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Risk Optimized Microgrid Resource Management

Abstract

This thesis proposes a risk based price adjustment method for a day ahead scheduling of a distribution side tiered community microgrid within a transactive energy style market. The system is organized into a master controller and local controller configuration to simulate behind meter activity that is not visible to the master controller. Conditional value at risk is used to assess the risk of distributed energy resources in each local controller and the risk for each local controller is aggregated providing each local controller a single risk value. Each device's, or local controller's, risk value is used to adjust the price of power for that device. The model both minimizes the risk for the aggregator and master controller, as well as incentivizes the participants to operate reliably. Dynamic loads, dispatchable and non-dispatchable generation, electric vehicles, battery energy storage, and conventional loads are all used within the model. Four cases are proposed to simulate the adoption of distributed energy resources where the price stability is studied in each case. The price results are found to be consistent at the master controller level for a non-risk adjusted and risk adjusted simulation, as well as with some manageable stability concerns.

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A Thesis

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Science

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In Partial Fulfillment

of the Requirements for the Degree

Master of Science

by

Thomas W. Cashel, III

August 2017

Advisor: Dr. Amin Khodaei

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Author: Thomas W. Cashel, III
Title: RISK OPTIMIZED MICROGRID RESOURCE MANAGEMENT
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Nomenclature

Abbreviations

BES	Battery Energy Storage
cVaR	Conditional Value at Risk
DER	Distributed Energy Resource
ED	Economic Dispatch
EV	Electric Vehicle
EV2G	Electric Vehicle to Grid
IoT	Internet of Things
LC	Local Controller
LMP	Locational Marginal Pricing
MC	Master Controller
MG	Microgrid
MIP	Mixed Integer Program
TE	Transactive Energy
UC	Unit Commitment
VaR	Value at Risk

Constants

α, β	Specified start and end times of an adjustable load
cu, cd	Min up and down times
RU, RD	Ramp up and ramp down rates
su, sd	Constant start up and shutdown costs

Indexes

$\wedge$	Index for calculated variable
$*$	Index for risk adjusted variable
b	Index for batteries/EV
d	Index for loads
i	Index for DERs
m, n	Index for buses
t	Index for time

Parameters

ρ	Market price of power
$F(\cdot)$	Generation Cost
g	Line conductance
MC	Minimum charging time
MD	Minimum discharging time
MU	Minimum operating time
P	DER output active Power
s	Line susceptance
SP	Stopping percentage
SU, SD	Start up / Shutdown cost

Sets

LC	Subscript for local controller set
MC	Subscript for master controller set
B	Set of BES and EV
B_{EV}	Subset of B identifying EVs
G	Set of Generators
l	Set of lines
L_m	Set of buses connected to bus m with a line

NT Number of hours
 R Set of non-dispatchable Generation

Variables

δ^* LC risk adjusted price for dynamic loads
 λ LMP, dual variable of nodal load balance equation
 ν BES charging State, 1 = charging, 0 = discharging
 π^* LC risk adjusted price for Generators
 θ Bus voltage angle
 φ^* LC risk adjusted price for BES
 C Energy stored in BES
 C^{trip} Energy consumed while EVs are driving
 D Load active power
 D^{adj} Adjustable load demand
 I Commitment State
 $loss$ System losses
 P^{ch}, P^{dch} Charge, discharge power
 P_M Power from Grid
 PL Active power of lines
 Q Reactive power
 QD Load reactive power
 QL Reactive power of lines
 T^{dch}, T^{ch} Consecutive discharging and charging hours
 T^{on}, T^{off} Consecutive on and off hours
 u BES discharge State, 1 = discharging, 0 = charging
 V Bus Voltage magnitude
 v Adjustable load state
 y Start up indicator
 z Shutdown indicator

Chapter 1

Introduction

1.1 General Overview

The United States' power consumption is growing year over year, taxing existing infrastructure, and creating new challenges for power system operators. Of increasing concern is the widespread adoption of Electric Vehicles (EV), which will further stress grid infrastructure [1]. To reduce the load on power system infrastructure and meet growing capacity requirements, generation capacity will be added, or loads will be reduced. Halting the growth of consumption is unlikely, but there are many solutions for optimizing the current system to meet demand, such as demand response, creative EV scheduling [10, 35], EV to grid systems [12], and other distributed resources.

With the advent of the Internet of Things (IoT), the ability to connect and remotely access devices creates huge opportunities for the expansion and optimization of current power system technologies [10]. Demand response is one of the first solutions leveraging this new connectivity, it allows a system operator to command a device to reduce its load [10]. With a growing number of devices this situation quickly becomes untenable for a system operator, giving rise to aggregators. The

aggregators manage the connection to a set of devices allowing the system operator to interface with a small number of aggregators, compared to number of devices [10, 39]. The current demand response operation method is inadequate, as the communications are not always two way and require the system operator to initiate the commands.

1.2 Transactive Energy

The concept of Transactive Energy (TE) has been studied extensively in academia, and was introduced as early as 1970 [13]. Due to the recent developments from the IoT and the widespread availability of high speed Internet access, TE is being tested in the field [13]. There are multiple schools of thought for TE, some fully transactional, others more participatory, this thesis focuses on the latter [27]. Through IoT connectivity and general smart grid advancements, devices have the ability to make decisions and act independently [13, 17, 21]. In this thesis a TE system will be defined as having an authority, such as a system operator or master controller whom provides a time updated price signal for devices with no required follow up communication. This simplifies the demand response method by allowing the authority to update a price a given number of times per day and allow devices or aggregators to make corresponding decisions. TE creates opportunities to improve the reliability and operation of the existing grid, but it also creates some challenging problems. Most notably the potential demand and price volatility that may occur from independent Distributed Energy Resources (DER) and loads participating in the market [31], [26].

1.3 Distributed Energy Resources

The advent and use of renewable energy sources, Battery Energy Systems (BES), and small scale generators are classified as DERs. The scale and distribution of the added DERs is also beneficial to the health and security of the overall grid, both power system security and national security. DERs allow for a more robust grid by distributing the generation of a larger single plant to multiple smaller plants spread across a region. This allows for a more secure grid, as the total capacity is not susceptible to local events or a single malfunction that causes unscheduled outages. The location of the smaller generation plants allows for placement closer to the intended loads, reducing transmission losses [34].

1.4 Microgrids

Microgrids (MG), as defined in [34], have numerous benefits and application in the current and future operation of the grid. They allow for a clear organization of what is and is not included within its boundaries, a more robust overall power system, more reliability for loads, and independent operation [8, 14, 18, 19, 33, 34]. For this thesis the MG definition from [34] is modified to describe a community MG, where the MG does not have to operate independently to meet the definition. A MG creates a convenient vehicle for aggregation and participation of DERs in a TE market. A community MG, with the right market mechanisms, allows each connected device to participate in a real-time power market, where each device is able to actively adjust its power consumption, without external intervention, based on its users preferences [26]. While this is one of the main ideas behind TE, it does create some interesting questions and problems. Privacy for the participants in this TE market becomes an issue. Each transaction, or change in power usage, of participating connected device is valuable information and must be protected. In

addition, the large amount of independent DERs with varying timing constraints create pricing and stability issues that must be addressed [10, 13, 21, 26, 31]. For this thesis, stability will refer to price stability, not dynamic stability. If devices participating in the market on the community MG make decisions that can be overridden with human interaction, this creates uncertainty and financial risk for the MG operator while planning the next days purchase of bulk power from the main grid.

1.5 Risk Classification

Risk is modeled in many different ways and has been studied extensively in finance, statistics, as well as power markets [15, 37, 38]. Consequently, decisions to invest in power system infrastructure are financially based and have been made using risk based analysis for years. MG scheduling while considering uncertainties is a well studied topic, [14, 19, 22–25, 29, 45, 46] and some use uncertainties to penalize actions in the system but very few use risk. In this thesis, a day ahead scheduling model for a MG is proposed using risk based optimization, specifically conditional value at risk (cVaR). Value at Risk (VaR) and cVaR are two methods of analyzing risk and represent the worst case scenarios of a portfolio. In [15], cVaR is able to be aggregated to represent an entire portfolio with a single cVaR value. This has the added benefit of increasing user privacy and security in the TE system by reducing the transmittal of user data. Other papers have studied a risk based method for MG, [28], [19], [42], [32], but this thesis will focus on the day-ahead scheduling problem and price stability when using a Master Controller (MC) and Local Controller (LC) method with a cVaR optimized solution.

1.6 Organization

The ability to accurately predict and schedule day ahead power purchases from the bulk market, while operating a TE based system where participants devices have high uncertainty, is important for the wide spread adoption of TE and MG systems at the distribution level. This thesis lays the framework for a scalable, risk based, scheduling model for a community MG with a MC/LC structure, while also addressing price and power stability concerns. The goal is to address a need for a robust risk based model that can be easily scaled from a device (LC) to residence (MC) system, and residence (LC) to aggregator (MC). The purpose of this thesis is to investigate the price and power stability in the proposed model. Future work will discuss how secure and robust this method is.

The rest of the thesis is organized as follows: the Problem Formulation chapter presents the problem formulation and equations used for the market scheduling problem; the Numerical Results chapter shows the numerical results of the proposed model and discussions; the Conclusions and Future Work chapter concludes the thesis and describes future work.

Chapter 2

Problem Formulation

2.1 General Overview

2.1.1 System Overview

Privacy of all connected devices participating in the TE market is a pressing issue. One way to assist in maintaining the privacy of each participant is to segment the market into two operators, a MC and a LC. For example; a MC aggregates a local neighborhood into a community MG where LC's, such as residences, operate the individual TE devices. The TE market is organized so that LC and MC can make independent decisions. A LC can optimize its resources for a specific need, and for this thesis the LC is minimizing the risk adjusted price. The LC is able to receive a risk adjusted price based on its aggregate cVaR and deconstruct it to optimize its operation based on the cVaR of each local DER. Due to the nature of cVaR and the organization of the market the MC can make risk adverse decisions based on the cVaR of each LC, which is the aggregated cVaR of the LC's local resources. Unlike the LC, which minimizes a risk adjusted price, the MC minimizes based on the bulk power price. This is a highly scalable TE based MC-LC model.

A day ahead optimal scheduling problem for a tiered community MG using a MC and LC is presented. The MG resources modeled in the optimal scheduling problem are BES, loads, and generators. All of these resources are categorized as DER. Generation is modeled as dispatchable generation and as non-dispatchable generation. Dispatchable generation is controlled by the MC. Non-dispatchable generation represents generation that cannot be controlled, similar to how renewables such as solar and wind are operate. Forecast error and hour to hour changes in generation output create a volatile power profile that is best modeled using a negative load [18].

BES units are ideal for smoothing the volatile power profile of renewables and are often used in conjunction with them for this reason. The BES resources are grouped into two sets, conventional BES and EV. BES have three states, consuming power, discharging power, or no action. The second set uses EV as BES (EV2G) with the same number of states but with less flexibility, as they must be fully charged at the end of a set time period. Loads are also grouped into two sets, fixed load, and dynamic load. A fixed loads demand must be met, while dynamic loads are able to reduce their energy consumption based on price, provided they meet given energy requirements over a set of time.

2.1.2 Problem Overview

The flowchart for the system's model is in Figure 2.1. The problem is broken up into MC and LC optimization problems. The MC is responsible for ensuring there is enough power to meet net demand by determining optimal unit commitment (UC) and economic dispatch (ED) of the dispatchable units, BES, and dynamic loads under its control. It is also responsible for supplying the risk adjusted locational marginal price (LMP) for each node in the MG system. The LMP is dual variable from the MC's nodal power flow equation Equation (2.2). The dual variable is

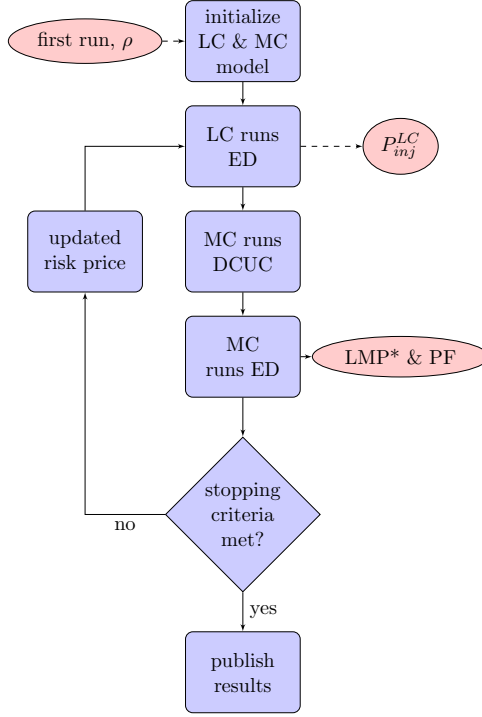


Figure 2.1: Model Flowchart

the amount the objective function Equation (2.1) would change if the sum of all constants in Equation (2.2) increased by 1.0. In other words, how much generation would need to increase if the constant load and power injections increased by 1.0. The LC is responsible for the ED of its local BES, dynamic loads, and generation, as well as providing the adjusted load back to the MC. During the first run the MC initializes its power price, renewable, and load forecast data and passes this to the LC. At this stage the MC has not run the first ED optimization so no marginal pricing exists; instead, the bulk power price is passed to all LCs as the first set of price data.

The LC solves an ED optimization problem using risk adjusted prices for each of its resources. The LC then provides the MC with its first set of load data. The MC uses the load data to solve a UC scheduling problem, then the commitment of

each unit is used to solve an ED and nodal power flow problem. Because the ED problem is linear, the dual variable of the nodal power flow equation is the LMP for each node. The MC then uses the cVaR for each LC to adjust the LMP price sent to each node, where the LC runs as described before. In subsequent iterations, the process is identical except the LC receives the risk adjusted LMP for its node and deconstructs the risk adjusted LMP for each of its local DER's, allowing each LC device to be scheduled based on its corresponding level of risk. Creating a self correcting risk based optimization problem with the price as a function of risk.

2.2 Master Controller

2.2.1 Objective Function

The objective of the MC problem is shown in Equation (2.1).

$$\sum_{i \in G} [F_i(P_{it}) I_{it} + SU_{it} + SD_{it}] + \rho_t P_{M,t}, \quad \forall t \quad (2.1)$$

The summation term in the objective function is the cost of the MC's dispatchable generation units including the start up and shutdown cost of each unit. The generation cost is represented by a piecewise linear model, simplifying the original quadratic cost function curve. The second term is the cost of power transferred from the main grid. When positive, it represents power purchased, and when negative it represents power sold to the grid. The MC objective is subject to DER, and power flow constraints.

$$P_{M,t} + \sum_{i \in G} P_{it} + \sum_{i \in B} P_{it} + \sum_{n \in L_m} PL_{mnt} = \sum_d D_{dt}^{adj} - \sum_{i \in R} P_{it} + \sum_{i \in LC} P_{it}, \quad \forall t \quad (2.2)$$

$$Q_{M,t} + \sum_{i \in G} Q_{it} + \sum_{i \in B} Q_{it} + \sum_{n \in L_m} Q_{Lmnt} = \sum_d DQ_{dt}^{adj} - \sum_{i \in R} Q_{it} + \sum_{i \in LC} Q_{it}, \quad \forall t \quad (2.3)$$

$$-P_M^{\max} \leq P_{M,t} \leq P_M^{\max}, \quad \forall t \quad (2.4)$$

The maximum allowed transmission to and from the main power grid is represented in Equation (2.4). The power balance equation Equation (2.2) ensures that the power from the main grid, the sum of all dispatchable generation, DER, BES, and line power flows are equal to the net load on the system. The net load includes adjustable loads, non-dispatchable generation, such as renewables, and the power injections from LCs. Non-dispatchable generation is modeled as a negative load.

2.2.2 Dispatchable Generation

Equation (2.5) shows the generation limits for the MCs dispatchable generation as well as the binary variable I_{it} , which indicates the commitment of each dispatchable generator facilitating the UC problem. The ramping limitations of the MCs dispatchable units are shown in Equation (2.6) and Equation (2.7). Equations (2.8) to (2.13) formulate the startup and shutdown costs as well as facilitate the minimum on and off times.

$$P_i^{\min} I_{it} \leq P_{it} \leq P_i^{\max} I_{it}, \quad \forall i \in G, \forall t \quad (2.5)$$

$$P_{it} - P_{i(t-1)} \leq RU_i, \quad \forall i \in G, \forall t \quad (2.6)$$

$$P_{i(t-1)} - P_{it} \leq RD_i, \quad \forall i \in G, \forall t \quad (2.7)$$

$$SU_{it} = su_i \cdot y_{it}, \quad \forall i \in G, \forall t \quad (2.8)$$

$$SD_{it} = sd_i \cdot z_{it}, \quad \forall i \in G, \forall t \quad (2.9)$$

$$y_{it} - z_{it} = I_{it} - I_{i(t-1)}, \quad \forall i \in G, \forall t \quad (2.10)$$

$$y_{it} + z_{it} \leq 1, \quad \forall i \in G, \forall t \quad (2.11)$$

$$cd_{it} \geq T_i^{off} y_{i,(t+1)}, \quad \forall i \in G, \forall t \quad (2.12)$$

$$cu_{it} \geq T_i^{on} z_{i,(t+1)}, \quad \forall i \in G, \forall t \quad (2.13)$$

2.2.3 Dynamic Loads

Dynamic loads are able to adjust their power consumption throughout the simulation but are limited to a minimum and maximum adjustment, as seen in Equation (2.14). The maximum represents the load in its normal state, the minimum is the load reduction allowed. The Dynamic loads can also be constrained by energy requirements in Equation (2.15), as well as have a minimum on time in Equation (2.16) [33].

$$D_{dt}^{\min} z_{dt} \leq D_{dt} \leq D_{dt}^{\max} z_{dt}, \quad \forall d, \forall t \quad (2.14)$$

$$\sum_{t \in [\alpha_d, \beta_d]} D_{dt} = E_d, \quad \forall d \quad (2.15)$$

$$T_{dt}^{on} \geq MU_d (z_{dt} - z_{d(t-1)}), \quad \forall d, \forall t \quad (2.16)$$

2.2.4 Battery Energy Storage

The equations for battery storage and EV are combined due to their similarities in operation, scheduling, and for simplicity. BES have three states represented by two binary variables Equation (2.19). Equation (2.17) and Equation (2.18) constrain the BES to a discharge and charging maximum for each time period. The capacity of the battery is represented in Equation (2.21). The minimum and maximum discharge times are constrained in Equation (2.23) and Equation (2.22). The current energy stored in the BES is represented in Equation (2.20) and takes into account inefficiencies in the discharge. The last term is the current BES capacity term, which

represents the energy used while an EV is being driven. Equation (2.24) represents the flexibility in the charging time of an EV and ensures an EV has a certain charge at the end of a set time period.

$$P_{it} \leq P_{it}^{dch, \max} u_{it} - P_{it}^{ch, \min} \nu_{it}, \quad \forall i \in B, \forall t \quad (2.17)$$

$$P_{it} \geq P_{it}^{dch, \min} u_{it} - P_{it}^{ch, \max} \nu_{it}, \quad \forall i \in B, \forall t \quad (2.18)$$

$$u_{it} - \nu_{it} \leq 1, \forall i \in B, \quad \forall t \quad (2.19)$$

$$C_{it} = C_{i,(t-1)} - \frac{P_{it} u_{it}}{\eta_i} - P_{it} \nu_{it} - C_{it}^{trip}, \quad \forall i \in B, \forall t \quad (2.20)$$

$$C_i^{\min} \leq C_{it} \leq C_i^{\max}, \quad \forall i \in B, \forall t \quad (2.21)$$

$$T_i^{ch} \geq MC_i(u_{it} - u_{i,(t-1)}), \quad \forall i \in B, \forall t \quad (2.22)$$

$$T_i^{dch} \geq MD_i(\nu_{it} - \nu_{i,(t-1)}), \quad \forall i \in B, \forall t \quad (2.23)$$

$$\sum_{t \in [\phi_i, \theta_i]} P_{it} = E_{it}, \quad \forall i \in B_{EV} \quad (2.24)$$

Equation (2.20) has a non-linear term, $P_{it} u_{it}$. This is linearized using mixed integer program (MIP) conversions.

2.2.5 Power Flow Without Losses

The following are linear equations to solve for the power flow at the distribution level without considering losses. These equations are solved during the first ED run of the MC. The magnitude at bus m is calculated by $1 + \Delta V_m$.

$$PL_{mnt} = g_{mn}(\Delta V_m - \Delta V_n) - s_{mn}(\Delta \theta_m - \Delta \theta_n), \quad \forall mn \in l, \forall t \quad (2.25)$$

$$QL_{mnt} = s_{mn}(\Delta V_m - \Delta V_n) - g_{mn}(\Delta \theta_m - \Delta \theta_n), \quad \forall mn \in l, \forall t \quad (2.26)$$

$$-PL_{mn}^{\max} \leq PL_{mnt} \leq PL_{mn}^{\max}, \quad t, \forall mn \in l, \forall t \quad (2.27)$$

$$-QL_{mn}^{\max} \leq QL_{mnt} \leq QL_{mn}^{\max}, \quad t, \forall mn \in l, \forall t \quad (2.28)$$

$$V_m^{\min} \leq V_m \leq V_m^{\max}, \quad \forall m \quad (2.29)$$

2.2.6 Power Flow With Losses

In order to solve the MC ED problem considering losses, the first ED run of the MC is solved. Then all equations are calculated again, but Equation (2.25) and Equation (2.26) are substituted with equations Equation (2.30) and Equation (2.31) respectively and ΔV_m is now represented by $\Delta \hat{V}_m$.

$$PL_{mnt} = g_{mn}(\Delta V_m - \Delta V_n) - s_{mn}(\Delta \theta_m - \Delta \theta_n) + g_{mn} \Delta \hat{V}_m (\Delta V_m - \Delta V_n), \quad \forall mn \in l, \quad \forall t \quad (2.30)$$

$$QL_{mnt} = s_{mn}(\Delta V_m - \Delta V_n) - g_{mn}(\Delta \theta_m - \Delta \theta_n) - s_{mn} \Delta \hat{V}_m (\Delta V_m - \Delta V_n), \quad \forall mn \in l, \forall t \quad (2.31)$$

2.2.7 Stopping Criteria

Due to the nested iterating MC and LC problems, an effort is made to prevent unnecessary iterations. However, with the chaotic nature of our LMP results, this becomes difficult

$$|P_{MLC}^{t-1} - P_{MLC}^t| > \frac{0.1}{S_{base}}, \quad \forall t \quad (2.32)$$

Equation (2.32) shows the first stage of the model's stopping criteria. The power injection for each LC at each time t is compared with the previous iteration's values.

