BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

AVISTA CORPORATION d/b/a AVISTA UTILITIES,

Respondent.

DOCKET NOS. UE-200900 and UG-200901 (*Consolidated*)

PAUL J. ALVAREZ AND DENNIS STEPHENS

ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT PADS-16

Avista Response to Public Counsel Data Request No. 110, Attachments A–N

April 21, 2021

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	02/09/2021
CASE NO.:	UE-200900 & UG-200901	WITNESS:	Heather Rosentrater
REQUESTER:	Public Counsel	RESPONDER:	Heather Webster Kyle Jonas
TYPE:	Data Request	DEPT:	Asset Maintenance
REQUEST NO.:	PC - 110	TELEPHONE:	509 495-8930 509-495-2695
		EMAIL:	heather.webster@avistacorp.com kyle.jonas@avistacorp.com

SUBJECT: Capital Additions, Test Year (Electric)

REQUEST:

Please refer to Heather L. Rosentrater, Exhibit HLR-11, at 2–13, and the Distribution Grid Modernization program generally.

a) Provide a list of feeders addressed by the program by year for 2018, 2019, and 2020.
b) For each feeder listed by year in response to subpart (a), provide (i) the miles of OH conductor that existed before "modernization" and (ii) the miles of OH conductor that existed after "modernization".
c) For each feeder listed by year in response to subpart (a), provide (i) the miles of UG cable that existed before "modernization" and (ii) the miles of UG cable that existed after "modernization".
d) For each feeder listed by year in response to subpart (a), provide a list of replaced equipment types, and the quantity (count or miles) of each which was classified as "failing" at the time of replacement.
e) For each equipment type replaced listed in response to subpart (d), provide the policies, processes, methods, methods, criteria, tests, or other means Avista uses to determine that each type was to be classified as "failing".
f) For each feeder listed by year in response to subpart (a), estimate the energy saved (in kWh) as a result of the work performed.
g) For each feeder listed by year in response to subpart (a), provide (i) the number of customers served by the feeder; and (ii) the number of customers served by the feeder submitting a reliability complaint in the five years preceding the year in which the feeder was "modernized".
h) For each feeder listed by year in response to subpart (a), provide a count of safety incidents related to replaced equipment in the five years preceding the year in which the feeder was "modernized", and identify the equipment replaced.
i) For each feeder listed by year in response to subpart (a), list the power quality issues observed in the five years preceding the year in which the feeder was "modernized".
j) For each feeder listed by year in response to subpart (a), provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which support of the statement "Over decades, many of these were built to different construction standards using a wide variety of materials. These factors contribute to increased outages that **take longer to restore** and **fall short of modern expectations** that utilities face."

k) For each feeder listed by year in response to subpart (a), provide the total cost of the work completed on the feeder in the year of "modernization".

l) For each feeder listed by year in response to subpart (a), provide, for each of the five years preceding the year of modernization, (i) the number of outages; (ii) the average duration of the outages.

m) For each feeder "modernized" in 2018, provide, for 2019 and 2020, (i) the number of outages; and (ii) the average duration of the outages.

n) For each feeder "modernized" in 2019, provide, for 2020, (i) the number of outages; and (ii) the average duration of the outages.

o) For each feeder listed by year in response to subpart (a), provide the number and types of "automation devices" that were installed on each.

p) Regarding "automation devices", provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation in support of the statement "Automation devices produce results immediately optimizing system performance, reducing costs, and reducing outages."

q) Regarding "automation devices", provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which show that automation devices "provide(d) value in dollars to rate payers" in excess of the cost of the devices in dollars to rate payers.

r) For each feeder listed by year in response to subpart (a), provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, or other documentation which show that the work "provide(d) value in dollars to rate payers" in excess of the cost of the work in dollars to rate payers.

s) For each feeder listed by year in response to subpart (a), provide the annual O&M savings estimated from the work completed in the "modernization" year. Provide all calculations, assumptions, worksheets, and other work completed to develop these estimates.

RESPONSE:

a) The table below shows the feeders addressed during 2018, 2019, and 2020. As explained in other responses, Avista's feeders are often addressed across multiple years in a Grid Modernization project through the process of analysis, selection, design and construction. The feeders on this list are either in design or in construction.

Table (a)1

2018	2019	2020
BEA12F2	BEA12F2	BEA12F2
F&C12F1	F&C12F1	F&C12F1
HOL1205	M15514	M15514
M15514	MIS431	MIS431
MIS431	RAT233	NE12F4
ORO1280	SIP12F4	ORO1282
PDL1201	SPR761	RAT233
RAT233	TUR112	ROS12F4
SPI12F1		ROS12F5
SPR761		SIP12F4
TUR112		SPR761
		TUR112

b) The miles of overhead conductor that existed prior to modernization for each feeder can be found in the attached Grid Modernization Feeder Baseline Reports, attached for the subject feeders, as PC-DR-110 Attachments A-N. Miles of overhead conductor post treatment are described in cases in the baseline report, but are also included in the design and asbuilt drawings and spec sheets for each feeder. Examples of one design sheet for one sub-polygon of one feeder project are provided in PC-DR-110 Attachments O and P, respectively. Depending on the feeder length, there can be up to a range of 30 polygons, with many of the polygons subdivided as in the examples provided. An example of one asbuilt sheet is provided in PC-DR-110 Attachment Q. The Grid Modernization project does not track this information in the form requested because it is not a useful metric for the management of the program.

c) The miles of underground conductor that existed prior to modernization for each feeder can be found in the attached Grid Modernization Feeder Baseline Reports, attached for the subject feeders, as PC-DR-110 Attachments A-N. Miles of underground conductor post treatment are described in cases in the baseline report, but are also included in the design and asbuilts for each feeder. Examples of one design sheet for one sub-polygon of one feeder project are provided in PC-DR-110 Attachments O and P, respectively. An example of one asbuilt sheet is provided in PC-DR-110 Attachment Q. The Grid Modernization project does not track this requested information because it is not a useful metric for the management of the program.

d) The list equipment replaced on the feeders in subpart (a) is consistent with the equipment identified in the Company's response to PC-DR-108 Attachment A. These parts are replaced based on the criteria outlined in the Distribution Feeder Management Plan, including assessments based on asset condition. The replaced equipment types that existed prior to modernization for each feeder can be found in the attached Grid Modernization Feeder Baseline Reports, attached for the subject feeders, as PC-DR-110 Attachments A-N. Lists of equipment types installed during the program are described in cases in the baseline report, but are also included in the design and asbuilts for each feeder. Examples of one design sheet for one sub-polygon of one feeder project are provided in PC-DR-110 Attachments O and P, respectively. An example of one asbuilt sheet is provided in PC-DR-110 Attachment Q. The Grid Modernization project does not track this requested information because it is not a useful metric for the management of the program.

e) Standard means of evaluating equipment for failure consist of visual inspections for signs of damage or substandard performance and inspections performed by Wood Pole Management. Please see also the guidelines in the Company's Distribution Feeder Management Plan provided in PC-DR-108. Please also see the Company's response to part (d), above, which documents include equipment to be replaced, including the rationale for end-of-life assets in particular instances, during a Grid Modernization project.

f) The table below shows the estimated kWh energy savings expected after completion of each project. These calculations are conservative in that not every energy efficiency improvement made during design and construction can be anticipated in the initial assessment. These estimates are derived from the initial assessments noted in the feeder baseline reports found in PC-DR-110 Attachment A-O. The primary reconductor savings are for trunk reconductor work only.

Table
(f)1

Feeder	State	Estimated Annual Pri. Reconductor MWh Savings	Estimated Annual Transformer Loss MWh Savings	Total Estimated Annual MWh Savings[1,2,3]
BEA 12F2	WA	8.8	260.5	269.3
F&C 12F1	WA	1.8	258.5	260.3
HOL 1205	ID	0	65.5	65.5
M15 514	ID	0	245.6	245.6
MIS 431	ID	128.8	128.3	257.1
ORO 1280	ID	3.5	108.2	111.7
ORO 1282	ID	TBD	103.0	TBD
PDL 1201	WA	23.5	165.5	189.0
RAT 233	ID	90.3	381.4	471.7
ROS 12F4	WA	2.6	64.1	66.8
ROS 12F5	WA	6.1	145.9	152.1
SIP 12F4	WA	10.5	272.8	283.3
SPI 12F1	WA	31.6	83.2	114.8
SPR 761	WA	49.9	55.7	105.6
TUR 112	WA	140.1	92.7	232.8

[1] Additional MWh savings estimated through Distribution Automation enabled improvements are not included in these figures

[2] Additional MWh savings estimated through the removal of Open Wire Secondary districts are not included in these figures

[3] Additional MWh savings estimated through power factor correction initiatives with capacitors, IVVC, or CVR are not included in these figures

g) The table below provides the density of customers on feeders* selected for Grid Modernization. Some of these feeders have completed construction, others are still in progress, and some are in the design phase.

Feeder	Customer Density (Customer/mi).	Customer Count
BEA12F2	115	2965
F&C12F1	145	3066
HOL1205	177	648
M15514	77	3230
MIS431	8	947
ORO1280	51	584
PDL1201	130	1639

RAT233	25	2560
SPI12F1	5	826
SPR761	7	457
TUR112	46	2451
SIP12F4	62	2094
NE12F4	62	1343
ORO1282	38	578
ROS12F4	159	967
ROS12F5	154	2021

**Data source 2019 Feeder Status Report*

Regarding the number of customer complaints, please see the Company's response to PC-DR-130, part (a).

h) Regarding the number of safety incidents, please see the Company's response to PC-DR-130, part (b).

i) Regarding the number of power quality issues, please see the Company's response to PC-DR-130, part (c). Each feeder selected for the Grid Modernization program undergoes an analysis by a distribution engineer which includes a review of voltage quality, among other factors. These power quality and other evaluations are described and documented in PC-DR-110 Attachments A-O. In addition to the subject reports, a summary of the analyses performed on selected feeders is described below. The following criteria are used in the investigation for the Analysis & Engineering segment for Avoided Cost in the Feeder Upgrade program. Each item corresponds to a specific section of the same name in each feeder's Baseline Report.

- Load Balancing
  Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which will mitigate the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts will commence toward the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

- High Loss Conductors
  High loss conductors (such as 6A, 8A, 6CR, 8CR) are inefficient conductors that result in line losses, especially where there is moderate to heavy loading. They are also some of the older conductors on the system that can have reliability concerns due to physical wear and damage over the years. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on replacing conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher loss conductors. An Engineering decision

can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also decide to reconductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management (WPM) reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

- Trunk Conductors

  Primary trunk conductors have the ability to negatively affect the reliability and efficiency of a distribution circuit. Primary trunk conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to: serve peak loading demands, provide adequate voltage levels, and do not cause significant and unnecessary line losses. In addition, Primary trunk conductors are analyzed to determine if they are sized appropriately for the system to be operated in an automated restoration scheme (FDIR). Primary trunk conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

- Lateral Conductors

  Lateral trunk conductors have the ability to negatively affect the reliability of a distribution circuit. Lateral conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to: serve peak loading demands, provide adequate voltage levels, and insure that they do not cause significant and unnecessary line losses. Primary lateral conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability and reliability.

- Voltage Quality

  Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeders are modeled in Synergi during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. In addition, primary laterals and trunks are reconductored with more efficient conductors to increase sagging voltage levels. In some scenarios, an additional conductor phase(s) may be installed to offload a heavily loaded phase and assist in supporting the voltage.

- Voltage Regulator Settings

  As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline voltage regulator settings. This is performed to reflect the changes to loading and to address the conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. The feeders are modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ANSI 84.1 ranges for all customers during the modeled scenarios, and to eliminate over-voltage and under-voltage situations.

- Line Losses

  The distribution of electricity at medium voltage results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and to improve voltage levels on feeders. Line losses are generally first addressed by balancing load on the phases between numerous strategic locations on the feeder. This action eliminates the unnecessary overloading of phases that may worsen line losses caused by loading. Line losses are then further minimized by replacing wire with more efficient conductor where conductor resistivity is high and/or where loading levels are moderate to high.

- Power Factor

  Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work. Power factor is a value that can fluctuate with the variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of over 17,000 hourly data pars covering at least a 24 month span to calculate the apparent power and power factor. This results in comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading – both in terms of time and quantity.

- Power Factor Correction

  The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to unity. A unity power factor is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and enacting a solution. The historical raw Watt and VAR data is reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loads to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed in more severe situations to raise the power factor to a reasonable base value, and then switched capacitor banks are installed to supplement the power factor when required by loading. This approach optimizes the correction of the power factor and reduces line losses.

j) The ability to maintain system reliability, reduce power quality issues, and restore service in a timely manner are among the many expectations of a modern utility. Standardized construction and materials provide more confidence in the grid's ability to perform because it reduces the number of variables in the system that could cause issues. An assortment of many different materials, equipment and designs in the distribution system results in a need for more craft training, supply chain management, and array of tools, resulting in increased efforts to maintain the same level of service. Furthermore, it is not practical to keep a business case or perform a study on every element on the system when a general application of lean business practices will suffice. Bringing existing lines up to more-current standards during Grid Modernization projects takes the proactive step of reducing outdated and obsolete parts of the system, improving code compliance, and reducing the risk of system failures. Please see also the discussions of this topic in the feeder baseline reports, provided as PC-DR-110 Attachments A-O.

k) Costs in the table below represent a combination of design and construction efforts undertaken in the Grid Modernization program during 2018, 2019, and 2020.

Table (k)1

2018 Feeders		2019 Feeders		2020 Feeders	
Feeder	Annual Cost	Feeder	Annual Cost	Feeder	Annual Cost
BEA12F2	$ 52,756.59	BEA12F2	$ 284,332.68	BEA12F2	$ 92,004.18
F&C12F1	$ 1,623,406.54	F&C12F1	$ 1,667,168.00	F&C12F1	$ 1,365,447.37
HOL1205	$ 1,351,586.30	M15514	$ 223,441.17	M15514	$ 992,586.28
M15514	$ 126,953.97	MIS431	$ 207,592.10	MIS431	$ 903,799.82
MIS431	$ 1,369,429.46	RAT233	$ 1,180,171.76	NE12F4	$ 28,579.03
ORO1280	$ 622,678.29	SIP12F4	$ 139,629.99	ORO1282	$ 69,926.24
PDL1201	$ 2,703,668.86	SPR761	$ 2,451,801.53	RAT233	$ 1,168,861.02
RAT233	$ 1,367,210.87	TUR112	$ 4,286,313.70	ROS12F4	$ 21,764.87
SPI12F1	$ 1,173,566.73			ROS12F5	$ 14,064.60
SPR761	$ 2,375,834.47			SIP12F4	$ 4,055.86
TUR112	$ 1,925,589.89			SPR761	$ 2,277,112.05
				TUR112	$ 317,241.25

l) Please see the Company's response to PC-DR-111.

m) Please see response above in part (l).

n) Please see response above in part (l).

o) The table below lists automated devices installed by Grid Modernization on the feeders listed in subpart (a).

Table
(o)1

Feeder	Viper Switch	Viper Recloser	Switched Cap Bank	Fixed Capacitor	Smart Midline Regulators
BEA 12F2	0	0	0	0	0
F&C 12F1	0	0	0	0	0
HOL 1205	1	1	1	1	0
M15 514	5	1	1	3	0
MIS 431	1	4	0	0	0
ORO 1280	1	1	1	1	0
ORO 1282	0	0	0	0	0
PDL 1201	3	1	1	1	0
RAT 233	2	4	0	1	0
ROS 12F4	0	0	0	0	0
ROS 12F5	0	0	0	0	0
SIP 12F4	1	1	0	0	0
SPI 12F1	0	3	1	0	0
SPR 761	0	1	1	1	0
TUR 112	0	1	1	1	1

Note: Not all devices listed were installed between the years 2018 and 2020.

p) For each automation device listed above, please refer to the applicable feeder baseline report, provided as PC-DR-110 Attachments A-O, wherein the potential value of automation has been assessed, and when recommended, the cost-effectiveness of the application has been demonstrated. Automation devices provide benefit by allowing for the isolation of outages and have the potential to reduce the number of customers experiencing an outage. The reduction in the duration of outages can be achieved through the installation of devices with communications that can either be controlled remotely or through a distribution management system (DMS). In addition, time and cost savings can be achieved through the remote application of hot-line-holds. FDIR, CVR, and IVVC can also be achieved through Grid Modernization when the necessary substation equipment and components are in place. Remote application of holds reduces the number of callouts for manual switching.

q) Please see the Company's response to part (p) above. The installation of automation devices does provide cost savings to customers. In 2019, an analysis was performed on the number of switching events that had occurred on each device that had been installed to date by the Grid Modernization Program. Table (q)1, below, shows the calculated O&M cost savings for each year based on the observed switching events. Utilization of automation devices varies based on outage events and the number of switching orders, so analysis included the total switching operations. Potential savings associated with any single switching action will depend on distance to travel and the time of day (because overtime rates might apply). The analysis used vehicle mileage rates, direct costs associated with labor, tools, and loadings based on average response time of 5 hours. The analysis did not include savings associated with outage reductions, only cost associated with labor and vehicle utilization and is considered a conservative estimate.

Table (q)1

Year	2017	2018	2019 (through Sept)
Conservative O&M cost savings	$ 139,067	$ 324,252	$ 288,145

Analysis and assumptions for the reported savings are included in Automation device activation data and hard O&M costs spreadsheet, which is provided as PC-DR-110 Attachment R.

r) Please refer to the feeder baseline reports provided for each feeder, attached as PC-DR-110 Attachments A-O, for the comprehensive evaluation of the cost effectiveness for our customers of each Grid Modernization project.

s) The Company's evaluation of the cost effectiveness of this program is performed in the analysis included in the attached feeder baseline reports (PC-DR-110 Attachments A-O). As noted earlier for feeder costs, and elsewhere in our responses pertaining to the use of comparative reliability data (e.g. PC-DR-111), each Grid Modernization feeder is addressed in a phased approach over a period of multiple years. As such, there is not a "modernization year" where costs savings can be strictly evaluated. In addition to this overlap in years, there is the annual variability we experience in factors that can drive outages and otherwise affect feeder performance. At this point in the program, the Company has not proposed to evaluate long-term capital and O&M costs just for Grid Modernization feeders, apart from our ongoing evaluation of the performance of electric distribution assets.

Grid Modernization Program

BEA 12F2 Feeder Analysis Report

October 13, 2017

Version 1

Prepared by

Shane Pacini, P.E.
Senior Distribution Engineer

Index

Overview

The following report was established to create a baseline analysis for BEA 12F2 as part of the Grid Modernization program.

BEA 12F2 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Beacon Substation in the Spokane service area. The feeder has 4.30 circuit miles of feeder trunk with 23.39 circuit miles of laterals that serves an urban mixture of residential and commercial loads in east-central Spokane, WA. BEA 12F2 serves 2898 customers during the current normal configuration. Additional feeder information is included throughout the sections of this report, as well as the 2015 Avista Feeder Status Report. BEA 12F2 is represented by the color *teal green* on the system map shown in Figure 1.

There are no primary metered customers on BEA 12F2.

Executive Summary

The following summary is provided as a preview of the findings and recommendations of the Grid Modernization program for the BEA 12F2 circuit.

Cost Avoidance and Energy Efficiency:

- Primary trunk is currently comprised of 556 AAC and 336 ACSR resulting in no recommendations for trunk reconductoring
- Opportunities exist to reconductor primary laterals due to a combination of physical condition, facility replacements, and high loss conductors
- Minimal phase changes will create balanced loading across numerous strategic points on the circuit
- Voltage regulator R/X settings and voltage output settings will not be provided, as the feeder has DMS enable IVVC/CVR that optimize the voltage levels.
- No switchable capacitor bank will be installed. The feeder already had three 600 kVAR switched capacitor banks that were installed as part of the SGIG Project.
- No fixed capacitor banks will be removed or installed.
- There is approximately 40,000' circuit feet of open wire secondary districts.
- An estimated 246 of the 472 transformers (52.1%) on the feeder will be replaced

Reliability and Capital Offset from Reduced O&M:

- SAIFI, SAIDI, CAIDI, and CEMI3 currently outpace the 2017 Avista Target values
- No Viper midline reclosers will be installed. The feeder has one Viper midline recloser that was installed as part of the SGIG Project.
- No Viper switches will be installed. The feeder has six Viper switches that were installed as part of the SGIG Project.
- 240 of the 499 poles (48.1%) on the circuit are will be replaced at a minimum due to the prescriptive replacement of the 60 year limit for mean-time to failure
- Comprehensive fuse coordination and sizing study was performed

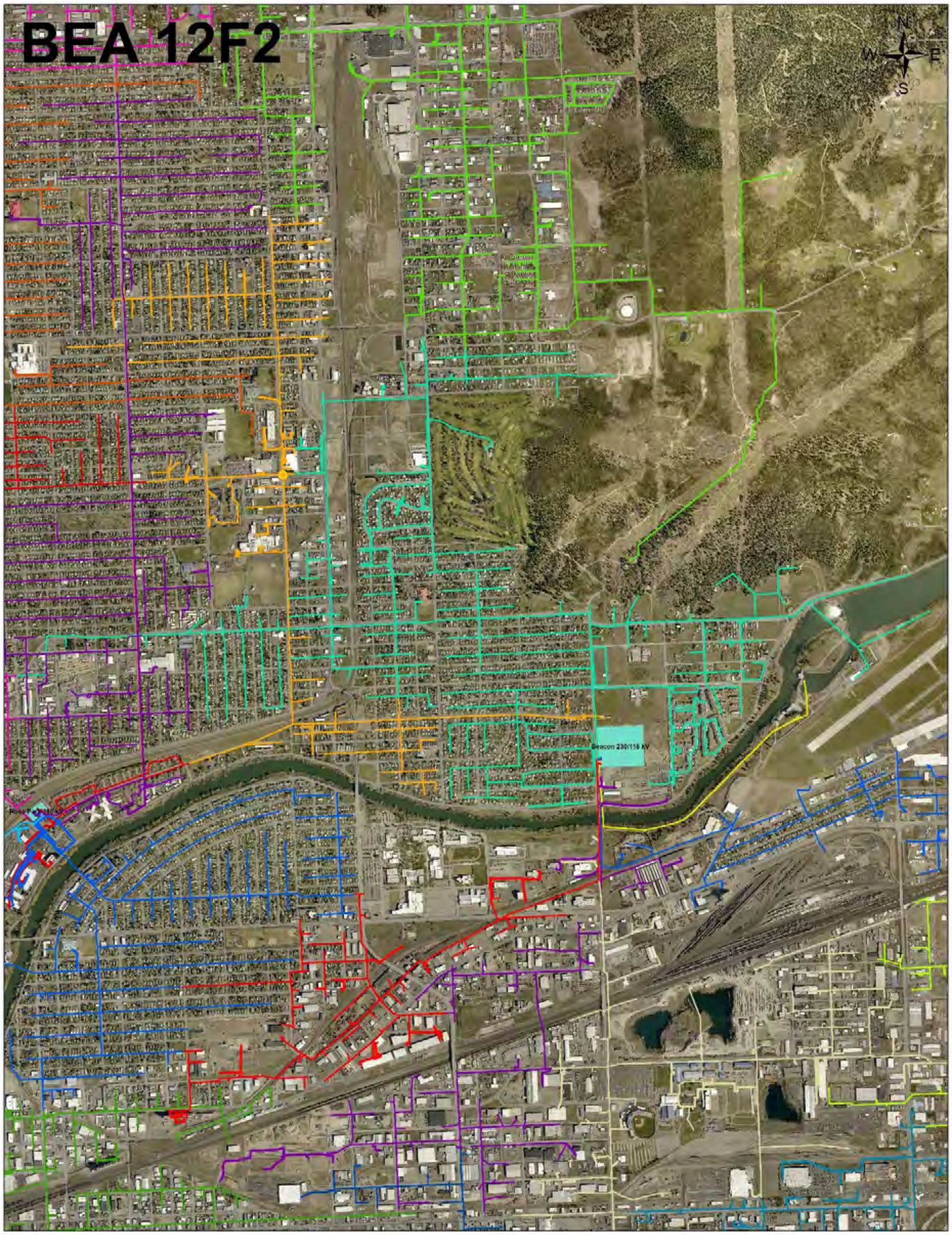

Figure 1. BEA 12F2 Circuit One-Line Diagram

Program Ranking Criteria

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (energy savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set could be measured on different scales, the normalization process offers the ability to convert each figure into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked for selection.

BEA 12F2 had a normalized total ranking of 0.518, ranking 17th on the list of over 340 feeders during the 2018-2020 selection period analyzed in 2015. The normalized data suggests that the selection of this feeder was due to relatively high potential to achieve avoided costs through energy savings efforts and efficiency improvements (65.13%), as well as the opportunity to reduce future O&M expenses through capital improvements (27.22%). Designers should consider these factors when fielding and designing the work on BEA 12F2.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.116	164.966	1655454.511
Normalized Data	0.099	0.964	0.565
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.040	0.338	0.141
Weight of Category %	7.65%	65.13%	27.22%

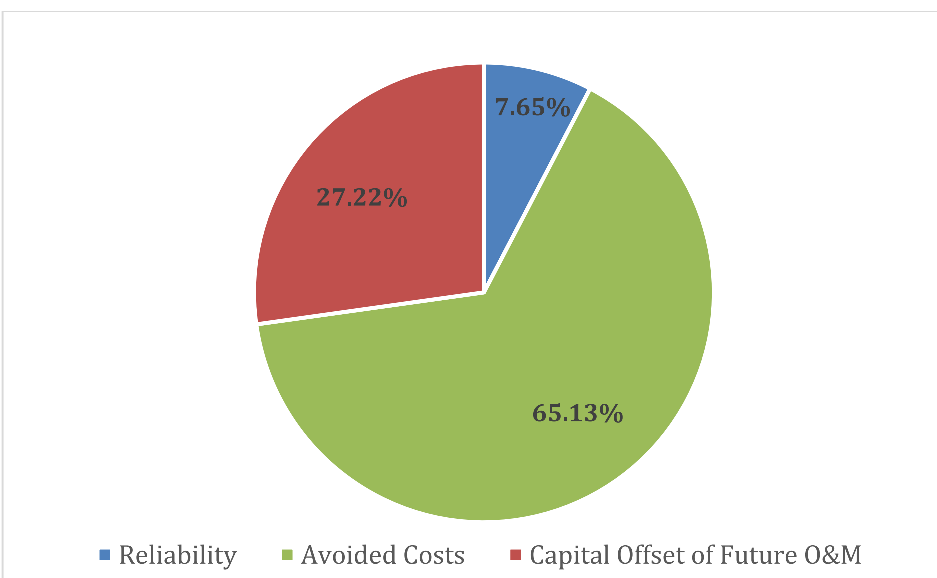

Figure 2. BEA 12F2 Feeder Selection Criteria

Reliability Index Analysis

Reliability indices are significant components of a utility's ability to measure long-term electric service performance, and are one indicator of system health or condition. The common reliability indices of CAIDI, SAIDI, SAIFI, and CEMI3 are used by the Grid Modernization Program to analyze and illustrate the historical reliability performance of the feeders, as well as to assist in justifying any proposed circuit improvements or automation deployments. Each historically averaged reliability index for a feeder is compared to the Avista target value for that calendar year to determine the reliability performance of a feeder.

BEA 12F2 was found to have 137 sustained distribution outages from 2006 through 2016 from OMT analysis, for an average annual figure of 12.2 sustained distribution outages. In addition, BEA 12F2 was found to have 29 momentary distribution outages from 2006 through 2016 from OMT analysis, for an average annual figure of approximately 3.6 momentary distribution outages. The key reliability indicators for BEA 12F2 were analyzed from 2006 to 2016 to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed circuit improvements or automation deployments. The table below shows the annual value for each respective reliability index on BEA 12F2 in the corresponding year. The reliability indices that Grid Modernization uses for Measurement and Reporting do not include Major Event Days (MED). Major Event Days is an industry standard that is used to evaluate major events, such as severe weather or storms, which can lead to unusually long outages in comparison to the distribution system's typical outage. The reliability indices that are being used do not include MED, as this is standard per IEEE and reflects the same reliability information that Avista shares with the respective state Utility Commissions.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2006	1.2%	1.26	81	65
2007	0.0%	0.09	14	160
2008	0.0%	0.12	17	144
2009	0.9%	1.89	104	55
2010	0.3%	0.96	17	17
2011	1.0%	2.49	62	25
2012	0.0%	1.03	77	74
2013	0.0%	0.13	18	139
2014	0.0%	0.19	36	190
2015	0.0%	0.37	111	299
2016	0.1%	0.11	15	145
Average	0.32%	0.785	50.19	119.41

The previous table illustrates the annual value for each respective reliability index on BEA 12F2 in the corresponding year. This information is also provided in graphical form in Figures 3 through 6. The information in these graphs do not include MEDs.

CEMI3 is defined as the Total Number of Customers Experiencing 3 or More Sustained Interruptions /divided by the Total Number of Customers Served. The performance of this metric has been very good, with many years of zero customers experiencing 3 or more sustained outages. This index is showing a declining linear trend during the 11 years of analyzed data. The CEMI3 index for BEA 12F2 has consistently been outperforming the annual Target value set internally by Avista.

SAIFI is defined as the Total Number of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has been inconsistent, and has relatively varied over the years. This index is showing a declining linear trend during the 11 years of analyzed data. The SAIFI index for BEA 12F2 has mostly been outperforming the annual Target value set internally by Avista, however there are some years where the target was not satisfied.

SAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has been inconsistent, and has relatively varied over the years. Despite the inconsistent performance, this index is showing a flat linear trend during the 11 years of analyzed data. The SAIDI index for BEA 12F2 has consistently been outperforming the annual Target value set internally by Avista, which is showing an increasing trend.

CAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Interruptions. The performance of this metric has largely been increasing since 2010, but it has relatively varied over the years. This index is showing a increasing linear trend during the 11 years of analyzed data. The CAIDI index for BEA 12F2 was outperforming the annual Target value set internally by Avista, however the internal target has not been met since 2012.

The average value of each index was calculated and then compared to the Avista 2017 Target values. All four of the historical averaged measured indices on BEA 12F2 are out performing the 2017 targets. This data suggests that customers experience relatively few outages on the feeder, and the average service restoration duration is within the desired range of Avista.

WA-ID Key Indicator	2017 Target	BEA 12F2	Variance
SAIFI Sustained Outages/Customer	1.12	0.785	0.335
SAIDI Outage Time/Customer (min)	151.00	50.19	100.81
CAIDI Ave Restoration Time (min)*	149.00	119.41	29.59
CEMI3 % of Customers >3 Outages	6.80%	0.32%	6.48%

*CAIDI values were converted from hours to minutes for this report

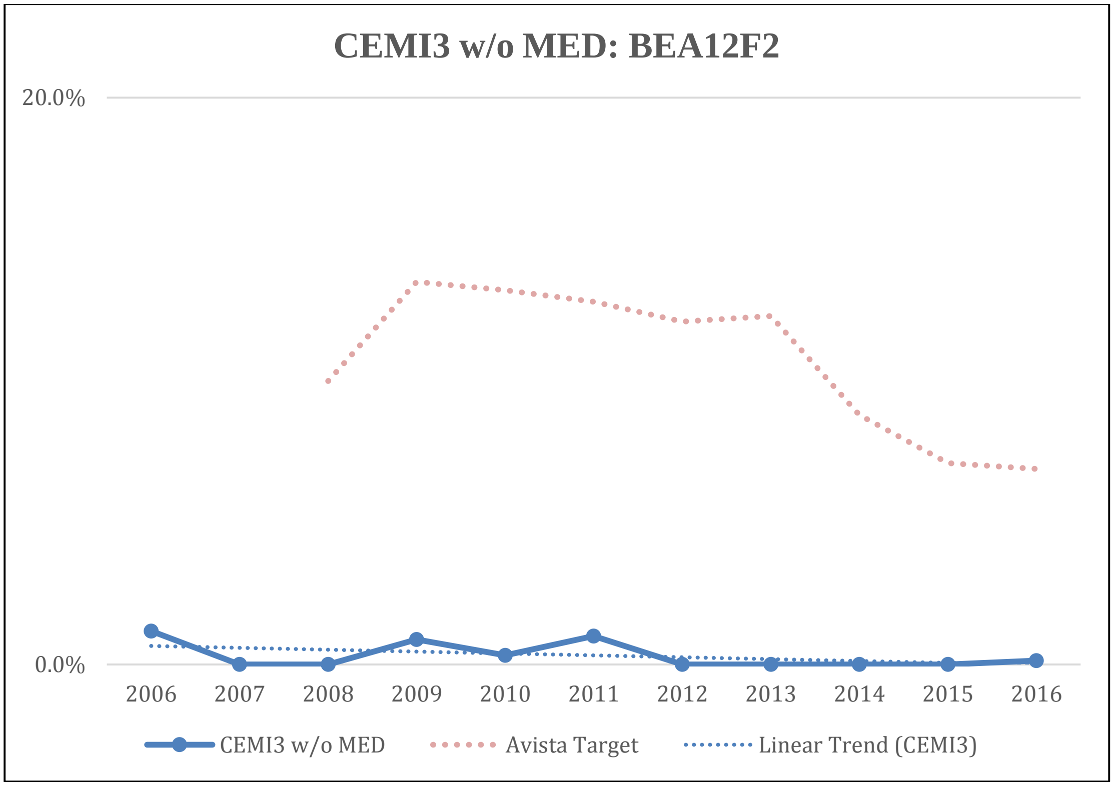

Figure 3. BEA 12F2 CEMI3 Performance

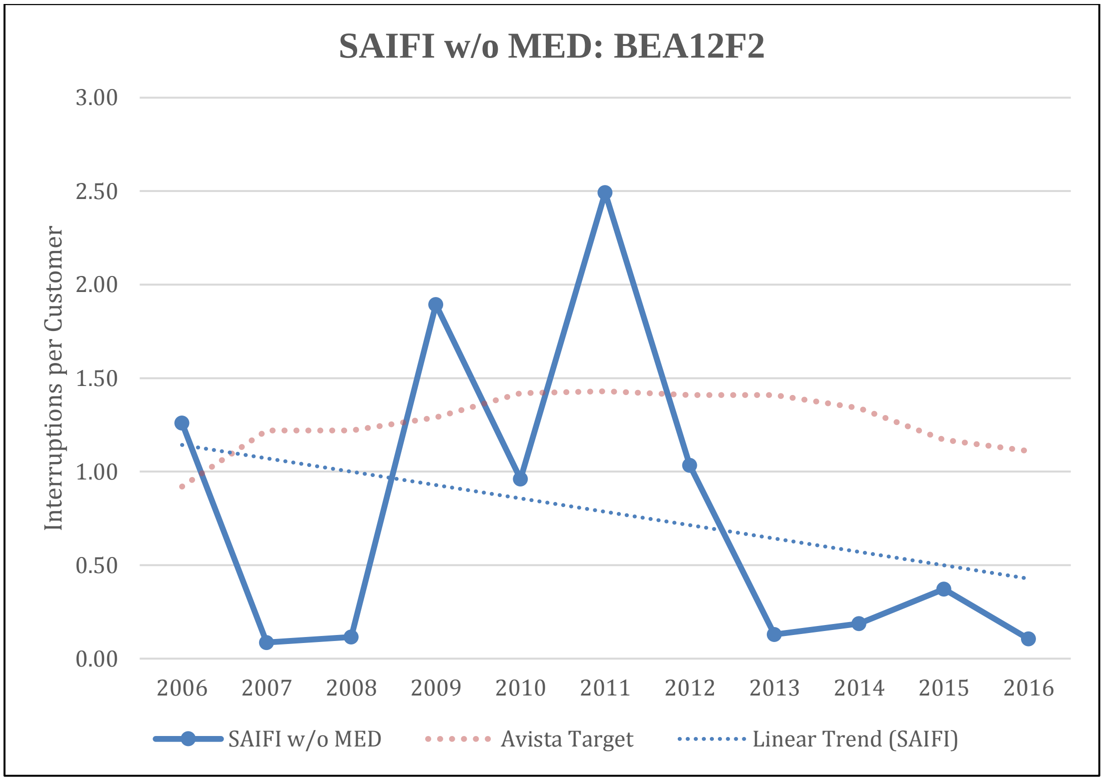

Figure 4. BEA 12F2 SAIFI Performance

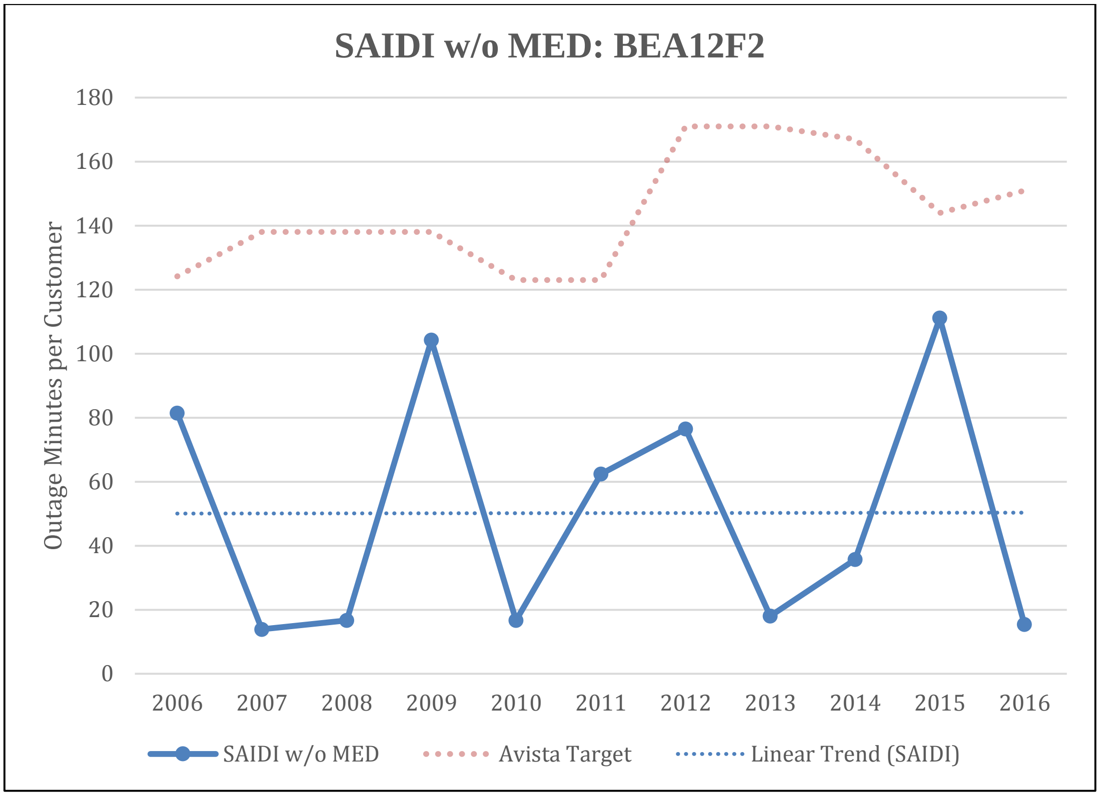

Figure 5. BEA 12F2 SAIDI Performance

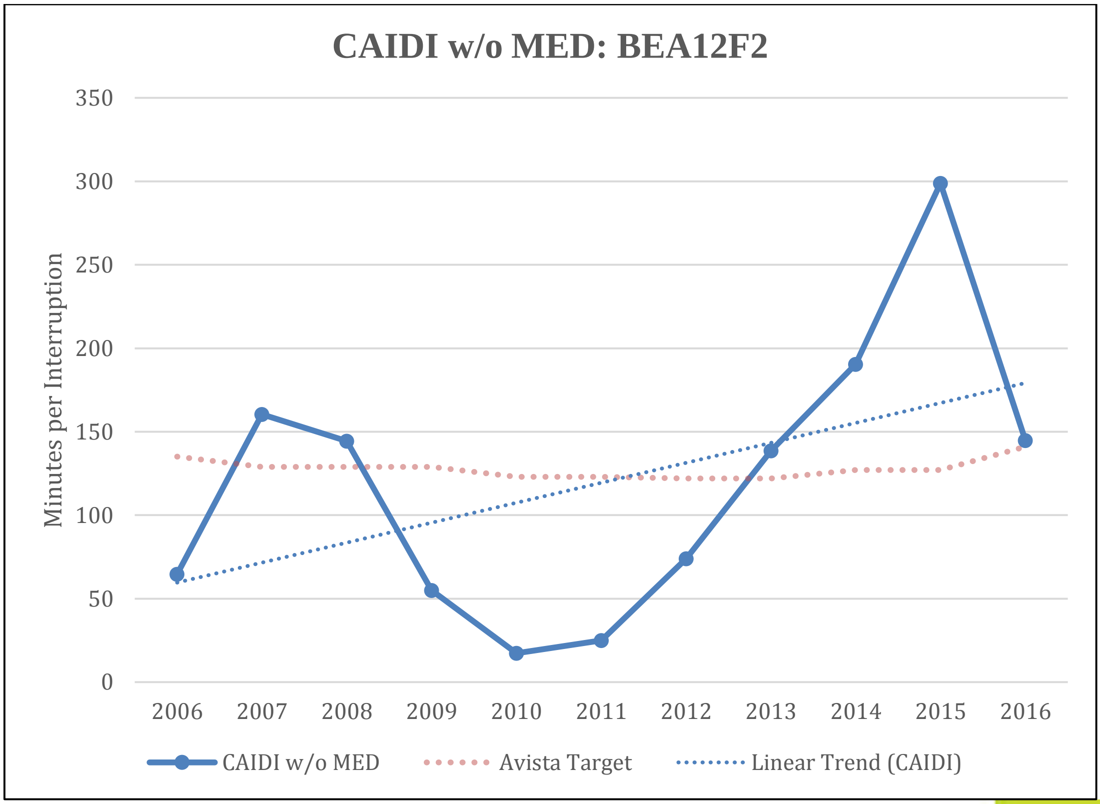

Figure 6. BEA 12F2 CAIDI Performance

Peak Loading

Three-phase ampacity loading from SCADA monitoring at the BEA 12F2 substation circuit breaker was analyzed from 7/14/15 to 7/13/17. The following ampacity loading values were established for BEA 12F2 during this timeframe. Loading information has been analyzed to determine if any data needed to be removed from selected timeframes due to temporary changes in loading from switching (verified through PI). It was identified that there were two time durations that should be excluded from the loading due to BEA 12F2 being in an abnormal feeder configuration and serving additional load from an adjacent feeder. Figure 7 illustrates the two durations that are excluded from loading analysis where additional load was serving during abnormal feeder configuration. The first duration of abnormal loading began at approximately 3/13/2017 8:00 AM and ended at approximately 4/4/2017 8:00 AM. Figures 8 and 9 illustrate the beginning and ending of the first abnormal loading occurrence. The second duration of abnormal loading began at approximately 4/10/2017 9:00 AM and ended at approximately 4/20/2017 8:00 AM. Figures 10 and 11 illustrate the beginning and ending of the first abnormal loading occurrence.

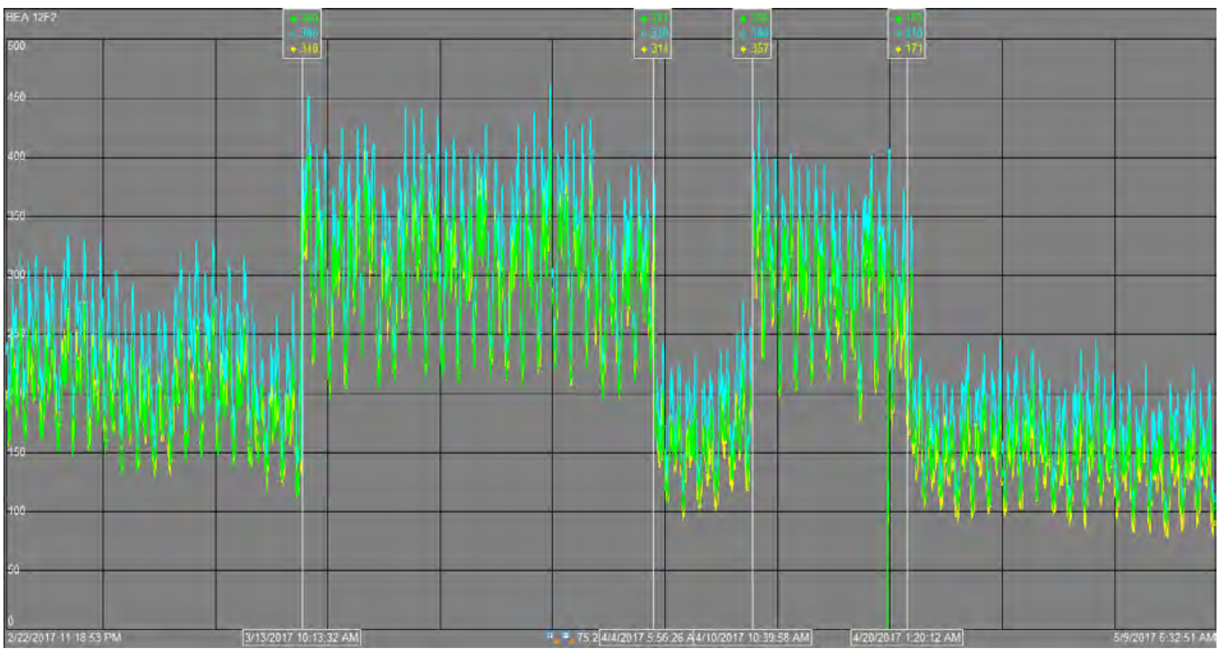

Figure 7. BEA 12F2 Abnormal Feeder Configuration Reflecting Additional Load Transfers

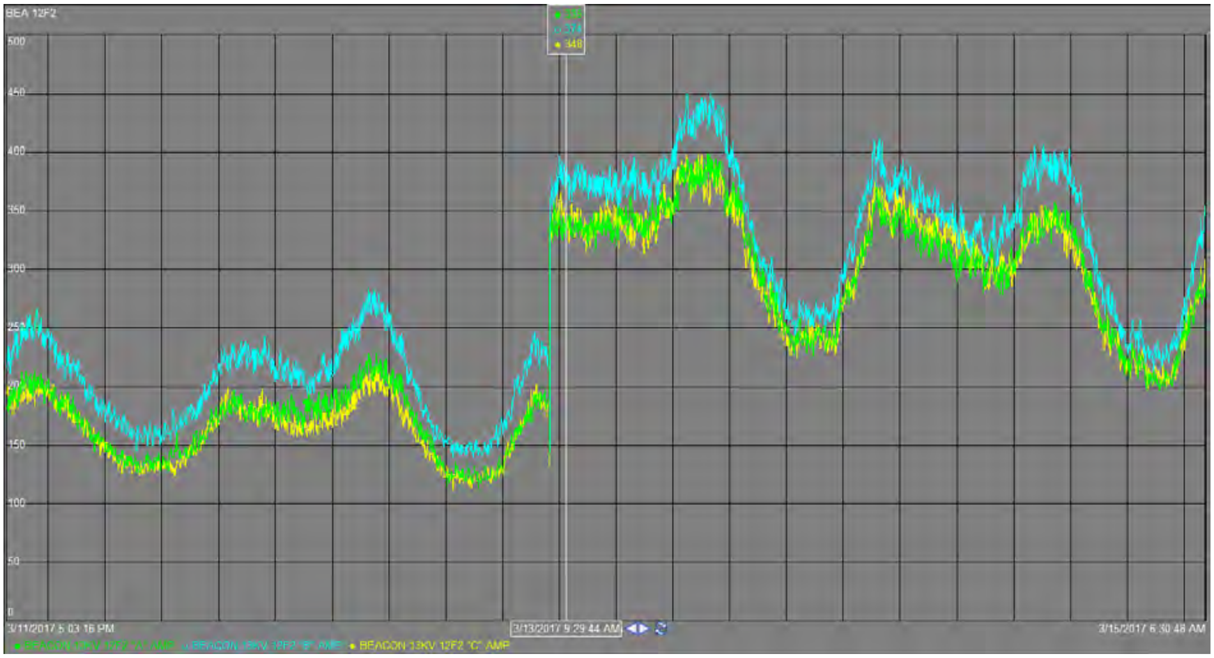

Figure 8. BEA 12F2 Start of Abnormal Feeder Configuration on 3/13/2017

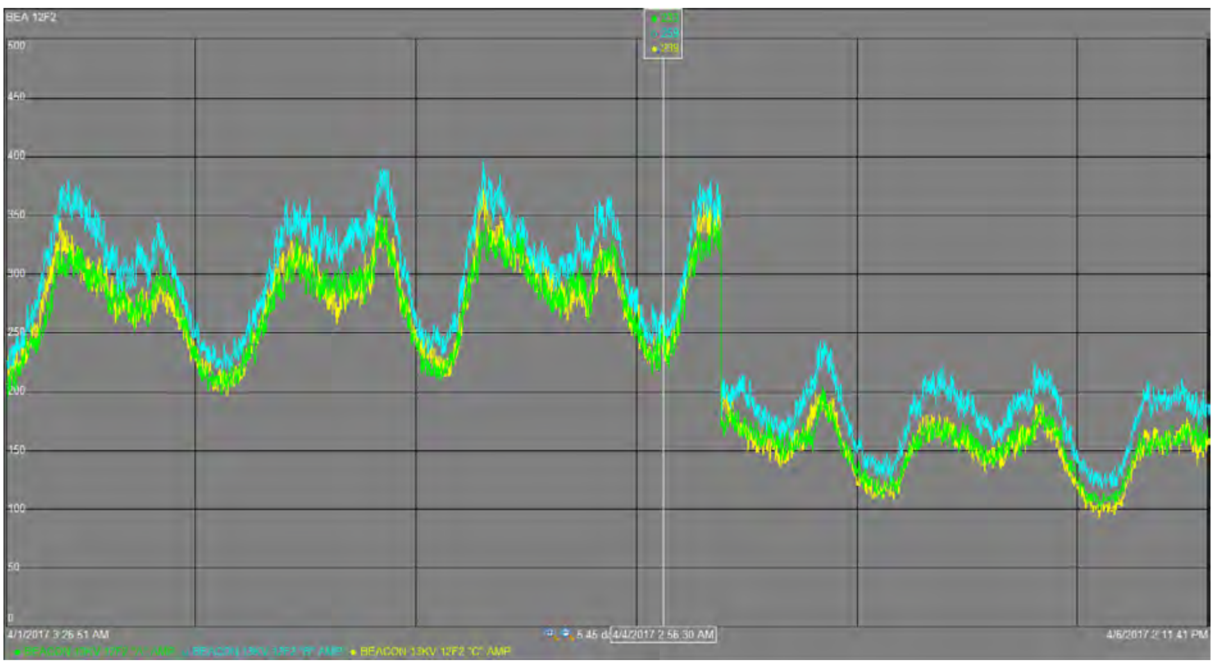

Figure 9. BEA 12F2 End of Abnormal Feeder Configuration on 4/4/2017

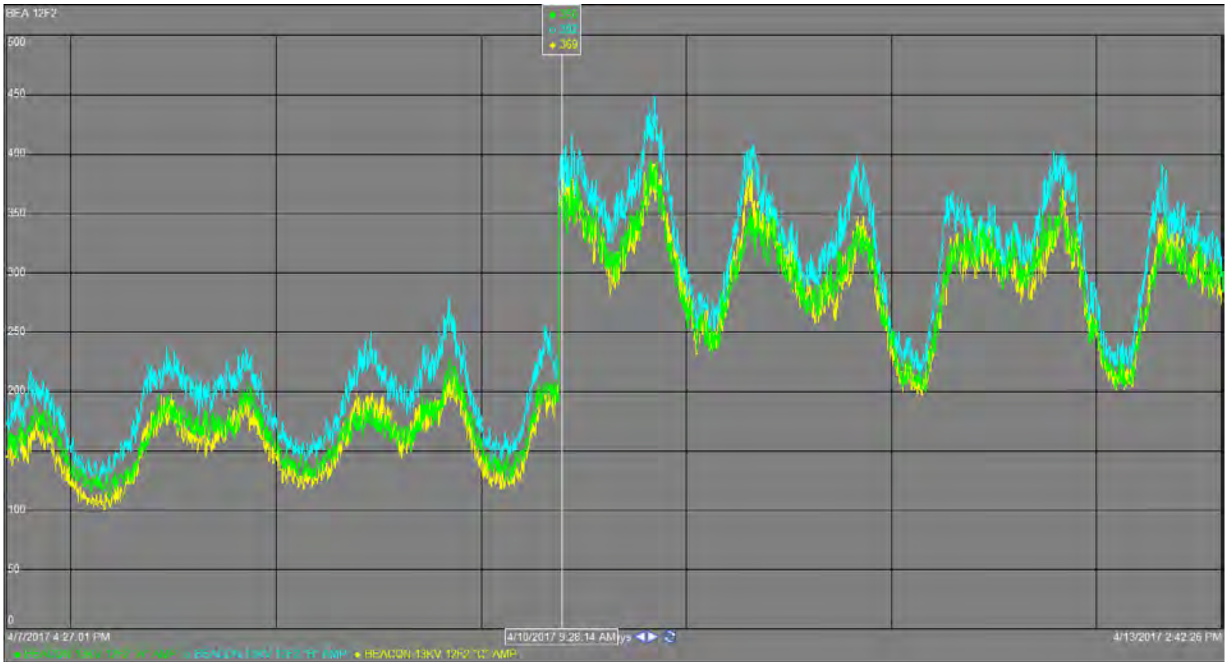

Figure 10. BEA 12F2 Start of Abnormal Feeder Configuration on 4/10/2017

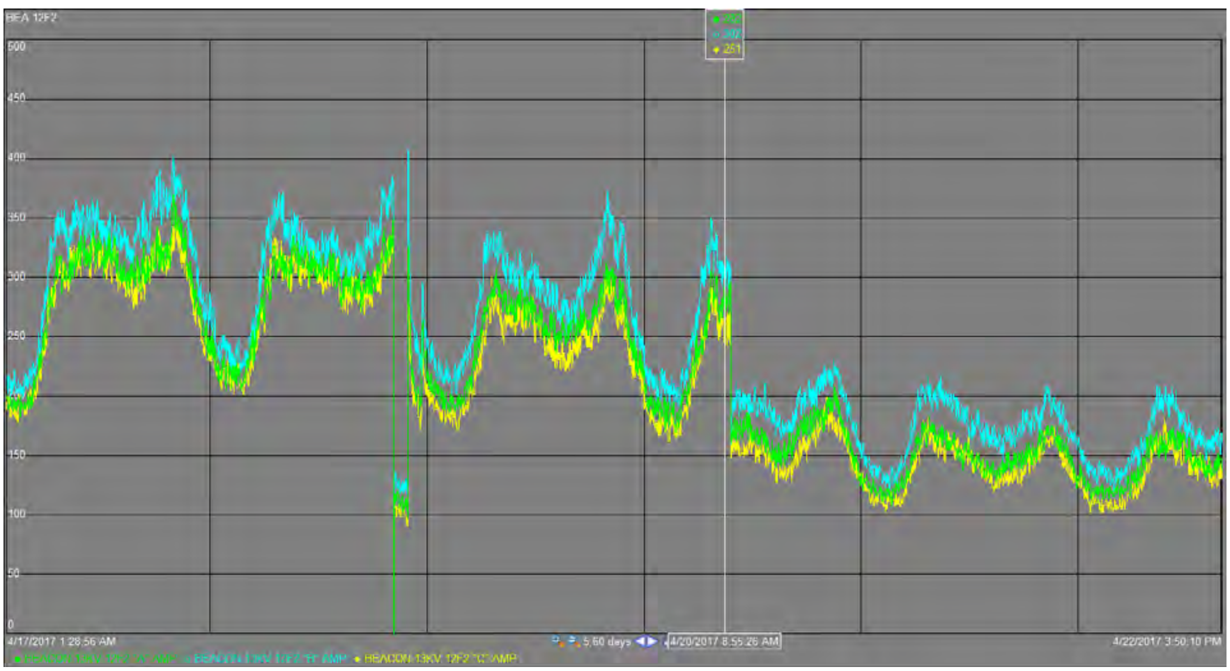

Figure 11. BEA 12F2 End of Abnormal Feeder Configuration on 4/20/2017

BEA 12F2 is a winter peaking feeder, with comparable peak values observed from early December through late February. There are distinct summer peaks as well on the feeder, however the winter peaks experience greater loading than the summer peaks. The values below reflect the adjusted data set where loading values during abnormal feeder configurations has been removed. The peak loading values for each phase are used in the Synergi model analysis for the feeder, except where average load values are noted for establishing kW losses.

	Before Balancing	
	Peak Loading	**Average Loading**
A-Phase	388 A	173 A
B-Phase	441 A	205 A
C-Phase	405 A	171 A
Average	411 A	183 A

	After Balancing	
	Peak Loading	**Average Loading**
A-Phase	408 A	182 A
B-Phase	421 A	196 A
C-Phase	405 A	171 A
Average	411 A	183 A

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from Synergi at the model's initial configuration before balancing or performing improvements on the circuit.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	3092	6909	44.75%
B-Phase	3517	6828	51.51%
C-Phase	3228	6650	48.54%

*kVA per Phase in Synergi as of 8/21/17

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	1381	6909	19.99%
B-Phase	1631	6828	23.89%
C-Phase	1360	6650	20.45%

*kVA per Phase in Synergi as of 8/21/17

Load Balancing

Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which will mitigate the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts will commence toward the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

Accurate load balancing can be analyzed and achieved on BEA 12F2 due to the three-phase ampacity loading from SCADA monitoring at the substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively before balancing:

	Connected KVA per Phase*
A-Phase	6909 kVA
B-Phase	6828 kVA
C-Phase	6650 kVA

* Connected kVA per Phase in AFM as of 8/21/17

The following list provides the phase changes to loads, laterals, or dips that can effectively balance the load on the phases between numerous strategic locations on the feeder, as illustrated in Figure 12. As a whole, the trunk sections and multi-phase laterals on BEA 12F2 were relatively balanced, however opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate the following change into their appropriate polygon designs:

1. **Polygon 9** – transfer 1Φ OH lateral east of Longfellow-Princeton & Rebecca (≈21 A peak loading, ≈11 A average loading) from BΦ to AΦ.

The result of this load transfer is listed in the following table. This change will approximately balance the feeder at the substation breaker to 408/421/405, as well as between the numerous strategic points to approximately sectionalize the feeder to optimize switching and load transfers.

	Existing			Proposed		
	A-Phase	**B-Phase**	**C-Phase**	**A-Phase**	**B-Phase**	**C-Phase**
BEA 12F2 Station Breaker	388	441	405	408	421	405
Switch #301	207	322	255	227	302	256
Recloser #Z87R	163	227	196	182	207	196
Switch #638	89	120	94	107	100	94

It is the Designer's responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any proposals for phase balancing prior to commencing the job designs.

The decision to move forward with the proposed phase change will be confirmed and approved by the Regional Operations Engineer, and coordinated by the Designer in their respective polygon design(s).

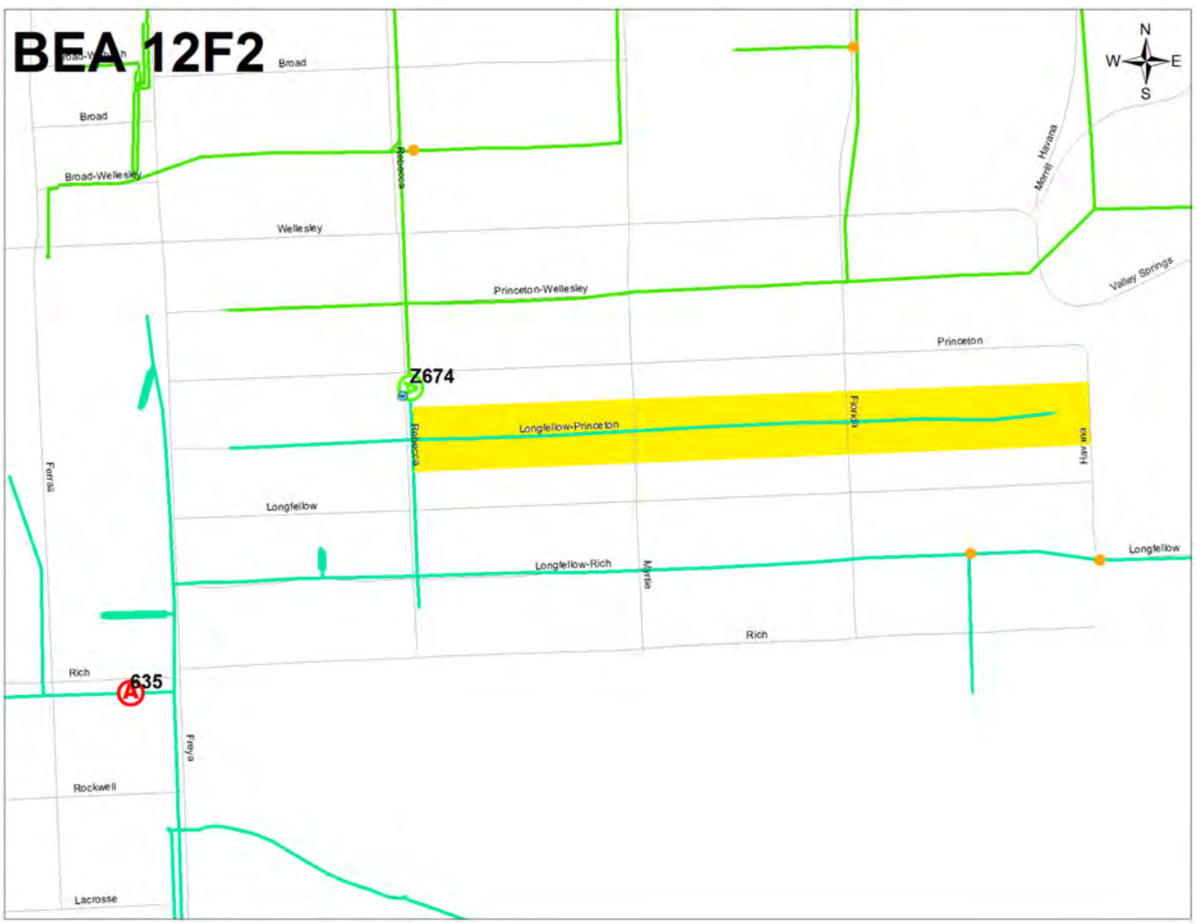

Figure 12. BEA 12F2 Feeder Balancing – Recommended Phase Change

Conductor

All primary conductors on BEA 12F2 were analyzed in Synergi using the balanced peak ampacity values identified in the *Peak Loading* section of this report. Specific attention was given to conductors that have the potential for being overloaded, have relatively high line losses, serve areas with unacceptable voltage quality, and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on BEA 12F2, as well as the proposals for improving the efficiency, voltage quality, and performance of the feeder.

High loss conductors are inefficient conductors that result in increased line losses, especially where there is moderate to heavy loading. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on replacing conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher loss conductors. An Engineering decision can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also decide to reconductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management (WPM) reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

The following table lists the various types of overhead conductors that are present on BEA 12F2, as well as the approximate circuit miles of each conductor type as analyzed through the Synergi modeling software on the creation date of the model. An initial analysis suggests that the only higher loss conductor present on the feeder is approximately 0.21 circuit miles of 6CR conductor. If any of these additional conductors are found during field analysis, the Designer shall determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

Approximate Circuit Miles by Conductor Type		
Conductor	**Miles**	**Ohm/Mile (50°C)**
6CR (Solid)	0.21	12.2981
4ACSR	3.28	2.4590
6A (CW)	0.56	2.44
6CU	10.84	2.417
2CN15	0.03	1.5419
1CN15	9.20	1.2229
2STCU	0.50	0.975
2CU	0.29	0.956
336ACSR	1.58	0.3027
556AAC	2.79	0.1855

The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the conductor analysis requirements for the Grid Modernization program. The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary conductor requiring attention.

The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweigh the significant work required to rebuild the existing line to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors. The ability to reconfigure and convert feeders for reliability and efficiency improvements is a characteristic that distinguishes Grid Modernization from other internal programmatic or capital work.

BEA 12F2 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, it is not likely that there are sections that would warrant reconfiguration due to proposed reconductoring, physical conditions, stubbing, and/or high resistant conductors. The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole tests and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

Any designs to reconfigure overhead circuits or convert to underground shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements. All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconfiguration or conversion to underground prior to initiating the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, are economically justifiable, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Primary Conductor Analysis

Primary conductors have the ability to negatively affect the reliability and efficiency of a distribution circuit. Primary conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to serve peak loading demands and provide adequate voltage levels, and insure that they do not cause significant and unnecessary line losses. Primary conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

Primary Trunk Conductor Analysis

The primary trunk conductors on BEA 12F2 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The entire feeder trunk is currently conductored with either 556 AAC or 336 ACSR in overhead applications. BEA 12F2 currently contains four overhead feeder ties through: switch Z143 (BEA 12F5), switch Z274 (ROS 12F5), switch Z328 (ROS 12F1), and switch Z674 (NE 12F4).

There are minimal findings to support upgrading the primary trunk conductors on BEA 12F2 based on capacity concerns given the large amount of high capacity conductors already present the feeder trunk and ties. In addition, line losses on the trunk are currently in the optimal range for both the peak and average loading scenarios, which has been aided by balancing the feeder and relatively lower loading conditions where higher loss conductors exist. There are not concerns with voltage quality and under voltage scenarios that could be improved through feeder trunk reconductoring.

Any designs to reconductor primary trunk shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary trunk prior to initiating the job designs. It may be determined that additional primary or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary trunk conductors based on the conditions dictated through field analysis.

Primary Lateral Conductor Analysis

The primary lateral conductors on BEA 12F2 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The laterals on BEA 12F2 were individually analyzed to determine if the wires were sized appropriately for load, line losses, and voltage quality. The analyzed models suggest reconductoring of selective laterals to meet peak loading conditions during normal system configuration, lower line losses, and promote improved voltage levels downstream. As part of the line loss analysis, attention was given to identify the presence of high loss conductors, even if relatively low loading levels did not provide high line losses.

- Reconductor existing 2-phase overhead lateral east of Buckeye & Havana with 2/0 ACSR primary and a 2/0 ACSR neutral (approximately 1100') in **Polygon 2**. Install new A-phase 2/0 ACSR primary conductor to existing lateral to create a 3-phase lateral. This existing 2-phase lateral is currently served by 6CU (approximately 640') and 4 ACSR (450'). The overhead single-phase load off of this three-phase lateral should be transferred to the new A-phase, if possible. Figure 13 illustrates this proposed reconductor.

In addition, the following list of laterals should be further examined by the assigned Designer in the field to support reconductoring these laterals to a minimum of 4ACSR. As part of the field analysis, the Designer should determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, potential benefits from relocation, etc. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program. Figure 16 identifies the primary laterals requiring additional field examination for possible replacement or reconfiguration on BEA 12F2

- **Polygon 4** – Approximately 730' of 6A, 3A peak (2% loaded). This single-phase, multi-span lateral serves two customers. The physical condition of the wire, in combination with the condition of the poles, should be analyzed in the field to determine if the lateral should be reconductored. Although not necessary, it could be determined to convert this lateral to underground if it is determined that multiple pole replacements are required and the conductor is found in poor physical condition. Figure 16 illustrates this proposed work.
- **Polygon 4** – Approximately 1840' of 6A, 1A peak (1% loaded). This single-phase, six span lateral serves a single home. The lateral contains a mixture of 40' Class 5 poles, leaning or twisted cross arms, sunken wood pins, and a minimum of two poles requiring replacement due to age. At a minimum this lateral is a candidate for reframing to Avista's A-1 standard. This lateral is also a candidate for converting to underground if it is determined that multiple pole replacements are required and the conductor is found in poor physical condition. Figure 14 illustrates this proposed reconfiguration.

- **Polygon 4** – Approximately 1100' of 6CR, 5A peak (29% loaded). This two-phase, three span lateral is a river crossing downstream of Upriver Dam. The line crosses the waterway twice: once downstream of the Upriver Dam spillway, and once across the intake to the Upriver Dam Powerhouse. The spans are approximately 690' and 420' respectively. A minimum of two of the four poles will require replacement due to age. The physical condition of the wire should be analyzed in the field to determine if the river crossing should be reconductored or converted to underground primary and served from a different source on the south side of the river. Marker balls shall be installed as part of any overhead reconductoring efforts. In addition, the field assessment and condition of the river crossing poles will also contribute in the decision to reconductor the crossing. Due to the difficulty involved with restringing a river crossing and the potential barriers involved with permitting, the decision to proceed with reconductoring will include the Grid Modernization Program Engineer and Program Manager based on the field findings by the Designer. Figure 15 illustrates this proposed reconductor.

Any designs to reconductor primary laterals shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary lateral conductors based on the conditions dictated through field analysis.

Figure 13. BEA 12F2 Primary Lateral Reconductor on Buckeye to 2/0 ACSR

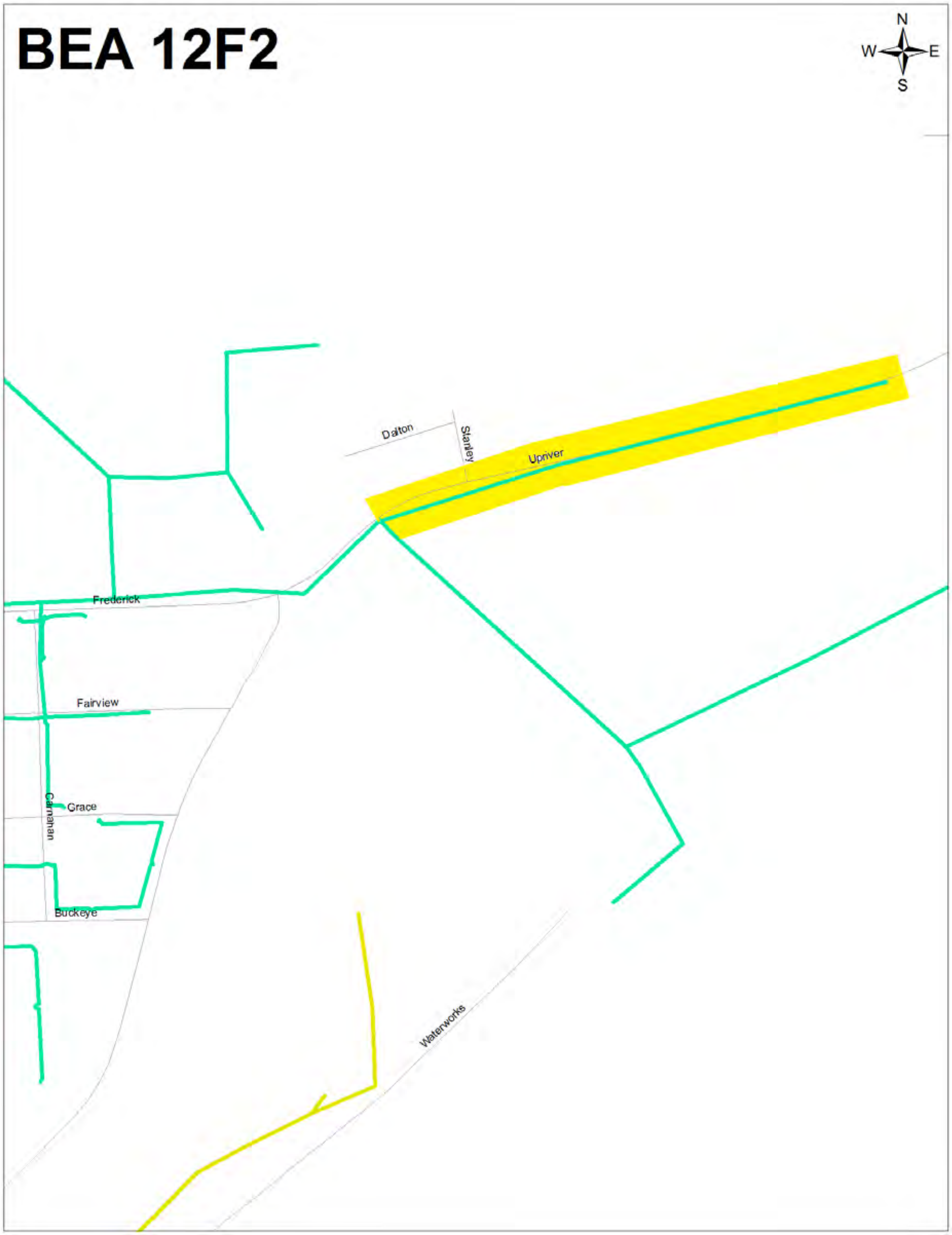

Figure 14. BEA 12F2 Primary Lateral Reconfiguration on Upriver

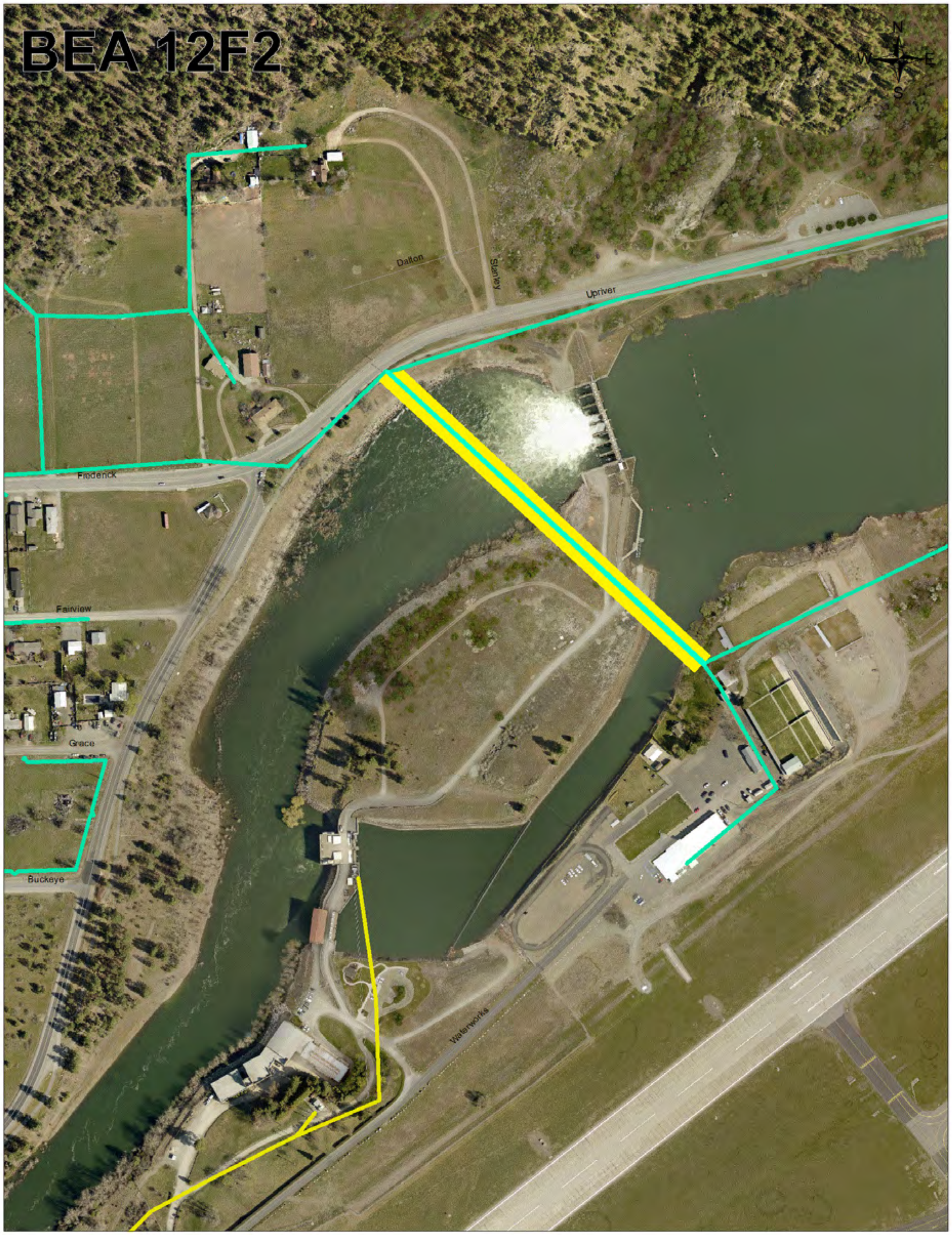

Figure 15. BEA 12F2 Primary Lateral Reconductor on Spokane River Crossing

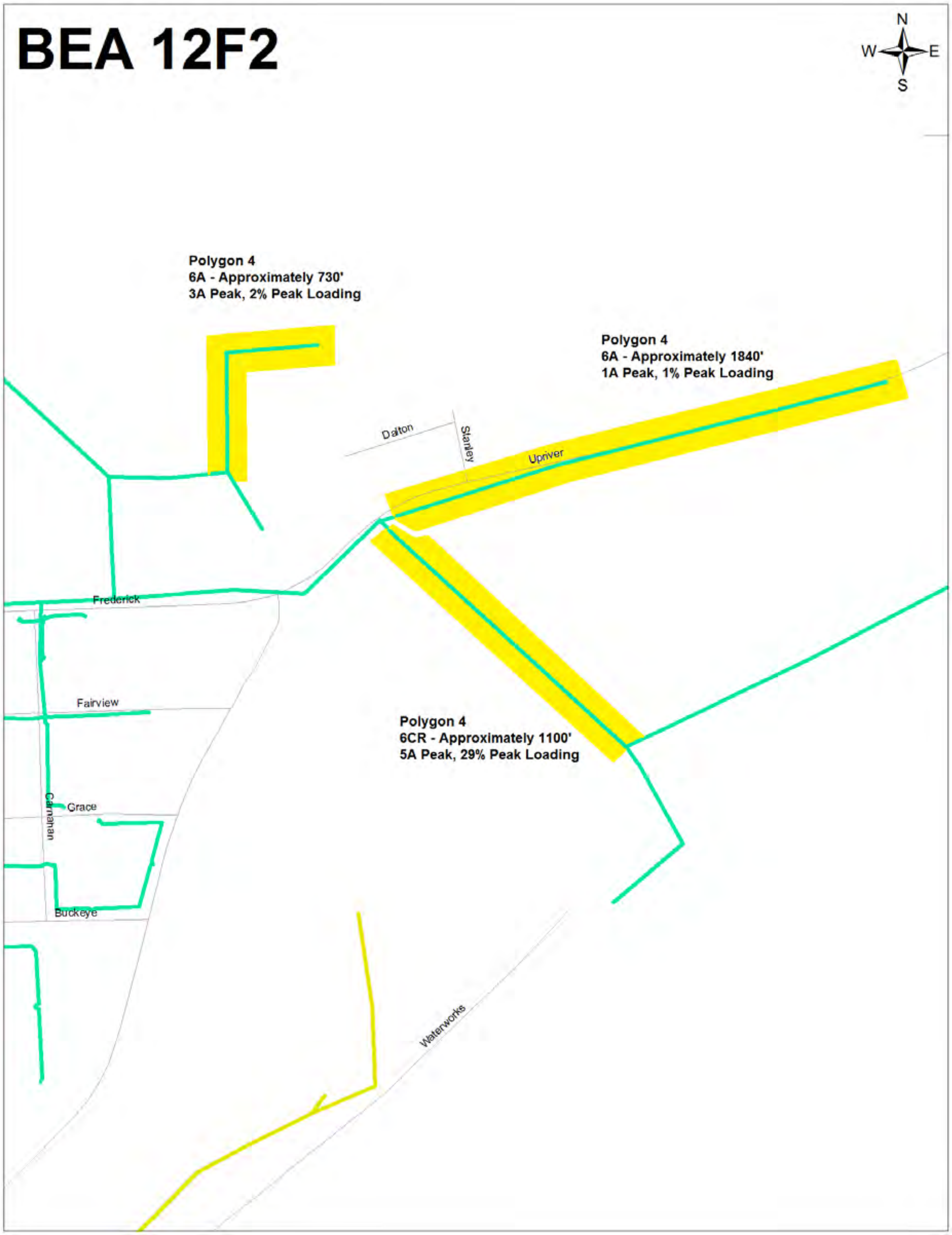

Figure 16. BEA 12F2 Primary Laterals Requiring Further Field Examination

Feeder Tie Locations and Opportunities

A reduction in the duration of outages can be achieved through rebuilding existing feeder ties and establishing new feeder ties. Existing feeder ties can be improved through increased capacity by reconductoring to higher ampacity conductors, as well as replacing existing manual switches with communications devices that can either be controlled remotely or through a distribution management system (DMS). New feeder ties can be established for circuits without connections to adjacent feeders or where additional ties could provide reliability improvements. Newly created feeder ties will generally be optimized by installing switches with communications that can either be controlled remotely or through a distribution management system (DMS).

BEA 12F2 currently contains four overhead feeder ties through: switch Z143 (BEA 12F5), switch Z274 (ROS 12F5), switch Z328 (ROS 12F1), and switch Z674 (NE 12F4). All four of these feeder ties were upgraded and automated during the Smart Grid Investment Grant (SGIG) project in 2010 through the installation of S&C SCADA-Mate devices.

There was one additional feeder tie opportunity that was analyzed for BEA 12F2. Despite the numerous feeder ties further downstream on the circuit, there is not a method to pick up the first half of the feeder (in terms of loading). A solution exists to install a tie switch close to the Beacon Substation with BEA 12F2 and BEA 12F5. The two feeders are collocated on the same structures for five spans. Either a manual air switch or an automated S&C SCADA-Mate could be utilized to establish an “top-bottom” tie for circuits that are located on the same structure.

After discussing this option with the Spokane Area Engineers, it was decided for Grid Modernization not to pursue establishing this tie. It was determined that the benefits may be small and the Area Engineers may not be use the device enough to justify the switch.

The decision to pursue additional feeder tie opportunities will be discussed and determined with the Regional Operations Engineer based on their anticipated frequency of using potential ties in the operation of the Spokane distribution system.

Figure 18 illustrates the location of the feeder ties on BEA 12F2, as well as the other distribution automation line devices.

Voltage Quality

Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. In addition, primary laterals and trunks are reconductored with more efficient conductors to increase sagging voltage levels. In some scenarios, an additional conductor phase(s) may be installed to offload a heavily loaded phase and assist in supporting the voltage.

The BEA 12F2 circuit was analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled in Synergi during both peak loading and average loading conditions, with both normal and abnormal circuit configurations.

The following information on the substation voltage regulators for BEA 12F2 was taken from Maximo, which is the system of record for Avista T&D assets.

Serial Numbers	A	B	C
BEA 12F2 Station Regulators	**0950004257**	**0950004258**	**0950004372**

Rated Power	**333 kVA**
Rated Current	**438 A**
C.T. Ratio	**500/.02**
Equipment P.T. Ratio	**60.0:1**
Corrected/Desired P.T. Ratio	**63.5:1**
Distribution Transformer Ratio	**63.5:1**

* Information in MAXIMO as of 8/18/17

Voltage Regulator Settings

As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline voltage regulator settings. This is performed to reflect the changes to loading and to address the conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. The feeder is modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ranges for all customers during the modeled scenarios, and to eliminate over-voltage and under-voltage situations.

BEA 12F2 has one existing stage of voltage regulation at the Beacon Substation. Due to the interconnected urban nature of the feeder, and the shorter feeder length, additional stages of midline voltage regulation are not recommended on the feeder to support voltage levels during normal configuration or times of switching.

The substation regulators at BEA 12F2 are enabled to be controlled through the Integrated Volt-VAR Compensation (IVVC) and Conservation Voltage Reduction (CVR) functions of Avista's Distribution Management System (DMS). The DMS algorithms will continuously provide equivalent R/X and voltage output settings that optimize the voltage levels on the distribution circuit based on the frequently changing loading conditions. The Grid Modernization Program will not be providing recommendations on the voltage regulators R/X settings or voltage output settings on feeders that have IVVC/CVR enabled.

The decision to move forward with implementing any changes to the voltage regulator settings will be pursued and provided by the Regional Operations Engineer.

Fuse Coordination and Sizing Analysis

Incorrect fuse sizes can compromise the reliability of the feeder through miscoordination of operation. Miscoordination can occur if the fuses in series are not correctly sized and managed to allow the furthest downstream device the opportunity to operate first. Fuses that are undersized and do not match the load being served can unnecessary operate and create unexpected outages. A customized fuse protection and coordination scheme has been determined to ensure that a consistent fusing philosophy is deployed and that all fuses are accurately sized.

Fuse sizing on BEA 12F2 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and underground risers. Fuse recommendations for BEA 12F2 were created by the Grid Modernization Program Engineer and approved by the Regional Operations Engineer. This file is located in the Electrical Engineering drive *c01m19* under the folder *Feeder Upgrade – Dist Grid Mod* folder. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

The fuse “blowing” philosophy was selected for BEA 12F2 where the largest fuse was selected that would accurately coordinate to: satisfy peak loading conditions, protect the downstream conductor(s), and for fuse-to-fuse coordination based on preloading of source-side fuse link (maximum fault current). A fuse “blowing” scheme is achieved by selecting the smallest allowable fuse for the first stage of protection by knowing the downstream connected kVA/phase and the largest transformer on the phase (using Distribution Construction Standard DU-2.500). If there was an upstream fuse in series with a lateral fuse, the *Distribution Feeder Protection General Guidelines* (Orange Book, S&C Table VII) was used in coordination with the fault duty found in the Synergi model to select the fuse size.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Line Losses

The distribution of electricity results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and to improve voltage levels on feeders. Line losses are generally addressed by balancing load on the phases between numerous strategic locations on the feeder, and then further minimized by replacing wire with more efficient conductors.

The primary trunk conductors on BEA 12F2 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the urban feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. It should be noted that there were not recommendations to reconductor the feeder trunk or ties, as most of these sections were upgraded 556 AAC and 336 ACSR during the Smart Grid Investment Project (SGIG).

	Polygon 2
Circuit Length (ft)	1093.4
Existing Average kW Losses	1.5
Existing Peak kW Losses	5.6
Proposed Average kW Losses	0.5
Proposed Peak kW Losses	2.1
Average kW Loss Savings	1.0
Peak kW Loss Savings	3.5
Reconductor MWh Savings *	8.76

* Estimated average annual kW losses

An initial Synergi load study estimates that a total of 100 kW in peak line losses currently exist on BEA 12F2 (1.07%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved to approximately 94 kW (1.00%).

Peak Values	**Existing**	**After Balancing**	**After Reconductor**
kW Demand	9640	9641	9737
kW Load	9537	9539	9640
kW Line Losses	100	98	94
kW Loss %	1.07 %	1.05 %	1.00 %

Transformer Core Losses

Core losses are an inherent characteristic of distribution transformers. Core losses negatively affect efficiency and do not change with fluctuation in loading. The Grid Modernization program analyzes the approximate energy savings that are achieved through the reduction in transformer core losses. Savings are obtained when transformers are replaced with more efficient units, whether being replaced due to overloading or based on PCB levels. The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more efficient. Consequently, transformer core losses are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of a near equivalent size.

All distribution transformers on BEA 12F2 shall be analyzed and appropriately sized to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP), incorporating flicker and voltage drop analysis. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the assigned Designer.

The roughly 472 distribution transformers on BEA 12F2 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It is estimated that approximately 118 transformers will require replacement based on the TCOP replacement criteria, with an additional 128 requiring replacement for being incorrectly sized to serve the connected loads. The replacement of these approximate 246 transformers will result in an estimated 29.74 kW reduction in core losses. This equates to an estimated annual savings of roughly 260.52 MWh. The estimated energy savings are achieved through the use of a unique algorithm that was created: to analyze each transformer on the feeder, determine the PCB/age replacement status, determine if the transformer is sized appropriately based on actual loading, make a recommendation on the appropriate size for the load, and then use historical core loss values to calculate the approximate energy savings that are achieved. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work, which is a form of line losses. Power factor is a value that can fluctuate with the variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of over 17,000 hourly data pars covering at least a 24 month span to calculate the apparent power and power factor. This results in comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading, both in terms of time and quantity.

MVAR and MW data at the BEA 12F2 substation circuit breaker was analyzed from 7/14/15 to 7/13/17. It was determined that BEA 12F2 had a lagging power factor 80.5% of the time during the time interval analyzed, and a leading power factor 19.5% of the time during the time interval analyzed. Additional detailed power factor information is available upon request. Some key power factor figures for BEA 12F2 are provided in the tables below.

Maximum Lagging Power Factor	99.99%
Minimum Lagging Power Factor	96.33%
Maximum Leading Power Factor	98.39%
Minimum Leading Power Factor	99.99%
Average Lagging Power Factor	99.85%
Median Lagging Power Factor	99.90%

The graph in Figure 17 shows the percent of time during the interval analyzed where the power factor on BEA 12F2 fell between the applicable ranges. This information is also provided in a table format.

	Lagging	Leading
99%-100%	80.33%	19.03%
98%-99%	0.17%	0.45%
97%-98%	0.01%	0.00%
96%-97%	0.01%	0.00%
95%-96%	0.00%	0.00%
94%-95%	0.00%	0.00%
93%-94%	0.00%	0.00%
92%-93%	0.00%	0.00%
91%-92%	0.00%	0.00%
90%-91%	0.00%	0.00%
80%-90%	0.00%	0.00%
70%-80%	0.00%	0.00%
60%-70%	0.00%	0.00%
Below 60%	0.00%	0.00%

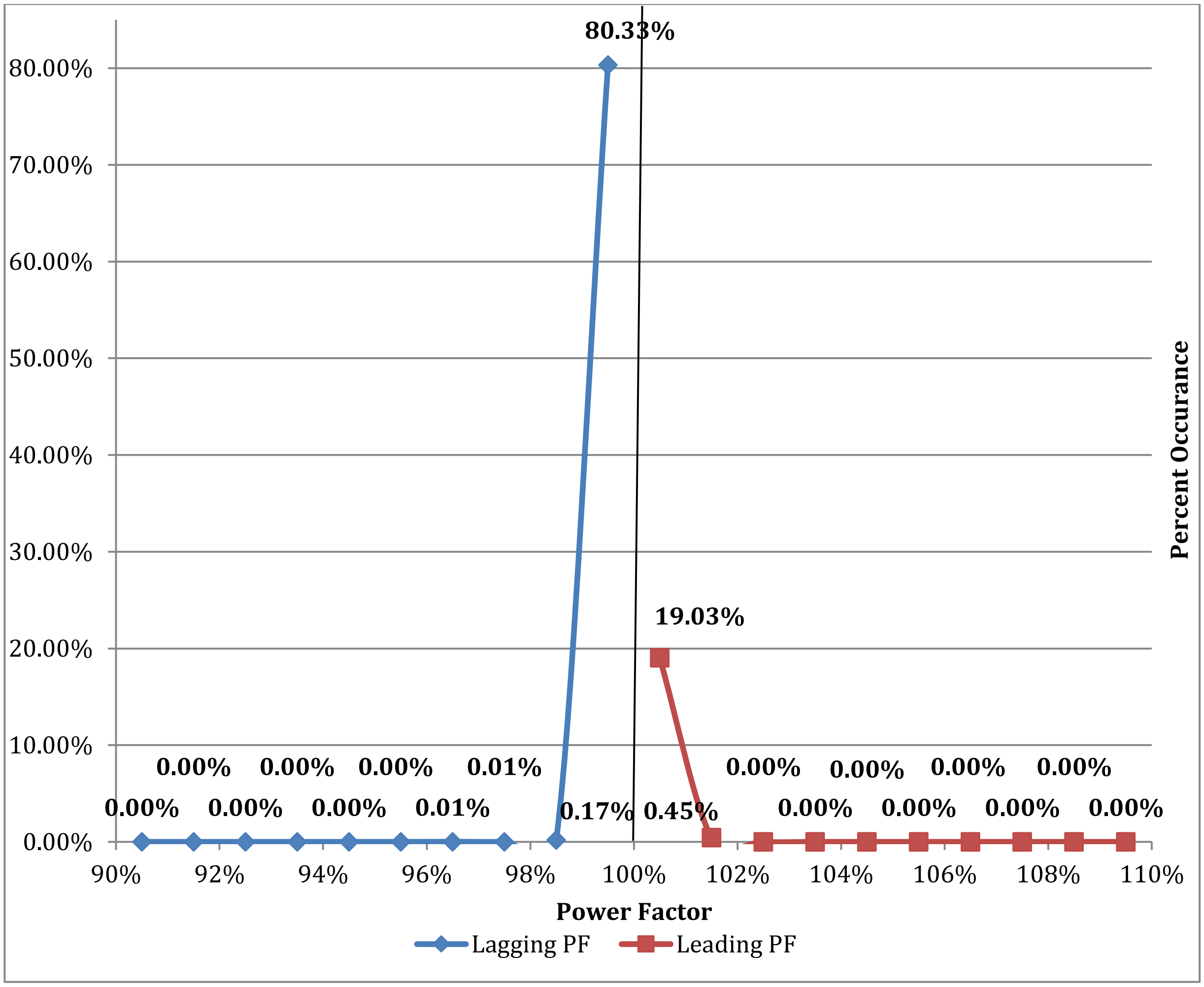

Figure 17. BEA 12F2 Existing Percent Occurance of Power Factor

Power Factor Correction

The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to unity. A power factor at or near unity is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and enacting a solution. The historical Watt and VAR data on the feeder was reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loads to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed in more severe situations to raise the power factor to a reasonable base value, and then switched capacitor banks are installed to supplement the power factor when required by loading. This approach optimizes the correction of the power factor and reduces line losses. The establishment of power factor also incorporates the field verification of existing deployed capacitor sizes, where it is not uncommon to discover capacitor banks that are incorrectly represented in Avista's GIS and modeling software.

There are four existing capacitor banks on BEA 12F2. One of the banks is a 600 kVAR fixed capacitor bank, and the other three are 600 kVAR switched capacitor banks (Z792F, Z793F, and Z794F). These four banks were confirmed in the field by a local Serviceman to each be 600 kVAR units.

The power factor on BEA 12F2 was consistently within the acceptable range with the existing deployed capacitor banks. The circuit consistently has a power factor between 0.99 lead and 0.99 lag approximately 99.4% of the time during the time interval analyzed. This performance is nearly optimal and provides near ideal reactive power compensation for the circuit throughout the year. After analyzing the existing devices on the feeder, it is not recommended to add or remove any capacitor banks as part of the Grid Modernization program.

The decision to move forward with implementing any changes to the capacitors sizes and location will be confirmed, approved, and coordinated by the Regional Operations Engineer.

Distribution Automation

The Grid Modernization program currently represents Avista's largest centralized program to fully automate and improve the operating functionality and efficiency of the distribution system through the installation of automated distribution line devices. Grid Modernization has been programmatically addressing the distribution automation needs of Avista since the end of 2013, and the program focuses on installing air switches, reclosers, capacitor banks, and voltage regulators with communications and remote operability. The reduction in the duration of outages can be achieved through the installation of communications equipment that can either be controlled remotely or through a distribution management system (DMS). In addition, the number of customers impacted by an outage as well as a reduction in the frequency of outages can be achieved through the installation of devices with fault sensing and tripping capabilities. Time and cost savings can be achieved through the remote application of hot-line-holds. Fault detection, isolation, and restoration, conservation voltage reduction, and integrated volt/VAR control can also be achieved through Grid Modernization when the necessary substation equipment and components are in place.

Distribution Automation was analyzed for deployment on BEA 12F2 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on BEA 12F2.

BEA 12F2 currently contains numerous automated distribution line devices from the previous work performed during the Smart Grid Investment Project (SGIG). After analyzing the existing devices on the feeder, it is not recommended to add or remove any distribution line automation devices as part of the Grid Modernization program.

