PNNL-20564

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

# Evaluation of Representative Smart Grid Investment Grant Project Technologies: Distribution Automation

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February 2012

Pacific Northwest
NATIONAL LABORATORY

PACIFIC NORTHWEST NATIONAL LABORATORY
*operated by*
BATTELLE
*for the*
UNITED STATES DEPARTMENT OF ENERGY
*under Contract DE-AC05-76RL01830*

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(2/2012)

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# Summary

This document is one of a series of five reports commissioned by the United States Department of Energy, Office of Electricity Delivery and Energy Reliability. The purpose of these reports is to estimate some of the benefits of deploying technologies similar to those implemented on the Smart Grid Investment Grant (SGIG) projects. Four technical reports cover the various types of technologies deployed in the SGIG projects: distribution automation, demand response, energy storage, and distributed generation. While the results of these reports provide insight into the variation of impacts by technology, feeder composition and region, it should be noted that the actual impacts and benefits of employing specific technologies in individual SGIG projects may vary from these projections. A fifth report in the series examines the benefits of deploying these technologies on a national level. This technical report examines the impacts of distribution automation technologies deployed in the SGIG projects.

# 1 Introduction

As part of the American Recovery and Reinvestment Act of 2009, the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) provided Smart Grid Investment Grant (SGIG) funding to 99 award recipients totaling $3.4 Billion [1]. Coupled with matching funds of $4.6 Billion from industry, the SGIG projects are intended to accelerate the modernization of the nation's electricity infrastructure. To help evaluate the effect of these projects, a set of impact metrics has been developed by the DOE [2]. Once the SGIG projects are complete, it will be possible to analyze collected field measurements and determine the exact benefit from each of the various technologies within each of the projects. OE has several initiatives operating in current and near-term time frames to assess impacts and disseminate information as data becomes available. These initiatives include analysis partnerships with individual SGIG recipients, specific technology assessments, stakeholder briefings, and improvements to existing algorithms and tools.

In order to examine the SGIG project benefits, the Pacific Northwest National Laboratory (PNNL) utilized the GridLAB-D simulation environment to conduct extensive simulations on representative technologies. GridLAB-D was originally developed at PNNL, via DOE OE funding, to provide an open source simulation environment to evaluate the impacts of emerging technologies on the nation's electricity infrastructure. The unique multi-disciplinary agent based structure of GridLAB-D allows for the effective evaluation of complex emerging technologies such as voltage optimization and demand response. These are the same technologies that being deployed as part of the SGIG projects.

The impact of these technologies, at the distribution feeder level across various climate regions of the United States [3], is presented in a series of 4 technical reports, of which this report is the first. Each of the 4 technical reports examines a class of technologies deployed in the SGIG projects. The 4 technical reports examine distribution automation, demand response, energy storage, and renewable integration. A 5$^{th}$ report uses the results of the four technical reports to generate a policy level examination of the various technologies. The final report includes extrapolation to a national level deployment at various penetration levels.

To ensure that the results of this report can be reproduced by other researchers, all of the tools, models, and materials used are openly available at [4]. Through detailed time-series simulations conducted in GridLAB-D, the impact of adding distribution automation capabilities to the grid can be examined on the relevant prototypical feeders. Utilities, regulators, vendors and other stakeholders interested in analyses more specific to their systems, goals, and conditions may make use of these open tools for their own purposes.

## 1.1 Report Scope

Due to the large number of SGIG projects and the wide range of specific implementations, it is not feasible to simulate each of the specific SGIG projects. In addition to the numerous implementations, it would be necessary to model the electrical infrastructure of each of the projects. To address these issues, the technical reports will model a selection of technologies that are representative of those seen in the SGIG projects, and it will examine their impact on a set of prototypical distribution feeders that are representative of those seen in the various climate regions of North America [3]. By utilizing representative technologies and prototypical distribution feeders, it will be possible for this report to estimate the feeder level impact of each technology. Once the impact of the technologies has been evaluated on the prototypical feeders, the results will be extrapolated to explore the impacts and considerations associated with deploying the technology on a national level.

The technologies deployed as part of the SGIG projects can be placed in one of two categories: direct and enabling. Direct technologies are those that provide direct benefit to the system. Enabling technologies are those that may not provide a direct benefit to the system, but they enable other beneficial technologies. As an example, a communications network does not provide any reduction in energy consumption, but it does enable demand response systems that create reductions in energy consumption.

The technical reports focus on the benefits obtained from the deployment of direct technologies when supported with the necessary enabling technologies.

### 1.1.1 Direct Representative Technologies

These are the 15 technologies that will be specifically analyzed using GridLAB-D simulations. Within each of the 4 technical reports there are one or more specific direct technologies that are examined.

Distribution Automation (DA)

- t1: Volt-VAR Optimization (VVO)
- t2: Capacitor Automation (CA)
- t3: Reclosers and Sectionalizers (R&S)
- t4: Distribution Management and Outage Management Systems (DMS&OMS)
- t5: Fault Detection Identification and Reconfiguration (FDIR)

Demand Response (DR)

- t6: TOU/CPP with enabling technologies
- t7: TOU/CPP without enabling technologies
- t8: TOU with enabling technologies
- t9: TOU without enabling technologies
- t10: Direct Load Control (DLC)

Energy Storage (ES)

- t11: Thermal Energy Storage (TES)

Distributed Generation (DG)

- t12: Solar residential
- t13: Solar commercial
- t14: Solar combined
- t15: Wind commercial

### 1.1.2 Enabling Technologies

In addition to technologies that provide direct benefits to the system, there are those that enable other technologies to benefit the system, but themselves may not provide a direct benefit. The majority of the projects in the SGIG program have committed to deploying a large number of enabling technologies that do not provide any direct measurable benefit. Despite the lack of a direct benefit, these technologies form the foundation needed for the technologies that do provide direct benefits to the system.

#### 1.1.2.1 Smart Meters

Traditional electromechanical metering devices have proven to be accurate and reliable over multiple decades, but have the significant disadvantage of requiring manual data collection; there is no network connectivity. The deployment of new “smart meters” is the largest common element to the SGIG projects, ranging from projects with a few thousand, to projects with multiple millions. These new meters are able to bi-directionally communicate information via a wired or wireless communications network. Communications to the customer can now include time-based electricity rates or event-triggered signals. Communications from the customer allow remote meter reading, as well as usage patterns.

### 1.1.2.2 Communications Infrastructure

Communications infrastructure, both wireless and wired, is an excellent example of an enabling technology. A communications infrastructure in an isolated environment does not provide any direct benefit to the system. However, direct technologies and capabilities, such as demand response, would not be possible without a supporting communications infrastructure. For the purposes of the conducted analysis, it is assumed that the required communications infrastructure is available, but it will not be simulated. Zero latency and infinite bandwidth is assumed. While an explicit communications system model is not used in this analysis, there are issues outside the scope of this work where a communications system model would be essential.

### 1.1.2.3 Human Machine Interface

Human Machine Interfaces (HMI) can exist in many forms. In a single family residence, the HMI can range from a simple thermostat to a fully functional Home Energy Management System (HEMS). An HMI can allow a residential user to see the current price of electricity, interact with their heating and cooling system, or with an energy storage system. By providing an end-user with more information about the current price of electricity and the state of their consumption, the effectiveness of demand response opportunities can be increased.

## 1.2 Report Structure

The structures of the four technical reports follow a similar design. The four reports share a common introduction in Section 1 with Section 2, discussing the representative technologies to be examined in each report. Section 3 contains the detailed feeder level examination of the impact of each technology, while Section 4 examines the change in the impact metrics between the base case and the case with various technologies. It should be noted that the base case is a representative simulation without new technologies; it is not representative of the operation of any actual SGIG project. Section 5 contains the concluding comments. Additionally, there are multiple appendices. Appendices A, B, and C are common to all 4 reports with Appendix A giving a detailed description of the SGIG impact metrics, Appendix B detailing the taxonomy of prototypical distribution feeders, and Appendix C discussing GridLAB-D and the simulation methodology. Appendix D is specific to each report and contains the plots produced for individual feeders from the simulations. Appendix E contains the impact metric values for each technology and is the basis for the differential impact metrics in Section 4.

The fifth report has a structure independent of the four technical reports.

# 2 Distribution Automation Technology Areas

Distribution Automation (DA) refers to a broad range of technologies that are focused on real-time monitoring and control. A review of the SGIG projects indicated that the DA technologies could be divided into five classes of technology: Volt-VAR Optimization (VVO), Capacitor Automation (CA), Reclosers and Sectionalizers (R&S), Distribution Management Systems and Outage Management Systems (DMS&OMS), and Fault Detection Identification and Restoration (FDIR).

The first two classes of technology to be examined, VVO and CA, require a relatively direct method of analysis. A base case simulation is performed for an entire year with the necessary metrics tracked, e.g., peak load and energy consumption. Then the simulation is re-run with the same customer behavior and boundary conditions, but with the specific technology implemented. The differences in metrics will indicate the impact that the selected technology has on the system.

The last three classes of technology to be examined can be conducted in the same manner as the first two, but there are limitations to how far the results can be extrapolated. A base case simulation is conducted for each feeder with a series of faults, and subsequent repair and restoration events, that produce IEEE-1366 statistics which are in the first and second quintile are developed. Each fault is classified as either momentary or sustained with an associated fault time, with the fault time is divided into several periods. The duration of a single fault is determined by how long it takes to identify the occurrence of a fault, time to locate the fault, time to repair the fault, and the time to place the feeder back into service. Each of the last three classes of technology affect the various periods of the fault time in accordance with implementation.

An important point to note in the last three technologies is that there are a significant number of possible fault combinations that will yield average IEEE-1366 statistics, each of which will have different operational impacts. Since a complete analysis of every possible combination of faults is outside of the scope of this work, a single set of representative faults will be used for the last three technologies: R&S, OMS&DMS, and FDIR. A consequence of using representative fault sets is that some benefits may be under estimated.

The following Sections, 2.1 through 2.5, will examine the five classes of technologies and their specific implantation in this report.

## 2.1 Volt-VAR Optimization (VVO)

Conservation Voltage Reduction (CVR) is a reduction of energy consumption resulting from a reduction of feeder voltage. CVR is an older name for a wide selection of implementations that have become known as Volt-VAR Optimization. While there have been numerous VVO systems deployed in North America, there has been little substantive analytic evaluation of the effect; the majority of the published results are based on empirical field measurements. As a result, it is difficult to extrapolate how this technology will behave on the various types of distribution feeders found throughout the nation.

To ensure that the results of this report can be reproduced by other researchers, all of the tools, models and materials used are openly available at [4]. In order to prevent showing bias to any particular commercial vendor, the method of VVO selected was from a twenty-year-old academic publication. While this method of VVO does not represent the current state of the art, it does contain the fundamental elements that are used in current commercial VVO schemes. The majority of VVO schemes contain two fundamental components: voltage optimization and reactive power compensation. For the purposes of this report, voltage optimization is achieved through the operation of substation voltage regulators in order to regulate the voltage at specific End of Line (EOL) points within a prescribed range. In this way, the peak load is reduced and the annual energy consumption is reduced. Reactive power compensation is achieved through the operation of shunt capacitors in order to maintain the power factor at the substation transformer within a prescribed band. By maintaining reactive power at the substation transformer near unity, losses are reduced.

### 2.1.1 SGIG Impact Metrics Affected by VVO

A detailed list of the SGIG impact metrics can be found in Appendix A. These metrics are for all of the SGIG projects. The following SGIG metrics are affected by VVO and will be tracked in this analysis:

Table 2.1: Impact metrics affected by VVO

| Index | Metric | Units |
|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh |
| 2 | Monthly Customer Electricity Usage | MWh |
| 3 | Peak Generation | kW |
| | Nuclear | % |
| | Solar | % |
| | Bio | % |
| | Wind | % |
| | Coal | % |
| | Hydroelectric | % |
| | Natural Gas | % |
| | Geothermal | % |
| | Petroleum | % |
| | Distributed Solar PV | % |

| Index | Metric | Units |
|---|---|---|
| | Distributed Wind | % |
| 4 | Peak Load | kW |
| | Controllable load | % |
| 7 | Annual Electricity Production | MWh |
| 12 | CO2 Emissions | Tons |
| 13 | SOx Emissions | Tons |
| | NOx Emissions | Tons |
| | PM-10 Emissions | Tons |
| 21 | Feeder Real Load | kW |
| | Feeder Reactive Load | kVAR |
| 29 | Distribution Losses | % |
| 30 | Distribution Power Factor | pf |
| 39 | CO2 Emissions | Tons |
| 40 | SOx Emissions | Tons |
| | NOx Emissions | Tons |
| | PM-10 Emissions | Tons |

### 2.1.2 Specific Implementation of VVO

Currently, there are numerous commercially available VVO schemes which implement some form of CVR, a selection of these can be found in [5]-[8]. For the purposes of this analysis, an openly available Volt-VAR optimization scheme will be implemented [9]. This is the same scheme that was implemented in the report that PNNL created in 2010 to examine the benefits of a national level deployment of CVR [14]. The analysis is being reproduced here because of changes in the prototypical feeders as well as refinements in the end-use load models used in GridLAB-D.

The implemented method of VVO is based on a dual function optimization scheme with the primary function being the reduction of voltage, and the second function being the management of reactive power at the substation transformer. Voltage is reduced using voltage regulators and End Of Line (EOL) measurements, and power factor is controlled using shunt capacitors.

#### 2.1.2.1 **VVO** Function 1: Voltage Reduction

The primary objective of the implemented VVO method is the reduction of energy consumption which is achieved by reducing the operating voltage to the low end of the ANSI standard C84.1 [10]. Operation in the low end of the ANSI band is achieved by adjusting the tap settings at the feeder regulators in order to reduce the voltage at the EOL measurements to 117V

+/- 1V. If the feeder has only a single regulator at the substation, then there is only a single set of EOL measurements. If there are multiple regulators, then there must be multiple sets of corresponding EOL measurements. Each set of EOL measurements must measure each of the three phases or else the system will not operate properly. A significant limitation of the implemented VVO scheme is that it assumes if there are multiple voltage regulators on the distribution feeder, they are operated in parallel. While this is sometimes the case, there are large distribution feeders with voltage regulators operated in series on long braches. As will be seen in later sections, this limitation can lead to a less than optimal operation of the implemented VVO scheme.

Under normal operating conditions, the EOL voltage measurements are sent to the central Volt-VAR controller. The Voltage Drop (VD) between the substation voltage ($V_o$) and the EOL voltage ($V_{EOL}$) is calculated. In the event that there are multiple EOL measurements, then the largest voltage drop is selected.

$$VD = V_o - V_{EOL} \tag{2.1}$$

Base on the voltage drop from the substation to the EOL, the control bandwidth ($V_{bw}$) is selected based on the predefined voltage drop value $VD^h$. The control bandwidth can be set to the low load bandwidth ($V_{bw\text{-}l}$) or the high load bandwidth ($V_{bw\text{-}h}$).

$$if\ VD < VD^h\ then\ V_{bw} = V_{bw-l} \tag{2.2}$$

$$if\ VD > VD^h\ then\ V_{bw} = V_{bw-h} \tag{2.3}$$

Once the appropriate control bandwidth is determined, the desired set voltage level ($V_{set}$) is compared to $V_{EOL}$. For a low load condition, the regulator operations are determined by (2.4) and (2.5).

$$if\ V_{EOL} < \left(V_{set} + V_{bw-l}\right)\ then + 1\ tap\ postion \tag{2.4}$$

$$if\ V_{EOL} > \left(V_{set} + V_{bw-l}\right)\ then - 1\ tap\ postion \tag{2.5}$$

For high load conditions, the regulator operations are determined by (2.6) and (2.7).

$$if\ V_{EOL} < \left(V_{set} + V_{bw-h}\right)\ then + 1\ tap\ postion \tag{2.6}$$

$$if\ V_{EOL} > \left(V_{set} + V_{bw-h}\right)\ then - 1\ tap\ postion \tag{2.7}$$

The voltage regulator is prevented from increasing or decreasing tap positions if the operation would cause the voltage at the substation to go outside the allowable operating range. If there are multiple voltage regulators on a distribution feeder, then each of the regulators is operated based on its local voltage and the EOL measurements associated with it.

#### 2.1.2.2 VVO Function 2: Power Factor Correction

The secondary objective of the implemented VVO method is to regulate the power factor as measured at the substation transformer; the goal being to regulate the power factor to a value of 1.00 +/- .05. If the power factor exceeds .95 leading or lagging, then the system will operate capacitors to bring the value back to within the desired operational band. Capacitors are operated in order of size on the basis of the largest capacitor is inserted first and removed last. For capacitors of the same size, they are operated on the basis of the furthest from the substation is inserted first and removed last. These heuristics determine the order of operation if there are multiple capacitors on a feeder.

Capacitors are switched ‘on’ based on (2.8) and switched ‘off’ based on (2.9).

$$swich\ on\ if\ Q_{bri} > d^{\max} Q_{ci} \tag{2.8}$$

$$swich\ off\ \ if\ Q_{bri} < d^{\min} Q_{ci} \tag{2.9}$$

where $Q_{ci}$ is the rating of the specific capacitor, and $d^{max}$ and $d^{min}$ are coefficients designed to prevent switching oscillations.

### 2.1.3 High Level VVO Simulation Results

In this section, the high level results of VVO will be examined. At this level of examination, the data will not be divided into monthly values; annual values will be examined. Simulation results for each of the prototypical distribution feeders will be examined with five cases of GC-12.47-1; one for each climate region. The high-level examination will include the ability of the implemented VVO system to reduce voltage as measured at the end of line and to regulate the power factor at the substation. The system’s ability to reduce peak load and annual energy consumption will also be examined, since these are the primary objective of the control system. System losses and emissions will also be examined.

#### 2.1.3.1 Voltage Reduction

It is common for distribution utilities to operate their feeders in the upper range of the ANSI C84.1 standard [10]. This is accomplished by setting the voltage regulators at the substation, if present, to near the top of the ANSI C84.1 range, a 125V equivalent voltage as seen by a customer connected at that point. By keeping the substation voltage just below the high voltage limit there is a high degree of confidence that no downstream point of the feeder will be below the low voltage limit, 114V. Figure 2.1 shows the average annual EOL voltages, by phase, for each of the prototypical feeders when the substation regulators are set to regulate at 125V equivalent. While Figure 2.1 is shown on a 120V nominal scale for consistency with the ANSI ranges, it is actually the voltage seen on the high side of the secondary transformer. As such, it is expected that there will be another couple of drop between what is shown and what the end-use customer will see at their point of interconnection.

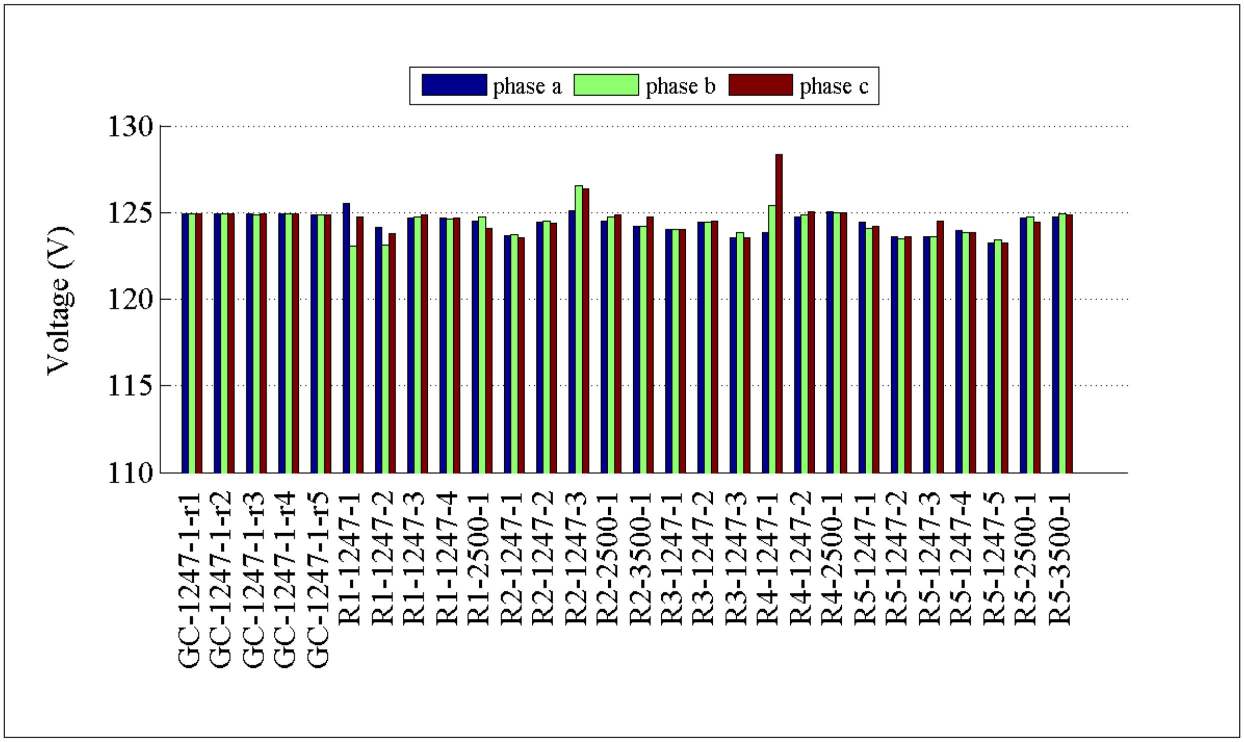



Figure 2.1: Average EOL voltage without VVO

As can be seen in Figure 2.1, the EOL voltages are well above the minimum values of ANSI C84.1. In some cases, the EOL voltages are excessively high because of the effects of local capacitors. On average, there is a significant margin for the reduction of voltage.

As discussed in Section 2.1.2.1, the primary function of the implemented VVO method is to reduce the voltage as measured at the EOL points. Figure 2.2 shows the average annual EOL voltages, by phase, for each of the prototypical feeders when the substation regulators are controlled by the VVO method described in Section 2.1.2.

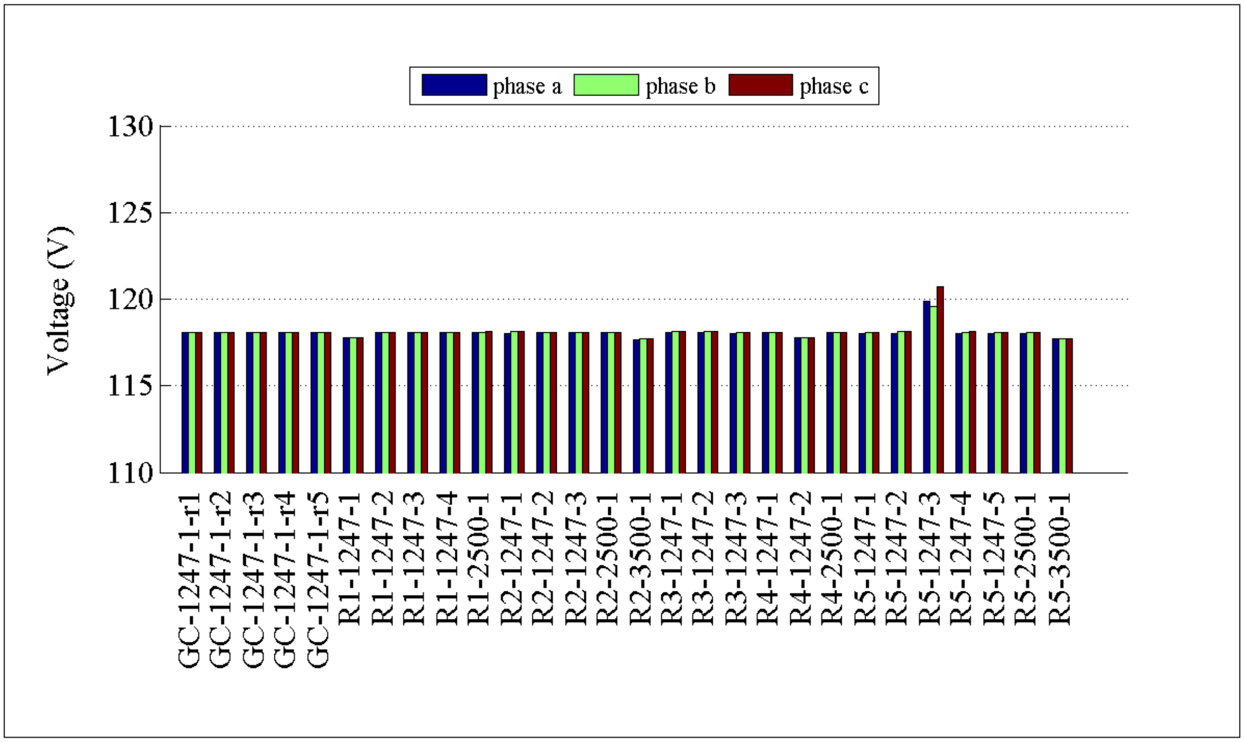



Figure 2.2: Average EOL voltage with VVO

From Figure 2.2, it can be seen that when the implemented VVO method is in service the average annual EOL voltage is approximately 117V equivalent, clearly indicating that the implemented VVO system effectively controls the EOL voltages. One feeder, R5-12.47-3 has a significantly higher average EOL voltage because not all of the voltage regulators are coordinated. The implemented of VVO is only capable of coordinating regulators that are in parallel, while feeder R5-12.47-3 has regulators that are in series [9]. As a result, only 2 of the 4 voltage regulators on the feeder are coordinated, with the other two being operated in output voltage control with a 121V band center. A more complex commercial VVO system could be able to coordinate the operation of series regulators and improve the system performance.

While Figure 2.1 and Figure 2.2 showed the average annual voltages, it is also necessary to examine the annual minimum voltage. In addition to maintaining the average annual voltage, it is necessary to maintain the instantaneous voltage. Figure 2.3 shows the minimum annual EOL voltages, by phase, for each of the prototypical feeders when the substation regulators are set to regulate at 125V equivalent. Similar to Figure 2.2, Figure 2.4 shows the minimum annual EOL voltages, by phase, for each of the prototypical feeders when the substation regulators are controlled by the VVO method described in Section 2.1.2. Once again, when VVO is in operation, the EOL voltages are constrained to a much narrower band, and are in the low end of the ANSI C84.1 range.

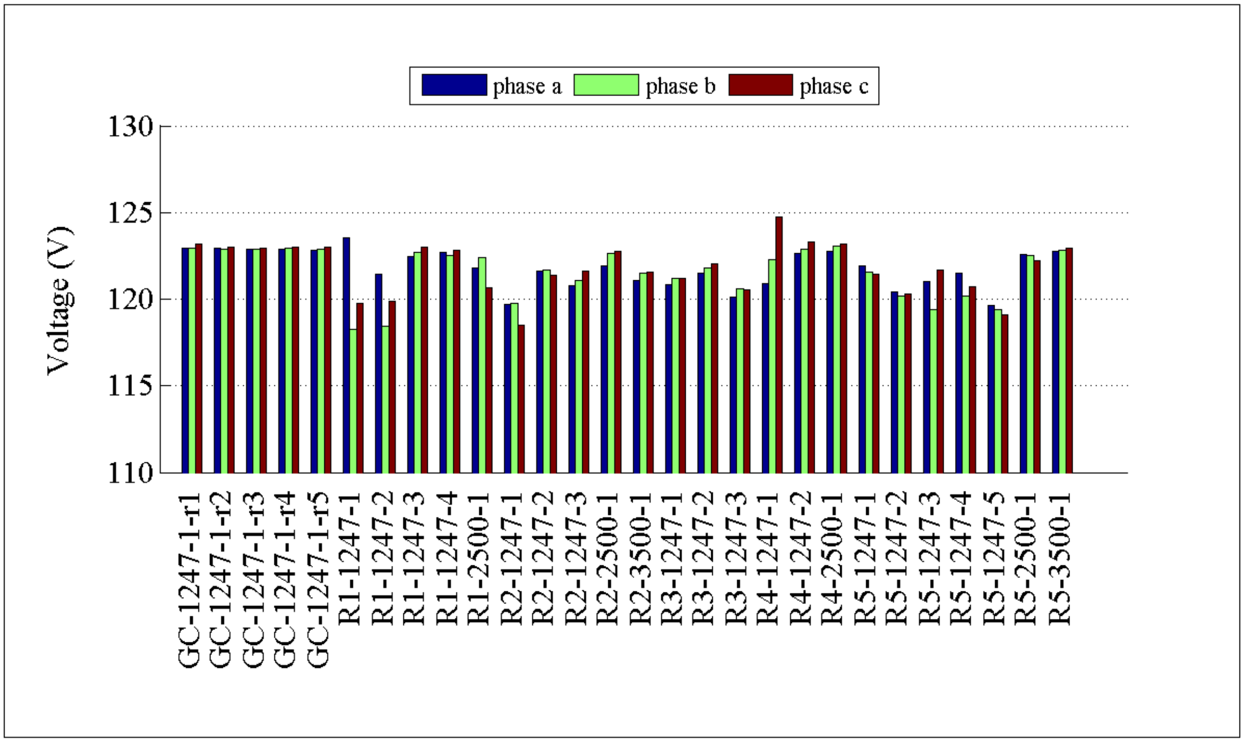



Figure 2.3: Minimum EOL voltage without VVO

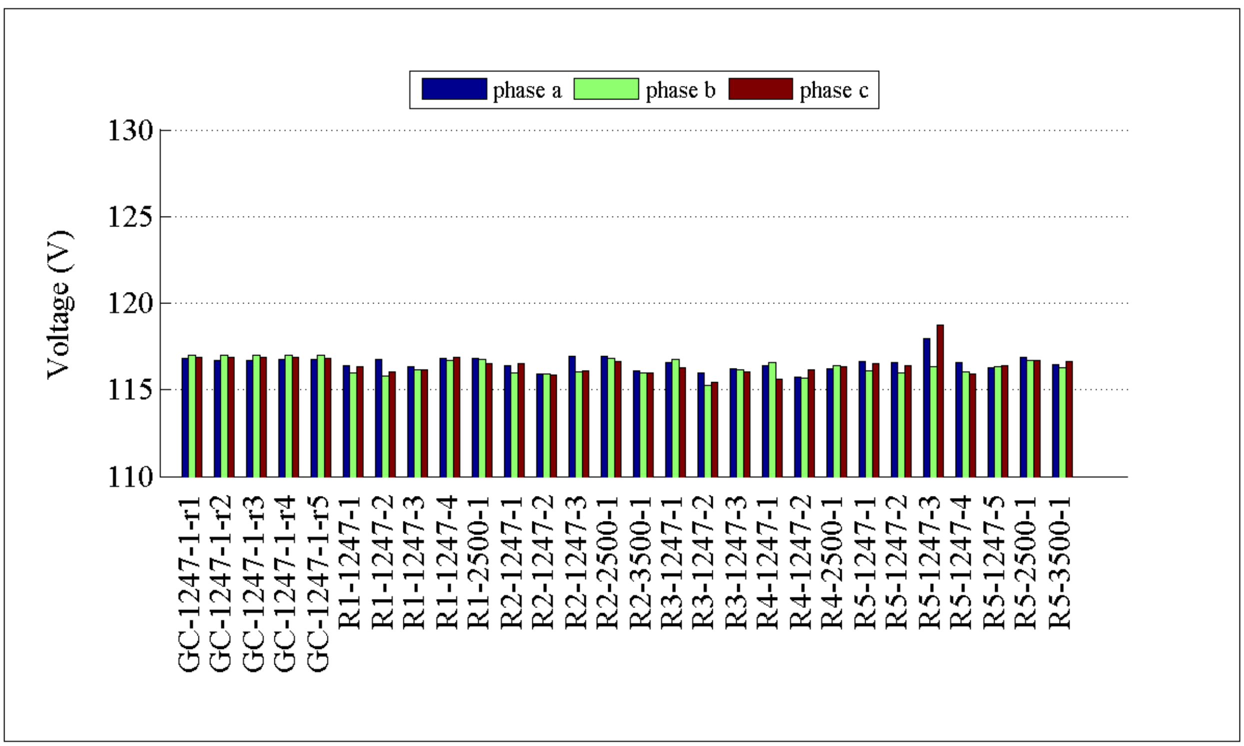



Figure 2.4: Minimum EOL voltage with VVO

### 2.1.3.2 Power Factor Regulation

The secondary objective of the implemented VVO method is to maintain the power factor as measured at the substation transformer within a prescribed band. Figure 2.5 shows the average annual power factor for each feeder for both the Base case and the VVO case. From Figure 2.5, it can be seen that the VVO system is maintaining the average power factor within the prescribed band.

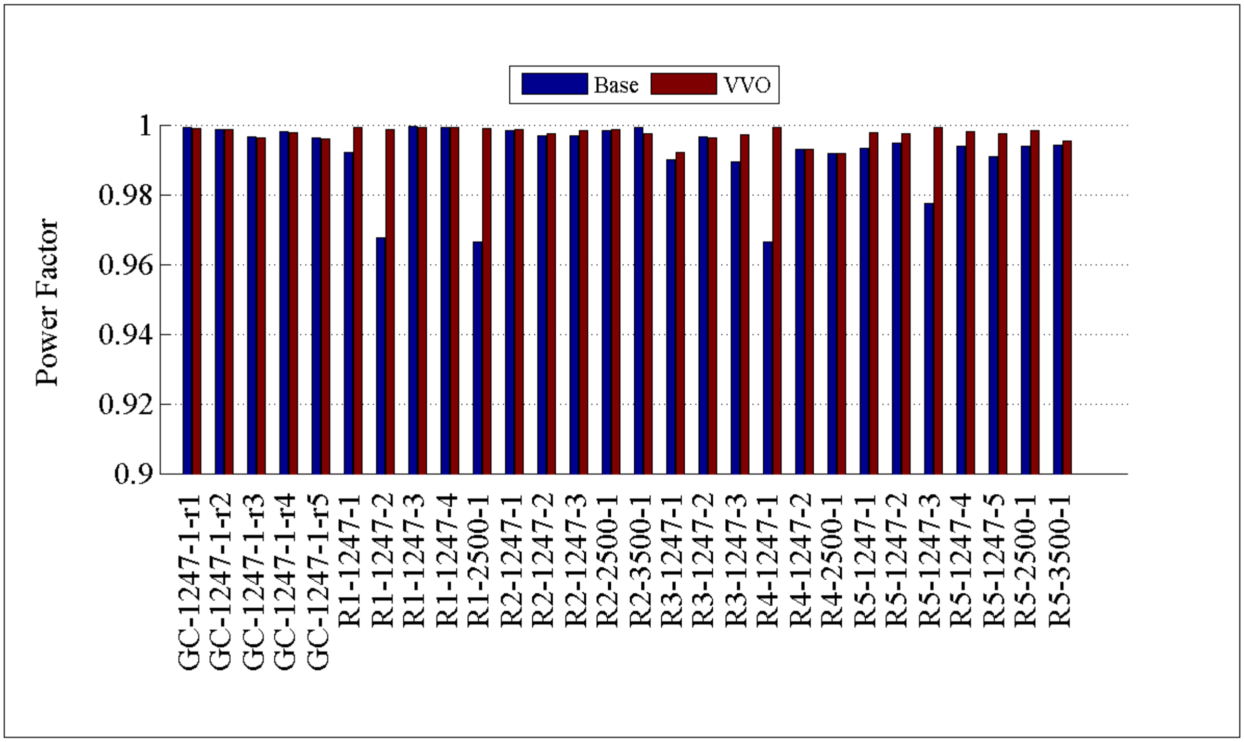



Figure 2.5: Comparison of average annual power factor by feeder

Figure 2.6 shows the minimum annual power factor by feeder. It can be seen that the VVO system is not always able to maintain the instantaneous power factor within the prescribed range, but it does improve it. Periods of low power factor correspond to times of high load when there are not enough shunt capacitors to offset the inductive load on the system. If additional capacitors were placed on the system, then the VVO system would be able to better control the power factor. But for the purposes of this work the impact of potential system upgrades in conjunction with the deployment of a new technology were not examined, but could be expected to be significant.

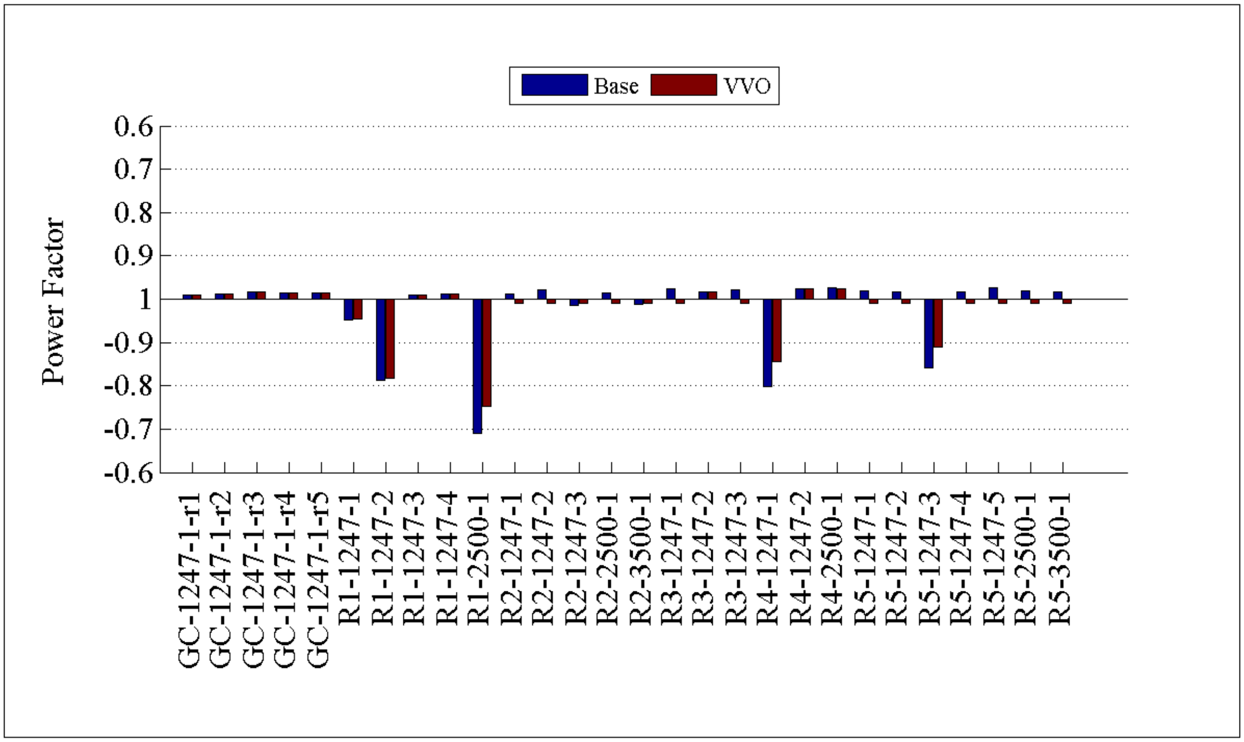



Figure 2.6: Comparison of minimum annual power factor by feeder

#### 2.1.3.3 Peak Annual Load

Peak reduction is one of the two major benefits of the implementing a VVO system. Peak reductions can be achieved in one of two ways; the first is for the VVO system to be in operation at all times and the second is for it to be in operation at select times. For the purposes of the simulations in this report the VVO system was in operation at all times. Figure 2.7 shows the annual peak for each feeder in both the Base case and the VVO case.

From Figure 2.7, it can be seen that in general VVO achieves a peak reduction. This is seen more clearly in Figure 2.8 and Figure 2.9, which show the change in peak load in kW and % respectively. In Figure 2.8 and Figure 2.9, it is immediately apparent that not all feeders see a reduction in their annual peak load. This is primarily due to the fact that the implemented VVO scheme was in operation at all times and was not optimized for peak reduction; it is optimized for energy reduction. A more complete commercial VVO system may be able to achieve a reduction in annual energy consumption and peak load reduction, but the implemented method only addresses the issues sequentially.

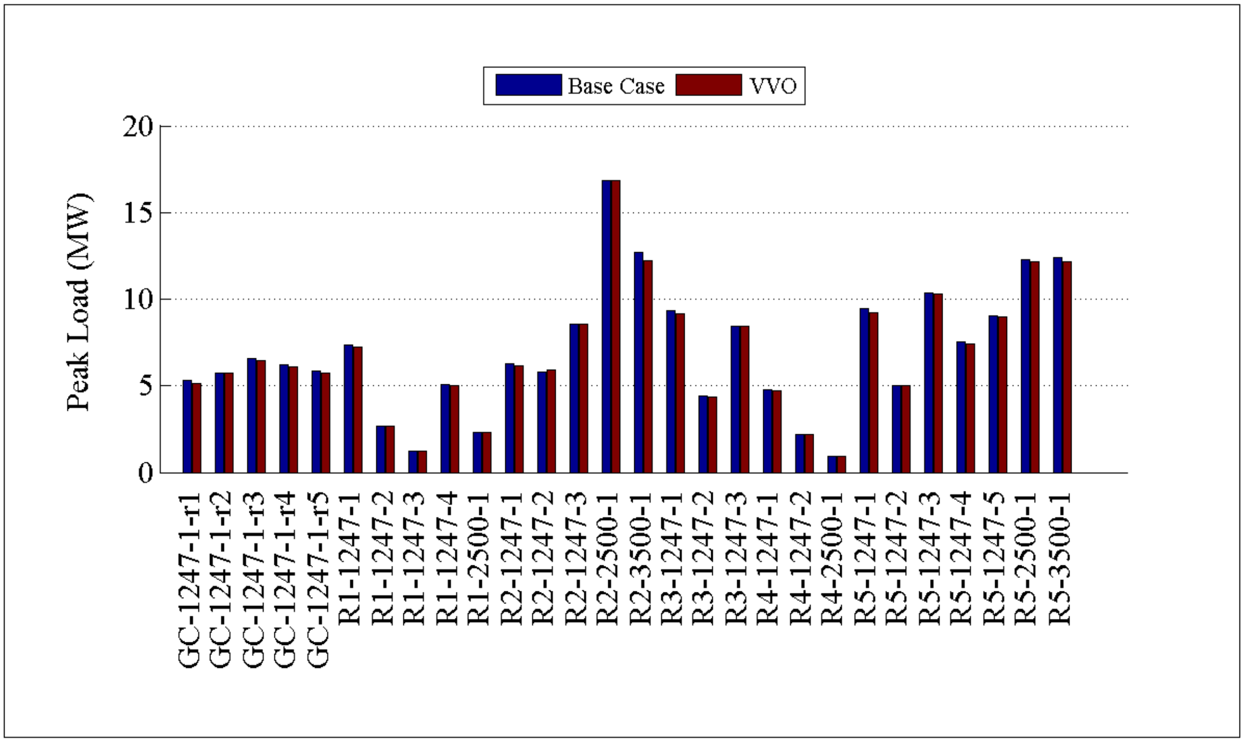



Figure 2.7: Comparison of peak load by feeder

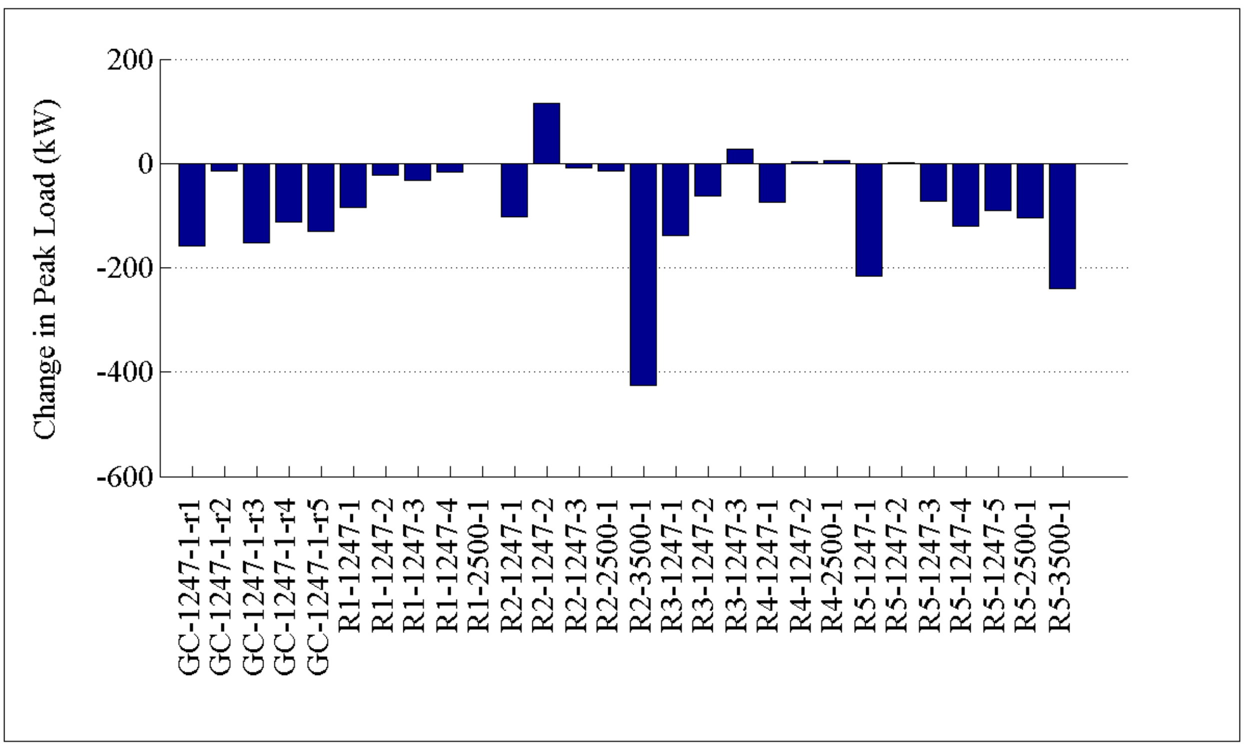



Figure 2.8: Change in peak load by feeder (kW)

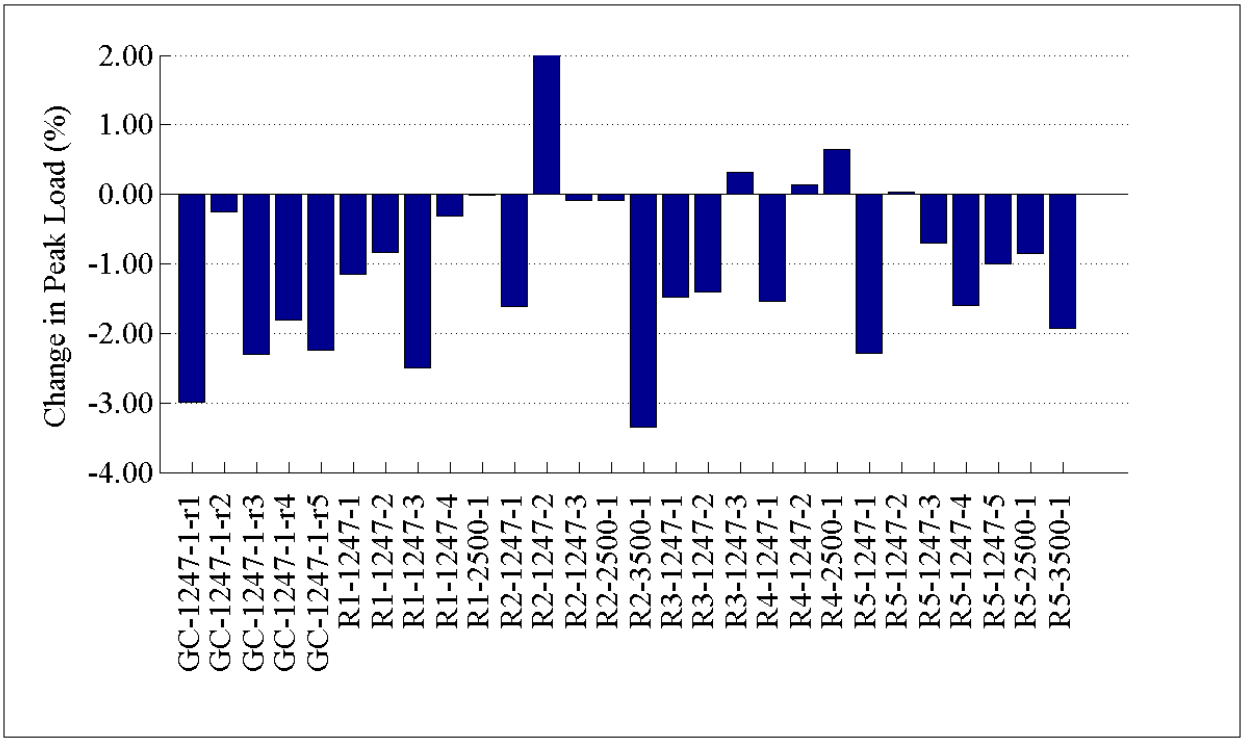



Figure 2.9: Change in peak load by feeder (%)

Peak load increased on five of the prototypically feeders; R2-12.47-2, R3-12.47-3, R4-12.47-2, R4-25.00-1, and R5-12.47-2. The examination of the peak load increase for each of these feeders will be examined in section D.1.

### 2.1.3.4 Annual Energy Consumption

The second major benefit of VVO is reduction in annual energy consumption. Figure 2.10 shows the annual energy consumption for each feeder in both the Base case and the VVO case. The annual energy consumption includes end-use load consumption as well as losses. From Figure 2.10, it can be seen that VVO achieves a reduction in annual energy consumption on all of the prototypical feeders. This is seen more clearly in Figure 2.11 and Figure 2.12, which show the change in MWh and change in % respectively.

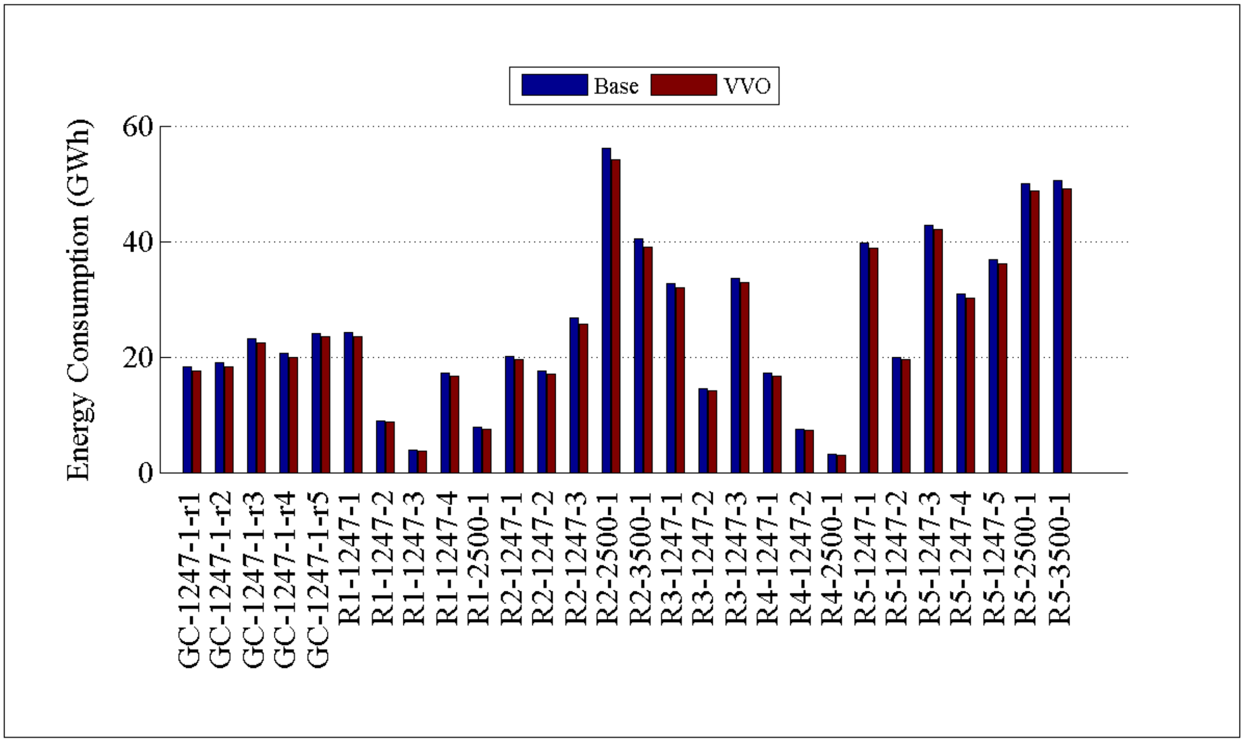



Figure 2.10: Comparison of annual energy consumption by feeder (GWh)

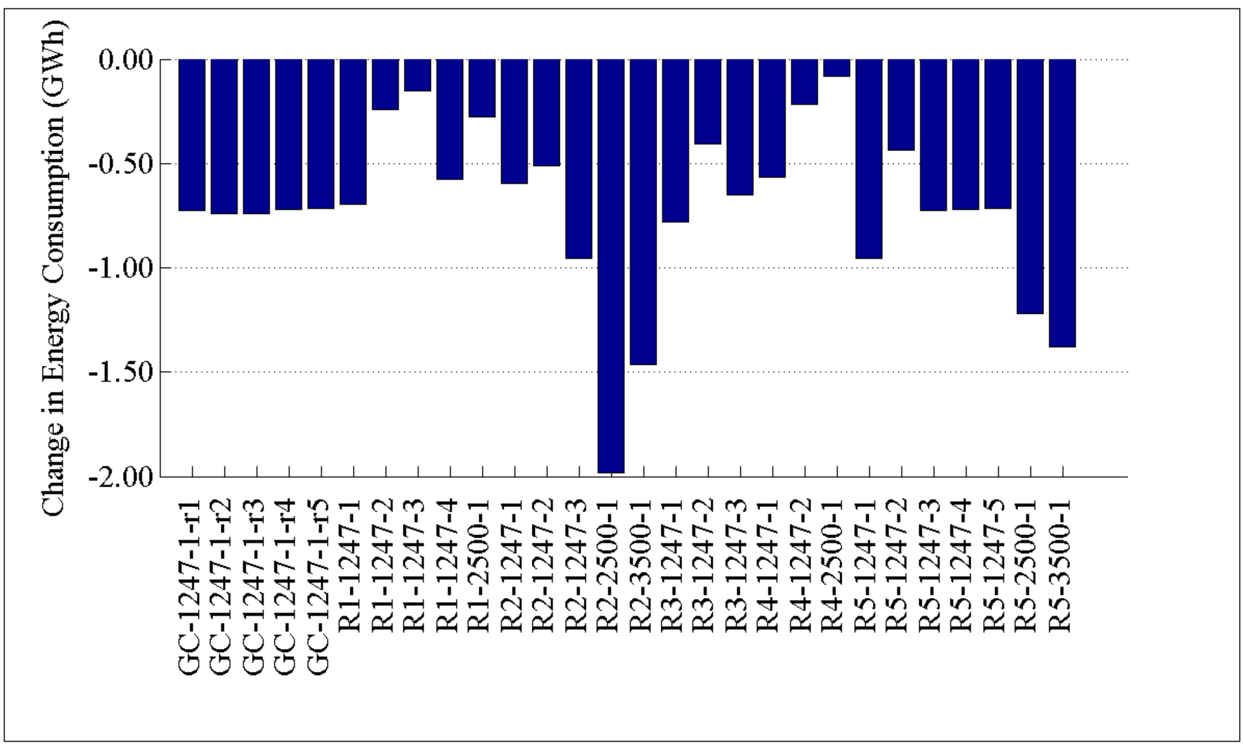



Figure 2.11: Change in annual energy consumption by feeder (GWh)

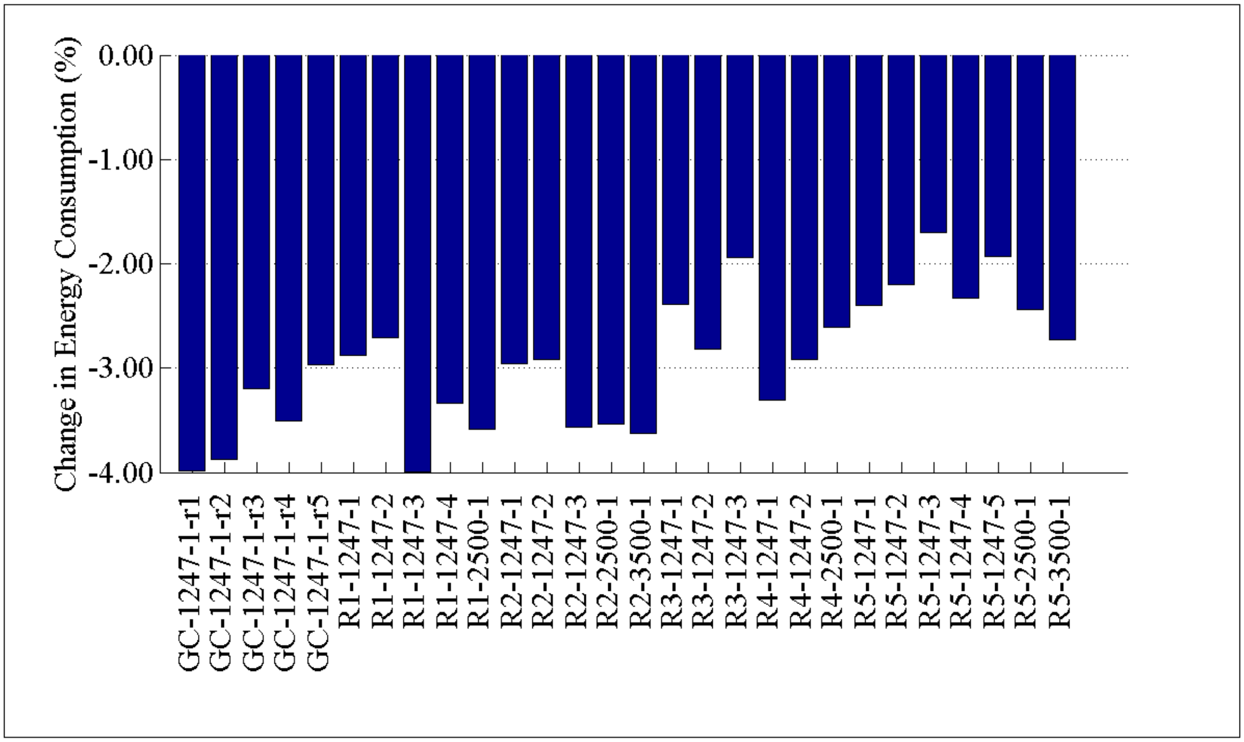



Figure 2.12: Change in annual energy consumption by feeder (%)

#### 2.1.3.5 Annual System Losses

While loss reduction is a component of the implemented VVO system, it is not the primary source of the energy consumption. From Figure 2.13 to Figure 2.15 it can be seen that VVO in general reduces the system losses, but in some situations, it does increase losses. Losses are affected by a number of factors, such as load composition and feeder design.

Even when system losses are reduced, the reduction is small in comparison to the reduction in end-use energy consumption. Loss reduction only accounts for a few percent of the total energy reduction.

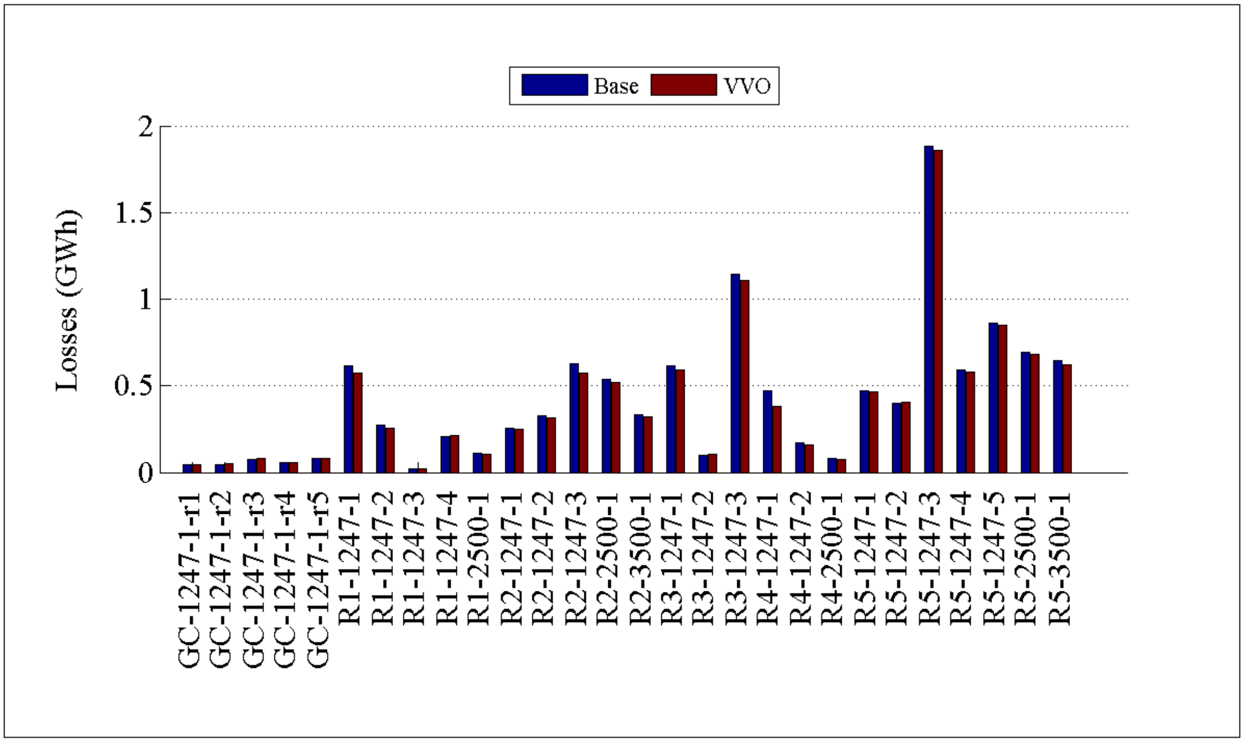



Figure 2.13: Comparison of total annual losses by feeder

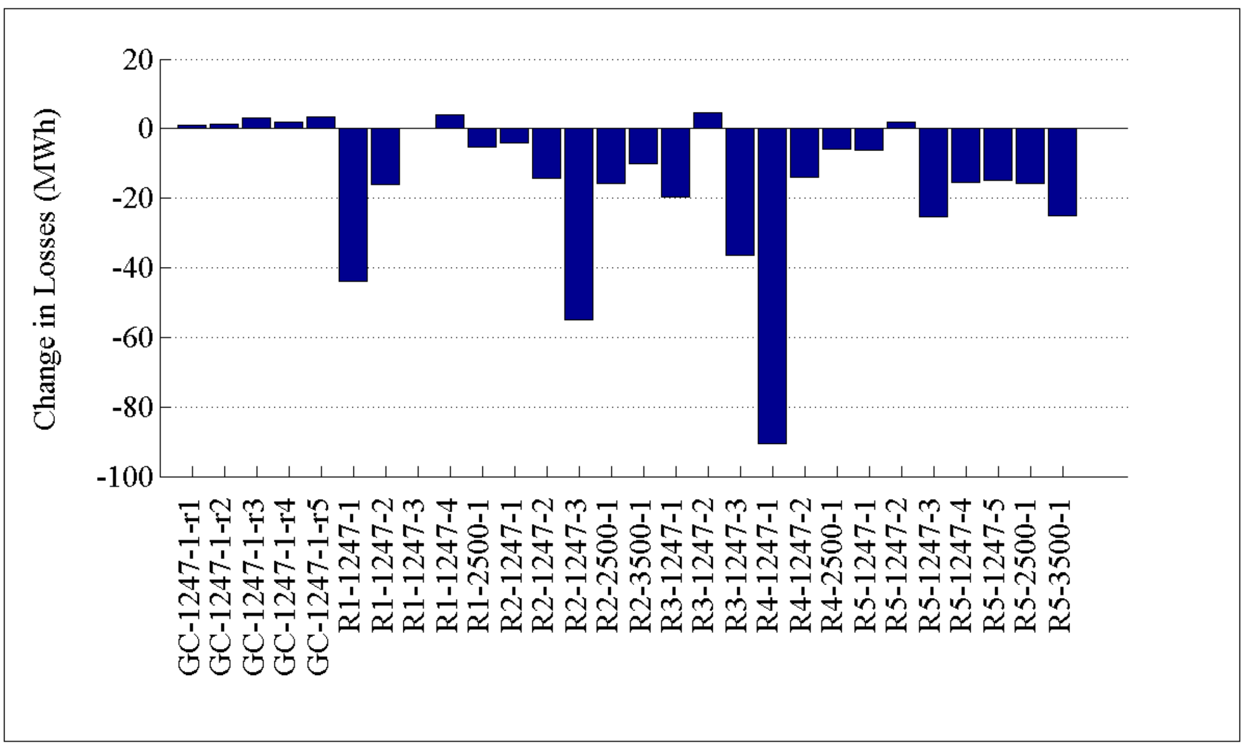



Figure 2.14: Change in total annual losses by feeder (MWh)

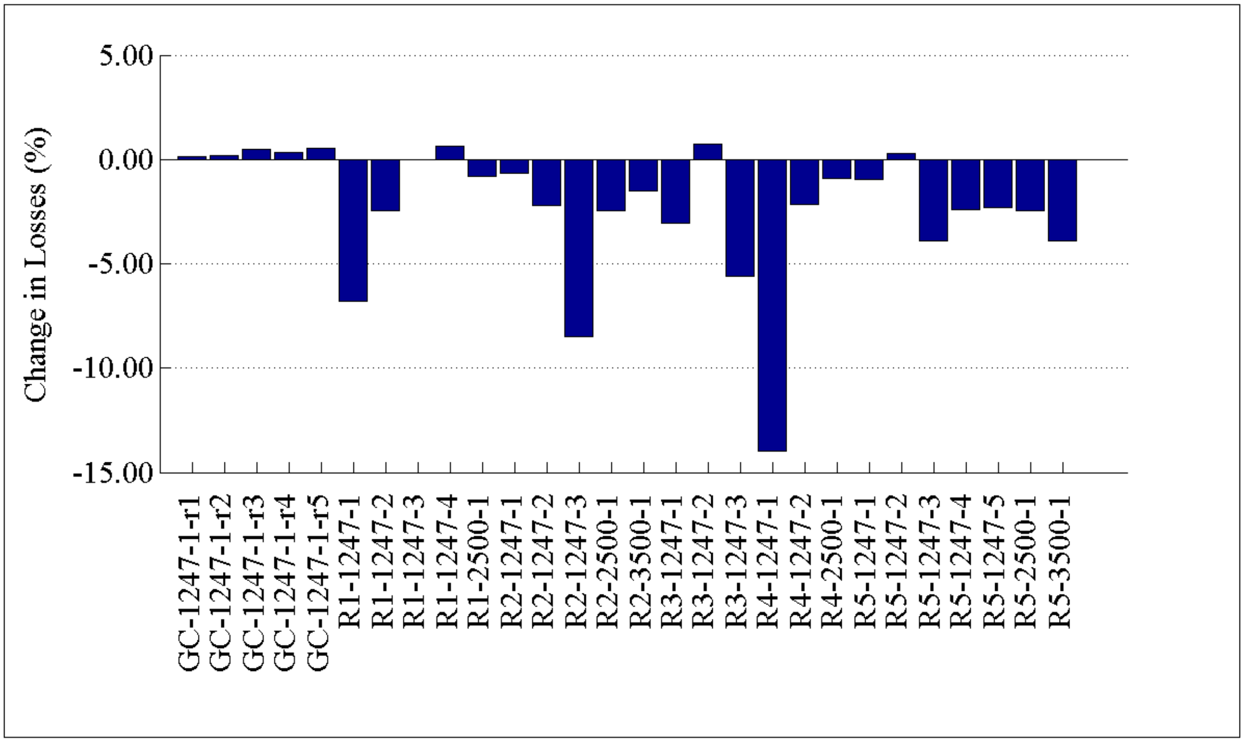



Figure 2.15: Change in total annual losses by feeder (%)

A key issue to note with Figure 2.15 is that the change in losses is represented as a percent of losses. For example, from Figure 2.15 it can be seen that R1-12.47-1 experienced approximately a 6.5% reduction in losses. This means that the magnitude of losses was reduced by 6.5%, not that total system consumption was reduced by 6.5%.

## 2.1.3.6 Annual $CO_2$ Emissions

It was seen in Figure 2.10 through Figure 2.12 that the annual energy consumption decreased for all of the feeders when VVO was in operation. From this, it follows that the annual emissions of $CO_2$ should decrease due to the reduced consumption of fossil fuels. Figure 2.16 through Figure 2.18 show the reductions in $CO_2$ emissions by feeder.

Environmental emissions for each feeder were estimated using a simple dispatch algorithm. Generation sources were sized by the regional generator types, and ranked to dispatch in an appropriate order. Full commitments were achieved before proceeding to the next generator. For example, consider a region where natural gas turbines dispatch first to support 250 MW of load, followed by 400 MW of petroleum-fired generation. To support 300 MW of load, the natural gas is fully dispatched, and then the remaining 50 MW is attributed to petroleum-fired generation. Representative heat rates and emission rates are then applied to these power outputs to determine the overall environmental impacts. The details of these rates, along with the dispatch orders for each region, are explained in Appendix B.3.

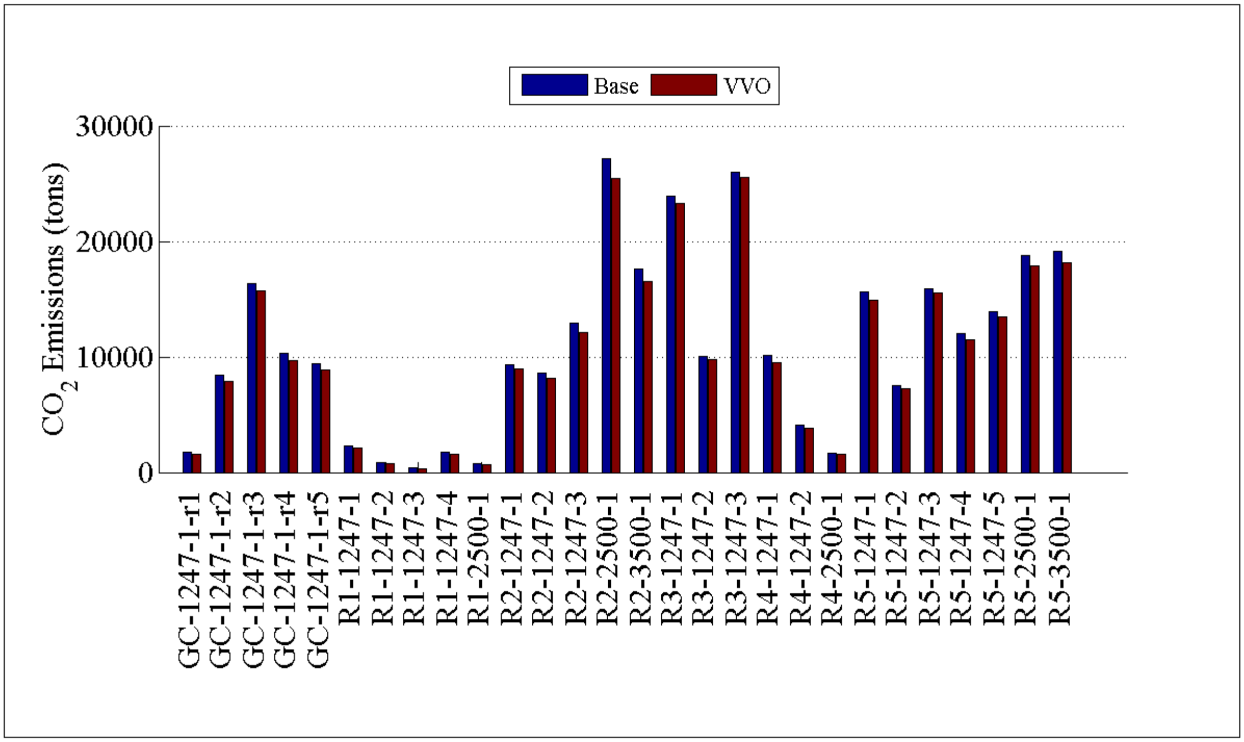



Figure 2.16: Comparison of total annual $CO_2$ emission by feeder

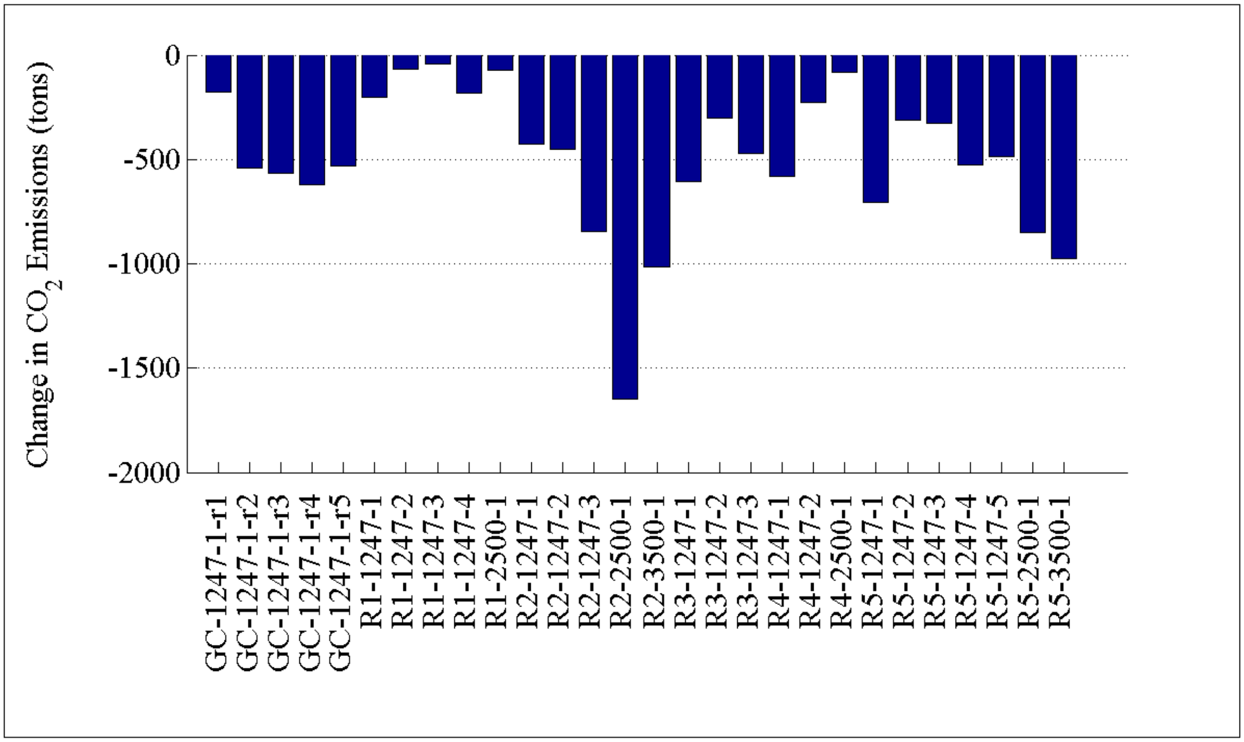



Figure 2.17: Change in total annual $CO_2$ emissions by feeder (tons)

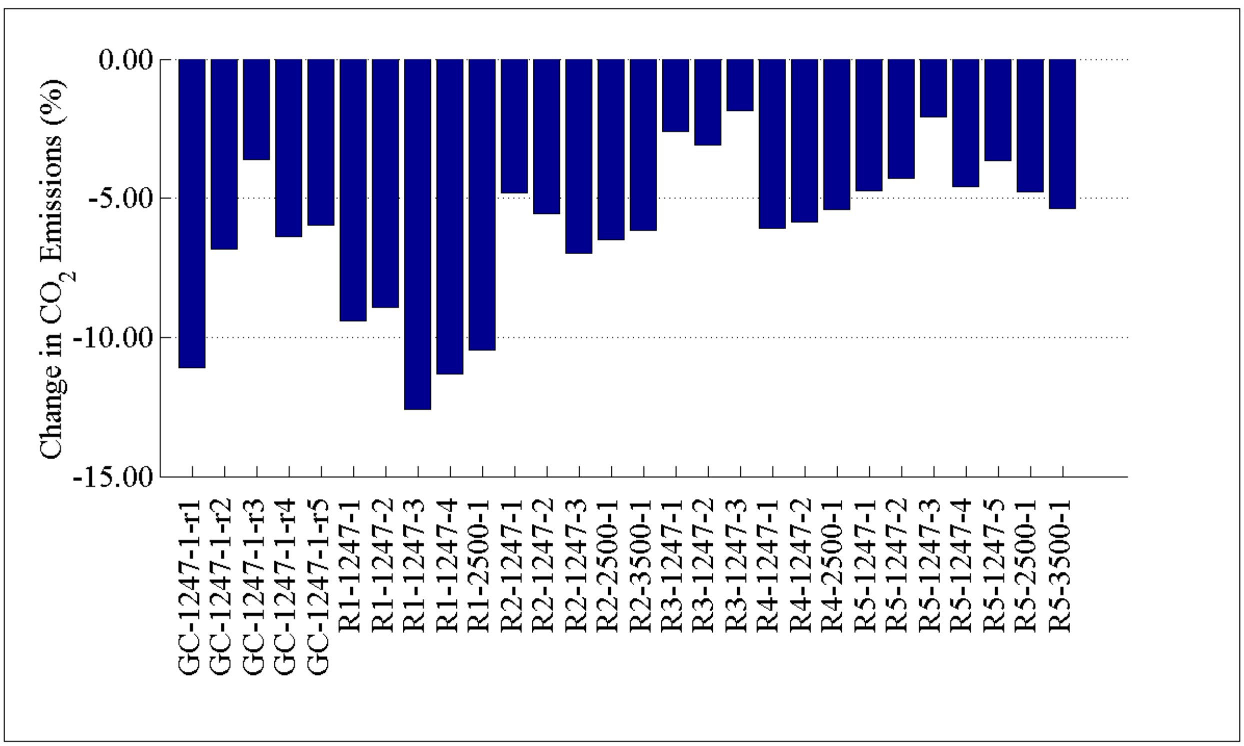



Figure 2.18: Change in total annual $CO_2$ emissions by feeder (%)

## 2.2 Capacitor Automation (CA)

Many of the shunt capacitors that are deployed on the nation's distribution feeders are either fused in place or operated by a manual switch. Generally, only smaller capacitor banks, less than 600 kVA, are fused, while larger banks are connected with switches. Manual switches allow for a coordinated operational scheme where banks are placed in service or taken out of service as needed. Manual switches have the benefit of being relatively low cost to install, but they do require qualified workers to travel to the actual capacitor location in order to operate it. Controlled capacitors operate based on local measurement values and generate greater system benefits, but have a higher capital cost. Regardless of whether the capacitor is fixed, manual or controlled, it is not standard practice to have a remote communications capability. The lack of a communications ability means that the current status of the capacitor is unknown, and there is no way to tell if the current set points or operational status are correct.

It is not uncommon for a utility to have multiple capacitors out of service and to not be aware of the condition. This can occur when the fuses connecting the capacitors to the feeder blow and there is no remote indication. These fuses can blow because of unrelated system faults or switching transients that cause large inrush currents to the capacitor banks; blown fuses can go without notice for days, weeks or even months. In capacitors that are controlled, set points can be incorrect because of system changes that normally occur over time. Load changes and system configuration changes are common occurrences that significantly affect the voltage profile of a distribution feeder. The result of these conditions is the capacitor banks may not be delivering the system benefits for which they were originally intended.

When capacitor banks are fully automated, the issues of blown fuses and operational set points can be directly addressed. When fuses blow and a capacitor is taken out of service, there is an immediate indication of the change of status. Additionally, local measurements can be compared to the internal set points to ensure that they meet the current operational needs. These capabilities ensure that the voltage profile along the feeder remains within tolerance, and it minimizes the amount of reactive power that must be supplied from the substation.

### 2.2.1 SGIG Metrics Affected by CA

The following SGIG metrics are affected by capacitor automation and will be tracked in this analysis:

Table 2.2: Impact metrics affected by capacitor automation

| Index | Metric | Units |
|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh |
| 2 | Monthly Customer Electricity Usage | MWh |
| 3 | Peak Generation | kW |
| | Nuclear | % |
| | Solar | % |
| | Bio | % |
| | Wind | % |
| | Coal | % |
| | Hydroelectric | % |
| | Natural Gas | % |
| | Geothermal | % |
| | Petroleum | % |
| | Distributed Solar PV | % |
| | Distributed Wind | % |
| 4 | Peak Load | kW |
| | Controllable load | % |
| 7 | Annual Electricity Production | MWh |
| 12 | CO2 Emissions | Tons |
| 13 | SOx Emissions | Tons |
| | NOx Emissions | Tons |
| | PM-10 Emissions | Tons |
| 21 | Feeder Real Load | kW |
| | Feeder Reactive Load | kVAR |
| 29 | Distribution Losses | % |
| 30 | Distribution Power Factor | pf |
| 39 | CO2 Emissions | Tons |
| 40 | SOx Emissions | Tons |
| | NOx Emissions | Tons |
| | PM-10 Emissions | Tons |

### 2.2.2 Specific Implementation of CA

In the base case simulations, the shunt capacitors are one of three types: fixed operation, manual operation, and voltage control operation. It is assumed that none of the installed capacitors has remote monitoring capabilities, and that capacitors in voltage control operation have non-optimal set points. Additionally, in the base case, the capacitors have a 90% in service rate. The 10% out of service rate reflects situations where the fuses on capacitors have blown and are removed the capacitor from service, sometimes for months at a time. A 10% outage rate for capacitors is considered a conservative number; some utilities have indicated that numbers can be as high as 30%.

For the specific implementation, the modes of operation are left unchanged, but a remote monitoring capability is added. This is representative of connecting the capacitors into the Supervisory Control And Data Acquisition (SCADA) system and the Distribution Management System (DMS) if present. The inclusion of automation allows for operators to identify conditions which remove capacitors from service and to dispatch line crews to place them back in service. For the purposes of this study, capacitors are placed back into service within 24 hours of an out of service condition being identified. The exception is if the capacitor is removed from service on a weekend, in which case it will be placed back into service on the following Monday. The net result is a system with a 99+% capacitor in service rate, vs. 90%. Capacitor automation also allows for adjustment of controlled capacitor set points. Updated control set points ensure that the voltages are controlled to the proper range.

### 2.2.3 High Level CA Simulation Results

In this section the high-level results of capacitor automation will be examined. At this level of examination, the data will not be divided into monthly values, annual values will be examined. Simulation results for each of the prototypical distribution feeders will be examined, with 5 cases of GC-12.47-1; one for each climate region. The high-level examination will study the impact of CA on peak load, annual energy consumption, and system losses.

#### 2.2.3.1 Annual Peak Load

Figure 2.19 through Figure 2.21 show the changes in peak reduction between the base case and with capacitor automation. Unlike VVO, which generally showed a reduction in peak load, automation of the capacitors has a minimal impact on peak load. This near null result can be attributed to the fact that in nearly 90% of the cases the state of the capacitors did not change. Of the 10% that did change, only those that changed operation during the peak period contributed to the change in peak load. The result is that peak load is rarely affected by capacitor automation unless there are significant changes to operational set points or a more complete automation scheme such as VVO.

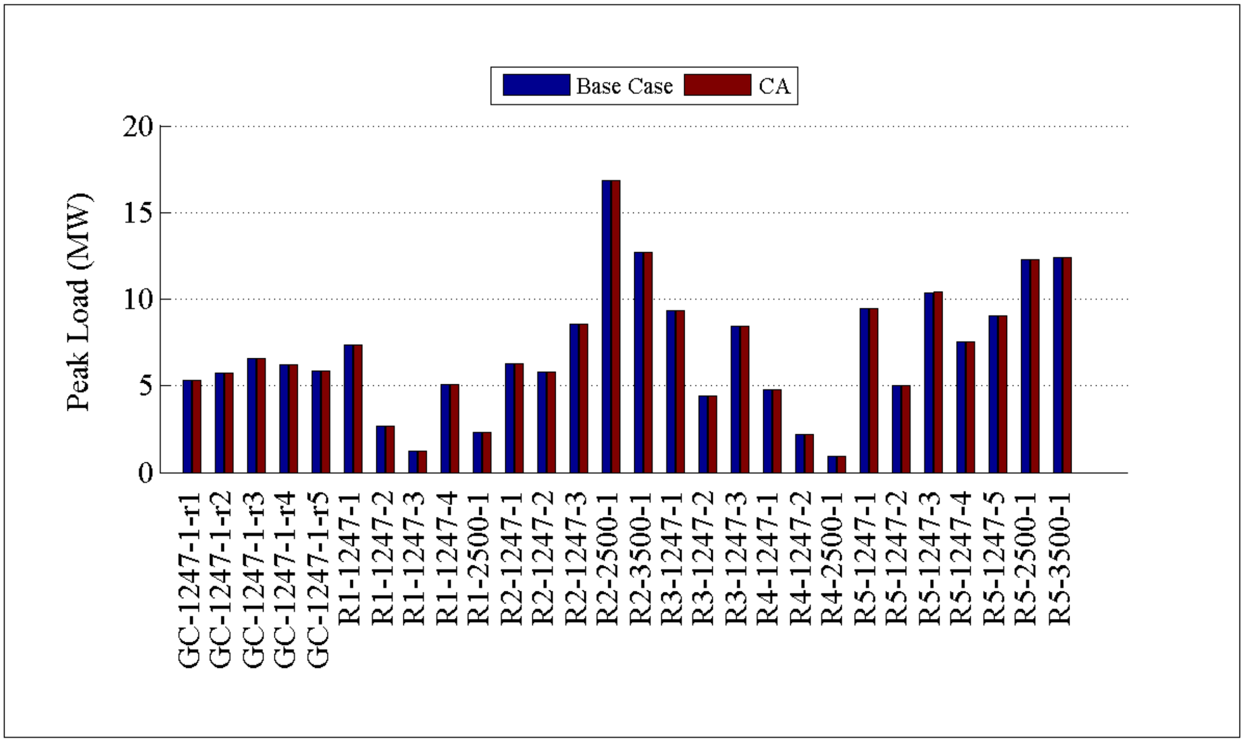



Figure 2.19: Comparison of peak load by feeder

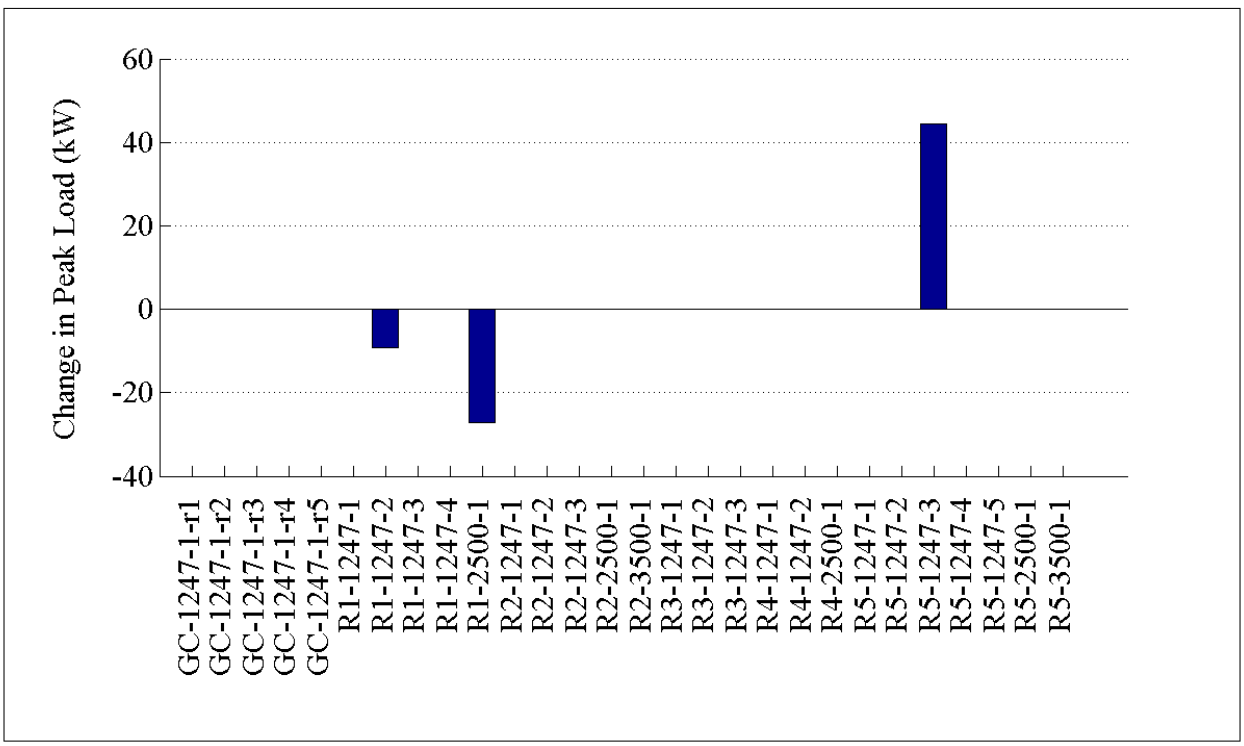



Figure 2.20: Change in peak load by feeder (kW)

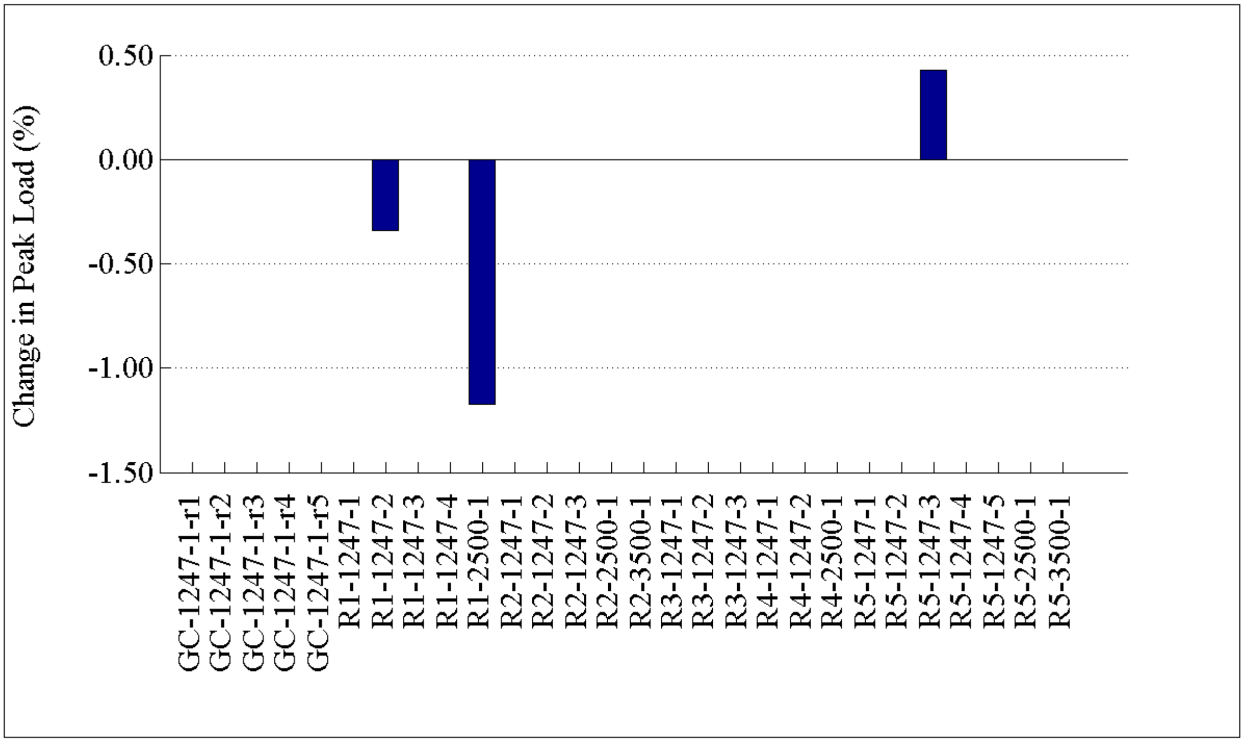



Figure 2.21: Change in peak load by feeder (%)

### 2.2.3.2 Annual Energy Consumption

Figure 2.22 through Figure 2.24 show the changes in annual energy consumption between the base case and with capacitor automation. Similar to peak reductions, automation of the capacitors has a minimal impact on annual energy consumption. Since there is a maximum of 10% change in the in service rate of capacitors over the entire year, it not unexpected that the changes in energy consumption would be negligible. In addition to the low percent change in the in service rate, some capacitors that were out of service due to blown fuses would not have been providing reactive power even if in service, because of their set points. As with peak load, the result is that energy consumption is rarely affected by capacitor automation unless there are significant changes to operational set points or a more complete automation scheme such as VVO.

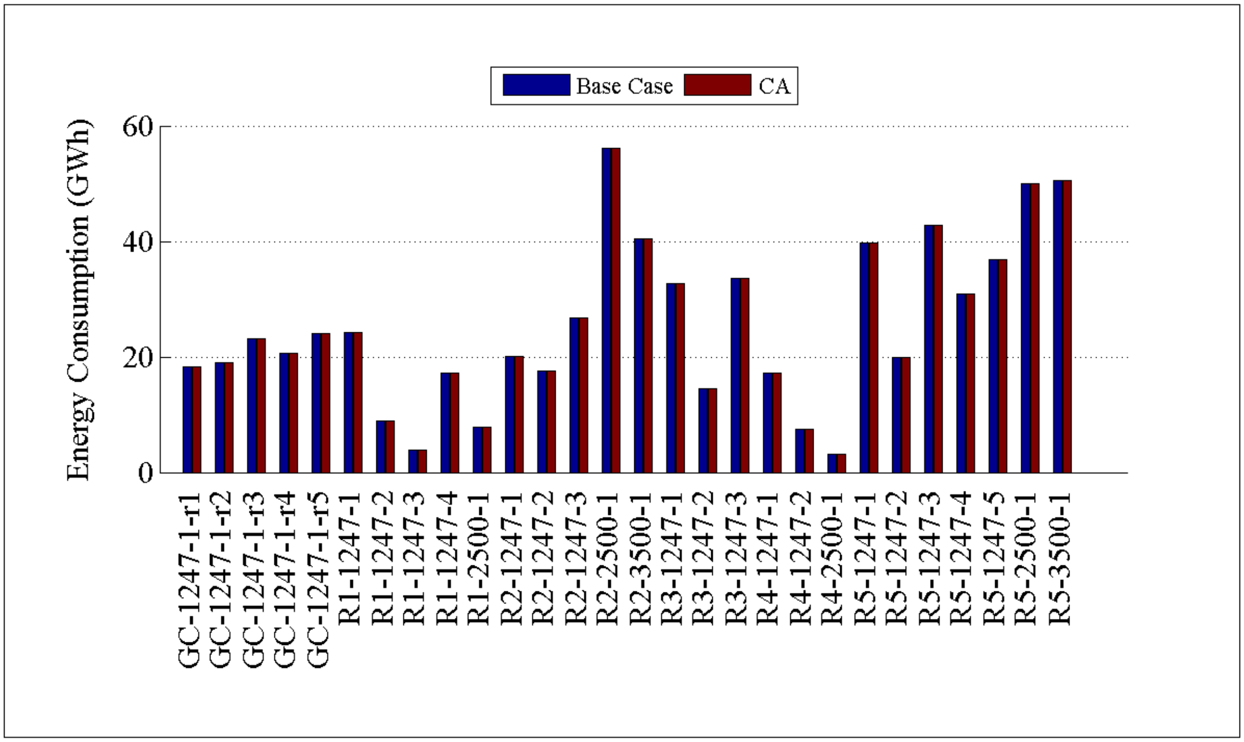



Figure 2.22: Comparison of annual energy consumption by feeder (MWh)

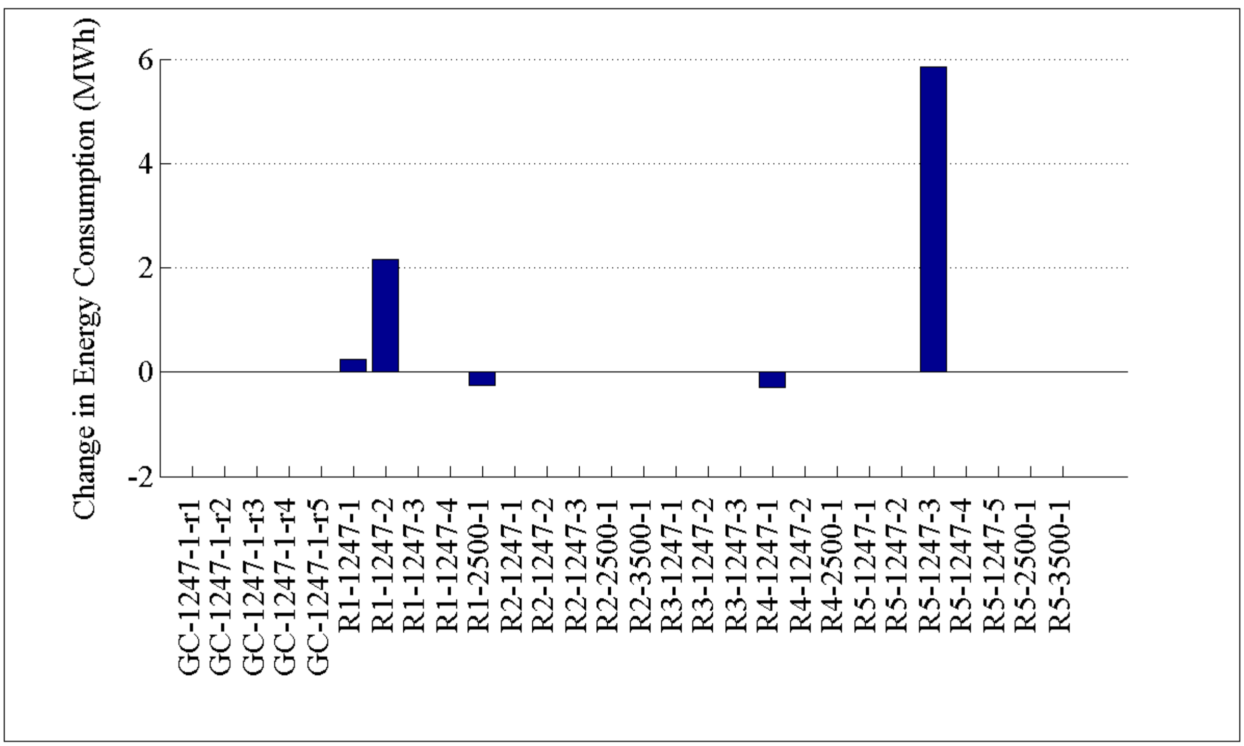



Figure 2.23: Change in annual energy consumption by feeder (MWh)

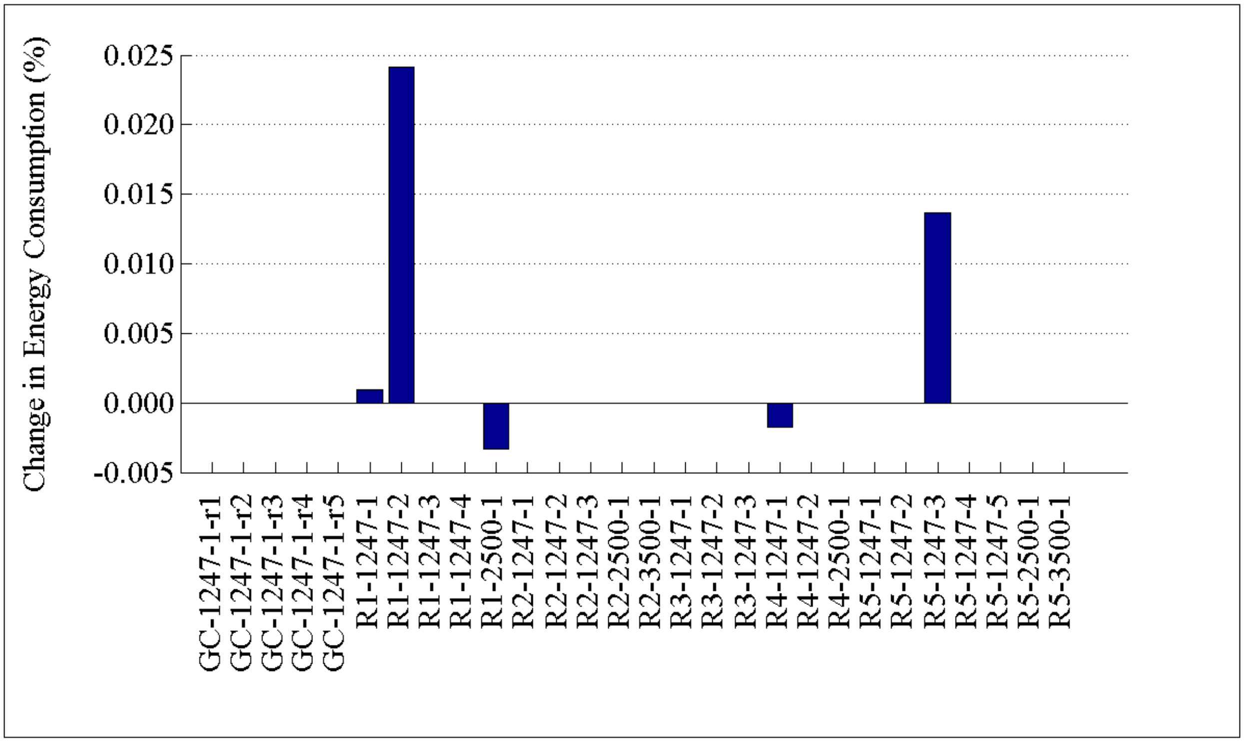



Figure 2.24: Change in annual energy consumption by feeder (%)

### 2.2.3.3 Annual System Losses

Figure 2.25 through Figure 2.27 show the changes in annual system losses between the base case and with capacitor automation. Similar to peak reduction and annual energy consumption, there are very few changes in the annual losses. The changes in annual losses that do occur are a function of the load type and feeder design. System losses are either series losses or shunt losses, each of which is affected by system voltage. For example, if a shunt capacitor that had been out of service is placed back in service; it could significantly raise the voltage on local transformers. If these transformers are inefficient, then their losses could increase more than the expected reduction in series line losses.

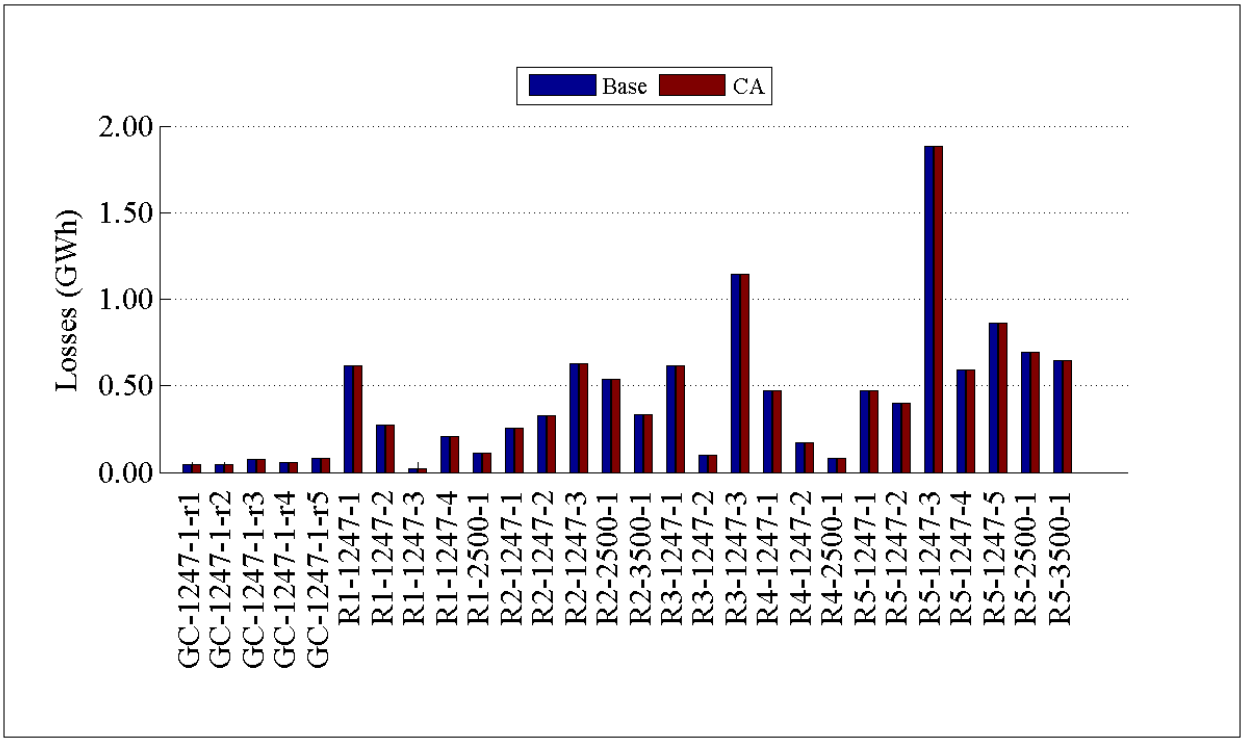



Figure 2.25: Comparison of total annual losses by feeder

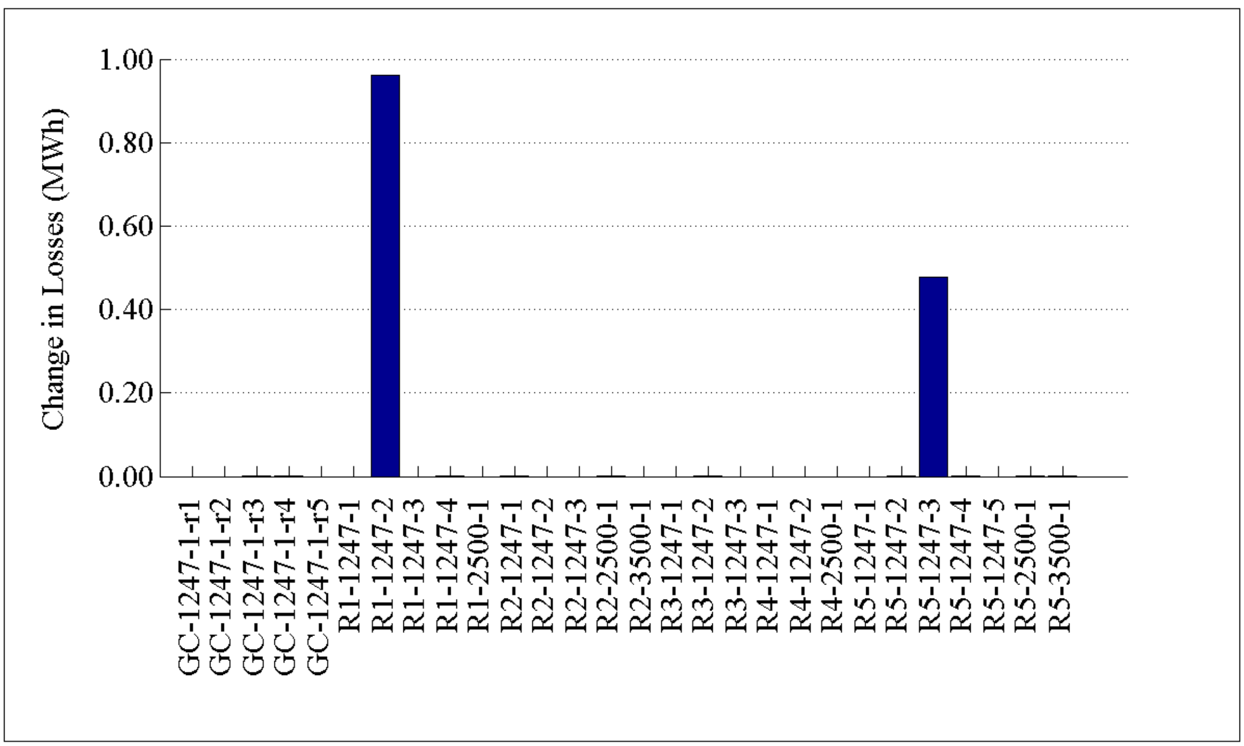



Figure 2.26: Change in annual losses by feeder (MWh)

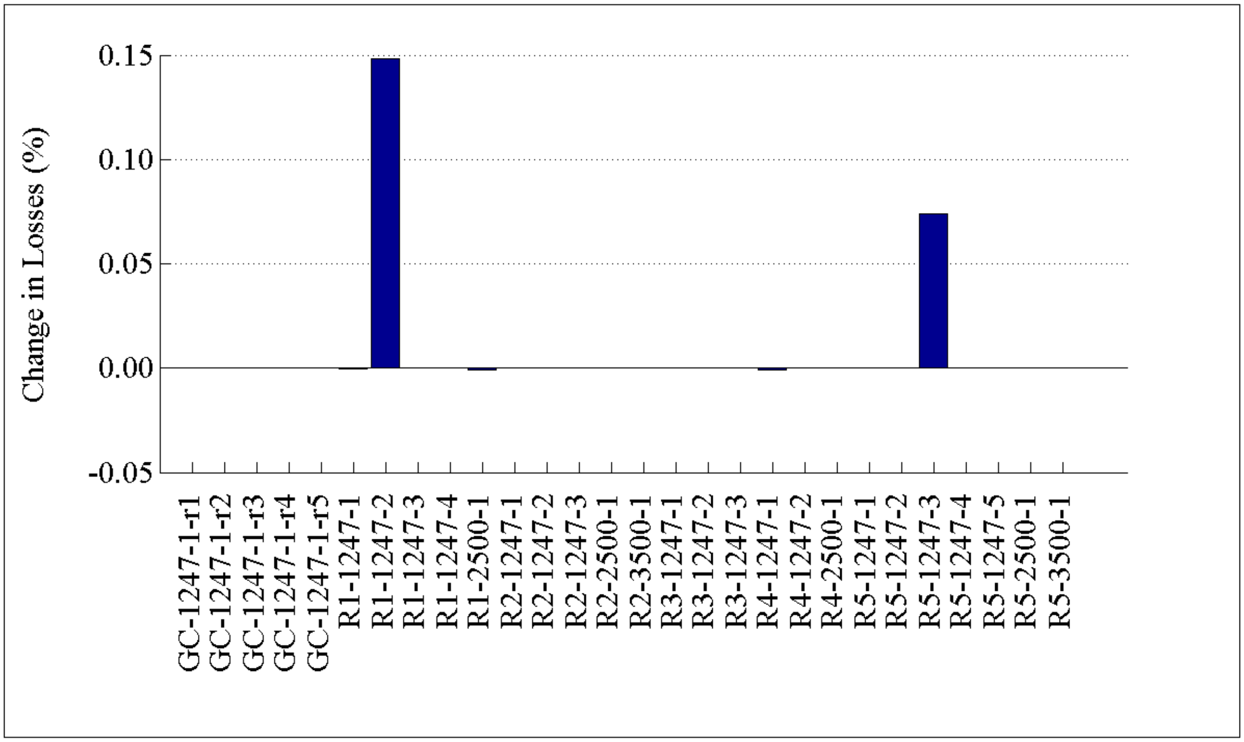



Figure 2.27: Change in annual losses by feeder (%)

## 2.3 Reclosers and Sectionalizers (R&S)

The most basic form of fault protection on a distribution feeder is the current limiting fuse. The current limiting fuse has the advantages of being low cost and effective at isolating faulted sections of the system. The disadvantage of a current limiting fuse is that once it experiences an over current condition, it must be replaced as the fuse element has melted. Additionally, there is no remote indication of which fuse in the system has blown. As a result, it can be difficult to identify that a fuse has blown and where it is located.

Reclosers and sectionalizers are devices that are designed to minimize the impact of failures on a distribution system. In contrast to fuses, reclosers and sectionalizers are dynamic devices that have internal control logic allowing them to open and close. Additionally, if a communications infrastructure is available, they are able to report their status via a SCADA system which can help to locate faults.

### 2.3.1 SGIG Metrics Affected by R&S

The following SGIG metrics are affected by the operation of reclosers and sectionalizers, and will be tracked in this analysis:

Table 2.3: Impact metrics affected by reclosers and sectionalizers

| Index | Metric | Units |
|---|---|---|
| 32 | SAIFI | Interruptions/yr. |
| 33 | SAIDI | Minutes |
| | CAIDI | Minutes |
| 34 | MAIFI | # |

### 2.3.2 Specific Implementation of R&S

The prototypical distribution feeders of [3] contain relatively few reclosers and no sectionalizers; protection is primarily achieved via current limiting fuses. In order to minimize the reliability impact of faults, both momentary and sustained, a coordinated scheme of reclosers and sectionalizers is implemented.

Reclosers are devices that are designed to interrupt fault current and are able to operate multiple times, or multiple shots, in order to clear momentary faults. For feeders that are subjected to momentary faults, due to vegetation or animals, the ability of a recloser to interrupt the fault current and then to reclose after a short period of time can prevent the need for a line crew to locate and travel to a remotely blown fuse. Many reclosers are of the "three shot" design which indicates that the recloser will open and reclose three times before locking into the open position. The three shot operation allows for three chances at clearing the fault before the recloser locks open. A recloser locked in the open position indicates a sustained fault, and in the absence of a communications system, requires a line crew to manually reset the recloser. In the presence of momentary faults, a single recloser can significantly improve reliability. If a feeder has a combination of momentary and sustained faults, then coordination with sectionalizers can be used to address the combination of fault types.

Sectionalizers are not designed to interrupt fault current, instead they are designed to open if fault current has been sensed and the current is interrupted by another device, i.e., a recloser. When reclosers and sectionalizers are coordinated, it is the recloser that momentarily interrupts the fault current and then the sectionalizer immediately upstream of the fault opens to isolate the fault. Then when the recloser recloses, the fault is clear because of the operation of the sectionalizer. Figure 2.28 shows an example system of a recloser with 3 sectionalizers on downstream branches.

If a momentary fault occurs anywhere downstream of the recloser, then it will operate giving the fault time to clear. The sectionalizers will be coordinated to not operate on the first two operations of the recloser in order to give it a chance to clear momentary faults. If a sustained fault occurs on any of the three branches, then the recloser will open, momentarily interrupting the fault current. If the fault is sustained and the fault does not clear on the first two recloser operations, then the sectionalizer on the branch with the fault will sense the fault current and open once the recloser has interrupted the fault current. When the recloser closes back in, the branch with the fault will be isolated and power will be restored to the customers on the two un-faulted branches. The result is that more customers may see a momentary loss of service, but fewer customers will experience a prolonged loss of service.

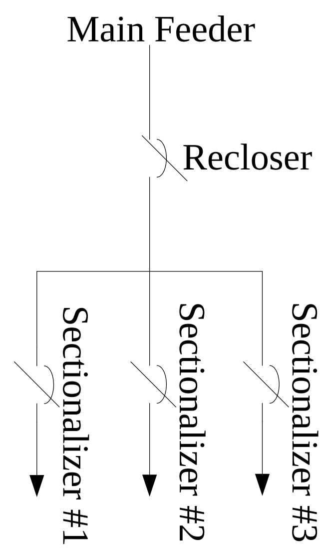



Figure 2.28: Typical recloser and sectionalizer layout

While Figure 2.28 shows a single recloser with 3 sectionalizers, it is possible to have 1 or more sectionalizers per recloser. Reclosers and sectionalizers can be single or multi-phased and are classified based on their operation, per phase or banked, and their lockout method, per phase or banked. Per phase operation is common on residential feeders where the loads are single phase, but for feeders with three phase loads, banked operation is necessary to prevent damage to end-use loads.

Table 2.4 shows the number of reclosers and sectionalizers added to each of the prototypical feeders in order to improve reliability. Since the prototypical feeders are "typical" feeders they do not have any significant reliability problems. Additionally, this analysis is only examining a single year so the number of fault locations is limited. As a result, the number of reclosers and sectionalizers needed to improve reliability is higher in some cases than would be expected for an operational feeder where just a few devices would improve reliability.

Table 2.4: Reclosers and sectionalizers added to taxonomy feeders

| Feeder | Reclosers | Sectionalizers |
|---|---|---|
| GC-1247-x | 2 | 1 |
| R1-1247-1 | 3 | 5 |
| R1-1247-2 | 1 | 1 |
| R1-1247-3 | 1 | 1 |
| R1-1247-4 | 2 | 4 |
| R1-2500-1 | 1 | 3 |
| R2-1247-1 | 4 | 8 |
| R2-1247-2 | 3 | 5 |
| R2-1247-3 | 7 | 31 |
| R2-2500-1 | 4 | 18 |
| R2-3500-1 | 8 | 21 |
| R3-1247-1 | 4 | 10 |
| R3-1247-2 | 4 | 9 |
| R3-1247-3 | 3 | 11 |
| R4-1247-1 | 1 | 3 |
| R4-1247-2 | 2 | 2 |
| R4-2500-1 | 1 | 0 |
| R5-1247-1 | 3 | 3 |
| R5-1247-2 | 3 | 7 |
| R5-1247-3 | 1 | 5 |
| R5-1247-4 | 8 | 6 |
| R5-1247-5 | 8 | 11 |
| R5-2500-1 | 9 | 6 |
| R5-3500-1 | 9 | 4 |

In addition to the benefits of autonomous recloser and sectionalizer operation, there is the benefit of being able to operate the units via the SCADA system. This has the benefit of reducing the time to place the affected end-use customers back in service after the fault has been fixed. In contrast to replacing a fuse, which requires the crew to drive to the fuse location, a recloser or sectionalizer connected via SCADA can be closed remotely in a few minutes whether by the operator or even the crew.

### 2.3.3 High Level R&S Simulation Results

In this section, the high level results of R&S will be examined. The high level examination will study the ability of implemented R&S scheme to improve the reliability of the distribution feeders, as measured by the metrics listed in Table 2.3.

### 2.3.3.1 System Average Interruption Frequency Index (SAIFI)

Figure 2.29 shows the base case SAIFI values, 'Base', as well as the SAIFI values after the reclosers and sectionalizers from Table 2.4 were added, 'R&S'; Figure 2.30 shows the differential values. From Figure 2.29 and Figure 2.30 it can be seen that the values of SAIFI either do not change or are reduced. The reduction in SAIFI values is driven by the operation of sectionalizers, which localize faults when they occur and reduce the number of customers that are affected by each fault. On some feeders, e.g. R3-12.47-2, the SAIFI value does not change despite the deployment of 4 reclosers and 9 sectionalizers. The reason for the static SAIFI values is that the faults on the system did not occur on the branches where sectionalizers were installed. If a sustained fault occurs between a recloser and a sectionalizer then the recloser will operate to attempt to clear the fault, and after three or five attempts it will lock into the open position, resulting in no net change in SAIFI.

At first glance, it may appear that there was no benefit to installing reclosers and sectionalizers on feeders with static SAIFI values; but this is not the case. While there may be no benefit for the year that was analyzed, there could be significant benefits the following year; this is the limitation of extrapolating statistical metrics based on one analysis.

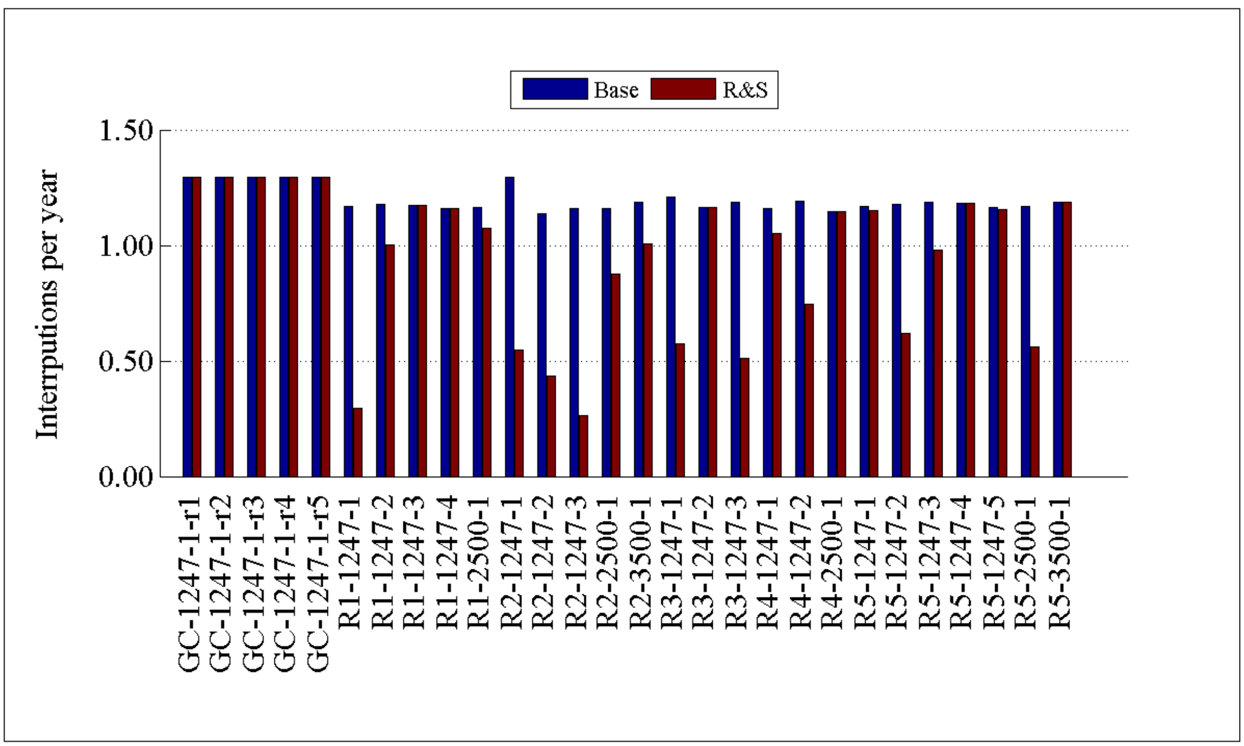



Figure 2.29: Comparison of SAIFI by feeder

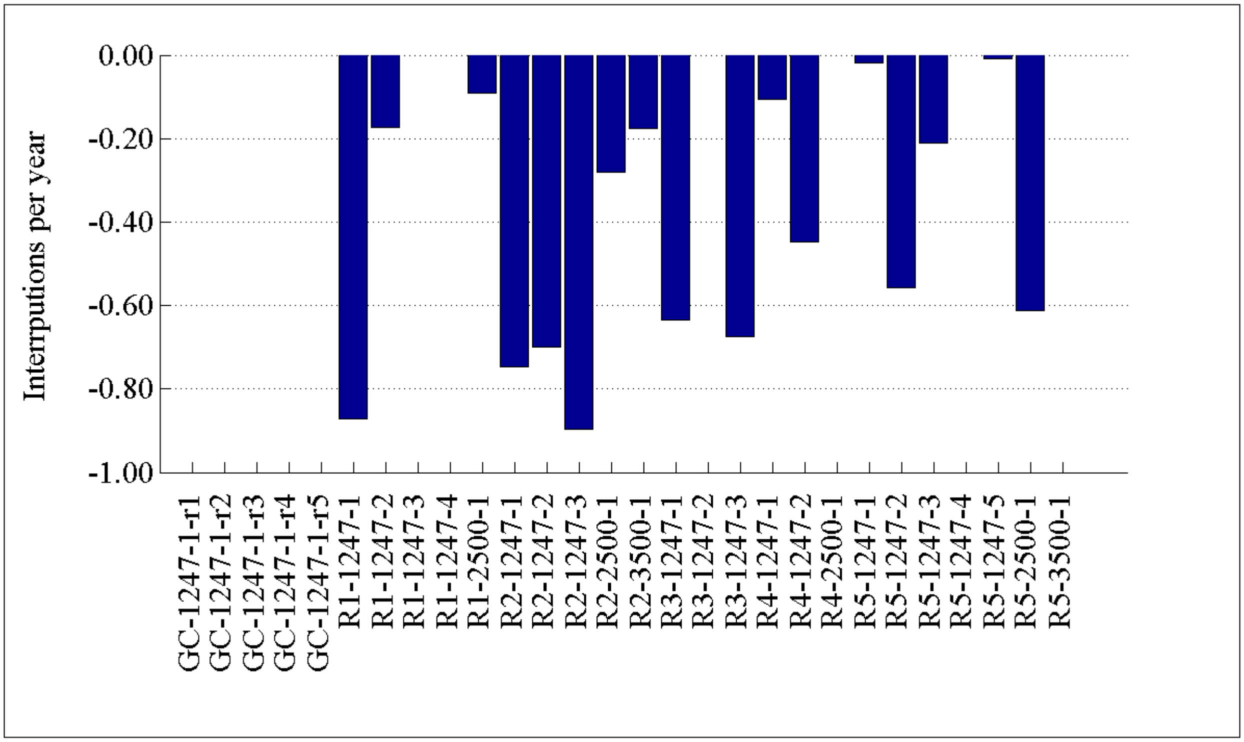



Figure 2.30: Change in SAIFI by feeder

## 2.3.3.2 System Average Interruption Duration Index (SAIDI)

Figure 2.31 shows the base case SAIDI values, 'Base', as well as the SAIDI values after the reclosers and sectionalizers from Table 2.4 were added, 'R&S'; Figure 2.32 shows the differential values. From Figure 2.31 and Figure 2.32, it can be seen that the values of SAIDI are always reduced. The reduction in SAIDI is due, in part, to the operation of sectionalizers, which limit the number of customers who are affected by any particular fault. A reduced SAIDI value is one of the largest benefits of deploying reclosers and sectionalizers on a distribution system.

One significant issue to note is that feeders that had no change in SAIFI do see a reduction in SAIDI. The reason for this is that while the reclosers and sectionalizers may have failed to reduce the number of customers who were affected by a fault, they are able to be place the affected portion of the feeder into service much quicker than replacing a fuse. The reduction in restoration time is due to the integration of the reclosers and sectionalizers with the SCADA system. Instead of dispatching a line crew to a blown fuse, including the required travel time and set up, a command can be issued over the SCADA system to remotely close the recloser or sectionalizer. As a result, the SAIFI value will remain unaffected, but the SAIDI value will decrease.

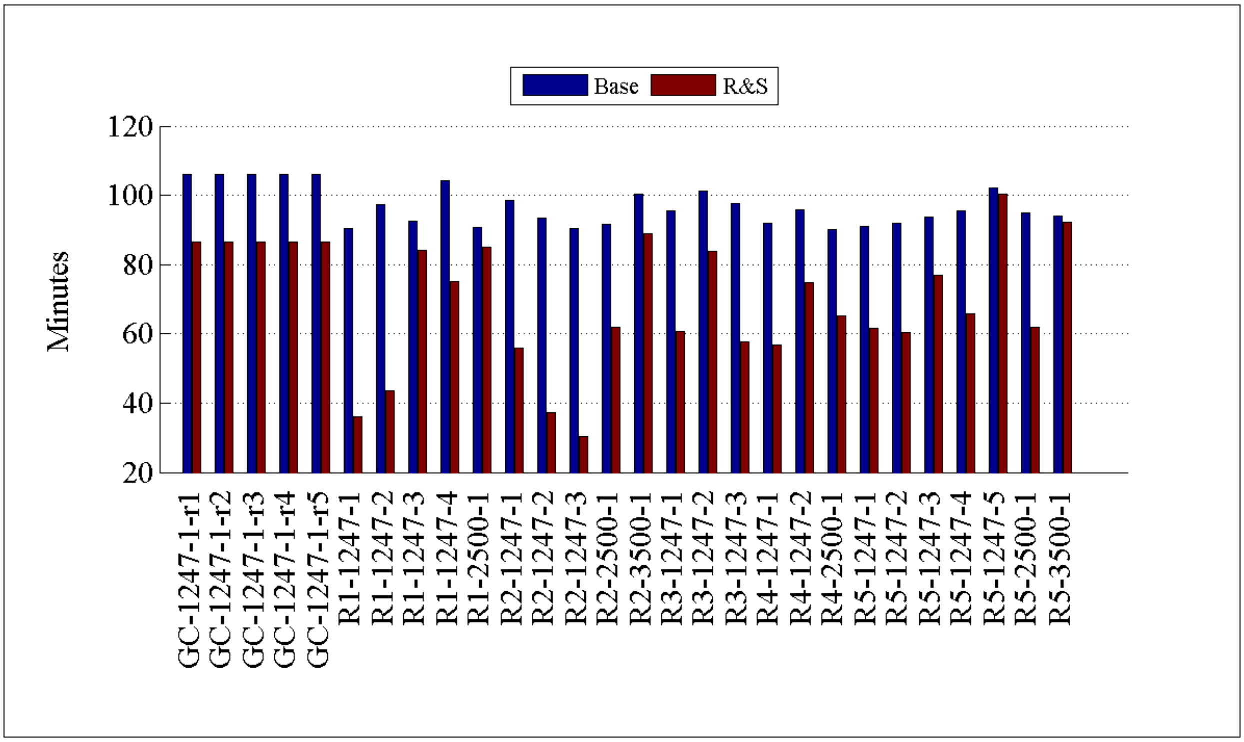



Figure 2.31: Comparison of SAIDI by feeder

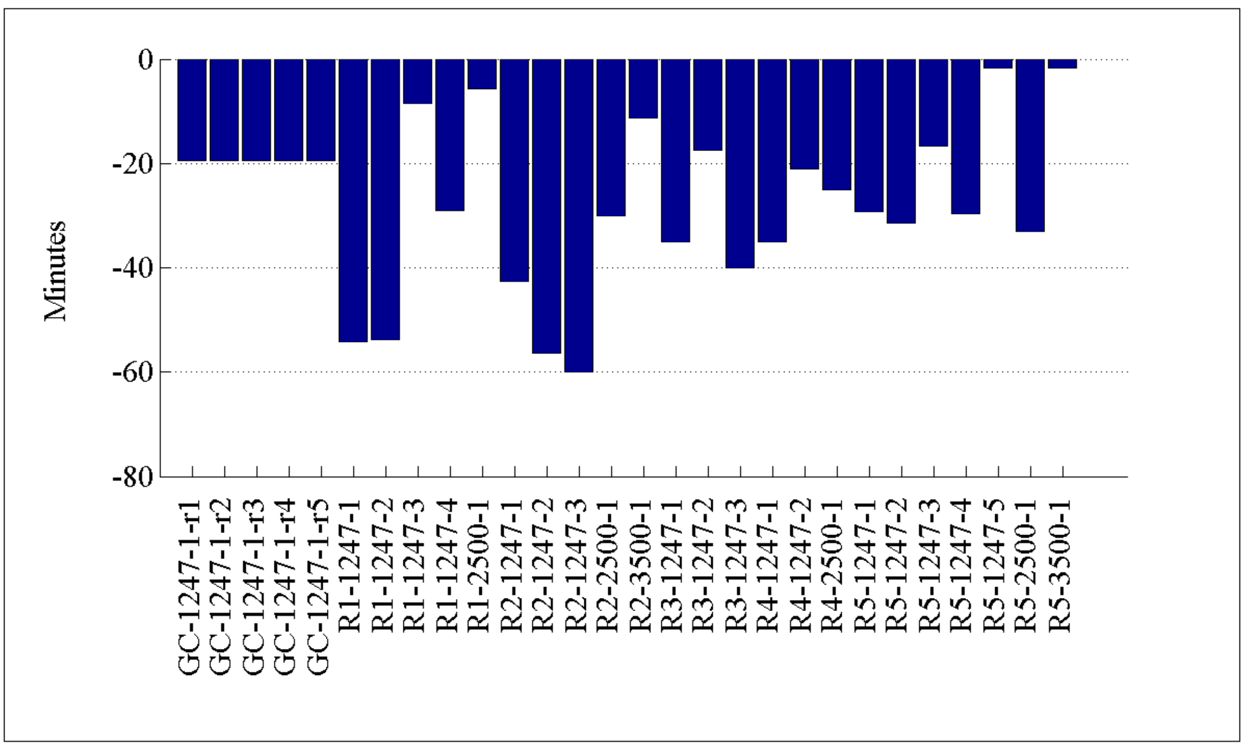



Figure 2.32: Change in SAIDI by feeder

### 2.3.3.3 Customer Average Interruption Duration Index (CAIDI)

CAIDI is the ratio of SAIDI to SAIFI [12] and represents the average duration of an interruption. Figure 2.33 shows the base case CAIDI values, 'Base', as well as the CAIDI values after the reclosers and sectionalizers from Table 2.4 were added, 'R&S'; Figure 2.34 shows the differential values. From Figure 2.33 and Figure 2.34, it can be seen that the values of CAIDI sometimes increase, and sometimes decrease.

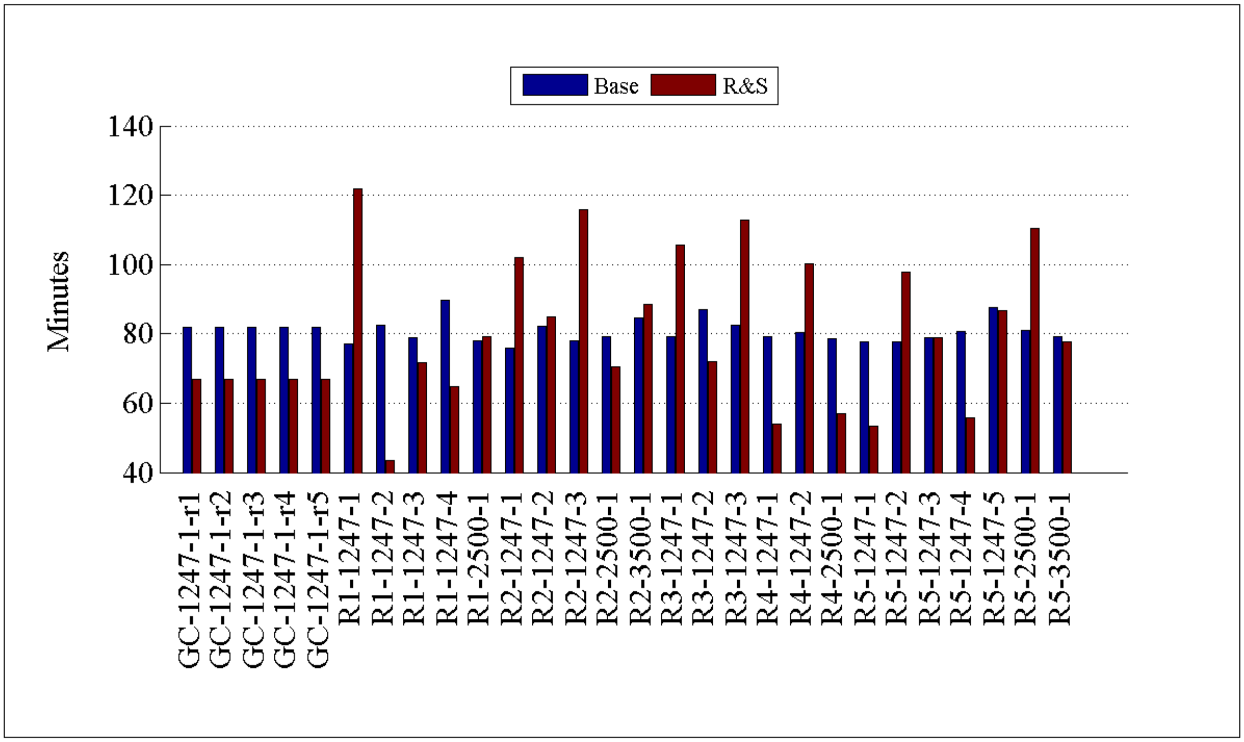



Figure 2.33: Comparison of CAIDI by feeder

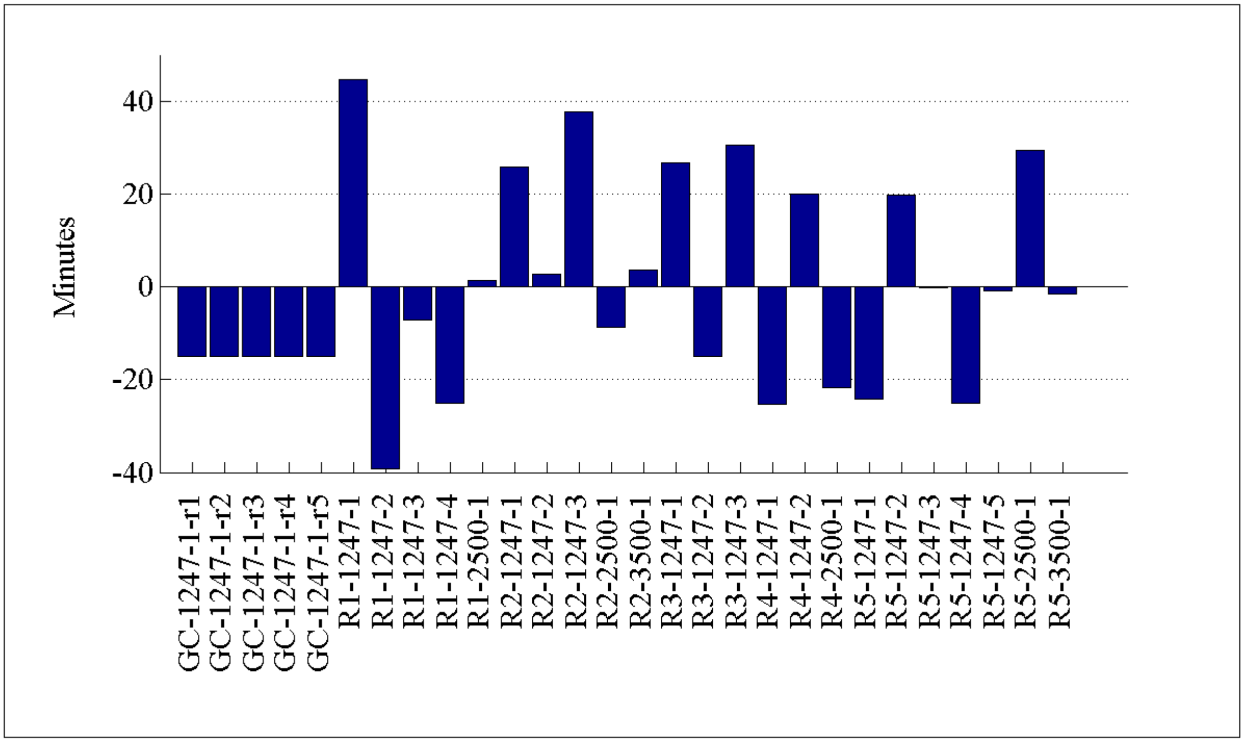



Figure 2.34: Change in CAIDI by feeder

The reason for the variability in CAIDI is due to the fact that it is calculated as the ratio of SAIDI to SAIFI; therefore, if SAIDI and SAIFI are not reduced by the same percentage, CAIDI will change. If an implemented system reduced the number of short duration faults to a greater extent than long duration faults, then CAIDI will increase despite the improvement in both SAIDI and SAIFI. For example, the inclusion of reclosers and sectionalizers on feeder R1-12.47-1 significantly reduced SAIDI and SAIFI, but since there was a greater impact on the number of customers affected, compared to the total durations, CAIDI increased.