If Equation (2.32) is met, a counter increments who's maximum value can be 792. The second stage of the stopping criteria checks to see if the counter divided by 792 meets a certain stopping percentage (SP). If the second stage is met, the model is allowed to stop. In addition to the stopping criteria, there is an iteration limit to prevent runaway P_{MLC} oscillation.

2.3 Local Controller

2.3.1 Objective Function

The LCs objective function is similar to the MC's in that its main objective is to minimize the cost of operation over a set of time. What makes it unique is that it is solving an ED optimization problem with a price that is a function of cVaR. The UC problem is not considered, all of the DER in the LC's scope are assumed to be able to ramp to full power within one hour, as seen in Equation (2.37). The risk adjusted LMP provided by the MC is decomposed by the LC so each DER has its own risk adjusted price. Decomposition of the risk adjusted LMP will be explained in a later section. While this does not provide the total cost for the LC's operation, it creates a minimization problem that is a function of each DER's risk.

$$\sum_t \left[P_{M_{MC}} \rho_{mn} + \sum_{i \in G_{LC}} F_i(P_{it}) \right] \quad (2.33)$$

$$\begin{aligned} & \left[D_t + \sum_{d \in d_{LC}} D_{dt}^{adj} \delta_d^* - \sum_{i \in B_{LC}} \left(P_{it}^{ch} \varphi_i^{*,ch} + P_{it}^{dch} \varphi_i^{*,dch} \right) \right. \\ & \quad \left. - \sum_{i \in G_{LC}} P_{it} \pi_i^* - \sum_{i \in R_{LC}} P_{it} \lambda_i^* \right] \\ & \quad * \rho^* + \sum_{i \in G_{LC}} F_i(P_{it}), \quad \forall t \end{aligned} \quad (2.34)$$

The first term in the objective Equation (2.34) is the cost of using power provided by the MC, and as in the MC objective Equation (2.1), if this term is negative it represents a sale of power. The second term is the risk adjusted cost of operating LC dispatchable generation. This term could easily be substituted for a piecewise linear model of risk adjusted cost. The third and fifth terms represent the risk adjusted cost of BES and all loads respectively. The fourth term is the risk adjusted price of selling renewable generation to the MC.

$$P_{M_{MC}} + \sum_{i \in G_{LC}} P_{it} + \sum_{i \in B_{LC}} P_{it} = \sum_{d \in d_{LC}} D_{dt}^{adj} - \sum_{i \in R_{LC}} P_{it} \sum_{d \in d_{LC}} D_{dt}, \quad \forall t \quad (2.35)$$

$$-P_{M_{MC}}^{\max} \leq P_{M_{MC}t} \leq P_{M_{MC}}^{\max}, \quad \forall t \quad (2.36)$$

$$0 \leq P_{it} \leq P_{it}^{\max}, \quad \forall i \in G_{LC}, \quad \forall t \quad (2.37)$$

For clarity, the LC power balance equation Equation (2.35), and power limits to and from the MC Equation (2.36) are shown above. The last term in Equation (2.35) represents the constant load of the LC.

2.3.2 Distributed Energy Resources

The LC DER constraints are identical to the MC constraints except they are solved on the device subsets for each LC on each power system node m .

$$D_{dt}^{\min} z_{dt} \leq D_{dt} \leq D_{dt}^{\max} z_{dt}, \quad \forall d \in d_{LC}, \forall t \quad (2.38)$$

$$\sum_{t \in [\alpha_d, \beta_d]} D_{dt} = E_d, \quad \forall d \in d_{LC} \quad (2.39)$$

$$T_{dt}^{on} \geq MU_d (z_{dt} - z_{d,(t-1)}) , \quad \forall d \in d_{LC}, \forall t \quad (2.40)$$

$$P_{it} \leq P_{it}^{dch,max} u_{it} - P_{it}^{ch,min} \nu_{it}, \quad \forall i \in B_{LC}, \forall t \quad (2.41)$$

$$P_{it} \geq P_{it}^{dch,min} u_{it} - P_{it}^{ch,max} \nu_{it}, \quad \forall i \in B_{LC}, \forall t \quad (2.42)$$

$$u_{it} - \nu_{it} \leq 1, \forall i \in B_{LC}, \quad \forall t \quad (2.43)$$

$$C_{it} = C_{i,(t-1)} - \frac{P_{it} u_{it}}{\eta_i} - P_{it} \nu_{it} - C_{it}^{trip}, \quad \forall i \in B_{LC}, \forall t \quad (2.44)$$

$$C_i^{min} \leq C_{it} \leq C_i^{max}, \quad \forall i \in B_{LC}, \forall t \quad (2.45)$$

$$T_i^{ch} \geq MC_i (u_{it} - u_{i,(t-1)}), \quad \forall i \in B_{LC}, \forall t \quad (2.46)$$

$$T_i^{dch} \geq MD_i (\nu_{it} - \nu_{i,(t-1)}), \quad \forall i \in B_{LC}, \forall t \quad (2.47)$$

$$\sum_{t \in [\phi_i, \theta_i]} P_{it} = E_{it}, \quad \forall i \in B_{EV_{LC}} \quad (2.48)$$

Many characteristics between the MC and LC are similar, and in most cases identical. This can be seen in Equations (2.38) to (2.48), where $B_{LC} \subseteq B$ and $d_{LC} \subseteq d$. The most notable difference is the LCs do not have dispatchable generation or binary variables. This is because LC problem is only solved once as an ED, which allows for a simpler implementation and operation of the LCs. Reactive power (Q) must be considered because of the power flow calculations at the MC level, but there is strict regulation for any DER with a capacity less than one MW only allowing a unity power factor [44]. For most LCs the reactive power component will come from the constant load.

2.4 Risk Adjustment

2.4.1 Conditional and Value at Risk Overview

Value at Risk (VaR) is a common measure of risk that indicates the quantile of a probability distribution for a portfolio's loss over a given period of time [16]. It indicates the probability of a portfolio losing a certain amount during a given time frame [38], with a certain confidence level [15]. VaR measures are preferable to other risk measures, such as the modified sorting ratio used in [28] because they contain information about all of the risk in the system being assessed, represented by a single number [15]. Figure 2.2 shows a normal distribution of historical outcomes and a $\phi\%$ confidence level. For example: if $\phi = 95$ and the outcome at the $1 - 95\%$ point in the distribution is 2, there is a 5%, $(1 - \phi\%)$, chance other outcomes will be worse than 2.

Conditional Value at Risk (cVaR) is another common risk metric and is superior to VaR because it contains information on what will happen if losses exceed the expected losses at a given VaR. cVaR is the average of potential losses beyond the VaR point, and consequently assess the worst case of the two [6]. In terms of Figure 2.2, it is the average from the $\phi\%$ confidence level to the least likely outcome

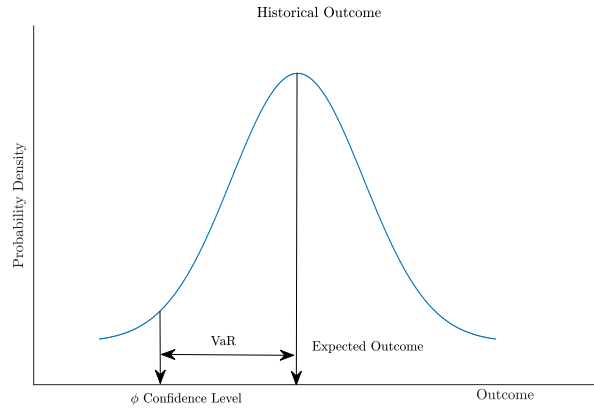


Figure 2.2: Historical VaR Demonstration

(left direction). To expand on the previous example: a cVaR with $\phi = 95$ value would be the average of the least valuable outcomes (left). A number of academic papers use cVaR to optimize various aspects of a MG's operation, [32] [38]. This thesis' goal is to use cVaR to create a risk adverse day ahead scheduling model using a historical cVaR simulation approach [38].

2.4.2 Price Adjustment

Power system aggregators and operators of community MGs are able to aggregate small scale generation and load and participate in the bulk power market. One of the challenges of this are the ability to accurately forecast and classify available assets. Additionally, participants in the MG need to be incentivized to both participate in the MG economy as well as be a reliable source. For example: if an EV was always scheduled to have a flexible charging schedule, but the owner always interrupted this schedule, the MG operators should not heavily rely on that asset for scheduling. VaR and cVar are widely used power system asset classifiers and as such are ideal for this scenario [41]. If every asset in the LC's scope usage is recorded, a historical cVaR can be assigned. The LC can then aggregate its own assets using a weighted mean based on its total power usage and transmit a single value to the MC. This allows for all of the usage data to be recorded at the LC's location, taming privacy and data protection issues.

$$\delta_{i \in d_{LC}}^* = \varphi_{i \in B_{LC}}^{*,ch} = \frac{(1 + RiskAdjustment_i)}{1 + LCRisk} \quad (2.49)$$

$$\pi_{i \in G_{LC}}^* = \lambda_{i \in R_{LC}}^* = \varphi_{i \in B_{LC}}^{*,dch} = \frac{(1 - RiskAdjustment_i)}{1 + LCRisk} \quad (2.50)$$

A power price that is a function of each asset's risk creates an incentive to use a DER asset in a reliable way. To simplify the price adjustment a piecewise risk

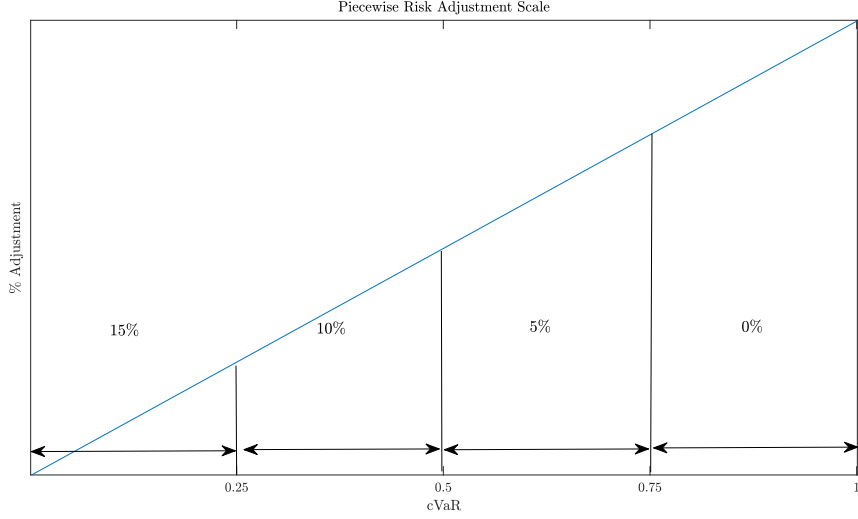


Figure 2.3: Piecewise Risk Adjustment

adjustment scale is used to create four risk adjustment tiers, see Figure 2.3. Each asset's historical cVaR is calculated and based on Figure 2.3 and a corresponding risk adjustment value is assigned, and depending on if the DER is a generator, Equation (2.50), or load, Equation (2.49), its price is adjusted accordingly. This allows for load's risk adjusted price to increase as they become more risky, and a generator's price to decrease as they become more risky. Equation (2.50) and Equation (2.49) are derived from the weighted mean used to calculate a LC's overall risk adjustment. By including them in the objective function each assets contribution to the LC's net power injection can be weighed. If the nodal power balance Equation (2.2) is solved for P_{MMC} and substituted into Equation (2.33), Equation (2.34) starts to take form. Adding the risk adjustment terms allows for the LC to prioritize less risky assets when solving the scheduling problem. The MC preforms the price adjustment before the LC receives a price. If the LC's risk value is one, the price is not adjusted, if it is less than one it is added to one, and then multiplied to the risk value.

Chapter 3

Numerical Results

An IEEE 33-bus system is used to investigate the proposed system and method, see Figure 3.4. All sectionalized switches are open. The system was modeled using a 2.3-GHz shared server using OSICPLEX 24.3.2 [3]. The power system and economic modeling was written and run in GAMS [4], the pre and post data processing was run using MatLab [5]. The system has 33 buses, 34 lines, and a varying amount of DERs distributed through out depending on the case. The data for this system was gathered from [9], [47], [30], [36], [40]. The model was run using an S_{base} of 100 MVA, V_{base} of 12.66 kV, and a Z_{base} of 1.602Ω . All solar and wind forecasts are available at <https://www.renewables.ninja/>. Original load data is from the Illinois Institute of Technology (IIT) campus microgrid. The hourly pricing is from ComEd, available at <https://hourlypricing.comed.com/live-prices/>. Both the price, load, and renewable data was scaled down from a MW scale to kW scale to accommodate this study.

3.1 Creating Risk Data

Because of a lack of ideal DER use data, the historical success was generated randomly using a triangle probability distribution. Each family of DERs was assigned

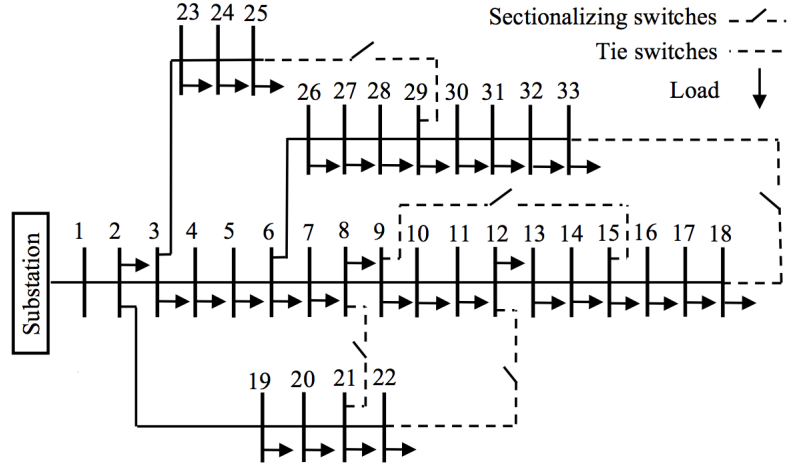


Figure 3.4: IEEE 33 Bus Test System, [9], [47], [30], [36], [40]

a different lower limit when generating each device's VaR. This was done under the assumption that a prosumer with a generator will operate it with the sole purpose of maximizing profit within the MG. While an EV or dynamic load, such as a dishwasher, may be more erratic in their use due to their designed purposes. The DER's individual VaR values are then used to create the cVaR values. Each DER's cVaR is then converted to a risk adjustment value per Figure 2.3. The ϕ confidence level is set at 95% for VaR and cVaR. It is important to note that only LC DER devices, excluding renewables, have a risk adjustment.

3.2 Model Run Results, With Risk Adjustment

The model is considered in multiple cases to simulate the adoption of TE enabled DERs over time. As the results progress, more LCs will have a randomly distributed but finite amount of DERs added to the system. In order to ensure feasibility and at least one point of line congestion the MC DERs will change as well. The following cases are run with the Model:

- Case 1: TE 0%, No LCs have TE enabled DERs.

- Case 2: TE 33%, 33% of LCs have TE enabled DERs.
- Case 3: TE 66%, 66% of LCs have TE enabled DERs.
- Case 4: TE 100%, 100% of LCs have at least one TE enabled DER.

Table 3.1 shows the DER distribution through the cases.

Table 3.1: DER Device Distribution

DER Type	Case 1, TE 0%		Case 2, TE 33%		Case 3, TE 66%		Case 4, TE 100%	
	MC	LC	MC	LC	MC	LC	MC	LC
Dynamic Load	3	0	0	5	3	11	3	17
Renewable	17	0	17	17	17	17	17	17
Generation	17	0	17	2	17	2	17	3
BES	18	0	18	8	18	14	26	18
EV	6	0	6	0	6	0	8	0

3.2.1 Case 1: TE 0% LC Penetration

Table 3.2: Price Results for all Cases, Prices in pu values

	Case 1, TE 0%		Case 2, TE 33%		Case 3, TE 66%		Case 4, TE 100%	
	MC	LC	MC	LC	MC	LC	MC	LC
Risk Price Solution	0.0279	0.0276	0.0208	0.0339	0.0241	0.0384	0.0213	0.0435
Number of Iterations	2		2		2		9	
Non-Risk Solution	0.028	0.0276	0.0208	0.0268	0.0239	0.0263	0.0211	0.0258
Number of Iterations	2		2		2		9	

For 0% TE enabled DER on the system, there is no risk adjustment because there are no DER devices to provide that information. The LC base loads allow a feasible and optimal solution of a two stage optimization problem; ED for the LCs, and a UC and ED for the MC. The following power injection (P_{inj}) figures are an aggregate power curve for a MC or LC's DERs. The price plotted for MCs is the bulk power price, so it will not reflect LMP or risk pricing. The LCs plotted LMP is risk adjusted.

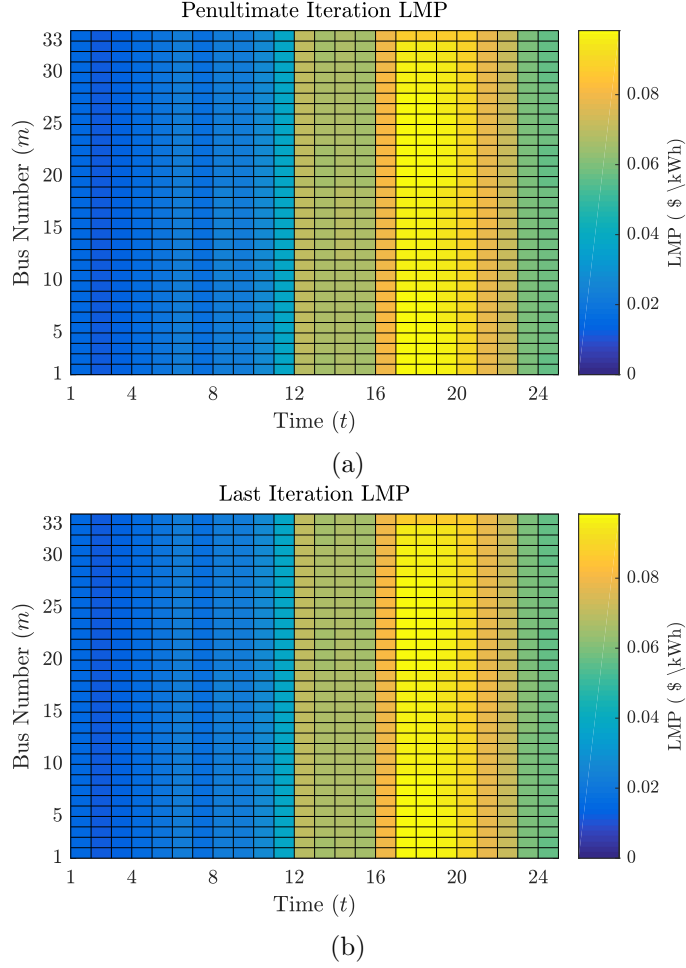


Figure 3.5: Case 1: Penultimate and Last, Price. Black indicates Congestion

Figure 3.5 and Figure 3.6 gives a quick overview of the model results. There is congestion around bus 30, and there was no notable voltage or reactive power oscillation.

Figure 3.8b and Figure 3.8a do not show much activity because there is no DER on this bus, but Figure 3.9a and Figure 3.9b show a BES increasing its oscillations. Bus 30 has a combination of conventional BES and EV operating, the oscillations are due to the final iteration having a solution that is a 1.06% improvement, from 0.0282 per unit (pu) to 0.0279 pu.

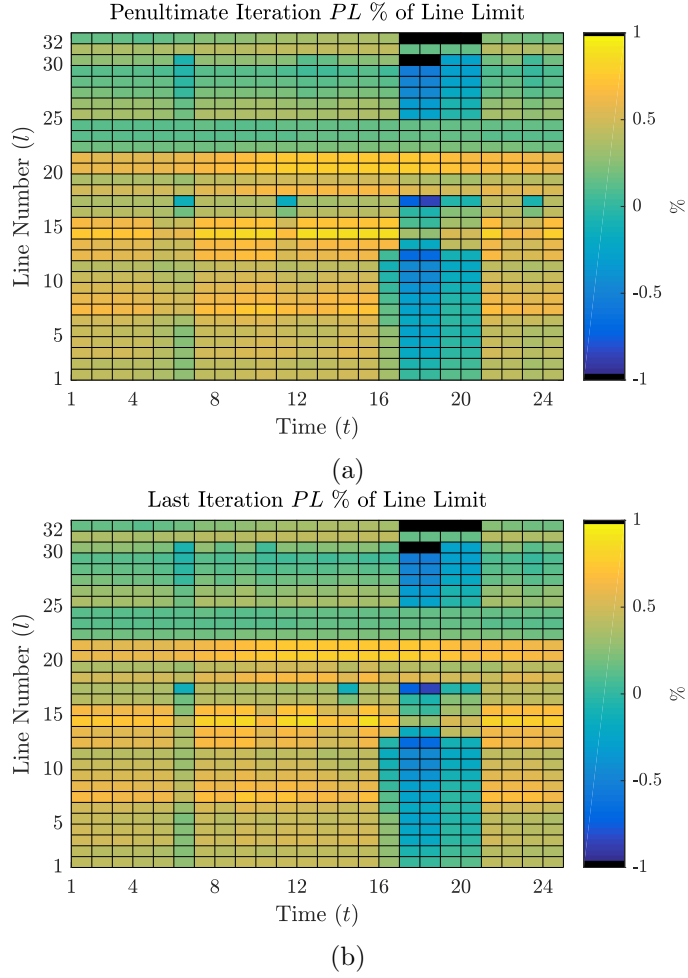


Figure 3.6: Case 1: Penultimate and Last, Line Flows. Black indicates Congestion



Figure 3.7: Legend for All Model P_{inj} Plots

The figures in Figure 3.11 and Figure 3.10 are not particularly interesting, but will be for comparison once the percentage of TE devices increases.

