nationalgrid

Raquel J. Webster
Senior Counsel

February 10, 2016

BY HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4592 - National Grid's Proposed FY 2017 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to OER Data Requests – Set 1</u>

Dear Ms. Massaro:

I have enclosed ten copies of National Grid's[1] responses to the first set of data requests issued by the Rhode Island Office of Energy Resources in the above-referenced docket.

Thank you for your attention to this matter. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4592 Service List
Leo Wold, Esq.
Steve Scialabba, Division
Greg Booth, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing were hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

_______________________________ February 10, 2016

Joanne M. Scanlon Date

Docket No. 4592 National Grid's Electric Infrastructure, Safety and Reliability Plan FY 2017 - Service List as of 12/10/15

Name/Address	E-mail Distribution	Phone
Raquel J. Webster, Esq. National Grid. 280 Melrose St. Providence, RI 02907	raquel.webster@nationalgrid.com; celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com;	401-784-7667
National Grid Jim Patterson Ryan Moe Amy Tabor Adam Crary	Jim.patterson@nationalgrid.com; Ryan.moe@nationalgrid.com; Amy.tabor@nationalgrid.com; Adam.crary@nationagrid.com; William.richer@nationalgrid.com;	
Leo Wold, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov; Steve.scialabba@dpuc.ri.gov; James.lanni@dpuc.ri.gov; Joseph.shilling@dpuc.ri.gov; John.spirito@dpuc.ri.gov; dmacrae@riag.ri.gov; Jmunoz@riag.ri.gov;	401-222-2424
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
Greg Booth Linda Kushner PowerServices, Inc 1616 E. Millbrook Road, Suite 210 Raleigh, NC 27609	gbooth@powerservices.com; Lkushner@powerservices.com;	919-256-5900
File an original & nine copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107

Christopher Kearns, OER	Christopher.Kearns@energy.ri.gov;	
	Danny.Musher@energy.ri.gov;	
	Nicholas.Ucci@energy.ri.gov;	

OER 1-1

Request:

This Data Request pertains to National Grid's Electric Infrastructure, Safety and Reliability Plan FY 2017 Proposal dated December 9, 2015 submitted by National Grid to the Rhode Island Public Utilities Commission ("Proposal"), specifically the "Long Range Plan" as referenced on Bates Stamp pages 12, 19, and 20 and Figure 1 on page 20.

(a) Please explain the background and purpose of the Long Range Plan.
(b) Please explain what the process of completing the Long Range Plan entails.
(c) Please explain the analysis used to form the basis of the Long Range Plan.
(d) Please identify the format or formats of the output of the analysis.
(e) Please provide a copy of the finalized East Bay study or the link where the study can be accessed.
(f) Please provide a copy of the portions of the Providence, Blackstone Valley North, and North Central Rhode Island studies that have been completed.
(g) Please provide a timeline including anticipated completion dates for the remaining study areas and the final Long Range Plan.
(h) Please explain how National Grid (the "Company") uses the results of the Long Range Plan to inform planning in the Energy Efficiency Program, System Reliability Procurement Program, and Renewable Energy Growth Program.

Response:

(a) The term "Long Range Plan" (LRP) was originally used by the Rhode Island Division of Public Utilities and Carriers' Consultant, Gregory L. Booth, PE, of PowerServices, Inc. in the Electric ISR Docket No. 4473. *See* Report of Gregory L. Booth, PE, concerning The Narragansett Electric Company d/b/a National Grid's Proposed FY 2015 Electric Infrastructure, Safety and Reliability Plan (Booth Report) (Exhibit GLB-1 to Pre-Filed Direct Testimony of Gregory L. Booth dated February 21, 2014). In his report, Mr. Booth stated:

> "Ideally, the LRP should extend 10+ years and serve as the basis for budget and construction work plans associated with substation and distribution feeder capacity projects. This plan should be developed in part from the system model in CYME and its resulting load flow, line capacity, and voltage profiles. This LRP will align asset replacements identified in the I&M program with the LRP process to avoid duplication and potential early obsolescence of system improvement expenditures."

See Booth Testimony at pages 8-9. Mr. Booth also noted that "[i]t was also determined that a complete system-wide study could not be accomplished in FY 2015 . . . ." However, he recommended "prioritizing and accelerating development of the Long Range Plan, to the extent possible" and stated that "[n]ew projects, unless compelled by imminent safety or reliability concerns, should be justified under the Long Range Plan before inclusion in the ISR Plan." *See* Booth Report at page 20. As it did during the Electric ISR proceeding in Docket No. 4473, National Grid maintains that its internal area study process is in line with Power Services' concept of a Long Range Plan. Although area studies do not provide an immediate system-wide view of the electric system issues (present and predicted), it is National Grid's opinion that an area study approach provides the best balance of comprehensive analysis against focus of study efforts where most needed. Overtime, through rotation and prioritization of the study areas, a system-wide view is obtained.

(b) To complete the LRP, National Grid has, and will conduct, a series of area studies. Each area study follows a series of logical step-wise milestones. These milestones intentionally encourage early and frequent consultation with various internal subject matter experts. National Grid's definition of each milestone is as follows:

- Pre-Kickoff Activities – Includes defining the study area, gathering data, gathering load and load growth information, and gathering customer information.
- Initial System Assessment – Includes building system models and an initial cursory analysis of issues.
- Study Kickoff meeting – Important multi-department meeting to present study definition and initial issues and gather other stakeholder input.
- Detailed System Assessment – Conduct detailed thermal, voltage, and reliability analysis, gather detailed asset condition analysis.
- Plan Development – Develop technically equivalent plans to address the comprehensive issues.
- Estimates Development – Review the plans with subject matter experts for feasibility and develop estimates.
- Recommended Plan Selection – With technical characteristics, feasibility reviews, and estimates, determine recommended plan(s).
- Technical Review – Important meeting to present study findings and recommended plan to internal stakeholders.
- Study Documentation – Complete and issue the study report.

OER 1-1, page 3

(c) Area study analysis generally includes capacity (normal and contingency configuration), voltage, reliability, reactive compensation, arc flash, fault duty, protection coordination, and asset condition reviews of the electric system. Excluding asset condition reviews and reliability analysis, National Grid uses the Siemens PTI PSS/e loadflow program for networked balanced three phase analysis and the CYMdist program for radial three phase unbalanced analysis. The ASPEN Oneliner program is also used for short circuit and relay coordination analysis.

(d) An area study is documented in a study report.

(e) The East Bay Study Report is provided as Attachment OER 1-1. Note that the Confidential Critical Energy Infrastructure Information has been redacted from this study.

(f) Although portions of the Providence, Blackstone Valley North, and North Central Rhode Island studies have been completed, study report sections have not been completed at this time. Analysis is often done in phases and analysis is often revisited upon further examination or consultation. As a result, documentation does not occur until the end of the study process.

(g) The latest timeline, including anticipated completion dates for the remaining study Areas, is as follows:

Rank	Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Study Status
1	Providence	364	19%	95	17	50%
2	East Bay	157	8%	23	7	**100%**
3A	Blackstone Valley North	145	7%	20	5	20%
3B	North Central Rhode Island	254	13%	35	10	20%
4	Central Rhode Island East	197	10%	38	10	0%
5	South County East	184	10%	21	9	
6	Central Rhode Island West	178	9%	30	11	
7	Newport	136	7%	54	14	
8	Blackstone Valley South	198	10%	60	13	
9	Tiverton	30	2%	4	1	
10	South County West	97	5%	12	6	
	TOTALS*	**1940**	**100%**	**392**	**103**	**22%**

* Study Status Total = % State Load weighted total

(h) National Grid does not use the area study results to inform planning in the Energy Efficiency Program. As noted on the OER's website, the "State provides a number of incentives and loan opportunities through the state's energy efficiency programs for homes, businesses, and municipalities." National Grid believes that the Energy Efficiency Program can remain independent of planning activities. National Grid does use the area study results to inform planning in the System Reliability Procurement Program (SRP). Non-wires alternatives are screened for feasibility during the Plan Development phase of any study. Should a non-wires alternative be deemed feasible, a further detailed review would be conducted (as an example, see Section 6.2 of the East Bay Area Study).

Importantly, the non-wires alternatives considered in the SRP would include targeted energy efficiency efforts and could include distributed resource options. National Grid does not use the area study results to inform planning in the Renewable Energy Growth Program (RE Growth Program). It is National Grid's understanding that the intent of the RE Growth Program is to encourage distributed generation projects throughout the state to meet Rhode Island's Energy Plan goals. Targeted distributed generation activities related to planning would be considered in the SRP.

This document has been redacted for Critical Energy Infrastructure Information (CEII). 10/9/2015

East Bay Area Study

Jack P. Vaz, PE

August 2015

Reviewed by: ______________________________ Date: ____________________
Ryan Constable, Distribution Planning & Asset Manager – New England, Network Strategy

Approved by: ______________________________ Date: ____________________
Alan LaBarre, Director, Distribution Planning and Asset Management, NE, Network Strategy

Table of Contents

Pages

LEGEND	
Al	Aluminum wire or cable
ARP	Asset Replacement Program
Cal/cm^2	Calories/square centimeter
capex	Capital expenditure (budget expenditure type)
Cu	Copper wire or cable
DPG	Distribution Planning Guide rev 1, dated February 2011
EMS	Energy Management System
GIS	Geographic Information System
ISO	Independent System Operator
kV	Kilovolts
LTC	Load Tap Changer
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
MW	Megawatts
MWh	Megawatt hour
MOV	Metal-Oxide Varistor
NE	New England
opex	Operations/Maintenance expenditure (budget expenditure type)
PT	Potential Transformer
RAPR	Remote Access Pulse Recorder
RI	Rhode Island
PUC	Public Utility Commission
SN	Summer Normal Rating of Equipment
SE	Summer Emergency Rating of Equipment

1. Executive Summary

A comprehensive study of the East Bay area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal (capacity) limits, contingency response capability (Distribution Planning Criteria), voltage performance (RI PUC requirements), breaker operating capability, arc flash review, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the system performance concerns existing and anticipated in the study area thru 2030.

The most recent major infrastructure development investment in the study area occurred in the 1990's with the construction of Wampanoag substation in East Providence and the expansion of Bristol substation. These investments relieved a highly utilized distribution and sub-transmission system. New investments are required to provide additional relief to the supply and distribution systems in the area. Additionally, there are a number of asset condition, safety, and reliability concerns that need to be addressed.

Three plans were developed to address existing area problems and to provide for future needs within the study area thru the year 2030. Each plan provides a comprehensive solution to address all concerns in the study area. The concerns include thermal loading near or above rated capability of equipment, contingency response capability that does not meet distribution planning guidelines, asset condition concerns, safety concerns, and reliability concerns.

Plan 1 includes building two new substations supplied from the 115kV transmission system. System rearrangement proposed within this plan reduces loading and dependence on the 23kV sub-transmission system. The following are the major modifications proposed:

- Replace the out of phase 23/12.47kV substation at Phillipsdale with a new 115/12.47kV station. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two-stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2MVAR two-stage capacitor banks.
- Build a new 115/12.47kV substation in the city of East Providence on a gas company owned land parcel adjacent to the 115kV transmission right-of-way. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two-stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2MVAR two-stage capacitor banks.
- Expand the existing 115/12.47kV substation at Warren by installing two new 12.47kV distribution feeder positions and a two-stage 7.2MVAR capacitor bank on each bus.

The Plan 1 total cost estimate (over all years) is \$37.70M (\$31.68M capex, \$2.14M opex, \$3.88M removal).

Plan 2 includes adding new distribution capacity supplied from an upgraded 23kV sub-transmission system and has limited investment in expansion of the 115kV transmission system. The following are the major modifications proposed:

- Replace the existing 23/4.16kV substation at Kent Corners with two 23/12.47kV modular feeders supplied from an upgraded 23kV system. The sub-transmission upgrades require approximately 7.50 miles of line reconductoring along a public roadway system.
- Build two new 23/12.47kV modular feeders on a Company owned site in East Providence. This was the location of Rumford substation which was retired and removed in the 1990's.
- Replace the existing out of phase 23/12.47kV substation at Phillipsdale with two new 23/12.47kV modular feeders. The new feeders would phase with the rest of the distribution system in the area.
- Build a new 115/23kV substation at Mink Street to supply the reinforced, upgraded, and expanded 23kV system. Construction would consist of a single 40MVA transformer supplying a single 23kV line.
- Address asset condition concerns at Phillipsdale and Warren 115/23kV substations. These two stations, along with Mink Street, will supply the 23kV system.

The Plan 2 total cost estimate (over all years) is $50.00M ($42.29M capex, $3.19M opex, $4.52M removal).

Plan 3 is a hybrid of Plan 1 and Plan 2. It includes expanding the 115kV transmission system along with expanding and reinforcing the 23kV sub-transmission system. The following are the major modifications proposed:

- Replace the existing out of phase 23/12.47kV substation at Phillipsdale with a new 115/12.47kV station. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two-stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2MVAR two-stage capacitor banks.
- Build a new 115/23kV substation at Mink Street to supply the reinforced, upgraded, and expanded 23kV system. Construction would consist of a single 40MVA transformer supplying a single 23kV line.
- Replace the existing 23/4.16kV substation at Kent Corners with two 23/12.47kV modular feeders supplied from an upgraded 23kV supply system. The sub-transmission upgrades require approximately 7.50 miles of line reconductoring along a public roadway system.
- Address asset condition concerns at Warren 115/23kV substation. This station, along with Mink Street, will supply the 23kV system.

The Plan 3 total cost estimate (over all years) is $41.20M ($34.29M capex, $2.45M opex, $4.46M removal).

Plan 1 is recommended for implementation. It provides a comprehensive solution to address all the concerns in the study area at least cost. The total cost of Plan 1 is $37.70M which is $13.00M lower in cost than Plan 2 and $3.50M lower in cost than Plan 3.

Plan 1 is least sensitive to load growth and offers the most flexibility for future expansion. Plan 1 eliminates most of 23kV sub-transmission system installed along public roadways which has significant exposure to motor vehicle accidents and tree related outages. Plan 2 and Plan 3 offer no economic or reliability benefits over Plan 1 and are more sensitive to higher than forecasted load growth.

2. Introduction

2.1 Purpose

A comprehensive study of the East Bay area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal (capacity) limits, contingency response capability (Distribution Planning Criteria), voltage performance (RI PUC requirements), breaker operating capability, arc flash review, reactive compensation performance, asset condition, and safety and environmental issues. The recommendations provide a comprehensive solution to address all the system performance concerns existing and anticipated in the study area thru 2030.

2.2 Problem

A study's initial system assessment is typically based on the needs identified through the Annual Planning process. The latest Annual Planning review showed a variety of normal and contingency capacity issues in the East Bay Area. Furthermore, informal asset condition reviews and inspection results indicated there may be growing asset condition concerns.

3. Background

3.1 Scope

3.1.1 Geographic Scope

The East Bay study area consists of the city of East Providence and the towns of Barrington, Bristol, and Warren. The study area is bounded to the east by the Commonwealth of Massachusetts, to the north by the City of Pawtucket, and to the west and south by the Providence River. The study area is shown geographically in Appendix 9.1.

3.1.2 Electrical Scope

Three 115kV transmission lines supply the load in the study area. Two lines, E-183E and F-184, originate at Brayton Point substation and one line, X-3, originates at Somerset substation. The study area has an extensive sub-transmission system consisting of five 23kV lines (2242, 2243, 2267, 2291, and 2295). One line diagrams are shown in Appendix 9.2.

Three 115/12.47kV substations (Bristol, Wampanoag, and Warren) supply approximately 115MW of area load. The remainder of the load, or approximately 63MW, is supplied from the 23kV sub-transmission system originating at Warren, Phillipsdale, and Mink Street substations. There is a small pocket of 4.16kV load, approximately 7.3MW, supplied from Kent Corners substation. Nine industrial customers are supplied directly from the 23kV sub-transmission system.

Mink Street, located in Massachusetts, has a 115/23/13.2kV 3-winding transformer that supplies both a 23kV line and a 13.2kV station. The 23kV line only supplies customers in Rhode Island. Mink Street is the only station located outside the study area that supplies East Bay customers.

3.2 Area Load and Load Forecast

The study area has approximately 43,000 customers with a peak electrical demand of 178MW. The study area is summer peaking and summer limited. This study used the most recent forecast developed by National Grid, the "2014 New England Electric Peak Forecast". It utilized the 95/5 extreme weather scenario case. Table 1 shows the forecasted load growth rate for the study area from 2015 to 2030.

TABLE 3.2 – Forecasted Load Growth Rate from 2015 to 2030 for Study Area

Forecasted Growth – East Bay					AVG	AVG
2015	2016	2017	2018	2019	'20 to '23	'24 to '30
2.3%	1.4%	1.0%	0.6%	0.7%	0.7%	0.8%

3.3 Active Projects

Two active transmission studies were reviewed to determine potential impacts on the East Bay study area infrastructure and the plans being considered in this study.

The Southeastern Massachusetts and Rhode Island (SEMA/RI) study is expected to address transmission supply constraints in the southeastern Massachusetts and Rhode Island areas which includes the East Bay area. The results from this transmission study are not expected to impact any of the improvements being proposed in the East Bay Area Study.

The state of Rhode Island has requested the company investigate the feasibility of undergrounding the E-183W transmission line from the Phillipsdale substation tap in East Providence to Franklin Square substation in Providence. One option identified is the installation of a transition structure for this 115kV line on the site being considered for a proposed East Providence substation. A preliminary review has not identified any major concerns with the site's ability to accommodate both projects.

3.4 Limitations on Infrastructure Development

The study area is an electrical island. It is bounded to the east by the Commonwealth of Massachusetts with a 13.2kV distribution system, to the north by the City of Pawtucket with a 13.8kV distribution system, and to the west and south by the Providence River. The study area is shown geographically in Appendix 9.1.

3.5 Assumptions & Guidelines

The current Distribution Planning Guide rev 1, February 2011 ("DPG") was used when performing this study. The guide describes the normal and contingency analysis, as well as considerations for safety, the environment, reliability, reactive compensation, load balance, voltage, and efficiency, used in National Grid's distribution planning studies.

The Distribution Planning & Asset Management department uses the Siemens PTI PSS/e loadflow program to analyze the transmission and sub-transmission system. This is the same program that is used by ISO NE and the National Grid Transmission Planning department.

The CYMdist 5.04 Revision 5.0 program was used to analyze radial three-phase unbalanced systems (distribution feeders). Databases are extracted from the GE-SmallWorld GIS System into a Microsoft Access format.

The ASPEN program was used to determine short circuit duty values at all substations.

4. Problem Identification

4.1 Thermal Loading

4.1.1 Normal Configuration - Thermal Loading

The distribution system in the East Bay area is heavily loaded with limited capacity to supply new load. Table 4.1.1 shows the projected feeder loading on the distribution system for the main limiting element of each circuit. Excluding the out of phase feeders and the small pocket of 4.16kV load, by 2020 approximately 50% of the feeders are projected to be loaded above 90% of SN rating. By 2026, 70% of the feeders are projected to be loaded above 90% of SN rating.

TABLE 4.1.1 - Projected Summer Normal Feeder Loading

Substation	Fdr	2020		2026		2028		2030	
		Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
BARRINGTON	4F1	330	64%	344	67%	350	68%	355	69%
BARRINGTON	4F2	468	92%	488	96%	496	97%	504	99%
BRISTOL	51F1	519	81%	543	84%	552	86%	561	87%
BRISTOL	51F2	481	91%	503	95%	511	96%	520	98%
BRISTOL	51F3	431	86%	451	90%	458	91%	466	93%
WAMPANOAG	48F1	488	97%	512	102%	520	104%	528	105%
WAMPANOAG	48F2	445	86%	466	91%	474	92%	482	94%
WAMPANOAG	48F3	559	110%	585	115%	595	117%	604	119%
WAMPANOAG	48F4	542	102%	568	107%	577	109%	586	111%
WAMPANOAG	48F5	461	95%	483	100%	491	101%	498	103%
WAMPANOAG	48F6	420	79%	440	83%	447	84%	455	86%
WARREN	5F1	379	89%	392	92%	398	94%	404	95%
WARREN	5F2	396	91%	411	95%	416	96%	422	97%
WARREN	5F3	393	76%	407	79%	413	80%	419	81%
WARREN	5F4	466	91%	483	95%	490	96%	496	97%
OUT OF PHASE FEEDERS									
PHILLIPSDALE	20F1	336	79%	352	83%	358	84%	363	85%
PHILLIPSDALE	20F2	398	94%	417	98%	424	100%	430	101%
WATERMAN AVE	78F3	263	64%	276	68%	281	69%	285	70%
WATERMAN AVE	78F4	248	61%	260	64%	264	65%	268	66%
4.16kV POCKET OF LOAD									
KENT CORNERS	47J2	336	82%	352	86%	358	88%	364	89%
KENT CORNERS	47J3	349	86%	366	90%	372	91%	378	93%
KENT CORNERS	47J4	382	94%	400	98%	406	100%	413	101%

Loading of distribution line sections of each feeder were analyzed using the CYME software. Minimal overloaded sections were identified as shown in Appendix 9.4.

There are no projected transformer or supply line normal configuration overloads within the study period.

4.1.2 Contingency Configuration - Thermal Loading

A contingency analysis was performed for all feeders in the study area. This analysis calculates a MWh 'exposure' or risk assuming a worst case component failure. The assumptions made for this analysis include:

- A one-hour response time before performing the first switching step to allow sufficient time for a crew to respond to the outage.
- Assumes 30-minutes to execute each additional switching step. This appears reasonable since the feeders in this area are relatively short.
- Assumes a failed component can be repaired within four hours. Some feeders have underground cable getaways which may require a longer repair time. Due to the fact that exposure is relatively small, a cable failure was not assumed in the calculations.
- Some feeders are double circuited on the same pole plant, primarily near the substation. Due to the fact that exposure is relatively small, a failure involving two feeders was not assumed in the calculations.
- The MWh calculations utilize the summer emergency ratings of the feeders.

Table 4.1.2 below shows the MWh exposure for each study area feeder and any remaining un-served load. Because the feeders are heavily loaded, nearly all exceed the MWh exposure recommended in the DPG. The DPG recommends mitigating any exposure in excess of 16MWh.

TABLE 4.1.2 - Calculated MWh exposure and Un-Served Load on Feeders

Substation	Feeder	MWh Exposure	Un-Served MW
BARRINGTON 4	4F1	18.2	3.45
BARRINGTON 4	4F2	22.7	2.91
BRISTOL 51A	51F1	24.7	2.36
BRISTOL 51A	51F2	25.2	4.06
BRISTOL 51A	51F3	21.1	2.52
WAMPANOAG 48	48F1	25.6	4.25
WAMPANOAG 48	48F2	23.5	4.52
WAMPANOAG 48	48F3	29.3	3.80
WAMPANOAG 48	48F4	42.0	10.31
WAMPANOAG 48	48F5	21.6	2.89
WAMPANOAG 48	48F6	26.2	5.15
WARREN 5	5F1	19.4	3.47
WARREN 5	5F2	24.5	5.00
WARREN 5	5F3	22.6	4.18
WARREN 5	5F4	21.0	0.99
WATERMAN AVENUE 78	78F3*	5.4	0.00
WATERMAN AVENUE 78	78F4*	5.3	0.00
PHILLIPSDALE 20	20F1*	23.9	5.67
PHILLIPSDALE 20	20F2*	13.6	1.08

* NOTE: These feeders are not in-phase with the remainder feeders. Any switching involving these feeders will require customers to be exposed to a short duration outage.