The following distribution line automation devices are currently deployed on the feeder:

Device Number	Location	Status	Device Type
Z58	Ralph & Rich 1PW	N.C.	S&C Scada-Mate Switch
Z87R	Market & Euclid 1PE	N.C.	G&W Viper Recloser
Z102	Havana & Fairview 1PN	N.C.	S&C Scada-Mate Switch
Z143	Garland & Crestline 2PE	N.O.	S&C Scada-Mate Switch
Z274	North Foothills & Hogan	N.O.	S&C Scada-Mate Switch
Z328	Crestline & Euclid	N.O.	S&C Scada-Mate Switch
Z674	Rebecca & Princeton	N.O.	S&C Scada-Mate Switch
Z792	Euclid & Lacey	N.C.	600 kVAR Switched Cap Bank
Z793	Euclid & Myrtle	N.C.	600 kVAR Switched Cap Bank
Z794	Freya & Rich 4PW	N.C.	600 kVAR Switched Cap Bank

Figure 18 illustrates the existing distribution line automation device locations on BEA 12F2.

BEA 12F2 is distribution automation ready at the Beacon Substation with the breakers, relaying, regulators, communications, and EMS/DMS ready.

The Grid Modernization program is not funded to perform work on adjacent feeders, including automation devices and reconductoring. Any requests to perform work on adjacent feeders are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on adjacent feeders.

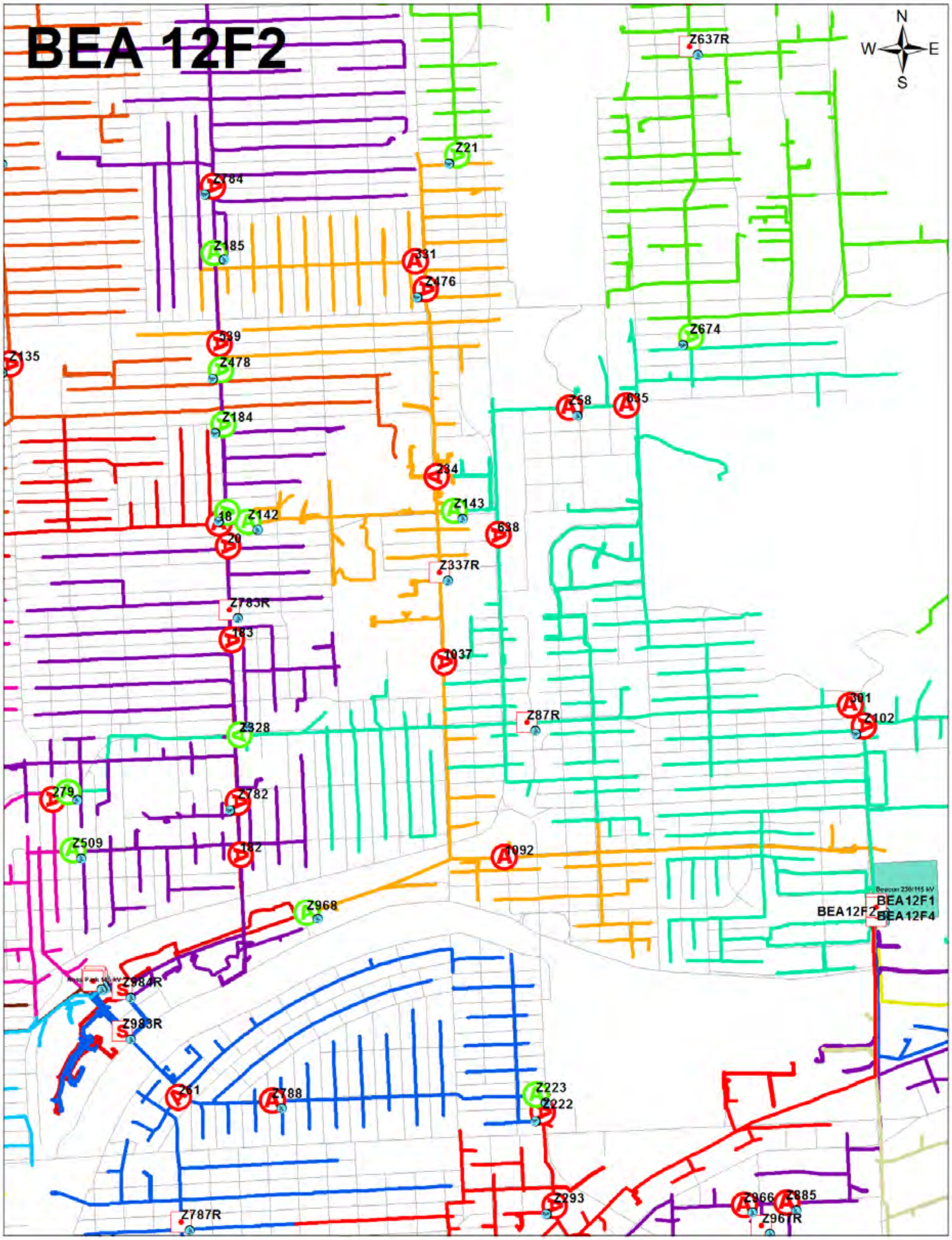

Figure 18. BEA 12F2 Automation Device Locations

Open Wire Secondary

Open wire secondary districts have the ability to negatively affect reliability due to the physical nature of construction and configuration. These districts are also predominantly located in areas with high vegetation growth and limited crew access. These factors have the ability to increase the number of outages and the duration of the outages. A circuit's reliability can be improved by strategically splitting the districts with dedicated transformers and replacing these districts with an appropriately sized dedicated neutral. Grid Modernization is also initiating a study to analyze and quantify the estimated amount of open wire districts on feeders, as well as the amount requiring replacement based on the criteria of the Distribution Feeder Management Plan (DFMP). This will assist in planning and budgeting appropriately to address the needs of the feeders.

Open wire secondary districts have been analyzed for replacement on BEA 12F2 in accordance to the Distribution Feeder Management Plan (DFMP). Approximately 40,000' circuit feet of open wire secondary is currently estimated to be on BEA 12F2. This figure was established from physical observations obtained through field analysis. The existing open wire districts are almost entirely vertically constructed, and is largely located along inaccessible back lot lines. The Designers shall consult the DFMP if open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts.

Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Attempts were made to identify every open wire district on the feeder, however the Designer may identify districts that were not captured in this report. The Designer shall follow the same procedure and consult the DFMP if unidentified districts are present in their assigned polygons.

Figures 19, 20, 21, 22, 23, 24, 25 and 26 identify the open wire secondary districts that were discovered for analysis or removal in each polygon.

- **Polygon 1**
  - Analyze whether to replace approximately 2600’ of vertical open wire on Grace-Buckeye due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1800’ of vertical open wire on Buckeye-Marietta due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 500’ of vertical open wire on Freya-Sycamore north of Carlisle due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 500’ of vertical open wire on Sycamore-Rebecca due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 500’ of vertical open wire on Freya-Sycamore south of Carlisle due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 600’ of vertical open wire on Carlisle-Montgomery due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 300’ of vertical open wire on Montgomery-Ermina due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1000’ of vertical open wire on Ermina-Upriver due to the physical condition and alley accessibility.
- **Polygon 3**
  - Analyze whether to replace approximately 2400’ of vertical open wire on Frederick-Fairview due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 2500’ of vertical open wire on Fairview-Cleveland due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 2400’ of vertical open wire on Cleveland-Grace due to the physical condition and alley accessibility.
- **Polygon 4**
  - Analyze whether to replace approximately 1200’ of vertical open wire on Grace-Buckeye due to the physical condition and alley accessibility.
- **Polygon 5**
  - Replace approximately 900’ of horizontal open wire on Courtland-Bridgeport.
  - Analyze whether to replace approximately 900’ of vertical open wire on Courtland-Bridgeport due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1100’ of vertical open wire on Bridgeport-Liberty due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 400’ of vertical open wire on Liberty-Euclid due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1300’ of vertical open wire on Liberty-Euclid due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1800’ of vertical open wire on Euclid due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1000’ of vertical open wire on Euclid-Fairview due to the physical condition and alley accessibility.

- **Polygon 6**
    - Analyze whether to replace approximately 900’ of vertical open wire on Fairview-Cleveland due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 500’ of vertical open wire on Cleveland-Grace due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 800’ of vertical open wire on Cleveland-Grace due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1100’ of vertical open wire on Grace-Buckeye due to the physical condition and alley accessibility.
- **Polygon 7**
    - Analyze whether to replace approximately 1500’ of vertical open wire on Cook-Altamont due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1800’ of vertical open wire on Smith-Cook due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1400’ of vertical open wire on Lacey-Smith due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1600’ of vertical open wire on Nelson-Lacey due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1100’ of vertical open wire on Regal-Nelson due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 200’ of vertical open wire on Regal-Nelson due to the physical condition and alley accessibility.
- **Polygon 8**
    - Analyze whether to replace approximately 300’ of vertical open wire on Courtland-Bridgeport due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 800’ of vertical open wire on Bridgeport-Liberty due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 800’ of vertical open wire on Liberty-Euclid due to the physical condition and alley accessibility.
- **Polygon 9**
    - Analyze whether to replace approximately 2400’ of vertical open wire on Princeton-Longfellow due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1600’ of vertical open wire on Longfellow-Rich due to the physical condition and alley accessibility.
- **Polygon 10**
    - Analyze whether to replace approximately 1200’ of vertical open wire on Garnet-Courtland due to the physical condition and alley accessibility.

Figure 19. Open Wire Secondary Districts on Polygon 1 of BEA 12F2

Figure 20. Open Wire Secondary Districts on Polygon 3 of BEA 12F2

Figure 21. Open Wire Secondary Districts on Polygon 4 of BEA 12F2

Figure 22. Open Wire Secondary Districts on Polygon 5 of BEA 12F2

Figure 23. Open Wire Secondary Districts on Polygon 6 of BEA 12F2

Figure 24. Open Wire Secondary Districts on Polygon 7 of BEA 12F2

Figure 25. Open Wire Secondary Districts on Polygon 8 of BEA 12F2

Figure 26. Open Wire Secondary Districts on Polygons 9 and 10 of BEA 12F2

Poles

All components of an overhead distribution system rely on the integrity and health of poles to ensure the system remains safe, reliable, and operational. The Grid Modernization program performs engineering and field examination of all of the poles and structures on a feeder to determine the removal, installation, replacement, or reinforcement based on requirements of the Distribution Feeder Management Plan (DFMP). A pole inspection report is requested and conducted to obtain an explicit list of poles on the feeder. The pole information from the inspection report provides detailed information for Grid Modernization to leverage in the assessment and proposals.

All poles and structures on BEA 12F2 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Wood Pole section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the BEA 12F2 circuit was performed from 6/7/2017 to 7/12/2017. The BEA 12F2 feeder was determined to contain 499 distribution poles at the time of analysis. The average age of distribution pole on the circuit is approximate 46 years, which places the average year of installation around 1971. 240 poles on the circuit are older than the 60 year limit for mean-time to failure, which results in the prescriptive replacement of 48.1% of wood poles at a minimum based on age alone.

The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	499
Average Pole Age in Years	46 (1971)
Year of Oldest Installed Pole	1934
Poles install between 1920-1929	0 (0%)
Poles install between 1930-1939	8 (2%)
Poles install between 1940-1949	50 (10%)
Poles install between 1950-1959	185 (37%)
Poles install between 1960-1969	35 (7%)
Yellow Tagged Poles (Re-enforceable)	13 (6%)
Red Tagged Poles (Replace)	2 (0.4%)
Average Pole Class	3.7
Class 4 Poles or Smaller	316 (63%)
Class 5 Poles of Smaller	68 (14%)

Transformers

All transformers on BEA 12F2 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

An improvement in the number of underground primary cable outages can be achieved by strategically replacing cable that has a known susceptibility to faulting. The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. This includes the targeted replacement of all pre-1982 non-jacketed primary cable, which Avista's historical data suggests has the highest failure rate of underground cable. Problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged, which allows water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable. In addition, the Program will replace any primary cable section that has multiple documented failures for either jacketed or non-jacketed primary cable.

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

Vegetation Management

Vegetation can pose serious reliability and safety problems for distribution feeders when not properly maintained. Trees can grow into overhead distribution lines as they mature, which creates access issues, public safety concerns, the possibility for trees or limbs to fall through the conductors, or the creation of electrical faults through physical contact. Proper vegetation maintenance along feeder corridors will remove many of these concerns while improving safety and system reliability. Vegetation Management will be included along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished between vegetation and Avista's primary and secondary conductors.

Grid Modernization's work is optimized when performed in coordination with Vegetation Management efforts. Vegetation management shall be employed on BEA 12F2 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

BEA 12F2 has been divided into 10 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Automation devices located within a polygon shall be sequentially renamed using alphabetic letters to reflect a sub-polygon (i.e. #9A, #9B, #9C, etc). Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Manager by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figures 27 illustrates the BEA 12F2 polygons and their boundaries. The CPC Design layer on AFM is available to provide more detailed boundaries of the polygons.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
  - Analyze whether to replace approximately 2600' of vertical open wire on Grace-Buckeye due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1800' of vertical open wire on Buckeye-Marietta due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 500' of vertical open wire on Freya-Sycamore north of Carlisle due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 500' of vertical open wire on Sycamore-Rebecca due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 500' of vertical open wire on Freya-Sycamore south of Carlisle due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 600' of vertical open wire on Carlisle-Montgomery due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 300' of vertical open wire on Montgomery-Ermina due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1000' of vertical open wire on Ermina-Upriver due to the physical condition and alley accessibility.
- **Polygon 2**
  - Reconductor existing 2-phase overhead lateral east of Buckeye & Havana with 2/0 ACSR primary and a 2/0 ACSR neutral (approximately 1100'). Install new A-phase 2/0 ACSR primary conductor to existing lateral to create a 3-phase lateral. This existing 2-phase lateral is currently served by 6CU (approximately 640') and 4 ACSR (450').
- **Polygon 3**
  - Analyze whether to replace approximately 2400' of vertical open wire on Frederick-Fairview due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 2500' of vertical open wire on Fairview-Cleveland due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 2400' of vertical open wire on Cleveland-Grace due to the physical condition and alley accessibility.

- **Polygon 4**
  - o Approximately 730' of 6A, 3A peak (2% loaded) requires further field examination for possible reconductor, replacement, or reconfiguration
  - o Approximately 1840' of 6A, 1A peak (1% loaded) requires further field examination for possible reconductor, replacement, or reconfiguration
  - o Approximately 1100' of 6CR, 5A peak (29% loaded) requires further field examination for possible reconductor, replacement, or reconfiguration
  - o Analyze whether to replace approximately 1200' of vertical open wire on Grace-Buckeye due to the physical condition and alley accessibility.
- **Polygon 5**
  - o Replace approximately 900' of horizontal open wire on Courtland-Bridgeport.
  - o Analyze whether to replace approximately 900' of vertical open wire on Courtland-Bridgeport due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1100' of vertical open wire on Bridgeport-LIberty due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 400' of vertical open wire on Liberty-Euclid due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1300' of vertical open wire on Liberty-Euclid due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1800' of vertical open wire on Euclid due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1000' of vertical open wire on Euclid-Fairview due to the physical condition and alley accessibility.
- **Polygon 6**
  - o Analyze whether to replace approximately 900' of vertical open wire on Fairview-Cleveland due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 500' of vertical open wire on Cleveland-Grace due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 800' of vertical open wire on Cleveland-Grace due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1100' of vertical open wire on Grace-Buckeye due to the physical condition and alley accessibility.
- **Polygon 7**
  - o Analyze whether to replace approximately 1500' of vertical open wire on Cook-Altamont due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1800' of vertical open wire on Smith-Cook due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1400' of vertical open wire on Lacey-Smith due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1600' of vertical open wire on Nelson-Lacey due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 1100' of vertical open wire on Regal-Nelson due to the physical condition and alley accessibility.
  - o Analyze whether to replace approximately 200' of vertical open wire on Regal-Nelson due to the physical condition and alley accessibility.

- **Polygon 8**
  - Analyze whether to replace approximately 300’ of vertical open wire on Courtland-Bridgeport due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 800’ of vertical open wire on Bridgeport-Liberty due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 800’ of vertical open wire on Liberty-Euclid due to the physical condition and alley accessibility.
- **Polygon 9**
  - Transfer 1Φ OH lateral east of Longfellow-Princeton & Rebecca (≈21 A peak loading, ≈11 A average loading) from BΦ to AΦ.
  - Analyze whether to replace approximately 2400’ of vertical open wire on Princeton-Longfellow due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1600’ of vertical open wire on Longfellow-Rich due to the physical condition and alley accessibility.
- **Polygon 10**
  - Analyze whether to replace approximately 1200’ of vertical open wire on Garnet-Courtland due to the physical condition and alley accessibility.

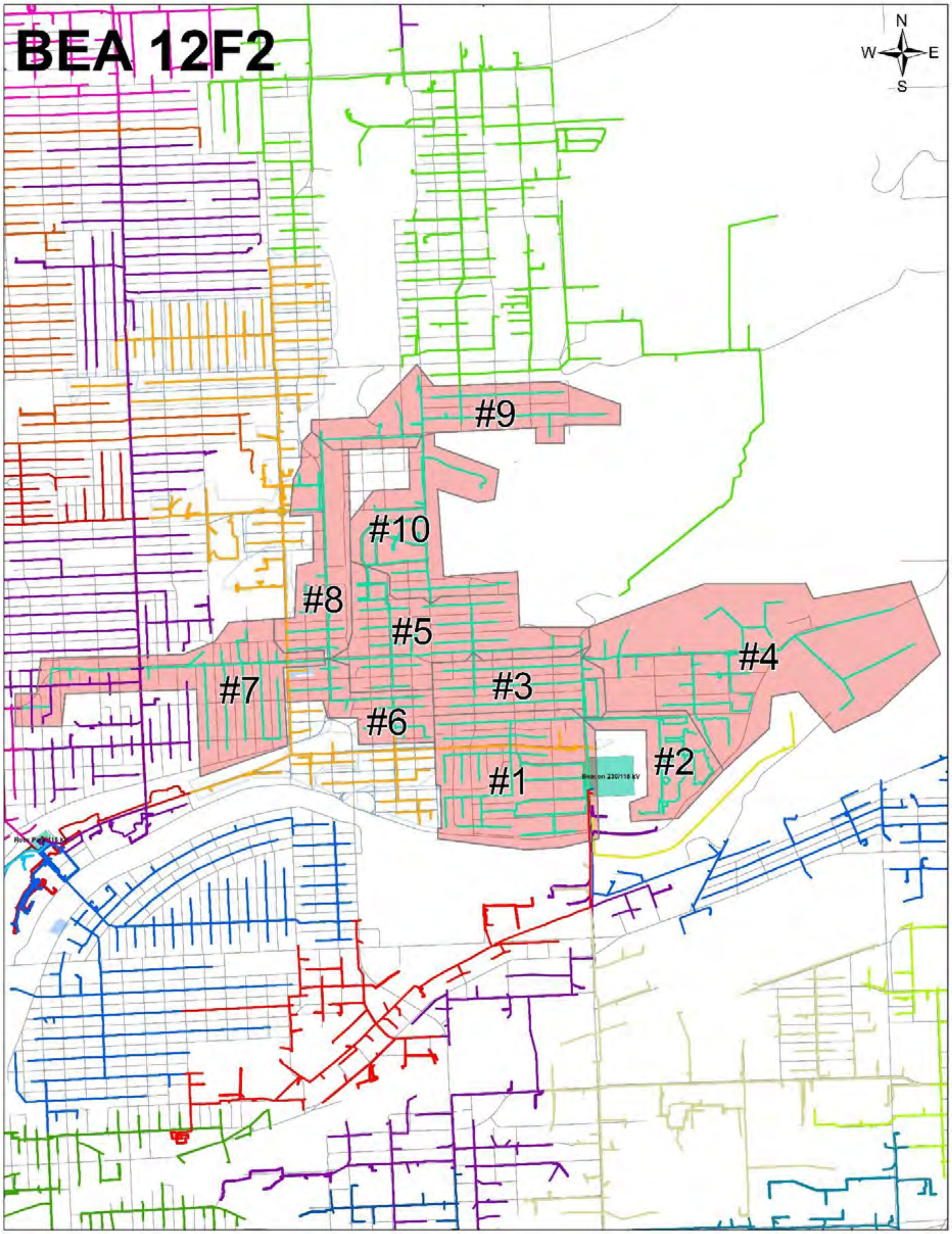

Figure 27. BEA 12F2 Assigned Polygon Numbers

Report Versions

Version 1 10/13/17 – Finalization of the initial feeder analysis report

Grid Modernization Program

F&C 12F1 Baseline Report

March 9, 2017

Version 2

Prepared by Shane Pacini

Index

Overview

The following report was established to create a baseline analysis for F&C 12F1 as part of the Grid Modernization program.

F&C 12F1 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Francis & Cedar Substation in the Spokane service area. The feeder has 5.41 circuit miles of feeder trunk with 16.54 circuit miles of laterals that serves a mixture urban residential and commercial loads in north Spokane. F&C 12F1 serves 3030 customers. Additional feeder information is included throughout the sections of this report, as well as the Avista Feeder Status Report. F&C 12F1 is represented as a dark yellow on the system map shown in Figure 1.

F&C 12F1 was partially rebuilt as part of the Spokane Smart Grid Investment Grant (SGIG). Substation and distribution line automation equipment was installed as part of that project. FDIR and IVVC are currently active on F&C 12F1

Figure 1. F&C 12F1 Circuit One-Line Diagram

Program Ranking Criteria

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (energy savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set could be measured on different scales, the normalization process offers the ability to convert each figure into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked for selection.

F&C 12F1 had a normalized total ranking of 0.471, ranking 32nd on the list of over 340 feeders. Further analysis suggests that the primary reasons this feeder was selected was due to relatively higher potential to achieve avoided costs through energy savings and efficiency improvements (72.37%), as well as the opportunity to reduce future O&M expenses through capital improvements (14.94%). Designers should consider these factors when fielding and designing the work on F&C 12F1.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.175	126.829	824531.834
Normalized Data	0.149	0.973	0.281
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.0600	0.341	0.070
Weight of Category %	12.69%	72.37%	14.94%

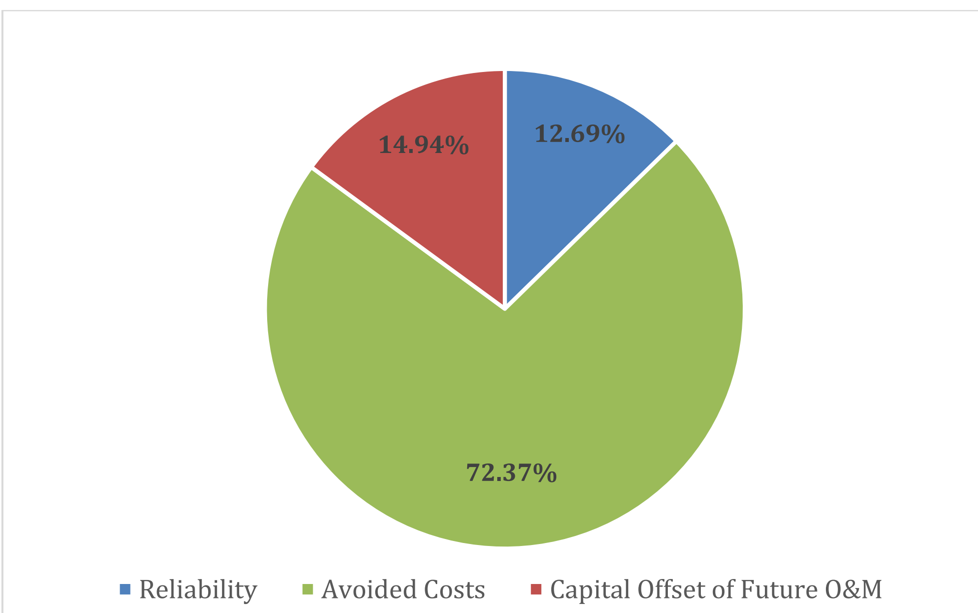

Figure 2. F&C 12F1 Selection Criteria

Reliability Indices

The key reliability indicators for F&C 12F1 were analyzed from 2006 to 2015 to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed circuit improvements or automation deployments. The table below shows the annual value for each respective reliability index on F&C 12F1 in the corresponding year. The reliability indices being used do not include major events days (MED), as this is standard per IEEE and reflects the same reliability information that Avista shares with the utility commissions.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2006	0.0%	0.10	15	160
2007	0.0%	0.11	13	121
2008	0.0%	0.13	19	146
2009	0.6%	0.26	38	148
2010	0.0%	0.44	58	133
2011	0.0%	0.19	14	72
2012	0.0%	0.19	21	108
2013	0.0%	1.08	97	89
2014	0.0%	0.04	9	217
2015	0.0%	0.02	4	233
Average	0.06%	0.256	28.85	142.82

The average value of each index was calculated and then compared to the Avista 2016 Target values. Three of the four historical averaged measured indices on F&C 12F1 are out performing the 2016 targets. Only the CAIDI index is just slightly underperforming. This data suggests that customers experience few outages on the feeder, however the average time to restore service during those few outages could be improved.

WA-ID Key Indicator	2016 Target	F&C 12F1	Variance
SAIFI Sustained Outages/Customer	1.11	0.256	0.854
SAIDI Outage Time/Customer (min)	151.00	28.85	122.15
CAIDI Ave Restoration Time (min)	141.00	142.82	-1.82
CEMI3 % of Customers >3 Outages	6.90%	0.06%	6.84%

Peak Loading

Three-phase ampacity loading from SCADA monitoring at the F&C 12F1 substation circuit breaker was analyzed from 8/18/14 to 8/17/16. The following loading values were established for F&C 12F1 during this timeframe. Loading information has been removed from selected timeframes due to temporary changes in loading from switching (verified through PI). F&C 12F1 is a summer peaking feeder, with comparable peak values observed from late June to August. The values below reflect the adjusted data set. The peak loading values for each phase are used in the Synergi model analysis for the feeder, except where average load values are noted for establishing kW losses.

	Before Balancing	
	Peak	**Average**
A-Phase	370 A	170 A
B-Phase	359 A	163 A
C-Phase	417 A	199 A

	After Balancing	
	Peak	**Average**
A-Phase	370 A	170 A
B-Phase	373 A	170 A
C-Phase	403 A	192 A

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from Synergi at the model's initial configuration before balancing or performing improvements on the circuit.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	2946	5247	56.15%
B-Phase	2865	5631	50.88%
C-Phase	3323	6434	51.65%

* Connected kVA per Phase in Synergi as of 8/18/16

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	1356	5247	25.84%
B-Phase	1298	5631	23.05%
C-Phase	1590	6434	24.71%

* Connected kVA per Phase in Synergi as of 8/18/16

Feeder Balancing

Accurate load balancing can be achieved on F&C 12F1 due to the three-phase ampacity monitoring at the Francis & Cedar 12F1 substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively before balancing:

	Connected KVA per Phase*
A-Phase	5247.0 kVA
B-Phase	5643.5 kVA
C-Phase	6433.5 kVA

*AFM as of 8/18/16

In addition, three-phase ampacity monitoring is also available on the distribution at two separate locations line due to the Z745R and Z157 automation devices that were installed during the Spokane Smart Grid Investment Grant (SGIG). This information is more accurate than the allocated peak amps that are historically used in this report's analysis.

The DMS data at device Z745R illustrates that B-phase is loaded approximately 5A below average throughout the duration analyzed when compared to A-phase and C-phase. A-phase is loaded approximately 3A above average throughout the duration analyzed when compared to other phases, while C-phase is loaded approximately 2A above average. This suggests that the load is effectively balanced downstream of the Z745R device, and therefore no proposals will be made downstream of this location to improve balancing.

The DMS data at device Z157 illustrates that B-phase is loaded approximately 33A below average throughout the duration analyzed when compared to A-phase and C-phase. A-phase is loaded approximately 17A above average throughout the duration analyzed when compared to other phases, while C-phase is loaded approximately 16A above average. This data corresponds with the data measured at the F&C 12F1 substation circuit breaker, and suggests that load can be transferred between phases to more effectively balance the downstream load.

The following list provides the loads, laterals, and underground risers that can effectively balance the load on the phases between numerous strategic locations on the feeder. As a whole, the trunk sections and multi-phase laterals on F&C 12F1 were relatively balanced, however opportunities were available to improve feeder balancing by transferring load. The Designer shall incorporate these changes into their appropriate polygon designs:

- **Polygon 4** – transfer 1Φ OH lateral north of Rockwell & Maple-Walnut (≈14A) from CΦ to BΦ.

The result of this load transfer is listed in the following table. This change will approximately balance the feeder at the substation breaker to 370/373/403, as well as between the numerous strategic points and devices on the circuit to approximately sectionalize the feeder.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any proposals for phase balancing prior to commencing the job designs.

The decision to move forward with the proposed phase change will be confirmed and approved by the Regional Operations Engineer, and coordinated by the Designer in thir applicable polygon design. Figure 3 illustrates the phase balancing proposal on F&C 12F1.

	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
F&C 12F1 Station Breaker	370	359	417	**370**	**373**	**403**
Z157	287	223	288	287	236	274
E of Z157	47	69	75	47	69	75
Z745R	104	159	132	104	159	132

Figure 3. F&C 12F1 Feeder Balancing – Phase Change Recommendation

Conductor

All primary conductors on F&C 12F1 were analyzed in Synergi using the balanced peak ampacity values identified above (370/373/403). Specific attention was given to conductors that were potentially overloaded, have relatively high line losses, serve areas with unacceptable voltage quality (primarily during peak conditions), and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on F&C 12F1, as well as the proposals for improving the efficiency, voltage quality, and performance of the feeder.

The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the approximate sections of primary requiring attention.

Transmission Engineering should be consulted by the assigned Designer for any work or reconductoring performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

F&C 12F1 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, it is not likely that there are sections that would warrant reconfiguration due to proposed reconductoring, physical conditions, stubbing, and/or high resistant conductors. The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer. It is the Designer's responsibility to consult the Program Engineer on any proposals for reconfiguration or conversion to underground prior to commencing the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, are economically justifiable, and to assist in identifying the appropriate material and equipment to install.

Trunk

The primary trunk conductors on F&C 12F1 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The majority of the feeder trunk is currently conductored with 556 AAC and 336 ACSR in overhead applications, which are some of the highest rated overhead conductors for urban settings recommended by the Distribution Construction standards (DO-3.105). This is primarily due to the reconductor efforts that were performed on the circuit during the Smart Grid Investment Project (SGIG).

Given the large amount of high capacity conductors already present on a majority of the feeder trunk and ties, there is minimal evidence to support upgrading the primary trunk conductors on F&C 12F1 based on capacity concerns alone. Line losses on the trunk are currently in the optimal range for both the peak and average loading scenarios, which has been aided by balancing the feeder and relatively lower loading conditions where high loss conductors exist.

There is one unique feature on F&C 12F1 that is not common with other Avista distribution circuits. There is approximately 5000' of paralleled 336 ACSR primary feeder trunk that begins directly outside of the substation and continues until the feeder branches nearly one mile away to the south. While this construction practice is not common, the loading does not justify the costs associate with reconductoring the trunk to the largest standard overhead conductor of 556 AAC. The peak loading on the highest loaded phase was captured at 403A during the 24 months of analysis. With a summer operating limit of 451A for 336 ACSR (671A for winter limit), the section of the trunk is loaded to approximately 89% when only one of the 336 ACSR circuits is considered (approximately 60% for winter). When both parallel 336 ACSR circuits are considered, each branch will equally carry approximately half of the current. This will only load the primary trunk to a maximum of 47% during summer loading conditions, and approximately 30% during winter loading conditions. This leaves ample ampacity to serve load from adjacent feeders in switching situations or outage restoration efforts.

Figures 4 and 5 illustrate the paralleled 336 ACSR trunk on F&C 12F1 as observed in the field.

Any designs to reconductor shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

Figure 4. Paralleled 336 ACSR trunk at Cedar-Walnut & Wabash

Figure 5. Paralleled 336 ACSR trunk at Cedar & Nebraska

Laterals

The primary lateral conductors on F&C 12F1 are generally sized appropriately to meet peak loading conditions during normal system configuration. The analyzed models suggest reconductoring only one lateral on the feeder based on peak loading conditions or downstream service voltage levels, however there are numerous lightly loaded laterals that contain high loss conductors. The Distribution Feeder Management Plan calls attention to these higher loss conductors, with emphasis on replacement conductors that have a resistance greater than 5 ohms per mile.

- **Polygon 5** – Reconductor 1Φ primary lateral east of A St & Olympic-Wabash from 6CR and 6A to 4ACSR with a 4ACSR neutral (approximately 2500'). Figure 6 illustrates the proposed lateral for reconductoring on F&C 12F1.

The following list of laterals should be further examined by the assigned Designer in the field to support reconductoring these laterals to a minimum of 4ACSR. As part of the field analysis, the Designer should determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, potential benefits from relocation, etc. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program. Figure 7 identifies the laterals on F&C 12F1 that are candidates for reconductoring based on containing high loss conductors.

- **Polygon 3** – Approximately 1700' of 6A, 33A peak (31% loaded)
- **Polygon 4** – Approximately 830' of 6A, 10A peak (10% loaded)
- **Polygon 5** – Approximately 300' of 6CR, 3A peak (14% loaded)
- **Polygon 5** – Approximately 580' of 6A, 7A peak (5% loaded)
- **Polygon 5** – Approximately 290' of 6CR, 1A peak (6% loaded)
- **Polygon 5** – Approximately 570' of 6A, 5A peak (5% loaded)
- **Polygon 5** – Approximately 290' of 6CR, 1A peak (6% loaded)
- **Polygon 5** – Approximately 600' of 6A, 10A peak (10% loaded)
- **Polygon 5** – Approximately 570' of 6CR, 3A peak (2% loaded)

There are laterals identified in this report that contain both high loss conductors and open wire secondary districts, as outlined later in the *Open Wire Secondary* section of this report. These laterals should be given special attention during design to determine the opportunities to remove and replace with current design standards. The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in identifying laterals where reconductoring is sensible.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Feeder Tie

F&C 12F1 currently contains six overhead feeder ties through: disconnect 299D (F&C 12F2), switch Z561 (F&C 12F5), switch Z119 (FWT 12F1), switch Z154 (C&W 12F1), switch Z518 (NW 12F4) and switch 743 (F&C 12F4). Four of these feeder ties were upgraded and automated during the Smart Grid Investment Grant (SGIG) project through the installation of S&C SCADAMate devices.

There is one remaining viable opportunity to establish a more robust feeder tie on F&C 12F1 with feeder F&C 12F4. This is located on the western third of the feeder at the existing #743 (N.O.) tie switch with F&C 12F4. The effort to make the tie at #743 more useful would require the reconductoring of approximately 1700' of 2STCU on F&C 12F1 to a minimum of 336 AAC with a 2/0 ACSR neutral. In addition, approximately 4800' of 2STCU trunk on F&C 12F4 would also need to be reconductored to optimize this tie. This proposal would create an automated tie with increase loading capability with a new feeder, however the benefits may be limited for both feeders – especially since F&C 12F1 has an existing automated feeder tie with NW 12F4 less than 1700' feet directly to the south.

After analyzing the options and loading scenarios adjacent to F&C 12F1, Grid Modernization is not recommending performing any work on the feeder tie with F&C 12F4 at switching device #743 through reconductoring or the addition of an automated switch. The decision to pursue additional feeder tie opportunities will be discussed and selected with the Regional Operations Engineer based on their anticipated frequency of using either tie in the operation of the central Spokane distribution system.

Figure 8 illustrates the location around the #743 device.

Figure 6. Polygon 5 Primary Lateral Recondcutor to 4 ACSR

Figure 7. Laterals Requiring Field Analysis for Reconductoring to 4 ACSR

Figure 8. Feeder Tie Location near #743

Voltage Quality

The loading on F&C 12F1 was first balanced between phases to eliminate the unnecessary overloading of phases which may exacerbate voltage quality problems. F&C 12F1 required minimal balancing efforts. These proposals were previously outlined in the *Feeder Balancing* section of this report. F&C 12F1 was analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled in Synergi during both peak loading and average loading conditions.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to F&C 12F1. During peak loading conditions, voltage levels nearest to the Francis & Cedar Substation, were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 124.7V. Voltage levels upstream of the Z157 device were slightly elevated, however all sections downstream were in the optimal range. The minimum voltage modeled on the feeder occurred on the longest single phase lateral at 121.5V

Figure 9 illustrates the modeled voltage levels at peak loading on F&C 12F1. Green illustrates voltages between 117–123 V. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	41	4.67	2112	827
122.00 - 124.00 V	302	15.59	6325	2048
124.00 - 126.00 V	29	2.74	471	185
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading

The voltage levels on the feeder were again analyzed before balancing load, however this time during average loading conditions. This scenario saw slightly higher voltage levels across the feeder.

During average loading conditions, voltage levels nearest to the Francis & Cedar Substation, were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 123.9V. Voltage levels upstream of the Z157 device were slightly elevated, however all sections downstream were in the optimal range. In addition, voltage levels just downstream of the Z157 were also higher than previously modeled during peak loading conditions. The minimum voltage modeled on the feeder occurred on the longest single phase lateral at 122.4V

Figure 10 illustrates the modeled voltage levels at average loading on F&C 12F1. Green illustrates voltages between 117–123 V. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	371	23.00	4166	3060
124.00 - 126.00 V	1	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 9. Modeled Voltage Levels at Peak Loading

Figure 10. Modeled Voltage Levels at Average Loading

The voltage levels on F&C 12F1 were re-analyzed after the trunk and lateral reconductoring and other improvements were performed. The feeder was modeled with these proposals in Synergi during both Peak loading and Average loading conditions.

Modeled Voltage Levels at Peak Loading after Proposals

The voltage levels on the feeder were analyzed after performing the identified changes and improvements to F&C 12F1. During peak loading conditions, voltage levels nearest to the Francis & Cedar Substation, were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 124.6V. Voltage levels upstream of the Z157 device were slightly elevated, however all sections downstream were in the optimal range. The minimum voltage modeled on the feeder occurred on the longest single phase lateral at 121.5V

Figure 11 illustrates the modeled voltage levels at peak loading on F&C 12F1. Green illustrates voltages between 117–123 V. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	39	4.31	1989	757
122.00 - 124.00 V	304	15.95	6449	2118
124.00 - 126.00 V	29	2.74	471	185
126.00 - 140.00 V	0	0.00	0	[illegible]

Modeled Voltage Levels at Average Loading after Proposals

The voltage levels on the feeder were again analyzed after balancing load, however this time during average loading conditions. This scenario saw slightly higher voltage levels across the feeder.

During average loading conditions, voltage levels nearest to the Francis & Cedar Substation, were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 123.9V. Voltage levels upstream of the Z157 device were slightly elevated, however all sections downstream were in the optimal range. In addition, voltage levels just downstream of the Z157 were also higher than previously modeled during peak loading conditions. The minimum voltage modeled on the feeder occurred on the longest single phase lateral at 122.4V

Figure 12 illustrates the modeled voltage levels at average loading on F&C 12F1. Green illustrates voltages between 117–123 V. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	371	23.00	4166	3060
124.00 - 126.00 V	1	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 11. Modeled Voltage Levels at Peak Loading after Proposals

Figure 12. Modeled Voltage Levels at Average Loading after Proposals

Voltage Regulator Settings

F&C 12F1 has one existing stage of voltage regulation at the Francis & Cedar Substation. Due to the interconnected urban nature of the feeder, and the shorter feeder length, additional stages of midline voltage regulation are not on the feeder to support voltage levels during normal configuration or times of switching.

A group of alternative settings was analyzed to show if there was the potential for improvement. The voltage levels on F&C 12F1 were re-analyzed and modeled with the voltage regulator settings change proposals in Synergi at peak loading conditions. However there were no noticeable improvements in voltage quality levels on the feeder with modified settings.

The decision to move forward with implementing any changes to the regulator settings will be confirmed, approved, and coordinated by the Regional Operations Engineer.

Fuse Sizing

Fuse sizing on F&C 12F1 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and underground risers. Fuse recommendations for F&C 12F1 were created by the Grid Modernization Program Engineer and verified by the Regional Operations Engineer. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Line Losses

The primary trunk conductors on F&C 12F1 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the rural feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. It should be noted that there were not recommendations to reconductor the feeder trunk or ties, as most of these sections were upgraded 556 AAC and 336 ACSR during the Smart Grid Investment Project (SGIG).

After the proposed work described in the *Trunk, Feeder Tie, and Lateral* sections are performed on F&C 12F1, it is estimated that the peak line losses could approximately be reduced by 0.6 kW through reconductor efforts, while the average loading line losses could approximately be reduced by up to 0.2 kW. In addition, approximately 1.75 MWh savings could be annually achieved assuming average loading conditions during normal system configuration.

	Polygon 5
Circuit Length (ft)	2505.5
Current Average kW Losses	0.2
Current Peak kW Losses	0.7
Proposed Average kW Losses	0.0
Proposed Peak kW Losses	0.1
Average kW Loss Savings	0.2
Peak kW Loss Savings	0.6
Reconductor MWh Savings *	1.752

* Estimated average kW losses over one year span

An initial Synergi load study estimates that a total of 134 kW in peak line losses currently exists on F&C 12F1 (1.52%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved to approximately 132 kW (1.50%).

Peak Values	**Existing**	**After Balancing**	**After Reconductor**
kW Demand	9045	9045	9044
kW Load	8908	8909	8908
kW Line Losses	134	133	132
kW Loss %	1.52 %	1.51 %	1.50 %

Transformer Core Losses

The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, transformer core losses are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of a near equivalent size.

All transformers on F&C 12F1 shall be analyzed and “right sized” by the assigned Designer to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP). In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the Designer.

The roughly 382 distribution transformers on F&C 12F1 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It was determined that approximately 261 transformers may require replacement based on right sizing and the TCOP replacement criteria. The replacement of these transformers will result in an estimated 29.51 kW reduction in core losses. This equates to an estimated annual savings of roughly 258.51 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

MVAR and MW data at the F&C 12F1 substation circuit breaker was analyzed from 8/18/14 to 8/17/16. It was determined that F&C 12F1 had a lagging power factor approximately 48.57% of the time and a leading power factor 51.43% of the time during the time interval analyzed. Detailed power factor information is available upon request. Some key power factor figures for F&C 12F1 are provided in the tables below.

Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	97.92 %
Maximum Leading Power Factor	99.99 %
Minimum Leading Power Factor	92.08 %

The graph in Figure 13 shows the percent of time during the interval analyzed where the power factor on F&C 12F1 fell between the applicable ranges. This information is also provided in a table format.

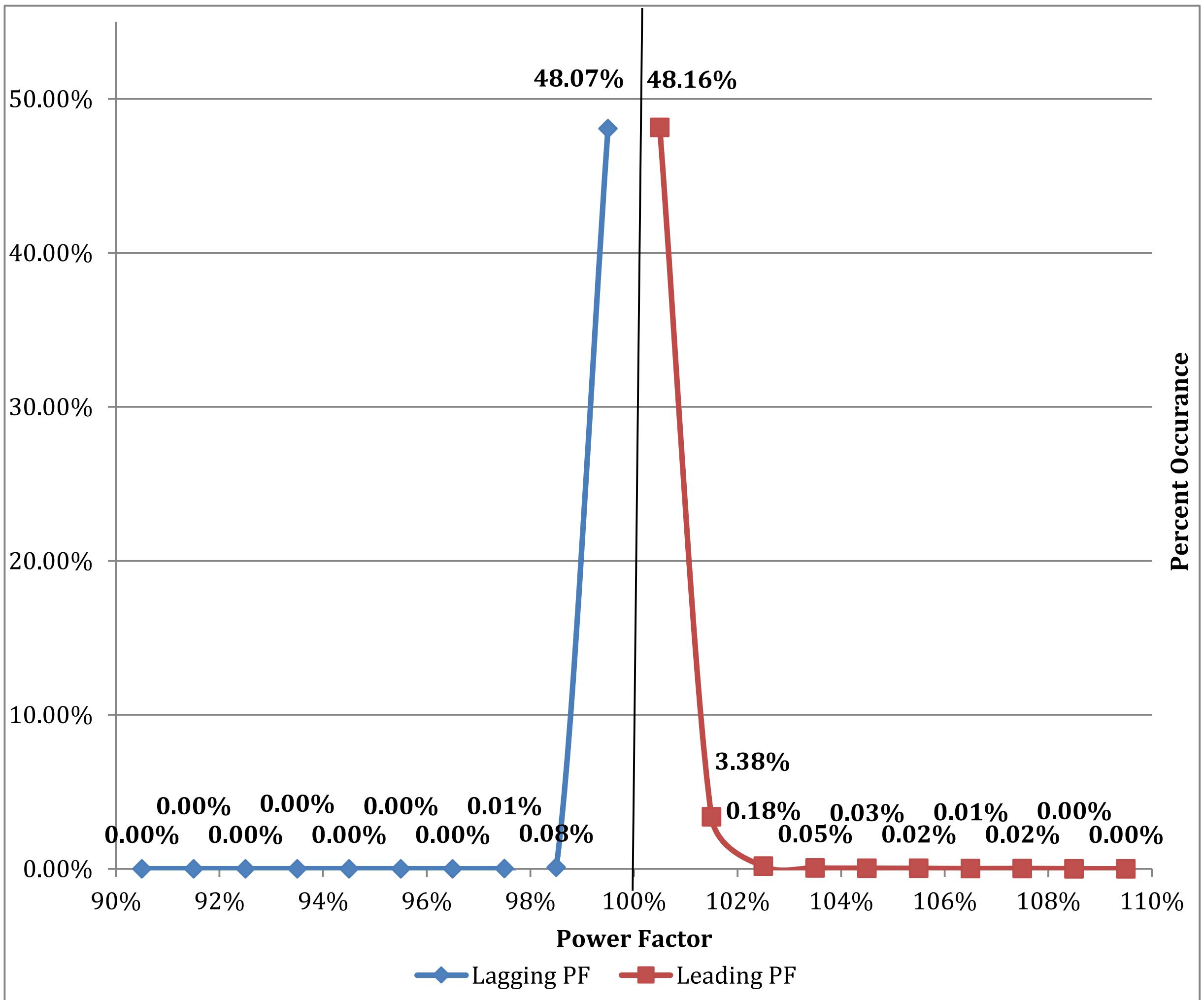

Figure 13. Existing Percent Occurance of Power Factor

	Lagging	Leading
Less than 90%	0.00%	0.00%
90%-91%	0.00%	0.00%
91%-92%	0.00%	0.00%
92%-93%	0.00%	0.02%
93%-94%	0.00%	0.01%
94%-95%	0.00%	0.02%
95%-96%	0.00%	0.03%
96%-97%	0.00%	0.05%
97%-98%	0.01%	0.18%
98%-99%	0.08%	3.38%
99%-100%	48.07%	48.16%

Power Factor Correction

There are four existing capacitor banks on F&C 12F1. There are three 600 kVAR switched capacitor banks (Z809F, Z810F, and Z811F) and one 600 kVAR fixed capacitor bank. The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times.

Numerous scenarios were modeled with the addition and subtraction of capacitance to determine if improvements could be made to the feeder's power factor. The existing power factor on F&C 12F1 is quite optimal, and cannot be significantly improved by changing the amount of capacitance on the feeder in the form of capacitor banks. It is recommended to not make any changes to the capacitor sizes, types, or locations on the feeder. The decision to move forward with implementing any changes to the capacitors will be confirmed, approved, and coordinated by the Regional Operations Engineer.

Automation

Distribution Automation was analyzed for deployment on F&C 12F1 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on F&C 12F1.

F&C 12F1 currently contains numerous automated distribution line devices from the previous work performed during the Smart Grid Investment Project (SGIG). After analyzing the existing devices on the feeder, it is recommended to not add or remove any automation devices as part of the Grid Modernization program.

The following automation devices are currently deployed on the feeder:

Device Number	Location	Status	Device Type
Z119	Rockwell & Cedar 1PN	N.O.	S&C – Switch
Z154	Maple & Glass	N.O.	S&C – Switch
Z157	Walnut & Wabash	N.C.	S&C – Switch
Z518	Broad & A	N.O.	S&C – Switch
Z561	Lincoln & Wabash	N.O.	S&C – Switch
Z745R	Wabash & Oak	N.C.	Viper – Recloser

Figure 14 illustrates the existing automation device locations on F&C 12F1.

F&C 12F1 is distribution automation ready at the Francis & Cedar Substation with the breakers, relaying, regulators, communications, and EMS/DMS ready.

Figure 14. F&C 12F1 Automation Device Locations

Open Wire Secondary

Open wire secondary districts have been analyzed for replacement on F&C 12F1 in accordance to the Distribution Feeder Management Plan (DFMP). Multiple districts were identified to exist on F&C 12F1. The Designers shall consult the DFMP if open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal or replacement.

Approximately 66,550 circuit feet of open wire secondary is currently estimated to be on F&C 12F1. This figure was established from physical observations obtained through field analysis. The existing open wire districts are almost entirely vertically constructed, and is largely located in alleys. Attempts were made to identify every open wire district on the feeder, however the Designer may identify districts that were not captured in this report. The Designer shall follow the same procedure and consult the DFMP if unidentified districts are present in their assigned polygons.

- **Polygon 1 –**
  - Analyze whether to replace 1220’ of vertical open wire on Dalke-Decatur due to the physical condition and alley accessibility.
  - Analyze whether to replace 1130’ of vertical open wire on Bismark-Dalke due to the physical condition and alley accessibility.
  - Analyze whether to replace 1160’ of vertical open wire on Central-Columbia due to the physical condition and alley accessibility.
  - Analyze whether to replace 790’ of vertical open wire on Columbia-Joseph to the physical condition and alley accessibility.
  - Analyze whether to replace 1230’ of vertical open wire on Joseph-Nebraska due to the physical condition and alley accessibility.
  - Analyze whether to replace 820’ of vertical open wire on Nebraska-Rowan due to the physical condition and alley accessibility.
  - Analyze whether to replace 3780’ of vertical open wire on Cedar-Walnut due to the physical condition and alley accessibility.
- **Polygon 2 –**
  - Analyze whether to replace 3080’ of vertical open wire on Lincoln-Monroe due to the physical condition and alley accessibility.
  - Analyze whether to replace 3080’ of vertical open wire on Madison-Monroe due to the physical condition and alley accessibility.
  - Analyze whether to replace 1920’ of vertical open wire on Jefferson-Madison due to the physical condition and alley accessibility.
  - Analyze whether to replace 1910’ of vertical open wire on Adams-Jefferson due to the physical condition and alley accessibility.
  - Analyze whether to replace 1920’ of vertical open wire on Adams-Hawthorne due to the physical condition and alley accessibility.
  - Analyze whether to replace 3180’ of vertical open wire on Adams-Cedar due to the physical condition and alley accessibility.

- **Polygon 3 –**
  - Analyze whether to replace 3480' of vertical open wire on Maple-Walnut due to the physical condition and alley accessibility.
  - Analyze whether to replace 1680' of vertical open wire on Ash-Maple due to the physical condition and alley accessibility.
  - Analyze whether to replace 4340' of vertical open wire on Ash-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 3360' of vertical open wire on Elm-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 1930' of vertical open wire on Cannon-Elm due to the physical condition and alley accessibility.
  - Analyze whether to replace 1810' of vertical open wire on Cannon-Elgin due to the physical condition and alley accessibility.
  - Analyze whether to replace 1850' of vertical open wire on Belt-Elgin due to the physical condition and alley accessibility.
- **Polygon 4 –**
  - Analyze whether to replace 1800' of vertical open wire on Maple-Walnut due to the physical condition and alley accessibility.
  - Analyze whether to replace 2990' of vertical open wire on Ash-Maple due to the physical condition and alley accessibility.
  - Analyze whether to replace 1130' of vertical open wire on Ash-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 1060' of vertical open wire on Elm-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 1100' of vertical open wire on Cannon-Elm due to the physical condition and alley accessibility.
  - Analyze whether to replace 1150' of vertical open wire on Cannon-Elgin due to the physical condition and alley accessibility.
  - Analyze whether to replace 900' of vertical open wire on Belt-Elgin due to the physical condition and alley accessibility.

- **Polygon 5 –**
  - Replace 720' of vertical open wire on Belt-Hemlock due to inaccessibility.
  - Replace 1150' of vertical open wire on Hemlock-Nettleton due to inaccessibility.
  - Replace 620' of vertical open wire on Nettleton-Cochran due to inaccessibility.
  - Analyze whether to replace 600' of vertical open wire on Everett-Sanson due to the physical condition and alley accessibility.
  - Analyze whether to replace 2460' of vertical open wire on Crown-Everett due to the physical condition and alley accessibility.
  - Analyze whether to replace 1990' of vertical open wire on Crown-Queen due to the physical condition and alley accessibility.
  - Analyze whether to replace 2180' of vertical open wire on Olympic-Queen due to the physical condition and alley accessibility.
  - Analyze whether to replace 2360' of vertical open wire on Olympic-Wabash due to the physical condition and alley accessibility.
  - Replace 390' of vertical open wire on Circle-Litchfield due to inaccessibility.
  - Replace 280' of vertical open wire on Circle-Broad due to inaccessibility.

Figures 15, 16, 17, 18, and 19 identify the open wire secondary districts that were discovered for analysis or removal in each polygon.

Figure 15. Open Wire Secondary Districts on Polygon 1 of F&C 12F1

Figure 16. Open Wire Secondary Districts on Polygon 2 of F&C 12F1

Figure 17. Open Wire Secondary Districts on Polygon 3 of F&C 12F1

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Figure 18. Open Wire Secondary Districts on Polygon 4 of F&C 12F1

Figure 19. Open Wire Secondary Districts on Polygon 5 of F&C 12F1

Poles

All poles and structures on F&C 12F1 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the *Wood Pole* section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the F&C 12F1 circuit was performed from 9/6/2016 to 10/11/2016. The F&C 12F1 feeder was determined to contain 976 distribution poles at the time of analysis. The average age of distribution pole on the circuit is approximate 53 years, which places the average year of installation around 1964. 617 poles on the circuit are older than the 60 year limit for mean-time to failure, which results in the prescriptive replacement of 63.2% of wood poles at a minimum based on age alone.

The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	976
Average Pole Age in Years	53 (1964)
Year of Oldest Installed Pole	1927
Poles install between 1920-1929	5 (1%)
Poles install between 1930-1939	7 (1%)
Poles install between 1940-1949	325 (33%)
Poles install between 1950-1959	285 (29%)
Poles install between 1960-1969	42 (4%)
Yellow Tagged Poles (Re-enforceable)	122 (12%)
Red Tagged Poles (Replace)	21 (2%)
Average Pole Class	4.0
Class 4 Poles or Smaller	730 (75%)
Class 5 Poles of Smaller	201 (21%)

Transformers

All transformers on F&C 12F1 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable.

Vegetation Management

Vegetation management shall be employed on F&C 12F1 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

F&C 12F1 has been divided into 5 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Automation devices located within a polygon shall be sequentially renamed using alphabetic letters to reflect a sub-polygon (i.e. #9A, #9B, #9C, etc). Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Manager by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figures 20 illustrates the F&C 12F1 polygons and their boundaries. The CPC design layer on AFM is available to provide more detailed boundaries of the polygons.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
  - Analyze whether to replace 1220' of vertical open wire on Dalke-Decatur due to the physical condition and alley accessibility.
  - Analyze whether to replace 1130' of vertical open wire on Bismark-Dalke due to the physical condition and alley accessibility.
  - Analyze whether to replace 1160' of vertical open wire on Central-Columbia due to the physical condition and alley accessibility.
  - Analyze whether to replace 790' of vertical open wire on Columbia-Joseph to the physical condition and alley accessibility.
  - Analyze whether to replace 1230' of vertical open wire on Joseph-Nebraska due to the physical condition and alley accessibility.
  - Analyze whether to replace 820' of vertical open wire on Nebraska-Rowan due to the physical condition and alley accessibility.
  - Analyze whether to replace 3780' of vertical open wire on Cedar-Walnut due to the physical condition and alley accessibility.
- **Polygon 2**
  - Analyze whether to replace 3080' of vertical open wire on Lincoln-Monroe due to the physical condition and alley accessibility.
  - Analyze whether to replace 3080' of vertical open wire on Madison-Monroe due to the physical condition and alley accessibility.
  - Analyze whether to replace 1920' of vertical open wire on Jefferson-Madison due to the physical condition and alley accessibility.
  - Analyze whether to replace 1910' of vertical open wire on Adams-Jefferson due to the physical condition and alley accessibility.
  - Analyze whether to replace 1920' of vertical open wire on Adams-Hawthorne due to the physical condition and alley accessibility.
  - Analyze whether to replace 3180' of vertical open wire on Adams-Cedar due to the physical condition and alley accessibility.
- **Polygon 3**
  - Analyze the condition of the existing poles and wire on the 1700' lateral of 6U, 33A peak (31% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze whether to replace 3480' of vertical open wire on Maple-Walnut due to the physical condition and alley accessibility.
  - Analyze whether to replace 1680' of vertical open wire on Ash-Maple due to the physical condition and alley accessibility.
  - Analyze whether to replace 4340' of vertical open wire on Ash-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 3360' of vertical open wire on Elm-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 1930' of vertical open wire on Cannon-Elm due to the physical condition and alley accessibility.
  - Analyze whether to replace 1810' of vertical open wire on Cannon-Elgin due to the physical condition and alley accessibility.

- Analyze whether to replace 1850’ of vertical open wire on Belt-Elgin due to the physical condition and alley accessibility.

- **Polygon 4**
  - Transfer 1Φ OH lateral north of Rockwell & Maple-Walnut (≈14A) from CΦ to BΦ.
  - Analyze the condition of the existing poles and wire on the 830’ lateral of 6A, 10A peak (10% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze whether to replace 1800’ of vertical open wire on Maple-Walnut due to the physical condition and alley accessibility.
  - Analyze whether to replace 2990’ of vertical open wire on Ash-Maple due to the physical condition and alley accessibility.
  - Analyze whether to replace 1130’ of vertical open wire on Ash-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 1060’ of vertical open wire on Elm-Oak due to the physical condition and alley accessibility.
  - Analyze whether to replace 1100’ of vertical open wire on Cannon-Elm due to the physical condition and alley accessibility.
  - Analyze whether to replace 1150’ of vertical open wire on Cannon-Elgin due to the physical condition and alley accessibility.
  - Analyze whether to replace 900’ of vertical open wire on Belt-Elgin due to the physical condition and alley accessibility.
- **Polygon 5**
  - Reconductor 1Φ primary lateral east of A St & Olympic-Wabash from 6CR to 4ACSR with a 4ACSR neutral (approximately 2500’)
  - Analyze the condition of the existing poles and wire on the 300’ lateral of 6CR, 3A peak (14% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 580’ lateral of 6A, 7A peak (5% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 290’ lateral of 6CR, 1A peak (6% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 570’ lateral of 6A, 5A peak (10% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 290’ lateral of 6CR, 1A peak (6% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 600’ lateral of 6A, 10A peak (10% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 570’ lateral of 6CR, 3A peak (2% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Replace 720’ of vertical open wire on Belt-Hemlock due to inaccessibility.

- Replace 1150’ of vertical open wire on Hemlock-Nettleton due to inaccessibility.
- Replace 620’ of vertical open wire on Nettleton-Cochran due to inaccessibility.
- Analyze whether to replace 600’ of vertical open wire on Everett-Sanson due to the physical condition and alley accessibility.
- Analyze whether to replace 2460’ of vertical open wire on Crown-Everett due to the physical condition and alley accessibility.
- Analyze whether to replace 1990’ of vertical open wire on Crown-Queen due to the physical condition and alley accessibility.
- Analyze whether to replace 2180’ of vertical open wire on Olympic-Queen due to the physical condition and alley accessibility.
- Analyze whether to replace 2360’ of vertical open wire on Olympic-Wabash due to the physical condition and alley accessibility.
- Replace 390’ of vertical open wire on Circle-Litchfield due to inaccessibility.
- Replace 280’ of vertical open wire on Circle-Broad due to inaccessibility.

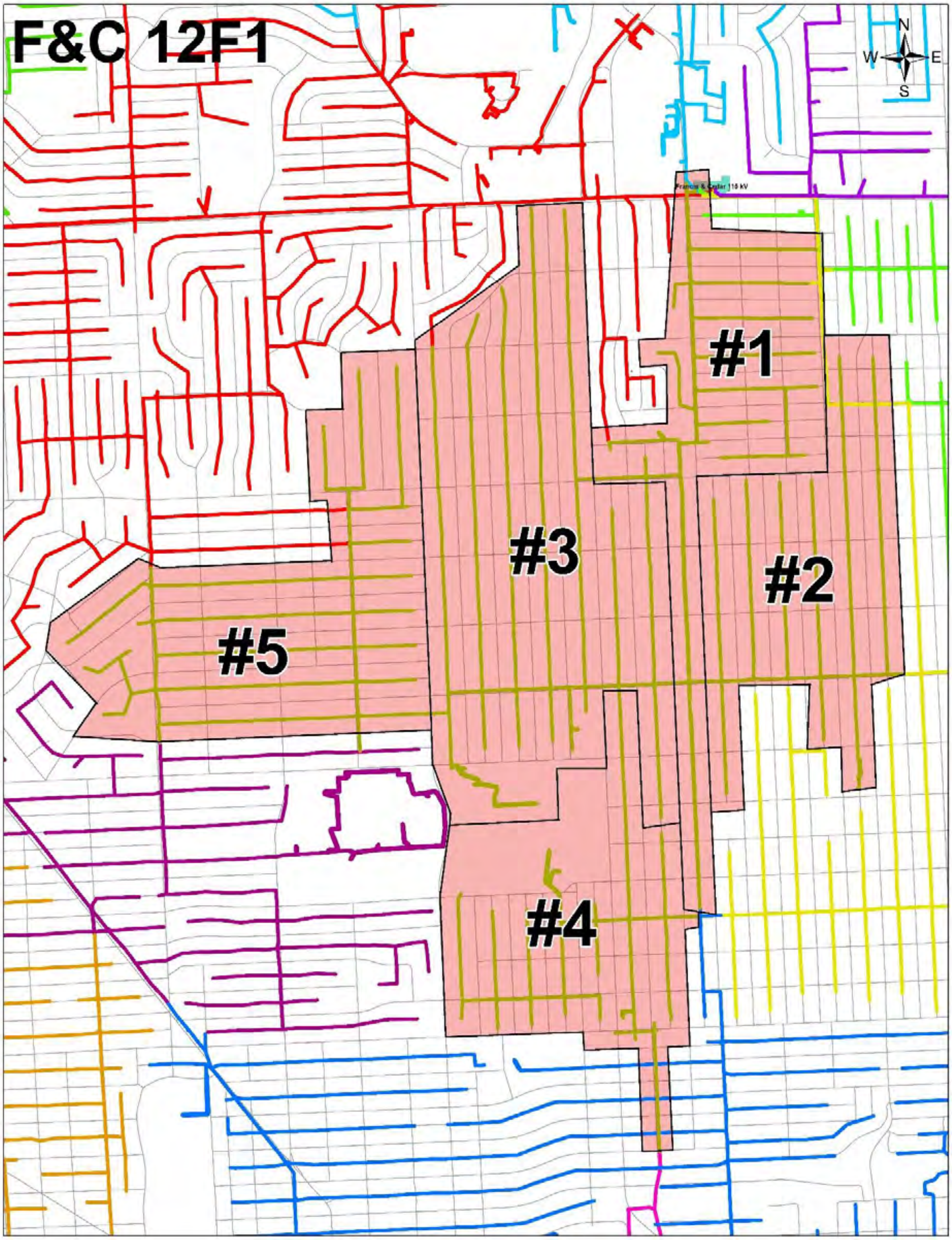


Figure 20. F&C 12F1 Polygon Numbers

<u>Report Versions</u>

Version 1	11/16/16 – Creation of the initial report
Version 2	3/9/17 – Added information from the Wood Pole Management Inspection report to the *Poles* Section

Grid Modernization Program

HOL 1205 Feeder Baseline Report

March 30, 2017

Version 1

Prepared by Shane Pacini

Index

<u>Overview</u>

The following report was established to create a baseline analysis for HOL 1205 as part of the Grid Modernization program.

HOL 1205 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Holbrook Substation in the Lewiston-Clarkston service area. The feeder has 0.58 circuit miles of feeder trunk with 3.06 circuit miles of laterals that serves an urban mixture of residential and commercial loads in north Lewiston, ID. HOL 1205 serves 647 customers during the current normal configuration. Additional feeder information is included throughout the sections of this report, as well as the 2015 Avista Feeder Status Report. HOL 1205 is represented by the color orange on the system map shown in Figure 1.

HOL 1205 serves the St. Joseph Regional Medical Center, which is primary metered.

<u>Executive Summary</u>

The following summary is provided as a preview of the findings and recommendations of the Grid Modernization program for the HOL 1205 circuit.

Avoid Costs and Energy Efficiency

- Primary trunk is currently comprised of 556 AAC, 336 ACSR, and 1000CN15 resulting in no recommendations for reconductoring
- Relatively low peak loading (average 115A peak per phase) illustrate minimum need to address reconductoring primary trunks and laterals
- Loading was already adequately balanced across strategic points on the circuit
- Voltage levels were elevated during normal and abnormal system configurations however this will be corrected through a revised output voltage setting
- One 600 kVAR switchable capacitor bank will be installed to support voltage, lower losses, optimize power factor, and provide future IVVC functionality
- Two 600 kVAR fixed capacitor banks will be removed that are causing a leading power factor throughout the entire year, allowing for power factor optimization
- There were no existing open wire secondary districts on the circuit
- An estimated 65 of the 119 transformers (54.6%) on the feeder will be replaced

Reliability and Capital Offset from Reduced O&M

- SAIFI, SAIDI, CAIDI, and CEMI3 currently satisfy the 2017 Avista Target values
- One Viper midline recloser will be installed to provide sectionalizing, fault sensing capabilities, and remote operability
- One Viper switch will be installed to provide remote operability, future FDIR functionality, and an automated tie switch to SLW 1316
- One manual 3-phase air switch will be installed to establish a tie to HOL 1205
- 89 of the 203 poles (43.2%) on the circuit are older than the prescriptive replacement of the 60 year limit for the Grid Modernization program
- Comprehensive fuse sizing and coordination study was performed

Figure 1. HOL 1205 Circuit One-Line Diagram

Program Ranking Criteria

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (energy savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set could be measured on different scales, the normalization process offers the ability to convert each figure into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked for selection.

HOL 1205 had a normalized total ranking of 0.459, ranking 42nd on the list of over 340 feeders during the 2018-2020 selection period. Further analysis suggests that a main reason this feeder was selected was due to relatively higher potential to achieve avoided costs through energy savings efforts and efficiency improvements, as well as the opportunity to reduce future O&M expenses through capital improvements. Designers should consider these factors when fielding and designing the work on HOL 1205.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.156	393.899	1001421.025
Normalized Data	0.133	0.916	0.342
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.053	0.321	0.085
Weight of Category %	11.62%	69.79%	18.59%

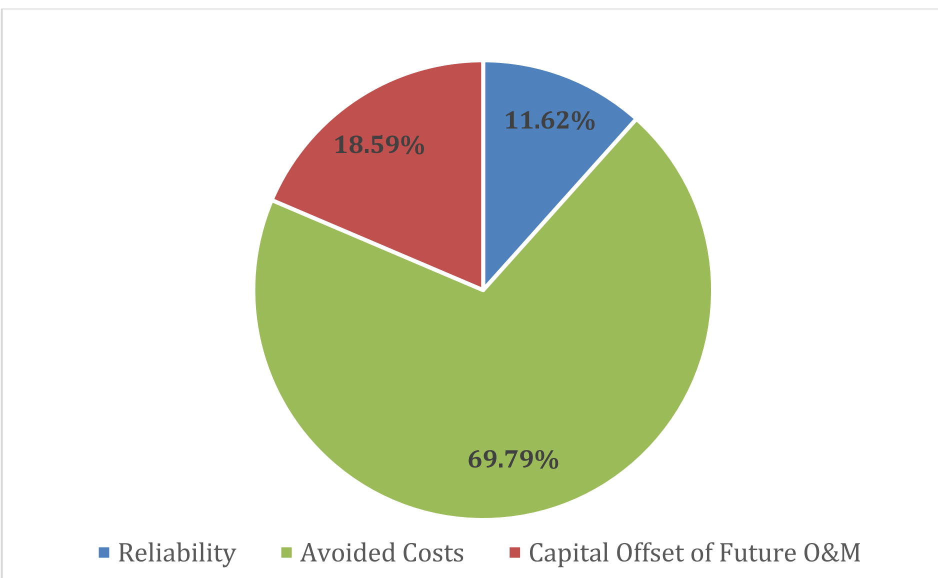


Figure 2. HOL 1205 Feeder Selection Criteria

Reliability

HOL 1205 was found to have 38 total reliability outages from 2009 to 2013 through Asset Management analysis. The key reliability indicators for HOL 1205 were analyzed from 2006 to 2015 to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed circuit improvements or automation deployments. The table below shows the annual value for each respective reliability index on HOL 1205 in the corresponding year. The reliability indices being used do not include major events days (MED), as this is standard per IEEE and reflects the same reliability information that Avista shares with the respective Utility Commission.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2006	0.0%	0.05	3	68
2007	0.0%	1.04	71	68
2008	0.0%	1.03	28	27
2009	0.0%	1.37	19	14
2010	1.6%	2.25	133	59
2011	0.0%	0.48	42	87
2012	0.0%	1.44	207	144
2013	0.0%	0.11	20	188
2014	1.3%	2.09	65	31
2015	0.0%	0.32	23	72
Average	0.29%	1.017	61.20	75.89

The average value of each index was calculated and then compared to the Avista 2016 Target values. All four of the historical averaged measured indices on HOL 1205 are out performing the 2016 targets. This data suggests that customers experience relatively few outages on the feeder, and the average service restoration duration is within the desired range of Avista.

WA-ID Key Indicator	2017 Target	HOL 1205	Variance
SAIFI Sustained Outages/Customer	1.12	1.017	0.103
SAIDI Outage Time/Customer (min)	151.00	61.20	89.80
CAIDI Ave Restoration Time (min)	149.00	75.89	73.11
CEMI3 % of Customers >3 Outages	6.80%	0.29%	6.51%

Peak Loading

Three-phase ampacity loading from SCADA monitoring at the HOL 1205 substation circuit breaker was analyzed from 11/30/14 to 11/29/16. The following loading values were established for HOL 1205 during this timeframe. Loading information has been analyzed to determine if data needed to be removed from selected timeframes due to temporary changes in loading from switching (verified through PI). HOL 1205 is a summer peaking feeder, with comparable peak values observed from late June to August. The values below reflect the adjusted data set. The peak loading values for each phase are used in the Synergi model analysis for the feeder, except where average load values are noted for establishing kW losses.

	Before Balancing	
	Peak	**Average**
A-Phase	101 A	57.8 A
B-Phase	126 A	68.0 A
C-Phase	118 A	65.4 A

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from Synergi at the model's initial configuration before balancing or performing improvements on the circuit.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	805	1658	48.55%
B-Phase	1004	2155	46.59%
C-Phase	941	1793	52.48%

*kVA per Phase in Synergi as of 11/21/16

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	461	1658	27.80%
B-Phase	542	2155	25.15%
C-Phase	521	1793	29.06%

*kVA per Phase in Synergi as of 11/21/16

Load Balancing

Accurate load balancing can be analyzed achieved on HOL 1205 due to the three-phase ampacity monitoring at the Holbrook 1205 substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively before balancing:

	Connected KVA per Phase*
A-Phase	1657.5 kVA
B-Phase	2154.5 kVA
C-Phase	1767.5 kVA

* Connected kVA per Phase in AFM as of 11/30/16

The analysis of the modeled load allocated on HOL 1205 suggests that the feeder is currently balance effectively across numerous strategic locations on the circuit. Therefore, Grid Modernization will not be recommending to make changes to balance the load on the phases. The table below shows the allocated load modeled on each phase during the peak loading scenario.

	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
HOL 1205 Station Breaker	101	126	118	101	126	118
F St. & 5th Ave	30	44	43	30	44	43
2nd St. & 5th Ave	23	24	21	23	24	21
3rd St. & 5th Ave	44	52	50	44	52	50

It is the Designer's responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any proposals for phase balancing prior to commencing the job designs.

The decision to move forward with the proposed phase change will be confirmed and approved by the Regional Operations Engineer, and coordinated by the Designer in their respective polygon design(s).

Conductor

All primary conductors on HOL 1205 were analyzed in Synergi using the balanced peak ampacity values identified above (101/126/118). Specific attention was given to conductors that were potentially overloaded, have relatively high line losses, serve areas with unacceptable voltage quality (primarily during peak conditions), and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on HOL 1205, as well as the proposals for improving the efficiency, voltage quality, and performance of the feeder.

The following table lists the various types of overhead conductors that are present on HOL 1205, as well as the approximate circuit miles of each conductor type. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on replacing conductors that have a resistance greater than 5 ohms per mile. An initial analysis does not suggest that these higher loss conductors are present on the circuit. If any of these conductors are found during field analysis, the Designer shall determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

Approximate Circuit Miles by Conductor Type		
Conductor	**Miles**	**Ohm/Mi (50 Deg)**
4ACSR	0.21	2.459
6CU	1.74	2.417
2ACSR	0.02	1.583
4CU	0.09	1.520
2CU	0.57	0.956
1/0CU	0.48	0.597
336AAC	0.26	0.305
336ACSR	1.09	0.303
250CU	0.01	0.260

The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the conductor analysis requirements for the Grid Modernization program. The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary requiring attention.

The Transmission Engineering department shall be consulted by the assigned Designer for any work or reconductoring performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

HOL 1205 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, it is not likely that there are sections that would warrant reconfiguration due to proposed reconductoring, physical conditions, stubbing, and/or high resistant conductors. The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer. It is the Designer’s responsibility to consult the Program Engineer on any proposals for reconfiguration or conversion to underground prior to commencing the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program’s scope, meets the system operations requirements, are economically justifiable, and to assist in identifying the appropriate material and equipment to install.

Trunk

The primary trunk conductors on HOL 1205 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The entire feeder trunk is currently conductored with 336 ACSR in overhead applications, with the exception being the three-phase 556 AAC branch feeding St. Joseph Regional Medical Center. A significant portion of the feeder trunk utilizes underground construction with 1000CN15 cable. The lone feeder tie on HOL 1205 with SLW 1316 is constructed with 336 ACSR conductor.

Given the large amount of high capacity conductors already present the feeder trunk and ties, and combined with the relatively low peak loading on the circuit during normal configuration, there is minimal evidence to support upgrading the primary trunk conductors on HOL 1205 based on capacity concerns alone. Line losses on the trunk are currently in the optimal range for both the peak and average loading scenarios, which has been aided by balancing the feeder and relatively lower loading conditions where high loss conductors exist. In addition, there are not concerns with voltage quality that could be improved through feeder trunk reconductoring.

Any designs to reconductor shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

Laterals

The primary lateral conductors on HOL 1205 are generally sized appropriately to meet peak loading conditions during normal system configuration. The laterals on HOL 1205 were individually reviewed to determine if the wires were sized appropriately for load, line losses, and voltage quality. The analyzed models do not suggest reconductoring laterals for any of these reasons. As part of the line loss analysis, attention was given to identify the presence of high loss conductors, even if relatively low loading levels did not provide high line losses.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Feeder Tie

HOL 1205 currently contains one gang-operated overhead feeder tie through air switch 1302 (SLW 1316). This lone tie occurs at the furthest point away from the origin of the feeder at the Holbrook substation and is near the primary metered St. Joseph's Regional Hospital. This tie will be upgraded to an automated Viper switch and will be discussed in further detail in the *Distribution Automation* section later in this report.

There is one clear opportunity to establish a more robust feeder tie on HOL 1205 with feeder HOL 1206. There are open jumpers near the intersection of 9^{th} & Main that separate HOL 1205 and HOL 1206. Each side of the open jumpers is constructed with three-phase overhead #2 CU primary, which has a limiting summer ampacity of 197A. HOL 1205 experiences a peak of 126A per phase, while HOL 1206 experiences a peak of around 250A per phase. The effort to improve the capacity and usefulness of this potential tie would require the reconductoring of approximately 1500' of #2 CU on HOL 1205 to a minimum of 336 AAC with a 2/0 ACSR neutral. In addition, approximately 700' of #2 CU conductor on HOL 1206 would also need to be reconductored to optimize this tie's potential value. This proposal could create an automated tie with increased loading capability, however the benefits may be limited for both feeders since HOL 1205 is a relatively lightly loaded feeder during peak scenarios, and HOL 1206 has multiple existing feeder tie locations.

After analyzing the options and loading scenarios adjacent to HOL 1205, Grid Modernization is not recommending performing any conductor work on the proposed feeder tie with HOL 1206. In order the make this potential tie more beneficial to the operation of the local system, a manual three-phase gang-operated air switch is proposed to replace the existing open jumpers. This new device will be assigned device number L1236 and will be located in **Polygon 1**. An automated Viper switch is not being elected for installation since the #2 CU conductor is not being upgraded to a higher operating capacity. Figure 3 illustrates the location of the proposed feeder tie to be established between HOL 1205 and HOL 1206 though the installation of the L1236 device.

The decision to pursue additional feeder tie opportunities will be discussed and determined with the Regional Operations Engineer based on their anticipated frequency of using potential ties in the operation of the L/C distribution system.

Figure 3. Feeder Tie for HOL 1205 and HOL 1206

Voltage Quality

The HOL 1205 circuit was analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled in Synergi during both peak loading and average loading conditions, with both normal and abnormal circuit configurations.

The following information on the substation voltage regulators for HOL 1205 was taken from Maximo. The Equipment P.T. Ratio of the voltage regulators (66.7:1) did not match the Desired P.T. Ratio (63.5:1) on the regulator controls. Therefore the initial analysis of the voltage quality on HOL 1205 utilized a voltage of 117V at minimum load to convert from the 63.5:1 ratio to achieve an effective 123V value for the 7620V system.

Serial Numbers	A	B	C
HOL 1205 Station Regulators	**J-222756**	**J-222816**	**J-222850**

Rated kVA	**250**
C.T. Ratio	**400/.02**
Equipment P.T. Ratio	**66.7:1**
Desired P.T. Ratio	**63.5:1**
Distribution Transformer Ratio	**63.5:1**

* Settings in MAXIMO as of 11/21/16

The data in the following sections suggest that the existing voltage regulator settings at the Holbrook substation are providing output voltages that are higher than necessary to serve average and peak load on the circuit during normal feeder configuration. In addition, the models suggest that the Holbrook substation is also providing output voltages that are higher than necessary to serve average and peak load on the feeder during situations where additional load from SLW 1316 is served. Recommendations will be provided that satisfy the voltage levels for the modeled scenarios.

Voltage Quality Analysis Before Incorporating Recommendations

Figures 4-7 illustrate the modeled voltage levels for the various scenarios on HOL 1205 before any proposed recommendations were incorporated into the models. Green illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V, which greater than +/- 6V of the ideal 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to HOL 1205. During peak loading conditions, voltage levels nearest to the Holbrook Substation, were elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 124.7V. The lowest voltage on the larger three-phase lateral west of 2nd St. & 5th Ave is 124.4V. The voltage modeled at the far south end of the feeder near the #1302 switch is 124.3V. The minimum voltage modeled on the feeder was 124.3V.

Figure 4 illustrates the modeled voltage levels at peak loading on HOL 1205.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	0	0.00	0	0
124.00 - 126.00 V	180	4.73	2058	649
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading

The voltage levels on the feeder were again analyzed before balancing load or incorporating conductor upgrade proposals, however this time during average loading conditions. This scenario saw slightly lower voltage levels across the feeder.

During average loading conditions, voltage levels nearest to the Holbrook Substation, were still slightly elevated however they were still with the acceptable range and lower than the Peak Loading scenario values. The maximum voltage modeled on the feeder occurred near the substation at approximately 123.9V. The lowest voltage on the larger three-phase lateral west of 2nd St. & 5th Ave is 123.8V. The voltage modeled at the far south end of the feeder near the #1302 switch is 123.7V. The minimum voltage modeled on the feeder was 123.7V.

Figure 5 illustrates the modeled voltage levels at average loading on HOL 1205.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	179	4.72	962	649
124.00 - 126.00 V	1	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 4. Modeled Voltage Levels at Peak Loading

Figure 5. Modeled Voltage Levels at Average Loading

Modeled Voltage Levels at Peak Loading before Proposals – Serving SLW 1316 to the #1332 from HOL 1205

Voltage levels nearest to the Holbrook Substation were elevated and slightly above the acceptable ANSI Range B voltage. The maximum voltage modeled on the feeder occurred near the substation at approximately 127.0V. Voltage levels on the original HOL 1205 circuit range from 127.0V down to 125.2V. Voltage levels on the newly served SLW 1316 circuit range from 125.1V down to 123.5V. The lowest modeled voltage at 123.4 V. Figure 6 identifies modeled voltage levels on HOL 1205 at peak loading and serving most of SLW 1316 from HOL 1205. SLW 1316 was estimated to have an allocated 310A per phase for the Peak Loading scenario.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	178	7.41	3501	436
124.00 - 126.00 V	244	6.65	3013	1136
126.00 - 140.00 V	37	1.35	914	125

Modeled Voltage Levels at Average Loading before Proposals – Serving SLW 1316 to the #1332 from HOL 1205

Voltage levels nearest to the Holbrook Substation as well as entire HOL 1205 feeder was modeled with optimal or acceptable ANSI Range B voltages. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.5V. Voltage levels on the original HOL 1205 circuit range from 125.5V down to 124.6V. Voltage levels on the newly served SLW 1316 circuit range from 124.5V down to 123.2V. The lowest modeled voltage at 123.2 V. Figure 7 identifies modeled voltage levels on HOL 1205 at average loading and serving most of SLW 1316 from HOL 1205. SLW 1316 was estimated to have an allocated 140A per phase for the Average Loading scenario.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	175	7.33	937	435
124.00 - 126.00 V	284	8.07	1420	1262
126.00 - 140.00 V	0	0.00	0	0

Figure 6. Modeled Voltage Levels at Peak Loading before Proposals – Serving SLW 1316 to the #1332 from HOL 1205

Figure 7. Modeled Voltage Levels at Average Loading before Proposals – Serving SLW 1316 to the #1332 from HOL 1205

Voltage Quality Analysis After Incorporating Recommendations

The voltage levels on HOL 1205 were re-analyzed after incorporating and modeling the upgrade proposals, and utilizing the proposed changes to the voltage regulator settings in the *Voltage Regulator Settings* section. The feeder was modeled with these proposals in Synergi during both Peak loading and Average loading conditions.

The following information on the substation voltage regulators for HOL 1205 was taken from Maximo. The Equipment P.T. Ratio of the voltage regulators (66.7:1) did not match the Desired P.T. Ratio (63.5:1) on the regulator controls. Therefore the initial analysis of the voltage quality on HOL 1205 utilized a voltage of 117V at minimum load to convert from the 63.5:1 ratio to achieve an effective 123V value for the 7620V system. Both the output voltage level and the voltage regulator settings were adjusted with numerous combinations in these models to optimize the voltage levels across the circuit.

Figures 8-9 illustrate the modeled voltage levels for the various scenarios on HOL 1205 after the proposed recommendations were incorporated into the models. Green illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V, which greater than +/- 6V of the ideal 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading after Proposals

The voltage levels on the feeder were analyzed after performing the identified changes and improvements to HOL 1205. During peak loading conditions, voltage levels nearest to the Holbrook Substation, were elevated however they lower than previously modeled. The maximum voltage modeled on the feeder occurred near the substation at approximately 121.6V. The lowest voltage on the larger three-phase lateral west of 2nd St. & 5th Ave is 121.3V. The voltage modeled at the far south end of the feeder near the #1302 switch is 121.1V. The minimum voltage modeled on the feeder was 121.1V.

Figure 8 illustrates the modeled voltage levels at peak loading on HOL 1205.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	179	4.72	2184	649
122.00 - 124.00 V	0	0.00	0	0
124.00 - 126.00 V	1	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading after Proposals

The voltage levels on the feeder were again analyzed after balancing load, however this time during average loading conditions. During peak loading conditions, voltage levels nearest to the Holbrook Substation, were elevated however they lower than previously modeled. The maximum voltage modeled on the feeder occurred near the substation at approximately 120.8V. The lowest voltage on the larger three-phase lateral west of 2nd St. & 5th Ave is 120.6V. The voltage modeled at the far south end of the feeder near the #1302 switch is 120.5V. The minimum voltage modeled on the feeder was 120.5V.

Figure 9 illustrates the modeled voltage levels at average loading on HOL 1205.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	179	4.72	978	649
122.00 - 124.00 V	0	0.00	0	0
124.00 - 126.00 V	1	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

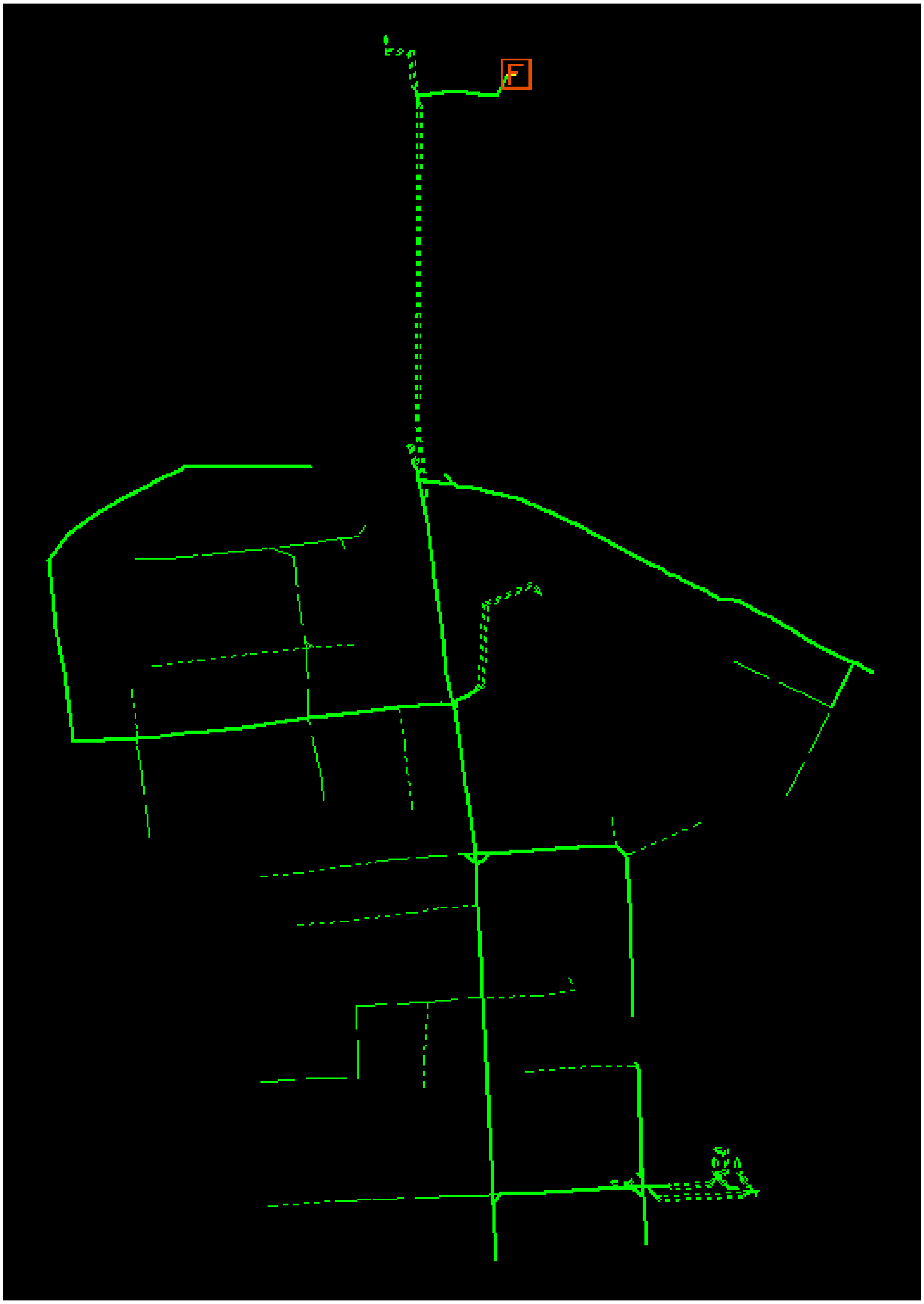


Figure 8. Modeled Voltage Levels at Peak Loading after Proposals

Figure 9. Modeled Voltage Levels at Average Loading after Proposals

Modeled Voltage Levels at Peak Loading after Proposals – Serving SLW 1316 to the #1332 from HOL 1205

Voltage levels nearest to the Holbrook Substation as well as entire HOL 1205 feeder was modeled with optimal or acceptable ANSI Range B voltages. The maximum voltage modeled on the feeder occurred near the substation at approximately 124.4V. Voltage levels on the original HOL 1205 circuit range from 124.4V down to 122.7V. Voltage levels on the newly served SLW 1316 circuit range from 122.6V down to 120.4V. The lowest modeled voltage at 120.4 V. SLW 1316 was estimated to have an allocated 310A per phase for the Peak Loading scenario.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	169	6.54	3795	632
122.00 - 124.00 V	278	8.71	3709	1064
124.00 - 126.00 V	12	0.16	61	1
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading after Proposals – Serving SLW 1316 to the #1332 from HOL 1205

Voltage levels nearest to the Holbrook Substation as well as entire HOL 1205 feeder was modeled with optimal or acceptable ANSI Range B voltages. The maximum voltage modeled on the feeder occurred near the substation at approximately 122.3V. Voltage levels on the original HOL 1205 circuit range from 122.3V down to 121.5V. Voltage levels on the newly served SLW 1316 circuit range from 121.5V down to 120.2V. The lowest modeled voltage at 120.2 V. SLW 1316 was estimated to have an allocated 140A per phase for the Average Loading scenario.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	410	13.41	2328	1682
122.00 - 124.00 V	47	1.99	125	15
124.00 - 126.00 V	2	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

Voltage Regulator Settings

HOL 1205 has one existing stage of voltage regulation at the Holbrook Substation. Due to the interconnected urban nature of the feeder, and the shorter feeder length, additional stages of midline voltage regulation are not recommended on the feeder to support voltage levels during normal configuration or times of switching.

A group of alternative settings was analyzed to show if there was the potential for improving voltage levels. The voltage levels on HOL 1205 were re-analyzed and modeled with the voltage regulator settings change proposals in Synergi at peak and average loading conditions.

The Equipment P.T. Ratio of the voltage regulators (66.7:1) did not match the Desired P.T. Ratio (63.5:1) on the regulator controls. Therefore the proposed analysis of the voltage quality on HOL 1205 utilized a proposed voltage of 114V at minimum load to convert from the 63.5:1 ratio to achieve a lower effective 120V value for the 7620V system.

The existing and proposed voltage regulator settings are provided in the table below:

	Existing*		Proposed	
Forward Settings	**R**	**X**	**R**	**X**
HOL 1205 Station Regulators	**3.0**	**7.0**	**3.0**	**7.0**

* Settings in Maximo, AFM, and SynerGEE as of 11/21/16

The decision to move forward with implementing any changes to the regulator settings will be confirmed, approved, and coordinated by the Regional Operations Engineer. These changes are proposed to illustrate the potential benefits to adjusting the settings.

The recent work at the Holbrook Substation upgraded HOL1205 to a Square D Type FVR vacuum breaker with SEL-351S relay. A full fiber connected 3-phase SCADA system was also installed. However, the voltage regulators on the feeder were not upgraded or connected, so this work would need to be completed in order to make HOL 1205 automation compatible from the substation perspective. Substation Engineering estimates approximately $90k to complete this work. HOL1205 is currently on the Substation Engineering list to receive new voltage regulators as part of a programmatic replacement in 2019. It is typically not planned to dig fiber into the integration system as part of this work. This information will be discussed with Substation Engineering through the Engineering Round Table to determine mutual interest, support, and prioritization.

Fuse Sizing

Fuse sizing on HOL 1205 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and underground risers. Fuse recommendations for HOL 1205 were created by the Grid Modernization Program Engineer and approved by the Regional Operations Engineer. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

The fuse “blowing” philosophy was selected for HOL 1205 where the largest fuse was selected that would accurately coordinate to: satisfy peak loading conditions, protect the downstream conductor(s), and for fuse-to-fuse coordination based on preloading of source-side fuse link (maximum fault current).

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Line Losses

The primary trunk conductors on HOL 1205 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the rural feeder. Line losses on the feeder were first addressed by analyzing load balancing on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. It should be noted that there were not recommendations to reconductor the feeder trunk or ties, as most of these sections were upgraded 556 AAC, 336 ACSR and 1000CN15, and peak loading on HOL 1205 is relatively low based on the ampacity of the trunk and lateral conductors.

An initial Synergi load study estimates that a total of 7 kW in peak line losses currently exist on HOL 1205 (0.41%), which is indicative to the relatively low peak loading during normal circuit configuration. It is estimated that peak line losses will remain relatively static since there were not any major system enhancements recommended through the form of load balancing or primary reconductor.

Peak Values	**Existing**
kW Demand	2613
kW Load	2602
kW Line Losses	7
kW Loss %	0.41 %

Transformer Core Losses

The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, transformer core losses are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of a near equivalent size.

All transformers on HOL 1205 shall be analyzed and “right sized” by the assigned Designer to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP). In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the assigned Designer.

The roughly 119 distribution transformers on HOL 1205 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It was determined that approximately 65 transformers may require replacement based on right sizing and the TCOP replacement criteria. The replacement of these transformers will result in an estimated 7.48 kW reduction in core losses. This equates to an estimated annual savings of roughly 65.52 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

MVAR and MW data at the HOL 1205 substation circuit breaker was analyzed from 11/30/14 to 11/29/16. It was determined that HOL 1205 had a leading power factor at all time during the time interval analyzed, and never achieved a lagging power factor. Detailed power factor information is available upon request. Some key power factor figures for HOL 1205 are provided in the tables below.

Maximum Lagging Power Factor	-
Minimum Lagging Power Factor	-
Maximum Leading Power Factor	98.18 %
Minimum Leading Power Factor	39.87 %

The graph in Figure 10 shows the percent of time during the interval analyzed where the power factor on HOL 1205 fell between the applicable ranges. Figure 11 shows additional details on the percent of time during the interval analyzed where the power factor on HOL 1205 was leading. This information is also provided in a table format.

