs are remunerated based on their actual costs has passed. Nowadays the economic regulation is in place to steer efficient investments. Network investments are no longer just to satisfy the load growth, or to higher the investments does not bring higher revenue. Network investments are incentivised by the regulation to be more efficient. Furthermore, the potential of DG to defer network investment is widely recognized in the regulation. Ignoring this potential of DG may decrease DSOs' efficiency. Last but not the least, network unbundling is a common practice in Europe. Ignoring the fact that DSOs and DG owners are different decision makers in studies can lead to inaccurate analysis.

Driven by the target of a higher DG integration and more efficient investments in the unbundled distribution networks, proper economic regulations are needed to facilitate this change. The objective of this project is to evaluate the impact from regulations on distribution network investment considering DG integration. In other words, this project aims to develop methods assist regulators to design desirable regulations to encourage the DSOs to make the "smart" decisions. In order to achieve that, a modelling approach is proposed to quantify the economic regulation impacts and the benefit of innovative investments. Regulations are encoded into the network investment model. The developed models, in other words, assist DSOs to make the "right" investment in the "right" place at the "right" time under the given regulation.

Sammanfattning

Mer och mer distribuerad generering kommer i framtiden anslutas till lokal- och regionnäten. Ett av EU:s klimatmål till år 2020 är att 20 % av EU:s elkonsumtion ska komma från förnyelsebar elproduktion som till stor del består av distribuerad generering. Många av investeringarna i förnyelsebar elproduktion i Sverige kommer troligtvis att ske i vindkraft, eftersom Energimyndigheten har föreslagit ett planeringsmål på 30 TWh vindkraft till år 2020. Nätägarna ska möjliggöra anslutning av distribuerad generering samtidigt som de måste uppfylla krav på elkvalitet och tillförlitlighet till en rimlig kostnad. Osäkerheten i var distribuerad generering ansluts kommer att påverka elnätsföretagens nätplanering. Den ökade andelen distribuerad generering i lokal- och regionnäten kommer att medföra både ökade kostnader och ökade vinster för nätägare, kunder och elproducenter. Hur mycket distribuerad generering som ansluts och hur kostnader och vinster ska fördelas mellan aktörerna i elbranschen kommer till en stor del att avgöras av vilka regelverk som upprättas.

Vilka blir de ekonomiska konsekvenserna av olika strategier för nätutbyggnad för distribuerad generering? Ska en nätägare få ekonomiska incitament för att ha varit kostnadeffektiv? Hur kompenseras producenter vid bortkoppling? Alla dessa frågeställningar beror på vilken avkastning regleringen tillåter samt hur andra delar av regleringen utformas. I detta projekt har matematiska metoder som kan ta hänsyn till osäkerheter kring hur mycket distribuerad generering som kommer att anslutas till näten har utvecklats för att utvärdera investeringsalternativ. Med hjälp av de utvecklade metoderna kan den optimala nätutbyggnaden givet en viss reglering identifieras. Man kan därmed få en bättre uppskattning av vilken utbyggnad man får beroende på hur nätregleringen är utformad. Dessutom kan man med dessa metoder utreda hur nätregleringen påverkar nätinvestering och föreslå mer effektiv nätreglering.

Contents

Chapter 1

Introduction

Economic regulation in power systems

Regulation conveys different meanings in different contexts in power systems. It can appear in the context of security or the environment as social regulation [1], where regulation seeks to protect workers' safety and the environment. It can appear in the context of power system operation as frequency regulation. This kind of regulation seeks to maintain the balance between generation and load. It can appear in the context of electricity market, the network investment supervision and network tariff designs as economic regulation. In this project, the economic regulation in power distribution is the focus. The following elements are defined as the basic scope of economic regulation in power systems [1]:

- *The design of rules for steering agents' behaviour towards the objectives defined by the regulator.*
- *The definition of the structure of the power industry, e.g. a vertically integrated or unbundled structure. For either structure, an appropriate business model is needed.*
- *The supervision of agents' behaviour. This involves reviewing their effectiveness to achieve the defined objectives and taking legal actions.*

The agents, in power systems, are referred to as utilities or service providers in the electricity industry. Traditionally power systems were vertically integrated world wide. In this type of structure, one utility has the monopoly on all functions from generation, transmission to distribution in power systems. These functions are illustrated in Fig. 1.1. The voltage levels for transmission and distribution lines differ among countries. The price of electricity is regulated. The utility's investment and operating practices are supervised by the government regulator.

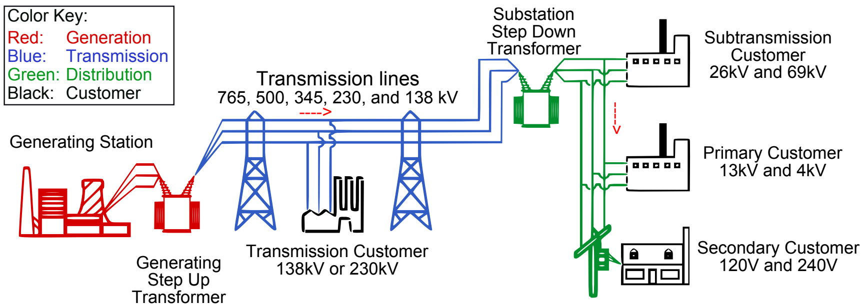


Figure 1.1: Simple diagram of electricity grids [2].

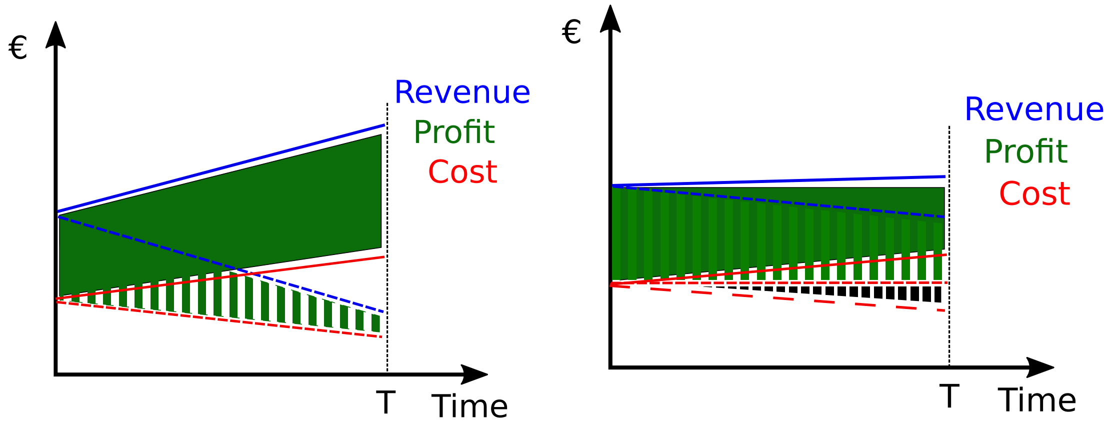
Since the end of the last century this traditional structure has changed in many countries. Chile started this process in 1982, followed by England and Wales, Norway, Sweden and some countries in South America. The main content of this change was to introduce market platforms for electricity trade [1]. Electricity wholesale markets and retail markets have been introduced for the electricity production and retail activities respectively. However, the transmission and distribution networks have remained to be monopolies, which are owned by either independent organisation, private investors, municipalities or the government. Therefore, electricity generation and trading are unbundled from the network activities. The "agents" in the unbundled power systems are referred to all service providers of the electricity generation, transmission, wholesale, distribution, retail, etc. The regulators can be an authority or a public body or a private body independent from the interests of the electricity industry according to the EU directive [3]. This change requires modification in power system planning and operation. It also requires new economic regulation for steering electricity market's and network companies' behaviour and new rules to review the effectiveness.

A distinction is drawn between the regulation for the electricity market and the network companies which are categorised as natural monopolies [4]. Regulation for the electricity market aims to ensure a competitive trading platform, for example, a minimum number of competitors, to correct monopolistic markets or imperfect information [1]. Regulation for network companies aims to ensure the economic and financial sustainability of the companies, and productive efficiency [4]. In other words, the regulation for network companies aims to ensure that the companies offer the lowest possible price without going bankrupt in the long-term. This project focuses on the area of regulation for network companies.

Many regulatory variables to assist the regulator to reach this goal are found in practise. One is the regulation of the revenues. The allowed revenues should be high enough to sustain the company and should not be so high that the consumers pay unjustifiably high prices. Another variable is to set quality standards and performance incentives. Quality standards are the requirements that the utilities have to meet. For example, reliability of supply, the voltage quality, etc. These requirements can be linked to the regulation of the revenues. Performance incentives are economic incentives to encourage the company perform better. For example, reducing the thermal losses in the network. Performance incentives can also be linked to the revenue regulation.

Many deregulated power systems have moved from the traditional cost-of-service regulation to incentive-based regulation on the revenue. In cost-of-service regulation, also known as rate-of-return regulation, the revenue that a network company is allowed to receive is based on the total cost, where the investment cost is compensated by an allowed rate-of-return set by the regulator [1]. The tariffs charged by the company are also set by the regulator. This regulation is implemented with slightly variations in different systems. However, incentive-based regulation is implemented in very different forms. The most common form is the revenue cap regulation, such as in Austria, Spain and Sweden, [5]. Under this design, the maximum yearly revenue of a company for a certain period is set by the regulator. The revenue target is set based on the historical performance with some efficiency measures and inflation adjustment.

Under the cost-of-service regulation, the increase of cost leads to a higher revenue and a higher profit of the utility as demonstrated in Fig. 1.2a. Two scenarios are demonstrated in this figure, one is the scenario where the cost increases; the other one is the scenario where the cost decreases. The profit is the difference between the revenue and the cost, which is marked by a shaded area in the figure. If the cost decreases, the profit decreases as well in Fig. 1.2a. Therefore, the cost-of-service regulation is not encouraging any "smart" investment. However, under the revenue cap regulation, if the cost increases more than the efficiency requirement, as indicated by the solid red line and dotted red line respectively in Fig. 1.2b, the profit decreases. If the company can improve the efficiency better than the regulator expected, which is indicated by the lower dashed red line, the profit for the company increases. The "extra" profit due to the extra efficiency improvement is indicated by the black strips. Therefore, the company has a significant incentive to reduce the cost.



(a) Profits under cost-of-service regulation. (b) Profits under revenue cap regulation.

Figure 1.2: DSO's profit over time under different economic regulations.

Another form of the incentive-based regulation is the price cap regulation, for example in the United Kingdom a few years ago[5]. In the price cap regulation, the maximum price that the company can charge the consumers is set by the regulator. It provides incentives to reduce costs as in the revenue cap regulation; however, it also provides incentives to increase electricity sales [4]. The increase of electricity sales may have little impact on the network infrastructure cost; therefore, with higher sales the company can receive a higher revenue and consequently a higher profit. Therefore, the price cap regulation is less compatible with energy efficiency goals than the revenue cap regulation.

In the incentive-based regulation, the high focus on the cost reduction may lead to deterioration of the quality of service. Therefore, other two regulatory variables, quality standards and performance incentives, are often applied to complement it [4]. If the company fails to satisfy the quality standards, it can lead to penalties.

Performance incentives can be positive or negative. They are often integrated in the revenue cap setting formula. A company's revenue cap may be increased or decreased depending on the performance incentives. Regulators need to define the correct and effective incentives to steer the performance. Therefore, methods to model different performance incentives, economic regulatory framework and the network investment are necessary for regulators to analyse the regulation impact on network cost and performances.

Distributed generation

Not only the regulation schemes changed in power systems in the recent years, power flows in the system have also changed. With the liberalisation of electricity markets and environmental concerns, distributed generation (DG) has developed rapidly [6]. With the development of technologies, the cost of DG units decreases. This also contributes to a further increase of DG installation [7]. The definition of DG in [8] is adopted in this project, which is an electric generation source connected directly to the distribution network or on the customer side of the meter. DG can be renewable generators like wind power plants and solar power plants, and traditional generators like gas turbines and fuel cells [6].

Traditionally the power in the power system flows only in one direction, from central power plants to transmission network then to distribution network, and down to consumers. The power in the power system can now flow from the consumer end back to the distribution network and even to the transmission network, as shown in Fig. 1.3. On the one hand, DG connection to the grid entails investment in new network infrastructure. It may also entail reinforcement in the existing network. On the other hand, DG integration has shown benefits of deferring network investment [9, 10, 11]. However, the deferment of investments and the schedule of reinforcements are highly sensitive to DG locations [12]. The beneficial impact on deferring the investment in the system may be diluted because of the "wrong" timing and location of DG. Therefore, DG integration should be taken into account in the network infrastructure investments.

The benefit of DG integration can be higher if DG curtailment is accepted [13, 14]. The amount of curtailed energy is closely related to the DG connection point, the connection line investment and the network reinforcement and operation. By

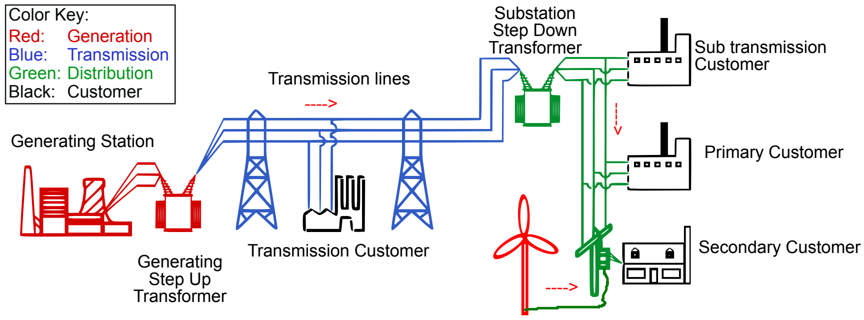


Figure 1.3: Simple diagram of electricity grids with DG integration.

accepting curtailment in combination with active control systems, more renewable generation can be accommodated in a distribution grid [13]. It is also shown that by changing the DG connection point to the grid and curtailment regulations the capacity factors of wind farms can be greatly increased [14]. Moreover, by allowing DG curtailment the network investment decreases [15]. However, allowing DG curtailment decreases the benefit of DG owners and increases the risk of investing in DG. DG curtailment is regulated in some countries to balance the benefits of the network companies and DG owners. Therefore, curtailment regulation can not be ignored when evaluating economic regulation impact on network infrastructure investment.

Network investment

Normally the network infrastructure planning begins with an estimation of the demand growth. With the increase of DG integration, the network planning will begin with an estimation of the demand and DG growth, especially in the distribution network. In this report, we use the term distribution system operator (DSO) to represent the owner and operator of the distribution network. Many DSOs can exist in one country. The DSOs decide the infrastructure investments including the substations, electric power lines, switching equipment, circuit breakers, protection relays, metering, etc. DSOs in unbundled power systems are assumed to not own generators, except for security reasons. Therefore, to plan the location and size of DG is not one of the DSOs' decisions, even as discussed in the foregoing, the DG location has high impact on the network investment.

Before the first DG connection, the cost of the network is recovered by network charges from all consumers. Due to DG connection, reinforcement in the existing network may increase. The reinforcement cost can be transferred to only the DG owner, or can be socialized by all the network users. Depending on how the connection fee for DG is charged, DG owners can choose the connection point to the grid while accepting the probability of energy curtailment at this point. For example, the income of a DG owner is from the sell of the generated energy, and from compensation from the curtailed energy if it is applicable. The connection cost of a DG owner can be due to the connection line only or due to the connection line and the reinforcement of the existing grid. If the DG owner tries to maximise its income or minimise the connection cost, different regulation on curtailment and connection charge can have a direct impact on the decision. Therefore, an investigation of the relationship between economic regulation and network investment interests DG developers as well.