There are no MWh exposure issues above guidelines[1] for the station transformers and subtransmission system. However, one contingency load-at-risk issue involving the supply from the Mink Street substation should be noted. Mink Street is a low-profile station with two transformers. This station is located in Seekonk, MA, but includes a three-winding power transformer with a 23kV tertiary winding supplying East Bay area load. Peak loading on the 23kV winding is limited to 12MVA because capacity is needed to supply the Massachusetts 13.2kV load. This limit results in approximately 14MW of un-served load for loss of the preferred supply to Barrington substation and limits the ability to add load to the 23kV system. A one line on Mink Street is shown in Appendix 9.2.

4.2 Voltage Performance

The PSS/e load flow program was utilized to model the electrical system to the 23kV sub-transmission level including step-down transformers to the distribution feeder level. The DPG recommends that customer service voltages be maintained to meet ANSI 84.1 guidelines. ANSI 84.1 requires that service voltages be maintained between 0.95 and 1.05 per unit during normal loading conditions and between 0.90 and 1.10 per unit during contingency conditions. Because of the ability to adjust transformer tap settings and with existing voltage regulation equipment, the supply system can vary greater than the required service voltage range. However for study purposes, the supply system is screened for potential issues using the ANSI 84.1 ranges. No

[1] The Distribution Planning Guide, dated Feb 2011, recommends mitigation of station transformer and subtransmission contingency issues when the load-at-risk exceeds 240 MWh.

voltage issues were identified during this screening effort. See Appendix 9.3 for loadflow diagrams.

The CYME program models all three phases of each distribution feeder for its entire length starting at the substation. Voltages at all points should be maintained between the range of 0.95 to 1.05 per unit, or from 114 volts to 126 volts on a 120 volt base. Minor violations were identified but these violations can be corrected through minor feeder balancing. See Appendix 9.4 for CYME diagrams.

4.3 Asset Condition

Asset condition reviews were conducted at each substation within the study area.

Mink Street is a low-profile station with two transformers. This station is located in Seekonk, MA, but includes a three-winding power transformer with a 23kV tertiary winding supplying East Bay area load. The asset condition review (for this study's purposes) is limited to this three-winding transformer and there are no immediate issues.

Barrington is a 23/12.47kV substation with a single transformer supplying two feeders with approximately 17MW of peak load. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- The sacrificial air break (1T23) on the 25MVA power transformer does not provide adequate protection and results in an elevated risk of transformer failure.
- The station bus does not comply with current minimum clearance requirements. Jersey barriers are currently used to prevent accidental contact as a temporary measure.
- The 4F2 recloser is no longer reliable. This recloser has been identified for replacement in the ARP.
- This station has no remote status, control and monitoring of all switching devices, transformers, voltage regulation and battery systems (no EMS).

Kent Corners is a 23/4.16kV substation supplying 7.3MW of peak load. Appendix 9.2 shows a one-line of the station. This station is the only 4.16kV station left in the area. It is a 1950's vintage station with mostly original equipment. A number of concerns exist at this station:

- The circuit breakers are no longer reliable.
- The 23kV air-break motor operators and live parts are obsolete and require custom made parts to continue to maintain these air-breaks.
- The station power transformers are 1950's vintage. Parts for transformer bushings are no longer manufacturer supported.
- There have been neighborhood complaints about transformer noise. Station is located in a heavily congested residential neighborhood.
- This station has no remote status, control and monitoring of all switching devices, transformers, voltage regulation and battery systems (no EMS).

The Phillipsdale 115/23kV substation supplies two 23/12.47kV stations and a number of industrial customers with a combined peak load of approximately 30MW. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- The power transformers are 1960's vintage. T1 transformer is the only transformer in the system with attached coolers. T2 transformer shows significant signs of aging and has been identified for replacement in the ARP. Replacement of the T2 transformer has been deferred pending completion of this study.
- Transformer grounding reactors are concrete encased with small visible cracks. There is no spare grounding reactor to respond to a failure.
- Transformer 23kV disconnect switches are non-gang operated and are not readily accessible to operate.
- The 23kV breakers are no longer reliable.
- The transformer and bus arrestors are obsolete.
- A timed scheme at the station prevents bus ties from occurring unless disabled. This scheme is complex to operate.

The Phillipsdale 23/12.47kV substation consists of non-standard equipment and construction. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- A single LTC transformer supplies two 12.47kV feeders with pole mounted line reclosers. The reclosers have a history of poor reliability.
- The distribution voltage from this station only phases with Waterman Avenue feeders. This results in a pocket of load being out of phase with the rest of the system and makes maintenance of the station equipment challenging.
- The LTC transformer is a delta/zig-zag with no system spare and only a single mobile transformer in the system suitable for this location. A transformer failure would tie up this mobile for an extended period.

The Warren 115/23kV station consists of two 30/40/50 MVA transformers supplying two 23kV lines with approximately 34MW of peak load. Appendix 9.2 shows a one-line of the station. A number of concerns exist at this station:

- The 23kV breakers have reliability concerns.
- The pin type insulators on the 23kV bus are obsolete.
- The 23kV protection is located in an old control house with electro-mechanical relays. Most of this protection is obsolete.
- There are obsolete GE Butyl Rubber PT's
- The RAPR system is obsolete.

The Waterman 23/12.47kV station is located just north of Wampanoag substation. It consists of two 10/12.5 MVA transformers supplying four feeders. Appendix 9.2 shows a one-line of the station. Only two Waterman feeders supply customer load because the other two feeders are landlocked by Wampanoag substation to the south. In addition, these two feeders only phase with Phillipsdale feeders which creates a pocket of out-of phase load in the area. A number of concerns exist at this station:

- The 23kV air-break switch is obsolete.
- The transformers have sacrificial high side air breaks switches which are obsolete.
- The 23kV capacitor bank has an obsolete VBM switch.
- The 23kV equipment is mounted on wood poles.

Most of the 23kV sub-transmission system consists of aged pole plant and small wire installed on congested public roadways. A one-line of the 23kV supply system is shown in Appendix 9.2. Only a small portion of this system has been rebuilt in the last 20-years. The remainder of the system consists of a mixture of 795 Al, 336.4Al, 2/0Cu, and 1/0Cu wire with 12.47kV under-build. A major investment to replace both the pole plant and wire size would be required to increase the capacity of this system.

4.4 Additional Analysis

4.4.1 Reliability Performance

A reliability review was conducted to check feeder indices against system targets. For calendar year 2014, the SAIFI target was 1.05 and SAIDI target was 71.9 minutes. No three year trends were identified requiring further reliability analysis. See Table 4.4.1 below.

TABLE 4.4.1 – Study Area Reliability Indices

	2014		2013		2012	
FEEDER	CKAIFI	CKAIDI	CKAIFI	CKAIDI	CKAIFI	CKAIDI
53-20F1	1.019	101.75	3.122	112.71	0.045	0.27
53-20F2	1.063	139.31	1.243	82.38	0.159	18.04
53-47J2	0.003	0.29	0.291	5.88	0.025	6.82
53-47J3	0.106	4.64	0.000	0.00	0.051	6.73
53-47J4	0.011	0.72	0.098	7.23	0.103	15.25
53-48F1	0.157	6.75	0.039	4.06	0.891	54.20
53-48F2	1.055	100.74	0.136	33.91	2.436	123.97
53-48F3	0.056	5.28	0.139	15.59	1.661	160.22
53-48F4	0.040	5.47	0.109	9.97	0.077	20.58
53-48F5	0.064	7.10	0.143	23.63	0.073	6.94
53-48F6	0.071	7.35	0.059	4.20	0.504	30.07
53-4F1	0.215	28.54	1.151	90.14	1.016	96.34
53-4F2	0.333	26.31	1.861	106.53	1.339	131.67
53-51F1	0.623	103.16	0.189	24.17	0.143	11.33
53-51F2	0.239	18.33	0.086	5.70	0.160	6.38
53-51F3	0.227	17.55	1.088	97.15	0.428	19.07
53-5F1	2.040	130.98	1.468	98.81	0.259	28.43
53-5F2	0.209	16.38	0.245	79.90	2.716	196.41
53-5F3	0.110	5.02	0.342	82.02	1.767	232.77
53-5F4	0.225	49.33	1.178	79.47	1.197	285.36
53-78F3	0.073	14.81	0.850	50.80	0.083	8.11
53-78F4	1.254	81.31	0.045	2.70	0.040	3.27

4.4.2 Arc Flash

On April 1, 2014, the United States Department of Labor's Occupational Safety and Health Administration ("OSHA") issued final rule 1910.269 requiring the employer to assess the workplace to identify employees exposed to hazards from flames or electric arcs. 1910.269 proposed compliance dates of January 1, 2015 and April 1, 2015 for completion of the hazard assessment and implementation of the assessment results respectively. As the industry adjusted to these new requirements and calculation methods, the dates were adjusted to March 31, 2015 and August 31, 2015.

As described above arc flash regulations were issued and analysis methods were reviewed and adjusted during the course of this study. A review using CYME fault current analysis and protection coordination values with ArcPro incident energy calculations provided an analysis in compliance with OSHA requirements. Appendix 9.5 shows the results of this analysis with no study area feeders indicating incident energies above 8 calories per centimeter squared (cal/cm2).

4.4.3 Fault Duty/Short Circuit Availability

The ASPEN program was used to calculate single phase to ground and three phase short circuit duty values at each area substation. These values were compared to the station breaker interrupting capabilities. The table in Appendix 9.6 summarizes the results of this analysis. No breakers in the study area where identified to have a short circuit duty exceeding their interrupting capability.

4.4.4 Reactive Compensation

ISO-NE conducts an annual survey of actual load power factor operations and compares it against the applicable standards. The latest survey has this overall area compliant at all times. The results of this survey are shown on Table 4.4.4 below:

TABLE 4.4.4: ISO-NE Power Factor Survey Results

	CURRENT LPF SURVEY SUMMARY						COMPLIANCE REPORT					
	Spring	Summer		Fall	Winter		Spring	Summer		Fall	Winter	
	9,195	22,177	27,360	9,271	18,180	21,448	9,195	22,177	27,360	9,271	18,180	21,448
	5/19/13	08/21/2013	07/19/13	9/29/13	12/4/13	12/17/13	5/19/13	08/21/2013	07/19/13	9/29/13	12/4/13	12/17/13
	4:00	18:00	17:00	5:00	18:00	18:00	4:00	18:00	17:00	5:00	18:00	18:00
Narragansett	0.983	0.997	0.995	0.983	0.998	0.999	compliant	compliant	compliant	compliant	compliant	compliant

The power factor performance of the study area's feeders is limited to those that have PI data availability. This includes only the 12.47kV feeders at Warren substation. Peak power factor performance for these feeders shows them to be near unity or leading, indicating adequate feeder reactive support. Available data for major 115kV transformer interfaces and the 23 kV sub-transmission lines also show power factor near unity or slightly lagging.

5. Plan Development

5.1 Consideration of Distributed Generation in Plan Development

The impact of existing and planned distributed generation ("DG") installations were considered in the plan formation. Installations of significant size (greater than [illegible] MW) appear on one 23 kV sub-transmission line (2267 line). There are two solar array sites on this line, one existing and one proposed, each sized at 3 MWs. Appendix 9.11 lists the existing and proposed DG within the study area.

The DG was analyzed from a hypothetical peak reduction perspective. Peak contribution factors, the ratio of the megawatts generated on peak versus the nameplate rating of the generator, can vary greatly on a daily or yearly basis as a result of location, weather, and other factors. Observing the 2014 summer data for the in-service solar array shows peak contribution factors of 77%, 40%, 23%, and 10% for 12:00PM, 3:00PM, 4:00PM, and 6PM respectively. Using a conservatively high peak contribution factor of 30% of nameplate, results in a possible peak reduction of 1.8 MW for the existing and proposed DG. This equates to approximately 45 amps at 23kV. There are no projected sub-transmission normal configuration overloads predicted in the study period. This peak reduction analysis resulted in no impact to the proposed plans.

Area DG was also analyzed from a comprehensive study-wide perspective. All area stations, except Wampanoag, have contingency load-at-risk issues and asset conditions issues (see Sections 4.1.2 and 4.3). The existing and proposed DG does not address or avoid necessary asset condition issues and is not significant or dependable in load levels to mitigate capacity issues. As a result, the comprehensive plans are also unaffected by the existing or proposed distributed generation.

5.2 Common Items

The Bristol/Warren area is electrically isolated from the East Providence/Barrington area. There are no feeder ties between these areas because of the Barrington River. The river forms a natural barrier that makes feeder ties between the areas neither practical nor economical.

Although there are no thermal concerns to resolve in the Bristol/Warren area, the feeders are highly utilized resulting in contingency load-at-risk exceeding the DPG guidelines. To resolve this issue, the following investments are recommended.

- Install a new feeder, 51F4, at Bristol substation. A one-line of the proposed work is shown in Appendix 9.7.
- Upgrade the thermal capability of the Warren 5F2 and 5F4 feeders. This involves upgrading the front end of both circuits.

The investments and expenses for the common items are shown in Table 5.2 below:

TABLE 5.2 - Estimated Cost of Common Items ($M)

Description	Capex	Opex	Removal	Total
East Bay Common Item (D-Sub)	$0.590	$0.075	$0.005	$0.670
East Bay Common Item (D-Line)	$0.620	$0.042	$0.153	$0.815
TOTAL (COMMON)	**$1.210**	**$0.117**	**$0.158**	**$1.485**

5.3 Plan – 1

This plan includes building two new substations supplied from the 115kV transmission system. System rearrangement proposed within this plan reduces loading and dependence on the 23kV sub-transmission system. The following are the major modifications proposed:

Construct a new 115/12.47kV Station at Phillipsdale:
Build a new 115/12.47kV substation at Phillipsdale. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, a 7.2 MVAR station capacitor bank, and four feeder positions. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, two 7.2MVAR capacitor bank, and eight feeder positions. A one line of this proposed station is shown in Appendix 9.8. The station would be supplied from the 115kV lines, X-3 and E-183W. The four new feeders from this station would:

- Replace the 23/12.47kV non-standard construction at Phillipsdale substation with standard station equipment, address the asset condition concerns, and provide capacity to supply new customers in the northern section of the City of East Providence.
- Eliminate out of phase feeder ties by correcting the voltage phasing. This would increase switching flexibility, reduce restoration time, and improve reliability since customers would not be exposed to short outages during switching.
- Retire Waterman substation to address asset condition concerns, eliminate the need for a major investment to upgrade the 23kV supply system, and eliminate the out of phase feeder ties that exist at Waterman.
- Reduce load on the 115/23kV station at Phillisdale from 30MW to 3MW. The long-term strategy would be to convert the two remaining 23kV customers to 12.47kV and retire the 23kV station. This approach eliminates a major investment on the 23kV station to address the asset condition and obsolete equipment concerns.

The new feeders would be routed on public roadways in new manhole and ductline infrastructure. Five industrial customers would be converted from 23kV to 12.47kV which would reduce load on the 23kV system, eliminate circuits installed in a difficult to access right-of-way adjacent to the railroad corridor, and eliminate a major investment to address the poor condition of the pole plant along this 23kV right-of-way.

The customers to be converted to 12.47kV are: Hasbro with (3) 500kVA transformers; Handy Harmon with (3) 667kVA transformers; Cape Cod Ice with (3) 333kVA transformers; BA Ballou with (3) 500kVA transformers; and Nyman Manufacturing which is primary metered customer with a peak demand of 1.70MW.

Construct a new 115/12.47kV Station in East Providence:
Build a new 115/12.47kV substation on First Street in East Providence on a gas company owned parcel next to the 115kV transmission right of way. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, a 7.2 MVAR station capacitor bank, and four feeder positions. The ultimate build-out would be two 40MVA LTC transformers

supplying straight-bus metal-clad switchgear with a tie breaker, two 7.2MVAR capacitor banks, and eight feeder positions. A one line of this proposed station and the site plan is shown in Appendix 9.8. The station would be supplied from the 115kV line, E-183W. The four new feeders from this station would:

- Provide capacity to relieve the heavily loaded distribution feeders in the area, address MWh violations, and provide capacity to supply load growth.
- Retire Kent Corners 23/4.16kV substation. This retirement would address the only remaining pocket of 4.16kV load in the area and is a component of a comprehensive plan to eliminate the need for a new 115/23kV station at Mink St.
- Be a component of a comprehensive approach that eliminates the need for a major upgrade of the 23kV supply system. The sub-transmission upgrades would require approximately 7.50 miles of line reconductoring along a public roadway system.

The four new feeders would be routed on public roadways in new manhole and ductline infrastructure. Kent Corners 4.16kV load would be converted to the 12.47kV system thru direct conversions and the use of step-down transformers to reduce cost. One industrial customer and a solar generator would be converted from 23kV to 12.47kV. The conversion of these customers is required to provide routes for the new 12.47kV feeders.

Add two new feeders at Warren Substation:
Expand Warren 115/12.47kV substation by adding two new distribution feeders and two 7.6MVAR station capacitor banks. The new feeders would be routed into Barrington and be used to retire Barrington substation. A one line of the proposed station expansion is shown in Appendix 9.8. This investment would address the asset and safety concerns at Barrington substation, eliminate the need for a new 115/23kV station at Mink Street, and eliminate the need for major upgrades on the 23kV supply system.

Substation Retirements:
The final component of this plan is to retire a number of substations in the study area and remove all equipment and foundations to below grade. The stations retirements are Mink Street 23kV station; Barrington substation; Kent Corners substation; Phillipsdale 23/12.47kV substation; Waterman substation; and retire the 2291 Line position at Warren substation. These substation retirements are part of a comprehensive plan to address all the issues in the study area at least cost.

The proposed mainline distribution for Plan 1 is shown in Appendix 9.8. The investments and expenses for Plan 1 are detailed in Table 5.3 below.

TABLE 5.3 - Estimated Investments and Expenses for Plan 1

Investment Description ($M)	Capex	Opex	Removal	Total
Phillipsdale Substation (T-Line)	$0.400	$0.020	$0.010	$0.430
Phillipsdale Substation (T-Sub)	$0.300	$0.000	$0.000	$0.300
Phillipsdale Substation (D-Line)	$3.716	$0.064	$0.260	$4.040
Phillipsdale Substation (D-Sub)	$6.020	$0.600	$0.380	$7.000
East Providence Substation (T-Line)	$0.400	$0.000	$0.000	$0.400
East Providence Substation (T-Sub)	$0.300	$0.000	$0.000	$0.300
East Providence Substation (D-Line)	$7.371	$0.405	$1.424	$9.200
East Providence Substation (D-Sub)	$6.020	$0.550	$0.030	$6.600
Warren Substation (D-Line)	$3.700	$0.100	$0.350	$4.150
Warren Substaion (D-Sub)	$3.450	$0.290	$0.175	$3.915
Mink Street Retirement (D-Sub)	$0.000	$0.020	$0.220	$0.240
Barrington Sub Retirement (D-Sub)	$0.000	$0.030	$0.345	$0.375
Kent Corners Sub Retirement (D-Sub)	$0.000	$0.030	$0.345	$0.375
Waterman Sub Retirement (D-Sub)	$0.000	$0.030	$0.345	$0.350
Plan 1 (T-Spend)	$1.400	$0.020	$0.010	$1.430
Plan 1 (D-Spend)	$30.277	$2.119	$3.874	$36.270
Total Spend	$31.677	$2.139	$3.884	$37.700

5.4 Alternative Plans

5.4.1 Plan – 2

This plan includes adding new distribution capacity supplied from an upgraded 23kV sub-transmission system and has limited investment in expansion of the 115kV transmission system. The following are the major modifications proposed:

Install two new 23/12.47kV Feeders at Phillipsdale substation
This alternative would build two new 23/12.47kV modular feeders at Phillipsdale substation. The new feeders would be used to retire the existing non-standard construction that currently exists at Phillipsdale and would correct the out-of-phase feeder ties. A one-line of the proposed station is shown in Appendix 9.9.

The existing 115/23kV station at Phillipsdale would supply the new modular feeders requiring the asset condition issues described in Section 4.3 to be addressed. The 1960's vintage power transformer would be replaced with 40 MVA transformers to address the reliability concerns. The 23kV breakers would be replaced along with the obsolete bus and transformer arrestors. The electromechanical relays would be upgraded with modern solid state relays. The timed bus tie scheme would be removed and EMS would be installed.

Install two new 23/12.47kV Feeders at Rumford substation
Plan 2 would install two new 23/12.47kV modular feeders at the former Rumford substation site located at 127 North Broadway in East Providence. Feeders would be supplied from the 115/23kV station at Phillipsdale. Access to the right-of-way along the railroad corridor would be improved and the obsolete pole plant would be replaced. A one-line of the proposed station is shown in Appendix 9.9.

The new Rumford substation feeders would provide capacity to supply new load growth, address MWh violations, and be used to retire Waterman Ave substation. The new feeders would also correct out-of-phase feeder ties, eliminate the need for asset replacement work at Waterman Ave substation, relocate the station away from Wampanoag substation, and move the station to a more robust 23kV supply system.

Waterman substation feeders are landlocked to the south by Wampanoag substation and the 23kV supply consists of small wire and aged pole plant that does not meet current standards for 23kV construction. As such, there is no economic or reliability benefit to maintaining Waterman Ave substation in its current location.

Install two new 23/12.47kV Feeders at Kent Corners substation
Plan 2 would install two new 23/12.47kV modular feeders at Kent Corners substation. The new feeders would provide capacity to relieve the heavily loaded distribution system in the area, address contingency load-at-risk issues, and provide capacity to supply new load growth. Investment would also eliminate the small pocket of 4.16kV load in the study area by retiring the existing Kent Corners 23/4.16kV station. A one-line of the proposed station is shown in Appendix 9.9.

Build a New 115/23kV Substation at Mink Street[2]

A new 115/23kV substation would be built at Mink Street to supply Kent Corners and Barrington substations. Construction would consist of a single 40MVA transformer supplying a single 23kV line. The station would be supplied by an existing 115kV line at Mink Street. A one-line of the proposed station is shown in Appendix 9.9.

Address Concerns at Barrington Substation

Plan 2 would address asset and safety concerns with Barrington substation. The sacrificial air break on the station transformer would be replaced with a circuit switcher, the bus work and taps would be raised to comply with current standards, the 4F2 VSA recloser would be replaced to address asset condition concerns and EMS would be installed at the station.

