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Design and Operation of Distribution Markets

Sina Parhizi
University of Denver

DESIGN AND OPERATION OF DISTRIBUTION MARKETS

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Sina Parhizi

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Advisor: Dr. Amin Khodaei

Author: Sina Parhizi
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ABSTRACT

The growing penetration of distributed prosumers especially microgrids poses new challenges to the operation of wholesale markets and distribution power systems. Price spikes and higher uncertainty are among these consequences. Distribution markets are envisioned as a remedy to streamline integration of distributed resources and microgrids in the electricity market. This dissertation offers an analytical formulation of electricity markets in the distribution level, considering various prevailing aspects of the market operation problem.

The prevailing challenges in regards to integration of microgrids in the electricity markets are illustrated first, and the distribution market operator (DMO) construct is outlined. The day-ahead scheduling of a microgrid participating in a DMO market is formulated and studied. Then the operation of distribution markets integrated with large numbers of responsive participants is considered, and its transactions with the distribution market participants on one hand, and the wholesale market on the other hand are modeled and studied. The market settlement and clearing, essential in operation of distribution markets, is considered and solved. The pricing mechanism in a distribution market is proposed and the relation of distribution and transmission and distribution prices is studied. A more advanced pricing mechanism considering voltages and reactive power is developed and studied. In order to offer a more accurate pricing structure within the distribution system, a linearized distribution power flow is utilized. The performance of the proposed

methods is analyzed and the results are presented. Markets have been recently envisioned to be a suitable instrument for integration of distributed energy resources in the distribution system, but most of the discussions surrounding this topic is at the conceptual level. In this work, it is demonstrated that distribution markets are effective in integrating microgrids and distributed resources in the electricity markets, and an analytical model is presented for design and operation of such markets.

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LIST OF ABBREVIATIONS

DER	Distributed energy resource
DG	Distributed generation unit
DMO	Distribution market operator
DR	Demand response
DSO	Distribution system operator
DSPP	Distributed System Platform Provider
ESS	Energy Storage System
ISO	Independent System Operator
MILP	mixed integer linear programming
PCC	Point of Common Coupling
REV	Reforming the Energy Vision
SCUC	Security-Constrained Unit Commitment
T&D	Transmission and Distribution

NOMENCLATURE

Chapter two:

D	Load demand.
i	Index for DERs.
I	Commitment state of dispatchable unit (1 when committed, 0 otherwise).
$F(P,I)$	Dispatchable unit operation cost.
LS	Load curtailment.
m	Index for microgrids.
P	DER output power.
P^{M}	Power transfer to the microgrid.
t	Index for hours.
ρ^{M}	Market price.
v	Penalty for scheduled power violation.
υ	Value of lost load.

Chapter three:

Sets and Indices:

ch	Superscript for energy storage charging mode.
d	Index for loads.
dch	Superscript for energy storage discharging mode.
D	Set of adjustable loads.
G	Set of dispatchable units.
i	Index for DERs.
s	Index for scenarios.
S	Set of energy storage systems.
t	Index for hours.
τ	Index for sub-periods.

Parameters:

c	Penalty for scheduled power violation.
DR	Ramp down rate.
DT	Minimum down time.
F	Operation cost function of dispatchable unit.
MC	Minimum charging time.
MD	Minimum discharging time.
MU	Minimum operating time.
pr	Probability of scenarios.
P^{sch}	Main grid power transfer assigned to the microgrid from the DMO.
U	Islanding binary indicator (1 when grid-connected, 0 when islanded).
UR	Ramp up rate.
UT	Minimum up time.
α , β	Specified start and end times of adjustable loads.

Variables:

C	Energy storage available (stored) energy.
D	Load demand.
I	Commitment state of dispatchable unit (1 when committed, 0 otherwise).
LS	Load curtailment.
P	DER output power.
P_M	Main grid power transfer determined via optimal scheduling.
ΔP_M	Main grid power transfer mismatch with respect to the assigned value.
ΔP_M^+	Positive main grid power transfer mismatch.
T^{ch}	Number of successive charging hours.
T^{dch}	Number of successive discharging hours.
T^{on}	Number of successive ON hours.
T^{off}	Number of successive OFF hours.
v	Energy storage charging state (1 when charging, 0 otherwise).
u	Energy storage discharging state (1 when discharging, 0 otherwise).
z	Adjustable load state (1 when operating, 0 otherwise)
δ	Power transfer violation indicator (1 when violated, 0 otherwise).
υ	Value of lost load.

Chapter four:

Indices:

b	Index for buses.
i	Index for DERs.
j	Index for segments of the load bids.
l	Index for transmission lines.
t	Index for hours.
m	Index for microgrids.
r	Superscript for responsive loads.
f	Superscript for fixed loads.

Parameters and functions:

B	Components of the bus-to-line incidence matrix.
c	Marginal cost of dispatchable units.
D^f	Total fixed load of all microgrids in the distribution network.
DR	Ramp down rate.
$F(P,I)$	Generation cost of the dispatchable unit.
$PL_l^{\max}$	Line flow limit.
UR	Ramp up rate.
U	Islanding indicator (1 when grid-connected, 0 when islanded).
v	Penalty for scheduled power deviation.
υ	Value of lost load.
x	Line impedance
$\rho(P)$	Cost function of generation units submitted to the ISO.
$\lambda(D)$	Consumption benefit of aggregated loads.

Variables:

d Load demand.
D The demand awarded from the ISO to the DMO.
PD^M Assigned demand to microgrids by the DMO.
DX The amount of load awarded to each segment of the bid
$DX^{\max}$ Segment in the variable load bid of the microgrid.
I Commitment state of dispatchable unit (1 when committed, 0 otherwise).
LS Load curtailment.
P DER output power.
P^M Scheduled power transfer from the DMO to the microgrid.
PL Line flow.
ΔP^M Power transfer deviation.
ΔP^{M+} Positive power transfer deviation.
δ Power transfer deviation indicator (1 when deviation is positive, 0 otherwise).
θ Bus angle.

Chapter five:

a Elements of the bus-line incidence matrix.
b Load benefit.
C_c Customer payments to the DMO.
C_u DMO payment to the ISO.
C_Δ DMO cost surplus.
f Superscript for fixed loads.
g Index for bid segments.
m Index for distribution network buses.
D Load demand.
P^M Total assigned power from the main grid.
PL Line power flow.
PL^{max} Line power flow limit.
DX The amount of load awarded to each segment of the bid.
PX^{max} Maximum capacity of each bid segment.
r Superscript for responsive loads (proactive customers).
t Index for hours.
λ Transmission locational marginal price (T-LMP).
λ^D Distribution locational marginal price (D-LMP).

Chapter six:

6.1)

a Elements of the bus-line incidence matrix.

b	Load benefit.
C_c	Customer payments to the DMO.
C_u	DMO payment to the ISO.
C_Δ	DMO cost surplus.
f	Superscript for fixed loads.
g	Index for bid segments.
μ	Penalty factor for the power deviation.
m	Index for distribution system buses.
D	Load demand.
P^M	Power transfer from the main grid.
PD^M	Total assigned power from the main grid.
PL	Line power flow.
PL^{max}	Line power flow limit.
DX	The amount of load awarded to each segment of the bid.
PX^{max}	Maximum capacity of each bid segment.
r	Superscript for responsive loads (proactive customers).
t	Index for hours.
ΔP	Power transfer deviation.
λ	Transmission locational marginal price (T-LMP).
λ^D	Distribution locational marginal price (D-LMP).
P_t^{pos}	Variables used to linearize absolute value.
P_t^{neg}	Variables used to linearize absolute value.

6.2)

Indices:

c	Index for points of interconnection.
i	Index for generation units.
m,n	Index for buses.
t	Index for time.
$\wedge$	Index for calculated variables.

Sets:

C_m	Set of generation units connected to bus *m.*
L	Set of lines.
L_m	Set of lines connected to bus *m*.
N	Set of buses.

Parameters:

b	Line susceptance.
B_m	Load benefit.
g	Line conductance.
PD	Load active power.

QD	Load reactive power.
λ	Transmission locational marginal price (T- LMP).
PL^{max}	Line power flow limit.

Variables:

P	Active power generation.
PL	Active line flow.
Q	Reactive power generation.
QL	Reactive line flow.
V	Bus voltage magnitude.
θ	Bus voltage angle.
λ^P	Distribution locational marginal price (D-LMP) for active power.
λ^Q	Distribution locational marginal price (D-LMP) for reactive power.

CHAPTER ONE: INTRODUCTION

For over a century, the electric power system has been functioning in a vertical structure, consisting of three levels of large-scale power generation, long-distance high voltage transmission, and widespread distribution to a variety of customers. Power system operators have been largely successful in delivering reliable and affordable electrical energy to the consumers. The extensive efforts in restructuring this system, mainly carried out in 1990s, changed generation sector in many parts of the world by increasing competition, but the distribution sector was still the same until recently. In the past decade, with the growing developments in small-scale distributed energy related research and technology development, increasing environmental concerns, and all-time-high demand for high reliability and quality power, a new and different future is being envisioned for the power system. The introduction of small-scale distributed energy resources, such as rooftop solar panels, energy storage and small-scale wind turbines, makes it possible for consumers to partially or fully supply their demand [1]–[3]. Advanced technology has enabled some loads to become elastic and price-responsive, thus enabling customers to become active participants in distribution systems and to manage their consumption for economic and reliability considerations [4]. The microgrid is one of these new technologies that can bring more reliable and higher quality power to consumers who need it. All these emerging developments fundamentally transform the way distribution system is operated. Another upcoming impact is increase in the level of load uncertainty in the distribution system [5]. The growing penetration of the proactive customers would cause price spikes as their loads are price-responsive and they could manage energy transactions with the local market based on day-ahead prices. Furthermore, rapidly growing distributed renewable energy resources are mostly nondispatchable and their generation is highly variable. Accurate forecasting techniques are necessary to help the system operator with making necessary decisions in managing the available resources [6]. These forecasting techniques, however, may still not be successful in providing a sufficiently accurate estimate on the state of the grid as the number of variable generation resources increases.

1.1 Microgrids

The microgrid, as defined by the U.S. Department of Energy, is "a group of interconnected loads and distributed energy resources (DERs) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes" [7]. Based on this definition, DER installations could be considered as a microgrid if comprised of three distinct characteristics: they must have electrical boundaries that are clearly defined, there must exist a master controller to control and operate DERs and loads as a single controllable entity, and the installed generation capacity must exceed the peak critical load thus it could be disconnected from the utility grid, i.e., the islanded mode, and seamlessly supply local critical loads. These characteristics further present microgrids as small-scale power systems with the ability of self-supply and islanding which could generate, distribute, and regulate the flow of electricity to local customers. Microgrids are more than just backup generation. Backup generation units have existed for quite some time to provide a temporary supply of electricity to local loads when the supply of electricity from the utility grid is interrupted. Microgrids, however, provide a wider range of benefits and are significantly more flexible than backup generation [8].

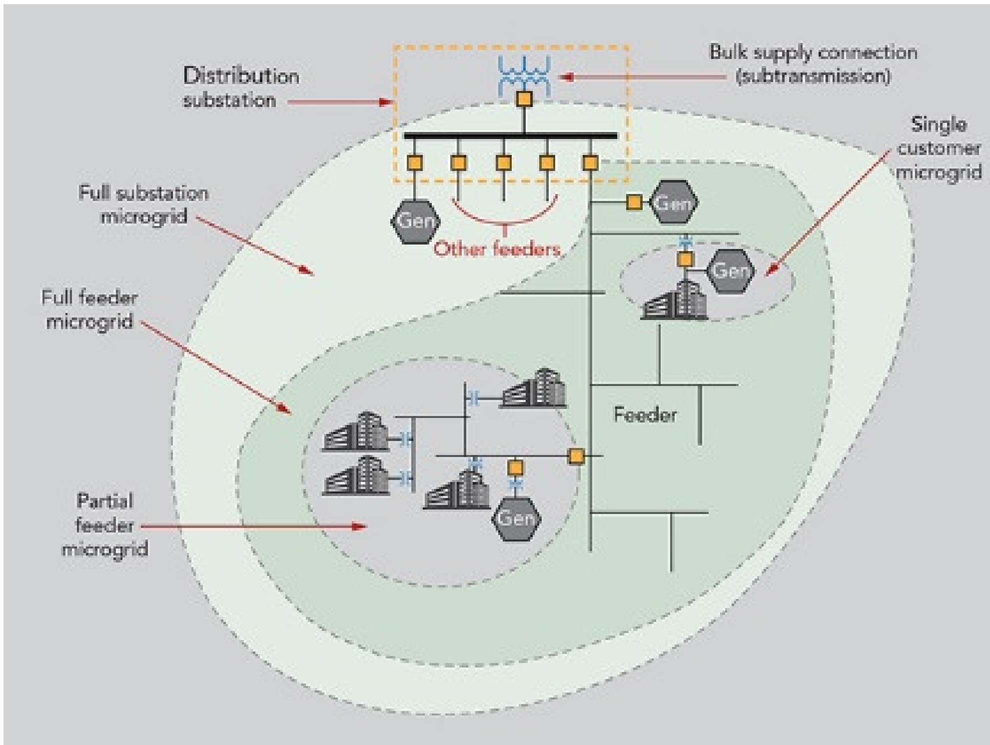

Figure 1.1 A typical microgrid. (Source: Sandia National Laboratory)

The concept of microgrids dates back to 1882 when Thomas Edison built his first power plant. Edison's company installed 50 DC microgrids in four years. At that time centrally controlled and operated utility grids were not yet formed. With the utility grid subsequently utilizing large centralized power plants which benefited from the economies of scale, and significantly increasing transmission connections for reliability purposes, the electric grid turned into a monopolistic utility by connecting isolated microgrids, and these microgrids faded away. There is a new wave in recent years, however, to deploy microgrids which is driven in part by the need for higher reliability and power quality, advancements in power electronics and DER technologies, and a more engaging generation of electricity consumers [9].

The main microgrid components include loads, DERs, master controller, smart switches, protective devices, as well as communication, control and automation systems. Microgrid loads are commonly categorized into two types: fixed and flexible (also known as adjustable or responsive). Fixed loads cannot be altered and must be satisfied under normal operating conditions while flexible loads are responsive to controlling signals. Flexible loads could be curtailed (i.e., curtailable loads) or deferred (i.e., shiftable loads) in response to economic incentives or islanding requirements. DERs consist of distributed generation units (DG) and distributed energy storage systems (ESS) which could be installed at electric utility facilities and/or electricity consumers' premises. Microgrid DGs are either dispatchable or nondispatchable. Dispatchable units can be controlled by the microgrid master controller and are subject to technical constraints depending on the type of unit, such as capacity limits, ramping limits, minimum on/off time limits, and fuel and emission limits. Nondispatchable units, on the contrary, cannot be controlled by the microgrid master controller since the input source is uncontrollable. Nondispatchable units are mainly renewable DGs, typically solar and wind, which produce a volatile and intermittent output power. The intermittency indicates that the generation is not always available and the volatility indicates that the generation is fluctuating in different time scales. These characteristics negatively impact the nondispatchable unit generation and increase the forecast error, therefore these units are commonly reinforced with ESS. The primary application of ESS is to coordinate with DGs to guarantee the microgrid generation adequacy. They can also be used for energy arbitrage, where the stored energy at low price hours is generated back to the microgrid when the market price is high. The ESS also plays a major role in microgrid islanding applications. Smart switches and protective devices manage the connection between DERs and loads in the microgrid by connecting/disconnecting line flows. When there is a fault in part of the microgrid, smart switches and protective devices disconnect the problem area and reroute the power, preventing the fault from propagating in the microgrid. The switch at the point of common coupling (PCC) performs microgrid islanding by disconnecting the microgrid from the utility grid. The microgrid scheduling in interconnected and islanded modes is performed by the microgrid master controller based on economic and security considerations. The master controller determines the microgrid interaction with the utility grid, the decision to switch between interconnected and islanded modes, and optimal operation of local resources. Communications, control, and automation systems are also used to implement these control actions and to ensure constant, effective, and reliable interaction among microgrid components.

Microgrids offer significant benefits for the customers and the utility grid as a whole: improved reliability by introducing self-healing at the local distribution network; improving grid resilience [10]; supporting distribution grid flexibility [11]; higher power quality by managing local loads; reduction in carbon emission by the diversification of energy sources; economic operation by reducing transmission and distribution (T&D) costs; utilization of less costly renewable DGs; and offering energy efficiency by responding to real-time market prices. The islanding capability is the most salient feature of a microgrid, which is enabled by using switches at the PCC, and allows the microgrid to be disconnected from the utility grid in case of upstream disturbances or voltage fluctuations. During utility grid disturbances, the microgrid is transferred from the grid-connected to the islanded mode and a reliable and uninterrupted supply of consumer loads is offered by local DERs. The islanded microgrid would be resynchronized with the utility grid once the disturbance is removed [12][13].

1.2 Distribution Markets

Enhanced complexity in managing a large number of microgrids and distributed resources in a foreseeable future, has made the case for developing new methodologies for the system operation and utility ratemaking in presence of microgrids. The concept of a Distribution System Operator (DSO) is recently proposed as an entity which is hosted in the distribution network to manage interaction of microgrids with the main grid. Considering that a DSO offers both grid and market functionalities, this work only focuses on the market operation and provides discussions under a Distribution Market Operator (DMO) concept. The DMO can be considered as the distribution level equivalent of the ISO, which is responsible for managing the electricity market and scheduling power transfers to achieve the optimal operation in the distribution network [14]. It may be discussed that a highly accurate load estimation would resolve the mentioned issues, in which the system operators would have a fairly accurate idea of load variations. However, it should be noted that necessity of the DSO is not limited to improving predictability. The DSO provides the local resilience capability [15] and reduces dependence on the ISO for providing balancing services, so the distribution system can maintain its service when the rest of the system is in abnormal condition [16]. It could also manage the energy transactions happening between the DERs and loads within the distribution system; demand for this service would grow as the number of such transactions increase [15]. New York Reforming The Energy Vision (REV) asserts that in order to "create a more robust retail market" it is necessary to provide market operations and grid operations at the distribution level [17]. Easing complexity of direct scheduling of responsive loads and DERs in the wholesale market, solving scalability issues and providing ancillary services are among other beneficial functionalities that the DSO can provide to the distribution system [16]–[18]. On the other hand, the ISOs may not have control over the demand side assets, so those assets need to have the capability to provide reserve and flexibility services to handle variable resources [19].