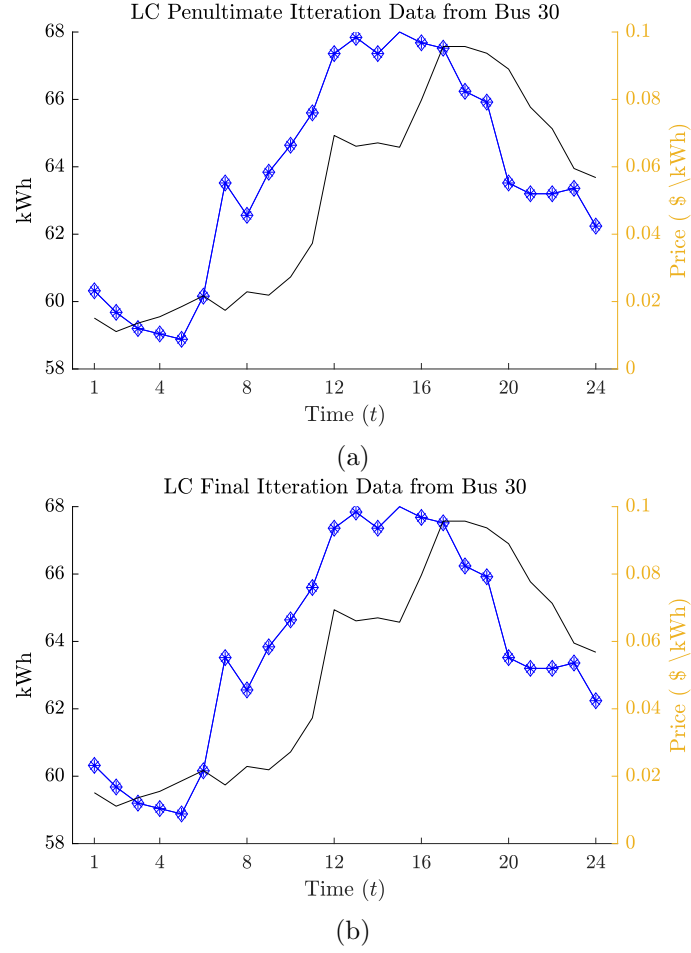


Figure 3.8: Case 1: LC DER P_{inj} at bus 30

3.2.2 Case 2: TE 33% LC Penetration

The prices shown in Figure 3.12a and Figure 3.12b are starting to show some diversity due to the risk adjustment. Table 3.1 shows the Case 2 increase in TE DER. To reiterate, only 33% of LCs have TE devices on them, but some may have more than one. The P_{inj} plots are starting to have more oscillations, most LC DERs have a minimum on and off time of an hour, with the exception of EVs who have an on/off of two.

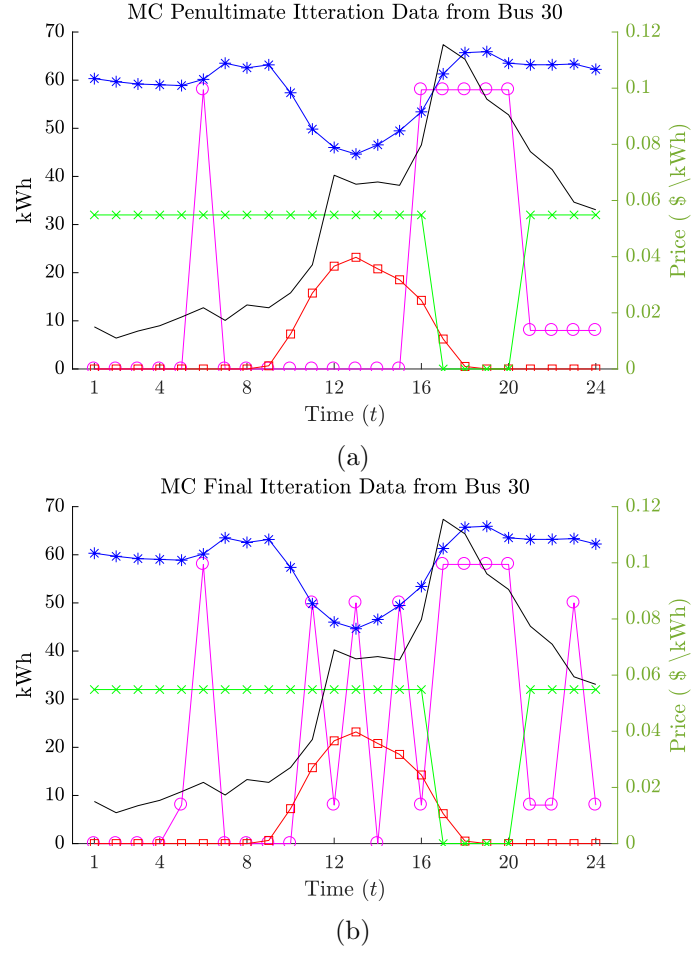


Figure 3.9: Case 1: MC DER P_{inj} at bus 30

Figure 3.12 and Figure 3.13 once again gives a quick overview of the model results. There is congestion around bus 30, and voltage did not change between the final two iterations in Case 2.

Figure 3.15a and Figure 3.15b show the BES oscillation reducing slightly. The BES devices are an EV2 and PowerPack, details in Table A.8 and Table A.9, this is the same configuration as in Case 1. The reduced oscillation could be from the reduced line usage throughout the system, Figure 3.13b, due to the addition of the DERs.

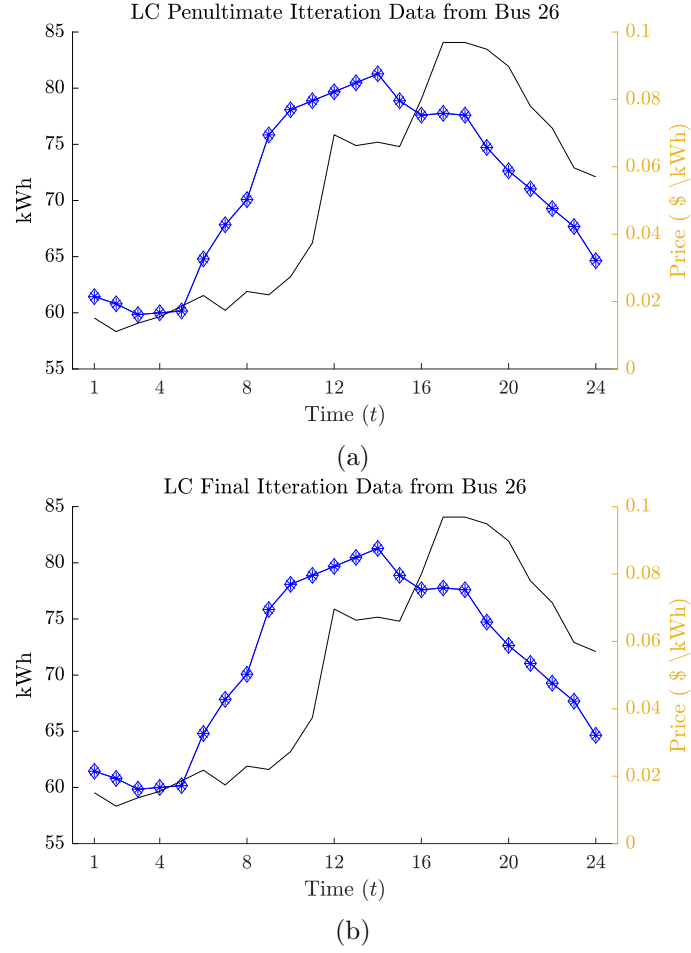


Figure 3.10: Case 1: LC DER P_{inj} at bus 26

Figure 3.16a, and Figure 3.16b, are quite different than Case 1's results due to the addition of the DERs. The BES, during high cost times between hours 16 and 20, starts discharging at peak cost as expected using the power it charged in hours 1 to 8 at low cost. It is also interesting to note the net P_{inj} for the LC on bus 26 becomes more erratic because of the DER participation. Table 3.2 shows the cost of the LC operation increased as expected because of the price adjustments of DERs but the cost of operating the MC was reduced.

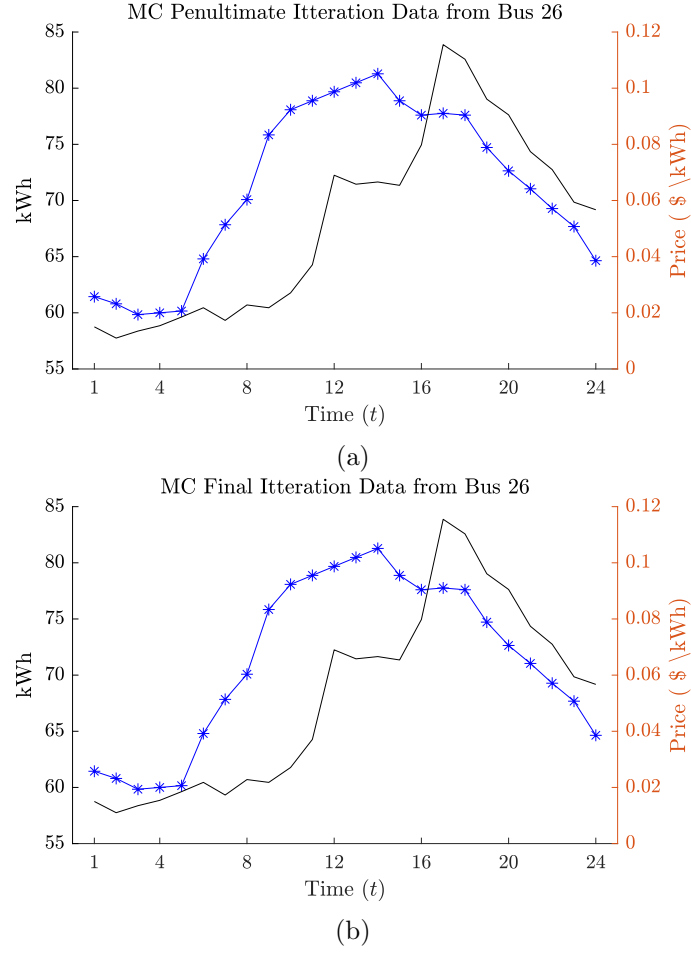


Figure 3.11: Case 1: MC DER P_{inj} at bus 26

3.2.3 Case 3: TE 66% LC Penetration

The prices shown in Figure 3.18a and Figure 3.18b are starting to trend away from high prices in congestion areas to nodes that have LCs with a high risk adjustment, showing the increasing influence the risk adjusted prices have on the models solutions.

Figure 3.20 shows the voltage is starting to oscillate through iterations. Figure 3.22a and Figure 3.22b show the MC BES oscillation increasing again, no changes to the DERs on LC on bus 30. Figure B.27a, and Figure B.27b, are very similar to Case 2's results. Bus 31 has some interesting P_{inj} values across the final two

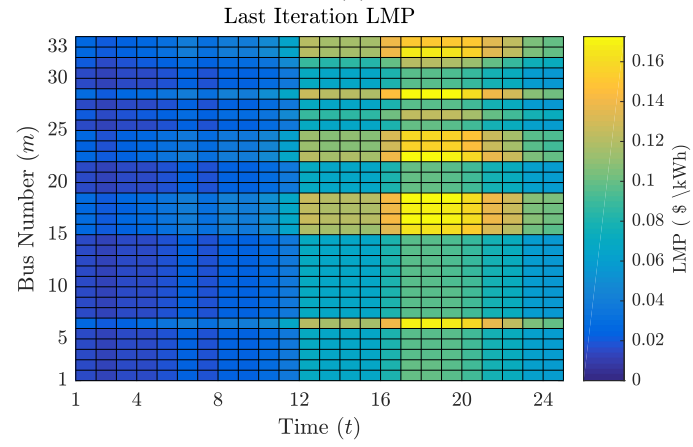
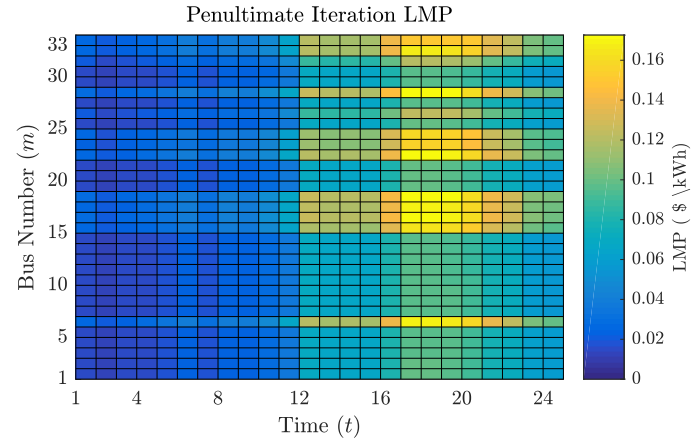


Figure 3.12: Case 2: Penultimate and Last Price. Black indicates Congestion

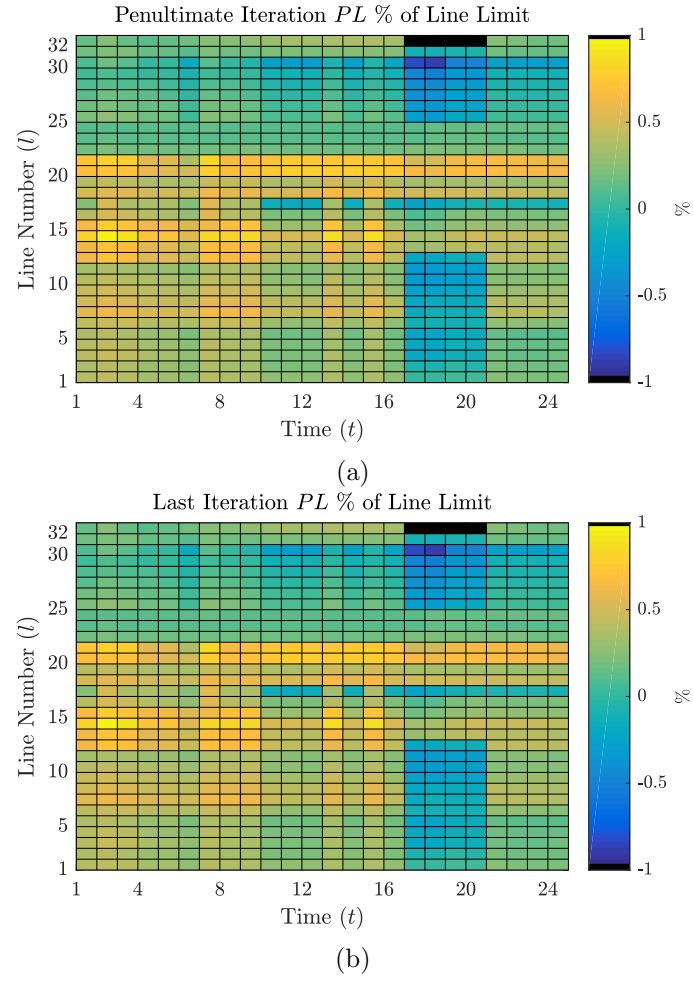


Figure 3.13: Case 2: Penultimate and Last Line Flows. Black indicates Congestion

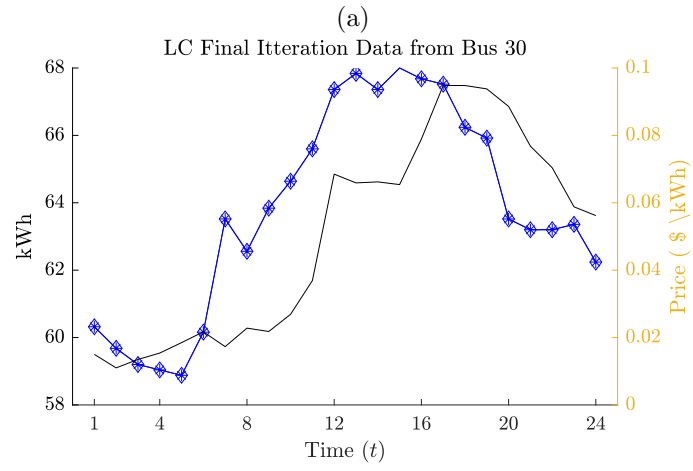
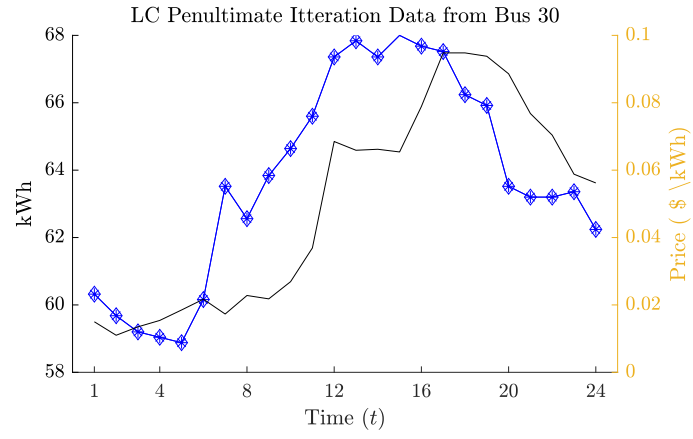
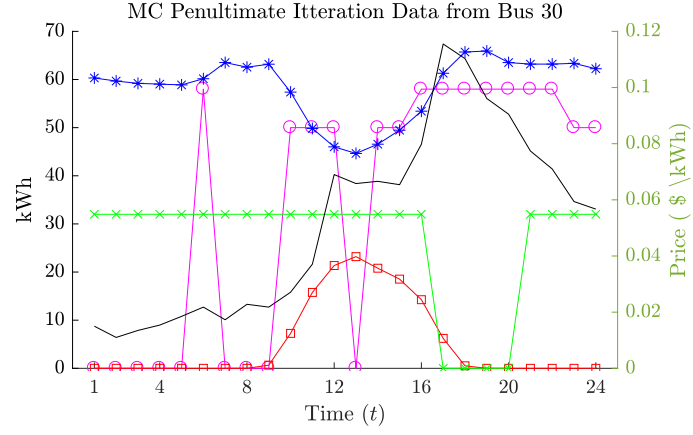
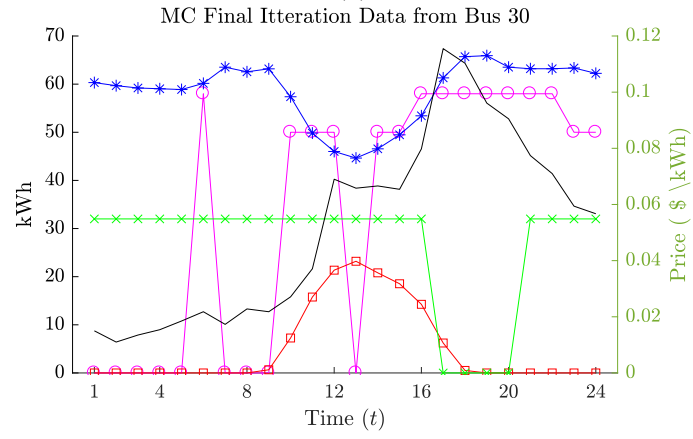


Figure 3.14: Case 2: LC DER P_{inj} at bus 30

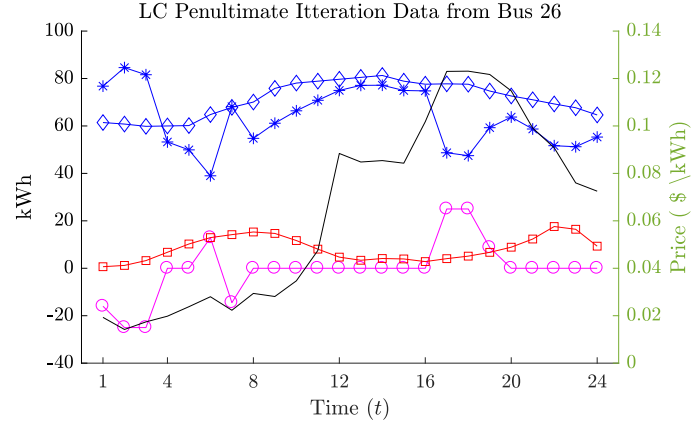


(a)

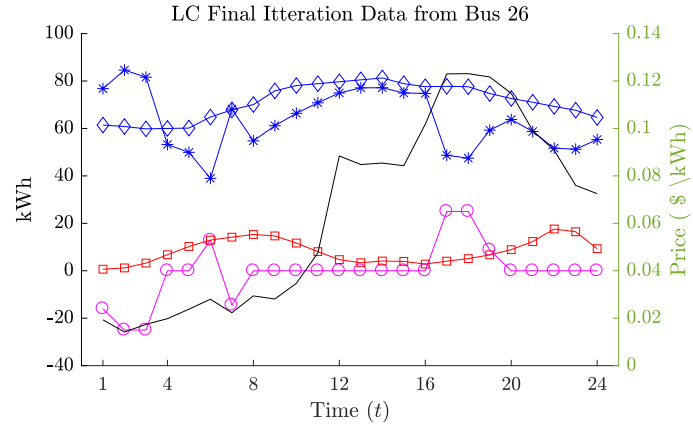


(b)

Figure 3.15: Case 2: MC DER P_{inj} at bus 30

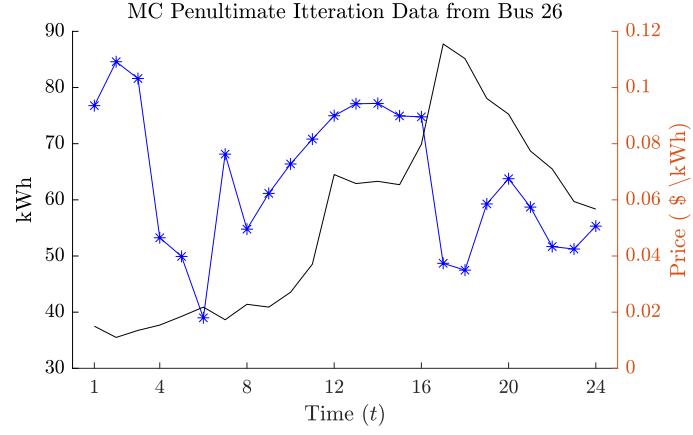


(a)