Upgrade and Reinforce the 23kV Sub-Transmission System

The 23kV sub-transmission system from Mink Street consists of a mixture of 336 Al, 2/0 Cu and 1/0 Cu wire. This system is not adequate to supply the proposed Kent Corners and Barrington substations. To supply these stations the small wire would have to be replaced with 795 Al open wire. Construction would consist of approximately 7.5 miles of double circuited roadway infrastructure along highly utilized and congested public roadways. This would require replacement of all the aged pole plant to meet current standards and to accommodate the larger wire size.

The normal supply to Barrington substation would be from the Warren 115/23kV station, a station with numerous asset condition concerns. As part of this plan, the asset condition concerns at Warren would be addressed. The 23kV breakers would be replaced along with all the obsolete pin type bus insulators. The obsolete protection would be upgraded and relocated from the old control house to the new control house. A one line of the proposed 23kV supply system is shown in Appendix 9.9.

This plan results in a comprehensive solution for the East Bay area and addresses all asset condition, safety, and reliability concerns. Plan addresses all thermal concerns, provides capacity to supply load growth, and addresses all distribution planning criteria violations. The required investments and expenses for Plan 2 are detailed in Table 5.4.1 below.

---

[2] Mink Street 115/23kV substation will be located in Massachusetts and supply customers in Rhode Island. It will be built, owned, and operated by the New England Power Company (NEPCo). An appropriate rate recovery mechanism needs to be developed. Rate recovery could occur thru a Transmission Rate Tariff or thru a Direct Assignment Charge. A Local Service Agreement may also need to be filed with the Federal Energy Regulatory Commission (FERC). If this plan were to be implemented, the legal department will be consulted to determine the most appropriate rate recovery mechanism for these assets.

TABLE 5.4.1 - Estimated Investments and Expenses for Plan 2

Investment Description ($M)	Capex	Opex	Removal	Total
Mink St Substation (T-Line)	$0.500	$0.000	$0.000	$0.500
Mink St Substation (T-Sub)	$3.500	$0.020	$0.220	$3.740
Phillipsdale Substation (T-Sub)	$9.000	$0.600	$0.080	$9.680
Phillipsdale Substation (D-Sub)	$3.550	$0.400	$0.350	$4.300
Phillipsdale Substation (D-Line)	$2.250	$0.050	$0.160	$2.460
Kent Corners Substation (D-Sub)	$3.600	$0.400	$0.350	$4.350
Kent Corners Substation (D-Line)	$10.200	$0.800	$2.600	$13.600
Rumford Substation (D-Sub)	$3.600	$0.360	$0.000	$3.960
Rumford Substation (D-Line)	$1.450	$0.050	$0.400	$1.900
Warren Substation (D-Sub)	$2.835	$0.300	$0.025	$3.160
Barrington Substation (D-Sub)	$1.800	$0.180	$0.020	$2.000
Waterman Sub (D-Sub)	$0.000	$0.030	$0.320	$0.350
Plan 2 (T-Spend)	$13.000	$0.620	$0.300	$13.920
Plan 2 (D-Spend)	$29.285	$2.570	$4.225	$36.080
Total Spend	$42.285	$3.190	$4.525	$50.000

5.4.2 Plan – 3

This plan is a hybrid of Plan 1 and Plan 2. It includes expanding the 23kV sub-transmission system to supply both existing and new 23/12.47kV distribution substations and includes expanding the 115kV system to supply a new 115/12.47kV station at Phillipsdale. The following are the major modifications proposed:

Construct a new 115/12.47kV Station at Phillipsdale

This option would build a new 115/12.47kV substation at Phillipsdale. Initial construction would consist of a single 40MVA LTC transformer, straight-bus metal-clad switchgear, a 7.2 MVAR station capacitor bank, and four feeder positions. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, two 7.2MVAR capacitor banks, and eight feeder positions. A one line of this proposed station is shown in Appendix 9.10. The station would be supplied from the 115kV lines, X-3 and E-183W. The four new feeders from this station would:

- Replace the 23/12.47kV non-standard construction at Phillipsdale with standard substation equipment, address the asset condition concerns, and provide capacity to supply new customers in the northern section of the City of East Providence.
- Eliminate out-of-phase feeder ties by correcting the voltage phasing. This would increase switching flexibility, reduce restoration time, and improve reliability since customers would not be exposed to short outages during switching.
- Retire Waterman substation to address asset condition concerns, eliminate the need for a major investment to upgrade the 23kV supply system, eliminate the out-of-phase feeder ties that exist at Waterman, and eliminate the need to build a new 115/23kV station at Mink Street.
- Reduce load on the 115/23kV station at Phillisdale from 30MW to 3MW. The long-term strategy would be to convert the two remaining 23kV customers to 12.47kV and to retire the 23kV station. This eliminates a major investment on the 23kV station to address the asset condition and obsolete equipment concerns.

The new feeders would be routed along city streets in new manhole and ductline infrastructure. Five industrial customers would be converted from the 23kV system to the 12.47kV system. This conversion eliminates circuits installed in a difficult to access right-of-way adjacent to the railroad corridor, and eliminates a major investment to address the poor condition of the pole plant along this 23kV right-of-way.

The customers to be converted to 12.47kV are: Hasbro with (3) 500kVA transformers; Handy Harmon with (3) 667kVA transformers; Cape Cod Ice with (3) 333kVA transformers; BA Ballou with (3) 500kVA transformers; and Nyman Manufacturing which is primary metered customer with 1.70MW of peak.

Install two new 23/12.47kV Feeders at Kent Corners substation

Plan 3 would install two new 23/12.47kV modular feeders at Kent Corners substation. The new feeders would provide capacity to relieve the heavily loaded distribution system in the area, address MWh violations, and provide capacity to supply new load growth. Investment would also eliminate the small pocket of 4.16kV load in the study area by retiring the existing Kent Corners 23/4.16kV station. A one-line of the proposed station is shown in Appendix 9.10.

Build new 115/23kV Substation at Mink Street[3]

A new 115/23kV substation would be built at Mink Street to supply Kent Corners and Barrington substations. Construction would consist of a single 40MVA transformer supplying a single 23kV line. The station would be supplied by an existing 115kV line at Mink Street. A one-line of the proposed station is shown in Appendix 9.10.

[3] Mink Street 115/23kV substation will be located in Massachusetts and supply customers in Rhode Island. It will be built, owned, and operated by the New England Power Company (NEPCo). An appropriate rate recovery mechanism needs to be developed. Rate recovery could occur thru a Transmission Rate Tariff or thru a Direct Assignment Charge. A Local Service Agreement may also need to be filed with the Federal Energy Regulatory Commission (FERC). If this plan were to be implemented, the legal department will be consulted to determine the most appropriate rate recovery mechanism for these assets.

Address Concerns at Barrington Substation

Plan 3 would address asset and safety concerns with Barrington substation. The sacrificial air break on the station transformer would be replaced with a circuit switcher, the bus work and taps would be raised to comply with current standards, the 4F2 VSA recloser would be replaced to address asset condition concerns and EMS would be installed at the station.

Upgrade and Reinforce the 23kV Sub-Transmission System:

The 23kV sub-transmission system from Mink Street consists of a mixture of 336 Al, 2/0 Cu and 1/0 Cu wire. This system is not adequate to supply the proposed Kent Corners and Barrington substations. To supply these stations the small wire would have to be replaced with 795 Al open wire. Construction would consist of approximately 7.5 miles of double circuited roadway infrastructure along highly utilized and congested streets. This would require replacement of all the aged pole plant to meet current standards and to accommodate the larger wire size.

The normal supply to Barrington substation would be from the Warren 115/23kV station, a station with numerous asset condition concerns. As part of this plan, the asset condition concerns at Warren would be addressed. The 23kV breakers would be replaced along with all the obsolete pin type bus insulators. The obsolete protection would be upgraded and relocated from the old control house to the new control house. A one line of the proposed 23kV supply system is shown in Appendix 9.10.

This plan results in a comprehensive solution for the East Bay area and addresses all asset condition, safety, and reliability concerns. Plan addresses all thermal concerns, provides capacity to supply load growth, and addresses all distribution planning criteria violations. The required investments and expenses for Plan 3 are detailed in Table 5.3.2 below.

TABLE 5.4.2 – Estimated Investments and Expenses for Plan 3:

Investment Description ($M)	Capex	Opex	Removal	Total
Phillipsdale Substation (T-Line)	$0.400	$0.000	$0.000	$0.400
Phillipsdale Substation (T-Sub)	$0.300	$0.000	$0.000	$0.300
Phillipsdale Substation (D-Line)	$4.430	$0.120	$0.545	$5.095
Phillipsdale Substation (D-Sub)	$6.020	$0.600	$0.380	$7.000
Kent Corners Substation (D-Sub)	$3.600	$0.400	$0.350	$4.350
Kent Corners Substation (D-Line)	$10.300	$0.800	$2.600	$13.700
Mink St Substation (T-Line)	$0.500	$0.000	$0.000	$0.500
Mink St Substation (T-Sub)	$3.500	$0.020	$0.220	$3.740
Mink St Substation (D-Line)	$0.600	$0.000	$0.000	$0.600
Warren Substation (D-Sub)	$2.840	$0.300	$0.025	$3.160
Barrington Substation (D-Sub)	$1.800	$0.180	$0.020	$2.005
Waterman Sub (D-Sub)	$0.000	$0.030	$0.320	$0.350
Plan 1 (T-Spend)	$4.700	$0.020	$0.220	$4.940
Plan 1 (D-Spend)	$29.590	$2.430	$4.240	$36.260
Total Spend	$34.290	$2.450	$4.460	$41.200

5.4.3 Do Nothing

Taking no action would leave all the problems mentioned in Section 4 unaddressed. Violations of the Distribution Planning Criteria would continue to exist and worsen as time goes by, adversely affecting customer service and reliability performance.

Taking no action could make supplying new customer loads very challenging and could result is the company operating the system above its rated capability.

6. Plan Considerations and Comparisons

6.1 Economic, Schedule, and Technical Comparisons

The estimated investments and expenses for the three Plans are shown in Table 6.1 below. The economic comparisons exclude the cost of common items.

TABLE 6.1 – Estimated Investments and Expenses for Plan 1, Plan 2, and Plan 3

	PLAN 1				PLAN 2				PLAN 3			
Description	Capex	Opex	Rem.	Total	Capex	Opex	Rem.	Total	Capex	Opex	Rem.	Total
East Bay (T-Line)	$0.80	$0.02	$0.01	$0.83	$0.50	$0.00	$0.00	$0.50	$0.90	$0.00	$0.00	$0.90
East Bay (T-Sub)	$0.60	$0.00	$0.00	$0.60	$12.50	$0.62	$0.30	$13.42	$3.80	$0.02	$0.22	$4.04
East Bay (D-Sub)	$15.50	$1.52	$1.85	$18.87	$15.29	$1.67	$1.13	$18.08	$14.29	$1.53	$1.14	$16.96
East Bay (D-Line)	$14.80	$0.60	$2.00	$17.40	$14.00	$0.90	$3.10	$18.00	$15.30	$0.90	$3.10	$19.30
TOTAL	$31.70	$2.14	$3.86	$37.70	$42.29	$3.19	$4.53	$50.00	$34.29	$2.45	$4.46	$41.20

Plan 1 is least sensitive to load growth and offers the most flexibility for future expansion. It eliminates most of the 23kV supply system installed along the roadway and with significant exposure to motor vehicle accidents and tree related outages. It adds new distribution capacity supplied from a more reliable 115kV system with little exposure to motor vehicle accidents and tree related outages. It has flexibility to add additional distribution feeders with a minimal investment on the supply system and with minimal permitting.

Plan 2 is the most sensitive to load growth. It upgrades the 23kV system to supply new 23/12.47kV distribution stations. The 23kV supply upgrades would consist of predominantly highly congested roadway construction and be limited to 795 aluminum open wire, which limits the capacity to 35MVA. Once this capacity is reached, the only economical approach would be to utilize the 115kV transmission system to supply new distribution stations. The 23kV supply system would have exposure to motor vehicle accidents and tree related outages due to the roadway construction. Although beyond the 15 year study horizon, this plan only defers the eventual need to implement portions of Plan 1 once the capacity of the 23kV supply system is utilized.

Plan 3 is a hybrid of Plan 1 and Plan 2. It is less flexible than Plan 1 but more flexible than Plan 2. It installs a new station supplied from the 115kV system and new distribution capacity supplied from a reinforced 23kV system. The 23kV supply would consist of predominantly roadway construction and be limited to 795 aluminum open wire, which limits the capacity to 35MVA. As with Plan 2, once this capacity is reached, the only economical approach would be to utilize the 115kV system to supply new distribution stations. The 23kV supply system would have exposure to motor vehicle accidents and tree related outages due to the roadway construction.

6.2 Non-Wires Alternatives Considerations

Where an issue has been identified, a Non-Wires Alternative may also be considered as an option to defer a transmission, sub-transmission, or distribution wires solution for a period of time. Considering Non-Wires Alternatives to every wires solution is not practical given the low cost of a large volume of potential wires solutions, the magnitude of load relief required in certain situations, the time to acquire Non-Wires Alternatives (and verify their availability) or instances where the issue is poor operating condition of the asset. As a result, Non-wires Alternatives are screened against the following four guidelines:

A. The Wires solution, based on Engineering judgment, will likely be more than $1M;
B. If load reduction is necessary, then it will be less than 20 percent of the total load in the area of the defined need;
C. Start of construction is at least 36 months in the future; and
D. The need is not based on Asset Condition.

Although the plans developed for this study will exceed $1M and the start of construction for the majority of the work will be at least 36 months in the future, there are significant asset condition issues within the study area as described in Section 4.3. Therefore Non-Wires Alternatives are not considered feasible to provide a comprehensive study area solution.

However, a Non-Wires solution could be investigated to address the contingency load-at-risk issues in Bristol and Warren in lieu of installing a new feeder at Bristol substation and upgrading the feeders at Warren substation. This solution, common to all plans (see Section 5.1), does not have an asset condition component. Since this investment is recommended in the outer years of the study (see Section 7.0), it provides sufficient lead time to investigate the feasibility of a non-wires solution for the area.

6.3 Permitting, Licensing, Real Estate, and Environmental Considerations

Common to all plans is permitting for distribution line poles. Depending on the town, these poles will be set either by Verizon or by National Grid. Pole sets for Plan 1 would consist of routine requests and standard construction and no major obstacles are expected. Plan 2 and Plan 3 would require upgrading the 23kV supply system with 795 bare aluminum conductors and would have 12.47kV distribution under-build. This construction would occur along highly congested public roadways and could face opposition from the Town of Barrington and the City of Providence. Guying this type of construction may require private property easements which could be challenging to obtain and could increase the cost of the plans.

The Warren 115/12.47kV substation was initially permitted for six feeders. Therefore, the addition of two feeders at this station should be routine with no major issues anticipated. The station SPCC plan will need to be updated with the additional equipment. The new Warren feeders would be routed to Barrington. The feeders would utilize a bridge crossing and underground infrastructure to be built on a bike path as part of a Department of Transportation

(DOT) bridge rebuild project. The company is currently coordinating the bridge crossing with the DOT bridge rebuild project.

The option to build a new 115/12.47kV station at Phillispdale has been reviewed at a conceptual level. Space at the station is limited, however, it is anticipated that sufficient space exists to build the proposed station. Construction of the new station will impact the existing 23/12.47kV station which needs to remain in-service during construction. It is anticipated that some of the existing equipment will need to be temporarily relocated while the new station is built. The existing station SPCC plan will need to be revised due to the new station.

The proposed 115/12.47kV station on First Street in East Providence will be built on a gas company owned site. The station will be supplied by a short tap from the 115kV line running thru the property. The 115kV tap will require a notification to the Rhode Island Energy Facility Siting Board (EFSB). The company is in the process of placing an Environmental Land Use Restriction (ELUR) on this site but it will not restrict the property from being used as a substation. The City of Providence has requested the company investigate undergrounding the 115kV line, E183W, to Franklin Square substation. One option is to install the E183W line riser structure at this site. The site appears to be large enough to accommodate both undergrounding the 115kV line and the proposed substation. Both projects will need to be coordinated.

The former Rumford substation site used to house a 23/4.16kV substation and has two 23kV supply lines running behind the site. This site is presently undeveloped. There are no major obstacles anticipated at this time that would prohibit the use of this site to install the proposed 23/12.47kV modular feeders and new taps from the 23kV supply lines.

Kent Corners substation is located in a small parcel of land as is located within a congested residential area. The proposed installation of two modular feeders at this station could face local opposition. In addition, the existing 4.16kV station would have to remain in service while the new 23/12.47kV modular feeders are being constructed which could impact the ability for the company to screen the station from the neighborhood. There have been numerous complaints about transformer noise at the station. Any construction at this location could result in potential neighborhood opposition.

6.4 Planned Outage Considerations

All three plans require work on 115kV supplied stations. Plan 1 and Plan 3 require tapping 115 kV transmission lines. Any required 115kV line outages will have to be coordinated with ISO-NE.

The existing Phillipsdale 23/12.47kV substation will have to remain in-service while the new 115/12.47kV substation at Phillipsdale in energized. This will required relocating some of the 12.47kV circuits. A preliminary review has not identified any major concerns with these relocations.

6.5 Asset Physical Security Considerations

National Grid Security department will be consulted during the design process for the new substations. Recommendations for improved security at existing area substations will also be solicited and incorporated.

6.6 System Loss Analysis

A loss analysis was conducted to compare Plan 1 to the existing system. The purpose of this comparison was to check that the recommended plan reduced losses, and by such a result would create a more efficient system. Table 6.6 demonstrates over 1MW of peak load loss savings with Plan 1.

TABLE 6.6 – Megawatt Loss Savings Analysis

Voltage Level	Existing Configuration	Plan 1 Configuration	MW Loss Savings
115kV	2.42	2.43	**-0.01**
23kV	0.99	0.27	**0.72**
12.47kV	4.96	4.79	**0.17**
4.16kV	0.28	0	**0.28**
Total	**8.65**	**7.49**	**1.16**

7. Conclusions and Recommendations

The three plans provide a comprehensive solution for the area and address all asset condition, safety, and reliability concerns. The plans address thermal loading concerns, provide capacity to supply new load growth, and addresses distribution planning criteria violations thru the study horizon period of 2030.

Plan 1 is recommended for implementation. Plan 1 provides a comprehensive solution to address all the concerns in the study area at least cost. The total cost of plan 1 is $37.70M which is $13.00M lower in cost then Plan 2 and $3.50M lower in cost than Plan 3.

Plan 1 is least sensitive to load growth and offers the most flexibility for future expansion. Plan eliminates most of 23kV supply system consisting of predominantly roadway construction with exposure to motor vehicle accidents and tree related outages. When needed, additional distribution capacity can be added with a minimal investment on the supply system and minimal permitting impact. The recommended capital spending by fiscal year for Plan 1 is shown in Table 7.0 below:

TABLE 7.0: Recommended Capital Spend by Fiscal Year:

Description	FP	TOTAL	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27
East Providence Sub (T-Line)	C049819	$0.40	0.00	0.02	0.08	0.12	0.12	0.06				
East Providence Sub (T-Sub)	C049820	$0.30	0.00	0.02	0.06	0.09	0.09	0.04				
East Providence Sub (D-Sub)	C046726	$6.00	0.06	0.30	1.20	1.80	1.80	0.84				
East Providence Sub (D-Line)	C046727	$7.40	0.07	0.37	1.48	2.22	2.22	1.04				
Warren Sub Expansion (D-Sub)	C065166	$3.50	0.04	0.18	0.70	1.05	1.05	0.49				
Warren Sub Expansion (D-Line)	C065187	$3.70	0.04	0.19	0.74	1.11	1.11	0.52				
Mink Street 23kV Retirement (D-Sub)	C065806	$0.00										
Barrington Sub Retirement (D-Sub)	C065293	$0.00										
Kent Corners Retirement (D-Sub)	C065295	$0.00										
Waterman Ave Re irement (D-Sub)	C065297	$0.00										
Phillipsdale Sub (T-Line)		$0.40				0 00	0.02	0.08	0.12	0.12	0 06	
Phillipsdale Sub (T-Sub)		$0.30				0 00	0.02	0.06	0.09	0.09	0 04	
Phillipsdale Sub (D-Sub)		$6.00				0 06	0.30	1.20	1.80	1.80	0 84	
Phillipsdale Sub (D-Line)		$3.72				0 04	0.19	0.74	1.11	1.11	0 52	
Common Items		$1.21							0.11	0.20	0 50	0.40
T-Spend		$1.40	$0.01	$0.04	$0.14	$0.22	$0.25	$0.24	$0.21	$0 21	$0.10	$0.00
D-Spend		$31.53	$0.21	$1.03	$4.12	$6.28	$6.67	$4.83	$3.02	$3.11	$1.86	$0.40

8. Factors Influencing Futures Studies

Unexpected significant load growth is one factor that could affect future studies. The recommended plan initially installs a single transformer and four feeders at Phillipsdale and East Providence substations. However, both substations will be permitted for two transformers and eight feeders. At least eight additional feeders (or approximately 80MW of distribution capacity) can be installed to accommodate unexpected future load growth.