## 2.3.3.4 Momentary Average Interruption Frequency Index (MAIFI)

MAIFI is the index that indicates the average number of momentary interruptions per customer, with momentary interruptions being defined as less than 5 minutes [12]. Figure 2.35 shows the base case MAIFI values, 'Base', as well as the MAIFI values after the reclosers and sectionalizers from Table 2.4 were added, 'R&S'; Figure 2.36 shows the differential values. From Figure 2.35 and Figure 2.36, it can be seen that the values of MAIFI does not consistently increase or decrease.

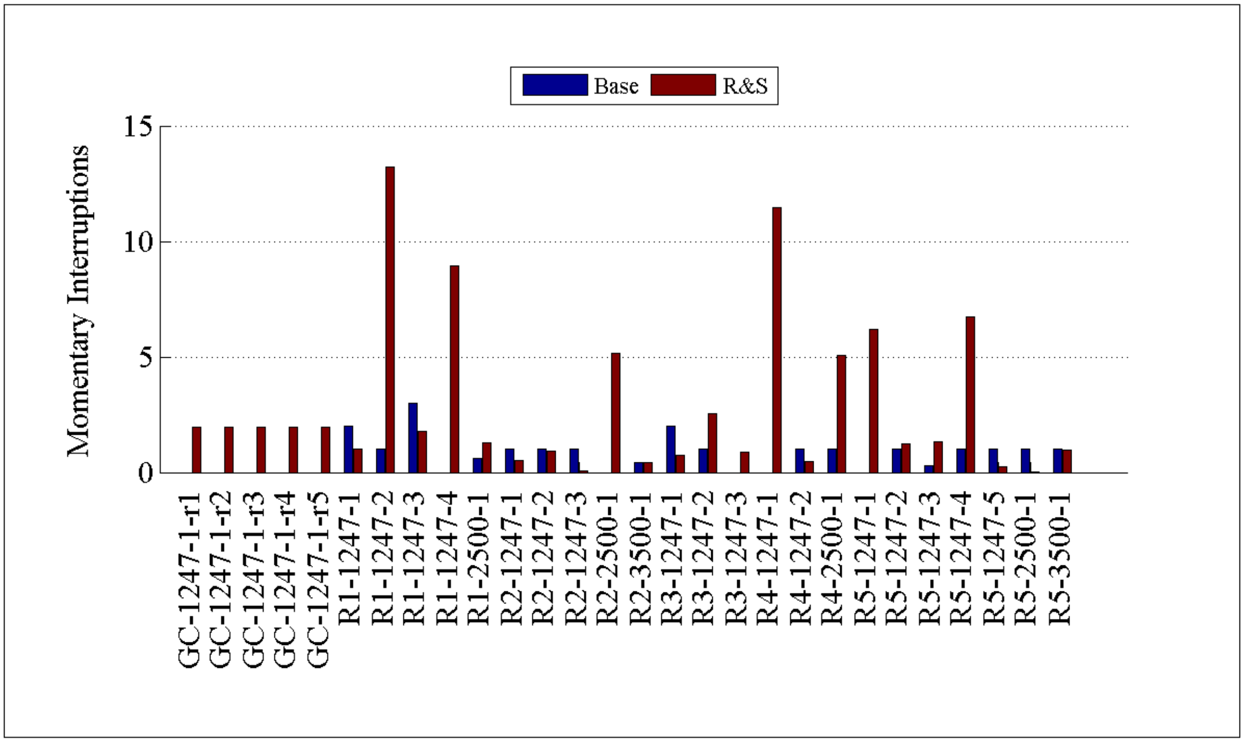



Figure 2.35: Comparison of MAIFI by feeder

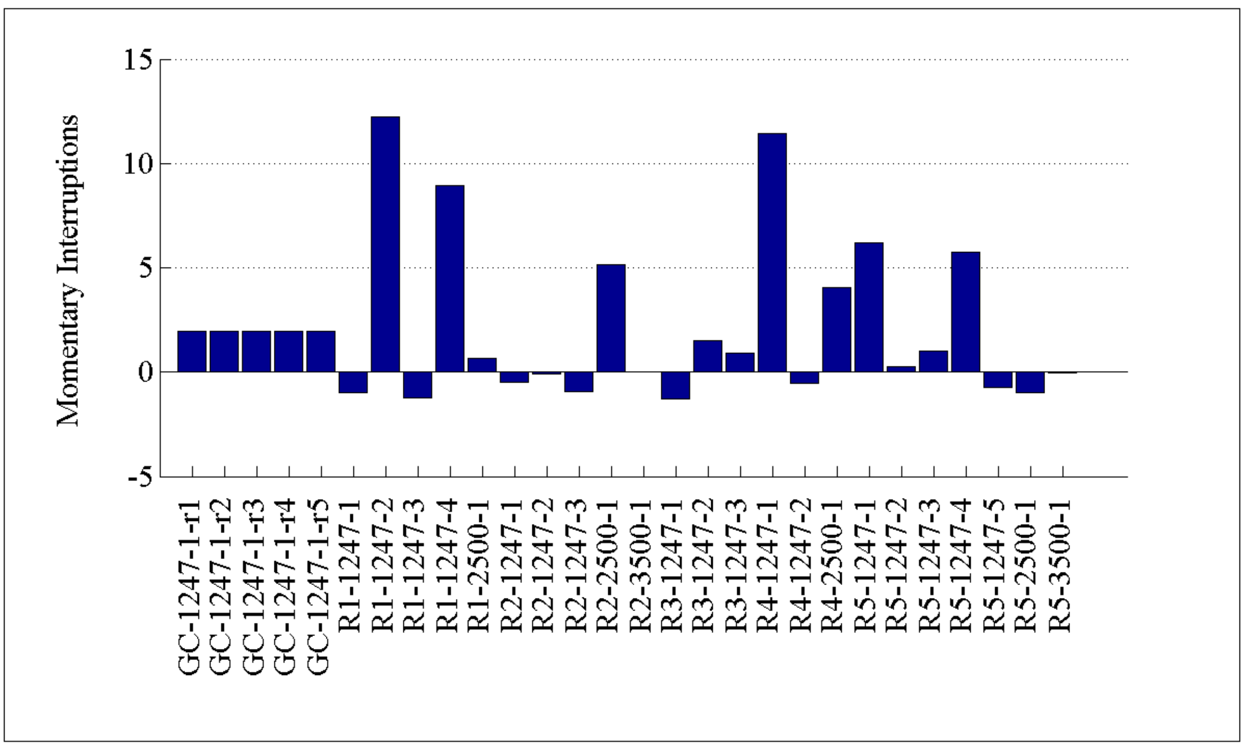



Figure 2.36: Change in MAIFI by feeder

The increases in MAIFI seen in Figure 2.36 can be attributed to the operation of reclosers. Under the base case, a momentary fault such as a tree branch or animal will be interrupted by a current limiting fuse, which will take longer than 5 minutes to replace. The result is that a momentary fault is turned into a sustained fault by the protection system. When reclosers are in operation, the sustained fault in the base case is converted into a momentary fault. A momentary outage initiated by a recloser is designed to prevent sustained fault from transient events. Another cause for an increase in MAIFI is that a recloser may affect many customers while interrupting the fault current, allowing a sectionalizer to separate the sustained fault from some customers, and increasing the number of customers with a momentary fault that would have otherwise been affected by the sustained fault. The net result is that while SAIFI and SAIDI may decrease, MAIFI can increase.

The cases where the MAIFI value goes down are attributed to feeders with fewer protective devices. The added recloser(s) operates and fewer customers are affected by a momentary fault, resulting in a reduced value of MAIFI. Whether MAIFI will increase or decrease is heavily dependent on the locations of the faults and the pre-existing protection devices.

## 2.4 Distribution Management and Outage Management Systems (DMS&OMS)

Distribution Management System (DMS) and Outage Management Systems (OMS) are separate management systems that can have various levels of integration. The DMS through the SCADA system is able to monitor and control various elements of the distribution system. The OMS is able to integrate Geographic Information Systems (GIS) and call in systems to determine the occurrence and location of a distribution level fault. It is also possible for an OMS to receive inputs from the DMS to indicate the status of breakers and other equipment to further improve the ability to detect and locate a fault. Not every distribution utility utilizes a DMS and/or OMS.

### 2.4.1 SGIG Metrics Affected by DMS&OMS

The following SGIG metrics are affected by DMS&OMS and will be tracked in this analysis:

Table 2.5: Impact metrics affected by DMS&OMS

| Index | Metric | Units |
|---|---|---|
| 32 | SAIFI | Interruptions/yr. |
| 33 | SAIDI | Minutes |
| | CAIDI | Minutes |
| 34 | MAIFI | # |

### 2.4.2 Specific Implementation of DMS&OMS

The exact capabilities of DMS and OMS systems vary significantly because of differences in hardware, software, and the infrastructure they are operating on. Regardless of the specific implementation, they are not generally able to prevent the occurrence of faults; protective devices are required for that. As a result, a DMS&OMS deployment will not reduce the number of faults or the number of customers that are affected by them; it will only reduce the duration of the outage. The reduction in the outage time is achieved through more effective fault detection and location. For the analysis conducted in this report, the presence of a DMS&OMS reduces the time required to identify and locate a fault by 15%; repair times are not affected.

### 2.4.3 High Level DMS&OMS Simulation Results

In this section, the high-level results of DMS&OMS will be examined. The high-level examination will study the ability of the implemented DMS&OMS to reduce the time necessary to restore power to end-use customers after the occurrences of a fault.

#### 2.4.3.1 System Average Interruption Frequency Index (SAIFI)

Because a DMS&OMS does not have the capability to affect the number of customers affected by a fault, it does not impact the SAIFI number.

#### 2.4.3.2 System Average Interruption Duration Index (SAIDI)

Unlike SAIFI, DMS&OMS are best suited to reduce SAIDI. Figure 2.37 shows the base case SAIDI values, 'Base', as well as the SAIDI values after the inclusion of a DMS&OMS system, 'DMS&OMS'; Figure 2.38 shows the differential values. From Figure 2.37 and Figure 2.38, it can be seen that the values of SAIDI are always reduced.

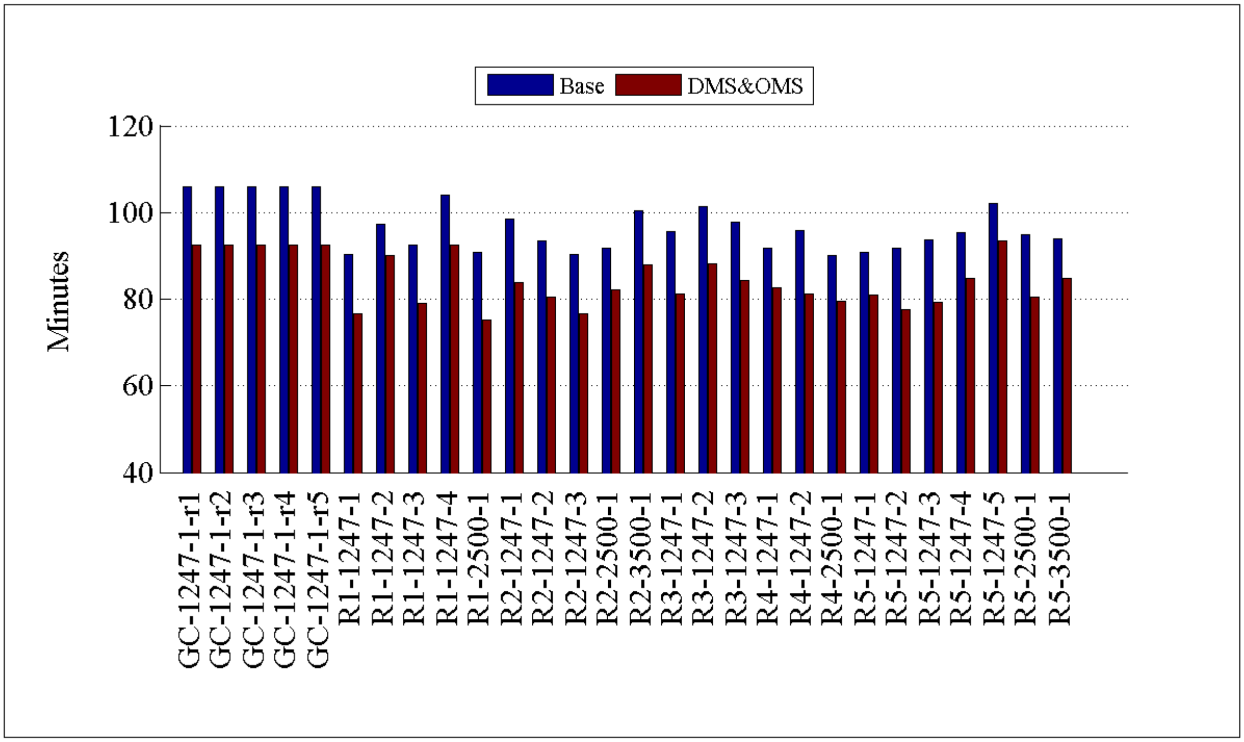



Figure 2.37: Comparison of SAIDI by feeder

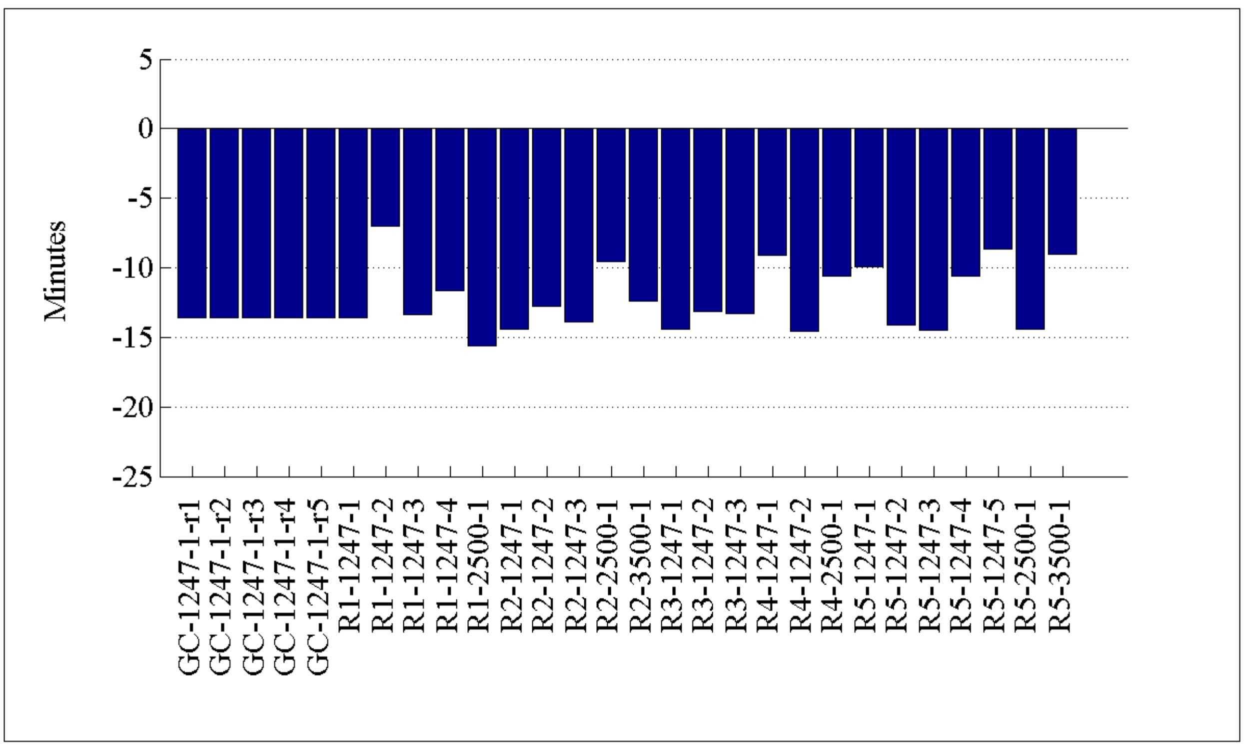



Figure 2.38: Change in SAIDI by feeder

### 2.4.3.3 Customer Average Interruption Duration Index (CAIDI)

Figure 2.39 shows the base case CAIDI values, 'Base', as well as the CAIDI values after the inclusion of a DMS&OMS system, 'DMS&OMS'; Figure 2.40 shows the differential values. From Figure 2.39 and Figure 2.40, it can be seen that the values of CAIDI are always reduced. The reduction in CAIDI is due to the reduced SAIDI values and the unchanged SAIFI values.

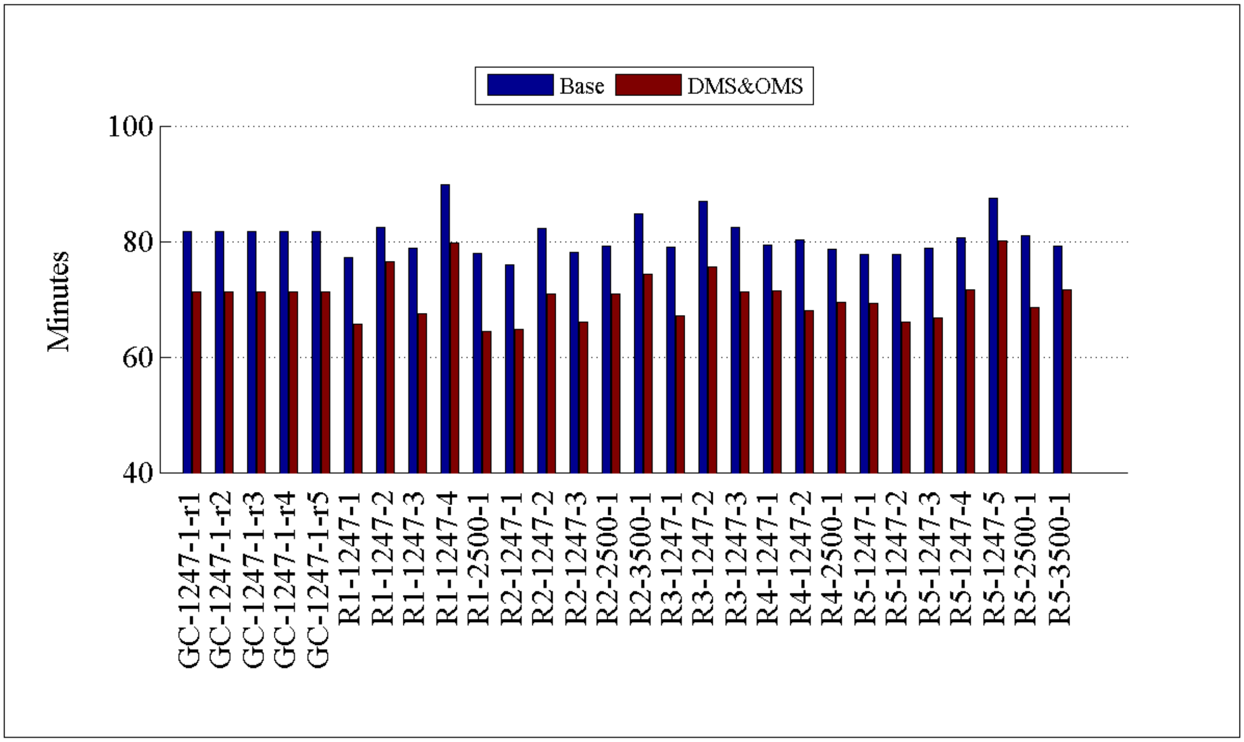



Figure 2.39: Comparison of CAIDI by feeder

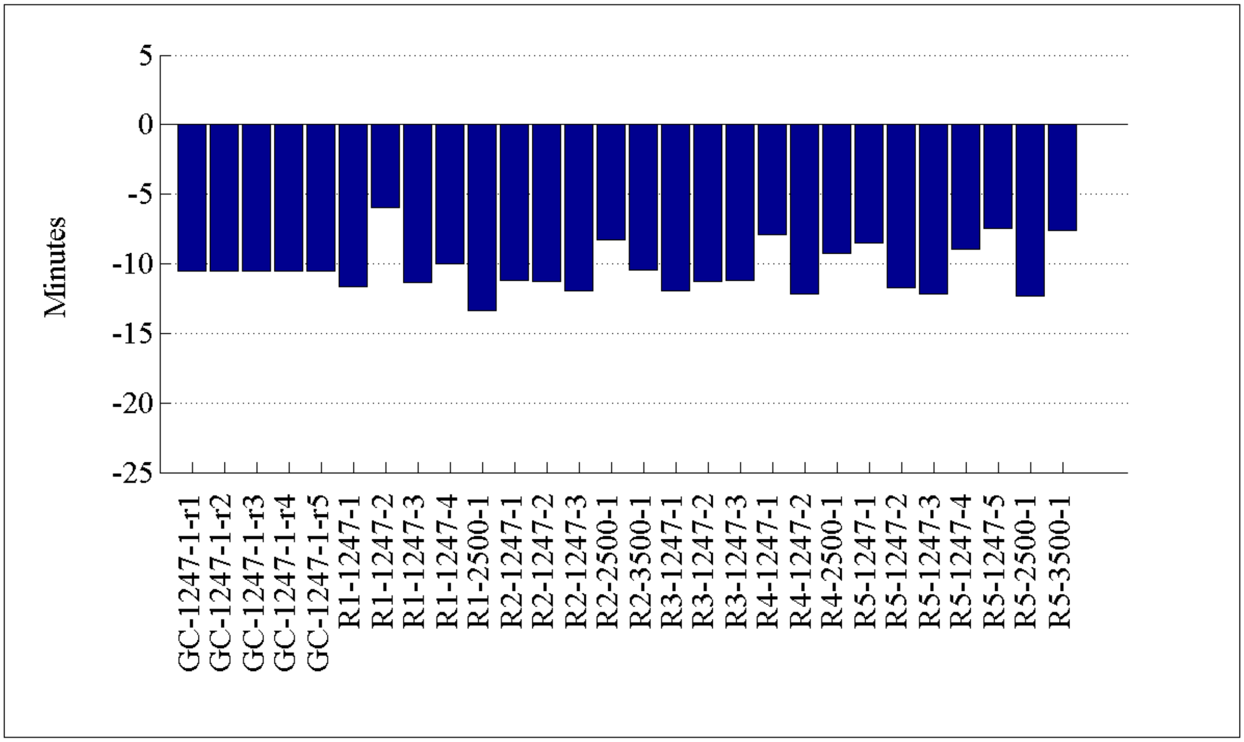



Figure 2.40: Change in CAIDI by feeder

### 2.4.3.4 Momentary Average Interruption Frequency Index (MAIFI)

Similar to SAIFI, DMS&OMS is not able to reduce the number of momentary faults. As a result, MAIFI is not affected by DMS&OMS.

## 2.5 Fault Detection Identification and Restoration (FDIR)

Fault Detection Identification and Restoration (FDIR) is a class of technologies whose goal is to identify the occurrence of a fault, record the occurrence, determine the fault location, and aid in the restoration process. It is a combination of advanced DMS&OMS systems, as well as a close integration of feeder level assets with the DMS. FDIR systems can also use automated switching, e.g. reclosers, sectionalizers and switches, to help minimize the number of customers affected by a fault.

### 2.5.1 SGIG Metrics Affected by FDIR

The following SGIG metrics are affected by FDIR and will be tracked in this analysis:

Table 2.6: Impact metrics affected by FDIR

| Index | Metric | Units |
|---|---|---|
| 32 | SAIFI | Interruptions/yr. |
| 33 | SAIDI | Minutes |
| | CAIDI | Minutes |
| 34 | MAIFI | # |

### 2.5.2 Specific Implementation of FDIR

While there are a number of proprietary FDIR systems, this analysis will use a basic representation of a full system. In this specific implementation, the FDIR system is tightly integrated with the DMS so that measured values from the shunt capacitors, reclosers, and sectionalizers are available for determining the location of the fault. Additionally, the capability exists to automatically reclose switches, reclosers, and sectionalizers, which further reduce the length of the outage. The net result is that the system operates with reclosers and sectionalizers and when a fault does occur, the time required to identify and locate the fault is reduced by 30%.

### 2.5.3 High Level FDIR Simulation Results

In this section the high-level results of FDIR will be examined. The high-level examination will examine the ability of the implemented FDIR to reduce the time necessary to restore power to end-use customers after the occurrences of a fault.

#### 2.5.3.1 System Average Interruption Frequency Index (SAIFI)

Figure 2.41 shows the base case SAIFI values, ‘Base’, as well as the SAIFI values after the FDIR system was added, ‘FDIR’; Figure 2.42 shows the differential values. From Figure 2.41 and Figure 2.42, it can be seen that the values of SAIFI either do not change or are reduced, similar to the effect of adding reclosers and sectionalizers.

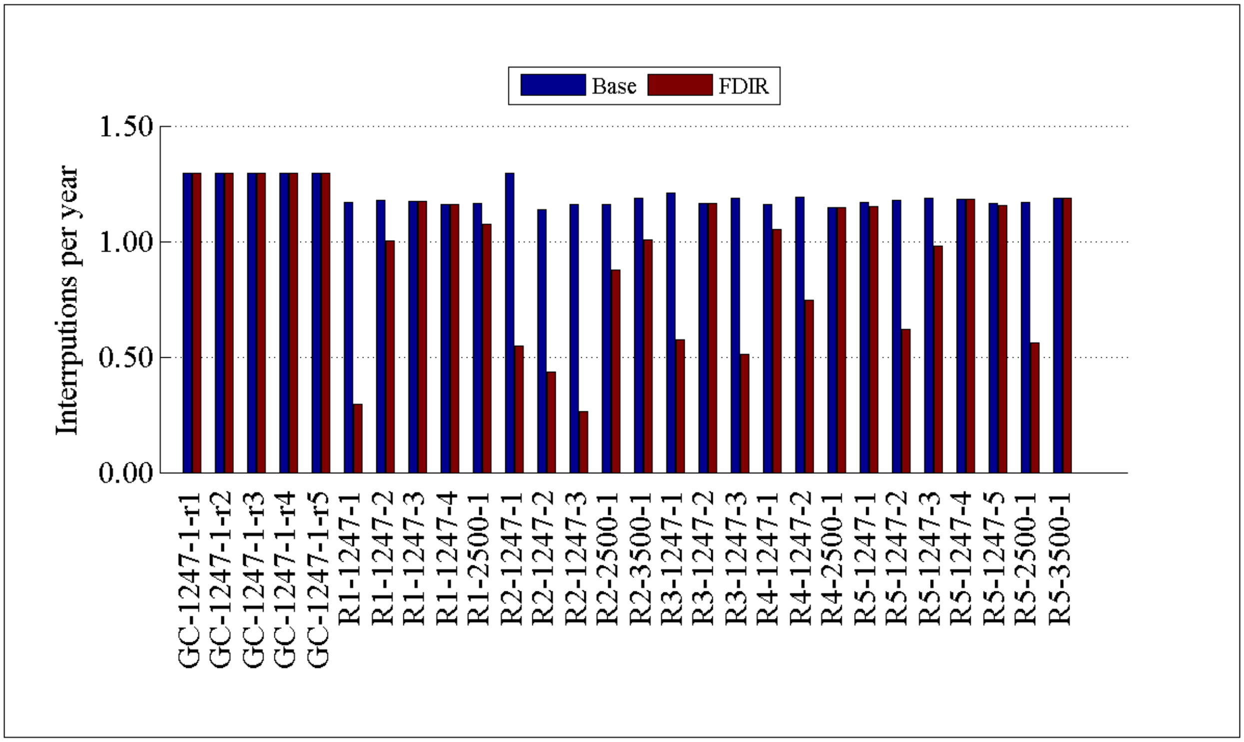



Figure 2.41: Comparison of SAIFI by feeder

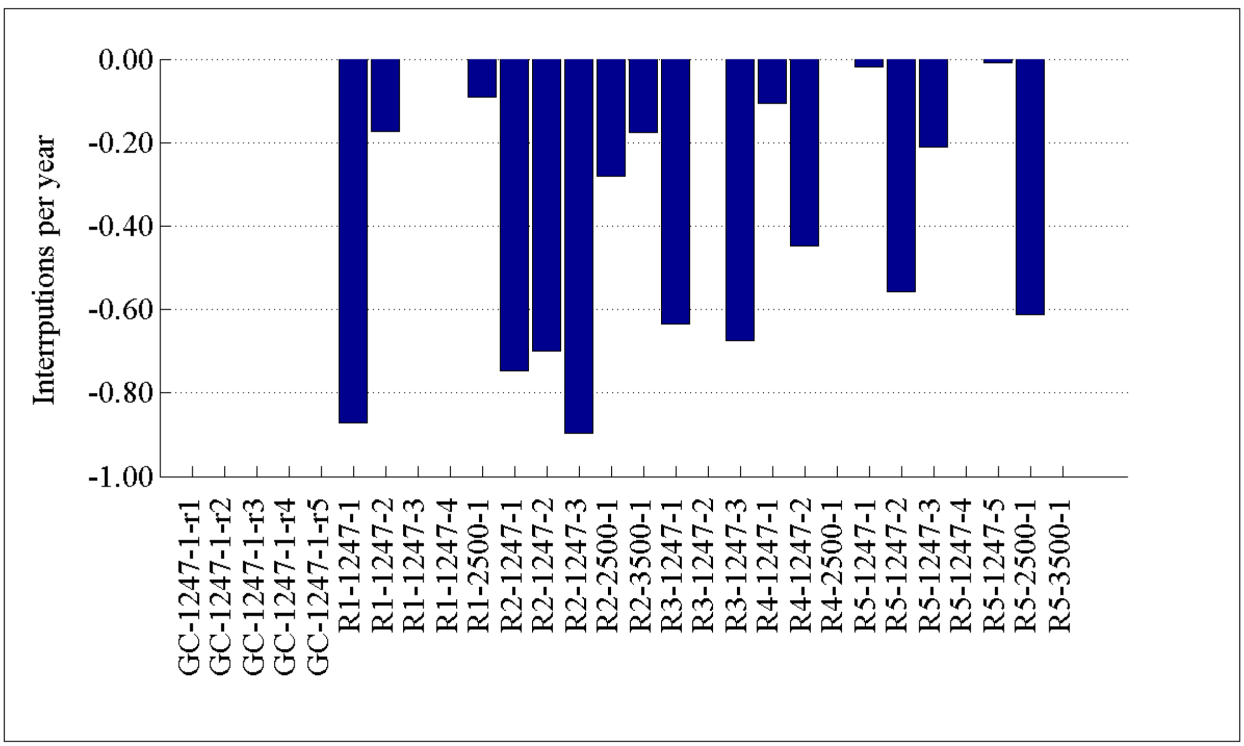



Figure 2.42: Change in SAIFI by feeder

### 2.5.3.2 System Average Interruption Duration Index (SAIDI)

Figure 2.43 shows the base case SAIDI values, ‘Base’, as well as the SAIDI values after the FDIR systems was added, ‘FDIR’; Figure 2.44 shows the differential values. From Figure 2.43 and Figure 2.44, it can be seen that the values of SAIDI are always reduced. The reduction in SAIDI is due to a combination of recloser and sectionalizer operations, as well as the increased ability of the FDIR system to identify and locate a fault.

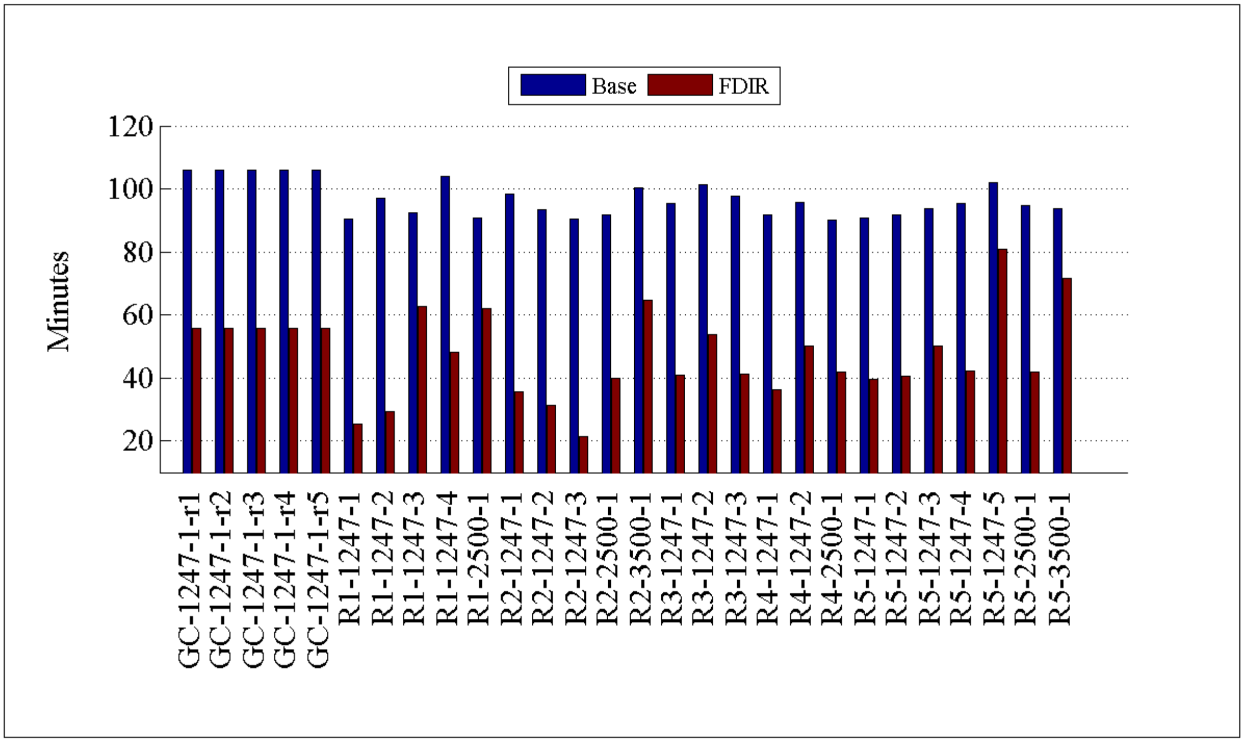



Figure 2.43: Comparison of SAIDI by feeder

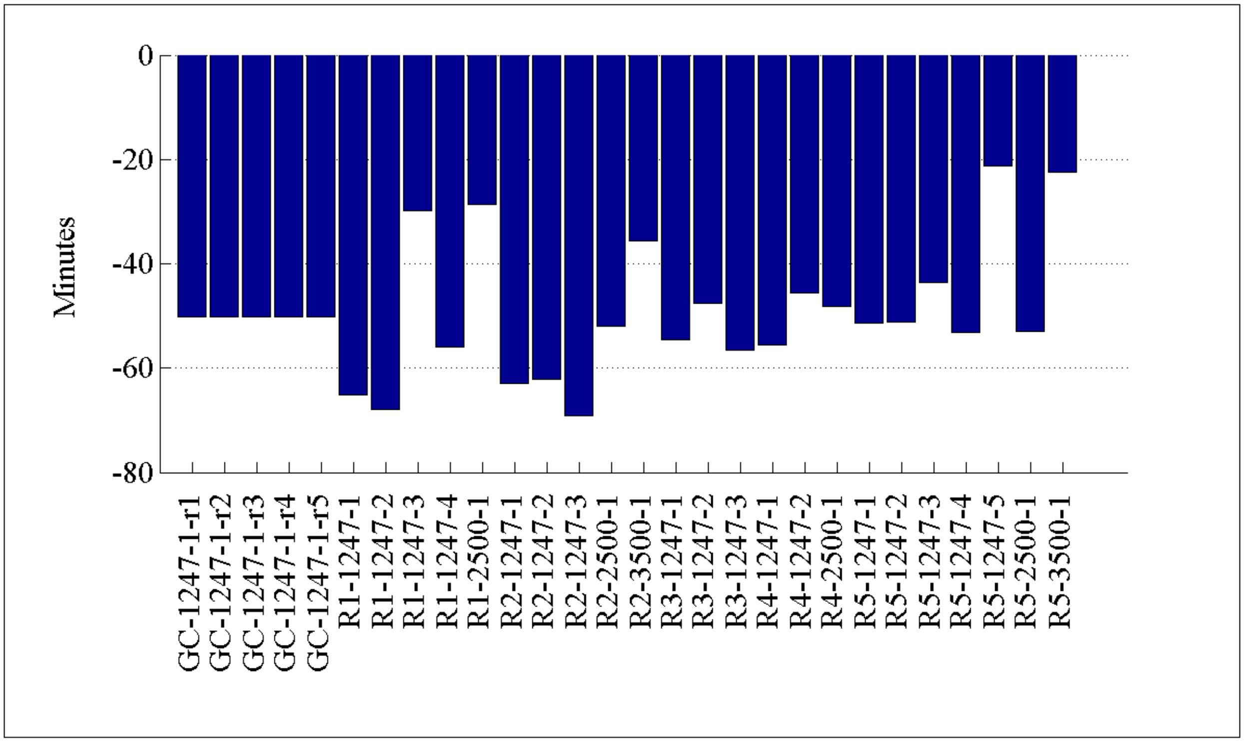



Figure 2.44: Change in SAIDI by feeder

### 2.5.3.3 Customer Average Interruption Duration Index (CAIDI)

Figure 2.45 shows the base case CAIDI values, 'Base', as well as the CAIDI values after the FDIR system was added, 'FDIR'; Figure 2.46 shows the differential values. From Figure 2.45 and Figure 2.46, it can be seen that the values of CAIDI in general decrease. The cases where CAIDI increases, R1-12.47-1 and R2-12.47-3, do so because of the significantly larger reductions in their SAIFI with respect to the reductions in SAIDI.

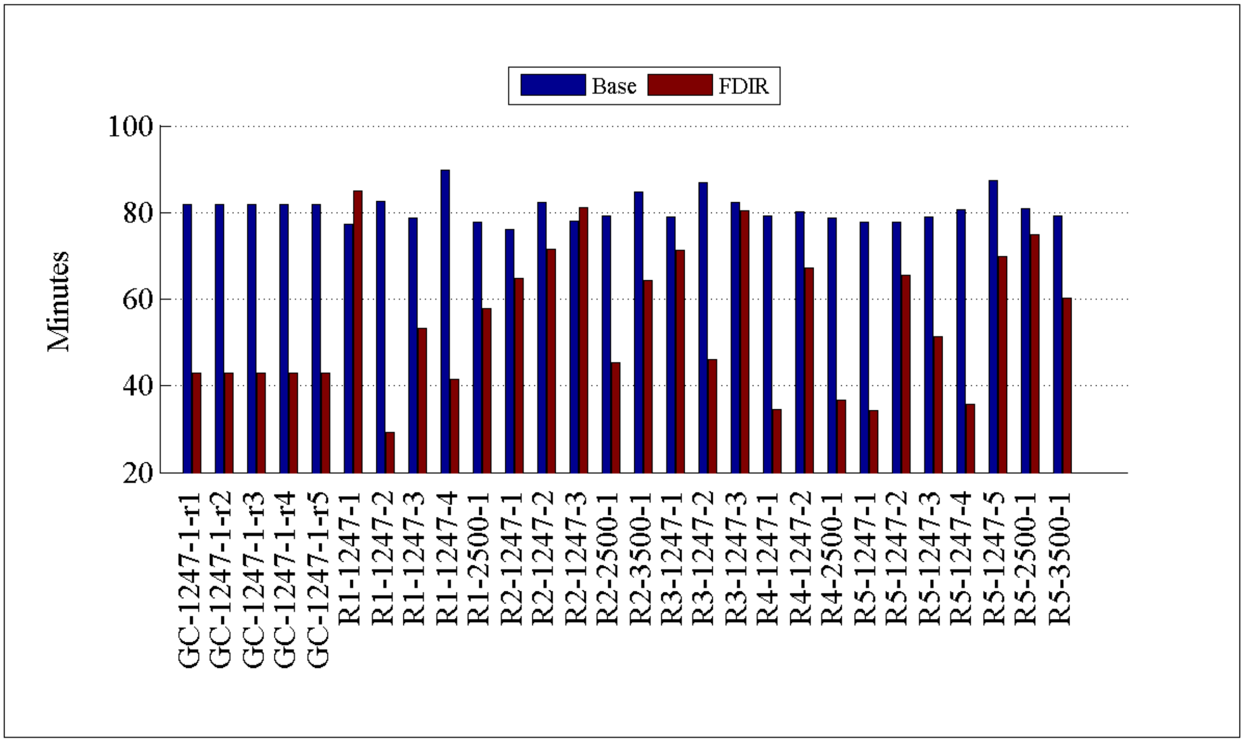



Figure 2.45: Comparison of CAIDI by feeder

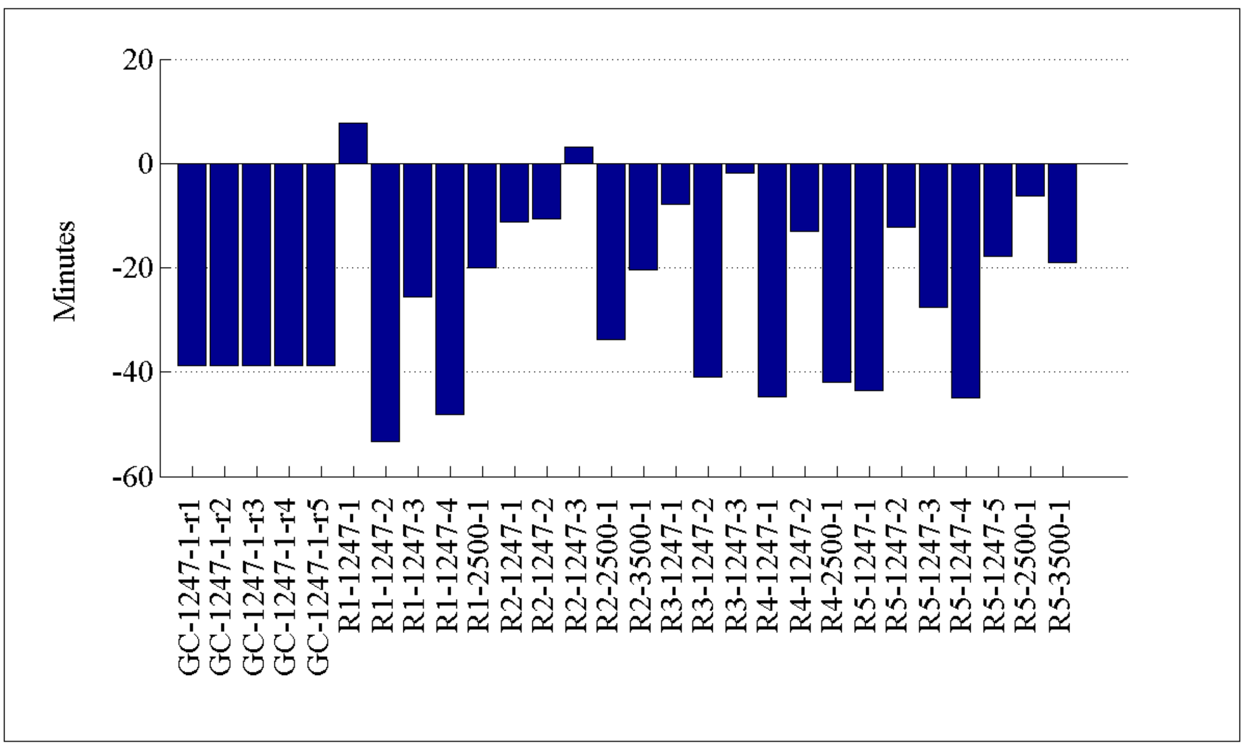



Figure 2.46: Change in CAIDI by feeder

## 2.5.3.4 Momentary Average Interruption Frequency Index (MAIFI)

Figure 2.47 shows the base case MAIFI values, 'Base', as well as the MAIFI values after the FDIR system was added, 'FDIR'; Figure 2.48 shows the differential values. From Figure 2.47 and Figure 2.48, it can be seen that the values of MAIFI do not consistently increase or decrease.

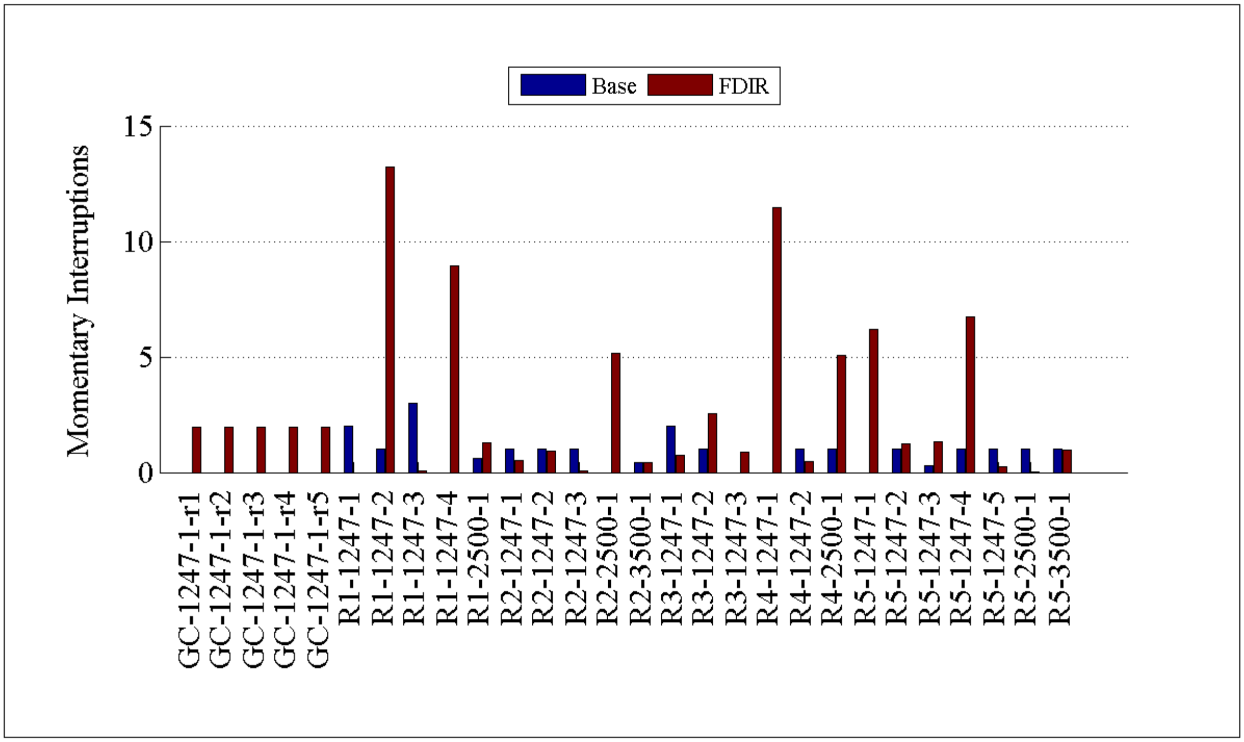



Figure 2.47: Comparison of MAIFI by feeder

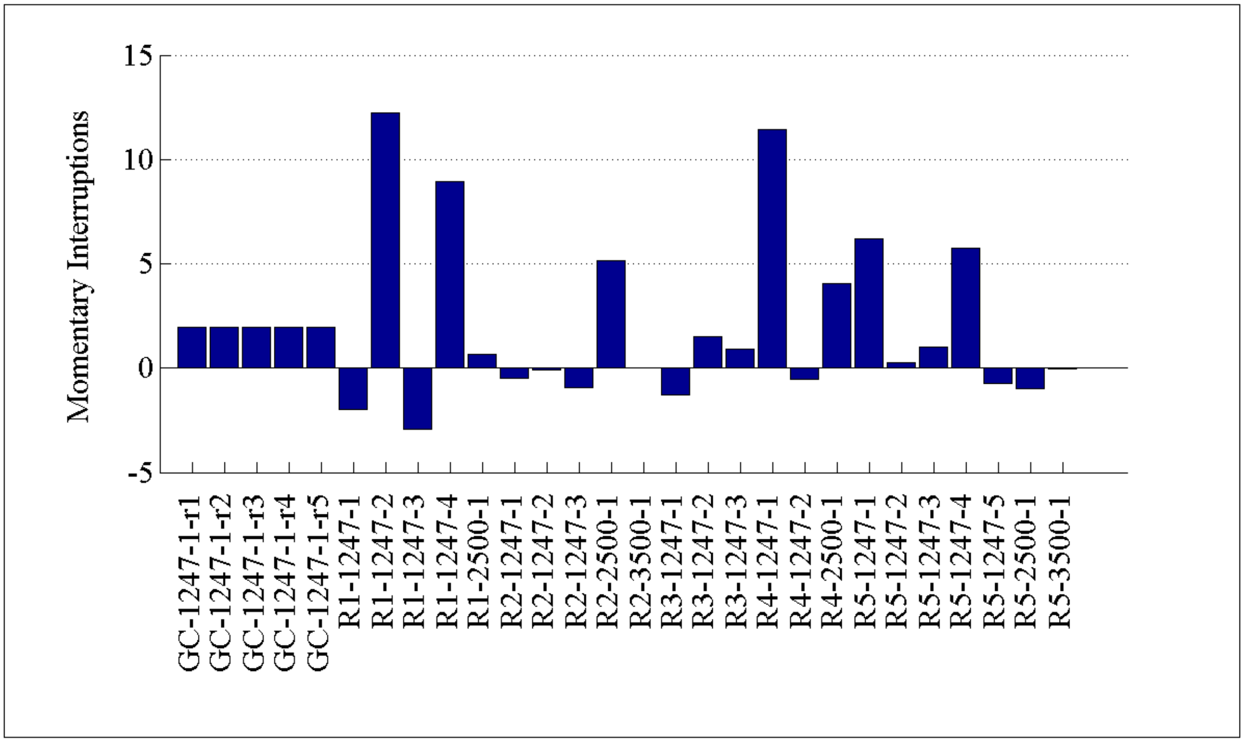



Figure 2.48: Change in MAIFI by feeder

# 3 Detailed Individual Prototypical Feeder Results

Due to the large number of plots generated by the simulations, it is not practical to place all of the results in this section. Section 3 will examine the output results of a single feeder and the output for the remaining feeders will be provided in Appendix D.

## 3.1 Volt-VAR Optimization

For VVO, there are 4 plots that will be displayed for each feeder; peak monthly demand, monthly energy consumption, monthly losses, and monthly $CO_2$ emissions.

### 3.1.1 Example Feeder GC-12-47-1_R1

Figure 3.1 through Figure 3.4 show the plots that are generated for feeder GC-12.47-1_R1. Peak monthly demand, monthly energy consumption, and monthly $CO_2$ emissions plot 'Base Case' and 'VVO'. Monthly losses plots "Base' and 'VVO' for 4 different loss types: losses in overhead lines 'OHL', underground lines 'UGL', transformers 'TFR', and triplex lines 'TPL'.

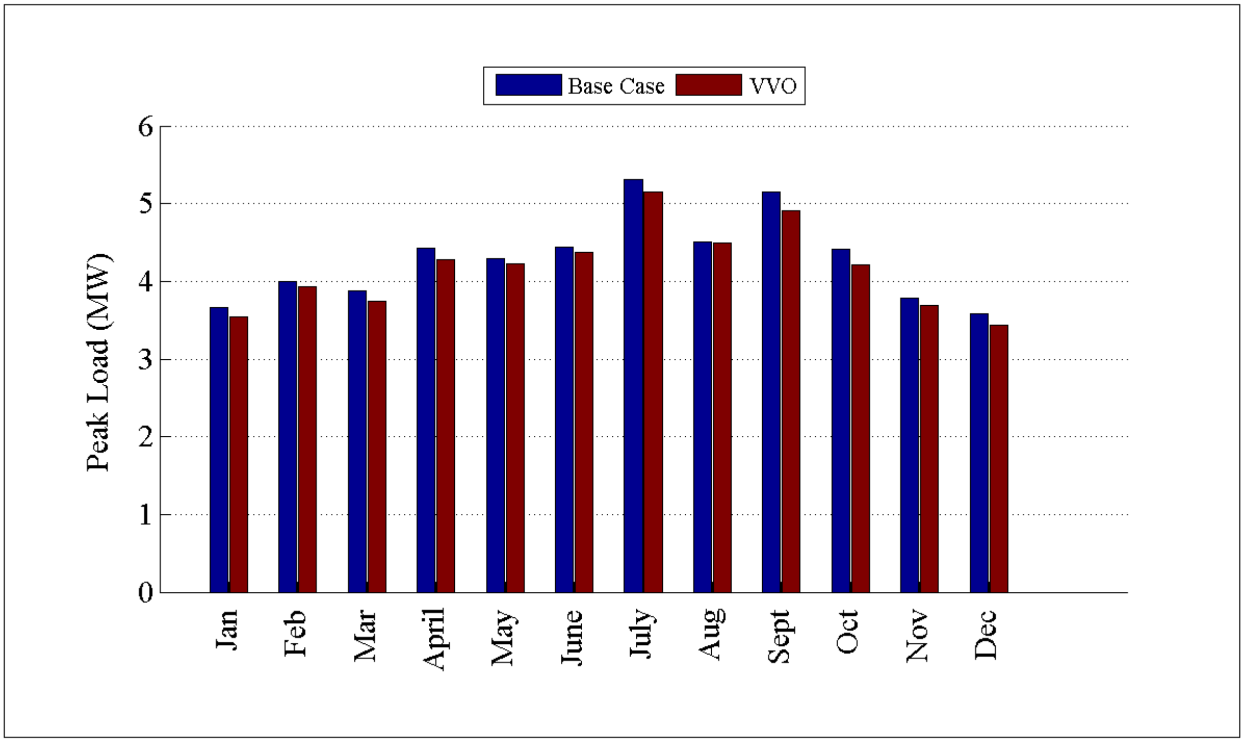



Figure 3.1: Comparison of peak load by month for GC-12.47-1_R1

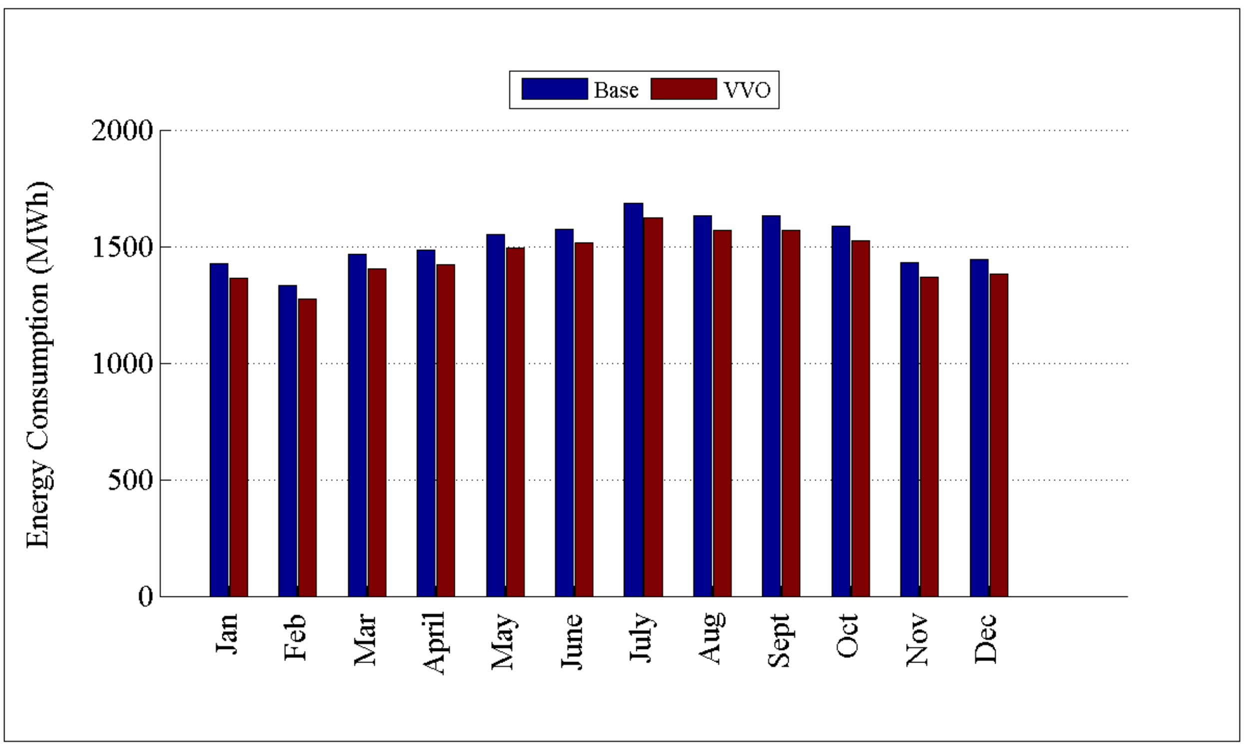



Figure 3.2: Comparison of energy consumption by month for GC-12.47-1_R1

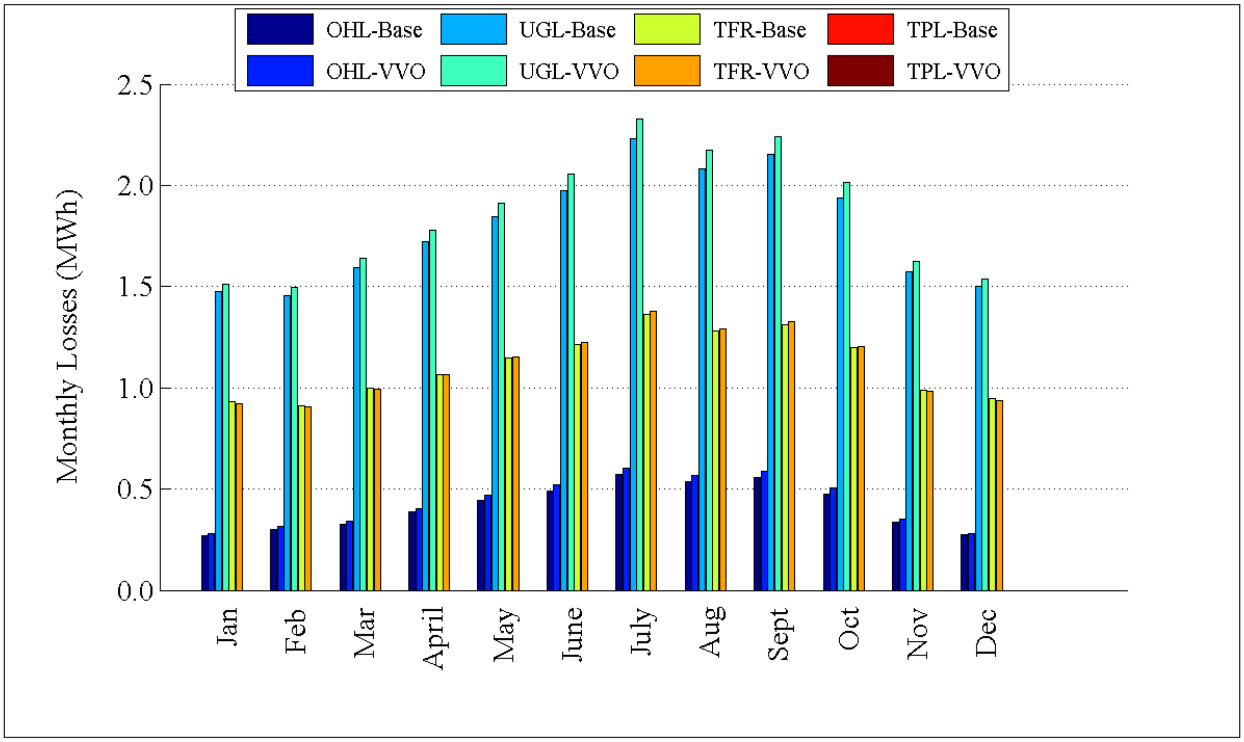



Figure 3.3: Comparison of losses by month for GC-12.47-1_R1

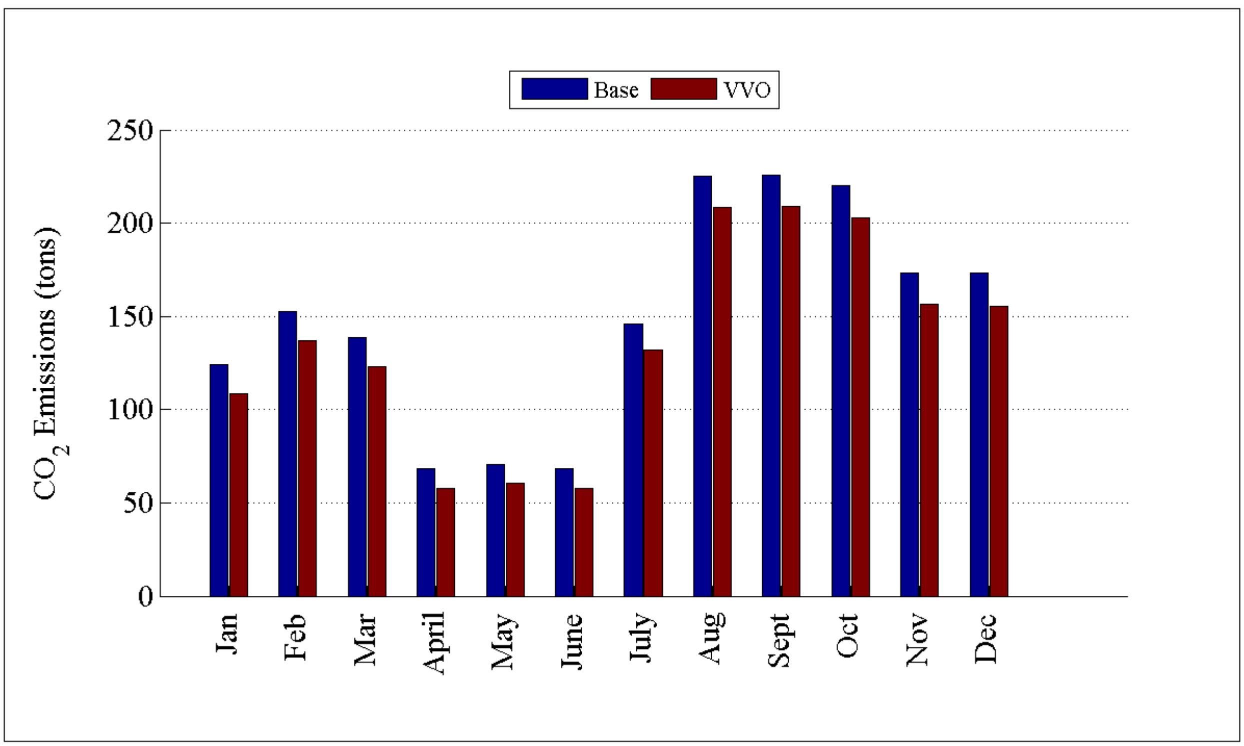



Figure 3.4: Comparison of CO2 emissions by month for GC-12.47-1_R1

## 3.2 Capacitor Automation

Identical to VVO, for CA there are 4 plots that will be displayed for each feeder; peak monthly demand, monthly energy consumption, monthly losses, and monthly $CO_2$ emissions. It is important to point out that CA provides benefits to the grid outside the SGIG metrics examined. These benefits are discussed in Section 5.3.2 of the Observations and Conclusions.

### 3.2.1 Example Feeder GC-12-47-1_R1

Figure 3.5 through Figure 3.8 show the plots that are generated for feeder GC-12.47-1_R1. Figure 3.5 through Figure 3.8 show the plots that are generated for feeder GC-12.47-1_R1. Peak monthly demand, monthly energy consumption, and monthly $CO_2$ emissions plot ‘Base Case’ and ‘VVO’. Monthly losses plots “Base’ and ‘VVO’ for 4 different loss types: losses in overhead lines ‘OHL’, underground lines ‘UGL’, transformers ‘TFR’, and triplex lines ‘TPL’.

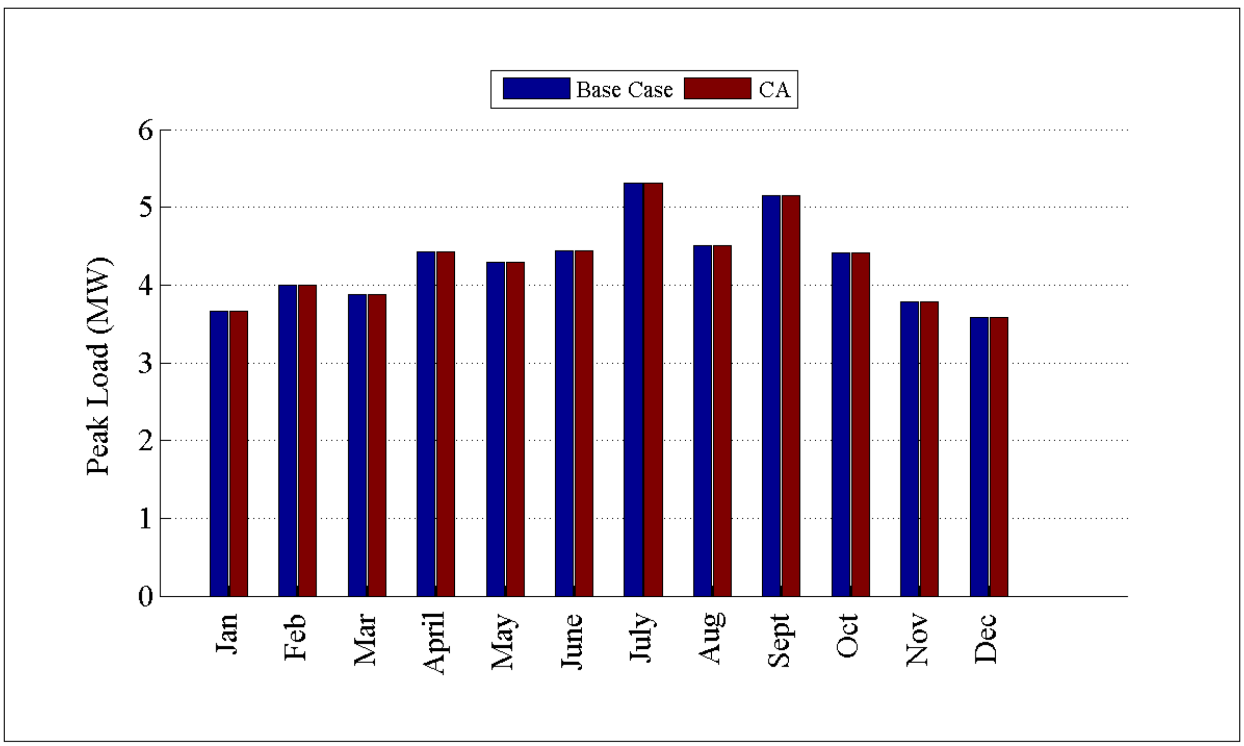



Figure 3.5: Comparison of peak load by month for GC-12.47-1_R1

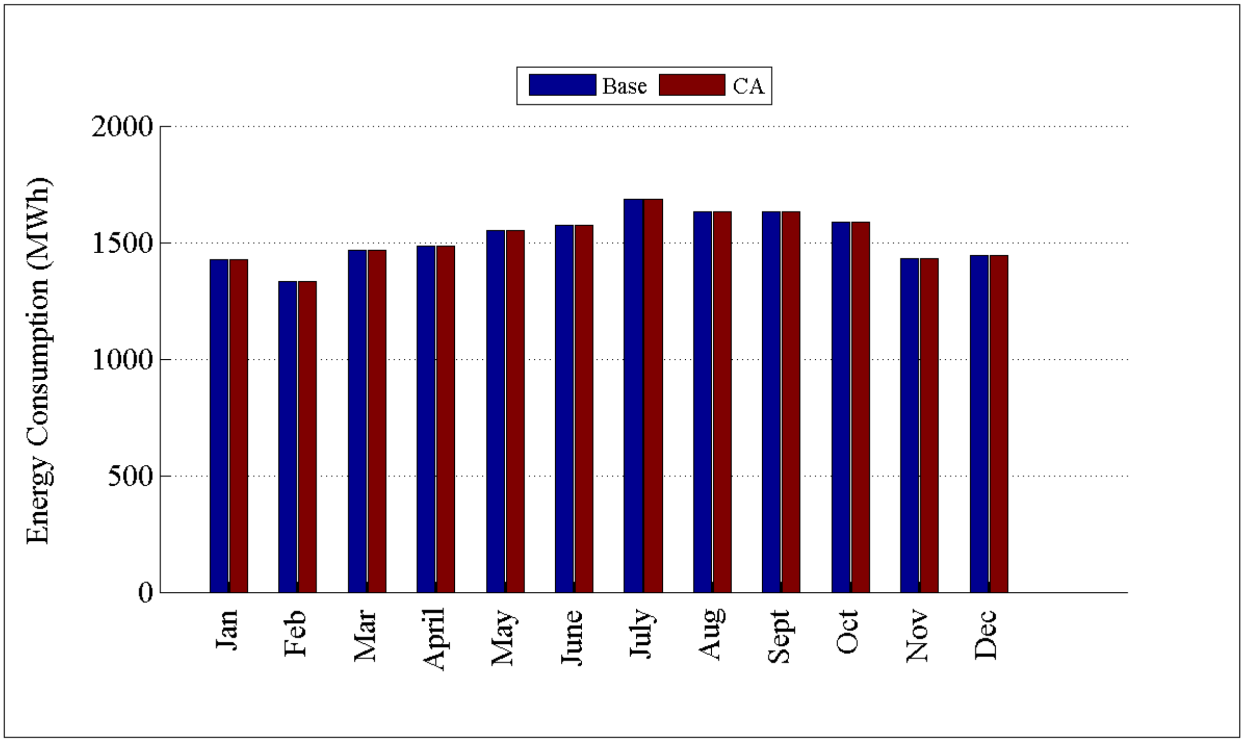



Figure 3.6: Comparison of energy consumption by month for GC-12.47-1_R1

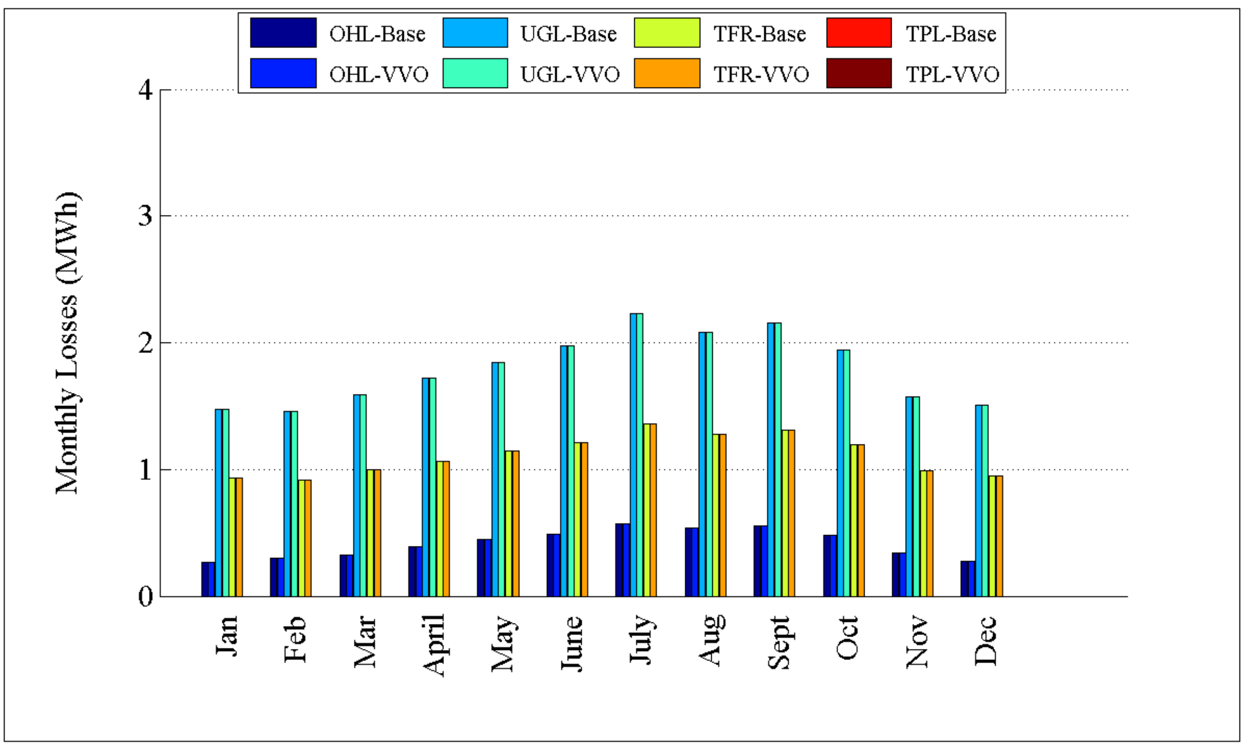



Figure 3.7: Comparison of losses by month for GC-12.47-1_R1

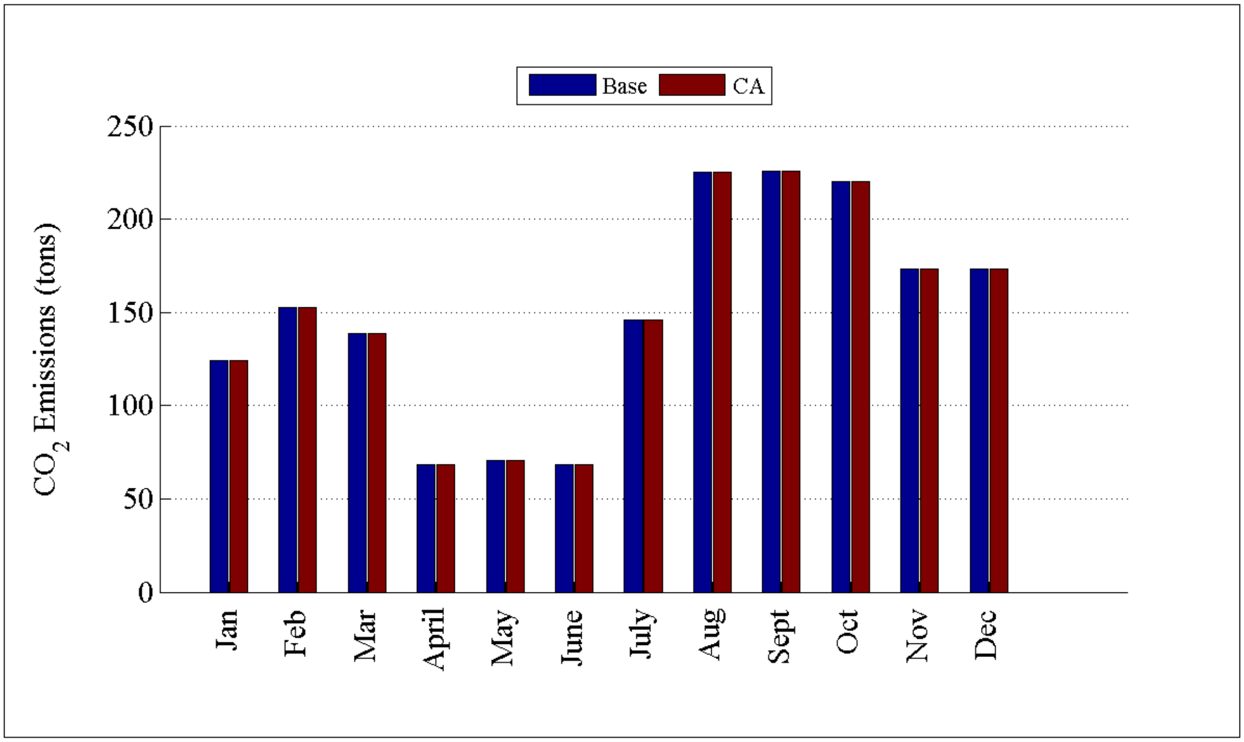



Figure 3.8: Comparison of CO2 emissions by month for GC-12.47-R1

## 3.3 Reclosers and Sectionalizers

Unlike VVO and CA, the IEEE 1366 statistics are annual values and do not have monthly values. As a result, there will be no monthly plots in Section 3 or Appendix D for R&S.

## 3.4 Distribution Management and Outage Management Systems

Unlike VVO and CA, the IEEE 1366 statistics are annual values and do not have monthly values. As a result, there will be no monthly plots in Section 3 or Appendix D for OMS&DMS.

## 3.5 Fault Detection Identification and Restoration

Unlike VVO and CA, the IEEE 1366 statistics are annual values and do not have monthly values. As a result, there will be no monthly plots in Section 3 or Appendix D for FDIR.

# 4 SGIG Impact Metric Values

Specific metric impact values are filled in for the metrics identified in Sections 2.1.1, 2.2.1, 2.3.1, 2.4.1, and 2.5.1, by feeder. The raw metric values, by technology and region are in Appendix E.

## 4.1 Conservation Voltage Reduction Impact Metrics

Table 4.1 through Table 4.5 gives the impact metrics for the prototypical feeders by climate region. The values given in Table 4.1 through Table 4.5 are differential values between the values in Table E.1 through Table E.5 and Table E.11 through Table E.15 and represent the impact of VVO on the prototypical feeders.

Table 4.1: VVO impact metrics for region 1

| Index | Δ Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | -83.20 | -74.59 | -25.89 | -17.45 | -66.21 | -31.28 |
| 2 | Monthly Customer Electricity Usage | MWh | -60.74 | -54.45 | -18.90 | -12.74 | -48.34 | -22.83 |
| 3 | Peak Generation | kW | -158.92 | -84.45 | -22.18 | -31.45 | -15.64 | -0.12 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.59 | -0.59 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | -0.04 |
| | Bio | % | 0.00 | 0.00 | 0.00 | 0.00 | -0.05 | 0.05 |
| | Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | -0.52 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 0.00 | -1.50 | 1.50 |
| | Hydroelectric | % | 0.00 | 0.00 | 0.00 | 0.00 | 10.56 | -10.56 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 0.00 | -9.86 | 9.86 |
| | Geothermal | % | -2.64 | -0.80 | -0.48 | -2.14 | -0.27 | 0.27 |
| | Petroleum | % | -0.35 | -0.35 | -0.35 | -0.35 | -0.33 | 3.23 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | -158.92 | -84.45 | -22.18 | -31.45 | -15.64 | -0.12 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | -728 | -697 | -243 | -153 | -576 | -279 |
| 12 | CO2 Emissions | Tons | -178.16 | -192.79 | -66.19 | -43.89 | -181.12 | -70.94 |
| 13 | SOx Emissions | Tons | -0.01 | -0.01 | 0.00 | 0.00 | -0.02 | 0.00 |
| | NOx Emissions | Tons | -0.01 | -0.02 | -0.01 | 0.00 | -0.02 | -0.01 |
| | PM-10 Emissions | Tons | -0.03 | -0.03 | -0.01 | -0.01 | -0.03 | -0.01 |
| 21 | Feeder Real Load | kW | -83.10 | -79.61 | -27.72 | -17.45 | -65.76 | -31.87 |
| | Feeder Reactive Load | kVAR | 0.60 | 327.47 | 243.64 | 0.05 | 0.24 | 105.02 |
| 29 | Distribution Losses | % | 0.01 | -0.11 | -0.10 | 0.02 | 0.07 | -0.02 |
| 30 | Distribution Power Factor | pf | -0.0001 | 0.0071 | 0.0311 | 0.0000 | 0.0000 | 0.0326 |
| 39 | CO2 Emissions | Tons | -178.34 | -200.26 | -69.06 | -44.05 | -182.26 | -72.09 |
| 40 | SOx Emissions | Tons | -0.01 | -0.01 | 0.00 | 0.00 | -0.02 | 0.00 |
| | NOx Emissions | Tons | -0.01 | -0.02 | -0.01 | 0.00 | -0.02 | -0.01 |
| | PM-10 Emissions | Tons | -0.03 | -0.03 | -0.01 | -0.01 | -0.03 | -0.01 |

Table 4.2: VVO impact metrics for region 2

| Index | Δ Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | -84.51 | -67.39 | -56.95 | -102.47 | -224.48 | -166.09 |
| 2 | Monthly Customer Electricity Usage | MWh | -61.69 | -49.20 | -41.57 | -74.80 | -163.87 | -121.25 |
| 3 | Peak Generation | kW | -14.65 | -101.36 | 115.28 | -7.58 | -15.10 | -424.90 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | -1.62 | 0.00 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.00 | 0.00 | -0.02 | 0.00 | 0.00 |
| | Wind | % | 0.00 | 0.00 | 0.00 | -0.29 | 0.00 | 0.00 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 1.64 | 0.00 | 0.00 |
| | Hydroelectric | % | 0.00 | -1.11 | 0.00 | -1.63 | 0.00 | -2.85 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 1.86 | 0.00 | 0.00 |
| | Geothermal | % | 0.00 | -0.07 | 0.00 | 0.00 | 0.00 | -0.07 |
| | Petroleum | % | -0.25 | -0.43 | 2.00 | 0.22 | -0.09 | -0.43 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | -14.65 | -101.36 | 115.28 | -7.58 | -15.10 | -424.90 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | -739 | -595 | -513 | -953 | -1,982 | -1,465 |
| 12 | CO2 Emissions | Tons | -539.25 | -424.83 | -440.16 | -810.17 | -1,634.49 | -1,009.83 |
| 13 | SOx Emissions | Tons | -0.23 | -0.18 | -0.19 | -0.36 | -0.71 | -0.42 |
| | NOx Emissions | Tons | -0.15 | -0.11 | -0.12 | -0.22 | -0.44 | -0.27 |
| | PM-10 Emissions | Tons | -0.08 | -0.06 | -0.07 | -0.12 | -0.24 | -0.15 |
| 21 | Feeder Real Load | kW | -84.38 | -67.88 | -58.57 | -108.75 | -226.30 | -167.22 |
| | Feeder Reactive Load | kVAR | 0.35 | -14.28 | -29.65 | 252.44 | -61.33 | 93.21 |
| 29 | Distribution Losses | % | 0.02 | 0.02 | -0.03 | -0.13 | 0.01 | 0.01 |
| 30 | Distribution Power Factor | pf | -0.0001 | 0.0002 | 0.0004 | 0.0013 | 0.0003 | -0.0018 |
| 39 | CO2 Emissions | Tons | -539.29 | -428.75 | -450.78 | -845.40 | -1,648.81 | -1,017.29 |
| 40 | SOx Emissions | Tons | -0.23 | -0.18 | -0.20 | -0.37 | -0.71 | -0.43 |
| | NOx Emissions | Tons | -0.15 | -0.11 | -0.12 | -0.23 | -0.44 | -0.27 |
| | PM-10 Emissions | Tons | -0.08 | -0.06 | -0.07 | -0.13 | -0.25 | -0.15 |

Table 4.3: VVO impact metrics for region 3

| Index | Δ Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | -84.96 | -86.81 | -47.06 | -70.19 |
| 2 | Monthly Customer Electricity Usage | MWh | -62.02 | -63.37 | -34.35 | -51.24 |
| 3 | Peak Generation | kW | -151.97 | -138.30 | -62.15 | 26.64 |
| | Nuclear | % | 1.07 | 0.00 | 0.00 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.02 | 0.00 | 0.00 | 0.00 |
| | Wind | % | 0.40 | 0.00 | 0.00 | 0.00 |
| | Coal | % | 1.28 | 0.00 | 0.00 | 0.00 |
| | Hydroelectric | % | 0.25 | 0.00 | 0.00 | 0.00 |
| | Natural Gas | % | -3.79 | 0.00 | 0.00 | 0.00 |
| | Geothermal | % | -1.25 | -1.23 | -1.16 | 0.00 |
| | Petroleum | % | -0.20 | -0.25 | -0.25 | 0.32 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | -151.97 | -138.30 | -62.15 | 26.64 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | -741 | -780 | -408 | -651 |
| 12 | CO2 Emissions | Tons | -569.19 | -591.81 | -304.69 | -444.15 |
| 13 | SOx Emissions | Tons | -0.20 | -0.21 | -0.10 | -0.14 |
| | NOx Emissions | Tons | -0.13 | -0.13 | -0.07 | -0.09 |
| | PM-10 Emissions | Tons | -0.08 | -0.09 | -0.05 | -0.07 |
| 21 | Feeder Real Load | kW | -84.60 | -89.05 | -46.53 | -74.33 |
| | Feeder Reactive Load | kVAR | 0.94 | -202.36 | 2.05 | -359.08 |
| 29 | Distribution Losses | % | 0.02 | -0.02 | 0.05 | -0.04 |
| 30 | Distribution Power Factor | pf | -0.0002 | 0.0020 | -0.0002 | 0.0077 |
| 39 | CO2 Emissions | Tons | -567.13 | -606.84 | -301.64 | -471.14 |
| 40 | SOx Emissions | Tons | -0.19 | -0.21 | -0.10 | -0.15 |
| | NOx Emissions | Tons | -0.13 | -0.14 | -0.06 | -0.10 |
| | PM-10 Emissions | Tons | -0.08 | -0.09 | -0.04 | -0.07 |

Table 4.4: VVO impact metrics for region 4

| Index | Δ Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | -82.48 | -54.49 | -23.28 | -8.61 |
| 2 | Monthly Customer Electricity Usage | MWh | -60.21 | -39.78 | -17.00 | -6.28 |
| 3 | Peak Generation | kW | -112.92 | -73.91 | 3.10 | 6.14 |
| | Nuclear | % | 0.00 | 1.67 | 0.00 | -1.67 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.03 | 0.00 | -0.03 |
| | Wind | % | 0.00 | -0.01 | 0.00 | 0.01 |
| | Coal | % | 0.00 | -1.08 | 0.00 | 1.08 |
| | Hydroelectric | % | -1.34 | 0.89 | 0.00 | -0.89 |
| | Natural Gas | % | 0.00 | -1.35 | 0.00 | 1.35 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | -0.48 | 2.61 | 0.14 | 0.83 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | -112.92 | -73.91 | 3.10 | 6.14 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | -720 | -568 | -218 | -81 |
| 12 | CO2 Emissions | Tons | -621.51 | -521.64 | -215.77 | -80.51 |
| 13 | SOx Emissions | Tons | -0.28 | -0.25 | -0.10 | -0.04 |
| | NOx Emissions | Tons | -0.17 | -0.15 | -0.06 | -0.02 |
| | PM-10 Emissions | Tons | -0.09 | -0.08 | -0.03 | -0.01 |
| 21 | Feeder Real Load | kW | -82.25 | -64.83 | -24.86 | -9.29 |
| | Feeder Reactive Load | kVAR | 1.18 | 460.03 | -2.56 | -1.15 |
| 29 | Distribution Losses | % | 0.02 | -0.45 | -0.12 | -0.13 |
| 30 | Distribution Power Factor | pf | -0.0001 | 0.0328 | 0.0000 | 0.0000 |
| 39 | CO2 Emissions | Tons | -621.27 | -580.63 | -225.70 | -84.70 |
| 40 | SOx Emissions | Tons | -0.28 | -0.27 | -0.11 | -0.04 |
| | NOx Emissions | Tons | -0.17 | -0.17 | -0.07 | -0.02 |
| | PM-10 Emissions | Tons | -0.09 | -0.09 | -0.03 | -0.01 |

Table 4.5: VVO impact metrics for region 5

| Index | Δ Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-55.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | -82.09 | -108.45 | -50.07 | -80.08 | -80.43 | -79.75 | -137.62 | -154.50 |
| 2 | Monthly Customer Electricity Usage | MWh | -59.93 | -79.17 | -36.55 | -58.46 | -58.72 | -58.22 | -100.47 | -112.79 |
| 3 | Peak Generation | kW | -130.68 | -215.66 | 1.90 | -73.30 | -120.08 | -90.76 | -104.40 | -239.90 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -0.32 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -0.02 | 0.00 |
| | Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.26 | 0.00 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.20 | 0.00 |
| | Hydroelectric | % | -0.38 | -0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.15 | -0.07 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -0.39 | 0.00 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | -1.86 | -1.86 | 0.04 | -0.71 | -1.59 | -1.00 | 1.18 | -1.86 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | -130.68 | -215.66 | 1.90 | -73.30 | -120.08 | -90.76 | -104.40 | -239.90 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | -716 | -956 | -437 | -727 | -720 | -714 | -1,221 | -1,379 |
| 12 | CO2 Emissions | Tons | -530.57 | -700.61 | -309.68 | -313.67 | -516.77 | -477.33 | -840.92 | -960.54 |
| 13 | SOx Emissions | Tons | -0.17 | -0.22 | -0.09 | -0.07 | -0.16 | -0.13 | -0.24 | -0.28 |
| | NOx Emissions | Tons | -0.11 | -0.15 | -0.06 | -0.05 | -0.11 | -0.09 | -0.16 | -0.19 |
| | PM-10 Emissions | Tons | -0.08 | -0.10 | -0.05 | -0.05 | -0.08 | -0.07 | -0.12 | -0.14 |
| 21 | Feeder Real Load | kW | -81.69 | -109.17 | -49.86 | -82.97 | -82.20 | -81.46 | -139.43 | -157.37 |
| | Feeder Reactive Load | kVAR | 1.79 | -311.66 | -153.31 | 448.42 | -258.54 | -428.15 | -477.46 | -110.84 |
| 29 | Distribution Losses | % | 0.03 | 0.01 | 0.05 | 0.02 | -0.01 | 0.00 | 0.00 | -0.02 |
| 30 | Distribution Power Factor | pf | -0.0002 | 0.0044 | 0.0027 | 0.0217 | 0.0041 | 0.0066 | 0.0044 | 0.0011 |
| 39 | CO2 Emissions | Tons | -530.09 | -707.06 | -312.00 | -325.53 | -527.54 | -488.11 | -852.35 | -975.82 |
| 40 | SOx Emissions | Tons | -0.17 | -0.22 | -0.09 | -0.08 | -0.16 | -0.13 | -0.24 | -0.28 |
| | NOx Emissions | Tons | -0.11 | -0.15 | -0.06 | -0.06 | -0.11 | -0.09 | -0.17 | -0.19 |
| | PM-10 Emissions | Tons | -0.08 | -0.10 | -0.05 | -0.05 | -0.08 | -0.07 | -0.13 | -0.14 |

## 4.2 Capacitor Automation Impact Metrics

Tables 4.6 through 4.10 give the impact metrics for the prototypical feeders by climate region. The values given in Tables 4.6 through 4.10 are differential values between the values in Tables E.1 through E.5 and E.16 through E.20 and represent the impact of CA on the prototypical feeders. As with the plots in the previous section, it is important to point out that CA provides benefits to the grid outside the SGIG metrics examined, hence many of the 0.00 impact terms. These benefits are discussed in Section 5.3.2 of the Observations and Conclusions.

Table 4.6: CA impact metrics for region 1

| Index | Δ Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 0.00 | 0.03 | 0.14 | 0.00 | 0.00 | -0.03 |
| 2 | Monthly Customer Electricity Usage | MWh | 0.00 | 0.02 | 0.10 | 0.00 | 0.00 | -0.02 |
| 3 | Peak Generation | kW | 0.00 | 0.00 | -9.13 | 0.00 | 0.00 | -27.16 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Hydroelectric | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -0.82 |
| | Petroleum | % | 0.00 | 0.00 | -0.34 | 0.00 | 0.00 | -0.35 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 0.00 | 0.00 | -9.13 | 0.00 | 0.00 | -27.16 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 0.00 | 0.23 | 2.16 | 0.00 | 0.00 | -0.26 |
| 12 | CO2 Emissions | Tons | 0.00 | 0.09 | 0.69 | 0.00 | 0.00 | -0.14 |
| 13 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 21 | Feeder Real Load | kW | 0.00 | 0.03 | 0.25 | 0.00 | 0.00 | -0.03 |
| | Feeder Reactive Load | kVAR | 0.00 | 0.00 | -76.49 | 0.00 | 0.00 | -0.01 |
| 29 | Distribution Losses | % | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 |
| 30 | Distribution Power Factor | pf | 0.0000 | 0.0000 | -0.0094 | 0.0000 | 0.0000 | 0.0000 |
| 39 | CO2 Emissions | Tons | 0.00 | 0.09 | 0.80 | 0.00 | 0.00 | -0.14 |
| 40 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.7: CA impact metrics for region 2

| Index | Δ Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | Monthly Customer Electricity Usage | MWh | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | Peak Generation | kW | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Hydroelectric | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 12 | CO2 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 13 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 21 | Feeder Real Load | kW | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Feeder Reactive Load | kVAR | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 29 | Distribution Losses | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 30 | Distribution Power Factor | pf | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 39 | CO2 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 40 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.8: CA impact metrics for region 3

| Index | Δ Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | Monthly Customer Electricity Usage | MWh | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | Peak Generation | kW | 0.00 | 0.00 | 0.00 | 0.00 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Hydroelectric | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 0.00 | 0.00 | 0.00 | 0.00 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 0.00 | 0.00 | 0.00 | 0.00 |
| 12 | CO2 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| 13 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| 21 | Feeder Real Load | kW | 0.00 | 0.00 | 0.00 | 0.00 |
| | Feeder Reactive Load | kVAR | 0.00 | 0.00 | 0.00 | 0.00 |
| 29 | Distribution Losses | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 30 | Distribution Power Factor | pf | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 39 | CO2 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| 40 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.9: CA impact metrics for region 4

| Index | Δ Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 0.00 | -0.03 | 0.00 | 0.00 |
| 2 | Monthly Customer Electricity Usage | MWh | 0.00 | -0.02 | 0.00 | 0.00 |
| 3 | Peak Generation | kW | 0.00 | 0.00 | 0.00 | 0.00 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Hydroelectric | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 0.00 | 0.00 | 0.00 | 0.00 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 0.00 | -0.30 | 0.00 | 0.00 |
| 12 | CO2 Emissions | Tons | 0.00 | -0.26 | 0.00 | 0.00 |
| 13 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| 21 | Feeder Real Load | kW | 0.00 | -0.03 | 0.00 | 0.00 |
| | Feeder Reactive Load | kVAR | 0.00 | 0.01 | 0.00 | 0.00 |
| 29 | Distribution Losses | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 30 | Distribution Power Factor | pf | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 39 | CO2 Emissions | Tons | 0.00 | -0.26 | 0.00 | 0.00 |
| 40 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.10: CA impact metrics for region 5

| Index | Δ Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 0.00 | 0.00 | 0.00 | 0.61 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | Monthly Customer Electricity Usage | MWh | 0.00 | 0.00 | 0.00 | 0.45 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | Peak Generation | kW | 0.00 | 0.00 | 0.00 | 44.40 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Nuclear | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Coal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Hydroelectric | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Natural Gas | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.00 | 0.00 | 0.00 | 0.43 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 0.00 | 0.00 | 0.00 | 44.40 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 0.00 | 0.00 | 0.00 | 5.86 | 0.00 | 0.00 | 0.00 | 0.00 |
| 12 | CO2 Emissions | Tons | 0.00 | 0.00 | 0.00 | 5.32 | 0.00 | 0.00 | 0.00 | 0.00 |
| 13 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 21 | Feeder Real Load | kW | 0.00 | 0.00 | 0.00 | 0.67 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Feeder Reactive Load | kVAR | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 |
| 29 | Distribution Losses | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 30 | Distribution Power Factor | pf | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 39 | CO2 Emissions | Tons | 0.00 | 0.00 | 0.00 | 5.65 | 0.00 | 0.00 | 0.00 | 0.00 |
| 40 | SOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | NOx Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | PM-10 Emissions | Tons | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## 4.3 Reclosers and Sectionalizers Impact Metrics

Table 4.11 through Table 4.15 gives the impact metrics for the prototypical feeders by climate region. The values given in Table E.11 through Table E.15 are differential values between the values in Table E.6 through Table E.10 and Table E.21 through Table E.25 and represent the impact of R&S on the prototypical feeders.

Table 4.11: R&S impact metrics for region 1

| Index | Δ Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.87 | -0.17 | 0.00 | 0.00 | -0.09 |
| 33 | SAIDI | Minutes | -19.46 | -54.11 | -53.68 | -8.46 | -29.00 | -5.64 |
| | CAIDI | Minutes | -15.00 | 44.72 | -39.15 | -7.21 | -25.00 | 1.40 |
| 34 | MAIFI | # | 1.95 | -1.00 | 12.23 | -1.21 | 8.95 | 0.68 |

Table 4.12: R&S impact metrics for region 2

| Index | Δ Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.75 | -0.70 | -0.90 | -0.28 | -0.18 |
| 33 | SAIDI | Minutes | -19.46 | -42.58 | -56.26 | -60.05 | -29.96 | -11.32 |
| | CAIDI | Minutes | -15.00 | 25.94 | 2.75 | 37.78 | -8.77 | 3.64 |
| 34 | MAIFI | # | 1.95 | -0.49 | -0.08 | -0.95 | 5.17 | 0.00 |

Table 4.13: R&S impact metrics for region 3

| Index | Δ Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.64 | 0.00 | -0.67 |
| 33 | SAIDI | Minutes | -19.46 | -34.93 | -17.49 | -39.98 |
| | CAIDI | Minutes | -15.00 | 26.67 | -15.00 | 30.52 |
| 34 | MAIFI | # | 1.95 | -1.27 | 1.52 | 0.90 |

Table 4.14: R&S impact metrics for region 4

| Index | Δ Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.11 | -0.45 | 0.00 |
| 33 | SAIDI | Minutes | -19.46 | -35.07 | -21.06 | -25.00 |
| | CAIDI | Minutes | -15.00 | -25.33 | 19.99 | -21.82 |
| 34 | MAIFI | # | 1.95 | 11.46 | -0.53 | 4.07 |

Table 4.15: R&S impact metrics for region 5

| Index | Δ Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.02 | -0.56 | -0.21 | 0.00 | -0.01 | -0.61 | 0.00 |
| 33 | SAIDI | Minutes | -19.46 | -29.30 | -31.38 | -16.70 | -29.59 | -1.77 | -33.05 | -1.73 |
| | CAIDI | Minutes | -15.00 | -24.23 | 19.91 | -0.11 | -25.00 | -0.86 | 29.54 | -1.46 |
| 34 | MAIFI | # | 1.95 | 6.21 | 0.26 | 1.01 | 5.75 | -0.74 | -1.00 | -0.03 |

## 4.4 Distribution Management and Outage Management Systems Impact Metrics

Table 4.16 through Table 4.20 gives the impact metrics for the prototypical feeders by climate region. The values given in Table 4.16 through Table 4.20 are differential values between the values in Table E.6 through Table E.10 and Table E.26 through Table E.30 and represent the impact of DMS&OMS on the prototypical feeders.

Table 4.16: DMS&OMS impact metrics for region 1

| Index | Δ Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 33 | SAIDI | Minutes | -13.62 | -13.59 | -7.02 | -13.35 | -11.64 | -15.59 |
| | CAIDI | Minutes | -10.50 | -11.62 | -5.96 | -11.38 | -10.03 | -13.38 |
| 34 | MAIFI | # | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.17: DMS&OMS impact metrics for region 2

| Index | Δ Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 33 | SAIDI | Minutes | -13.62 | -14.45 | -12.79 | -13.88 | -9.55 | -12.41 |
| | CAIDI | Minutes | -10.50 | -11.16 | -11.26 | -11.98 | -8.24 | -10.47 |
| 34 | MAIFI | # | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.18: DMS&OMS impact metrics for region 3

| Index | Δ Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | 0.00 | 0.00 | 0.00 |
| 33 | SAIDI | Minutes | -13.62 | -14.39 | -13.17 | -13.26 |
| | CAIDI | Minutes | -10.50 | -11.91 | -11.30 | -11.19 |
| 34 | MAIFI | # | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.19: DMS&OMS impact metrics for region 4

| Index | Δ Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | 0.00 | 0.00 | 0.00 |
| 33 | SAIDI | Minutes | -13.62 | -9.13 | -14.56 | -10.63 |
| | CAIDI | Minutes | -10.50 | -7.88 | -12.20 | -9.27 |
| 34 | MAIFI | # | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4.20: DMS&OMS impact metrics for region 5

| Index | Δ Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 33 | SAIDI | Minutes | -13.62 | -9.94 | -14.10 | -14.48 | -10.58 | -8.69 | -14.45 | -9.02 |
| | CAIDI | Minutes | -10.50 | -8.50 | -11.71 | -12.19 | -8.94 | -7.45 | -12.34 | -7.61 |
| 34 | MAIFI | # | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## 4.5 Fault Detection Identification and Restoration Impact Metrics

Table 4.21 through Table 4.25 gives the impact metrics for the prototypical feeders by climate region. The values given in Table 4.21 through Table 4.25 are differential values between the values in Table E.6 through Table E.10 and Table E.31 through Table E.35 and represent the impact of FDIR on the prototypical feeders.

Table 4.21: FDIR impact metrics for region 1

| Index | Δ Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.87 | -0.17 | 0.00 | 0.00 | -0.09 |
| 33 | SAIDI | Minutes | -50.27 | -65.12 | -67.86 | -29.92 | -55.92 | -28.68 |
| | CAIDI | Minutes | -38.75 | 7.66 | -53.29 | -25.51 | -48.21 | -20.06 |
| 34 | MAIFI | # | 1.95 | -2.00 | 12.23 | -2.95 | 8.95 | 0.68 |

Table 4.22: FDIR impact metrics for region 2

| Index | Δ Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.75 | -0.70 | -0.90 | -0.28 | -0.18 |
| 33 | SAIDI | Minutes | -50.27 | -62.91 | -62.11 | -69.14 | -51.94 | -35.56 |
| | CAIDI | Minutes | -38.75 | -11.19 | -10.65 | 3.10 | -33.81 | -20.41 |
| 34 | MAIFI | # | 1.95 | -0.49 | -0.08 | -0.95 | 5.17 | 0.00 |

Table 4.23: FDIR impact metrics for region 3

| Index | Δ Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.64 | 0.00 | -0.67 |
| 33 | SAIDI | Minutes | -50.27 | -54.66 | -47.67 | -56.56 |
| | CAIDI | Minutes | -38.75 | -7.76 | -40.89 | -1.92 |
| 34 | MAIFI | # | 1.95 | -1.27 | 1.52 | 0.90 |

Table 4.24: FDIR impact metrics for region 4

| Index | Δ Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.11 | -0.45 | 0.00 |
| 33 | SAIDI | Minutes | -50.27 | -55.47 | -45.60 | -48.16 |
| | CAIDI | Minutes | -38.75 | -44.71 | -12.93 | -42.03 |
| 34 | MAIFI | # | 1.95 | 11.46 | -0.53 | 4.07 |

Table 4.25: FDIR impact metrics for region 5

| Index | Δ Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 0.00 | -0.02 | -0.56 | -0.21 | 0.00 | -0.01 | -0.61 | 0.00 |
| 33 | SAIDI | Minutes | -50.27 | -51.44 | -51.26 | -43.53 | -53.25 | -21.28 | -53.00 | -22.41 |
| | CAIDI | Minutes | -38.75 | -43.47 | -12.22 | -27.56 | -44.99 | -17.71 | -6.15 | -18.91 |
| 34 | MAIFI | # | 1.95 | 6.21 | 0.26 | 1.01 | 5.75 | -0.74 | -1.00 | -0.03 |

# 5 Conclusions and Observations

The majority of SGIG projects are implementing some form of distribution automation. The primary reasons for the deployment of these technologies are to increase system efficiency and system reliability. This section will present the conclusions and observations from the analysis of representative distribution automation technologies from the SGIG projects.

## 5.1 Distribution Automation Conclusions and Observations

During the simulation of distributed automation technologies the SGIG impact metrics were used, and other metrics of interest were identified. This section will provide some overall observations and conclusions, including some assumptions, from this analysis. A brief summary of this section will be presented in Section 5.2

Distribution automation technologies are utility centric technologies that increase the reliability and efficiency of a distribution system. Additionally, they provide secondary benefits to the higher level transmission system. VVO and CA are two DA technologies that directly address the efficiency of a distribution system. R&S, DMS&OMS, and FDIR are three DA technologies that directly address the reliability of a distribution system.

VVO is a technology designed to optimize the voltage profile of a distribution feeder and to reduce annual energy consumption. By deploying a relatively small amount of equipment a utility can reduce the annual energy consumption by 2% to 4%. While there are substantial reductions in energy consumption, the end-use customers receive the same quality of service; the system is just operated at a more efficient point. The VVO control algorithm provides some peak reduction, but the implemented method was not optimized for this purpose. Additionally, VVO systems on the distribution system could be coordinated to provide benefits to the higher voltage sub-transmission and transmission systems. This DA technology represents one of the most impactful technologies with respect to the required infrastructure improvements.

CA is a technology that is designed to address the operational issues associated with remote capacitors that are not monitored. Because of their potentially remote locations capacitors can be out of service for prolonged periods of time without the utility being aware of the condition. The primary benefits of CA are the improvement of the distribution feeder voltage and increased asset utilization. Improved voltage profiles allow utilities to defer, possibly indefinitely, capital upgrades at the distribution level. Increased asset utilization can also allow utility to defer capital upgrades. In both cases, a utility can provide the same number of customers with less equipment.

R&S is a technology that is designed to address faults at the distribution level, and to increase reliability. For distribution feeders that do not experience faults, or experience very few, this technology will provide limited benefit. But for feeders that experience numerous temporary faults, reliability can be increased significantly when using reclosers in place of traditional overcurrent fuses. When a distribution feeder experiences permanent faults, sectionalizers can be used in conjunction with reclosers so that the fault affects a smaller number of end-use customers. The combination of reclosers and sectionalizers provides for a robust fault tolerant system but can require significant additional equipment.

DMS&OMS is a set of technologies that represent the operational center of a distribution system. A complete DMS&OMS provides numerous benefits to a utility, many of which are outside the scope of this analysis. For the purposes of this study the ability of a DMS&OMS to increase system reliability has been examined. Because of the increased visibility of the distribution system it is possible for a utility to more quickly identify the location of a fault on the distribution system. While the system allows the utility to more quickly identify the occurrence of a fault, there is no capacity to isolate the fault; only the time to locate the fault is reduced. As previously mentioned, a DMS&OMS gives a utility better visibility of their system allowing for the development of more effective operational and planning strategies. Additionally, DMS&OMS provide the infrastructure necessary to effectively integrate many of the other emerging technologies such as energy storage, electric vehicles, and demand response systems. So while DMS&OMS provides a direct benefit, it is also an enabling element for other technologies.

FDIR is a set of technologies that can take many forms. From automated switching programs to active fault locating system, when integrated with a DMS&OMS, FDIR can provide one of the most complete solutions to increasing reliability. Similar to R&S, FDIR will provide limited specific benefit to feeders that have a high reliability. But, for feeders with poor reliability FDIR can provide significant benefits. Because of the complexity of FDIR systems, distribution feeders should be completely evaluated before the deployment of this technology.

The following section will provide a high level summary of observations and conclusion of this report. First, DA results as a whole will be summarized, and then the individual DA technologies results will be summarized.

## 5.2 Distribution Automation Observations and Conclusions Summary

The analysis presented in this report has shown that with a few exceptions, the benefits of the DA technologies deployed in the SGIG projects can be quantified and tracked using the SGIG metrics guidebook [2]. From the analysis conducted, and the metrics tracked, the following conclusions and observations can be made about DA technologies:

1) DA technologies are a utility centric approach to addressing operational issues; the end-use customer is not actively engaged.

2) DA technologies can effectively address reliability and efficiency.

3) DA technologies should be deployed as part of a well-structured planning process, not all technologies are appropriate for all feeders.

4) In this report DA technologies were deployed at the distribution level, but they will have impacts at the transmission level as well.

## 5.3 Observations and Conclusions Summary for Specific Technologies

The following subsections will give observations and concluding comments for the five technology classes within the DA area.

### 5.3.1 Observations and Conclusions Summary for VVO

From the analysis of VVO, the following conclusions and observations can be made:

1) The primary benefit of the implemented VVO is reduced annual energy consumption. Annual energy reduction on the order of 2% to 4% can be achieved on a per feeder basis.

2) Peak load in general can be reduced, but sometimes will increase due to interactions with the end-use load; the implemented VVO was designed for energy reduction and not peak load reduction.

3) Reductions in losses are small in comparison to the reduction in end-use loads.

4) Corresponding reductions in $CO_2$ emissions can be achieved that are on the order of 5% to 10%.

5) The implemented VVO system was a 10-year-old openly published method, newer more advanced commercially available products would be expected to be more effective.

### 5.3.2 Observations and Conclusions Summary for CA

From the analysis of CA, the following conclusions and observations can be made:

1) The primary benefit of the implemented CA is the improvement of the distribution feeder voltage profile. An improved voltage profile allows for a utility to place additional load on a system thereby increasing the asset utilization. To properly evaluate this benefit it would be necessary to examine operations over a 10-20 year time frame to capture load growth. This type of analysis was outside the scope of this report.

2) No significant changes were observed in peak load reduction, annual energy consumption, distribution system losses, or $CO_2$ emissions. This was due to the small differential change in capacitor operations.

3) CA provides a utility with numerous benefits that are either not directly tracked though the SGIG smart grid metrics or were outside the scope of this analysis. If these metrics are included then CA provides numerous benefits that make it a viable technology to deploy. Potential metrics are:

    a. Deferred transmission capacity investment: This is a SGIG smart grid metric but a full analysis would require financial analysis of a specific utility and their long term planning strategy.

    b. Deferred distribution capacity investment: This is a SGIG smart grid metric but a full analysis would require financial analysis of a specific utility and their long term planning strategy. The value of improved voltage profiles would be shown in this metric.

    c. Power quality: Shunt capacitors have a natural tendency to shunt higher frequencies to ground, improving the power quality of the system. While this is not their primary intent this benefit does exist and could help to mitigate the effect of end-use loads or distributed resources that introduce non fundamental frequencies onto the distribution system.

### 5.3.3 Observations and Conclusions Summary for R&S

From the analysis of R&S the following conclusions and observations can be made:

1) The primary benefit of the implemented R&S is increasing reliability; it does not affect the peak load or annual energy consumption except by the isolation of system faults.

2) R&S has the potential to significantly improve the reliability of a distribution feeder, SAIDI reductions of 10% to 40%.

3) The prototypical distribution feeders used fault values to generate typical IEEE-1366 statistics. If R&S is deployed on a feeder that is well outside the normal values, i.e. $4^{th}$ quintile, then the R&S benefits will be significantly higher. As a result, this report may under estimate the benefits of R&S for a large number of feeders.

4) Reclosers are effective at addressing momentary faults, MAIFI, and sectionalizers are effective at addressing sustained faults, SAIDI and SAIFI.

5) A coordinated system of reclosers and sectionalizers can significantly improve SAIFI, SAIDI, CAIDI, and MAIFI.

6) For systems with high reliability the inclusions of R&S is unnecessary.

### 5.3.4 Observations and Conclusions Summary for DMS&OMS

From the analysis of DMS&OMS the following conclusions and observations can be made:

1) The primary benefit of the implemented DMS&OMS is increasing reliability; it does not affect the peak load or annual energy consumption except by the isolation of system faults.

2) DMS&OMS decreases SAIDI and CAIFI by allowing for a quicker and more accurate identification and location of faults. This reduces SAIDI and CAIFI by approximately 20%.

3) DMS&OMS is not able to affect SAIFI and MAIFI because there are no devices to actively prevent faults.

4) The prototypical distribution feeders used fault values to generate typical IEEE-1366 statistics. If DMS&OMS is deployed on a system where the majority of feeders have values that are well outside the normal values, i.e. 4$^{th}$ quintile, then the DMS&OMS benefits will be significantly higher. As a result, this report may under estimate the benefits of R&S for certain systems.

5) DMS&OMS provides a utility with numerous benefits that are either not directly tracked though the SGIG smart grid metrics or were outside the scope of this analysis. If these metrics are included then CA provides numerous benefits that make it a viable technology to deploy. Potential metrics are:

    a. Deferred distribution capacity investment: This is a SGIG smart grid metric but a full analysis would require financial analysis of a specific utility and their long term planning strategy. DMS&OMS provides a more effective operational picture for a utility allowing them to better plan and schedule critical events.

    b. Improved integration of future technologies: Because of the improved operational picture a DMS&OMS will allow a utility to better integrate emerging technologies such as distributed generation, electric vehicles, and demand response programs.

### 5.3.5 Observations and Conclusions Summary for FDIR

From the analysis of FDIR the following conclusions and observations can be made:

1) The primary benefit of the implemented FDIR is increasing reliability; it does not affect the peak load or annual energy consumption except by the isolation of system faults.

2) When coordinated with reclosers, sectionalizers, and the DMS&OMS, the FDIR system is one of the most effective ways to increase the reliability of a distribution feeder.

3) All relevant IEEE-1366 reliability metrics can be significantly improved with a coordinated FDIR system.

4) The prototypical distribution feeders used fault values to generate typical IEEE-1366 statistics. If FDIR is deployed on a feeder that is well outside the normal values, i.e. $4^{th}$ quintile, then the FDIR benefits will be significantly higher. As a result, this report may under estimate the benefits of R&S for a large number of feeders.

5) Because of the significant amount of equipment that must be deployed, a fully coordinated FDIR system is only necessary on systems with low reliability.

# Appendix A: SGIG Program Impact Metrics

An important component of the SGIG projects is the transfer of information from the individual projects to the broader industry audience. The aim of this transfer is to allow individuals, research organizations and utilities to better understand the performance of the various technologies deployed on the various projects. Due to the large amount of potential data, it is not feasible for each grant recipient to provide all of the available raw data. To address the issue of data collection, the "Guidebook for ARRA Smart Grid Program Metrics and Benefits" [2] was developed as a starting point for the discussion of data collection and impact categories. Specifically, the document contained a table of impact metrics against which each project could be evaluated; it is these metrics that are used in the 4 technical reports in this series to evaluate the impact of the various technologies. Table A.1 is a complete list of all 74 metrics listed in the Guidebook and is included in this appendix as a reference. Not every metric is used for each technology, only those that are relevant to the specific technology are examined in Section 2.

Table A.1: SGIG program impact metrics from guidebook

| # | Metric | Project Value | System Value | Remarks |
|---|---|---|---|---|
| A 2.1 IMPACT METRICS: AMI and Customer Systems | | | | |
| Metrics Related Primarily to Economic Benefits | | | | |
| 1 | Hourly Customer Electricity Usage | kWh<br>$/kWh | Not Applicable | Hourly electricity consumption information (kWh) and applicable retail tariff rate. Nature of this data will be negotiated with DOE |
| 2 | Monthly Customer Electricity Usage | MWh<br>$/kWh | Not Applicable | Monthly electricity consumption information (kWh) and applicable retail tariff rate. The nature of this data will be negotiated with DOE |
| 3 | Peak Generation and Mix | MW<br>Mix | MW<br>Mix | Specify intermittent generation by type and amount |
| 4 | Peak Load and Mix | MW<br>Mix | MW<br>Mix | Specify controllable load by type |
| 5 | Annual Generation Cost | $ | $ | Total cost of generation to serve load |
| 6 | Hourly Generation Cost | $/MWh | $/MWh | Aggregate or market price of energy in each hour |
| 7 | Annual Electricity Production | MWh | MWh | Total electricity produced by central generation |
| 8 | Ancillary Services Cost | $ | $ | Total cost of Ancillary services |
| 9 | Meter Operations Cost | $ | Not Applicable | Includes operations, maintenance, reading and data management |
| 10 | Truck Rolls Avoided | # | Not Applicable | Could include trips for meter reading, connection/disconnection, inspection and maintenance |

| # | Metric | Project Value | System Value | Remarks |
|---|---|---|---|---|
| Metrics Related Primarily to Environmental Benefits | | | | |
| 11 | Meter Operations Vehicle Miles | Miles | Not Applicable | Total miles accumulated related to meter operations |
| 12 | $CO_2$ Emissions | Tons | Tons | Could be modeled or estimated |
| 13 | Pollutant Emissions ($SO_x$, $NO_x$, PM-10) | Tons | Tons | Could be modeled or estimated |
| Metrics Related Primarily to AMI System Performance | | | | |
| 14 | Meter Data Completeness | % | Not Applicable | Portion of meters that are online and successfully reporting in |
| 15 | Meters Reported Daily by 2AM | % | Not Applicable | Portion of meter reads received by 2AM the following day |
| A 2.2 Impact Metrics: Electric Distribution Systems | | | | |
| Metrics Related to Economic Benefits | | | | |
| 16 | Hourly Customer Electricity Usage* | kWh $/kWh | Not Applicable | Hourly electricity consumption information (kWh) and applicable retail tariff rate. |
| 17 | Annual Storage Dispatch* | KWh | Not Applicable | Total number of hours that storage is dispatched for retail load shifting |
| 18 | Average Energy Storage Efficiency* | % | Not Applicable | Efficiency of energy storage devices installed |
| 19 | Monthly Demand Charges* | $/kW-month | Not Applicable | Average commercial or industrial demand charges |
| 20 | Distribution Feeder or Equipment Overload Incidents | # | Not Applicable | The total time during the reporting period that feeder or equipment loads exceeded design ratings |
| 21 | Distribution Feeder Load | MW MVAR | Not Applicable | Real and reactive power readings for those feeders involved in the project. Information should be based on hourly loads |
| 22 | Deferred Distribution Capacity Investments | $ | Not Applicable | The value of the capital project(s) deferred, and the time of the deferral |
| 23 | Equipment Failure Incidents | # | Not Applicable | Incidents of equipment failure within the project scope, including reason for failure |
| 24 | Distribution Equipment Maintenance Cost | $ | Not Applicable | Activity based cost for distribution equipment maintenance during the reporting period |
| 25 | Distribution Operations Cost | $ | Not Applicable | Activity based cost for distribution operations during the reporting period |
| 26 | Distribution Feeder Switching Operations | # | Not Applicable | Activity based cost for feeders switching operations during the reporting period |
| 27 | Distribution Capacitor Switching Cost | $ | Not Applicable | Activity based cost for capacitor switching operations during the reporting period |
| 28 | Distribution Restoration Cost | $ | Not Applicable | Total cost for distribution restoration during the reporting period |
| 29 | Distribution Losses | % | Not Applicable | Losses for the portion of the distribution system involved in the project. Modeled or calculated. |

| # | Metric | Project Value | System Value | Remarks |
|---|---|---|---|---|
| 30 | Distribution Power Factor | pf | Not Applicable | Power factor for the portion of the distribution system involved in the project. Modeled or calculated. |
| 31 | Truck Rolls Avoided | # | Not Applicable | Estimate of the number of times a crew would have been dispatched to perform a distribution operations or maintenance function |
| Metrics Related Primarily to Reliability Benefits | | | | |
| 32 | SAIF | Index | Not Applicable | As defined in IEEE Std 1366-2003, and do not include major events days. Only events involving infrastructure that is part of the project should be included. |
| 33 | SAIDI/CAIDI | Index | Not Applicable | |
| 34 | MAIFI | Index | Not Applicable | |
| 35 | Outrage Response Time | Minutes | Not Applicable | Time between outage occurrence and action initiated |
| 36 | Major Event Information | Event Statistics | Not Applicable | Information should including, but not limited to project infrastructure involved (transmission lines, substations and feeders), cause of the event , number of customers affected, total time for restoration, and restoration costs. |
| 37 | Number of High Impedance Faults Cleared | # | Not Applicable | Faults cleared that could be designed as high impedance or slow clearing |
| Metrics Related Primarily to Environmental Benefits | | | | |
| 38 | Distribution Operations Vehicle Miles | Miles | Not Applicable | Total miles for distribution operations and maintenance during the reporting period |
| 39 | CO2 Emissions | Tons | Tons | Could be modeled or estimated |
| 40 | Pollutant Emissions (SOx, NOx, PM-10) | Tons | Tons | Could be modeled or estimated |
| A 2.3 Impact Metrics: Electric Transmission Systems | | | | |
| Metrics Related Primarily to Economic Benefits | | | | |
| 41 | Annual Storage Dispatch* | MWh | MWh | Total number of hours that storage is dispatched for wholesale energy markets or Ancillary services |
| 42 | Capacity Market Value* | $/MW | $/MW | Capacity value |
| 43 | Ancillary Services Prices* | $/MWh | $/MWh | Ancillary service price during hours when Storage was dispatched |
| 44 | Annual Generation Cost | Not Applicable | $ | Total cost generation to serve load |

| # | Metric | Project Value | System Value | Remarks |
|---|---|---|---|---|
| 45 | Hourly Generation Cost | Not Applicable | $/MWh | Aggregate or market price of energy in each hour |
| 46 | Peak Generation and Mix | Not Applicable | MW Mix | Specify intermittent generation by type and amount |
| 47 | Peak Load and Mix | Not Applicable | MW Mix | Specify controllable load by type |
| 48 | Annual Generation Dispatch | Not Applicable | MW Mix | Total electricity produced by central generation |
| 49 | Ancillary Services Cost | Not Applicable | $ | Total cost of Ancillary services |
| 50 | Congestion Cost | MW | Not Applicable | Total transmission congestion cost during the reporting period |
| 51 | Transmission Line or Equipment Overload Incidents | # | Not Applicable | The total time during the reporting period that line loads exceeded design ratings |
| 52 | Transmission Line Load | MW MVAR | Not Applicable | Real and reactive power readings for those lines involved in the project. Information should be based on hourly loads |
| 53 | Deferred Transmission Capacity Investments | $ | Not Applicable | The value of the capital project(s) deferred, and the time of the deferral |
| 54 | Equipment Failure Incidents | # | Not Applicable | Incidents of equipment failure within the project scope, including reason for failure |
| 55 | Transmission Equipment Maintenance Cost | $ | Not Applicable | Activity based cost for transmission equipment maintenance during the reporting period |
| 56 | Transmission Operations Cost | $ | Not Applicable | Activity based cost for transmission operations during the reporting period |
| 57 | Transmission Restoration Cost | $ | Not Applicable | Total cost for transmission restoration during the reporting period |
| 58 | Transmission Losses | % | Not Applicable | Losses for the portion of the transmission system involved in the project. Could be modeled or calculated. |
| 59 | Transmission Power Factor | pf | Not Applicable | Power factor for the portion of the transmission system involved in the project. Could be modeled or calculated. |
| Metrics Related Primarily to Transmission Reliability | | | | |
| 60 | BPS Transmission Related Events Resulting in Loss of Load (NERC ALR 1-4) | # | Not Applicable | BPS Transmission Related Events Resulting in Loss of Load (NERC ALR 1-4) |
| 61 | Energy Emergency Alert 3 (NERC ALR 6-2) | # | Not Applicable | Energy Emergency Alert 3 (NERC ALR-6-2) |
| Metrics Related Primarily to Environmental Benefits | | | | |

| # | Metric | Project Value | System Value | Remarks |
|---|---|---|---|---|
| 62 | Transmission Operations Vehicle Miles | Miles | Not Applicable | Total mileage for transmission operations and maintenance during the reporting period |
| 63 | CO2 Emissions | tons | tons | Could be modeled or estimated |
| 64 | Pollutant Emissions (SOx, NOx, PM-10) | tons | tons | Could be modeled or estimated |
| Metrics Related Primarily to Energy Security Benefits | | | | |
| 65 | Number, Type, and Size | Events Cause Load Lost | Not Applicable | Causes could include line trips, generator trips, or other large disturbances |
| 66 | Duration | Minutes/ Hours | Not Applicable | |
| 67 | PMU Dynamic Data | PMU Data | Not Applicable | From related PMU's |
| 68 | Detection | Application | Not Applicable | Application that detected the event |
| 69 | Events Prevented | # | Not Applicable | Include reason for prevention |
| Metrics related primarily to PMU/PDC System Performance | | | | |
| 70 | PMU Data Completeness | % | Not Applicable | Portion of PMU that are operational and successfully provided data |
| 71 | Network Completeness | % | Not Applicable | Portion of PMUs networked into regional PDCs |
| 72 | PMU/PDC Performance | Reliability Quality | Not Applicable | |
| 73 | Communications Performance | Availability | Not Applicable | |
| 74 | Application Performance | Description | Not Applicable | Usefulness of applications, including reliability improvements, markets and congestion management, operational efficiency |

The metrics shown in Table A.1 were developed for field demonstrations and were not originally intended for simulations. To address this issue, definitions of the metrics in Table A.1 as implemented in the analysis will be given. Because the simulations in this report only examine impacts at the distribution level, transmission level impact metrics will not be examined. Of the distribution metrics, many will not be used because they are associated with a monetary cost that would require information from a specific utility; for example, meter operation costs.

The metrics will be presented in two separate places in this report. Appendix E will contain the metric values for each technology on each feeder. These values are individual to a single technology.  Section 4.1, 4.2, 4.3, 4.4, and 4.5 will show the difference in metric values between the base case and the specific technology, for each feeder.

1) **Hourly customer electricity usage:** Instead of reporting a time series of values for an entire year this metric will report the average hourly end-use consumption.

2) **Monthly customer electricity usage:** Instead of reporting a time series of values for an entire year this metric will report the average monthly end-use consumption.

3) **Peak generation and mix:** This metric will report the peak generation as well as the percentages for generation composition.  This is the generation that is required to supply the demand as measured at the substation.  The generation composition will include the breakdown of central generation as well as distributed resources on the distribution system.

4) **Peak load and mix:** This is the maximum annual end-use demand as consumed by the end-use customers.  This is the load that the utilities meter and charge for.  The percent of load that is controllable will also be included.

5) **Annual generation cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

6) **Hourly generation cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

7) **Annual electricity production:** This metric reports the total energy that is required to supply the demand as measured at the substation

8) **Ancillary services cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

9) **Meter operations cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

10) **Truck rolls avoided:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

11) **Meter operations vehicle miles:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

12) **$CO_2$ emissions:** This metric measures the $CO_2$ emissions required to supply the electricity to the end-use load.

13) **Pollutant emissions:** This metric measures SOx, NOx, and PM-10 emissions required to supply the electricity to the end-use load.

14) **Meter data completeness:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

15) **Meter reported daily by 2 a.m.:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

16) **Hourly customer electricity usage:** For the purposes of this work, this metric is identical to metric 1, and will not be used.

17) **Annual storage dispatch:** This metric examines the total number of hours that energy storage is dispatched.

18) **Average energy storage efficiency:** This is the average round trip efficiency for all energy storage units on a feeder.

19) **Monthly demand charge:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

20) **Distribution feeder or equipment overloads incidents:** Because the taxonomy of prototypical feeders is used for analysis there are not overloads included. This is because the average distribution feeder does not normally have overload conditions. As a result, this metric will not be used.

21) **Distribution feeder load:** This metric gives the annual average hourly load as measured at the substation. Both real and reactive powers are examined.

22) **Deferred distribution capacity investment:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

23) **Equipment failure incidents:** Because the conducted analysis uses representative technologies, there is no information associated with equipment failure. The only failures are faults included for the analysis of FDIR. As a result this metric will not be used.

24) **Distribution equipment maintenance cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

25) **Distribution operations cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

26) **Distribution feeder switching operations:** Because this is dependent on the operational procedures and business structure of specific utilities, this metric will not be used in evaluating the simulation results.

27) **Distribution capacitor switching costs:** Because this is dependent on the operational procedures and business structure of specific utilities, this metric will not be used in evaluating the simulation results.

28) **Distribution restoration cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

29) **Distribution losses:** This metric measures the distribution losses; both series and shunt losses are included. Series losses due to overhead lines, underground lines, transformers, and triplex lines are included. Shunt losses due to underground lines and transformers are included. For the purposes of this metric all losses are combined into a single value but some plots will be provided that break the losses into the various components.

30) **Distribution power factor:** The distribution power factor is the power factor as calculated at the substation.

31) **Truck tolls avoided:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

32) **SAIFI:** As defined in IEEE standard 1366, SAIFI is the system average interruption frequency index. SAIFI indicated how often the average customer experiences a sustained interruption and is calculated by dividing the sum of the total number of customers interrupted by the total number of customers served.

33) **SAIDI/CAIDI:** As defined in IEEE standard 1366, SAIDI is the system average interruption duration index. SAIDI indicates the total duration of interruption for the average customers and is calculated by dividing the sum of the customer interruption durations by the total number of customers served. As defined in IEEE standard 1366 CAIDI is the customer average interruption duration index. CAIDI represents the average time required to restore service and is calculated by dividing the sum of the customer interruption durations by the total number of customers interrupted.

34) **MAIFI:** As defined in IEEE standard 1366, MAIFI is the momentary average interruption frequency index. MAIFI is the average frequency of momentary interruptions and is calculated by dividing the sum of the total number of customer momentary interruptions by the total number of customers served.

35) **Outage response time:** When a fault occurs on the system there are several important times. How long to identify the existence of a fault, how long to locate the fault, and how long to repair the fault. The outage response time is the time between the occurrence of the fault and the time to identify the existence of the fault.

36) **Major event information:** Major events generally impact a large geographic area which includes multiple distribution substations and the interconnecting transmission or sub-transmission system. Since this report is looking primarily at individual feeders this metric will not be used.

37) **Number of high impedance faults cleared:** This metric is based on the occurrence of high impedance faults in a specific system. The occurrence of faults is only handled in the fault detection identification and restoration technology; high impedance faults are not specifically examined.

38) **Distribution operations vehicle miles:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

39) **$CO_2$ emissions:** This metric measures the $CO_2$ emissions required to supply the demand as measured at the substations.

40) **Pollutant emissions:** This metric measures the SOx, NOx, and PM-10 emissions required to supply the demand as measured at the substations.

# Appendix B: Taxonomy of Prototypical Distribution Feeders

As part of the DOE-OE Modern Grid Initiative (MGI) efforts in 2008, a Taxonomy of Prototypical Distribution Feeders was developed [2]. The feeders within this taxonomy were designed to provide researchers with an openly available set of distribution feeder models which are representative of those seen in the continental United States. To construct these representative feeder models, actual feeder models were obtained from utilities across the country and their fundamental characteristics were examined. A detailed statistical analysis was conducted to determine the optimal subset of feeders that could effectively represent the entire data set. The development of the complete Taxonomy of feeders was an extensive process and is fully documented in the report titled "Modern Grid Initiative Distribution Taxonomy Final Report" [2].

Because climate and energy consumption are closely coupled, the prototypical feeders were divided into five climate regions, Figure B.1, based on the U.S DOE handbook (1980) providing design guidance for energy-efficient small office buildings [13].

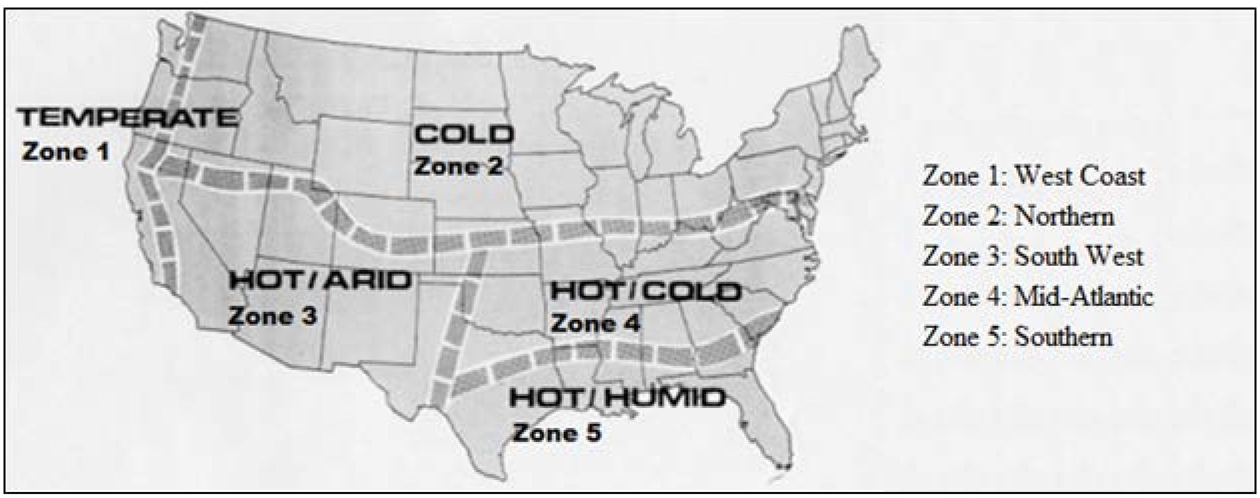



Figure B.1: Climate Zones Used for Development of Prototypical Feeders

Within each of the climate zones, there are a set of feeders that are approximations of the types of feeders that are seen within that zone. Table B.1 gives a summary of the 24 prototypical feeders, including feeder name, base voltage, peak load, and a qualitative description. The peak loading used for the SGIG project analysis is slightly different than the original values from the 2008 report. The difference in peak load is due to improved modeling methods used to represent the end-use load. These methods will be discussed in Section B.2.1 and B.2.2. Additional description of the prototypical feeders can found in Section B.4.