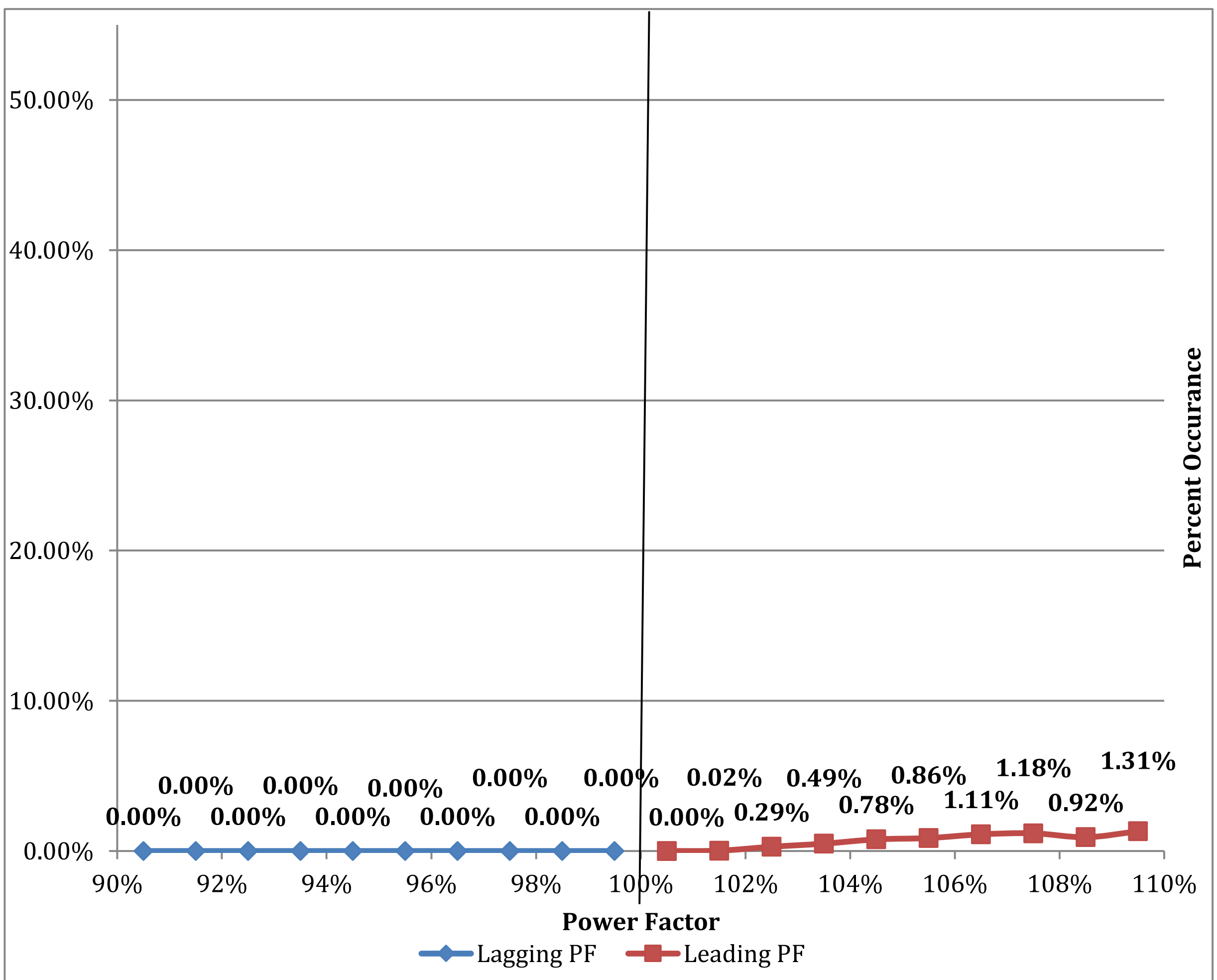


Figure 10. Existing Percent Occurance of Power Factor

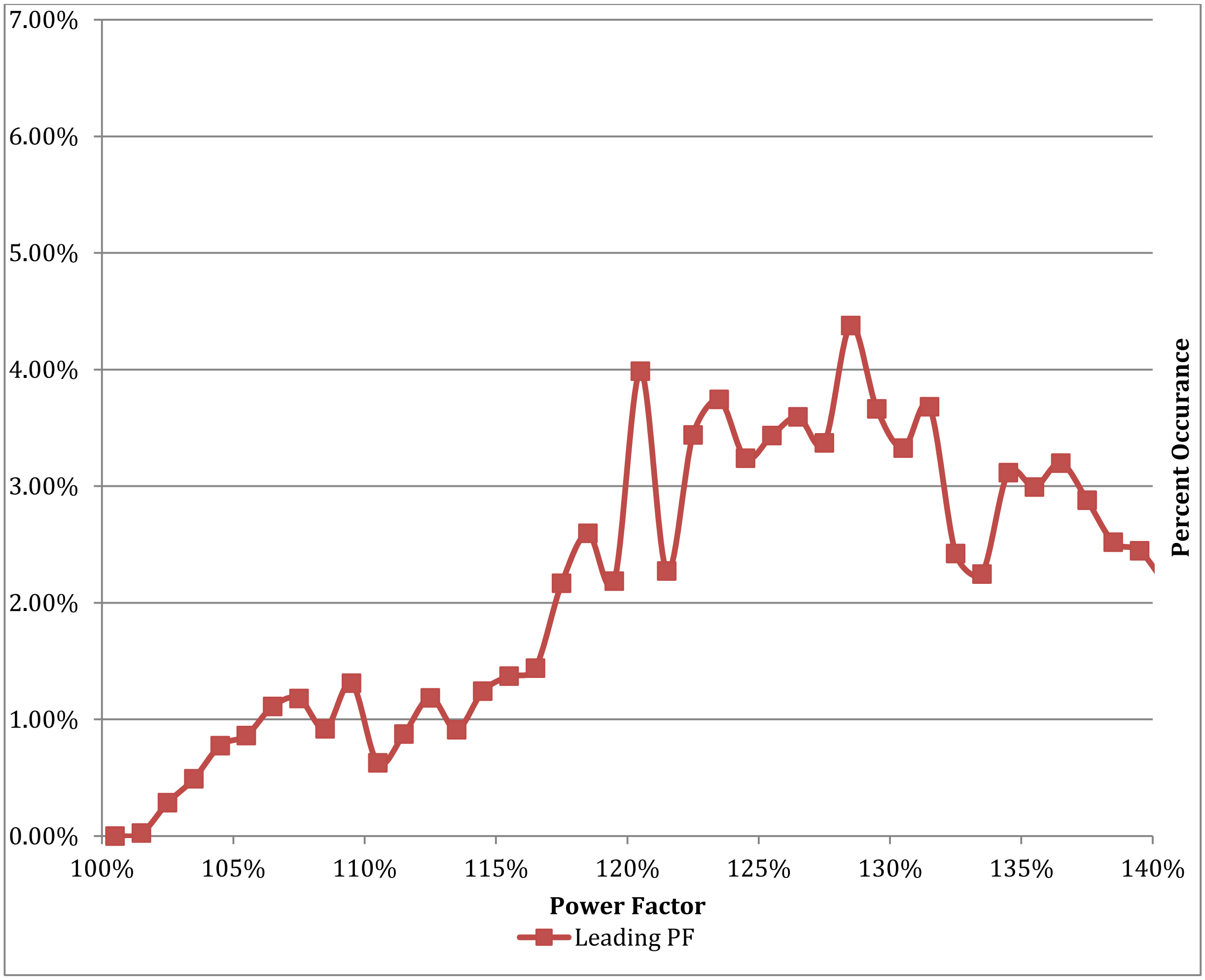


Figure 11. Existing Percent Occurance of Leading Power Factor

	Lagging	Leading
Below 60%	0.00%	12.32%
60%-70%	0.00%	30.99%
70%-80%	0.00%	35.21%
80%-90%	0.00%	14.60%
90%-91%	0.00%	1.31%
91%-92%	0.00%	0.92%
92%-93%	0.00%	1.18%
93%-94%	0.00%	1.11%
94%-95%	0.00%	0.86%
95%-96%	0.00%	0.78%
96%-97%	0.00%	0.49%
97%-98%	0.00%	0.29%
98%-99%	0.00%	0.02%
99%-100%	0.00%	0.00%

Power Factor Correction

There are two existing fixed capacitor banks on HOL 1205. These two banks were confirmed in the field by a local Serviceman to each be 600 kVAR units. The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor with the known capacitors values. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times.

The power factor on HOL 1205 was consistently outside of the acceptable range with the existing capacitors. The circuit consistently had a significantly "leading" power factor, which suggests that too much capacitance is existing on the circuit. It is recommended to remove both of the 600 kVAR fixed capacitor banks in **Polygon 2** and install one switched 600 kVAR capacitor bank in **Polygon 2**. These changes would assist with bringing the feeder into the optimal range for power factor correction, as well as improving the leading power factor when necessary.

To illustrate, the feeder was first reanalyzed with the proposed removal of one of the 600 kVAR fixed capacitor banks. The power factor was slightly improved, with the analysis suggesting that the HOL 1205 circuit would now have a leading power factor roughly 99.2% of the time, as well as now having lagging power factor occurrences. Some key power factor figures for HOL 1205 are provided in the tables below.

Average Lagging Power Factor	98.46 %
Median Lagging Power Factor	99.97 %
Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	25.64 %

Average Leading Power Factor	90.64 %
Median Leading Power Factor	91.38 %
Maximum Leading Power Factor	99.99 %
Minimum Leading Power Factor	66.75 %

The graph in Figure 12 shows the percentage of time during the re-analyzed interval where the power factor on HOL 1205 fell between the applicable ranges with one of the 600 kVAR fixed capacitor banks removed. This information is also provided in a table format.

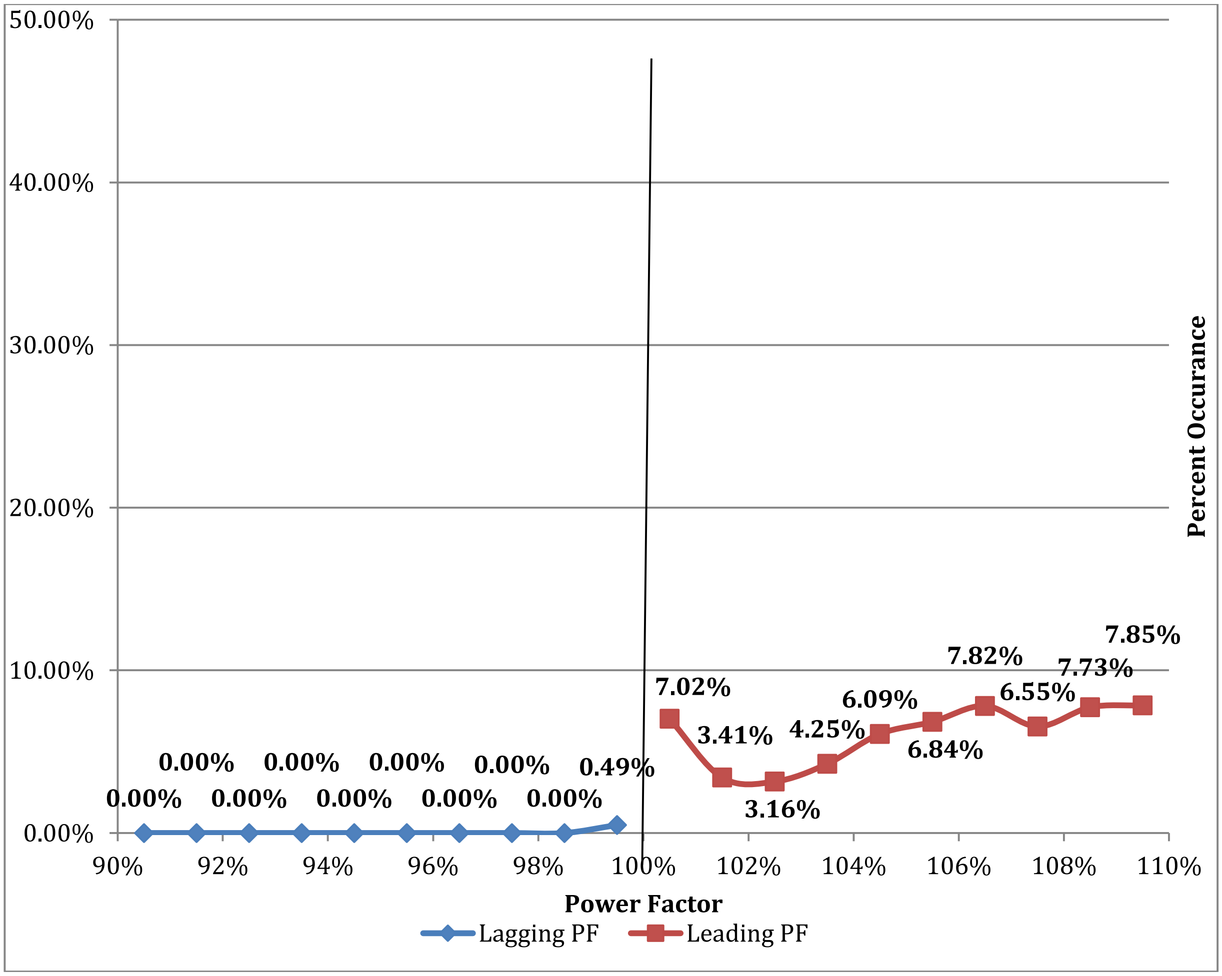


Figure 12. Proposed Percent Occurance of Power Factor with 600 kVAR Removal

	Lagging	Leading
Less than 90%	0.00%	38.67%
90%-91%	0.00%	7.85%
91%-92%	0.00%	7.73%
92%-93%	0.00%	6.55%
93%-94%	0.00%	7.82%
94%-95%	0.00%	6.84%
95%-96%	0.00%	6.09%
96%-97%	0.00%	4.25%
97%-98%	0.00%	3.16%
98%-99%	0.00%	3.41%
99%-100%	0.49%	7.02%

Next, the feeder was first reanalyzed with the proposed removal of both of the 600 kVAR fixed capacitor banks. The power factor was significantly improved, with the analysis suggesting that the HOL 1205 circuit would now have a lagging power factor roughly 98.7% of the time, as well as a less frequent leading power factor occurrences. Some key power factor figures for HOL 1205 are provided in the tables below.

Average Lagging Power Factor	98.97 %
Median Lagging Power Factor	99.37 %
Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	11.84 %

Average Leading Power Factor	99.98 %
Median Leading Power Factor	99.99 %
Maximum Leading Power Factor	99.99 %
Minimum Leading Power Factor	99.92 %

The graph in Figure 13 shows the percentage of time during the re-analyzed interval where the power factor on HOL 1205 fell between the applicable ranges with both of the 600 kVAR fixed capacitor banks removed. This information is also provided in a table format.

This information of the two re-analyzed data sets illustrate what could be achieved with the power factor on the feeder with the removal of one 600 kVAR fixed capacitor bank and the installation of one 600 kVAR switchable capacitor bank. Figure 12 represents the scenario where the lone switched capacitor bank is turned “on”, while Figure 13 represents the scenario where the lone switched capacitor bank is turned “off”. Both scenarios provide corrected power factor and lowered line losses from reduced reactive power flow.

The decision to move forward with implementing any changes to the capacitors sizes and location will be confirmed, approved, and coordinated by the Regional Operations Engineer.

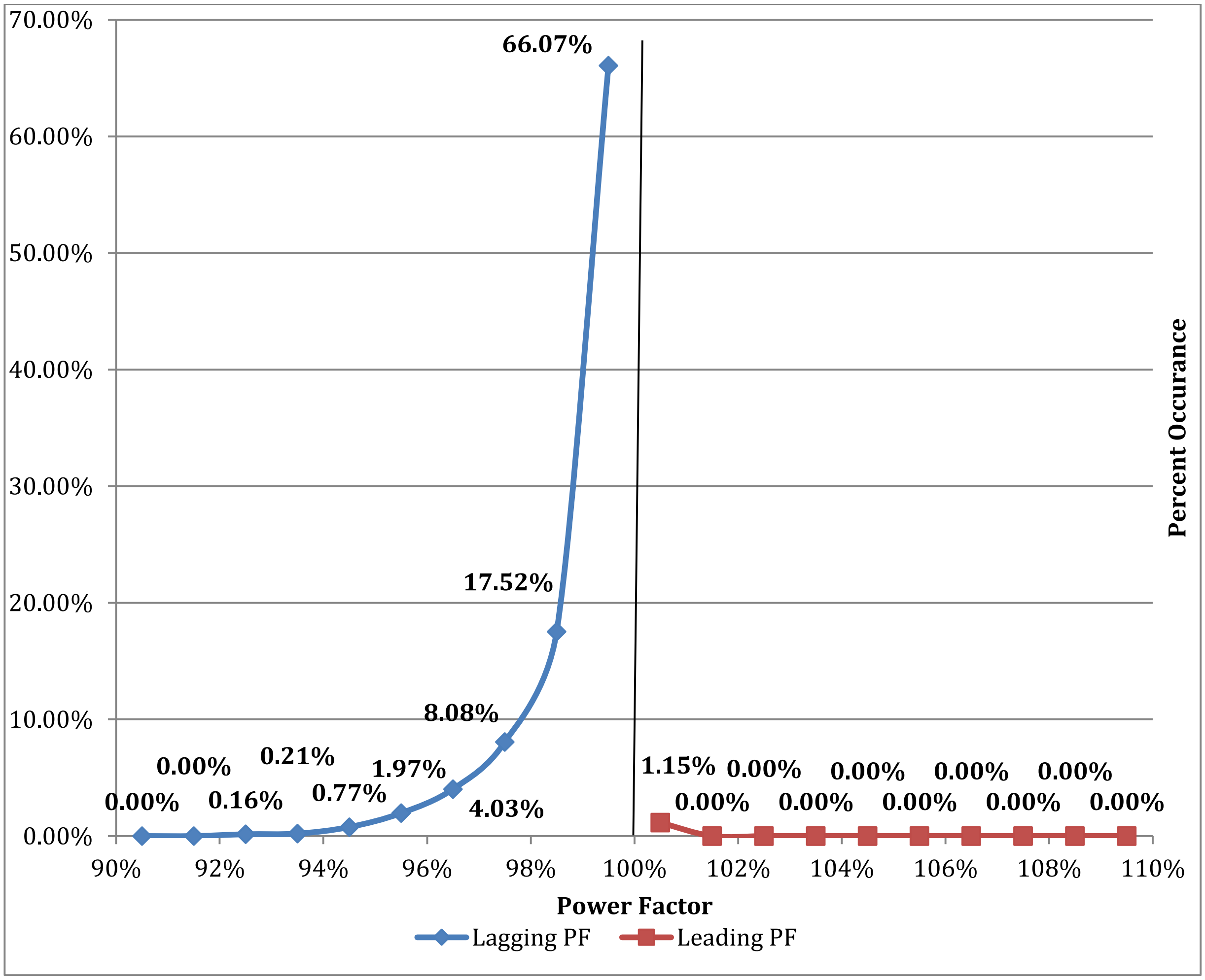


Figure 13. Proposed Percent Occurance of Power Factor with 1200 kVAR Removal

	Lagging	Leading
Less than 90%	0.00%	0.00%
90%-91%	0.00%	0.00%
91%-92%	0.00%	0.00%
92%-93%	0.16%	0.00%
93%-94%	0.21%	0.00%
94%-95%	0.77%	0.00%
95%-96%	1.97%	0.00%
96%-97%	4.03%	0.00%
97%-98%	8.08%	0.00%
98%-99%	17.52%	0.00%
99%-100%	66.07%	1.15%

Distribution Automation

Distribution Automation was analyzed for deployment on HOL 1205 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on HOL 1205.

HOL 1205 does not currently have a midline recloser to assist in fault detection and isolation. Installing a new automated midline Viper recloser in **Polygon 2** will provide these benefits, as well as sectionalize the feeder into two near equal sections based on the modeled amps allocated by connected kVA.

- Install Viper tie switch (ZL1302R, N.O.) near 6th Ave & 5th St in **Polygon 3** and remove the existing #1302 air switch.
- Install Viper tie recloser (ZL1235R, N.C.) south of 2nd Ave & 5th St in **Polygon 2**.
- Install three-phase gang-operated manual air switch (L1236, N.O.) south of Main St & 9th St in **Polygon 1** and remove the existing open jumpers.
- Install 600 kVAR switched capacitor bank (ZL2001F, N.C.) north of 3rd Ave & 5th St in **Polygon 2** and remove the existing 600 kVAR fixed capacitor bank.

The following automation devices are proposed for deployment on HOL 1205:

Device Number	Location	Status	Device Type
ZL1302R	6th Ave & 5th St	N.O.	Viper – Tie Switch
ZL1235R	S of 2nd Ave & 5th St	N.C.	Viper – Recloser
L1236*	S of Main St & 9th St	N.O.	Manual Air Switch – Tie
ZL2001F	N of 3rd Ave & 5th St	N.C.	600 kVAR switched cap bank

*The L1236 device will not be automated or have communications

Figure 14 illustrates the proposed automation device locations for HOL 1205.

The recent work at the Holbrook Substation upgraded HOL1205 to a Square D Type FVR vacuum breaker with SEL-351S relay. A full fiber connected 3-phase SCADA system was also installed. However, the voltage regulators on the feeder were not upgraded or connected. This work would need to be completed in order to make HOL 1205 automation compatible from the substation perspective. Substation Engineering estimates approximately $90k to complete this work. HOL1205 is currently on the Substation Engineering list to receive new voltage regulators as part of a programmatic replacement in 2019. It is typically not planned to dig fiber into the integration system as part of this work. This information was previously discussed in the *Voltage Regulator Settings* section.

In order to promote complete automation on HOL 1205, Grid Modernization will notify Substation Engineering of the intended line automation work on the feeder and the request to upgrade the voltage regulators. The decision on when the requested work will be performed will ultimately be made through discussions with Substation Engineering and the Engineering Roundtable prioritization of resources.

The Grid Modernization program is not funded to perform work on adjacent feeders, including additional automation devices. Any requests to perform work on adjacent feeders are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on adjacent feeders.

The proposed automation line device locations identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with either the Regional Operations Engineer, General Foreman, or District Manager to address any construction or Standards related concerns with the selected location.

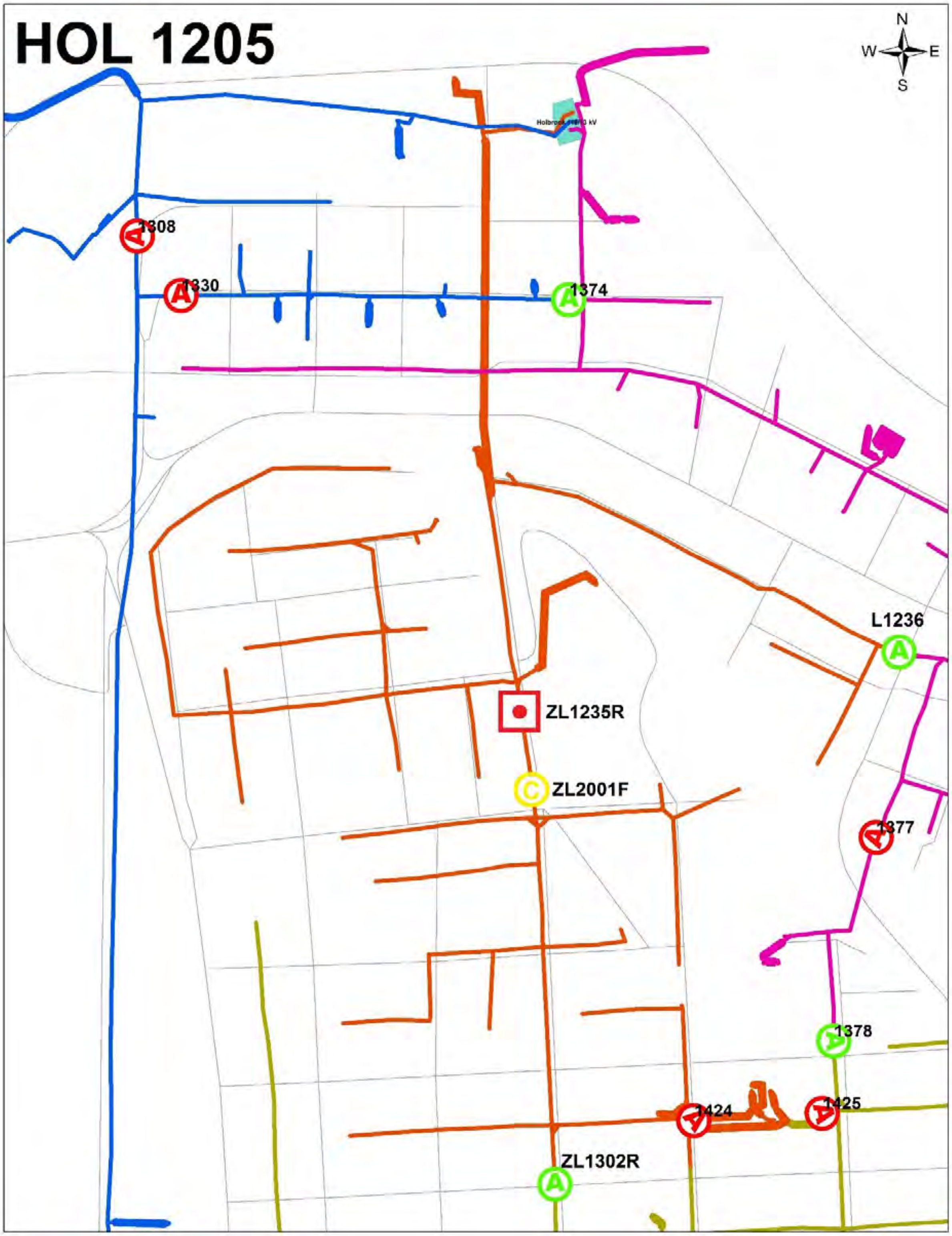


Figure 14. HOL 1205 Automation Device Locations

Open Wire Secondary

Open wire secondary districts have been analyzed for replacement on HOL 1205 in accordance to the Distribution Feeder Management Plan (DFMP). After analyzing the feeder through field observations, it was determined there were not any vertical or horizontal open wire secondary districts identified on HOL 1205. The Designers shall consult the DFMP if open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Poles

All poles and structures on HOL 1205 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Wood Pole section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the HOL 1205 circuit was performed from 1/23/2017 to 1/31/2017. The HOL 1205 feeder was determined to contain 203 distribution poles at the time of analysis. The average age of distribution pole on the circuit is approximate 52 years, which places the average year of installation around 1965. 89 poles on the circuit are older than the 60 year limit for mean-time to failure, which results in the prescriptive replacement of 43.2% of wood poles at a minimum based on age alone.

The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	203
Average Pole Age in Years	52 (1965)
Year of Oldest Installed Pole	1922
Poles install between 1920-1929	12 (6%)
Poles install between 1930-1939	43 (21%)
Poles install between 1940-1949	18 (9%)
Poles install between 1950-1959	17 (8%)
Poles install between 1960-1969	24 (12%)
Yellow Tagged Poles (Re-enforceable)	14 (6%)
Red Tagged Poles (Replace)	1 (0.5%)
Average Pole Class	3.8
Class 4 Poles or Smaller	128 (62%)
Class 5 Poles of Smaller	43 (21%)

Transformers

All transformers on HOL 1205 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable.

Vegetation Management

Vegetation management shall be employed on HOL 1205 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

HOL 1205 has been divided into 3 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Automation devices located within a polygon shall be sequentially renamed using alphabetic letters to reflect a sub-polygon (i.e. #9A, #9B, #9C, etc). Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Manager by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figures 15 illustrates the HOL 1205 polygons and their boundaries. The CPC design layer on AFM is available to provide more detailed boundaries of the polygons.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
  - Install three-phase gang-operated manual air switch (L1236, N.O.) south of Main St & 9th St in **Polygon 1** and remove the existing open jumpers.
- **Polygon 2**
  - Install Viper tie recloser (ZL1235R, N.C.) south of 2nd Ave & 5th St.
  - Install 600 kVAR switched capacitor bank (ZL2001F, N.C.) north of 3rd Ave & 5th St and remove the existing 600 kVAR fixed capacitor bank.
  - Remove the existing 600 kVAR fixed capacitor bank west of 2nd Ave & 3rd St.
- **Polygon 3**
  - Install Viper tie switch (ZL1302R, N.O.) near 6th Ave & 5th St and remove the existing #1302 air switch.

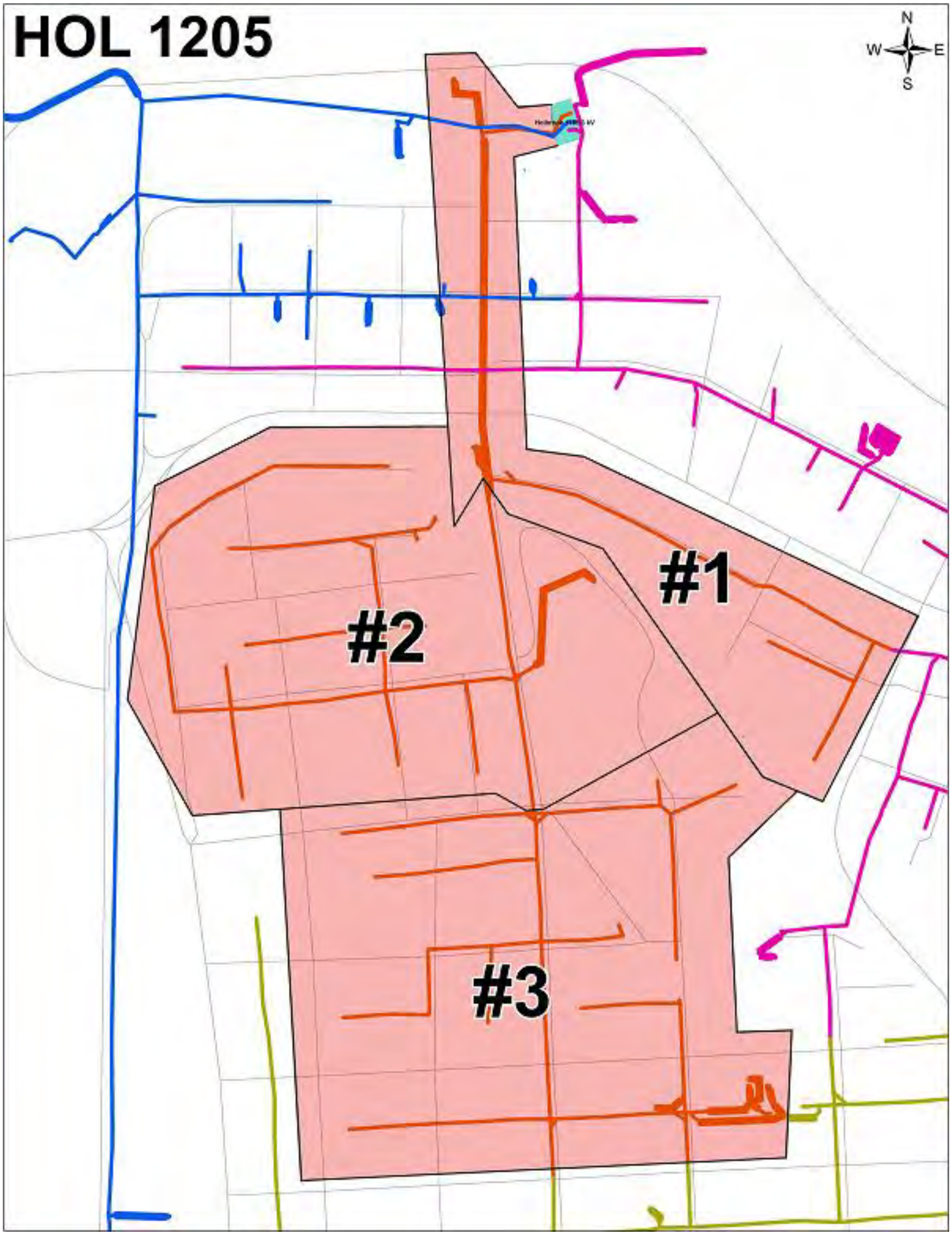


Figure 15. HOL 1205 Polygon Numbers

Report Versions

Version 1 3/30/17 – Creation of the initial report

Grid Modernization Program

M15 514 Feeder Analysis Report

April 30, 2018

Version 1

Prepared by

Shane Pacini, P.E.
Senior Distribution Engineer

Index

Overview

The following report was established to create a baseline feeder analysis for M15 514 as part of the Grid Modernization program.

M15 514 is a 13.2/7.62 kV distribution feeder served from Transformer #2 at the Moscow 115kV Substation in the Moscow/Pullman (Palouse) service area. The feeder has 4.66 circuit miles of feeder trunk with 36.53 circuit miles of laterals that serves an urban and rural mixture of residential and commercial loads in east Moscow, ID. M15 514 serves 3218 customers during the current normal configuration. Additional feeder information is included throughout the sections of this report, as well as the 2016 Avista Feeder Status Report. There are currently not any primary metered customers on M15 514. M15 514 is represented by the color *brown* on the system map shown in Figure 1.

Executive Summary

The following summary is provided as a preview of the findings and recommendations of the Grid Modernization program for the M15 514 circuit.

Cost Avoidance and Energy Efficiency:

- Primary trunk is currently comprised of 556 AAC, 3/0 STCU, and 4/0 ACSR, or 2/0 ACSR resulting in no recommendations for reconductoring
- Opportunities exist to potentially reconductor primary laterals due to a combination of physical condition, facility replacements, and high loss conductors
- Minimal phase changes will create balanced loading across numerous strategic points on the circuit
- Voltage levels were acceptable during peak and average loading under normal system configurations however future load growth in rural areas can change this
- One 600 kVAR switchable capacitor bank will be installed to support voltage, lower losses, optimize power factor, and provide future IVVC functionality
- Three 600 kVAR fixed capacitor banks will be removed that are causing a leading power factor throughout the entire year, allowing for power factor optimization
- There is approximately 2,300’ circuit feet of open wire secondary districts.
- An estimated 304 of the 678 transformers (44.8%) on the feeder will be replaced

Reliability and Capital Offset from Reduced O&M:

- The historical averaged SAIDI, CAIDI, and CEMI3 indices are positively performing when compared to the 2018 Avista Target values
- One Viper midline recloser will be installed to provide sectionalizing, fault sensing capabilities, and remote operability
- Six Viper switches will be installed to provide remote operability, future FDIR functionality, and either automated sectionalizing or feeder ties.
- 226 of the 1133 poles (19.9%) on the circuit are will be replaced at a minimum due to the prescriptive replacement of the 60 year limit for mean-time to failure
- Comprehensive fuse coordination and sizing study was performed

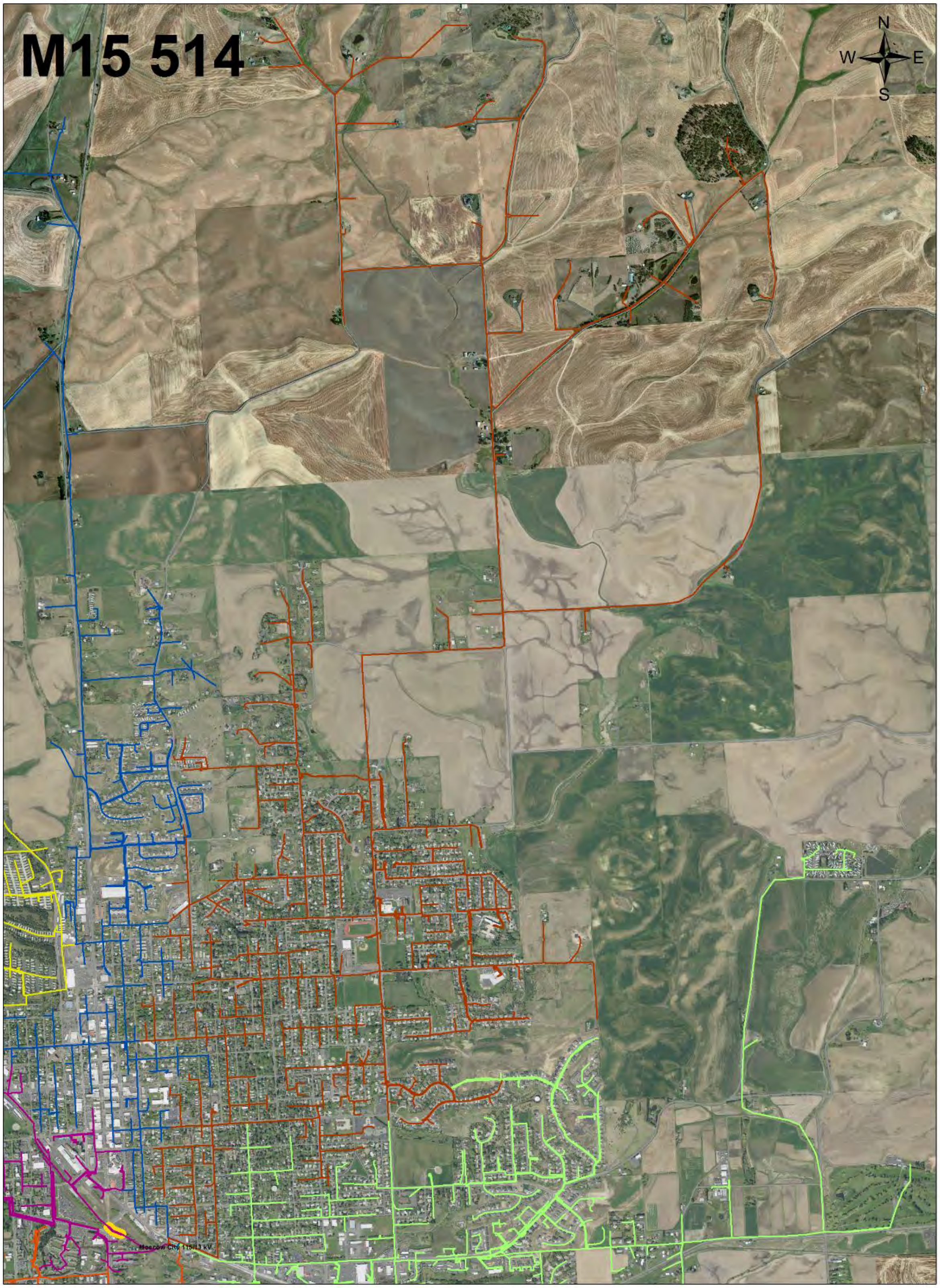


Figure 1. M15 514 Circuit One-Line Diagram

Program Ranking Criteria

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (energy savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set could be measured on different scales, the normalization process offers the ability to convert each figure into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked for selection.

The 2016 Avista Feeder Status Report contains detailed information on each distribution circuit and assesses each feeder in three key areas: health, performance, and criticality. The Health metric analyzes items such as the age of the wood pole population and projected reject rate, reliability indices, and OH-UG ration.
The Performance metric analyzes items such as the thermal utilization, efficiency, voltage, power factor, and reliability indices. The Criticality metric analyzes items such as customer density, commercial account density, load density, and the essential services on the circuit. M15 514 was determined to be performing well in terms of Health and Performance, and is seen as being relatively non-critical based on the customers that are served.

Metric	Rating Value	Rating Scale
Health	3.70	Good to Very Good
Performance	3.63	Good to Very Good
Criticality	1.30	Very Low to Low

The 2016 Avista Feeder Status Report provides the following ranks for M15 514 in the Pullman-Moscow: 7th in Thermal Utilization (57%), 1st in Winter Peak Amps (420), and 6th in Summer Peak Amps (319).

In terms of the Grid Modernization Program's independent assessment of the feeder, M15 514 had a normalized total ranking of 0.477, ranking 30th on the list of over 340 feeders during the 2018-2020 selection period analyzed in 2015.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.104	81.86	1149452.32
Normalized Data	0.089	0.982	0.39
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.035	0.343	0.098

Reliability Index Analysis

Reliability indices are significant components of a utility's ability to measure long-term electric service performance, and are one indicator of system health or condition. The common reliability indices of CAIDI, SAIDI, SAIFI, and CEMI3 are used by the Grid Modernization Program to analyze and illustrate the historical reliability performance of the feeders, as well as to assist in justifying any proposed circuit improvements or automation deployments. Each historically averaged reliability index for a feeder is compared to the Avista target value for that calendar year to determine the reliability performance of a feeder.

M15 514 was found to have 70 sustained distribution outages from 2006 through 2016 from OMT analysis, for an average annual figure of 6.4 sustained distribution outages. In addition, M15 514 was found to have 58 momentary distribution outages from 2006 through 2016 from OMT analysis, for an average annual figure of approximately 5.3 momentary distribution outages. The key reliability indicators for M15 514 were analyzed from 2006 to 2016 to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed circuit improvements or automation deployments. The table below shows the annual value for each respective reliability index on M15 514 in the corresponding year. The reliability indices that Grid Modernization uses for Measurement and Reporting do not include Major Event Days (MED). Major Event Days is an industry standard that is used to evaluate major events, such as severe weather or storms, which can lead to unusually long outages in comparison to the distribution system's typical outage. The reliability indices that are being used do not include MED, as this is standard per IEEE and reflects the same reliability information that Avista shares with the respective state Utility Commissions.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2006	0.1%	1.12	81	72
2007	0.4%	2.18	50	23
2008	0.1%	1.09	119	109
2009	14.9%	2.69	126	47
2010	0.0%	0.20	24	118
2011	0.0%	0.21	12	58
2012	0.1%	2.06	158	77
2013	0.4%	1.20	181	151
2014	0.3%	2.13	111	52
2015	2.7%	2.12	153	72
2016	0.0%	0.10	26	255
Average	1.73%	1.37	94.6	94.1

The previous table illustrates the annual value for each respective reliability index on M15 514 in the corresponding year. This information is also provided in graphical form in Figures 2 through 5. The information in these graphs do not include MEDs.

CEMI3 is defined as the Total Number of Customers Experiencing 3 or More Sustained Interruptions /divided by the Total Number of Customers Served. The performance of this metric has been very good, with many years of near zero customers experiencing 3 or more sustained outages. This index is showing a near flat linear trend during the 11 years of analyzed data. The CEMI3 index for M15 514 has consistently outperformed the annual Target value set internally by Avista, with one exception in 2009.

SAIFI is defined as the Total Number of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has been relatively consistent over the years. This index is showing a declining linear trend during the 11 years of analyzed data. The SAIFI index for M15 514 has mostly been outperforming the annual Target value set internally by Avista, however there are some years where the target was not satisfied.

SAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has been inconsistent, and has relatively varied over the years. Despite the inconsistent performance, this index is showing an increasing trend during the 11 years of analyzed data. The SAIDI index for M15 514 has consistently been outperforming the annual Target value set internally by Avista, which is also showing an increasing trend.

CAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Interruptions. The performance of this metric has generally been increasing since 2006, but it has relatively varied over the years. This index is showing an increasing linear trend during the 11 years of analyzed data. The CAIDI index for M15 514 was outperforming the annual Target value set internally by Avista until 2013, however the internal target has since been periodically met.

The average value of each index was calculated and then compared to the Avista 2017 Target values. The historical averaged measured indices on M15 514 are positively performing when compared to the 2018 targets, with the lone exception of SAIFI. This data suggests that customers generally experience relatively few sustained outages on the feeder, and the average service restoration duration is within Avista's desired range.

WA-ID Key Indicator	2018 Target	M15 514	Variance
SAIFI Sustained Outages/Customer	1.14	1.37	0.23
SAIDI Outage Time/Customer (min)	167.00	94.6	72.4
CAIDI Ave Restoration Time (min)*	154.00	94.1	59.9
CEMI3 % of Customers >3 Outages	6.60%	1.73%	4.87%

*CAIDI values were converted from hours to minutes for this report

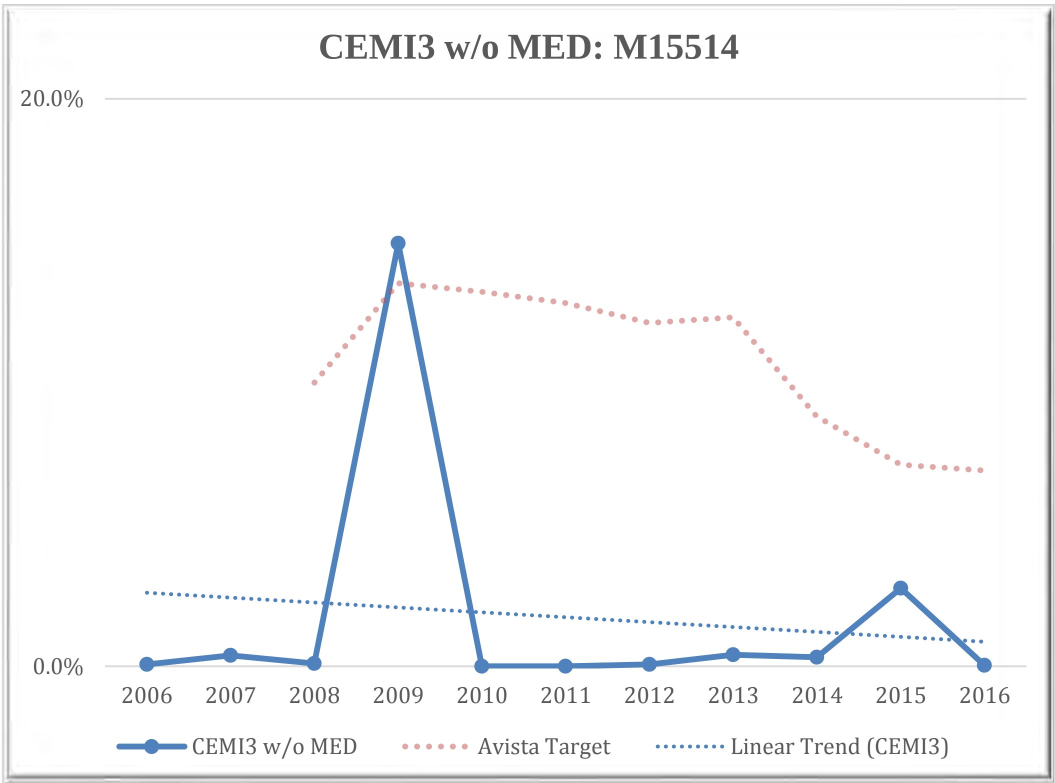


Figure 2. M15 514 CEMI3 Performance

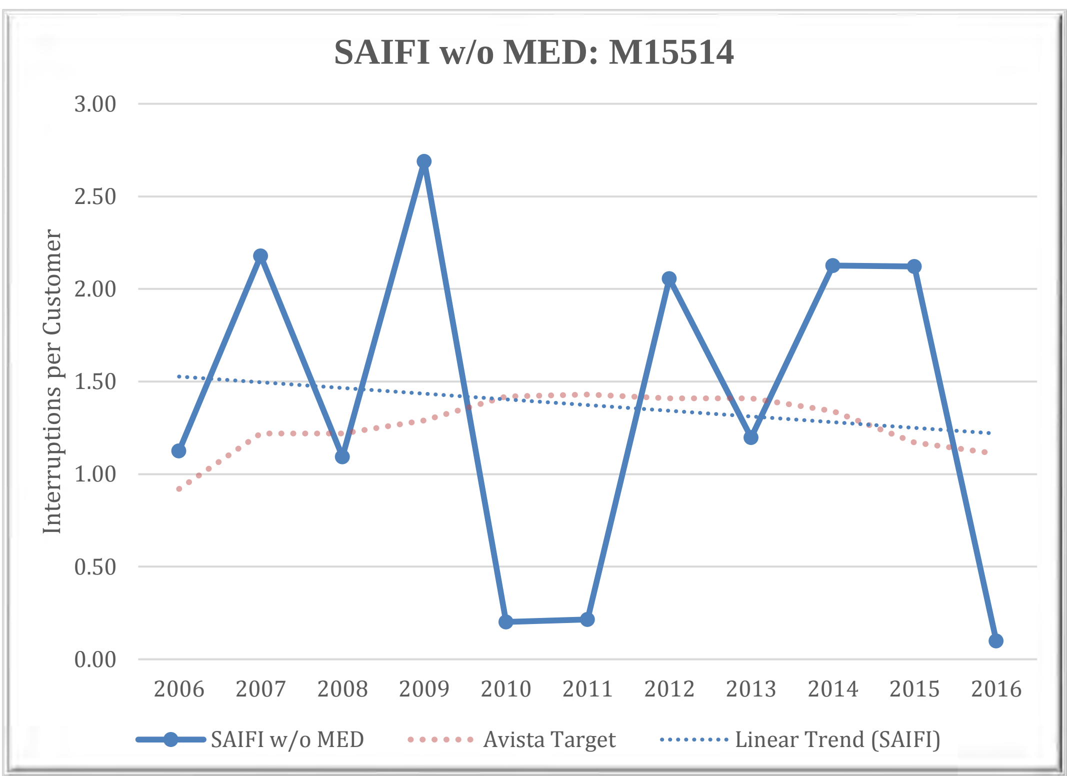


Figure 3. M15 514 SAIFI Performance

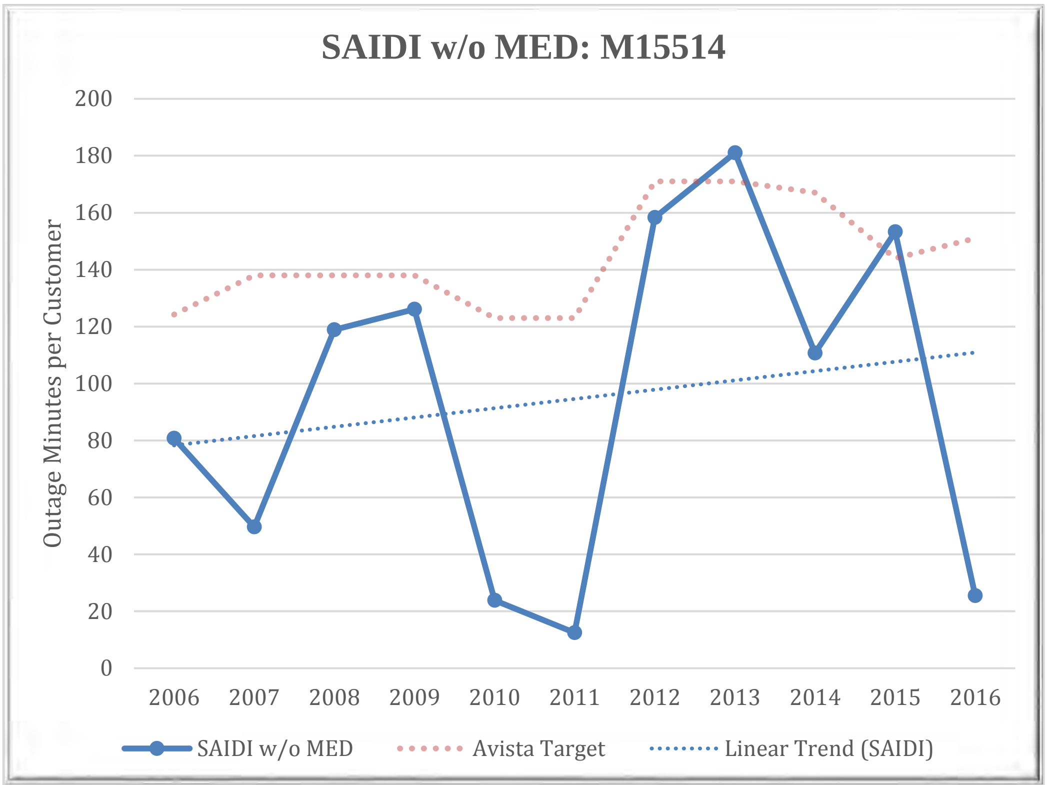


Figure 4. M15 514 SAIDI Performance

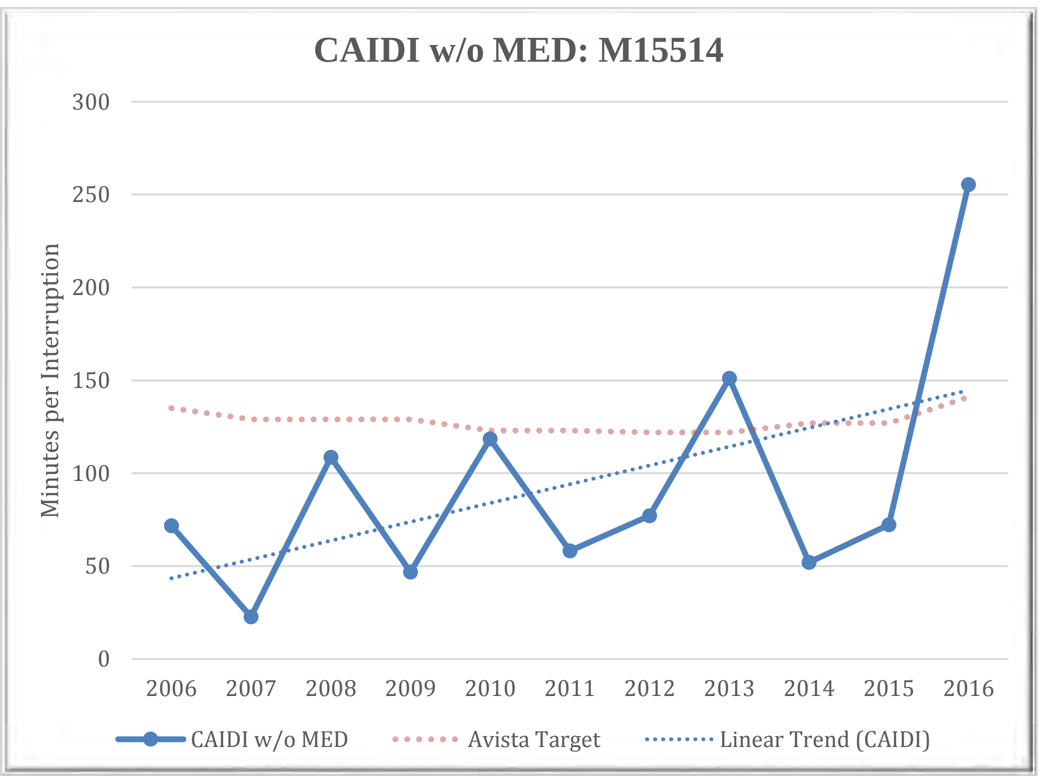


Figure 5. M15 514 CAIDI Performance

Peak Loading

Three-phase ampacity loading from primary meter monitoring directly outside of the M15 514 substation circuit breaker was analyzed from 9/1/16 to 1/7/18. A revenue metering quality Primary Meter Package was installed directly outside of the feeder in the summer of 2016. The metering package went online on 8/31/16 and it has been reporting successfully since that time. The following ampacity loading values were established for M15 514 during this timeframe. Loading information has been analyzed to determine if any data needed to be removed from selected timeframes due to temporary changes in loading from switching (verified through PI). It was identified that there were two time durations that should be excluded from the loading due to M15 514 reporting abnormal loading. Figure 6 illustrates the first duration of abnormal loading that began at approximately 7/10/2017 11:45 AM and ended at approximately 7/12/2017 12:00 AM. Figure 7 illustrates the second duration of abnormal loading that began at approximately 9/12/2017 11:45 AM and ended at approximately 9/13/2017 10:00 PM.

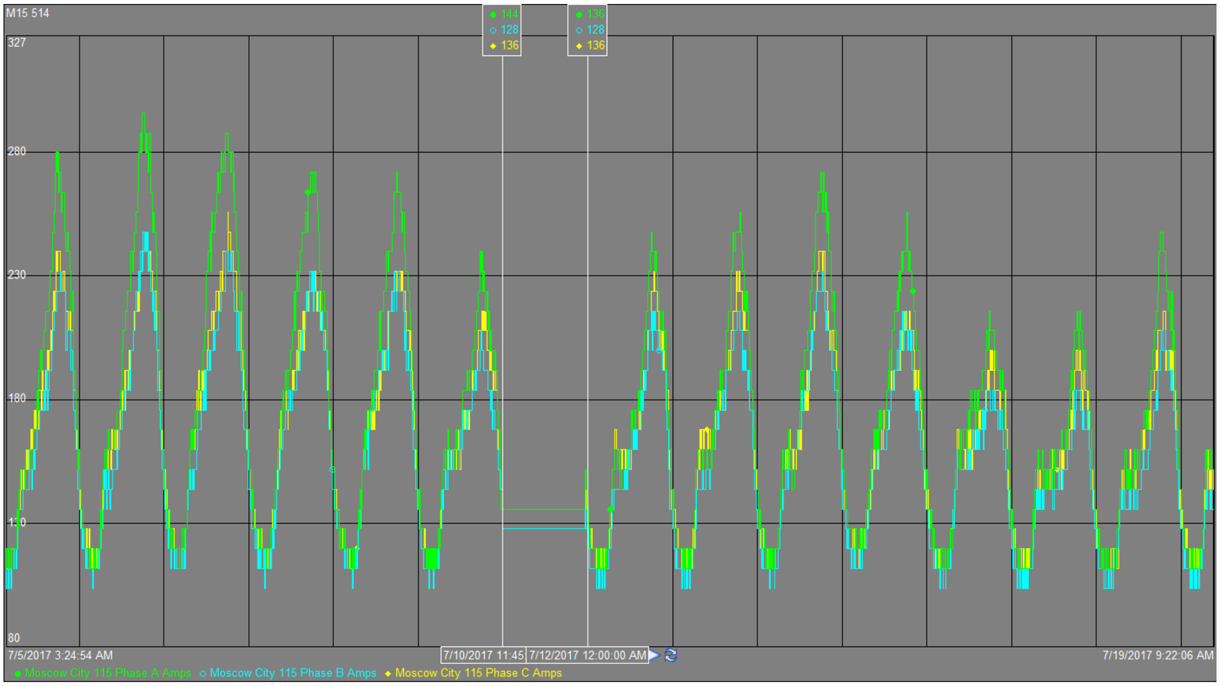


Figure 6. M15 514 Abnormal Feeder Configuration Reflecting Additional Loading

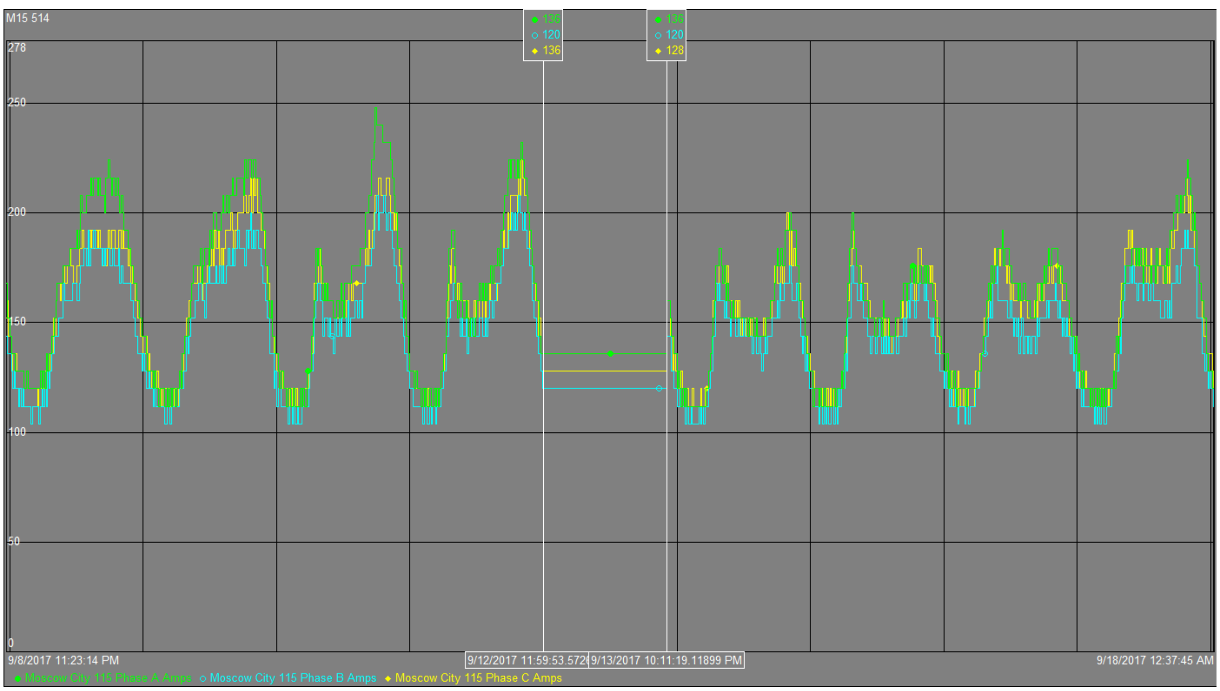


Figure 7. M15 514 Abnormal Feeder Configuration Reflecting Additional Loading

M15 514 is a winter peaking feeder, with comparable peak values observed from early December through early February. There are distinct summer peaks as well on the feeder, however the winter peaks experience greater loading than the summer peaks. The values below reflect the adjusted data set where loading values during abnormal feeder configurations has been removed. The peak loading values for each phase are used in the Synergi model analysis for the feeder, except where average load values are noted for establishing kW losses.

	Before Balancing	
	Peak Loading	**Average Loading**
A-Phase	392 A	197 A
B-Phase	360 A	185 A
C-Phase	408 A	198 A
Average	387 A	193 A

	After Balancing	
	Peak Loading	**Average Loading**
A-Phase	384 A	194 A
B-Phase	381 A	196 A
C-Phase	396 A	193 A
Average	387 A	194 A

Approximate percent loading figures were established through Demand Factor by analyzing the ratio of the maximum apparent power demand observed upon the circuit to the total kVA load that is actually connected. This was performed on a per phase basis from values extracted through Synergi at the model's initial configuration before balancing or performing improvements on the circuit.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	3126	8067	38.7%
B-Phase	2871	7568	37.9%
C-Phase	3253	7835	41.5%

*kVA per Phase in Synergi as of 3/26/18

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	1572	8067	19.5%
B-Phase	1470	7568	19.4%
C-Phase	1576	7835	20.1%

*kVA per Phase in Synergi as of 3/26/18

Load Balancing

Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which will mitigate the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts will commence toward the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

Accurate load balancing can be analyzed and achieved on M15 514 due to the three-phase ampacity loading from a revenue metering CT/PT cluster installed directly outside of the substation before any load is served. The following loading values for peak ampacity and connected KVA totals per phase were taken from AFM before balancing:

	Connected KVA per Phase*
A-Phase	8066 kVA
B-Phase	7567 kVA
C-Phase	7834 kVA

* Connected kVA per Phase in AFM as of 3/26/18

The following list provides the phase changes to loads, laterals, or dips that can effectively balance the load on the phases between numerous strategic locations on the feeder, as illustrated in Figure 8. As a whole, the trunk sections and multi-phase laterals on M15 514 were relatively balanced, however opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate the following change into their appropriate polygon designs:

1. **Polygon 7** – transfer 1Φ OH lateral east of Eisenhower Street & E D. Street intersection (≈9 A peak loading, ≈5 A average loading) from CΦ to BΦ.
2. **Polygon 10** – transfer 1Φ OH lateral south of N Polk St & E Public Ave intersection (≈25 A peak loading, ≈13 A average loading) from CΦ to AΦ.
3. **Polygon 13** – transfer 1Φ URD lateral east of N Mountain View Road & E Public Ave intersection (≈22 A peak loading, ≈12 A average loading) from AΦ to CΦ.
4. **Polygon 14** – transfer 1Φ OH lateral west of W Mountain View Road & Slonaker Drive intersection (≈12 A peak loading, ≈6 A average loading) from AΦ to BΦ.

The result of these proposed load transfers are reflected in the following table. This change will approximately balance the feeder at the substation breaker to 384/381/396 during peak loading conditions, as well as between the numerous strategic points to approximately sectionalize the feeder to optimize switching and load transfers. The balancing locations are illustrated in Figure 9.

Location	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
1	392	360	408	384	381	396
2	0	0	63	0	0	63
3	326	278	267	318	298	255
4	306	219	260	298	239	248
5	54	54	63	54	54	63
6	54	32	63	54	41	54
7	199	136	137	191	147	134
8	64	88	119	87	88	94
9	55	83	105	78	83	81
10	22	19	0	0	19	22
11	63	0	0	51	12	0

It is the Designer’s responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any proposals for phase balancing prior to commencing the job designs.

The decision to move forward with the proposed phase change(s) will be confirmed and approved by the Regional Operations Engineer, and coordinated by the Designer in their respective polygon design(s).

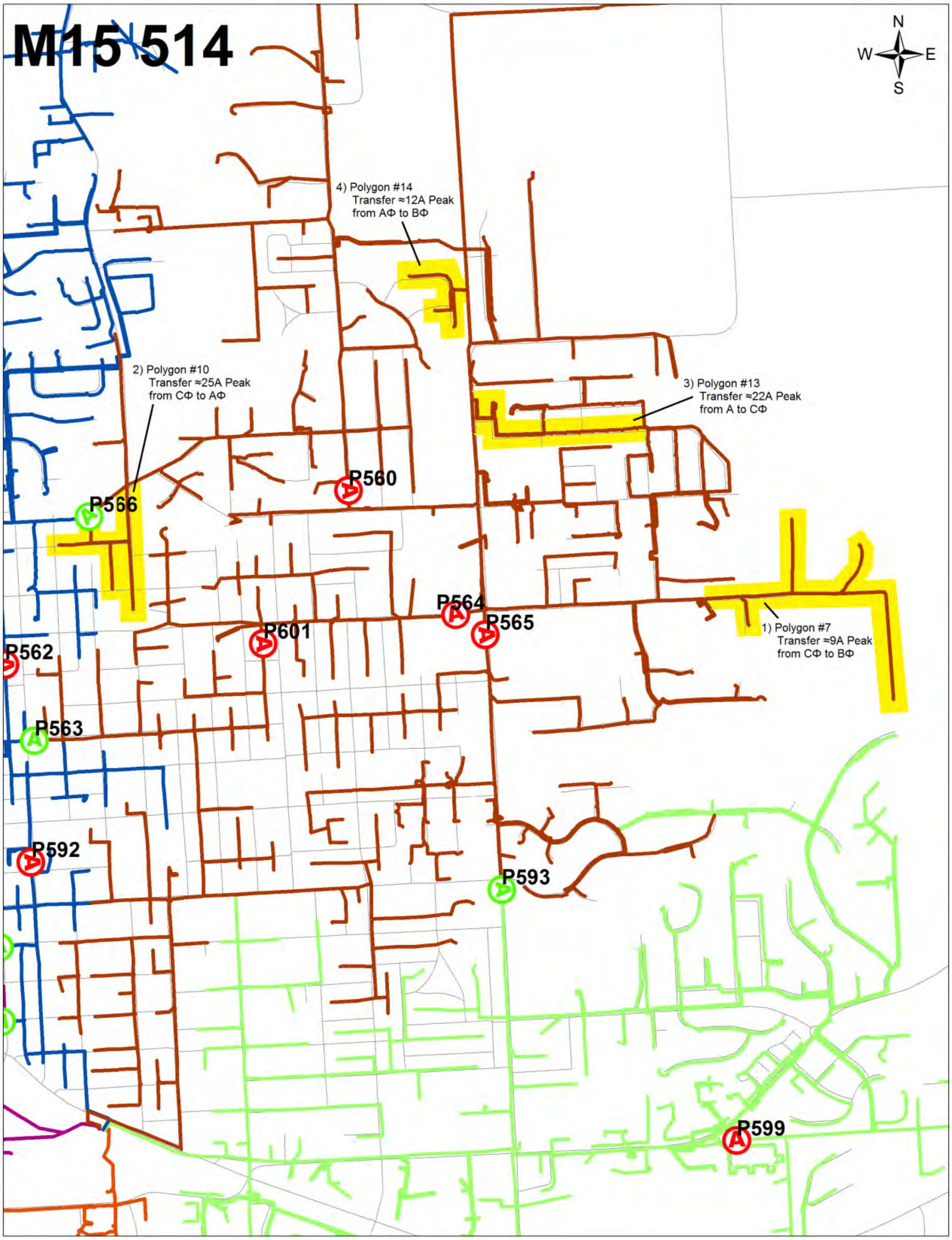


Figure 8. M15 514 Feeder Balancing – Recommended Load Transfers

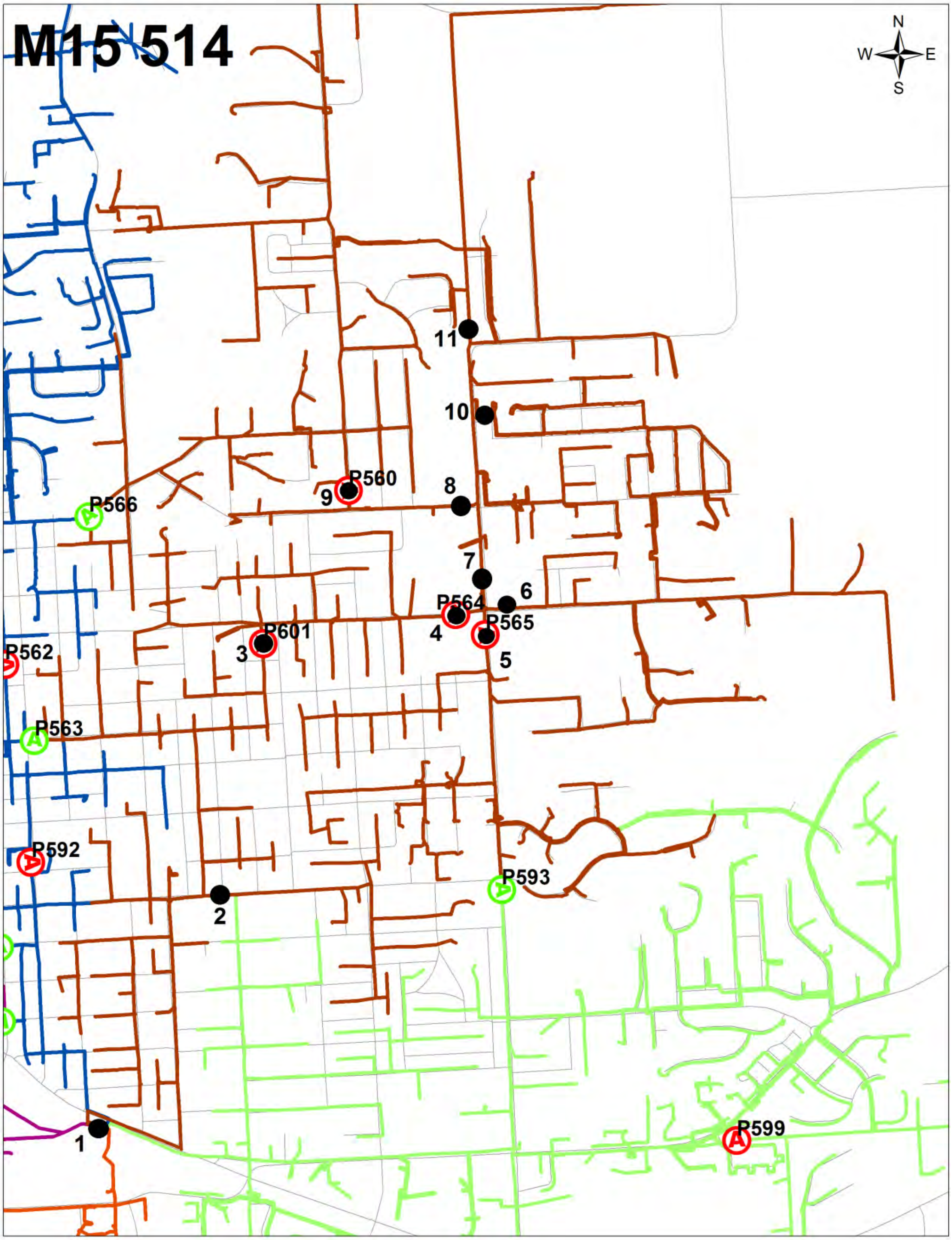


Figure 9. M15 514 Feeder Balancing – Balancing Measurement Locations

Conductor

All primary conductors on M15 514 were analyzed in Synergi using the balanced peak ampacity values identified in the *Peak Loading* section of this report. Specific attention was given to conductors that have the potential for being overloaded, have relatively high line losses, serve areas with unacceptable voltage quality, and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on M15 514, as well as the proposals for improving the efficiency, voltage quality, and performance of the feeder.

High loss conductors are inefficient conductors that result in increased line losses, especially where there is moderate to heavy loading. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on replacing conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher loss conductors. An Engineering decision can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also decide to reconductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management (WPM) reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

The following table lists the various types of overhead conductors that are present on M15 514, as well as the approximate circuit miles of each conductor type as analyzed through the Synergi modeling software on the creation date of the model. An initial analysis suggests that 6CR and 6CW are both present on the feeder, at approximately 0.11 circuit miles and 0.15 circuit miles respectively. If any of these additional conductors are found during field analysis, the Designer shall determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

Approximate Circuit Miles by Conductor Type		
Conductor	**Miles**	**Ohm/Mile (50°C)**
6CR (Solid)	0.11	12.2981
6CW	0.15	7.2044
4ACSR	5.37	2.4590
6A	1.02	2.4400
6CU	12.48	2.4170
2ACSR	0.31	1.5830
2CN15	1.9	1.5419
4CU	0.46	1.5196
1CN15	13.52	1.2229
1/0ACSR	0.02	1.0340
2STCU	0.38	0.9750
1/0CN15	0.24	0.9702
2/0ACSR	1.07	0.8430
4/0ACSR	0.25	0.5730
3/0STCU	0.96	0.3863
556AAC	2.35	0.1855
750CUXLP_SPG	0.03	0.0897

The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the conductor analysis requirements for the Grid Modernization program. The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary conductor requiring attention.

The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure. M15 514 is underbuilt on transmission structures along N Mountain View Road from the P593 switch north to W Mountain View Road, as well as along E Empire Lane.

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of a greenfield project outweigh the significant work required to rebuild the existing line to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors. The ability to reconfigure and convert feeders for reliability and efficiency improvements is a characteristic that distinguishes Grid Modernization from other internal programmatic or capital work.

M15 514 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, there is one section of overhead conductor in **Polygon 14** that could warrant reconfiguration due to proposed reconductoring, physical conditions, stubbing, and/or high resistant conductors. There is a 3300' overhead, single-phase 6CU lateral that is currently located in farmland that is not readily accessible from road access. The section of overhead lateral could be inaccessible to maintain or repair at certain times of the year based on soil moisture conditions or the status of crops being actively grown. The assigned Designer shall analyze the conditions of the existing poles and wire to help determine if the lateral should be relocated along N Mountain View Road to the east. The proposed construction of a new school to the southwest of this conductor section should be considered in any relocation efforts under the consultation of the Regional Operations Engineer. Figure 10 illustrates this section of overhead lateral in question for further field analysis by the assigned Designer.

The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole tests and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

Any designs to reconfigure overhead circuits or convert to underground shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements. All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconfiguration or conversion to underground prior to initiating the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, are economically justifiable, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

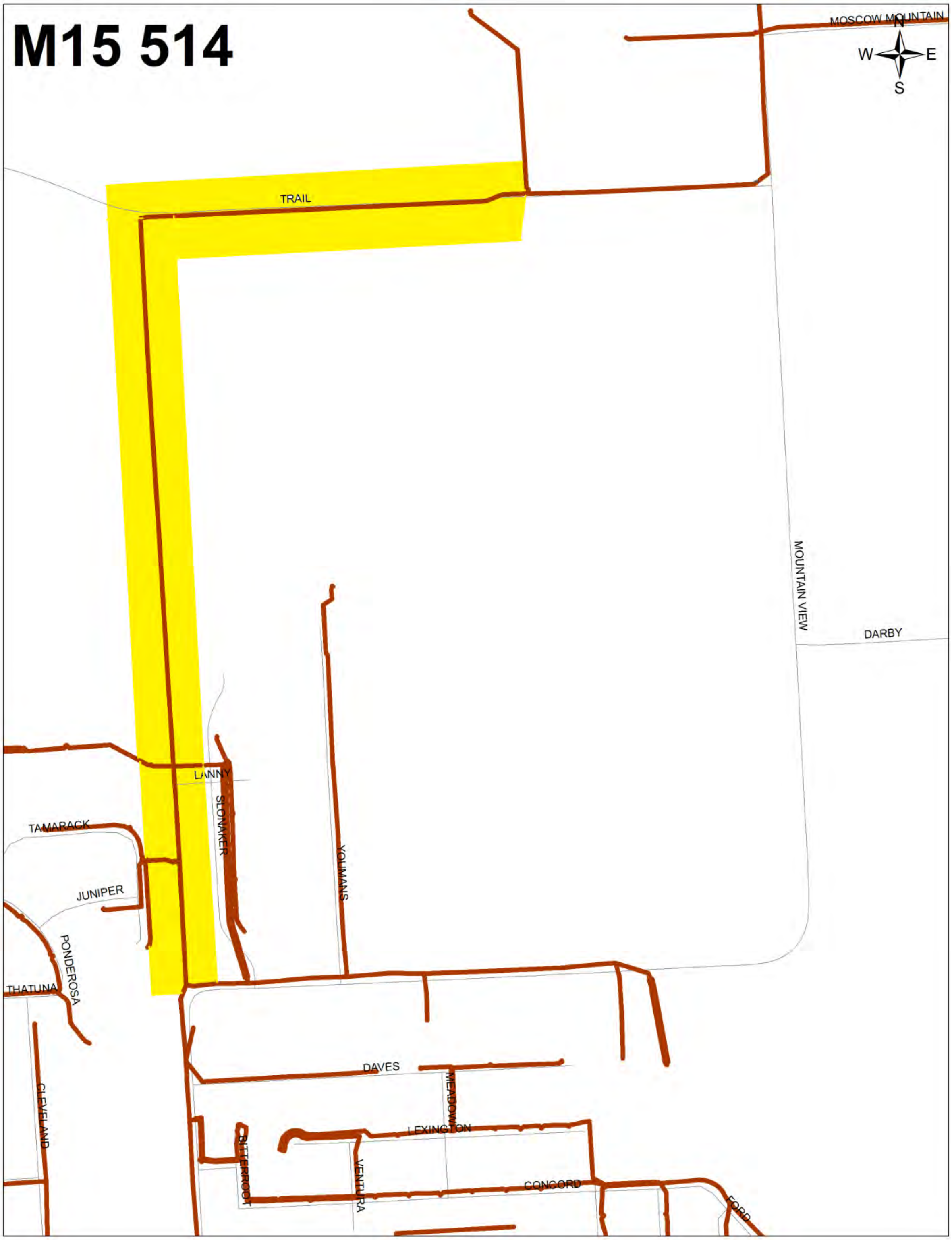


Figure 10. M15 514 Primary Lateral Reconfiguration in Polygon 14

Primary Conductor Analysis

Primary conductors have the ability to negatively affect the reliability and efficiency of a distribution circuit. Primary conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to serve peak loading demands and provide adequate voltage levels, and insure that they do not cause significant and unnecessary line losses. Primary conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

Primary Trunk Conductor Analysis

The primary trunk conductors on M15 514 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The entire feeder trunk and feeder ties are currently conductored with either 556 AAC, 3/0 STCU, 4/0 ACSR, or 2/0 ACSR in overhead applications. M15 514 currently contains three overhead feeder ties through: switch P563 (M15 513), switch P593 (M15 512), and switch P566 (M15 513).

The primary trunk conductors on M15 514 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. Peak loading on the highest loading section of 3/0 STCU only reached 51% of the conductor's ampacity rating. Peak loading on the highest loading section of 4/0 ACSR only reached 30% of the conductor's ampacity rating. Peak loading on the highest loading section of 2/0 ACSR only reached 34% of the conductor's ampacity rating. The feeder tie with M15 513 at switch P563 is composed of 556 AAC, and has a normal peak loading of only 2%. The feeder tie with M15 512 at switch P593 is composed of 3/0 STCU, and has a normal peak loading of only 17%. The feeder tie with M15 513 at switch P566 is composed of 2/0 ACSR, and has a normal peak loading of only 34%. This section of 2/0 ACSR is the one identified concern for reconductoring, however this would only be for switching purposes, as normal peak loading conditions are not a overloading concern.

There are minimal findings to support upgrading the primary trunk conductors on M15 514 based on capacity concerns given the large amount of high capacity conductors already present the feeder trunk and ties. In addition, line losses on the trunk are currently in the optimal range for both the peak and average loading scenarios, which has been aided by balancing the feeder and relatively lower loading conditions where higher loss conductors exist. There are not concerns with voltage quality and under voltage scenarios that could be significantly improved through feeder trunk reconductoring.

Any designs to reconductor primary trunk shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary trunk prior to initiating the job designs. It may be determined that additional primary or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary trunk conductors based on the conditions dictated through field analysis.

Primary Lateral Conductor Analysis

The primary lateral conductors on M15 514 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The laterals on M15 514 were individually analyzed to determine if the wires were sized appropriately for load, line losses, and voltage quality. As part of the line loss analysis, attention was given to identify the presence of high loss conductors, even if relatively low loading levels did not provide high line losses.

The analyzed models do not require the immediate reconductoring of laterals to meet peak loading conditions during normal system configuration, lower line losses, or promote improved voltage levels downstream. However, there were laterals that were identified with slightly elevated loading levels that may be supported for enhancement based on the findings of more granular field analysis. The following laterals should be further examined by the assigned Designer in the field to support reconductoring these laterals or installing an additional primary phase. As part of the field analysis, the Designer should determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, potential benefits from relocation, etc. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

- **Polygon 2** – Approximately 1300' of 6CU, 64A peak (58% loaded). This single-phase, multi-span lateral serves 238 customers. The physical condition of the wire, in combination with the condition of the poles, should be analyzed in the field to determine if the lateral should be reconductored. Although not necessary from a loading perspective, it could also be determined to install an additional primary phase to this lateral if it is determined that the existing poles and wire are in good physical condition. Figure 11 illustrates the 6CU single-phase primary lateral requiring additional field examination on M15 514.
- **Polygons 9 and 11** – Approximately 2100' of 6CU, 68A peak (61% loaded). This three-phase, multi-span lateral serves 216 customers. The physical condition of the wire, in combination with the condition of the poles, should be analyzed in the field to determine if the lateral should be reconductored. A minimum conductor size of 2/0 ACSR should be used if the decision is made to reconductor. Figure 12 illustrates the 6CU three-phase primary lateral requiring additional field examination for possible reconductoring on M15 514.

Any designs to reconductor primary laterals shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary lateral conductors based on the conditions dictated through field analysis.

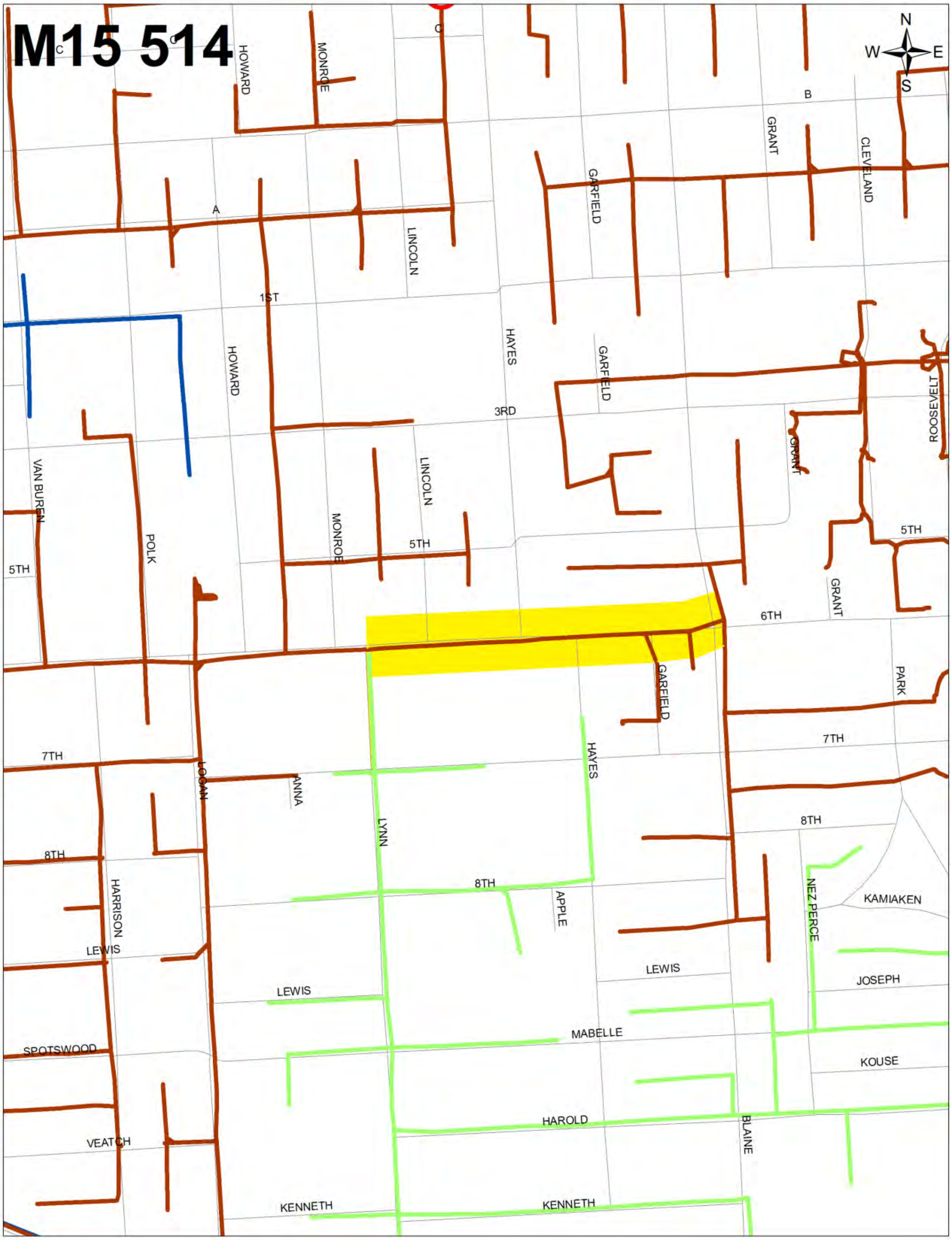


Figure 11. M15 514 Primary Lateral Reconductor in Polygon 2 on E. 6th Street

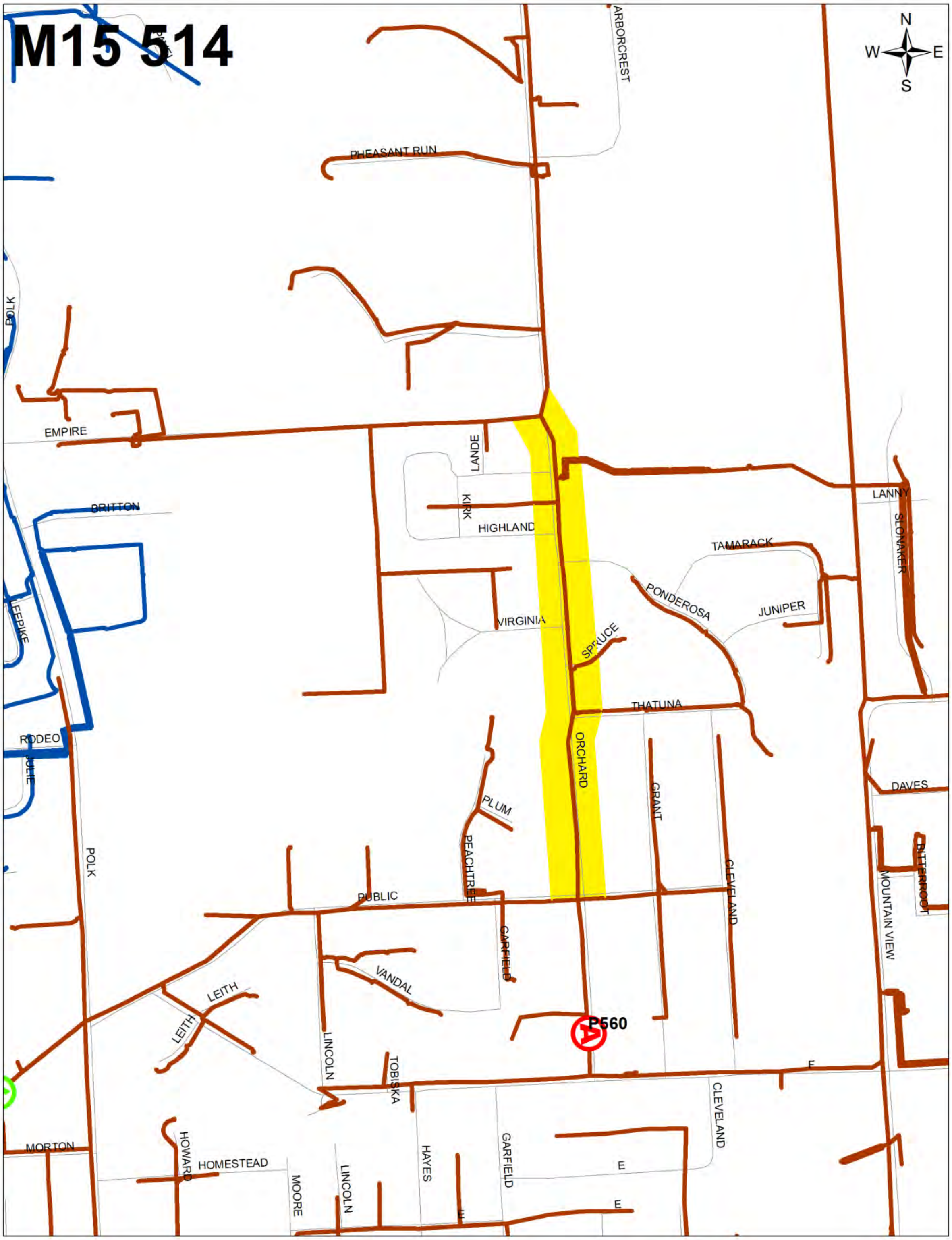


Figure 12. M15 514 Primary Laterals Reconductor in Polygons 9 & 11

Feeder Tie Locations and Opportunities

A reduction in the duration of outages can be achieved through rebuilding existing feeder ties and establishing new feeder ties. Existing feeder ties can be improved through increased capacity by reconductoring to higher ampacity conductors, as well as replacing existing manual switches with communications devices that can either be controlled remotely or through a distribution management system (DMS). New feeder ties can be established for circuits without connections to adjacent feeders or where additional ties could provide reliability improvements. Newly created feeder ties will generally be optimized by installing switches with communications that can either be controlled remotely or through a distribution management system (DMS).

M15 514 currently contains three overhead feeder ties through: switch P563 (M15 513), switch P593 (M15 512), and switch P566 (M15 513). The feeder tie with M15 513 at switch P563 is composed of 556 AAC, and has a normal peak loading of only 2%. The feeder tie with M15 512 at switch P593 is composed of 3/0 STCU, and has a normal peak loading of only 17%. The feeder tie with M15 513 at switch P566 is composed of 2/0 ACSR, and has a normal peak loading of only 34%. All three of these feeder ties have three-phase, group-operated manual air switches.

M15 514 is adjacent to only two other feeders: M15 512 and M15 513. In addition, much of M15 514 is bordered by rural farmland. The Regional Operations Engineer requested an additional tie from M15 514 to M15 512. The installation of a Manual Three-Phase Gang-Operated Air Switch (P109, N.O.) south of E 6th Street & S. Lynn Street in **Polygon 2** will establish a tie between the feeders near the substation source.

The decision to pursue additional feeder unidentified tie opportunities will be discussed and determined with the Regional Operations Engineer based on their anticipated frequency of using potential ties in the operation of the Moscow-Pullman distribution system.

Figure 20 illustrates the location of the feeder ties on M15 514, as well as the other distribution automation line devices.

Voltage Quality

Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. In addition, primary laterals and trunks are reconductored with more efficient conductors to increase sagging voltage levels. In some scenarios, an additional conductor phase(s) may be installed to offload a heavily loaded phase and assist in supporting the voltage.

The M15 514 circuit was analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled in Synergi during both peak loading and average loading conditions, with both normal and abnormal circuit configurations.

The following information on the substation voltage regulators for M15 514 was taken from Maximo, which is the system of record for Avista T&D assets. The Equipment P.T. Ratio of the voltage regulators (63.5:1) match the Desired P.T. Ratio (63.5:1) on the regulator controls. Therefore the initial analysis of the voltage quality on M15 514 utilized an effective 123V base value for the 7620V_{LN} system.

Serial Numbers	A	B	C
M15 514 Station Regulators	M-576224PDR	M-576279PDR	M-576223PDR

Rated Power	250 kVA
Rated Current	328 A
C.T. Ratio	400/.02
Equipment P.T. Ratio	63.5:1
Corrected/Desired P.T. Ratio	63.5:1
Distribution Transformer Ratio	63.5:1

* Information in MAXIMO as of 4/5/18

Voltage Quality Analysis Before Incorporating Recommendations

Figures 13-14 illustrate the modeled voltage levels for the various scenarios on M15 514 before any proposed recommendations were incorporated into the models. "Green" illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. "Yellow" illustrates voltage levels between 114–117 V and 123–126V. "Red" illustrates voltage levels lower than 114V and greater than 126V, which are greater than +/- 6V of the 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to M15 514. During peak loading conditions, voltage levels nearest to the Moscow 115kV Substation, were elevated however they were still acceptable. The highest voltage modeled occurred near the substation at approximately 125.4V. The lowest voltage modeled is 116.7V, which occurred at the farther north ends of the long single phase lateral north of town. Figure 13 illustrates the modeled voltage levels at peak loading on M15 514.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	77	9.14	307	43
118.00 - 120.00 V	29	2.90	138	25
120.00 - 122.00 V	126	6.83	1579	444
122.00 - 124.00 V	599	25.28	5882	2196
124.00 - 126.00 V	88	3.04	996	519
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading

The voltage levels on the feeder were again analyzed, however this time during average loading conditions. During average loading conditions, voltage levels nearest to the Moscow 115kV Substation, were still slightly elevated however they were still with the acceptable range and lower than the Peak Loading scenario values. The maximum voltage modeled occurred near the substation at approximately 124.6V. The lowest voltage modeled is 119.9V, which occurred at the farther north ends of the long single phase lateral north of town. Figure 14 illustrates the modeled voltage levels at average loading on M15 514.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	22	1.78	25	8
120.00 - 122.00 V	85	10.49	164	45
122.00 - 124.00 V	724	32.01	3804	2689
124.00 - 126.00 V	88	2.91	488	484
126.00 - 140.00 V	0	0.00	0	0

Figure 13. Modeled Voltage Levels at Peak Loading before Proposals

Figure 14. Modeled Voltage Levels at Average Loading before Proposals

Voltage Quality Analysis After Incorporating Recommendations

The voltage levels on M15 514 were re-analyzed after incorporating and modeling the upgrade proposals. The feeder was modeled with these proposals in Synergi during both Peak loading and Average loading conditions.

The following information on the substation voltage regulators for M15 514 was taken from Maximo. The Equipment P.T. Ratio of the voltage regulators (63.5:1) matched the Desired P.T. Ratio (63.5:1) on the regulator controls. Therefore the initial analysis of the voltage quality on M15 514 utilized an effective 123V base value for the 7620V_{LN} system. Both the output voltage level and the voltage regulator settings were adjusted and modeled with numerous combinations in these models to optimize the voltage levels across the circuit.

Figures 15-16 illustrate the modeled voltage levels for the various scenarios on M15 514 after the proposed recommendations were incorporated into the models. Green illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V, which greater than +/- 6V of the ideal 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading after Proposals

The voltage levels on the feeder were analyzed after balancing load and performing the identified changes and improvements to M15 514. During peak loading conditions, voltage levels nearest to the Moscow 115kV Substation, were elevated however they were still acceptable. The highest voltage modeled occurred near the substation at approximately 125.4V. The lowest voltage modeled is 116.9V, which occurred at the farther north ends of the long single phase lateral north of town. Figure 15 illustrates the modeled voltage levels at peak loading on M15 514.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	77	9.14	308	43
118.00 - 120.00 V	28	2.61	60	10
120.00 - 122.00 V	172	8.64	2105	601
122.00 - 124.00 V	545	23.66	5365	2040
124.00 - 126.00 V	97	3.13	1072	532
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading after Proposals

The voltage levels on the feeder were analyzed after balancing load and performing the identified changes and improvements to M15 514. During average loading conditions, voltage levels nearest to the Moscow 115kV Substation, were still slightly elevated however they were still with the acceptable range and lower than the Peak Loading scenario values. The maximum voltage modeled occurred near the substation at approximately 124.7V. The lowest voltage modeled is 120.1V, which occurred at the farther north ends of the long single phase lateral north of town. Figure 15 illustrates the modeled voltage levels at average loading on M15 514.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	107	12.28	191	53
122.00 - 124.00 V	716	31.84	3789	2649
124.00 - 126.00 V	96	3.07	532	524
126.00 - 140.00 V	0	0.00	0	0

Figure 15. Modeled Voltage Levels at Peak Loading after Proposals

Figure 16. Modeled Voltage Levels at Average Loading after Proposals

Voltage Regulator Settings

As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline voltage regulator settings. This is performed to reflect the changes to loading and to address the conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. The feeder is modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ranges for all customers during the modeled scenarios, and to eliminate over-voltage and under-voltage situations.