Aim and scope of the project

The main objective of this project is to evaluate the impact from regulations on the distribution network investment. In other words, this project aims to develop methods to assist regulators to design desirable regulations to encourage the DSOs to make the "smart" decisions; and to assist DSOs to build the "right" line in the "right" place at the "right" time considering the current regulation.

Chapter 2

Regulation on distribution systems with distributed generation

DSOs are natural monopolies, so their revenues and performances have to be regulated. Traditionally, the revenue of the DSO is based on cost-of-service, also called rate-of-return scheme, where a predefined rate of return on the capital investment is guaranteed and other operational costs are passed through. There is then little incentive for the DSO to minimize the costs. To improve the economic efficiency, traditional revenue regulation model is not suited any more, one solution is to implement incentive regulation, which includes revenue cap regulation and/or performance regulation.

Moreover, in Europe, the unbundling rules, according to the Article 14/7 of the Directive 2003/54/EC [12], prohibit DSOs from owning generation plants. At the same time, it is recommended that when planning the distribution network, DG that might replace the need to upgrade electricity capacity shall be considered by the DSO. Research has shown that DG can reduce the system losses, improve voltage profile, enhance system reliability etc [16, 17]. Therefore, regulations of DSOs should recognize the impact of DG on DSOs' performance and cost[5].

The growth of distributed generation (DG) is adding complexity to the distribution network investment and network regulation. Different connection fee schemes can impact the DSO's network investment decision and the DG owners' decisions[5]. Connection charge fee schemes allocates the costs and risks between DG producers and DSOs [18]. Moreover, DG integration is especially challenging for the generation from renewable energy with high variability. The network investment can be based on accommodating the energy produced from DG without curtailment; however, a part of these investments might be only relevant for a few hours annually when the generation is much higher than the average. Therefore, energy curtailment is an option to decrease the investment [19]. However, energy producers may suffer economic losses due to curtailment. Furthermore, curtailing renewable energy can intuitively be viewed as noneconomical given its low marginal cost. Therefore, curtailed producers may receive compensation according to energy curtailment regulation, which defines the compensation rules in terms of the price, the quantity and the payer. Energy curtailment can be caused by network constraints, security constraints in the grid, low electricity price, and strategic bidding [20]. The curtailment of DG due to network constraints is the focus of this thesis.

2.1 Revenue cap regulation

Under the revenue cap regulation, the maximum yearly revenue that the DSO is allowed to earn in a year is limited by the revenue from the previous year considering inflation and performance for a period of several years [4]. These revenues are adjusted annually due to unexpected events, e.g. extreme weather. The revenue cap regulation can also be implemented considering DG integration. There are several proposals in [21] [22] [23] to adjust the allowed revenue for DSOs in order to encourage them to connect more distributed energy resources (DERs). DG integration is a part of DER integration. Other DERs can be distributed energy storage and electric vehicles.

In general, there are three ways to adjust the allowed revenue for DSOs to facilitate DER integration, which are presented in eq.(2.1) [24]. The DSO is incentivized by an increase of their revenue cap by connecting more DER. The component can be one of three elements: a percentage of the total DER connection cost (α), an average reward for connected DER capacity (β) or an average reward for DER generation (γ). In some proposed regulatory schemes in [25], the additional component can be a combination of those three elements.

$$R_t = R_{t-1} * \text{adjustment factor} + \begin{cases} \alpha \cdot €_{\text{DER}} & \alpha : (\%), \\ \beta \cdot P_{\text{DER}} & \beta : (€/kW), \\ \gamma \cdot G_{\text{DER}} & \gamma : (€/MWh). \end{cases} \tag{2.1}$$

where R_t represents the revenue cap in year t, *adjustment factor* is usually set by the regulators according to the economic indexes, $€_{\text{DER}}$ represents the DER connection cost, P_{DER} represents the total installed capacity of DER, and G_{DER} represents the generation from DERs.

In practice, excess revenue is returned to customers in some way, so that the cap is achieved ex post [26]. This is also known as a revenue-sharing scheme. Another way to share profit with consumers is called the sliding scale method which avoids a certain level of information asymmetry [21]. The sharing rules is presented in (2.2).

$$R = b * \text{revenue cap} + (1 - b) * \text{cost} \tag{2.2}$$

In Sweden, revenue cap regulation is applied but there is no special incentives for DER integration. The incentives focus on quality and performances. The components in the Swedish revenue cap for the current regulatory period of years 2016-2019 is illustrated in Figure 2.1 [27]. The DSOs provide information about their costs and performances to the regulator. The regulator defines the parameters to calculate the revenue cap. Efficiency change defines the efficiency improvement requirement on the operations. Depreciation method describes how to depreciate the capital cost. Return of capital is defined to reward the capital investment. The quality and network utilization indices are used to quantify the incentives for qualified and efficient network investment. The revenue cap is calculated for each DSO based on its cost and performances.

The revenue cap defines the maximum total revenue that a DSO can receive for the regulatory period. The calculation for the allowed return on costs is presented in [27], the performance incentive from the quality regulation is presented in [28], and the calculation and motivation for the performance incentives from network utilization are presented in [29]. A realistic evaluation of the regulatory asset base is crucial. In Sweden, a standard cost catalogue is implemented [30]. The catalogue shows standard replacement costs for specific assets.

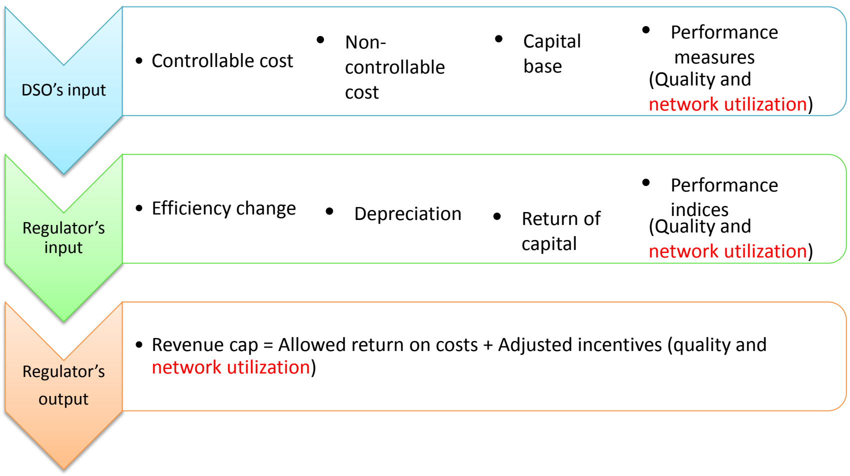


Figure 2.1: Swedish revenue cap regulation framework.

2.2 Performance regulation

In the performance regulation, choosing performance indicators is one of the challenges. Qualitative analysis on different performance indicators, used in European countries and proposed ones, are presented in [31]. Some guidelines are also given by CEER in [31]. CEER selected some performance indicators for further qualitative analysis in [32]. The selection criteria of performance indicators are:

1. *The variation would determine a quantifiable benefits to grid users and in general, society as a whole;*

2. *It is possible to determine, measure of calculate, the value of the index in a sufficiently accurate and objective way;*

3. *The value of the index can be influenced (even if to a limited extent) by the network operator or the system operator; this includes metering;*

4. *The index should be as far as possible, technology neutral.*

The performance indicators implemented from January 2016 in Sweden fulfils all the above criteria and send out incentives to facilitate demand side management (DSM) and innovative solutions. They, which have not earlier been analysed quantitatively in a systematic manner, are modelled and analysed in this thesis. The performance incentives for distribution networks utilization in Sweden are calculated based on two performance indicators [29]. One is to motivate the DSO to reduce **losses** in the network, the other is to motivate the DSO to increase the **load factor**.

Network **losses** can be affected by the DSO's investment decision. An incentive to reduce the losses can benefit the network users, since the cost of losses will be recuperated from them; and can benefit the society, since less energy will be produced to cover the losses. The economic incentive from loss reduction is shared by the DSO and the customers. The ratio to share is determined by the regulator. A similar formulation of incentives for loss reduction can be found in some other European countries, for example Austria and Spain [32].

The **load factor** of the network is the ratio between the average power and the peak power on the feeding point (or connection point) of a distribution network. It is considered as an index for efficient utilization of the networks in the Swedish regulation. This is because one effective way of using the network is to level off the flow profiles, considering there is load and generation in the network. The load factor defined in the Swedish regulation is the yearly mean value of the daily ratios during a regulatory period. The higher the ratio is, the smaller the flow variation on average is during each day. Therefore, the capacity of the network is used more efficiently. This incentive aims to encourage DSOs to recognize the contribution from the DG or DSM to the network.

By levelling off the flows in the network, the peak power in the network and also the losses can be reduced, giving the total energy unchanged. Therefore, it can lead to network investment reduction. The loss reduction can be doubly rewarded by these two incentives. However, they are still different incentives. The loss reduction incentive provides a static value for the loss reduction at any time; the loss reduction in the peak load moments provides a more dynamic value for the loss reduction. Therefore, the loss reduction at times of peak load is more beneficial than that at other times. This reflects different benefits of the loss reduction at different times.

The performance of the DSO depends not only on DSO's investment decision, but also on objective reasons such as the geography of the network, the types of consumer or DG and the size of the company. In order to limit the impact of the objective reasons, the Swedish regulator sets a limit on the sum of the economic incentives each DSO can obtain. More detailed settings in the Swedish performance regulation are presented in Chapter 3.2.

2.3 Curtailment regulation

Curtailment in this thesis is defined as the difference between the energy that is potentially available from the generation unit and the energy that is actually produced. The reasons for curtailment can be categorized into four kinds: network constraints, security constraints in the grid, excess generation relative to load and strategic bidding [20]. In the distribution level, the most relevant reason for curtailment is the network constraints. Curtailment due to network constraints can be interpreted as underinvestment in the network or excess generation. Achieving a balance between the network investment and DG integration is an important aspect for designing the curtailment regulation.

Curtailed energy is not always compensated. Energy can be curtailed due to the low price, either the low electricity market price or green certificate price or high price to down regulate. This kind of curtailment is generally referred to as voluntary curtailment, which is not compensated. Examples of voluntary short-term curtailment are shown in [20, 33]. Compensation is relevant when the curtailment is due to the grid limitation. This kind of curtailment is generally referred to as involuntarily curtailment [20].

Two regulatory options for curtailment due to network constraints are proposed in [20]. One is referred to as the *quantity-regulatory* approach. A pre-agreed maximum curtailment level is defined by regulators. Until this level no compensation is needed, while beyond this level, the DSO compensates DG owners' lost revenue. The expected curtailment cost up to the pre-agreed curtailment level can provide locational signals for the DG owners [20]. The other option is referred to as the *price-regulatory* approach. A compensation price, which is lower than the electricity price for the DG, is set by the regulator. Therefore, DSOs partially compensate the curtailment. This approach is expected to speed up the network investment and leads to an optimal investment where the marginal cost of the network extension is equal to that of the curtailment expenses [20]. The modelling of these two regulatory options for curtailment is presented in Chapter 3.2.

2.4 Connection charge regulation for DG

Connection charge schemes for DG are stated in the regulation. There are in general three types depending on how the cost of the network connection for DG is shared between the DSO and the DG owners [34]. One is called shallow connection charge, which means that the DG owner only pays for the investment from the grid connection point to the DG. One is called deep connection charge, which means that the DG owner pays for the connection line and the necessary reinforcement in the upper stream network. The third one is called the shallowish charge, which means that the DG owner pays the connection line and part of the reinforcement in the upper stream network.

The implementation of shallow charges implies for the DSO that it recovers cost over time, e.g., by means of use of system (UoS) charges. As for DG producers, the shallow charge scheme is preferable due to lower financial expenses upfront and lower risk exposure [18]. As for the DSOs, the deep charge scheme is preferable due to the locational signal for the DG producers and cost coverage [18]. Implementations of these charging schemes are different in different countries. Even in the same countries, the charging schemes can be different for different generators. Some examples are presented in [35, 18, 36]. The modelling of shallow and deep regulatory options for DG connection charge is presented in Chapter 3.2.

Chapter 3

The developed network investment optimisation model (NIOM)

A NIOM is developed to anticipate the DSOs' investment decisions under different economic regulations and their expected performances. The model formulation starts from analysing and modelling relevant regulations. The objectives, variables and constraints are chosen with the consideration of the regulation. At the same time, the data input model is chosen in order to consider uncertainties and correlations in the planning horizon. Different models to represent the load and DG uncertainty can impact the investment model formulation as well. When the network investment model is formulated, a suitable solution method is used to find the optimal solution and the solution pool. The solution method can affect the formulation of the model. For example, in this report, we use a linear method to solve the problem and it requires the model to be formulated accordingly. Last but not the least, reliability indices are calculated for the selected solutions by a reliability model. The solutions in the solution pool are used as alternatives if the reliability of the optimal solution is not satisfying.

The investment decisions considered in the model are choices of new DG connection routes, conductors of the connection lines, substations updates and reinforcements in the existing lines. These decisions as well as the optimal timing of these decisions are represented by integer variables. When the uncertainty is disclosed, the second stage decisions are taken. In this model, the second stage decisions are the timing and amount of DG curtailment and the imported energy from the upper stream grid. Load shedding is assumed not to be allowed. These decisions depend on the current in each line and voltage in each node, which are determined when the uncertain load and DG production are realized. Some of the variables can also be used to evaluate the DSOs' performances.

The investment model considers essential network constraints such as voltage, thermal limits, power flow balance, regulatory constraints identified from the regulation modelling module and other logical constraints for the investment alternatives. A successive liner programming approach [37] is adopted to linearise the AC power flow constraints. The linear programming approach is chosen for the computation advantages, especially in solving problems with integers.

3.1 Modelling of input data uncertainties

3.1.1 Motivation for the chosen modelling approach

The network infrastructure investment largely depends on the load and DG profiles in the system. Some articles, for example [15, 38, 39, 40, 41], have used single or a few levels of loads and DG. However, loads and DG are fluctuating by nature. Hence, a few levels of loads and DG may not provide sufficient information, especially for the calculation of curtailment and losses. It would be ideal to use time series load and DG data to represent the fluctuation and correlation. However, these data are rarely available at each bus in a given distribution system for the planning periods. Moreover, even if these data are available, the size of the data can be large. This demands a systematic way of using the available data to capture its fluctuating nature and the correlation between them. Using marginal distribution to model the DG and load fluctuation and using copulas to model the correlation between them are found to be flexible and suited for power systems [42, 43].

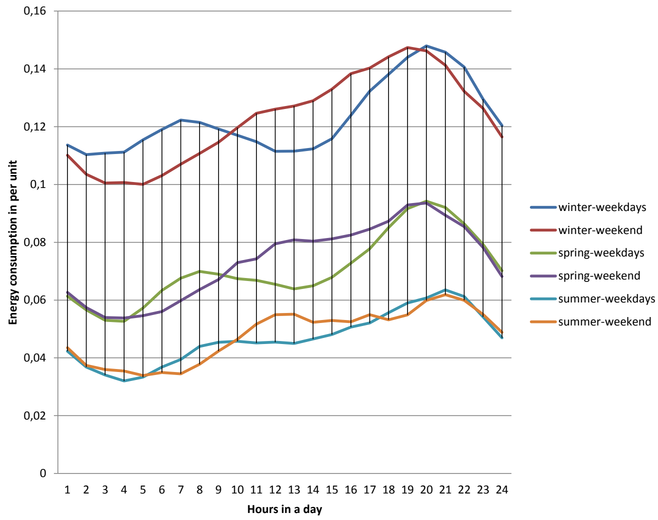


Figure 3.1: The load pattern for seasons and weekday/weekend.