Table B.1: Summary of prototypical feeders

| Feeder | Base kV | Peak kVA | Description |
|---|---|---|---|
| R1-12.47-1 | 12.5 | 4,300 | Moderate suburban and rural |
| R1-12.47-2 | 12.47 | 2,400 | Moderate suburban and light rural |
| R1-12.47-3 | 12.47 | 1,800 | Small urban center |
| R1-12.47-4 | 12.47 | 4,900 | Heavy suburban |
| R1-25.00-1 | 24.9 | 2,300 | Light rural |
| R2-12.47-1 | 12.47 | 6,700 | Light urban |
| R2-12.47-2 | 12.47 | 6,700 | Moderate suburban |
| R2-12.47-3 | 12.47 | 4,800 | Light suburban |
| R2-25.00-1 | 24.9 | 21,300 | Moderate urban |
| R2-35.00-1 | 34.5 | 6,900 | Light rural |
| R3-12.47-1 | 12.47 | 11,600 | Heavy urban |
| R3-12.47-2 | 12.47 | 4,000 | Moderate urban |
| R3-12.47-3 | 12.47 | 9,400 | Heavy suburban |
| R4-12.47-1 | 13.8 | 6,700 | Heavy urban with rural spur |
| R4-12.47-2 | 12.5 | 2,100 | Light suburban and moderate urban |
| R4-25.00-1 | 24.9 | 1,000 | Light rural |
| R5-12.47-1 | 13.8 | 10,800 | Heavy suburban and moderate urban |
| R5-12.47-2 | 12.47 | 4,200 | Moderate suburban and heavy urban |
| R5-12.47-3 | 13.8 | 4,800 | Moderate rural |
| R5-12.47-4 | 12.47 | 6,200 | Moderate suburban and urban |
| R5-12.47-5 | 12.47 | 8,500 | Moderate suburban and light urban |
| R5-25.00-1 | 22.9 | 9,300 | Heavy suburban and moderate urban |
| R5-35.00-1 | 34.5 | 12,100 | Moderate suburban and light urban |
| GC-12.47-1 | 12.47 | 5,400 | Single large commercial or industrial |

The original prototypical feeders were modeled in detail from the substation to the end-use point of interconnection, but did not include detailed load models. To use these feeders for an accurate analytic assessment of the SGIG projects, it was necessary to model the end-use load in the appropriate level of detail as was done for the 2010 report on Conservation Voltage Reduction [14].

## B.1 End-use Load Models

The taxonomy of prototypical feeders accurately represents the electrical infrastructure of the distribution feeders, but not the end-use loads. Since it is the end-use loads that consume the majority of the energy on a distribution feeder, it is critical to accurately represent their operation.

For the taxonomy of feeders to be of use the end-use loads are classified into various categories. In 2010 an analysis of conservation voltage reduction was conducted in GridLAB-D that classified loads as shown in Table B.2 [14]. Because the analysis of the SGIG projects includes technologies other than conservation voltage reduction, a more complete handling of end-use load classifications is necessary and will be discussed in detail in section B.2. This is especially true of technologies such as demand response where the physical characteristics of the buildings are fundamental.

Table B.2: End-use load classifications

| Load Class | Description |
|---|---|
| Residential 1 | Pre-1980 <2000 sqft. |
| Residential 2 | Post-1980 <2000 sqft. |
| Residential 3 | Pre-1980 >2000 sqft. |
| Residential 4 | Post-1980 >2000 sqft. |
| Residential 5 | Mobile Homes |
| Residential 6 | Apartment Complex |
| Commercial 1 | >35 kVA |
| Commercial 2 | <35 kVA |
| Industrial | All Industrial |

Regardless of how end-use loads are classified, the component end-use loads are modeled as a combination of ZIP models and multi-state physical models. The ZIP load model and the multi-state model are described in the following sections.

## B.1.1 ZIP Loads

ZIP models are two state models, energized and de-energized. When energized there is only a single operational state and the energy consumption can be determined using (B1) for real power, (B2) for reactive power, and (B3) as a constraint [16].

$$P_i = \left[ \frac{|V_a^2|}{|V_n^2|} \cdot |S_n| \cdot Z_{\%} \cdot \cos(Z_\theta) + \frac{|V_a|}{|V_n|} \cdot |S_n| \cdot I_{\%} \cdot \cos(I_\theta) + |S_n| \cdot P_{\%} \cdot \cos(P_\theta) \right] \tag{B1}$$

$$Q_i = \left[ \frac{|V_a^2|}{|V_n^2|} \cdot |S_n| \cdot Z_{\%} \cdot \sin(Z_\theta) + \frac{|V_a|}{|V_n|} \cdot |S_n| \cdot I_{\%} \cdot \sin(I_\theta) + |S_n| \cdot P_{\%} \cdot \sin(P_\theta) \right] \tag{B2}$$

$$100 = Z_{\%} + I_{\%} + P_{\%} \tag{B3}$$

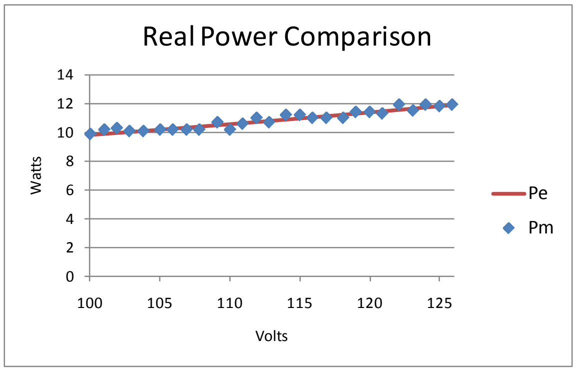
where:

$P_i$ : real power consumption of the i[th] load
$Q_i$: reactive power consumption of the i[th] load
$V_a$: actual terminal voltage
$Vn$: nominal terminal voltage
$S_n$: apparent Power consumption at nominal voltage
$Z_{\%}$: percent of load that is constant impedance
$I_{\%}$: percent of load that is constant current
$P_{\%}$: percent of load that is constant power
$Z_{\theta}$: phase angle of constant impedance component
$I_{\theta}$: phase angle of constant current component
$P_{\theta}$: phase angle of constant power component

In a time-variant load representation, the coefficients of the ZIP model, $V_{\mathrm{n}}$, $S_{\mathrm{n}}$, $Z_{\%}$, $I_{\%}$, $P_{\%}$, $Z_{\theta}$, $I_{\theta}$, and $P_{\theta}$, remain constant, but the power consumption, $P_i$ and $Q_i$, of the $i^{th}$ load varies with the actual terminal voltage, $V_a$. The ZIP model is similar to the polynomial representation used in many commercial software packages. In the polynomial representation of the ZIP load, the constant coefficient is equivalent to $P_{\%}$, the linear coefficient is equivalent to $I_{\%}$, and the quadratic coefficient is equivalent to $Z_{\%}$. The ZIP model only varies the power consumption as a function of actual terminal voltage, $V_a$.

In (B1) and (B2), there are six constants that define the voltage dependent behavior of the ZIP load: $Z_{\%}, I_{\%}, P_{\%}, Z_{\theta}, I_{\theta}$, and $P_{\theta}$. Because the actual value of the distribution feeder voltage continually changes, it is critical to understand how the energy consumption of end-use loads will vary. Specifically, what are the six constants that accurately reflect various end-use loads? For loads such as a heating element, it is clear that the load is 100% Z, but for more complicated loads such as a Liquid Crystal Display (LCD) or Compact Florescent Light (CFL), the proper ratios are not as apparent.

As part of the 2010 report on conservation voltage reduction a number of laboratory tests were conducted to determine the six constants for various end-use loads; these values have been incorporated into the end-use load models for this study. Figure B.2 is an example of the laboratory testing that was conducted on a 13W compact florescent light bulb.



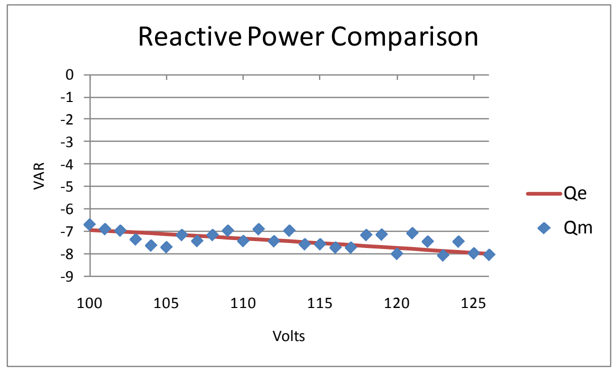




Figure B.2: Voltage dependent energy consumption of 13W CFL

| | ZIP Values | | | | | |
|---|---|---|---|---|---|---|
| | Z-% | I-% | P-% | Z-pf | I- pf | P-pf |
| CFL-13W | 40.85% | 0.67% | 58.49% | -0.88 | 0.42 | -0.78 |

In traditional distribution analysis ZIP models are generally not developed for every individual load, instead models are developed for load classes such as residential, commercial, and industrial. Every load within a given load class then uses the same ZIP values with the exception of the apparent power consumption at nominal voltage, $S_n$. The value of $S_n$ for each load may change at 1-hour intervals to generate a daily load profile at the feeder level. The use of similar ZIP values for each load class, which only change at 1-hour intervals, is not able to represent coincidental load peaks that occur at the distribution level.

## B.1.2 Single-State Detailed Physical Models

When the energy consumption of an end-use load is a function of variables other than terminal voltage, the use of a ZIP model is not adequate. This is true of any load with an external control system or an internal control loop. To illustrate this issue, the air conditioning system of a single family residence will be examined while in the cooling mode. As with the ZIP model, an air conditioning system is a two state model (ON or OFF), but only has a single operational state.

Because a cooling system operates to maintain internal air temperature within a band, parameters such as near term history of operation, time of year, outside air temperature, building construction, and terminal voltage will impact the instantaneous power consumption, as well as the energy consumption. To examine these issues, a physical model of the cooling system and the structure of the building, is constructed using an equivalent thermal parameter (ETP) model [16]. Because the ETP model has been shown to be an accurate representation of residential and small commercial building instantaneous power draw, as well as energy consumption, it will be used for the formulation of the physical model.

Figure B.3 is a diagram showing the heat flow for the ETP model of a single family residence, i.e., a house. While the heating/cooling system can be one of any numerous types, for the purposes of this paper, it is assumed that the system is a heat pump in the cooling mode. In addition to the heat removal of the heat pump while cooling and the heat gain through the building exterior, there are two additional significant flows of heat within a house: incident solar radiation and internal gains from waste heat generated by end-use loads. These sources and sinks of heat constitute the total heat energy exchange in the house. This flow of heat is then divided between the air in the house and the mass of the house, i.e., walls and furniture. A portion of the incident solar energy shining through a window will heat the interior air of the house, while the remaining incident energy will be absorbed by the walls, floors, and furniture. The same division occurs with the waste heat from end-use loads. The internal air temperature of the house is thermally coupled to the internal mass temperature, and the internal air temperature is then thermally coupled to the outside air temperature through the thermal envelope of the house.

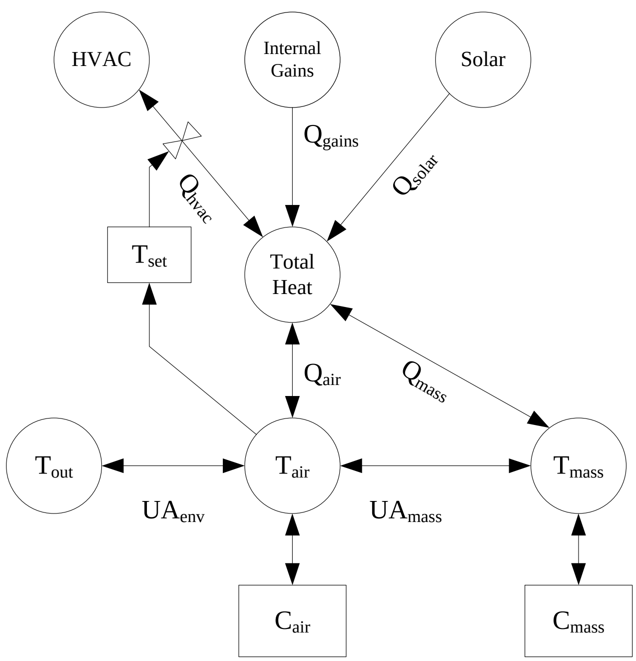


Figure B.3: The ETP mode of a residential heating/cooling system

where,

| | |
|---|---|
| $C_{air}$: | air heat capacity (Btu/°F) |
| $C_{mass}$: | mass heat capacity (Btu/°F) |
| $UA_{env}$: | external gain/heat loss coefficient (Btu/°F-h) |
| $UA_{mass}$: | internal gain/heat loss coefficient (Btu/°F-h) |
| $T_{out}$: | air temperature outside the house (°F) |

| | |
|---|---|
| $T_{air}$: | air temperature inside the house (°F) |
| $T_{mass}$: | mass temperature inside the house (°F) |
| $T_{set}$: | temperature set points of HVAC system (°F) |
| $Q_{air}$: | heat rate to house air (Btu/h) |
| $Q_{gains}$: | heat rate from appliance waste heat (Btu/h), |
| $Q_{hvac}$: | heat rate from HVAC system (Btu/h), |
| $Q_{mass}$: | heat rate to house mass (Btu/h), and |
| $Q_{solar}$: | heat rate from solar gains (Btu/h). |

Equation (B4) is the second order differential equation that describes the heat flows shown in Figure B.3 [16]. Its solution determines the time-varying temperature of the house, both air and mass, given the thermal inputs. With the inside air temperature, $T_{air}$, known, the thermal behavior of the heat pump system in response to the defined thermostatic set point, $T_{set}$, can be determined.

$$a\frac{d^2T_{air}}{dt^2} + b\frac{dT_{air}}{dt} + cT_{air} = d \tag{B4}$$

Where,

$$a = \frac{C_{mass} \cdot C_{air}}{UA_{mass}}$$

$$b = \frac{C_{mass} \cdot (UA_{env} + UA_{mass})}{UA_{mass}} + C_{air}$$

$$c = UA_{env}$$

$$d = Q_{mass} + Q_{air} + (UA_{env} \cdot T_{out})$$

With the temperature of the house known from (B4) and the occupant-controlled set point fixed, the operation of the cooling system can be determined. Based on these values, the cooling system will operate long enough to remove the heat necessary to maintain the inside air temperature, $T_{air}$, within the desired range. The electrical input energy to the motor, $S_{comp\text{-}motor}$, necessary to provide the thermal heat energy, is a function of two elements: the heat flow through the cooling unit, $Q_{hvac}$, and the electrical losses of the compressor motor, $S_{losses}$; as shown in (B5) [15]–[16].

$$S_{comp-motor} = \left[Q_{hvac}\left(T_{out}, V_T, COP\right) + S_{losses}\left(V_T\right)\right] \quad \text{(B5)}$$

The coefficient of performance (*COP*) is a scalar value that relates the cooling rate of the heat pump unit to the mechanical power delivered by the compressor as a function of temperature and operation time. A higher value of COP indicates less electrical power is necessary to remove a given amount of heat from the air. $V_T$ is the terminal voltage of the system compressor motor. Additionally, it should be noted that $Q_{hvac}$ is expressed in terms of British thermal units (Btu) consistent with the conventions of the heating/cooling industry in the United States and the derivation of the ETP model of [16], while $S_{losses}$ is expressed in SI units. As a result, the two terms of (B5) must be converted using the conversion of 1.0 Btu/h = 0.2931 W.

Because both of the elements of (B5) are voltage dependent, changes in line voltage will cause a change in power consumption. The cooling system's heat removal rate, $Q_{hvac}$, can be solved using heat transfer equations based on the available mechanical torque of the compressor [16]. The motor losses, $S_{losses}$, can be determined using the traditional split phase motor model of [15] and [16]. When (B5) is implemented in a time-series simulation, the result is a model that determines the energy consumption, both real and reactive, of the cooling system as a function of the outside air temperature, the inside air temperature, equipment parameters, terminal voltage, and occupant-controlled set point.

Unlike ZIP models that apply the same values to each load in a given load class, physical models are specific to each individual load. The values of physical models vary on a 1 second or 1 minute basis to capture the true time-variant nature of the end-use load.

The previous example of a physical model has examined a heat pump in the cooling mode, which is one of multiple operational states. Because of the design of heat pumps, their energy consumption varies according to their current operational state. To properly capture the energy consumption it is necessary to construct a multi-state load model.

### B.1.3 Multi-State Detailed Physical Models

A multi-state time-variant load model uses more than one state to describe the energy consumption of an end-use load. Each state is governed either by a ZIP model and/or a physical model, with transitions between states determined by either internal state transition rules or external signals. For example, a typical heat pump has four normal operating states: State 1 (*off*), State 2 (*cooling*), State 3 (*heating-normal*), and State 4 (*heating-emergency*). State 2 operates as described in the previous section, and State 3 follows a similar description but with different values that represent the change in the heating cycle, i.e., heat is added instead of removed. State 4 operates as State 3, except that the COP is 1.0 and the load is a ZIP model. There are other abnormal states such as “stalled compressor motor” or "low refrigerant charge", but they will not be examined in this paper. Additionally, there are numerous heat pump types and many differing thermostatic controllers that are commercially available, but this paper will discuss a "typical" design. Because a heat pump has two heat-flow configurations, the value of $T_{set}$ must be split into a heating set point, $T_{low}$, and a cooling set point, $T_{high}$. These set points determine the mode of operation of the heat pump system at any given time: *off*, *cooling*, *heating-normal*, or *heating-emergency*, as shown in Figure B.4.

For a simple single state simulation, the heat pump system would be operating to either heat or cool the house, as discussed in the previous section. For a time-series simulation, the multi-state model captures the transitions between states. While a heat pump system may not transition through all operational states in a single day, it is likely that it will transition through more than one state in any given day. For example, on a mild autumn night, the heat pump may operate to heat the house, then as the sun heats the house during the day, it may be necessary to switch to cooling.

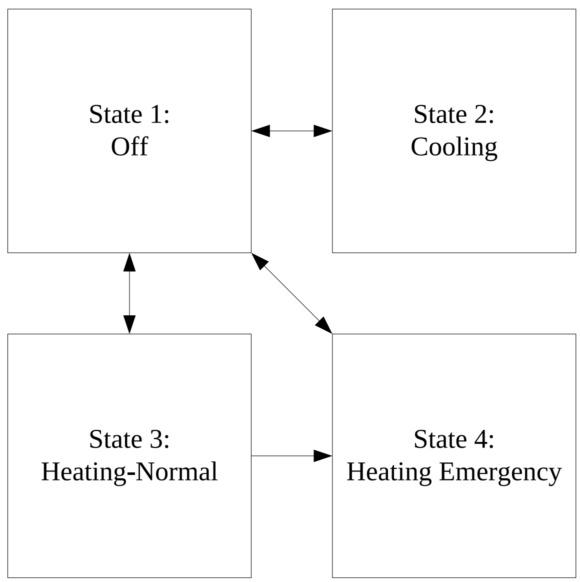



Figure B.4: Multi-state load model

To be in States 2, 3, or 4, the heat pump unit must be turned "on" with defined set points, both occupant-controlled and internal. The occupant-controlled set points are $T_{high}$ and $T_{low}$. If the internal air temperature $T_{air}$ rises above $T_{high}$ plus a dead band, $DB_{high}$, then the heat pump will start cooling. If $T_{air}$ decreases below $T_{low}$ minus a dead band, $DB_{low}$ then the heat pump will start heating normally. If $T_{out}$ decreases to a temperature, $T_{aux}$, where the heat pump efficiency becomes too low to effectively heat the home, the system will start heating in the emergency state using resistive heating elements. In addition to the internal control parameters of $T_{aux}$, the $DB_{low}$ and $DB_{high}$ are internal parameters that are not occupant-controlled, but are included to prevent the heat pump from cycling excessively. Table B.3 gives the logic for the allowable state transitions shown in Figure B.4.

Table B.3: Heat pump state transition logic

| From State | To State | Transition Rule |
| --- | --- | --- |
| 1 | 2 | $T_{air} > (T_{high} + DB_{high})$ |
| 1 | 3 | $T_{air} < (T_{low} - DB_{low})$ |
| 1 | 4 | $T_{air} < (T_{low} - DB_{low})$ & $T_{out} < T_{aux}$ |
| 2 | 1 | $T_{air} < (T_{high} - DB_{high})$ |
| 3 | 1 | $T_{air} > (T_{low} + DB_{low})$ |
| 3 | 4 | $T_{out} < T_{aux}$ |
| 4 | 1 | $T_{air} > (T_{low} + DB_{low})$ |

Each of the four discrete states of operation has a different set of characteristics that determine the instantaneous power consumption. In State 1, there is no power draw because the system is off. In State 2 and State 3, there is an electric fan motor plus a compressor motor. Similar to State 3, State 4 provides heating with an associated electric fan for ventilation, but with the difference that heating is provided by resistive heating elements and not a heat pump. The instantaneous power draw of the four states shown in Figure B.4 is given by (B6)-(B9).

State 1: *Off*

$$S_{HVAC} = 0 \tag{B6}$$

State 2: *Cooling*

$$S_{HVAC} = S_{fan-motor} + S_{comp-motor} \tag{B7}$$

State 3: *Heating-Normal*

$$S_{HVAC} = S_{fan-motor} + S_{comp-motor} \tag{B8}$$

State 4: *Heating-Emergency*

$$S_{HVAC} = S_{fan-motor} + \frac{V_T^2}{R_{elements}} \tag{B9}$$

where,

| | |
|---|---|
| $S_{fan\text{-}motor}$: | apparent power of ventilation fan motor (VA) |
| $S_{comp\text{-}motor}$: | apparent power of compressor motor (VA) |
| $V_T$: | terminal voltage of the heat pump unit (V) |
| $R_{elements}$: | resistance of the heating coil elements (Ω) |

While the power consumption for State 2 and State 3, given by (B7) and (B8) respectively appear to be the same, there are different internal models for $Q_{hvac}$, particularly with respect to the COPs. With the instantaneous power draw determined by (B6)-(B9), the time necessary to heat or cool the house to within the occupant-controlled set points is determined by the solution to (B4). The result is that variations in temperature, voltage, and efficiency are translated into a variable duty cycle of the heat pump. This information can then be used to determine the instantaneous power demand and the energy consumption of the heat pump over time.

## B.2 Model Extraction and Population

Section B.1 discussed the physical infrastructure of the distribution feeders and gave an overview of the level of detail that is modeled at the end-use. This section describes how the detailed end-use models are populated onto the prototypical distribution feeders.

The taxonomy of prototypical feeders was originally populated with a series of spot loads representing a standard peak load study. Each spot load was classified as residential, commercial, agricultural, or industrial. In this analysis, due to the broad nature of industrial and agricultural loads and the difficulty in accurately representing these loads, each of these loads was re-classified as commercial, leaving only residential and commercial loads. Each load was replaced with building models appropriate to the region of the United States where the prototypical feeder was located. The representative commercial and residential models will be described here.

### B.2.1 Residential Loads

At each triplex node, the residential spot load was replaced with a number of residential house models, which under peak conditions approximately matched the original spot load. The number of house models replacing the original peak load depended upon a scaling factor unique to each taxonomy feeder model and was used to calibrate the populated feeder model to the peak load study. For example, if the original spot load was 10 kVA and the feeder scaling factor was determined to be 5 kVA / house, the spot load would be replaced with two house models. In all cases, the number of homes was rounded to the nearest integer, while the residual from the rounding was used as a weighting factor. For example, if the same 10 kVA load was used with a scaling factor of 5.5 kVA / home, the number of homes would be 1.82. The number was rounded to two homes and the difference of 0.18 was used as a weighting factor on the square footage of the homes populated at that location, creating two house models with a slightly lower than the average square footage. The scaling factor was used to calibrate the new feeder model to the peak load study. Multiple annual simulations were run on each feeder until the peak load for the annual simulation approximately equaled that of the peak load study.

The parameters of each home were determined by the climate region the feeder was located in. Data from the Energy Information Administration's (EIA) 2005 Residential Energy Consumption Survey [17] was used to create a population of homes for each feeder which contained the average characteristics from that region. The EIA divides the country into ten regions, while the U.S. DOE Handbook providing design guidance for energy-efficient small office buildings [13], which was used to create the taxonomy feeders, only uses five. Table B.4 shows the weighting factors used to map the characteristics between the two sets of regional data.

Table B.4: Table of weighting factors for mapping regional parameters

| Taxonomy Feeder Climate Regions | | Building Survey Climate Region Weighting | |
|---|---|---|---|
| 1 | West Coast | 1 | Pacific |
| 2 | Northern | 0.5 | Mountain |
| | | 1 | W N Central |
| | | 1 | E N Central |
| | | 1 | Mid Atlantic |
| | | 1 | New England |
| 3 | Southwest | 0.5 | Mountain |
| | | 0.33 | W S Central |
| 4 | Mid-Atlantic | 0.33 | W S Central |
| | | 0.5 | E S Central |
| | | 0.5 | S Atlantic |
| 5 | Southern | 0.33 | W S Central |
| | | 0.5 | E S Central |
| | | 0.5 | S Atlantic |

From the EIA data and the weighting factors, a set of key, average building parameters were created as a basis for the population of each feeder. The residential building models were broken into three types: single family homes, apartments, and mobile homes. The age of the home was used to create a set of thermal integrity levels for each housing age and type, from poorly insulated to well insulated, and key parameters were assigned by region and age of home. Table B.5 shows the average thermal integrity properties by age of the single family homes, apartments, and mobile homes. Each of these parameters was then randomized, where appropriate, around the average value with either a normal or uniform distribution to create a diversified population which approximately represents the average household characteristics in that region. More details on the randomizations used can be found in the feeder generator script found on the open source repository [4]. Table B.6, Table B.7, and Table B.8 provide a breakdown of the percentage of single family homes, apartments, and mobile homes, and their corresponding ages, used in creating the randomized population of buildings per region. In addition, other average parameter values were extracted from the EIA documentation, including square footage, cooling and heating set points, heating type, air conditioning penetration, electric water heater penetration, and pool pump penetration. These are listed in Table B.9 through Table B.11.

Table B.5: Residential thermal integrity values by age of home

| | R Roof | R Wall | R Floor | Glass Layers | Glass Type | Glazing Treatment | Window Frame | R Door | Air Infiltration | COP High | COP Low |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Single Family | | | | | | | | | | | |
| Pre-1940 | 16 | 10 | 10 | 1 | Glass | Clear | Alum. | 3 | 0.75 | 2.8 | 2.4 |
| 1940-1949 | 19 | 11 | 12 | 2 | Glass | Clear | Alum. | 3 | 0.75 | 3.0 | 2.5 |
| 1950-1959 | 19 | 14 | 16 | 2 | Glass | Clear | Alum. | 3 | 0.50 | 3.2 | 2.6 |
| 1960-1969 | 30 | 17 | 19 | 2 | Glass | Clear | TB | 3 | 0.50 | 3.4 | 2.8 |
| 1970-1979 | 34 | 19 | 20 | 2 | Glass | Clear | TB | 3 | 0.50 | 3.6 | 3.0 |
| 1980-1989 | 36 | 22 | 22 | 2 | Low-e | Clear | TB | 5 | 0.25 | 3.8 | 3.0 |
| 1990-2005 | 48 | 28 | 30 | 3 | Low-e | Abs. | Ins. | 11 | 0.25 | 4.0 | 3.0 |
| Apartment | | | | | | | | | | | |
| Pre-1960 | 13 | 12 | 9 | 1 | Glass | Clear | Alum. | 2 | 0.75 | 2.8 | 1.9 |
| 1960-1989 | 20 | 12 | 13 | 2 | Glass | Abs. | TB | 3 | 0.25 | 3.0 | 2.0 |
| 1990-2005 | 29 | 14 | 13 | 2 | Low-e | Refl. | Ins. | 6 | 0.13 | 3.2 | 2.1 |
| Mobile Home | | | | | | | | | | | |
| 1960-1989 | 13 | 9 | 12 | 1 | Glass | Clear | Alum. | 2 | 0.75 | 2.8 | 1.9 |
| 1990-2005 | 24 | 12 | 18 | 2 | Low-e | Clear | TB | 3 | 0.75 | 3.5 | 2.2 |

Note 1: R is in units of °F.sf.h/BTU, air infiltration is in units of air changes / hour, COP is in units of BTU/kWh

Note 2: Low-e refers to low emissivity glass, Abs. refers to absorptive glass, Refl. refers to reflective glass, Alum. refers to an aluminum frame, TB refers to thermal break insulation, Ins. refers to insulated

Table B.6: Percentage of single family homes in total population by age and region

| | Pre-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-2005 |
|---|---|---|---|---|---|---|---|
| Region 1 | 8.05 | 7.24 | 10.90 | 8.67 | 13.84 | 12.64 | 12.97 |
| Region 2 | 15.74 | 7.02 | 12.90 | 9.71 | 9.41 | 7.44 | 15.32 |
| Region 3 | 4.48 | 2.52 | 8.83 | 8.43 | 11.85 | 13.15 | 24.11 |
| Region 4 | 5.26 | 3.37 | 8.06 | 8.27 | 10.81 | 12.49 | 25.39 |
| Region 5 | 5.26 | 3.37 | 8.06 | 8.27 | 10.81 | 12.49 | 25.39 |

Table B.7: Percentage of apartments in total population by age and region

| | Pre-1960 | 1960-1989 | 1990-2005 |
|---|---|---|---|
| Region 1 | 3.56 | 12.23 | 2.56 |
| Region 2 | 4.81 | 8.87 | 3.03 |
| Region 3 | 1.98 | 11.59 | 4.78 |
| Region 4 | 2.17 | 10.91 | 5.02 |
| Region 5 | 2.17 | 10.91 | 5.02 |

Table B.8: Percentage of mobile homes in total population by age and region

| | 1960-1989 | 1990-2005 |
|---|---|---|
| Region 1 | 5.54 | 1.81 |
| Region 2 | 8.87 | 3.03 |
| Region 3 | 5.24 | 3.02 |
| Region 4 | 4.91 | 3.33 |
| Region 5 | 4.91 | 3.33 |

Table B.9: Percentage of key building parameters by region

| | Heating Fuel Type | | | With Air Conditioner | With Electric Water Heater | With Pool Pump* | One-Story Home* |
|---|---|---|---|---|---|---|---|
| | Non-Electric | Heat Pump | Resistance | | | | |
| Region 1 | 70.51 | 3.21 | 26.28 | 43.48 | 25.45 | 9.04 | 68.87 |
| Region 2 | 89.27 | 1.77 | 8.96 | 75.28 | 25.15 | 5.91 | 52.10 |
| Region 3 | 67.23 | 5.59 | 27.18 | 52.59 | 34.80 | 8.18 | 77.45 |
| Region 4 | 44.25 | 19.83 | 35.92 | 96.73 | 64.28 | 6.57 | 70.43 |
| Region 5 | 44.25 | 19.83 | 35.92 | 96.73 | 64.28 | 6.57 | 70.43 |

*Note: Percentage with pool pumps and one-story homes was only applied to single family homes.

Table B.10: Percentage of nighttime heating and cooling set points by housing type

| | Single Family | Apartment | Mobile Home |
|---|---|---|---|
| Set point (°F) | Cooling | | |
| 65-69 | 9.8 | 15.5 | 13.8 |
| 70-70 | 14.0 | 20.7 | 17.2 |
| 71-73 | 16.6 | 10.3 | 17.2 |
| 74-76 | 30.6 | 31.0 | 27.6 |
| 77-79 | 20.6 | 15.5 | 13.8 |
| 80-85 | 8.4 | 6.9 | 10.3 |
| | Heating | | |
| 59-63 | 14.1 | 8.5 | 12.9 |
| 64-66 | 20.4 | 13.2 | 17.7 |
| 67-69 | 23.1 | 14.7 | 16.1 |
| 70-70 | 16.3 | 27.9 | 27.4 |
| 71-73 | 12.0 | 10.9 | 8.1 |
| 74-79 | 14.1 | 24.8 | 17.7 |

Table B.11: Average square footage by building type and region

| | Single Family | Apartment | Mobile Home |
|---|---|---|---|
| Region 1 | 2209 | 820 | 1054 |
| Region 2 | 2951 | 798 | 1035 |
| Region 3 | 2370 | 764 | 1093 |
| Region 4 | 2655 | 901 | 1069 |
| Region 5 | 2655 | 901 | 1069 |

Of note is the cooling and heating set points found in Table B.10. Heating and cooling set points bins were chosen randomly and independently, except to require that the heating set point be below the cooling set point. Within each bin a uniform distribution was used to determine the actual nighttime set point for each home. Additionally, data from the surveys showed average daytime versus nighttime offsets. Offsets were uniformly distributed between zero and twice the average offset, and the time at which the offsets occurred was randomized across the population. Figure B.5 provides a few examples of the diversity of cooling set points established through this methodology, while Figure B.6 shows the average cooling set point on a summer day of all the residential homes within the R1-12.47-2 feeder.

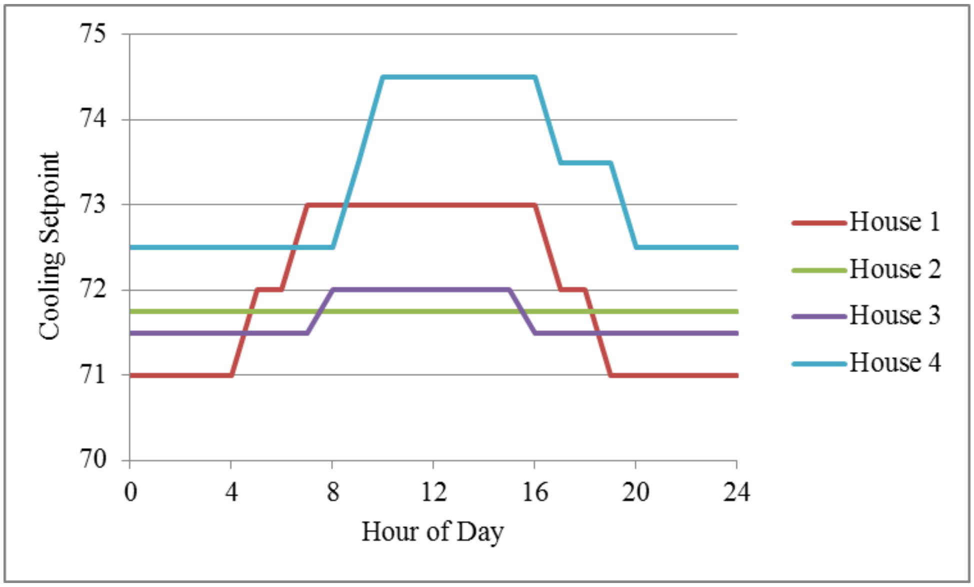



Figure B.5: Exemplary cooling set points diversified with time and daytime and nighttime offsets

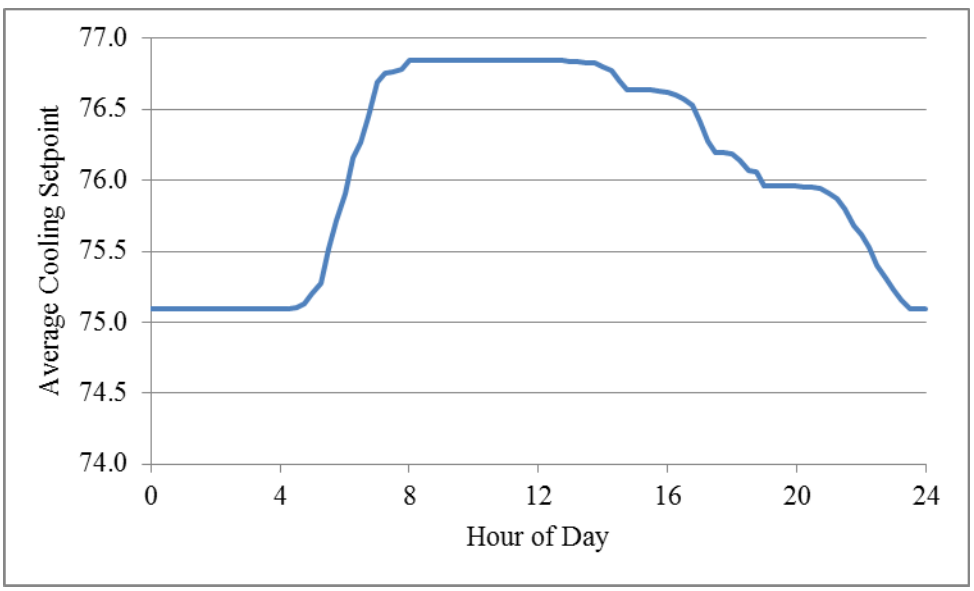



Figure B.6: Average cooling set points of entire population of R1-1247-2

It is important to note that the populated building models were not designed to represent any particular feeder circuit or city in the United States, but rather as a blended average of large climate regions within the United States. While this will not perfectly capture the behavior of any particular city or utility, it is designed as a representative analysis. Additional methods exist where a utility can provide very specific load data which is much more representative of the local population, and design an analysis which is much more suited to that particular application.

The parameter values, in conjunction with estimated demand, were used to describe the state models of the hot water heater, HVAC system, and pool pump. However, additional loads were represented as scheduled ZIP loads. "Appliances" such as refrigerators and lights were divided into two categories: responsive and unresponsive loads. Responsive loads indicate that the customer is able to modify the behavior of the appliance due to a price signal, while unresponsive loads indicate that the customer is typically not willing or able to modify the behavior without investment in additional technologies (e.g. demand response enabled appliances). Responsive loads included lights, plug loads, clothes washers, clothes dryers, dishwashers, cooking ranges, and microwaves, while unresponsive loads included refrigerator and freezer loads. These were divided in anticipation of demand response studies and the shift of customer behavior that is associated with Time-of-Use or Critical Peak pricing. ELCAP load data [18] was used to create a base hourly load profile for responsive and unresponsive loads, with adjustments made for 20 years of increased efficiency and increased or decreased demand, and included seasonal and weekday versus weekend effects, as shown in Figure B.7 and Figure B.8. Additionally, loads were scaled as a function of square footage using a regression, again using ELCAP data. The proper scalar from the regression is shown in (B10):

$$k = 324.9 * \textit{floor area}^{.442} * 1000 / 8760 \tag{B10}$$

The scalar was then randomized +/- 20% over a uniform distribution. While this provided no single home with a load shape representative of a time-series of an actual home, the aggregate load shape was representative of an entire population of homes, and internal loading of each home provided internal heat gains appropriate to that size of home.


Figure B.7: Average energy consumption of responsive loads

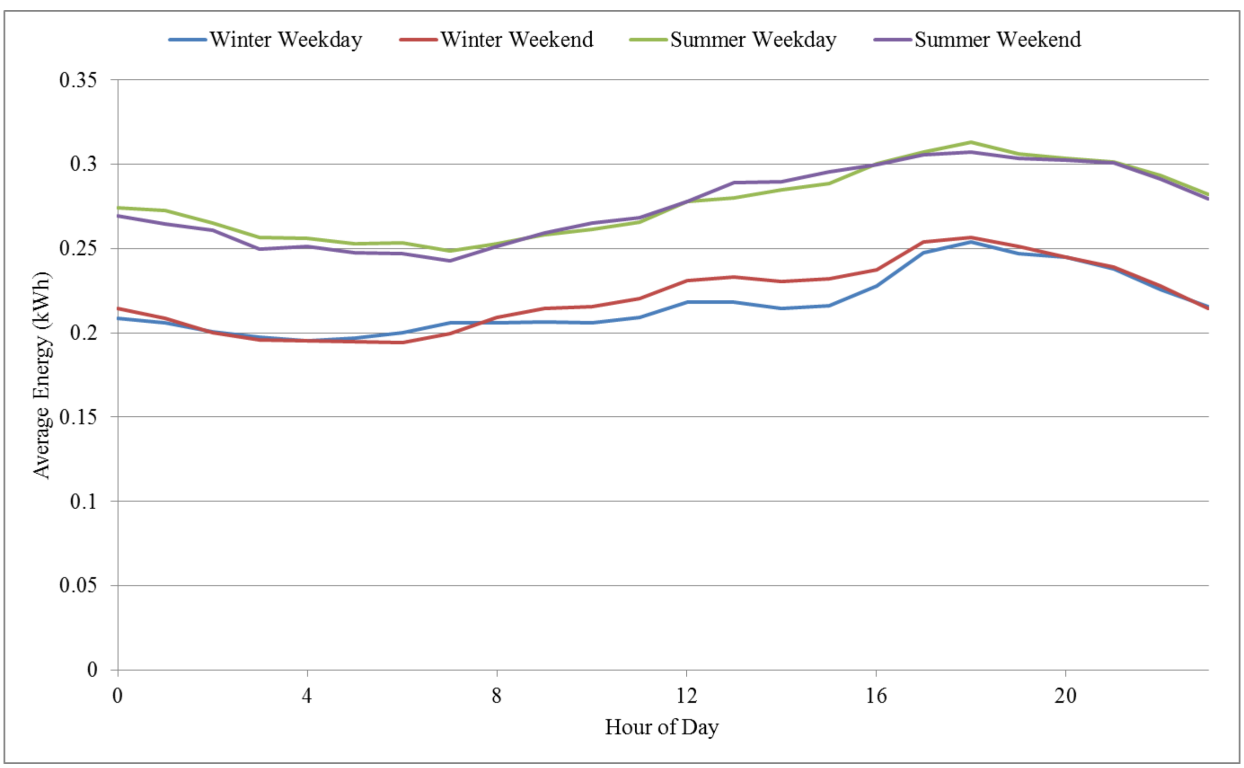



Figure B.8: Average energy consumption of unresponsive loads

### B.2.2 Commercial Loads

At this time, a fully implemented, multi-zone commercial building model is not available within GridLAB-D. However, to represent the "zones" of a commercial building, multiple house models were created to represent the commercial load. These loads were created using very generic commercial building characteristics and load patterns. The commercial loads (and the re-classified industrial and agricultural loads) were divided into three types: office buildings, large retail "box" buildings, and small retail strip malls. The key characteristics of these models were developed through federally-supported building codes and end-use metering studies, and are not based on regional differences as the residential models were [19]-[20]. Population of the prototypical feeders and the three types of buildings was performed by size of the original load and the number of phases the load was attached to. Similar to the residential loading, a scalar was used to calibrate the loading on each feeder model, modifying the number of loads and size of each load.

Office buildings were represented by a three-story, fifteen-zone model as shown in Figure B.9. These replaced loads within the taxonomy feeder that were three-phase and "larger", as defined by the scaling factor. The average square footage was 40,000 sf., with a uniform deviation of 50%, while maintaining the geometrical relationship of each zone. Each of the zones has identical parameter values, except square footage, aspect ratio, external wall area, external floor area, and external ceiling area. Assumptions are made in this model to better represent the zonal attributes of a commercial building. It is assumed that the adjacent zone has approximately the same air and mass temperature as the current zone, so that there is no heat transfer across the boundaries. This means that the internal wall, ceiling, or floor areas do not lose or gain heat from adjacent zones, and can therefore be ignored when defining the thermal envelope of the building. For example, Zone 5 on the second floor in Figure B.9 will have an external wall area of 0 sf., an external floor area of 0 sf., and an external ceiling area of 0 sf. This zone would only have heat added (or removed) through end-use loads and the HVAC system. Zone 2 on the third floor will have an external wall area equal to one-half its total wall area, and external floor area also equal to 0 sf., and an external ceiling area equal to its floor area, allowing additional heat flows across the external boundaries. By defining each zone within the constraints of the geometrical model, then defining where heat transfer across boundaries is allowed and not allowed, a zonal model can be roughly represented. Notice that Figure B.9 contains a variable 'x'. This variable would be adjusted by the randomly chosen square footage so that $3*1.5*x^2$ equaled the total square footage, while all other parameters except for the widths of Zones 1-4 adjusted within the geometrical constraints. The other building type zones were defined in a similar manner. Table B.12 shows the key parameters used to define the office building zones. Additionally, since the office building is considered a larger, single owner, customer billing was performed as an aggregate of all the "zones".

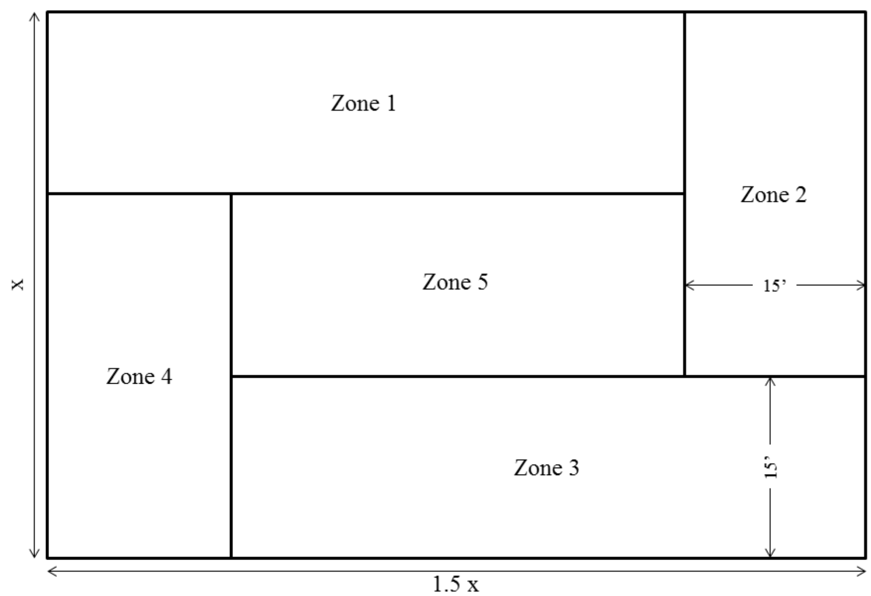



Figure B.9: Office zonal floor plan representing 1 of 3 identical floors

Table B.12: Key parameters for commercial buildings

| | Office | Big Box | Strip Mall |
|---|---|---|---|
| Square Footage | 40,000 +/- 50% | 20,000 +/- 50% | 2400 +/ 30% |
| Ceiling Height | 13 | 14 | 12 |
| Air Infiltration | 0.69 | 1.5 | 1.76 |
| R Roof | 19 | 19 | 19 |
| R Wall | 18.3 | 18.3 | 18.3 |
| R Floor | 46 | 46 | 40 |
| R Door | 3 | 3 | 3 |
| Glazing Layers | 2 | 2 | 2 |
| Glass Type | Glass | Glass | Glass |
| Glazing Treatment* | Low S | Low S | Low S |
| Window Frame | None | None | None |
| No. of Doors* | 0 | 0 / 1 / 24 | 1 |
| Window to Wall Ratio | 0 / 0.33 | 0 / 0.76 | 0.03 / 0.05 |
| Internal Gains (W/sf) | 3.24 | 3.6 | 3.6 |
| Cooling COP | 3 +/- 20% | 3 +/- 20% | 3 +/- 20% |

*Note: Low S refers to low solar glazing.

*Note: Number of doors refers to the number of doors externally exposed, and is translated into a wall area used by the doors - 24 doors refers to the surface area used by 24 doors. Office accounts for door area in the window area.

Big box retail buildings were represented as a one-story, six-zone model as shown in Figure B.10, and were used to replace “larger” two-phase loads and “smaller” three-phase loads, as defined by the scaling factor. The overall square footage was defined as 20,000 sf., with a uniform deviation of 50%. Table B.12 shows the key parameters used to define the retail big box building zones. Again, this building was considered a single occupant and customer billing was performed on the aggregate of all the “zones”.

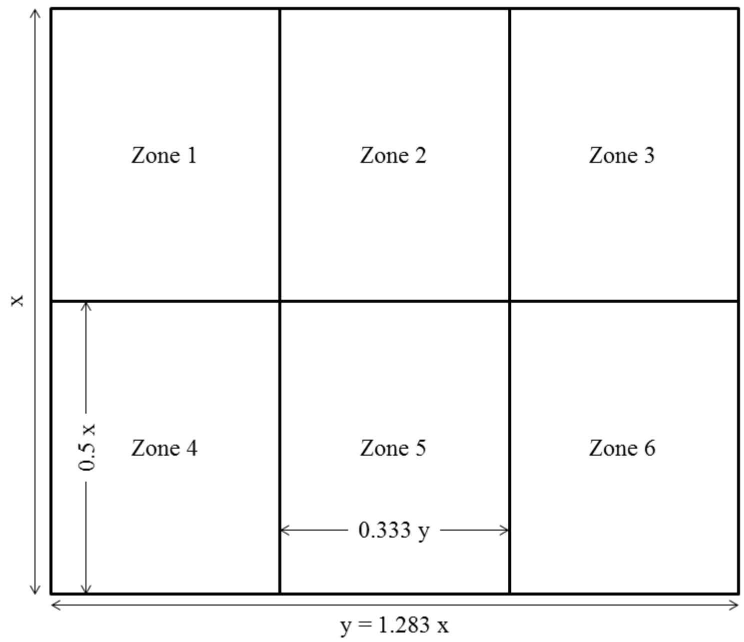



Figure B.10: Retail “big box” zonal floor plan

A retail strip mall model was used to represent all other loads, including all one-phase loads and “smaller” two- or three-phase loads. These were represented by one-story, single-zone models connected in series as shown in Figure B.11. Individual zones were defined as 1200 or 2400 sf., with a uniform deviation of 30%. Table B.12 shows the key parameters used to define the retail strip mall building zones. In this case, ownership was considered on a per-zone basis, so customer billing was also performed on a per-zone basis.

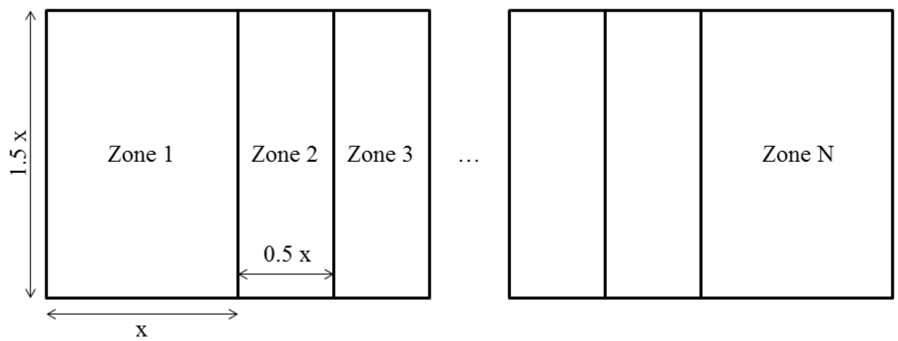



Figure B.11: Retail strip mall zonal floor plan with N zones depending upon scaling factor

Additionally, it was assumed that all commercial buildings had both heating and cooling systems and heating was always represented by a gas heating unit rather than a heat pump or resistive heat unit. Again, internal loads are very important drivers for both heating and cooling of the space, displacing heating load while adding cooling load. Commercial building load is highly occupant driven, and is typically very recurring. Data from end-use metering projects was used to create average end-use load shapes for weekdays and weekends [21]. Again, certain loads were slightly scaled up or down to reflect changes in efficiencies or standard usage. Weekdays are assumed to be Mon-Fri for office buildings, Mon.-Sun. for big box buildings, and Mon.-Sat. for strip malls. Average load shapes are shown in Figure B.12 through Figure B.15. Notice that the y-axis is in units of W/sf. The load shape applied to each zone is scaled as a function of square footage then randomized on a zonal basis by +/- 20% over a uniform distribution. In addition to the magnitude randomization, the load shape was also randomly "skewed" in time. Each of the zones within the building were considered to be on the same schedule, however, across the population of buildings, not all started and ended at the same time. The load shapes were temporally shifted from those shown in Figure B.12 through Figure B.15 in 30-minute blocks using a normal distribution of average of 0 minutes and standard deviation of 30 minutes. This produced a more diversified load across the entire population.

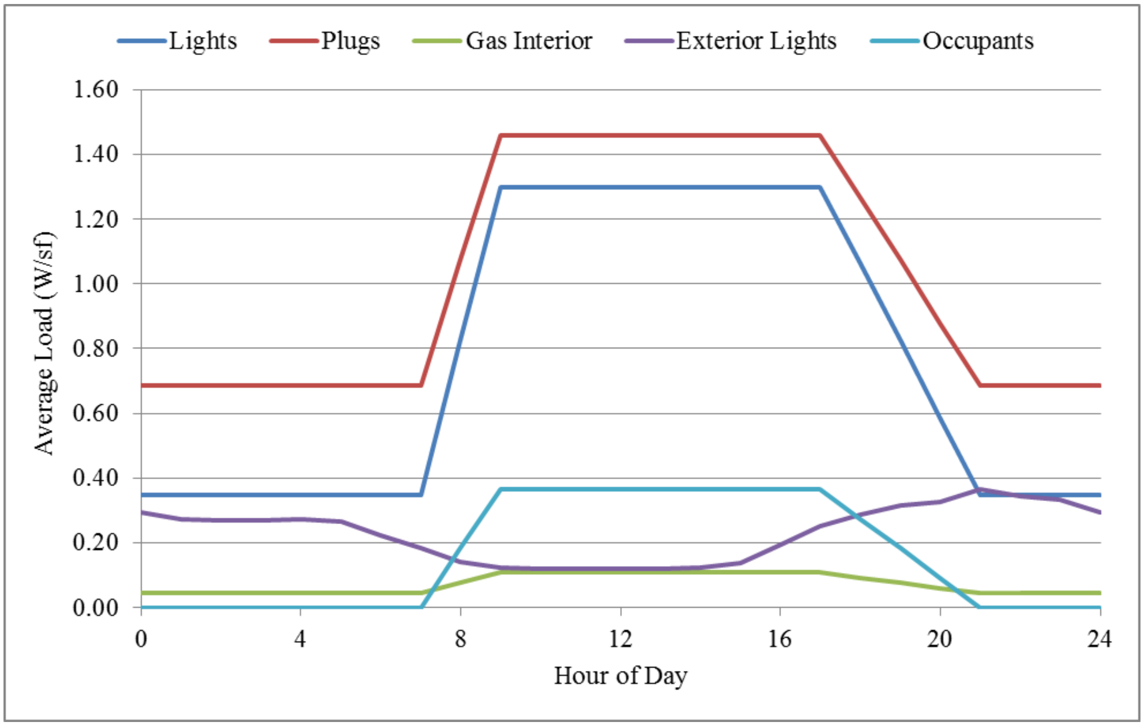



Figure B.12: Average office end-use load shape (weekday)

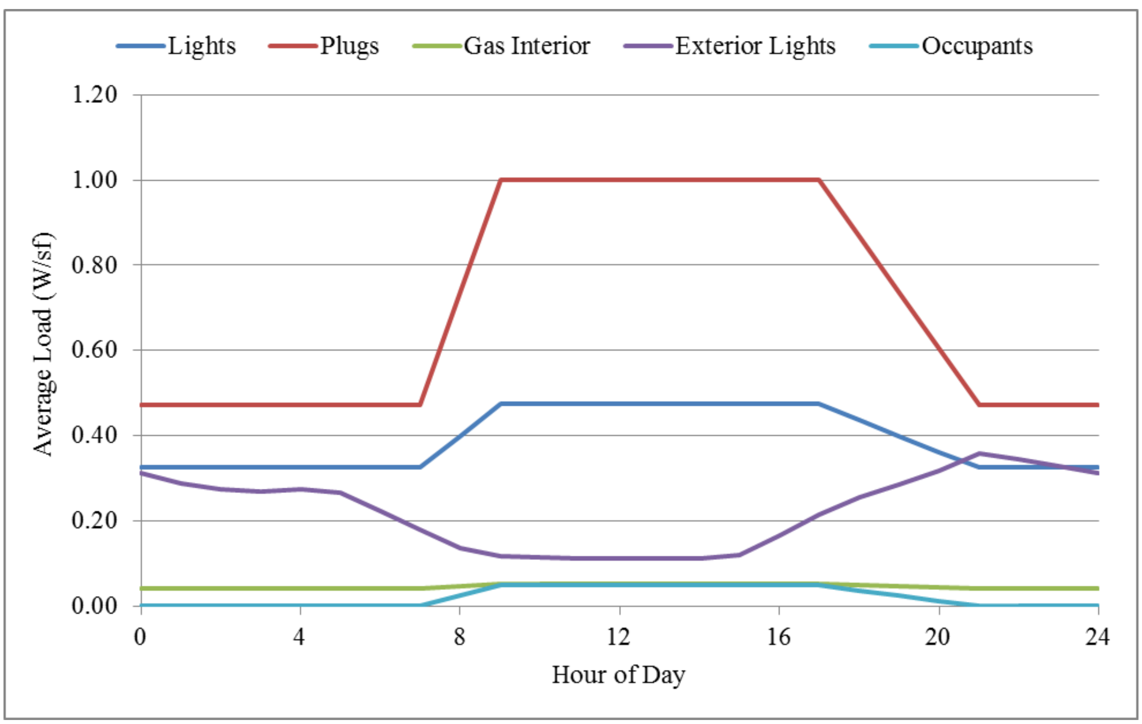



Figure B.13: Average office end-use load shape (weekend)

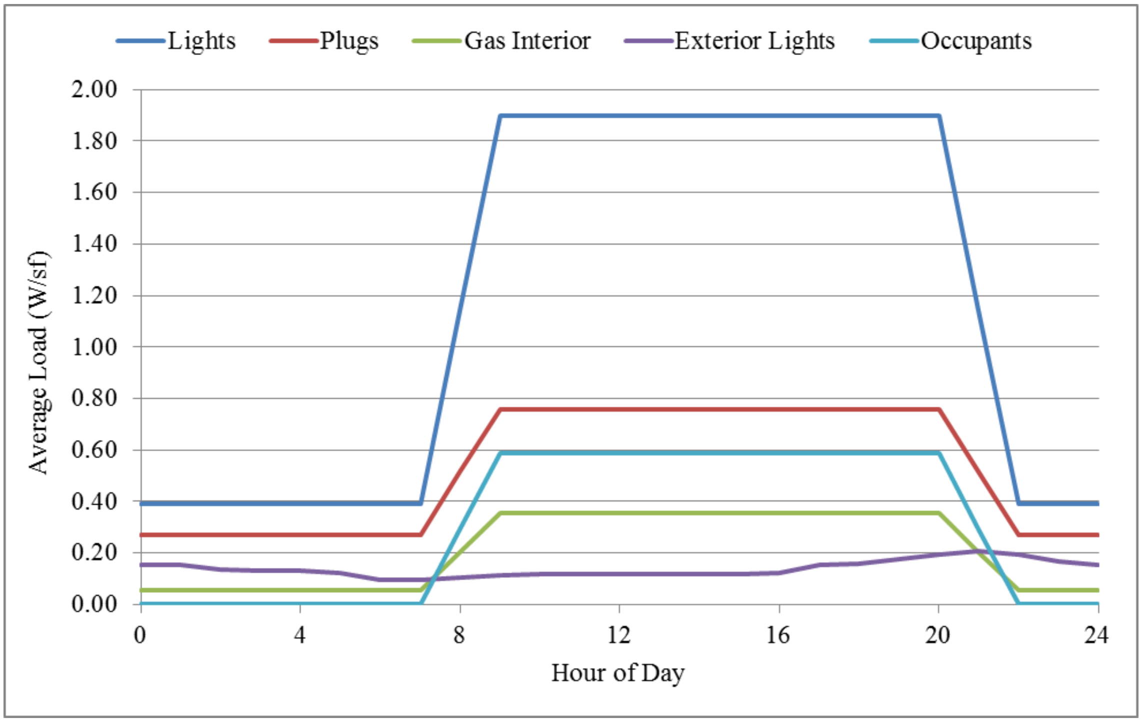



Figure B.14: Average big box and strip mall end-use load shape (weekday)

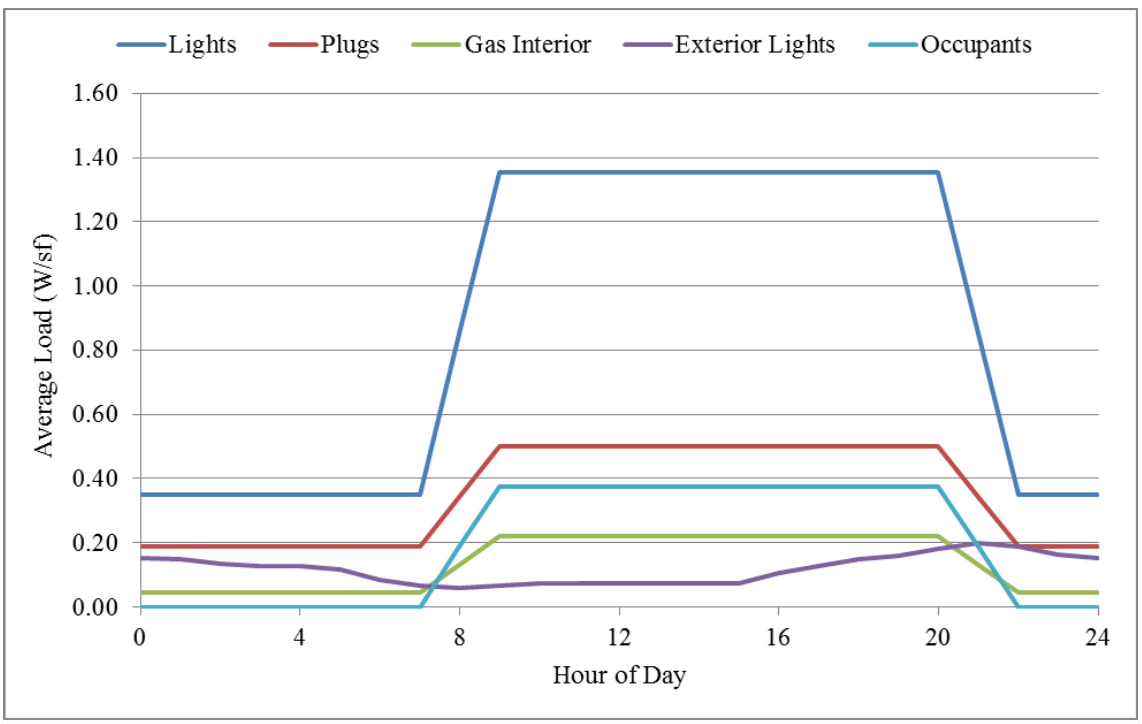



Figure B.15: Average big box and strip mall end-use load shape (weekend)

Finally, there were a number of loads on the prototypical feeders that were far smaller than could be described by a building model at peak load, often less than 1 kVA. While there are a number of options for representation of these loads, such as traffic lights or a small espresso stand, it was determined that without data to indicate what these loads represented they would be best represented by street lighting loads. These small loads were converted to a scheduled one-, two-, or three-phase load, depending on the original load and the full rated load was applied during dark hours and zero load was applied during daylight hours. While it is understood that this is not an accurate representation of true street light loading and operation, the loads were small enough and infrequent enough that a simple scheduled load had little to no effect on the overall operation of the feeder circuits.

## B.3 Taxonomy Feeder Emission Profiles

Increasing operational efficiency of the electrical power system can lead to a reduction in pollutant emissions. Peak load reduction or peak shifting has been shown to reduce emissions, mainly due to reducing the need to use "peaker" units. These are typically older, less efficient generators, designed for quick start-up and shutdown, and are often single cycle natural gas turbine generators or petroleum fired plants. Reduction in overall energy consumption or shifting of production to more efficient energy sources can also reduce emissions by reducing the amount of fuel burned for electricity production. Solutions for the amount of emissions created are traditionally performed at the transmission level, using optimal power flow and economic dispatch, and are typically not well-suited for distribution level simulation. The following section is a brief description of how GridLAB-D estimates emissions impacts at the distribution level.

To capture the emissions level benefits to the system, generation mixes were assumed in each region and the nine most heavily consumed fuels for electrical generation in the U.S. were used. In each region, the fuels are dispatched in order from first to last by capacity factor, as shown in Table B.13. Exceptions are made for a number of the renewable resources, such as wind, solar, and biomass, as they are assumed to be dispatched when available. The level of penetration by each fuel type was determined for each region by month as shown in Table B.14-Table B.18. These values were determined from the EIA's Annual Electric Generator Report [17], utilizing state-by-state breakdowns of annual energy production.

Table B.13: Dispatch order of fuel by region

| Region | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Order of dispatch | Nuclear | Nuclear | Nuclear | Nuclear | Nuclear |
| | Solar | Solar | Solar | Solar | Solar |
| | Biomass | Biomass | Biomass | Biomass | Biomass |
| | Wind | Wind | Wind | Wind | Wind |
| | Hydroelectric | Coal | Coal | Coal | Natural Gas |
| | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Coal |
| | Coal | Hydroelectric | Hydroelectric | Hydroelectric | Hydroelectric |
| | Geothermal | Geothermal | Geothermal | Geothermal | Geothermal |
| | Petroleum | Petroleum | Petroleum | Petroleum | Petroleum |

Table B.14: Percent of energy consumed, broken down by fuel type and month in region 1

| Region 1 | Jan | Feb | Mar | April | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nuclear | 9.86 | 8.68 | 11.47 | 13.08 | 10.63 | 9.73 | 10.68 | 8.93 | 10.09 | 8.5 | 9.83 | 10.41 |
| Solar | 0.01 | 0.08 | 0.18 | 0.23 | 0.25 | 0.24 | 0.25 | 0.24 | 0.21 | 0.15 | 0.09 | 0.04 |
| Biomass | 0.58 | 0.78 | 0.77 | 0.72 | 0.73 | 0.73 | 0.67 | 0.65 | 0.72 | 0.82 | 0.81 | 0.73 |
| Wind | 2.37 | 1.86 | 4.39 | 4.57 | 4.63 | 5.44 | 4.07 | 4.66 | 3.55 | 3.64 | 3.17 | 1.44 |
| Hydroelectric | 43.43 | 37.29 | 38.84 | 49.88 | 56.78 | 58.39 | 36.88 | 29.63 | 26.32 | 31.09 | 36.02 | 36.29 |
| Natural Gas | 34.61 | 41.6 | 34.96 | 25.6 | 22.89 | 21.1 | 41.38 | 48.31 | 51.24 | 45.88 | 42.02 | 42.13 |
| Coal | 5.44 | 5.77 | 5.42 | 2.14 | 0.45 | 0.86 | 2.88 | 4.09 | 4.38 | 5.97 | 4 | 5.14 |
| Geothermal | 3.29 | 3.49 | 3.51 | 3.35 | 3.29 | 3.1 | 2.84 | 3.09 | 3.11 | 3.54 | 3.63 | 3.35 |
| Petroleum | 0.43 | 0.45 | 0.45 | 0.43 | 0.35 | 0.41 | 0.36 | 0.38 | 0.39 | 0.4 | 0.44 | 0.47 |

Table B.15: Percent of energy consumed, broken down by fuel type and month in region 2

| Region 2 | Jan | Feb | Mar | April | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nuclear | 26.47 | 26.9 | 27.74 | 25.27 | 28.52 | 27.95 | 26.33 | 24.75 | 27.04 | 25.09 | 25.63 | 25.42 |
| Solar | 0 | 0 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0 | 0 |
| Biomass | 0.64 | 0.72 | 0.82 | 0.9 | 0.92 | 0.84 | 0.82 | 0.76 | 0.83 | 0.85 | 0.89 | 0.75 |
| Wind | 2.23 | 2.71 | 2.9 | 3.34 | 2.79 | 1.7 | 1.41 | 1.6 | 1.73 | 2.82 | 3.22 | 2.99 |
| Coal | 49.62 | 49.36 | 46.7 | 46.31 | 44.39 | 45.54 | 47.18 | 46.33 | 46.05 | 49.04 | 49.05 | 50.69 |
| Natural Gas | 12.31 | 13.49 | 14.19 | 14.67 | 13.43 | 14.47 | 16.33 | 19.87 | 17.97 | 15.73 | 14.51 | 13.22 |
| Hydroelectric | 6.11 | 5.99 | 6.92 | 9.11 | 9.51 | 9.05 | 7.42 | 6.08 | 5.98 | 6.13 | 6.34 | 6.43 |
| Geothermal | 0.07 | 0.07 | 0.08 | 0.08 | 0.08 | 0.07 | 0.07 | 0.07 | 0.08 | 0.07 | 0.08 | 0.08 |
| Petroleum | 2.55 | 0.74 | 0.64 | 0.32 | 0.34 | 0.37 | 0.43 | 0.6 | 0.33 | 0.27 | 0.28 | 0.43 |

Table B.16: Percent of energy consumed, broken down by fuel type and month in region 3

| Region 3 | Jan | Feb | Mar | April | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nuclear | 9.82 | 8.88 | 10.24 | 11.6 | 10.83 | 9.72 | 8.65 | 8.5 | 7.13 | 8.62 | 9.63 | 9.38 |
| Solar | 0.01 | 0.05 | 0.13 | 0.16 | 0.17 | 0.13 | 0.13 | 0.14 | 0.13 | 0.1 | 0.06 | 0.03 |
| Biomass | 0.22 | 0.28 | 0.29 | 0.29 | 0.25 | 0.25 | 0.23 | 0.21 | 0.25 | 0.27 | 0.29 | 0.26 |
| Wind | 2.13 | 3.08 | 3.26 | 3.77 | 2.8 | 2.45 | 2.05 | 2.2 | 2.34 | 3.55 | 3.02 | 2.77 |
| Coal | 50.18 | 43.95 | 41.77 | 42.34 | 43.59 | 41.52 | 40.24 | 41.42 | 43.7 | 47.9 | 49.94 | 46.58 |
| Natural Gas | 32.79 | 37.12 | 37.34 | 33.17 | 33.92 | 37.88 | 41.67 | 41.48 | 40.32 | 33.07 | 31.29 | 34.43 |
| Hydroelectric | 2.89 | 4.75 | 4.95 | 6.72 | 6.68 | 6.4 | 5.58 | 4.59 | 4.47 | 4.74 | 3.76 | 4.6 |
| Geothermal | 1.63 | 1.62 | 1.7 | 1.67 | 1.53 | 1.4 | 1.25 | 1.26 | 1.42 | 1.52 | 1.79 | 1.7 |
| Petroleum | 0.32 | 0.26 | 0.32 | 0.28 | 0.24 | 0.25 | 0.2 | 0.2 | 0.22 | 0.24 | 0.22 | 0.24 |

Table B.17: Percent of energy consumed, broken down by fuel type and month in region 4

| Region 4 | Jan | Feb | Mar | April | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nuclear | 23.16 | 23.97 | 23.95 | 24.4 | 24.92 | 22.45 | 23.15 | 21.91 | 23.58 | 24.33 | 23.99 | 22.77 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 0.21 | 0.19 | 0.21 | 0.25 | 0.21 | 0.18 | 0.18 | 0.18 | 0.21 | 0.22 | 0.22 | 0.18 |
| Wind | 0.69 | 0.88 | 1.03 | 1.16 | 0.78 | 0.64 | 0.53 | 0.6 | 0.59 | 1.13 | 1.18 | 1.04 |
| Coal | 61.55 | 60.14 | 57.45 | 58.24 | 57.41 | 56.92 | 56.89 | 57.14 | 56.06 | 58.36 | 58.48 | 59.96 |
| Natural Gas | 9.98 | 11.44 | 12.86 | 11.25 | 11.38 | 16.04 | 16.75 | 17.49 | 16.14 | 10.51 | 9.83 | 10.19 |
| Hydroelectric | 3.37 | 2.67 | 3.71 | 4.21 | 4.73 | 3.32 | 2.05 | 2.2 | 3.09 | 5.09 | 5.96 | 5.51 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Petroleum | 1.04 | 0.71 | 0.8 | 0.49 | 0.56 | 0.45 | 0.45 | 0.48 | 0.36 | 0.36 | 0.34 | 0.36 |

Table B.18: Percent of energy consumed, broken down by fuel type and month in region 5

| Region 5 | Jan | Feb | Mar | April | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nuclear | 18.26 | 18.55 | 18.53 | 17.36 | 14.67 | 13.53 | 13.74 | 13.85 | 13.65 | 12.7 | 14.94 | 16.41 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 0.46 | 0.45 | 0.48 | 0.46 | 0.3 | 0.31 | 0.31 | 0.33 | 0.34 | 0.39 | 0.46 | 0.46 |
| Wind | 2.14 | 2.6 | 2.7 | 2.95 | 1.91 | 1.74 | 1.44 | 1.48 | 1.43 | 2.52 | 2.63 | 2.26 |
| Natural Gas | 38.8 | 41.01 | 45.26 | 44.78 | 47.26 | 51.29 | 51.75 | 51.68 | 51.03 | 47.55 | 43.83 | 41.73 |
| Coal | 37.3 | 34.53 | 29.66 | 30.82 | 32.04 | 30.37 | 30.38 | 30.17 | 30.72 | 33.46 | 35.06 | 35.97 |
| Hydroelectric | 1.42 | 0.86 | 1.57 | 1.51 | 1.61 | 0.78 | 0.58 | 0.63 | 0.99 | 1.75 | 2.12 | 2.35 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Petroleum | 1.62 | 2 | 1.79 | 2.12 | 2.2 | 1.96 | 1.8 | 1.86 | 1.84 | 1.62 | 0.95 | 0.82 |

At each 15-minute measurement interval, the energy consumed over the previous interval is used to determine the amount of energy delivered by each fuel source. The peak load of the base case for each month is used to scale the percentages. Figure B.16 shows an example of how this is performed in GridLAB-D using June in Region 3. It can be seen that the peak load for that month would utilize all the generation fuels at the levels shown in Table B.16. At the shown 15-minute period, the base case load is approximately 95% of the peak for June for this particular feeder. During the same 15-minute period, the representative technology case is only 87% of the base case peak feeder loading. This results in a reduction of generation by approximately 3% for hydroelectric and 5% for natural gas. This calculation is performed at every 15-minute interval to determine the energy consumed by each fuel type over the course of the entire annual simulation of 1-minute intervals.

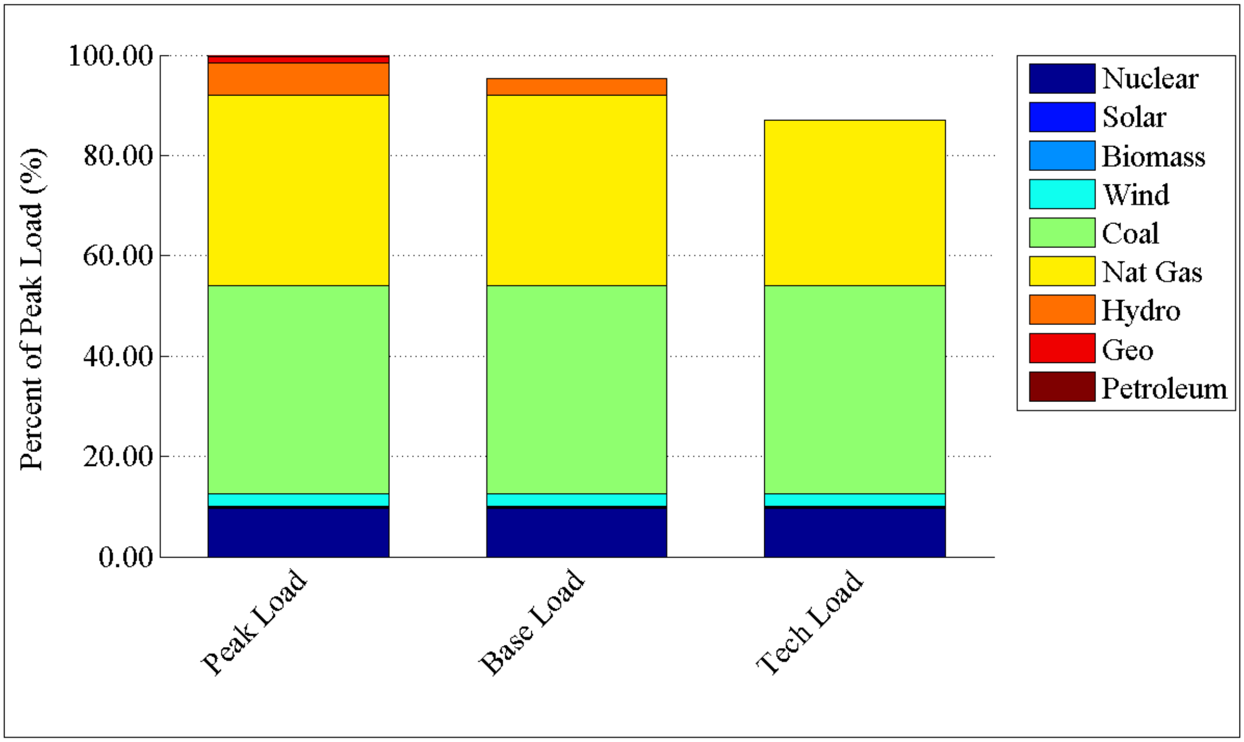



Figure B.16: Exemplary 15-minute interval comparing fuel dispatch for the peak load versus the base case load versus a technology modified load.

Assumed average thermal efficiencies are then used to convert the energy delivered to the amount of fuel used, where applicable. The values used are shown in Table B.19. Finally, assumed average values for conversion efficiencies are used to convert from fuel used to emissions levels for carbon dioxide, sulfur dioxide, and nitrous oxides. The conversion values assumed are shown in Table B.20. These values are not indicative of any single plant, but rather broad averages across the U.S. While this is a very simplified means of dispatching and assigning generation, ignoring complex issues such as inefficiencies due to warm-up cycles, maintenance periods, and economic or optimal dispatching, it should provide a general indication of how changes in operation of a distribution circuit can reduce pollutant emissions.

Table B.19: Average thermal efficiencies by fuel type.

| | MBTUs / MWh |
|---|---|
| Nuclear | 10.46 |
| Solar | N/A |
| Biomass | 12.93 |
| Wind | N/A |
| Natural Gas | 8.16 |
| Coal | 10.41 |
| Hydroelectric | N/A |
| Geothermal | 21.02 |
| Petroleum | 11 |

Table B.20: Pollutant production per BTU of fuel (lbs./MBTU)

| | $CO_2$ | $SO_2$ | $NO_x$ | PM-10 |
|---|---|---|---|---|
| Nuclear | 0 | 0 | 0 | 0.017157 |
| Solar | 0 | 0 | 0 | 0.03 |
| Biomass | 195 | 0 | 0.08 | 0.0232 |
| Wind | 0 | 0 | 0 | 0 |
| Natural Gas | 117.08 | 0.001 | 0.0075 | 0 |
| Coal | 205.57 | 0.1 | 0.06 | 0 |
| Hydroelectric | 0 | 0 | 0 | 0 |
| Geothermal | 120 | 0.2 | 0 | 0 |
| Petroleum | 225.13 | 0.1 | 0.04 | 0 |

## B.4 Taxonomy Feeder Descriptions

The previous sections have described the details of how each of the prototypical feeders is populated with end-use loads. This section is a reproduction of the individual prototypical feeder descriptions from [3] which describes the characteristics of the primary distribution system.

### B.4.1 Feeder 1: GC-12.47-1

This feeder is representative of a single large commercial or industrial load, such as a very large shopping mall or a small lumber mill. These feeders may supply the load through a single large transformer or a group of smaller units. While there may be a couple of smaller loads the behavior of the feeder is primarily determined by the single large customer. This is a 12.47 kV feeder with a peak load of approximately 5,400 kVA.

### B.4.2 Feeder 2: R1-12.47-1

This feeder is a representation of a moderately populated suburban and rural area. This is composed mainly of single family residences with small amounts of light commercial. Approximately 60% of the circuit-feet are overhead and 40% are underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.5 kV feeder with a peak load of approximately 4,300 kVA.

### B.4.3 Feeder 3: R1-12.47-2

This feeder is a representation of a moderately populated suburban and lightly populated rural area. This is composed mainly of single family residences with small amounts of light commercial. Approximately 70% of the circuit-feet are overhead and 30% underground. It would not be expected that this feeder is connected to adjacent feeders through normally open switches. Even though there are not adjacent feeders for transferring the load, the total feeder loading is low because of the sparse rural loading. In this model an urban substation is feeding a rural load through a long primary circuit. The majority of the load is located relatively distant with respect to the substation. This is a 12.47 kV feeder with a peak load of approximately 2,400 kVA.

### B.4.4 Feeder 4: R1-12.47-3

This feeder is a representation of a moderately populated urban area. This is composed mainly of mid-sized commercial loads with some residences, mostly multi-family. Approximately 85% of the circuit-feet are overhead and 15% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. Since this is a small urban core the loading of the feeder is well below 60%. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 1,800 kVA.

### B.4.5 Feeder 5: R1-12.47-4

This feeder is a representation of a heavily populated suburban area. This is composed mainly of single family homes and heavy commercial loads. None of the circuit-feet are overhead and 100% are underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 4,900 kVA.

### B.4.6 Feeder 6: R1-25.00-1

This feeder is a representation of a lightly populated rural area. This is composed of a mixture of residential, light commercial, industrial, and agricultural loads. Approximately 60% of the circuit-feet are overhead and 40% underground. It would be expected that this feeder is not connected to adjacent feeders through normally open switches. Due to rural location and low population density the feeder is not heavily loaded. The low population density and wide are covered are why this feeder is operated at 24.9 kV. The majority of the load is located relatively distant with respect to the substation. This is a 24.9 kV feeder with a peak load of approximately 2,300 kVA.

### B.4.7 Feeder 7: R2-12.47-1

This feeder is a representation of a lightly populated urban area. This is composed of single family homes, moderate commercial loads, light industrial loads, and some agricultural loads. This feeder supplies a college and an airport. Approximately 25% of the circuit-feet are overhead and 75% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 6,700 kVA.

### B.4.8 Feeder 8: R2-12.47-2

This feeder is a representation of a moderately populated suburban area. This is composed mainly of single family homes with some light commercial loads. Approximately 80% of the circuit-feet are overhead and 20% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 6,700 kVA.

### B.4.9 Feeder 9: R2-12.47-3

This feeder is a representation of a lightly populated suburban area. This is composed of single family homes, light commercial loads, light industrial loads, and some agricultural loads. Approximately 20% of the circuit-feet are overhead and 80% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 4,800 kVA.

### B.4.10 Feeder 10: R2-25.00-1

This feeder is a representation of a moderately populated suburban area. This is composed mainly of single family homes with some light and moderate commercial loads. Approximately 60% of the circuit-feet are overhead and 40% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. This is a heavily loaded feeder, well over 60%, with the majority of the load is located relatively near the substation. This is a 24.9 kV feeder with a peak load of approximately 21,300 kVA.

### B.4.11 Feeder 11: R2-35.00-1

This feeder is a representation of a lightly populated rural area. This is composed mainly of single family homes with some light and moderate commercial loads. Approximately 90% of the circuit-feet are overhead and 10% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. But due to the long distances significant portions of the load cannot be shifted to adjacent feeders. In this model a single substation is serving a large geographic area, this is the reason for the higher voltage level; voltage regulators are used on this system. The majority of the load is located relatively distant with respect to the substation. This is a 34.5 kV feeder with a peak load of approximately 6,900 kVA.

### B.4.12 Feeder 12: R3-12.47-1

This feeder is a representation of a heavily populated urban area. This is composed of single family homes, heavy commercial loads, and a small amount of light industrial loads. Approximately 25% of the circuit-feet are overhead and 75% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. Due to the heavy commercial loads it would be expected that this feeder would be loaded to a high percentage of its rating. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 11,600 kVA.

### B.4.13 Feeder 13: R3-12.47-2

This feeder is a representation of a moderately populated urban area. This is composed of single family homes, light commercial loads, and a small amount of light industrial loads. Approximately 33% of the circuit-feet are overhead and 67% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 4,000 kVA.

### B.4.14 Feeder 14: R3-12.47-3

This feeder is a representation of a heavily populated suburban area. This is composed mainly of single family homes with some light agricultural loads. Approximately 75% of the circuit-feet are overhead and 25% underground. It would be expected that this feeder has limited connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 75% to ensure the ability to transfer some loads from other feeders, and vice versa. Due to the low density of suburban loads the majority of the load is located relatively distant with respect to the substation. This is a 12.45 kV feeder with a peak load of approximately 9,400 kVA.

### B.4.15 Feeder 15: R4-12.47-1

This feeder is a representation of a heavily populated urban area with the primary feeder extending into a lightly populated rural area. In the urban areas the load is composed of moderate commercial loads with single and multi-family residences. On the rural spur the load is primarily single family residences. Approximately 92% of the circuit-feet are overhead and 8% underground. This feeder has connections to adjacent feeders in the urban area, but limited connections in the rural areas. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. Most of the urban load is located near the substation while the rural load is located at a substantial distance. This is a 13.8 kV feeder with a peak load of approximately 6,700 kVA.

### B.4.16 Feeder 16: R4-12.47-2

This feeder is a representation of a lightly populated suburban area with a moderately populated urban area. The lightly populated suburban area is composed mostly of single family residences. The commercial complex is a single facility. Approximately 92% of the circuit-feet are overhead and 8% underground. This feeder has connections to adjacent feeders in the commercial complex, but limited connections in the rural areas. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. Most of the suburban load is located near the substation while the commercial load is located at a substantial distance. This is a 12.5 kV feeder with a peak load of approximately 2,100 kVA.

### B.4.17 Feeder 17: R4-25.00-1

This feeder is a representation of a lightly populated rural area. The load is composed of single family residences with some light commercial. Approximately 88% of the circuit-feet are overhead and 12% underground. This feeder has connections to adjacent feeders. This combined with the low load density ensures the ability to transfer most of the loads from other feeders, and vice versa. Most of the load is located at a substantial distance from the substation, as is common for higher voltages in rural areas. This is a 24.9 kV feeder with a peak load of approximately 1,000 kVA.

### B.4.18 Feeder 18: R5-12.47-1

This feeder is a representation of a heavily populated suburban area and a moderate urban center. This is composed mainly of single family homes and moderate commercial loads. Approximately 95% of the circuit-feet are overhead and 5% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most loads from other feeders, and vice versa. The suburban load is near the substation while the commercial load is at the end of the feeder. This is a 13.8 kV feeder with a peak load of approximately 10,800 kVA.

### B.4.19 Feeder 19: R5-12.47-2

This feeder is a representation of a moderate suburban area with a heavy urban area. This is composed mainly of heavy commercial and single family residences. Approximately 38% of the circuit-feet are overhead and 62% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most loads from other feeders, and vice versa. The heavy commercial load is near the substation while the single family residences are at the end of the feeder. This is a 12.47 kV feeder with a peak load of approximately 4,200 kVA.

### B.4.20 Feeder 20: R5-12.47-3

This feeder is a representation of a moderately populated rural area. This is composed mainly of single family residences with some light commercial. Approximately 92% of the circuit-feet are overhead and 8% underground. It would be expected that this feeder has limited connections to adjacent feeders through normally open switches. Due to the low load density of the large rural area the feeder is less than 50% loaded. The majority of the load is located relatively distant with respect to the substation. Voltage regulators are used on this feeder. This is a 13.8 kV feeder with a peak load of approximately 4,800 kVA.

### B.4.21 Feeder 21: R5-12.47-4

This feeder is a representation of a moderately populated suburban and urban area. This is composed mainly of single family residences with some moderate commercial loads. Approximately 37% of the circuit-feet are overhead and 63% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. Most of the commercial load is near the substation and the residential load is spread out along the length of the entire feeder. This is a 12.47 kV feeder with a peak load of approximately 6,200 kVA.

### B.4.22 Feeder 22: R5-12.47-5

This feeder is a representation of a moderately populated suburban area with a lightly populated urban area. This is composed mainly of single family residences with some light commercial loads. Approximately 48% of the circuit-feet are overhead and 52% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. The residential load is spread out across the entire length of the feeder. The primary feeder extends a significant distance before there is any significant load, an express configuration. This is a configuration that can be seen in a well-established area when a new feeder must be routed through an existing area in order to reach areas of new load growth. This is a 12.47 kV feeder with a peak load of approximately 8,500 kVA.

### B.4.23 Feeder 23: R5-25.00-1

This feeder is a representation of a heavily populated suburban area with a moderately populated urban area. This is composed mainly of single family residences with some moderate commercial loads. Approximately 35% of the circuit-feet are overhead and 65% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 66% to ensure the ability to transfer most of the loads from other feeders, and vice versa. The residential load is spread out across the entire length of the feeder with the moderate commercial center near the substation. This is a 22.9 kV feeder with a peak load of approximately 9,300 kVA.

### B.4.24 Feeder 24: R5-35.00-1

This feeder is a representation of a moderately populated suburban area with a lightly populated urban area. This is composed mainly of single family residences with some moderate commercial loads. Approximately 10% of the circuit-feet are overhead and 90% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. The residential load is spread out across the entire length of the feeder with the moderate commercial center near the substation. This feeder is representative of a substation that is built in a “green field” where significant load growth is expected. The first feeders must go a significant distance before they reach the load, over time the load moves towards the substation and past it. This is a 34.5 kV feeder with a peak load of approximately 12,100 kVA.

# Appendix C: Simulation Technology and Methodology

Simulations of the different project technologies and programs were accomplished using the GridLAB-D software. GridLAB-D provides an agent-based multi-disciplinary environment for the examination and evaluation of emerging technologies. By providing a multi-disciplinary simulation environment, it is possible to bring together diverse teams of experts from multiple fields of study to holistically examine complex systems.

GridLAB-D has been developed through funding from the Department of Energy, Office of Electricity. Through $5.5 million of direct funding and supporting projects from DOE-OE, GridLAB-D has developed significant capabilities for analyzing smart grid deployments. The capabilities center on the functionality needed to simulate a distribution feeder power flow and attached loads. The development has included: unbalanced three-phase power flow solvers; detailed end-use models, particularly of a residential home's thermal integrity, HVAC cycles and water heater cycles; and a transactive market that supports double auction bidding. Different combinations of these capabilities enabled simulations of the various technologies and programs evaluated in this report.

GridLAB-D conducts time-series simulations with variable time steps. The solution at each time step is a quasi-steady state solution for each of the modules. Convergence is achieved within each module and convergence across modules is coordinated via the GridLAB core as illustrated in Figure C.1.

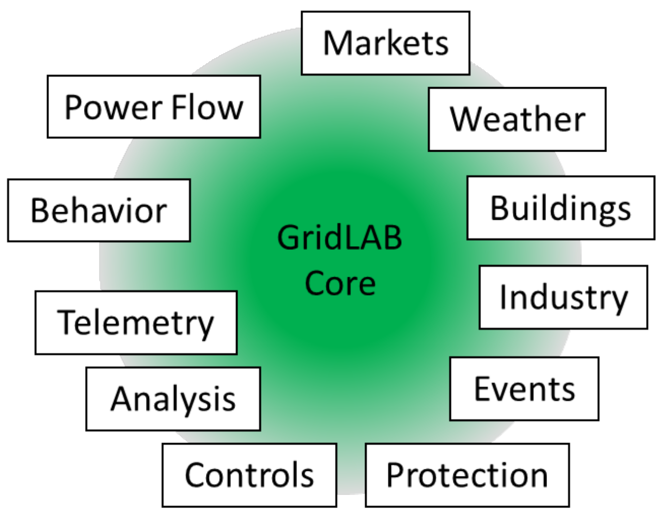



Figure C.1: GridLAB-D architecture

Time steps are also coordinated by the GridLAB-D core. This is necessary because the various modules in the simulation will generally have different time step requirements. At the end of a time step, every object in the model returns a ‘sync’ time that indicates how long the object will remain constant without outside influence.  The GridLAB core then examines every object and determines what the smallest sync time is; this then becomes length of the next step.  This process is performed at every time step so that the system has a variable step size.  For a given state variable an example of the variable step sizes are shown in Figure C.2.

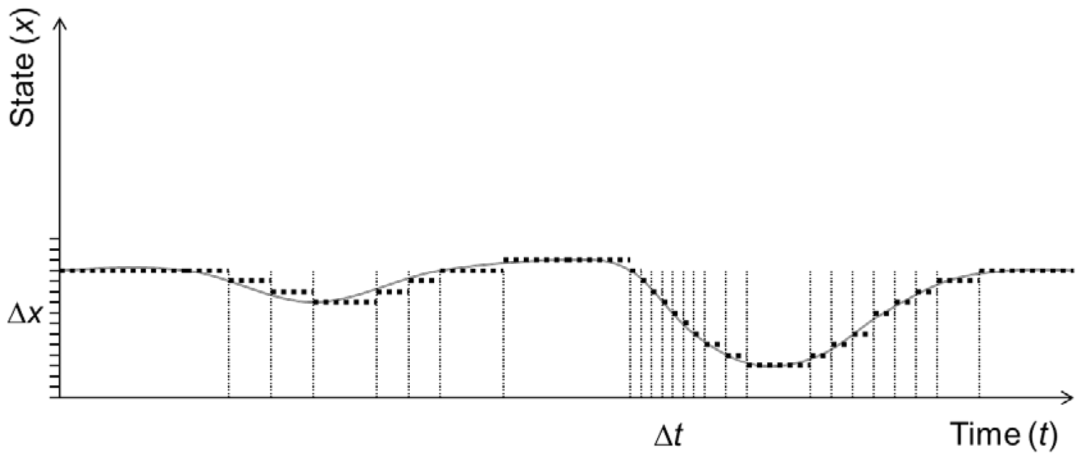



Figure C.2: Variable step sizes in GridLAB-D simulation

When analyzing operations at the distribution level, the major dynamics of interest are mid-term and occur on the order of minutes to hours.  For the purposes of this analysis, a minimum time step of one minute was enforced.  For operations that occur at intervals of less than one minute, such as a 45-second delay on a voltage regulator, the operation is aggregated up to the one minute time step; multiple operations cannot occur during the enforced minimum of one minute.  Because of the large number of objects and the forced minimum, the simulation proceeded at one-minute time steps for the majority of the simulations.  As a result, there are approximately 500,000 time steps in an annual simulation of a single prototypical feeder.

Since the simulations for the SGIG analysis are being conducted over a one year period, the minimum step size has been set to one minute.  Even with a minimum one minute step size there is the possibility of 525,600 time steps in a single simulation.  If a one second minimum step size were used there would be no significant increase in accuracy because most of the dynamic behavior has a time constant greater than one minute.  Additionally, the number of time steps would increase by a factor of sixty resulting in significantly more computing time.

# Appendix D: Plots for Individual Feeder Results

This appendix contains the individual plots for each of the prototypical feeds for each technology, where necessary. Depending on the technology, different values will be plotted, consistent with those shown in Section 3.

## D.1 VVO Plots

Consistent with the plots shown in Section 3.1.1, peak monthly demand, monthly energy consumption, and monthly $CO_2$ emissions plot 'Base Case' and 'VVO'. Monthly losses plots "Base' and 'VVO' for 4 different loss types; losses in overhead lines 'OHL', underground lines 'UGL', transformers 'TFR', and triplex lines 'TPL'.

### D.1.1 Detailed VVO Plots for GC-12.47-1_R1

The plots for this feeder were already presented in Section 3.1.1.