The Equipment P.T. Ratio of the voltage regulators (63.5:1) matched the Desired P.T. Ratio (63.5:1) on the regulator controls. Therefore the initial analysis of the voltage quality on M15 514 utilized an effective 123V base value for the 7620V_{LN} system.

A group of alternative settings were analyzed to show if there was the potential for improving voltage levels. The voltage levels on M15 514 were re-analyzed and modeled with the voltage regulator settings change proposals in Synergi at peak and average loading conditions. It was determined that the existing settings at the substation voltage regulators are providing the optimal output voltage levels to best serve all customers on the feeder.

M15 514 has one existing stage of voltage regulation at the Moscow 115kV Substation. Although the interconnected urban nature of the feeder traditionally does not suggest the need of additional stages of midline voltage regulation, the long rural lateral at the end of the feeder does pose the risk of having voltage levels below the acceptable range during peak loading. Additional stages of midline voltage regulation are not immediately recommended on the feeder to support voltage levels during normal peak configuration, however it may be determined that additional midline voltage regulation is required if loading increases on the long, single-phase lateral.

The existing and proposed voltage regulator settings are provided in the table below:

	Existing*		Proposed	
Forward Settings	**R**	**X**	**R**	**X**
M15 514 Station Regulators	**2.0**	**2.0**	**2.0**	**2.0**

* Settings in Maximo, AFM, and SynerGEE as of 4/5/18

The decision to move forward with implementing any changes to the regulator settings will be confirmed, approved, and coordinated by the Regional Operations Engineer.

The substation equipment associated with M15 514 is not automation compatible and would require upgrading to make this distribution circuit completely automated. The circuit breaker is a Westinghouse ES model, however the substation voltage regulators were upgraded as part of a programmatic replacement in Q2 2018 from General Electric ML-32's. It has also been identified that the Moscow City Substation has an outdated RTU-based SCADA system which, if it was necessary to upgrade, could be done prior to any major rebuild of the substation. The addition of adding modern three-phase SCADA to the site is estimated at approximately $300k plus any additional costs of getting communications to the site. Grid Modernization has notified Substation Engineering of the proposed work on the feeder and the opportunity to upgrade the station breaker and voltage regulators, however the decision to perform any upgrades will ultimately be made with Substation Engineering through the Engineering Round Table to determine mutual interest, support, budgetary funding, and resource prioritization.

Fuse Coordination and Sizing Analysis

Incorrect fuse sizes can compromise the reliability of the feeder through miscoordination of operation. Miscoordination can occur if the fuses in series are not correctly sized and managed to allow the furthest downstream device the opportunity to operate first. Fuses that are undersized and do not match the load being served can unnecessary operate and create unexpected outages. A customized fuse protection and coordination scheme has been determined to ensure that a consistent fusing philosophy is deployed and that all fuses are accurately sized.

Fuse sizing on M15 514 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and underground risers. Fuse recommendations for M15 514 were created by the Regional Operations Engineer and approved by the Grid Modernization Program Engineer. This file is located in the Electrical Engineering drive *c01m19* under the folder *Feeder Upgrade – Dist Grid Mod* folder. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

The fuse “blowing” philosophy was selected for M15 514 where the largest fuse was selected that would accurately coordinate to: satisfy peak loading conditions, protect the downstream conductor(s), and for fuse-to-fuse coordination based on preloading of source-side fuse link (maximum fault current). A fuse “blowing” scheme is achieved by selecting the smallest allowable fuse for the first stage of protection by knowing the downstream connected kVA/phase and the largest transformer on the phase (using Distribution Construction Standard DU-2.500). If there was an upstream fuse in series with a lateral fuse, the *Distribution Feeder Protection General Guidelines* (Orange Book, S&C Table VII) was used in coordination with the fault duty found in the Synergi model to select the fuse size.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Line Losses

The distribution of electricity results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and to improve voltage levels on feeders. Line losses are generally addressed by balancing load on the phases between numerous strategic locations on the feeder, and then further minimized by replacing wire with more efficient conductors.

The primary trunk conductors on M15 514 are sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the urban feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. It should be noted that there were not recommendations to reconductor the feeder trunk or ties. The peak loading levels are within the acceptable limits for the feeder trunk sections that are respectively conductored with 556 AAC, 4/0 ACSR, 3/0STCU, and 2/0 ACSR.

An initial Synergi load study estimates that a total of 159 kW in peak line losses currently exist on M15 514 (1.79%). After balancing the load on the feeder and correcting the power factor, it is estimated that peak line losses can be improved to approximately 156 kW (1.75%). Since there were not any major system enhancements recommended through the form of primary or lateral reconductoring, it is estimated that peak line losses will remain relatively static or demonstrate slight improvements as modeled through Synergi.

Peak Values	**Existing**	**After Balancing**	**After Cap Removal**
kW Demand	9064	9072	9068
kW Load	8902	8912	8910
kW Line Losses	159	157	156
kW Loss %	1.79 %	1.76 %	1.75 %

Transformer Core Losses

Core losses are an inherent characteristic of distribution transformers. Core losses negatively affect efficiency and do not change with fluctuation in loading. The Grid Modernization program analyzes the approximate energy savings that are achieved through the reduction in transformer core losses. Savings are obtained when transformers are replaced with more efficient units, whether being replaced due to overloading or based on PCB levels. The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more efficient. Consequently, transformer core losses are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of a near equivalent size.

All distribution transformers on M15 514 shall be analyzed and appropriately sized to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP), incorporating flicker and voltage drop analysis. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the assigned Designer.

The roughly 678 distribution transformers on M15 514 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It is estimated that approximately 171 transformers will require replacement based on the TCOP replacement criteria, with an additional 133 requiring replacement for being incorrectly sized to serve the connected loads. The replacement of these 304 transformers would result in the prescriptive replacement of approximately 44.8% of the distribution transformers on M15 514. The replacement of these transformers will result in an estimated 28.04 kW reduction in transformer core losses. This equates to an estimated annual savings of roughly 245.6 MWh. The estimated energy savings are achieved through the use of a unique algorithm that was created: to analyze each transformer on the feeder, determine the PCB/age replacement status, determine if the transformer is sized appropriately based on actual loading, make a recommendation on the appropriate size for the load, and then use historical core loss values to calculate the approximate energy savings that are achieved. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work, which is a form of line losses. Power factor is a value that can fluctuate with the variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of up to 17,000 hourly data pars covering a desired 24 month span to calculate the apparent power and power factor. This results in comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading, both in terms of time and quantity.

Three-phase ampacity loading from primary meter monitoring directly outside of the M15 514 substation circuit breaker was analyzed from 9/1/16 to 1/7/18. A revenue metering quality Primary Meter Package was installed directly outside of the feeder in the summer of 2016. The analysis of the data determined that M15 514 had a lagging power factor 0% of the time during the time interval analyzed, and a leading power factor 100% of the time during the time interval analyzed. Additional detailed power factor information is available upon request. Some key power factor figures for M15 514 are provided in the tables below.

Maximum Lagging Power Factor	00.0%
Minimum Lagging Power Factor	00.0%
Maximum Leading Power Factor	100.0%
Minimum Leading Power Factor	73.3%
Average Leading Power Factor	93.3%
Median Lagging Power Factor	94.8%

The graph in Figure 17 shows the percent of time during the interval analyzed where the power factor on M15 514 fell between the applicable ranges. This information is also provided in a table format.

	Lagging	**Leading**
99%-100%	00.00%	4.91%
98%-99%	00.00%	11.60%
97%-98%	00.00%	11.27%
96%-97%	00.00%	10.51%
95%-96%	00.00%	9.88%
94%-95%	00.00%	8.91%
93%-94%	00.00%	7.43%
92%-93%	00.00%	6.02%
91%-92%	00.00%	5.39%
90%-91%	00.00%	4.19%
80%-90%	00.00%	16.10%
70%-80%	00.00%	3.77%

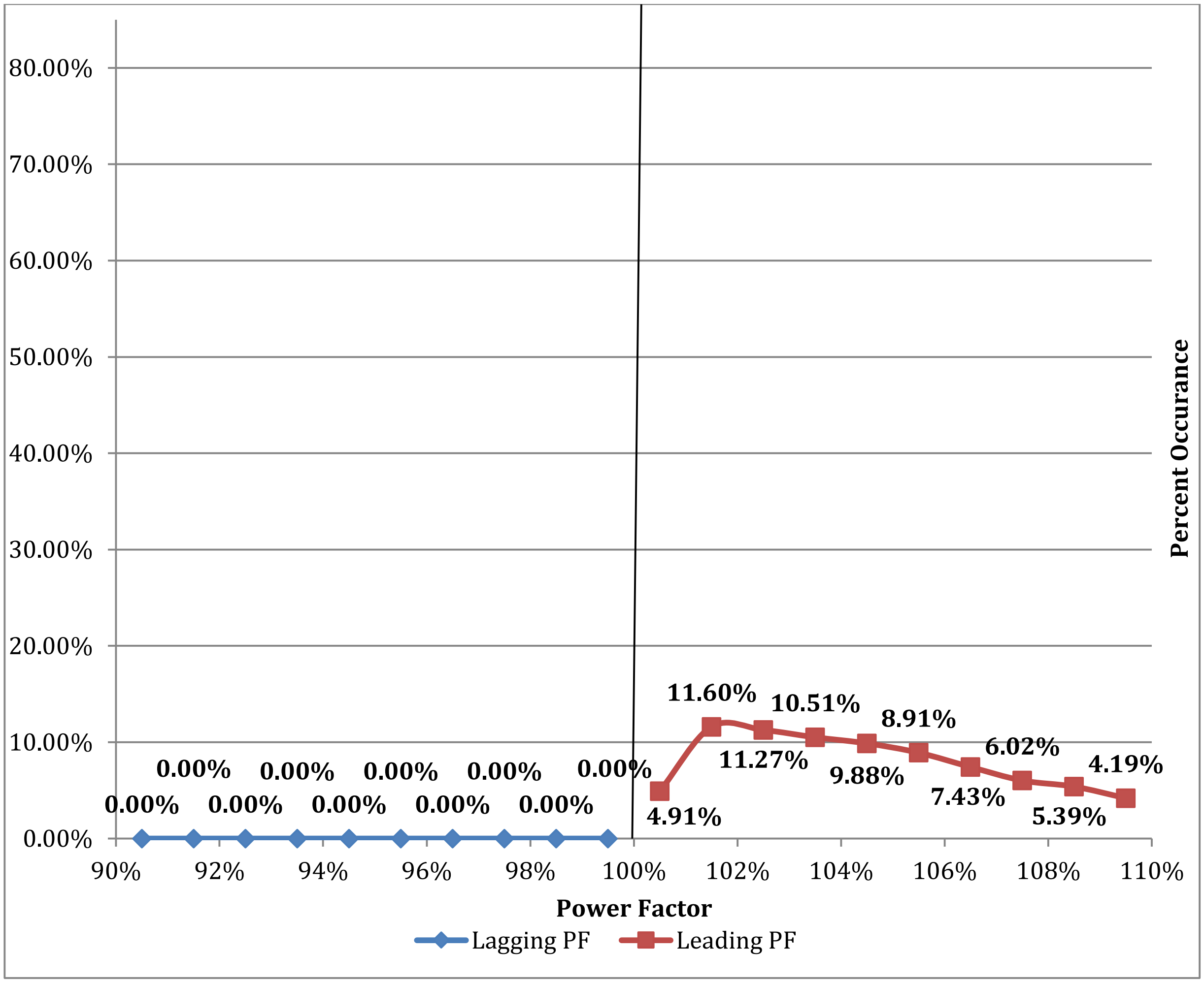


Figure 17. M15 514 Existing Percent Occurance of Power Factor

Power Factor Correction

The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to unity. A power factor at or near unity is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and enacting a solution. The historical Watt and VAR data on the feeder was reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loads to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed in more severe situations to raise the power factor to a reasonable base value, and then switched capacitor banks are installed to supplement the power factor when required by loading. This approach optimizes the correction of the power factor and reduces line losses. The establishment of power factor also incorporates the field verification of existing deployed capacitor sizes, where it is not uncommon to discover capacitor banks that are incorrectly represented in Avista's GIS and modeling software.

There are three existing 600 kVAR fixed capacitor banks on M15 514. The size of these three capacitor banks were confirmed in the field by a local Serviceman to each be 600 kVAR units.

The actual MW and MVAR data was reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times.

The power factor on M15 514 was consistently outside of the acceptable range with the existing capacitors. The circuit consistently had a significantly "leading" power factor, which suggests that too much capacitance is existing on the circuit. It is recommended to remove all three of the 600 kVAR fixed capacitor banks in **Polygons 4, 8, and 9** and install one switched 600 kVAR capacitor bank in **Polygon 4**. These changes would assist with bringing the feeder into the optimal range for power factor correction, as well as improving the leading power factor when necessary.

To illustrate, the feeder was first reanalyzed with the proposed removal of two of the 600 kVAR fixed capacitor banks. The power factor was noticeably improved, with the analysis suggesting that the M15 514 circuit would now have a leading power factor roughly 81.9% of the time, as well as now having lagging power factor occurrences for approximately 18.1% of the time. Some key power factor figures for M15 514 are provided in the tables below.

Average Lagging Power Factor	99.67 %
Median Lagging Power Factor	99.97 %
Maximum Lagging Power Factor	100.00 %
Minimum Lagging Power Factor	97.78 %

Average Leading Power Factor	99.56 %
Median Leading Power Factor	91.80 %
Maximum Leading Power Factor	99.99 %
Minimum Leading Power Factor	96.24 %

The graph in Figure 18 shows the percentage of time during the re-analyzed interval where the power factor on M15 514 fell between the applicable ranges with two of the 600 kVAR fixed capacitor banks removed. This information is also provided in a table format.

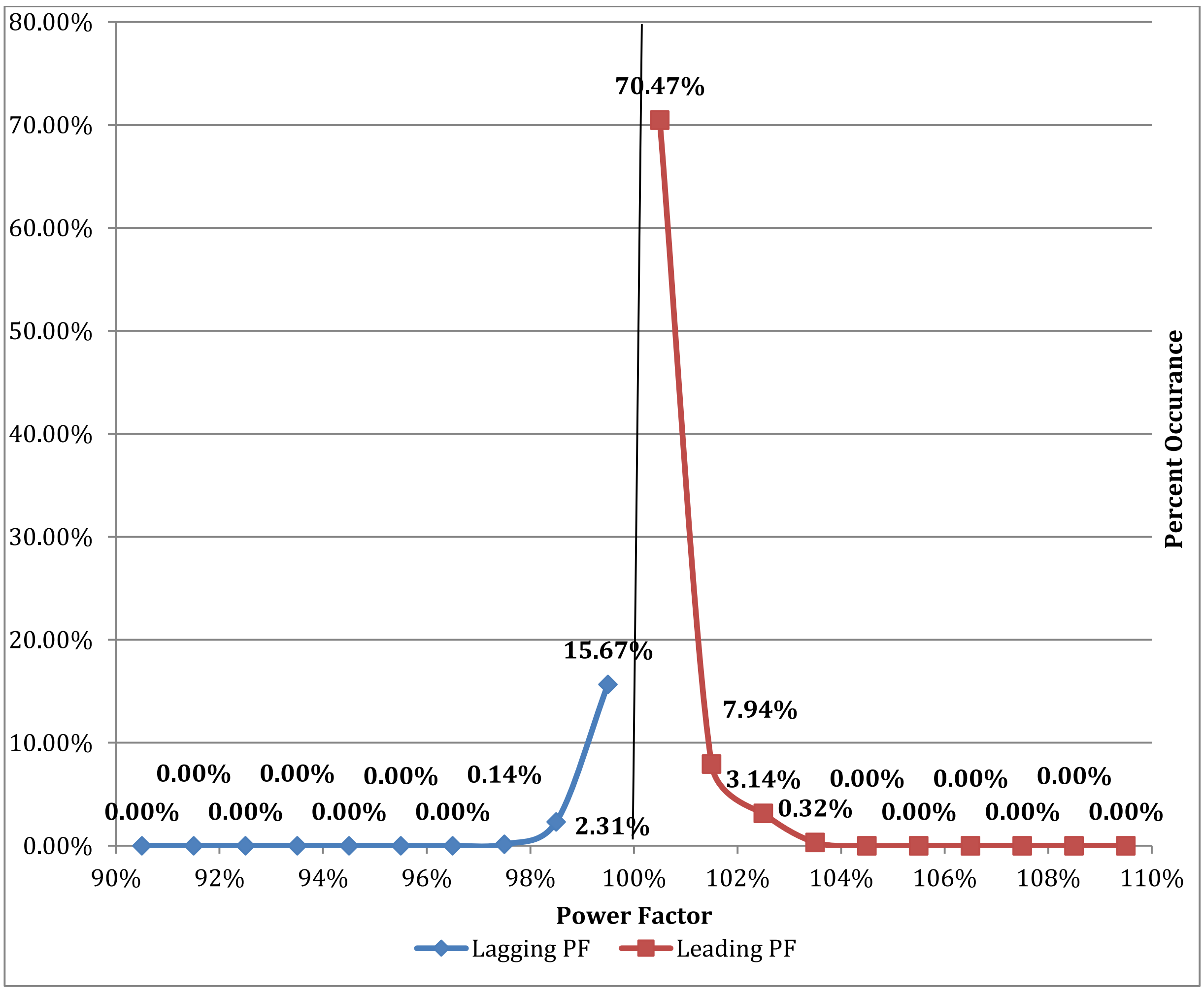


Figure 18. Proposed Percent Occurance of Power Factor with 1200 kVAR Removed

	Lagging	Leading
99%-100%	15.67%	70.47%
98%-99%	2.31%	7.94%
97%-98%	0.14%	3.14%
96%-97%	0.00%	0.32%
95%-96%	0.00%	0.00%
94%-95%	0.00%	0.00%
93%-94%	0.00%	0.00%
92%-93%	0.00%	0.00%
91%-92%	0.00%	0.00%
90%-91%	0.00%	0.00%
Less than 90%	0.00%	0.00%

Next, the feeder was first reanalyzed with the proposed removal of the three 600 kVAR fixed capacitor banks. The power factor was again noticeably improved, with the analysis suggesting that the M15 514 circuit would now have a lagging power factor roughly 100.0% of the time, with no leading power factor occurrences. Some key power factor figures for M15 514 are provided in the tables below.

Average Lagging Power Factor	99.35 %
Median Lagging Power Factor	99.60 %
Maximum Lagging Power Factor	99.95 %
Minimum Lagging Power Factor	95.20 %

Average Leading Power Factor	0.00%
Median Leading Power Factor	0.00%
Maximum Leading Power Factor	0.00%
Minimum Leading Power Factor	0.00%

The graph in Figure 19 shows the percentage of time during the re-analyzed interval where the power factor on M15 514 fell between the applicable ranges with all three of the 600 kVAR fixed capacitor banks removed. This information is also provided in a table format.

This information of the two re-analyzed data sets illustrate what could be achieved with the power factor on the feeder with the removal of the three 600 kVAR fixed capacitor banks and the installation of one 600 kVAR switchable capacitor bank. Figure 18 represents the scenario where the lone switched capacitor bank is turned “on”, while Figure 19 represents the scenario where the lone switched capacitor bank is turned “off”. Both scenarios provide corrected power factor and lowered line losses from reduced reactive power flow.

The decision to move forward with implementing any changes to the capacitors sizes and location will be confirmed, approved, and coordinated by the Regional Operations Engineer.

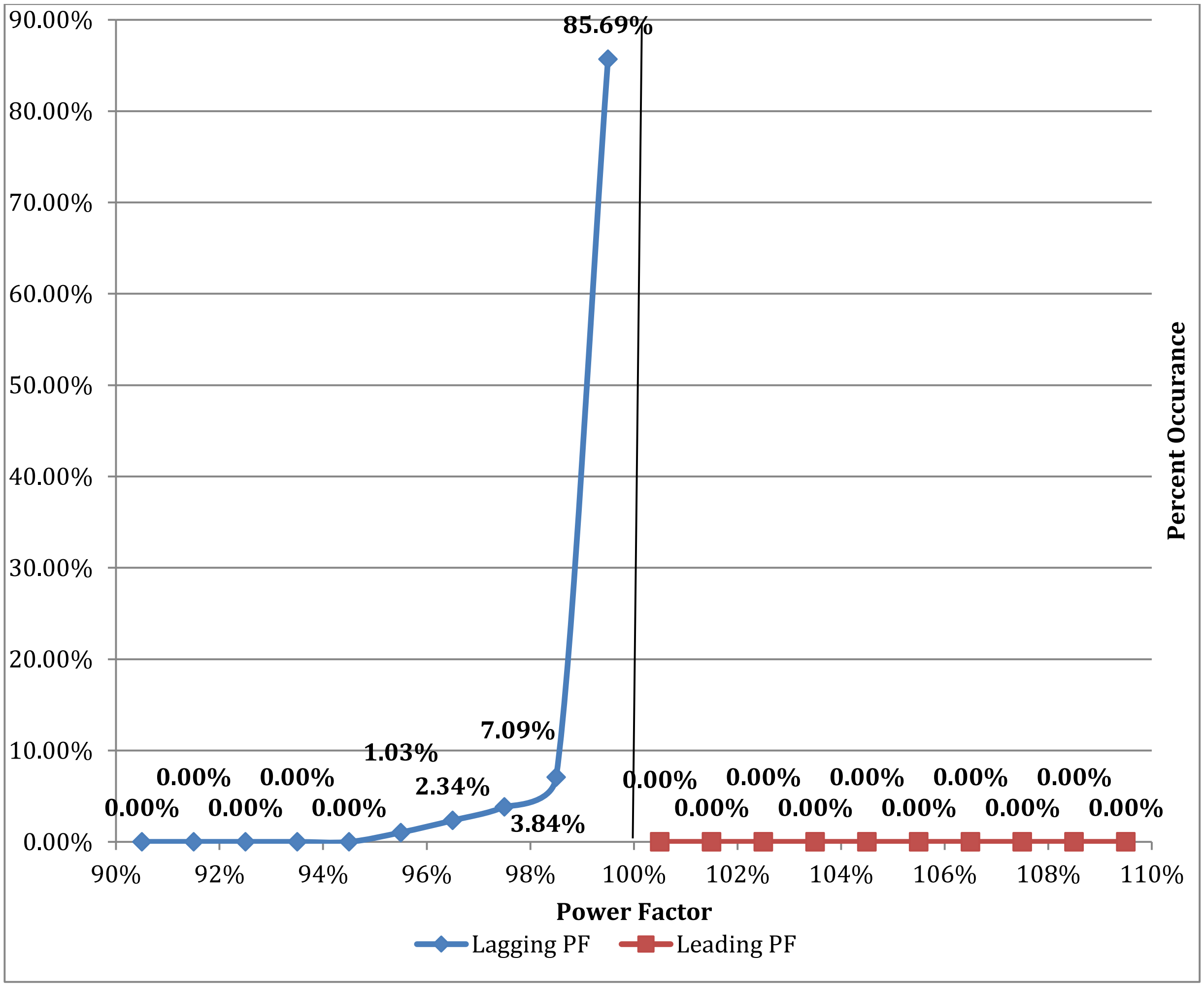


Figure 19. Proposed Percent Occurance of Power Factor with 1800 kVAR Removal

	Lagging	Leading
99%-100%	85.69%	0.00%
98%-99%	7.09%	0.00%
97%-98%	3.84%	0.00%
96%-97%	2.34%	0.00%
95%-96%	1.03%	0.00%
94%-95%	0.00%	0.00%
93%-94%	0.00%	0.00%
92%-93%	0.00%	0.00%
91%-92%	0.00%	0.00%
90%-91%	0.00%	0.00%
Less than 90%	0.00%	0.00%

Distribution Automation

The Grid Modernization program currently represents Avista's largest centralized program to fully automate and improve the operating functionality and efficiency of the distribution system through the installation of automated distribution line devices. Grid Modernization has been programmatically addressing the distribution automation needs of Avista since the end of 2013, and the program focuses on installing air switches, reclosers, capacitor banks, and voltage regulators with communications and remote operability. The reduction in the duration of outages can be achieved through the installation of communications equipment that can either be controlled remotely or through a distribution management system (DMS). In addition, the number of customers impacted by an outage as well as a reduction in the frequency of outages can be achieved through the installation of devices with fault sensing and tripping capabilities. Time and cost savings can be achieved through the remote application of hot-line-holds. Fault detection, isolation, and restoration, conservation voltage reduction, and integrated volt/VAR control can also be achieved through Grid Modernization when the necessary substation equipment and components are in place.

Distribution Automation was analyzed for deployment on M15 514 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on M15 514.

M15 514 does not currently have a midline recloser to assist in fault detection and isolation. Installing a new automated midline G&W Viper recloser in **Polygon 8** will provide these benefits, as well as sectionalize the feeder into two near equal sections based on the modeled peak amps allocated by connected kVA.

- Install 600 kVAR switched capacitor bank (ZP100F, N.C.) W of E. D St & N. Mountain View Rd in **Polygon 4**.
- Install G&W Viper recloser (ZP101R, N.C.) north of E. F Street & N. Mountain View Road in **Polygon 8.** Install north of pole #159862.
- Install G&W Viper recloser (ZP102R, N.C.) west of N. Mountain View Road & E. F Street in **Polygon 8**.
- Install G&W Viper switch (ZP103R, N.C.) west of E. D Street & N. Mountain View Road in **Polygon 4** and remove the existing #P564 air switch.
- Install G&W Viper switch (ZP104R, N.C.) south of E. D Street & N. Mountain View Road in **Polygon 5** and remove the existing #P565 air switch.
- Install G&W Viper tie switch (ZP105R, N.O.) with M15 512 near E. 6th Street & N. Mountain View Road in **Polygon 6** and remove the existing #P593 air switch.
- Install G&W Viper tie switch (ZP106R, N.O.) with M15 513 north of E. Morton Street & N. Van Buren Street in **Polygon 10** (2 poles east of the current #P566 location) and leave the existing #P566 air switch.
- Install G&W Viper tie switch (ZP107R, N.O.) with M15 513 near E. A Street & N. Jefferson Street in **Polygon 3** and remove the existing #P563 air switch.

- Install Manual Three-Phase Gang-Operated Air Switch (P108, N.C.) south of E. A Street between N. Howard Street and N. Monroe Street in **Polygon 3**.
- Install Manual Three-Phase Gang-Operated Air Switch (P109, N.O.) south of E 6th Street & S. Lynn Street in **Polygon 2**.

The following automation devices are proposed for deployment on M15 514:

Device Number	Location	Status	Device Type
ZP100F	W of E. D St & N. Mountain View Rd	N.C.	600 kVAR Switched Cap
ZP101R	N of E. F St & N. Mountain View Rd	N.C.	G&W Viper – Recloser
ZP102R	W of E. F St & N. Mountain View Rd	N.C.	G&W Viper – Recloser
ZP103R	W of E. D St & N. Mountain View Rd	N.C.	G&W Viper – Switch
ZP104R	S of E. D St & N. Mountain View Rd	N.C.	G&W Viper – Switch
ZP105R	E. 6th St & N. Mountain View Road	N.O.	G&W Viper – Switch
ZP106R	N of E. Morton St & N. Van Buren St	N.O.	G&W Viper – Switch
ZP107R	E. A St & N. Jefferson St	N.O.	G&W Viper – Switch
P108	E. A St between Howard & Monroe	N.C.	Manual 3-Ph Air Switch
P109	S of E. 6th St & S. Lynn St	N.O.	Manual 3-Ph Air Switch

Figure 20 illustrates the proposed automation device locations for M15 514.

The proposed automation line device locations identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with either the Regional Operations Engineer, General Foreman, or District Manager to address any construction or Standards related concerns with the selected location(s).

The substation equipment associated with M15 514 is not automation compatible and would require upgrading to make this distribution circuit completely automated. The circuit breaker is a Westinghouse ES model, however the substation voltage regulators were upgraded as part of a programmatic replacement in Q2 2018 from General Electric ML-32's. It has also been identified that the Moscow City Substation has an outdated RTU-based SCADA system which, if it was necessary to upgrade, could be done prior to any major rebuild of the substation. The addition of adding modern three-phase SCADA to the site is estimated at approximately $300k plus any additional costs of getting communications to the site. Grid Modernization has notified Substation Engineering of the proposed work on the feeder and the opportunity to upgrade the station breaker and voltage regulators, however the decision to perform any upgrades will ultimately be made with Substation Engineering through the Engineering Round Table to determine mutual interest, support, budgetary funding, and resource prioritization.

In order to promote complete automation on M15 514, Grid Modernization has notified Substation Engineering of the intended line automation work on the feeder and the request to upgrade the necessary equipment to make this feeder fully automation compatible from the substation perspective. The decision on the funding source and when the requested work will be performed will ultimately be made through discussions with Substation Engineering and the Engineering Roundtable prioritization of resources.

The Grid Modernization program is not funded to perform work on adjacent feeders, including additional automation devices. Any requests to perform work on adjacent feeders are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on adjacent feeders.

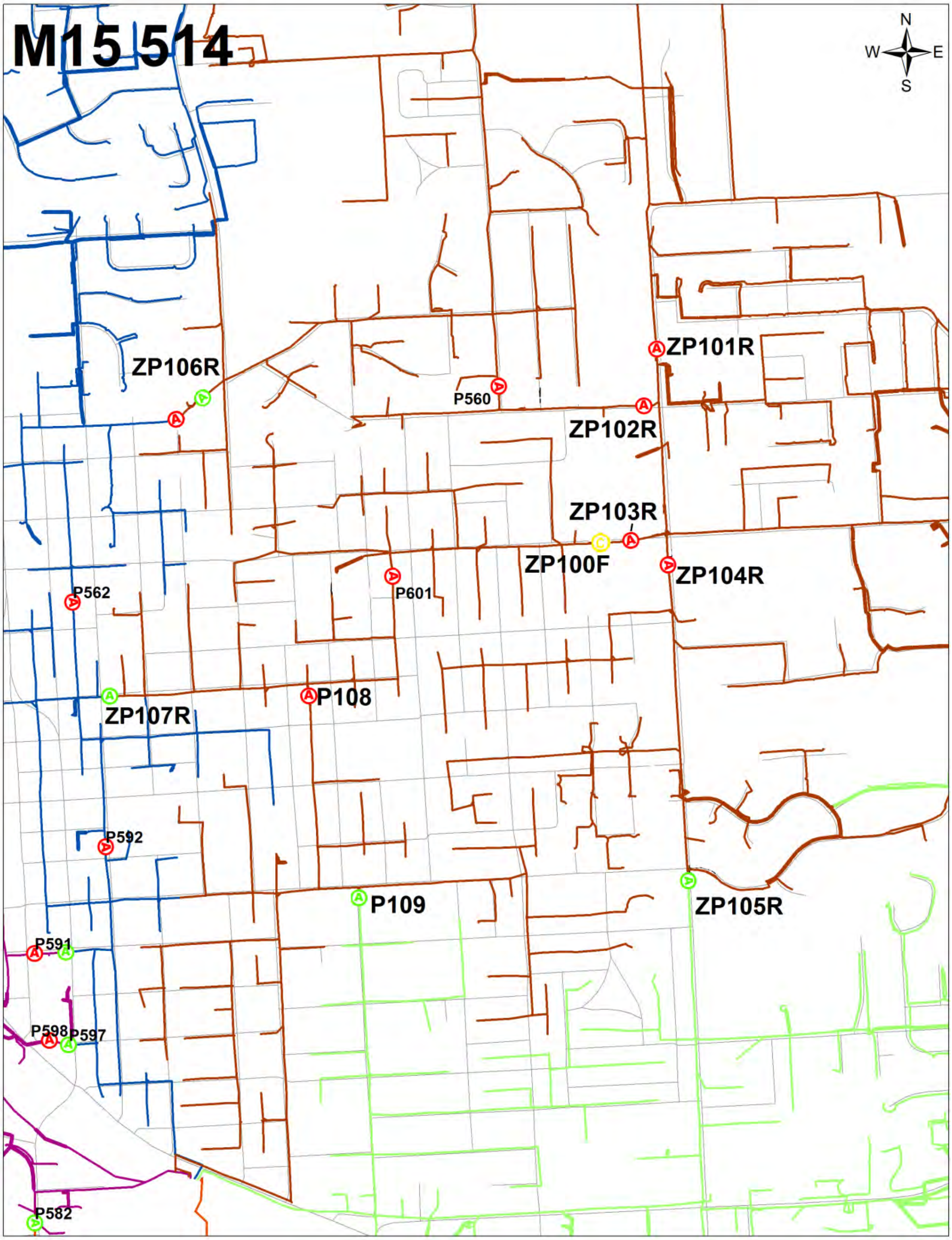


Figure 20. M15 514 Automation Device Locations

Open Wire Secondary

Open wire secondary districts have the ability to negatively affect reliability due to the physical nature of construction and configuration. These districts are also predominantly located in areas with high vegetation growth and limited crew access. These factors have the ability to increase the number of outages and the duration of the outages. A circuit's reliability can be improved by strategically splitting the districts with dedicated transformers and replacing these districts with an appropriately sized dedicated neutral. Grid Modernization is also initiating a study to analyze and quantify the estimated amount of open wire districts on feeders, as well as the amount requiring replacement based on the criteria of the Distribution Feeder Management Plan (DFMP). This will assist in planning and budgeting appropriately to address the needs of the feeders.

Open wire secondary districts have been analyzed for replacement on M15 514 in accordance to the Distribution Feeder Management Plan (DFMP). Approximately 2,300' circuit feet of open wire secondary is currently estimated to be on M15 514. This figure was established from physical observations obtained through field analysis. The existing open wire districts are almost entirely vertically constructed, and are mostly located along inaccessible back lot lines. The Designers shall consult the DFMP if open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts.

Figure 21 identifies the open wire secondary districts that were discovered for analysis or removal in each polygon.

1. Replace approximately 400' of vertical open wire between 7th and 8th due to inaccessibility in **Polygon 2**.
2. Replace approximately 600' of vertical open wire between Garfield & Blaine north of B St. due to inaccessibility and vegetation in **Polygon 4.**
3. Analyze whether to replace approximately 500' of vertical open wire Between Hayes & Garfield south of F St. due to alley accessibility in **Polygon 4.**
4. Replace approximately 450' of vertical open wire between Garfield & Blaine south of B St. due to inaccessibility and vegetation in **Polygon 5.**
5. Replace approximately 350' of combined horizontal and vertical open wire between Orchard & Grant along F St. due to the physical construction in **Polygon 8.**

Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Attempts were made to identify every open wire district on the feeder, however the Designer may identify districts that were not captured in this report. The Designer shall follow the same procedure and consult the DFMP if unidentified districts are present in their assigned polygons.

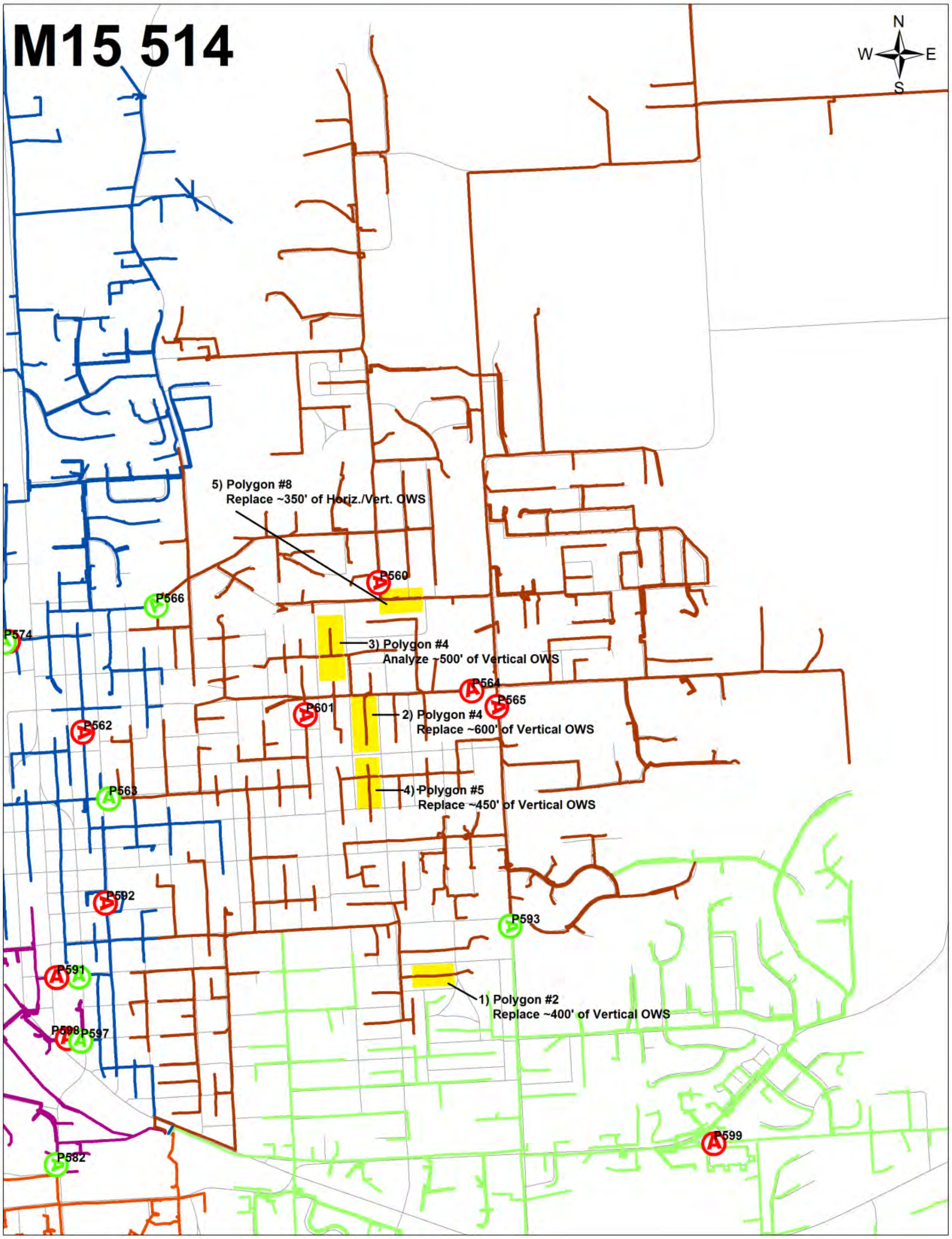


Figure 21. Open Wire Secondary Districts on M15 514

Pole Analysis

All components of an overhead distribution system rely on the integrity and health of poles to ensure the system remains safe, reliable, and operational. The Grid Modernization program performs engineering and field examination of all of the poles and structures on a feeder to determine the removal, installation, replacement, or reinforcement based on requirements of the Distribution Feeder Management Plan (DFMP). A pole inspection report is requested and conducted to obtain an explicit list of poles on the feeder. The pole information from the inspection report provides detailed information for Grid Modernization to leverage in the assessment and proposals.

All poles and structures on M15 514 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Wood Pole section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the M15 514 circuit was performed from 1/24/2018 to 3/1/2018. The M15 514 feeder was determined to contain 1133 distribution poles at the time of analysis. The average age of distribution pole on the circuit is approximate 38 years, which places the average year of installation around 1980. 226 poles on the circuit are older than the 60 year limit for mean-time to failure, which results in the prescriptive replacement of 19.9% of wood poles at a minimum based on age alone.

The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	1133
Average Pole Age in Years	38 (1980)
Year of Oldest Installed Pole	1930
Poles install between 1920-1929	0 (0%)
Poles install between 1930-1939	66 (6%)
Poles install between 1940-1949	35 (3%)
Poles install between 1950-1959	131 (12%)
Poles install between 1960-1969	154 (114%)
Yellow Tagged Poles (Re-enforceable)	29 (3%)
Red Tagged Poles (Replace)	6 (1%)
Average Pole Class	3.9
Class 4 Poles or Smaller	758 (67%)
Class 5 Poles of Smaller	266 (23%)

Transformers

All transformers on M15 514 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

An improvement in the number of underground primary cable outages can be achieved by strategically replacing cable that has a known susceptibility to faulting. The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. This includes the targeted replacement of all pre-1982 non-jacketed primary cable, which Avista's historical data suggests has the highest failure rate of underground cable. Problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged, which allows water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable. In addition, the Program will replace any primary cable section that has multiple documented failures for either jacketed or non-jacketed primary cable.

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

Vegetation Management

Vegetation can pose serious reliability and safety problems for distribution feeders when not properly maintained. Trees can grow into overhead distribution lines as they mature, which creates access issues, public safety concerns, the possibility for trees or limbs to fall through the conductors, or the creation of electrical faults through physical contact. Proper vegetation maintenance along feeder corridors will remove many of these concerns while improving safety and system reliability. Vegetation Management will be included along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished between vegetation and Avista's primary and secondary conductors.

Grid Modernization's work is optimized when performed in coordination with Vegetation Management efforts. Vegetation management shall be employed on M15 514 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

M15 514 has been divided into 17 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Automation devices located within a polygon shall be sequentially renamed using alphabetic letters to reflect a sub-polygon (i.e. #9A, #9B, #9C, etc). Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Manager by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figure 22 illustrates the M15 514 polygons and their boundaries. The CPC Design layer on AFM is available to provide more detailed boundaries of the polygons.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 2**
  - Install Manual Three-Phase Gang-Operated Air Switch (P109, N.O.) south of E 6th Street & S. Lynn Street.
  - Analyze whether to reconductor or install additional primary phase of the single-phase 1300’ of 6CU lateral, 64A peak (58% loaded). The physical condition of the wire, in combination with the condition of the poles, should be analyzed in the field.
  - Replace approximately 400’ of vertical open wire between 7th and 8th due to inaccessibility
- **Polygon 3**
  - Install G&W Viper tie switch (ZP107R, N.O.) with M15 513 near E. A Street & N. Jefferson Street and remove the existing #P563 air switch.
  - Install Manual Three-Phase Gang-Operated Air Switch (P108, N.C.) south of E. A Street between N. Howard Street and N. Monroe Street.
- **Polygon 4**
  - Install G&W Viper switch (ZP103R, N.C.) west of E. D Street & N. Mountain View Road and remove the existing #P564 air switch.
  - Install 600 kVAR switched capacitor bank (ZP100F, N.C.) W of E. D St & N. Mountain View Rd and remove the existing 600 kVAR fixed capacitor bank.
  - Replace approximately 600’ of vertical open wire between Garfield & Blaine north of B St. due to inaccessibility and vegetation
  - Analyze whether to replace approximately 500’ of vertical open wire Between Hayes & Garfield south of F St. due to alley accessibility
- **Polygon 5**
  - Install G&W Viper switch (ZP104R, N.C.) south of E. D Street & N. Mountain View Road and remove the existing #P565 air switch.
  - Replace approximately 450’ of vertical open wire between Garfield & Blaine south of B St. due to inaccessibility and vegetation
- **Polygon 6**
  - Install G&W Viper tie switch (ZP105R, N.O.) with M15 512 near E. 6th Street & N. Mountain View Road and remove the existing #P593 air switch.

- **Polygon 7**
  - Transfer 1Φ OH lateral east of Eisenhower Street & E D. Street intersection (≈9 A peak loading, ≈5 A average loading) from CΦ to BΦ.
- **Polygon 8**
  - Install G&W Viper recloser (ZP101R, N.C.) north of E. F Street & N. Mountain View Road. Install north of pole #159862.
  - Install G&W Viper recloser (ZP102R, N.C.) west of N. Mountain View Road & E. F Street.
  - Remove the existing 600 kVAR fixed capacitor bank east of N Mountain View Road & E Public Ave intersection
  - Replace approximately 350’ of combined horizontal and vertical open wire between Orchard & Grant along F St. due to the physical construction
- **Polygon 9**
  - Analyze whether to reconductor the three-phase 2100’ of 6CU lateral, 68A peak (61% loaded). The physical condition of the wire, in combination with the condition of the poles, should be analyzed in the field. A minimum conductor size of 2/0 ACSR should be used if the decision is made to reconductor.
  - Remove the existing 600 kVAR fixed capacitor bank south of N. Orchard Ave & E Ponderosa Dr.
- **Polygon 10**
  - Transfer 1Φ OH lateral south of N Polk St & E Public Ave intersection (≈25 A peak loading, ≈13 A average loading) from CΦ to AΦ.
  - Install G&W Viper tie switch (ZP106R, N.O.) with M15 513 north of E. Morton Street & N. Van Buren Street (2 poles east of the current #P566 location) and leave the existing #P566 air switch.
- **Polygon 11**
  - Analyze whether to reconductor the three-phase 2100’ of 6CU lateral, 68A peak (61% loaded). The physical condition of the wire, in combination with the condition of the poles, should be analyzed in the field. A minimum conductor size of 2/0 ACSR should be used if the decision is made to reconductor.
- **Polygon 13**
  - Transfer 1Φ URD lateral east of N Mountain View Road & E Public Ave intersection (≈22 A peak loading, ≈12 A average loading) from AΦ to CΦ.
- **Polygon 14**
  - Transfer 1Φ OH lateral west of W Mountain View Road & Slonaker Drive intersection (≈12 A peak loading, ≈6 A average loading) from AΦ to BΦ.
  - Analyze whether to relocate a 3300’ overhead, single-phase 6CU lateral that is currently located in farmland that is not readily accessible from road access. The assigned Designer shall analyze the conditions of the existing poles and wire to help determine if the lateral should be relocated along N Mountain View Road to the east.

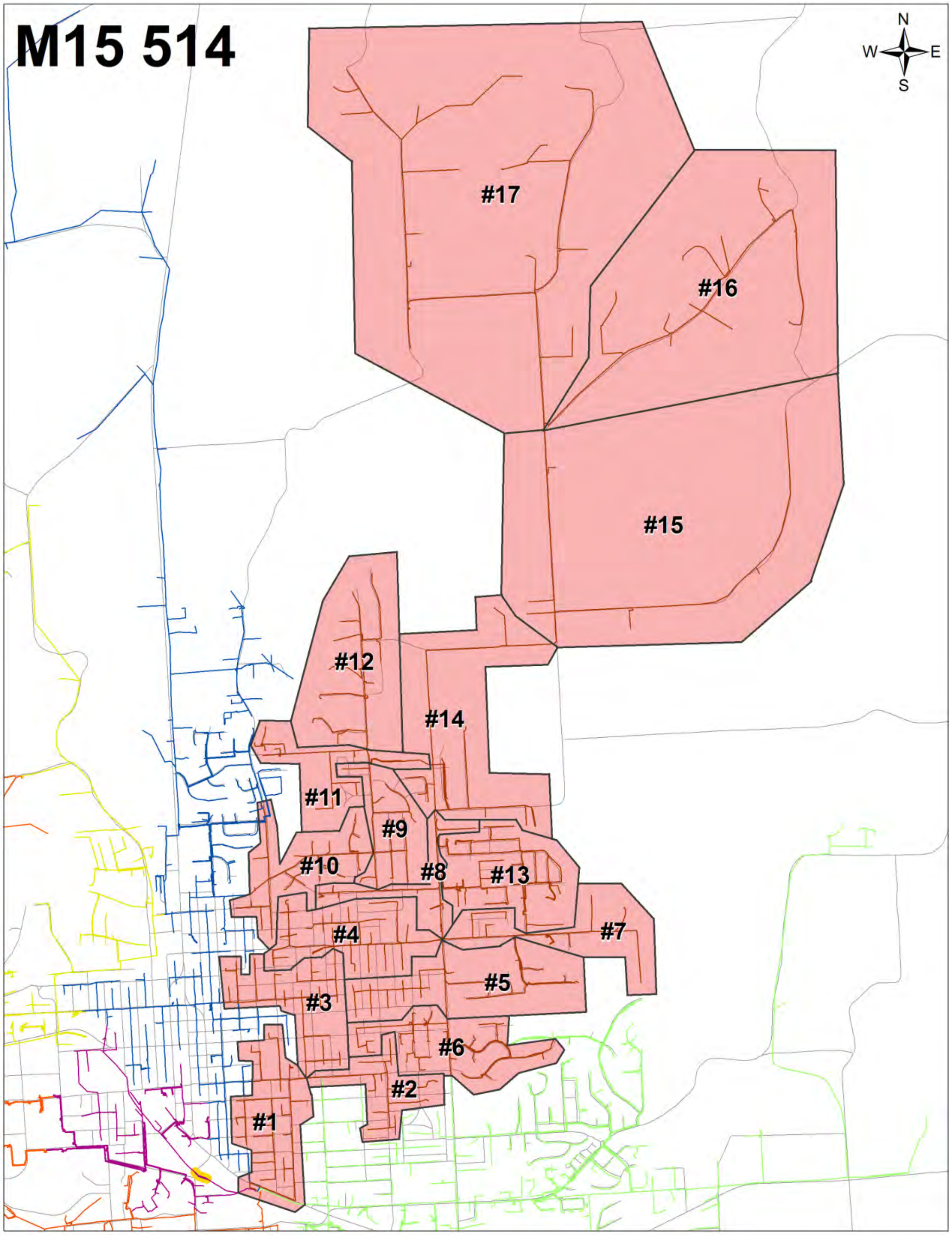


Figure 22. M15 514 Assigned Polygon Numbers

Report Versions

Version 1 4/30/18 – Creation of the initial report

Grid Modernization Program

MIS 431 Baseline Report

8/22/2016

Version 1

Prepared by Shane Pacini

Index

Overview

The following report was established to create a baseline analysis for MIS 431 as part of the Grid Modernization program.

MIS 431 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Mission Substation in the Kellogg service area. The feeder has 69.41 miles of feeder trunk with 170.96 miles of laterals that serves predominantly rural residential loads west of Pinehurst, ID. Additional feeder information is layered throughout the sections of this report, as well as the Avista Feeder Status Report. MIS 431 is represented as a green color on the system map shown in Figure 1.

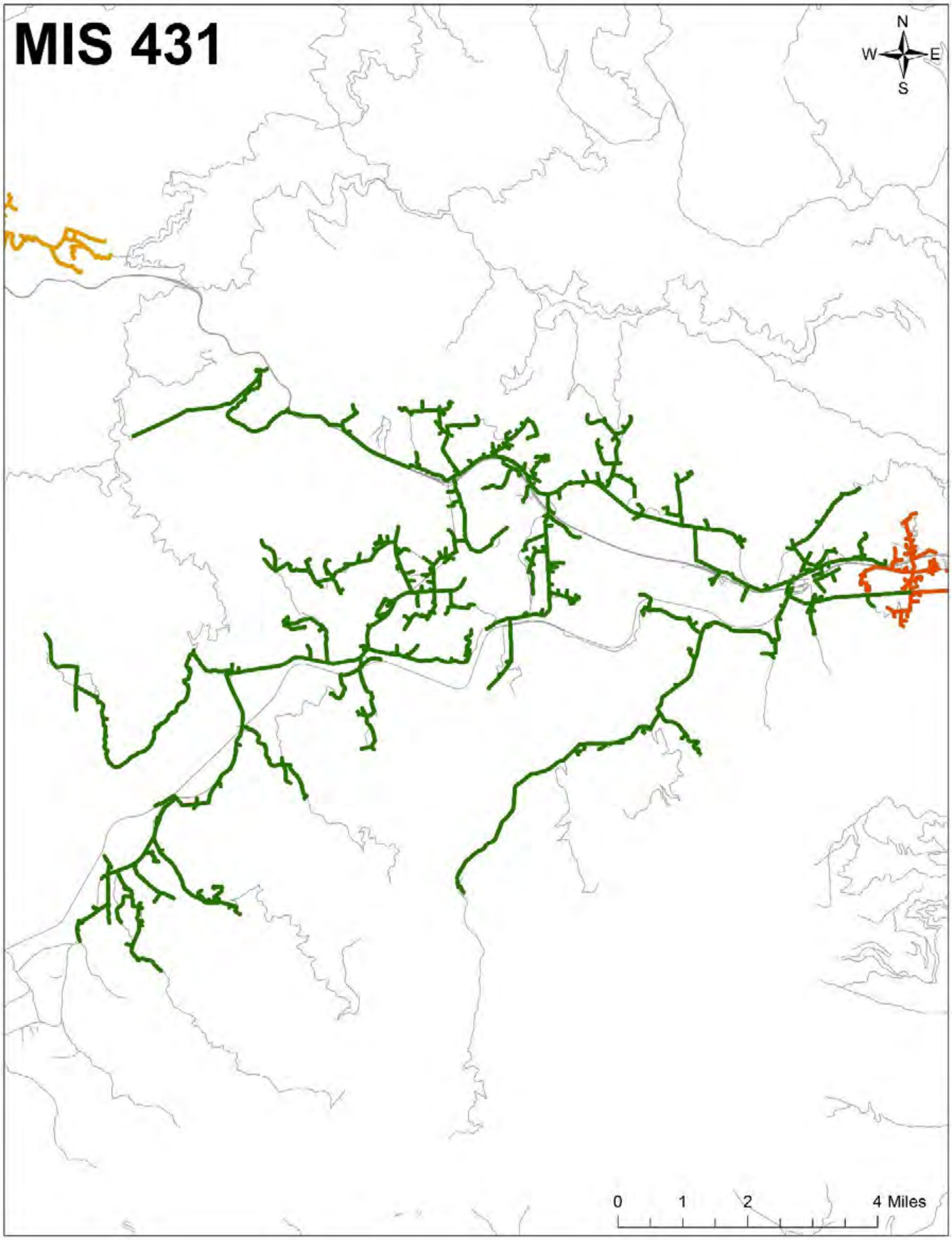


Figure 1. MIS 431 One-Line Diagram

Program Ranking Criteria

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (Energy Savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set could be measured on different scales, the normalization process offers the ability to convert each into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked.

MIS 431 had a normalized total ranking of 0.441, ranking 49th on the list of over 340 feeders. Further analysis suggests that the primary reasons this feeder was selected was due to relatively higher potential to achieve avoided costs through energy savings and efficiency improvements (73.32%), as well as the opportunity to reduce future O&M expenses through capital improvements (20.09%). Designers should consider these factors when fielding and designing the work on MIS 431.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.08622993	365.8691815	1038262.215
Normalized Data	0.07363317	0.921757676	0.354096196
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.02945326	0.322615186	0.088524049
Weight of Category %	6.68%	73.22%	20.09%

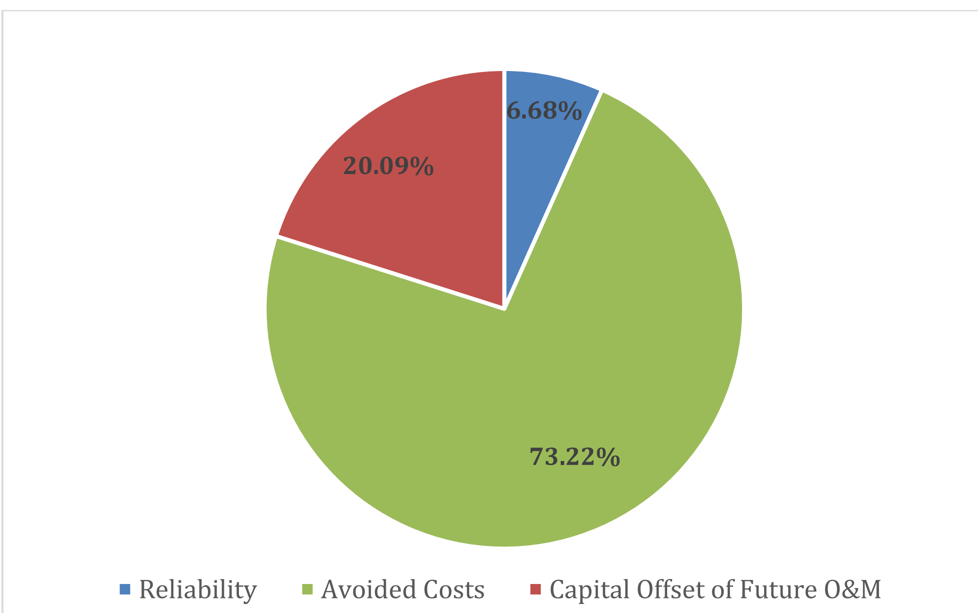


Figure 2. MIS 431 Selection Criteria

Reliability Indices

The key reliability indicators for MIS 431 were analyzed from 2006 to 2015 to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed automation deployments. The table below shows the annual value for each respective reliability index on MIS 431 in the corresponding year. The reliability indices being used do not include major events days (MED), as this is standard per IEEE and reflects the same reliability information that Avista shares with the Commission.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2006	4.8%	0.59	91	154
2007	22.4%	2.43	398	164
2008	62.7%	4.93	654	132
2009	1.8%	1.97	204	104
2010	39.3%	2.68	377	141
2011	66.1%	5.09	701	137
2012	43.1%	5.05	464	92
2013	5.7%	2.12	175	83
2014	30.5%	3.37	345	103
2015	23.3%	1.16	227	195
Average	29.98%	2.94	363.51	130.47

The average value of each index was calculated and then compared to the Avista 2015 Target values. Three of the four historical averaged (measured) indices on MIS 431 are underperforming when compared to the 2015 targets. This data suggests that customers experience numerous, prolonged outages on the feeder that are below the desired levels set by Avista's target values.

WA-ID Key Indicator	2016 Target	MIS 431	Variance
SAIFI Sustained Outages/Customer	1.11	2.94	-1.83
SAIDI Outage Time/Customer (min)	151.00	363.51	-212.51
CAIDI Ave Restoration Time (min)	141.00	130.47	10.53
CEMI3 % of Customers >3 Outages	6.90%	29.98%	-23.08%

Peak Loading

Ampacity loading on MIS 431 is not monitored through SCADA. Therefore, load history was utilized from the monthly Substation Inspection Reports to establish accurate loading figures for the feeder. Three phase ampacity loading from the monthly Substation Inspection Reports at the MIS 431 substation circuit breaker was analyzed from 1/31/14 to 4/8/16. The following loading values were established for MIS 431 during this timeframe. MIS 431 is a winter peaking feeder, with comparable peak values occurring from December through February. The peak loading values for each phase are used in the SynerGEE model analysis for the feeder, except where Average Peak load values are noted for establishing kW losses. Average Peak represents an average of monthly peak values, and not traditional average loading.

	Before Balancing	
	Peak	**Average Peak**
A-Phase	177 A	114.5 A
B-Phase	139 A	82.6 A
C-Phase	142 A	86.3 A

	After Balancing	
	Peak	**Average Peak**
A-Phase	161 A	101.6 A
B-Phase	154 A	92.1 A
C-Phase	143 A	90.6 A

Based on the reliance of the monthly substation inspection reports, conservative efforts will be made to fully balance the feeder as the actual three phase ampere allocations are not known.

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from SynerGEE at the model's initial configuration before balancing.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	1411	3825	36.89%
B-Phase	1108	5360	20.67%
C-Phase	1132	4240	26.70%

* Connected kVA per Phase in SynerGEE as of 6/17/16

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	913	3825	23.87%
B-Phase	658	5360	12.28%
C-Phase	688	4240	16.23%

* Connected kVA per Phase in SynerGEE as of 6/17/16

Feeder Balancing

As previously stated, minimal efforts will be made at this point in the analysis to balance the feeder, as the actual peak ampere loading information for each individual phase was only identified through the monthly substation inspection reports and not through SCADA monitoring. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA before balancing:

	Connected KVA per Phase*
A-Phase	3849.5 kVA
B-Phase	5357.5 kVA
C-Phase	4249.5 kVA

* Connected kVA per Phase in AFM as of 5/31/16

The following list provides the loads, laterals, and dips that can effectively balance the load on the phases between numerous strategic locations on the feeder, shown in Figure 3. As a whole, the trunk sections and multi-phase laterals on MIS 431 were relatively balanced, however opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate these changes into their appropriate polygon designs:

1. **Polygons 6 & 8** – transfer portion of 4 ACSR OH lateral south Latour Creek Road (≈15 A peak) from C-phase to B-phase. This lateral will also have a new B-phase 4 ACSR conductor installed to accommodate the load transfer, as described in the *Laterals* section. Figure 3 illustrates the phase balancing proposal on Polygons 6 & 8.
2. **Polygon 28** – transfer 2CN15 URD lateral (≈16 A peak) from A-phase to C-phase. This will help mitigate downstream low voltage issues due to a heavily loaded A-phase, and reduce the loading on the upstream conductors. Figure 4 illustrates the phase balancing proposal on Polygons 28.

The result of these load transfers are listed in the following table. These changes will approximately balance the feeder at the substation breaker to 161/154/143, as well as between the numerous strategic points and devices on the circuit to approximately sectionalize the feeder.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any proposals for phase balancing prior to commencing the job designs.

	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
MIS 431 Station Breaker	177	139	142	161	154	143
C439	127	91	80	109	93	94
C434	49	49	63	52	62	49
C432R	12	32	43	13	45	29
C435R	89	58	32	71	59	41

It is recommended to balance the section of PIN 443 that would be transferred to MIS 431 due to the probability of load being transferred. The load downstream of device C445 on PIN 443 during normal configuration should be balanced. During peak loading this section is loaded as follows: 97/40/111. Loading at the PIN 443 substation breaker is 182/101/214. This suggests that load can be transferred downstream of C445 from C-phase to B-phase and assist in balancing both the west branch of the feeder and the entire loading on the feeder.

It is recommended that the Regional Operations Engineer complete the following phase change to assist in Grid Modernizations work on MIS 431:

1. **PIN 443** – transfer C-phase (≈31A peak) to B-phase on the single-phase overhead lateral south of the main feeder trunk along French Gulch Road. This will help balance the sectionalized load transferred to MIS 431, mitigate downstream low voltage issues due to a heavily loaded A-phase, and reduce the loading on the upstream conductors.

This proposed phase change would bring the loading downstream of device C445 on PIN 443 during normal configuration to approximately 97/70/80. In addition, loading at the PIN 443 substation breaker would be improved to is 181/132/183.

The decision to move forward with the proposed phase change will be confirmed, approved, and coordinated by the Regional Operations Engineer. Figure 5 illustrates the phase balancing proposal on PIN 443.

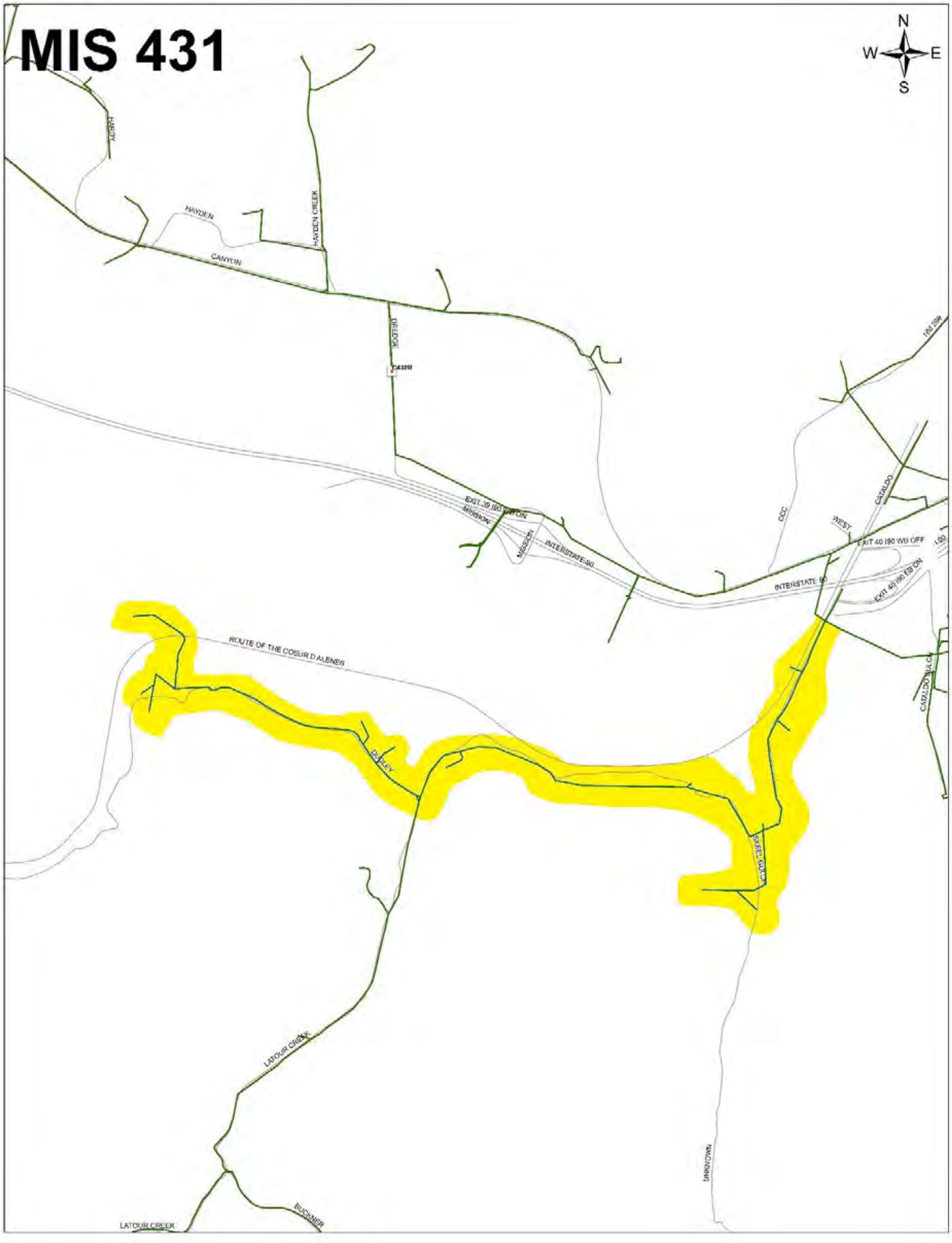


Figure 3. Lateral Phase Balancing on Polygons 6 & 8

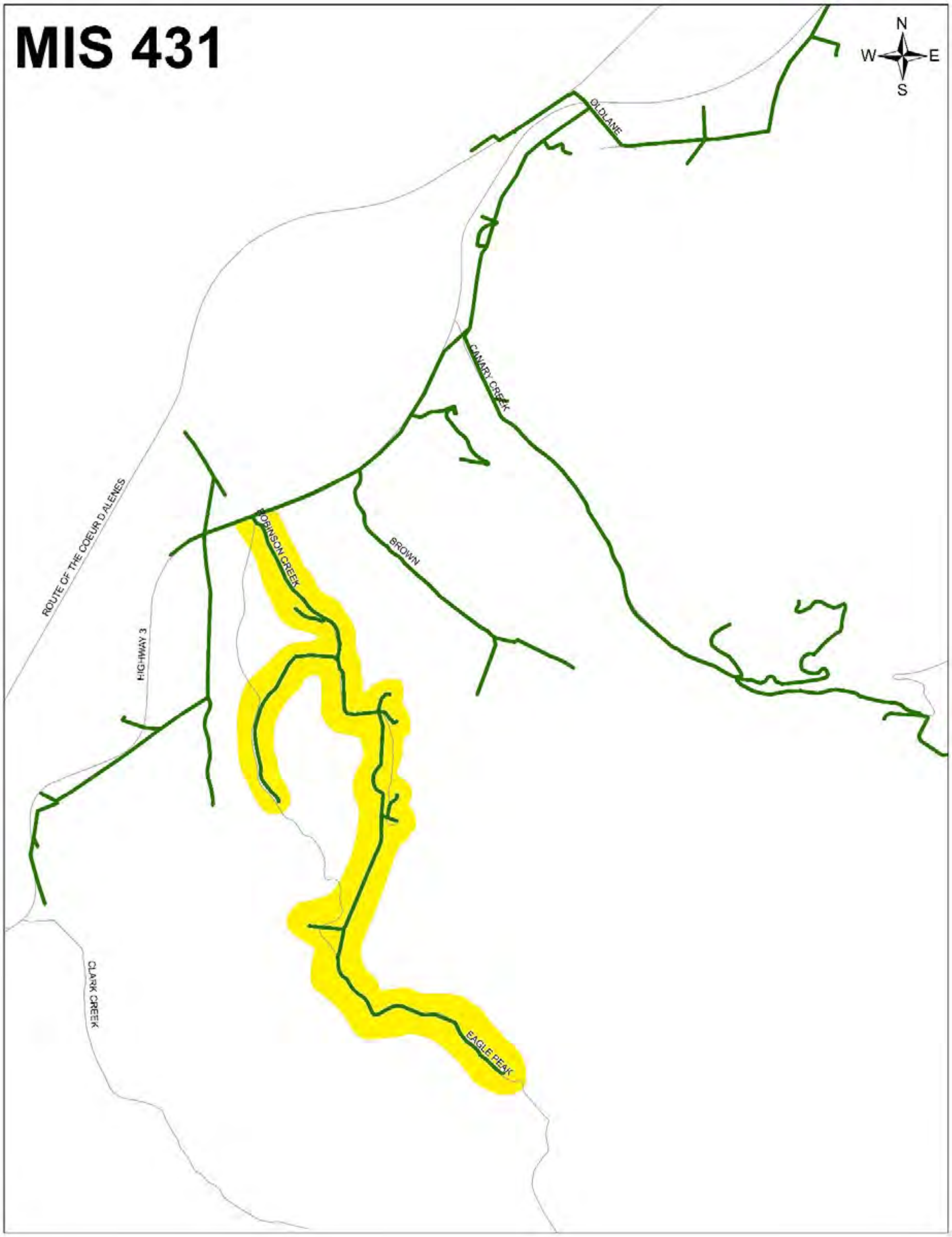


Figure 4. Lateral Phase Balancing on Polygon 28

Figure 5. Lateral Phase Balancing on PIN 443

Conductor

All primary conductors on MIS 431 were analyzed in SynerGEE using the balanced peak ampacity values identified above (161/154/143). Specific attention was given to conductors that were potentially overloaded, have relatively high line losses, serve areas with unacceptable voltage quality (primarily during peak conditions), and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on MIS 431, as well as the proposals for improving the efficiency and performance of the feeder.

The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary requiring attention.

Transmission Engineering should be consulted by the assigned Designer for any reconductoring performed on Transmission structures where there is Distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure. A majority of the primary feeder trunk east of the Mission Substation will be underbuilt on CDA-Pine Creek 115kV transmission line.

CDA-Pine Creek 115kV Transmission Rebuild

There is an existing capital project sponsored by Transmission Engineering to rebuild the existing CDA-Pine Creek 115kV transmission line to the east of the Mission Substation. This includes removing approximately 21,000' of existing 115kV line currently crossing through the Mission Slough, and relocating the line to overbuild the existing MIS 431 distribution feeder trunk along Canyon Rd. Transmission Engineering (Bryan Hyde) is currently designing this project, and is scheduled to begin the overbuild construction of MIS 431 from Mission Substation to I-90 in Q2-Q3 2018, with some minor miscellaneous work occurring in Q2-Q3 2017.

Grid Modernization has met with Transmission Engineering to determine the timeline and scope of the work involved overbuilding the existing feeder and the corresponding pole replacements. This includes receiving an explicit list of identified distribution poles to be replaced with transmission structures. Transmission Engineering has confirmed that they will bear the cost for the new structures that are over-building MIS 431, in addition to covering the costs for any labor and materials associated with transferring the existing distribution equipment and materials (including cross arms, transformers, risers, line devices, etc.).

The proposed route of the CDA-Pine Creek 115kV Rebuild project is shown as a blue line in Figure 6.

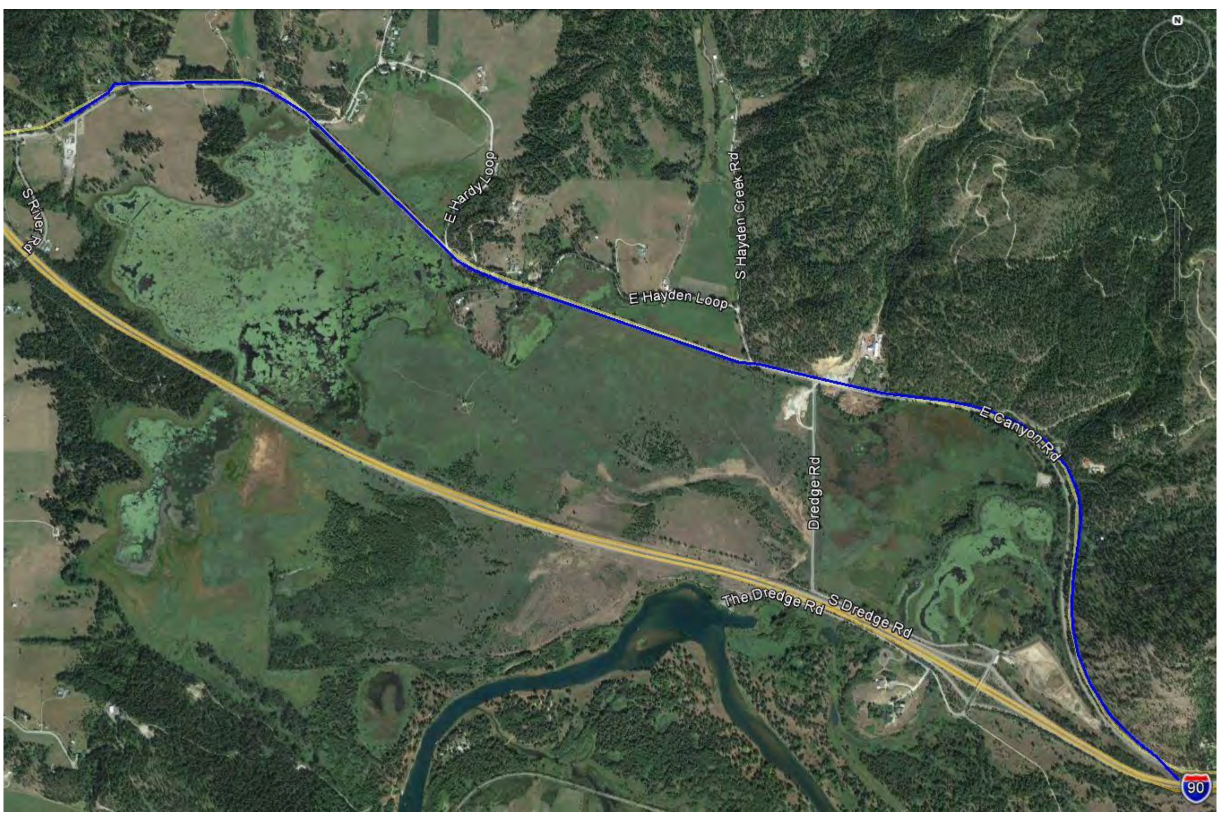


Figure 6. Proposed Route of the CDA-Pine Creek 115kV Rebuild

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

MIS 431 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, there are sections that could warrant reconfiguration due to proposed reconductoring, physical conditions, stubbing, and/or high resistant conductors. The assigned Designer is responsible to further analyze each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer. It is the Designer’s responsibility to consult the Program Engineer on any proposals for reconfiguration or conversion to underground prior to commencing the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program’s scope, meets the system operations requirements, and to assist in identifying the appropriate material and equipment to install.

Trunk

The primary trunk conductors on MIS 431 were first analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The feeder trunk is currently comprised of a large mix of conductors. 2/0 ACSR is the principal conductor used on the eastern branch of the circuit and part of the western branch. All sections of primary are loaded under 40% of carrying capability during peak loading scenarios, with the one exception listed below where peak loading on the undersized 6CU conductor is as high as 52% of rated capacity. Line losses on the trunk are generally in an acceptable range for this scenario, which has been aided by balancing the feeder and relatively lower loading conditions where high loss conductors exist.

- Reconductor 3Φ trunk south of I-90 & Idaho Highway 3 to 2/0 ACSR primary with a 2/0 ACSR neutral (approximately 13,600’) in **Polygon 19**. This section of trunk is currently served by 6CU. This section of the feeder is undersized for serving as primary feeder trunk an experiences relatively high percent loading during peak times of year. This reconductor will help to lower line losses and promote improved voltage levels downstream. The Designer should investigate whether it is cost effective to relocate the proposer reconductored trunk or to rebuild in place. Figure 7 illustrates the primary trunk reconductor on this section.

The designs to reconductor shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

Laterals

The primary lateral conductors on MIS 431 are generally sized appropriately to meet peak loading conditions during normal system configuration. The analyzed models suggest reconductoring of selective laterals to lower line losses and promote improved voltage levels downstream. The Distribution Feeder Management Plan calls attention to these higher loss conductors, with emphasis on replacement conductors that have a resistance greater than 5 ohms per mile.

- Install new B-phase 4 ACSR conductor to existing lateral on Latour Creek Road primary (approximately 11,100') in **Polygon 6** to create a 2-phase lateral. This existing lateral is currently served by only C-phase 4 ACSR. Approximately 15A peak load will be transferred from C-phase to the new B-phase, as described in the *Feeder Balancing* section. Figure 8 illustrates this section.
- The assigned Designer should investigate the existing 4 ACSR and 1CN15 cable west of the step-down transformer in **Polygon 15** to determine if the conductor requires replacement in accordance with the DFMP. In addition, the lateral should be investigated to determine if relocation or reconfiguration would provide significant improvements to the reliability of the downstream customer. Figure 9 illustrates this section.

The following list of laterals should also be further examined by the assigned Designer in the field to support reconductoring these laterals to 4ACSR. As part of the field analysis, the Designer should determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, potential benefits from relocation, etc. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

1. **Polygon 5** – Approximately 1590' of 6CR, 2A peak (9% loaded)
2. **Polygon 11** – Approximately 920' of 8CW, 5A peak (17% loaded)
3. **Polygon 11** – Approximately 380' of 8CW, 1A peak (3% loaded)
4. **Polygon 11** – Approximately 2940' of 6CR, 1A peak (6% loaded)
5. **Polygon 14** – Approximately 7180' of 6CW, 11A peak (25% loaded)
6. **Polygon 16** – Approximately 970' of 6CR, 1A peak (3% loaded)
7. **Polygon 17** – Approximately 1900' of 6CR, 1A peak (5% loaded)
8. **Polygon 17** – Approximately 810' of 6CR, 3A peak (18% loaded)
9. **Polygon 18** – Approximately 2050' of 6CR, 1A peak (4% loaded)
10. **Polygon 22** – Approximately 1160' of 6CR, 1A peak (1% loaded)
11. **Polygon 24** – Approximately 360' of 6CR, 5A peak (28% loaded)
12. **Polygon 24** – Approximately 280' of 6CR, 2A peak (12% loaded)
13. **Polygon 24** – Approximately 5770' of 6CR, 2A peak (9% loaded)
14. **Polygon 28** – Approximately 1900' of 6CR, 1A peak (4% loaded)
15. **Polygon 28** – Approximately 6640' of 6CR, 2A peak (12% loaded)

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Feeder Tie

MIS 431 currently contains one overhead feeder tie to PIN 443 through the normally open line cutouts C448. This tie is conductored with a combination of 2/0 ACSR and 2/0 CU from the Mission Substation to the open C448 device. The Regional Operations Engineers have historically used this tie to back feed from MIS 431 almost as far as the Pine Creek substation, as well as to back feed from PIN 443 towards the Mission Substation.

The criticality of this lone feeder tie to PIN 443 justifies reinforcing the devices and installing voltage regulators to provide acceptable voltage levels during transfers. A series of automated Viper reclosers and switches with communication capabilities will assist in improving the reliability and usefulness of the existing feeder tie. The C448 device should first be replaced with an automated Viper switch (ZC448R) to provide three-phase gang-operated switching, as well as remote operability to the tie. The existing C432R Kyle midline recloser would then be replaced with an automated Viper midline recloser (ZC432R) to provide automated sectionalization and remote operability. One additional Viper midline recloser (ZC434R) would be installed just outside of the substation to isolate the east branch of the feeder, to provide automated sectionalization, and remote operability. This device would replace the existing switch (C434).

In addition to the upgraded devices on the east branch to reinforce the feeder tie to PIN 443, the existing Kyle midline recloser (C435R) on the west branch should be replaced with an automated Viper midline recloser (ZC435R) to provide automated sectionalization and remote operability. One additional Viper midline recloser (ZC439R) would be installed just outside of the substation to isolate the east branch of the feeder, to provide automated sectionalization, and remote operability. This device would replace the existing switch (C439).

- Install Viper recloser (ZC432R, N.C.) south of Canyon Rd & Dredge Rd and remove the existing C432R Kyle recloser in **Polygon 1**.
- Install Viper recloser (ZC434R, N.C.) just outside of the Mission Substation on the east branch and remove the existing C434 switch in **Polygon 1**.
- Install Viper recloser (ZC435R, N.C.) east of Idaho Hwy 3 & 4th of July Creek Rd and remove the existing C435R Kyle recloser in **Polygon 16**.
- Install Viper recloser (ZC439R, N.C.) just outside of the Mission Substation on the west branch and remove the existing C439 switch in **Polygon 10**.
- Install Viper switch (ZC448R, N.O.) south of Hunt Gulch Rd & Hughes Rd and remove the existing C448 open cutouts in **Polygon 7**.
- Install midline voltage regulators (ZC433V, N.O.) west of US Interstate 90 & S Latour Creek Rd in **Polygon 4**.

The decision to upgrade feeder tie opportunity will be discussed and decided with the Regional Operations Engineer based on the anticipated frequency of use.

Figure 18 illustrates the proposed automation device locations on MIS 431.

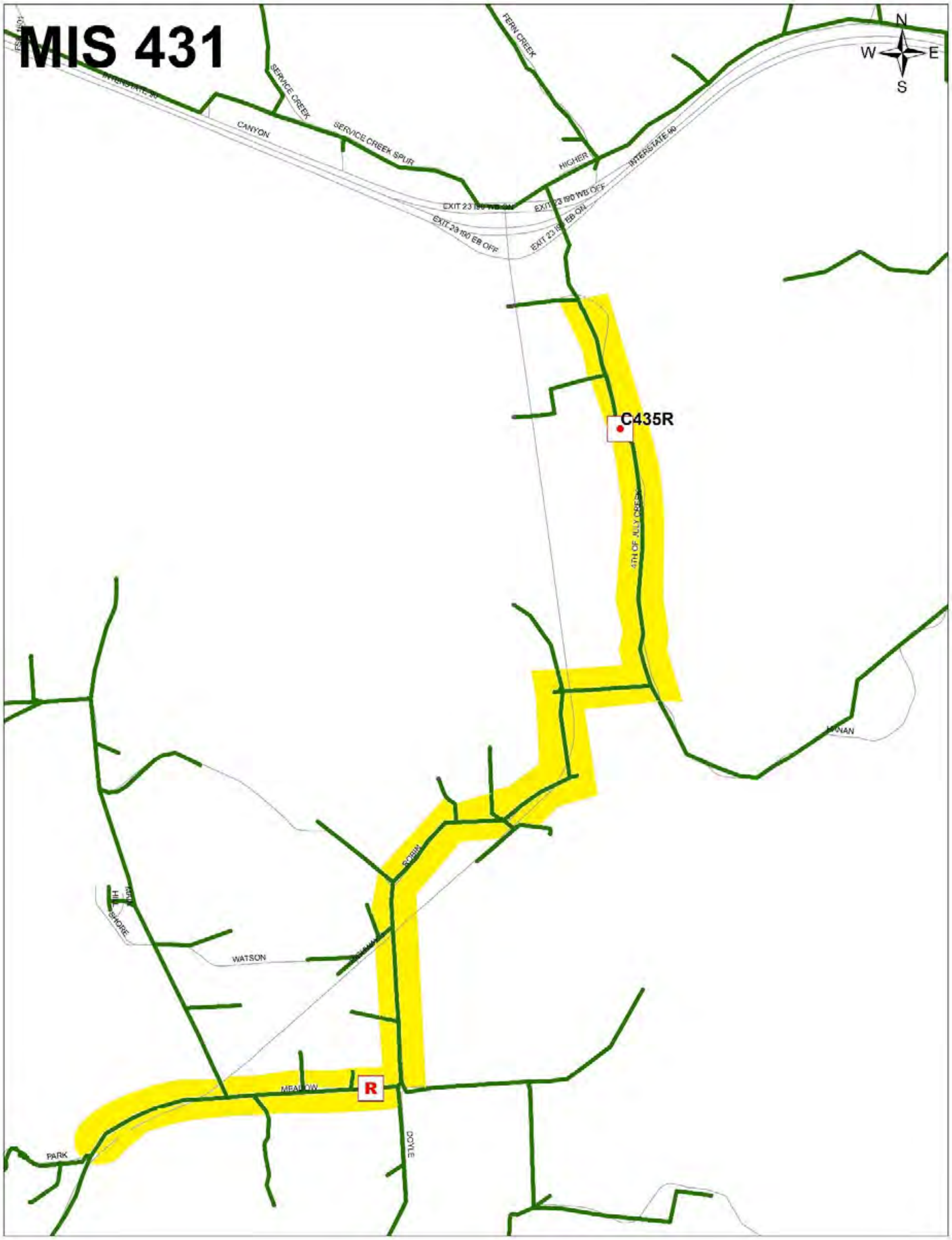


Figure 7. Polygon 16 Feeder Trunk Reconductor to 2/0 ACSR

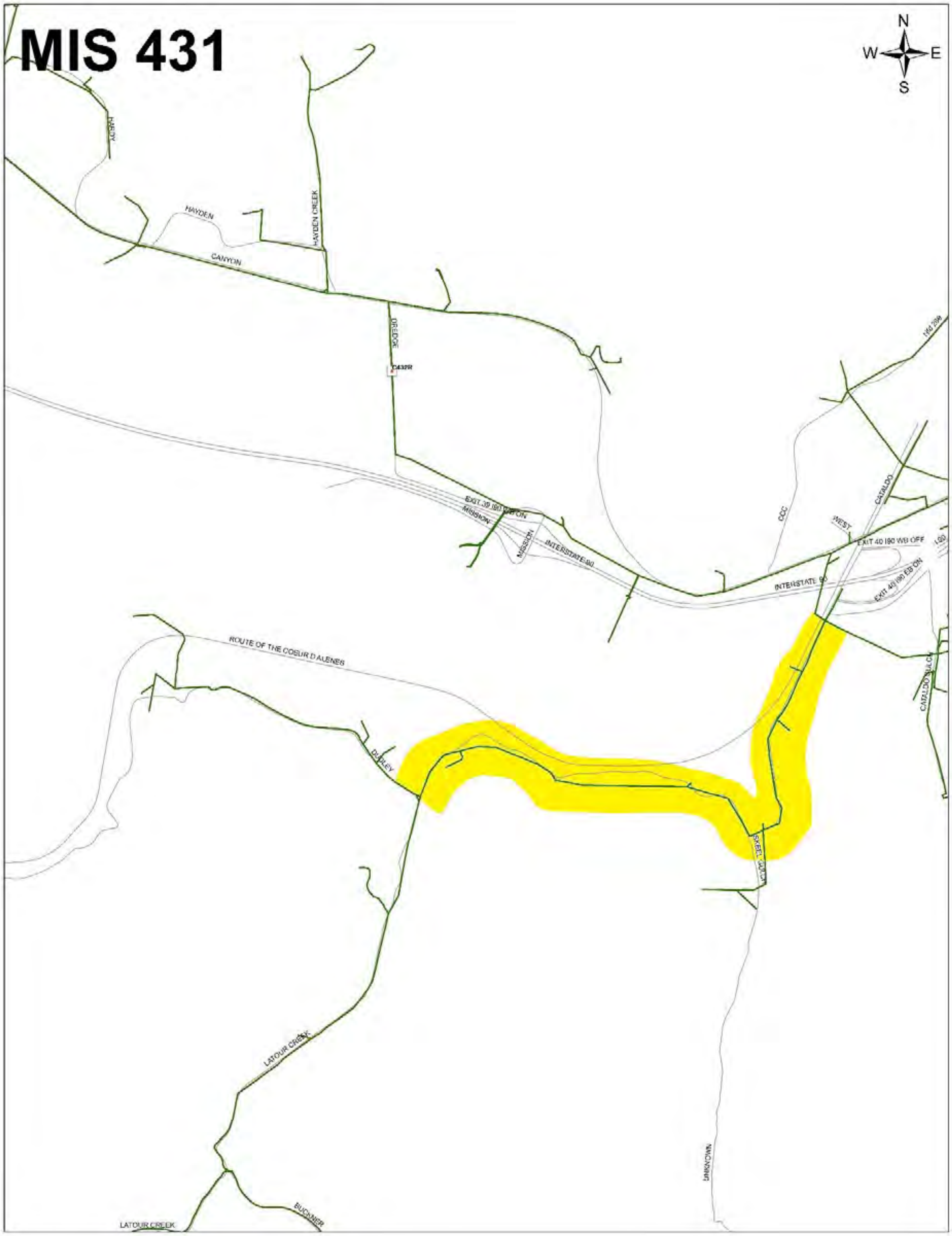


Figure 8. Polygon 6 Add 4 ACSR B-phase to Latour Creek Road Lateral

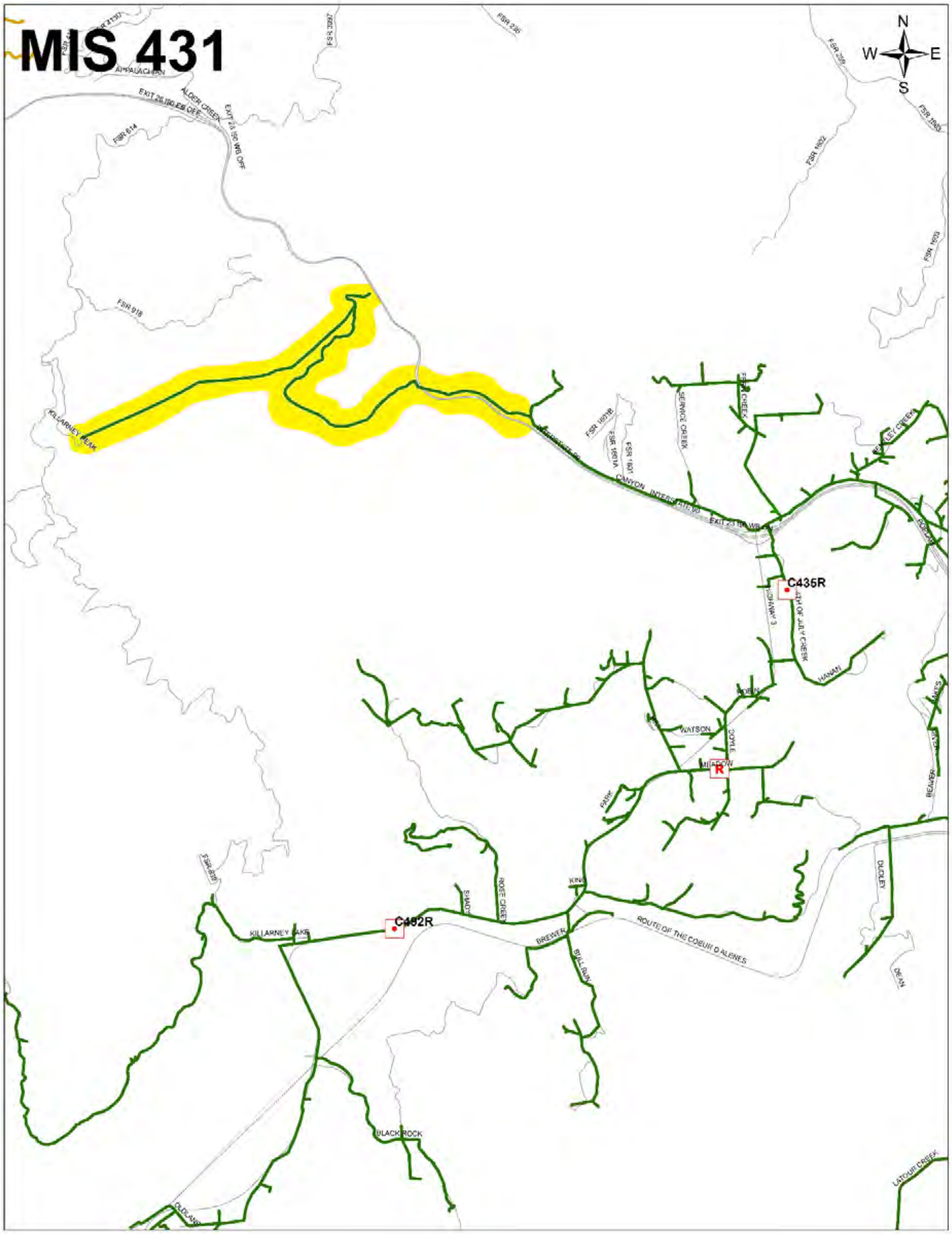


Figure 9. Polygon 15 Lateral Requiring further Investigation

Voltage Quality

MIS 431 was analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable ANSI Range A or B operating limits. The feeder was modeled in SynerGEE during both peak loading and Average loading conditions.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to MIS 431. During peak loading conditions, voltage levels just downstream of both sets of voltage regulators were within the acceptable levels ANSI Range A limits.

The maximum voltages modeled on the feeder occurred downstream of the station voltage regulators at approximately 125.4V. Voltage levels on the west branch that are downstream of the existing midline voltage regulators were the lowest on the feeder. Voltage levels on A-phase at the far southwest laterals of the feeder were modeled as low as 111.8V. This suggest that some conservative load balancing should be performed to lessen the load on A-phase. The highest modeled voltage on the west branch was modeled at 124.0V on A-phase.

Similarly, voltage levels downstream of the C432 midline were within the allowable ANSI Range A limits. The lowest modeled voltage on east branch of the circuit is 117.3V on C-phase, while the highest modeled voltage on A-phase is 124.4V.

Figure 10 illustrates the voltage levels MIS 431. Green illustrates voltages between 117–123 V. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	41	3.21	116	21
114.00 - 116.00 V	23	1.36	93	15
116.00 - 118.00 V	59	10.22	199	47
118.00 - 120.00 V	142	22.99	312	97
120.00 - 122.00 V	269	30.26	642	201
122.00 - 124.00 V	307	27.52	992	241
124.00 - 126.00 V	285	21.51	1059	194
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading

The voltage levels on the feeder were again analyzed before balancing load, however this time during Average loading conditions. This scenario saw more optimal voltage levels across most of the feeder. During average loading conditions, voltage levels just downstream of both sets of voltage regulators were within the acceptable levels.

The maximum voltages modeled on the feeder occurred downstream of the station voltage regulators at approximately 124.7V. Voltage levels on the west branch that are downstream of the existing midline voltage regulators were the lowest on the feeder. Voltage levels on A-phase at the far southwest laterals of the feeder were modeled as low as 115.0V. This suggest that some conservative load balancing should be performed to lessen the load on A-phase. The highest modeled voltage on the west branch was modeled at 123.5V on A-phase.

Similarly, voltage levels downstream of the C432 midline were within the allowable ANSI Range A limits. The lowest modeled voltage on east branch of the circuit is 119.4V on C-phase, while the highest modeled voltage on A-phase is 123.9V.

