Configurable, Coordinated, Model-based Control in Electrical Distribution Systems

Joshua Clayton Hambrick

A dissertation submitted to the faculty of the Virginia Polytechnic Institute and State University in partial fulfillment of the requirements for the degree of

Doctor of Philosophy

in

Electrical Engineering

Committee Members:

Robert P. Broadwater (Chair)

Yilu Liu

Virgilio A. Centeno

William T. Bauman

Terry L. Herdman

April 28th, 2010
Blacksburg, Virginia

Keywords: (power systems, control, distribution, model-based)

Configurable, Coordinated, Model-based Control in Electrical Distribution Systems

Joshua Clayton Hambrick

ABSTRACT

Utilities have been planning, building, and operating electrical distribution systems in much the same way for decades with great success. The electrical distribution system in the United States has been consistently reliable; an impressive feat considering its amazing complexity. However, in recent years, the electrical distribution system landscape has started to undergo drastic changes. Emerging applications of technologies such as distributed generation, communications, and power electronics offer both opportunities and challenges to power system operators as well as customers and developers.

In this work, Graph Trace Analysis along with an integrated system model are used to develop algorithms and analysis methods necessary to facilitate the implementation of these new technologies on the electrical distribution system. A penetration limit analysis is developed to analyze the impact of distributed generation on radial distribution feeders. The analysis considers generation location, equipment rating, voltage violations, and flicker to determine the amount of generation that can be safely attached to a circuit.

A real-time, hierarchical, model-based control method is developed that coordinates the operation of all control devices on electrical distribution circuits. The controller automatically compensates for changes in circuit topology as well as the addition or removal of control devices from the active circuit. Additionally, the controller allows the integration of modern, "smart" equipment with legacy control devices to facilitate incremental modernization strategies.

Finally, a framework is developed to allow the testing of new analysis and control methodologies for electrical distribution systems. The framework can be used to test scenarios

over multiple consecutive hourly or sub-hourly time points. The framework is used to demonstrate the effectiveness of the model-based controller versus existing operating methods for a distribution circuit test case.

Table of Contents

List of Tables

List of Figures

Chapter 1 Introduction

1.1 Overview

The Electrical Distribution System (EDS) is generally considered the portion of the electric power system between the bulk power sources and the consumer [1]. The goal of an EDS is to provide power to the end users efficiently, reliably, and within established operating criteria. These criteria consist of voltage and frequency requirements that are designed to protect both the utility's grid infrastructure as well as devices receiving their power from the grid.

Historically, the vast majority of electrical power is supplied by large, centralized generation sources such as coal, nuclear, and hydro power plants through a high-voltage transmission system. The power is stepped down to primary distribution levels (typically between 12 and 15 kV) through a sub-transmission system, and then stepped down again and delivered to the end users via the EDS. Figure 1.1 illustrates the typical electrical grid configuration.

The architecture of an EDS can vary widely based on any number of factors including location, load density, and utility design philosophy. In the United States, there are two major configurations for distribution systems, the radial system and the networked system. Radial systems are the most common type of EDS and are designed to serve load along a single path, typically from a substation. Networked distributions systems may have multiple paths between the source or sources and the load. Networked systems are not as common as radial systems but are often used where continuity of service is important. Both radial and networked distribution circuits can be designed to be reconfigurable. The path from the source to the load, often referred to as the circuit topology, can often be changed to restore customers after an outage or to relieve heavily loaded portions of the system.

The two major controlled quantities in the electrical power system are voltage and frequency. Frequency is controlled through real power sources, and voltage is controlled through reactive power sources and transformer manipulation.

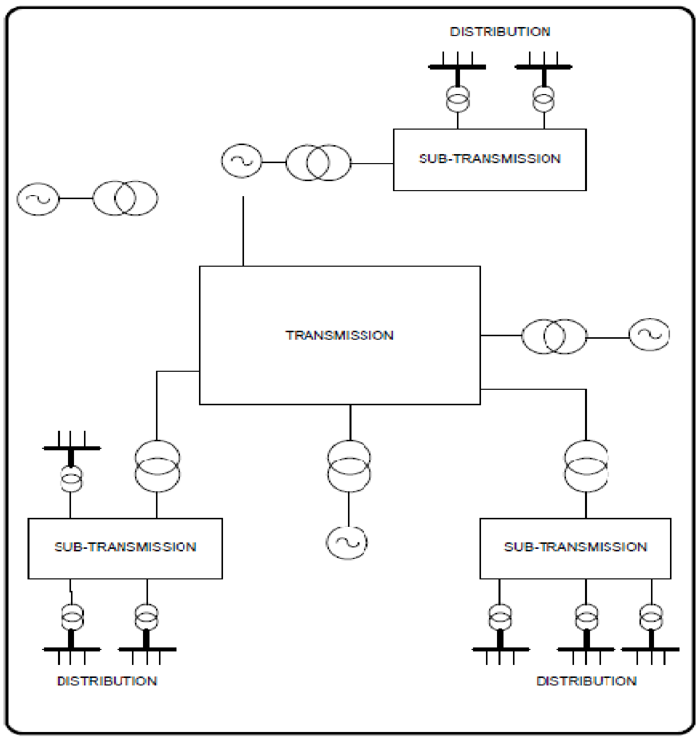


Figure 1.1 Electrical Power System

For the most part, real power is controlled at the bulk power sources by the turbine-generator control system. In the United States, most real electrical power is supplied by converting mechanical power from steam, water, or wind into electrical power. The electrical frequency is an indication of the ratio of load to generation. As long as the load matches the generation, the frequency will remain constant. If the load exceeds generation the frequency will decrease, and if generation exceeds load the frequency will increase. In the United States, the frequency is regulated to 60 Hz.

As power travels from generation sources to the loads, losses, seasonal load changes, disturbances, and other unpredictable events make it necessary to control the voltage at the distribution level. Utilities generally strive to maintain the voltage criteria specified in ANSI 84.1 [2] and shown in Figure 1.2.

Reactive power is not consumed to do work the way real power is; however, the existence of reactive power is necessary for the grid to operate and therefore reactive power must be delivered. The delivery of reactive power contributes to both voltage changes as well as losses. Most elements present in AC power systems have some reactive component. Reactive power is not explicitly regulated, but it greatly affects the efficiency of the EDS. The majority of losses in the electrical power system are caused by current flowing through conductors. These losses, commonly referred to as copper losses, occur in lines, transformers, and any device which carries current. Equation (1.1) describes the copper losses in an electrical system.

$$P_{Loss} = |\mathbf{I}|^2 R \tag{1.1}$$

The current **I** in a system is given by

$$\mathrm{I} = \frac{\mathbf{S}^*}{\mathbf{V}} \tag{1.2}$$

where **V** is the complex voltage. **S** is the apparent power and is given by

$$\mathbf{S} = P + jQ \tag{1.3}$$

where P is real power and Q is reactive power. P is largely dictated by the load attached to the system. Load is difficult to actively control. At present, the main method of load control is under-frequency load shedding and is generally only used as a last resort when the grid is on the verge of a major instability or when grid devices are close to catastrophic failures. Thus, minimizing the reactive power Q is the most effective way to reduce losses.

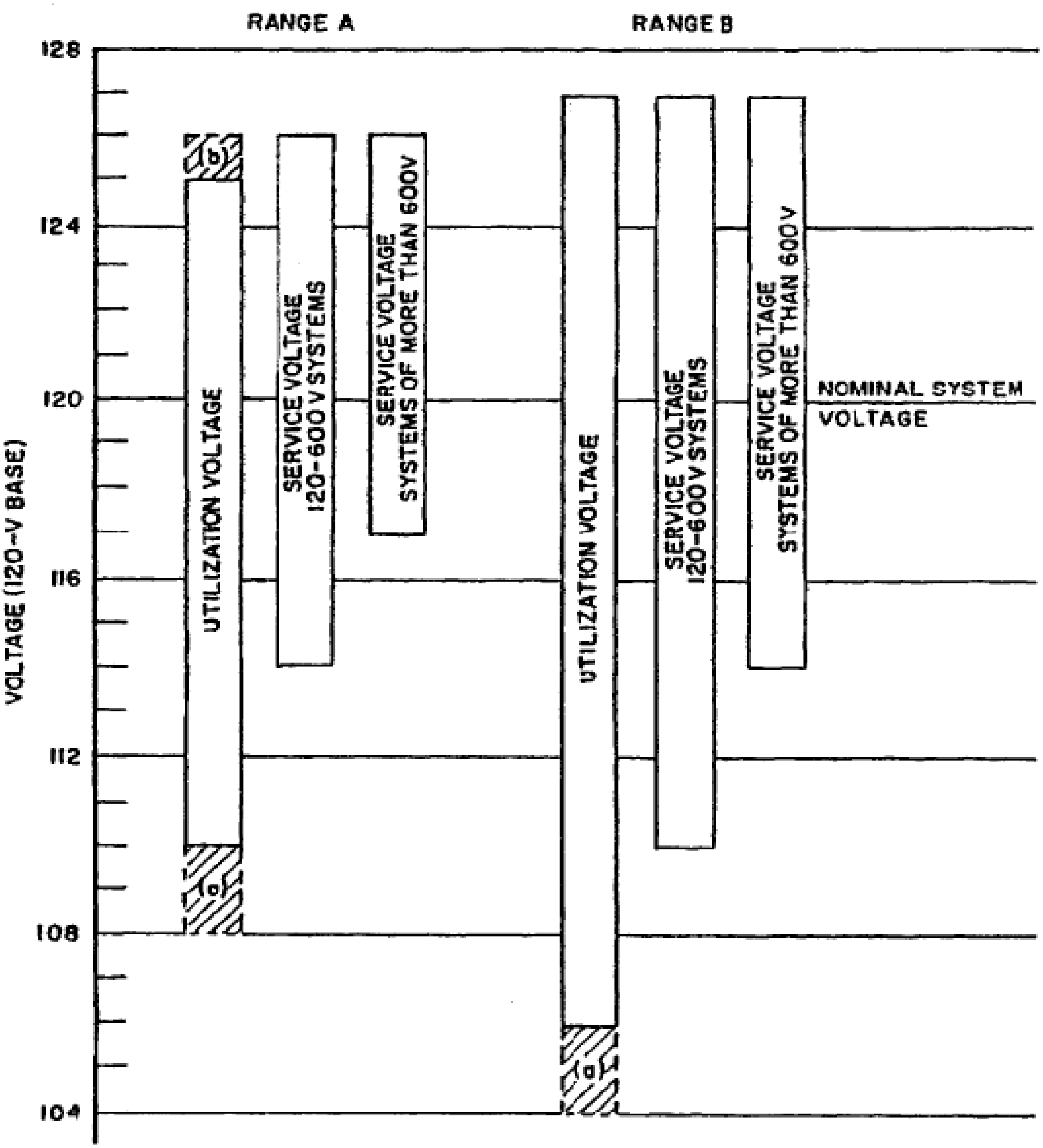


Figure 1.2 ANSI 84.1 Voltage ranges

The load on a circuit as well as the expected load growth play a very large role in EDS design. Specifically, circuits need to survive their expected peak load without violating any of the operating criteria mentioned above or any of the device thermal or capacity ratings. The load on a given circuit, however, can vary wildly throughout the year. These load variations are a function of many variables including geographical region, types of customers on the circuit, types of water heaters, and types of heating and cooling.

Utilities and system operators illustrate loading on their systems using a Load Duration Curve (LDC). The LDC is a chart of the load for the entire year sorted from peak load to minimum load.

Figure 1.3 shows the LDC for the Midwest ISO from 2006 through 2008. While individual distribution circuits may have different load profiles, the LDC shows that the overall system consistently has a very steep drop from peak generation levels. In other words, the system is at peak load levels, the operating point which so greatly impacts the EDS design process, for only a few hours per year.

Traditionally, devices that control the voltage and the reactive power flow on a distribution circuit are controlled independently and designed to survive peak load conditions. Devices such as capacitors, voltage regulating transformers, and load tap changers typically operate on local set-points and are generally not aware of topology changes or the state of other control devices on the circuit. Common control devices and their effects on distribution circuits will be discussed in detail in below.

Because circuits can operate away from their designed loading points for much of the year, control devices will sometimes conflict with each other causing them to oscillate or “hunt”. Hunting causes a device to operate more often than designed which leads to increased wear on the machinery, accelerated maintenance schedules, and eventually early device replacement. Often control device set-points are widened to keep devices from hunting; however, doing so can decrease the effectiveness of the control device.

In addition to load variability, changes in circuit topology also impact the performance of EDS control devices. Topology changes can be scheduled or unscheduled. Examples of scheduled topology changes include reconfiguration for loss minimization, isolation of components under maintenance, and reconfiguration to reduce loading on a heavily loaded circuit. Unscheduled topology changes are common to EDS due to protective device action such as fuses blowing or breaker operation.

To help alleviate some of the control issues, utilities are investing in new, “smart” devices that have increased control and communication capabilities. Though these devices offer flexibility and opportunities for more advanced control strategies, a utility cannot simply discard and replace its entire infrastructure overnight. Planners must find ways to allow advanced and legacy control devices to coexist in both planning and operating processes for the foreseeable future.

1.1 Typical Control Devices

The voltage criteria discussed above have historically been maintained by two types of control devices: voltage regulating transformers and capacitors. Additionally, many types of DER such as synchronous machines and DER with inverter-based interconnections are capable of regulating voltage on the circuit. Currently, however, the IEEE 1547 DER interconnection standard recommends that DER operate at a fixed power factor [3]. In this configuration, DER are not used to control voltage on a distribution circuit. As DER become more common, utilities may start to look to DER for voltage support.

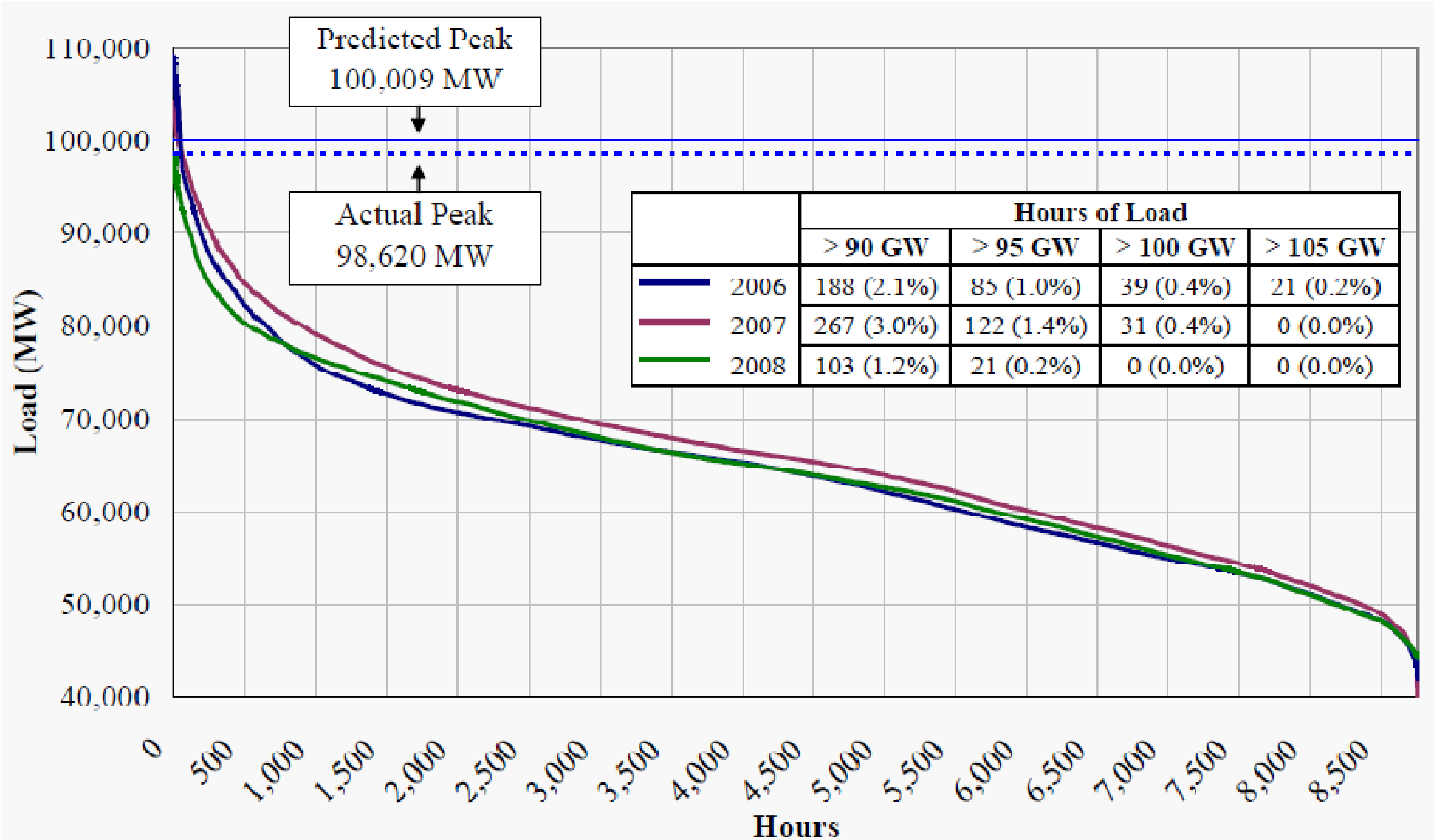


Figure 1.3 Midwest ISO Load Duration Curves [4]

One method of assessing the affect a control device is having on a circuit is a voltage profile. A voltage profile is a plot of the voltage rise or drop from a point on a circuit, often an end point, back to the substation. The following sections, from a technical report on EDS voltage regulation [5], are representative of the effects the different types of control devices have on the voltage profile of a circuit. The actual effects a control device has are dependant on a number of factors including loading, topology, and device ratings.

Figure 1.4 shows the voltage profile for a simulation of a test circuit with no control devices active. Note that distribution voltages are commonly normalized to 120 V. In this case, a distribution voltage level of 13.2 kV is equal to 120 V. Distance 0 corresponds to the substation transformer. The solid line indicates a primary transformer voltage (sub-transmission voltage) of 105%, and the dashed line indicates a primary voltage of 95%. The steep drop at Distance 0 is due to the voltage drop through the substation transformer. The shape of the remaining curve is determined by the line characteristics and the load being served. Since no control devices are active on the circuit and the load is largely inductive, the voltage drops steadily as the distance from the substation increases.

1.1.1 Load Tap Changers

Load Tap Changers (LTC) are transformers that are able to adjust their turns ratio, usually between 5% and 10% of rated voltage. The purpose of the LTC is to maintain a consistent voltage at the beginning of a distribution feeder by minimizing the impacts of transmission and sub-transmission voltage variability. Planners sometimes utilize line drop compensation in conjunction with the LTC to account for the effects of loading on the circuit. Line drop compensation approximates an impedance and adjusts the voltage set-point based on the load on the transformer. In this fashion, the LTC can use local voltage and current

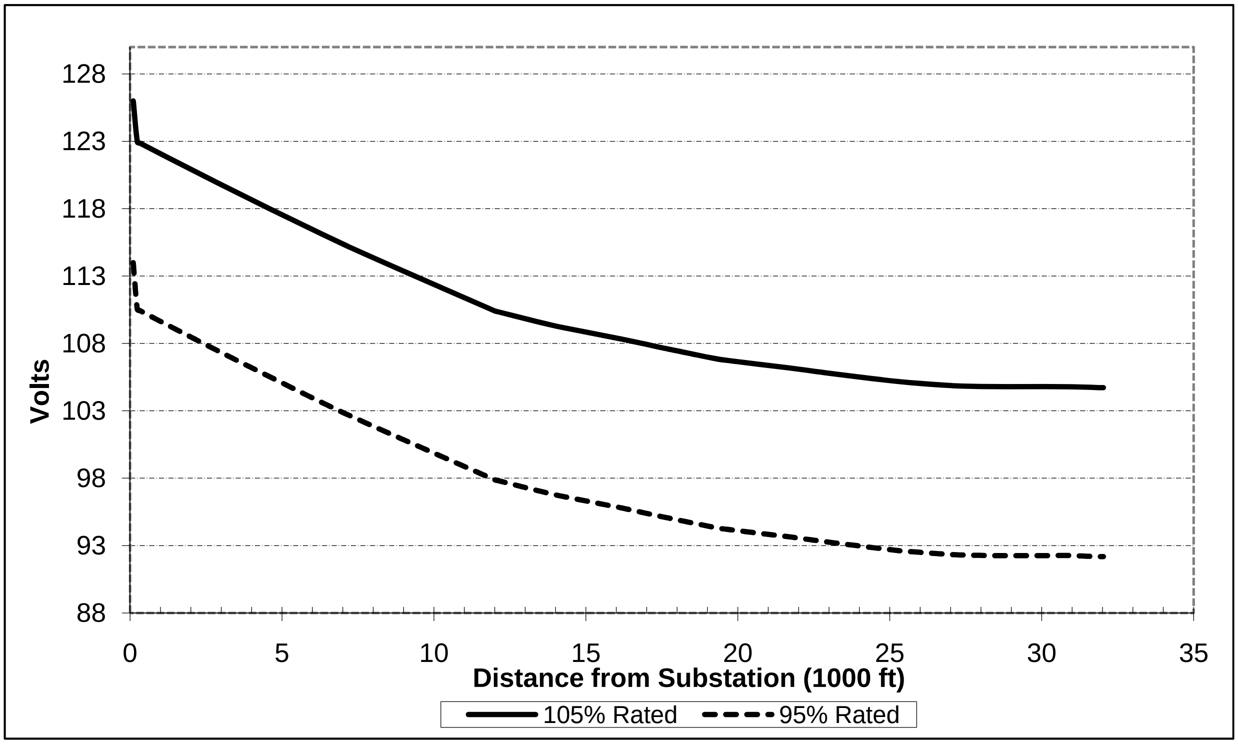


Figure 1.4 Voltage profile: no active control

measurements to compensate for a voltage drop somewhere out on the circuit instead of at the LTC location.

Figure 1.5 shows the test circuit corresponding to Figure 1.4 with the LTC active. The LTC is set to maintain 124.5 ± 1 V on the secondary of the transformer with no line drop compensation. The steep voltage changes around 0, step down for 105% and step up for 95%, are due to LTC maintaining its voltage set-point. Over a 10% range in primary voltage, the LTC maintains a fairly constant voltage at the transformer secondary.

Figure 1.6 compares LTC control with the no control case. From this figure it is clear that, for the most part, the LTC just shifts the voltage profile higher. The shape of the curve may change slightly due to the overall voltage dependency of the loads. In this case, however, the shape of the curve remains consistent between the two cases.

1.1.2 Voltage Regulating Transformers

Voltage Regulating Transformers or Voltage Regulators (VR) are similar to LTC in functionality [6]. VR are usually 1:1 transformers with adjustable taps that can increase or decrease the output voltage as necessary. VR are used to correct voltage on distribution circuits, typically where the voltage begins to dip below acceptable levels. Like LTC, distribution system planners will often use line drop compensation to include the effects of loading on the voltage profile.

Figure 1.7 shows the effects of a VR on the test circuit compared to the LTC only case. The VR is installed about 12,500 ft. from the LTC. Both the LTC and VR are set to maintain a voltage of 124.5 ± 1 V with no LDC. Like LTC, the VR provides a step shift in the voltage where it is installed and does not greatly affect the shape of the voltage profile.

1.1.3 Capacitors

Distribution circuits and loads tend to be inductive. Capacitors supply much needed leading reactive power to the EDS. Capacitors can be either located at the substation or out on the circuit. Substation capacitors are generally used to support transmission voltage and usually do not have a great impact on distribution circuit, particularly when LTC are in use. If capacitors are located on the circuit then the reactive power does not need to be transmitted from the substation, the current is reduced and therefore the voltage drop is less.

On distribution circuits, capacitors can be fixed or switched. A fixed capacitor is always connected to the circuit. Switched capacitors are connected and disconnected from the EDS as they are needed. Common control techniques for switched capacitors include strategies based on reactive power and voltage feedback, as well as temperature and time.

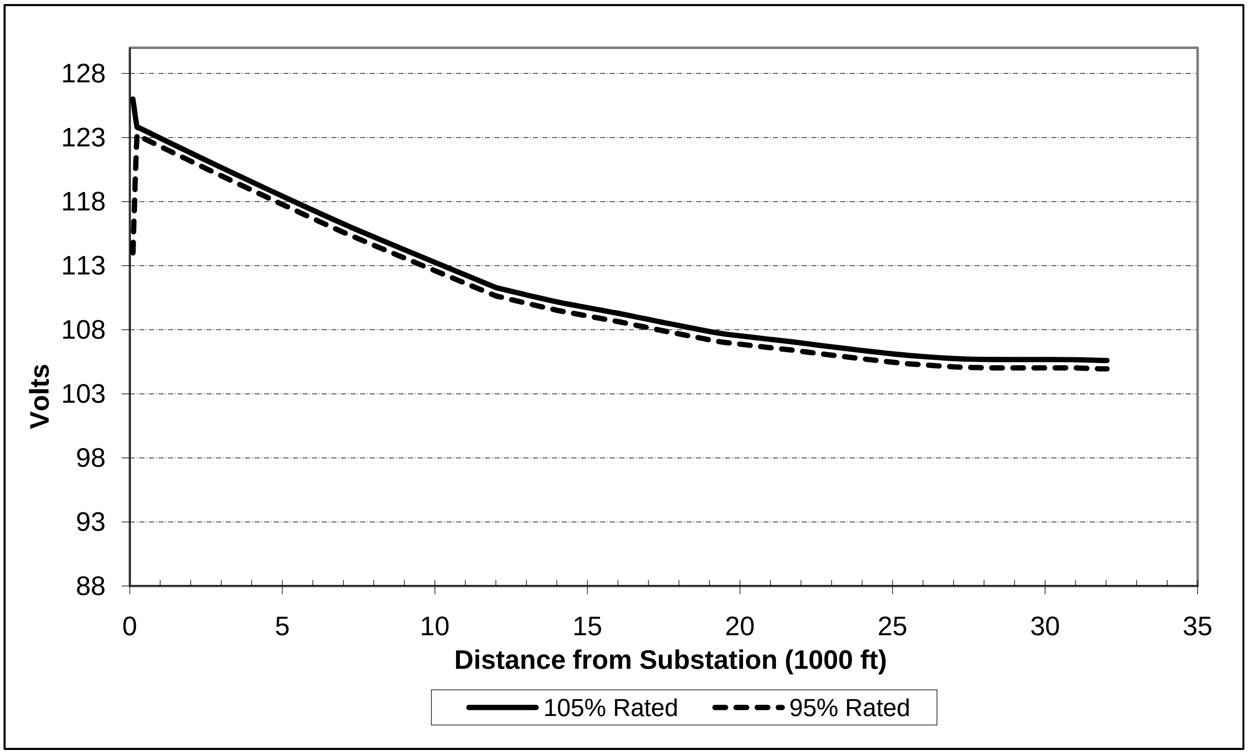


Figure 1.5 Load profile: LTC only

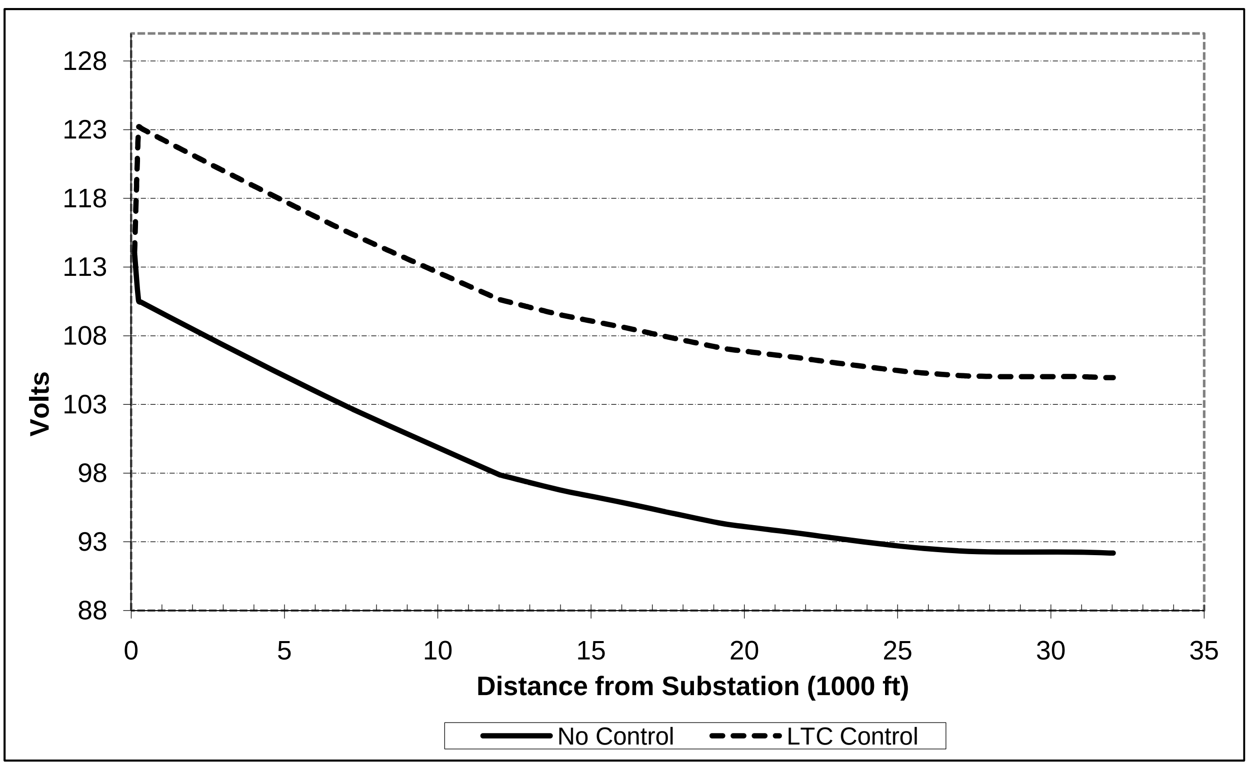


Figure 1.6 Voltage profile: impacts of LTC

Switched capacitors can be single- or multi-step. When a single-step capacitor is switched on, the entire capacitive reactive power supply is switched onto the circuit at once. Switching the capacitors on and off has been known to cause severe transients on the EDS. For this reason, EDS operators will often schedule capacitor switching operations at times when few people are likely to notice, and multiple capacitor operations may be staggered.

