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Abstract

In this thesis, a retail market mechanism that provides differentiated reliability services is proposed. The differentiated reliability services beyond the standard level utilize advanced metering infrastructure, automated distribution reconfiguration and distributed generation (DG). The service quality at the standard level is regulated, while high reliability services are offered through a market mechanism. This proposed market mechanism is designed in two different models of managing the distribution networks. The first model assumes that an independent distribution system operator (DSO) as an administrative firm provides operational support for delivery and reliability services in a retail market, while the second model does not have a DSO. Main reliability market participants are distribution utilities, retail electricity providers (REPs), non-utility-owned DG units, and end users. The REPs, as end users' representatives and aggregators, purchase delivery service with high reliability level and backup power from the utilities and DG units, respectively. The prices for these services are based on bidding by all market participants. Bids are created by each market participant optimizing its objective with respect to its own interests; therefore, the market participant can assess the investment costs and manage its own risk in setting the service charge. Notably, the proposed market mechanism, which is based on knowing customers' willingness to pay, and preferences for reliability, aims to give long-term investment signals to service providers for planning investments in new technologies at value. In addition, the provision of high reliability services can be considered a means that enables the service providers to improve system resilience. The modified IEEE Roy Billinton Test System Bus 2 is simulated to demonstrate proof-of-concept for the proposed retail market by showing the process of settling the service prices and utilities' expected compensation design. By comparing the settled service prices between the two market models, we show that the service prices are quite similar, but the number of end users obtaining backup power is different.

Keywords: electricity retail market, differentiated reliable service, reliability assessment, reconfiguration, distributed generation

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Chapter 1: Toward the provision of differentiated reliable services

A traditional electric power system is designed as centralized generation infrastructure, delivering power through transmission and distribution systems to end users. However, unexpected circumstances, such as sudden increasing of energy demands or equipment failure could cause interruptions in electricity delivery and, consequently, decrease reliability of the electric power system. In addition, the failures of power delivery usually originate in the distribution networks [1]. Although power interruptions rarely occur, their impact could cause from small to large damage, depending on various factors, such as time and duration of a power interruption, etc. Moreover, individual customers value a power interruption differently, which results in they having a different preference for a reliable service. For instance, customers who require high reliability are willing to pay more to avoid a power interruption.

Differentiated reliability service based on customers' preferences can be possible with available modernized technologies, such as advanced communication systems, distribution automation, and distributed generation (DG). These smart grid technologies have been increasingly integrated in distribution systems and enable utilities to effectively manage power outages. To assess reliability levels for customers, the value of reliability service to customers is a significant information that provides price signals to utilities to make informative and effective investments to adopt new technologies. However, this information is not taken into account in the current regulatory schemes of reliability. To include customers' reliability preferences in investment decisions, a market mechanism that offers differentiated reliability services beyond the standard level is proposed.

As smart grid features and technologies have been increasingly integrated in distribution networks, the reliability assessment and distribution operations will be more complex and need a new approach to support the integration and coordination of these new technologies in a cost-effective manner. In this chapter, we introduced current regulatory schemes of reliability in U.S. distribution systems and future tendency of managing the modern power grids, and gave overview of the provision of differentiated reliability services.

1.1 Regulatory schemes of reliability in U.S. distribution systems and their future tendency

Reliability of distribution systems is regulated by the state regulatory commissions. Most, but not all, state regulatory commissions have required utilities to report reliability performance of their regions every year. The reliability performance of distribution systems is related to the availability of the distribution facilities required to deliver power to customer load points. There are various reliability indices used to measure system reliability, but the two most common indices usually used in a report are the system average interruption frequency index (*SAIFI*), and the system average interruption duration index, (*SAIDI*) [2]. The utilities collect information on actual power outages, including outage durations and number of interrupted customers, and then calculate the reliability indices as following equations.

$$SAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers}} \tag{1-1}$$

$$SAIDI = \frac{\text{Sum of customer interruption durations}}{\text{Total number of customers}} \tag{1-2}$$

Details of collecting data related to power interruptions vary from one regulatory jurisdiction to another. These details depend on how the elements of an interruption are defined. For example, in some jurisdictions, sustained interruptions are defined as interruptions that last at least five minutes, while in other jurisdictions, sustained interruptions are those that last more than one minute. Besides, some jurisdictions may count outages resulting from storms, but not other severe weather or natural disasters. It should be noted that variation in the definitions of interruptions makes comparisons of reliability indices across jurisdictions difficult and inconsistent.

The reliability indices are used to establish guidelines and reliability target levels for utilities in operating and planning the systems. The guidelines and reliability target levels are usually implemented locally in jurisdictions. In tracking the reliability performance of utilities, the regulators usually compare the reliability performance of each utility to its performance in the past over years [2]. The historical data on reliability performance is deployed to assess an acceptable reliability level or a reliability target level for future reliability assessments.

The regulation of reliability in U.S. is based generally on cost of service (COS) and to a lesser extent, on performance based regulation (PBR). The regulation of reliability intends to assign appropriate cost responsibilities to utility companies so that the companies can provide reliable services according to the reliability target levels. However, both COS and PBR have strengths and weaknesses in providing reliability.

For COS, the regulatory rules ensure the utilities' capital cost recovery, but they do not provide incentives for cost efficiency [3]. Since the utilities have better information on costs than the regulator, they can estimate the service charges according to their investment costs plus some profits, while the regulator determines whether those service charges are justified or not. However, the regulator may have difficulties in making a fare judgment since the regulator may be unable to access to the relevant information or have limited understanding of that information. The regulation in which the utilities' cost and income are directly linked tends to be rather inefficient [4]. As a result, the utilities subjected to COS rarely have incentives to be economically efficient. In addition, this is likely to lead utility companies to over-invest in reliability; therefore, customers may unknowingly pay higher costs for services.

On the other hand, PBR promotes cost savings in a way that utilities will gain more profit from the cost they save. Basically, under PBR, an allowable price or total revenue cap of utilities is set over a given time period. This approach is also known as RPI–X regulation, where RPI refers to the Retail Price Index (like the U.S. Consumer Price Index), and X is the adjustment factor determined by the regulator. By reducing costs relative to RPI, the utilities are able to increase their profits. However, if incentives for cost savings are too strong, reliability of a system could be deteriorated from postponed maintenance and investments [5]. Therefore, PBR requires defining a proper performance matrix so that reliability is not degraded.

As distribution companies are expected to invest and operate the systems in a cost-effective manner, there are increasing interests in the implementations of PBR to regulate reliability performance of utilities. Under this regulatory scheme, the regulators can incorporate rewards or penalties for each utility according to reliability measures, such as frequency and duration of power outages that utilities can interrupt customers. For instance, rewards and penalties are assigned to Southern California Edison Company in respect of the average annual number and duration of interruptions in rolling two years with included storm events, but excluded catastrophic events [6].

Furthermore, regulatory schemes related to the provision of reliability have been expanded to a value-based planning framework. In this framework, the economic value of reliability improvements takes into account the costs and benefits experienced by both the utility and its customers. The value-based planning approach attempts to locate the optimal point of investment in reliability by considering the impacts on costs and benefits experienced by both the utility and its customers. The optimal point of investment, as shown in Figure 1.1, is where the sum of the utility cost and interruption cost is minimized. Besides, this optimal point could be considered a target reliability level for utilities to offer to all customers. The value based approach is considered to be one approach that promotes the reliability investments in a cost-effective manner. The reliability assessment in this framework, for instance, has been recognized by the state regulators, the Illinois Commerce Commission [7].

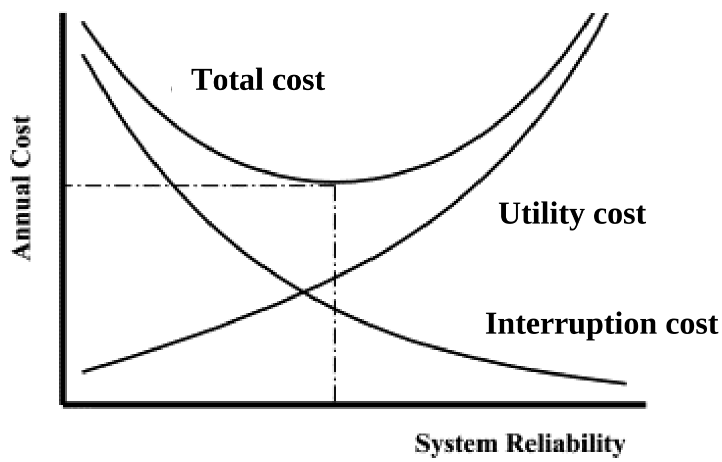


Figure 1.1: Cost/benefit analysis for system reliability

In assessing the costs and benefits of reliability investments, the utility costs related to enhancing reliability are estimated and verified from historical data on investments, operations and maintenance. On the other hand, the value of reliability service to customers is measured through the reliability impacts and interruption costs to customers, which are inherently more uncertain. Utilities usually have historical data of system reliability to calculate the reliability indices for system components. Based on the statistical data of system reliability, it is possible for the utilities to predict and observe the reliability improvement of modified systems. However, due to the variation of reliability indices year to year, the reliability assessments are not simple [7].

To estimate the interruption costs, there are a variety of methods to be adopted, such as macroeconomic method, survey-based method, case study, etc. The choice among these estimation methods can affect the average interruption cost estimates [7]. The most widely used method is a survey-based one because the interruption costs are estimated from customers' data and the costs obtained by survey can be applied to a wide variety of geographical areas and interruption circumstances [7]. For the U.S., an electric reliability planning tool known as Interruption Cost Estimate (ICE) Calculator has been developed by Nexant and Lawrence Berkeley National Laboratory. The tool provides estimates of the interruption costs and the value of reliability improvement in both a static and dynamic environment.

The investment assessment based on the value of reliability service is important in today's increasingly complex power system. Due to a vertically integrated electric industry, the reliability assessment of traditional power system is conducted separately without the collaboration between distribution and transmission systems. However, as distribution systems have increasingly integrated with smart grid features and technologies, the reliability assessment will be more complex and need a new approach to evaluate the new potential technologies in a way that is cost-effective and differs from traditional grid investments. The value of reliability service to customers is a significant information that provides price signals to utilities to make informative and effective investments. In addition, the information on customers' preference for reliability will enable the utilities to adopt other effective technologies to provide reliability services that fit to customers' needs.

The advent of smart grid features and technologies in distribution systems, such as distributed energy resource and demand response, have changed the system operations to be broadly decentralized and localized. There are various applications of distributed energy resource and demand response, and one of those applications is reliability enhancement. The presence of distributed energy resource and demand response in distribution systems has potential to improve reliability of both transmission and distribution systems, but this may need a new level of management to ensure that new services get delivered efficiently.

1.2 Options for managing the modern distribution system

As distribution networks are growing more complicated due to the presence of distributed energy resource and demand response, new approaches of distribution operations need to be developed to support the integration and coordination of these new technologies in a cost-effective manner. Different options of managing the modern power grids have been proposed. One option proposed by interstate renewable energy council is an integrated distribution planning (IDP) process [9], but this option is limit to deal with only the increased integration of distributed generation (DG). To take into consideration all available distributed energy resources, another direction of managing these complex distribution system, such as distribution system platform [10] and independent distribution system operator [11]-[13], has been proposed and gained attention recently; however, this option requires a reformation of distribution operations in the way that one entity is responsible for co-optimization of all available distributed energy resources.

The IDP is considered an approach to dealing with the high penetration of DG. The utilities are concerned about the increased integration of DG, since the traditional distribution systems were not designed to cooperate a large numbers of DG which can cause bi-directional power flow in the systems. This requires the utilities to process the interconnection of DG efficiently without degradation of service quality. To achieve that, the IDP determines the ability of distribution circuits to host DG by leveraging the exisitng distribution planning efforts with a consideration of anticipated DG growth. If the anticipated growth exceeds the available DG capacity on the distribution circuit, the utility can identify additional infrastructure that may be necessary to accommodate that anticipated growth. In addition, the utility may publish the available capacity of DG and any planned upgrades that would affect hosting capacity.

However, despite the limit of IDP which considers only DG, new option of managing the distributed energy resources and demand response, such as distribution system platform and independent distribution system operator, has been proposed. In the distribution system platform (DSP) and independent distribution system operator (IDSO) model, there is one entity that looks across all available options of distributed energy resource including demand response to optimize the distributed system. This entity will also interact with the bulk power system to make the most efficient usages of resources. The difference between these two models is that for DSP, existing utilities are expected to play a role as service providers, while IDSO is an independent market-maker, which is the entity separated from the existing utility. The way that the existing utilities still play a role as service providers may cause difficulties in setting up a regulatory environment that effectively incentivizes the distribution utility to optimize across all possible distributed energy resources.

1.3 Toward the provision of differentiated reliability services beyond the standard reliability level

As electric distribution networks move toward modernized distribution grids, they will become capable of supporting a more efficient integration of new technologies, and of providing differentiated services specified by the customer needs. These modernized distribution grids will open opportunities for service providers to offer differentiated electricity services to customers who may have preferences for specific service attributes.

One of basic service attributes needed is differentiated reliability provision at value. Customers not only desire for more reliable services, but they also have different preferences and willingness to pay for reliability. Customers' preferences for reliability depend on how they value the electricity service. If customers are less accepting of power outages, they are likely to pay more to obtain a more reliable service. On the other hand, some customers will be more tolerant of power interruptions so they tend to pay less if reliability is improved. This variation among customers' exposure to risks from the grid disruptions will lead to variation among preferences for reliability.

If a charging price for a reliable service was not a concern, all customers would prefer to receive the most reliable service. However, investments in reliability are made based on making a compromise between reliability benefits and cost; reliability is invariably related to the risk of service interruptions. The provision of high reliable service will come at a cost of service. Customers have different preferences and willingness to pay for reliability; therefore, it is necessary to account for these differences when designing for reliability. Notably, undifferentiated provision of reliability indirectly forces customers to pay for the service that they may value differently [3].

We start by observing that provision of reliability options to customers is possible in the modernized electricity networks where advanced communication systems are used to support network reconfiguration and participation of DG. An advanced communication system enables utilities to monitor and operate the power grids during abnormal conditions more effectively. The data collected from monitoring the systems could be used to predict the possible failure events and their locations [14]. This would prevent power outages beforehand and decrease the chance of power outages in the systems. In addition, detecting faults as soon as they occur would also decrease the outage duration.

In addition, with the advanced communication systems, network reconfiguration can be done remotely to reroute power when a usual route is unable to deliver power to customers. Furthermore, if the grids are isolated from the main substations, DG as backup generators in the isolated grids will be called to serve customers. These available technologies will open opportunities for utilities to offer differentiated reliability services to customers according to their preferences.

However, at present customers' preferences for reliability are rarely taken into account when making investment decisions in enhancing reliability. Current practices to reliability investments tend to focus on cost-benefit decisions in order to acquire the optimal reliability, where the total cost of the investment cost and customer damage cost is minimized as averaged over all customers served. These decision practices, which neglect the truth that customers have different willingness to pay and preferences for reliability, could lead to an inaccurate assessment of the true value of investments in reliability. The value of reliability can be revealed through the customers' willingness to pay and preferences. The information on customers will provide price signals to service providers in order to make informative and effective investments.

To include customers' reliability preferences in investment decisions, we propose a market mechanism that offers differentiated reliability services beyond the standard level. This standard level is considered a basic required service provided to all customers. The standard level is regulated and evaluated based on social value by a cost-benefit analysis. On the other hand, the reliability service above the standard level offers options to customers who are willing to pay more. The high reliability service will be offered in a form of a delivery service with high reliability level for given pre-arranged power supply. To determine the cost of high reliability, the mechanism is designed to unbundle the costs of providing the higher reliability service from the costs of providing the standard delivery service. Accordingly, the charge for a high reliability service will be an addition to the charge for a standard delivery service.

The reliability options will be offered to customer groups rather than to individual customers. Customers may be classified into different groups corresponding to their locations, and preferences. For instance, people living in the same neighborhood and preferring high reliability service could be considered one customer group. However, if customers living in the same areas select different reliability levels, customers choosing the high reliability service will receive a priority to be served, while customers not purchasing the high reliability service may be disconnected in order to avoid free riders.

Since the differentiated reliability services are offered beyond the standard levels, utilities must make sure that the service quality that all customers currently receive meets the standard levels. The standard levels, which can be different depending on customers' districts or regions, could be set according to the historical reliability levels or the levels assessed by the value-based approach. Therefore, before offering the high reliability services, utilities are required to evaluate the reliability levels that customers currently receive, and ensure that those level meet the standard levels of those areas. To enforce these practices, regulators may apply penalties to the utilities if they fail to provide such services.

The proposed market mechanism will be one means that supports the provision of differentiated reliability service. The market mechanism will enable service providers to obtain explicit investment signals in integrating new technologies into the systems which are able to offer differentiated services according to customer preferences. In this work, the technologies deployed to provide differentiated reliability services are distribution automation including communication and control systems, network reconfiguration and DG. The implementations and challenges of integrating these technologies are discussed in chapter 2.

In the provision of high reliability services, utilities are obligated to meet reliability targets offered to customers. To meet a reliability target, the utilities can deploy results from reliability evaluation to plan investments, operations and maintenance in enhancing reliability. In addition, data related to power outages can be processed into useful information for managing power outages. A framework for achieving the reliability target and a basic reliability evaluation are introduced in chapter 3.

The proposed market mechanism is designed based on two restructured retail market models: one with an independent distribution system operator (DSO) and another one without DSO. The DSO is an administrative firm that provides operational support for delivery and reliability services in a retail market. In these both models, a distribution utility will not interact with end users; load serving entities, which in this work is called retail electricity providers, will have this duty and be responsible for aggregating loads and customer information, and purchasing electricity services for their customers. The problem formulations including numerical examples are explained in chapter 4 – 6. In chapter 7, comparison of two market structures and an issue of liability costs of utility are provided.

Chapter 2: Available technologies and challenges in support of differentiated reliability options

We start by observing that provision of reliability options to customers is possible in the modernized electricity networks where advanced communication systems are used to support network reconfiguration and participation of DG. Various communication and information technologies enable utilities to monitor and operate the power grids during abnormal conditions more effectively. With the advanced communication systems, network reconfiguration can be done remotely to reroute power when a usual route is unable to deliver power to customers. Furthermore, if the grids are isolated from the main substations, DG as backup generators in the isolated grids will be called to serve customers. These available technologies are available and will open opportunities for utilities to offer differentiated reliability services to customers according to their preferences. The implementations and challenges of integrating these technologies are discussed as follows.

2.1 Reconfiguration by switching devices

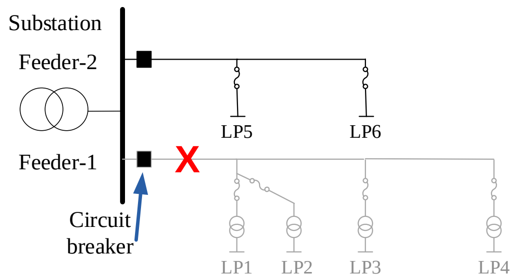
Network reconfiguration, which is the process of operating switching devices to change the topological structure of networks, can be deployed for several purposes. The reconfiguration can be applied to reduce losses, balance feeder loads and alleviate overload conditions of a network [15]-[17]. The reconfiguration can improve power quality issues such as voltage deviation [17], voltage stability [18], and voltage sags [19]. In addition, the reconfiguration can offer reliability improvement in distribution networks [20]-[24].

In this work, network reconfiguration is deployed to improve reliability by rerouting power flows when a usual route is unable to deliver power to customers [21]. The reconfiguration can be performed by opening and/or closing switching devices installed in distribution networks, such as circuit breakers (CBs), reclosers, normally closed switches (NCSs) or normally open switches (NOSs), to alter the topological structure of distribution feeders. The reconfiguration of the distribution network requires supervisory control and data acquisition (SCADA) to monitor and control switching devices remotely from a control center according to systematic reconfiguration algorithms.

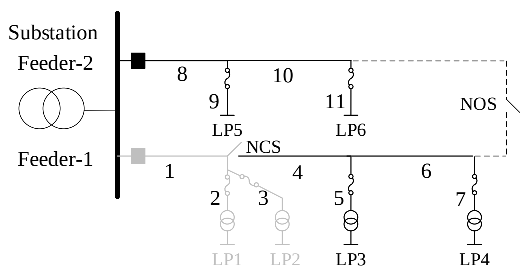
These switching devices are capable of different functions [25]. CBs and reclosers can autonomously interrupt fault currents and perform load switching commands. The operation of CBs and reclosers is generally based on time-current so with proper coordination, they can remove fault currents independently of remote communication systems. In other words, CBs and reclosers can utilize the information from local relays, such as current or voltage, to trip the switches.

On the other hand, NCSs are solely capable of executing load switching commands, but they are easily coordinated with other protective devices without changing the settings of the previous coordination. NCSs can be equipped with CBs or reclosers to isolate permanent faults to limit outages to smaller sections. Typically, a NCS counts fault interruptions that trigger the CB or recloser to open the circuit. When the count reaches the programmed number of interruptions, the NCS will automatically open. For NOSs, they will be remotely signaled to open and close.

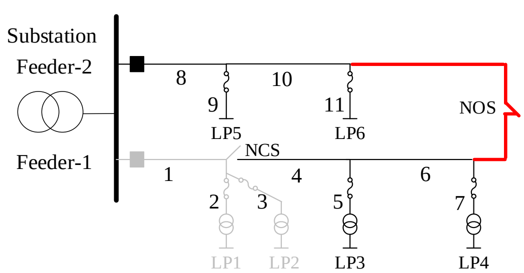
To illustrate how switching devices can be used to reroute power, simple reconfiguration is shown in Figure 2.1. Supposed that a fault occurs at “X” as shown in Figure 2.1-(a), CB will operate to remove fault current from the system; consequently, all end users located behind the CB will be interrupted. However, if NCS and NOS are installed in the system as shown in Figure 2.1-(b), the CB operates to interrupt the fault current flowing from the substation, and then the NCS opens to limit the interruption to the first two load points. After that, the NOS is closed to connect between two feeders so that the load points behind the NCS can be supplied by another feeder as shown in Figure 2.1-(c).



(a) CB clears the fault and leads to all loads behind the CB disconnected



(b) CB opens to clear the fault and NCS is opened to disconnect LP-1 and LP-2



(c) NOS is closed to reroute power

Figure 2.1: Reconfiguration of distribution system when a fault occurs near a substation

The installation of switches for the reconfiguration of the network should balance the benefits in reliability improvement against the costs of switches. While more “smart” switches operated according to systematic reconfiguration algorithms generally improves reliability level, the decision to install them must be compared to the investment costs. Therefore, the placement of switches requires optimization of both investment costs and cumulative reliability enhancements over longer time periods [26].

In addition, if the system already has numerous switches, operators tend to prefer to minimize the switching operations in restoring a service, since more number of switching operations implies incurring in additional operation costs [27]-[28]. Furthermore, due to the numerous numbers of switches in the distribution system, the possible switch operations can become a complex decision-making for system operators in real time. To solve this problem, algorithms for real-time network reconfiguration have been developed. For instance, the reconfiguration algorithms may deploy heuristic graph compression to reduce operational complexity [29], or a switching logic for reconfiguration may be determined in advance and stored in a database for the use by system operators in real time [30].

2.2 Distributed generation

Distributed generation (DG) refers to generating power close to end users by small-scale technologies. DG’s size and location are considered the key features that make DG differs from conventional centralized generation. Due to the small size of DG, it can be installed on medium and/or low voltage distribution network. DG will offer flexibility for sizing and siting into the distribution network.

In today's distribution networks, the use of DG can offer several benefits, such as provision of voltage support [34]-[35], reduction of power losses [36]-[37], improvements in power quality [38]-[39], reductions in land-use effects, and reduction in vulnerability to terrorism [31]. DG can be utilized to enhance system reliability and resilience, such as provision of backup power to the individuals or entire grids. The installation of DG in distribution networks can improve reliability on the transmission level by providing spinning reserve and transmission capacity release. The use of DGs for reliability purpose depends on their size and location [32].

The integration of DG in distribution grids can ensure the continuity of electricity services when power interruptions happen in distribution and transmission systems. The installation of DG units spread over the grids can improve system reliability, since the grids can be served by any of these generation spots [32]. In addition, during unexpected situations such as emergency or system outages, DG as on-site standby generation can be deployed to supply electricity to customers and critical loads [40]-[41]. The presence of DG in the grids can lessen the dependence on one centralized generation and decrease the risks of losing electricity due to faults in the distribution and transmission level. As a result, the DG can increase system reliability, and improve infrastructure resilience.

DG can be considered reserve power, used for peak load shaving and load management programs [42]. One benefit of reserve power in distribution networks is to avoid congestions in networks. With the proper size and location, the DG can reduce power flow inside the transmission network to fit transmission capacity and improve voltage profile [42]. Since the DG is not restricted by the centralization of the power, it can be placed in the certain locations where peak load originates, and the costs needed to update system for that peak is allocated to distribution networks or customers that create those peaks, not to all customers. This could lead to an efficient estimation of available reserve and deter the building of new power lines, while customers would be charged for reliability with a fair price.

The DG units utilized for the reliability purpose are usually called to supply loads only during unexpected circumstances such as peak load or system outages. These DG units should be allowed to operate in an islanding mode, which is a situation that the isolated grids are supplied by only local DG units. The DG units serving the grids for the reliability purpose must be reliable so that they can respond promptly to unexpected changes in the system. DG technologies that are usually used to enhance reliability, for instance, are diesel generators, and combined cycle gas turbines. The intermittent energy resources can be also utilized as a backup power supply, but they are necessary to have energy storage, such as battery.

The DG in distribution networks can lead to complexity in operation, control and protection of the networks. Most conventional distribution networks have a simple protection system, and are not designed to support the injected current of DG which causes bidirectional power flow in the networks. In addition, since DG may be operated in an islanding mode, the communication systems are required to monitor and control DG during the process of isolating and reconnecting the grids. Notably, the operating strategy of distribution networks and protection systems need to be revised before deploying DG.

In addition to the technical issues, the implementations of DG are complicated due to economic and procedural barriers. For instance, the tariff structure should be redesigned corresponding to the value of DG in order to give the efficient incentives to the utilities in integrating DG. Without proper incentives, the utilities may see DG as a burden since they have to pay for the costs of system upgrades and deal with the technical issues caused by DG.

Consequently, the utilities hesitate to allow the integration of DG. These barriers should be eliminated to open an opportunity for DG to be considered as one potential solution of reliability problems. To achieve that, new regulatory approaches or the necessary market mechanisms should be established.

2.3 Distribution automation including communication and control systems

The key feature that makes electric grid smarter is an information exchange among entities within the system, which requires communication and control systems. By collaborating communications and control systems with field devices in the networks, distribution automation (DA) is developed to assist system operators to acquire data from sensors, process the data, and send control signals to perform a number of distribution system functions. Therefore, communications and control systems change a passive distribution system to an active or responsive one.

In the DA, communication networks are designed to deliver control signals and information between control systems and distribution automation devices. Basically, the communication systems, such as supervisory control and data acquisition (SCADA), are used to connect between distribution management system (DMS), which is a IT system at the control center, and substations, while the wireless or power line carrier communications are used to connect between substations and field devices [43]. The degree of complexity of the communication networks depend on how control signals and information are utilized in the grid. The example of an integrated high performance and highly reliable communications network for successful deployment and operation of a smart grid is presented in [44].

One of DA applications is enhancement of reliability. DA enables distribution networks to respond to power interruptions more efficiently. With DA, data from sensors, monitors, and field devices will be sent to a DMS, which works as visualization and decision support systems, to assist system operators in monitoring and controlling distribution systems. The DMS can also interface with information management tools, such as outage management systems (OMS), geographic information systems (GIS), and customer information systems (CIS), for an efficient outage management and a full view of distribution operations [43]. These new functions are referred to as remote automated monitoring and control in distribution grids.

With this remote automated monitoring and control technologies, utilities are capable of identifying faults and executing emergency operations to limit the outages and restore the distribution systems efficiently. The utilities can determine the scope of outages and the likely location of problems based on the complied information on customer calls, smart meter outage notifications, and fault data from substations and devices on feeder lines, and send repair crews to certain outage locations more quickly with information on the problem they will need to solve.

In addition, the monitoring and control technologies enable the utilities to acquire accurate detailed data to assess reliability of customers and relate it to the grid equipment status. The utilities can monitor distribution system conditions as well as feeder and equipment conditions that may contribute to faults and outages. The statistical data of faults and equipment failures that have been collected for years can be used to predict likely outages and schedule maintenance before the occurrence of interruptions. The results of such data-supported reliability evaluation can be used to plan operations and maintenance as well as investments in reliability enhancements.

It should be noted that although reliability is at the forefront of these and drives utilities to upgrade the grid with DA equipment, this upgrade will be cost-effective if DA is deployed in support of many functions, not any specific function [45]. Besides the reliability enhancement, DA can support other functions in distribution systems, such as monitoring and controlling voltage and voltage-ampere reactive, demand response or distributed generation, etc. By deploying DA, operations and maintenance of systems will be more efficient and effective.

