Protection, Control and Automation Requirements for Potential DOD Microgrid Systems

A Thesis

Presented in Partial Fulfillment of the Requirements for the

Degree of Master of Science

with a

Major in Electrical Engineering

in the

College of Graduate Studies

University of Idaho

by

Ajay Sitaula

Major Professor: Brian K. Johnson, Ph.D.

Committee Members: Herbert Hess, Ph.D.; Joseph Law, Ph.D.

Department Administrator: Mohsen Guizani, Ph.D.

December 2016

AUTHORIZATION TO SUBMIT THESIS

This thesis of Ajay Sitaula, submitted for the degree of Master of Science with a major in Electrical Engineering and titled "Protection, Control and Automation Requirements for Potential DOD Microgrid Systems," has been reviewed in final form. Permission, as indicated by the signatures and dates given below, is now granted to submit final copies to the College of Graduate Studies for approval.

Major Professor: ______________________________ Date: ____________
Brian K. Johnson, Ph.D.

Committee Members: ______________________________ Date: ____________
Herbert Hess, Ph.D.

______________________________ Date: ____________
Joseph Law, Ph.D.

Department Administrator: ______________________________ Date: ____________
Mohsen Guizani, Ph.D.

ABSTRACT

Currently, the majority of the Department of Defense (DOD) facilities (particularly military bases) operate with aging electrical infrastructure that was designed in the 1960s or 70s and since been patched to make it work. The reliability of the overall distribution is generally lower than the utility serving outside the facilities. The aging infrastructures lack consistency and standardization. As the electrical infrastructures become unsustainable (which they will at some point), the DOD will be forced to overhaul them with major system upgrade projects. Recently, DOD and Department of Energy (DOE) also have established various initiatives and task forces to explore feasibility of making DOD facilities more energy independent and secure so that in the event of long-term utility lost they can sustain operations for extended period of time. The best way to accomplish these initiatives is to implement a stable microgrid system in these facilities. As the DOD facilities go through major infrastructure overhaul, integrating microgrid ready design concepts to such upgrade projects would make the DOD smart microgrid systems most practical and cost effective.

Majority of the DOD facility load and distribution system is different from the typical utility loads. Typical utility load encompasses a larger geographical area and has various types of loads (such as residential, commercial, and industrial) scattered in different areas. DOD facilities on the other hand have all of the different types of loads in a very close proximity and in smaller scale. In addition, the DOD facilities also have critical and extra-critical loads which need multiple redundancy and backup generation right next to the non-critical loads. In order to implement an effective microgrid at such facilities, the existing infrastructure must be upgraded to a point where every major switching device is intelligent and capable of high-speed communications. On-site generation, high-speed control and protection, effective load-shedding, and system auto-reconfiguration are essential requirements for an effective and sustainable microgrid.

This thesis defines microgrid for permanent DOD installations and establishes a representative existing electrical system based on the typical electrical configurations and load characteristics found at the majority of the permanent military installations. Baseline requirements for an installation-wide large-scale microgrid system is defined and a range of component upgrade or system reconfiguration is outlined to meet the microgrid requirements. A representative microgrid-ready system is developed for modelling and technical studies such as load-flow, short-circuit, and on-site generator stability analysis. Based on the results of the studies, key technical challenges and recommended mitigations are outlined for DOD microgrid design considerations. Based on various literature reviews, a conceptual network layout of an example communication architecture for the representative microgrid-ready system is also presented.

ACKNOWLEDGEMENTS

I thank my major professor, Dr. Brian K. Johnson for being my mentor and guide all through my Master's program. He has taken keen interest in supporting me at every stage of my research with prompt inspirations and timely suggestions, kindness and enthusiasm which helped me, to a great extent, in completing my thesis.

I am thankful for my Employer City Light & Ponsientwer, Inc for providing me with financial support and access to commercial grade software for modelling and analysis. Also, I am grateful for all the military installations and their electrical shop and engineering department personnel that I have collaborated with during last eight years.

Last but not least, I would like to thank my family for their sacrifice and support throughout my academic endeavour. I would not be able to complete this thesis without their unwavering belief and support.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYMS

AC – Alternating Current

AMI – Advanced Metering Infrastructure

ANSI – American National Standards Institute

ATS – Automatic Transfer Switch

BBTU – Billion British Thermal Units

BIL – Basic Impulse Level

BLDG. – Building

CHP – Combined Heat and Power

Cogen – Cogeneration

CONFIG – Configuration

CT – Current Transformer

CTI – Coordination Time Interval

DA – Distribution Automation

DER – Distributed Energy Resources

DMFR – Digital Multi-Functional Relay

DNP – Distributed Network Protocol

DOD – Department of Defense

DOE – Department of Energy

DON – Department of Navy

ETAP – Electrical Transient Analyzer Program

FA – Oil Natural Air Forced (Legacy ANSI nomenclature that was replaced by ONAF)

FY – Fiscal Year

GW - Gigawatt

HVAC – Heating, Ventilation, and Air Conditioning

ID - Identification

IEC - International Electrotechnical Commission

IED – Intelligent Electronic Device

kV – kilo-Volt

kVA – kilo-Volt Ampere

LTC - Load Tap Changer

MVA – Mega-Volt Ampere

NO – Normally Open

OA – Oil Natural Air Natural (Legacy ANSI nomenclature that was replaced by ONAN)

ONAF – Oil Natural Air Forced

ONAN – Oil Natural Air Natural

OSI - Open System Interconnection

PCC – Point of Common Coupling

PMS – Pad-Mounted Switch

POD – Point of Demarcation

RDECOM P&E TFT – Research, Development and Engineering Command Power and Energy Technical Focus Team

SC – Short Circuit

SCADA – Supervisory Control and Data Acquisition System

SPIDERS – Smart Power Infrastructure Demonstration of Energy Reliability and Security

TCC – Time Coordination Curve

TCP/IP - Transmission Control Protocol/Internet Protocol

TOC – Time Overcurrent

uGRID – Microgrid

UPS – Uninterruptable Power Supply

VFI – Vacuum Fault Interrupter

VT – Voltage Transformer

WSN - wireless Sensor Networks

XFMR - Transformer

CHAPTER 1: INTRODUCTION

The United States Department of Defence (DOD) is the largest single energy consumer in the world. A significant portion of the total energy used by the DOD is consumed by its bases, also known as installations. The bases are the military's power projection platforms that facilitate research, development, testing, training, storage, mobilization, administrative, command, control, troop readiness, and public relations functions. Electricity, natural gas, and petroleum based liquid fuels are the primary energy sources that fulfil energy requirements by the military bases. There are more than 500 military bases throughout the US and abroad. Approximately 99% of the electricity demand to the bases is supplied by the commercial grid from outside the base [1]. For most part, the electric power generation sites are far away from the bases, which leaves them vulnerable to disturbances to transmission, sub-transmission, or even local distribution systems outside the base.

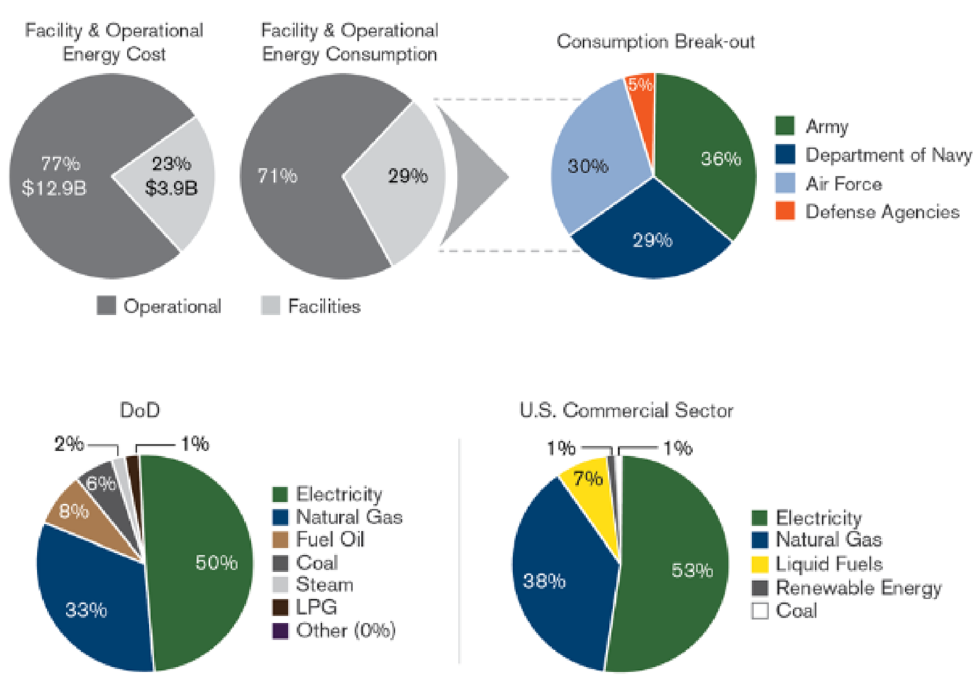


Figure 1.1 – DOD Energy Consumption (FY2015) for Facilities and Operations [2]

Figure 1.1 shows DOD energy consumption cost and percentage by facilities versus operational use and by type of energy sources. Notice that the electricity is the largest source of the energy used by all the DOD facilities. In FY 2015, DOD facilities used 211,095 billion British Thermal Units (BBTU) of facility energy out of which 50% was electricity [2]. The US Army is the largest consumer of facility energy followed by the Air Force and the Department of Navy (DON). Therefore, strengthening and securing electricity supply and making electrical distribution grid within the installations more reliable and resilient are essential to ensure successful missions and operations of our military installations even if there is a major crisis outside the installations.

1.1 Typical Utility Interconnections and Distribution Arrangements

The majority of the military bases receive utility power at distribution or sub-transmission voltage levels. Typical voltage levels at the point of demarcation (POD) range from 35kV to 138kV. Many of the bases have more than one point of utility supply; however, there are handful of bases that rely on single utility supply at the POD. For those bases with multiple supply points, many of them have different levels of voltages at their POD, which creates issues with interconnections and back feeding of electrical circuits within the base distribution systems. Phase rotations, neutral wire configurations, and grounding system are also not always consistent between the various supplies to the bases. Utility supply circuits at lower voltage levels are often routed through a long distance and supply many other load centers before entering to the base. Such supply circuits exhibit lower fault duty, voltage drops, frequent interruptions, and unreliable power.

Figure 1.2 shows the typical configurations of primary distribution systems defined by the "Joint Departments of the Army and Air Force, TM 5-811-1/AFJMAN 32-1080, Electrical Power Supply and Distribution" design manual published in 1995 [3] .

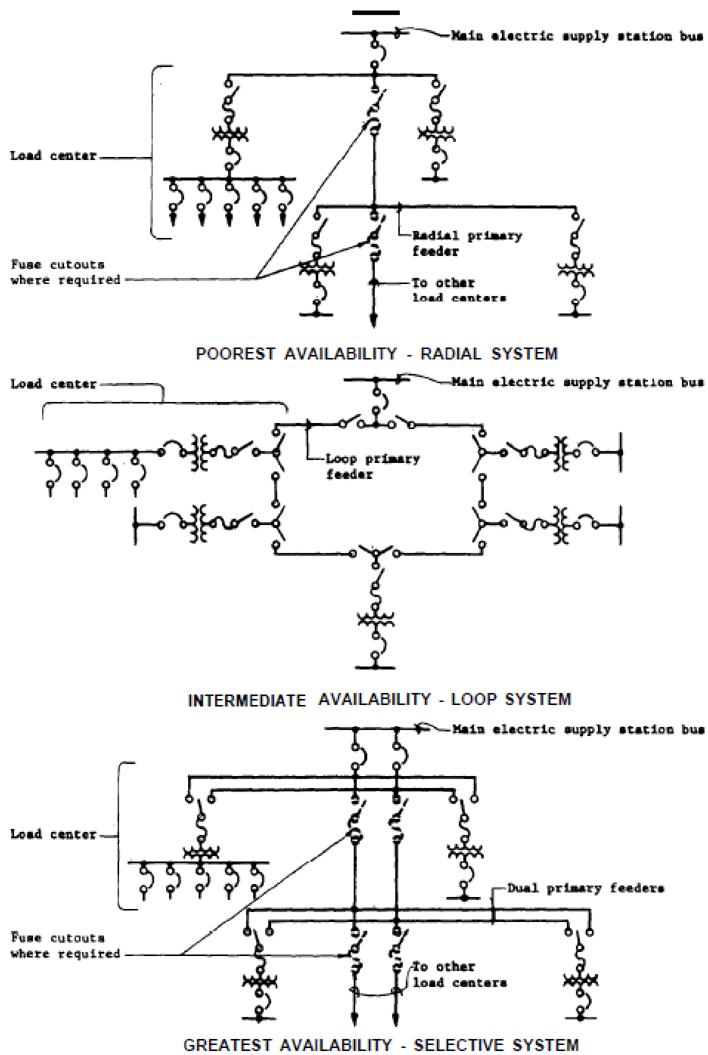


Figure 1.2 – Commonly Used Primary Distribution Arrangements for Army and Air Force Installations [3]

Most of the US military bases are several decades old and therefore contain fairly old electrical infrastructure. As shown in the Figure 1.2, the Army and Air Force design manual classifies 3 types of commonly designed primary distribution arrangements. The first one (top) is a radial circuit arrangement and it is the one most commonly used across many of the installations throughout the US. The second one (middle) is a less common arrangement, but can be seen as one form or another at many of the bases. The third one (bottom) is rare and only used at handful of newer installations. The radial arrangement is most common due to reduced cost of installation, ease of switching operations, ease of design of protection schemes, and for metering purposes. However, this arrangement lacks redundancy and system restoration capabilities ultimately impacting reliability of the power system to the end user.

1.2 Load Characteristics

DOD facilities feature similar types of electrical loads to those typically seen in medium scale cities. However, they may be scaled down in size and confined within a smaller geographical area. Such types of loads include commercial buildings, industrial facilities, residential areas, hospitals, airport(s), schools, and shopping centers. In addition to the typical electrical loads types listed above, many of the installations also include military specific mission critical loads such as ammunition storage and handling facilities, communication and controls, data centers and research/testing laboratories. The electrical service requirements for the mission critical loads set the DOD systems apart from utility systems.

The daily load profile for typical DOD facilities vary substantially because most of the people working inside the DOD facilities may leave the site during the evening and night. Commercial, industrial, schools, and shopping centers usually have minimal occupancy during the night. Hospitals, data centers, climate controlled testing laboratories, and ammunition storage facilities on the other hand exhibit fairly constant daily load profiles. Airfield and hanger electrical loads profile experience large variations depending on how often the aircrafts are taken in and out from the hangers every day. Unlike typical utility transformers outside the DOD, DOD facility service transformers are more lightly loaded. This is mainly due to lack of technical obligations and oversights to “right size” the equipment during the design phase because the DOD installations typically pay energy bills as a bulk that is metered at the point of demarcation (POD) with the local utility. Many of the service transformers are also sized for facilities with certain mission, and later on the facilities get repurposed to different missions or functions.

UFC 3-540-01 classifies facility loads to three main categories: uninterruptable, essential, and nonessential [4]. Uninterruptable loads require continuous power and cannot experience even momentary power disruptions. Loads in this category usually involve life safety or include hazardous or industrial process equipment, command, control, computer, data center, and communications systems. These loads will usually require the use of battery backup or an uninterruptible power system (UPS) to power them until supplied with power from an engine generator system. Essential loads require backup power, but can be deenergized until they can be supplied from an engine generator system. Loads in this category usually include HVAC loads to vital facilities or other load types that can be deenergized for short periods without severe consequence. Nonessential loads can be deenergized for extended periods without severe consequence. Although these loads might be classified as nonessential, they might still be capable of being energized from engine generators, depending on the facility design. For most systems, nonessential loads do not require generator backup.

1.3 Backup Generators

Facilities that include uninterruptable and essential loads typically include backup generators also known as emergency generators. Such generators are engine-driven with either diesel or natural gas fuel. UFC 3-540-01 defines six example configurations of backup generators for DOD facilities. Among the six configurations, two of them are the most commonly used by most of the DOD facilities that require backup generators. As shown in Figure 1.3 and Figure 1.4, the two most common configurations are (1) Single Engine Generator Supply to Essential Loads and (2) Single Engine Generator Configuration for Whole Building Supply.

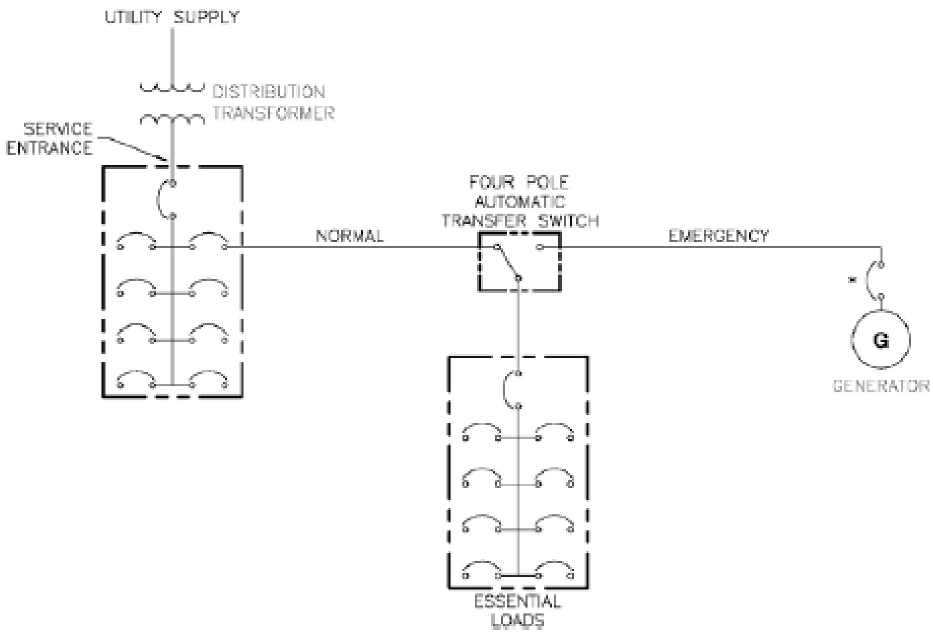


Figure 1.3 – Single Engine Generator Supply to Essential Loads [4]

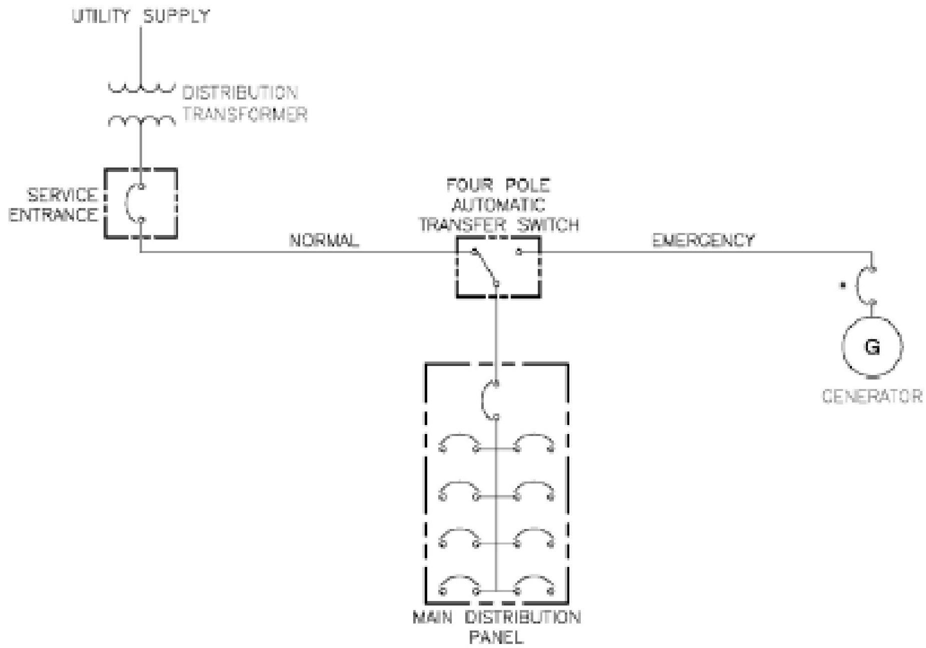


Figure 1.4 – Single Engine Generator Configuration for Whole Building Supply [4]

The first backup generator configuration shown in Figure 1.3 shows a separate service panel with essential load where the backup generator is connected with the automatic transfer switch (ATS). The second backup generator configuration, as shown in the Figure 1.4, has the entire facility load service panel connected to the backup generator via ATS switch. If the utility power is out, the backup generator is designed to pick up the entire facility load. The configuration shown in Figure 1.4 is the most common one because it is the easiest to design and implement. However, the downside of this configuration is that it needs to be designed for worst case maximum demand of the facility and often will have to be lightly loaded.

1.4 Reliability and Energy Security

The current US electrical grid heavily relies on ageing 20th century technology where power generation is centralized in remote areas and power is transmitted through long interconnected transmission lines before it gets to the local distribution systems and load centers. Typically, DOD facilities are located at the far end of the electrical utility's distribution system and almost completely dependent on commercial electrical power from the national electrical grid via local utilities. Any disruptions to the local, regional, or national grid network directly impacts electrical supply to DOD installations.

The US electrical grid is highly susceptible to several threats such as severe weather or natural disasters, direct physical attacks, cyber-attacks, major equipment failures, or human errors. Within the transmission portion of the grid, there are 55,000 transmission substations, and according to a Federal Energy Regulatory Commission study, the loss of just nine of these nodes could result in a regional or nationwide outage that could last for weeks or possibly months, with restoration delayed by lack of available replacements [5].

As shown in Figure 1.5, US electrical system is divided into three major regional grid systems knowns as the Western, Eastern, and Texas Interconnections. Although there are AC links between these three major grids systems, they are not strong enough to help the regions during emergencies. Intentional and coordinated attacks, either physical or cyber, by international or domestic adversaries can take down any of the grids for long term, leaving DOD facilities within the region out of power for a sustained period of time.

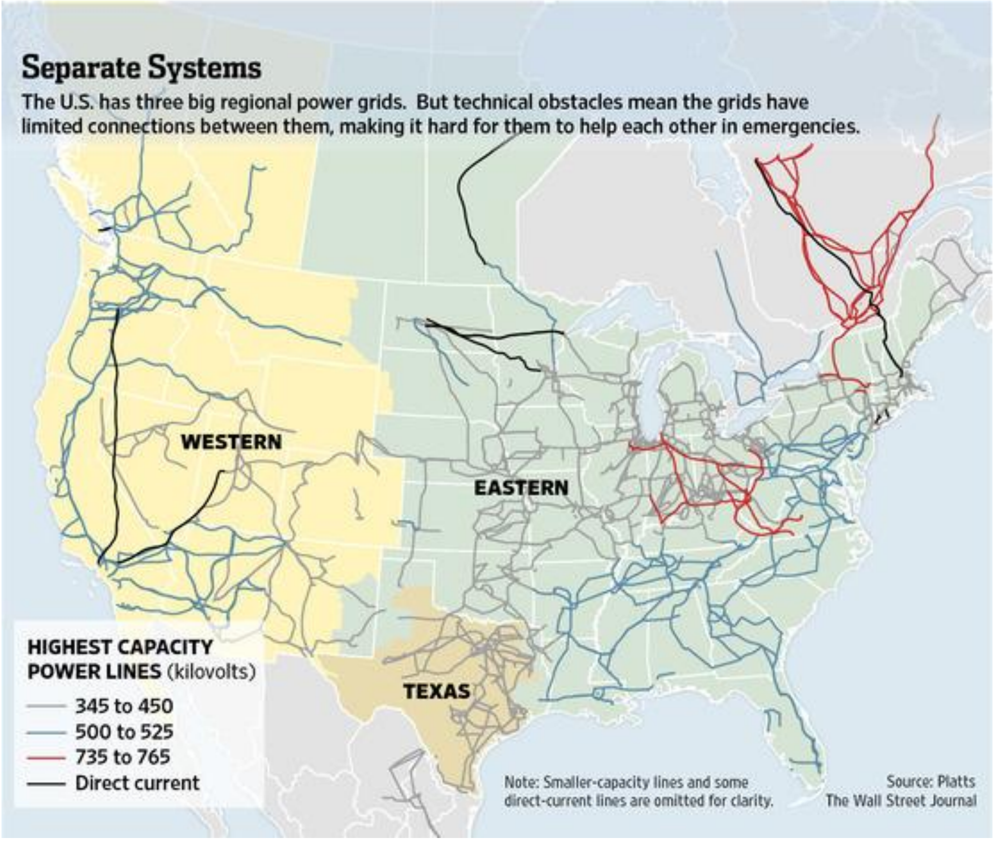


Figure 1.5 – Overview of the US Electrical Grid [6]

At military installations across the country, critical communication facilities and data centers are operational 24 hours a day 365 days a year to receive and analyze vital data to identify threats and provide direction and support to our troops. Control and command centers operate around the clock to provide direct support and direction to men and women in uniform who put their lives in line to keep us safe. Hospitals and medical centers across the DOD facilities provide vital care and supports to troops, veterans, and their families. Laboratories and testing centers provide platforms for proving tests of military weapons, vehicles, communication devices, and other accessories that need quick turnaround for field deployment to give troops a technical advantage against adversaries. Military installations also provide important platforms for troop training, preparedness, and deployment for war fighting and disaster relief efforts. A resilient electrical power supply, especially during the emergency situations, is extremely vital to keep all the operations smooth so that military bases are always ready to fulfil their purpose and commitments.

In recent years, DOE Office of Electricity Delivery and Energy Reliability (OE) is introducing various initiatives to modernize the U.S. electrical grid. The main goal of the OE is to ensure a resilient, reliable, and flexible electric grid as the modernization efforts continue. In order to achieve its goal, the OE is leveraging technology innovations and institutional support [7]. Figure 1.6 illustrates the OE's vision for grid modernization.

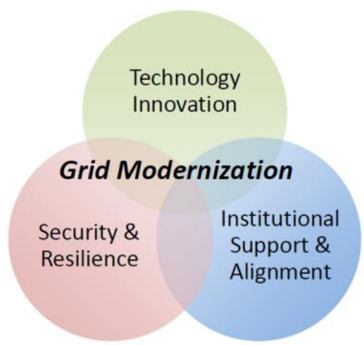


Figure 1.6 – DOE Initiatives for Grid Modernization [7]

As defined by [2] "DOD energy resilience is, the ability to prepare for and recover from energy disruptions that impact mission assurance on military installations. Further, it is the necessary planning and capability to ensure available, reliable, and quality power to continuously accomplish DOD missions". To achieve such energy resiliency as defined above, the DOD must establish two baseline requirements within the electrical distribution system in its installations: (1) reliable and economical on-site (distributed) generation and (2) smart electrical infrastructure that can sense external utility disruptions and quickly isolate and reconfigure itself to operate independently in a base-wide microgrid fashion.

1.5 Problem Statement

The majority of existing electrical distribution systems within the DOD installations present several problems and obstacles that prevent the DOD from assuming the degree of reliability that is required to achieve energy resiliency and security as defined in Section 1.4. One of the deficiencies for achieving desired energy resiliency is the lack of on-site generations that are stable, sustainable, economical, and readily available to supply base load in the event the external commercial power is lost. Although most of the critical facilities have emergency back-up generators, they are costly to operate and maintain. Such generators may fulfill short or medium term (hours or days) outages. However, they may not be capable to operate for long-term outages that may last for weeks and even months. Recently, there has been increased research and development on distributed generation to include combined heat and power, renewables, and micro-nuclear plants which are suitable for DOD installations [5].

Another major, but less understood, deficiency for achieving desired energy resiliency in DOD installations is the lack of smart (automated) sensing, communications, protection, control, switching, sectionalizing, and auto-reconfiguration capabilities in the substations and distribution systems. Majority of the DOD electrical infrastructure is old and aging. As a result, a frequent equipment failure is becoming dominant cause for power outages in many of the installations. In addition, because the existing system is mostly manual, the restoration efforts take significant amount of time causing outages to last for an extended period [8]. Figure 1.7 provides percent distribution of causes for utility outages and typical duration data of the outages in DOD installations. Notice that the equipment failure is the dominant cause of the utility outages in FY2015.

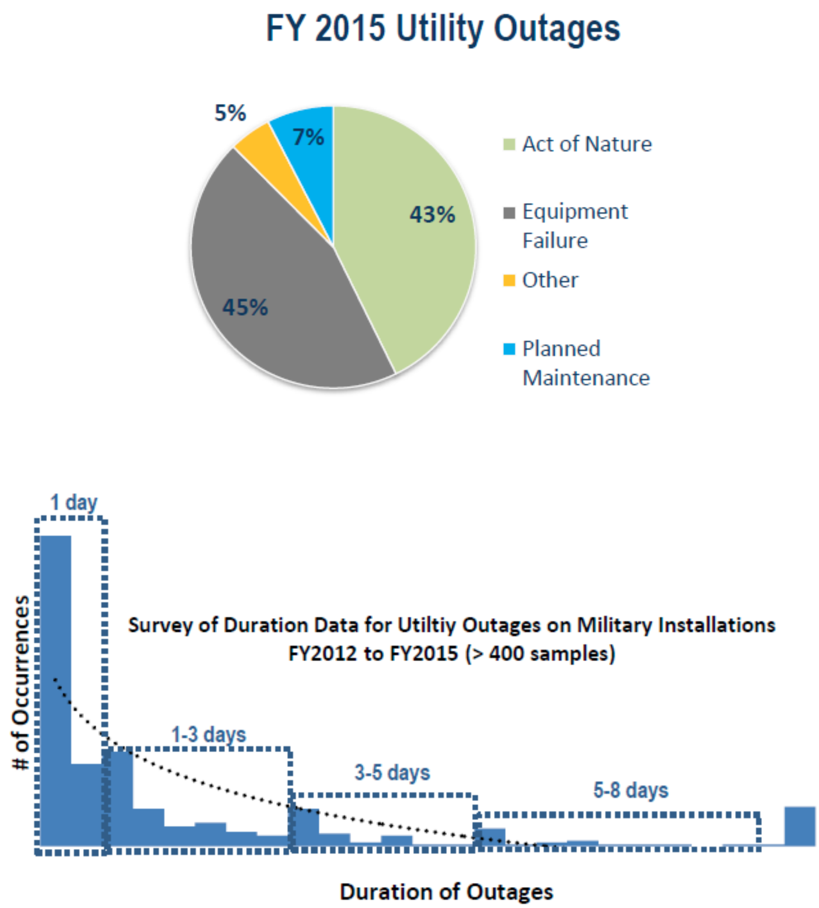


Figure 1.7 – Sample of Utility Outages and Durations for DOD Installations [8]

Lately DOD is funding major upgrade projects to replace and renew electrical infrastructures across the US. However, there may be not enough considerations given to microgrid-ready systems when funding such upgrades or replacements.

Besides the need for onsite generation and upgrade of the aging infrastructure, a successful implementation of microgrids requires careful analysis of technical challenges such as switching configurations for various load-flow scenarios, parallel versus islanded operations of the on-site generation, coordination with backup generators, short circuit analysis and re-coordination of protective devices, dynamic response of generator machines during islanding, load-shedding schemes, and speed or latency of communications protocols.

1.6 Objectives of this Thesis

The main objectives of this study are following:

1. Define what a microgrid is for DOD installations – **Chapter 2**.
2. Establish generalized single-line diagram of a distribution system that represents typical DOD existing electrical systems – **Chapter 3**.
3. Outline recommended upgrades/changes to the representative system that makes the system microgrid ready – **Chapter 3**.
4. Update the representative single-line to a microgrid-ready system – **Chapter 3**.
5. Develop a simulation model of the representative microgrid ready system – **Chapter 4**.
6. Perform load-flow analysis and outline technical challenges and recommended solutions for onsite generation and microgrid operations – **Chapter 5**.
7. Perform short circuit analysis, high-level coordination study, and outline issues and solutions for on-site generation and microgrid operations – **Chapter 5**.
8. Perform high-level frequency response analysis of the on-site generators and determine required communication and switching speed for stable operation of microgrid – **Chapter 5**.
9. Research and define a recommended communications architecture and protocol selections for the representative microgrid-ready system – **Chapter 6**.
10. Outline recommendations for future studies – **Chapter 7**.

CHAPTER 2: REVIEW OF MICROGRID SYSTEMS

The U.S. power grid is the largest interconnected electrical system that connects electricity producers and consumers by transmission and distribution lines and related facilities. The U.S. power grid has evolved into three large interconnected systems that move electricity around the country [6]. The three grid systems are known as the Eastern Interconnection, Western Interconnection, and Texas Interconnection. Each of the three grid systems contain many AC synchronous generators, a vast number of transmission lines, substations, switching stations, distribution lines, and load centers all working together to form a giant interconnected and synchronous network of electrical system. Figure 2.1 shows a basic diagram of the grid system to illustrate major components of an AC grid system.

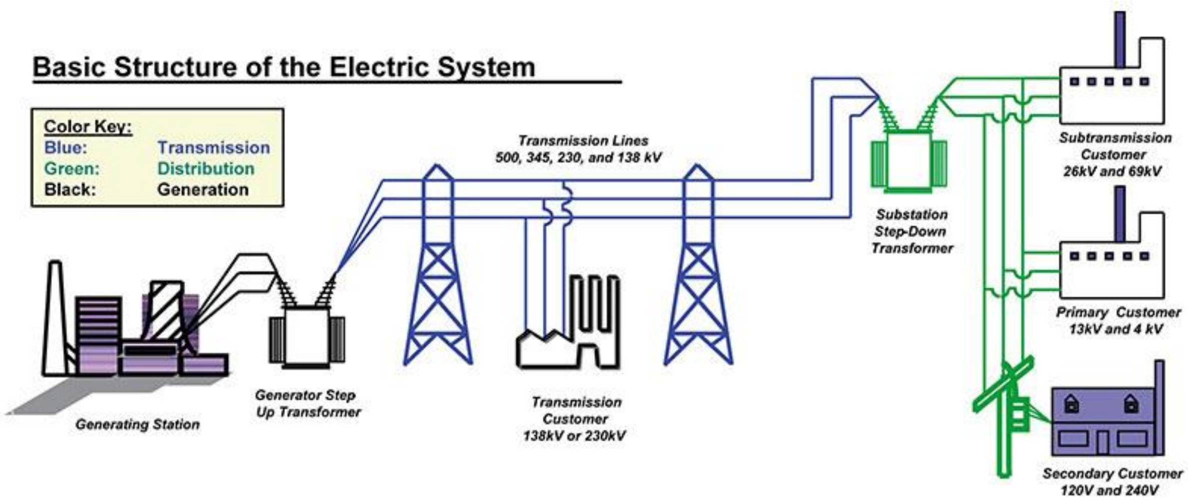


Figure 2.1 – Basis Structure of Electrical Grid System [9]

Any electrical system that operates independent from the main grid system can be qualified as a microgrid. Such system may include local generation resource(s), a local distribution grid, with local control that operates and provides power to local loads within acceptable electrical parameters. Most critical facilities such as hospitals, military facilities, emergency response centers, data centers, processing plants, and oil/gas refineries typically utilize backup generators, automatic transfer switches (ATS), and uninterrupted power supply (UPS) systems to provide electricity during loss of commercial electrical utility grid. When these backup generators and UPS are operating independent from the commercial utility they effectively form a type of microgrid system.

2.1 DOD Definition of Microgrid

Within the DOD installations, most of the critical facilities are equipped with backup generators and ATS systems. These backup generators are sized based on the maximum critical loads of their building at the time of the design. In the event of loss of utility power to the facility, the ATS disconnects the main switchgear bus with the utility source, starts the backup generator, and transfers the generator to the main switchgear bus or emergency switchgear bus. The backup generators are typically setup to operate standalone and they only control voltage and frequency. There are no means of power quality assurance or load-shedding scheme. Luckily, most of the backup generators are seldom overloaded, or for that matter, even loaded to an important or significant share of their capacity.

Although, the standalone backup generators at DOD installations act as basic form of microgrid, according to the DOE definition of a microgrid they may not fit the criteria to be qualified as a microgrid for improving resiliency of a base. U.S. Government–approved microgrid definition is that developed by the Department of Energy (DOE) Microgrid Exchange Group; which states: “A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and island-mode” [10]. This definition requires the local grid to have ability to operate in grid-connected mode (paralleled mode) and island-mode, which disqualifies all the standalone backup generators and emergency load system. The definition also requires a single controllable entity with respect to the grid which requires much more system integration, communication, and a centralize control and energy management system that typical DOD installations do not currently practice.

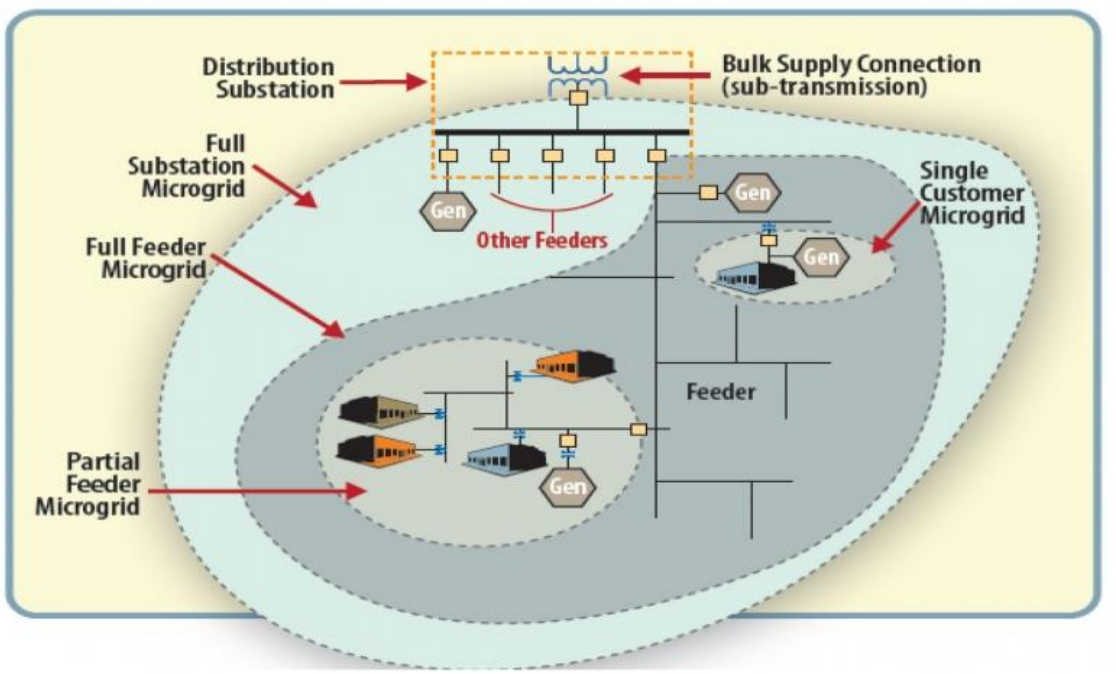


Figure 2.2 – Classification of Microgrid Systems [11]

As, illustrated in the Figure 2.2, DOE Office of Electricity and Energy Reliability describes a microgrid as “localized grids that can disconnect from the traditional grid to operate autonomously and help mitigate grid disturbances to strengthen grid resilience” [11]. However, such configuration could be created at single facility, partial feeder, full feeder, or full substation level as shown in Figure 2.2. CIGRE (International Council on Large Electrical Systems) defines “Microgrids are electricity distribution systems containing loads and distributed energy resources, (such as distributed generators, storage devices, or controllable loads) that can be operated in a controlled, coordinated way either while connected to the main power network or while islanded" [12]. Both U.S. DOE and CIGRE definition of microgrid have two basic requirements: (1) microgrid must local contain source(s) and load(s) under local control and (2) microgrid must be able to operate in parallel (utility connected) and islanded modes.

The definition of microgrid for the purpose of this study is an area-wide distribution system within a DOD installation that includes at least one substation, local generation, and combination of loads that are critical, essential, and non-critical in nature. The definition of microgrid for permanent DOD installations is as following "A DOD installation microgrid is an integrated energy system consisting of interconnected loads and energy resources which, as an integrated system, can island from the local utility grid and function as a stand-alone system" [13].

2.2 Size of Existing Microgrid Systems and Projected Growth

In recent years, there has been a significant increase in microgrid research, development, and demonstration projects. There are hundreds of microgrid demonstration projects underway around the world. Many of the microgrid projects are fully functional and currently operating. Those microgrid projects include buildings, commercial districts, communities, industrial sites, hospitals, military, mining, universities, and urban setups. The size of ongoing microgrid projects also range from few kilowatts to tens of megawatts. As shown in Figure 2.3, in the US as of second quarter of 2016 there are about 156 operational microgrids with approximately 1.54 gigawatt (GW) of capacity [14]. The graph in the Figure 2.3 shows that the operational microgrid capacity may reach as high as 3.71 GW by 2020. It is worth noting that combined heat and power (CHP) seems to be the dominant generation source for existing microgrids in the US.