3.1.2 Modelling the input uncertainties with correlations

In this report, we use fitted marginal distributions to model the fluctuation and use copulas to model the correlation. Historical data of load and DG production is firstly used to differentiate several levels due to different fluctuation patterns. Take an example of daily energy consumption in a distribution network in Sweden, which is shown in Fig. 3.1. Weekdays and weekends show distinguished consumption patterns, and different seasons show distinguished consumption patterns. Spring and autumn show similar pattern; so it is not presented in the figure. Therefore, six groups of load and DG production are identified in this example. This is called time-dependent stochasticity [44]. The time-dependence of this stochasticity is removed by distinguishing load levels with different statistical characteristics.

The scenario modelling approach is illustrated in Fig. 3.2. There are four planning periods in the planning horizon. In the first period, eight groups of the input data are identified in this example. Each group contains load and DG data of the same time duration. It is assumed that the groups remain the same in the following periods. Therefore, the eight groups that identified in the first period evolves to the next one on a path as shown in Fig. 3.2. If n scenarios are generated for each groups and there are three planning periods in the planning horizon, it becomes $32*n$ scenarios. Scenarios in the next planning period consider the growth or decrease in load and capacity of installed DG units compared to the previous period. Therefore, the scenarios evolve to the next period on one path. The number of scenarios can largely impacts the computation time. To gain tractability, a scenario reduction process is applied. A scenario tree can be constructed and reduced by method described in [45] and [46]. The toolbox SCENRED in GAMS [47] is used to perform it.

In order to generate correlated load and DG scenarios for each group, copulas are applied, as demonstrated in Fig. 3.3. The process starts from obtaining marginal distributions of load and DG which are $f(x), g(x)$ in a group. The marginal distributions are then transformed to the copula space or uniform space by applying the cumulative distribution function (cdf) transformation [42]. In this uniform space, the linear correlation between variables is the same as the rank correlation [42]. Samples from these distributions are then used to fit a copula function $C(u, v)$, indicated by the empty arrows in the figure. The copula function preserves the correlation between load and DG. The copula is assumed to be chosen by the user based on their experiences. The most commonly used copulas are the Gaussian copula for linear correlation, Gumbel copula for extreme distributions, and the Archimedean copula and the t-copula for dependence in tail [43]. In this report, we choose the Gaussian copula. To obtain fluctuating loads and DG (correlated load and DG inputs) scenarios in each group, samples are drawn from the copula function. These samples have the required dependence between load and DG but they are in the uniform space. Then these samples are transformed back to the original data space, as indicated by the yellow arrow in the figure. These samples are referred to as scenarios in this paper.

3.2 Modelling of regulations

The studied regulations are implemented in many countries with different variation. In this thesis, we use the regulation implemented in Sweden as an example to explain the modelling approach. Some variations are also presented.

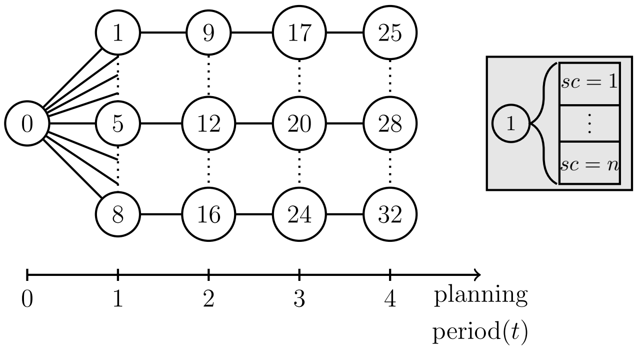


Figure 3.2: Scenario fan within the perspective of decision framework.

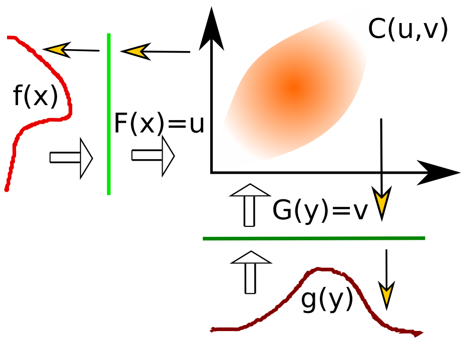


Figure 3.3: The generation process for correlated samples.

3.2.1 Modelling of revenue cap regulation

The components in the Swedish revenue cap for the current regulatory period of years 2016-2019 are illustrated in Figure 2.1. The revenue cap is modelled as two parts [29]. One part is the adjusted incentives, the other one is the allowed return on costs. The allowed return on costs which is not influenced by the incentives is assumed to be defined by the procedure in [27].

$$\hat{R}^{EG} = \hat{R} + \omega \tag{3.1}$$

where,

$\hat{R}$ = Allowed return on costs during the regulatory period

ω = Adjusted incentive during the regulatory period

$\hat{R}^{EG}$ = Revenue cap during the regulatory period

3.2.2 Modelling of performance regulation

The adjusted incentives consist of performance regulation on quality and network utilization in Sweden. Quantitative impact from quality regulation has been studied in [48]; however, quantitative studies on the performance regulation on network utilization have not been found. The performance incentives for distribution networks utilization in Sweden are calculated based on two performance indicators as presented in Chapter 2. One is to motivate the DSO to reduce **losses** in the network, the other is to motivate the DSO to increase the **load factor**. In this section, the modelling methods for them are presented.

Incentive for loss reduction

The economic incentive from loss reduction in the Swedish regulation is defined based on a self benchmark approach. The loss is normalized by the total imported or exported energy in the network and this normalized loss serves as an indicator for loss reduction. This indicator is compared with a reference value which is determined from historical data. The difference is valued by the electricity price. We refer to this approach as a quantity-regulatory scheme. A similar approach has been applied in Portugal [49].

The incentive for **loss** reduction by a quantity-regulatory scheme is modelled according to the definition in [29]:

$$\omega_1 = \lambda_{loss} \left(\frac{E_0^{loss}}{E_0^Q} - \frac{E^{loss}}{E^Q} \right) E^Q * \alpha \tag{3.2}$$

where,

ω_1 = Incentive from loss reduction during the regulatory period

λ_{loss} = Price of energy losses

E_0^{loss} = Reference value of energy losses

E^{loss} = Energy loss during the regulatory period

E_0^Q = Reference value of the energy flow through the feeding point Q

E^Q = Energy flow through the feeding point Q during the regulatory period

α = DSO's share of benefit from loss reduction

In the developed model, the energy loss is calculated based on power flow equations, which is only the energy that dissipated as resistive heating in the electrical equipments. In reality, the losses are defined by two measurements. One is the measurement on the network user's side, the other is at the feeding point. The difference between these two measurement is considered as losses [49]. Therefore, the losses that obtained from the measurement contain the losses from resistive heating, electricity thefts, and not metered electricity consumption, etc. Therefore, the modelled energy loss is a conservative approximation of the incentives from loss reduction.

Incentive for load factor increase

In the regulation, the economic incentive from the load factor increase is related to the network fee DSOs paid to the upper stream grid. This fee is normalized by the total imported or exported energy in the network. This normalized sum is compared with a reference value which is determined from historical data. If the sum increases, the incentive is set to zero. If the sum decreases, the incentive will increase accordingly with the load factor. This sum can decrease due to wind power integration [50]. The incentive for network **load factor** increase is defined as [29]:

$$\omega_2 = \left(\frac{B_0}{E_0^Q} - \frac{B}{E^Q} \right) E^Q m_{fp} \tag{3.3a}$$

$$m_{fp} = \frac{1}{n_{day}} \sum_{day=1}^{n_{day}} \frac{P_{day}^{avg}}{\hat{P}_{day}} \tag{3.3b}$$

where,

ω_2 = Incentive from network load factor increase during the regulatory period

B_0 = Reference value of the fee paid to the upper stream grid

B = Fee paid to the upper stream grid during the regulatory period

m_{fp} = Load factor at the feeding point

P_{day}^{avg} = Average power at the feeding point in a day during the regulatory period

$\hat{P}_{day}$ = Peak power at the feeding point in a day during the regulatory period

n_{day} = Number of days

We model the network fee paid to the upper stream grid by two parts [51]; one part is related to the subscribed capacity, the other part is related to the transported energy as shown in (3.4). The subscribed capacity is decided by the DSO for the coming years. It is assumed that the DSO always subscribes the capacity according to the peak power in the network. The price of the network fee to the upper stream grid is assumed unchanged from the reference years and the considered regulatory period. In order to model this incentive (3.3a) linearly, the load factor at the load point is used. Modelling the load factor at the load point is also reasonable, because the DSM devices are implemented at the load points. The load factor at the load point and the feeding point are the same if the network is lossless and there is no DG in the network.

$$\begin{aligned} \omega_2 &= \left(\frac{\beta^P \hat{P}_0 + \beta^E E_0^Q}{E_0^Q} - \frac{\beta^P \hat{P}^Q + \beta^E E^Q}{E^Q} \right) E^Q m_{lp} \\ &= \left(\frac{\hat{P}_0}{E_0} E^Q - \hat{P}^Q \right) \beta^P m_{lp} \end{aligned} \tag{3.4}$$

where,

β^P = Network fee for the subscribed peak power to the upper stream grid ($e/kW, yr$)

β^E = Network fee for the consumed energy to the upper stream grid (e/kWh)

$\hat{P}_0$ = Reference value of the peak power at the feeding point

$\hat{P}$ = Peak power at the feeding point during the regulatory period

m_{lp} = Load factor at the load point

The limit on the total incentive

The limit on the total economic incentive each DSO can obtain is defined as a percentage (γ_{inc}) of the allowed return on costs in the Swedish regulation [29]. Furthermore, the incentive for the load factor is only counted if it is positive. These constraints are shown in Fig. 3.4 and modelled as follows:

$$\omega = \begin{cases} \gamma_{inc} * \hat{R}, & \text{if } \omega_1 + \omega_2' \geq \gamma_{inc} * \hat{R} \\ \omega_1 + \omega_2', & \text{if } -\gamma_{inc} * \hat{R} \leq \omega_1 + \omega_2' \leq \gamma_{inc} * \hat{R} \\ -\gamma_{inc} * \hat{R}, & \text{if } \omega_1 + \omega_2' \leq -\gamma_{inc} * \hat{R} \end{cases} \tag{3.5}$$

where,

$$\omega_2' = \begin{cases} \omega_2, & \text{if } \omega_2 \geq 0 \\ 0, & \text{if } \omega_2 < 0 \end{cases} \tag{3.6}$$

In order to model the constraint (3.5) linearly, two positive variables (Z_1, Z_2)

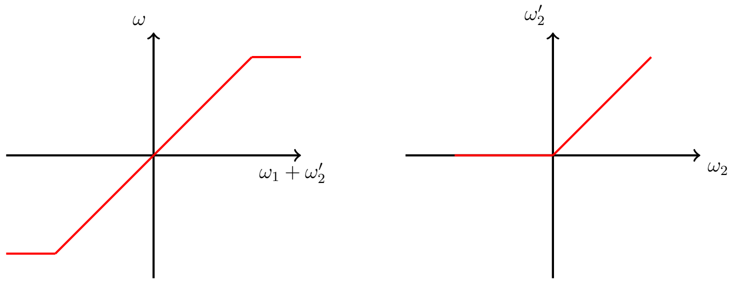


Figure 3.4: The limits on the total incentive.

are introduced with a penalty in the objective function:

$$\omega = \omega_1 + \omega_2' \tag{3.7a}$$
$$-\gamma_{inc} * \hat{R} \leq \omega + Z_1 - Z_2 \leq \gamma_{inc} * \hat{R} \tag{3.7b}$$
$$\hat{R}^{EG} = \hat{R} + \omega + Z_1 - Z_2 \tag{3.7c}$$
$$Z_1 \geq 0 \tag{3.7d}$$
$$Z_2 \geq 0 \tag{3.7e}$$

In order to model the constraint (3.6) linearly, a binary variable (D_{pos}) are introduced.

$$\omega_2' \leq D_{pos} * M \tag{3.8a}$$
$$\omega_2' \leq \omega_2 + (1 - D_{pos}) * M \tag{3.8b}$$

3.2.3 Modelling of DG curtailment

Two variations of curtailment regulation are modelled. The curtailed energy in the system is assumed to be regulated by either the quantity-regulatory approach or the price-regulatory approach, as introduced in Chapter 2. If it is regulated by the quantity-regulatory approach, the cost of curtailment (C_t^{cur}) is based on the curtailment that is above the pre-agreed maximum curtailment level. This excess part is modelled by positive variables $g_t^{n,cm}$ as shown in (3.9a). γ_{cur} is the pre-agreed maximum curtailment level as a share of available DG. (3.9a) is valid for each DG unit in each planning period. If it is regulated by the price-regulatory approach, the total curtailed energy is the sum of the curtailed energy in all scenarios, as shown in (3.9b).

$$\sum_{sc \in N_{sc}} P_{t,sc}^{n,cur} * Pb_{sc} * \tau_t - g_t^{n,cm} \leq \gamma_{cur} \sum_{sc \in N_{sc}} P_{t,sc}^{n} * Pb_{sc} * \tau_t \quad n \in N_{DG} \tag{3.9a}$$

$$\sum_{sc \in N_{sc}} P_{t,sc}^{n,cur} * Pb_{sc} * \tau_t = g_t^{n,cm} \quad n \in N_{DG} \tag{3.9b}$$

where,

γ_{cur} = Maximum curtailment percentage.

$P_{t,sc}^{n,cur}$ = Curtailed power in planning period t and scenario sc on node n.

Pb_{sc} = Probability of scenario sc.

τ_t = Time duration of planning period t.

$P_{t,sc}^{n}$ = Available power in planning period t and scenario sc on node n.

$g_t^{n,cm}$ = Curtailed energy from node n that is compensated in planning period t.

3.2.4 Modelling of DG connection and unbundling regulation

In the unbundled power systems, the connection lines of DG are decided by the DG owners instead of the DSOs. In the deep connection fee regime, it is assumed that DG owners choose connection lines which have the least price offered by DSOs and that DSOs offer a price which is equal to the cost. Therefore, in this case the lines to connect DG are determined by the cost for DSOs or the profit of DSOs. The connection lines are then determined by the network investment model. However, in the shallow connection fee regime, DG owners choose connection lines from their own interest. Modelling DG owners' interest is outside the scope. Therefore, the connection lines are treated as given parameters. This enables the model to minimise reinforcement cost on the network given the connection lines that DG owners propose.

3.2.5 A summary of the models

A summary of modelling these four kinds of regulation is presented in Table 3.1. In reality each power system is under a combination of regulations.

Table 3.1: A summary of modelled regulations

Regulatory issues		Modelling
Revenue cap regulation		(3.1)
Performance regulation – losses	Reward and penalty	(3.2)
Performance regulation – load factors	Reward only	(3.4) (3.8)
Performance regulation – the total	Limited incentive	(3.7)
Curtailment regulation	Quantity-regulatory	(3.9a)
	Price-regulatory	(3.9b)
DG connections/unbundling	Deep	DG connection lines as output
	Shallow	DG connection lines as input

3.3 Formulation of the developed NIOM

The distribution network infrastructure investment is modelled as a two-stage decision making optimisation problem with recourse. The first stage investment decisions are made under uncertainties of load and DG. When the uncertainty is disclosed, the second stage decisions are taken. The investment model presented here considers essential network constraints such as voltage, thermal limits and power balance. It is compatible with the economic constraints from economic regulation as presented in Section 3.2. Some constraints are modelled as linear constraints according to the algorithm which is applied to solve it.