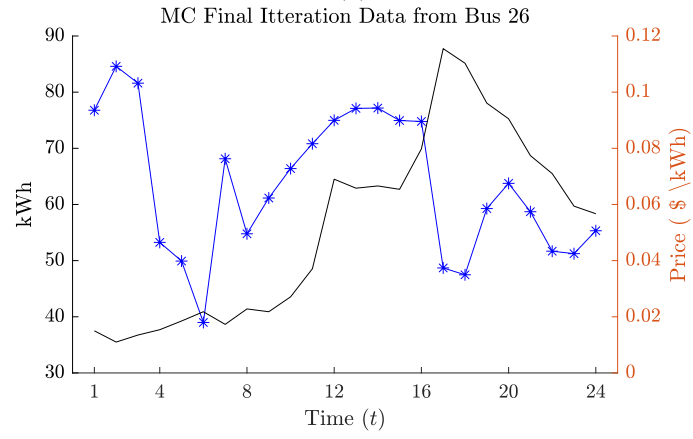


(b)

Figure 3.16: Case 2: MC and LC DER P_{inj} at bus 26



(a)



(b)

Figure 3.17: Case 2: MC and LC DER P_{inj} at bus 26

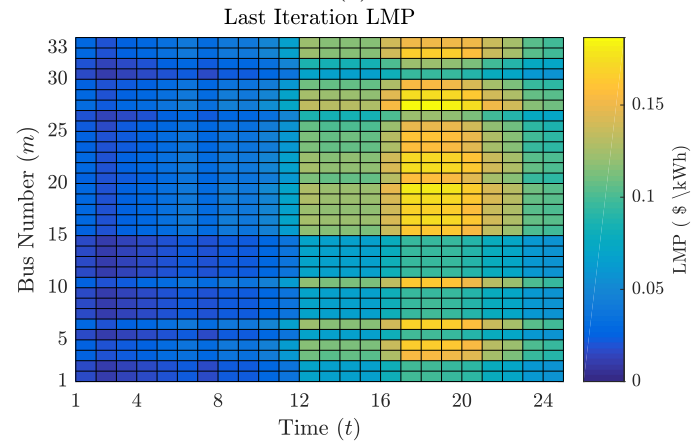
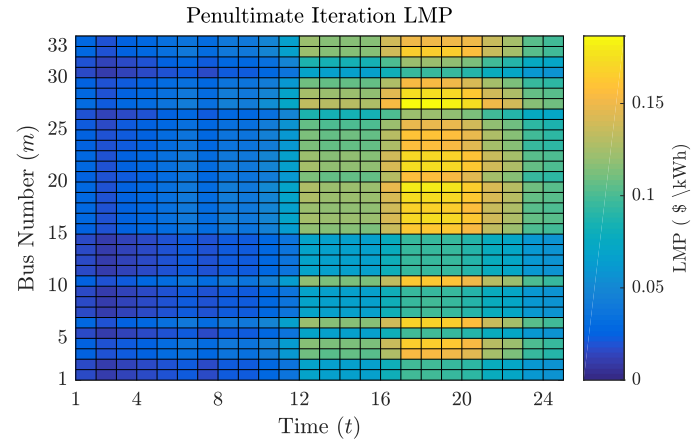


Figure 3.18: Case 3: Penultimate and Last, Price and Line Flows. Black indicates Congestion

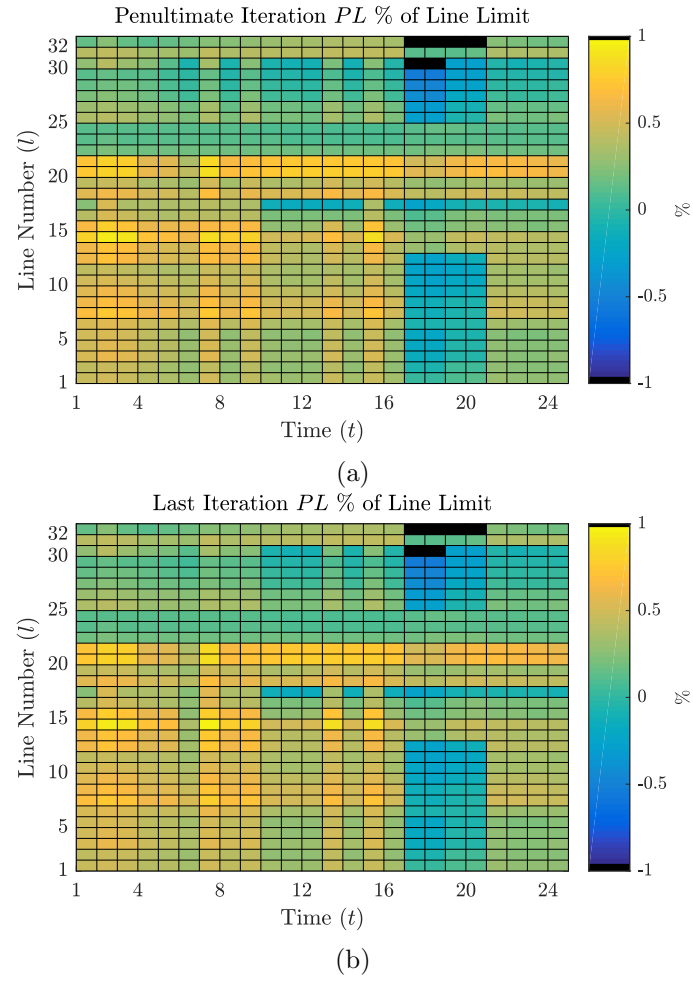


Figure 3.19: Case 3: Penultimate and Last, Price and Line Flows. Black indicates Congestion

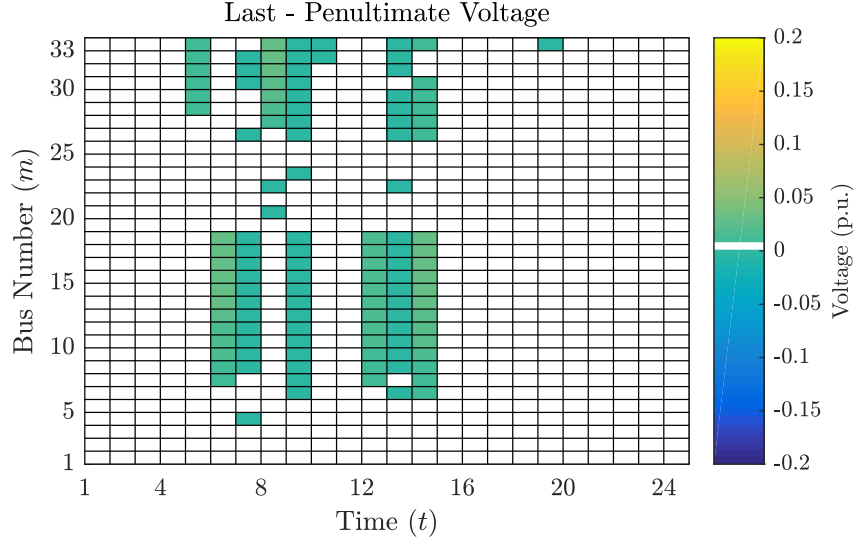


Figure 3.20: Case 3 Voltage Difference in Final and Penultimate Iterations

iterations in Figure 3.24 and Figure 3.23. Line 30 is connected to buses 30 and 31, and the line is congested during the 17th and 18th hours of the model's run. Even with the most congestion on lines 32 and 30, bus 27 has the highest prices due to its high risk adjustment of 1.936.

3.2.4 Case 4: TE 100% LC Penetration

The prices shown in Figure 3.25a and Figure 3.25b are following the same trend as Case 3, though the price gradients have become more gradual since Case 2. A significant change in the model's solution during the TE 100% case occurred. The model was stuck in an oscillating solution during the second iteration and was unable to escape. A large number of the LC and MC nodal power injections and LMPs were oscillating until the maximum number of iterations (9). The following LCs were oscillating between their penultimate and final values: Figure B.37, Figure B.36, Figure B.35, Figure B.34, Figure B.33, Figure B.32, Figure B.31, Figure B.30.

As the number of TE devices increases in the MG system, the voltage needs to be manipulated more by the solver. When compared to the previous cases (Figure 3.20)

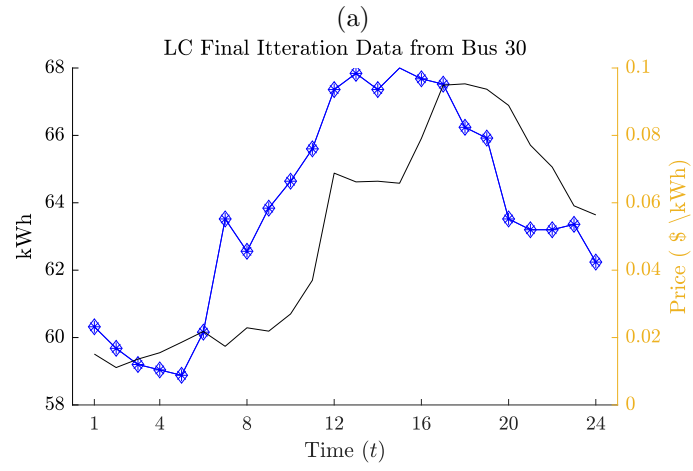
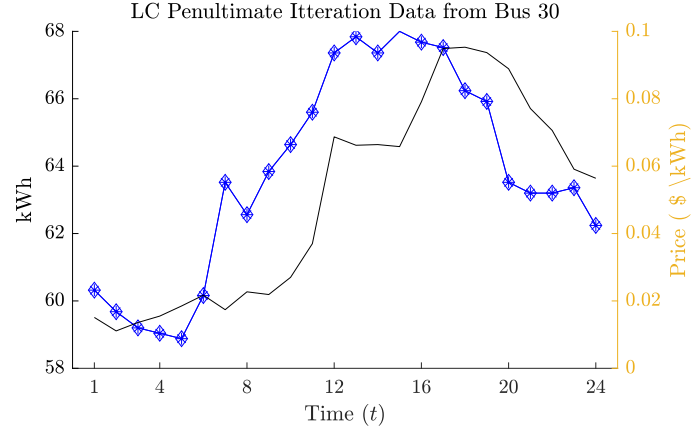
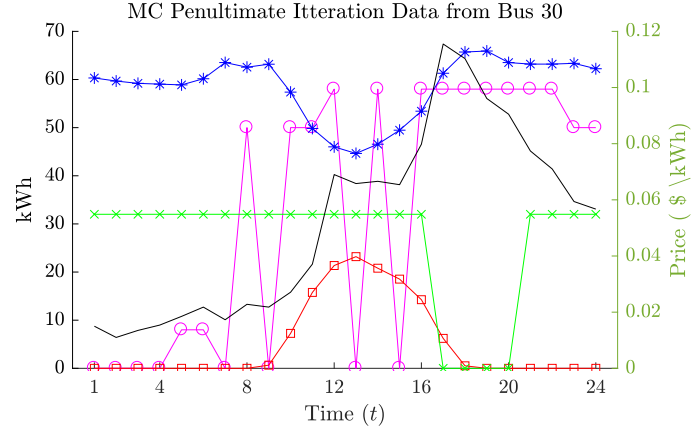
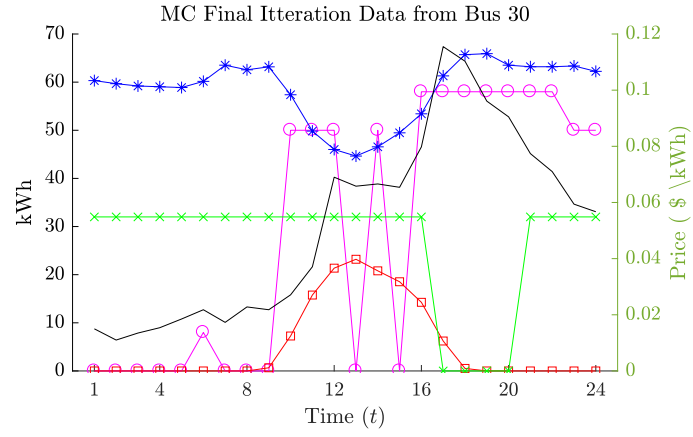


Figure 3.21: Case 3: LC DER P_{inj} at bus 30

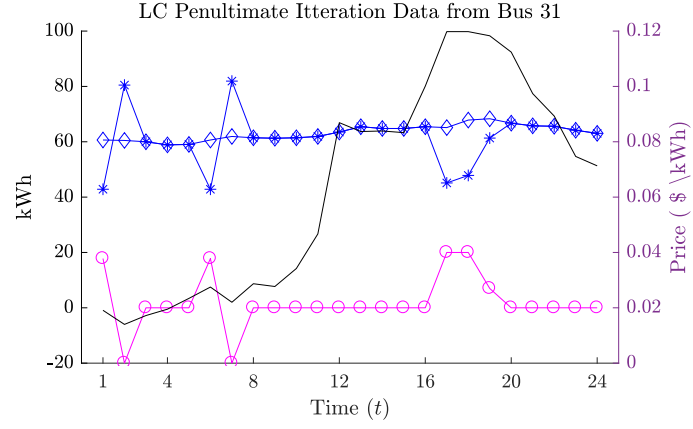


(a)

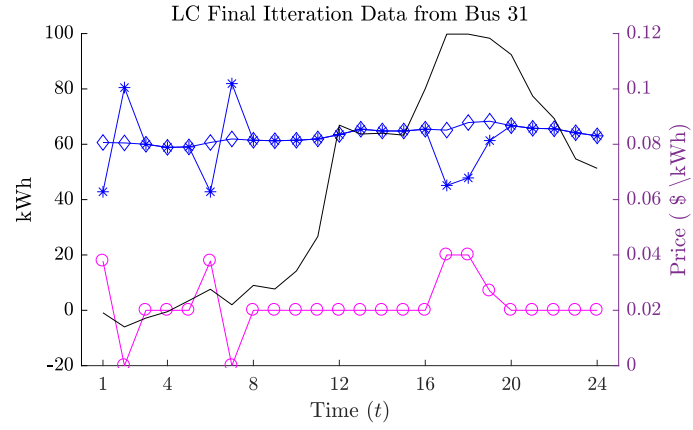


(b)

Figure 3.22: Case 3: MC DER P_{inj} at bus 30

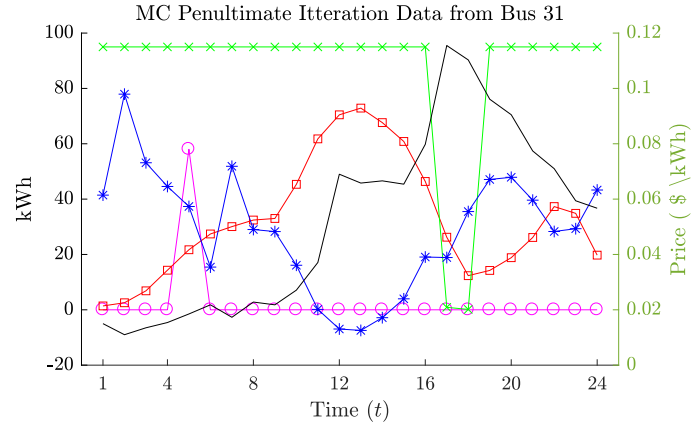


(a)

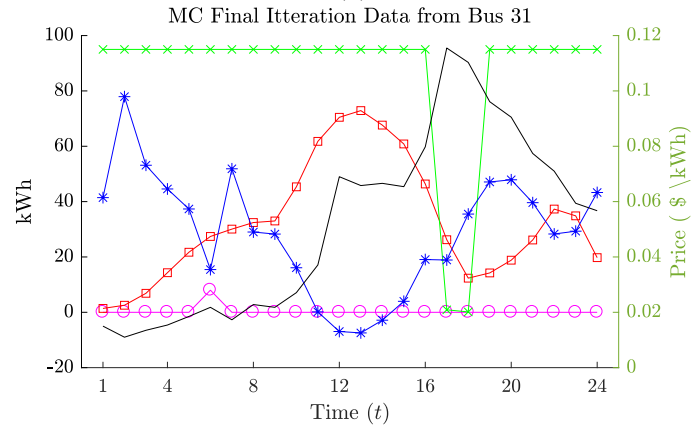


(b)

Figure 3.23: Case 3: MC and LC DER P_{inj} at bus 31

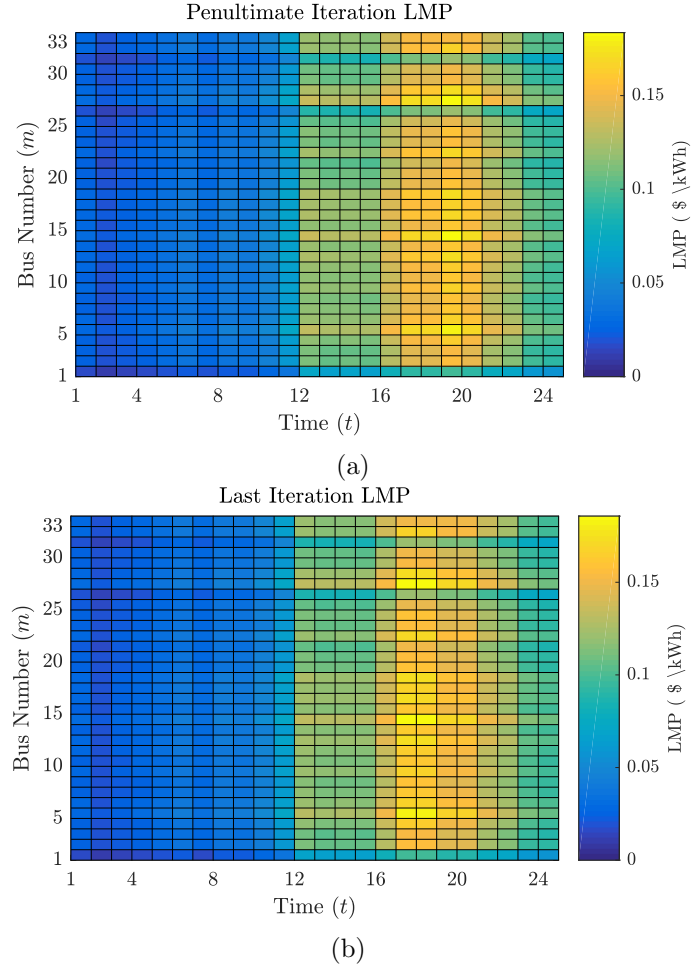


(a)



(b)

Figure 3.24: Case 3: MC and LC DER P_{inj} at bus 31



it is apparent in Figure B.29 the additional devices create a more complex problem to solve. It is interesting to see the increase in LMP diversity compared to Case 1. Those small differences in price can create value for established market participants using TE DERs but they reduce the price volatility which is a huge incentive for early adopters.

3.2.5 Cases 1 $\rightarrow$ 4 With No Risk Price Adjustment

Cases 1 through 4 were run again with no risk adjusted pricing but with the exact same parameters. The MC solution was extremely close in value and its trend to the risk adjusted simulation run. As expected, the LC solution increased as more risky

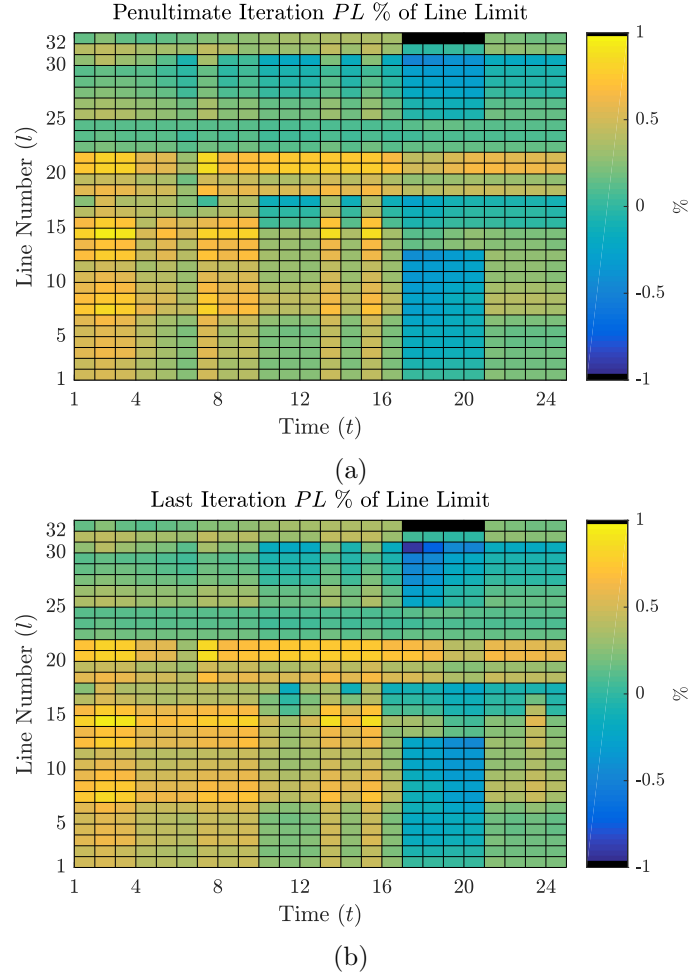


Figure 3.26: Case 4: Penultimate and Last, Price and Line Flows. Black indicates Congestion

DERs were added to the MG system. Refer to Appendix C for a selection of the no risk simulation results.

3.3 Discussion

Running multiple adoption rates of TE devices through the model simulated a neighborhood or a community MG, transitioning from a grid of the past to a grid of the future. The adoption of TE technology cannot be left out of the thoughts of

professionals creating TE devices. Integrating new products with a legacy system usually poses more challenges than a new system. The four cases analyzed showed how the price and power injections react to the iterative process of a MC - LC organized community MG and demonstrated a risk based price modification scheme. The risk based solution of the MC was very similar to the non risk based solution, and while not exact, it does show that the risk price modification's purpose; to assist aggregators scheduled with uncertain DERs, and incentivized market participants to operate their TE DER in a more economical way.