Multi-step switched capacitors can be tied to the distribution circuit in stages. By using a finer control method, multi-step capacitors can alleviate many of the problems associated with single-step capacitors.

Figure 1.8 illustrates the effects of capacitors on the circuit. Unlike the LTC and VR, the capacitors do not simply shift the voltage. Instead, by compensating for inductive reactive power on the circuit, capacitors change the shape of the load profile curve.

1.1.4 Distributed Energy Resources

DER are sources of real and reactive power connected at the distribution levels. Common examples of DER include photovoltaics (PV) and emergency backup generators. Unlike capacitors and VR, DER are not presently utilized by the utility for EDS control, in part because DER tend to be customer owned.

Some utilities make use of dispatchable DER in a number of ways [7], including the reduction of EDS circuit peak. Dispatchability refers to the ability to control the real power output of the DER. PV systems, for example, are not considered dispatchable because the output is dependent on solar radiation. A diesel generator is considered dispatchable because the real output can be controlled.

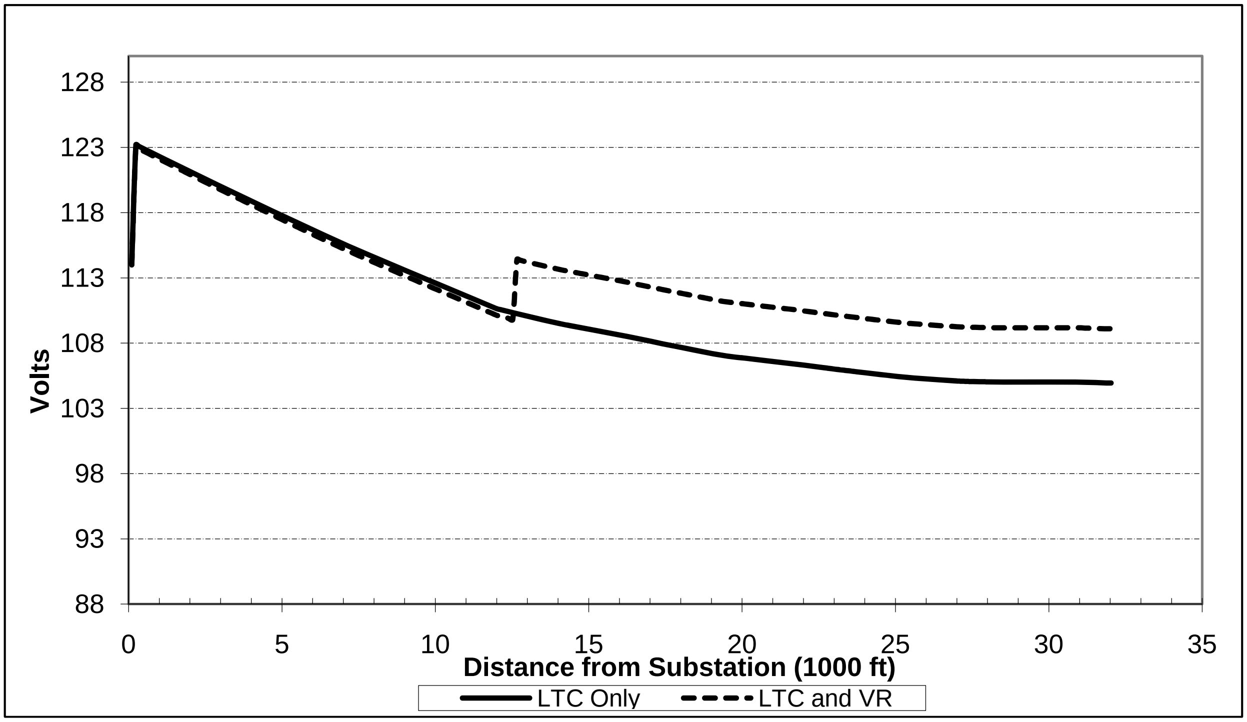


Figure 1.7: Voltage profile impacts of VR

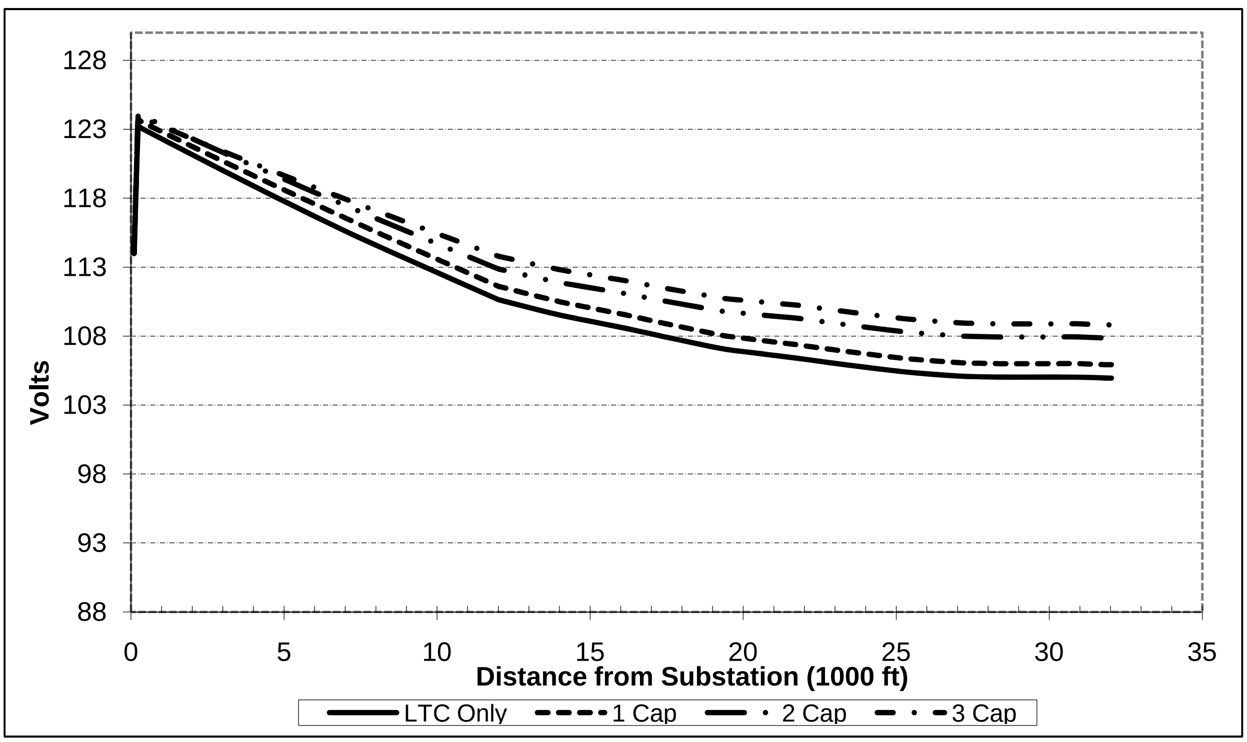


Figure 1.8: Voltage profile impacts of capacitors

Unlike the control devices mentioned to this point, DER have both a real and a reactive element. For this reason, DER can provide a great amount of flexibility in EDS control. Figure 1.9 illustrates the impact of DER real power injection on EDS voltage with no reactive power contribution. Figure 1.10 shows the impact of reactive power on EDS voltage with a fixed real power injection of 100%. For these plots, both the LTC and VR are active.

1.2 Dissertation Justification and Outline

Utilities have been planning, building, and operating EDS in much the same way for decades with great success. The electrical power system in the United States has been consistently reliable, an impressive feat considering its amazing complexity. However, in recent years, the EDS landscape has started to undergo drastic changes. Emerging applications of technologies such as communications and power electronics offer both opportunities and challenges to EDS operators as well as customers and developers. Distributed Energy Resources (DER) including diesel and natural gas generators, energy storage, photovoltaic (PV) systems, and small wind turbines are becoming more and more common on the EDS. Since most EDS were designed to serve power from the substation in one direction only, DER can present a number of challenges to the system planner [8].

Additionally, loads themselves have undergone significant changes, and increased customer participation through real-time pricing promises to complicate things further. Wide spread adoption of "Smart" appliances, home area networks, and energy management systems could drastically impact load profiles and limit the effectiveness of commonly accepted EDS design methodologies.

To support the design and operation of the EDS in the midst of such fundamental changes, the planning and operation process must be reevaluated. In many cases, the general

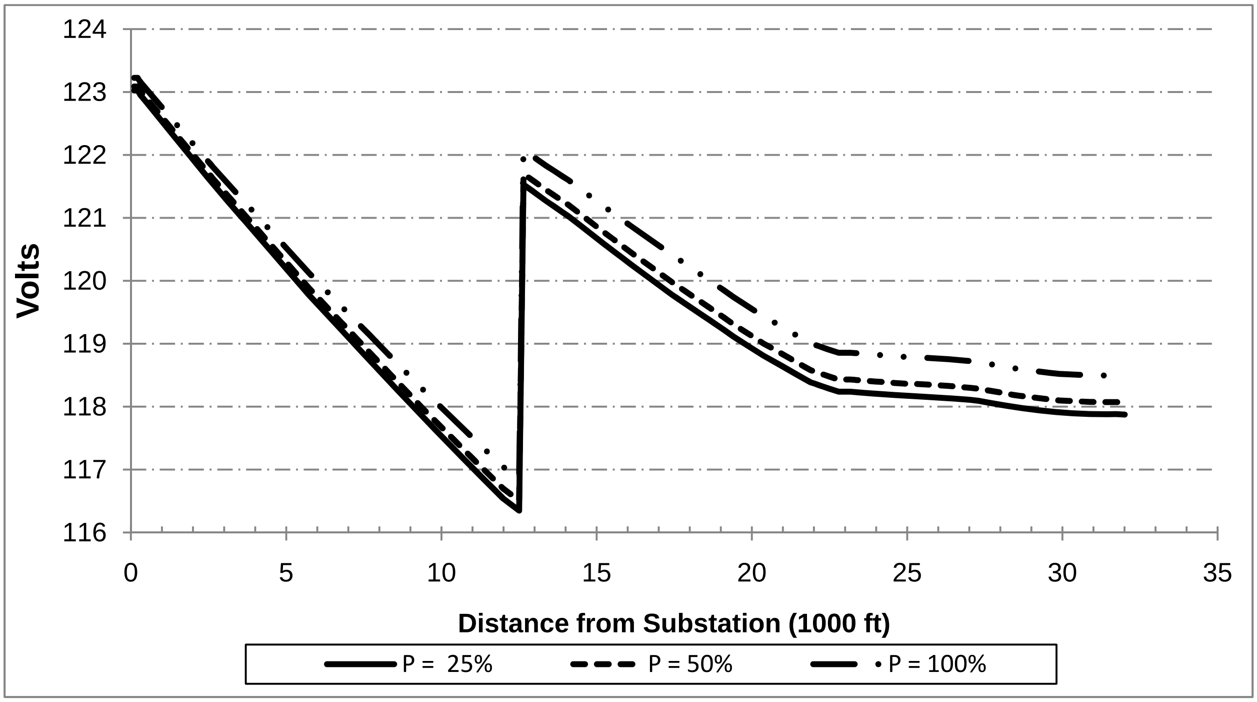


Figure 1.10 Voltage profile: impact of DER real power

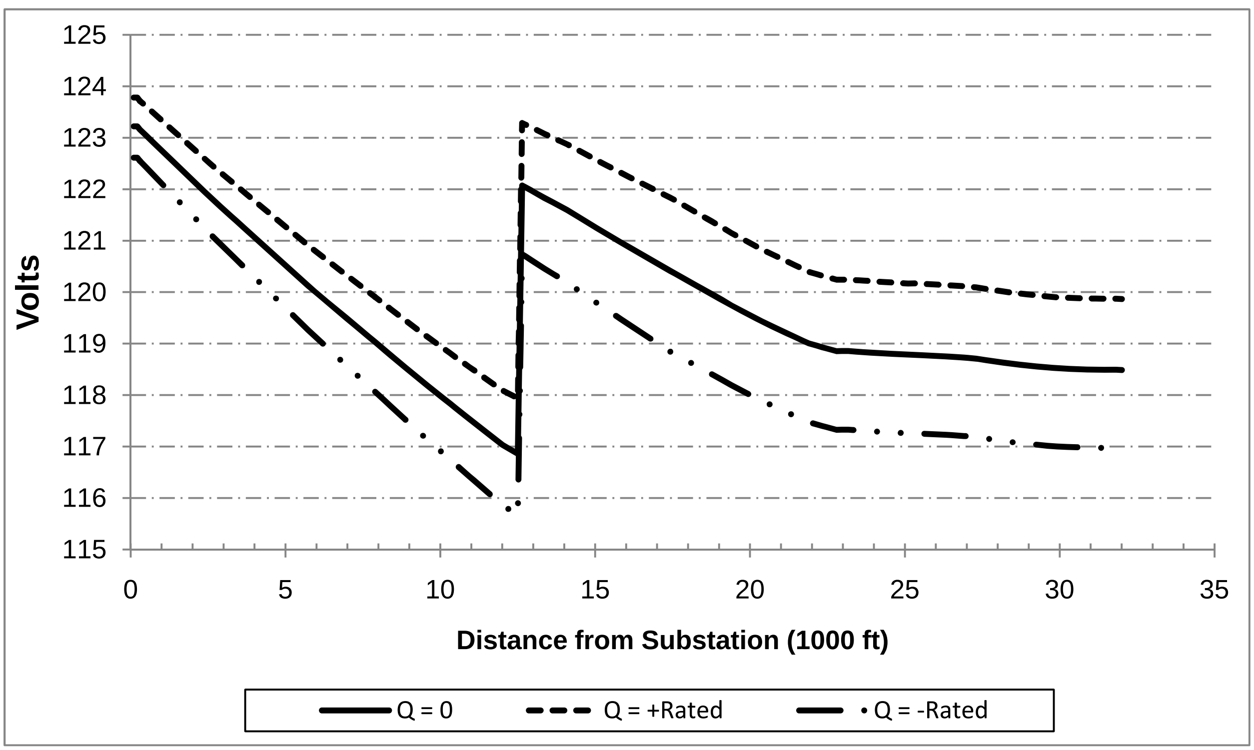


Figure 1.9 Voltage profile: impact of DER reactive power

guidelines and "rules of thumb" that have served utility engineers so well in the past were not designed to deal with the modern and future EDS. Additionally, load growth and an aging infrastructure are forcing utilities to reconsider how they operate their distribution systems. The excess transmission and distribution capacity utilities once enjoyed has eroded, and now utilities are trying to reduce the amount of power they must generate and transmit by improving the efficiency of their systems.

This work presents a number of new tools, analysis methods, and metrics intended to assist planners, customers, and developers as they face the challenges of the rapidly approaching modern EDS. These tools, along with a brief description, are listed below.

- **Distribution Penetration Analysis**: Penetration refers to the amount of DER, either as a single unit or in aggregate, interconnected on a circuit or collection of circuits. Traditionally, penetration has been calculated based on the rated capacity of the DER and the maximum load. While a satisfactory metric when DER is relatively scarce, the growing popularity of DER along with the variability of some DER sources such as wind and solar create a demand for a more thorough analysis. The distribution penetration analysis fills this gap in current technology by determining the size at which DER violate EDS criteria such as voltage, loading, or flicker.
- **Real-time Coordinated Control:** Real-time coordinated control refers to configurable, hierarchal, model-based control (CHMC) of the EDS. The CHMC described in this work is a dual-mode, topology independent algorithm which provides steady-state operating points to the local controllers of control devices commonly found on the EDS. The CHMC allows the EDS to be self-healing; it automatically detects and utilizes control

devices connected to the EDS. Additionally, the CHMC is a method for integrating legacy, autonomous distribution control devices into the modern EDS.

- **Advanced Time Series Analysis:** Traditionally, EDS analysis was performed for few but important conditions on the EDS such as peak and minimum load. Software has made it possible to more quickly perform common EDS analysis tasks; however, utilities commonly lack enough data to perform such tasks at every hourly time point. To calculate hourly quantities, utilities often use estimated load profiles based on statistical analysis of customer types [9], but these load profiles generally do not contain data for an entire year. Furthermore, the measurement and resource data necessary to do a complete and accurate analysis may have a different fidelity. This analysis provides a framework to perform EDS analyses for multiple hourly time points, up to a year, and provides a mechanism to compare scenarios over time. Additionally, iterative algorithms such as the CHMC listed above need to run multiple times in an hour for the simulation to accurately reflect the real world results. This analysis can perform multiple steady-state solutions over an interval to accommodate such algorithms.

The tools above are all model-based. Most utilities of any size use some form of model-based analysis to assist in the planning and operation of their EDS. Historically, due to shortcoming in either the software capabilities or the models themselves, utilities have adopted a splintered approach to EDS modeling with each department within a utility often selecting a different tool with a different model to perform their specific functions. Planning may have a different tool and model than protection, and so on. Since these tools may also be from different vendors, the models and software packages are rarely completely compatible. These issues can limit the effectiveness of model-based analysis and control. One solution is the Integrated System Model (ISM), discussed below.

1.3 The EDS Integrated System Model

An ISM is a modeling concept where all data necessary to solve problems within the domain are contained within the model. In the realm of EDS analysis and for the purposes of this work, an ISM is defined as a single model that contains all data needed to perform any EDS planning, operation, and control study. By including all of the necessary data into a single model, the need to produce and maintain multiple representations of the same system (in this case, the EDS) is eliminated. The ISM promotes a cohesive analysis environment within a utility and reduces the time needed to construct and validate the EDS model.

The ISM used for the majority of this work consists of a hierarchal set of relational databases [10]. These databases fully describe all electrical systems, circuits, components, and their functions. Furthermore, the databases describe the topological, spatial, and temporal relationships of each element. For such a model, Graph Trace Analysis (GTA) is a powerful and convenient method of describing these relationships. An introductory discussion of GTA is presented below.

1.4 Graph Trace Analysis

GTA is built upon a combination of ideas from physical network modeling, graph theory, and generic programming [11]. In physical network modeling, each element is represented by a set of through and across variables. In the case of the EDS, the through variable is the electric current through the element, and the across variable is the voltage drop across the element.

The container with iterator interface aspect of generic programming is used extensively by GTA to manage the elements of the physical network [12]. For a given physical network element, iterators are used to address other elements that have a meaningful relationship to the element under examination. Such relationships include the source element, the feeder path element, and physically connected elements, among others. Table 1.1 contains a list of these relationships along with a brief description of each.

In addition to allowing quick reference to important circuit elements, iterators can be used in GTA to generate sets of elements know as traces. For example, by repeatedly using the iterator to the feeder path element, a set of elements can be constructed that represents a trace from any element to its source. This particular set is known as a feeder path trace and will be utilized heavily in this work. Other important traces include the forward trace and the backward trace. These traces will be described in detail in later sections. Table 1.2 contains a list of traces used in this work.

In this work, p is used to describe the address or "pointer" of a particular element. This nomenclature is derived from programming languages such as C/C++, where a pointer refers to the location in memory of a data structure. Additionally, GTA uses the Object Constraint Language (OCL) to describe operations on sets and elements.

Table 1.1 Description of element relationships

Name	Description
Cmp	Element or component
pF	Pointer to the next element in the topology list
pB	Pointer to the prior element in the topology list
pFp	Pointer to the feeder path element. The feeder path element is the element that supplies power to Cmp
pS	Pointer to the reference source element. Each element can have only 1 reference source element.
pBr	Pointer to the brother element. The brother element is the first component in the forward trace direction that is not fed from the given component, where both components have the same reference source
pAdj	Pointer to the adjacent element., or an element across a sectionalizing devie
pSys	Pointer to the system. The system is a collection of circuits.
pCkt	Pointer to the circuit. The circuit is a collection of elements or components with a common reference source.

Table 1.2 Description of traces

Trace Name	Description
FT	Forward Trace. Uses pF to collect the set of elements from Cmp to the last element in the topology list.
BT	Backward Trace. Uses pB to produce the set of elements from Cmp to the starting element of the topology list.
FPT	Feeder Path Trace. Uses pFp to collect the set of elements between Cmp and the reference source.
BRT	Brother Trace. Uses pBr to collect the set of elements between Cmp and its brother

Chapter 2 Distribution Penetration Analysis

2.1 Overview and problem description

As described in Chapter 1, most EDS were designed to deliver power in a single direction, typically from a substation to an end load. When DER is interconnected at the distribution level, it introduces the possibility of multi-directional power flow. Though always present to some degree, the growing popularity of DER over the past decades have EDS operators concerned. If small enough, DER has very little impact on the EDS. However, in large numbers or size, DER can have a dramatic impact. The size of the DER relative to the load on the circuit is commonly referred to as penetration. The classical or rated penetration, described in Equation (2.1), is a commonly accepted method for expressing the level of DER on a section of the EDS [13].

$$Classical\ Penetration = \frac{DER\ Rating}{Peak\ Load\ on\ Circuit} \tag{2.1}$$

Utilities use the classical penetration definition when considering the impact of adding DER to an EDS circuit at a high level. However, as penetrations of DER rise, more analysis is necessary to accurately assess the impact of DER addition. This section describes an application which determines the largest DER addition possible before violating circuit criteria.

2.2 Design

The first step in the design process was establishing criteria to consider when analyzing DER penetration. The application described in this work considers the following:

- **Overload:** DER operation can cause circuit elements to exceed rated capacity.

- **High voltage:** DER operation can cause the EDS voltage to exceed acceptable limits on the circuit.
- **Low voltage:** DER, generally through reactive power injection, can cause the EDS voltage to drop below acceptable limits.
- **Flicker:** connecting and disconnecting DER can cause voltage fluctuations. The term "flicker" originates from voltage fluctuations which result in a noticeable variation in visible light; however, in this case flicker refers to the voltage fluctuation only [14].
- **Reverse power:** DER can cause power to be fed back through the substation to the transmission or sub-transmission system.
- **Fault contribution:** any DER attached to the circuit can contribute to an EDS fault. Too much fault contribution can cause the EDS protection system to miss-operate.

Another factor that is very important in establishing DER penetration limits is the DER location. For this reason, the application described in this work allows flexibility in choosing the DER location for analysis. For batch analysis jobs, several predefined locations were programmed into the application. Additionally, the application includes the ability to choose specific locations for DER penetration analysis.

After the maximum DER size for a given location is established, the reactive power dispatch from DER is considered. The application attempts to use reactive power injections from the DER to increase the performance of the circuit. The application determines the optimal power factor for both loss and capacity improvement.

Finally, some EDS circuits may have criteria violations prior to running the penetration application. Some criteria violation such as low voltage and component overloads may be alleviated by the addition of DER. The application therefore determines if the addition of DER can alleviate existing problems prior to determining the penetration limit.

2.3 Solution method

The flow diagram for the penetration limits application is shown in Figure 2.1. The penetration application begins by determining the location of the DER. Batch options for DER location include analysis at the beginning, middle and end point, at the largest load location, and at an existing DER location.

If the beginning, middle, and end analysis option is selected, the application first determines the end location. On an EDS circuit, many endpoints may exist. The analysis described here uses the end point farthest from the substation. Once the end point farthest from the substation is found, the midpoint is calculated by using a feeder path trace back to the substation from the end point. The beginning point is the first location starting from the substation that is suitable for DER interconnection. If the largest load is selected, the DER is placed at the point of interconnection of the largest load on the system.

Once the DER locations have been determined, the penetration analysis is performed for each location. The penetration analysis application has two solution methods: brute-force and bisection search. These methods are described in detail below.

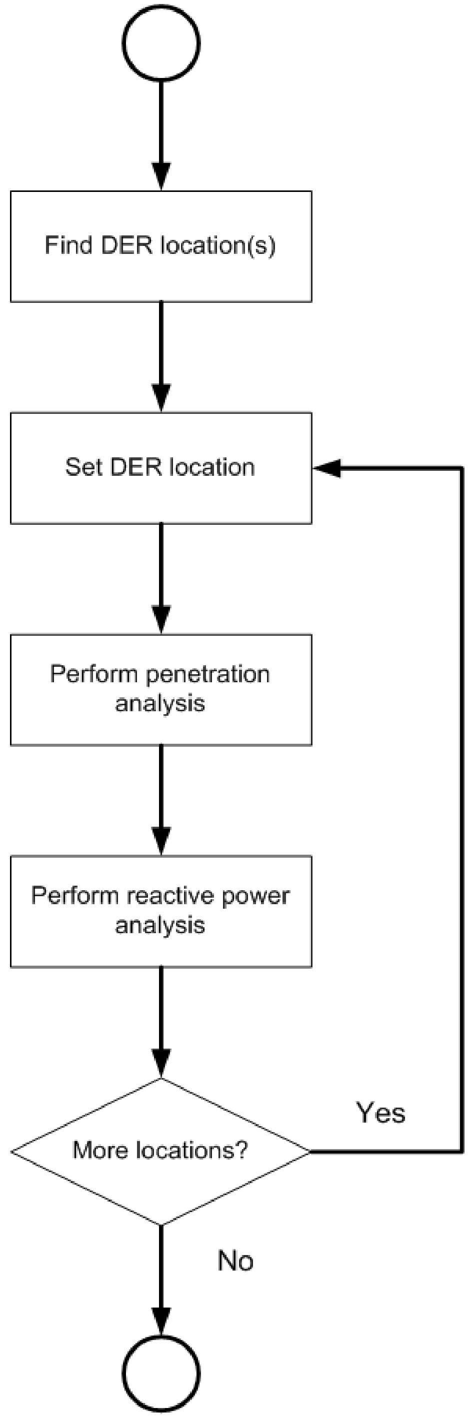


Figure 2.1 Penetration analysis flow diagram

2.3.1 Brute-force method

The brute force method is a slow yet accurate way of determining maximum DER penetration. The DER output is set to a minimum value and then the power injection is incremented by a user specified value. After each increment, the algorithm checks to see if one or more criteria are violated. When criteria are violated, the search is abandoned.

The solution speed of the brute force method depends on the step size. A smaller step size leads to more iterations of the algorithm, but results in a more accurate solution. Likewise, a larger step size will complete more quickly but at the expense of accuracy.

2.3.2 Bisection search method

The bisection search method is a common search algorithm in computer science. A bisection search is an iterative solution method where the solution space is divided in half, evaluated, and then divided in half again until an accuracy criterion is satisfied. Depending on the accuracy criterion, the bisection search can be completed much faster than the brute force method with similar results.

In this application, two factors complicate the bisection search: the consideration of multiple criteria and the consideration of DER on circuits with existing criteria violations. Figure 2.2 illustrates the issues that complicate the search. Before a bisection search can be used, a range with a known acceptable solution must be established; however, there is no guarantee that an acceptable operating point exists. To determine an acceptable operating range, the application employs a simple search over a gross range as described below.

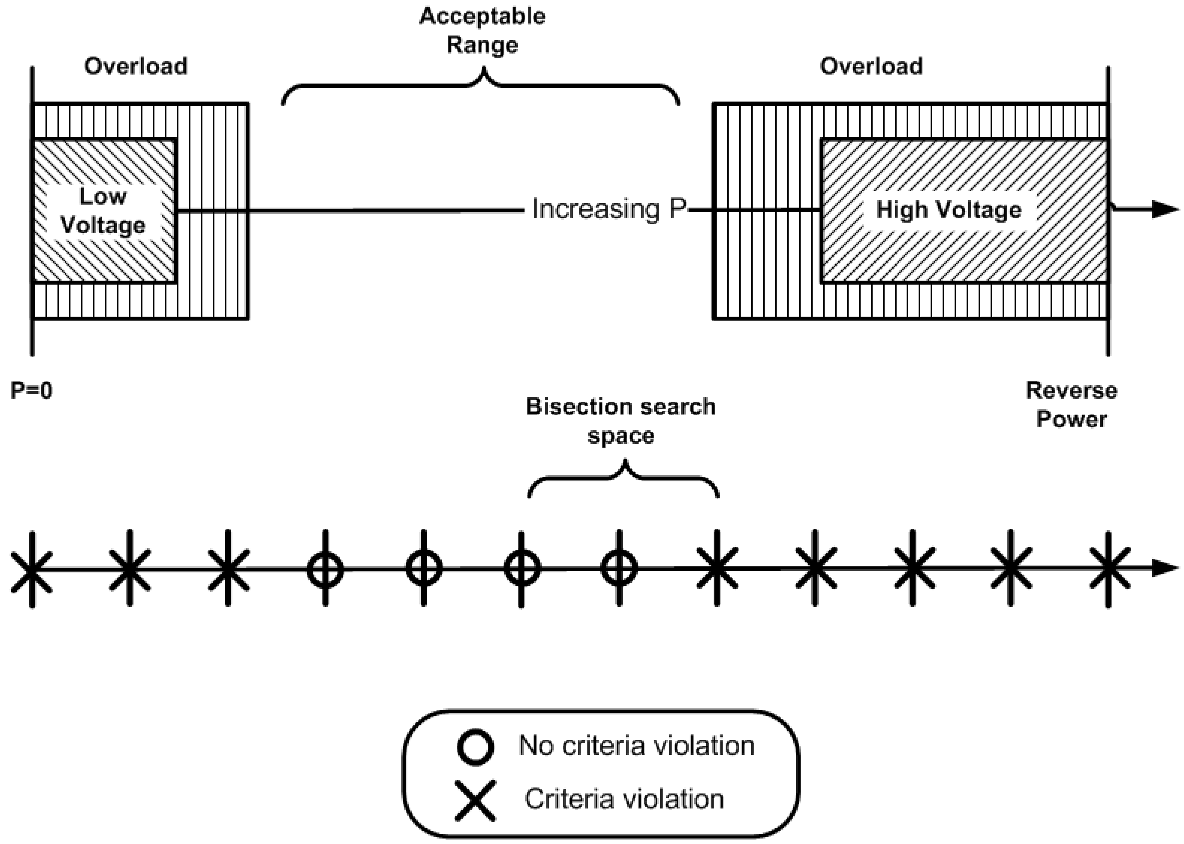


Figure 2.2 Bisection solution search space

First, the algorithm forces reverse power as a failure criterion for the bisection search (the application allows individual criterion to be selected/de-selected for consideration). Then, assuming a real power injection from the DER equal to the load on circuit would result in a reverse power condition, the gross maximum upper limit is set to the amount of load on the circuit at the time of analysis. The gross lower limit is set to 0. The application then subdivides the gross output power range into 10 sections and evaluates each section for criteria violations. If an acceptable operating point range of points is found, the boundary of the highest acceptable test injection becomes the bisection search space. If no acceptable operating points are found, the application exits.