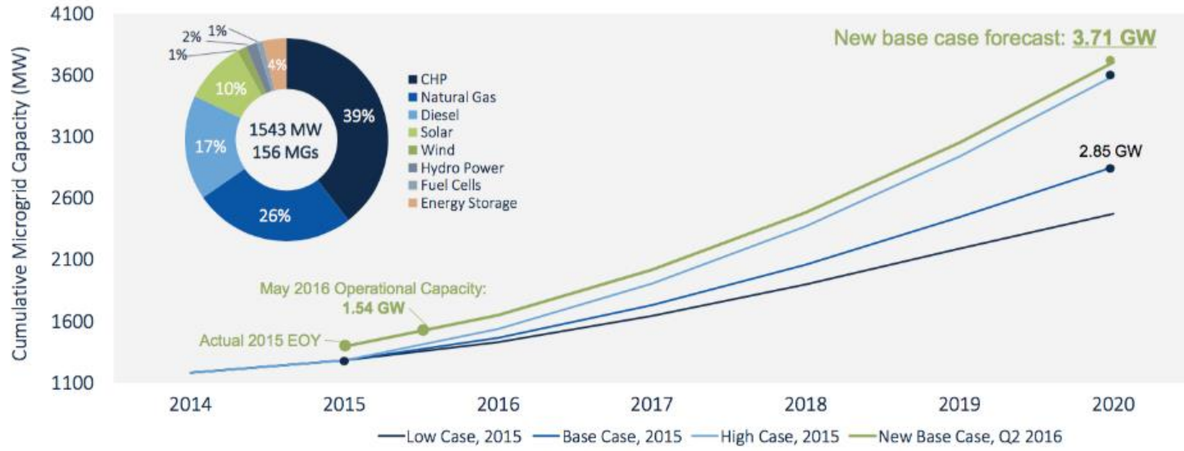


Figure 2.3 – Operational Microgrids in the US as of Q3 2016 and Projected Growth [14]

2.3 Literature Review - DOD Specific Microgrid Research and Demonstrations

Sandia National Laboratories (SNL), the Army Research Laboratory (ARL), Berkley National Laboratories, Oak Ridge National Laboratories (ORNL), and the National Renewable Energy Laboratory (NERL) are some of the institutes that are heavily involved in research, development, and demonstrations of DOD specific microgrid projects throughout the US. The DOE and DOD are heavily involved with funding, policy making, and coordination of the efforts by the R&D institutes, industry, and DOD installations.

DOD Annual Energy Management Report FY2015, Section 5 – Enhancing Energy Resilience, outlines the DOD's short term and long term plans for improving and assuring energy resiliency within DOD permanent installations. The short-term plan includes reducing demand, gathering/reporting data, executing on-going energy resilience initiatives, and engaging other federal, state, local agencies, and technology providers. The long term plan includes pursuing advanced technologies that will help enhance the energy resiliency of its installations [2]. Smart microgrids and energy storage technologies are the main focus of DOD's long term strategy. The DOD has established several microgrid test bed efforts throughout its permanent installations. Microgrid demonstration projects at Fort Bliss, Texas, Marine Corps Air Ground Combat Center at Twenty-Nine Palms, California, and Los Angeles Air Force Base, California are examples of microgrid projects that are currently operational [2].

The Smart Power Infrastructure Demonstration of Energy Reliability and Security (SPIDER) project was proposed by Joint Capability Technology Demonstration (JCTD) task force in 2008 based on recommendations from the Defense Science Board Task Force on DOD Energy Security [15]. The main goal of this project was to demonstrate cyber defense and smart microgrid capabilities on three military installations – Joint Base Pearl Harbor-Hickem (JBPHH), Hawaii, Fort Carson, Colorado, and Camp Smith, Hawaii – in three implementation phases. Reference [16] outlines main purpose, provides an overview of the technology, project phases, operational objectives, and outcomes of the SPIDERS project. Phase one of the project focused on a circuit level demonstration of cybersecurity and integrated renewable energy at JBPHH. Phase two of the project was a microgrid demonstration at Fort Carson, Colorado that focused on a cluster of seven buildings in the densely populated area of the post that represented a variety of categories with respect to critical operations. Solar photovoltaic arrays were used as a renewable energy resource along with the addition of electrical vehicles for storage. Existing generators were directly connected to the distribution grid using bypass breakers. A number of manual switches were also replaced with motor-operated switches to provide automated switching capabilities. Phase three of the SPIDERS project was implemented at Camp Smith, Hawaii, which covers 220 acres of land and includes multiple administrative buildings, barracks, housing units, and other buildings. A base-wide microgrid demonstration project was implemented at Camp Smith that includes major system component upgrades, new utility-grade generators, integrated storage interfaced with inverter modules, and a cyber-secure microgrid control system [16].

Reference [17] outlines the effectiveness of the SPIDERS demonstration project. The report indicates that overall the microgrid operation was successful. However, it had a few setbacks and issues. One of the issues was an under frequency condition during the islanded mode where the frequency dropped below 57 Hz for over 5 minutes. There was miscommunication between the microgrid operators and the generator maintenance technicians. As a result, a decision was made to maintain the SPIDERS microgrid while performing maintenance on a generator without the corresponding training of SPIDERS operators or the maintenance team for this operation. This had serious consequences as it took over an hour for system to resume operations [17].

Although there are several demonstration microgrid projects underway within DOD installations, microgrid technologies still require significant research, development, and design considerations. Reference [18] outlines steps for designing microgrids concepts. The design process outlined in Reference [18] includes data gathering and stakeholder coordination, technical modelling and simulation, and analysis activities. The key properties of the design methodology are safety, reliability, security, sustainability, cost effectiveness, and resiliency. The report outlines three operating conditions – normal, typical emergency, and abnormal emergency. The typical emergency condition is caused by local abnormal conditions that cause manageable utility outages that are in line with the historic reliability figures; whereas, abnormal emergency are high impact/low frequency regional electrical blackout caused by weather, equipment failure, operator errors, physical attacks, or cyber-attacks [18]. The microgrid's primary benefit is certainly realized when abnormal emergency occurs. However, microgrid also provides energy resiliency and improvements to the local distribution system during typical emergency and even in normal mode of operations.

The U.S. Army Research Laboratory (ARL) hosted an Army workshop on Advanced Microgrid Concept and Technologies on June 7-8, 2012. The workshop released a report "Advanced Microgrid Concepts and Technologies Workshop", dated April 2013, that outlines major findings of the workshop [19]. According to the report, in a military sense, the definition for microgrid developed by the RDECOM P&E TFT is: "A microgrid is a group of 2 interconnected loads and distributed energy resources (DER) within clearly defined electrical boundaries that acts as a single controllable entity and capable of storing, distributing, managing, importing and exporting power, and has interfaces with other relevant grids" [19].

Business Executives for National Security (BENS) Task Force on microgrids published a report (reference [20]), dated Fall 2012, that outlines financial modelling of the DOD installation microgrids, analyzes alternative ownership/operation business models, discusses size and scope criteria for the microgrids, lists impediments to microgrid developments, and discusses prospective on implementation considerations [20]. The report concludes that a microgrid with significant renewable generation assets can be achieved at reduced annual energy cost to DOD at only 25% of its domestic installations due to limitations on the feasibility of renewable energy which is heavily location dependent and since access to third-party capital is also limited to handful of states. At many installations microgrid may operate at an increased cost to DOD, as a "security premium". Another factor that DOD must consider for economical microgrids is the operation and ownership of the microgrid. The report concludes that a contractor-owned and operated approach may be more cost effective than a government owned and operated model [20].

Another financial challenge for DOD microgrid development is the size and scope of the smart microgrid. There are legitimate mission assurance interests for providing excessive power generation within the installation fence so that DOD installations can assist homeland defense operations during the times of crisis by powering local public infrastructure outside the fence. However, by extending electrical services beyond the fence, the DOD directly enters the realm of existing electrical utilities. This also adds complexities to microgrid implementation by requiring a network of generation assets, substations, transmission lines, management technology, and customer billing systems. Therefore, proper sizing and scoping of microgrid system within DOD installations is a critical process to successful implementation and operation of such system [20].

Reference [13] evaluates existing DOD microgrid projects, categorizes the efforts based on common and measurable parameters, and performs cost-benefit trade-off analyses for different microgrid architectures. This report highlights the fact that the DOD microgrid may become more economical by taking into account the need of the local commercial electric grid and then designing/implementing systems so that they help with the commercial needs. It concludes that although each installation has unique challenges and mission requirements, the natural progression for microgrid implementation is toward a more integrated system that allows for greater flexibility and potentially longer off-grid operations [13]. However, additional research and site demonstrations are required to fully understand the economic and technical trade-offs for advanced microgrid systems.

Reference [21] outlines benefits of CHP plants for industrial and commercial facilities where electricity is presently being purchased from the grid and fuel is burned separately in an on-site furnace or boiler to produce thermal energy. Reference [22] includes various case studies regarding CHP implementation and performance during natural disasters such as superstorm Sandy. The report concludes that in general CHP systems, especially those that run consistently throughout the year to produce power, are more reliable in an emergency than backup generators. The CHP plant is also more likely to be properly maintained, operated by trained staff, and have a steady supply of fuel [22]. Reference [23] highlights that modular small scale nuclear plants can provide economical and reliable power for military installations despite some regulatory hurdles.

For all potential DOD microgrid systems infrastructure upgrade, economical and reliable on-site generations, reliable communication backbone, advanced control and protection systems, and skilled technicians/operators are essential for successful implementation. This thesis focuses on DOD infrastructure upgrades, proposes a practical microgrid concept layout, and analyzes mode of operations, as well as control and protection of the proposed microgrid. For the purpose of this study, a combined heat and power (CHP) plant and existing backup generators are utilized to form a microgrid system.

CHAPTER 3: REPRESENTATIVE SYSTEM CONFIGURATION

The U.S. DOD has more than 500 permanent installations throughout the country. Table 3.1 shows a summary of permanent military installations per service. The U.S. Army has the greatest number of installations followed by the Air Force and then the Navy. With some exceptions, typically Army installations occupy larger geographical area and have more population than the Air Force or Navy installations.

Department of Defense
Base Structure Report
FY 2015 Baseline

SERVICE	Active	Reserve	Guard	Other	Total
ARMY	103	8	102	9	222
NAVY	104	3	0	0	107
AIR FORCE	86	10	87	0	183
WHS	1	0	0	0	1
DoD Total	**294**	**21**	**189**	**9**	**513**

Table 3.1 – US DOD Permanent Installations by Service [24]

As shown in Figure 3.1, a typical DOD permanent installations features airfield(s), industrial complexes, testing facilities, administrative buildings, ammunition storage, hangers, housing, medical center(s), shopping complex(s), and school(s) etc. An Army or Navy base may have a smaller air field and a much larger test range or ammunition storage facility, whereas an Air Force installation may contain large air field(s) and limited or no test range area. For practical purposes, generally both have similar electrical loads.

Figure 3.1 – Buckley Air Force Base Aerial Photo [25]

3.1 Representative Existing DOD Electrical System

The majority of the permanent and large DOD installations in the U.S. receive power from the local utility at sub-transmission voltages that range from 46kV to 138kV. Many of them may also receive utility supply at two different voltage levels, including distribution voltages (35kV or less). The utility supply voltage is stepped down at the local distribution substation(s) typically located at the POD or inside the fence to supply the distribution system. Figure 3.2 illustrates a representative but simplified single-line view of a typical military installation electrical system.

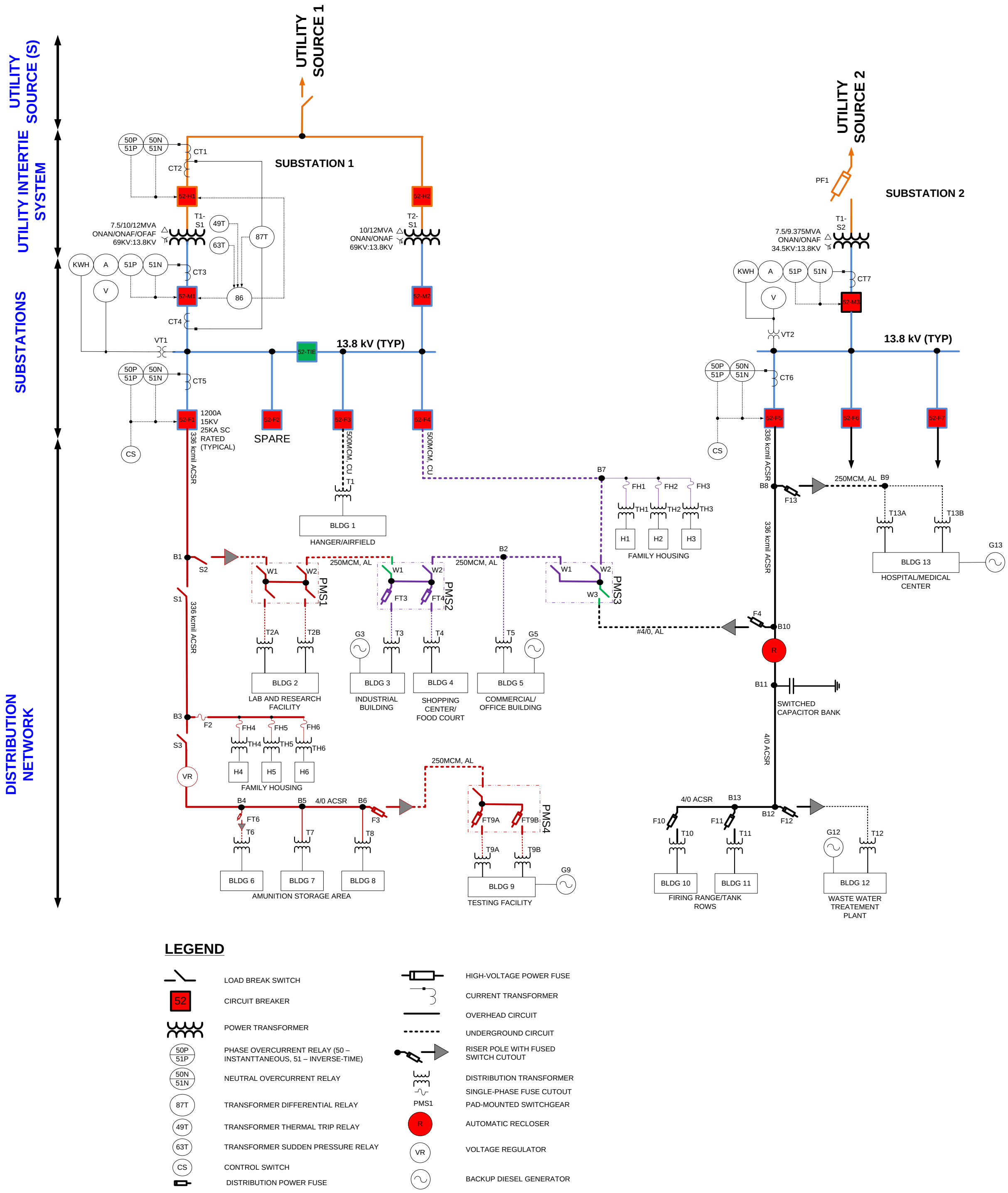


Figure 3.2 – Representative Single Line of Typical DOD Electrical Systems

The single line shown in the Figure 3.2 is developed based on the author's working experience with many Army and Air Force base electrical systems throughout the U.S. The single line diagram does not represent the system of any specific military base. The objective of this study is not to present details of any specific system due to their sensitivity. Instead, it outlines a representative single line that can be utilized to understand the general layout of the existing electrical systems, their load characteristics, and switching configurations. It can then be modified to design and analyze advanced protection and control schemes, communication architectures, onsite generation resources, and microgrid applications for a broad range of military installations.

3.2 Detailed Description of the Representative Existing System

As shown in the Figure 3.2, the orange lines represent utility source feeders, the blue lines represent the substation configuration, and the red, purple, and black lines represent distribution system feeders and switching configurations. The distribution system is comprised of substations, overhead lines, underground lines, overhead load break switches, multi-way pad-mounted switches, fused disconnect switches, overhead and pad-mounted service transformers, emergency backup generators, and facility load centers. The emergency backup generators are connected to the facility level electrical systems at a 480V main switchgear bus at the generation location.

3.2.1 Utility Supply and Point of Connections

The utility supply voltage at substation 1 is 69kV and at substation 2 it is 34.5kV. The two different utility supply voltages hint that the base was probably supplied from 69kV at the beginning. Later it may have needed another substation to supply new load growth in the area and due to budget and time constraints the new substation may have connected to a nearby 34.5kV distribution line. Figure 3.3 shows an aerial view of a substation yard of one of the US Air Force Bases. It can be seen that a single incoming transmission line is connected to a couple of substation power transformers via a combination of disconnect switches and high voltage circuit breakers. Substation 1, shown in Figure 3.2, resembles very similar configuration as the configuration shown in Figure 3.3. Substation 2 on the other hand connects a single power transformer to the utility source utilizing a fused disconnect switch.

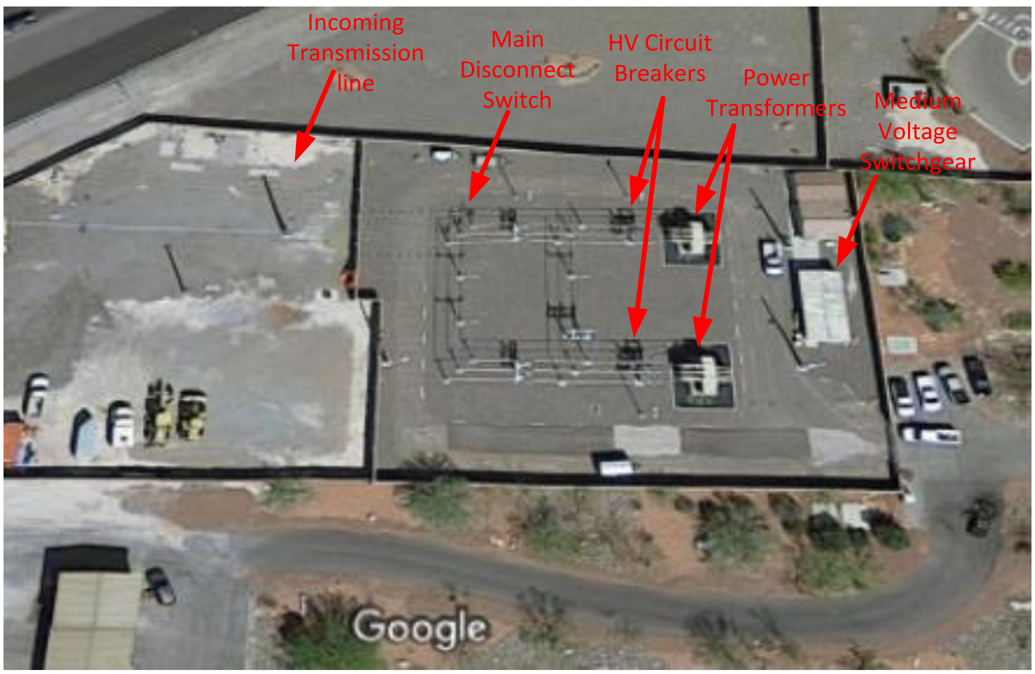


Figure 3.3 – Substation Layout of One of the Air Force Bases [26]

3.2.2 Substations

Figure 3.2 illustrates typical distribution substations that include utility source connections, power transformers, medium voltage switchgear(s), and distribution feeders. Power transformer ratings for typical DOD substations vary from 5 MVA to 50MVA at 55° Celsius temperature rise and Oil Natural Air Natural (ONAN) cooling mechanism. The representative system includes 7.5MVA power transformers. Each of the power transformers also include load tap changers (LTC) for automatically regulating voltages at the substation medium voltage buses. The power transformers are connected as a delta on the primary and as a wye on the secondary with solidly grounded neutral at the wye side. The distribution voltages at the Army installations are typically 13.8kV whereas the Air Force utilizes 12.47kV [3]. Both of the system voltages fall into 15kV voltage class.

For the purpose of this study, 13.8kV is used as the nominal medium voltage distribution for the representative system. The medium voltage switchgear at the substation 1 include two main breakers and one tie breaker that connect two distribution buses. The main breakers are connected to the power transformers. This configuration is more common throughout the installations since it provides greater redundancy at the substation level. However, since both of the transformers are supplied by a single 69kV line, the substation is not immune to complete power outage in the event of loss of utility source. Substation 2, on the other hand, has just a single transformer and single-bus medium voltage switchgear configuration with no redundancies.

The protection schemes for the majority of existing DOD distribution substations are limited to overcurrent elements that comprise a combination of phase inverse-time overcurrent, neutral/ground inverse-time overcurrent, phase instantaneous overcurrent and neutral/ground instantaneous overcurrent elements, as applicable. Power transformers are protected by either differential relays or fused disconnects. Although recently there has been a major push to upgrade old electromechanical or solid state protective relays with digital relays, the majority of the protective relays are still electromechanical or solid state types.

Figure 3.4 – Typical Feeder Protection Relay Front Panel

Figure 3.4 shows a typical metal-clad switchgear feeder circuit breaker front panel that includes electromechanical relays, breaker control switches, and an amp meter. The representative system includes electromechanical relays, control switches, and analog meters. The power transformers at the substation 1 have a differential protection scheme whereas the power transformers at substation 2 are protected by fuses. Although fuses are a simple, economical, and reliable method of protection, they are slow and can cause single-phase-open conditions. Therefore, fuse protection is not recommended for power transformers at substations. Differential relays provide high-speed three phase tripping for faults within the zone of protection and do not require rigorous coordination with the downstream protective devices.

3.2.3 Distribution System

Electrical distribution systems at major DOD installations typically include similar components as a commercial utility distribution systems such as overhead lines, underground lines, switches, reclosers, capacitors, voltage regulators, and service transformers. The distribution system shown in Figure 3.2 includes primary and secondary circuits, riser poles with fuse cut-outs, pad-mounted switches with load-break ways and/or fused ways (Note: underground or pad-mounted distribution switches include multiple circuit termination points called "ways"), overhead switches, service transformers and loads. The primary and secondary circuits are rated at 15kV and operate at 13.8kV nominal. Fuses are the primary protective devices for the secondary (tap) feeders and distribution transformers, although some cases have reclosers along some long overhead lines. Pole-mounted voltage regulators or fixed switching capacitor banks are utilized to regulate the voltage for long primary circuits that supply test ranges or remote ammunition storage sites.

The service transformers are typically connected delta at the primary and wye at the secondary side. The neutral at the secondary wye configuration is solidly grounded with full neutral conductors running along with the phase conductors. The load types include commercial buildings, industrial facilities, and residential areas. Critical loads such as industrial building (BLDG 3), commercial building (BLDG 5), testing facility (BLDG 9), waste water treatment Plant (BLDG 12), and hospital (BLDG 13) have emergency backup generators.

As shown in Figure 3.5, the backup generators are connected to the low-voltage main bus via an ATS. The ATS senses the utility voltage at the point of connection. If the voltage is lost for predefined period, it declares a "loss of utility" and sends a start signal to the generator. Once the generator starts and the voltage and frequency at the generator line-side is within acceptable level, the ATS switches the building loads to the generator. Some ATS have capability to automatically switch back to the commercial utility once the service is back and stable, whereas, others are designed to manually switch back to the utility.

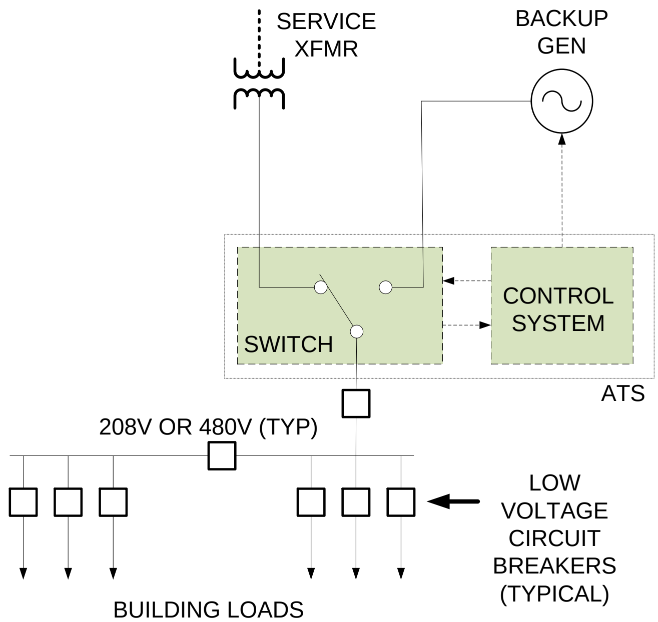


Figure 3.5 – Typical Emergency Backup Generator and ATS Configuration for Critical Load

3.3 Prerequisites for DOD Microgrid-Ready Systems

The majority of the DOD installation's electrical infrastructures are not fully equipped for implementing an effective, stable, and economical microgrid operations as they exist today. Proper implementation of a base-wide microgrid system requires all of the following fundamental capabilities [27]:

1. Local generation resources (conventional and/or renewable)
2. Energy storage systems (if renewable energy resources are used)
3. Advanced digital metering and monitoring systems
4. Reliable and smart switching apparatus
5. Redundant primary feeder loops (for automated system reconfiguration)
6. Controllable loads (load shedding)

7. Advanced microgrid controller(s)

8. Advanced protective relays and controls

9. Secure, reliable and high-speed communication infrastructures

10. High-speed and deterministic communication protocols

Figure 3.6 provides graphical representation of a conceptual DOD installation microgrid. The figure portraits a simplified and representative layout of the typical DOD installations and shows key microgrid-specific requirements as outlined above.

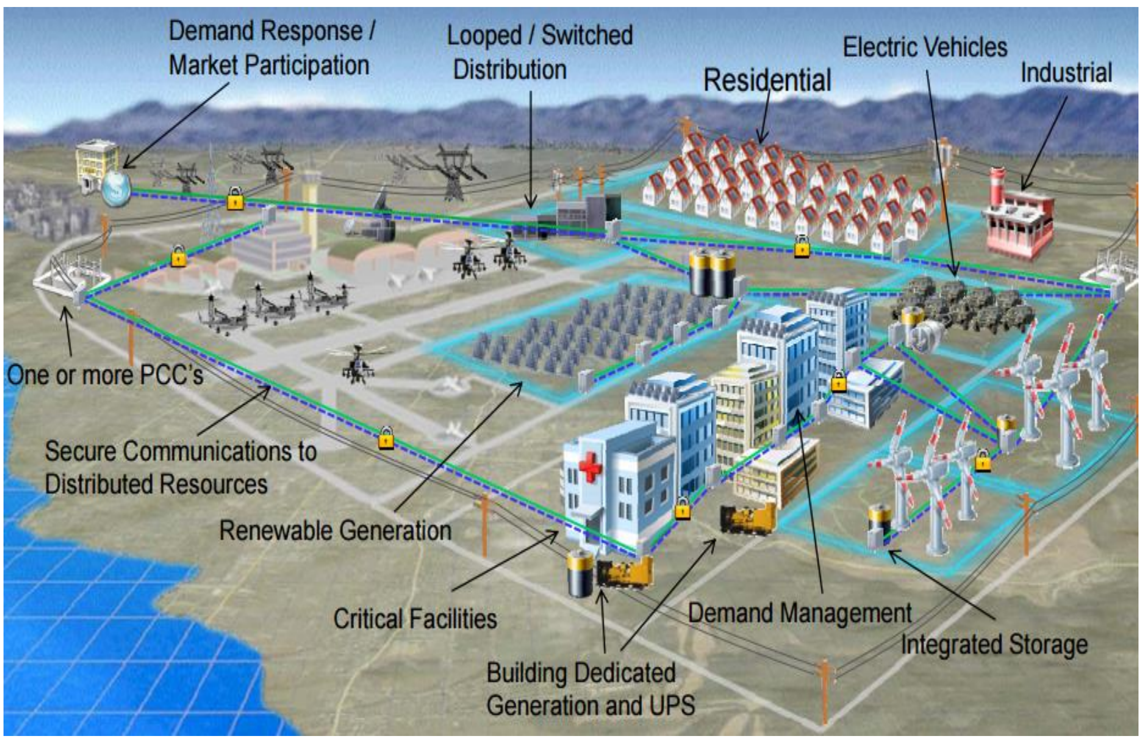


Figure 3.6 – Anatomy of DOD Installation Microgrid Layout [28]

Figure 3.7 shows a simplified conceptual single-line layout of a microgrid ready system where all the fundamental components of a microgrid ready system is depicted. Local generation is the most essential component of microgrid because without it there is no supply of electricity for the islanded grid system. If the local generation is predominantly renewable resources such as solar or wind, it is essential to have various energy storage systems so that they can stabilize dynamic operation of microgrid during both fluctuating generation output and load demand [29].

As shown in the Figure 3.7, the advanced metering and monitoring systems include three tiers of infrastructures – (1) field sensors such as current transformers (CTs), voltage transformers (VTs), and transducers; (2) local intelligent electronic devices (IEDs) such as advanced meters, digital protective relays, fault indicators, and electronic controllers for distribution switches, reclosers, sectionalizers, voltage regulators, and capacitor banks; and (3) data concentrators such as distribution automation controllers, substation automation controllers, generator control system, microgrid controller, and master SCADA system.

An ideal microgrid ready system must be equipped with advanced switching components that operate reliably and fast. Circuit breakers, reclosers, vacuum fault interrupters, and motorized switches are integral parts of such switching systems. As shown in the Figure 3.7, redundant primary feeder loop configurations and advanced switching apparatuses provide multiple paths between generations and loads. Digital relays, controllers, and high-speed communication network allow quick and automated fault detection, isolation, and system restoration functions to ensure stable and resilient operation of the microgrid system. The automation network also provides vital system metering and monitoring data at a granular level.

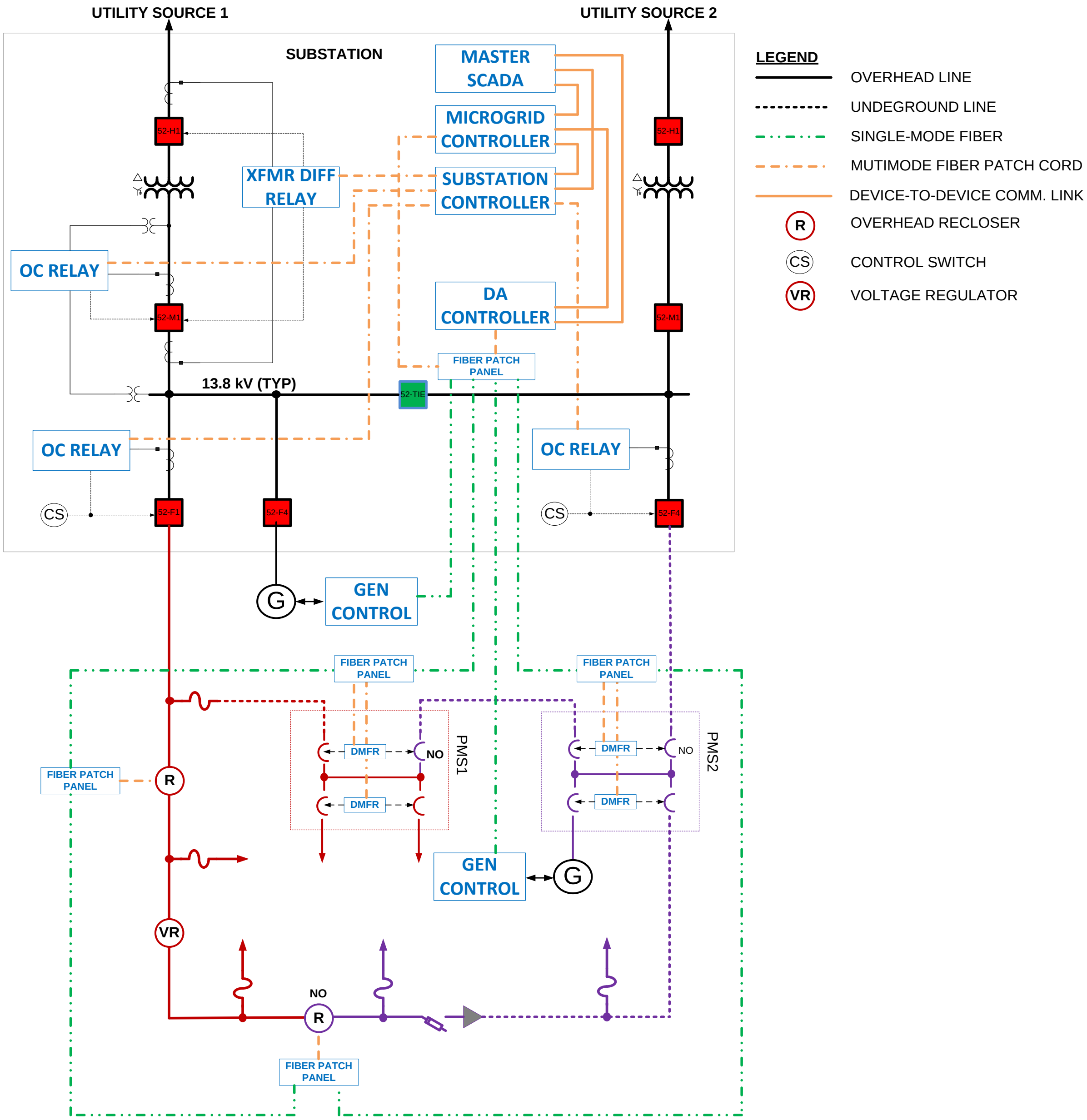


Figure 3.7 – Simplified Conceptual Microgrid Ready System Single Line

Smart switching devices in the distribution system also provide finer control to facility loads and enable the microgrid controller to effectively monitor and control load and perform load-shedding and generation control functions. The advanced microgrid controller monitors real-time system status, issues various control commands to the generator controls for grid connected or islanded mode operations, performs load-shedding functions, and communicates system status to master SCADA system.

Digital protective relays and controls provide adaptive protection functions for grid-connected and microgrid modes of operation. High-speed communication networks, such as the fiber optic lines shown in Figure 3.7, provide reliable and high-speed bandwidth for adequate data flow across the system. Carefully chosen communication protocol(s) can enable deterministic, high-speed, and seamless communications between various devices across the network. In summary, a reliable DOD microgrid requires all the components from local generation, smart switching apparatus, looped and redundant primary feeders, controllable loads, advanced controllers, advanced metering and monitoring devices, advanced protective relays, to high-speed communication system.

3.4 Key Microgrid-Related Deficiencies of the Exiting DOD Electrical Systems

The existing electrical systems of typical DOD installations exhibit numerous deficiencies that prevent them from qualifying as a microgrid-ready. Although there has been a surge of research and development activities for DOD microgrid applications in recent years, just a handful of the research activities are focused on assessing the conditions of existing distribution infrastructures. This is primarily due to sensitive nature and limited access to the DOD electrical infrastructures and assets by the public, research laboratories, and academic institutions. Although the field operators are usually knowledgeable and experienced with the operations and maintenance of the electrical assets within the DOD installations, unlike typical utility electrical systems, the DOD systems typically lack adequate engineering support, documentations, standards reinforcement, and a steady flow of funding for capital improvements.

The majority of the DOD electrical systems were last upgraded several decades ago and are currently in need for major upgrades. Many of the systems were upgraded in bits and pieces by different government contractors over long period of time and exhibit design deficiencies and signs of inconsistencies. The representative single-line diagram presented in Figure 3.2 illustrates many of the common deficiencies that need to be addressed to create a microgrid-ready system. Below is a list of the key common deficiencies (to qualify as microgrid ready) and recommended mitigation alternatives.

- **Deficiency #1: electromechanical relays and analog metering devices –** majority of the DOD installation electrical substations still utilize electromechanical or solid state relays and analog (dial type) metering devices that are largely obsolete technologies. Most of the electromechanical relays utilize either electromagnetic attraction or induction principles for their operation. A basic overcurrent electromechanical protective relay operates when the magnitude of an operating signal is larger than the magnitude of the restraining unit for a set time dial period [30]. When solid-state technology was introduced, the amplitude and phase comparison were implemented using discrete components which resulted no moving parts.

  Recommended mitigation: microprocessor-based relays, also known as numerical relays or digital relays – microprocessor relays were first introduced in 1979 [30]. With the advent of numerical relays the research and development focus has shifted from hardware to software. The main advantages of the numerical relays are their multifunction protective elements, cost, compactness, flexibility, reliability, low burden on CTs, and self-monitoring capabilities. They also include metering, monitoring, advanced communication interface and protocol support, logic settings, group settings, event reporting, sequence of event records, user friendly displays, and control functions. The numerical relays can provide advance and adaptive protection, logic based control, metering, monitoring, and communications functions that are essential to an advanced microgrid operation. Replacing existing electromechanical or solid state relays with numerical relays or specifying them for new substations is highly recommended as DOD facilities move toward major infrastructure upgrade.

- **Deficiency #2: fuse-based protection throughout the distribution system –** fuse based protection of power lines and apparatus in a distribution system is common among DOD installations. Although the fuse protection is economical, simple, and effective for basic overcurrent protection, they present problems for microgrid operations. One of main problems with fuse-based protection for a microgrid system is inflexibility for adjustments of the protective settings such as different time-inverse overcurrent characteristic curves or definite-time overcurrent threshold. When a distribution system switches from grid-connected mode to microgrid mode of operation, there may be major changes to the available fault duty at any given node of the distribution system. If the fuse is used to protect a branch line or a commercial load, it becomes impractical to achieve coordinated protection objectives since the new fault duty may require different characteristic curves or pickup settings.

  Recommended mitigation: digital overcurrent devices – digital overcurrent devices are typically outfitted with pad-mounted switches, vacuum fault interrupters, or overhead reclosers. They replace fuse and provide many of the functionalities that a digital relay provides. One can program them to adjust protective settings and characteristic curves as system configuration changes. They also provide communication interface for remote controls, metering, and monitoring functions.

- **Deficiency #3: all manual field switches –** the majority of the DOD installation distribution systems utilize manual switching apparatuses. They are simple and cost effective for conventional operations of the distribution system. However, they are not effective for microgrid operations where an automated system reconfiguration and switching is necessary.

  Recommended mitigation: smart switching apparatuses – smart distribution switching apparatuses such as vacuum fault interrupters, reclosers, or motorized switches are typically outfitted with electrical operating mechanism that is automatic and fast for tripping and closing actions. As mentioned above, they are also equipped with communication-enabled electronic overcurrent devices. Utilizing their smart operating mechanisms and electronic overcurrent devices one can fully automate the field switching. Such smart switching apparatuses will also facilitate high-speed load shedding when needed.

- **Deficiency #4: inadequate interties and redundancies –** although normally-opened feeder interties and redundancies do exist within the majority of the DOD installation distribution systems, typically there are not enough of them for microgrid. Many of the existing interconnecting feeders have inadequate capacity to back-feed entire load of the other feeder. Typically there exist a weak link (smaller conductors with inadequate ampacity) that prevent from fully utilizing the existing interties.

  Recommended mitigation: upgrade existing interties and add more lines as needed – many of the existing intertie circuits require conductor replacement to increase their capacity. Additional distribution lines may be necessary to have more than one redundant path to any given loads.

- **Deficiency #5: lack of ability to control loads at facility level –** as previously discussed, since the existing systems feature manual switching, fuse protection, and no communications, it is impossible to automatically control the loads at facility level without upgrading these apparatus to smart switches and implement reliable communications. Load characteristics play vital role in microgrid operations, stability, and control. It is imperative to properly classify and control loads so that microgrid operation can deliver the expected reliability to pre-specified load categories [29].

  Recommended mitigation: smart switching apparatuses and communication network – as discussed in items 2 and 3 above, smart switching apparatuses provide remote control and monitoring capabilities at the distribution level. A reliable, fast, and secure communication network that connects all the smart switches to a central microgrid controller can enable load control at the facility level.

- **Deficiency #6: lack of real-time metering and monitoring capabilities –** as mentioned before, existing systems comprise of electromechanical or solid state relays, analog meters, manual switching, and fuse-based distribution protections which make metering, monitoring, and data trending almost impossible. For microgrid operation it is important to have high resolution metering data and status of all the loads and switching apparatus. Microgrid controller(s) need real-time system status, power-flow, and predicted behaviour of the system before they make logical decisions for switching, load shedding, and distributed generator controls.

Recommended mitigation: implement digital relaying, smart switching apparatuses, and robust communication network and master SCADA system – as discussed above, digital relays, smart switching apparatuses, robust communication network enable flow of real-time high-resolution data. A centralized master SCADA system provides means for system data collection, storage, analysis, and trending that can be utilized by various system controllers.