In [20] a price-based simultaneous operation of microgrids and the Distribution Network Operator (DNO) is proposed. In New York, the new concept of Distributed System Platform Provider (DSPP) is introduced as part of the Reforming the Energy Vision program [17] where the transformation of existing utility operations to integrate high penetration of microgrids and DERs is discussed. DSPPs can be formed as new entities or be part of the currently existing electric utilities. An independent DSPP would be able to set up a universal market environment instead of one for each utility. It would also be less suspected of exercising market power. A utility-affiliated DSPP, however, would be able to perform several functionalities currently possessed by electric utilities without necessitating additional investments. In California, the state public utilities commission has ruled to establish regulations to guide investor-owned electric utilities in developing their

Distribution Resources Plan proposals. Studies in [15], [21] provide a framework for this ruling, defined as a DSO, which is in charge of operation of local distribution area and providing distribution services. The DSO is further responsible to provide forecasting and measurement to the ISO and manage power flow across the distribution system. It is also suggested that the DSO adopt further roles such as coordination of dispersed units in the distribution network and providing an aggregate bid to the ISO. The study in [19] proposes a DSO as an ISO for the distribution network, which is responsible for balancing supply and demand at the distribution level, linking wholesale and retail market agents, and linking the ISO to the demand side. As opposed to the European definition of the DSO, the proposed entity in [19] interacts directly with the ISO. The study further presents a spectrum of different levels of the DSO autonomy in operating the distribution system and the degree of ISO's control over it. From the least autonomy to the most autonomy, this spectrum entails the DSO to be able to perform the forecasting and send it to the ISO, be responsible for balancing the supply and demand, be able to receive offers from DERs, aggregate them and bid into the wholesale market, and eventually be able to control the retail market so that various DERs can have transactions not only with the DSO but among themselves. In [22], an independent distribution system operator (IDSO) is proposed to be responsible for distribution grid operation, while grid ownership remains in the hands of utilities. The IDSO is envisioned to provide market mechanisms in the distribution system, enable open access, and ensure safe and reliable electricity service. The IDSO will reduce the operation burden on utilities and determine the true value of resources more objectively. The necessity of distribution markets in integrating proactive customers has been emphasized in the literature [23]–[25]. While different terminology is used to define this intermediate entity between the ISO and proactive customers, all the proposals share some common characteristics.

1.3 DMO Model Outline

The distribution market operator (DMO) is an entity proposed in [14][23] to facilitate the establishment of market mechanisms in distribution systems. The DMO, as an intermediate entity, communicates with the ISO and proactive customers to enable participation of customers in the wholesale market. The DMO receives the demand bids from customers in the distribution system, aggregates them and submits a single aggregated bid to the ISO. After market clearing by the ISO, the DMO divides the assigned power awarded to it between the participated customers. The DMO can be part of the electric utility company or be formed as a separate entity. One important issue that needs to be taken into account is that the DMO can be formed as a new entity or be part of the currently existing electric utilities. An independent DMO would be able to set up a universal market environment instead of one for each utility. It would also be less suspected of exercising market power. On the other hand, a utility-affiliated DMO would be able to perform several functionalities currently possessed by electric utilities without necessitating additional investments. Considering the listed advantages, distribution markets can be considered as both beneficial and necessary components in modern power grids which will help accommodate a large penetration of active customers. Therefore, identifying the detailed operation of these new entities, along with efficient modeling of market clearing and settlement, is of ultimate importance, as focused on in this chapter.

The market mechanism is illustrated in figure 1.2 in which the financial transactions are performed by the DMO while the physical transactions (the actual flow of power from generation companies to loads) is performed by the load serving entity (LSE). The discussed DMO in this work is a platform that enables market activities for end-use customers, coordinates with the utility to improve grid operations, and interacts with the ISO to determine demand bid awards. The DMO will further facilitate establishing a competitive electricity market in the distribution network to exchange energy and grid services with customers, and expedite a more widespread integration of DERs from a system operator's perspective by addressing prevailing integration challenges.

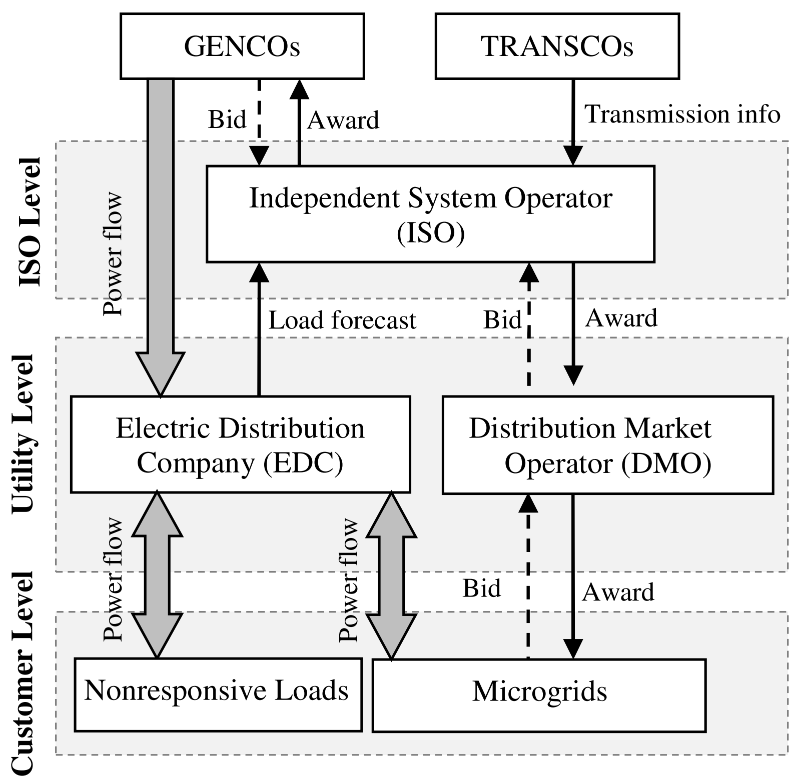

Figure 1.2 Microgrid market participation through the proposed DMO

Two major responsibilities of the DMO within this structure are: 1) To receive demand bids from the microgrids (and other responsive loads if any), combine them, and offer an aggregated bid to the ISO, and 2) To receive the day-ahead schedule from the ISO, solve a resource scheduling problem for its service territory, and subsequently determine microgrids' shares from the awarded power. Microgrids would submit their bids to the DMO (in the form of monotonically decreasing demand bids) and later be notified by the DMO on the amount of awarded power (henceforth referred to as the assigned power). Other responsive loads can be considered at the Customer level without loss of generality. The main grid power transfer to the microgrid would be the amount of power assigned to the microgrid by the DMO, hence it would be known to the system operator in advance and therefore eliminate the uncertainties caused by microgrids to a large extent. Once the main grid power transfer is reported to the microgrid, for the 24 hours of the next day, the microgrid would solve a market-based scheduling problem to optimally schedule its DERs and loads. Only private microgrids are considered in this work as there could be some regulatory barriers in market participation of utility-owned microgrids.

This framework offers several advantages:

- The microgrid demand is set by the DMO and known with certainty on a day-ahead basis. This will lead to manageable peak demands and increased operational reliability and efficiency. Microgrids will have the capability to deviate from the assigned power (as it will be further discussed in this work), however it will be at the expense of paying a penalty, hence potential deviations would be minimal.

- The microgrid can exchange power with the main grid and act as a player in the electricity market. The DMO would serve as an intermediate entity between the ISO and microgrids that facilitates microgrids market participation and coordinates the microgrids with the main grid to minimize the risks posed by microgrids operational uncertainties.
- Establishing the DMO is beneficial to the ISO as it allows a significant reduction in the required communication infrastructure among microgrids and the ISO.
- The DMO can be formed as a new entity or be part of the currently existing electric utilities. An independent DMO would be able to set up a universal market environment instead of one for each utility. It would also be less suspected of exercising market power. On the other hand, a utility-affiliated DMO would be able to perform several functionalities currently possessed by electric utilities without necessitating additional investments.

Implementation of the DMO would fix the aforementioned problems that utilities face when they integrate microgrids. However, in order for the proposed framework to work reliably, it is necessary that the microgrid controller schedules its resources based on the assigned power transfer, considering that microgrid controller seeks the least-cost schedule of local resources. It will be assumed that deviations from the assigned value will be penalized based on the market price or a relatively larger value that can effectively prevent and/or reduce deviations. In this work, it is assumed that the penalty will be applied when the deviation is positive, i.e., the microgrid's scheduled power is larger than the assigned power by the DMO, or in other words, when the microgrid appears as a larger load compared to the assigned power by the DMO. Negative deviation will not be penalized in the proposed model as the microgrid helps with reducing load (increasing generation) in the distribution network. This issue is further investigated in numerical simulations.

In the price-based scheduling method, the ISO receives load forecasts from Electric Distribution Companies (EDC) and determines the day-ahead unit schedules by solving a security-constrained unit commitment (SCUC) problem. The ISO will also determine locational marginal prices (LMPs) which will be further used by microgrids for scheduling purposes. In the price-based method, contrary to the market-based method, there is no need for microgrids to offer bids and participate in the market, and moreover, the main grid power transfer will be determined via a local cost minimization problem rather than being determined by the DMO via a market mechanism. In either method, however, the microgrid needs to determine the optimal schedule of local DERs and loads to address its energy needs and ensure a reliable supply of local loads. Next chapter will further detail the necessity for DMO, and its characteristics.

1.4 Dissertation Overview

The main body of this dissertation is divided in six chapters, which is written using the collection of articles published during the Ph.D. studies. These articles are listed at the publication chapter at the end of this dissertation. In this section, each section is summarized.

Chapter 1 provides an introduction to the problem, through examples and a survey of the literature.

Chapter 2, outlines the distribution markets. Distribution market operators are envisioned to facilitate distributed resources participation in electricity markets. However, because of unique characteristics of the distribution systems DMOs require special modeling and operation considerations to achieve efficient and optimal solution.

In chapter 3, a model was proposed for optimal scheduling of a microgrid participating in the distribution market. Subhourly dispatch was employed to achieve the most economical schedule of microgrid DERs and loads while taking nondispatchable generation variations into account and making sure that the main grid power transfer scheduled by the DMO is achieved. Stochastic optimization was used to account for uncertainties due to islanding and variations in loads and nondispatchable generation. Simulations were performed using CPLEX and the obtained results were studied to show how microgrid can be optimally scheduled while taking distribution market decisions into consideration. Chapter 4 considers this problem from the broader perspective of DMO and ISO as well as the microgrid.

The DMO operation was further analyzed in chapter 5 in which the distribution market clearing and settlement models were proposed and formulated. Two approaches for distribution market clearing were discussed, including the constant power clearing and the variable power clearing. Although the variable power clearing model has been discussed in the literature, it was shown that this model can potentially cause variability and uncertainty in the load managed by the DMO. The constant power clearing model, on the other hand, solved this issue while bringing a potential drawback since the total payment by customers could become larger than the payment to the ISO. Both issues, however, require additional investigations as discussed and signified in this section.

In chapter 6, pricing at the distribution level is discussed. The interdependency of distribution prices is studied. Then, a new linearized power flow method was utilized to enhance the distribution market operation and allow accurate pricing based on location-dependent marginal values. This method could advance the existing pricing models for distribution systems to account for decisive pricing factors such as congestion, losses, and voltage limits, while allowing the calculation of both active and reactive D-LMPs. Several cases on a test system were studied to demonstrate the effectiveness of the proposed model and to evaluate its impact on active and reactive pricing in a radial distribution system.

CHAPTER TWO: CHALLENGES OF DISTRIBUTED RESOURCE INTEGRATION

2.1 Introduction

Despite their various benefits, microgrids and distributed resources bring challenges to the power system operation as it has been carried out so far. Increasing demand-side elasticity and active participation of loads in the power system, commonly in response to electricity price variations, is highly stressed to operate the system more efficiently and to avoid high price spikes caused by inelastic loads [26]. Microgrids allow an efficient integration and control of large penetration of responsive loads which would further increase the demand-side elasticity. Moreover, distributed generation and energy storage support a relatively fast and highly controllable load. However, these resources are typically scheduled based on a price-based scheduling model, i.e., the microgrid controller determines the least-cost schedule of available DERs and loads, as well as the main grid power transfer, based on the day-ahead market prices (which are forecasted by the microgrid or the electric utility). Under this scheme, the utility forecasts an estimate of the microgrids' loads in its service territory and submits it to the system operator. Once the price of electricity is determined, through the wholesale market, the utility sends the actual prices to microgrids. Although it might seem efficient, this approach has the potential to cause several drawbacks when the microgrid penetration in distribution network is high, including but not limited to shifting the peak hours. This approach is prone to cause new peaks since there is a high probability that microgrids follow a different schedule compared to the one forecasted by the utility once actual prices are received, considering that the power demand in responsive loads is inversely proportional to electricity prices. The increase in the number of entities with responsive loads operated based on price-based scheme would intensify this issue. In other words, setting the price centrally by the system operator and sending it to microgrids, so they can accordingly schedule their resources, can potentially result in significant uncertainty in the system load profile. The increased penetration of DERs and microgrids would also make it more challenging to ensure distribution system reliability [15].

The concept of aggregators was one of the ideas that was proposed to address these issues. Aggregators discussions can be found in [27], where it is proposed to iteratively collect power generated by microgrids, sell this power to the main grid, and accordingly gain profit via a price-based scheduling. In [28] an aggregator for electric vehicles with fixed energy cost is proposed. The study in [29] proposes a framework for interactions between the customers in a distribution system as well as the main grid, while [30] proposes an entity between the market operator and customers that compensates the aggregators for the services they provide. A coupon incentive-based demand response model is further proposed in [31] enabling customers to increase their flexibility and lower their costs. The proposed model in [32] enables a demand response aggregator to participate in the electricity market, considering market price to be constant. It is further applied to microgrids in [33].

In this chapter, the existing approaches to microgrid scheduling is investigated, and the challenges facing them is pointed out. Alternative approaches are introduced to tackle the prevailing challenges.

2.2 Price-Based Optimal Scheduling Model

Microgrid control is commonly performed in a hierarchical three-level scheme, including primary, secondary, and tertiary levels [34][35]. The first two levels are responsible for droop control and frequency/voltage regulations in response to load variations and/or islanding. At the third level, the microgrid controller seeks to minimize the microgrid operation cost, i.e., the generation cost of local DERs, as well as the energy exchange with the main grid, to supply forecasted local loads in a certain period of time (typically one day). This problem is subject to a variety of operational constraints, such as power balance and DER limitations. The scheduling problem can be solved centrally through a central controller [36][37] or in a decentralized way where each entity communicates with others as an agent to obtain the optimal schedule for the entire microgrid [38][39]. A variety of methodologies are proposed in the literature to solve the microgrid optimal scheduling problem, including deterministic, heuristic, and stochastic methods. Mixed integer programming (MIP) is widely used to formulate resource scheduling problems [40][41][42] and is further used here to model the microgrid price-based scheduling problem.

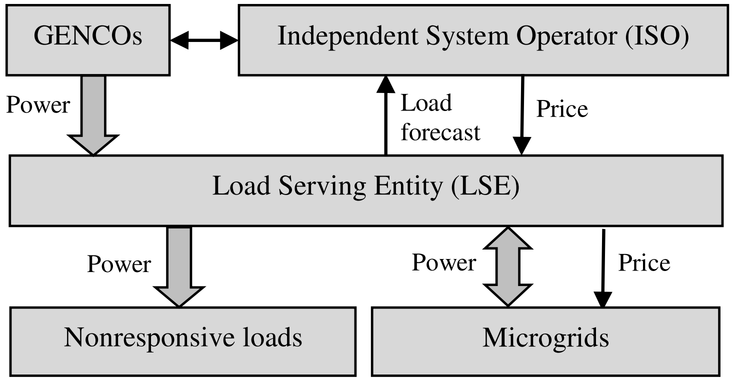

Figure 2.1 The price-based microgrid scheduling framework.

The wholesale market structure considering the microgrid price-based scheduling scheme is shown in Fig. 2.1. The aggregate demand of the distribution network, including the demand of microgrids, responsive customers, and nonresponsive customers, is forecasted and submitted to the ISO by the load serving entity (LSE). The LSE is the utility company which is responsible for ensuring a reliable flow of power from generation companies to customers via transmission and distribution networks. Based on the demand data, as well as the generation and transmission data obtained respectively from generation companies (GENCOs) and transmission companies (TRANSCOs), the ISO runs the unit commitment and economic dispatch problems to determine the optimal schedule of generation units and the locational marginal prices (LMPs) at every system bus. Microgrids use LMPs at their associated bus and solve the price-based optimal scheduling problem as defined in (2.1)-(2.6):

$$\min \sum_{t}\sum_{i}(F_{im}(P_{imt}, I_{imt}) + \upsilon LS_{mt} + \rho_{m}^{M} P_{mt}^{M}) \tag{2.1}$$

$$P_{mt}^{M} + \sum_{i} P_{imt} + LS_{mt} = \sum_{d} D_{mdt} \qquad \forall t \tag{2.2}$$

$$P_{im}^{\min} I_{imt} \le P_{imt} \le P_{im}^{\max} I_{imt} \qquad \forall t, \forall i \qquad (2.3)$$

$$\sum_t P_{imt} = E_{im} \qquad \forall t \qquad (2.4)$$

$$\sum_t f_{im}(P_{imt}, I_{imt}) \le 0 \qquad \forall i \qquad (2.5)$$

$$-P_m^{M,\max} \le P_{mt}^M \le P_m^{M,\max} \qquad \forall t \qquad (2.6)$$

The three terms in the objective function represent the operation cost, the load curtailment cost, and the main grid power transfer cost. The operation cost is the cost of power production by dispatchable units as well as startup and shut down costs. The load curtailment cost is defined as the value of lost load times the amount of load curtailment. The value of lost load is assumed as on opportunity cost based on the cost the consumer is willing to pay to have reliable uninterrupted service. It is commonly used as a measure to represent loads criticality [43]. The power transfer cost is equal to the amount of power transferred to the microgrid from the main grid times the associated LMP to which the microgrid is connected. The objective is subject to a set of operational constraints. The power balance constraint (2.2) ensures that the sum of the main grid power transfer plus the locally generated power matches the microgrid load, while load curtailment variable is added to ensure that this balance is satisfied at all times (in particular during the islanded operation when adequate generation may not be available). In the power balance equation, nondispatchable unit generation and fixed load values are forecasted, where dispatchable unit generation, adjustable load, load curtailment, and energy storage power are the variables. All operational constraints associated with DERs and loads are formulated using three general constraints (2.3)-(2.5), respectively representing power constraints, energy constraints, and time-coupling constraints. Power constraints (2.3) account for generation minimum/maximum capacity limits, storage minimum/ maximum charge/discharge power, and flexible load minimum/maximum capacity limits. Energy constraints (2.4) account for energy storage state of charge limit and flexible load required energy in each cycle. Time-coupling constraints (2.5) represent any constraint that link variables in two or more scheduling hours, including dispatchable units ramp up/down, minimum on/off times, energy storage rate and profile of charge/discharge, and adjustable loads minimum operating time and load pickup/drop rates. The detailed formulation of these constraints can be found in [4]. The main grid power transfer is restricted by its associated limits, which are imposed by the capacity of the line connecting the microgrid to the main grid, in (2.6).