The oscillation seen during Case 4 was expected, there are existing well established methods such as Lagrangian relaxation to soften constraints so the model can continue [41], controlling computational oscillation is out of this thesis' scope. The goals and abilities of a TE market are similar to demand response in that they both have the ability to shift load and reduce net consumption [20]. In a broad sense, TE is the next evolution of demand response.

Risk is a common theme in power system planning, and through the four scenarios, a system was demonstrated that allows participants at the distribution level in the broader power market through a community MG or aggregator. A risk value was used to modify power prices at the LCs without creating large power system disruption. The system creates opportunity and security for both the aggregator as well as the prosumer. Risk, and specifically cVaR, has been researched in the area of MGs with aggregators in [32] and [42]. Ngyuen and Shen focused on maximizing the aggregators profit using a scenario based stochastic programming method. Mohan in [28] uses the sortino ratio, another risk metric, to classify an aggregator or MG's power assets to make the best financial decisions. While this thesis similarly focuses on minimizing risk for the aggregator when running scheduling simulations, we also used risk to add an incentive consumers participation in the grid, through TE. The

formulation of a price as a function of risk has many benefits. It allows LC and MC users know what assets are unreliable, and incentives users who operate in a contract free market to operate their TE enabled DERs reliably and consistently.

Chapter 4

Conclusions and Future Work

A scalable, risk adverse, privacy minded, TE solution that both minimizes risk for an aggregator as well as incentives new market participants was developed. The tiered MC-LC system was proposed as a vehicle for an evolving TE market. The tiered system allowed for the simulation of behind meter devices to influence the day ahead scheduling model. The MC-LC system and risk aggregation method is scalable. A novel risk adjusted LC objective function was proposed to minimize both cost and risk for each LC. The use of cVaR to assign risk in this thesis was in an effort to add to existing designs and analyze the stability of the scheduling problem with aggregated risk adjustment, while attempting to determine the feasibility of an evolving TE MG system. The price adjustment for each DER used the proposed risk adjustment scale, allowing for a minimum and maximum price adjustment independent from a cVaR value. The proposed piecewise risk adjustment scale needs refinement to prevent the LC costs from increasing unreasonably, but the stability of the system was shown to be no worse than that of a non-risk adjusted simulation. Multiple scenarios were run with varying amounts of TE DERs in the system to show the price stability in the system as TE DER adoption increased. As expected, the risk adjusted stability was similar to the non-risk adjusted stability until the

final case. In the final case the model oscillated between two solutions, and would have continued oscillating if it did not hit the iteration limit showing the importance of the model's stopping criteria. MIP conversion was used to linearize some of the DER's non-linear terms, including BES, EV, dynamic loads, and dispatchable and non-dispatchable generation. The non-risk and risk adjusted simulations total MG cost for the MC were very close, illustrating the value of this risk adjustment; illustrating the viability of a model using risk as both a consumer incentive and aggregator scheduling tool.

4.1 Future Work

Implementing this method using a stochastic scenario model implementation would be interesting, and may create a more robust set of results. Comparing the tiered LC MC system to a flat MG with no TE but all the same resources would be interesting and should be done before this topic moves forward. As stated earlier, as the community microgrid becomes saturated with TE devices, the price volatility will be reduced significantly reducing value for participants. Creating a new dynamic incentive program to keep participants motivated is important. This is similar to the Blockchain mining vs. transaction fee argument and exists in many markets that grow quickly. The parallels to Blockchain are quite interesting as the more Blockchain participants the better the network, similar to a TE network in terms of power volatility.

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Appendix A

Test System

Table A.1: IEEE 33 Bus Test System R and X Line 1 to 19, [9], [47], [30], [36], [40]

Line Number	Bus Numbers		Resistance and Reactance (pu)	
	From	To	R (pu)	X (pu)
1	1	2	0.0575	0.0293
2	2	3	0.3076	0.1567
3	3	4	0.2284	0.1163
4	4	5	0.2378	0.1211
5	5	6	0.5110	0.4411
6	6	7	0.1168	0.3861
7	7	8	0.4439	0.1467
8	8	9	0.6426	0.4617
9	9	10	0.6514	0.4617
10	10	11	0.1227	0.0406
11	11	12	0.2336	0.0810
12	12	13	0.9159	0.7206
13	13	14	0.3379	0.4448
14	14	15	0.3687	0.3282
15	15	16	0.4656	0.3400
16	16	17	0.8042	1.0738
17	17	18	0.4567	0.3581
18	2	19	0.1023	0.0976
19	19	20	0.9385	0.8457

Table A.2: IEEE 33 Bus Test System R and X Line 20 to 37, ‘**’ denotes a tie-line, [9], [47], [30], [36], [40]

Line Number	Bus Numbers		Resistance and Reactance (pu)	
	From	To	R (pu)	X (pu)
20	20	21	0.2555	0.2985
21	21	22	0.4423	0.5848
22	3	23	0.2815	0.1924
23	23	24	0.5603	0.4424
24	24	25	0.5590	0.4374
25	6	26	0.1267	0.0645
26	26	27	0.1773	0.0903
27	27	28	0.6607	0.5826
28	28	29	0.5018	0.4371
29	29	30	0.3166	0.1613
30	30	31	0.6080	0.6008
31	31	32	0.1937	0.2258
32	32	33	0.2128	0.3308
33	8**	21**	1.2479	1.2479
34	9	15**	1.2479	1.2479
35	12	22**	1.2479	1.2479
36	18**	33**	0.3120	0.3120
37	25**	29**	0.3120	0.3120

Table A.3: IEEE 33 Bus Test System, G and B Line 1 to 19, [9], [47], [30], [36], [40]

Line Number	Bus Numbers		Conductance and Susceptance (pu)	
	From	To	G (pu)	B (pu)
1	1	2	13.7980	-7.0337
2	2	3	2.5814	-1.3148
3	3	4	3.4772	-1.7709
4	4	5	3.3394	-1.7008
5	5	6	1.1213	-0.9680
6	6	7	0.7179	-2.3729
7	7	8	2.0311	-0.6712
8	8	9	1.0263	-0.7374
9	9	10	1.0218	-0.7243
10	10	11	7.3490	-2.4297
11	11	12	3.8215	-1.3249
12	12	13	0.6744	-0.5306
13	13	14	1.0830	-1.4255
14	14	15	1.5132	-1.3468
15	15	16	1.4006	-1.0228
16	16	17	0.4469	-0.5966
17	17	18	1.3559	-1.0632
18	2	19	5.1150	-4.8811
19	19	20	0.5881	-0.5299

Table A.4: IEEE 33 Bus Test System G and B Line 20 to 37, ‘**’ denotes a tie-line, [9], [47], [30], [36], [40]

Line Number	Bus Numbers		Conductance and Susceptance (pu)	
	From	To	G (pu)	B (pu)
20	20	21	1.6551	-1.9335
21	21	22	0.8227	-1.0878
22	3	23	2.4216	-1.6547
23	23	24	1.0993	-0.8681
24	24	25	1.1095	-0.8681
25	6	26	6.2689	-3.1931
26	26	27	4.4786	-2.2802
27	27	28	0.8515	-0.7508
28	28	29	1.1331	-0.9871
29	29	30	2.5076	-1.2772
30	30	31	0.8321	-0.8224
31	31	32	2.1886	-2.5509
32	32	33	1.3753	-2.1384
33	8**	21**	0.4007	-0.4007
34	9	15**	0.4007	-0.4007
35	12	22**	0.4007	-0.4007
36	18**	33**	1.6028	-1.6028
37	25**	29**	1.6028	-1.6028

Table A.5: Line Power Flow Limits [9], [47], [30], [36], [40]

Bus Number	Nominal load	
	P (KW)	Q(KVAR)
1	0	0
2	100	60
3	90	40
4	120	80
5	60	30
6	60	20
7	200	100
8	200	100
9	60	20
10	60	20
11	45	30
12	60	35
13	60	35
14	120	80
15	60	10
16	60	20
17	60	20
18	90	40
19	90	40
20	90	40
21	90	40
22	90	40
23	90	50
24	420	200
25	420	200
26	60	25
27	60	25
28	60	20
29	120	70
30	200	600
31	150	70
32	210	100
33	60	40

Table A.6: Renewable Forecast Data, (1 MW Scale)

Wind		Solar	
Time (h)	Power (MW)	Time (h)	Power (MW)
0	1	0	1
1	0.01322	1	0
2	0.02403	2	0
3	0.06473	3	0
4	0.13498	4	0
5	0.20476	5	0
6	0.25852	6	0
7	0.28360	7	0
8	0.30599	8	0
9	0.29378	9	0.01829
10	0.23373	10	0.20163
11	0.16129	11	0.43800
12	0.09395	12	0.59316
13	0.06749	13	0.64447
14	0.08228	14	0.57771
15	0.07862	15	0.51471
16	0.05639	16	0.39603
17	0.08115	17	0.17281
18	0.10236	18	0.01459
19	0.13424	19	0
20	0.17768	20	0
21	0.24656	21	0
22	0.35193	22	0
23	0.32881	23	0
24	0.18635	24	0

Table A.7: MC Dynamic Loads

Name	D min	D max	PF	min up time	start time	end time	Energy Need
MCDynamci1	100	200	1	0	0	12	0
MCDynamci2	50	150	-0.5	1	0	12	0
MCDynamci3	100	110	-0.7	1	0	12	0
MCDynamci4	35	300	-0.9	2	0	12	0
MCDynamci5	300	600	-0.8	3	0	12	0

Table A.8: MC BES Equipment, Part 1, [2], [43]

Name	dch Max	dch Min	ch Max	ch Min	η	PF	Capacity Min
EV1	10	0	10	0	0.89	1	0
EV2	8	0	7	0	0.89	1	0
PowerPack50		0	50	0	0.88	0.8	0

Table A.9: MC BES Equipment, Part 2, [2], [43]

Name	Capacity Max	ch min Time	dch min Time	if EV = 1	Energy needed	Start time	C trip
EV1	85	2	2	1	45	0	35
EV2	60	2	2	1	20	0	15
PowerPack210	210	2	2	0	0	0	0

Table A.10: MC Renewable Equipment Scaling Values (MW to kW)

Name	Pscale	PF
MCSolar1	0.28	1
MCSolar2	0.61	1
MCSolar3	0.12	1
MCSolar4	0.33	1
MCSolar5	0.13	1
MCSolar6	1	1
MCSolar7	0.26	1
MCSolar8	0.53	1
MCSolar9	0.69	1
MCSolar10	0.36	1
MCWind1	0.26	1
MCWind2	0.87	1
MCWind3	0.05	1
MCWind4	0.48	1
MCWind5	0.76	1
MCWind6	0.52	1
MCWind7	0.95	1
MCWind8	0.53	1
MCWind9	0.18	1
MCWind10	0.19	1

Table A.11: MC Generation Equipment,Part 1, [11]

Name	Pmin	Pmax	Qmin	Qmax	SD cost	SU cost	RU	RD
MCGenCom4	24	240	-200	200	1	10	240	240
MCGenCom5	32	320	-300	300	1.5	15	300	300
MCGenCom6	95	950	-800	800	2	20	475	475
MCGenIndu4	24	240	-200	200	1	10	240	240
MCGenIndu5	32	320	-300	300	1.5	15	300	300
MCGenIndu6	95	950	-800	800	2	20	475	475

Table A.12: MC Generation Equipment,Part 2, [11]

Name	Min On Time	Min Off Time	last comit- ment	time in state	last power	\$/kW
MCGenCom4	1	0	0	0	0	0.0954284
MCGenCom5	2	1	0	2	0	0.08755512
MCGenCom6	2	2	1	3	100	0.09458656
MCGenIndu4	1	0	0	1	0	0.0862514
MCGenIndu5	2	1	0	2	0	0.07901652
MCGenIndu6	2	2	0	2	0	0.08560976

Table A.13: LC Dynamic Load Equipment

Name	D min	D max	PF	Min Up Time	Start Time	End Time	Energy Need
Dynamic1	10	20	1	0	0	12	0
Dynamic2	10	30	1	1	0	12	10
Dynamic3	20	40	1	1	0	12	0
Dynamic4	35	50	1	2	0	12	40
Dynamic5	30	60	1	3	0	12	0

Table A.14: LC BES Equipment, Part 1, [43], [2], [7]

Name	dch Max	dch Min	ch Max	ch Min	η
PowerWall1	5	0	5	0	0.89
PowerWall2	10	0	10	0	0.89
PowerWall3	15	0	15	0	0.89
PowerWall4	20	0	20	0	0.89
PowerWall5	25	0	25	0	0.89
PowerWall6	30	0	30	0	0.89
EV1	10	0	10	0	0.89
EV2	8	0	7	0	0.89

Table A.15: LC BES Equipment, Part 2, [43], [2], [7]

Name	Capacity Min	Capacity Max	ch min Time	dch min Time	if EV = 1	Energy needed	Start time
PowerWall1	0	13.2	1	1	0	0	0
PowerWall2	0	26.4	1	1	0	0	0
PowerWall3	0	39.6	1	1	0	0	0
PowerWall4	0	52.8	1	1	0	0	0
PowerWall5	0	66	1	1	0	0	0
PowerWall6	0	79.2	1	1	0	0	0
EV1	0	85	2	2	1	45	0
EV2	0	60	2	2	1	20	0

Table A.16: LC BES Equipment, Part 3, [43], [2], [7]

Name	C trip	endtime	Capacity day before
PowerWall1	0	24	0
PowerWall2	0	24	0
PowerWall3	0	24	15
PowerWall4	0	24	0
PowerWall5	0	24	0
PowerWall6	0	24	0
EV1	35	0	0
EV2	15	0	0

Table A.17: LC Renewables Equipment Scaling Values (MW to kW)

Name	Pscale	PF
Solar1	0.005	1
Solar2	0.01	1
Solar3	0.015	1
Solar4	0.02	1
Solar5	0.025	1
Solar6	0.03	1
Solar7	0.035	1
Solar8	0.04	1
Solar9	0.045	1
Solar10	0.05	1
Wind1	0.005	1
Wind2	0.01	1
Wind3	0.015	1
Wind4	0.02	1
Wind5	0.025	1
Wind6	0.03	1
Wind7	0.035	1
Wind8	0.04	1
Wind9	0.045	1
Wind10	0.05	1

Table A.18: LC Generator Equipment, [11]

Name	Pmin	Pmax	Qmin	Qmax	C(\$/kW)
LCGen1	0	28	0	0	0.1146483
LCGen2	0	61	0	0	0.11922034
LCGen3	0	190	0	0	0.11064112

Table A.19: LC Base Load Power Factor

Bus	1	2	3	4	5	6	7	8	9	10	11	
PF	0.93	0.81	0.95	0.95	0.85	0.73	0.93	0.82	1.00	0.87	0.86	
Bus	12	13	14	15	16	17	18	19	20	21	22	
PF	0.91	0.76	0.8	0.93	0.78	0.83	0.99	0.93	1	0.83	0.99	
Bus	23	24	25	26	27	28	29	30	31	32	33	
PF	0.83	0.73	0.77	0.78	0.91	0.91	0.91	0.71	0.8	0.87	0.71	

Table A.20: LC Base Load Data, Buses 1-11, kW Values

Bus	1	2	3	4	5	6	7	8	9	10	11
Time (h)											
1	0.00	62.88	61.28	61.60	61.92	61.92	62.56	62.56	62.24	62.72	62.56
2	0.00	62.08	60.32	60.48	61.28	61.60	61.44	61.92	61.44	62.24	62.08
3	0.00	61.92	59.84	59.52	60.16	60.48	60.32	61.60	60.32	61.28	61.92
4	0.00	61.12	59.52	59.20	60.48	60.00	60.64	60.80	60.16	60.64	61.44
5	0.00	60.80	59.36	59.68	60.16	60.00	60.16	60.16	60.00	60.80	61.12
6	0.00	64.16	60.32	60.80	65.60	64.16	64.16	64.16	64.32	62.08	62.40
7	0.00	69.28	63.52	61.76	69.12	68.64	69.76	68.96	68.32	64.00	62.72
8	0.00	71.04	62.88	60.64	71.04	71.04	71.04	71.20	70.72	63.20	61.60
9	0.00	75.20	63.68	60.64	75.36	75.04	74.72	76.32	76.96	64.48	61.12
10	0.00	77.76	65.76	61.60	78.88	78.56	75.36	78.56	78.40	65.60	61.92
11	0.00	78.56	66.56	62.88	79.68	79.36	76.64	78.88	79.36	67.04	63.20
12	0.00	80.16	67.84	64.32	80.32	80.16	76.96	80.48	79.52	67.68	64.96
13	0.00	81.12	68.48	65.12	81.60	81.28	77.28	80.80	80.48	68.00	65.76
14	0.00	80.80	68.48	65.44	81.92	81.44	80.16	80.64	79.84	67.52	64.64
15	0.00	80.48	68.16	64.80	80.00	79.52	78.56	79.84	79.20	67.36	64.80
16	0.00	80.00	67.52	64.96	79.84	79.84	78.72	78.56	78.24	66.72	65.12
17	0.00	78.40	67.84	65.12	79.68	80.32	78.72	78.72	77.60	67.52	65.76
18	0.00	77.44	66.72	68.16	79.04	79.84	78.08	79.04	76.64	67.52	69.28
19	0.00	72.00	65.92	67.84	74.08	74.40	73.76	74.72	73.76	67.36	68.64
20	0.00	70.24	63.68	65.92	72.48	73.12	72.00	72.64	71.20	65.44	68.00
21	0.00	68.32	62.88	65.28	71.04	71.04	71.20	71.52	69.60	64.32	67.52
22	0.00	66.56	62.88	65.12	69.12	69.92	69.76	69.76	68.16	63.84	66.24
23	0.00	64.48	62.88	64.00	67.36	67.68	68.00	66.72	66.88	63.68	65.92
24	0.00	62.88	61.92	62.88	64.64	64.64	64.80	64.32	64.96	62.88	64.00

Table A.21: LC Base Load Data, Buses 12-22, kW Values

Bus	12	13	14	15	16	17	18	19	20	21	22
Time (h)											
1	62.24	62.40	61.60	61.92	61.92	59.84	60.16	62.24	61.76	61.76	62.24
2	61.60	61.12	60.48	61.28	60.32	59.20	59.52	61.60	61.28	60.64	61.28
3	60.96	60.64	60.16	60.32	59.84	59.20	59.52	60.96	60.32	60.00	60.64
4	60.80	59.84	60.32	60.00	59.52	58.24	59.52	60.64	60.16	59.68	59.68
5	60.80	59.52	59.20	60.00	59.04	58.08	59.04	60.48	60.32	58.88	59.84
6	65.12	63.20	63.84	63.52	64.00	59.20	60.48	65.92	64.00	63.52	63.36
7	68.80	69.76	68.80	68.16	67.52	62.56	62.24	68.96	69.12	67.84	67.68
8	70.08	70.56	70.40	70.08	69.60	62.40	60.80	70.40	70.56	70.24	69.28
9	74.24	75.36	74.72	74.56	74.08	63.52	61.28	74.24	74.56	73.76	74.88
10	78.72	77.92	77.28	76.80	75.52	64.32	61.28	77.28	77.92	77.76	79.04
11	78.72	78.56	78.88	77.28	76.16	65.60	62.08	77.92	78.88	78.24	80.16
12	78.88	79.68	80.16	78.24	77.60	66.72	63.20	78.24	79.68	80.00	80.32
13	79.36	79.84	80.96	78.88	77.92	67.68	65.44	80.00	80.96	80.48	81.12
14	79.68	79.84	81.92	79.52	77.44	67.20	65.44	79.52	80.64	80.64	80.80
15	78.88	79.20	79.68	78.08	76.96	66.72	64.80	79.04	80.64	79.68	79.84
16	78.56	79.04	80.00	77.12	76.96	66.88	65.12	77.44	80.00	78.72	78.88
17	78.24	79.52	79.52	77.60	75.36	66.88	65.60	78.24	79.20	78.88	79.20
18	77.76	76.64	78.24	77.44	74.24	66.40	68.64	77.60	78.72	77.60	78.72
19	73.60	72.96	73.60	72.32	69.44	65.12	68.32	73.60	73.92	72.80	74.40
20	71.20	71.20	72.16	71.04	67.52	63.20	66.88	71.68	72.16	71.84	71.84
21	70.08	69.92	70.72	69.76	65.92	62.24	66.24	70.88	70.88	70.24	70.56
22	68.64	69.12	68.96	68.80	65.28	61.60	66.24	68.80	68.96	68.80	69.44
23	67.68	67.04	67.84	65.92	63.68	62.72	64.80	66.08	66.88	67.20	67.20
24	64.80	64.64	64.80	63.68	62.24	61.92	64.16	64.32	64.80	64.32	64.96