3.3.1 Variables

The investment decisions considered in the model are the new DG connection routes and conductors of the connection lines ($D_t^{l,al}, al \in AL, l \in K_{dg}$), substations updates ($D_t^{n,al}, al \in AL, n \in N_s$) and reinforcements in the existing lines ($D_t^{l,al}, al \in AL, \quad l \in L$). Note that the timing of these decisions are also considered. These variables are made under uncertainties of load and DG, which are

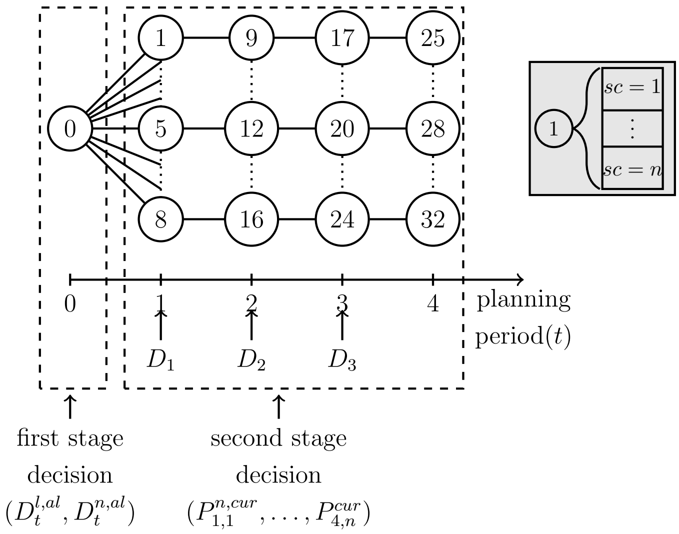


Figure 3.5: Scenario fan within the perspective of decision framework.

referred to as the first stage decision variables in a two-stage stochastic optimisation problem. The relations between the stage and the variables are illustrated in Fig. 3.5.

When the uncertainty is disclosed, which can be any scenario (sc) from 1-n in Fig. 3.5, the second stage decisions are taken. In this model, the second stage decision variables are the timing and amount of DG curtailment($P_{t,sc}^{cur}$). Load shedding is modelled but assumed not to be allowed. These decisions depend on the current in each line and voltage in each node, which are also determined when the uncertain load and DG production are realized.

3.3.2 Objective function

Two objective functions are modelled. One is to minimise the net present value (NPV) of the total expense in the network as shown in (3.10). The total expense is the sum of the expense for the network infrastructure and network operation. Cost minimisation is an ideal case. The solution from it can serve as a reference value. The other one is to maximise the NPV of the total profit for the DSO in a regulatory period as shown in (3.11). The profit is the revenue minus the cost. The revenue is limited by a revenue cap. The solution from profit maximisation is assumed to be a rational DSO's decision under incentive regulations.

The capital expenditure (C_t^{cap}) is determined at the beginning of the planning horizon and is for the investment of replacement of or updating the existing lines or substations and installation of new lines. Whether the cost of the connection lines for DG is included in the capital expenditure depends on the connection charge regulation, as explained in Section 3.2.4. The connection line cost is included in the case of deep connection charge, and it is excluded in the case of shallow connection charge. The expenses for operation in (C_t^{oper}) is considered at the beginning of each planning period. It corresponds to the cost of losses and DG curtailment during this planning period. However, whether and how the cost of losses and curtailment are included in the operational expense depends on the economic regulation, as explained in Section 3.2.3.

$$min\ NPV\left(\sum_{t=1}^{T}(C_t^{cap}+C_t^{oper})\right) \tag{3.10}$$

$$max\ NPV\left(\sum_{t=1}^{T}(R_t-(C_t^{cap}+C_t^{oper}))\right) \tag{3.11}$$

where,

$$C_t^{cap}=\sum_{l\in R}\sum_{al\in AL}C_{l,al}^{R,AL}D_t^{l,al}+\sum_{l\in K}\sum_{al\in AL}C_{l,al}^{K,AL}D_t^{l,al}+\sum_{n\in N_s}\sum_{al\in AL}C_{n,al}D_t^{n,al} \tag{3.12a}$$

$$C_t^{oper}=C_t^{loss}+C_t^{cur} \tag{3.12b}$$

$$C_t^{loss}=\sum_{sc\in N_{sc}}P_{t,sc}^{loss}*\lambda_{loss}*Pb_{t,sc}*\tau_t \tag{3.12c}$$

$$C_t^{cur}=\sum_{n\in N_{DG}}g_t^{n,cm}*\lambda_{cur} \tag{3.12d}$$

3.3.3 Technical constraints

Power balance at each node, Kirchhoff's current law (KCL), Kirchhoff's voltage law (KVL), voltage and thermal limits and logical limits are constraints considered in this model. Most of the constraints are similar to constraints in a conventional network planning model such as the one in [39]. The modified parts compared to [39] are that: (i) correlated load and DG scenarios are considered, (ii) AC power flow equations are used instead of DC power flow equations, and (iii) DG production and location are not optimised by the DSO.

The technical constraints for the network investment model are shown as follows.

1. power balance

$$f(V^n_{re,t,sc}, V^n_{im,t,sc}, I^n_{re,t,sc}, I^n_{im,t,sc}) = (P^n_{t,sc} - P^{n,cur}_{t,sc}) + j*(Q^n_{t,sc} - Q^{n,cur}_{t,sc}) \quad \text{for} \quad n \in N \tag{3.13}$$

2. KCL and KVL

$$\mathbf{A} I^L_{re,t,sc} = I^N_{re,t,sc}, \quad I^l_{re,t,sc} = \sum_{al \in AL} I^{l,al}_{re,t,sc} \quad l \in L \tag{3.14a}$$

$$\mathbf{A} I^L_{im,t,sc} = I^N_{im,t,sc}, \quad I^l_{im,t,sc} = \sum_{al \in AL} I^{l,al}_{im,t,sc} \quad l \in L \tag{3.14b}$$

$$(\mathbf{A}^\top{}_l V^N_{re,t,sc}) E^{l,al} - (R^{l,al} I^{l,al}_{re,t,cs} - X^{l,al} I^{l,al}_{im,t,sc}) E^{l,al} = 0 \quad l \in L, al \in AL \tag{3.14c}$$

$$(\mathbf{A}^\top{}_l V^N_{im,t,sc}) E^{l,al} - (R^{l,al} I^{l,al}_{im,t,cs} + X^{l,al} I^{l,al}_{re,t,sc}) E^{l,al} = 0 \quad l \in L, al \in AL \tag{3.14d}$$

3. losses

$$(V^{N_S}_{t,sc} I^{N_S}_{t,sc})_{re} + \sum_{n \in N_{DG}} P^n_{t,sc} - \sum_{n \in N_{DG}} P^{n,cur}_{t,sc} - \sum_{n \in N_{LD}} P^n_{t,sc} = P^{loss}_{t,sc} \tag{3.15}$$

4. physical limits

$$|V^N_{t,sc}| \le V^N_{max} \tag{3.16a}$$

$$V^N_{min} \le |V^N_{t,sc}| \tag{3.16b}$$

$$|I^{l,al}_{t,sc}| \le I^{l,al}_{max} E^{l,al} \quad l \in L, \quad \text{and} \quad |I^{N_S}_{t,sc}| \le I^{N_S}_{max} E^{N_S,al} \tag{3.16c}$$

$$P^{n,cur}_{t,sc} \le P^n_{t,sc}, \quad n \in N_{DG} \tag{3.17a}$$

$$Q^{n,cur}_{t,sc} \le Q^n_{t,sc}, \quad n \in N_{DG} \tag{3.17b}$$

5. logical constraints

$$\sum_{t \in T} \sum_{al \in AL} D^{l,al}_t \le 1 \quad l \in R \cup K, \tag{3.18a}$$

$$E^{l,al}_t \le E^{l,al}_{t-1} + D^{l,al}_t \quad l \in R \cup K, al \in AL \tag{3.18b}$$

$$\sum_{al \in AL} E^{l,al}_t = 1 \quad l \in R \cup K \tag{3.18c}$$

$$\sum_{al \in AL} E^{l,al}_t \le 1 \quad l \in K_{dg}, \quad dg \in N_{DG} \tag{3.18d}$$

$$\sum_{t \in T} \sum_{al \in al} E^{l,AL}_t \ge 1 \quad l \in K_{dg},, \quad dg \in N_{DG} \tag{3.18e}$$

Constraint (3.13) represents the power balance in each node. It is approximated by the first order Taylor expansion as shown in (3.19-3.20b). The expansion is evaluated at a starting point in the first iteration. If the iteration continues, it is re-evaluated at the previous operation point. They are shown in (3.20a) and (3.20b) respectively, where the subscription t and sc are not shown for readability.

$$\begin{aligned} f_p(V_{re}^n, V_{im}^n, I_{re}^n, I_{im}^n, V_{re}^{n,d}, V_{im}^{n,d}, I_{re}^{n,d}, I_{im}^{n,d}) &= P^n - P^{n,cur} \\ f_q(V_{re}^n, V_{im}^n, I_{re}^n, I_{im}^n, V_{re}^{n,d}, V_{im}^{n,d}, I_{re}^{n,d}, I_{im}^{n,d}) &= Q^n - Q^{n,cur} \\ n \in N, \quad d &= h-1 \end{aligned} \tag{3.19}$$

$$f_p = V_{re}^{n,d} I_{re}^n + V_{im}^{n,d} I_{im}^n + V_{re}^n I_{re}^{n,d} + V_{im}^n I_{im}^{n,d} - (V_{re}^{n,d} I_{re}^{n,d} + V_{im}^{n,d} I_{im}^{n,d}) \tag{3.20a}$$

$$f_q = V_{im}^{n,d} I_{re}^n - V_{re}^{n,d} I_{im}^n - V_{re}^n I_{im}^{n,d} + V_{im}^n I_{re}^{n,d} - (V_{im}^{n,d} I_{re}^{n,d} - V_{re}^{n,d} I_{im}^{n,d}) \tag{3.20b}$$

Constraints (3.14a-3.14b) represent the Kirchhoff's current law (KCL). Constraints (3.14c-3.14d) represent the Kirchhoff's voltage law (KVL). Constraints (3.14c-3.14d) are valid if a line exists between two nodes. A big number M is added to make sure that only if the line does exist, there is an equality constraint that represents KVL, as shown in (3.21a-3.21b).

$$(\mathbf{A}^\top{}_l V_{re,t,sc}^N) - R^{l,al} I_{re,t,cs}^{l,al} + X^{l,al} I_{im,t,sc}^{l,al} \leq M(1 - E^{l,al}) \tag{3.21a}$$

$$(\mathbf{A}^\top{}_l V_{im,t,sc}^N) - R^{l,al} I_{im,t,cs}^{l,al} - X^{l,al} I_{re,t,sc}^{l,al} \leq M(1 - E^{l,al}) \tag{3.21b}$$

Equality constraint (3.15) calculates the thermal losses in the system. This is the difference between the injected energy and the consumed energy. The thermal loss is an important variable since it can be linked with the incentive performance regulation. It is also part of the operational cost that used in the reference case where the total cost is minimised. Constraint (3.17) ensures that the curtailment is not more than the DG production.

Constraints from (3.18a) to (3.18e) show the logical constraints for the investment and availability of each branch and alternatives. Equation (3.18a) shows that maximum one investment on each branch (and substation) is permitted in the planning horizon. Equation (3.18b) shows that the alternatives for replacement or connection branches (and substation) are available only after the corresponding investment has been done. Equation (3.18c) shows that only one alternative of replacement branches will be available in a period. Equation (3.18d) shows that at most one branch among the connection branches is built to connect DG in one period. Equation (3.18e) shows that all DG should be connected in the end of the planning period.

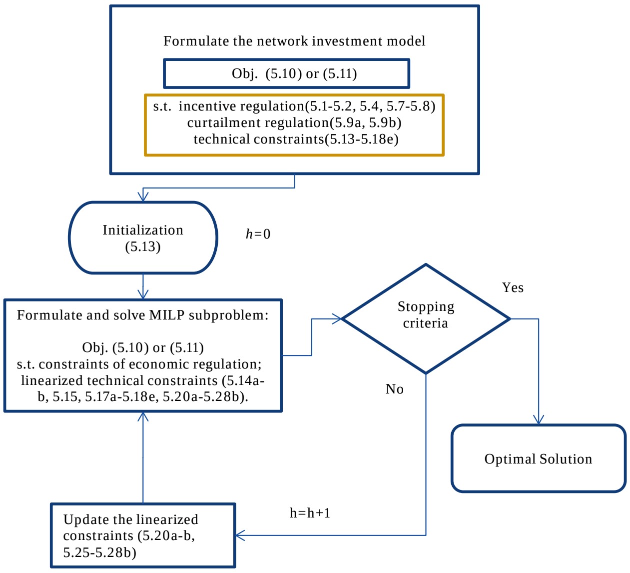


Figure 3.6: Outline of the solution method for NIOM.

3.4 Modelling of reliability

Reliability indices, expected energy not served (EENS), system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) are calculated for the obtained systems. Since reliability requirements are not modelled explicitly in the optimization model, the optimal solution may be less desirable when the cost of reliability is considered. Therefore, a solution pool with several best solutions in the optimization are saved to further study the system reliability.

The switching devices in the system which are used for preventing the extension of failure in the system and maintenances, are not modelled and therefore the reliability is evaluated through a compromise solution between an upper and a lower bound on the reliability level. The upper bound is calculated assuming that no switching devices are installed in the network, while the lower bound is calculated assuming that all branches are equipped with switching devices. The compromise is modelled by an *improvement coefficient* [52]. It is a coefficient to simulate the effect of a compromise solution in switching device location. The reliability level is estimated by an analytical method considering all line failures, one at a time, and load levels [53, 40]. DG units are considered as alternative supplying sources when an outage occurs [53]. The simulation steps are summarized as:

1. Select a solution file from the pool.
2. Obtain the network configuration in a planning period.
3. Select a load/DG scenario and a failure event.
4. Evaluate the upper bound and lower bound of reliability indices given the failure rate and restoration time.
5. Repeat step 3-4 for all scenarios and all failure events in the planning period. The expected value for those indices are calculated per period.
6. Repeat 2-5 for all planning periods. An improvement coefficient is defined to calculate the estimated reliability indices.
7. Repeat 1-6 for all solutions

Chapter 4

The developed network investment assessment model (NIAM)

4.1 Modelling of line capacity

A general DLR calculation model is developed based on the standard line capacity calculation. It is simplified and easy to be implemented.

4.1.1 Standard line capacity calculation

IEEE standard 738 [54] gives a standard formula for calculating the current of bare overhead conductors. It is based on steady-state heat balance:

$$I = \sqrt{\frac{q_c + q_r - q_s}{R_c}} \tag{4.1}$$

where q_c is the convective cooling, q_r is the radiative cooling, and q_s is the solar heating. R_c is the resistance of the conductor at temperature T_c. Solar radiation is neglected and the variation of resistance is neglected for the line capacity calculation in this paper. The line capacity can be calculated as below [54]:

$$I_{max}^{DLR} \approx \max \tag{4.2}$$

$$\begin{cases} \dfrac{\sqrt{[1.01 + 0.0371 * (\frac{D*\rho_f*v}{\mu_f})^{0.52}] * [k_f * K_{angle} * \Delta T]}}{\sqrt{R_c}}; \\ \dfrac{\sqrt{[0.0119(\frac{D*\rho_f*v}{\mu_f})^{0.6}] * [k_f * K_{angle} * \Delta T]}}{\sqrt{R_c}} \end{cases}$$

where $\Delta T = T_c - T_a$. D is the conductor diameter, ρ_f is the density of air at temperature T_f ($T_f = \frac{T_c+T_a}{2}$, where T_c and T_a are conductor temperature and ambient air temperature respectively), v is the speed of air stream at conductor, μ_f is the dynamic viscosity of air at temperature T_f, k_f is the wind direction factor at temperature T_f, K_{angle} is the parameter represents the angle between wind speed and the conductor axis. The formula above corresponds to low wind speeds, while the one below corresponds to high wind speeds. However at any wind speed, the larger of the two value is used [54].