With the range established, the bisection search algorithm can begin. The algorithm divides the range in half and evaluates the circuit at the power injection corresponding to the range midpoint. If the midpoint has no criteria violation, the solution is in the upper half of the range. If the midpoint has a criteria violation, the solution is in the lower half of the range. The range that includes the solution is divided in half again, and the process is repeated until the remaining range is below a specified value. The specified value determines the accuracy of the solution as well as the number of repetitions needed before a solution is reached. Figure 2.3 illustrates the binary search method.

2.4 Reactive power analysis

` After the maximum real power is determined from either the brute force method or the bisection search method, the application can determine any benefits to reactive power dispatch. The application sweeps through a specified range of power factors to determine the optimal reactive power injection with regard to minimizing losses or increasing capacity benefits.

Reactive power dispatch can impact the maximum size of DER installations. However, because reactive power dispatch is not commonly allowed for DER on the EDS, the reactive power analysis was not included as an integral part of the solution process. The analysis was still included in the application to help quantify potential benefits to reactive power dispatch using DER.

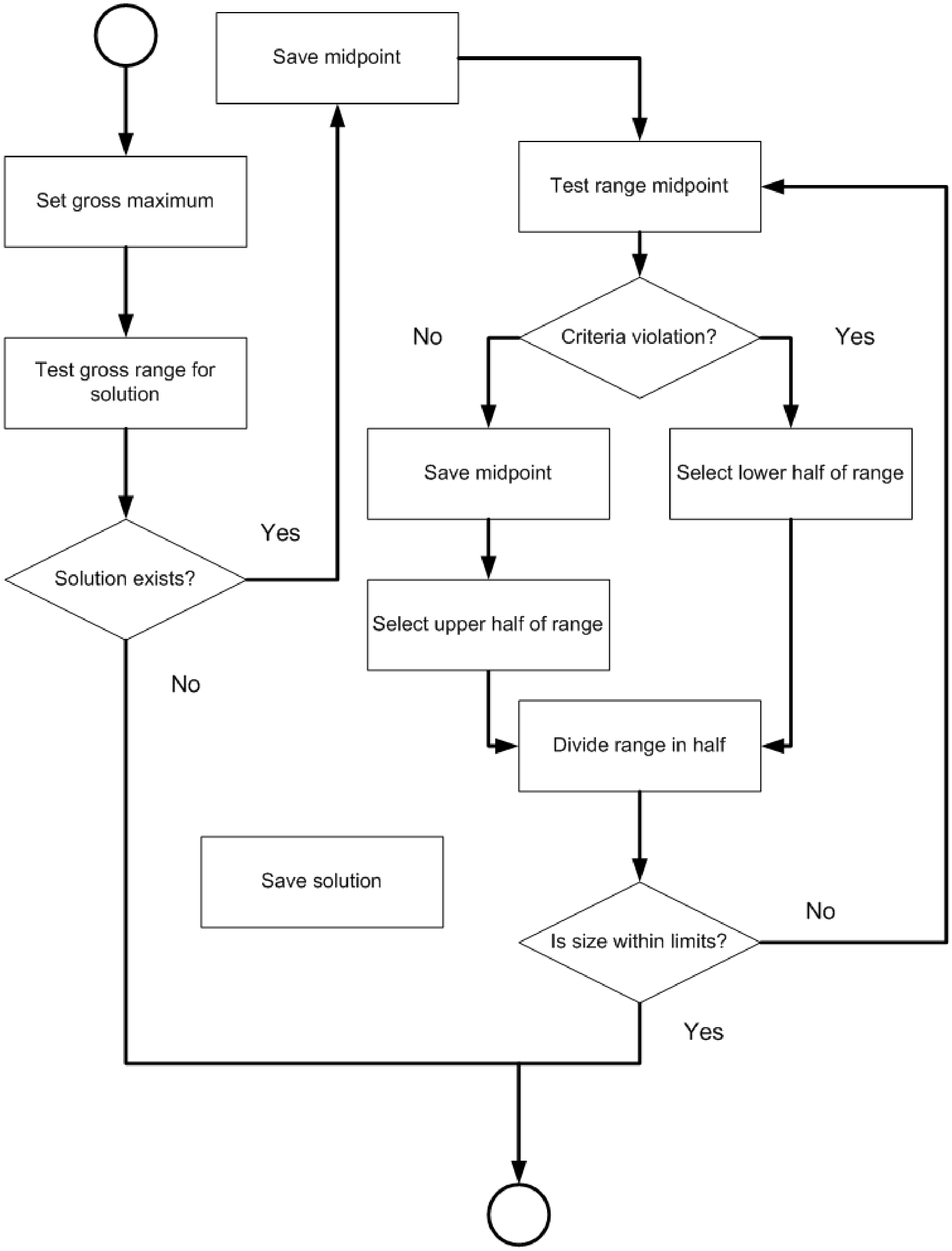


Figure 2.3 Bisection search method flow diagram

2.1 Simulation results

The penetration application was simulated on a test circuit for a heavy load and a light load condition. The test circuit is shown in Figure 2.4 including the locations of the beginning, midpoint, and endpoint interconnection points as determined by the algorithm.

Table 2.1 shows the simulation results for the heavy load condition, and Table 2.2 shows the results of the simulation for the light load condition. Due to existing violations on the circuit, the bisection search method was used in both cases.

The results show that DER placed at the beginning of a circuit do not greatly impact the performance of the circuit with regard to losses. They do, however, offer the greatest benefit to released capacity. Released capacity describes the difference in power supplied by the substation with and without the DER. In both cases, the midpoint DER had the greatest impact on circuit losses.

The results also indicate that DER placed away from the substation are more sensitive to voltage issues. For the heavy load case, both the midpoint and endpoint DER locations violated flicker criteria. On the light load condition, the endpoint DER violated high voltage criteria. Additionally, because the midpoint and endpoint DER violated voltage constraints, the maximum DER sizes were not as sensitive to loading as the beginning DER location.

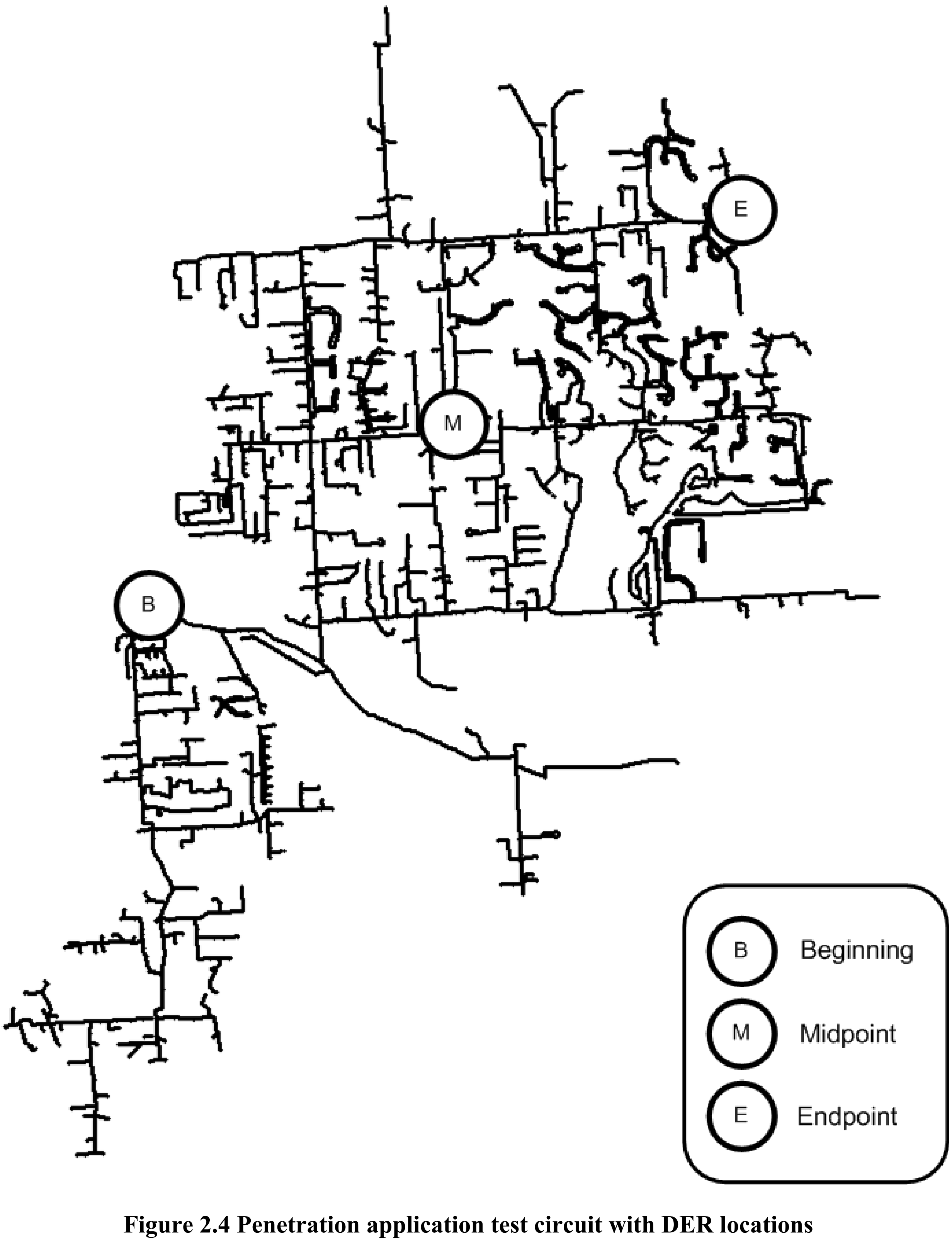


Figure 2.4 Penetration application test circuit with DER locations

Table 2.1 Penetration analysis results for heavy load condition

	Beginning Location	**Mid Location**	**End location**
Maximum DER size	10,136 kW	6,883 kW	5,873 kW
Criteria violated	Reverse Power	Flicker	Flicker
Loss improvement	0	45.4 %	34.9 %
Released capacity	70.3 %	56.5 %	48.0 %
Highest voltage	125.1 V	125.3 V	125.4 V
Lowest voltage	114.0 V	116.6 V	116.4 V
Highest flicker	2.6 V	6.0 V	6.0 V
Lowest capacity	19.0 %	62.4 %	56.0 %

Table 2.2 Penetration analysis results for light load condition

	Beginning Location	**Mid Location**	**End location**
Maximum DER size	5,071 kW	5,031 kW	5,031 kW
Criteria violated	Reverse Power	Reverse Power	High Voltage
Loss improvement	0 %	26.3 %	0 %
Released capacity	87.8 %	87.7 %	86.7 %
Highest voltage	125.5 V	125.5 V	126.0 V
Lowest voltage	121.2 V	121.5 V	121.3 %
Highest flicker	2.6 V	4.7 V	5.3 V
Lowest capacity	61.4 %	87.9 %	77.4 %

Chapter 3 Configurable, hierarchal, model-based control

3.1 Overview

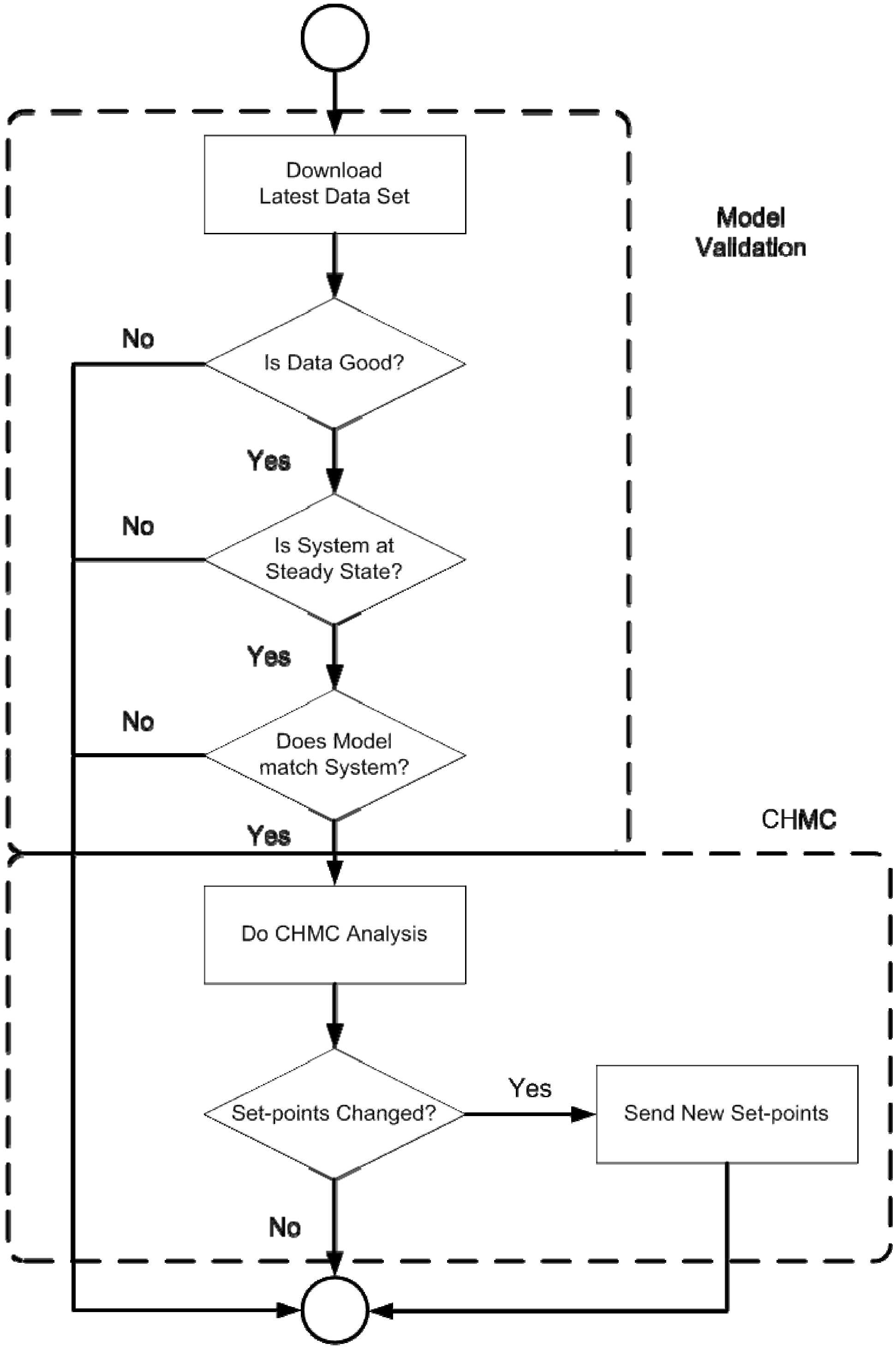
Traditionally, control devices on the EDS act independently, making decisions based on local information. As described in Chapter 1, this configuration can lead to inefficient operation of the EDS. In the past decade, communication and control capabilities for control devices have improved, and utilities are looking for ways to better use these devices to extend the life and usefulness of EDS components. To that end, the following section describes a model-based control method that improves operation of the EDS while respecting the existing infrastructure.

The CHMC described in this work was part of a pilot project to be implemented and field tested. As such, the limitations of the EDS and communication infrastructure influenced the design of the CHMC. The functionality of the CHMC is largely dictated by the criteria listed below.

- **Steady-state:** The CHMC provides steady-state operating points to control devices on the circuit. The design assumes the local controllers maintain stability under dynamic and transient conditions.
- **Real time**: The CHMC must be able to assess the state of the system and provide a solution in real- to near real-time. The speed at which the CHMC must provide updated set-points to the local controllers is a function of many variables and may vary by application. In the pilot project, an update speed of approximately 5 minutes was largely dictated by the communication network.

- **Standard Computing Equipment:** The CHMC must be able to provide solutions in real- to near real-time using standard computing equipment in a substation or a remote location such as a distribution control center.
- **Fail-safe Operation:** The control devices must continue to function without violating operating criteria in the event of CHMC hardware failure or communication failure.
- **Incorporate Legacy Equipment:** The CHMC may not have control over all of the control devices on the system. The controller must be able to account for the impacts of control devices beyond the influence of the CHMC.
- **Configurable**: Due to the nature of the EDS, scheduled and un-scheduled topology changes occur frequently and control devices are often taken in and out of service. These changes can significantly impact the performance of control devices on the system; therefore, the CHMC must be able to detect and appropriately respond to such changes.
- **Loss Minimization versus Capacity Constrained:** When the circuit is capacity constrained, damage to utility equipment is a real and immediate possibility. The CHMC should recognize when the circuit is capacity constrained, abandon the search for a more efficient operating point, and take appropriate measures to increase available capacity on the circuit.

The EDS controller to be implemented for this project consists of two software modules: model validation and the CHMC. Figure 3.1 shows the overview of the EDS controller. The model validation portion of the project was necessary to ensure the data being fed to the CHMC is accurate, that the model satisfactorily matched the physical system, and that the physical system was in steady state.


Download
Latest Data Set
Model
Validation
No
Is Data Good?
Yes
No
Is System at
Steady State?
Yes
No
Does Model
match System?
Yes
CHMC
Do CHMC Analysis
Set-points Changed?
Yes
Send New Set-points
No

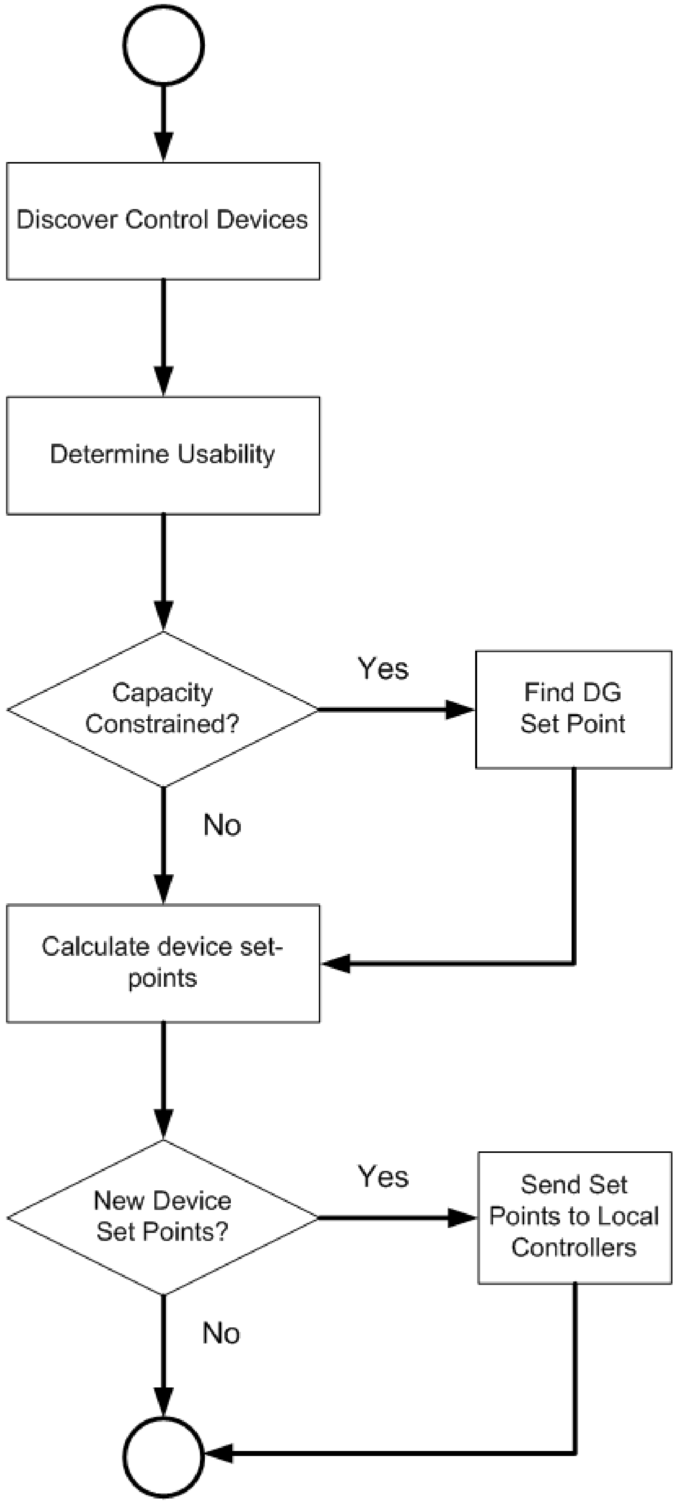


Figure 3.2 CHMC flow diagram

Figure 3.2 show the overview of the CHMC control algorithm. The CHMC has four major phases: device discovery, determination of device usability, set-point calculation, and set-point transmission. The different phases will be described in detail in the following sections.

3.2 Review of previous work

This section presents the results of a literature search surrounding advanced distribution control. It may be helpful to the reader to address a nomenclature issue regarding the subject; specifically the terms advanced distribution automation (ADA) and advanced distribution control (ADC). Both terms refer to the use of sensors and autonomous devices to improve the operation of the EDS. ADA commonly involves automatic EDS protection, reconfiguration, and restoration [15], where ADC, as it is used in this work, is primarily concerned with improving the operation of the EDS using control devices.

The majority of earlier ADC research efforts revolved around more efficient use of capacitors, sometimes referred to as "reactive dispatch". As illustrated in Chapter 1, capacitors improve the efficiency of the circuit by reducing the current flowing in the circuit elements. .Many approaches have been suggested for capacitor dispatch, including tabu searches [16], dynamic programming [17], network-topology-based approaches [18], and interior point methods [19]. Most of these approaches involve preprocessing data, typically a day or more in advance, using load predictions, and providing hourly capacitor set-points for a fixed topology.

In [20] the authors analyze interactions between distributed generation and capacitors. An algorithm is presented which factors the variable real and reactive injections from distributed generation in an optimal capacitor scheduling problem.

Reference [20] explores coordinating multiple control devices to satisfy a set of weighted objective functions. The authors use a Genetic Algorithm to sort through possible solutions of a balanced, radial feeder, implementing several strategies based on different weighting criteria. The Genetic Algorithm solution was used due to the large number of possible solutions of the constrained combinatorial optimization problem.

Recently, approaches which rely on multi-agents have been proposed as an EDS control solution [21][22]. Multi-agents make use of distributed intelligence to manage the behavior of different EDS elements such as DER and customer demand response.

Finally, many "Smart Grid" efforts have been aimed at improving distribution through greater utilization of emerging technologies such as advanced metering and DER [23]. References [24] and [25] describe the importance of Volt / Var control on the EDS, and provide potential methods for doing so.

The CHMC described in this paper offers several key improvements and novel concepts that do not presently exist in distribution control schemes, either implemented or in literature. These contributions are listed below.

- **Incremental optimization:** The CHMC does not guarantee a globally optimal solution; instead, each time it is run, it provides an improved solution which tends to trend towards an optimal solution. The implementation of this concept greatly reduces computation time and allows the CHMC to run in real-time.
- **Comprehensive integrated control:** The CHMC coordinates many different types of control devices commonly found on the modern EDS including VRs, capacitors, DER.
- **Automatic device discovery and classification:** The CHMC automatically discovers control devices on the EDS that it can use to improve the EDS operating point.
- **Automatic topology recognition and compensation:** The CHMC recognizes and compensates for scheduled and unscheduled changes in circuit topology.

3.3 Automatic device discovery

The first step in the control process is the control device discovery phase. In this phase, the CHMC searches the system to find devices that can be used to produce an improved operating point for the circuit under analysis. The controller uses GTA to parse through the circuit and build a set of control devices connected to the system. A forward trace to select the control devices from all components of a circuit is given by

$$CD = FT_{pS} \rightarrow select(Cmp \rightarrow type == Control\ Device) \qquad (3.1)$$

In Equation(3.1, *CD* is the set of all control devices on the circuit. The subscript *pS* indicates the forward trace is started from the first element in the circuit. The trace then iterates through the collection using pF until it reaches the last element. If the element under test is a control device, the element is placed in *CD*.

The CHMC, however, needs to be aware of control devices in adjacent circuits because these control devices could be switched onto the circuit under analysis. To accomplish this, a set of adjacent circuits is formed. This set of adjacent circuits, *AC*, is given by

$$\begin{gathered} AC = FT_{pS} \rightarrow select(exists(Cmp \rightarrow pAdj)) \rightarrow \\ collect(Cmp \rightarrow pAdj \rightarrow pS) \end{gathered} \qquad (3.2)$$

Equation (3.2) builds a set of the starting elements for each of the adjacent circuits. Once the adjacent circuits are found, the circuits can be parsed for control devices that could be attached to the circuit. Building upon Equation (3.1, the control devices discovered by the CHMC is given by

$$\begin{aligned} CD = AC \rightarrow select(&FT_{pS} \\ &\rightarrow select(Cmp \rightarrow type == Control\ Device)) \end{aligned} \qquad (3.3)$$

The result of Equation (3.3 is a set of all control devices on the circuit under test as well as any circuit that could be connected to the circuit under test. Since the control device discovery phase is executed each time the controller is executed, if the EDS is reconfigured, the CHMC will automatically detect new control devices on the system.

3.4 Determine Control Device Usability

Usability refers to the ability of the CHMC to manipulate a particular control device to provide an improved operating point for the circuit under test. The CHMC uses a number of factors to determine the usability of control devices. These criteria are listed below.

- **Mode of Control:** .Mode of control usually refers to manual versus automatic control where manual mode involves interaction to change device states, either from an operator or a remote signal. When in automatic mode, the control device is typically adjusting its own state based on control logic and instrumentation.
- **Mode of operation:** Mode of operation refers to local versus remote control. For operator safety, most control devices can be placed in local control to prevent external manipulation of a control device while work is being performed.
- **Communication Capability:** Communication capability refers to the ability of a control device to receive and respond to remote control signals.
- **Connectivity:** Connectivity refers to the electrical connection between the control device and the circuit under test.

Because control devices can be taken in and out of service for a number of reasons, the usability of a control device is determined each time the controller is executed. While the modes and communication capability are properties of the control device, the CHMC uses a feeder path trace to determine the electrical connectivity, as shown below.

$$isEmpty(FPT \rightarrow select(Cmp \rightarrow SwitchStatus == Open)) \quad (3.4)$$

Equation (3.6 is true only if none of the elements of the feeder path trace from an element back to the reference source is open. Or, if Equation (3.6 is true, the element being tested is connected to the source. The set of usable control devices, UCD, is given by

$$\begin{aligned} &UCD = CD \rightarrow select(\\ &\quad isEmpty\big(FPT \rightarrow select(Cmp \rightarrow SwitchStatus == Open)\big) \\ &\quad\quad and\ (Cmp \rightarrow OperatingMode == Remote) \\ &\quad\quad and\ (Cmp \rightarrow ControlMode == Automatic) \\ &\quad\quad and\ (Cmp \rightarrow Communication == True)) \end{aligned} \quad (3.5)$$

A device's ability to communicate with the CHMC is also determined every time the controller is executed by the model validation algorithm. In this case, device communication refers not only to a device's ability to communicate, but the integrity of the communication path between the CHMC and the device. If a control device loses the ability to communicate due to a communication device failure, for example radio interference or a failed telecommunication component, model validation will set this flag to False.

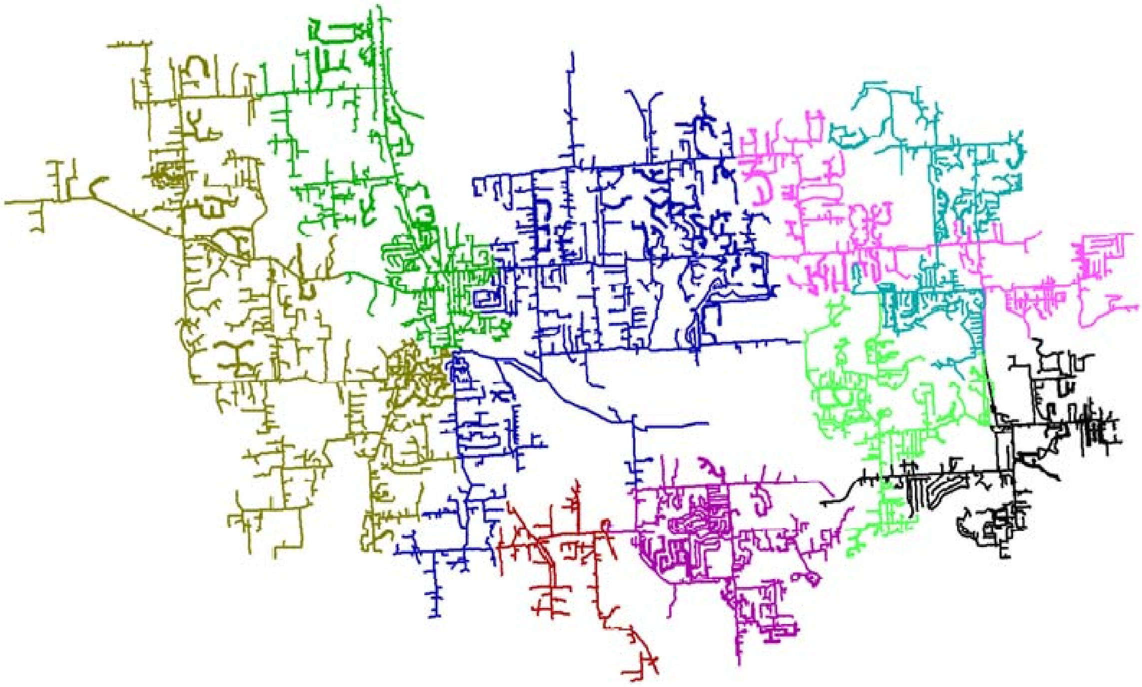


Figure 3.3 Local system of circuits

Consider the circuit pictured in Figure 2.4. This circuit is actually part of a larger system of circuits that can be reconfigured. Figure 3.3 shows the test circuit along with the other local circuit. The collection of circuits in Figure 3.3 is formed from operation plans that determine what circuits could potentially be tied in whole or in part to the circuit under test. The circuit under test is the dark blue circuit. Each of the circuits has control devices that could be switched onto the circuit under test. Note, though all of the circuits can be reconfigured to have some or all of their load supplied by the circuit under test, some are not actually adjacent as it is defined above. In other words, some parts of circuits must be switched onto adjacent circuits before being attached to the circuit under test. The importance of this distinction will be made clear in the following section. The same system of circuits is shown in Figure 3.3 with the location of control devices indicated on the map.