### D.1.2 Detailed VVO Plots for R1-12.47-1

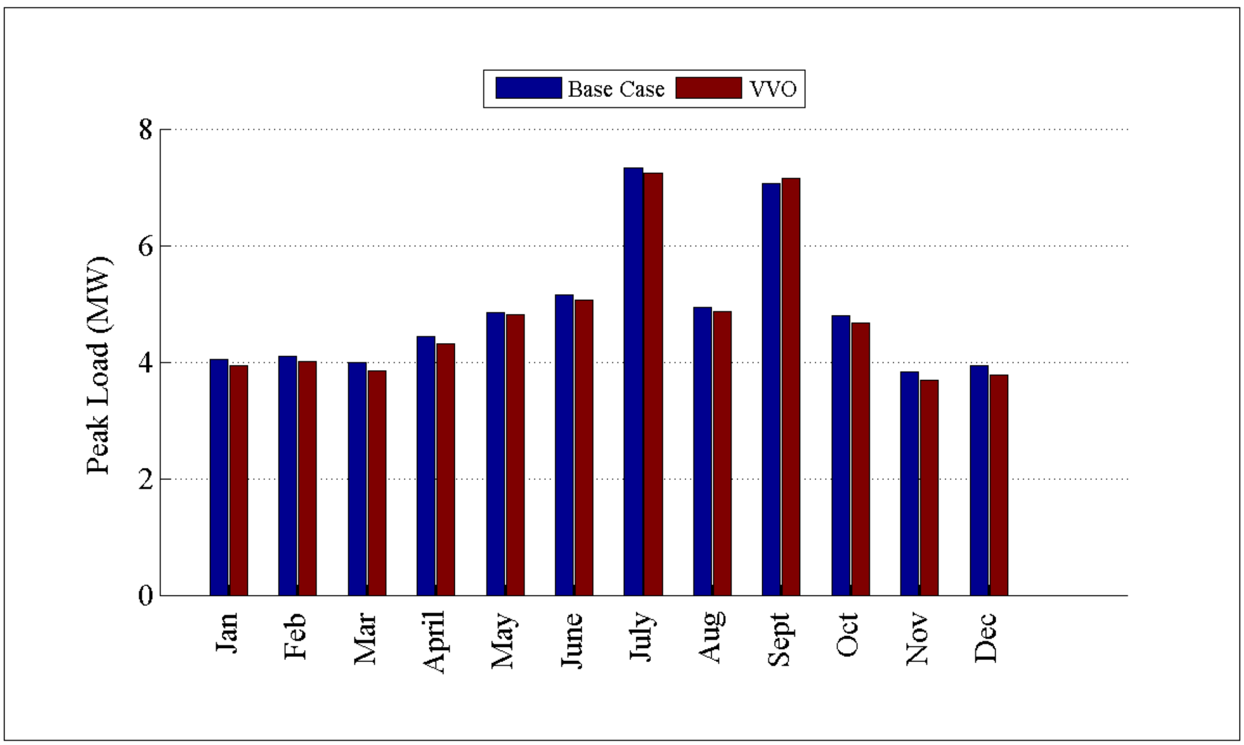



Figure D.1: Comparison of peak load by month for R1-12.47-1

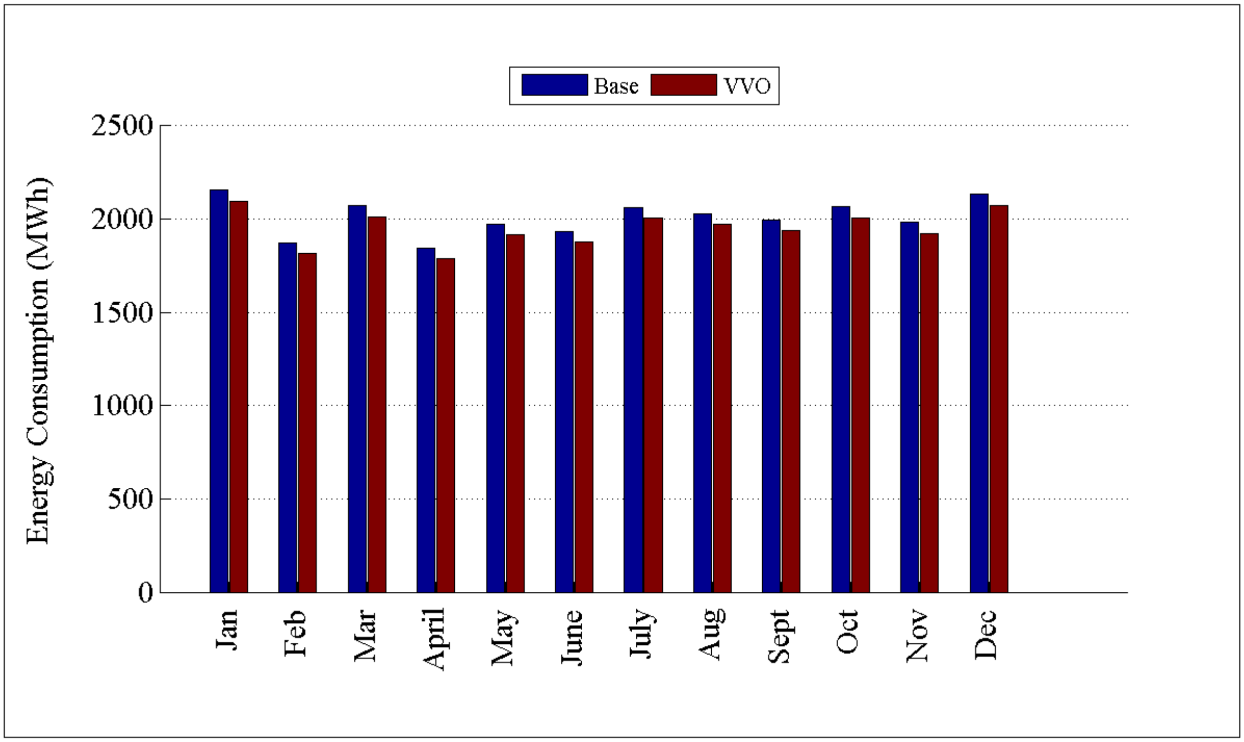



Figure D.2: Comparison of energy consumption by month for R1-12.47-1

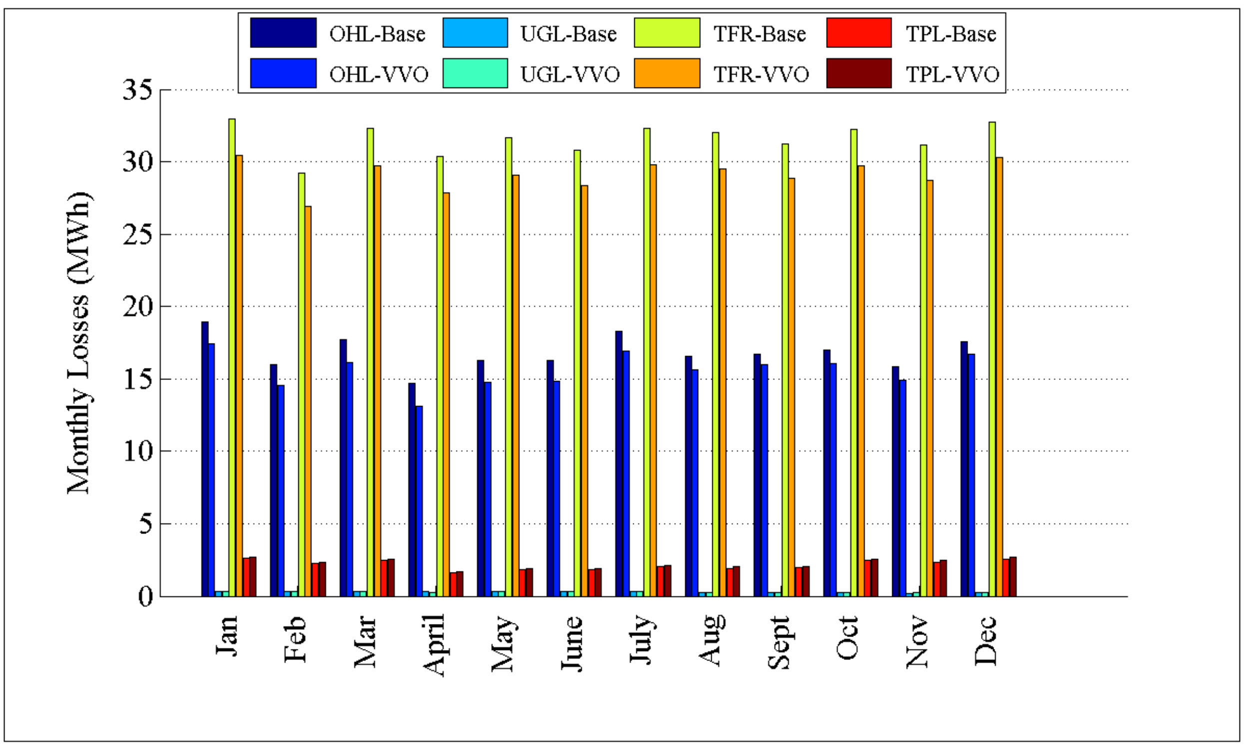



Figure D.3: Comparison of losses by month for R1-12.47-1

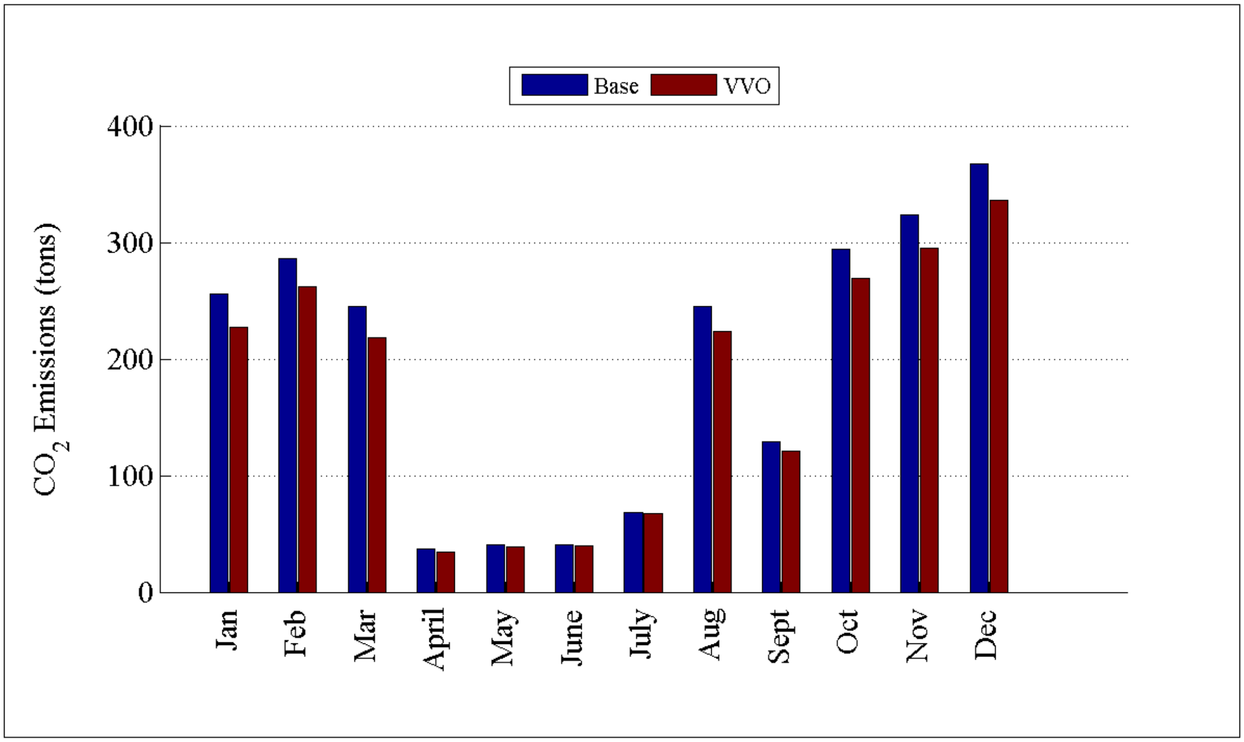



Figure D.4: Comparison of $CO_2$ emissions by month for R1-12.47-1

## D.1.3 Detailed VVO Plots for R1-12.47-2

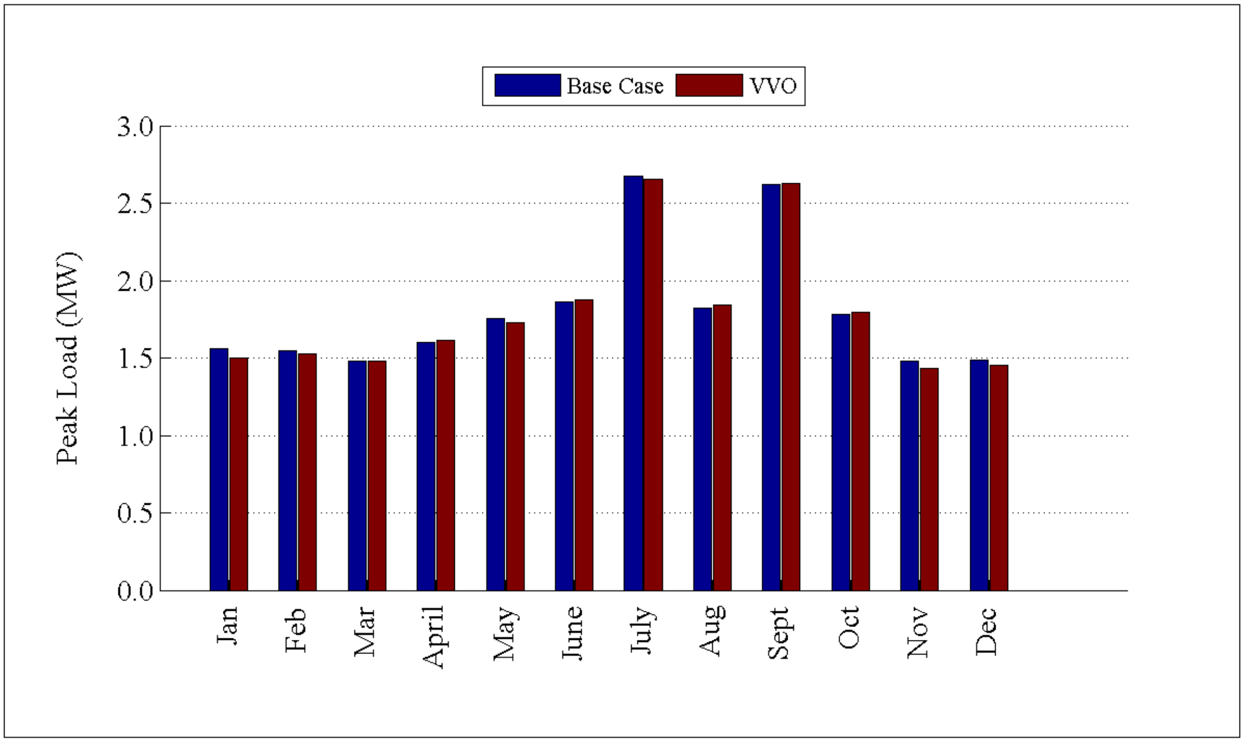



Figure D.5: Comparison of peak load by month for R1-12.47-2

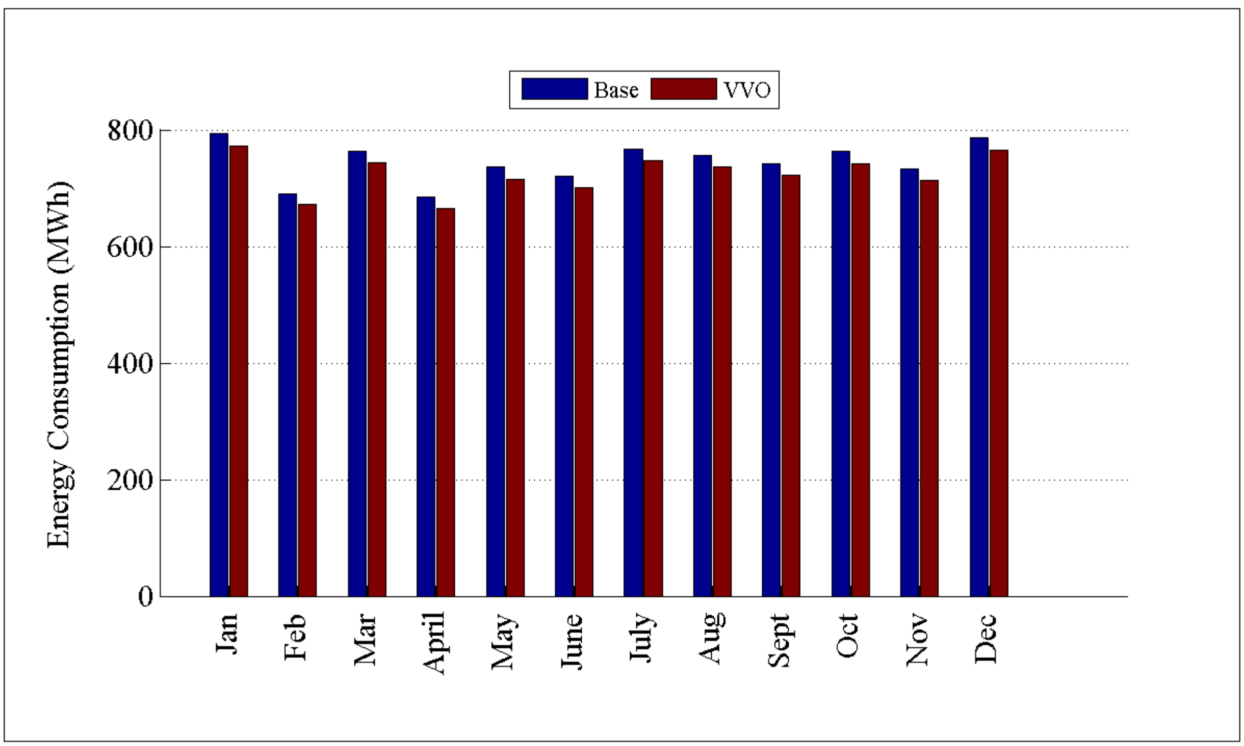



Figure D.6: Comparison of energy consumption by month for R1-12.47-2

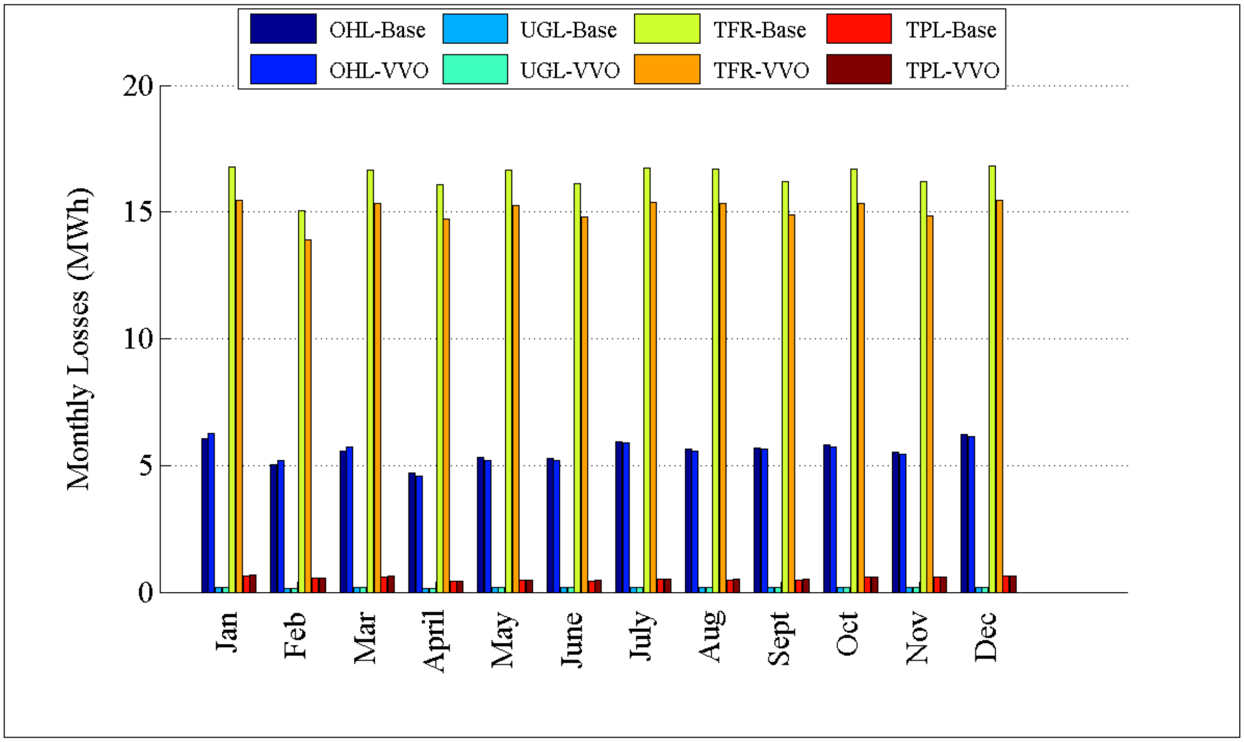



Figure D.7: Comparison of losses by month for R1-12.47-2

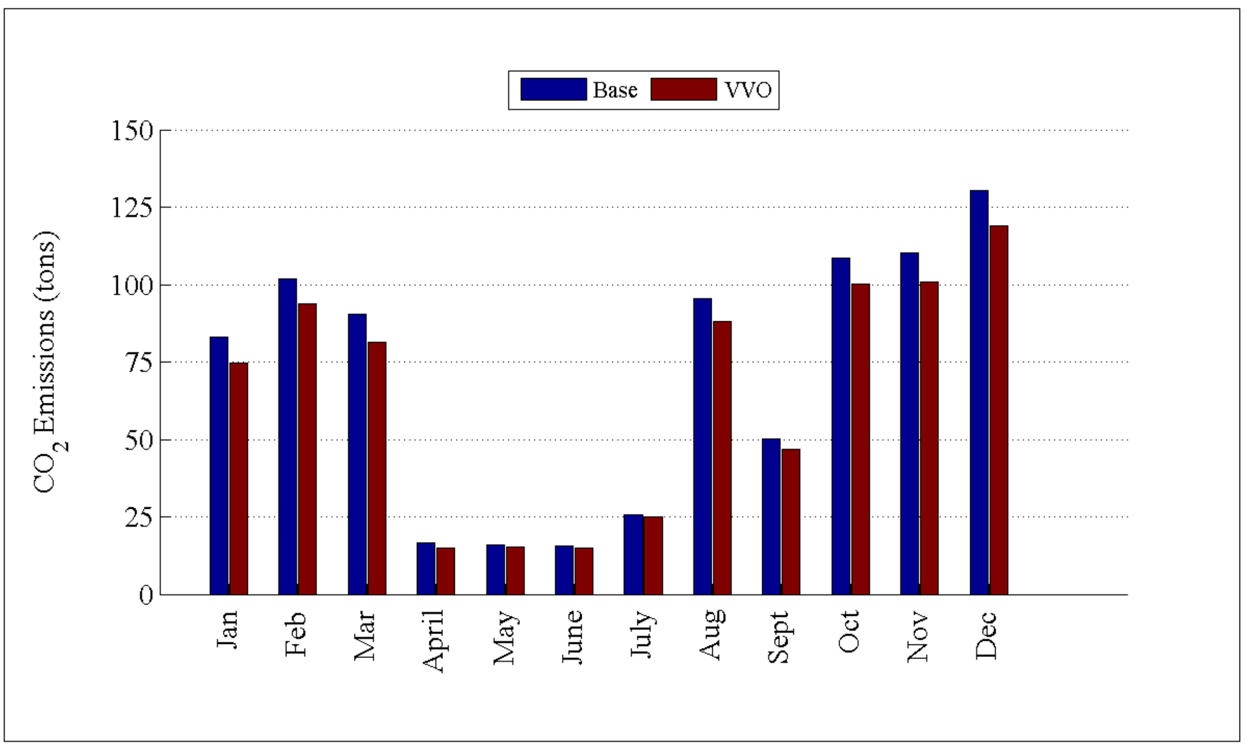



Figure D.8: Comparison of $CO_2$ emissions by month for R1-12.47-2

### D.1.4 Detailed VVO Plots for R1-12.47-3

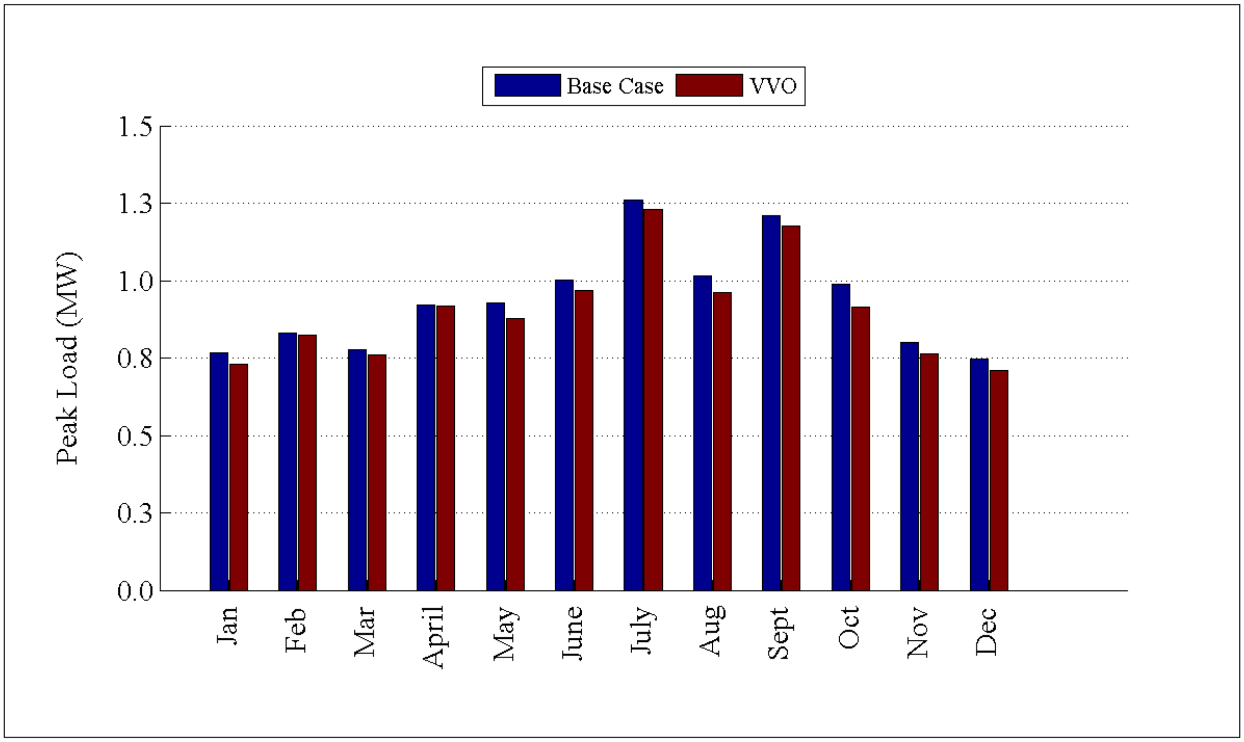



Figure D.9: Comparison of peak load by month for R1-12.47-3

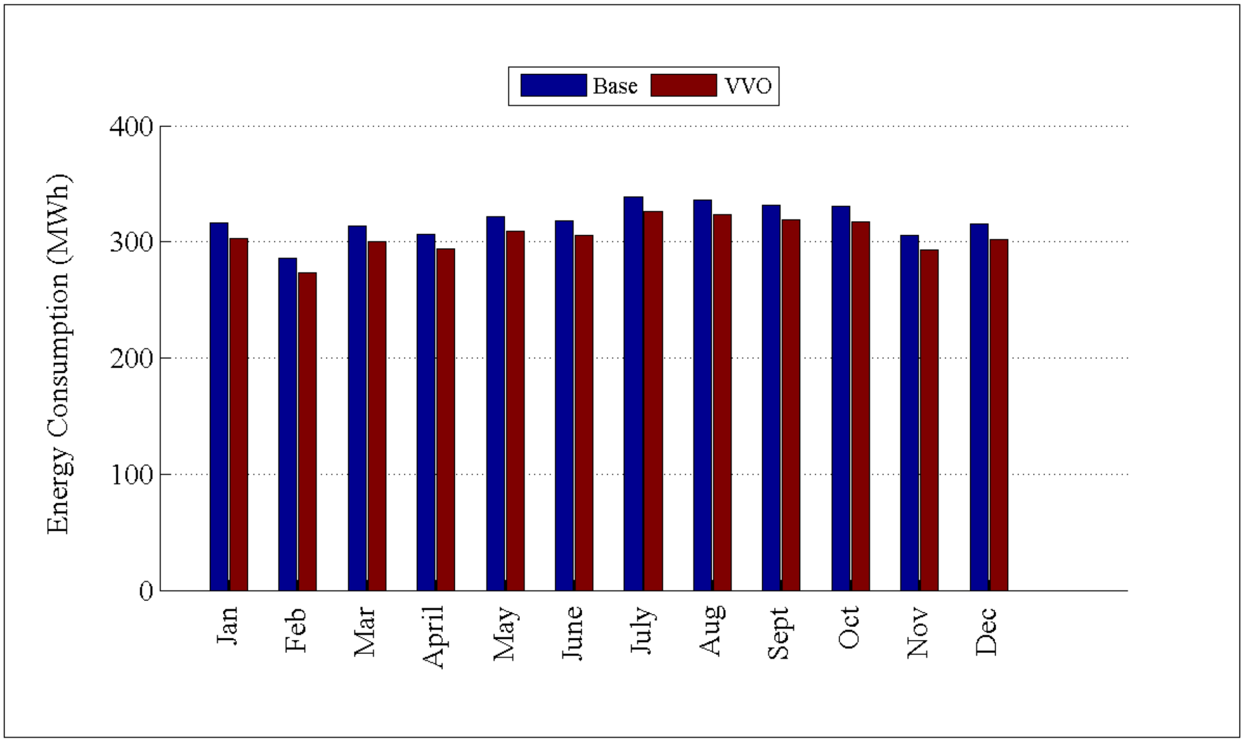



Figure D.10: Comparison of energy consumption by month for R1-12.47-3

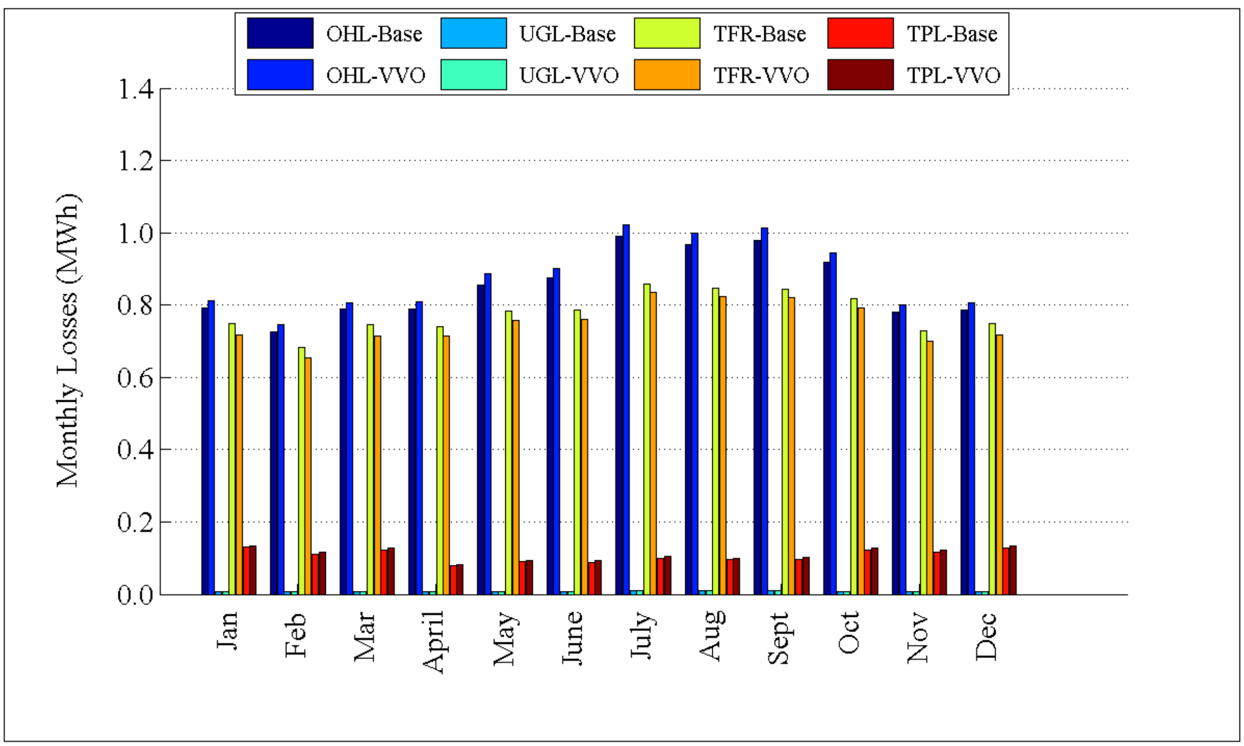



Figure D.11: Comparison of losses by month for R1-12.47-3

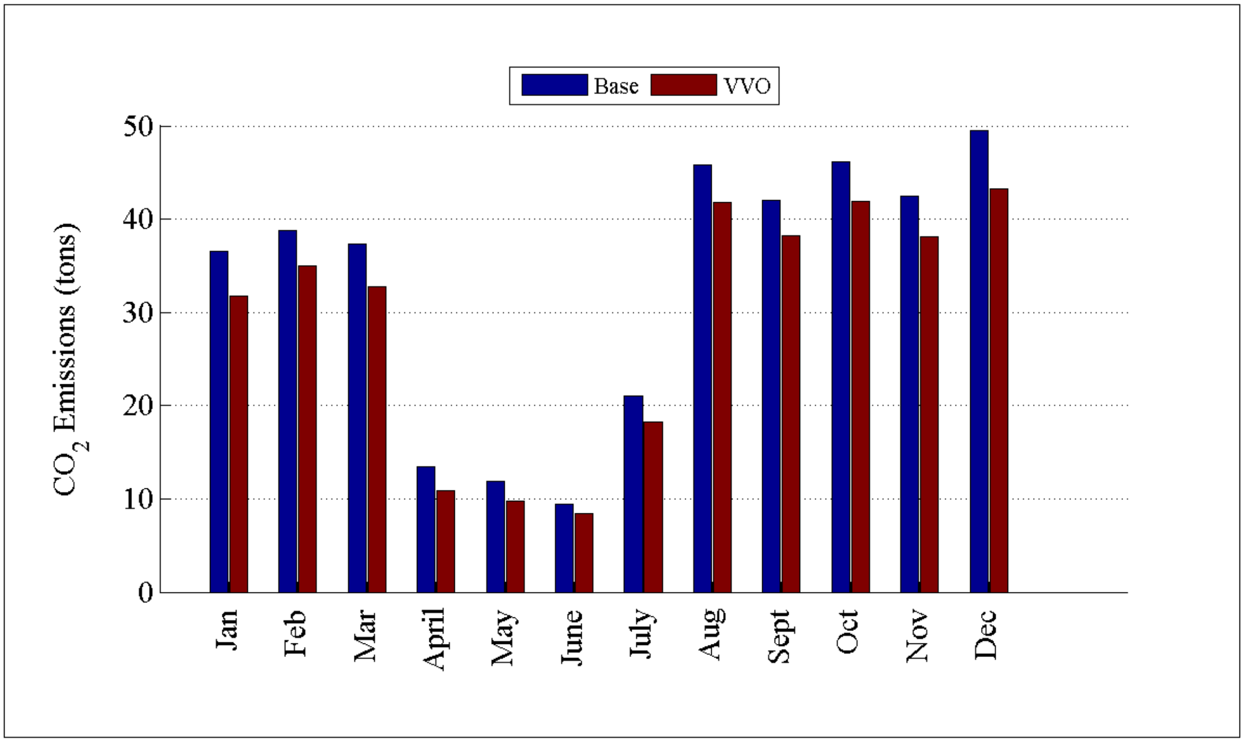



Figure D.12: Comparison of $CO_2$ emissions by month for R1-12.47-3

## D.1.5 Detailed VVO Plots for R1-12.47-4

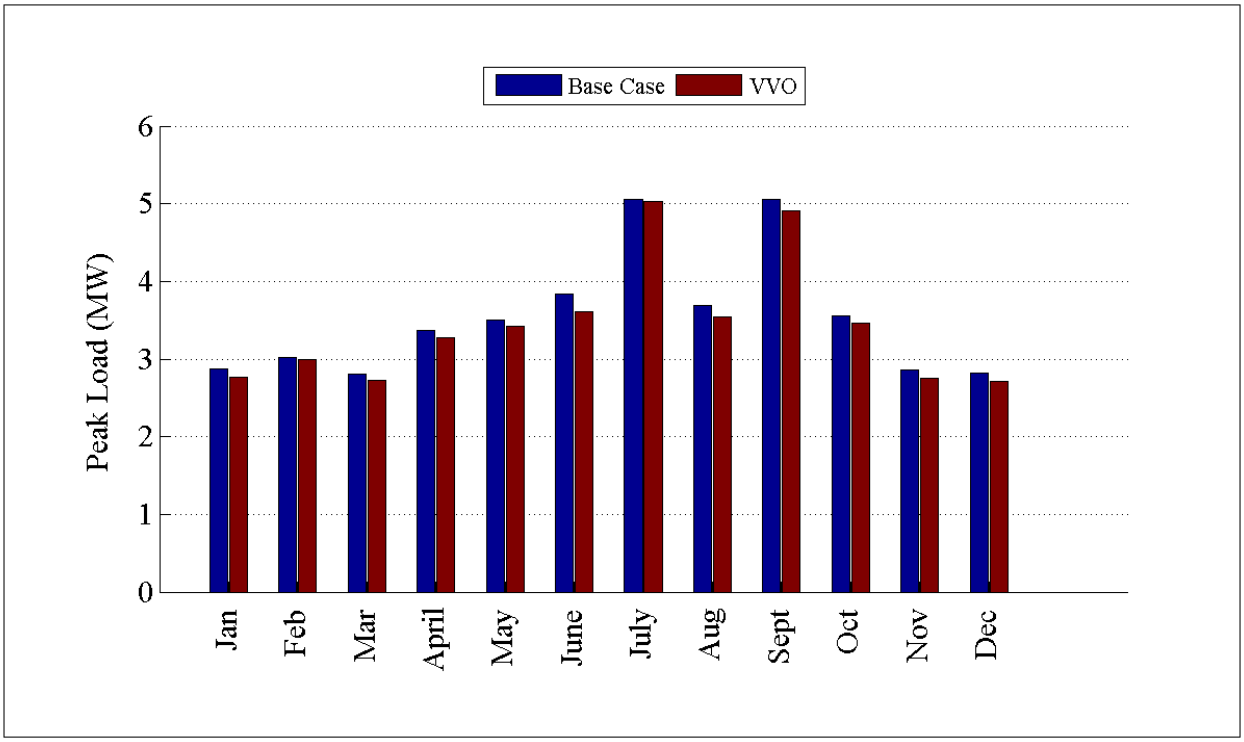



Figure D.13: Comparison of peak load by month for R1-12.47-4

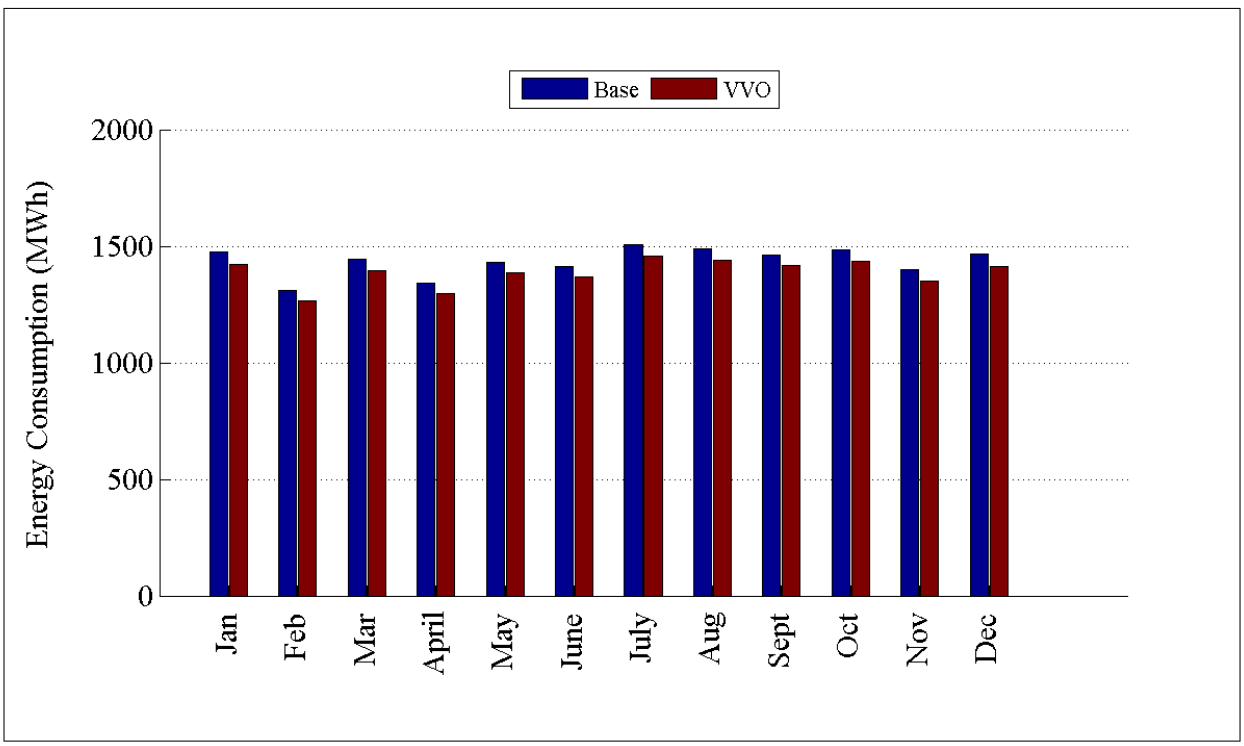



Figure D.14: Comparison of energy consumption by month for R1-12.47-4

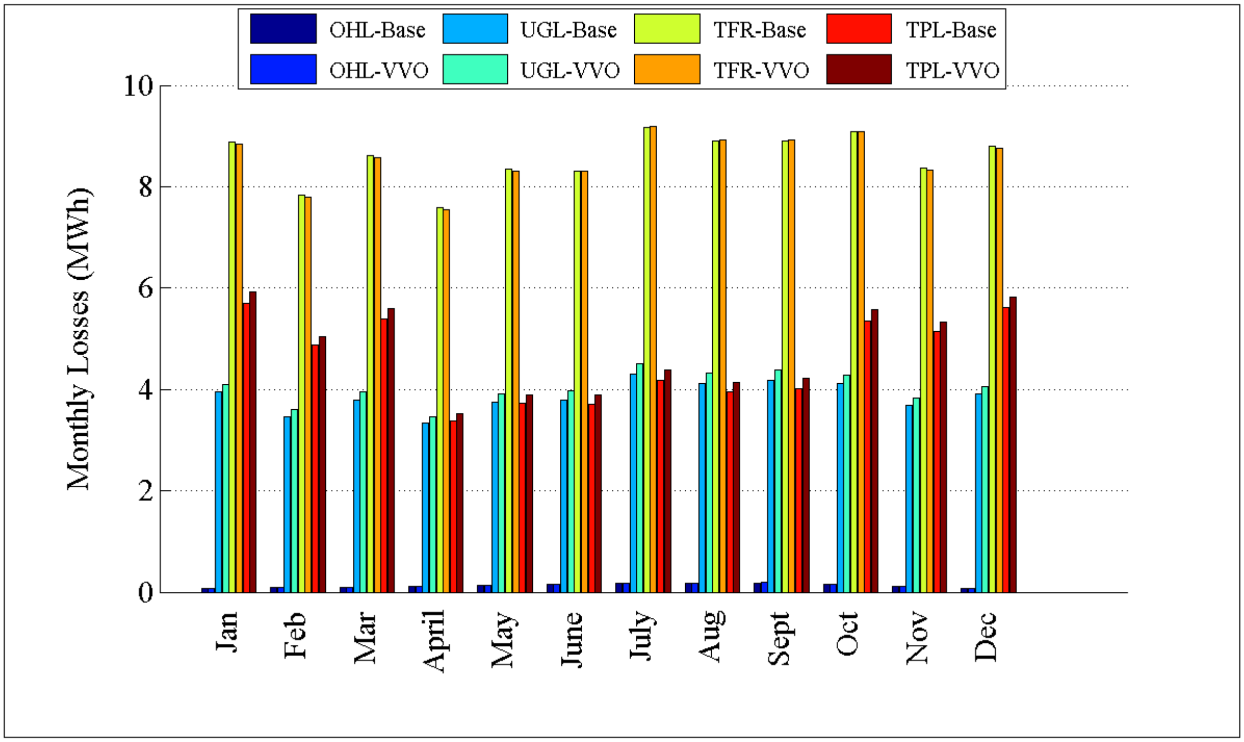



Figure D.15: Comparison of losses by month for R1-12.47-4

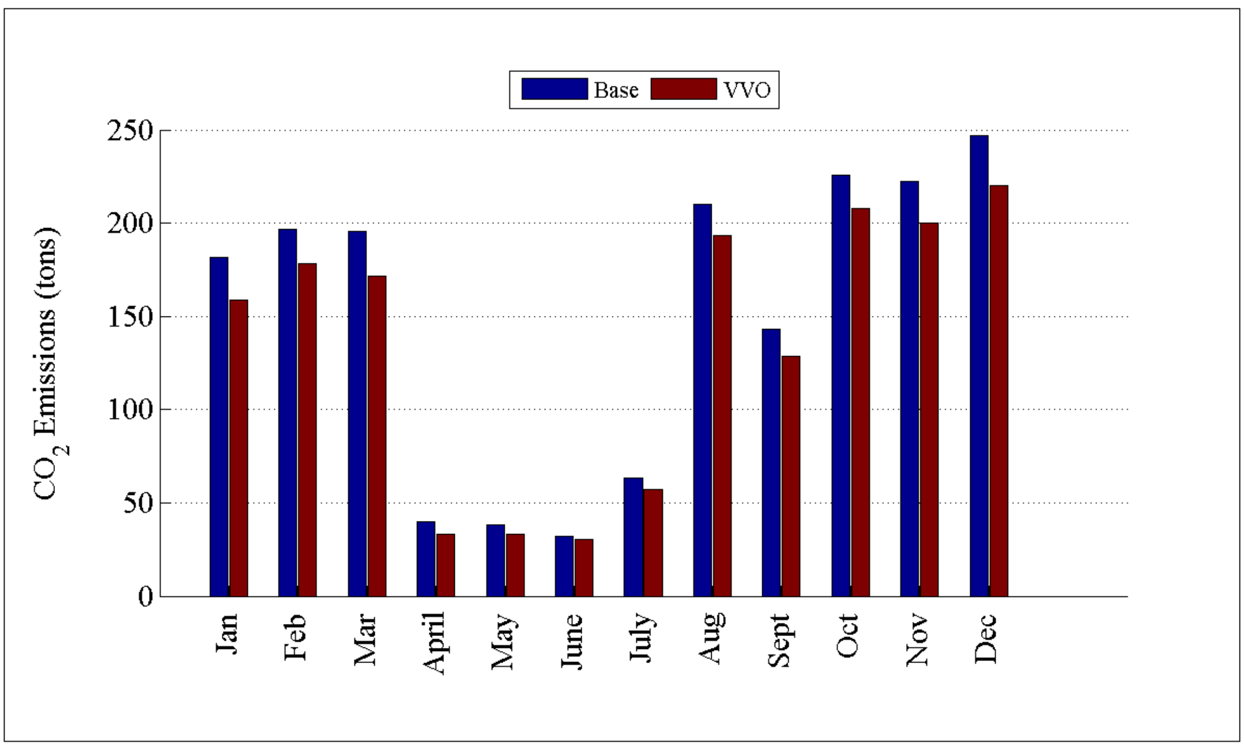



Figure D.16: Comparison of $CO_2$ emissions by month for R1-12.47-4

## D.1.6 Detailed VVO Plots for R1-25.00-1

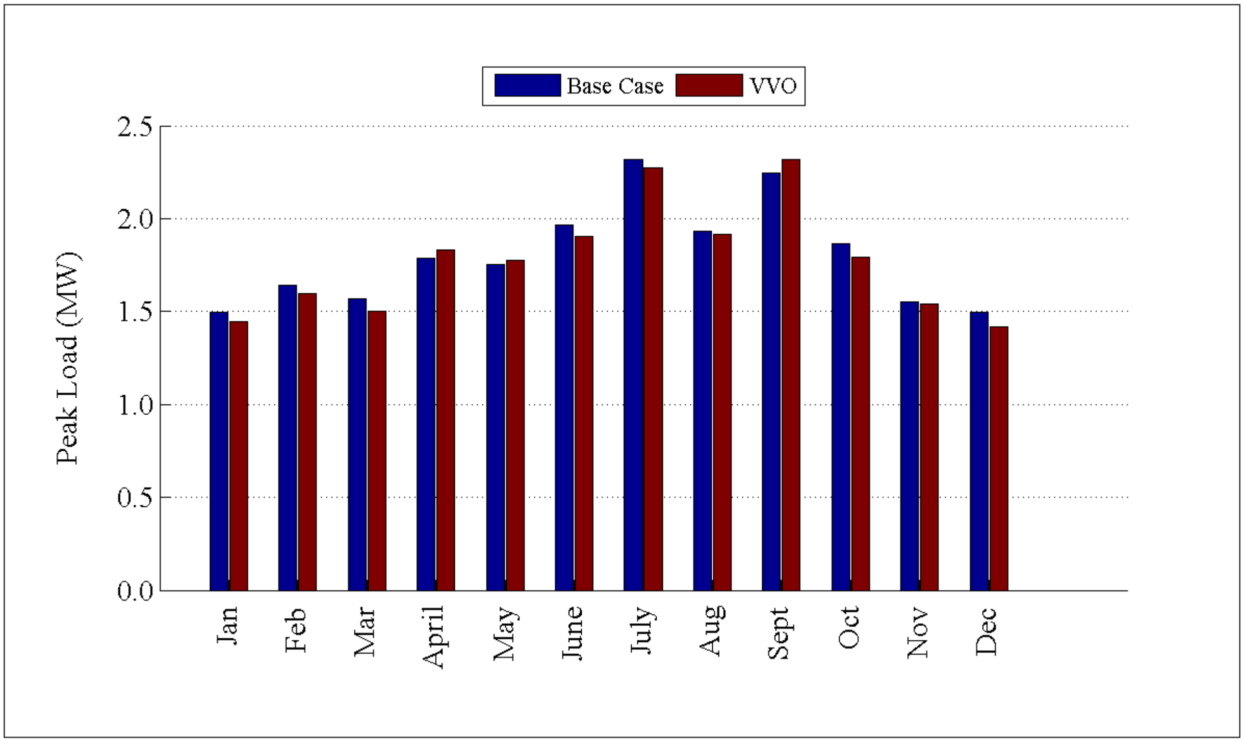



Figure D. 17: Comparison of peak load by month for R1-25.00-1

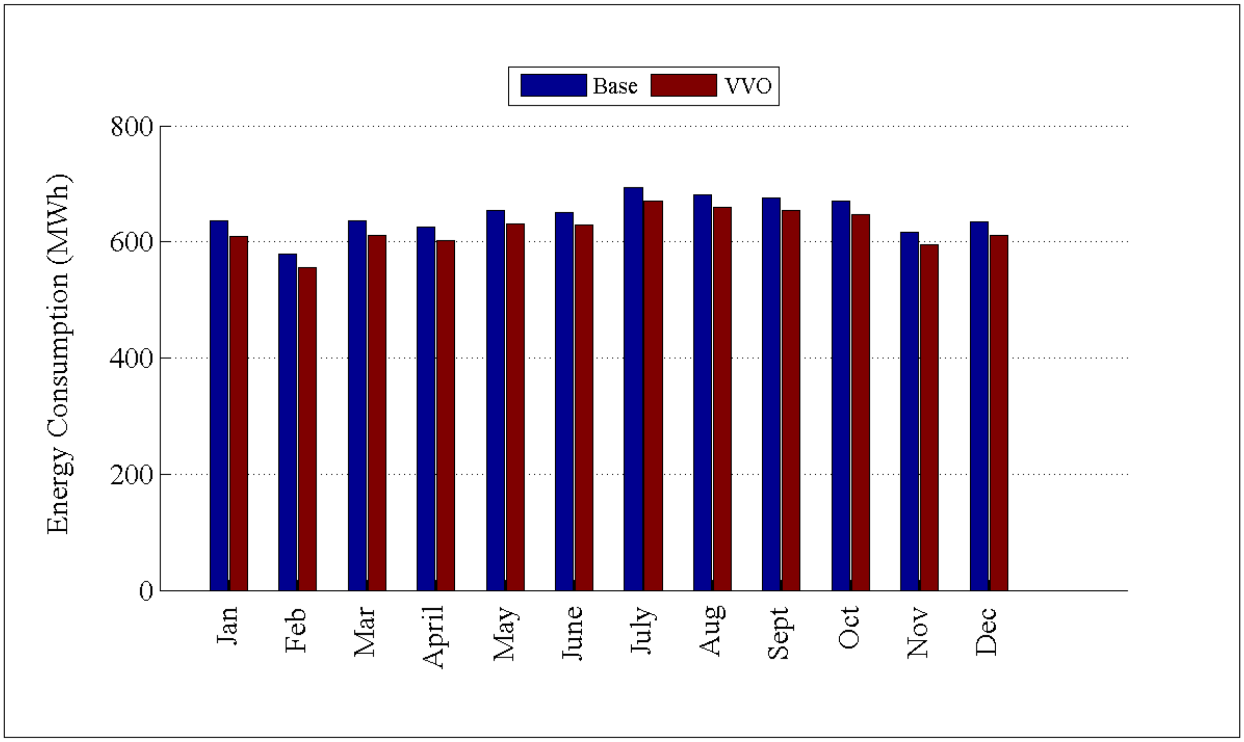



Figure D. 18: Comparison of energy consumption by month for R1-25.00-1

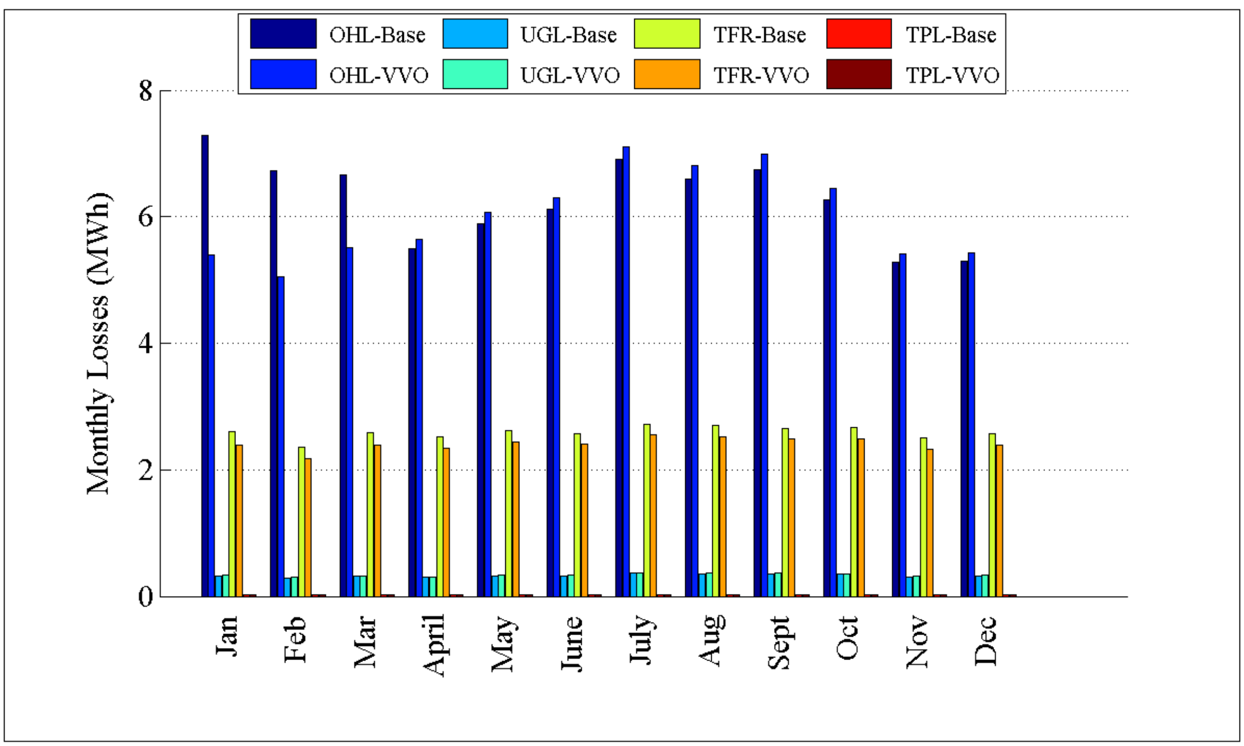



Figure D. 19: Comparison of losses by month for R1-25.00-1

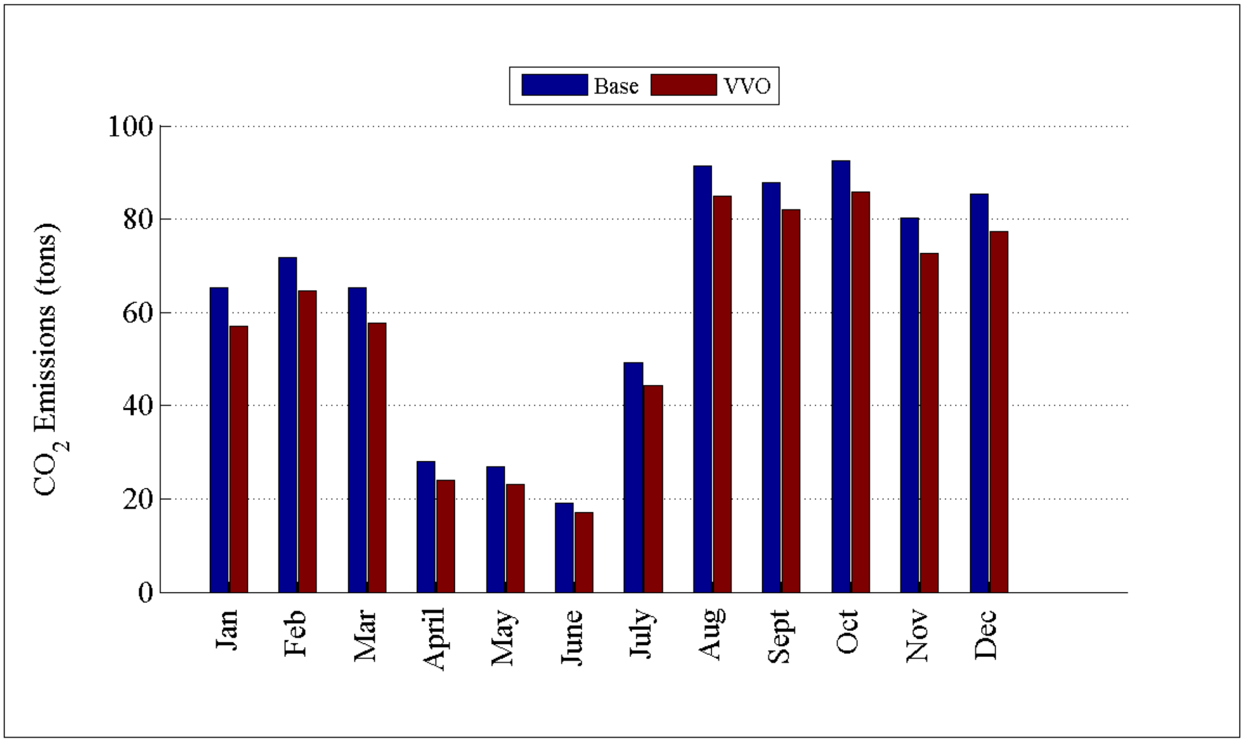



Figure D. 20: Comparison of $CO_2$ emissions by month for R1-25.00-1

## D.1.7 Detailed VVO Plots for GC-12.47-1_R2

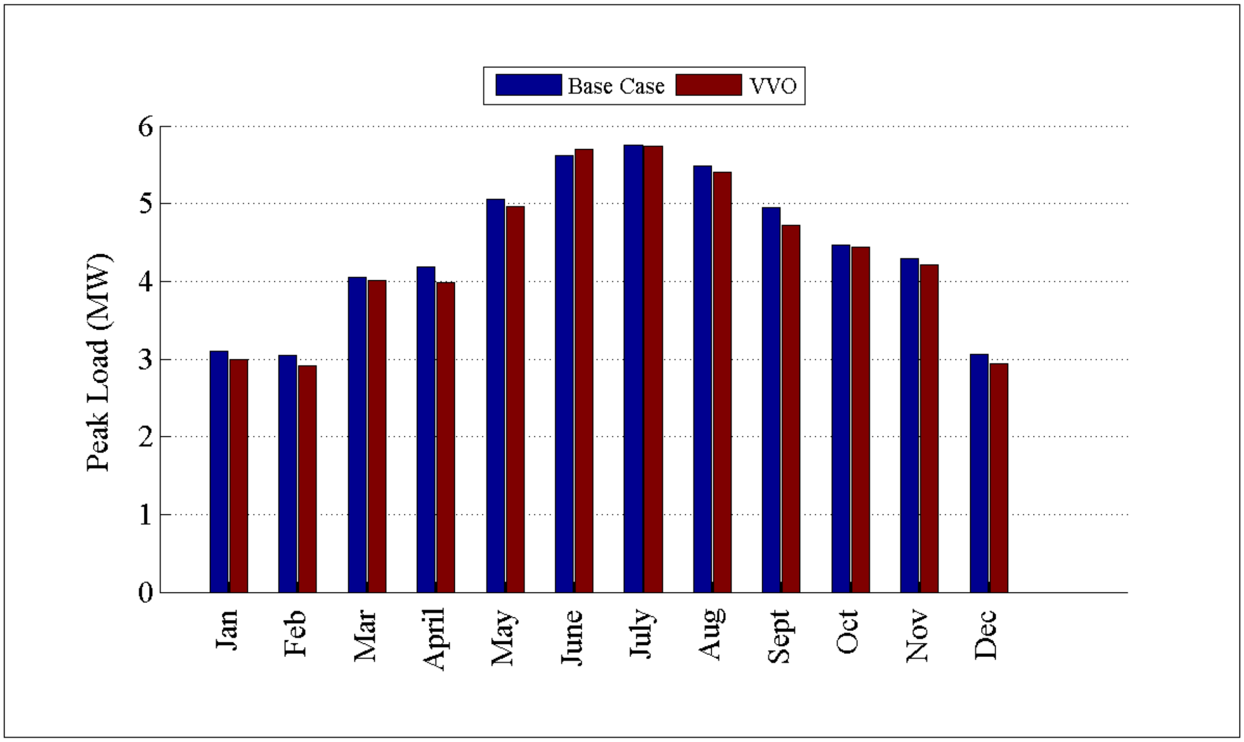



Figure D.21: Comparison of peak load by month for GC-12.47-1_R2

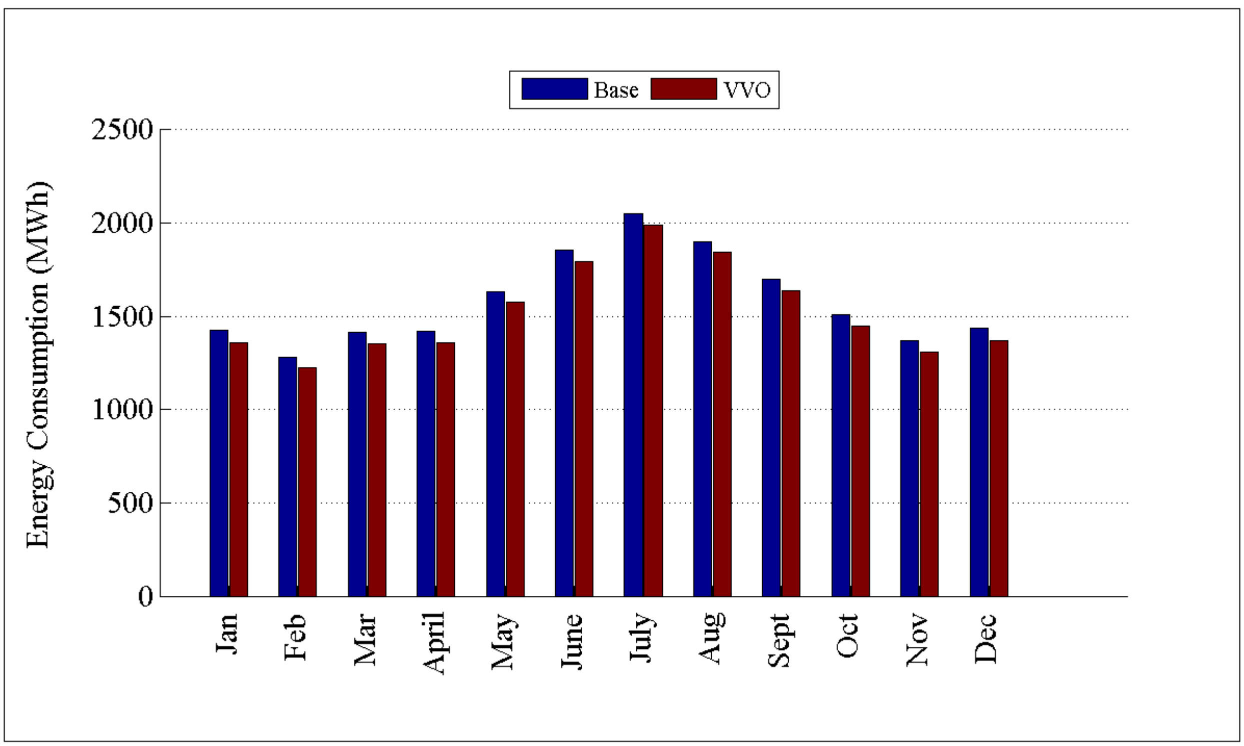



Figure D.22: Comparison of energy consumption by month for GC-12.47-1_R2

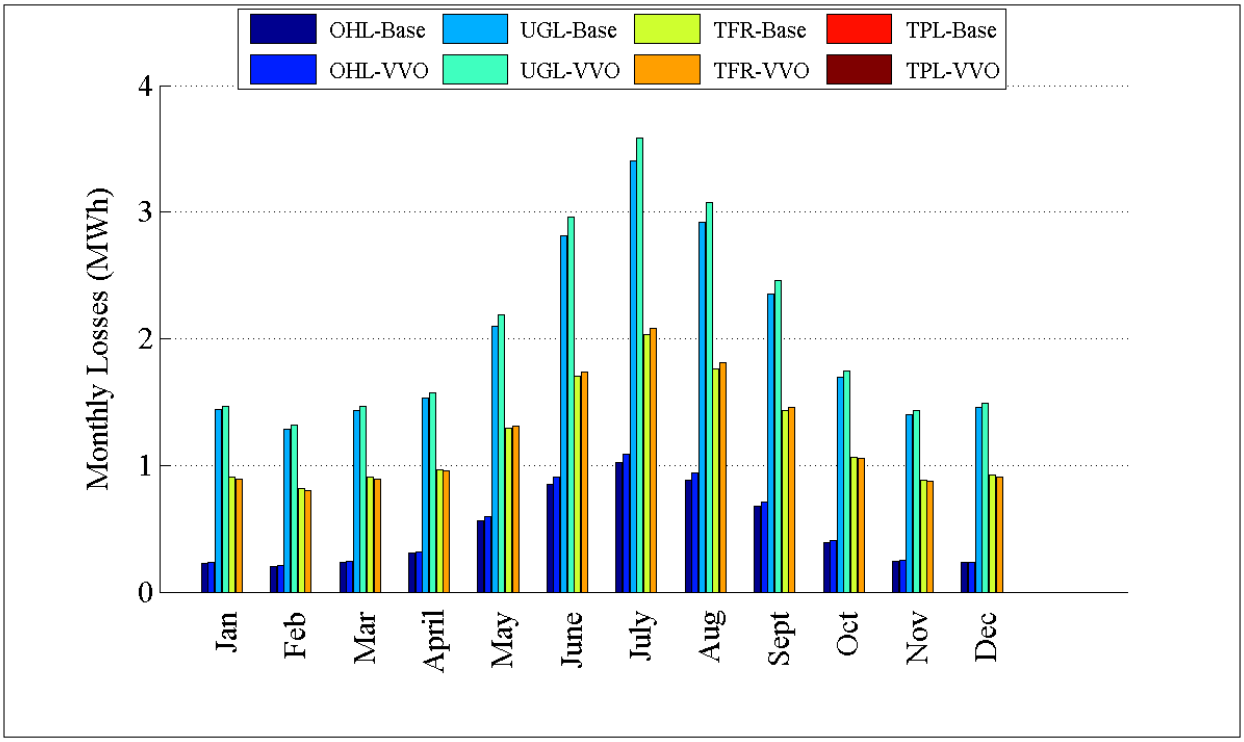



Figure D.23: Comparison of losses by month for GC-12.47-1_R2

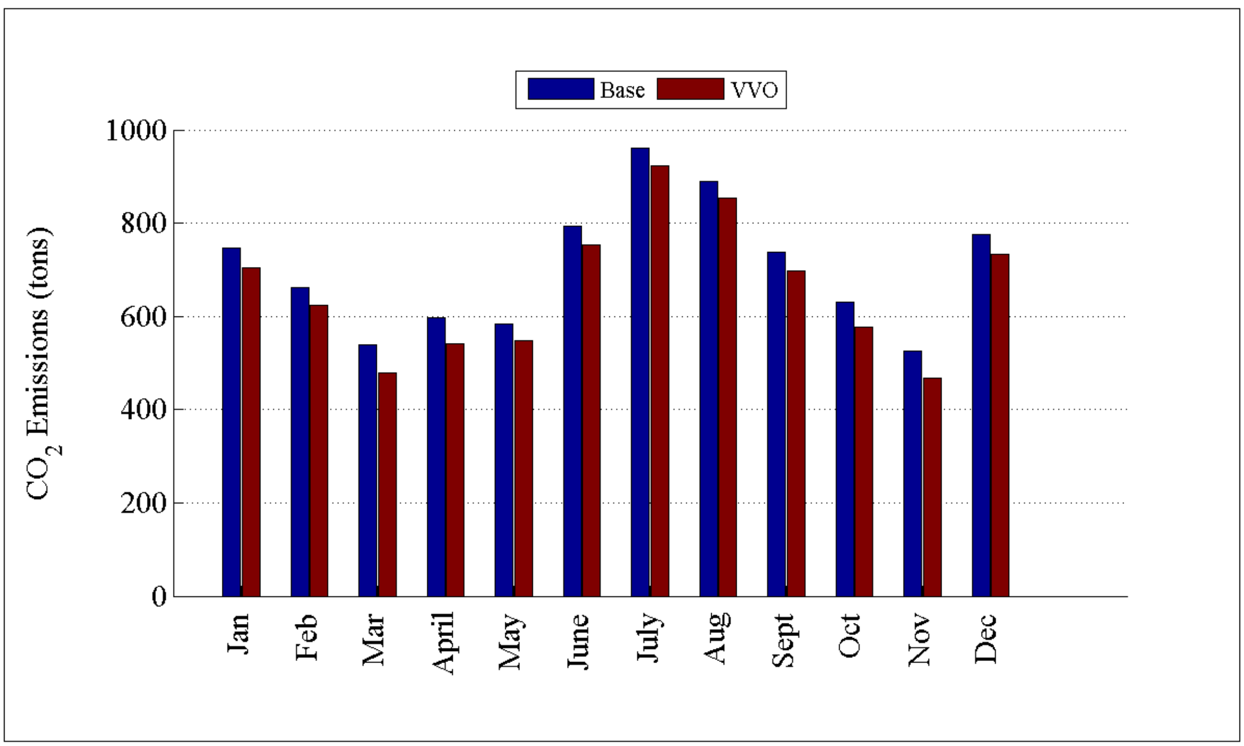



Figure D.24: Comparison of $CO_2$ emissions by month for GC-12.47-1_R2

### D.1.8 Detailed VVO Plots for R2-12.47-1

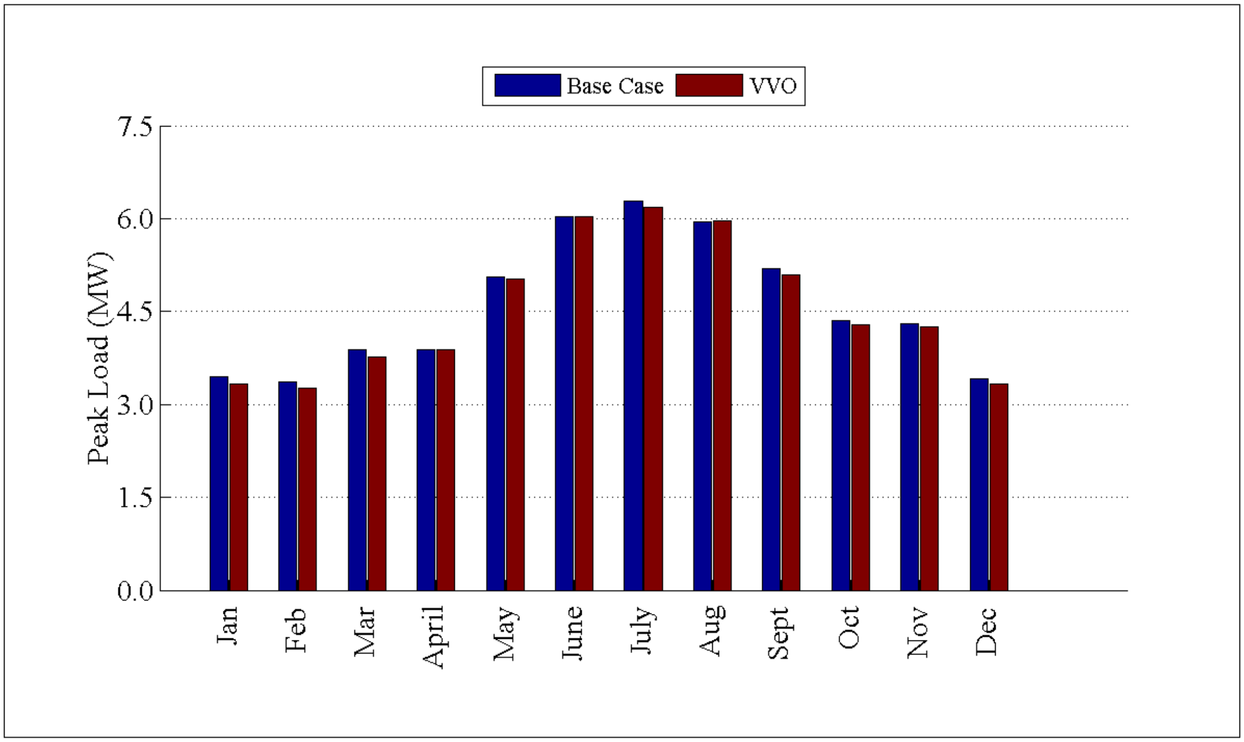



Figure D.25: Comparison of peak load by month for R2-12.47-1

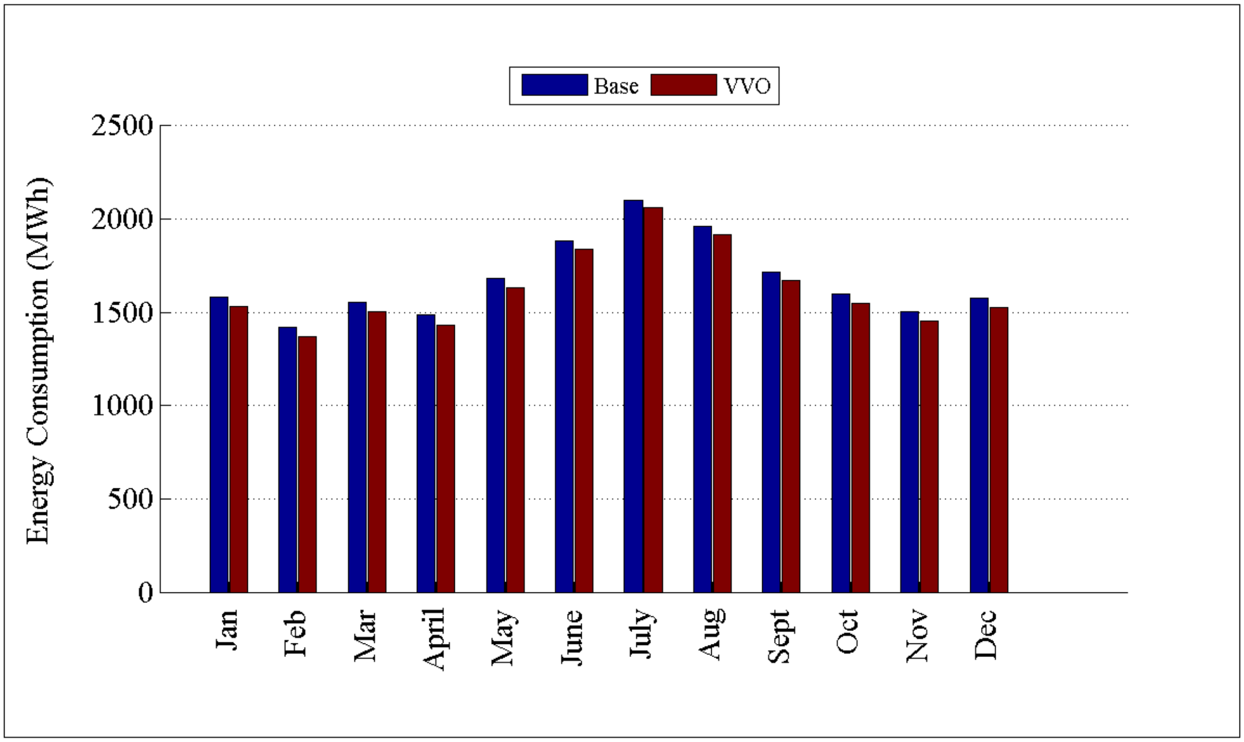



Figure D.26: Comparison of energy consumption by month for R2-12.47-1

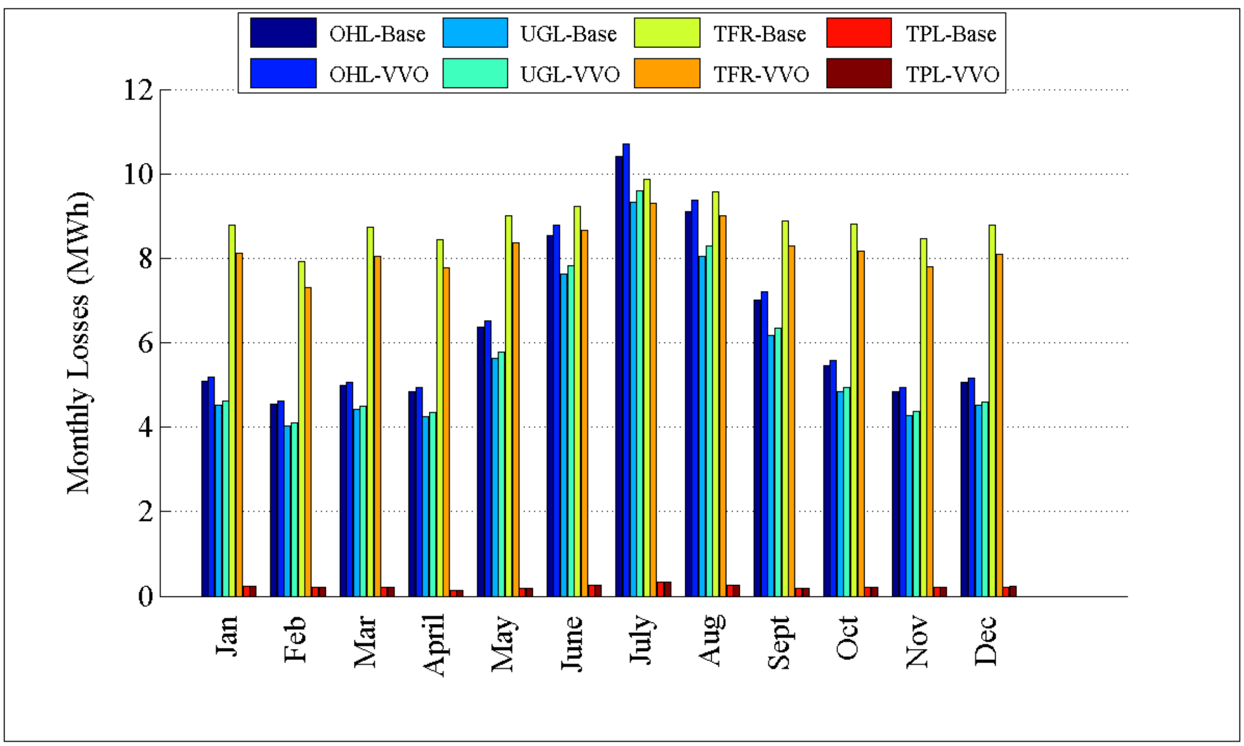



Figure D.27: Comparison of losses by month for R2-12.47-1

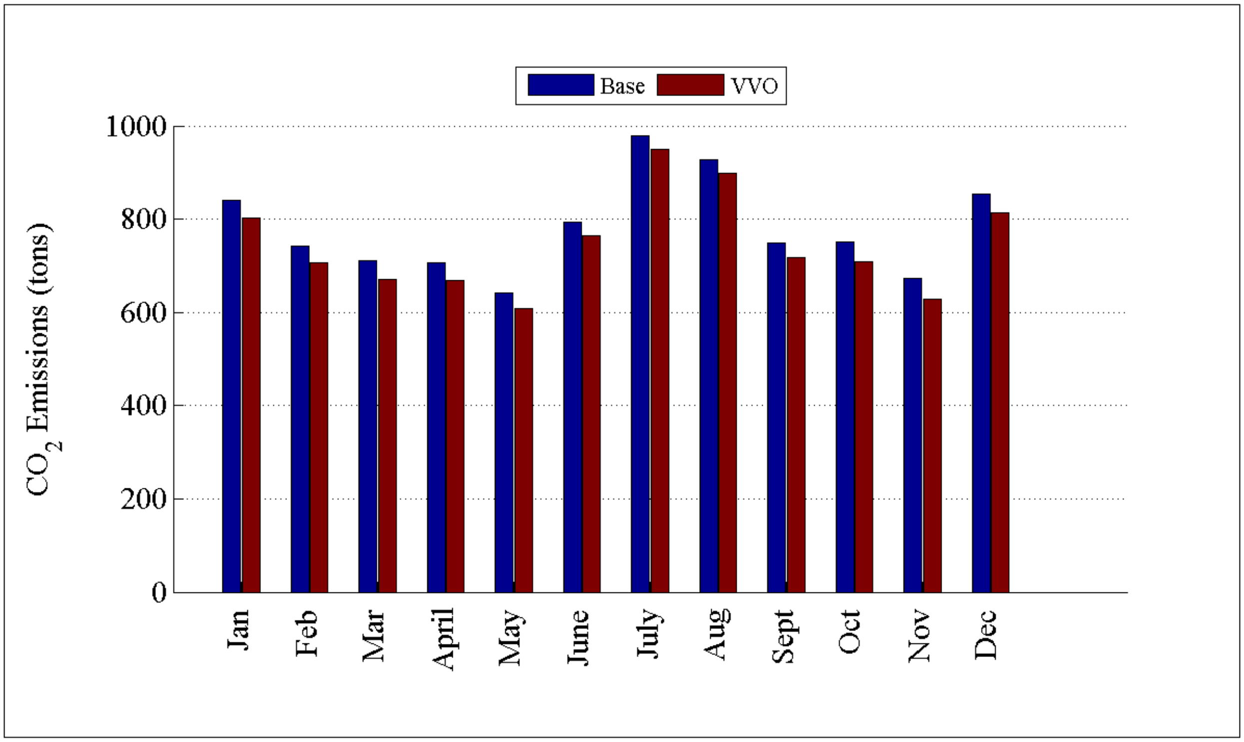



Figure D.28: Comparison of $CO_2$ emissions by month for R2-12.47-1

### D.1.9 Detailed VVO Plots for R2-12.47-2

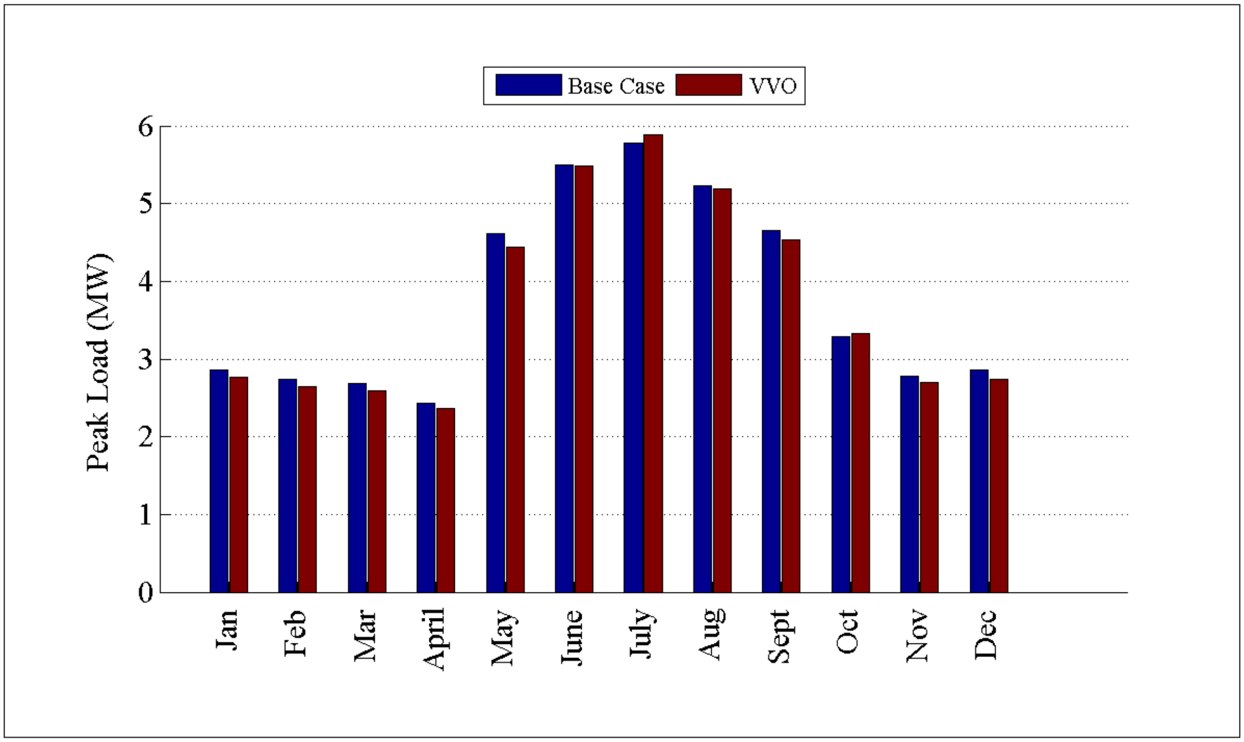



Figure D.29: Comparison of peak load by month for R2-12.47-2

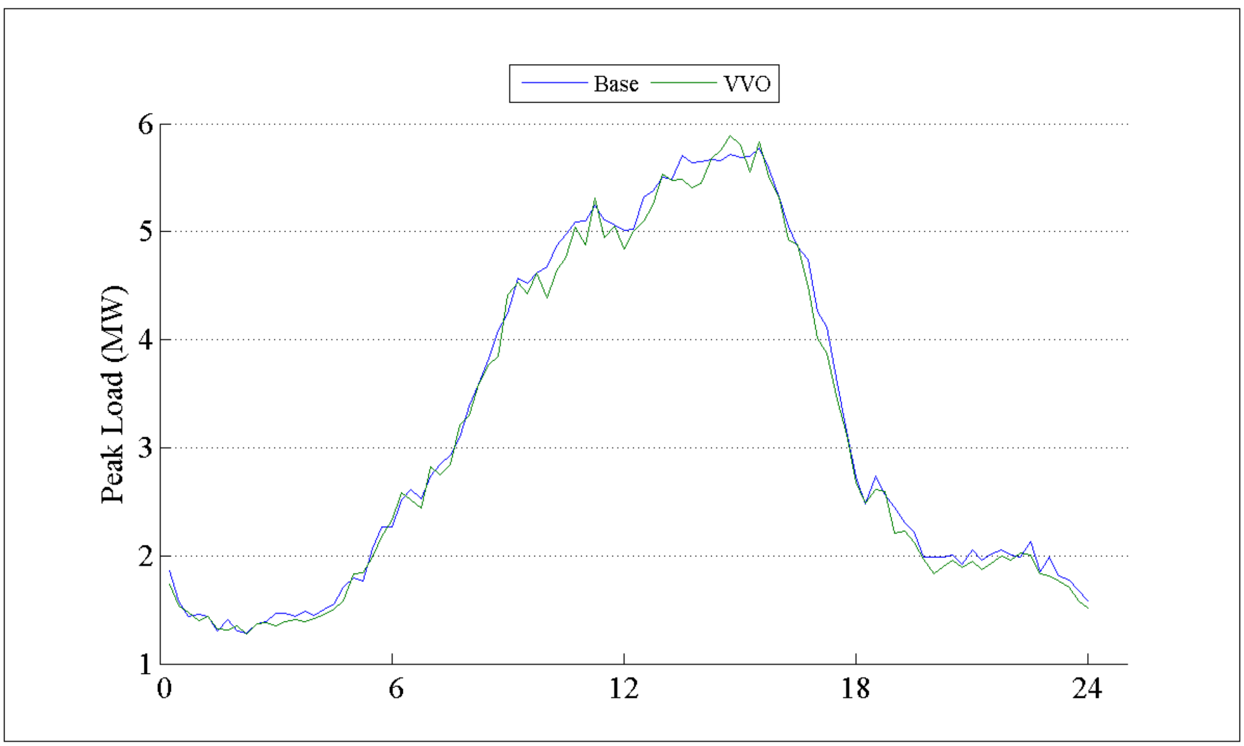



Figure D.30:Peak load day for R2-12.47-2

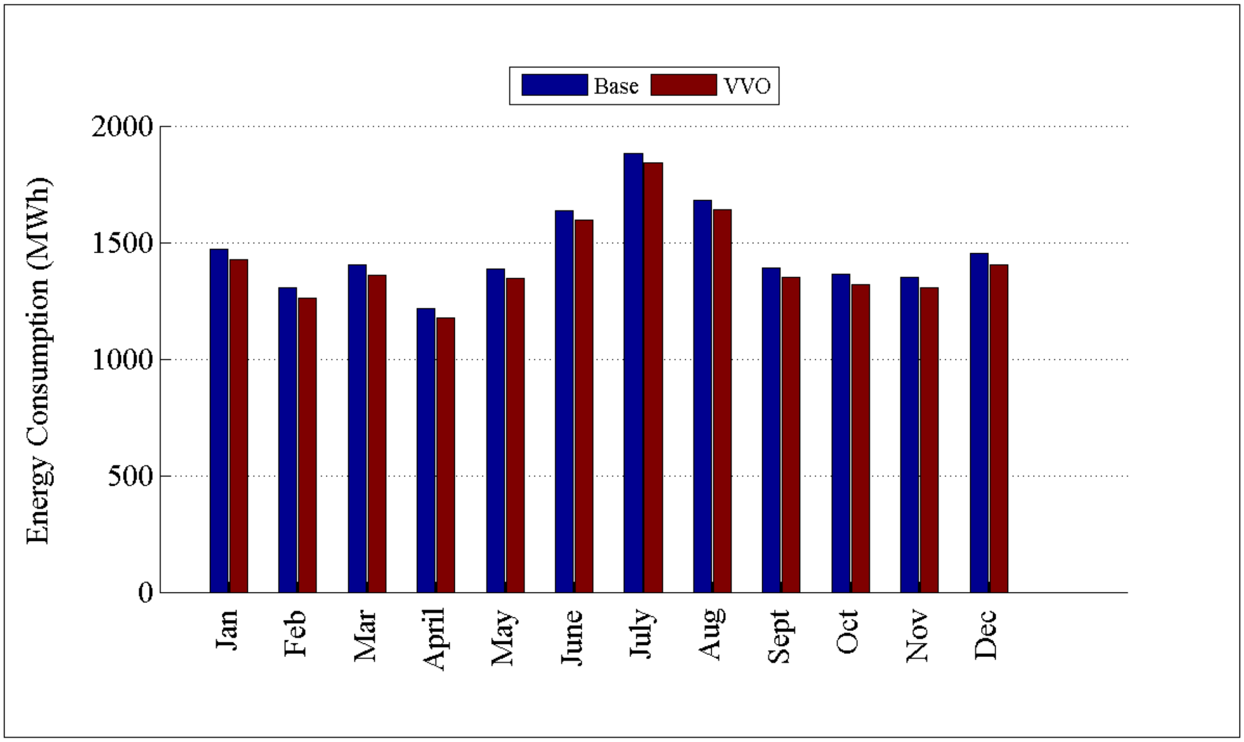



Figure D.31: Comparison of energy consumption by month for R2-12.47-2

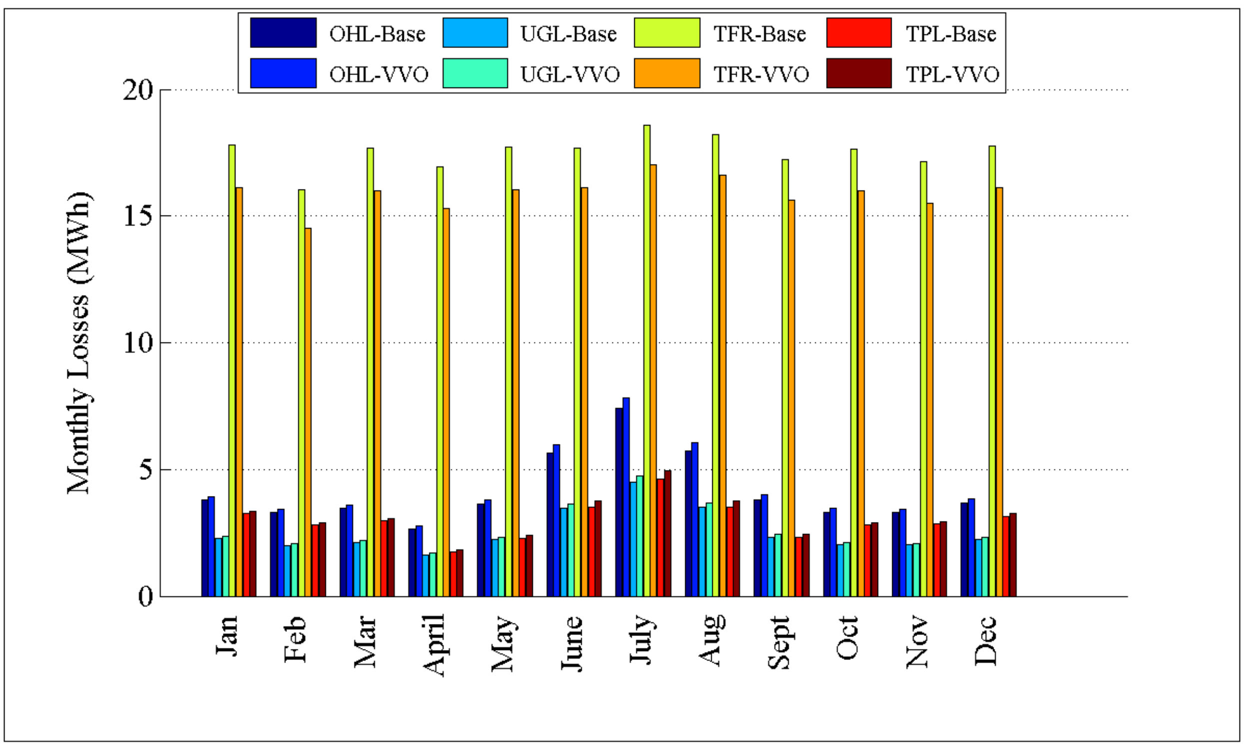



Figure D.32: Comparison of losses by month for R2-12.47-2

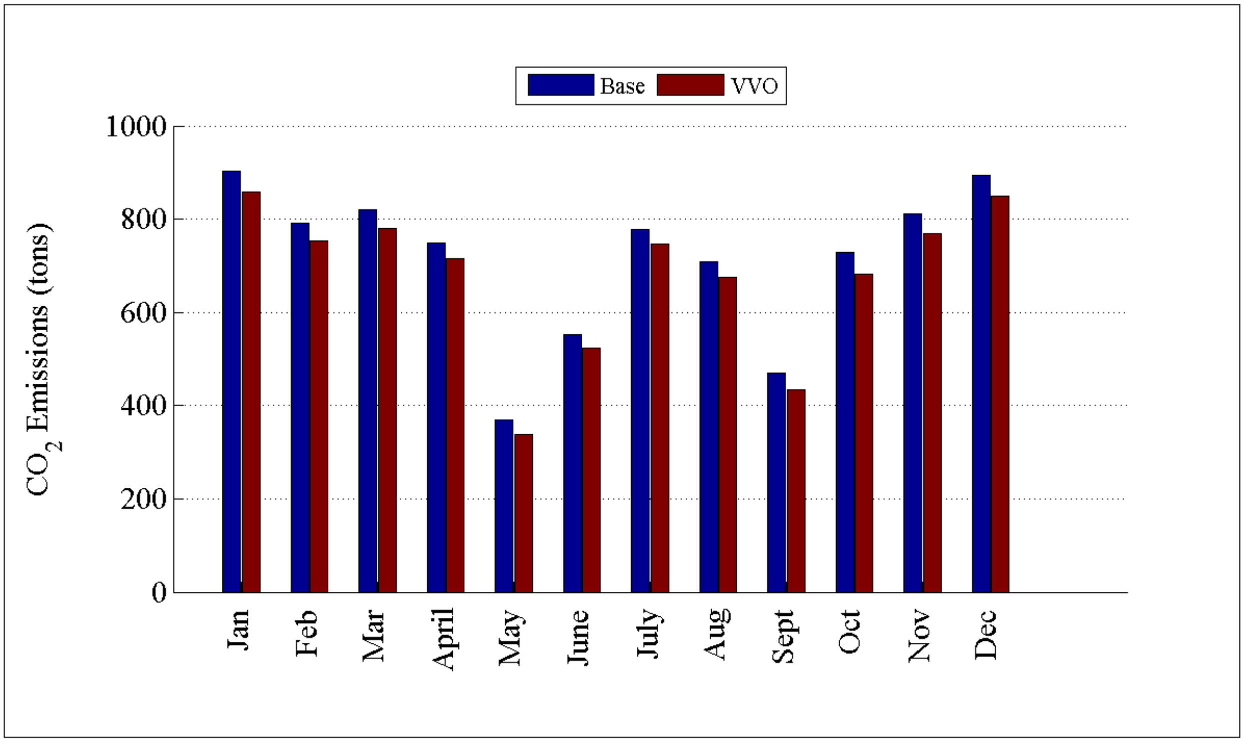



Figure D.33: Comparison of $CO_2$ emissions by month for R2-12.47-2

### D.1.10 Detailed VVO Plots for R2-12.47-3

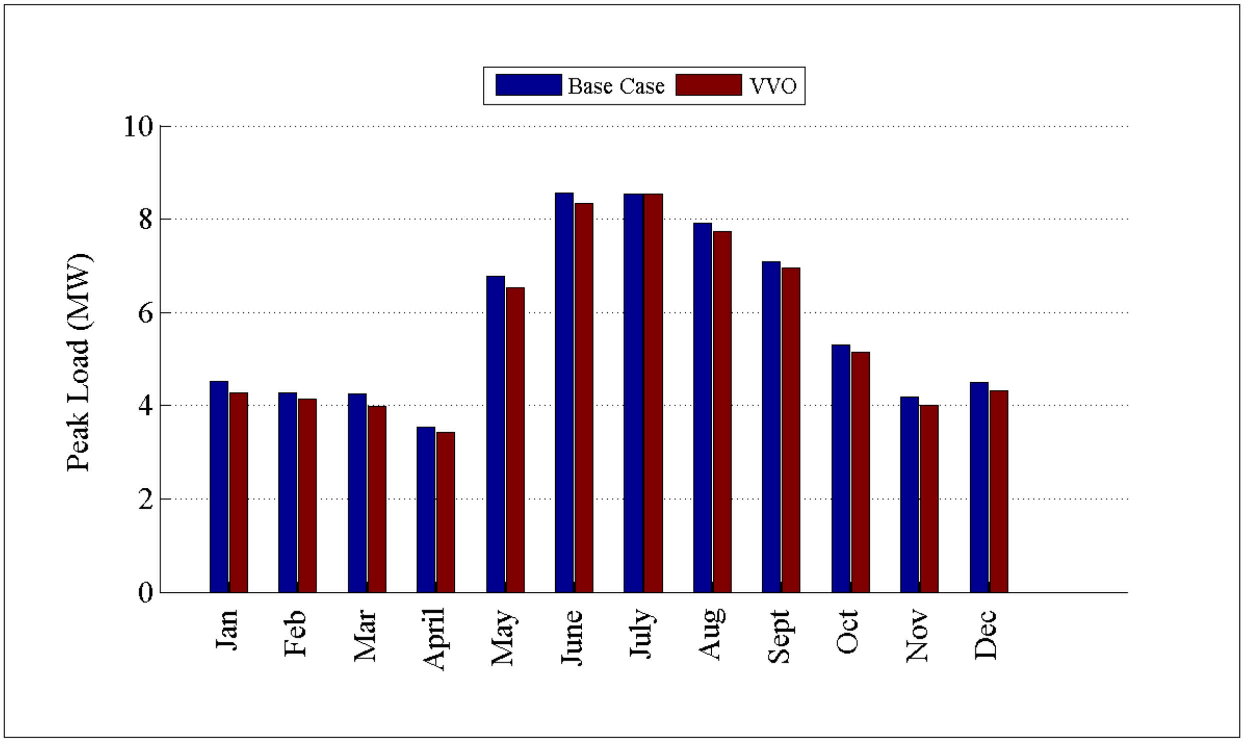



Figure D.34: Comparison of peak load by month for R2-12.47-3

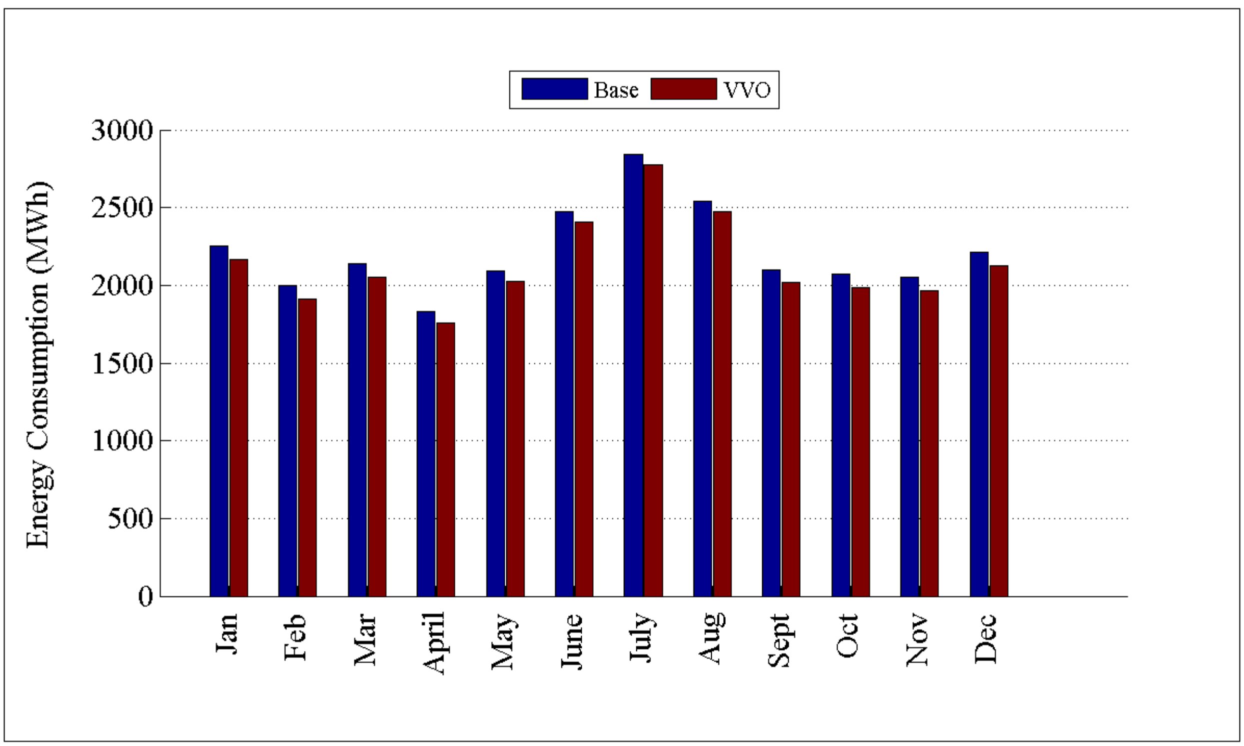



Figure D.35: Comparison of energy consumption by month for R2-12.47-3

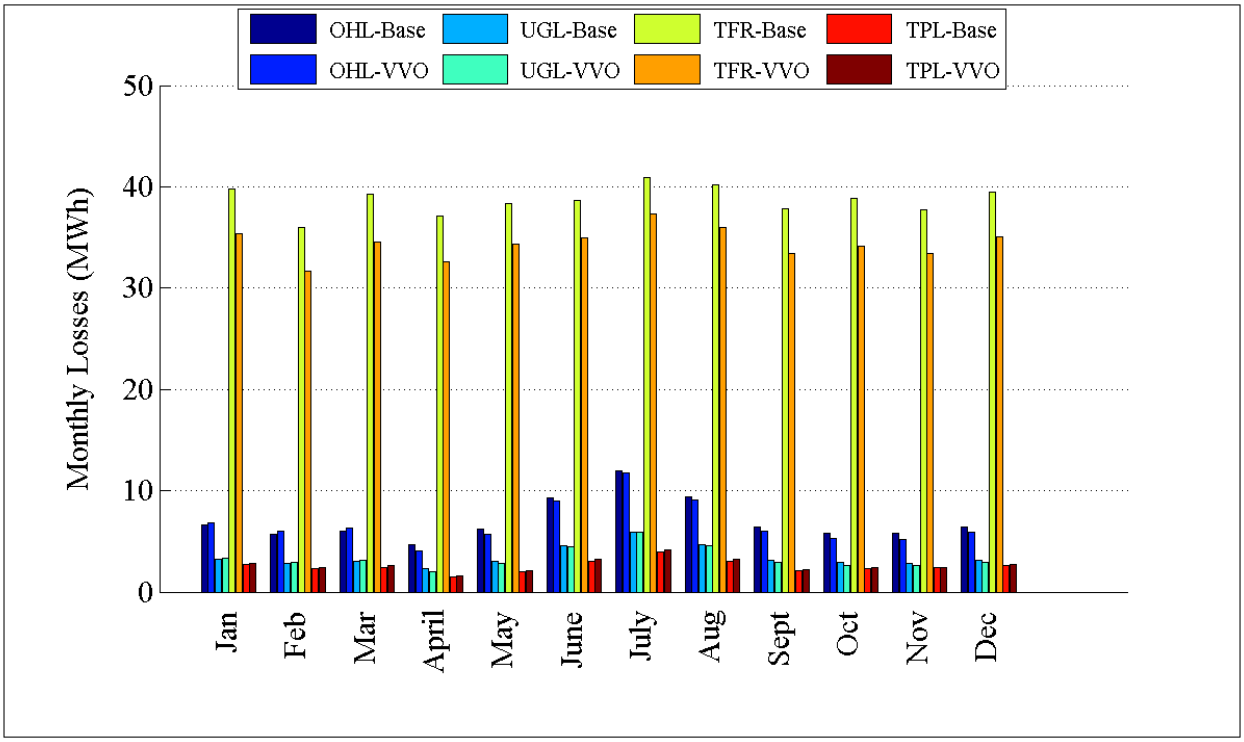



Figure D.36: Comparison of losses by month for R2-12.47-3

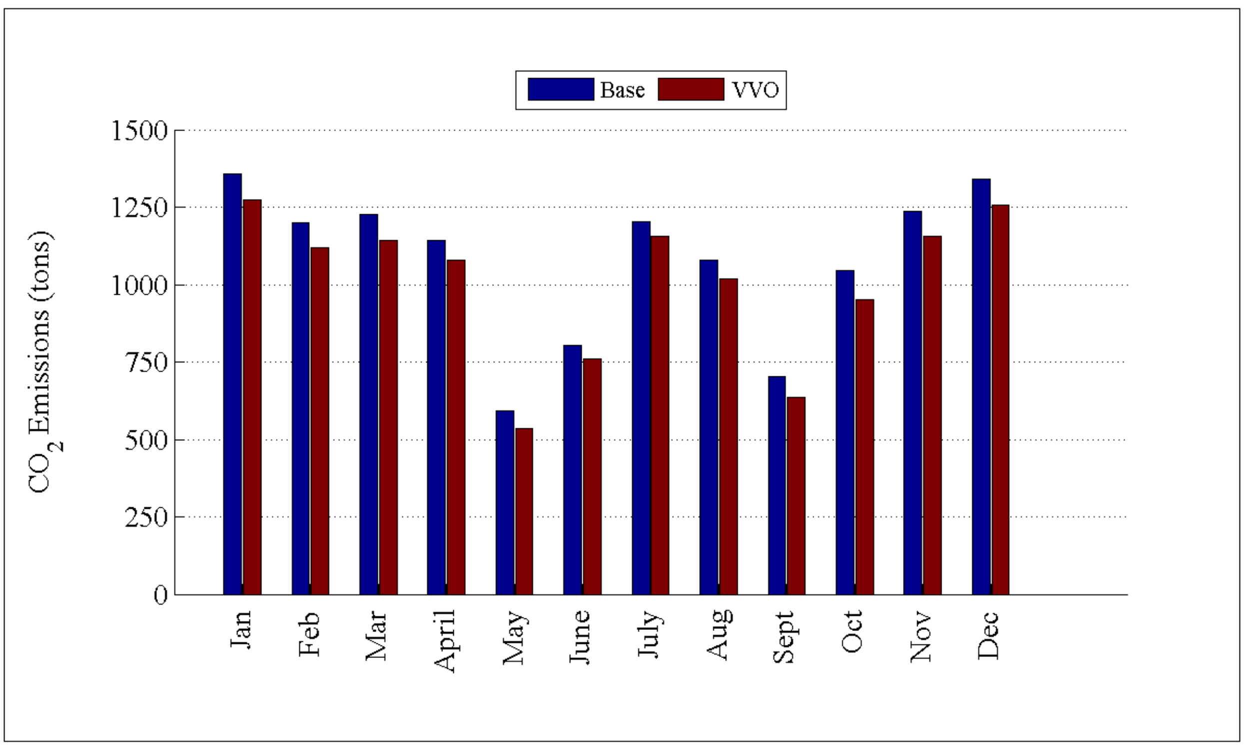



Figure D.37: Comparison of $CO_2$ emissions by month for R2-12.47-3

### D.1.11 Detailed VVO Plots for R2-25.00-1

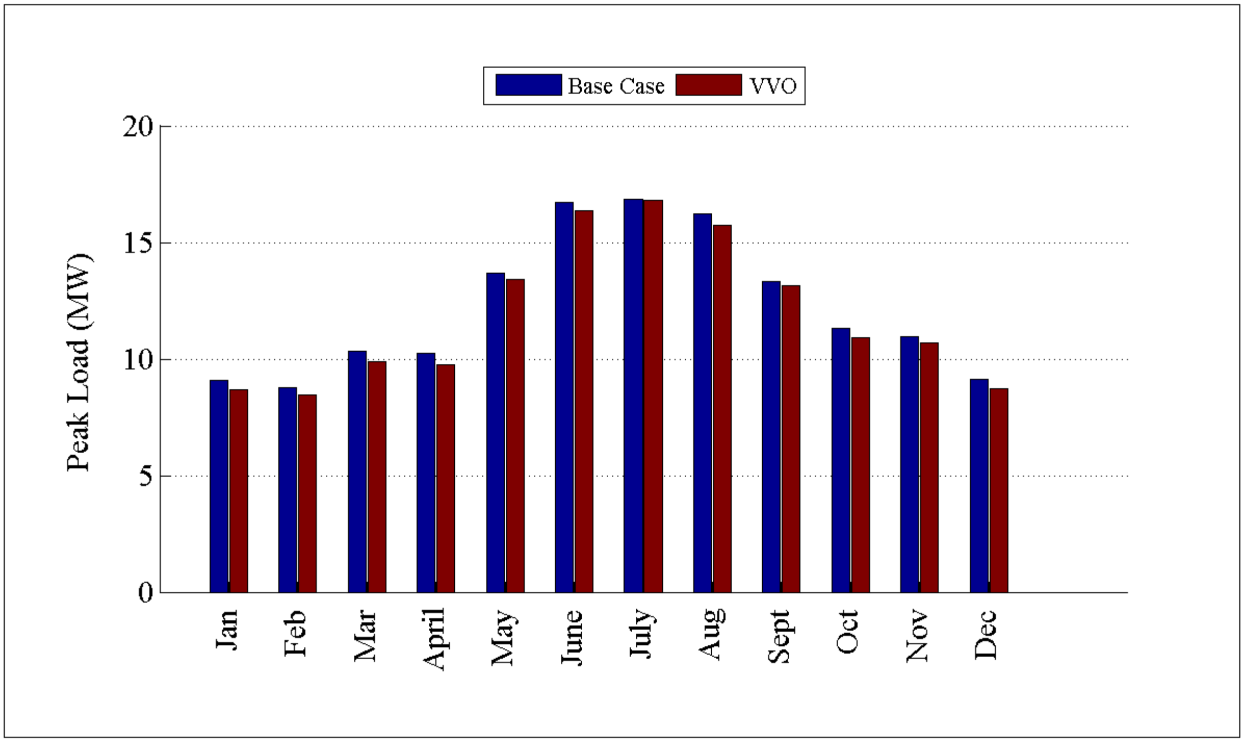



Figure D.38: Comparison of peak load by month for R2-25.00-1

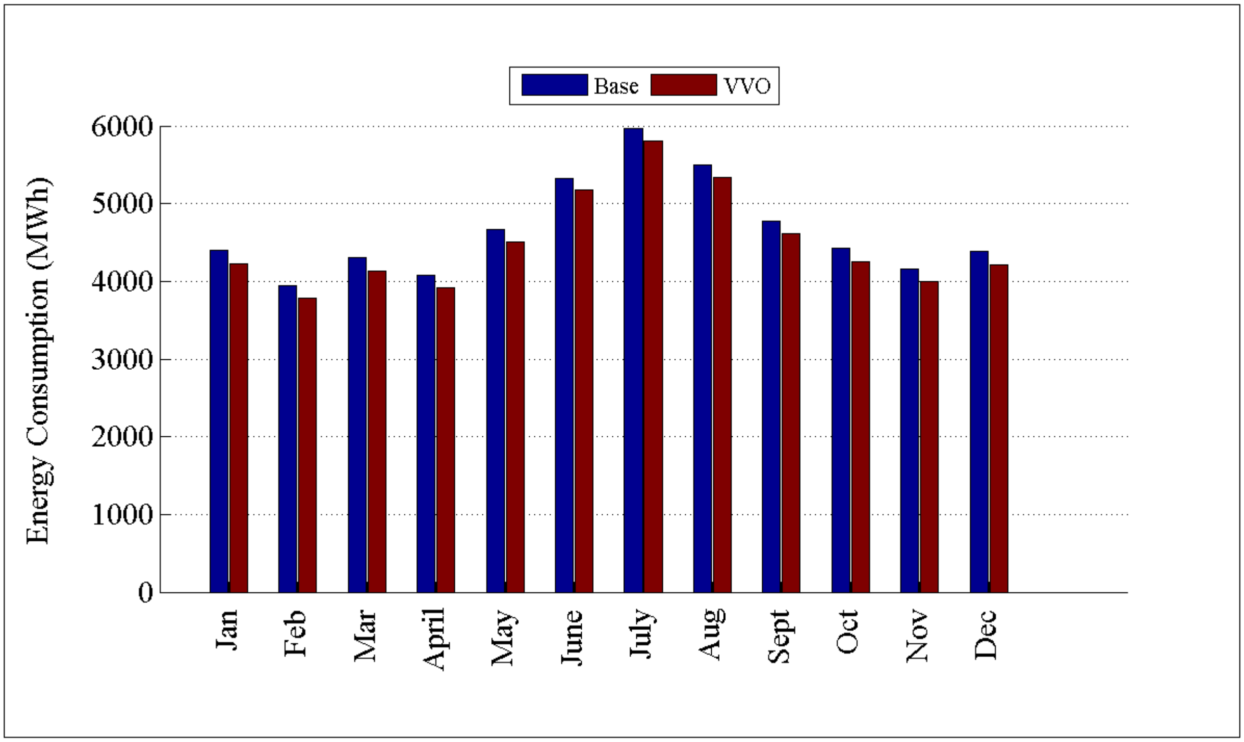



Figure D.39: Comparison of energy consumption by month for R2-25.00-1

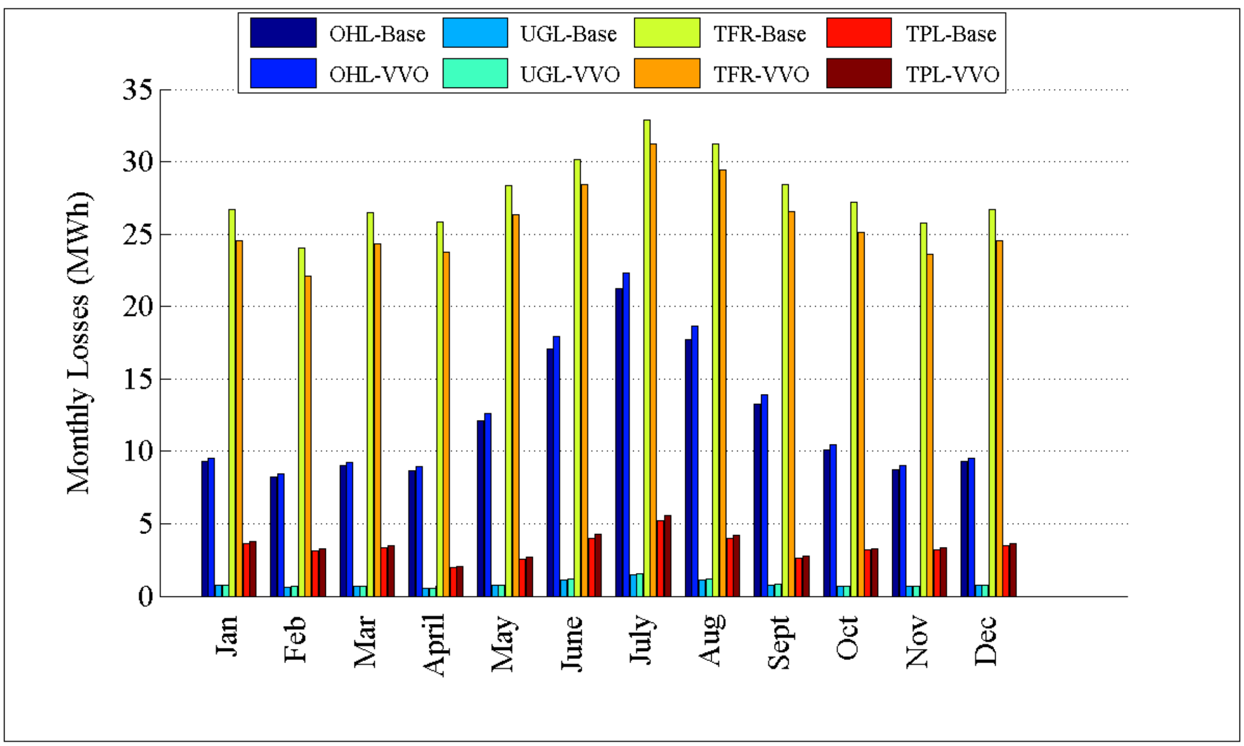



Figure D.40: Comparison of losses by month for R2-25.00-1

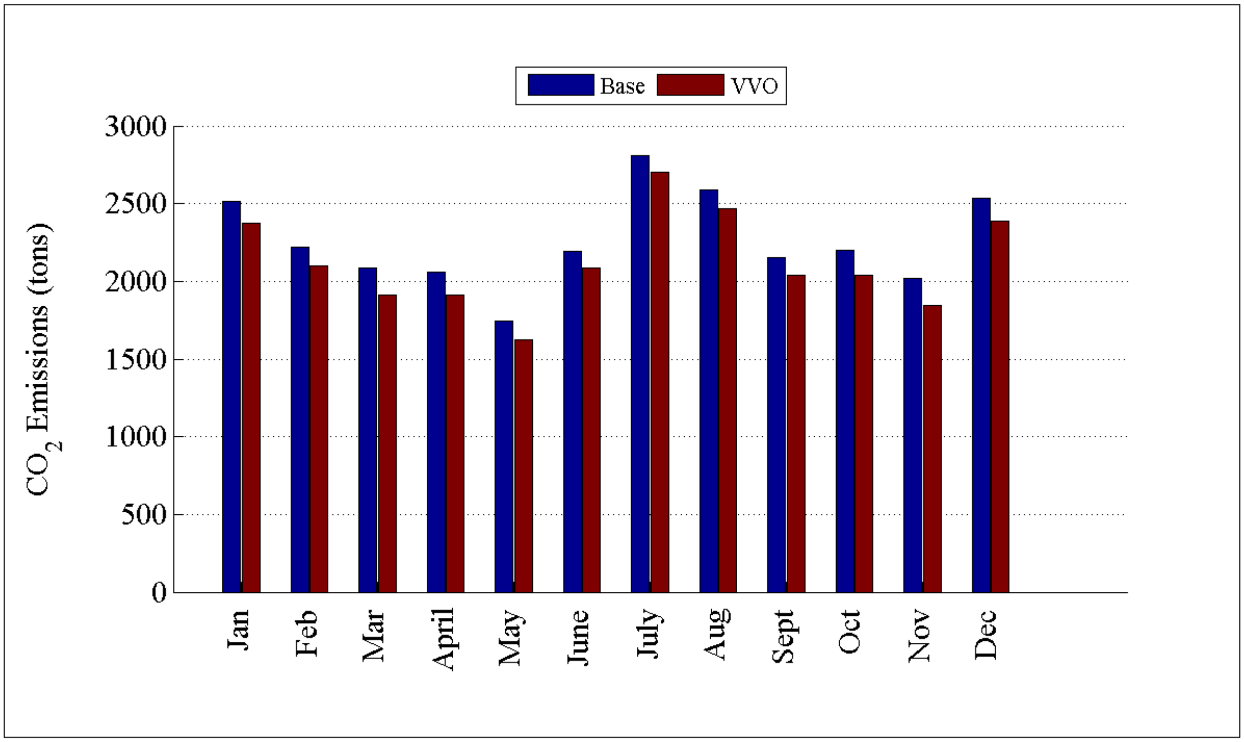



Figure D.41: Comparison of $CO_2$ emissions by month for R2-25.00-1

### D.1.12 Detailed VVO Plots for R2-35.00-1

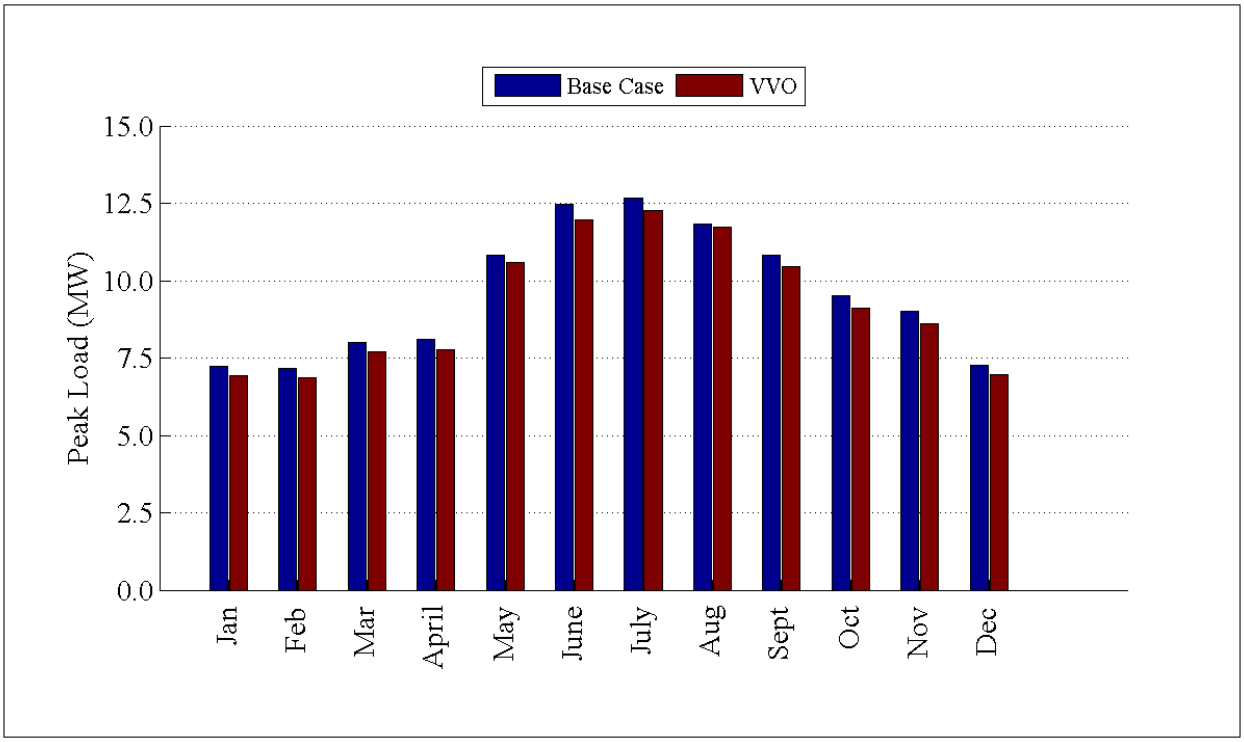



Figure D.42: Comparison of peak load by month for R2-35.00-1

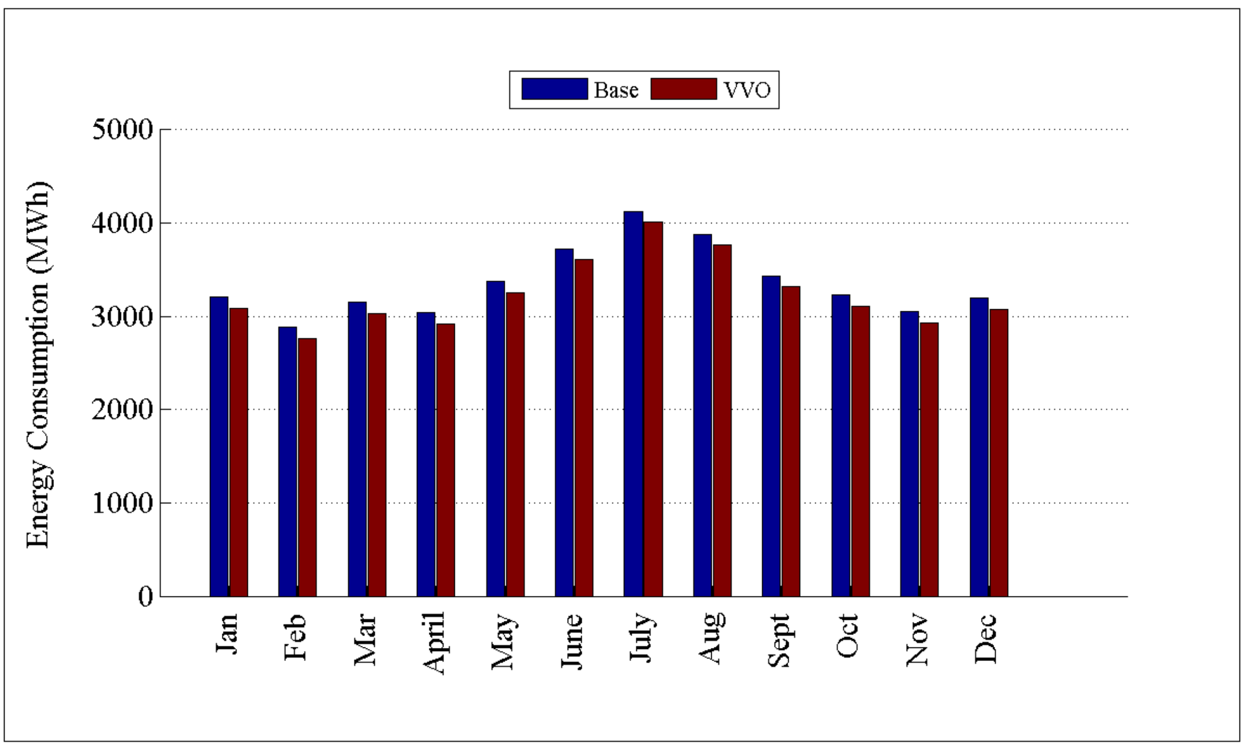



Figure D.43: Comparison of energy consumption by month for R2-35.00-1

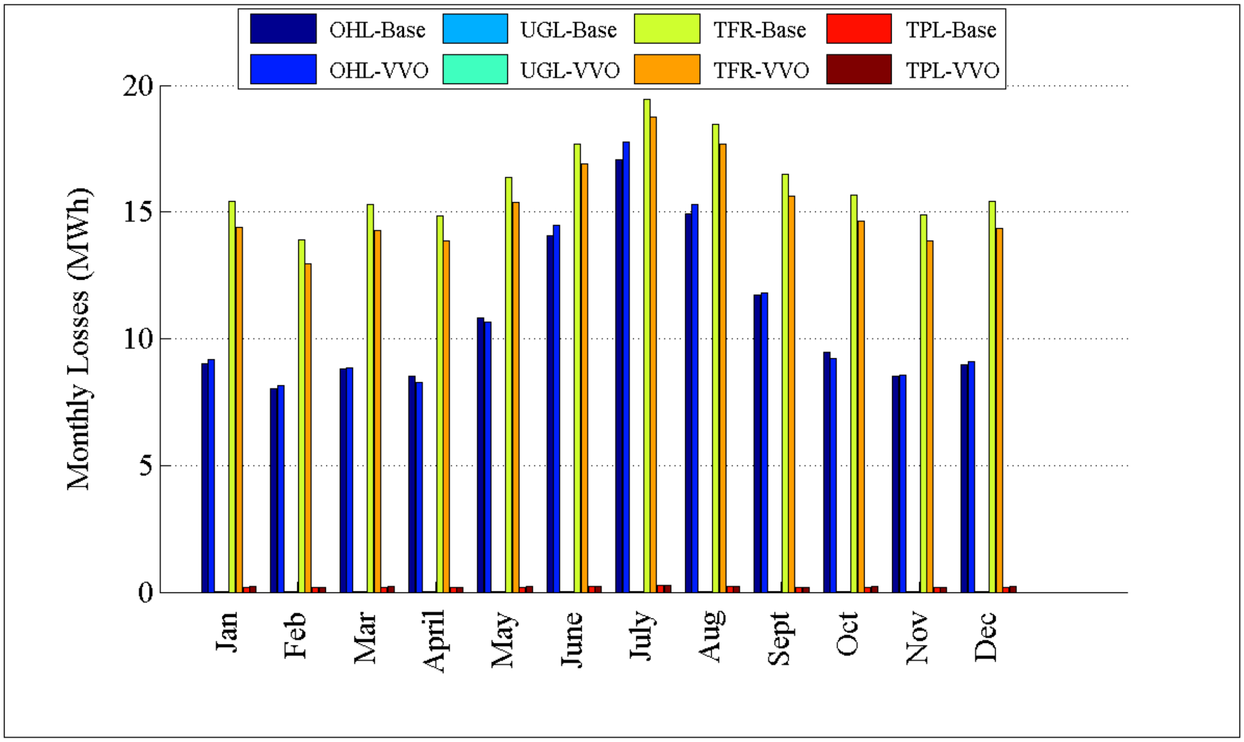



Figure D.44: Comparison of losses by month for R2-35.00-1

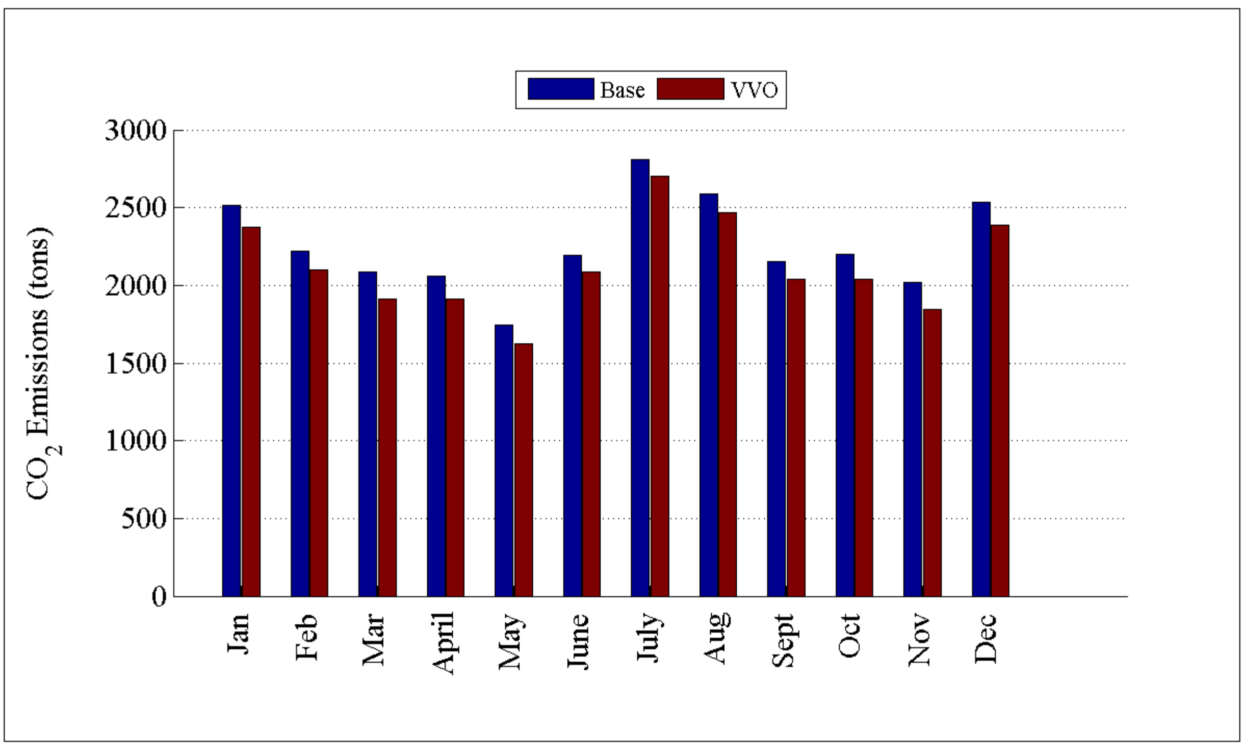



Figure D.45: Comparison of $CO_2$ emissions by month for R2-35.00-1

### D.1.13 Detailed VVO Plots for GC-12.47-1_R3

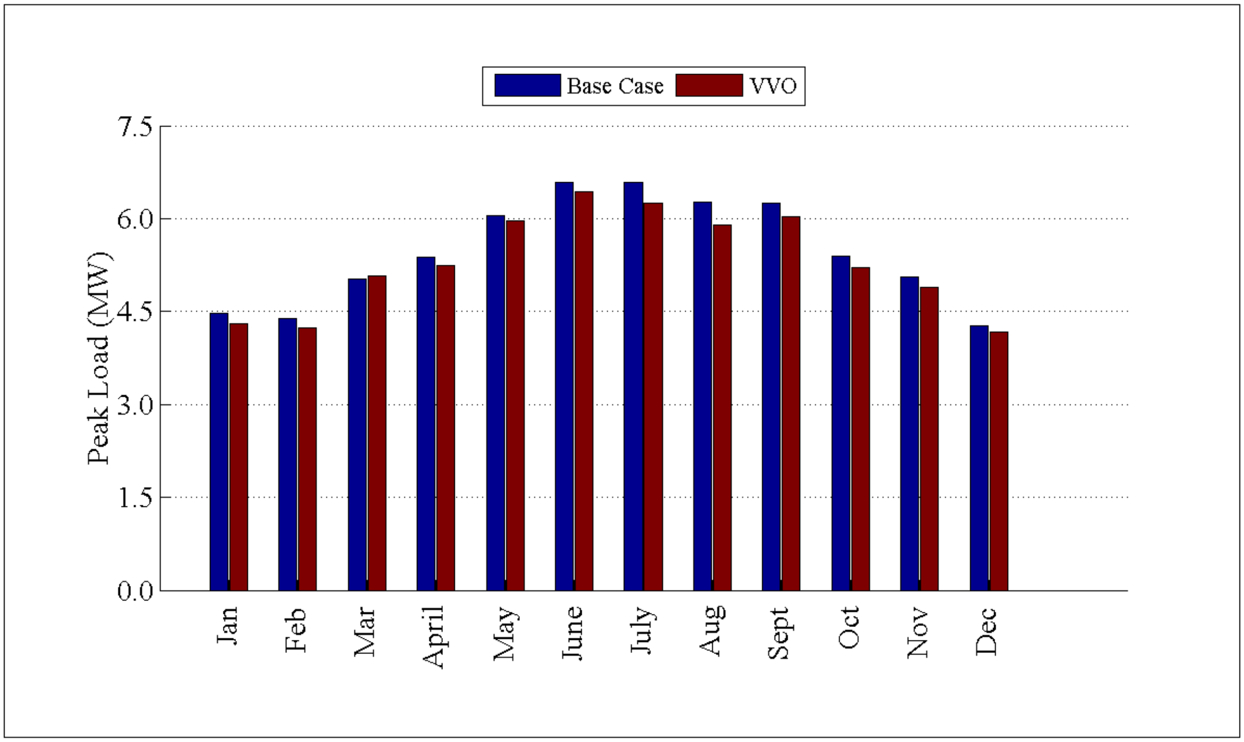



Figure D.46: Comparison of peak load by month for GC-12.47-1_R3

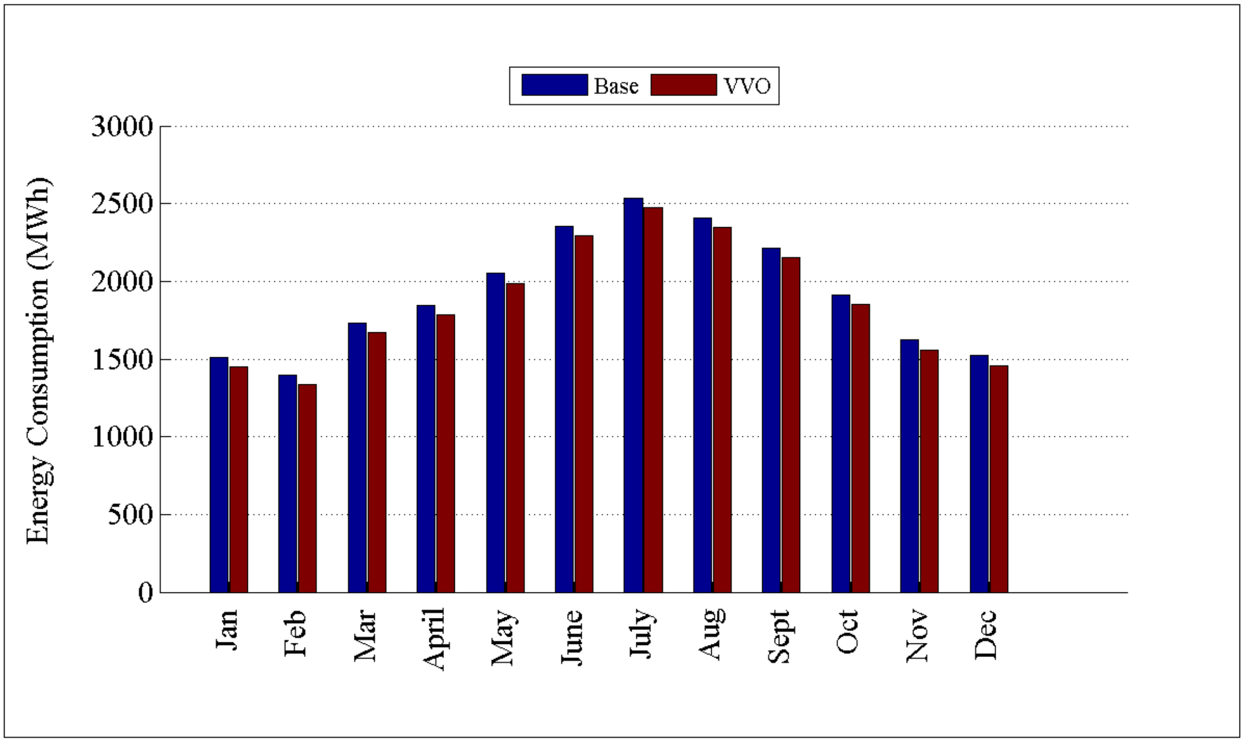



Figure D.47: Comparison of energy consumption by month for GC-12.47-1_R3

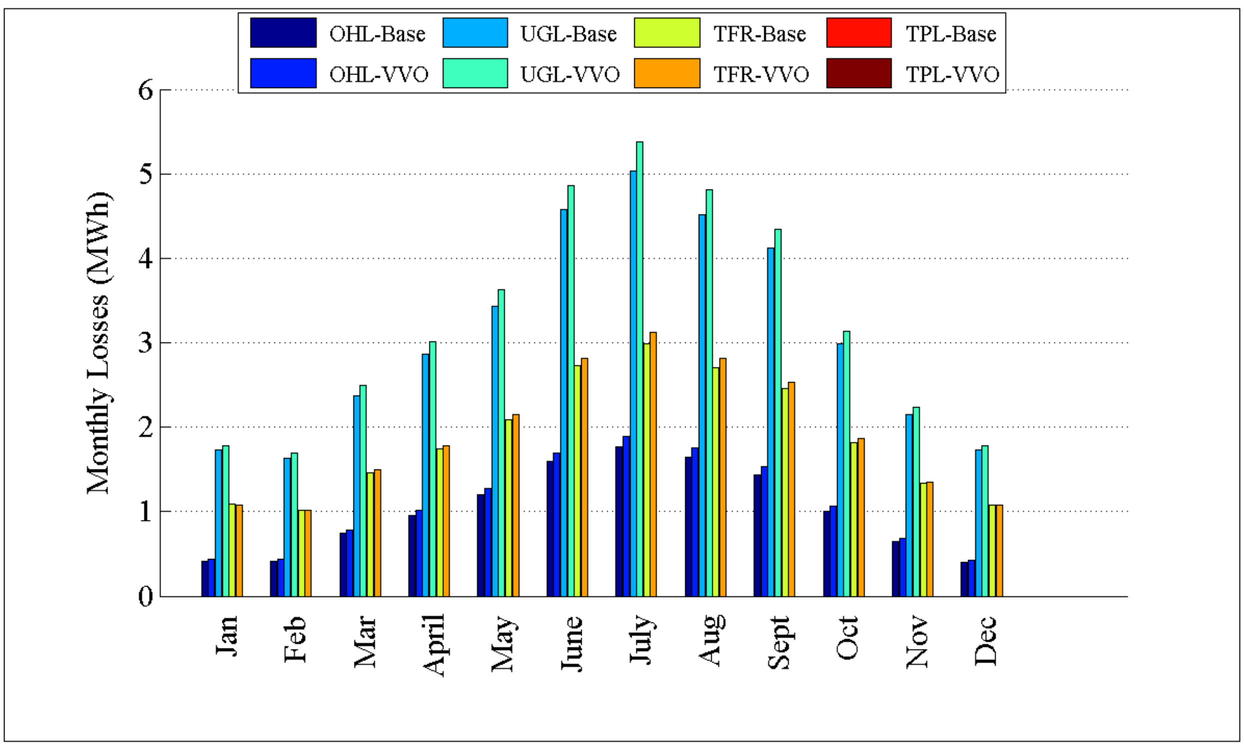



Figure D.48: Comparison of losses by month for GC-12.47-1_R3

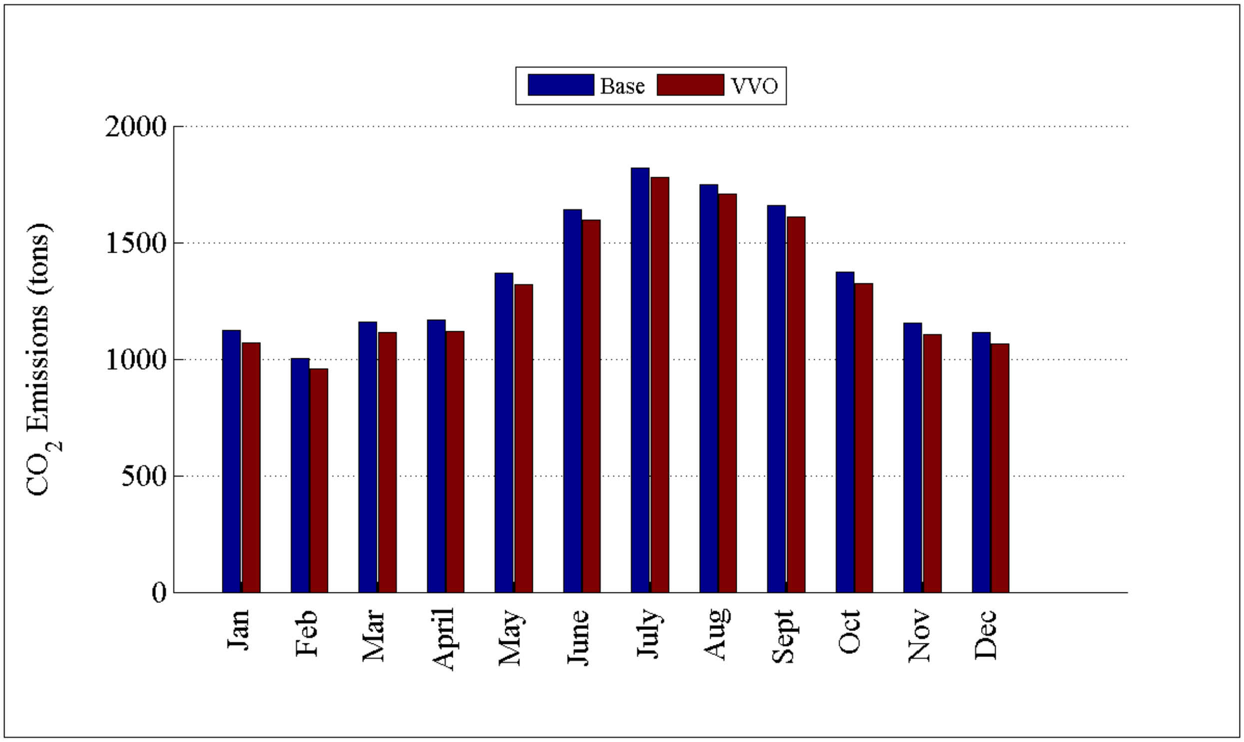



Figure D.49: Comparison of $CO_2$ emissions by month for GC-12.47-1_R3

### D.1.14 Detailed VVO Plots for R3-12.47-1

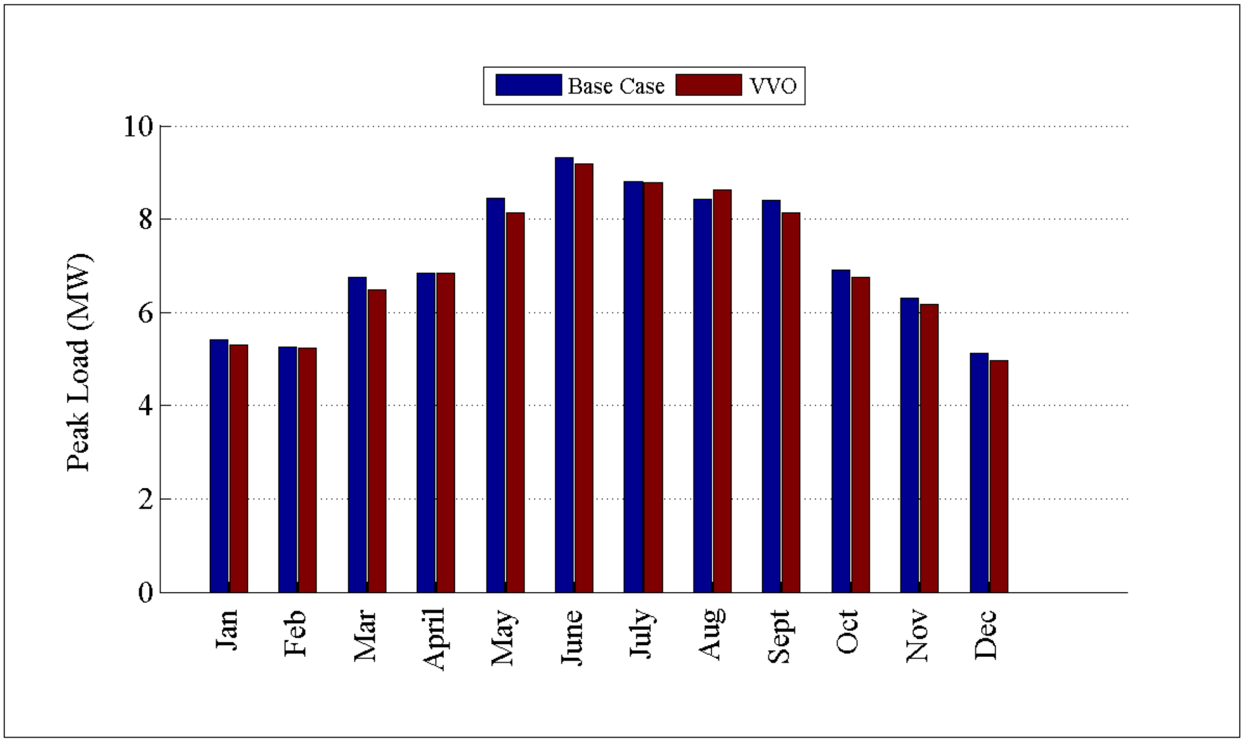



Figure D.50: Comparison of peak load by month for R3-12.47-1

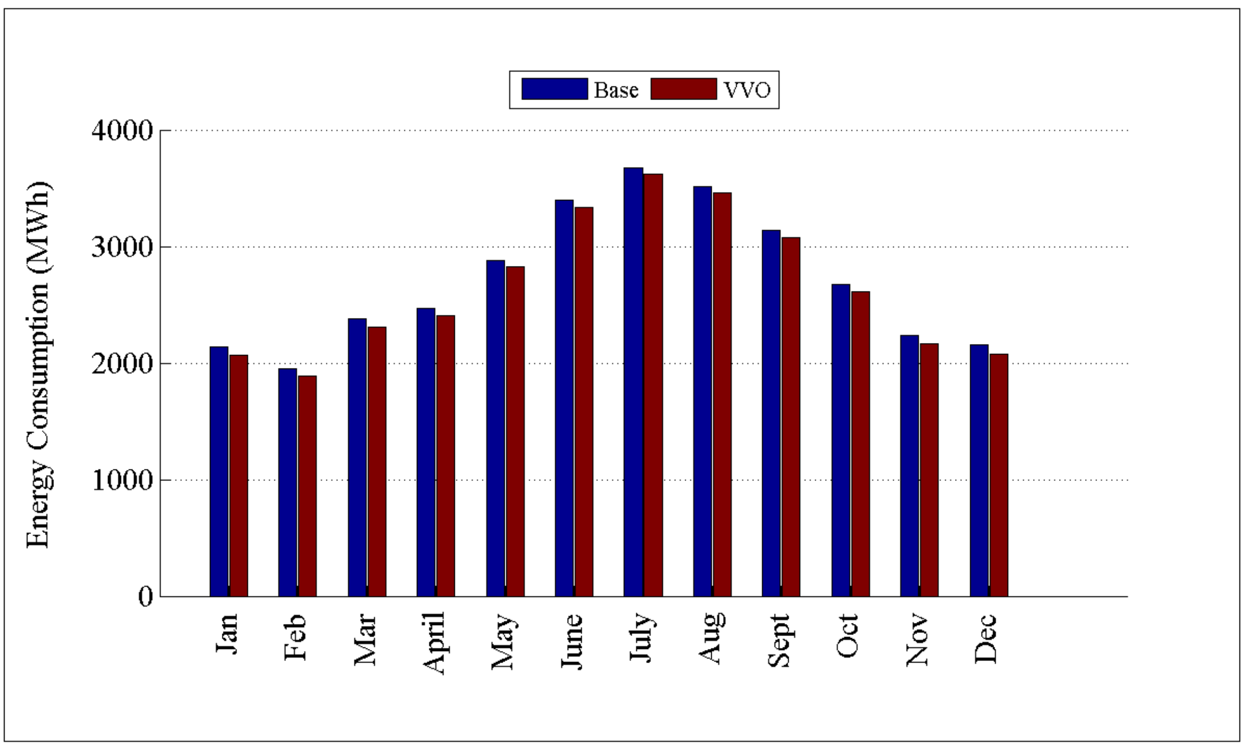



Figure D.51: Comparison of energy consumption by month for R3-12.47-1

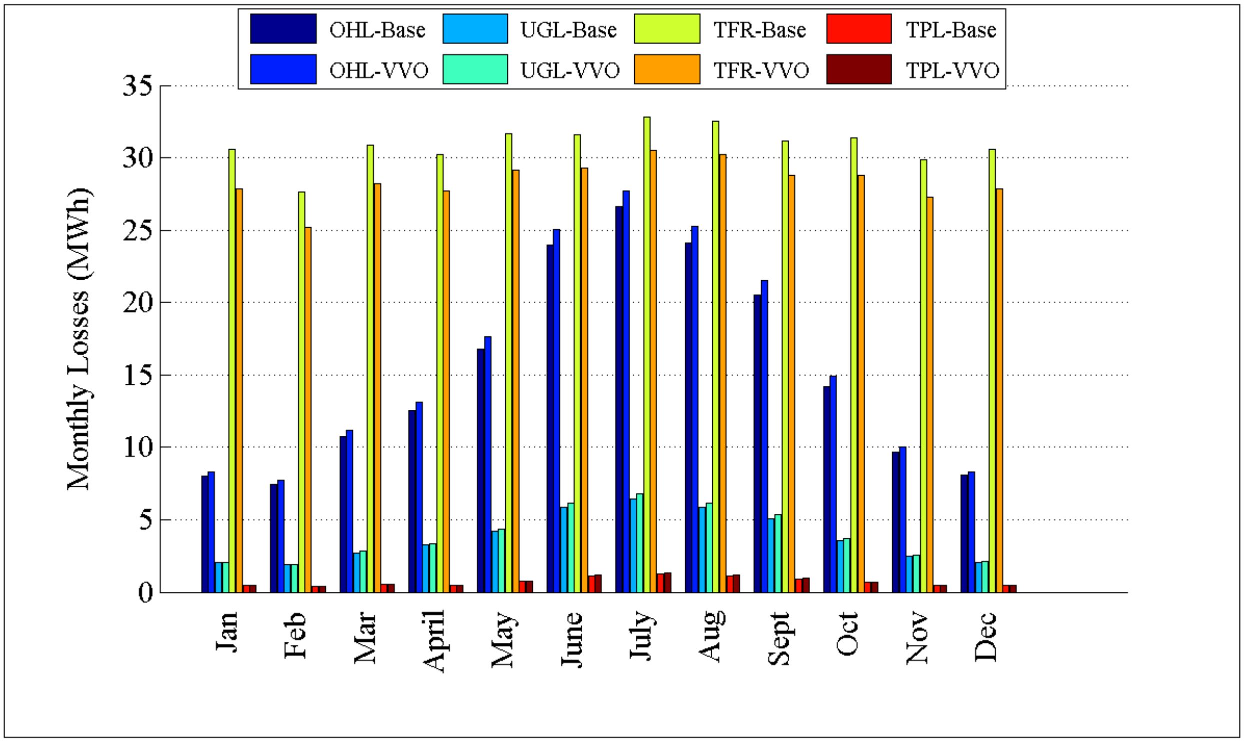



Figure D.52: Comparison of losses by month for R3-12.47-1

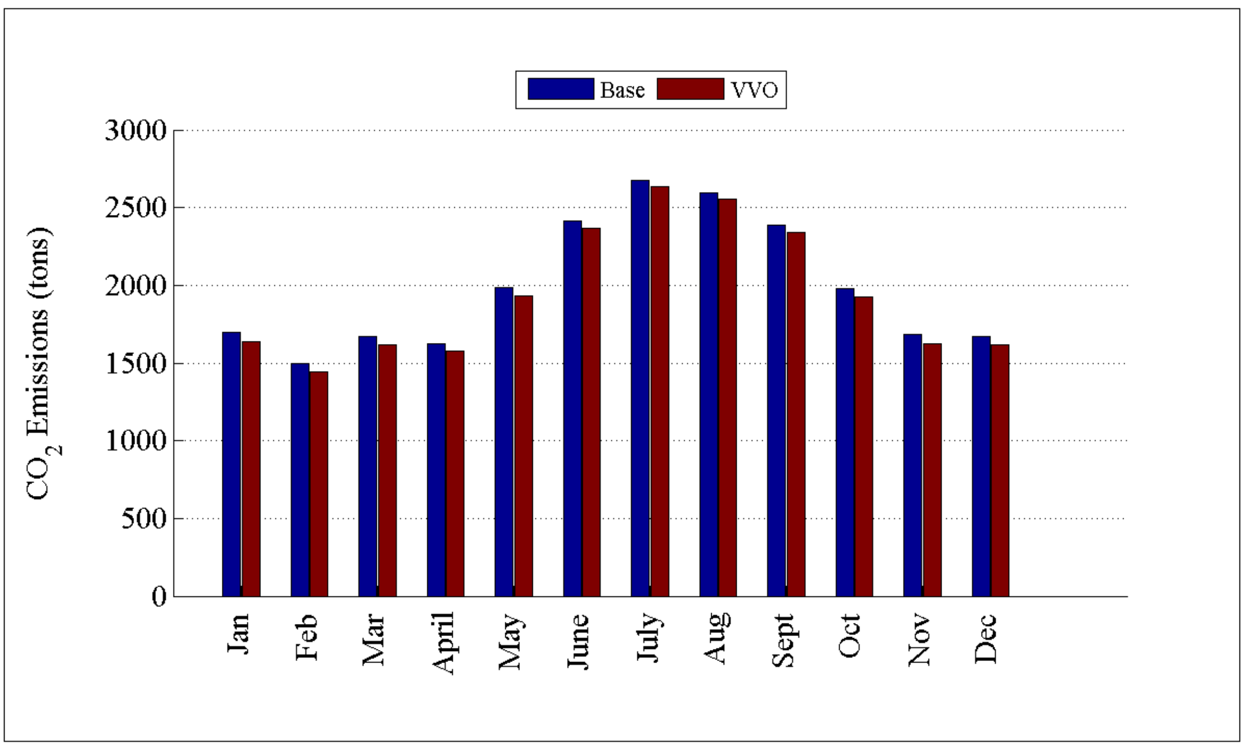



Figure D.53: Comparison of $CO_2$ emissions by month for R3-12.47-1

## D.1.15 Detailed VVO Plots for R3-12.47-2

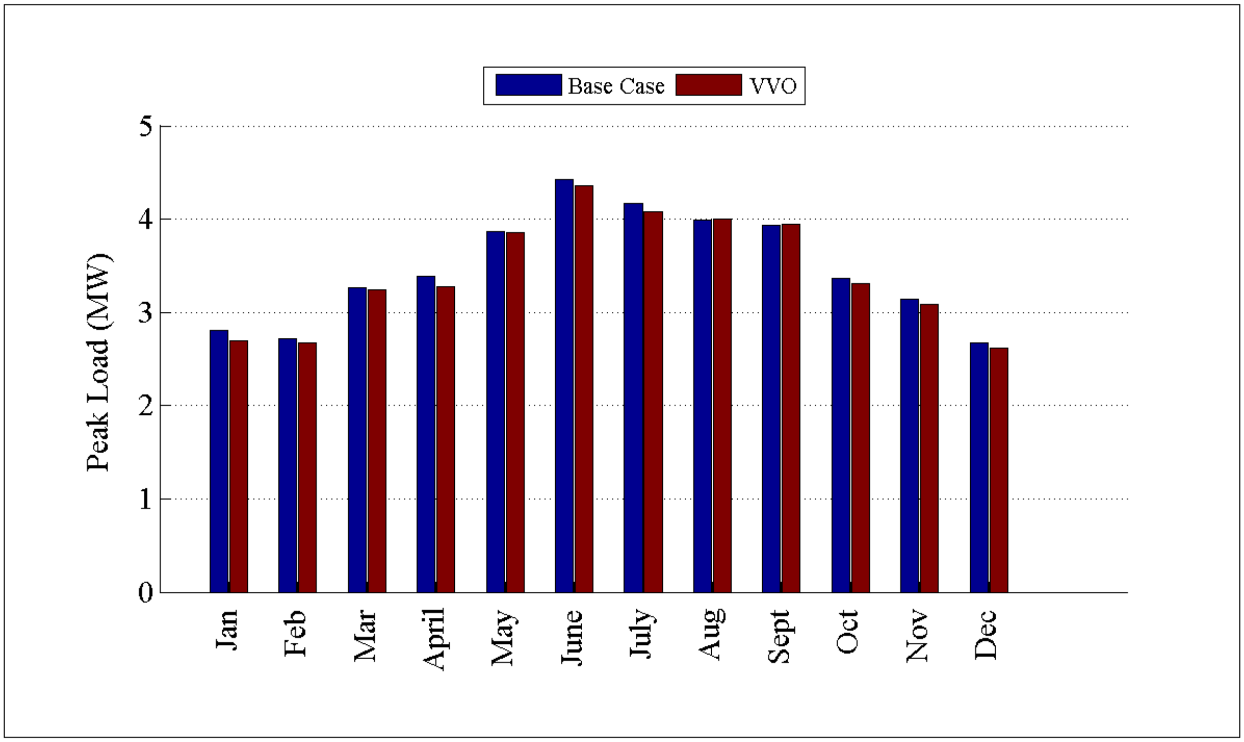



Figure D.54: Comparison of peak load by month for R3-12.47-2

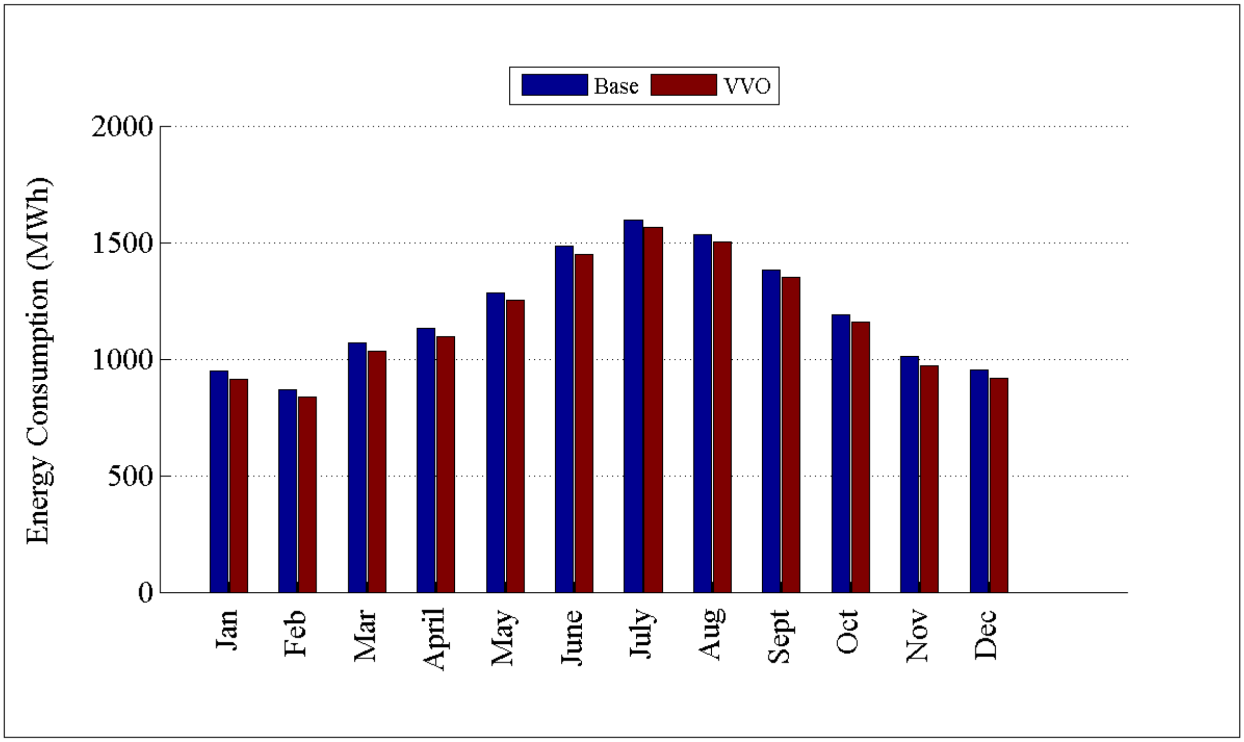



Figure D.55: Comparison of energy consumption by month for R3-12.47-2

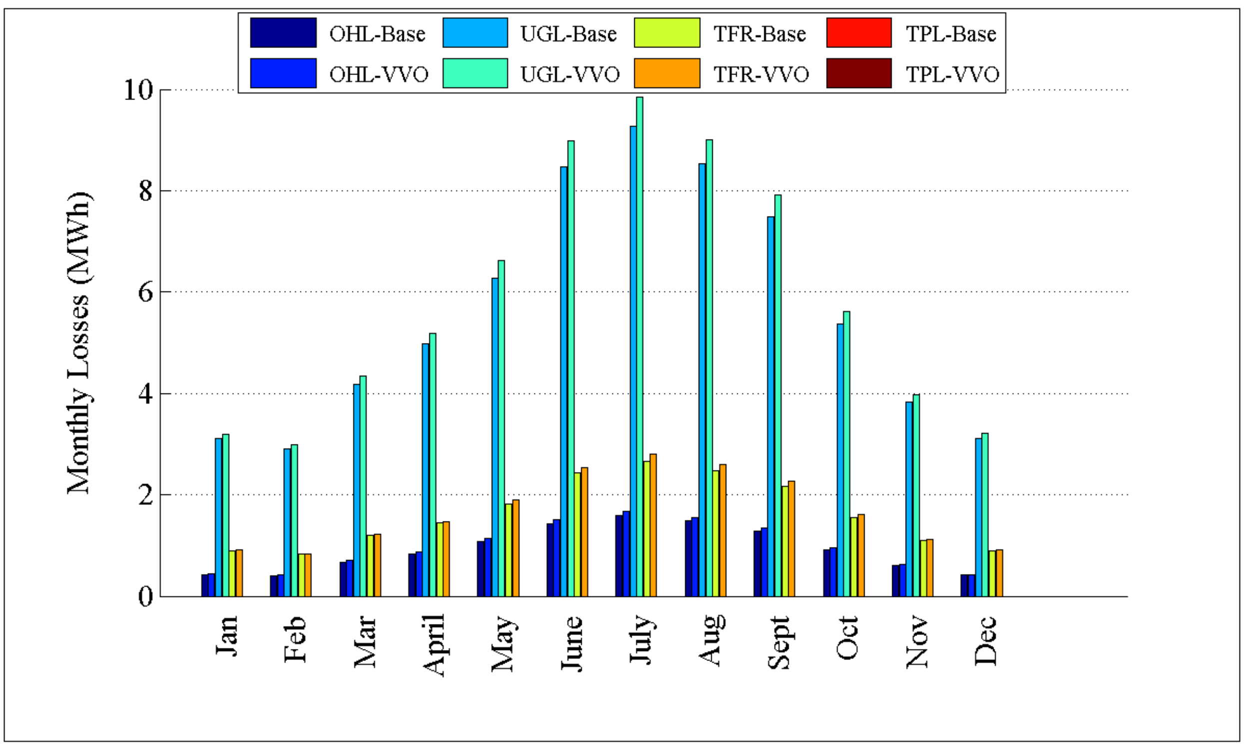



Figure D.56: Comparison of losses by month for R3-12.47-2

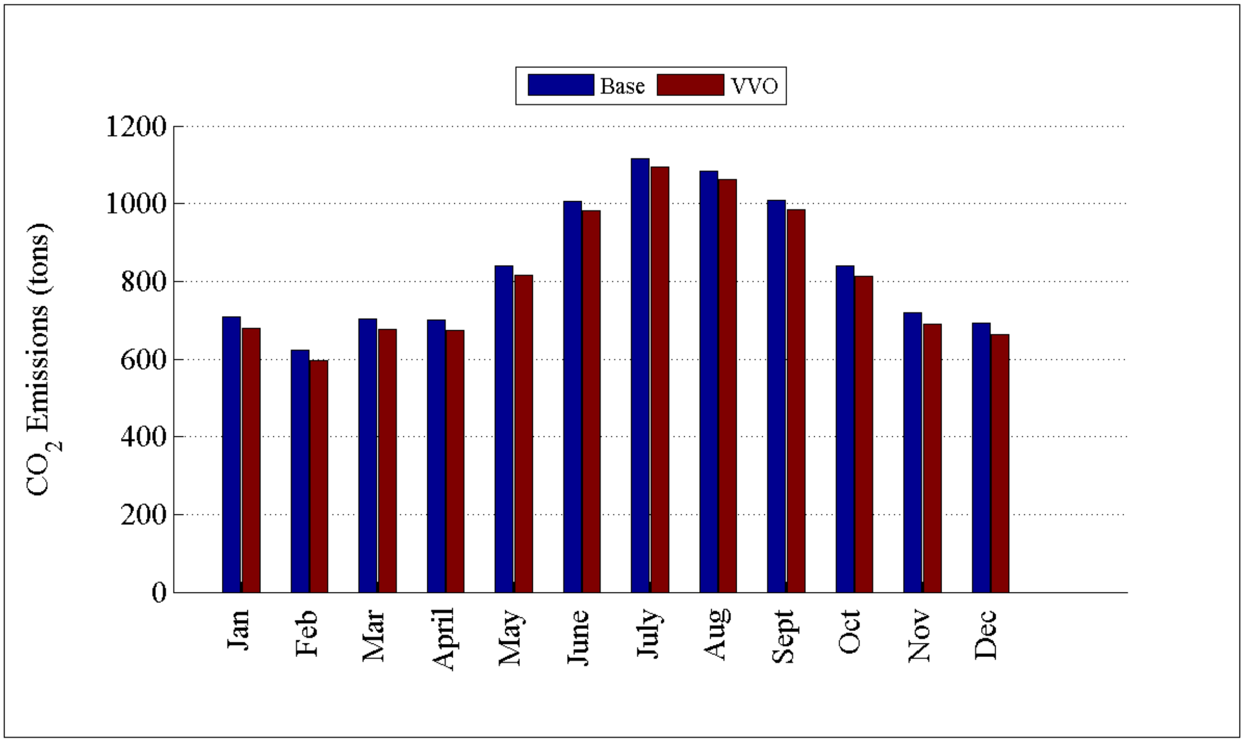



Figure D.57: Comparison of $CO_2$ emissions by month for R3-12.47-2

### D.1.16 Detailed VVO Plots for R3-12.47-3

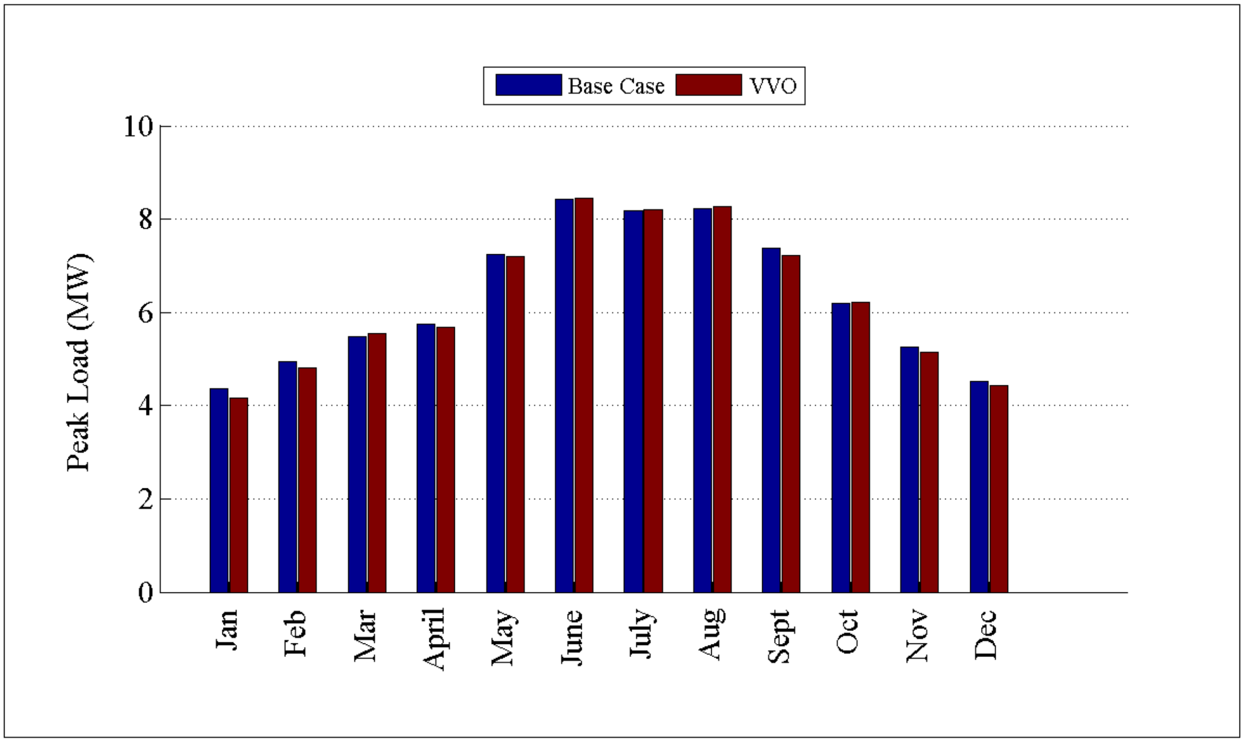



Figure D.58: Comparison of peak load by month for R3-12.47-3