The line capacity in reality is varying with many parameters as shown in (4.2), however, it is useful to simplify it to be easily implemented for electric power system planning and operation. In general, there are two ways to simplify the capacity calculation, SLR and DLR.

4.1.2 Calculation of static line rating (SLR)

SLR needs the parameters from a scenario, which usually is the worst scenario considering the worst possible conductor temperature, the ambient air temperature and the wind speed. For example, Engineering Recommendation (ER) P27 [55] proposes to calculate seasonal thermal ratings using assumed temperatures for different seasons and for a constant wind speed of 0.5 m/s and zero solar radiation [56]. The conventional relations between T_f, μ_f, ρ_f and k_f can be found in Standard 738 [54].

$$I_{max}^{SLR} = \frac{\sqrt{[1.01 + 0.0371 * (\frac{D*\rho_f*v^{SLR}}{\mu_f})^{0.52}] * [k_f * K_{angle} * \Delta T^{SLR}]}}{\sqrt{R^{SLR}}} \tag{4.3}$$

where v^{SLR} is the wind speed, ΔT^{SLR} is the temperature difference, R^{SLR} is the line resistance in the worst scenario. Other parameters depends on T_f also correspond to the worst scenario.

4.1.3 Calculation of dynamic line rating (DLR)

DLR estimates the line ampacity in real time with monitored weather conditions taking account of the wind cooling effect [57]. It can be obtained using a variety of methods: conductor sag and tension monitoring, vibration mode analysis, conductor temperature and local weather data [58] [57]. Temperature and wind speed are the parameters that affect DLR significantly, furthermore, the higher the wind speed, the higher the wind power production and (simultaneous) transfer capacity. As for the correlation between temperature and the wind speed are unclear, their impact on capacity ratio are studied separately. Here a simplified DLR calculation model is developed based on the assumption that wind impact on the line rating and temperature impact on that are independent. This is demonstrated as a reasonable assumption in Paper IV.

The proposed DLR model is based on the the capacity ratio between DLR and SLR. This ratio (η) is a function of wind speed and temperature, as shown in (4.4) . The variation of resistance due to temperature is neglected for the line capacity calculation in this paper. Under the independence assumption, η_v and η_T are obtained separately.

$$\eta(v,T) = \frac{I_{max}^{DLR}}{I_{max}^{SLR}} \approx \eta_v * \eta_T \tag{4.4}$$

where η_v is the ratio related to the wind speed, and η_T is the ratio related to the relevant temperature values. Given the same temperature for DLR and SLR calculation, all the temperature related parameters (ρ_f, μ_f, k_f and ΔT) are the same for both cases. We also use the wind speed v that is perpendicular to the conductor, so the wind direction factor K_{angle} is equal to 1. The parameters to define η_v can be estimated for both low wind speed ($\eta_{low}(v)$) and high wind speed ($\eta_{high}(v)$). Note that even the wind speed is very low, the line rating ratio should not be lower than 1.

$$\eta_v = \max \tag{4.5}$$

$$\begin{cases} 1; \\ \eta_{low}(v) \approx \dfrac{1}{v_{SLR}^{0.26}} * v^{0.26} = \alpha * v^{0.26}; \\ \eta_{high}(v) \approx \dfrac{0.566}{v_{SLR}^{0.26}}(\dfrac{\rho_f}{\mu_f})^{0.04} D^{0.04} v^{0.3} = \beta * D^{0.04} * v^{0.3}. \end{cases}$$

where $\alpha = v_{SLR}^{-0.26}$ and $\beta = \frac{0.559}{v_{SLR}^{0.26}}(\frac{\rho_f}{\mu_f})^{0.04}$. Conventional $v_{SLR} = 0.5$, then $\alpha \approx 1.1975$.

If we further assume that some of the temperature related parameters, ρ_f, μ_f and k_f, are the same in the DLR and SLR calculation. Therefore, the value of β is set by the T_f in SLR calculation. $\eta(v, T)$ is derived as:

$$\eta(v, T) = \max \tag{4.6}$$

$$\begin{cases} 1; \\ \approx \eta_{low}(v)\sqrt{\dfrac{T_c - T_a}{T_c - T_a^{SLR}}} = \eta_{low}(v)\eta_T; \\ \approx \eta_{high}(v)\sqrt{\dfrac{T_c - T_a}{T_c - T_a^{SLR}}} = \eta_{low}(v)\eta_T. \end{cases}$$

where η_T can be expressed as:

$$\eta_T \approx \sqrt{\frac{T_c - T_A}{T_c - T_a^{SLR}}} = \gamma \Delta T^{0.5} \tag{4.7}$$

where $\gamma = \sqrt{\frac{1}{T_c - T_a^{SLR}}}$ and $\Delta T = T_c - T_a$

4.2 Formulation of the developed NIAM

This developed NIAM applies the developed DLR calculation model to analyse impact from DLR on wind power integration. The main inputs for the analysis are the wind speed and the ambient temperature. Two outputs produced from the analysis are investment in wind power connection and curtailed wind power, which can be used for the decision-making in power distribution. The model is based on life cycle cost analysis (LCCA). Life cycle cost (LCC) is the annualized cost of an investment during its entire economic lifetime. LCCA often includes costs of investments, outages, maintenance, interests and incomes (modelled as negative costs) [59]. The estimated lifetime is limited by the technical lifetime, technical developments and expansions in power distribution systems [59]. The LCCA without considering the incomes is performed as follows in each simulation.

$$\mathbf{LCC}^{inv} = Capex + \sum_{i=1}^{LT} \frac{Opex_i}{q^i} - \frac{R}{q^{LT}} \tag{4.8}$$

$$q = 1 + \frac{z}{100} \tag{4.9}$$

The flow chart of the algorithm is shown in Fig 4.1. First, as shown in Box a, the

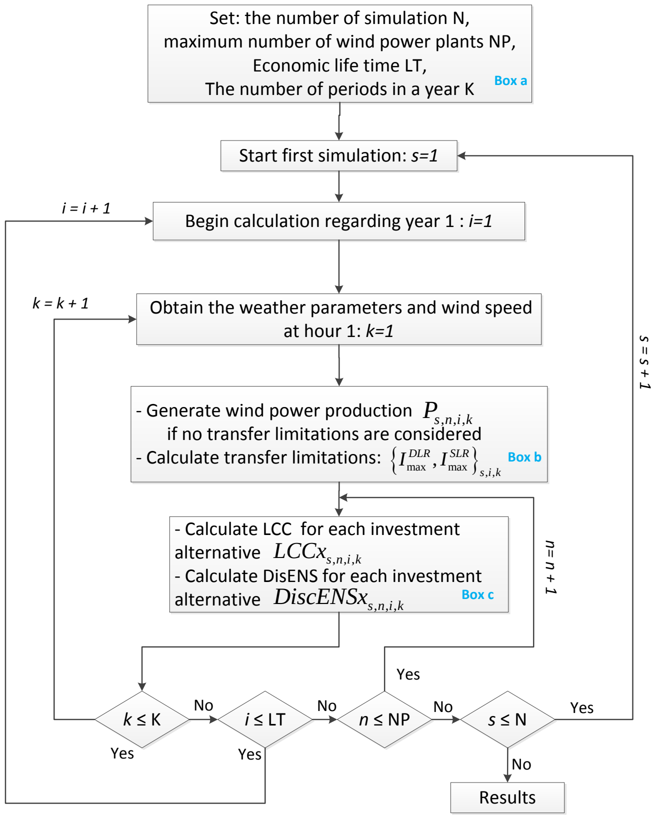


Figure 4.1: Model for assessing wind power connection using SLR and DLR.

number of simulations(S), the maximum number of wind power plants (NP), the economic life time of the power plants (LT) and the number of periods in a year (K) are set. A common way to divide the year is into months, i.e. $K = 12$. Hence, there are $S * LT * K$ generations of stochastic variables for a certain number of WP plants.

Then, as shown in Box b, stochastic (temperature and wind power production) inputs are generated in each simulation. To save time without losing any generality, the same stochastic variables are used for calculation regarding different numbers of wind power plants. In this model, wind power production is assumed to be correlated only to wind speed and not to temperature. By comparing the generated wind power and the line limits, the permissive transferred power is obtained.

The income from transferred power is considered as negative costs. It is discounted to the net present value (NPV). Therefore the LCC for the investment, Box c, is calculated as in (4.10-4.14).

$$
\begin{aligned}
Inc_{s,n,i,k} &= \min(P_{s,n,i,k}, \widehat{P}_{s,n,i,k}) * E_{price} && (4.10)\\
\widehat{P}_{s,i,k} &= \widehat{I}_{s,i,k} * U_N && (4.11)\\
\widehat{I}_{s,i,k} &\in \{I^{DLR}_{max}, I^{SLR}_{max}\}_{s,i,k} && (4.12)\\
LCC_{s,n,i,k} &= LCCx^{inv} - \frac{1}{(1+z)^i} * Inc_{s,n,i,k} && (4.13)\\
LCC_{s,n} &= LCCx^{inv} - \sum_{i=1}^{LT} \frac{1}{(1+z)^i} \sum_{k=1}^{12} Inc_{s,i,k} && (4.14)
\end{aligned}
$$

where k represents any period in a year, i represents any year during LT, n denotes the number of the wind farms, s presents any simulation. $\widehat{P}_{s,i,k}$ is the maximum allowed power on the connection line, which is calculated by the maximum line capacity and nominal voltage at the connection point of wind power plants. x represents different investment alternatives. If the average LCC is negative at the end of the economic lifetime, this indicates that the investment is profitable.

The amount of disconnected energy (DiscENS) is recorded in each simulation, as shown in Box c, if it is applicable. It reflects the utilisation of the network and the renewable energy. It is assumed that the DSO can disconnect the wind power plants or ask wind power plant owners to reduce the production. The exported wind power is limited by the line rating, so when wind power plants produce more than the limit, the extra energy will be curtailed. In the model, the production of the wind power plants is first generated without considering the transmission limits, then the sum of curtailed power is calculated according to the limits. Therefore, the curtailed energy is modelled by DiscENS.

$$DiscENS_{s,n,i,k} = \max(P_{s,n,i,k}, \widehat{P}_{s,n,i,k}) - P_{s,n,i,k} \quad (4.15)$$

Although costs of introducing DLR are not considered in this simulation model.

However, by calculating the difference in profit between SLR and DLR, it reveals the benchmarking cost for introducing DLR.

Chapter 5

Application of developed models

5.1 Application of NIOM

To apply the proposed NIOM, a radial network with 21 load nodes and two DG plants which have asked for connection is created. The type and size of the DG are not decided by the DSO due to the unbundling regulation. The distribution network is displayed in Fig. 5.1. It operates at 24.9 kV. Two wind farms are in the pipeline to be connected. In the figure, the square node represents the feeding substation, the wind turbines represent wind farms, and the circles are the load points and wind farm locations (N22 and N23). Continuous lines denote the existing network and dashed lines are candidate routes for new connections. The system details (node data and line data) can be found in [60].

Investment for one regulatory period of four years is considered in the case study. A DG owner applies for a connection to N22 in year 2 and another DG owner applies for a connection to N23 in year 3. The installed capacity of DG accounts for 47% of the total load. In this grid, all lines have two alternatives for upgrade, $AL1$ is the initial line and $AL2$, $AL3$ are the alternatives to upgrade. There are three paths to connect each new wind farm into the network. $L8$, $L13$, and $L21$ are for N22. $L9$, $L15$, and $L24$ are for N23. Each new path has three alternatives.

5.1.1 Case study for incentive regulation

This application looks into the DSOs' investment decisions and performances under the Swedish distribution network regulation, which is a revenue cap frame with performance incentives. In the application, the input load profiles are with three different load factors (m_{lp}) but the same total yearly energy consumption at each load point. Load shedding

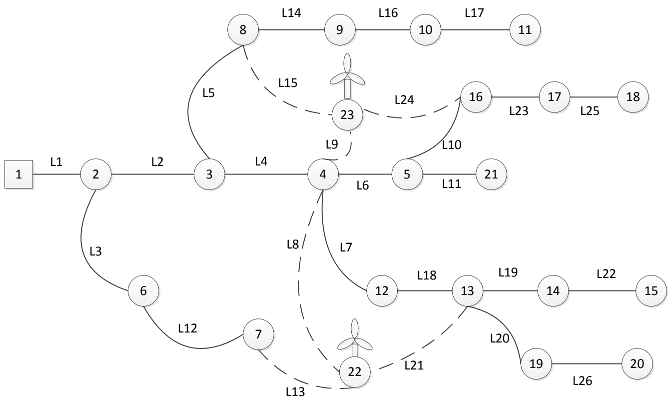


Figure 5.1: Diagram of the 23-node network.

is assumed to be not allowed. DG owners pay a fee based on deep connection cost and their curtailment is compensated by the electricity price. The network infrastructure investment cost is calculated for two situations, with DG and without DG. DSOs' investment decision is based on maximizing the total profit within the regulatory framework. Furthermore, the decisions based on minimizing the total cost are presented as a comparison. Ideally, the DSO opts for the decisions resulting the least total costs considering both operational cost and capital cost.

Benchmark price for load factor increase

The total profit of the DSO increases with the increase of m_{lp} value in both with and without DG cases. By comparing profits between different m_{lp} values, the benchmark price to invest in increasing m_{lp} values is obtained. If the investment to increase m_{lp} is lower than the benchmark price, it is profitable to invest in increasing m_{lp}. For example, the benchmark price to increase m_{lp} from 0.5 to 0.6 is 84.31×10^5 e, and the benchmark price to increase m_{lp} from 0.6 to 0.7 is 122.20×10^5 e if there is DG in the system. By comparing these two benchmark prices, the incentive to increase load factor from medium to high is higher than from low to medium in the system with DG. In the systems where there is no DG, the benchmark price to increase m_{lp} from 0.5 to 0.6 is 227.37×10^5 e, and the benchmark price to increase m_{lp} from 0.6 to 0.7 is 119.51×10^5 e. By comparing these two benchmark prices, the incentive to increase load factor from low to medium is higher than from medium to high in the system with DG. Furthermore, the economic incentive for the DSO to invest in increasing the load factor, for example through ANM, are high, accounting for more than 18% of the profits, in systems with or without DG. With the same m value, the profit is higher in the system with DG than without DG. However, the profit in the system with DG is over-estimated because the allowed return on costs is assumed to be the same as in the system without DG. The potential deferral of network investment due to the DG connection is not considered in the regulation.

Benchmark price for loss reduction

By implementing different incentive regulations, the infrastructure investment costs and profits of the DSO are obtained by the developed model. The infrastructure investment costs do not vary nor do the operational costs, but the total profits do. This means that the economic incentive in loss reduction is not high enough to change the infrastructure investment decisions.

The reward for reducing losses in kWh can be estimated for a given network. The reward is measured by the increased revenue cap due to the loss reduction. In this example, comparing the case with and without the incentive for loss reduction, the gain due to loss reduction is 7.37×10^5 e in the case with DG and and 6.72×10^5 e in the case without DG. The reward/penalty price for loss reduction/increase, which is the incentive ω_1 divided by the reduced losses in kWh, is 0.053 €/kWh in this case for the system with DG. It is 0.001 €/kWh higher than the expected electricity price. The reward/penalty price for loss reduction/increase is 0.048 €/kWh in this case for the system without DG, which is 0.004 €/kWh lower than the expected electricity price. These prices can be used as a benchmark to evaluate the cost to reduce losses.