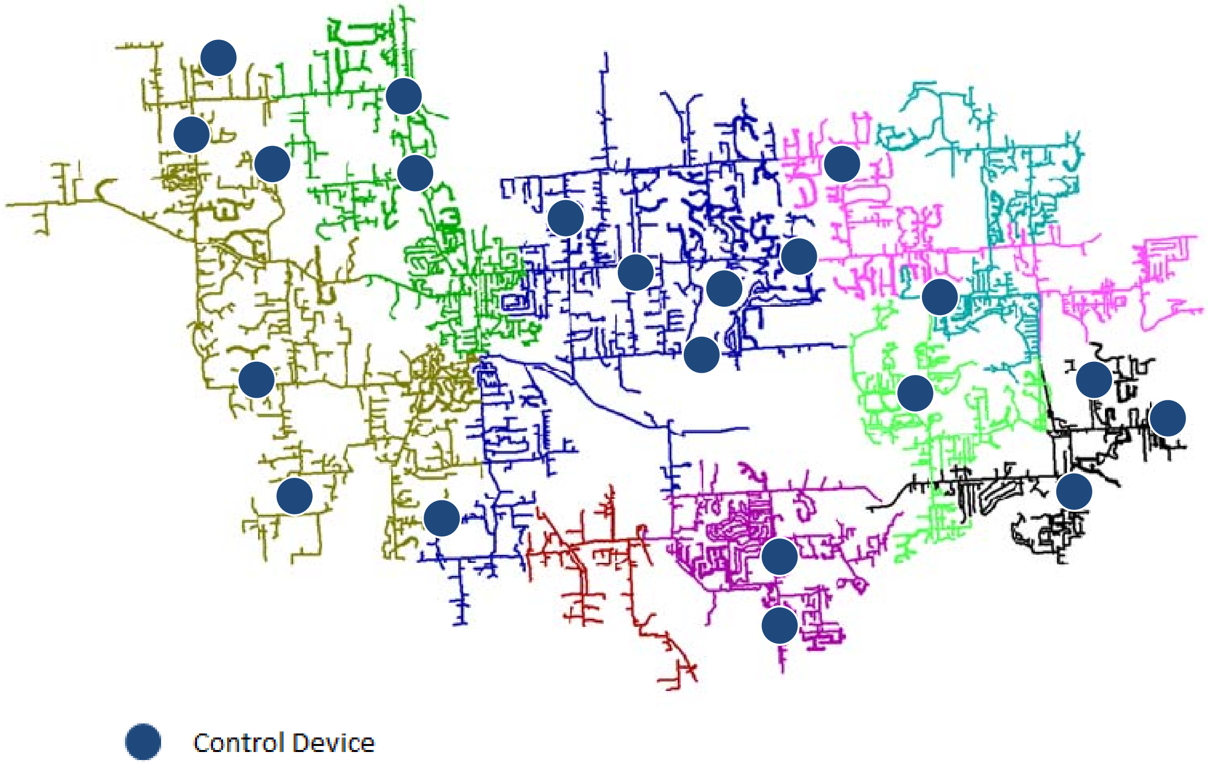


Figure 3.4 Local system of circuits with control devices shown

For the following simulations, it is assumed that the only criteria not met for usability is the connectivity requirement. All other criteria, mode of operation, mode of control and communication capability are assumed to be in the appropriate state for utilization by the CHMC.

The results of the CHMC discovery algorithm are show in Table 3.1. Notice that even though 20 control devices are shown in Figure 3.4, only 18 are show in the results. This is because, as discussed above, some of the circuits in the system are not actually adjacent to the circuit under test..If a reconfiguration that takes place makes them adjacent to the circuit under test, the algorithm will detect the change and update itself accordingly.

Table 3.1 Results of device discovery algorithm for large system

Device	Device Type	Usability
2193347409061	Voltage Regulator	False
2204393408841	Voltage Regulator	True
2194006394314	Voltage Regulator	False
2180986409156	Voltage Regulator	False
2209761395251	Switched Capacitor	True
2216409400113	Switched Capacitor	True
2215787400852	Switched Capacitor	True
2197935399833	Switched Capacitor	False
2193091407628	Switched Capacitor	False
2193309385647-1	Switched Capacitor	False
2192497387044	Switched Capacitor	False
2180939409395	Switched Capacitor	False
2185733404758	Switched Capacitor	False
2214449383068	Switched Capacitor	False
2214890379687	Switched Capacitor	False
2218278404487	Switched Capacitor	False
2236801391195-1	Switched Capacitor	False
CSN_0_1_2629_88	Synchronous Generator	True

Because the majority of the control devices are not connected to the circuit under test, the Usability flag is shown as false. The CHMC detects 1 VR, 3 switched shunt capacitors, and a synchronous type DER connected to the circuit under test.

To illustrate how the algorithm behaves when topology changes, consider the simplified system of circuits shown in Figure 3.5. In this system, the circuit under test is connected to one other adjacent circuit. The adjacent circuit has a number of control devices. The system is then reconfigured so that a control device from the second circuit is now connected to the circuit under test. The results of this simulation are shown in Table 3.2

Prior to the reconfiguration, Table 3.3 shows the same set of control device connected to the circuit under test as well as a switched shunt capacitor connected to the adjacent circuit. Post reconfiguration, the CHMC detects the connectivity of the switched shunt capacitor and determines that it can be used along with the other control devices to find an improved operating point for the circuit under test.

3.5 Calculating Device Set-points

Once the control devices on a distribution system have been discovered and classified as usable or unusable, the CHMC can use available devices to improve the operation of the EDS. The first priority of any controller in the electrical power system must be to maintain voltage, frequency, and loading criteria on the circuit. A controller that offers an improved operating point relative to some objective function at the expense of one of these criteria is of no use to a utility.

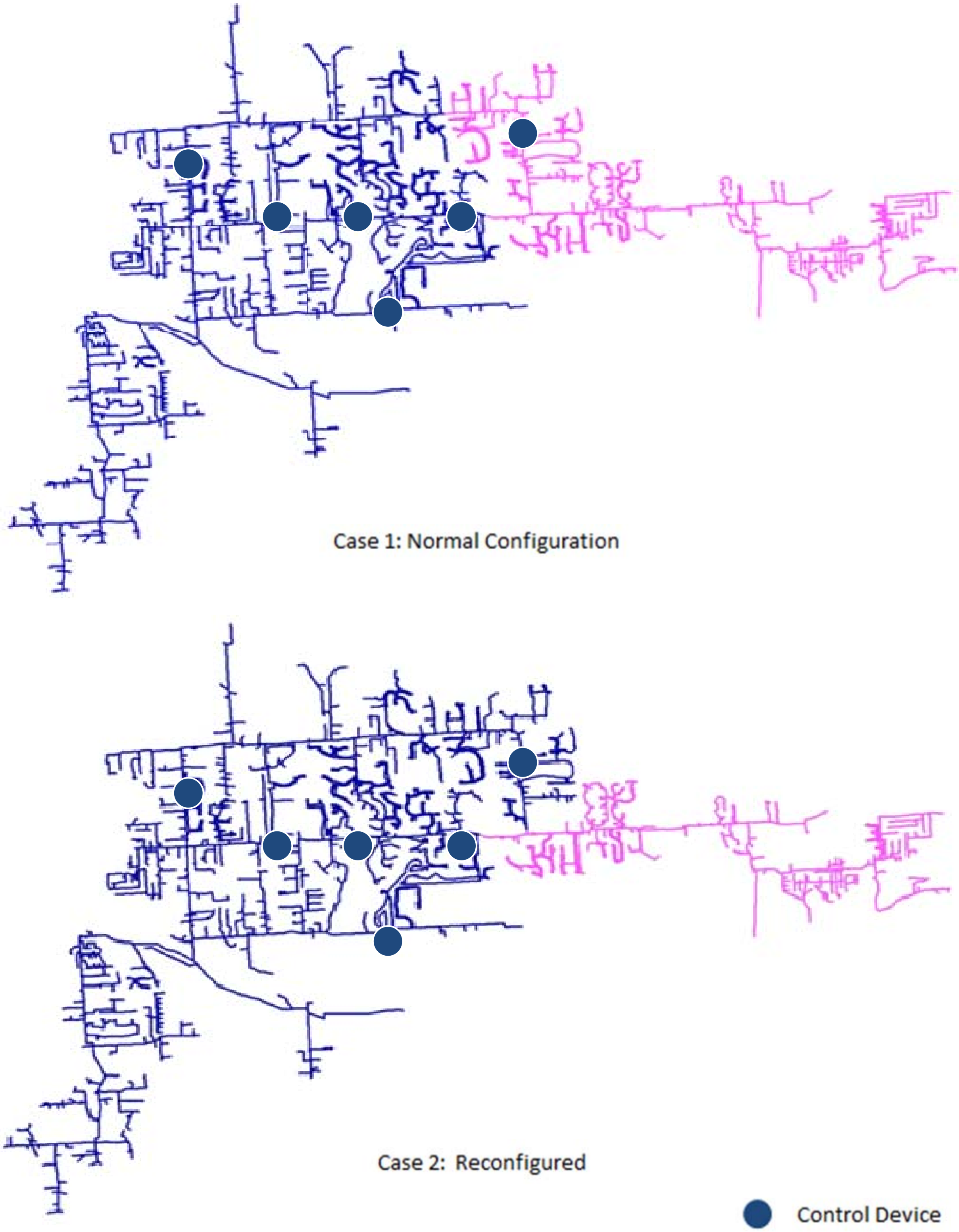


Figure 3.5 Device discovery test system

Table 3.2 Results of device discovery algorithm for reconfiguration

Before Reconfiguration		
Device	**Device Type**	**Usability**
2204393408841	Voltage Regulator	True
2209761395251	Switched Capacitor	True
2216409400113	Switched Capacitor	True
2215787400852	Switched Capacitor	True
2218278404487	Switched Capacitor	False
CSN_0_1_2629_88	Synchronous Generator	True
After Reconfiguration		
2204393408841	Voltage Regulator	True
2209761395251	Switched Capacitor	True
2216409400113	Switched Capacitor	True
2215787400852	Switched Capacitor	True
2218278404487	Switched Capacitor	True
CSN_0_1_2629_88	Synchronous Generator	True

While frequency must be maintained at the customer service entry, electrical frequency is generally very robust at the distribution level and requires a real power source to change. While distributed generation is becoming more common, DER usually do not appear in large enough quantities at the distribution level to have a meaningful impact on system frequency. Even at higher levels of distributed generation penetration, frequency is typically considered under system level analysis and not in distribution analysis. For these reasons, the frequency control is neglected in the controller design.

3.5.1 System Voltage Criteria

Traditionally, distribution control schemes involve monitoring the voltage at a few locations throughout the circuit, usually local to the voltage control devices. The voltage control plan, often referred to as distribution system voltage regulation, is implemented based on this local feedback. Voltage drop through distribution transformers, secondary, and service connections are usually assumed based on circuit loading and are often worst-case values. More complex schemes use “drop compensation” to adjust the voltage set-point for different loading conditions.

Under traditional voltage control schemes, violations of circuit voltage criteria may go completely undetected because the voltage is only monitored at a few points in the circuit. In fact, a violation may persist on a circuit unnoticed by the utility until a customer files a complaint. By the time a violation is discovered in this fashion, damage to utility and customer equipment may have already occurred.

One benefit of a model-based design is the ability to accurately estimate electrical quantities at any point on the circuit with relatively few measurements, including voltage estimates at the customer service entry. Appendix A describes the accuracy of these estimates and provides an example of field validation of estimated quantities.

With a voltage estimate at all points at the circuit available, a criterion may be established that captures the overall voltage regulation of the circuit, not just the voltage at a few select points. The Voltage Deviation Total (VDT), described in Equation (3.6, effectively captures an overall picture of the quality of voltage using every customer estimated service entry voltage as input.

$$VDT = \sum V_D$$

$$V_D = \begin{cases} V_i - V_{UB} & V_i > V_{UB} \\ 0 & V_{UB} > V_i > V_{LB} \\ V_{LB} - V_i & V_{LB} > V_i \end{cases} \tag{3.6}$$

where

V_i = Voltage at each customer meter or service entry

V_{UB} = Upper bound of acceptable voltage range

V_{LB} = Lower bound of acceptable voltage range

Some consideration was given to the method of best representing the overall picture of customer voltage in the control criterion. In addition to the sum of the voltage deviations described in Equation (3.6), a sum of deviation squared method was investigated.

By using the sum of the deviation from acceptable limits, the VDT balances the extent of the voltage excursions with the number of voltage excursion. In contrast, the sum of deviation squared approach more heavily weights the severity of the excursion.

To illustrate, consider the results of the two methods for a single 10 V excursion versus ten 1 V excursions. The result of the sum of deviations methods returns the same in either case (10); however, the sum of deviation squared approach returns a value of 100 for a 10 V excursion compared to 10 for the ten 1 V excursions. The more severe excursion is much heavily weighted than multiple smaller excursions.

The sum of deviations approach was selected for the criteria because the results are more balanced and predictable. Furthermore, because the severity of the excursion and the number of excursions both increase the likelihood of damaging utility or customer equipment, no apparent reason was found to significantly weight severity over number. Further experience with the algorithm may provide cause to revisit the approach.

Utilities must maintain voltage on the circuit at the customer service entry; therefore, the VDT is calculated wherever a load is attached to the circuit. The GTA expression for the VDT is given by

$$\begin{aligned}
&FT \rightarrow select(Cmp \rightarrow Load == True) \\
&\rightarrow collect(\, if \; Cmp \rightarrow Voltage \\
&> V_{UB} \; then \, VDT + (Cmp \\
&\rightarrow Voltage - V_{UB}) \; else \; if \; Cmp \rightarrow Voltage \\
&< V_{LB} \; then \, VDT + (V_{LB} - Cmp \rightarrow Voltage))
\end{aligned} \tag{3.7}$$

3.5.2 Loading

Similar to service voltage, the CHMC can use measurements and load profiles to estimate the loading of every component on the circuit. Equation 3.8 describes the method used to capture the overall loading on the circuit relative to the device capacity ratings, or the Weighted Capacity Total (WCT).

$$\begin{gathered}
WCT = \sum C_D \\
C_D = \begin{cases} C_L - C_i & C_i < C_L \\ k(C_L - C_i) & C_i < 0 < C_L \\ 0 & C_i \geq C_L \end{cases}
\end{gathered} \tag{3.8}$$

where

C_i = remaining capacity of device i

C_L = capacity limit

k = weighting factor

A sum was used as the criterion for many of the same reasons as the VDT. The WCT looks only at the capacity of devices on the primary of the distribution circuit up to and excluding distribution transformers. The distribution transformer was excluded because distribution transformers may be designed to exceed their rating during peak load periods [26].

In this case, a weighted total was used to provide a tiered approach to capacity violation relief. The tiered approach facilitates the use of dispatchable DER prior to reaching capacity limits on circuit elements.. Dispatchable DER is sometimes used to reduce the substation load on a distribution circuit during the most heavily loaded times. Operation in this manner is commonly referred to as load following or peak shaving.

` The distribution transformer is used as a boundary to determine which elements are on the primary of the circuit. The GTA statement which builds a set of primary circuit elements is given by

$$\begin{aligned} PCE = FT \rightarrow select(\ Cmp \rightarrow Type! \\ = DistributionTransformer\ and\ isEmpty(FPT \\ \rightarrow select(Cmp \rightarrow Type\ ! \\ = DistributionTransformer \end{aligned} \tag{3.9}$$

The WCT total is given by

$$\begin{aligned} PCE \rightarrow collect(\ if\ Cmp \rightarrow Capacity \\ < 0\ then\ WCT \\ + (k(C_L - Cmp \rightarrow Capacity))else\ if\ Cmp \\ \rightarrow Capaity \\ < C_L\ then\ WCT + \ (C_L - Cmp \rightarrow Capacity)) \end{aligned} \tag{3.10}$$

3.5.3 Loss minimization

The final criterion considered is system losses. As described in Chapter 1, losses occur on the EDS whenever the circuit is energized. The CHMC tries to use the control devices on the circuit to minimize the amount of energy lost in the process of delivering power to the end user.

The CHMC looks at all system components to calculate the loss total, given by

$$LT = \sum P_i \tag{3.11}$$

where

P_i = lost power for component i

The GTA statement for LT is

$$FT \rightarrow collect(LT + Cmp \rightarrow RealLoss) \tag{3.12}$$

3.5.4 Solution Methodology

The first step in the solution methodology is to classify the usable control devices. Control devices on a distribution system can be classified in a number of ways. The CHMC in this work classifies control devices primarily based on the resolution of available control. The major control types are as follows:

- **Single-step Control Device (SCD)** – SCD are characterized by binary control. Generally, this means they are either on (connected to the distribution system) or off (disconnected from the distribution system). SCD often have a large steady-state and transient impacts on the distribution system when they change states. A common example of a SCD is a switched shunt capacitor bank.
- **Multiple-step Control Device (MCD)** – MCD are characterized by multiple operating states and therefore typically offer a finer level of control relative to SCD. Additionally, MCD generally have less impact on the distribution system when they change from one operating point to an adjacent operating point. When changing many states in a single control iteration, MCD can greatly impact the steady-state operation point of a circuit;

however, the transient impact of multiple state changes is usually not as sever e as a SCD. A common example of a MCD is a voltage regulating transformer.

- **Hybrid Control Device (HCD) –** HCD can behave as either a SCD or a MCD, depending on the current operating state. An illustrative example of a HCD is a dispatchable DG. If the DG is off, the HCD can behave as a SCD if it has a minimum generation set point. Once on and connected the distribution system, however, the real and reactive control of the generator behave as a MCD. Additionally, a single control device can be composed of multiple device types of different types. Using the same example as above, the dispatchable DG can be broken into two components: real and reactive control. If the DG has a minimum power output , the real control will behave as a HCD. The reactive power control, however, will behave as a MCD.

Additionally, a single control device can be composed of multiple device types of different types. Using the same example as above, the dispatchable DG can be broken into two components: real and reactive control. If the DG has a minimum power output, the real control will behave as a HCD. The reactive power control, however, will behave as a MCD. Table 3.3 shows a number of control devices found on distribution systems and their corresponding categories

In Table 3.3, the step type indicates if the control device operates in discrete steps or in a continuous range. A control device that operates in a continuous range may be set to any value within the range. Practically, shortcomings in the communications and controls make it impossible for any device to be truly continuous; however, the step size is usually fine when compared to the discrete controllers. To reduce the complexity of the solution, the CHMC further reduces the granularity of the continuous control devices by converting the range into

Table 3.3 Example control devices and types

Control Device	Category	Step Type
Voltage Regulating Transformer	MCD – Voltage	Discrete
Load Tap Changer	MCD – Voltage	Discrete
Single-step Switched Shunt Capacitor	SCD – Reactive Power	Discrete
Multi-step Switched Shunt Capacitor	MCD – Reactive Power	Discrete
Diesel Generator with minimum power requirement	HCD – Real Power MCD – Reactive Power	Continuous
Residential PV system	MCD – Reactive Power	Continuous
PV System with advanced inverter controls	MCD – Real Power MCD – Reactive Power	Continuous
Load Shedding	SCD – Real Power	Discrete
Storage	MCD – Real Power MCD – Reactive Power	Continuous
Vehicle to Grid - Plug-in electric vehicles	MCD – Real Power MCD – Reactive Power	Continuous

discrete steps. When considering the step size, a trade-off exists between solution accuracy and solution time. This will be discussed in detail in later sections.

One major challenge of distribution system optimization, particularly in real-time applications, is the potentially large number of possible solutions. The number of possible solutions depends on the number and type of control devices on the circuit and whether they are phase or gang-operated. Table 3.4 gives some examples of combinations of control devices and the number of possible solutions.

Table 3.4 Number of solutions for control device combinations

Control Devices	**Solutions**
1 gang-operated, 3-phase switched shunt capacitor 1 gang-operated, 3-phase load-tap changer, 16 step	32
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step	8,192
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 gang-operated, 3-phase voltage regulator, 32 step	262,144
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 phase-operated, 3-phase voltage regulator, 32 step	268,435,436
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 phase-operated, 3-phase voltage regulator, 32 step 1 gang-operated, 3-phase DER, 32 step real, 32 step reactive	274,877,906,944
3 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 phase-operated, 3-phase voltage regulator, 32 step 1 gang-operated, 3-phase DER, 32 step real, 32 step reactive	1,099,511,627,776

To reduce the problem to a manageable number of solutions, the CHMC uses three characteristics of the EDS. These properties are discussed below.

- **It is generally impractical to consistently achieve a globally optimal solution.** A number of issues affect the ability to actually achieve an optimal solution on a typical EDS circuit. First, common control devices were not intended to change often and rapidly. Many have delays built into them to keep them from operating too frequently. Additionally, the communication infrastructure on many EDS systems can have a significant delay, sometimes on the order of 10 minutes. These delays, coupled with constantly changing load, make it impractical to implement an optimal solution without some sort of predictive algorithm. Finally, even though models can predict the operation of the EDS with good accuracy, since calculations are still dependent on statistical models of loads, some error will always exist. In other words, a calculated "optimal" cannot be guaranteed; it will always have some error and uncertainty.
- **A solution in the neighborhood of the current operating point is preferred to a solution far away from the current operating point.** In other words, the movement of control devices should be minimized. Using the above as justification to pursue an improved solution rather than an optimal solution, this characteristic is used to limit the number of possible solutions in the space.
- **Some control combinations are mutually exclusive.** Some device actions, particularly from SCD, can greatly traumatize the system. For this reason, EDS planners often stagger the operation of devices such as switched shunt capacitors which can inject severe voltage transients onto the system. The CHMC keeps the same approach. Only a single SCD can operate in a particular iteration.

The above EDS characteristics can have a dramatic impact on the number of solutions that need to be investigated. To illustrate the potential solution reduction, the reduction techniques above are applied to the configurations from Table 3.4. For the purposes of this exercise, the MCD are limited to within 4 steps of their current operating position, with the exception of DER which maintain their entire range. If any SCD operation occurs, all other device actions prohibited. The results of the reduction are shown in **Table 3.5**.

For the reduced system, the number of possible solutions is given by

$$number\ of\ solutions = n_{SCD} + n_{MCD}^{x} + (2n_{DER})^{y} \qquad (3.13)$$

where

n_{SCD} = number of SCD

n_{MCD} = number of MCD

n_{DER} = number of DER

x = number of MCD steps allowed

y = number of DER steps

While the number of combinations can still be quite large, the reduction in the solution space can be quite dramatic. This reduction can be quite important when supplying solutions in real time.

Now that the criteria that govern the CHMC control algorithm have been established, an exhaustive search over the solution space using a nested optimization approach was used to satisfy these objectives. A brief discussion follows on why a nested optimization approach is used.

Table 3.5 Impact of solution reduction techniques

Control Devices	Original	Reduced
1 gang-operated, 3-phase switched shunt capacitor 1 gang-operated, 3-phase load-tap changer, 16 step	32	5
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step	8,192	65
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 gang-operated, 3-phase voltage regulator, 32 step	262,144	257
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 phase-operated, 3-phase voltage regulator, 32 step	268,435,436	4,097
1 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 phase-operated, 3-phase voltage regulator, 32 step 1 gang-operated, 3-phase DER, 32 step real, 32 step reactive	274,877,906,944	4,194,304
3 gang-operated, 3-phase switched shunt capacitor 1 phase-operated, 3-phase load-tap changer, 16 step 1 phase-operated, 3-phase voltage regulator, 32 step 1 gang-operated, 3-phase DER, 32 step real, 32 step reactive	1,099,511,627,776	4,194,307

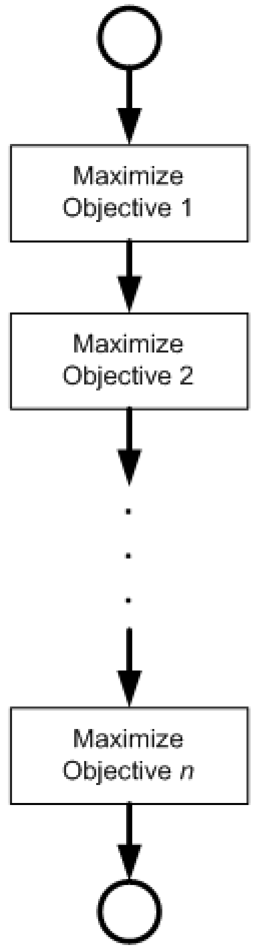


Figure 3.6 Nested optimization approach

A nested optimization approach is a hierarchal optimization method for multi-objective optimization problems. The objectives to be maximized are ranked, in this case according to their priority. The set of solutions are then maximized sequentially; the solutions of later stages are selected from a subset of solutions that satisfy the previous stages. Figure 3.6 illustrates this optimization approach. .

To use the nested optimization approach, the criteria need to be ranked. Of the three criteria, two criteria are far more important than the third. Voltage and loading must be maintained on the circuit, regardless of efficiency. The choice really lies in prioritizing the loading versus voltage criteria. The reason the CHMC uses the voltage criteria as the highest priority is explained next.

In a hierarchical optimization, the highest priority criteria will always be optimized at the expense of the lower priority criteria. Due to the positive voltage dependency of many types of loads, lowering the voltage on the EDS will often lower the load, and therefore lower the current [27]. When the CHMC begins trying to alleviate loading violations (minimizing the WCT), it may try to reduce the voltage, potentially out of the acceptable range.

If the VDT is the highest priority, the CHMC will always try to maintain the voltage on the circuit within the acceptable range. Maintaining this voltage range and therefore the VDT does not directly contradict with the WCT objective, so the CHMC will more reliably produce operating points that maintain operating criteria.

Figure 3.7 describes the CHMC decision process. When the controller is executed, the current operating condition is treated as the base case. The VDT, WCT, and LT are calculated and saved as the minimum. This ensures there is always a solution. Additionally, treating the base case as minimum initially ensures the CHCM will only suggest new device set-points if an improved solution is made.

Using the device limits as described above, a recursive algorithm is used to test all possible combinations of control devices. For each unique combination *n*, the VDT, WCT and LT are tested against the minimum. The decision process is as follows.

If the VDT_n is less than the saved minimum VDT_{min}, the solution is automatically accepted. It should be noted that the VDT will always be 0 if there is no voltage violation on the circuit; therefore, the only way a solution will automatically be accepted is if the overall circuit voltage is improved. Likewise, if VDT_n is greater than VDT_{min}, the solution is rejected. If VDT_n

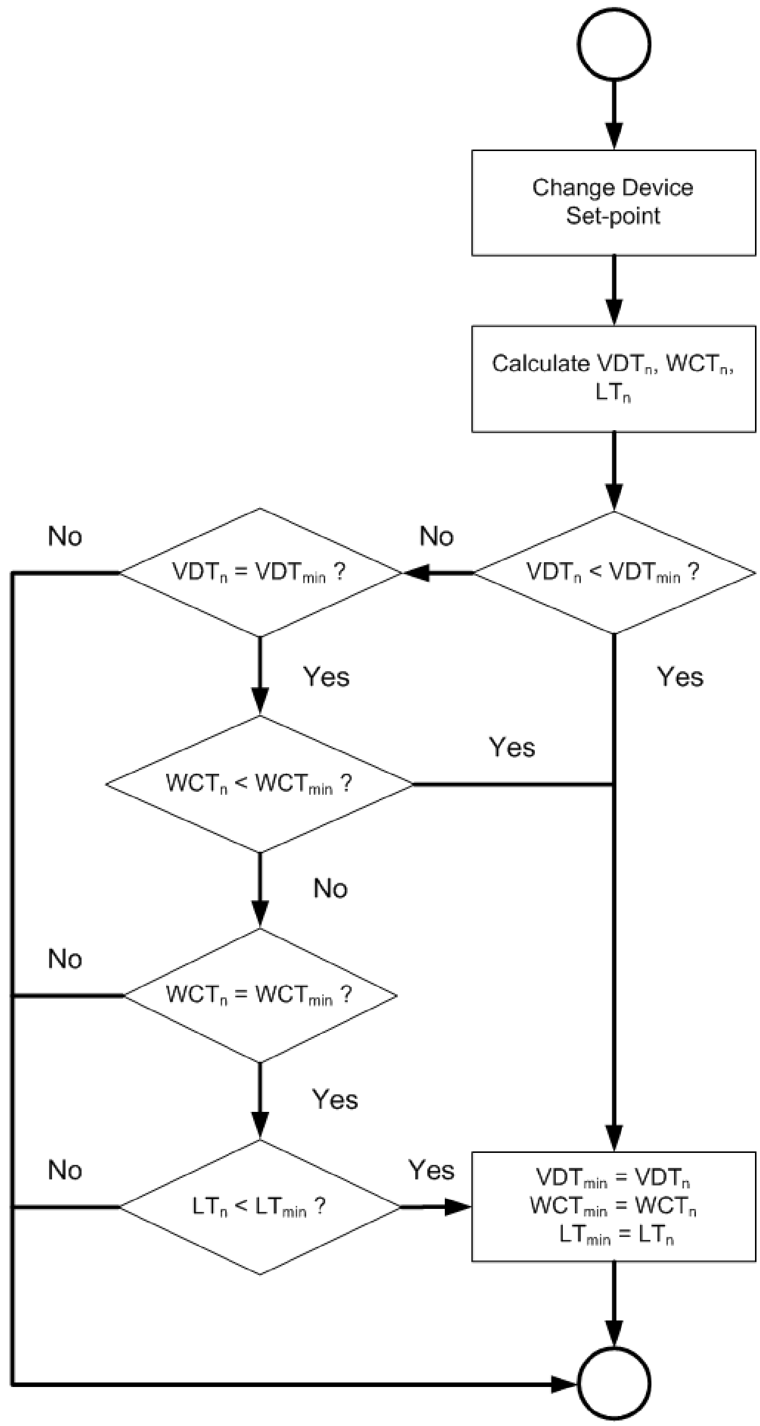


Figure 3.7 CHMC decision tree

is the same as VDT_{min}, which would include the case where no voltage violations exist on the circuit, the CHMC proceeds to test the WCT metric.