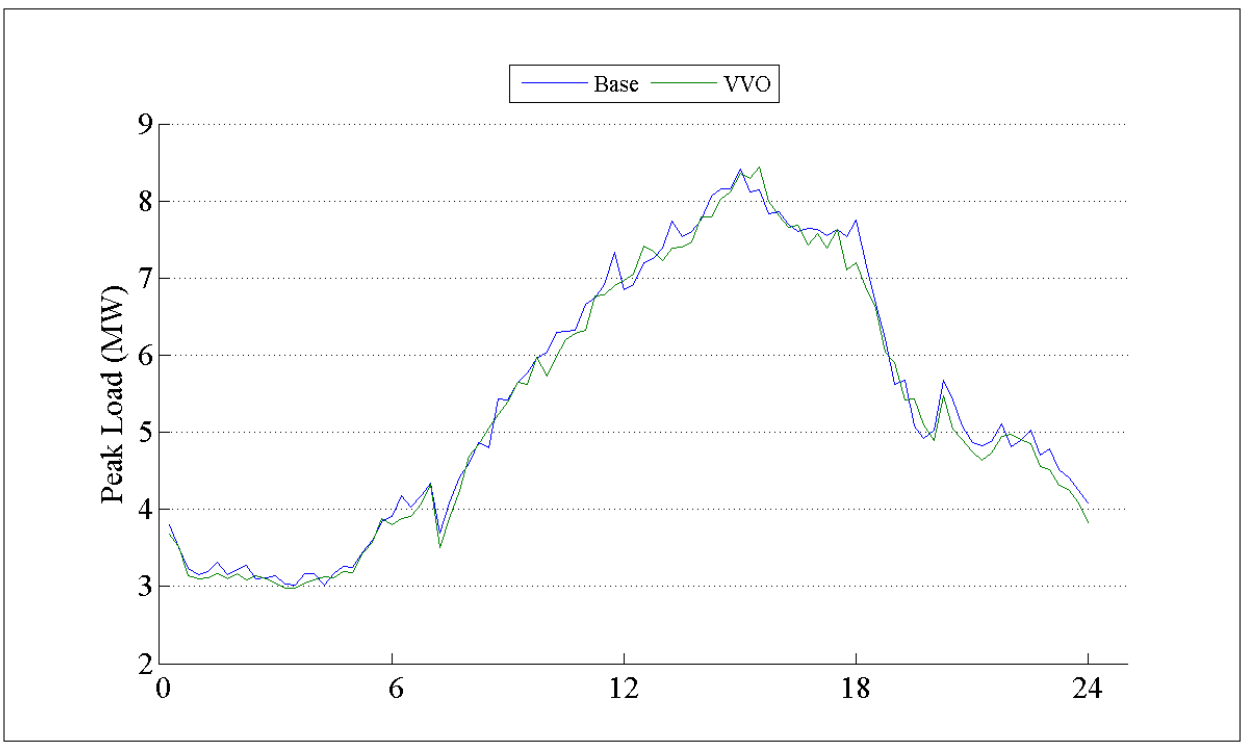



Figure D.59: Peak load day for R3-12.47-3

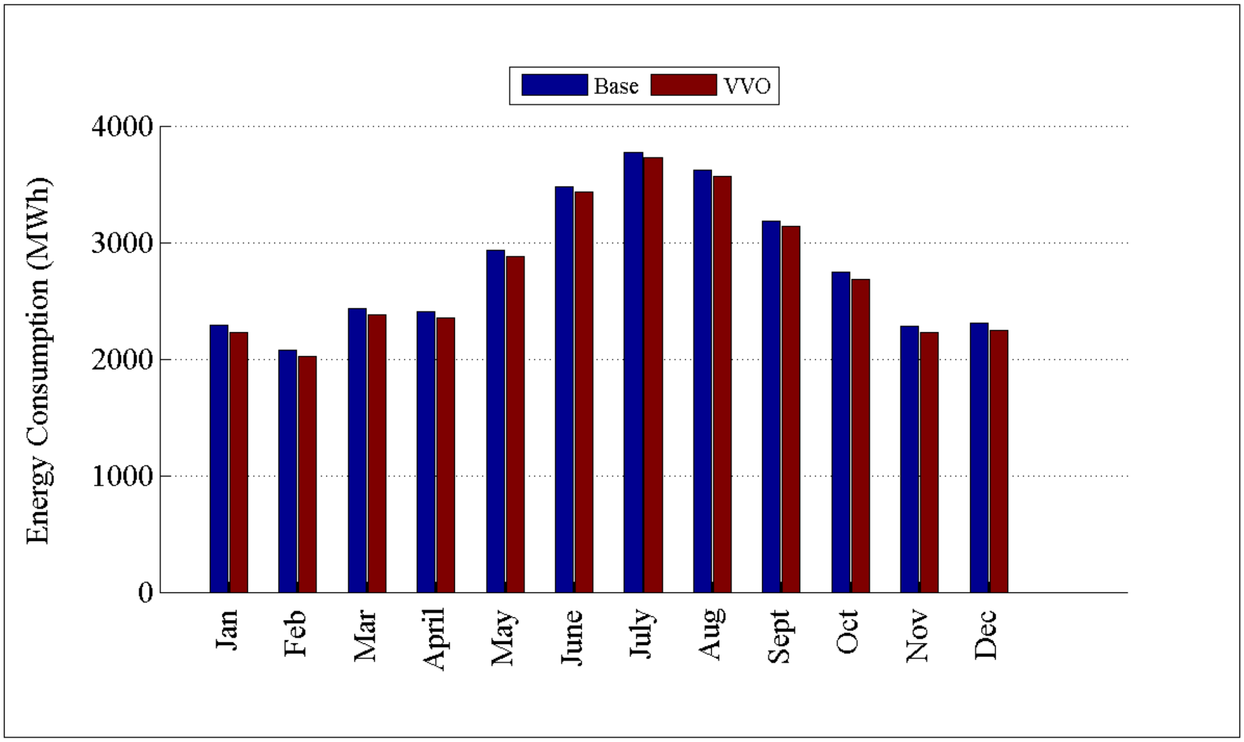



Figure D.60: Comparison of energy consumption by month for R3-12.47-3

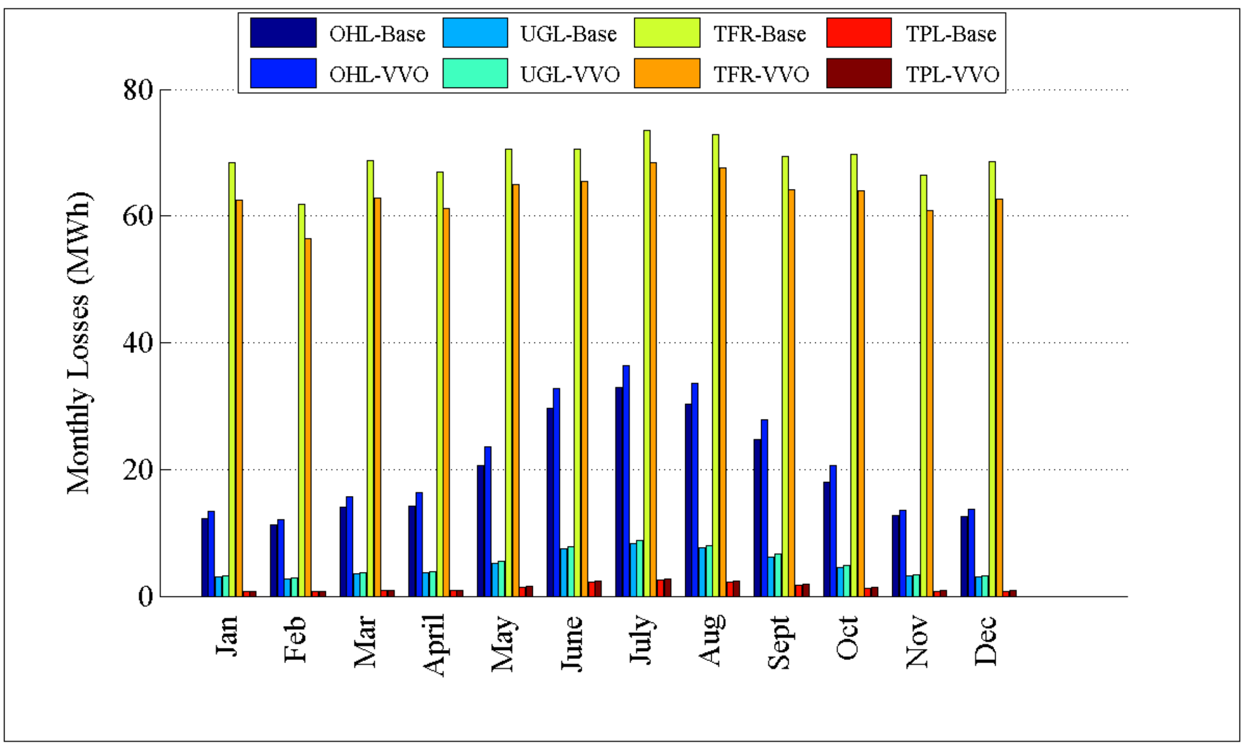



Figure D.61: Comparison of losses by month for R3-12.47-3

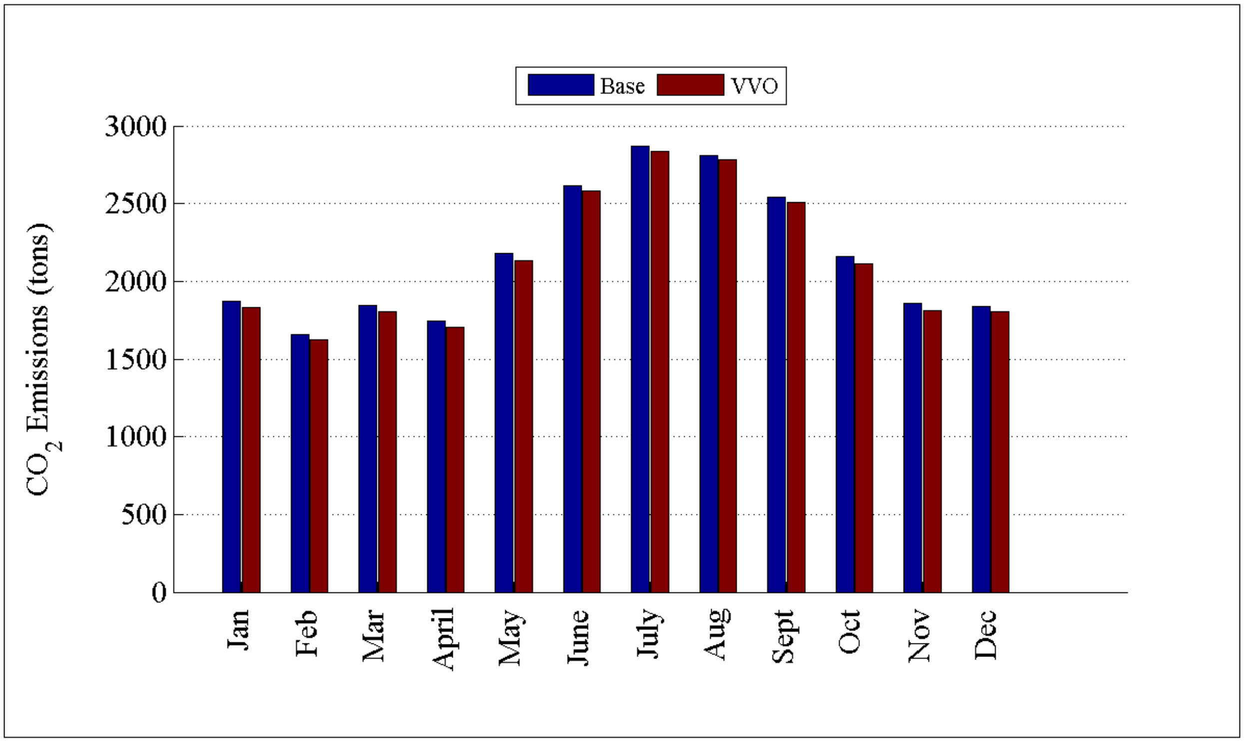



Figure D.62: Comparison of $CO_2$ emissions by month for R3-12.47-3

### D.1.17 Detailed VVO Plots for GC-12.47-1_R4

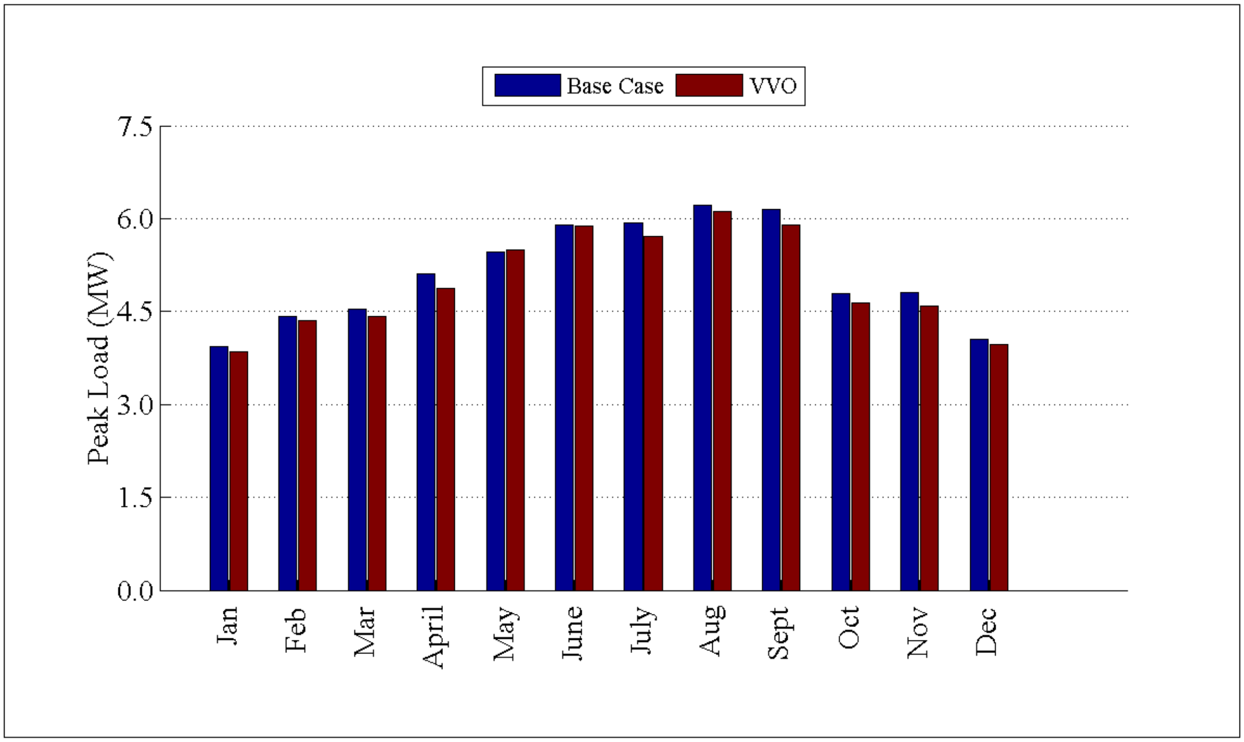



Figure D.63: Comparison of peak load by month for GC-12.47-1_R4

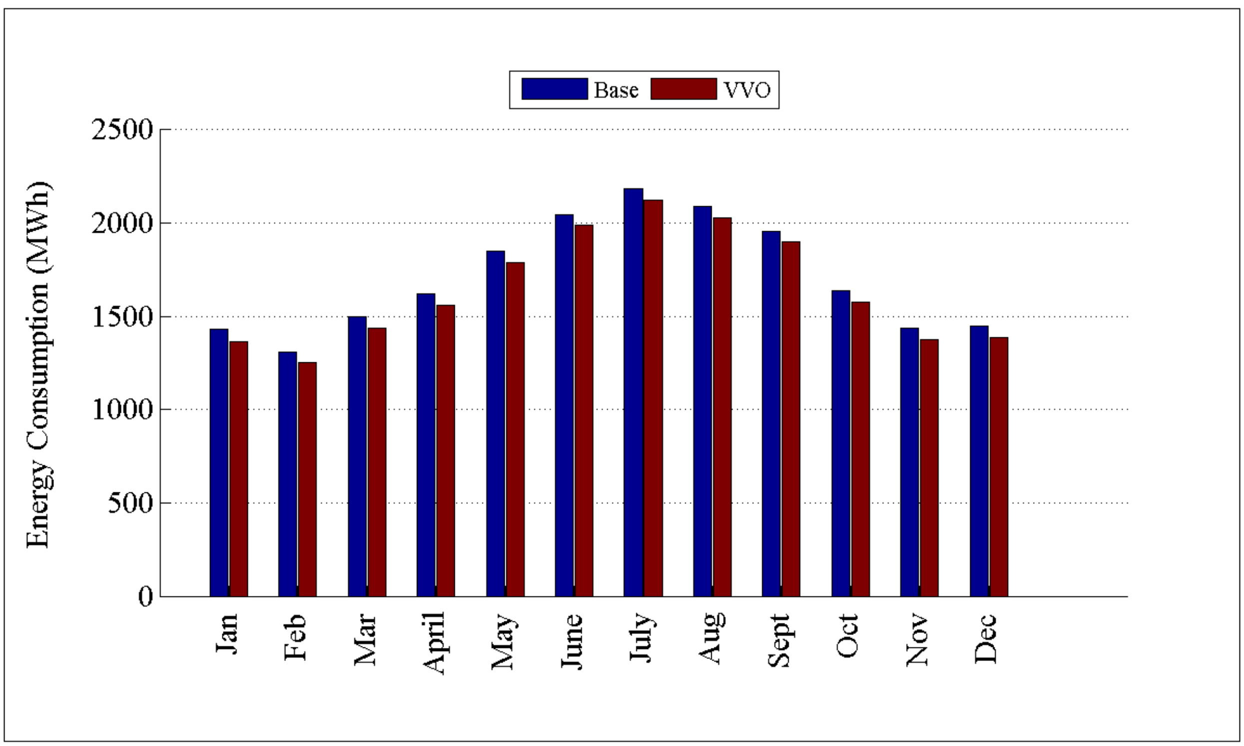



Figure D.64: Comparison of energy consumption by month for GC-12.47-1_R4

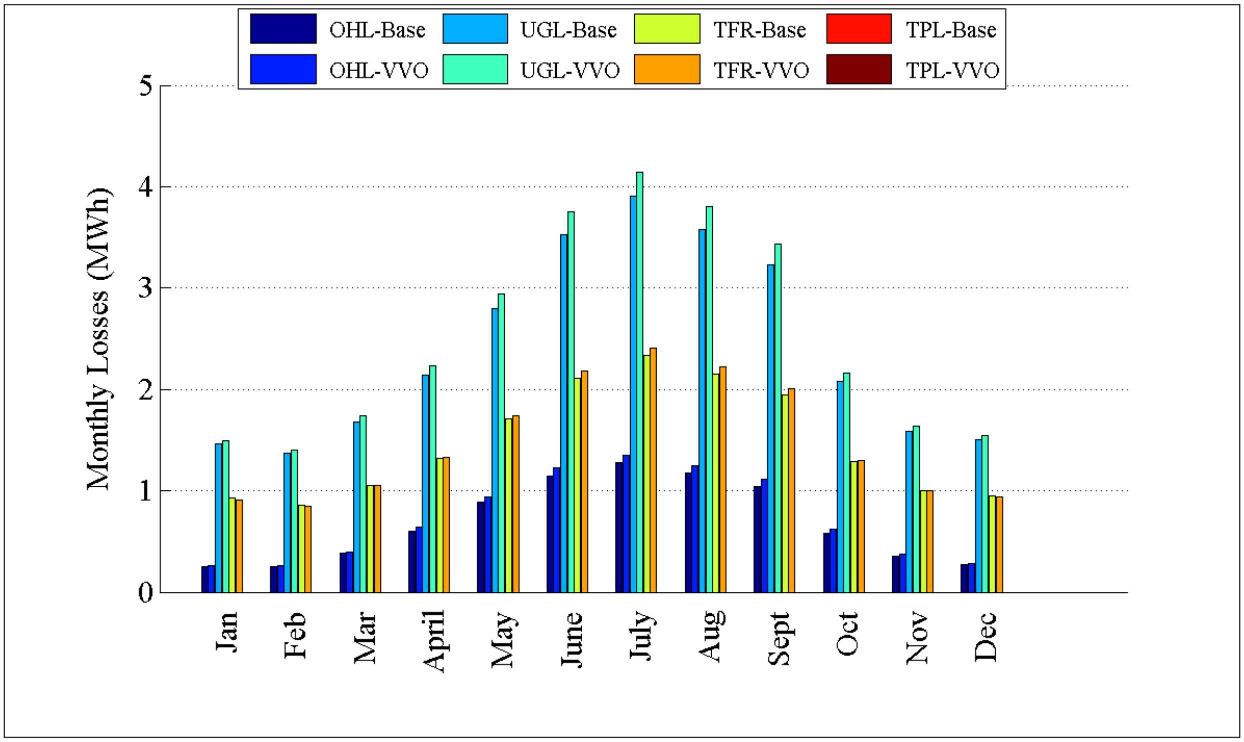



Figure D.65: Comparison of losses by month for GC-12.47-1_R4

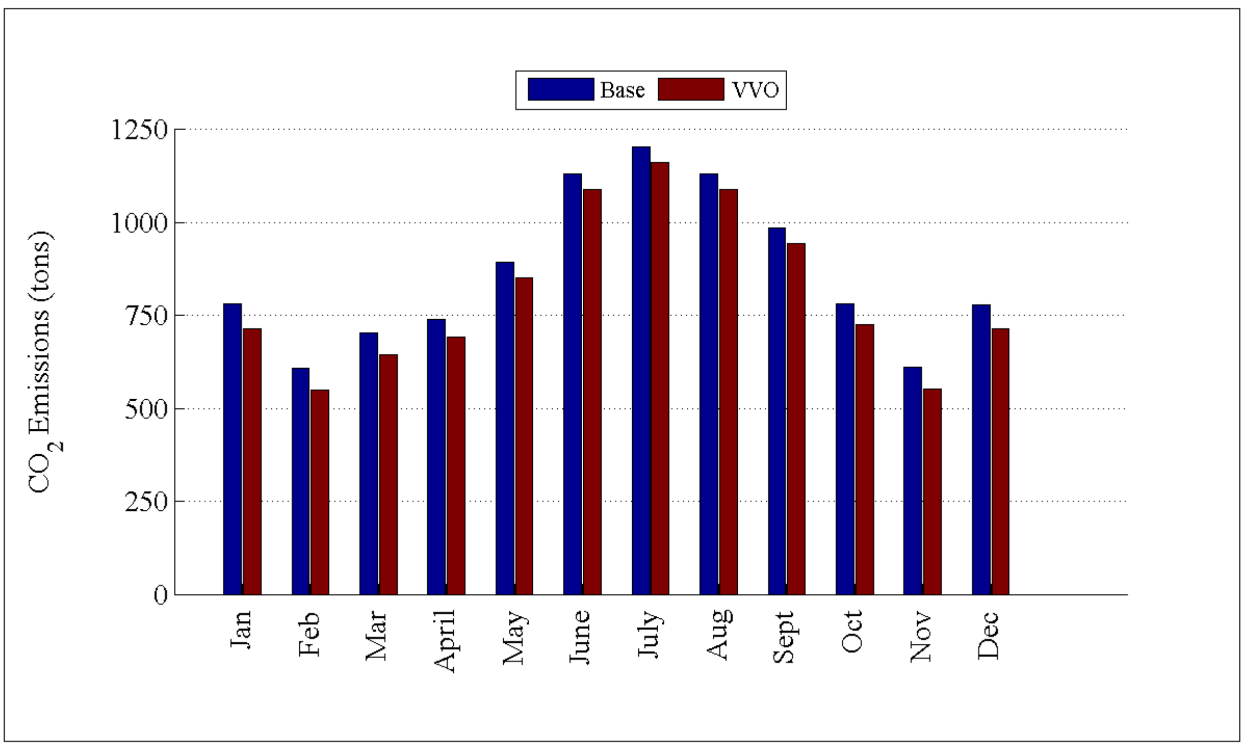



Figure D.66: Comparison of $CO_2$ emissions by month for GC-12.47-1_R4

## D.1.18 Detailed VVO Plots for R4-12.47-1

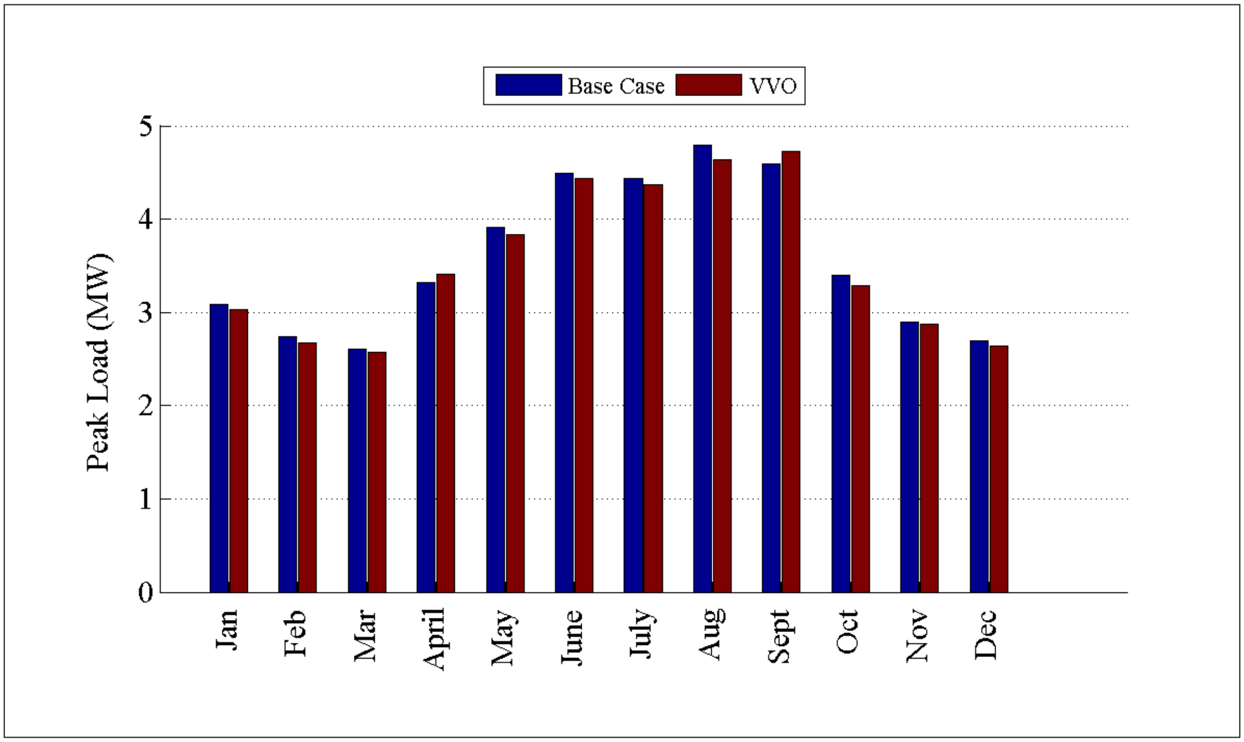



Figure D.67: Comparison of peak load by month for R4-12.47-1

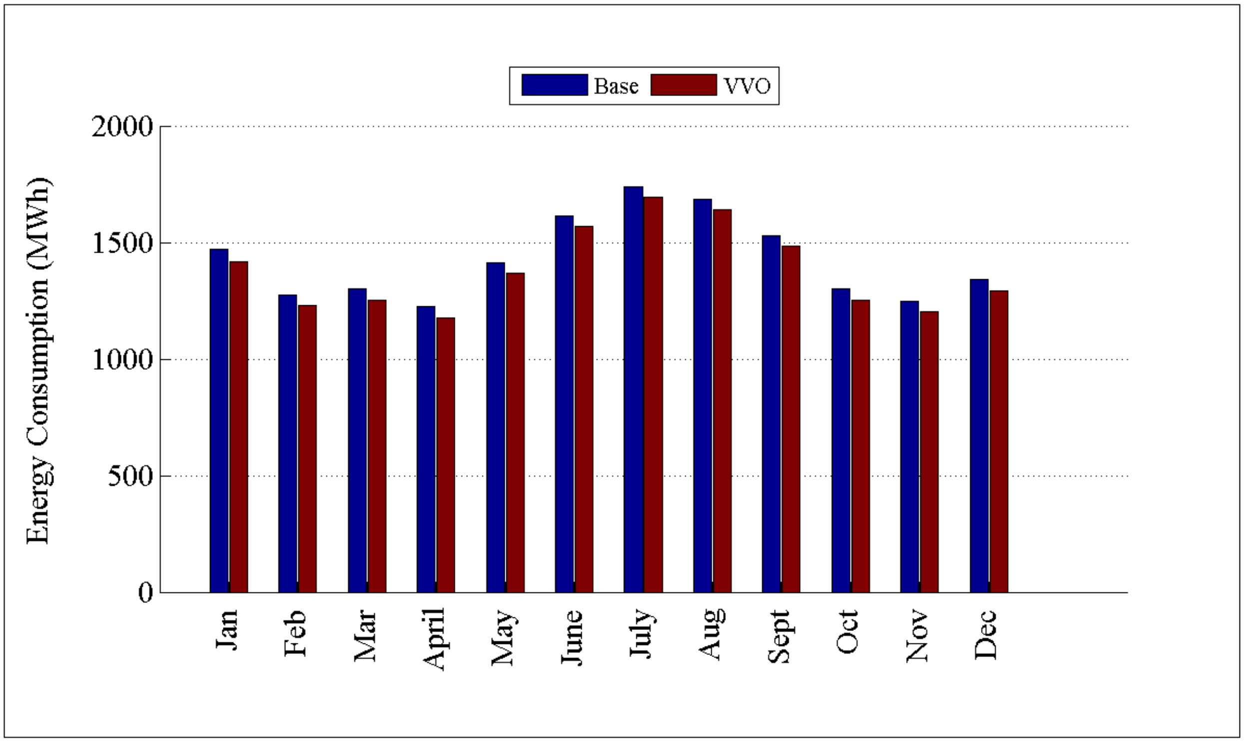



Figure D.68: Comparison of energy consumption by month for R4-12.47-1

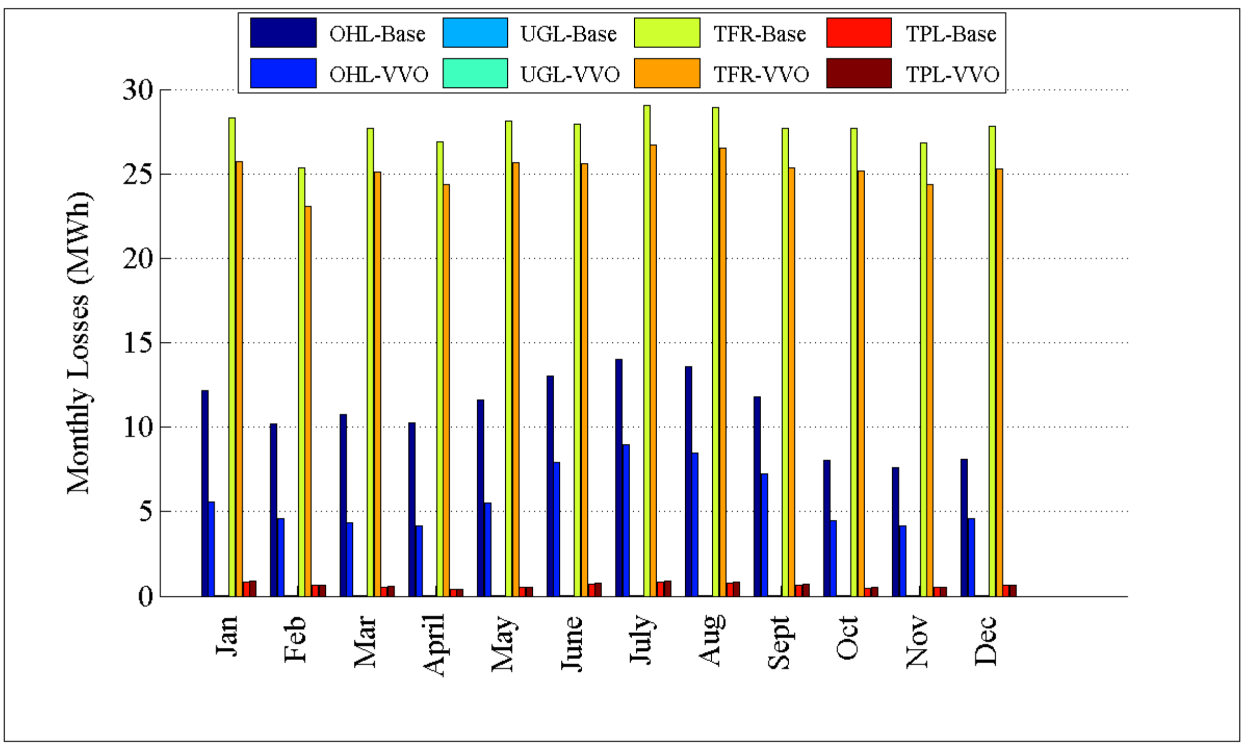



Figure D.69: Comparison of losses by month for R4-12.47-1

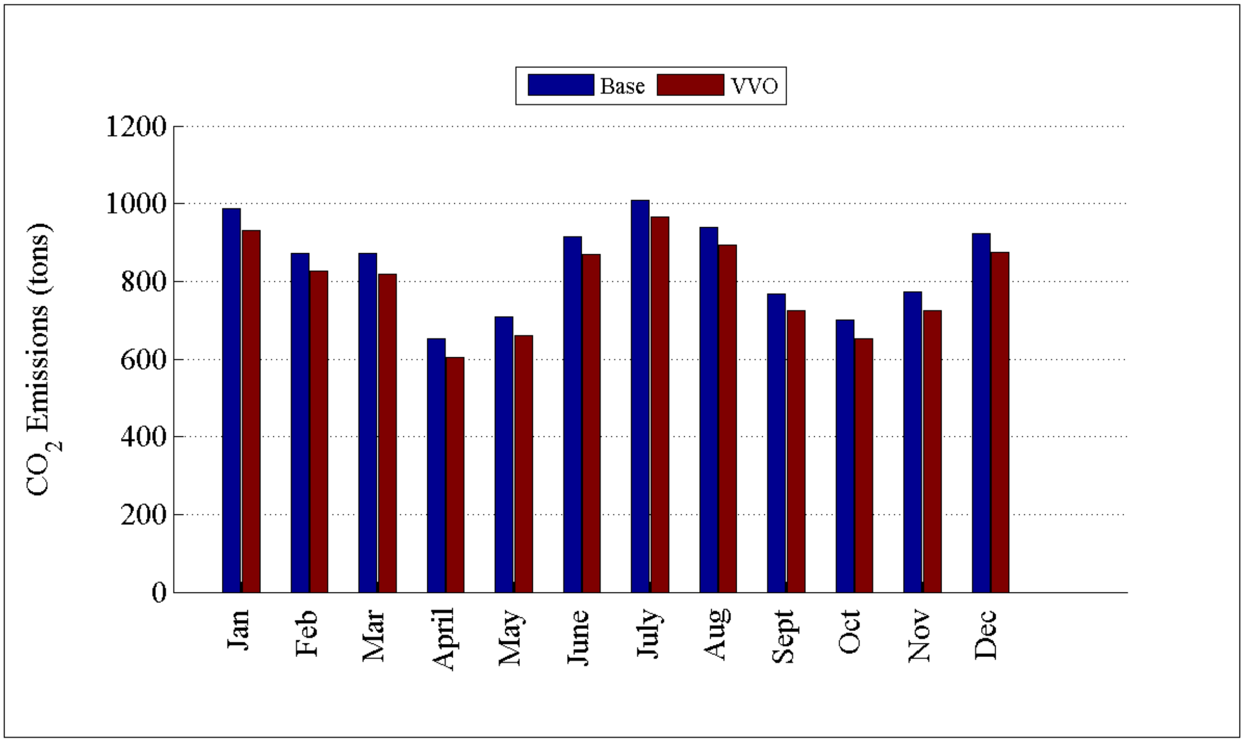



Figure D.70: Comparison of $CO_2$ emissions by month for R4-12.47-1

### D.1.19 Detailed VVO Plots for R4-12.47-2

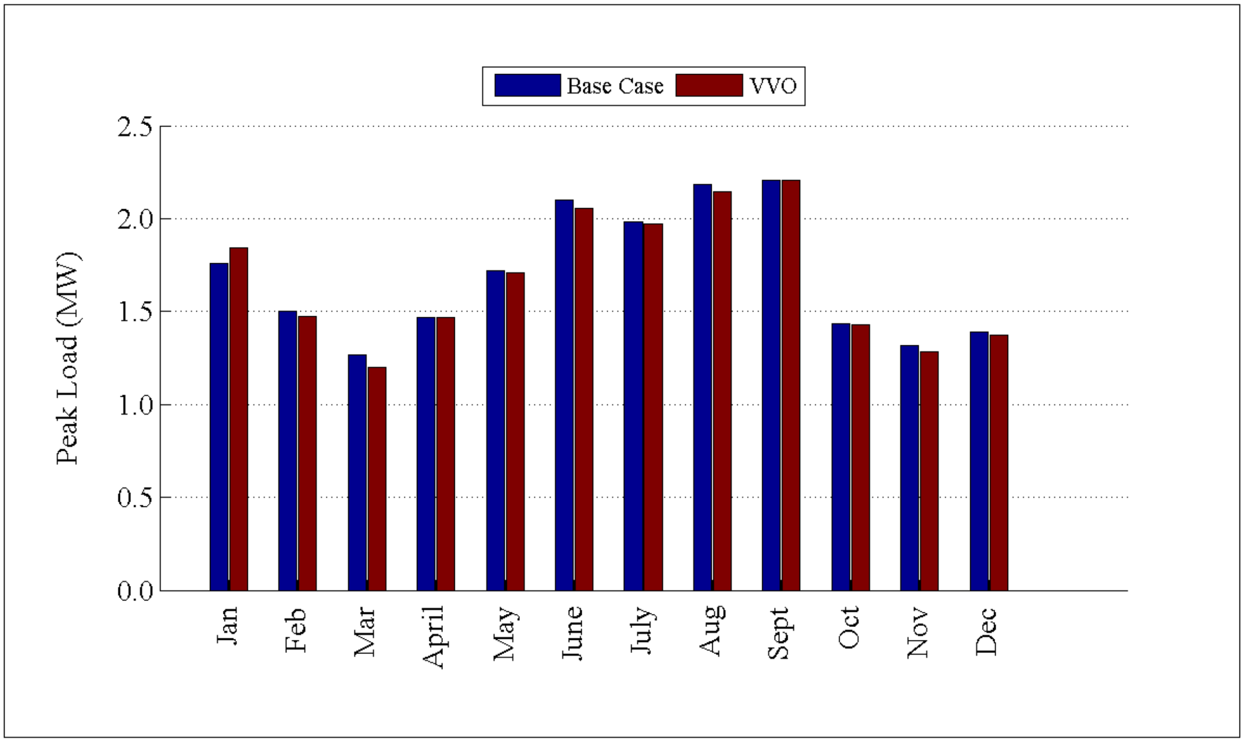



Figure D.71: Comparison of peak load by month for R4-12.47-2

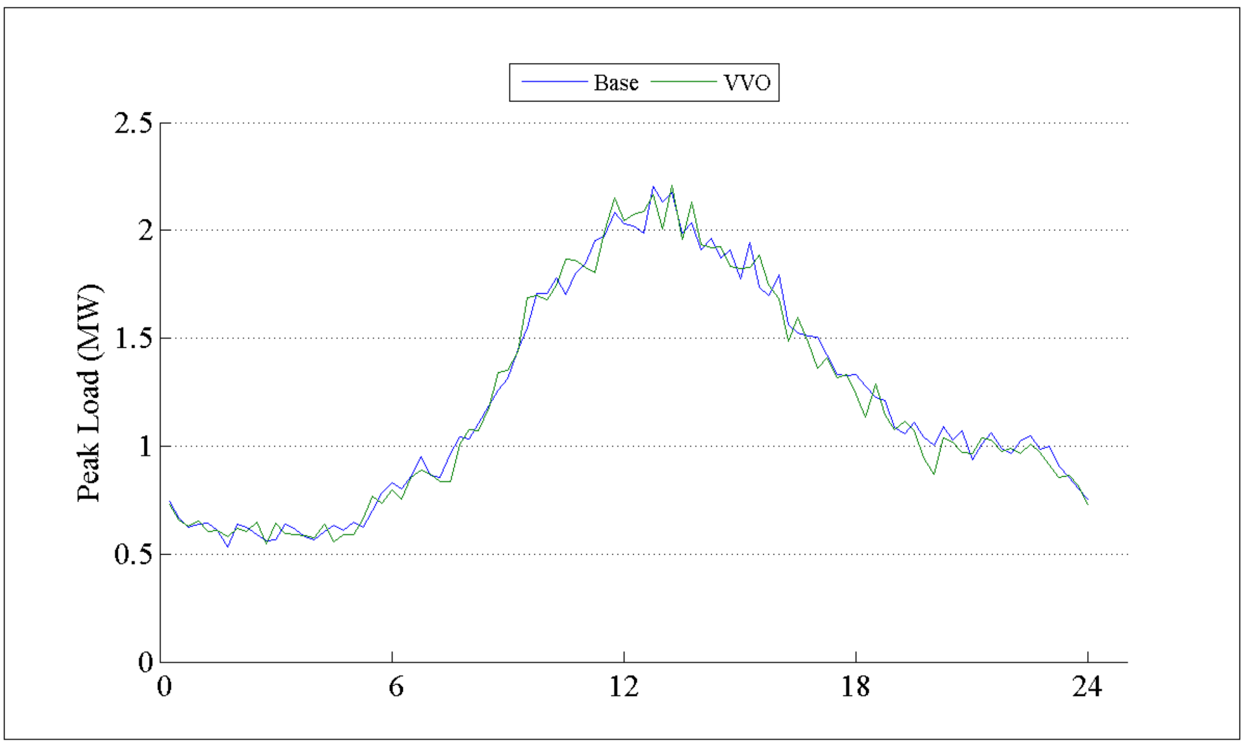



Figure D.72: Peak load day for R4-12.47-2

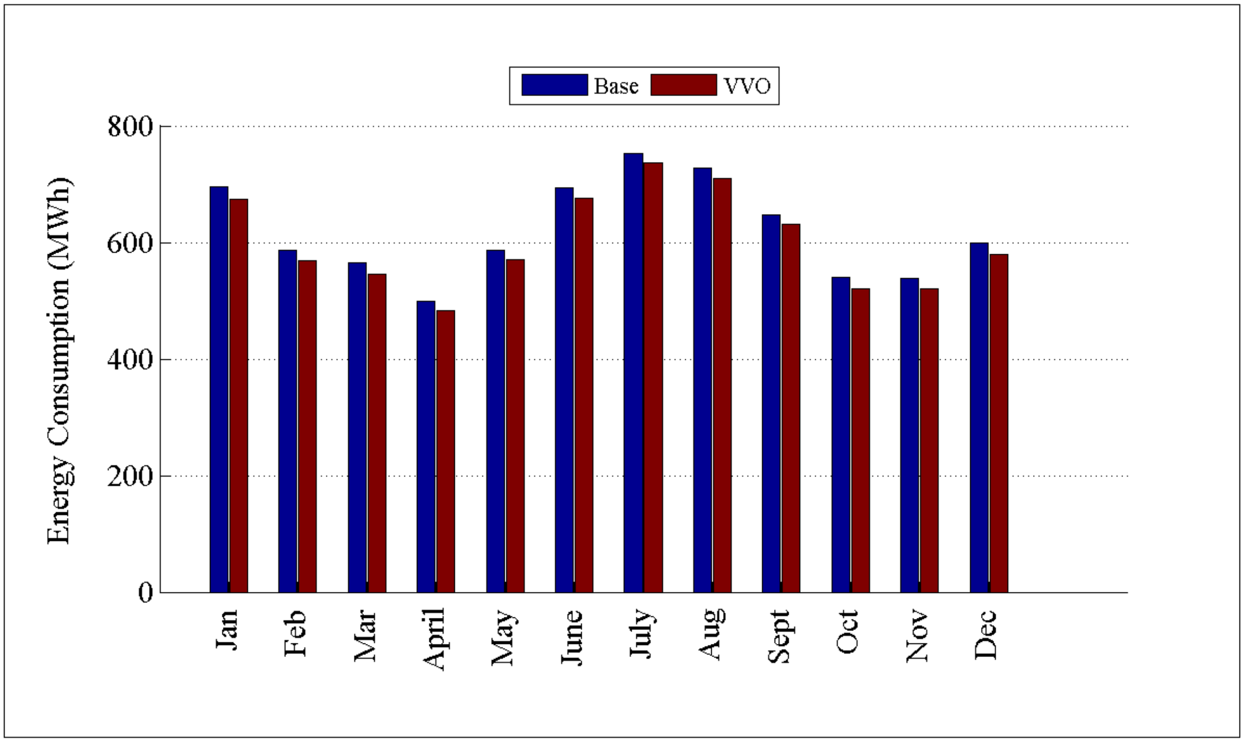



Figure D.73: Comparison of energy consumption by month for R4-12.47-2

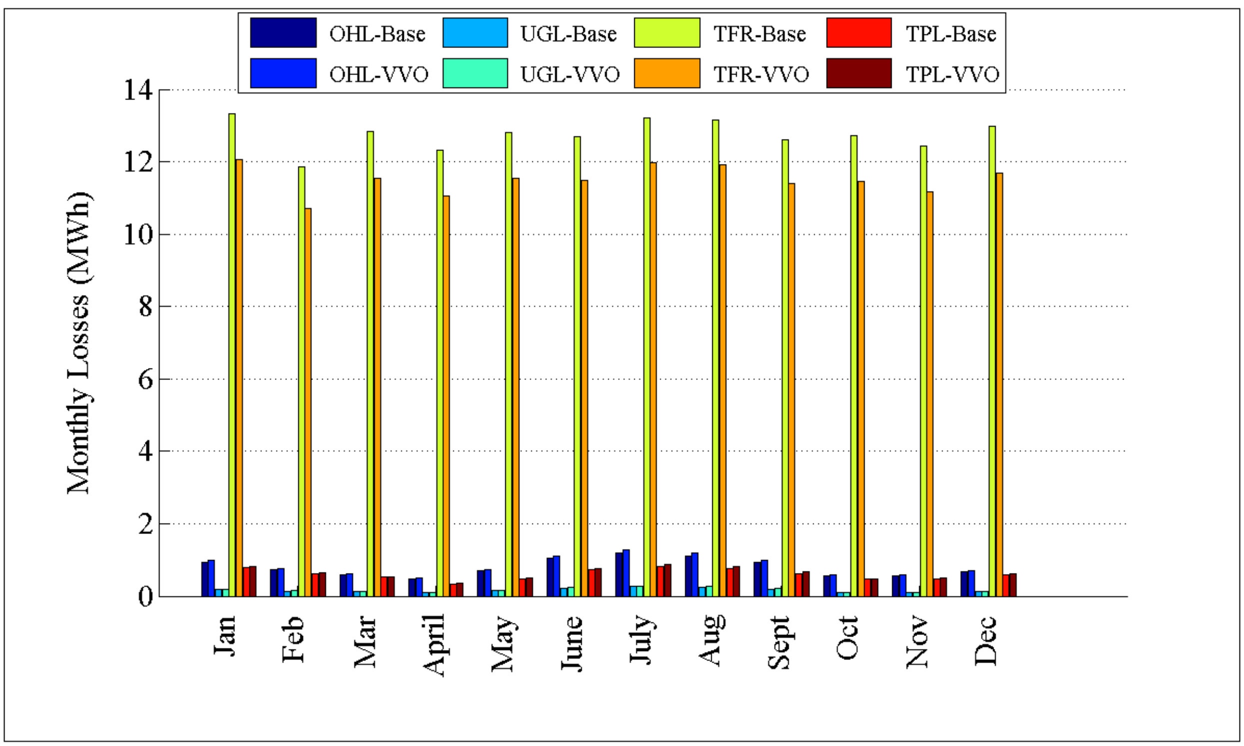



Figure D.74: Comparison of losses by month for R4-12.47-2

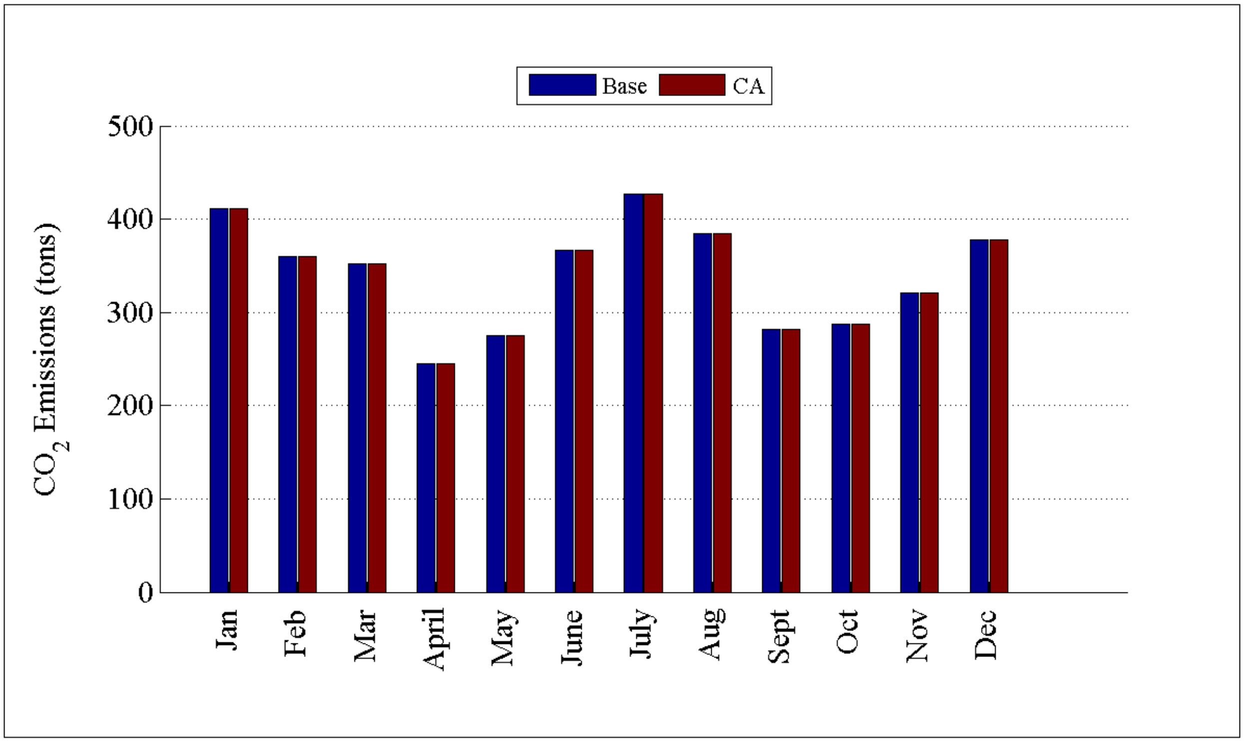



Figure D.75: Comparison of $CO_2$ emissions by month for R4-12.47-2

### D.1.20 Detailed VVO Plots for R4-25.00-1

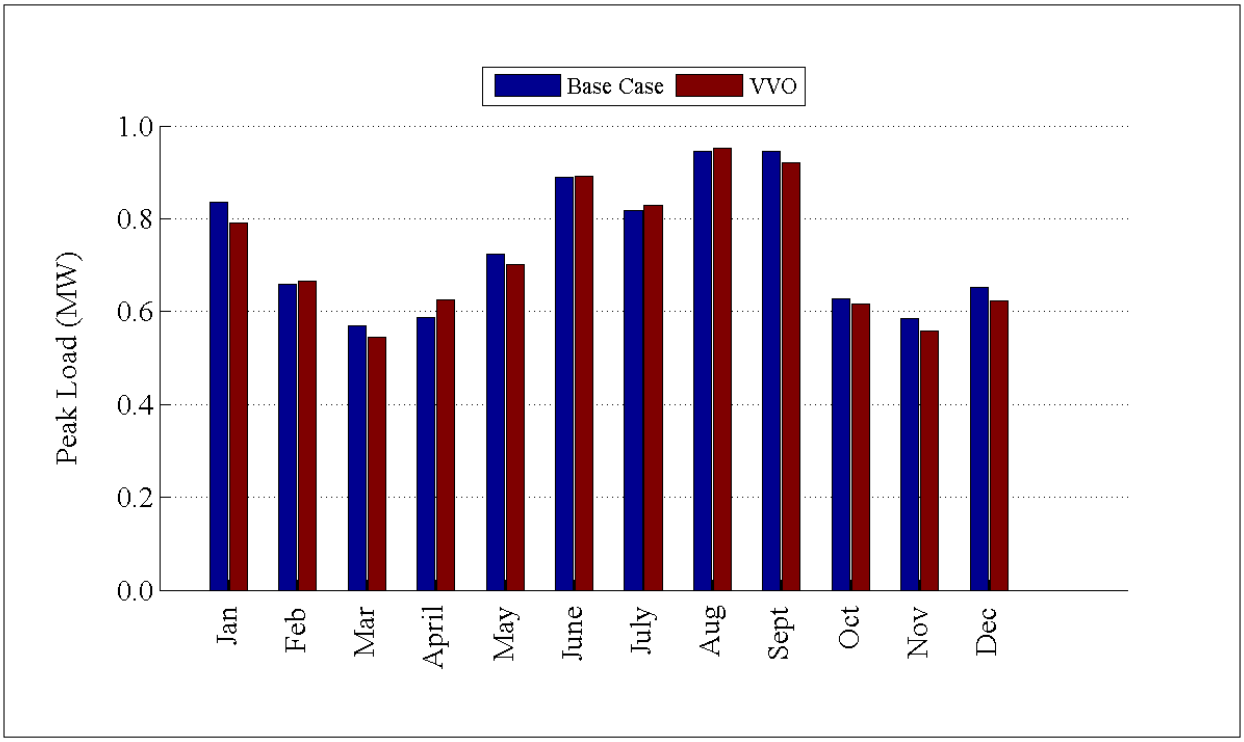



Figure D.76: Comparison of peak load by month for R4-25.00-1

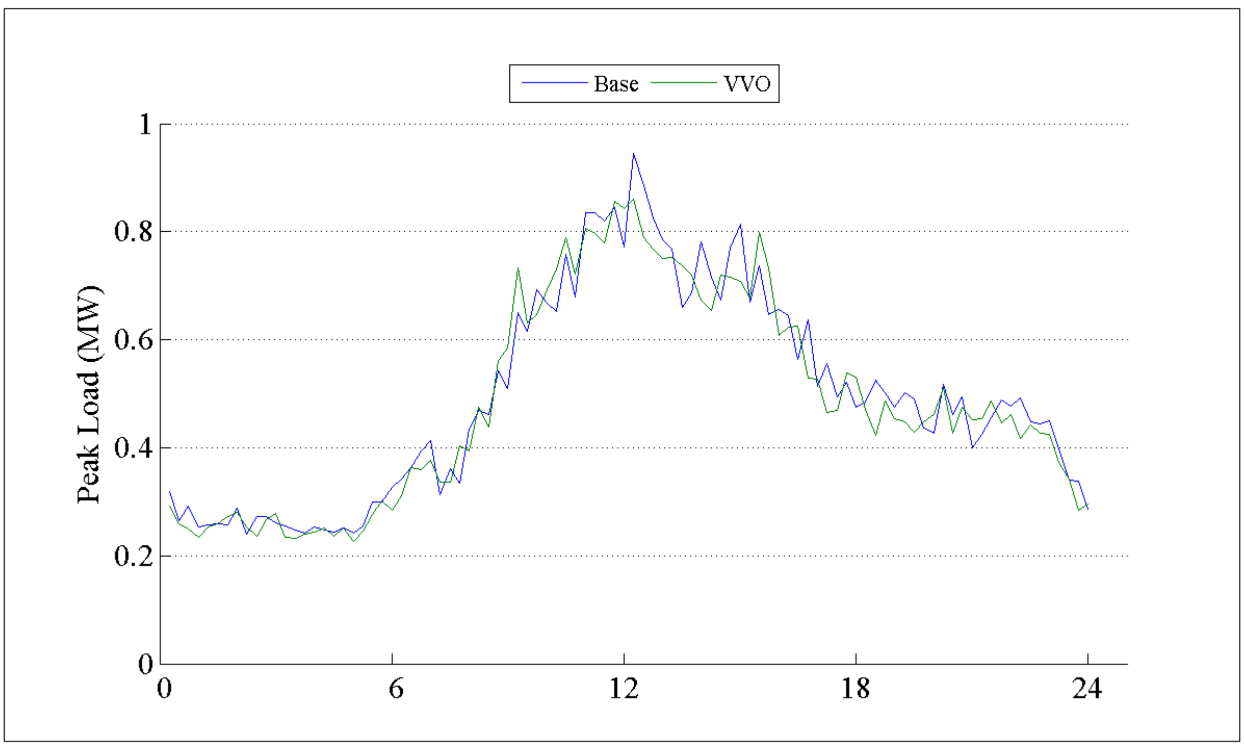



Figure D.77: Peak load day for R4-25.00-1

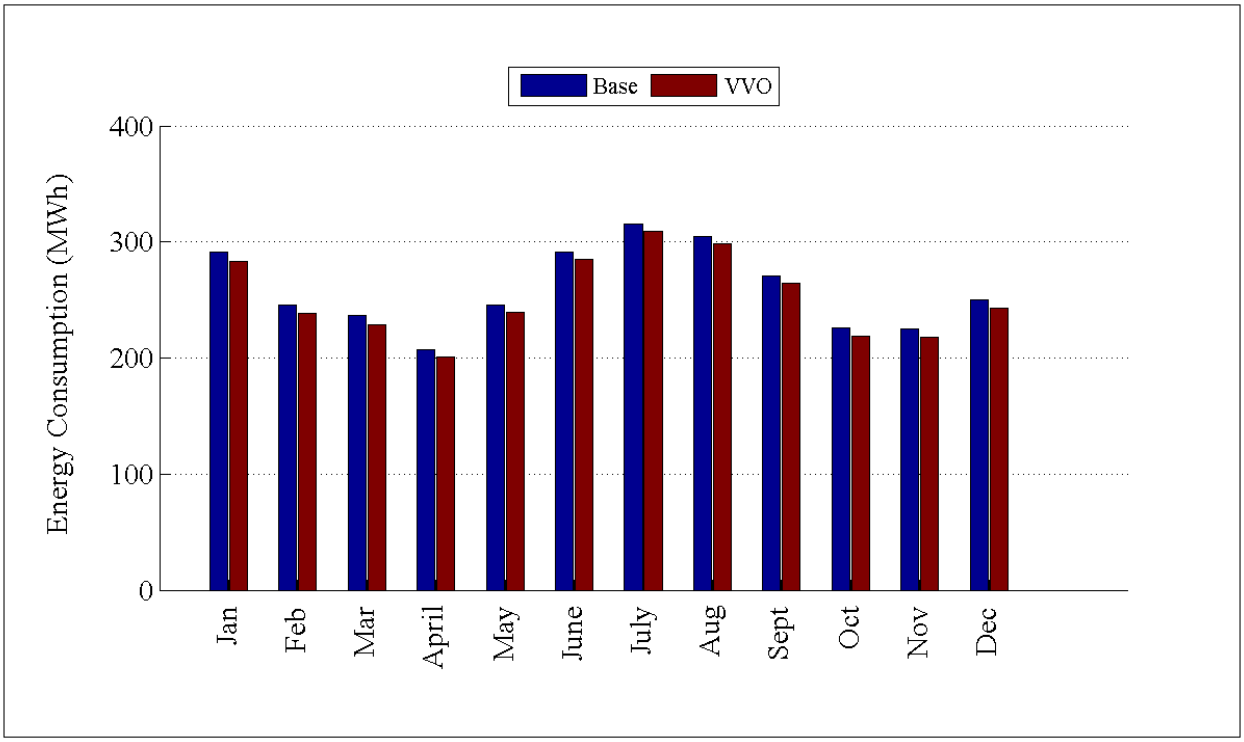



Figure D.78: Comparison of energy consumption by month for R4-25.00-1

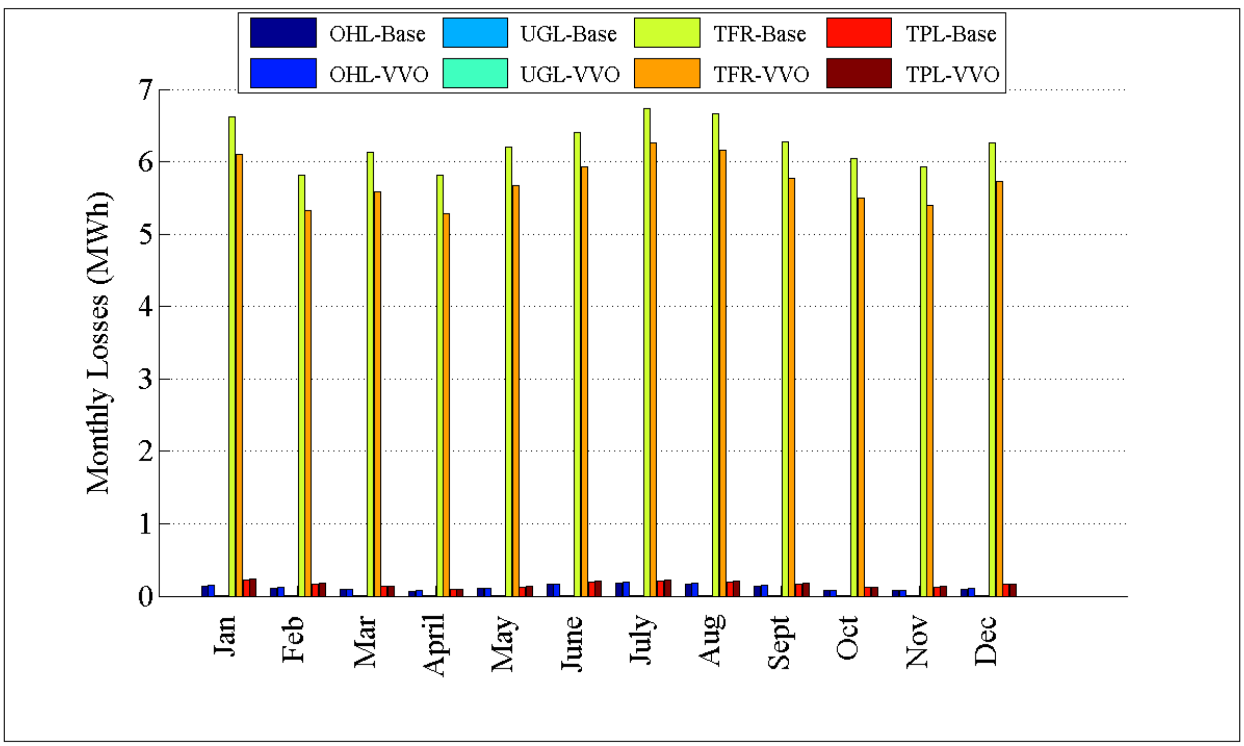



Figure D.79: Comparison of losses by month for R4-25.00-1

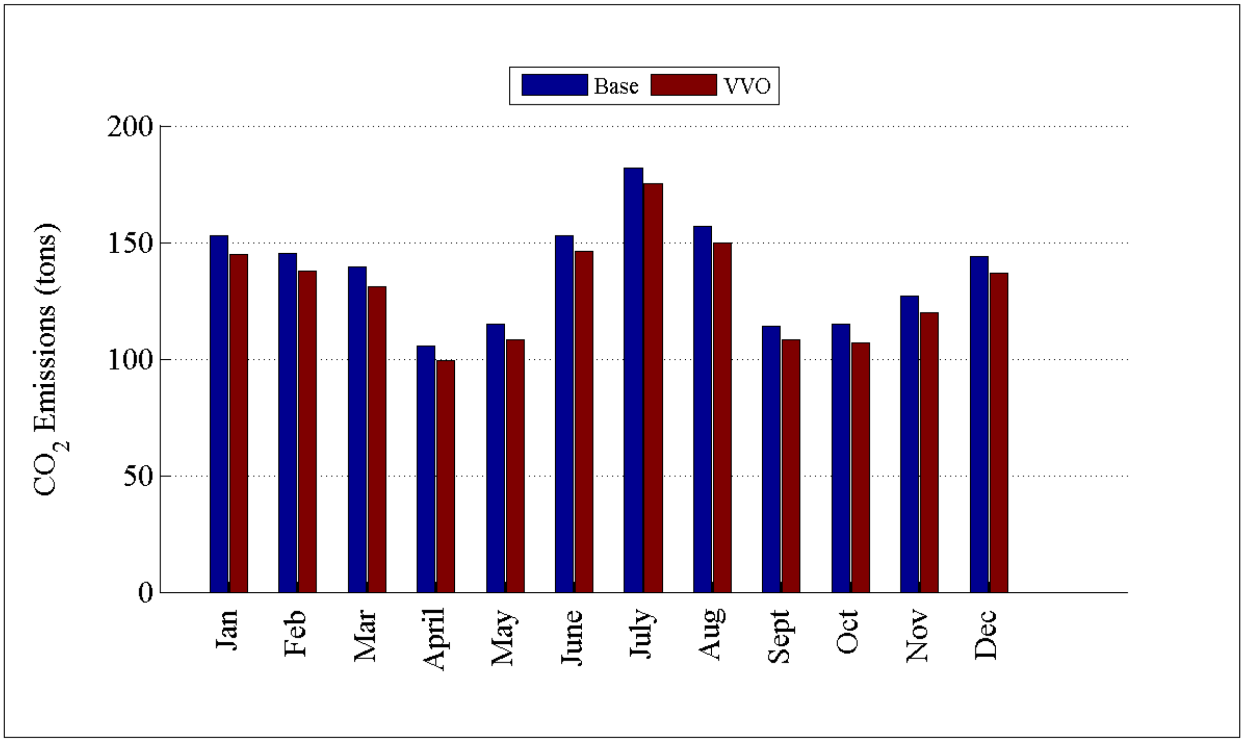



Figure D.80: Comparison of $CO_2$ emissions by month for R4-25.00-1

### D.1.21 Detailed VVO Plots for GC-12.47-1_R5

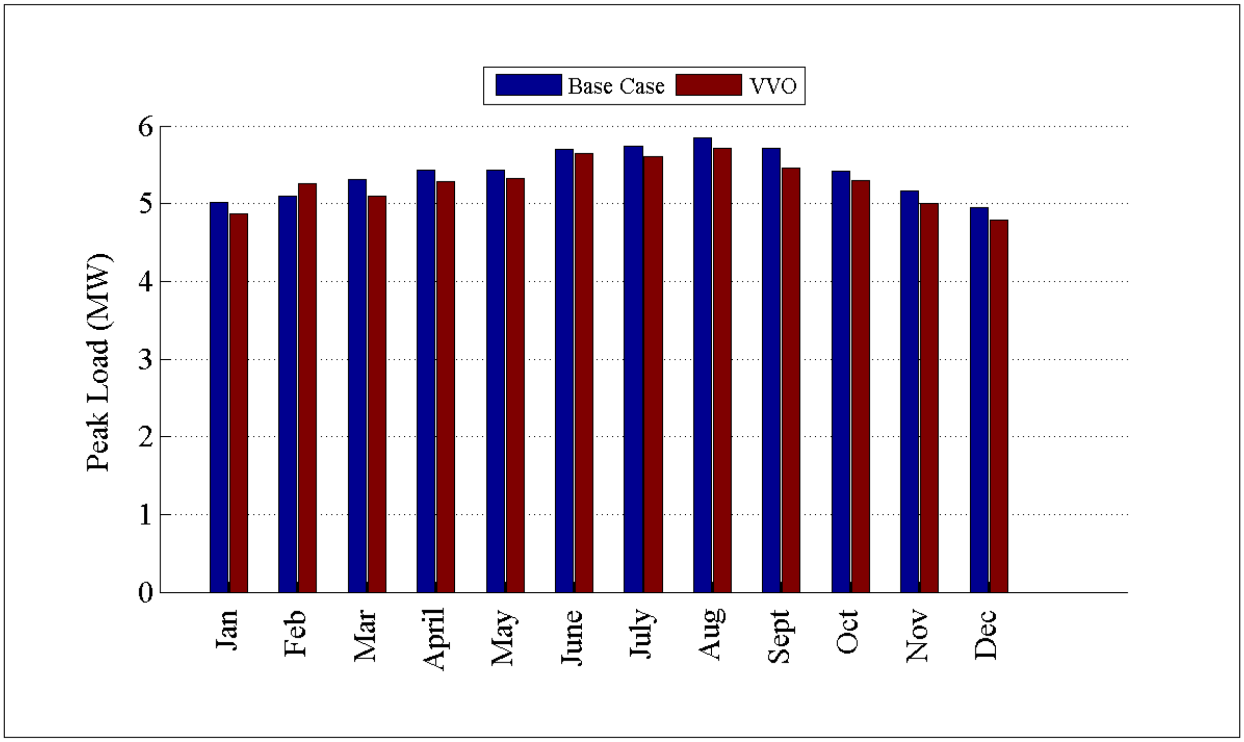



Figure D.81: Comparison of peak load by month for GC-12.47-1_R5

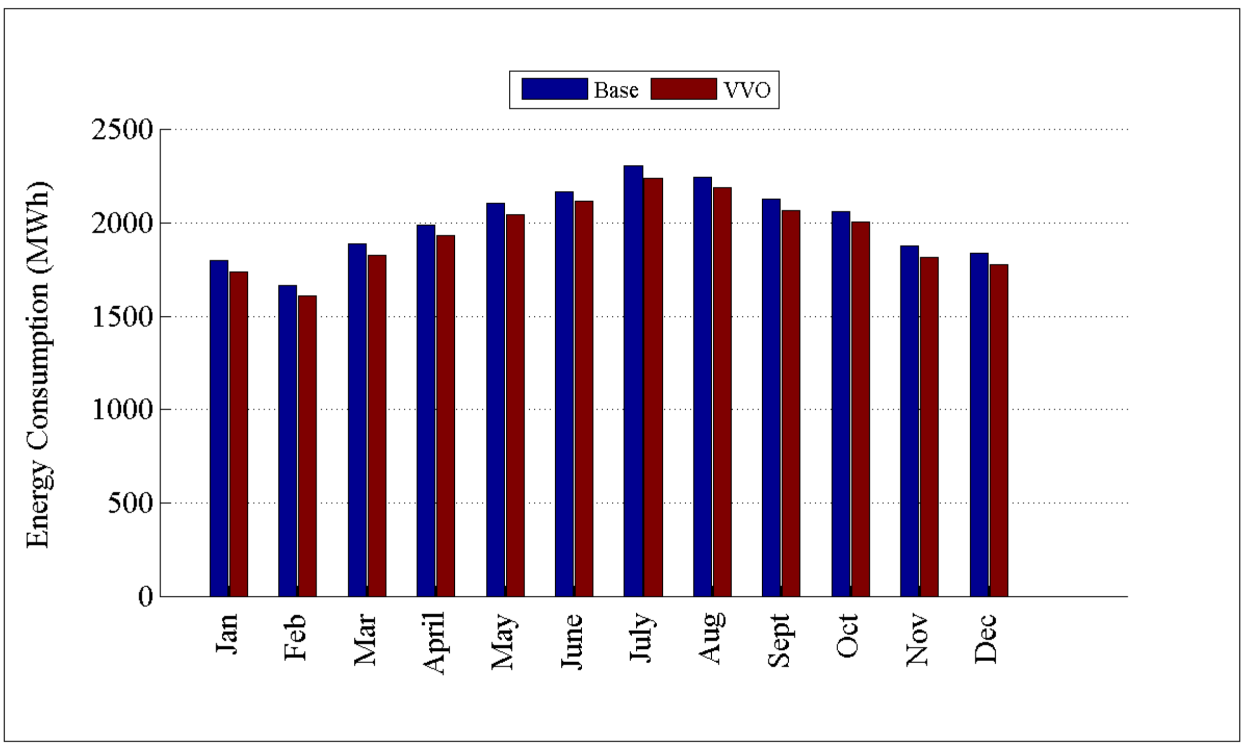



Figure D.82: Comparison of energy consumption by month for GC-12.47-1_R5

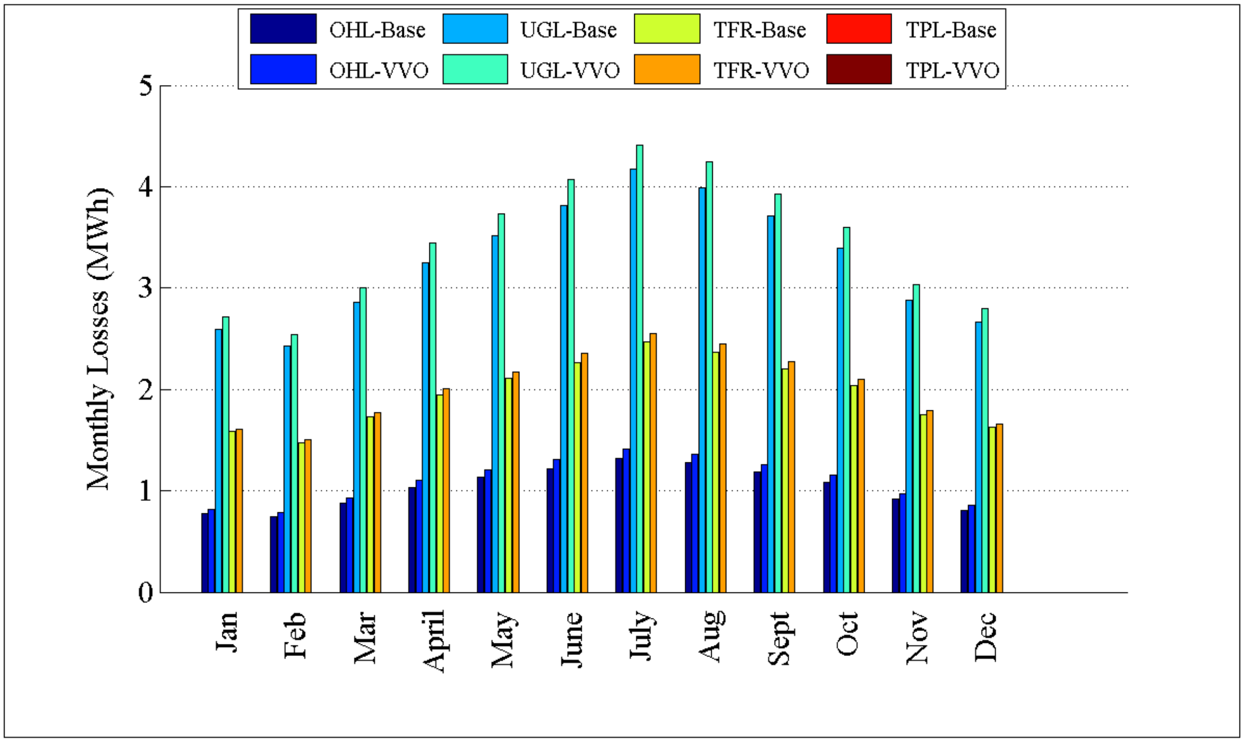



Figure D.83: Comparison of losses by month for GC-12.47-1_R5

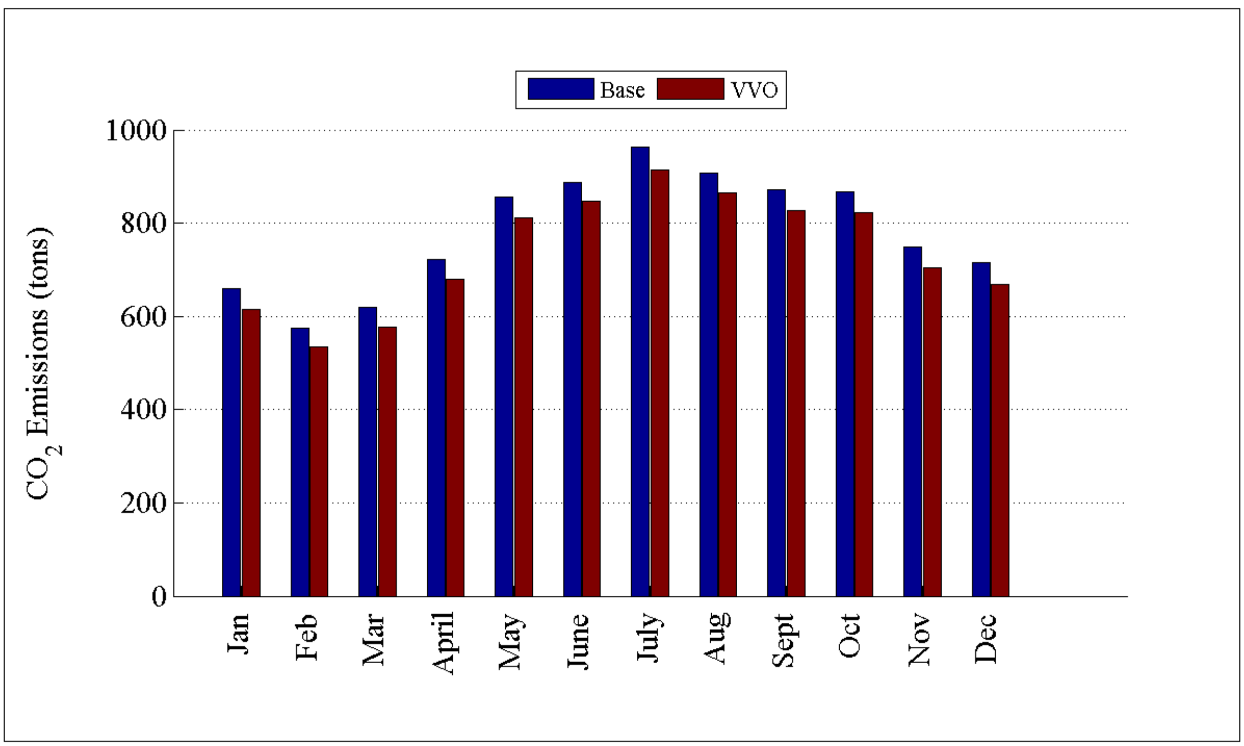



Figure D.84: Comparison of $CO_2$ emissions by month for GC-12.47-1_R5

## D.1.22 Detailed VVO Plots for R5-12.47-1

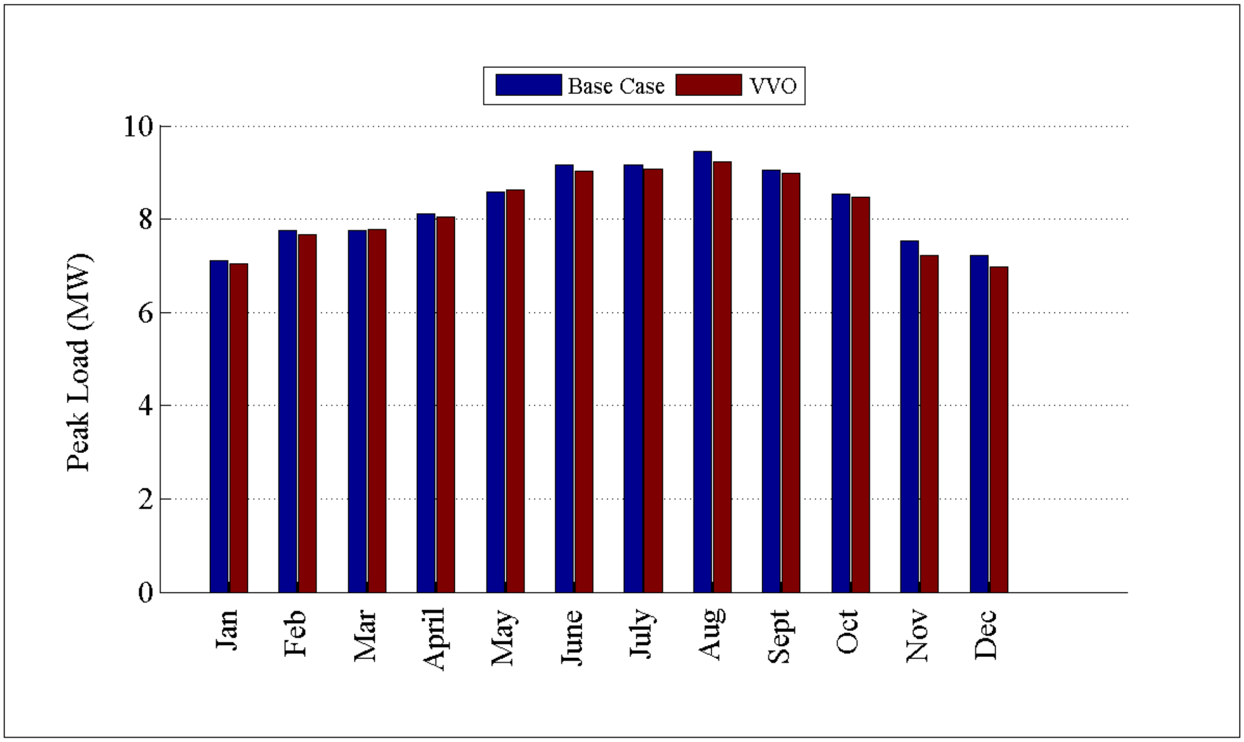



Figure D.85: Comparison of peak load by month for R5-12.47-1

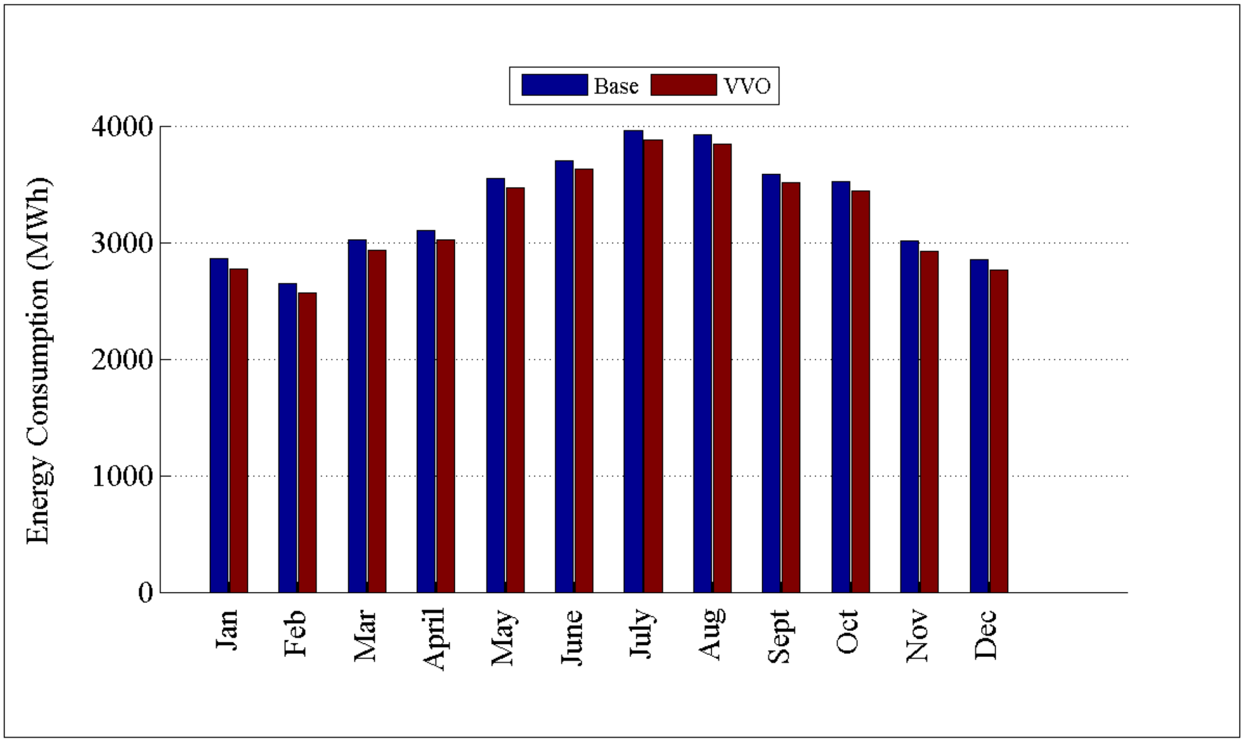



Figure D.86: Comparison of energy consumption by month for R5-12.47-1

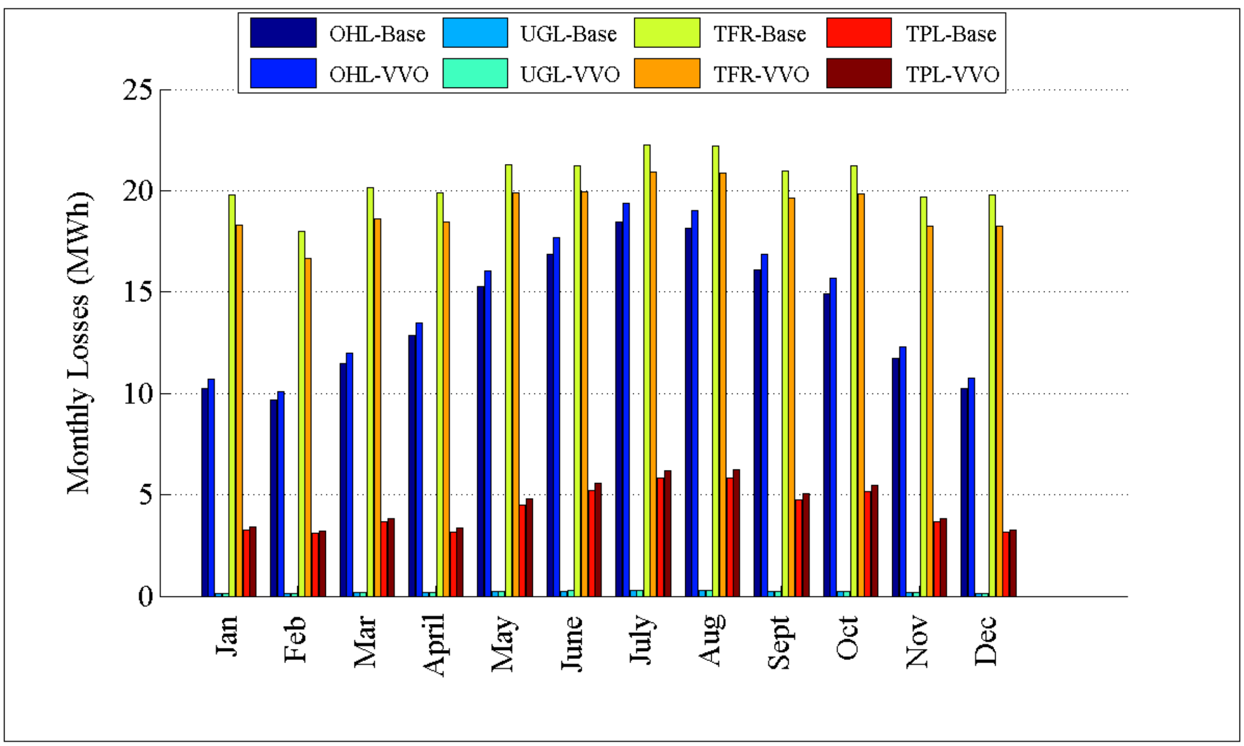



Figure D.87: Comparison of losses by month for R5-12.47-1

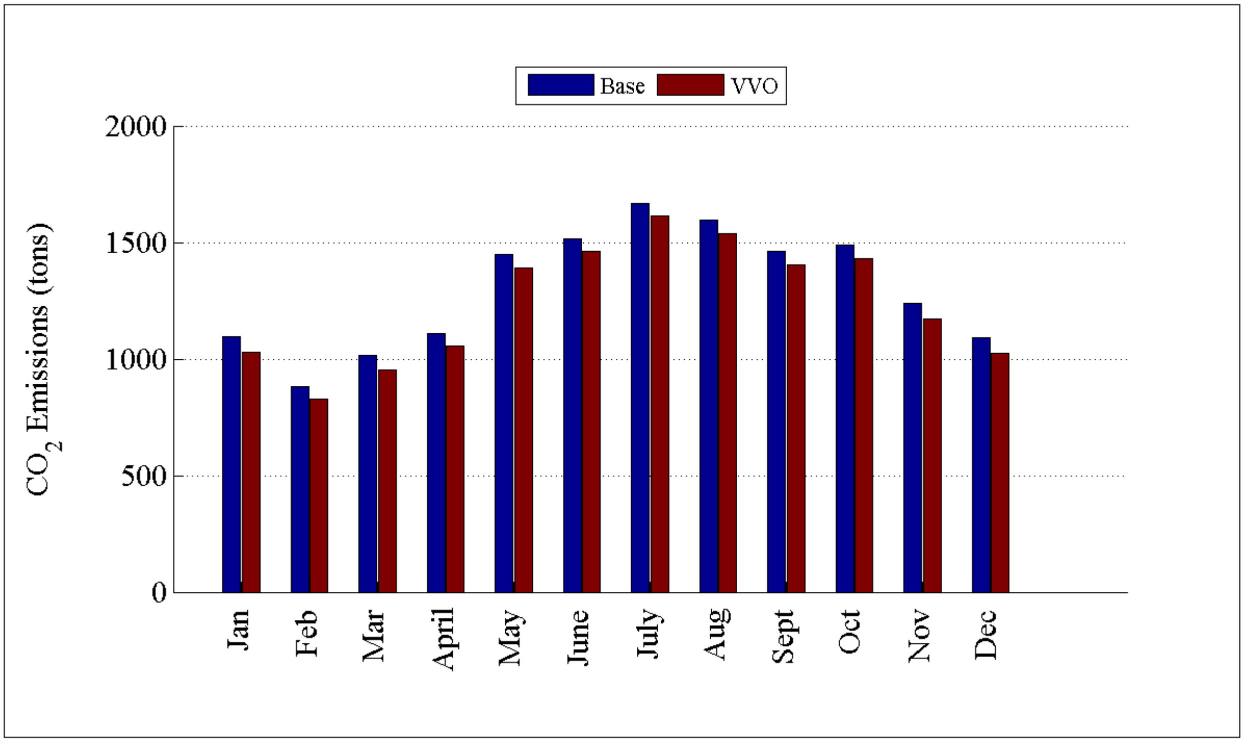



Figure D.88: Comparison of $CO_2$ emissions by month for R5-12.47-1

### D.1.23 Detailed VVO Plots for R5-12.47-2

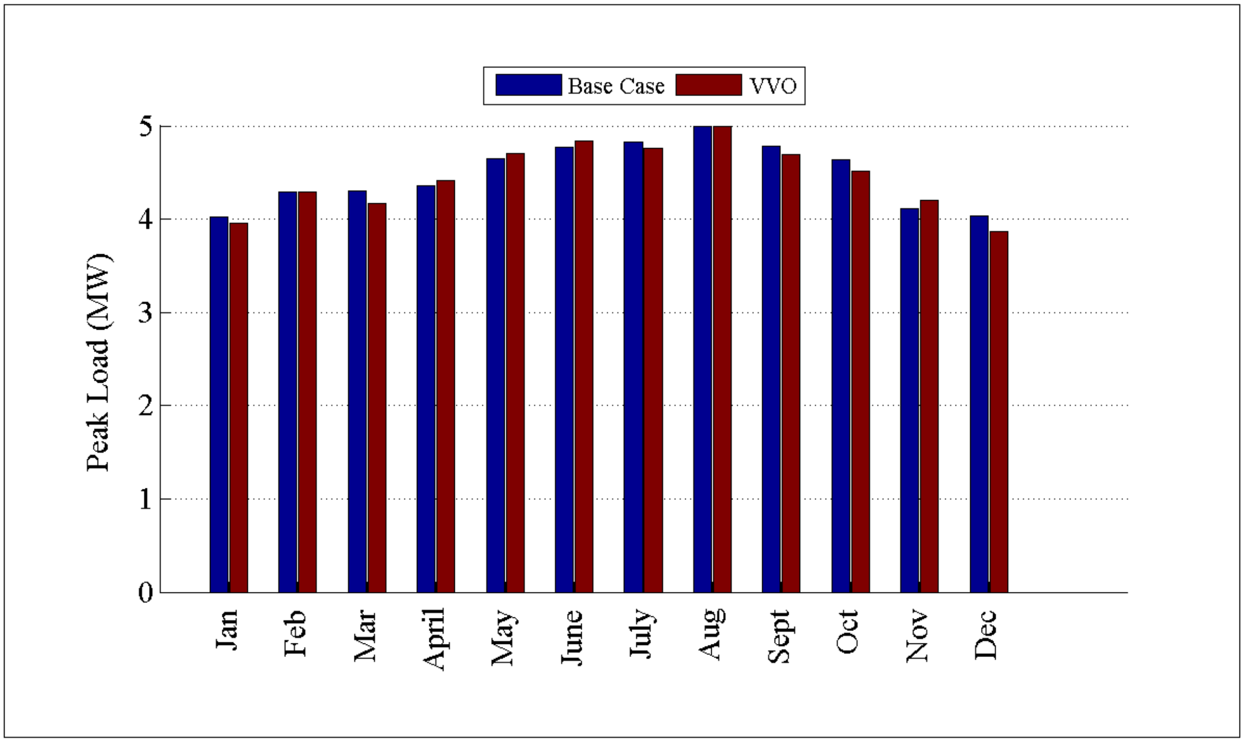



Figure D.89: Comparison of peak load by month for R5-12.47-2

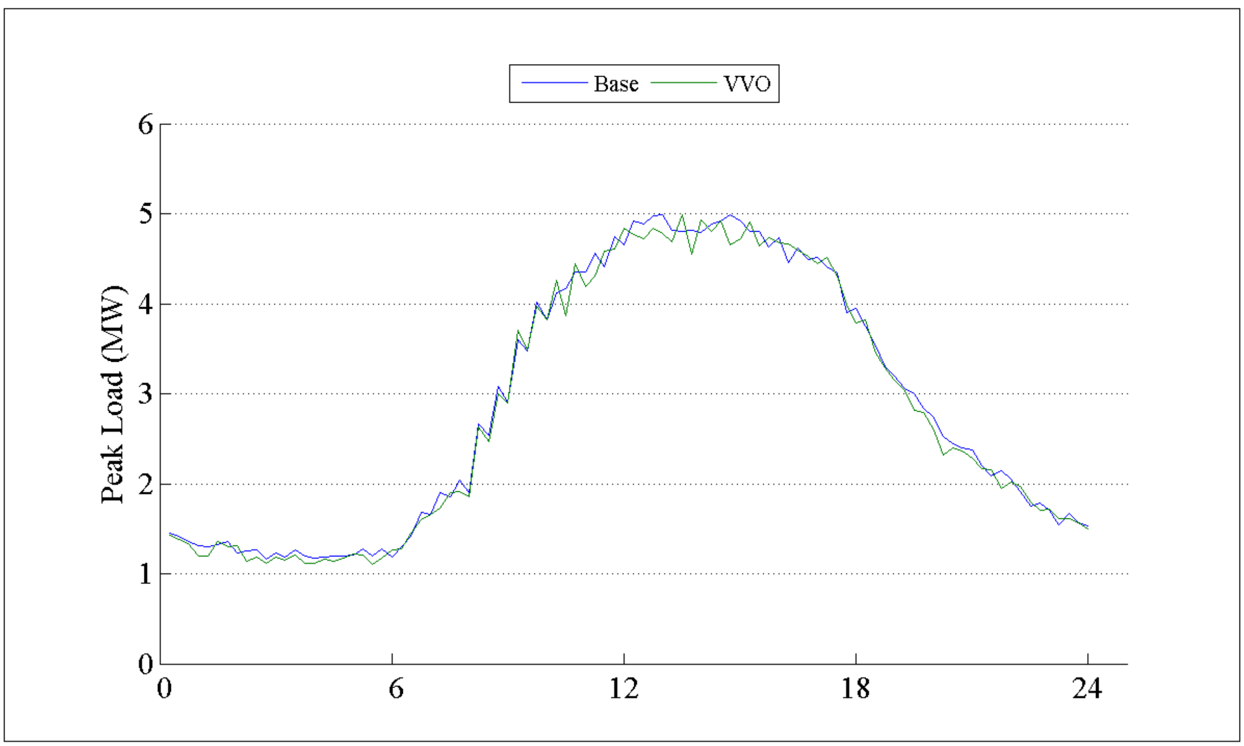



Figure D.90: Peak load day for R5-12.47-2

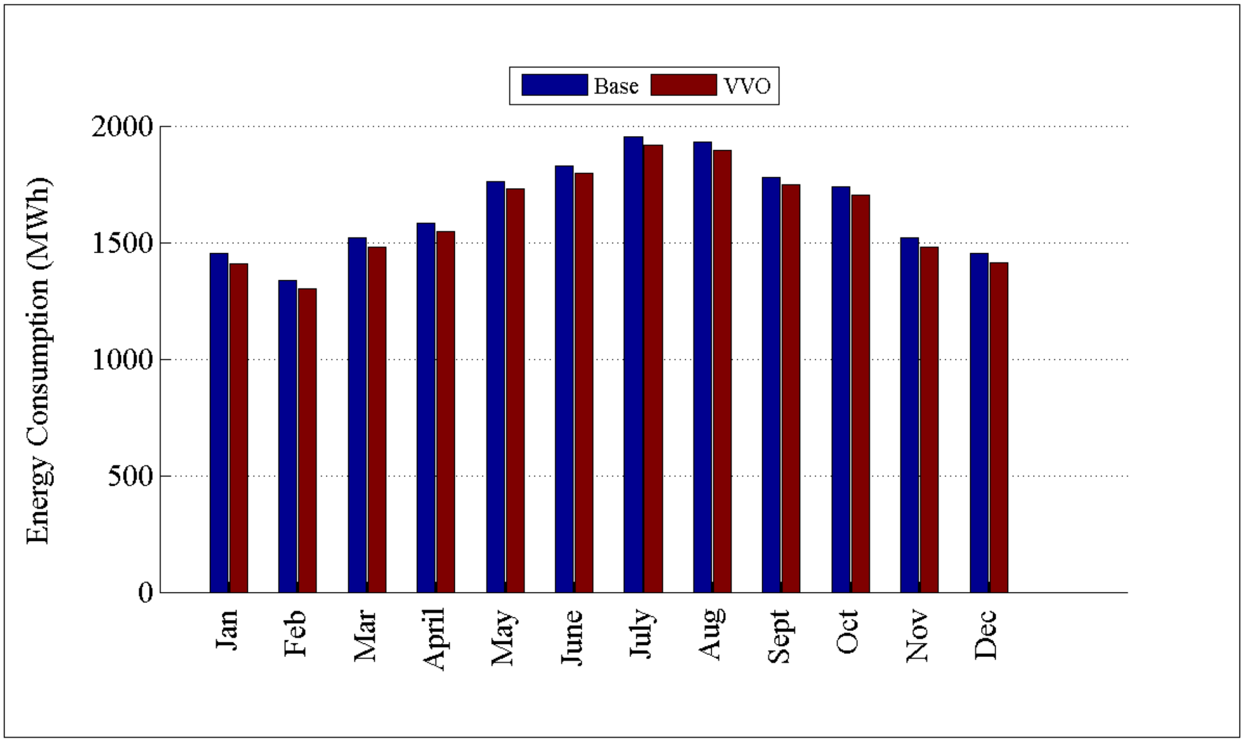



Figure D.91: Comparison of energy consumption by month for R5-12.47-2

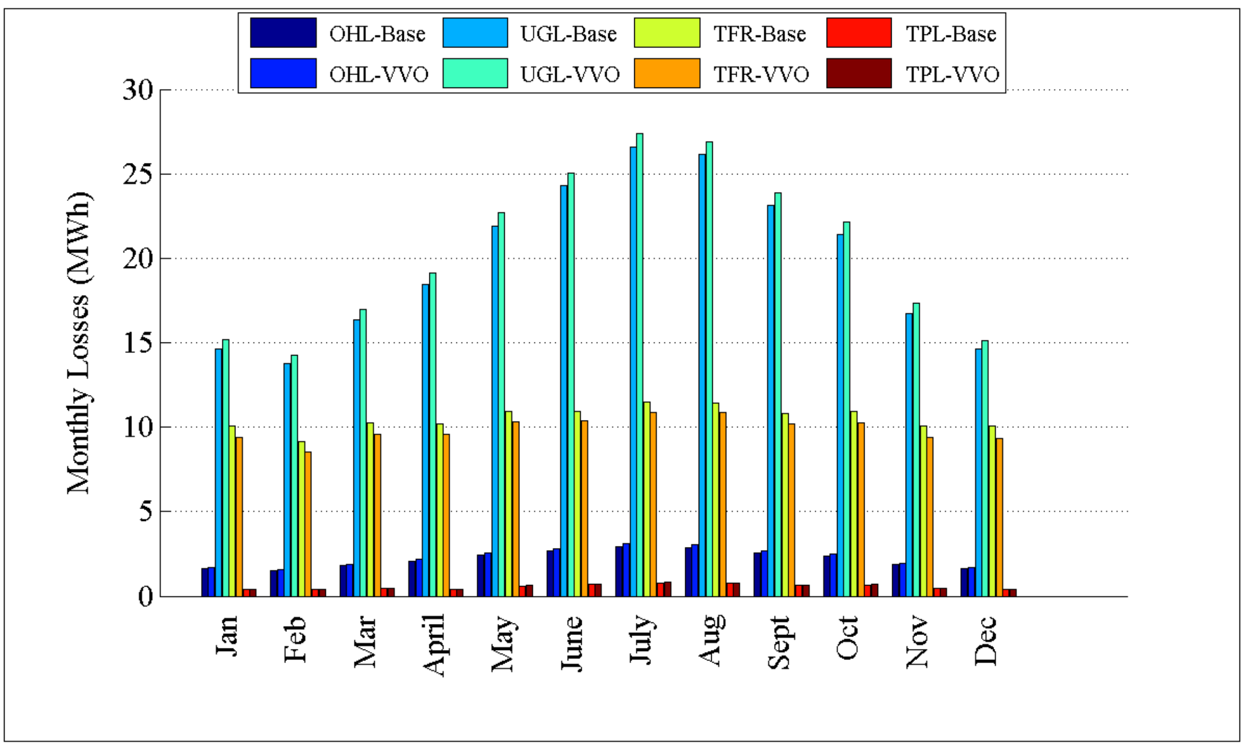



Figure D.92: Comparison of losses by month for R5-12.47-2

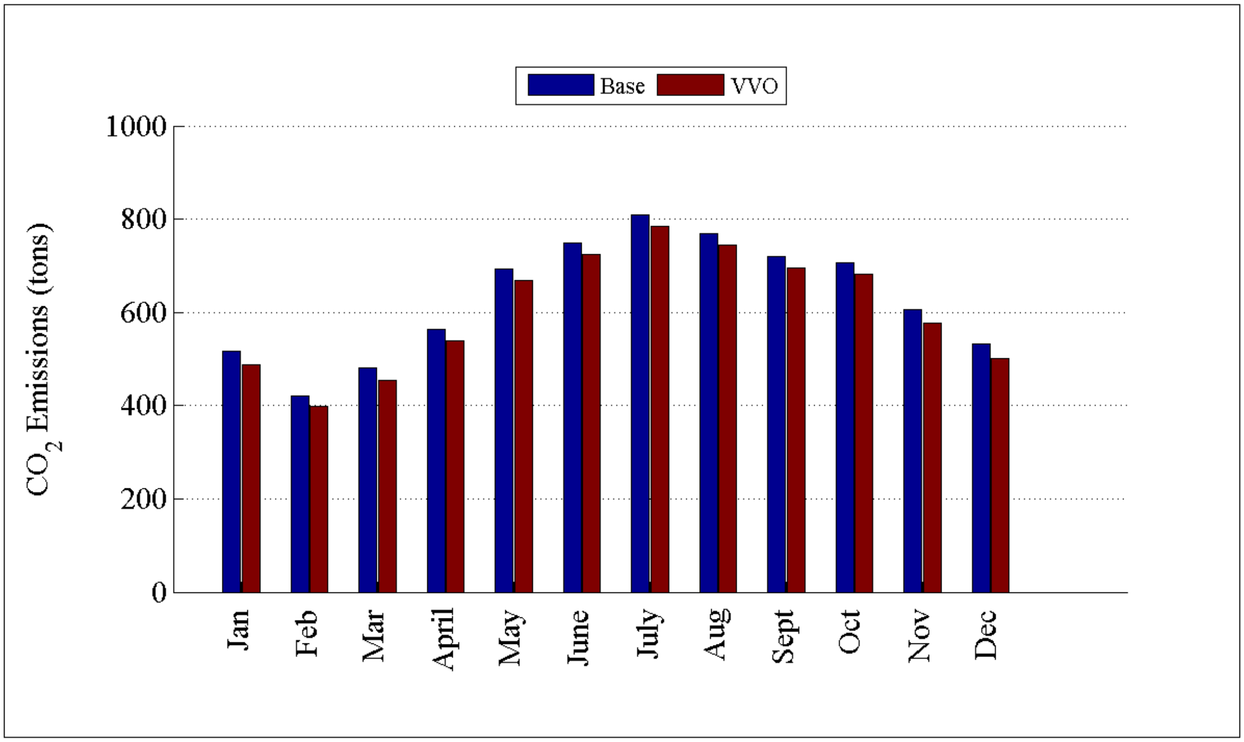



Figure D.93: Comparison of $CO_2$ emissions by month for R5-12.47-2

### D.1.24 Detailed VVO Plots for R5-12.47-3

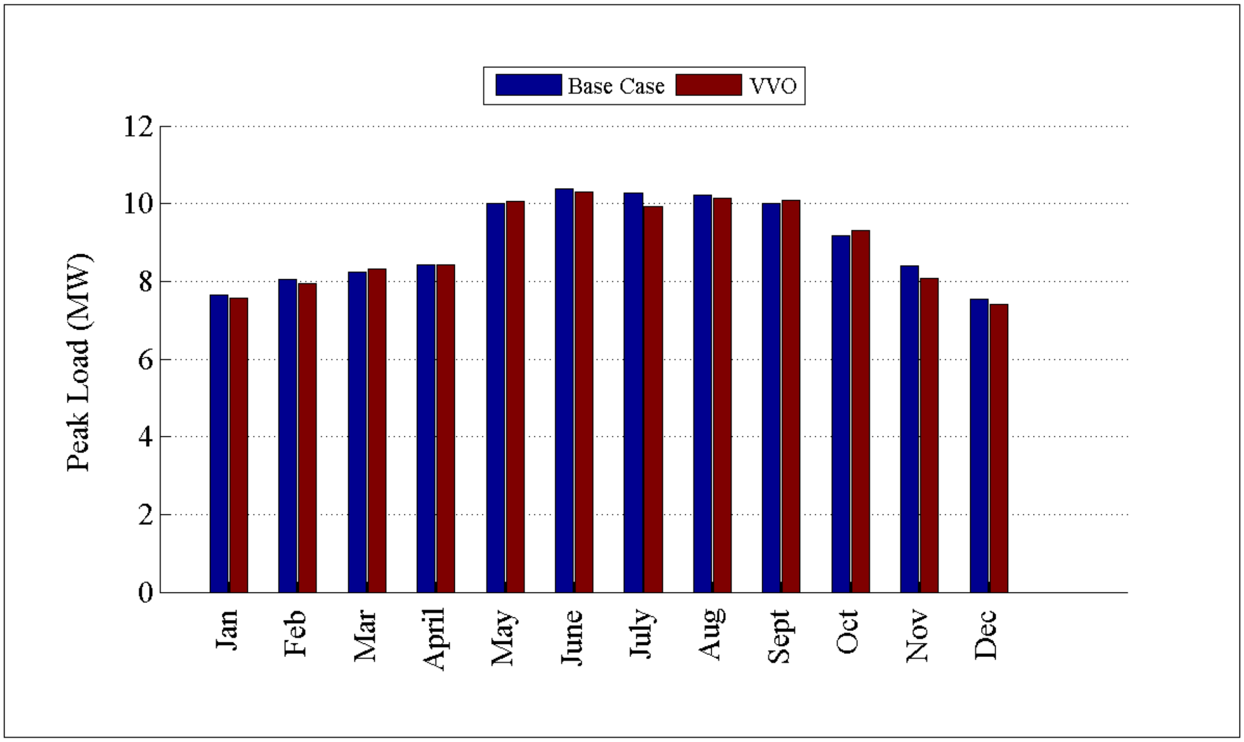



Figure D.94: Comparison of peak load by month for R5-12.47-3

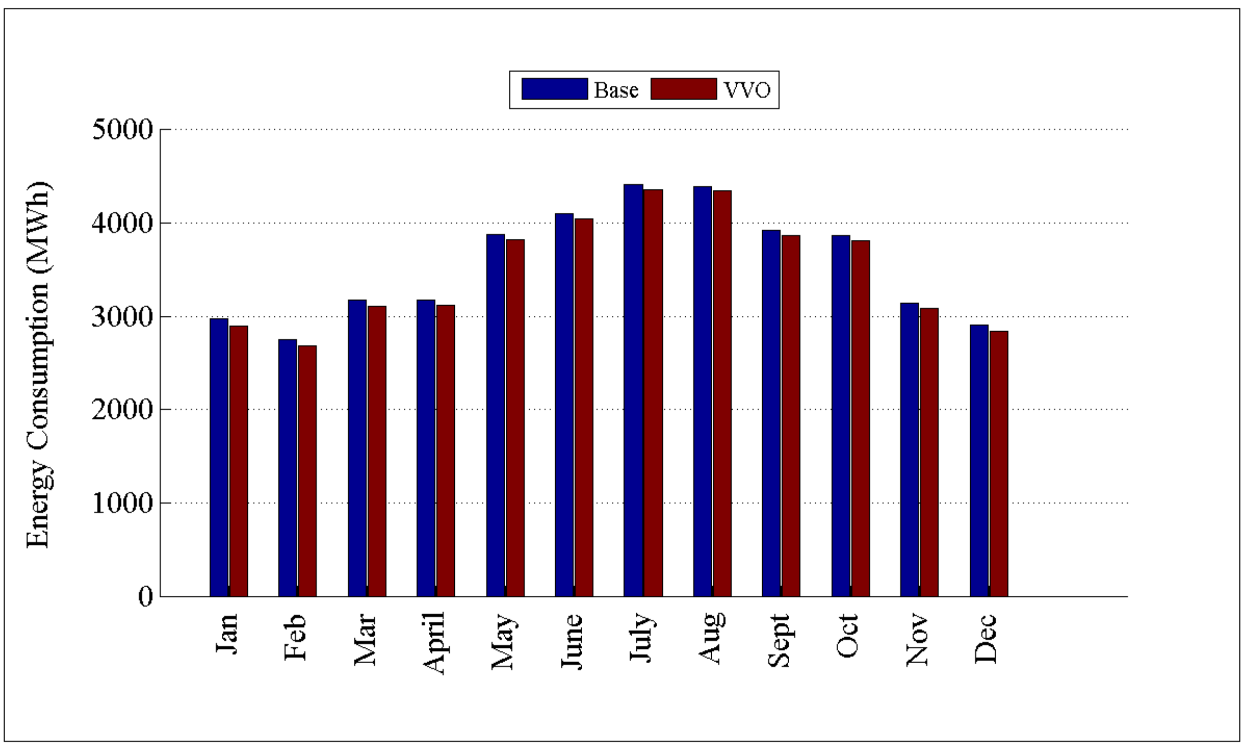



Figure D.95: Comparison of energy consumption by month for R5-12.47-3

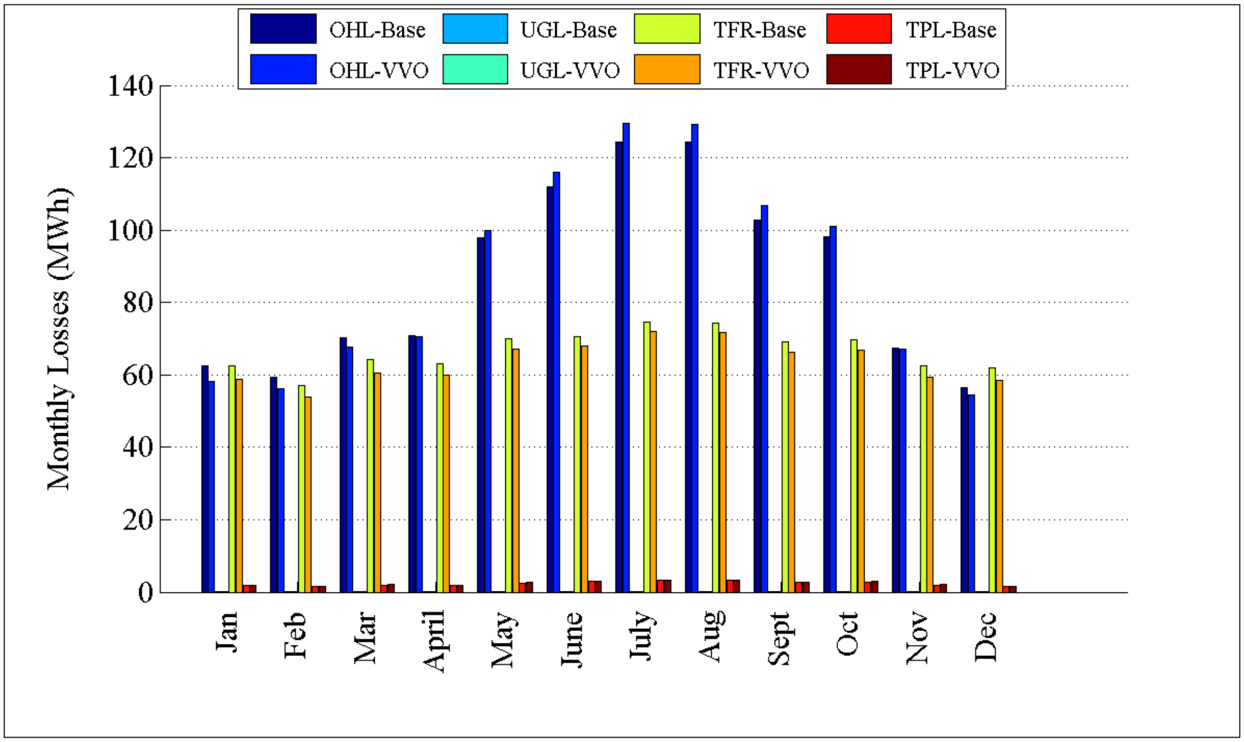



Figure D.96: Comparison of losses by month for R5-12.47-3

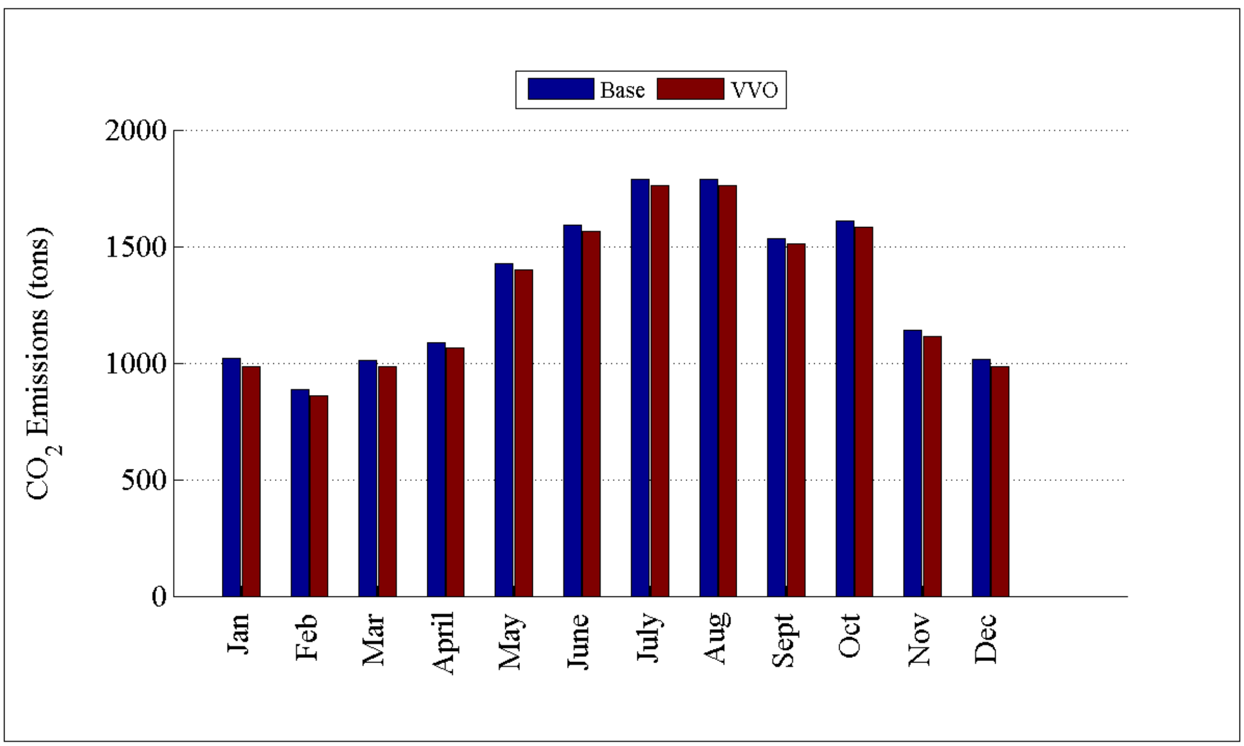



Figure D.97: Comparison of $CO_2$ emissions by month for R5-12.47-3

### D.1.25 Detailed VVO Plots for R5-12.47-4

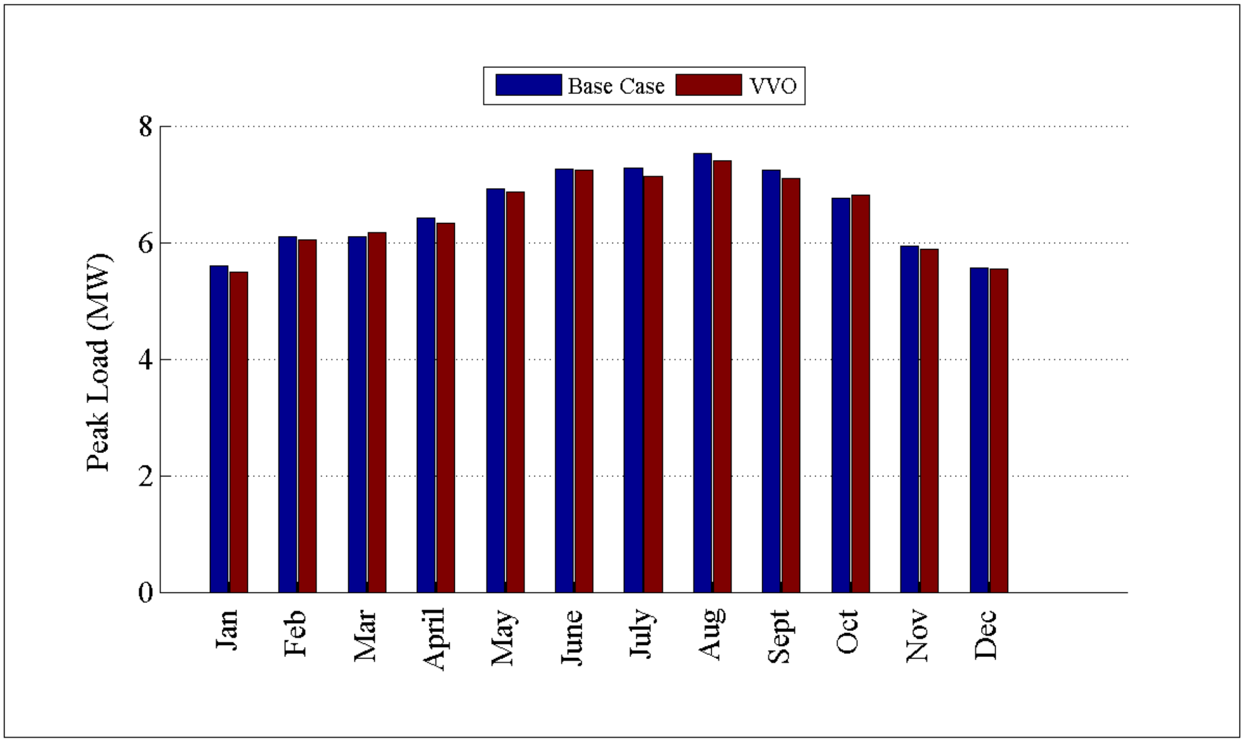



Figure D.98: Comparison of peak load by month for R5-12.47-4

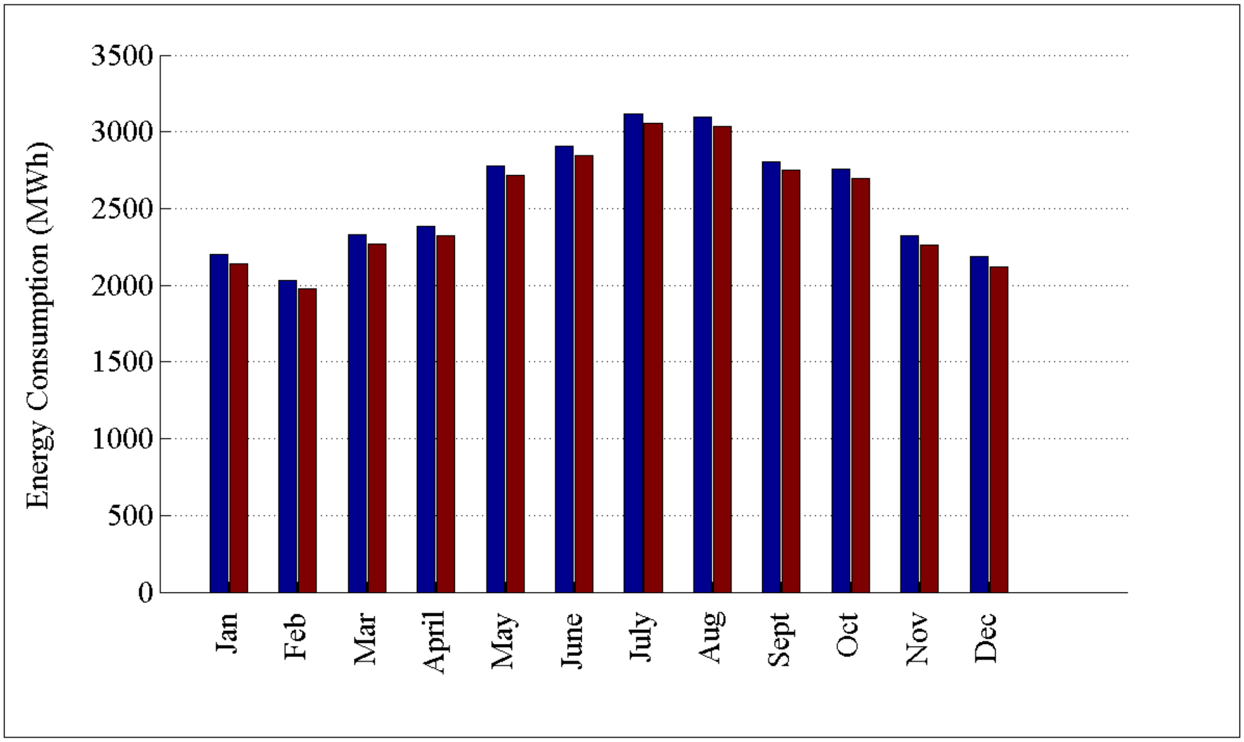



Figure D.99: Comparison of energy consumption by month for R5-12.47-4

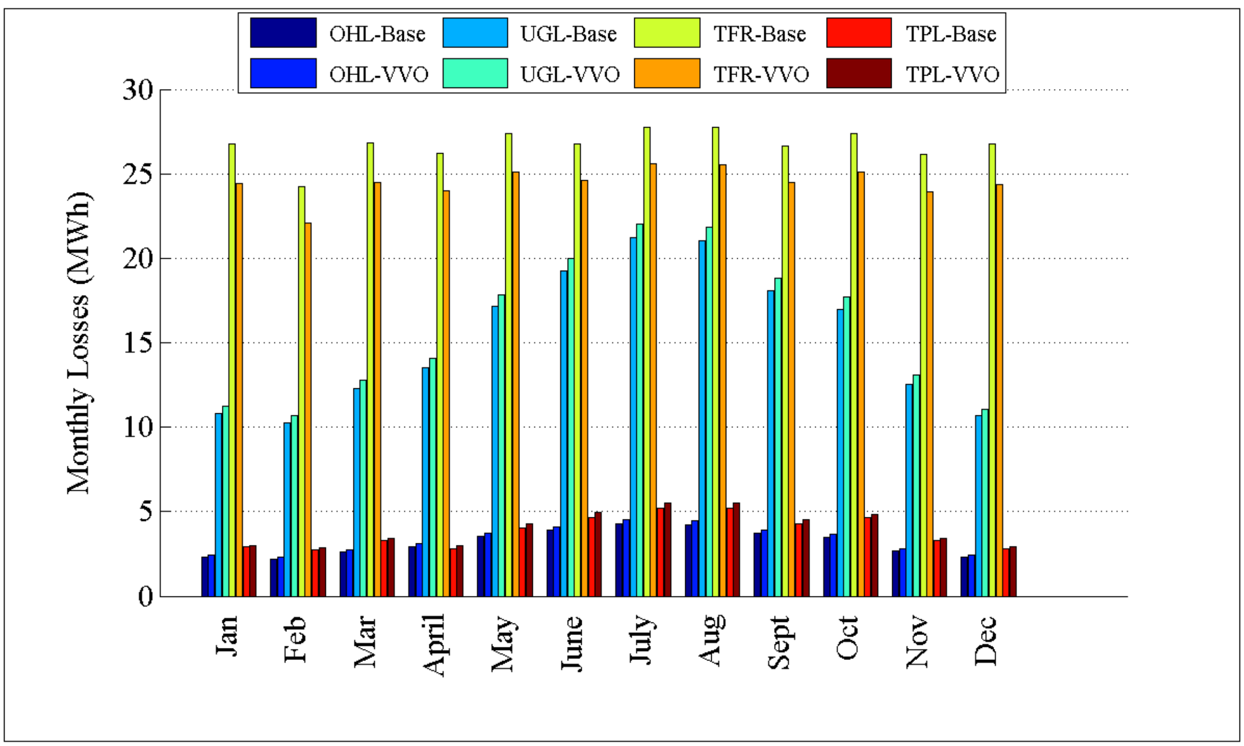



Figure D.100: Comparison of losses by month for R5-12.47-4

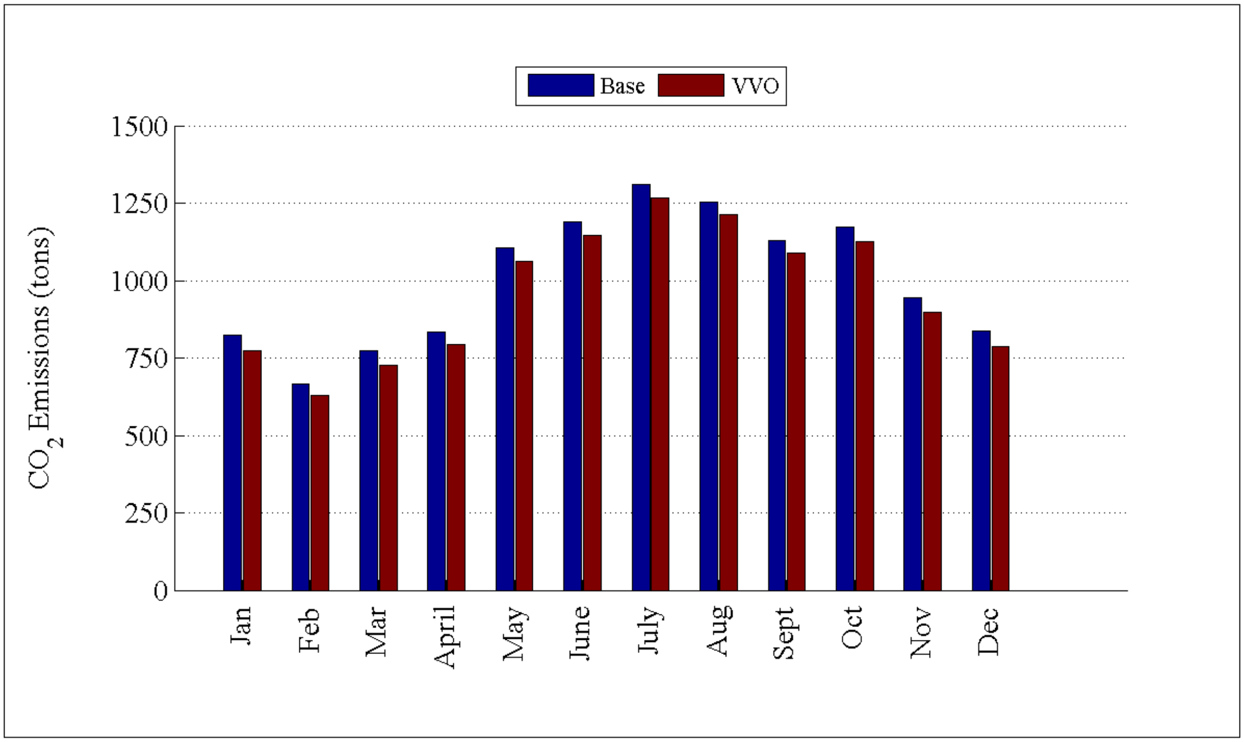



Figure D.101: Comparison of $CO_2$ emissions by month for R5-12.47-4

### D.1.26 Detailed VVO Plots for R5-12.47-5

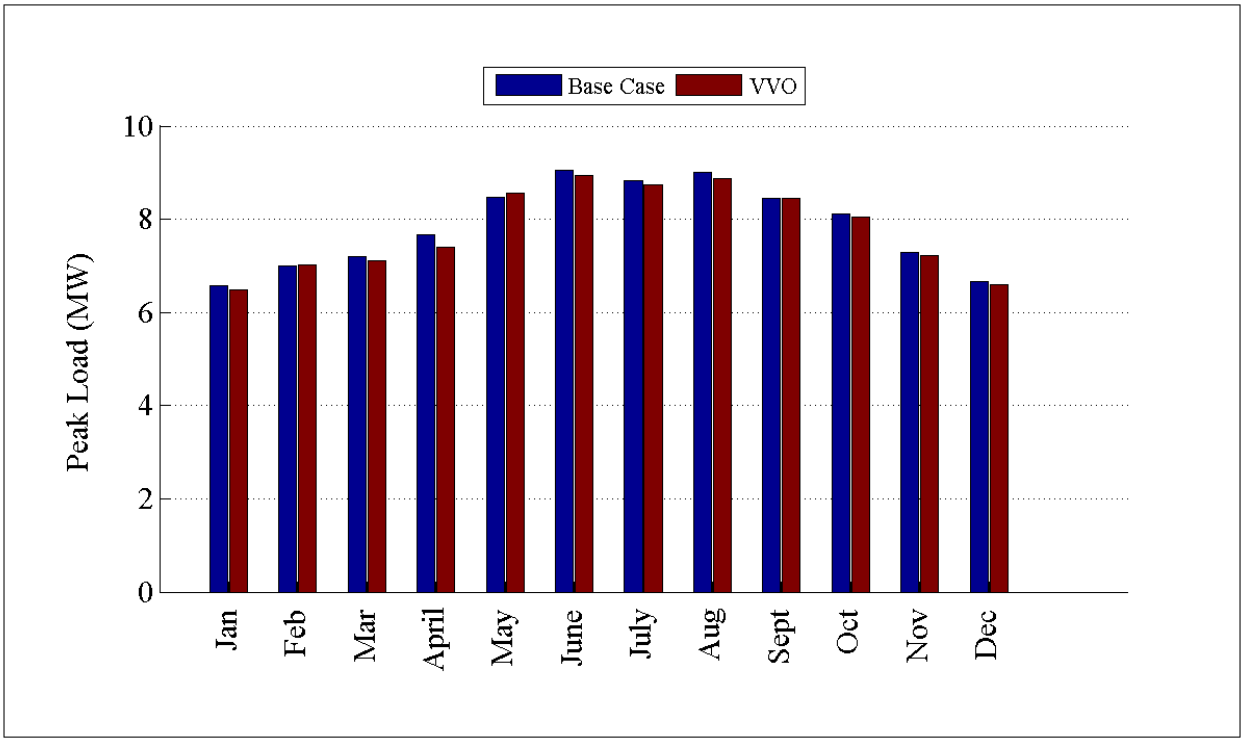



Figure D.102: Comparison of peak load by month for R5-12.47-5

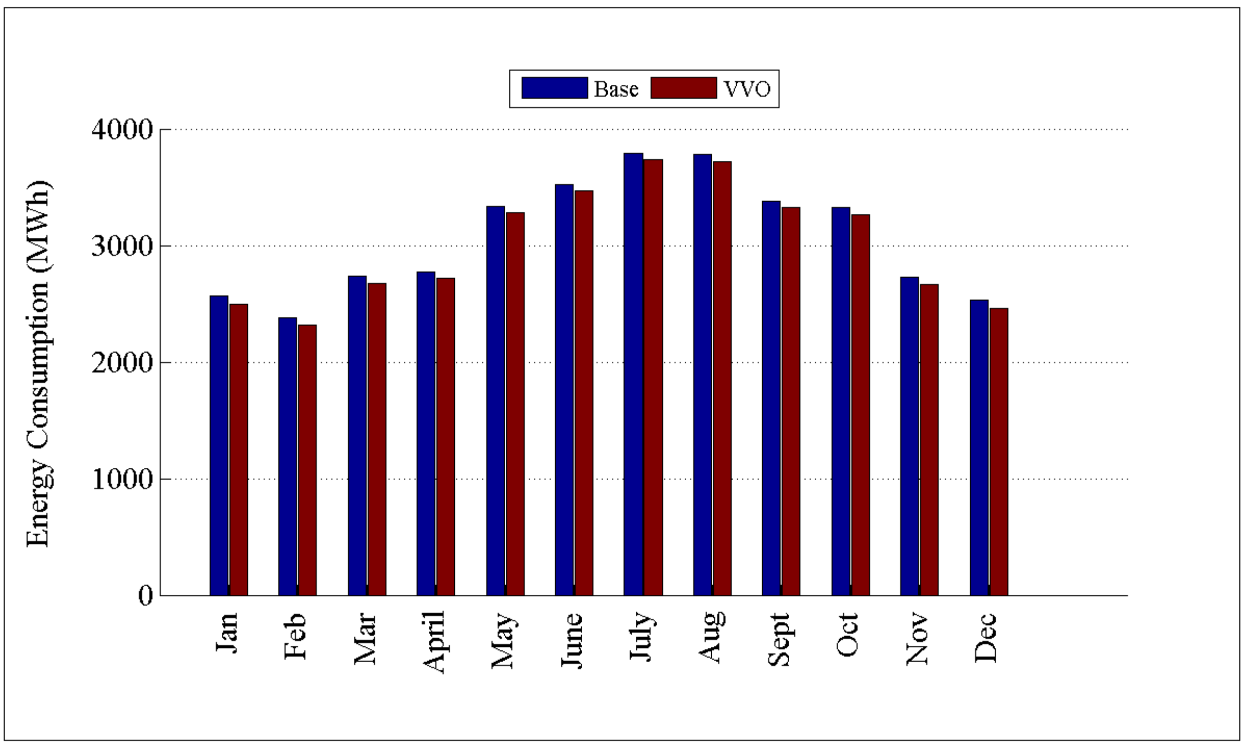



Figure D.103: Comparison of energy consumption by month for R5-12.47-5

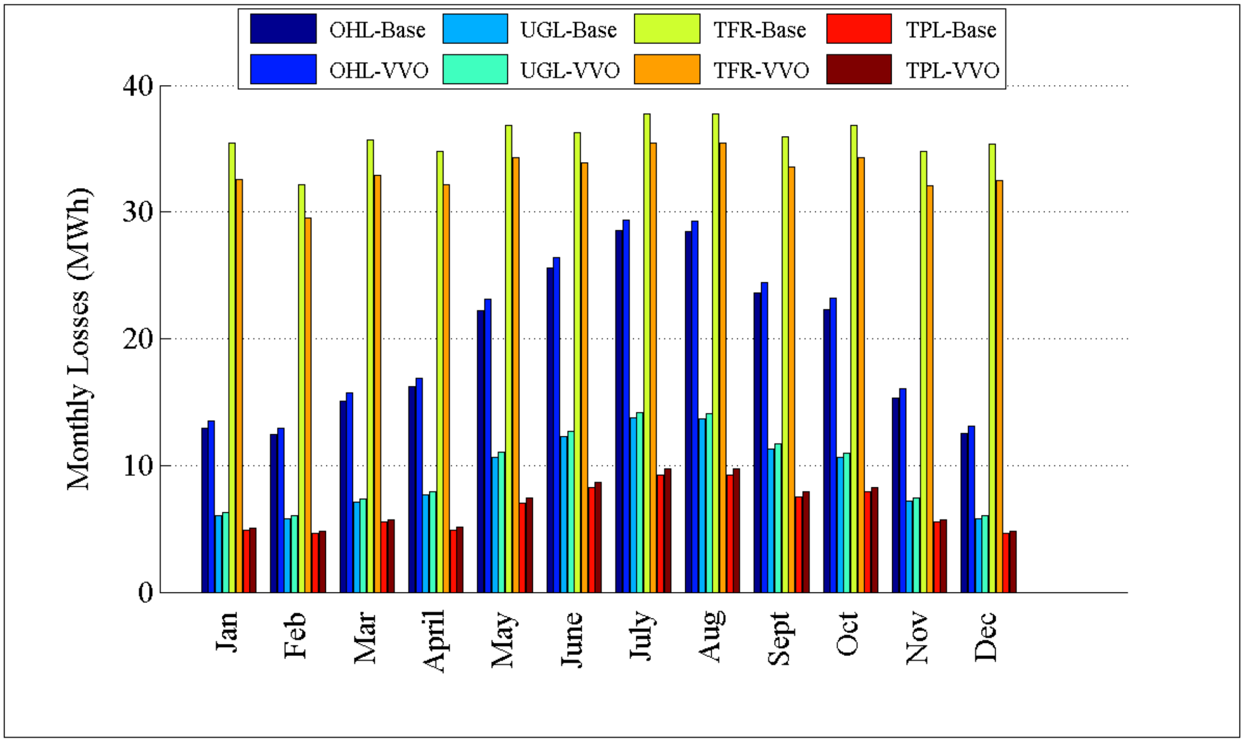



Figure D.104: Comparison of losses by month for R5-12.47-5

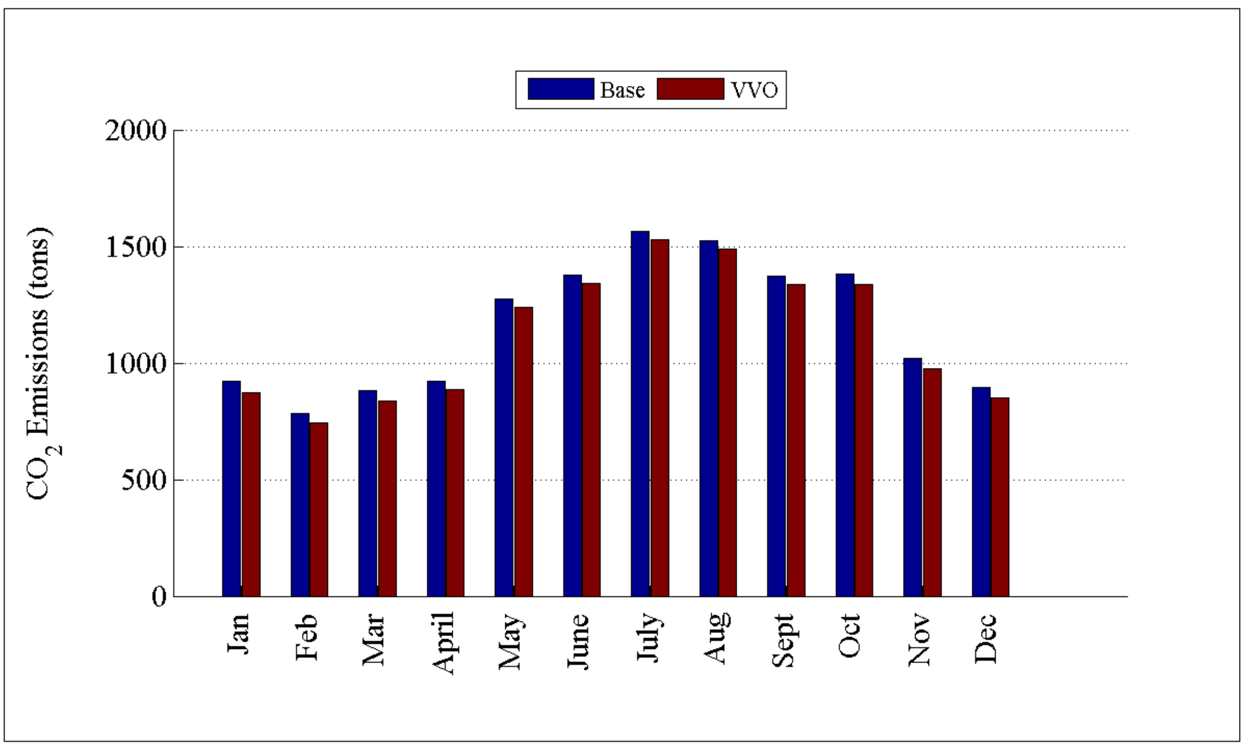



Figure D.105: Comparison of $CO_2$ emissions by month for R5-12.47-5

### D.1.27 Detailed VVO Plots for R5-25.00-1

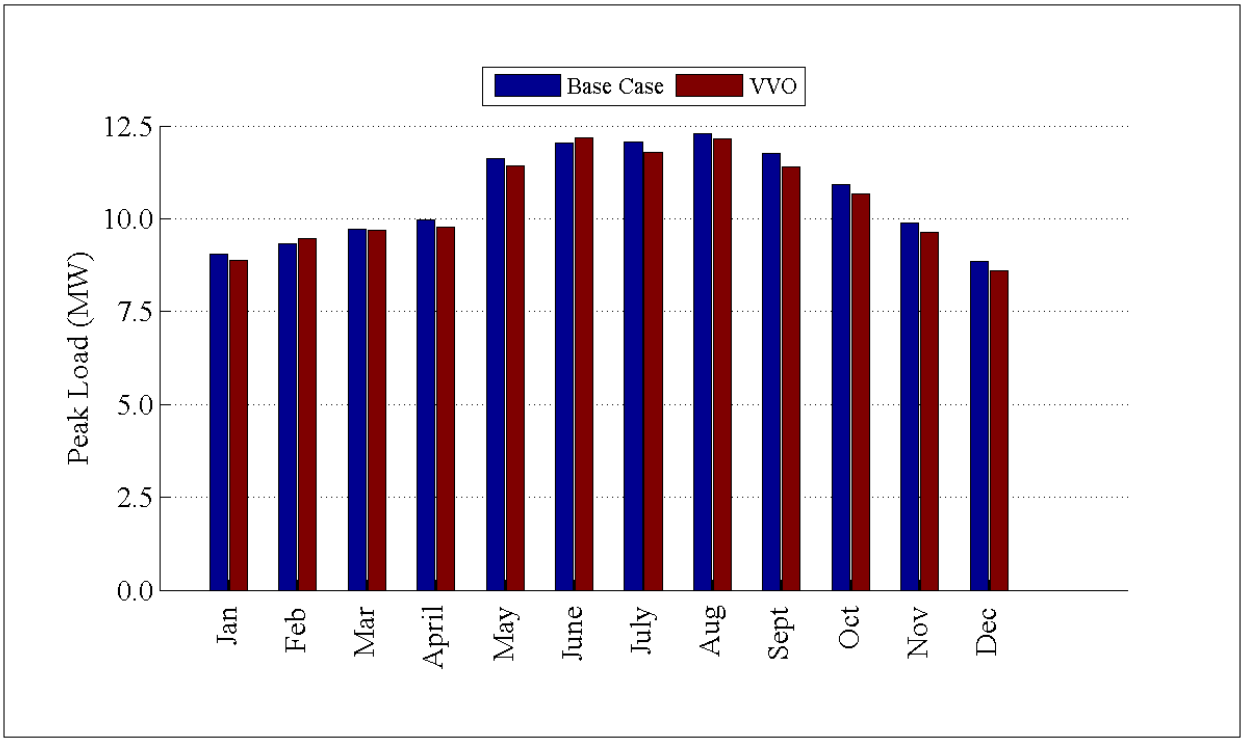



Figure D.106: Comparison of peak load by month for R5-25.00-1

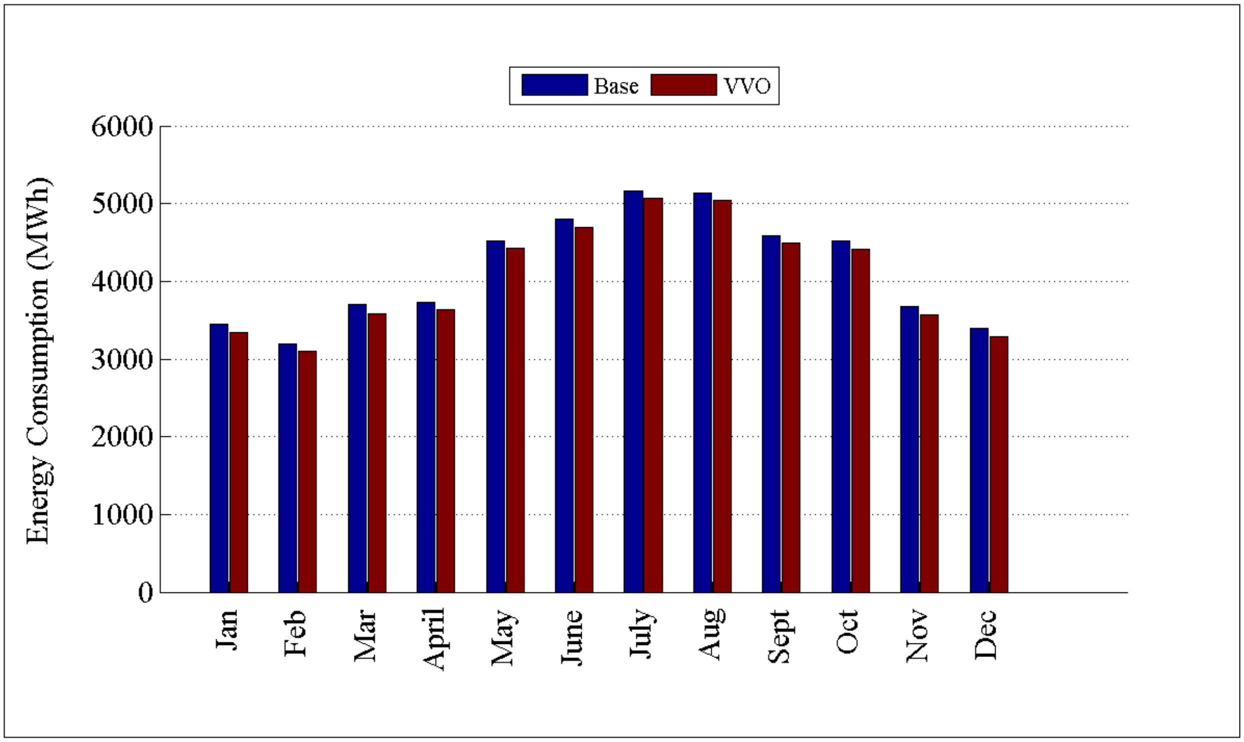



Figure D.107: Comparison of energy consumption by month for R5-25.00-1

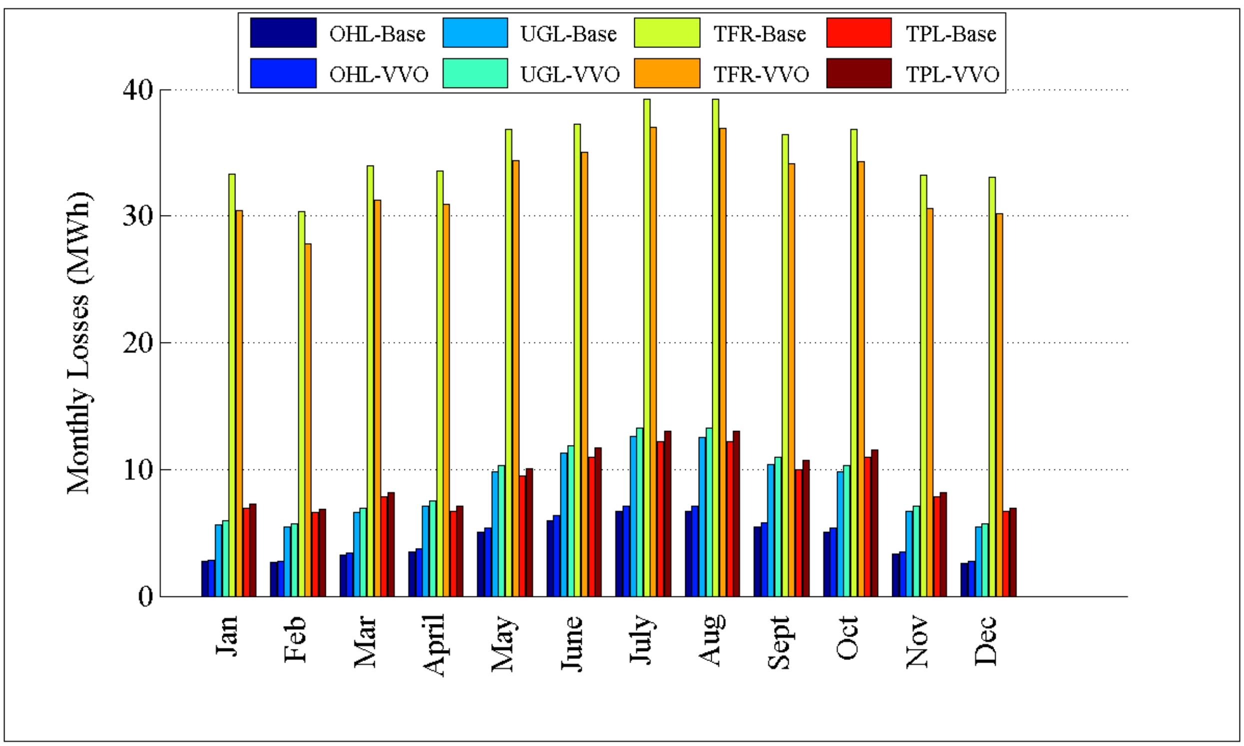



Figure D.108: Comparison of losses by month for R5-25.00-1

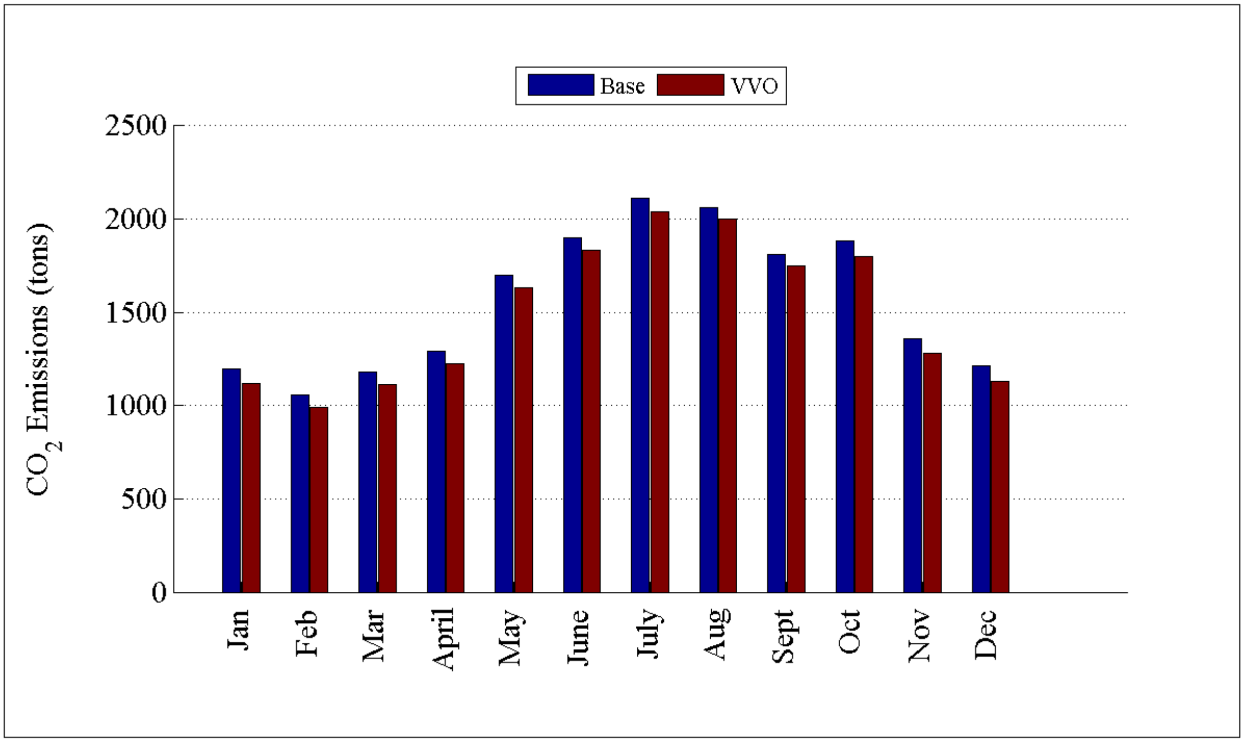



Figure D.109: Comparison of $CO_2$ emissions by month for R5-25.00-1

### D.1.28 Detailed VVO Plots for R5-35.00-1

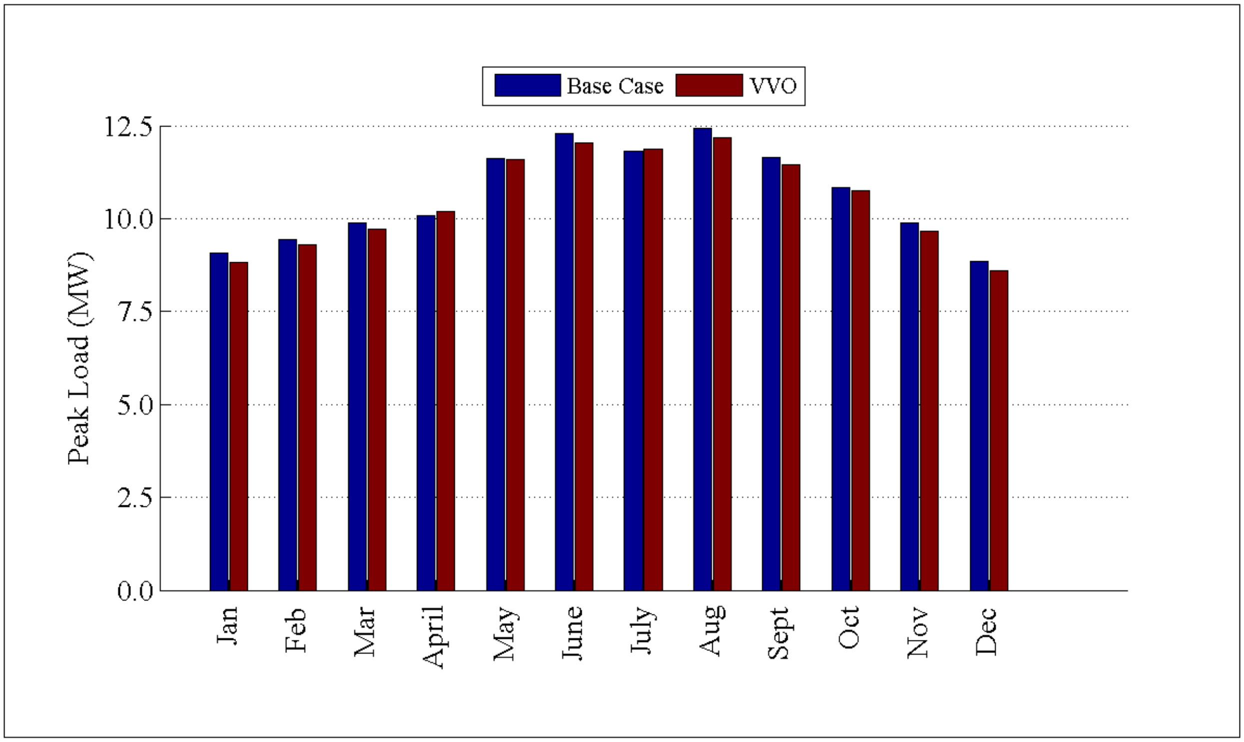



Figure D.110: Comparison of peak load by month for R5-35.00-1

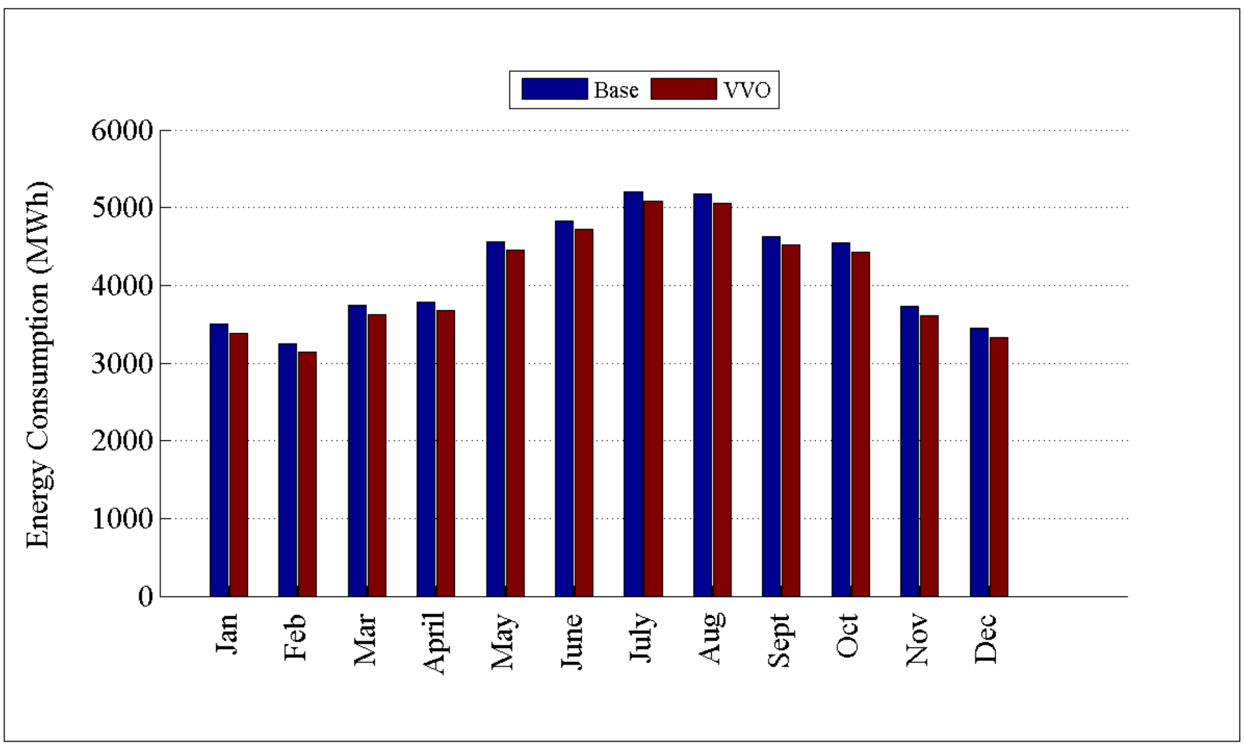



Figure D.111: Comparison of energy consumption by month for R5-35.00-1

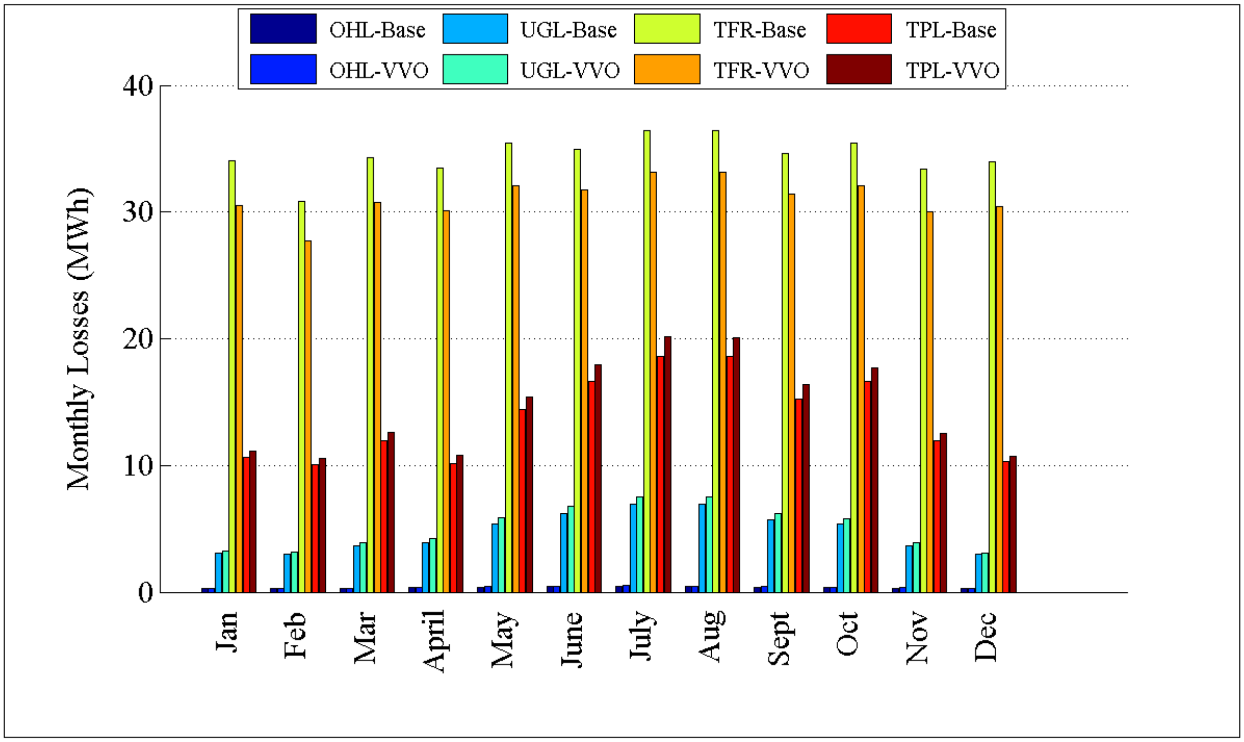



Figure D.112: Comparison of losses by month for R5-35.00-1

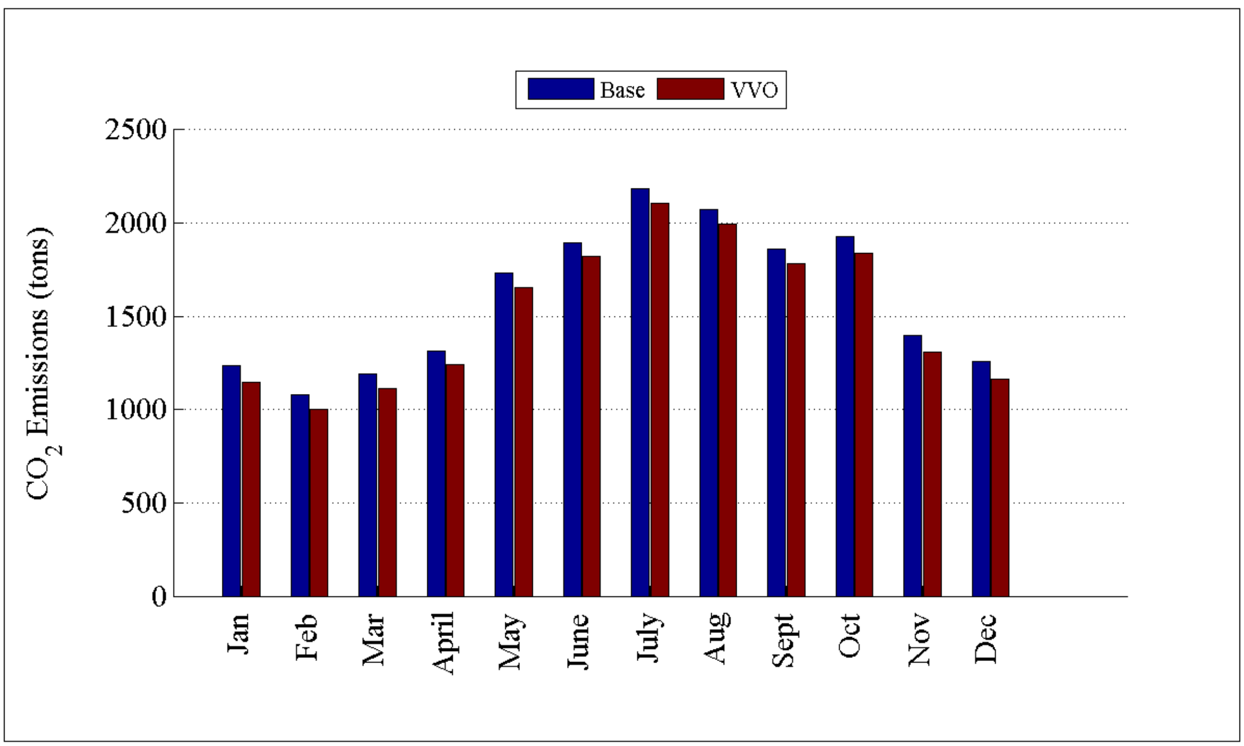



Figure D.113: Comparison of $CO_2$ emissions by month for R5-35.00-1

## D.2 Capacitor Automation Plots

Consistent with the plots shown in Section 3.2.1, peak monthly demand, monthly energy consumption, and monthly $CO_2$ emissions plot 'Base Case' and 'VVO'. Monthly losses plots "Base' and 'VVO' for 4 different loss types; losses in overhead lines 'OHL', underground lines 'UGL', transformers 'TFR', and triplex lines 'TPL'.

### D.2.1 Detailed CA Plots for GC-12.47-1_R1

The plots for this feeder were already presented in Section 3.2.1.