3.5 Conceptual Microgrid Ready System

Section 3.4 outlined key deficiencies of the existing DOD installation electrical systems that prevent them from qualifying as a microgrid-ready system. Figure 3.8 presents proposed upgrades to the representative existing system that was illustrate in Figure 3.2. The proposed upgrades include following changes:

1. Replace electromechanical or solid state relays with digital multifunctional relays.
2. Upgrade existing pad-mounted manual switches with smart switches that are equipped with vacuum fault interrupters, digital multifunctional relays, and communication devices.
3. Add reclosers, equipped with digital multifunctional relays and communication devices, to various overhead locations to provide adequate fault detections, sectionalizing and automated switching.
4. Add more intertie circuits and increase capacity of certain circuit segments to make them adequate for full scale back-feeding.

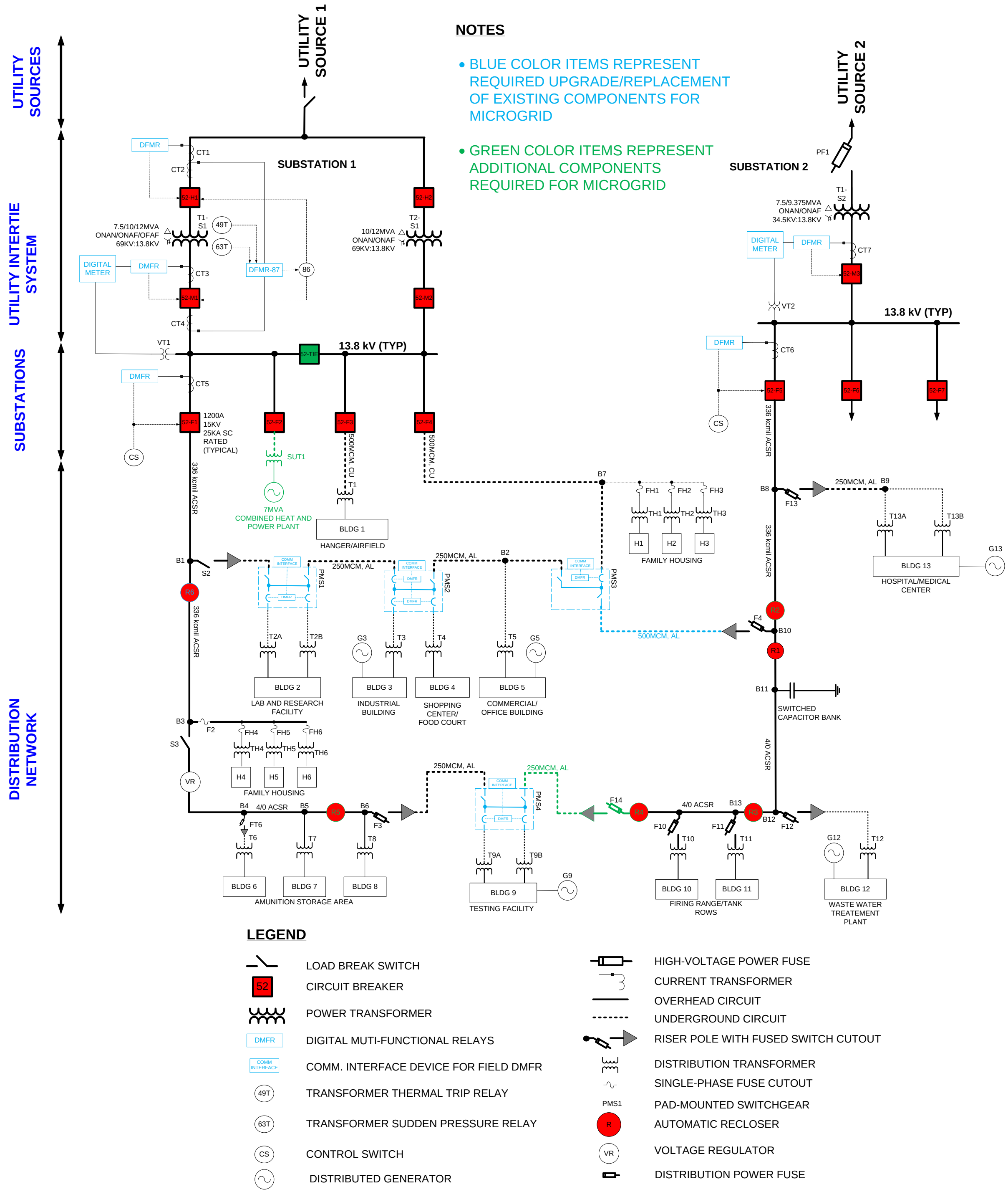


Figure 3.8 – Representative Microgrid-Ready System Single Line Diagram

CHAPTER 4: REPRESENTATIVE MICROGRID SYSTEM MODEL

Representative system component parameters are collected from sample DOD installations and generalized to use for model development. Due to sensitivity of the data, this report does not specify any location or name of the DOD installations from where the data are derived. Figure illustrates the steps taken to model the representative microgrid-ready system.

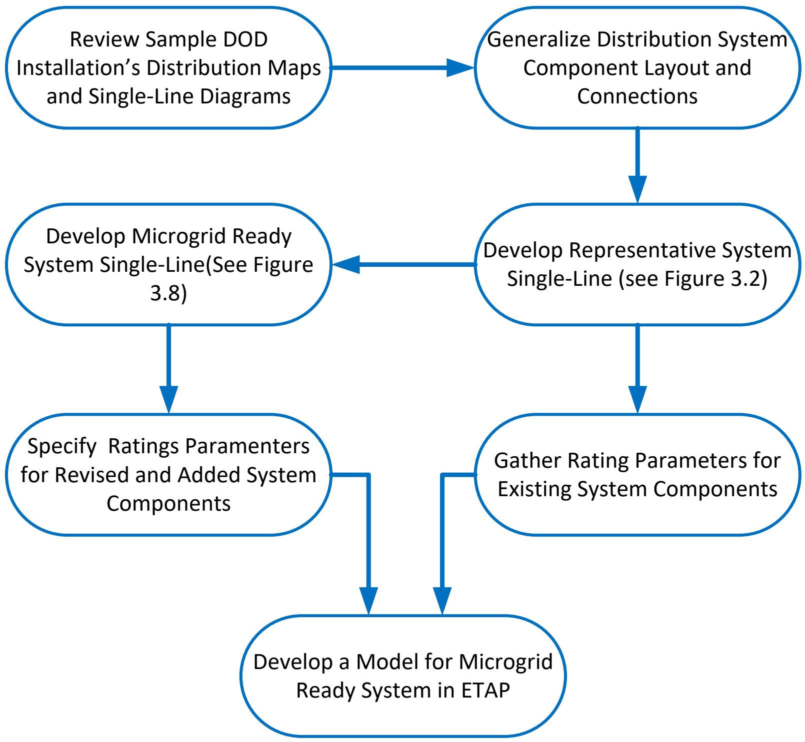


Figure 4.1 – Steps for Developing Models for the Studies

4.1 Existing System Data Gathering and Analysis

Figure 3.2 shows a single-line view of the representative existing system that is derived from various DOD installation electrical distribution systems. The single-line diagram includes typical system components with unique identification numbers. Nameplate data and pictures of typical apparatus were collected from various representative DOD electrical systems. Such apparatus include transformers, medium voltage switchgear, circuit breakers, cable and conductors, pad-mounted switches, reclosers, voltage regulators, and capacitor banks. The lengths of cables and conductors between various devices are estimated to depict real-world geospatial layout.

4.1.1 Substation

Table 4.1 lists ratings for key substation 1 and 2 apparatus. The ratings are based on the actual nameplate pictures of the existing system apparatus from sample DOD installations.

Parameters	**Ratings**		
Circuit Breaker ID	**52-H1, 52-H2**	**52-M1, 52-M2, 52-TIE, 52-F1, 52-F2, 52-F3, 52-F4**	**52-M3, 52-F5, 52-F6, 52-F7**
Manufacturer	Westinghouse		
Model	690GM5000	150VCP-W501	150VCP-W501
Rated Max Voltage (kV)	69	15	15
Continuous Current (A)	2000	1200	1200
Short Circuit Current (A)	40,000A	25,000	18,000
Interrupting Time (cycles)	5	5	5
Control Voltage (VDC)	125	125	125
Power Transformer ID	**T1-S1**	**T2-S2**	**T1-S3**
Primary Voltage (V)	69000	69000	34500
Secondary Voltage (V)	13800Y/7967	13800Y/7967	13800Y/7967
BIL-HV (KV)	550	550	200
BIL-LV (KV)	110	110	110
Configuration	Delta-Wye	Delta-Wye	Delta-Wye
MVA	7.5/10/12	10/12	7500/9375
Cooling Class	ONAN/ONAF/OFAF	ONAN/ONAF	ONAN/ONAF
Grounding	Solid	Solid	Solid
Percent Impedance (%Z)	8.7	8.1	6.46

Table 4.1 Substations 1 and 2 Key Apparatus Ratings

4.1.2 Distribution Switches

The representative distribution system includes pad-mounted multi way switches, overhead load-break switches, and fused cut-outs (disconnect switches with fuses in series). Table 4.2 shows typical switches incorporated in the representative existing system.

Pad-Mounted Switches							
Switch ID	**Type**	**Rated Voltage (kV)**	**BIL (kV)**	**Current Rating (LB ways) (A)**	**Current Rating (Fused Ways)(A)**	**Max. Fuse Rating (A)**	**SC Rating (kA)**
PMS1	PME-10	17	95	600	NA	NA	25
PMS2	PME-9	17	95	600	200	200E	14
PMS3	PMH-13	17	95	600	NA	NA	25
PMS4	PMH-7	17	95	600	200	200E	14

Fused Cutouts					
Switch ID	**Type**	**Rated Voltage (kV)**	**BIL (kV)**	**Max. Fuse Rating (A)**	**SC Rating (kA)**
F1	Fuse Link	15	110	200	12.5
F2	Fuse Link	15	110	200	12.5
F3	Fuse Link	15	110	200	12.5
F4	Fuse Link	15	110	200	12.5
F10	Fuse Link	15	110	200	12.5
F11	Fuse Link	15	110	200	12.5
F12	Fuse Link	15	110	200	12.5
F13	Fuse Link	15	110	200	12.5
Overhead Switches					
Switch ID	**Type**	**Rated Voltage (kV)**	**BIL (kV)**	**Current Rating (A)**	**SC Rating (kA)**
S1	Alduti-Rupter	17	110	600	25
S2	Alduti-Rupter	17	110	600	25
S3	Alduti-Rupter	17	110	600	25

Table 4.2 – Existing Distribution System Switch Types and Ratings

4.1.3 Service Transformers

Table 4.3 lists all the service transformers ID, building number, load type, and nameplate ratings. The nameplate data were collected from actual 13.8kV system service transformers that serve similar type of load centers as listed in the table.

XFMR ID	BLDG. No.	kVA	PHASES	HV (V)	LV (V)	HV BIL (kV)	% Z	Cooling Class
T1	BLDG 1	1500	3	13800	480Y/277	95	5.68	OA
T2A	BLDG 2	1000	3	13800	480Y/277	95	5.7	OA
T2B	BLDG 2	1000	3	13800	480Y/277	95	5.7	OA
T3	BLDG 3	3000	3	13800	480Y/277	95	7.04	OA/FA
T4	BLDG 4	500	3	13800	480Y/277	95	5.57	OA
T5	BLDG 5	750	3	13800	480Y/277	95	5.6	OA
T6	BLDG 6	112.5	3	13800	208Y/120	95	2.4	OA
T7	BLDG 7	75	3, 1-ph	14400/24940 GRDY	120/240	NA	2.1	OA
T8	BLDG 8	75	3 1-PH	14400/24940 GRDY	120/240	NA	2.1	OA
T9A	BLDG 9	1000	3	13800	480Y/277	95	5.7	OA
T9B	BLDG 9	1000	3	13800	480Y/277	95	5.7	OA
T10	BLDG 10	112.5	3 1-PH	14400/24940Y	120/240	NA	2.38	OA
T11	BLDG 11	150	3 1-PH	13800/23900Y	120/240	125	1.9	OA
T12	BLDG 12	1000	3	13800	480Y/277	95	5.7	OA
T13A	BLDG 13	1500	3	13800	480Y/277	95	5.59	OA
T13B	BLDG 13	1500	3	13800	480Y/277	95	5.59	OA
TH1	H1	25	1	13800	120/240	95	3.2	OA
TH2	H2	25	1	13800	120/240	95	3.2	OA
TH3	H3	25	1	13800	120/240	95	3.2	OA
TH4	H4	25	1	13800/23900Y	120/240	125	2.9	OA
TH5	H5	25	1	13800/23900Y	120/240	125	2.9	OA
TH6	H6	25	1	13800/23900Y	120/240	125	2.9	OA

Table 4.3 – Existing Distribution System Service Transformers

4.1.4 Power Lines

The length, type, size, and configuration of distribution power lines, for the purpose of this research, are estimated based on the geographical layouts and electrical system data collected from numerous DOD installations. They are intended to represent typical existing powerlines that are connecting similar apparatuses in the field. Table A.1 (in Appendix A) provide a list of all the powerlines with essential data that is required to model them.

4.1.5 Backup Generators

There are five backup generators included in the representative existing system. Each of the facilities with a backup generator is considered critical load. Table 4.4 summarizes make/model, fuel type, and nameplate ratings that will be used to model the generators in ETAP.

Gen ID	**G3**	**G5**	**G9**	**G12**	**G13**
Make/Model	Cummins/ DQFAD	Caterpiller/ C15	Kohler/ 500REOZVC	Cummins/ DFEJ	Caterpiller/ C27
Fuel Type	Diesel	Diesel	Diesel	Diesel	Diesel
Rated Voltage (V)	277/480	277/480	277/480	277/480	277/480
Frequency	60	60	60	60	60
Phases	3	3	3	3	3
Rated kW	1000	350	500	450	750
Power Factor	0.8	0.8	0.8	0.8	0.8
Connection	WYE-grounded	WYE-grounded	WYE-grounded	WYE-grounded	WYE-grounded
Speed (RPM)	1800	1800	1800	1800	1800
Control Type	Digital	Digital	Digital	Digital	Digital

Table 4.4 – Existing Distribution System Backup Generator Data

4.1.6 Other Apparatus

The representative system also includes a voltage regulator, a capacitor bank, and an automatic recloser. Voltage regulators and/or capacitor banks are found in some of the DOD installations that have long overhead lines that require voltage regulation. Automatic reclosers are not common but can be found in a handful of installations that have long overhead distribution lines. Table 4.5 and Table 4.6 provide voltage regulator and automatic recloser nameplate data. The capacitor bank is rated at 600kVAR and configured to be single step switched.

Voltage Regulator	
Parameters	**Ratings**
Rated Voltage (V)	13800Y/7967
BIL (KV)	95
Range of Regulation	±10%
Steps	32 - 5/8% each
Configuration	(3) single-phase
kVA	250/280
Cooling Class	ONAN
Grounding	Solid

Table 4.5 – Sample Distribution System Voltage Regulator Nameplate Data

Automatic Recloser	
Parameters	**Ratings**
Rated Voltage (V)	15000
BIL (KV)	95
Continuous Current Rating (A)	600
Interrupting Current Rating (kA)	12.5
Interrupting Time (ms)	45
Insulation Type	Solid Dielectric
Controller Type	Electronic

Table 4.6 – Sample Distribution System Automatic Recloser Nameplate Data

4.1.7 Estimated Load Data for Representative Existing System

Table 4.7 lists estimated load for each of the loads that is connected as a conventional lumped load model at the secondary side of the service transformers. The table presents load type per transformer/building and various loading scenarios. The design load is the same as the service transformer kVA rating. The average loading, annual peak loading, and annual minimum loading scenarios are shown as percentage of the design load. Note that even for the peak loading scenario most of the loads are significantly below the service transformer rating. This is typical for the majority of the DOD installations because unlike commercial utilities, DOD installations tend to oversize service transformers for reasons such as lack of proper load calculation when a facility is built, the building's mission changes, and no metering and billing to individual tenant inside the base.

The design load, average load, peak load, and min load values are used for performing load-flow study for various loading scenarios. The motor load and static load are shown as the percentage distribution of that load for any loading scenario that is selected for the load-flow study.

XFMR ID	BLDG. No.	Description	Load Type	Design Load (kVA)	Avg (%)	Peak (%)	Min (%)	Motor Load (%)	Static Load (%)	PF (%)
T1	BLDG 1	HANGER/AIRFIELD	I	1500	15	50	5	60	40	85
T2A	BLDG 2	LAB AND RESEARCH FACILITY	C	1000	50	75	25	60	40	85
T2B	BLDG 2	LAB AND RESEARCH FACILITY	C	1000	50	75	25	60	40	85
T3	BLDG 3	INDUSTRIAL BUILDING	I	3000	40	80	25	60	40	85
T4	BLDG 4	SHOPPING CENTER/FOOD COURT	C	500	50	80	20	30	70	95
T5	BLDG 5	COMMERCIAL/OFFICE BLDG	C	750	25	60	5	40	60	90
T6	BLDG 6	AMMO STORAGE AREA	I	112.5	20	30	15	60	40	85
T7	BLDG 7	AMMO STORAGE AREA	I	75	20	30	15	60	40	85
T8	BLDG 8	AMMO STORAGE AREA	I	75	20	30	15	60	40	85
T9A	BLDG 9	TESTING FACILITY	C	1000	30	80	10	60	40	85
T9B	BLDG 9	TESTING FACILITY	C	1000	30	80	10	60	40	85
T10	BLDG 10	FIRING RANGE/TANK ROWS	I	112.5	30	60	10	60	40	85
T11	BLDG 11	FIRING RANGE/TANK ROWS	I	150	30	60	10	60	40	85
T12	BLDG 12	WWTP	I	1000	60	7	50	70	30	85
T13A	BLDG 13	HOSPITAL/MEDICAL CENTER	C	1500	40	85	30	60	40	85
T13B	BLDG 13	HOSPITAL/MEDICAL CENTER	C	1500	40	85	30	60	40	85
TH1	H1	FAMILY HOUSING	R	25	20	75	5	20	80	95
TH2	H2	FAMILY HOUSING	R	25	20	75	5	20	80	95
TH3	H3	FAMILY HOUSING	R	25	20	75	5	20	80	95
TH4	H4	OFFICER HOUSING	R	25	20	75	5	20	80	95
TH5	H5	OFFICER HOUSING	R	25	20	75	5	20	80	95
TH6	H6	OFFICER HOUSING	R	25	20	75	5	20	80	95

Table 4.7 – Estimated Load Data for Existing Distribution System

(Note: for Load Type, I = Industrial, C = Commercial, R = Residential)

4.2 Additional Equipment Data for Microgrid-Ready System

As discussed in Chapter 3 and shown in

Figure 3.8, the representative existing system required upgrades to various system apparatus and addition of some new components. Protective relays, pad-mounted switches, and some of the power lines required upgrades. Multiple reclosers are also added to facilitate distribution automation. Below is a summary of upgrades and additions to the existing system to make it microgrid-ready.

- Replace existing electromechanical and solid state relays at substations 1 and 2 with digital (microprocessor) multi-function relays (DMFR) (see Figure 4.2). ETAP's built-in SEL-751 relay model is used for modelling purposes.
- Replace existing PMS1 and PMS4 manual switches with new control-ready switches that have two load-break ways, two VFI ways, and a DMFR with communication interface (see Figure 4.3).
- Replace existing PMS2 manual switch with a new control-ready switch that has one load-break way, three VFI ways, and two DMFRs with communication interface (see Figure 4.3)
- Replace existing PMS3 manual switch with a new control ready switch that has two load-break ways, one VFI way, and a DMFR with communication interface (see Figure 4.3)
- Upgrade underground line segment between PMS3 and B10/F4 from 4/0 cable to 500MCM cable.
- Replace existing overhead switch S2 with a new recloser equipped with electronic controller and communication interface.
- Install new underground distribution line to connect PMS4 with node B13/F10. This addition will create a main distribution loop that has two feeders with

normally opened tie point that can back-feed the entire load along the loop in the event any one of the feeder is tripped at the substation.

- Add four more reclosers (R2, R3, R4, and R5) throughout the overhead distribution line to facilitate distribution automation.
- Add a 5MW combined heat and power (CHP) generation plant next to substation 1 and connect the plant to one of the spare substation feeders.
- Add fiber-optic communication lines between all the field switches, reclosers, substations, and generator controllers to create high-speed communication links (this is discussed more in detail in Chapter 6).

Figure 4.2 illustrates differences between electromechanical relays and DMFRs. The new relays will provide flexible and adaptive protection during changing modes of microgrid operation. They are equipped with metering, monitoring, and communication capabilities that will be utilized by the microgrid master controller to gather real-time power flow and switching status.

Figure 4.3 provides single-line diagram comparison and example pictorial view of the existing pad-mounted switches (PMSs) and new control-ready PMSs. The new control-ready field switches with VFIs and DMFRs will also provide flexible protection and fast load shedding and automated switching functions for the microgrid operations. The new reclosers and some of the VFIs along the main feeder loop will sense fault, isolate and sectionalize faulted segment, and automatically restore rest of the system within seconds.

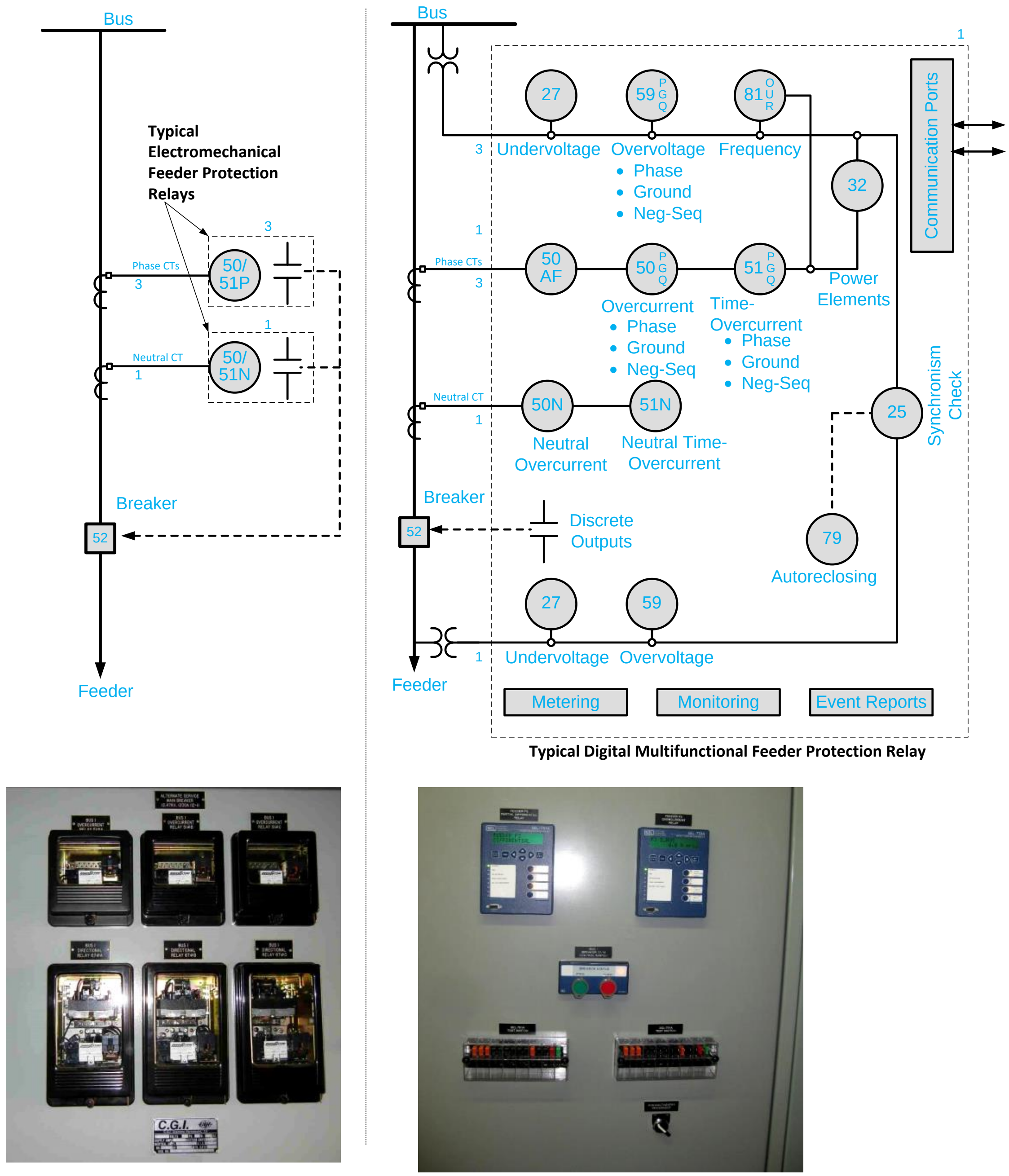


Figure 4.2 – Example Comparison between Electromechanical Relays vs. DMFRs

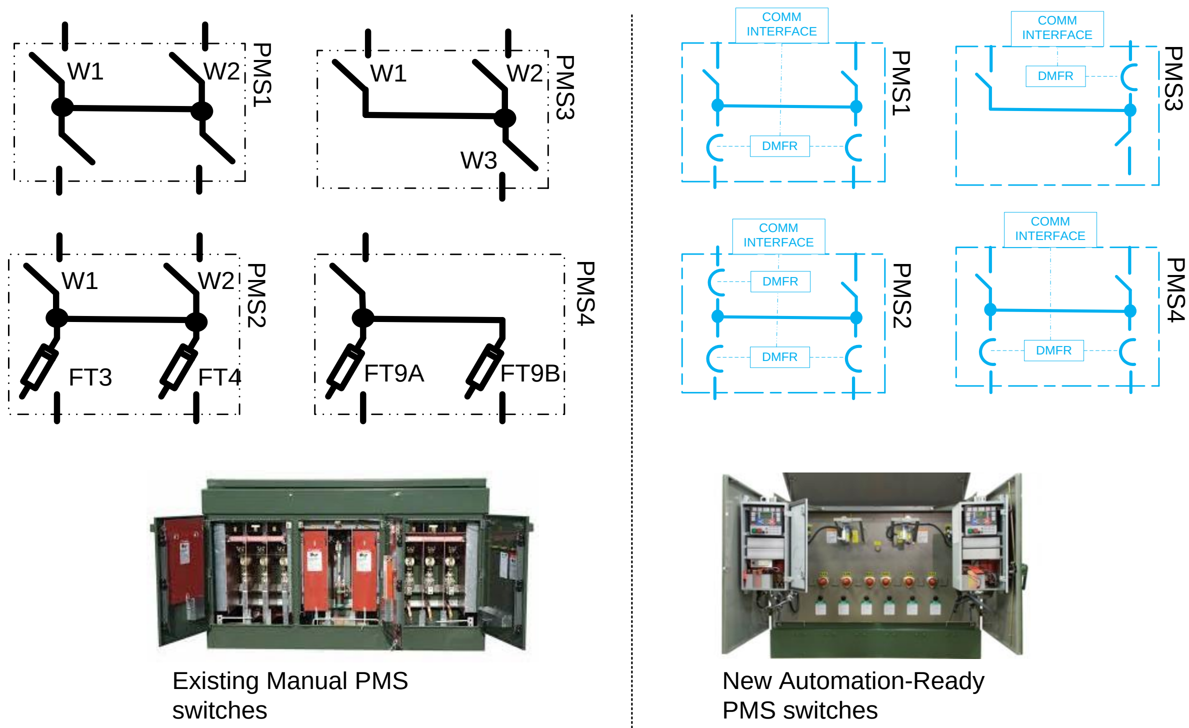


Figure 4.3 – Comparison between Existing and Upgraded PMSs

On-site combined heat and power (CHP) generation is added to provide adequate local power supply to enable substation-level microgrid operation. The on-site generation could be of any form as long as it provides stable and reliable power generation. Selecting the best form of on-site generation for various type of military installation is beyond the scope of this study. This study choose CHP generation because it is an efficient and clean approach to generate electricity and thermal energy from single fuel source [21]. The military installations are well suited for CHP application because majority of them have industrial complexes that use significant amount of thermal energy for heating and cooling. Furthermore, many of the bases already have thermal distribution infrastructure in place.

For the purpose of this study, a 5MW rated Solar Turbines Taurus 60 simple-cycle gas turbine generator set is used to model the CHP plant generation. A 5MVA 4160V to 13.8kV step-up transformer is utilized to step up the CHP secondary voltage. Table 4.8 outlines basic technical data for the generator and the step-up transformer.

Equipment ID	**CHP Plant (Generator)**
Make/Model	Solar Turbines/Taurus 60
Fuel Type	Dual (Natural Gas and Diesel)
Rated Voltage (V)	4160
Frequency	60
Phases	3
Poles	4
Phase Configuration	Wye
Rated kW/kVA	5200/6000
Power Factor	0.8
Connection	WYE
Rotating Speed (RPM)	1800
Control Type	Digital
Exciter Type	Permanent Magnet
Grounding	Resistance Grounded
Equipment ID	**T-GEN (Step-up Transformer)**
Primary Voltage (V)	13800Y/7967
Secondary Voltage (V)	4160Y/2400
BIL-HV (KV)	110
BIL-LV (KV)	95
Configuration	Wye-Wye
MVA	5
Cooling Class	ONAN/ONAF
Grounding	Solidly grounded Primary, Resistance Grounded Secondary
Percent Impedance (%Z)	7.75% (Typical)

Table 4.8– CHP Generator and Step-Up Transformer Data.

Figure 4.4 provides a single-line view of the CHP generator and step-up transformer system. The CHP generator is connected to 5kV medium voltage switchgear with generator breaker (52-GEN) and generator protection relay. The 5kV switchgear supplies the plant auxiliary loads and connects the CHP generation to the distribution system via the 5MVA step-up transformer.

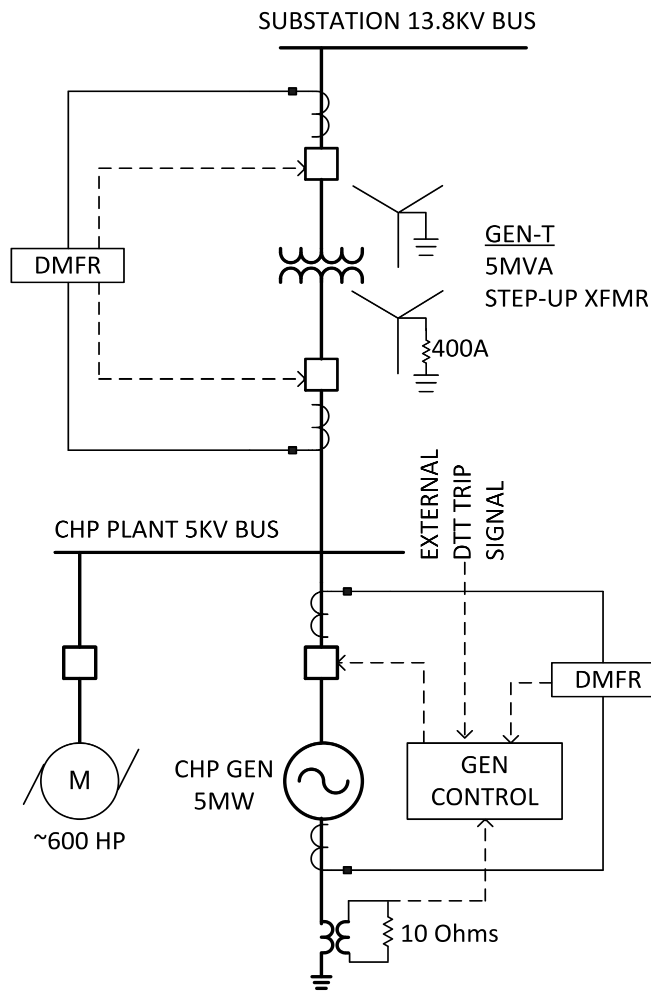


Figure 4.4– Single-Line Configurations of New CHP Generator System

4.3 System Modelling

This study uses Electrical Transient Analyzer Program (ETAP) software for system modelling and analysis purposes. The ETAP base package includes a set of core tools, embedded analysis modules, and engineering libraries that allow users to create, configure, customize, and manage electrical system models. The core tools include one-line diagram builder, element editors, device libraries, configuration manager, report manager, project and study wizards, multi-dimensional database, theme manager, data exchange, and user access management [31]. Figure 4.5 shows typical interface of the software in edit mode.

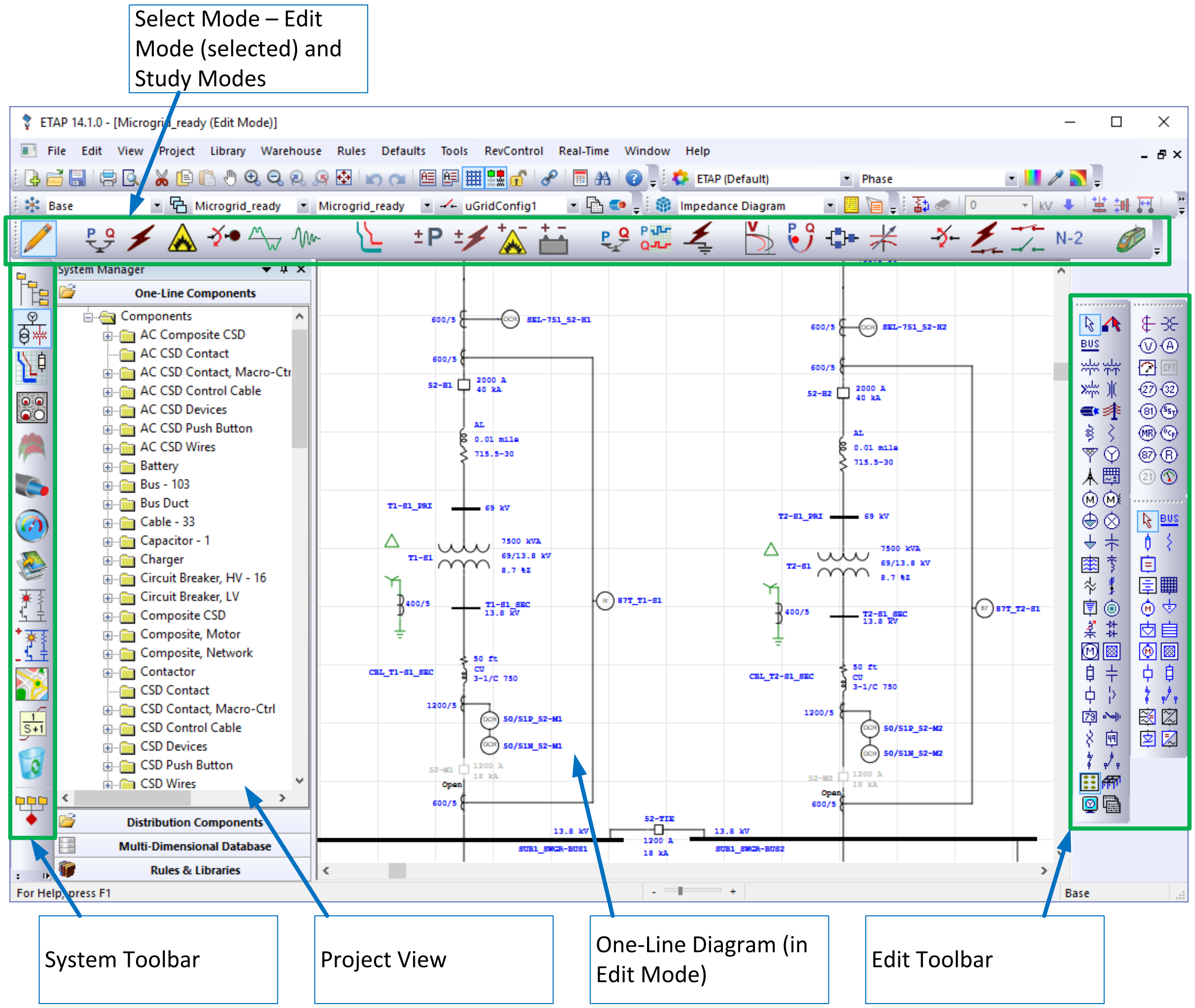


Figure 4.5 – Single-line configurations of existing and new PMS switches

In summary, the modelling part of the software has three fundamental elements – one-line diagram, database, and device library. One-line diagram provides a layout view of the system modelled in a one-line view. The database keeps track of component data such as attributes, ratings, and technical parameters that characterize the component. The device library contains technical data for commonly used power system apparatuses and allows a user to quickly populate various data field by only requiring make and model of a component. The software also includes a set of various analytical tools such as load-flow, short-circuit, arc-flash analysis, transient stability analysis, and protective relay coordination. These analytical tools will be utilized to perform studies in Chapter 5.

Models of the microgrid ready-system is created using ETAP software and component data discussed in Section 4.2. The following sections describe details of modelling various types of components that make up the distribution system.

4.3.1 Buses

The term "bus" means any point where more than one piece of equipment is attached. Buses are designated by voltage class and are categorized based on equipment type. ETAP provided each bus as a modelling connection point for analytical computations. Not all buses require analytical attention; some of them only serve to provide the connection point between cables and other equipment. Such buses are called nodes and appear as "dots" in the model.

Figure 4.6 shows typical single-line representation and typical ratings and configuration information for a 69kV bus.

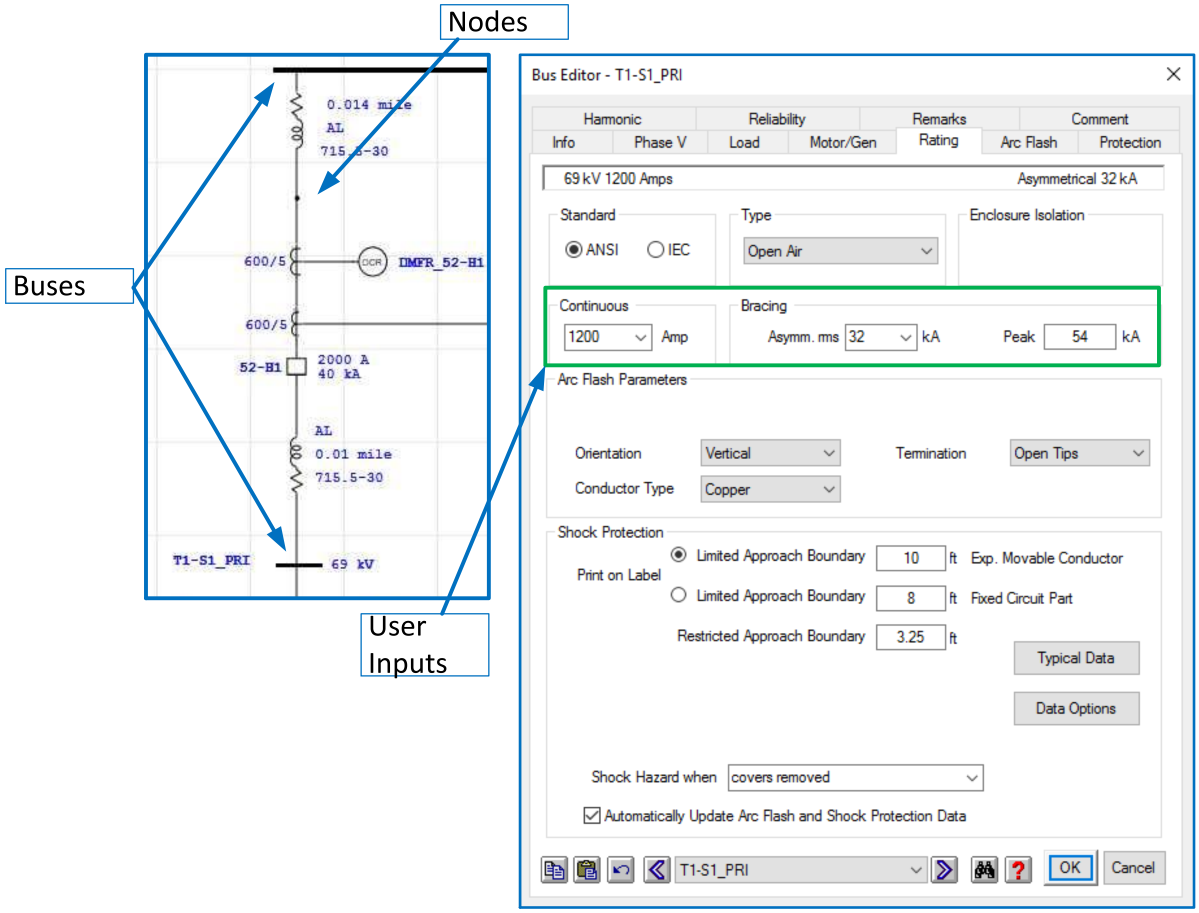


Figure 4.6– Single-Line View and Parameter Editor Window for Bus Model

4.3.2 Power Transformers

The key parameters fields for power transformer model that require user input include electrical rating, impedance data, voltage regulation taps, and grounding configuration. Table 4.1 provided most of the data required to model the power transformers. For data entry, ETAP requires primary voltage, secondary voltage, and kVA ratings. All the other fields are either calculated or pre-configured by ETAP. Figure 4.7 shows typical power transformer single-line and parameter windows.