Table A.22: LC Base Load Data, Buses 23-33, kW Values

Bus	23	24	25	26	27	28	29	30	31	32	33
Time (h)											
1	62.72	61.12	60.96	61.44	62.56	60.96	61.60	60.32	60.64	61.76	62.24
2	61.76	60.64	61.12	60.80	61.76	60.80	61.12	59.68	60.48	60.80	60.96
3	61.28	59.84	60.48	59.84	61.44	60.00	60.96	59.20	60.00	60.00	60.64
4	60.96	59.36	59.68	60.00	60.96	59.04	60.16	59.04	58.88	59.68	60.16
5	60.64	59.36	59.84	60.16	60.32	58.88	60.32	58.88	59.04	59.84	60.64
6	63.36	60.96	61.12	64.80	63.36	62.40	62.88	60.16	60.64	65.76	64.16
7	68.48	64.64	62.72	67.84	68.32	67.04	68.00	63.52	61.92	68.32	69.92
8	70.40	63.68	61.44	70.08	70.24	69.44	69.60	62.56	61.44	70.40	70.72
9	74.56	64.96	61.76	75.84	75.36	73.44	73.12	63.84	61.28	74.72	74.40
10	76.64	66.08	62.40	78.08	78.56	76.32	76.16	64.64	61.44	77.76	78.72
11	78.56	67.52	62.72	78.88	78.56	78.88	77.76	65.60	61.92	78.56	80.16
12	79.04	68.16	63.52	79.68	80.16	79.36	79.04	67.36	63.52	79.20	81.44
13	79.36	69.28	65.44	80.48	80.64	80.48	79.68	67.84	65.44	80.48	83.84
14	79.68	68.96	64.80	81.28	80.96	80.48	79.84	67.36	64.80	80.96	83.84
15	78.56	69.12	64.64	78.88	79.20	79.52	78.40	68.00	64.80	79.36	82.72
16	78.40	68.00	64.64	77.60	78.40	77.44	77.76	67.68	65.44	78.40	81.92
17	77.76	67.04	65.28	77.76	78.72	77.60	76.64	67.52	65.12	77.76	81.28
18	76.80	67.52	67.84	77.60	78.24	76.80	75.68	66.24	67.84	76.96	79.84
19	72.16	66.72	67.68	74.72	74.08	73.12	71.36	65.92	68.32	73.28	75.04
20	70.72	65.12	66.08	72.64	72.64	71.36	69.28	63.52	66.72	71.68	73.44
21	68.64	63.84	66.08	71.04	70.72	69.92	67.52	63.20	65.76	69.76	71.36
22	67.20	63.20	66.56	69.28	69.76	68.64	66.40	63.20	65.60	68.64	69.28
23	66.24	63.20	64.48	67.68	67.68	66.08	64.00	63.36	64.16	66.56	66.56
24	63.36	62.24	63.36	64.64	64.48	63.36	61.92	62.24	63.04	64.32	64.32

Appendix B

Risk Adjusted Simulation Data

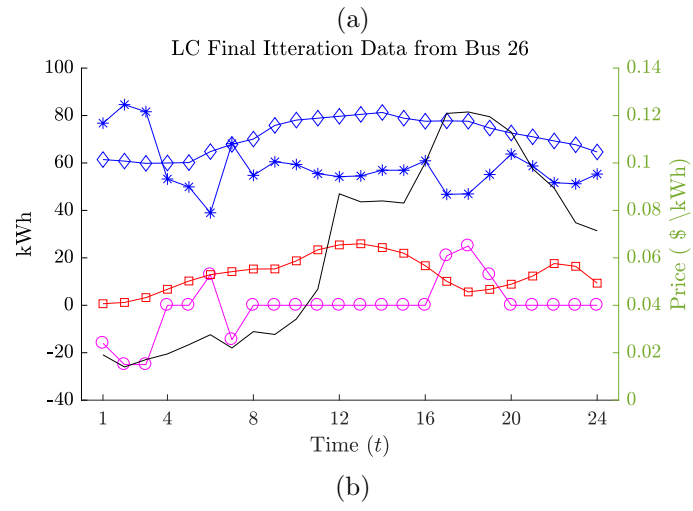
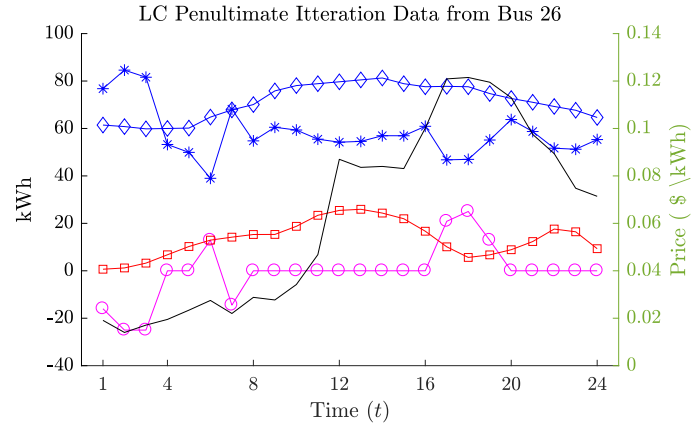
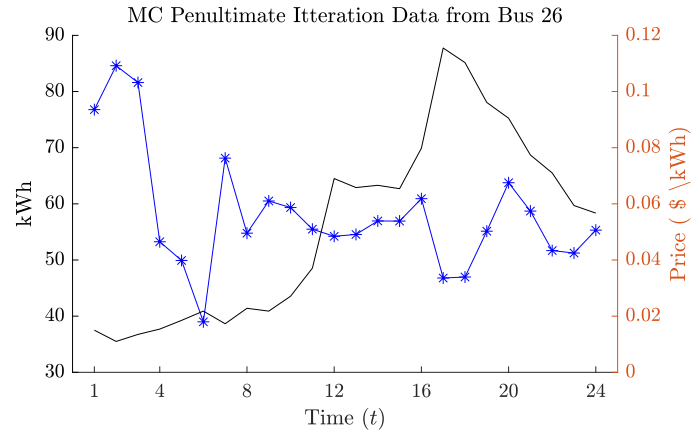
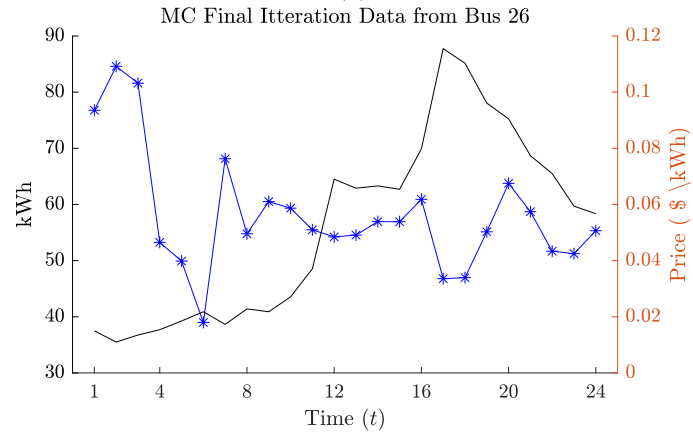


Figure B.27: Case 3: LC DER P_{inj} at bus 26



(a)



(b)

Figure B.28: Case 3: MC DER P_{inj} at bus 26

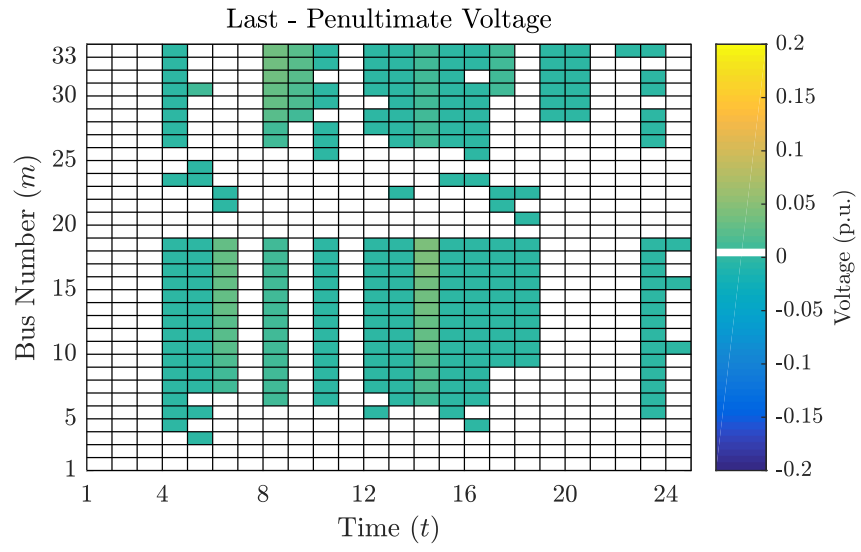
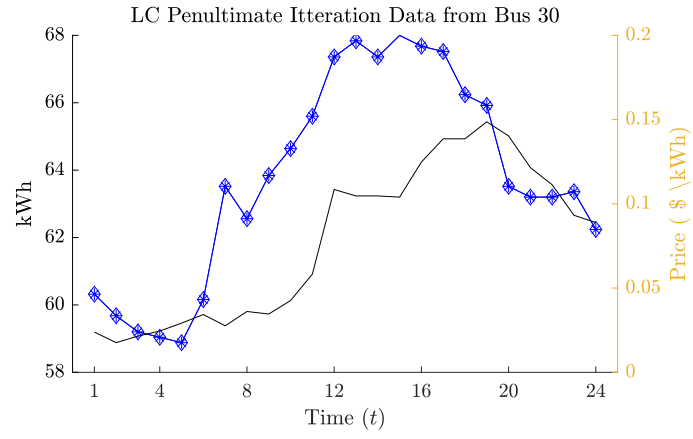
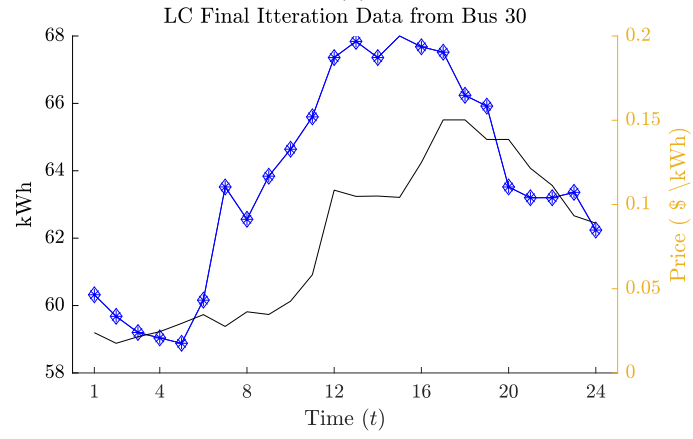


Figure B.29: Case 4 Voltage Difference in Final and Penultimate Iterations

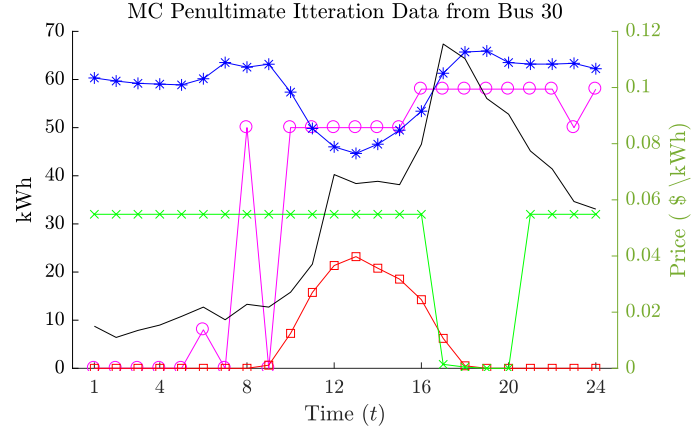


(a)

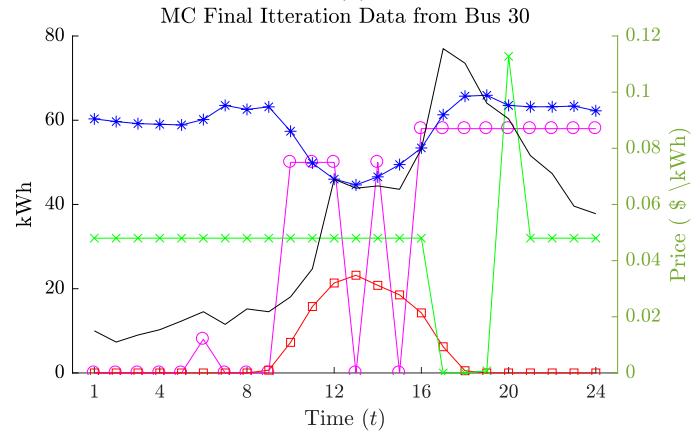


(b)

Figure B.30: Case 4: LC DER P_{inj} at bus 30

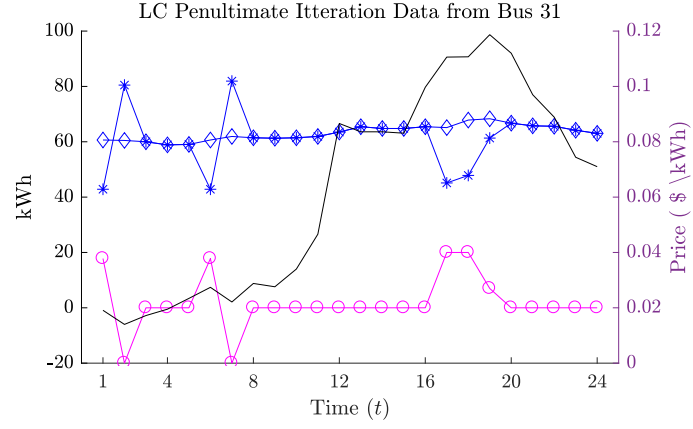


(a)

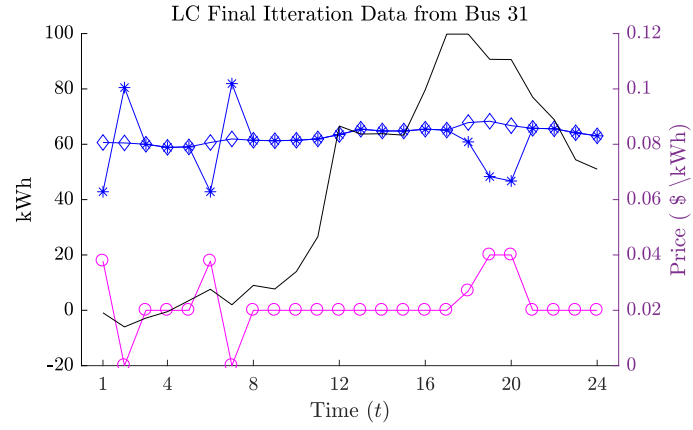


(b)

Figure B.31: Case 4: MC DER P_{inj} at bus 30

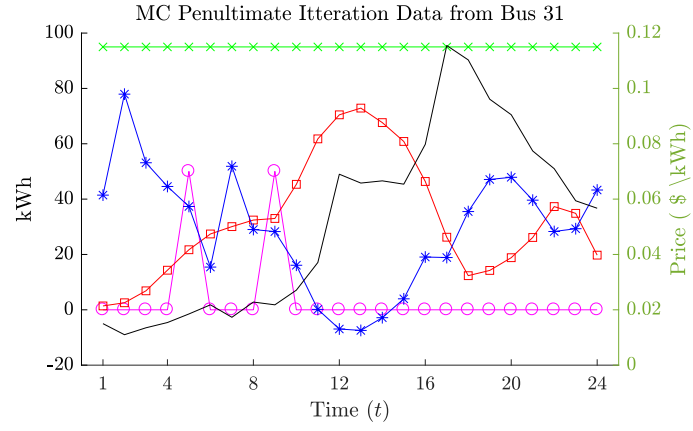


(a)

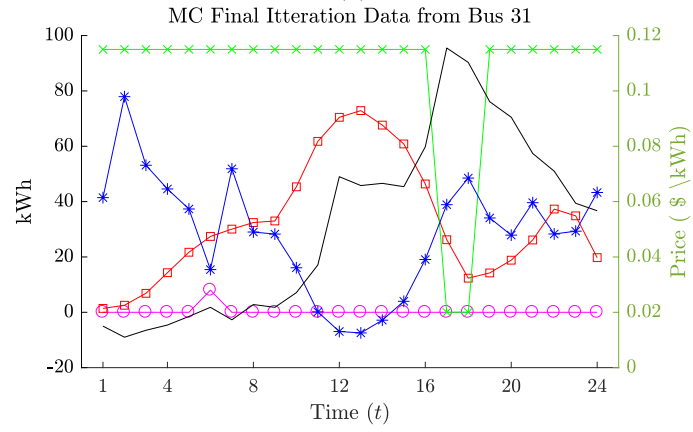


(b)

Figure B.32: Case 4: LC DER P_{inj} at bus 31

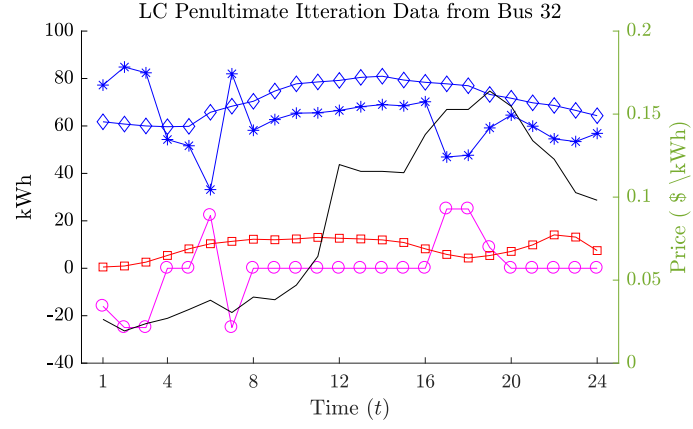


(a)

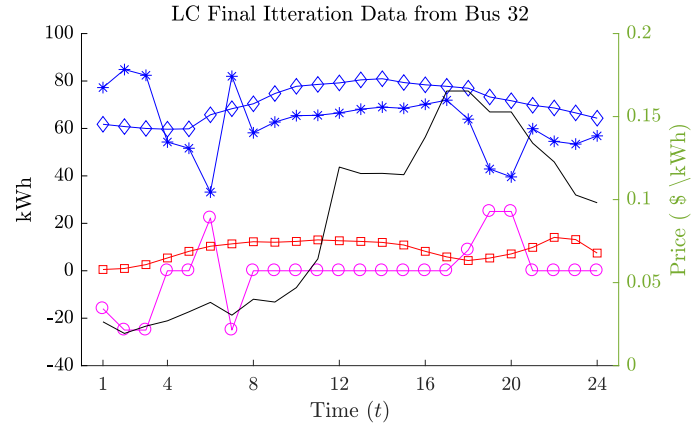


(b)

Figure B.33: Case 4: MC DER P_{inj} at bus 31

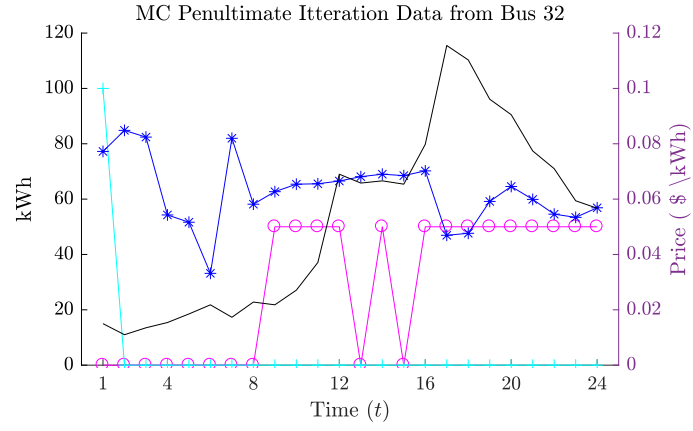


(a)

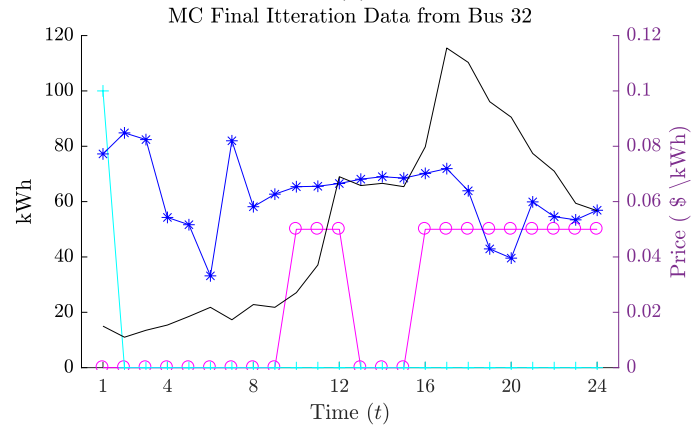


(b)

Figure B.34: Case 4: LC DER P_{inj} at bus 32

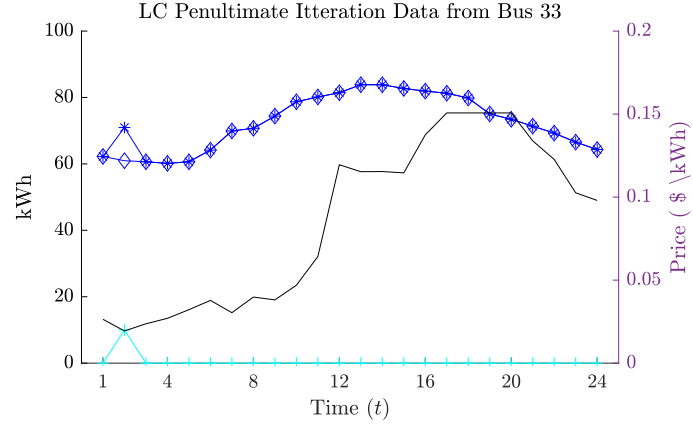


(a)

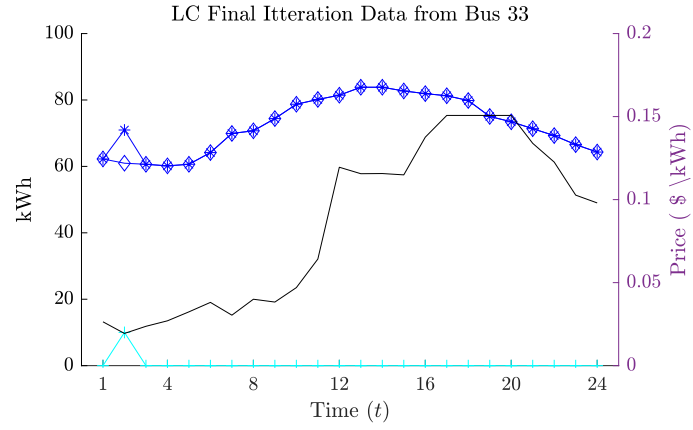


(b)