### D.2.2 Detailed CA Plots for R1-12.47-1

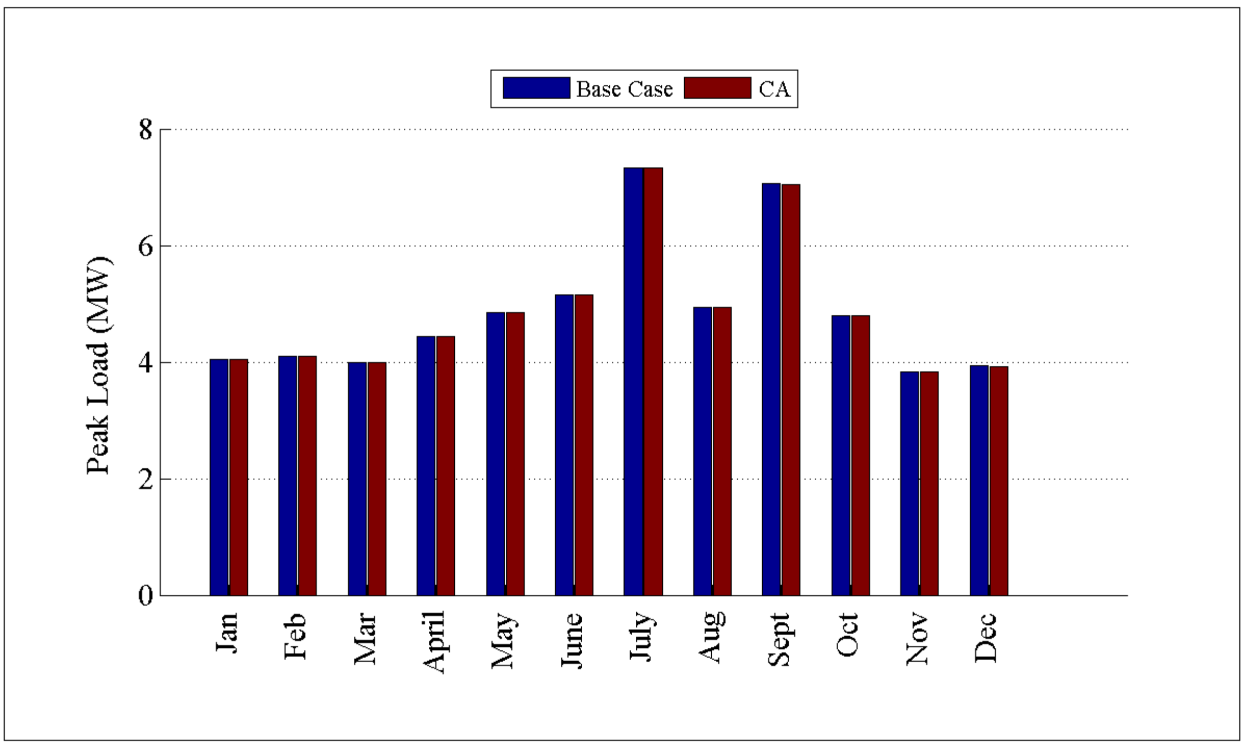



Figure D.114: Comparison of peak load by month for R1-12.47-1

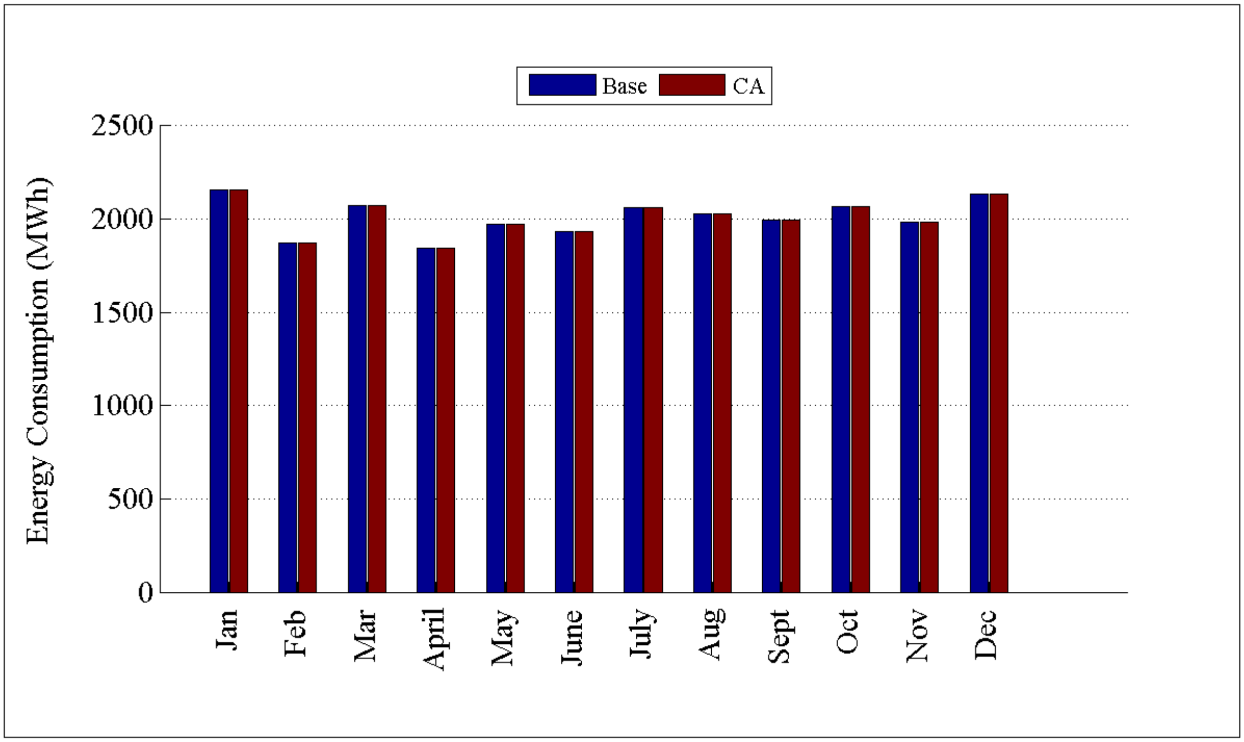



Figure D.115: Comparison of energy consumption by month for R1-12.47-1

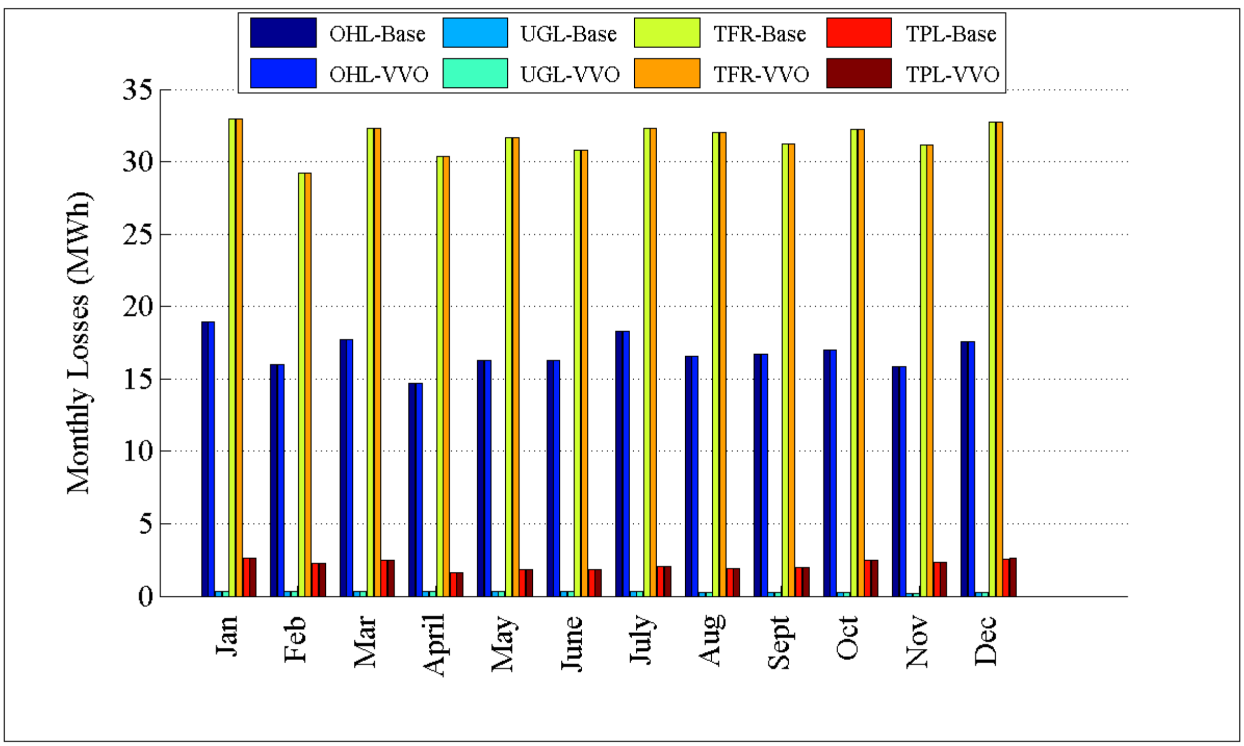



Figure D.116: Comparison of losses by month for R1-12.47-1

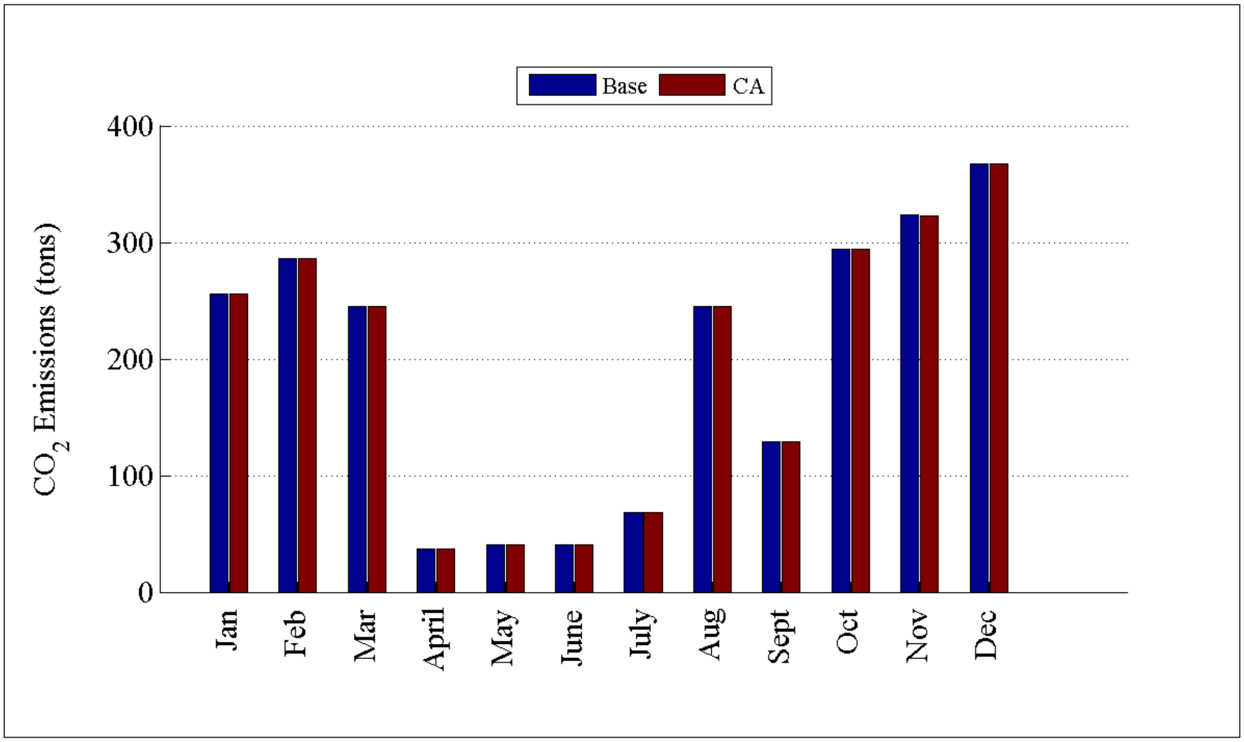



Figure D.117: Comparison of $CO_2$ emissions by month for R1-12.47-1

## D.2.3 Detailed CA Plots for R1-12.47-2

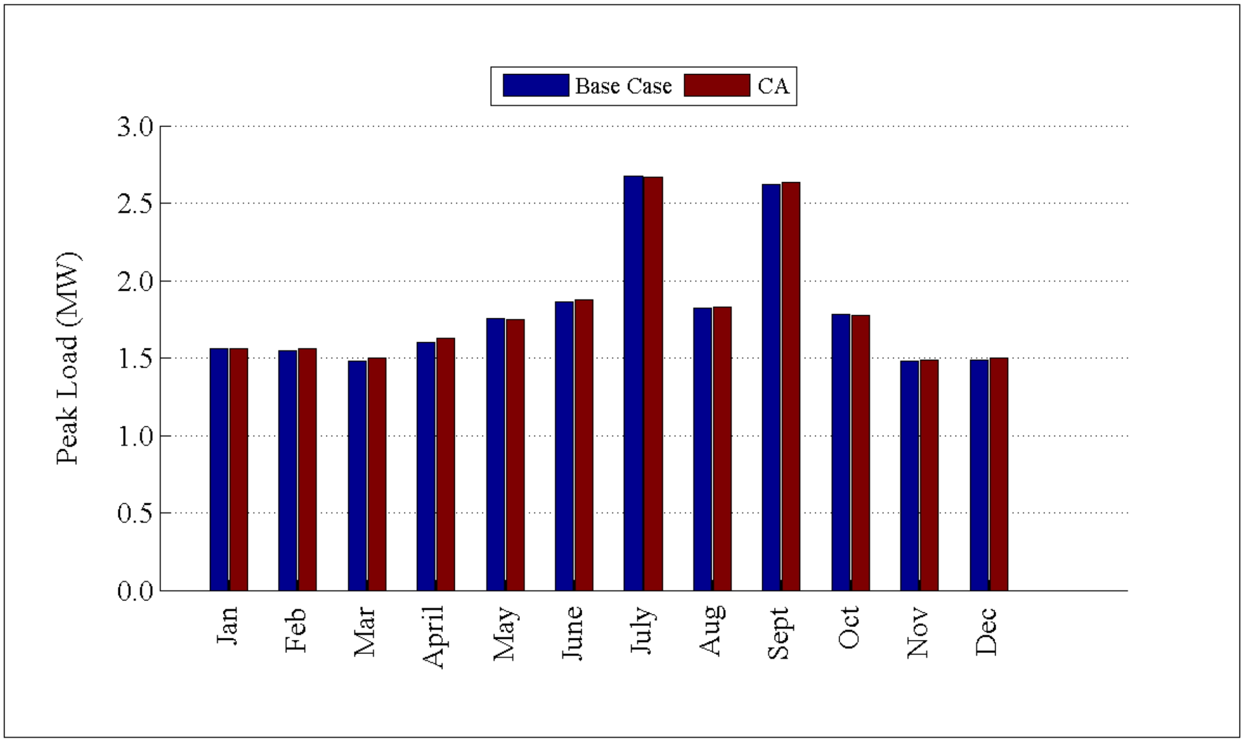



Figure D.118: Comparison of peak load by month for R1-12.47-2

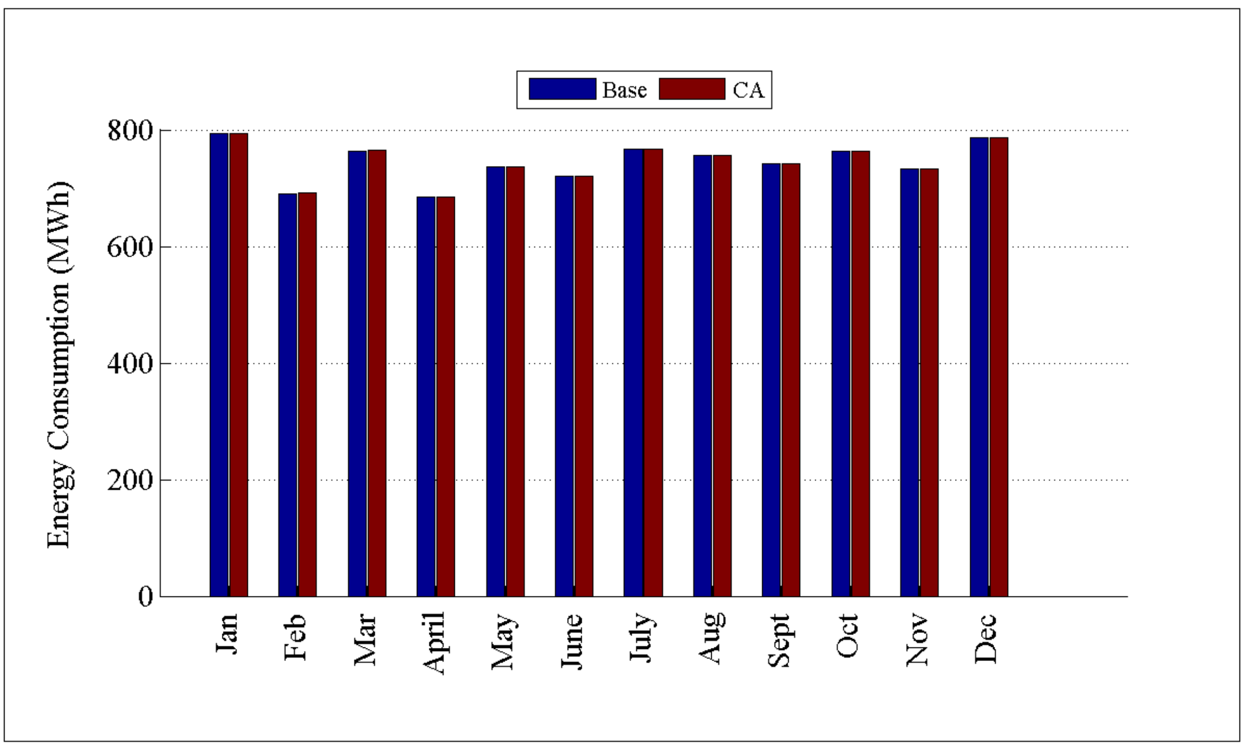



Figure D.119: Comparison of energy consumption by month for R1-12.47-2

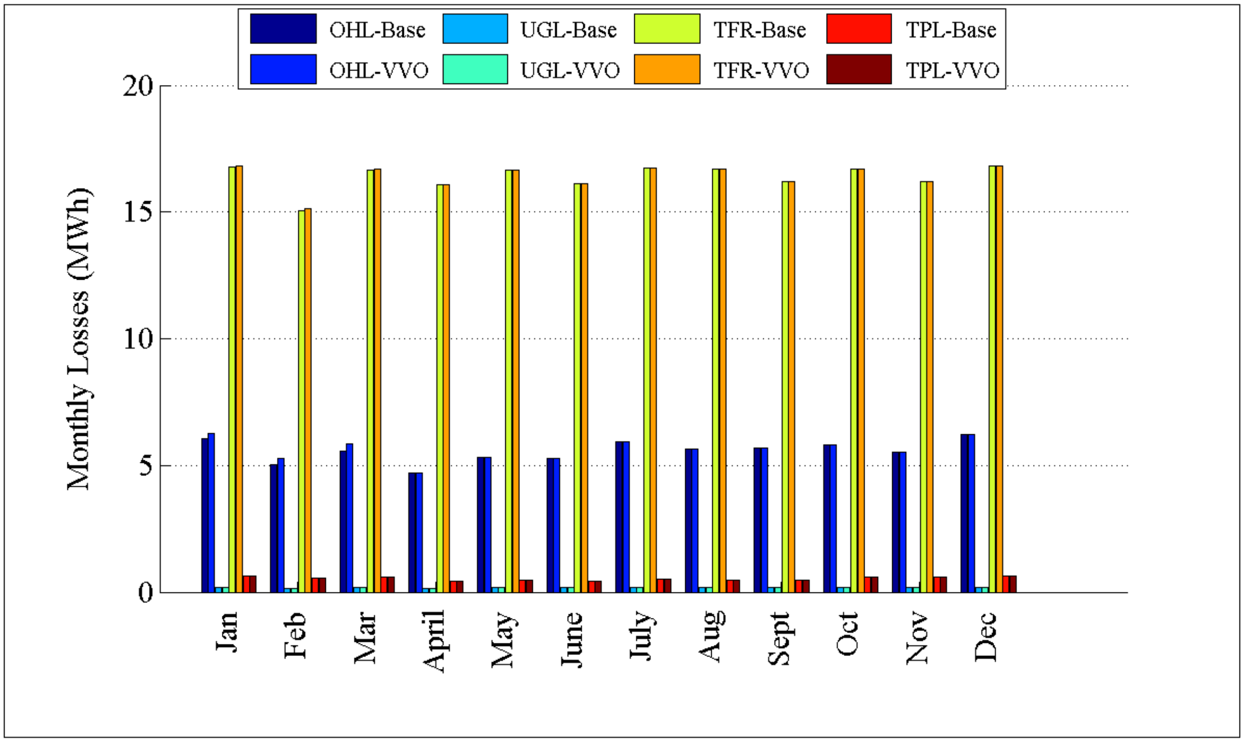



Figure D.120: Comparison of losses by month for R1-12.47-2

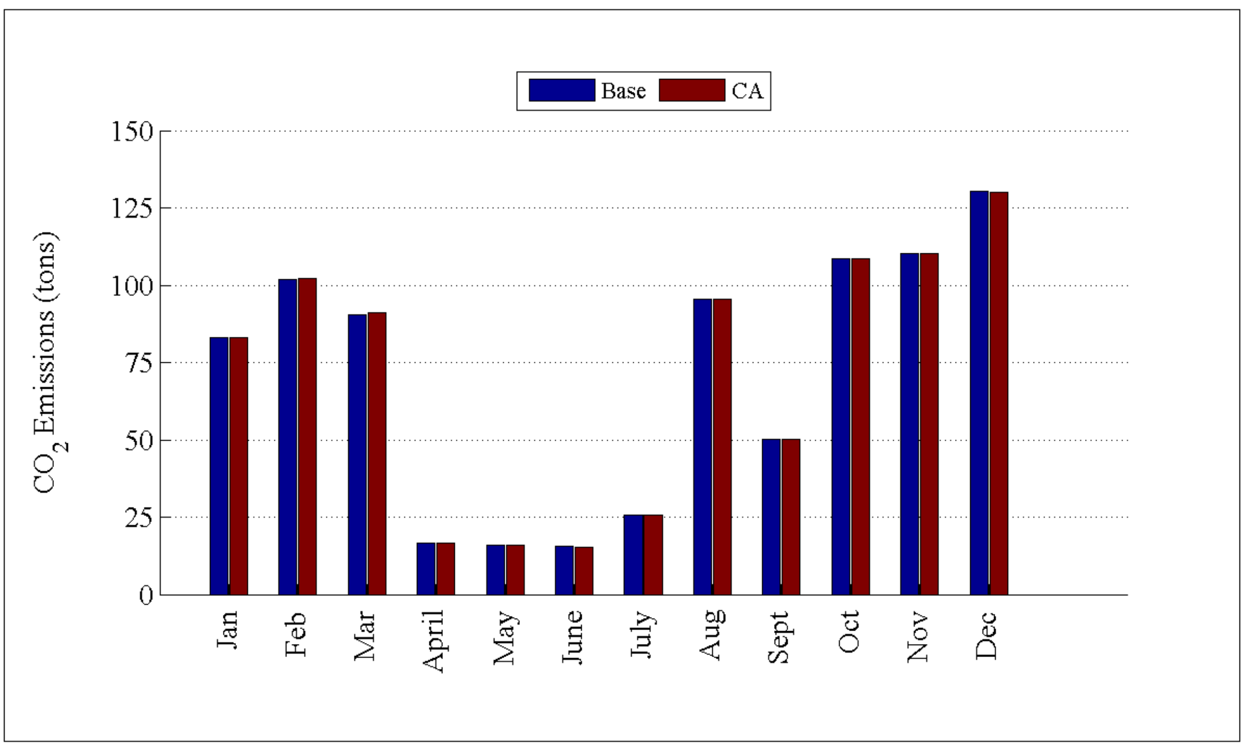



Figure D.121: Comparison of $CO_2$ emissions by month for R1-12.47-2

## D.2.4 Detailed CA Plots for R1-12.47-3

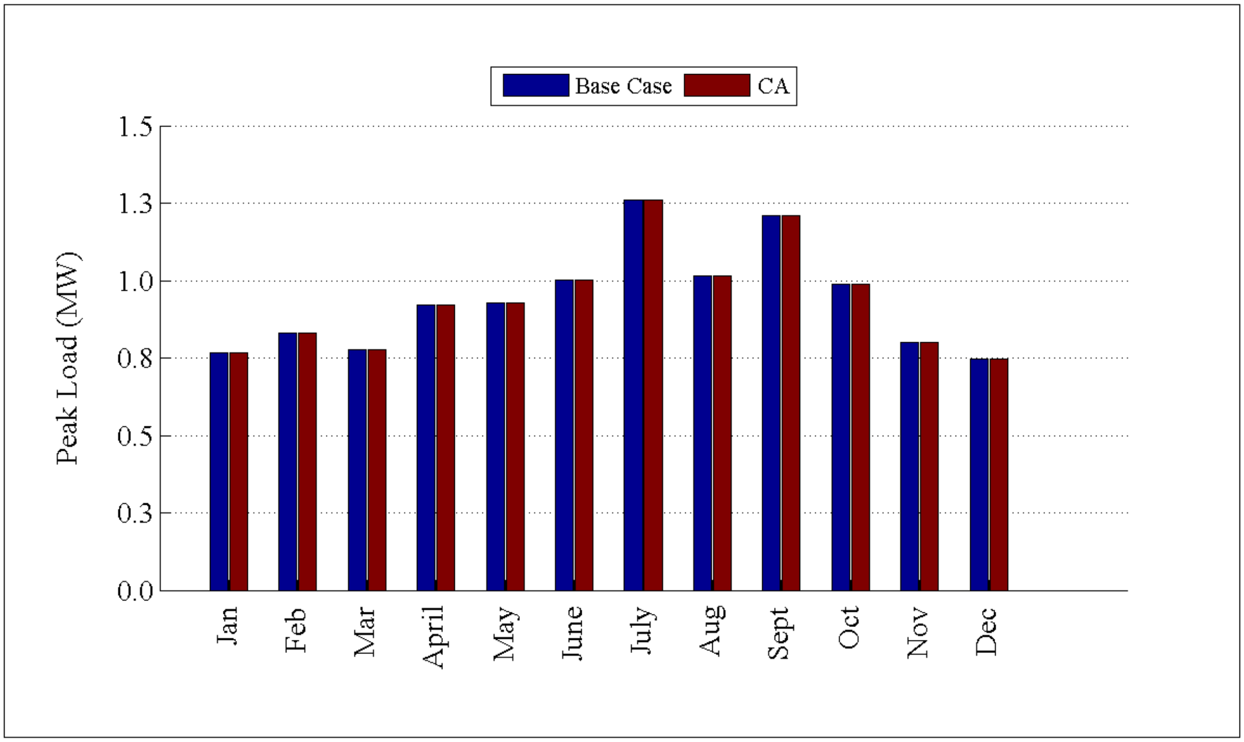



Figure D.122: Comparison of peak load by month for R1-12.47-3

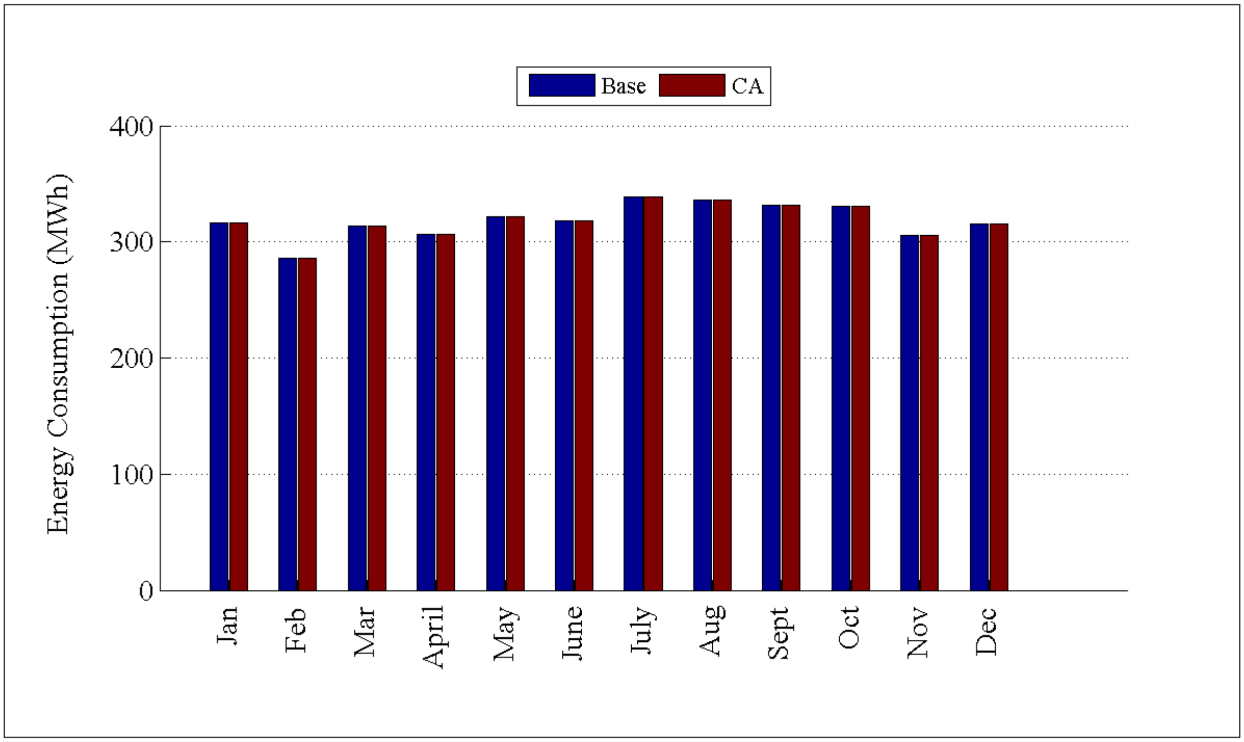



Figure D.123: Comparison of energy consumption by month for R1-12.47-3

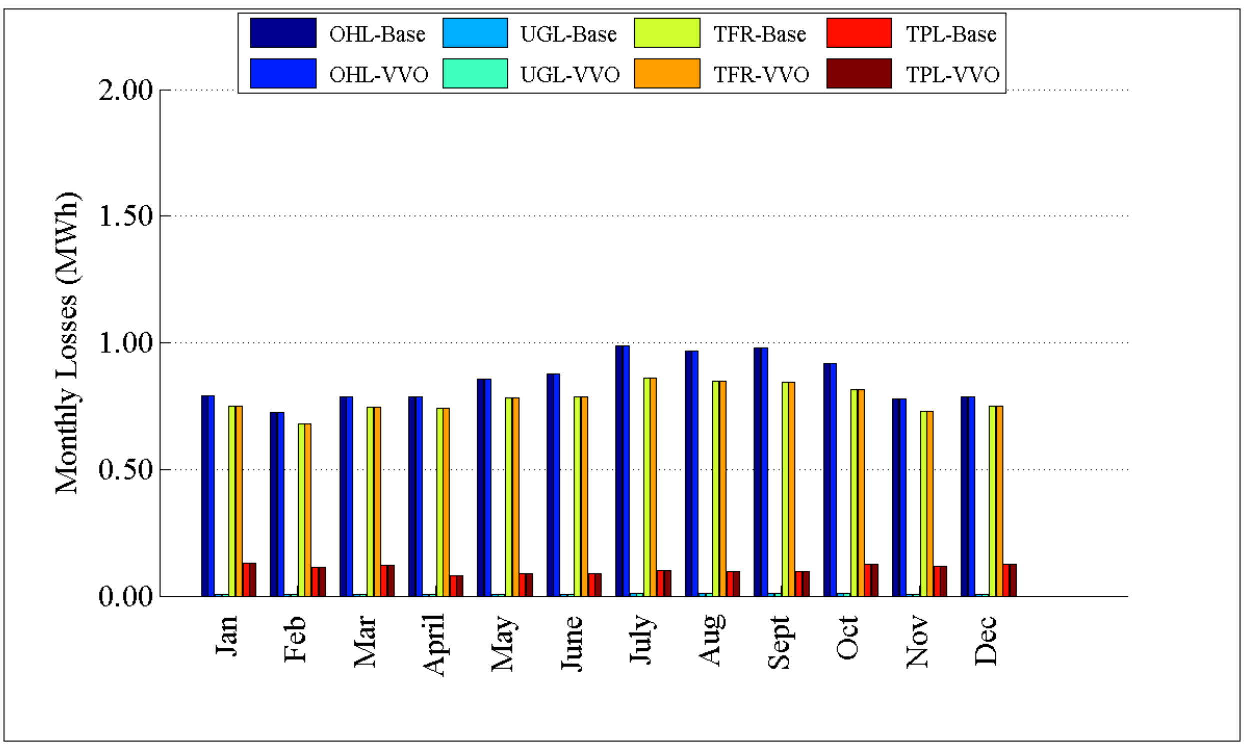



Figure D.124: Comparison of losses by month for R1-12.47-3

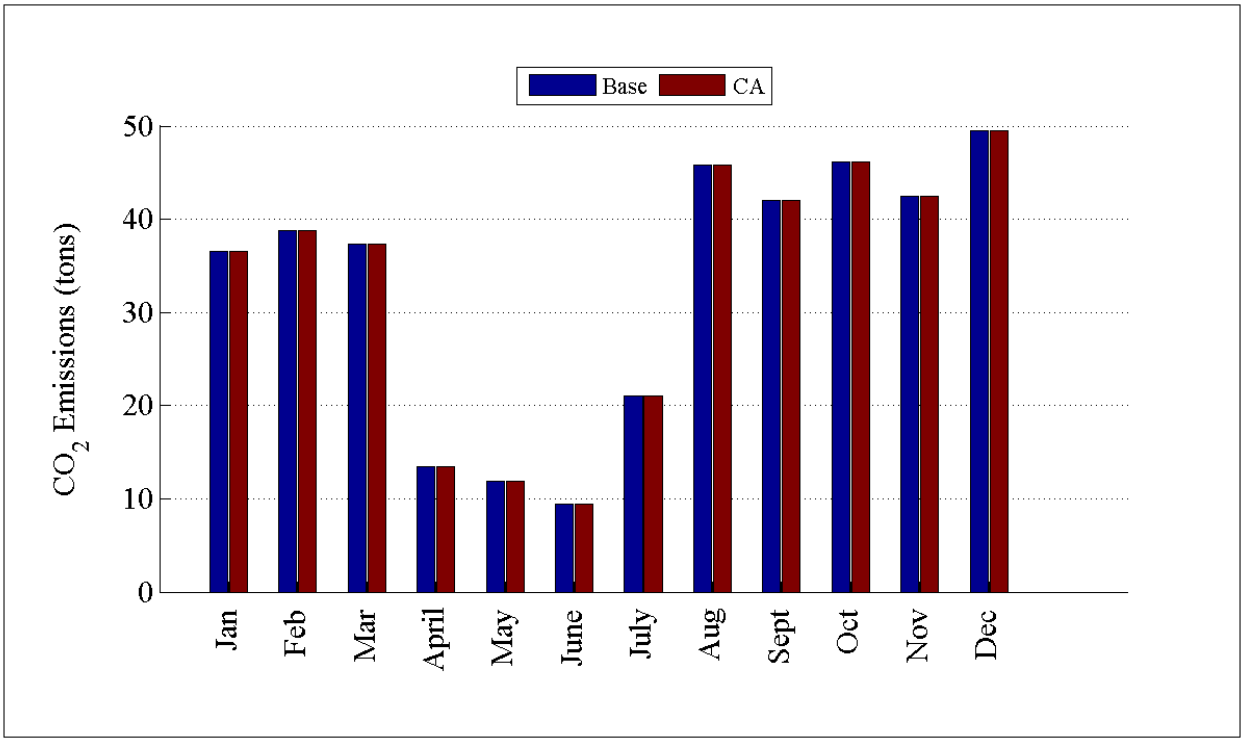



Figure D.125: Comparison of $CO_2$ emissions by month for R1-12.47-3

### D.2.5 Detailed CA Plots for R1-12.47-4

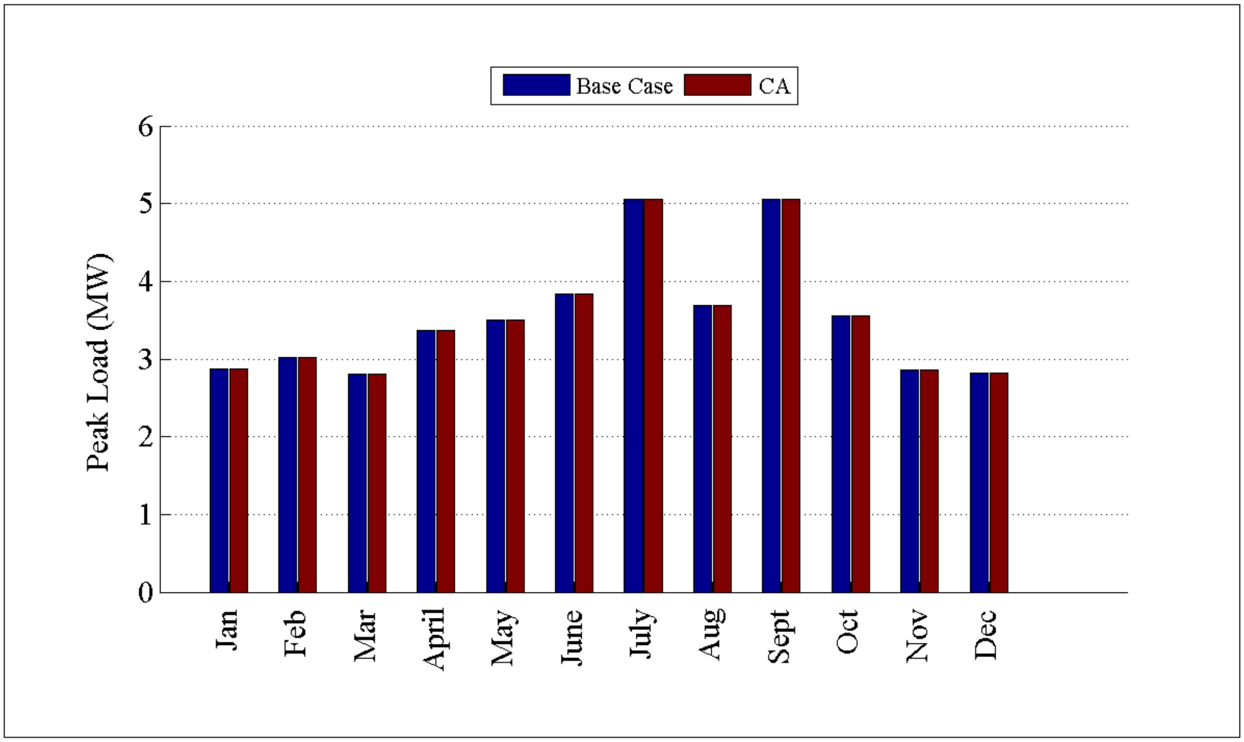



Figure D.126: Comparison of peak load by month for R1-12.47-4

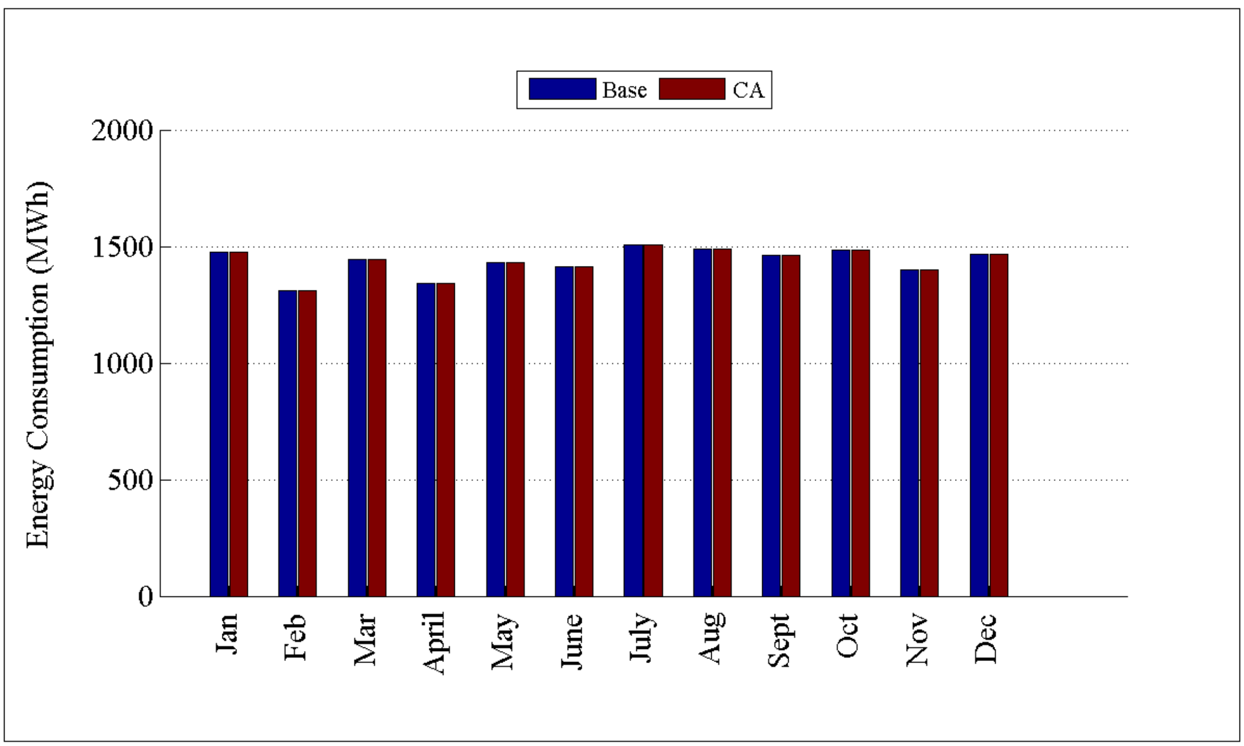



Figure D.127: Comparison of energy consumption by month for R1-12.47-4

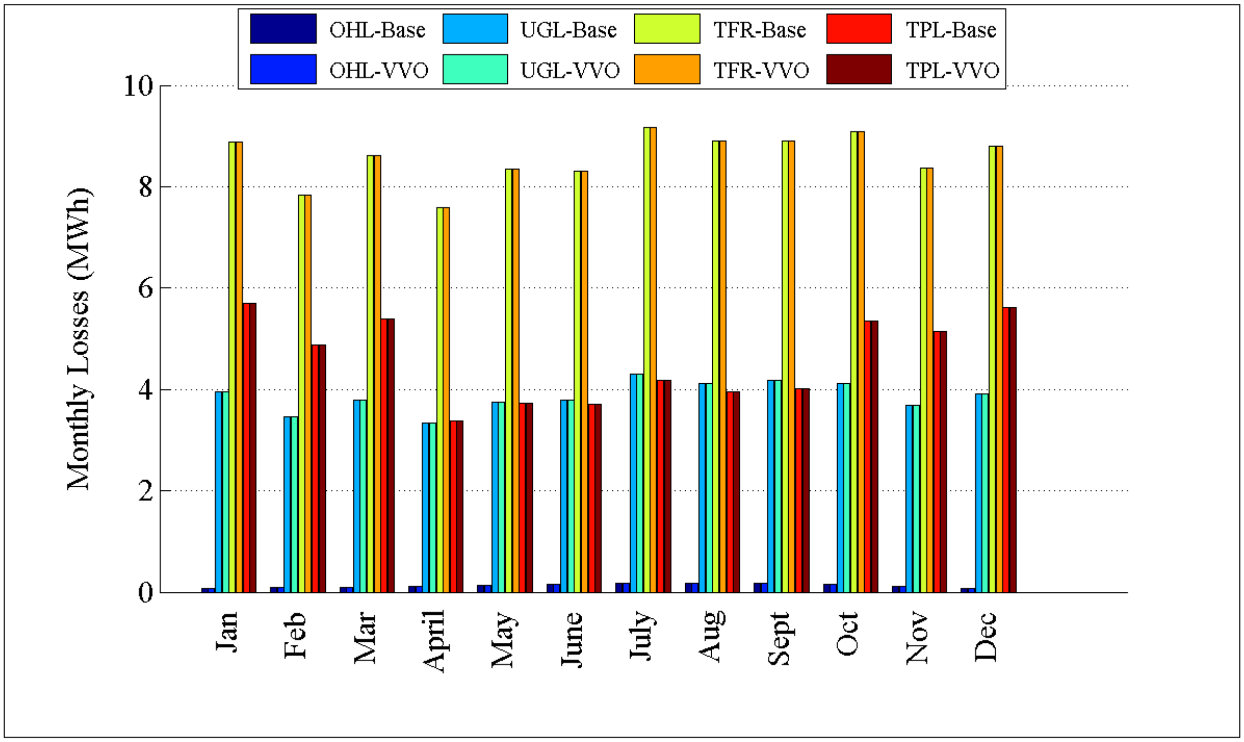



Figure D.128: Comparison of losses by month for R1-12.47-4

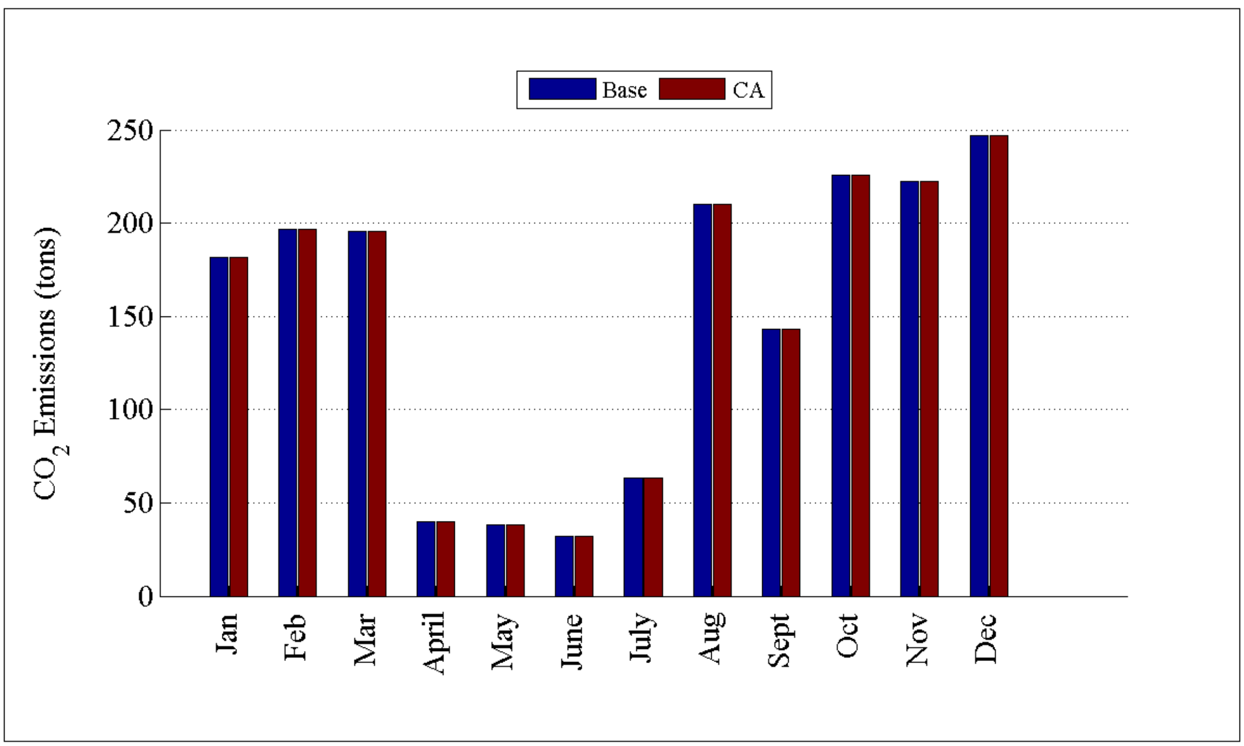



Figure D.129: Comparison of $CO_2$ emissions by month for R1-12.47-4

## D.2.6 Detailed CA Plots for R1-25.00-1

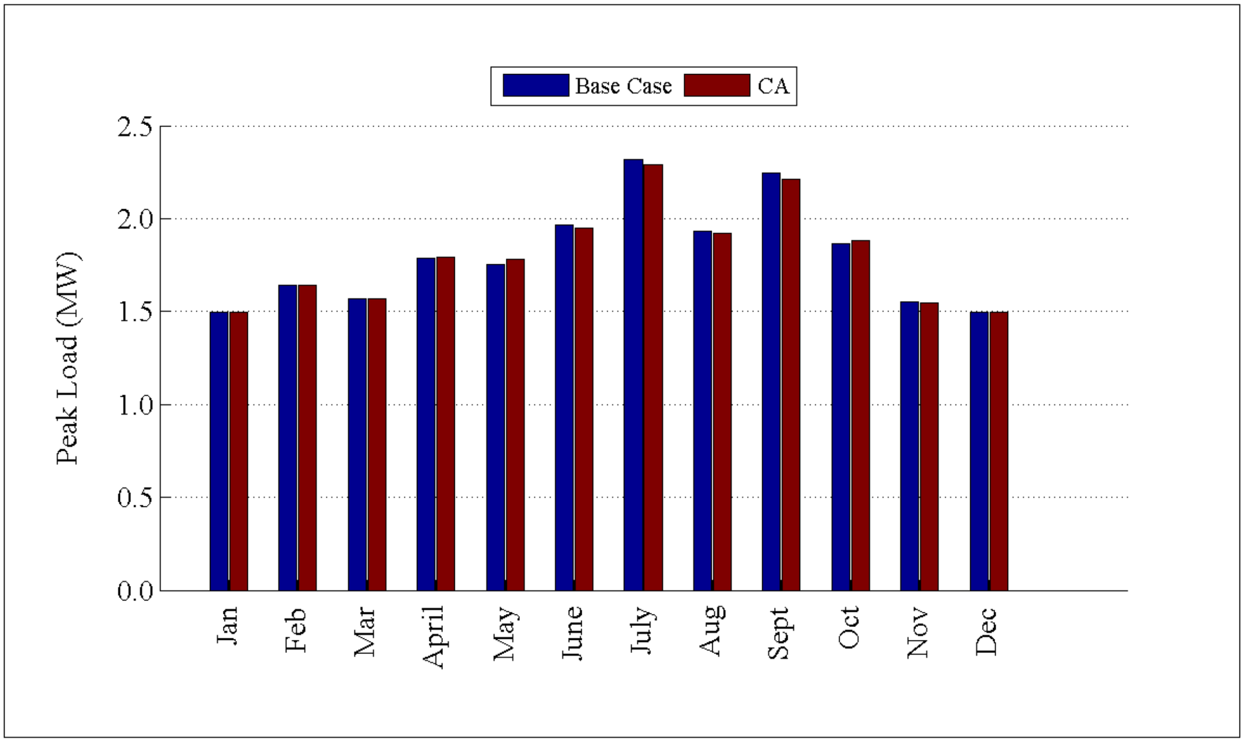



Figure D.130: Comparison of peak load by month for R1-25.00-1

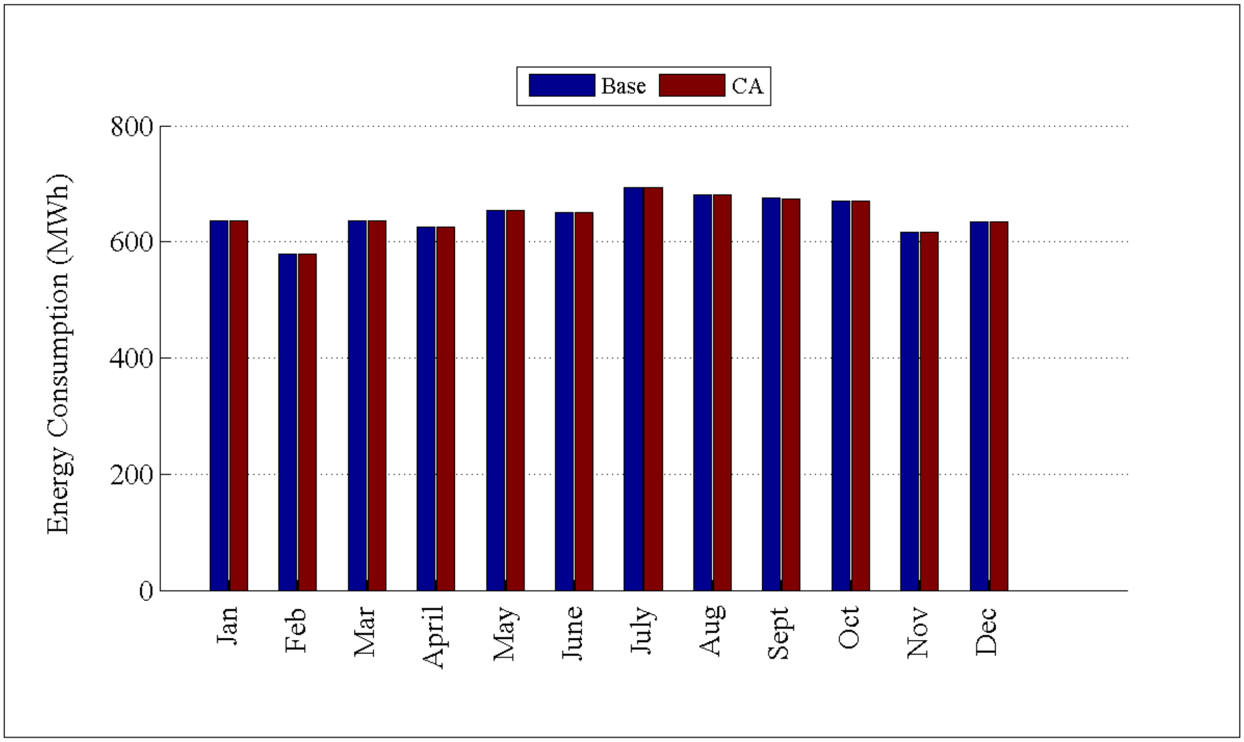



Figure D.131: Comparison of energy consumption by month for R1-25.00-1

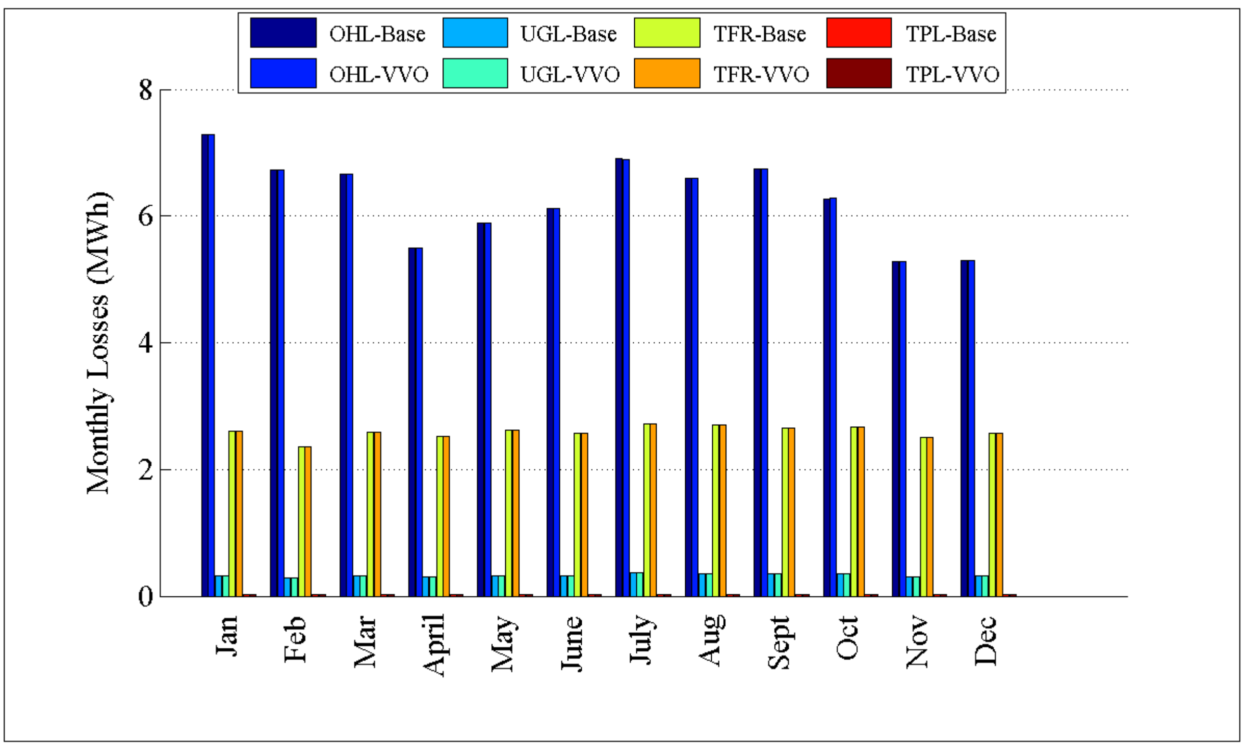



Figure D.132: Comparison of losses by month for R1-25.00-1

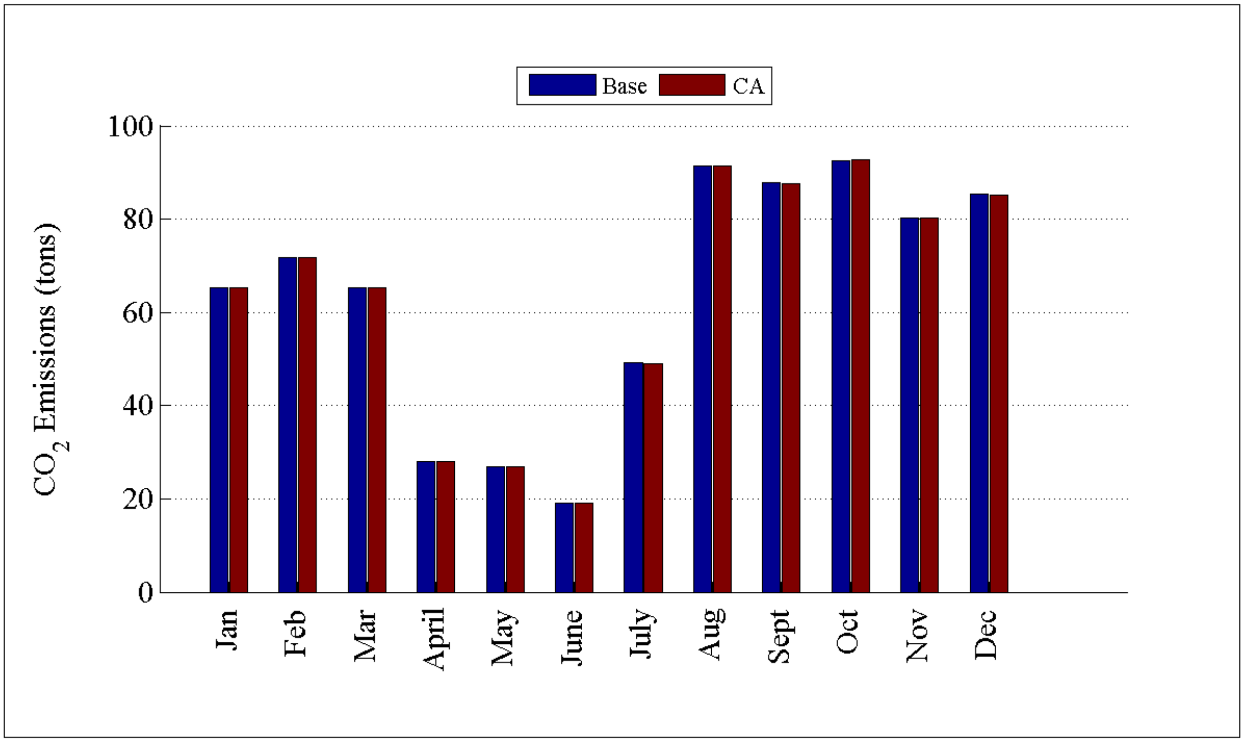



Figure D.133: Comparison of $CO_2$ emissions by month for R1-25.00-1

## D.2.7 Detailed CA Plots for GC-12.47-1_R2

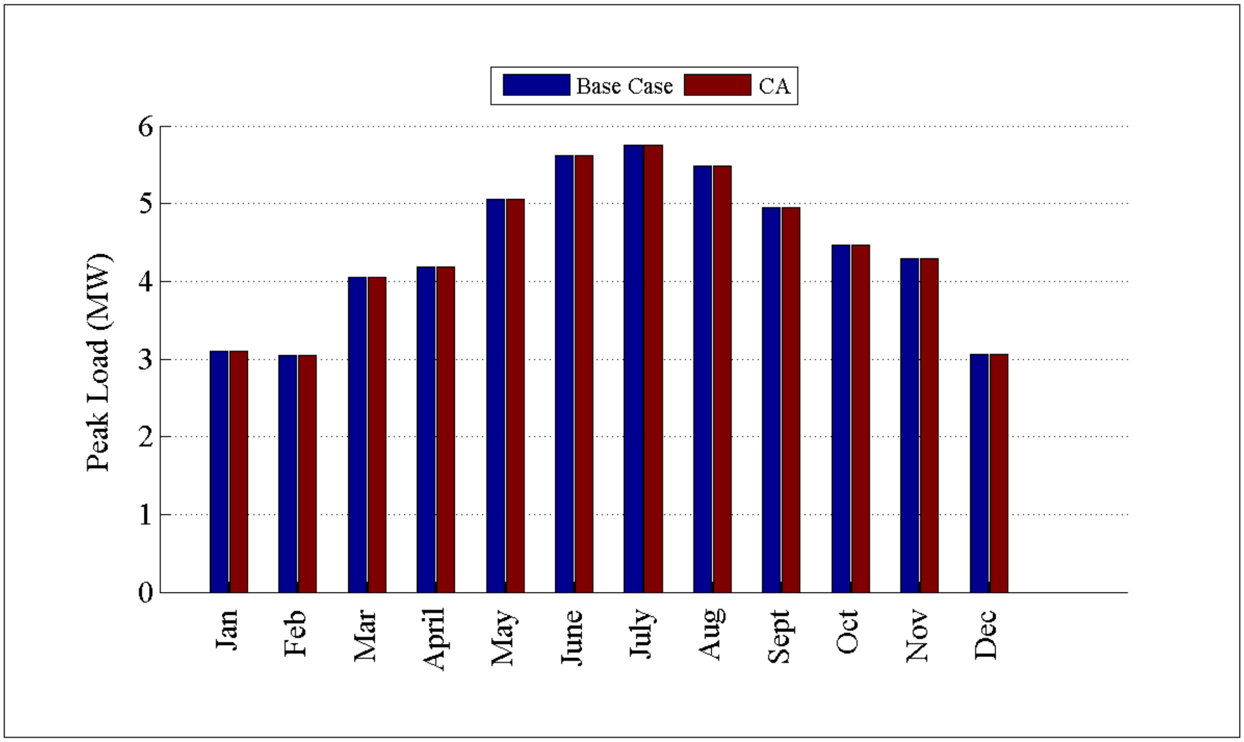



Figure D. 134: Comparison of peak load by month for GC-12.47-1_R2

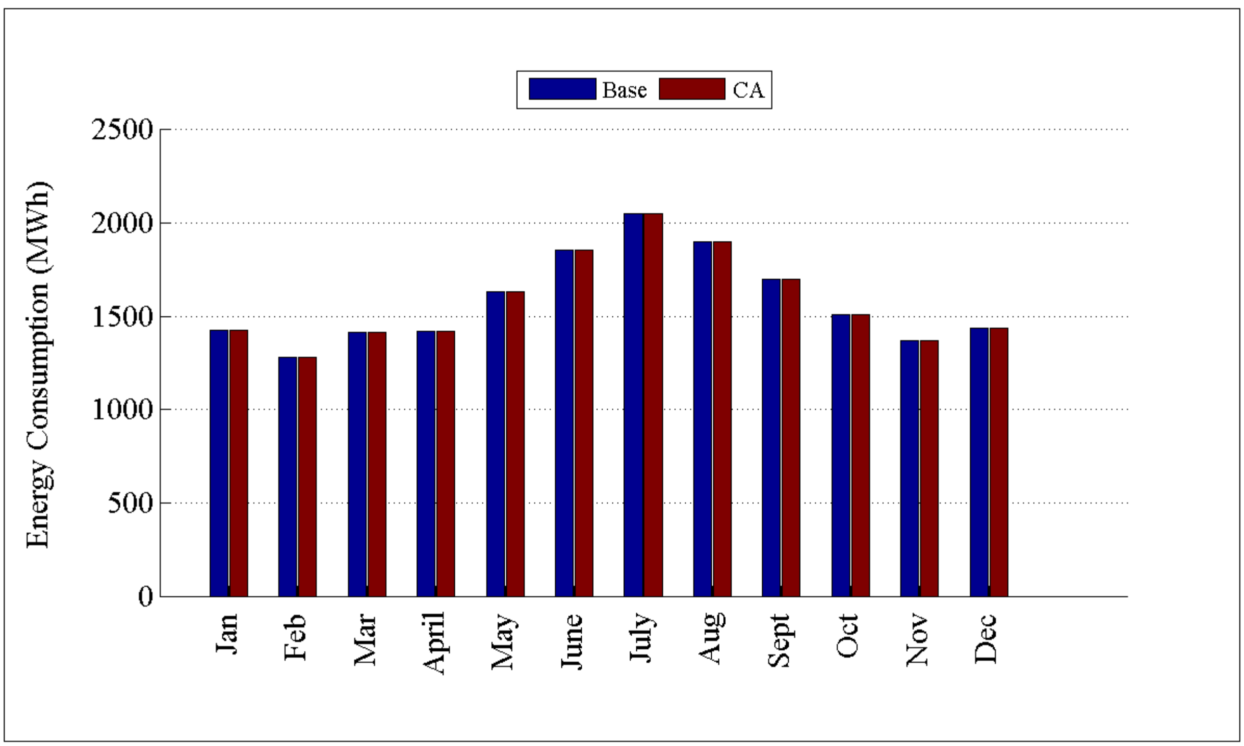



Figure D. 135: Comparison of energy consumption by month for GC-12.47-1_R2

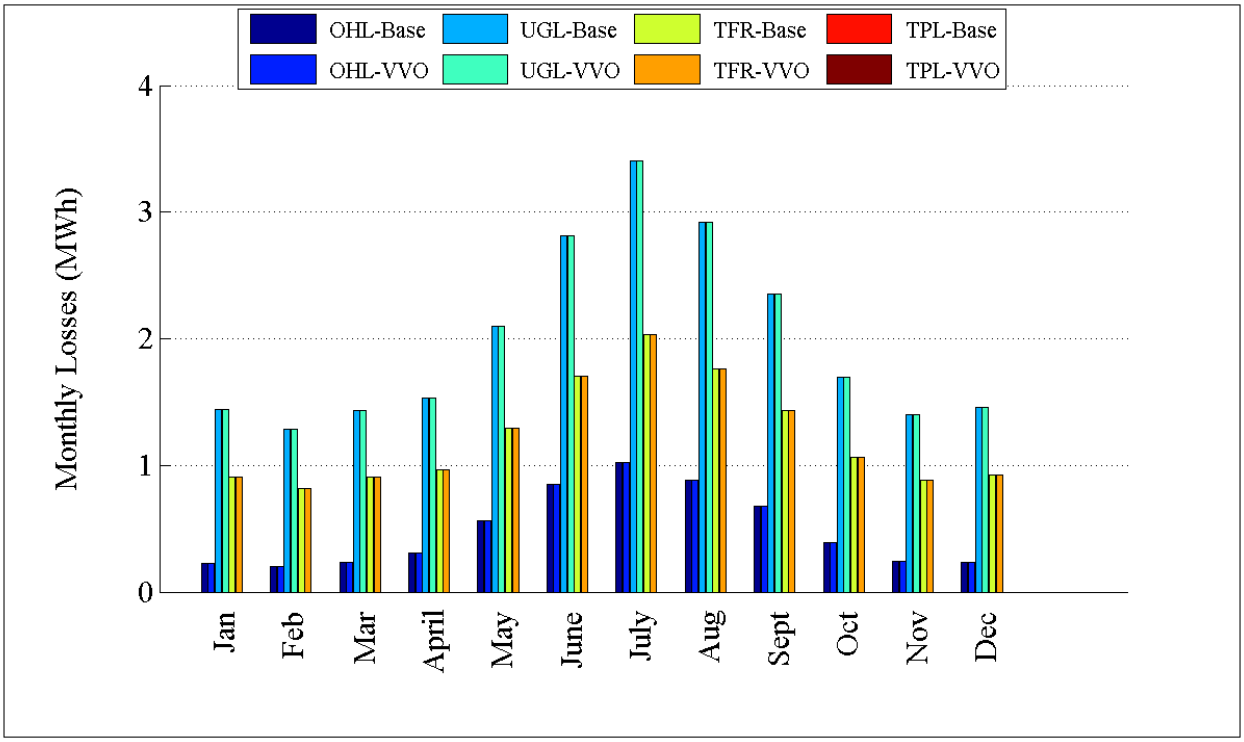



Figure D. 136: Comparison of losses by month for GC-12.47-1_R2

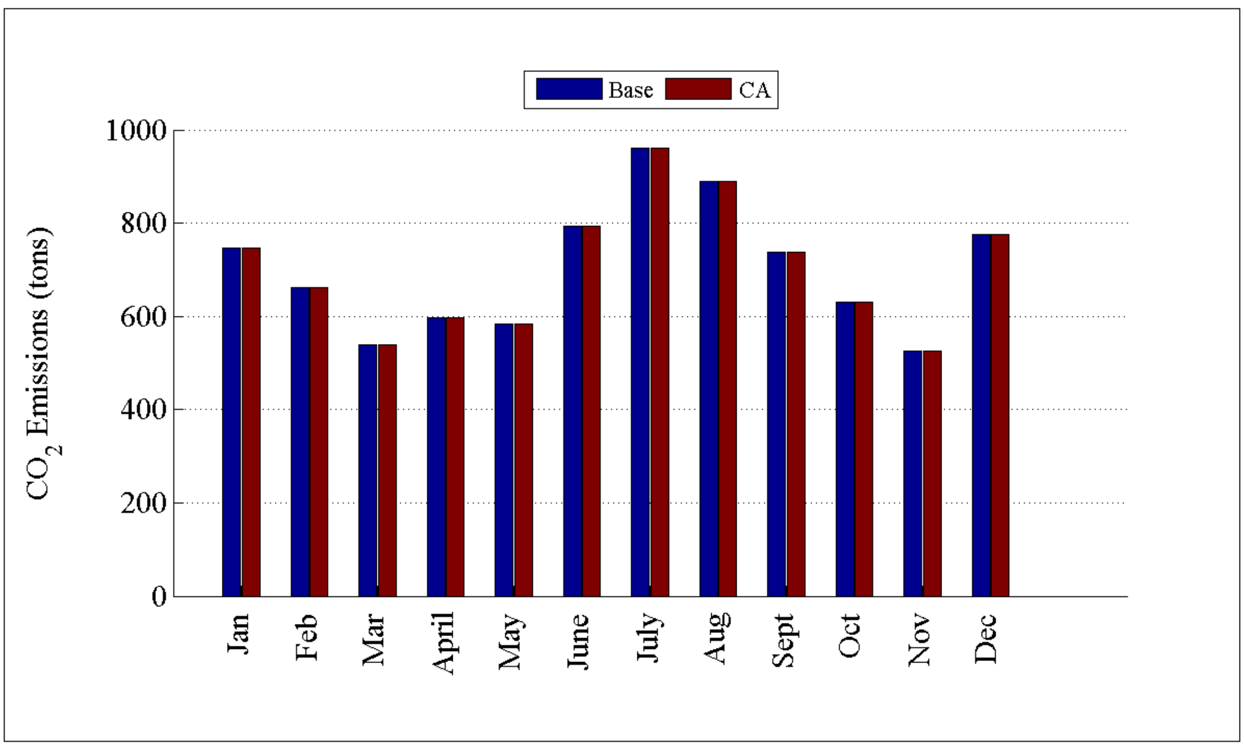



Figure D. 137: Comparison of $CO_2$ emissions by month for GC-12.47-1_R2

### D.2.8 Detailed CA Plots for R2-12.47-1

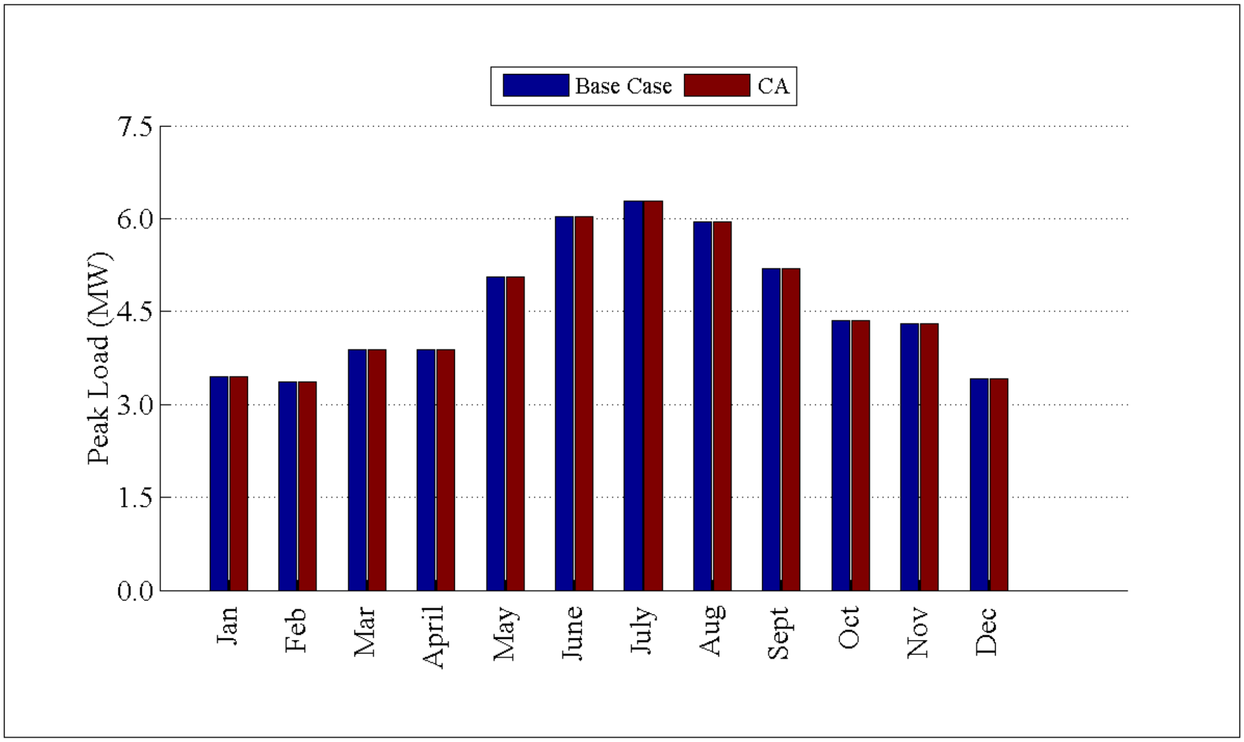



Figure D.138: Comparison of peak load by month for R2-12.47-1

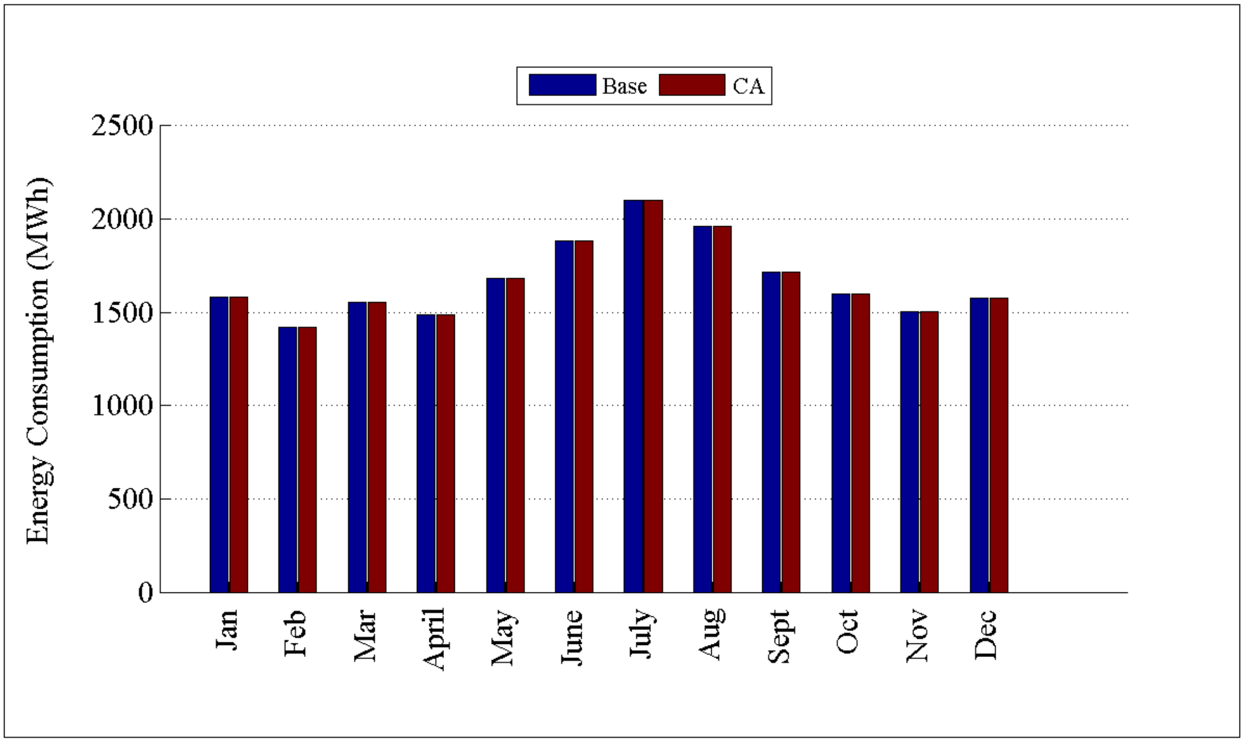



Figure D.139: Comparison of energy consumption by month for R2-12.47-1

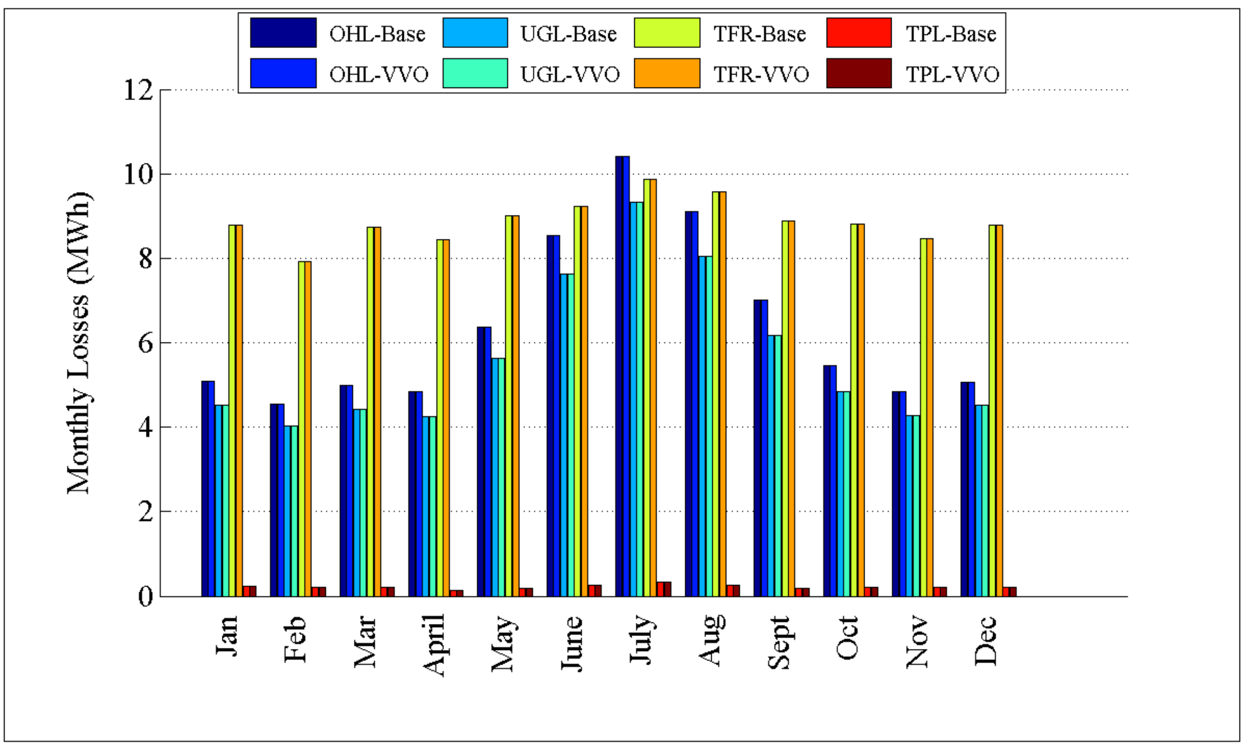



Figure D.140: Comparison of losses by month for R2-12.47-1

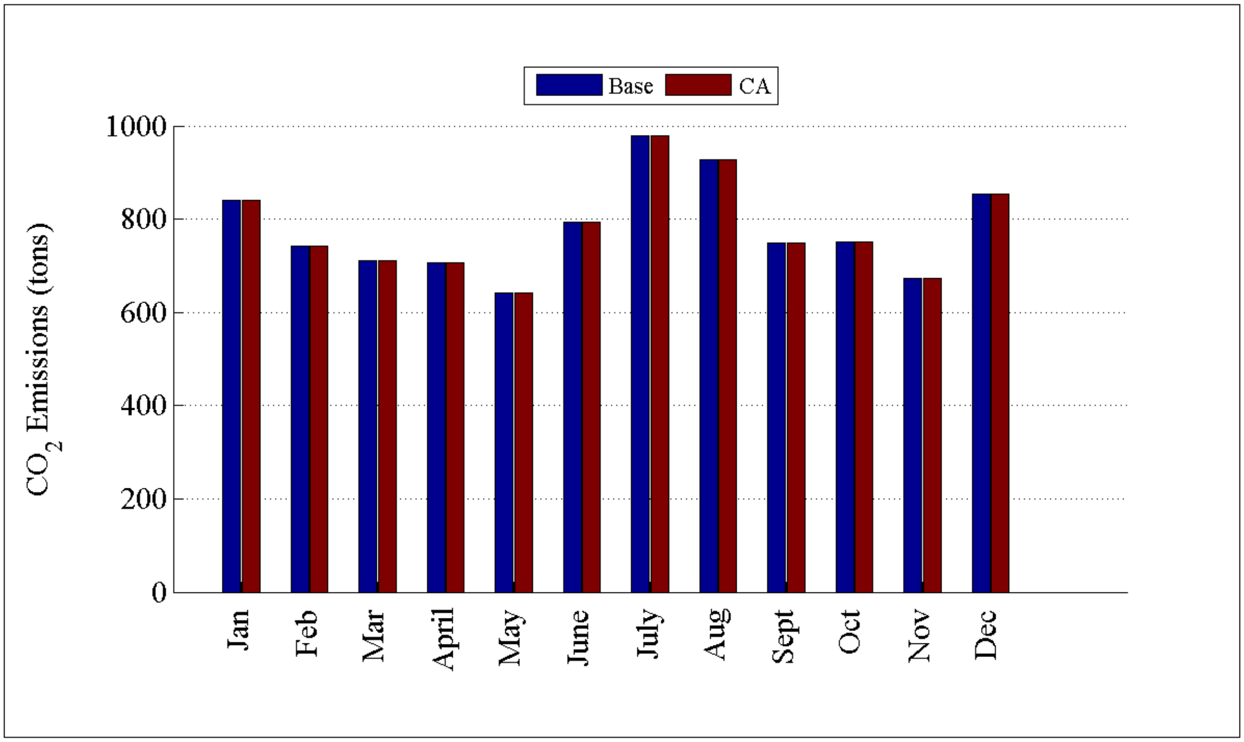



Figure D.141: Comparison of $CO_2$ emissions by month for R2-12.47-1

### D.2.9 Detailed CA Plots for R2-12.47-2

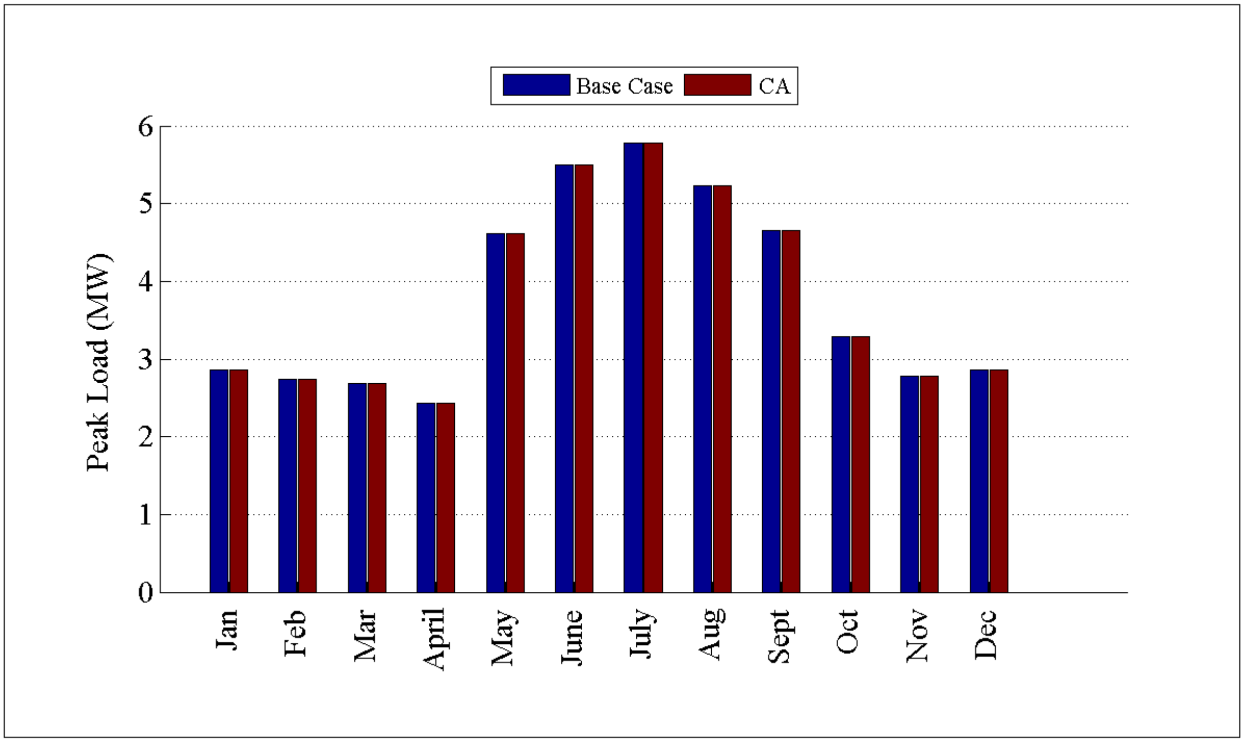



Figure D.142: Comparison of peak load by month for R2-12.47-2

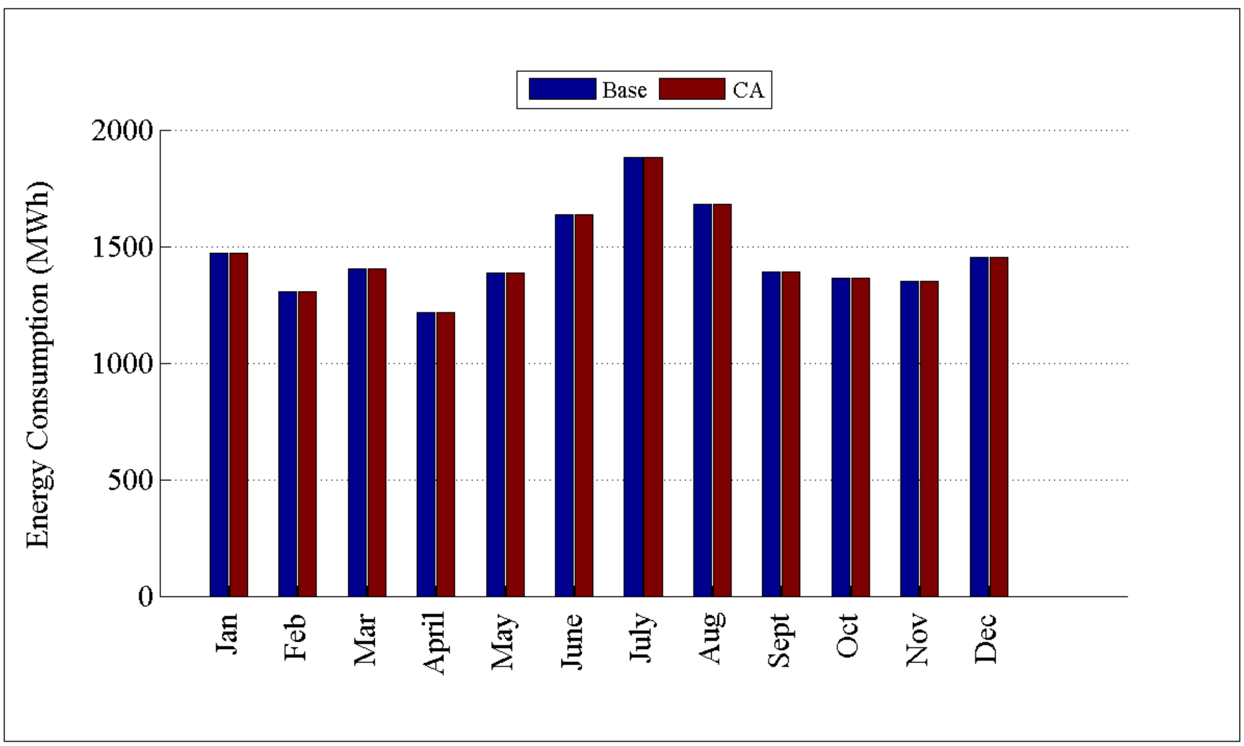



Figure D.143: Comparison of energy consumption by month for R2-12.47-2

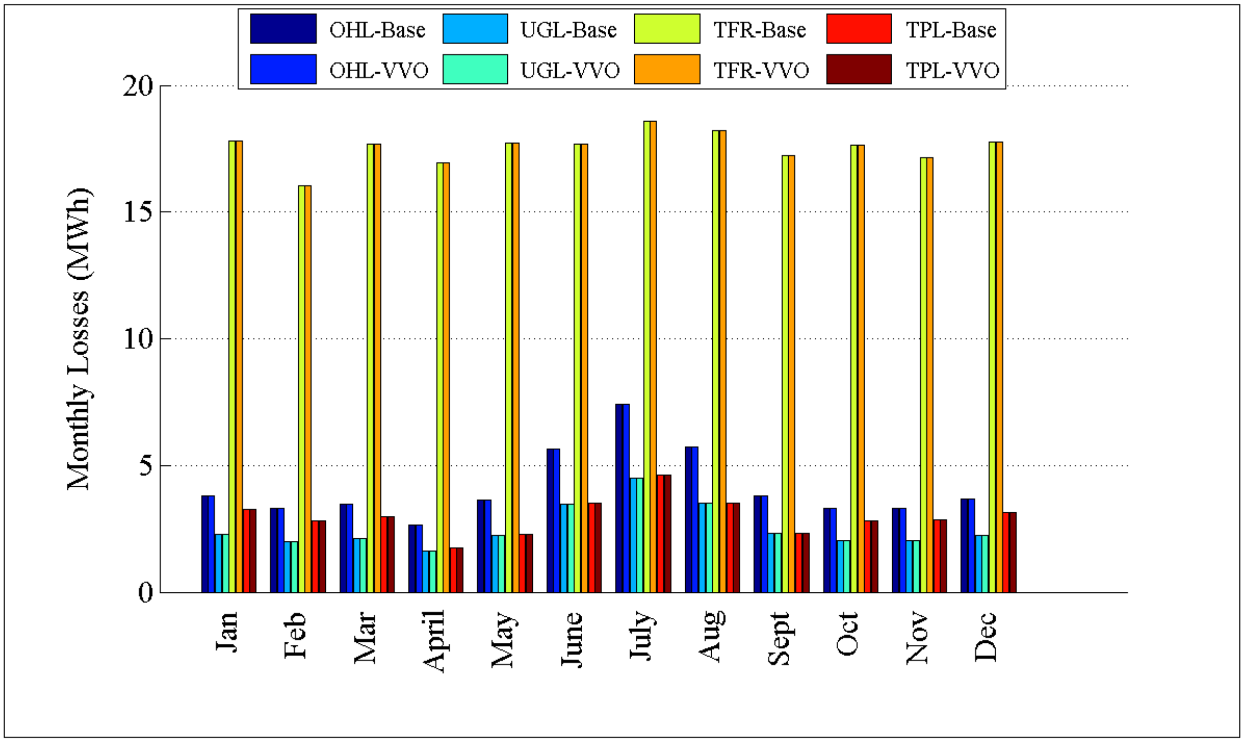



Figure D.144: Comparison of losses by month for R2-12.47-2

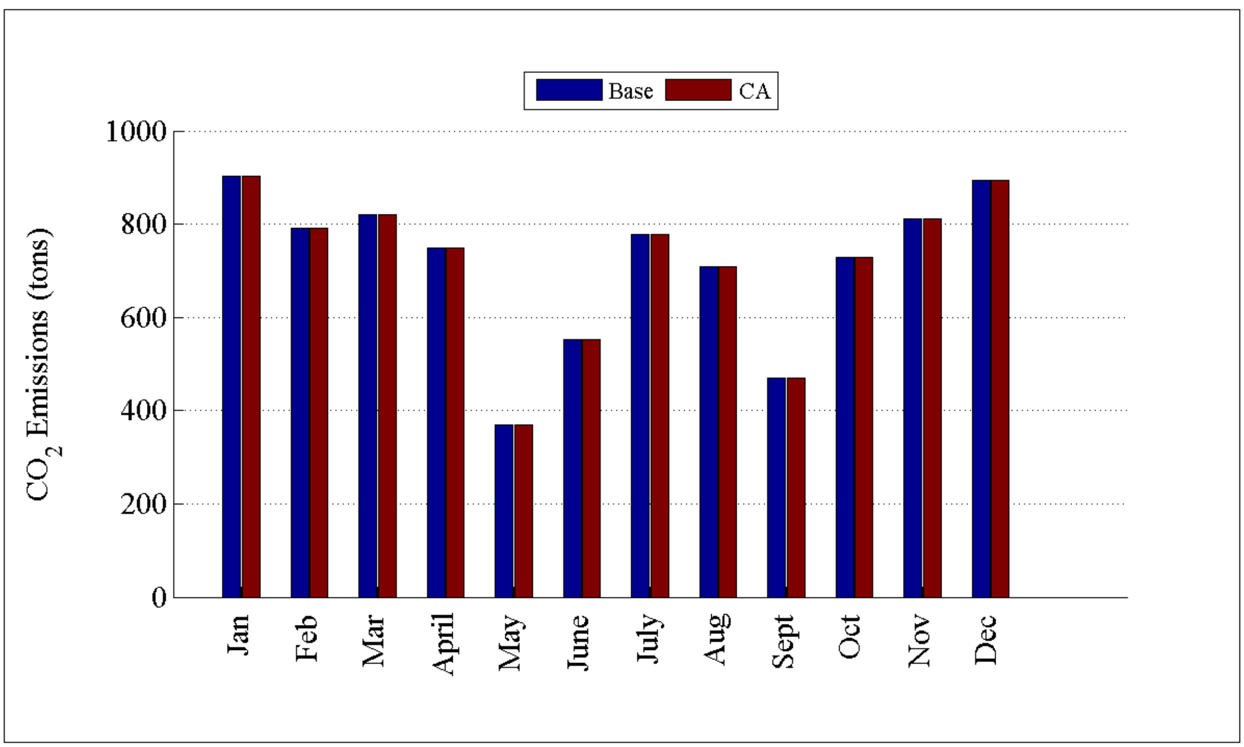



Figure D.145: Comparison of $CO_2$ emissions by month for R2-12.47-2

## D.2.10 Detailed CA Plots for R2-12.47-3

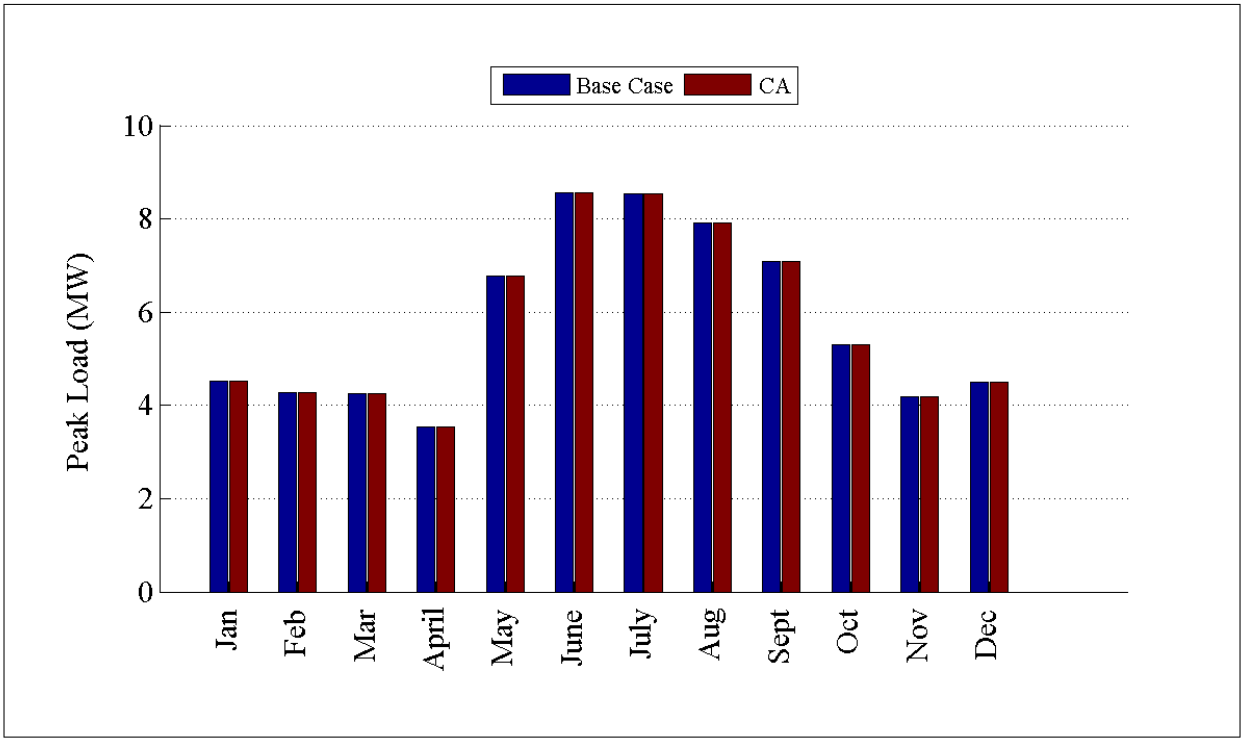



Figure D.146: Comparison of peak load by month for R2-12.47-3

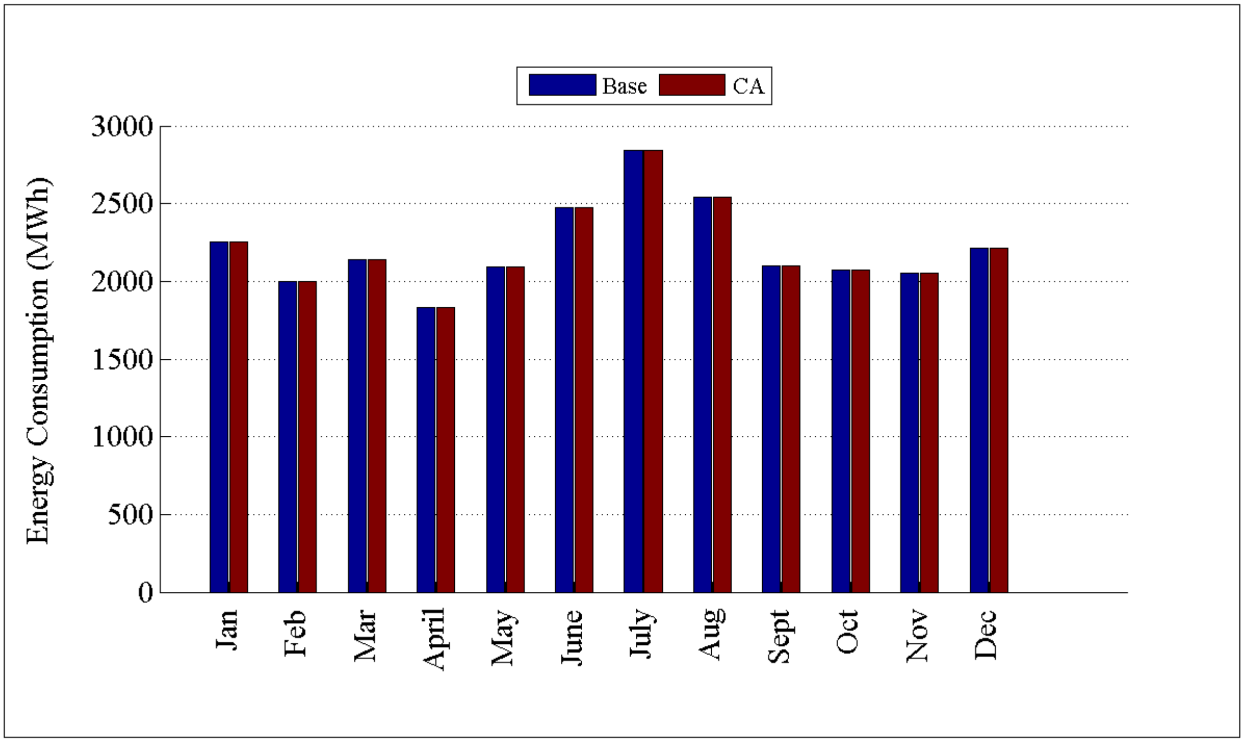



Figure D.147: Comparison of energy consumption by month for R2-12.47-3

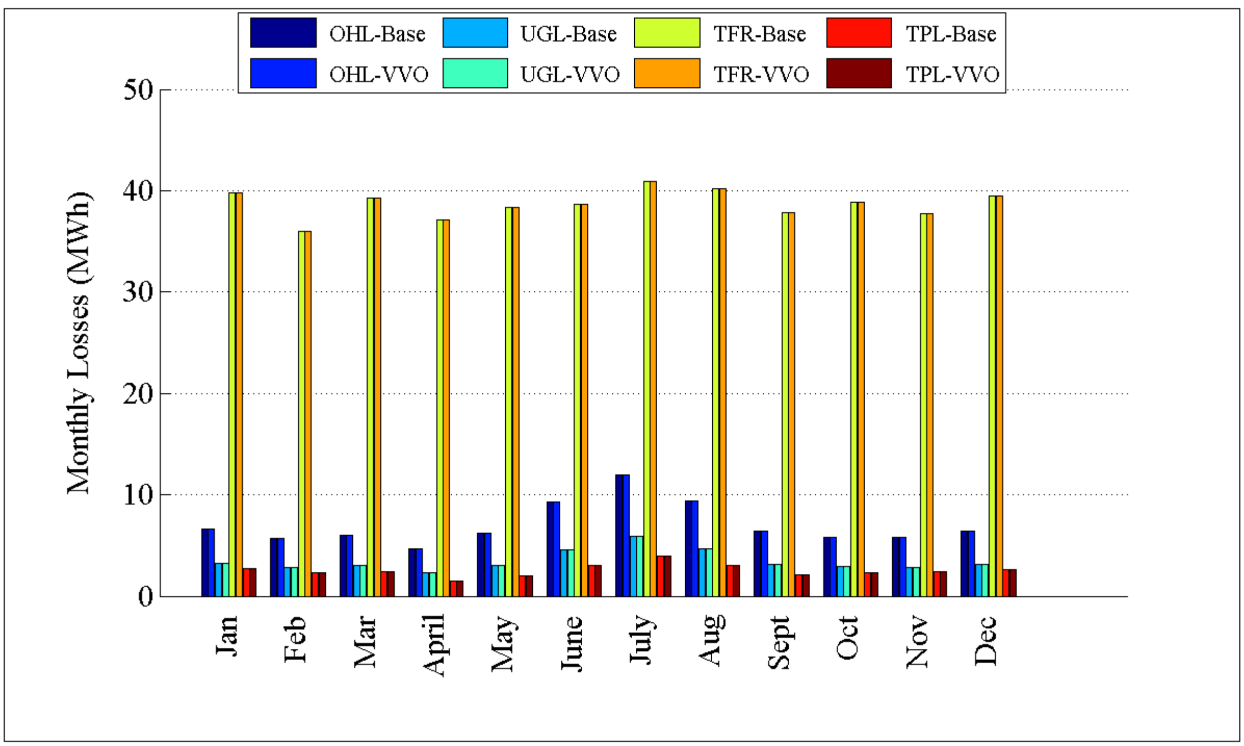



Figure D.148: Comparison of losses by month for R2-12.47-3

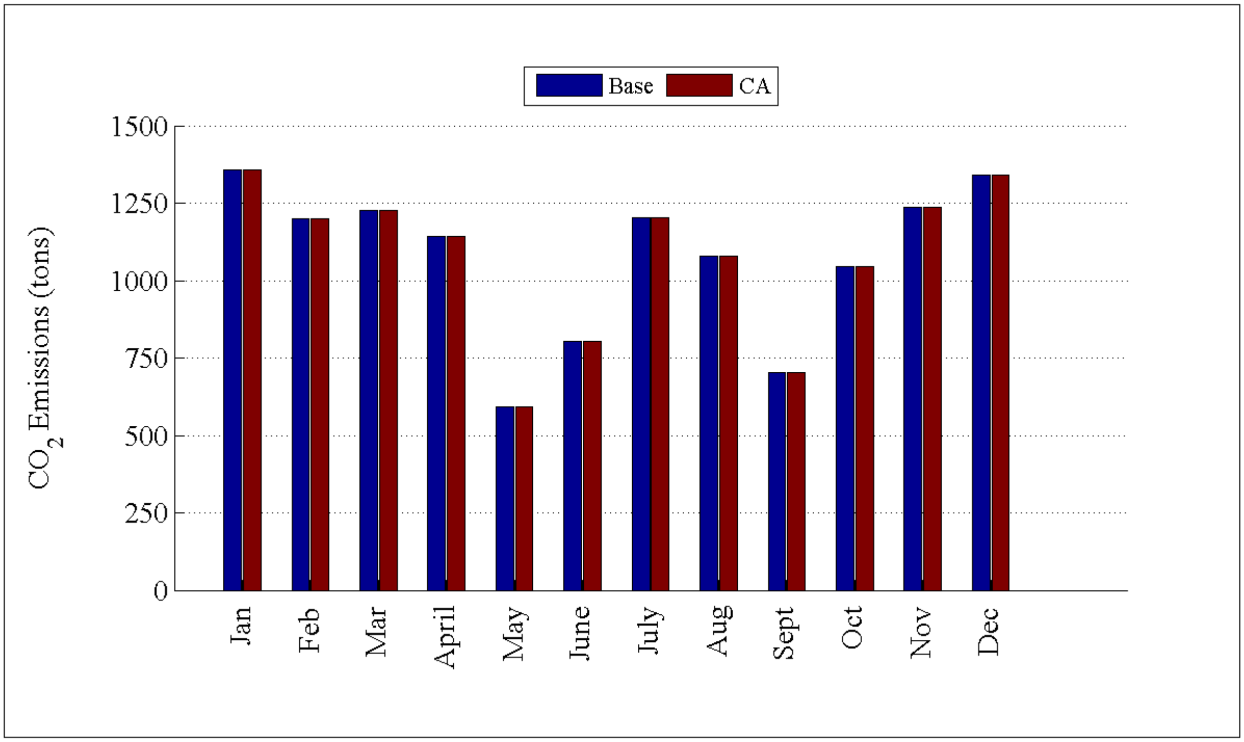



Figure D.149: Comparison of $CO_2$ emissions by month for R2-12.47-3

### D.2.11 Detailed CA Plots for R2-25.00-1

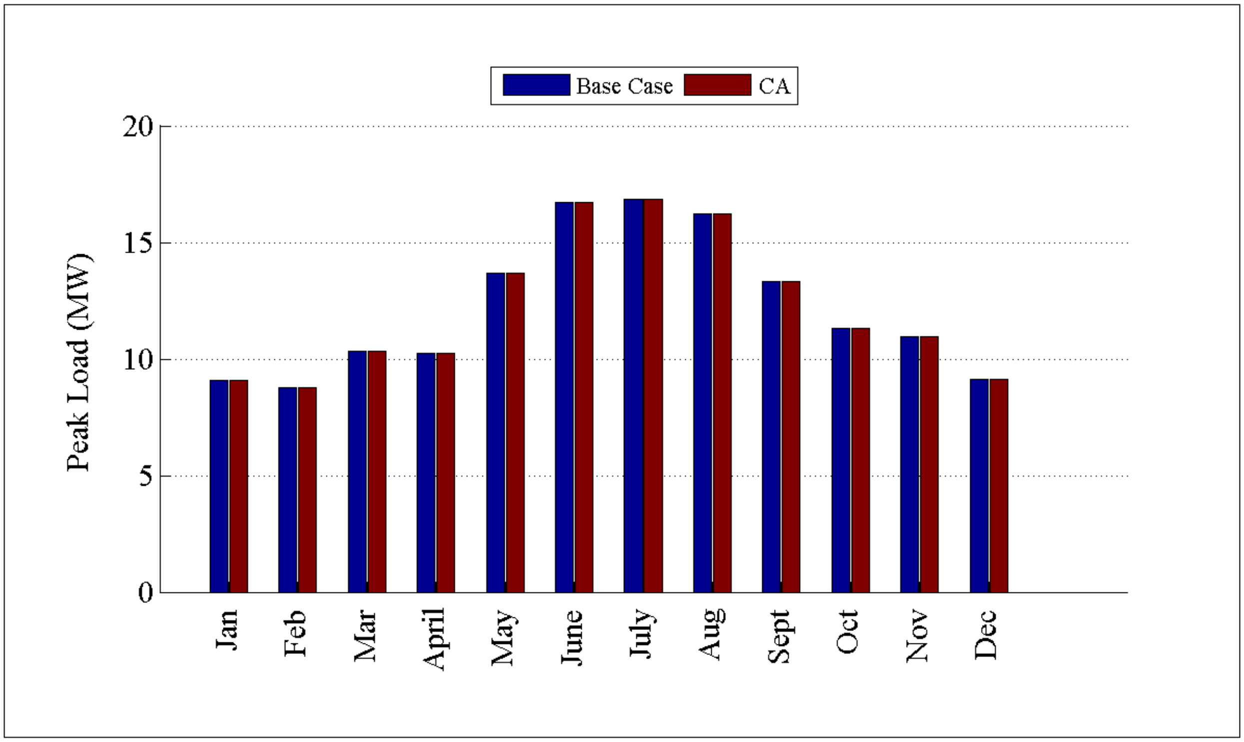



Figure D.150: Comparison of peak load by month for R2-25.00-1

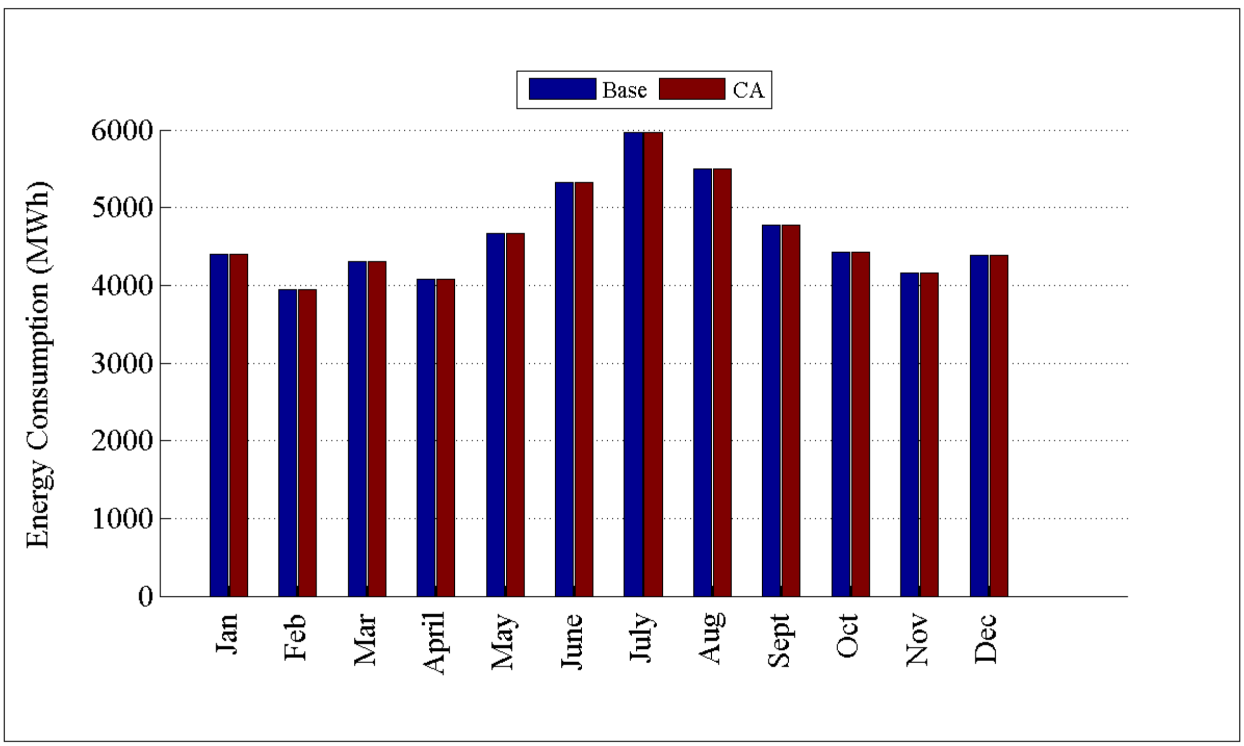



Figure D.151: Comparison of energy consumption by month for R2-25.00-1

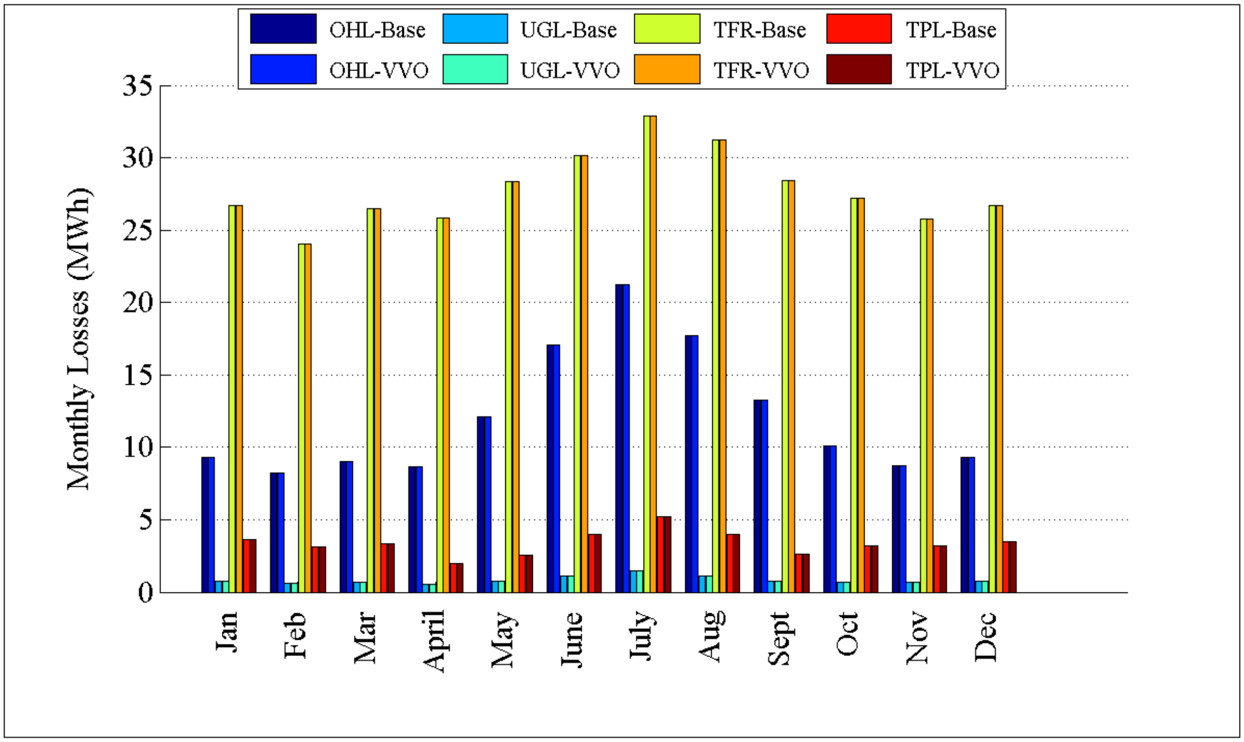



Figure D.152: Comparison of losses by month for R2-25.00-1

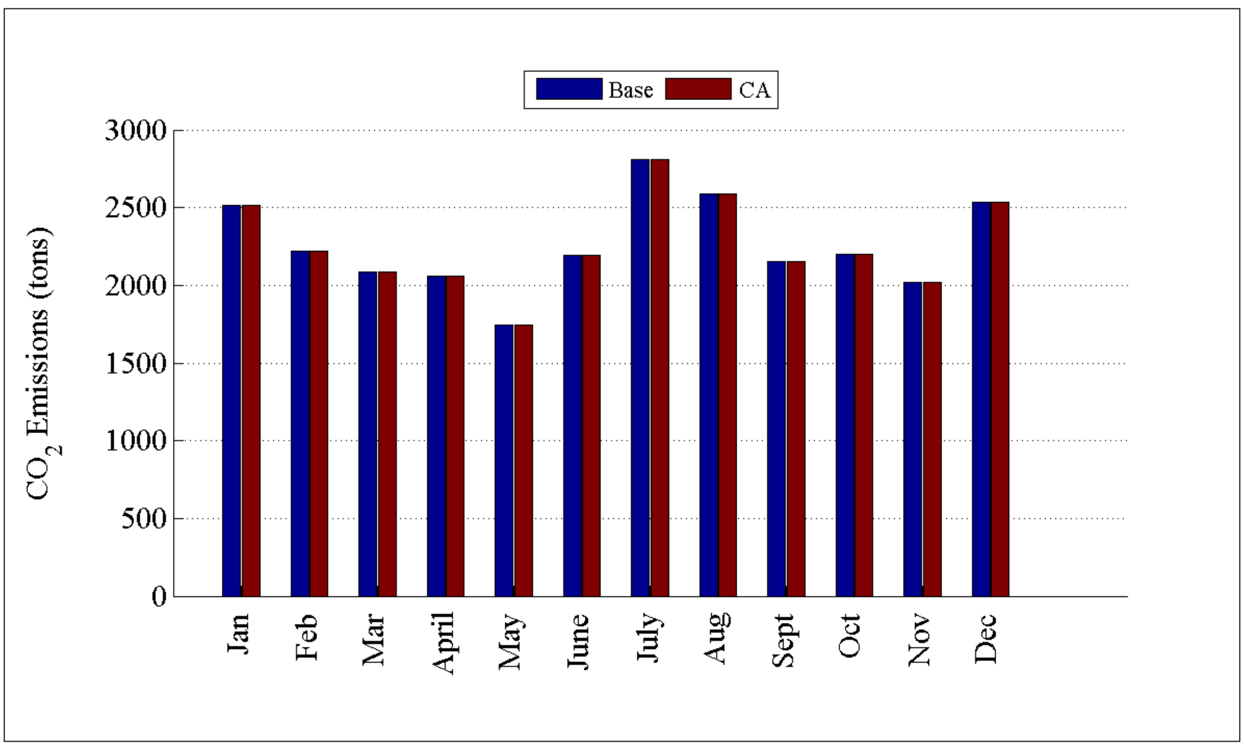



Figure D.153: Comparison of $CO_2$ emissions by month for R2-25.00-1

## D.2.12 Detailed CA Plots for R2-35.00-1

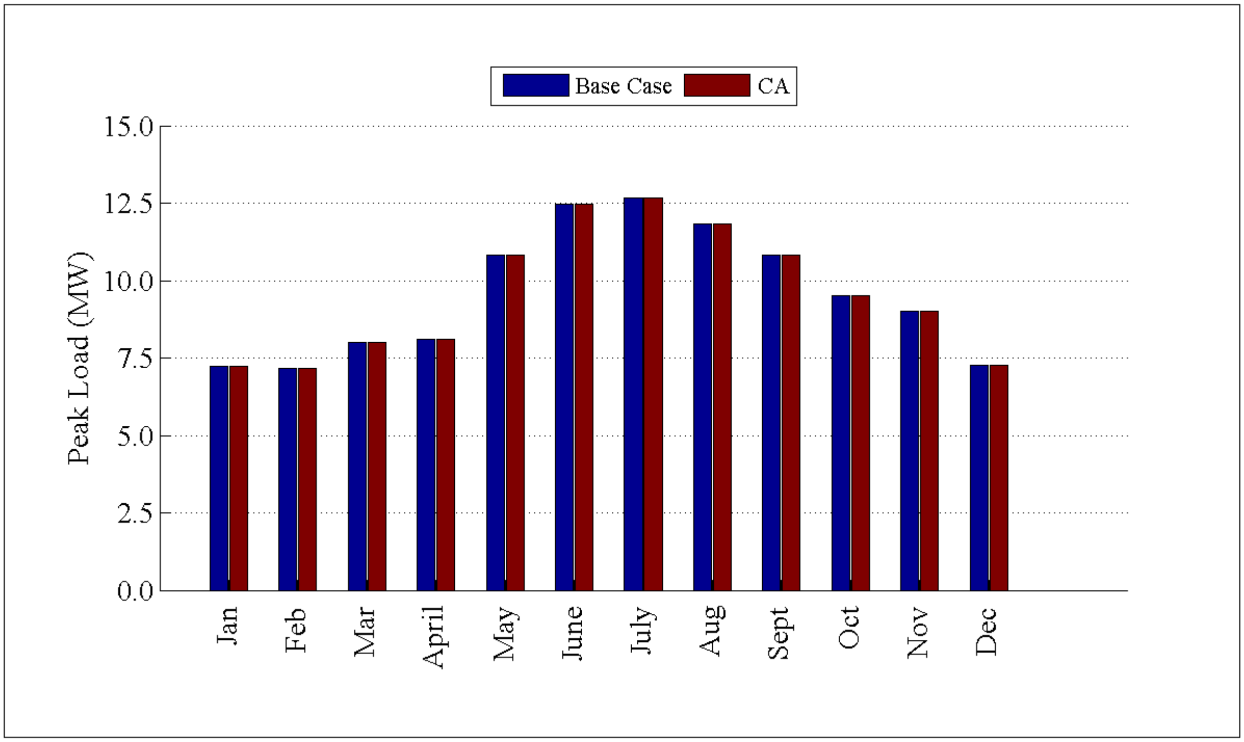



Figure D.154: Comparison of peak load by month for R2-35.00-1

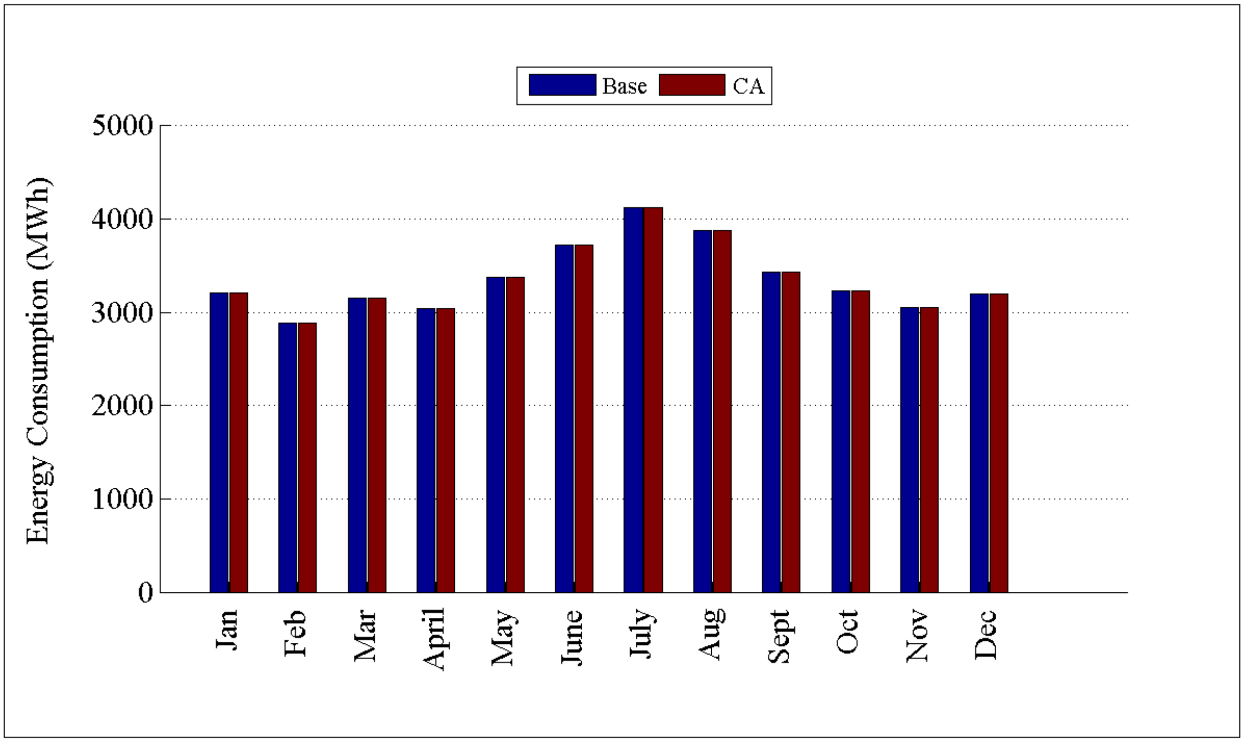



Figure D.155: Comparison of energy consumption by month for R2-35.00-1

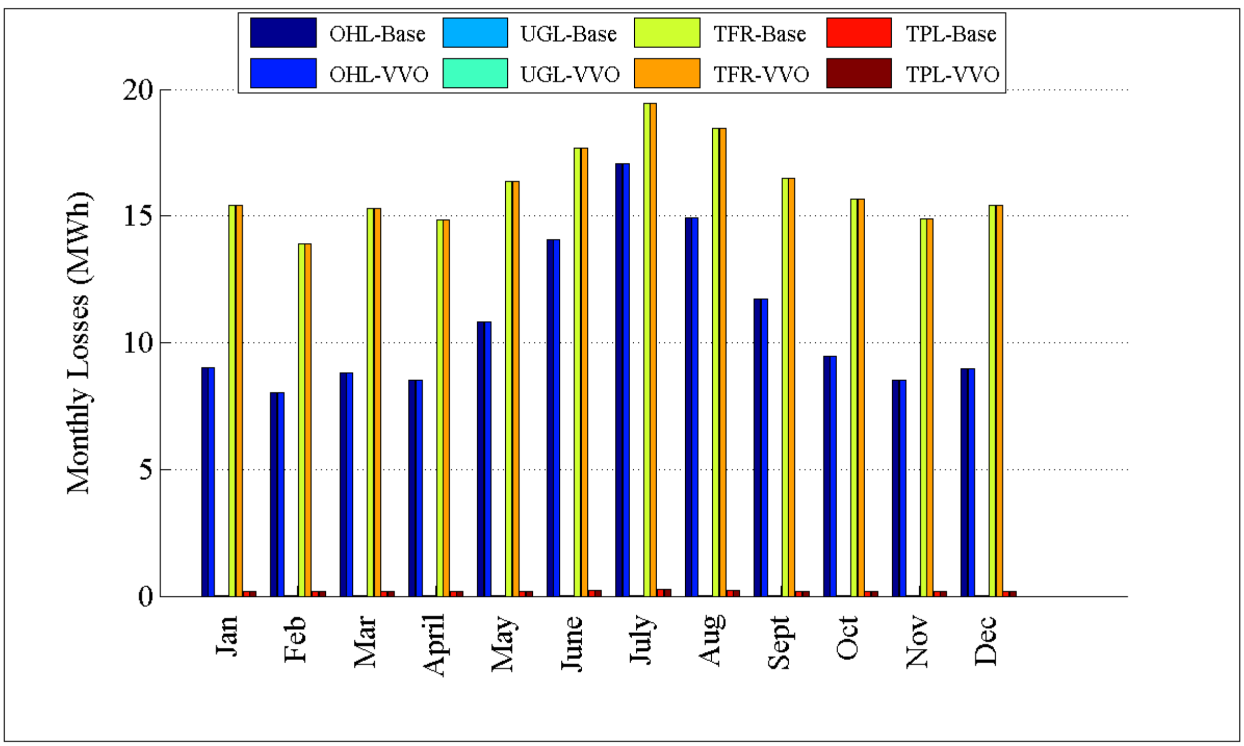



Figure D.156: Comparison of losses by month for R2-35.00-1

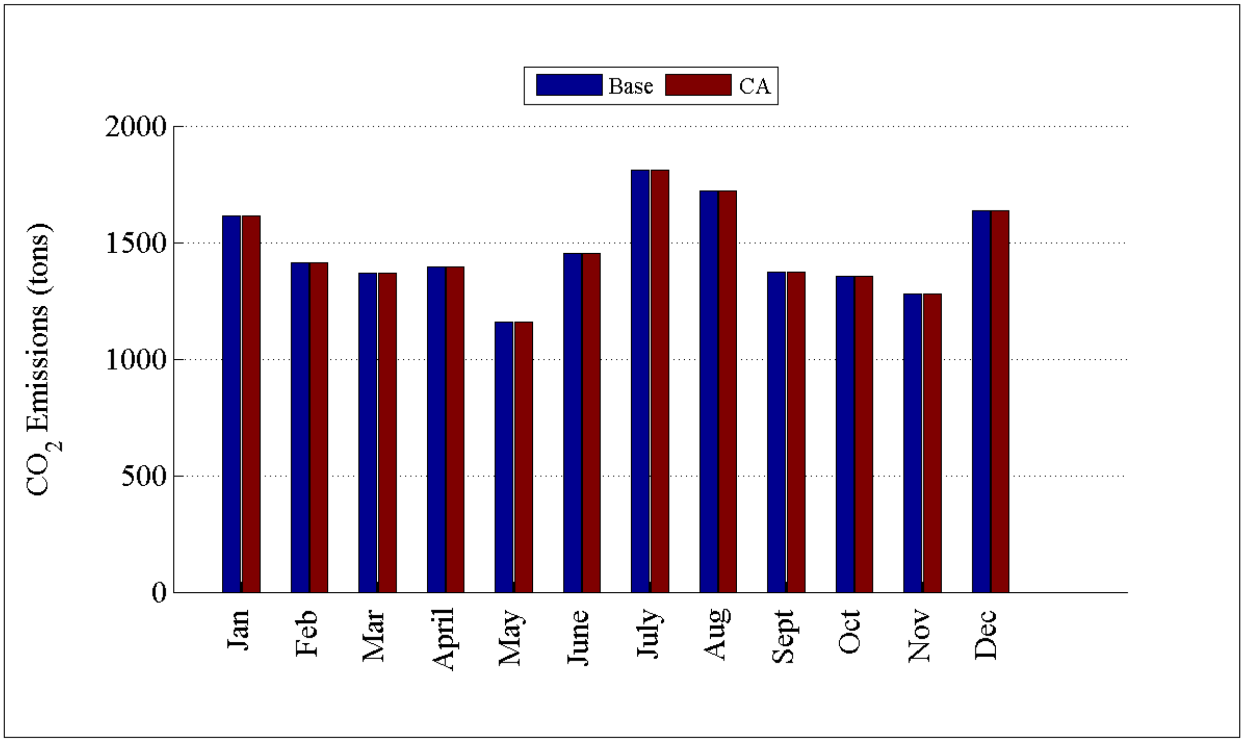



Figure D.157: Comparison of $CO_2$ emissions by month for R2-35.00-1

### D.2.13 Detailed CA Plots for GC-12.47-1_R3

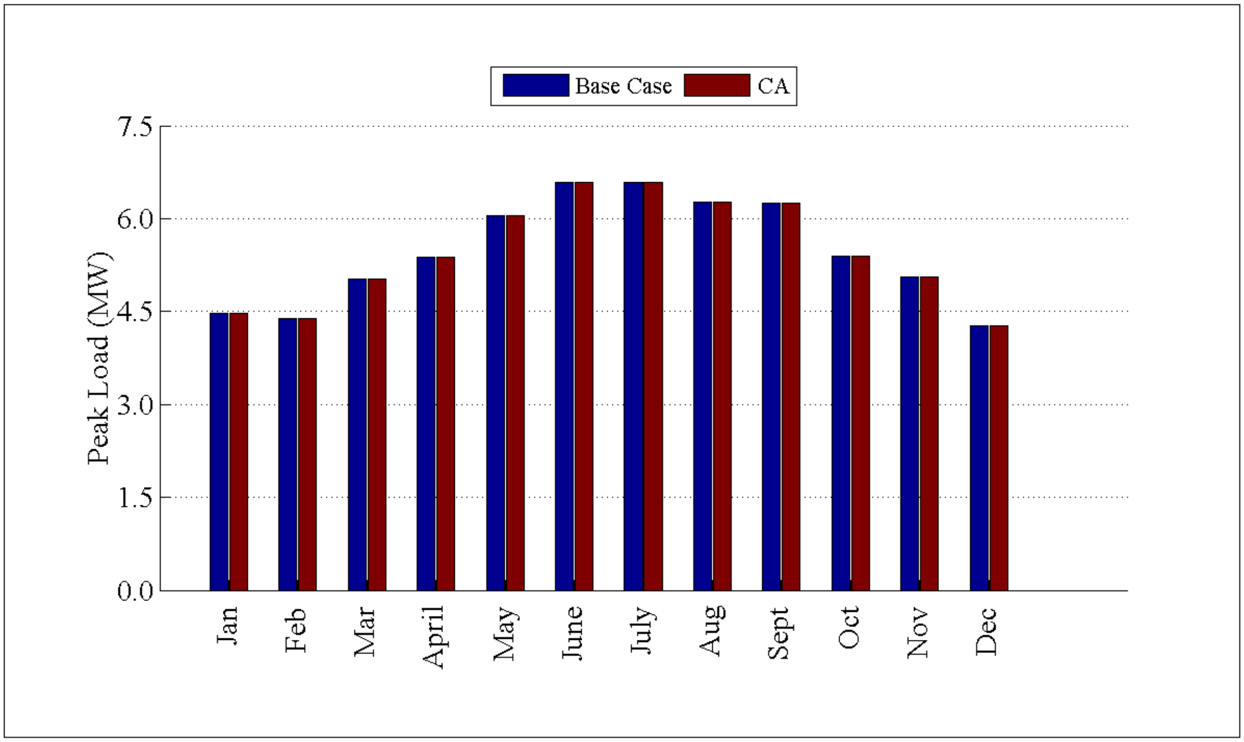



Figure D.158: Comparison of peak load by month for GC-12.47-1_R3

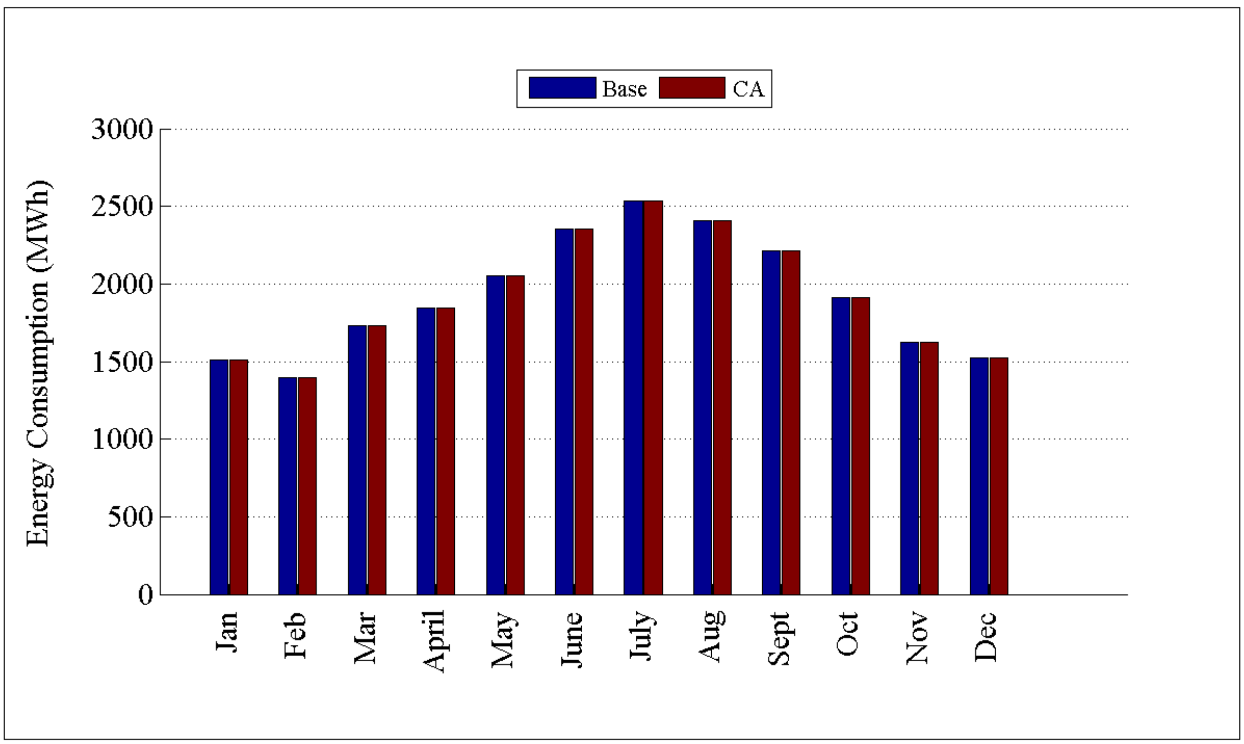



Figure D.159: Comparison of energy consumption by month for GC-12.47-1_R3

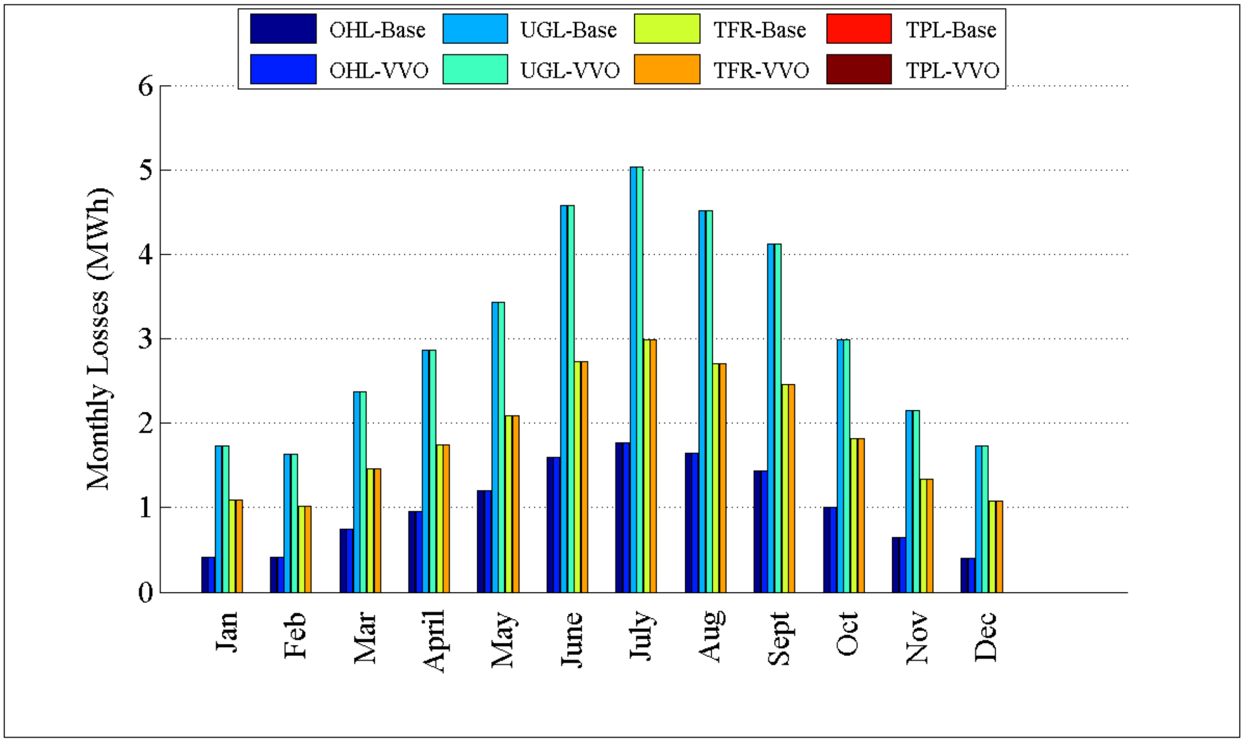



Figure D.160: Comparison of losses by month for GC-12.47-1_R3

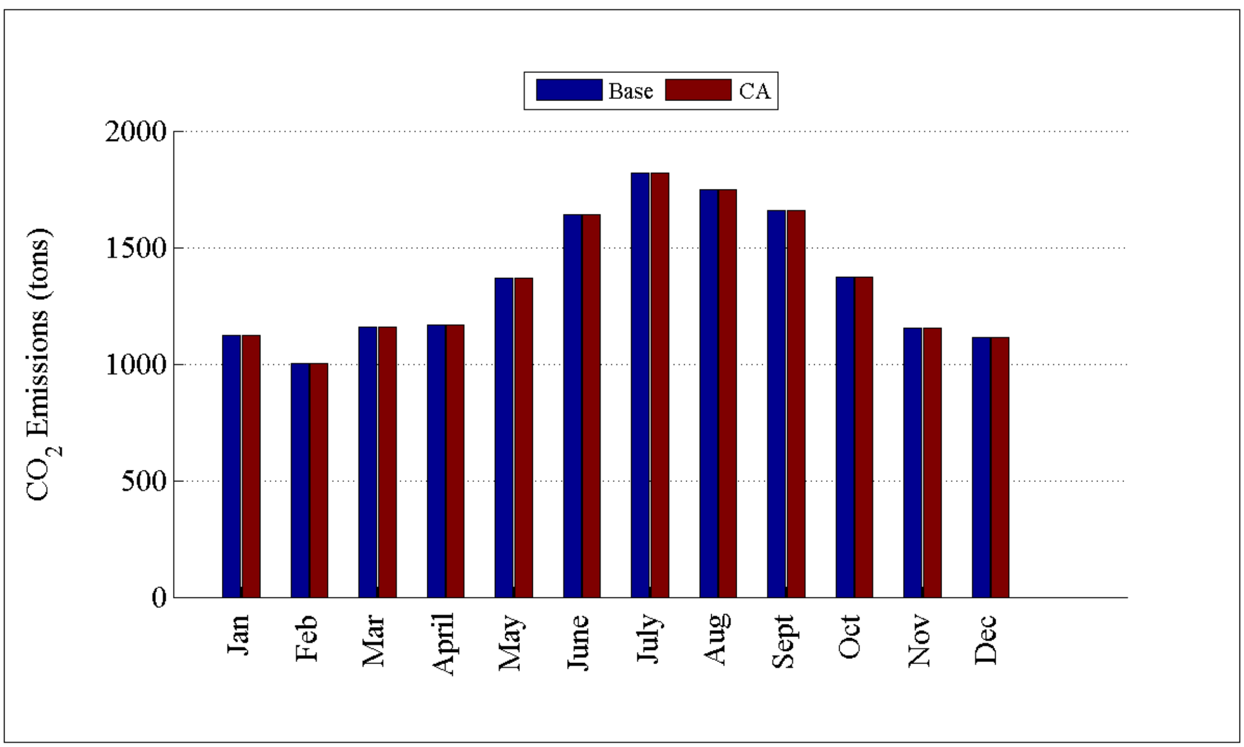



Figure D.161: Comparison of $CO_2$ emissions by month for GC-12.47-1_R3

### D.2.14 Detailed CA Plots for R3-12.47-1

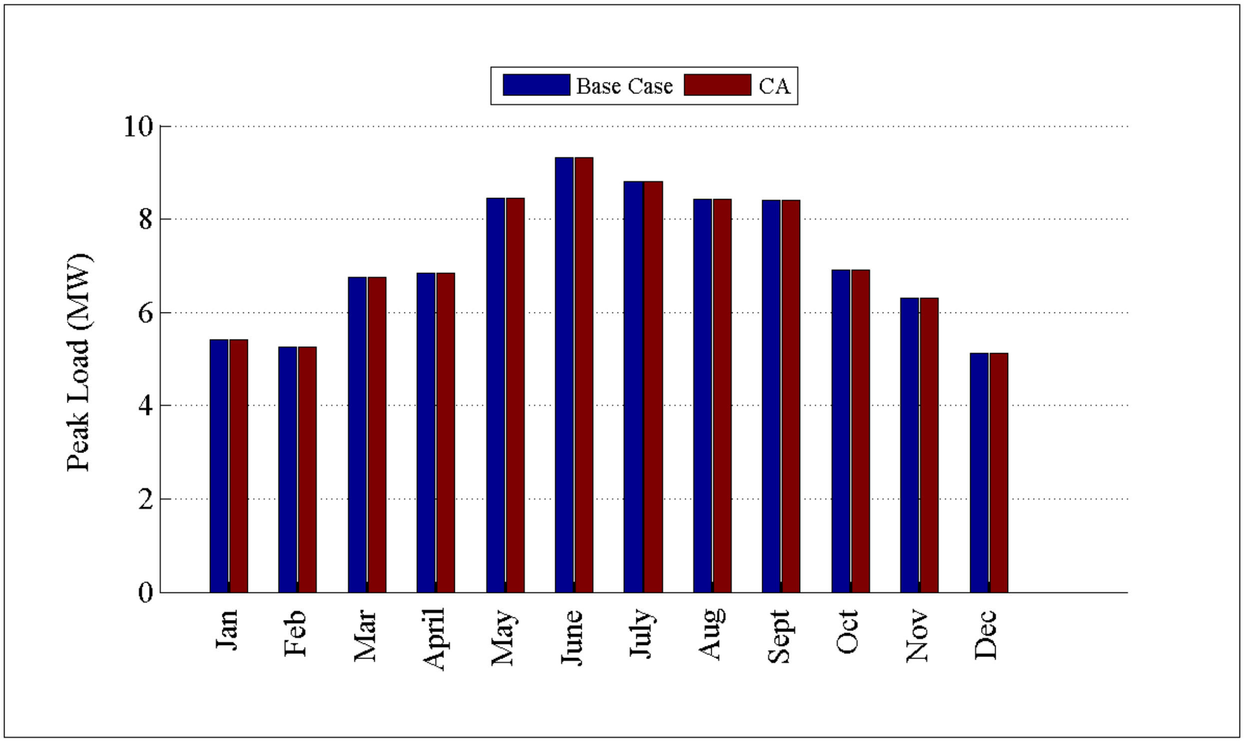



Figure D.162: Comparison of peak load by month for R3-12.47-1

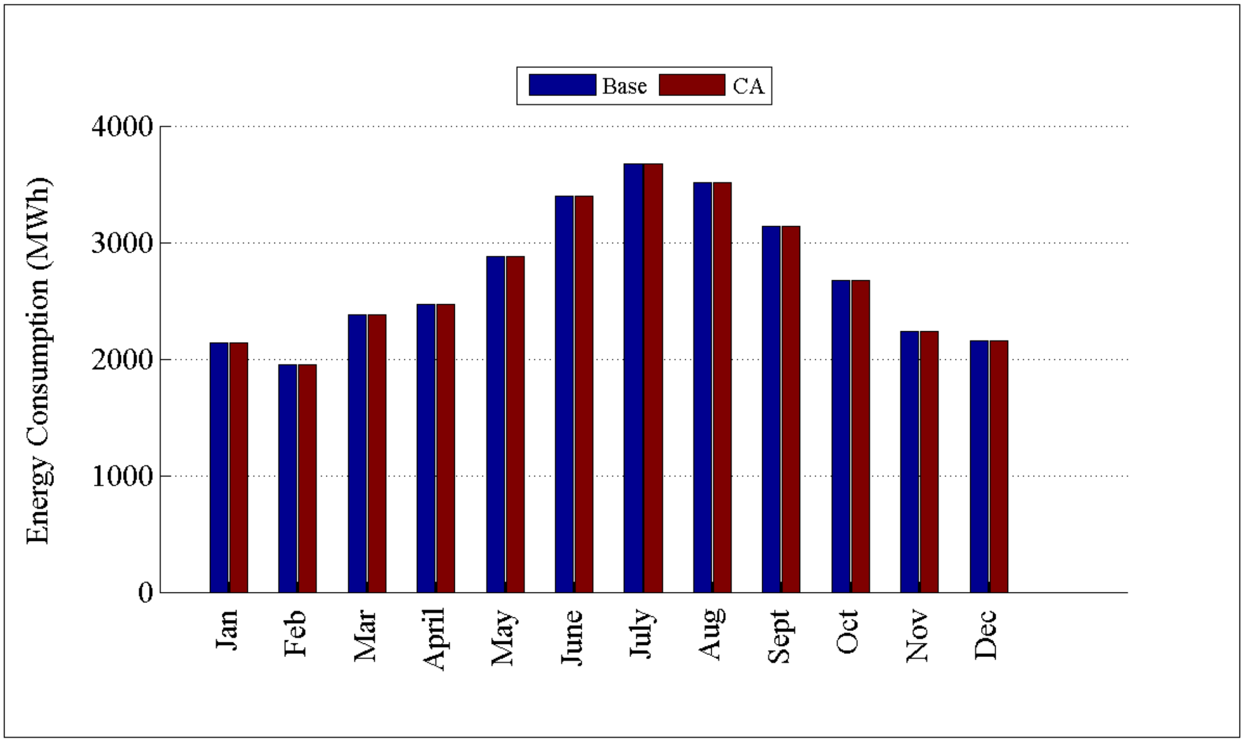



Figure D.163: Comparison of energy consumption by month for R3-12.47-1

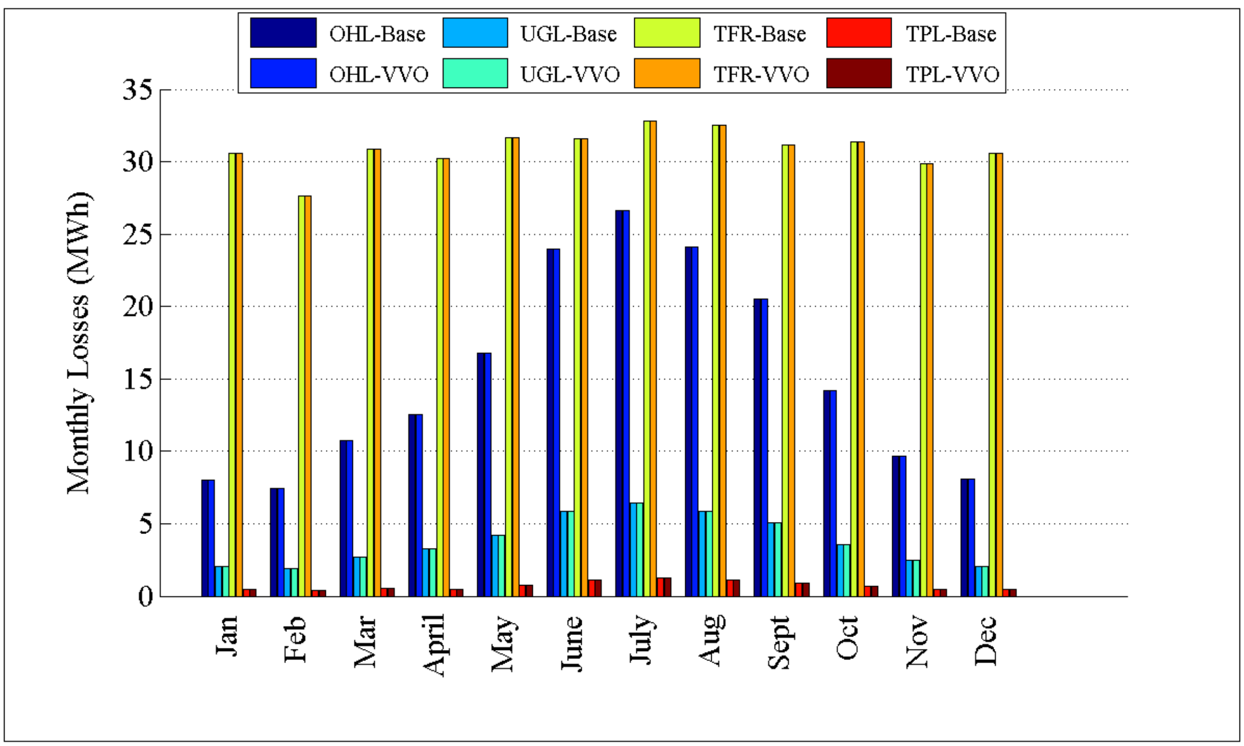



Figure D.164: Comparison of losses by month for R3-12.47-1

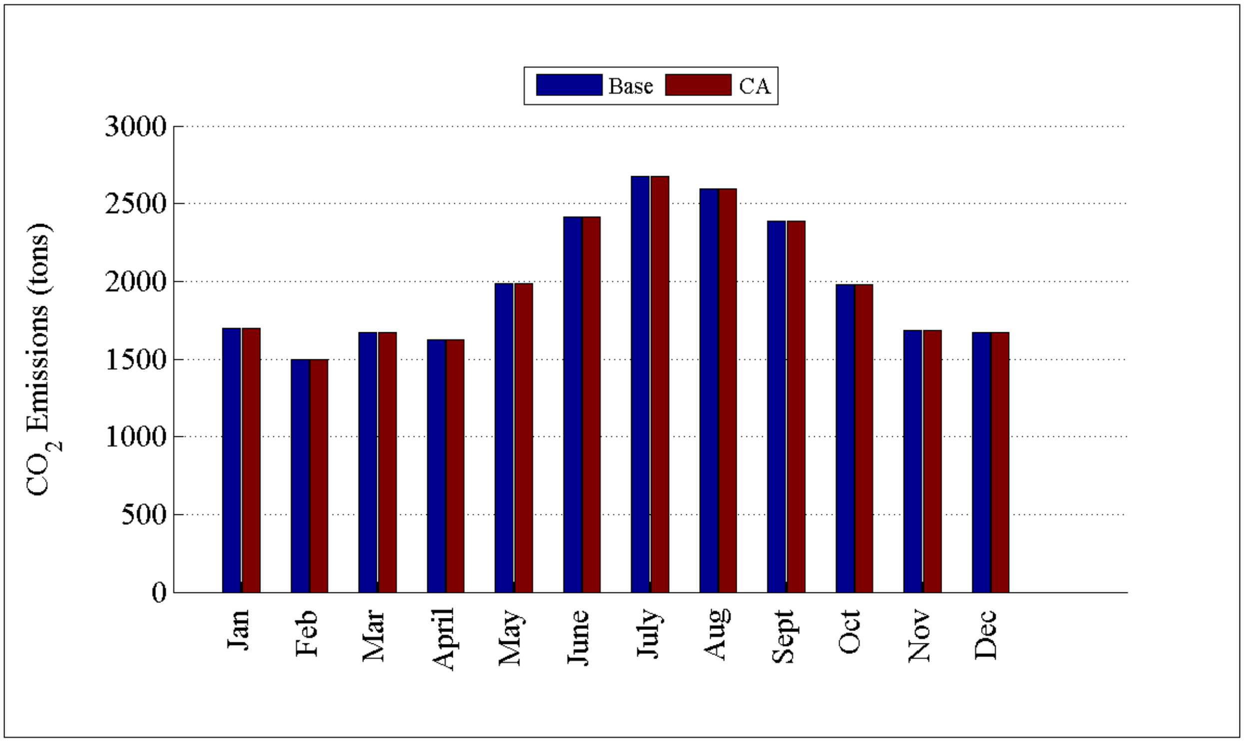



Figure D.165: Comparison of $CO_2$ emissions by month for R3-12.47-1

### D.2.15 Detailed CA Plots for R3-12.47-2

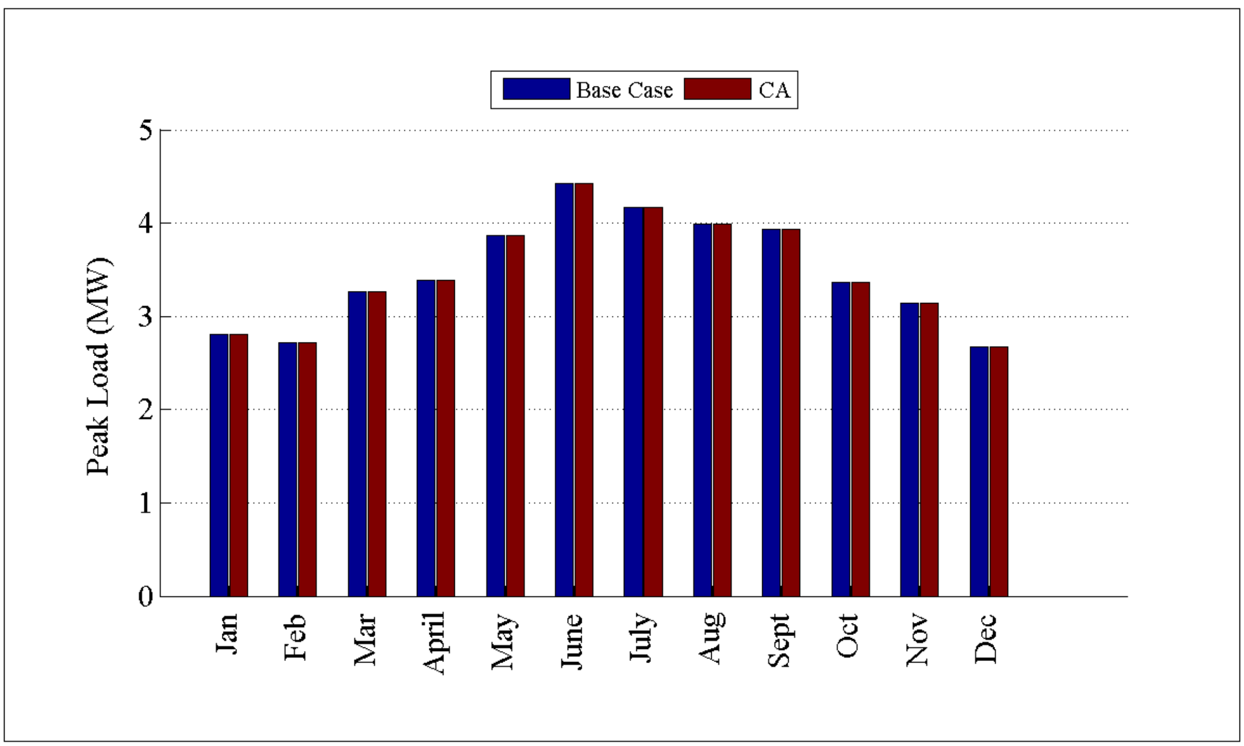


Figure D.166: Comparison of peak load by month for R3-12.47-2

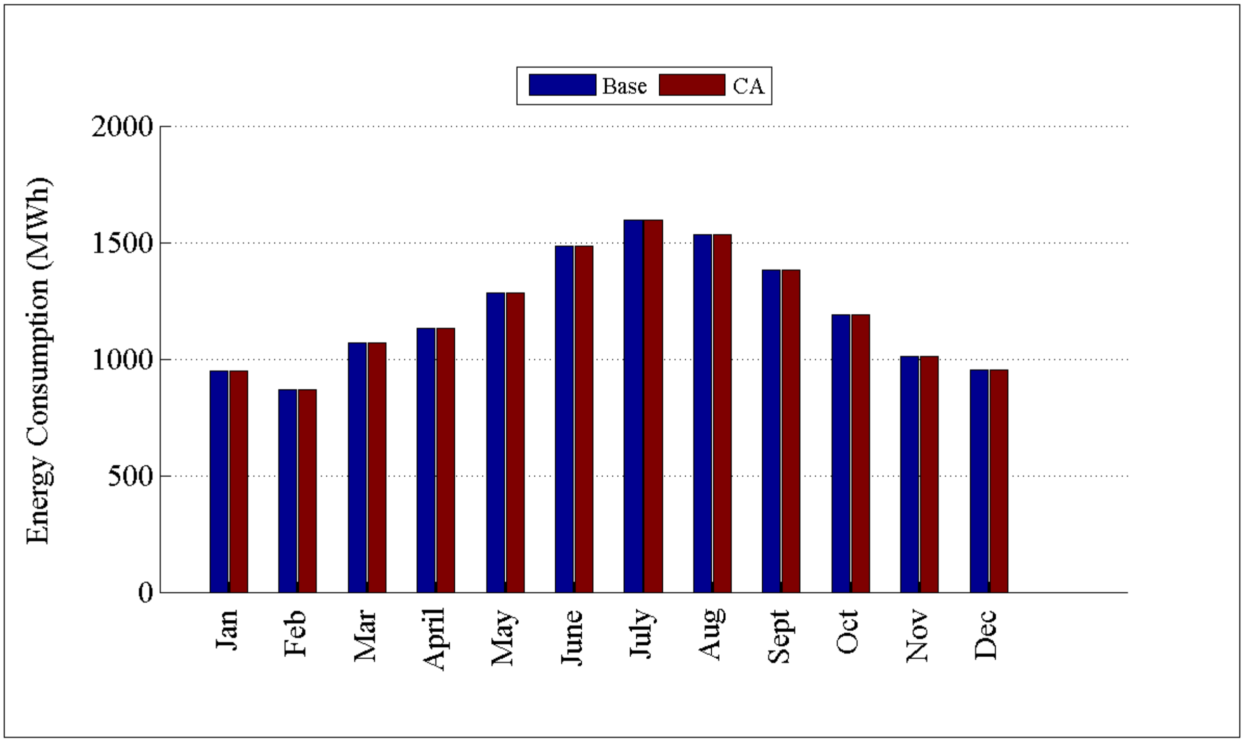



Figure D.167: Comparison of energy consumption by month for R3-12.47-2

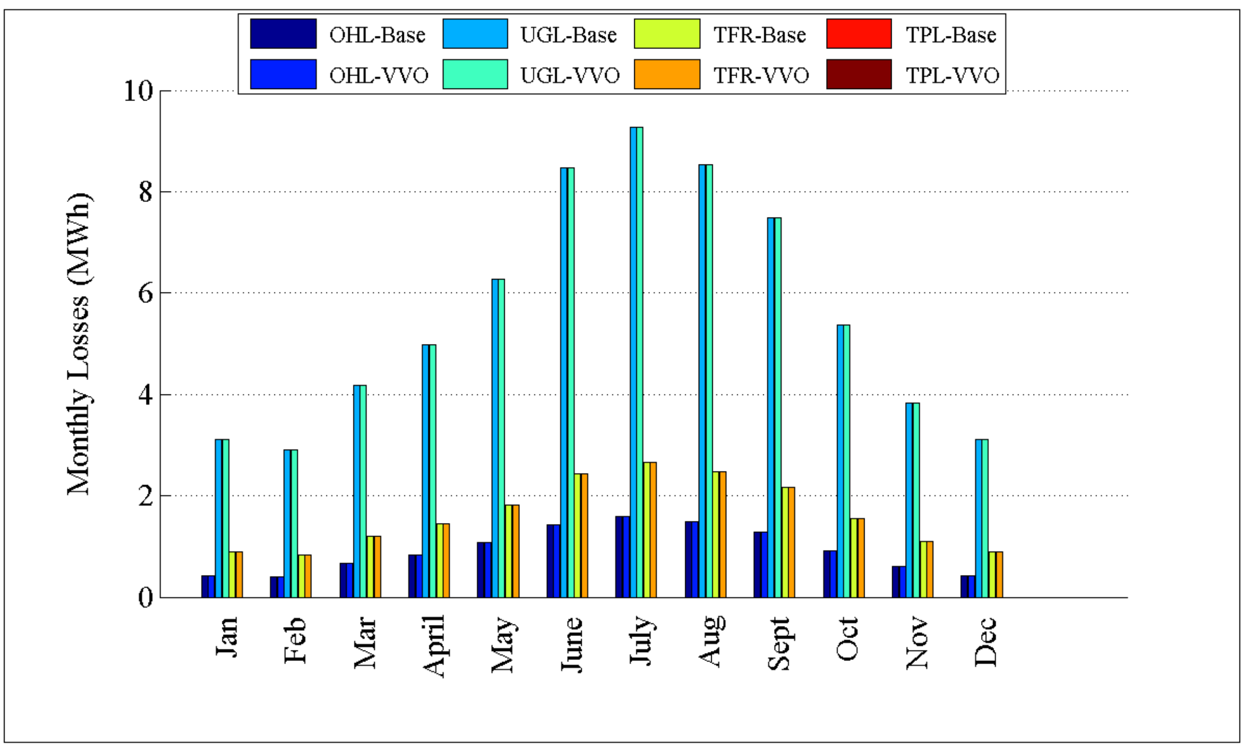


Figure D.168: Comparison of losses by month for R3-12.47-2

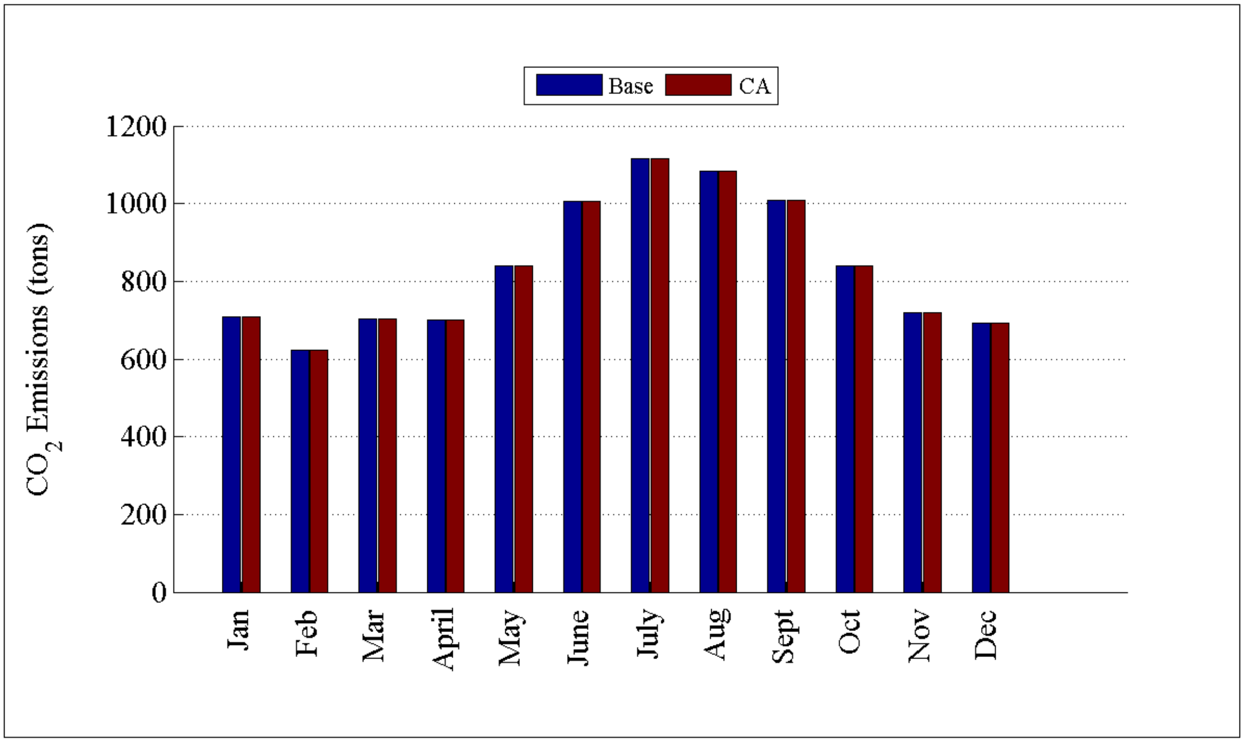



Figure D.169: Comparison of $CO_2$ emissions by month for R3-12.47-2

### D.2.16 Detailed CA Plots for R3-12.47-3

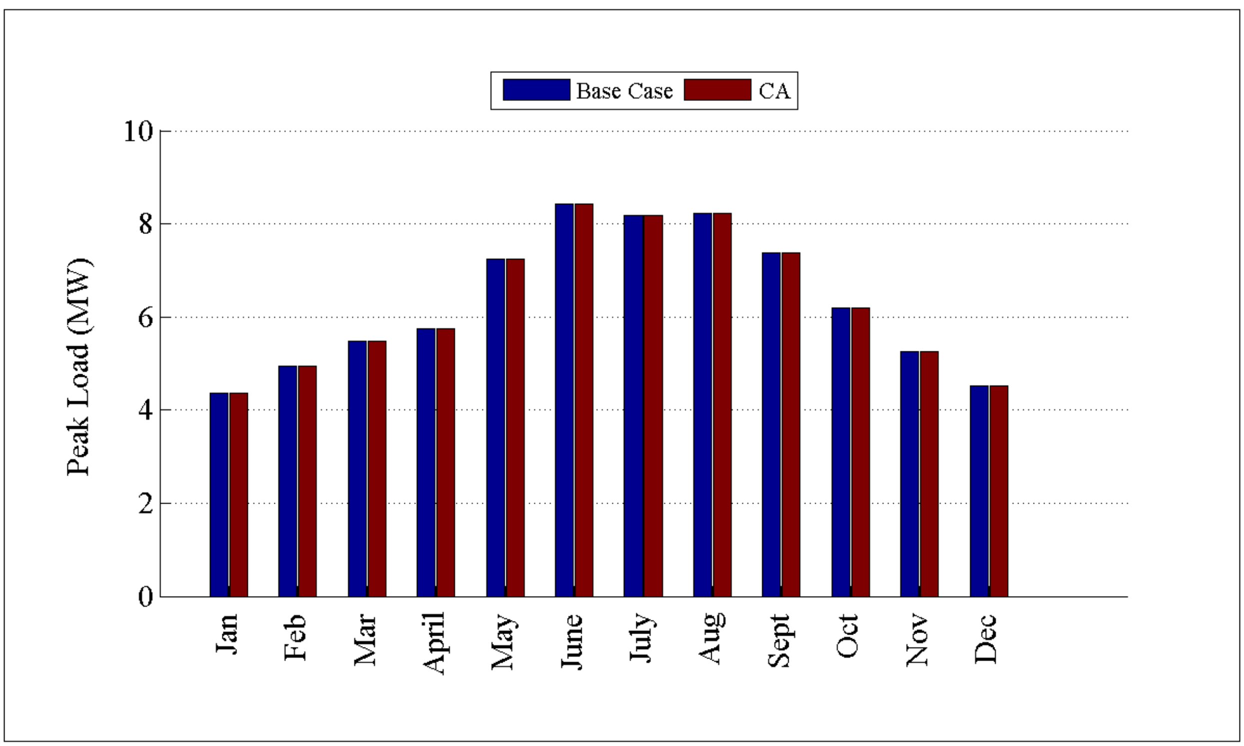


Figure D.170: Comparison of peak load by month for R3-12.47-3

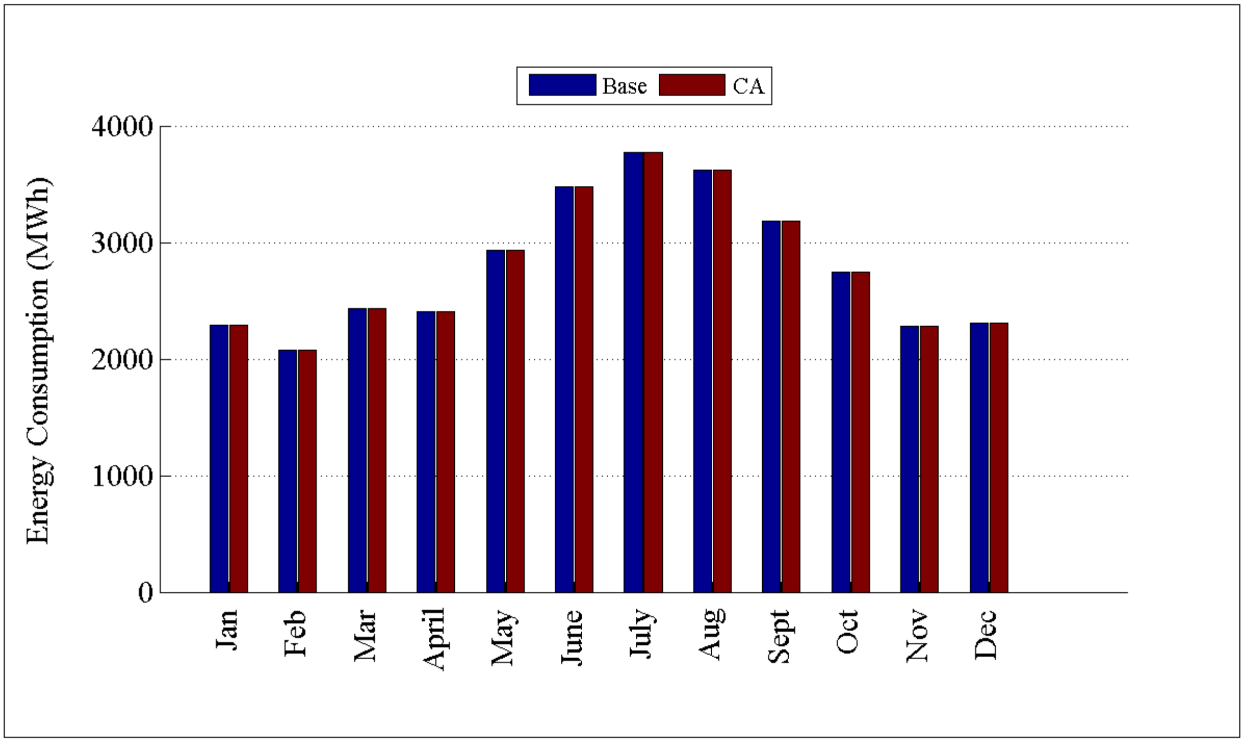



Figure D.171: Comparison of energy consumption by month for R3-12.47-3

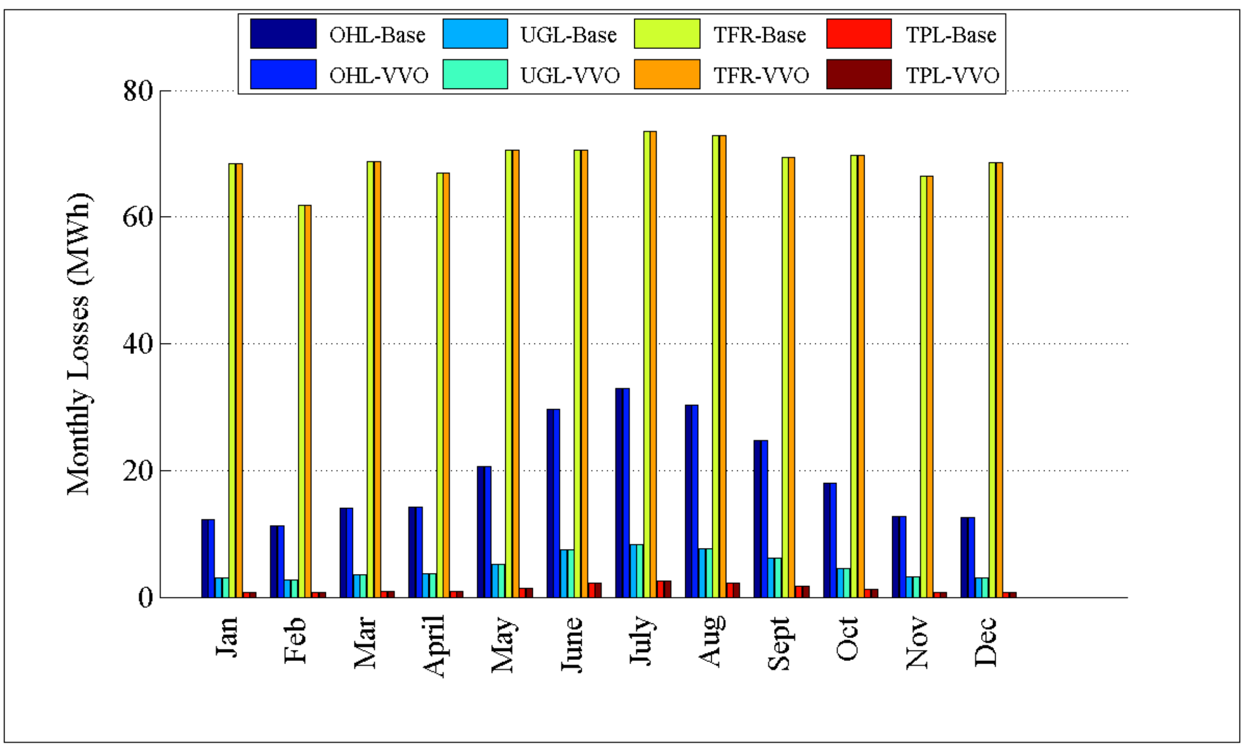


Figure D.172: Comparison of losses by month for R3-12.47-3

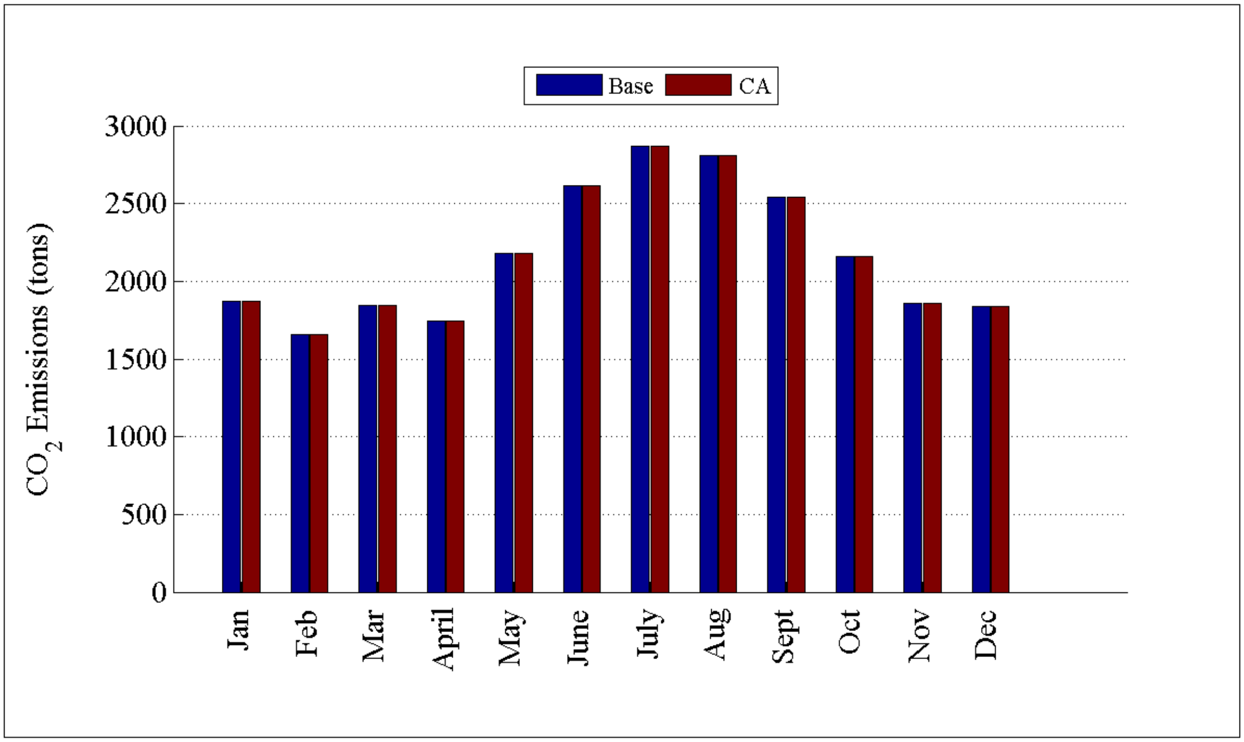



Figure D.173: Comparison of $CO_2$ emissions by month for R3-12.47-3

### D.2.17 Detailed CA Plots for GC-12.47-1_R4

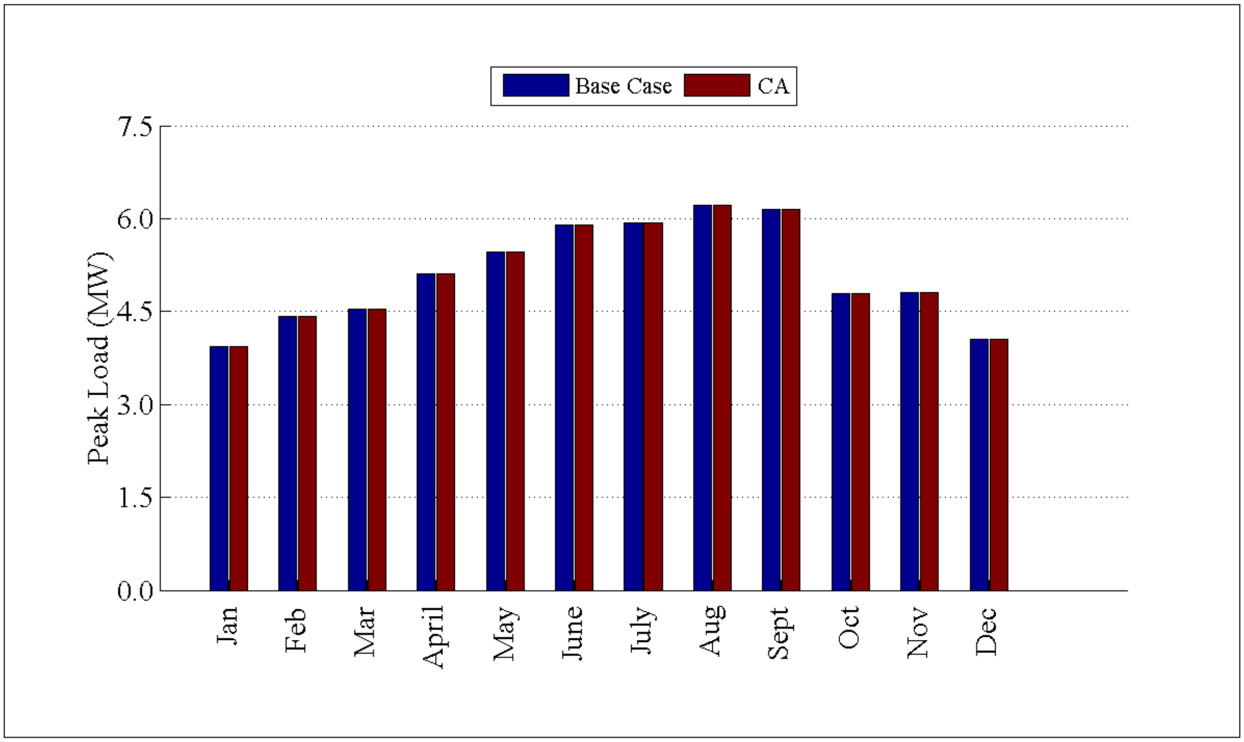



Figure D.174: Comparison of peak load by month for GC-12.47-1_R4

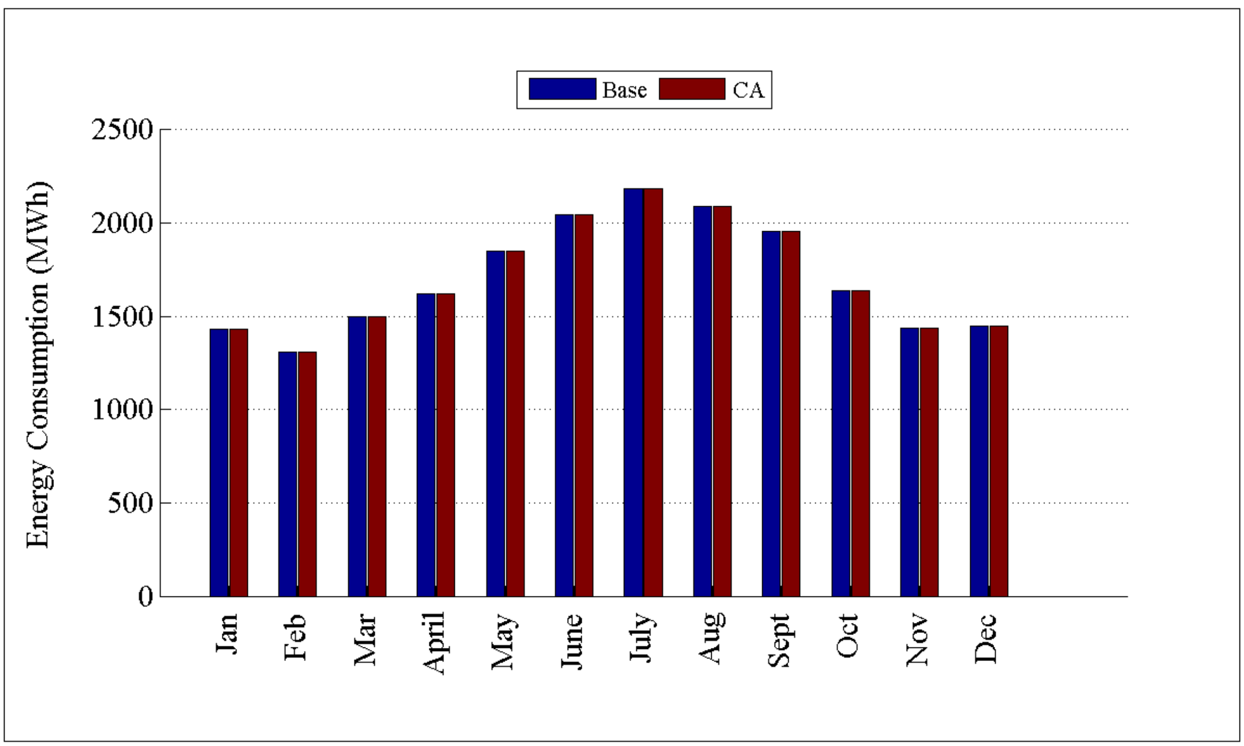



Figure D.175: Comparison of energy consumption by month for GC-12.47-1_R4

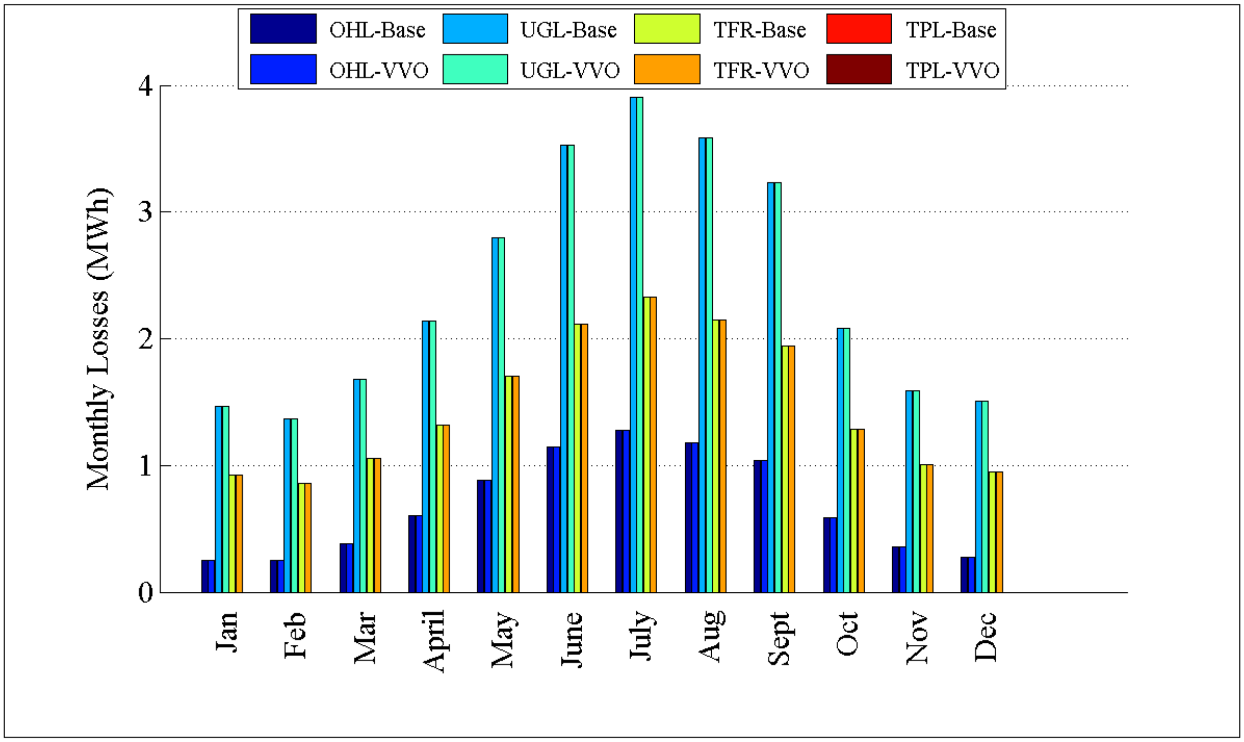



Figure D.176: Comparison of losses by month for GC-12.47-1_R4

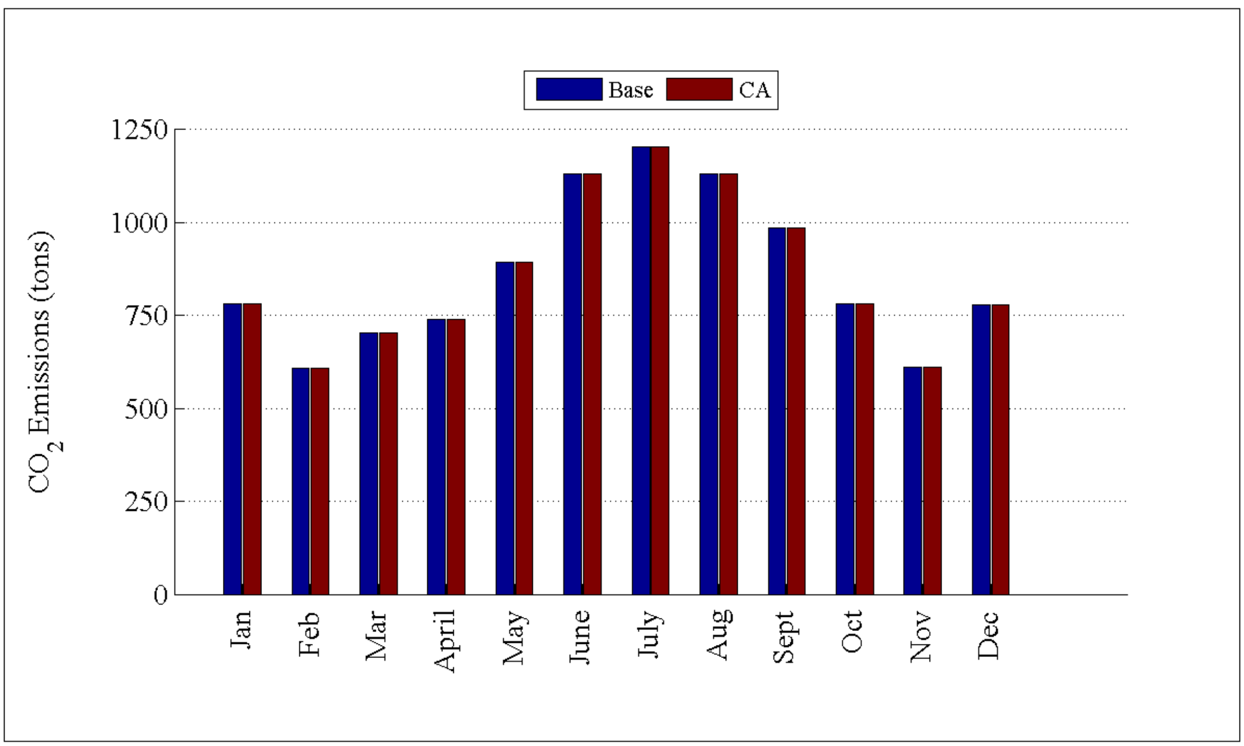



Figure D.177: Comparison of $CO_2$ emissions by month for GC-12.47-1_R4

## D.2.18 Detailed CA Plots for R4-12.47-1

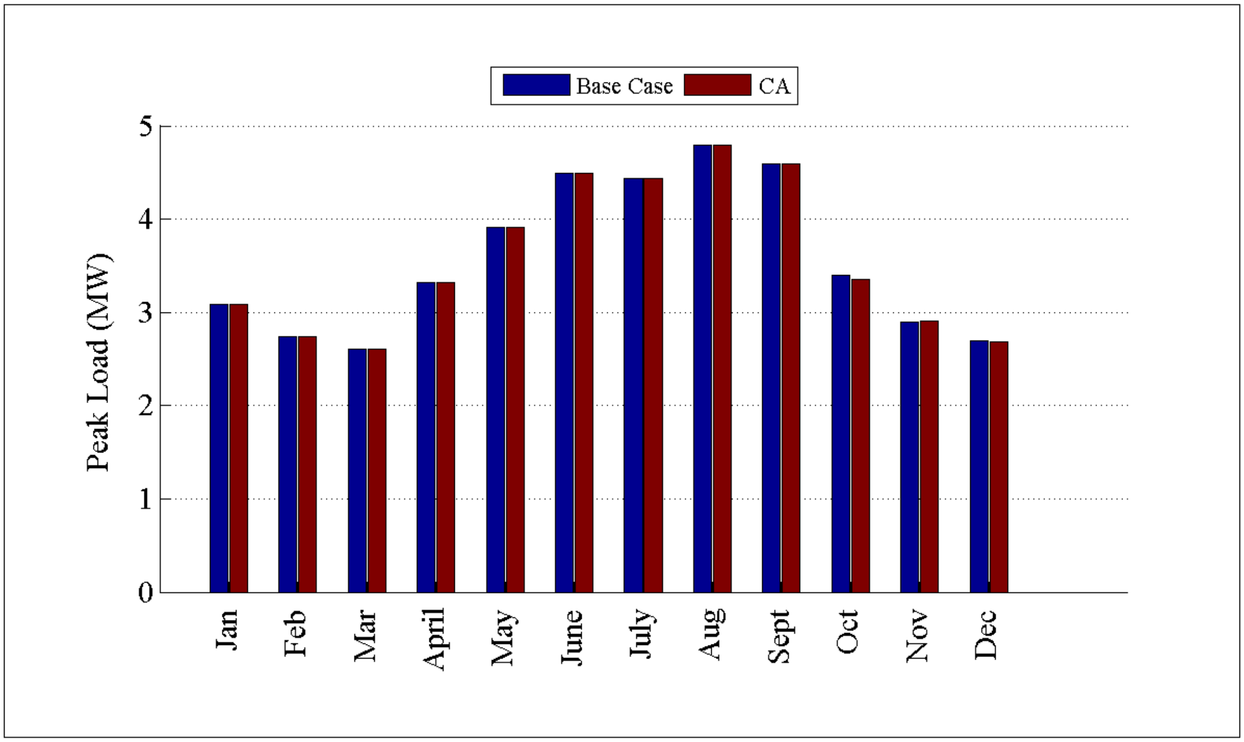



Figure D.178: Comparison of peak load by month for R4-12.47-1

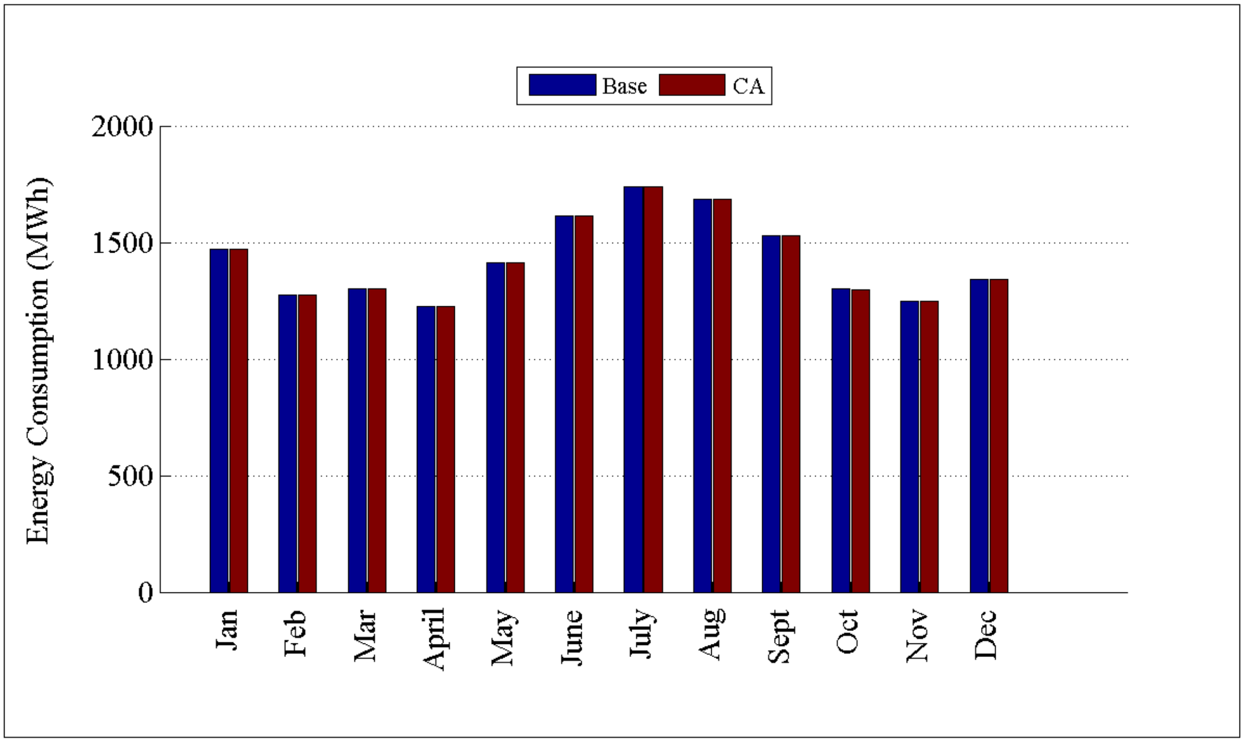



Figure D.179: Comparison of energy consumption by month for R4-12.47-1

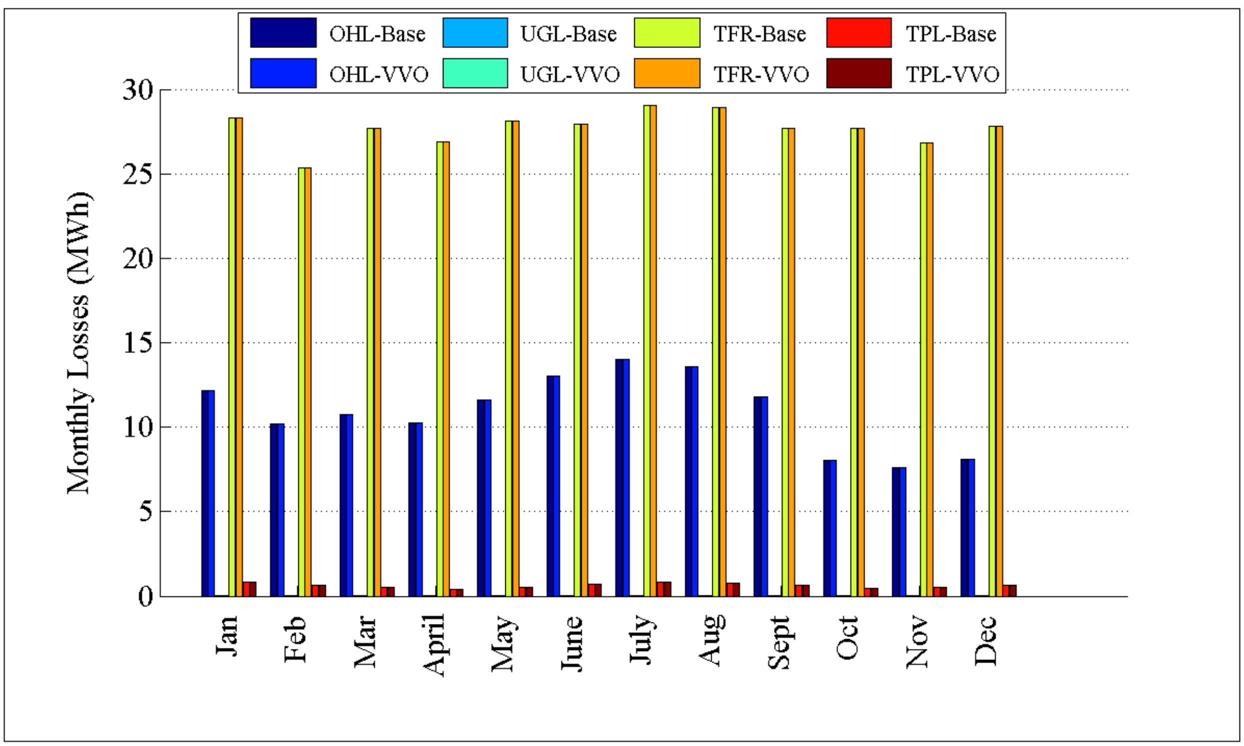



Figure D.180: Comparison of losses by month for R4-12.47-1

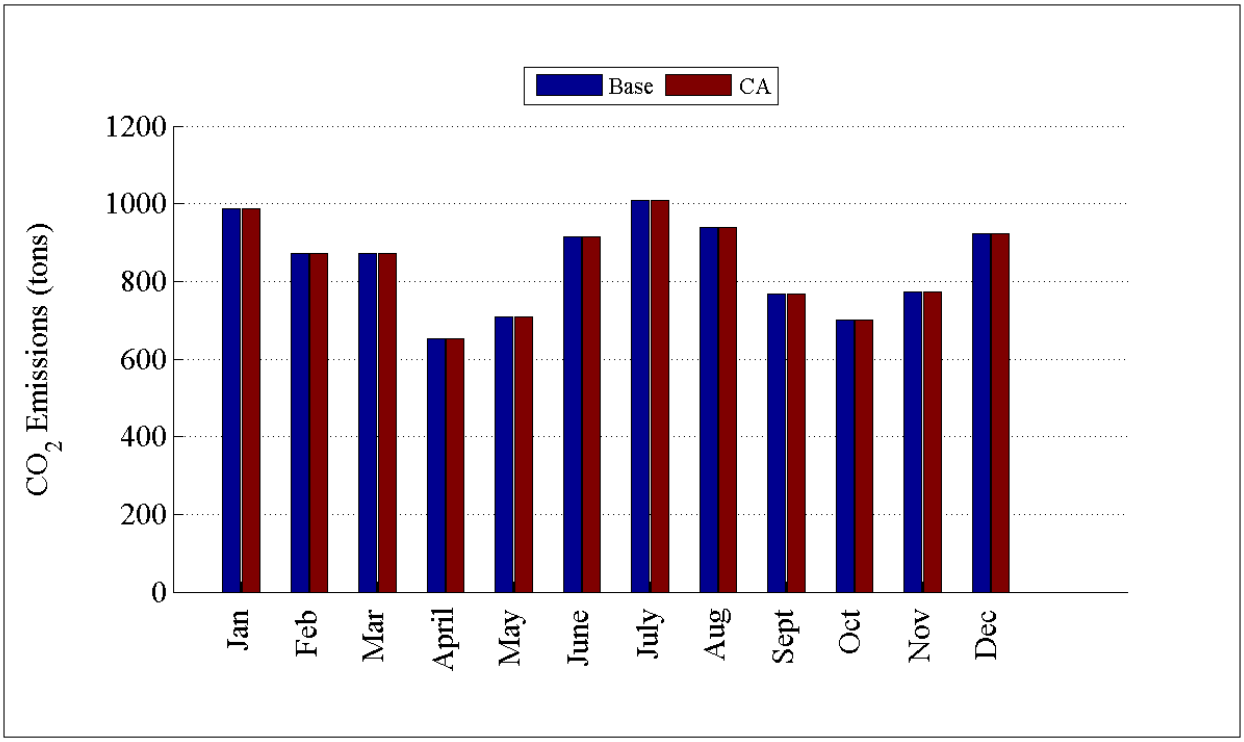



Figure D.181: Comparison of $CO_2$ emissions by month for R4-12.47-1

### D.2.19 Detailed CA Plots for R4-12.47-2

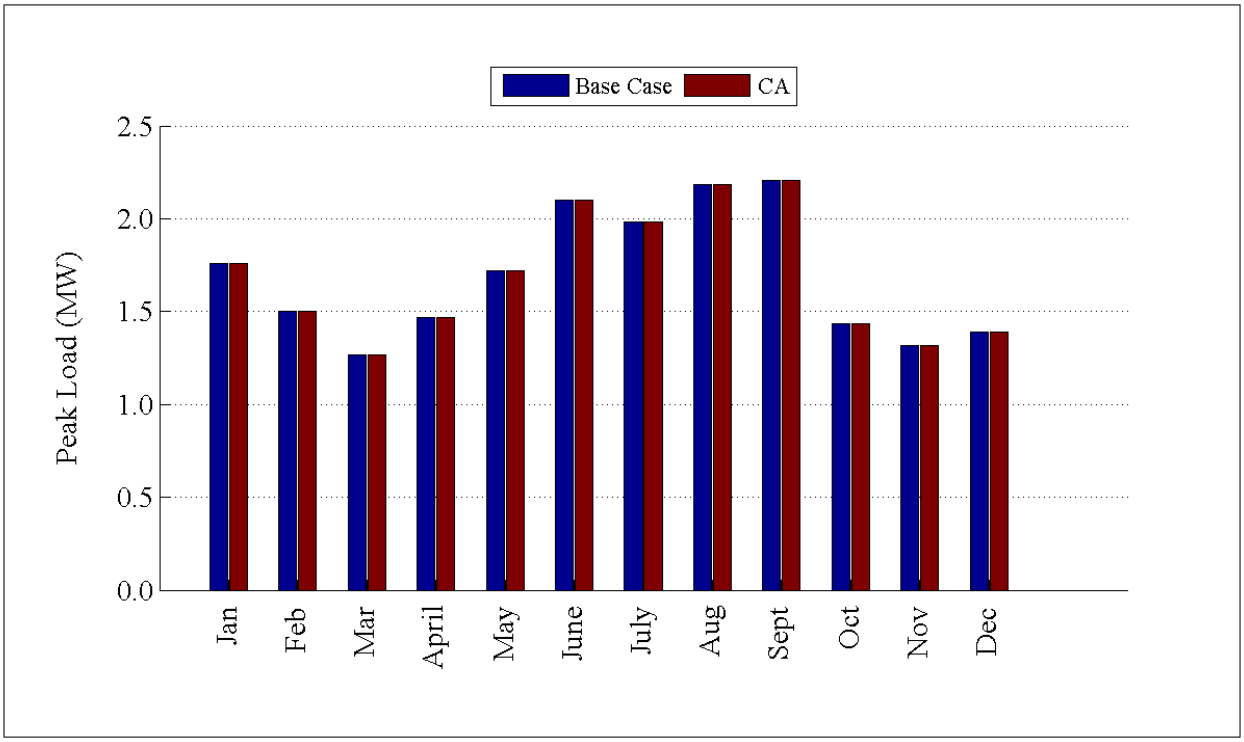



Figure D.182: Comparison of peak load by month for R4-12.47-2

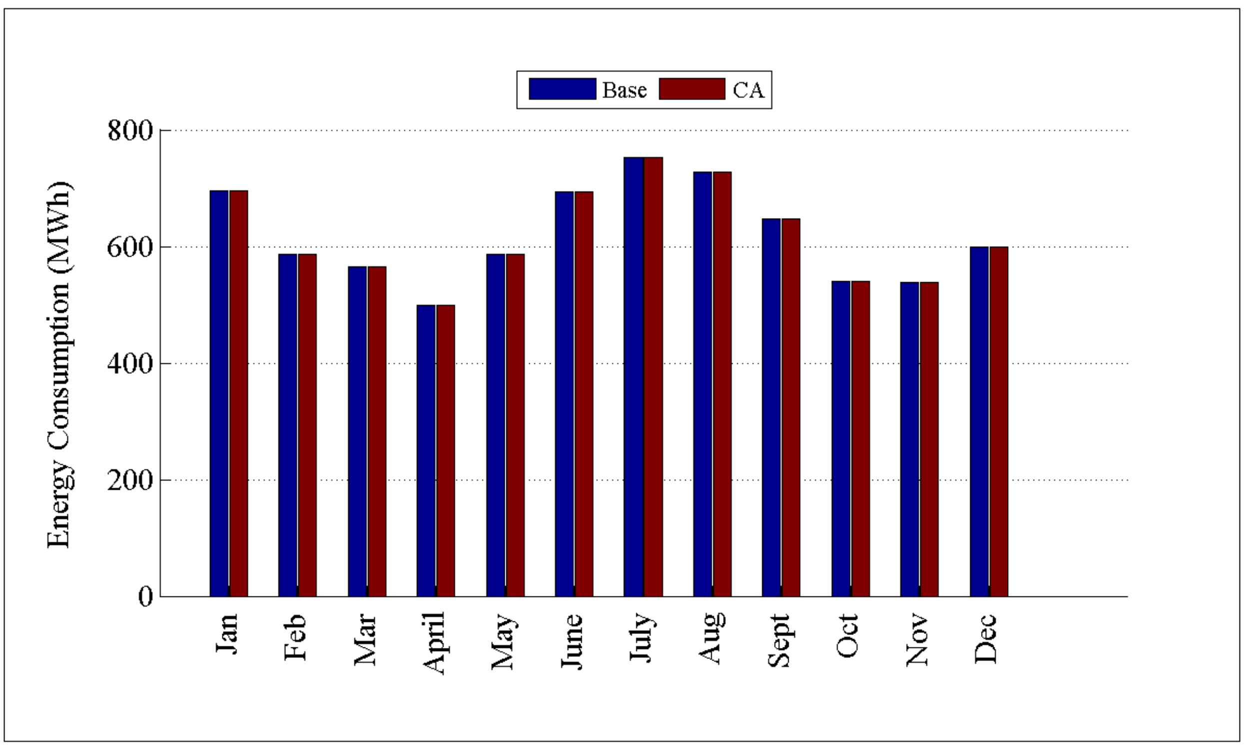



Figure D.183: Comparison of energy consumption by month for R4-12.47-2

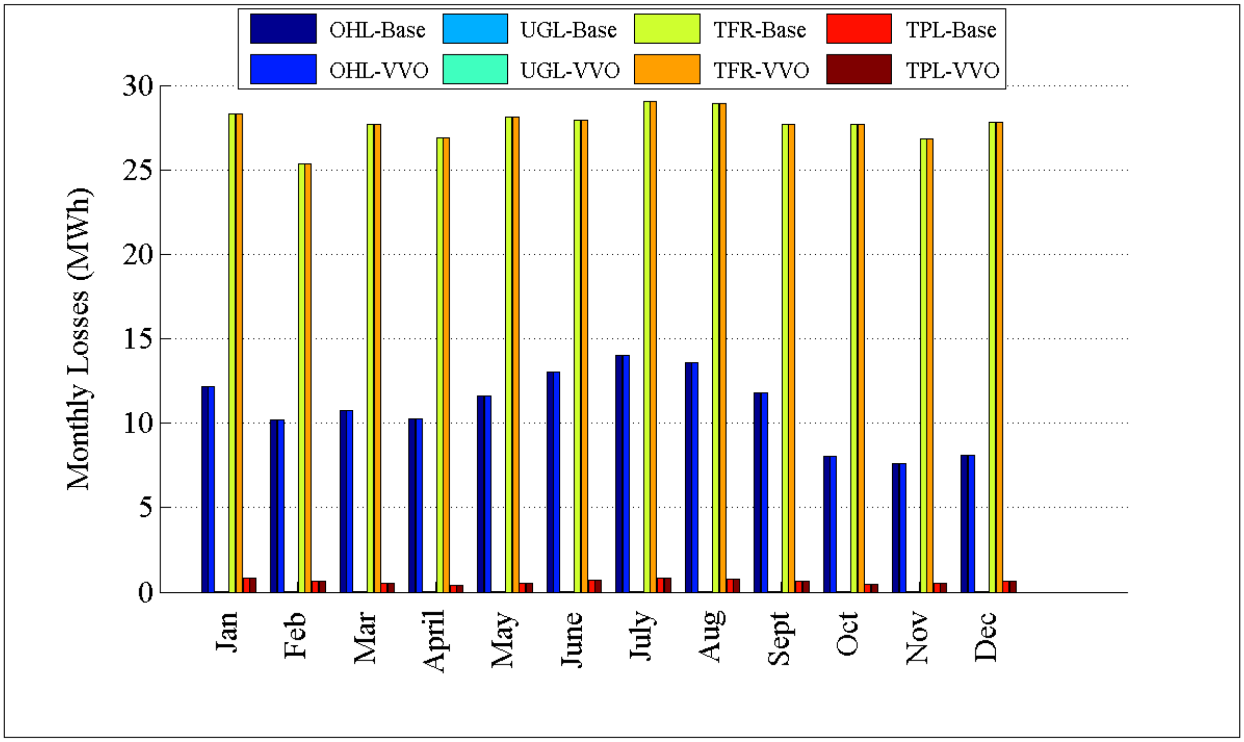



Figure D.184: Comparison of losses by month for R4-12.47-2

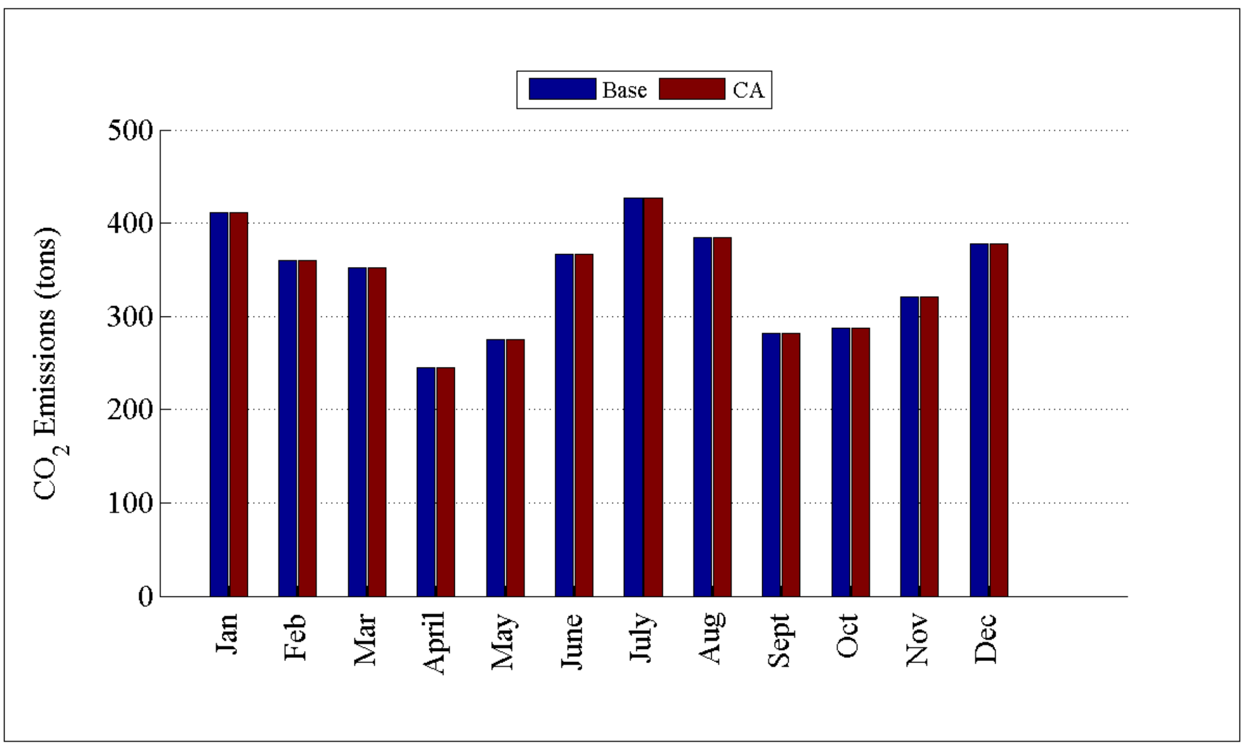



Figure D.185: Comparison of $CO_2$ emissions by month for R4-12.47-2

### D.2.20 Detailed CA Plots for R4-25.00-1

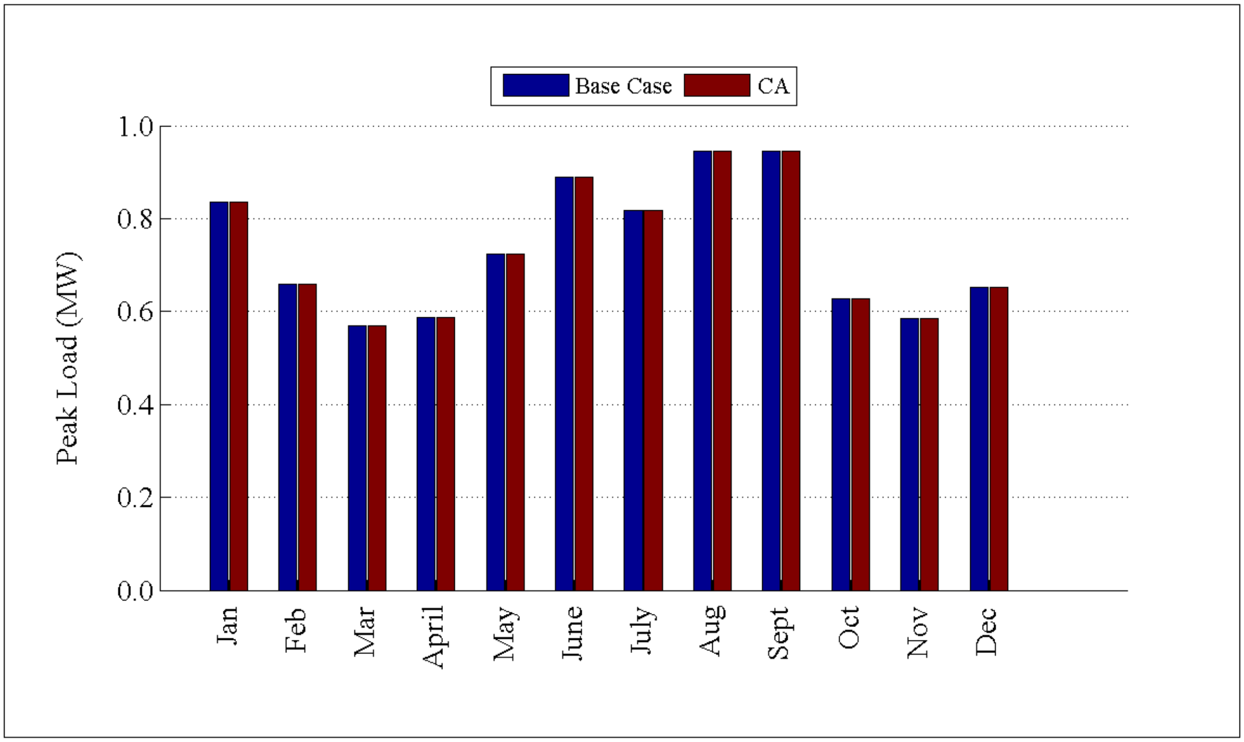



Figure D.186: Comparison of peak load by month for R4-25.00-1

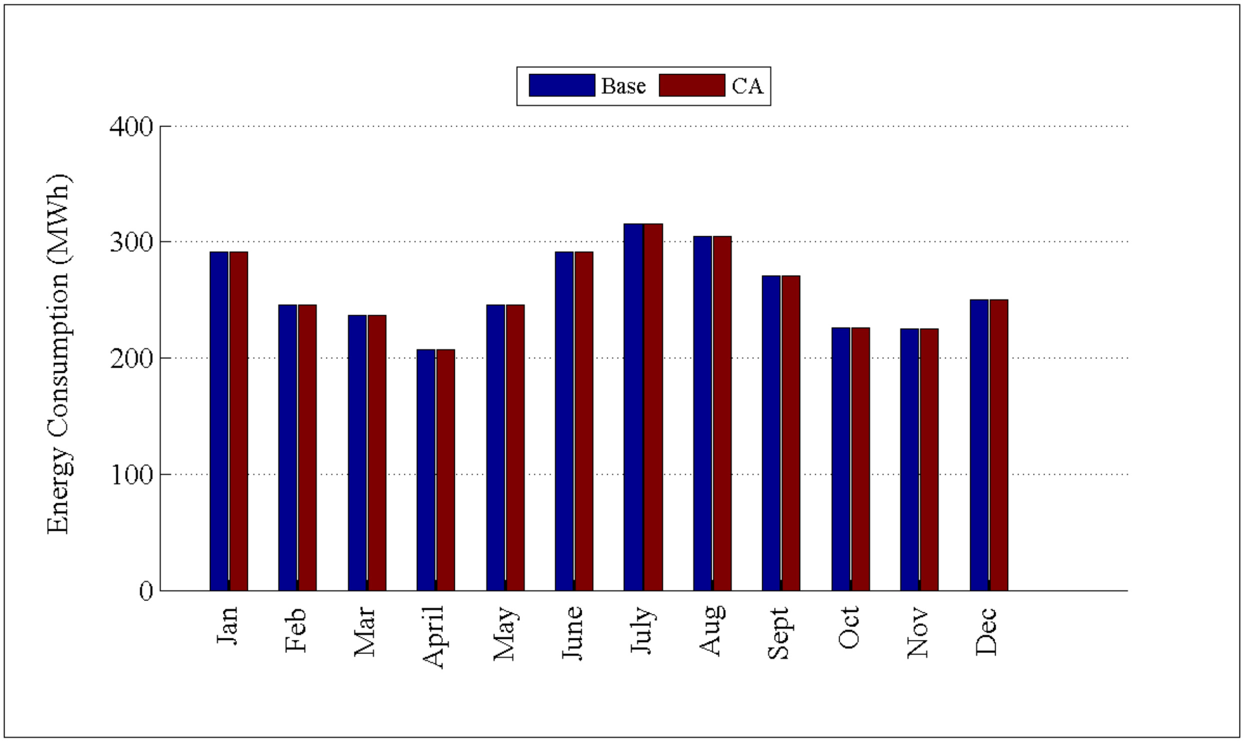



Figure D.187: Comparison of energy consumption by month for R4-25.00-1

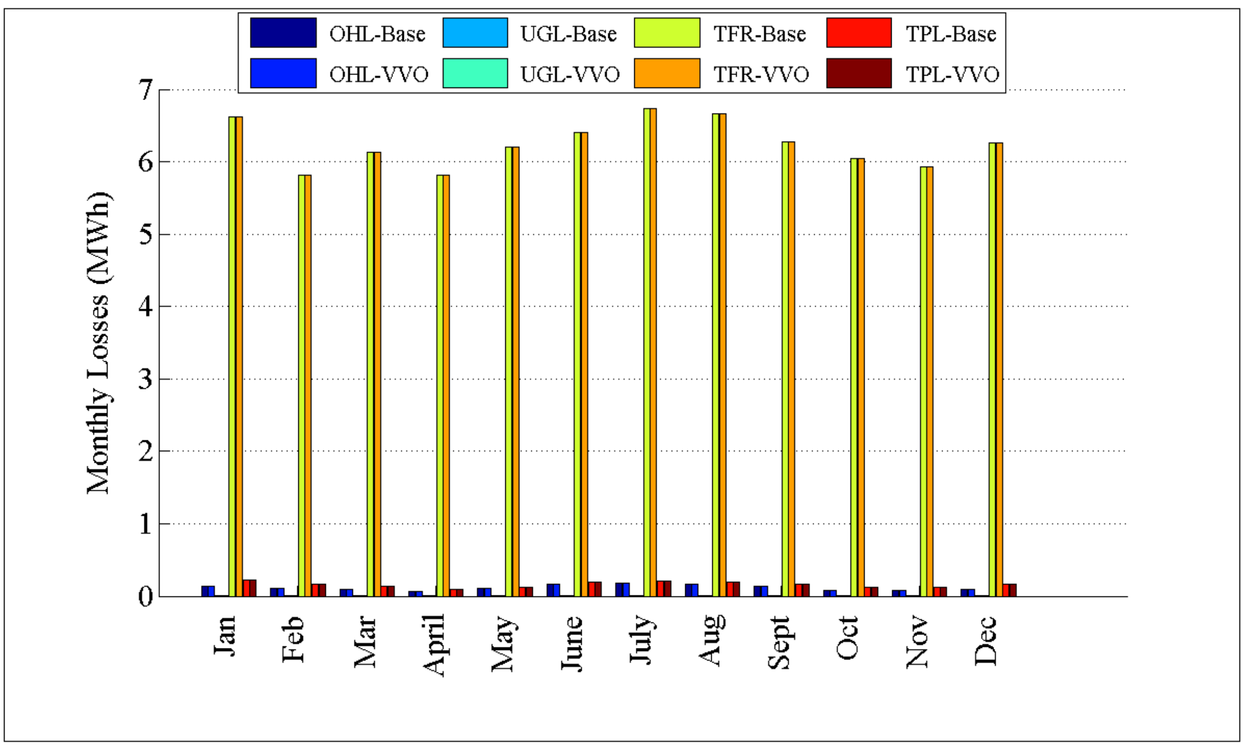



Figure D.188: Comparison of losses by month for R4-25.00-1

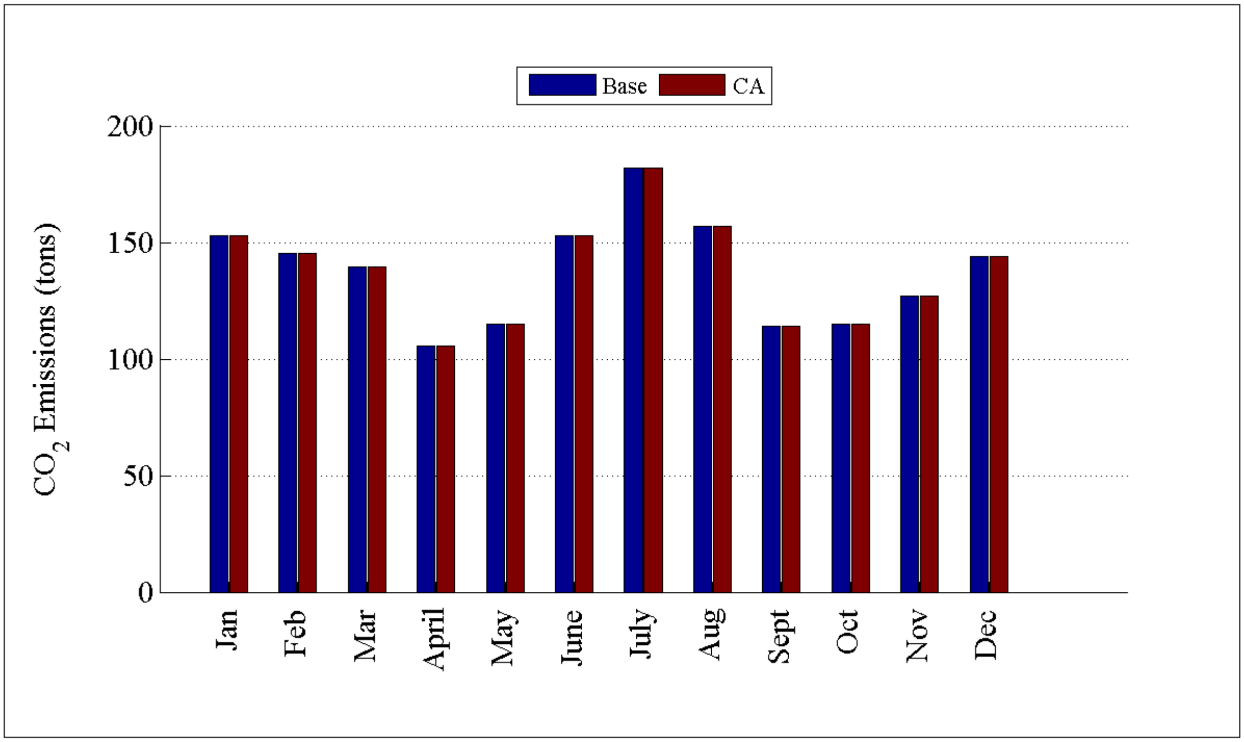



Figure D.189: Comparison of $CO_2$ emissions by month for R4-25.00-1

## D.2.21 Detailed CA Plots for GC-12.47-1_R5

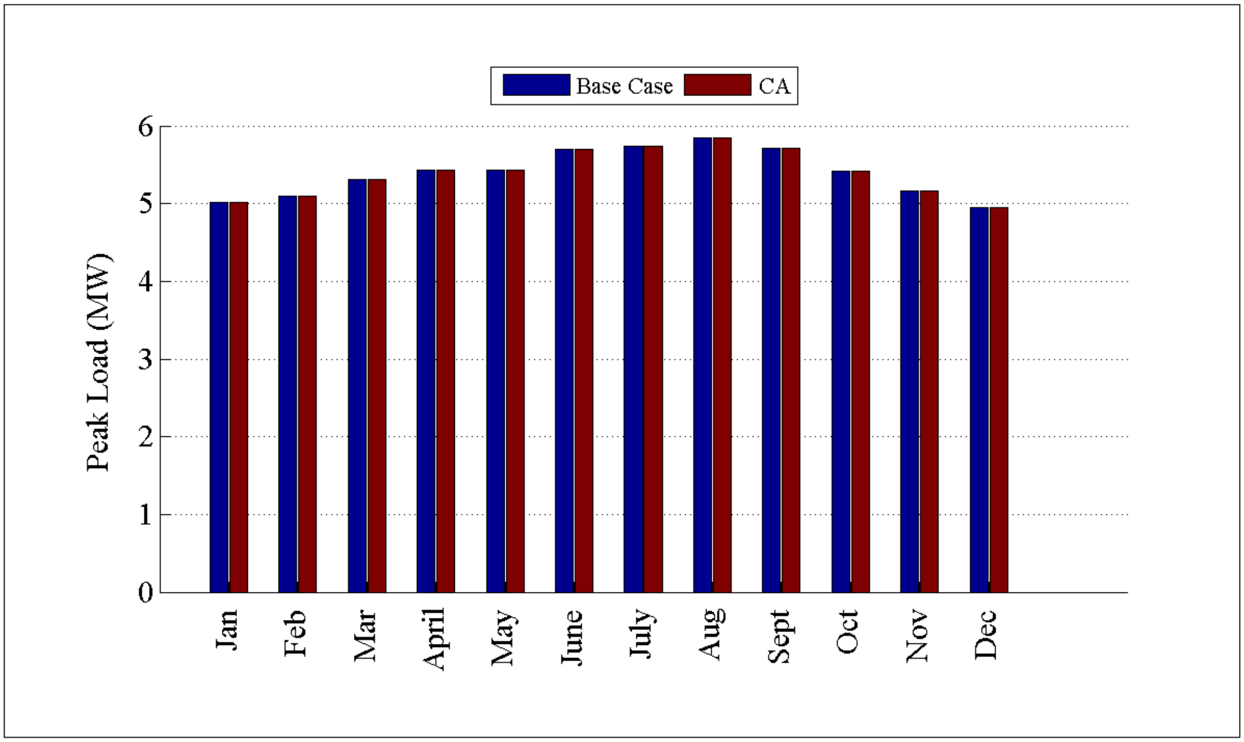



Figure D.190: Comparison of peak load by month for GC-12.47-1_R5

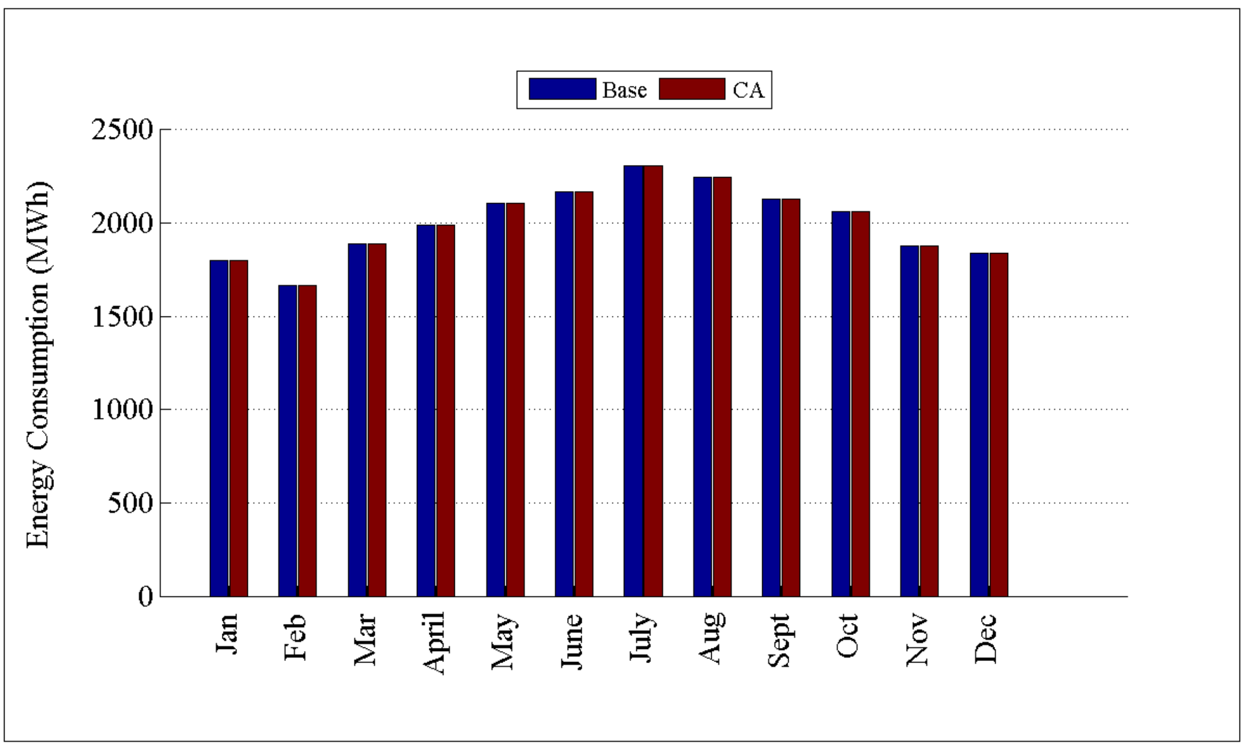



Figure D.191: Comparison of energy consumption by month for GC-12.47-1_R5

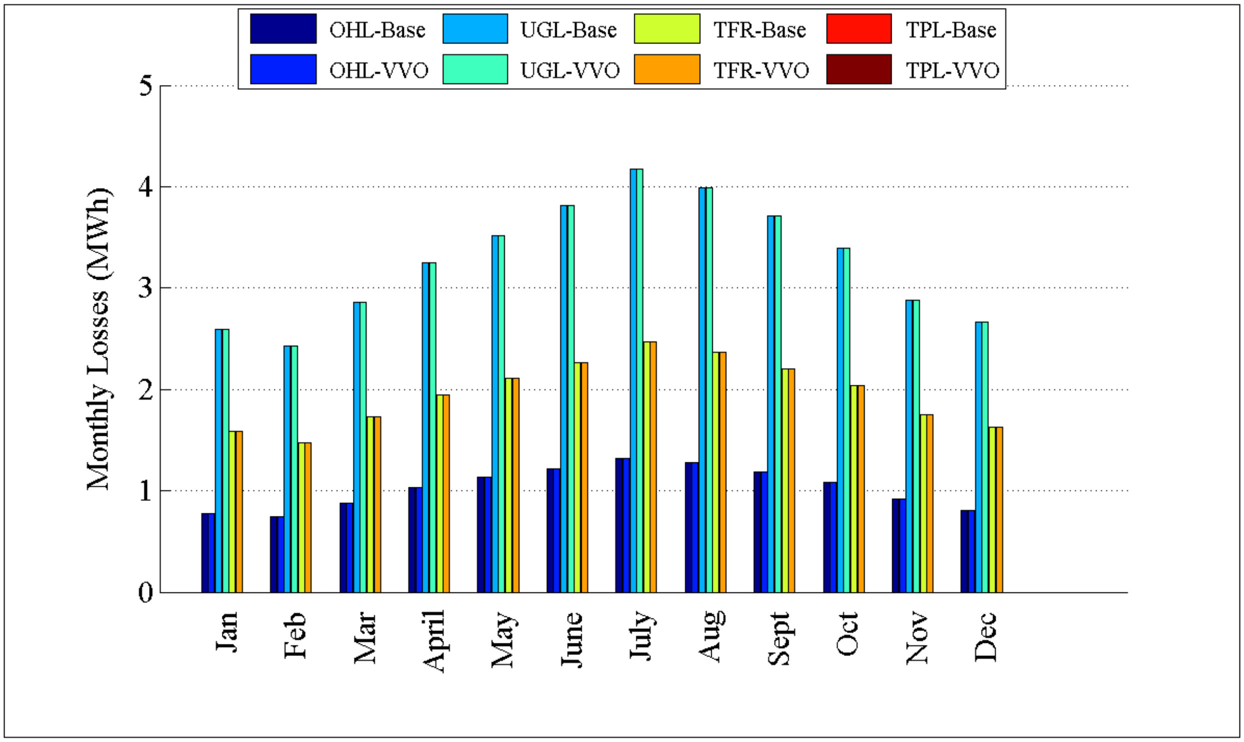



Figure D.192: Comparison of losses by month for GC-12.47-1_R5

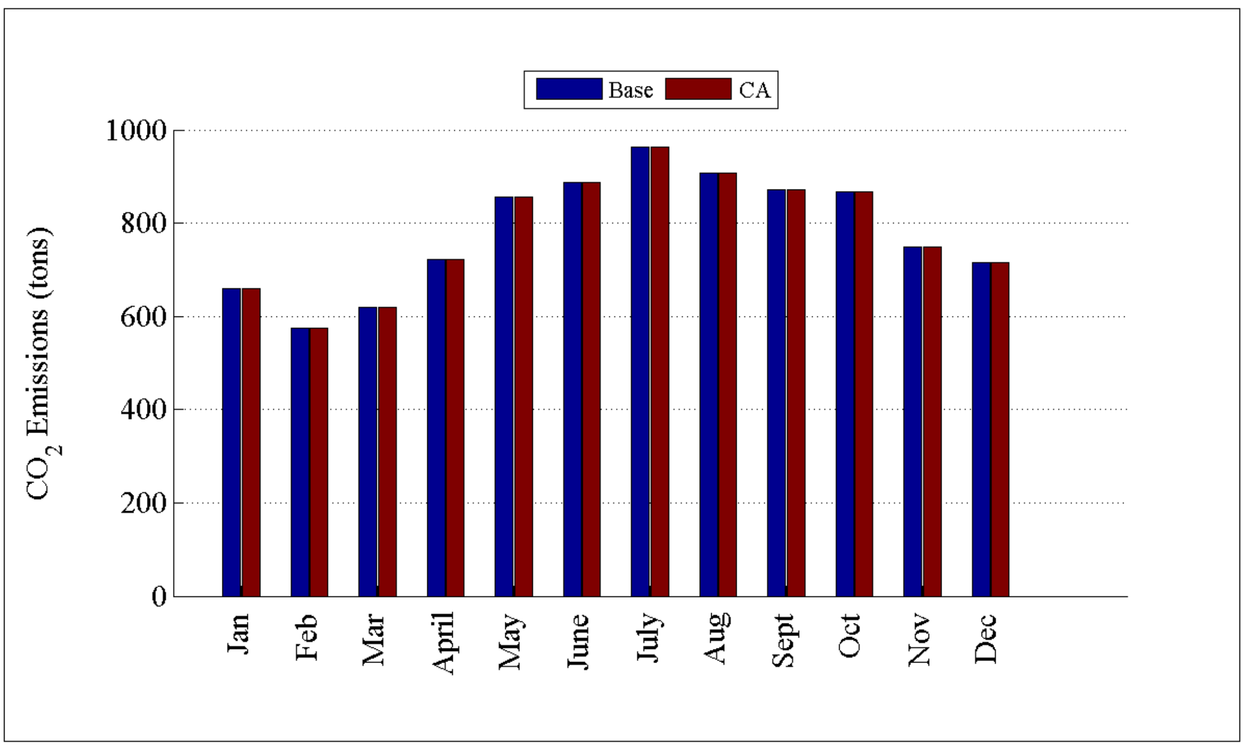



Figure D.193: Comparison of $CO_2$ emissions by month for GC-12.47-1_R5

### D.2.22 Detailed CA Plots for R5-12.47-1

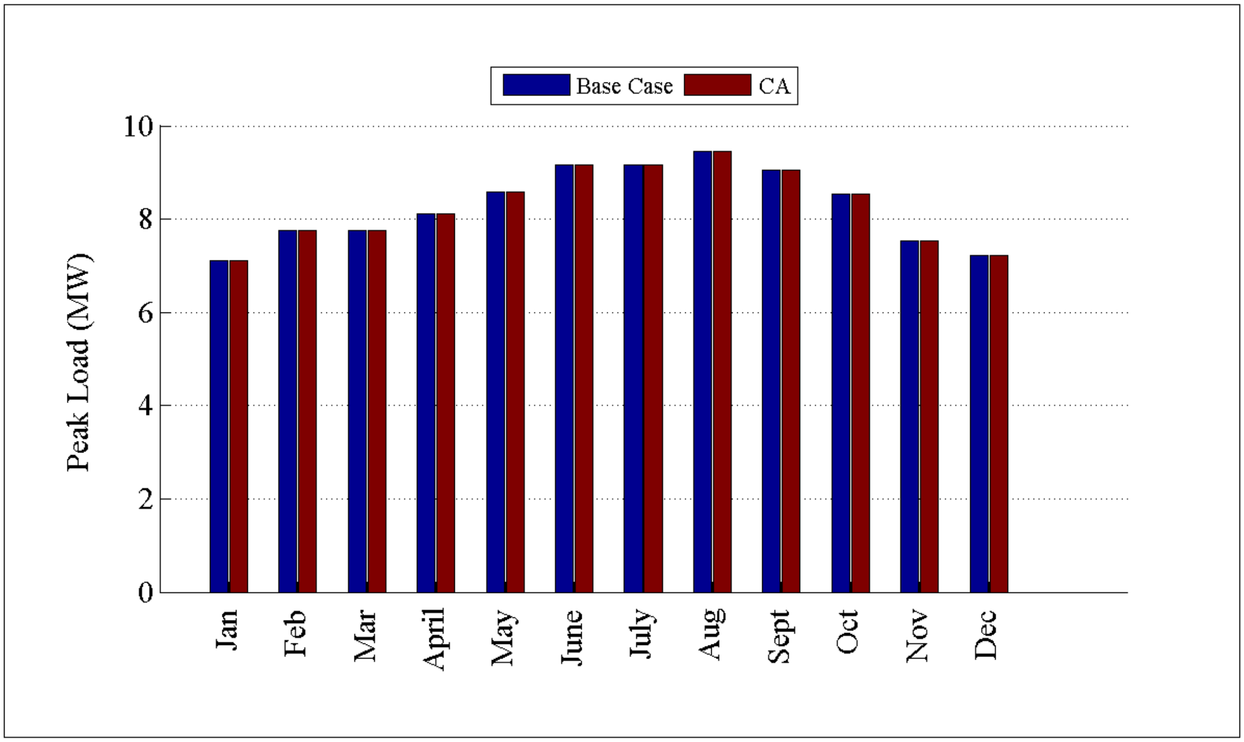



Figure D.194: Comparison of peak load by month for R5-12.47-1

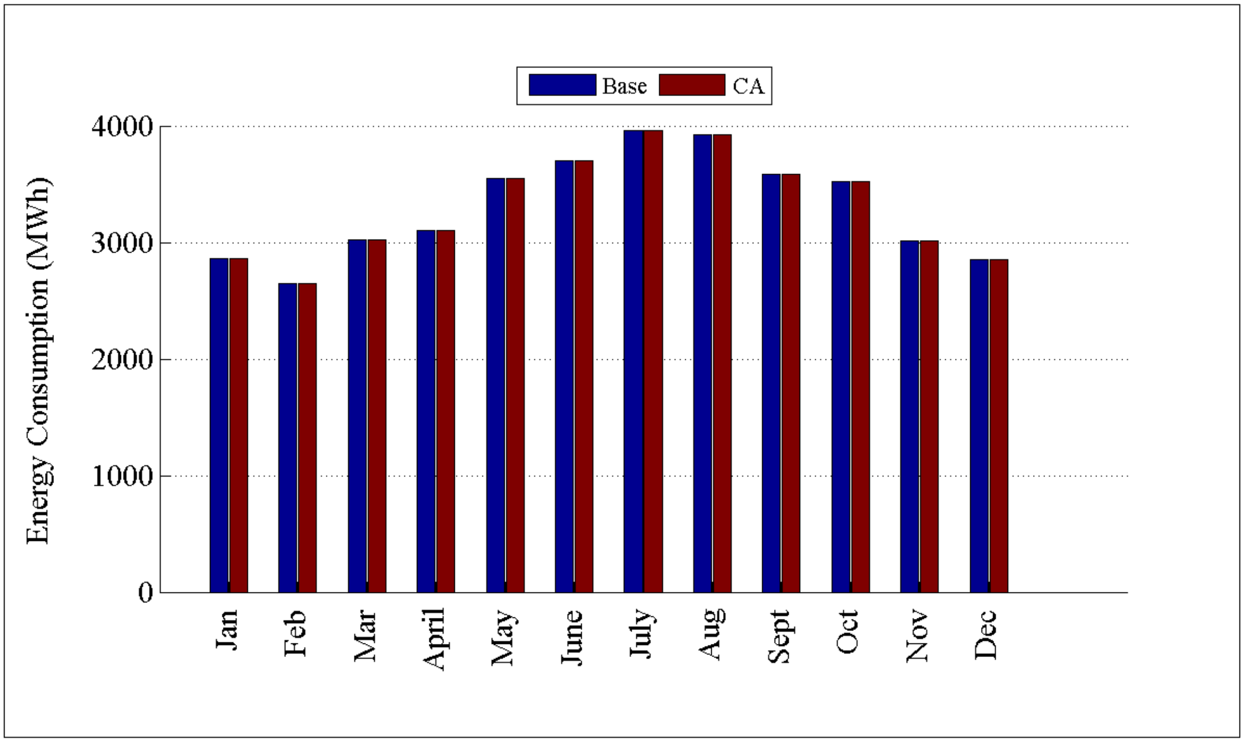



Figure D.195: Comparison of energy consumption by month for R5-12.47-1

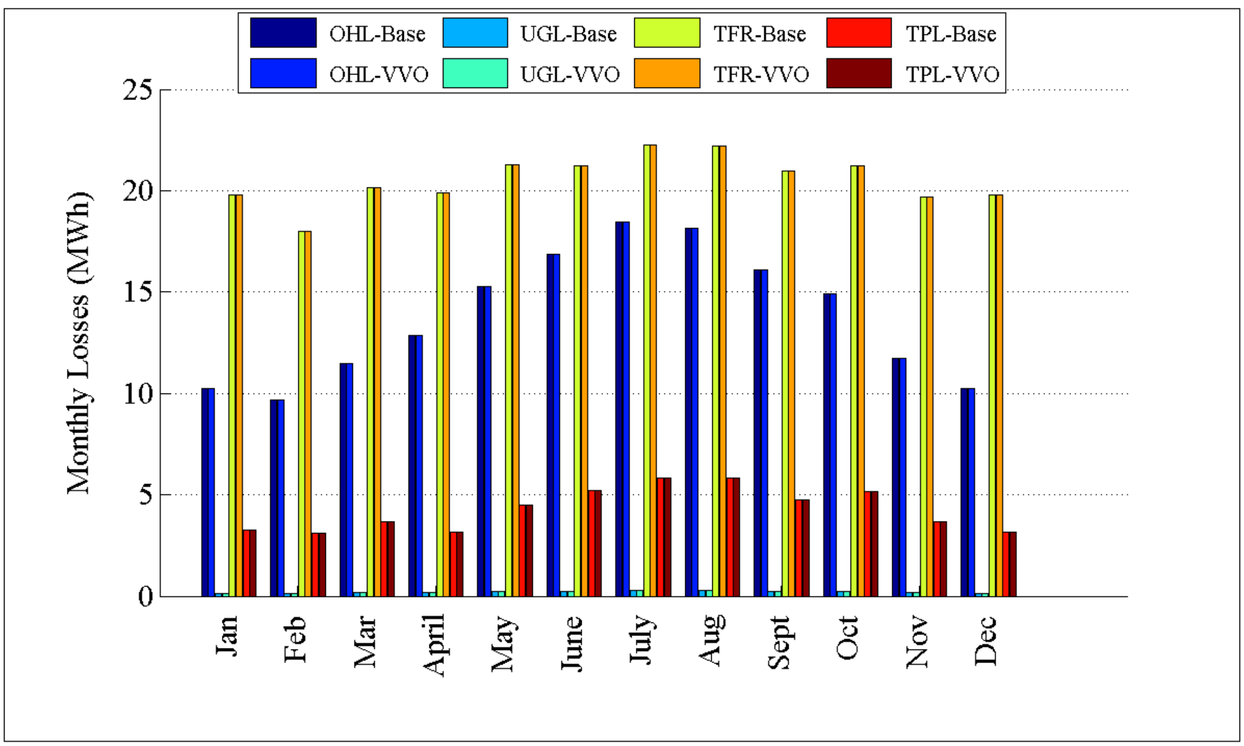



Figure D.196: Comparison of losses by month for R5-12.47-1

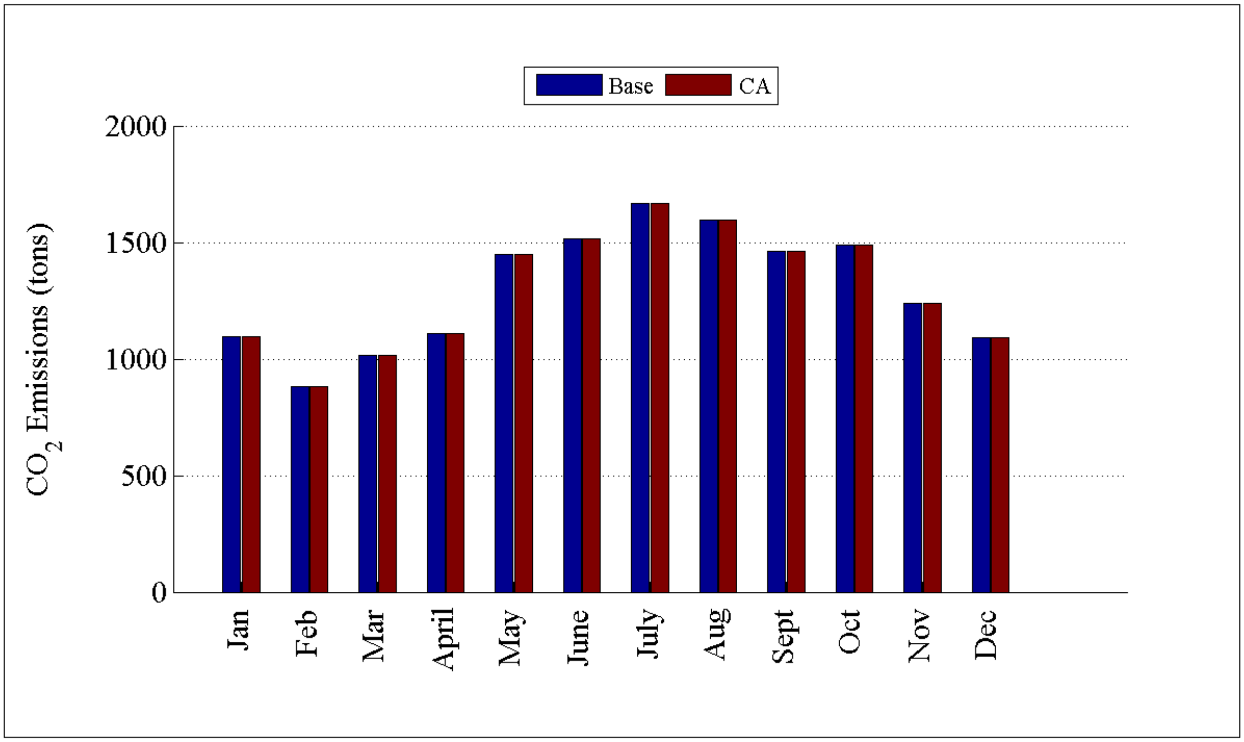



Figure D.197: Comparison of $CO_2$ emissions by month for R5-12.47-1

### D.2.23 Detailed CA Plots for R5-12.47-2

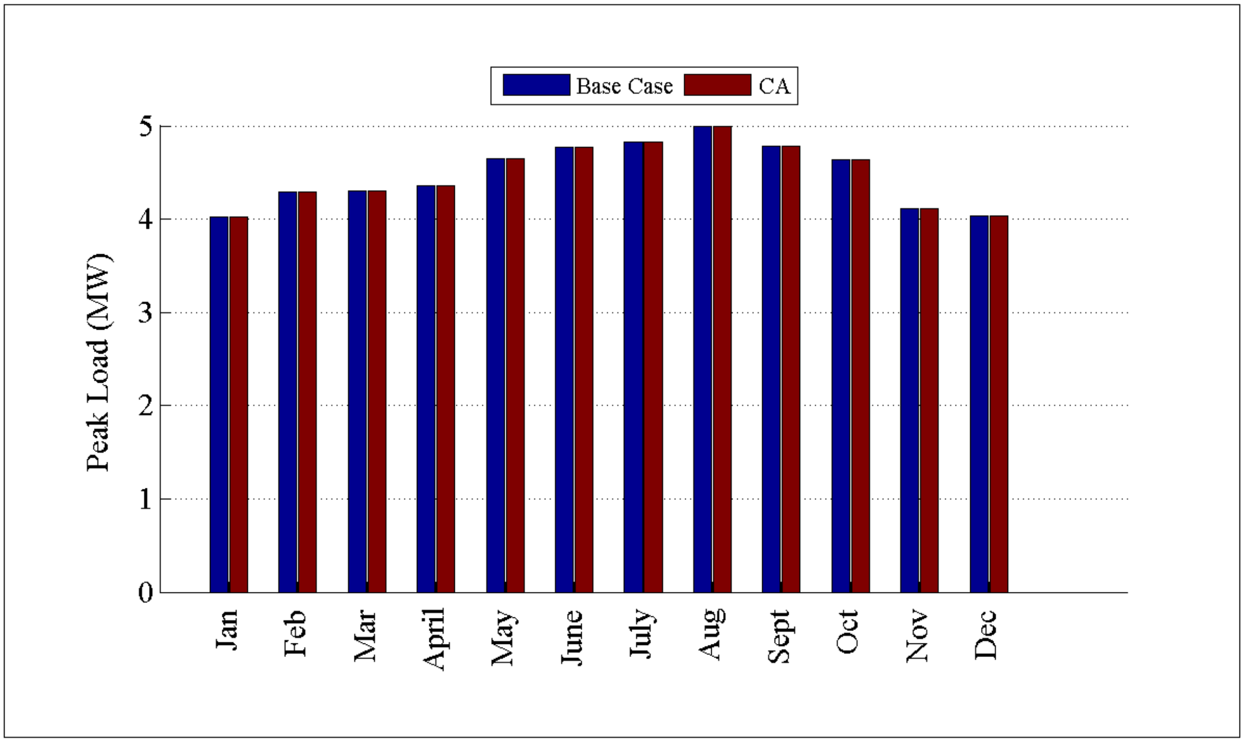



Figure D.198: Comparison of peak load by month for R5-12.47-2

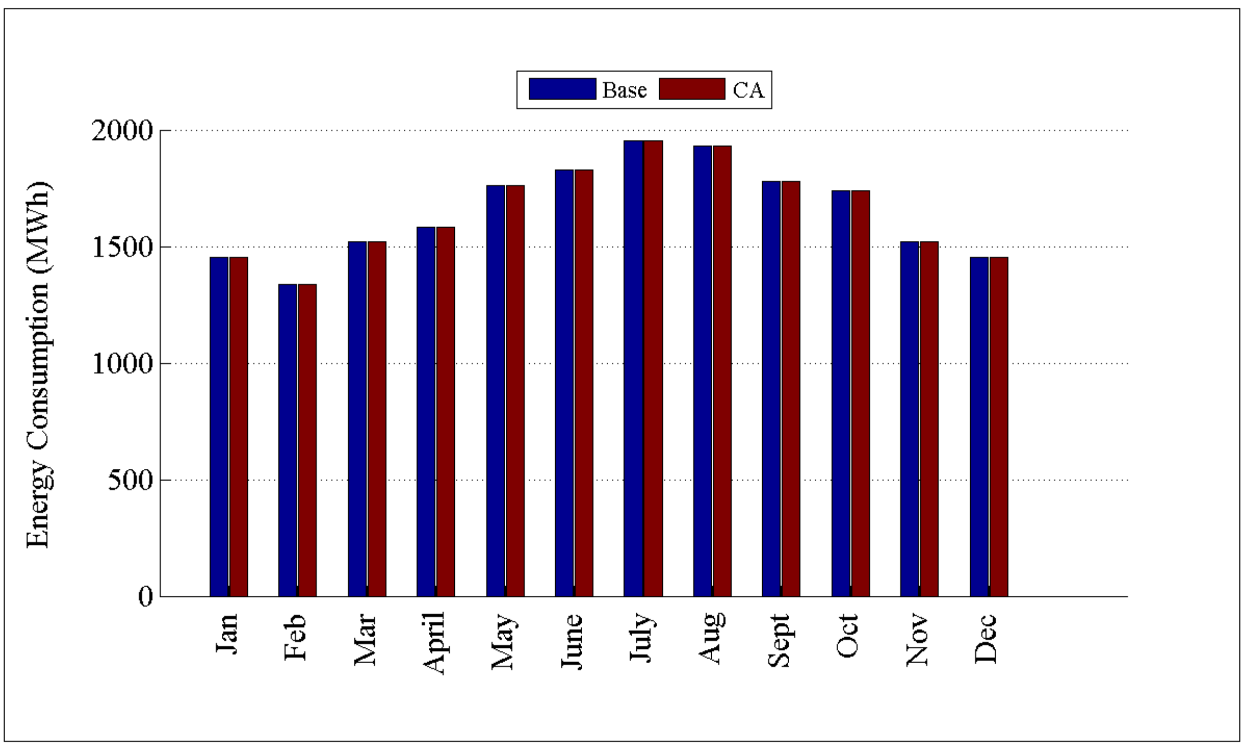



Figure D.199: Comparison of energy consumption by month for R5-12.47-2

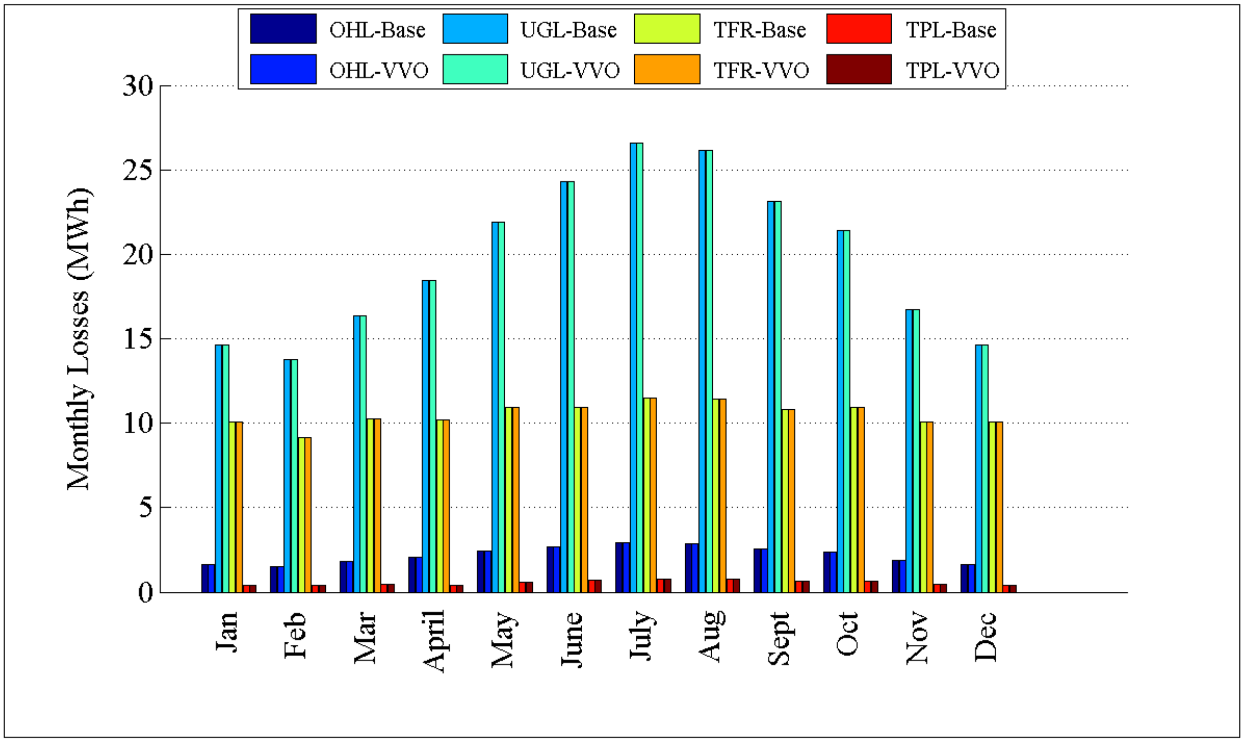



Figure D.200: Comparison of losses by month for R5-12.47-2

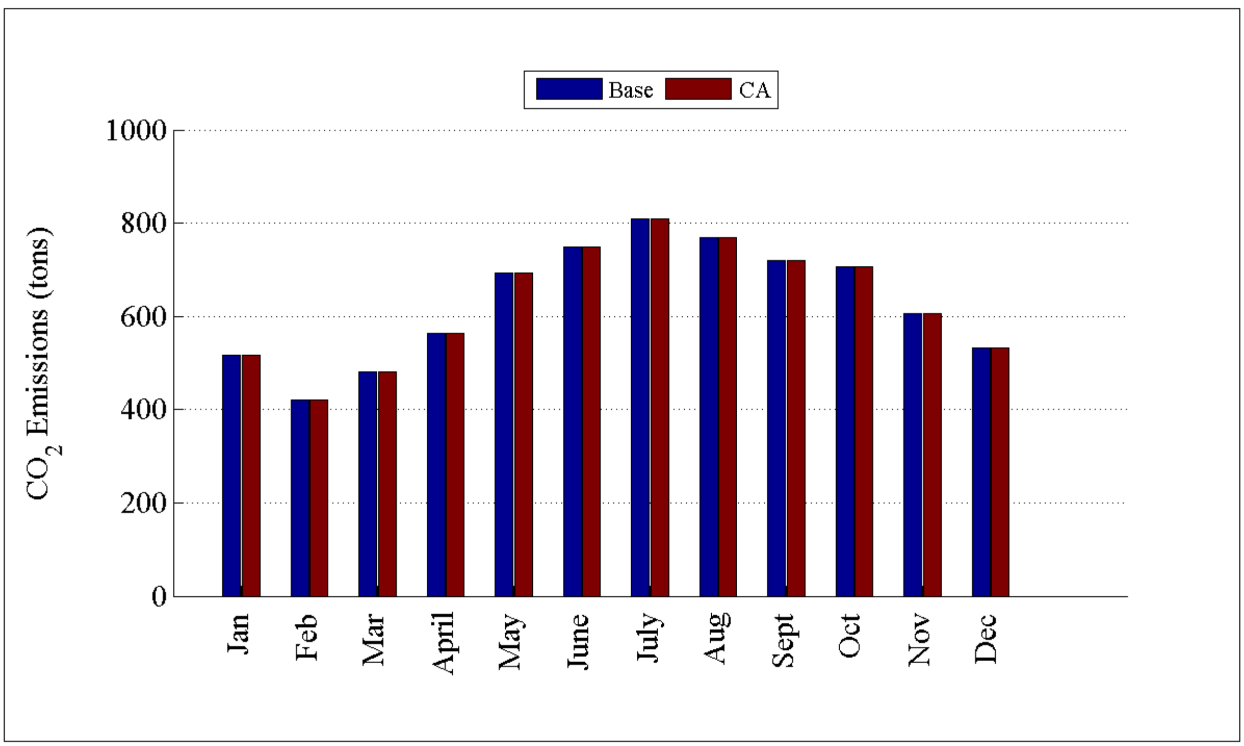



Figure D.201: Comparison of $CO_2$ emissions by month for R5-12.47-2

## D.2.24 Detailed CA Plots for R5-12.47-3

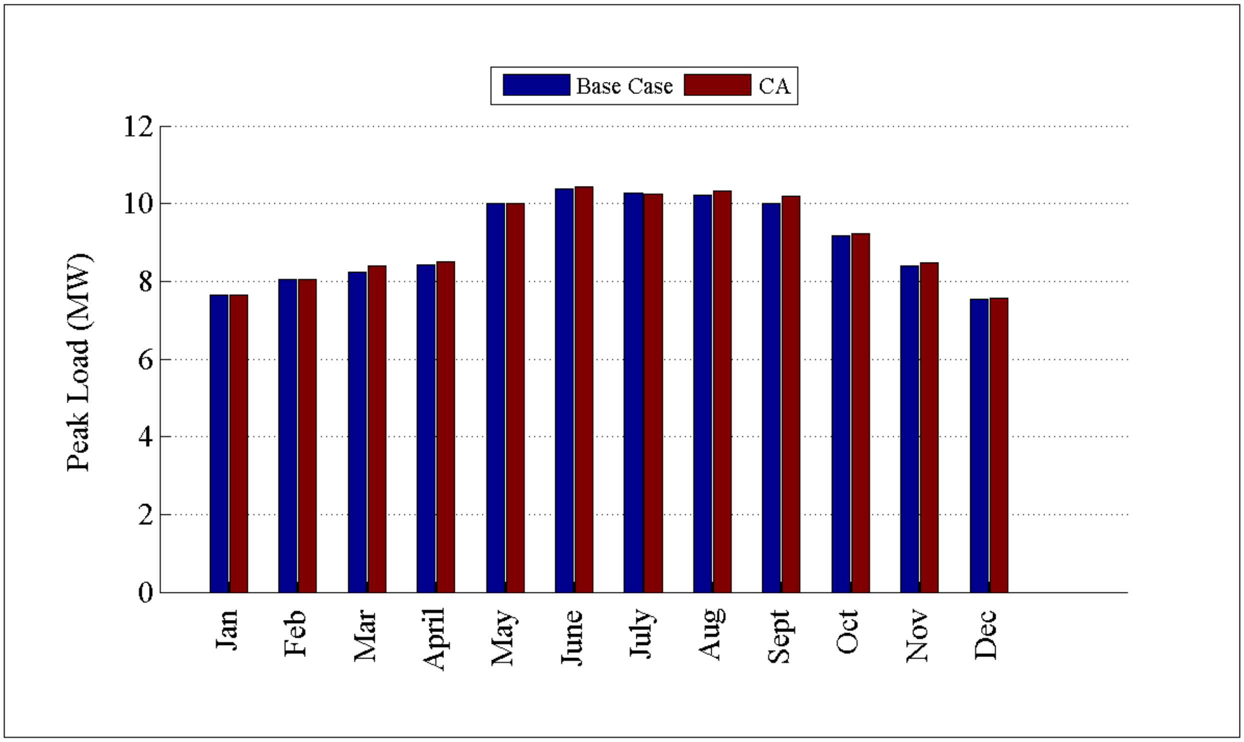



Figure D.202: Comparison of peak load by month for R5-12.47-3

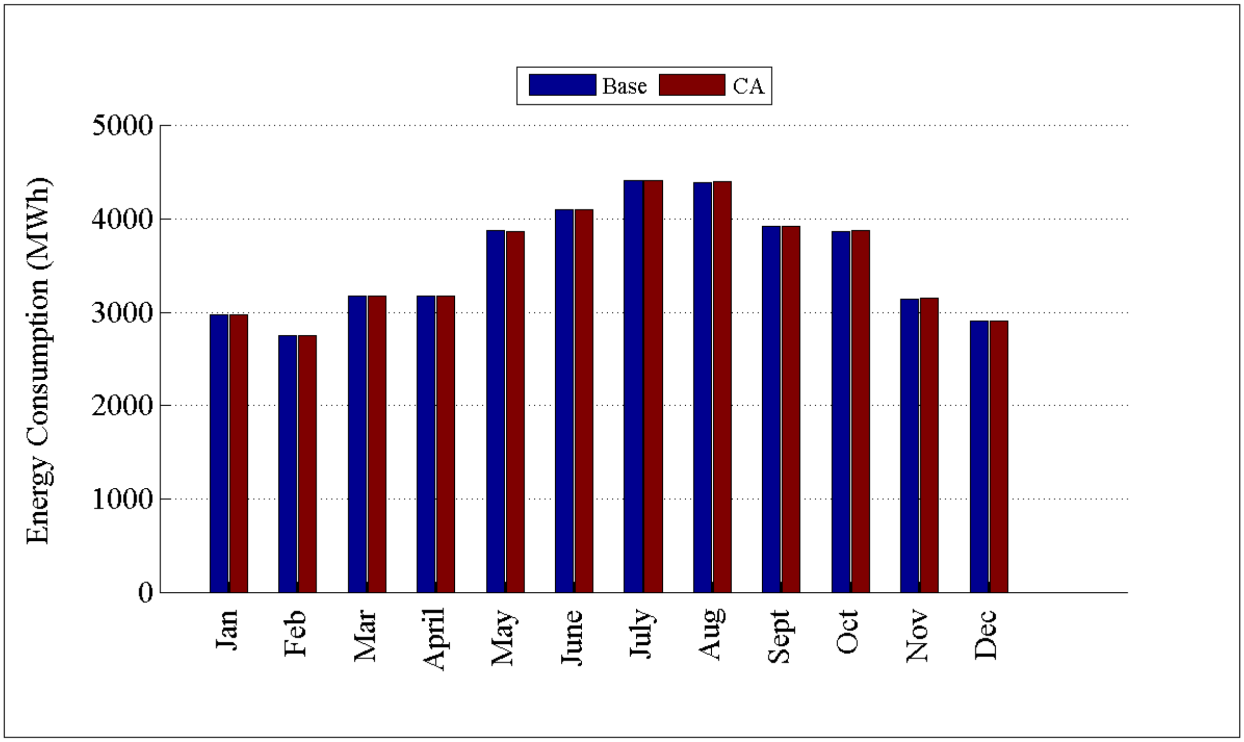



Figure D.203: Comparison of energy consumption by month for R5-12.47-3

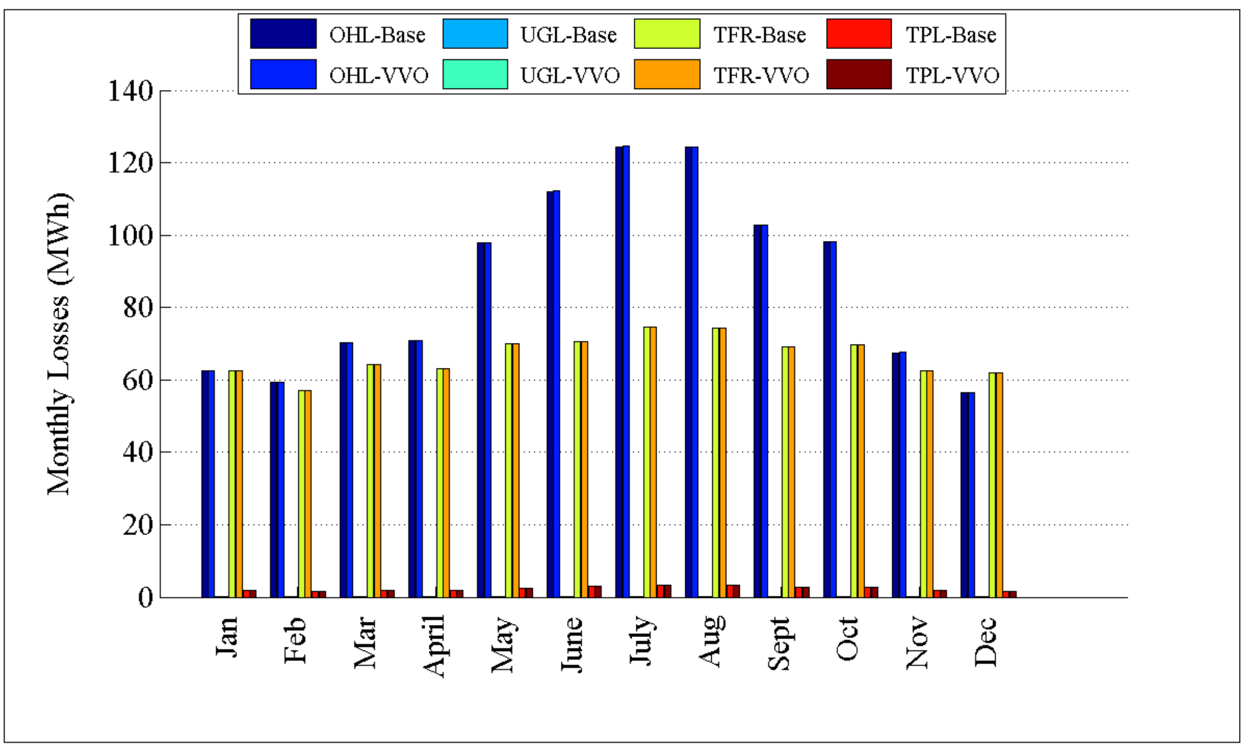



Figure D.204: Comparison of losses by month for R5-12.47-3

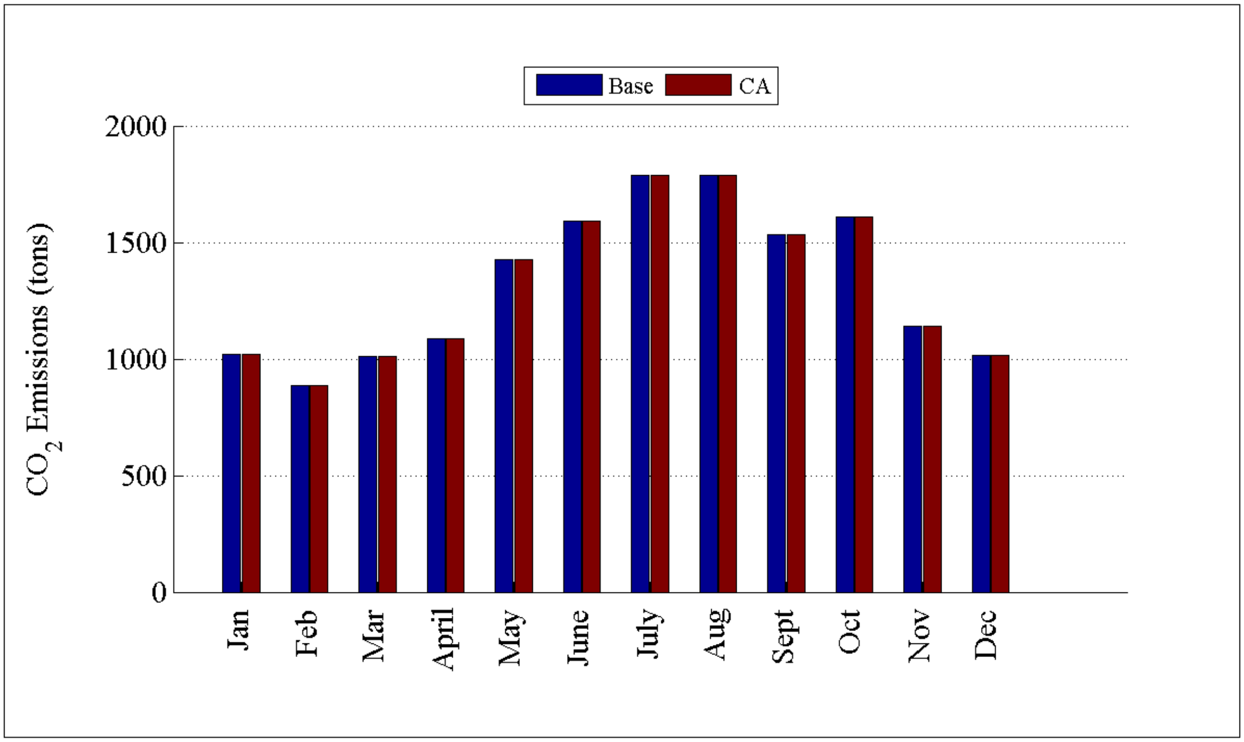



Figure D.205: Comparison of $CO_2$ emissions by month for R5-12.47-3

### D.2.25 Detailed CA Plots for R5-12.47-4

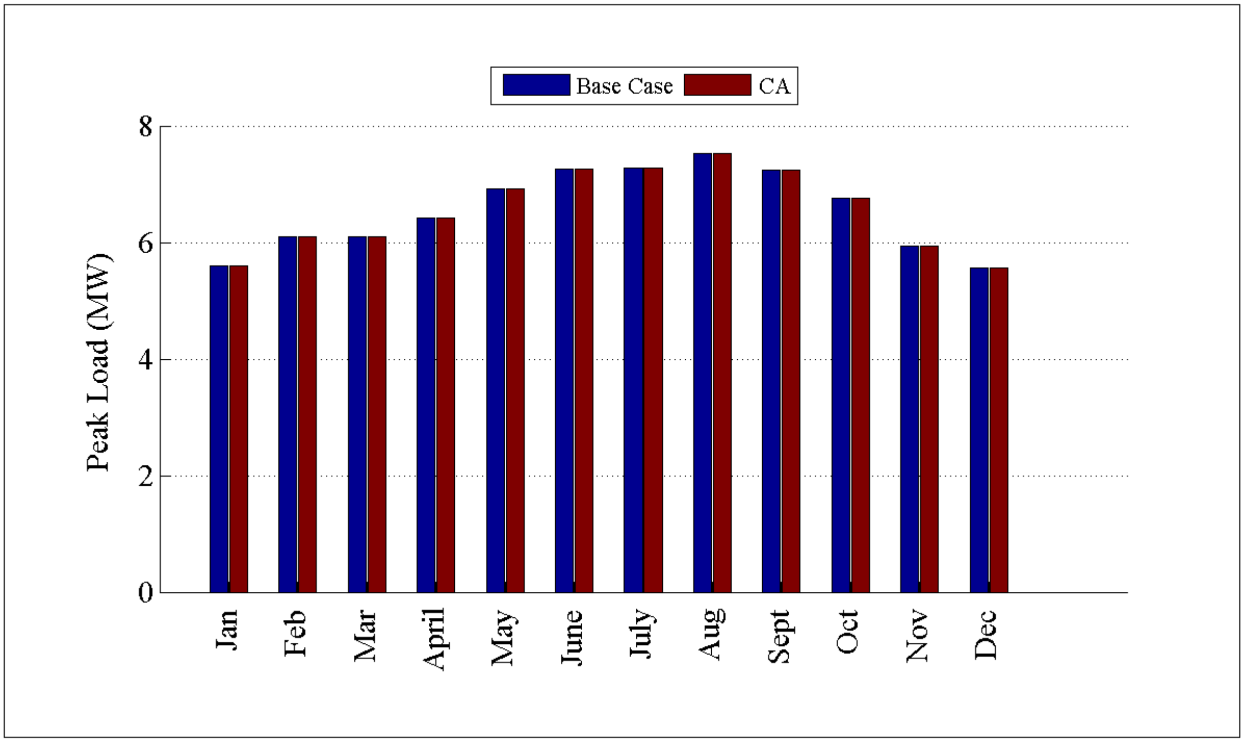



Figure D.206: Comparison of peak load by month for R5-12.47-4

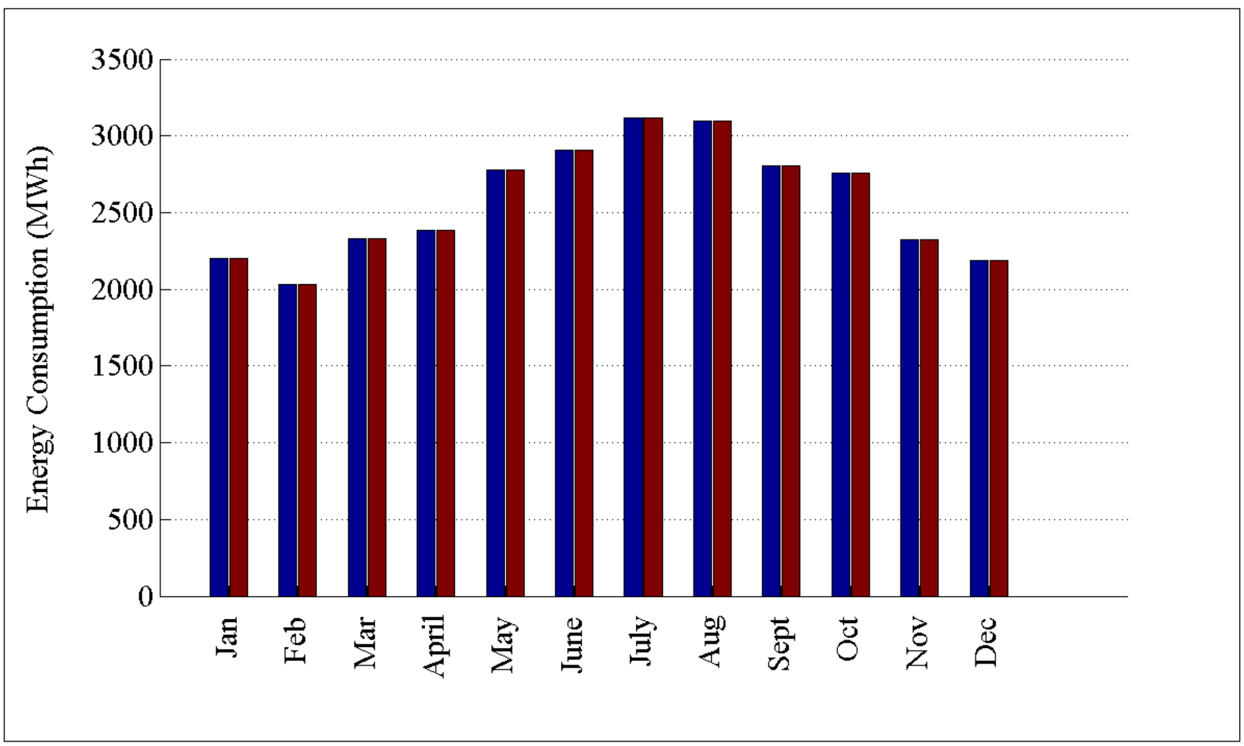



Figure D.207: Comparison of energy consumption by month for R5-12.47-4

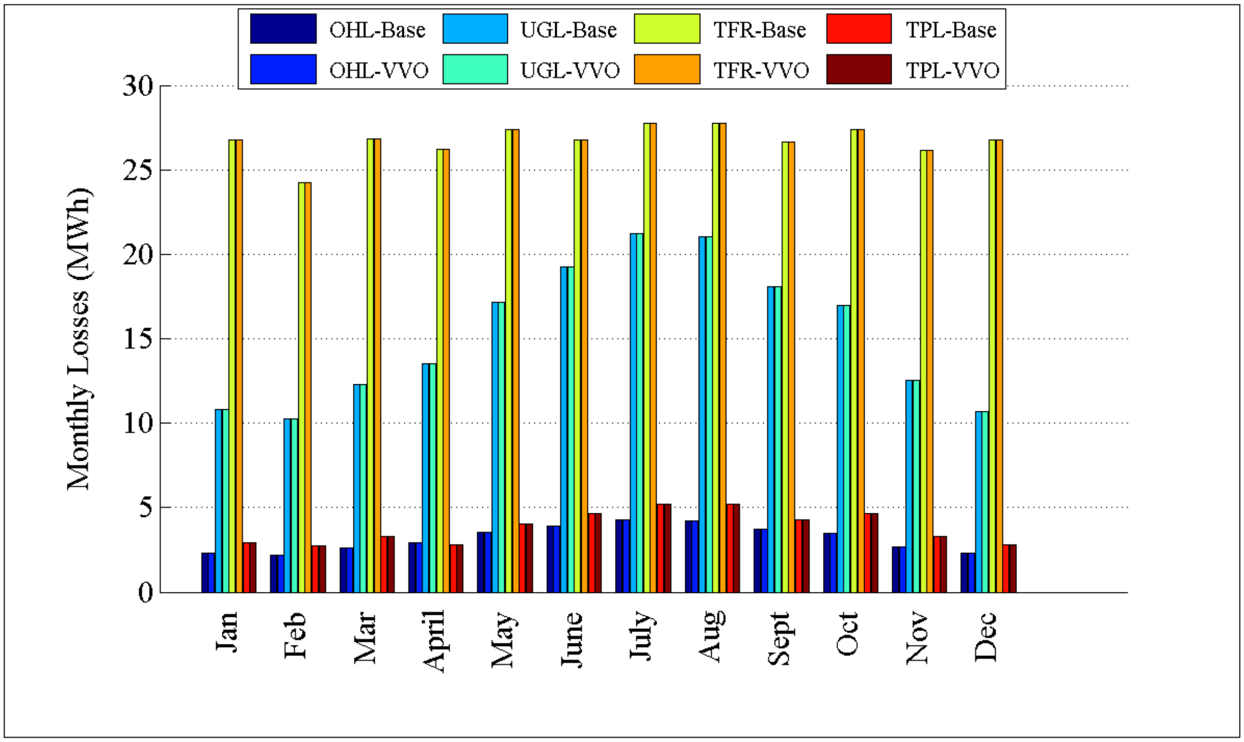



Figure D.208: Comparison of losses by month for R5-12.47-4

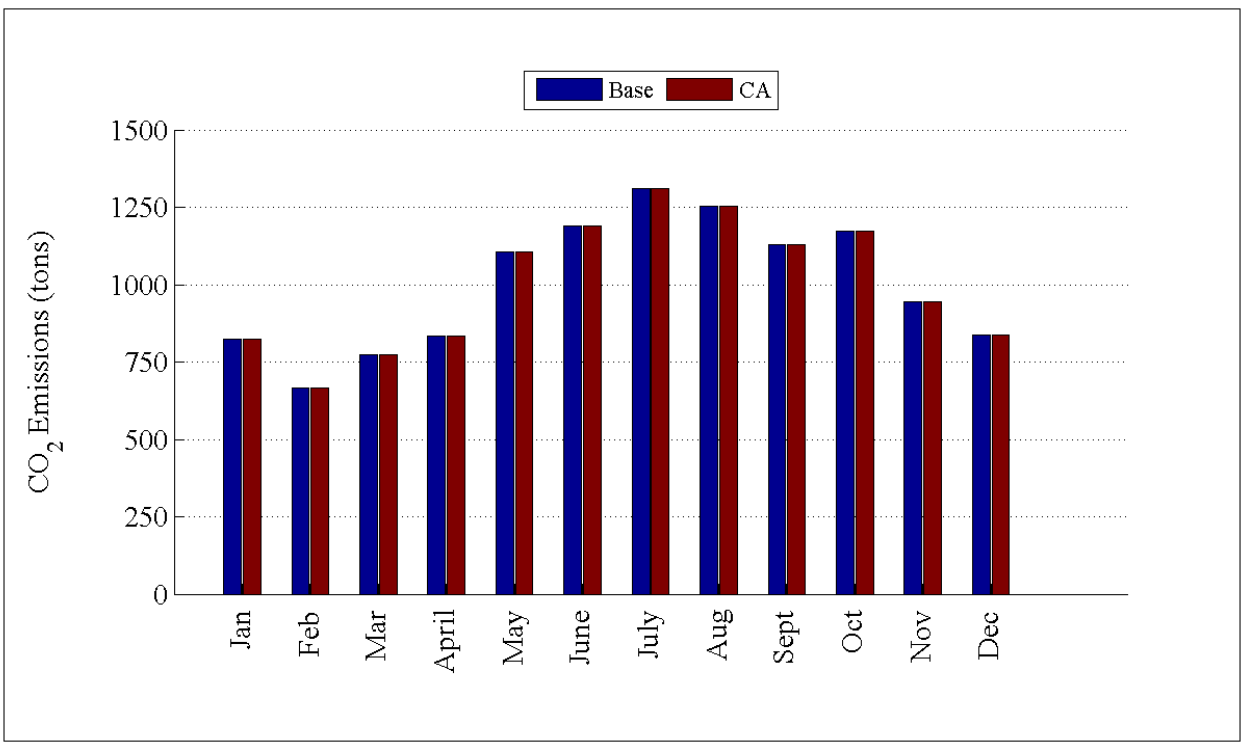



Figure D.209: Comparison of $CO_2$ emissions by month for R5-12.47-4

### D.2.26 Detailed CA Plots for R5-12.47-5

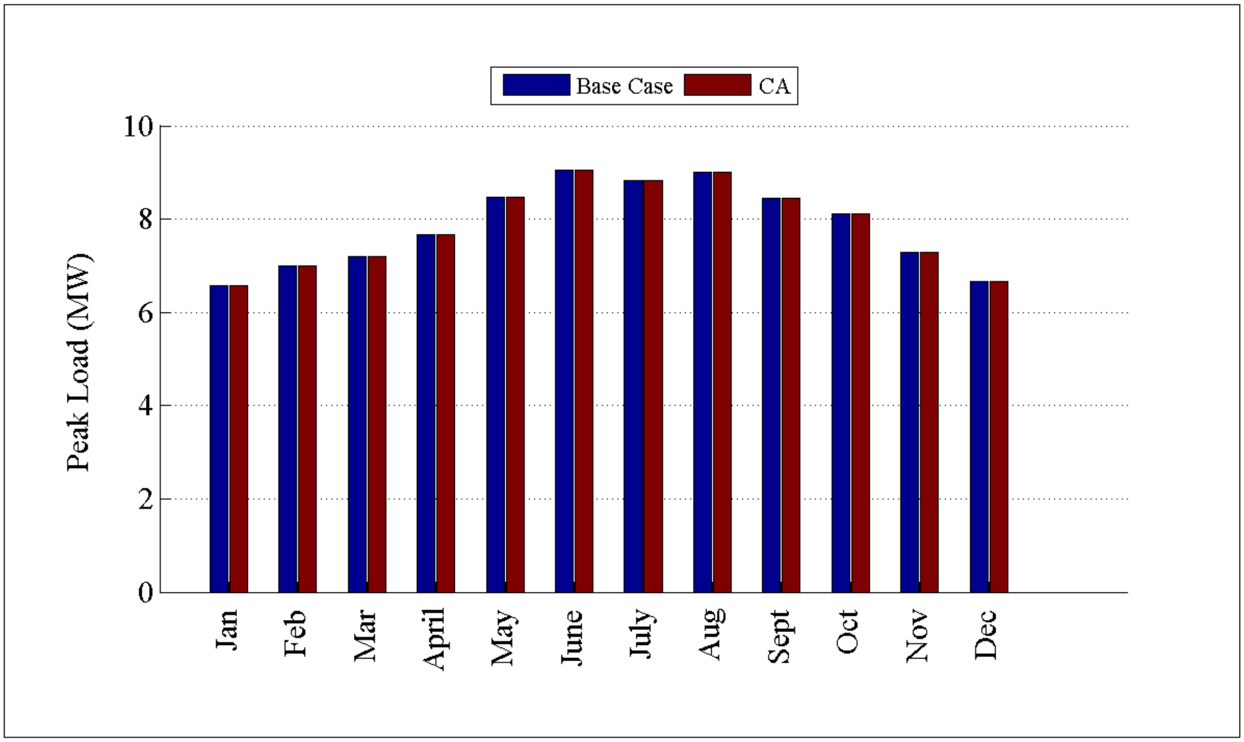



Figure D.210: Comparison of peak load by month for R5-12.47-5

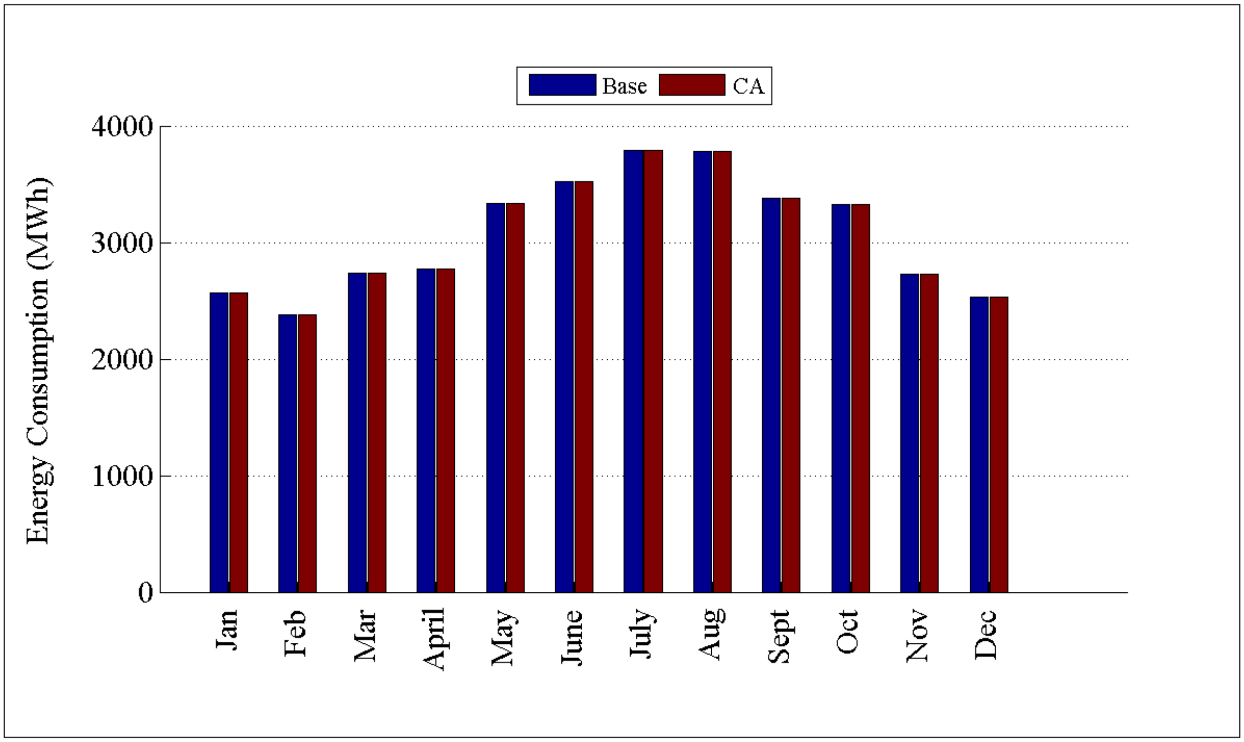



Figure D.211: Comparison of energy consumption by month for R5-12.47-5

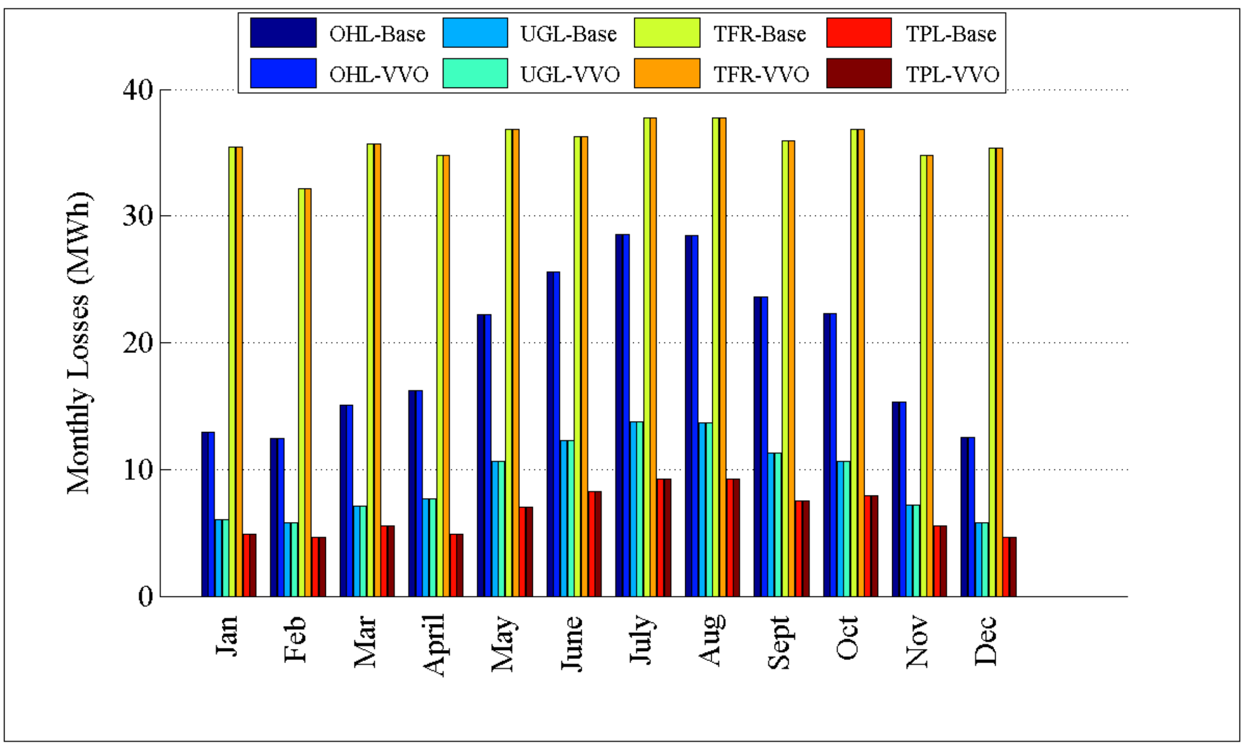



Figure D.212: Comparison of losses by month for R5-12.47-5

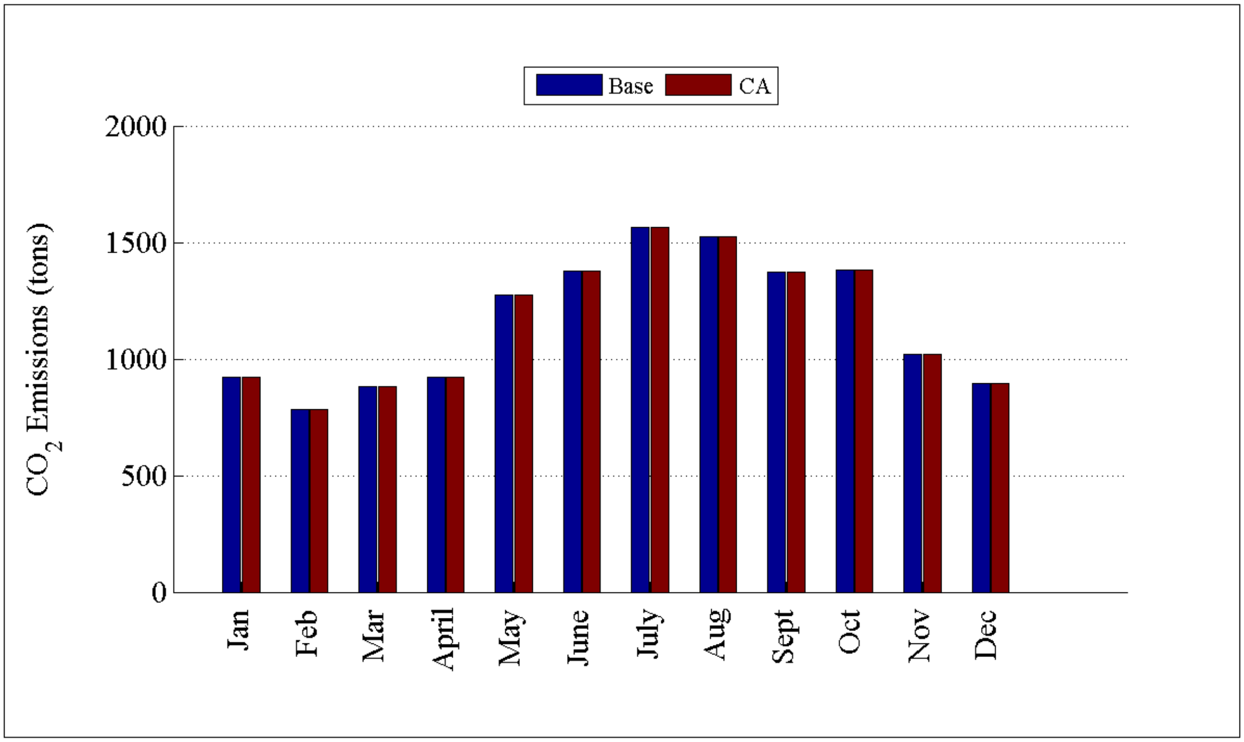



Figure D.213: Comparison of $CO_2$ emissions by month for R5-12.47-5

### D.2.27 Detailed CA Plots for R5-25.00-1

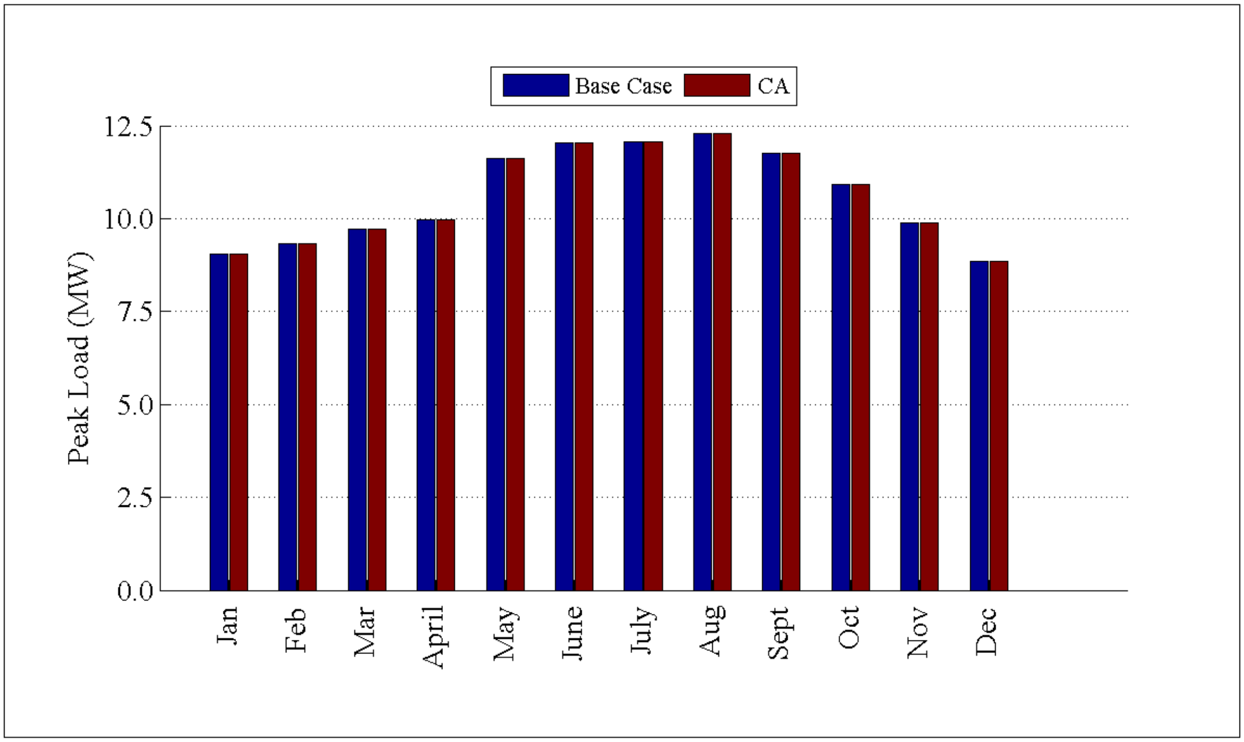



Figure D.214: Comparison of peak load by month for R5-25.00-1

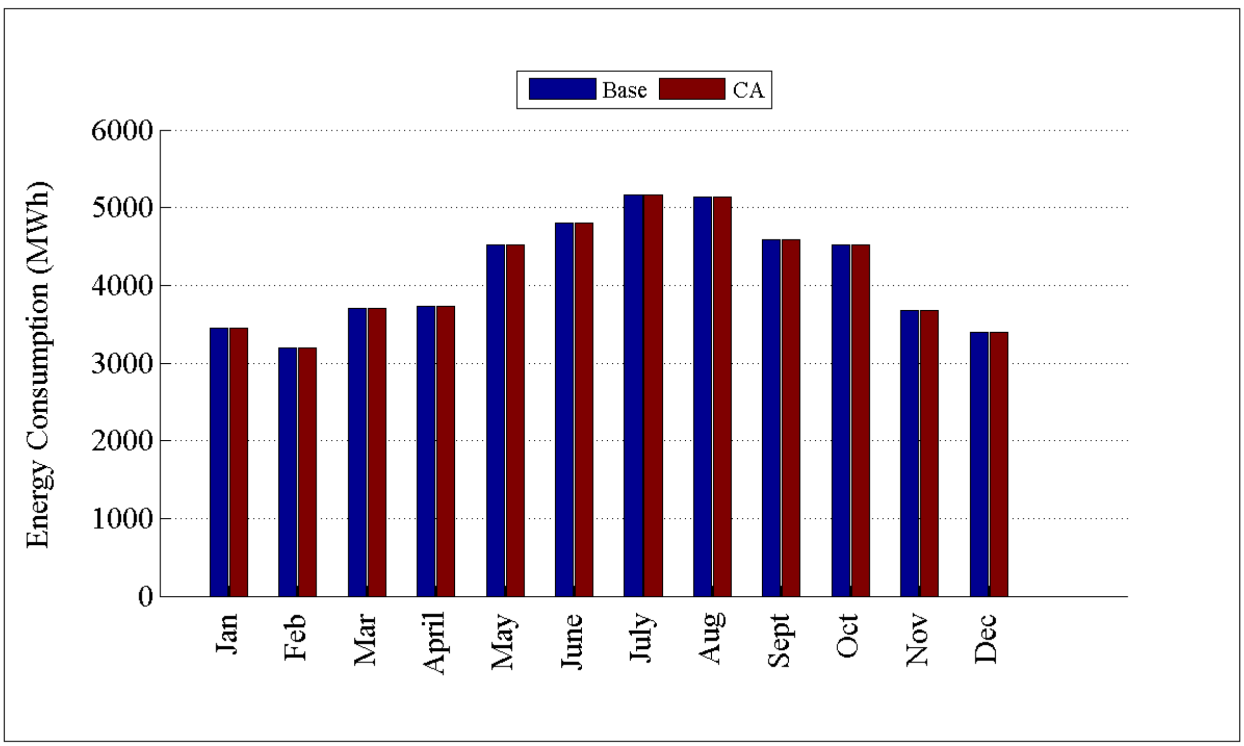



Figure D.215: Comparison of energy consumption by month for R5-25.00-1

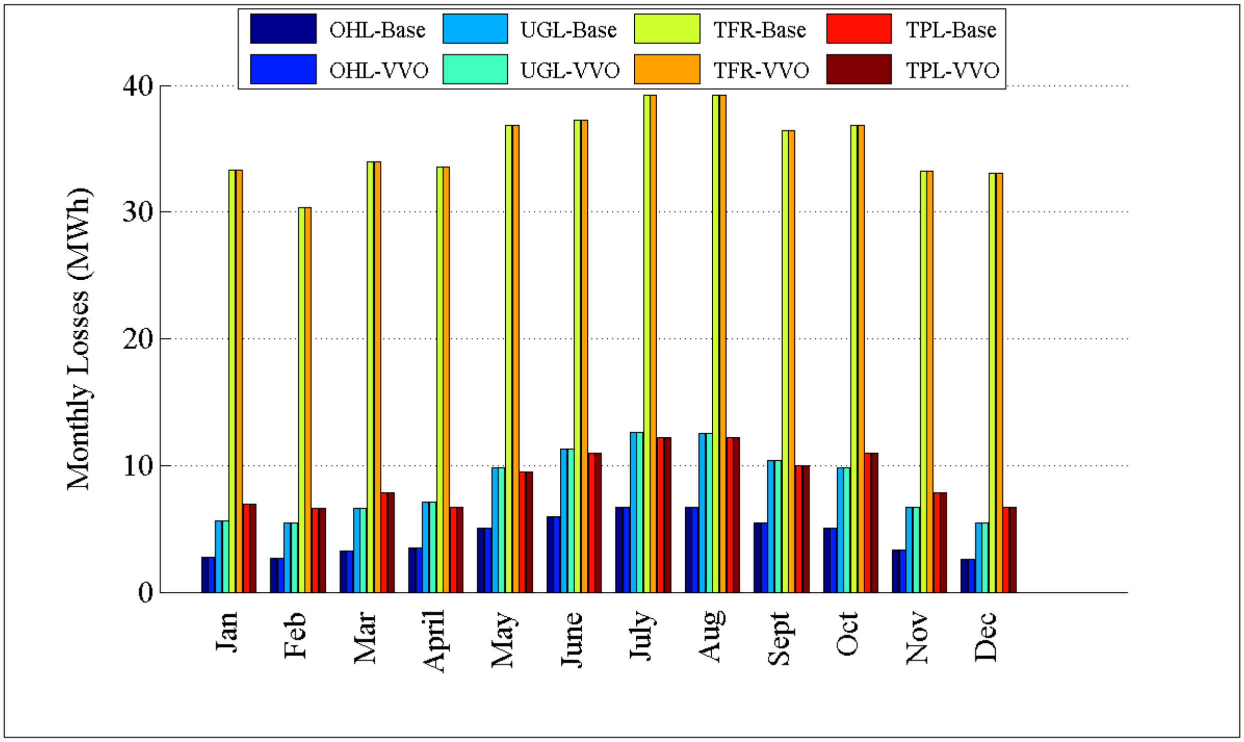



Figure D.216: Comparison of losses by month for R5-25.00-1

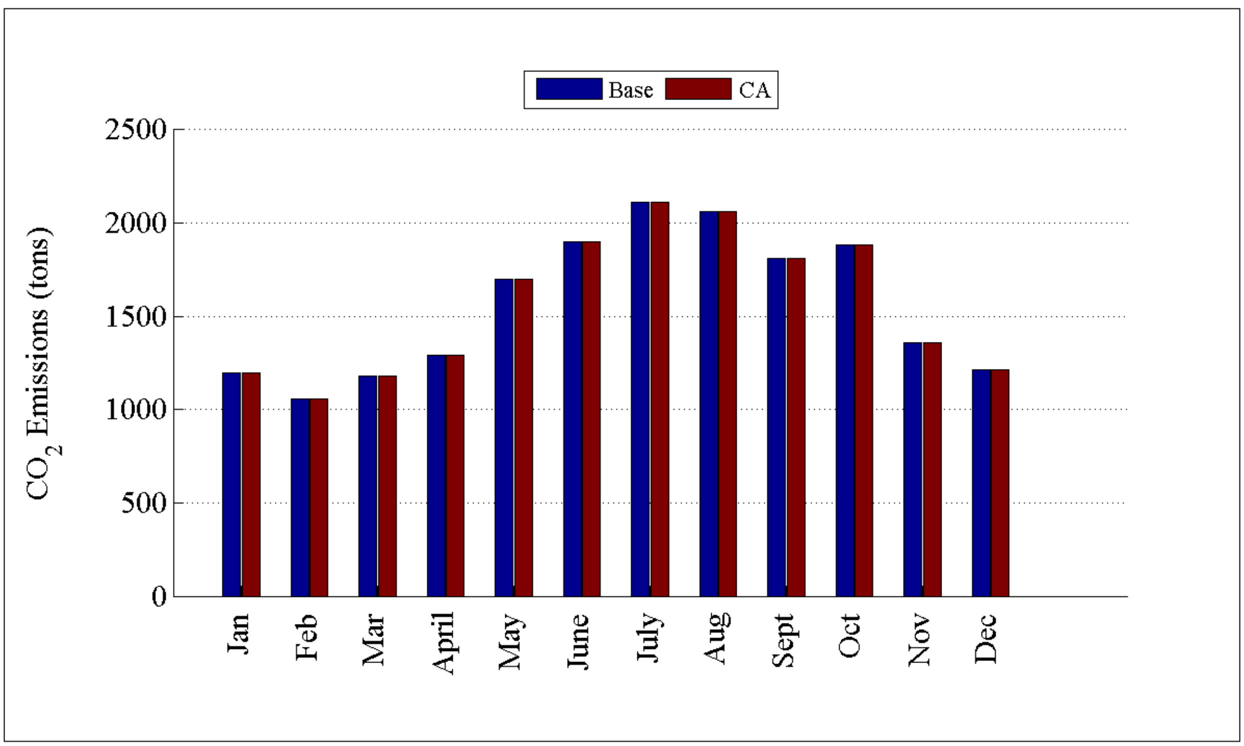



Figure D.217: Comparison of $CO_2$ emissions by month for R5-25.00-1

## D.2.28 Detailed CA Plots for R5-35.00-1

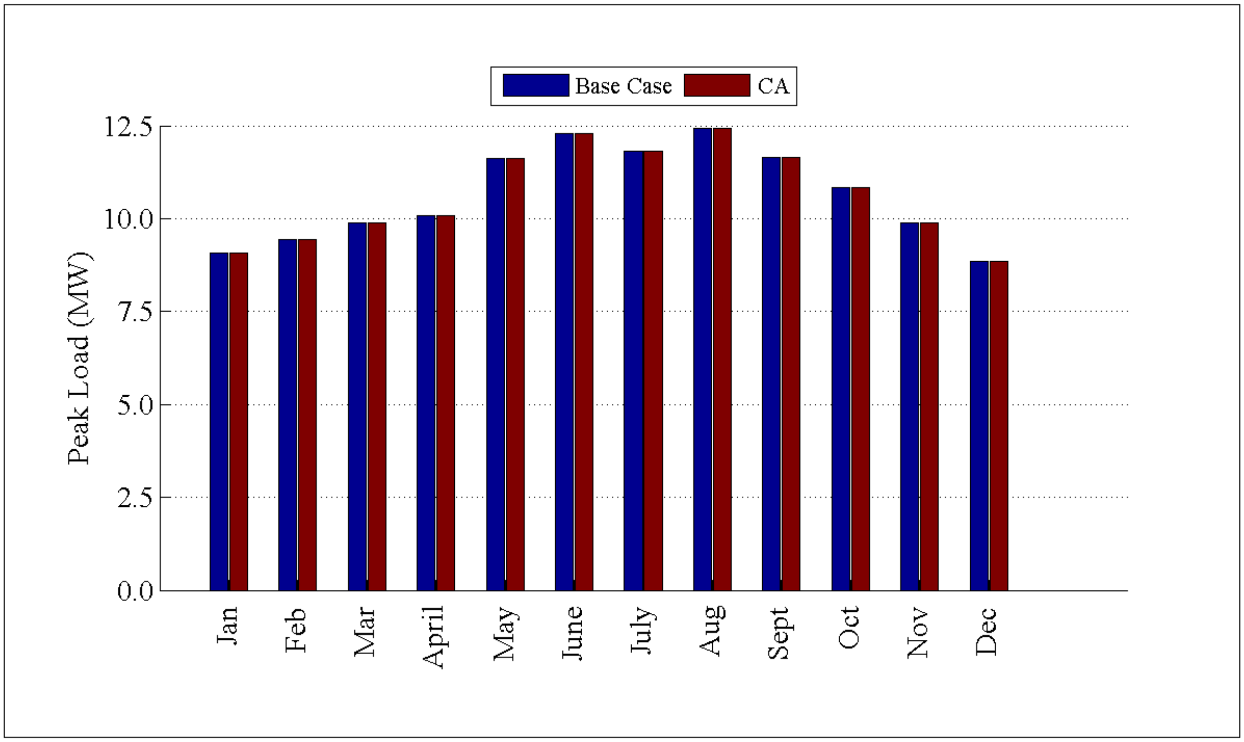



Figure D.218: Comparison of peak load by month for R5-35.00-1

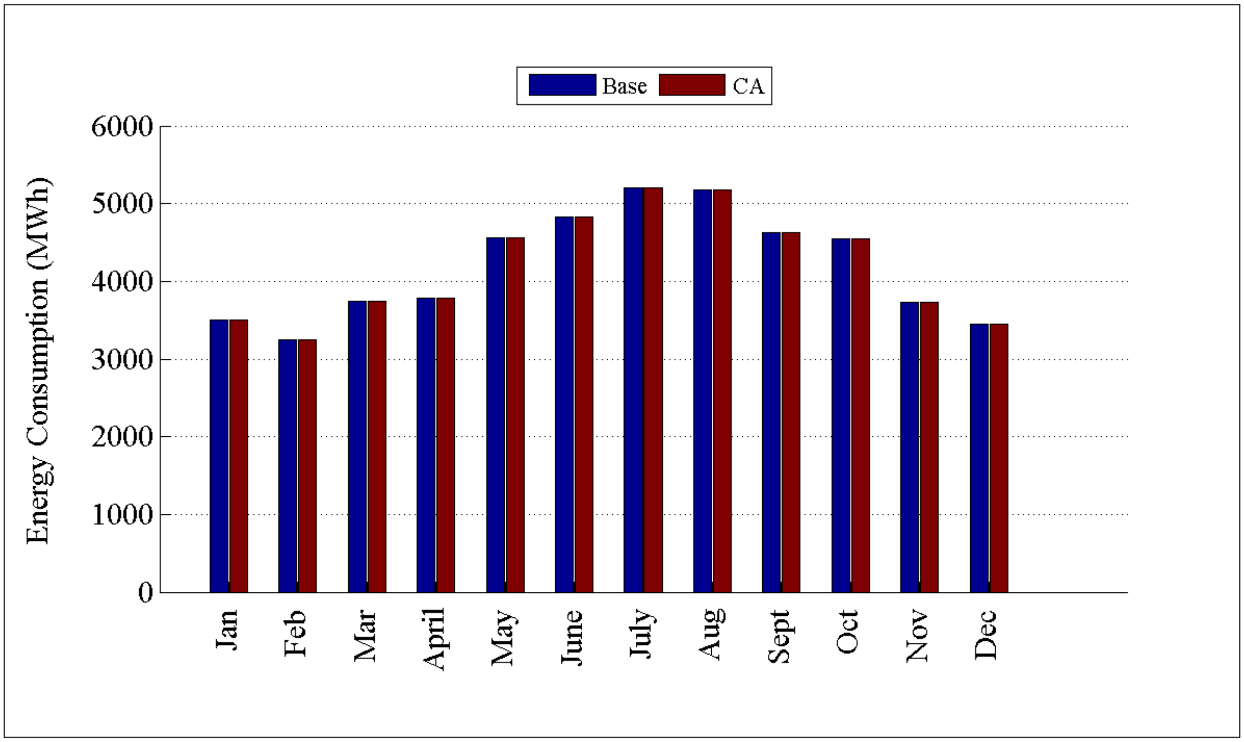



Figure D.219: Comparison of energy consumption by month for R5-35.00-1

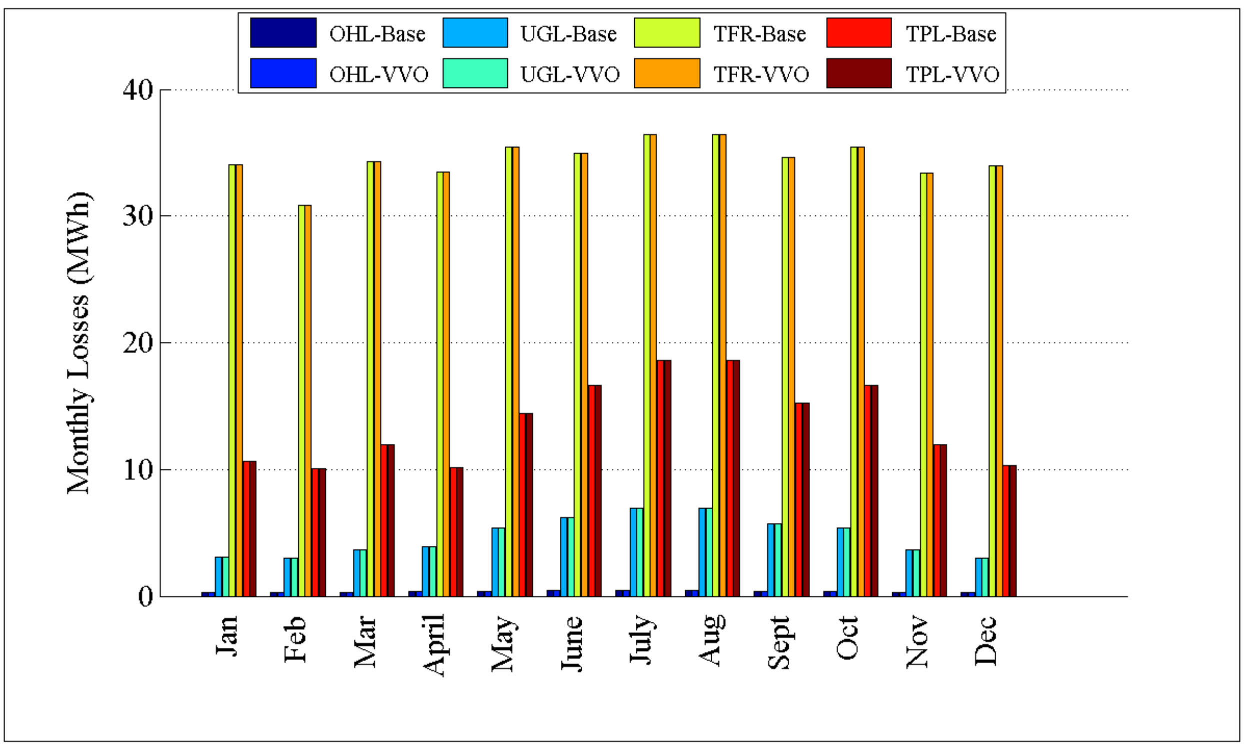



Figure D.220: Comparison of losses by month for R5-35.00-1

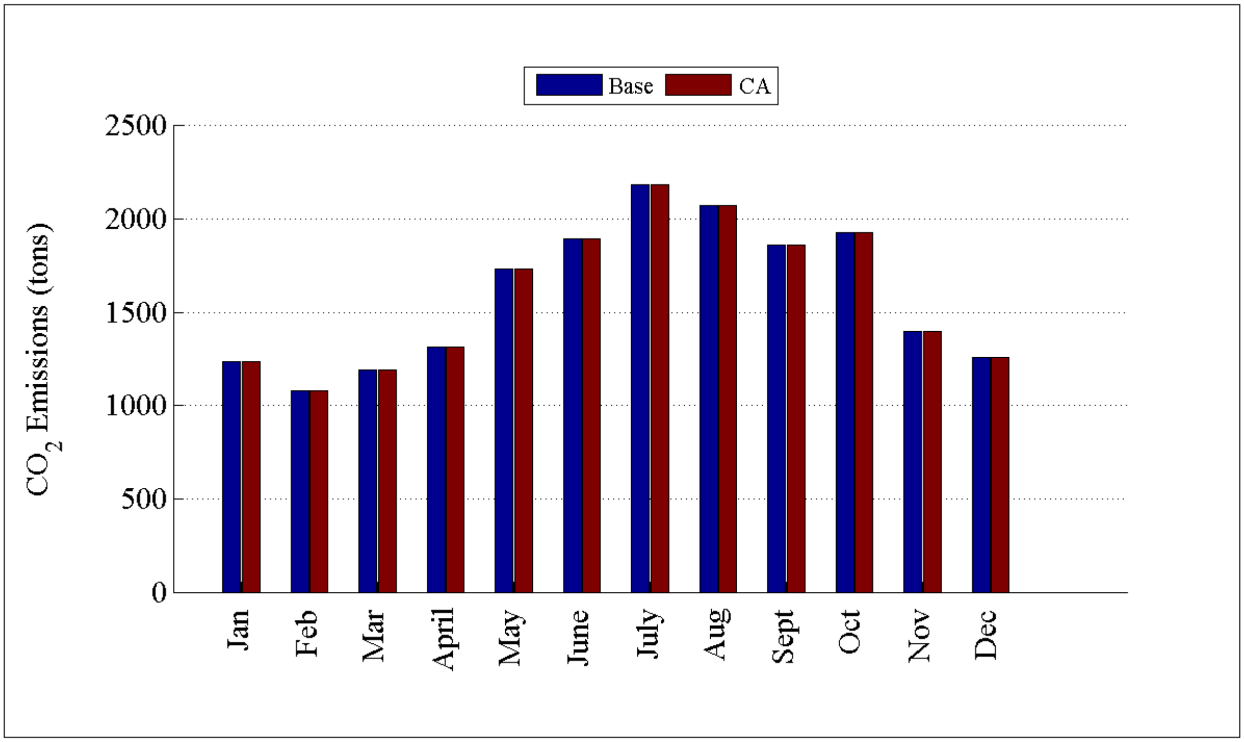



Figure D.221: Comparison of $CO_2$ emissions by month for R5-35.00-1

## D.3 Reclosers and Sectionalizers Plots

Reclosers and sectionalizers, as implemented here, do not have a noticeable impact on emissions.

## D.4 Distribution Management and Outage Management System Plots

Distribution Management and Outage Management Systems, as implemented here, do not have a noticeable impact on emissions.

## D.5 FDIR Plots

Fault Detection Identification and Restoration, as implemented here, do not have a noticeable impact on emissions.

# Appendix E: Individual Feeder Impact Metrics

This appendix contains the raw performance metric values for each technology on each of the prototypical distribution feeders. The impact matrices in Section 4.1, 4.2, 4.3, 4.4, and 4.5 are calculated from the raw values in this appendix.

## E.1 Individual Performance Metrics for Base Case

Table E.1: Base case performance metrics for region 1

| Index | Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,083 | 2,692 | 992 | 435 | 1,948 | 875 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,521 | 1,965 | 724 | 317 | 1,422 | 639 |
| 3 | Peak Generation | kW | 5,313 | 7,329 | 2,675 | 1,261 | 5,050 | 2,317 |
| | Nuclear | % | 10.68 | 10.68 | 10.68 | 10.68 | 10.09 | 10.68 |
| | Solar | % | 0.25 | 0.25 | 0.25 | 0.25 | 0.21 | 0.25 |
| | Bio | % | 0.67 | 0.67 | 0.67 | 0.67 | 0.72 | 0.67 |
| | Wind | % | 4.07 | 4.07 | 4.07 | 4.07 | 3.55 | 4.07 |
| | Coal | % | 2.88 | 2.88 | 2.88 | 2.88 | 4.38 | 2.88 |
| | Hydroelectric | % | 36.88 | 36.88 | 36.88 | 36.88 | 26.32 | 36.88 |
| | Natural Gas | % | 41.38 | 41.38 | 41.38 | 41.38 | 51.24 | 41.38 |
| | Geothermal | % | 2.84 | 2.84 | 2.84 | 2.84 | 3.11 | 2.84 |
| | Petroleum | % | 0.35 | 0.35 | 0.35 | 0.35 | 0.38 | 0.35 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | MW | 5,288 | 7,085 | 2,590 | 1,247 | 4,924 | 2,261 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 18,290 | 24,196 | 8,964 | 3,829 | 17,276 | 7,776 |
| 12 | CO2 Emissions | Tons | 1,783 | 2,273 | 818 | 392 | 1,774 | 752 |
| 13 | SOx Emissions | Tons | 0.03 | 0.03 | 0.01 | 0.01 | 0.04 | 0.01 |
| | NOx Emissions | Tons | 0.24 | 0.28 | 0.10 | 0.05 | 0.22 | 0.10 |
| | PM-10 Emissions | Tons | 0.25 | 0.32 | 0.12 | 0.06 | 0.25 | 0.11 |
| 16 | Electricity Usage* | kWh | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Annual Storage Dispatch* | kWh | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Average Energy Storage Efficiency* | % | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | Feeder Real Load | MW | 2,088 | 2,762 | 1,023 | 437 | 1,972 | 888 |
| | Feeder Reactive Load | MVAR | 68 | -284 | -200 | 11 | 62 | -70 |
| 29 | Distribution Losses | % | 0.23 | 2.54 | 3.05 | 0.56 | 1.21 | 1.44 |
| 30 | Distribution Power Factor | pf | 0.9994 | 0.9925 | 0.9678 | 0.9997 | 0.9995 | 0.9666 |
| 39 | CO2 Emissions | Tons | 1,787 | 2,332 | 844 | 394 | 1,796 | 763 |
| 40 | SOx | Tons | 0.03 | 0.03 | 0.01 | 0.01 | 0.04 | 0.01 |
| | NOx | Tons | 0.24 | 0.29 | 0.11 | 0.05 | 0.22 | 0.10 |
| | PM-10 | Tons | 0.25 | 0.33 | 0.12 | 0.06 | 0.26 | 0.11 |

Table E.2: Base case performance metrics for region 2

| Index | Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,169 | 2,268 | 1,970 | 2,975 | 6,342 | 4,576 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,584 | 1,656 | 1,438 | 2,171 | 4,630 | 3,340 |
| 3 | Peak Generation | kW | 5,749 | 6,287 | 5,777 | 8,555 | 16,840 | 12,676 |
| | Nuclear | % | 26.33 | 26.33 | 26.33 | 27.95 | 26.33 | 26.33 |
| | Solar | % | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| | Bio | % | 0.82 | 0.82 | 0.82 | 0.84 | 0.82 | 0.82 |
| | Wind | % | 1.41 | 1.41 | 1.41 | 1.70 | 1.41 | 1.41 |
| | Coal | % | 47.18 | 47.18 | 47.18 | 45.54 | 47.18 | 47.18 |
| | Hydroelectric | % | 7.42 | 7.42 | 7.42 | 9.05 | 7.42 | 7.42 |
| | Natural Gas | % | 16.33 | 16.33 | 16.33 | 14.47 | 16.33 | 16.33 |
| | Geothermal | % | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| | Petroleum | % | 0.43 | 0.43 | 0.43 | 0.37 | 0.43 | 0.43 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | MW | 5,720 | 6,166 | 5,647 | 8,360 | 16,622 | 12,533 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 19,050 | 20,128 | 17,588 | 26,686 | 56,091 | 40,417 |