Discussion

In this application, we studied the performance of the different incentive regulatory regimes for distribution network investment with and without DG. We found that the incentive for load factor increase does impact on the network infrastructure investment, but the incentive for loss reduction does not. With the increase of load factor, less network infrastructure cost is observed. We also estimated the benchmark prices for investing in increasing load factor and decreasing losses in the Swedish regulation framework by the proposed method. This approach can also be applied in other regulation frameworks by adjusting the regulatory constraints and parameters. These benchmark prices can be used to evaluate the feasibility of investing in improving performance indices. They can also be used by regulators to evaluate the impact of the performance incentives. We observed in this case study that although the total performance incentive is lower in the system with DG than without DG, the total profit is higher. For detailed results and analysis, please refer to Publication II.

5.1.2 Case study for curtailment regulation

Quantity-regulatory approach

In this case study, the quantity-regulatory approach for curtailment is investigated. Each DG owner is compensated for the annual curtailed energy which is above a predefined level. This level is referred to as *non-compensated level* in this case study. The non-compensated level is 3% per year for each DG unit. The production is remunerated by feed-in tariff (FiT) (0.13 €/kWh) and is compensated by the same price if the production is curtailed. Different non-compensated levels are applied, and different compensation prices are discussed in this case study.

DG owners pay for the shallow connection charge; therefore, the connection lines are decided from the DG owners' interest not considering the reinforcement of the rest of the grid. In this application, we assume that L13 AL2 T2 (AL 2 of the line L13 is built at year 2) and L24 AL1 T3 (AL 1 of the line L24 is built at year 3) are chosen by the DG owners. The DSO minimising C_{total} as in (3.10) with constraints (3.13-3.18), (3.9a), where $\lambda_{cur} = \lambda_{el}^{DG}$ and two DG connections are given.

The results for applying the quantity-regulatory approach are presented in Table 5.1. It shows that the higher the non-compensated curtailment level is, the lower the total expected cost and the higher the optimal curtailment levels. Moreover, allowing a lower non-compensated annual curtailment level does not lead to more reinforcement for the network, since paying for curtailing energy in some years is more beneficial than reinforcing the network. The higher the curtailment is the lower the thermal loss is; however, the impact is small.

In order to investigate the relation between the network investment and the non-compensated curtailment level, the optimal network investment with different maximum annual curtailment levels are simulated without compensation. The simulation starts from the curtailment level 3% since the connection lines for DG are chosen based on accepting this curtailment level. In Fig. 5.2, the optimal solutions are based on minimising $C_{total} = \sum_{t=1}^{T}(\delta_t^{cap} C_t^{cap})$ in (3.10) with constraints (3.13)-(3.18) and (3.9a), where $g_t^{N_{DG,cm}} = 0$ and changing γ from 3% to 50%. The avoided network reinforcement cost is the difference between the minimum capex when γ is 3% and when γ is higher. The avoided capex increases as the maximum annual DG curtailment level increases. Due to the nature of integer optimisation, the increase is stepwise. The increase stops when

Table 5.1: Results for the case under quantity-regulatory approach

γ	3%	15%
$\lambda_{cur}(€/kWh)$	0.13	0.13
Total cost(k€)	590.450	580.712
Capex(k€)	472.405	472.405
Connection cost(k€)	37.33	37.33
Compensation (N22,N23)(k€)	9.40, 0	0, 0
Curtailment percentage (N22,N23)	5.3%, 3%	15%, 0%
Loss percentage	2.83%	2.82%

the maximum annual DG curtailment level is 8%.

By adjusting the non-compensated curtailment level, the benefit for the DSO increases while the value of curtailed energy remains the same. The value of curtailed energy is related to its opportunity cost. In this case, the opportunity cost is evaluated by the FiT for renewable energy. Furthermore, by increasing the FiT, the distance between the avoided total cost and value of curtailed energy can change, and therefore the benefit for the DSO can change. In this case when the FiT increases by five times, the value of allowing curtailment decreases and the maximum benefit for the DSO is reached when the maximum annual curtailment level is between 4% and 5%, as shown in Fig. 5.3.

Price-regulatory approach

In this case study, the price-regulatory approach for curtailment is investigated. If the compensation price is the same as or higher than the electricity price for DG, the DG owners lack incentives to increase the penetration level of distributed energy. Therefore, the curtailed energy is suggested to be compensated with a price that is less than the price to sell the same quantity of energy [20].

In this case, the DG owner chooses connection points considering necessary network reinforcement since the DG owner pays for the reinforcement and possible energy curtailment. The connection decision is based on maximising the DG owner's benefit, which is $((g^{N_{DG},tot} - g^{N_{DG},cur}) * \lambda_{el}^{DG} + g^{N_{DG},cur} * \lambda_{cm} - C_{network})$. where $C_{network}$ is the network cost due to the DG connection. Given λ_{cm} is less than λ_{el}^{DG} in the price-regulatory approach and λ_{el}^{DG} is exogenous, the decision will be based on minimising $C_{network}$ which is C_{total} as in (3.10) where $C_t^{oper} = C_t^{cur}$ and $\lambda_{cur} = \lambda_{el}^{DG} - \lambda_{cm}$, with

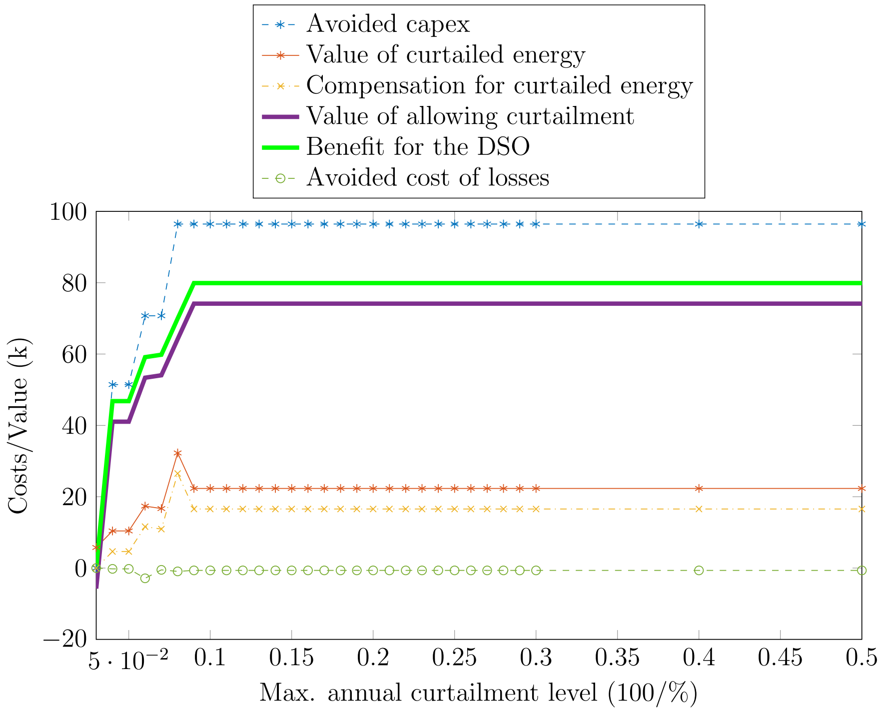


Figure 5.2: FiT is 0.13 €/kWh.

constraints (3.13)-(3.18) and (3.9b).

Table 5.2 presents the results in this case. By increasing the price, the capex decreases stepwise. Table 5.2 shows the three steps observed in this case. With the increase of the compensation price, the total curtailment increases. Furthermore, with the increase of the compensation price, the network investment decreases but the connection cost may increase. Comparing the case where the compensation price is 0.08 €/kWh with 0.026 €/kWh, the curtailment level is higher and the connection cost is also higher. This is because when the connection line is L21, reinforcement on L3 is necessary and the cost to reinforce L3 is high. However, when the connection line is L13 AL2, although it is more expensive than L21 AL1, curtailment in the planning periods makes that the reinforcement on L3 is no longer necessary. On the other hand, the curtailment in the case with compensation price 0.11 € /kWh is higher than the case with compensation price 0.08 €/kWh, and the connection cost is lower. This is because the compensation price is so high that it is not worth reinforcing the network and investing in a larger capacity of the connection line from the DG owners' perspective.

By allowing different annual curtailment levels in the same network, the minimum capex and the optimal curtailment are simulated. The avoided capex, avoided cost of

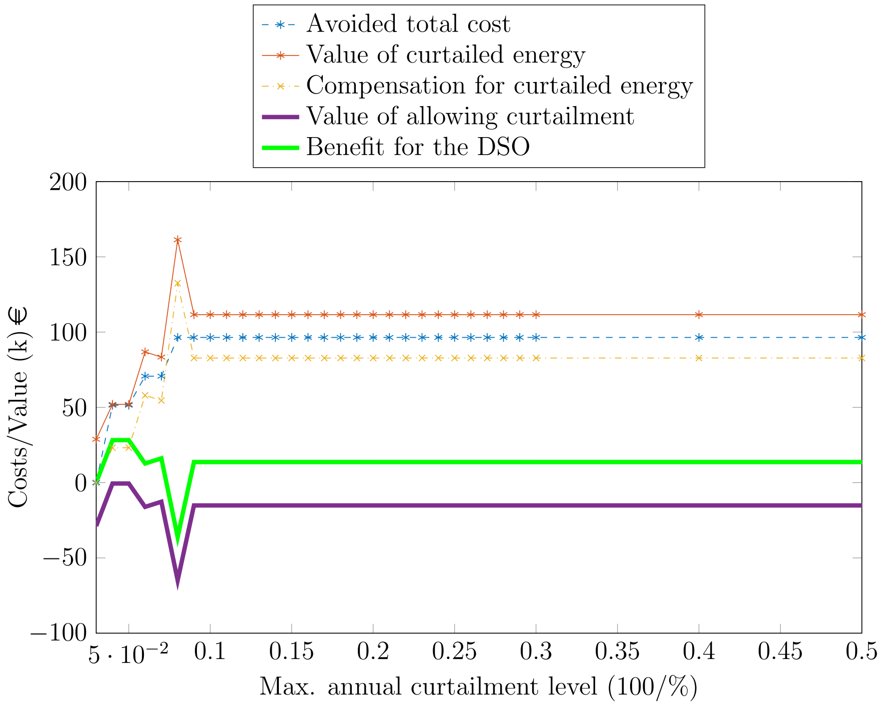


Figure 5.3: FiT is 0.65 €/kWh.

losses, and the value of curtailed energy are plotted, as shown in Fig. 5.4. It shows that the value of curtailed energy is always higher than the avoided total cost. The benefit of the DG owner is the difference between the avoided capex and the economic loss due to the low compensation price for curtailed energy. The economic loss is the value of the curtailed energy minus the compensation for it. It is better to curtail some energy for the DG owner when the compensation price is higher, and vice versa as shown in Fig. 5.5. The maximum benefit is 8.89 k€ when the compensation price is 0.11 €/kWh, while the the maximum benefit is 0 when the compensation price is 0.026 €/kWh.

Discussion

The non-compensated curtailment level in the quantity-regulatory approach for energy curtailment due to network constraints can affect the benefit for the DSO but not the optimal investment. Therefore, this level is used to share the cost between the DSO and the DG owners. The compensation price can affect the optimal investment for the DSO. Using the quantitative model, the compensation price which changes the optimal investment can be identified, in this case, the optimal investment for the DSO changes

Table 5.2: Results for the case under price-regulatory approach

λ_{cm}(€/kWh)	0.026	0.08	0.11
Total cost(k€)	481.487	480.980	472.596
Capex (k€)	481.487	472.405	461.757
Curtailment(%) (N22,N23)	0%, 0%	5.4%, 0%	16.8%, 0%
Connection lines	L21 AL1 T2	L13 AL2 T2	L13 AL1 T2
	L24 AL1 T3	L24 AL1 T3	L24 AL1 T3
Connection cost (k€)	28.53	37.33	26.68

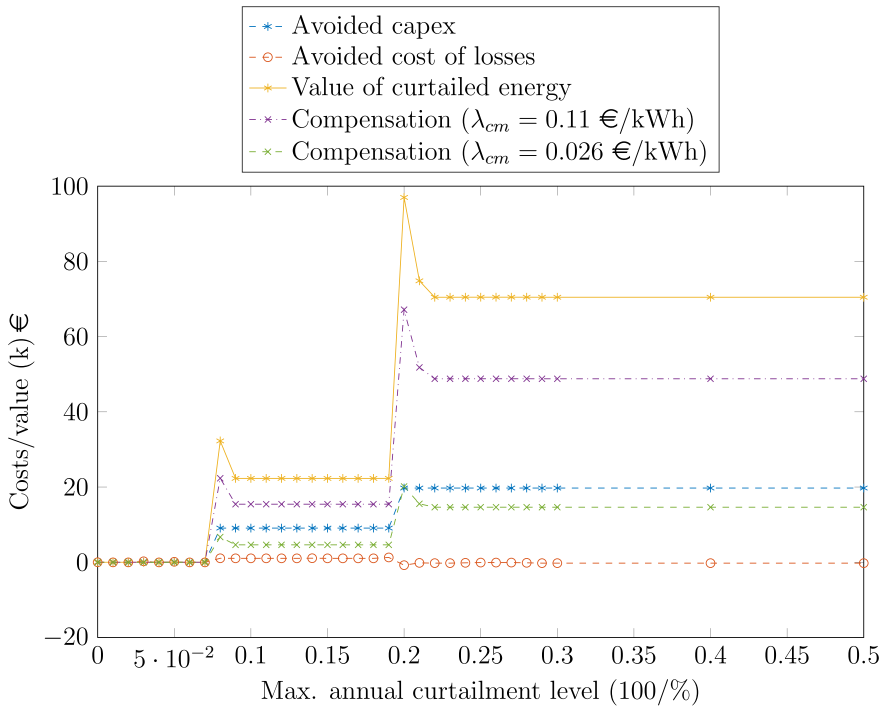


Figure 5.4: Avoided cost/value vs. Max. curtailment level.

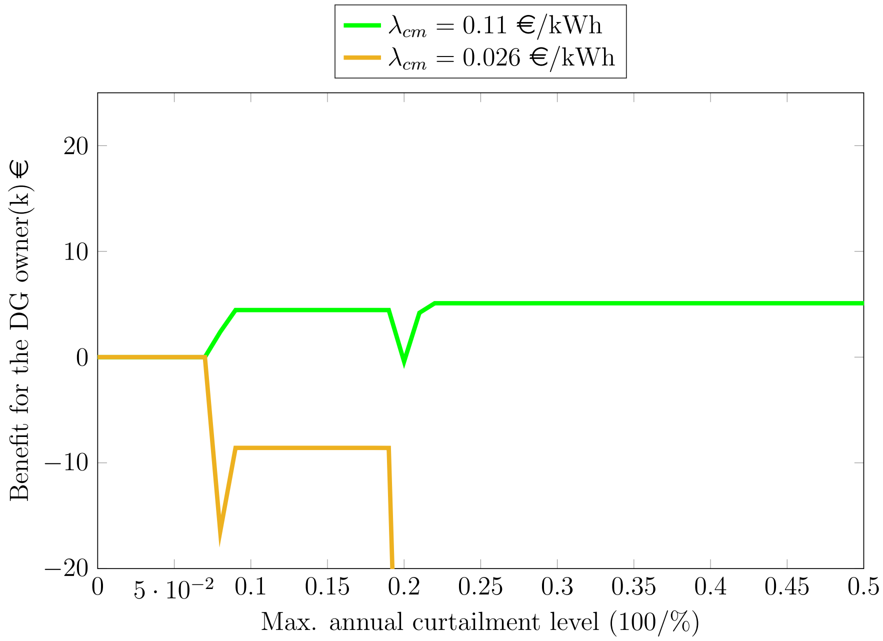


Figure 5.5: Benefits for the DG owners with different compensations.

when the compensation price is five times higher.