2.3 Illustrative Example

The IEEE 6-bus test system is used to demonstrate the impact of the price-based microgrid scheduling on changing the system net load. The IEEE 6-bus system data and the microgrid data are borrowed from [44] and [4], respectively. Fig. 2.2 shows the aggregated system net load with 50% microgrid penetration at each load bus in two cases: i) the forecasted load that is provided by the utility to the ISO. The ISO has used the forecasted load to determine the commitment and the dispatch of available generation units, and further calculate the LMPs; and ii) the actual load once calculated LMPs are sent to microgrids and microgrids have scheduled their DERs and loads. As this figure demonstrates, microgrids can potentially result in a complete change in the system load profile. The ISO’s challenge is to remove the mismatch between the generation and the load, since generation units are committed and dispatched based on the forecasted load while the system encounters a revised load.

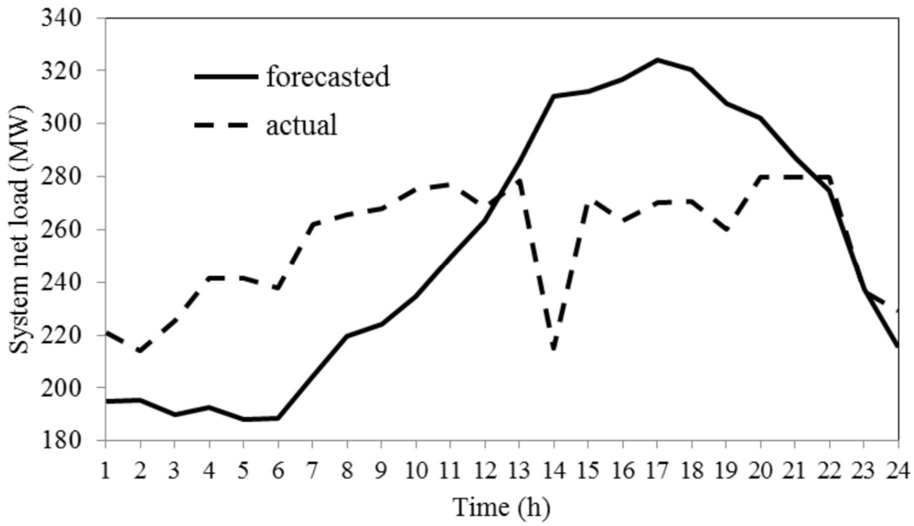

Figure 2.2 The aggregated system load in two cases: forecasted load by the utilities, and the actual load after microgrids scheduling.

2.4 Proposed Paradigms

This section discusses three paradigms to address the load uncertainty challenges introduced by high penetration microgrids: 1) Removing the generation-load imbalance by redispatching committed generation units, i.e., similar to the current practice in grid control; 2) Communicating the revised load to the ISO to solve the unit commitment again and obtain new unit schedule and LMP values; 3) Introducing a distribution market to locally manage microgrids, i.e., to shift from the price-based scheduling scheme to a market-based scheduling scheme.

2.4.1 Paradigm 1

The ISO would redispatch the committed generation units to compensate the mismatch created due to the change in system demand. Fig. 2.3 shows the required change in generation at each bus (the other generator dispatch did not change). Under this paradigm, the generation-load imbalance can be eliminated; the amount of change in dispatch is significant and might not be feasible in some occasions without a change in unit commitment.

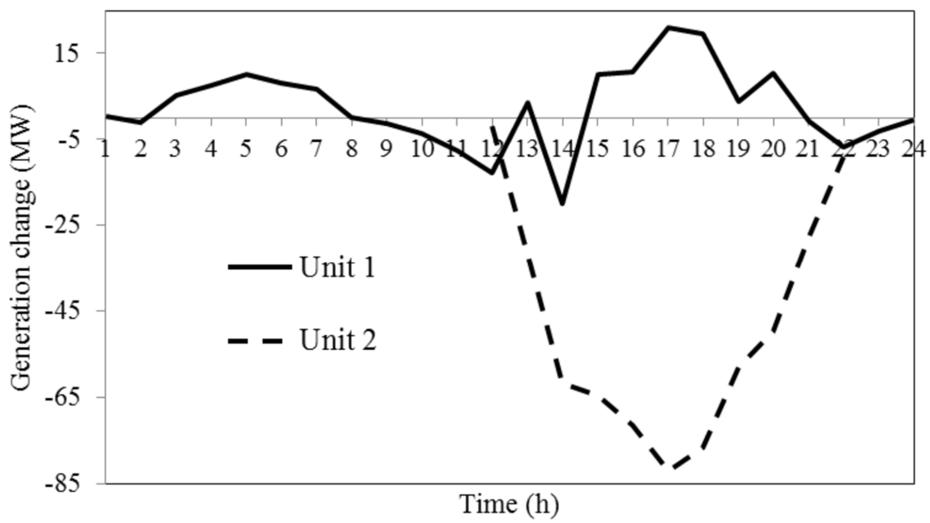

Figure 2.3 Change in generation after ISO redispatches the units.

2.4.1 Paradigm 2

Under this paradigm, the revised load is communicated to the ISO to solve the unit commitment again and obtain new unit schedule and LMP values. This paradigm should be performed in a day-ahead fashion and would require a reliable communication infrastructure among the ISO and microgrids. An example for this paradigm is shown in

Fig. 2.4 where the load at bus 3 is replaced with microgrids. The microgrid load is oscillating as the ISO and microgrids communicate price and load in each iteration.

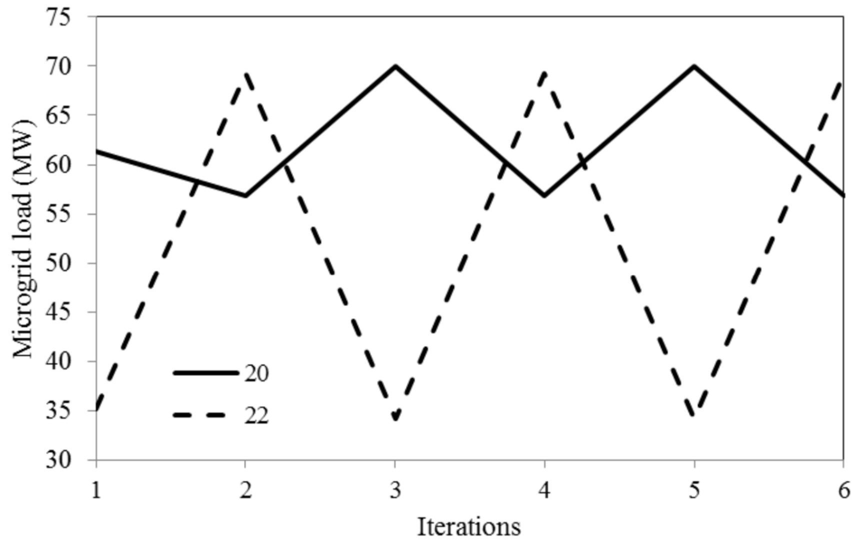

Figure 2.4 Microgrid load at hours 20 and 22.

Fig. 2.5 Shows the system average LMP at the same hours. When the microgrid responds to the price set by the ISO, the ISO has to reschedule the system resources resulting in a new price. Microgrids will also reschedule their resources according to this new price. As the number of buses with microgrids increases, the price oscillations also increase. With a larger penetration of microgrids in the system, the system load becomes more responsive and causes more volatility in system LMPs.

2.4.3 Paradigm 3

The uncertainty in the system operation and the need to commit adequate reserve to support load variations causes troubles for the ISO to reliably operate the system. Hence, alternative models to manage microgrids are being actively sought. Under this paradigm, a new entity, here called Distribution Market Operator (DMO), is introduced to establish a competitive electricity market in the distribution level. Microgrids would be players in the distribution market and participate in the electricity price calculations. Microgrids would submit their demand bids to the DMO, which would in turn aggregate the bids and submit it to the ISO. The ISO determines the awarded power to each DMO, where the DMO subsequently disaggregate the awarded bids to participated microgrids. Microgrids would be obliged to follow the awarded power once the market is cleared. This would significantly reduce uncertainties the ISO faces as the penetration of microgrids in the system increases.

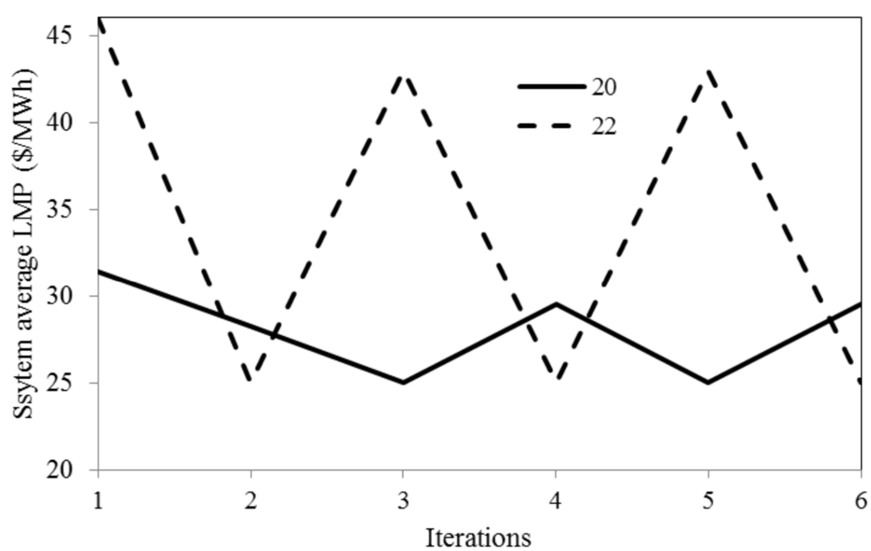

Figure 2.5 System average LMP at hours 20 and 22.

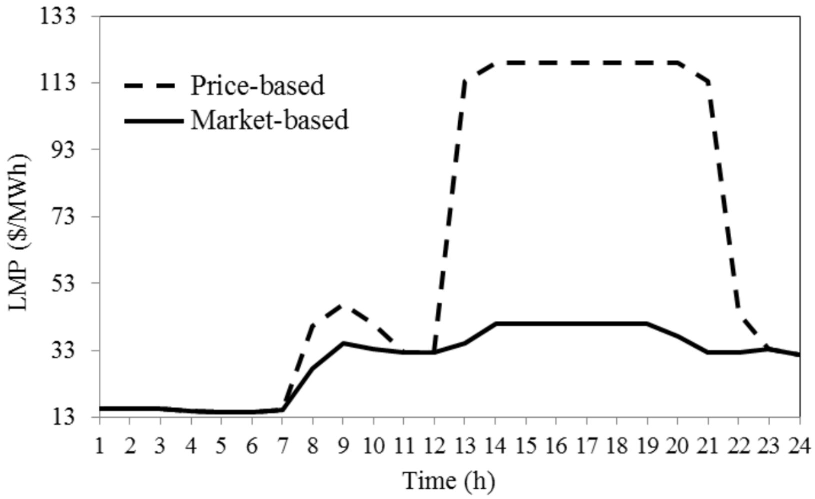

Figure 2.6 LMP at bus 60

Fig. 2.6 shows the impact of using DMO in the 118-bus IEEE standard test system at bus 60. It is observed that market-based scheduled microgrid result in a lower price at the bus they are connected to. The microgrid is scheduled in one step and its operation cost would not vary as its demand remains determined one day ahead. Next chapter will further discuss DMO and outline its characteristics.

CHAPTER THREE: MICROGRID MARKET-BASED SCHEDULING

3.1 Introduction

In previous chapter, challenges facing price-based microgrid scheduling in an electricity market was discussed, and possible solutions were introduced. In this chapter microgrid optimal scheduling under market-based approach is explored and studied. The proposed model optimally schedules the microgrid while complying with main grid power transfer schedule imposed on the microgrid by the market.

3.2 Formulation

3.2.1 Objective

The objective of this problem is to determine the least-cost day-ahead schedule of loads, dispatchable generation units, and energy storage in the microgrid (3.1) when the profile of the main grid power transfer over the scheduling horizon is known (i.e., determined and announced by the DMO). In order to take the associated uncertainties into consideration, a stochastic scenario-based optimization model is employed as proposed in [46]. Each scenario simulates an outcome with a uniformly distributed random nondispatchable unit generation and load.

$$\min \mathrm{E}\left[\sum_{s} pr_s \sum_{t} \sum_{\tau} \left(\sum_{i \in G} F_i(P_{it\tau s}, I_{it}) + \upsilon LS_{t\tau s} + c\Delta P^{+}_{M,t\tau s} \right)\right] \qquad (3.1)$$

The objective includes three terms of operation cost of dispatchable units (which includes generation cost, and startup/shut down costs), the load curtailment cost (defined as the value of lost load times the amount of load curtailment) and the penalty for deviation from the scheduled main grid power transfer. The objective is weighted, using probability, and summed over all scenarios.

3.2.2 Operational Constraints

The objective is subject to the following operational constraints:

$$\sum_i P_{it\tau s} + P_{M,t\tau s} + LS_{t\tau s} = \sum_d D_{dt\tau s} \quad \forall t, \forall \tau, \forall s \tag{3.2}$$

$$P_i^{\min} I_{it} \le P_{it\tau s} \le P_i^{\max} I_{it} \qquad \forall i \in G, \forall t, \forall \tau, \forall s \tag{3.3}$$

$$P_{it\tau s} - P_{it(\tau-1)s} \le UR_i \qquad \forall i \in G, \forall t, \forall \tau, \forall s \tag{3.4}$$

$$P_{it(\tau-1)s} - P_{it\tau s} \le DR_i \qquad \forall i \in G, \forall t, \forall \tau, \forall s \tag{3.5}$$

$$T_{it}^{\text{on}} \ge UT_i (I_{it} - I_{i(t-1)}) \qquad \forall i \in \text{G}, \forall t \tag{3.6}$$

$$T_{it}^{\text{off}} \ge DT_i (I_{i(t-1)} - I_{it}) \qquad \forall i \in \text{G}, \forall t \tag{3.7}$$

$$P_{it\tau s} \le P_i^{dch,\max} u_{it} - P_i^{ch,\min} v_{it} \qquad \forall i \in S, \forall t, \forall \tau, \forall s \tag{3.8}$$

$$P_{it\tau s} \ge P_i^{dch,\min} u_{it} - P_i^{ch,\max} v_{it} \qquad \forall i \in S, \forall t, \forall \tau, \forall s \tag{3.9}$$

$$u_{it} + v_{it} \le 1 \qquad \forall i \in S, \forall t \tag{3.10}$$

$$C_{it\tau s} = C_{it(\tau-1)s} - P_{it\tau s} \Delta\tau \qquad \forall i \in S, \forall t, \forall \tau, \forall s \tag{3.11}$$

$$0 \le C_{it\tau s} \le C_i^{\max} \qquad \forall i \in S, \forall t, \forall \tau, \forall s \tag{3.12}$$

$$T_{it}^{ch} \ge MC_i (u_{it} - u_{i(t-1)}) \qquad \forall i \in S, \forall t \tag{3.13}$$

$$T_{it}^{dch} \ge MD_i (v_{it} - v_{i(t-1)}) \qquad \forall i \in S, \forall t \tag{3.14}$$

$$D_d^{\min} z_{dt} \le D_{dt\tau s} \le D_d^{\max} z_{dt} \qquad \forall d \in D, \forall t, \forall \tau, \forall s \tag{3.15}$$

$$\sum_{t\in[\alpha_d,\beta_d]} D_{dt\tau s} = E_d \qquad \forall d \in D, \forall \tau, \forall s \tag{3.16}$$

$$T_{dt}^{on} \geq MU_d (z_{dt} - z_{d(t-1)}) \qquad \forall i \in D, \forall t \tag{3.17}$$

The power balance constraint is considered in (3.2) to make sure that the sum of the main grid power transfer plus the locally generated microgrid power matches the total load, while load curtailment variable is added to ensure that this balance is satisfied at all times. The nondispatchable generation and fixed load values are forecasted in this constraint while they will change in each scenario. Dispatchable unit constraints include generation minimum/maximum limits (3.3), ramp up/down limits (3.4)-(3.5), and minimum up/down time limits (3.6)-(3.7). Energy storage constraints include maximum charging and discharging constraints (3.8)-(3.9), charging/discharging mode (3.10), available stored energy limits (3.11)-(3.12), and minimum charge/discharge time (3.13)-(3.14). Adjustable loads constraints include rated power limit (3.15), required energy consumption in a certain period specified by [α_d, β_d] (3.16), and minimum operating time (3.17). In the case of inter-temporal constraints, such as minimum up/down times, it must be ensured that at the first period τ of each hour t, the constraint holds with respect to the last period of the previous hour.

3.2.3 Main Grid Power Transfer Deviation Modeling

The main grid power transfer for each microgrid is scheduled and assigned by the DMO. However, microgrid can deviate from the scheduled power transfer and pay a penalty as proposed in (3.1).

$$-P_M^{\max} U_{t\tau s} \leq P_{M,t\tau s} \leq P_M^{\max} U_{t\tau s} \quad \forall t, \forall \tau, \forall s \tag{3.18}$$

$$\Delta P_{M,t\tau s} = P_{M,t\tau s} - P_{M,t}^{sch} \qquad \forall t, \forall \tau, \forall s \tag{3.19}$$

$$-P_M^{\max}\delta_{ts} \le \Delta P_{M,t\tau s}^{+} \le P_M^{\max}\delta_{ts} \quad \forall t, \forall \tau, \forall s \tag{3.20}$$

$$-P_M^{\max}(1-\delta_{ts}) \le \Delta P_{M,t\tau s} - \Delta P_{M,t\tau s}^{+} \le P_M^{\max}(1-\delta_{ts}) \qquad \forall t, \forall \tau, \forall s \tag{3.21}$$

To model the islanded operation, binary variable $U_{t\tau s}$ is generated in each scenario to model islanding incidents by zeroing out the main grid power transfer (3.18). The main grid power transfer mismatch from the amount scheduled by the DMO is set by (3.19). If the main grid power transfer mismatch is positive, the objective is penalized, where δ=1 and ΔP^{+}=ΔP using (3.20) and (3.21).