| 12 | CO2 Emissions | Tons | 8,419 | 9,246 | 8,417 | 12,627 | 26,866 | 17,434 |
| 13 | SOx Emissions | Tons | 3.81 | 4.21 | 3.88 | 5.82 | 12.33 | 7.86 |
| | NOx Emissions | Tons | 2.43 | 2.67 | 2.46 | 3.69 | 7.81 | 5.02 |
| | PM-10 Emissions | Tons | 1.25 | 1.37 | 1.25 | 1.87 | 3.99 | 2.58 |
| 16 | Electricity Usage* | kWh | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Annual Storage Dispatch* | kWh | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Average Energy Storage Efficiency* | % | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | Feeder Real Load | MW | 2,175 | 2,298 | 2,008 | 3,046 | 6,403 | 4,614 |
| | Feeder Reactive Load | MVAR | 92 | 116 | 146 | -130 | 333 | 69 |
| 29 | Distribution Losses | % | 0.25 | 1.27 | 1.87 | 2.36 | 0.96 | 0.82 |
| 30 | Distribution Power Factor | pf | 0.9989 | 0.9987 | 0.9973 | 0.9973 | 0.9986 | 0.9996 |
| 39 | CO2 Emissions | Tons | 8,440 | 9,365 | 8,578 | 12,932 | 27,125 | 17,579 |
| 40 | SOx | Tons | 3.82 | 4.26 | 3.95 | 5.96 | 12.45 | 7.93 |
| | NOx | Tons | 2.44 | 2.71 | 2.51 | 3.78 | 7.88 | 5.06 |
| | PM-10 | Tons | 1.25 | 1.39 | 1.27 | 1.92 | 4.03 | 2.61 |

Table E.3: Base case performance metrics for region 3

| Index | Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,635 | 3,661 | 1,642 | 3,705 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,924 | 2,673 | 1,199 | 2,705 |
| 3 | Peak Generation | kW | 6,594 | 9,315 | 4,422 | 8,417 |
| | Nuclear | % | 8.65 | 9.72 | 9.72 | 9.72 |
| | Solar | % | 0.13 | 0.13 | 0.13 | 0.13 |
| | Bio | % | 0.23 | 0.25 | 0.25 | 0.25 |
| | Wind | % | 2.05 | 2.45 | 2.45 | 2.45 |
| | Coal | % | 40.24 | 41.52 | 41.52 | 41.52 |
| | Hydroelectric | % | 5.58 | 6.40 | 6.40 | 6.40 |
| | Natural Gas | % | 41.67 | 37.88 | 37.88 | 37.88 |
| | Geothermal | % | 1.25 | 1.40 | 1.40 | 1.40 |
| | Petroleum | % | 0.20 | 0.25 | 0.25 | 0.25 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | MW | 6,554 | 9,122 | 4,364 | 8,157 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 23,160 | 32,687 | 14,483 | 33,603 |
| 12 | CO2 Emissions | Tons | 16,269 | 23,430 | 9,963 | 25,107 |
| 13 | SOx Emissions | Tons | 7.03 | 10.24 | 4.25 | 11.14 |
| | NOx Emissions | Tons | 4.38 | 6.36 | 2.66 | 6.88 |
| | PM-10 Emissions | Tons | 2.42 | 3.49 | 1.48 | 3.74 |
| 16 | Electricity Usage* | kWh | 0 | 0 | 0 | 0 |
| 17 | Annual Storage Dispatch* | kWh | 0 | 0 | 0 | 0 |
| 18 | Average Energy Storage Efficiency* | % | 0 | 0 | 0 | 0 |
| 21 | Feeder Real Load | MW | 2,644 | 3,731 | 1,653 | 3,836 |
| | Feeder Reactive Load | MVAR | 219 | 484 | 143 | 547 |
| 29 | Distribution Losses | % | 0.33 | 1.87 | 0.69 | 3.40 |
| 30 | Distribution Power Factor | pf | 0.9969 | 0.9904 | 0.99685 | 0.98973 |
| 39 | CO2 Emissions | Tons | 16,323 | 23,877 | 10,032 | 25,991 |
| 40 | SOx | Tons | 7.05 | 10.44 | 4.28 | 11.53 |
| | NOx | Tons | 4.39 | 6.48 | 2.67 | 7.12 |
| | PM-10 | Tons | 2.43 | 3.56 | 1.49 | 3.87 |

Table E.4: Base case performance metrics for region 4

| Index | Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,339 | 1,909 | 832 | 347 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,708 | 1,393 | 607 | 253 |
| 3 | Peak Generation | kW | 6,221 | 4,798 | 2,205 | 945 |
| | Nuclear | % | 21.91 | 21.91 | 23.58 | 23.58 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.18 | 0.18 | 0.21 | 0.21 |
| | Wind | % | 0.60 | 0.60 | 0.59 | 0.59 |
| | Coal | % | 57.14 | 57.14 | 56.06 | 56.06 |
| | Hydroelectric | % | 2.20 | 2.20 | 3.09 | 3.09 |
| | Natural Gas | % | 17.49 | 17.49 | 16.14 | 16.14 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.48 | 0.48 | 0.33 | 0.33 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | MW | 6,186 | 4,701 | 2,171 | 928 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 20,550 | 17,195 | 7,457 | 3,118 |
| 12 | CO2 Emissions | Tons | 10,321 | 9,844 | 3,994 | 1,608 |
| 13 | SOx Emissions | Tons | 4.91 | 4.72 | 1.92 | 0.77 |
| | NOx Emissions | Tons | 3.00 | 2.87 | 1.17 | 0.47 |
| | PM-10 Emissions | Tons | 1.54 | 1.47 | 0.60 | 0.24 |
| 16 | Electricity Usage* | kWh | 0 | 0 | 0 | 0 |
| 17 | Annual Storage Dispatch* | kWh | 0 | 0 | 0 | 0 |
| 18 | Average Energy Storage Efficiency* | % | 0 | 0 | 0 | 0 |
| 21 | Feeder Real Load | MW | 2,346 | 1,963 | 851 | 356 |
| | Feeder Reactive Load | MVAR | 138 | -413 | 98 | 45 |
| 29 | Distribution Losses | % | 0.28 | 2.76 | 2.32 | 2.53 |
| 30 | Distribution Power Factor | pf | 0.9982 | 0.9666 | 0.9934 | 0.9920 |
| 39 | CO2 Emissions | Tons | 10,350 | 10,123 | 4,089 | 1,650 |
| 40 | SOx | Tons | 4.93 | 4.86 | 1.96 | 0.79 |
| | NOx | Tons | 3.00 | 2.95 | 1.19 | 0.48 |
| | PM-10 | Tons | 1.54 | 1.51 | 0.61 | 0.25 |

Table E.5: Base case performance metrics for region 5

| Index | Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,747 | 4,490 | 2,226 | 4,669 | 3,468 | 4,116 | 5,627 | 5,689 |
| 2 | Monthly Customer Electricity Usage | MWh | 2,005 | 3,278 | 1,625 | 3,408 | 2,532 | 3,005 | 4,108 | 4,153 |
| 3 | Peak Generation | kW | 5,841 | 9,451 | 4,992 | 10,384 | 7,531 | 9,041 | 12,282 | 12,428 |
| | Nuclear | % | 13.85 | 13.85 | 13.85 | 13.53 | 13.85 | 13.53 | 13.85 | 13.85 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.33 | 0.33 | 0.33 | 0.31 | 0.33 | 0.31 | 0.33 | 0.33 |
| | Wind | % | 1.48 | 1.48 | 1.48 | 1.74 | 1.48 | 1.74 | 1.48 | 1.48 |
| | Coal | % | 30.17 | 30.17 | 30.17 | 30.37 | 30.17 | 30.37 | 30.17 | 30.17 |
| | Hydroelectric | % | 0.63 | 0.63 | 0.63 | 0.78 | 0.63 | 0.78 | 0.63 | 0.63 |
| | Natural Gas | % | 51.68 | 51.68 | 51.68 | 51.29 | 51.68 | 51.29 | 51.68 | 51.68 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 1.86 | 1.86 | 1.86 | 1.98 | 1.86 | 1.98 | 1.86 | 1.86 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | MW | 5,810 | 9,319 | 4,848 | 9,772 | 7,373 | 8,784 | 12,088 | 12,270 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 24,144 | 39,806 | 19,900 | 42,781 | 30,976 | 36,921 | 49,992 | 50,486 |
| 12 | CO2 Emissions | Tons | 9,364 | 15,419 | 7,414 | 15,195 | 11,809 | 13,594 | 18,504 | 18,904 |
| 13 | SOx Emissions | Tons | 1.55 | 2.23 | 1.11 | 1.64 | 1.70 | 1.66 | 2.19 | 2.34 |
| | NOx Emissions | Tons | 1.38 | 2.11 | 1.04 | 1.82 | 1.61 | 1.72 | 2.31 | 2.41 |
| | PM-10 Emissions | Tons | 1.37 | 2.26 | 1.09 | 2.23 | 1.73 | 1.99 | 2.71 | 2.77 |
| 16 | Electricity Usage* | kWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Annual Storage Dispatch* | kWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Average Energy Storage Efficiency* | % | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | Feeder Real Load | MW | 2,756 | 4,544 | 2,272 | 4,884 | 3,536 | 4,215 | 5,707 | 5,763 |
| | Feeder Reactive Load | MVAR | 248 | 542 | 242 | -357 | 407 | 594 | 650 | 641 |
| 29 | Distribution Losses | % | 0.33 | 1.19 | 2.02 | 4.41 | 1.92 | 2.34 | 1.39 | 1.28 |
| 30 | Distribution Power Factor | pf | 0.9964 | 0.9937 | 0.9952 | 0.9779 | 0.9942 | 0.9913 | 0.9942 | 0.9944 |
| 39 | CO2 Emissions | Tons | 9,395 | 15,605 | 7,567 | 15,895 | 12,040 | 13,919 | 18,766 | 19,150 |
| 40 | SOx | Tons | 1.55 | 2.26 | 1.14 | 1.72 | 1.73 | 1.70 | 2.22 | 2.37 |
| | NOx | Tons | 1.39 | 2.14 | 1.06 | 1.91 | 1.65 | 1.76 | 2.34 | 2.44 |
| | PM-10 | Tons | 1.38 | 2.29 | 1.11 | 2.33 | 1.77 | 2.04 | 2.75 | 2.81 |

## E.2 Individual Performance Metrics for Base Case 2

Table E.6: Base case 2 performance metrics for region 1

| Index | Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.17 | 1.18 | 1.17 | 1.16 | 1.17 |
| 33 | SAIDI | Minutes | 106.05 | 90.32 | 97.20 | 92.49 | 104.12 | 90.74 |
| | CAIDI | Minutes | 81.75 | 77.22 | 82.52 | 78.84 | 89.76 | 77.88 |
| 34 | MAIFI | # | 0.00 | 2.00 | 1.00 | 3.00 | 0.00 | 0.62 |

Table E.7: Base case 2 performance metrics for region 2

| Index | Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.29 | 1.14 | 1.16 | 1.16 | 1.18 |
| 33 | SAIDI | Minutes | 106.05 | 98.39 | 93.38 | 90.43 | 91.75 | 100.39 |
| | CAIDI | Minutes | 81.75 | 76.02 | 82.25 | 78.06 | 79.17 | 84.72 |
| 34 | MAIFI | # | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.43 |

Table E.8: Base case 2 performance metrics for region 3

| Index | Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.21 | 1.17 | 1.19 |
| 33 | SAIDI | Minutes | 106.05 | 95.53 | 101.37 | 97.68 |
| | CAIDI | Minutes | 81.75 | 79.06 | 86.96 | 82.42 |
| 34 | MAIFI | # | 0.00 | 2.00 | 1.00 | 0.00 |

Table E.9: Base case 2 performance metrics for region 4

| Index | Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.16 | 1.19 | 1.15 |
| 33 | SAIDI | Minutes | 106.05 | 91.84 | 95.77 | 90.18 |
| | CAIDI | Minutes | 81.75 | 79.28 | 80.25 | 78.70 |
| 34 | MAIFI | # | 0.00 | 0.00 | 1.00 | 1.00 |

Table E.10: Base case 2 performance metrics for region 5

| Index | Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.17 | 1.18 | 1.19 | 1.18 | 1.17 | 1.17 | 1.19 |
| 33 | SAIDI | Minutes | 106.05 | 90.88 | 91.81 | 93.70 | 95.44 | 102.06 | 94.82 | 93.88 |
| | CAIDI | Minutes | 81.75 | 77.73 | 77.77 | 78.87 | 80.63 | 87.50 | 80.98 | 79.20 |
| 34 | MAIFI | # | 0.00 | 0.00 | 1.00 | 0.31 | 1.00 | 1.00 | 1.00 | 1.00 |

## E.3 Individual VVO Performance Metrics

Table E.11: VVO performance metrics for region 1

| Index | Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,000 | 2,617 | 966 | 417 | 1,882 | 844 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,460 | 1,911 | 705 | 305 | 1,374 | 616 |
| 3 | Peak Generation | kW | 5,154 | 7,245 | 2,653 | 1,230 | 5,035 | 2,317 |
| | Nuclear | % | 10.68 | 10.68 | 10.68 | 10.68 | 10.68 | 10.09 |
| | Solar | % | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.21 |
| | Bio | % | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.72 |
| | Wind | % | 4.07 | 4.07 | 4.07 | 4.07 | 4.07 | 3.55 |
| | Coal | % | 2.88 | 2.88 | 2.88 | 2.88 | 2.88 | 4.38 |
| | Hydroelectric | % | 36.88 | 36.88 | 36.88 | 36.88 | 36.88 | 26.32 |
| | Natural Gas | % | 41.38 | 41.38 | 41.38 | 41.38 | 41.38 | 51.24 |
| | Geothermal | % | 0.20 | 2.04 | 2.36 | 0.70 | 2.84 | 3.11 |
| | Petroleum | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 3.58 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 5,129 | 7,001 | 2,568 | 1,216 | 4,908 | 2,261 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 17,562 | 23,498 | 8,721 | 3,676 | 16,700 | 7,497 |
| 12 | CO2 Emissions | Tons | 1,605 | 2,080 | 752 | 348 | 1,593 | 681 |
| 13 | SOx Emissions | Tons | 0.01 | 0.02 | 0.01 | 0.00 | 0.02 | 0.01 |
| | NOx Emissions | Tons | 0.22 | 0.27 | 0.10 | 0.05 | 0.20 | 0.09 |
| | PM-10 Emissions | Tons | 0.23 | 0.29 | 0.11 | 0.05 | 0.23 | 0.10 |
| 21 | Feeder Real Load | kW | 2,005 | 2,682 | 996 | 420 | 1,906 | 856 |
| | Feeder Reactive Load | kVAR | 68 | 44 | 44 | 11 | 62 | 35 |
| 29 | Distribution Losses | % | 0.25 | 2.43 | 2.96 | 0.58 | 1.27 | 1.42 |
| 30 | Distribution Power Factor | pf | 0.9994 | 0.9995 | 0.9989 | 0.9997 | 0.9994 | 0.9993 |
| 39 | CO2 Emissions | Tons | 1,609 | 2,132 | 775 | 350 | 1,613 | 690 |
| 40 | SOx Emissions | Tons | 0.01 | 0.02 | 0.01 | 0.00 | 0.02 | 0.01 |
| | NOx Emissions | Tons | 0.22 | 0.27 | 0.10 | 0.05 | 0.20 | 0.09 |
| | PM-10 Emissions | Tons | 0.23 | 0.30 | 0.11 | 0.05 | 0.23 | 0.10 |

Table E.12: VVO performance metrics for region 2

| Index | Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,085 | 2,201 | 1,913 | 2,872 | 6,117 | 4,410 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,522 | 1,607 | 1,397 | 2,097 | 4,466 | 3,219 |
| 3 | Peak Generation | kW | 5,734 | 6,185 | 5,892 | 8,547 | 16,825 | 12,251 |
| | Nuclear | % | 26.33 | 26.33 | 26.33 | 26.33 | 26.33 | 26.33 |
| | Solar | % | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| | Bio | % | 0.82 | 0.82 | 0.82 | 0.82 | 0.82 | 0.82 |
| | Wind | % | 1.41 | 1.41 | 1.41 | 1.41 | 1.41 | 1.41 |
| | Coal | % | 47.18 | 47.18 | 47.18 | 47.18 | 47.18 | 47.18 |
| | Hydroelectric | % | 7.42 | 6.31 | 7.42 | 7.42 | 7.42 | 4.57 |
| | Natural Gas | % | 16.33 | 16.33 | 16.33 | 16.33 | 16.33 | 16.33 |
| | Geothermal | % | 0.07 | 0.00 | 0.07 | 0.07 | 0.07 | 0.00 |
| | Petroleum | % | 0.18 | 0.00 | 2.43 | 0.59 | 0.34 | 0.00 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 5,705 | 6,065 | 5,762 | 8,353 | 16,607 | 12,108 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 18,311 | 19,533 | 17,075 | 25,733 | 54,109 | 38,952 |
| 12 | CO2 Emissions | Tons | 7,880 | 8,821 | 7,977 | 11,817 | 25,231 | 16,425 |
| 13 | SOx Emissions | Tons | 3.58 | 4.03 | 3.69 | 5.46 | 11.62 | 7.44 |
| | NOx Emissions | Tons | 2.28 | 2.56 | 2.34 | 3.47 | 7.37 | 4.75 |
| | PM-10 Emissions | Tons | 1.17 | 1.31 | 1.18 | 1.75 | 3.74 | 2.44 |
| 21 | Feeder Real Load | kW | 2,090 | 2,230 | 1,949 | 2,938 | 6,177 | 4,447 |
| | Feeder Reactive Load | kVAR | 92 | 102 | 117 | 122 | 272 | 162 |
| 29 | Distribution Losses | % | 0.26 | 1.29 | 1.84 | 2.23 | 0.96 | 0.83 |
| 30 | Distribution Power Factor | pf | 0.9988 | 0.9989 | 0.9977 | 0.9986 | 0.9989 | 0.9978 |
| 39 | CO2 Emissions | Tons | 7,900 | 8,936 | 8,127 | 12,086 | 25,477 | 16,561 |
| 40 | SOx Emissions | Tons | 3.59 | 4.08 | 3.76 | 5.59 | 11.73 | 7.50 |
| | NOx Emissions | Tons | 2.29 | 2.59 | 2.38 | 3.55 | 7.44 | 4.79 |
| | PM-10 Emissions | Tons | 1.17 | 1.33 | 1.21 | 1.79 | 3.78 | 2.46 |

Table E.13: VVO performance metrics for region 3

| Index | Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,550 | 3,575 | 1,595 | 3,635 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,862 | 2,610 | 1,164 | 2,654 |
| 3 | Peak Generation | kW | 6,442 | 9,177 | 4,359 | 8,444 |
| | Nuclear | % | 9.72 | 9.72 | 9.72 | 9.72 |
| | Solar | % | 0.13 | 0.13 | 0.13 | 0.13 |
| | Bio | % | 0.25 | 0.25 | 0.25 | 0.25 |
| | Wind | % | 2.45 | 2.45 | 2.45 | 2.45 |
| | Coal | % | 41.52 | 41.52 | 41.52 | 41.52 |
| | Hydroelectric | % | 5.83 | 6.40 | 6.40 | 6.40 |
| | Natural Gas | % | 37.88 | 37.88 | 37.88 | 37.88 |
| | Geothermal | % | 0.00 | 0.17 | 0.24 | 1.40 |
| | Petroleum | % | 0.00 | 0.00 | 0.00 | 0.57 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 6,402 | 8,983 | 4,302 | 8,183 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 22,419 | 31,907 | 14,076 | 32,952 |
| 12 | CO2 Emissions | Tons | 15,700 | 22,838 | 9,658 | 24,663 |
| 13 | SOx Emissions | Tons | 6.83 | 10.04 | 4.15 | 11.01 |
| | NOx Emissions | Tons | 4.25 | 6.22 | 2.59 | 6.79 |
| | PM-10 Emissions | Tons | 2.34 | 3.40 | 1.44 | 3.68 |
| 21 | Feeder Real Load | kW | 2,559 | 3,642 | 1,607 | 3,762 |
| | Feeder Reactive Load | kVAR | 219 | 282 | 145 | 188 |
| 29 | Distribution Losses | % | 0.35 | 1.86 | 0.74 | 3.36 |
| 30 | Distribution Power Factor | pf | 0.9967 | 0.9924 | 0.9966 | 0.9975 |
| 39 | CO2 Emissions | Tons | 15,756 | 23,271 | 9,731 | 25,520 |
| 40 | SOx Emissions | Tons | 6.86 | 10.23 | 4.18 | 11.39 |
| | NOx Emissions | Tons | 4.27 | 6.34 | 2.61 | 7.02 |
| | PM-10 Emissions | Tons | 2.35 | 3.47 | 1.45 | 3.80 |

Table E.14: VVO performance metrics for region 4

| Index | Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,257 | 1,854 | 808 | 338 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,647 | 1,354 | 590 | 247 |
| 3 | Peak Generation | kW | 6,108 | 4,724 | 2,208 | 951 |
| | Nuclear | % | 21.91 | 23.58 | 23.58 | 21.91 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.18 | 0.21 | 0.21 | 0.18 |
| | Wind | % | 0.60 | 0.59 | 0.59 | 0.60 |
| | Coal | % | 57.14 | 56.06 | 56.06 | 57.14 |
| | Hydroelectric | % | 0.86 | 3.09 | 3.09 | 2.20 |
| | Natural Gas | % | 17.49 | 16.14 | 16.14 | 17.49 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.00 | 3.09 | 0.47 | 1.16 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 6,073 | 4,627 | 2,174 | 934 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 19,830 | 16,627 | 7,239 | 3,037 |
| 12 | CO2 Emissions | Tons | 9,700 | 9,323 | 3,778 | 1,527 |
| 13 | SOx Emissions | Tons | 4.63 | 4.48 | 1.81 | 0.73 |
| | NOx Emissions | Tons | 2.82 | 2.72 | 1.10 | 0.45 |
| | PM-10 Emissions | Tons | 1.45 | 1.39 | 0.56 | 0.23 |
| 21 | Feeder Real Load | kW | 2,264 | 1,898 | 826 | 347 |
| | Feeder Reactive Load | kVAR | 139 | 47 | 95 | 44 |
| 29 | Distribution Losses | % | 0.30 | 2.31 | 2.20 | 2.40 |
| 30 | Distribution Power Factor | pf | 0.9981 | 0.9995 | 0.9934 | 0.9920 |
| 39 | CO2 Emissions | Tons | 9,729 | 9,543 | 3,863 | 1,565 |
| 40 | SOx Emissions | Tons | 4.65 | 4.58 | 1.86 | 0.75 |
| | NOx Emissions | Tons | 2.83 | 2.78 | 1.13 | 0.46 |
| | PM-10 Emissions | Tons | 1.45 | 1.42 | 0.58 | 0.23 |

Table E.15: VVO performance metrics for region 5

| Index | Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,665 | 4,382 | 2,176 | 4,588 | 3,388 | 4,037 | 5,490 | 5,535 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,945 | 3,199 | 1,588 | 3,350 | 2,473 | 2,947 | 4,007 | 4,040 |
| 3 | Peak Generation | kW | 5,710 | 9,236 | 4,994 | 10,311 | 7,411 | 8,950 | 12,177 | 12,188 |
| | Nuclear | % | 13.85 | 13.85 | 13.85 | 13.53 | 13.85 | 13.53 | 13.53 | 13.85 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.33 | 0.33 | 0.33 | 0.31 | 0.33 | 0.31 | 0.31 | 0.33 |
| | Wind | % | 1.48 | 1.48 | 1.48 | 1.74 | 1.48 | 1.74 | 1.74 | 1.48 |
| | Coal | % | 30.17 | 30.17 | 30.17 | 30.37 | 30.17 | 30.37 | 30.37 | 30.17 |
| | Hydroelectric | % | 0.25 | 0.21 | 0.63 | 0.78 | 0.63 | 0.78 | 0.78 | 0.56 |