2.4 Application of network reconfiguration and DG in support of differentiated reliability options

Modernized utilities owning and operating the necessary equipment and communications can implement network reconfiguration and management of DGs to provide differentiated reliability of service. The network reconfiguration becomes a basic means of rerouting power to customers who opt for high reliability. To reconfigure the networks, SCADA is required to monitor and control switching devices remotely from a control center according to systematic reconfiguration algorithms which are optimized to ensure differentiated power delivery. In addition, the reconfiguration needs to coordinate with direct load management (DLM) or advanced metering infrastructure (AMI) to control loads, and ensure that certain customers receive reliability services as they pay.

DG is used as a backup power to serve customers who demand high reliability when power grids are disconnected from the main substations. DG is called to serve customers only during abnormal conditions so they are in a standby mode for most of the time. To incentivize the participation of DG units in providing such a service, these DG units may get paid two different rates, one rate is when the DG units are in a standby mode, and another rate is when the power is actually delivered to customers [46]. In addition, a long-term contract, which could be lucrative for DG owners, may be applied to attract local generators to provide backup power.

Protection systems must be revised to account for changes created by reconfiguration and presence of DG. The integration of DG could alter fault currents, depending on the size, number and location of the DG [47], and could cause bidirectional fault currents. To detect reverse fault currents from the DG, relays should upgrade to bidirectional relays. In addition, another possible method to detect faults in such a situation is digital protective relays. The digital protective relays are programmable based on microprocessors and the new relays can be equipped with monitoring capabilities. Therefore, the digital protective relays could deploy novel approaches to identify equipment exposed to conditions outside the acceptable operating range. For instance, smart protective relays develop a machine learning approach based on binary hypothesis testing, support vector machines to detect fault conditions [48].

Furthermore, the communication systems are required to monitor DG during the operation in islanding and grid reconnection mode [49]. Voltage and frequency in an isolated grid must be monitored and controlled in order to keep the balance of power supply and demand. To reconnect the islanded grid back to the utility grid, the difference of voltage angle between both grids should be synchronized before reconnection. Moreover, load asymmetry and single-phase DG units in distribution networks can lead the voltage phase difference in every phase A, B and C; therefore, asymmetry between phases should be reduced before resynchronization of both grids [50].

One concern with providing the differentiated reliability service is delivering the service to certain customers in the same load point. To achieve this, distribution automation and SCADA are required for coordinating switching devices and DLM/AMI to disconnect customers who do not pay for the high reliability level. The utility will have information on the reliability level of each customer, and determine the disconnection logic of customers in advance. The DLM/AMI allows system operators to disconnect particular customers at each load point [33]. The disconnection of these customers should be done in order to avoid free riders. The DLM/AMI should be developed to connect customers' appliances for the uses during a normal and abnormal condition. For example, customers would receive power to run all appliances they need during a normal condition; however, there would be a switch that could limit customers' electricity usage during an abnormal condition. Another way to provide reliability options is to offer customers living in the different areas with different reliability levels.

2.5 Summary

In the modernized electricity networks where advanced communication systems are used to support network reconfiguration and participation of DG, it is possible to offer reliability options to customers. An advanced communication system enables utilities to monitor and operate the power grids during abnormal conditions more effectively. With the availability of advanced communication systems, network reconfiguration can be done remotely to reroute power when a usual route is unable to deliver power to customers. Furthermore, if the grids are isolated from the main substations, DG as backup generators in the isolated grids will be called to serve customers. These available technologies will open opportunities for utilities to offer differentiated reliability services to customers according to their preferences. However, one should not underestimate the challenge of innovating while attempting to implement such novel solutions since these new technologies could create impacts of economics, risks and uncertainties on utilities' system planning and operations.

Chapter 3: Overview of framework for achieving a reliability target

In the provision of high reliability services, utilities are obligated to meet reliability targets offered to customers. To achieve a reliability target, utilities no only depend on investments in enhancing reliability, but also on operation and maintenance planning including the execution of the plans. The effective decisions on investments, operations and maintenance can be made based on the results of assessing system reliability, which requires accurate and sufficient reliability data. In this chapter, we give an overview of how utility can meet the reliability targets and discuss some policy implications that would encourage utilities to meet these.

3.1 Basic framework for achieving a reliability target

Utilities are expected to provide reliable services that meet the reliability target set by regulators. Several state regulators in the U.S. have set the minimum reliability levels to be maintained by utilities [51]. The minimum reliability levels are considered a basic required service provided to all customers. The standard reliability level can be set according to the historical reliability levels of that distribution system or assessed by the value-based approach, which considers the impacts on costs and benefits experienced by both the utility and its customers.

In addition, in establishing and monitoring reliability standards, customer satisfaction for services and characteristics of individual distribution systems, such as design or geography, should be taken into account [52]. The reliability standards can be specified based on load point indexes [51], [53] and system indexes [54]–[56]. The reliability indexes can be monitored on an annual basis [54], [56], or for two or more consecutive years [51], [57].

The integration of digital communication systems and information technologies enhance the abilities of utilities to monitor and control equipment and devices in distribution system. This results in utilities being able to integrate new technologies, such as advanced metering, distribution automation, distribution generation and distributed storage, etc., to enhance reliability and manage power outages efficiently. In addition, with these communication systems and information technologies, monitoring the reliability and collecting data related to power outages become possible. The data related to power outages, such as weather, operation and maintenance, age of equipment etc., can be processed into information on failure of equipment or components in the systems [58]-[68]. The accurate and sufficient data will enable utilities to assess reliability of equipment and reliability of customers. The results from the reliability evaluation can be used to plan the investments in enhancing reliability and the operation and maintenance as shown in Figure 3.1.

In modernized distribution systems, information management is considered one of the important parts of power outage management. As shown in the framework, data related to power outages can be turned into useful and actionable information that enables grid operators and repair crews to manage outages and restorations more precisely and cost-effectively. In addition, the results from reliability evaluations will enable the utilities to make effective decisions on investments in reliability, and make optimal plans for the operation and maintenance of networks. The optimal operation during power interruptions can minimize the impact of faults, while the optimal maintenance planning will prevent the faults and decrease a chance of power outages. The effective decision on the investments, operations and maintenance will result in utilities saving costs of providing reliable services.

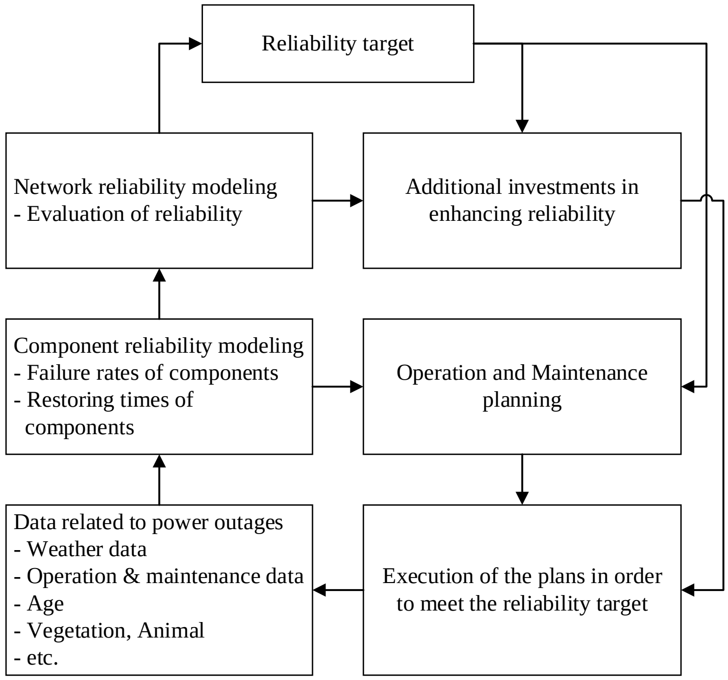


Figure 3.1: The basic framework to achieve the reliability target by operation and maintenance planning and additional investments in reliability

3.2 Importance of failure rate and repair time to reliability evaluation and operation and maintenance

In the evaluation of reliability, information on failure rates and repair times of components is necessary. The failure rates and repair times are statistical data determined from the aggregated data of failures occurring in system and their down time durations. These data can be established from operational field data or experimental testing [58]. The data collected from the actual systems are likely to give more accurate information on failure rates and repair times of equipment, but this can take years to collect sufficient data since power outages do not often happen.

On the other hand, experimental testing is usually conducted by equipment manufacturers under controlled conditions, but these conditions may not cover the actual conditions when equipment are used in real systems. To use these data, the actual conditions of system need to be included. Factors that could affect the failure can be classified into three main categories: (1) endogenous factors, such as material, length, or age, (2) exogenous factors, such as weather condition, or environment, and (3) operation and maintenance factors, such as voltage, current, or, maintenance action [59]. For the repair times of components, they are usually influenced by weather conditions and available repair resources [60].

The failure rates and repair times are unique characteristics of systems. It is best to use data acquired from one's own system. The availability of these data including the data of factors previously mentioned would improve modeling of failure rates and repair times of components. The simplistic model using average failure rate values can produces useful results for design and planning of the reliability enhancement [61]. For more accurate failure rates, models of estimating failure rates will include other factors, such as weather [62], age [63], or vegetation [64].

However, if the reliability data are unavailable due to poor quality or deficiency of information, it is possible to use data from other pooled data that have some similar reliability measure, and such similarities are usually found in components or systems that have operated under the same environmental and operational conditions. To use data from other sources, we need to perform confidence interval analysis [65]-[66], or deploy sophisticated Bayesian approaches to extract specific reliability data from the database [59].

The information on a probability that equipment could fail is also important in operation and maintenance. By monitoring equipment condition, it is possible to predict the chance that the equipment could fail. If the component has a high probability of failure, it can imply that the component is likely not in a good condition [67]. By knowing the probability of equipment failure, it is possible to schedule preventive maintenance on the right equipment at the right time before failures happening [67]. The protective actions can improve reliability, and for many failure causes, the protective actions are more efficient and cost effective in preventing and eliminating those causes [64].

With the information on equipment conditions, utilities can make the effective operation and maintenance planning for providing reliable services to customers. The utilities can conduct the acquisition, use and disposal of assets in respect to the reliability benefits, costs and risks over the life time of assets [68]. Knowledge that is extracted out of equipment conditions will support the future decision making of the utilities so the utilities can manage their assets more effectively. Decisions associated with operations and maintenance are made based on compromising between reliability benefits and spending cost through accepting a level of risk.

Therefore, by collecting appropriate data, utilities will be able to evaluate reliability of equipment and apply results of that evaluation in planning, operating and maintaining of reliability. To obtain sufficient and accurate data for the reliability evaluation, monitoring reliability and collecting the data should be done in details at a component level, and then build up to a network level by incorporating communications and information technologies. Such monitoring will improve visualizing grid status and foreseeing imminent failures.

3.3 Reliability evaluation and its implementations

3.3.1 Basic evaluation of expected reliability level [69]

For planning, utilities can use analytical techniques to evaluate an expected reliability level of each load point (LP) in terms of expected failure, λ (failure/year), and expected annual outage time, U (hours/year). The analytical techniques estimate the outages at each load point when each component is unavailable by representing components of a system in a mathematical model of failure and restoration processes. One of important assumptions behind the analytical techniques is that the component failures are independent events.

Since a network is composed of number components, the analytical techniques may combine with approximate techniques to reduce sets of considered components into one equivalent component. As components in the network are connected in series or parallel, a failure rate, λ_{eq} (failures/year) and repair time, r_{eq} (hours) of the equivalent components can be calculated as follows.

For N components in series,

$$\lambda_{eq} = \sum_{n \in N} \lambda_n \tag{3-1}$$

$$r_{eq} = \frac{\sum_{n \in N} \lambda_n r_n}{\sum_{n \in N} \lambda_n} \tag{3-2}$$

For 2 components in parallel,

$$\lambda_{eq} = \frac{\lambda_1 \lambda_2 (r_1 + r_2)}{1 + \lambda_1 r_1 + \lambda_2 r_2} = \lambda_1 \lambda_2 (r_1 + r_2) \tag{3-3}$$

$$\text{when } \lambda_n r_n \ll 1$$

$$r_{eq} = \frac{r_1 r_2}{r_1 + r_2} \tag{3-4}$$

For 3 components in parallel:

$$\lambda_{eq} = \lambda_1 \lambda_2 \lambda_3 (r_1 r_2 + r_2 r_3 + r_3 r_1) \tag{3-5}$$

$$r_{eq} = \frac{r_1 r_2 r_3}{r_1 r_2 + r_2 r_3 + r_3 r_1} \tag{3-6}$$

By applying the series-parallel approximate technique, we can obtain a new equivalent network for reliability assessment. To evaluate reliability of each load point, the events that would cause an outage on the selected load point are identified, and then the consequences of all these failure events for that load point are summed as shown in the following equations.

$$\lambda_k = \sum_{e \in E_i} \lambda_e \tag{3-7}$$

$$U_k = \sum_{e \in E_k} \lambda_e r_e \tag{3-8}$$

where λ_k and U_k are the failure rate (failures/year), and the annual outage time (hours/year) of load point k, respectively. On other hand, λ_e, and r_e are the failure rate (failures/year) and repair time (hours) of failure event e, respectively. E_k is a set of failure events for load point k.

When obtaining λ_k and U_k for all load points, *SAIDI* and *SAIFI* can be calculated by the following equations.

$$SAIFI = \frac{\sum_{k=1}^{\text{no. of load point}} \lambda_k N_k}{\sum_{k=1}^{\text{no. of load point}} N_k} \tag{3-9}$$

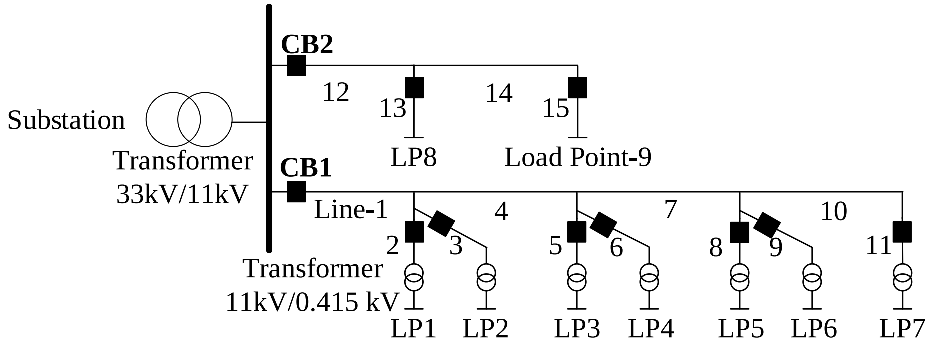
$$SAIDI = \frac{\sum_{k=1}^{\text{no. of load point}} U_k N_k}{\sum_{k=1}^{\text{no. of load point}} N_k} \tag{3-10}$$

where N_k is the number of customer at load point k.

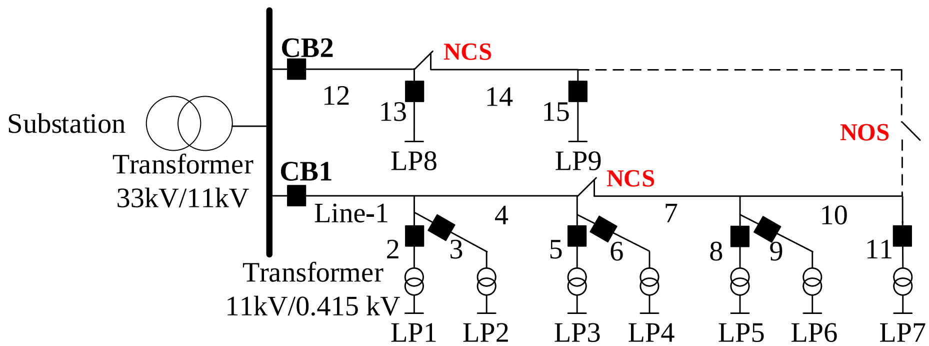
3.3.2 Reliability evaluation of distribution systems with switching devices and DG

Switching devices and DG have potential to improve reliability. The switches, such as reclosers, normally closed switches (NCSs) and normally open switches (NOSs), can improve reliability by limiting a fault in a small area and creating an alternative route to deliver power to customers when failures of power lines or equipment in the grids cause main power supplies be unable to deliver power to end users. However, if the main power supplies are unavailable, DG can be deployed to serve customers in the distribution grids. To illustrate how to assess the reliability improvement with switching devices and DG, we applied the analytical techniques to calculate the reliability level of the LP-7 of two systems as shown in Figure 3.2. The networks are modified from Roy Billiton Test System Bus 2 (RBTS Bus 2) [70].

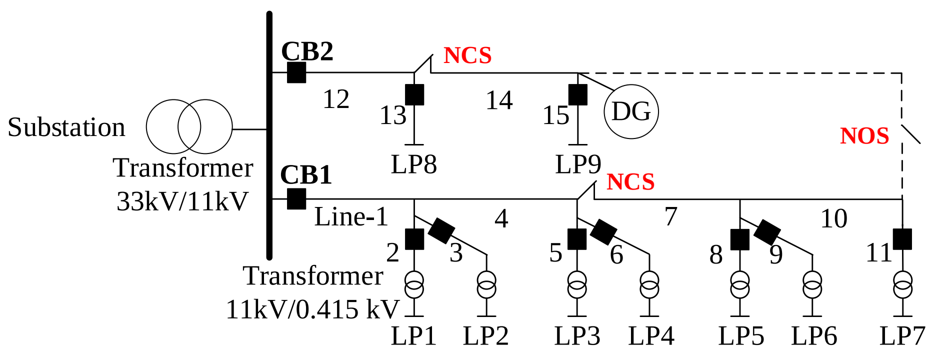
In Figure 3.2-(a), protection devices for isolating faults are circuit breakers (CB), while in Figure 3.2-(b) and (c), there are NCSs and NOS installed in an addition. Furthermore, Figure 3.2-(c) includes DG in the system. We assumed that for these three systems, some possible fault events that could happen and cause power interruptions to the LP-7 are listed as shown in Table 3.1. Given the failure rate and repair time of each fault event, we could calculate the failure rate and the annual outage time of the LP-7. The switches and DG are assumed to complete reconfiguring in 2 minutes.



(a) Circuit breakers



(b) Circuit breakers, NCSs, and NOS



(c) Circuit breakers, NCSs, NOS and DG

Figure 3.2: Feeder-1 and Feeder-2 of RBTS Bus 2

Table 3.1: Evaluation of an expected reliability level of LP-7

Failure event	Figure 3.2-(a)			Figure 3.2-(b)			Figure 3.2-(c)		
	λ	r	U	λ	r	U	λ	r	U
Transformer 33kV/11kV	0.01500	12	0.1800	0.01500	12	0.1500	0.01500	0.03	0.0005
Transformer 11kV/0.415kV	0.01500	12	0.1800	0.01500	12	0.1500	0.01500	12	0.1500
Line-1	0.04875	5	0.2438	0.04875	0.03	0.0015	0.04875	0.03	0.0015
Line-4	0.04875	5	0.2438	0.04875	0.03	0.0015	0.04875	0.03	0.0015
Line-7	0.04875	5	0.2438	0.04875	5	0.2438	0.04875	5	0.2438
Line-10	0.03900	5	0.1950	0.03900	5	0.1950	0.03900	5	0.1950
Line-11	0.05200	5	0.2600	0.05200	5	0.2600	0.05200	5	0.2600
Line-1 & Line-12 (Islanded grid)	0.00238	12	0.0285	0.00238	12	0.0285	0.00238	0.03	0.0000
Total	0.26963		1.5748	0.26963		1.0303	0.26963		0.8523

According to the results as shown in Table 3.1, the presence of switches and DG improves the reliability of the LP-7. With these switches, the expected outage duration of the LP-7 is decreased. In addition, when there is a failure of transformer 33kV/11kV or a failure of Line-1 and Line-12 together, the LP-7 is served by DG. However, the expected failure of LP-7 is the same for all cases.

3.3.3 Reliability assessments to meet a reliability target

To meet a reliability target, utilities may need to make investments in system upgrades or install additional devices in the systems. Reliability parameters can be included in investment assessments to support the utilities in making efficient investments in reliability enhancement.

For instance, if a utility considers to improve reliability to meet a standard level by switching devices, the effectiveness of installing these devices depends on the switch number and location. The problem of optimal switch placement tends to be formulated by incorporating the costs and benefits from a utility and customers as reliability-worth assessment [71]-[73]. The costs of a utility are the investment costs, while the benefits of customers are evaluated in form of interruption or outage costs. The optimal number and locations of switches will bring the minimum total costs of investments and customer interruptions. To ensure the standard reliability level, reliability parameters, such as outage duration, can be included in the problem formulation as shown in eq.(3-11) - (3-16).

Given failure rates and repair times of equipment in the systems, a utility is able to evaluate reliability of each load point, and find the switch locations that minimize the switch number and ensure the minimum reliability level of all customers. We assumed that the reliability standard level set by regulators is measured in terms of the annual outage duration, U_S (hours/year).

$$\min_{nc_{ij},no_{ij}} nc_{ij} + no_{ij} - \sum_{k=1}^{\text{no. of load point}} \left(U_{nc_{ij},no_{ij},k} - U_{S,k}\right)^2 \tag{3-11}$$

s.t.

$$nc_{ij}, no_{ij} \in \{0,1\}, \qquad \forall (i,j) \in cSW \tag{3-12}$$

$$U_{nc_{ij},no_{ij},k} \leq U_{S,k}, \qquad \forall k \tag{3-13}$$

$$t_{nc_{ij},no_{ij},e} \in T_{nc_{ij},no_{ij}}, \qquad \forall e \tag{3-14}$$

$$\left|F_{ij,e}\right| \leq F_{ij,max}, \qquad \forall (i,j) \in A, \forall e \tag{3-15}$$

$$V_{j,min} \leq \left|V_{j,e}\right| \leq V_{j,max}, \qquad \forall j \in A, \forall e \tag{3-16}$$

In the formulation, nc_{ij} and no_{ij} are decision variables of NCS and NOS on a branch (i,j), respectively. If a NCS is installed on the branch (i,j), then $nc_{ij} = 1$. Similarly, if a NOS is installed on the branch (i,j), then $no_{ij} = 1$. cSW is a set of branch candidates for installing NCSs and NOSs. In $U_{S,k}$ is the standard outage duration of load point k. $U_{nc_{ij},no_{ij},k}$ is the annual outage duration of load point k when switches are installed on the branch (i,j).

$U_{nc_{ij},no_{ij},k}$, as the annual outage duration of load point k, can be calculated by eq.(3-17) for all considered interruption events E_k that affect this load point. The failure rate, λ_e (failures/year) and repair time, r_e,(hours) of failure event e are given. The value of $U_{nc_{ij},no_{ij},k}$ depends on the locations of NCSs and NOSs.

$$U_{nc_{ij},no_{ij},k} = \sum_{e \in E_k} \lambda_e r_e \tag{3-17}$$

The problem includes the constraint of network topology. By applying graph theory, the network topology can be represented by a spanning tree, $T(V,A)$, where V is the set of nodes or buses and A is the set of edges or branches [74]. The set of feasible spanning trees, $T_{nc_{ij},no_{ij}}$, depend on switch location of nc_{ij} and no_{ij}. In other words, different switch allocations give different partitioning sections of the network. When an interruption event of e occurs, the configuration of network, $t_{nc_{ij},no_{ij},e}$, must be feasible according to $T_{nc_{ij},no_{ij}}$. In addition, limits on power flows and voltages must be satisfied at the average load level.

To illustrate the optimal switch placement, we deployed the two-feeder system of RBTS BUS 2 as shown in Figure 3.3. The existence of circuit breakers were assumed to be sufficient to make the reliability level of all customers meet $U_S = 2$ hours/year, which was estimated by eq. (3-17), and the location candidates for installing switches were indicated by ‘A’-‘’D’ for NCSs and ‘E’ for NOS as shown in Figure 3.3. All switching devices in the system would never fail. The fault events are assumed to be independent, and the failure rate and repair time of each fault event is given as shown in Appendix-A.

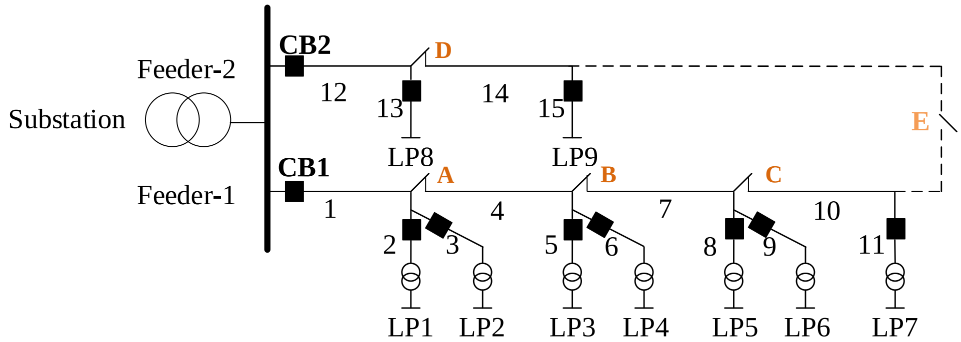


Figure 3.3: Feeder-1 and Feeder-2 of RBTS Bus 2 with location candidates of switching devices

According to the results, the network needs two more switches, one NCS installing on location ‘B’ and one NOS installing on location ‘E’ as shown in Figure 3.4. By installing these two switches, the annual outage duration of LP-1 to LP-7 will be reached the standard level. However, the annual outage duration of LP-8 and LP-9 does not change.

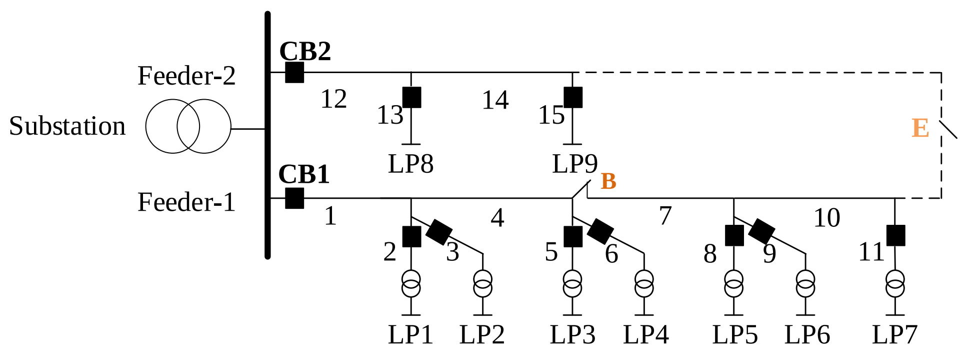


Figure 3.4: NCS and NOS installed at location ‘B’ and ‘E’ to improve reliability level to meet the given standard level.

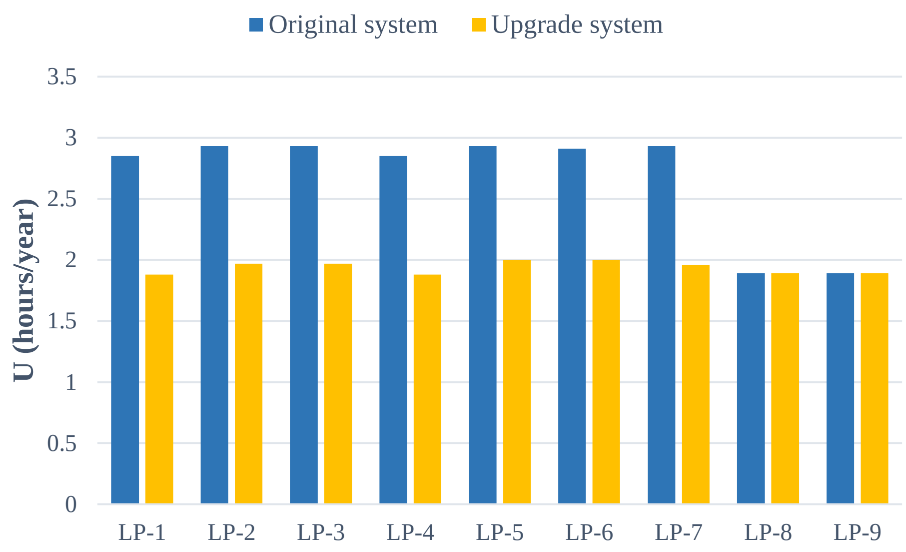


Figure 3.5: Expected annual outage duration (*U*) of each load point of the original and upgraded systems

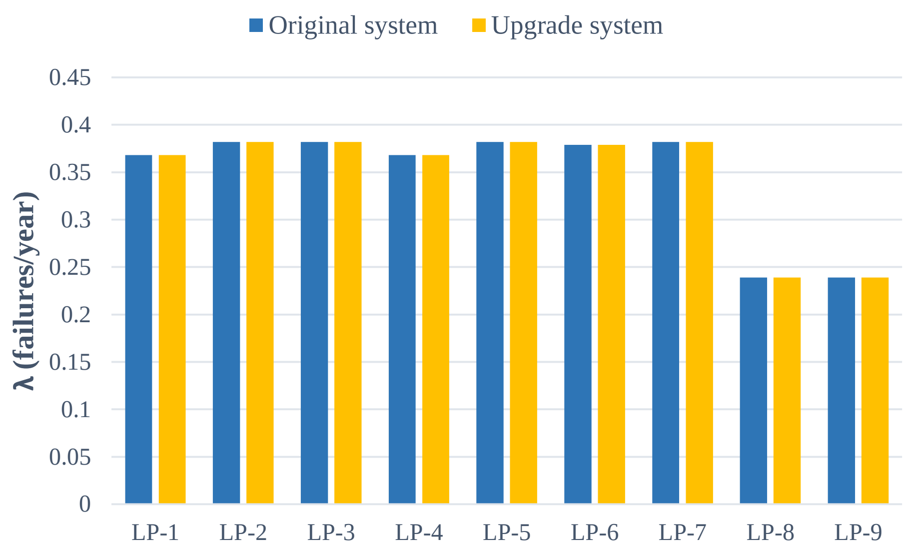


Figure 3.6: Expected failure (λ) of each load point of the original and upgraded system

3.4 Incentives given to utilities to meet a reliability target

As reliability is one of important service qualities of distribution systems, different types of financial incentives are given to utilities to provide reliable services that meet reliability targets. For instance, utilities' capital cost recovery is ensured under the cost of service regulation or an allowable rate or revenue cap of utilities is set over a given time period under the performance based regulation. In addition, utilities may be rewarded for their over-performance and penalized for their under-performance. Penalties may be set by considering the probability that the following year's reliability performance, such as SAIFI or SAIDI, is below reliability targets; the penalties will be paid to either regulators or customers or both depending on agreements [74].