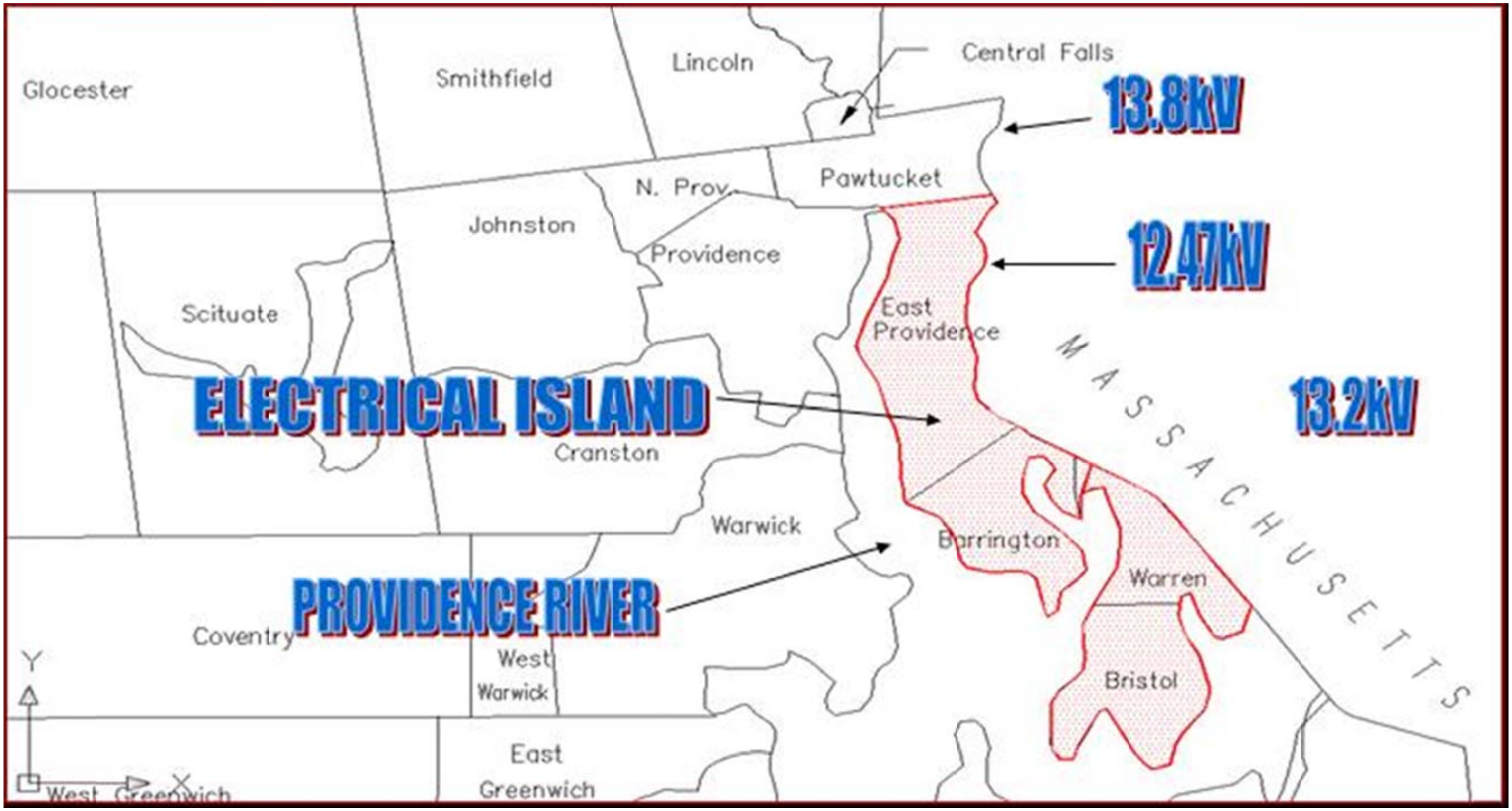
The Phillipsdale 115/23kV substation has numerous asset condition concerns which are being deferred. Loading on the 23kV station will be reduced to approximately 3MW and the station will supply only two industrial customers. It is recommended that this area be reviewed in the next few years and consideration be given to fully retire Phillipsdale 23kV station in lieu of performing any major asset replacement work.

A transmission study is currently being performed for the Southeastern Massachusetts and Rhode Island area. One potential plan involves extending the 115kV line from Bristol substation to Aquidneck Island. This will provide an option to eliminate the 23kV supply to Bristol substation and allow for the retirement of the 23kV station at Warren. If this transmission investment is to occur, it is recommended that any asset replacement work at the Warren 23kV station be compared against supplying Bristol substation with a second 115kV line. Even today, for various n-1 contingencies, the 23kV line is not capable of supplying the full Bristol load.

9. Appendix

9.1 Area Maps

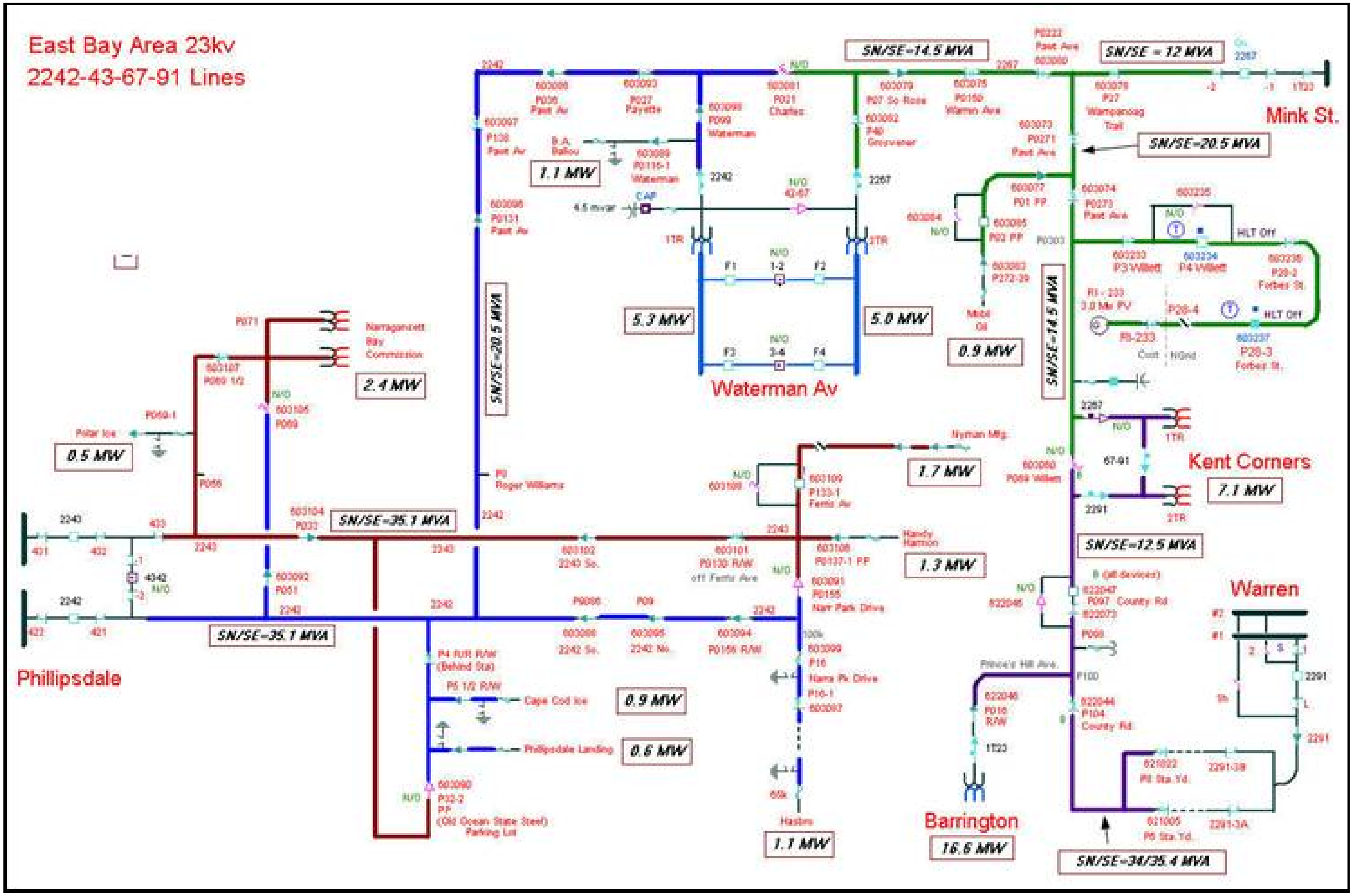
FIGURE 9.1.1 – STUDY AREA



9.2 One Line Diagrams

[redacted]

FIGURE 9.2.2 – 23kV SUPPLY SYSTEM ONE-LINE DIAGRAM



[redacted]

FIGURE 9.2.4 – BARRINGTON SUBSTATION ONE-LINE DIAGRAM

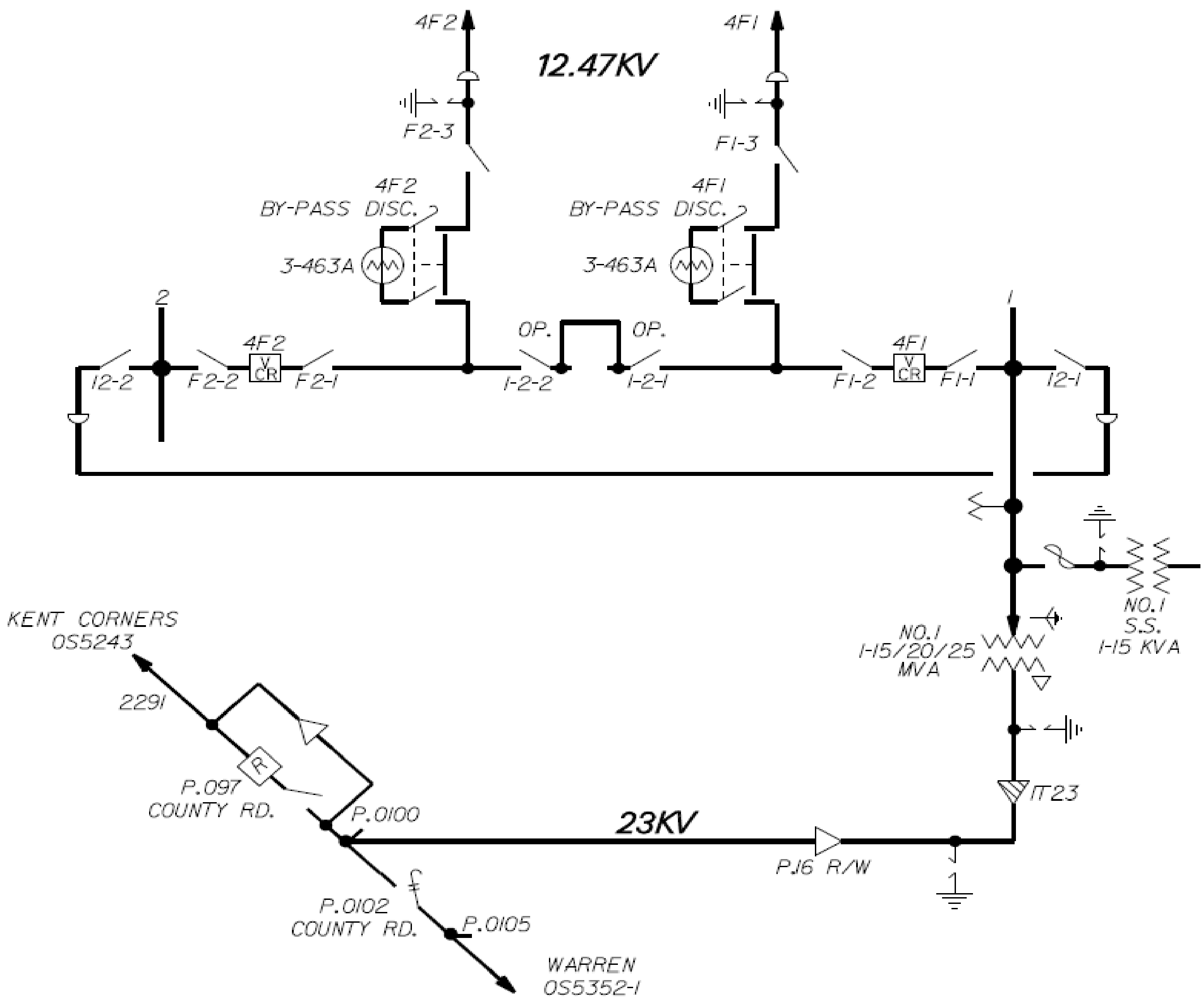


FIGURE 9.2.5 – KENT CORNERS SUBSTATION ONE-LINE DIAGRAM

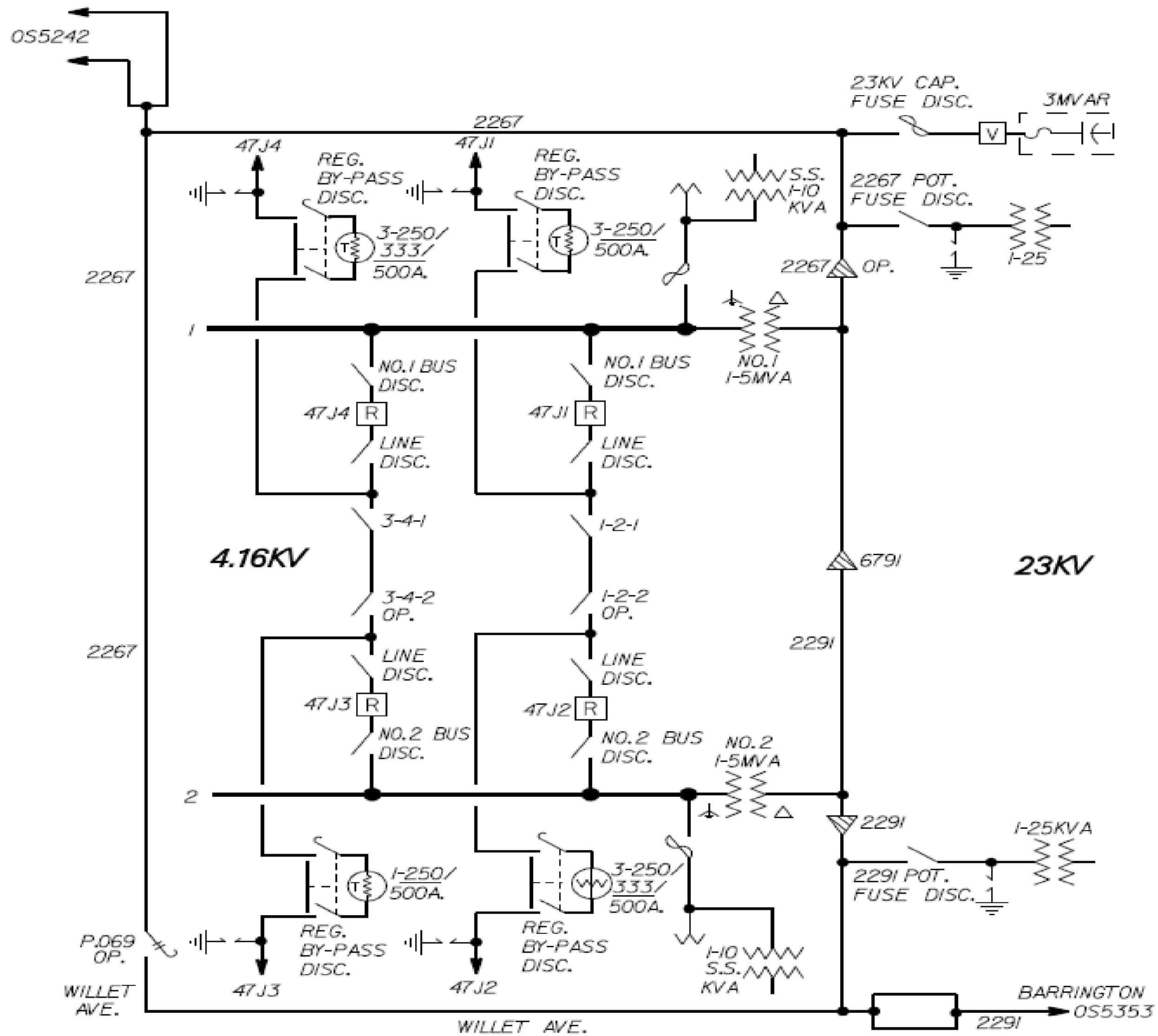
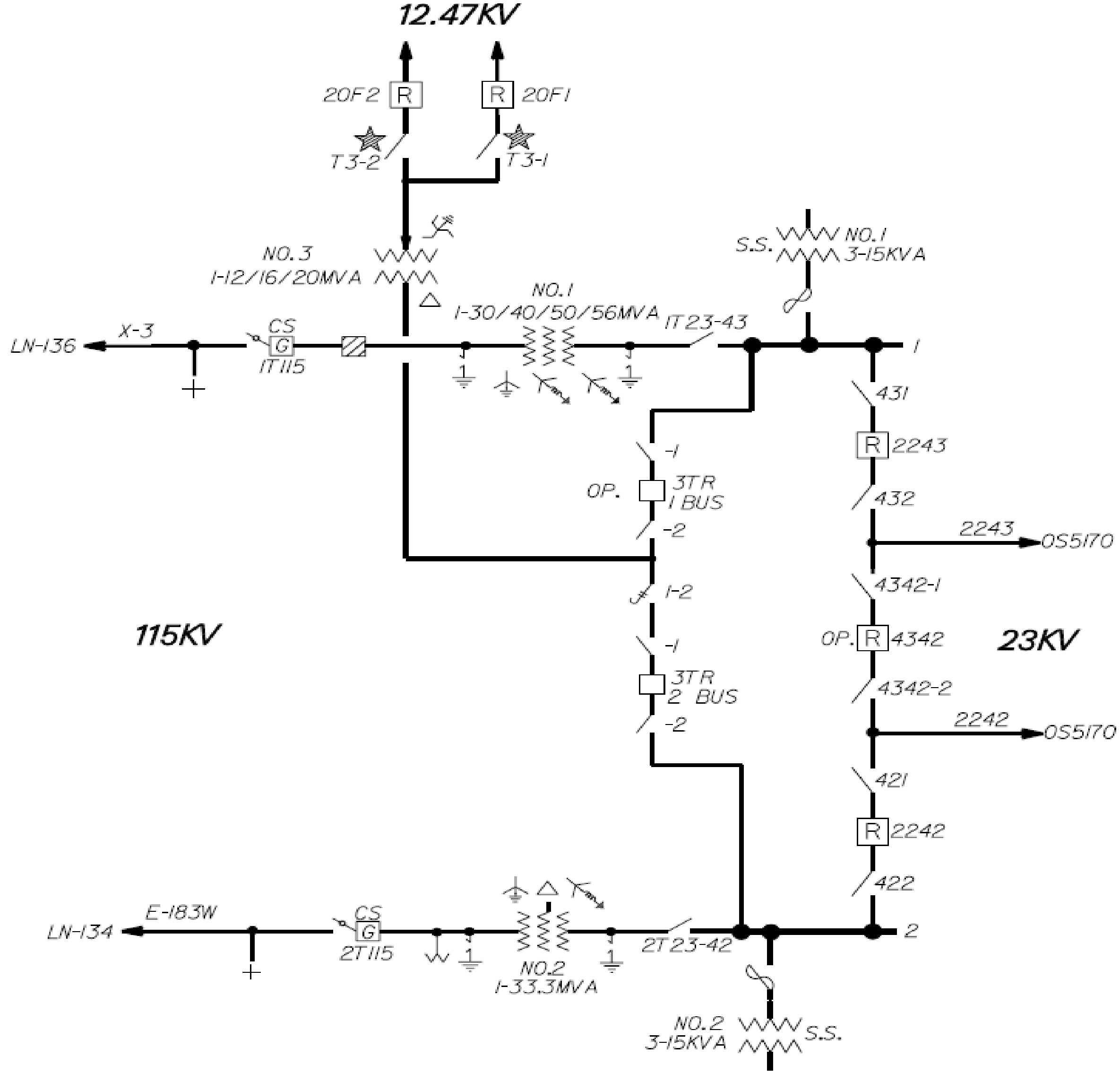
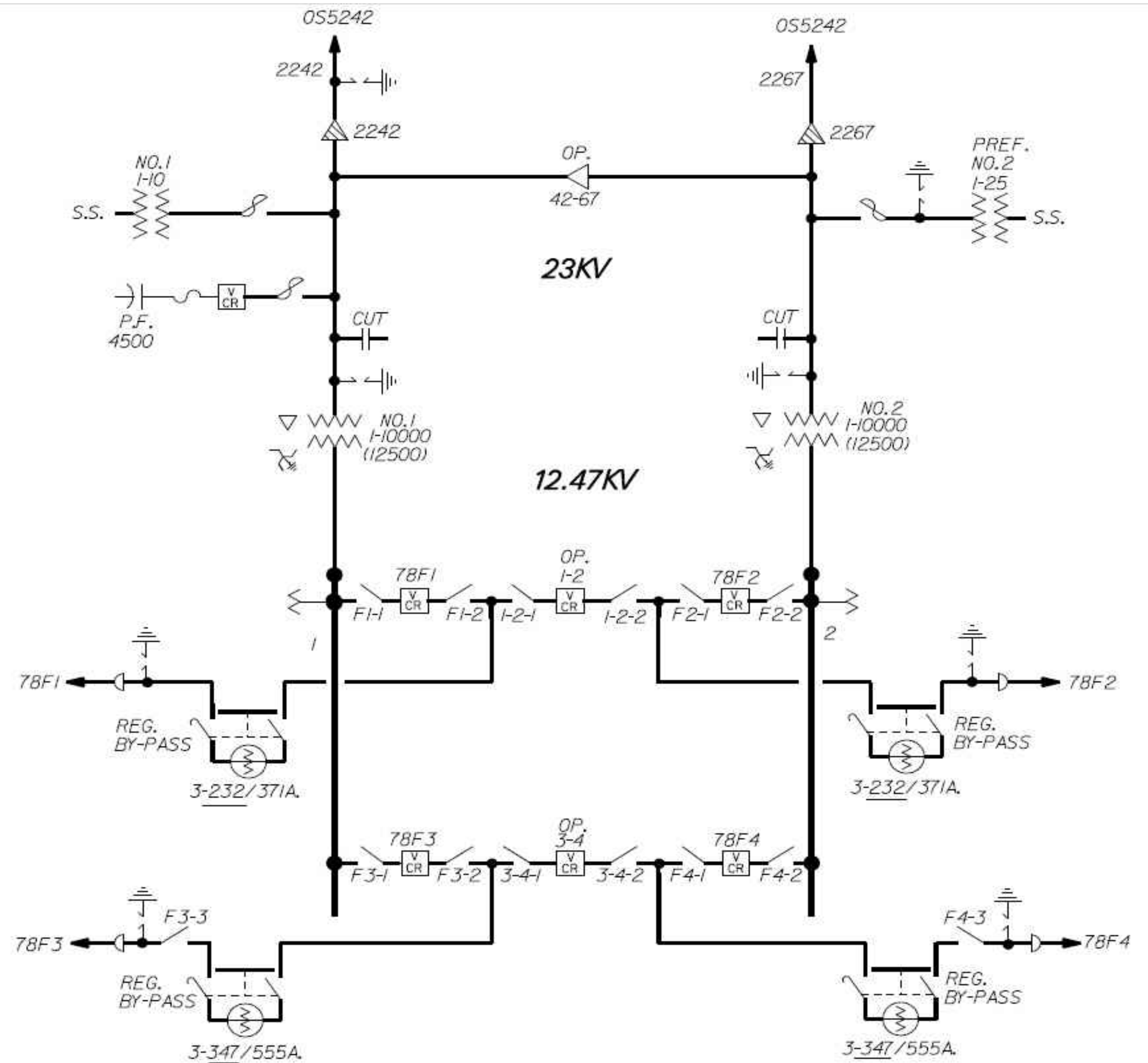


FIGURE 9.2.6 – PHILLIPDALE SUBSTATION ONE-LINE DIAGRAM



[redacted]

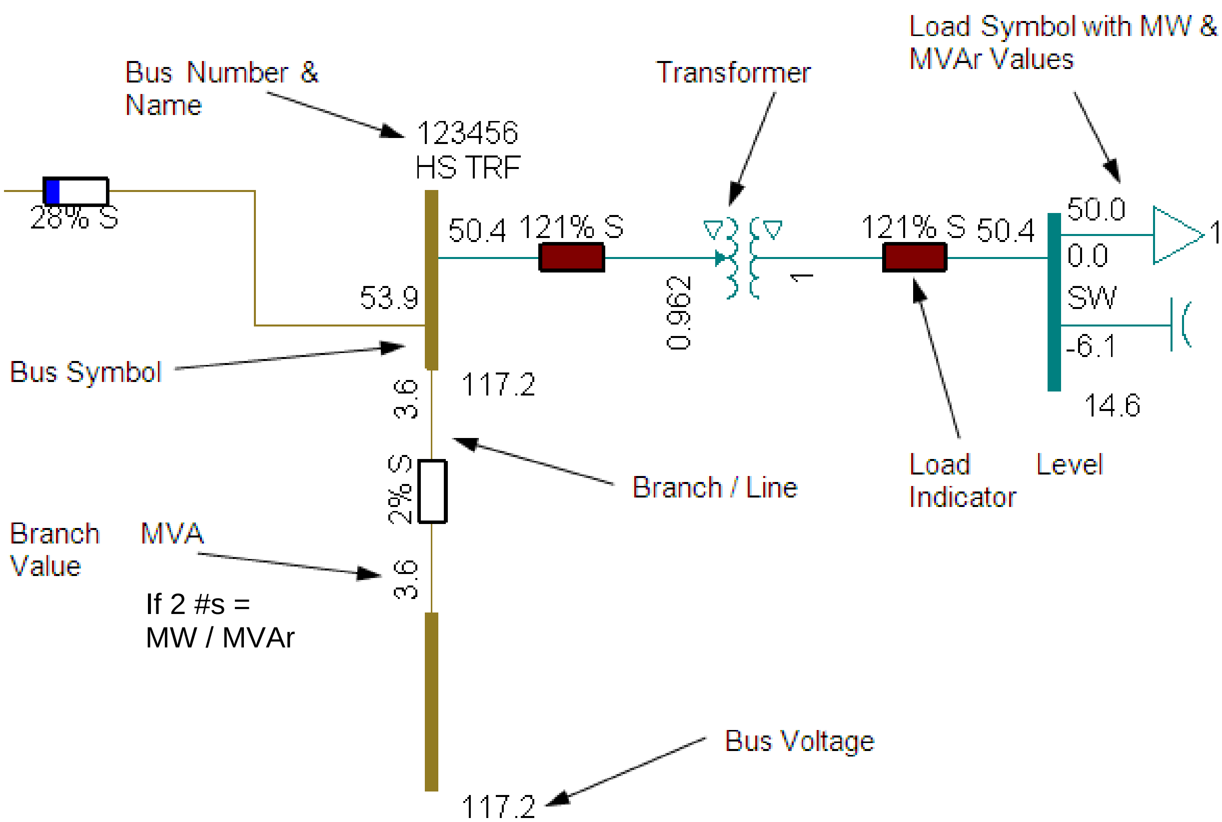
FIGURE 9.2.8 - WATERMAN SUBSTATION ONE-LINE DIAGRAM



9.3 Loadflow Diagrams

This section contains the electrical one-line loadflow diagrams. The diagrams show transformer and subtransmission power flows throughout the study area. Included below are notes and guides to assist the review of these diagrams.