Figure 11 illustrates the voltage levels MIS 431. Green illustrates voltages between 117–123 V. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	41	3.21	78	21
116.00 - 118.00 V	13	0.81	36	7
118.00 - 120.00 V	74	11.81	170	63
120.00 - 122.00 V	284	40.16	379	176
122.00 - 124.00 V	542	49.36	1164	426
124.00 - 126.00 V	172	11.72	315	123
126.00 - 140.00 V	0	0.00	0	0

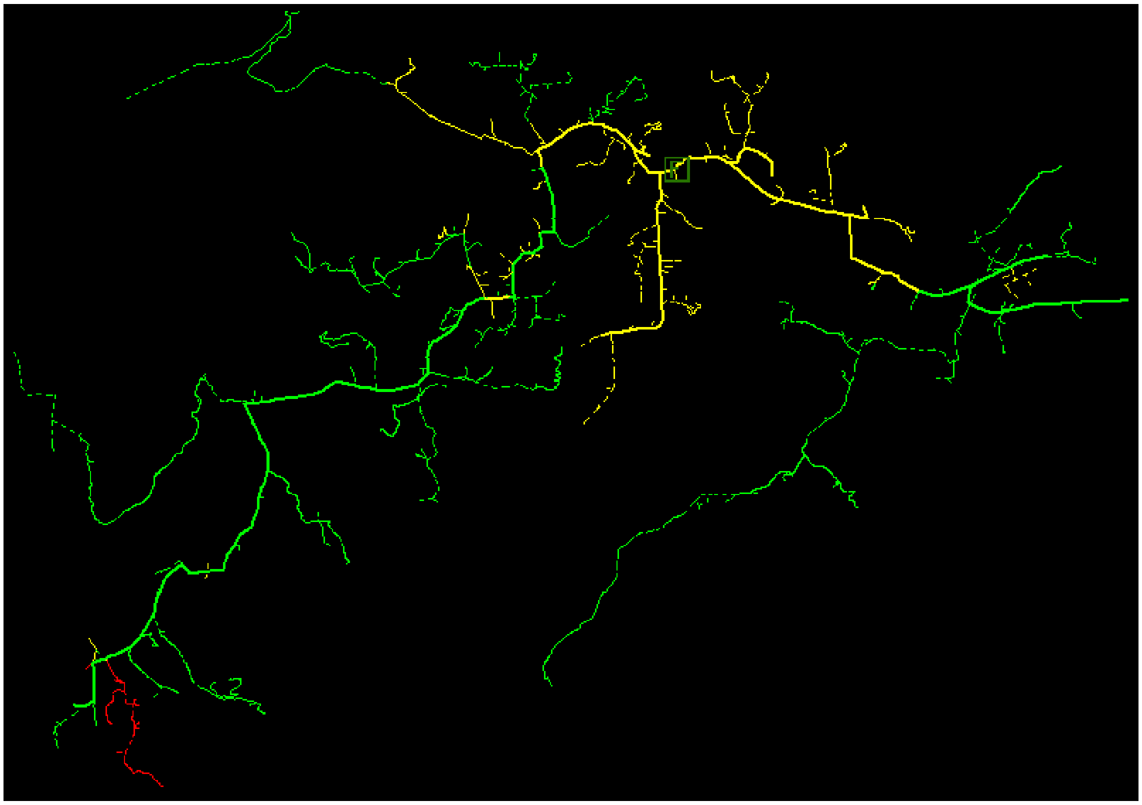


Figure 10. Modeled Voltage Levels at Peak Loading

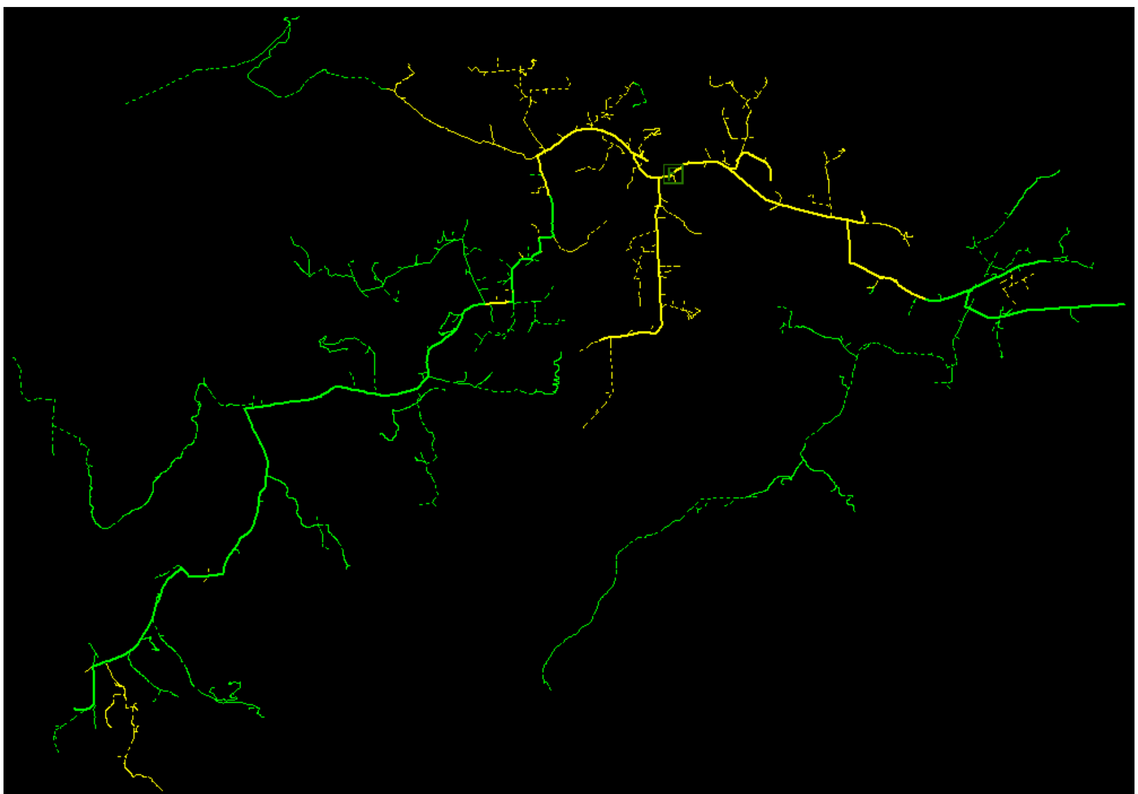


Figure 11. Modeled Voltage Levels at Average Loading

The voltage levels on MIS 431 were re-analyzed after the trunk and lateral reconductoring and other improvements were performed. The feeder was modeled with these proposals in SynerGEE during both Peak loading and Average loading conditions.

Modeled Voltage Levels at Peak Loading after Proposals – Normal Configuration

During peak loading conditions, voltage levels were improved with the new settings changes proposed in the *Voltage Regulator Settings* section. Voltage levels nearest to the Mission Substation, were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.4V. Voltage levels at the farthest extents of the feeder were within optimal levels, with the lowest modeled voltage at 117.1 V. Figure 12 identifies modeled voltage levels on MIS 431 at peak loading and normal configuration.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	52	4.28	120	31
118.00 - 120.00 V	134	19.18	305	78
120.00 - 122.00 V	184	26.25	499	149
122.00 - 124.00 V	519	49.74	1780	398
124.00 - 126.00 V	237	17.61	767	160
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading after Proposals - Normal Configuration

During average loading conditions, voltage levels were improved with the new settings changes proposed in the *Voltage Regulator Settings* section. Voltage levels nearest to the Mission Substation, were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.4V. Voltage levels at the farthest extents of the feeder were within optimal levels, with the lowest modeled voltage at 119.9 V. Figure 13 identifies modeled voltage levels on MIS 431 at average loading and normal configuration.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	32	2.53	48	18
120.00 - 122.00 V	187	24.71	262	110
122.00 - 124.00 V	485	57.74	930	402
124.00 - 126.00 V	422	32.10	933	286
126.00 - 140.00 V	0	0.00	0	0

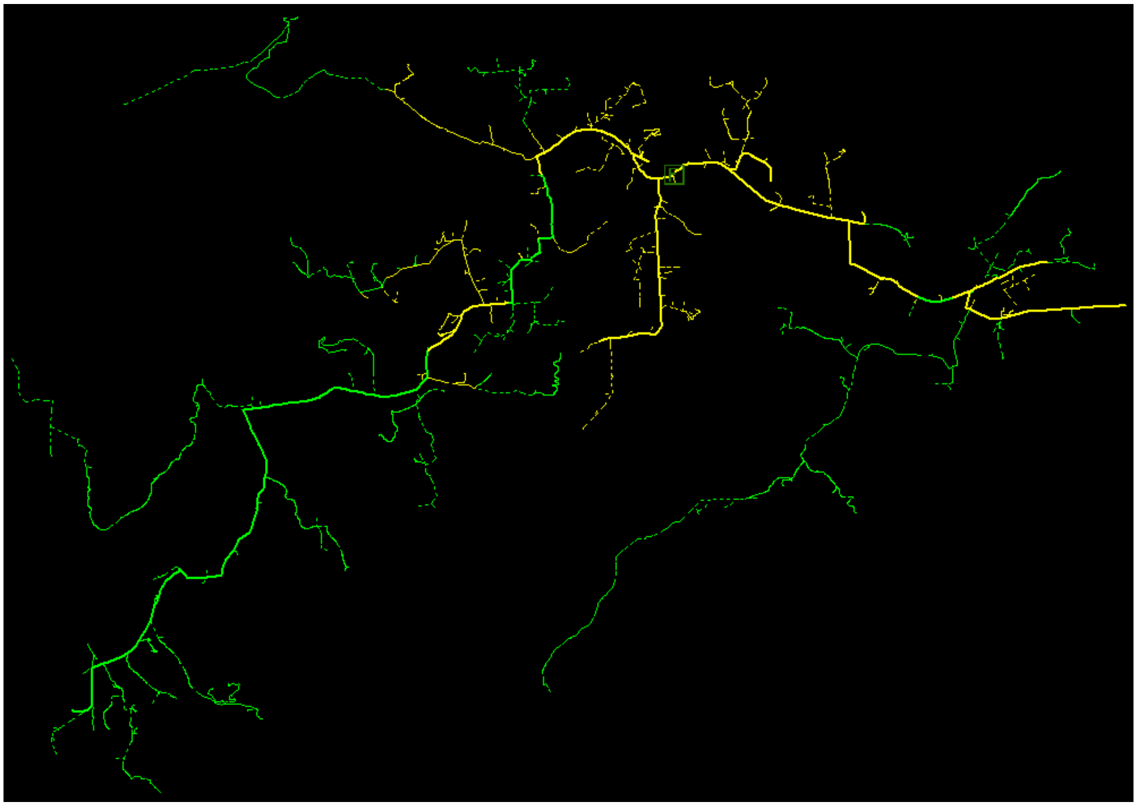


Figure 12. Peak Loading Voltage Levels after Proposals, Normal Configuration

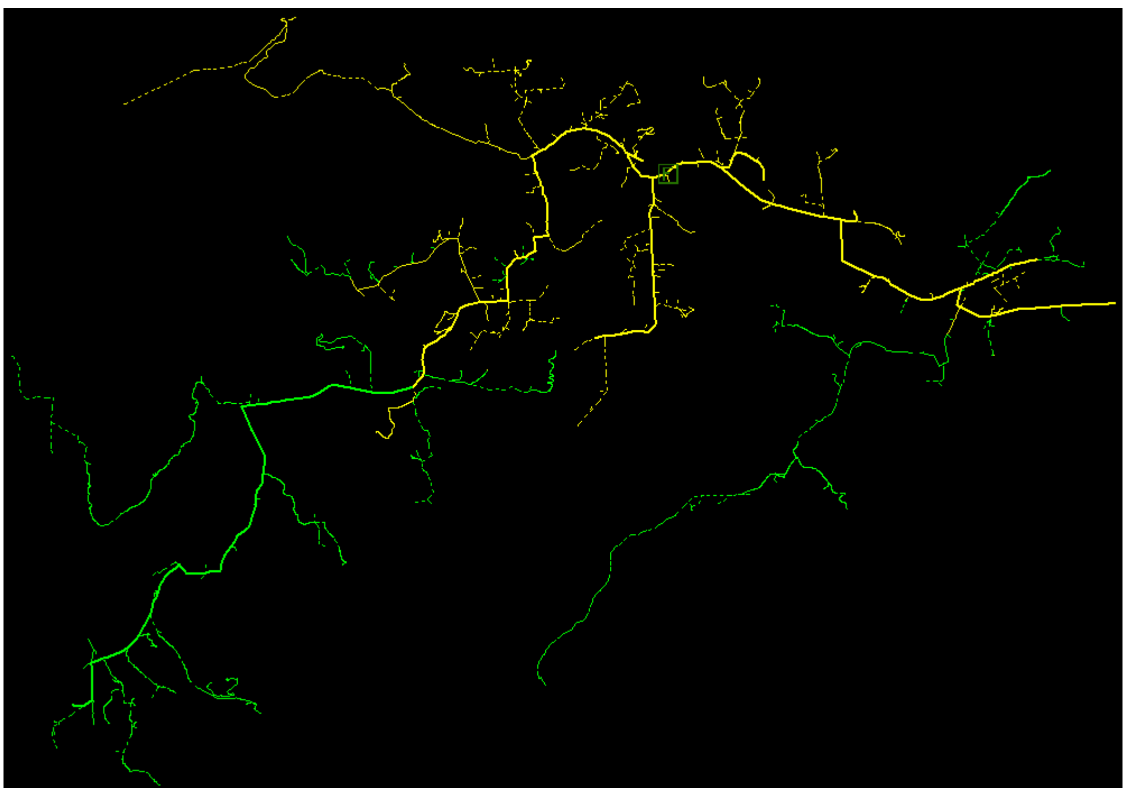


Figure 13. Average Loading Voltage Levels after Proposals, Normal Configuration

The installation of the ZC448R switch between MIS 431 and PIN 443 will create a three-phase remotely operable tie between the feeders. The feeder was modeled with these proposals in SynerGEE during both Peak loading and Average loading conditions to ensure that adequate voltage levels are provided adequate when load is transferred.

Modeled Voltage Levels at Peak Loading after Proposals – Serving PIN 443 to the C445 from MIS 431

Voltage levels nearest to the Mission Substation were elevated, however the majority of the feeder was modeled with optimal or acceptable ANSI Range B voltages. The maximum voltage modeled on the feeder occurred near the substation at approximately 126.9V. Although these voltage levels seem high, the models do not incorporate the voltage drop from the point of transformation downstream to the service wire and metering point. Voltage levels at the farthest extents of the feeder were within optimal levels, with the lowest modeled voltage at 118.7 V. Figure 14 identifies modeled voltage levels on MIS 431 at peak loading and serving part of PIN 443 from MIS 431.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	2	0.13	11	2
114.00 - 116.00 V	5	0.42	26	4
116.00 - 118.00 V	25	2.00	89	28
118.00 - 120.00 V	193	16.53	659	284
120.00 - 122.00 V	685	67.05	2648	768
122.00 - 124.00 V	537	53.75	1919	416
124.00 - 126.00 V	462	41.57	1631	395
126.00 - 140.00 V	110	8.00	334	79

Modeled Voltage Levels at Average Loading after Proposals – Serving PIN 443 to the C445 from MIS 431

Voltage levels nearest to the Mission Substation as well as entire MIS 431 feeder was modeled with optimal or acceptable ANSI Range B voltages. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.4V. Voltage levels at the farthest extents of the feeder were within optimal levels, with the lowest modeled voltage at 119.8 V. Figure 15 identifies modeled voltage levels on MIS 431 at peak loading and serving part of PIN 443 from MIS 431.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	41	3.04	63	32
120.00 - 122.00 V	716	67.38	1320	969
122.00 - 124.00 V	783	78.20	1622	649
124.00 - 126.00 V	400	30.61	856	285
126.00 - 140.00 V	79	10.21	110	40

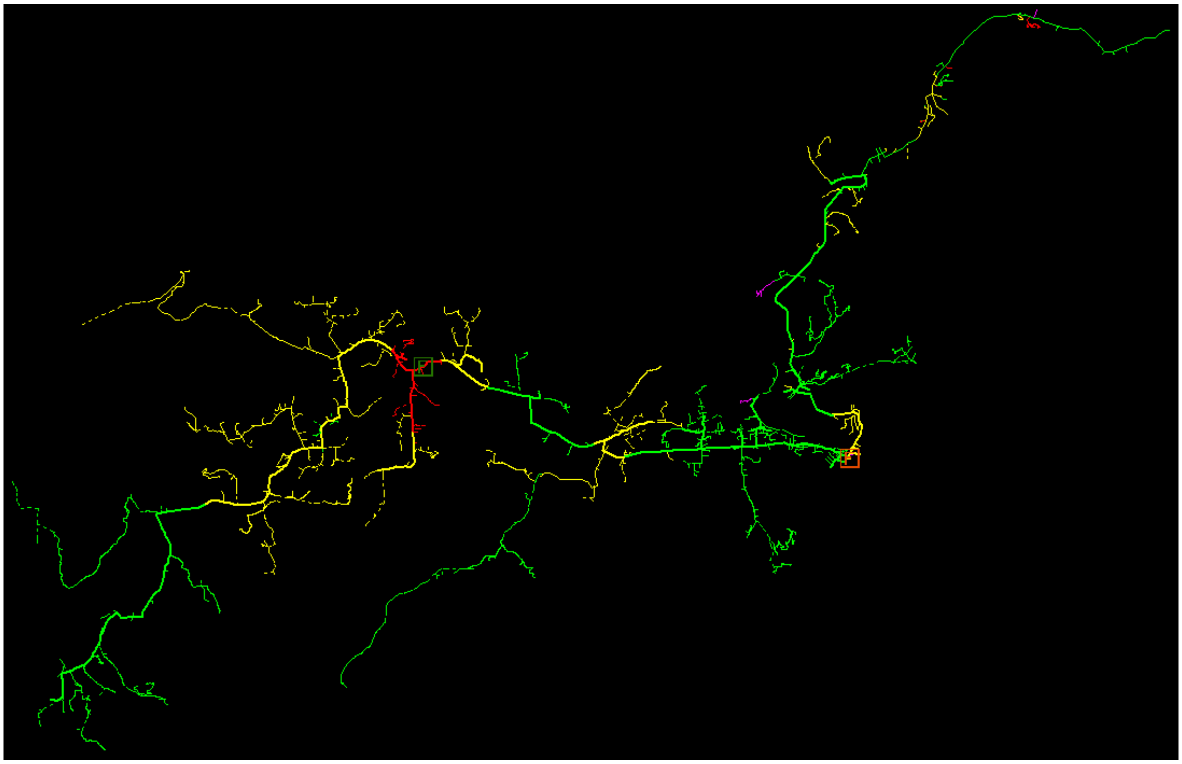


Figure 14. Peak Loading Voltage Levels after Proposals, Abnormal Configuration

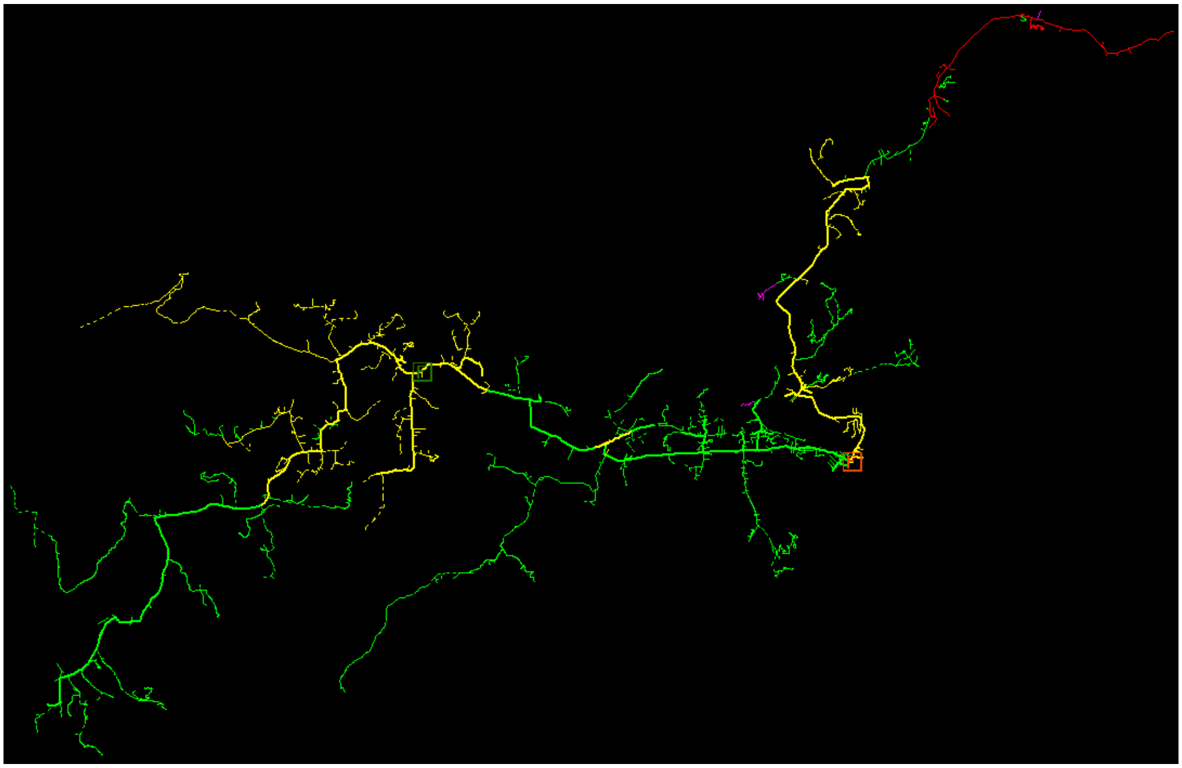


Figure 15. Average Loading Voltage Levels after Proposals, Abnormal Configuration

Modeled Voltage Levels at Peak Loading after Proposals – Serving MIS 431 to the C492R from PIN 443

Voltage levels upstream of the proposed ZC443R were low as well as downstream of the C435R, however the majority of the feeder was modeled with optimal or acceptable voltages for ANSI Range B. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.1V. The lowest modeled voltage was at 107.0 V. These could be raised by adding a stage of midline regulators on PIN 443 or reconductoring part of PIN 443, which is outside of the scope of the Grid Modernization program. It is possible to serve additional load on MIS 431 if additional steps are taken on PIN 443. Figure 16 identifies modeled voltage levels on PIN 443 at peak loading and serving part of MIS 431 from PIN 443.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	448	43.82	1469	413
114.00 - 116.00 V	129	10.74	460	81
116.00 - 118.00 V	286	28.17	951	333
118.00 - 120.00 V	275	21.09	866	251
120.00 - 122.00 V	96	7.84	429	91
122.00 - 124.00 V	266	27.27	1068	244
124.00 - 126.00 V	306	22.83	1363	431
126.00 - 140.00 V	19	2.24	51	17

Modeled Voltage Levels at Average Loading after Proposals – Serving all of MIS 431 from PIN 443

Voltage levels nearest to the Pine Creek Substation as well as entire MIS 431 feeder was modeled with optimal or acceptable voltages for ANSI Range B. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.3V. The lowest modeled voltage was at 113.4 V. Figure 17 identifies modeled voltage levels on PIN 443 at peak loading and serving all of MIS 431 from PIN 443.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	28	1.95	64	19
114.00 - 116.00 V	89	12.10	200	81
116.00 - 118.00 V	365	31.01	685	331
118.00 - 120.00 V	268	27.56	562	265
120.00 - 122.00 V	390	34.46	683	370
122.00 - 124.00 V	342	33.37	569	295
124.00 - 126.00 V	458	38.77	1052	574
126.00 - 140.00 V	79	10.21	111	40

It is recommended for the Regional Operations Engineers to analyze the settings on the existing PIN 443 midline voltage regulators to ensure downstream voltages are appropriate and optimal.

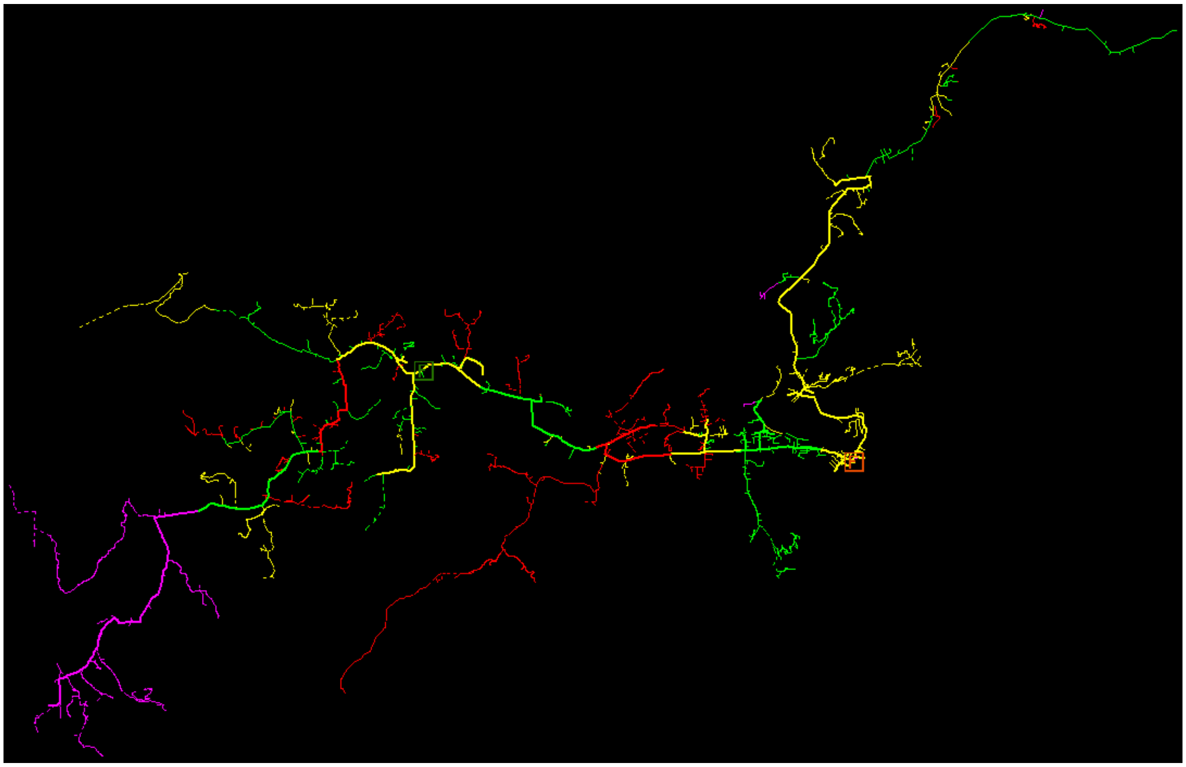


Figure 16. Peak Loading Voltage Levels after Proposals, Abnormal Configuration

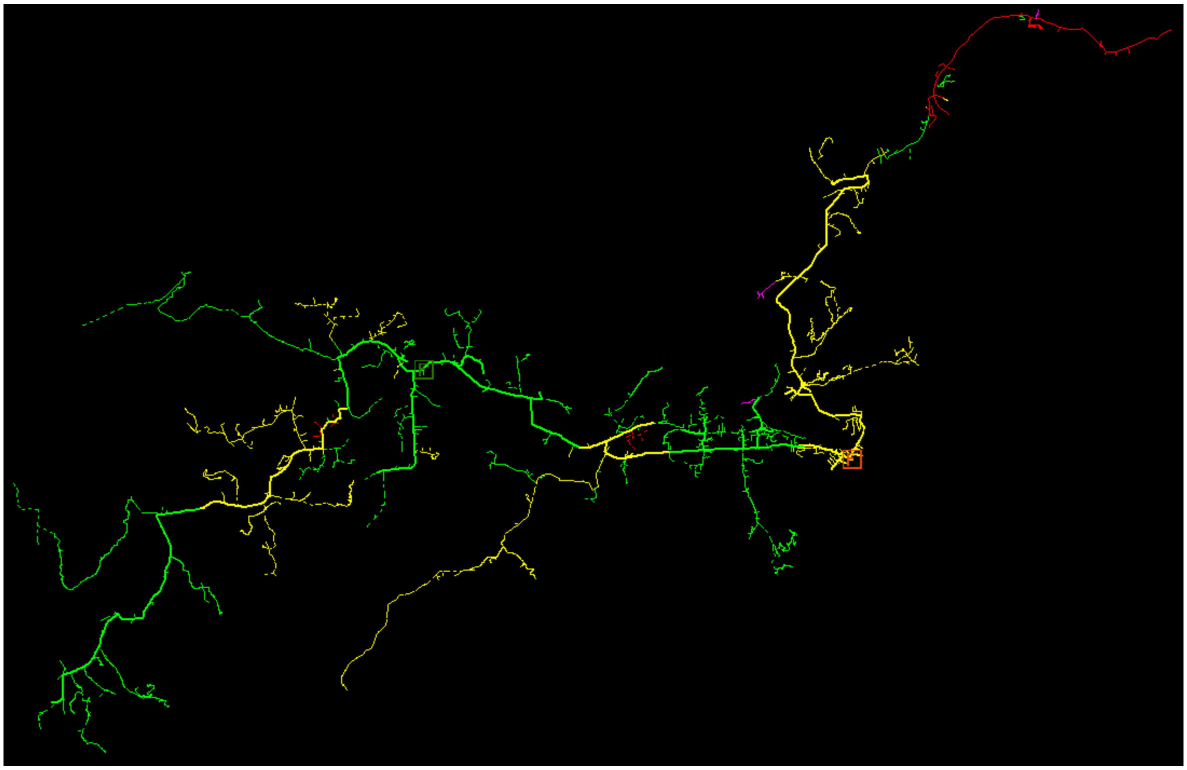


Figure 17. Average Loading Voltage Levels after Proposals, Abnormal Configuration

Voltage Regulator Settings

MIS 431 has two existing stages of voltage regulation: one at the Mission Substation, and another set of midline regulators downstream of the C435R midline recloser. An additional stage of midline voltage regulation is proposed on the east branch of the feeder to support voltage levels during normal configuration and times of switching. The ZC443V midline regulators are proposed for installation west of US Interstate 90 and S Latour Creek Rd in **Polygon 4**.

A group of alternative settings was analyzed to show if there was the potential for improvement. The voltage levels on MIS 431 were re-analyzed and modeled with the voltage regulator settings change proposals in SynerGEE at peak loading conditions, as seen below.

The existing and proposed voltage regulator settings are provided in the table below:

	Existing*		Forward		Reverse	
Forward Settings	**R**	**X**	**R**	**X**	**R**	**X**
MIS 431 Station Regulators	**1.5**	**1.5**	**2.5**	**2.3**	**-**	**-**
MIS 431 Midline Regulators	**4.8**	**1.7**	**6.4**	**2.6**	**-**	**-**
MIS 431 ZC443R Regulators	**-**	**-**	**3.7**	**1.4**	**1.3**	**1.3**

* Settings in METS and SynerGEE as of 6/20/16

The decision to move forward with implementing any changes to the regulator settings will be confirmed, approved, and coordinated by the Regional Operations Engineer. These changes are proposed to illustrate the potential benefits to adjusting the settings.

MIS 431 recently had the newer vintage of voltage regulators with the CL7 control installed, making these devices automation compatible. However the station breaker is a Westinghouse 1970's vintage with ES Recloser and Electro-Mechanical Relays, and is not automation ready. Grid Modernization will notify Substation Engineering of our work on the feeder and the opportunity to upgrade the station breaker, however the decision to upgrade will ultimately be made by Substation Engineering.

Fuse Sizing

Fuse sizing on MIS 431 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and risers. Fuse recommendations for MIS 431 were created by the Regional Operations Engineer in coordination with the Grid Modernization Program Engineer. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Line Losses

The primary trunk conductors on MIS 431 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and Average loading conditions during normal system configuration, and improve voltage levels on the rural feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading.

After the proposed reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections are performed on MIS 431, it is estimated that the peak line losses could approximately be reduced by up to 35.7 kW, while the Average loading line losses could approximately be reduced by up to 14.7 kW. In addition, approximately 128.8 MWh savings could be annually achieved assuming Average loading conditions during normal system configuration.

	Polygon 19
Circuit Length (ft)	13666.8
Current Average kW Losses	22.4
Current Peak kW Losses	54.3
Proposed Average kW Losses	7.7
Proposed Peak kW Losses	18.6
Average kW Loss Savings	14.7
Peak kW Loss Savings	35.7
Reconductor MWh Savings *	128.8

* Estimated Annual Average kW losses

An initial SyngerGEE load study estimates that a total of 194 kW in peak line losses currently exists on MIS 431 (5.44%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved from 194 kW (5.44%) to approximately 114 kW (3.18%).

Peak Values	**Existing**	**Final Proposal**
kW Demand	3577	3577
kW Load	3391	3471
kW Line Losses	194	114
kW Loss %	5.44 %	3.18 %

Transformer Core Losses

The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, "no load losses" are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of an appropriate size.

All transformers on MIS 431 shall be analyzed and "right sized" by the assigned Designer to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP). In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the Designer.

The roughly 618 distribution transformers on MIS 431 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It was determined that approximately 255 transformers may require replacement based on right sizing and the TCOP criteria replacements. The replacement of these transformers will result in an estimated 14.65 kW reduction in core losses. This equates to an annual savings of roughly 128.33 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

MVAR and MW data on MIS 431 is not monitored through SCADA. Without detailed real and reactive power flow data, there is not historical evidence available to make an informed decision for correcting the power factor on MIS 431 as part of the Grid Modernization project. Accurate power factor correction can be completed at a later date once a history of loading information is established through distribution line automation devices or SCADA monitoring at the Mission Substation.

There is one existing 600 kVAR fixed capacitor bank on MIS 431 located downstream of the existing C435R device on the west branch.

Automation

Distribution Automation was analyzed for deployment on MIS 431 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on MIS 431.

The following automation devices will be deployed or relocated on the feeder:

Device Number	Location	Status	Device Type
ZC432R*	S of Canyon & Dredge	N.C.	Viper – Recloser
ZC434R	W of Canyon & River Road	N.C.	Viper – Recloser
ZC435R*	E of Hwy 3 & 4th of July Creek	N.C.	Viper – Recloser
ZC439R*	W of Canyon & River Road	N.C.	Viper – Recloser
ZC448R*	S of Hunt Gulch & Hughes	N.O.	Viper – Switch
ZC433V	W of I-90 & Latour Creek Rd	N.C.	Midline Voltage Regulator

* Existing line device that is being replaced with automated device

Figure 18 illustrates the proposed automation device locations on MIS 431.

MIS 431 recently had the newer vintage of voltage regulators with the CL7 control installed, making these devices automation compatible. However the station breaker is a Westinghouse 1970's vintage with ES Recloser and Electro-Mechanical Relays, and is not automation ready. Grid Modernization will notify Substation Engineering of our work on the feeder and the opportunity to upgrade the station breaker, however the decision to upgrade will ultimately be made by Substation Engineering.

The proposed automation line device locations identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with either the Regional Operations Engineer, and General Foreman or District Manager to address any construction or Standards related concerns with the selected location.

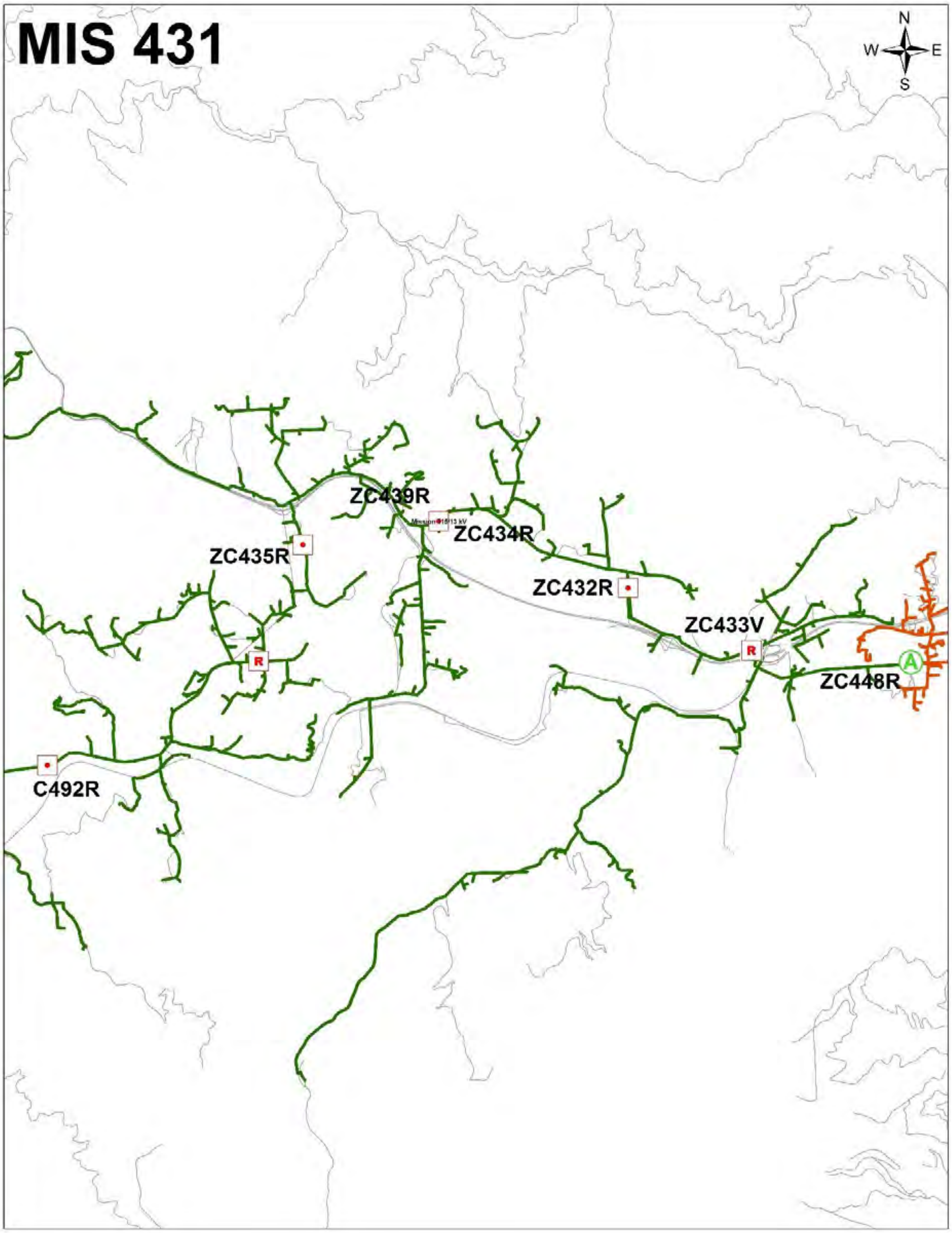


Figure 18. MIS 431 Proposed Automation Device Locations

Open Wire Secondary

Open wire secondary districts have been analyzed for replacement on MIS 431 in accordance to the Distribution Feeder Management Plan (DFMP). After analyzing the feeder through field observations, there were not any vertical or horizontal open wire secondary districts identified on MIS 431. The Designer shall consult the DFMP if open wire secondary districts are discovered in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Transformers

All transformers on MIS 431 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Poles

All poles and structures on MIS 431 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the *Wood Pole* section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable.

Vegetation Management

Vegetation management shall be employed on MIS 431 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

MIS 431 has been divided into 28 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager. The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Engineer by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
  - Install Viper recloser (ZC432R, N.C.) south of Canyon Rd & Dredge Rd and remove existing C432R Kyle recloser.
  - Install Viper recloser (ZC434R, N.C.) just outside of the Mission Substation on the east branch and remove the existing C434 switch.
- **Polygon 4**
  - Install midline voltage regulators (ZC433V, N.O.) west of US Interstate 90 & S Latour Creek Rd.
- **Polygon 5**
  - Analyze the condition of the existing poles and wire on the 1590' lateral of 6CR, 2A peak (9% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 6**
  - Install new B-phase 4 ACSR conductor to existing lateral on Latour Creek Road primary (approximately 11,100') to create a 2-phase lateral. This existing lateral is currently served by only C-phase 4 ACSR.
  - Transfer portion of 4 ACSR OH lateral south Latour Creek Road (≈15 A peak) from C-phase to B-phase.
- **Polygon 7**
  - Install Viper switch (ZC4448R, N.O.) south of Hunt Gulch Rd & Hughes Rd and remove existing C448 open cutouts.
- **Polygon 8**
  - Transfer portion of 4 ACSR OH lateral south Latour Creek Road (≈15 A peak) from C-phase to B-phase.
- **Polygon 10**
  - Install Viper recloser (ZC439R, N.C.) just outside of the Mission Substation on the west branch and remove the existing C439 switch.

- **Polygon 11**
    - Analyze the condition of the existing poles and wire on the 920’ lateral of 8CW, 5A peak (17% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
    - Analyze the condition of the existing poles and wire on the 380’ lateral of 8CW, 1A peak (3% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
    - Analyze the condition of the existing poles and wire on the 2940’ lateral of 6CR, 1A peak (6% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 14**
    - Analyze the condition of the existing poles and wire on the 7180’ lateral of 6CW, 11A peak (25% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 15**
    - The 1CN15 underground cable at the west end of this polygon experienced multiple faults prior to the mid-1990’s. At that time, the local office elected to step down the primary voltage to 2400/4200 V on this cable to preserve the life and mitigate future faults. This resulted in two transformers in series to provide the 2400/4200 V. The assigned Designer should replace the existing two transformer in series to provide a single transformer of the appropriate rating that directly steps the voltage down from 7620/13200 V to 2400/4300 V.
    - The assigned Designer should investigate the existing 4 ACSR and 1CN15 cable west of the step-down transformer to determine if the conductor or replace requires replacement in accordance with the DFMP. In addition, the lateral should be investigated to determine if relocation or reconfiguration would provide significant improvements to the reliability of the downstream customer.
- **Polygon 16**
    - Install Viper recloser (ZC435R, N.C.) east of Idaho Hwy 3 & 4th of July Creek Rd and remove existing C435R Kyle recloser.
    - Analyze the condition of the existing poles and wire on the 970’ lateral of 6CR, 1A peak (3% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 17**
    - Analyze the condition of the existing poles and wire on the 1900’ lateral of 6CR, 1A peak (5% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
    - Analyze the condition of the existing poles and wire on the 810’ lateral of 6CR, 3A peak (18% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 18**
    - Analyze the condition of the existing poles and wire on the 2050’ lateral of 6CR, 1A peak (4% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.

- **Polygon 19**
  - Reconductor 3Φ trunk south of I-90 & Idaho Highway 3 to 2/0 ACSR primary with a 2/0 ACSR neutral (approximately 13,600').
- **Polygon 22**
  - Analyze the condition of the existing poles and wire on the 1160' lateral of 6CR, 1A peak (1% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 24**
  - Analyze the condition of the existing poles and wire on the 360' lateral of 6CR, 5A peak (28% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 280' lateral of 6CR, 2A peak (12% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 5770' lateral of 6CR, 2A peak (9% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 28**
  - Transfer 2CN15 URD lateral (≈16 A peak) from A-phase to C-phase. This will help mitigate downstream low voltage issues due to a heavily loaded A-phase, and reduce the loading on the upstream conductors.
  - Analyze the condition of the existing poles and wire on the 1900' lateral of 6CR, 1A peak (4% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 6640' lateral of 6CR, 2A peak (12% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.

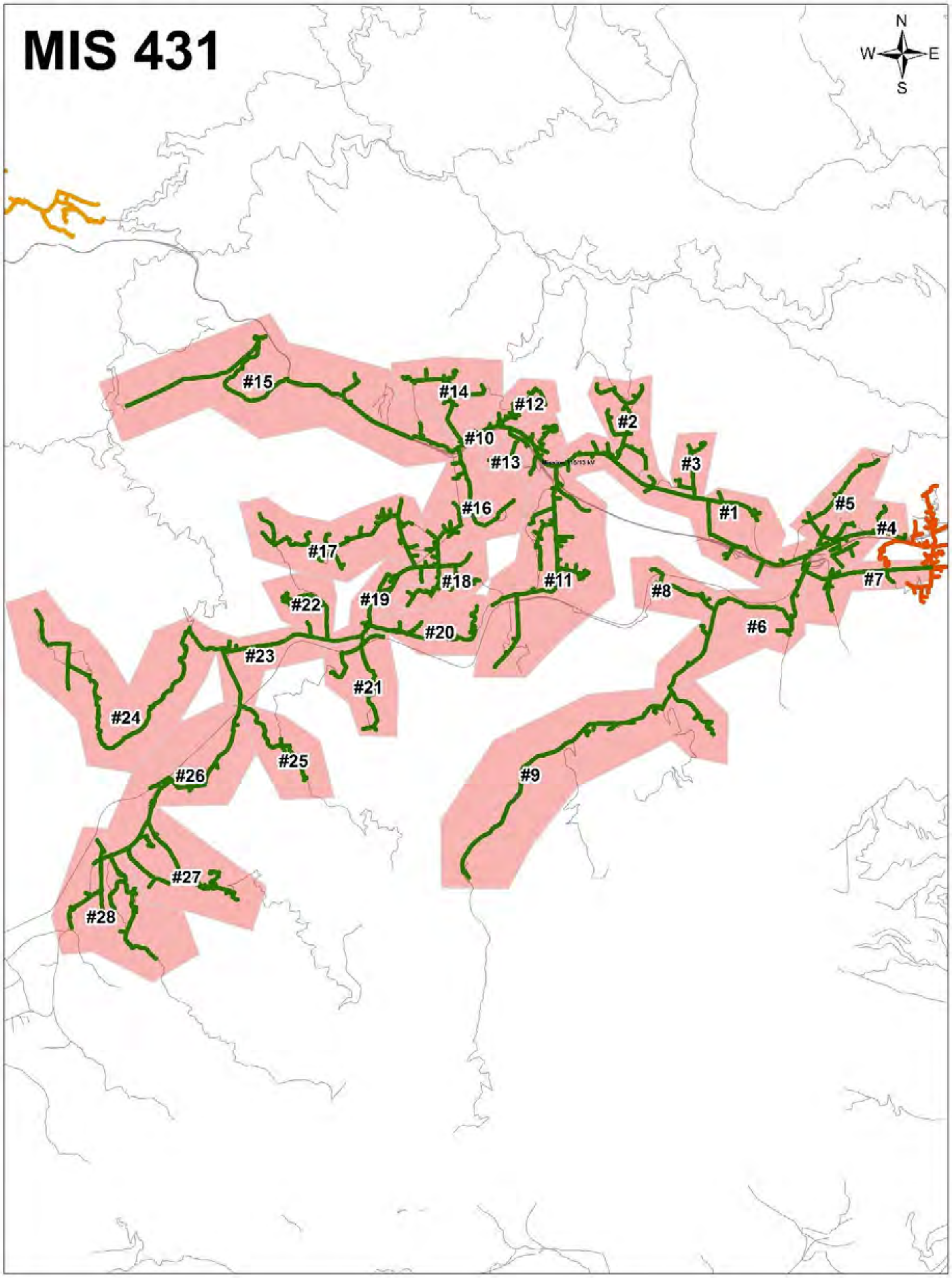


Figure 19. MIS 431 Polygon Numbers

Report Versions

Version 1 8/22/16 – Finalization of the initial report

Grid Modernization Program

ORO 1280 Baseline Report

2/3/2016

Version 2

Prepared by Shane Pacini

Index

Overview

The following report was established to create a baseline analysis for ORO 1280 as part of the Grid Modernization program.

ORO 1280 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Orofino Substation in the Grangeville service area. The feeder has 8.55 miles of feeder trunk with 21.75 miles of laterals that serves predominately rural residential loads, including the town of Orofino, ID. Additional feeder information is layered throughout the sections of this report. ORO 1280 is represented as a blue color on the system map shown in Figure 1.

Figure 1. ORO 1280 One-Line Diagram

Peak Loading

Three phase ampacity loading from SCADA monitoring at the ORO 1280 substation circuit breaker was analyzed from 12/10/12 to 12/09/14. The following loading values were established for ORO 1280 during this timeframe. Loading information has been removed from selected timeframes due to temporary changes in loading from switching (verified through PI). ORO 1280 is a winter peaking feeder, with comparable peak values observed between December and February. The values below reflect the adjusted data set. The peak loading values for each phase are used in the SynerGEE model analysis for the feeder, except where median load values are noted for establishing kW losses.

	Before Balancing	
	Peak	Median
A-Phase	198.0 A	74.0 A
B-Phase	108.0 A	41.0 A
C-Phase	136.0 A	57.0 A

	After Balancing	
	Peak	Median
A-Phase	147 A	54.9 A
B-Phase	160 A	60.7 A
C-Phase	136 A	57.0 A

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from SynerGEE at the model's initial configuration before balancing.

	Estimated Peak Loading Conditions		
	Demand kVA*	Connected kVA*	% Loading
A-Phase	1579	3130	50.44%
B-Phase	845	2192	38.55%
C-Phase	1084	2125	51.01%

* Connected kVA per Phase in SynerGEE as of 12/29/14

	Estimated Median Loading Conditions		
	Demand kVA*	Connected kVA*	% Loading
A-Phase	590	3130	18.85%
B-Phase	327	2192	14.92%
C-Phase	454	2125	21.36%

* Connected kVA per Phase in SynerGEE as of 12/29/14

Feeder Balancing

Accurate load balancing can be achieved on ORO 1280 due to the three phase ampacity monitoring at the Orofino 1280 substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively before balancing:

	Connected KVA per Phase*
A-Phase	3119 kVA
B-Phase	2187 kVA
C-Phase	2180 kVA

* Connected kVA per Phase in AFM as of 12/29/14

The following list provides the laterals and dips that can effectively balance the load on the phases between numerous strategic locations on the feeder, shown in Figure 2. As a whole, the trunk sections and multi-phase laterals on ORO 1280 are relatively balanced, however opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate these changes into their appropriate polygon designs:

1. **Polygon 2** – transfer 1Φ OH lateral west of Vida & H (≈12 A) from AΦ to BΦ.
2. **Polygon 4** – transfer 1Φ OH lateral north of Brown & C (≈41 A) from AΦ to BΦ.

The result of these load transfers are listed in the table below. These changes will approximately balance the feeder at the substation breaker to 147/160/136, as well as between the numerous strategic points to approximately sectionalize the feeder.

	Existing			Proposed		
	A-Phase	**B-Phase**	**C-Phase**	**A-Phase**	**B-Phase**	**C-Phase**
Station Breaker	198	108	136	**147**	**160**	**136**
E of Michigan & H	59	78	105	59	78	105
W of Michigan & H	109	28	31	70	65	31
S of Michigan & H	28	4	6	16	15	6
N of Michigan & C	63	6	17	22	47	17

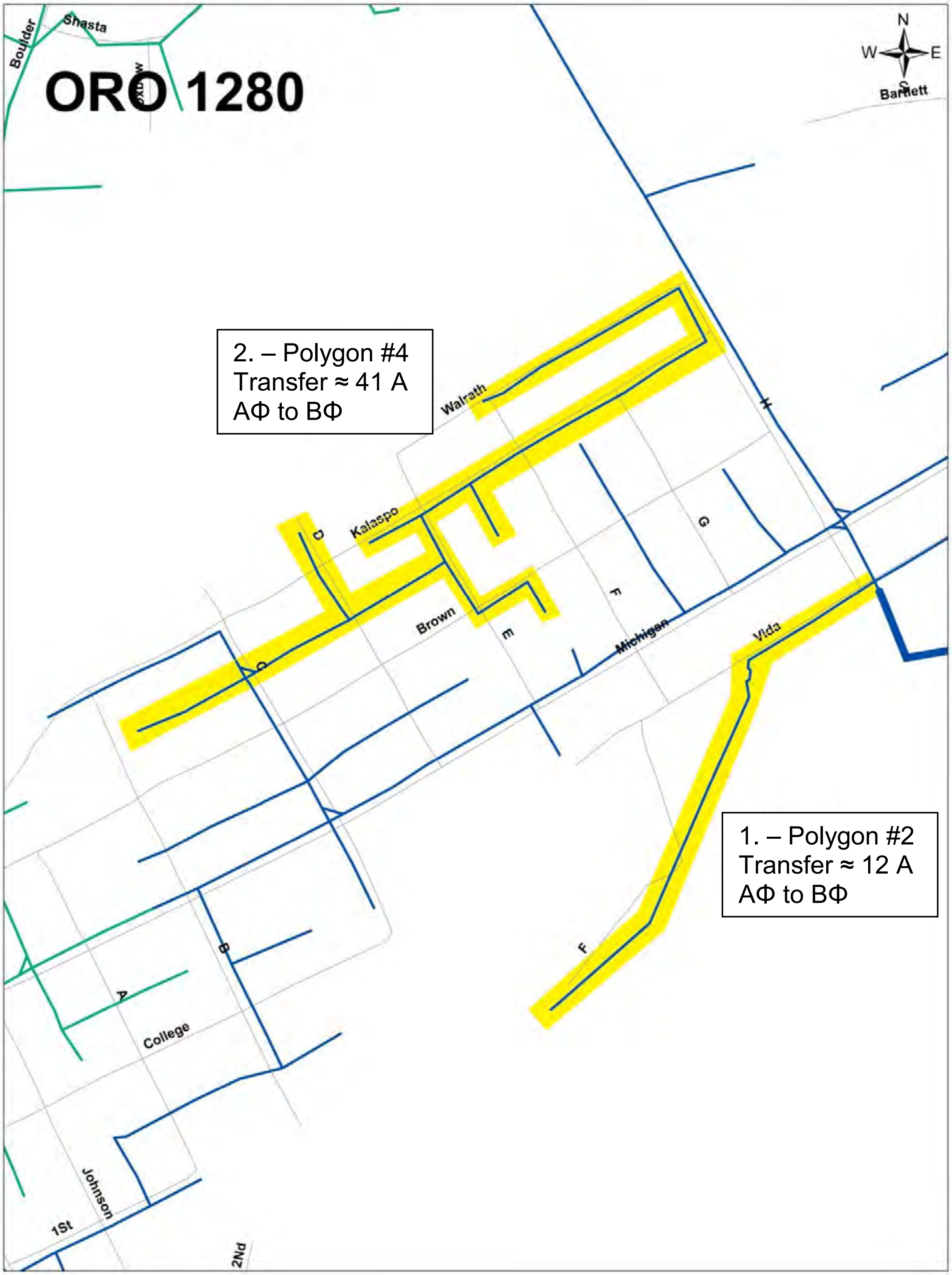


Figure 2. Feeder Balancing – Recommended Phase Changes

Conductor

All primary conductors on ORO 1280 were analyzed in SynerGEE using the balanced peak ampacity values identified above (147/160/136). Specific attention was given to conductors that were potentially overloaded, have relatively high line losses, serve areas with unacceptable voltage quality (primarily during peak conditions), and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on ORO 1280, as well as the proposals for improving the efficiency and performance of the feeder.

The respective Designer for each polygon will be responsible for incorporating all proposed conductor associate design changes in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of conductor requiring attention.

Transmission Engineering should be consulting for any reconductoring or pole loading changes performed on Transmission structures where there is Distribution underbuild to ensure the pole class is adequate for the loading on the structure.

Feeder Reconfiguration

There is latitude within the Grid Modernization program to identify and relocate sections of the feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when the benefits of rebuilding in place are negligible, or if reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

ORO 1280 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, there are two specific sections of the primary feeder trunk that could warrant reconfiguration based on the current design placement. In both sections, the primary trunk is largely accessible off of secondary roads, however relocating the entire trunk along Michigan Avenue would: eliminate unnecessary railroad crossings, eliminate guying and anchoring, and eliminate parallel overhead laterals in the near vicinity of the primary trunk.

These potential sections are illustrated in Figure 3. These highlighted sections should not be interpreted as mandatory for reconfiguration, or as being the only sections that are candidates for reconfiguration. The assigned Designer is responsible to further analyze each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in indentifying locations where configuration or conversion is sensible. Designers should pay special attention to the number of stubbed poles or poles identified for replacement on each section of line, as the cumulative effect of these numerous poles could greatly support the proposal to configure or relocate.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer. It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconfiguration or conversion to underground prior to commencing the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and to assist in identifying the appropriate material and equipment to install.

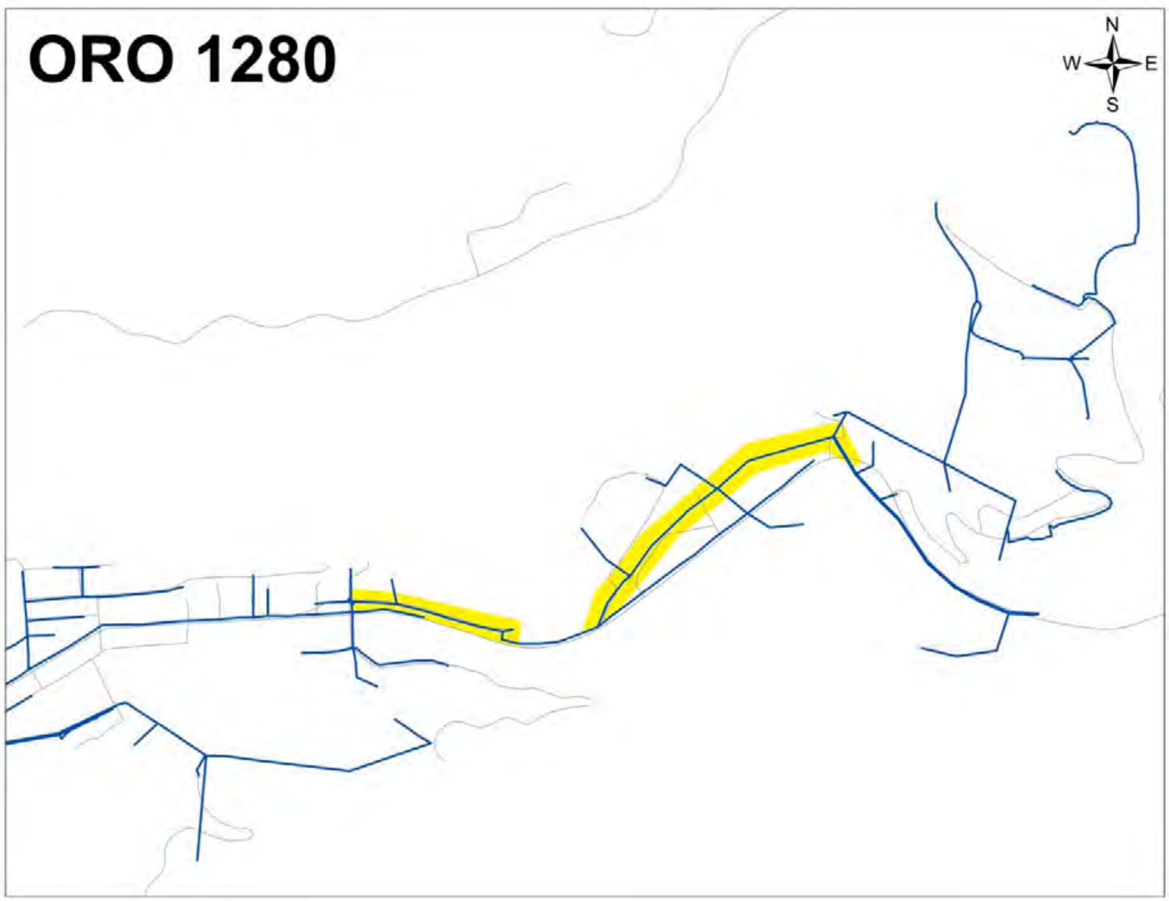


Figure 3. ORO 1280 Potential Sections for Reconfiguration

Trunk

The primary trunk conductors on ORO 1280 are sized appropriately to meet peak loading conditions during normal system configuration. The majority of the trunk is currently conductored with 1/0 ACSR, 2/0 ACSR, and 4/0 ACSR in overhead applications and 1CN15 in underground applications. All sections of 1/0 ACSR are loaded under 35% of carrying capability during peak loading scenarios, and therefore there is minimal support to upgrade this conductor type. Line losses on the trunk are currently in the desired range for this scenario, which has been aided by balancing the feeder and already utilizing some of the more efficient conductor options in the current material standards. In addition, there are no voltage quality concerns that would be improved through reconductoring the trunk.

- Reconductor 3Φ trunk east of Michigan & H to 2/0 ACSR with a 2/0 ACSR neutral (approximately 300') in **Polygon 5**. This section of trunk is currently served and 6CU conductor that is heavily loaded, as well as being undersized for serving as primary feeder trunk. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. Figure 4 illustrates the primary trunk reconductor on this section.

The designs to reconductor shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

Laterals

The primary lateral conductors on ORO 1280 are sized appropriately to meet peak loading conditions during normal system configuration. The analyzed models do not suggest reconductoring any of the laterals on the feeder based on peak loading conditions, downstream service voltage levels, or relatively high line losses.

- There is an existing three-phase lateral on the east end of ORO 1280 in **Polygon 9** that is abnormally constructed and should be rebuilt to adhere to Avista's construction standards. The lateral is configured with two primary A-phase conductors and one primary B-phase conductor. This non-standard construction resulted from storm damage and the reframing of the pole. The reframing resulted in the inability to jumper C-phase appropriately, therefore A-phase was vertically jumpered to serve two of the conductors on the three-phase lateral. The assigned Designer should reconfigure the lateral and the buck pole off of the primary trunk to incorporate A,B, and C-phase. The existing 4ACSR primary conductors are adequate to serve the load on the three-phase lateral. Figure 5 illustrates the location of the three-phase lateral.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs. It may be determined that additional laterals could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with the South Region Operations Engineer to validate any future proposals to address lateral conductors based on the conditions identified through field analysis.

Feeder Tie

ORO 1280 currently contains two overhead feeder ties to ORO 1281. Both of these ties contain single phase switching devices. The existing blade disconnect switches east of Main & 1st in **Polygon 3** will be replaced with a Viper tie switch (ZL1541R, N.O.). The existing solid door cutouts east of Michigan & A in **Polygon 3** will be replaced with a three-phase gang-operated manual air switch (1527, N.O.). Figure 10 illustrates the location of the devices on the feeder.

The two feeder ties are currently conductored with 1/0 ACSR or 4/0 ACSR. Since the 4/0 ACSR section is also feed upstream by 1/0 ACSR (approximately 2000'), the smaller conductor is ultimately the limiting factor when serving periodic loads from ORO 1281. The entire load of ORO 1281 cannot be transferred to ORO 1280 during peak load. However roughly 160 A of balanced load can be picked up without overloading any trunk conductors on ORO 1280, with the peak loading assumptions detailed in the previous *Peak Loading* section. The SynerGEE models suggest that ORO 1280 is able to serve both ORO 1280 and ORO 1281 during the median loading assumptions detailed in the previous *Peak Loading* section, while staying well below the conductor ampacity limits.

Reconductoring either feeder tie or upstream trunk is not recommended as part of the Grid Modernization work unless frequent load transfers are expected where ORO 1280 is serving significant load from ORO 1281.

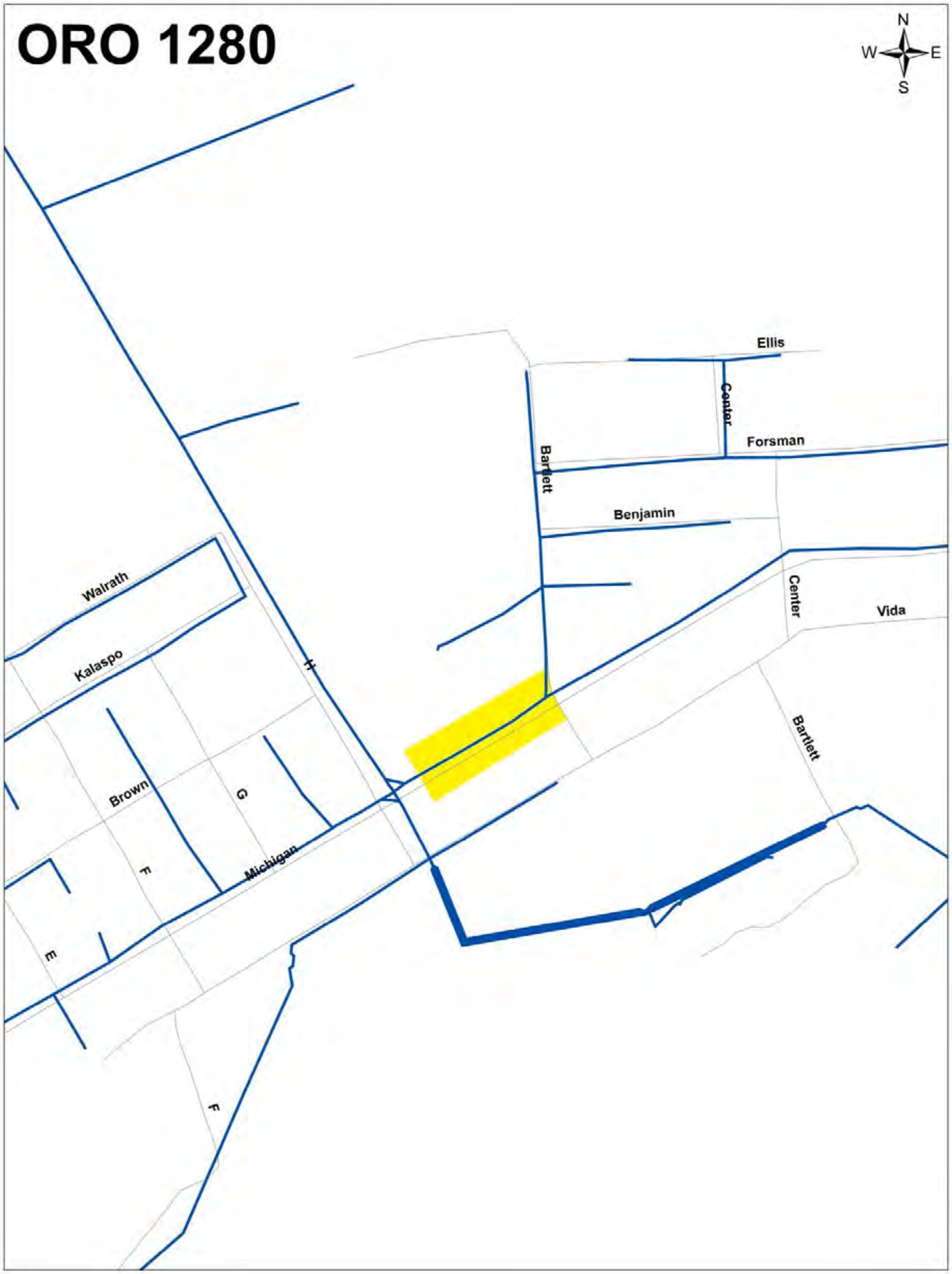


Figure 4. Polygon 5 Feeder Trunk Reconductor to 2/0 ACSR

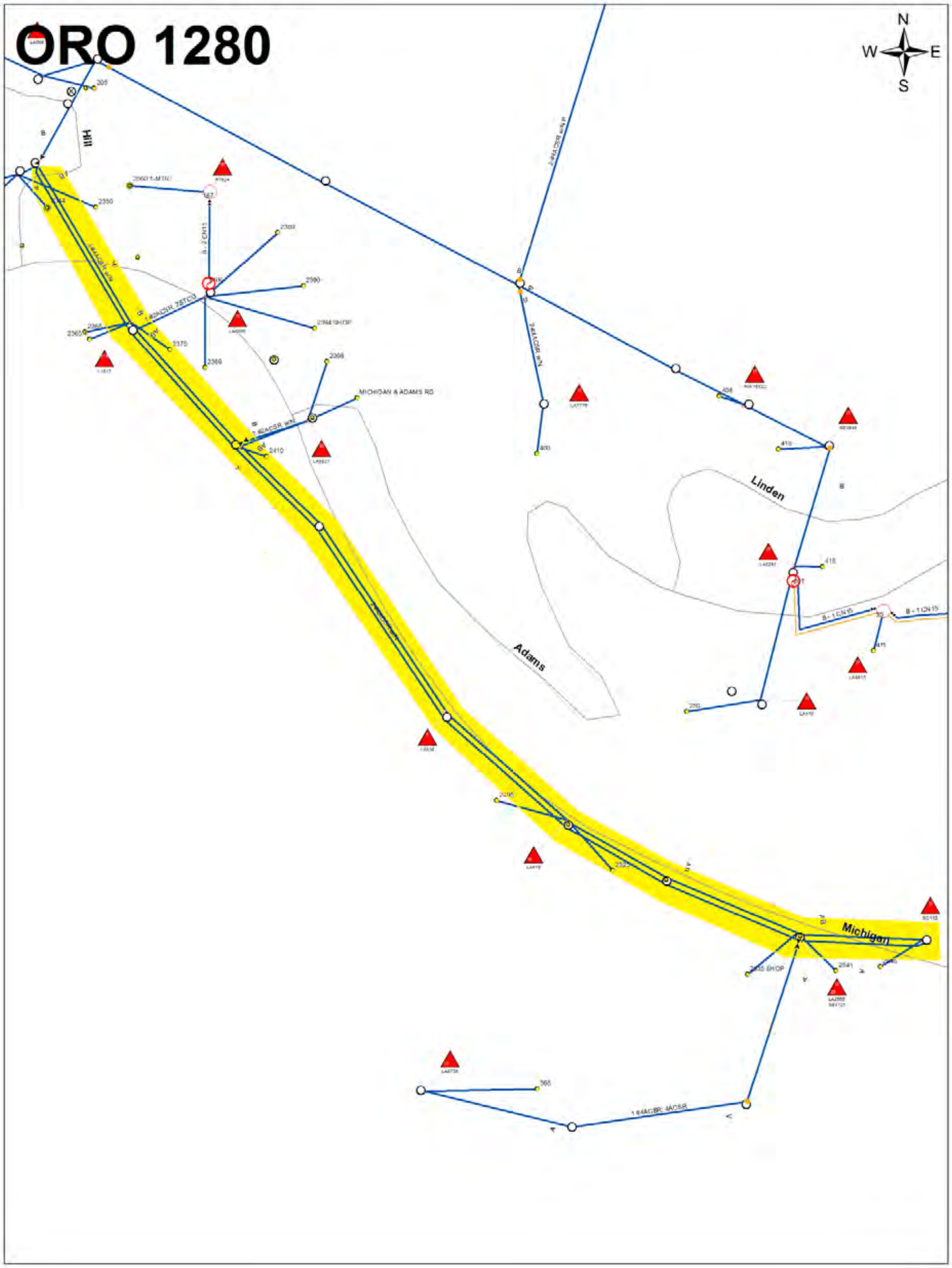


Figure 5. Polygon 9 Non-Standard Three Phase Lateral

Voltage Quality

The loading on ORO 1280 was first balanced between phases to eliminate the unnecessary overloading of phases which may exacerbate voltage quality problems. ORO 1280 needed to be effectively balanced at numerous switching and sectionalzing points on the feeder. These proposals were previously outlined in the *Feeder Balancing* section of this report. ORO 1280 was then analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable limit required by the NESC (114V-126V). The feeder was modeled in SynerGEE during both peak loading and median loading conditions.

- The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to ORO 1280. During peak loading conditions, voltage levels remained within the allowable limits, with the highest voltages near the Orofino Substation. The maximum voltage modeled was approximately 125.2V, while the lowest voltage was 122.0V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	177	9.02	1801	468
124.00 - 126.00 V	83	3.25	1172	117
126.00 - 140.00 V	0	0.00	0	0

- Again, the voltage levels on the feeder were analyzed before balancing load, however this time during median loading conditions. This scenario saw slightly higher voltage levels across the feeder, however relatively high voltage levels are still present near the Orofino Substation. The maximum voltage modeled was approximately 124.4V, while the lowest voltage was 122.8V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	154	7.37	516	380
124.00 - 126.00 V	106	4.91	386	205
126.00 - 140.00 V	0	0.00	0	0

The voltage levels on ORO 1280 were re-analyzed after the short primary trunk reconductoring and balancing efforts were identified. The feeder was modeled with these proposals in SynerGEE during both peak loading and median loading conditions, as seen below.

- During peak loading conditions, voltage levels remained within the allowable limits. Relatively high voltage levels occurred closer to the substation as to be expected, including the town of Orofino. The majority of the feeder trunks were estimated between 124V-125V, while the farthest east registering between 122V-123V. The maximum voltage modeled was approximately 124.6V, while the lowest voltage was 122.1V. Figure 6 represents service level voltages at peak load conditions.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	80	4.64	762	214
124.00 - 126.00 V	180	7.63	2229	371
126.00 - 140.00 V	0	0.00	0	0

- During median loading conditions, voltage levels remained within the allowable limits, and roughly comparable to levels during peak loading conditions. The higher voltage levels occurred closer to the substation as to be expected, including the town of Orofino. The majority of the feeder trunks were estimated between 123V-124V, while the farthest east registering between 122V-123V. The maximum voltage modeled was approximately 124.7V, while the lowest voltage was 122.9. Figure 7 represents service level voltages at mediam load conditions.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	56	3.74	181	102
124.00 - 126.00 V	204	8.53	724	483
126.00 - 140.00 V	0	0.00	0	0

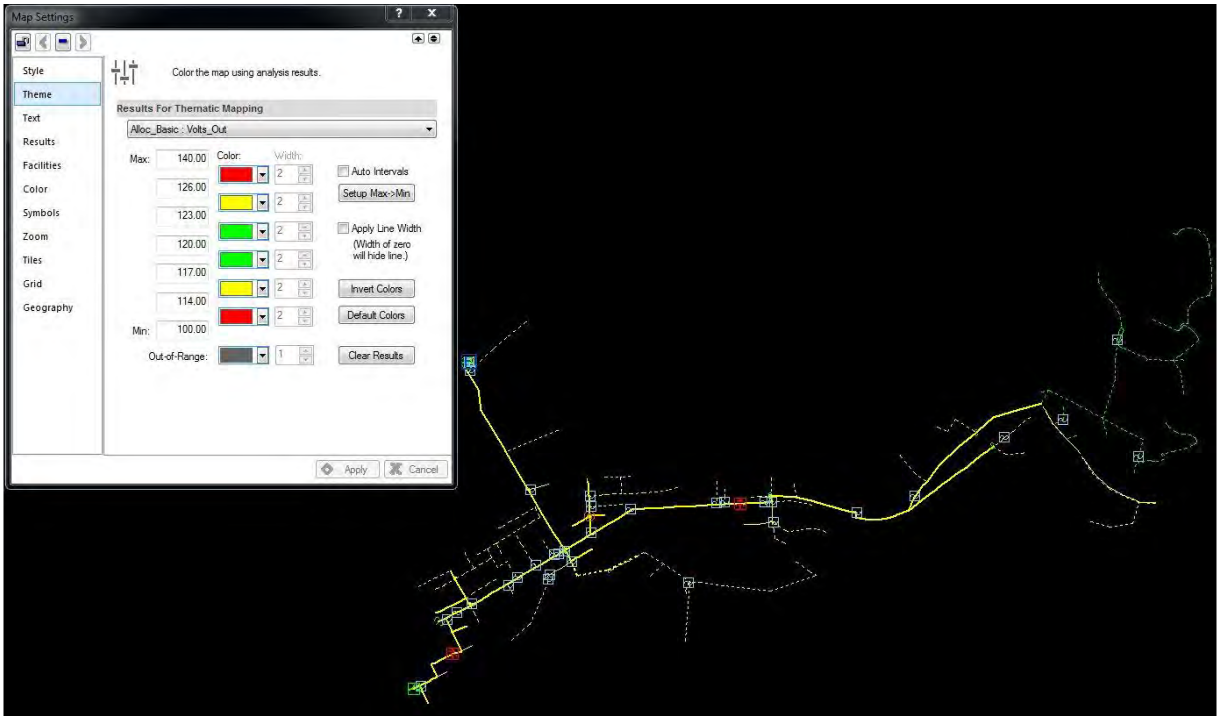


Figure 6. Service Voltage Levels at Peak Load Conditions

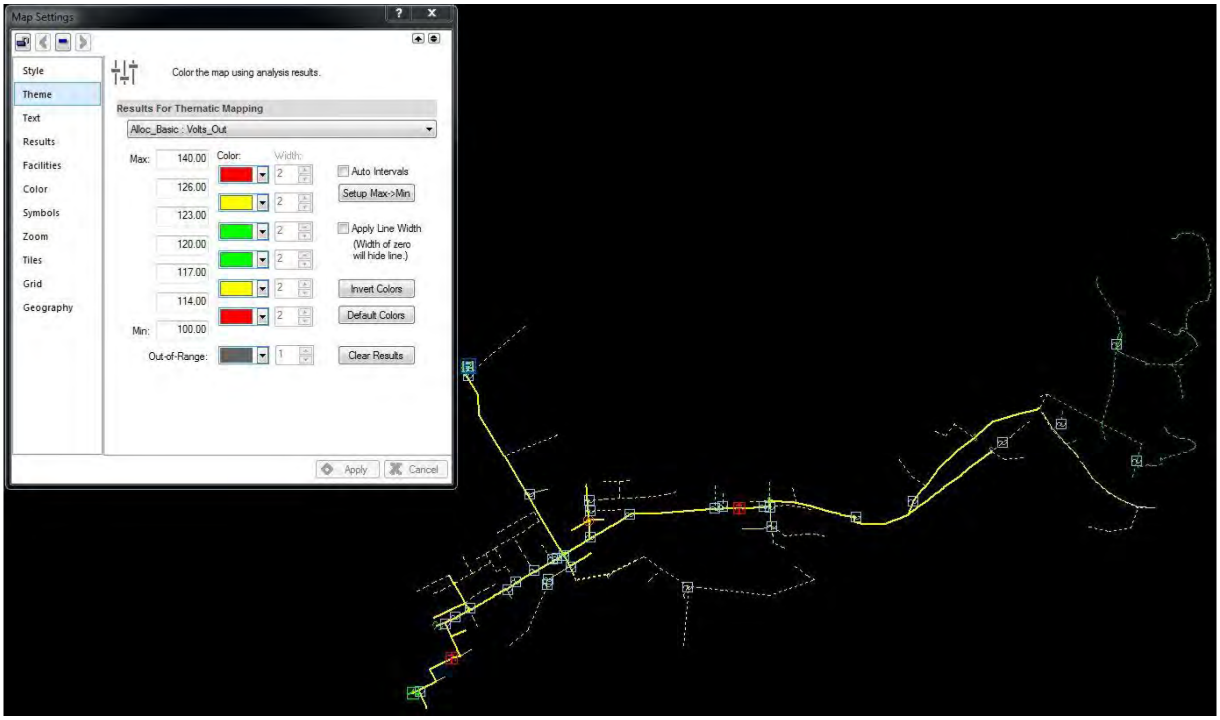


Figure 7. Service Voltage Levels at Median Load Conditions

Voltage Regulator Settings

ORO 1280 has one existing stage of voltage regulation at the Orofino Substation. The voltage levels on the feeder were modeled in SynerGEE during both peak loading and median loading conditions. The voltage levels across ORO 1280 remain between 121.3V-124.5V in all modeled scenarios. The existing settings produce results that are acceptable and appropriate to provide allowable voltage levels on ORO 1280. There is not an overwhelming need to make any changes to the station voltage regulators if field reports confirm that these settings have proven to be consistently accurate.

However, a group of alternative settings was analyzed to show if there was the potential for improvement. It was determined that the voltage levels on the feeder could be refined and slightly lowered by adjusting the existing settings. The voltage levels on ORO 1280 were re-analyzed and modeled with the voltage regulator setting change proposals in SynerGEE during both peak loading and median loading conditions, as seen below.

The decision to move forward with implementing any changes to the regulator settings will be confirmed, approved, and coordinated by the South Region Operations Engineer. These changes are proposed to illustrate the potential benefits to adjusting the settings.

The existing and proposed voltage regulator settings are provided in the table below:

	Existing		Proposed	
Forward Settings	**R**	**X**	**R**	**X**
ORO 1280 Station Regulators	**3**	**3**	**2**	**3**

* Settings in METS and SynerGEE as of 12/29/14

- During peak loading conditions, voltage levels on the feeder were noticeably lowered when compared to the original regulator settings while still remaining well within the allowable limits. The majority of the feeder trunks were estimated between 122V-125V, while the farthest east registering between 122V-123V. The maximum voltage modeled was approximately 125.4V, while the lowest voltage was 122.1.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	234	10.68	2828	535
124.00 - 126.00 V	26	1.59	144	50
126.00 - 140.00 V	0	0.00	0	0

- During median loading conditions, voltage levels on the feeder were noticeably lowered when compared to the original regulator settings while still remaining well within the allowable limits. The majority of the feeder trunks were estimated between 123V-124V, while the farthest east registering between 122V-123V. The maximum voltage modeled was approximately 123.9V, while the lowest voltage was 122.6.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	259	12.27	901	585
124.00 - 126.00 V	1	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

Distribution System Operations has recommended to install automation compatible voltage regulators and a breaker recloser in the substation to provide future FDIR and IVVC capabilities depending on the custom solution that is developed with the line devices. The Grid Modernization program will request the installation of the station voltage regulators by Substation Engineering, however Grid Mod is currently unable to personally secure the installation of the station breaker recloser due to scheduling and resource constraints within Substation Engineering and the Electric Shop. The Grid Mod Project Manager is responsible on working with the Substation Engineering Manager to coordinate the installation of equipment within the Substation as part of Grid Modernization's planned work.

Fuse Sizing

Fuse sizing on ORO 1280 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and transformers (where applicable). Fuse recommendations for ORO 1280 were created by the Grid Modernization Program Engineer and verified by the South Region Operations Engineer. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult the Grid Modernization Program Engineer with any questions regarding fuse sizing and coordination.

There may be situations where the transformers sizes on a lateral are adjusted (increased or decreased) to more accurately reflect customer loads. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with the transformer fuse(s).

Line Losses

The primary trunk conductors on ORO 1280 have been sized appropriately to minimize line losses at peak and median loading conditions during normal system configuration, and improve voltage levels on the rural feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading.

After the proposed reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections are performed on ORO 1280, it is estimated that the peak line losses could be reduced by approximately 1.7 kW, while the median loading line losses could be reduced by approximately 0.4 kW. In addition, up to 3.5 MWh savings could be achieved annually assuming median loading conditions during normal system configuration.

	6CU to 2/0 ACSR
Circuit Length (ft)	282
Current Median kW Losses	0.6
Current Peak kW Losses	2.7
Proposed Median kW Losses	0.2
Proposed Peak kW Losses	1.0
Median kW Loss Savings	0.4
Peak kW Loss Savings	1.7
Reconductor MWh Savings *	3.5

* Estimated median kW losses over one year span

An initial SyngerGEE load study estimates that a total of 38 kW in peak line losses currently exists on ORO 1280 (1.20%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved to approximately 33 kW (1.05%).

Peak Values	**Existing**	**After Balancing**	**After Trunk Reconductor**
kW Demand	3448	3453	3453
kW Load	3406	3415	3417
kW Line Losses	38	35	33
kW Loss %	1.20 %	1.10 %	1.05 %

Transformer No Load Losses

The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, No Load Losses are generally lower on newer units compared to a transformer of the same size from an older vintage. No Load Losses can therefore be minimized through the replacement of older transformer to newer units of the correct size.

All transformers on ORO 1280 shall be analyzed and “right sized” by the assigned Designer to most accurately reflect the customer loads. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the Designer.

The roughly 225 distribution transformers on ORO 1280 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It was determined that approximately 135 transformers will require replacement based on right sizing and the TCOP criteria replacements. The replacement of these transformers will result in an estimated 12.35 kW reduction in No Load Losses. This equates to an annual savings of roughly 108.2 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer.

Power Factor

MVAR and MW data at the ORO 1280 substation circuit breaker was analyzed from 12/10/12 to 12/09/14. It was determined that ORO 1280 had a leading power factor at all times during the time interval analyzed. Detailed power factor information is available upon request. Some key power factor figures for ORO 1280 are provided in the tables below.

Average Leading Power Factor	84.35 %
Median Leading Power Factor	85.81 %
Maximum Leading Power Factor	98.34 %
Minimum Leading Power Factor	53.97 %

The graph in Figure 8 shows the percent of time during the interval analyzed where the power factor on ORO 1280 fell between the applicable ranges. This information is also provided in a table format.

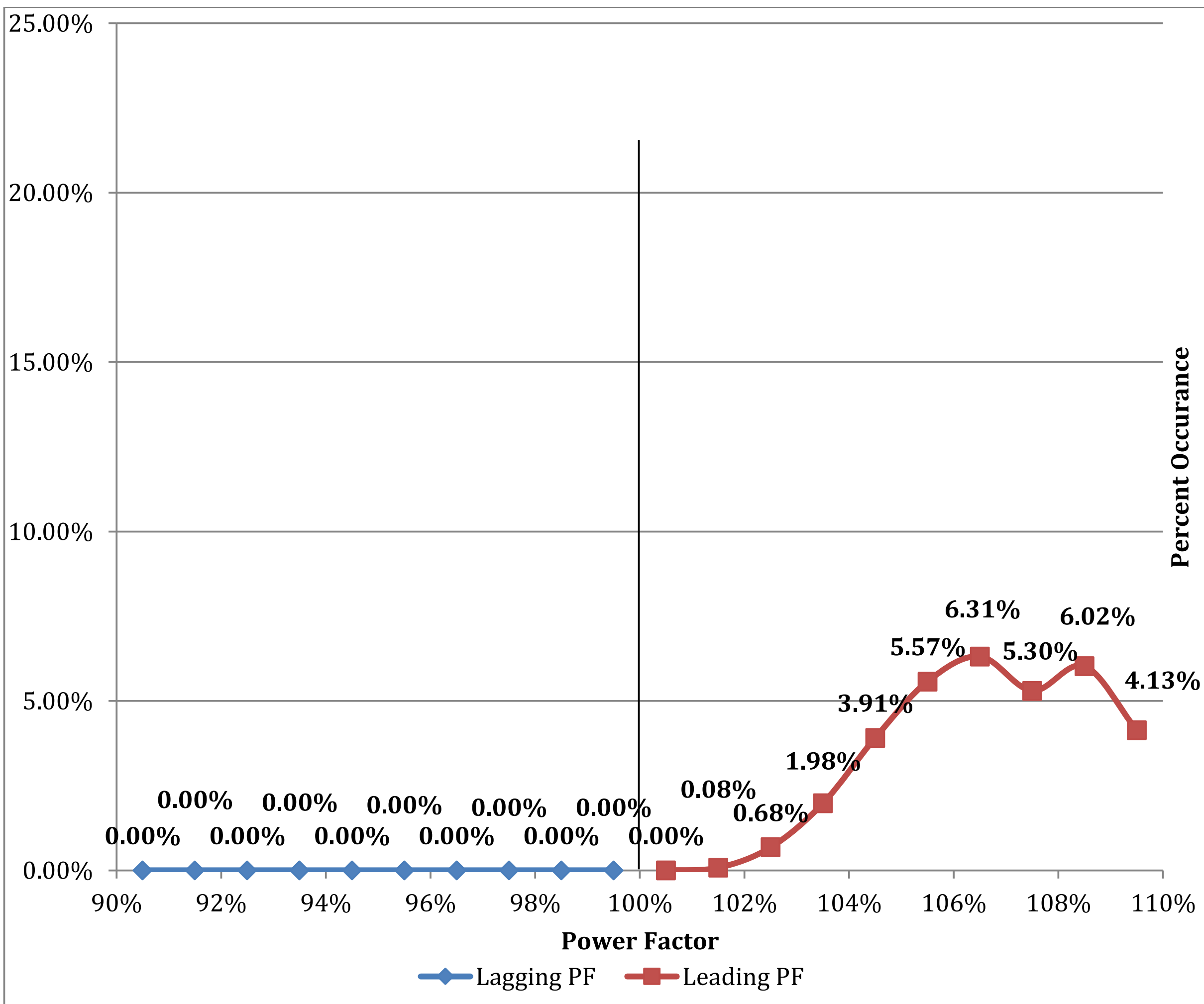


Figure 8. Existing Percent Occurance of Power Factor

	Lagging	Leading
Less than 90%	0.00%	66.01%
90%-91%	0.00%	4.13%
91%-92%	0.00%	6.02%
92%-93%	0.00%	5.30%
93%-94%	0.00%	6.31%
94%-95%	0.00%	5.57%
95%-96%	0.00%	3.91%
96%-97%	0.00%	1.98%
97%-98%	0.00%	0.68%
98%-99%	0.00%	0.08%
99%-100%	0.00%	0.00%

Power Factor Correction

The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times.

The power factor on ORO 1280 was consistently outside of the acceptable range. There is an existing 600 kVAR and 300 kVAR fixed capacitor banks on ORO 1280. It is recommended to remove the 300 kVAR fixed capacitor bank in **Polygon 6** and replace the 600 kVAR fixed capacitor bank to a switched 600 kVAR capacitor bank in **Polygon 3**. These changes would assist with bringing the feeder into the optimal range for power factor correction, as well as improving the lagging power factor when necessary.

To illustrate, the feeder was first reanalyzed with the proposed removal of the 600 kVAR fixed capacitor bank, and the 300 kVAR fixed capacitor bank left in service. The power factor was significantly improved, with the analysis suggesting that the ORO 1280 would have now have a lagging power factor roughly 9.3% of the time, as well as marked improvements to the leading power factor occurrences. Some key power factor figures for ORO 1280 are provided in the tables below.

Average Lagging Power Factor	99.46 %
Median Lagging Power Factor	99.64 %
Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	96.95 %

Average Leading Power Factor	99.03 %
Median Leading Power Factor	99.35 %
Maximum Leading Power Factor	99.99 %
Minimum Leading Power Factor	92.31 %

The graph in Figure 9 shows the percentage of time during the re-analyzed interval where the power factor on ORO 1280 fell between the applicable ranges. This information is also provided in a table format.

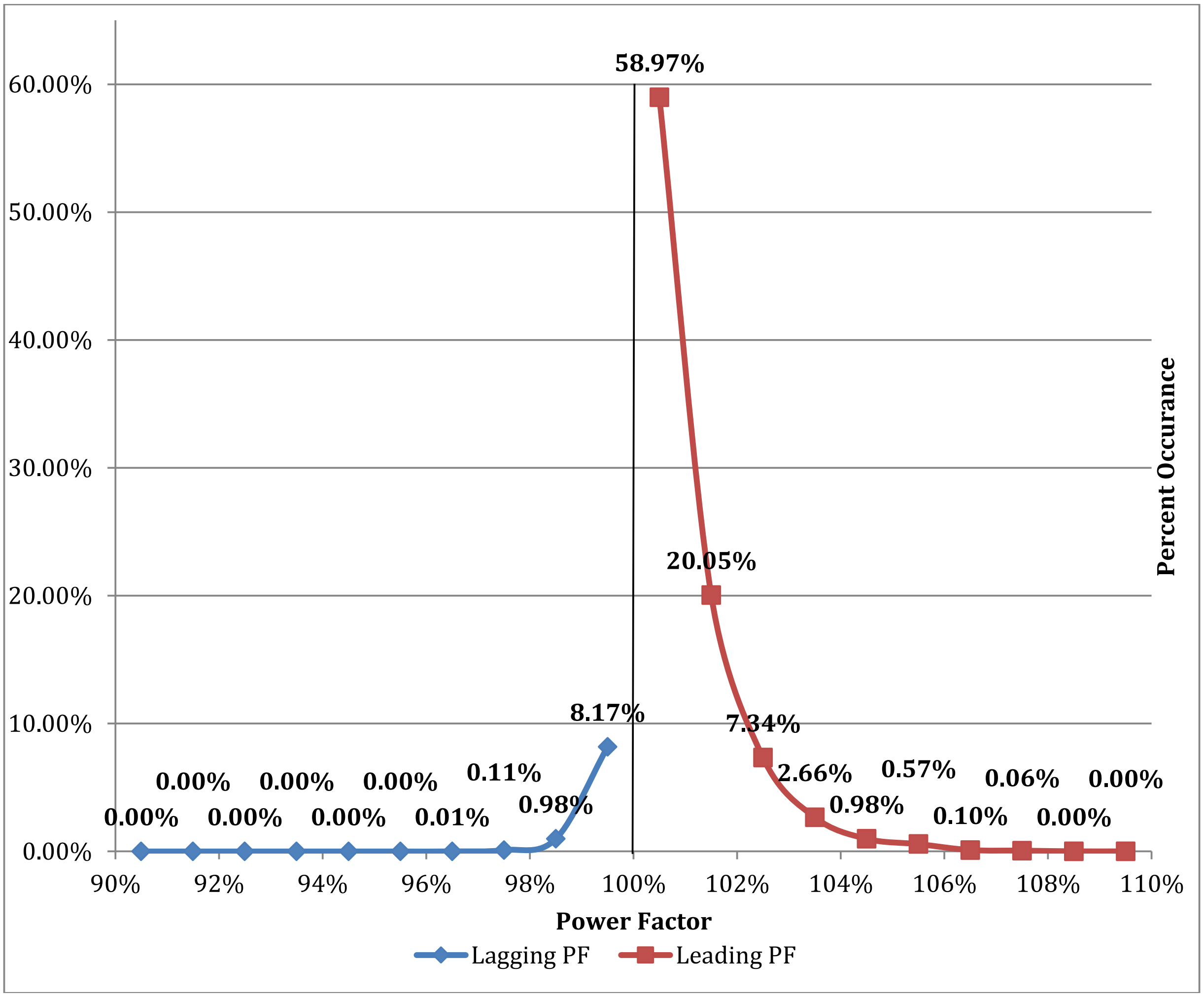


Figure 9. Proposed Percent Occurance of Power Factor

	Lagging	Leading
Less than 90%	0.00%	0.00%
90%-91%	0.00%	0.00%
91%-92%	0.00%	0.00%
92%-93%	0.00%	0.06%
93%-94%	0.00%	0.10%
94%-95%	0.00%	0.57%
95%-96%	0.00%	0.98%
96%-97%	0.01%	2.66%
97%-98%	0.11%	7.34%
98%-99%	0.98%	20.05%
99%-100%	8.17%	58.97%

Next, the feeder was analyzed with the proposed replacement of the 600 kVAR fixed capacitor bank to a switched bank, and the removal of the 300 kVAR fixed capacitor bank. The power factor was significantly improved, with the analysis suggesting that the ORO 1280 would have now have an average lagging power factor of 98.38%, and would also suggest that the feeder could operate without a leading power factor. Some key power factor figures for ORO 1280 are provided in the tables below.

Average Lagging Power Factor	98.38 %
Median Lagging Power Factor	99.26 %
Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	83.79 %

Average Leading Power Factor	0.00 %
Median Leading Power Factor	0.00 %
Maximum Leading Power Factor	0.00 %
Minimum Leading Power Factor	0.00 %

The graph in Figure 10 shows the percentage of time during the re-analyzed interval where the power factor on ORO 1280 fell between the applicable ranges. This information illustrates what the power factor on the feeder would look when the 600 kVAR capacitor bank is switched off. This information is also provided in a table format.