3.5 Summary and policy implications

Digital communication systems and information technologies enable utilities to collect reliability data in details so utilities can use the data to evaluate reliability, predict the possibility of equipment failures and schedule or plan proper maintenance. The measures of reliability should be done in the level of load point or at least feeder since the reliability characteristics are different due to the diversities in service areas, load densities, circuit ratios, system topologies, and weather environments, etc. The regulators should encourage utilities to monitor and report reliability based on load point indexes. This will help regulators receive information in detail on feeders or areas that need attention to the reliability improvement.

Regulators should encourage utilities to incorporate distribution system reliability assessment into design, operation and maintenance planning. Reliability assessment will enable utilities to make effective decisions on investments in reliability, and make an optimal plans for operation and maintenance of networks. However, to preform reliability assessment, sufficiency of reliability data is an important factor that needs attention. The utilities need enough historical reliability data of equipment and system, either from the own systems or other pooling data, to perform reliability assessments. If the utilities do not have such sufficient data and need to use reliability data from other sources, validation methods are needed to gain confidence of using reliability model with other sources of data [59], [65]-[66].

The minimum reliability should be required to ensure that the changing utility environment does not adversely affect system reliability to customers. In addition, for the provision of differentiated high reliability services, the minimum reliability will be a standpoint where a utility can charge more for the high reliability service. Therefore, the utility should ensure that all customers obtain the standard reliability. By performing reliability assessments, the utility is able to adopt effective means of design and maintenance strategies that will bring reliability of all customers to the standard levels.

Chapter 4: Overview of proposed retail market structures

In this chapter, the proposed market structures for providing differentiated reliability services are introduced. The market mechanism is designed based on a restructured retail market model with different options in managing the reliability market: one with an independent distribution system operator (DSO) and another one without DSO. The restructured retail market models or retail choice model will allow customers to choose load serving entities or retail electricity providers, which are offering the services (price/service quality) that best meet customers' needs.

4.1 Overview

By observing retail market structures in the U.S., the electric market structures can be classified into two models: the traditional utility model and the retail choice model. The traditional utility model, which is the most common model in the U.S., is known as the vertically integrated utility, where energy and delivery services are bundled and provided to customers by a utility. Customers are not allowed to select another provider for any of these services, and the service charges are set by regulators.

Unlike the traditional model, the retail choice model or restructured retail market model gives service options for customers to select. Details of this market structure are varied by states, but basically customers are allowed to purchase energy from other retail energy suppliers that are offered in those service areas, while the local utility is responsible for power delivery only. The restructured retail market model is expected to create competitive environment for retail suppliers to provide differentiated service products that better match to customer preferences. The retail energy suppliers are the same firms working as load serving entities, and these firms will be referred to as retail electricity providers[1] (REPs) in this thesis.

By observing that customers not only desire more reliable services, but also have different preferences and willingness to pay for reliability, the provision of differentiated reliability services could enable customers to obtain reliability service as they pay. In addition, the information on customers' preferences and willingness to pay for reliability will give investment signals to the utility and other third parties to enhance reliability.

To achieve this, we propose a reliability market that offers differentiated reliability services beyond a standard level by considering an installation of more switches and DG units in systems. The service quality at the standard level is regulated based on social value, which could be evaluated using a cost-benefit analysis; on the other hand, high reliability services are offered through a market mechanism.

The proposed reliability market mechanism is designed based on the restructured retail market model by considering two different models in managing the distribution networks. The first model will have the independent distribution system operator (DSO) as an administrative firm that provides operational support for delivery and reliability services in a retail market, while the second model does not have the DSO.

Main market participants in these two reliability market models are distribution utilities, REPs, DG units, and end users. The local utility and the REP are not the same companies. The

[1] The term is taken from the retail market structure in Texas.

distribution utility, as an owner of facilities, will make investments in enhancing delivery and reliability services, and operate systems in a way that meets the demands of customers. The information on customers' demands is given by REPs. The REPs will aggregate loads and customer information to procure electricity services for their customers.

Customer-owned DG units participating in this reliability market are utilized as a backup generators to serve customers when power grids get disconnected from main substations, which in this circumstance, is known as an islanding operation. To integrate DG units in the system, the utility must upgrade its communication and control systems, as well as its protection systems, so as to support the DG in islanding mode. These backup DG units will be called upon to serve customers during times of unavailable grid-connection; so most of the time, these DG units are on standby. One way to attract DG units to provide backup power is to offer two price rates for selling backup power [76]. One rate is for the DG unit being on standby $(\hat{\rho}_{RS})$, but if power is delivered to customers, the generator will receive another price rate $(\hat{\rho}_{RD})$, which is much higher than the standby price.

The high reliability service is offered in a form of a delivery service with a high reliability level. The costs of providing the higher reliability service is unbundled from the costs of providing the standard delivery service. The unbundled services will reveal the true costs of reliability and encourages customers to select the reliable service according to their preferences. Accordingly, the charge for high reliability service will be in addition to the charge for standard delivery service.

Prices for high reliability services will be settled through the bidding of market participants. Notably, the prices for the high reliability services are in a unit of dollar per electric energy, but the total cost that end users pay for the reliability services with or without backup power is in a unit of dollar per month. The reliability market structure with and without the DSO are shown in Figure 4.1 and Figure 4.2, respectively.

4.1.1 Model-I: Reliability market structure with DSO

The formation of DSO, which was proposed by J. Wellinghoff[2] as well as L. Kristov and P.D. Martini[3], is considered to be a new approach to manage the distribution systems. The DSO has not implemented on any distribution systems in the U.S. yet. The DSO is formed to manage the increasingly complex distribution systems, and open opportunities for distributed energy resources, such as demand response, DG, electric vehicles, microgrids, etc., to compete with traditional energy service providers.

The DSO has no financial interest in any of the service providers and makes sure that all service providers have equal access to the distribution networks. The DSO will be in charge of making market transactions based on information acquired from the market participants. The utility, REPs and DG units will exchange information or interact each other through the DSO.

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[2] In Case No. 14-M-0101, and in the article "Rooftop Parity" in Fortnightly (Aug 2014).
[3] In the white paper "21st Century Electric Distribution System Operations" (May 2014)

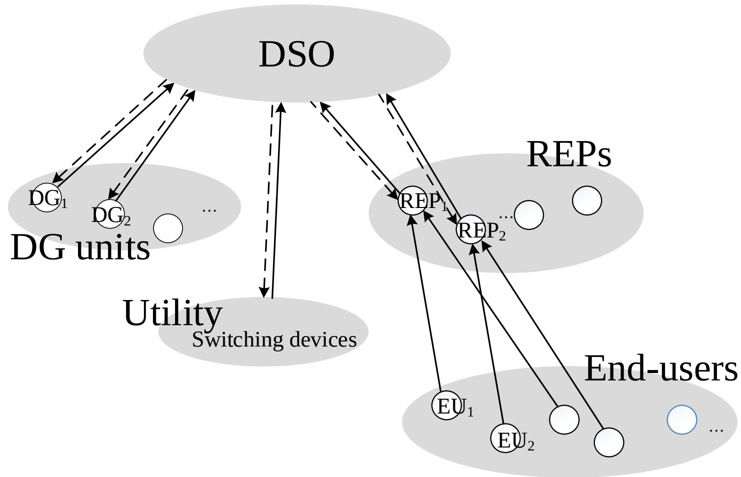


Figure 4.1: Model-I: Reliability market structure with the DSO

4.1.2 Model-II: Reliability market structure without DSO

In this model, market participants exchange necessary information or interact to each other by themselves. The utility will provide network users with information they need for accessing to the networks. Each REP will contract with the utility and DG units to procure reliability service and backup power that will satisfy the needs of their customers. The backup power will be provided by customer-owned DG units, which either already exist or plan to install a new capacity in the system.

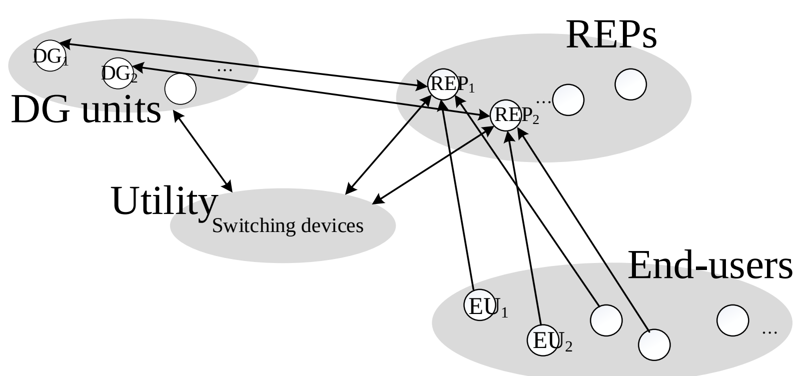


Figure 4.2: Model-II: Reliability market structure without the DSO

4.2 Assumptions of the proposed market

4.2.1 End users' willingness to pay

In this thesis, end users' willingness to pay for the high reliability service is defined as the maximum additional monthly expenses that an end user is willing to pay to experience total shorter-duration power outages occurring in a year. End users are assumed to be honest when they give information on their willingness to pay for the high reliability service to REPs. The REPs will contact service providers to procure the high reliability service according to end users' willingness to pay.

For end users obtaining the high reliability service, the service charges will not exceed their willingness to pay. End users who are willing to pay more for the reliability services tend to obtain the higher reliability services. However, end users with different willingness to pay may obtain the same reliability services. The lumpiness in the proposed reliability market could lead to gaming by end users. To remove the lumpiness, DLM/AMI should be developed to allow customers to adjust their electricity consumption during a normal and abnormal condition.

4.2.2 Selecting objective of market participants

The prices for the high services will be settled through the bidding of market participants. Market participants create their own bids by optimizing its objective with respect to its own interests. The objective of market participants can be different depending on their interests or regulatory rules of that market. For instance, in the proposed reliability market, the objective of a DSO is to look over the system of interest by maximizing the long-run social welfare since the DSO is founded to open access for distributed energy resources to the distribution system. On the other hand, the objective of a DG unit is to maximize its expected profits, while the objective of a utility is to maximize the number of served end users and minimize the investment costs. Details about bid function estimation, information exchanges, price-setting, and investment decisions are explained in the next chapters.

4.2.3 Contracts

In both market structures, the high reliability services are provided in a form of forward contracts to create long-term price signals to the utility and DG owners in making investments. For the market structure without DSO, the contracts are formed between the DSO and market participants. On the other hand, for the market structure without DSO, the contracts are bilateral contracts formed between the REP and utility, and between the REP and DG unit. In addition, customers purchasing these services also have a contract with an REP. If the customers decide to break the contract, they have to pay break costs, which cover the costs and expenses of preparing the service that has been done, to the REP.

The reliability market shall be opened ahead, maybe at least one year, before services are delivered. The forward contracts shall give the utility adequate time to schedule installations of new switches, since the installations of new switches without appropriate plans can cause power interruptions that could affect a large number of customers. In addition, new DG units will have sufficient time to complete a construction before the time of delivering the services.

A transaction period for new contracts may be opened once or twice a year, depending on demands for high reliability services. The new transaction may be opened to revise prices of the services. The contract duration for the services should be sufficient to provide proper investment signals to a utility and DG owners. Otherwise customers could choose to receive the high reliability level at the beginning, and then switch back to the standard level after switches have been installed.

The utilities are obligated to meet reliability targets, both standard level and new reliability targets offered to customers, according to the agreements. The high reliability level will be measured in terms of the reduction in total outage duration in a year (hour/year). The details of what constitutes an interruption, such as the duration of each outage and the frequency of interruptions, would be agreed upon in a contract.

In addition, the agreement concerns only failures of equipment of devices occurring in the distribution networks; the DG units are assumed fully reliable[4], but if they are unable to serve customers, in practice, they will be penalized. If the utilities fail to meet the agreements, they have to pay compensation to customers, and may be also fined by regulators in the case of failing to meet the reliability standard. The compensations for not meeting the reliability standard could be estimated from the interruption costs of power outages[5], while the compensations for not meeting the new reliability targets could be the customers' willing to accept the service interruptions.

4.3 Summary

We are proposing two models of the retail market mechanism that provides differentiated high reliability services. The difference between these two models is the existence of DSO in managing the reliability market. In these two models, market participants are a distribution utility,

[4] Future work will include a combination of failures by the distribution grid and by the DGs.
[5] Department of Energy provides a tool for estimating interruption costs in http://icecalculator.com/.

REPs, non-utility-owned DG units, and end users. The local utility is not the same company as the REPs. In the market, the REPs, as customer representatives, contact the utility and DG units for purchasing delivery service with high reliability level and backup power, respectively. The prices for these services will be settled through the bidding of market participants.

Chapter 5: Model-I: Retail market structure with DSO

This chapter presents the information that needs to be exchanged among the market participants and the process by which service prices are settled in the market structure with DSO. The prices for high reliability services, which include improved delivery service and backup power, will be settled through bidding of market participants as shown in Figure 5.1. The bids will be constructed in the form of a function. The utility, REPs and DG units, as market participants, will report their information on bidding to the DSO, and the DSO will proceed market clearing based on information acquired from the market participants. To illustrate this process, the market mechanism was implemented on the modified IEEE RBTS Bus2.

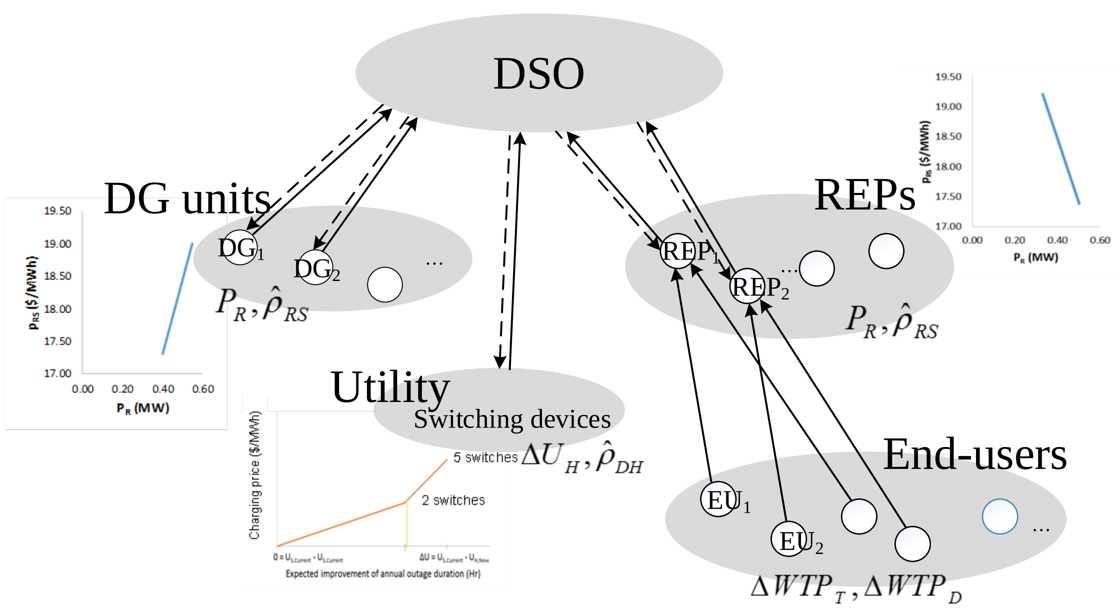


Figure 5.1: Reliability market structure of model-I with information exchanges

The market is designed to offer a single and/or two reliability levels. For the provision of two reliability levels, one of them must be the minimum reliability level requested by the REP. The prices for high reliability service will be settled through bidding of market participants. Those bids will be created in the form of a function. To create their own bids for high reliability services, market participants are required to exchange the initial information shown in Table 5.1. Some information exchanges can happen in parallel with other exchanges, while others need to happen later due to data they need from earlier steps. Details about bid function estimation, price-setting, and investment decisions are explained as follows.

Table 5.1: Initial information exchanges in the proposed market model-I (F: Information flow from entity, and T: Information flow to entity)

Information flow from to	Information
F: DG unit T: DSO	The request to participate in the market, and the anticipated power of the DG unit
F: DSO T: Utility	The locations of participating DG units
F: Utility T: DSO	The probability that DG will be called (γ_{DG})
F: DSO T: DG unit	γ_{DG}, and the anticipated prices paid to DG for actual delivered power ($\hat{\rho}_{RD}$) and for standby ($\hat{\rho}_{RS}$)
F: DG unit T: DSO	The bid function of DG unit k $\left(\hat{B}_{DG,k}(P_R, \hat{\rho}_{RD}) = \hat{\rho}_{RS}^{DG,k}\right)$, showing a relation of the backup power sold on the reliability market (P_R), $\hat{\rho}_{RD}$ and $\hat{\rho}_{RS}$
DSO	The aggregated bid function of DG units $\left(\hat{B}_s(P_R, \hat{\rho}_{RD}) = \hat{\rho}_{RS}^{s}\right)$

Table 5.1: Initial information exchanges in the proposed market model-I (continued)

Information flow from to	Information
F: REP T: DSO	The request for high reliability service
F: Utility T: DSO	The standard reliability level (U_S)
F: DSO T: REP	U_S
F: REP T: End user	U_S
F: End user T: REP	The end user's decision to obtain the service
F: REP T: DSO	The number of end users who purchase high reliability service at load point n $\left(N_{H,n}\right)$, the forecasted total annual amount of energy that the end users consume during normal conditions at load point n $(\hat{e}_{AN,n})$, the maximum power needed during a normal power interruption at load point n $\left(P_{R,H,n}^{max}\right)$, the minimum improved reliability level that an REP expects a utility to offer end users $\left(\Delta U_{H_m}\right)$
F: DSO T: Utility	$N_{H,n}$, e_{AN}, ΔU_{H_m}, and the combination of possibly scheduled DG units, according to $\hat{B}_s(P_R, \hat{\rho}_{RD})$
F: Utility T: DSO	The bid function of improved reliability service at load point n $\left(\hat{B}_{U,n}(\Delta U_H, P_R) = \hat{\rho}_{DH}^{U,n}\right)$ showing the relation between incremental improved reliability level (ΔU_H), the price of delivery service with high reliability (ρ_{DH}), and P_R

Table 5.1: Initial information exchanges in the proposed market model-I (continued)

Information flow from to	Information
F: Utility T: DSO	The total number of power interruptions (N_F), and the average time it takes to restore normal power flow (r_{ave})
F: DSO T: REP	ΔU_H, γ_{DG}, N_F, r_{ave}, $\hat{\rho}_{DH}$ of ΔU_H, $\hat{\rho}_{RD}$, and $\hat{\rho}_{RS}$
F: REP T: End user	N_F,and r_{ave}
F: End user T: REP	The additional monthly expenses that an end user is willing to pay to experience total shorter-duration power outages occurring in a year (ΔWTP_T for utilizing backup power, and ΔWTP_D for not utilizing backup power), and the wattage of appliance that the end user needs (w_d)
F: REP T: DSO	The aggregated demand functions of REP l at load point n $\left(\hat{B}_{REP,l,n}\left(P_{R,DG}, \hat{\rho}_{RD}, \hat{\rho}_{DH}\right) = \hat{\rho}_{RS}^{REP,l,n}\right)$, showing the relation between backup power ($P_{R,DG}$), $\hat{\rho}_{RS}$, $\hat{\rho}_{RD}$, and $\hat{\rho}_{DH}$
DSO	The aggregated bid function of REPs $\left(\hat{B}_d\left(P_{R,DG}, \hat{\rho}_{RD}, \hat{\rho}_{DH}\right) = \hat{\rho}_{RS}^{d}\right)$

5.1 DG Unit

The objective of a DG unit is to maximize the expected profit. To create bid functions, each DG unit determines the optimal amount of power that provide the maximum profit by which the generator owner can recover the investment costs in year Y_{DG}. The bid function of a DG unit shows the P_R that the DG unit's owner is willing to sell on the market with respect to the prices of $\hat{\rho}_{RD}$ and $\hat{\rho}_{RS}$. The information needed to create the bid function is shown in Table 5.1. The DG unit possesses the information about investment costs, and obtains the anticipated prices and other information from the DSO. With all of these data, the DG unit can determine the optimal amount of power sold on the market as formulated in eq.(5-1)-(5-3).

Table 5.2: Information required from a DG unit and DSO in order to create the DG unit's bid function

DG unit	The generating cost function $\left(C(P)\right)$, the investment costs including the capital cost (C_{CP}) and the operation and maintenance costs (C_{OM}), the expected recovery year (Y_{DG})
DSO	γ_{DG}, $\hat{\rho}_{RD}$ and $\hat{\rho}_{RS}$

$$\max_{P_{R,k}} E\{\pi_k\} = 8760\left(\left(1-\gamma_{DG,k}\right)\hat{\rho}_{RS} + \gamma_{DG,k}\hat{\rho}_{RD}\right)P_{R,k} - 8760\gamma_{DG,k}C\left(P_{R,k}\right) \tag{5-1}$$

s.t.

$$C_{CP}P_{R,k} + D_{Y_{DG}}\left(C_{OM}P_{R,k} - E\{\pi_k\}\right) \leq 0 \tag{5-2}$$

$$P_{DG,k}^{min} \leq P_{R,k} \leq P_{DG,k}^{max} \tag{5-3}$$

where

$P_{R,k}$	Amount of power that the DG unit k sells on the reliability market
$C(P)$	Quadratic generating cost function of the distributed generator, which is $aP^2 + bP + c$
C_{CP}	Capital cost of the DG unit ($/MW)
C_{OM}	Operation and maintenance cost of the DG unit ($/MW)
$P_{DG,k}^{min}$, $P_{DG,k}^{max}$	Minimum and maximum power of distributed generator k

$D_{Y_{DG}}$	Discount factor, $D_{Y_{DG}} = \sum_{y=1}^{Y_{DG}} (1 + r_d)^{-y}$

By solving the above problem formulation, the DG unit's owner will obtain a $\hat{\rho}_{RS}$ and P_R data point for bidding. To extend this bid point to a bid function, the $\hat{\rho}_{RD}$ is fixed, while the $\hat{\rho}_{RS}$ is perturbed for $\pm 2.5\%$ and $\pm 5\%$ in order to find the new optimal P_R. After that, by fitting these data points to a first-degree polynomial, the DG obtains a linear bid function to submit to the DSO. However, if the perturbation of $\hat{\rho}_{RS}$ does not affect P_R, the bid function can be constant functions.

5.2 Utility

A distribution utility's bid function is defined as the relation between an improved reliability level and the price for that reliability level. To determine a utility's bid function, the utility maximize the number of served end users and minimize the investment costs.

Table 5.3: Information required from a utility and DSO in order to create a utility's bid function

Utility	The statistical data about system reliability: failure rate (λ_e) and repair time (r_e), the costs of switches and upgraded equipment for supporting the DG units, the investment costs including the capital cost (C_{cp}) and the operation and maintenance costs (C_{om}), the payback period allowed by regulators (Y_u)
DSO	The locations of the DG units, the combination of possibly scheduled DG units according to $\hat{B}_s(P_R, \hat{\rho}_{RD})$, $N_{H,n}$, $\hat{e}_{AN,n}$, ΔU_{H_m}, and $P_{R,H,n}^{max}$

The improved reliability level is measured in terms of an incremental reduction of outage duration (ΔU_H). The service prices (ρ_{DH}), which differ depending on the reliability level, are assessed from the investment costs of enhancing reliability through an installation of switching devices and an integration of DG units. To assess the reliability level and the price, the utility possesses information about system reliability and investment costs, and obtains the information it needs about the DG units and REPs from the DSO as shown in Table 5.3.

With this information, the utility will search for the optimal switch number and locations that allow the reliability level to reach both the minimum and target levels. The optimal number and locations of switches should maximize the number of served end users as a primary goal, with minimizing investment costs as a secondary goal. The problem of searching for the optimal number and locations of switches is formulated as a multi-objective optimization. The number of end users and the investment cost will be normalized; more weight is assigned to the number of end users. This problem also includes the constraints of network topology, and limits on power flows and voltages.

$$\underset{cL_{p,q}=\{nc_{ij},no_{ij}\}}{\text{Max}} W_{UH}\mathcal{N}_{UH} + W_{UM}\mathcal{N}_{UM} - \mathcal{C}_{TS} \tag{5-4}$$

where

$$\mathcal{N}_{UH} = \frac{\sum_{n=1}^{No.\ of\ LP} N_{H,n}\, v_n^{cL_{p,q},dgL_k}}{\sum_{n=1}^{No.\ of\ LP} N_{H,n}} \tag{5-5}$$

$$\mathcal{N}_{UM} = \frac{\sum_{n=1}^{No.\ of\ LP} N_{H,n}\, w_n^{cL_{p,q},dgL_k}}{\sum_{n=1}^{No.\ of\ LP} N_{H,n}} \tag{5-6}$$

$$\mathcal{C}_{TS} = \frac{pC_{cp,nc} + qC_{cp,no} + (p+q)D_{Y_u}C_{om,sw}}{p'C_{cp,nc} + q'C_{cp,no} + (p'+q')D_{Y_u}C_{om,sw}} \tag{5-7}$$

$$v_n^{cL_{p,q},dgL_k} = \begin{cases} 1, & U_n^{cL_{p,q},dgL_k} \le U_H \\ 0, & U_n^{cL_{p,q},dgL_k} > U_H \end{cases}, \qquad \forall n \tag{5-8}$$

$$w_n^{cL_{p,q},dgL_k} = \begin{cases} 1, & U_n^{cL_{p,q},dgL_k} \le U_{H_m} \\ 0, & U_n^{cL_{p,q},dgL_k} > U_{H_m} \end{cases}, \qquad \forall n \tag{5-9}$$

$$U_n^{cL_{p,q},dgL_k} = \sum_{e \in E_n} \lambda_e r_e \left(1 - s_{n,e}^{cL_{p,q},dgL_k}\right) \tag{5-10}$$

s.t.

$$nc_{ij}, no_{ij} \in \{0,1\}, \qquad \forall (i,j) \in cSW \tag{5-11}$$

$$dg_{\hat{k}} = 1, \qquad \forall \hat{k} \in dgL_k \tag{5-12}$$

$$t_e^{cL_{p,q},dgL_k} \in T^{cL_{p,q},dgL_k}, \qquad \forall e \tag{5-13}$$

$$\sum_{j \in B_S} P_{S,e,j} + \sum_{j \in B_{RH}} P_{R,H,j}^{max} = 0, \qquad \forall e \tag{5-14}$$

$$\left|F_{e,ij}\right| \le F_{ij}^{max}, \qquad \forall (i,j) \in A, \forall e \tag{5-15}$$

$$F_j^{min} \le \left|V_{e,j}\right| \le V_j^{max}, \qquad \forall j \in J, \forall e \tag{5-16}$$

where

U_H	New target reliability level
W_{UH}, W_{UM}	Assigned weight for the number of end users receiving U_H, and U_{H_m}, respectively
$C_{cp,nc}, C_{cp,no}$	Capital cost of NCS and NOS, respectively

$C_{om,sw}$	Operation and maintenance costs of NCS and NOS
p', q'	Maximum number of NCS and NOS that can be installed in the system according to branch candidates, $p + q \leq p^{max} + q^{max}$
$v_n^{cL_{p,q},dgL_k}$	Decision variable if $U_n^{cL_{p,q},dgL_k}$ meets U_H
$w_n^{cL_{p,q},dgL_k}$	Decision variable if $U_n^{cL_{p,q},dgL_k}$ meets U_{H_m}
$U_n^{cL_{p,q},dgL_k}$	Expected annual outage duration of the load n when the p NCSs and q NOSs are installed at location $cL_{p,q}$, and the k DG units installed at location dgL_k
$s_{n,e}^{cL_{p,q},dgL_k}$	Binary decision variable of load point n when fault event e occurs
nc_{ij}, no_{ij}	Binary decision variables of installing NCS and NOS on a branch (i, j), respectively (nc_{ij} or $no_{ij} = 1$ if a switch is installed on the branch)
cSW	Set of branch candidates where NCSs and NOSs can be installed
dg_j	Status of a DG unit located on bus j
$t_e^{cL_{p,q},dgL_k}$	Configuration of the network when interruption event e occurs
$T^{cL_{p,q},dgL_k}$	Feasible network configuration when the p NCSs and q NOSs are installed at location $cL_{p,q}$, and the k DG units are installed at location dgL_k
$P_{S,e,j}$	Power supply during interruption event e
B_S, B_{RH}	Buses of power supply, and end users buying the high reliability service, respectively
$F_{e,ij}, V_{e,j}$	Power flow on a branch (i, j), and voltages on a bus j, respectively, during interruption event e

The values of $v_n^{cL_{p,q},dgL_k}$ and $w_n^{cL_{p,q},dgL_k}$ are subject to the variables of load location n, the p NCSs and q NOSs installed at location $cL_{p,q}$, and the k DG units installed at location dgL_k. $U_n^{cL_{p,q},dgL_k}$ is calculated by eq.(5-10) for all considered interruption events E_n that will affect the load point [69]. λ_e (failures/year) and r_e (hours) of failure event e are given. The variable $s_{n,e}^{cL_{p,q},dgL_k}$ represents the status of load point n when fault event e occurs. The value of $s_{n,e}^{cL_{p,q},dgL_k}$ depends on the network configurations, which differ according to the locations of the installed switches and the presence of DG units in the system.