General Layout



LEGEND
Green = 5kV Class Equipment
Blue-Gray = 15kV Class Equipment
Aqua = 25kV Class Equipment
Tan = 35kV Class Equipment
Salmon = 46kV Class Equipment
Green = 69kV Class Equipment
Brown = 115kV Class Equipment

[redacted]

[redacted]

[redacted]

[redacted]

9.4 CYME Radial Distribution Analysis Diagrams

Figure 9.4.1 – CYME East Bay Existing Configuration – :ircuit Arrangement

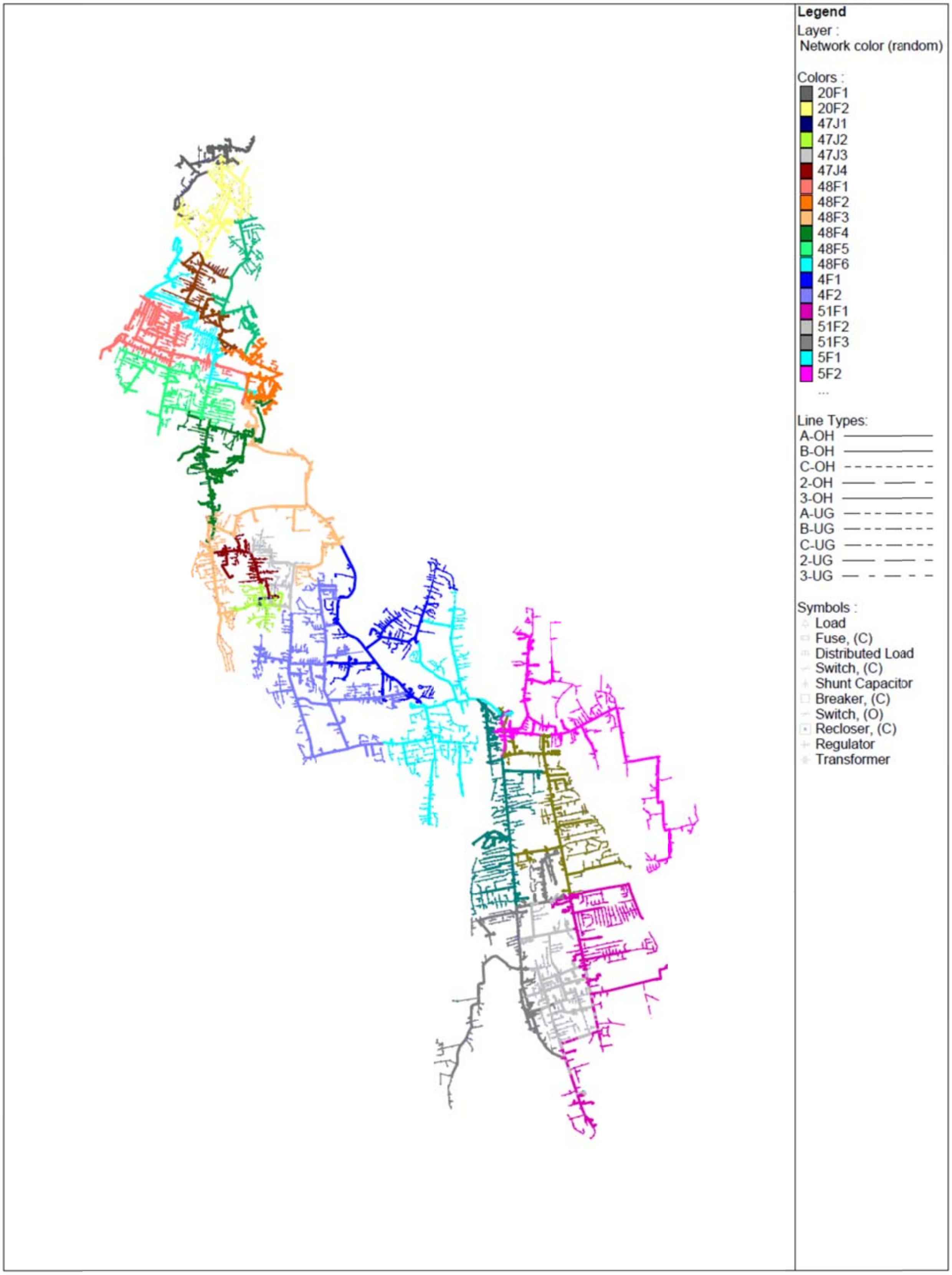


Figure 9.1.2 – CYME East Bay Existing Configuration – Loading Analysis

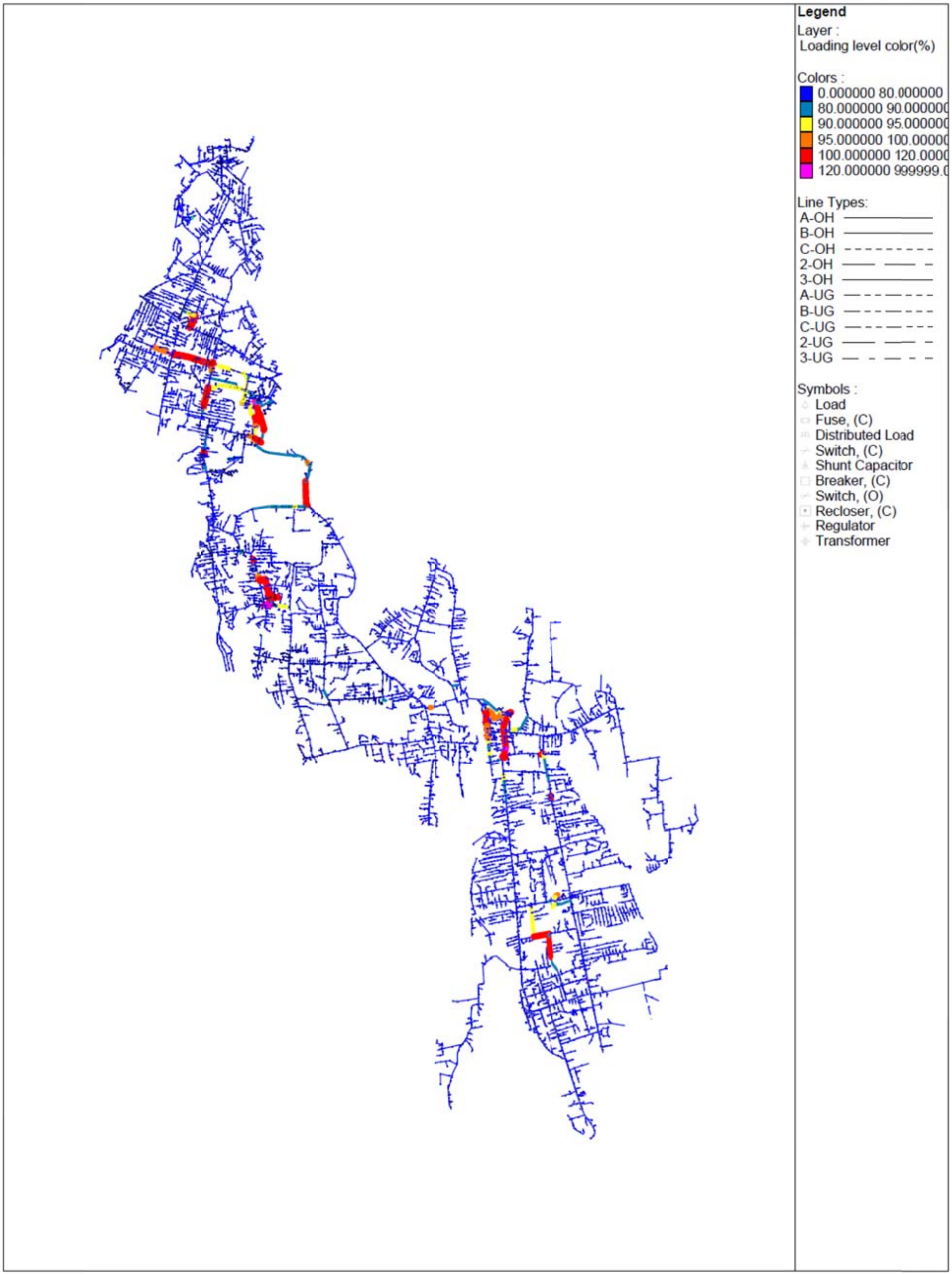


Figure 9.4.3 – CYME East Bay Existing Co figuration – Voltage Analysis

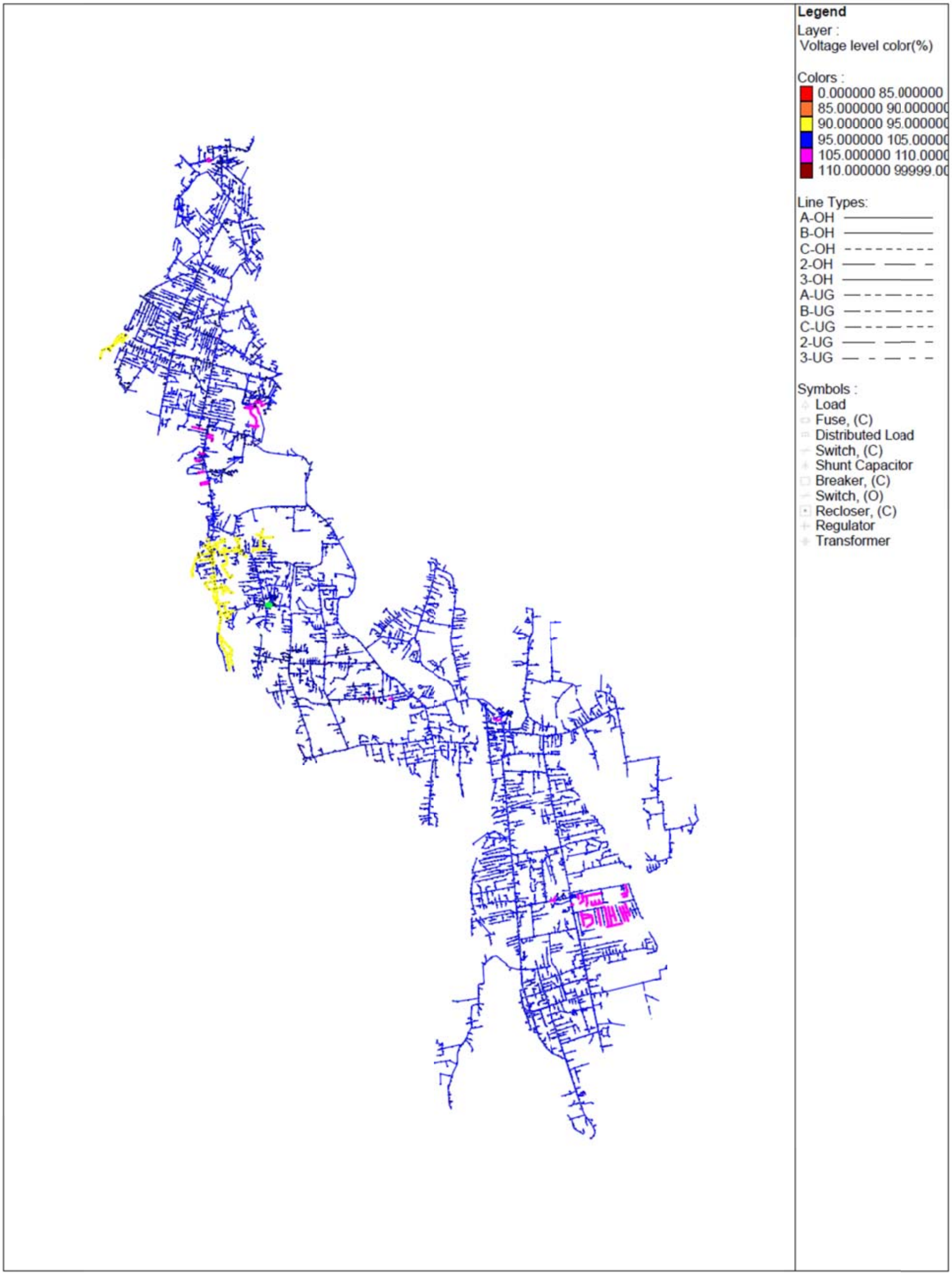


Figure 9. .4 – CYME East Bay Plan 1 Configuration – C rcuit Arrangement

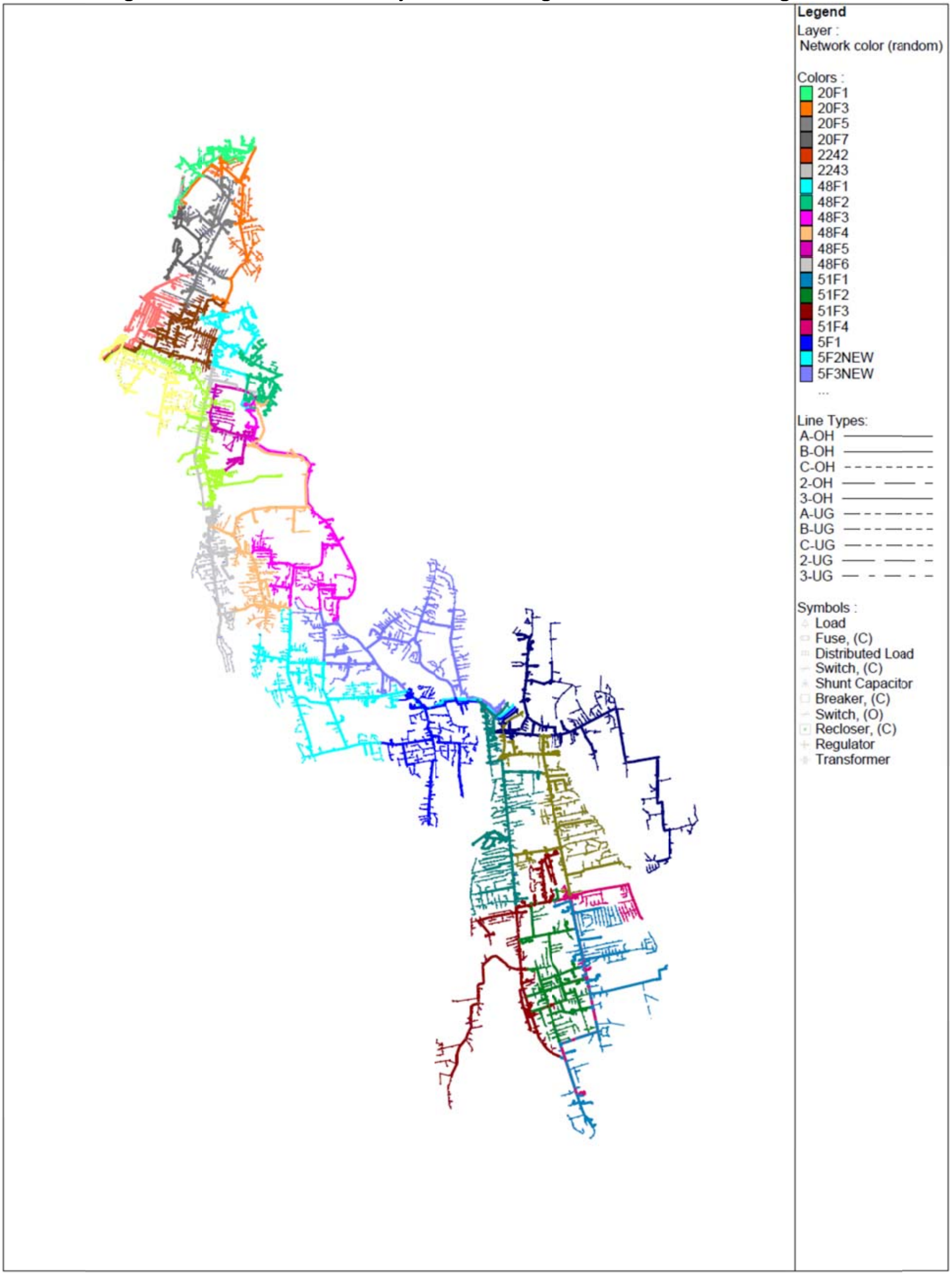


Figure 9.4.5 – CYME East Bay Plan 1 Configuration – Loading Analysis

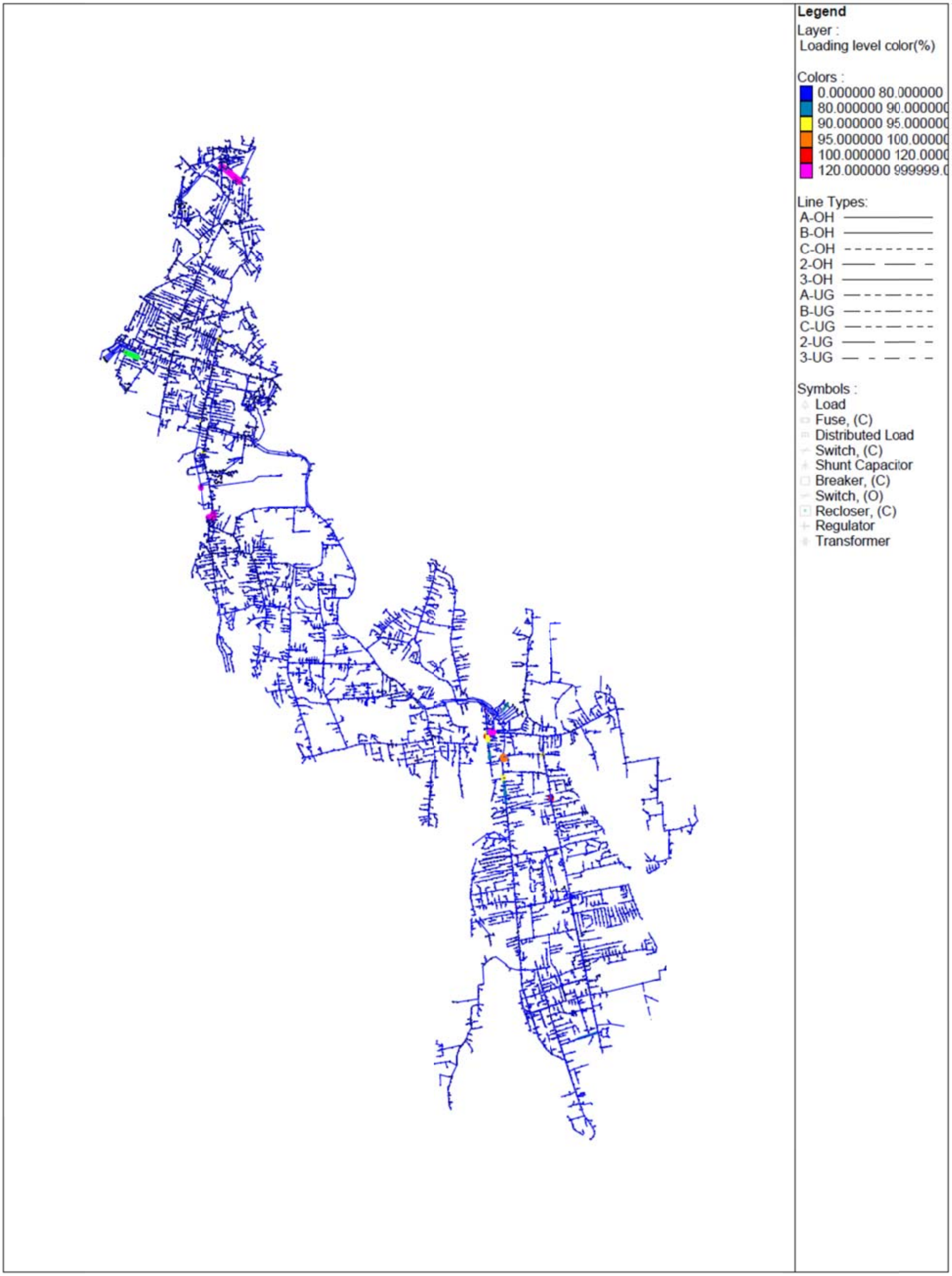
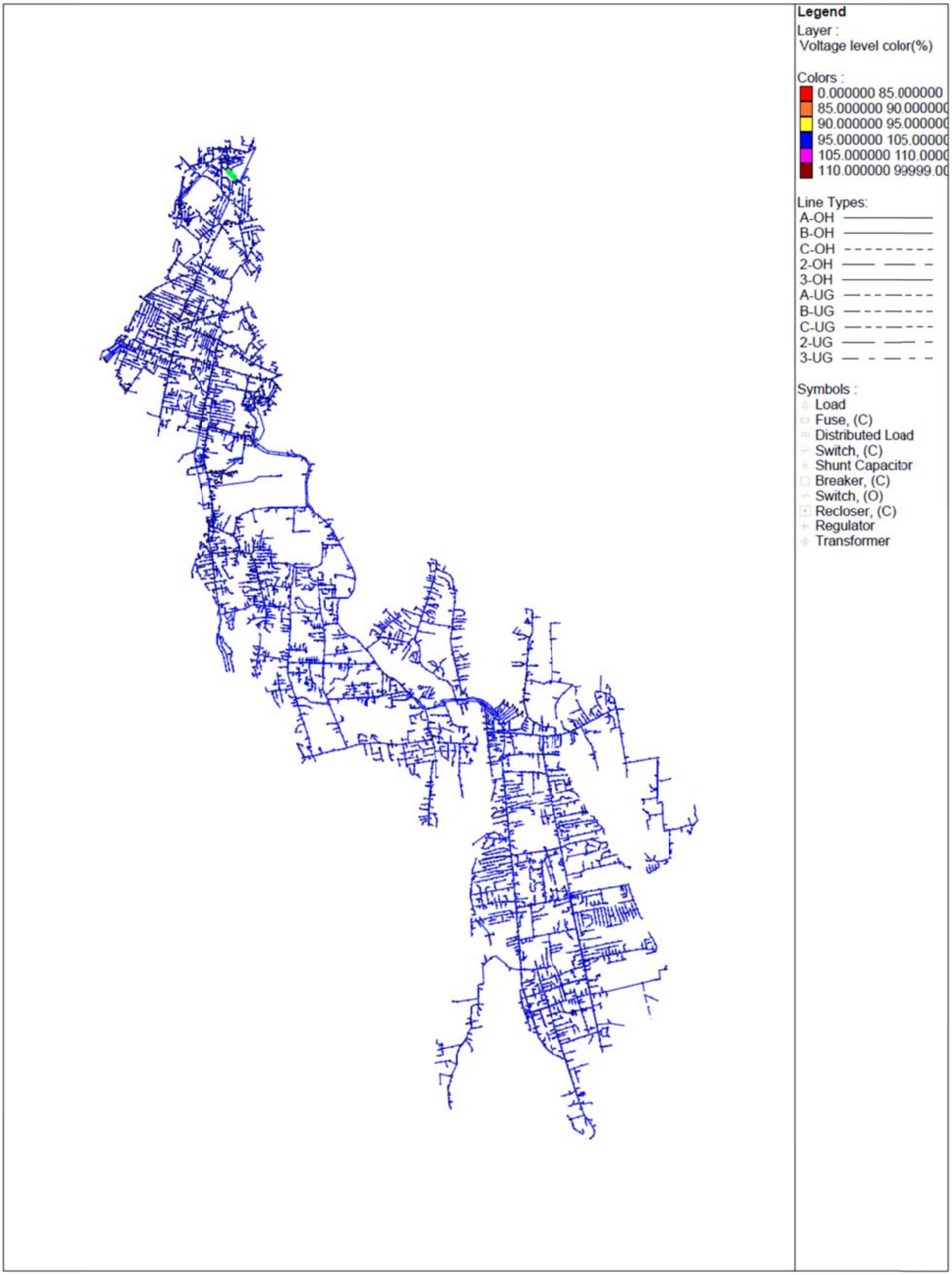


Figure 9.4.6 – CYME East Bay Plan 1 Configuration – Voltage Analysis



9.5 Arc Flash Analysis

Substation	Feeder	Voltage (kV)	LG Fault Current (Amps)	Clearing Time (secs)	Incident Energy (cal/cm^2)
BARRINGTON 4	4F1	12.47	4,972	0.2269	1.16
BARRINGTON 4	4F2	12.47	5,011	0.1404	0.73
BRISTOL 51A	51F2	12.47	4,590	0.3278	1.51
BRISTOL 51A	51F1	12.47	6,275	0.2951	2.07
BRISTOL 51A	51F3	12.47	6,797	0.3947	3.09
KENTS CORNER 47	47J2	4.16	7,673	0.1553	1.44
KENTS CORNER 47	47J1	4.16	7,756	0.1562	1.47
KENTS CORNER 47	47J3	4.16	7,872	0.1555	1.49
KENTS CORNER 47	47J4	4.16	8,142	0.1509	1.51
PHILLIPSDALE 20	20F2	12.47	4,711	0.2222	1.06
PHILLIPSDALE 20	20F1	12.47	4,712	0.1656	0.79
WAMPANOAG 48	48F5	12.47	6,077	0.3043	2.05
WAMPANOAG 48	48F6	12.47	6,080	0.3042	2.05
WAMPANOAG 48	48F2	12.47	6,165	0.3001	2.06
WAMPANOAG 48	48F1	12.47	6,351	0.2918	2.09
WAMPANOAG 48	48F3	12.47	6,472	0.2210	1.62
WAMPANOAG 48	48F4	12.47	6,590	0.2825	2.12
WARREN 5	5F2	12.47	6,586	0.2215	1.66
WARREN 5	5F4	12.47	6,597	0.3949	2.97
WARREN 5	5F1	12.47	7,069	0.4716	3.90
WARREN 5	5F3	12.47	7,199	0.3176	2.69
WATERMAN AVENUE 78	78F4	12.47	4,348	0.1691	0.73
WATERMAN AVENUE 78	78F3	12.47	4,551	0.1466	0.67

9.6 Fault Duty Analysis

Substation	Description	Position	Operating kV	Rated IC (A)	3-Phase Fault (A)	1-Phase Fault (A)
Barrington 4	VSA-12	4F1 VCR	12.4	12,000	4,286	5,054
Barrington 4	VSA	4F2 VCR	12.4	12,000	4,286	5,054
Bristol 51	SDV	2T23 VCB	23	20,000	4,033	2,583
Bristol 51	PVDB1 15.5-20-2	51F1 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-2	51F2 VCB	12.4	20,000	3,869	4,660