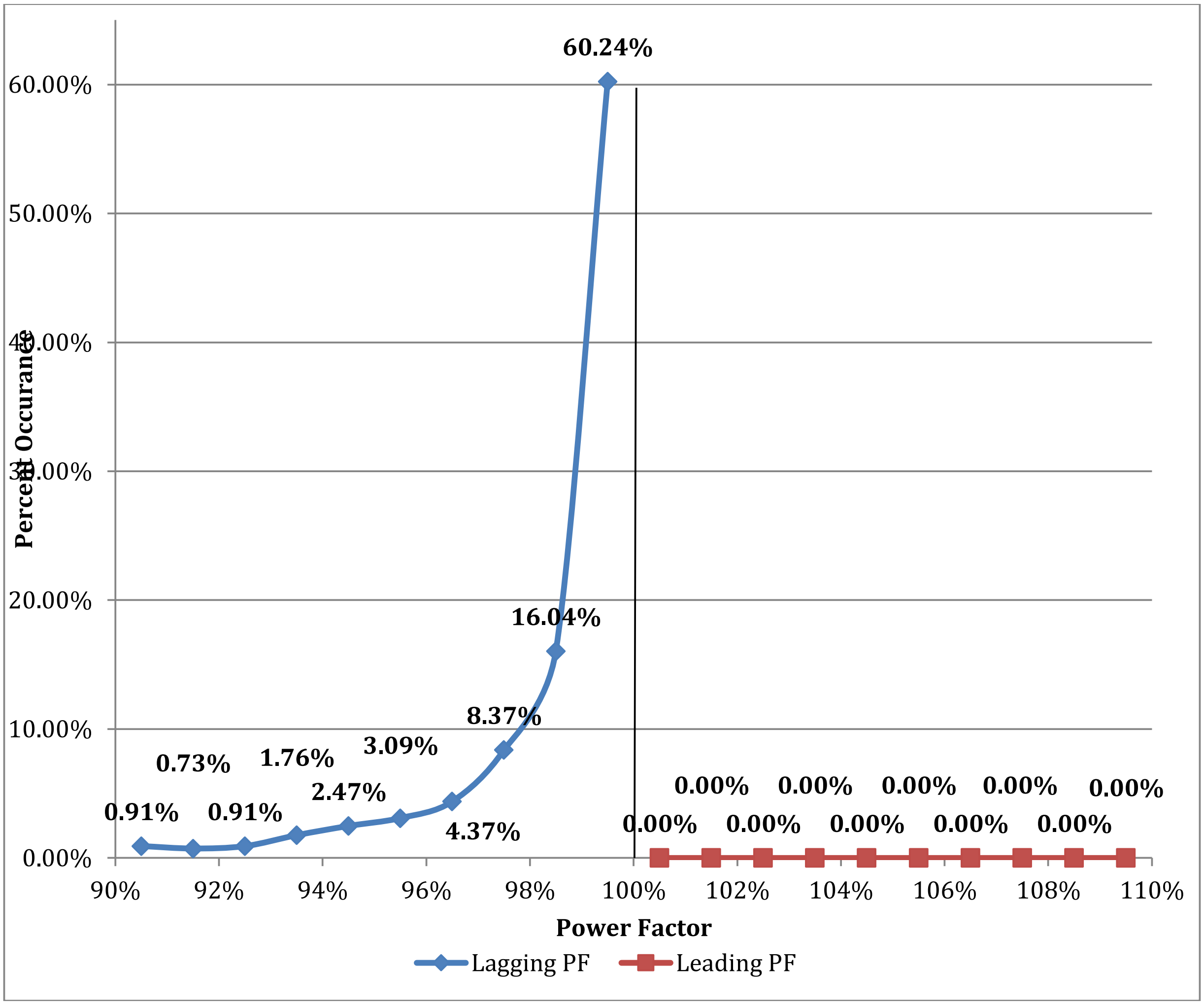


Figure 10. Proposed Percent Occurance of Power Factor

	Lagging	Leading
Less than 90%	1.10%	0.00%
90%-91%	0.91%	0.00%
91%-92%	0.73%	0.00%
92%-93%	0.91%	0.00%
93%-94%	1.76%	0.00%
94%-95%	2.47%	0.00%
95%-96%	3.09%	0.00%
96%-97%	4.37%	0.00%
97%-98%	8.37%	0.00%
98%-99%	16.04%	0.00%
99%-100%	60.24%	0.00%

Automation

Distribution Automation will be deployed on ORO 1280 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the South Region Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on ORO 1280.

ORO 1280 currently contains two overhead feeder ties to ORO 1281. Both of these ties are single phase switching devices. The existing blade disconnect switches east of Main & 1st in **Polygon 3** will be replaced with a Viper tie switch (ZL1541R, N.O.). The existing solid door cutouts east of Michigan & A in **Polygon 3** will be replaced with a three-phase gang-operated manual air switch (1527, N.O.).

The Grid Modernization program is not funded to perform work on ORO 1281. Any requests to perform work on ORO 1281 are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on ORO 1281.

The following automation devices will be deployed on the feeder:

Device Number	Location	Status	Device Type
ZL1540R	E of Michigan & Bartlett	N.C.	Viper – Recloser
ZL1541R	E of Main & 1st	N.O.	Viper – Tie Switch
ZL1535F	S of College & B	N.C.	Switched 600 kVAR Cap Bank

Figure 11 illustrates the proposed automation device locations on ORO 1280.

Distribution System Operations has recommended to install automation compatible voltage regulators and a breaker recloser in the substation to provide future FDIR and IVVC capabilities depending on the custom solution that is developed with the line device. Grid Modernization will request the installation of the station voltage regulators by Substation Engineering; however Grid Mod is currently unable to secure the installation of the station breaker recloser due to scheduling and resource constraints.

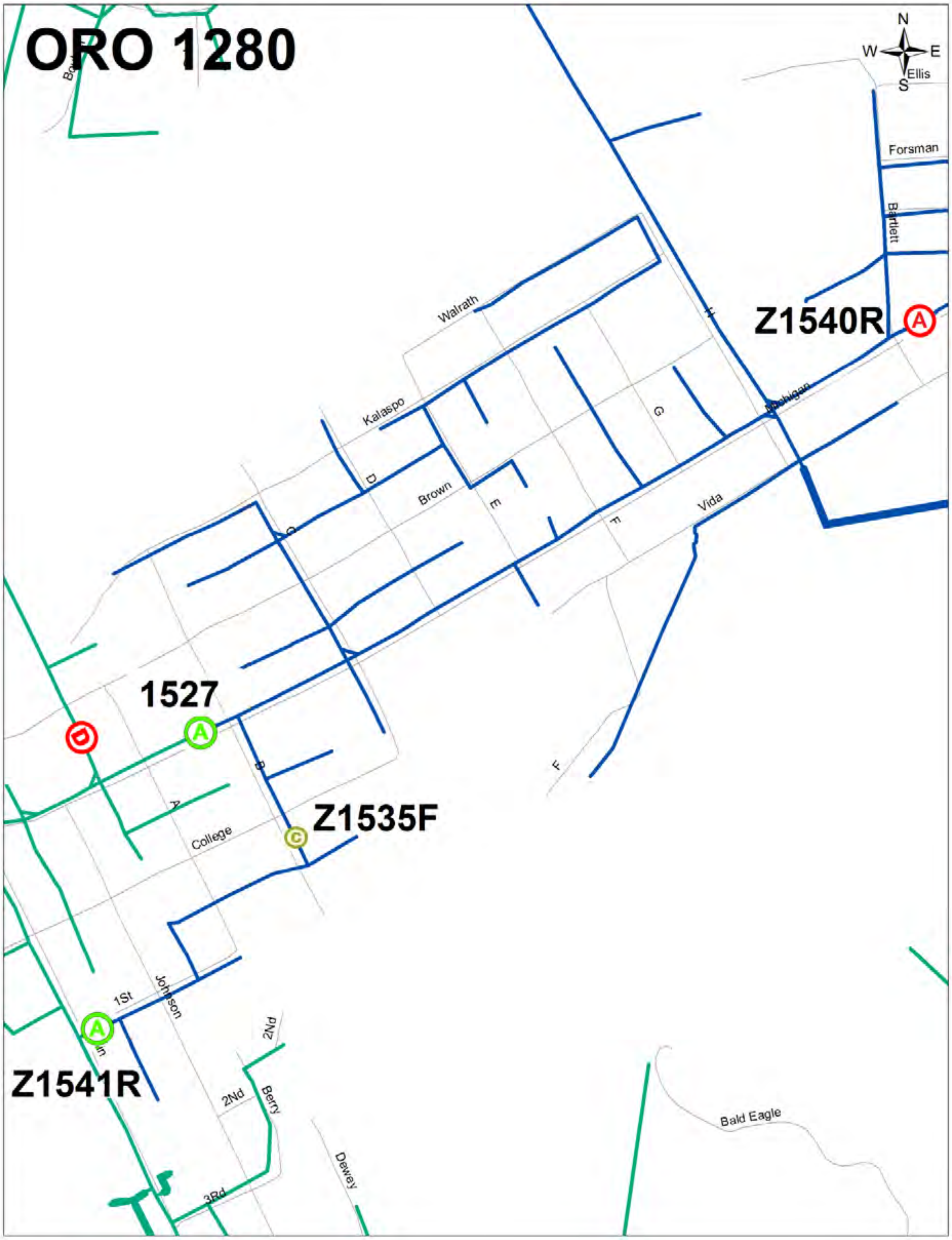


Figure 11. ORO 1280 Proposed Automation Device Locations

Open Wire Secondary

Open wire secondary districts have been analyzed for replacement on ORO 1280 in accordance to the Distribution Feeder Management Plan (DFMP). After analyzing the feeder through field observations, there were not any open wire secondary districts identified on ORO 1280. The Designer shall consult the DFMP if open wire secondary districts are discovered in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Poles

All poles and structures on ORO 1280 shall be examined by the assigned Designer for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the *Wood Pole* section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

Transformers

All transformers on ORO 1280 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable.

Tree Trimming

Vegetation management shall be employed on ORO 1280 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with the Vegetation Management department. A methodical trimming scheduled developed by the Designers that encompasses all assigned polygons is strongly recommended to reduce travel costs and maximize the allotted budget for the feeder.

Design Polygons

ORO 1280 has been divided into 10 polygons for the Grid Modernization project work. The polygons were created in an attempt to divide the work into near equivalent segments in regards to design and crew time. Additional considerations such as automation devices, reconductoring, geography, road access, and location of laterals further assisted in defining the boundaries of the polygons. Additional polygons can be created if necessary to better organize the work on the feeder, however they will be subsets of the existing numbered polygons.

All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as notifying the Program Engineer by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figure 12 illustrates the proposed polygons for ORO 1280.

The following polygon summary lists the identified items that shall be incorporated into the final job designs:

- **Polygon 2**
  - Transfer 1Φ OH lateral west of Vida & H (≈12 A) from AΦ to BΦ.
- **Polygon 3**
  - Install three-phase gang-operated air switch (1527, N.O.) east of Michigan & A, and remove existing solid door cutouts.
  - Install Viper tie switch (ZL1541R, N.O.) east of Main & 1st, and remove existing blade disconnect switches.
  - Install switched 600 kVAR capacitor bank (ZL1535F, N.C.) south of College & B, and remove existing fixed 600 kVAR capacitor bank
- **Polygon 4**
  - Transfer 1Φ OH lateral north of Brown & C (≈41 A) from AΦ to BΦ.
- **Polygon 5**
  - Install Viper recloser (ZL1540R, N.C.) east of Michigan & Bartlett.
  - Reconductor 3Φ trunk east of Michigan & H from 6CU to 2/0 ACSR with a 2/0 ACSR neutral (approximately 300').
- **Polygon 6**
  - Remove existing fixed 300 kVAR capacitor bank
- **Polygon 7**
  - Analyze the condition of the existing poles and wire on the 3-phase primary to determine if the trunk is a candidate for reconfiguration along Michigan Avenue.
- **Polygon 8**
  - Analyze the condition of the existing poles and wire on the 3-phase primary to determine if the trunk is a candidate for reconfiguration along Michigan Avenue.
- **Polygon 9**
  - Reconfigure the three-phase lateral and the buck-pole jumpering off of the primary trunk to incorporate A,B, and C-phase.

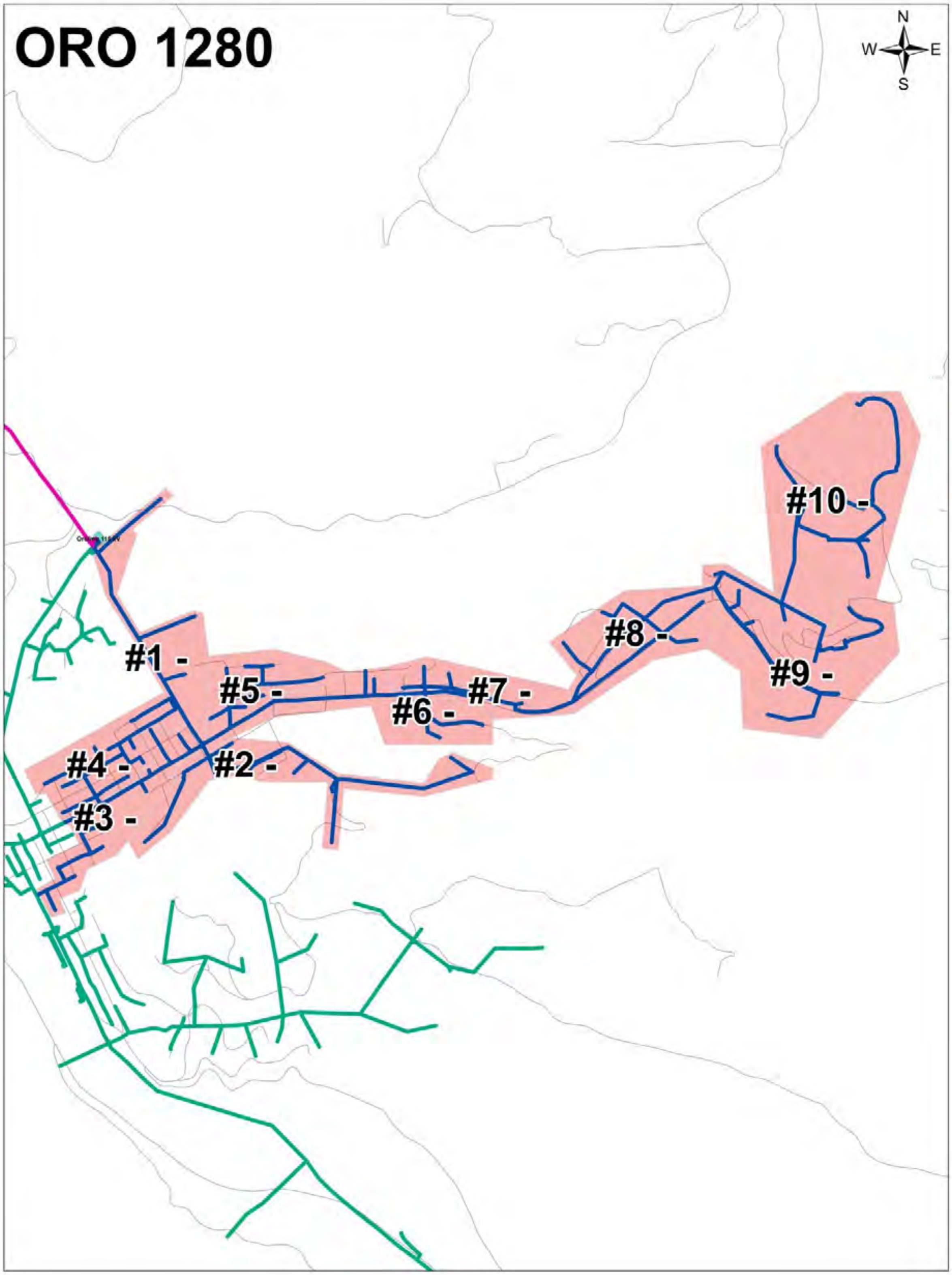


Figure 12. ORO 1280 Polygon Numbers

Report Versions

Version 1	10/19/15 – Creation of the initial report
Version 2	2/2/16 – Updating the automation devices in the L/C and Grangeville area(s) to have an 'L' designator after the 'Z'.

Grid Modernization Program

ORO 1282 Feeder Analysis Report

June 1st, 2020

Version 1

Prepared by

Shane Pacini, P.E.
Senior Distribution Engineer

Index

Overview

The following report was established to create a baseline analysis for ORO 1282 as part of the Grid Modernization program.

ORO 1282 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Orofino Substation in Orofino, ID. The feeder has approximately 5.10 circuit miles of feeder trunk with approximately 2.15 circuit miles of laterals that primarily serve a rural mixture of residential and light commercial loads west of the town of Orofino, ID. ORO 1282 serves 585 customers during the current normal configuration. Additional feeder information is included throughout the sections of this report, as well as the 2018 Avista Feeder Status Report. ORO 1282 is represented by the color *pink* on the system map shown in Figure 1.

There are not any primary metered accounts on ORO 1282.

Executive Summary

The Grid Modernization Program is a capital initiative that was established in 2013 to holistically evaluate and systematically address the improvement of Avista's approximately 12,000 circuit miles of overhead and underground primary electric distribution lines. The objective of the Program is to provide a thorough examination of Avista's electric distribution circuits for programmatically addressing the modernization and upgrading of the facilities. The targeted improvement to the critical components on the system will result in significant upgrades to the broad areas of performance, health, reliability, efficiency, asset condition, operability, and distribution automation.

Grid Modernization performs a comprehensive inventory of each electric feeder in the system to appropriately prioritize and select the feeders that will benefit the most from the Program. The feeder criteria information is used to rank the potential benefits for each circuit compared against the other distribution feeders on Avista's system. The Program focuses on selecting and improving the relatively poorer performing feeders that have been assessed in order to achieve the most opportunities for improvement.

While the efforts of the program will provide significant upgrades to all of these wide-ranging categories, each circuit that is selected has its distinct characteristics, strengths and weaknesses. For example, a circuit may have exceptional reliability metrics, however the feeder may present the opportunities to capture significant line loss savings. This variability between circuits translates into a unique tailored solution for each feeder where the improvement opportunities may reside in various different areas.

The number of sustained outages, overall health performance, and asset condition of the facilities and components on ORO 1282 were primary contributing factors to the selection of this circuit. For example, it is estimated that significant pole replacements will occur on the circuit. It is estimated that 332 of the 427 poles (77.8%) on the circuit will be replaced due to condition, age, height, and classification requirements.

In addition, approximately 110 transformers (45.8%) on the feeder will be replaced due to being undersized or contain a higher than desired presence of Polychlorinated Biphenyls (PCBs). The replacement of these older units will result in improved efficiency through core loss savings, and improved health and performance.

The following summary is provided as a preview of the findings and recommendations of the Grid Modernization program for the ORO 1282 circuit:

- Primary trunk is currently comprised of mainly 2/0 ACSR resulting in no recommendations for trunk reconductoring based on peak loading
- Moderate peak loading (180A peak per phase average) warrant a need to strategically address reconductoring select higher loss primary laterals
- Opportunities exist to reconductor primary laterals due to a combination of physical condition, facility replacements, and identified high loss conductors
- Moderate phase changes will create balanced loading across numerous strategic points on the circuit
- One 600 kVAR switchable capacitor bank will be installed to support voltage, lower losses, optimize power factor, and provide future IVVC functionality
- Two 600 kVAR fixed capacitor banks will be removed that are causing a leading power factor throughout the entire year, allowing for power factor optimization
- Approximately 7,300' conductor feet of unidentified underground cable has been identified by the URD Cable Program.
- An estimated 110 of the 240 transformers (45.8%) on the feeder will be replaced based on targeted PCB levels and identified as being undersized
- Voltage levels were within ANSI Range A and B operating limits
- There were no existing open wire secondary districts identified on the circuit

- 332 of the 427 poles (77.8%) on estimated to be replaced due to condition, age, height, and classification requirements
- SAIDI and CAIDI currently satisfy the 2020 Avista Target values
- SAIFI and CEMI3 currently fail to satisfy the 2020 Avista Target values
- One Viper midline recloser will be installed to provide sectionalizing, fault sensing capabilities, remote operability, and Hot Line Hold deployment
- One Viper tie switch will be installed to provide remote operability, future FDIR functionality, and an automated tie switch to ORO 1281
- One Viper truck switch will be installed to provide remote operability and Hot Line Hold deployment, and future FDIR functionality
- Comprehensive fuse sizing and coordination study was performed

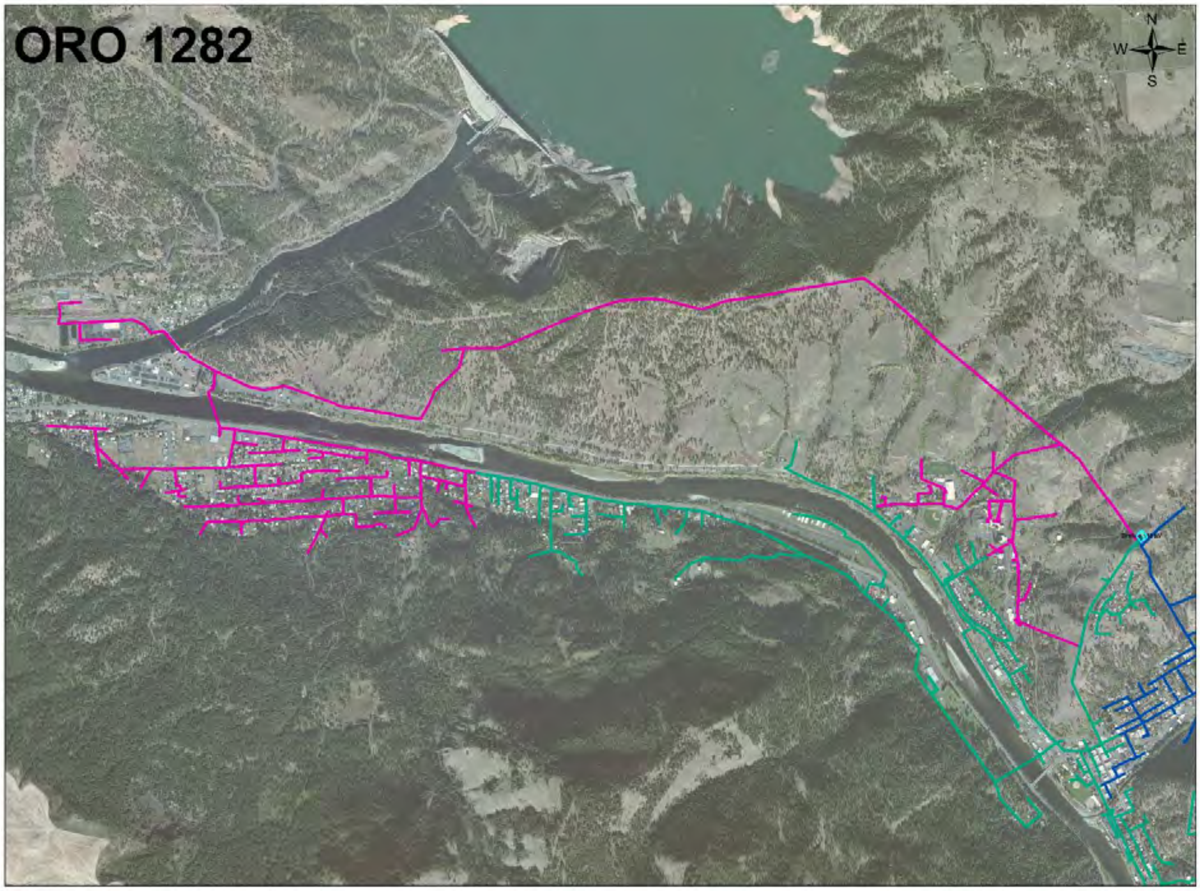


Figure 1. ORO 1282 Circuit One-Line Diagram

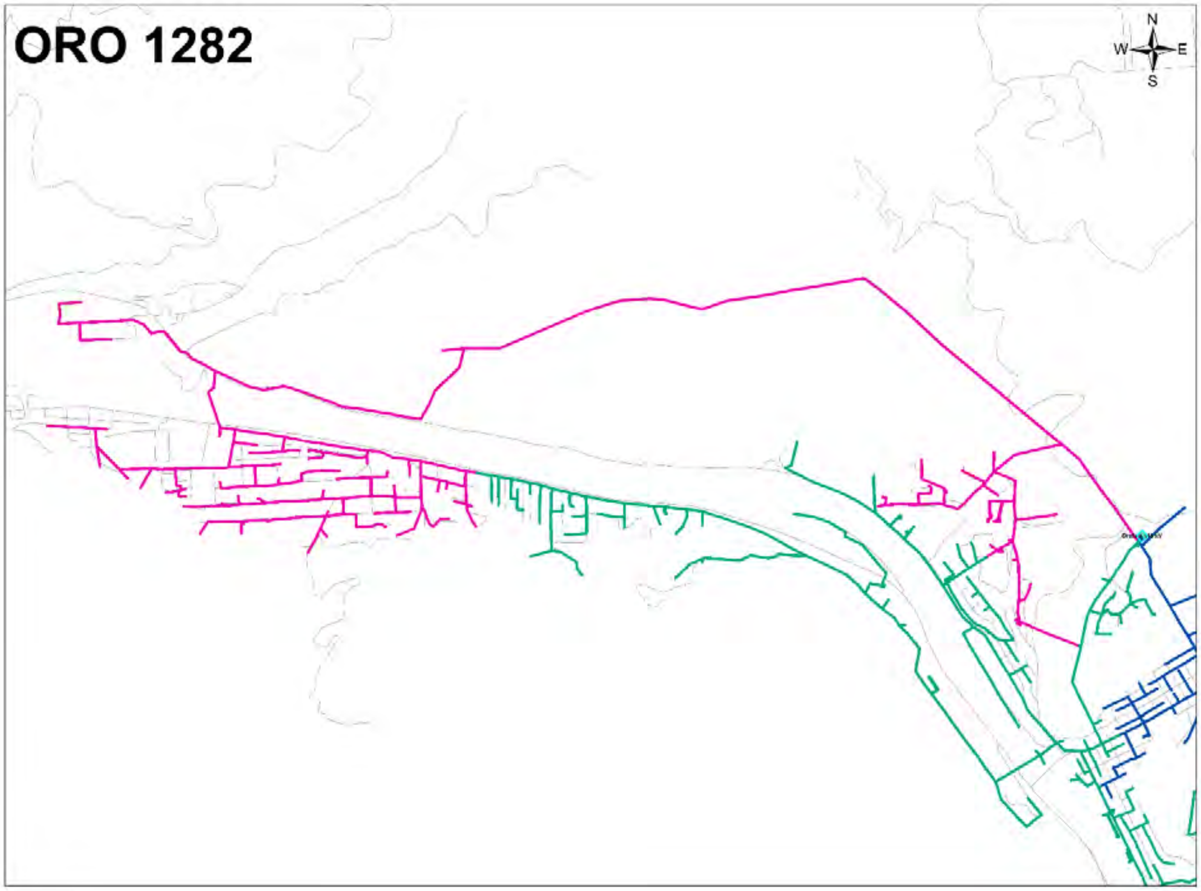


Figure 2. ORO 1282 Circuit One-Line Diagram

Program Ranking Criteria

The 2018 Avista Feeder Status Report contains detailed information on each distribution circuit and assesses each feeder in three key areas: health, performance, and criticality. The Health metric analyzes items such as the age of the wood pole population and projected reject rate, reliability indices, and OH-UG ratio.
The Performance metric analyzes items such as the thermal utilization, efficiency, voltage, power factor, and reliability indices. The Criticality metric analyzes items such as customer density, commercial account density, load density, and the essential services on the circuit.

The Grid Modernization Program selects feeders by first individually analyzing the three categories of the Feeder Status Report. This research is performed on every distribution feeder in the system. Health and Performance are combined with Criticality to create a comprehensive score for each circuit. The comprehensive scores are not weighted or normalized. The summation of the values for each of the three categories creates the overall score for each feeder. The overall scores are then ranked from highest to lowest to create a prioritized selection list. The prioritized feeders then receive a qualitative analysis to incorporate additional considerations including: automation opportunities, primary metered customers, feeder length, feeder location, substation upgrades, etc.

The 2018 Avista Feeder Status Report illustrates that ORO 1282 had a rating value of 74 in terms of Health, 71 on Performance, and 52 in terms of Criticality and the customers that are served. These ratings are each based on a 100-point scale.

Metric	Rating Value
Health	74
Performance	71
Criticality	52

ORO 1282 had a total combined ranking of the 1st lowest performing feeder on the list of approximately 350 circuits during the most recent selection and prioritization period analyzed in late 2018 using the 2018 Feeder Status Report.

In addition, the 2018 Avista Feeder Status Report provides the following ranks for ORO 1282 in the Grangeville service area. There are currently 21 feeders in the Grangeville service area.

- 1st highest in terms of the Feeder Status Report Criticality metric (2.6)
- 7th highest in Winter Peak Amps (169)
- 8th highest Thermal Utilization (57%)
- 8th worst CEMI3 performance (11%)
- 8th highest in Summer Peak Amps (127)
- 10th worst in Max Imbalance (29%)
- 10th worst SAIFI performance (1.55)

Reliability Index Analysis

Reliability indices are significant components of a utility's ability to measure long-term electric service performance, and are one indicator of system health or condition. The common reliability indices of CAIDI, SAIDI, SAIFI, and CEMI3 are used by the Grid Modernization Program to analyze and illustrate the historical reliability performance of the feeders, as well as to assist in justifying any proposed circuit improvements or automation deployments. Each historically averaged reliability index for a feeder is compared to the Avista target value for that calendar year to determine the reliability performance of a feeder.

The key reliability indicators for ORO 1282 were analyzed from 2006 to 2018 to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed circuit improvements or automation deployments. ORO 1282 was found to have 34 sustained distribution outages from 2006 through 2018 through an OMT analysis, for an average annual figure of approximately 2.6 sustained distribution outages. In addition, ORO 1282 was found to have 32 momentary distribution outages from 2006 through 2018 through an OMT analysis, for an average annual figure of approximately 2.5 momentary distribution outages. The table below shows the annual value for each respective reliability index on ORO 1282 for the last five years of data. The reliability indices that Grid Modernization uses for measurement and reporting do not include Major Event Days (MED). Major Event Days is an industry standard that is used to evaluate major events, such as severe weather or storms, which can lead to unusually long outages in comparison to the distribution system's typical outage. The reliability indices that are being used do not include MED, as this is standard per IEEE and reflects the same reliability information that Avista shares with the respective state Utility Commissions.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2014	0.0%	0.02	2	101
2015	0.0%	0.34	23	68
2016	0.0%	0.14	20	145
2017	36.1%	2.45	370	151
2018	11.3%	1.55	129	83
Average	9.5%	4.50	108.8	109.6

The previous table illustrates the annual value for each respective reliability index on ORO 1282 for the last five years of data. This information is also provided in graphical form in Figures 3 through 6. The information in these graphs do not include MEDs.

CEMI3 is defined as the Total Number of Customers Experiencing 3 or More Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has been very good, with many years of zero customers experiencing 3 or more sustained outages, with the recent exceptions of 2017 and 2018. This index is showing an increasing linear trend due to the last two years of data. The CEMI3 index for ORO 1282 has consistently been outperforming the annual Target value set internally by Avista, with the recent exceptions of 2017 and 2018.

SAIFI is defined as the Total Number of Customer Sustained Interruptions divided by the Total Number of Customers Served. SAIFI stands for System Average Interruption Frequency Index. The performance of this metric has been inconsistent and has varied over the years. This index is showing a declining linear trend during the 13 years of analyzed data. The SAIFI index for ORO 1282 has generally been outperforming the annual Target value set internally by Avista, however there were multiple years where the target was not satisfied.

SAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Served. SAIDI stands for System Average Interruption Duration Index. The performance of this metric has been inconsistent and has varied over the years. Despite the inconsistent performance, this index is showing a decreasing linear trend during the 13 years of analyzed data. The SAIDI index for ORO 1282 has generally been outperforming the annual Target value set internally by Avista, however there were multiple years where the target was not satisfied.

CAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customer Interruptions. CAIDI stands for Customer Average Interruption Duration Index. The performance of this metric has been inconsistent and has widely varied over the years. This index is showing a flat linear trend during the 13 years of analyzed data. The CAIDI index for ORO 1282 has occasionally outperformed the annual Target value set internally by Avista, however there were multiple years where the target was not satisfied.

The average value of each index was calculated and then compared to the Avista 2020 Target values. Two of the four historical averaged measured indices on ORO 1282 failed to meet the 2020 targets. This data suggests that customers experienced numerous sustained outages on the feeder, however the average outage duration and service restoration duration is within the desired range of Avista.

WA-ID Key Indicator	2020 Target	ORO 1282	Variance
SAIFI Sustained Outages/Customer	1.08	4.50	3.42
SAIDI Outage Time/Customer (min)	166.00	108.8	57.2
CAIDI Ave Restoration Time (min)*	155.0	109.6	45.4
CEMI3 % of Customers >3 Outages	6.5%	9.5.%	3.0%

*CAIDI values were converted from hours to minutes for this report

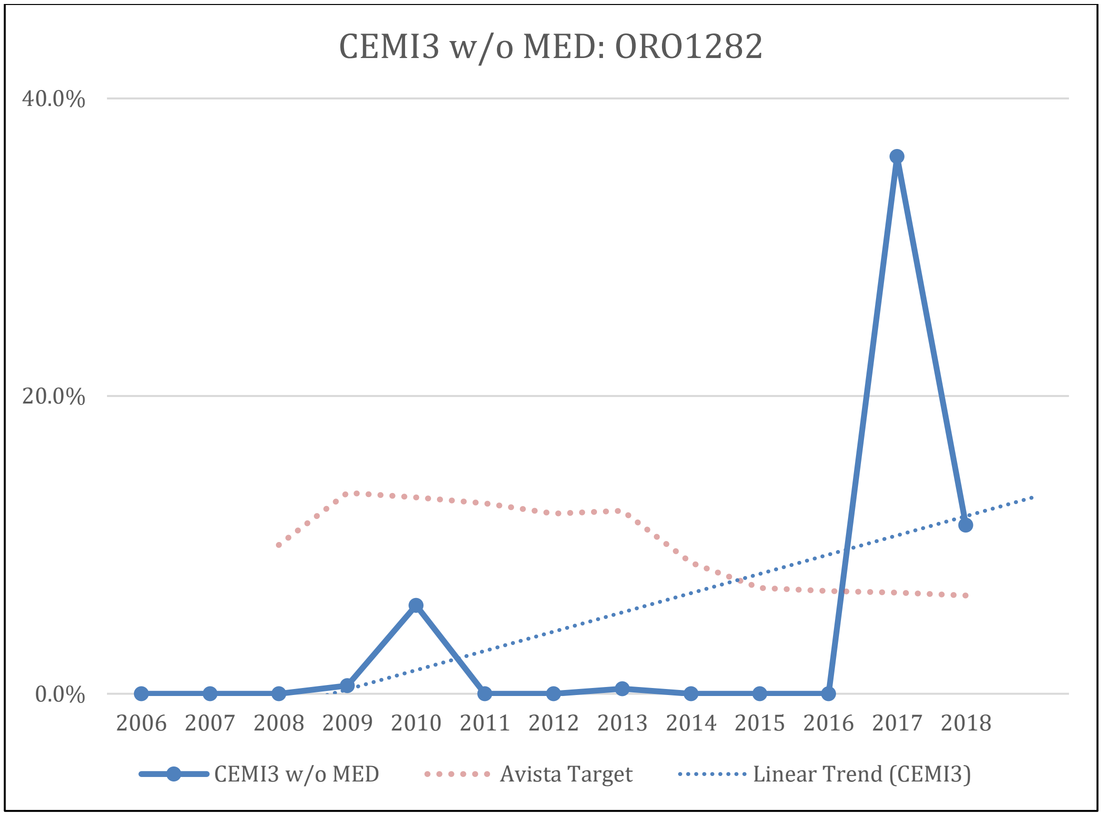


Figure 3. ORO 1282 CEMI3 Performance

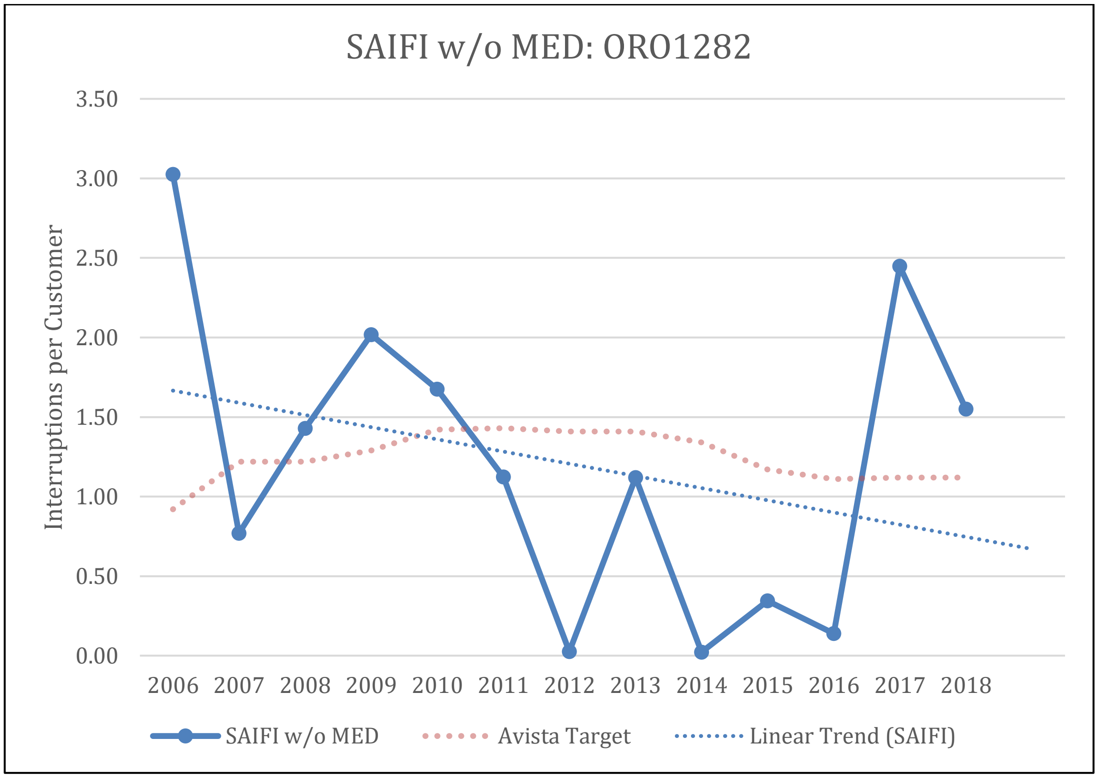


Figure 4. ORO 1282 SAIFI Performance

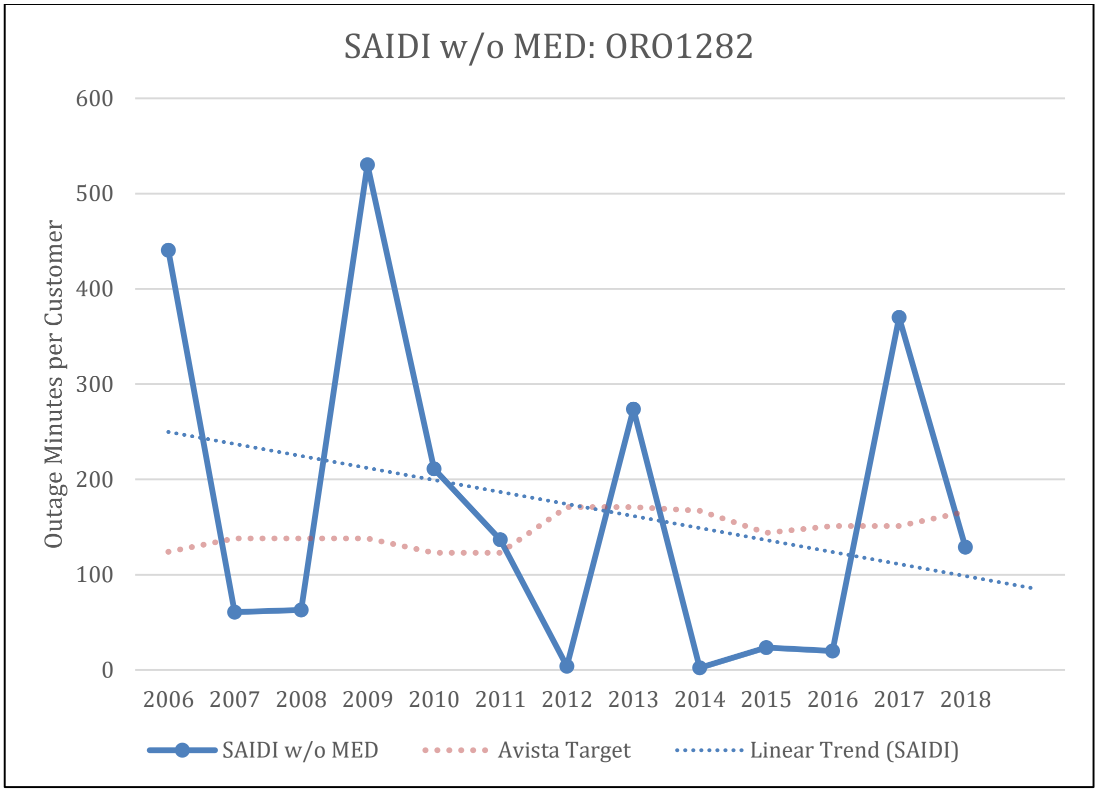


Figure 5. ORO 1282 SAIDI Performance

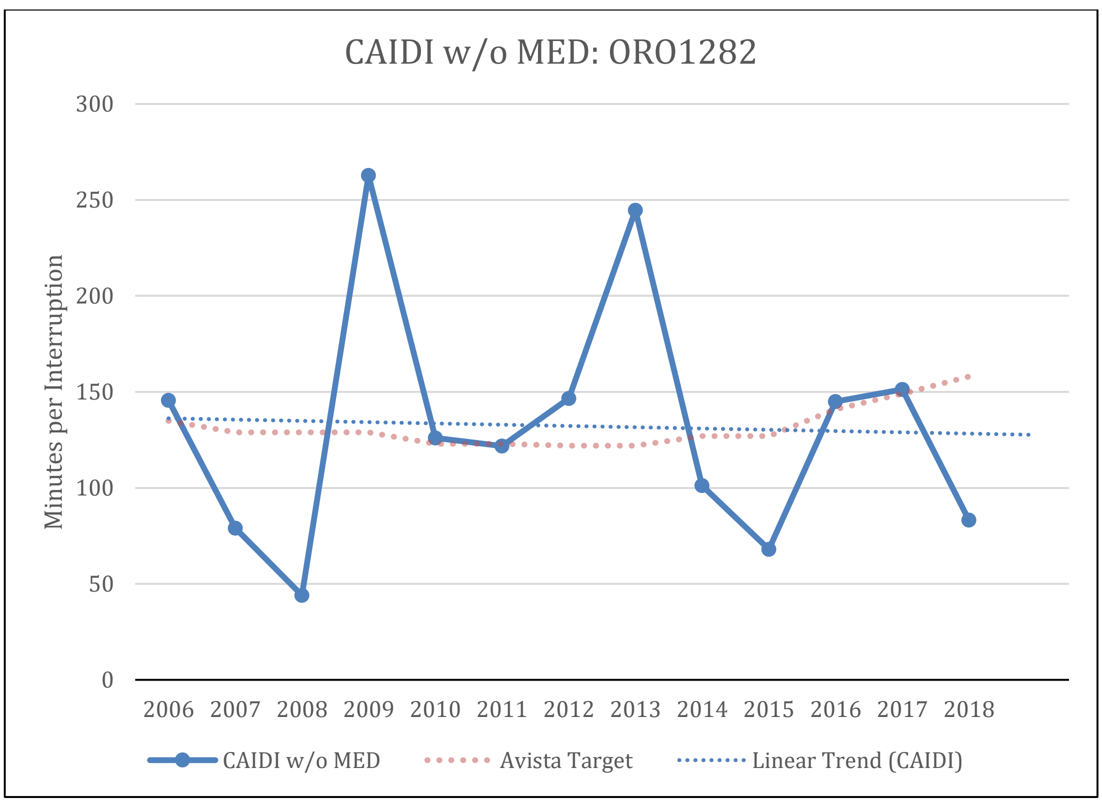


Figure 6. ORO 1282 CAIDI Performance

Peak Loading

Three-phase ampacity loading from SCADA monitoring at the ORO 1282 substation circuit breaker was analyzed from 1/7/18 to 1/7/20. The following ampacity loading values were established for ORO 1282 during this timeframe. Loading information has been analyzed to determine if any data needed to be removed from selected timeframes due to temporary changes in loading from switching (verified through PI). It was identified that there were six time durations that should be excluded from the loading due to ORO 1282 being in an abnormal feeder configuration or serving additional load from an adjacent feeder.

The following Figures illustrate multiple durations that are excluded from loading analysis where additional load was served or transferred from during abnormal feeder configuration.

The first duration of abnormal loading began at approximately 2/20/2018 7:00 AM and ended at approximately 2/20/2018 9:00 AM. In this occurrence, A-phase experience a noticeable reduction in load, followed by a brief escalation in loading likely due to inrush. Figure 7 illustrates the beginning and ending of the first abnormal loading occurrence.

The second duration of abnormal loading began at approximately 3/26/2018 5:00 AM and ended at approximately 6/17/2018 7:00 AM. In this occurrence, all three phases experienced a noticeable increased shift in load, followed by noticeable decreased shift in load. Figure 8 illustrates the beginning and ending of the second abnormal loading occurrence.

The third duration of abnormal loading began at approximately 1/20/2019 1:00 AM and ended at approximately 1/22/2019 4:00 PM. In this occurrence, all three phases experienced a noticeable decreased shift in load. Figure 9 illustrates the beginning and ending of the second abnormal loading occurrence.

The fourth duration of abnormal loading began at approximately 5/16/2019 7:00 PM and ended at approximately 6/13/2019 2:00 AM. In this occurrence, all three phases experienced noticeable increased and decreased shifts in load. Figure 10 illustrates the beginning and ending of the second abnormal loading occurrence.

The fifth duration of abnormal loading began at approximately 7/17/2019 4:00 PM and ended at approximately 8/2/2019 3:00 PM. In this occurrence, all three phases experienced noticeable decreased shift in load. Figure 11 illustrates the beginning and ending of the second abnormal loading occurrence.

The sixth duration of abnormal loading began at approximately 10/15/2019 9:00 AM and ended at approximately 10/18/2019 3:00 PM. In this occurrence, all three phases experienced noticeable decreased shift in load. Figure 12 illustrates the beginning and ending of the second abnormal loading occurrence.

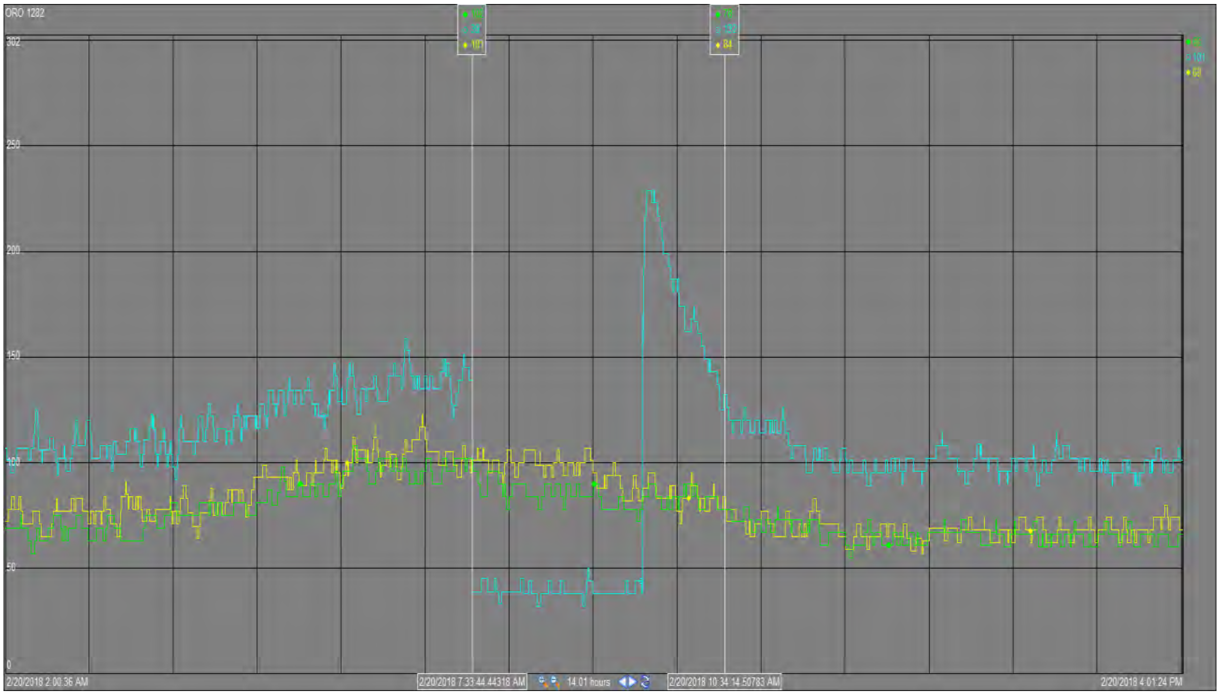


Figure 7. ORO 1282 Abnormal Feeder Configuration from 2/20/18 to 2/20/18

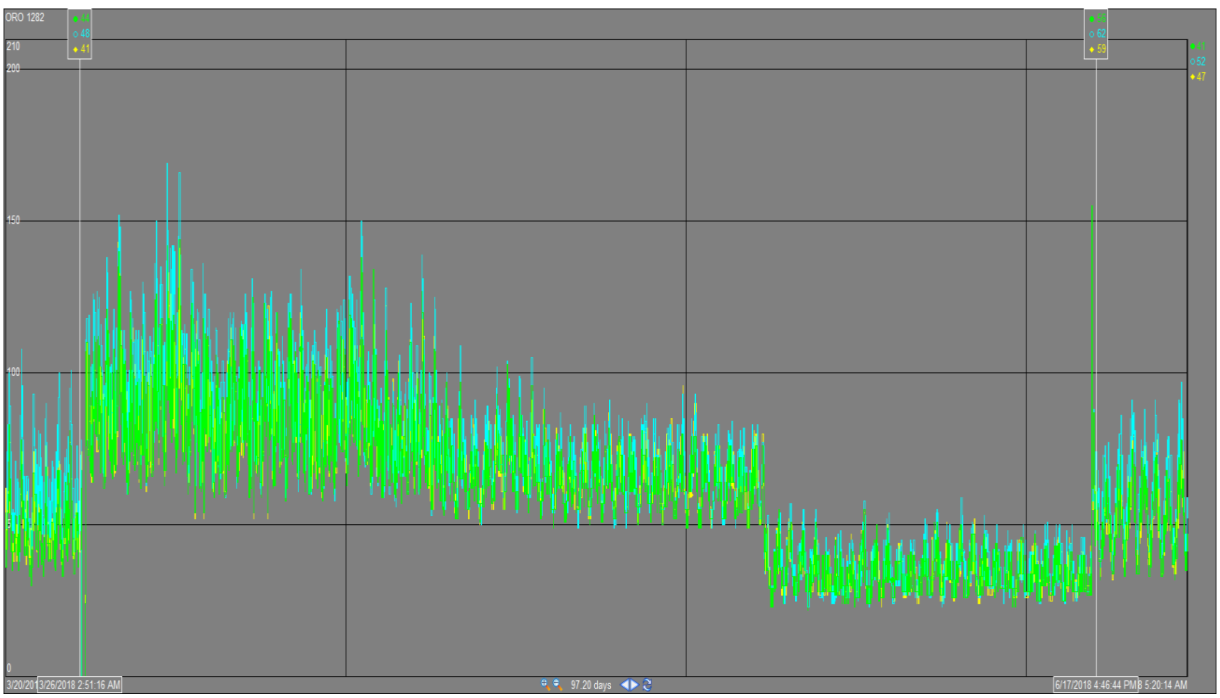


Figure 8. ORO 1282 Abnormal Feeder Configuration from 3/26/18 to 6/17/18

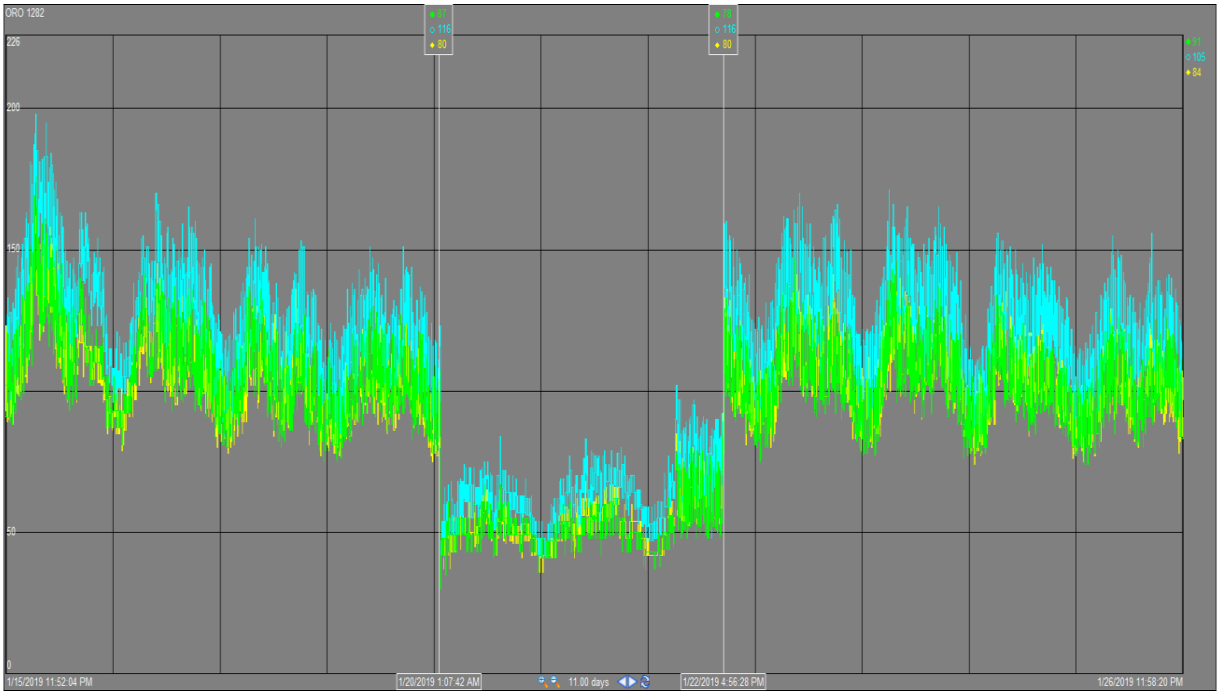


Figure 9. ORO 1282 Abnormal Feeder Configuration from 1/20/19 to 1/22/19

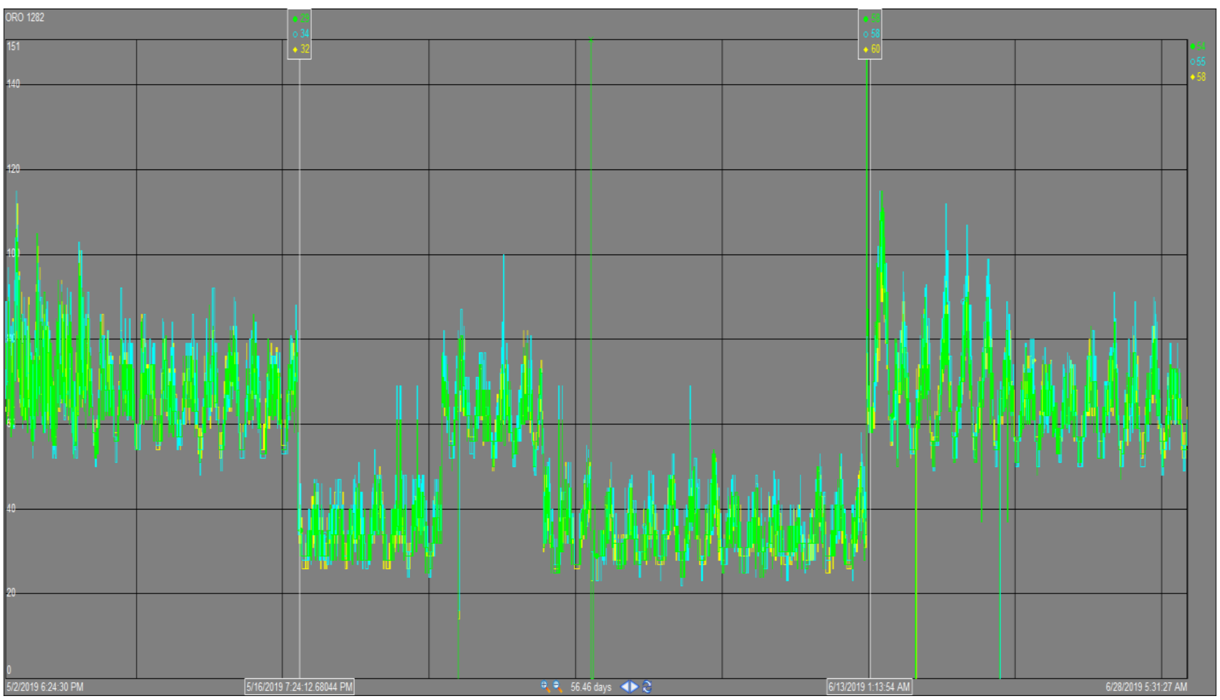


Figure 10. ORO 1282 Abnormal Feeder Configuration from 5/16/19 to 6/13/19

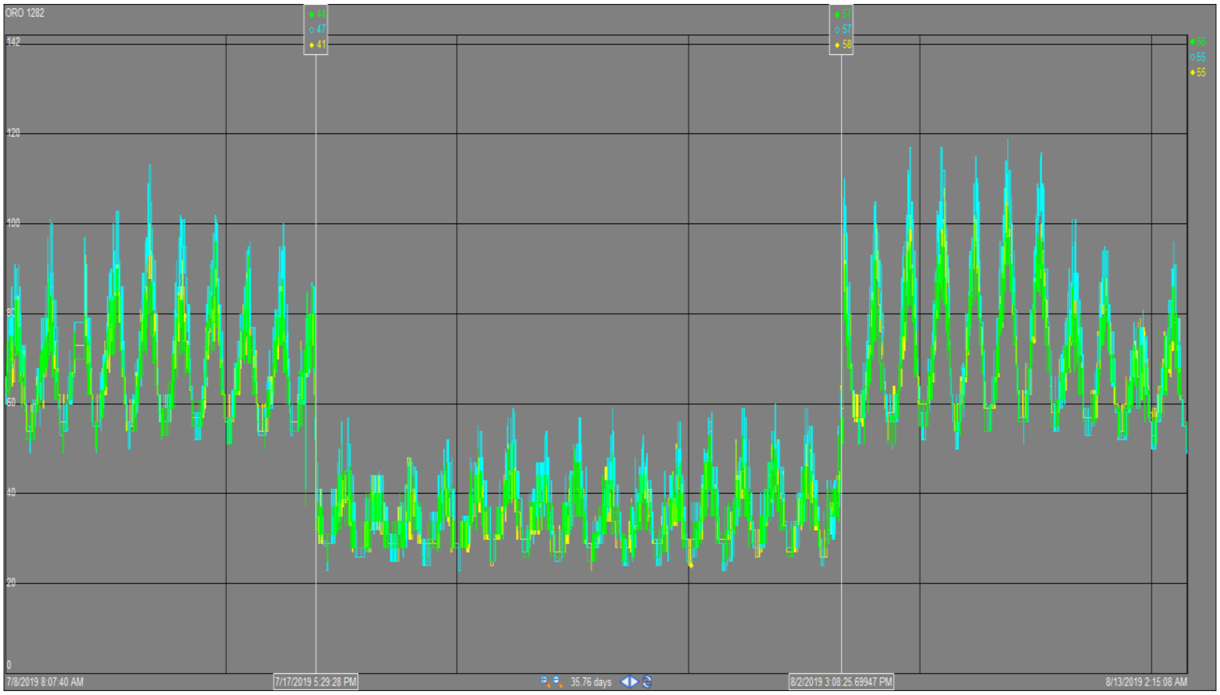


Figure 11. ORO 1282 Abnormal Feeder Configuration from 7/17/2019 to 8/2/19

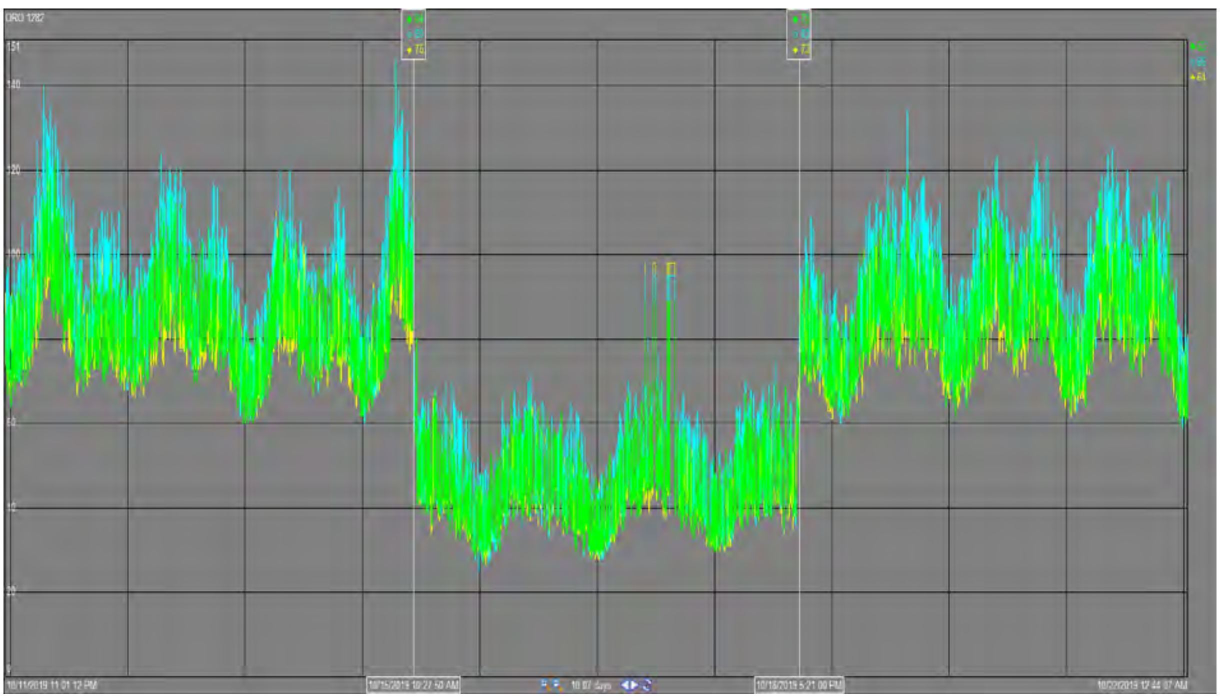


Figure 12. ORO 1282 Abnormal Feeder Configuration from 10/15/19 to 10/18/19

ORO 1282 is a winter peaking feeder during the analyzed duration, with the highest loading occurring in early December, and comparable peak values observed until early March. The summer peak values that were observed were well below the winter peak values. The values below reflect the adjusted data set where loading values during abnormal configurations has been removed. B-phase is continuously the highest loaded phase on the circuit, with a non-coincident peak occurring on 12/7/18. A-phase and C-phase had near coincident peaks during this same time, however their values were slightly lower at that time than their respective non-coincident peak. A-phase and C-phase both had coincident peaks during the two years analyzed on 2/7/19. The peak loading values for each phase are used in the Synergi model analysis for the feeder, except where average load values are noted for establishing kW losses.

	Before Balancing	
	Peak Loading	**Average Loading**
A-Phase	168 A	77 A
B-Phase	202 A	88 A
C-Phase	171 A	79 A
Average	180 A	81 A

	After Balancing	
	Peak Loading	**Average Loading**
A-Phase	189 A	86 A
B-Phase	181 A	79 A
C-Phase	171 A	79 A
Average	180 A	81 A

Approximate percent loading figures were established through Demand Factor by analyzing the ratio of the maximum apparent power demand observed upon the circuit to the total kVA load that is actually connected. This was performed on a Per Phase and Total basis from values extracted through Synergi at the model's initial configuration before balancing or performing improvements on the circuit.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**Demand Factor**
A-Phase	1312	3154	41.6%
B-Phase	1578	4174	37.8%
C-Phase	1336	3381	39.5%
Total	4226	10708	39.5%

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**Demand Factor**
A-Phase	676	3154	21.4%
B-Phase	748	4174	17.9%
C-Phase	695	3381	20.6%
Total	2219	10709	19.8%

*Values taken from Synergi Model created on 1/13/19

Load Balancing

Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which will mitigate the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts will commence toward the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

Accurate load balancing can be analyzed and achieved on ORO 1282 due to the three-phase ampacity loading from SCADA monitoring at the substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively before balancing:

	Connected KVA per Phase*
A-Phase	3439 kVA
B-Phase	4424 kVA
C-Phase	3357 kVA

* Connected kVA per Phase in AFM as of 12/31/19

The following list provides the lateral phase changes that can improve the balance during peak load on the phases between numerous strategic locations on the feeder, as illustrated in Figure 13. As a whole, the trunk sections and multi-phase laterals on ORO 1282 were reasonably balanced, with approximately 34A of difference between the highest and lowest loaded phases during modeled peak loading conditions. However opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate the following lateral phase changes into the appropriate polygon designs:

1. **Polygon 7** – transfer 1Φ OH lateral south of US Highway 12 & 115th Street (≈12 A peak loading, (≈5 A average loading) from AΦ to BΦ.
2. **Polygon 8** – transfer 1Φ OH lateral west of Vista Avenue & 129th Street (≈33 A peak loading, ≈14 A average loading) from BΦ to AΦ.

The result of this load transfer is listed in the following table. This change will approximately balance the feeder at the substation breaker to 189/181/171, as well as between the numerous strategic points to approximately sectionalize the feeder to optimize switching and load transfers.

	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
ORO 1282 Station Breaker	168	202	171	189	181	171
140T at #102202	120	129	119	120	129	119
SW of #102204	19	49	43	19	49	43
SE of #102204	120	80	78	120	80	78
Switch #1363	55	81	58	76	59	58
80T at #305124	0	44	16	33	11	17
E of #305103	54	36	41	43	48	41
80T at #102422	32	11	18	32	11	18

It is the Designer's responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any additional proposals for phase balancing prior to finalizing the job designs.

The decision to move forward with the proposed phase change will be confirmed and approved by the Regional Operations Engineer, and coordinated by the Designer in their respective polygon design(s).

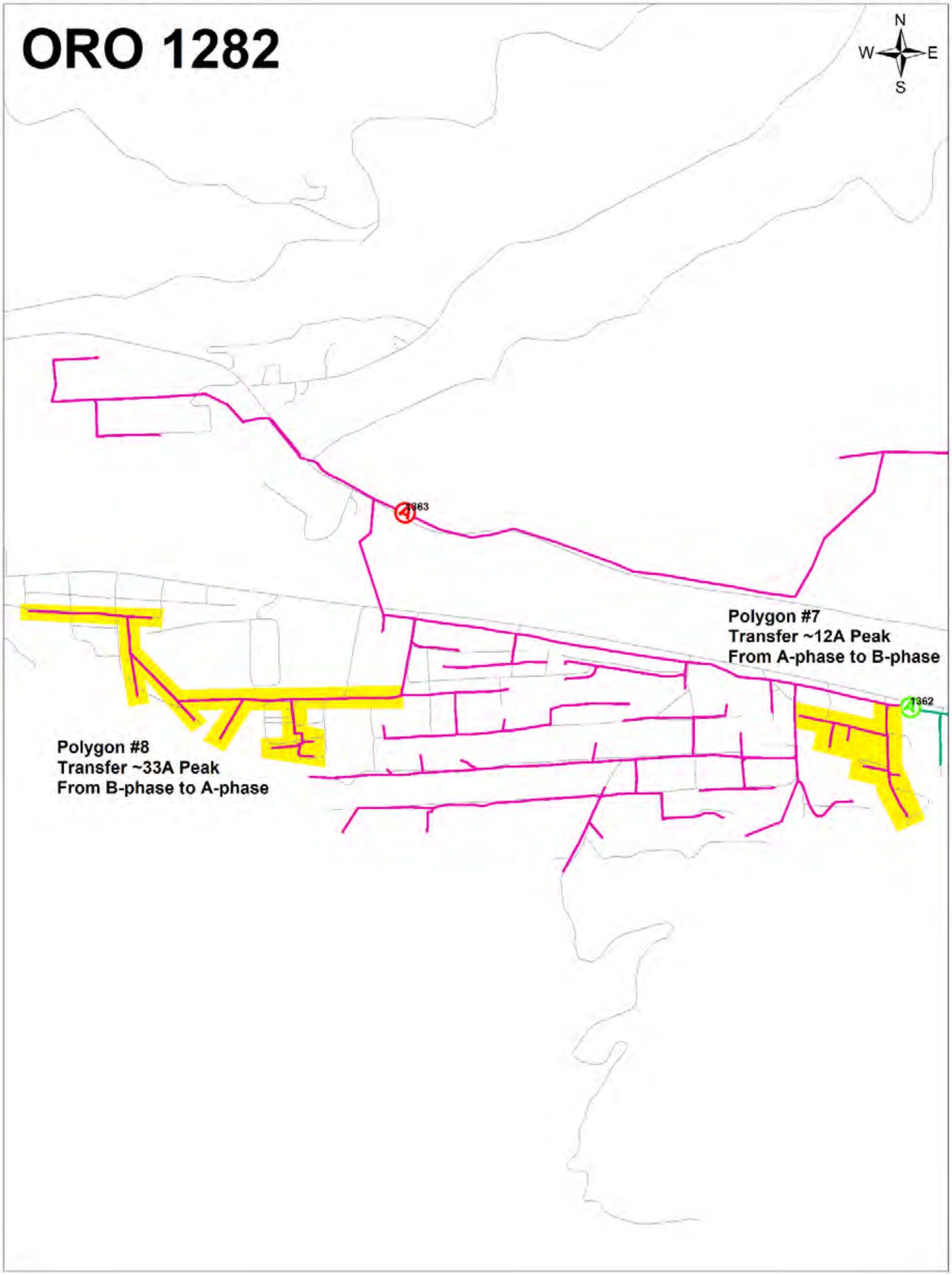


Figure 13. ORO 1282 Feeder Load Balancing Phase Change Recommendations

Conductor

All primary conductors on ORO 1282 were analyzed in Synergi using the balanced peak ampacity values identified in the *Peak Loading* section of this report. Specific attention was given to conductors that have the potential for being overloaded, have relatively high line losses, serve areas with unacceptable voltage quality, and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on ORO 1282, as well as the proposals for improving the efficiency, voltage quality, and performance of the feeder.

High loss conductors are inefficient conductors that result in increased line losses, especially where there is moderate to heavy loading. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on the suggested replacement of conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher loss conductors. An Engineering decision can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also decide to reconductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management (WPM) reports, physical condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

The following table lists the various types of overhead conductors that are present on ORO 1282, as well as the approximate circuit miles of each conductor type as analyzed through the Synergi modeling software on the creation date of the model. An initial analysis suggests that there are relatively few higher loss conductors present on the ORO 1282. If any higher loss conductors are found during field analysis, the Designer shall determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors. It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any additional reconductoring proposals prior to beginning the job designs.

The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the conductor analysis requirements for the Grid Modernization program. The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary conductor requiring attention.

Approximate Circuit Miles by Conductor Type		
Conductor	**Miles**	**Ohm/Mile (50°C)**
1/0ACSR	0.04	1.0340
1CN15	0.85	1.2229
2/0ACSR	4.86	0.8430
2/0CU	0.01	0.4810
2ACSR	0.39	1.5830
2CN15	0.97	1.5419
2CU	0.96	0.9560
2STCU	0.04	0.9750
4/0ACSR	0.01	0.5730
4ACSR	4.56	2.4590
556AAC	0.02	0.1855
6A (CW)	1.11	2.4400
6CU	1.79	2.4170

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweigh the significant work required to rebuild the existing line to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors. Utility studies suggest that converting from Overhead to Underground has been shown to be cost effective when the conversion costs to Underground do not exceed 3x to 5x the Overhead equivalent. The ability to reconfigure and convert feeders for reliability and efficiency improvements is a characteristic that distinguishes Grid Modernization from other internal programmatic or capital work.

ORO 1282 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, there are large remote section of the feeder trunk that could be candidates for reconfiguration or relocation. These sections are difficult to access and may result in long duration outages. With that said, these remote sections of the feeder have recently received attention by the Orofino office with strategic pole replacements, wider vegetation clearances, and the introduction of raptor construction. The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole tests, OMT information, and conductor analysis. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible. Approval from the Orofino Local Rep and the Regional Area Engineer should be received prior to moving forward with any design proposals to relocation or reconfigured these sections. Figure 14 illustrates the sections with potential opportunities for relocation or reconfiguration.

Any designs to reconfigure overhead circuits or convert to underground shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements. All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer. It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconfiguration or conversion to underground prior to initiating the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, are economically justifiable, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Area Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

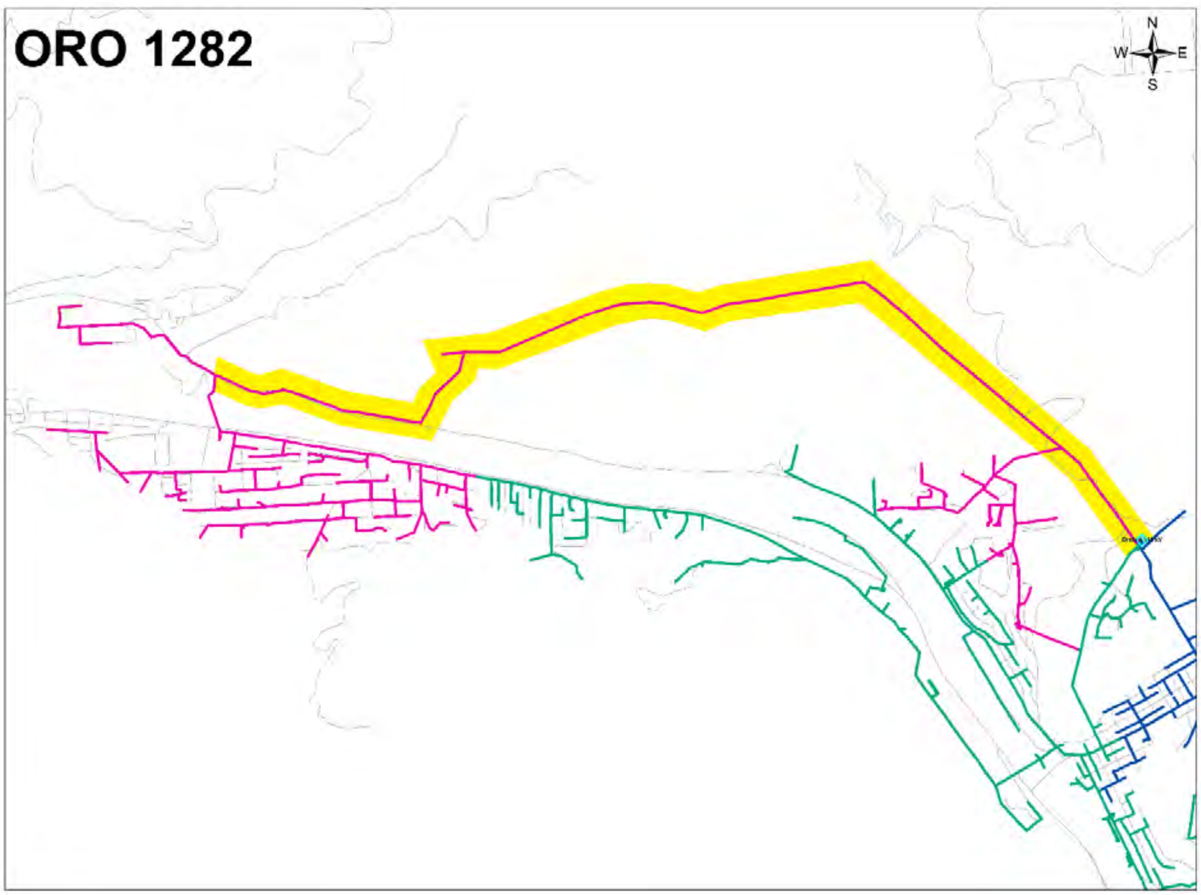


Figure 14. Potential Opportunites for Relocation or Reconfiguration

Clearwater River Crossing near Clearwater Power's Ahsahka Substation

In approximately 1998, the Idaho State Highway 7 bridge over the Clearwater River was reconstructed. Avista had an overhead river crossing (ORO 1282) that was removed around that time to facilitate the construction of the bridge. It was decided at that time by Avista not to rebuild the overhead river crossing. Instead, Avista pursued a temporary connection from Clearwater Power's Ahsahka Substation to serve the Avista customers on the west side of the river. The eleven current Avista meter points are presently being primary metered by Avista from Clearwater Power.

The re-establishment of the overhead river crossing is a complex undertaking, as evidenced by the approximately 22 years that have passed without the development of a long term solution to reconnect these customers directly to Avista's distribution system. There are benefits and drawbacks to rebuilding the river crossing. The decision and solution to reconstruct the river crossing will be an intradepartmental effort that will require external coordination with Clearwater Power, Idaho Department of Transportation, the Department of Lands, the Bureau of Indian Affairs, and the Army Corp of Engineers.

Re-establishing the overhead river crossing at this location is not within scope for the Grid Modernization Program. A re-established river crossing would not provide improvements to reliability, circuit efficiency, performance, or voltage quality to the customers being served west of the river. While the Program does acknowledge the potential internal benefits of rebuilding the river crossing to serve our customers from our own facilities, the nature of the work and the measureable outcomes are not within the scope of the Program. Grid Modernization will address the existing facilities on both sides of the river, but will not address the construction of the river crossing. Figure 15 illustrates the location of the river crossing that was removed around 1998.

Due to potential confusion and safety concerns by field and office employees unfamiliar with this situation, it is recommended to properly reflect this scenario within AFM and Designer. AFM currently includes notes stating that the river crossing does not exist, however this apparent electrical connection is visualized in both AFM and Synergi. The local office is encouraged to pursue the removal of the visualization of the electrical connection. In addition, the portion of the circuit on the northwest side of the Clearwater River should be renamed and assigned a feeder layer color that is different from ORO 1282. These changes would clearly reflect the two different power sources that are present, and would allow for more accurate identification and modeling.

Figure 15. River Crossing Opportunity at Clearwater River near Ahsahka

Primary Conductor Analysis

Primary conductors can have the ability to negatively affect the reliability, voltage quality, and efficiency of a distribution circuit. Primary conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to serve peak loading demands and provide adequate voltage levels, and insure that they do not cause significant and unnecessary line losses. Primary conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

Primary Trunk Conductor Analysis

The primary trunk conductors on ORO 1282 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The entire feeder trunk is currently conductored with a majority of 2/0ACSR, some 2CU, and a brief section of 1/0ACSR. ORO 1282 currently contains one overhead feeder tie through switch #1362 with ORO 1281.

The Synergi models for ORO 1282 do not support upgrading the primary trunk conductors based on capacity concerns given the large amount of medium capacity conductors already present the feeder trunk and ties. In addition, line losses on the trunk are currently in the optimal range for both the peak and average loading scenarios, which has been aided by balancing the feeder and relatively lower loading conditions where higher loss conductors exist. In addition, there are not any concerns with modeled voltage quality that requires being address through feeder trunk reconductoring.

Any designs to reconductor primary trunk shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary trunk prior to initiating the job designs. It may be determined that additional primary or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. . This could also include the conversion of any overhead primary to underground if it is determined that multiple pole replacements are required, and the conductor is found to be in poor physical condition or identified for replacement. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary trunk conductors based on the conditions dictated through field analysis.

Primary Lateral Conductor Analysis

The primary lateral conductors on ORO 1282 were individually analyzed to identify if the wires were sized appropriately for loading, line losses, and voltage quality during peak normal system configuration. The analyzed models suggest reconductoring select laterals to meet peak loading conditions during normal system configuration, lower line losses, and promote improved voltage levels downstream. As part of the line loss analysis, attention was given to identify the presence of high loss conductors, even if relatively low loading levels did not provide high line losses.

ORO 1282 is known to contain both 6CU conductor and 6A conductor, which is a higher loss primary conductor that is targeted for replacement. The circuit contains approximately 1.11 circuit miles of 6A and 1.79 circuit miles of 6CU. All 6A and 6CU conductors should be removed and replaced with a minimum of 4ACSR. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program. In addition, the Designer shall consult the *Wildfire Resiliency Plan* and the *Wildfire Resiliency* section of this report for additional information on reconductoring existing small gauge primary wire.

Figures 16 and 17 identifies the 6A primary laterals that require reconductoring on ORO 1282.

- Reconductor existing 3-phase 6A overhead lateral south of Dunlap Road & Shellburn Drive with 4ACSR primary and a 4ACSR neutral (approximately 1000') in **Polygon 2**.
- Reconductor existing 3-phase 6A overhead lateral north of Shriver Road & School with 4ACSR primary and a 4ACSR neutral (approximately 1140') in **Polygon 2**.
- Reconductor existing 1-phase 6A overhead lateral near 128th Street & Hartford Avenue with 4ACSR primary and a 4 ACSR neutral (approximately 1440') in **Polygon 8**.
- Reconductor existing 1-phase 6A overhead lateral south of Jerome Avenue & 123rd Street with 4ACSR primary and a 4ACSR neutral (approximately 370') in **Polygon 9**.
- Reconductor existing 3-phase 6A overhead lateral south of US Highway 12 & 118th Street with 4ACSR primary and a 4ACSR neutral (approximately 1300') in **Polygon 9**.

Figures 18 and 19 identifies the 6CU primary laterals that require reconductoring on ORO 1282.

- Reconductor existing 1-phase 6CU overhead lateral east of Hospital Drive Trailer Ct with 4ACSR primary and a 4ACSR neutral (approximately 770') in **Polygon 3**.
- Reconductor existing 1-phase 6CU overhead lateral south of US Highway 12 & 115th Street with 4ACSR primary and a 4ACSR neutral (approximately 2500') in **Polygon 7**.

- Reconductor existing 3-phase and 1-phase 6CU overhead lateral west and north of Indio Avenue & 122nd Street with 4ACSR primary and a 4ACSR neutral (approximately 5300') in **Polygon 9**.
- Reconductor existing 3-phase and 1-phase 6CU overhead lateral west and east of Jerome Avenue & 122nd Street with 4ACSR primary and a 4ACSR neutral (approximately 2500') in **Polygon 9**.
- Reconductor existing 1-phase 6CU overhead lateral east of Rodeyo Drive with 4ACSR primary and a 4ACSR neutral (approximately 350') in **Polygon 9**.

In addition to the removal and replacement of smaller gauge higher loss conductor, there is one addition lateral that requires reconductoring to incorporate an additional phase to achieve optimized load balancing. An additional phase (A-phase) of 4ACSR primary (approximately 720') south of US Highway 12 & 129th Street shall be installed in **Polygon 8** to allow downstream load to be transferred to A-phase. The existing 4ACSR neutral is appropriately sized, and does not require reconductoring. Figure 20 illustrates the primary lateral to add the additional phase of 4ACSR primary.

In addition, all laterals should be examined by the Designer in the field to identify additional small gauge, high loss wire that would require reconductoring to comply with the Distribution Feeder Management Plan. As part of the field analysis, the Designer should also weigh and incorporate the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, potential benefits from relocation, etc. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

There are no known platted residential developments that are tentatively proposed or under construction on ORO 1282.

Any designs to reconductor primary laterals shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. This could also include the conversion of any overhead laterals to underground if it is determined that multiple pole replacements are required, and the conductor is found to be in poor physical condition or identified for replacement. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary lateral conductors based on the conditions dictated through field analysis.

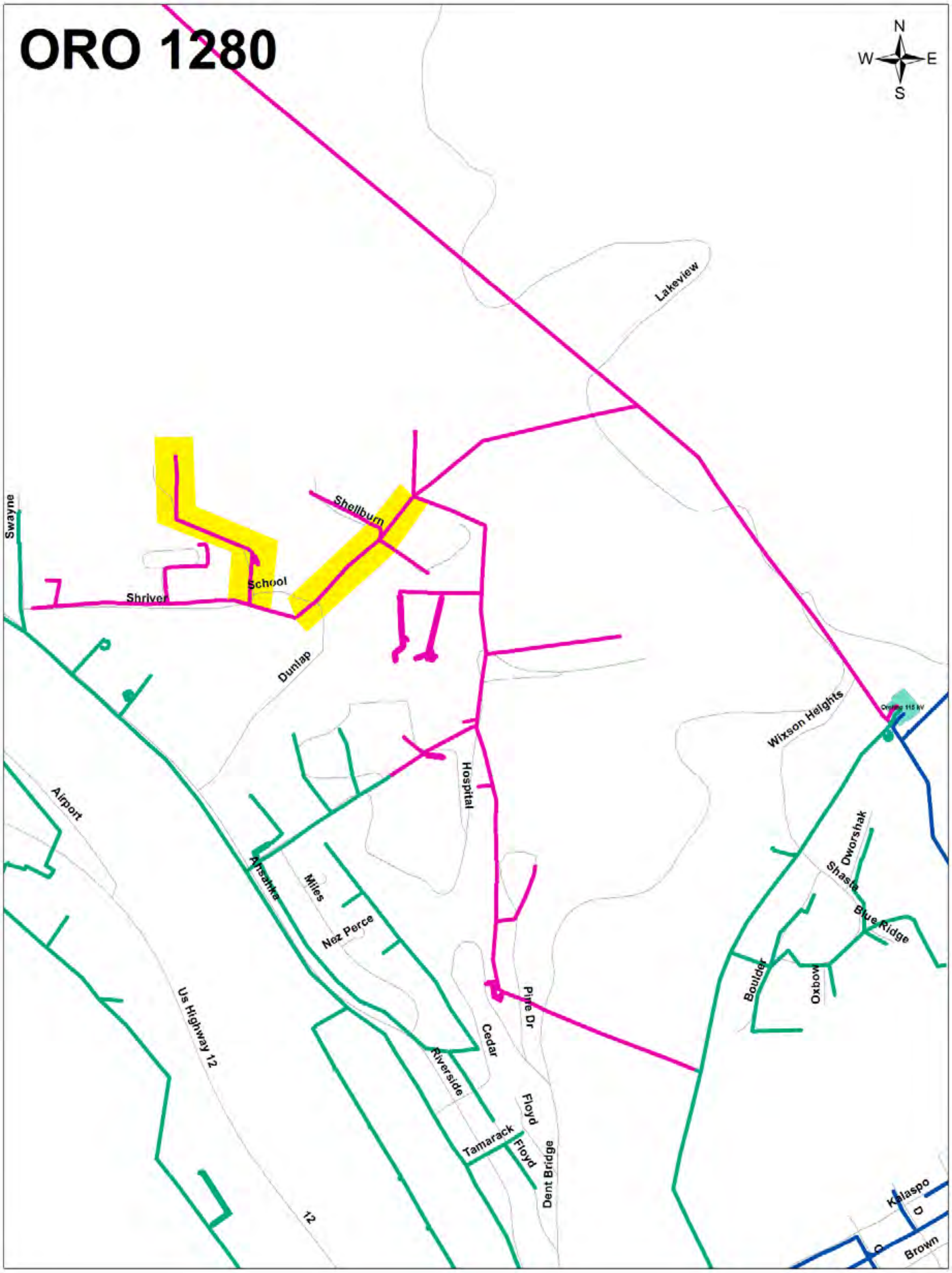


Figure 16. 6A Primary Laterals Requiring Reconductor

Figure 17. 6A Primary Laterals Requiring Reconductor

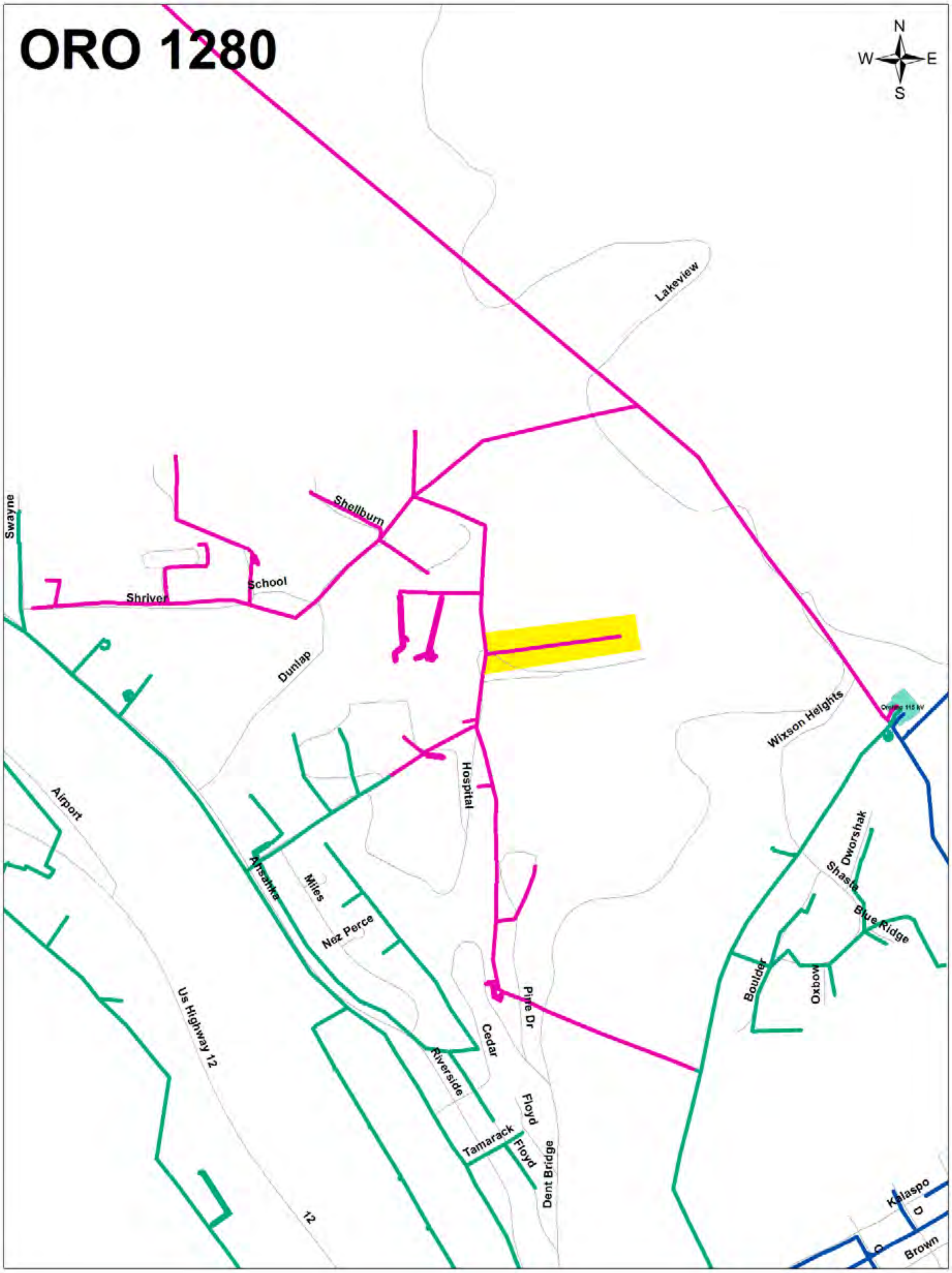


Figure 18. 6CU Primary Laterals Requiring Reconductor

Figure 19. 6CU Primary Laterals Requiring Reconductor

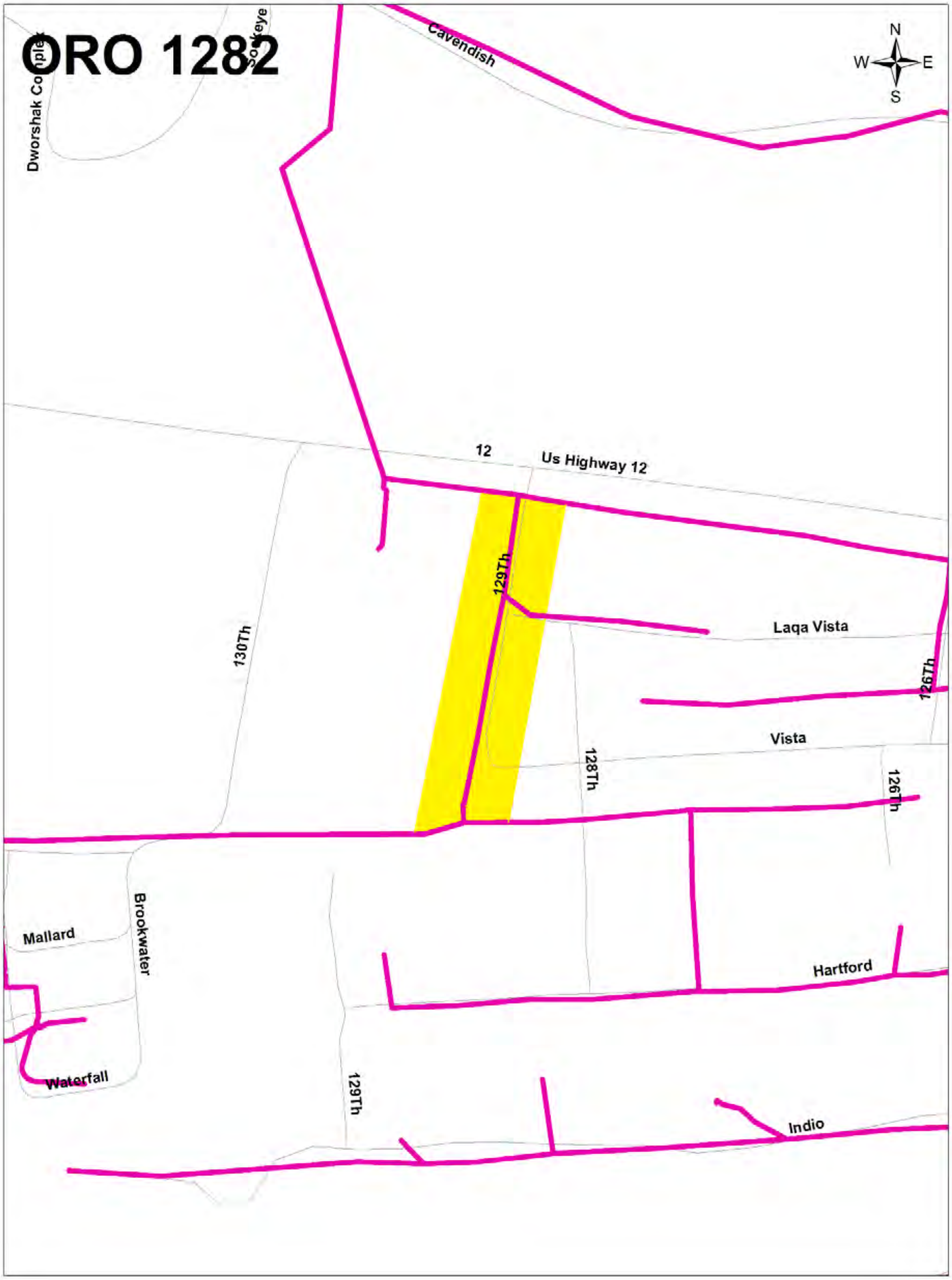


Figure 20. Install Additional Phase of 4ACSR Primary for Load Balancing

Feeder Tie Locations and Opportunities

A reduction in the duration of sustained outages can be achieved through rebuilding existing feeder ties and establishing new feeder ties. Existing feeder ties can be improved through increased capacity by reconductoring to higher ampacity conductors, as well as replacing existing manual switches with communications devices that can either be controlled remotely or through a distribution management system (DMS). New feeder ties can be established for circuits without connections to adjacent feeders or where additional ties could provide reliability improvements. Newly created feeder ties will generally be optimized by installing switches with communications that can either be controlled remotely or through a DMS.

ORO 1282 currently has only one adjacent feeder in ORO 1281, and already contains a manual overhead feeder tie connection to this circuit through switch #1362.