The network configurations are subject to the constraints of the network topology. By applying graph theory, the network topology can be represented by a spanning tree, $T(J, A)$, where J is the set of nodes or buses and A is the set of edges or branches [77]. The set of feasible spanning trees, $T^{cL_{p,q},dgL_k}$, depends on the switch locations of nc_{ij} and no_{ij}. In other words, different switch allocations give different partitioning sections of the network. When interruption event e occurs, the spanning trees that consist of faults will be removed, and then the remaining spanning trees will be configured to $t_e^{cL_{p,q},dgL_k}$. This new configuration must be feasible according to $T^{cL_{p,q},dgL_k}$, and must be able to connect to any power source bus, either in the main substation or the DG unit.

After finding the optimal number and locations of the switches $\left(cL_{p,q}^*\right)$ for the given target reliability level, and the locations of the DG units, the utility estimates the service charge $\rho_{DH,U_H^{cL_{p,q}^*,dgL_k}}$ from the revenue (R_{Exp}); by means of this charge, the utility expects to recover the investment costs of providing such services and make a profit. The investment costs include the capital cost, the operation and maintenance costs of both the switches and upgraded equipment for the DG units. The $\rho_{DH,U_H^{cL^*_{p,q},dgL_k}}$ will cover the energy consumption of end users both during normal and outage conditions.

The price rate for the reliability enhancement should be related to how an end user pay an electric bill. By definition, the utility will charge the REPs for the additional energy delivery that is a result of the reliability improvement for the entire year ($\hat{P}_{R,H}\Delta U_H^{cL^*_{p,q},dgL_k}$). However, this charge needs to be adjusted to the applicable rate for end users. One way to do that is to allocate the annual total charge of the additional energy delivery to the total energy consumption including the additional energy expected to deliver if the power interruptions occur. As a result, the service charge $\rho_{DH,U_H^{cL^*_{p,q},dgL_k}}$ which is adjusted to be consistent with the monthly electric bill, can be estimated as shown in eq.(5-17)-(5-19). The REPs provide the utility with the expected annual energy consumption ($\hat{e}_{AN}$).

$$pC_{cp,nc} + qC_{cp,no} + kC_{cp,E_{DG}} + D_{Y_u}\left((p+q)C_{om,sw} + kC_{om,E_{DG}} - R_{Exp}\right) = 0 \tag{5-17}$$

$$R_{Exp} = \rho_{DH,U_H^{cL^*_{p,q},dgL_k}}\left(\sum_{n=1}^{No.of\ LP} \hat{e}_{AN,n} + \hat{P}_{R,H,n}\Delta U_{H,n}^{cL^*_{p,q},dgL_k}\right) \tag{5-18}$$

$$\Delta U_{H,n}^{cL^*_{p,q},dgL_k} = U_S - U_{H,n}^{cL^*_{p,q},dgL_k} \tag{5-19}$$

where

R_{Exp}	Expected revenue
U_S	Standard reliability level
$U_{H,n}^{cL^*_{p,q},dgL_k}$	Target reliability level at load point n
$C_{cp,E_{DG}}$, $C_{om,E_{DG}}$	Capital cost and operation and maintenance cost of upgraded equipment for the DG units

D_{Y_u} Discount factor, $D_Y = \sum_{y=1}^{Y_u}(1+r_d)^{-y}$

For all different target reliability levels and combinations of DG units, the utility searches for the optimal number and locations of the switches, and for the best price to charge. The relation between different $\Delta U_{H,n}^{cL_{p,q}^{*},dgL_k}$ and $\rho_{DH,U_H^{cL_{p,q}^{*},dgL_k}}$ is considered a bid function. This bid function will also be plotted according to a load location because each load location can have different reliability levels. The bid functions are in a form of ΔU_H and $\hat{\rho}_{DH}$ data points; these bid functions with the number of served end users at that location will be submitted to the DSO.

5.3 REP

An REP purchases high reliability services, which include improved reliability levels and backup power, for end users by bidding through the reliability market, and the prices of reliability services will be settled by the DSO. To make profits from this trading, the REP may charge some margin (ϕ_r) on the true costs of the reliability services ($C_{RS}(\cdot)$), since the REP cannot take much action on these service costs.

In the reliability market, the reliability services are offered on a long-term contract. This long-term contract could be consider a burden for the REP, since end users might terminate the contract before it ends, and this would lead to the REP losing income to cover those contract costs. Given a rate of decline in REP's revenue each year (σ), a discount rate (r_d) and a contract period (Y_C), net present value of REP's profits for the entire contract period can be calculated as shown in eq.(5-20).

$$\pi = \sum_{y=1}^{Y_C} (1 + r_d)^{-y} \left(\phi_r (1 - \sigma)^{y-1} C_{RS}(\cdot) - C_{RS}(\cdot)\right) \tag{5-20}$$

If the REP expects to obtain the profits at least X percent of $C_{RS}(\cdot)$ per year, the REP can solve for ϕ_r as shown eq.(5-29). The REP chooses ϕ_r to use in determining bid functions for end users. Since a price is one of factors that drives end users to switch a retail service provider [78], it could imply that the value of ϕ_r and σ are correlated moving in the same direction. The REP shall choose small value of ϕ_r to avoid service provider switching. In addition, setting of ϕ_r is limited by end user's willingness to pay.

$$\sum_{y=1}^{Y_C} (1 + r_d)^{-y} X C_{RS}(\cdot) \leq \sum_{y=1}^{Y_C} (1 + r_d)^{-y} \left(\phi_r (1 - \sigma)^{y-1} C_{RS}(\cdot) - C_{RS}(\cdot)\right) \tag{5-21}$$

$$\phi_r \geq \frac{\sum_{y=1}^{Y_C} (1 + r_d)^{-y} (1 + X)}{\sum_{y=1}^{Y_C} (1 + r_d)^{-y} (1 - \sigma)^{y-1}} \tag{5-22}$$

5.4 End user

Given the service prices by the DSO, the REP will determine bid functions to purchase the high reliability services which include improved reliability levels, and backup power for end users. These bid functions will be created from individual end users' information first, and then the individual bid functions will be aggregated to the bid functions of the REP.

To create the bid functions of an individual end user, the REP will receive the necessary information from the end user and the DSO as shown in Table 5.4. The REP obtains the information on appliances that each end user need during a power outage and their WTP for high reliability service. The appliances needed by end users are prioritized according to their needs.

By assuming the end users are educated about the reliability service, they will receive the information on U_S so that they can decide whether they will purchase the service. After that, the REP decides on ΔU_{H_m} and informs the end users of the reduction in the number of power interruptions (N_F) and the average duration for restoring power (r_{ave}) so the end users can decide on appliances needed during a power outage, ΔWTP_T, and ΔWTP_D.

Table 5.4: Information required from an REP, DSO, and end users in order to create the REP's bid function

REP	$\hat{e}_{AN,n}$, ΔU_{H_m}
DSO	$\Delta U_H, \gamma_{DG}, N_F, r_{ave}, \rho_D, \hat{\rho}_{DH}$ of ΔU_H, $\hat{\rho}_{RD}$, and $\hat{\rho}_{RS}$
End users	w_d, ΔWTP_T, ΔWTP_D

With this information, the REP determines the maximum amount of backup power available to end users during extended power interruptions as well as the amount of power available during normal power interruptions. In determining backup power, priority of appliances is also taken into account; the total cost that end users pay for the reliability services with or without backup power must not exceed the amount that end users are willing to pay as shown in eq. (5-28) -(5-29).

$$\max_{x_d, y_d} \frac{P_{R,DG,j}}{\sum_d w_{d,j}} + \frac{\sigma_{R,DG,j}}{\sum_d d} + \frac{P_{R,H,j}}{\sum_d w_{d,j}} + \frac{\sigma_{R,H,j}}{\sum_d d} \tag{5-23}$$

where

$$P_{R,DG,j} = x_1 w_{1,j} + \cdots + x_D w_{D,j} \tag{5-24}$$

$$\sigma_{R,DG,j} = x_1(1) + \cdots + x_D(D) \tag{5-25}$$

$$P_{R,H,j} = y_1 w_{1,j} + \cdots + y_D w_{D,j} \tag{5-26}$$

$$\sigma_{R,H,j} = y_1(1) + \cdots + y_D(D) \tag{5-27}$$

s.t.

$$\begin{aligned} &\phi_r\big(8760\big((1-\gamma_{DG})\hat{\rho}_{RS} + \gamma_{DG}(\hat{\rho}_{RD} + \rho_D + \hat{\rho}_{DH})\big)P_{R,DG,j} \\ &\qquad + (\rho_D + \hat{\rho}_{DH})\big(\Delta U_{H_m} + r_{ave}F\big)P_{R,H,j} + \hat{\rho}_{DH}\hat{e}_{AN,n}\big) \\ &\qquad \leq 12(\Delta WTP_{T,j}) \end{aligned} \tag{5-28}$$

$$\phi_r\left((\rho_D + \hat{\rho}_{DH})\big(\Delta U_{H_m} + r_{ave}F\big)P_{R,H,j} + \hat{\rho}_{DH}\hat{e}_{AN,j}\right) \leq 12(\Delta WTP_{D,j}) \tag{5-29}$$

$$P_{R,DG,j} = \begin{cases} P_{R,DG,j}, & P_{R,DG,j} \geq w_{D,j} \\ 0, & P_{R,DG,j} < w_{D,j} \end{cases} \tag{5-30}$$

where

$P_{R,DG,j}$	Amount of power that end user j will need from the DG during extended power interruptions
$P_{R,H,j}$	Amount of power that end user j will need during normal power interruptions
$w_{d,j}$	Wattage of the appliances that end user j needs, D: highest priority
ρ_D	Price of standard delivery service.
x_d , y_d	Binary variables of utilized appliance d.
$\sigma_{R,DG,j}$, $\sigma_{R,H,j}$	Priority of appliances for an estimation of $P_{R,DG,j}$, and $P_{R,H,j}$
ΔU_{H_m}	Minimum incremental improvement of reliability level (hours/year)
r_{ave}	Average duration for restoring normal power after an interruption

N_F	Number of power interruptions
ϕ_r	Margin charged on true costs
$\hat{\rho}_{DH}$	Anticipated price of high reliability delivery service

For each end user, the REP will solve the above problem in order to obtain a $\hat{\rho}_{RS}$ and $P_{R,DG}$ data point for bidding. This bid point will be extended to a bid function by solving the same problem for different $\hat{\rho}_{RS}$. To determine the new $P_{R,DG}$, $\hat{\rho}_{DH}$ and $\hat{\rho}_{RD}$ will be fixed, and then $\hat{\rho}_{RS}$ is perturbed for $\pm 2.5\%$ and $\pm 5\%$. In addition, the new $P_{R,DG}$ will be determined by using the same values of $\hat{\rho}_{RS}$, but perturbing $\hat{\rho}_{DH}$ for $+2.5\%$ and $+5\%$. As a result, the REP will obtain 15 $\hat{\rho}_{RS}$ and $P_{R,DG}$ data points for each end user. By fitting these data points having the same $\hat{\rho}_{DH}$ to a first-degree polynomial, the REP obtains 3 bid functions. The REP follows this process to obtain bid functions of all individual end users. These bid functions will be aggregated with respect to the same $\hat{\rho}_{RS}$, $\hat{\rho}_{DH}$ and load point, and then be submitted to the DSO.

In addition, $P_{R,H}$ from solving the above problem is used to identify which of end users cannot afford to pay for these high reliability services. The number of end users who can purchase these services and $\hat{e}_{AN,n}$ are updated and reported to the DSO in order to pass these data to the utility. The utility will use these data for updating $\hat{\rho}_{DH}$.

5.5 DSO

The objective of the system looking over the system of interest is to maximize the long-run social welfare. The DSO collects all the bid functions from the utility, DG units, and REPs to proceed market clearing in order to settle the prices of backup power and delivery service. The process of market clearing starts by clearing the price of backup power, and continues with the price of improved delivery service. The process repeat for several iterations before being terminated. The process of market clearing is explained step by step below.

Step 1: For iteration m, the DSO collects the bid functions of the DG units, utility, and REPs. The bid functions of the DG units and REPs are aggregated to the system level. For the bid functions of REPs, they are submitted and aggregated corresponding to load points.

Step 2: The DSO finds $P^*_{R,k}$, and $\hat{\rho}^*_{DH}$ that maximize welfare of DG units and REPs. In this step, the DSO requires the information on constraints of the distribution networks from the utility to solve the below optimization problem.

$$\min_{P^*_{R,k},\hat{\rho}^*_{DH}} \sum_k \hat{\rho}_{RS}^{DG,k} P_{R,k} - \sum_l \sum_n \hat{\rho}_{RS}^{REP,l,n} P_{R,DG,l,n} \tag{5-31}$$

s.t.

$$\sum_k P_{R,k} - \sum_l \sum_n P_{R,DG,l,n} = 0 \tag{5-32}$$

$$P_{DG,k}^{min} \le P_{R,k} \le P_{DG,k}^{max} \tag{5-33}$$

$$|F_{ij}| \le F_{ij,max}, \qquad \forall (i,j) \in A \tag{5-34}$$

where $\hat{\rho}_{RS}^{DG,k} = \hat{B}_{DG,k}(P_{R,k}, \hat{\rho}_{RD})$ and $\hat{\rho}_{RS}^{REP,l,n} = \hat{B}_{REP,l,n}(P_{R,DG}, \hat{\rho}_{RD}, \hat{\rho}_{DH})$ are the bid function of DG unit k and of REP l at load point n, respectively. $P^*_R = \sum_k P^*_{R,k}$, $\hat{\rho}^*_{RS} = \max\left(\hat{B}_{DG,k}(P^*_{R,k}, \hat{\rho}^*_{DH})\right)$, and $\hat{\rho}^*_{DH}$ will be used in the next step.

In the step 2, if the solution cannot be found in the 1st iteration, the new $\hat{\rho}_{RS}$ and $\hat{\rho}_{DH}$ will be given to the DG units and REPs for a couple of times before terminating the process with no transaction occurring. The new values of $\hat{\rho}_{RS}$ and $\hat{\rho}_{DH}$ can be chosen from the bid functions of DG and utility.

Step 3: By using P_R^* and $\hat{\rho}_{DH}^*$ from the step 2, the DSO finds the maximum ΔU_H that satisfies eq.(5-36)-(5-37).

$$\max_{\Delta U_H^*} \Delta U_H \tag{5-35}$$

s.t.

$$\Delta U_H \geq \Delta U_{H_m} \tag{5-36}$$

$$\hat{\rho}_{DH}^* - \hat{B}_U(\Delta U_H, P_R^*) \geq 0 \tag{5-37}$$

where $\hat{\rho}_{DH}^s = \hat{B}_U(\Delta U_H, P_R^*)$ is the utility's bid function of the improved delivery service with given P_R^* .

Step 4: The DSO sends $\hat{\rho}_{RS}^*$ and $\hat{\rho}_{DH}^*$ to the REP to update the bid function of the backup power. In addition, for the provision of two reliability levels, the DSO sends $\hat{\rho}_{DH}^{s*} = \hat{B}_U(\Delta U_H^*, P_R^*)$ and $\hat{\rho}_{DH_m}^{s*} = \hat{B}_U\left(\Delta U_{H_m}, P_R^*\right)$ to the REP to update the number of end users who purchase these services and $\hat{e}_{AN,n}$. On the other hand, for the provision of a single reliability level, the DSO sends only $\hat{\rho}_{DH}^{s*} = \hat{B}_U(\Delta U_H^*, P_R^*)$ to the REP. After that, the new iteration will start. The process of clearing prices will be ended when the value of $\hat{\rho}_{RS}$ and $\hat{\rho}_{DH}$ does not change.

5.6 Numerical Example

5.6.1 Test system and assumptions

To illustrate how it works, the market mechanism was implemented on the modified IEEE RBTS Bus 2 [70]. In this test system, we assumed that all switching devices and DG units in the system would never fail. In addition, the existence of circuit breakers, as shown in Figure 5.2, were assumed to be sufficient to make the reliability level of all end users meet $U_S = 3.5$ hours/year, which was estimated by eq.(5-10). The considered interruption events were the results of transformer and power line failures, and disconnections of main substations.

The location candidates for installing switching devices are shown in Figure 5.2: the locations 'A'–'J' for NCS and the locations 'K'-'M' for NOS. We assumed that the capital costs of the switching devices (including wires) were $20,000 for NCS and $85,000 for NOS. The annual O&M cost of the switches was $200. The capital cost of upgraded equipment for the DG units was $340/kW[6], and the annual O&M cost was 5% of the capital cost. A 0.5-MW DG unit at locations '1' and '2' would participate in the market. The contract of reliability services would be 5 years with a 7% discount rate. An REP would decide on $\Delta U_{H_m} = 1.8$ hours/year. The REP expected to gain profits at least 7% each year, and its revenue was predicted to decrease 0.5% each year. The end user data were assumed, and are shown in the Appendix-B.

[6] The information on costs comes from the consultant report "Distributed generation integration cost study" prepared for the California Energy Commission (November 2013).

By exchanging all the necessary information among market participants, the DSO would inform the DG units and REPs of the initial prices of the services as follows: $\hat{\rho}_{RD} = \$600, \hat{\rho}_{RS} = \$13.78$, and $\hat{\rho}_{DH} = \$10.6$ /MWh.

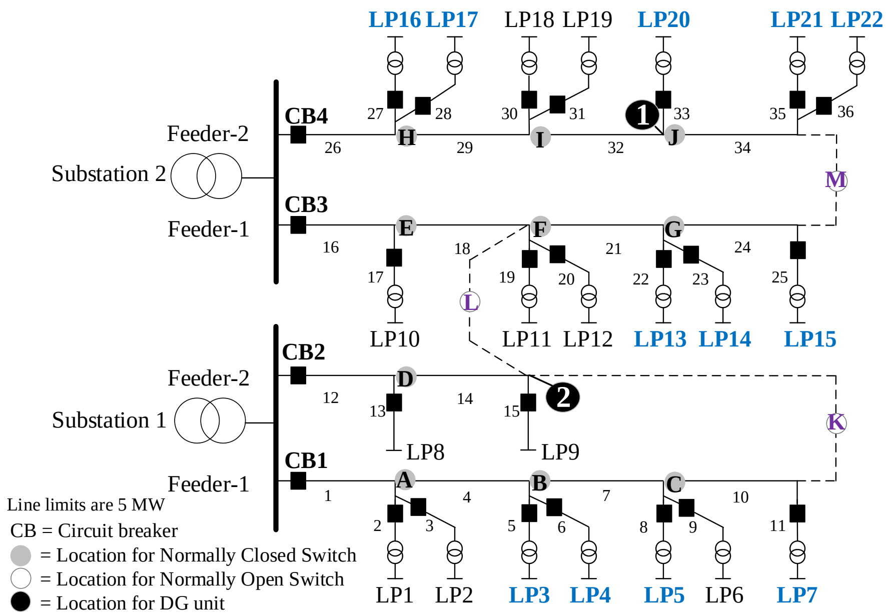
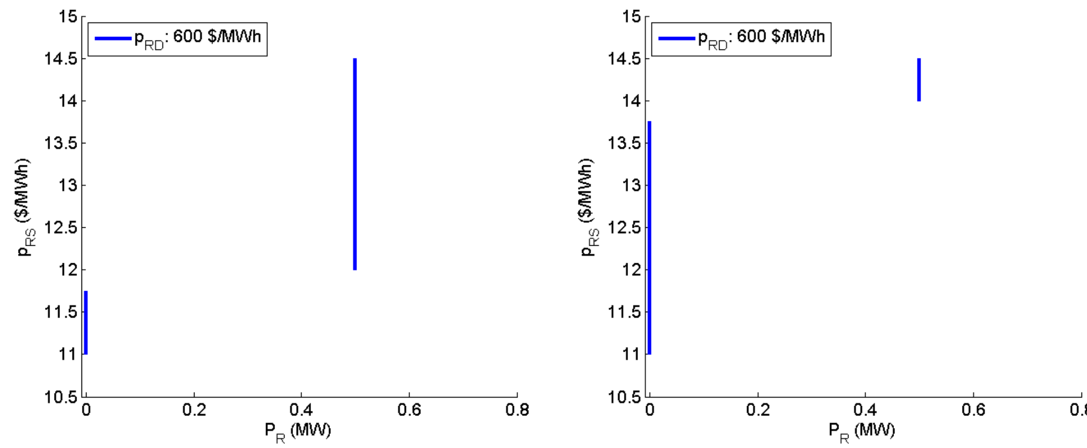


Figure 5.2: Modified RBTS Bus 2 for model-I

The prices for high reliability services, which include improved delivery service and backup power, will be settled through bidding of market participants. To understand the process of market clearing, we show the bid functions of each market participants and the process of settling the service prices if the REP decides to offer two reliability levels. The results of the provision of two reliability levels are compared to that of a single level.

5.6.2 DG unit's bid function

Assuming that the information on costs of DG unit at location '1' is $C(P)$: $0.01P^2 + 599.9.0P + 10$, C_{OM}: \$6,000 /year, and C_{CP}: \$ 371,000/MW, while that of DG unit at location '2' is $C(P)$: $0.5P^2 + 1110.2P + 20$, C_{OM}: \$5,000 /year, and C_{CP}: \$ 371,000/MW. Given the initial prices of the services and γ_{DG} = 0.0041, the DG unit at location '1' and '2' obtained the bid function as shown in Figure 5.3 to submit to the DSO. According to these bid functions, these DG units tend to sell all of their capacity as long as $\hat{\rho}_{RS}$ is high enough to allow the generators to recover the investment costs within the expected period.



(a) DG at location '1' (Bus 34) (b) DG at location '2' (Bus 15)

Figure 5.3: Bid function considering different DG locations with $\hat{\rho}_{RD} = \$600, \hat{\rho}_{RS} = \$13.78$, and $\hat{\rho}_{DH} = \$10.6$ /MWh

5.6.3 Utility's bid function

The utility determined the optimal locations of the switches, and the ρ_{DH} that maximizes the number of served end users for different ΔU_H. The information about ΔU_H and ρ_{DH} was plotted as a bid function. In each iteration of market clearing process, the DSO updates the integrated DG units, and then the utility creates new bid functions. As shown in Figure 5.4, the DSO considered to integrate both DG units in the beginning of the market clearing process, and then updated the DG integration to 1 DG unit at location '1'. The bid function would include the information on the optimal locations of the switches and the number of served end users. For instance, by considering an integration of a DG unit at location '1', 2090 end users will obtain the reliability level at $\Delta U_{H_m} = 1.8$ hours/year if switching devices are installed at location 'ABCFGHKLM'. However, if the reliability level is offered at $\Delta U_H = 1.9$ hours/year, 1730 end users will obtain this reliability level and 360 (2090-1730) end users will receive the reliability level at $\Delta U_{H_m} = 1.8$ hours/year. Since the problem is formaulated to offer two reliabiliy levels, the number showing on the bid function is the number of end users who receiving that reliability level, while the rest of end users will obtain the reliability level at ΔU_{H_m}.

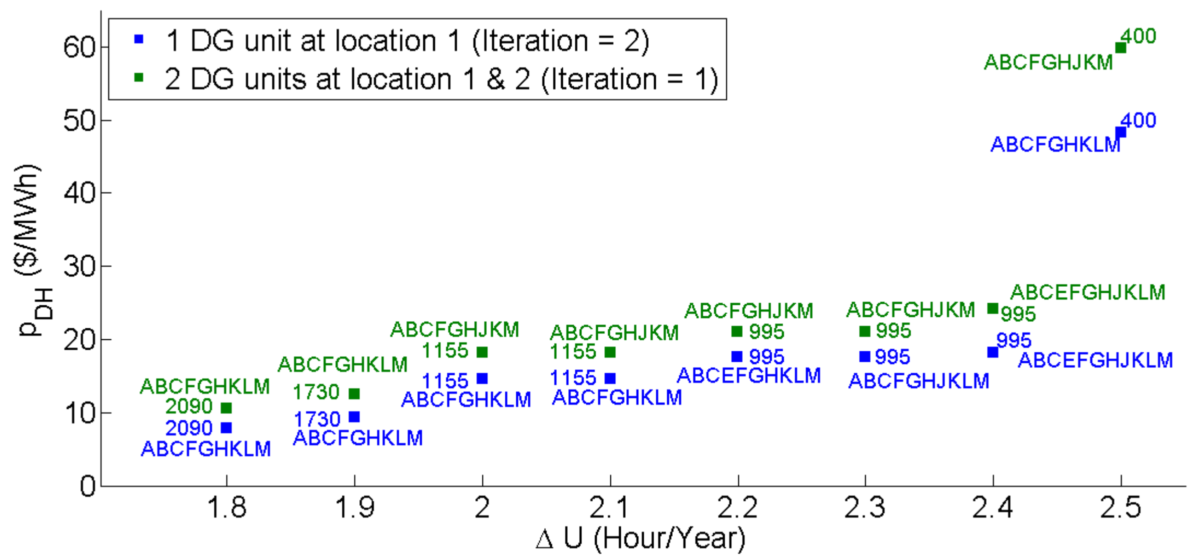


Figure 5.4: Utility's bid function with the optimal locations of installed switches and the number of served end users

However, the bid function with the information about the number of served end users was submitted to the DSO. Since reliability depends on end user locations, the bid function was also submitted according to load points. For instance, as the bid functions shown in Table 5.5-Table 5.6, the utility could not charge end users at LP-16 since the reliability level at this load point did not meet the minimum level ($\Delta U_{H_m} = 1.8$ hours/year) agreed upon with the REPs. On the other hand, the utility could charge end users at LP-15 for the maximum reliability level with $\Delta U_H =$ 2.5.