3.3 Numerical Simulations

A microgrid with four dispatchable generation units, a nondispatchable unit, five adjustable loads and one energy storage is considered for simulating the proposed market-based microgrid scheduling model. The microgrid characteristics, as well as forecasted values for fixed load and nondispatchable generation, are borrowed from [45]. Table 3.1 shows the scheduled main grid power transfer, with a mismatch penalty of \$150/MWh.

A total of 100 scenarios are generated to simulate errors in the forecasted subhourly (10-minute) nondispatchable generation and islanding from the main grid. The optimal commitment of the dispatchable units for all scenarios and the schedules of energy storage, loads, and generation dispatch for each scenario are also obtained. The operating cost is obtained as \$39,566. The resulting commitment schedule is given in Table 3.2 where bold numbers show the change compared to the case without islanding. During peak times 14-21 all units are committed to supply local loads and also ensure availability of sufficient generation during transition to islanding. The energy storage is also discharged at its maximum power during islanding periods to contribute to the load balance.

TABLE 3.1
MAIN GRID POWER TRANSFER SCHEDULED BY THE DMO

Time (h)	1	2	3	4	5	6
Power (MW)	0.70	5.60	4.90	5.60	6.30	5.60
Time (h)	7	8	9	10	11	12
Power (MW)	4.90	5.60	6.30	4.90	5.60	5.60
Time (h)	13	14	15	16	17	18
Power (MW)	6.30	5.60	6.30	7.00	8.40	9.80
Time (h)	19	20	21	22	23	24
Power (MW)	11.20	10.50	9.80	7.70	6.30	5.60

TABLE 3.2
DER SCHEDULE CONSIDERING 1-HOUR ISLANDING

Unit	Hours (1-24)																						
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	**1**	**1**
G3	1	**1**	**1**	**1**	**1**	0	0	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	0	0
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	0	0	0

The problem is further solved for a variety of islanding hours to show the impact of the number of islanding hours on the microgrid scheduling results. The operation cost for all cases is shown in Fig. 3.1. The load curtailment is added to the objective as a penalty term with a cost of \$10,000/MWh. As the duration of islanding increases, a larger portion of loads needs to be curtailed. This factor together with increasing need for generation of dispatchable units increases the total operation cost.

Sensitivity to the scheduled main grid power transfer is analyzed by considering a reduced 100 scenarios. Fig. 3.2 shows the operation cost when the main grid power transfer is a fraction of values in Table 3.1. Increasing main grid power transfer would lessen the need to microgrid generation and may accordingly cause some dispatchable units that were already committed to be turned off at some hours, thus it would decrease the operation cost. In case an islanding happens at these hours, since there are fewer units committed and available to generate, there might be more load curtailment. When the power transfer is relatively low, the number of units that turn off is relatively few and even if they turn off at some hours the overall reduction in the generation cost outweighs the increase in load curtailment cost at some scenarios with islanding at those hours. For example, when the power transfer is increased from 0.35 times of values in Table 3.1 to 0.5, G3 is turned off at hour 7, load curtailment cost increases from \$992 to \$1,814 and generation cost reduces from \$66,560 to \$60,362.

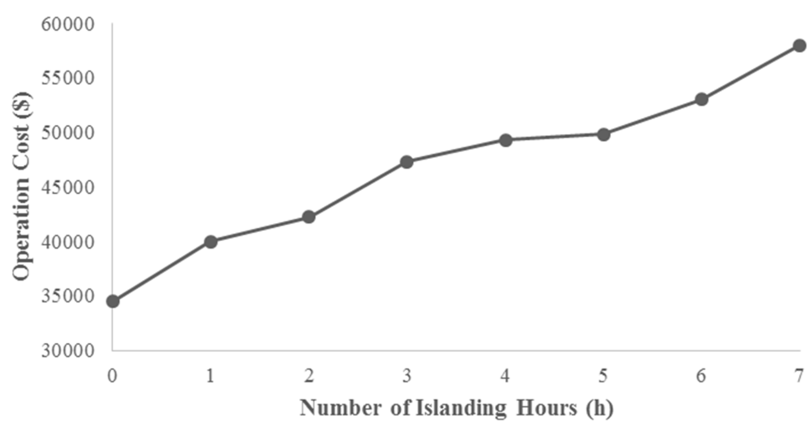

Figure 3.1 Microgrid operation cost as a function of number of islanding hours

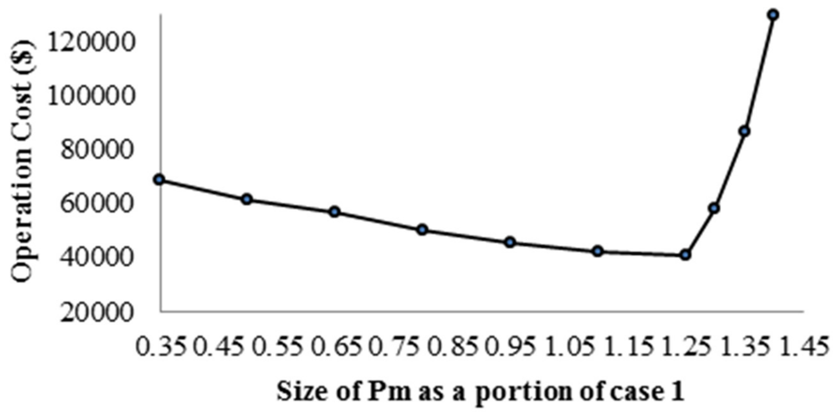

Figure 3.2 Microgrid operation cost as a function of main grid power transfer

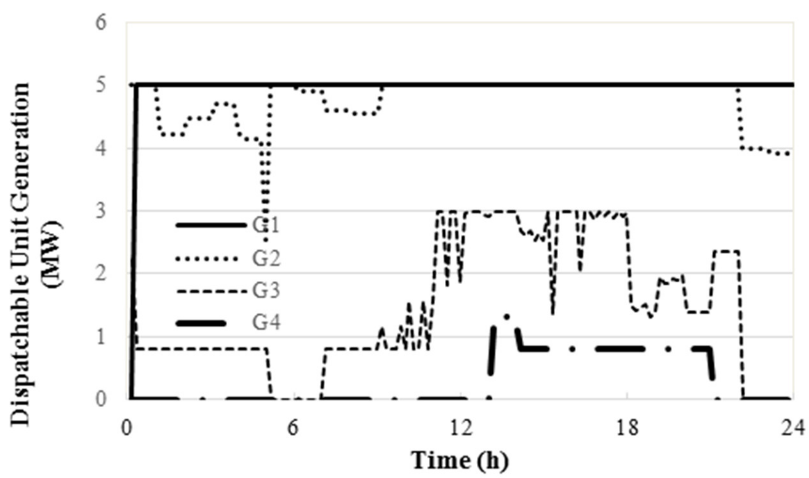

Figure 3.3 Generation of different dispatchable units at a scenario with islanding between hours 12-14

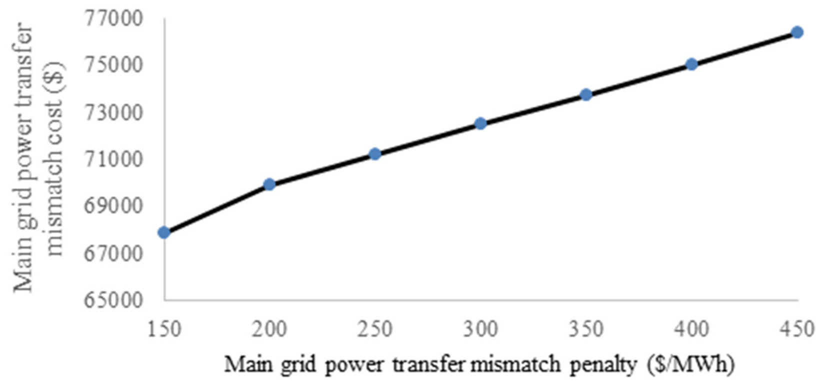

Figure 3.4 Microgrid operation cost with different penalties for excess main grid power transfer.

As the power transfer increases, however, previously committed units are turned off at more hours and therefore load curtailment cost for scenarios with islanding could increase. When the main grid power transfer is increased from 1.25 times values in Table 3.1 to 1.4, some units are turned off at high load hours 19-21 and 23 leading to load curtailment cost increasing from $4,131 to $11,0694 while generation cost reduces from $37,029 to $32,235. With a smaller main grid power transfer, dispatchable units are committed at more hours but generate at the minimum power in the normal operation. Fig. 3.3 shows the generation of different dispatchable units for a scenario where islanding occurs between hours 12 and 14.

Up to this point, all simulations were conducted for the microgrid with an infinite power transfer mismatch penalty. Enabling the microgrid with the capability to increase its main grid power transfer beyond the amount assigned to it by the DMO and instead paying a penalty would eliminate the load curtailment that otherwise might have been needed. This feature reduces the operation cost significantly. Fig. 3.5 depicts the increase in operation cost as this penalty increases. It is seen that with lower penalties for transferring additional amounts of main grid power than scheduled, the total operation cost of the microgrid drops.

CHAPTER FOUR: DISTRIBUTION MARKET OPERATION

4.1 Introduction

Previous chapter discussed the microgrid optimal scheduling problem from the microgrid central controller perspective. In this chapter, the same problem is considered in the broader DMO perspective. The three levels of the market structure discussed in chapter 2, are formulated in this chapter to provide an insight on the data exchange, represent optimization problems involved in different levels, and further enable numerical studies on microgrids scheduling.

4.2 Market-Based Microgrid Optimal Scheduling Problem Formulation

4.2.1 Microgrid

Microgrids determine the least-cost day-ahead schedule of their loads, dispatchable generation units, and energy storage considering a known profile for the main grid power transfer, which is determined and assigned by the DMO, over the scheduling horizon. Each microgrid *m* solves the proposed market-based optimal scheduling problem (4.1)-(4.10):

$$\min \sum_t \sum_i [F_{im}(P_{imt}, I_{imt}) + \upsilon_m LS_{mt} + \nu_m \Delta P_{mt}^{M+}] \qquad (4.1)$$

$$P_{mt}^{M} + \sum_i P_{imt} + LS_{mt} = d_{mt} \qquad \forall t \qquad (4.2)$$

$$P_{im}^{\min} I_{imt} \le P_{imt} \le P_{im}^{\max} I_{imt} \qquad \forall t, \forall i \qquad (4.3)$$

$$\sum_t P_{imt} = E_{im} \qquad \forall t \qquad (4.4)$$

$$\sum_t f_{im}(P_{imt}, I_{imt}) \le 0 \qquad \forall i \qquad (4.5)$$

$$-P_m^{M,\max} U_{mt} \le P_{mt}^M \le P_m^{M,\max} U_{mt} \qquad \forall t \qquad (4.6)$$

$$\Delta P_{mt}^M = P_{mt}^M - PD_{mt}^M \qquad \forall t \qquad (4.7)$$

$$-P^{M,\max}\delta_{mt} \le \Delta P_{mt}^{M+} \le P^{M,\max}\delta_{mt} \qquad \forall t \qquad (4.8)$$

$$-P^{M,\max}(1-\delta_{mt}) \le \Delta P_{mt}^M - \Delta P_{mt}^{M+} \le P^{M,\max}(1-\delta_{mt}) \qquad \forall t \qquad (4.9)$$

$$-P^{M,\max}(1-\delta_{mt}) + \varepsilon \le \Delta P_{mt}^M \le P^{M,\max}\delta_{mt} \qquad \forall t \qquad (4.10)$$

The three terms in the objective function (4.1) represent the operation cost, the load curtailment cost, and the deviation cost, respectively. The operation cost is the cost of power production as well as startup and shut down costs of dispatchable units. The load curtailment cost is defined as the value of lost load times the amount of load curtailment. The value of lost load is assumed as an opportunity cost based on the cost that the consumer is willing to pay to have reliable uninterrupted service. It is commonly used as a measure of load criticality [47]. The deviation cost is the penalty imposed on the microgrid in case the microgrid schedule deviates from the power transfer assigned by the DMO. The objective is subject to a set of operational constraints (4.2)-(4.10). The power balance equation (4.2) ensures that the sum of the main grid power plus the locally generated power from DERs matches the total load, while load curtailment variable is added to ensure that the power balance is satisfied at all times. Nondispatchable generation and fixed load values are assumed to be forecasted with acceptable accuracy and are treated as uncontrollable parameters. There of course would be uncertainties associated with possible forecast errors, which will be studied in a follow-on work. All operational constraints associated with DERs and loads are formulated using three general constraints (4.3)-(4.5), respectively representing power constraints, energy constraints, and time-coupling constraints. Power constraints (4.3) account for power capacity limits, such as dispatchable generation minimum/maximum capacity limits, energy storage minimum/ maximum charge/discharge power, and flexible load minimum/maximum capacity limits. Energy constraints (4.4) account for energy characteristics of a specific DER or load, such as energy storage state of charge limit and flexible load required energy in a cycle. Time-coupling constraints (4.5) represent any constraint that links variables in two or more scheduling hours, such as dispatchable units ramp up/down rates and minimum on/off times, energy storage rate and profile of charge/discharge, and adjustable loads minimum operating time and load pickup/drop rates. Using these constraints, any type of DER and load can be efficiently modeled. A detailed modeling of microgrid DERs and loads can be found in [48]. The main grid power transfer is restricted by its associated limits (imposed by the capacity of the line connecting the microgrid to the main grid) in (4.6). The islanding is modeled using a binary islanding indicator U which would zero out the main grid power transfer when 0. The main grid power deviation to be penalized in the objective is determined in (4.7)-(4.10). Constraint (4.7) calculates the deviation by subtracting the scheduled power via the optimal scheduling, P^M, by the assigned power from the DMO, PD^M. Constraints (4.8)-(4.10) determine the penalty if the calculated deviation is positive. An auxiliary binary variable δ is used for this purpose. When δ=0 the power transfer to be penalized is zero, i.e., the scheduled power is less than the assigned power. However, when δ=1 the power transfer to be penalized is equal to the positive deviation calculated in (4.7).

4.2.2 DMO

The DMO has two objectives: first, to combine individual bids received from microgrids in its territory to create an aggregated bid and accordingly send the aggregated bid to the ISO to participate in the energy market; second, to disaggregate the awarded quantity by the ISO to individual microgrids in accordance with their respective bids. These two tasks are discussed in the following:

Bid aggregation: Fig. 4.1 depicts a typical demand bid curve submitted by a microgrid to the DMO at a specific hour t. The bid consists of fixed and variable parts. The fixed part shows the microgrid nonresponsive load which must be fully supplied under normal operation conditions and cannot be altered. The variable part, on the other hand, shows the microgrid flexibility in reducing its consumption from its total load. It consists of several segments. The reduction in consumption can be achieved either via load curtailment or local DER generation. The DMO combines the individual microgrid bids and obtains an aggregated bid to be sent to the ISO. The fixed loads are collectively added to obtain the total fixed load in the DMO service territory (4.11).

$$D_t^f = \sum_m d_{mt}^f \qquad \forall t \qquad (4.11)$$

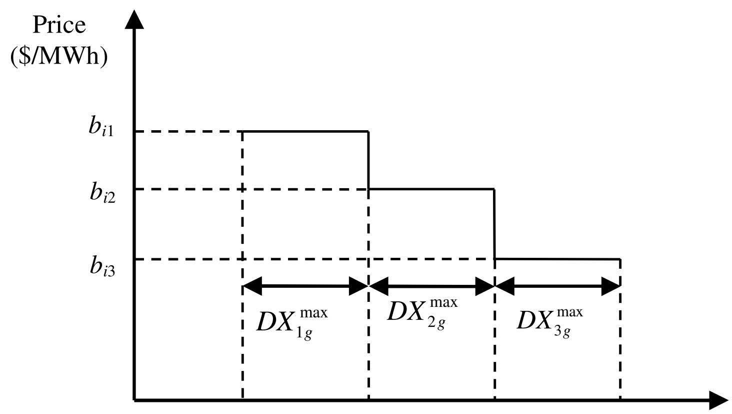

Fig. 4.1 Demand bid curve for microgrid *m* with a three-segment bid.

Quantity disaggregation: Once the ISO determines the awarded power to the DMO, the DMO disaggregates the power to microgrids in its service territory. The DMO maximizes the objective function (4.12) by determining the optimal allocated power to each microgrid based on the submitted bids.

$$\max \sum_t \sum_m \sum_j c_{mj} DX_{mjt} \tag{4.12}$$

$$DX_{mjt} \le DX_{mj}^{\max} \qquad \forall m, \forall t, \forall j \tag{4.13}$$

$$d_{mt}^r = \sum_j DX_{mjt} \qquad \forall m, \forall t \tag{4.14}$$

$$d_{mt}^f + d_{mt}^r = PD_{mt}^M \qquad \forall m, \forall t \tag{4.15}$$

$$\sum_{m} PD_{mt}^{M} = D_{bt} \qquad \forall t \qquad (4.16)$$

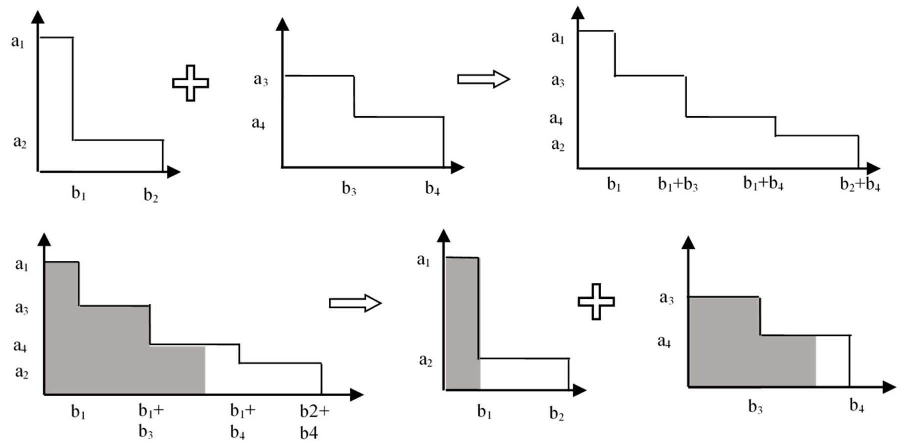

Fig. 4.2 An example of DMO aggregating two submitted bids (top), and disaggregating awarded power (bottom). Vertical and horizontal axes show price and load, respectively.