Figure B.35: Case 4: MC DER P_{inj} at bus 32

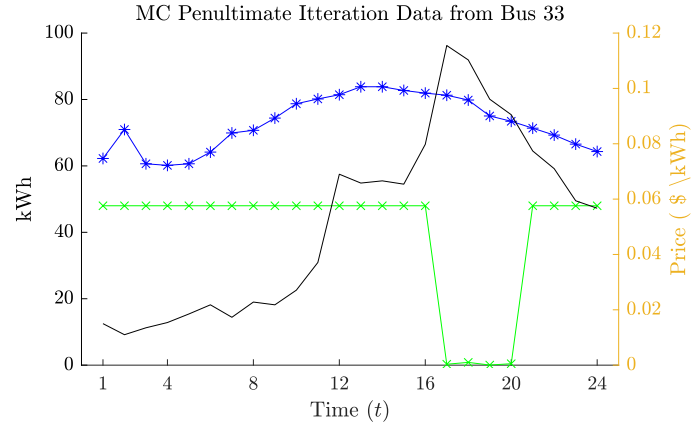


(a)

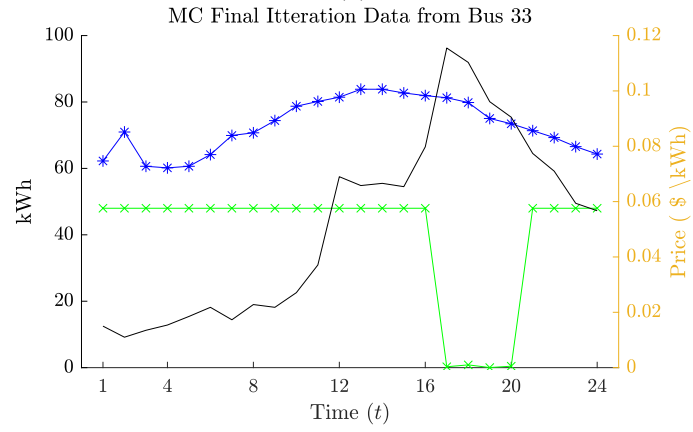


(b)

Figure B.36: Case 4: LC DER P_{inj} at bus 33



(a)



(b)

Figure B.37: Case 4: MC DER P_{inj} at bus 33

Appendix C

Non-Risk Adjusted Simulation Data

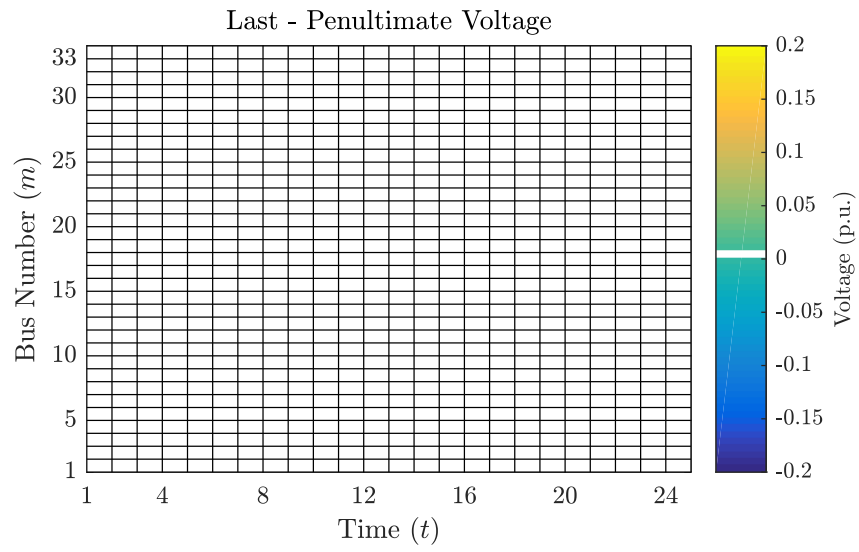
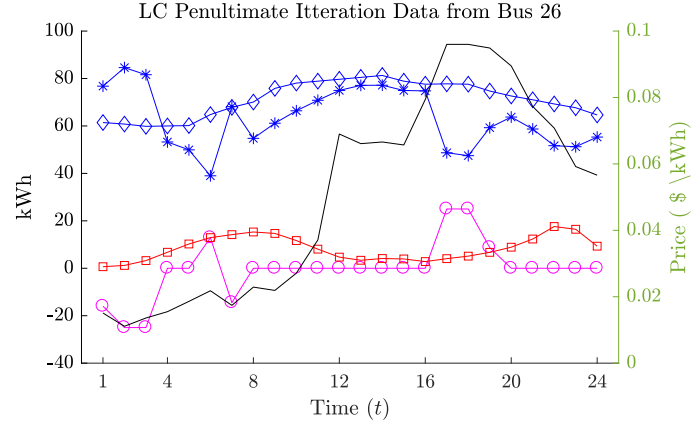
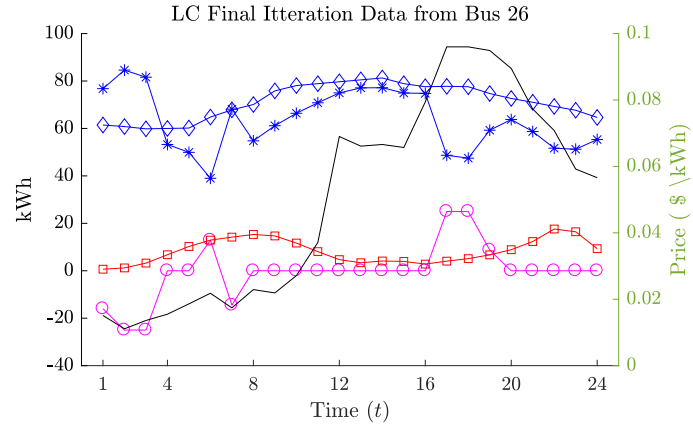


Figure C.38: Case 2 Voltage Difference in Final and Penultimate Iterations, Not Risk Adjusted

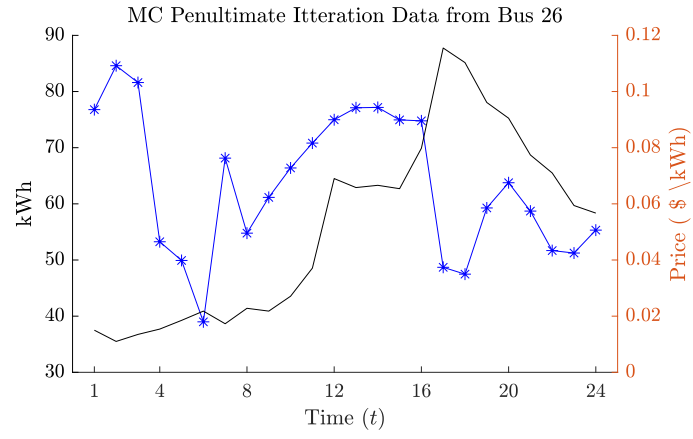


(a)

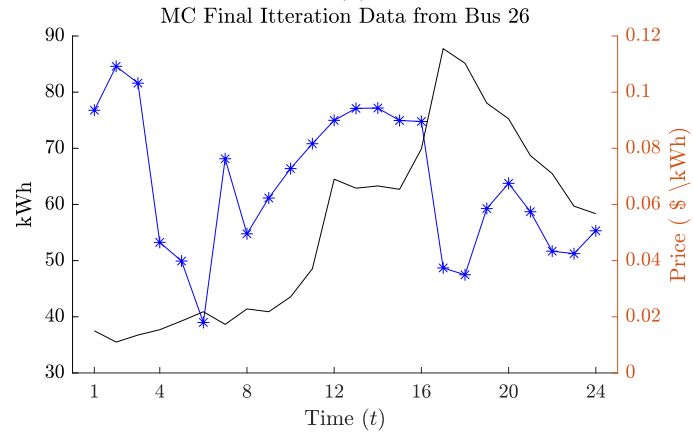


(b)

Figure C.39: Case 2: LC DER P_{inj} at bus 26, Not Risk Adjusted



(a)



(b)

Figure C.40: Case 2: MC DER P_{inj} at bus 26, Not Risk Adjusted

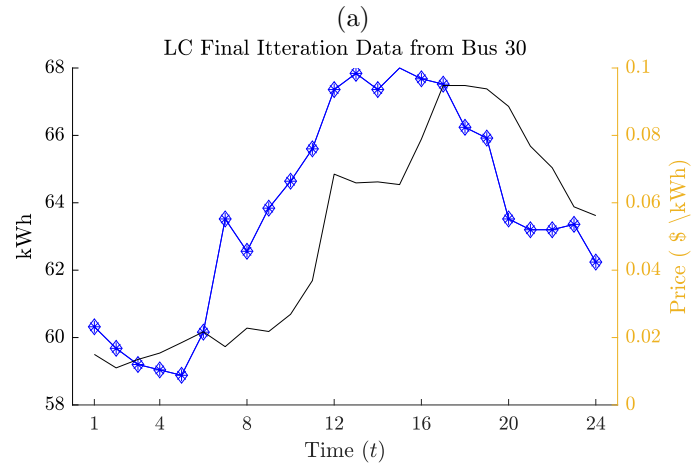
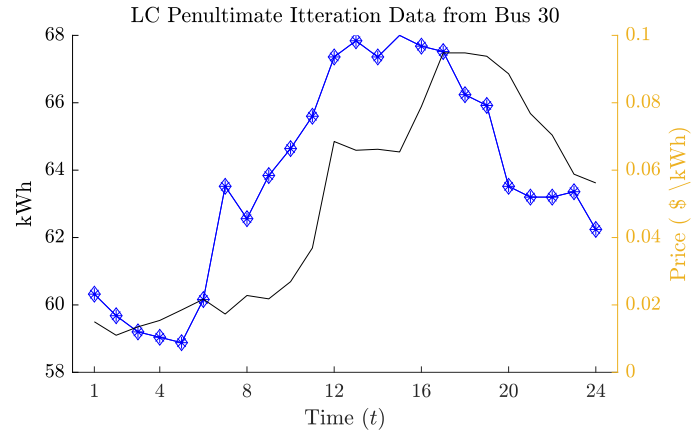
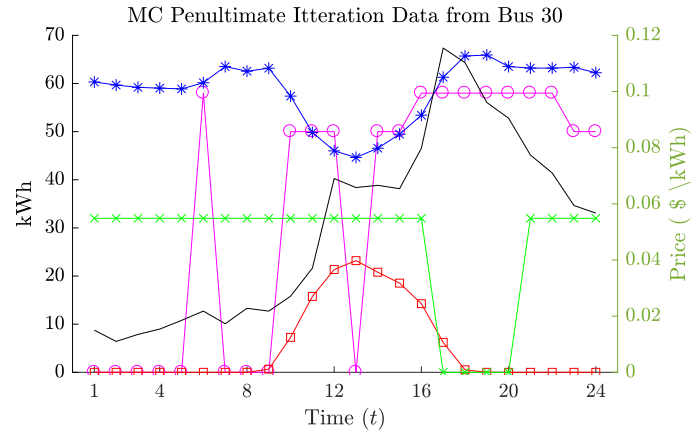
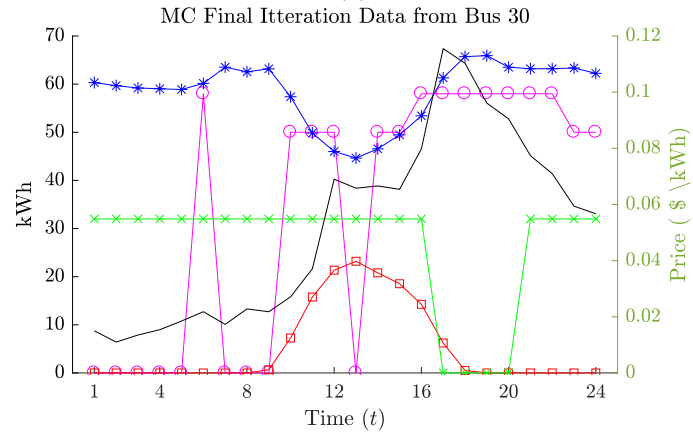


Figure C.41: Case 2: LC DER P_{inj} at bus 30, Not Risk Adjusted



(a)



(b)

Figure C.42: Case 2: MC DER P_{inj} at bus 30, Not Risk Adjusted

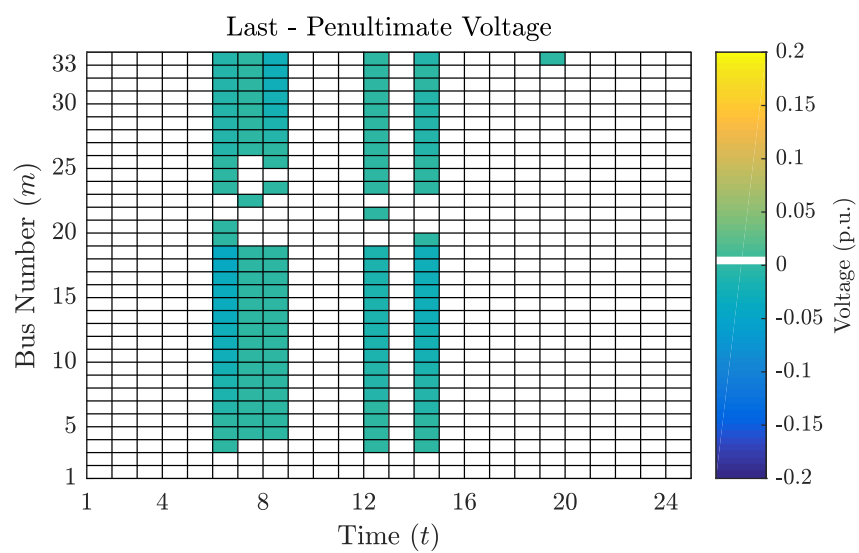
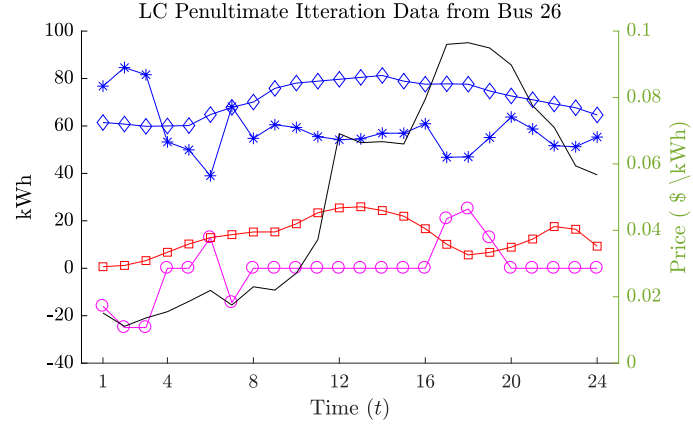
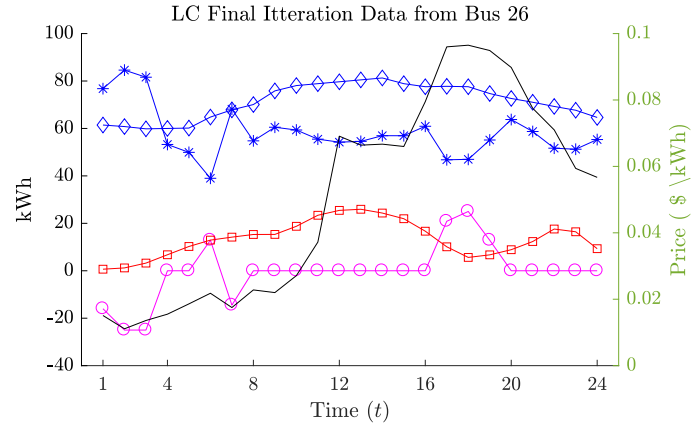


Figure C.43: Case 3 Voltage Difference in Final and Penultimate Iterations, Not Risk Adjusted

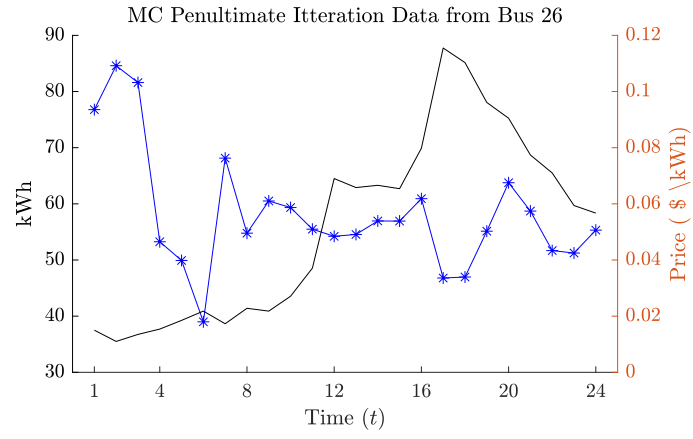


(a)

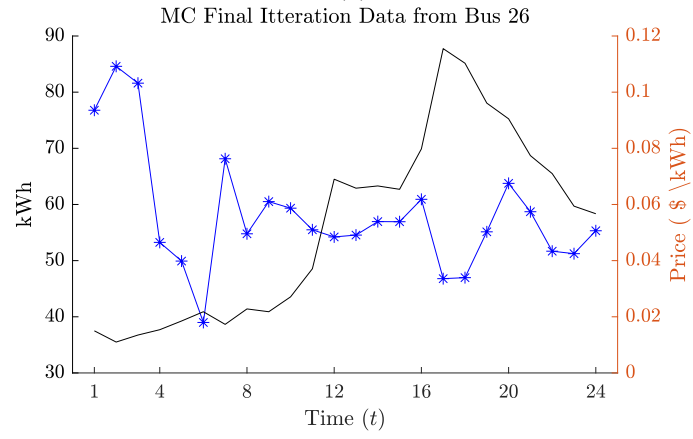


(b)

Figure C.44: Case 3: LC DER P_{inj} at bus 26, Not Risk Adjusted



(a)



(b)

Figure C.45: Case 3: MC DER P_{inj} at bus 26, Not Risk Adjusted

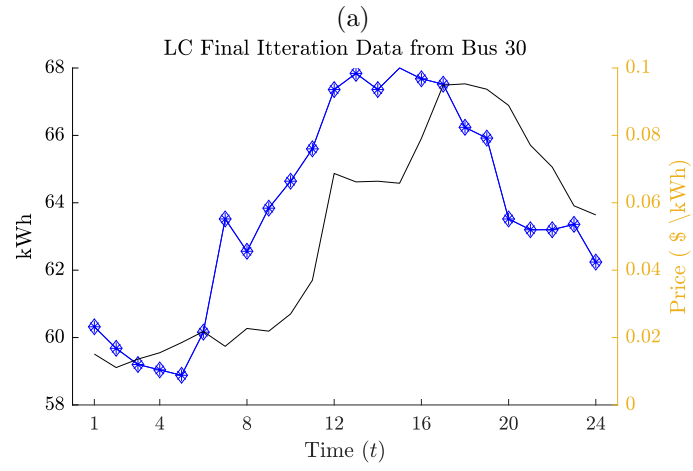
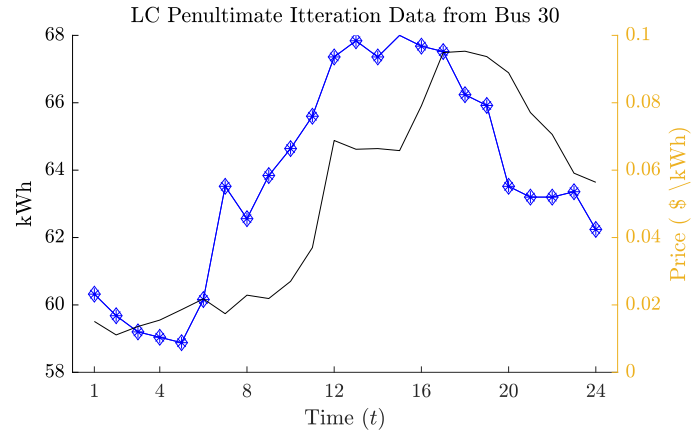
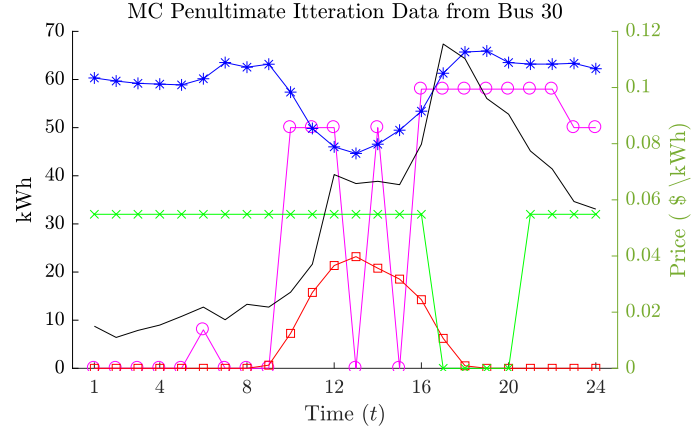
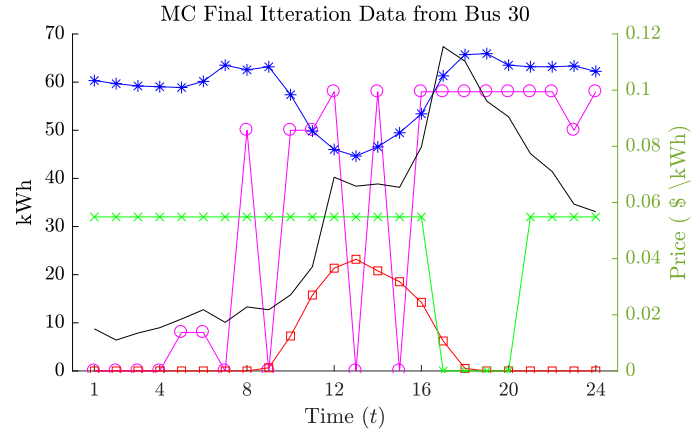