Table 5.5: Utility's bid function of each load point when considering the installation of 2 DG units at location '1' and '2'

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
$\hat{\rho}_{DH}$ (\$/MWh)	10.602	12.554	19.757	19.757	23.568	23.568	24.172	60.171
	Number of end users							
LP-3	175	175						
LP-4	160	160	160	160				
LP-5	200	200						
LP-7	200	200	200	200	200	200	200	200
LP-13	200	200						
LP-14	180							
LP-15	200	200	200	200	200	200	200	200
LP-16								
LP-17	180							
LP-20	190	190	190	190	190	190	190	
LP-21	190	190	190	190	190	190	190	
LP-22	215	215	215	215	215	215	215	

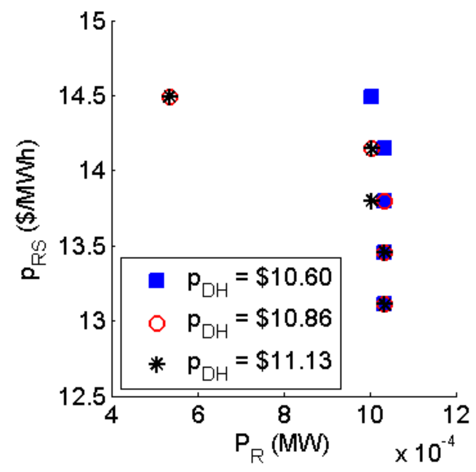
Table 5.6: Utility's bid function of each load point when considering the installation of 1 DG unit at location '1'

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
$\hat{\rho}_{DH}$ (\$/MWh)	7.860	9.308	14.647	14.647	17.629	17.629	18.232	48.316
	Number of end users							
LP-3	175	175						
LP-4	160	160	160	160				
LP-5	200	200						
LP-7	200	200	200	200	200	200	200	200
LP-13	200	200						
LP-14	180							
LP-15	200	200	200	200	200	200	200	200
LP-16								
LP-17	180							
LP-20	190	190	190	190	190	190	190	
LP-21	190	190	190	190	190	190	190	
LP-22	215	215	215	215	215	215	215	

5.6.4 REP's bid function

The REP received the information from an end user, and then determined the $\hat{\rho}_{RS}$ and $P_{R,DG}$ data points for that individual end user, as shown in Table 5.7.

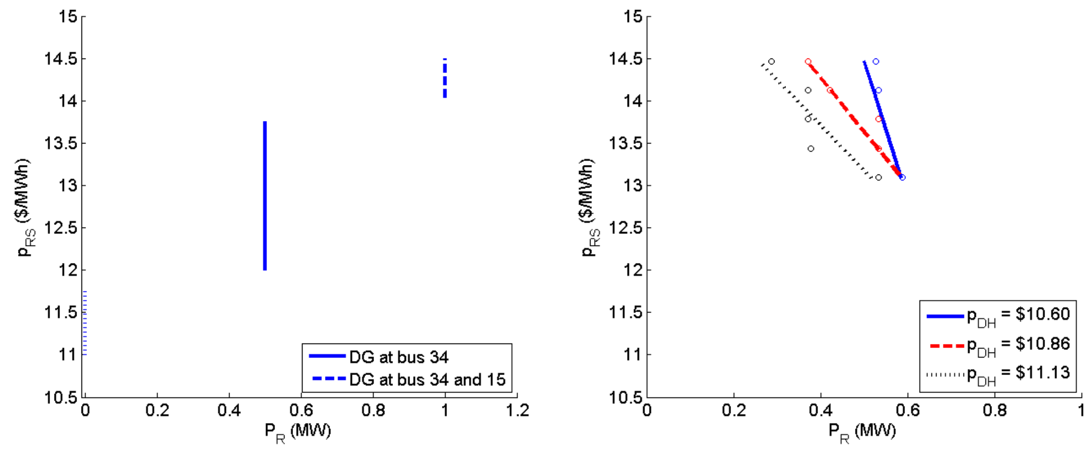
Table 5.7: End user's information and his/her $\hat{\rho}_{RS}$ and $P_{R,DG}$ data points calculated by an REP

<table>
<tr><td>ΔWTP_T: $22 /month</td><td rowspan="4">
</td></tr>
<tr><td>ΔWTP_D: $10 /month</td></tr>
<tr><td>Appliances ordered from high to low priority:
• Refrigerator 200 W
• Cell phone recharge 5 W
• TV 300 W
• Light 30 W
• Microwave 500 W
• A/C 5000 W</td></tr>
<tr><td>Minimum power needed: Refrigerator 200 W</td></tr>
</table>

The REP determined bid functions of all individual end users, and aggregated the bid functions corresponding to the same $\hat{\rho}_{RS}$ $\hat{\rho}_{DH}$, and load points After that, these bid functions were submitted to the DSO.

5.6.5 Settling service charges

After the DSO received all bid functions from the market participants, the bid functions of the DG units were aggregated to the system level as shown in Figure 5.5-(a). On the other hand, the bid functions of REPs were aggregated with respect to the same $\hat{\rho}_{DH}$, and load points, but for the illustration purpose, the REP's bid functions at each load point were aggregated together as shown in Figure 5.5-(b).



(a) (b)

Figure 5.5: The aggregated bid functions of the (a) DG units as the supply function, and (b) REPs as demand function for backup power

With these bid functions, the DSO proceeded with market clearing in order to settle the backup power, service charges, and number of switches, as shown in Figure 5.6-Figure 5.9. During the process of settling the prices, bid functions including related information have been exchanged among the market participants for several iterations before the prices of $\hat{\rho}_{RS}$ and $\hat{\rho}_{DH}$, are settled as summarized in Figure 5.10.

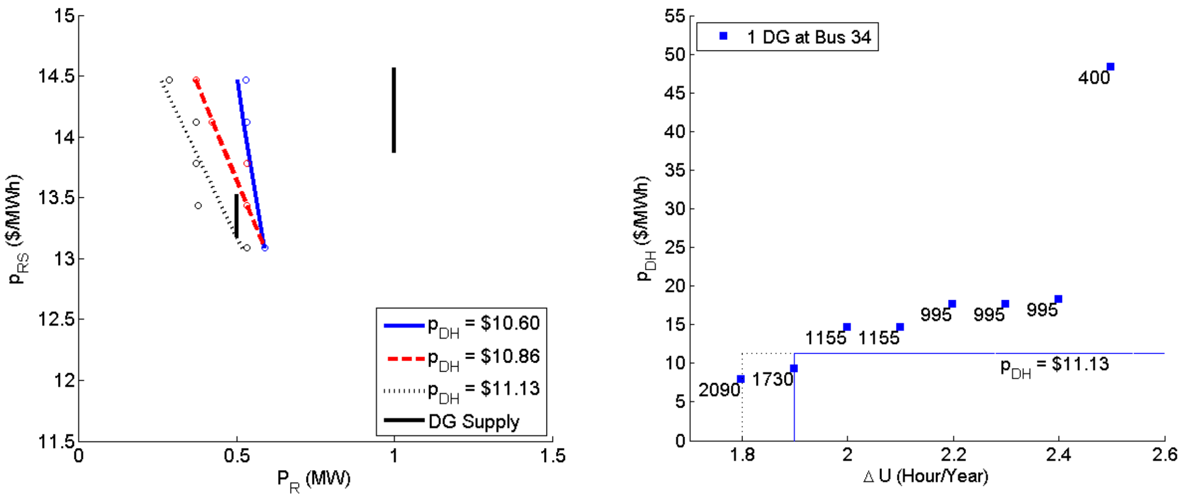


Figure 5.6: The settling of backup power and delivery service in the iteration $m = 1$ with the settled price of backup power $(\hat{\rho}_{RS}) = \$13.20$ /MWh and the settled price of delivery service with high reliability level $(\hat{\rho}_{DH}) = \$11.13$ /MWh

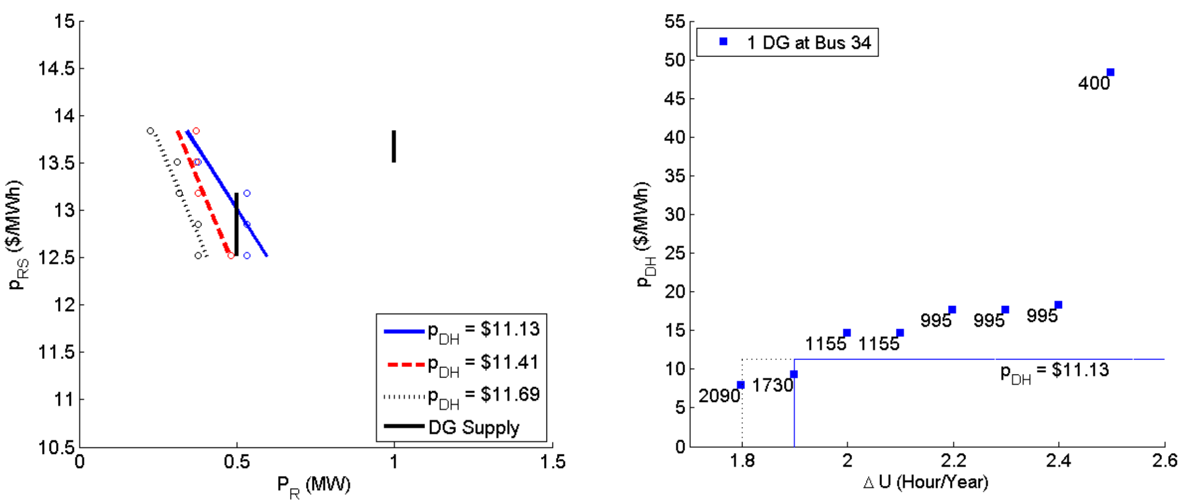


Figure 5.7: The settling of backup power and delivery service in the iteration $m = 2$ with the settled price of backup power $(\hat{\rho}_{RS}) = \$13.08$ /MWh and the settled price of delivery service with high reliability level $(\hat{\rho}_{DH}) = \$11.13$ /MWh

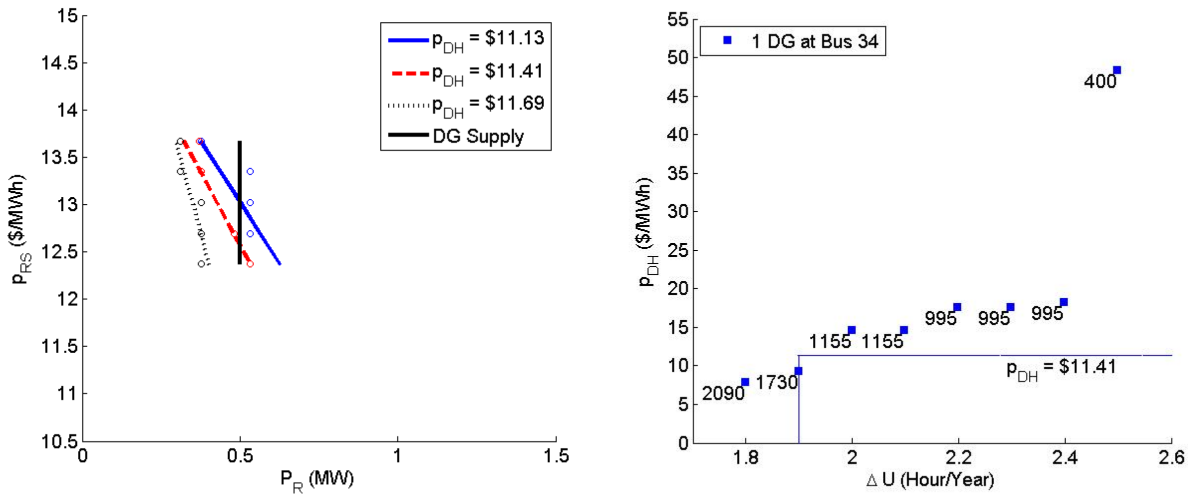


Figure 5.8: The settling of backup power and delivery service in the iteration $m = 3$ with the settled price of backup power $(\hat{\rho}_{RS}) = \$12.61$ /MWh and the settled price of delivery service with high reliability level $(\hat{\rho}_{DH}) = \$11.41$ /MWh

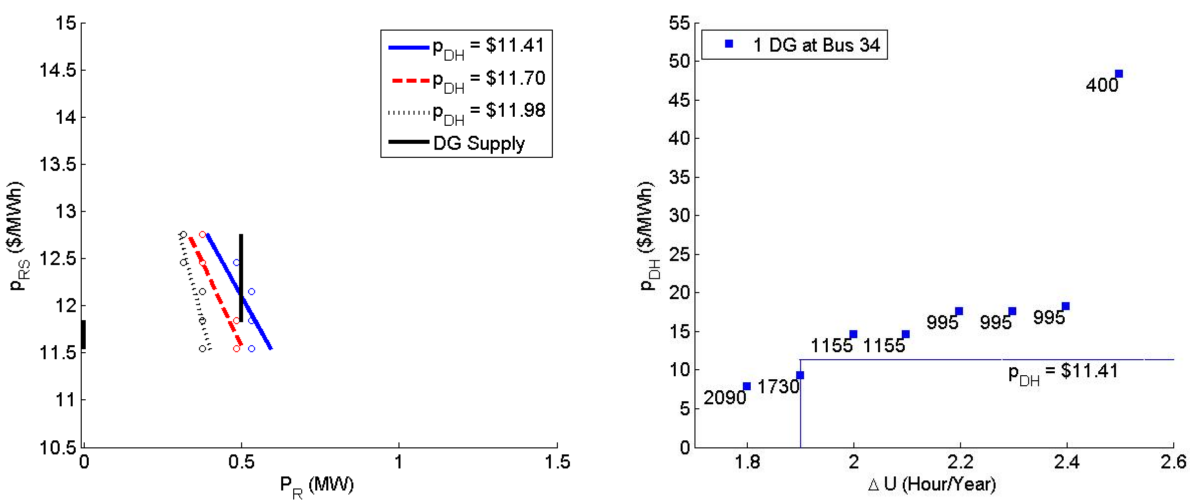


Figure 5.9: The settling of backup power and delivery service in the iteration $m = 7$ with the settled price of backup power $(\hat{\rho}_{RS}) = \$12.20$ /MWh and the settled price of delivery service with high reliability level $(\hat{\rho}_{DH}) = \$11.41$ /MWh

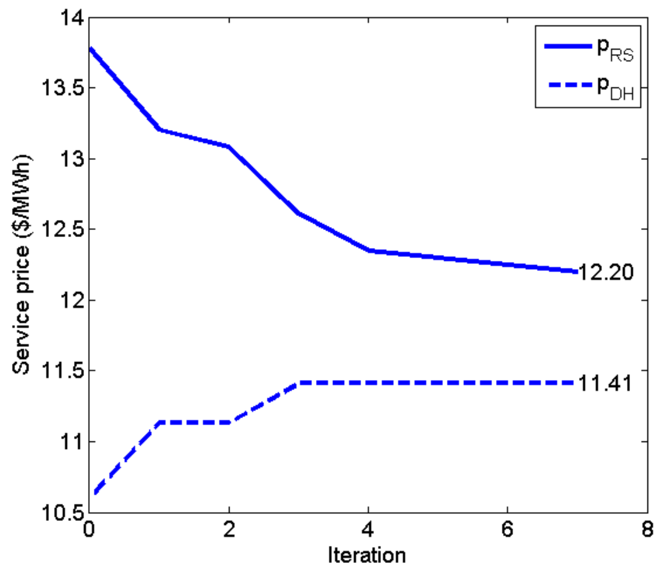


Figure 5.10: Service prices for backup power (ρ_{RS}) and delivery service with high reliability (ρ_{DH}) at each iteration

For the 1st iteration ($m = 1$), the supply and demand function of the backup power intersected at $P_R^1 = 0.5$ MW, $\rho_{RD}^1 = \$600$, $\rho_{RS}^1 = \$13.20$, and $\hat{\rho}_{DH}^1 = \$11.13$ /MWh. Based on P_R^1 and $\hat{\rho}_{DH}^1$, the maximum reliability level would be at ΔU_H =1.9 hours/year. The number of end users who purchase these services and $\hat{e}_{AN,n}$ did not change since according to their ΔWTP_D, all end users can afford to pay for the reliability services at ΔU_H =1.8 and 1.9 hours/year without backup power.

The market clearing process continued and was terminated in the 7th iteration. The backup power, and service charges were settled at $P_R =$ 0.5 MW, $\rho_{RD} =$ \$600, $\rho_{RS} =$ \$12.20, $\rho_{DH,\Delta U_H=1.8} =$ \$7.86, and $\rho_{DH,\Delta U_H=1.9} =$ \$9.31 /MWh. The switches were installed at 'ABCFGHKLM'. The numbers of end users served at different reliability levels are shown in Table 5.8, and the amount of power that each load point obtains are shown in Figure 5.11.

By observing the results of providing two reliability levels, the lower reliability level is provided to end users at LP-14 and LP-17 due to the limits of considered technologies, while willingness to pay of these end users is high enough to purchase the higher reliability services. To improve the reliability of these load points, the utility may need to deploy other technologies or the REP searches for other DG units or service providers.

Table 5.8: Numbers of end user served at different reliability options for the provision of 2 reliability levels

Reliability level	Number of end users	
	With backup power	Without backup power
$\Delta U_H = 1.9$, $\rho_{DH} =$ \$9.31 /MWh	705	1025
$\Delta U_H = 1.8$, $\rho_{DH} =$ \$7.86 /MWh	185	175
$\Delta U_H = 0$	-	180

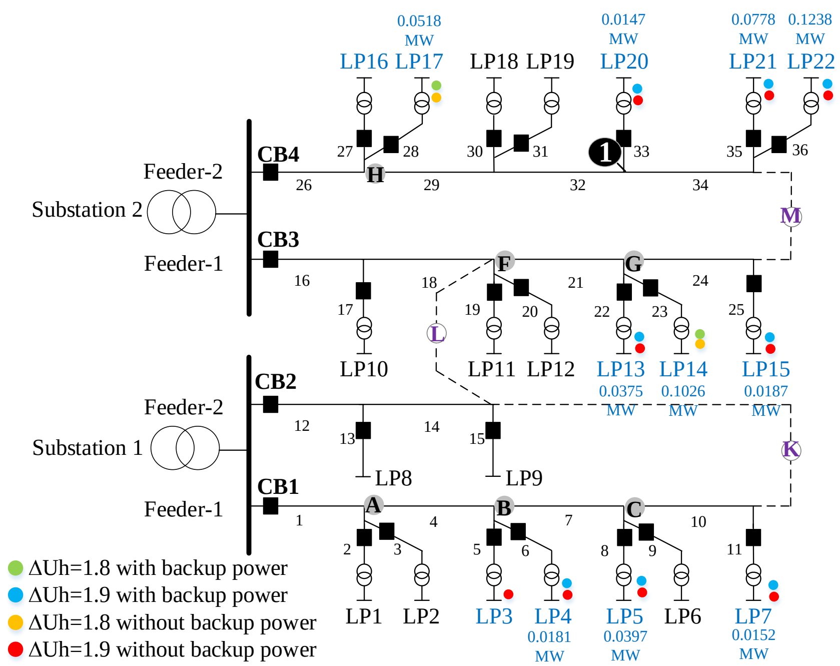


Figure 5.11: Reliability level and amount of backup power at each load point for the provision of 2 reliability levels

Furthermore, if the DSO decided to offer a reliability service with a single high reliability level at $\Delta U_H = 1.9$, the backup power, and service charges were settled at $P_R = 0.5$ MW, $\rho_{RD} =$ \$600, $\rho_{RS} =$ \$12.23, and $\rho_{DH,\Delta U_H=1.9} =$ \$9.31 /MWh. The switches were installed at 'ABCFGHKLM'. The numbers of end users served at the different reliability levels are shown in Table 5.9, and the amount of power that each load point obtains are shown in Figure 5.12.

Table 5.9: Numbers of end user served at different reliability options for a provision of single reliability level at $\Delta U_H = 1.9$

Reliability level	Number of end users	
	With backup power	Without backup power
$\Delta U_H = 1.9$, $\rho_{DH} =$ \$9.31 /MWh	1190	540
$\Delta U_H = 0$	-	540

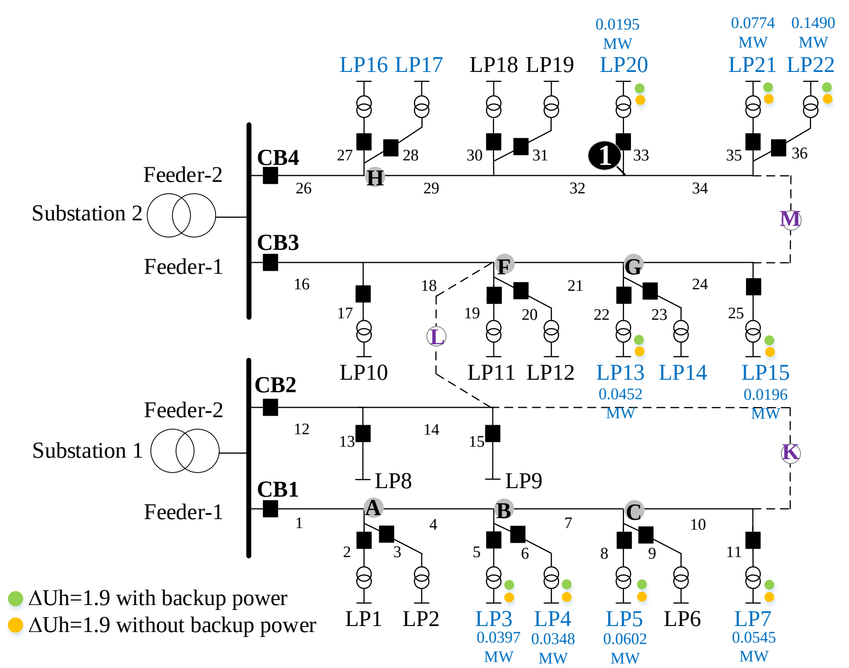


Figure 5.12: Reliability level and amount of backup power at each load point for the provision of single reliability level at $\Delta U_H = 1.9$

The number of end users obtaining backup power under the provision of two reliability levels is less than that of a single reliability level. For more details, the numbers of end users obtaining backup power at each load point are shown in Table 5.10. According to the results, backup power served to the end users at LP-14, and LP-17 is distributed to the end users at other load points when it changes from the provision of two levels to the provision of a single level.

Table 5.10: Numbers of end users obtaining backup power under the provision of two reliability levels and of a single reliability level at $\Delta U_H = 1.9$ at each load point

LP	Two reliability levels	Single reliability level at $\Delta \mathrm{U_H} = 1.9$
3	0	80
4	60	110
5	125	200
7	50	200
13	30	85
14	135	0
15	65	65
16	0	0
17	50	0
20	90	90
21	115	190
22	170	170

In the market structure with DSO, bids and other information related to bidding are exchanged through the DSO, and the DSO will proceed market clearing by maximizing the long-run social welfare based on that given information. According to the results, the prices of delivery service with high reliability level (ρ_{DH}) under the provision of two reliability levels and single reliability level are the same; on the other hand, the prices of backup power (ρ_{RS}) under the provision of two reliability levels is slightly lower than that under the provision of a single level. For the number of unserved end users, although more end users under the provision of two reliability levels can obtain the high reliability services, the number of end users not receiving backup power is less than that under the provision of a single reliability level.

5.7 Discussion

The differentiated reliability services will allow more customers to obtain the services at fair price. By providing a single high reliability level, some customers may not be served since they cannot afford for that specific high reliability level, or the technologies adopted by the utility cannot bring the reliability level of these customers to meet the reliability target level. However, if the provision of differentiated reliability services is allowed, more customers will obtain the reliability services but with different reliability levels, while thee are charged according to the services they obtain. The utility can manage to deploy appropriate technologies to provide differentiated reliability services for different customers.

In the market environment, the role of utility will be changed to be another service provider that owns infrastructures in distribution level, and the utility has to compete with other service providers who may be able to offer the reliability services at lower prices. The market will allow the utility to manage the investment costs in providing high reliability level by itself. For instance, the utility may decide to either make large investments to offer high reliability services to all customers, or lose some customers in order to lower the investment costs. The utility's investment strategy will depend on customers' willingness to pay and preferences for reliability.

On the other hand, the DSO is a market decision maker and responsible for achieving fair charges for market participants and system efficiency. The DSO requires a similar level of knowledge, and skills as the utility to optimize across all possible resources integrated in the systems. The DSO must be allowed to have access to the utility's information that is necessary for deciding on market transactions. For instance, in the reliability market, the DSO requires network constraints for settling the service prices.

However, although the DSO looks over the entire system of interest, a value of DG locations in enhancing reliability is not taken into account when settling the service prices. In this market structure, the major decision factor in selecting which of DG units to purchase backup power is their costs. However, these costs of DG units may trade off with reliability improvement of the system. To include the value of DG location in making decision on DG units, the DSO requires assistance from the utility in evaluating impacts of DG units on system reliability. The impacts of DG units on reliability will be discussed in chapter 7 later.

Chapter 6: Model-II: Retail market structure without DSO

This chapter presents the retail market structure without DSO. In this market structure, market participants will negotiate service prices directly to the entities involved in service sales and purchases through bidding as shown in Figure 6.1. The market is designed to offer a single and/or two reliability levels. For the provision of two reliability levels, one of them must be the minimum reliability level requested by the REP. An REP procures high reliability services that include improved delivery service and backup power from a utility, and DG units, respectively.

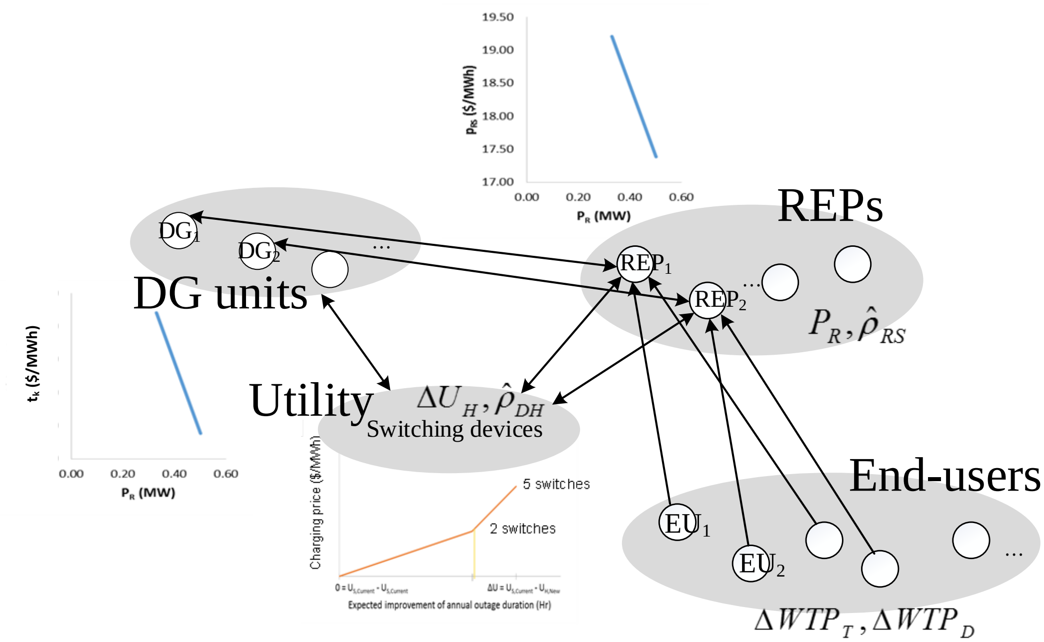


Figure 6.1: Reliability market structure of model-II with information exchanges

In this market structure, the prices for high reliability service will be also settled through bidding of market participants, while the bids will be constructed in the form of a function. The REP and the utility negotiate for settling the prices of improved delivery services. On the other hand, in settling the prices of backup power, each DG unit decides the quantities of backup power according to the REP's bid functions, and then pass these data to the utility for settling the prices. To deliver those backup power quantities, the utility will charge delivery fees to the DG units in order to incentivize the DG units to adjust their transactions according to network constraints.

In the beginning of market clearing process, the initial information as shown in Table 1 is exchanged to estimate the initial service prices. After that, these prices will be given to market participants to create a bid function, and then then the utility, REPs and DG proceed the information exchanges until the service prices are settled. To illustrate this process, the market mechanism was implemented on the modified IEEE RBTS Bus2. The details of estimating bidding prices, and settling the prices of services are explained as follows.

Table 6.1: Initial information exchanges in the proposed market model-II (F: Information flow from entity, and T: Information flow to entity)

Information flow from to	Information
F: REP T: Utility	The request for the high reliability service
F: Utility T: REP	The standard reliability level (U_S)
F: REP T: End user	U_S
F: End user T: REP	The end user's decision to obtain the service
F: REP T: Utility	The number of end users who purchase the high reliability service in the load point n $\left(N_{H,n}\right)$, the total annual amount energy that the end users consume during normal condition at the load point n ($e_{AN,n}$), the maximum power needed during a normal power interruption at each load point $\left(P_{R,H}^{max}\right)$, the minimum improved reliability level that a REP expects a utility to offer to end users $\left(\Delta U_{H_m}\right)$, and the locations and capacity of potential DG units

Table 6.1: Initial information exchanges in the proposed market model-II (continued)

Information flow from to	Information
F: Utility T: DG unit	The probability that DG will be called (γ_{DG})
F: DG unit T: REP	The anticipated prices for actual delivered power ($\hat{\rho}_{RD}$) and standby ($\hat{\rho}_{RS}$) Note: REP and DG unit have a bilateral contract.
F: Utility T: REP	The initial bid function of improved reliability service at load point n showing a relationship between an incremental improved reliability level (ΔU_H) and price of delivery service with high reliability ($\hat{\rho}_{DH}$), the total number of power interruptions (N_F), the average duration of restoring a normal power interruption (r_{ave}), and reliability index showing incremental improvement of reliability level by $\widehat{DG}_k$ ($\Delta RI_{\widehat{DG}_{k,j}}$)
F: REP T: End user	N_F,and r_{ave}
F: End user T: REP	The additional monthly expenses that an end user is willing to pay to experience total shorter-duration power outages occurring in a year (ΔWTP_T for utilizing backup power, and ΔWTP_D for not utilizing backup power), and the wattage of appliance that the end user needs during power outages (w_d)

6.1 REP

An REP in this market structure does not only work similarly to one in the market structure with DSO, but it also has to decide on which of DG units to purchase. The REP will determine high reliability services that satisfy its end users according to their given information, and procures such services, which are offered on a long-term contract, for the end users. In this market structure, the REP will interact with a utility and DG units directly, which open opportunities for the REP to select the services that fit to end users' needs. In this trading, the REP will gain profits from charging some margin (ϕ_r) on the true costs of the reliability services ($C_{RS}(\cdot)$); the value of ϕ_r can be set as mentioned in Chapter 5.