Constraint (4.13) guarantees that each segment of load is limited by its maximum. The total responsive demand for each microgrid is the sum of the loads dispatched to each associated segment (4.14). The awarded load is calculated as the summation of the fixed and responsive loads (4.15), and accordingly, the amount of power flow from the ISO to the DMO as the summation of the awarded loads is set by (4.16) as the total load dispatched to all load segments is equal to the assigned power by the ISO. Fig. 4.2 provides a graphical representation of the bid aggregation and quantity disaggregation by the DMO. The distribution line limits in this model are assumed to be adequately large to handle any power transfer without causing congestion in the distribution network. Additional constraints, however, can be simply added to the model, including but not limited to distribution line power flow and limits, ramp rate constraints, etc. Another important constraint that can be considered is the load shifting capability of microgrids. Modeling the load shifting would require the inclusion of time-coupling constraints among hourly bids. This topic is addressed for ISOs in previous work of authors [49]. For market-based microgrid optimal scheduling problem, however, load shifting will be considered in a follow-on research of this work.

4.2.3 ISO

The ISO receives the generation and transmission information from GENCOs and TRANSCOs, and demand bids from DMOs, solves the SCUC problem to determine units schedule followed by a security-constrained optimal power flow to determine unit dispatch, line flow, and LMPs. The ISO's objective, when considering demand bids, will be to maximize the system social welfare, rather than minimizing the total operation cost, as formulated in (4.17).

$$\max\left\{\sum_t \sum_b \lambda_{bt}(D_{bt}) - \sum_t \sum_i \rho_{it}(P_{it})\right\} \tag{4.17}$$

$$\sum_{i\in G_b} P_{it} - \sum_{l\in L_b} PL_{lt} = D_{bt} \qquad \forall t, \forall b \tag{4.18}$$

$$P_i^{\min} I_{it} \le P_{it} \le P_i^{\max} I_{it} \qquad \forall t, \forall i \tag{4.19}$$

$$\sum_t P_{it} = E_i \qquad \forall t \tag{4.20}$$

$$\sum_t f_i(P_{it}, I_{it}) \le 0 \qquad \forall t, \forall i \tag{4.21}$$

$$|PL_{lt}| \le PL_l^{\max} \qquad \forall t, \forall l \tag{4.22}$$

$$PL_{lt} = \sum_b \frac{B_{lb}\theta_{bt}}{x_l} \qquad \forall t, \forall l \tag{4.23}$$

The ISO maximizes objective function (4.17) which is the system social welfare, i.e., consumption payments minus generation costs. This objective is subject to the power balance constraint (4.18), unit constraints (4.19)-(4.21), transmission line limits (4.22), and transmission line power flow (4.23). Unit constraints include unit output limits, unit spinning/operating reserve limit, ramp up/down rate limits, min up/down time limits, fuel limits, and emission limits. Details of the SCUC model can be found in [49].

4.3 Numerical Simulations

The proposed market-based microgrid scheduling model is studied and compared with the price-based scheduling using the IEEE 118-bus standard test system (shown in Fig. 4.3). A total of 5 microgrids are considered to be connected to bus 60 with a total installed DG capacity of 50 MW which is equal to 51% of the peak load at this bus. The specifications of microgrid DGs are given in Table 4.1. Specifications of adjustable loads, energy storage, and fixed loads are borrowed from [48]. Two cases are considered as follows:

Case 1: Price-based microgrid optimal scheduling.

Case 2: Market-based microgrid optimal scheduling.

Case 1: In this case, the ISO uses the forecasted microgrid loads to clear the market and accordingly determine hourly LMP values. Microgrids individually perform their own scheduling using the LMP values. With microgrids being connected to bus 60, five lines in the system including one of those connected to the bus 60 become congested at peak hours. The total microgrid operation cost is calculated as $74,447. In this case, the actual amount of load at the bus to which microgrids are connected will not match the amount originally considered by the ISO when clearing the wholesale market. If the ISO runs the economic dispatch with the actual microgrids net loads, which would be less than the microgrid load used initially by the ISO to determine the LMPs, the prices would change. This change in LMPs can be considered as a major drawback in the price-based model where there is a mutual and uncontrolled interaction between the calculated LMPs and microgrids net load. Another drawback that needs to be considered is that the mismatch between the initially forecasted load and the actual load, after microgrid optimal scheduling, needs to be addressed by the ISO by redispatching the committed units. The redispatch will potentially result in an economic loss for the system as the new solution will diverge from the already determined optimal dispatch solution.

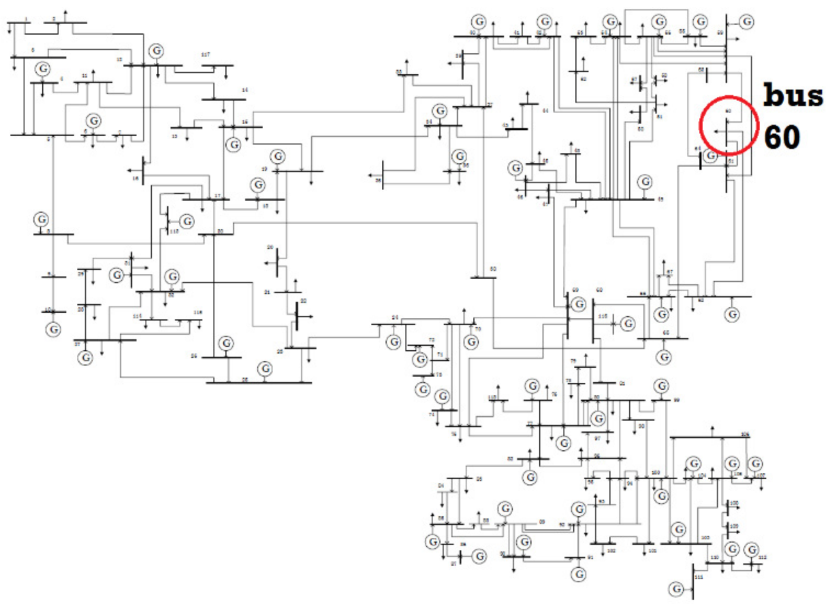

Fig. 4.3 IEEE 118-bus standard test system.

Case 2: The bid each microgrid sends to the DMO is created based on the capacity and marginal costs of its dispatchable DGs. For example, microgrid 2 will have a four-step bid: 1 MW at \$70.9/MWh, 1 MW at \$59.3/MWh, 3 MW at \$37.3/MWh, and 5 MW at \$29.1/MWh, as derived from Table 4.1. Using this bid, the demand responsiveness of the microgrid is modeled by local generation of dispatchable DGs. The total microgrid operation cost in this case is \$48,568 which shows 34.76% reduction from that of Case 1.

Table 4.2 shows the committed DGs in each microgrid, in which bold values represent changes from the price-based optimal scheduling solution in Case 1. This table indicates that many DGs committed in Case 1 are not committed in Case 2. In Case 1, microgrid lowers its power transfer as a response to the market price, therefore it has to commit more local resources to supply loads. DG1 of each microgrid is the most committed unit in both cases, since it has the lowest marginal cost compared to other DGs in the same microgrid.

Fig. 4.4 depicts the hourly net load at bus 60 to which microgrids are connected. It is observed that during the early hours the values of net load in the two cases are close. This is due to the low price of electricity during early hours, when a large portion of the submitted bid from the DMO is awarded by the ISO, resulting in a power transfer close to the total load of the microgrids. In Case 1, the entire demand is supplied by the main grid for the same reason. At hours 8-24, as the electricity price increases, the microgrids loads are partially supplied by local DGs.

TABLE 4.1

COST CHARACTERISTICS OF DG UNITS

	CAPACITY (MW)				
	MG1	MG2	MG3	MG4	MG5
DG1	4	5	3	4	3
DG2	3	3	3	3	3
DG3	2	1	2	2	2
DG4	1	1	2	1	2
	PRICE ($/MWh)				
DG1	27.5	29.1	27.4	28.3	33.5
DG2	43.1	37.3	38.2	35.3	41.1
DG3	64.3	59.3	55.2	60.3	65.5
DG4	69.6	70.9	61.1	62.4	72.2

TABLE 4.2
THE COMMITMENT SCHEDULE OF MICROGRID DGS

		1-24																							
MG 1	DG1	1	1	1	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	DG2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DG3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DG4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MG 2	DG1	0	0	0	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	DG2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0
	DG3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DG4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MG 3	DG1	1	1	1	1	1	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	DG2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0
	DG3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DG4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MG 4	DG1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	DG2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0
	DG3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DG4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MG 5	DG1	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	1	1	1	0	0	0	0
	DG2	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0
	DG3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DG4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fig. 4.5 depicts the hourly LMP at bus 60, i.e. the electricity price for the power transferred to the DMO. Case 2 represents a significantly lower price in peak and close to peak hours, which accordingly results in fewer DG commitments, as it is more economical to purchase power from the main grid, and a lower operation cost. Accordingly the microgrid net load is increased in this case. Fig. 4.6 depicts the average LMP of all buses in the system. The values for market-based model are close to or lower than the values for the price-based model except for hours 13 to 22. This result advocates that although the market-based scheduling may result in lower LMPs for microgrids, it may not necessarily reduce the system LMP on other network buses. The total system operation cost is reduced

from \$1,074,504 in the price-based model to \$1,009,734 in the market-based model. To identify the changes in values/trends of LMPs, when such a market is available at all network buses, is worth further investigation.

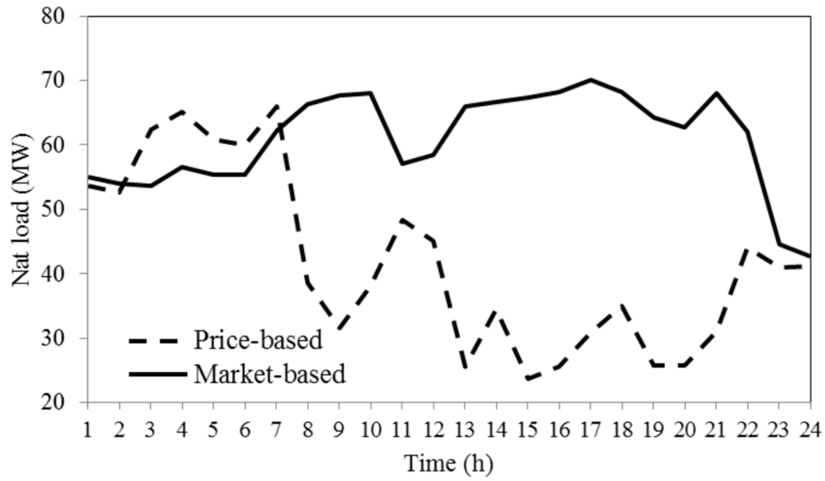

Fig. 4.4 Net load at bus 60

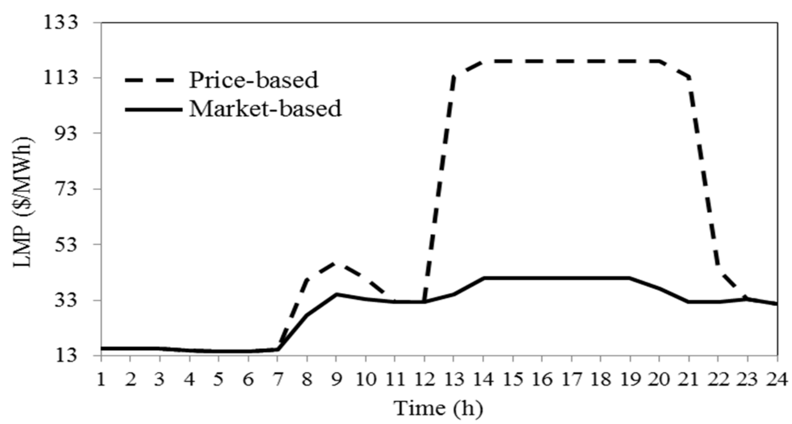

Fig. 4.5 LMP at bus 60

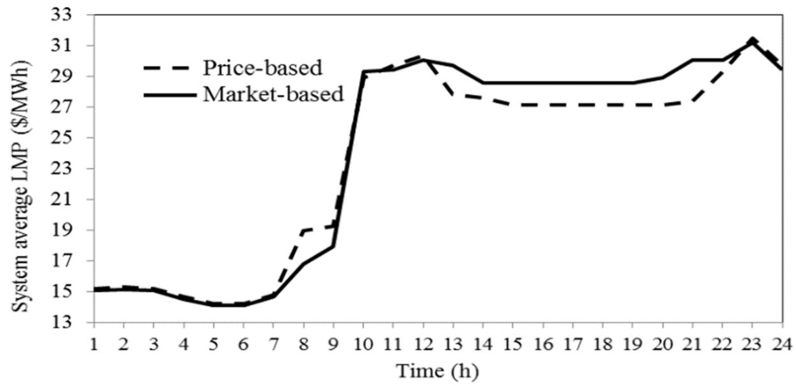

Fig. 4.6 Average LMP of 118-bus system

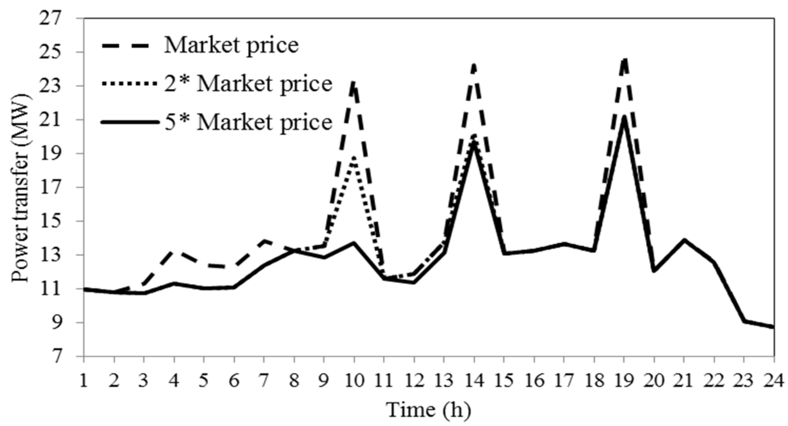

Fig. 4.7 Power transfer to microgrid 3 at different levels of deviation penalties.

To demonstrate the viability of the proposed deviation reduction method and ensuring that microgrid will follow the DMO assigned power transfers, the impact of the power transfer deviation penalty is further studied. Fig. 4.7 depicts the main grid power transfer to a selected microgrid (Microgrid 3) at different levels of deviation penalties. It is assumed that the forecasted microgrid load increases twofold at hours 10, 14 and 19.

Penalties equal to the market price, two times the market price, and five times the market price are considered. The cost of power transfer deviations are respectively calculated as \$2,053, \$1,777 and \$3,170. As the penalty increases, the amount of deviation from assigned power decreases but the deviation cost does not change linearly. The microgrid total operation cost will however decrease. Thus it can be seen that higher penalties reduce the amount of deviation to reach the desired values. However, when the penalty becomes too high (comparable to the VOLL) microgrids may prefer to curtail some loads rather than paying for the penalty in purchasing power from the main grid.

In order to further show the impact of power deviation penalty on the scheduling solutions, two scenarios are considered; in the first scenario the microgrid is scheduled based on a price-based scheme after receiving the prices determined by the DMO; in the second scenario the absolute value of the power deviation, instead of only the positive deviation, is penalized. The microgrid operation cost reduces to \$47,380 using price-based scheduling, as the microgrid reduces the power purchase from the main grid at the peak hours and uses its own resources that become price competitive at those times. When the absolute value of the deviations is penalized, the total microgrid operation cost rises to \$50,539, as microgrid is obligated to closely follow the scheduled power transfer and hence would reduce generation of some its resources to purchase more power from the main grid, which results in a higher operation cost. This shows that penalizing power deviation is key to ensuring certainty in the power scheduled by the DMO. Penalizing the absolute value of power deviation can increase the microgrid operation cost, even if the power deviation would result in a surplus of power which is manageable by the system operator. The decision to penalize only the positive deviations or the absolute deviation should be made by the distribution system operator based on the probable congestion scenarios.

CHAPTER FIVE: DISTRIBUTION MARKET CLEARING AND SETTLEMENT

5.1 Introduction

In this chapter, the market clearing and settlement by DMO is discussed. Two alternatives are considered for market clearing and the results for each are provided and compared. Market settlement is calculated to payments by the customers and generators is determined.

5.2 Distribution Market Clearing

Proactive customers in the distribution system offer their demand bid to the DMO. A typical bid consisting of three segments is depicted in Fig. 5.1. The DMO combines the individual bids and sends an aggregated bid to the ISO to be considered in the wholesale market. Once the ISO receives load bids (from DMOs) and generation bids (from GENCOs) it solves the security-constrained unit commitment and economic dispatch problems to determine the optimal unit and load schedules as well as locational marginal prices in the transmission level (T-LMP). The obtained schedule and prices are accordingly announced to DMOs and GENCOs. Each DMO would need to divide this assigned power among proactive customers in its service territory, i.e., it would "clear" the distribution market.