Bristol 51	PVDB1 15.5-16-1	51F3 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-1	1-2 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-2	3-4 VCB	12.4	20,000	6,714	6,897
Bristol 51	PVDB1 15.5-20-2	51C2 VCB	12.4	20,000	3,869	4,660
Kents Corner 47	OZ-15-100	47J4 OCB	4.16	10,000	6,900	8,150
Kents Corner 47	OZ-210	47J3 OCB	4.16	10,000	6,900	8,150
Kents Corner 47	OZ-110	47J1 OCB	4.16	10,000	6,900	8,150
Kents Corner 47	OZ-210	47J2 OCB	4.16	10,000	6,900	8,150
Phillipsdale 20	23KS500-12C	3 TRF 2 BUS	23	18,000	8,890	1,101
Phillipsdale 20	FKD-25.8-11000	2243 OCB	23	11,000	8,890	1,101
Phillipsdale 20	SDO 23 500	2242 OCB	23	11,000	7,411	754
Phillipsdale 20	SDO 23 500	4342 OCB	23	11,000	8,890	1,101
Phillipsdale 20	FKD-25.8-11000-3	3 TR 1 BUS	23	18,000	8,890	1,101
Wampanoag 48	PVDB1 15.5	48F1 VCB	12.4	20,000	6,712	6,774
Wampanoag 48	PVDB1 15.5-16-1	48F2 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-16-1	48F3 VCB	12.4	20,000	6,712	6,774
Wampanoag 48	PVDB1 15.5-20-2	48F4 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	48F5 VCB	12.4	20,000	6,712	6,774
Wampanoag 48	PVDB1 15.5-20-2	48F6 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	1-2 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	3-4 VCB	12.4	20,000	7,120	7,190
Wampanoag 48	PVDB1 15.5-20-2	5-6 VCB	12.4	20,000	7,120	7,190
Warren 5	FKA-38-22000-6Y	5 TR OCB	23	22,000	16,463	16,280
Warren 5	345G1500	6 TR OCB	23	22,000	16,463	16,280
Warren 5	345G1500	2295 OCB	23	22,000	16,463	16,280
Warren 5	34.5KS1500-12D	2291 OCB	23	22,000	16,463	16,280
Warren 5	PVDB1 15.5-20-2	5F1 VCB	12.4	20,000	7311	7424
Warren 5	PVDB1 15.5-20-2	5F2 VCB	12.4	20,000	6652	6764
Warren 5	PVDB1 15.5-20-2	5F3 VCB	12.4	20,000	7311	7424
Warren 5	PVDB1 15.5-20-2	5F4 VCB	12.4	20,000	6652	6764
Warren 5	PVDB1 15.5-20-2	1-2 VCB	12.4	20,000	7311	7424
Warren 5	PVDB1 15.5-20-2	3-4 VCB	12.4	20,000	7311	7424
Waterman Ave 78	VSA-12	78F4 VCR	12.4	12,000	3920	2914
Waterman Ave 78	VSA	78F3 VCR	12.4	12,000	3920	2914
Waterman Ave 78	VSA	3-4 VCR	12.4	12,000	3920	2914

9.7 Plan Development – Common Items

[redacted]

9.8 Plan Development – Plan 1

FIGURE 9.8.1 – PHILLIPSDALE SUBSTATION ONE LINE-DIAGRAM (PLAN 1)

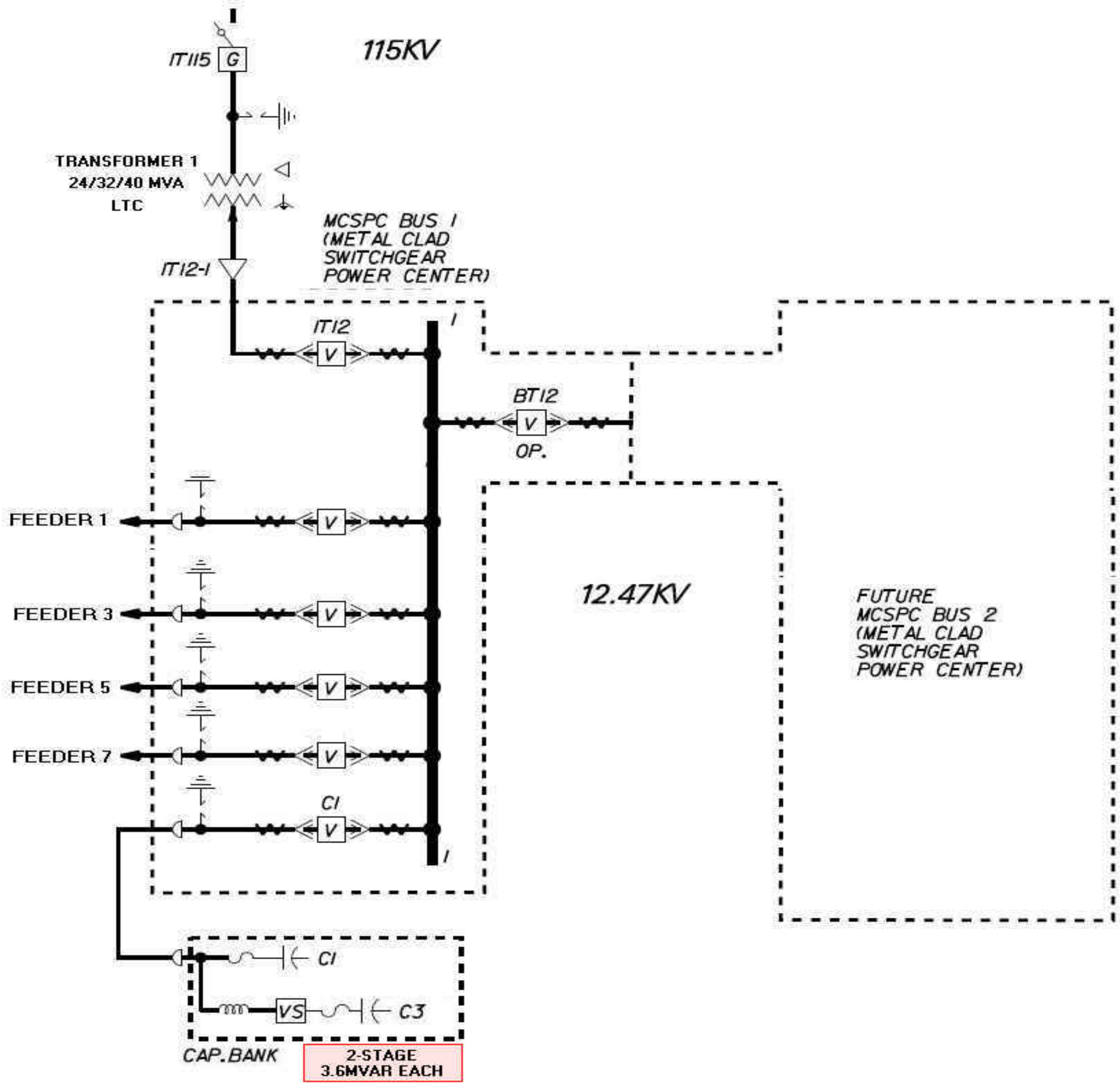


FIGURE 9.8.2 – EAST PROVIDENCE SUBSTATION ONE LINE-DIAGRAM (PLAN 1)

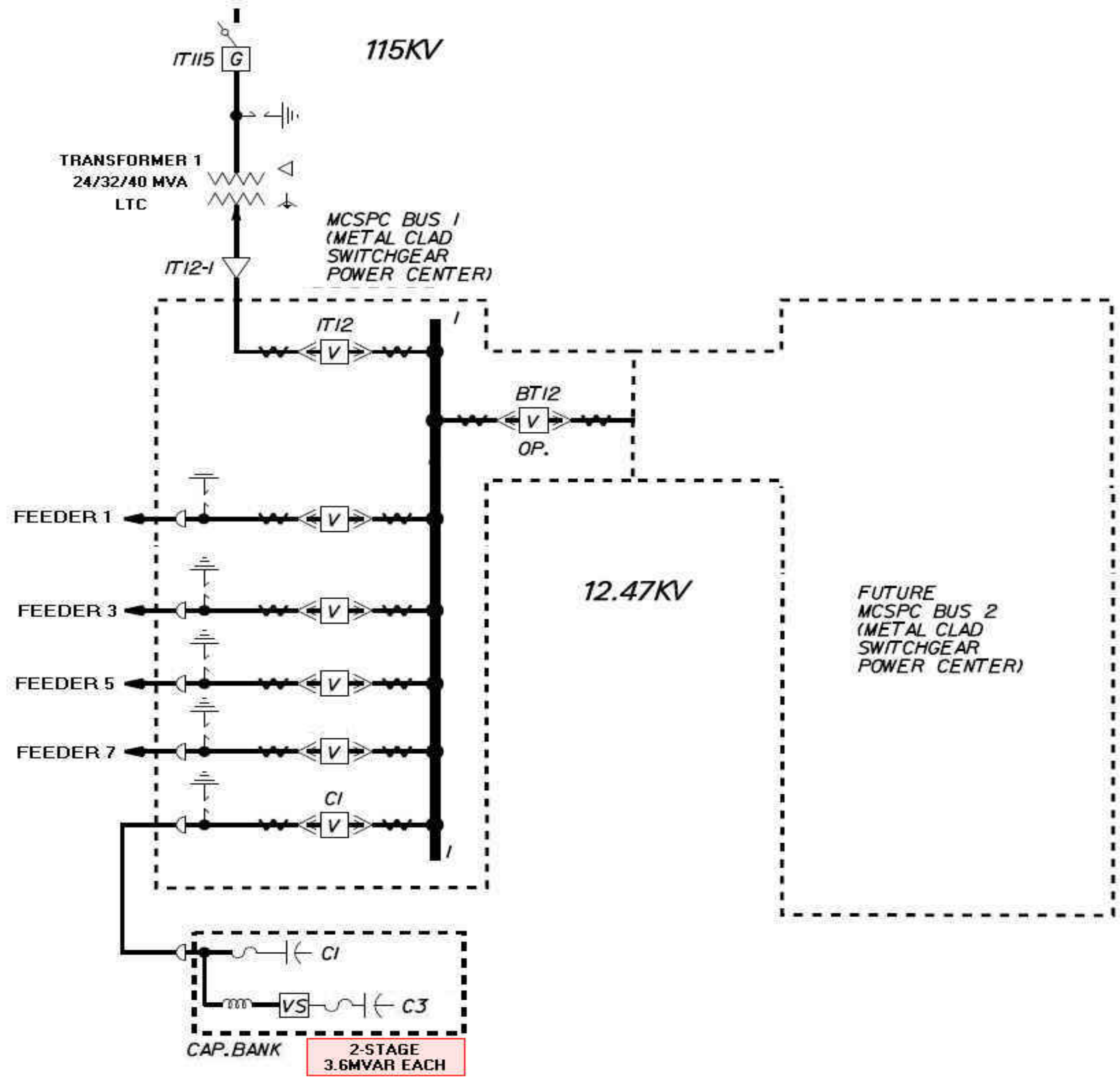


FIGURE 9.8.3 – EAST PROVIDENCE SUBSTATION SITE PLAN (PLAN 1)

[redacted]

FIGURE 9.8.5 – PROPOSED MAINLINE DISTRIBUTION NORTH (PLAN 1)

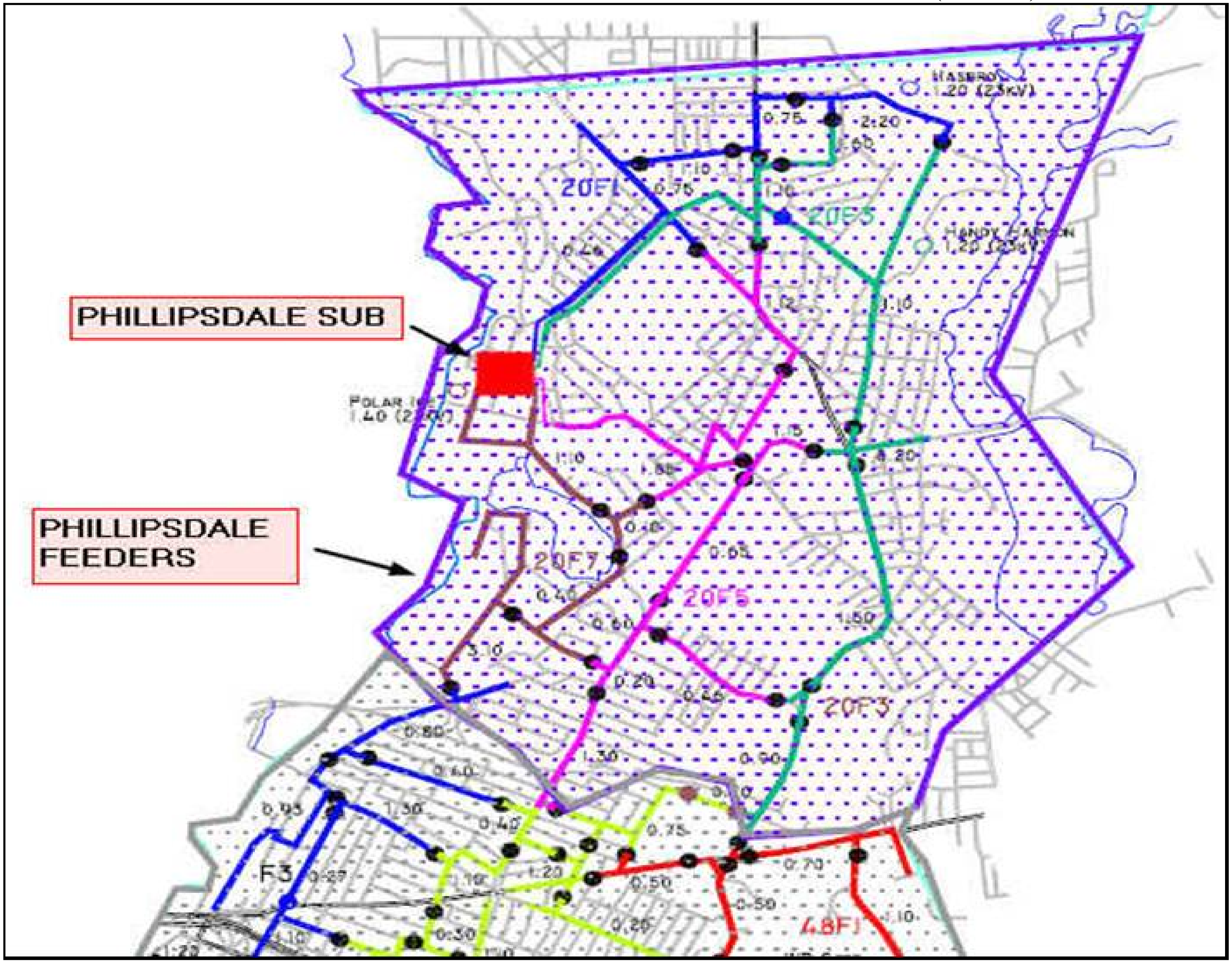
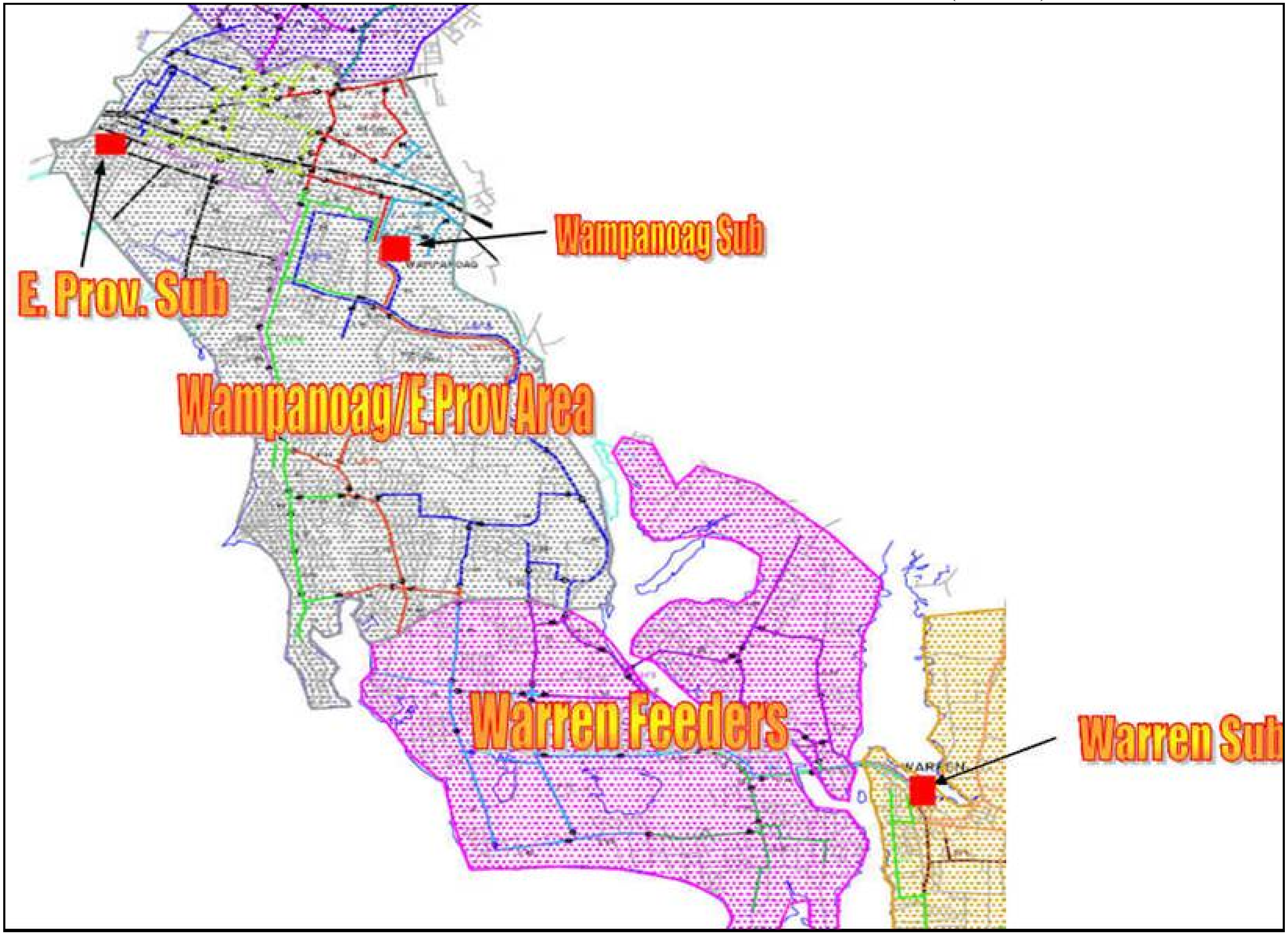