The WCT is evaluated the same way the VDT is evaluated. If the WCT is improved, the solution is accepted; if the WCT is worse, the solution is rejected. .The LT is only evaluated if the WCT is at the saved minimum value.

Finally, the LT is evaluated. In this case, if LT_n is greater than or equal to LT_{min}, the solution is rejected. If LT_n is less than LT_{min}, the solution is accepted.

Because all comparisons are between solutions in the space and not compared to absolutes, this solution method is very portable. In other words, even though the makeup of circuits can vary greatly from circuit to circuit with respect to total load, efficiency, customer types, etc., the solution method is unaffected. This property also helps the

3.6 Set-point transmission

After set-points for the particular control iteration are determined, the CHMC compares the new set-points against the current set-points of the field devices. If they are the same, the CHMC ends the control loop and waits for the next iteration. If there are any differences, the CHMC transmits the new set-points to the field controllers.

The set-points are transmitted via a secure communication protocol over the internet to an EDS control and monitoring center. The center then dispatches the commands to the local controllers of the EDS control device.

When the control set-points are dispatched, the CHMC updates the model to the desired set-point. The model validation algorithm, which uses the same model as the CHMC, then monitors the circuit measurement feedback. When the model and system are in sufficient agreement, the model validation algorithm executes the CHMC again.

3.7 Miscellaneous control considerations

3.7.1 DER Dispatch

From a strictly loss perspective, DER real power injection will tend to lower the losses on the circuit. However, for a number of reasons, it may not be desirable run the DER at maximum output. Fuel costs, emissions contracts, and reduced life-cycle are a few reasons why the DER output should be limited.

Commonly, cost functions are used to weigh the detriments of running DER versus the potential benefits. In a cost function, a weighting is assigned to the parameters, and the unit is dispatched based on if the result of the function is net positive or net negative.

The CHMC in this work does not include cost functions for DER dispatch. Instead, it assumes the DER should be set to the minimum output necessary to alleviate a constrained condition. The methodology for dispatching the DER is shown in Figure 3.8.

3.7.2 Cool-down timers

Many EDS control devices, such as switched shunt capacitors, have maintenance and life-cycle schedules based on the number of operations they perform. For this reason, the total number of operations in a given time period may be limited. Furthermore, natural load variations could cause control device oscillations if allowed to move without any delay.

Many of the references included above used day-ahead scheduling to limit the number of movements capacitors will make. However, such dispatching could cause problems if an unscheduled reconfiguration takes place.

The CHMC makes use of cool-down timers to restrict the movement of certain types of control devices. A cool-down timer is a counter that disallows the movement of control devices

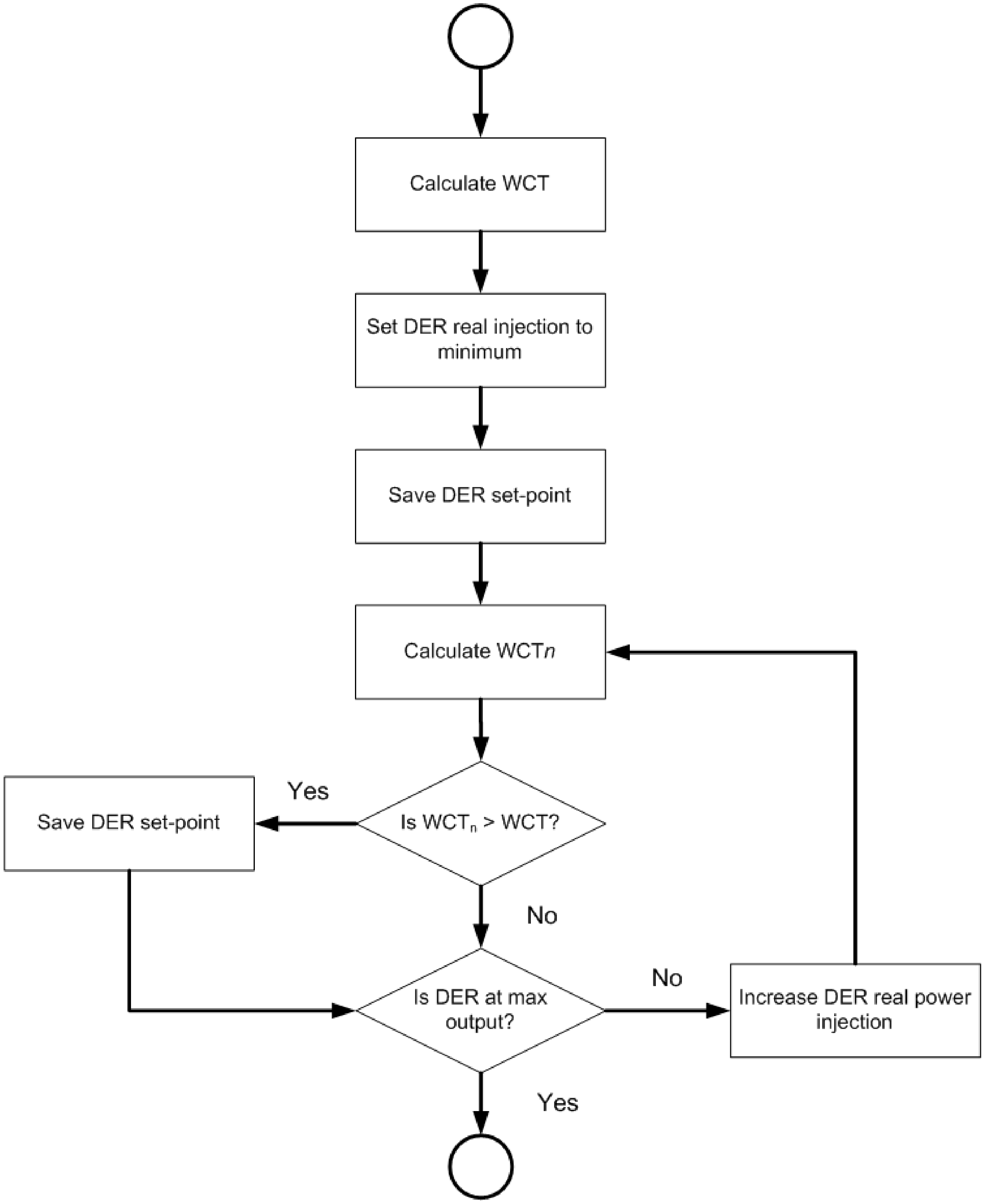


Figure 3.8 DER dispatch flow diagram

for a period of time after particular types of control operations occur. The cool-down timers serve two purposes: to limit unnecessary device movement, and to allow the system to come to equilibrium after a potentially traumatic device operation.

Additionally, the CHMC uses two types of timers. The first limits the movement of a particular device, for example a capacitor after it operates. The second limits all control device movement after an operation.

The cool-down timers used in the CHMC are iteration based. For example, if SCD have a cool-down timer of 2, that means when they operate, they will not be allowed to operate again for 2 iterations. The actual lockout time is dependent on the frequency of the control iterations.

3.7.3 Voltage criteria relaxation

To give the CHMC flexibility, the voltage criteria can be relaxed when attempting to alleviate capacity constrained situations. Lowering voltage, which often decreases load, can help alleviate over-loaded components. When the CHMC enters capacity constrained operation (WCT > 0), the CHMC calculates the VDT using emergency voltage ranges.

3.7.4 Voltage bandwidth and step size

For fail-safe operation, voltage set-points are dispatched to EDS control devices such as VRs. In the event of a communication failure or other software or hardware failure, the control devices will still operate appropriately to maintain their set-points.

While this fail-safe operation is paramount for a successful EDS controller, it can add significant variability. Specifically, when the CHMC dispatches a control device, it does not know where the device will settle in its range.

For example, if a VR is dispatched to 120.5 ±1 V, the VR could be regulating anywhere from 119.5 to 121.5 V, generally depending on if the VR enters the range from the top or the bottom.

The CHMC uses this property of certain control devices to further simplify the solution search. The CHMC reduces the number of possible steps by converting the voltage range into steps. The conversion is based on the bandwidth supplied with the VR set-point.

For a VR that regulates 5% in 32 steps, the range of the VR is 114 to 126 V over 32 steps, or .375 V / step. In this case, a ±1 V bandwidth would cover 5 steps. Since 5 steps is the minimum number of steps to guarantee device movement, the CHMC moves the control device in 5 step intervals. In other words, the CHMC must dispatch a voltage outside the current dead band before device movement should be expected.

Chapter 4 Advanced time series analysis

4.1 Overview

Modern EDS design requires more advanced simulation techniques than those that have been relied upon in the past. The classical method of analyzing one or two time points is not adequate when planning for newer technologies such as renewable DER integration, demand response, and PHEV. Reference [28] describes the importance of times series data in variable generation scenarios such as wind studies.

In addition to variable resource data, advance control algorithms such as the CHMC described in Chapter 3 cannot be accurately simulated using the single time step approach. Storage options and some resources such as concentrating solar plants have energy charge / discharge profiles and thermal histories, making accurate simulation for a single hourly set-point difficult.

Time series analysis is becoming more common in EDS analysis software. One common hurdle for those performing time series analysis for the EDS is different time resolutions between data sets. The most common data resolution used for EDS analysis is hourly average data. However, many statistical models of loads, the basis for any EDS analysis, are commonly very limited. For example, a utility may develop hourly load models for 4 typical days a year: winter weekday, winter weekend, summer weekday, summer weekend. Other utilities may model a week of load per month.

Resource data, on the other hand, is commonly available for every hour of the year. Solar and wind data, developed from meteorological data sets for a variety of geographical locations, can vary greatly from day to day, even over a relatively short period of time such as a week or month. This variability makes it difficult to create accurate statistical models with weekly or monthly resolutions. While simplifications can be made for worst-case scenario type analysis, the duration of events such as storms and extended cloudy periods can be important when analyzing time sensitive events such as renewable related storage scenarios.

Finally, Supervisory Control and Data Acquisition (SCADA) systems can also gather data in different time resolutions. Sub-hourly data, such as 15-minute interval data, is not uncommon. Full year data is often not available for all circuits.

This section describes an advance time series analysis tool which resolves many of the data issues described above. Additionally, the tool allows the user to compare different control scenarios and analysis algorithms over varying time periods.

4.2 Design

Figure 4.1 shows external data needed to do a comprehensive EDS analysis with variable DER. In the original software implementation of the load flow analysis, the simulation environment was governed by the load model. More specifically, the number of available analysis time points depended on the resolution of the load modes. If the load model had 2,016 hourly load points (1 week for each month), the available simulations were limited to those time points. For most EDS analysis, this method provides sufficient resolution. However, for detailed yearly analysis including variable resource data, more resolution is desired. Additionally, the load flow software has the ability to scale the load to match measurements at different points in the circuit. The time varying analysis described here builds upon the load data and measurement scaling capabilities.

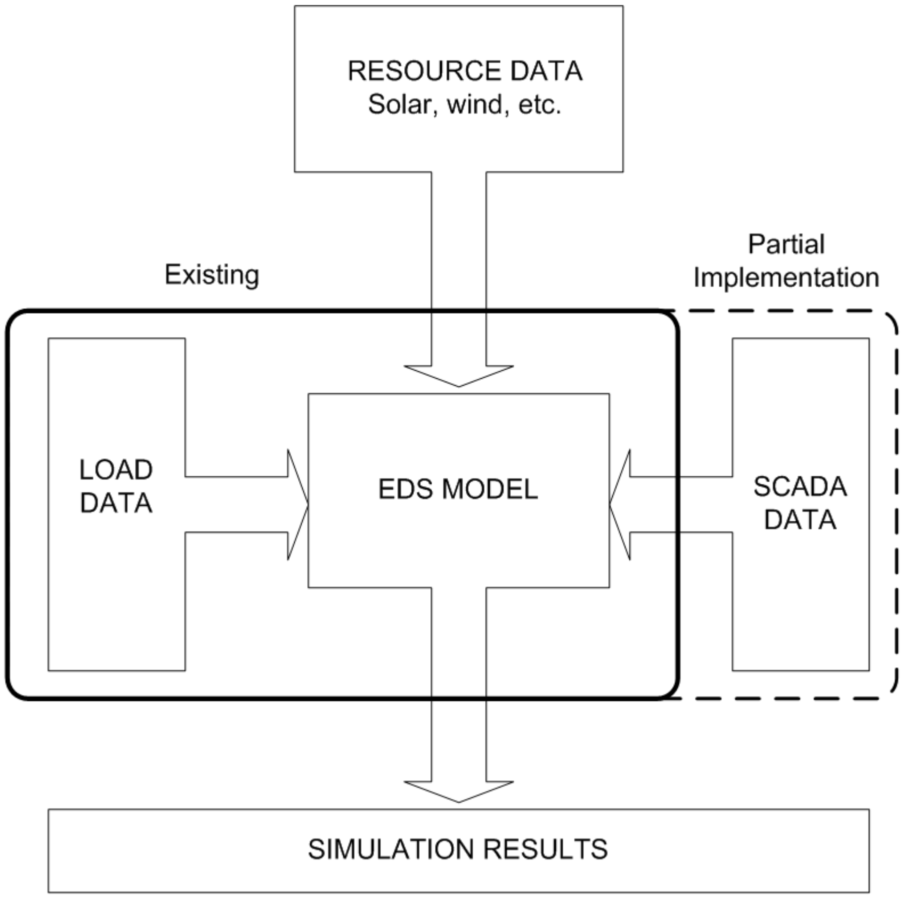


Figure 4.1 Simulation data sources

In order to use the data sources described in Figure 4.1 for analysis, the data sources must be time synchronized. This is accomplished by establishing a data framework that governs the solution process. The data framework contains an entry for every hourly time points, 8,760 time points for a normal year. The data from different sources is then loaded into the framework.

To utilize the built in functionality of the analysis software, the framework time point must be mapped to an analysis time point. As discussed above, the analysis time point is dependent on the load statistic scheme used by the utility. Mapping the analysis time point to the data framework time point generally involves determining the type of day being analyzed. For example, if a utility uses the 1 week per month load scheme, the mapping from the data framework time (which is based on the calendar year being analyzed) to the analysis time point is straight forward. However, if a utility uses another load scheme such as those based on summer and winter, the specific transition dates for summer and winter must be defined.

After the analysis point is determined, the data from the framework can be loaded into the model. Generation and measurement data are loaded into the model for the current analysis time point, and the analysis is performed. The results from the analysis are also stored in the data framework.

Next, the data framework time point is incremented. The process repeats until all framework time points selected for analysis have been evaluated. Figure 4.2 shows the analysis flow diagram.

4.3 Sub-hourly simulation

For traditional control methods such as control based on regulating to a set-point (voltage or reactive power), average hourly simulation can reasonably approximate control actions. For more complex algorithms, a single simulation based on average hourly load may not give an accurate representation of how the algorithm will behave.

The sub-hourly simulation was born out of the necessity to more completely test the CHMC algorithm. Even though the controller only provides steady state operating points, the CHMC is a time-based, iterative control method. As such, the effects of delays and multiple analysis runs need to be evaluated.

The sub-hourly simulation runs each hourly time point multiple times before progressing to the next time point. These sub-hourly iterations allow time based algorithms such as the CHMC to be more accurately simulated. For example, because the CHMC restricts the movement of control devices to limit the solution space, the controller can take several iterations before arriving at the final solution for that load point. A single hourly simulation would only

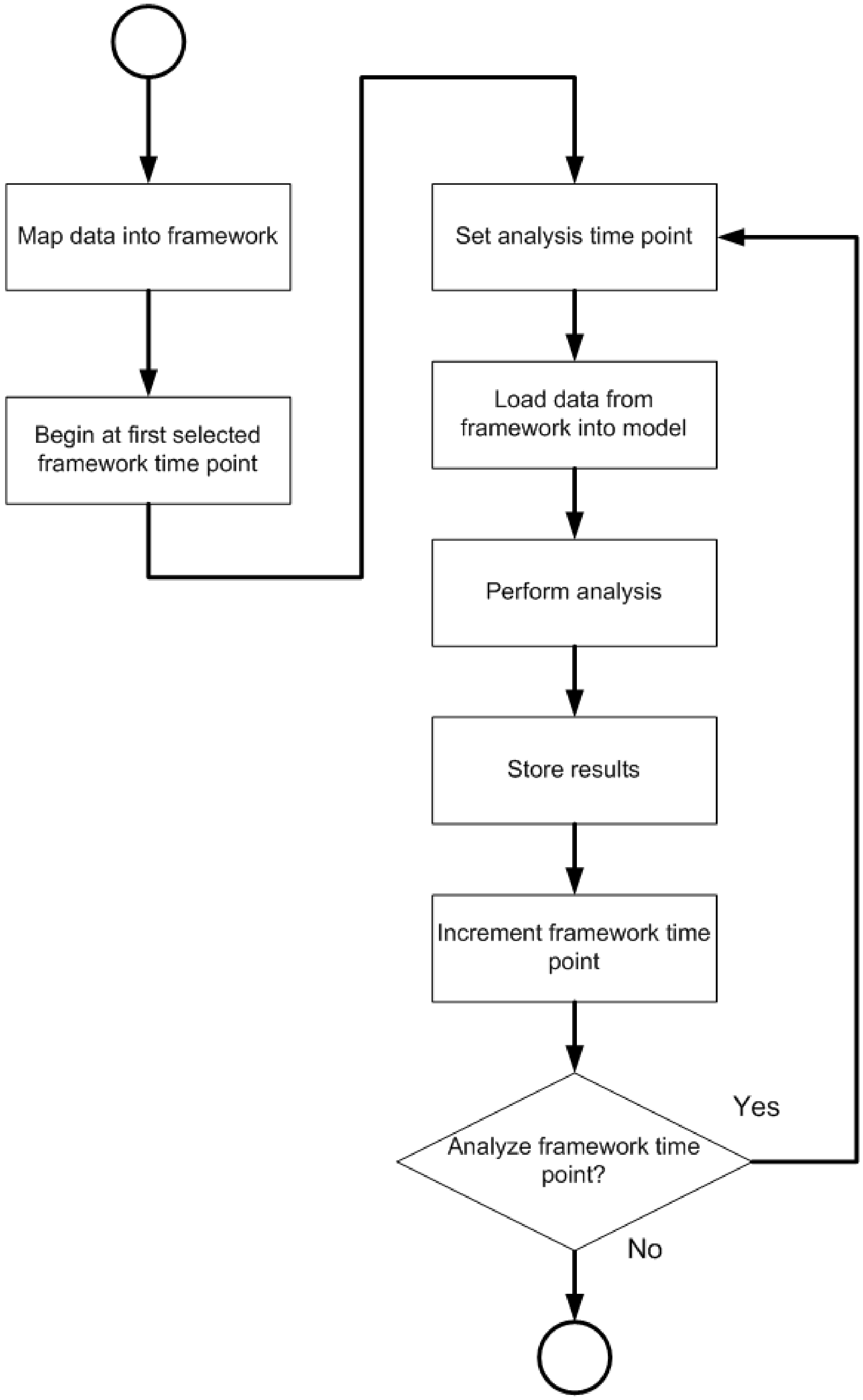


Figure 4.2 Advanced time series analysis flow diagram

take the results of the first iteration and therefore could potentially misrepresent the CHMC behavior. Additionally, simulation using sub-hourly iterations could more accurately model the effect of staggered capacitor operation as well as model the effect of regulating transformer delays.

4.4 Load smoothing

While sub-hourly simulations can allow iterative algorithm to more closely match the way they would behave when implemented, step changes between hourly load levels is a poor representation of the physical system. These step changes could add significant error to advance control algorithm evaluation.

To more closely emulate actual load, a load smoothing algorithm was added to the sub-hourly simulation method described above. The load smoothing works by using linear interpolation to estimate the load between hourly load points. Figure 4.3 shows the effects of load smoothing. For this comparison, the number of sub-hourly iterations is 4. The impact of both the sub-hourly iteration and the load smoothing will be more closely examined in the following chapter.

4.5 Model-based simulated SCADA

SCADA systems are used by virtually all utilities to monitor and control the electrical power system, including the EDS. Algorithms that work with SCADA systems, such as the CHMC described in Chapter 3, often need to test input and output functionality before being deployed into the field. This section describes the development of a model-based simulated SCADA system that facilitates this process.

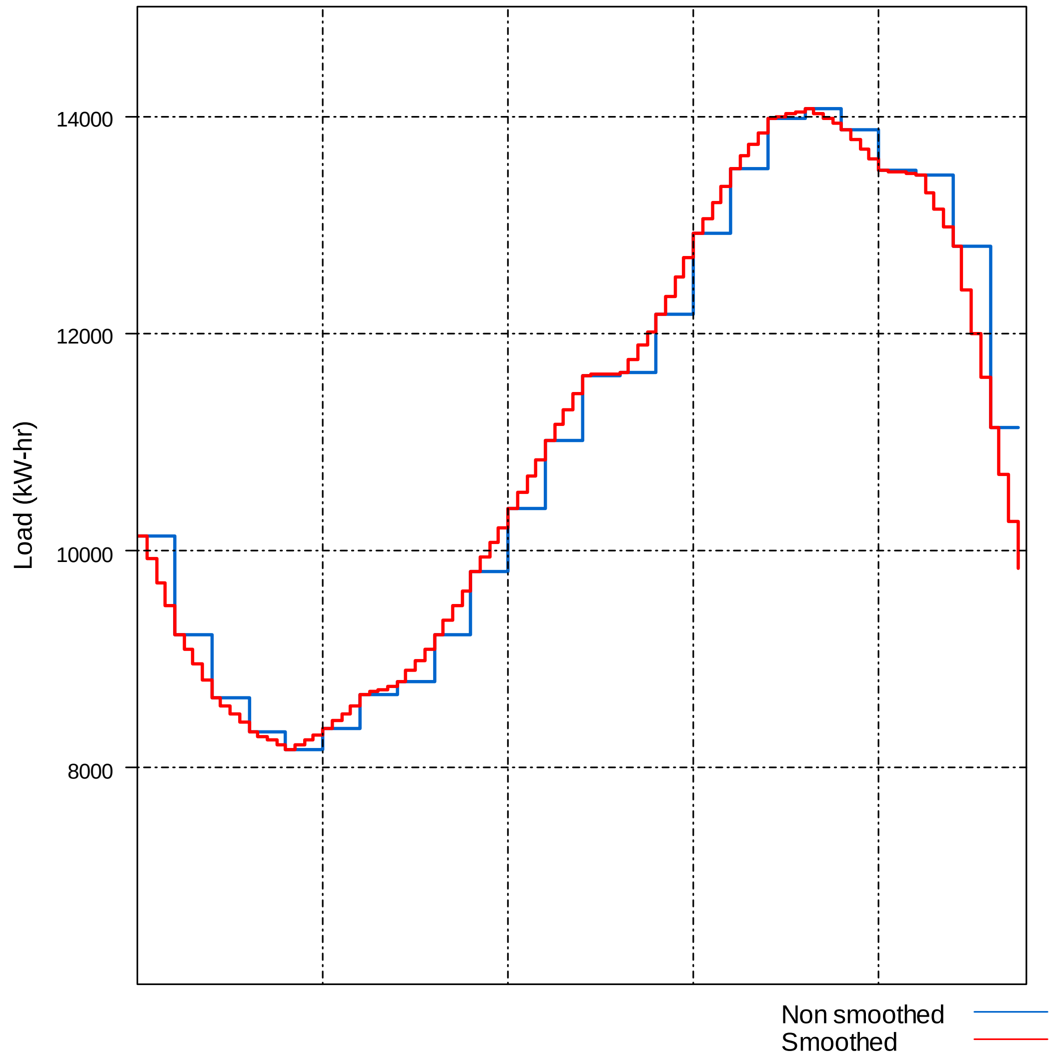


Figure 4.3 Effects of load smoothing

The flow diagram of the simulated SCADA system is shown in Figure 4.4. The simulated SCADA starts by loading a configuration file. The file associates the location of the measurements in the physical system to a component in the model. Additionally, the configuration file tells the simulated SCADA which quantities the algorithm is looking for, such as phase-a voltage, current flow, or power flow. In the case of the CHMC from Chapter 3, the model that the simulated SCADA uses is identical to the model the CHMC uses. However, the models may be different in some cases.

After the configuration file is loaded, the simulated SCADA checks for any input from the test algorithm. For example, the CHMC can send control device set-points to the SCADA system. The simulated SCADA system receives these commands and makes appropriate changes to the devices in the model.

Next, the simulated SCADA performs a load flow analysis on the model. The results of the load flow analysis are the measurements that will be sent to the test algorithm. Based on the configuration file, the simulated SCADA system creates an output file to be sent to the test algorithm. The CHMC communicates with SCADA using XML, therefore the simulated SCADA used XML in this case.

A web server hosted on the same computer as the simulated SCADA program facilitates the connection between the simulated SCADA system and the test algorithm. Unless the program is exited, the simulated SCADA algorithm runs in a continuous loop with a user definable delay. The output file remains available on the server between iterations so that the simulated SCADA and test system can run asynchronously.

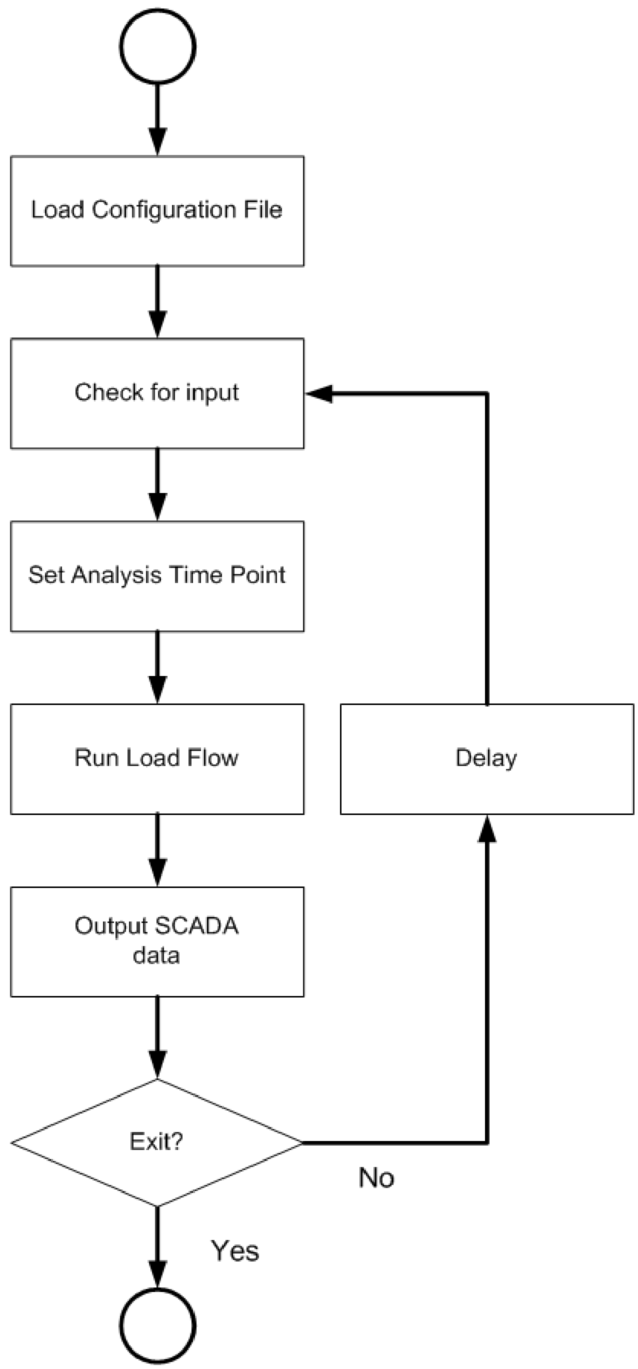


Figure 4.4 Simulated SCADA flow diagram

Chapter 5 Simulation results

5.1 Overview

In this chapter, the advanced time series simulation framework developed in Chapter 4 will be used to test the functionality of the CHMC developed in Chapter 3. First, the CHMC will be tested on a simple test circuit against the optimal circuit configuration. The CHMC will then be compared to normal control on a distribution test circuit. In this case, the normal control refers to the existing control scheme on the circuit. The control methods were compared for light and heavy load days.

5.2 Simple test circuit and results

A distribution test circuit was constructed to test the functionality of the CHMC. The test circuit, shown in Figure 5.1, consists of a 3-phase, phase operated VR, a 3-phase, gang operated capacitor bank, and several time varying loads. The circuit was designed to be simple enough that an optimal solution could be calculated using an exhaustive search over the entire solution space.

Figure 5.2 shows the result of a 24 hour simulation of the simple test circuit. The CHMC very closely matches the exhaustive solution. Table 5.1 shows the results of the simulation. The CHMC algorithm loss total is within .5% of the exhaustive search, while maintaining the voltage and loading criteria. Of particular interest is the solution time; the exhaustive search for the simple circuit took approximately 1,300 times longer to complete than the CHMC.