Since the REP has a duty to procure reliability services for its end users, it will search for DG units that will bring as much benefits as possible to its end users. Those benefits can be determined from the amount of back power obtained by end users ($P_{R,\Delta U_{H_m},\widehat{DG}_k}$), and incremental improvement of reliability level by each DG unit ($\Delta RI_{\widehat{DG}_k}$). In addition, the REP will decide on reliability levels for its end users, and this can be done by considering from the amount of backup power ($P_{R,\widehat{\Delta U}_H}$) and the improved reliability level ($\widehat{\Delta U}_H$) that end users will receive.

To achieve these two tasks, the REP requires the information on $\Delta RI_{\widehat{DG}_k}$ and $\widehat{\Delta U}_H$ from the utility and the prices of backup power from DG units to decide on the optimal reliability level and DG units for each end user. Given these data and individual end user's information, the REP can find the optimal DG unit by comparing $B_{\widehat{DG}_k}$ of each DG unit, which is calculated as shown eq. (6-1)-(6-2). The price of that optimal DG unit will be used to calculate $B_{\widehat{\Delta U}_H}$ in eq. (6-3)-(6-4), and by comparing $B_{\widehat{\Delta U}_H}$ of each reliability level, the reliability level that maximizes $B_{\widehat{\Delta U}_H}$ will be considered an optimal reliability level. $P_{R,\Delta U_{H_m},\widehat{DG}_k}$, $P_{R,DG,\widehat{\Delta U}_H}$ and $P_{R,\widehat{\Delta U}_H}$ are obtained by solving the optimization problem in eq.(6-5)-(6-12). For any end users, if their $P_{R,\widehat{\Delta U}_H}$ is equal to zero, it means that they cannot afford to pay for these high reliability services.

Depending on end user's preference, the REP may assign more weight to the terms of $P_{R,\Delta U_{H_m},\widehat{DG}_k}$ and $P_{R,DG,\widehat{\Delta U}_H}$ if the end user prefers to receive more backup power; on the other hand, if reliability is end users' concern, more weight can be assigned to the terms of $\Delta RI_{\widehat{DG}_k}$and $\widehat{\Delta U}_H$. This will allow the REP to design a suitable service package for its end users.

$$B_{\widehat{DG}_k,j} = W_1 \frac{P_{R,\Delta U_{H_m},\widehat{DG}_k,j} - P^{min}_{R,\Delta U_{H_m},j}}{P^{max}_{R,\Delta U_{H_m},j} - P^{min}_{R,\Delta U_{H_m},j}} + W_2 \frac{\Delta RI_{\widehat{DG}_k,j} - \Delta RI^{min}_j}{\Delta RI^{max}_j - \Delta RI^{min}_j} \tag{6-1}$$

$$\Delta RI_{\widehat{DG}_k,j} = \begin{cases} \Delta RI_{\widehat{DG}_k,j}, & P_{R,\Delta U_{H_m},\widehat{DG}_k,j} > 0 \\ 0, & P_{R,\Delta U_{H_m},\widehat{DG}_k,j} = 0 \end{cases} \tag{6-2}$$

$$B_{\widehat{\Delta U}_H,j} = W_3 \frac{P_{R,DG,\widehat{\Delta U}_H,j} - P^{min}_{R,DG,j}}{P^{max}_{R,DG,j} - P^{min}_{R,DG,j}} + W_4 \frac{\widehat{\Delta U}_{H,j} - \Delta U_{H_m}}{\widehat{\Delta U}^{max}_j - \Delta U_{H_m}} \tag{6-3}$$

$$P_{R,\widehat{\Delta U}_H,j} = \begin{cases} P_{R,\widehat{\Delta U}_H,j}, & \widehat{\Delta U}_{H,j} > 0 \\ 0, & \widehat{\Delta U}_{H,j} = 0 \end{cases} \tag{6-4}$$

where

ΔU_{H_m}	Minimum improved reliability level requested by an REP
$P_{R,\Delta U_{H_m},\widehat{DG}_k,j}$	Amount of backup power that the end user j would purchase from $\widehat{DG}_k$ at the reliability level ΔU_{H_m}
$P^{min}_{R,\Delta U_{H_m},j}$, $P^{max}_{R,\Delta U_{H_m},j}$	Minimum and maximum value of $P_{R,\Delta U_{H_m},\widehat{DG}_k,j}$
$\Delta RI_{\widehat{DG}_k,j}$	Incremental improvement of reliability level by $\widehat{DG}_k$
ΔRI^{min}_j, ΔRI^{max}_j	Minimum and maximum value of $\Delta RI_{\widehat{DG}_k,j}$
$P_{R,\Delta U_{H_m},\widehat{DG}_k,j}$	Amount of backup power that the end user j would purchase from $\widehat{DG}_k$ at the reliability level ΔU_{H_m}
$P_{R,DG,\widehat{\Delta U}_H,j}$	Amount of power that the end user j will need from DG during extended power interruptions
$P_{R,\widehat{\Delta U}_H,j}$	Amount of power that the end user j will need during normal power interruptions
$\widehat{\Delta U}_{H,j}$	Total incremental reliability improvement of the end user j
$\widehat{\Delta U}^{max}_j$	Minimum improved reliability level offered by a utility

W_1, W_2, W_3, W_4 Assigned weight

However, in practical, end users may not receive optimal services as they desire due to variety of factors, such as low willingness to pay of end users, high service prices, network constraints, and etc. Therefore, instead of finding one optimal option of DG unit and reliability level for each end user, the REP ranks DG units and reliability levels of each end user according to $B_{\widehat{DG}_k}$ and $B_{\widehat{\Delta U}_H}$, and then determines the rankings of the most assigned reliability levels and DG units among these end users. These rankings will be used to adjust the reliability levels and DG units of end users as well as transactions with a utility and DG units. For instance, instead of purchasing backup power in a small amount from all candidate DG units, the REP may choose to procure a large amount from only first two top ranking DG units. This depends on the REP's business strategy.

6.2 End user

The reliability level and DG unit assigned to end users will be used in creating bid functions for backup power. For each end user, the REP will determine the maximum amount of backup power available to that end user during extended and normal power interruptions. The problem of determining the optimal backup power, which is the same as one in Chapter 5, is formulated as follows.

$$\max_{x_d, y_d} \frac{P_{R,DG,j}}{\sum_d w_{d,j}} + \frac{\sigma_{R,DG,j}}{\sum_d d} + \frac{P_{R,H,j}}{\sum_d w_{d,j}} + \frac{\sigma_{R,H,j}}{\sum_d d} \qquad (6\text{-}5)$$

where

$$P_{R,DG,j} = x_1 w_{1,j} + \cdots + x_D w_{D,j} \tag{6-6}$$

$$\sigma_{R,DG,j} = x_1(1) + \cdots + x_D(D) \tag{6-7}$$

$$P_{R,H,j} = y_1 w_{1,j} + \cdots + y_D w_{D,j} \tag{6-8}$$

$$\sigma_{R,H,j} = y_1(1) + \cdots + y_D(D) \tag{6-9}$$

s.t.

$$\begin{aligned} \phi_r\Big(8760\big((1-\gamma_{DG})\hat{\rho}_{RS} + \gamma_{DG}(\hat{\rho}_{RD} + \rho_D + \hat{\rho}_{DH})\big)P_{R,DG,j} \\ + (\rho_D + \hat{\rho}_{DH})\big(\Delta U_{H_m} + r_{ave}F\big)P_{R,H,j} + \hat{\rho}_{DH}\hat{e}_{AN,n}\Big) \\ \le 12(\Delta WTP_{T,j}) \end{aligned} \tag{6-10}$$

$$\phi_r\left((\rho_D + \hat{\rho}_{DH})\big(\Delta U_{H_m} + r_{ave}F\big)P_{R,H,j} + \hat{\rho}_{DH}\hat{e}_{AN,n}\right) \le 12(\Delta WTP_{D,j}) \tag{6-11}$$

$$P_{R,DG,j} = \begin{cases} P_{R,DG,j}, & P_{R,DG,j} \ge w_{D,j} \\ 0, & P_{R,DG,j} < w_{D,j} \end{cases} \tag{6-12}$$

where

$P_{R,DG,j}$	Amount of power that the end user j will need from DG during extended power interruptions
$P_{R,H,j}$	Amount of power that the end user j will need during normal power interruptions
$w_{d,j}$	Wattage of appliance that the end user j needs, D: highest priority
ρ_D	Price of standard delivery service.
x_d , y_d	Binary variables of the utilized appliance d.

$\sigma_{R,DG,j}$, $\sigma_{R,H,j}$	Priority of appliances for an estimation of $P_{R,DG,j}$, and $P_{R,H,j}$
ΔU_{H_m}	Minimum incremental improvement of reliability level (hour/year)
r_{ave}	Average duration of restoring a normal power interruption
N_F	Reduction number of power interruptions
ϕ_r	Margin charged on true costs
$\hat{\rho}_{DH}$	Anticipated price of delivery service with high reliability

To create the bid function of an individual end user, the REP will solve the above problem for different $\hat{\rho}_{RS,\widehat{DG}_k^*}$ but fixed $\hat{\rho}_{DH,\widehat{\Delta U}_H^*}$ and $\hat{\rho}_{RD,\widehat{DG}_k^*}$. The different $\hat{\rho}_{RS,\widehat{DG}_k^*}$, for instance, are obtained by perturbing $\hat{\rho}_{RS,\widehat{DG}_k^*}$ for $\pm 2.5\%$ and $\pm 5\%$, and thereby the REP will obtain five $\hat{\rho}_{RS,\widehat{DG}_k^*}$ and $P_{R,\widehat{DG}_k^*}$ data points. These data points will be fitted to a first-degree polynomial as the individual end users' bid function. The REP follows this process to obtain bid functions of all individual end users, and then all bid functions corresponding to the same DG units and load points will be aggregated to a system level, and submitted to DG units.

It should be noted that the utility and REPs have to educate end users about the information on reliability before the end users decide to purchase the reliability service. Before end users decide on participating in the reliability market, the utility provides the REP with the information that is necessary for the REP and its end users (Table 6.1) to decide on whether they will purchase the high reliability services. Assuming the end users have understood about these services, they can prioritize appliances needed during a power outage and indicate ΔWTP_T, and ΔWTP_D.

6.3 DG unit

Once the DG unit obtains the bid functions from the REP, it determines the amount of backup power sold to the end users by maximizing its own profits. However, when making purchase decisions, the transactions between the DG unit and REP could cause a violation of network capacity since the DG unit and REP have no information about network conditions. Therefore, to manage power flow in the network, service fees for delivery power can be an option to incentivize the DG unit to adjust its transactions [79]. By including these delivery fees, each DG unit can solve the following optimization problems to maximize its benefits.

$$\min_{P_{kj}} C_k\left(\sum_j P_{kj}\right) + \sum_j t_{kj}P_{kj} - \sum_j D_{kj}(P_{kj}) \tag{6-13}$$

s.t.

$$P_{DG,k}^{min} \leq \sum_j P_{kj} \leq P_{DG,k}^{max} \tag{6-14}$$

$$P_j^{min} \leq P_{kj} \leq P_j^{max} \tag{6-15}$$

where

P_{kj}	Amount of backup power that DG unit k sells to load point j at price $d_{kj}(P_{kj})$
$D_{kj}(P)$	Quadratic demand function of load point j
$C(P)$	Quadratic generating cost function of distributed generator
t_{kj}	Delivery fee for DG unit k to send power to load point j
$P_{DG,k}^{min}$, $P_{DG,k}^{max}$	Minimum and maximum power of DG unit k
P_j^{min}, P_j^{max}	Minimum and maximum power of load point j purchasing from DG unit k

As $C(P)$ and $D_{kj}(P)$ in eq.(6-13) are quadratic functions, the above optimization problem can be rewritten as:

$$\min_{P_{kj}} \frac{1}{2} P_k{}' Q_k P_k + h_k' P_k + t_k' P_k \tag{6-16}$$

s.t.

$$P_{DG,k}^{min} \leq \sum_j P_{kj} \leq P_{DG,k}^{max} \tag{6-17}$$

$$P_j^{min} \leq P_{kj} \leq P_j^{max} \tag{6-18}$$

where

P_k	Vector of P_{kj} or backup power that DG unit k sells to load point j
t_k	Vector of service charges for delivering P_k

The sufficient condition for this optimization problem is $Q_k P_k + h_k + t_k = 0$, and this equation is considered to be a delivery demand function of DG unit k. This demand function and the information on minimum and maximum power of DG unit and load points are reported to the utility for settling the service prices. The delivery demand function is submitted to the utility in a form of $P_k = -Q_k^{-1} t_k - Q_k^{-1} h_k$.

Once the utility settles the amount of backup power, this information is reported back to DG unit to calculate the prices of backup power, the expected profits and capital recovery costs by eq.(6-19)-(6-21). Such amount of backup power, $\hat{\rho}_{RS}$, and $\hat{\rho}_{RD}$ should satisfy eq.(6-20)-(6-21) so that the DG owner can recover the investment costs in an anticipated year. If these conditions are not satisfied, $\hat{\rho}_{RS}$, and $\hat{\rho}_{RD}$ will be updated and given to the REP to estimate the new bid functions for backup power.

$$\hat{\rho}_{RS,k} = \frac{\sum_j D_{kj}(P_{kj})\, P_{kj}}{\sum_j P_{kj}} \tag{6-19}$$

$$C_{CP}\, P_{R,k} + D_{Y_{DG}}\left(C_{OM} P_{R,k} - E\{\pi_k\}\right) \leq 0 \tag{6-20}$$

$$\begin{aligned} E\{\pi_k\} = 8760 &\left(\left(1 - \gamma_{DG,k}\right)\hat{\rho}_{RS,k} + \gamma_{DG,k}\hat{\rho}_{RD,k}\right) P_{R,k} \\ &- 8760\gamma_{DG,k}\left(C\left(P_{R,k}\right) + T\left(P_{R,k}\right)\right) \end{aligned} \tag{6-21}$$

where

C_{CP}	Capital cost of the DG unit (\$/MW)
C_{OM}	Operation and maintenance cost of the DG unit (\$/MW)
$D_{Y_{DG}}$	Discount factor, $D_{Y_{DG}} = \sum_{y=1}^{Y_{DG}} (1 + r_d)^{-y}$
Y_{DG}	Expected recovery year

6.4 Utility

In this market structure, a utility has three main duties: to determine bid functions for improved delivery services including related information on reliability, and to settle the service price of backup power. To determine the bid functions, the local utility will receive the information on end users and potential DG units from the REPs to evaluate the service price (ρ_{DH}) for the new reliability level, which is measured in terms of an incremental reduction of outage duration (ΔU_H). The service prices, which are different depending on the reliability levels, are assessed from the investment costs of enhancing reliability by an installation of switching devices and an integration of DG units. The relationship between an improved reliability level and the charging price of that reliability level is considered a bid function of the utility.

The objective of the utility is to maximize the profits from providing delivery service with high reliability level. The profits can be estimated by maximizing the number of served end users for the maximum revenue, and minimizing the investment costs. The utility searches for the optimal number and locations of switches, and estimate the charging prices for the different target reliability levels. The optimal switch number and locations will enhance the reliability services in such a way that brings the most end users to obtain the services as they desire and give the low investment costs. To achieve this, the problem of searching optimal number and locations of switches is formulated similarly to the one in Chapter 5. After obtaining the bid functions, the utility reports them to the REP.

In addition to the bid functions, the utility provides the REP with the information on incremental improvement of reliability level due to integrating of each candidate DG unit. The reliability improvement is measured in terms of the expected reduction of outage duration comparing to the standard reliability level (U_S). By this definition, the reliability improvement therefore can be calculated as shown in eq.(6-22). This information will be used by an REP to decide on which of DG units that offer more reliability improvement to end users regardless of the costs.

$$\Delta RI_{\widehat{DG}_k,n} = U_S - U_{\widehat{DG}_k,n} \tag{6-22}$$

where

$\Delta RI_{\widehat{DG}_k,n}$	Incremental reliability improvement due to integrating of $\widehat{DG}_k$, which is measured in terms of reduction of outage duration
$U_{\widehat{DG}_k,n}$	Reliability level of load point n when considering only $\widehat{DG}_k$ installed in the reference network

$U_{\widehat{DG}_k,n}$ is calculated similarly to the reliability level in eq.(5-10), but the reference network refers to the network that is upgraded to meets ΔU_{H_m} when considering an integration of all candidate DG units.

To settle the price of backup power and its delivery fees, the utility will receive the delivery demand functions from DG units in a form of $P_k = -Q_k^{-1}h_k - Q_k^{-1}t_k$. The utility obtains the delivery fees by solving the following optimization problem. This problem is derived from the dual problem of DG unit k when given $t_k = \sum_l(\mu_{\bar{l}}^+ + \mu_{\bar{l}}^-)(DF_{\bar{l}k} - DF_{\bar{l}j}) = A'_k\mu$ [79]. The matrix A_k is formed from distribution factor matrix (DF) of the network, and $F_{\bar{l}}^{max}$is capacity of line $\bar{l}$.

$$\underset{\mu}{\text{Max}} \sum_k -\frac{1}{2}\mu' A_k Q_k^{-1} A'_k \mu - \mu' A_k Q_k^{-1} h_k - \sum_{\bar{l}} (\mu_{\bar{l}}^+ + \mu_{\bar{l}}^-) F_{\bar{l}}^{max} \tag{6-23}$$

s.t.

$$\mu \geq 0 \tag{6-24}$$

$$P_{DG,k}^{min} \leq -\mathbf{1}_{1,xj} Q_k^{-1}(h_k + A'_k\mu) \leq P_{DG,k}^{max} \tag{6-25}$$

$$P_{k,j}^{min} \leq -Q_k^{-1}(h_k + A'_k\mu) \leq P_{k,j}^{max} \tag{6-26}$$

where

$$A_k = \begin{cases} DF_{\bar{l}k} - DF_{\bar{l}j} & if\ \bar{l} \leq L \\ DF_{(\bar{l}-L)j} - DF_{(\bar{l}-L)k} & otherwise \end{cases} \tag{6-27}$$

$$\mu' = \begin{bmatrix} \mu_1^+ & \cdots & \mu_{\bar{l}}^+ & \mu_1^- & \cdots & \mu_{\bar{l}}^- \end{bmatrix} \tag{6-28}$$

The results of $P_k = -Q_k^{-1}h_k - Q_k^{-1}A'_k\mu$ and t_k will be reported back to DG unit k. If P_k satisfies conditions of DG unit k, the service prices for this DG unit is settled. However, if not, this DG unit will update the price to the REP trading with this DG unit, and the market clearing process is repeated.

6.5 Numerical Example

6.5.1 Test system and assumptions

For a proof of concept, the market mechanism was implemented on the modified RBTS Bus 2 [70]. The test system and assumptions are similar to the one in Chapter 5. We assumed that possible interruption events were a result of transformer and power lines failures, and disconnections of main substations. The existing circuit breakers as shown in Figure 6.2 would be sufficient to make the reliability level of all end users meet the standard reliability level, $U_S = 3.5$ hours/year.

All switching devices and DG units in the system would never fail. Candidate locations for installing switching devices are shown in Figure 6.2, the location 'A'–'J' for NCS, and the location 'K'-'M' for NOS. The capital costs of switching devices were $20,000 for NCS, and $85,000 for NOS including wires. The annual O&M cost of switches was $200. The capital cost of upgraded equipment for supporting DG units was $340/kW[7], and annual O&M cost was 5% of the capital cost. The contract of reliability services would be 5 years with a 7% discount rate. The REP would decide on $\Delta U_{H_m} = 1.8$ hours/year. The REP expected to gain profits at least 7% each year, and its revenue was predicted to decrease 0.5% each year.

[7] Information on costs is from a consultant report "Distributed generation integration cost study" prepared for California Energy Commission (November 2013).

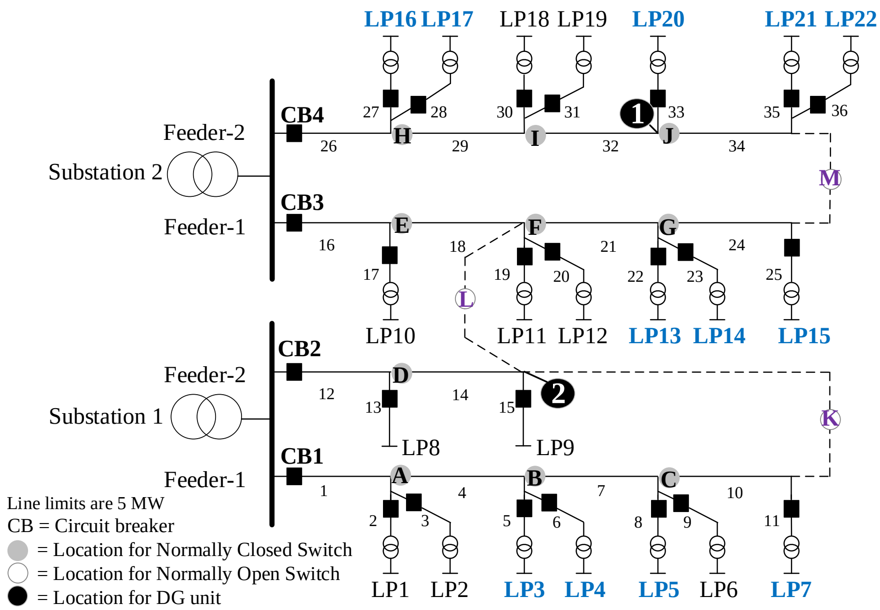


Figure 6.2: Modified RBTS Bus 2 for model-II

An REP was interested to purchase backup power from a 0.5-MW DG unit located at the location '1' and '2'. The information on DG unit located at the location '1' (bus 34) is $C(P) = 0.01P^2 + 599.9P + 10$, C_{OM}= \$6,000 /year, and C_{CP} = \$185,500. The information on DG unit located at the location '2' (bus 15) is $C(P) = 0.5P^2 + 1110.2P + 20$, C_{OM} = \$5,000 /year, and C_{CP} = \$185,500. The probability that DG units are called (γ_{DG}) is 0.0041. For the initial service prices, $\hat{\rho}_{RD} = 600$ was proposed to both DG units, and then by solving eq.(6-20)-(6-21), DG-1 and DG-2 were willing to sell all 0.5 MW on the reliability market if a price of backup service is higher than \$11.83 for DG-1 and \$13.78 /MWh for DG-2.

To demonstrate the market clearing process, we show the bid functions of each market participants including information required for determining those bid functions when the REP offers two reliability levels; the results of the provision of two reliability levels will be compared to that of a single level.

6.5.2 Information exchanged among market participant and settling of service prices

Once end users decided to purchase the high reliability service, the REP reported the information about end users and potential DG units to the utility to assess the service charges, and then the 1st iteration of market clearing process started. In this 1 iteration, ranking of DG units will be determined and used as decision guidance for the entire process of market clearing, while and the ranking of reliability levels will be updated in each iteration.

The initial service charged were estimated by considering each DG unit integrated in the system at the minimum reliability level ΔU_{H_m}. The charges with number of served end users at each load point were given to the REP as shown in Table 6.2; the utility also provided the REP with $\Delta RI_{\widehat{DG}_k}$ as shown in Table 6.3. According to the given service charges and $\Delta RI_{\widehat{DG}_k}$, the integration of DG-1 is less expensive and better improves reliability than that of DG-2.

Once the REP received all necessary data from the utility, DG units and end users, it proceeded two following processes: (1) assign the reliability level and DG unit to end users and create rankings of reliability and DG units (2) estimate the bid function based on the decision from the process (1).

To select the reliability level and DG unit for each end user, the REP checked the possible reliability levels of the end user and estimated P_R regarding to the given $\hat{\rho}_{RS}$ and $\hat{\rho}_{RD}$ from the DG units and $\hat{\rho}_{DH}$ from the utility, and then then P_R and ΔRI were substituted in eq.(6-1)-(6-2) to decide on DG unit. For instance, one of end users in LP-5 has information as given as in Table 6.4. According to the information on reliability levels and prices in Table 6.2, this end user would obtain high reliability service at $\Delta U_{H_m} = 1.8$ hours/year with different amounts of backup power from DG-1 and DG-2 as shown in Table 6.5. By substituting these P_R and ΔRI in eq.(6-1)-(6-2), B_{DG-1} is greater than B_{DG-2} so the REP assigned DG-1 to this end user.

Table 6.2: Service prices and number of served end users at each load point for the reliability service at ΔU_{H_m} = 1.8 hours/year, when considering to an integration of each candidate DG unit in the system

ΔU_{H_m} = 1.8 hours/year	DG-1	DG-2
$\hat{\rho}_{DH}$ ($/MWh)	7.860	8.593
LP-3	175	175
LP-4	160	160
LP-5	200	200
LP-7	200	200
LP-13	200	200
LP-14	180	180
LP-15	200	200
LP-16		
LP-17	180	180
LP-20	190	
LP-21	190	190
LP-22	215	215

Table 6.3: Reduction of outage duration when each DG unit k is in the network ($\Delta RI_{\widehat{DG}_k}$)

Load point	$\Delta RI_{\widehat{DG}_1}$	$\Delta RI_{\widehat{DG}_2}$
LP-3	1.992	1.992
LP-4	2.147	2.147
LP-5	1.998	1.998
LP-7	2.646	2.646
LP-13	1.911	1.911
LP-14	1.861	1.861
LP-15	2.537	2.482
LP-16	1.713	1.713
LP-17	1.861	1.861
LP-20	2.476	0.355
LP-21	2.218	2.163
LP-22	2.167	2.112

By repeating this process for all end users, the result showed that DG-1 was assigned to all end users; accordingly, DG-1 ranked number one between these two DG units. However, when the REP estimated the amount of backup power regarding to the given $\hat{\rho}_{RS}$ and $\hat{\rho}_{RD}$ of DG-1, the amount of backup power needed by all end users would exceed the capacity of DG-1. As a result, for the 1st iteration, the REP decided to integrate both DG units and reported this decision to the utility. After the utility received the update information on DG units, it estimated bid functions, as shown in Table 6.6, and submitted the bid functions back to the REP. The bid functions were used to decide on a reliability level for end users and create a ranking of reliability levels.

Table 6.4: End user's information

ΔWTP_T: \$20 /month
ΔWTP_D: \$7 /month
Appliances ordering from high to low priority: • Refrigerator 600 W • Cell phone recharge 5 W • Radio 200 W • Light 30 W • Light 30 W • Light 30 W • Microwave 1500 W • TV 250 W • A/C 3000 W
Minimum power needed: Refrigerator 600 W

Table 6.5: Amount of backup power of end user whose information is given in Table 5.7 when considering to integrate one DG unit in the system

$\Delta U_{H_m} = 1.8$ hours/year	DG-1 ($\hat{\rho}_{RS,DG-1} = 11.83$)	DG-2 ($\hat{\rho}_{RS,DG-2} = 13.78$)
P_R(kW)	0.595	0
ΔRI	1.998	0

For instance, according to the bid functions given in Table 6.6, the possible reliability levels for the same end users shown above are $\Delta U_H = 1.8$ and 1.9 hours/year. To select between these two reliability levels, the REP determined the amount of backup power received by this end regarding to those two reliability levels, and then calculated $B_{\widehat{\Delta U}_H}$. For this iteration, The price used to estimate the amount of backup power was $\hat{\rho}_{RS,DG-2}$, which is the most expensive one between the two considered DG units.

Table 6.6: Utility's bid function of each load point when considering the installation of 2 DG units at location '1' and '2' (Iteration 1)

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
$\hat{\rho}_{DH}$ ($/MWh)	10.602	12.554	19.757	19.757	23.568	23.568	24.172	60.171
	Number of end users							
LP-3	175	175						
LP-4	160	160	160	160				
LP-5	200	200						
LP-7	200	200	200	200	200	200	200	200
LP-13	200	200						
LP-14	180							
LP-15	200	200	200	200	200	200	200	200
LP-16								
LP-17	180							
LP-20	190	190	190	190	190	190	190	
LP-21	190	190	190	190	190	190	190	
LP-22	215	215	215	215	215	215	215	

With the given $\hat{\rho}_{RS,DG-2}$ and $\hat{\rho}_{DH}$ in Table 6.6, the results showed that this end user could not afford to pay for backup power; accordingly, the reliability level at $\Delta U_H = 1.9$ is better than one at $\Delta U_H = 1.8$. However, when considering the reliability levels assigned to all end users, most end users were assigned to receive the reliability level at $\Delta U_H = 1.8$; the ranking of assigned reliability levels for all end users is shown in Table 6.7.