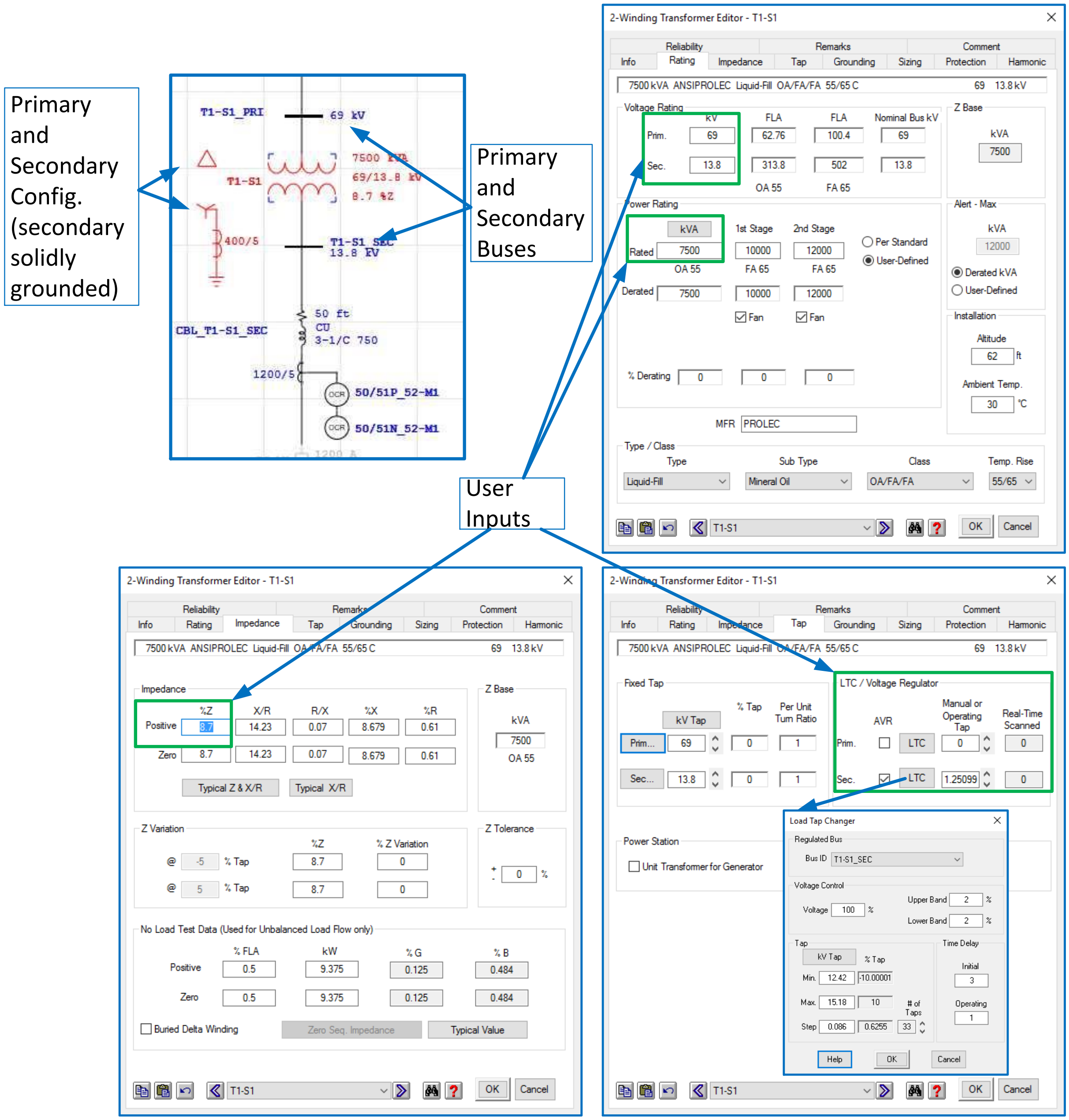


Figure 4.7 – Single-Line View and Parameters for Power Transformer Model

For impedance data, the user can enter positive sequence impedance and X/R ratio, and then ETAP copies the entered values to zero sequence fields. If the X/R ratio or the impedance data is not available, a user can also select “Typical Z & X/R” or “Typical X/R” and ETAP pre-populates typical impedance values for the size and type of transformer. For the voltage regulation parameters, there is a "Tap" dialog where user can select no-load tap changers (Fixed Tap) or (LTC/Voltage Regulator) settings for primary and secondary voltages. All three of the substation power transformers in this study utilize LTCs to regulate voltage at the secondary bus. The LTCs are set to regulate the bus voltage at 100% with ±2% band and initial time delay of 3sec. All the substation power transformers in this study are two winding delta primary and wye secondary with the secondary neutral leg solidly grounded.

4.3.3 Circuit Breakers

Circuit breakers are modelled using ETAP's built-in device library. As shown in Figure 4.8, the circuit breaker rating parameter section allows user to choose circuit breaker model from a library with the manufacturer and model info. When a specific circuit breaker type and model is chosen all the ratings data are pre-populated.

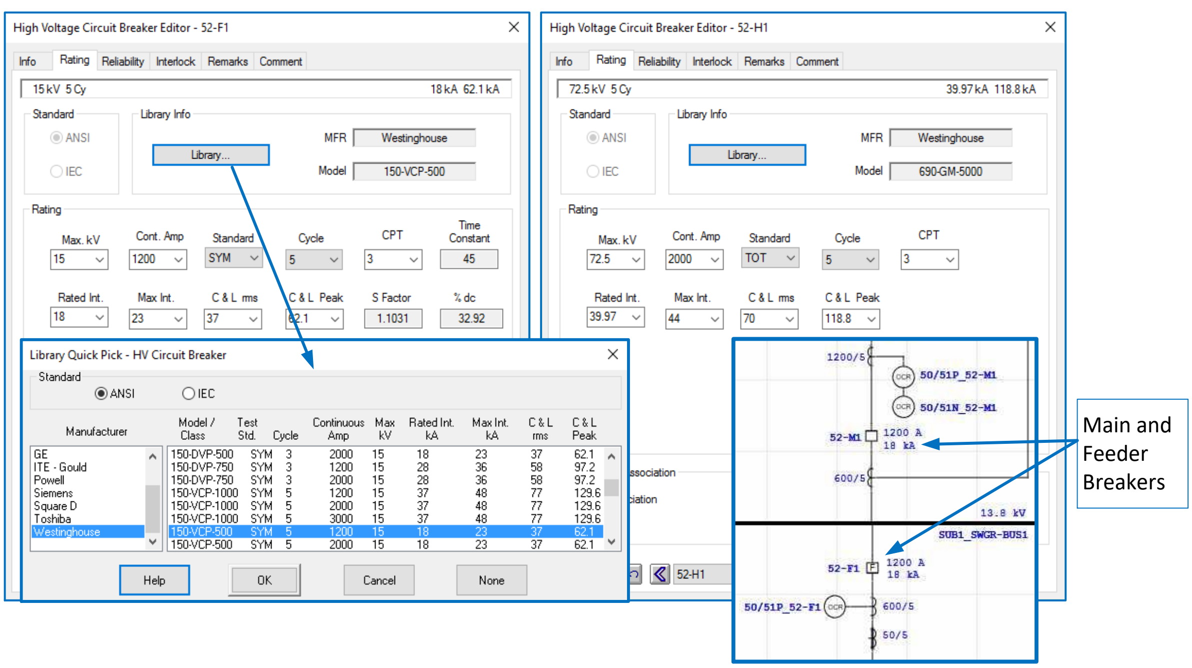


Figure 4.8 – Single-Line View and Parameters for Circuit Breaker Model

4.3.4 Protective Relays

Protective relays are modelled using ETAP's built-in device library. As shown in Figure 4.9, the relay editor's "OCR" tab allows user to select a specific type and function of protective relay from a library with manufacturer's name and model. The user can also choose multiple functions for each relay. For this study, the relay function is limited to overcurrent protection. Most common electromechanical or digital relays can be found in the device library.

Once the particular relay is selected from the library, the "OCR" tab displays the relay overcurrent settings fields. For electromechanical relays, there is just single "Settings" option that provides inverse-time overcurrent and instantaneous overcurrent setting fields. For digital multifunctional relays the "OCR" tab provides setting fields for phase, ground (residual), neutral, and negative sequence overcurrent elements.

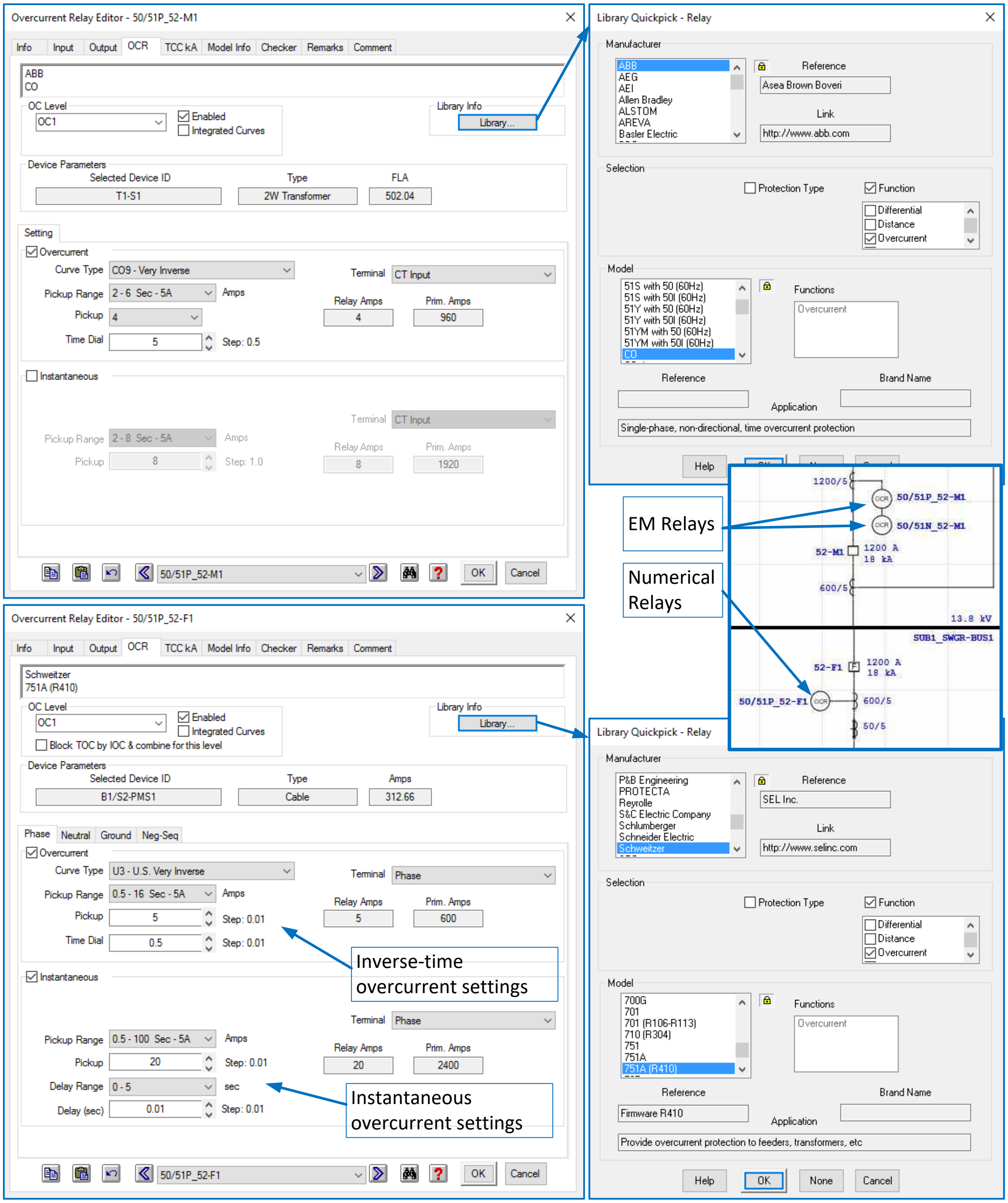


Figure 4.9 – Single-Line View and Parameters Dialog for Protective Relay Model

4.3.5 Power Line Data Entry

Figure 4.10 and Figure 4.11 show overhead and underground line models with key parameter fields. Similar to the models for circuit breakers and relays, power line (both overhead and underground) models utilize ETAP's device library of cable and conductors for detailed technical parameters to populate electrical ratings and calculate impedances values.

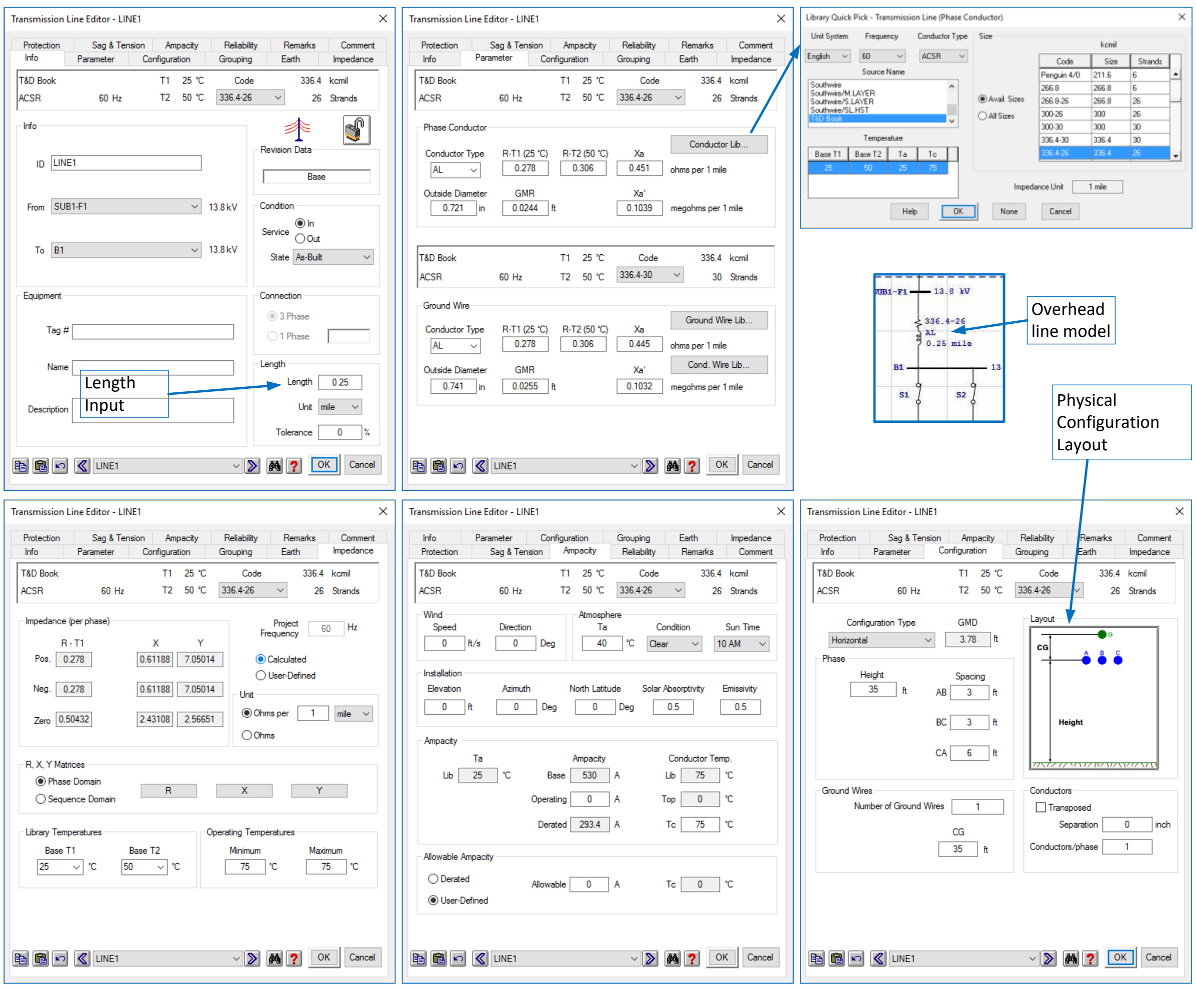


Figure 4.10 – Single-Line View and Parameter Dialogs for Overhead Line Model

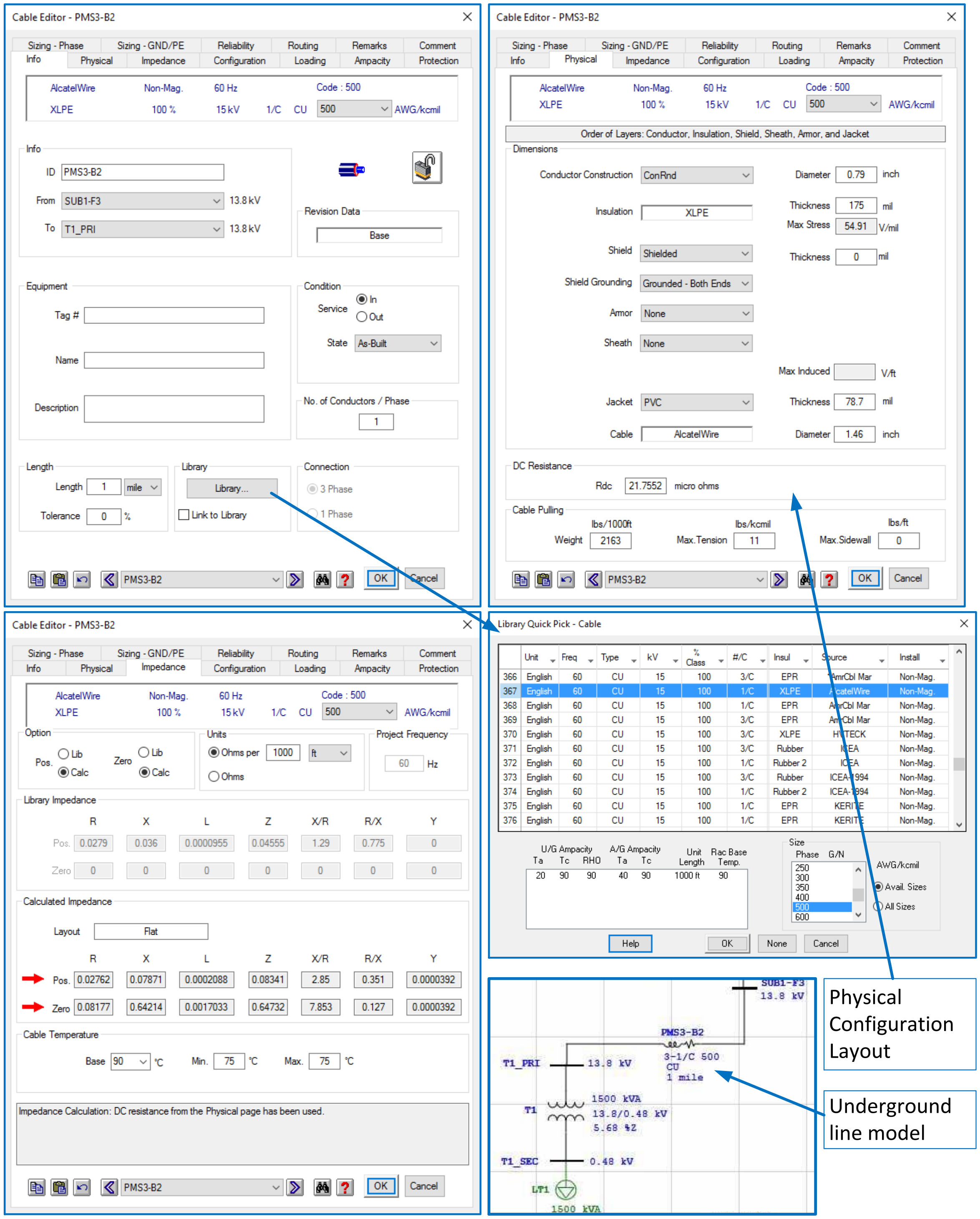


Figure 4.11 – Single-Line View and Parameter Dialogs for Underground Line Model

Both of the models require user to input some of the parameters such as cable/conductor configuration and circuit length. Once a specific cable/conductor type is selected from the library, ETAP pre-populates all the required electrical ratings for the model.

4.3.6 Switches

The load-break ways of pad-mounted multi-way switches are modelled by connecting multiple single throw switches in a bus. VFI ways are modelled as reclosers since their functions and features are identical (see Section 4.3.7 Reclosers for model details). All of the overhead load-break switches are modelled as single-throw switches. Fused cut-outs are modelled as a combination of a single-through switch with a fuse in series.

Figure 4.12 shows parameter fields and single-line view of a typical single-throw switch.

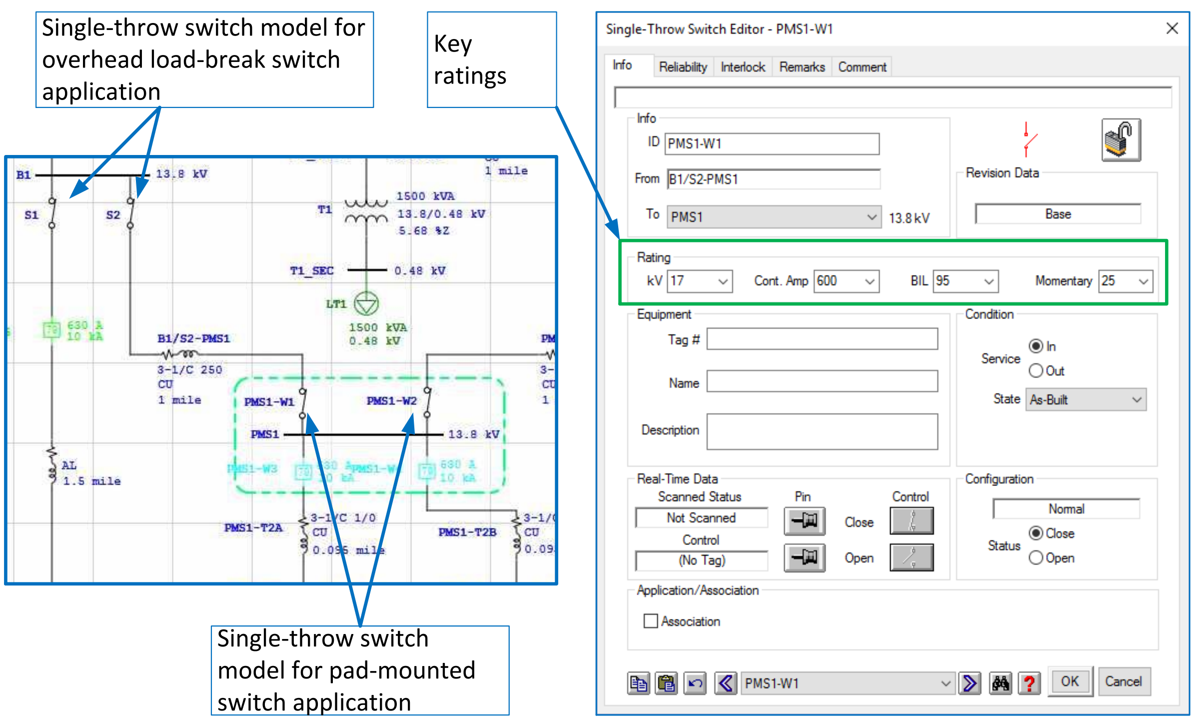


Figure 4.12 – Single-Line View and Parameter Dialogs for Single-Throw Switch Model

4.3.7 Reclosers

ETAP has built-in models for most of the medium voltage reclosers on the market. As shown in Figure 4.13, the user only needs the make and model of the recloser and controller. The controller model is similar to the relay model where user can input specific overcurrent protection settings. The only difference is that the recloser overcurrent pickup range is shown in primary amps because there is no separate CT model for the reclosers, meaning that the pickup value can be set in primary amps regardless of the CT ratio.

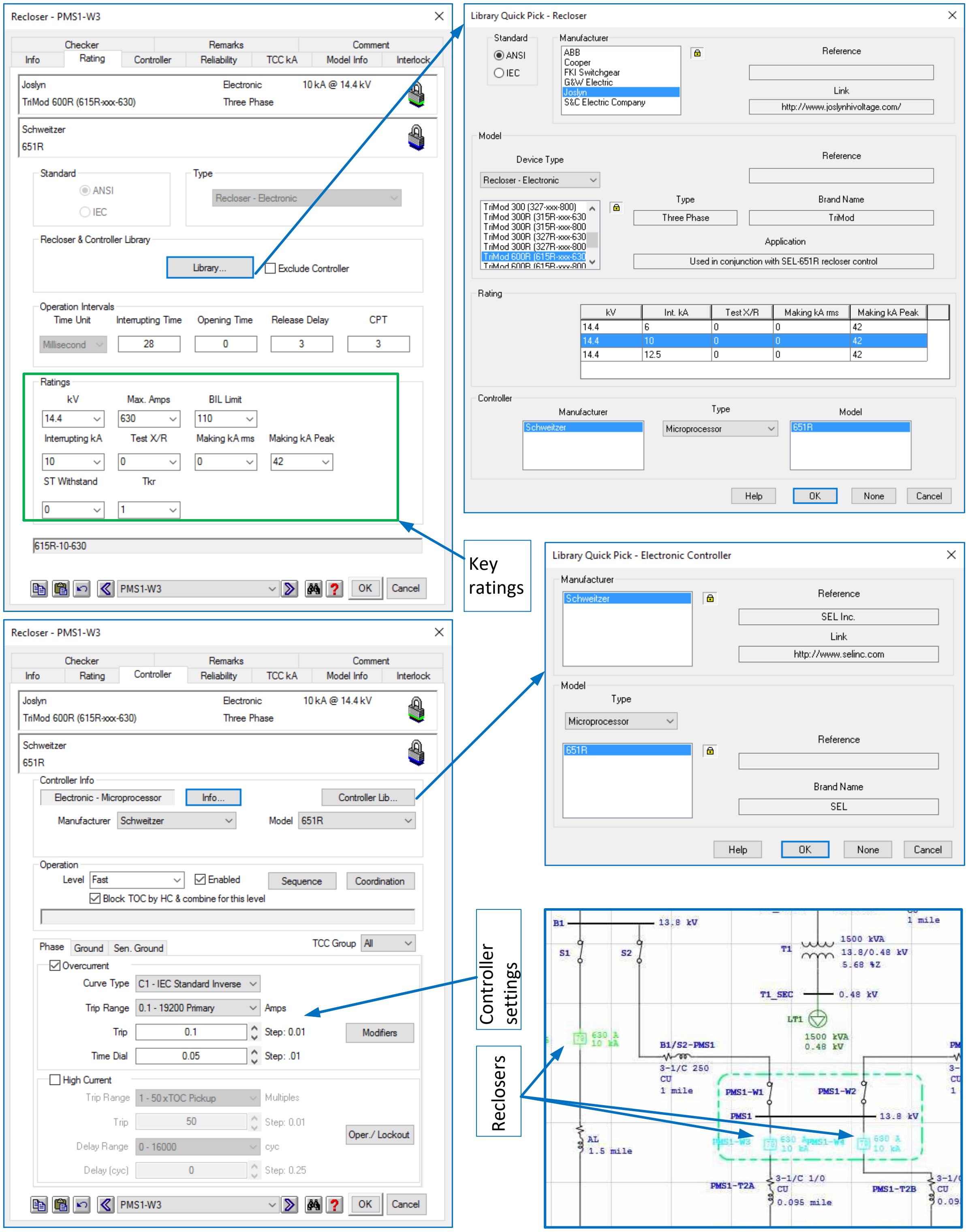


Figure 4.13 – Single-Line View and Parameters for Recloser Model

4.3.8 Service Transformers

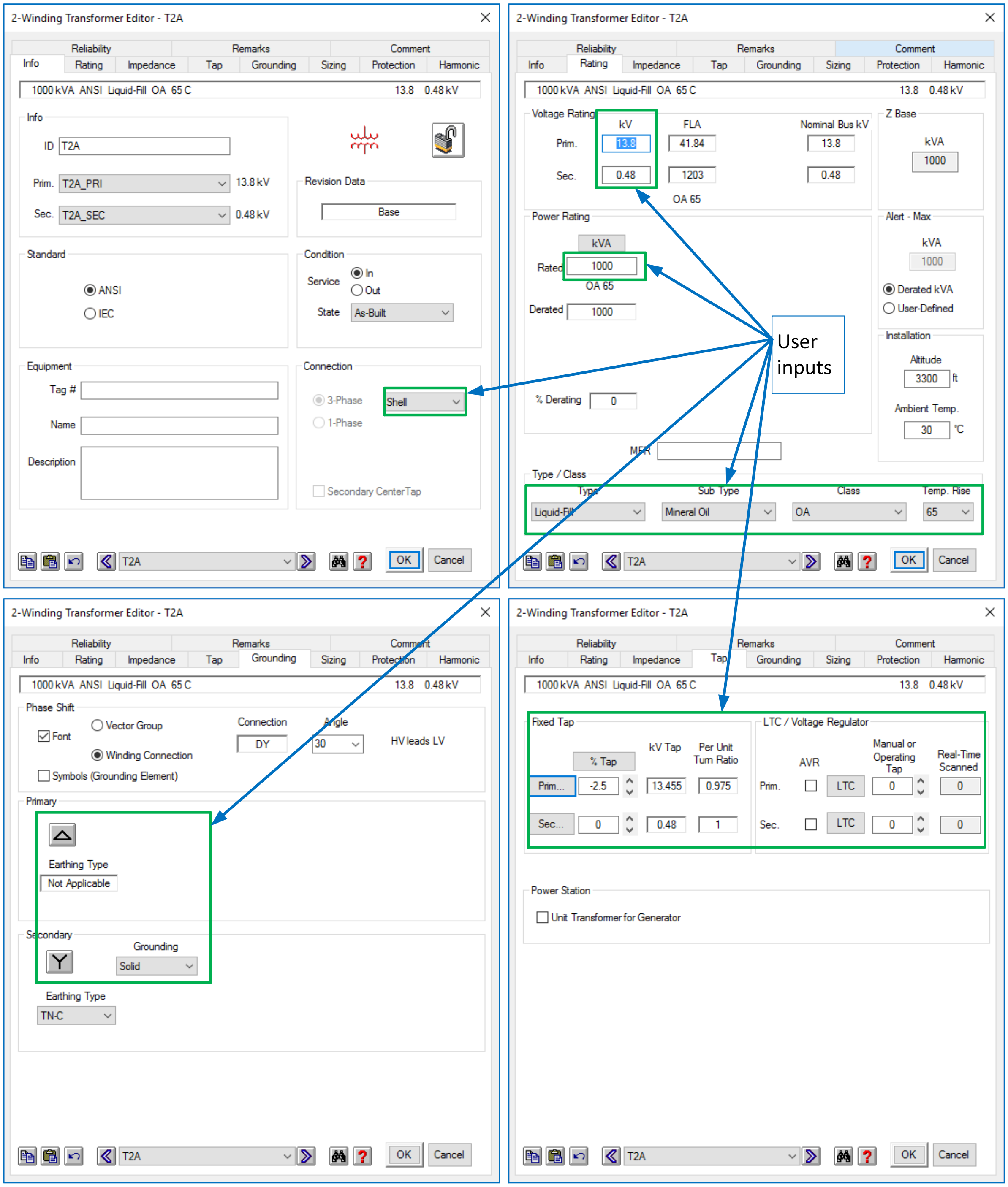


Figure 4.14 – Single-Line View and Parameter Dialogs for Typical Service Transformer Model

The service transformers are modelled similar to the power transformers. The only differences are that the service transformers do not have any LTCs and they typically feature simple cooling mechanisms, meaning no forced air or forced oil cooling. For transformers with unknown impedance and/or X/R ratio, ETAP provided “typical” values are used.

Figure 4.14 shows a typical user input parameter window of a service transformer.

4.3.9 Voltage Regulators

In ETAP, voltage regulators are modelled similar to transformers except that the primary and secondary voltages are kept same. The “LTC/Voltage Regulator” under “Tap” field is utilized to program the voltage regulator setting parameters.

4.3.10 Capacitor Banks

The representative distribution system includes one pole-top distribution class 13.8kV rated 600kVAr capacitor bank for voltage regulation purposes. Figure 4.15 shows the model single-line and data inputs for the capacitor bank. The capacitor bank is a shunt mounted and grounded unit with basic fuse protection.

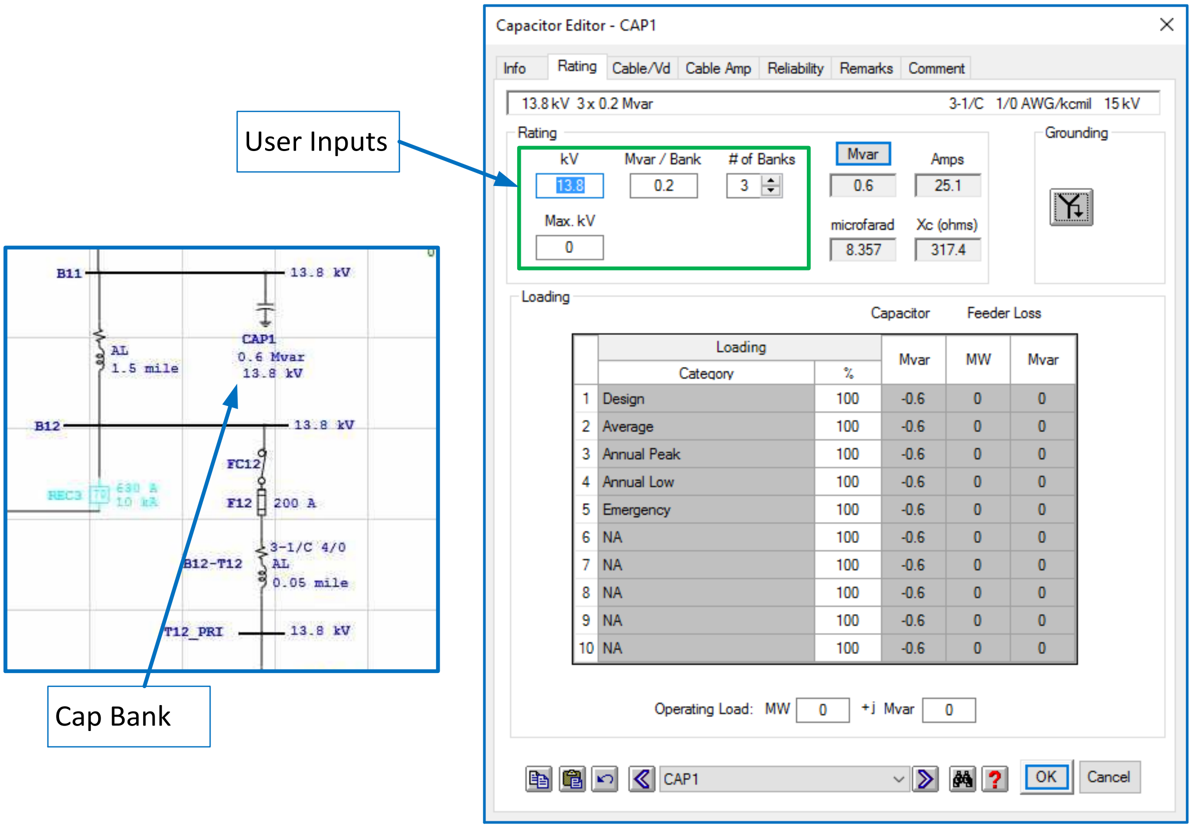


Figure 4.15 – Single-Line View and Parameter Dialogs for Typical Capacitor Bank Model

4.3.11 Combined Heat and Power System

As shown in Figure 4.16, the CHP system model includes the generator, 5kV switchgear with circuit breakers and relays, auxiliary load, and a step-up transformer. The circuit breakers and relays model are created similar to Sections 4.3.3 and 4.3.4. The step-up transformer is modelled similar to substation power transformers except that its configuration is solidly grounded wye on the primary side and resistance grounded wye on the secondary side. The step-up transformer also does not have load tap changer enabled for voltage regulation since it may see reverse power flow when the PHC generator is out and auxiliary loads are still up. The auxiliary load model is created the same as all the other load models, as described in Section 0. This section mainly focuses on CHP generator stead-steady model. The ratings data from Table

4.8 and the generator loading values for various loading categories are entered into the model. ETAP’s built in “typical data” is used for impedance values other values. Also the exciter and governor models use ETAP’s built in models and sample parameter data for small gas turbines. Basic overcurrent relays are also modelled with the medium voltage switchgear to evaluate overcurrent coordination challenges presented by the microgrid operations.

Figure 4.16 – Single-Line View and Parameter Dialogs for CHP Generator Model

4.3.12 Backup Generators

The backup generators are modelled very similar to CHP generator, except that generator type is selected "Diesel." In the existing representative system, the backup generators are connected to a power grid via ATS that starts to generators when it senses loss of utility. The microgrid-ready model also incorporates a simple single-throw switch in parallel to the ATS so that the backup generators can be brought online during an island mode operation. Figure 4.17 shows the single-line view of a typical backup generator system.

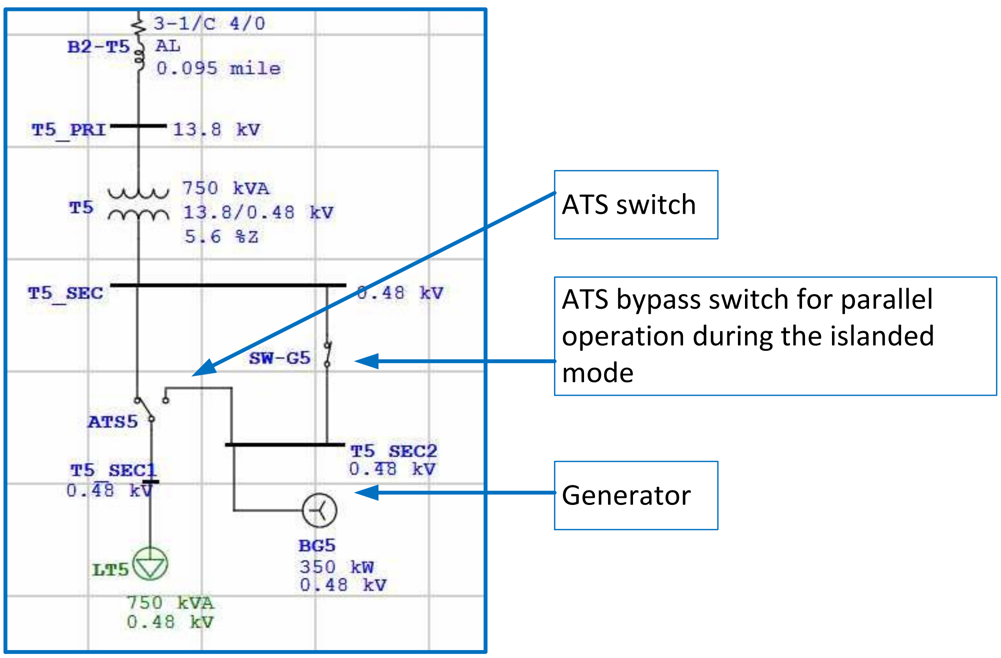


Figure 4.17 – Single-Line View of a Backup Generator Model

4.3.13 Loads

Loads are modelled as conventional lumped loads at the secondary terminal of the service transformers. The lumped load has two components – motor load and static load. The percentage of each component may vary depending on the type and size of the load application. As discussed in Section 4.1.7, the kVA rating of the load model is chosen to be the same as the connected service transformer ratings. Detailed and dynamic models of the loads are beyond the scope of this thesis. Future work could explore the detailed characteristics and dynamic behaviour of the loads in military installations and develop more accurate load models.

Table 4.7 provided the essential data for all of the load models. The Four different loading categories – Design, Average, Annual Peak, and Annual Low – are defined to facilitate load-flow analysis for various loading conditions. Figure 4.18 shows typical load model inputs.