The compensation price in the price-regulatory approach for energy curtailment due to network constraints impacts the optimal network investment. When the price increases, the network investment decreases but not necessarily the connection cost. Furthermore, the compensation price indirectly drives the network reinforcement. In this case, when the compensation price is higher than 0.08 €/kWh and lower than 0.13 €/kWh (which is the electricity price for DG), two levels of network reinforcement are observed.

Comparing the avoided total cost in both cases, the avoided total cost is much lower in the case under the price-regulatory approach. This confirms that the deep connection charge gives locational incentives for the DG connection. Therefore, the DG connects to the points which causes less reinforcement in the network. The network cost is more sensitive to the compensation price in the case under the price-regulatory approach than that under the quantity-regulatory approach.

The value of curtailed energy is the total value over the planning horizon; however, the avoided total cost is the NPV of the investment. During the lifetime of the investment, curtailed energy is higher than is calculated here. Therefore, the value of curtailed energy is under-estimated and the value of allowing curtailment is over-estimated here.

For detailed results and analysis, please refer to Publication I.

5.2 Application of NIAM

The developed NIAM is applied on a remote windy area in Sweden, where a wind farm has been connected to the distribution network. More wind power (WP) plants can be installed in that area since the connection line has been built and the windy area can host more wind turbines. This model is able to identify the optimal number of WP plants in the network for applying SLR and DLR, and the level of utilization of the network in terms of the curtailed wind power. In addition, results from three kinds of DLR models are compared to show the advantages of the proposed DLR model.

In this example, the profits of installing another 1 to 7 wind power plants are investigated and stochastic variables are generated monthly. The DSO is obliged to connect customers (consumers and producers). However, the producer will pay for the investments needed for the connection (deep connection fee). Hence, it is necessary for WP owners to perform cost analysis on the possible ways to connect WP plants: whether to build a new line, or to apply DLR on the connection lines. On the one hand, extending the capacity of the lines (building one extra line) can be challenging in a reasonable time frame and budget and to refuse the connection of new wind farms is not an option. In some areas, it is increasingly difficult to build additional lines or even physical upgrading the old lines. On the other hand, DLR calculation is rather complex. And the difficulty is to make all power system players agree on and allow the risks.

In this case study it is found that if the wind speed is less than 1.34 m/s it is considered as low wind speed, i.e. when the wind speed is lower than 1.34 m/s, it is always applicable to use the low wind speed formula in (4.2), and when the wind speed is higher than 1.34 m/s, it is always applicable to use the high wind speed formula in (4.2).

The studied investment alternatives using the SLR model are named *SLR 1*, which applies SLR on the existing network to identify the network transmission limit, and *SLR 2*, which is to build an extra connection line in order to increase the transmission limit. Two variants of the proposed DLR calculation model presented in section 4 are also implemented as investment alternatives: *i*) a simplified version referred to as *DLR 1* when only the temperature impact on line rating is considered as in (4.7), *ii*) a simplified version referred to as *DLR 2* when only the wind impact on line rating is considered as in (4.5), and *iii*) the proposed DLR model is referred to as *DLR 3* which takes the temperature and wind speed impact on line rating into consideration as in (4.6). These five alternatives are compared to show the value of a complex DLR model considering both wind speed and temperature impact.

5.2.1 Case study for evaluating investment in DLR

Four aspects of five investment alternatives are analysed. First the different profits by different alternatives with an increase of the number of wind power plants are presented. Then the DiscENS values are compared with the increase of wind power plants. After that the optimal wind power plants to be connected to the grid is identified. Last the value of introducing DLR is presented.

Total profits

As the number of WP plants increases, the profits first increase and then decrease in any investment alternative as shown in Fig 5.6. Applying *SLR 1* in the existing network is profitable until the number of WP plants reaches six. Applying *SLR 2* becomes profitable when the number of wind power plants exceeds four. This investment alternative is not that attractive since even the maximum possible profit is very low. Comparing the profits of applying *DLR 1*, *DLR 2* and *DLR 3*, the profit of applying *DLR 3* is always the highest. The difference increses as the number of installed wind power plants. This shows that the if only one element is considered in DLR estimation, the potential of DLR is much underestimated.

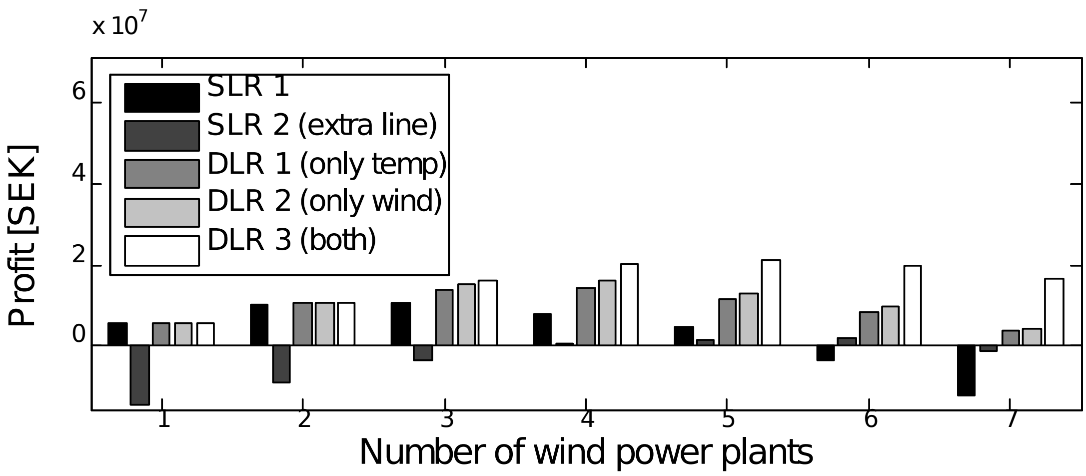


Figure 5.6: Total profits using different investment alternatives.

Table 5.3: Maximum profits and optimal number of WP plants using different investment alternatives

Option	Optimal nr.	Profit(SEK)		
		Aver.	max	min
SLR 1	3	$1.09 * 10^7$	$1.16 * 10^7$	$1.03 * 10^7$
SLR 2	6	$0.19 * 10^7$	$0.31 * 10^7$	$0.05 * 10^7$
DLR 1	4	$1.45 * 10^7$	$1.53 * 10^7$	$1.36 * 10^7$
DLR 2	4	$1.61 * 10^7$	$1.70 * 10^7$	$1.52 * 10^7$
DLR 3	5	$2.12 * 10^7$	$2.22 * 10^7$	$2.00 * 10^7$

Optimal amount of wind power

The optimal number of wind power plants for four investment alternatives can be observed from Fig 5.6 as well. Table 5.3 summarises the optimal decision. Using *DLR 3* can result the highest profit without considering the cost of introducing DLR. It shows that the optimal investment alternative is dependent on the potential of wind power resource or the wind power plants connection.

DiscENS comparison

The disconnected energy due to transfer limitations increases with the number of WP plants, as shown in Fig 5.7. It is always the option applying *SLR 1* that leads to the highest DiscENS. While the lowest DiscENS happens in applying *SLR 2* or *DLR 3*. *DLR 3* has the lowest discENS among all the DLR models. This shows that the proposed DLR model increases the utilization of the network. Moreover, the DiscENS in *SLR 1* option is much higher than that using *SLR 2*. This shows that building an extra line can decrease the DiscENS more efficiently than DLR option and increase the utilization of renewable energy significantly in this case.

The value of DLR

The cost of applying DLR is not included in the profit calculation. Therefore the difference between their profits, which reveals the value of implementing DLR (or the maximum investment in DLR in order to be profitable), is more relevant. It can be seen that the value of DLR is increasing as the number of WP plants increases. Figure 5.8

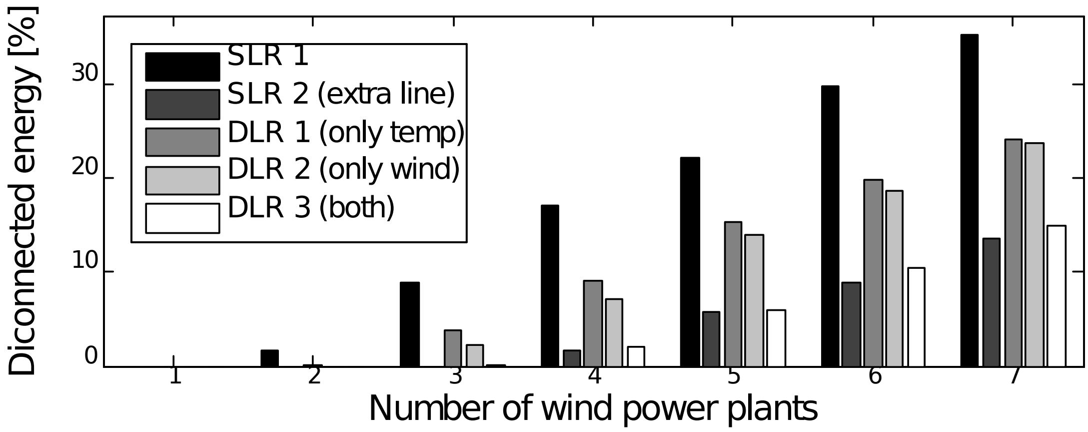


Figure 5.7: Disconnected wind power [%] using different investment alternatives.

shows different profits comparing DLR models to *SLR 1*. The difference reflects the the value of introducing DLR. In any model of DLR this value increases with the number of WP plants. When the WP plants are fewer, the value of using DLR is less. Introducing *DLR 3* has higher value than *DLR 2* and *DLR 1*. This value can be used to evaluate whether it is profite to install devices for DLR.

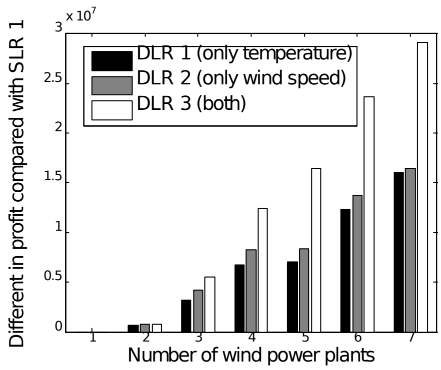


Figure 5.8: The value of applying DLR.

Discussion

With DLR, the limits of the lines are more accurate and better utilization of the network can lead to benefits. Consequently, the existing system can host more wind power without extension. The wind power plant owners can also export more power, consumers can purchase more green energy and the network owner can defer reinforcement of, and new investment in, lines. In other words, the same amount of wind power can be hosted with fewer and/or thinner power lines. On the other hand, sensors and other equipment have to be installed and a lot of data have to be managed in control rooms. Another possible disadvantage with DLR compared with installation of a new line of higher capacity is higher losses, because the same amount of power then is transported on a line with higher resistance. The control room and sensor issues can however be easier to solve using a simplified, but still accurate, DLR model as proposed here.

Chapter 6

Conclusions

In this project, the economic regulation impact on network investment is investigated. The proposed NIOM establishes a contribution to quantify economic incentive ex ante in the incentive regulation, as shown in Fig. 6.1. The quantified incentive of reaching a certain performance is the maximum cost that the DSO can benefit by investing in alternative solutions, such as active network management (ANM) technologies, to reach this performance giving the respective performance incentive. Given the desired performances by the regulation, the incentive for investing in any technology to achieve these performances is obtained from the proposed NIOM. Furthermore, the proposed NIOM also quantifies the impact of different curtailment regulations. DG curtailment is tightly related with DG connection charges; therefore, the cost and benefit, and DG integration levels are studied under different combinations of curtailment regulations and connection charge schemes.

Moreover, different ANM technologies can enable the DSO to achieve the goal that the regulation sets. The optimal investment considering specific innovative investment alternatives and traditional investment alternatives has been studied, for example implementation of dynamic line rating (DLR) in DG integration. In this project, a NIAM is proposed for implementing DLR in unbundled distribution network with DG integration.

Different service providers in power systems can benefit from the results. DSOs can use the NIOM or NIAM to optimise their investment, traditional and innovative alternatives, given DG integration and economic regulation. The ANM technology companies can use the results, such as the quantified incentive, as the benchmark for the cost of their products. The regulators can use the models to anticipate DSOs' investment and performance, and therefore design desirable regulation.

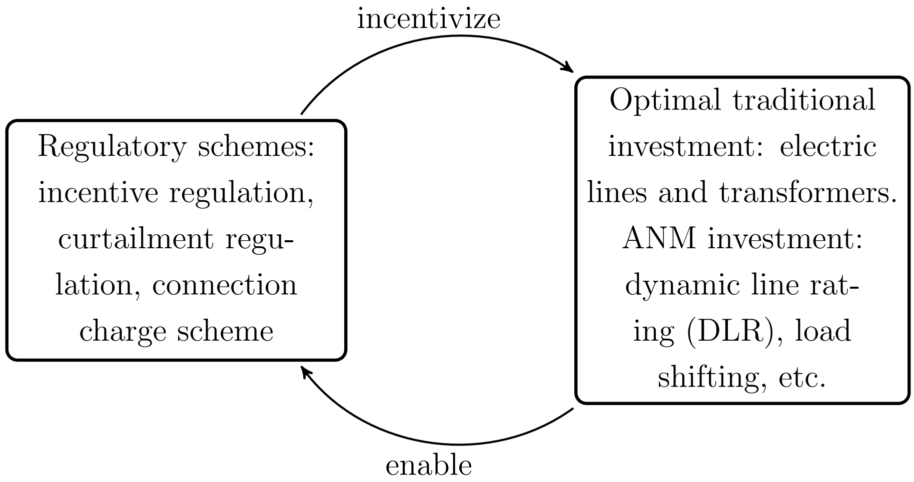


Figure 6.1: The relationship between regulation and investments.

6.1 Case study implications

The developed models have been applied in synthetic networks. Cases with different combinations of economic regulations are studied. Seven main conclusions drawn from these case studies are summarised below:

1. **Incentive on loss reduction**

   The reward/penalty price for loss reduction/increase, which is the economic incentive divided by the reduced losses in kWh, is 0.053 € in this case for the system with DG. It is 0.001 € higher than the expected electricity price. The reward/penalty price for loss reduction/increase is 0.048 €/kWh in this case for the system without DG, which is 0.004 €/kWh lower than the expected electricity price. These prices can be used as a benchmark to evaluate the cost to reduce losses. In the studied case, the incentive for loss reduction is not high enough to change the infrastructure investment.

2. **Incentive on a more even load profile**

   The increase of the load factor (which is the ratio between the average power and the maximum power at the feeding point) leads to a lower cost investment decision. The infrastructure investment cost decreases by 24% and 37% when the load factor increases from 0.5 to 0.6 in the case with and without DG respectively. With the same load factor value, the investment cost is lower in the system with DG than that without DG. This is because the DG in the system defers some of the reinforcements. Furthermore, the economic incentive for the DSO to invest in increasing the load factor, for example through demand side management, is high, accounting for more than 18% of the profit, in systems with or without DG.