Table 6.7: Ranking of reliability levels assigned to end users (1: Level assigned to most end users)

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
Ranking	1	2	-	-	-	-	-	-

To offer services to as many end users as possible, the REP decided to offer both reliability level at $\Delta U_H = 1.8$ and 1.9 hours/year. According to the REP's decisions on reliability levels and

DG units, the REP determined the individual end users' bid functions for backup power and aggregated all of those bid functions to a system level as shown in Table 6.8 (Iteration 1).

Table 6.8: Aggregated bid function for backup power of each load point

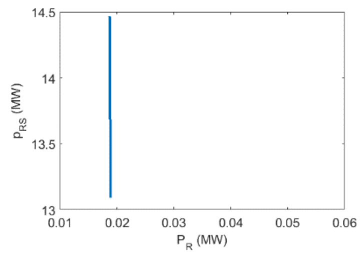
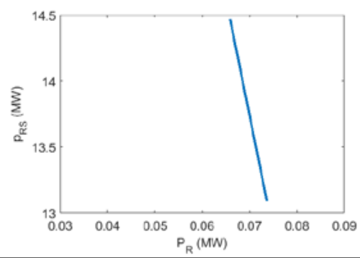
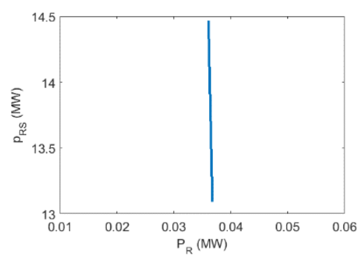
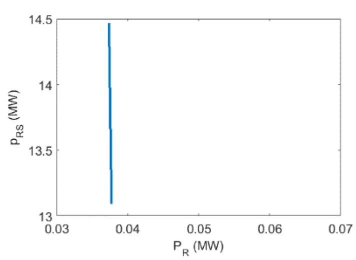
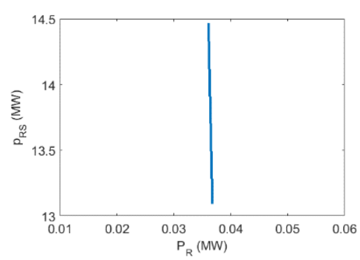
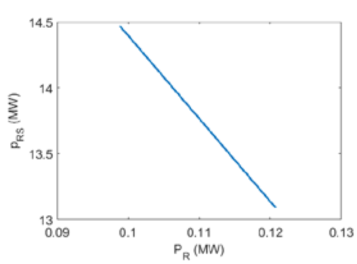
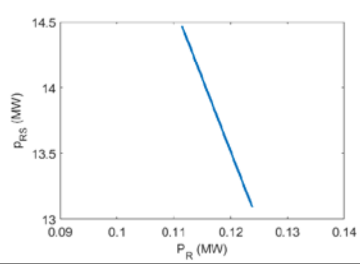
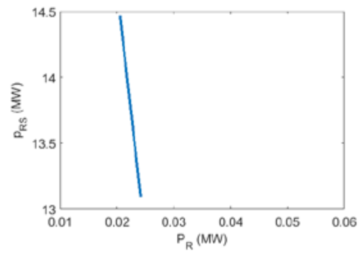
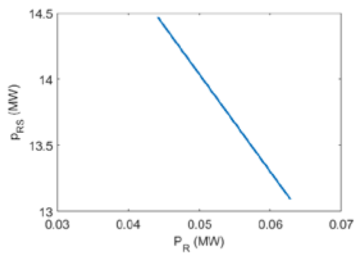
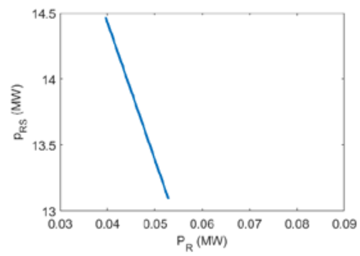
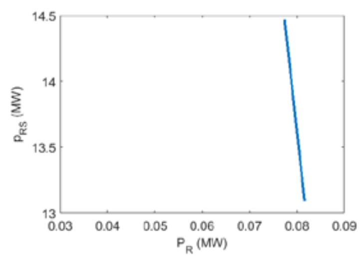
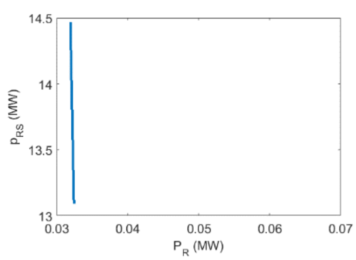
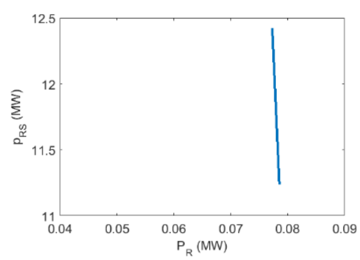
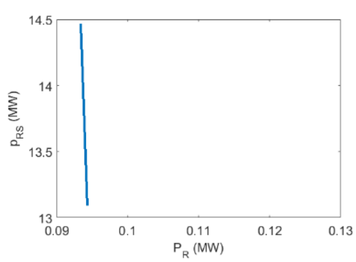
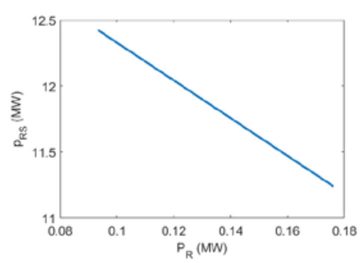
<table>
<tr><th>Load point</th><th>Iteration 1
(2 DG units, 2 reliability levels)</th><th>Iteration 2
(1 DG unit, 2 reliability levels)</th></tr>
<tr><td>LP-4</td><td>N/A</td><td>
</td></tr>
<tr><td>LP-5</td><td>N/A</td><td>
</td></tr>
<tr><td>LP-7</td><td>N/A</td><td>
</td></tr>
<tr><td>LP-13</td><td>
</td><td>
</td></tr>
<tr><td>LP-14</td><td>
</td><td>
</td></tr>
</table>

Table 6.8: Aggregated bid function for backup power of each load point (continued)

<table>
<tr><th>Load point</th><th>Iteration 1
(2 DG units, 2 reliability levels)</th><th>Iteration 2
(1 DG unit, 2 reliability levels)</th></tr>
<tr><td>LP-15</td><td>N/A</td><td></td></tr>
<tr><td>LP-17</td><td></td><td></td></tr>
<tr><td>LP-20</td><td>N/A</td><td></td></tr>
<tr><td>LP-21</td><td></td><td></td></tr>
<tr><td>LP-22</td><td></td><td></td></tr>
</table>

The results showed that for the 1st iteration, end users only in LP-13, LP-14, LP-17, LP-21, and LP-22 can afford to pay for backup power at these given prices, and the maximum total P_R of these load points is less than the capacity of either DG-1 or DG-2. Therefore, the REP decided to purchase backup power only from DG-1 according to the ranking of DG units.

This new decision was reported to the utility to estimate new bid functions, which are shown in Table 6.9. When the REP obtained the new bid functions from the utility, the processes of assigning the reliability level and the DG unit and creating bid functions were repeated for the 2nd iteration. The aggregated bid functions for the update decision are shown in Table 6.8 (iteration 2).

Table 6.9: Utility's bid function of each load point when considering the installation of 1 DG unit at location '1' (Iteration 2)

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
$\hat{\rho}_{DH}$ (\$/MWh)	7.860	9.308	14.647	14.647	17.629	17.629	18.232	48.316
	Number of end users							
LP-3	175	175						
LP-4	160	160	160	160				
LP-5	200	200						
LP-7	200	200	200	200	200	200	200	200
LP-13	200	200						
LP-14	180							
LP-15	200	200	200	200	200	200	200	200
LP-16								
LP-17	180							
LP-20	190	190	190	190	190	190	190	
LP-21	190	190	190	190	190	190	190	
LP-22	215	215	215	215	215	215	215	

For the utility, its bid functions will include the information on the number of served end users and the optimal locations of switching devices are shown in Figure 6.3.

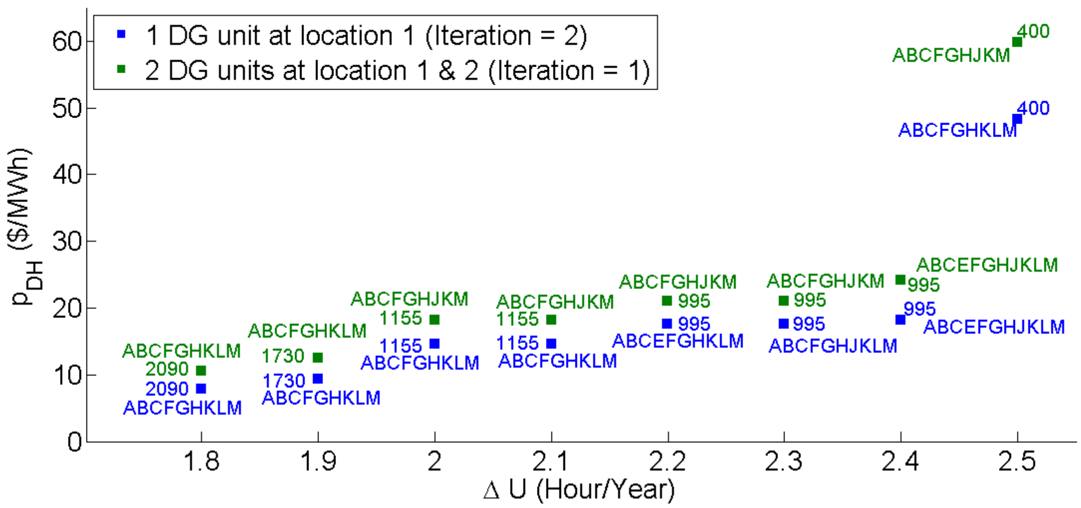


Figure 6.3: Prices of delivery service with high reliability level (ρ_{DH}) for different reliability levels (ΔU_H) with optimal locations of installed switches and number of served end users

The process of settling the prices occurred for several iterations before the prices of $\hat{\rho}_{RS}$ and $\hat{\rho}_{DH}$, were settled as shown in Figure 6.4. During the iteration 2nd – 12th, since the demands for backup power exceeded the capacity of DG-1, $\hat{\rho}_{DH}$ was increased to give priority to the end users who have high willingness to pay to obtain backup power.

After settling on bid functions for DG-1, the REP submitted these bid functions to DG-1 to determine delivery demand functions $P_k = -Q_k^{-1}t_k - Q_k^{-1}h_k$, and then these delivery demand functions including power limits of DG-1 and loads would be submitted to the utility for settling the price of backup power.

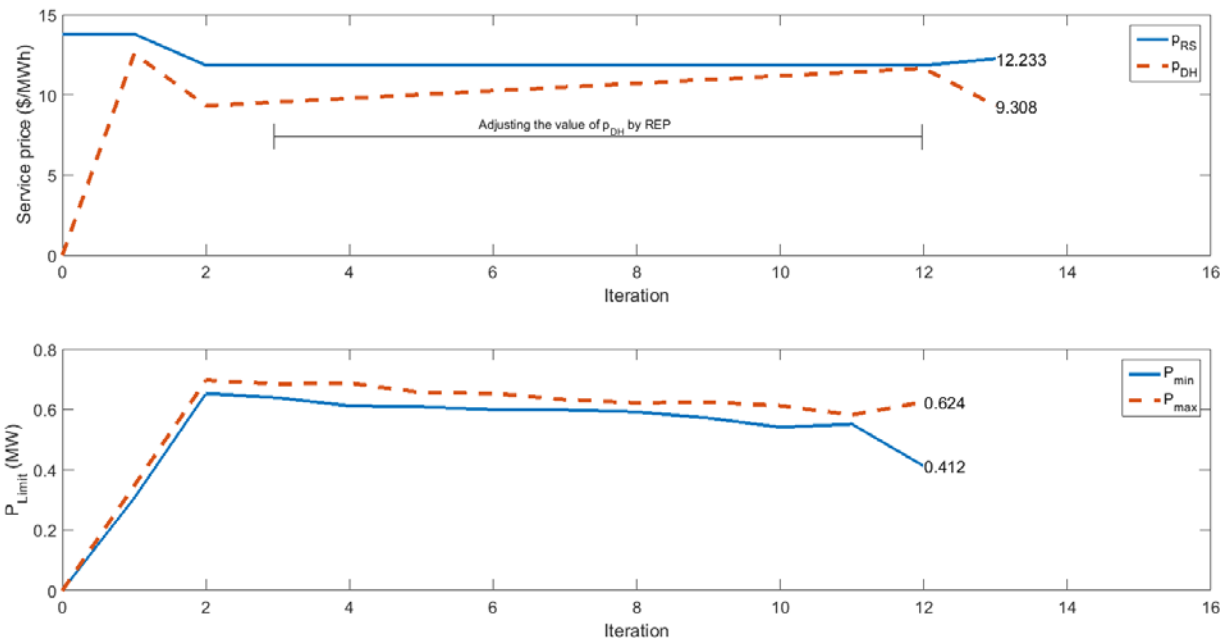


Figure 6.4: Settling the prices for backup power (ρ_{RS}) and delivery service with high reliability (ρ_{DH}) at each iteration (above) and maximum and minimum power at each iteration (below)

For the provision of two reliability levels, the backup power and service charges were settled at $P_R = 0.5$ MW, $\rho_{RD} = \$600$, $\rho_{RS} = \$12.23$, $\rho_{DH,\Delta U_H=1.8} = \$7.86$, and $\rho_{DH,\Delta U_H=1.9} = \$9.31$ /MWh. The switches were installed at ‘ABCFGHKLM’. The numbers of end users served at different reliability levels are shown in Table 6.10, and Figure 6.5 shows the total amount of backup power and end users’ reliability levels at each load point.

Table 6.10: Number of served and unserved end users for the provision of 2 reliability levels

Reliability level	Number of end users	
	With backup power	Without backup power
$\Delta U_H = 1.9$, $\rho_{DH} = \$9.31$ /MWh	705	1025
$\Delta U_H = 1.8$, $\rho_{DH} = \$7.86$ /MWh	285	75
$\Delta U_H = 0$	-	180

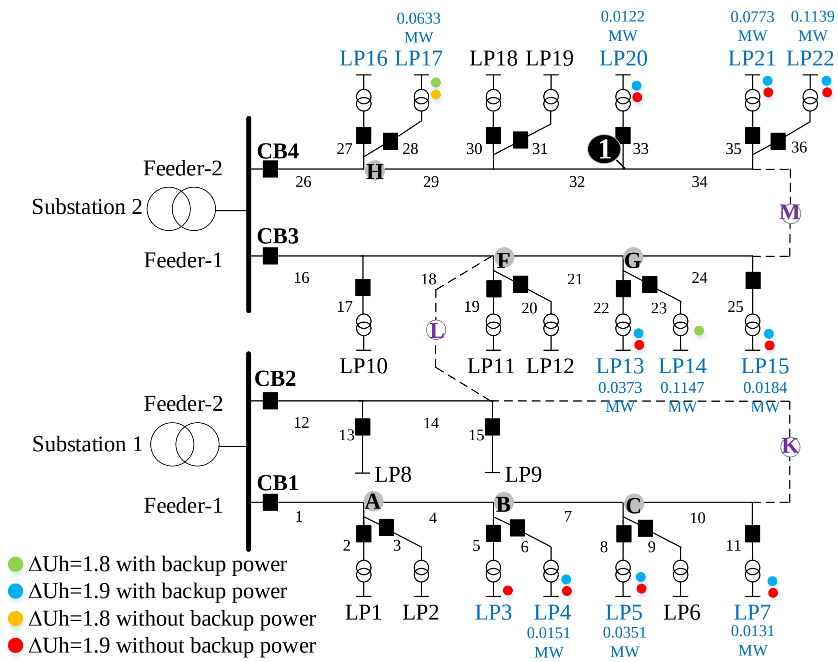


Figure 6.5: Reliability level and amount of backup power at each load point for the provision of 2 reliability levels

For a provision of a single reliability level at $\Delta U_H = 1.9$, the backup power and service charges were settled at $P_R = 0.5$ MW, $\rho_{RD} = \$600$, $\rho_{RS} = \$12.25$, and $\rho_{DH,\Delta U_H=1.9} = \$9.31$. The switches were installed at 'ABCFGHKLM'. The numbers of end users served at different reliability levels shown in Table 6.11, and Figure 6.6 shows the total amount of backup power and end users' reliability levels at each load point.

Table 6.11: Number of served and unserved end users for the provision of a single reliability level

Reliability level	Number of end users	
	With backup power	Without backup power
$\Delta U_H = 1.9$, $\rho_{DH} = \$9.31$ /MWh	1190	540
$\Delta U_H = 0$	-	540

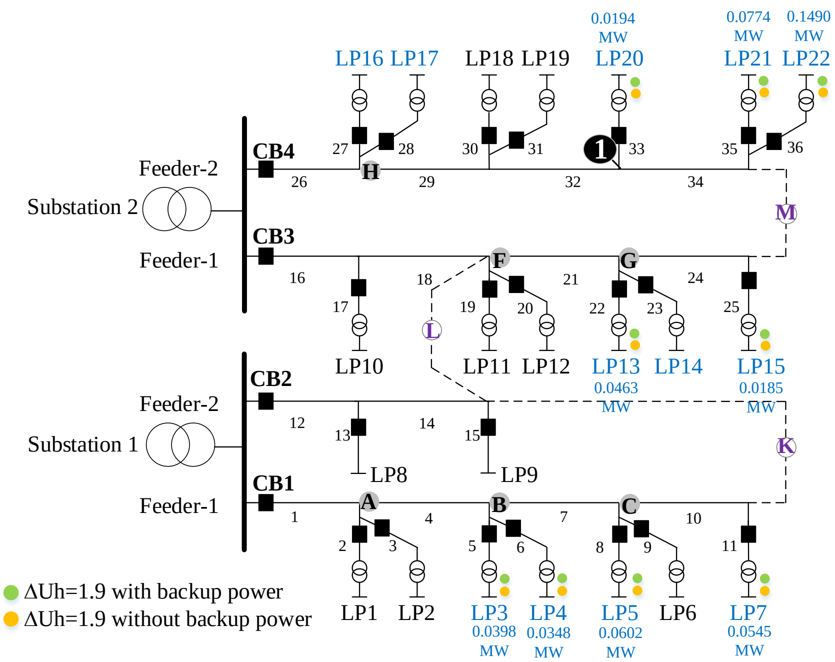


Figure 6.6: Reliability level and amount of backup power at each load point for the provision of a single reliability level at $\Delta U_H = 1.9$

Table 6.12: Numbers of end users obtaining backup power under the provision of two reliability levels and of a single reliability level at $\Delta U_H = 1.9$ at each load point

LP	Two reliability levels	Single reliability level at $\Delta U_H = 1.9$
3	0	80
4	60	110
5	125	200
7	50	200
13	30	85
14	180	0
15	65	65
16	0	0
17	105	0
20	90	90
21	115	190
22	170	170

The service prices under the provision of two reliability levels and single reliability level are the same, except the prices of backup power. The prices of backup power are $12.23/MWh under the provision of two reliability levels and $12.25/MWh under the provision of single reliability level. In addition, the number of unserved end users under the provision of a single reliability at $\Delta U_H = 1.9$ is larger than that of two reliability levels.

On the other hand, when looking into the number of end users obtaining backup power, the provision of a single reliability level can provide backup power to more end users. According to the numbers of end users obtaining backup power at each load point in Table 6.12, backup power served to the end users at LP-14, and LP-17 is distributed to the end users at other load points when it changes from the provision of two levels to the provision of a single level.

6.6 Discussion

In this market structure, REPs negotiate with a utility and DG units directly for improved delivery service, and backup power, respectively. The REPs will report their demands for backup power to DG units to decide on quantities of power. To control the delivery of backup power not over the network constraints, the utility will charge delivery fees to the DG units in order to incentivize the DG units to adjust their transactions.

As REPs are decision makers in procuring reliability services for their end users, they require some information showing benefits of DG on the reliability service. This information on reliability is necessary for the REPs in balancing between the cost and reliability when procuring services for their end users. This information should be provided by the utility, which has the best information about the system reliability. The utility may develop an index showing the reliability improvement due to integrating DG units. This index is not only useful for the REPs in this market structure, but the DSO can also deploy this index when considering to integrate DG units.

By comparing the results between the two market models under the provision of two reliability levels, the prices of delivery service with high reliability level are the same, while the prices of backup power in the first model are slightly lower than that in the second model. Although the prices of backup power are slightly different, the numbers of end users obtaining backup power and the quantities of backup power at each load point are clearly different because of the approaches to assigning reliability levels to end users. The REP in the second model can decide a reliability level for each end user directly, while the DSO in the first model can look into end users' information on the system level, not the individual level. Therefore, in the first model, all end users will be treated the same during settling the price of backup power. However, if a reliability level of end users is settled by the same way as shown in the provision of a single reliability level, the outcomes from two models are quite similar.

Chapter 7: Conclusion and open questions

7.1 Comparison of two market models

As new technologies have been developed and increasingly integrated in distribution networks, retail markets may need restructuring to open opportunities to other service providers/third parties to access to the system, and offer different services that respond to customers' need.

To open access to the distribution system, a utility should change to mainly provide a delivery service including other related services in support of integrating new technologies, and the utility should not be the company providing an energy service in order to allow other energy providers and distributed resources to compete each other. REPs as third parties are responsible for procuring energy and other electricity services for their customers. These changes will affect the utility directly, which result in the utility requiring to develop new strategies or services to respond to such changes.

The high reliability services under the proposed reliability market can be one of opportunities for the utility to gain incomes. The utility makes investments in enhancing reliability services; the utility's investment costs also include the costs of upgrade system in support of integrating non-utility-owned DG units. The investment decisions are made based on customers' demands for high reliability services determined by the REPs.

The high reliability services can be provided under two market structures with or without DSO. The DSO will be in charge of optimizing market transactions, and make sure that all service providers have equal access to the distribution networks. As a result, the DSO must be allowed to have access to the utility's information that is necessary for optimizing market transactions. In the reliability market, all market participants will report their information on bidding to the DSO, and the DSO will proceed market clearing based on that information. The DG units are selected according to their bidding prices; however, the impact of DG location on reliability improvement is not taken into account.

On the other hand, in the market structure without DSO, the market participants will negotiate for purchasing services by themselves so each REP can have different strategies to procure reliability services for their customers. Each DG unit will decide on the quantities of backup power according to the REP's bid functions, and then pass these data to the utility settle the prices. To deliver those backup power quantities, the utility will charge delivery fees to the DG units in order to incentivize the DG units to adjust their transactions according to network constraints.

When considering the same objective of selecting DG units, the differences of results between two models come from the approach to assigning a reliability level to end users. The REPs in the second model can decide a reliability level for each end user directly based on bid functions obtained from the utility. On the other hand, the DSO in the first model looks into end users' information on the system level, not the individual level; as a result, during settling the price of backup power, all end users who can afford to pay for backup power will be treated as they obtain the same reliability level, not different levels as it is done in the second model. With these different approaches, the numbers of end users obtaining backup power under the provision of two reliability levels are different.

7.2 Impact of DG location on enhancing reliability

The use of DG units for reliability purpose should take their location into consideration, since the DG units that better improve reliability of customers may have the high service charges. The impact is considered in the market model without DSO. To consider this impact when making a decision on which of DG units to interconnect, it requires information on reliability of those DG units from the utility. For instance, the utility may develop an index showing incremental improvement of reliability level of each load point due to integrating of each candidate DG unit ($\Delta RI_{\widehat{DG}_k,n}$). Based on this information, the REPs as decision makers in the second market model can create rankings of DG units for the use in decide on which of DG units to purchase backup power. The impact of DG location on reliability should be considered in the first market model as well.

To illustrate the decisions without considering this impact, the market mechanism was implemented on the modified RBTS Bus 2 with the same assumptions as shown in Chapter 5, except the generating cost of 2 DG units. The information on DG unit located at the location '1' (bus 34) was changed to $C(P) = 0.5P^2 + 1110.2P + 20$, C_{OM} = \$5,000 /year, and C_{CP} = \$185,500, while the information on DG unit located at the location '2' (bus 15) is $C(P) = 0.01P^2 + 599.9P + 10$, C_{OM}= \$6,000 /year, and C_{CP} = \$185,500.

If the DG cost is a priority concern, the DG unit at location '2' (DG-2) will be chosen to serve end users under the provision of two reliability levels. With this decision, the utility obtained bid functions as shown in Table 7.1. The backup power, and service charges were settled at P_R = 0.5 MW, ρ_{RD} = \$600, ρ_{RS} = \$11.90, $\rho_{DH,\Delta U_H=1.8}$ = \$8.59, and $\rho_{DH,\Delta U_H=1.9}$ = \$10.35/MWh. The switches were installed at ‘ABCFGHKLM’. The numbers of end users served at different reliability levels are shown in Table 7.2.

Table 7.1: Utility’s bid function of each load point when considering the installation of 1 DG unit at location ‘2’

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
$\hat{\rho}_{DH}$ ($/MWh)	8.593	10.353	17.415	17.415	21.623	33.222	48.316	89.445
	Number of customers							
LP-3	175	175						
LP-4	160	160	160	160				
LP-5	200	200						
LP-7	200	200	200	200	200	200	200	200
LP-13	200	200						
LP-14	180							
LP-15	200	200	200	200	200	200	200	
LP-16								
LP-17	180							
LP-20								
LP-21	190	190	190	190	190	190		
LP-22	215	215	215	215	215			

Table 7.2: Numbers of served and unserved customers for a provision of 2 reliability levels when DG-2 installed in the system

Reliability level	Number of customers	
	With backup power	Without backup power
$\Delta U_H = 1.9$, $\rho_{DH} = \$10.353$ /MWh	615	925
$\Delta U_H = 1.8$, $\rho_{DH} = \$8.593$ /MWh	285	75
$\Delta U_H = 0$	-	370

On the other hand, if end users’ reliability is a priority concern, the DG unit at location ‘1’ (DG-1) will be selected and the utility’s bid functions is obtained as given in

Table 7.3. The backup power, and service charges were settled at $P_R = 0.5$ MW, $\rho_{RD} = \$600$, $\rho_{RS} = \$14.41$, $\rho_{DH,\Delta U_H=1.8} = \$7.86$, and $\rho_{DH,\Delta U_H=1.9} = \$9.31$ /MWh. The switches were installed at ‘ABCFGHKLM’. The numbers of end users served at different reliability levels are shown in Table 7.4.

Table 7.3: Utility's bid function of each load point when considering the installation of 1 DG unit at location '1'

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
$\hat{\rho}_{DH}$ ($/MWh)	7.860	9.308	14.647	14.647	17.629	17.629	18.232	48.316
	Number of end users							
LP-3	175	175						
LP-4	160	160	160	160				
LP-5	200	200						
LP-7	200	200	200	200	200	200	200	200
LP-13	200	200						
LP-14	180							
LP-15	200	200	200	200	200	200	200	200
LP-16								
LP-17	180							
LP-20	190	190	190	190	190	190	190	
LP-21	190	190	190	190	190	190	190	
LP-22	215	215	215	215	215	215	215	

Table 7.4: Numbers of served and unserved customers for a provision of 2 reliability levels when DG-1 installed in the system

Reliability level	Number of customers	
	With backup power	Without backup power
$\Delta U_H = 1.9$, $\rho_{DH} = \$9.308$ /MWh	705	1,025
$\Delta U_H = 1.8$, $\rho_{DH} = \$7.860$ /MWh	285	75
$\Delta U_H = 0$	-	180

Although the cost of DG-1 is higher than that of DG-2, the integration of DG-1 can much improve reliability of end users than that of DG-2. The installations of DG units in different locations will cost the utility in upgrading system differently. If the utility is a decision maker in integrating DG units, it will decide to select DG-1 due to the lower costs of system upgrade as shown in Figure 7.1.