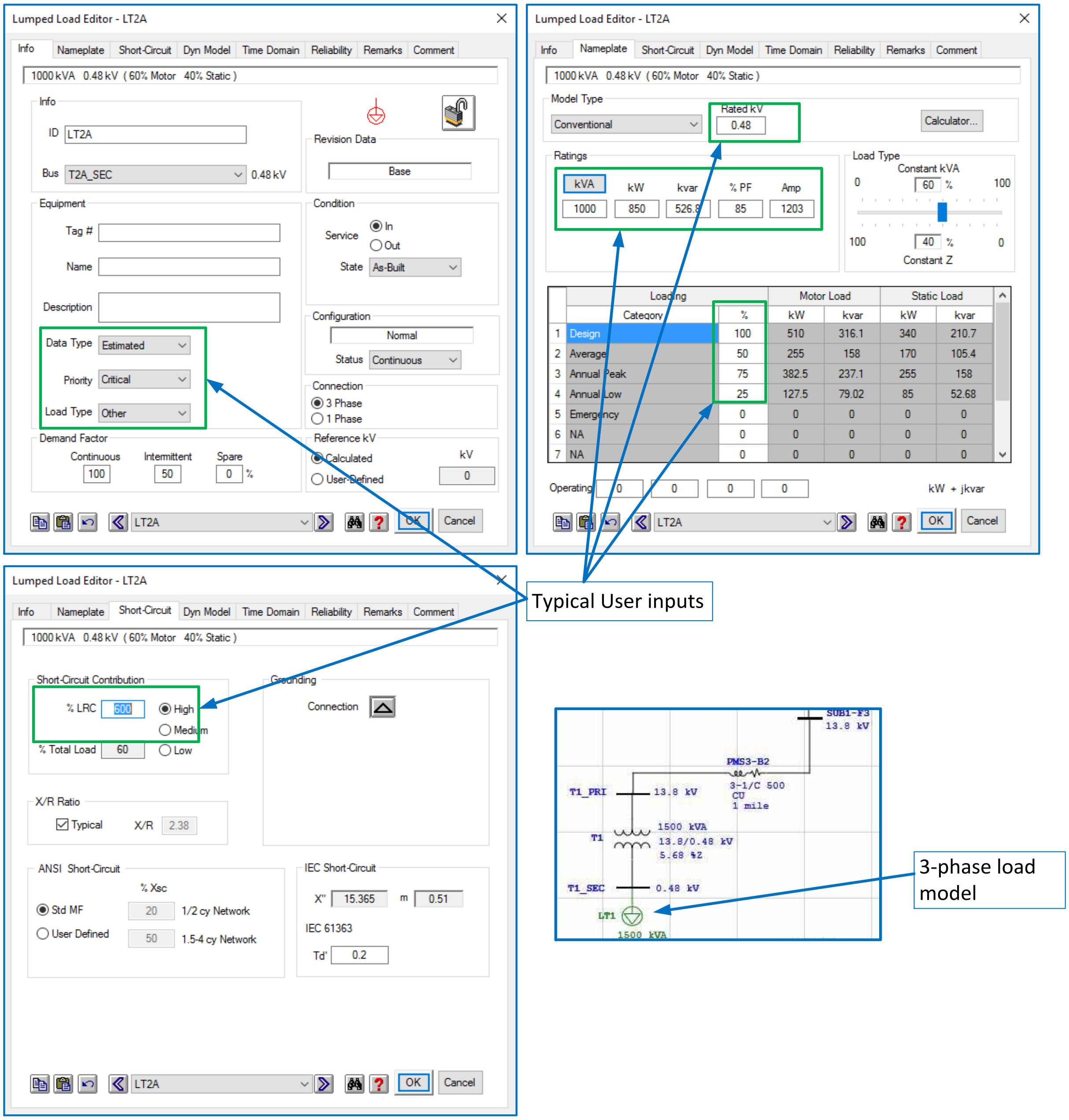


Figure 4.18 – Single-Line View and Parameter Dialogs for Typical Lumped Load Model

CHAPTER 5: SYSTEM STUDIES

As described in Chapter 4, a detailed model of the microgrid ready representative system was created in ETAP for system analysis. Such analysis include load-flow and voltage drop, short circuit, protective relaying and coordination, and frequency response of the local generation system during microgrid operations. The primary focus of the abovementioned analysis is to identify various engineering challenges presented by microgrid operations. Section 5.1 outlines various study scenarios that were developed in ETAP to analyse system performance for various operating modes under different loading and switching scenarios. Sections 5.2, 5.3, 5.4, and 5.5 summarize load flow and voltage drop analysis, short circuit analysis, protective relaying and coordination study, and CHP generator frequency response study. The key observations for each of the analysis are outlined in Sections 5.2.4, 5.3.3, 5.4.2, and 5.5.2, respectively. Section 5.6 then summarizes the key challenges that were observed for each of the analysis and outlines recommended mitigations.

5.1 Study Scenarios

Study scenarios were developed based on operating modes, switching scenarios, and loading categories. There are a total of three operating modes:

1. **Normal mode** – no on-site generation, utility on, and radial feeders with normally opened tie points (for example, switching configurations shown in Figure 5.1).
2. **Cogen mode** – on-site generation operating in parallel with utility source (for example, Figure 5.1 with 52-GEN and 52-TIE breakers closed).

3. **Microgrid (uGRID) mode** – at least one of the utility source lost and local generator(s) operating in islanded mode (for example, Figure 5.1 with 52-GEN and 52-TIE breakers closed and 52-M1 and 52-M2 opened).

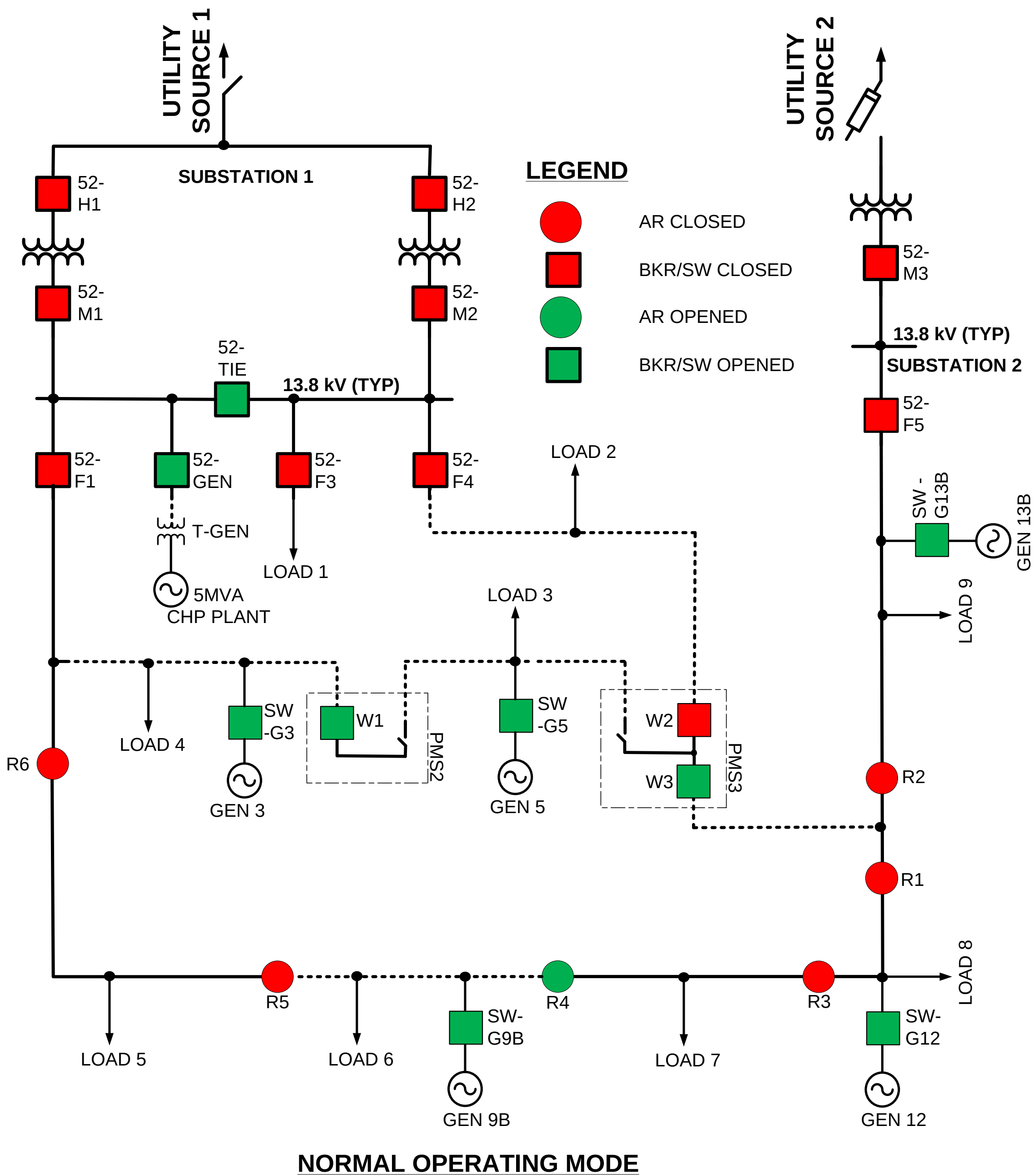


Figure 5.1 – Simplified Normal Mode Switching Configuration of Representative Microgrid-Ready System

Figure 5.1 presents a simplified single-line view of the normal operating mode of the representative system. The single-line shows key switching points such as circuit breakers, VFI ways, reclosers, and backup generator switches that are available for various switching configurations. For normal mode operation the 5MVA CHP generation plan is disconnected from the system which represents no on-site cogeneration.

The following system attributes and switching configurations are used in normal operating mode:

- The utility source 1 supplies to substation 1 and the utility source 2 supplies to substation 2.
- Substation 1 tie breaker (52-TIE) is opened.
- Feeder F1 (52-F1) supplies to LOAD 4, 5, and 6; Feeder F3 supplies to LOAD 1; Feeder 4 supplies to LOAD 2 and 3; Feeder F5 supplies to LOAD 7, 8, 9.
- PMS2-W1 is normally-opened (NO) tie point between F1 and F4, PMS3-W3 is NO between F4 and F5, R4 is NO between F1 and F5.

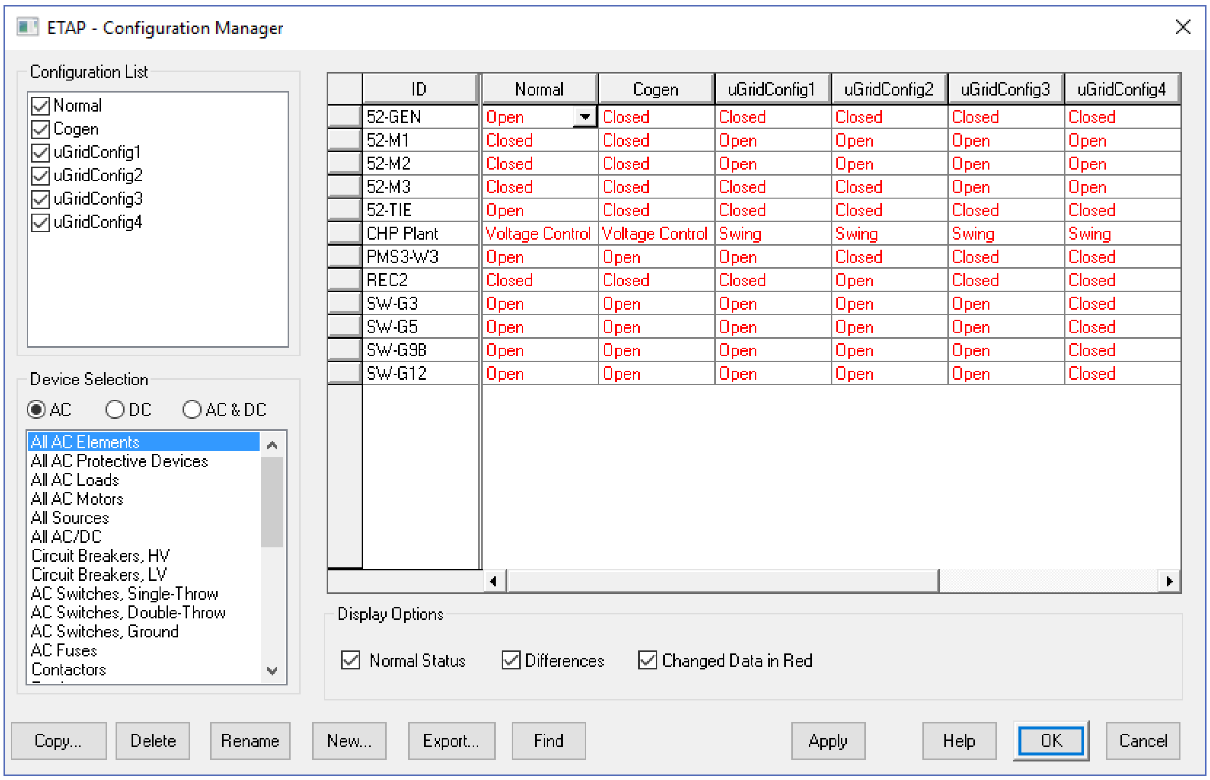
Table 5.1 outlines switching scenarios and generator control mode for normal, cogen, and uGRID modes of operation. The cogen mode has all the same switching configuration as the normal mode except that the 52-TIE and 52-GEN breakers are closed and the CHP plant generator is operating in parallel with utility source 1. Microgrid mode configuration 1 (uGRID, CONFIG1) is similar to the cogen mode except that the utility is lost and 52-M1 and 52-M2 are both opened to create an island that includes the Feeder F1, Feeder F3, and Feeder F4 loads.

MODES OF OPERATION	NORMAL	COGEN	uGRID			
			CONFIG1	CONFIG2	CONFIG3	CONFIG4
SWITCHES	**STATUS**	**STATUS**	**STATUS**	**STATUS**	**STATUS**	**STATUS**
52-M1	CLOSED	CLOSED	**OPEN**	**OPEN**	**OPEN**	**OPEN**
52-M2	CLOSED	CLOSED	**OPEN**	**OPEN**	**OPEN**	**OPEN**
52-TIE	OPEN	**CLOSED**	**CLOSED**	**CLOSED**	**CLOSED**	**CLOSED**
52-GEN	OPEN	**CLOSED**	**CLOSED**	**CLOSED**	**CLOSED**	**CLOSED**
PMS2-W1	OPEN	OPEN	OPEN	OPEN	OPEN	OPEN
PMS3-W3	OPEN	OPEN	OPEN	**CLOSED**	**CLOSED**	**CLOSED**
REC2	CLOSED	CLOSED	CLOSED	**OPEN**	CLOSED	CLOSED
REC4	OPEN	OPEN	OPEN	OPEN	OPEN	OPEN
SW-G3	OPEN	OPEN	OPEN	OPEN	OPEN	**CLOSED**
SW-G5	OPEN	OPEN	OPEN	OPEN	OPEN	**CLOSED**
SW-G9B	OPEN	OPEN	OPEN	OPEN	OPEN	**CLOSED**
SW-G12	OPEN	OPEN	OPEN	OPEN	OPEN	**CLOSED**
52-M3	CLOSED	CLOSED	CLOSED	CLOSED	**OPEN**	**OPEN**
ALL OTHER SW	CLOSED	CLOSED	CLOSED	CLOSED	CLOSED	CLOSED
SOURCE CONTROL MODE						
UTILITY 1	SWING	SWING	**OFF**	**OFF**	**OFF**	**OFF**
UTILITY 2	SWING	SWING	SWING	SWING	**OFF**	**OFF**
CHP PLANT	OFF	**VOLTAGE**	**SWING**	**SWING**	**SWING**	**SWING**
GEN 3	OFF	OFF	OFF	OFF	OFF	**VOLTAGE**
GEN 5	OFF	OFF	OFF	OFF	OFF	**VOLTAGE**
GEN 9B	OFF	OFF	OFF	OFF	OFF	**VOLTAGE**
GEN 12	OFF	OFF	OFF	OFF	OFF	**VOLTAGE**
GEN 13B	OFF	OFF	OFF	OFF	OFF	**VOLTAGE**

Table 5.1 – System Operating Modes and Switching Configurations for Study Scenarios

Microgrid mode configuration 2 (uGRID, CONFIG2) moves the NO tie point from between Feeder F4 and F5 to Recloser R2 to form a larger loop including Feeder F1 and F4 that covers LOAD 1-8. Microgrid mode configuration 3 (uGRID, CONFIG3) represents base-wide microgrid operation where both of the utility sources are lost and all substation main breaker are tripped open. Microgrid mode configuration 4 (uGRID, CONFIG4) is an extension of CONFIG3 where all the backup generators are brought online to supply load demand.

Table 5.2 shows the ETAP switching scenario configurations that mirror the scenarios outlined in the Table 5.1. The labels “uGridConfig1”, “uGridConfig2”, “uGridConfig3”, and “uGridConfig4” listed under the Configuration List in Table 5.2 are analogous to “uGRID, CONFIG1”, “uGRID, CONFIG2”, “uGRID, CONFIG3”, and “uGRID, CONFIG4” in Table 5.1.



ID	Normal	Cogen	uGridConfig1	uGridConfig2	uGridConfig3	uGridConfig4
52-GEN	Open	Closed	Closed	Closed	Closed	Closed
52-M1	Closed	Closed	Open	Open	Open	Open
52-M2	Closed	Closed	Open	Open	Open	Open
52-M3	Closed	Closed	Closed	Closed	Open	Open
52-TIE	Open	Closed	Closed	Closed	Closed	Closed
CHP Plant	Voltage Control	Voltage Control	Swing	Swing	Swing	Swing
PMS3-W3	Open	Open	Open	Closed	Closed	Closed
REC2	Closed	Closed	Closed	Open	Closed	Closed
SW-G3	Open	Open	Open	Open	Open	Closed
SW-G5	Open	Open	Open	Open	Open	Closed
SW-G9B	Open	Open	Open	Open	Open	Closed
SW-G12	Open	Open	Open	Open	Open	Closed

Table 5.2 – ETAP Switching Scenarios for Each Configuration

5.2 Load Flow Voltage Drop Analysis

For each operating scenario outlined in Table 5.1, a load-flow and voltage drop analysis is conducted for three loading categories:

1. Maximum – peak thermal demand from an annual load profile for each load.
2. Minimum – minimum thermal demand from an annual load profile for each load.
3. Average – average of the minimum and maximum annual load profile.

As shown in Figure 5.2, reduced partial loading significantly effects the efficiency of a gas turbine based generator. Emissions are also increased when a gas turbine is loaded less than 50% of rated output capacity [32]. For this study, 65%, 85%, and 98% are selected for minimum, average, and maximum loading levels for the CHP plant. In general, standby and prime-rated diesel generators are designed to operate at 50% to 85% loading [33]. Less than 30% loading for extended period of time can significantly impact uptime and generator life. For this study, 50%, 75%, and 95% for minimum, average, and maximum loading levels are selected for all of the backup generators.

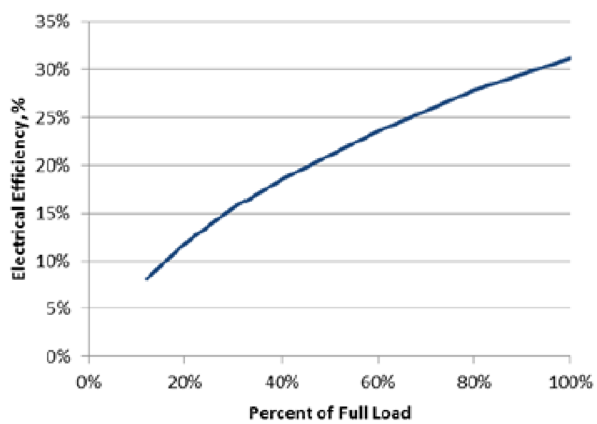


Figure 5.2 – Effect of Partial Load Operation on Efficiency of Typical Gas Turbine Generator [32].

Table 4.7 provided average, maximum, and minimum loading data for each of the lumped load models as percentage of the design load value. Table 5.3 outlines the onsite generator percent loading for average, maximum, and minimum loading levels that are used to model each of the generator loading categories. The ETAP load flow study cases utilize these generator loading categories to match system loading categories for steady-state load-flow analysis. The loading categories are disabled when the CHP generator becomes a swing bus generator during uGRID modes of operation. ETAP does not allow power output limits for a swing bus generator under steady-state power flow. Therefore, during the uGRID modes of operation the CHP generator can exceed its capacity ratings as it tries to support the entire load.

GEN ID	Type	Design Load (kW)	Avg. Load	Avg. Load (kW)	Max Load	Max Load (kW)	Min Load	Min Load (kW)
CHP Plant	Cogen	5000	85%	4250	98%	4900	65%	3250
G3	Backup	1000	75%	750	95%	950	50%	500
G5	Backup	350	75%	270	95%	340	50%	180
G9B	Backup	500	75%	380	95%	480	50%	250
G12	Backup	450	75%	340	95%	430	50%	230
G13B	Backup	750	75%	570	95%	720	50%	380

Table 5.3 – Onsite Generators Loading Categories for Steady-State Load Flow Analysis

The following are the criteria used for determining abnormal performance of the system. Such abnormal performances include apparatus overloading, generator overloading, generator underloading, reverse power flow, and unacceptable voltage drop.

- **Apparatus overloading:** system components (such as lines, transformers, regulators, capacitors, reclosers, buses etc.) are considered overloaded if they experience power flow greater than their continuous current (or full load amperage) rating.
- **Generator overloading:** if a generator is loaded greater than its 98% of kW ratings it is considered as a generator overload condition.
- **Generator underloading:** if a generator is loaded less than its 50% of the kW rating it is considered as a generator underload condition.
- **Reverse power flow:** if the power flows toward the utility during the cogen mode of operation it is considered as a reverse power flow condition. Reverse

power flow may not be desirable for many of the DOD microgrid if the local utility doesn't have tariff power purchase agreement with the installation.

- **Unacceptable voltage drop:** if a bus (or node) experiences less than 95% voltage magnitude relative to rated voltage it is considered unacceptable voltage drop.

5.2.1 Load Flow and Voltage Drop Analysis for Average Loading Condition

Table 5.4 and Table 5.5 provide summary of load flow simulation results that highlight power flow and voltage drop conditions for different operating scenarios under average loading conditions. The utility source is the swing bus during normal and cogen operating mode; whereas the CHP generator becomes the swing bus during microgrid operations. The empty cells in Table 5.4, Table 5.6, and Table 5.8 indicate generation source being offline. The red coloured cells indicate abnormal performance of the system under steady-state load flow analysis.

Summary of results:

ID	Rated kV	NORMAL AVG	COGEN AVG	uGRID1 AVG	uGRID2 AVG	uGRID3 AVG	uGRID4 AVG
BG3							750
BG5							270
BG9B							380
BG12							340
BG13B							570
CHP Plant			4250	3729.5	4305.3	5316.9	3035.1
UTILITY 1	69	3676.4	-527.1	0	0	0	0
UTILITY 2	34.5	1608.9	1608.9	1608.9	1021.9	0	0

Table 5.4 – Local Generators and Utility Sources Power Flow Results (in kW) for Different Operating Scenarios during Average Loading Condition

Bus ID	Nom kV	NORMAL AVG	COGEN AVG	uGRID1 AVG	uGRID2 AVG	uGRID3 AVG	uGRID4 AVG
T3_SEC	0.48	93.95	95.6	96.01	95.86	95.15	100
T4_SEC	0.48	94.54	96.17	96.58	96.43	95.73	98.25
T12_SEC	0.48	98.24	98.24	98.24	96.02	94.62	100

Table 5.5 – Summary of Voltage Drop (% of Rated Nominal Voltage) Cases during Average Loading Condition

5.2.2 Load Flow and Voltage Drop Analysis for Maximum Loading Condition

Table 5.6 and Table 5.7 provide summaries of load flow simulation results that highlight power flow and voltage drop conditions for different operating scenarios under maximum loading conditions.

Summary of results:

ID	Rated kV	NORMAL MAX	COGEN MAX	uGRID1 MAX	uGRID2 MAX	uGRID3 MAX	uGRID4 MAX
BG3							950
BG5							340
BG9B							480
BG12							430
BG13B							720
CHP Plant			4900	6550.8	7334.3	9476.3	6532
UTILITY 1	69	6452.4	1583	0	0	0	0
UTILITY 2	34.5	2915.7	2915.7	2915.7	2138.3	0	0

Table 5.6 – Local Generators and Utility Sources Power Flow Results (in kW) for Different Operating Scenarios during Maximum Loading Condition

Bus ID	Nom kV	NORMAL MAX	COGEN MAX	uGRID1 MAX	uGRID2 MAX	uGRID3 MAX	uGRID4 MAX
T9A_SEC	0.48	92.47	92.27	92.47	92.53	92.51	94.16
T3_SEC	0.48	91.44	92.28	93.04	93.05	91.48	97.73
T3_SEC1	0.48	91.44	92.28	93.04	93.05	91.48	97.73
T4_SEC	0.48	92.23	93.05	93.79	93.8	92.27	95.6
T5_SEC	0.48	93.41	94.23	94.98	94.99	93.45	99
T5_SEC1	0.48	93.41	94.23	94.98	94.99	93.45	99
T9B_SEC	0.48	92.47	92.27	92.47	92.53	92.51	96.98
T9B_SEC1	0.48	92.47	92.27	92.47	92.53	92.51	96.98
PMS2	13.8	94.87	95.69	96.44	96.45	94.9	98.27
T3_PRI	13.8	94.8	95.63	96.38	96.39	94.84	98.25
T4_PRI	13.8	94.84	95.67	96.42	96.43	94.88	98.25
T2B_SEC	0.48	94.87	95.23	95.98	96.04	96.02	96.2
T12_SEC	0.48	95.64	95.64	95.64	93.79	90.68	97.64
T12_SEC1	0.48	95.64	95.64	95.64	93.79	90.68	97.64
T13A_SEC	0.48	96.68	96.68	96.68	96.57	89.47	93.78
B8	13.8	99.9	99.9	99.9	99.79	92.77	97
B9	13.8	99.84	99.84	99.84	99.73	92.71	96.97
B10	13.8	99.74	99.74	99.74	97.93	94.91	98.27
B11	13.8	99.34	99.34	99.34	97.52	94.48	98.35
B12	13.8	98.6	98.6	98.6	96.77	93.72	98.08
B13	13.8	98.52	98.52	98.52	96.69	93.63	97.99
SUB2-F5	13.8	100.35	100.35	100.35	100.21	92.77	97
SUB2-F6	13.8	100.35	100.35	100.35	100.21	92.77	97
SUB2-F7	13.8	100.35	100.35	100.35	100.21	92.77	97
SUB2_SWGR-BUS1	13.8	100.35	100.35	100.35	100.21	92.77	97
T10_PRI	13.8	98.51	98.51	98.51	96.68	93.62	97.98
T10_SEC	0.208	97.34	97.34	97.34	95.51	92.44	96.82
T11_PRI	13.8	98.5	98.5	98.5	96.68	93.62	97.98
T11_SEC	0.208	97.58	97.58	97.58	95.75	92.68	97.05
T12_PRI	13.8	98.59	98.59	98.59	96.76	93.7	98.07
T13A_PRI	13.8	99.81	99.81	99.81	99.7	92.68	96.94
T13B_PRI	13.8	99.81	99.81	99.81	99.7	92.68	96.96
T13B_SEC	0.48	96.68	96.68	96.68	96.57	89.47	96.5
T13B_SEC1	0.48	96.68	96.68	96.68	96.57	89.47	96.5

Table 5.7 – Summary of Voltage Drop (% of Rated Nominal Voltage) Cases during Maximum Loading Condition

5.2.3 Load-Flow and Voltage Drop Analysis for Minimum Loading Condition

Table 5.8 provides a summary of load flow simulation results that highlights power flow for different operating scenarios under minimum loading conditions. No voltage drop issues were present during any of the operating modes because the system was lightly loaded.

Summary of results:

ID	Rated kV	NORMAL MIN	COGEN MIN	uGRID1 MIN	uGRID2 MIN	uGRID3 MIN	uGRID4 MIN
BG3							500
BG5							180
BG9B							250
BG12							230
BG13B							380
CHP Plant			3250	1898.5	2349.7	3107.8	1547.8
UTILITY SOURCE1	69	1899.6	-1340.8	0	0	0	0
UTILITY SOURCE2	34.5	1226.7	1226.7	1226.7	769	0	0

Table 5.8 – Local Generators and Utility Sources Power Flow Results (in kW) for Different Operating Scenarios during Minimum Loading Condition

5.2.4 Key Observations

1. None of system components, except for the CHP generator, experienced thermal overloading conditions for any of the operating scenarios because all the service transformers are loaded well below their rated capacity even for the maximum loading conditions.
2. The CHP generator electrical power output was close to the specified percent loading level (as shown in Table 5.3) during the cogen mode; whereas, its output adjusted to different levels to support the local load demand during microgrid modes of operation.

That is because the CHP generator is set to voltage control with fixed real power during cogen mode and to swing bus control for microgrid mode of operations.

3. Utility source 1 experienced reversed power flow during the cogen mode of operations under average and minimum loading due to excess power generation at the CHP plant.
4. The CHP generator experienced minor overloading during the average loading under uGRID3 configuration. It experienced major overloading during the maximum loading condition under all of the microgrid modes of operation. The overloading conditions were due to significantly larger load compared to the CHP generator capacity at the time of system islanding.
5. A couple of the 480V buses experienced undervoltage condition during average loading under normal mode operation.
6. A large number of buses at different voltage levels experienced undervoltage during maximum loading under normal mode.
7. The cogen mode operation improved the voltage profile and reduced the number of buses with undervoltage conditions under all loading scenarios.
8. The uGRID1 and uGRID2 configurations seem to experience slightly improved voltage profiles across the system.
9. The uGRID3 configuration experienced the worst voltage drops across the system.
10. The uGRID4, which has same switching configuration as uGRID3 but with the addition of more distributed generators in the microgrid, experienced the best voltage profile even in heavy loading conditions.

5.3 Short Circuit Analysis

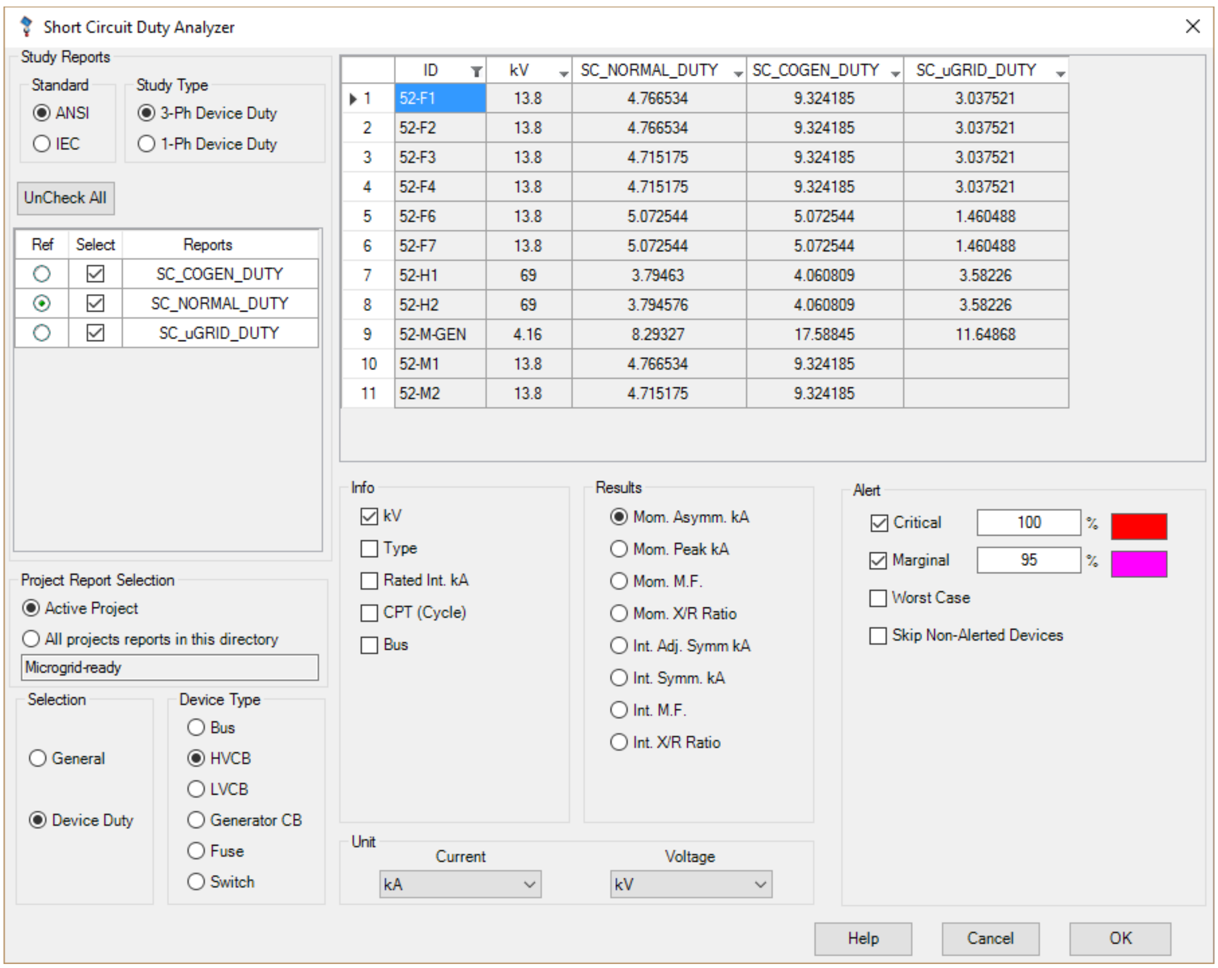
Two types of short circuit studies – “ANSI Device Duty” and “ANSI All Fault Interrupting” – are conducted in ETAP for normal, cogen, uGRID3, and uGRID4 modes of operation. The uGRID1 and uGRID2 operating modes are omitted from the short circuit studies because they exhibit similar results to the uGRID3 configuration. For each type of short circuit study all of the buses are faulted with 3-phase, line-to-ground, line-to-line, and line-to-line-to-ground faults.

The “ANSI Device Duty” fault simulation utilizes the ½ cycle network to calculate momentary short circuit current and protective device duties at the ½ cycle after the fault. The ½ cycle network is also known as a subtransient network where all rotating machines are represented using their subtransient reactances. The fault currents under the subtransient network exhibits significant amount AC and DC components that eventually decay toward steady-state conditions (typically 30 cycles after the fault). The device duty short-circuit data are utilized to determine circuit breaker closing and latching capabilities, fuse interrupting capabilities, switchgear bus bracing, and instantaneous relay settings during a fault [34].

The “ANSI All Fault Interrupting” fault simulation utilizes a 1.5-4 cycle network also known as a transient network. For this type of fault simulation, all the rotating machine models utilize transient reactances. This type of fault data is utilized to evaluate high voltage circuit breaker interrupting duty and coordinate inverse-time overcurrent protective devices. Typical high-voltage circuit breaker interrupting times are rated at between 3 to 5 cycles where the breaker contacts actually start parting earlier than their rated interrupting times [34].

5.3.1 Summary of "ANSI Device Duty" Short Circuit Results

Figure 5.3 provides comparison of available momentary asymmetrical fault current duty (in kA) for substations 1 and 2 circuit breakers. The figure is an example of how the device duty fault currents vary for different operating modes. Although, none of the fault current duty results exceeded their apparatus ANSI device duty ratings, similar variations in fault current duty were observed at all of the apparatus during the different modes of operation.



	ID	kV	SC_NORMAL_DUTY	SC_COGEN_DUTY	SC_uGRID_DUTY
1	52-F1	13.8	4.766534	9.324185	3.037521
2	52-F2	13.8	4.766534	9.324185	3.037521
3	52-F3	13.8	4.715175	9.324185	3.037521
4	52-F4	13.8	4.715175	9.324185	3.037521
5	52-F6	13.8	5.072544	5.072544	1.460488
6	52-F7	13.8	5.072544	5.072544	1.460488
7	52-H1	69	3.79463	4.060809	3.58226
8	52-H2	69	3.794576	4.060809	3.58226
9	52-M-GEN	4.16	8.29327	17.58845	11.64868
10	52-M1	13.8	4.766534	9.324185	
11	52-M2	13.8	4.715175	9.324185	

Figure 5.3 – ANSI Device Duty Fault Comparison for Circuit Breakers for Different Operating Modes

5.3.2 Summary of "ANSI All Fault Interrupting" Short Circuit Results

Bus		3-Phase Fault (kA)				Line-to-Ground Fault (kA)			
		NORMAL	COGEN	uGRID 3	uGRID 4	NORMAL	COGEN	uGRID 3	uGRID 4
ID	kV	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)
B_H1	13.80	2.247	3.348	1.334	1.787	1.440	1.823	0.059	0.059
B_H2	13.80	2.040	2.847	1.265	1.664	1.339	1.654	0.059	0.059
B_H3	13.80	1.845	2.435	1.197	1.542	1.241	1.496	0.059	0.059
B1	13.80	3.026	5.719	1.491	1.940	2.968	5.308	0.060	0.060
B10	13.80	1.923	1.923	1.166	1.608	1.352	1.352	0.059	0.059
B11	13.80	1.453	1.453	0.989	1.317	0.973	0.973	0.058	0.059
B12	13.80	1.164	1.164	0.857	1.114	0.759	0.759	0.058	0.058
B13	13.80	1.016	1.016	0.777	0.983	0.659	0.659	0.057	0.058
B15	13.80	0.766	0.839	0.638	0.778	0.498	0.530	0.057	0.057
B2	13.80	1.960	2.731	1.265	1.760	1.041	1.223	0.059	0.059
B3	13.80	2.236	3.364	1.282	1.621	1.750	2.346	0.060	0.060
B4	13.80	0.957	1.086	0.752	0.914	0.659	0.720	0.058	0.058
B5	13.80	0.858	0.956	0.695	0.846	0.575	0.620	0.057	0.058
B6	13.80	0.779	0.854	0.646	0.789	0.510	0.544	0.057	0.057
B7	13.80	2.446	3.885	1.399	1.903	1.537	1.990	0.060	0.060
B8	13.80	3.139	3.139	0.983	1.327	2.903	2.903	0.059	0.059
B9	13.80	3.086	3.086	0.978	1.321	2.788	2.788	0.059	0.059
B-H4	13.80	2.156	3.168	1.256	1.580	1.677	2.211	0.059	0.060
B-H5	13.80	2.116	3.074	1.243	1.560	1.642	2.148	0.059	0.059
B-H6	13.80	2.076	2.983	1.230	1.539	1.608	2.087	0.059	0.059
Bus3	13.80	3.151	6.290	1.530	1.998	3.211	6.209	0.060	0.060
PMS1	13.80	2.562	4.196	1.376	1.745	2.081	2.955	0.059	0.060
PMS2	13.80	1.766	2.347	1.190	1.645	0.907	1.039	0.059	0.059
PMS3	13.80	2.194	3.254	1.348	1.872	1.213	1.475	0.059	0.060
PMS4	13.80	0.773	0.848	0.642	0.785	0.504	0.537	0.057	0.057
SUB1_SWGR-BUS1	13.80	3.202	6.437	1.527	1.999	3.346	6.696	0.060	0.060
SUB1_SWGR-BUS2	13.80	3.200	6.437	1.527	1.999	3.322	6.696	0.060	0.060
SUB1-F1	13.80	3.202	6.437	1.527	1.999	3.346	6.696	0.060	0.060
SUB1-F2	13.80	3.202	6.437	1.527	1.999	3.346	6.696	0.060	0.060
SUB1-F3	13.80	3.200	6.437	1.527	1.999	3.322	6.696	0.060	0.060
SUB1-F4	13.80	3.200	6.437	1.527	1.999	3.322	6.696	0.060	0.060

Bus		3-Phase Fault (kA)				Line-to-Ground Fault (kA)			
		NORMAL	COGEN	uGRID 3	uGRID 4	NORMAL	COGEN	uGRID 3	uGRID 4
ID	kV	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)	kA (Mag.)
SUB2_SWGR-BUS1	13.80	3.544	3.544	0.943	1.256	3.730	3.730	0.058	0.059
SUB2-F5	13.80	3.544	3.544	0.943	1.256	3.730	3.730	0.058	0.059
SUB2-F6	13.80	3.544	3.544	0.943	1.256	3.730	3.730	0.058	0.059
SUB2-F7	13.80	3.544	3.544	0.943	1.256	3.730	3.730	0.058	0.059
T1_PRI	13.80	2.745	4.796	1.419	1.815	2.091	3.054	0.060	0.060
T10_PRI	13.80	0.990	0.990	0.763	0.960	0.644	0.644	0.057	0.058
T11_PRI	13.80	0.990	0.990	0.763	0.960	0.644	0.644	0.057	0.058
T12_PRI	13.80	1.159	1.159	0.854	1.110	0.754	0.754	0.058	0.058
T13A_PRI	13.80	3.046	3.046	0.974	1.314	2.724	2.724	0.058	0.059
T13B_PRI	13.80	3.046	3.046	0.974	1.316	2.724	2.724	0.058	0.059
T2A_PRI	13.80	2.513	4.056	1.362	1.723	2.012	2.813	0.059	0.059
T2B_PRI	13.80	2.513	4.056	1.362	1.723	2.013	2.815	0.059	0.059
T2-S1_SEC	13.80	3.204	6.433	2.984	2.984	3.330	6.693	3.167	3.167
T3_PRI	13.80	1.749	2.314	1.183	1.635	0.897	1.024	0.059	0.059
T4_PRI	13.80	1.731	2.282	1.174	1.617	0.891	1.016	0.059	0.059
T5_PRI	13.80	1.934	2.678	1.255	1.741	1.025	1.200	0.059	0.059
T6_PRI	13.80	0.946	1.071	0.745	0.904	0.650	0.709	0.058	0.058
T7_PRI	13.80	0.826	0.914	0.674	0.816	0.555	0.596	0.057	0.058
T8_PRI	13.80	0.751	0.820	0.628	0.763	0.494	0.526	0.057	0.057
T9A_PRI	13.80	0.770	0.843	0.640	0.782	0.501	0.534	0.057	0.057
T9B_PRI	13.80	0.770	0.843	0.640	0.782	0.501	0.534	0.057	0.057
VR1_PRI	13.80	1.645	2.129	1.081	1.333	1.169	1.394	0.059	0.059
VR1_SEC	13.80	1.259	1.524	0.907	1.107	0.949	1.091	0.059	0.059
GEN_BUS	4.16	5.400	11.364	6.263	7.272	0.396	11.820	0.397	0.397

Table 5.9 – Comparison of "ANSI All Fault Interrupting" Fault Currents at 13.8kV and 4.16kV Buses during Different Operating Scenarios

Table 5.9 provides the 1.5-4 cycle 3-phase and line-to-ground fault magnitude data for all of the 13.8kV buses under normal, cogen, uGRID3 and uGRID4 operating modes. The line-to-line and line-to-line-to-ground fault data are not included in the table because the current magnitudes are less than the three phase values and do not really provide any additional information for this analysis. It is important to note that during the normal mode of operation the utility is the primary source of fault currents, whereas during cogen mode both utility and local generation (CHP generator in this study) contribute to the fault current. During the microgrid mode operation, the local generator (s) are the only primary source of fault current.