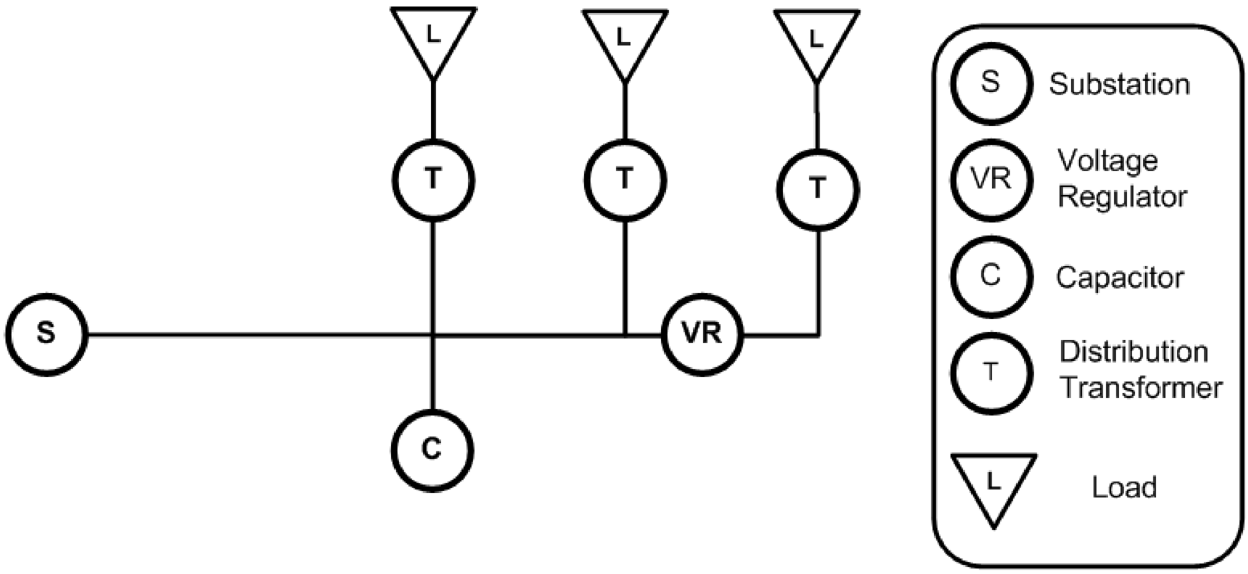


Figure 5.1 Simple test circuit

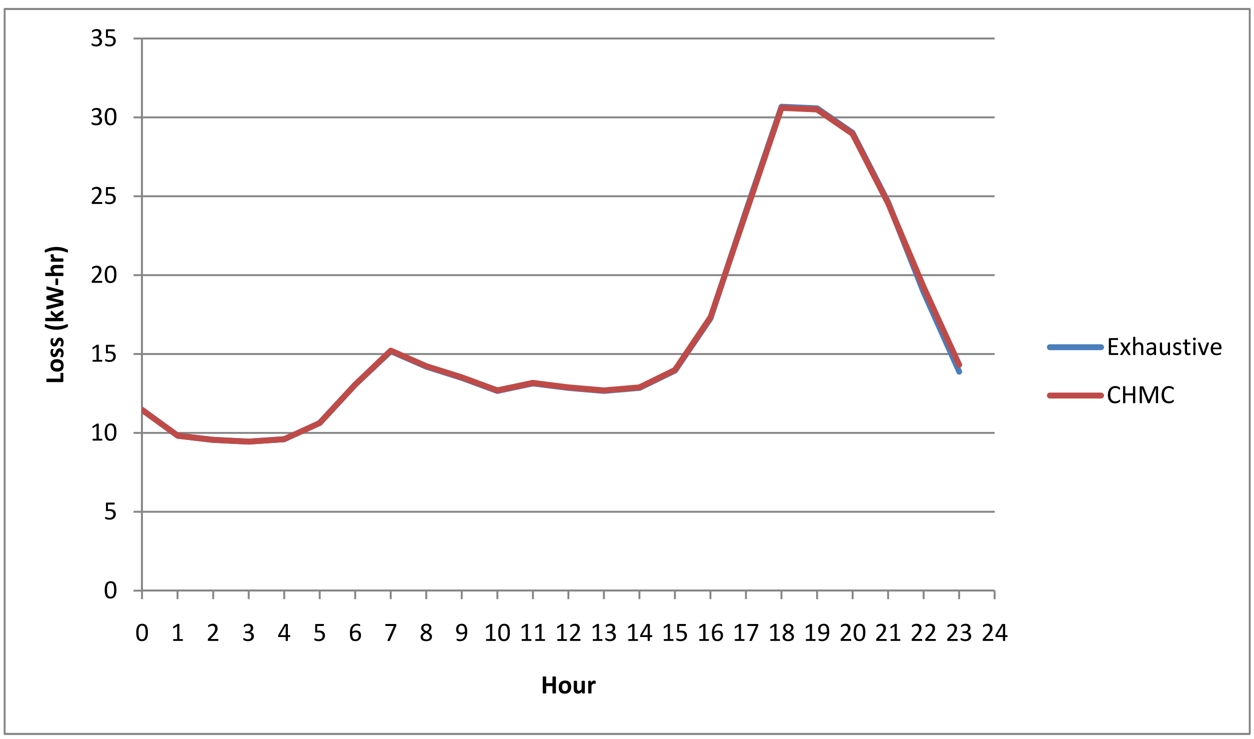


Figure 5.2 Simple Test Circuit - Losses

Table 5.1 Comparison for control methods on simple test circuit

Case	Total Losses (kW-hr)	Max VDT	Max WCT	Computation Time (s)
CHMC	384.93	17.76	0	1
Exhaustive Search	383.61	16.81	0	1,303

5.3 Distribution test circuit

The distribution test circuit used for this work has a largely residential customer base. The test circuit is a 13.2 kV, Y-connected circuit with a 16 MVA peak load. Figure 5.3 shows the circuit schematic including the location of the control devices. The circuit contains 3 switched shunt capacitor banks, a voltage regulator, and a synchronous DER.

The normal control used in these simulations is based on actual utility practice for this circuit. The details of the control parameters are listed in Table 5.2.

Table 5.2 Description of normal control

Control Device	Operation Mode	Description
Cap 1	Time Clock	Light load days: Off Heavy load days: On 07:00 to -23:00
Cap 2	--	Always on
Cap 3	Time Clock	Light load days: Off Heavy load days: On 07:00 to -23:00
Voltage Regulator	Voltage Control	124.5 ± 1 V, local voltage sensing
Synchronous DER	Peak Shaving	Real: Limit to 650 A at feeder Reactive: Unity power factor

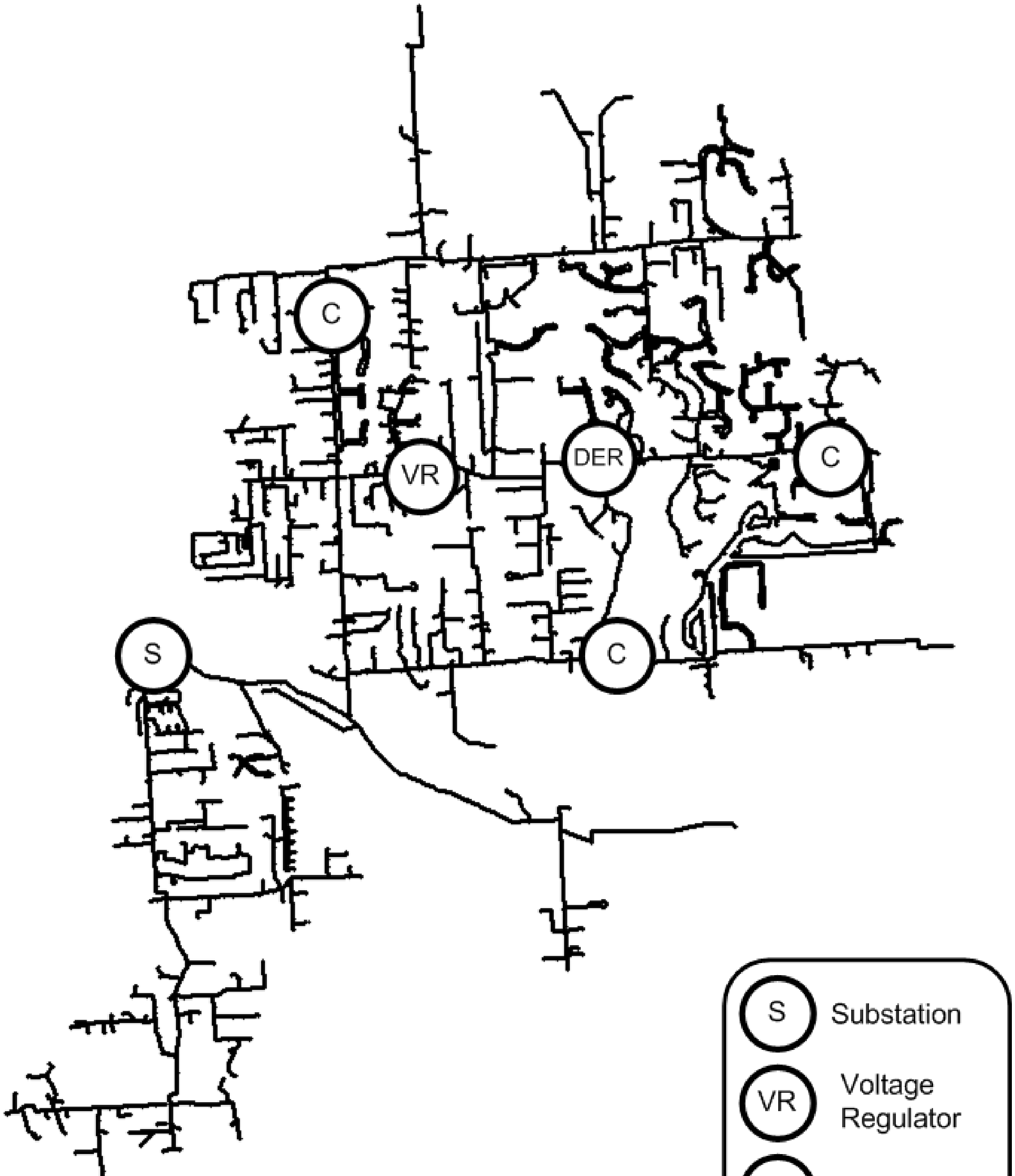


Figure 5.3 Test circuit including control device locations

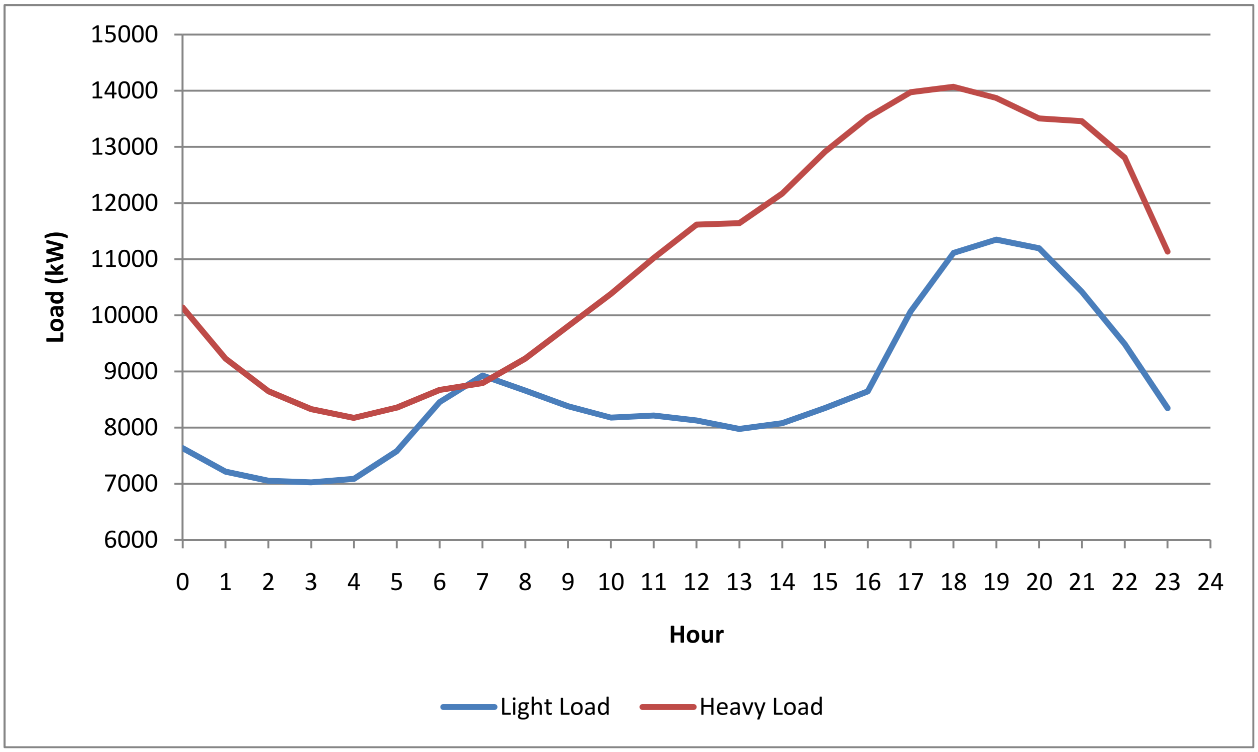


Figure 5.4 Heavy and light day load profiles

The CHMC was compared against normal control for two scenarios: a light load day and a heavy load day. The load profiles for these scenarios are shown in Figure 5.4.

5.3.1 Solution time

Table 5.3 shows a comparison of the computation time for the different solution methods for a single analysis time point. Note, the solutions methods were not optimized, and the results of the comparison are not meant to represent the shortest time necessary for each method. The results are intended only to show relative computational effort. As with the simple test circuit, these results show that the reduction in the size of the solution space has greatly reduced the solution time.

Table 5.3 Comparison of solution time

	Normal Control	Exhaustive Search	CHMC
Solution Time (s):	1	9,755	10

5.3.2 Comparison between the CHMC and normal control

This comparison is between normal control and the CHMC for a simulation with hourly time points. The results of the heavy load simulations are shown in Figure 5.5 and Table 5.4. The results of the light load simulations are shown in Figure 5.6 and Table 5.5.

In both cases, the CHMC is able to improve the circuit operation relative to the control criteria. For the heavy day, the CHMC was able to reduce losses on the system by 4.5% while improving both the voltage and current criteria. Additionally, the total feeder consumption was reduced by 4.3% and the peak load was reduced by 1.5%. Much of the improvement in this case can be traced to more aggressive use of the distributed generation, which may be undesirable.

On the light load day, the CHMC improved losses by 5.5%, while greatly improving the voltage criteria. On the light load day, the CHMC has much more flexibility to use control devices to minimize losses. On the heavy load day, the control devices are much more constrained by the circuit criteria. Additionally, the heavy load day is the design point for the normal control, so the normal control is expected to run at its peak efficiency.

Table 5.4 Heavy load day: CHMC versus normal control, hourly

	Normal	CHMC	Improvement
Total Losses (kW-hr):	8,199	7,833	4.5 %
Max. VDT	316.2	284.9	9.9 %
Max WCT	139.8	117.4	16.0 %
Max Feeder Flow (kVA):	14,342	14,133	1.5 %
Feeder usage (kVA-hr)	283,004	270,744	4.3 %
Generation (kW-hr):	6,933	9,552	-37.3 %

Table 5.5 Light load day: CHMC versus normal control, hourly

	Normal	CHMC	Improvement
Total Losses (kW-hr):	5,694	5,378	5.5 %
Max. VDT	60.3	40.4	33.0 %
Max WCT	0	0	0 %
Max Feeder Flow (kVA):	12,302	11,532	6.3 %
Feeder usage (kW-hr)	222,366	206,714	7.0 %
Generation (kW-hr):	0	0	0 %

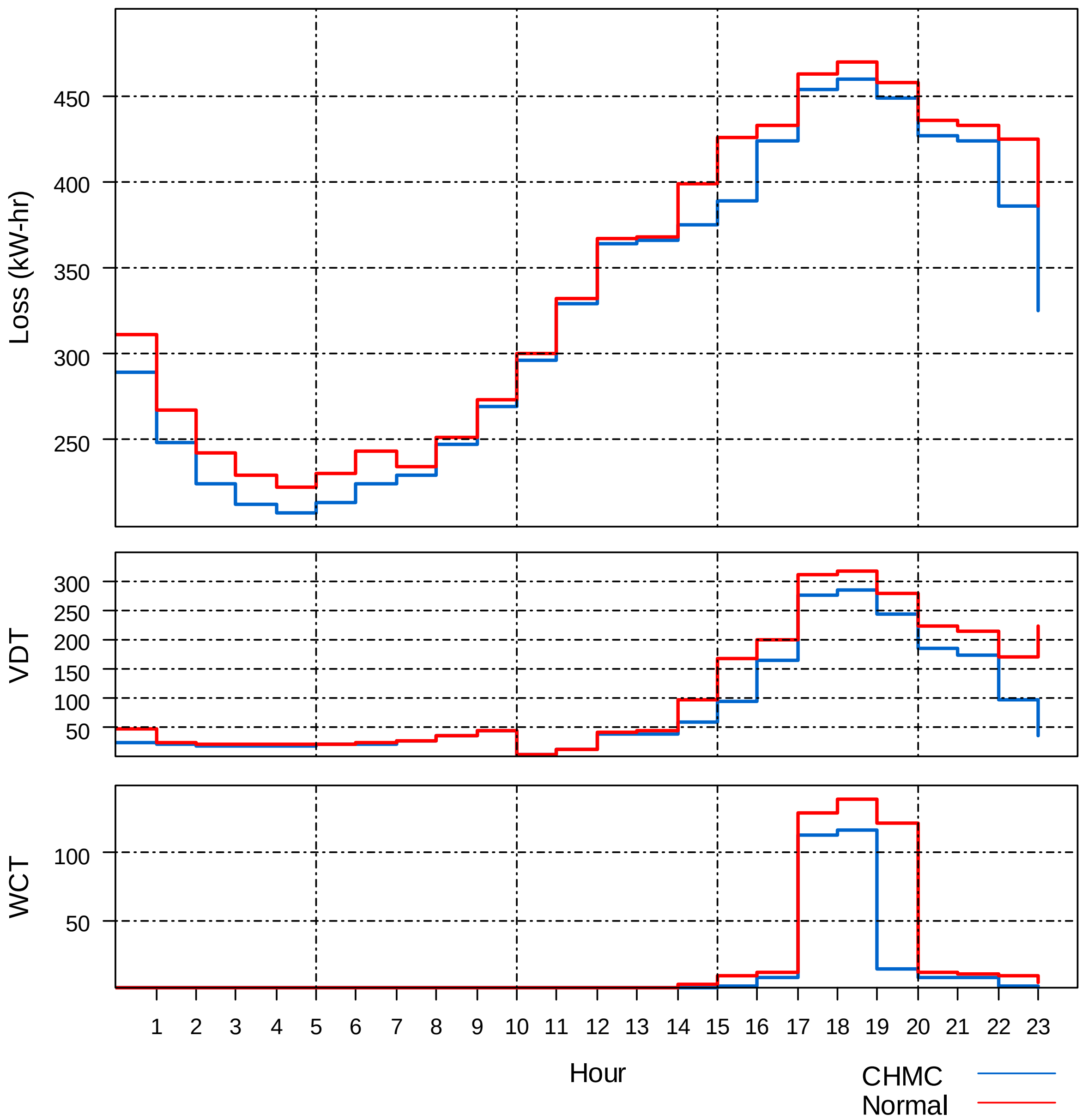


Figure 5.5 Heavy load day: CHMC versus normal control, hourly

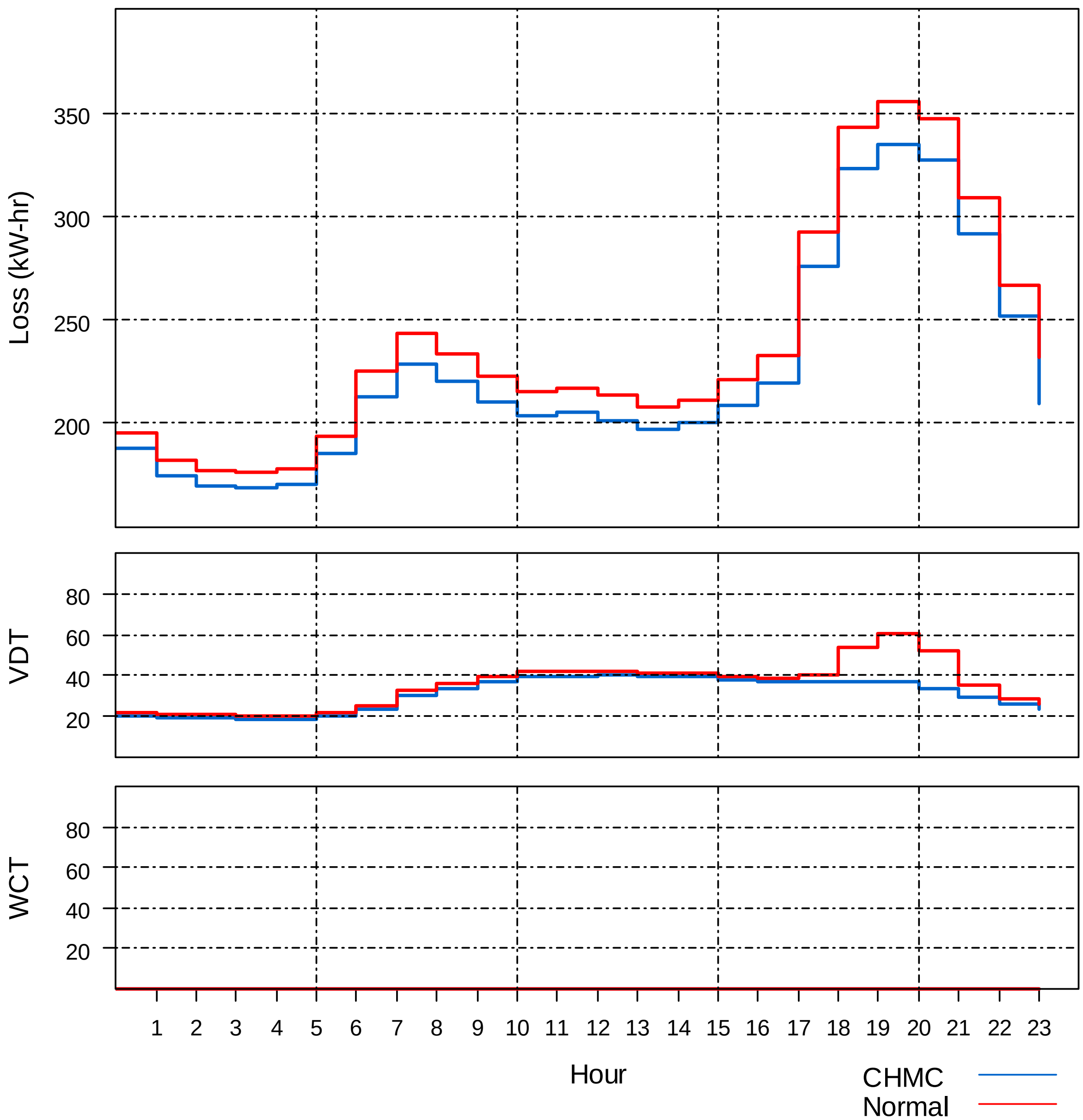


Figure 5.6 Light load day: CHMC versus normal control, hourly

5.3.3 Sub-hourly iterations

In this comparison, sub-hourly time points are simulated to allow the CHMC to behave more as it would in the field. Each hourly load point is simulated 4 times before advancing to the next load point. The sub-hourly simulation allows the controller to make adjustments incrementally.

The heavy load simulation results are shown in Figure 5.7 and Table 5.6, and the light load simulation results are shown in Figure 5.8 and Table 5.7. The results in this case are almost identical to the single hourly time point simulation.

Figure 5.9 shows a comparison between hourly and sub-hourly simulation for a heavy load day, and Figure 5.10 shows a comparison between hourly and sub-hourly simulation for a light load day. As the results mentioned above indicated, these plots show very little difference between hourly and sub-hourly simulations. This indicates that even though there can be large load steps between hourly time points, the CHMC limitations are generally wide enough to compensate in a single control iteration.

Table 5.6 Heavy load day: CHMC versus normal control, multiple hourly iterations

	Normal	CHMC	Improvement
Total Losses (kW-hr):	8,199	7,836	4.4 %
Max. VDT	316.2	284.9	9.9 %
Max WCT	139.8	117.4	16.0 %
Max Feeder Flow (kVA):	14,342	14,133	1.5 %
Feeder usage (kVA-hr)	283,004	270,368	4.5 %
Generation (kW-hr):	6,933	9,516	-37.3 %

Table 5.7 Light load day: CHMC versus normal control, multiple hourly iterations

	Normal	CHMC	Improvement
Total Losses (kW-hr):	5,694	5,376	5.6 %
Max. VDT	60.3	40.4	33.0 %
Max WCT	0	0	0 %
Max Feeder Flow (kVA):	12,302	11,532	6.3 %
Feeder usage (kVA-hr)	222,246	206,568	7.1 %
Generation (kW-hr):	0	0	0 %