3. **The limitation on the total economic incentive**

   The limitation on the total economic incentives is defined as a percentage of the total incentive account for the total profit. Different limitations (from 5% to 20% in the case study) can result in different solutions. However, the infrastructure investment cost does not change in this case study. The DSO would not invest more just to obtain higher incentives or invest less due to too low allowed incentives. Thus the limits on the total incentive do not distort the optimal solution from the infrastructure investment point of view.

4. **Curtailment regulation - quantity-regulatory approach**

   Results show that the higher the non-compensated curtailment level is, the lower the total expected cost for the DSO. However, the reinforcement plan is the same in both cases and therefore the capex is the same. The optimal curtailment level is higher when the non-compensated curtailment level is higher. Allowing a lower non-compensated annual curtailment level does not lead to more reinforcement for the network, since paying for curtailing energy in some years is more beneficial than reinforcing the network. Furthermore, the higher the curtailment is the lower the thermal loss is; however, the impact is small. In addition, the compensation price also has little impact on the investment decision. In this case, the optimal investment for the DSO changes when the compensation price is five times higher.

5. **Curtailment regulation - price-regulatory approach**

   The compensation price in the price-regulatory approach for energy curtailment due to network constraints affects the optimal network investment. When the price increases, the network investment decreases but not necessarily the connection cost. This is because a strong connection line can reduce the reinforcement in the rest of the network in some cases. Furthermore, the compensation price indirectly drives the network reinforcement. In this case, when the compensation price is between 0.08 €/kWh and 0.13 €/kWh (which is the electricity price for DG), three levels of network reinforcement are observed.

6. **DG connection charge**

The DG connects to the points which causes less reinforcement in the network under the deep connection charge case. The result confirms that the deep connection charge gives locational incentives for the DG connection. However, there is a trade-off between deep connection charges and facilitating entry for small-sized DG owners. The lack of transparency in calculating the connection cost can lead to an inefficient allocation of the grid capacity.

7. **Assessing investing in DLR**

   With DLR, the limits of the lines are more accurate and a better utilization of the network can lead to benefits. Consequently, the existing system can host more wind power without extension. The DG owners can also export more power, the network owner can defer reinforcement and new investment. In other words, the same amount of DG can be hosted with fewer and/or thinner power lines. On the other hand, sensors and other equipment have to be installed and a lot of data have to be managed in control rooms. Another possible disadvantage with DLR compared with installation of a new line of higher capacity is higher losses, because the same amount of power then is transported on a line with higher resistance.

Bibliography

[1] C. Batlle and C. Ocaña, *Regulation of the Power Sector.* Spring-Verlag, 2013, ch. Electricity Regulation: Principles and Institutions, pp. 125–150.

[2] U.S.- Canada power system outage task force, “Final report on the august 14, 2003 blackout in the united states and canada: Causes and recommendations,” Tech. Rep., 2004.

[3] D. 2003/54/EC, “of the european parliment and of the council of 26 june 2003 concerning common rules for the internal market in electricity and repealing directive 96/92/ec,” 2003.

[4] T. Gómez, *Regulation of the Power Sector.* Spring-Verlag, 2013, ch. Monopoly Regulation, pp. 164–170.

[5] M. Scheepers, D. Bauknecht, J. Jansen, J. D. Joode, T. Gómez, D. Pudjianto, S. Ropenus, and G. Strbac, “Regulatory improvements for effective integration of dg into electricity distribution networks,” Tech. Rep., 2007. [Online]. Available: http://www.ecn.nl/docs/library/report/2007/e07038.pdf

[6] G. Pepermans, J. Driesen, D. Haeseldonckx, R. Belmans, and W. D'haeseleer, “Distributed generation: definition, benefits and issues,” *Energy Policy*, vol. 33, no. 6, pp. 787–798, Apr. 2005.

[7] J. Gowdy and J. Venn, “Distributed generation and demand study - technology growth scenarios to 2030,” Regen SW, 2016, uK.

[8] T. Ackermann, A. Göran, and L. Söder, “Distributed generation: a definition,” *Electric Power Systems Research*, vol. 57, no. 3, pp. 195–204, Apr. 2001.

[9] A. Piccolo and P. Siano, “Evaluating the impact of network investment deferral on distributed generation expansion,” *Power Systems, IEEE Transactions on*, vol. 24, no. 3, pp. 1559–1567, Aug 2009.

[10] L. F. Ochoa, A. Padilha-Feltrin, and G. P. Harrison, "Evaluating distributed generation impacts with a multiobjective index," *Power Delivery, IEEE Transactions on*, vol. 21, no. 3, pp. 1452–1458, 2006.

[11] P. Siano, "Assessing the Impact of Incentive Regulation for Innovation on RES Integration," *IEEE Transactions on Power Systems*, vol. 29, no. 5, pp. 2499–2508, Sep. 2014.

[12] D. T. C. Wang, L. F. Ochoa, and G. P. Harrison, "Distributed generation and security of supply: Assessing the investment deferral," in *2009 IEEE Bucharest PowerTech*. IEEE, Jun. 2009, pp. 1–8.

[13] L. Kane and G. Ault, "A review and analysis of renewable energy curtailment schemes and principles of access: Transitioning towards business as usual," *Energy Policy*, vol. 72, pp. 67–77, 2014.

[14] L. Kane and G. W. Ault, "Evaluation of Wind Power Curtailment in Active Network Management Schemes," *Power Systems, IEEE Transactions on*, vol. 30, no. 2, pp. 672–679, Mar. 2015.

[15] Z. Hu and F. Li, "Cost-Benefit Analyses of Active Distribution Network Management, Part II," *IEEE Transactions on Smart Grid*, vol. 3, no. 3, pp. 1067–1074, Sep. 2012.

[16] E. J. Coster, J. M. A. Myrzik, B. Kruimer, and W. L. Kling, "Integration Issues of Distributed Generation in Distribution Grids," *Proceedings of the IEEE*, vol. 99, no. 1, pp. 28–39, Jan. 2011.

[17] R. Viral and D. K. Khatod, "Optimal planning of distributed generation systems in distribution system: A review," *Renewable and Sustainable Energy Reviews*, vol. 16, no. 7, pp. 5146–5165, Sep. 2012.

[18] S. Ropenus, H. K. Jacobsen, and S. T. Schröder, "Network regulation and support schemes: How policy interactions affect the integration of distributed generation," *Renewable Energy*, vol. 36, no. 7, pp. 1949–1956, Jul. 2011.

[19] S. Ropenus, S. T. Schröder, H. Jacobsen, L. Olmos, T. Gomez, and R. Cossent, "Assessment of interactions between the economics of distributed generators, distribution system operators and markets," Energy Research Centre of the Netherlands (ECN), Tech. Rep., 2009.

[20] H. K. Jacobsen and S. T. Schröder, "Curtailment of renewable generation: Economic optimality and incentives," *Energy Policy*, vol. 49, pp. 663–675, 2012.

[21] D. Bauknecht and G. Brunekreeft, "Chapter 13: Distributed generation and network regulation," in *Competitive Electricity Markets-Design, Implementation, Performance*, F. P. Sioshansi, Ed.

[22] J. De Joode, J. Jansen, A. Van der Welle, and M. Scheepers, "Increasing penetration of renewable and distributed electricity generation and the need for different network regulation," *Energy Policy*, vol. 37, no. 8, pp. 2907–2915, 2009.

[23] P. Frías, T. Gómez, and J. Rivier, "Integration of Distributed Generation in Distribution Networks: regulatory challenges," in *16th Power Systems Computation Conference*, 2008.

[24] Y. Huang, "Electricity distribution network planning considering distributed generation," 2014.

[25] de Joode J., van der Welle A., and J. J., "D10-business models for dsos under alternative regulatory regimes," DG-GRID Project, 2007.

[26] G. Guthrie, "Regulating Infrastructure: The Impact on Risk and Investment," *Journal of Economic Literature*, vol. 44, no. 4, pp. 925–972, Dec. 2006. [Online]. Available: http://www.jstor.org/stable/30032390

[27] S. Bergerland, C. J. Wallnerström, and P. Hilber, "Summary of the swedish tariff regulation and impact of changes on investmtent strategies," in *Proc. 23rd International Conference on Electricity Distribution, (CIRED2015)*, Lyon, France, 2015.

[28] E. Grahn, L. ström, and K. Alvehag, "Incentivizing continuity of supply in sweden," in *Proc. European Energy Market Conference, (EEM'16)*, Porto, Portugal, 2016.

[29] G. Gigenborg, L. W. Öhling, and C. J. Wallnerström, "Incentive scheme for efficient utilization of electricity network in sweden," in *Proc. European Energy Market Conference, (EEM'16)*, Porto, Portugal, 2016.

[30] Task Force DSO Investment Action Plan, "Electricity distribution investments: What regulatory framework do we need?" A EURELECTRIC report, 2014.

[31] European Regulators Group for Electricity and Gas (ERGEG), "Position paper on smart grids- an ergeg conclusion paper," Position Paper, 2010.

[32] Council of European Energy Regulators (CEER), "Ceer status review on european regulatory approaches enabling smart grids solutions," Ref: C13-EQS-57-04, 2014.

[33] C. Brandstätt, G. Brunekreeft, and K. Jahnke, "How to deal with negative power price spikes??flexible voluntary curtailment agreements for large-scale integration of wind," *Energy Policy*, vol. 39, no. 6, pp. 3732–3740, 2011.

[34] P. Frías, T. Gómez, R. Cossent, and J. Rivier, "Improvements in current European network regulation to facilitate the integration of distributed generation," *International Journal of Electrical Power and Energy Systems*, vol. 31, no. 9, pp. 445–451, 2009.

[35] Union of the elelctricity industry-EURELECTRIC, "Network tariff structure for a smart energy system."

[36] V. Sakhrani and J. E. Parsons, "Electricity network tariff architectures-a comparison of four OECD countries," International Council on Large Electric Systems (CIGRE), Tech. Rep., 2010.

[37] A. Castillo, P. Lipka, J. P. Watson, S. S. Oren, and R. P. O'Neill, "A Successive Linear Programming Approach to Solving the IV-ACOPF," *IEEE Transactions on Power Systems*, vol. 31, no. 4, pp. 2752–2763, Jul. 2016.

[38] R. Ranjan, B. Venkatesh, and D. Das, "A new algorithm for power distribution system planning," *Electric Power Systems Research*, vol. 62, no. 1, pp. 55–65, May 2002.

[39] S. Haffner, L. F. A. Pereira, L. A. Pereira, and L. S. Barreto, "Multistage Model for Distribution Expansion Planning With Distributed Generation ;Part I: Problem Formulation," *IEEE Transactions on Power Delivery*, vol. 23, no. 2, pp. 915–923, Apr. 2008.

[40] C. L. Borges and V. F. Martins, "Multistage expansion planning for active distribution networks under demand and Distributed Generation uncertainties," *International Journal of Electrical Power & Energy Systems*, vol. 36, no. 1, pp. 107–116, Mar. 2012.

[41] G. Celli and F. Pilo, "MV network planning under uncertainties on distributed generation penetration," in *Power Engineering Society Summer Meeting*, vol. 1. IEEE, 2001.

[42] G. Papaefthymiou and D. Kurowicka, "Using copulas for modeling stochastic dependence in power system uncertainty analysis," *IEEE Transactions on Power Systems*, vol. 24, no. 1, pp. 40–49, Feb 2009.

[43] H. V. Haghi, M. T. Bina, M. Golkar, and S. Moghaddas-Tafreshi, "Using copulas for analysis of large datasets in renewable distributed generation: {PV} and wind power integration in iran," *Renewable Energy*, vol. 35, no. 9, pp. 1991 – 2000, 2010.

[44] G. Papaefthymiou, "Integration of stochastic generation in power systems," Dissertation at Delft University of Technology, 2007.

[45] H. Heitsch and W. Romisch, "Scenario tree modeling for multistage stochastic programs," *Mathematical Programming*, vol. 118, no. 2, pp. 371–406, 2009.

[46] ——, "Scenario tree reduction for multistage stochastic programs," *Computational Management Science*, vol. 6, no. 2, pp. 117–133, May 2009.

[47] B. A. McCarl, A. Meeraus, P. van der Eijk, M. Bussieck, S. Dirkse, P. Steacy, and F. Nelissen, "Mccarl gams user guide," Version, 2014.

[48] K. Alvehag and K. Awodele, "Impact of reward and penalty scheme on the incentives for distribution system reliability," *IEEE Transactions on Power Systems*, vol. 29, no. 1, pp. 386–394, Jan 2014.

[49] European Regulators Group for Electricity and Gas (ERGEG), "Treatment of losses by network operators," Position Paper, 2009.

[50] L. Söder, "The value of wind power for an owner of a local distribution network," in *Proc. 15th International Conference on Electricity Distribution, (CIRED99)*, Nice, France, 1999.

[51] S. Nursebo, P. Chen, O. Carlson, and L. B. Tjernberg, "Optimizing Wind Power Hosting Capacity of Distribution Systems Using Cost Benefit Analysis," *IEEE Transactions on Power Delivery*, vol. 29, no. 3, pp. 1436–1445, Jun. 2014.

[52] V. Miranda, J. V. Ranito, and L. M. Proenca, "Genetic algorithms in optimal multistage distribution network planning," *Power Systems, IEEE Transactions on*, vol. 9, no. 4, pp. 1927–1933, Nov. 1994.

[53] H. Falaghi, C. Singh, M. R. Haghifam, and M. Ramezani, "DG integrated multistage distribution system expansion planning," *International Journal of Electrical Power & Energy Systems*, vol. 33, no. 8, pp. 1489–1497, Oct. 2011.

[54] "Ieee standard for calculating the current-temperature of bare overhead conductors," *IEEE Std 738-2006 (Revision of IEEE Std 738-1993)*, pp. c1–59, 2007.

[55] E. N. A. (ENA), "Engineering recommendation p27-current rating guide for high voltage overhead lines operationg in the uk distribution system," 1986.

[56] L. Ochoa, L. Cradden, and G. Harrison, "Demonstrating the capacity benefits of dynamic ratings in smarter distribution networks," in *Innovative Smart Grid Technologies (ISGT), 2010*, 2010, pp. 1–6.

[57] E. Fernandez, I. Albizu, M. Bedialauneta, A. Mazon, and P. Leite, "Dynamic line rating systems for wind power integration," in *Power Engineering Society Conference and Exposition in Africa (PowerAfrica), 2012 IEEE*, 2012, pp. 1–7.

[58] S. Abdelkader, S. Abbott, J. Fu, B. Fox, D. Flynn, L. McClean, L. Bryans, and N. I. Electricity, "Dynamic monitoring of overhead line ratings in wind intensive areas," in *European Wind Energy Conf.(EWEC)*, 2009.

[59] C. J. Wallnerström, "On incentives affecting risk and asset management of power distribution," Ph.D. dissertation, KTH, Electromagnetic Engineering, 2011, qC 20110815.

[60] Y. Huang, "23-node testing system," https://kth.box.com/s/6gsesmg05nlmb8lwquuh, KTH, Sweden, 2014.

ECONOMIC REGULATION IN POWER DISTRIBUTION

Driven by the target of a higher distributed generation integration and more efficient investments in the unbundled distribution networks, proper economic regulations are needed to facilitate this change.

This project has developed new tools and methods for evaluate the impact from regulations on distribution network investment considering distributed generation integration. In other words, this project aims to develop methods assist regulators to design desirable regulations to encourage the distribution system operators to make the "smart" decisions. At the same time, these methods assist distribution system operators to make the "right" investment in the "right" place at the "right" time under the given regulation.

Energiforsk is the Swedish Energy Research Centre – an industrially owned body dedicated to meeting the common energy challenges faced by industries, authorities and society. Our vision is to be hub of Swedish energy research and our mission is to make the world of energy smarter!

Energiforsk