FIGURE 9.8.6 – PROPOSED MAINLINE DISTRIBUTION SOUTH (PLAN 1)



9.9 Plan Development – Plan 2

FIGURE 9.9.1 – PHILLIPSDALE SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

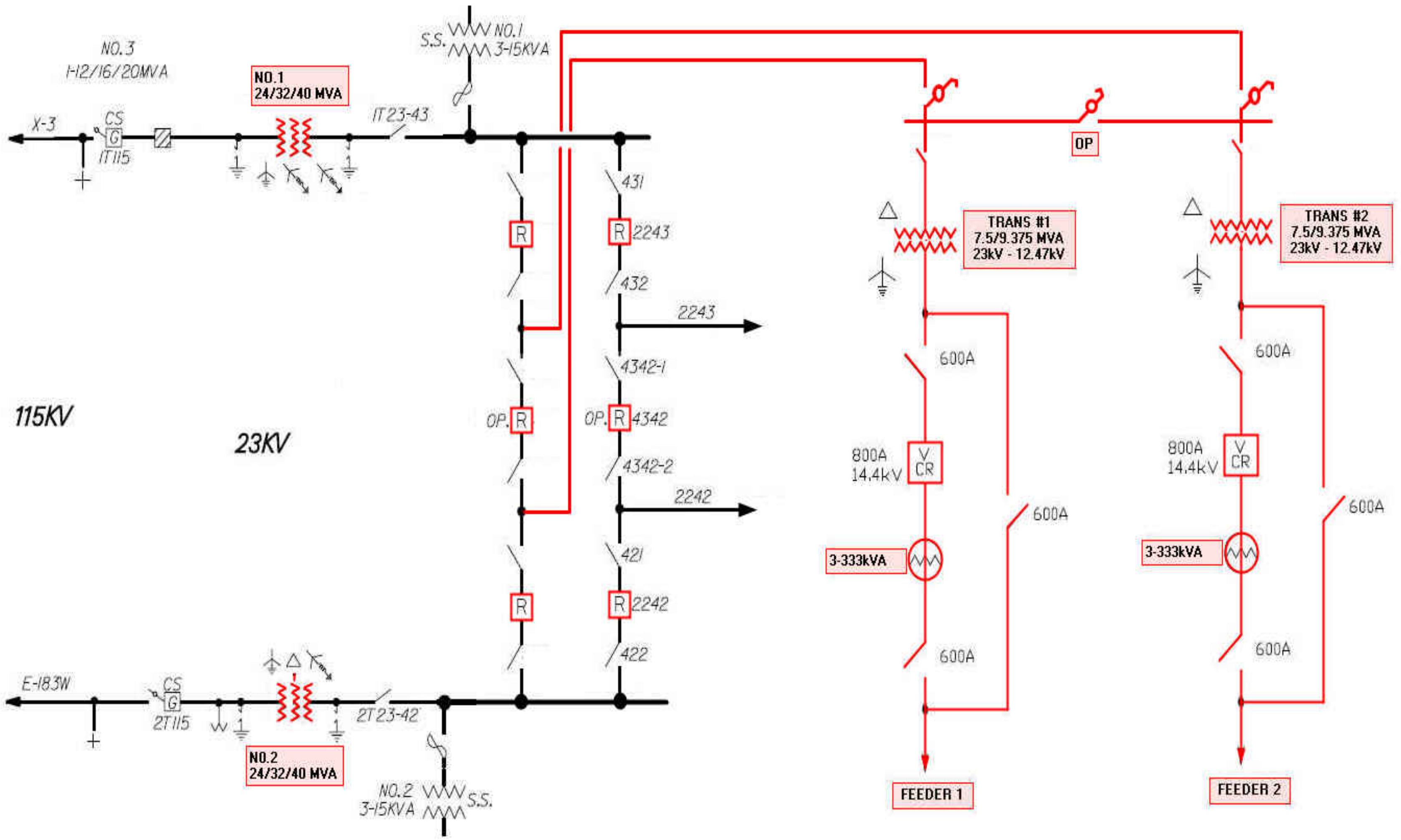


FIGURE 9.9.2 – RUMFORD SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

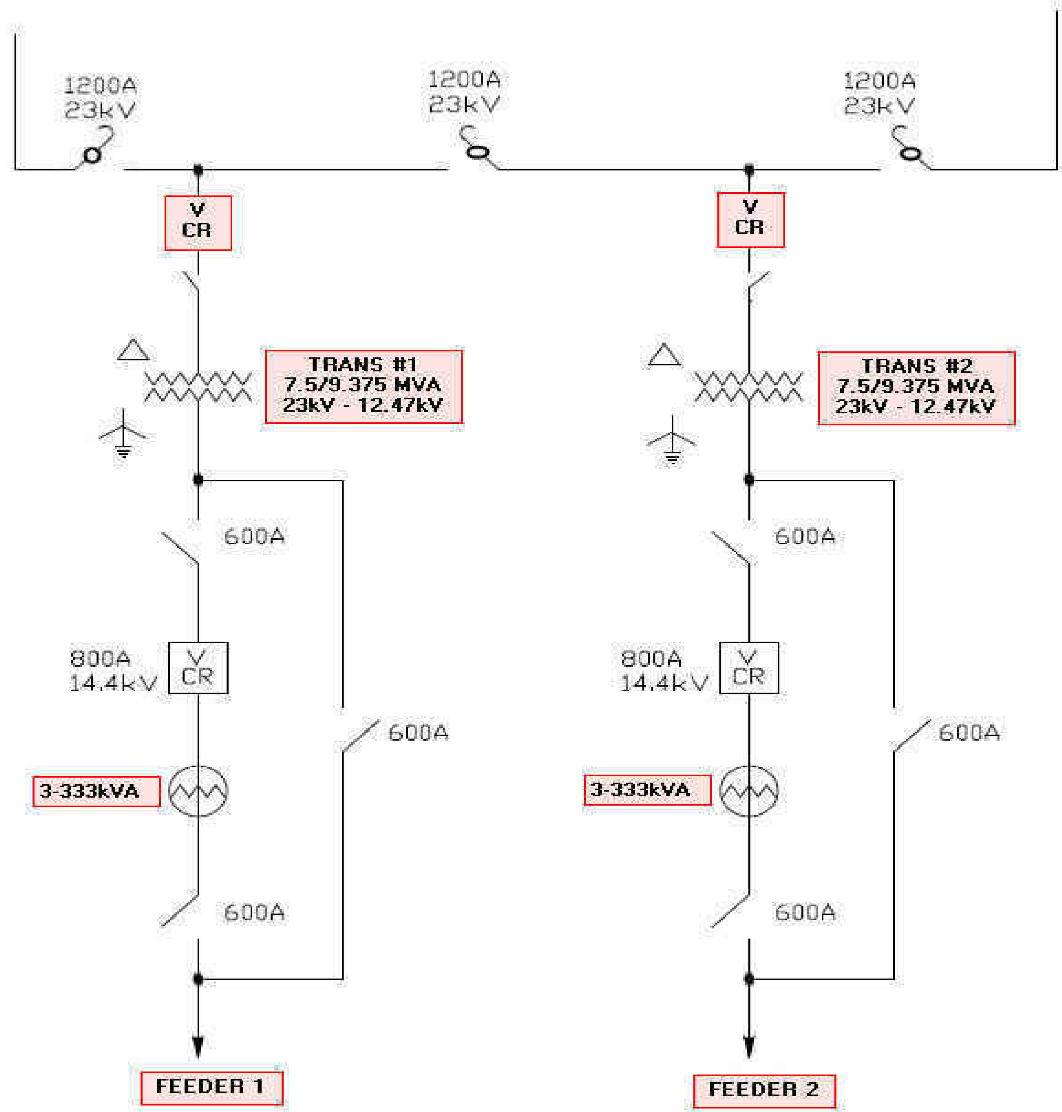


FIGURE 9.9.3 – KENT CORNERS SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

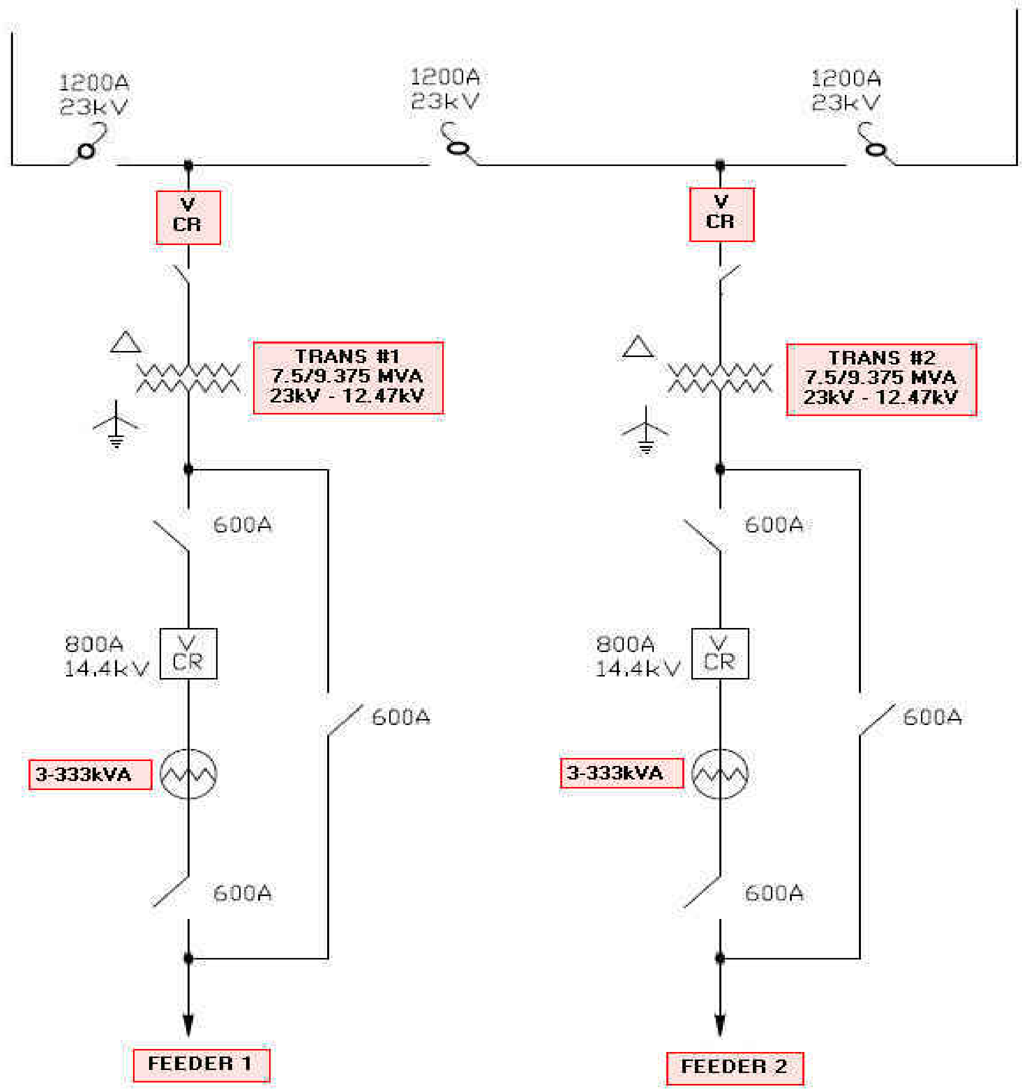
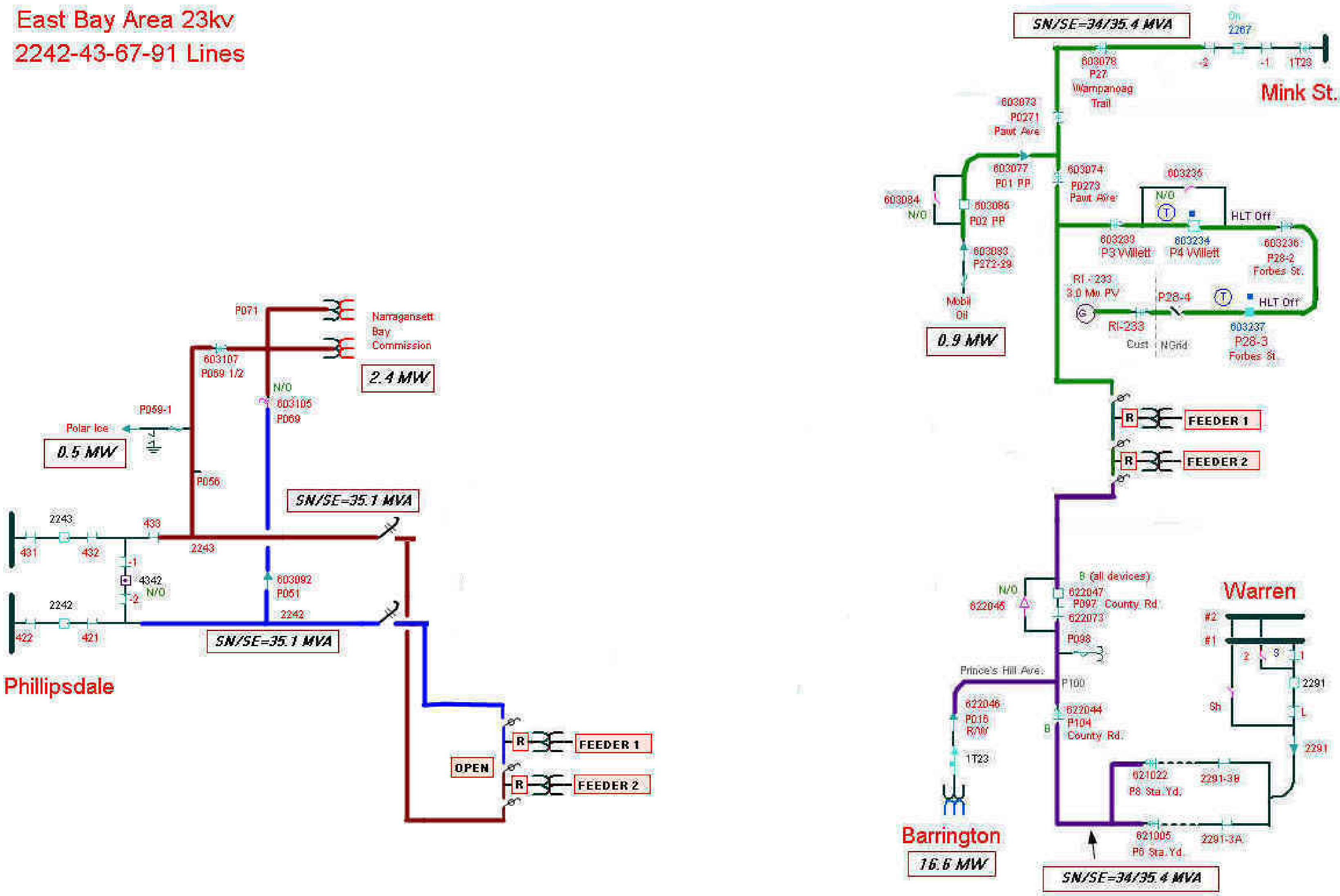


FIGURE 9.9.4 – MINK STREET SUBSTATION ONE-LINE DIAGRAM (PLAN 2)

[redacted]

FIGURE 9.9.5 – PROPOSED 23KV SUPPLY SYSTEM (PLAN 2)



9.10 Plan Development – Plan 3

FIGURE 9.10.1 – PHILLIPSDALE SUBSTATION ONE-LINE DIAGRAM (PLAN 3)