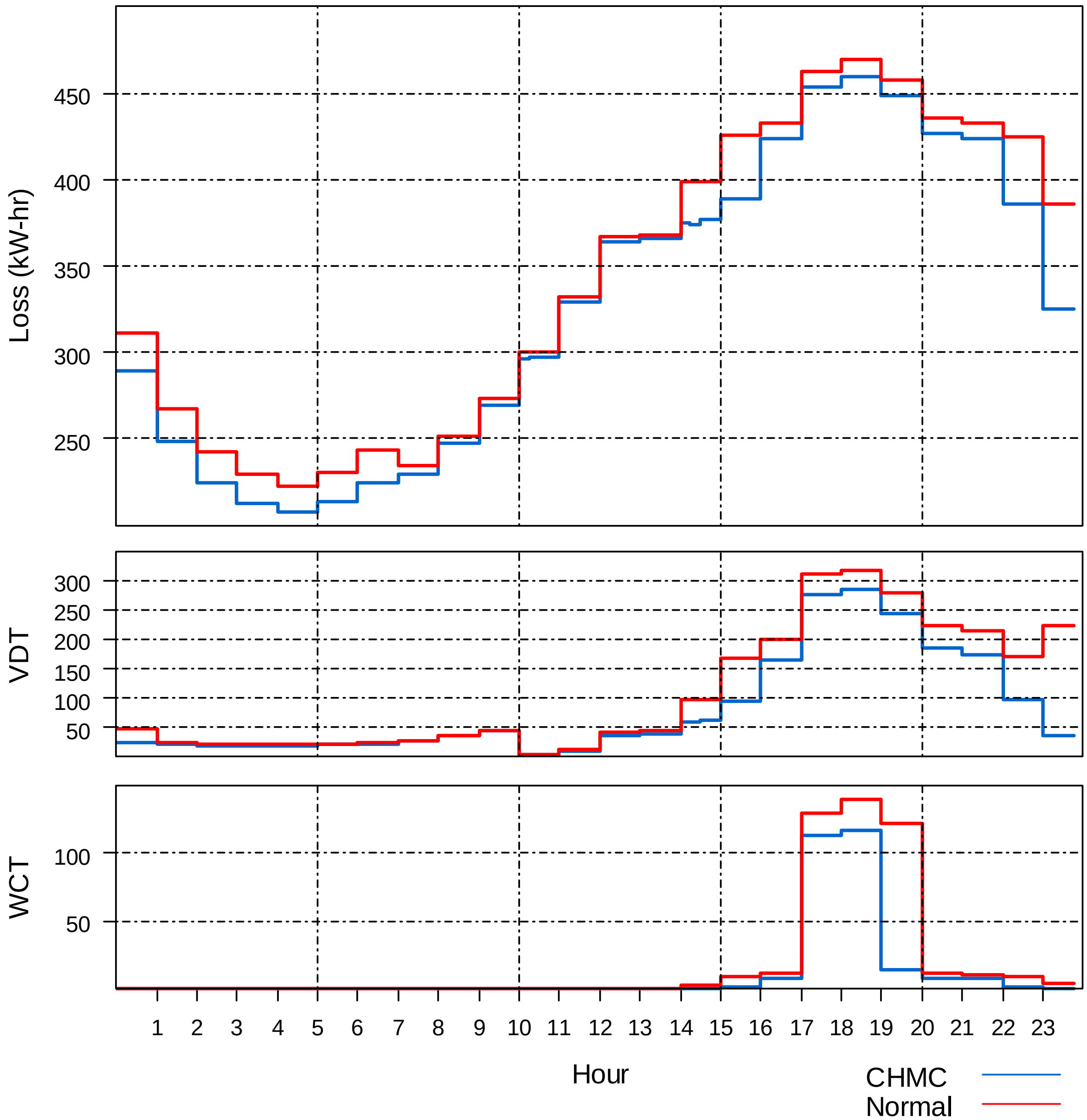


Figure 5.7 Heavy load day: CHMC versus normal control, sub-hourly iterations

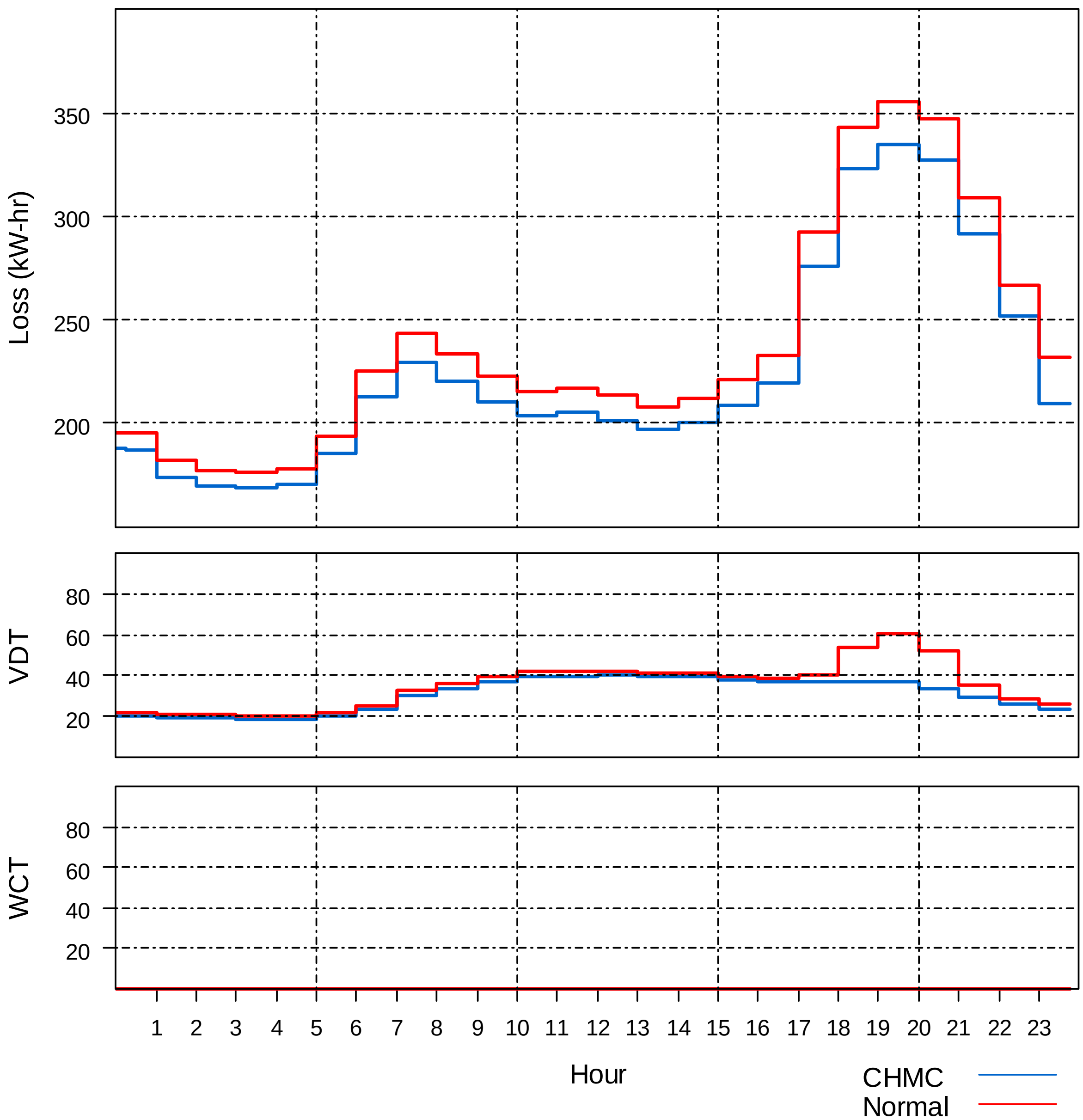


Figure 5.8 Light load day: CHMC versus normal control, sub-hourly iterations

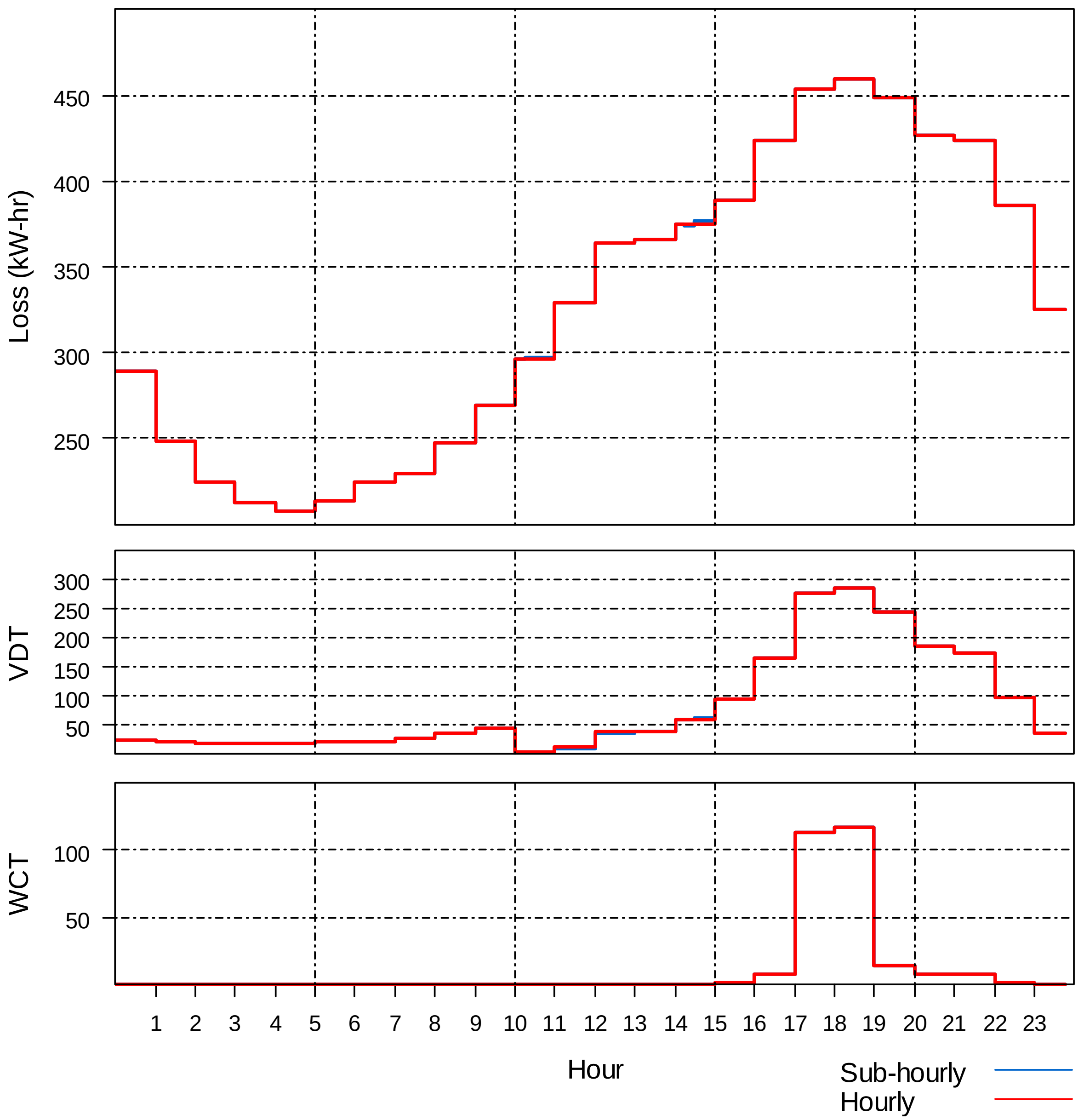


Figure 5.9 Heavy load day: Comparison between hourly and sub-hourly simulation

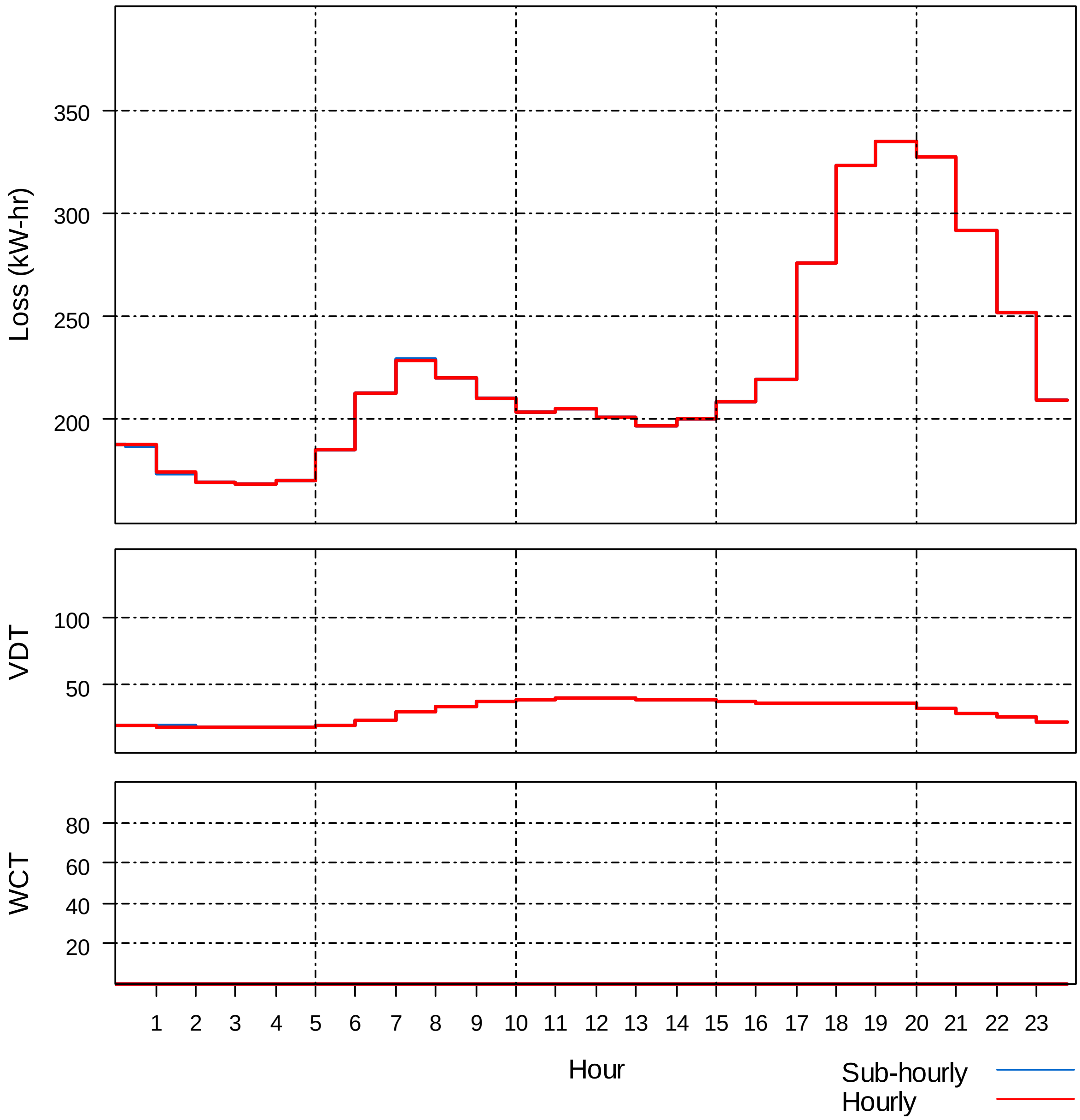


Figure 5.10 Light load day: comparison between hourly and sub-hourly simulation

5.3.4 Load smoothing

In this comparison, the sub-hourly simulations are expanded upon by adding the load smoothing described in Chapter 4. Even though the linear interpolation of the hourly set-points will not exactly match the EDS, the sub-hourly simulations with load smoothing more closely resemble the physical system because load does not generally change in discrete steps.

The heavy load day results are shown in Figure 5.11 and Table 5.8, and the light load results are shown in Figure 5.12 and Table 5.9. Again, the results from the smoothed system match the previous runs. The CHMC is able to substantially improve the system for light and heavy load days.

To get a more detailed picture of how the load smoothing impacts the CHMC performance, the smoothed an non-smoothed simulations were plotted together. Figure 5.13 shows the results for the heavy load day, and Figure 5.14 shows the results for the light load day.

When compared against the sub-hourly iteration case without smoothing, the smoothed load case makes the impact of control device movement much more noticeable. Additionally, although the loss is fairly consistent, in both the heavy and light load cases, the VDT and WCT plots show significant differences.

Table 5.8: Heavy load day, CHMC versus normal control, load smoothing

	Normal	CHMC	Improvement
Total Losses (kW-hr):	8,173	7,818	4.4 %
Max. VDT	318.6	284.9	10.9 %
Max WCT	139.8	122.5	12.7 %
Max Feeder Flow (kVA):	14,341	14,160	1.3 %
Feeder usage (kVA-hr)	282,540	270,368	4.3 %
Generation (kW-hr):	6,927	9,483	-36.9 %

Table 5.9 Light load day, CHMC versus normal control, load smoothing

	Normal	CHMC	Improvement
Total Losses (kW-hr):	5,687	5,371	5.6 %
Max. VDT	60.3	40.97	32.0 %
Max WCT	0	0	0 %
Max Feeder Flow (kVA):	12,302	11,543	6.2 %
Feeder usage (kVA-hr)	222,245	206,568	7.1 %
Generation (kW-hr):	0	0	0 %

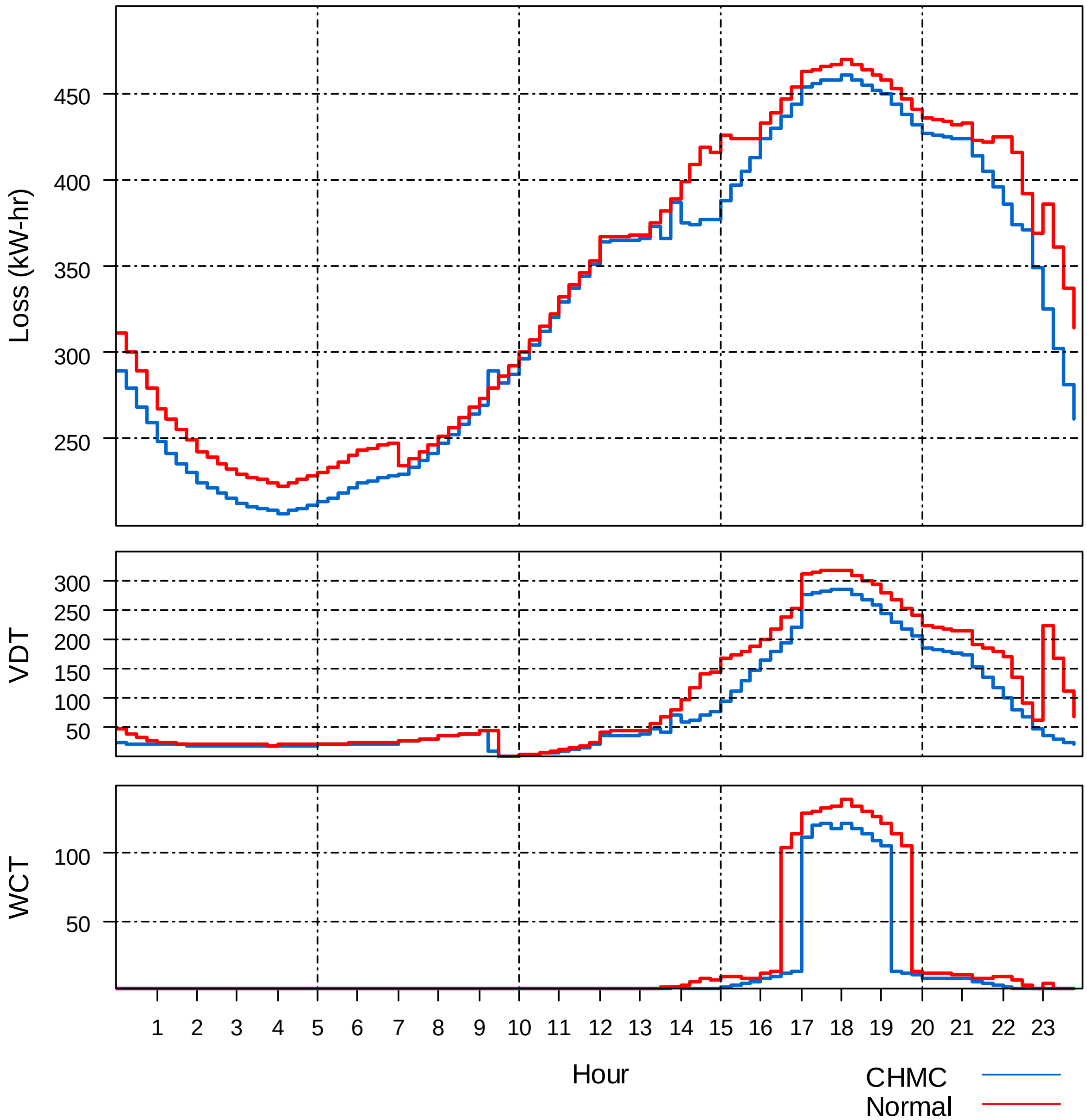


Figure 5.11 Heavy load day: CHMC versus normal control, load smoothing

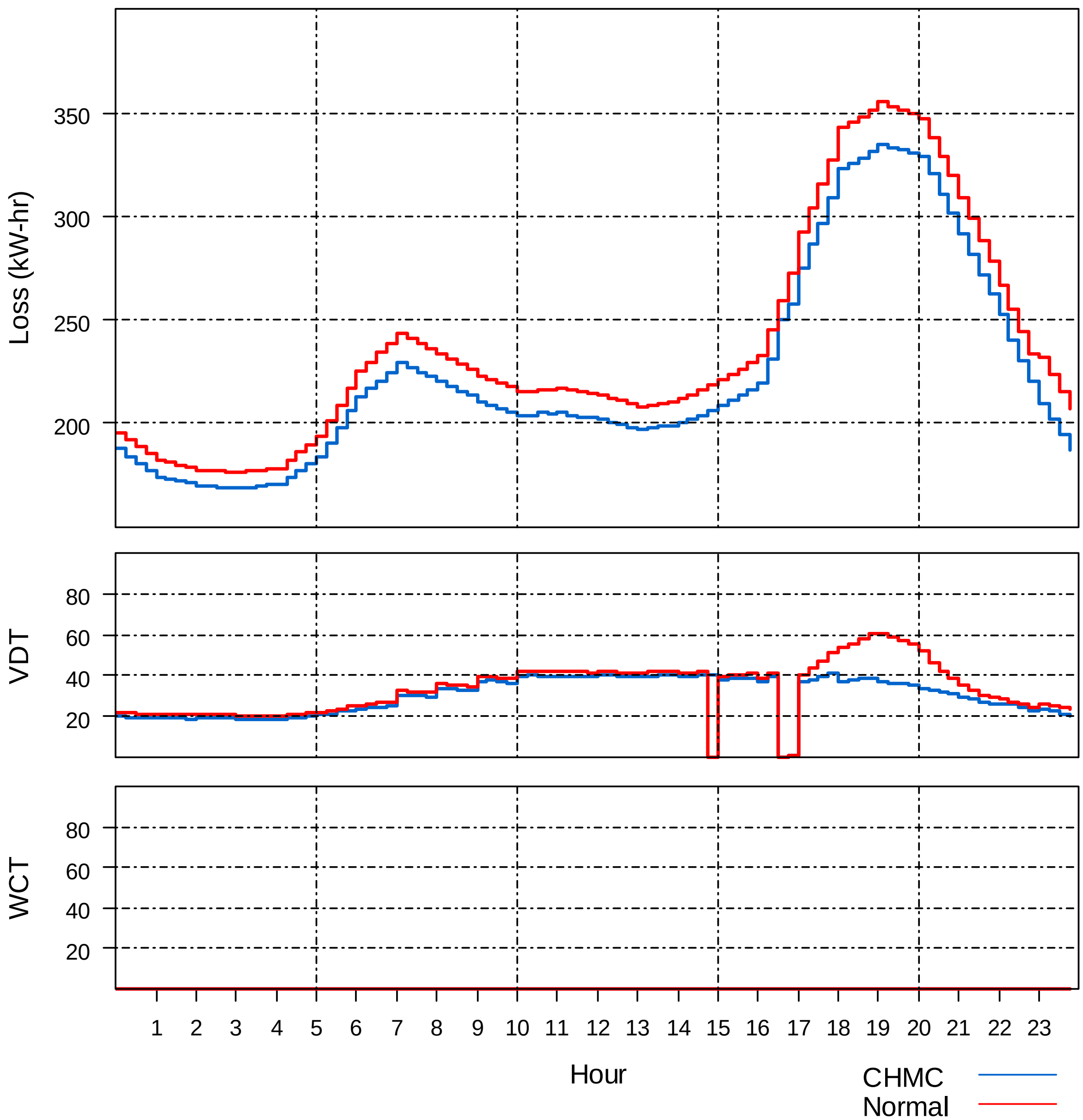


Figure 5.12 Light load day: CHMC versus normal control, load smoothing

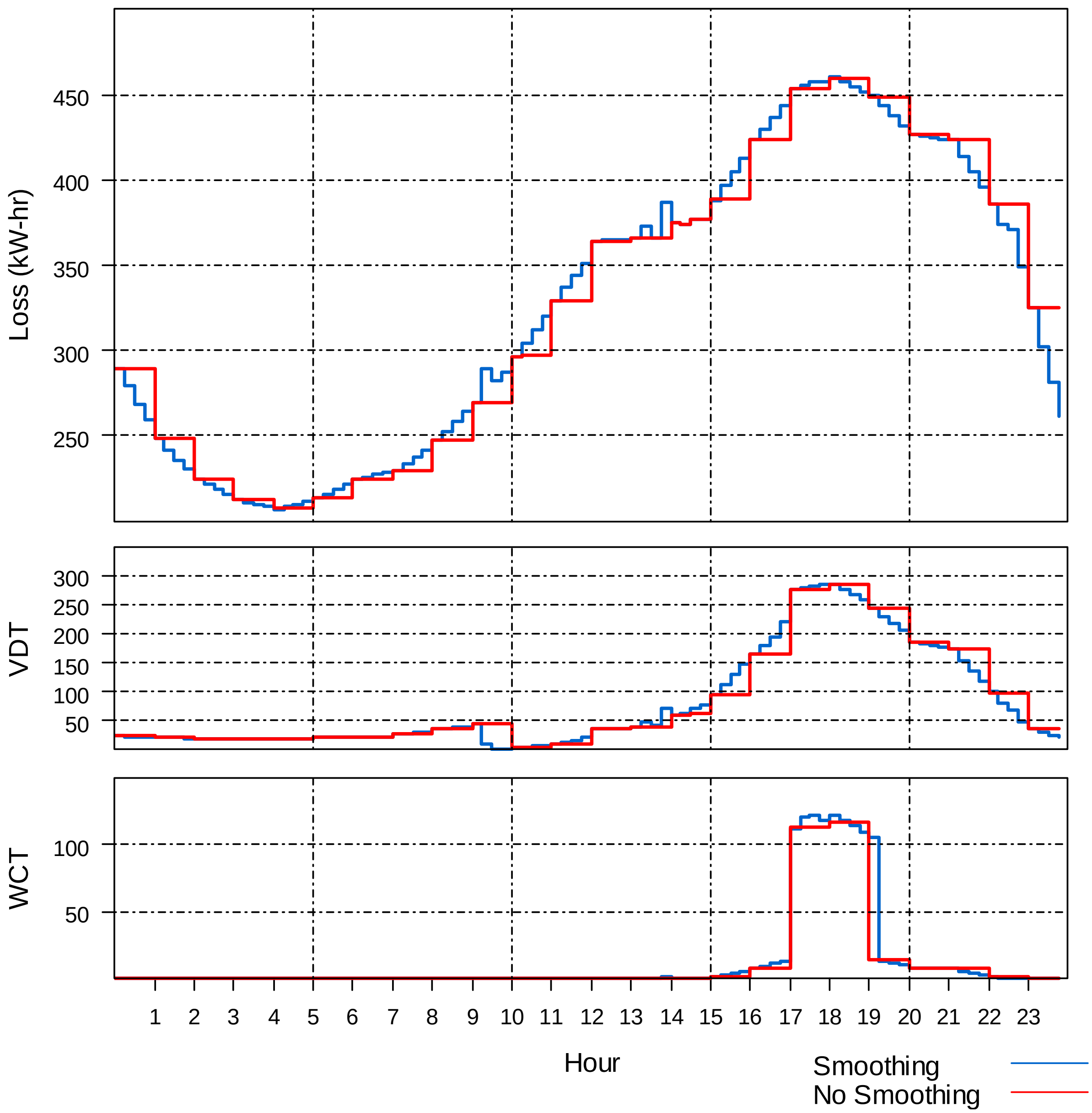


Figure 5.13 Heavy load day: Smoothing versus no smoothing

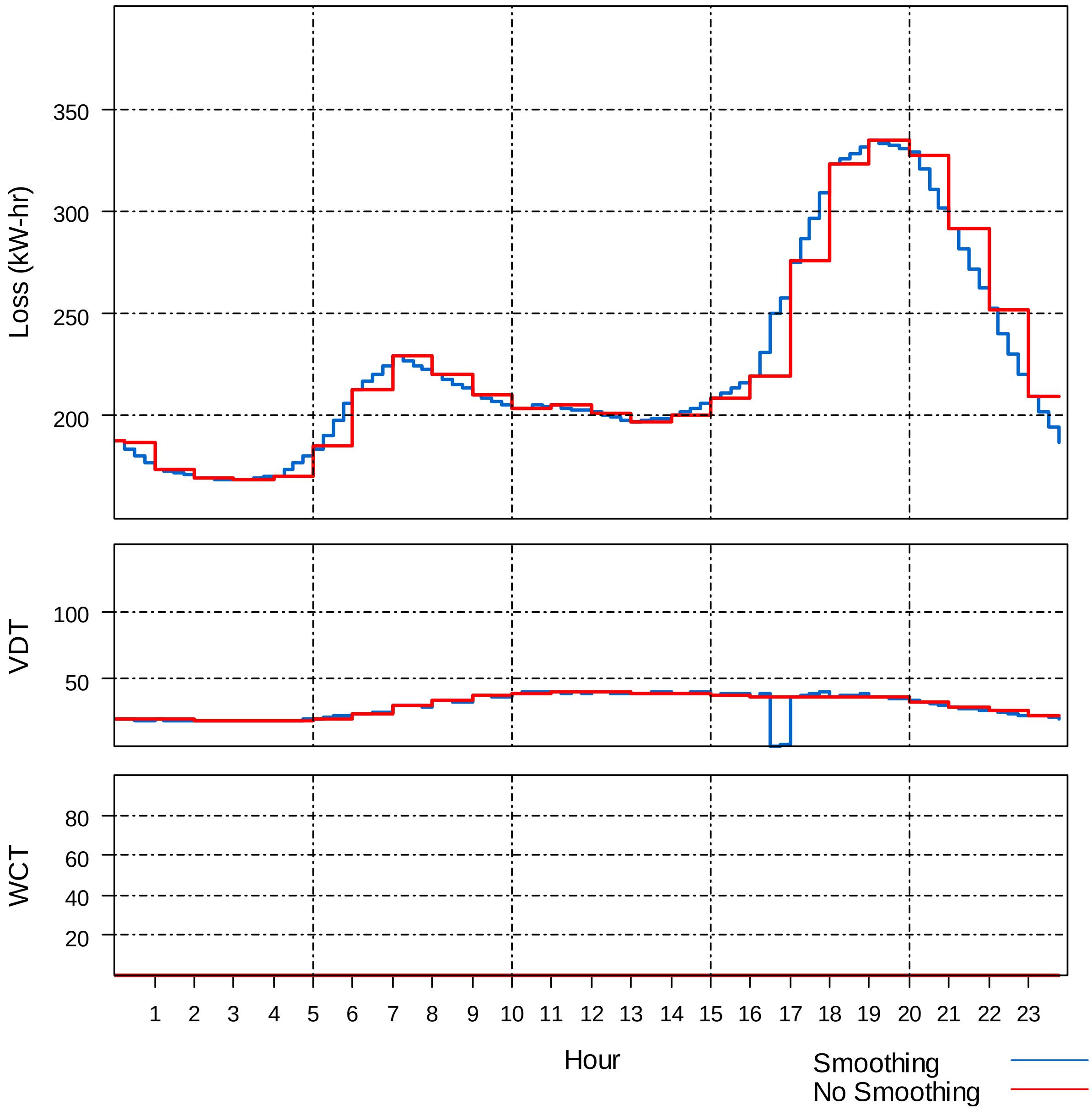


Figure 5.14 Heavy load day: smoothing versus no-smoothing

5.3.5 Effects of cool-down timers

In this comparison, the effects of cool down timers are analyzed. Ideally, the cool-down timer would ensure control devices did not operate too often without greatly impacting the CHMC performance.

To determine the impact of the cool-down timers, the results of multiple runs of the CHMC algorithm, with and without timers, were compared. First, cool-down timers of 1 iteration for SCD and 2 iterations for HCD were used. With 4 iterations simulated per hour, this is the equivalent of a 15 minute delay for SCD and a 30 minute delay for HCD. Figure 5.15 shows the results for a heavy load day and Figure 5.16 shows the results for a light load day.

On the heavy load day, some evidence of the short cool-down timers is seen around 14:00. However, the overall performance of the CHMC is not greatly affected. For the light load day, the impact of the cool-down timers is negligible.

Next, the cool-down timers were lengthened to 2 iterations for the SCD and 4 iterations for the HCD (30 minutes and 60 minutes respectively). The simulations for heavy and light load days were performed again. The results for the heavy load day are shown in Figure 5.17 and the results for the light load day are shown in Figure 5.18.

This time, some evidence of the cool-down timers are evident in both the heavy and light load simulations. In all cases, the effects are located around periods of rapidly changing load, and the performance of the CHMC with cool-down timers is not greatly diminished.