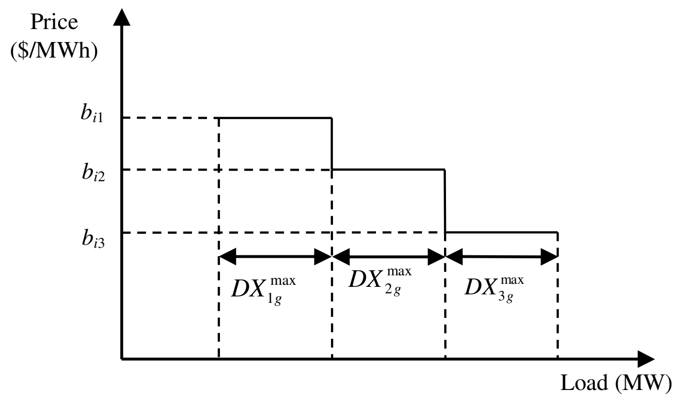

Fig. 5.1 Demand bid curve for customer at bus *i* with a three-segment bid

In doing so, the DMO seeks to maximize the distribution network social welfare, i.e., load benefits minus generation cost (which is the cost of assigned power from the main grid), as proposed in (5.1).

$$\max \sum_t \sum_i \sum_g b_{ig} DX_{igt} - \sum_t \lambda_t P_t^M \tag{5.1}$$

This objective is subject to distribution network and proactive customers prevailing constraints (5.2)-(5.6):

$$\sum_l a_{lm} PL_{lt} = D_{mt}^f + D_{mt}^r \qquad \forall t, \forall m \tag{5.2}$$

$$\sum_l a_{l0} PL_{lt} - P_t^M = 0 \qquad \forall t \tag{5.3}$$

$$D_{mt}^r = \sum_g DX_{mgt} \qquad \forall t, \forall m \tag{5.4}$$

$$0 \le DX_{mgt} \le DX_{mg}^{\max} \qquad \forall t, \forall m, \forall g \tag{5.5}$$

$$-PL_l^{\max} \le PL_{lt} \le PL_l^{\max} \qquad \forall t, \forall l \tag{5.6}$$

The power balance at each bus is ensured by (5.2) in which the power injected to each bus from connected lines is equal to the summation of loads from passive and proactive customers. The power balance at the bus connecting the distribution network to the upstream transmission network is ensured by (5.3) in which the power transferred by the main grid is distributed among lines connected to this bus (here the bus number 0). The load of passive customers will be constant, while that of proactive customers is variable and defined by (5.4). The scheduled load of proactive customers is determined based on the scheduled power consumption in each bud segment, in which each segment is limited by its associated maximum capacity (5.5). Line power flows are limited by the line capacity limits (5.6). Since the distribution network is considered to be radial, a viable distribution power flow can be guaranteed by simultaneously considering (5.2), (5.4), and (5.5).

The proposed market clearing model can be solved based on two completely different assumption which are based on the market design: constant power and variable power, as discussed in the following:

5.2.1 Constant Power Clearing

The quantity of the power assigned by the ISO to the DMO is determined via the wholesale market clearing and announced to the DMO, hence it is constant. The LMP at the distribution bus is also determined by the ISO, thus the second term in (5.1) is constant and can be omitted from the proposed model. In this case, the DMO would distribute the assigned power to proactive customers via the proposed market clearing model. One issue that needs to be considered here is that the T-LMP does not appear in the optimization problem, hence the calculated distribution locational marginal prices (D-LMPs) can be potentially different from the T-LMP.

5.2.2 Variable Power Clearing

In this case the DMO will schedule distribution resources based on the T-LMP determined by the ISO, however, it can deviate from the assigned power, i.e., it can purchase variable amount of power from the main grid. Therefore in the objective function (5.1), the main grid power P_t^M is considered a variable whose value is to be determined in the optimization problem, rather than a parameter set by the ISO and given as a fixed value to the DMO. The variable power clearing model has been discussed in the literature [48][49]. Although straight-forward and easy to implement, as it utilizes the same model as ISO uses for the wholesale market clearing, this model bring about the risk of causing new peaks in the grid. When the prices are low, all customers would tend to purchase more power than they would have purchased if the prices were lower, and this would create a shortage of power. On the other hand, if the prices are too high, the customers would tend to use their own local generation to supply their load, hence creating a potential surplus. All these possible responses result in market uncertainties, hence reducing the benefits of implementing a distribution market.

5.3 Distribution Market Settlement

The DMO determines the D-LMPs for each distribution bus in each operation time period as a byproduct of the market clearing process. The D-LMP in each bus is calculated as the dual variable of the power balance equation in that bus (5.2). Using D-LMPs the market can be settled, i.e., the payments from customers and the payments to the main grid can be determined. The payment of each customer is calculated as the D-LMP times the associated load. The total customer payments is the summation of all payments as proposed in (5.7), in which D_{mt} includes both passive and proactive customers' loads. The payment to the utility is calculated as the T-LMP times the assigned power by the ISO (5.8). Since losses are ignored in the proposed market clearing model, the sum of the distribution loads will be equal to the total power assigned by the ISO (5.9).

$$C_c = \sum_t \sum_m \lambda_{mt}^D D_{mt} \tag{5.7}$$

$$C_u = \sum_t \lambda_t P_t^M \tag{5.8}$$

$$P_t^M = \sum_m D_{mt} \qquad \forall t \tag{5.9}$$

Considering the payments, the DMO cost surplus can be calculated as the difference between the two calculated payments as in (5.10):

$$C_\Delta = C_c - C_u = \sum_t \sum_m (\lambda_{mt}^D - \lambda_t) D_{mt} \tag{5.10}$$

The obtained C_Δ can be negative, positive, or zero, based on the calculated payments. The existing DMO proposals currently lack the required mechanisms, similar to what exists for the ISOs (such as auction revenue right and financial transmission right mechanisms) [50], to ensure that the cost surplus will reach zero by efficiently distributing the surplus earning to customers. This issue can potentially be a major concern regarding the fairness of the DMOs which is worthy of further investigation.

5.4 Numerical Simulation

The IEEE 13-bus test system [51] in used to investigate the viability and the merits of the proposed distribution market clearing and settlement processes. Fig. 5.2 depicts this system in which proactive customers are located at buses 2, 3, 5-7, and 10- 13.

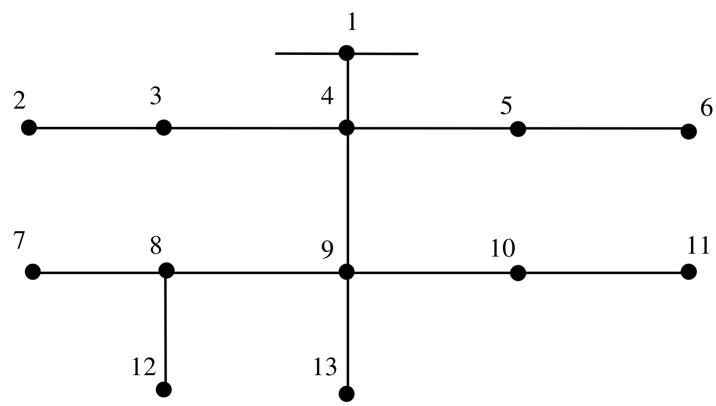

Fig. 5.2 IEEE 13-bus standard test system.

Three cases are considered: Case 1: Variable power market clearing and settlement; Case 2: Constant power market clearing and settlement ignoring line flow limits; and Case 3: Constant power market clearing and settlement considering line flow limits.

Case 1: Fig. 5.3 shows the hourly average D-LMP and the hourly T-LMP at the point of connection to the main grid. As shown, the D-LMPs are higher than the T-LMP in most of the hours, which is a result of the congestion in lines 5-6 and 8-7. As the prices increase, there will be a reduction in the amount of power purchased from the main grid, hence the congestion will be eliminated, and accordingly, D-LMPs and the T-LMP become equivalent. This situation happens in hours 2, 13, 14, and 16. In this case, the DMO receives

$2034 from customers while paying $1900 to the ISO. The cost surplus of $134 is due to the congestion in the distribution network which needs to be distributed among customers.

Case 2: Fig. 5.4 depicts an example profile of the power assigned to the DMO via the wholesale market. The D-LMPs are determined via the distribution market clearing with constant power and based on the load bids submitted by proactive customers as $0.355/MWh. Using the given power profile, no lines are congested (resulting in equal D-LMP in all buses), the load payment is calculated as $2148, and the payment to the main grid is calculated as $2046 ($102 surplus).

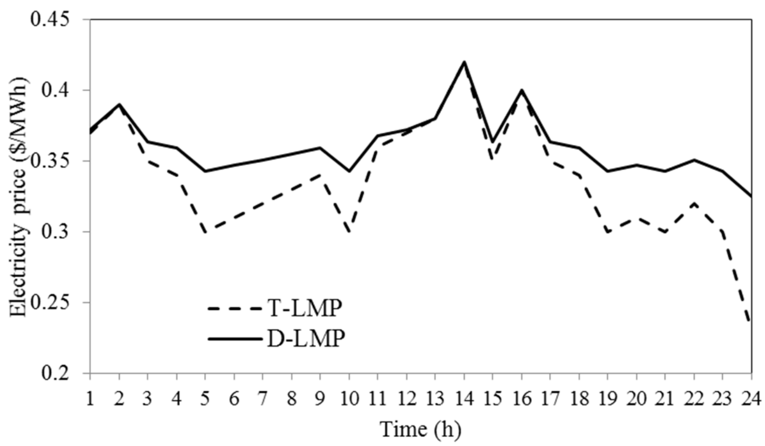

Fig. 5.3 LMP at the bus connected to high voltage system (T-LMP), and average of LMP at distribution system busses (D-LMPs).

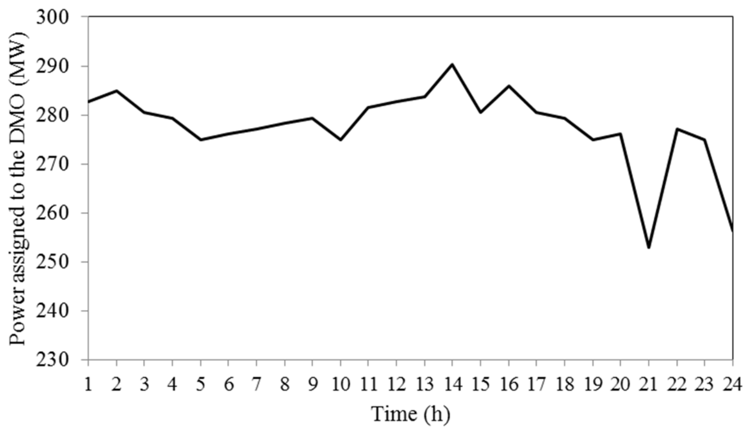

Fig. 5.4 The schedule of power assigned to the DMO over the 24-hour horizon.

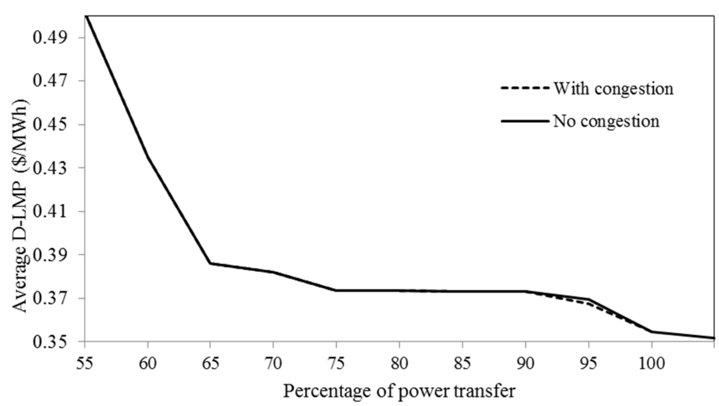

Fig. 5.5 Average D-LMPs across the distribution network buses as a function of total assigned power.

Case 3: Fig. 5.5 shows that the average D-LMPs in the distribution network decrease as the amount of assigned power increases. Customers located at buses 10 and 13 are offering higher bids to purchase power. When line 4-9 becomes congested, the loads awarded to those customers decrease and since the bid is monotonically decreasing, the prices at those buses increase. D-LMPs at buses upstream this line similarly decrease, as they will be awarded more power. Table 5.1 lists the average D-LMPs at distribution buses over the 24 hour horizon in this case. Lines 5-6 and 4-9 are congested, thus D-LMPs at buses downstream these lines (i.e., buses 6-13) have increased.

Table 5.1

Average D-LMPs at Distribution Buses

Bus	2	3	4	5	6	7	8	9	10	11	12	13
Price ($/MWh)	0.278	0.278	0.278	0.278	0.353	0.373	0.373	0.373	0.373	0.373	0.373	0.373

When the power assigned to the DMO is similar to Fig. 5.4, the customers' payment to the DMO is $2134 and the payment to the ISO is $2046 ($88 surplus). If the assigned power is increased by 10%, the customers' payment to the DMO will be $2209, and the payment to the ISO will be $2250 ($41 surplus). This result advocates that the payment to the DMO under constant power clearing model is subject to the amount of assigned power, and independent from the T-LMP. The DMO cost surplus also can considerably change as the assigned power changes.

CHAPTER SIX: DISTRIBUTION MARKET PRICING

6.1 Introduction

One of the important issues in operation distribution markets is choosing the proper pricing mechanism to ensure attributing optimal valuation of the resources and services. Because of market clearing by the DMO, a variety of pricing mechanisms for the distribution market may be considered. Depending on the type of mutual transactions between the DMO and the ISO, distribution locational marginal prices (D-LMP) can be either coupled or independent of LMPs at point of interconnection to the transmission system. In the market-based scheduling approach to distribution resource scheduling, here proactive customers, where DMOs submit the aggregate bid of microgrids to the ISO and get awarded according to it, D-LMPs would be independent of transmission LMPs and would be functions of bids submitted by participants in the distribution market. However, in the price-based approach where proactive customers schedule their loads according to the day-ahead prices announced by the ISO, transmission LMPs would be reflected in the D-LMPs [52], [53].

A game theory-based method is utilized in [54] to allocate the losses resulted by the integration of distributed resources among the participants to calculate the D-LMP. A three-phase current injection method is used in [55] to calculate D-LMPs. Decentralized approaches like dynamic tariff have been used in [56] to manage congestion in the distribution system. Authors in [57] propose methods to study formation of D-LMPs in radial distribution systems. Approaches used in these works are commonly based on nonlinear models, and/or ignore the impact of losses and reactive power on the marginal prices.

The radial topology of the distribution system would cause the D-LMPs to ascend as it goes downstream the feeder. This means that it is likely for certain customers located at the end of the feeders to be subject to higher prices although they have not had any roles in creating line congestions. One of the other major differences between the distribution and transmission systems is the difference in voltages at different locations within the distribution system. In the transmission system, voltage levels are generally around 1 p.u., making it possible for the optimization of unit commitment and economic dispatch to utilize DC power flow models, as this assumption does not pose any major challenges to the accuracy of the final solution. This is not the case in the distribution system, as low levels of X/R ratio require voltages to be considered as variables in the power flow calculations in order to achieve accurate solutions [58]. These challenges unique to the distribution system make the pricing more complex compared to the transmission systems where mesh networks provide multiple paths for the flow of power, making the congestion management less concerning and more flexible.

In this chapter, first interdependency of transmission and distribution pricing is discussed. Then a more advanced pricing mechanism considering reactive power is introduced.

6.2 Interdependency of Transmission and Distribution Pricing

This section focuses on how the locational marginal prices in the transmission side of the DMO (i.e., T-LMP) are reflected in the distribution system locational marginal prices (i.e., D-LMP). Furthermore, microgrids will be considered for studies as a representative of proactive customers. Microgrids models, however, can be simplified to model any other type of the proactive customer, such as prosumers or responsive consumers.

The DMO's objective is to maximize the distribution system social welfare (6.1), i.e., load benefits minus generation cost (which is the cost of assigned power from the main grid). This section proposes to add the last term in the objective to penalize violations in the assigned power.

$$\max \sum_t \sum_m \sum_g b_{mg} DX_{mgt} - \sum_t \lambda_t P_t^M - \sum_t \mu \,|\, \Delta P_t^M \,| \tag{6.1}$$

The power assigned to the DMO by the ISO is determined via the wholesale market clearing, hence it is constant. The T-LMP is also determined by the ISO. The penalty coefficient μ is multiplied with the deviation to ensure that the assigned power will be followed in the distribution network. The objective is subject to distribution network and microgrids prevailing constraints (6.2)-(6.6):

$$\sum_l a_{lm} PL_{lt} = D_{mt} \qquad \forall t, \forall m \tag{6.2}$$

$$\sum_l a_{l0} PL_{lt} - P_t^M = 0 \qquad \forall t \tag{6.3}$$

$$D_{mt} = \sum_g DX_{mgt} + D_{mt}^f \qquad \forall t, \forall m \tag{6.4}$$

$$0 \le DX_{mgt} \le DX_{mg}^{\max} \qquad \forall t, \forall m, \forall g \tag{6.5}$$

$$-PL_l^{\max} \leq PL_{lt} \leq PL_l^{\max} \qquad \forall t, \forall l \qquad (6.6)$$

$$\Delta P_t^M = P_t^M - PD_t^M \qquad \forall t \qquad (6.7)$$

$$\Delta P_t^M = P_t^{pos} - P_t^{neg} \qquad \forall t \qquad (6.8)$$

$$|\Delta P_t^M| = P_t^{pos} + P_t^{neg} \qquad \forall t \qquad (6.9)$$

$$P_t^{neg} \geq 0 \qquad \forall t \qquad (6.10)$$

$$P_t^{pos} \geq 0 \qquad \forall t \qquad (6.11)$$

The nodal power balance is ensured in (6.2) where the power injected to each bus from connected lines is equal to total bus load. The power balance at transmission-distribution interface is ensured by (6.3) in which the power transferred by the main grid is distributed among lines connected to this bus (here the bus number 0). The load of passive customers will be constant, while that of proactive customers is variable and defined by the associated segments (6.4). The scheduled load of microgrids is determined based on the scheduled power consumption in each bid segment, in which each segment is limited by its associated maximum capacity (6.5). Line power flows are limited by the line capacity limits (6.6). The added penalty in the objective function, which is represented as the absolute value of the deviation makes the problem nonlinear. In order to linearize this term and to ensure a linear programming problem, (6.8)-(6.11) are used. P_t^{neg} and P_t^{pos} are two non-negative variables used to model the absolute value. If the variable inside the absolute value is positive, P_t^{neg} would be equal to zero and when the value is negative P_t^{pos}

would be equal to zero. This is guaranteed to happen since the problem is formulated as a linear programming minimization solved by the Simplex method.

The D-LMP in each bus is calculated as the dual variable of the power balance equation in that bus (6.2), i.e., as a byproduct of the proposed clearing problem. The relationship between the D-LMP and the T-LMP depends on the value of the penalty factor μ. In this section, the distribution market clearing is conducted in two ways based on the penalty factor: grid-following clearing and grid-independent clearing, as discussed further in the following:

6.2.1 Grid-Following Clearing

When μ=0 in the proposed formulation, the D-LMP at bus 0 of the distribution (point of connection to the transmission network) will be equal to the T-LMP. In this case the DMO is permitted to import power from the utility grid more/less than the power assigned to it by the ISO, as there would be no penalty. This results in the T-LMP to be reflected in the D-LMPs within the distribution system. At down-stream buses, however, D-LMPs will be determined based on the T-LMP, marginal cost of dispatchable units, and possible distribution line congestions.

6.2.2 Grid-independent Clearing

As the amount of μ is increased, the DMO seeks to minimize the deviation of the scheduled power with the assigned power transfer set by the ISO. In this case the dependency of D-LMPs to the T-LMP will be lowered. For the very large values of the penalty factor, there would be no violation of the power transfer schedule determined by the ISO, while the D-LMPs will be merely functions of the dispatchable units' marginal price and possible distribution line congestions.