5.3.3 Key Observations

1. Both “ANSI Device Duty” and “ANSI All Fault Interrupting” fault simulation results indicate that the cogen mode operation compared to the normal mode seems to cause a significant increase in the fault duties across the system. Furthermore, the buses closer to the local generation (CHP plant) experience greater increase in fault duty compared to the buses that are further from the CHP generator.
2. When the operating scenario is switched to the microgrid modes all of the buses throughout the microgrid system experienced significant drop in available fault duty (subtransient or transient). The drop in 3-phase fault duty is due to the weaker local generation source during the uGRID modes as compared to normal or cogen modes. Whereas, the line-to-ground fault currents during the uGRID modes are limited to significantly lower levels by the neutral grounding resistances at the CHP generator and its step-up transformer.
3. The 3-phase fault duty is slightly increased across the microgrid system when all the backup generators are added to the local generation pool in uGRID4. The buses closer to the distributed generators experienced greater increase in 3-phase fault duty compared to buses that are further away from the generators.

5.4 Protective Relaying and Coordination Study

A complete protective relaying and coordination study of either the existing or the microgrid ready representative system is beyond the scope of this study. Instead, this study will focus on some of the protective device coordination challenges presented by microgrid operation as compared to the existing representative system.

5.4.1 Summary of coordination study results

Protection of existing representative system is achieved by a combinations of fuses, inverse-time overcurrent relays, and instantaneous overcurrent relays that are coordinated with intentional time delays. Figure 5.4 illustrates an example phase time-inverse overcurrent coordination curves between substation 1 main breaker (52-M2) relays, feeder breaker (52-F4) relays, and the largest fuse downstream from the 52-F4 that is protecting the largest service transformer.

As shown in Figure 3.2, the 52-F4 relays need to be coordinated with the power fuse at PMS2-3 that is protecting transformer T3. The 52-M2 relays (50/51P 52-M2) need to be coordinated with the 52-F4 relays (50/51P 52-F4). A minimum coordination time interval (CTI) of 0.1 seconds is used for coordinating fuse with the upstream electromechanical relay. A minimum of 0.3 sec time delay is used for relay to relay coordination between relays at 52-F4 and 52-M2. As shown in Figure 5.4, because the time dial settings increment step for the electromechanical relays is 0.5, the CTI between PMS2-W3 fuse and 50/51P 52-F4 is 0.191 seconds for the maximum fault current of 1.961 kA at the PMS2-W3. The CTI between 50/51P 52-F4 and 50/51P 52-M2 is 0.336 seconds for maximum available fault of 4.411 kA at the 52-M2 bus.

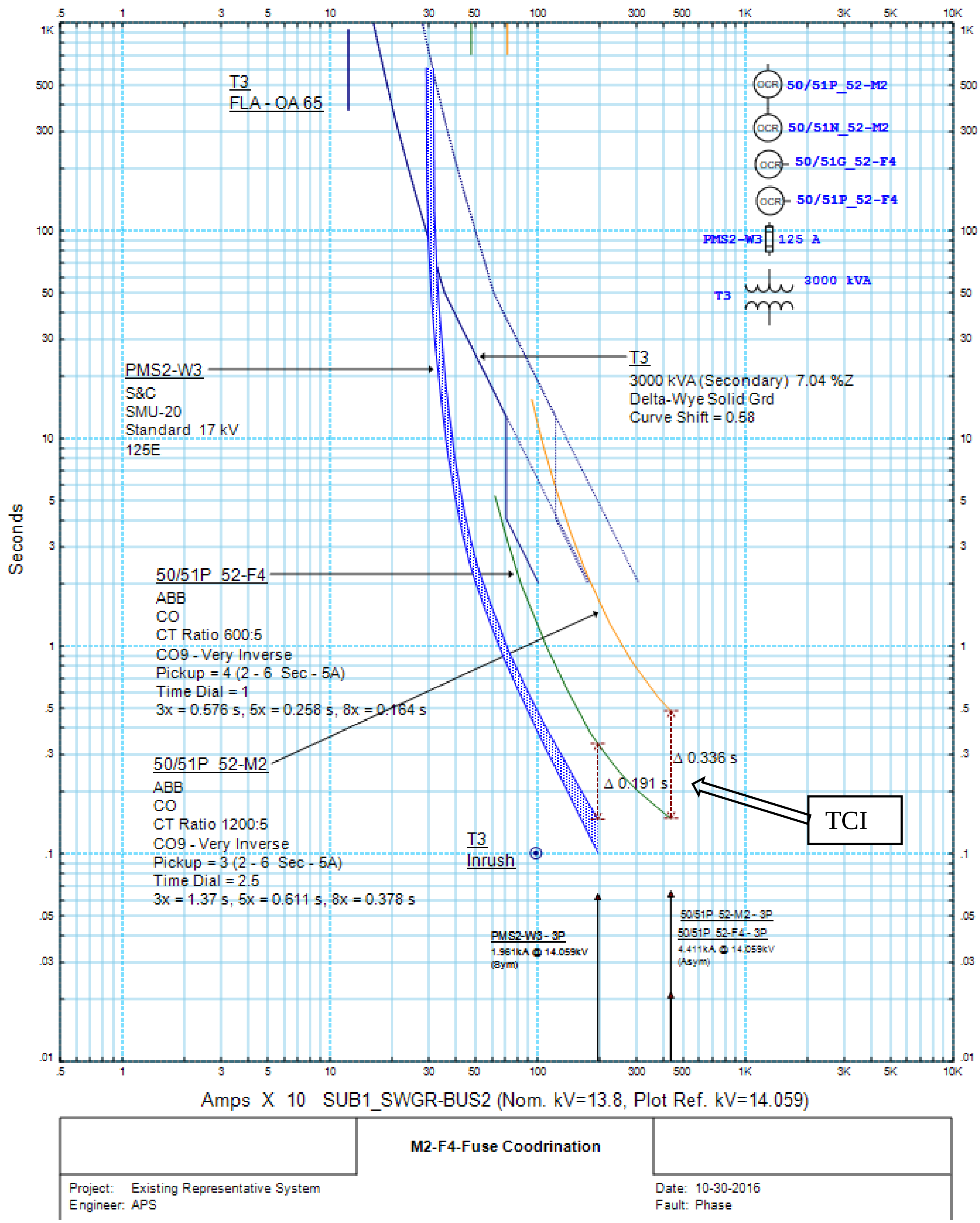


Figure 5.4 – An Example Phase TOC Coordination between PMS2-W3 Fuse, 52-F4 Relay, and 52-M2 Relay for Existing Representative System

Figure 5.4 represents the simplicity of getting protective coordination between relays and fuses for the existing representative system. The utility supply is the only primary source available for fault current contributions which results a single maximum fault duty value per bus that needs to be considered for determining coordination intervals.

The protective scheme and coordination between protective devices becomes significantly more complex for microgrid-ready representative system because (1) the microgrid system has more protective devices along the feeder that require careful coordination, and (2) different modes of operation present different levels of fault duty at any given bus that makes the CTI invalid when the operating mode is changed.

Figure 5.5 presents a similar phase TOC coordination as the one in Figure 5.4 for microgrid ready system under normal operating mode. The microgrid ready configuration changes PMS2-W3 fuse to a VFI relay, adds another VFI relay at the PMS3-W2, and changes the 52-F4 and 52-M2 relays to digital relays. For all of the digital relays (VFI and digital) a SEL-751 relay model is used in the ETAP.

When coordinating inverse time overcurrent relays the TCI is recommended to be between 0.3-0.4 seconds. Coordination between circuit-breakers equipped with direct-acting trip units can as low as possible as long as their characteristic curves do not overlap. VFIs and reclosers are considered circuit breakers with direct acting trip units, and therefore, require small TCI margin. The TCI between PMS2-W3 VFI relay and PMS3-W2 VFI relay is 0.204 seconds.

The time coordination curves (TCC) chart in Figure 5.5 shows the relay settings and the CTIs at maximum fault current levels near the downstream devices. The CTIs indicated in the Figure 5.5 are considered as properly coordinated.

Figure 5.6 presents the same coordination curves (no changes are made to any of the relay settings) as the Figure 5.5 with updated maximum fault currents and resulting new CTIs for cogen mode of operation. The maximum fault currents at each of the downstream devices significantly increase and the CTIs decrease resulting a mis-coordinated protective relay system. In this case, if a fault occurs between circuit breaker 52-F4 and PMS3 switch, assuming 52-M1 has identical settings as the 52-M2, both 52-M1 and 52-M2 relays could operate to clear the fault resulting an unintended island condition and possible loss of service to the entire system connected to substation 1.

Figure 5.7 also presents the same coordination curves and settings as the Figure 5.5 with the updated maximum fault currents and resulting new CTIs for the microgrid mode (uGRID3) operation. The maximum fault currents at each of the downstream devices significantly decrease and drop well below the normal mode operation. The CTIs also drastically increase to a point where the relays would take long time to operate for any given fault. In some instances, the relays may not trip for minutes. As a result, electrical apparatus along the faulted circuit may experience greater thermal stress that would ultimately impact their useful life.

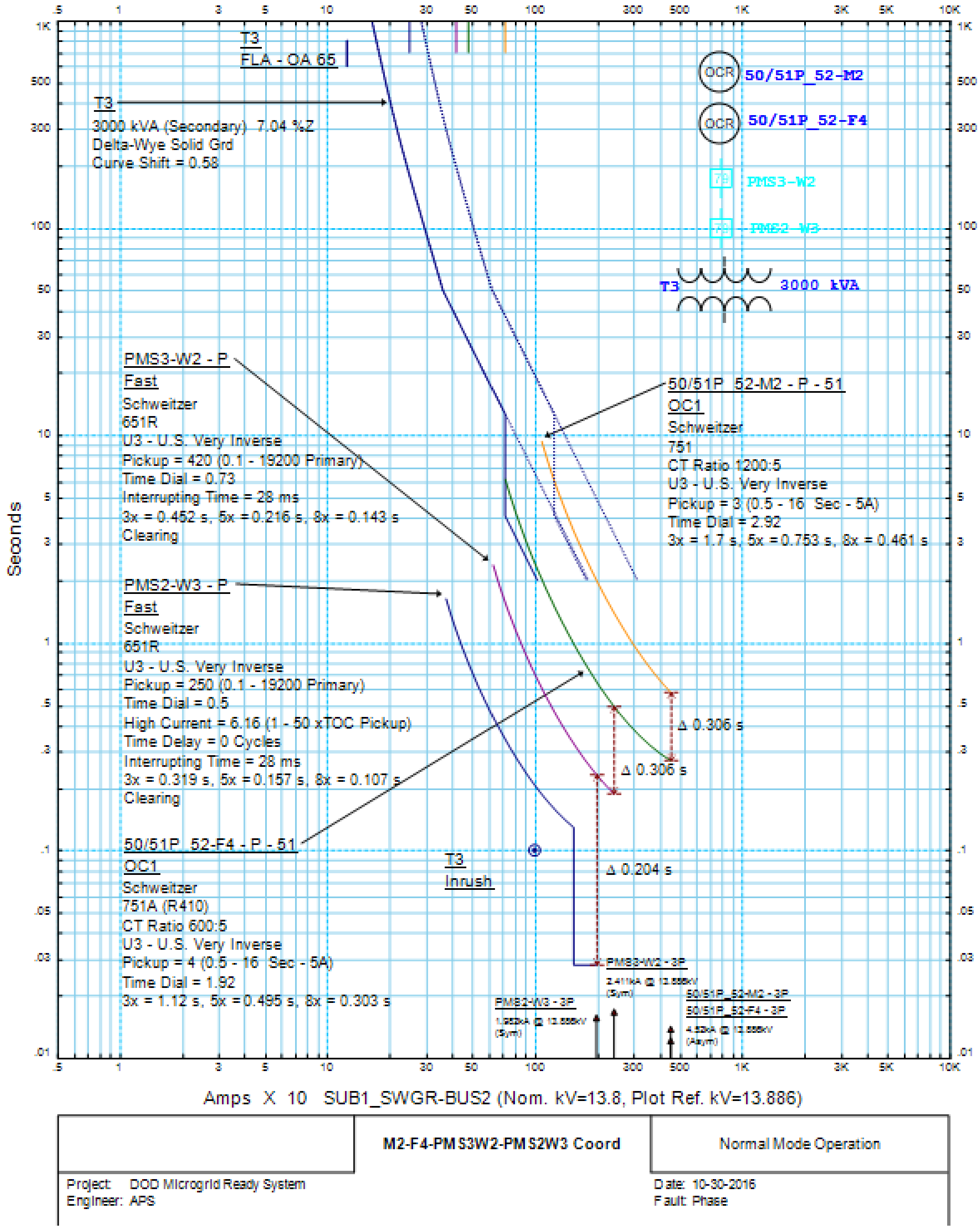


Figure 5.5 – An Example Phase TOC Coordination between PMS-W2 VFI Relay, PMS-W3 VFI 52-F4 Relay, and 52-M2 Relay for Microgrid-Ready System under Normal Mode

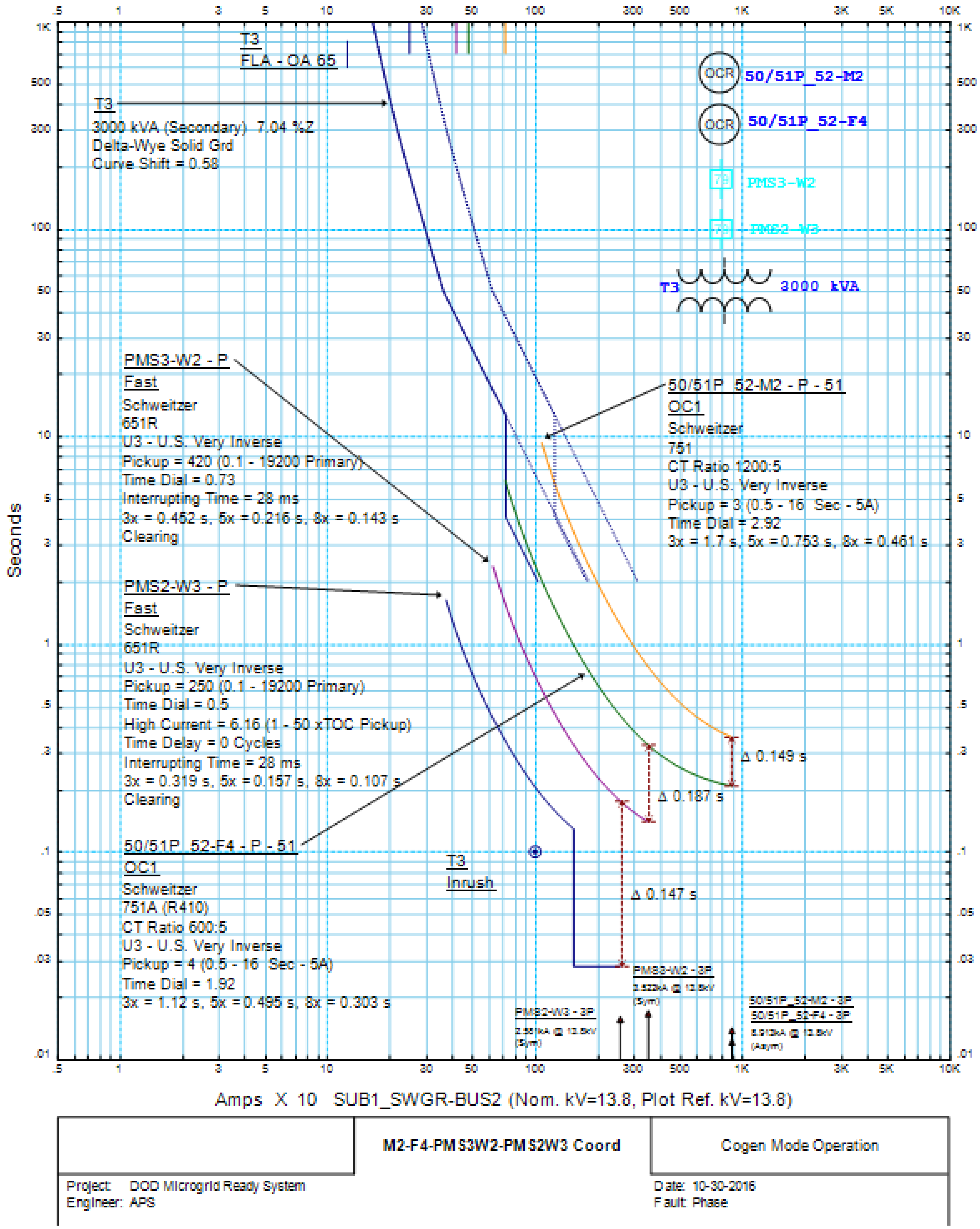


Figure 5.6 – An Example Phase TOC Coordination between PMS-W2 VFI Relay, PMS-W3 VFI 52-F4 Relay, and 52-M2 Relay for Microgrid-Ready System under Cogen Mode

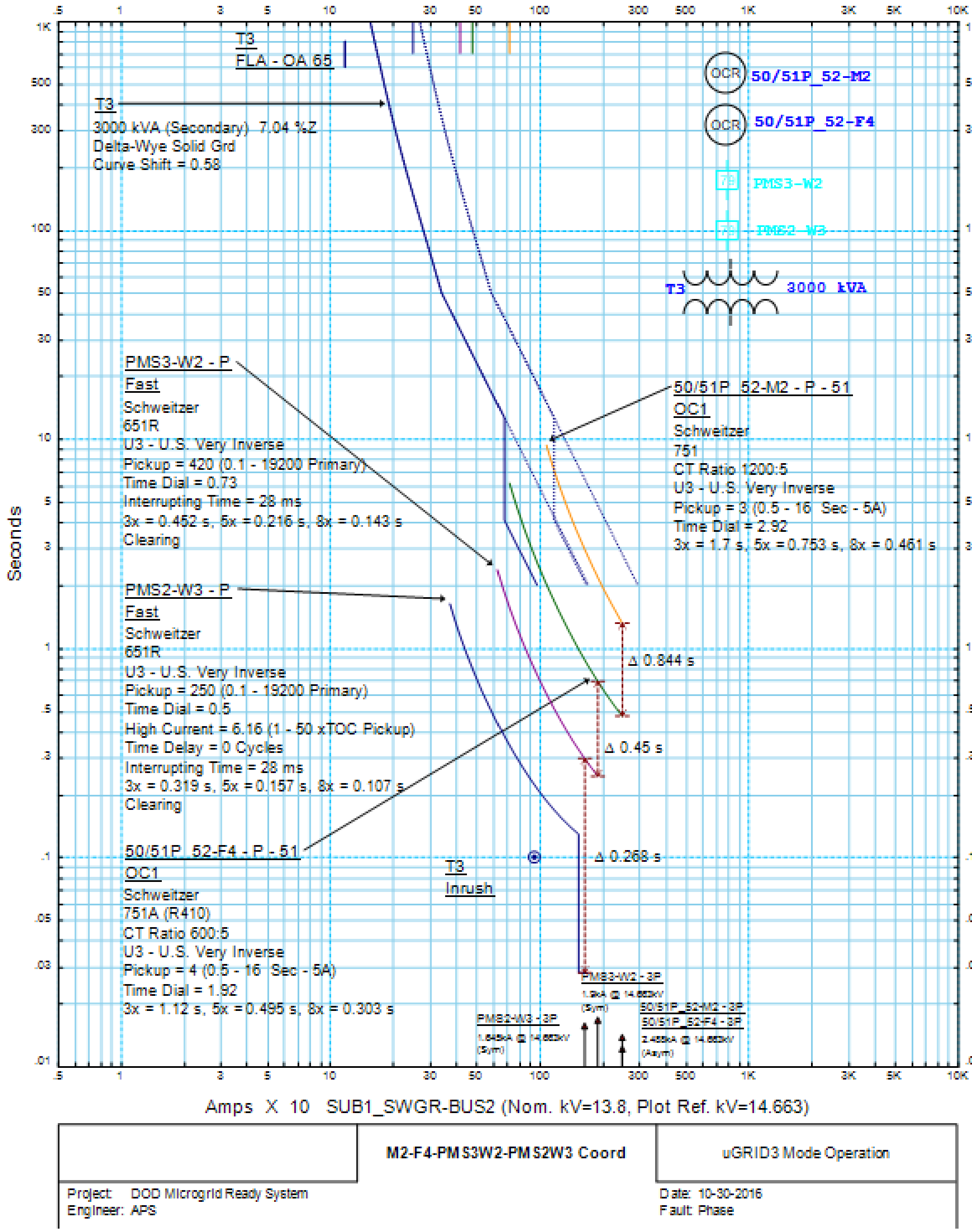


Figure 5.7 – An Example Phase TOC Coordination between PMS-W2 VFI Relay, PMS-W3 VFI 52-F4 Relay, and 52-M2 Relay for Microgrid-Ready System under uGRID3 Mode

5.4.2 Key Observations

1. Time based TOC coordination is fairly simple for the existing representative system where feeders are radial, the available maximum short circuit duty at the downstream device is fixed, and fewer protective devices require coordination.
2. The coordination of TOC elements becomes more complex and sometime impossible for microgrid system where changes in modes of operation results in drastically different maximum available fault currents at the downstream devices which causes well-coordinated relays and VFI settings to become invalid when the mode of operation is changed.
3. As compared to normal mode of operation, the cogen mode resulted in a significant increase in maximum available fault currents at the buses where the protective devices are located. Whereas, uGRID3 mode resulted substantially lower maximum fault currents compared to the normal mode. This demonstrates the challenge for traditional time-based relay coordination.
4. Feeders at microgrid ready system have number of additional reclosers and VFIs which increase number of TOC protective devices that need to be considered for coordination. Time-based coordination approach inherently increases the time dial of the upstream devices and make them less sensitive [35].

5.5 Frequency Response Analysis of CHP Generator

Frequency response analysis of the CHP generator during the transition from cogen mode to microgrid mode of operation is performed utilizing ETAP’s Transient Stability Analysis tool. The main objective of the frequency response analysis is to determine frequency and power output responses of the CHP generator during the transition. The analysis also attempts to determine the speed required for load-shedding or load adding actions in order to keep the local generation stable. In North America, the industry practice generator governor control is 5 percent droop, which means a generator should go from zero to full capacity if the frequency changes by 5 percent or 3 Hz [36]. For the purpose of this study, system frequencies between 61.5 Hz and 58.5 is considered stable and acceptable frequency. The following four scenarios are considered for frequency response analysis.

1. Transition from cogen to uGRID1 mode during the maximum loading
2. Transition from cogen to uGRID1 mode during the minimum loading
3. Transition from cogen to uGRID1 mode during the maximum loading with load-shedding action
4. Transition from cogen to uGRID1 mode during minimum loading with load adding action

5.5.1 Summary of Frequency Response Analysis Results

Figure 5.8 and Figure 5.10 show the CHP generator frequency response curves during a transition from cogen to uGRID1 mode with maximum and minimum loading conditions respectively. Figure 5.9 and Figure 5.11 present the respective real power output during the transition.

The accumulative maximum load of the system under cogen mode of operation is a little over 6 MW. As shown in the Figure 5.9, during the cogen mode and right before islanding, the CHP generator is producing 4.951 MW of power and the utility source is supplying the rest. When utility source 1 is suddenly disconnected to form the uGRID1 at time 0.3 seconds, the

CHP generator starts supplying the entire load, which is significantly greater than the generator rated power output of 5 MW. As a result, the system frequency continues decreasing even the real power output stabilizes near 6 MW. The linear decline of the frequency is the indication of unstable power system operation. The generator governor is unable to control the frequency since the connected loads exceed the generator capacity.

Similarly, the total minimum load of the cogen system is approximately 2 MW. As shown in the Figure 5.11, the CHP generator is producing 3.294 MW of real power right before the cogen mode is switched to uGRID1 mode at time 0.3 seconds. At the instant the system is islanded, the CHP generator experiences sudden drop in load which causes increase in generator speed thus increasing system frequency. As shown in Figure 5.10 and Figure 5.11, eventually the frequency seems to stabilize around 63.5 Hz and power to just below 2 MW. In this case, the governor may eventually correct the frequency. However, the governor response time may not be fast enough to keep the frequency within acceptable range.

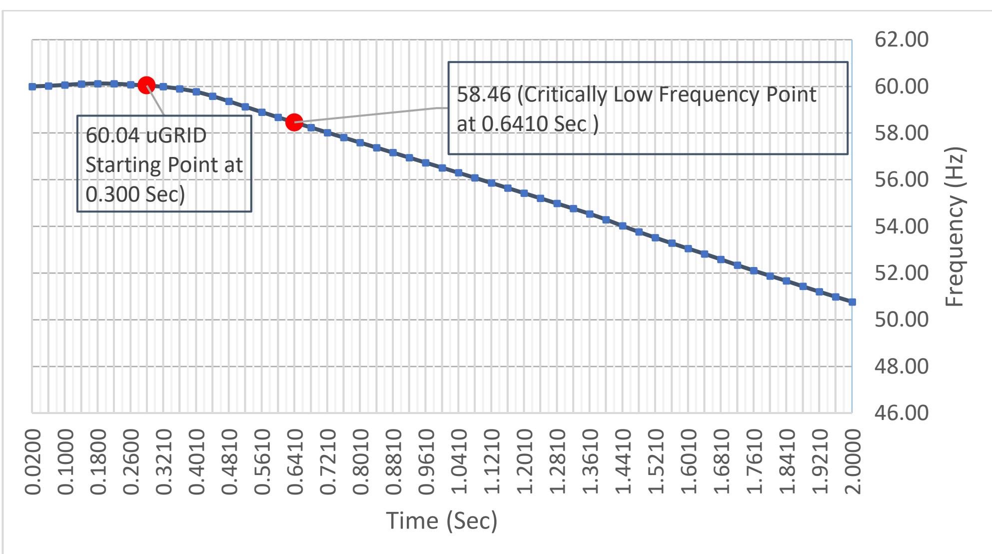


Figure 5.8 –Frequency Response when uGRID1 is formed under Maximum Loading Conditions

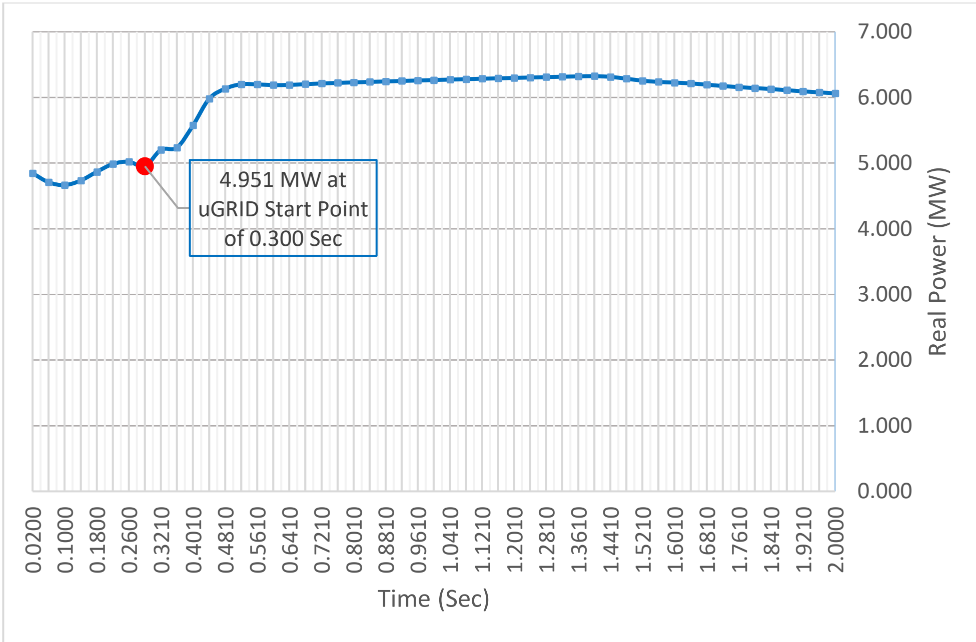


Figure 5.9 – CHP Generator Real Power Output when uGRID1 is formed under Maximum Loading Conditions

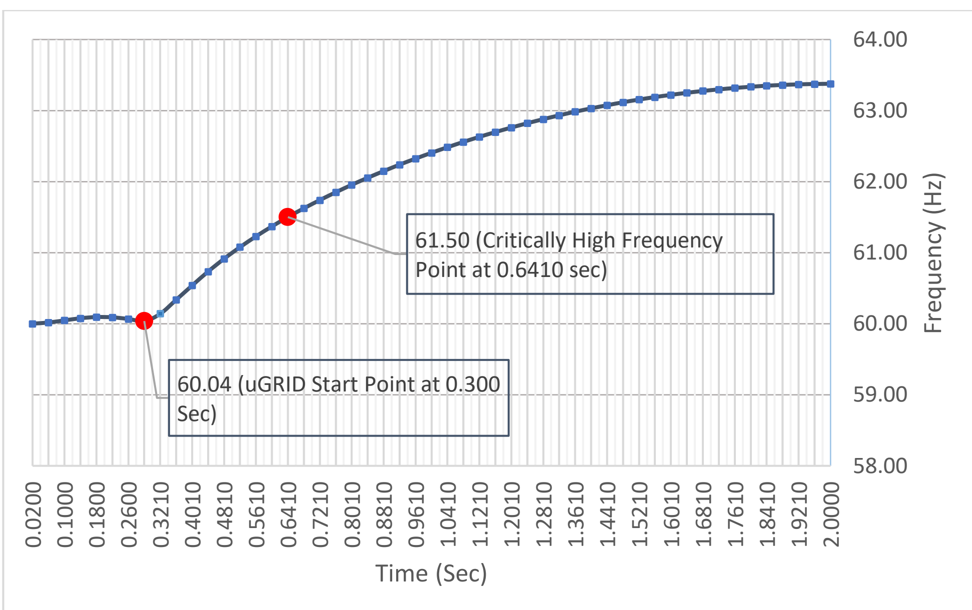


Figure 5.10 – System Frequency Response when uGRID1 is formed under Minimum Loading Conditions

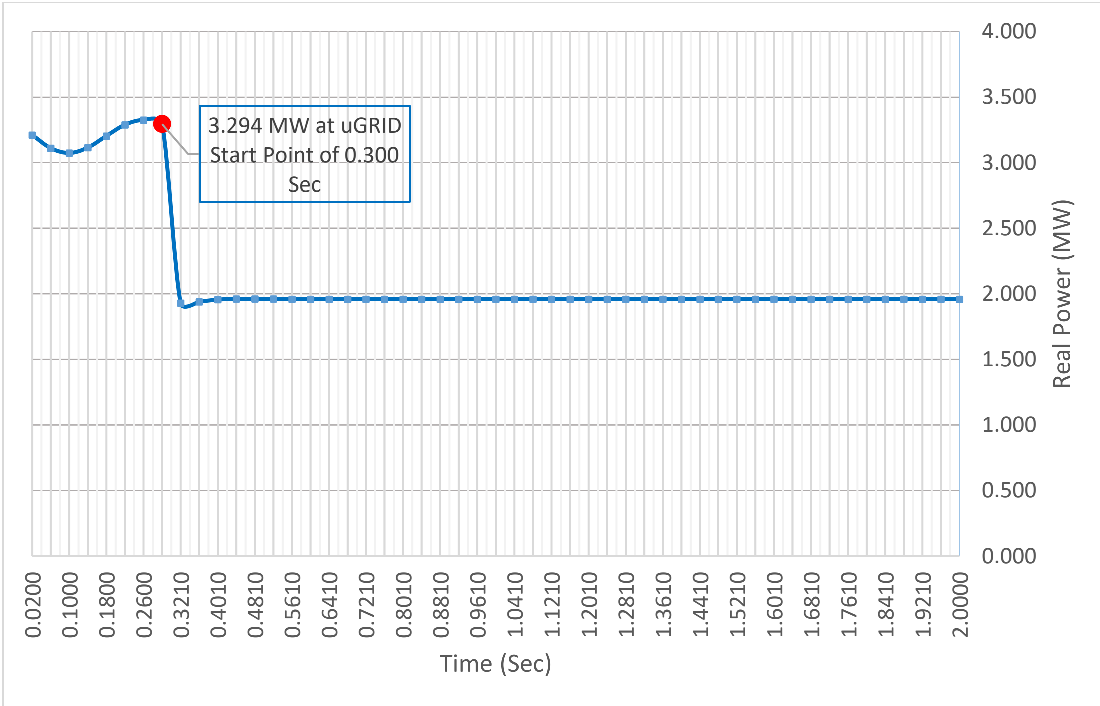


Figure 5.11 – Generator Real Power Output when uGRID1 is formed under Minimum Loading Conditions

Figure 5.12 and Figure 5.13 illustrate frequency response and real power profile of the CHP generator when the system is islanded from cogen mode to uGRID1 mode during maximum load with a load shedding action applied. In this example, within 0.3 seconds after the mode of operation is changed from cogen mode to uGRID1, approximately 2 MW of load, buildings 2A, 2B, and 9A, is shed from the microgrid system. Figure 5.12 shows the frequency recover due to load shedding action at time 0.6 second, which eventually stabilizes near 60 Hz resulting a stable operation of the power system under microgrid.

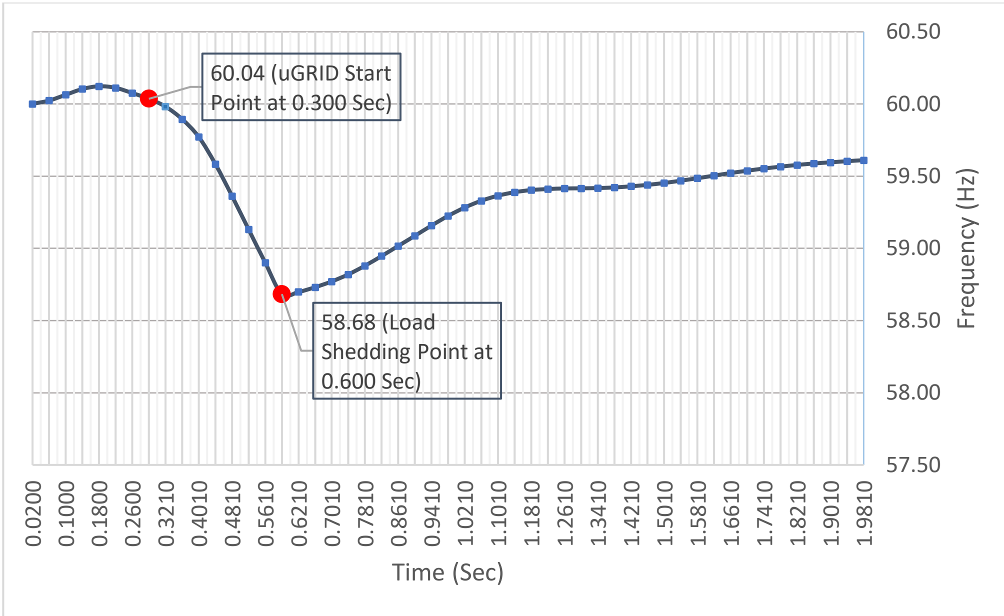


Figure 5.12 – Frequency Response as uGRID1 forms and Load is shed under Maximum Loading Conditions

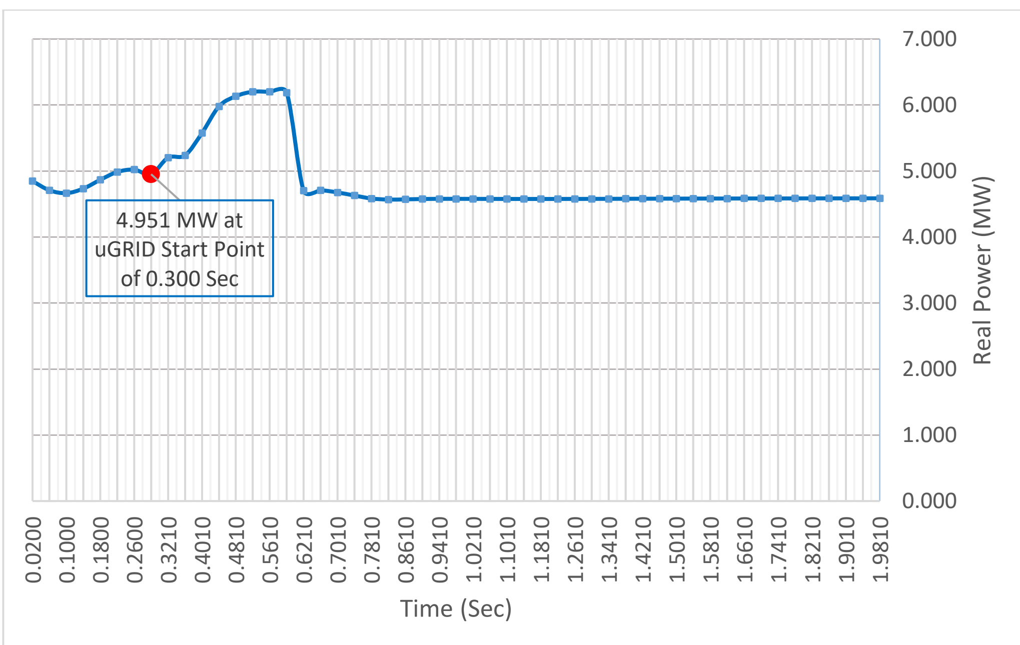


Figure 5.13 – CHP Generator Real Power Profile as uGRID1 forms and Load is shed under Maximum Loading Conditions

Figure 5.14 and Figure 5.15 illustrate the effect of load adding to the system frequency and the CHP generator real power output when uGRID1 is formed from a cogen mode under minimum loading condition. In this case, as the frequency starts to increase after the uGRID is formed at time 0.3 seconds, part of the load from feeder F5, which is supplied by substation 2 until this point, is switched to the microgrid system by opening recloser R2 and closing PMS3-W3. This adds approximately 1.3 MW of load to the system at time 0.6 seconds resulting recovery of the frequency. After the addition of load, the system frequency stabilizes around 60 Hz providing acceptable power quality to the loads.