Device Number	Feeder Tie	Status	Device Type
1362	ORO 1281	N.O.	S&C 400A LB Air Switch

The existing normally open solid door cutouts between ORO 1282 and ORO 1281 west of the Idaho Correctional Institution in **Polygon 3** will be upgraded to a manual air switch (G127, N.O.). This will upgrade the single-phase switching devices to a three-phase ganged operated switching device that will improve the safety and speed involved with operating this tie. Figure 21 illustrates the location of the proposed manual air switch on ORO 1282.

While there are not any additional circuits to create new feeder ties with, the existing feeder tie with ORO 1281 can be enhanced. Even though both ORO 1281 and ORO 1282 are both served from Transformer #1 at the Orofino Substation, the creation of a new automated tie with communications would provide improved reliability and flexibility for both circuits. ORO 1282 is conductored with #2CU (205A summer ampacity) to the west of the switch location, while ORO 1281 is conductored with 1/0 ACSR (208A summer ampacity) to the east of the switch location. This enhancement opportunity will be discussed further in the *Distribution Automation* section of this report.

Figure 22 illustrates the location of the existing manual air switches and distribution feeder tie on ORO 1282.

Figure 36 illustrates the locations of the proposed distribution automation lines devices ORO 1282.

The decision to pursue additional switching devices or feeder tie opportunities will be discussed and determined with the Regional Area Engineer based on their anticipated frequency of using potential ties in the operation of the Spokane distribution system.

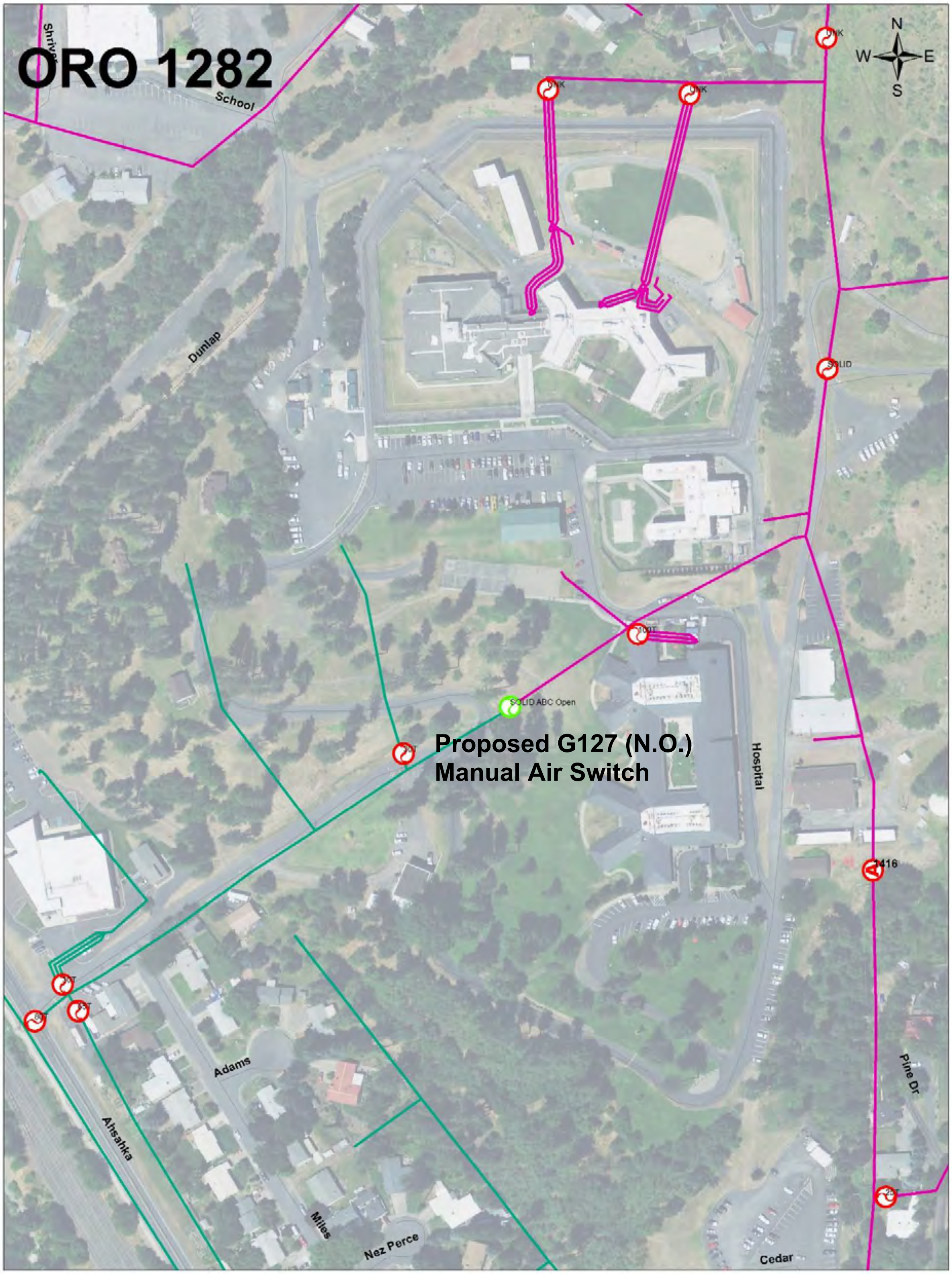


Figure 21. Proposed G127 Normal Open Manual Air Switches Feeder Tie

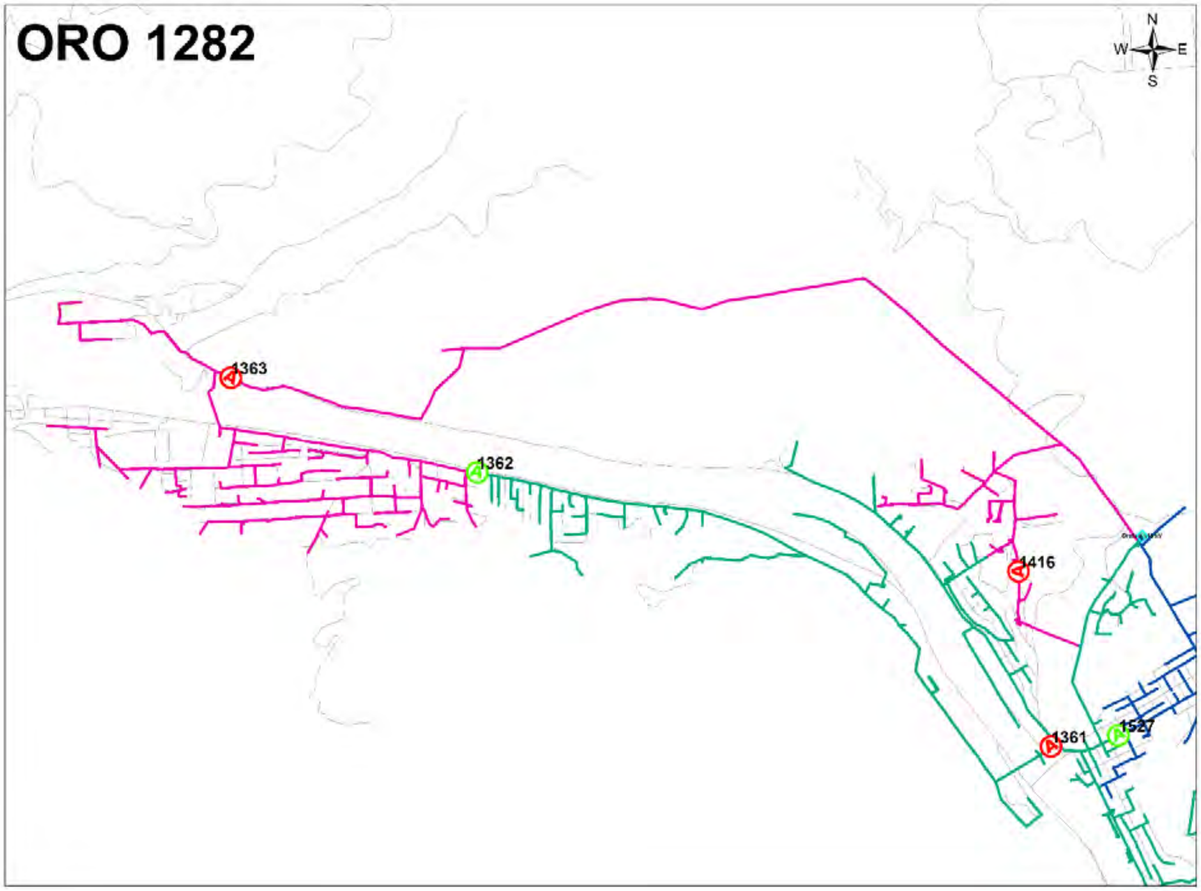


Figure 22. Existing Manual Air Switches and Feeder Tie on ORO 1282

<u>Transmission Underbuild</u>

ORO 1282 was identified to contain approximately 5,500’ circuit feet of primary distribution underbuild on existing transmission lines. ORO 1282 is collocated on the *Dworshak-Orofino* 115 kV transmission line in **Polygon 1** on approximately 8 poles from structures 2/1 to 3/2.

The Transmission Engineering Department will be contacted before the start of the project to inform the group of the proposed Grid Modernization work on this circuit in an effort to inform and promote collaboration. In addition, the Transmission Engineering Department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is underbuilt distribution to ensure the pole class is adequate for the physical loading on the structure.

Figure 23 illustrates the locations where ORO 1282 primary distribution is underbuilt on the Dworshak-Orofino 115kV line.

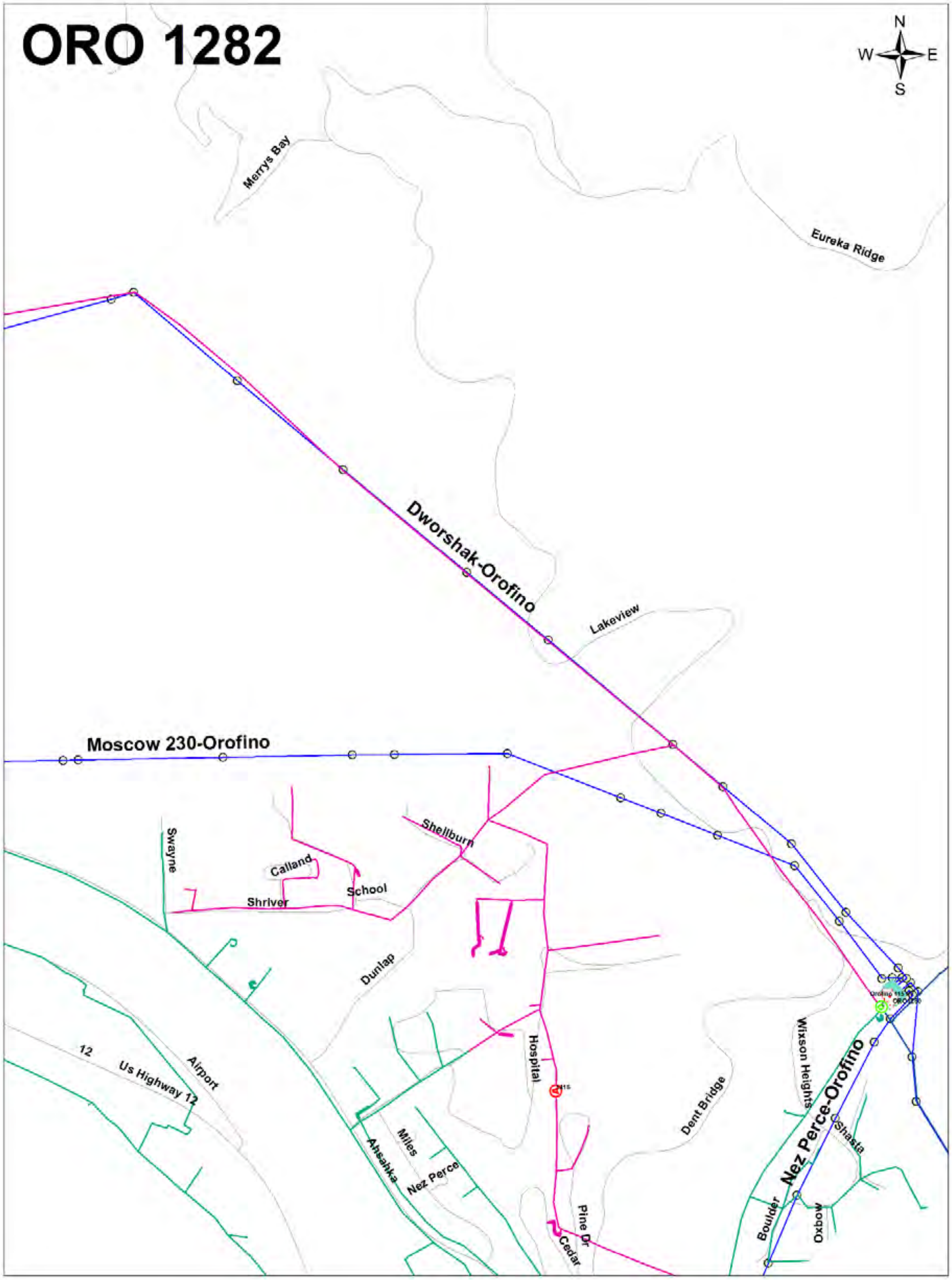


Figure 23. ORO 1282 Distribution Underbuild on Dworshak-Orofino 115kV Line

Wildfire Resiliency

The effort to ensure that distribution facilities are more resilient with respect to fire ignition and the impact of fire is a fundamental objective for Electric Utilities. There is consensus throughout Avista to expand upon the asset maintenance efforts associated with fire risk zones, otherwise known as Wildland Urban Interface (WUI) areas. WUI areas are generally characterized as rural or forested areas adjacent to urban population centers where wildfire poses a significant threat to human life, property, and infrastructure. It is in these WUI areas where electric infrastructure is particularly at-risk to wildfire events. Avista's Wildfire Resiliency Plan has outlined suggested improvements to the distribution system to reduce the impacts on wildfire in terms of frequency and being a potential source of ignition. The following categories outline the suggested practices of the Wildfire Resiliency Plan, as well as describe how the Grid Modernization program is already actively addressing these recommendations.

Fiberglass cross arms are proven to be more reliable than their wood cross arm equivalent. In addition, fiberglass cross arms have drastically reduced the occurrence of pole fires created by tracking between a wood pole and wood cross arm. The Wildfire Resiliency Plan requires replacing all wood cross arms with fiberglass cross arms within WUI Tier 2 and 3 areas. The Grid Modernization Program currently analyzes the characteristics of wood cross arm (condition, type, age, length, balanced physical loading, pin type, leaning, visible moss, attached equipment and materials, etc.) when determining whether to replace with a fiberglass arm. The Designer shall specifically consult the *Cross Arm* section of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

Prior to the 1960's, small gauge copper and steel wire was a common construction practice for overhead conductor. Over the last 50 years, small gauge copper wire such as #8CU and #6CU has been identified with an increased risk in annealing and breaking, which represents a reduced strength compared to modern ACSR conductors (Aluminum Conductor Steel-Reinforced). This results in an increased possibility of fire ignition if the compromised wire makes contact with the ground, conductors, or vegetation. The Wildfire Resiliency Plan requires replacing all primary wire that is #6 CU/Crapo or smaller with ACSR conductors within WUI Tier 2 and 3 areas. The Grid Modernization Program currently analyzes the characteristics of primary wire when determining whether to reconductor. The Designer shall specifically consult the *Overhead Conductor* section of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

The installation of open wire secondary districts has not been a recommended new-construction practice at Avista since the 1950's. These districts typically utilize uninsulated primary wire to create 120/240V aerial bus work that has traditionally been deployed along urban streets and alleys. The use of the open wire construction method results in an increased possibility of fire ignition if the uninsulated wires make contact with vegetation growing through the district – or the source of a phase-to-phase or phase-to-ground fault. The Wildfire Resiliency Plan requires removing all open wire secondary districts within WUI Tier 2 and 3 areas. The Designer shall specifically consult the *Open Wire Secondary* section of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

Wildlife, such as birds and small animals, can create electrical contact with energized overhead power lines, which can result as a source for possible fire ignition and distribution outages. The use of wildlife guards can reduce the ability for animal and birds to make electrical contact by covering the conductor and electrical connections of energized components. Animal guards can include: transformer bushing covers, cutouts covers, arrestor covers, and pin insulator covers. The Wildfire Resiliency Plan requires installing animal guards on structures and equipment within WUI Tier 2 and 3 areas. Avian guards shall be installed within identified Avian Zones in accordance with the Overhead Construction Standards, regardless of the WUI area. In addition, avian protection framing guidelines and other mitigation efforts (such as covered wire, flight diverters, etc) can be utilized to further minimize wildlife contacting energized components on the distribution system. The Designer shall specifically consult the *Avian/Raptor Protection* section of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

Designers should strongly consider the installation of steel or ductile iron poles to replace wood structures in critical locations. Critical pole locations can include, but not be limited to: highway/railroad/river/canyon crossings, major equipment or device poles (switches, reclosers, regulators), and heavily guyed structures. While it is not cost effective to convert all wood structures to steel poles, replacing the critical structures mitigates catastrophic damage during fire, high wind, and weather events. The Wildfire Resiliency Plan strongly recommends replacing all critical wood poles with steel poles within WUI Tier 2 and 3 areas. The Designer shall specifically consult the *Wood Pole* and *Steel Pole* sections of the Distribution Feeder Management Plan and the Overhead Construction Standards for specific parameters on the requirements for the Grid Modernization program.

Figure 24 illustrates the wildland urban interface (WUI) areas that are adjacent to ORO 1282.

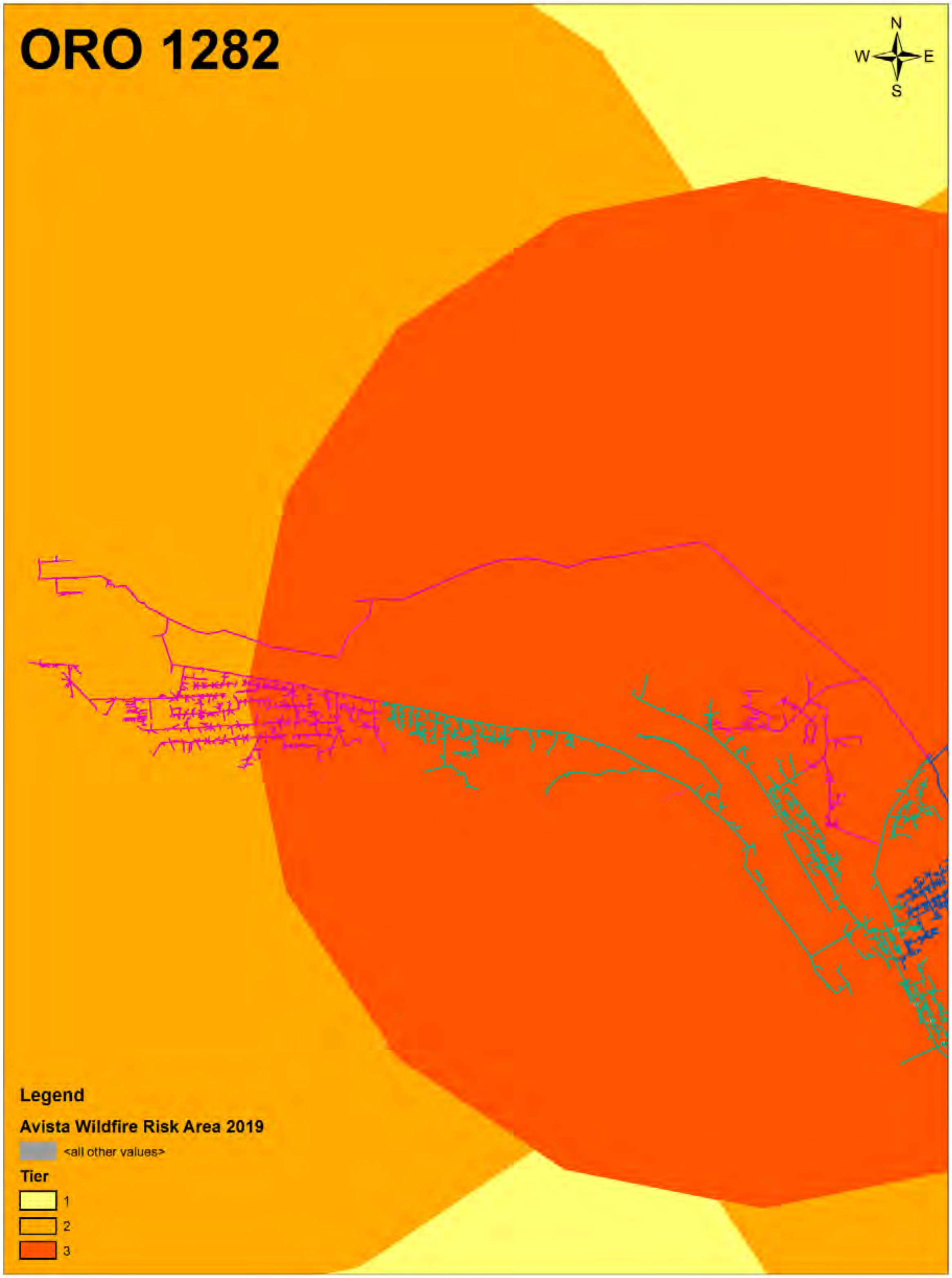


Figure 24. Wildland Urban Interface Tiers for ORO 1282

Voltage Quality

Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. In addition, numerous primary laterals will be reconductored with more efficient conductors to support voltage levels. In some scenarios, an additional conductor phase(s) may be installed to offload a heavily loaded phase and assist in supporting the voltage.

The ORO 1282 circuit was analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled in Synergi during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. A voltage base of 123V was used for the models in Synergi.

The following information on the substation voltage regulators for ORO 1282 was taken from Maximo, which is the system of record for Avista T&D assets.

Serial Numbers	A	B	C
ORO 1282 Station Regulators	**6827-30**	**6827-35**	**6827-56**

Rated Power	**187 kVA**
Rated Current	**246 A**
C.T. Ratio	**250/.02**
Equipment P.T. Ratio	**63.5:1**
Corrected/Desired P.T. Ratio	**63.5:1**
Distribution Transformer Ratio	**63.5:1**

* Information in MAXIMO as of 4/8/2020

The data in the following sections suggest that the existing voltage regulator settings at the Orofino115kV substation are providing output voltages that are appropriate to serve average and peak load on the circuit during normal feeder configuration. In addition, the models suggest that the Moscow 115kV substation is also providing output voltages that are higher than necessary to serve average and peak load on the feeder during situations where additional load from ORO 1281 is served.

Voltage Quality Analysis Before Incorporating Recommendations

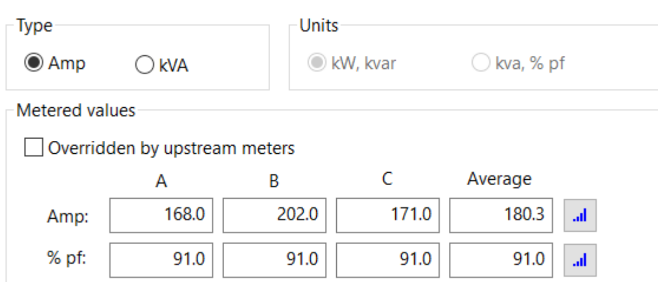
Figures 25 and 26 illustrate the modeled voltage levels for multiple scenarios on ORO 1282 before any proposed recommendations were incorporated into the models. These scenarios fall under ANSI 84.1 Range A operating limits. Range A provides the normally expected voltage tolerance on the utility supply for a given voltage class. The utilization equipment (loads) are expected to function and provide full satisfactory performance for Range A voltage tolerance. For Range A this variation of allowable service voltage is +5% to -5% for system operating 600V and below. The occurrence of service voltage variation outside this range should be infrequent. *Green* illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. *Yellow* illustrates voltage levels between 114–117 V and 123–126V. *Red* illustrates voltage levels lower than 114V and greater than 126V. These modeled values are estimated on the high side of the individual distribution transformers before any voltage drop through the transformer or secondary.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to ORO 1282. During peak loading conditions, voltage levels nearest to the Orofino 115kV Substation were elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation in Polygon 1 at approximately 126.3V, however the voltage was down to 124.5V at the first customer served. The minimum voltage modeled on the feeder was 121.1V in Polygon 8. These modeled voltages do not suggest of service level voltage problems on ORO 1282 based on the known information incorporated into the model. No corrective actions are recommended based on the modeled voltage levels at peak loading during normal configuration before incorporating recommendations.

Figure 25 illustrates the modeled voltage levels at peak loading on ORO 1282.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	115	2.26	415	180
122.00 - 124.00 V	401	9.81	3254	338
124.00 - 126.00 V	86	3.95	158	67
126.00 - 140.00 V	0	0.00	0	0



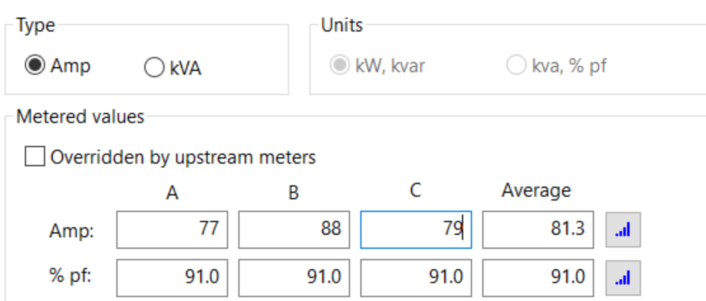
Modeled Voltage Levels at Average Loading

The voltage levels on the feeder were again analyzed before implementing any of the recommended proposals, however this time during average loading conditions. This scenario saw slightly higher voltage levels across the feeder.

During average loading conditions, voltage levels nearest to the Orofino 115kV Substation were still slightly elevated however they were still with the acceptable range and slightly lower than the Peak Loading scenario values. The maximum voltage modeled on the feeder occurred near the substation in Polygon 1 at approximately 125.5V, with the voltage levels closer to 123.6V at the first customer served. The minimum voltage modeled on the feeder was 123.2V in Polygon 8. These modeled voltages do not suggest of service level voltage problems on ORO 1282 based on the known information incorporated into the model. No corrective actions are recommended based on the modeled voltage levels at average loading during normal configuration before incorporating recommendations.

Figure 26 illustrates the modeled voltage levels at average loading on ORO 1282.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	420	9.13	1477	398
124.00 - 126.00 V	182	6.89	255	187
126.00 - 140.00 V	0	0.00	0	0



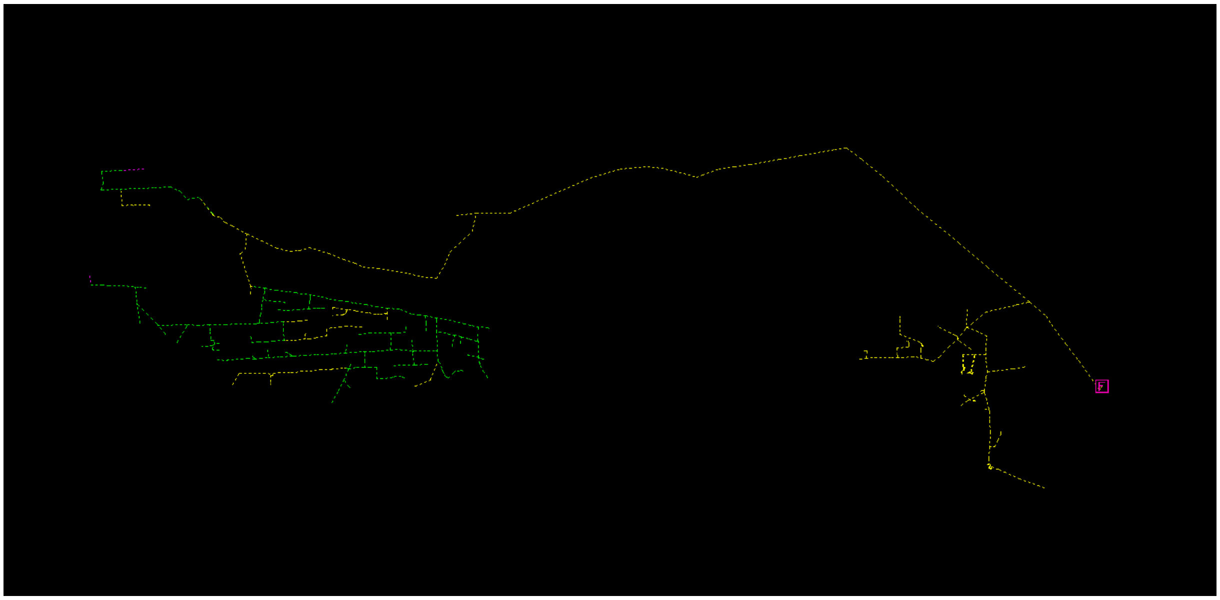


Figure 25. Modeled Voltage Levels at Peak Loading Before Recommendations

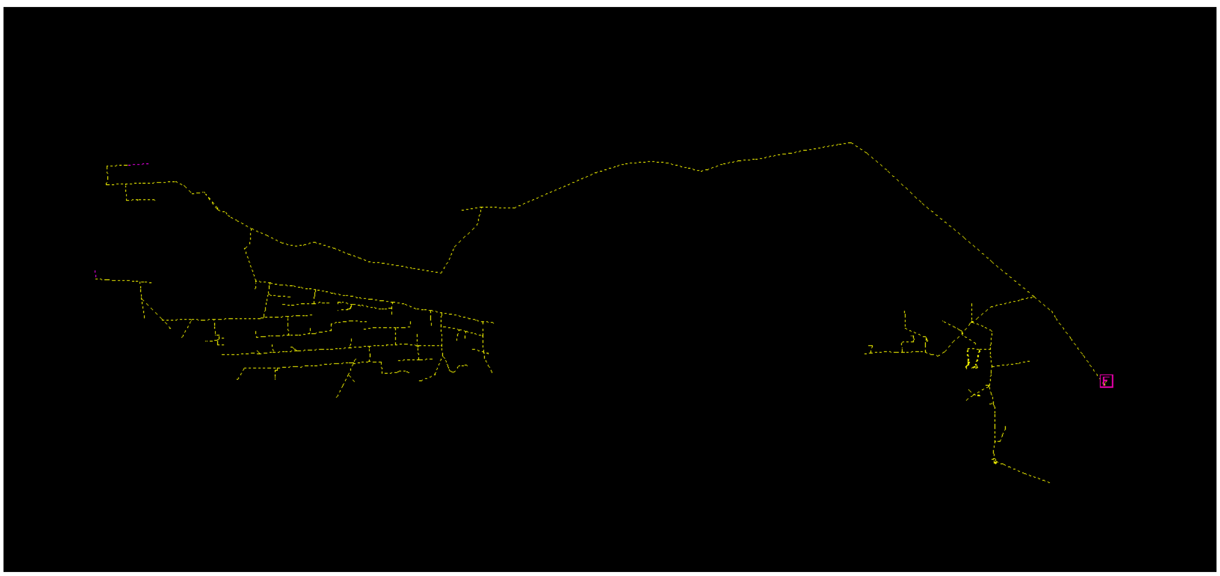


Figure 26. Modeled Voltage Levels at Average Loading Before Recommendations

Voltage Quality Analysis Before Incorporating Recommendations When Serving Additional Load from Adjacent Feeders

Figure 27 illustrates the modeled voltage levels on ORO 1282 before any proposed recommendations were incorporated into the models, however this time when serving additional load. This scenario falls under ANSI 84.1 Range B operating limits. Range B provides voltage tolerances above and below range A limits that necessarily result from practical design and operating conditions on supply or user systems or both. These conditions should be limited in extent, frequency and duration. When these variations occur, measures should be taken within a reasonable time frame to get back to range A. For range B this variation of allowable service voltage is +5.8% to -8.3% for system operating 600V and below.

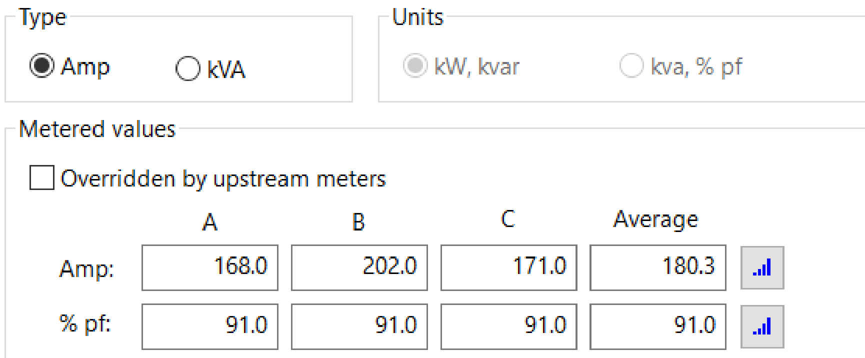
Green illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. *Yellow* illustrates voltage levels between 110–117 V and 123–127V. *Red* illustrates voltage levels lower than 110V and greater than 127V. These modeled values are estimated on the high side of the individual distribution transformers before any voltage drop through the transformer or secondary.

Modeled Voltage Levels at Peak Loading before Proposals – Serving ORO 1281 to the #1361 from ORO 1282 through the #1362

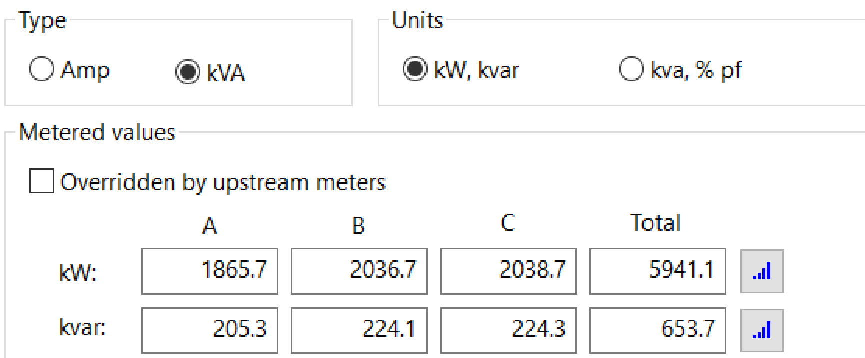
During peak loading conditions, voltage levels nearest to the Orofino 115kV Substation were elevated however they were still acceptable under Range B. The maximum voltage modeled on the feeder occurred near the substation in Polygon 1 at approximately 128.6V, however the voltage was down to 126.3V at the first customer served. The minimum voltage modeled on the feeder was 115.5V for the furthest customer at the newly created open point with ORO 1281 near switch #1361. Figure 24 illustrates the modeled voltage levels at this scenario. While approaching the lower limits, these modeled voltages do not suggest of service level voltage problems on ORO 1282 based on the known information incorporated into the model. No corrective actions are recommended based on the modeled voltage levels at peak loading during abnormal configuration before incorporating recommendations.

The voltage range values in the table below reflect the sections on both ORO 1281 and ORO 1282.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	193	4.91	893	203
116.00 - 118.00 V	267	6.10	1334	293
118.00 - 120.00 V	182	6.47	660	215
120.00 - 122.00 V	58	2.90	71	30
122.00 - 124.00 V	163	11.12	709	114
124.00 - 126.00 V	604	13.44	5858	480
126.00 - 140.00 V	18	0.90	36	14



Modeled ORO 1282 Metered Information



Modeled ORO 1281 Metered Information

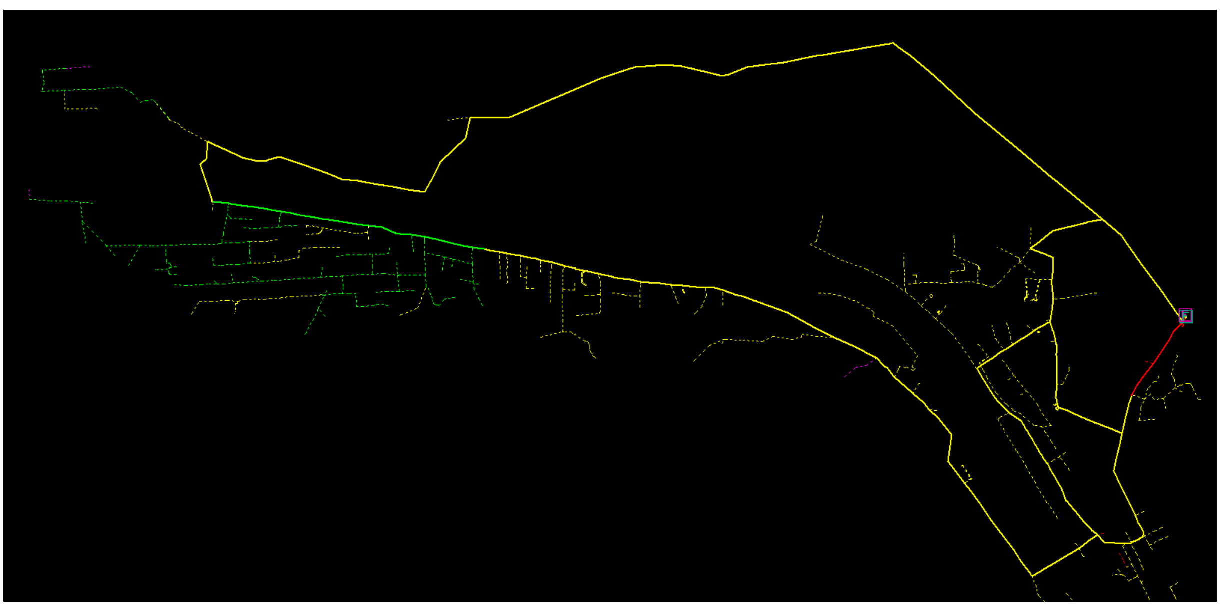


Figure 27. Modeled Voltage Levels at Peak Loading before Proposals – Serving ORO 1281 to the #1361 from ORO 1282

Voltage Quality Analysis After Incorporating Recommendations

The voltage levels on ORO 1282 were re-analyzed after incorporating and modeling the upgrade proposals. The feeder was modeled with these proposals in Synergi during both Peak loading and Average loading conditions.

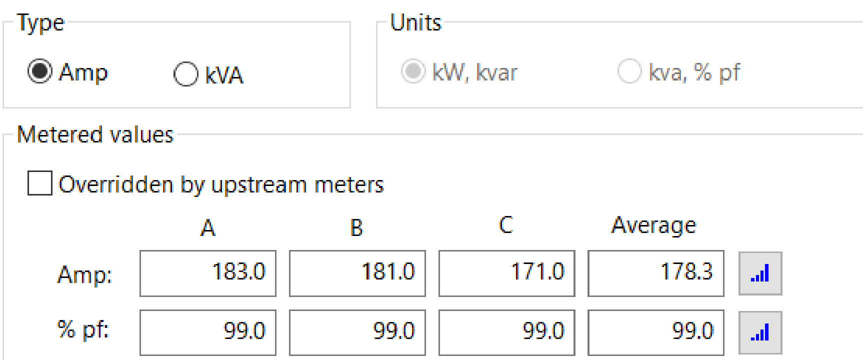
Figures 28-29 illustrate the modeled voltage levels for multiple scenarios on ORO 1282 before any proposed recommendations were incorporated into the models. These scenarios fall under ANSI 84.1 Range A operating limits. Range A provides the normally expected voltage tolerance on the utility supply for a given voltage class. The utilization equipment (loads) are expected to function and provide full satisfactory performance for Range A voltage tolerance. For Range A this variation of allowable service voltage is +5% to -5% for system operating 600V and below. The occurrence of service voltage variation outside this range should be infrequent. *Green* illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. *Yellow* illustrates voltage levels between 114–117 V and 123–126V. *Red* illustrates voltage levels lower than 114V and greater than 126V. These modeled values are estimated on the high side of the individual distribution transformers before any voltage drop through the transformer or secondary.

Modeled Voltage Levels at Peak Loading after Proposals

The voltage levels on the feeder were analyzed after performing the identified changes and improvements to ORO 1282. During peak loading conditions, overall voltage levels were slightly improved across the circuit. Voltage levels nearest to the Orofino 115kV Substation were elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation in Polygon 1 at approximately 126.3V, however the voltage was down to 124.7V at the first customer served. The minimum voltage modeled on the feeder was 121.0V in Polygon 9. These modeled voltages do not suggest of service level voltage problems on ORO 1282 based on the known information incorporated into the model. No corrective actions are recommended based on the modeled voltage levels at peak loading during normal configuration after incorporating recommendations.

Figure 28 illustrates the modeled voltage levels at peak loading on ORO 1282.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	121	2.34	422	192
122.00 - 124.00 V	294	6.73	1574	317
124.00 - 126.00 V	158	5.89	2120	65
126.00 - 140.00 V	4	0.02	0	0

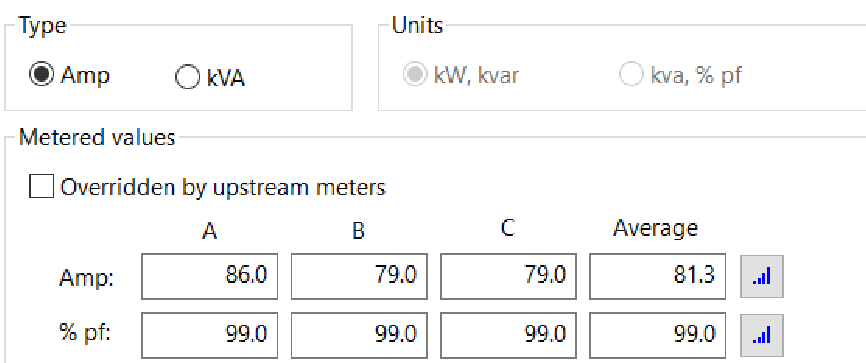


Modeled Voltage Levels at Average Loading after Proposals

The voltage levels on the feeder were analyzed after performing the identified changes and improvements to ORO 1282. During average loading conditions, overall voltage levels were slightly lowered across the circuit. Voltage levels nearest to the Orofino 115kV Substation were elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation in Polygon 1 at approximately 125.5V, however the voltage was down to 124.2V at the first customer served. The minimum voltage modeled on the feeder was 123.6V in Polygon 9. These modeled voltages do not suggest of service level voltage problems on ORO 1282 based on the known information incorporated into the model. No corrective actions are recommended based on the modeled voltage levels at average loading during normal configuration after incorporating recommendations.

Figure 29 illustrates the modeled voltage levels at average loading on ORO 1282.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	424	8.55	1633	410
124.00 - 126.00 V	153	6.43	253	164
126.00 - 140.00 V	0	0.00	0	0



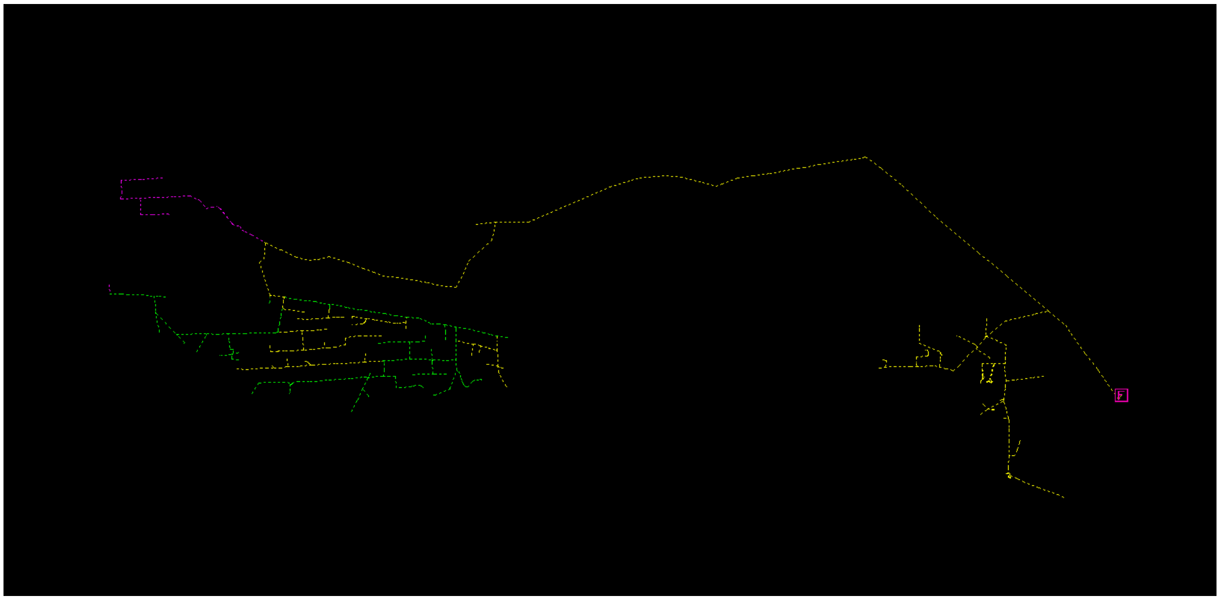


Figure 28. Modeled Voltage Levels at Peak Loading After Recommendations

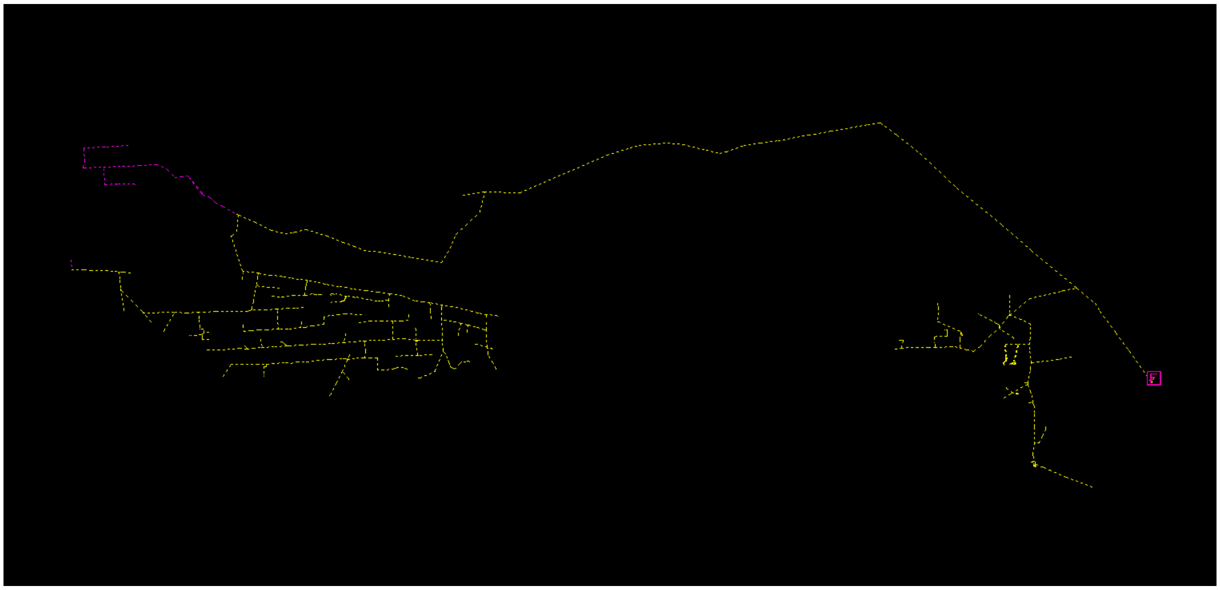


Figure 29. Modeled Voltage Levels at Peak Loading After Recommendations

Voltage Quality Analysis after Incorporating Recommendations When Serving Additional Load from Adjacent Feeders

Figure 30 illustrate the modeled voltage levels for the various scenarios on ORO 1282 before any proposed recommendations were incorporated into the models, however this time when serving additional load. This scenario falls under ANSI 84.1 Range B operating limits. Range B provides voltage tolerances above and below Range A limits that necessarily result from practical design and operating conditions on supply or user systems or both. These conditions should be limited in extent, frequency and duration. When these variations occur, measures should be taken within a reasonable time frame to get back to Range A. For Range B this variation of allowable service voltage is +5.8% to -8.3% for system operating 600V and below.

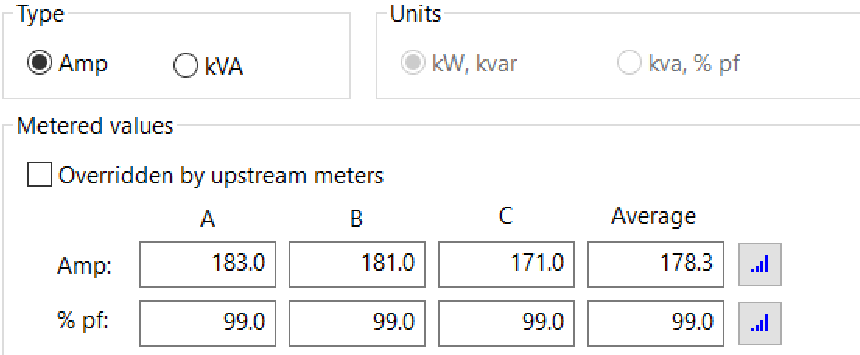
Green illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. *Yellow* illustrates voltage levels between 110–117 V and 123–127V. *Red* illustrates voltage levels lower than 110V and greater than 127V. These modeled values are estimated on the high side of the individual distribution transformers before any voltage drop through the transformer or secondary.

Modeled Voltage Levels at Peak Loading after Proposals – Serving ORO 1281 to the #1361 from ORO 1282 through the #1362

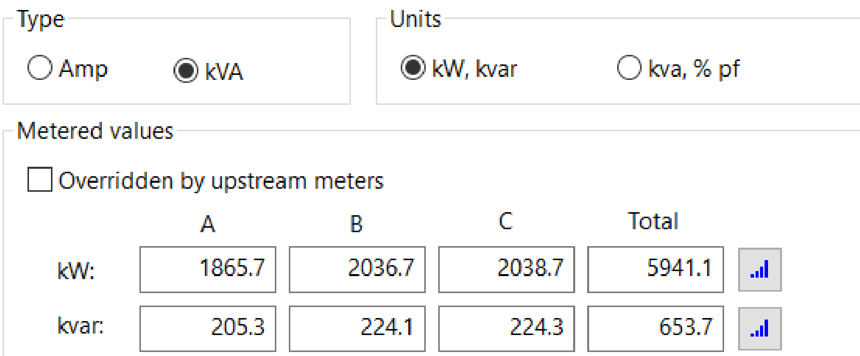
During average loading conditions, voltage levels nearest to the Orofino 115kV Substation were elevated however they were still acceptable under Range B. The maximum voltage modeled on the feeder occurred near the substation in Polygon 1 at approximately 129.4V, however the voltage was down to 126.9V at the first customer served. The minimum voltage modeled on the feeder was 115.9V for the furthest customer at the newly created open point with ORO 1281 near switch #1361. Figure 28 illustrates the modeled voltage levels at this scenario. While approaching the lower limits, these modeled voltages do not suggest of service level voltage problems on ORO 1282 based on the known information incorporated into the model. No corrective actions are recommended based on the modeled voltage levels at peak loading during abnormal configuration before incorporating recommendations.

The voltage range values in the table below reflect the sections on both ORO 1281 and ORO 1282.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	175	3.95	944	211
116.00 - 118.00 V	218	5.78	1219	259
118.00 - 120.00 V	205	6.24	665	202
120.00 - 122.00 V	74	2.82	195	57
122.00 - 124.00 V	165	11.35	709	114
124.00 - 126.00 V	511	11.99	4188	451
126.00 - 140.00 V	112	2.68	1930	43



Modeled ORO 1282 Metered Information



Modeled ORO 1281 Metered Information

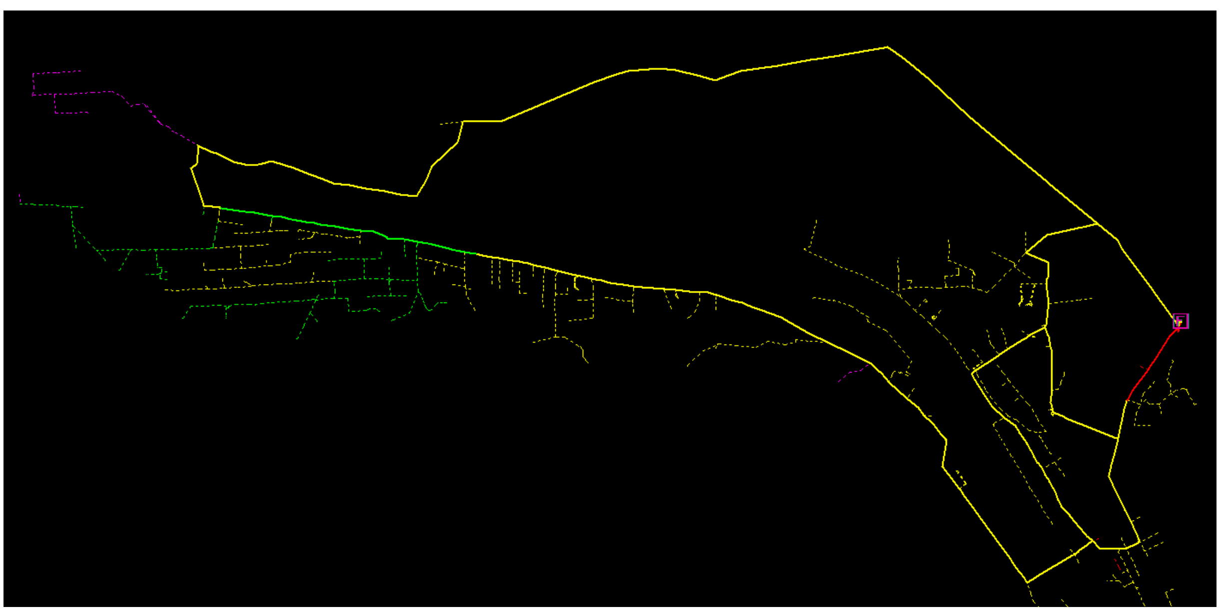


Figure 30. Modeled Voltage Levels at Peak Loading after Proposals – Serving ORO 1281 to the #1361 from ORO 1282

Voltage Regulator Settings

As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline voltage regulator settings. This is performed to reflect the changes to loading and to address the conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. The feeder is modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ranges for all customers during the modeled scenarios, and to eliminate over-voltage and under-voltage situations.

ORO 1282 has one existing stage of voltage regulation at the Orofino 115kV Substation. At this time, additional stages of midline voltage regulation are not recommended on the feeder to support voltage levels during normal configuration or times of switching due to the interconnected urban nature of the feeder and the relatively shorter feeder length.

It was determined that the existing voltage regulator settings at the Orofino 115kV Substation are providing appropriate voltage levels during average and peak loading scenarios. The decision to move forward with implementing any changes to the voltage regulator settings will be confirmed and implemented by the Regional Area Engineer. The existing and proposed voltage regulator settings are provided in the table below:

	Existing*		Proposed	
Forward Settings	**R**	**X**	**R**	**X**
ORO 1282 Station Regulators	**2**	**5**	**2**	**5**

* Settings in Maximo, AFM, and SynerGEE as of 1/14/19

ORO 1282 currently has Siemens MJ-X regular controllers to pair with the existing Siemens JFR station voltage regulators (7.6kV 219A 167kVA). The voltage regulators have fiber that is connected with the substation panel house. The MJ-X regular controllers are not automation compatible and must be upgraded to the newest standard Cooper CL-7 regulator controllers. Substation Engineering estimates that it will cost approximately $60k for the voltage regulators and voltage regulator controllers' upgrade and integration. In addition, the station breaker is an S&C Type FVR (15kV, 1200A, 12kA interrupting). The station breaker has a SEL 351R recloser control that is connected with fiber to the substation panel house. This combination is automation compatible and would not require any additional upgrades to bring the substation into full automation compatibility.

In order to promote complete automation on ORO 1282, Grid Modernization has notified Substation Engineering of the intended line automation work on the feeder and the necessary substation equipment upgrades to make this feeder fully automation compatible from the substation perspective. ORO 1282 is not currently scheduled on any Substation Engineering list to receive a programmatic replacement or upgrade.

Fuse Coordination and Sizing Analysis

Incorrect fuse sizes can compromise the reliability of the feeder through miscoordination of operation. Miscoordination can occur if the fuses in series are not correctly sized and managed to allow the furthest downstream device the opportunity to operate first. Fuses that are undersized and do not match the load being served can unnecessary operate and create unexpected outages. A customized fuse protection and coordination scheme has been determined to ensure that a consistent fusing philosophy is deployed and that all fuses are accurately sized.

Fuse sizing on ORO 1282 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and underground risers. Fuse recommendations for ORO 1282 were created by the Grid Modernization Program Engineer and approved by the Regional Operations Engineer. These map files are located in the Electrical Engineering drive *c01m19* under the *ORO 1282* folder within the *Feeder Upgrade – Dist Grid Mod* folder. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Area Engineer with any questions regarding fuse sizing and coordination.

The fuse “blowing” philosophy was selected for ORO 1282 where the smallest fuse was selected that would accurately coordinate to: satisfy peak loading conditions, protect the downstream conductor(s), and for fuse-to-fuse coordination based on preloading of source-side fuse link (maximum fault current). Distribution Construction Standard DU-2.500 was used as a reference to begin selecting the smallest allowable fuse for the downstream connected kVA/phase and the largest transformer on the phase. However, the *Distribution Feeder Protection General Guidelines* (Orange Book, S&C Table VII) was used in coordination with the fault duty found in the Synergi model to select the fuse size if there was an upstream fuse in series with a lateral fuse.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant increases or decreases to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Figures 31 and 32 illustrate the proposed fuse sizes for improved coordination on ORO 1282.

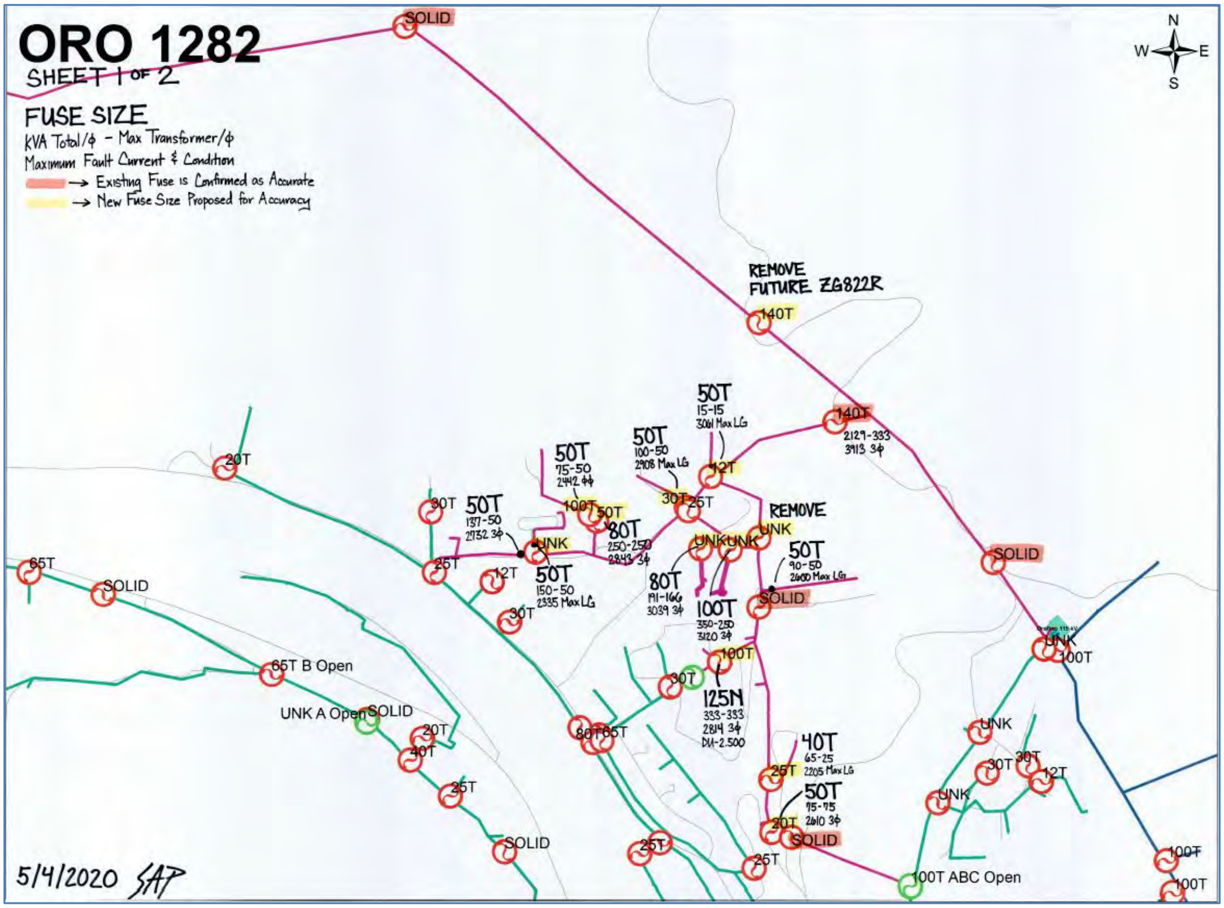


Figure 31. Fuse Size & Coordination Recommendations, Sheet 1 of 2

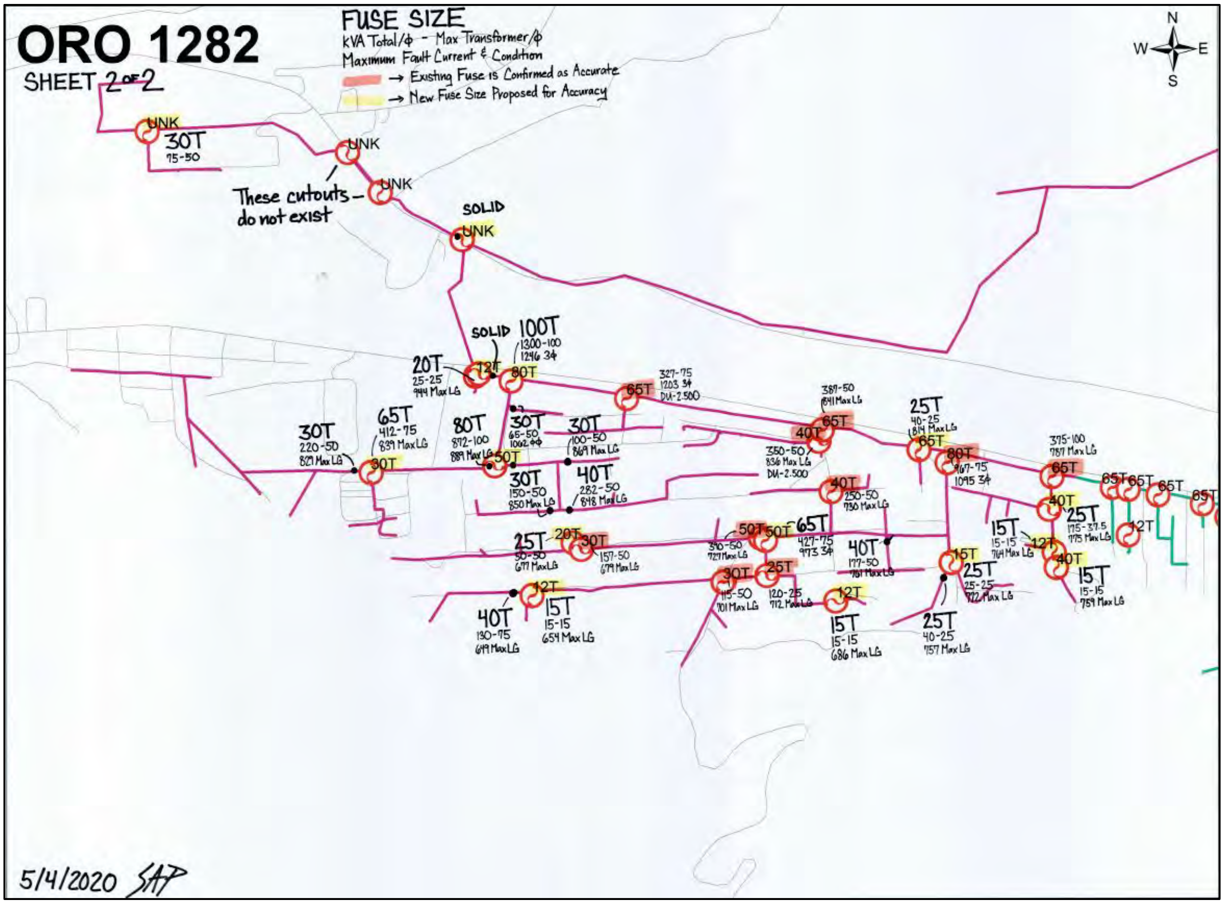


Figure 32. Fuse Size & Coordination Recommendations, Sheet 2 of 2

Line Losses

The distribution of electricity results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors, among other improvements. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and to improve voltage levels on feeders. Line losses are generally addressed by balancing load on the phases between numerous strategic locations on the feeder, and then further minimized by replacing wire with more efficient conductors.

The primary trunk conductors on ORO 1282 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the urban feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. It should be noted that there were not recommendations to reconductor the feeder trunk or ties, as these sections are currently sized appropriately to serve the peak loading on ORO 1282, as well as load transfers to and from ORO 1281.

Approximately 17,000 circuit feet of 6A and 6CU primary laterals have been identified for reconductor to 4ACSR as part of Grid Modernization's targeted conductor replacements. Although this is a significant amount of reconductor, there is a minimal difference in the ohms/mile resistance between 4ACSR and the conductors that it is replacing, and therefore negligible difference in the line loss improvements. The negligible difference in line loss improvements is also supported by relatively lower loading on these sections of conductors. The approximately 17,000 circuit feet of reconductor will result in minimal line loss savings, however a specific quantity is not being captured or reported by the Grid Modernization Program.

An initial Synergi load study estimates that a total of 105 kW in peak line losses currently exist on ORO 1282 (2.56%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved to approximately 104 kW (2.54%).

Peak Values	**Existing**	**After Balancing**	**After Reconductor**
kW Demand	4226	4225	4225
kW Load	4118	4118	4118
kW Line Losses	105	104	104
kW Loss %	2.56%	2.54%	2.54%

Transformer Core Losses

Core losses are an inherent characteristic of distribution transformers. Core losses negatively affect efficiency and do not change with fluctuation in loading. The Grid Modernization program analyzes the approximate energy savings that are achieved through the reduction in transformer core losses. Savings are obtained when transformers are replaced with more efficient units, whether being replaced due to overloading or based on PCB levels. The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more efficient. Consequently, transformer core losses are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of a near equivalent size.

All distribution transformers on ORO 1282 shall be analyzed and appropriately sized to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP), incorporating flicker and voltage drop analysis. Replacing traditional oil filled transformers with seed-based oil is required when installing a padmount or overhead transformer within 50 feet of a waterway. The definition of waterway is a channel or body of water, and can be perennial or annual in nature. This can be streams, creeks, lakes, rivers and wetlands regulated by local, state or federal jurisdiction. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the assigned Designer.

The roughly 240 distribution transformers on ORO 1282 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It is estimated that approximately 81 transformers will require replacement based on the TCOP replacement criteria, with an additional 29 requiring replacement for being undersized to serve the connected loads. The replacement of these 110 transformers would result in the estimated replacement of approximately 45.8% of the distribution transformers on ORO 1282. The replacement of these transformers will result in an estimated 11.76 kW reduction in transformer core losses. This equates to an estimated annual savings of roughly 103 MWh. The estimated energy savings are achieved through the use of a unique algorithm that was created: to analyze each transformer on the feeder, determine the PCB/age replacement status, determine if the transformer is sized appropriately based on actual loading, make a recommendation on the appropriate size for the load, and then use historical core loss values to calculate the approximate energy savings that are achieved. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Area Engineer or the local office.

Power Factor

Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work, which is a form of line losses. Power factor is a value that can fluctuate with the variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of up to 17,000 hourly data pairs covering a desired 24 month span to calculate the apparent power and power factor. This results in comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading, both in terms of time and quantity.

MVAR and MW data at the ORO 1282 substation circuit breaker was analyzed from 1/7/18 to 1/7/20. It was determined that ORO 1282 had a leading power factor 99.7% of the time during the time interval analyzed, and a lagging power factor 0.3% of the time during the time interval analyzed. Additional detailed power factor information is available upon request. Some key power factor figures for ORO 1282 are provided in the tables below.

Maximum Lagging Power Factor	00.30%
Minimum Lagging Power Factor	99.70%
Average Lagging Power Factor	99.99%
Median Lagging Power Factor	99.54%
Maximum Leading Power Factor	55.65%
Minimum Leading Power Factor	99.99%
Average Leading Power Factor	89.05%
Median Leading Power Factor	91.75%

The graph in Figure 33 shows the percent of time during the interval analyzed where the power factor on ORO 1282 fell between the applicable ranges. There were no recorded instances where data fell outside this range. This information is also provided in a table format.

	Lagging	**Leading**
99%-100%	0.30%	5.26%
98%-99%	0.00%	3.23%
97%-98%	0.00%	2.36%
96%-97%	0.00%	4.94%
95%-96%	0.00%	6.30%
94%-95%	0.00%	7.26%
93%-94%	0.00%	6.85%
92%-93%	0.00%	6.68%
91%-92%	0.00%	11.14%
90%-91%	0.00%	4.59%
80%-90%	0.00%	27.76%
Below 80%	0.00%	13.33%

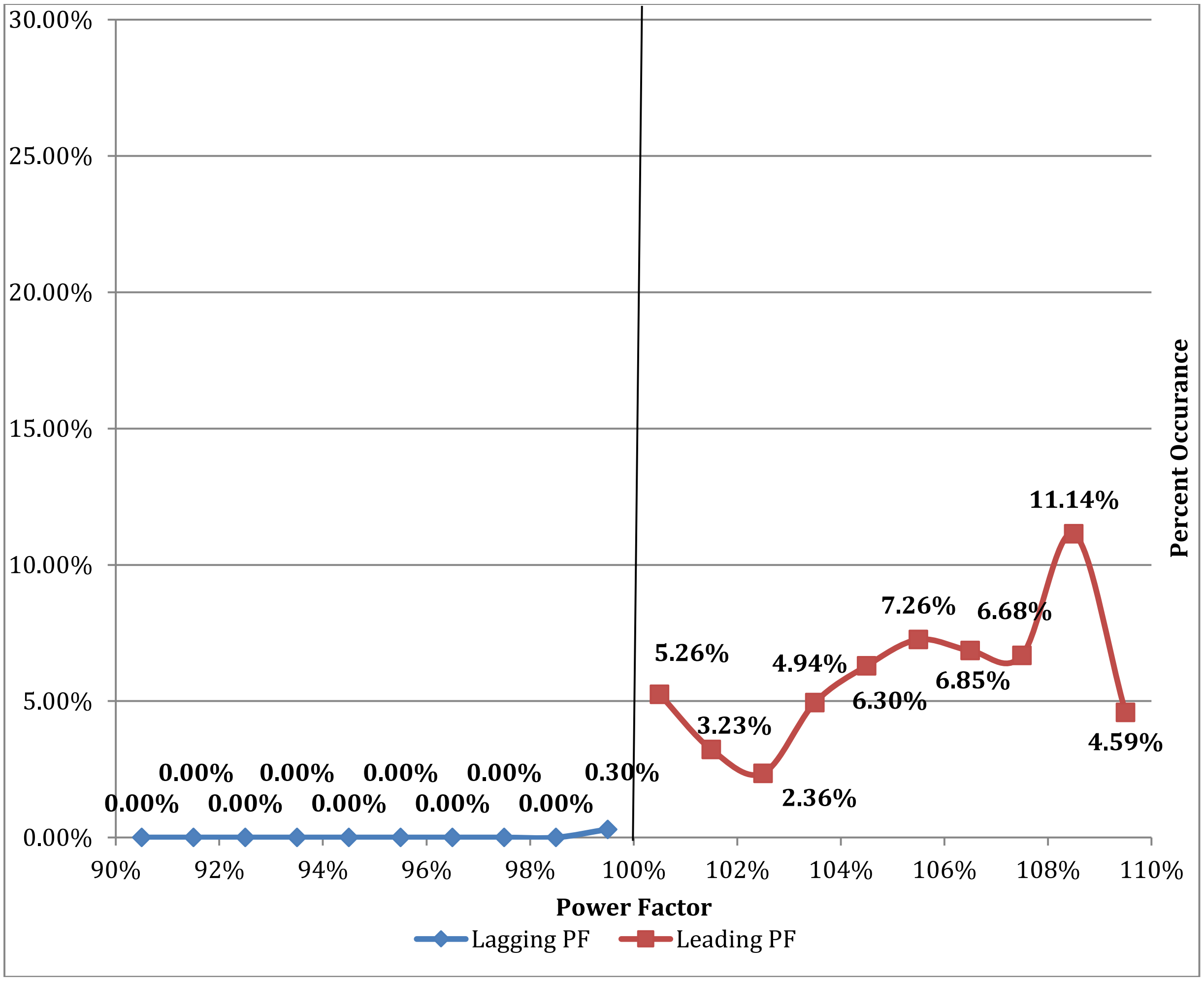


Figure 33. ORO 1282 Existing Percent Occurance of Power Factor

Power Factor Correction

The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to a unity power factor. A power factor at or near unity is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit's power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and deploying a solution. The historical Watt and Volt-Ampere Reactive (VAR) data on the feeder was reanalyzed with a variable VAR to adjust the resulting power factor with the known installed capacitor values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loading conditions to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed in more severe situations to raise the power factor to a reasonable base value, and then switched capacitor banks are installed to supplement the power factor when required by loading. This approach optimizes the correction of the power factor and reduces line losses. The establishment of accurate power factor values also incorporates the field verification of existing deployed capacitor sizes, where past experience has shown that it is not uncommon to discover capacitor bank sizes that are incorrectly represented in Avista's GIS and modeling software.

There are two existing 600 kVAR fixed capacitor banks on ORO 1282. These two capacitor bank sizes were visually confirmed in the field by a local Serviceman to each be 600 kVAR units. One of the capacitor banks is a two-canister, three-bushing style bank; while the other capacitor bank is a three-canister, two-bushing style bank.

The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor with the known capacitors values. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times. The power factor on ORO 1282 was regularly outside of the acceptable range with the existing deployed capacitor banks. The circuit consistently had a significantly "leading" power factor, which suggests that too much capacitance is existing on the circuit. It is recommended to remove both of the 600 fixed kVAR capacitor banks in **Polygons 3 and 5,** and install a 600 kVAR switched capacitor bank (ZG820F, N.C.) in **Polygon 3**. These changes would assist with bringing the feeder into the optimal range for power factor correction, as well as greatly improving the leading power situation.

To illustrate, the feeder was reanalyzed first with the proposed removal of one of the 600 kVAR fixed capacitor banks. The power factor was slightly improved, with the analysis suggesting that the ORO 1282 circuit would now have a leading power factor roughly 80.7% of the time, as well as having lagging power factor occurrences 19.3% of the time. Some key power factor figures for ORO 1282 are provided in the tables below.

Maximum Lagging Power Factor	99.99%
Minimum Lagging Power Factor	90.45%
Average Lagging Power Factor	97.77%
Median Lagging Power Factor	98.29%
Maximum Leading Power Factor	83.03%
Minimum Leading Power Factor	99.99%
Average Leading Power Factor	97.48%
Median Leading Power Factor	98.37%

The graph in Figure 34 shows the percentage of time during the re-analyzed interval where the power factor on ORO 1282 fell between the applicable ranges with one of the 600 kVAR fixed capacitor banks removed. This information is also provided in a table format.

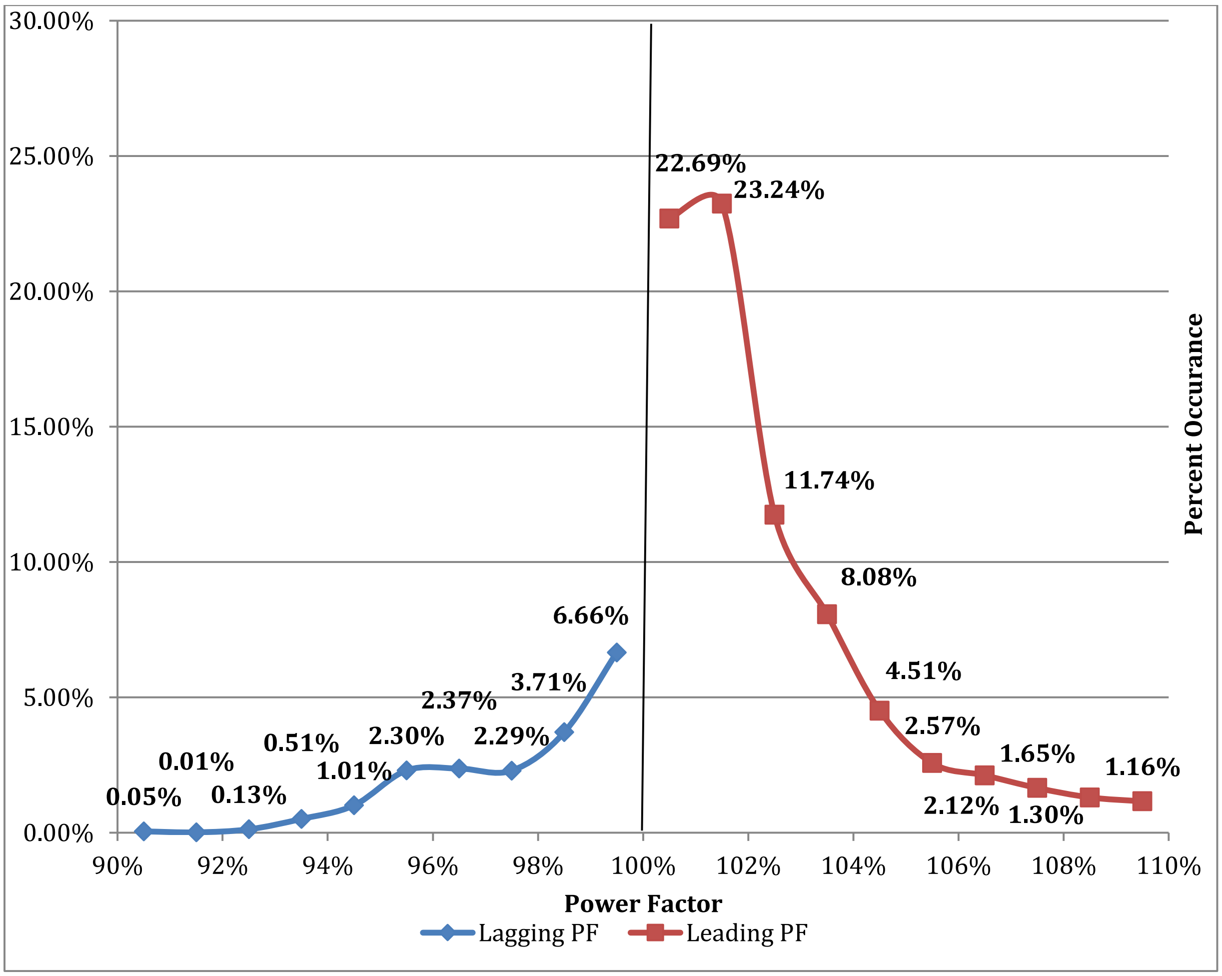


Figure 34. Proposed Percent Occurance of Power Factor with 600 kVAR Removal

	Lagging	Leading
99%-100%	6.66%	22.69%
98%-99%	3.71%	23.24%
97%-98%	2.29%	11.74%
96%-97%	2.37%	8.08%
95%-96%	2.30%	4.51%
94%-95%	1.01%	2.57%
93%-94%	0.51%	2.12%
92%-93%	0.13%	1.65%
91%-92%	0.01%	1.30%
90%-91%	0.05%	1.16%
80%-90%	0.00%	1.62%

Next, the feeder was first reanalyzed with the proposed removal of both of the 600 kVAR fixed capacitor banks. The power factor was significantly shifted from leading to lagging, with the analysis suggesting that the ORO 1282 circuit would now have a lagging power factor 100% of the time, with no leading power factor occurrences. Some key power factor figures for ORO 1282 are provided in the tables below.

Maximum Lagging Power Factor	99.86%
Minimum Lagging Power Factor	52.53%
Average Lagging Power Factor	95.28%
Median Lagging Power Factor	98.94%
Maximum Leading Power Factor	0.0%
Minimum Leading Power Factor	0.0%
Average Leading Power Factor	0.0%
Median Leading Power Factor	0.0%

The graph in Figure 35 shows the percentage of time during the re-analyzed interval where the power factor on ORO 1282 fell between the applicable ranges with both of the 600 kVAR fixed capacitor banks removed. This information is also provided in a table format.

This information of the two re-analyzed data sets illustrate what could be achieved with the power factor on the feeder with the removal of both 600 kVAR fixed capacitor banks and the installation of one 600 kVAR switchable capacitor bank. Figure 34 represents the scenario where the lone switched capacitor bank is switched “on”, while Figure 35 represents the scenario where the lone switched capacitor bank is switched “off”. Both scenarios provide corrected power factor and lowered line losses from reduced reactive power flow.

The decision to move forward with implementing any changes to the capacitors sizes and location will be confirmed, approved, and coordinated by the Regional Area Engineer.

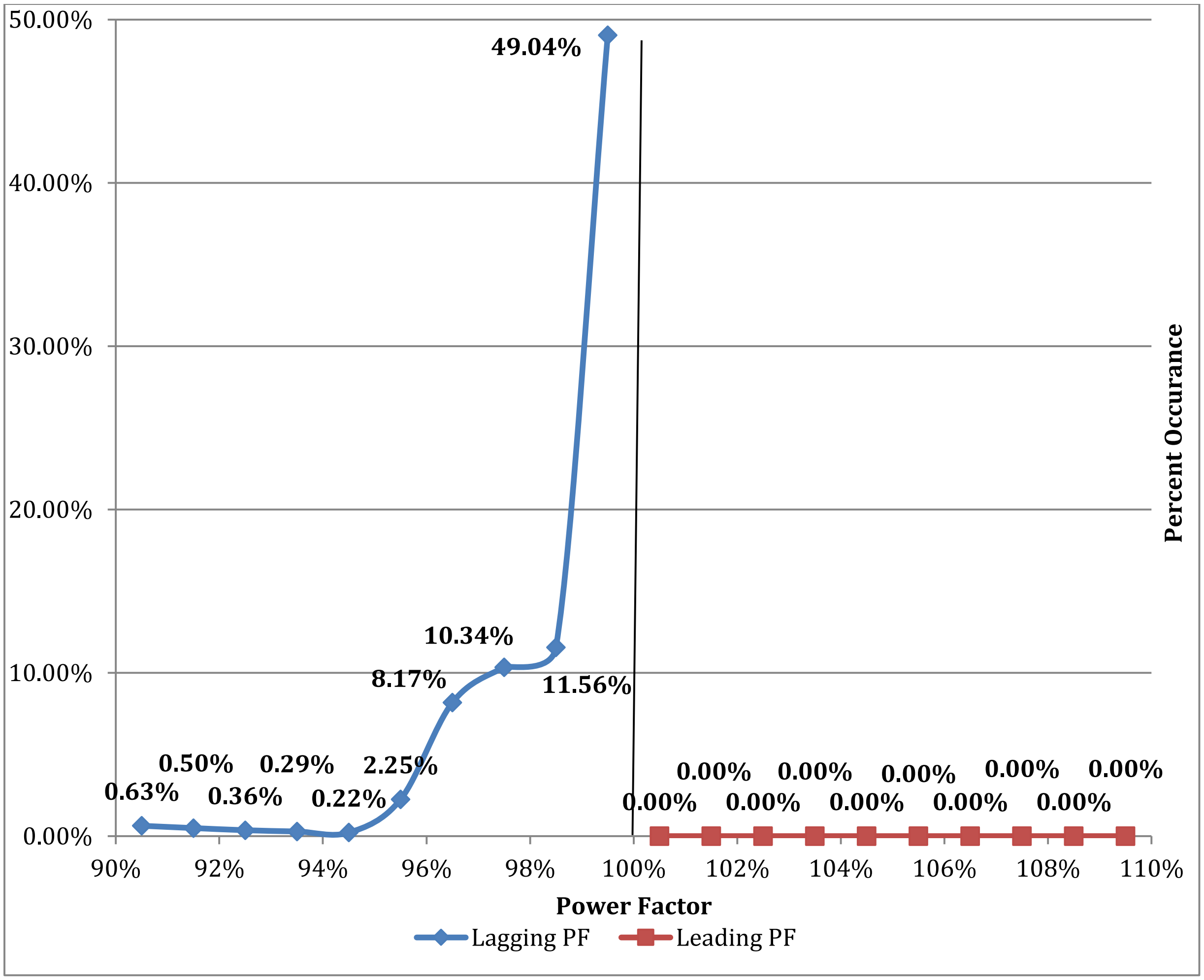


Figure 35. Proposed Percent Occurance of Power Factor with 1200 kVAR Removal

	Lagging	Leading
99%-100%	49.04%	0.00%
98%-99%	11.56%	0.00%
97%-98%	10.34%	0.00%
96%-97%	8.17%	0.00%
95%-96%	2.25%	0.00%
94%-95%	0.22%	0.00%
93%-94%	0.29%	0.00%
92%-93%	0.36%	0.00%
91%-92%	0.50%	0.00%
90%-91%	0.63%	0.00%
Below 90%	16.65%	0.00%

Distribution Automation

The Grid Modernization program currently represents Avista's largest centralized program to fully automate and improve the operating functionality and efficiency of the distribution system through the installation of automated distribution line devices. Grid Modernization has been programmatically addressing the distribution automation needs of Avista since the end of 2013, and the program focuses on installing air switches, reclosers, capacitor banks, and voltage regulators with communications and remote operability. The reduction in the duration of outages can be achieved through the installation of communications equipment that can either be controlled remotely or through a distribution management system (DMS). In addition, the number of customers impacted by an outage as well as a reduction in the frequency of outages can be achieved through the installation of devices with fault sensing and tripping capabilities. Time and cost savings can be achieved through the remote application of hot-line-holds. Fault detection, isolation, and restoration, conservation voltage reduction, and integrated volt/VAR control can also be achieved through Grid Modernization when the necessary substation equipment and components are in place.

Distribution Automation was analyzed for deployment on ORO 1282 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Area Engineer to address the specific characteristics and issues associated with the load, customers, and geography on ORO 1282.

The following automation line devices are proposed for deployment on ORO 1282:

- Install 600 kVAR switched capacitor bank (ZG820F, N.C.) east of pole #102204 in **Polygon 3** and remove the existing 600 kVAR fixed capacitor bank.
- Install G&W Viper tie switch (ZG821R, N.O.) east of US Highway 12 & 115th Street in **Polygon 7** and remove the existing #1362 manual air switch that ties with ORO 1281.
- Install G&W Viper midline recloser (ZG822R, N.C.) northwest of Dent Bridge Road & Lake View Road in **Polygon 1** that replaces existing 140T fuses.
- Install G&W Viper trunk switch (ZG823R, N.C.) east of Idaho State Highway 7 & Sockeye Drive in **Polygon 5** and remove existing #1363 manual air switch.

Device Number	Location	Status	Device Type
ZG820F	E of pole #102204	N.C.	600 kVAR Switched Cap Bank
ZG821R	E of US Hwy 12 & 115th St	N.O.	G&W Viper Tie Switch
ZG822R	NW of Dent Bridge Rd & Lake View Rd	N.C.	G&W Viper Midline Recloser
ZG823R	E of ID State Hwy 7 & Sockeye Dr	N.C.	G&W Viper Trunk Switch

ORO 1282 does not currently have a midline recloser to assist in fault detection, isolation, and restoration. Installing a new automated G&W Viper midline recloser (ZG822R, N.C.) in **Polygon 1** will provide these benefits, as well as sectionalize the feeder into two near equal sections based on the modeled amps allocated by connected kVA.

Figure 36 illustrates the proposed automation line device locations for ORO 1282.

ORO 1282 currently has Siemens MJ-X regular controllers to pair with the existing Siemens JFR station voltage regulators (7.6kV 219A 167kVA). The voltage regulators have fiber that is connected with the substation panel house. The MJ-X regular controllers are not automation compatible and must be upgraded to the newest standard Cooper CL-7 regulator controllers. Substation Engineering estimates that it will cost approximately $60k for the voltage regulators and voltage regulator controllers' upgrade and integration. In addition, the station breaker is an S&C Type FVR (15kV, 1200A, 12kA interrupting). The station breaker has a SEL 351R recloser control that is connected with fiber to the substation panel house. This combination is automation compatible and would not require any additional upgrades to bring the substation into full automation compatibility.

In order to promote complete automation on ORO 1282, Grid Modernization has notified Substation Engineering of the intended line automation work on the feeder and the necessary substation equipment upgrades to make this feeder fully automation compatible from the substation perspective. ORO 1282 is not currently scheduled on any Substation Engineering list to receive a programmatic replacement or upgrade.

The Grid Modernization program is not funded to perform work on adjacent feeders, including additional automation devices. Any requests to perform work on adjacent feeders are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on adjacent feeders.

The proposed line device location(s) identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with the Regional Area Engineer, Local Representative, or A Manager to address any construction or Standards related concerns with the selected location.

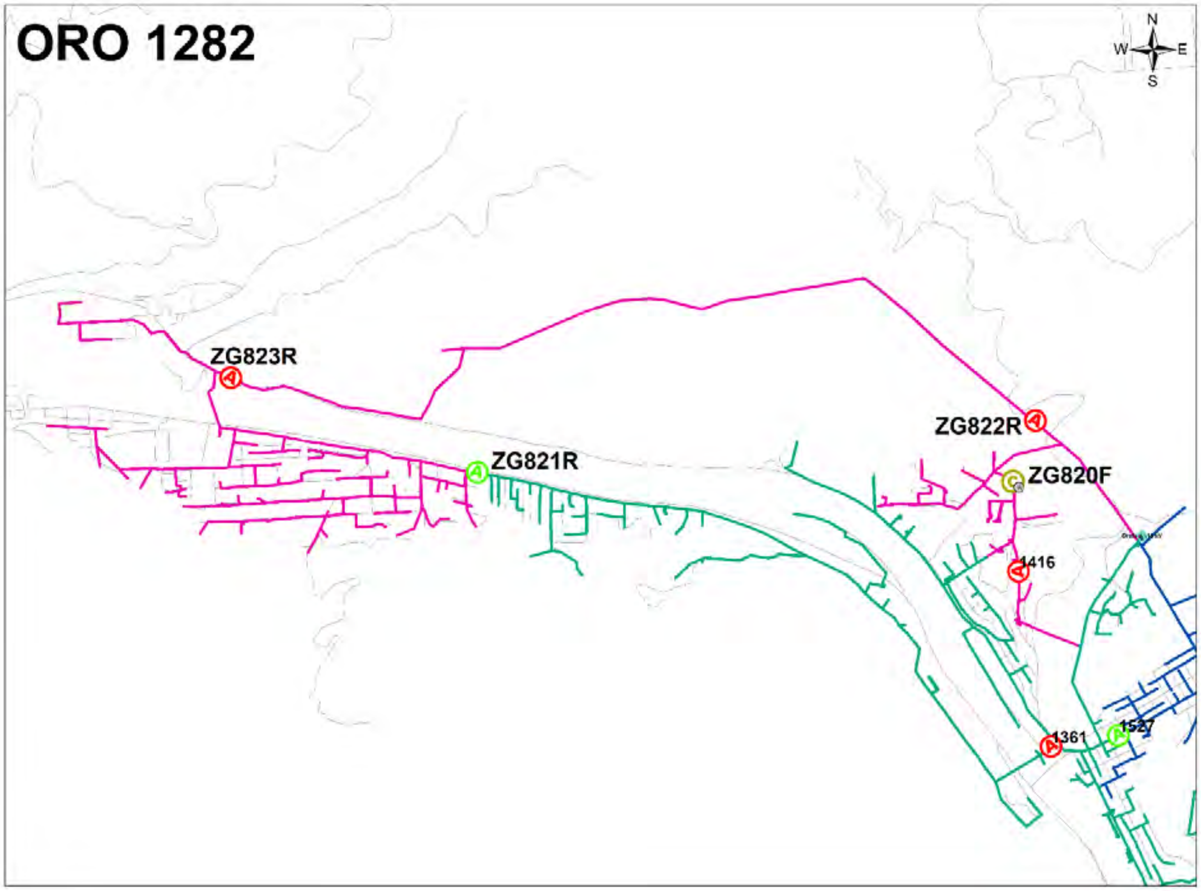


Figure 36. Distribution Line Automation Device Locations on ORO 1282

Open Wire Secondary

Open wire secondary districts have the ability to negatively affect reliability due to the physical nature of construction and configuration. These districts are also predominantly located in areas with high vegetation growth and limited crew access. These factors have the ability to provide the source for fire ignition, as well as increase the number of outages and the duration of the outages. A distribution circuit's reliability and safety can be improved by strategically removing the aging three-wire districts, sectionalizing the districts with dedicated transformers, and installing a dedicated neutral and triplex secondary wire. Grid Modernization is also initiating a study to analyze and quantify the estimated amount of open wire districts on feeders, as well as the amount requiring replacement based on the criteria of the Distribution Feeder Management Plan (DFMP). This will assist in planning and budgeting appropriately to address the needs of the feeders.

Open wire secondary districts have been analyzed for replacement on ORO 1282 in accordance to the Distribution Feeder Management Plan (DFMP). After analyzing the feeder through field observations, it was determined there were not any vertical or horizontal open wire secondary districts identified on ORO 1282. The Designers shall consult the DFMP if open wire secondary districts are determined to be present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Attempts were made to identify every open wire district on the feeder, however the Designer may identify districts that were not captured in this report. The Designer shall follow the same procedure and consult the Wildfire Resiliency Plan and the DFMP if unidentified districts are present in their assigned polygons. These documents will provide detailed information and guidance for removing open wire secondary districts.

Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Environmental

ORO 1282 was identified to contain approximately 46,000' circuit feet of distribution primary trunk and laterals that fall within the identified avian protection zone or encroach upon the 200' environmental shoreline buffer in Avista's GIS mapping system. The avian protection zones are located within **Polygons 2 through 9**. Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space. Any designs to structures within the identified avian protection zone shall adhere to the Avista Electric Distribution Overhead Construction and Material Standards, Distribution Feeder Management Plan (DFMP), and the Avista Avian Protection Plan to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements and environmental regulations. Figure 37 illustrates the avian protection zone as it relates to ORO 1282.

ORO 1282 does contain distribution facilities near designated wetlands in **Polygon 8**. Figure 38 illustrates the wetlands in this location and the proximity to existing distribution facilities.

ORO 1282 contains one existing three-phase overhead primary distribution river crossing that spans approximately 590' between structures in **Polygon 5**. The structures on either side of the river (#102320 and #300879) appear to fall within the avian zone and 200' environmental shoreline buffer in Avista's GIS mapping system. Any designs to replace or perform work on the structures within the identified shoreline boundary shall adhere to the Avista Electric Distribution Overhead Construction and Material Standards, Distribution Feeder Management Plan (DFMP), and the Avista Avian Protection Plan to ensure that all construction criteria are satisfied to bring this crossing up to new installation requirements and environmental regulations. Figures 39 and illustrate the three-phase river crossing in Polygon 5.

As previously discussed in this report, the previous river crossing that was removed around 1998 near the existing the Idaho State Highway 7 bridge over the Clearwater River will not be reconstructed as part of Grid Modernization's work on the circuit. Re-establishing the overhead river crossing at this location is not in scope for the Grid Modernization Program. A river crossing would not provide improvements to reliability, circuit efficiency, performance, or voltage quality. Grid Modernization will address the existing facilities on both sides of the river, but will not address the construction of the river crossing.