6.2.3 Market Settlement

Using D-LMPs, obtained from either methods, the market can be settled, i.e., the payments from customers and the payments to the utility can be determined. The payment of each customer is calculated as the D-LMP times the associated load. The total customer payments is the summation of all payments (6.12), in which D_{mt} includes both consumers and microgrids. The payment to the utility is calculated as the T-LMP times the assigned power by the ISO (6.13). Since losses are ignored in the proposed market clearing model, the sum of the distribution loads will be equal to the total power assigned by the ISO (6.14).

$$C_c = \sum_t \sum_m \lambda_{mt}^D D_{mt} \tag{6.12}$$

$$C_u = \sum_t \lambda_t P_t^M \tag{6.13}$$

$$P_t^M = \sum_m D_{mt} \qquad \forall t \tag{6.14}$$

Considering the payments, the DMO cost surplus can be calculated as the difference between the two calculated payments as in 6.(15):

$$C_\Delta = C_c - C_u = \sum_t \sum_m (\lambda_{mt}^D - \lambda_t) D_{mt} \tag{6.15}$$

The obtained C_Δ can be negative, positive, or zero. The cost settlement is one of the challenges facing DMOs as they operate radial networks, as opposed to the wholesale power system operated by ISOs, and they should guarantee a fair market participation by customers at different locations across the feeders. This issue will be the topic of a future research by authors.

6.2.4 Numerical Results

The IEEE 13-bus test system [51] in used to investigate the viability and the merits of the proposed processes. Fig. 6.1 depicts this system in which microgrids are located at buses 2, 3, 5-7, and 10-13. Each customer submits a four-segment power demand bid of maximum 10 MW. A large capacity for distribution lines is considered, however it is assumed that lines 3-8 and 4-5 have smaller capacities and then subject to potential congestions. Various cases have been studied considering the various values for parameters in (1).

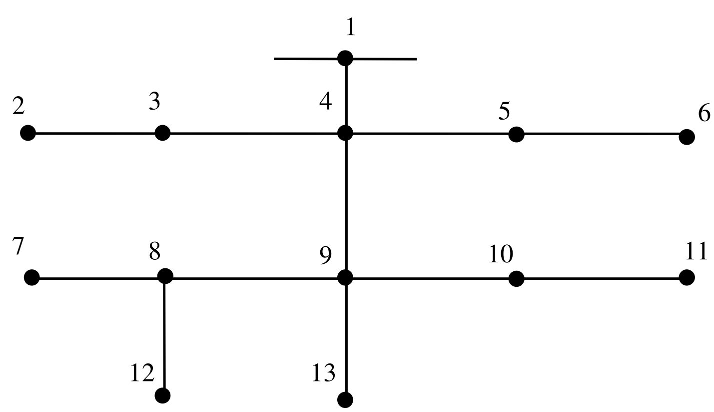

Fig. 6.1 IEEE 13-bus standard test system.

Case 1: In this case μ is assumed to be 0, and the distribution market clearing results for a variety of T-LMPs is determined. The results of this case are shown in Fig. 6.2, which illustrates the effect different values of the T-LMP on the marginal price of each bus in the distribution system. A scaling factor is used to change T-LMPs. As the scaling factor increases the power is to be purchased at a higher rate, resulting in a lower power transfer from the ISO and more local generation. This results in lower congestion as the prices of the all busses tend to be equal at higher values of the scaling factor. At lower T-LMP values, D-LMPs follow the T-LMPs and can also impact the grid prices as they respond to the price variations by modifying their power injections. At lower scaling factors, congestion at line 3-8 results in a rise of D-LMPs in buses 6-12. These buses have the same D-LMPs as the lines in the downstream of the feeder do not become constrained.

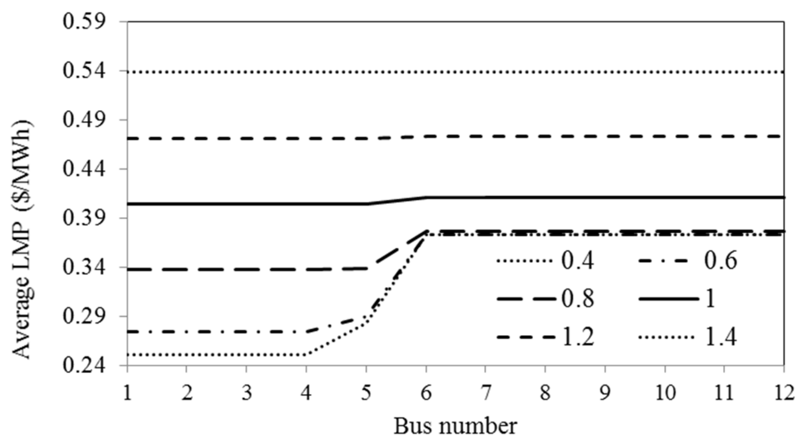

Fig. 6.2 Daily average LMP at each bus for different T-LMP values (using a scaling factor)

Case 2: In this case the second term in (6.1) is assumed to be 0, i.e., the T-LMP is negligible, and μ is varied, so the independent operation of the distribution market can be analyzed. The results of this case are shown in Fig. 6.3, which illustrates the effect of raising μ on D-LMPs. As μ increases, the DMO seeks to minimize the deviation from the assigned power transfer. The prices, however, tend to approach the prices when the scheduled power is used without any option to deviate. When μ approaches infinity, the D-

LMPs are functions of marginal prices of the dispatchable units and become independent of the T-LMPs. This would result in the settlement costs of the distribution system be higher, lower, or equal to the payments to the ISO depending on the marginal costs.

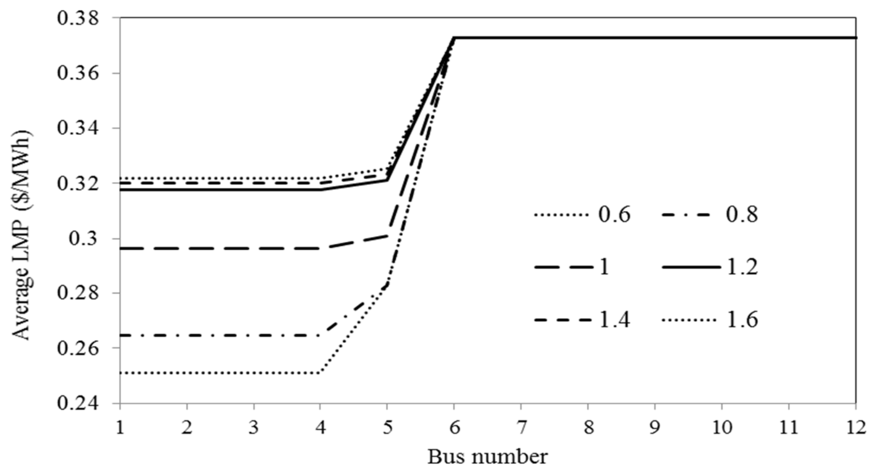

Fig. 6.3 Daily average D-LMP as a function of μ.

Case 3: In this case the T-LMP and μ are both nonzero. The results of this case are shown in Figs. 6.4 and 6.5. In Fig. 6.4, T-LMP scaling factor varies between 0.1 and 0.9 while μ is kept at 1. The corresponding difference between the customers' payment to the DMO and payment to the ISO is depicted in Fig. 6.5 (a deficit for the DMO). It means that while the DMO tries to minimize the deviation of the power transfer with respect to the scheduled power, a term exists in the objective that seeks to minimize the power transfer (even at the expense of higher deviation) to reduce the payments to the ISO.

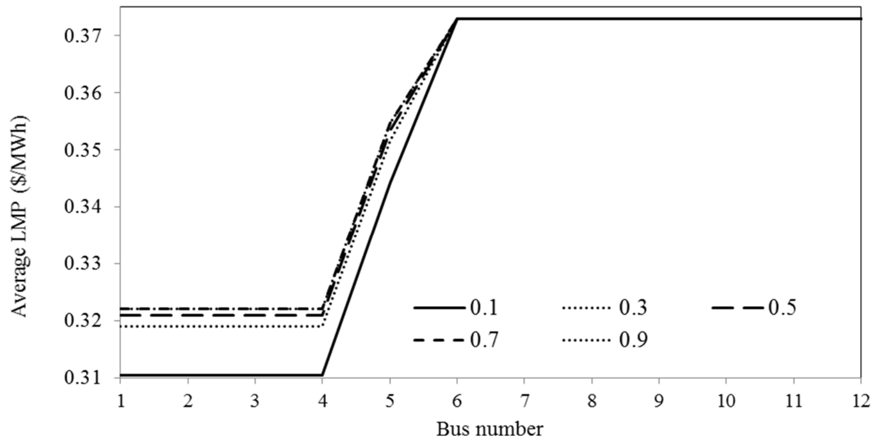

Fig. 6.4 Daily average D-LMPs as a function of scaling factors while μ =1.

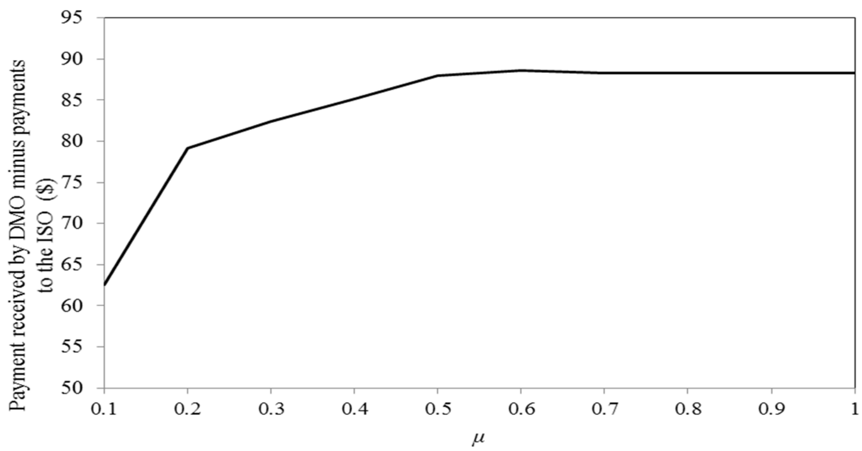

Fig. 6.5 Payment received by DMO minus payments to the ISO.

6.3 Active/Reactive Locational Pricing

In this section, a linearized power flow model is employed by the DMO to calculate the D-LMPs in a distribution system with responsive customers. The model considers bus voltages, system losses, and reactive power.

6.3.1 Power Flow Linearization

In this section a linearized power flow model is proposed to be used in the DMO market operation. The model allows taking losses and voltage magnitudes into account and provides a realistic model of the distribution system in comparison with existing work [24], [52]. The active and reactive power flow in line *mn*, from bus *m* to bus *n*, can be obtained from the following equations:

$$PL_{mn} = g_{mn}V_m^2 - V_mV_n(g_{mn}\cos(\theta_m-\theta_n)+b_{mn}\sin(\theta_m-\theta_n)) \tag{6.16}$$

$$QL_{mn} = -b_{mn}V_m^2 - V_mV_n(-b_{mn}\cos(\theta_m-\theta_n)+g_{mn}\sin(\theta_m-\theta_n)) \tag{6.17}$$

Since the voltage angles in adjacent buses within the distribution system are close, the trigonometric terms in the above equations can be simplified using the following equations:

$$\sin(\theta_m-\theta_n)\approx\theta_m-\theta_n \quad \text{and} \quad \cos(\theta_m-\theta_n)\approx 1 \tag{6.18}$$

Plugging these values in the power flow equations would result in simplified equations:

$$PL_{mn} = g_{mn}(V_m^2 - V_mV_n) - b_{mn}V_mV_n(\theta_m-\theta_n) \tag{6.19}$$

$$QL_{mn} = -b_{mn}(V_m^2 - V_mV_n) - g_{mn}V_mV_n(\theta_m-\theta_n) \tag{6.20}$$

Next step is to define new variables. As depicted in Fig. 6.7, the point of interconnection is assumed to be the reference bus, where voltage is assumed to be 1 pu and voltage angle is assumed to be 0 rad (any other values can be considered without loss of generality).

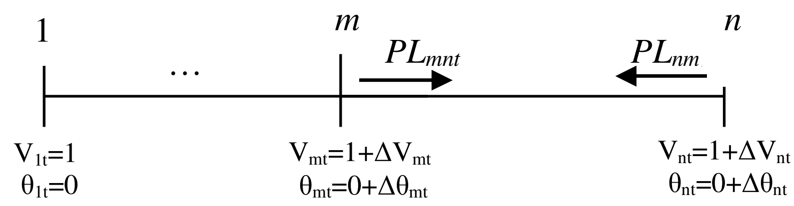

Figure 6.6 The line flow model.

The voltage at any bus can be written as a function of its voltage deviation with respect to the reference bus, as shown in Fig. 6.6. Using these new variables in the above equations would result in the following equations:

$$\begin{aligned} PL_{mn} &= g_{mn}(\Delta V_m - \Delta V_n) - b_{mn}(\Delta\theta_m - \Delta\theta_n) \\ &+ g_{mn}\Delta\hat{V}_m(\Delta V_m - \Delta V_n) \end{aligned} \tag{6.21}$$

$$\begin{aligned} QL_{mn} &= -b_{mn}(\Delta V_m - \Delta V_n) - g_{mn}(\Delta\theta_m - \Delta\theta_n) \\ &- b_{mn}\Delta\hat{V}_m(\Delta V_m - \Delta V_n) \end{aligned} \tag{6.22}$$

These equations offer linearized models, only if the last term in each can be linearized. To solve this problem, the power flow equations will be divided in two stages. In the first stage, the last term in (6.21) and (6.22) are ignored (i.e., $g_{mn}\Delta V_m(\Delta V_m\text{-}\Delta V_n)$ and $b_{mn}\Delta V_m(\Delta V_m\text{-}\Delta V_n)$) and the power flow is determined using linear equations. In the second stage, the calculated voltage magnitudes are used in the last terms of the line flow equations to offer fully linearized equations, i.e., $\Delta\hat{V}$ is fixed and known.

6.3.2 DMO Operation

The power flow model detailed in Section II is used in the DMO market clearing problem to determine the distribution system operation and obtain the optimal schedule for the local resources. This improves the models previously proposed in [24], [52]. The objective function is to maximize the social welfare by maximizing the load benefit of the system while minimizing the cost of energy purchase from the distribution system:

$$\max \quad \sum_t \sum_m B_m(PD_{mt}) - \sum_t \sum_c \lambda_t P_{ct} \tag{6.23}$$

This objective is subject to following constraints:

$$\sum_{c \in C_m} P_{ct} - \sum_{n \in L_m} PL_{mnt} = PD_{mt} \quad \leftrightarrow \lambda^P \quad \forall m, \forall t \tag{6.24}$$

$$\sum_{c \in C_m} Q_{ct} - \sum_{n \in L_m} QL_{mnt} = QD_{mt} \leftrightarrow \lambda^Q \quad \forall m, \forall t \tag{6.25}$$

$$\begin{aligned} PL_{mnt} &= g_{mn}(\Delta V_{mt} - \Delta V_{nt}) - b_{mn}(\Delta\theta_{mt} - \Delta\theta_{nt}) \\ &+ g_{mn}\Delta\hat{V}_{mt}(\Delta V_{mt} - \Delta V_{nt}) \qquad \forall mn \in L, \forall t \end{aligned} \tag{6.26}$$

$$\begin{aligned} QL_{mnt} &= -b_{mn}(\Delta V_{mt} - \Delta V_{nt}) - g_{mn}(\Delta\theta_{mt} - \Delta\theta_{nt}) \\ &- b_{mn}\Delta\hat{V}_{mt}(\Delta V_{mt} - \Delta V_{nt}) \qquad \forall mn \in L, \forall t \end{aligned} \tag{6.27}$$

$$\Delta\theta_{1t} = 0 \qquad \forall t \tag{6.28}$$

$$\Delta V_{1t} = 0 \qquad \forall t \tag{6.29}$$

$$\Delta V_m^{\min} \le \Delta V_{mt} \le \Delta V_m^{\max} \qquad \forall m, \forall t \tag{6.30}$$

$$-PL_{mn}^{\max} \le PL_{mnt} \le PL_{mn}^{\max} \qquad \forall mn \in L, \forall t \tag{6.31}$$

$$-QL_{mn}^{\max} \le QL_{mnt} \le QL_{mn}^{\max} \qquad \forall mn \in L, \forall t \tag{6.32}$$

$$PD_m^{\min} \le PD_{mt} \le PD_m^{\max} \qquad \forall m, \forall t \tag{6.33}$$

$$QD_m^{\min} \le QD_{mt} \le QD_m^{\max} \qquad \forall m, \forall t \tag{6.34}$$

Equations (6.24) and (6.25) are active and reactive power balance equations at each bus, respectively. The right hand side of these equations represents the nodal load which is responsive and can be controlled by customers. On the left hand side, the power purchased from the upstream network, here transmission system, is considered. The transmission system is treated as an infinite bus which can offer unlimited active and reactive power. Active and reactive power flow at each line are represented respectively by (6.26) and (6.27), as discussed in Section 6.3.1. Voltage magnitude and angle at the point of interconnection to the transmission system are assumed to be constant, with deviations equal to zero (6.28)-(6.29). Bus voltage magnitudes, active power flows, and reactive power flows are limited by their respective limits as in (6.30), (6.31), and (6.32), respectively. Responsive load active and reactive power limits are represented by (6.33) and (6.34), respectively.

The problem is solved in two stages. In the first stage, $\Delta\hat{V}_{mt}$ in (6.26) and (6.27) is assumed to be zero, resulting in losses to be ignored, and then initial bus voltage magnitudes are obtained. In the second stage, obtained voltage magnitudes are used to update the line flow equations and then solve the entire problem again.

Dual variables of (6.24) and (6.25) are equal to D-LMPs for active and reactive power, respectively (which denote the cost increase due to a unit increase in load at the respective buses). These D-LMPs encompass components associated with energy prices, losses, voltage limits, and line congestion, as will be further discussed in the next section.

6.3.3 Case Studies

The IEEE 33-bus distribution system (depicted in Fig. 6.7), as a standard test system, is used to study the proposed DMO operation problem and analyzing system D-LMPs. Tables 6.1 and 6.2 present system specifications. Load benefits include four steps of \$60/MWh, \$100/MWh, \$110/MWh and \$120/MWh for equal segments of the load in each bus. Four cases are considered as follows:

Case 1: Ignoring line congestion, losses, and voltage limits.