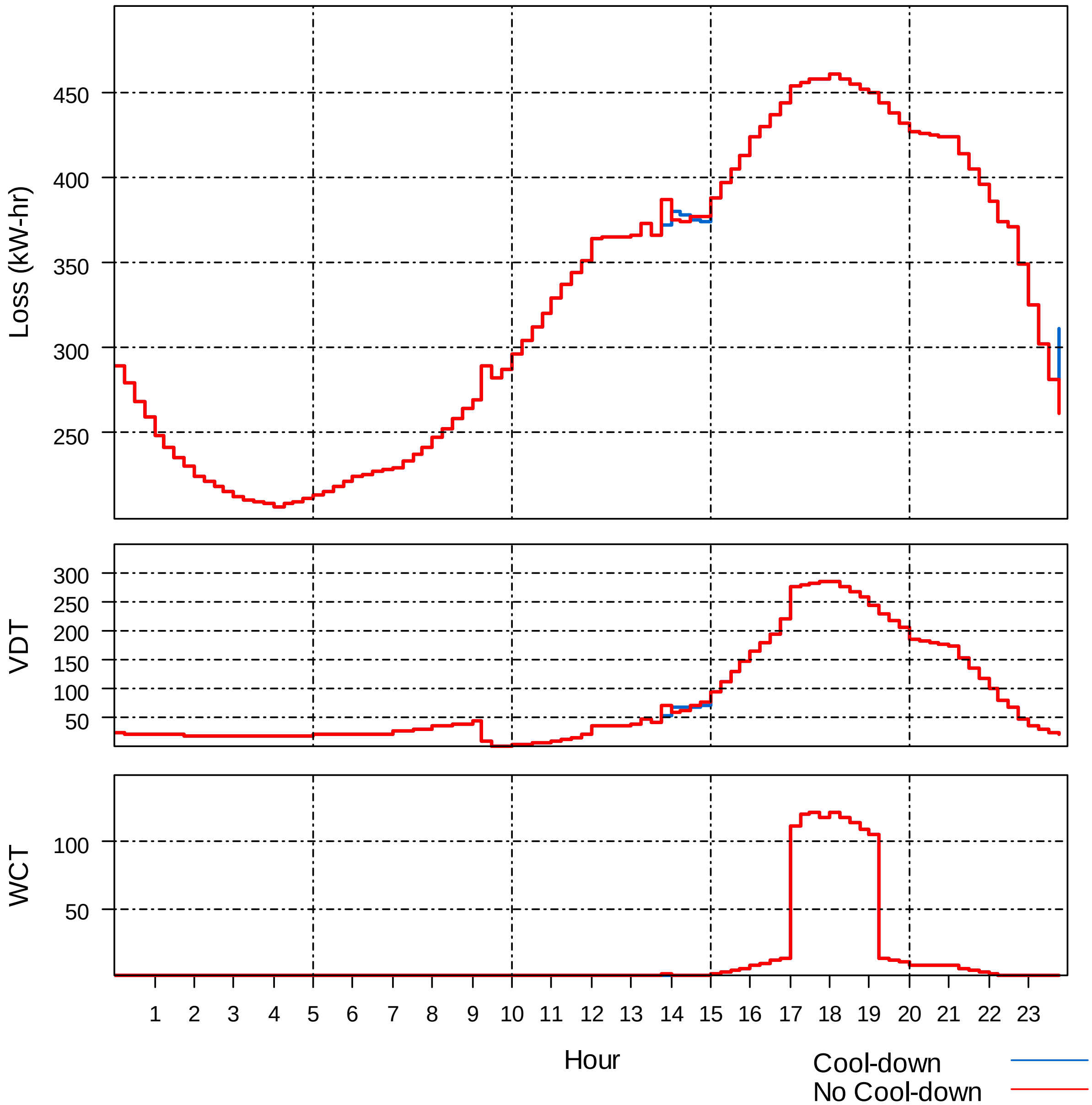


Figure 5.15 Heavy load day: CHMC with and without short cool-down timers

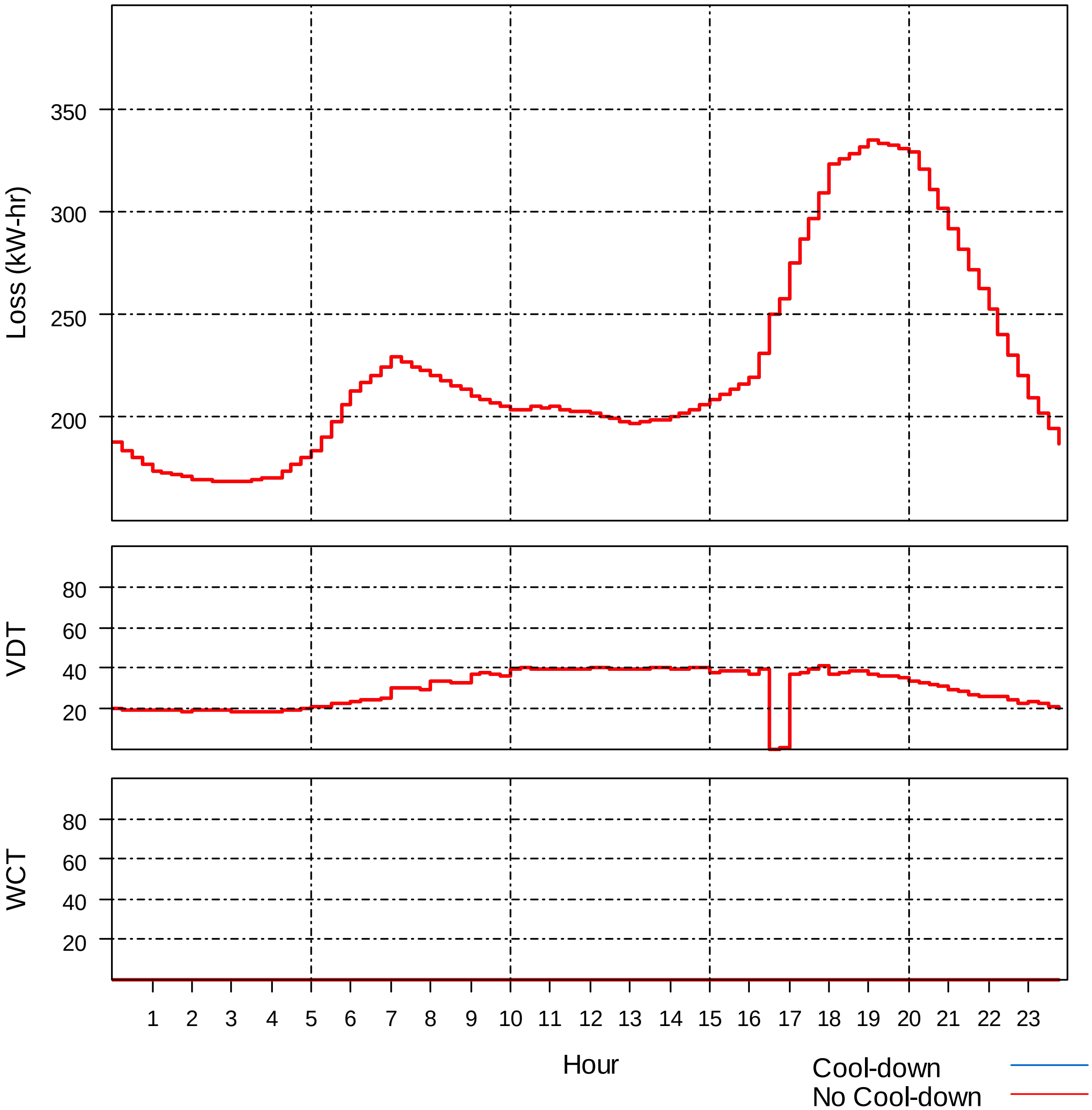


Figure 5.16 Light load day: CHMC with and without short cool-down timers

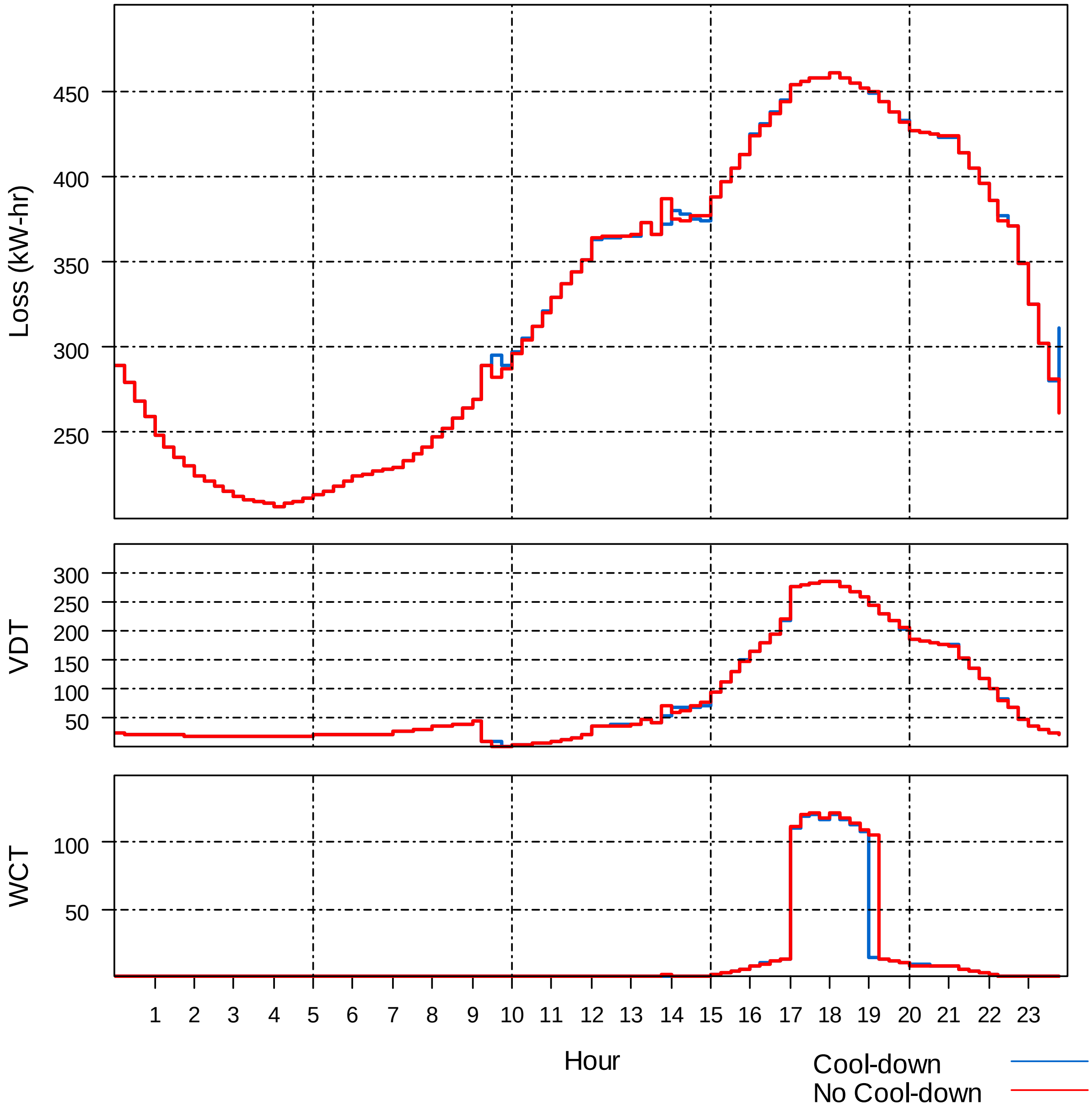


Figure 5.17 Heavy load day: CHMC with and without longer cool-down timers

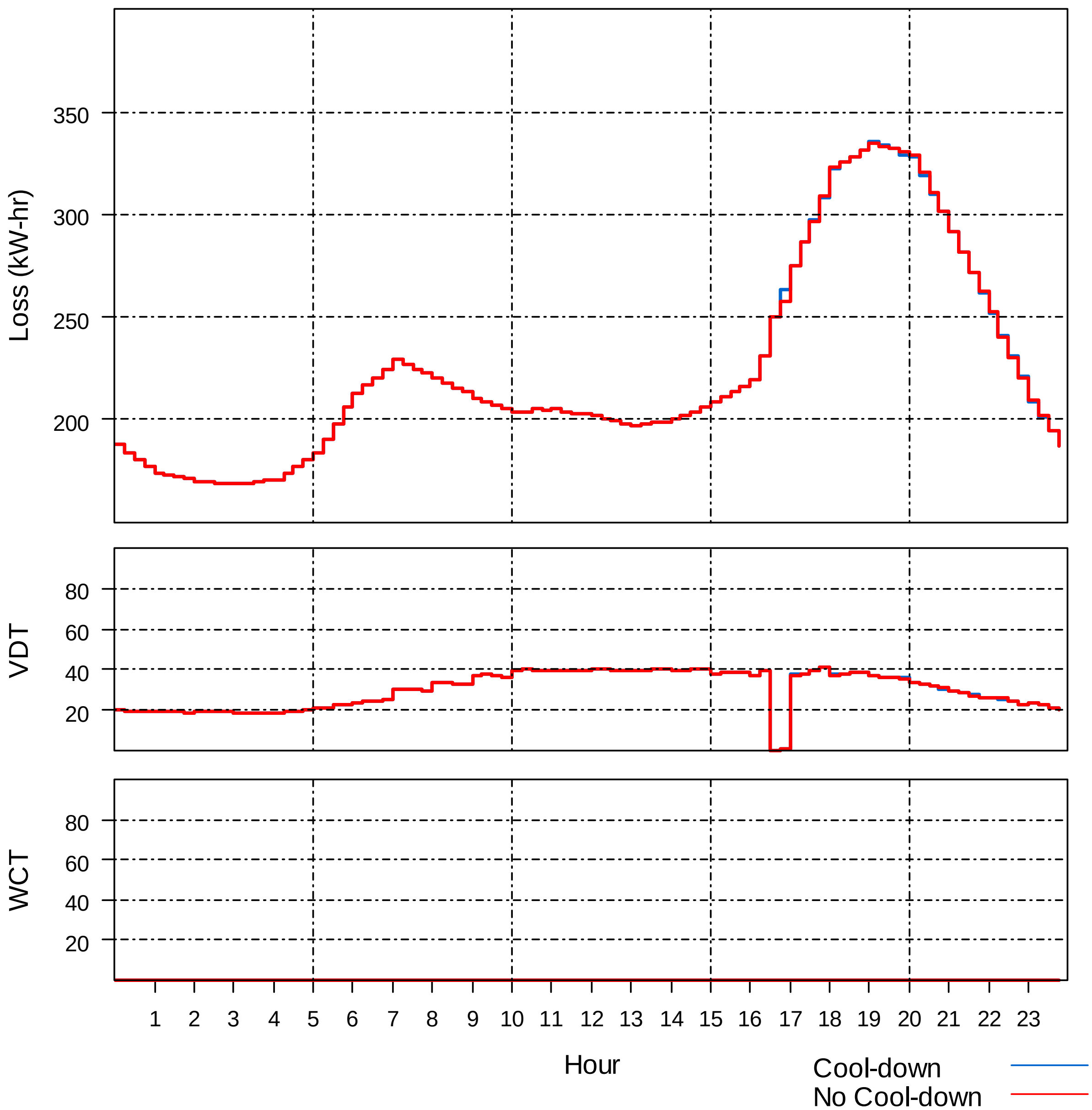


Figure 5.18 Light load day: CHMC with and without longer cool-down timers

5.3.6 Lost device compensation example

In this comparison, the CHMC is evaluated in an abnormal circuit condition. In this scenario, Capacitor 2 is disconnected from the EDS at 14:00 on the light load day. This test shows how well the two scenarios can adapt to unscheduled topology changes without human intervention.

Table 5.10 shows the detailed results for the simulation, and Figure 5.19 shows the plots. When the capacitor is lost at 14:00, in both cases the losses immediately increase. In the evening, when the load on the circuit increases to peak levels, the CHMC is able to compensate for the lost capacitor using other control devices, keeping the VDT in check. Under normal control, the VDT increases rapidly as the circuit load increases.

Table 5.11 shows the impact that the lost capacitor had on the different control schemes. Again, the CHMC is not as severely impacted as the normal control scheme. The CHMC performed 1.6% worse from a loss perspective; however, it was able to maintain voltage on the circuit. The normal control performed 2.2% worse from a loss perspective, and the voltage violation increased dramatically, indicated by a 89% increase in the VDT criteria.

Table 5.11 also compares the performance of the CHMC in the abnormal condition (without capacitor 2) and the normal control under normal conditions (with the capacitor). This comparison indicates that even with fewer devices, the CHMC can still improve EDS operation over normal control. The CHMC is able to decrease losses by 4.1% while improving circuit voltage.

Table 5.10 CHMC versus normal control, device failure

	Normal	**CHMC**	**Improvement**
Total Losses (kW-hr):	5,811	5,455	6.1 %
Max. VDT	113.97	44.0	61.4 %
Max WCT	0	0	0 %
Max Feeder Flow (kVA):	12,666	11,864	6.3 %
Feeder usage (kVA-hr)	225,464	208,551	7.5 %
Generation (kW-hr):	0	0	0 %

Table 5.11 Performance of controllers in abnormal versus normal operating conditions

	Normal without Cap2 vs. Normal	**CHMC without Cap2 vs. CHMC**	**CHMC without Cap2 vs. Normal**
Total Losses (kW-hr):	-2.2 %	-1.6 %	4.1 %
Max. VDT	-89.0 %	-0.1 %	27.0 %
Max WCT	0 %	0 %	0 %
Max Feeder Flow (kVA):	-3.0 %	-2.8 %	3.6 %
Feeder usage (kVA-hr)	-1.4 %	-1.0 %	6.2 %
Generation (kW-hr):	0 %	0 %	0 %

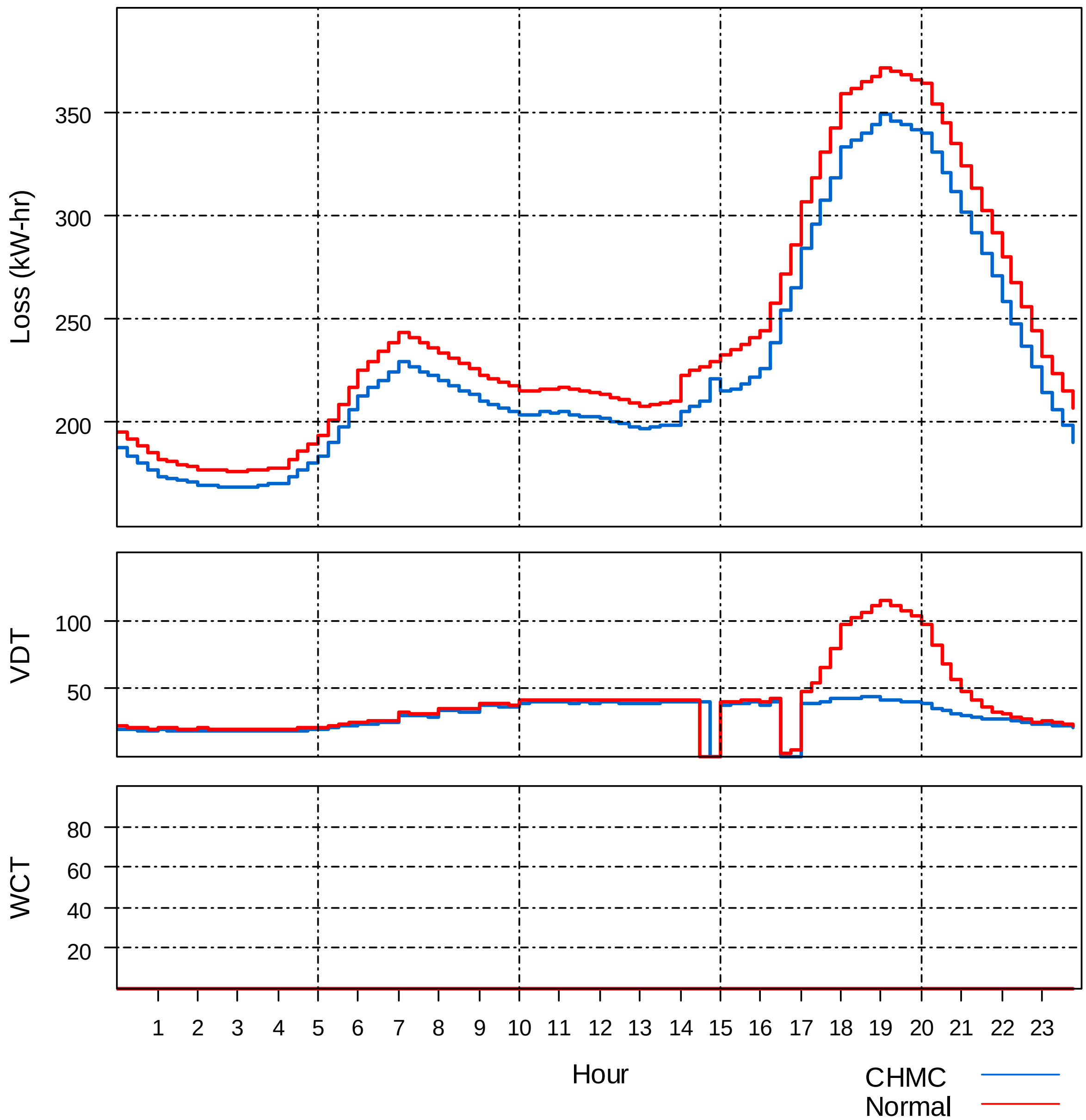


Figure 5.19 CHMC versus normal control, device failure

Chapter 6   Final remarks

This work presents new tools, algorithms, and test methods to facilitate the development of the modern distribution system. These model-based approaches to EDS operation, analysis, and design utilize an ISM along with GTA to fill gaps in current research and technology. Major contributions of this work are summarized as follows:

- A DER penetration analysis application that considers multiple failure criteria, including loading, voltage, and fault levels. The application provides several options for analysis locations and quantifies potential benefits of reactive power dispatch.
- The CHMC described in this work provides a framework to coordinate all EDS control devices to reduce losses while maintaining voltage and loading criteria.
- The incremental approach for EDS control provides a method to limit the solution space as well as a mechanism to achieve reliable, real-time application
- GTA is used to enable automatic EDS device discovery, enabling the controller described in this work to adapt to and compensate for changes in circuit topology
- A simulation framework was developed to facilitate the testing and troubleshooting of advanced EDS control algorithms. The framework ties together load, resource, and SCADA data from multiple sources and provides a method to perform sub-hourly simulations based on readily available hourly data sets.

Analyzing the impacts of DER penetration, a growing concern for utilities, requires a departure from analysis and design techniques utilized by EDS engineers in the past. To successfully integrate high penetrations of DER into the EDS, many different aspects must be considered. Voltage regulation, equipment loading, power quality, and protection schemes can all be impacted by DER. The penetration application described here leverages the ISM modeling concepts to build a comprehensive analysis tool. By including design aspects normally considered by multiple utility entities (planning, protection, and operation), this application can quantify the impacts of DER integration.

The CHMC described in this work provides a robust, flexible, real-time coordinated control algorithm for the EDS. Using properties of the EDS to reduce the problem scope, a satisfactory solution time was achieved while still improving operation. The controller automatically discovers and compensates for topology reconfigurations which occur frequently at the distribution level. Additionally, it allows "smart" devices to coexist with legacy devices, allowing utilities to perform incremental upgrades to the EDS.

Finally, the advanced analysis framework developed here provides a means to analyze complex EDS algorithms and impacts. The framework is used to analyze the feasibility and potential benefits of the CHMC.

The work described in this dissertation provides the foundation for many potential future research efforts. Plans exist to use the penetration application designed here to quantify system wide impacts of DER on utility distribution circuits and to help develop an estimate of how much DER capacity can be installed before major EDS problems arise. Furthermore, the analysis could be expanded to include the impacts of quasi-static or dynamic DER integration issues.

While the advanced time series analysis framework allows engineers to analyze more complex algorithms than can be done with traditional models and analysis tools, the linearly interpolated load is a simplistic method of approximating sub-hourly EDS load change. Research on the behavior of loads could provide insight into a more accurate method of modeling sub-hourly load based on hourly load data. Additionally, current research on solar and wind variability could be integrated into the framework to provide a comprehensive analysis environment for renewable DER integration studies.

The CHMC provides a means to classify and utilize EDS control devices. Many efforts are underway to develop models for emerging EDS technologies such as energy storage, inverter based technologies, and customer demand response. Once available, these models can be classified and utilized by the CHMC along with the more traditional EDS control devices discussed in this work.

References

[1] *Electrical Transmission and Distribution Reference Book*, East Pittsburgh, PA: Westinghouse Electric Corporation, 1964.

[2] *ANSI C84.1-1995 Electrical Power Systems and Equipment - Voltage Ratings (60 Hz)*, Rosslyn, Virginia: American National Standard, 1996.

[3] *1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*, IEEE, 2003.

[4] D. Patton, "2008 State of the Market Report Midwest ISO," 2009.

[5] M. Davis, R. Broadwater, and J. Hambrick, "Modeling and Verification of Distributed Generation and Voltage Regulation Equipment for Unbalanced Distribution Power Systems," 2007.

[6] W. Kersting, "Distribution feeder voltage regulation control," *Rural Electric Power Conference, 2009. REPC '09. IEEE*, 2009.

[7] J. Hambrick, M. Dilek, L. Yishan, R. Seguin, H. Asgeirsson, and R. Broadwater, "Model-based DG control as an economic solution to load growth," *2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century*, IEEE, 2008, pp. 1-5.

[8] "Edison Electric Institute Distributed Resource Task Force Interconnection Study," 2000.

[9] A. Sargent, R. Broadwater, J. Thompson, and J. Nazarko, "Estimation of diversity and kWHR-to-peak-kW factors from load research data," *IEEE Transactions on Power Systems*, vol. 9, 1994, pp. 1450-1456.

[10] R. Broadwater, J. Thompson, M. Ellis, H. Ng, N. Singh, and D. Loyd, "Application programmer interface for the EPRI Distribution Engineering Workstation," *Power Systems, IEEE Transactions on*, vol. 10, 1995, pp. 499-505.

[11] L.R. Feinauer, K.J. Russell, and R.P. Broadwater, "Graph Trace Analysis and Generic Algorithms for Interdependent Reconfigurable System Design and Control," *Naval Engineers Journal*, vol. 120, 2008, pp. 29-40.

[12] R.P. Broadwater, J.C. Thompson, and T.E. Mcdermott, "Pointers and linked lists in electric power distribution circuit analysis," *Power Industry Computer Application Conference*, 1991, pp. 16-21.

[13] "California Distributed Energy Resource Guide."

[14] R.C. Dugan, M.F. McGranaghan, and H.W. Beaty, *Elecrical Powe Systems Quality*, New York: McGraw-Hill, 1996.

[15] J.A. Momoh, *Electric Power Distribution, Automation, Protection, and Control*, Boca Raton, FL: CRC Press, 2008.

[16] H. Mori and Y. Iimura, "Dual tabu search for capacitor control in distribution systems," *IEEE PES Power Systems Conference and Exposition*, Ieee, 2004, pp. 169-174.

[17] Y.Y. Hsu and H.C. Kuo, "Dispatch of capacitors on distribution system using dynamic programming," *Generation, Transmission and Distribution, IEE Proceedings C*, vol. 140, 1993, pp. 433-438.

[18] J. Teng and C. Chang, "A Network-Topology-Based Capacitor Control Algorithm for Distribution Systems," *Transmission and Distribution Conference and Exhibition*, IEEE, 2002.

[19] S. Granville, "Optimal reactive dispatch through interior point methods," *IEEE Transactions on Power Systems*, vol. 9, 1994, p. 136–146.

[20] J. Teng, C. Chen, C. Chen, and Y. Liu, "Optimal capacitor control for unbalanced distribution systems with distributed generations," *Sustainable Energy Technologies, 2008. ICSET 2008. IEEE International Conference on*, 2008, pp. 755-760.

[21] a. Al-Hinai and A. Feliachi, "Application of intelligent control agents in power systems with distributed generators," *IEEE PES Power Systems Conference and Exposition*, Ieee, 2004, pp. 1613-1618.

[22] M. Pipattanasomporn, H. Feroze, and S. Rahman, "Multi-agent systems in a distributed smart grid: Design and implementation," *IEEE/PES Power Systems Conference and Exposition*, Ieee, 2009, pp. 1-8.

[23] R.E. Brown, "Impact of Smart Grid on distribution system design," *2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century*, Ieee, 2008, pp. 1-4.

[24] E.T. Jauch, "An Effective, Poor Man s Smart Distribution Volt/Var Management System," *Rural Electric Power Conference*, IEEE, 2009.

[25] N. Markushevich and E. Chan, "Integrated Voltage, Var Control and demand response in distribution systems," *2009 IEEE/PES Power Systems Conference and Exposition*, IEEE, 2009, pp. 1-4.

[26] T. Gonen, *Electric Power Distribution System Engineering*, Boca Raton, FL: CRC Press, 2008.

[27] M.W. Davis, T.J. Krupa, and M.J. Diedzic, "The Economics of Direct Control of Residential Loads on the Design and Operation of the Distribution System Part II Load Characteristics," *Power Apparatus and Systems, IEEE Transactions on*, vol. PAS-102, 1983, pp. 654-665.

[28] T. Boehme, A.R. Wallace, and G.P. Harrison, "Applying Time Series to Power Flow Analysis in Networks With High Wind Penetration," *Power Systems, IEEE Transactions on*, vol. 22, 2007, pp. 951-957.

Appendix A

To ensure accurate results, the model must represent the physical system as closely as possible. One major challenge of distribution circuit modeling is correctly modeling the load. Traditionally, large models use constant power load models to reduce computational load and decrease simulation time.

A study was performed on a section of the Detroit Edison system which measured changes in real and reactive power with respect to changes in voltage. The results are shown in Table A.1. The reason for the relatively large change in reactive power in the summer compared to the winter is the heavy use of induction motors in air conditioners during the summer months.

Table A.1 Voltage dependency of load

Types Of Days	%ΔV	%ΔP/%ΔV	%ΔQ/%ΔV
Winter – Average Load	5.4	.76	2.32
Winter – High Load	5.5	.96	2.11
Summer	7.0	1.26	4.66

The load models available for comparison are constant power, constant current, and voltage dependant current. Voltage dependant current can be configured to represent a composite load. The voltage dependency factor was determined using the summer results of the above study. Simulations were performed using the different methods of load modeling, and the results were compared with field measurements. The results are shown in Table A.2.

Table A.2 Load modeling comparison

Date of Test	Constant Current	Constant Power	Voltage Dependant Current
7/17/06	11.76%	**N/A**	8.91%
7/29/06	15.42%	**N/A**	11.23%
7/31/06	**N/A**	**N/A**	8.56%

The comparison in Table A.2 was done based on customer load data only. The simulations used no scaling from circuit measurements. Cases marked with N/A failed to converge because the voltage drop on the circuit was too great. The voltage dependent current model was consistently better than the constant current model and was the only method that converged for all three test cases.

Scaling loads to match actual circuit measurements at points on the circuit can make the simulation more accurately reflect the physical system. Table A.3 shows a comparison of simulation data with field data using the voltage dependant current load model and circuit measurements.

Using circuit measurements in the simulation allows the model to very closely match the actual values on the distribution circuit. Most of the simulated values are within the expected error of the measuring devices, and a controller using this model should yield good results.

Table A.3 Field Data Verification

		Current			Voltage			PF		
Location	**Node**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**
Start of Circuit	1	565.00	651.00	637.00	126.00	126.00	126.00	0.95	0.95	0.95
			2.2%			**0.3%**			**5.7%**	
Generator	10	18.31	17.24	17.00	122.50	122.50	120.25	0.96	0.96	0.96
			2.3%			**1.1%**			**0.0%**	
VR 1	9	282.60	255.70	238.00	123.48	123.69	124.19	0.94	0.95	0.94
			3.7%			**0.2%**			**2.4%**	
Cap 1*	6	48.57	108.20	13.00	118.25	117.75	121.08			
			3.0%			**0.7%**				
Cap 2*	12	51.96	14.00	23.83	120.65	118.40	118.65			
			2.0%			**1.5%**				
Cap 3*	13	65.84	27.09	53.70	117.05	116.93	118.15			