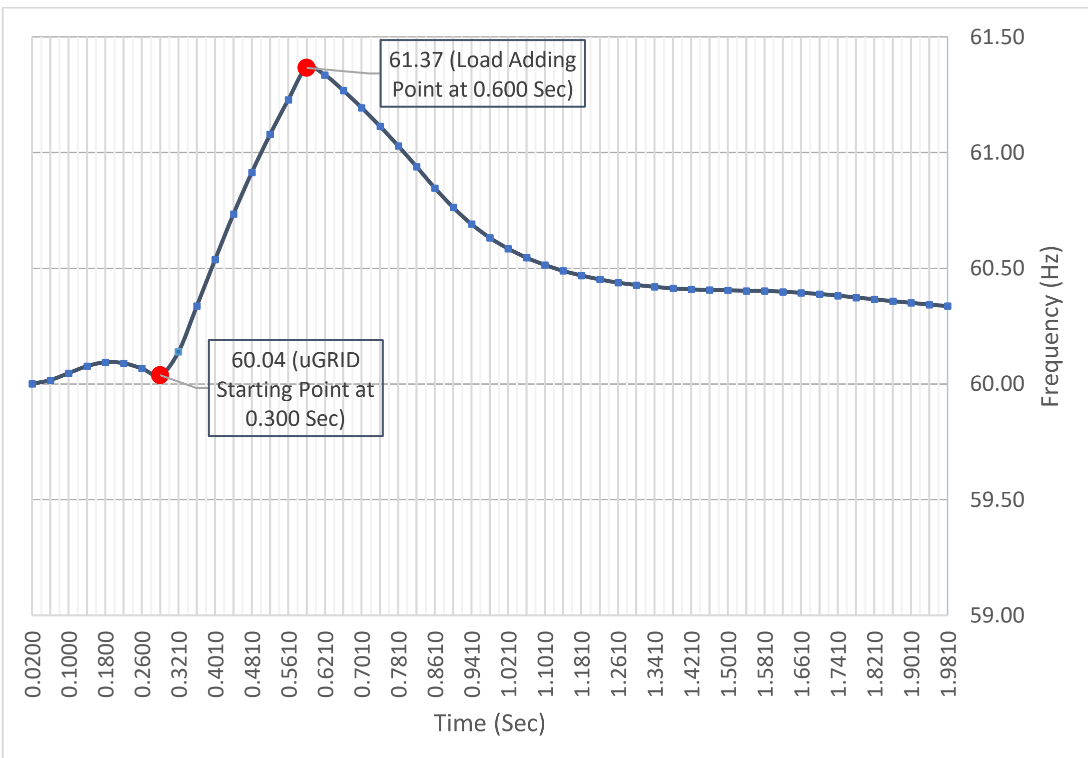


Figure 5.14 – Frequency Response as uGRID1 forms and Load is added under Minimum Loading Conditions

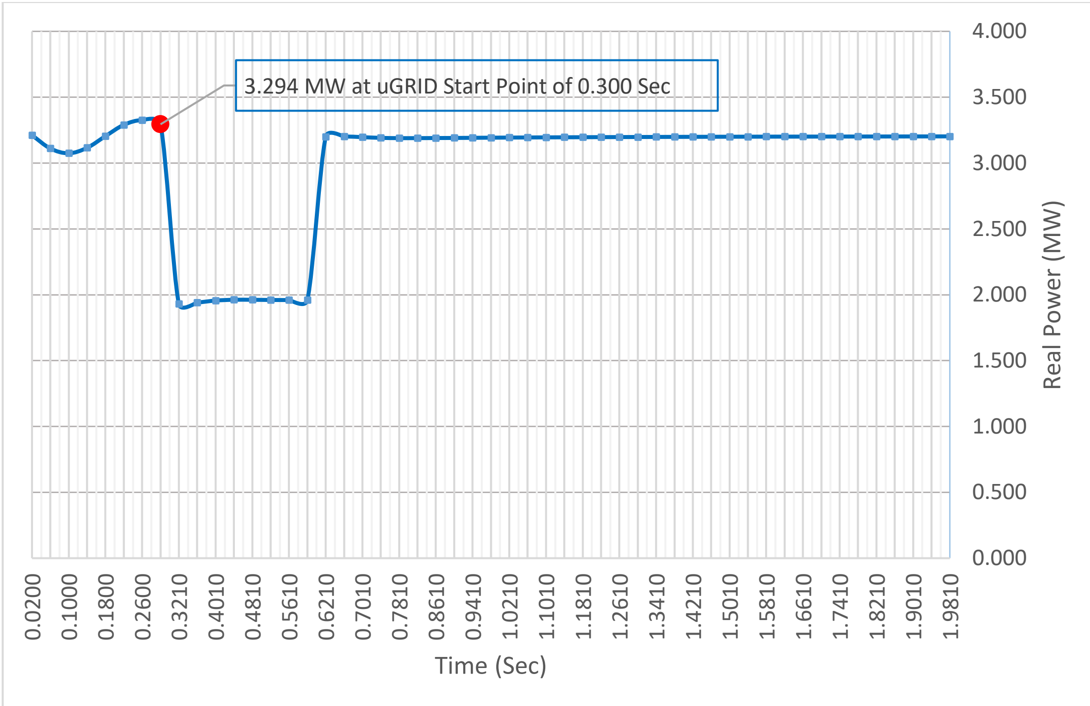


Figure 5.15 – CHP Generator Real Power Profile as uGRID1 forms and Load is added under Minimum Loading Conditions

5.5.2 Key Observations

1. When the system is switched from cogen mode of operation to uGRID1 mode of operation during the maximum loading condition, the frequency started dropping linearly and reached the critically low level of 58.5 Hz within 0.34 seconds.
2. Although, the power generation was constant at right above 6 MW, the frequency kept dropping at a same rate indicating very unstable operations, because the total connected load is much greater than the CHP generator capacity.
3. When the system is switched from cogen mode of operation to uGRID1 mode of operation during the minimum loading condition, the frequency started increasing and

reached to the critically high level of 61.5 Hz within 0.34 seconds. The frequency then eventually stabilised around 63.5 Hz.

4. For both of the microgrid operating conditions (during maximum loading and minimum loading) the frequency reached a critically low or critically high point respectively within a similar timeframe of 0.34 seconds. This result indicates that a load shedding or load adding action for this particular system must be completed within a time window of 0.34 seconds from the time of disconnect to insure stability and quality of the system frequency.
5. Figure 5.12 illustrates the load shedding action during uGRID1 mode during maximum loading scenario where load is shed slightly earlier than 0.34 seconds. The graph in the figure shows that a successful frequency regulation is achieved without compromising power quality.
6. Similarly, Figure 5.14 shows the load adding action during uGRID1 with minimum loading where loads are added slightly earlier that 0.34 seconds. The graph shows that a successful frequency correction is achieved without impacting power quality.

5.6 Engineering Challenges and Recommended Mitigations

The following is a summary of key microgrid-related engineering challenges for DOD electrical systems that are comparative to the representative system developed and analysed in this thesis. The key challenges are derived from the analysis and observations in Sections 5.2-5.5. Recommended mitigations are also provided for each of the challenges described.

- **Challenge #1:** gas turbine based generator and diesel fuel generators provide desirable efficiency and longevity when they are loaded between 50% and 100% of their rated power output. The changing nature of loads and certain switching configurations within the distribution system may not always provide required load for the generators when operating in a microgrid. The engineering challenge is to optimally size the local generators so that they have adequate loads at all times.

Recommended mitigations:

1. Properly model the system under consideration, determine all switching and loading scenarios, and carefully simulate load flow to identify minimum and maximum loading conditions under different switching scenarios.
2. Size the on-site generation capacity to match the minimum and maximum loading ranges so that they fit within the generator loading requirements.
3. Implement a fast communication and switching system that can quickly reconfigure the microgrid system based on the real-time load monitoring.

- **Challenge #2:** When local generators are cogenerating with the utility, the distribution system components and buses seem to experience substantial increase in subtransient (1/2 cycle) fault duty. This introduces a risk that the available subtransient fault levels may exceed the device ratings during the cogen operation mode.

Recommended mitigations:

1. Perform short-circuit analysis to identify if any of the system component ratings exceed subtransient fault levels before installing cogeneration system.
2. Consider updating standards and specifications to increase the subtransient fault duty ratings requirements for system components that would be procured for new installations, upgrades, and retrofits so that they can withstand increased fault duties if and when cogen is introduced.

- **Challenge #3:** during the cogen or microgrid modes of operations the 1.5-4 cycles short circuit fault duties at each bus seem to drastically increase or decrease compared to normal mode operation. Traditional time based overcurrent protective device coordination seem to become invalid with different level of fault currents during cogen or microgrid modes of operation.

  Recommended mitigations:

  1. Perform coordination studies for each mode of operation and determine specific overcurrent protection settings for each mode of operation.
  2. Most modern mainstream microprocessor relays offer multiple independent settings groups for configuring protective settings and control logics. We could utilize different group settings for different modes of operation. The relays provide programmable logic for switching the settings group.
  3. Many of the microprocessor relays also provide multiple level of overcurrent protective elements with a control logic that can be programmed to activate or deactivate the element. We could program various levels of overcurrent protective elements and enable or disable them based on the modes of operation.
  4. Utilize high-speed communications to coordinate protective devices rather than relying on traditional time-based coordination (see Chapter 6 for more details).

- **Challenge #4:** When the microgrid is formed with a CHP generator and a step-up transformer with neutral resistance grounding, the distribution system buses experience very low ground fault currents during single-line-to-ground faults. In such conditions, the existing ground fault relays may not be able to detect the new ground fault currents, which presents challenge for protection engineers.

Recommended mitigations:

1. Similar to Figure 5.16, grounding transformer could be installed in the distribution system (typically at the substation) to provide a return path for the ground fault currents so that the relays at the substation can sense the ground fault and trip the circuit breakers. Figure 5.16 shows a concept grounding transformer implementation where a circuit breaker protecting the grounding transformer is interlocked with the generator circuit breaker. The interlock system can be configured so that it puts the grounding transformer in to service only when the CHP generator is supplying to an uGRID mode of operation.

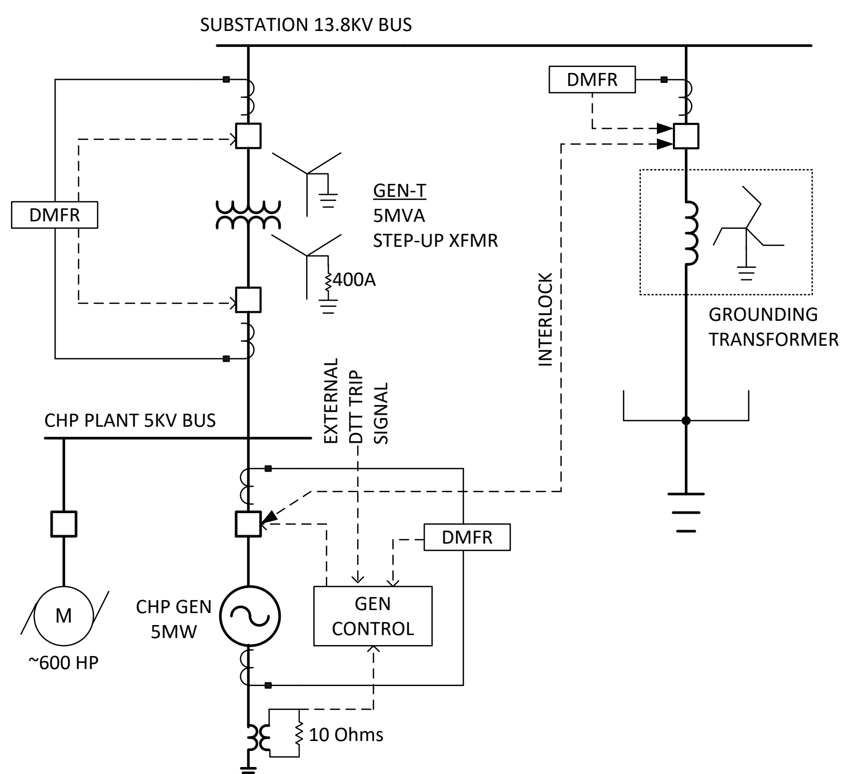


Figure 5.16 – An Example Single-Line Diagram of Grounding Transformer Application to Representative Microgrid-Ready System

2. Consider installing step-up transformer with solidly grounded primary side that provides path for ground faults on the distribution system.

- **Challenge #5:** if a cogen system islands during heavy loading conditions where local load demand is significantly greater that the local generation, system frequency starts drifting downward making the power system unstable.

Recommended mitigations:

1. Implement a fast load-shedding scheme to balance the load to not exceed maximum local generation capability. The loads should be prioritized to different tiers such as non-essential, essential, critical, and mission-critical. A metering and monitoring system should keep track of real-time load levels for each category of loads. A centralized microgrid controller should constantly determine whether load-shedding is needed and what loads should be shed if the system becomes islanded. If the system does get islanded, high-speed load shedding commands should be sent to respective switching devices. The load shed action should be completed before the frequency drops below the critical limits. Section 5.5 determined 0.3 seconds as the required speed of load-shedding action for the representative system considered for this study.
2. A fast-acting spinning reserve (grid synchronized generator or battery/inverter system that is ready to supply loads on short notice) could be also considered if the microgrid is a fairly large system. A detailed analysis must be conducted to determine if the spinning reserve is economically feasible and is fast enough to act during an islanding event. The battery/inverter system may be cost prohibitive for large scale microgrid systems.

3. Instead of a single large on-site generator, the DOD installations may also consider multiple smaller on-site generators that can operate in parallel with the local utility and collectively generate more power than the maximum on-site load demand. For this kind of arrangement to be feasible, the local utility must allow reverse power to their system during the cogen mode. In the event of a microgrid formation, the microgrid controller could control (ramp up or down) the distributed generators outputs to match the load rather than load-shedding. This option requires a thorough technical and economic analysis before implementation.

- **Challenge #6:** if a cogen system islands during light loading conditions where the local load demand is much less than the generator output settings, the microgrid system frequency increased and stabilized to a level greater that may not be acceptable for the load power quality requirements.

Recommended mitigations:

1. Similar to the load-shedding scheme, a fast load adding scheme could be implemented to add more load to the microgrid from an adjacent utility system in order to correct the sudden increase in system frequency. However, this will require a high speed communication and easily switchable adjacent loads.
2. Multiple smaller generators could be configured for the microgrid system where, if required, some of the generators could ramp down or even shut down if the load within the microgrid is light in the event it get islanded. This, however, can present adverse challenge during heavy loading conditions. A detailed feasibility study must conducted before considering this approach.

CHAPTER 6: COMMUNICATION SYSTEMS FOR DOD MICROGRID

A reliable and high-speed communication system is an essential component of the proposed DOD microgrid. Figure 6.1 illustrates a conceptual interconnection network for the DOD microgrid-ready representative system.

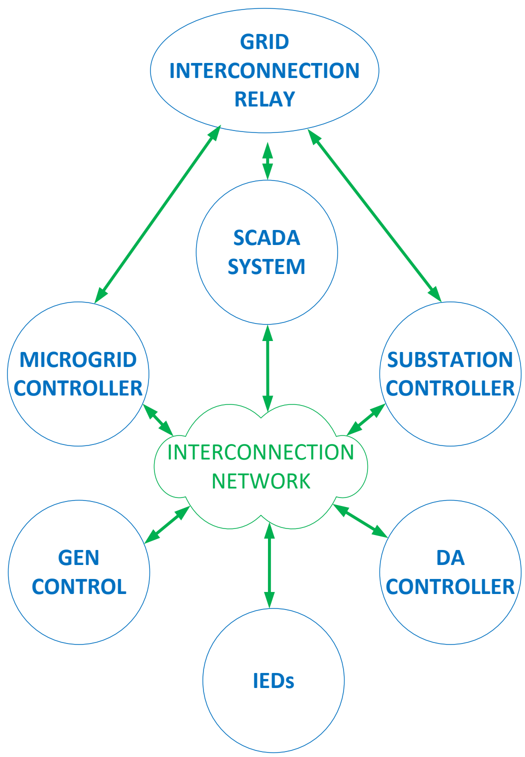


Figure 6.1 – Conceptual Communications Network for the DOD Representative Microgrid System

The microgrid-ready representative system includes various intelligent electronic devices (IEDs) such as DMFRs and meters that are equipped with communication interfaces. The IEDs connect to the field sensors such as current transformers, voltage transformers, and transducers. IEDs are typically equipped with multifunctional capabilities such as metering, monitoring, protection, and control functions. Distribution automation (DA) controllers and substation controllers (typically located at the substation) provide data concentration, parsing, and protocol conversion functions. The SCADA system collects, presents, and stores essential system data. SCADA also provides centralized control interfaces for system operators. A physical communication backbone throughout the distribution system must interconnect IEDs, controllers, and SCADA system. The following list summarizes typical communication system activities one could observe throughout the microgrid platform.

1. The grid interconnection relay uses a communication interface to inform the microgrid controller and the substation controller of changes in modes of operation.
2. The microgrid controller provides various control commands to distributed generator controls and informs DA controller with the status of the mode of operation using communication interface.
3. The substation controller and the DA controller communicate with all of the field DMFRs about the changes in the mode of operation. DMFRs change their protection group settings or enable/disable certain protective elements based on the information received.
4. DMFRs also utilize peer-to-peer communication to implement fast tripping and blocking actions as part of communication-assisted coordination schemes.
5. Substation and field DMFRs identify fault(s), isolate faulted sections, and communicate the event to the DA controller. The DA controller keeps track of normally opened feeder tie points and communicates with all the other DMFRs to facilitate automatic restoration of unfaulted sections once the fault is isolated.
6. Distribution system IEDs constantly communicate metering and monitoring data with the DA controller and the SCADA system.

7. Substation IEDs constantly communicate metering and monitoring data to the substation controller and the SCADA system.
8. The SCADA system provides human-machine interface (HMI) where operators can visualize system status, metering data, mode of operations and issue various control commands.
9. The SCADA system communicates operator-initiated control commands to specific field devices.
10. The interconnection network provides reliable and secure communication gateways and paths to facilitate all levels of inter-device communications.

6.1 Background on Communication Options for DOD Microgrid

The communications system for a DOD installation-wide microgrid system has multifunctional requirements. There are various microgrid functions such as island detection, protection, automation, generation control, load-shedding, and SCADA that require a communication network [37].

Reference [38] provides a comprehensive review of islanding detection techniques for distributed energy resources. The paper discusses passive, active, and remote island detection techniques. The passive and active techniques are local to the point of common coupling (PCC) and do not require communication to the remote utility system. The remote techniques utilize communication between the utility and the microgrid controller where the upstream utility circuit breaker relays send transfer trip signals to the local microgrid controller. Even for the passive and active techniques, the relays used for such techniques need to communicate island detection to the microgrid controller.

References [39] and [40] provide extensive details of how the communications could be utilized for protection schemes for microgrids. In reference [39] the authors propose communication-based protection scheme that utilize digital relays and a centralized controller. The proposed protection system relies primarily on line current differential protection. Reference [40] proposes similar communication-assisted line current differential protection scheme for microgrid systems. It also discusses communication technologies and their performance requirements for such protection schemes. The paper highlights that in order to implement effective differential protection for microgrids, a reliable communication media that is capable of transferring the information in less than 2ms is desired to clear a fault within 6 cycles. A backup directional overcurrent or voltage elements can operate if the communication is lost. The reference [40] stresses the fact that a microgrid, where communication system has multiple functions, requires high-bandwidth, deterministic, and high-speed communications.

Reference [41] provides an in-depth insight on the evolution of technologies and business case for distribution automation. The paper reviews installations and the experiences of two microgrid systems – Washington State University (WSU) and Illinois Institute of Technology (IIT) – that integrate distribution automation as one of the key technologies.

Figure 6.2 presents a four-tier distribution system communication architecture proposed by the paper.

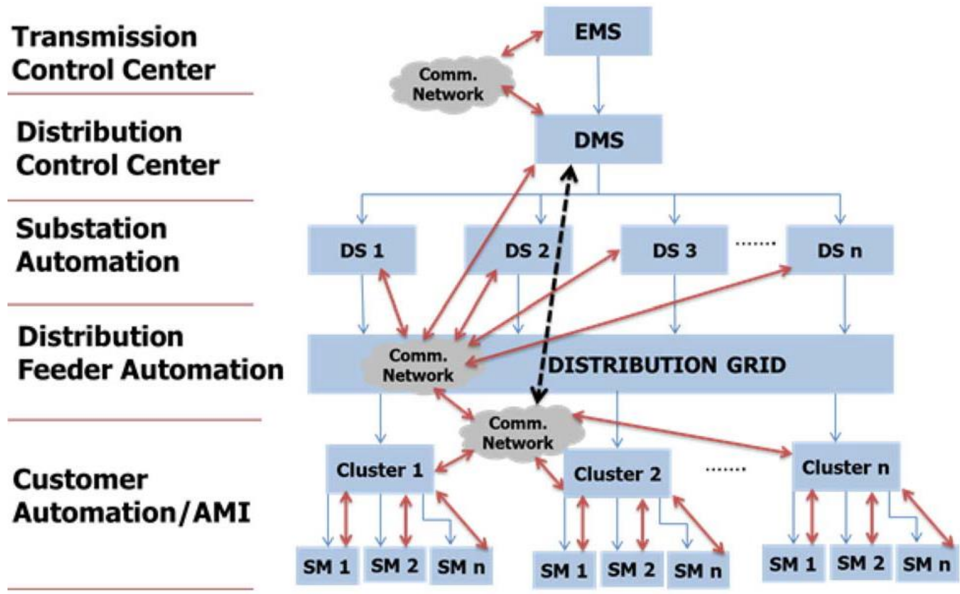


Figure 6.2 – Typical Four-Tier Distribution Communication System Architecture [41]

In the proposed distribution communications architecture, a Distribution Control Center, Substation Automation, Distribution Feeder Automation, and Customer Automation/AMI are the four tiers of overall DA. The paper suggests a fiber-optic or copper based communication network for substation automation and some form of wireless network for the distribution feeder automation and customer automation/AMI system [41]. The wireless network would be the most cost effective solution for the DOD DA communications. However, since there are already many other mission-critical military communications that use wireless technologies, adding more wireless technologies may cause unintended interferences.

Reference [42] describes a generator control architecture. In an AC microgrid (or macrogrid in that matter) the generator control system includes three main functions – droop control (also known as primary control), frequency regulations (also known as secondary control), and optimal dispatch. Droop control instantaneously balances generation with the demand through local action utilizing speed governor.

Typically droop control is designed to proportionally divide the supply instantaneous load changes to all the connected generators with respect to their rating. The droop control provide reliable local control to compensate for change in load but results in frequency deviation. Area-wide frequency regulation or automatic generation control (AGC) is required to regulate system frequency close to 60 Hz where there are more than one distributed generators. A frequency regulation system typically utilizes closed-loop controller that adjusts each generator's set-point based upon the integral of the frequency error. This type of controller is centralized where all the system measurements and control signals are telemetered to and from the generating units. The optimal dispatch is a tertiary control that seeks to determine most economical way to allocate generation demand among all the generators. This control function is achieved by executing various decision-making algorithms at a centralized controller that also measures various system operating parameters [42].

Droop control can function locally and therefore does not require communication. The other two control functions require communication network, especially when operating in a large-scale microgrid with multiple generation units.

As discussed in Sections 5.5 and 5.6, when the microgrid system is islanded during heavy loading or light loading conditions, a high-speed load-shedding scheme is essential to ensure stable operations. The smart switches that perform load-shedding are dispersed throughout the distribution system. High speed communication between the microgrid controller and the relays that control smart switches is the best way one can achieve required load-shedding speed [43].

6.2 Review of Communication Methods, Topologies, and Protocols

A communication system for a DOD microgrid must provide high-speed and be reliable performance for protection, automation, control, and load-shedding requirements. Besides being fast and reliable, the communication system must be secure as well. Because its application involves control, automation, and protection that all require strict quality of service, the communication system in the microgrid (or macrogrid) is a target for malicious interference also known as cyber-attacks [44]. Careful assessment of the available communication interfaces, topologies, and protocols should be the first step in designing proper communication infrastructure for a microgrid. Location, terrain, layout, size, expected data traffic, and budget are some of the key factors that may influence selection of certain communication interfaces and topologies.

6.2.1 Communication Methods

Communication methods used in the electrical utilities can be divided into two main categories – wired and wireless [45]. The wired communication method includes power line carrier (PLC), cable, RS-485 bus, and fiber-optic (FO) lines. Wireless method includes wireless spectrum, microwave, digital radio, cellular, and wireless sensor networks (WSNs) [46], [47]. Each of the communication methods offers advantages and disadvantages. Table 6.1 provides a comparison of abovementioned methods in terms of transfer speed (or bandwidth), transfer distance, external interference, attenuation and losses, cost of construction, cost of operation, and maintenance workload.

Communication methods	Wired Communications				Wireless Communications			
	PLC	Cable	RS-485	FO Lines	Spectrum	Micro wave	Digital radio	Sensor Network
Transmission Medium	Power lines	twisted pair	Shielded twisted pair	SM or MM Fiber	Free space	Free space	Free space	Free space
Transfer speed	≤ 28.8 kbps	300-4800 kbps	< 19.2 kbps	Up to 10 Gbps	< 128 Mbps	< 128 Mbps	< 128 Mbps	< 128 Mbps
Transfer distance	5-15 km	Long	< 2 km	Long	< 50km	< 50km	< 50km	Long
External interference	High	Medium	High	None	Low	High	High	High
Attenuation and losses	High	Medium	High	Low	Low	Low	Low	Low
Cost of construction	Low	Low	Medium	High	High	High	Medium	High
Cost of O&M	Low	Medium	Medium	Low	Low	Medium	Low	Medium

Table 6.1 – Comparison of Typical Communication Methods used in Electrical Utilities [46], [47]

A wireless communication system is the most flexible and cost effective solution for large area deployment. Wireless technologies using mesh technology can route data around multiple node failures, making it very reliable. The common challenges of wireless communication include probabilistic channel behaviour, accidental and directed interference or jamming, and eavesdropping if not properly encrypted [46]. Since DOD sites in general already contain high volume of military wireless communications, implementation of wireless communications for DOD microgrid may be much more challenging compared to a non-military microgrid.

Based on the Table 6.1, a combination of fiber-optic lines and one of the wireless media options seems to be the best communication solution for DOD microgrid systems. WSN seems to promise real-time and reliable monitoring and automation requirements for electrical systems. Some of the advantages of WSN include monitoring in harsh environments, large coverage (with expandable sensors), greater fault tolerance (multiple routing options), improved accuracy, efficient communication (local data filter capabilities), self-configuration, and lower cost [47].

6.2.2 Communication Network Topologies

Communication network topology options include point-to-point, bus, star, ring, mesh, tree, and hybrid [48]. Figure 6.3 shows diagrams of each of the topologies listed above. Ring and star topologies are the two most commonly used communication topologies in electrical grid communication systems. Star topology is most common in substations, where ring is more widely used in distribution networks.

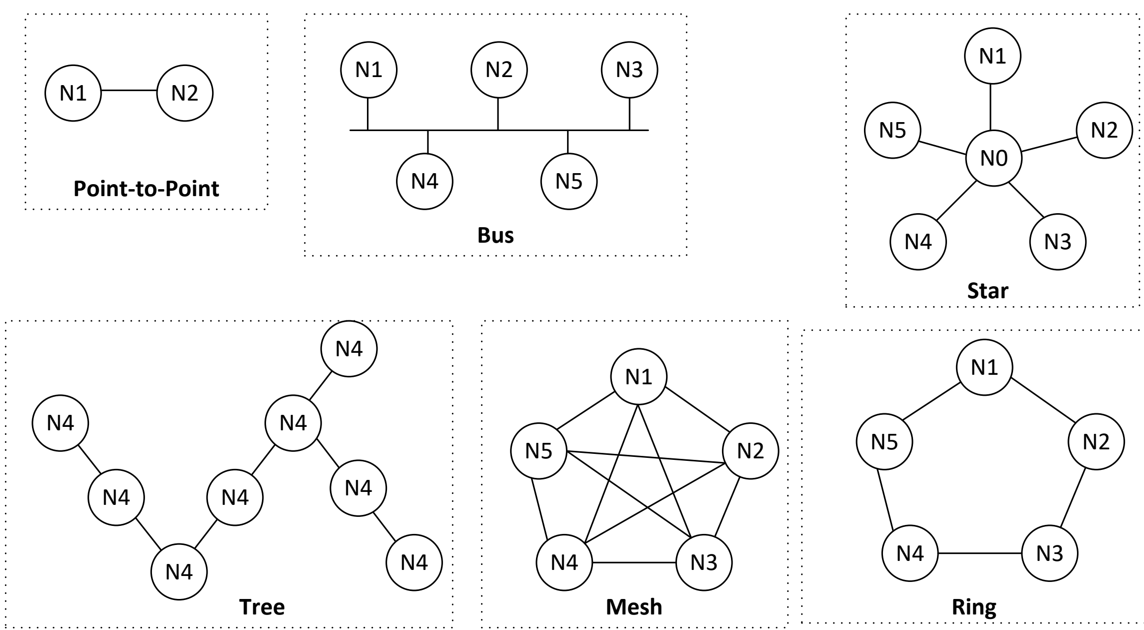


Figure 6.3 – Commonly used communication physical network topologies [48]

A point to point connection is a dedicated connection between two devices and thus reliable; however, it lacks expandability. A bus network provides economic data transfer between multiple nodes. However, the hub or the backbone is subject to a single point-of-failure. A star network is more resilient and reliable since it has dedicated connections between nodes and controller. However, it can be costly for long distance connections. A tree configuration is suited for a network that is widely spread and divided in to many branches. It is also susceptible to single point of failure. A mesh network interconnects each device to one another and provide the most reliability in the network. However, it can be very costly to implement especially if it is a wired network. A ring topology connects all the nodes to each other in a looped circle. With the proper switching devices it can provide redundant path between nodes and the controller [48].

Reference [49] provides a detailed comparison between star and ring communication topologies for electrical power system. Unavailability, initial cost, life cost, ease of diagnostic testing, and data transfer were the main criteria used for the comparison. The paper concluded that when the average distance between nodes is small (175ft or less), the equipment and fiber cost of star system is less than the comparable cost of the ring systems. For substations, a star topology is the preferred solution over ring type solution due to increased reliability and comparable cost. For distribution systems, although the start topology provides lower hardware cost and more reliability, it can be cost prohibitive if a wired communication method is chosen [49]. However, the star topology for distribution systems may be better choice if wireless communication methods are feasible.

6.2.3 Communication Protocols

The transmission Control Protocol/Internet Protocol (TCP/IP) suite is the most commonly used and widely available protocols for electrical utility communication architectures. The protocol suite includes a layered architecture where each layer performs functionality using one or more protocols. Although the TCP/IP was originally designed for an internet, it can be used in any private network that utilizes local area network, also known as an Ethernet network.

The open System Interconnection (OSI) architecture is the benchmark communication architecture. It contains seven layers. OSI is protocol-independent theoretical model that provides guidelines for developing network architectures. TCP/IP utilizes four of the layers shown in the OSI model – Application, Transport, Network, and Link layers [50]. Figure 6.4 presents a TCP/IP suite model as compared to OSI model and describes typical protocols for each layer.

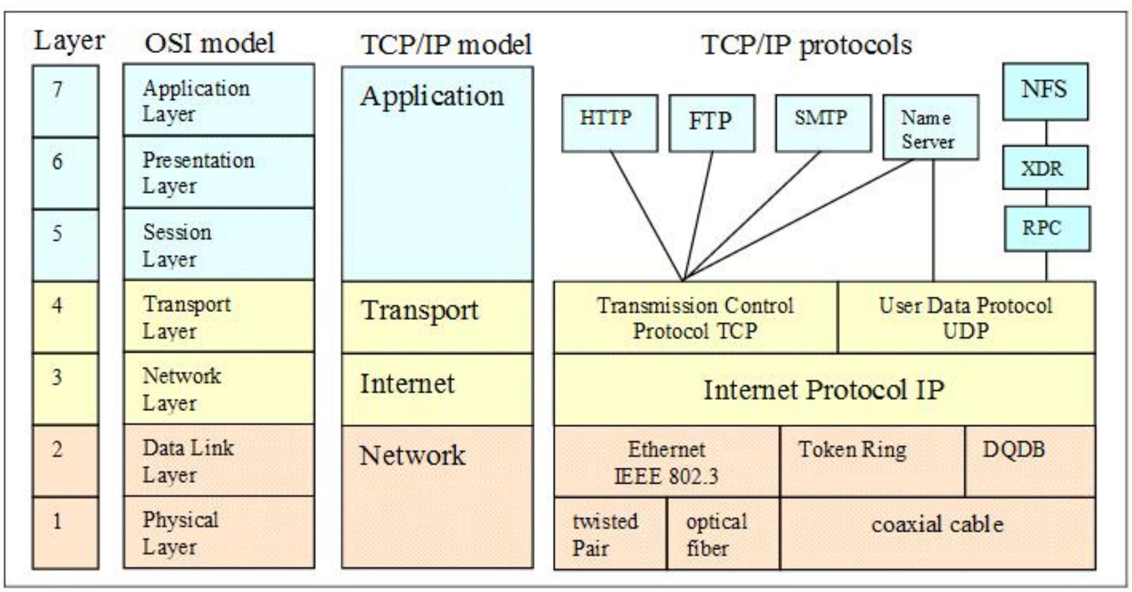


Figure 6.4 – Various Communication Physical Network Topologies [51].

In the TCP/IP model, the application layer has protocols that govern process-to-process communication which enables data sharing within the host or between multiple hosts. Network Timing Protocol (NTP), Secure Shell (SSH), Extensible Markup Language Remote Protocol Call (XML-RPC), Hypertext Transfer Protocol (HTTP), Modbus, Control Access Network (CANbus), and Distributed Network Protocol (DNP3) are some of the key protocols that run in the application layer. The transport layer enables host-to-host communications where the hosts are separated by routers. TCP and User Data Protocol (UDP) are examples running in this layer. The internet (or network) layer enable devices to communicate securely with each other using physical links. Protocols in this layer include IPv4, IPv6, and IPsec. The data link (or physical) layer supports local network communication without routers. Ethernet and serial are example protocols that run in this layer [50].

Modbus and DNP are most commonly used protocols in the North American utility SCADA system. Modbus is a legacy protocol that was originally designed for process control systems and is restricted to one data point transfer at a time. DNP3 is the current dominant Master/Slave protocol in SCADA systems that features multiple data point transfers. That means it can capsulate boolean and floating data points in a single message to reduce data traffic. Both Modbus and DNP3 protocols are relatively slow and are therefore not acceptable for communication-based protections and high-speed automation. Serial communication protocols are highly reliable and fast for point-to-point communication and they are widely used for protection applications. However, they are not suited for microgrid systems where the communication system needs to accommodate high-speed communicate with larger bandwidth and over longer distances [52].

IEC 61850 is an internationally adopted interoperability standard that provides communication protocol packages that are solely designed to serve electrical utility industry. Its main focus is to streamline power system communication design that involves engineering, functionalities, and nomenclature. The standard has developed hundreds of across-platform words that are used to specify standardized data sets. The functionalities include protection, control, and monitoring which makes it a well-equipped protocol set for microgrid operations [50], [52]. A significant difference between IEC 61850 and other similar protocol is that it provides not only existing data models but also a platform for future data models that have not yet been defined [52].

The IEC 61850 standard utilizes a number of protocols such as Manufacturer Message Specification (MMS), Generic Object Oriented Substation Events (GOOSE), and Stamped Measured Values (SMV). The protocol services from this standard are intended to run over Ethernet networks. The services include the following functions [50]:

- Retrieve device description
- Fast and reliable host-to-host status information exchange
- Reporting data or sequence of events
- Data logging
- Retrieving analog or sampled values from sensors
- Time synchronization
- File transfer to configure on-line field devices

6.3 Recommendations for DOD Microgrid Communications System Design

Based on the discussions in Section 6.2, the following are the recommendations for choosing a communication system for the representative microgrid-ready system developed in this study:

- DOD sites already include various mission critical wireless communications and there is a risk of unintended interference. Although the cost of wireless technology may be less than a wired system, it also poses greater security vulnerability. Therefore, wired communication links should be considered whenever feasible. Among all the available wired communication methods, fiber-optic seems to provide the best value over the long-term. Therefore, fiber-optic lines should be considered when upgrading system components to make the existing system microgrid-ready.
- Since star topology seems to provide greater reliability with comparable cost for short distance connections, substation IEDs and controllers should be configured in a star topology. For longer distance distribution automation devices, a ring topology with managed switches that have self-healing capability may provide cost effective yet reliable communications.
- Instead of conventional protocols like Modbus, DNP, or other proprietary protocols, IEC 61850 standard-based protocol services can provide centralized, simplified, vendor-neutral and standardized communication solutions for microgrid operations.

Per the recommendations above, Figure 6.5 illustrates a conceptual communication architecture for the representative microgrid ready system. There are many factors involved in choosing the best communication method, topology, and protocol. In many cases, combinations of wired and wireless methods with hybrid topologies and various protocols may be required.

The intent of the conceptual communication architecture shown in Figure 6.5 is to illustrate one of the options that engineers at DOD installations may explore when designing communication systems.

The conceptual communication architecture includes a ring bus fiber-optic network that connects Ethernet switches at various nodes. Each of the Ethernet switches connects to field recloser control relays, VFI control relays, and distributed backup generator controllers in a star configuration. The Ethernet switch at each node within the ring network provides alternative routing of data if any one of the fiber links is out of service.

At each of the substations, all of the IEDs are connected to an Ethernet switch in star configurations, which then connects to the substation controller. The ring fiber-optic network from the distribution side connects to a DA controller and a microgrid controller via redundant fiber lines. The microgrid controller can control backup generators and shed loads at the distribution level using redundant fiber lines and the ring network.

The DA controller, microgrid controller, substation controllers, SCADA system are all connected to an Ethernet switch (hub). It provides them with two-way communications path for transmitting various metering, monitoring, and control data among each other.

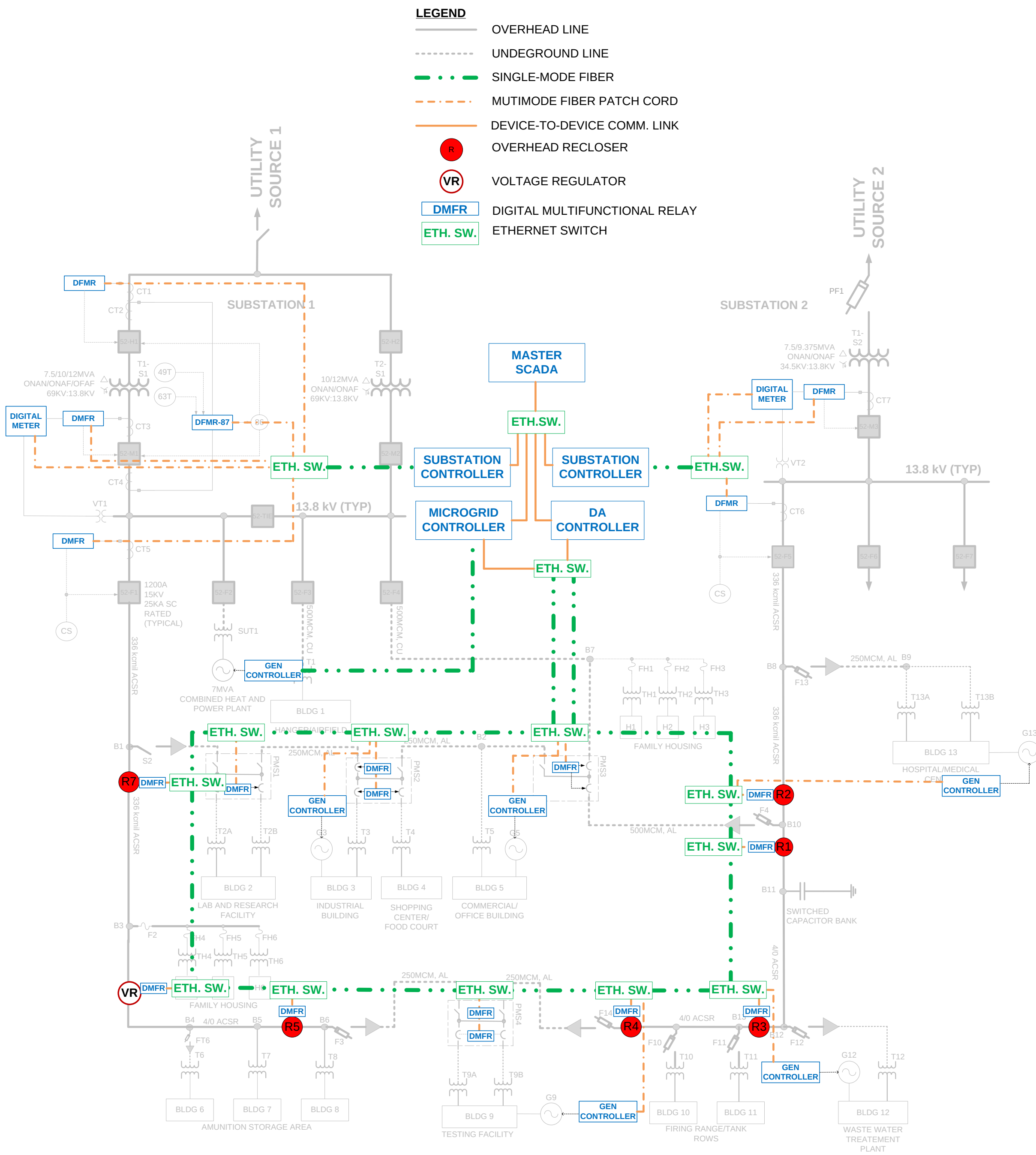


Figure 6.5 – Conceptual Communication Architecture for the Representative Microgrid-Ready System.

CHAPTER 7: CONCLUSIONS AND FUTURE WORK

7.1 Summary

In recent years, the DOD has been seeking to enhance energy security and resiliency for its permanent installations through distributed on-site generation and microgrid system implementations. Although we have seen increased research, development, and demonstration of smaller scale microgrid systems, there are still many challenges that prevent the DOD from realizing stable and commercial-grade microgrids for large-scale (installation-wide) systems. One of the most challenging issues for implementing the installation-wide microgrid systems is the status of the existing infrastructure. At the current state, the majority of the existing electrical infrastructures in DOD installations are not equipped with the required technologies such as IEDs, smart switches, automation controllers, and communication backbones. Another major challenge is the lack of stable, reliable, and economical on-site generation. Proper system modelling and analysis is necessary to understand load-flow at various operating conditions, evaluate short-circuit impacts to protection schemes and device duty ratings, and comprehend generator frequency response under islanded modes of operation. Communication architecture, protective relaying schemes, and distribution automation, microgrid control, and SCADA system must be carefully considered before designing a microgrid system.