Case 2: Considering the impact of congestion

Case 3: Considering the impact of losses

Case 4: Considering the impact of voltage limits

Case 1: In this case losses, congestion and voltage limits are ignored by temporarily relaxing associated constraints. The system operation cost in this case is calculated as \$641,142. As energy price is the only factor impacting the pricing, D-LMPs are the same in each bus and are equal to the LMP at the point of interconnection to the transmission system. The average daily active power D-LMP is equal to \$33.66/MWh across all the buses. The D-LMPs for reactive power in this case are minuscule.

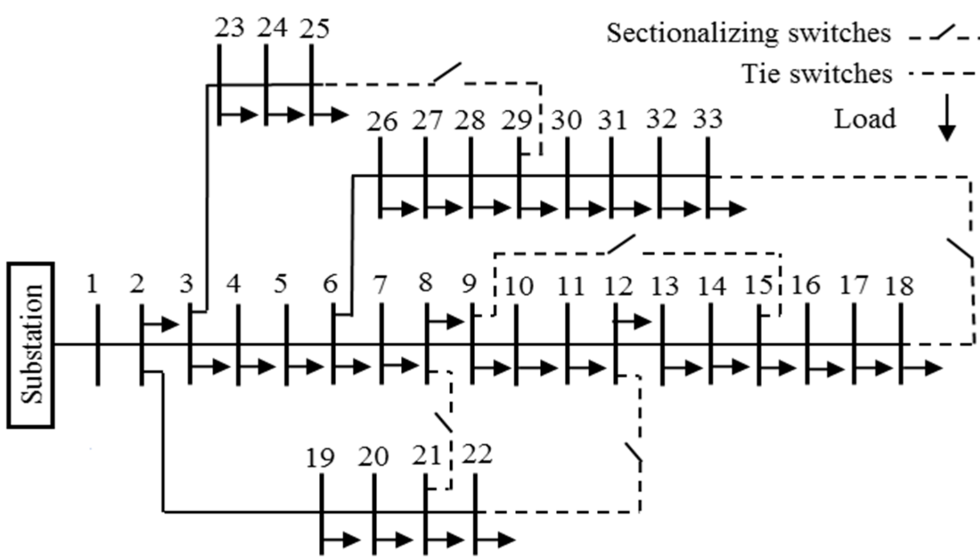

Figure 6.7 IEEE standard 33-bus test system.

Case 2: In this case line flow limits are considered. This causes congestion in five lines (17, 20, 21, 22, and 32) where the power flowing through these lines would reach the respective maximum. The system social welfare is $637,350. As there is congestion in the system, loads connected to buses supplied by these lines would be reduced. Consequently, the benefits related to these loads are dropped and social welfare is reduced in comparison with Case 1.

Fig. 6.8 depicts the active power D-LMPs at each bus in this case, showing that D-LMPs are comprised of two terms, one energy price term which is similar in all buses and a congestion term which is added only in buses impacted by congestion. At other buses that are not impacted by congestion, the congestion component of the D-LMP is zero and the energy component is the only factor determining the prices, so their price does not change with respect to Case 1. The highest increase in D-LMP occurs at buses 16, 17, and .as much as 78% 18The D-LMPs for reactive power in this case are minuscule.

TABLE 6.1 LINE SPECIFICATIONS

From bus	To bus		R (pu)	X (pu)	P (kW)	Q (kVAR)
1	2		0.0575	0.0293	4600	4600
2	3		0.3076	0.1567	4100	4100
3	4		0.2284	0.1163	2900	2900
4	5		0.2378	0.1211	2900	2900
5	6		0.5110	0.4411	2900	2900
6	7		0.1168	0.3861	1500	1500
7	8		0.4439	0.1467	1050	1050
8	9		0.6426	0.4617	1050	1050
9	10		0.6514	0.4617	1050	1050
10	11		0.1227	0.0406	1050	1050
11	12		0.2336	0.0810	1050	1050
12	13		0.9159	0.7206	500	500
13	14		0.3379	0.4448	450	450
14	15		0.3687	0.3282	300	300
15	16		0.4656	0.3400	250	250
16	17		0.8042	1.0738	250	250
17	18		0.4567	0.3581	100	100
2	19		0.1023	0.0976	500	500
19	20		0.9385	0.8457	500	500
20	21		0.2555	0.2985	210	210
21	22		0.4423	0.5848	110	110
3	23		0.2815	0.1924	1050	1050
23	24		0.5603	0.4424	1050	1050
24	25		0.5590	0.4374	500	500
6	26		0.1267	0.0645	1500	1500
26	27		0.1773	0.0903	1500	1500
27	28		0.6607	0.5826	1500	1500
28	29		0.5018	0.4371	1500	1500
29	30		0.3166	0.1613	1500	1500
30	31		0.6080	0.6008	500	500
31	32		0.1937	0.2258	500	500
32	33		0.2128	0.3308	100	100

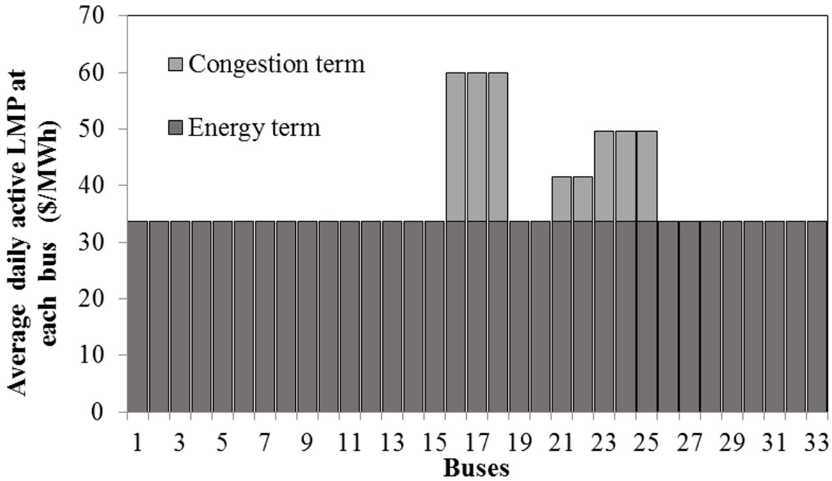

Figure 6.8 Active nodal D-LMP in Case 2.

Table 6.2 Transmission Locational Marginal Prices

Hour	1	2	3	4	5	6	7	8
T-LMP ($/MWh)	37	39	35	34	30	31	32	33
Hour	9	10	11	12	13	14	15	16
T-LMP ($/MWh)	34	30	36	37	38	42	35	40
Hour	17	18	19	20	21	22	23	24
T-LMP ($/MWh)	35	34	30	31	30	32	30	23

Case 3: In this case both losses and congestion are considered. The operation cost is increased to $625,181. Because of losses, more power needs to be purchased from the transmission system for supplying same amount of load, raising the purchase expenses and lowering the social welfare. Fig. 6.9 depicts the active nodal D-LMPs in this case. The factors impacting the D-LMPs are energy prices, congestion, and losses. In each of the feeders, D-LMPs gradually rise for buses located further downstream, as power supplied to these buses must flow through more lines resulting in a higher loss factor. Also, because of losses in the lines downstream the feeders, the power flow in other lines must rise in

order to account for losses in those lines, leading to even higher congestion at some lines that are close to or at their line flow limits. *This is the main factor resulting in D-LMPs .increase in buses 22-24*

It can be seen that the D-LMP in this is accumulation of energy price, congestion, and loss factors. Congestion factor is dominant and has the most impact in changing D-LMPs across different buses. Also, when a line is congested in a feeder, this congestion would impact D-LMPs of all the buses downstream that line, no matter if the downstream lines are congested or not. This is one of the characteristics observed in distribution systems due to their radial nature. The impact of line congestion on reactive power D-LMPs is negligible.

Case 4: In this case, impact of bus voltage limits is studied. The voltage deviation limits are set 0.05 per unit (i.e., minimum and maximum limits of 0.95 pu and 1.05 pu, respectively). The operation cost in this case is calculated as $626,139. Due to voltage limitations, less power can flow in the lines and the amount of served loads shrink, leading to lower load benefit and social welfare. Fig. 6.10 depicts the active power D-LMPs at each bus in this case.

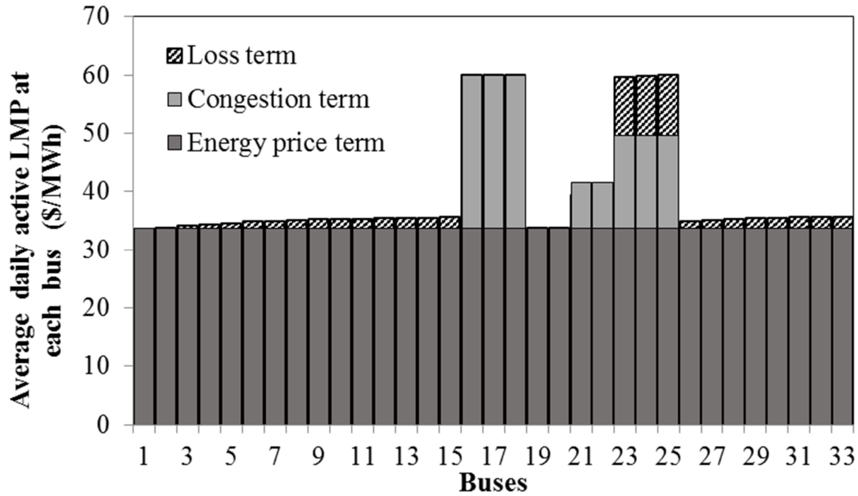

Figure 6.9 Active D-LMP at each bus in case 3.

The voltage magnitudes are constrained in the longest feeder, as it encounters the largest voltage drop, thus hitting the lower limit. Since the other feeders are connected to middle of this bus, their D-LMPs will also grow compared to previous cases even though voltages of buses within these feeders are not constrained themselves. As voltage drops along the distribution feeders are limited, less power can be purchased and the social welfare drops.

In the feeder consisting of buses 23, 24, and 25 the lines were already congested in Case 2, so the added voltage limits do not impact D-LMPs in these buses. In the feeder ending at bus 18, that has the largest number of buses, except for the three ending lines other lines were not congested. Considering voltage limits impacts D-LMPs of buses located at this feeder and increases the respective values even more than that of Case 2. Fig. 6.11 depicts the reactive power D-LMPs at each bus in this case which show a dramatic rise compared to previous cases. It advocates that reactive D-LMPs are most impacted by voltage limits rather than line congestion and losses.

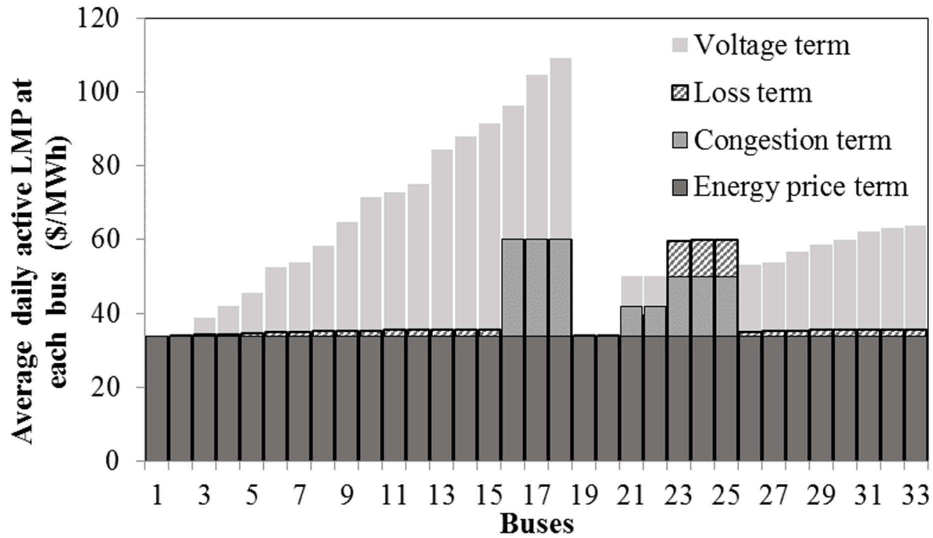

Figure 6.10 Active D-LMP at each bus in case 4.

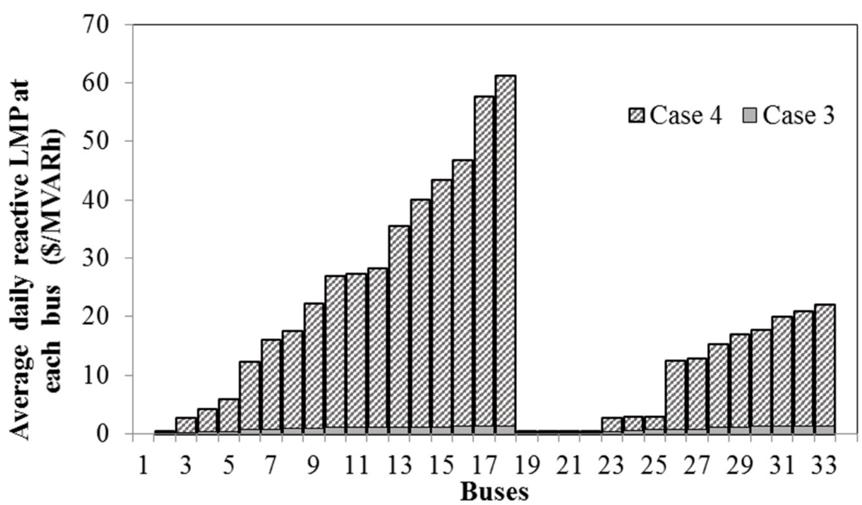

Figure 6.11 Reactive D-LMP at each bus in Case 3.

A sensitivity analysis on voltage limits is further performed. Fig. 6.12 demonstrates how changing voltage limits can impact the active power D-LMPs. Voltage limits are lowered by 10%, 20% and 30% from the values considered in Case 3. The lower voltage limits result in higher D-LMPs in the constrained feeders. In buses 2-18, 10% and 20% changes in limits do not constrain the voltages, however a 30% decrease in the limits results in the bus voltages to become constrained, thus raising the D-LMPs towards the end of the feeder.

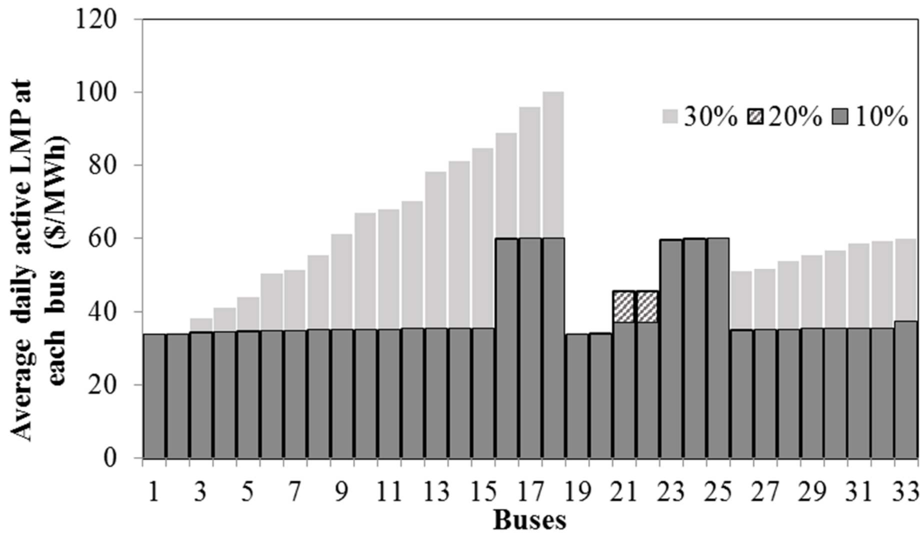

Figure 6.12 Active D-LMP in different voltage limits.

CHAPTER SEVEN: CONCLUSION AND FUTURE DIRECTIONS

Microgrid and distributed energy resources penetration is currently growing across the globe. Various challenges and concerns around these market participants require a comprehensive study on this topic. The growing presence of responsive customers in the distribution system has created concerns regarding operation of ISO markets and operation of distribution systems. This has led to efforts to create distribution markets.

In this dissertation, design and operation of such markets was investigated. An analytical model of distribution market operator (DMO) was presented to be responsible for market operations in distribution system. Although there have been recent discussions about establishing markets in the distribution systems, most of them are at the conceptualization level. In this work, operation of an electricity market was quantitively and analytically modeled in the distribution level, with participation of buyers and sellers of power. The participation of a microgrids in this market was studied more closely, and the pricing mechanism employed by the distribution market operator was formulated and developed.

Next steps to this work includes considering aspects such as islanding, the role of reconfiguration in distribution system, ancillary services, prevailing uncertainties in the system and enhancing the systm cooperation through utilizing the values for reactive :power pricing in this dissertation

- Microgrids are essentially capable of disconnecting themselves from the main grid and self-sustain. This phenomenon was considered in parts of this work, but needs further investigation regarding how it would impact the pricing and operation of other components of the power system.
- Distribution market participants like storage, microgrids and distributed generation are valuable assets to provide ancillary services to the power system. DMO can exploit this opportunity by providing platforms for regulation, ramping and other products to serve the flexibility needs of the power systems.
- Distribution systems are phase unbalanced. One of the future directions of this .research would be investigating impact of this phase unbalance

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•S.Parhizi, A. Khodaei, “Market-based Microgrid Optimal Scheduling,” IEEE International Conference on Smart Grid Communications (SmartGridComm), 2015

•S.Parhizi, A. Khodaei, M.Shahidehpour “Market-based Versus Price-based Microgrid OptimalScheduling,” IEEE Transactions on Smart Grid, 2016

•S.Parhizi, A. Khodaei “Investigating the Necessity of Distribution Markets in Accomodating High Penetration Microgrids,” IEEE PES Transmission Distribution Conference Exposition, 2016

•S. Parhizi, A. Khodaei, S. Bahramirad, “ Distribution Market Clearing and Settlement,” IEEE PES General Meeting, 2016.

•S.Parhizi, A. Khodaei ”Interdependency of Transmission and Distribution Pricing”, ISGT 2016

•S.Parhizi, A. Majzoobi, A. Khodaei “ Net-Zero Settlement in Distribution Markets,” IEEE PES General Meeting, 2017

•S.Parhizi, A. Khodaei, “Active/Reactive Locational Pricing in Distribution Networks,” IEEE International Conference on Transmission and Distribution, 2018 *Under Review*