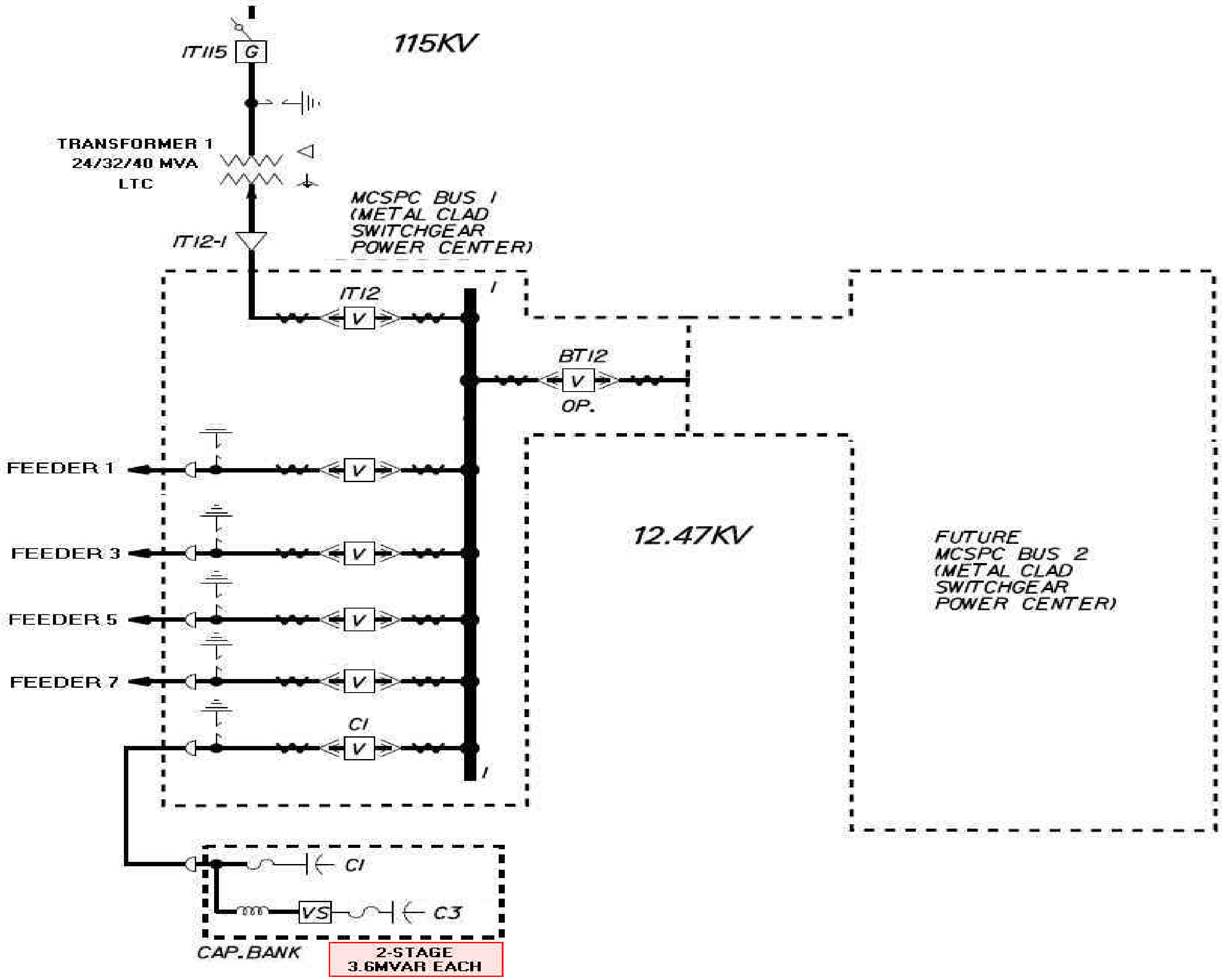
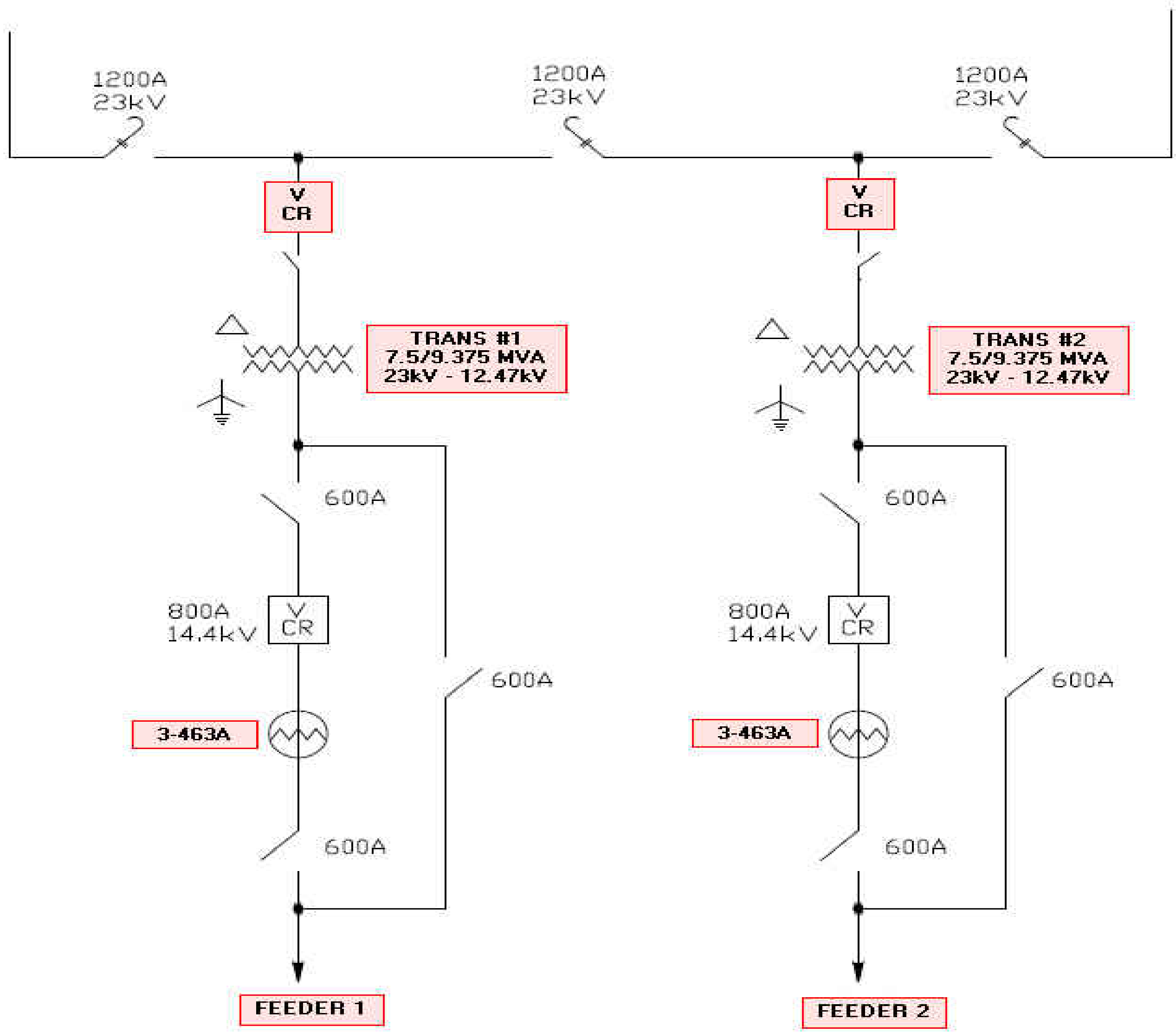
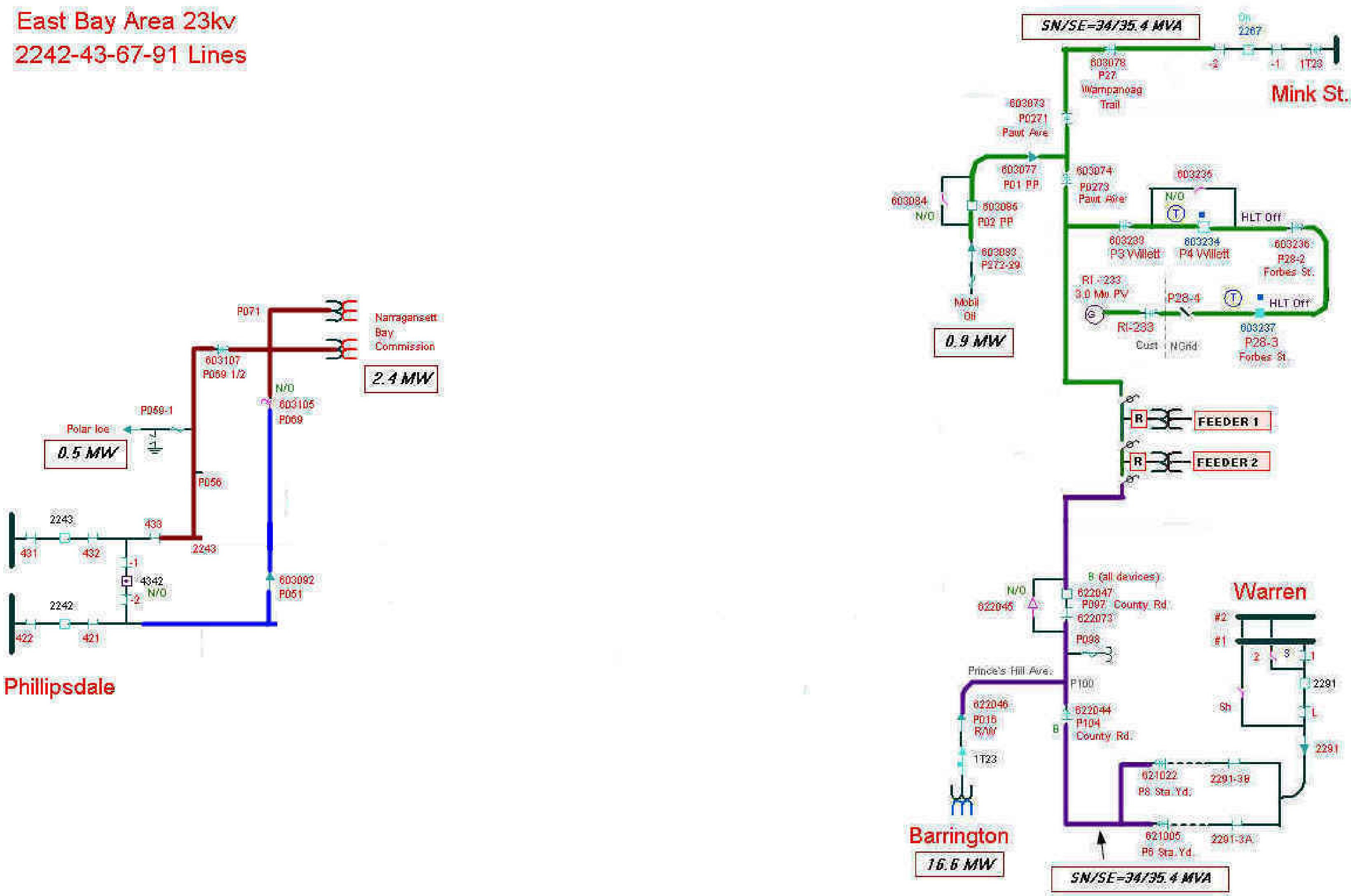


FIGURE 9.10.2 – KENT CORNERS SUBSTATION ONE-LINE DIAGRAM (PLAN 3)



[redacted]

FIGURE 9.10.4 – PROPOSED 23KV SUPPLY SYSTEM (PLAN 3)



9.11 Distributed Generation Within the Study Area

FIGURE 9.11.1 – Existing and Proposed Distributed Generation – East Bay Area

Feeder #	Organization Name	Existing Capacity (kW)	Proposed Capacity (kW)	Type
2267	FORBES STREET PROJECT LLC	3000	0	Solar
2267	FORBES STREET PROJECT LLC	0	3000	Solar
53-20F1	NATIONAL SECURITY CORP	45.6	0	Solar
53-20F2	DAVID CHOPY	4	0	Solar
53-48F1	MARVIC ENTERPRISES INC	0	7	Solar
53-48F3	JENNY K FLANAGAN	0	2.15	Solar
53-48F4	EAST BAY STORAGE	0	75	Solar
53-4F2	ROGER E DESLAURIERS	3.87	0	Solar
53-4F2	NOAH PHILIP	3.44	0	Solar
53-51F2	JOHN BRANDO	4	0	Solar
53-51F2	ELIZABETH RADUCHA	5	0	Solar
53-51F3	SAFE-WAY AUTO SALES INC	50	0	Wind
53-51F3	CLEMS ELECTRIC CO	28	0	Solar
53-5F1	GEOFFREY ALLEN	0	3.6	Solar
53-5F2	WESLEY J MILLER	3.66	0	Solar
53-5F2	TYSAS AND COMPANY INC	1.29	0	Solar
53-5F3	THOMAS FAIRCHILD	0	0.57	Solar
53-5F3	BEN LUK	0	6.45	Solar
TOTAL		3,149	3,095	

OER 1-2

Request:

This Data request pertains to the Proposal, specifically the testimony on Bates Stamp page 12 that reads, "[d]istributed generation resources are incorporated into the area load forecasting models for [the long range] studies."

(a) Please explain how distributed generation ("DG") resources are incorporated into the area load forecasting models.
(b) Please indicate what information the Company uses to forecast what DG will be developed.
(c) Please explain how these forecasts are developed including whether a top down or bottom up approach is taken. If the Company forecasts of DG are top down estimates, please explain what in the Company's opinion would be needed to develop bottom up DG forecasts (e.g. by circuit).
(d) Please explain how the Company address probabilistic issues in this DG forecast, in other words, the relative certainty that DG will be developed.
(e) Please explain how forecasted DG is treated in terms of reliable contribution to distribution system needs (e.g. does any of the forecasted DG in certain areas reduce the need for system investments due to load growth).

Response:

(a) The Company tracks historical distributed generation (DG) installations and makes projections for future installations based on applications in the queue (for the short term) and state policy targets (for the long term). To the extent that DG installations have already been installed on specific feeders and in specific areas, these reductions would be reflected as reductions in both the historical and future loads for those areas.
The current approach is a "top-down" approach and the general process for projecting future DG is to assume that the Company will meet the state policy goal over the long term. In Rhode Island, this target is 200 MW (direct current) by the year 2019. In the short term, over the next one to two years, installations are based on those applications in the DG interconnection queue and their expected average time to connection. After the policy target is met, it is assumed that there will still be some level of DG that continues to be installed versus a complete discontinuation of DG.

Prepared by or under the supervision of: Joseph F. Gredder

OER 1-2, page 2

(b) The Company uses a number of informational sources for its current "top-down" approach to DG projections. These include:

- State Policy Targets (for long term projections);
- Historical DG Installations (for historical MW connected and the mix of solar vs. other technologies; about 85% to date);
- DG applications in the installation queue and their average time from application to connection to the grid (for near-term new additional installations);
- Monthly Coincident Factors (to convert installed MW to their impacts at the times of Company peaks (calculated monthly but approximately 40% on an annualized basis; this is similar to what ISO-NE uses);
- Conversion from MW in DC voltage to MW in AC voltage based on historical differences in DC to AC nameplate ratings, currently at 0.91 (for use in converting DC based policy targets to AC impacts on the network)

(c) As discussed in the Company's responses to sections (a) and (b) above, the Company currently uses a "top-down" approach to its DG projections.

There are a number of items needed to enable a "bottom up" approach, including but not limited to:

- Acquiring, training, and use of a power flow modeling tool that can accurately model DG impacts for each customer on each feeder;
- Determining the technical and financial potential for DG for each customer on each circuit;
- Determining the propensity, or likelihood for each customer on each circuit to install future DG equipment;
- Additional and more complete data regarding the existing network. This would include infrastructure to provide supervisory control and monitoring as many more points on the existing electric system than currently exists.

As described above, a "bottom up" forecast approach would require modeling of every customer. The application of such a forecast would require electric system modeling to every customer, real time data acquisition at potential small intervals (minutes), and storage for such data.

(d) This is the first planning cycle where DG projections have been explicitly incorporated as reductions to the peak loads. For this cycle, the "top-down" approach was a non-probabilistic approach wherein it was assumed that the state policy goal would be met. To date, installations as well as interconnection applications in the queue indicate that this is a reasonable approach at this time. As the Company refines this "top-down" approach, probabilities to capture macroeconomics, state policies, and broader regional market trends may be considered.

As described in 1-2(c), a "bottom up" DG forecast could consider probabilities to address technical potential, financial characteristics, customer likelihood for adoption, and future expansion ability.

(e) The reliable contribution of DG to distribution system needs is the subject of industry debate. Despite the lack of comprehensive historical data on this subject, National Grid's Electric Peak (MW) Forecast considers a 91% inverter loss factor and a 40% peak coincidence factor. These factors are applied to the forecasted nameplate DG to derive a forecasted peak reduction. As National Grid gathers yearly data, it is expected these factors would be refined. With the overall growth rates reduced by this DG component, the forecast is simply applied in distribution planning analysis. National Grid does not intend to conduct a second study without DG reductions to determine what infrastructure was avoided. As done for energy efficiency reductions, through forecast adjustments, system investments required to address capacity constraints would be impacted.

OER 1-3

Request:

This Data request pertains to the Proposal, specifically Bates Stamp page 65 where the Company describes how energy efficiency ("EE") savings are reflected in the capacity planning model. Please explain what aspects, if any, of this forecast is applied based on the geographic uptake of EE measures historically through the EE program, rather than as a top down factor applied statewide.

Response:

To the extent that energy efficiency reductions have already occurred in the historical area loads, these reductions are captured, and loads were, therefore, lower in these specific areas. These reductions would continue into the future and are reflected as reductions to future forecast rates, resulting in lower loads. Regarding projections for future additional energy efficiency reductions, since the energy efficiency program targets are not spatially projected, neither are their reductions to future loads. In the current "top-down" approach, future reductions are applied based on their pro-rata share of loads.

Notably, the "bottom-up" approach, discussed in the Company's response to the OER's Data Request No. 1-2, focuses not only on the network, but also on the customers' adoption of all market-based technologies. Programs would apply equally to all Distributed Energy Resources, including energy efficiency, demand response, energy storage, and electric vehicles.

OER 1-4

Request:

This Data request pertains to the Proposal, specifically Bates Stamp page 64 where the Company indicates that an econometric model is used to forecast summer and winter peak loads as part of its capacity planning process. Please indicate whether the Company has compared past forecasts of peak loads to the actual peak loads measured in subsequent years. If so, please provide the results.

Response:

The Company does not generally compare past forecasts of peak loads to actual loads measured in subsequent years. The Forecast consists of three scenarios:

- Normal "50/50" weather is the average weather on the past 20 seasonal peak days.
- Extreme "90/10" weather is such that it is expected that 90% of the time, the predicted load under this scenario should not be exceeded. It is similarly inferred that 90/10 weather should occur no more than once in a ten-year period.
- Extreme "95/5" weather is such that it is expected that 95% of the time, the predicted load under this scenario should not be exceeded. It is similarly inferred that 95/5 weather should occur no more than one time in a twenty-year period.

In summary, the Company considers an average case and two 'not-to-exceed' cases. A worthwhile comparison of predicted peaks to actual peaks would only occur if the actual peak weather was equal to or near the extreme scenarios, specifically the "90/10" weather, or the "95/5" weather. This is an uncommon occurrence. However, the Company can 'weather-adjust' the actual peak to provide a more meaningful comparison to the forecast cases. The table below shows example comparisons from the first predicted year of a forecast to the subsequent weather-adjusted actual. Note that the Company changed the forecasting basis from a Power Supply Area to an ISO Zone basis over the 2012 and 2013 period. A meaningful comparison of PSA based forecasts to ISO Zone based actuals is not possible.

OER 1-4, page 2

A	B	C	D	E	F
Forecast	Year	Predicted MW - Extreme Weather	Actual MW	Actual MW Adjusted to Extreme Weather	Accuracy (C-E)/C
Spring 2010	2010	1779	1749	1755	1.35%
Spring 2011	2011	1807	1777	1777	1.66%
Fall 2013	2014	2040	1653	1971	3.38%
Fall 2014	2015	2029	1743	2018	0.54%

Prepared by or under the supervision of: Joseph F. Gredder

OER 1-5

Request:

This Data request pertains to the Proposal, specifically to the Newport Substation Project referenced on Bates Stamp pages 66 and 67.

(a) Please provide the load relief amount needed in MW for the Newport Substation project.
(b) Please explain whether the Company in its judgment believes the Rhode Island Office of Energy Resources' Solarize Rhode Island initiative on Aquidneck Island will have an impact on the load relief issues that the Newport Substation Project is seeking to address.

Response:

(a) The Newport Substation Project is needed to provide approximately 22 MW of capacity in the City of Newport and in the southern sections of Middletown. This capacity is required to relieve the highly loaded sub-transmission supply system and to address asset condition, safety, reliability, and environmental concerns associated with a number of small 23/4.16 kV substations located in this area.

(b) National Grid understands the current status of the Rhode Island Office of Energy Resources' (OER) Solarize Rhode Island initiative on Aquidneck Island to include approximately 400 kW of nameplate solar generation. Using the 91% inverter loss factor and 40% peak coincidence factor described in the Company's response to the OER's Data Request No. 1-2(e), this results in a peak reduction of 146 kW. In the Company's judgment, this peak reduction is not substantial enough to impact the load relief requirements. Please note that, as described in the Company's response to the OER's Data Request No. 1-5(a), the Newport Substation Project addresses other issues in addition to load relief.

Prepared by or under the supervision of: Ryan Constable

OER 1-6

Request:

This Data request pertains to the Proposal, specifically to the Volt/VAR Management Project referenced on Bates Stamp pages 72, 73, and 74.

(a) Please explain the background and purpose of the Volt/VAR Management Project.
(b) Please explain what the process of completing the Volt/VAR Management Project entails.
(c) Please provide a timeline including anticipated completion dates for the Volt/VAR Management Project and any subsequent evaluations.
(d) Please explain what in the Company's judgment would make the project a success.
(e) Please indicate whether the Company has plans to propose an expansion of the pilot to other areas if the project is a success.

Response:

a) The 'Volt VAR Management project' consists of two processes: (1) Volt VAR Optimization (VVO); and (2) Conservation Voltage Reduction (CVR). VVO is the process of utilizing distribution devices (regulators and capacitors) to level out the voltage profile along a feeder, and reduce the amount of reactive power flow. CVR is the process of reducing the delivery voltage to customers with the intent of reducing demand and energy usage. In addition to the VVO/CVR control aspect of this project, the Company is simultaneously investigating ownership of a private wireless mesh communications network to support the control of the distribution devices. A communications network is required for the VVO/CVR control system to operate.

   The overall purpose of the VVO/CVR project is to reduce customer's energy usage by lowering the voltage levels at the delivery point, while still maintaining the voltage above the minimum requirements. Specifically, the project will implement the communications and control necessary to coordinate both VVO and CVR, utilizing distribution field devices such as Capacitors, Regulators, and Load Tap Changers.

   The Volt VAR management project's benefits to customers, and the Company are as follows:

Direct Benefits to Customers:

- Reduce customer Energy Usage
- Reduce Demand
- Improve Voltage Compliance

Benefits to National Grid:

- Reduce System Losses
- Improve Flexibility in meeting New England ISO Power Factor performance
- Improve Planning & Operations with increased system performance monitoring
- Decrease equipment operations which reduces equipment wear and would allow for extending equipment maintenance cycles

b) The process of completing the Volt VAR Management project involves the study of the project area to develop both an electric and communications design to support the automatic control of the equipment on the feeder to manage the voltage and power factor. Currently, at National Grid, communications and control have been established for two feeders of the Putnam Pike Substation area, with one remaining feeder to be completed in FY2016. In addition, the infrastructure which provides data connectivity between National Grid emergency management system (EMS), the RF Network Management server, the VVO Controller, and the field devices is also complete. This will be followed by deployment of the technology in the Tower Hill area on four feeders in FY2017.

c) The Company will complete the work in the Putnam Pike area in FY2016, and begin a six-month Measurement and Verification (M&V) analysis, including the peak summer months, for the Putnam Pike feeders. The Company will complete the work in the Tower Hill area in FY2017, which will include the performance of a six-month M&V analysis.

d) The Company has not laid out formal success and failure criteria for the Volt VAR management project. However, quantifying the impacts of the project will be key to determining project success, and will allow for the evaluation of the technology from a cost/benefit basis perspective going forward.

e) The Company does not have any formal plans to propose an expansion of the Volt VAR management project to other areas if the project is a success. However, if the project demonstrates that a reasonable value can be achieved, the Company will investigate proposing an expansion that would utilize and build upon the infrastructure and lessons learned from this project.

Prepared by or under the supervision of: James Perkinson

OER 1-7

Request:

This Data request pertains to the Proposal, specifically Attachment 1 on Bates Stamp page 77 entitled "FY 2017 Capital Spending by Key Driver Category and Budget Classification". Please explain why capital spending is negative in several categories.

Response:

Capital spending is negative in several categories because there are three major transactions that can cause a negative "spend" in a project or a category of projects. These major transactions are as follows:

1) Contribution in Aid of Construction (CIAC): When cash is received prior to the commencement of a project, the project starts with a "negative" balance. As costs are incurred for the project, the negative balance is offset, and the overall project cost moves towards $0 balance or into the positive cost range if the costs exceed the CIAC received. In categories where most projects receive CIAC's, the timing of receipts versus expenditures can lead the category to a negative balance at a point in time. The categories most affected by CIAC's are Third-Party Attachments (FY2011), Distributed Generation (FY2013), and New Business.

2) Project Reimbursement: These transactions are similar to CIAC's except that, unlike CIACS, the reimbursement in this category is received after the costs for the project are incurred. Depending on the timing of the costs versus the timing of reimbursements, the entire category may turn into a negative balance. This is certainly the case when significant costs are incurred in one fiscal year and the reimbursement is not received until a future fiscal year. Most department of transportation (DOT) projects are reimbursable and, therefore, the Public Requirements (FY2013) budget classification may reflect a negative balance for a given fiscal year.

3) Journal Entries/Project Cost transfers: Capital costs incurred in a fiscal year and which are transferred to a different project or different cost category (i.e., transfer from capital into cost of removal or expense) during a subsequent fiscal year can lead to a negative capital total in a budget classification for a given fiscal year. This is sometimes the case for a Corporate/Administrative/General project (FY2014), where costs may be collected within an administrative project temporarily for future transfer.

Prepared by or under the supervision of: Glen DiConza

OER 1-8

Request:

Please confirm whether or not the Company receives an incentive to perform under budget for the Electric Infrastructure, Safety, and Reliability Plan. If yes, please describe opportunities for such incentives approved by the Rhode Island Public Utilities Commission. Also, please specify all previously earned incentives by plan year, where applicable.

Response:

The Electric Infrastructure, Safety, and Reliability (ISR) Plan exists pursuant to R.I. General Laws Section 39-1-27.7.1 (the Decoupling Act) and is prepared and submitted to the Rhode Island Public Utilities Commission (PUC) in compliance with the Decoupling Act. The Decoupling Act specifically provides the Company compensation for investments in its distribution system as well as recovery of expenses associated with its Inspection and Maintenance (I&M) Program and Vegetation Management (VM) Program. Capital investments are recovered through the annual revenue requirement of such investments until such time as the Company begins recovery of the investments in base distribution rates, and the recovery of expenses of the I&M and VM Programs is dollar-for-dollar. To date, the Company has neither received, nor has been given the opportunity to earn incentives in any plan years of the Electric ISR Plan for performing work under budget, for achieving certain targets, or for any other reason.

Prepared by or under the supervision of: James H. Patterson