Figure C.46: Case 3: LC DER P_{inj} at bus 30, Not Risk Adjusted

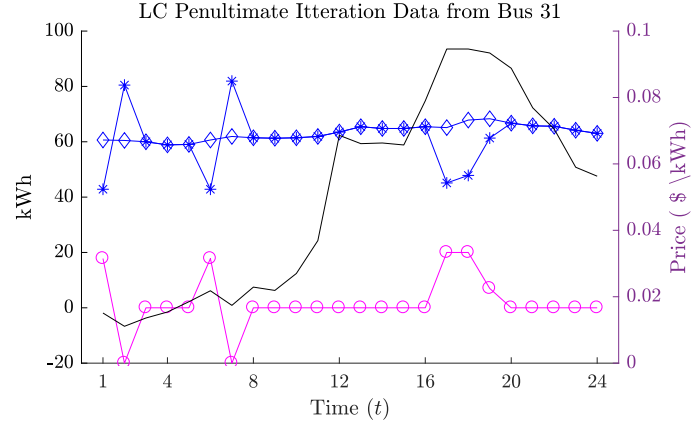


(a)

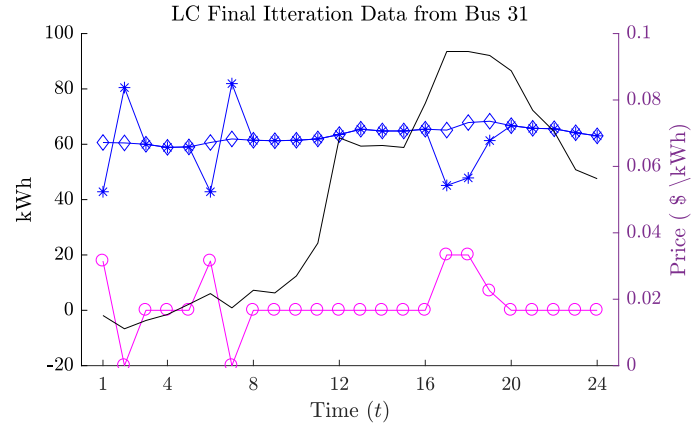


(b)

Figure C.47: Case 3: MC DER P_{inj} at bus 30, Not Risk Adjusted

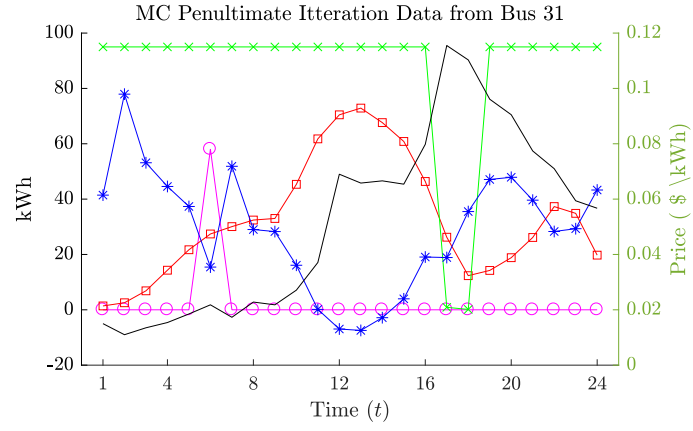


(a)

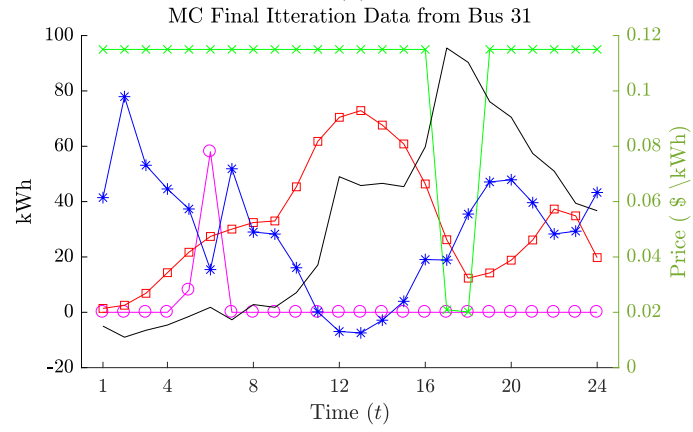


(b)

Figure C.48: Case 3: LC DER P_{inj} at bus 31, Non-Risk Adjusted



(a)



(b)

Figure C.49: Case 3: MC DER P_{inj} at bus 31, Non-Risk Adjusted

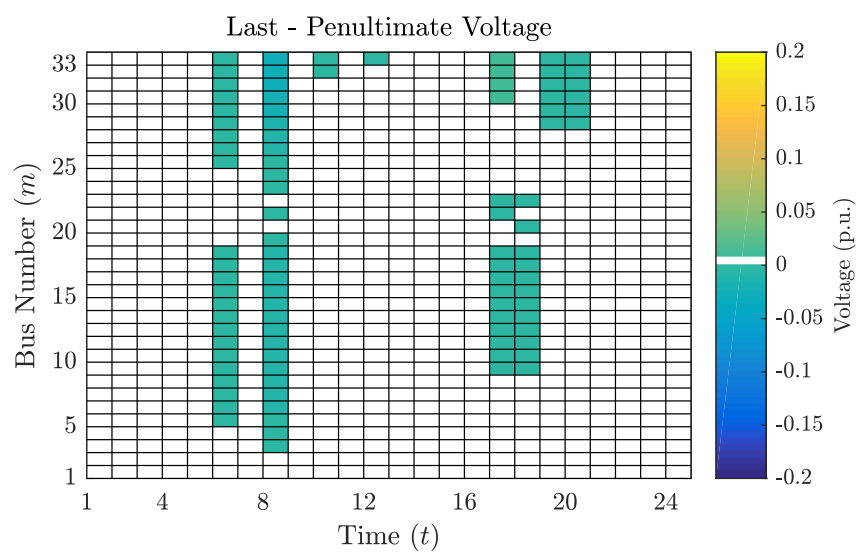


Figure C.50: Case 4 Voltage Difference in Final and Penultimate Iterations, Not Risk Adjusted

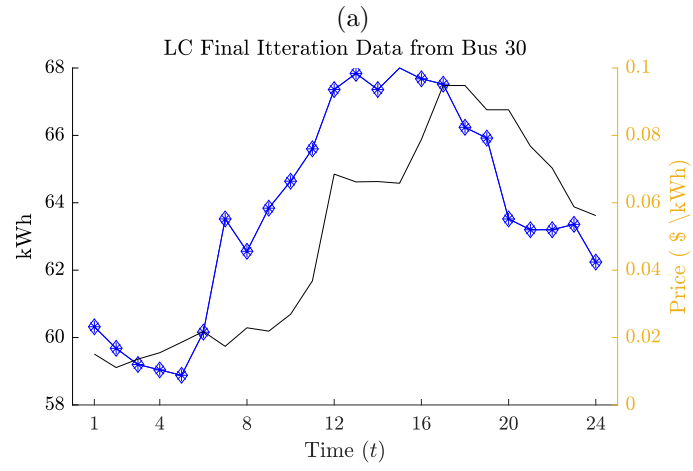
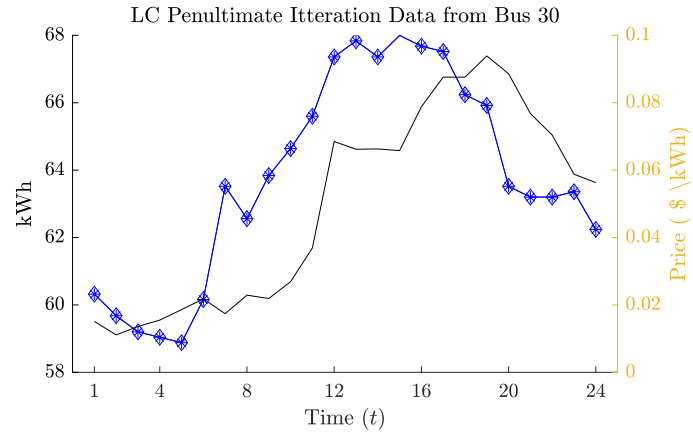
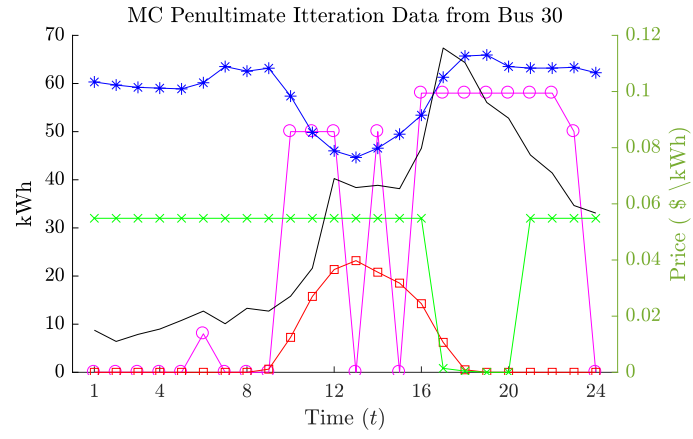
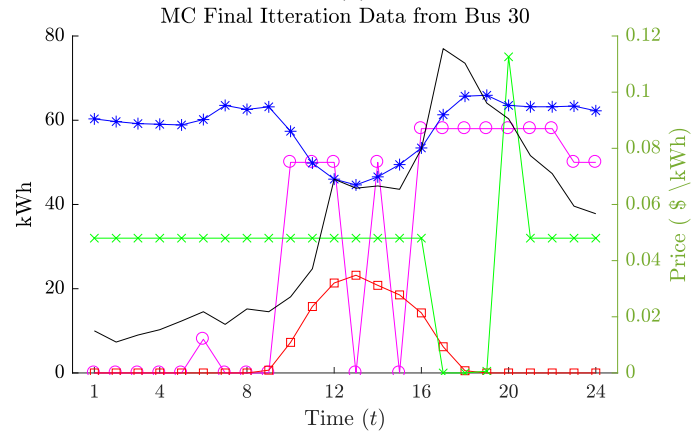


Figure C.51: Case 4: LC DER P_{inj} at bus 30, Not Risk Adjusted

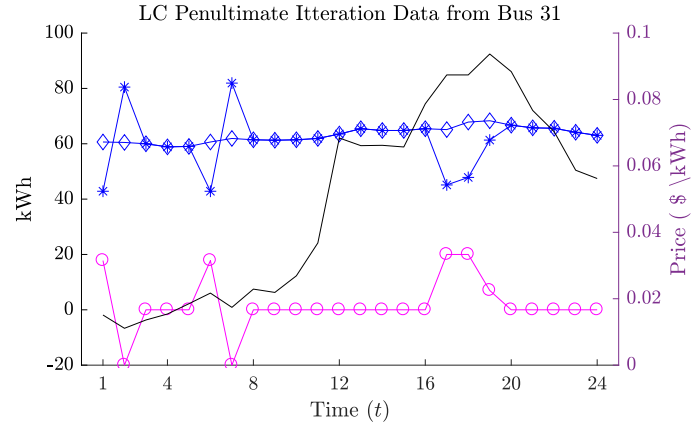


(a)

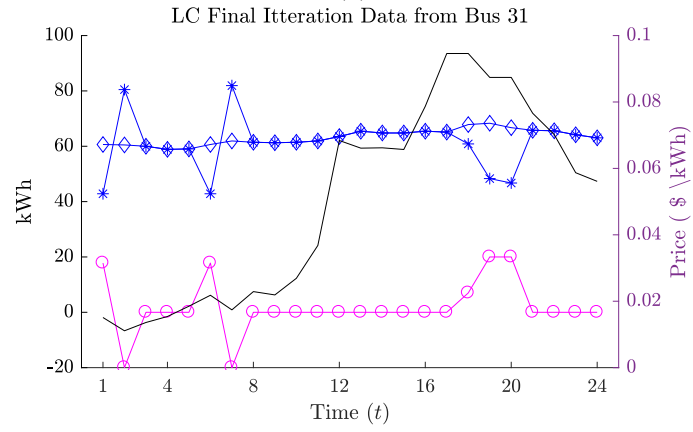


(b)

Figure C.52: Case 4: MC DER P_{inj} at bus 30, Not Risk Adjusted

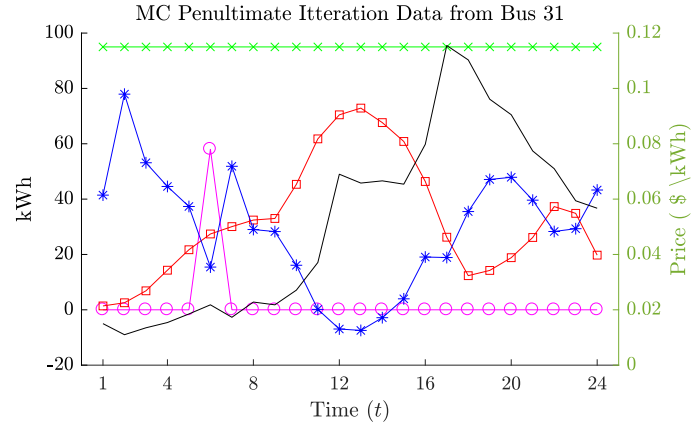


(a)

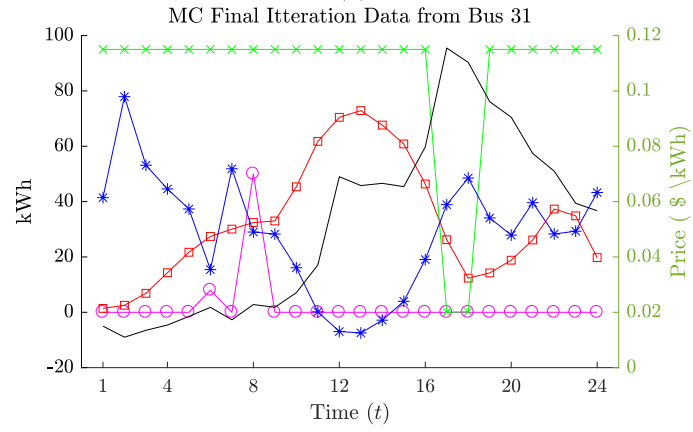


(b)

Figure C.53: Case 4: LC DER P_{inj} at bus 31, Non-Risk Adjusted

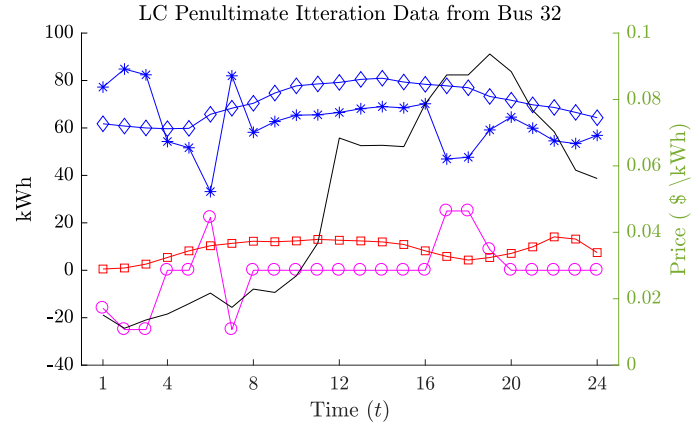


(a)

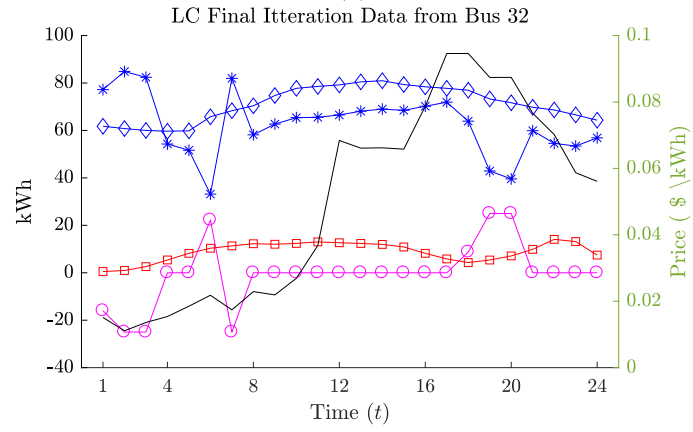


(b)

Figure C.54: Case 4: MC DER P_{inj} at bus 31, Non-Risk Adjusted

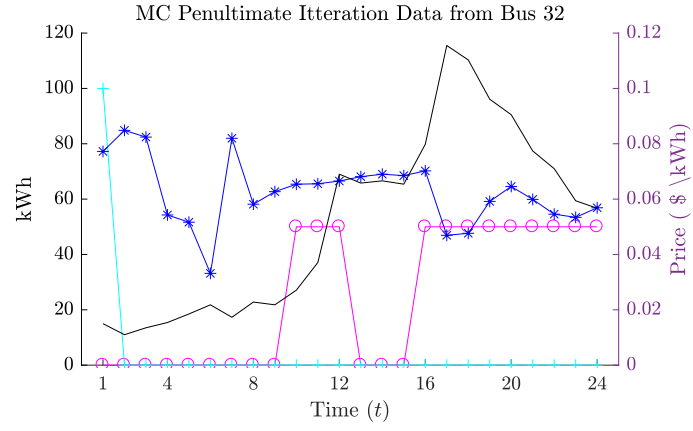


(a)

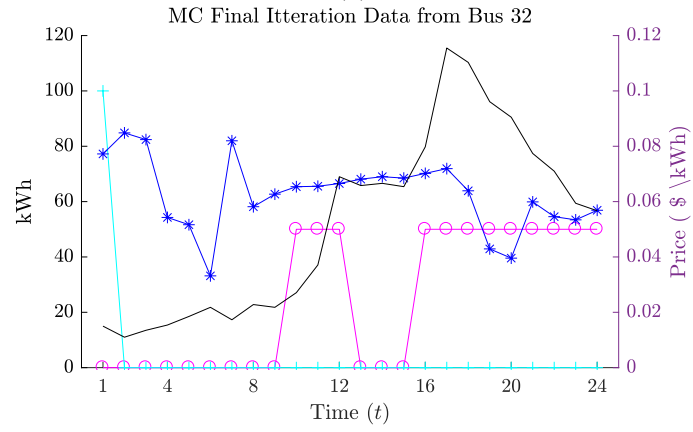


(b)

Figure C.55: Case 4: LC DER P_{inj} at bus 32, Non-Risk Adjusted

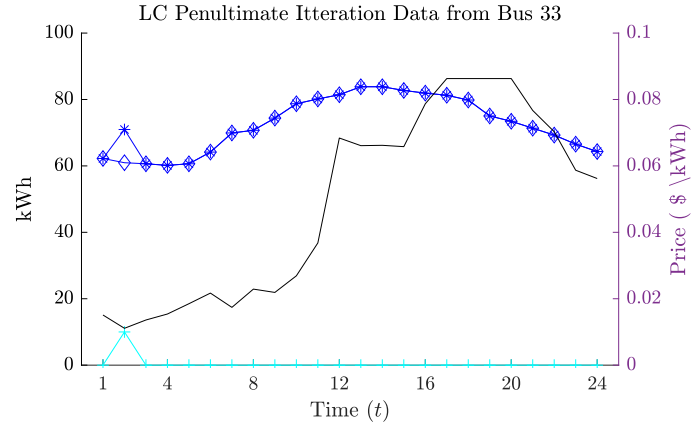


(a)

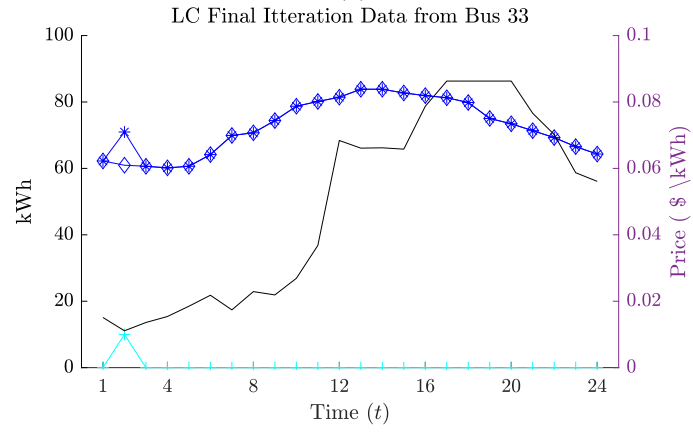


(b)

Figure C.56: Case 4: MC DER P_{inj} at bus 32, Non-Risk Adjusted

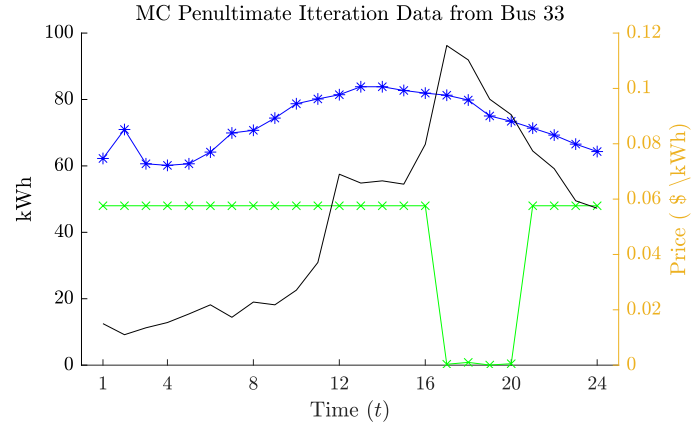


(a)

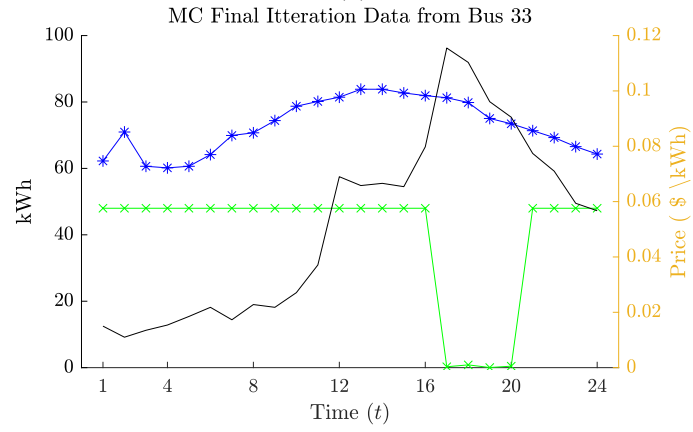


(b)

Figure C.57: Case 4: LC DER P_{inj} at bus 33, Non-Risk Adjusted



(a)



(b)

Figure C.58: Case 4: MC DER P_{inj} at bus 33, Non-Risk Adjusted