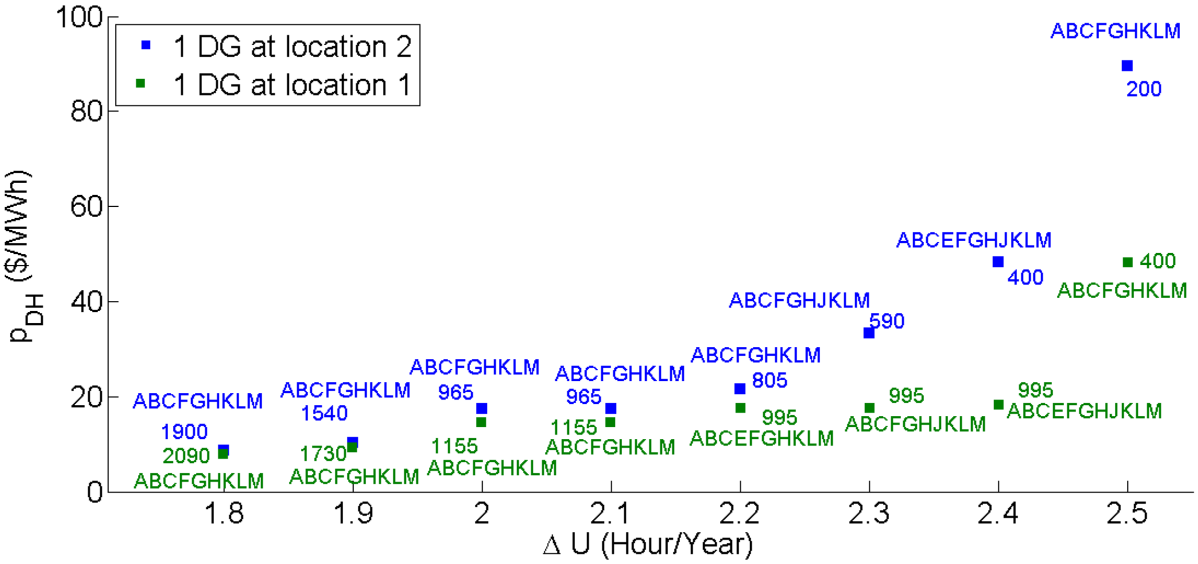


Figure 7.1: Prices of delivery service with high reliability level (ρ_{DH}) for different reliability levels (ΔU_H) when considering an installation of DG-1 or DG-2

7.3 Reliability improvement by building new power lines

At some higher reliability level, installing more switches might not be the option when the reliability is not improved that much compared to the high costs of investments. Instead of installing switches, the utility may consider to build new wires to enhance reliability if it enables the utility to serve more customers at a lower service charge.

To compare the costs of installing switches to that of building new power lines, the same test system with 0.5-MW DG unit located at the location '1'as given in Chapter 5 was deployed to assess the charging prices if new lines and NCSs were installed to meet the new reliability target.

In the test system as shown in Figure 7.2, the location 'A'–'J' are candidate locations for installing NCS and the connection 'i'– 'xi' are candidate connections for new power line. The capital costs were $20,000 for NCSs, and $200,000/mile for wires[8]. The information on connection distance is given in the Appendix-C.

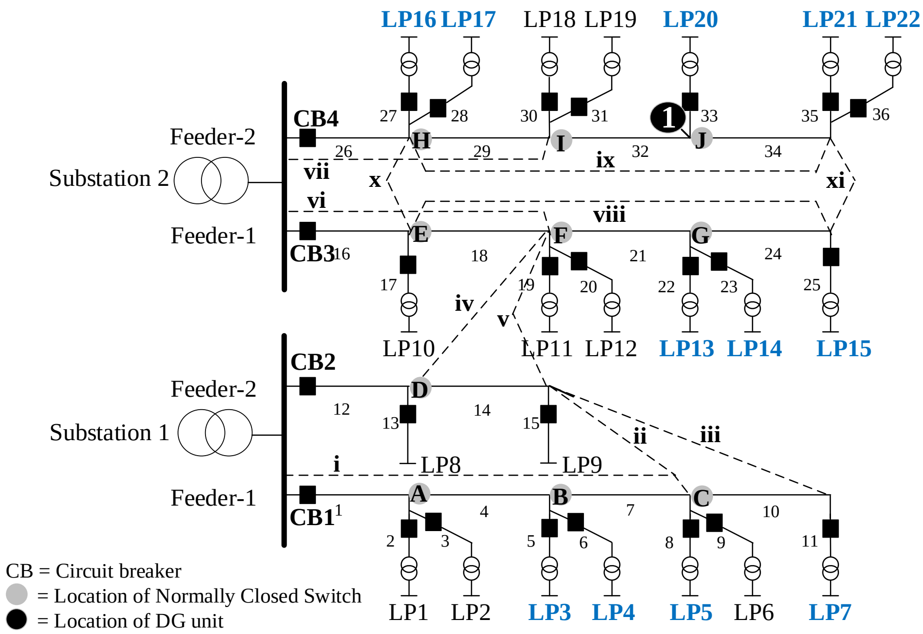


Figure 7.2: Modified RBTS Bus 2 with candidate locations for installing NCSs and power lines

[8] Wire costs are from a report "Out of sight, out of mind 2012: An updated study on the undergrounding of overhead power lines" (January 2013).

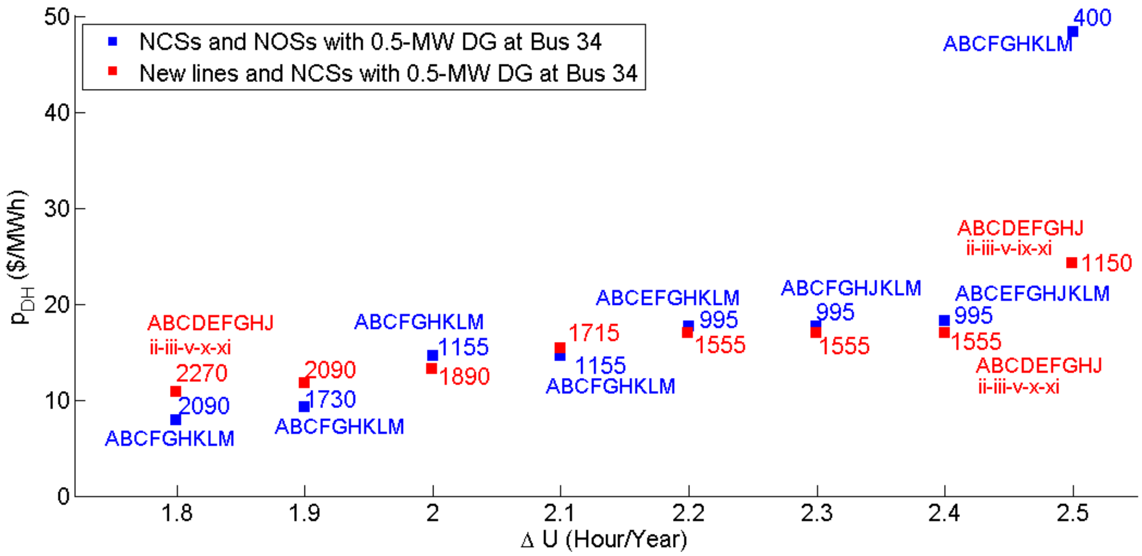


Figure 7.3: Prices of delivery service with high reliability level (ρ_{DH}) for different reliability levels (ΔU_H) when considering to install NCSs and power lines at the optimal locations

The problem formulation of optimal number and locations for NCSs and wires is similar to the one shown in section 5.2. According to the results shown in Figure 7.3 and Table 7.5, by installing more NCSs and new power lines, more end users will obtain the high reliability service; however, the service charges will be higher than those of installing only NCSs and NOSs. These service charges are too high for the same end users considered in in Chapter 5. These new power lines could be built if other aspects, such as delivering the increased energy demands to end users, are considered.

Table 7.5: Utility's service charges considering an installation of switches, power lines and a DG unit at location '1'

ΔU_H (hour/yr)	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2. 5
$\hat{\rho}_{DH}$ ($/MWh)	10.889	11.814	13.294	15.343	16.997	16.997	15.343	24.268

7.4 Utility's expected compensation

Under the provision of higher reliability services, a utility is obligated to compensate customers if it fails to deliver the services as agreed. The compensation should be extracted from customers' information on willingness to accept outages, which is not the same value as the willingness to pay. According to [80], end users' willingness to pay is $10 – $40/month, while end users' willingness to accept is more than $1000 /outage for 2-day outages.

With the above information, end users' willingness to accept outages was assumed to greater than 25 – 100 times of their willingness to pay. For instance, if end user have $\Delta WTP_T =$ $\$20$/month and $\Delta WTP_D =$ $7/month, the willingness to accept outages of this end user will be $500 – 2,000/outage for 2-day outages or $10.42 – $41.67/hour if he/she receives backup power. On the other hand, his/her willingness to accept outages will be $175 – 700/outage for 2-day outages or $3.65 – 14.58/hour if he/she does not obtain any backup power.

The willingness to accept outages regarding to the above assumption was used to define the customers' compensations. By assuming that any end users obtaining the same reliability option would receive the same compensation, the compensation that would satisfy all end users in that group would be the highest willingness to accept outages of end users among the group. For example, according to the result in Table 6.10, we can obtain compensation of each reliability option as shown in Table 7.6.

Table 7.6: Compensation of each reliability option regarding to the given end user's information and the results in Table 6.10

Reliability level	Compensation ($/hour)	
	With backup power [min,max]	Without backup power [min,max]
$\Delta U_H = 1.9$	$18.62 - 72.92$	$5.21 - 20.83$
$\Delta U_H = 1.8$	$11.46 - 45.83$	$3.65 - 14.58$

According to these compensations, a utility can estimate an expected compensation by using eq.(7-1), and the utility's expected compensation is $29,105–115,014/year. Furthermore, the utility can acquire the information on the possibility of any fault events that could lead to high compensation as shown in Table 7.7. With this information, the utility can monitor the events that could lead to the high compensations and determine which preventative actions are economically efficient. In addition, the utility should be able to operate the systems during power outages in the way that minimizes the total compensation of the system [30], [81].

$$\text{Expected compensation} = \sum_{e \in E_n} \lambda_e r_e \sum_{nh \in LP_H} tComp_{nh}\left(1 - s_{nh,e}\right) \qquad (7\text{-}1)$$

where

$s_{nh,e}$ Binary decision variable of the load point nh when the fault event e occurs (1: the load point is served)

LP_H Load points of customers receiving the high reliability level

$tComp_{nh}$ Total compensation of all customers in the load point nh

Table 7.7: Compensation by important cases of outages

	Compensation ($/hour) [min,max]	Fault events
Highest λ_e	3,400 – 13,334 2,718 – 10,677 2,197 – 8,646 2,063 – 8,249 1,713 – 6,771 1,477 – 5,906 911 – 3,645	Disconnection of line 36 Disconnection of line 8 Disconnection of line 33 Disconnection of line 23 Disconnection of line 11 Disconnection of line 26 Disconnection of line 5
Highest compensation (Excluding DG failure)	11,353 – 44,812	Disconnection of line 21 & 29 Disconnection of line 21 & 32 Disconnection of line 21 & 34
Lowest compensation (Excluding DG failure)	911 – 3,645	Disconnection of line 5
DG failure	16,393 – 64,470	

7.5 Policy implications

- **Value based investments in providing of high reliability service**

Investments based on the value of services will be essential to the provision of reliability and resiliency. The value of services is the key information that will enable service providers to integrate new technologies to offer differentiated and improved services. The current practices in making investment decisions on reliability tend to focus on social value, but neglect the reality that customers have different willingness to pay and dissimilar preferences for reliability. The reliability investments based on social value should be applied to regulate the reliability standard, which is a basic service provided to all customers. On the other hand, the reliability service above the standard level will be options for customers who are willing to pay more.

The proposed market mechanism will be one means that supports the provision of differentiated reliability service. The market mechanism is designed to provide long-term investment signals to service providers in integrating new technologies into the systems which are able to offer differentiated services according to customer preferences. The service providers can accordingly assess the investment costs of high reliability accurately, and make the value of reliability explicit, since the service of a standard and high reliability will be unbundled. Furthermore, the true costs of reliability will allow customers to compare the cost of reliability provided by utility companies to the cost of other alternatives that also enhance reliability. This will lead to a competitive retail environment in integrating new technologies for the reliability enhancement.

- **Information required in providing of high reliability service**

The accurate and sufficient data related to power interruptions will enable utilities to assess reliability of equipment and customers effectively. By incorporating communications and information technologies, it is possible to obtain sufficient and accurate data for the reliability evaluation. Reliability monitoring and the data collection should be done in details at a component level, and then build up to a network level. Such monitoring will improve visualizing grid status and foreseeing imminent failures. Accordingly, the utility will be able to evaluate reliability, predict the possibility of equipment failures and schedule or plan proper maintenance. Therefore, the reliability monitoring and data collection should be done in a constructive way.

Under the proposed reliability market either with or without the DSO, the information on benefits of DG in enhancing reliability service for customers is necessary in making decision on DG units to purchase backup power. The utility may develop an index showing the reliability improvement resulting from DG units. This index is not only useful in the proposed market, but the utility can also deploy this index when considering to integrate DG in conventional distribution networks. The utility can deploy this index to gain approval from regulators in upgrading the system and integrating DG.

The information on customers' willingness to pay and compensation for reliability to the customers is necessary in assessing investments and settling the price in the proposed market. In this thesis, the information we need from customers includes the additional monthly expenses that a customer is willing to pay to experience shorter-duration power outages with and without utilizing backup power, and the wattage of appliance that the customer needs for the use during power outages.

However, we still need further knowledge of customers' willingness to pay and compensation. Advanced metering infrastructure can be used by REPs to study customers' satisfaction to the reliability services, and create knowledge on customer preferences. The compensation should be related to the customers' willingness to accept outage. The utility and REPs have to educate customers to ensure that they understand this information before they decide to purchase those differentiated reliability services.

- **Incentivizing utilities to ensure quality of service through compensation scheme**

For the provision of differentiated reliability services, the utility is obligated to provide delivery service according to the agreements. The agreement concerns only failures of equipment of devices occurring in the distribution networks. If the utilities fail to meet the agreements, they have to pay compensation which should be estimated from the customers' willing to accept the service interruptions. These compensations are applied to incentivize the utilities to manage outages efficiently; however, at the same time, these compensations would also impose the costs on the utilities, and thus could increase the cost of service. The utilities have to consider this issue when setting its service charge.

Since the differentiated reliability services are offered beyond the standard levels, regulators should ensure that the reliability level received by all customers meets the standard level. The standard level, which may differ by areas, should be set according to the historical reliability level or the level assessed by the cost-benefit analysis or any other value-based approaches. Therefore, before offering the higher reliability services, the utilities are required to assess the reliability levels that customers currently receive, and ensure that those levels meet the standard level of those areas. To enforce these practices, regulators may apply penalties to the utilities if they fail to provide such services. These practices aim to prevent a general degrading of expected level of reliability.

For the failures caused by others sources, such as DG or transmission systems, they are out of the utility's responsibility. However, penalties must be applied to DG units that fail to serve customers. For failures from transmission system, transmission operators may agree to pay the service charges if the utility and DG units can serve customers during that outage. Or the transmission operators and distribution utility may have agreement to share the costs of compensation if the utility makes investments in enhancing reliability by including the chance of outage occurring from the transmission level.

- **System resilience with the provision of high reliability service**

The high reliability services can be considered in terms of the enhancement of system resilience. The high reliability service will not only offer to customers who have such needs, but also critical social services, such as police stations, grocery stores, gas stations, and etc. The continued provision of critical social services will secure community during a prolonged outage. The minimum backup power required for each community could be estimated from the amount of power used to run these critical social services.

- **Future retail electricity structure**

An integration of new technologies in distribution systems will affect utility's operation and revenue directly. This is one of reasons that cause the utility hesitate to integrate new technologies. It is inevitable for the utility to not allow other service providers or distributed resources to have access to distribution systems. Consequently, to respond to such changes, the utility has to develop new operation strategies or new products/services to alleviate the impacts on its operation and revenue. The utility may change to focus on providing a delivery service and other supplemental services in support of integrating new technologies. For instance, a provision of high reliability service can be an option for the utility.

Investments based on the value of services will be essential to the future of sustainable electricity industry, either restructured or regulated retail market structure. The impacts on costs and benefits experienced by both the service providers and customers are the key information that should be taken into account in investment decisions. If this information is explicit, it would enable service providers to integrate new technologies into offering differentiated and improved services that fit to customers' preferences.

As new technologies integrated in distribution systems have potential to enhance reliability on both distribution and transmission level, reliability assessments should collaborate between distribution and transmission level. For instance, distributed energy resources, such as demand response and DG, in distribution systems has potential to reduce reserve power and prevent network congestions on the transmission level. These benefits of DG should be taken into account in assessing reliability on the transmission level.

7.6 Conclusion

By collaborating information and communication technologies with distribution automation, the utilities are capable of collecting and analyzing real-time feeder and equipment conditions that may contribute to faults and outages. Accurate and sufficient data of equipment condition are useful for assessing reliability of customers and equipment in the systems, and the results from the reliability assessment can be used to plan operations and maintenance as well as investments in reliability enhancement. Therefore, the reliability monitoring and data collection should be done in a constructive way in order to extract the useful data for planning in reliability enhancement.

The proposed market mechanism, which is based on knowing customers' willingness to pay, and preferences for reliability, aims to give long-term investment signals to service providers for planning investments in new technologies at value. The prices for these services are based on bids created by each market participant optimizing its objective with respect to its own interests. This allows the market participants to assess the investment costs and manage its own risk in setting the service charge. In addition, the high reliability services can be considered a means that enables the service providers to improve system resilience.

The high differentiated reliability services can be implemented on the market model with and without a DSO. The two models give different results because REPs in the market model without the DSO can assign a reliability level to each end user directly, while for the market model with the DSO, the DSO can look into end users' information on the system level, not the individual level.

7.7 Open questions

This thesis presents a concept of the market mechanism of providing differentiated reliability services. The market mechanism promotes the informative and effective investments in reliability. Customers are given the opportunity to obtain their preferred reliability services at a fair price, and are not forced to pay for reliability services they do not need.

However, several aspect of the propose mechanism requires further investigations, such as, details of service quality offered to customers, and contract duration of providing higher reliability services. The contract duration for the services should be sufficient to provide proper investment signals to a utility and DG owners. In addition, uncertainties due to the provision of reliability services in a long-term contracts such as changes in customer behavior and preference should be identified and evaluated.

The proposed reliability market requires knowledge of customers' preferences for reliability, willingness to pay for improved reliability and willingness to accept outages. With this knowledge, REPs would be able to design the package of reliability service that suits to customers' needs. The REPs can deploy advanced metering infrastructure to create knowledge on customers' preferences and satisfaction to the reliability services. The compensation should be related to the customers' willingness to accept outage.

The practicality of the proposed approach from a total business perspective is yet to be verified; therefore, more background research and models are needed. Different reliability preferences even from adjacent customers can complicate the viability, which in turn might geographically localize the areas of service. From a general customer perspective, this might be partiality in service towards different regions. To avoid these issues, it is necessary to engage in customer education regarding their options for reliable service.

The reliability assessments should collaborate between distribution and transmission level. Although this thesis considers only failures that happen in the distribution networks, it can be extended to include the outages on the transmission levels. Transmission operators may either design mechanisms that would bring the value of deploying new technologies to improve reliability on both levels or agree to share the costs if the utility and DG units can also consider the chance of outage occurring from the transmission level.

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Appendices

Appendix-A

Table A.1: Number of customer and average load level at each load point

	No. of customers	Average load level at each load point (MW)
LP-1	80	0.535
LP-2	100	0.535
LP-3	80	0.535
LP-4	100	0.566
LP-5	90	0.566
LP-6	100	0.454
LP-7	60	0.454
LP-8	90	1.000
LP-9	90	1.150

Impedance of main feeder (ohm/km) 0.299+0.335j

Impedance of lateral feeder (ohm/km) 0.493+0.366j

$F_{ij,max} = 5\ MW$

Table A.2: Failure events

Failure event			
	λ	r	U
Transformer 33kV/11kV	0.01500	12	0.2250
Transformer 11kV/0.415kV	0.01500	12	0.1500
Line-1	0.04875	5	0.2925
Line-2	0.03900	5	0.2340
Line-3	0.05200	5	0.3120
Line-4	0.04875	5	0.2925
Line-5	0.05200	5	0.3120
Line-6	0.03900	5	0.2340
Line-7	0.04875	5	0.2925
Line-8	0.05200	5	0.3120
Line-9	0.04875	5	0.2925
Line-10	0.03900	5	0.2340

Line-11	0.05200	5	0.3120
Line-12	0.04875	5	0.2925
Line-13	0.05200	5	0.3120
Line-14	0.03900	5	0.2340
Line-15	0.05200	5	0.3120
Line-1 & Line-2	0.00190	12	0.0228
Line-1 & Line-3	0.00254	12	0.0304
Line-1 & Line-4	0.00238	12	0.0285
Line-1 & Line-5	0.00254	12	0.0304
Line-1 & Line-6	0.00190	12	0.0228
Line-1 & Line-7	0.00238	12	0.0285
Line-1 & Line-8	0.00254	12	0.0304
Line-1 & Line-9	0.00238	12	0.0285
Line-1 & Line-10	0.00190	12	0.0228
Line-1 & Line-11	0.00254	12	0.0304
Line-1 & Line-12	0.00238	12	0.0285
Line-1 & Line-13	0.00254	12	0.0304
Line-1 & Line-14	0.00190	12	0.0228
Line-1 & Line-15	0.00254	12	0.0304
Line-4 & Line-2	0.00190	12	0.0228
Line-4 & Line-3	0.00254	12	0.0304
Line-4 & Line-5	0.00254	12	0.0304
Line-4 & Line-6	0.00190	12	0.0228
Line-4 & Line-7	0.00238	12	0.0285
Line-4 & Line-8	0.00254	12	0.0304
Line-4 & Line-9	0.00238	12	0.0285
Line-4 & Line-10	0.00190	12	0.0228
Line-4 & Line-11	0.00254	12	0.0304
Line-4 & Line-12	0.00238	12	0.0285
Line-4 & Line-13	0.00254	12	0.0304
Line-4 & Line-14	0.00190	12	0.0228
Line-4 & Line-15	0.00254	12	0.0304
Line-7 & Line-2	0.00190	12	0.0228
Line-7 & Line-3	0.00254	12	0.0304
Line-7 & Line-5	0.00254	12	0.0304
Line-7 & Line-6	0.00190	12	0.0228
Line-7 & Line-8	0.00254	12	0.0304
Line-7 & Line-9	0.00238	12	0.0285
Line-7 & Line-10	0.00190	12	0.0228
Line-7 & Line-11	0.00254	12	0.0304
Line-7 & Line-12	0.00238	12	0.0285
Line-7 & Line-13	0.00254	12	0.0304
Line-7 & Line-14	0.00190	12	0.0228
Line-7 & Line-15	0.00254	12	0.0304

Line-10 & Line-2	0.00152	12	0.0183
Line-10 & Line-3	0.00203	12	0.0243
Line-10 & Line-5	0.00203	12	0.0243
Line-10 & Line-6	0.00152	12	0.0183
Line-10 & Line-8	0.00203	12	0.0243
Line-10 & Line-9	0.00190	12	0.0228
Line-10 & Line-11	0.00203	12	0.0243
Line-10 & Line-12	0.00190	12	0.0228
Line-10 & Line-13	0.00203	12	0.0243
Line-10 & Line-14	0.00152	12	0.0183
Line-10 & Line-15	0.00203	12	0.0243
Line-12 & Line-2	0.00190	12	0.0228
Line-12 & Line-3	0.00254	12	0.0304
Line-12 & Line-5	0.00254	12	0.0304
Line-12 & Line-6	0.00190	12	0.0228
Line-12 & Line-8	0.00254	12	0.0304
Line-12 & Line-9	0.00238	12	0.0285
Line-12 & Line-11	0.00254	12	0.0304
Line-12 & Line-13	0.00254	12	0.0304
Line-12 & Line-14	0.00190	12	0.0228
Line-12 & Line-15	0.00254	12	0.0304
Line-14 & Line-2	0.00152	12	0.0183
Line-14 & Line-3	0.00203	12	0.0243
Line-14 & Line-5	0.00203	12	0.0243
Line-14 & Line-6	0.00152	12	0.0183
Line-14 & Line-8	0.00203	12	0.0243
Line-14 & Line-9	0.00190	12	0.0228
Line-14 & Line-11	0.00203	12	0.0243
Line-14 & Line-13	0.00203	12	0.0243
Line-14 & Line-15	0.00203	12	0.0243

Appendix-B

Table B.3: Customer data

LP	No. of end users	e_{AN} of each end user (MWh/yr)	ΔWTP_T ($/month)	ΔWTP_D ($/month)
3	80	10.54	17	10
	95	13.90	22	13
4	50	7.73	13	7
	60	7.54	11	6
	50	10.54	17	10

5	90	6.81	11	6
	75	5.45	8	5
	35	11.29	20	7
7	70	5.45	8	5
	80	10.54	17	10
	50	7.54	11	6
13	50	13.90	22	13
	65	6.55	11	6
	55	10.54	17	10
	30	10.94	35	10
14	70	8.12	22	10
	45	5.45	8	5
	65	11.29	20	7
15	65	6.81	11	6
	105	6.55	11	6
	30	7.73	13	7
16	30	7.54	11	6
	40	7.73	13	7
	45	6.81	11	6
	65	10.94	35	10
17	50	8.12	22	10
	75	7.73	13	7
	55	5.45	8	5
20	90	7.54	11	6
	70	6.55	11	6
	30	13.90	22	13
21	75	10.54	17	10
	60	8.12	22	10
	55	6.81	11	6
22	45	7.73	13	7
	95	11.29	20	7
	75	10.94	35	10

End user's information

Annual energy consumption	7.536 MWh
ΔWTP_T	\$11 /month
ΔWTP_D	\$6 /month
Appliances ordering from high to low priority	Refrigerator 192 W Radio 200 W Light 60 W Light 60 W Microwave 1500 W

	A/C 1000 W
Minimum power needed	Refrigerator 192 W

Annual energy consumption	6.813 MWh
ΔWTP_T	$11 /month
ΔWTP_D	$6 /month
Appliances ordering from high to low priority	Refrigerator 250 W Radio 150 W Cell phone charge 5 W Light 30 W Water pump 2000 W Microwave 1500 W
Minimum power needed	Refrigerator 250 W

Annual energy consumption	10.944 MWh
ΔWTP_T	$33 /month
ΔWTP_D	$10 /month
Appliances ordering from high to low priority	Refrigerator 700 W Cell Phone recharge 5 W Radio 200 W Water pump 1900 W Light 30 W Light 30 W Light 30 W Microwave 1500 W LCD TV 250 W A/C 5000 W
Minimum power needed	Refrigerator 700 W

Annual energy consumption	7.734 MWh
ΔWTP_T	$13 /month
ΔWTP_D	$7 /month
Appliances ordering from high to low priority	Refrigerator 450 W TV 250 W Light 30 W Light 30 W A/C 5000 W
Minimum power needed	Refrigerator 450 W

Annual energy consumption	10.539 MWh

ΔWTP_T	\$17 /month
ΔWTP_D	\$10 /month
Appliances ordering from high to low priority	Refrigerator 500 W Cell Phone recharge 5 W Radio 200 W Light 30 W Light 30 W Microwave 1500 W LCD TV 200 W
Minimum power needed	Refrigerator 500 W

Annual energy consumption	5.447 MWh
ΔWTP_T	\$8 /month
ΔWTP_D	\$5 /month
Appliances ordering from high to low priority	Refrigerator 180 W Radio 150 W Cell phone recharge 5 W Light 30 W Microwave 1500 W
Minimum power needed	Refrigerator 180 W

Annual energy consumption	11.292 MWh
ΔWTP_T	\$20 /month
ΔWTP_D	\$10 /month
Appliances ordering from high to low priority	Refrigerator 500 W Cell phone recharge 5 W Radio 200 W Water pump 1900 W Light 30 W Light 30 W Light 30 W Microwave 1500 W LCD TV 250 W A/C 3000 W
Minimum power needed	Refrigerator 500 W

Annual energy consumption	13.900 MWh
ΔWTP_T	\$22 /month
ΔWTP_D	\$13 /month

Appliances ordering from high to low priority	Refrigerator 700 W Cell phone recharge 10 W Radio 200 W Water pump 2500 W Light 60 W Light 60 W Light 60 W Microwave 1500 W LCD TV 400 W A/C 5000 W
Minimum power needed	Refrigerator 700 W

Annual energy consumption	6.554 MWh
ΔWTP_T	$11 /month
ΔWTP_D	$6 /month
Appliances ordering from high to low priority	Refrigerator 500 W TV 250 W Cell phone recharge 5 W Light 30 W Light 30 W Microwave 1500 W A/C 5000 W
Minimum power needed	Refrigerator 500 W

Annual energy consumption	8.121 MWh
ΔWTP_T	$22 /month
ΔWTP_D	$10 /month
Appliances ordering from high to low priority	Refrigerator 200 W Cell phone recharge 5 W TV 300 W Light 30 W Microwave 500 W A/C 5000 W
Minimum power needed	Refrigerator 200 W

Appendix-C

Table C.4: Length of candidate lines

Line ID	Length (km)
i	1
ii	0.7
iii	0.5
iv	1
V	0.5
vi	1
vii	1
viii	0.6
ix	0.6
x	0.5
xi	0.7