| | Natural Gas | % | 51.68 | 51.68 | 51.68 | 51.29 | 51.68 | 51.29 | 51.29 | 51.68 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.00 | 0.00 | 1.90 | 1.27 | 0.27 | 0.98 | 3.04 | 0.00 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 5,679 | 9,103 | 4,850 | 9,699 | 7,253 | 8,693 | 11,983 | 12,031 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 23,428 | 38,849 | 19,463 | 42,054 | 30,256 | 36,208 | 48,770 | 49,108 |
| 12 | CO2 Emissions | Tons | 8,834 | 14,719 | 7,104 | 14,882 | 11,292 | 13,117 | 17,663 | 17,944 |
| 13 | SOx Emissions | Tons | 1.38 | 2.01 | 1.02 | 1.57 | 1.54 | 1.53 | 1.95 | 2.06 |
| | NOx Emissions | Tons | 1.27 | 1.97 | 0.98 | 1.77 | 1.51 | 1.63 | 2.15 | 2.22 |
| | PM-10 Emissions | Tons | 1.30 | 2.16 | 1.04 | 2.18 | 1.66 | 1.92 | 2.59 | 2.63 |
| 21 | Feeder Real Load | kW | 2,674 | 4,435 | 2,222 | 4,801 | 3,454 | 4,133 | 5,567 | 5,606 |
| | Feeder Reactive Load | kVAR | 250 | 231 | 88 | 92 | 148 | 166 | 173 | 530 |
| 29 | Distribution Losses | % | 0.35 | 1.20 | 2.07 | 4.42 | 1.91 | 2.34 | 1.40 | 1.27 |
| 30 | Distribution Power Factor | pf | 0.9962 | 0.9981 | 0.9979 | 0.9996 | 0.9983 | 0.9979 | 0.9986 | 0.9955 |
| 39 | CO2 Emissions | Tons | 8,865 | 14,898 | 7,255 | 15,570 | 11,512 | 13,431 | 17,913 | 18,174 |
| 40 | SOx Emissions | Tons | 1.38 | 2.04 | 1.04 | 1.64 | 1.57 | 1.57 | 1.98 | 2.09 |
| | NOx Emissions | Tons | 1.27 | 1.99 | 1.00 | 1.85 | 1.54 | 1.67 | 2.18 | 2.25 |
| | PM-10 Emissions | Tons | 1.30 | 2.19 | 1.06 | 2.28 | 1.69 | 1.97 | 2.62 | 2.66 |

## E.4 Individual CA Performance Metrics

Table E.16: CA performance metrics for region 1

| Index | Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,083 | 2,692 | 992 | 435 | 1,948 | 875 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,521 | 1,965 | 724 | 317 | 1,422 | 639 |
| 3 | Peak Generation | kW | 5,313 | 7,329 | 2,666 | 1,261 | 5,050 | 2,290 |
| | Nuclear | % | 10.68 | 10.68 | 10.68 | 10.68 | 10.09 | 10.68 |
| | Solar | % | 0.25 | 0.25 | 0.25 | 0.25 | 0.21 | 0.25 |
| | Bio | % | 0.67 | 0.67 | 0.67 | 0.67 | 0.72 | 0.67 |
| | Wind | % | 4.07 | 4.07 | 4.07 | 4.07 | 3.55 | 4.07 |
| | Coal | % | 2.88 | 2.88 | 2.88 | 2.88 | 4.38 | 2.88 |
| | Hydroelectric | % | 36.88 | 36.88 | 36.88 | 36.88 | 26.32 | 36.88 |
| | Natural Gas | % | 41.38 | 41.38 | 41.38 | 41.38 | 51.24 | 41.38 |
| | Geothermal | % | 2.84 | 2.84 | 2.84 | 2.84 | 3.11 | 2.02 |
| | Petroleum | % | 0.35 | 0.35 | 0.01 | 0.35 | 0.38 | 0.00 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 5,288 | 7,085 | 2,581 | 1,247 | 4,924 | 2,234 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 18,290 | 24,196 | 8,966 | 3,829 | 17,276 | 7,776 |
| 12 | CO2 Emissions | Tons | 1,783 | 2,273 | 819 | 392 | 1,774 | 751 |
| 13 | SOx Emissions | Tons | 0.03 | 0.03 | 0.01 | 0.01 | 0.04 | 0.01 |
| | NOx Emissions | Tons | 0.24 | 0.28 | 0.10 | 0.05 | 0.22 | 0.10 |
| | PM-10 Emissions | Tons | 0.25 | 0.32 | 0.12 | 0.06 | 0.25 | 0.11 |
| 21 | Feeder Real Load | kW | 2,088 | 2,762 | 1,024 | 437 | 1,972 | 888 |
| | Feeder Reactive Load | kVAR | 68 | -284 | -276 | 11 | 62 | -70 |
| 29 | Distribution Losses | % | 0.23 | 2.54 | 3.06 | 0.56 | 1.21 | 1.44 |
| 30 | Distribution Power Factor | pf | 0.9994 | 0.9925 | 0.9584 | 0.9997 | 0.9995 | 0.9666 |
| 39 | CO2 Emissions | Tons | 1,787 | 2,332 | 845 | 394 | 1,796 | 762 |
| 40 | SOx Emissions | Tons | 0.03 | 0.03 | 0.01 | 0.01 | 0.04 | 0.01 |
| | NOx Emissions | Tons | 0.24 | 0.29 | 0.11 | 0.05 | 0.22 | 0.10 |
| | PM-10 Emissions | Tons | 0.25 | 0.33 | 0.12 | 0.06 | 0.26 | 0.11 |

Table E.17: CA performance metrics for region 2

| Index | Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,169 | 2,268 | 1,970 | 2,975 | 6,342 | 4,576 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,584 | 1,656 | 1,438 | 2,171 | 4,630 | 3,340 |
| 3 | Peak Generation | kW | 5,749 | 6,287 | 5,777 | 8,555 | 16,840 | 12,676 |
| | Nuclear | % | 26.33 | 26.33 | 26.33 | 27.95 | 26.33 | 26.33 |
| | Solar | % | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| | Bio | % | 0.82 | 0.82 | 0.82 | 0.84 | 0.82 | 0.82 |
| | Wind | % | 1.41 | 1.41 | 1.41 | 1.70 | 1.41 | 1.41 |
| | Coal | % | 47.18 | 47.18 | 47.18 | 45.54 | 47.18 | 47.18 |
| | Hydroelectric | % | 7.42 | 7.42 | 7.42 | 9.05 | 7.42 | 7.42 |
| | Natural Gas | % | 16.33 | 16.33 | 16.33 | 14.47 | 16.33 | 16.33 |
| | Geothermal | % | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| | Petroleum | % | 0.43 | 0.43 | 0.43 | 0.37 | 0.43 | 0.43 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 5,720 | 6,166 | 5,647 | 8,360 | 16,622 | 12,533 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 19,050 | 20,128 | 17,588 | 26,686 | 56,091 | 40,417 |
| 12 | CO2 Emissions | Tons | 8,419 | 9,246 | 8,417 | 12,627 | 26,866 | 17,434 |
| 13 | SOx Emissions | Tons | 3.81 | 4.21 | 3.88 | 5.82 | 12.33 | 7.86 |
| | NOx Emissions | Tons | 2.43 | 2.67 | 2.46 | 3.69 | 7.81 | 5.02 |
| | PM-10 Emissions | Tons | 1.25 | 1.37 | 1.25 | 1.87 | 3.99 | 2.58 |
| 21 | Feeder Real Load | kW | 2,175 | 2,298 | 2,008 | 3,046 | 6,403 | 4,614 |
| | Feeder Reactive Load | kVAR | 92 | 116 | 146 | -130 | 333 | 69 |
| 29 | Distribution Losses | % | 0.25 | 1.27 | 1.87 | 2.36 | 0.96 | 0.82 |
| 30 | Distribution Power Factor | pf | 0.9989 | 0.9987 | 0.9973 | 0.9973 | 0.9986 | 0.9996 |
| 39 | CO2 Emissions | Tons | 8,440 | 9,365 | 8,578 | 12,932 | 27,125 | 17,579 |
| 40 | SOx Emissions | Tons | 3.82 | 4.26 | 3.95 | 5.96 | 12.45 | 7.93 |
| | NOx Emissions | Tons | 2.44 | 2.71 | 2.51 | 3.78 | 7.88 | 5.06 |
| | PM-10 Emissions | Tons | 1.25 | 1.39 | 1.27 | 1.92 | 4.03 | 2.61 |

Table E.18: CA performance metrics for region 3

| Index | Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,635 | 3,661 | 1,642 | 3,705 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,924 | 2,673 | 1,199 | 2,705 |
| 3 | Peak Generation | kW | 6,594 | 9,315 | 4,422 | 8,417 |
| | Nuclear | % | 8.65 | 9.72 | 9.72 | 9.72 |
| | Solar | % | 0.13 | 0.13 | 0.13 | 0.13 |
| | Bio | % | 0.23 | 0.25 | 0.25 | 0.25 |
| | Wind | % | 2.05 | 2.45 | 2.45 | 2.45 |
| | Coal | % | 40.24 | 41.52 | 41.52 | 41.52 |
| | Hydroelectric | % | 5.58 | 6.40 | 6.40 | 6.40 |
| | Natural Gas | % | 41.67 | 37.88 | 37.88 | 37.88 |
| | Geothermal | % | 1.25 | 1.40 | 1.40 | 1.40 |
| | Petroleum | % | 0.20 | 0.25 | 0.25 | 0.25 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 6,554 | 9,122 | 4,364 | 8,157 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 23,160 | 32,687 | 14,483 | 33,603 |
| 12 | CO2 Emissions | Tons | 16,269 | 23,430 | 9,963 | 25,107 |
| 13 | SOx Emissions | Tons | 7.03 | 10.24 | 4.25 | 11.14 |
| | NOx Emissions | Tons | 4.38 | 6.36 | 2.66 | 6.88 |
| | PM-10 Emissions | Tons | 2.42 | 3.49 | 1.48 | 3.74 |
| 21 | Feeder Real Load | kW | 2,644 | 3,731 | 1,653 | 3,836 |
| | Feeder Reactive Load | kVAR | 219 | 484 | 143 | 547 |
| 29 | Distribution Losses | % | 0.33 | 1.87 | 0.69 | 3.40 |
| 30 | Distribution Power Factor | pf | 0.9969 | 0.9904 | 0.9968 | 0.9897 |
| 39 | CO2 Emissions | Tons | 16,323 | 23,877 | 10,032 | 25,991 |
| 40 | SOx Emissions | Tons | 7.05 | 10.44 | 4.28 | 11.53 |
| | NOx Emissions | Tons | 4.39 | 6.48 | 2.67 | 7.12 |
| | PM-10 Emissions | Tons | 2.43 | 3.56 | 1.49 | 3.87 |

Table E.19: CA performance metrics for region 4

| Index | Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,339 | 1,909 | 832 | 347 |
| 2 | Monthly Customer Electricity Usage | MWh | 1,708 | 1,393 | 607 | 253 |
| 3 | Peak Generation | kW | 6,221 | 4,798 | 2,205 | 945 |
| | Nuclear | % | 21.91 | 21.91 | 23.58 | 23.58 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.18 | 0.18 | 0.21 | 0.21 |
| | Wind | % | 0.60 | 0.60 | 0.59 | 0.59 |
| | Coal | % | 57.14 | 57.14 | 56.06 | 56.06 |
| | Hydroelectric | % | 2.20 | 2.20 | 3.09 | 3.09 |
| | Natural Gas | % | 17.49 | 17.49 | 16.14 | 16.14 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 0.48 | 0.48 | 0.33 | 0.33 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 6,186 | 4,701 | 2,171 | 928 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 20,550 | 17,195 | 7,457 | 3,118 |
| 12 | CO2 Emissions | Tons | 10,321 | 9,844 | 3,994 | 1,608 |
| 13 | SOx Emissions | Tons | 4.91 | 4.72 | 1.92 | 0.77 |
| | NOx Emissions | Tons | 3.00 | 2.87 | 1.17 | 0.47 |
| | PM-10 Emissions | Tons | 1.54 | 1.47 | 0.60 | 0.24 |
| 21 | Feeder Real Load | kW | 2,346 | 1,963 | 851 | 356 |
| | Feeder Reactive Load | kVAR | 138 | -413 | 98 | 45 |
| 29 | Distribution Losses | % | 0.28 | 2.76 | 2.32 | 2.53 |
| 30 | Distribution Power Factor | pf | 0.9982 | 0.9666 | 0.9934 | 0.9920 |
| 39 | CO2 Emissions | Tons | 10,350 | 10,123 | 4,089 | 1,650 |
| 40 | SOx Emissions | Tons | 4.93 | 4.86 | 1.96 | 0.79 |
| | NOx Emissions | Tons | 3.00 | 2.95 | 1.19 | 0.48 |
| | PM-10 Emissions | Tons | 1.54 | 1.51 | 0.61 | 0.25 |

Table E.20: CA performance metrics for region 5

| Index | Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Hourly Customer Electricity Usage | kWh | 2,747 | 4,490 | 2,226 | 4,669 | 3,468 | 4,116 | 5,627 | 5,689 |
| 2 | Monthly Customer Electricity Usage | MWh | 2,005 | 3,278 | 1,625 | 3,408 | 2,532 | 3,005 | 4,108 | 4,153 |
| 3 | Peak Generation | kW | 5,841 | 9,451 | 4,992 | 10,429 | 7,531 | 9,041 | 12,282 | 12,428 |
| | Nuclear | % | 13.85 | 13.85 | 13.85 | 13.53 | 13.85 | 13.53 | 13.85 | 13.85 |
| | Solar | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Bio | % | 0.33 | 0.33 | 0.33 | 0.31 | 0.33 | 0.31 | 0.33 | 0.33 |
| | Wind | % | 1.48 | 1.48 | 1.48 | 1.74 | 1.48 | 1.74 | 1.48 | 1.48 |
| | Coal | % | 30.17 | 30.17 | 30.17 | 30.37 | 30.17 | 30.37 | 30.17 | 30.17 |
| | Hydroelectric | % | 0.63 | 0.63 | 0.63 | 0.78 | 0.63 | 0.78 | 0.63 | 0.63 |
| | Natural Gas | % | 51.68 | 51.68 | 51.68 | 51.29 | 51.68 | 51.29 | 51.68 | 51.68 |
| | Geothermal | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Petroleum | % | 1.86 | 1.86 | 1.86 | 2.41 | 1.86 | 1.98 | 1.86 | 1.86 |
| | Distributed Solar PV | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Distributed Wind | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Peak Load | kW | 5,810 | 9,319 | 4,848 | 9,817 | 7,373 | 8,784 | 12,088 | 12,270 |
| | Controllable load | % | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | Annual Electricity Production | MWh | 24,144 | 39,806 | 19,900 | 42,787 | 30,976 | 36,921 | 49,992 | 50,486 |
| 12 | CO2 Emissions | Tons | 9,364 | 15,419 | 7,414 | 15,201 | 11,809 | 13,594 | 18,504 | 18,904 |
| 13 | SOx Emissions | Tons | 1.55 | 2.23 | 1.11 | 1.65 | 1.70 | 1.66 | 2.19 | 2.34 |
| | NOx Emissions | Tons | 1.38 | 2.11 | 1.04 | 1.83 | 1.61 | 1.72 | 2.31 | 2.41 |
| | PM-10 Emissions | Tons | 1.37 | 2.26 | 1.09 | 2.23 | 1.73 | 1.99 | 2.71 | 2.77 |
| 21 | Feeder Real Load | kW | 2,756 | 4,544 | 2,272 | 4,884 | 3,536 | 4,215 | 5,707 | 5,763 |
| | Feeder Reactive Load | kVAR | 248 | 542 | 242 | -356 | 407 | 594 | 650 | 641 |
| 29 | Distribution Losses | % | 0.33 | 1.19 | 2.02 | 4.41 | 1.92 | 2.34 | 1.39 | 1.28 |
| 30 | Distribution Power Factor | pf | 0.9964 | 0.9937 | 0.9952 | 0.9779 | 0.9942 | 0.9913 | 0.9942 | 0.9944 |
| 39 | CO2 Emissions | Tons | 9,395 | 15,605 | 7,567 | 15,901 | 12,040 | 13,919 | 18,766 | 19,150 |
| 40 | SOx Emissions | Tons | 1.55 | 2.26 | 1.14 | 1.72 | 1.73 | 1.70 | 2.22 | 2.37 |
| | NOx Emissions | Tons | 1.39 | 2.14 | 1.06 | 1.91 | 1.65 | 1.76 | 2.34 | 2.44 |
| | PM-10 Emissions | Tons | 1.38 | 2.29 | 1.11 | 2.33 | 1.77 | 2.04 | 2.75 | 2.81 |

## E.5 Individual Reclosers and Sectionalizers Performance Metrics

Table E.21: Reclosers and sectionalizers performance metrics for region 1

| Index | Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 0.30 | 1.00 | 1.17 | 1.16 | 1.07 |
| 33 | SAIDI | Minutes | 86.59 | 36.21 | 43.52 | 84.03 | 75.12 | 85.10 |
| | CAIDI | Minutes | 66.75 | 121.94 | 43.37 | 71.63 | 64.76 | 79.28 |
| 34 | MAIFI | # | 1.95 | 1.00 | 13.23 | 1.79 | 8.95 | 1.30 |

Table E.22: Reclosers and sectionalizers performance metrics for region 2

| Index | Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 0.55 | 0.44 | 0.26 | 0.88 | 1.01 |
| 33 | SAIDI | Minutes | 86.59 | 55.82 | 37.12 | 30.38 | 61.79 | 89.07 |
| | CAIDI | Minutes | 66.75 | 101.96 | 85.00 | 115.83 | 70.40 | 88.36 |
| 34 | MAIFI | # | 1.95 | 0.51 | 0.92 | 0.05 | 5.17 | 0.43 |

Table E.23: Reclosers and sectionalizers performance metrics for region 3

| Index | Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 0.57 | 1.17 | 0.51 |
| 33 | SAIDI | Minutes | 86.59 | 60.60 | 83.89 | 57.70 |
| | CAIDI | Minutes | 66.75 | 105.73 | 71.96 | 112.94 |
| 34 | MAIFI | # | 1.95 | 0.73 | 2.52 | 0.90 |

Table E.24: Reclosers and sectionalizers performance metrics for region 4

| Index | Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.05 | 0.75 | 1.15 |
| 33 | SAIDI | Minutes | 86.59 | 56.77 | 74.71 | 65.18 |
| | CAIDI | Minutes | 66.75 | 53.95 | 100.24 | 56.88 |
| 34 | MAIFI | # | 1.95 | 11.46 | 0.47 | 5.07 |

Table E.25: Reclosers and sectionalizers performance metrics for region 5

| Index | Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.15 | 0.62 | 0.98 | 1.18 | 1.16 | 0.56 | 1.19 |
| 33 | SAIDI | Minutes | 86.59 | 61.58 | 60.42 | 77.00 | 65.85 | 100.28 | 61.77 | 92.15 |
| | CAIDI | Minutes | 66.75 | 53.50 | 97.68 | 78.75 | 55.63 | 86.64 | 110.52 | 77.74 |
| 34 | MAIFI | # | 1.95 | 6.21 | 1.26 | 1.33 | 6.75 | 0.26 | 0.00 | 0.97 |

## E.6 Individual DMS&OMS Performance Metrics

Table E.26: DMS&OMS performance metrics for region 1

| Index | Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.17 | 1.18 | 1.17 | 1.16 | 1.17 |
| 33 | SAIDI | Minutes | 92.43 | 76.73 | 90.18 | 79.14 | 92.48 | 75.15 |
| | CAIDI | Minutes | 71.25 | 65.60 | 76.56 | 67.47 | 79.72 | 64.50 |
| 34 | MAIFI | # | 0.00 | 2.00 | 1.00 | 3.00 | 0.00 | 0.62 |

Table E.27: DMS&OMS performance metrics for region 2

| Index | Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.29 | 1.14 | 1.16 | 1.16 | 1.18 |
| 33 | SAIDI | Minutes | 92.43 | 83.95 | 80.59 | 76.55 | 82.20 | 87.98 |
| | CAIDI | Minutes | 71.25 | 64.86 | 70.98 | 66.07 | 70.93 | 74.25 |
| 34 | MAIFI | # | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.43 |

Table E.28: DMS&OMS performance metrics for region 3

| Index | Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.21 | 1.17 | 1.19 |
| 33 | SAIDI | Minutes | 92.43 | 81.14 | 88.20 | 84.42 |
| | CAIDI | Minutes | 71.25 | 67.15 | 75.66 | 71.23 |
| 34 | MAIFI | # | 0.00 | 2.00 | 1.00 | 0.00 |

Table E.29: DMS&OMS performance metrics for region 4

| Index | Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.16 | 1.19 | 1.15 |
| 33 | SAIDI | Minutes | 92.43 | 82.72 | 81.21 | 79.56 |
| | CAIDI | Minutes | 71.25 | 71.40 | 68.05 | 69.43 |
| 34 | MAIFI | # | 0.00 | 0.00 | 1.00 | 1.00 |

Table E.30: DMS&OMS performance metrics for region 5

| Index | Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-25.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.17 | 1.18 | 1.19 | 1.18 | 1.17 | 1.17 | 1.19 |
| 33 | SAIDI | Minutes | 92.43 | 80.95 | 77.71 | 79.22 | 84.86 | 93.37 | 80.37 | 84.86 |
| | CAIDI | Minutes | 71.25 | 69.23 | 66.06 | 66.68 | 71.70 | 80.06 | 68.64 | 71.59 |
| 34 | MAIFI | # | 0.00 | 0.00 | 1.00 | 0.31 | 1.00 | 1.00 | 1.00 | 1.00 |

## E.7 Individual FDIR Performance Metrics

Table E.31: FDIR performance metrics for region 1

| Index | Metric | Units | GC-12.47-1 R1 | R1-12.47-1 | R1-12.47-2 | R1-12.47-3 | R1-12.47-4 | R1-25.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 0.30 | 1.00 | 1.17 | 1.16 | 1.07 |
| 33 | SAIDI | Minutes | 55.78 | 25.21 | 29.33 | 62.57 | 48.20 | 62.06 |
| | CAIDI | Minutes | 43.00 | 84.88 | 29.23 | 53.34 | 41.55 | 57.82 |
| 34 | MAIFI | # | 1.95 | 0.00 | 13.23 | 0.05 | 8.95 | 1.30 |

Table E.32 : FDIR performance metrics for region 2

| Index | Metric | Units | GC-12.47-1 R2 | R2-12.47-1 | R2-12.47-2 | R2-12.47-3 | R2-25.00-1 | R2-35.00-1 |
|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 0.55 | 0.44 | 0.26 | 0.88 | 1.01 |
| 33 | SAIDI | Minutes | 55.78 | 35.49 | 31.27 | 21.28 | 39.81 | 64.82 |
| | CAIDI | Minutes | 43.00 | 64.83 | 71.60 | 81.16 | 45.36 | 64.31 |
| 34 | MAIFI | # | 1.95 | 0.51 | 0.92 | 0.05 | 5.17 | 0.43 |

Table E.33: FDIR performance metrics for region 3

| Index | Metric | Units | GC-12.47-1 R3 | R3-12.47-1 | R3-12.47-2 | R3-12.47-3 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 0.57 | 1.17 | 0.51 |
| 33 | SAIDI | Minutes | 55.78 | 40.87 | 53.70 | 41.12 |
| | CAIDI | Minutes | 43.00 | 71.31 | 46.07 | 80.50 |
| 34 | MAIFI | # | 1.95 | 0.73 | 2.52 | 0.90 |

Table E.34: FDIR performance metrics for region 4

| Index | Metric | Units | GC-12.47-1 R4 | R4-12.47-1 | R4-12.47-2 | R4-25.00-1 |
|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.05 | 0.75 | 1.15 |
| 33 | SAIDI | Minutes | 55.78 | 36.38 | 50.17 | 42.02 |
| | CAIDI | Minutes | 43.00 | 34.57 | 67.32 | 36.67 |
| 34 | MAIFI | # | 1.95 | 11.46 | 0.47 | 5.07 |

Table E.35: FDIR performance metrics for region 5

| Index | Metric | Units | GC-12.47-1 R5 | R5-12.47-1 | R5-12.47-2 | R5-12.47-3 | R5-12.47-4 | R5-12.47-5 | R5-25.00-1 | R5-35.00-1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | SAIFI | Interruptions /yr. | 1.30 | 1.15 | 0.62 | 0.98 | 1.18 | 1.16 | 0.56 | 1.19 |
| 33 | SAIDI | Minutes | 55.78 | 39.44 | 40.55 | 50.16 | 42.19 | 80.78 | 41.82 | 71.47 |
| | CAIDI | Minutes | 43.00 | 34.26 | 65.55 | 51.30 | 35.64 | 69.79 | 74.83 | 60.29 |
| 34 | MAIFI | # | 1.95 | 6.21 | 1.26 | 1.33 | 6.75 | 0.26 | 0.00 | 0.97 |

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