Chapter 2 provided a baseline representation of existing DOD electrical systems that can be utilized to conduct studies related to microgrid design. Chapter 3 summarized various microgrid-related deficiencies of the existing representative system and outlined upgrades and changes required to create a microgrid-ready system. A detailed microgrid-ready model was developed in Chapter 4 to provide a realistic commercial-grade test bed for technical studies and analysis. The load-flow analysis, short-circuit analysis, protective relay coordination study, and generator frequency response analysis in Chapter 5 were intended to demonstrate some of the technical challenges that installation-wide (or substation-level) microgrid operations may face. Chapter 5 also outlined some recommended mitigations for the observed technical challenges. Chapter 6 highlighted the importance of proper communication system design that involves selection and suitable communication methods, topologies, and protocols.

7.2 Conclusions

Based on the research and analysis conducted in this study, it is fair to conclude following:

1. The majority of the existing DOD installation's electrical distribution systems may require substantial system upgrade to qualify them as truly a microgrid-ready.
2. Detailed system modelling and analysis are necessary to understand the various technical challenges and develop solutions to mitigate them.
3. A real-world distribution system exhibits many switching scenarios and loading conditions that pose challenges for properly sizing on-site generation to match capacity and demand.
4. On-site generation presents different levels of short-circuit currents under varying modes of operation. Depending on the size and type of on-site generation short-circuit current can exceed the ratings of existing equipment during cogen operation. The changing short-circuit current levels also result in overcurrent relay mis-coordination for relays that may be properly coordinated before.
5. Distributed generators can significantly improve local system voltage profiles and reduce line losses.

6. Following a change in operating modes (i.e. changing from cogen to microgrid mode) during heavy loading conditions, the on-site generation can experience greater load than their capacity and experience frequency dives and generator instability. A high-speed load shedding scheme is needed to avoid such instability and maintain power quality.
7. A reliable, resilient, and secure communication backbone is a key to successful implementation of microgrids. Such communication systems enable advanced protection that is adaptive to changing short-circuit currents, distribution automation that automatically isolates a faulted section and restores rest of the system, and advanced generator control that can perform high-speed load-shedding and frequency regulation.
8. Implementation of a fiber-optic communication system with a hybrid (star and ring) topology, and IEC 61850 based protocols seem to provide the most optimal and reliable communication system for conceptual DOD microgrid system.

7.3 Suggestions for Future Research

This study has outlined a representative existing system and established a baseline model for a DOD-specific substation-level microgrid-ready system. It is impossible to cover all aspects of microgrid design consideration in this study. Based on observations and analysis, the following future work is suggested:

- This study utilized a single CHP plant for cogen operation and building level backup generators for additional on-site generation during heavy load. There are many other combinations of on-site generation and storage technologies that may exhibit very different performance characteristics and challenges. It is recommended to modify this model to explore on-site generation options and perform studies to determine the impacts of different options.

- Grounding configurations in distributed generators have a profound impact on voltage profiles and ground fault levels during faults involving ground. A detailed analysis of different grounding configurations, exploring their advantages and disadvantages, challenges, and mitigations would be a great aid to DOD system designers.
- A detailed analysis of islanding detection and microgrid creation schemes is beyond the scope of this study since it requires extensive technology review, scheme design, modelling, and testing. The model developed in this study could be used to design islanding detection, isolation, and intentional microgrid creation schemes and evaluate their performance during switching scenarios and loading conditions.
- Chapter 6 provided a high-level literature review and insight to factors to consider when designing communication systems for microgrid. Setting up a laboratory test-bed and conducting performance testing for various communications architectures to determine performances under various microgrid operations would be a great addition to this study.
- Although there are many technical aspects of DOD microgrid that require further research and analysis, it would be impossible to implement microgrid without looking at cost versus benefit. The model created in this study could be modified to perform a detailed economic analysis of various configurations of DOD microgrid system to determine most economical approach.
- Development of detailed and dynamic load models for the typical DOD installation loads is beyond the scope of this thesis. One could collect more field data for various

types of loads outlined in this thesis and develop more detailed and dynamic load models for future analysis.

- Proper security, whether it is physical or cyber, of all the microgrid components is one of the keys to a successful and sustained microgrid operation. As discussed in Section 6.2, a communication network in a microgrid system is subject to malicious cyber-attacks. There are also many key IEDs and apparatus physically located throughout the microgrid perimeter that are subject to physical attacks or vandalism. A detailed analysis of various security configurations, their pros and cons, and recommended measures for DOD installations could be a great add to this thesis.

REFERENCES

[1] Holland, Andrew; Cunningham, Nick; Huppmann, Kaitlyn; Joyce, William, "Powering Military Bases: DOD's Installation Energy Efforts." www.AmericanSecurityProject.org, Jul-2013.

[2] "Office of the Assistant Secretary of Defense (Energy, Installations, and Environment) Department of Defense Annual Energy Management Report," DOD Annual Energy Management Report, Jun. 2016.

[3] "TM 5-811-1/AFJMAN 32-1080, Electrical Power Supply and Distribution." Departments of the Army and the Air Force, Feb-1995.

[4] "UFC 3-540-01 Engine-Driven Generator Systems for Backup Power Applications." U.S. ARMY CORPS OF ENGINEERS, NAVAL FACILITIES ENGINEERING COMMAND, AIR FORCE CIVIL ENGINEER CENTER, 01-Aug-2014.

[5] "National Security and Assured U.S. Electrical Power." CNA Military Advisory Board, 2015.

[6] R. Smith, "U.S. Risks National Blackout From Small-Scale Attack," *WSJ*. [Online]. Available: http://www.wsj.com/articles/SB10001424052702304020104579433670284061220. [Accessed: 18-Nov-2016].

[7] D. Ton, "DOE Microgrids Program Overview," Office of Electricity Delivery & Energy Reliability, 03-Jun-2015.

[8] A. Castillo, "DOD Energy Resilience," presented at the Energy Exchange, Rhode Island Convention Center, Providence, Rhode Island, 09-Aug-2016.

[9] "How the Electricity Grid Works," *Union of Concerned Scientists*. [Online]. Available: http://www.ucsusa.org/clean-energy/how-electricity-grid-works. [Accessed: 18-Nov-2016].

[10] "DOE Microgrid Workshop Report," DOE, Office of Electricity Delivery and Energy Reliability Smart Grid R&D Program, San Diego, California, Aug. 2011.

[11] "The Role of Microgrids in Helping to Advance the Nation's Energy System | Department of Energy." [Online]. Available: http://energy.gov/oe/services/technology-development/smart-grid/role-microgrids-helping-advance-nation-s-energy-system. [Accessed: 19-Nov-2016].

[12] C. Marnay *et al.*, "Microgrid Evolution Roadmap," in *2015 International Symposium on Smart Electric Distribution Systems and Technologies (EDST)*, 2015, pp. 139–144.

[13] S. B. Van Broekhoven, N. Judson, S. V. Nguyen, and W. D. Ross, “Microgrid Study: Energy Security for DOD Installations,” Jun. 2012.

[14] O. Saadeh, “Green Technology | Cleantech and Renewable Energy News and Analysis.” [Online]. Available: https://www.greentechmedia.com/research/report/gtm-research-note-us-microgrid-market-update-q2-2016. [Accessed: 19-Nov-2016].

[15] G. Ka’iliwai and W. Jost, “SPIDERS Energy Security JCTD Proposal,” Nov-2009.

[16] “Technology Transition Final Public Report Smart Power Infrastructure Demonstration for Energy Reliability and Security (SPIDERS),” Naval Facilities Engineering Command, Technology Transition Final Public Report, Dec. 2015.

[17] J. Barr, M. Hadley, F. Tuffner, and K. Schneider, “Utility Assessment Report for SPIDERS Phase 2: Ft. Carson (Rev 1.0),” Pacific Northwest National Laboratory, Richland, Washington 99352, Utility Assessment Report, Jan. 2014.

[18] R. Jensen, J. E. Stamp, J. P. Eddy, J. M. Henry, K. Munoz-Ramos, and T. U. Abdallah, “Methodology for Preliminary Design of Electrical Microgrids.,” Sandia National Laboratories (SNL-NM), Albuquerque, NM (United States), 2015.

[19] E. Shaffer, P. Roege, and T. Zheleva, “Advanced Microgrid Concepts and Technologies Workshop,” DTIC Document, 2013.

[20] “Power the Fight: Capturing Smart Microgrid Potential for DOD Installation Energy Security,” BENS TASK FORCE ON MICROGRIDS, Fall 2012.

[21] “Combined Heat and Power (CHP) Technical Potential in the United States,” U.S. Department of Energy, DOE/EE-1328, Mar. 2016.

[22] A. Hampson, “Combined heat and power: Enabling resilient energy infrastructure for critical facilities,” Oak Ridge National Laboratory (ORNL), 2013.

[23] M. King, R. L. Huntzinger, and T. Nguyen, *Feasibility of Nuclear Power on US Military Installations*. CNA, 2011.

[24] “Department of Defense Base Structure Report - FY 2015 Baseline,” Department of Defense, 2015.

[25] “Panoramio - Photo of Buckley Air Force Base, Aurora, CO.” [Online]. Available: https://ssl.panoramio.com/photo/90208412. [Accessed: 19-Nov-2016].

[26] “Google Maps - Nellis Air Force Base Substation,” *Google Maps*, 2016. [Online]. Available: https://www.google.com/maps/place/Nellis+AFB,+NV/@36.245311,-115.0449359,94m/data=!3m1!1e3!4m5!3m4!1s0x80c8dd979f1a4539:0x890a4a296fadb5ef!8m2!3d36.2414162!4d-115.0508066. [Accessed: 19-Nov-2016].

[27] "IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems," *IEEE Std 15474-2011*, pp. 1–54, Jul. 2011.

[28] T. Glenwright, "Military Microgrids," Boeing Energy, 2012.

[29] B. S. Hartono, Y. Budiyanto, and R. Setiabudy, "Review of microgrid technology," in *2013 International Conference on QiR (Quality in Research)*, 2013, pp. 127–132.

[30] M. S. Sachdev, R. Das, and others, "Understanding microprocessor-based technology applied to relaying," *Rep. Work. Group -01 Relaying Pract. Subcomm. IEEE Power Syst. Relaying Comm.*, p. 91, 2009.

[31] "ETAP Product Overview - Enterprise Software Solution for Electrical Power Systems." [Online]. Available: https://etap.com/docs/default-source/Brochures/etap-product-overview.pdf?sfvrsn=28. [Accessed: 19-Nov-2016].

[32] K. Darrow, R. Tidball, J. Wang, and A. Hampson, "Catalog of CHP technologies," *ICF Int Funding US Environ. Prot. Agency Comb. Heat Power Partnersh. US Dept Energy*, 2015.

[33] "The Impact of Generator Set Underloading," *BLOG: POWER PERSPECTIVES*, 16-Mar-2015. [Online]. Available: https://forums.cat.com/t5/BLOG-Power-Perspectives/The-Impact-of-Generator-Set-Underloading/ba-p/69719. [Accessed: 19-Nov-2016].

[34] "ETAP Help 14.1." Operations Technology, Inc.

[35] "IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems," *ANSI/IEEE Std 242-1986*, p. 0_1-, 1986.

[36] M. A. Hanley and J. Ilic, "Frequency instability problems in North American interconnections," *Natl. Energy Technol. Lab. Pittsburgh PA USA*, p. 59, 2011.

[37] C. K. Veitch, J. M. Henry, B. T. Richardson, and D. H. Hart, "Microgrid cyber security reference architecture," *Sandia Nat LabHierarch SNL-NM Albuq. NM USA Tech Rep SAND2013-5472*, 2013.

[38] R. S. Kunte and W. Gao, "Comparison and review of islanding detection techniques for distributed energy resources," in *Power Symposium, 2008. NAPS '08. 40th North American*, 2008, pp. 1–8.

[39] E. Sortomme, M. Venkata, and J. Mitra, "Microgrid protection using communication-assisted digital relays," in *IEEE PES General Meeting*, 2010, pp. 1–1.

[40] S. Ranjbar and S. Jamali, "Comprehensive protection of medium-voltage microgrids," in *Smart Grid Conference (SGC), 2014*, 2014, pp. 1–7.

[41] R. Das *et al.*, “Distribution automation strategies: Evolution of technologies and the business case,” in *2015 IEEE Power Energy Society General Meeting*, 2015, pp. 1–1.

[42] S. T. Cady, A. D. Domínguez-García, and C. N. Hadjicostis, “A Distributed Generation Control Architecture for Islanded AC Microgrids,” *IEEE Trans. Control Syst. Technol.*, vol. 23, no. 5, pp. 1717–1735, Sep. 2015.

[43] D. S. Ramos, T. E. Del Carpio-Huayllas, R. L. Vasquez-Arnez, and others, “Load Shedding Application within a Microgrid to Assure Its Dynamic Performance during Its Transition to the Islanded Mode of Operation,” *Energy Power Eng.*, vol. 5, no. 07, p. 437, 2013.

[44] “Chapter 3: Enabling Modernization of the Electric Power System Technology Assessment | Measurements, Communications, and Controls - QTR2015-3E-Measurements-Communications-and-Controls.pdf.” [Online]. Available: http://energy.gov/sites/prod/files/2015/09/f26/QTR2015-3E-Measurements-Communications-and-Controls.pdf. [Accessed: 19-Nov-2016].

[45] S. Safdar, B. Hamdaoui, E. Cotilla-Sanchez, and M. Guizani, “A survey on communication infrastructure for micro-grids,” in *2013 9th International Wireless Communications and Mobile Computing Conference (IWCMC)*, 2013, pp. 545–550.

[46] H. Chen and N. h Yu, “A survey of communication technology in distribution network,” in *2012 China International Conference on Electricity Distribution (CICED)*, 2012, pp. 1–8.

[47] V. C. Gungor and F. C. Lambert, “A survey on communication networks for electric system automation,” *Comput. Netw.*, vol. 50, no. 7, pp. 877–897, 2006.

[48] S. Santra and P. P. Acharjya, “A Study And Analysis on Computer Network Topology For Data Communication,” *Int. J. Emerg. Technol. Adv. Eng.*, vol. 3, no. 1, 2013.

[49] G. W. Scheer, “Comparison of fiber-optic star and ring topologies for electric power substation communications,” in *proceedings of the 1st Annual Western Power Delivery and Automation Conference, Spokane, WA*, 1999.

[50] A. Bani-Ahmed, L. Weber, A. Nasiri, and H. Hosseini, “Microgrid communications: State of the art and future trends,” in *2014 International Conference on Renewable Energy Research and Application (ICRERA)*, 2014, pp. 780–785.

[51] “A Beginner’s Guide to Ethernet 802.3 Application Note (EE-269).” [Online]. Available: http://d3i5bpxkxvwmz.cloudfront.net/articles/2011/11/17/-Ethernet-802-3-1321592561.pdf. [Accessed: 19-Nov-2016].

[52] B.-K. Yoo *et al.*, “Communication architecture of the IEC 61850-based micro grid system,” *J. Electr. Eng. Technol.*, vol. 6, no. 5, pp. 605–612, 2011.

Appendix A – Power Line Data for ETAP Line Models

From	To	Length (miles)	# of Phases	line Type	Cond. Size	Neutral Size (all CU)	Cond. Type	Insulation
SUB1-F1	B1	0.25	3	OH	336 kcmil	full	ACSR	Air
B1/S1	B3	1.5	3	OH	336 kcmil	full	ACSR	Air
B3/F2	FH4	0.1	3	OH	#2	full	ACSR	Air
FH4	FH5	0.05	3	OH	#2	full	ACSR	Air
FH5	FH6	0.05	3	OH	#2	full	ACSR	Air
FH4	TH4	0.05	2	OH	#2	full	ACSR	Air
FH5	TH5	0.05	2	OH	#2	full	ACSR	Air
FH6	TH6	0.05	2	OH	#2	full	ACSR	Air
B3/S2	VR	2	3	OH	#4/0	full	ACSR	Air
VR	B4	2.5	3	OH	#4/0	full	ACSR	Air
B4/FT6	T6	0.095	3	UG	#2	full	CU	EPR
B4	B5	1.2	3	OH	#4/0	full	ACSR	Air
B5	T7	0.223	3	OH	#2	full	ACSR	Air
B5	B6	0.5	3	OH	#4/0	full	ACSR	Air
B6	T8	0.284	3	OH	#2	full	ACSR	Air
B6/F3	PMS4-W1	0.15	3	UG	250 MCM	16 -#10	AL	XLPE
PMS4-W2	T9A	0.05	3	UG	#2	full	CU	EPR
PMS4-W3	T9B	0.05	3	UG	#2	full	CU	EPR
B1/S2	PMS1	1	3	UG	250 MCM	#4/0	CU	XLPE
PMS1	T2A	0.095	3	UG	#1/0	#2	CU	XLPE
PMS1	T2B	0.095	3	UG	#1/0	#2	CU	XLPE
PMS1	PMS2	1.4	3	UG	250 MCM	#4/0	CU	XLPE
PMS2/FT3	T3	0.095	3	UG	#4/0	20 - #12	AL	TRXLPE
PMS2/FT4	T4	0.095	3	UG	#2	full	CU	EPR
PMS2	B2	0.5	3	UG	250 MCM	#4/0	CU	XLPE
B2	T5	0.284	3	UG	#4/0	20 - #12	AL	TRXLPE
B2	PMS3	1	3	UG	250 MCM	#4/0	CU	XLPE

From	To	Length (miles)	# of Phases	line Type	Cond. Size	Neutral Size (all CU)	Cond. Type	Insulation
PMS3	B7	1	3	UG	500 MCM	250MCM	CU	XLPE
B7	SUB1-F4	2	3	UG	500 MCM	250MCM	CU	XLPE
PMS3	B10/F4	3	3	UG	#4/0	20 - #12	AL	TRXLPE
B7	FH1	0.5	3	UG	#2	full	CU	EPR
FH1	TH1	0.047	2	UG	#2	full	CU	EPR
FH1	FH2	0.5	3	UG	#2	full	CU	EPR
FH2	TH2	0.047	2	UG	#2	full	CU	EPR
FH2	FH3	0.5	3	UG	#2	full	CU	EPR
FH3	TH3	0.047	2	UG	#2	full	CU	EPR
SUB2-F5	B8	0.5	3	OH	336 kcmil	full	ACSR	Air
B8/F13	B9	0.095	3	UG	250 MCM	#4/0	CU	XLPE
B9	T13A	0.047	3	UG	#1/0	#2	CU	XLPE
B9	T13B	0.047	3	UG	#1/0	#2	CU	XLPE
B8	B10	2.5	3	OH	336 kcmil	full	ACSR	Air
B10	R	0.05	3	OH	336 kcmil	full	ACSR	Air
R	B11	1.5	3	OH	336 kcmil	full	ACSR	Air
B11	B12	1.5	3	OH	#4/0	full	ACSR	Air
B12	B13	1	3	OH	#4/0	full	ACSR	Air
B13/F10	T10	0.12	3	OH	#1/0	full	ACSR	Air
B13/F11	T11	0.12	3	OH	#1/0	full	ACSR	Air
B12/F12	T12	0.05	3	UG	#4/0	20 - #12	AL	TRXLPE

Table A.1 – Existing Distribution System Power Line Data for Modelling

Appendix B – ETAP Model Input Data

The following pages include various component input data that was directly exported from ETAP model.

Project:	DOD Microgrid Ready System	Page:	1
Location:	Generic	Date:	11-20-2016
Contract:		SN:	
Engineer:	APS	Revision:	Base
Filename:	Microgrid-ready	Config.:	Cogen

ETAP
14.1.0C

Study Case: ALL BUSES

Induction Machine Input Data

Induction Machine			Rating (Base)			Positive Seq. Imp.				Grounding			Zero Seq. Imp.		
ID	Type	Qty	kVA	kV	RPM	X"/R	% R	% X"	% X'	Conn.	Type	Amp	X/R	% R0	% X0
M-STARTUP	Motor	1	520.27	4.160	1800	19.08	0.968	18.46	46.15	Wye	Open		19.08	0.97	18.46

Total Connected Induction Machines (= 1): 520.3 kVA

Lumped Load Input Data

Lumped Load	Lumped Load				Motor Loads									
Lumped Load	Rating		% Load		Loading		X/R Ratio		Impedance (Machine Base)			Grounding		
ID	kVA	kV	MTR	STAT	kW	kvar	X''/R	X'/R	% R	% X''	% X'	Conn.	Type	Amp.
LT1	1500.0	0.480	60	40	765.0	474.1	2.38	2.38	8.403	20.00	50.00	Delta		
LT2A	1000.0	0.480	60	40	510.0	316.1	2.38	2.38	8.403	20.00	50.00	Delta		
LT2B	1000.0	0.480	60	40	510.0	316.1	2.38	2.38	8.403	20.00	50.00	Delta		
LT3	3000.0	0.480	60	40	1530.0	948.2	2.38	2.38	8.403	20.00	50.00	Delta		
LT4	500.0	0.480	30	70	142.5	46.8	2.38	2.38	8.403	20.00	50.00	Delta		
LT5	750.0	0.480	40	60	270.0	130.8	2.38	2.38	8.403	20.00	50.00	Delta		
LT6	112.5	0.208	60	40	57.4	35.6	2.38	2.38	8.403	20.00	50.00	Delta		
LT7	75.0	0.208	60	40	38.3	23.7	2.38	2.38	8.403	20.00	50.00	Delta		
LT8	75.0	0.208	60	40	38.3	23.7	2.38	2.38	8.403	20.00	50.00	Delta		
LT9A	1000.0	0.480	60	40	510.0	316.1	2.38	2.38	8.403	20.00	50.00	Delta		
LT9B	1000.0	0.480	60	40	510.0	316.1	2.38	2.38	8.403	20.00	50.00	Delta		
LT10	112.5	0.208	60	40	57.4	35.6	2.38	2.38	8.403	20.00	50.00	Delta		
LT11	150.0	0.208	60	40	76.5	47.4	2.38	2.38	8.403	20.00	50.00	Delta		
LT12	1000.0	0.480	70	30	595.0	368.7	2.38	2.38	8.403	20.00	50.00	Delta		
LT13A	1500.0	0.480	60	40	765.0	474.1	2.38	2.38	8.403	20.00	50.00	Delta		
LT13B	1500.0	0.480	60	40	765.0	474.1	2.38	2.38	8.403	20.00	50.00	Delta		

Total Connected Lumped Loads (= 16): 14275.0 kVA

Power Grid Input Data

Power Grid	Connected Bus	Rating		% Positive Seq. Impedance 100 MVA Base			Grounding	% Zero Seq. Impedance 100 MVA Base		
ID	ID	MVASC	kV	X/R	R	X	Type	X/R	R0	X0
UTILITY SOURCE1	UTILITY_MAIN	398.025	69.000	2.50	9.33083	23.32708	Wye - Solid	2.50	27.076920	67.69231
UTILITY SOURCE2	UTILITY_MAIN2	398.025	34.500	2.50	9.33083	23.32708	Wye - Solid	2.50	27.076920	67.69231

Total Power Grids (= 2) 796.051 MVA

Synchronous Generator Input Data

Synchronous Generator		Rating			Positive Seq. Impedance					Grounding			Zero Seq. Impedance		
							% Xd"								
ID	Type	MVA	kV	RPM	X"/R	% R	Adj.	Tol.	% Xd"	Conn.	Type	Amp	X/R	% R0	% X0
CHP Plant	Gas Turbo	6.250	4.160	1800	19.00	1.000	19.00	0.0	28.00	Wye	Resistor	400.00	7.00	1.000	7.00

Total Connected Synchronous Generators (= 1): 6.250 MVA

2-Winding Transformer Input Data

Transformer	Rating					Z Variation			% Tap Setting		Adjusted	Phase Shift	
ID	MVA	Prim. kV	Sec. kV	% Z	X/R	+ 5%	- 5%	% Tol.	Prim.	Sec.	% Z	Type	Angle
T-GEN	5.000	13.800	4.160	6.50	12.14	0	0	0	0	0	6.50	YNyn	0.00
T1	1.500	13.800	0.480	5.68	7.10	0	0	0	0	0	5.68	Dyn	30.00
T1-S1	7.500	69.000	13.800	8.70	14.23	0	0	0	0	1.251	8.70	Dyn	30.00
T1-S2	7.500	34.500	13.800	7.50	14.23	0	0	0	0	1.877	7.50	Dyn	30.00
T2-S1	7.500	69.000	13.800	8.70	14.23	0	0	0	0	0.626	8.70	Dyn	30.00
T2A	1.000	13.800	0.480	5.70	5.79	0	0	0	-2.500	0	5.70	Dyn	30.00
T2B	1.000	13.800	0.480	5.70	5.79	0	0	0	0	0	5.70	Dyn	30.00
T3	3.000	13.800	0.480	7.04	10.67	0	0	0	0	0	7.04	Dyn	30.00
T4	0.500	13.800	0.480	5.57	3.09	0	0	0	0	0	5.57	Dyn	30.00
T5	0.750	13.800	0.480	5.60	3.96	0	0	0	0	0	5.60	Dyn	30.00
T6	0.113	13.800	0.208	2.40	2.47	0	0	0	0	0	2.40	Dyn	30.00
T7	0.075	13.800	0.208	2.10	2.47	0	0	0	0	0	2.10	Dyn	30.00
T8	0.075	13.800	0.208	2.10	2.47	0	0	0	0	0	2.10	Dyn	30.00
T9A	1.000	13.800	0.480	5.70	5.79	0	0	0	0	0	5.70	Dyn	30.00
T9B	1.000	13.800	0.480	5.70	5.79	0	0	0	0	0	5.70	Dyn	30.00
T10	0.113	13.800	0.208	2.38	2.47	0	0	0	0	0	2.38	Dyn	30.00
T11	0.150	13.800	0.208	1.90	2.47	0	0	0	0	0	1.90	Dyn	30.00
T12	1.000	13.800	0.480	5.70	5.79	0	0	0	0	0	5.70	Dyn	30.00
T13A	1.500	13.800	0.480	5.59	7.10	0	0	0	0	0	5.59	Dyn	30.00
T13B	1.500	13.800	0.480	5.59	7.10	0	0	0	0	0	5.59	Dyn	30.00
VR_1	7.500	13.800	13.800	7.00	14.23	0	0	0	0	5.000	7.00	YNyn	0.00

Line/Cable Input Data

ohms or siemens per 1000 ft per Conductor (Cable) or per Phase (Line)

Line/Cable			Length									
ID	Library	Size	Adj. (ft)	% Tol.	#/Phase	T (°C)	R1	X1	Y1	R0	X0	Y0
B1/S2-PMS1	15NCUS1	250	5280.0	0.0	1	75	0.0619	0.08619	0.0000275	0.3551381	0.39289	0.0000275
B1/S2-PMS4	15NCUS1	250	5280.0	0.0	1	75	0.0619014	0.0861893	0.0000275	0.355137	0.3928939	0.0000275
B2-PMS3	15NCUS1	250	5280.0	0.0	1	75	0.0619014	0.0861893	0.0000275	0.355137	0.3928939	0.0000275
B2-T5	15NALN1	4/0	501.6	0.0	1	75	0.1002652	0.0887643	0.0000257	0.1050586	0.5082019	0.0000257
B4/FT6-T6	15MCUS1	2	501.6	0.0	1	75	0.2002927	0.13		0.4940555	0.499	
B6/F3-PMS2	15NALS1	250	792.0	0.0	1	75	0.0850178	0.0866149	0.0000275	0.0923018	0.5349021	0.0000275
B6/F3-PMS4	15NALS1	250	792.0	0.0	1	75	0.0850178	0.0866149	0.0000275	0.0923018	0.5349021	0.0000275
B7-B_H1	15NCUS1	2	2640.0	0.0	1	75	0.2193682	0.053		0.3490817	0.135	
B8-B9	15NCUS1	250	501.6	0.0	1	75	0.0517139	0.0866149	0.0000275	0.0565119	0.5060526	0.0000275
B9-T13A	15MCUS1	1/0	248.2	0.0	1	75	0.1278059	0.121		0.4234761	0.463	
B9-T13B	15MCUS1	1/0	248.2	0.0	1	75	0.1278059	0.121		0.4234761	0.463	
B12-T12	15NALS1	4/0	264.0	0.0	1	75	0.1002652	0.0887643	0.0000238	0.1028683	0.4661108	0.0000238
B_H1-B_H2	15NCUS1	2	2640.0	0.0	1	75	0.2193682	0.053		0.3490817	0.135	
B_H2-B_H3	15NCUS1	2	2640.0	0.0	1	75	0.2193682	0.053		0.3490817	0.135	
CBL_T1-S1_SEC	15NCUS1	750	50.0	0.0	1	75	0.0247982	0.074		0.2937627	0.213	
CBL_T1-S2_SEC	15NCUS1	750	50.0	0.0	1	75	0.0247982	0.074		0.2937627	0.213	
CBL_T2-S1_SEC	15NCUS1	750	50.0	0.0	1	75	0.0247982	0.074		0.2937627	0.213	
PMS1-T2A	5.0NCUS1	1/0	501.6	0.0	1	75	0.1300453	0.0965239	0.0000323	0.2772315	0.4592537	0.0000323
PMS1-T2A2	5.0NCUN1	500	501.6	0.0	1	75	0.0331524	0.0785066	0.0000625	0.1986803	0.420918	0.0000625
PMS1-T2B	15NCUS1	1/0	501.6	0.0	1	75	0.1306909	0.0964685	0.0000235	0.2964199	0.4401391	0.0000235
PMS2-T3	15NCUS1	4/0	501.6	0.0	1	75	0.0709724	0.0883594	0.0000257	0.2641447	0.3922002	0.0000257

Line/Cable Input Data

ohms or siemens per 1000 ft per Conductor (Cable) or per Phase (Line)

Line/Cable			Length									
ID	Library	Size	Adj. (ft)	% Tol.	#/Phase	T (°C)	R1	X1	Y1	R0	X0	Y0
PMS2-T4	15MCUS1	2	501.6	0.0	1	75	0.2002927	0.13		0.4940555	0.499	
PMS3-B2	15NCUN1	500	5280.0	0.0	1	75	0.026344	0.0787071	0.0000435	0.0779896	0.6421357	0.0000435
PMS3-B7	15NCUS1	500	5280.0	0.0	1	75	0.026344	0.0787071	0.0000435	0.0779896	0.6421357	0.0000435
PMS4-T9A	15MCUS1	2	264.0	0.0	1	75	0.2002927	0.13		0.4940555	0.499	
PMS4-T9B	15MCUS1	2	264.0	0.0	1	75	0.2002927	0.13		0.4940555	0.499	
SUB1_F4-B7	15NCUS1	500	10560.0	0.0	1	75	0.026344	0.0787071	0.0000392	0.0779896	0.6421357	0.0000392
PMS1-PMS2	15NCUS1	250	5280.0	0.0	1	75	0.0619014	0.0861893	0.0000275	0.355137	0.3928939	0.0000275
PMS3-B10/F4	15NCUN1	500	15840.0	0.0	1	75	0.026344	0.0787071	0.0000435	0.0779896	0.6421357	0.0000435
LINE1		336.	1320.0	0.0	1	75	0.0632576	0.1158857	0.0000013	0.1102781	0.4612895	0.0000005
Line2		336.	7920.0	0.0	1	75	0.0632576	0.1158857	0.0000013	0.1101832	0.4616781	0.0000005
Line3		211.	13200.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005
Line4		211.	7920.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005
Line5		336.	2640.0	0.0	1	75	0.0632576	0.1158857	0.0000013	0.1101832	0.4616781	0.0000005
Line6		211.	6336.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005

Line/Cable Input Data

ohms or siemens per 1000 ft per Conductor (Cable) or per Phase (Line)

Line/Cable			Length									
ID	Library	Size	Adj. (ft)	% Tol.	#/Phase	T (°C)	R1	X1	Y1	R0	X0	Y0
Line8		211.	6336.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005
Line9		66.4	1177.4	0.0	1	75	0.3731062	0.1564312	0.0000011	0.4586768	0.5596501	0.0000005
Line10		336.	13200.0	0.0	1	75	0.0632576	0.1158857	0.0000013	0.1101832	0.4616781	0.0000005
Line11		66.4	1177.4	0.0	1	75	0.3731062	0.1564312	0.0000011	0.4586768	0.5596501	0.0000005
Line13		211.	7920.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005
Line15		66.4	528.0	0.0	1	75	0.3731062	0.1564312	0.0000011	0.4586768	0.5596501	0.0000005
Line16		211.	7920.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005
Line17		66.4	264.0	0.0	1	75	0.3731062	0.1564312	0.0000011	0.4586768	0.5596501	0.0000005
Line19		66.4	264.0	0.0	1	75	0.3731062	0.1564312	0.0000011	0.4586768	0.5596501	0.0000005
Line21		66.4	633.6	0.0	1	75	0.3731062	0.1564312	0.0000011	0.4586768	0.5596501	0.0000005
Line23		66.4	633.6	0.0	1	75	0.3731062	0.1564312	0.0000011	0.4586768	0.5596501	0.0000005
Line27		211.	5280.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005
X-1		715.	73.9	0.0	1	75	0.0664445	0.1358174	0	0.1204093	0.5394053	0.0000001
X-2		715.	73.9	0.0	1	75	0.0664445	0.1358174	0	0.1204093	0.5394053	0.0000001
X-3		715.	52.8	0.0	1	75	0.0255536	0.1142502	0	0.0792502	0.5575057	0.0000001
X-4		715.	52.8	0.0	1	75	0.0255536	0.1142502	0	0.0792502	0.5575057	0.0000001
X-6		266.	105.6	0.0	1	75	0.0454385	0.1346811	0	0.0993284	0.5382689	0.0000001
X-94		266.	105.6	0.0	1	75	0.0454385	0.1346811	0	0.0993284	0.5382689	0.0000001
Line7		211.	264.0	0.0	1	75	0.1399622	0.1411145	0.0000013	0.2063304	0.5052478	0.0000005

Bus Input Data

	Bus				Initial Voltage	
ID	Type	Nom. kV	Base kV	Sub-sys	%Mag.	Ang.
B-H4	Load	13.800	13.800	1	100.00	-30.00
B-H5	Load	13.800	13.800	1	100.00	-30.00
B-H6	Load	13.800	13.800	1	100.00	-30.00
B1	Load	13.800	13.800	1	100.00	-30.00
B2	Load	13.800	13.800	1	100.00	-30.00
B3	Load	13.800	13.800	1	100.00	-30.00
B4	Load	13.800	13.800	1	100.00	-30.00
B5	Load	13.800	13.800	1	100.00	-30.00
B6	Load	13.800	13.800	1	100.00	-30.00
B7	Load	13.800	13.800	1	100.00	-30.00
B8	Load	13.800	13.800	2	100.00	-30.00
B9	Load	13.800	13.800	2	100.00	-30.00
B10	Load	13.800	13.800	2	100.00	-30.00
B11	Load	13.800	13.800	2	100.00	-30.00
B12	Load	13.800	13.800	2	100.00	-30.00
B13	Load	13.800	13.800	2	100.00	-30.00
B15	Load	13.800	13.800	1	76.71	-30.00
Bus2	Load	69.000	69.000	1	100.00	0.00
Bus3	Load	13.800	13.800	1	99.46	-30.00
Bus4	Load	69.000	69.000	1	100.00	0.00
B_H1	Load	13.800	13.800	1	100.00	-30.00
B_H2	Load	13.800	13.800	1	100.00	-30.00
B_H3	Load	13.800	13.800	1	100.00	-30.00
GEN_BUS	Gen.	4.160	4.160	1	100.00	-30.00
GEN_BUS2	Load	4.160	4.160	1	100.00	-30.00
PMS1	Load	13.800	13.800	1	100.00	-30.00
PMS2	Load	13.800	13.800	1	100.00	-30.00
PMS3	Load	13.800	13.800	1	100.00	-30.00
PMS4	Load	13.800	13.800	1	100.00	-30.00
SUB1-F1	Load	13.800	13.800	1	98.27	-30.00
SUB1-F2	Load	13.800	13.800	1	98.27	-30.00
SUB1-F3	Load	13.800	13.800	1	98.27	-30.00
SUB1-F4	Load	13.800	13.800	1	98.27	-30.00
SUB1_SWGR-BUS1	Load	13.800	13.800	1	98.27	-30.00
SUB1_SWGR-BUS2	Load	13.800	13.800	1	98.27	-30.00

Bus					Initial Voltage	
ID	Type	Nom. kV	Base kV	Sub-sys	%Mag.	Ang.
SUB2-F5	Load	13.800	13.800	2	98.27	-30.00
SUB2-F6	Load	13.800	13.800	2	98.27	-30.00
SUB2-F7	Load	13.800	13.800	2	98.27	-30.00
SUB2_SWGR-BUS1	Load	13.800	13.800	2	98.27	-30.00
T1-S1_PRI	Load	69.000	69.000	1	99.39	-0.28
T1-S1_SEC	Load	13.800	13.800	1	100.00	-30.00
T1-S2_PRI	Load	34.500	34.500	2	99.39	-0.28
T1-S2_SEC	Load	13.800	13.800	2	100.00	-30.00
T1_PRI	Load	13.800	13.800	1	100.00	-30.00
T1_SEC	Load	0.480	0.480	1	100.00	-60.00
T2-S1_PRI	Load	69.000	69.000	1	99.39	-0.28
T2-S1_SEC	Load	13.800	13.800	1	100.00	-30.00
T2A_PRI	Load	13.800	13.800	1	100.00	-30.00
T2A_SEC	Load	0.480	0.480	1	100.00	-60.00
T2B_PRI	Load	13.800	13.800	1	100.00	-30.00
T2B_SEC	Load	0.480	0.480	1	100.00	-60.00
T3_PRI	Load	13.800	13.800	1	100.00	-30.00
T3_SEC	Load	0.480	0.480	1	100.00	-60.00
T3_SEC1	Load	0.480	0.480	1	100.00	-60.00
T4_PRI	Load	13.800	13.800	1	100.00	-30.00
T4_SEC	Load	0.480	0.480	1	100.00	-60.00
T5_PRI	Load	13.800	13.800	1	100.00	-30.00
T5_SEC	Load	0.480	0.480	1	100.00	-60.00
T5_SEC1	Load	0.480	0.480	1	99.54	-61.71
T6_PRI	Load	13.800	13.800	1	100.00	-30.00
T6_SEC	Load	0.208	0.208	1	100.00	-60.00
T7_PRI	Load	13.800	13.800	1	100.00	-30.00
T7_SEC	Load	0.208	0.208	1	100.00	-60.00
T8_PRI	Load	13.800	13.800	1	100.00	-30.00
T8_SEC	Load	0.208	0.208	1	100.00	-60.00
T9A_PRI	Load	13.800	13.800	1	100.00	-30.00
T9A_SEC	Load	0.480	0.480	1	100.00	-60.00
T9B_PRI	Load	13.800	13.800	1	100.00	-30.00
T9B_SEC	Load	0.480	0.480	1	100.00	-60.00
T9B_SEC1	Load	0.480	0.480	1	99.54	-61.71
T10_PRI	Load	13.800	13.800	2	100.00	-30.00
T10_SEC	Load	0.208	0.208	2	100.00	-60.00

Bus					Initial Voltage	
ID	Type	Nom. kV	Base kV	Sub-sys	%Mag.	Ang.
T11_PRI	Load	13.800	13.800	2	100.00	-30.00
T11_SEC	Load	0.208	0.208	2	100.00	-60.00
T12_PRI	Load	13.800	13.800	2	100.00	-30.00
T12_SEC	Load	0.480	0.480	2	100.00	-60.00
T12_SEC1	Load	0.480	0.480	2	99.54	-61.71
T13A_PRI	Load	13.800	13.800	2	100.00	-30.00
T13A_SEC	Load	0.480	0.480	2	100.00	-60.00
T13B_PRI	Load	13.800	13.800	2	100.00	-30.00
T13B_SEC	Load	0.480	0.480	2	100.00	-60.00
T13B_SEC1	Load	0.480	0.480	2	99.54	-61.71
UTILITY1	Load	69.000	69.000	1	100.00	0.00
UTILITY_MAIN	SWNG	69.000	69.000	1	100.00	0.00
UTILITY_MAIN2	SWNG	34.500	34.500	2	100.00	0.00
VR1_PRI	Load	13.800	13.800	1	100.00	-30.00
VR1_SEC	Load	13.800	13.800	1	100.00	-30.00
PMS1-PMS2~	Load	13.800	13.800	0	100.00	0.00
PMS3-B10/F4~	Load	13.800	13.800	0	100.00	0.00
Line7~	Load	13.800	13.800	0	100.00	0.00

90 Buses Total

All voltages reported by ETAP are in % of bus Nominal kV.
Base kV values of buses are calculated and used internally by ETAP.