The replacement of traditional padmount or overhead oil filled transformers within 50 feet of a designated waterway will require the installation of seed-based oil. The definition of waterway is a channel or body of water, and can be perennial or annual in nature. This can be streams, creeks, lakes, rivers and wetlands regulated by local, state or federal jurisdiction. All projects in or near a sensitive area which require the installation of transformers containing FR3 fluid must go through the Environmental Affairs department for approval. The project will be reviewed to determine if an FR3 transformer is warranted and or if there could be alternate location for the transformer to eliminate the need to use an FR3 transformer.

The Environmental Compliance department shall be consulted by the assigned Designer to provide direction and assistance on any questions related with the avian protection zone, shoreline, wetlands, or other environmentally sensitive areas.

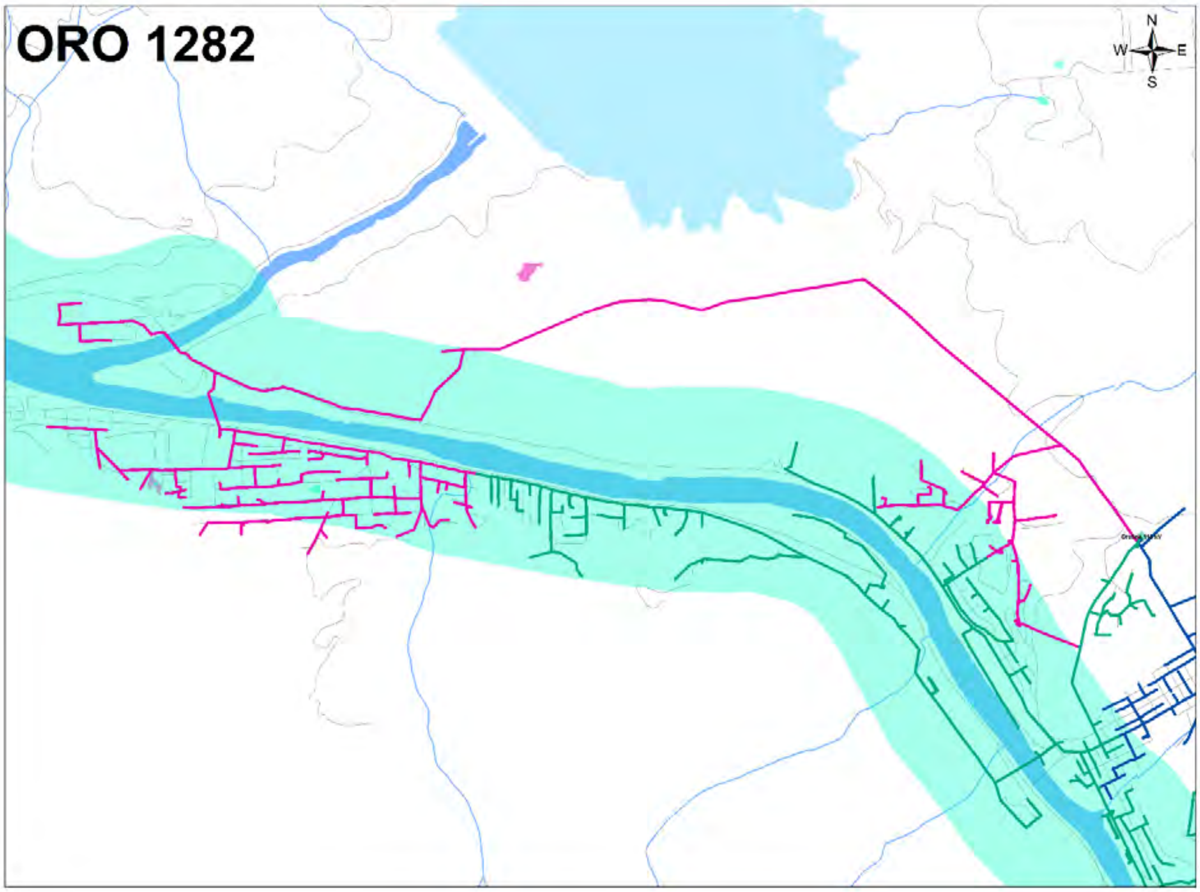


Figure 37. ORO 1282 Avian Protection Zone and Shoreline

Figure 38. Designated Wetlands in Polygon 8 of ORO 1282

Figure 39. Overhead Primary River Crossing in Polygon 5 of ORO 1282

Poles

All components of an overhead distribution system rely on the integrity and health of poles to ensure the system remains safe, reliable, and operational. The Grid Modernization program performs engineering and field examination of all of the poles and structures on a feeder to determine the removal, installation, replacement, or reinforcement based on requirements of the Distribution Feeder Management Plan (DFMP). A pole inspection report is requested and conducted to obtain an explicit list of poles on the feeder. The pole information from the inspection report provides detailed information for Grid Modernization to leverage in the assessment and proposals.

All poles and structures on ORO 1282 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Wood Pole section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the ORO 1282 circuit was performed from 6/28/2019 to 7/18/2019. The ORO 1282 feeder was determined to contain 427 distribution poles at the time of inspection. The average age of distribution pole on the circuit is approximate 36.4 years, which places the average year of installation around 1984. It is estimated that approximately 332 wood poles (77.8%) on the feeder will be replaced due to height, age, class, or inspection condition. The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	427
Average Pole Age in Years	36.4 (1984)
Year of Oldest Installed Pole	1946
Poles install between 1920-1929	0 (0%)
Poles install between 1930-1939	0 (0%)
Poles install between 1940-1949	1 (0.2%)
Poles install between 1950-1959	16 (3.7%)
Poles install between 1960-1969	91 (21.1%)
60 Year Replacement Criteria	18 (4.2%)
Yellow Tagged Poles (Re-enforceable)	23 (5.4%)
Red Tagged Poles (Replace)	1 (0.2%)
Average Pole Height	41.5
Average Pole Class	4.0
Class 4 Poles or Smaller	311 (72.8%)
Class 5 Poles or Smaller	101 (23.7%)
Estimated Total Pole Replacements	332 (77.8%)

Transformers

All transformers on ORO 1282 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. Designers should consider the nature of the load being served by transformers when selecting the most appropriate size, as certain loads may have higher load factors compared to traditional residential or commercial customers. Transformer sizes may have to be increased to safely and accurately serve the customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

The replacement of traditional padmount or overhead oil filled transformers within 50 feet of a designated waterway will require the installation of seed-based oil. The definition of waterway is a channel or body of water and can be perennial or annual in nature. This can be streams, creeks, lakes, rivers and wetlands regulated by local, state or federal jurisdiction.

Underground Facilities

An improvement in the number of underground primary cable outages can be achieved by strategically replacing cable that has a known susceptibility to faulting. The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. This includes the targeted replacement of all pre-1982 non-jacketed primary cable, which Avista's historical data suggests has the highest failure rate of underground cable. Problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged, which allows water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable. In addition, the Grid Modernization Program will replace any primary cable section that has multiple documented failures for either jacketed or non-jacketed primary cable.

The URD Cable Program has identified approximately 7,300' conductor feet of unidentified underground cable on the circuit. It has been previously observed in programmatic cable replacement efforts that approximately 20% of the unknown cable segments end up being identified as first generation unjacketed cable. The file containing the segment information is located in the Electrical Engineering drive *c01m19:\Feeder Upgrades - Dist Grid Mod\ORO 1282\~Admin\Baseline Analysis/ORO 1282 URD Segments*. Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding the replacement of first generation non-jacketed primary cable or padmount transformers for the Grid Modernization program.

Vegetation Management

Vegetation can pose serious reliability and safety problems for distribution feeders when not properly maintained. Trees can grow into overhead distribution lines as they mature, which creates access issues, source of fire ignition, public safety concerns, the possibility for trees or limbs to fall through the conductors, or the creation of electrical faults through physical contact. Proper vegetation maintenance along feeder corridors will remove many of these concerns while improving safety and system reliability. Vegetation Management will be included along easements where feeder reconductoring is being performed and/or poles are being replaced. Appropriate clearances need to be reestablished between vegetation and Avista's primary and secondary conductors so as not to compromise Avista's Vegetation Management Standards.

Grid Modernization's work is optimized when performed in coordination with Vegetation Management efforts. Vegetation management shall be employed on ORO 1282 where applicable or required. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

ORO 1282 has been divided into 9 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regard to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Automation devices located within a polygon shall be sequentially renamed using alphabetic letters to reflect a sub-polygon (i.e. #9A, #9B, #9C, etc). Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Manager by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figure 40 illustrates the ORO 1282 polygons and their boundaries. The CPC Design layer on AFM is available to provide more detailed boundaries of the polygons.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
    - Install G&W Viper tie midline recloser (ZG822R, N.C.) northwest of Dent Bridge Road & Lake View Road that replaces existing 140T fuses.
    - Primary distribution underbuild is on the *Dworshak-Orofino* 115 kV transmission line for approximately 5,500'. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures to ensure the pole class is adequate for the physical loading on the structure.
- **Polygon 2**
    - Reconductor existing 3-phase 6A overhead lateral south of Dunlap Road & Shellburn Drive with 4ACSR primary and a 4ACSR neutral (approximately 1000').
    - Reconductor existing 3-phase 6A overhead lateral north of Shriver Road & School with 4ACSR primary and a 4ACSR neutral (approximately 1140')

- **Polygon 3**
  - Reconductor existing 1-phase 6CU overhead lateral east of Hospital Drive Trailer Ct with 4ACSR primary and a 4ACSR neutral (approximately 770')
  - Remove 600 kVAR three-canister, two-bushing style fixed capacitor bank
  - Install 600 kVAR switched capacitor bank (ZG820F, N.C.) east of pole #102204.
  - Install a three-phase ganged operated air switch (G127, N.O) and remove the existing normally-open solid door cutouts between ORO 1282 and ORO 1281 west of the Idaho Correctional Institution.
  -
- **Polygon 5**
  - Install G&W Viper trunk switch (ZG823R, N.C.) east of Idaho State Highway 7 & Sockeye Drive and remove existing #1363 manual air switch.
  - Remove 600 kVAR two-canister, three-bushing style fixed capacitor bank.
  - Review the existing three-phase overhead primary distribution river crossing that spans approximately 590' between structures (#102320 and #300879. Any work performed within the identified shoreline boundary shall adhere to the Avista Electric Distribution Overhead Construction and Material Standards, Distribution Feeder Management Plan (DFMP), and the Avista Avian Protection Plan to ensure that all construction criteria are satisfied to bring this crossing up to new installation requirements and environmental regulations.
- **Polygon 7**
  - Install G&W Viper tie switch (ZG821R, N.O.) east of US Highway 12 & 115th Street and remove the existing #1362 manual air switch that ties with ORO 1281.
  - Reconductor existing 1-phase 6CU overhead lateral south of US Highway 12 & 115th Street with 4ACSR primary and a 4ACSR neutral (approximately 2500').
  - Transfer 1Φ OH lateral south of US Highway 12 & 115th Street (≈12 A peak loading, (≈5 A average loading) from AΦ to BΦ.
- **Polygon 8**
  - Install an additional phase (A-phase) of 4ACSR primary (approximately 720') south of US Highway 12 & 129th Street to allow downstream load to be transferred to A-phase. The existing 4ACSR neutral is appropriately sized, and does not require reconductoring.
  - Transfer 1Φ OH lateral west of Vista Avenue & 129th Street (≈33 A peak loading, ≈14 A average loading) from BΦ to AΦ.
  - Reconductor existing 1-phase 6A overhead lateral near 128th Street & Hartford Avenue with 4ACSR primary and a 4 ACSR neutral (approximately 1440').
  - Review existing and proposed distribution facilities located near designated wetlands with Environmental Compliance.

- **Polygon 9**
  - o Reconductor existing 1-phase 6A overhead lateral south of Jerome Avenue & 123rd Street with 4ACSR primary and a 4ACSR neutral (approximately 370').
  - o Reconductor existing 3-phase 6A overhead lateral south of US Highway 12 & 118th Street with 4ACSR primary and a 4ACSR neutral (approximately 1300').
  - o Reconductor existing 3-phase and 1-phase 6CU overhead lateral west and north of Indio Avenue & 122nd Street with 4ACSR primary and a 4ACSR neutral (approximately 5300')
  - o Reconductor existing 3-phase and 1-phase 6CU overhead lateral west and east of Jerome Avenue & 122nd Street with 4ACSR primary and a 4ACSR neutral (approximately 2500')
  - o Reconductor existing 1-phase 6CU overhead lateral east of Rodeyo Drive with 4ACSR primary and a 4ACSR neutral (approximately 350')

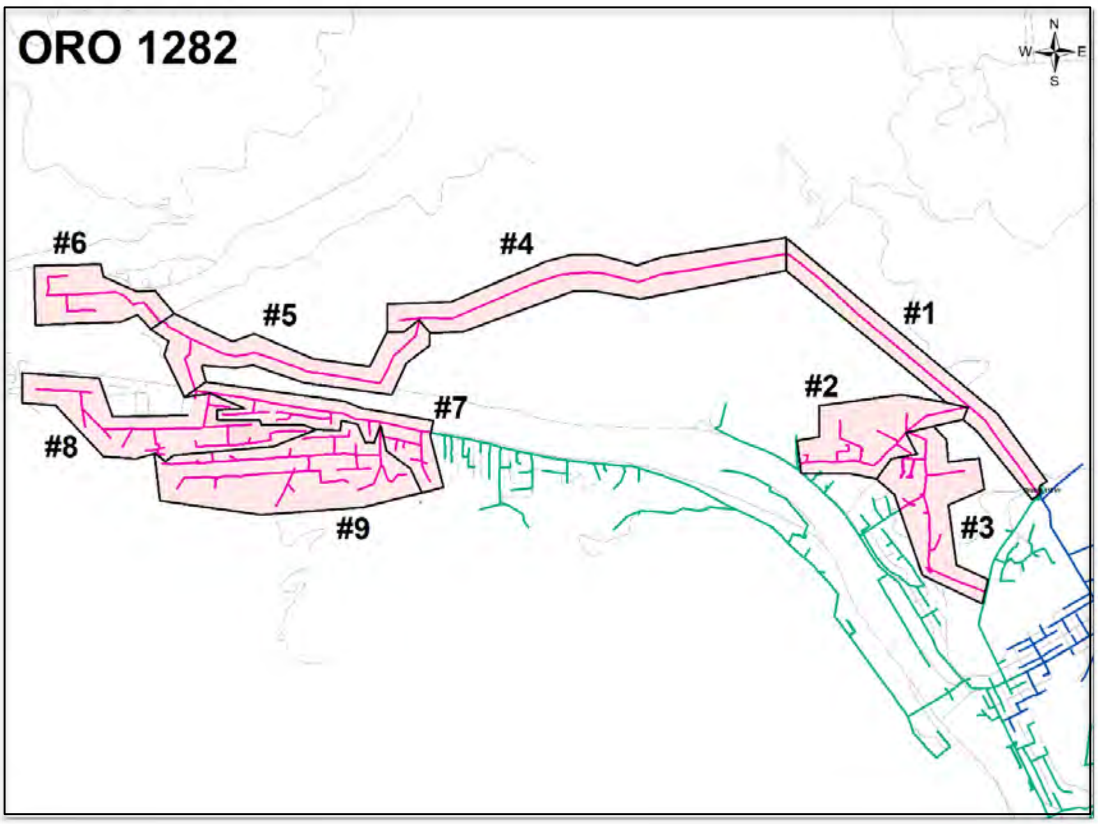


Figure 40. ORO 1282 Assigned Polygon Numbers

Report Versions

Version 1 6/1/20 – Creation of the initial report

The figures, photos, and images found in this report can be located in c01m19:\Feeder Upgrades - Dist Grid Mod\ORO1282\~Admin\Baseline Analysis

Grid Modernization Program

PDL 1201 Baseline Report

April 17th, 2017

Version 2

Prepared by Shane Pacini

Index

Overview

The following report was established to create a baseline analysis for PDL 1201 as part of the Grid Modernization program.

PDL 1201 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Pound Lane Substation in the Lewiston/Clarkston service area. The feeder has 11.7 miles of feeder trunk with 28.03 miles of laterals that serves urban residential and commercial loads, including the northeast part of Clarkston, WA. Additional feeder information is layered throughout the sections of this report, as well as the Avista Feeder Status Report. PDL 1201 is represented as a teal green color on the system map shown in Figure 1.

Figure 1. PDL 1201 One-Line Diagram

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (Energy Savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set that could be measured on different scales, the normalization process offers the ability to convert each number into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked.

PDL 1201 had a normalized total ranking of 0.528, ranking 14th on the list of over 340 feeders in the 2018-2020 analysis. Further analysis reveals that the primary reasons this feeder was selected was due to relatively higher potential to achieve avoided costs through energy savings and efficiency improvements (65.24%), as well as the opportunity to reduce future O&M expenses through capital improvements (29.12%). Designers should consider these factors when fielding and designing the work on PDL 1201.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.08714350	$72.67	$1,803,707.97
Normalized Data	0.07441328	0.98445939	0.61514916
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.02976531	0.34456079	0.15378729
Weight of Category %	5.64%	65.24%	29.12%

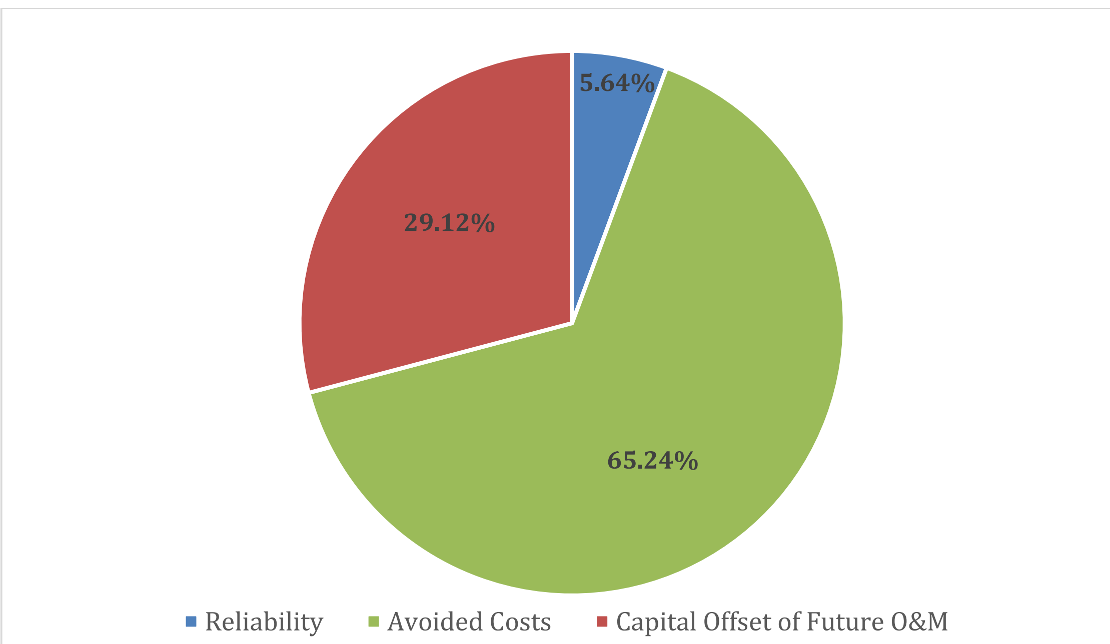


Figure 2. PDL 1201 Selection Criteria

Peak Loading

Single-phase ampacity loading from SCADA monitoring at the PDL 1201 substation circuit breaker was analyzed from 3/28/14 to 3/27/16, representing two continuous years of loading history in one hour intervals. Only B-Phase loading information for this feeder is monitored by SCADA in the Pound Lane substation. 442.8 amps was established as the peak reading during the duration examined, with 181.6 amps as the average value.

The peak value of 442.8 amps can be confirmed as being within the consistent range of the historical summer peaks on PDL 1201 as seen in the in the 2014 Feeder Status Report. Assuming a correlation between amps and the accurate connected kVA values for each phase found in AFM, it is estimated that the peak/average values for A-phase to be roughly less than B-phase. It is similarly estimated that the peak/average values for C-phase to be roughly greater than B-phase. This philosophy can be supported with the PDL 1201 data in the 2012 Feeder Status Report.

The following loading values were established for PDL 1201 during this timeframe. The values for A-phase will be selected as 95% of the measured values for B-phase, while the values for C-phase will be selected as 105% of the measured values for B-phase. Loading information has been removed from selected timeframes due to temporary changes in loading from switching (verified through PI). PDL 1201 is summer peaking feeder, with comparable peak values observed from June through August. The values below reflect the adjusted data set. The peak loading values for each phase are used in the SynerGEE model analysis for the feeder, except where Average load values are noted for estimating kW losses.

	Unbalanced Values	
	Peak	**Average**
A-Phase	421.0 A	172.0 A
B-Phase	442.8 A	181.6 A
C-Phase	464.0 A	190.0 A

Based on the accurate data that is limited to B-phase loading, conservative efforts will be made to fully balance the feeder as the actual three phase ampere allocations are not known.

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from SynerGEE at the model's initial configuration.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	3289	5724	57.46%
B-Phase	3459	6017	57.49%
C-Phase	3624	7149	50.69%

* Connected kVA per Phase in SynerGEE as of 4/1/16

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	1344	5724	23.48%
B-Phase	1410	6017	23.43%
C-Phase	1475	7149	20.63%

* Connected kVA per Phase in SynerGEE as of 4/1/16

Feeder Balancing

As previously stated, minimal efforts will be made at this point in the analysis to balance the feeder, as the actual peak ampere loading information for each individual phase was not able to be identified. AFM currently shows the following values for connected KVA totals per Phase:

	Connected KVA per Phase*
A-Phase	5724.17 kVA
B-Phase	6016.67 kVA
C-Phase	7076.67 kVA

* Connected kVA per Phase in AFM as of 4/19/16

If possible, it is recommended to attempt balancing the single-phase loads (by connected kVA) between the phases on multi-phase laterals. Designers are advised to transfer single phase loads between different phases with caution. It is recommended to use the table above as a rule of thumb to more closely even the load disparity between A-Phase and C-Phase. It is the Designer's responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any proposals for phase balancing prior to commencing the job designs.

Conductor

All primary conductors on PDL 1201 were initially analyzed in SynerGEE using the estimated peak ampacity values previously identified (421.0/442.8/464.0). Specific attention was given to conductors that were potentially overloaded, have relatively high line losses, serve areas with unacceptable voltage quality (primarily during peak conditions), and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on PDL 1201, as well as the proposals for improving the efficiency and performance of the feeder.

The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary conductor requiring attention.

Transmission Engineering should be consulted by the assigned Designer for any reconductoring performed on Transmission structures where there is Distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

PDL 1201 was initially analyzed to identify sections that are potential candidates for reconfiguration. Based upon the established nature of the area being served and the presence of high capacity conductors, there does not appear to be sections that would initially warrant reconfiguration. The assigned Designer is responsible to further analyze each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory. It is the Designer’s responsibility to consult the Program Engineer on any proposals for reconfiguration or conversion to underground prior to commencing the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program’s scope, satisfies the system operations requirements, and to assist in identifying the appropriate material and equipment to install.

Pound Lane Fiber Extension Project

There is an existing project sponsored by Enterprise Technology (ET) to expand company owned fiber from the Dry Gulch Substation to the Pound Lane Substation, and then continue north to the Clarkston Service Center. Approximately 7200' of this fiber extension will be collocated on PDL 1201 distribution structures. Network Engineering is scheduled to begin installing OPGW from Dry Gulch to Pound Lane in Q3-Q4 2016, and then to continue with the fiber installation from the Pound Lane Substation to the Clarkston Service Center in 2017.

Grid Modernization has met with Transmission Engineering and Network Engineering to determine the timeline and scope of the work involved with extending the fiber, and to identify the affects the fiber work may have on the Grid Modernization project. At this time, it is believed that very minimal distribution rebuild work will need to occur to accommodate the fiber, however the final fiber route and construction approach is not finalized.

The Designer is responsible for organizing a methodical tree trimming schedule in coordination with Transmission Engineering and Network Engineering that encompasses all assigned polygons affected by the fiber work.

Trunk

The primary trunk conductors on PDL 1201 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. Almost the entire primary overhead feeder trunk and feeder tie connections are currently conductored with 556 AAC, which is the highest rated overhead conductor for urban settings recommended by the Distribution Construction standards (DO-3.105).

Under peak loading scenarios, the 556 AAC trunk is loaded from 61% to 76% of capacity between the substation and Elm St., which is where the first large three-phase lateral occurs. The remainder of the 556 AAC trunk is loaded from 16% to 42% of capacity between downstream of Elm St. There is one 1800' section of three-phase primary trunk that is reconductored with 1/0 CU, however this lightly loaded section of trunk ranges from 13% to 43% of loading capacity.

Given the large amount of high capacity conductor already present on a majority of the feeder trunk and ties, there is minimal evidence to support upgrading the primary trunk conductors on PDL 1201 based on capacity concerns alone. Line losses on the trunk are currently in the desired range for this scenario based on the existing conductor types.

Any designs to reconductor shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

Laterals

The primary lateral conductors on PDL 1201 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The primary lateral conductors on PDL 1201 are generally sized appropriately to meet peak loading conditions during normal system configuration. The majority of the laterals are currently conductored with 4CU and 6CU in overhead applications and 1CN15 in underground applications. Line losses on the trunk are currently in the desired range for this scenario based on the existing conductor types, which has been aided by relatively lower loading conditions where higher loss conductors exist. There are two three-phase laterals on the feeder that should be reconductored based on high loading capacity during peak loading conditions.

- Reconductor three-phase lateral east of 9th & Poplar to 336 AAC with a 2/0 ACSR neutral (approximately 1800’) in **Polygon 6**. This section of lateral/trunk is currently served by a combination of 6CU and 4ACSR. In addition for being undersized for serving as major three-phase lateral, this section of the feeder serves the central business district in Clarkston. 336 AAC was selected over 2/0 ACSR for reconductoring the primary due to the increase loss savings and nominal material cost difference. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. Figure 3 illustrates the three-phase lateral reconductor on this section.
- Reconductor three-phase lateral east of 9th & Elm to 336 AAC with a 2/0 ACSR neutral (approximately 1650’) in **Polygon 5**. This section of lateral/trunk is currently served by 2/0ACSR conductor. In addition for being undersized for serving as major three-phase lateral, this section of the feeder serves the central business district in Clarkston. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. Figure 4 illustrates the primary trunk reconductor on this section.

It is the Designer’s responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program’s scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Feeder Tie

PDL 1201 currently contains four overhead ties to adjacent feeders through the following switching devices:

Air Switch	Feeder Tie
#1304	PDL 1202
#1387	SLW 1368
#1397	DRY 1208
#1516	PDL 1202

In addition to the normally open feeder tie devices, PDL 1201 has numerous normally closed trunk devices for manually sectionalizing the feeder.

PDL 1201 is candidate for receiving automated switching devices due to the densely loaded urban setting and the numerous existing interconnection points with adjacent feeders. While there are currently no other automated feeders in the Clarkston area, establishing PDL 1201 as the automation foundation for the region will aid in expanding distribution line automation into the last of Avista's four major metropolitan areas.

It is proposed to convert three of the existing manual feeder tie air switches to automated Viper switches (#1387, #1397, and #1516). This would create three automated feeder ties at three different strategic points on the feeder with three different feeders respectively (SLW 1368, DRY 1208, and PDL 1202). The automated devices would provide an automated alternate feed at sectionalized portions of the feeder to aid in switching, outage restoration, and reduction in outage duration.

- Install Viper switch (ZL1397R, N.O.) east of the Fair St. & 13th St intersection, and remove the existing 1397 air switch in **Polygon 4**.
- Install Viper switch (ZL1516R, N.O.) east of the Elm St. & 10th St intersection, and remove the existing 1516 air switch in **Polygon 4**.
- Install Viper switch (ZL1387R, N.O.) southeast of the Elm St. & 8th St intersection, and remove the existing 1387 air switch in **Polygon 5**.

Each of the three proposed automated feeder ties are conductored with 556 AAC on either side of the tie, and would not require additional work to rebuild or reconductor.

The decision to pursue the automation tie proposals will be discussed and selected with the Regional Operations Engineer based on their anticipated frequency of using each tie in the operation of the Clarkston distribution system.

Figure 3. Polygon 6 Three-Phase Lateral Reconductor to 336 AAC

Figure 4. Polygon 5 Three-Phase Lateral Reconductor to 336 AAC

Voltage Quality

PDL 1201 was then analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable operating limits. The feeder was modeled in SynerGEE during both peak loading and Average loading conditions.

As previously mentioned in the *Feeder Balancing* section of this report, minimal efforts will be made at this point in the analysis to balance PDL 1201, as the actual peak ampere loading information for each individual phase was not able to be identified. Therefore, the feeder was unable to be balanced between phases to eliminate the unnecessary overloading of phases which may exacerbate voltage quality problems.

Modeled Voltage Levels at Peak Loading before Proposals

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to PDL 1201. During peak loading conditions, voltage levels nearest to the Pound Lane Substation (south of the intersection of Chestnut & 13th) were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.6V. Voltage levels downstream of the intersection of Chestnut & 13th were within the optimal range, and were consistently between 120.3V and 122.9V. The lowest voltages occurred at the far northeast and southeast laterals of the feeder and ranged between 120.1V to 120.8V. Figure 5 illustrates the voltage levels modeled at peak loading after including the previous proposals from the report.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	261	11.18	8798	1217
122.00 - 124.00 V	56	2.55	1317	431
124.00 - 126.00 V	7	0.88	0	0
126.00 - 140.00 V	1	0.00	0	0

Figure 5. Modeled Voltage Levels at Peak Loading before Proposals

Modeled Voltage Levels at Average Loading before Proposals

The voltage levels on the feeder were again analyzed after the reconductoring proposals, however this time during average loading conditions. Voltage levels nearest to the Pound Lane Substation (west and south the intersection of Chestnut & 10th) were slightly elevated however they were still acceptable. The higher voltage levels modeled on this section of the feeder ranged between 122.8V to 124.5V. Voltage levels downstream of the intersection of Chestnut & were within the optimal range, and were consistently between 122.0V and 122.5V. The lowest voltages occurred at the far northeast and southeast laterals of the feeder and ranged between 121.6V to 122.0V. Figure 6 illustrates the voltage levels modeled at average loading after including the previous proposals from the report.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	92	3.89	1303	426
122.00 - 124.00 V	226	9.92	2876	1222
124.00 - 126.00 V	7	0.80	0	0
126.00 - 140.00 V	0	0.00	0	0

The voltage levels on PDL 1201 were re-analyzed after the trunk and lateral reconductoring and other improvements were performed. The feeder was modeled with these proposals in SynerGEE during both peak loading and Average loading conditions.

Figure 6. Modeled Voltage Levels at Average Loading before Proposals

Modeled Voltage Levels at Peak Loading after Proposals

During peak loading conditions, voltage levels nearest to the Pound Lane Substation (south of Chestnut Street), were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.6V. Voltage levels downstream of the intersection of Chestnut & 13th were within the optimal range, and were consistently between 120.5V and 122.8V. The lowest voltages occurred at the far northeast and southeast laterals of the feeder and ranged between 120.5V to 120.8V. Figure 7 illustrates the voltage levels modeled at peak loading after including the previous proposals from the report.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	261	11.18	8812	1217
122.00 - 124.00 V	56	2.55	1317	431
124.00 - 126.00 V	7	0.88	0	0
126.00 - 140.00 V	1	0.00	0	0

Modeled Voltage Levels at Average Loading after Proposals

The voltage levels on the feeder were again analyzed after the reconductoring proposals, however this time during Average loading conditions. Voltage levels nearest to the Pound Lane Substation (west and south the intersection of Chestnut & 10th) were slightly elevated however they were still acceptable. The higher voltage levels modeled on this section of the feeder ranged between 122.7V to 124.5V. Voltage levels downstream of the intersection of Chestnut & were within the optimal range, and were consistently between 121.8V and 122.5V. The lowest voltages occurred at the far northeast and southeast laterals of the feeder and ranged between 121.8V to 122.3V. Figure 8 illustrates the voltage levels modeled at average loading after including the previous proposals from the report.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	58	2.20	890	146
122.00 - 124.00 V	260	11.61	3292	1502
124.00 - 126.00 V	7	0.80	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 7. Modeled Voltage Levels at Peak Loading after Proposals

Figure 8. Modeled Voltage Levels at Average Loading after Proposals

Voltage Regulator Settings

PDL 1201 has one existing stage of voltage regulation at the Pound Lane Substation. The voltage levels on the feeder were modeled in SynerGEE during both peak loading and median loading conditions. The existing settings produce voltage results that are acceptable and appropriate to remain within the allowable voltage levels on PDL 1201.

However, a group of alternative settings was analyzed to show if there was the potential for improvement. The voltage levels on PDL 1201 were re-analyzed and modeled with the voltage regulator setting change proposals in SynerGEE at peak loading conditions, as seen below.

The existing and proposed voltage regulator settings are provided in the table below:

	Existing*		Proposed	
Forward Settings	**R**	**X**	**R**	**X**
PDL 1201 Station Regulators	**2.0**	**7.0**	**2.5**	**4.1**

* Settings in METS and SynerGEE as of 4/27/16

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	260	11.15	8803	1213
122.00 - 124.00 V	57	2.58	1330	435
124.00 - 126.00 V	7	0.88	0	0
126.00 - 140.00 V	1	0.00	0	0

Due to the minimal improvement and difference in the regulator settings, it is not recommended to pursue changing the regulator settings.

The decision to move forward with implementing any changes to the regulator settings will be confirmed, approved, and coordinated by the Regional Operations Engineer. These changes are proposed to illustrate the potential benefits to adjusting the settings.

PDL 1201 is currently not equipped with automation compatible voltage regulators and breaker recloser in the substation to provide the ability for future FDIR and IVVC capabilities.

Fuse Sizing

Fuse sizing on PDL 1201 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and risers. Fuse recommendations for PDL 1201 were created by the Grid Modernization Program Engineer and verified by the Regional Operations Engineer. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Line Losses

The primary conductors on PDL 1201 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the feeder.

After the proposed reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections are performed on PDL 1201, it is estimated that the peak line losses could approximately be reduced by up to 12.4 kW, while the average loading line losses could approximately be reduced by up to 2.7 kW. In addition, up to 23.5 MWh savings could be annually achieved assuming average loading conditions during normal system configuration.

	Polygon 5	Polygon 6	Total
Circuit Length (ft)	1657	1800	3457
Current Average kW Losses	2.3	1.9	4.2
Current Peak kW Losses	11.4	8.0	19.4
Proposed Average kW Losses	0.9	0.6	1.5
Proposed Peak kW Losses	4.3	2.7	7.0
Average kW Loss Savings	1.4	1.3	2.7
Peak kW Loss Savings	7.1	5.3	12.4
Reconductor MWh Savings *	12.2	11.3	23.5

* Estimated Average kW losses over one year span

An initial SyngerGEE load study estimates that a total of 253 kW in peak line losses currently exists on PDL 1201 (2.47%). After performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved from 253 kW (2.47%) to approximately 239 kW (2.33%).

Peak Values	Existing	After Polygon 6 Reconductor	After Polygon 5 Reconductor
kW Demand	10372	10216	10371
kW Load	10115	9973	10129
kW Line Losses	253	240	239
kW Loss %	2.47 %	2.38 %	2.33 %

Transformer Core Losses

The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, “no load losses” are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of an appropriate size.

All transformers on PDL 1201 shall be analyzed and “right sized” by the assigned Designer to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP). In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the Designer.

The roughly 396 distribution transformers on PDL 1201 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It was determined that approximately 218 transformers may require replacement based on right sizing and the TCOP criteria replacements. The replacement of these transformers will result in an estimated 18.89 kW reduction in core losses. This equates to an annual savings of roughly 165.48 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

MVAR and MW data at the PDL 1201 substation circuit breaker was not available through SCADA to analyze the power factor of the feeder. While MVAR and MW data wasn't available for PDL 1201, there was MVAR and MW data for Pound Lane Transformer #1 which serves both PDL 1201 and PDL 1203. MVAR and MW data for Pound Lane Transformer #1 was analyzed from 3/28/14 to 3/27/16, representing two continuous years of loading history in one hour intervals. It was determined that Transformer #1 had a leading power factor approximately 63.7% of the time and a lagging power factor roughly 35.8% of the time during the time interval analyzed. Detailed power factor information is available upon request. There are four existing fixed capacitor banks on PDL 1201: 300, 300, 600, and 600 kVAR. Some key power factor figures for Transformer #1 are provided in the table below.

Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	94.51 %
Maximum Leading Power Factor	99.99 %
Minimum Leading Power Factor	93.13 %

The graph in Figure 9 shows the percent of time during the interval analyzed where the power factor on Transformer #1 fell between the applicable ranges. This information is also provided in a table format.

	Lagging	Leading
Less than 90%	0.00%	0.00%
90%-91%	0.00%	0.00%
91%-92%	0.00%	0.00%
92%-93%	0.00%	0.00%
93%-94%	0.00%	0.02%
94%-95%	0.29%	0.03%
95%-96%	2.97%	0.03%
96%-97%	3.68%	0.35%
97%-98%	4.48%	1.15%
98%-99%	5.78%	7.85%
99%-100%	18.81%	54.57%

Due to not having substantial MW and MVAR data to support specific adjustments with the capacitor banks on PDL 1201, it is not recommended to add, remove, or replace the fixed capacitor banks on PDL 1201 solely on the available data. The cumulative power factor across PDL 1201 and PDL 1203 appears to be within the desire range based on the information from Transformer #1. However, two older style 3-bushing 600 kVAR fixed capacitors bank were identified on the feeder in **Polygon 2** and **Polygon 7.** These fixed capacitor banks are proposed to be replaced with equivalent sized 600 kVAR switched capacitor banks.

Accurate power factor correction can be accomplished at a future date once a history of loading information is established through more detailed SCADA monitoring through automated devices on the line with communication capabilities.

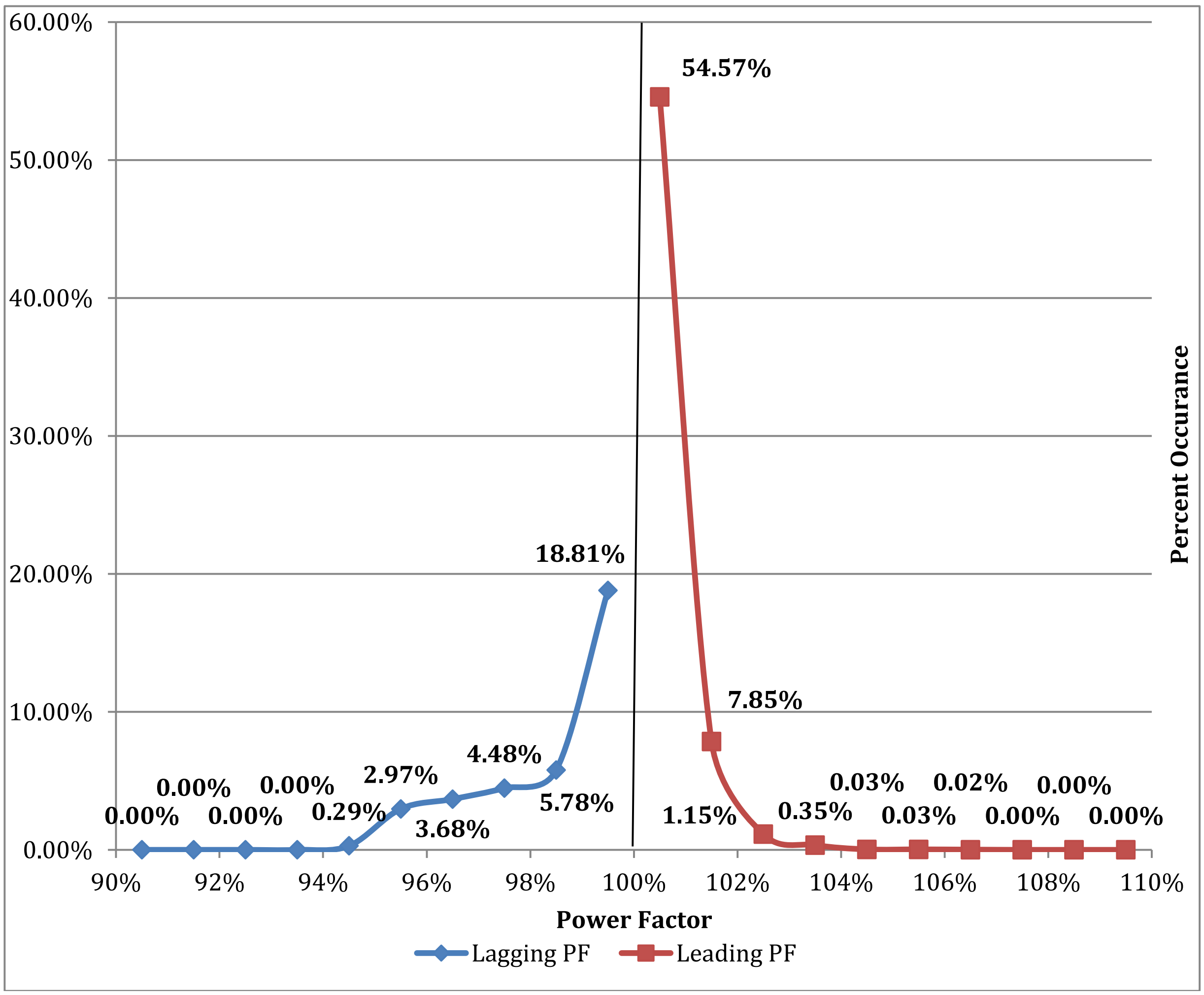


Figure 9. Existing Percent Occurance of Power Factor

Automation

Distribution Automation was analyzed for deployment on PDL 1201 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and configuration on PDL 1201.

The key reliability indicators for PDL 1201 were analyzed from 2012 to 2015 to assist in justifying any proposed automation deployments. The average value of each index was calculated and then compared to the Avista 2015 Target values. The historical averages on PDL 1201 have outperformed three of the four indices: SAIFI, SAIDI, and CEMI3. CAIDI is the only index that PDL 1201 is not meeting the 2015 target. This information suggests that customers experience very few outages on the feeder, however the average outage duration that any given customer would experience does not meet the Avista target.

WA-ID Key Indicator	2015 Target	PDL 1201	Variance
SAIFI Sustained Outages/Customer	1.17	0.423	0.747
SAIDI Outage Time/Customer (min)	144.00	28.92	115.08
CAIDI Ave Restoration Time (hrs)	127.00	151.15	-24.15
CEMI3 % of Customers >3 Outages	7.10%	0.41%	6.69%

PDL 1201 does not currently have a midline recloser to assist in fault detection and isolation. Converting the existing #1388 device in **Polygon 4** from a manual air switch to an automated midline Viper recloser will provide these benefits, as well as sectionalize the feeder into two near equal sections based on the modeled amps allocated by connected kVA.

The following automation devices are proposed for deployment on PDL 1201:

Device Number	Location	Status	Device Type
ZL1387R	SE of Elm St. & 8th St.	N.O.	Viper - Switch
ZL1388R	N of Elm St. & 9th St.	N.C.	Viper – Recloser
ZL1397R	E of Fair St. & 13th St.	N.O.	Viper - Switch
ZL1516R	E of Elm St. & 10th St.	N.O.	Viper - Switch
ZL3001F	W of Fair St. & 1st St.	N.C.	Switched 600 kVAR Cap Bank
ZL5001F	N of Highlave Ave & 13th St.	N.C.	Switched 600 kVAR Cap Bank

Figure 10 illustrates the proposed automation device locations on PDL 1201.

PDL 1201 is not distribution automation ready at the Pound Lane Substation. It is recommended to eventually install automation compatible voltage regulators and a breaker recloser in the substation to support future FDIR and IVVC capabilities. Grid Modernization will request the installation of the station voltage regulators by Substation Engineering; however Grid Mod is currently unable to secure the installation of the station breaker recloser due to scheduling and resource constraints.

The Grid Modernization program is not funded to perform work on adjacent feeders, including additional automation devices. Any requests to perform work on adjacent feeders are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on adjacent feeders.

The proposed automation line device locations identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with either the Regional Operations Engineer, General Foreman, or District Manager to address any construction or Standards related concerns with the selected location.

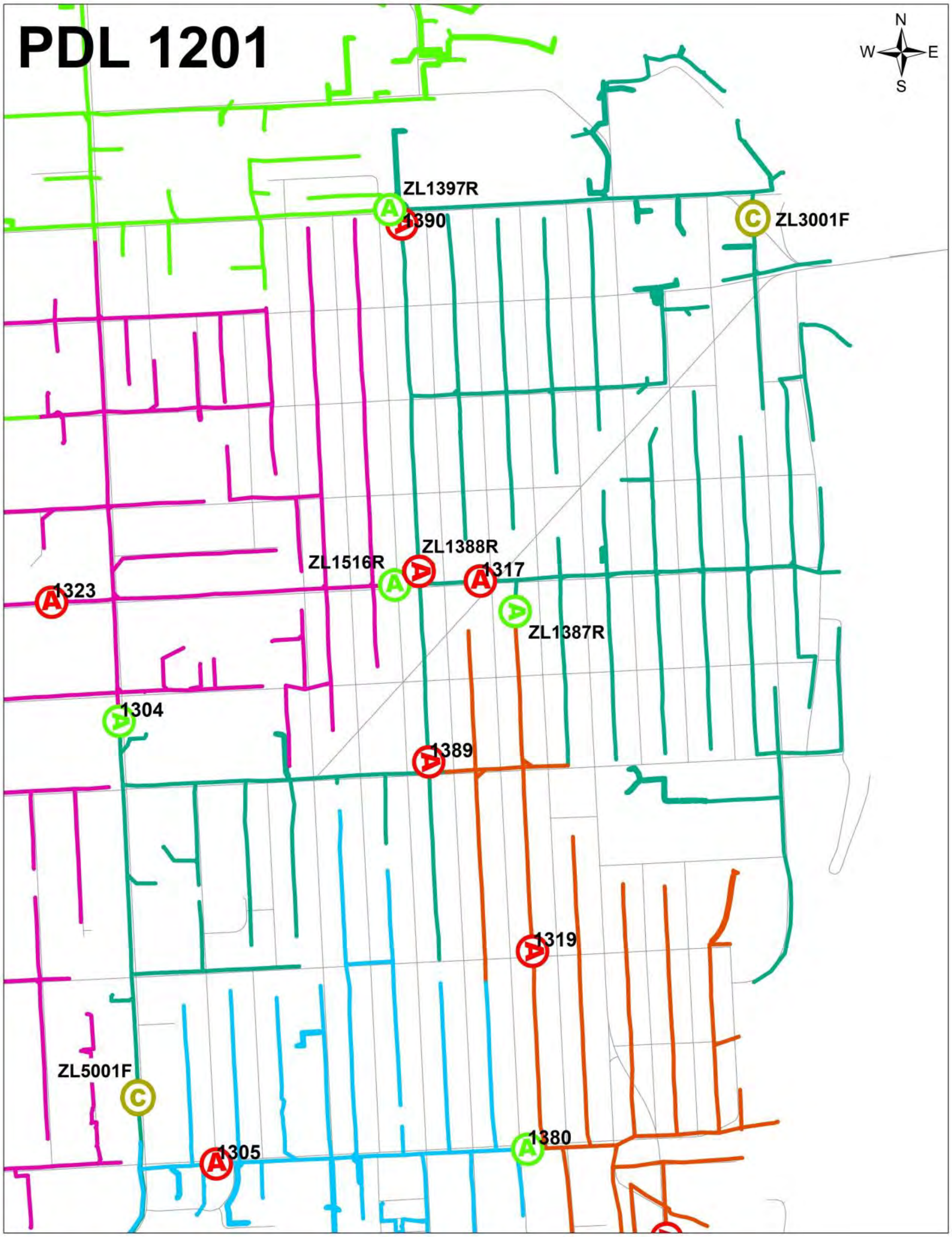


Figure 10. PDL 1201 Proposed Automation Device Locations

Poles

All poles and structures on PDL 1201 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Wood Pole section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the PDL 1201 circuit was performed from 4/20/2016 to 5/9/2016. The PDL 1201 feeder was determined to contain 518 distribution poles at the time of analysis. The average age of distribution pole on the circuit is approximate 44 years, which places the average year of installation around 1972. 166 poles on the circuit are older than the 60 year limit program limit for mean-time to failure, which results in the prescriptive replacement of 32.0% of wood poles at a minimum based on age alone.

The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	518
Average Pole Age in Years	44 (1972)
Year of Oldest Installed Pole	1926
Poles install between 1920-1929	9 (1.7%)
Poles install between 1930-1939	11 (2.1%)
Poles install between 1940-1949	73 (14.1%)
Poles install between 1950-1959	93 (18.0%)
Poles install between 1960-1969	59 (11.4%)
Yellow Tagged Poles (Re-enforceable)	9 (1.7%)
Red Tagged Poles (Replace)	1 (0.2%)
Average Pole Class	3.9
Class 4 Poles or Smaller	370 (71.4%)
Class 5 Poles of Smaller	76 (14.7%)

Open Wire Secondary

Open wire secondary districts have been analyzed for replacement on PDL 1201 in accordance to the Distribution Feeder Management Plan (DFMP). After analyzing the feeder through field observations, there were not any vertical or horizontal open wire secondary districts identified on PDL 1201. The Designer shall consult the DFMP if open wire secondary districts are discovered in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Transformers

All transformers on PDL 1201 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable.

Tree Trimming

Vegetation management shall be employed on PDL 1201 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

PDL 1201 has been divided into 7 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Engineer by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 2**
    - Install 600 kVAR switched capacitor bank (ZL5001F, N.C.) north of the Highland Ave and 13th Street intersection, and remove the existing 600 kVAR fixed capacitor bank.
- **Polygon 4**
    - Install midline Viper recloser (ZL1388R, N.C.) north of the Elm St. & 9th St intersection, and remove the existing 1388 air switch.
    - Install Viper switch (ZL1516R, N.O.) east of the Elm St. & 10th St intersection, and remove the existing 1516 air switch.
    - Install Viper switch (ZL1397R, N.O.) east of the Fair St. & 13th St intersection, and remove the existing 1397 air switch.
- **Polygon 5**
    - Reconductor three-phase lateral east of 9th & Elm to 336 AAC with a 2/0 ACSR neutral (approximately 1650').
    - Install Viper switch (ZL1387R, N.O.) southeast of the Elm St. & 8th St intersection, and remove the existing 1387 air switch.
- **Polygon 6**
    - Reconductor three-phase lateral east of 9th & Poplar to 336 AAC with a 2/0 ACSR neutral (approximately 1800').
- **Polygon 7**
    - Install 600 kVAR switched capacitor bank (ZL3001F, N.C.) west of the Fair St. and 1st Street intersection, and remove the existing 600 kVAR fixed capacitor bank.

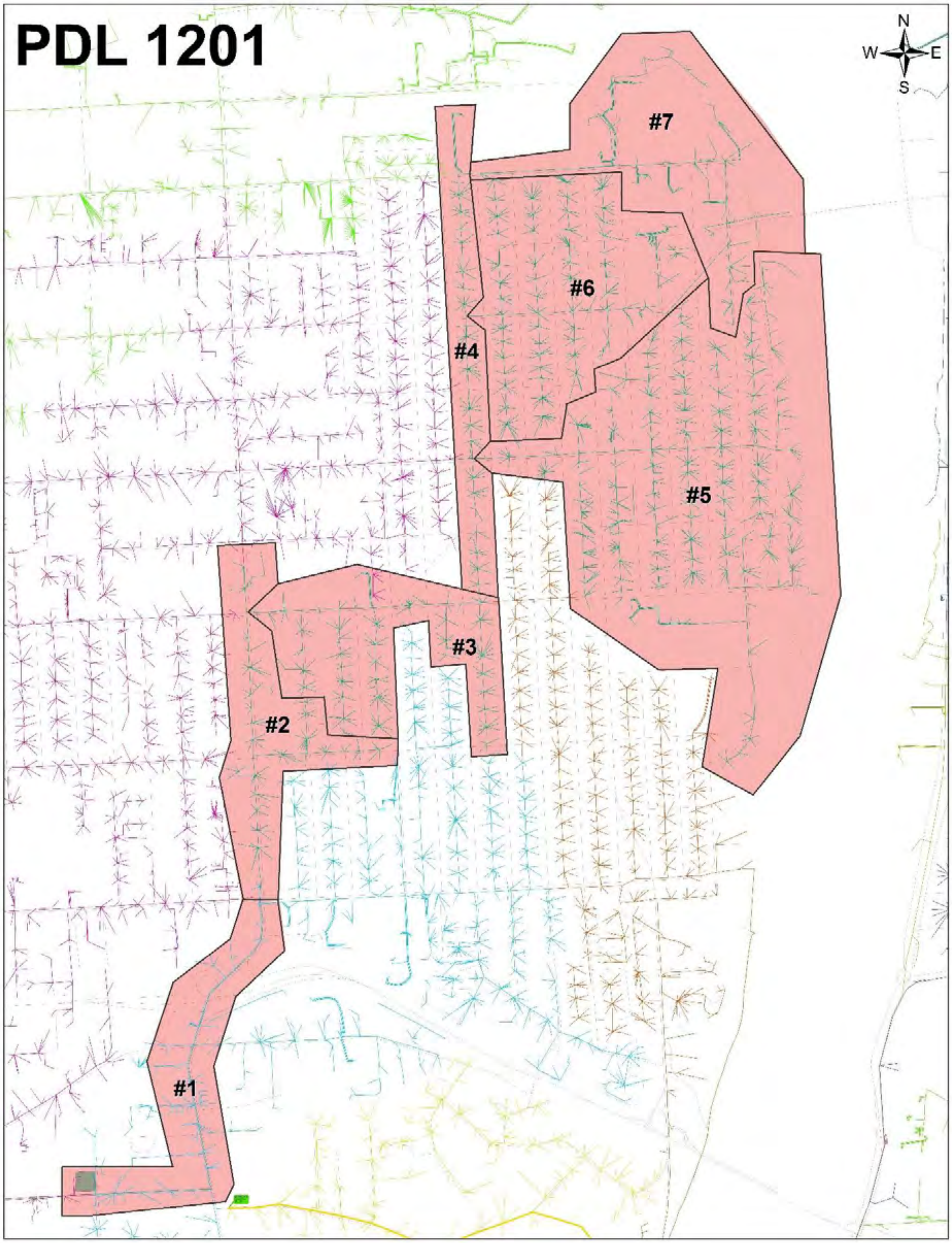


Figure 11. PDL 1201 Polygon Numbers

Report Versions

Version 1	5/27/16 – Creation of the initial report. Approval of the report was received by the local office on 6/28/16.
Version 2	4/17/17 – Identified the replacement of pole #132818 which resulted in the replacement of an existing 600 kVAR 3-bushing style, fixed capacitor bank. A 600 kVAR switched capacitor bank (ZL3001F, N.C.) will be installed west of the Fair St. and 1st Street intersection. Figure 10 was also updated to reflect this change. Added information from the Wood Pole Management Inspection report to the *Poles* Section

Grid Modernization Program

RAT 233 Baseline Report

3/17/2015

Version 5

Prepared by Shane Pacini

Index

Overview

The following report was established to create a baseline analysis for RAT 233 as part of the Grid Modernization program.

RAT 233 is a 13.2/7.62 kV distribution feeder served from Transformer #2 at the Rathdrum Substation in the Coeur d'Alene service area. The feeder has 31.23 miles of feeder trunk with 162.55 miles of laterals that serves predominately rural residential loads, including the town of Rathdrum, ID. RAT 233 contains numerous feeder ties to different feeders in the area. Additional feeder information is layered throughout the sections of this report. RAT 233 is represented as a lime green color on the system map shown below.

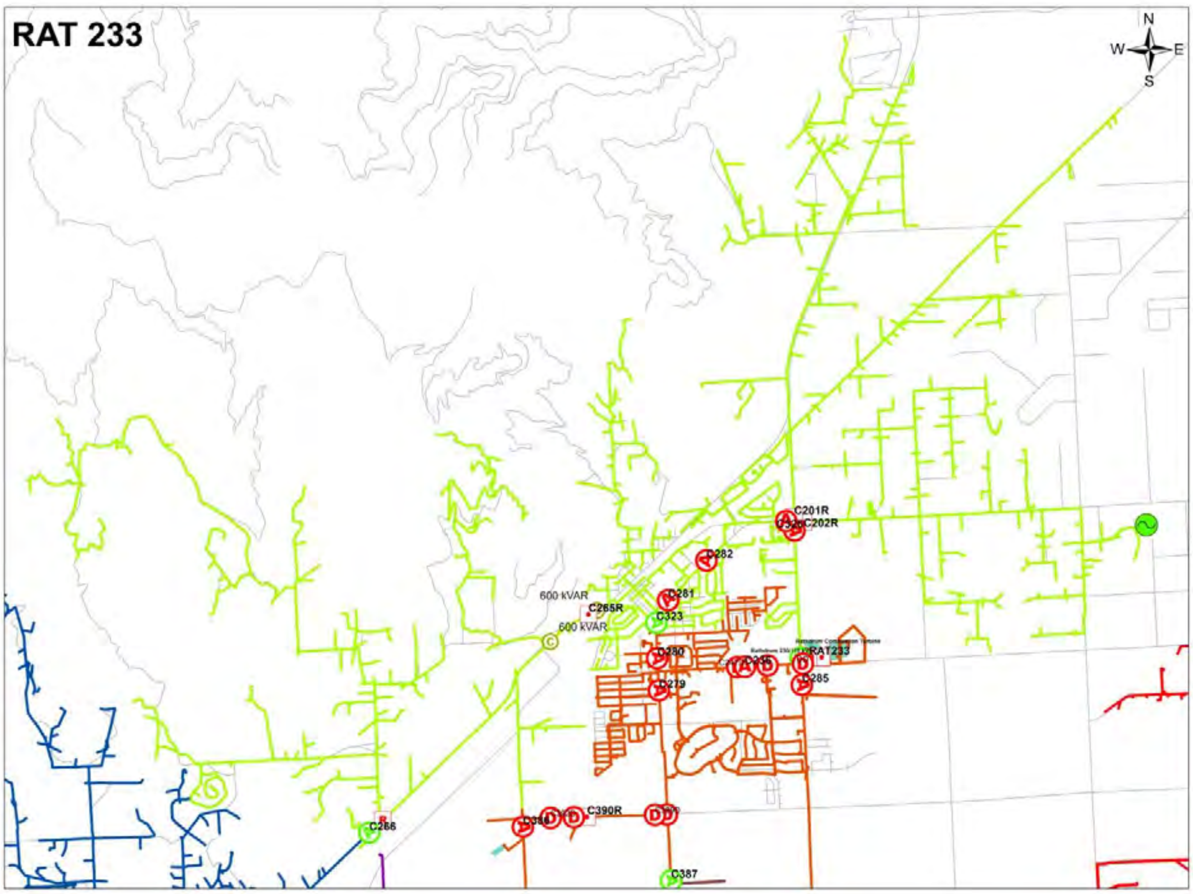


Figure 1. RAT 233 One-Line Diagram

Peak Loading

Three phase ampacity loading from SCADA monitoring at the RAT 233 substation circuit breaker was analyzed from 3/28/13 to 6/16/14. The following loading values were established for RAT 233 during this timeframe. Loading information has been removed from selected timeframes due to temporary changes in loading from switching (verified through PI). RAT 233 is a winter peaking feeder, with comparable peak values occurring between November and February. The values below reflect the adjusted data set. The peak loading values for each phase are used in the SynerGEE model analysis for the feeder, except where median load values are noted for establishing kW losses.

	Before Balancing	
	Peak	Median
A-Phase	395 A	190 A
B-Phase	429 A	204 A
C-Phase	342 A	173 A

	After Balancing	
	Peak	Median
A-Phase	388 A	186.6 A
B-Phase	383 A	182.1 A
C-Phase	395 A	199.8 A

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from SynerGEE at the model's initial.

	Estimated Peak Loading Conditions		
	Demand kVA*	Connected kVA*	% Loading
A-Phase	3151	10216	30.84%
B-Phase	3420	12405	27.57%
C-Phase	2726	10943	24.91%

* Connected kVA per Phase in SynerGEE as of 5/23/14

	Estimated Median Loading Conditions		
	Demand kVA*	Connected kVA*	% Loading
A-Phase	1515	10216	14.83%
B-Phase	1626	12405	13.11%
C-Phase	1380	10943	12.61%

* Connected kVA per Phase in SynerGEE as of 5/23/14

Feeder Balancing

Accurate load balancing can be achieved on RAT 233 due to the three phase ampacity monitoring at the Rathdrum 233 substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively:

	Peak Amps	Connected KVA per Phase*
A-Phase	395 A	10513 kVA
B-Phase	429 A	12470 kVA
C-Phase	342 A	10967 kVA

* Connected kVA per Phase in AFM as of 6/17/14

The following list provides laterals and dips that are candidates for effectively balancing the load on the phases between numerous strategic locations on the feeder, shown in Figure 2. As a whole, the multi-phase laterals on RAT 233 are relatively balanced, however opportunities are available to improve feeder balancing by transferring loads. The CPCs should not incorporate these changes into their designs, as the Coeur d'Alene Operations Engineers will provide a separate switching procedure to accomplish the following phase changes:

1. **Polygon 1** – transfer URD riser lateral at Meyer and Silverado (≈7 A) from AΦ to BΦ.
2. **Polygon 2** – transfer OH lateral south of Trails End and Krieg (≈17 A) from AΦ to CΦ. This purpose for this transfer will be expanded on in the Lateral section of this report.
3. **Polygon 11** – transfer OH lateral north of Silver and Golden (≈11 A) from BΦ to CΦ.
4. **Polygon 15** – transfer OH lateral north of Ohio and Crenshaw (≈18 A) from BΦ to AΦ.
5. **Polygon 18** – transfer OH lateral northwest of Reservoir, Ada, and Oneida (≈25 A) from BΦ to CΦ.

The result of these load transfers are listed in the table below. These changes will approximately balance the feeder at the substation breaker to 388/383/395, as well as between the numerous strategic points to approximately sectionalize the feeder.

	Existing			Proposed		
	A-Phase	**B-Phase**	**C-Phase**	**A-Phase**	**B-Phase**	**C-Phase**
RAT 233 Breaker	395	429	342	***388***	***383***	***395***
ZC202R	77	66	45	59	66	60
ZC201R	62	71	53	61	60	63
ZC335R	230	278	207	248	236	234
ZC282R	148	244	156	165	202	181
C281	113	204	140	130	162	165
ZC265R	62	69	40	61	69	41

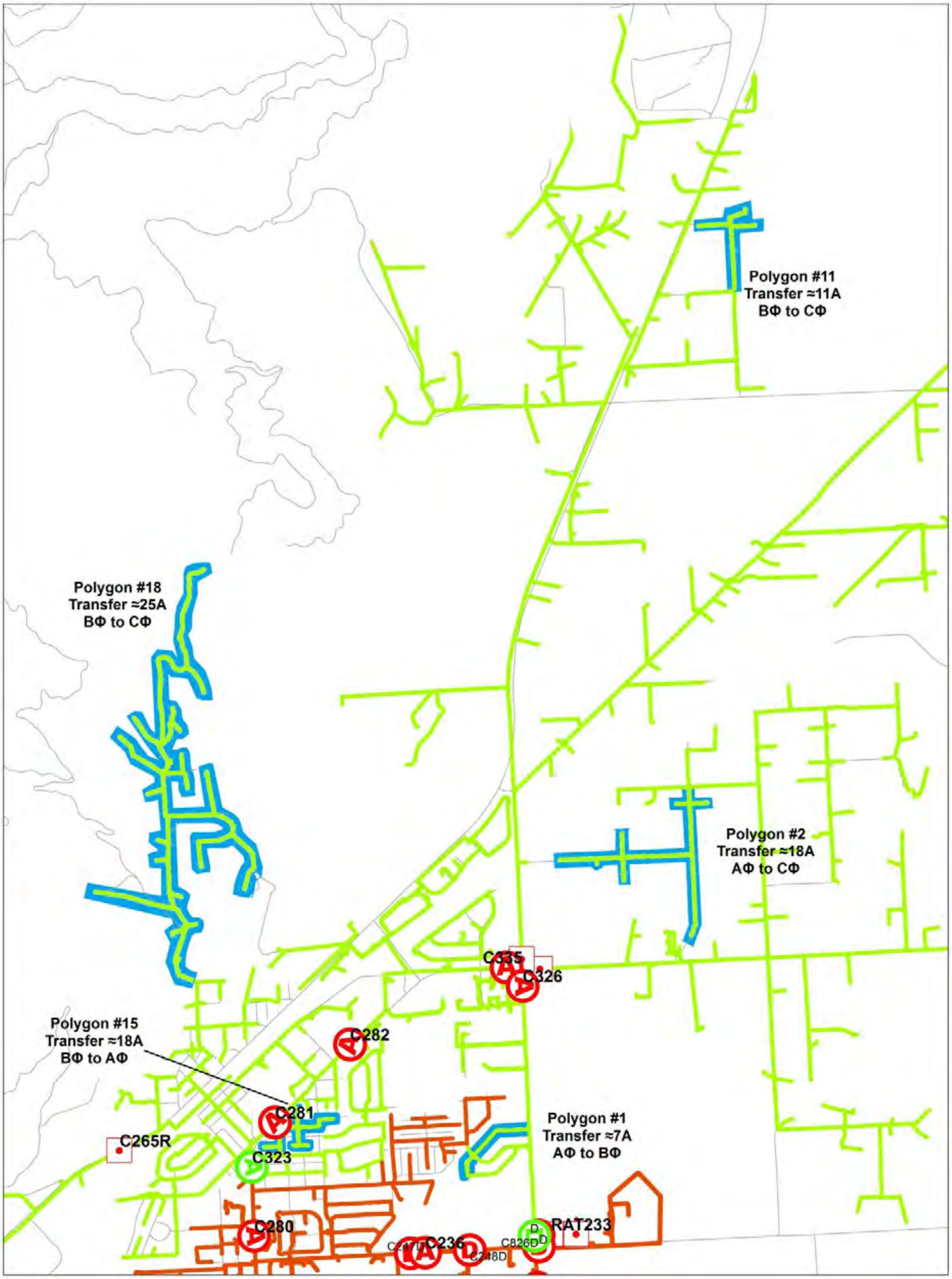


Figure 2. Feeder Balancing – Recommended Phase Changes

Conductor

All primary conductors on RAT 233 were analyzed in SynerGEE using the balanced peak ampacity values identified above (388/383/395). Specific attention was given to overloaded conductors, conductors with relatively high line losses, conductors that serve areas with unacceptable voltage quality (primarily during peak conditions), and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on RAT 233, as well as the proposals for improving the efficiency and performance of the feeder.

The respective CPC for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary requiring reconductoring.

Transmission Engineering should be consulted for any reconductoring performed on Transmission structures where there is Distribution underbuild to ensure the pole class is adequate for the loading changes on the structure.

Feeder Reconfiguration

There is latitude within the Grid Modernization program to identify and relocate sections of the feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when the benefits of rebuilding in place are negligible, or if reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

RAT 233 was analyzed to identify sections that are candidates for reconfiguration. Upon review, there were not any overwhelmingly apparent sections that warranted reconfiguration due to loading, physical conditions, and reliability concerns. It is recommended for the assigned CPC to further analyze each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in indentifying locations where configuration or conversion is sensible. CPCs should pay special attention to the existing single-phase laterals to the north and west of Highway 41 that have tree issues and with significant number or yellow/red tagged poles, as these may be candidates for reconfiguration.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned CPC during their field observations and material inventory - unless specifically directed by the Grid Modernization Program Engineer. It is the CPC’s responsibility to consult the Program Engineer on any proposals for reconfiguration prior to commencing the job designs. The CPC shall work with the Program Engineer to ensure the proposed work remains within the program’s scope, meets the system operations requirements, and to assist in identifying the appropriate material and equipment to install.

Trunk

The primary trunk conductors on RAT 233 are generally sized appropriately to meet peak loading conditions during normal system configuration. However, there are two sections of trunk that have portions that are heavily loaded, as well as portions that also contain undersized conductors that are moderately loaded.

- Reconductor 3Φ trunk east of the C202R recloser on Hwy 53 to 2/0 ACSR with a 2/0 ACSR neutral (approximately 10,000') in **Polygons 2 and 4**. This section of trunk is currently served with 6A and 4 ACSR conductors that are heavily loaded in numerous areas, as well as being undersized for serving as primary feeder trunk. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. Figure 3 illustrates the primary trunk reconductor on this section.

- Reconductor 3Φ trunk north of the C201R recloser on Hwy 53 to 2/0 ACSR with a 2/0 ACSR neutral (approximately 12,000') in **Polygons 6 and 9**. This section of trunk is currently served and 4 ACSR conductor that is heavily loaded, as well as being undersized for serving as primary feeder trunk. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. Figure 4 illustrates the primary trunk reconductor on this section.

The designs to reconductor shall adhere to the current Distribution Construction and Material Standards and Distribution Feeder Management Plan to ensure that all construction criteria are satisfied to bring these sections up to current standards.

Feeder Tie

RAT 233 currently contains overhead feeder ties to RAT 231 and IDR 253, including three separate ties between with RAT 231. One of these ties to RAT 231 is undersized with 6A and 4 ACSR conductors, which could make this tie unusable in many scenarios. In order to create a feeder tie with more capacity and versatility for this section of RAT 233, a section of the existing feeder trunk in Polygon 21 will be reconductored to better accommodate periodic load transfers with RAT 231. This section does not approach the existing conductors' ampacity limits during normal loading and configuration, however these limits are exceeded when serving transferred load during near-peak loading conditions. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. The reconductor of this section of feeder tie on RAT 233 will occur in coordination with the planned reconductor of the adjacent section of feeder tie on RAT 231 to 2/0ACSR.

- Reconductor 3Φ primary trunk south of C327 cutouts to C309 cutouts to 2/0 ACSR with a 2/0 ACSR neutral (approximately 5000 circuit feet) in **Polygon 21**. Figure 5 illustrates the primary trunk reconductor on this section.

The designs to reconductor shall adhere to the current Distribution Construction and Material Standards and Distribution Feeder Management Plan to ensure that all construction criteria are satisfied to bring these sections up to current standards.

Figure 3. Polygons 2 and 4 Primary Reconductor to 2/0 ACSR

Figure 4. Polygons 6 and 9 Primary Reconductor to 2/0 ACSR

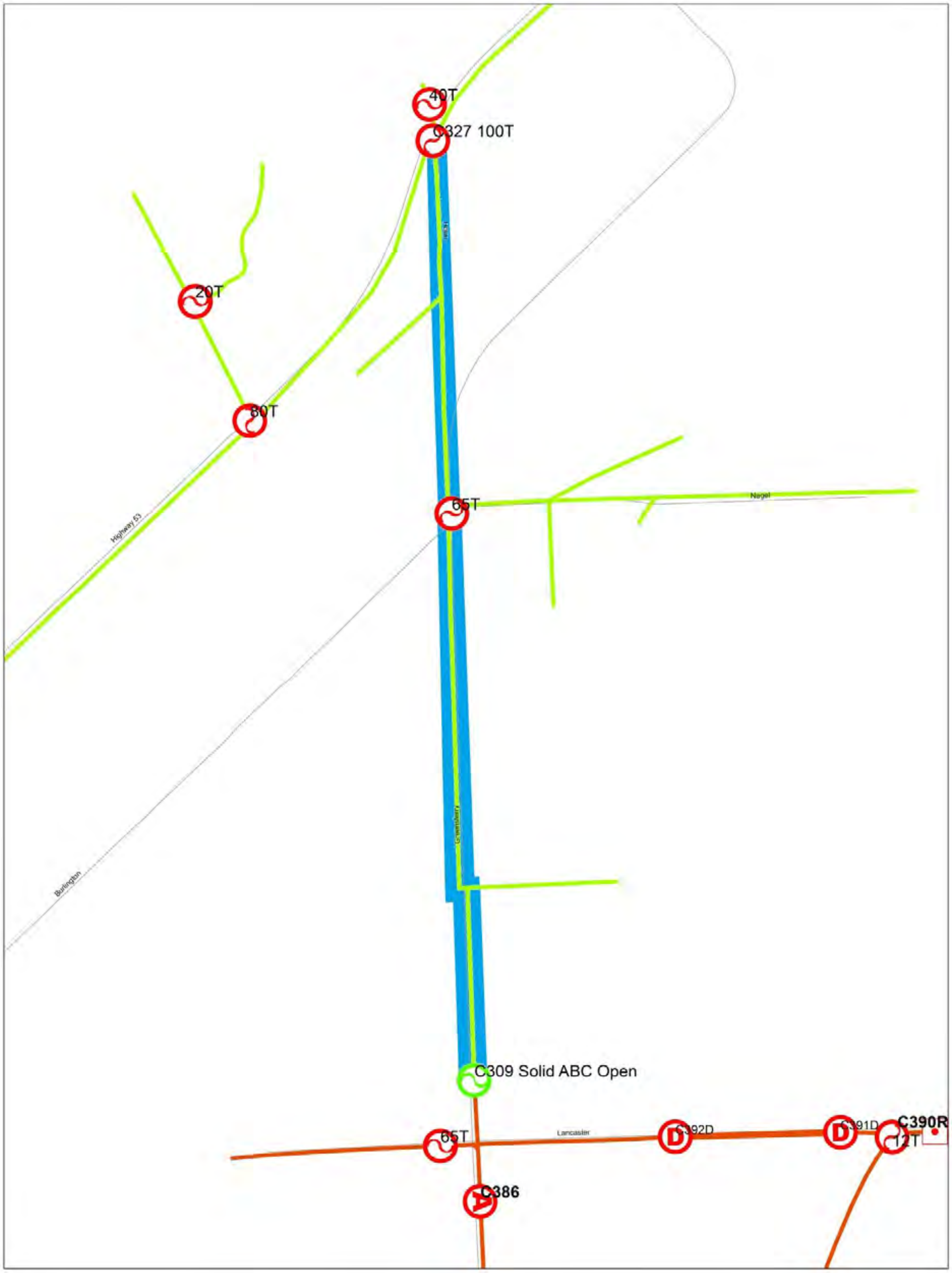


Figure 5. Polygon 21 Primary Reconductor to 2/0 ACSR

Laterals

The primary lateral conductors on RAT 233 are generally sized appropriately to meet peak loading conditions during normal system configuration. There are three laterals that have been initially identified for reconductoring as part of Grid Modernization's work on the feeder:

- Add an additional phase to the 2Φ lateral east of Greensferry and Nagel, and reconductor to 2/0 ACSR with a 2/0 ACSR neutral (approximately 2,500') in **Polygon 21.** This 3Φ overhead lateral will then be connected to the existing underground primary on RAT 231 via a new underground dip of 3Φ #1 AL (approximately 500'). The new 3Φ URD will be extended to a future JE3 that will be installed as part of the residential development work in the area. This URD extension will require an easement from the appropriate landowners. This reconductor and extension will create a new feeder tie in an area that is anticipated to experience load growth in the coming years. This work is not intended to be reconfigured, but rather rebuilt in place. Figure 6 illustrates the lateral conductor on this section.

- Extend 1Φ lateral on CΦ at Hwy 53 and Trails End to 4 ACSR with a 4 ACSR neutral (approximately 500') in **Polygons 2 and 3**. This will allow the moderately loaded lateral on Fowler Road to be reconfigured into two lighter loaded laterals. By splitting this into two laterals, different phases can be used to serve the load in an effort to balance this section of the feeder. The fusing and proposed open point on this loop will be recommended in a separate document by the Coeur d'Alene Operations Engineers. Figure 7 illustrates the lateral conductor on this section.

- Extend 1Φ lateral on AΦ at Hwy 41 and Rice Road to 4 ACSR with a 4 ACSR neutral (approximately 800') in **Polygon 12**. 2 spans of 6CR and 6A on the south side of lower Twin Lakes off of Gunning Road (approximately 1400') will remain to create a loop feed for the area. This will eliminate overloaded section of 6CR, while also splitting the moderately loaded lateral into two lighter loaded laterals. The fusing and proposed open point on this loop will be recommended in a separate document by the Coeur d'Alene Operations Engineers. Figure 8 illustrates the lateral conductor on this section.

It is the CPC's responsibility to consult the Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs, as well as the Coeur d'Alene Operations Engineers. It may be determined that additional laterals could be reconductored due to existing material conditions and improved performance with reconfiguration. The CPC shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install.

Figure 6. Polygon 21 Lateral OH Reconductor and URD Extension along Nagel

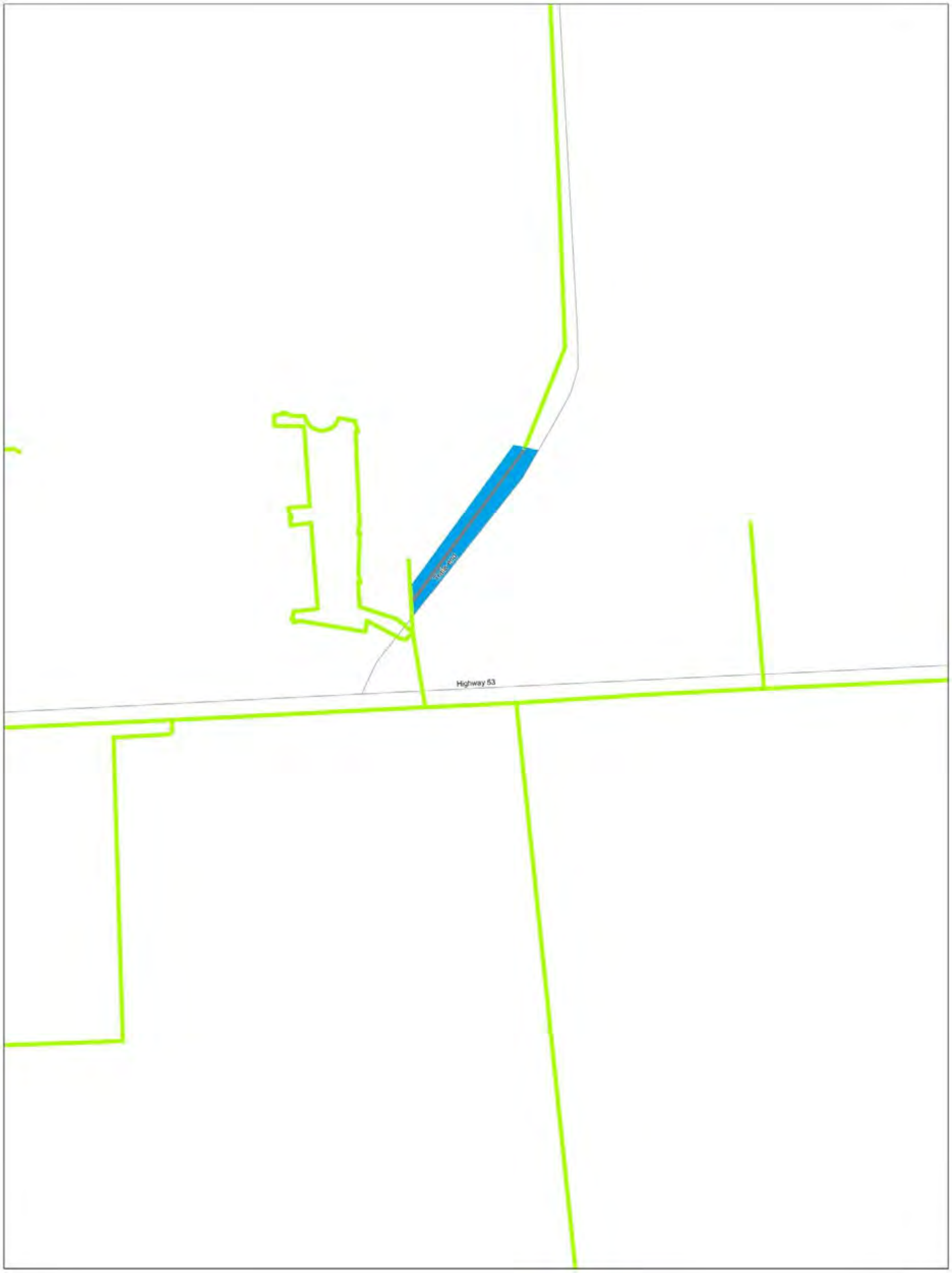


Figure 7. Polygon 2 Lateral Reconductor at Hwy 53 and Trails End Road

Figure 8. Polygon 12 Lateral Reconductor at Hwy 41 and Rice Road

Voltage Quality

The loading on RAT 233 was first balanced between phases to eliminate the unnecessary overloading of phases which may exacerbate voltage quality problems. RAT 233 needed to be effectively balanced at numerous switching and sectionalzing points on the feeder. These proposals were previously outlined in the *Feeder Balancing* section of this report. RAT 233 was then analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable limit required by the NESC (114V-126V). The feeder was modeled in SynerGEE during both peak loading and median loading conditions.

- During peak loading conditions, voltage levels remained within the allowable limits. The higher voltage levels occurred closer to the substation as to be expected, including the town of Rathdrum. The majority of the feeder trunks were estimated between 123V-126V, while most of the laterals radiating out from the feeder's core registering between 119V-123V. The maximum voltage modeled was approximately 124.6V, while the lowest voltage was 118.6V. Figure 9 represents service level voltages at peak load conditions.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	96	8.22	250	51
120.00 - 122.00 V	344	24.37	1373	353
122.00 - 124.00 V	1269	71.48	7288	1942
124.00 - 126.00 V	25	1.82	212	81
126.00 - 140.00 V	0	0.00	0	0

- During median loading conditions, voltage levels remained within the allowable limits, but slightly higher overall when compared to levels during peak loading conditions. The higher voltage levels occurred closer to the substation as to be expected, including the town of Rathdrum and along Highway 53. The majority of the feeder trunks were estimated between 123V-124V, while most of the laterals radiating out from the feeder's core registering between 121V-123V. The maximum voltage modeled was approximately 123.9V, while the lowest voltage was 121. Figure 10 represents service level voltages at medium load conditions.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	172	13.96	284	158
122.00 - 124.00 V	1561	91.92	4197	2269
124.00 - 126.00 V	1	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

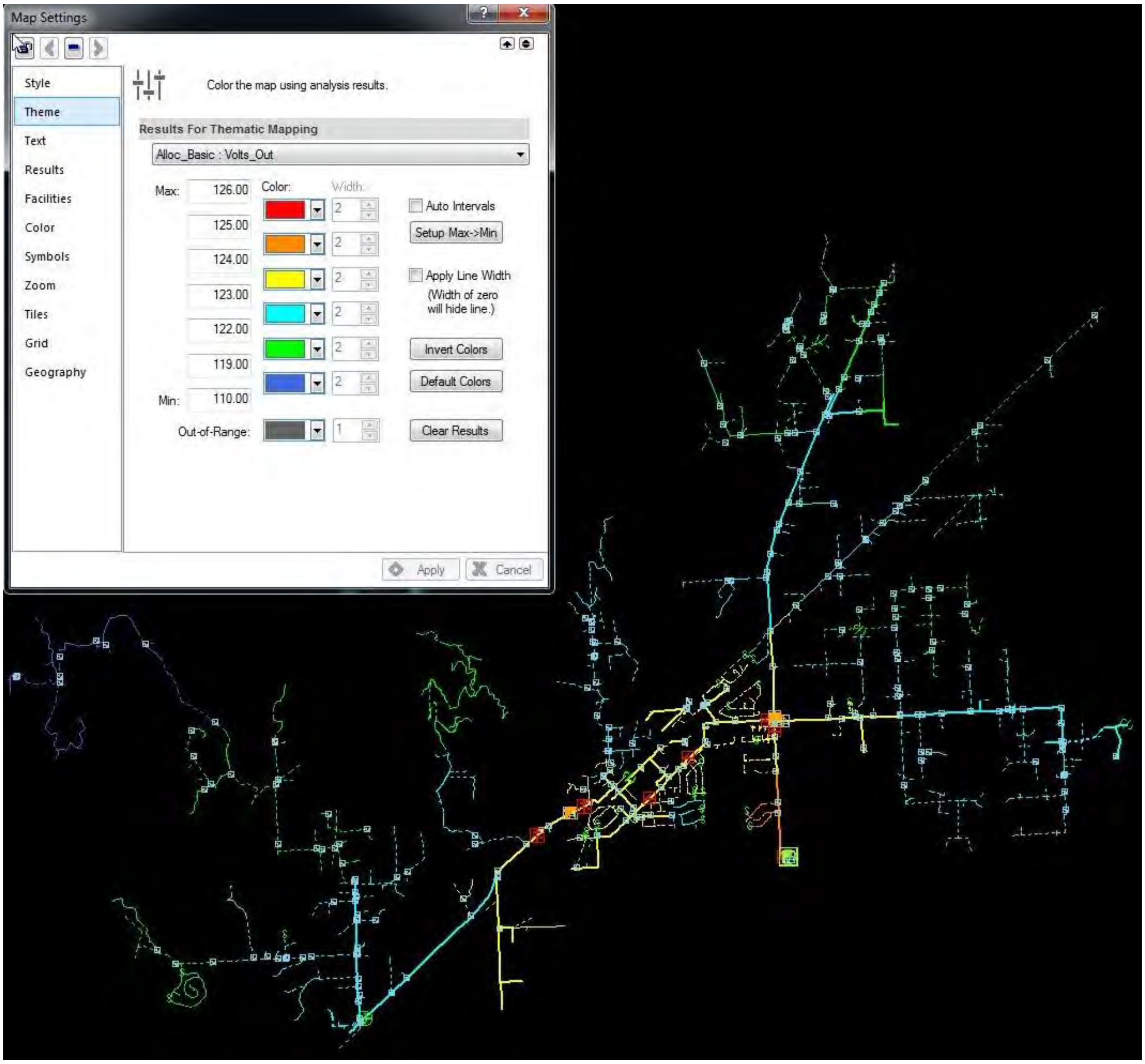


Figure 9. Service Voltage Levels at Peak Load Conditions

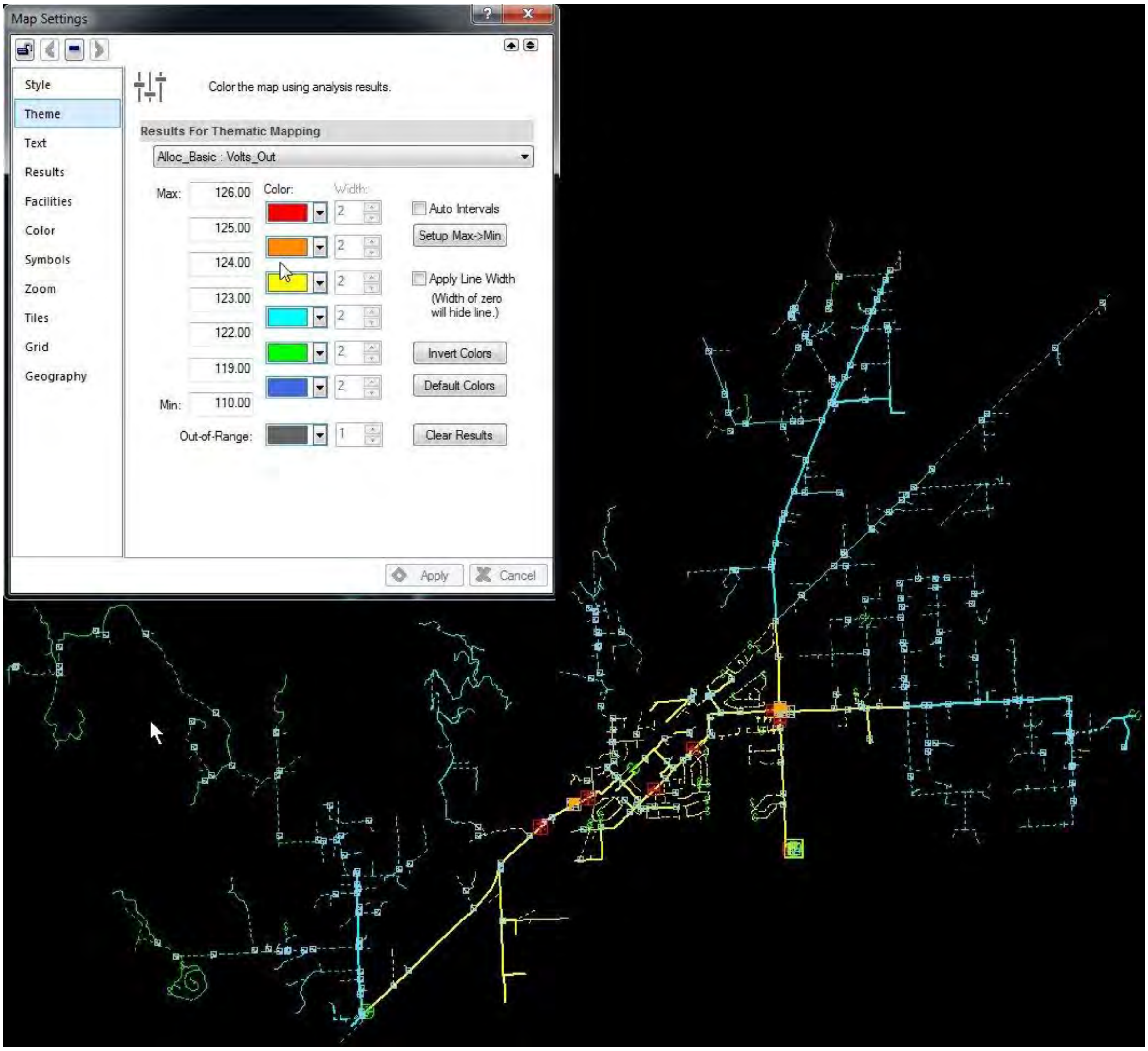


Figure 10. Service Voltage Levels at Median Load Conditions

Voltage Regulator Settings

RAT 233 has two existing stages of voltage regulation: one at the Rathdrum Substation and a set of midline regulators at Hwy 53 and Idaho Road. The voltage levels on the feeder were modeled in SynerGEE during both peak loading and median loading conditions. The voltage levels across RAT 233 remain between 118.6V-124.6V in both modeled scenarios. While this would initially suggest that voltage levels could be reduced slightly for median and peak loading scenarios during normal feeder configuration, these acceptable voltages are appropriate to provide allowable voltage levels when additional load is served by RAT 233.

The implementation of IVVC or CVR on RAT 233 would provide automation in managing the voltage level and profile on the feeder. The recommendation to pursue either initiative will depend on the recommendations of the Distribution System Operations department and the Coeur d'Alene Operations Engineers. Reducing the feeder voltage levels and profile could contribute to optimize the feeder's performance, provide energy savings, and assist in reducing energy losses.

The existing regulators at Hwy 53 and Idaho Road will be replaced with smart regulators (ZC879V) as part of the Grid Modernization work. In addition, a new set of midline voltage regulators will be installed at approximately Highway 41 and Diagonal Road (ZC880V). Revised voltage regulator settings are recommended on RAT 233 with the introduction of an additional stage of regulation, as well as the reconductoring of the primary trunk. Any changes to the regulator settings will be determined and coordinated by the Coeur d'Alene Operations Engineers, including the settings for the new ZC880V regulators. The existing and proposed voltage regulator settings are provided in the following tables:

	Existing	
Forward Settings	**R**	**X**
RAT 233 Station Regulators	1.30	1.80
ZC879V Midline Regulators	0.80	2.60
ZC880V Midline Regulators	-	-

	Existing	
Reverse Settings	**R**	**X**
ZC879V Midline Regulators	3.20	3.30

Fuse Sizing

Fuse sizing on RAT 233 shall be verified and incorporated by the CPC into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and transformers (where applicable). Fuse recommendations for RAT 233 were created by the Coeur d'Alene Operations Engineers. The CPC shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The CPC shall consult the Coeur d'Alene Operations Engineers with any questions regarding fuse sizing and coordination.

There may be situations where the transformers sizes on a lateral are "right sized" (increased or decreased) to more accurately reflect customer loads. If there are significant changes to the overall connected kVA on a lateral, the CPC shall consult the Coeur d'Alene Operations Engineers to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with the transformer fuse(s).

Losses

The primary trunk conductors on RAT 233 have been sized appropriately to minimize line losses at peak and median loading conditions during normal system configuration. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading.

After the proposed reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections are performed on RAT 233, it is estimated that the peak line losses could be reduced by as much as 41.8 kW, while the median loading line losses could be reduced by as much as 10.3 kW. In addition, up to 180.5 MWh savings could be captured over a two year span assuming median loading conditions during normal system configuration.

	E of C202R	**N of C201R**	**S of C327**
Circuit Length	10,200	12,000’	5,000’
Current Median kW Losses	6.0	9.8	0.0
Current Peak kW Losses	23.8	39.4	0.2
Proposed Median kW Losses*	2.0	3.5	0.0
Proposed Peak kW Losses	8.2	13.4	0.0
Median kW Loss Savings	4.0	6.3	0.0
Peak kW Loss Savings	15.6	26.0	0.2
Reconductor MWh Savings (Median) ***	70.1	110.4	0.0

* Losses are estimated as negligible and near zero
** Primary and neutral conductor material cost only
*** Estimated median kW losses over two year span

An initial SyngerGEE load study estimates that a total of 184 kW in peak line losses currently exists on RAT 233 (2.05%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved to approximately 156 kW (1.75%).

Peak Values	**Existing**	**After Balancing**	**After Trunk Reconductor**
kW Demand	9287	9283	9281
kW Load	9096	9078	9119
kW Line Losses	184	199	162
kW Loss %	2.05 %	2.21 %	1.75 %

In addition to the estimated line loss savings described above, there will be additional loss savings captured through the “right sizing” replacement of distribution transformers. The cumulative reduction in connected kVA will not be quantified until all of the polygons are addressed by CPCs, however there are estimated savings through the suggested transformer replacements through the TCOP program. The TCOP recommendations will reduce the connected kVA on RAT 233 by an estimated 3065 kVA. By eliminating idle transformers and reducing the connected kVA being served, the transformer core and copper losses can be minimized – helping to reduce the overall losses on the feeder, and improve system efficiency.

Transformer No Load Losses

The review of historically purchased transformers illustrates that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. No Load Losses are generally lower on newer units compared to a transformer of the same size from an older vintage. These Losses can be minimized through the replacement of older transformer to newer units of a more appropriate size.

All transformers on RAT 233 shall be analyzed and “right sized” by the assigned Designer to most accurately reflect the customer loads. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the Designer.

The roughly 1117 distribution transformers on RAT 233 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It was determined that 658 transformers will require replacement based on right sizing and the TCOP criteria replacements. The replacement of these transformers will result in an estimated 43.54 kW reduction in No Load Losses. This equates to an annual savings of roughly 381.41 MWh.

Power Factor

MVAR and MW data at the RAT 233 substation circuit breaker was analyzed from 3/28/12 to 6/16/14. It was determined that RAT 233 had a leading power factor 86.9% of the time during the time interval analyzed, with a lagging power factor 13.1% of the time. Additional detailed power factor information is available upon request. Some key power factor figures for RAT 233 are provided in the tables below.

	Lagging	Leading
Average Power Factor	99.68 %	99.67 %
Median Power Factor	99.92 %	99.83 %
Maximum Power Factor	99.99 %	99.99 %
Minimum Power Factor	91.77 %	74.15 %

The table below shows the percent of time during the interval analyzed where the power factor on RAT 233 fell between the applicable ranges. This information is also provided in graphical form in Figure 11.

	Lagging	Leading
90%-91%	0.00%	0.00%
91%-92%	0.01%	0.00%
92%-93%	0.02%	0.00%
93%-94%	0.01%	0.00%
94%-95%	0.12%	0.00%
95%-96%	0.04%	0.00%
96%-97%	0.08%	0.01%
97%-98%	0.12%	0.43%
98%-99%	0.25%	6.73%
99%-100%	12.5%	79.71%

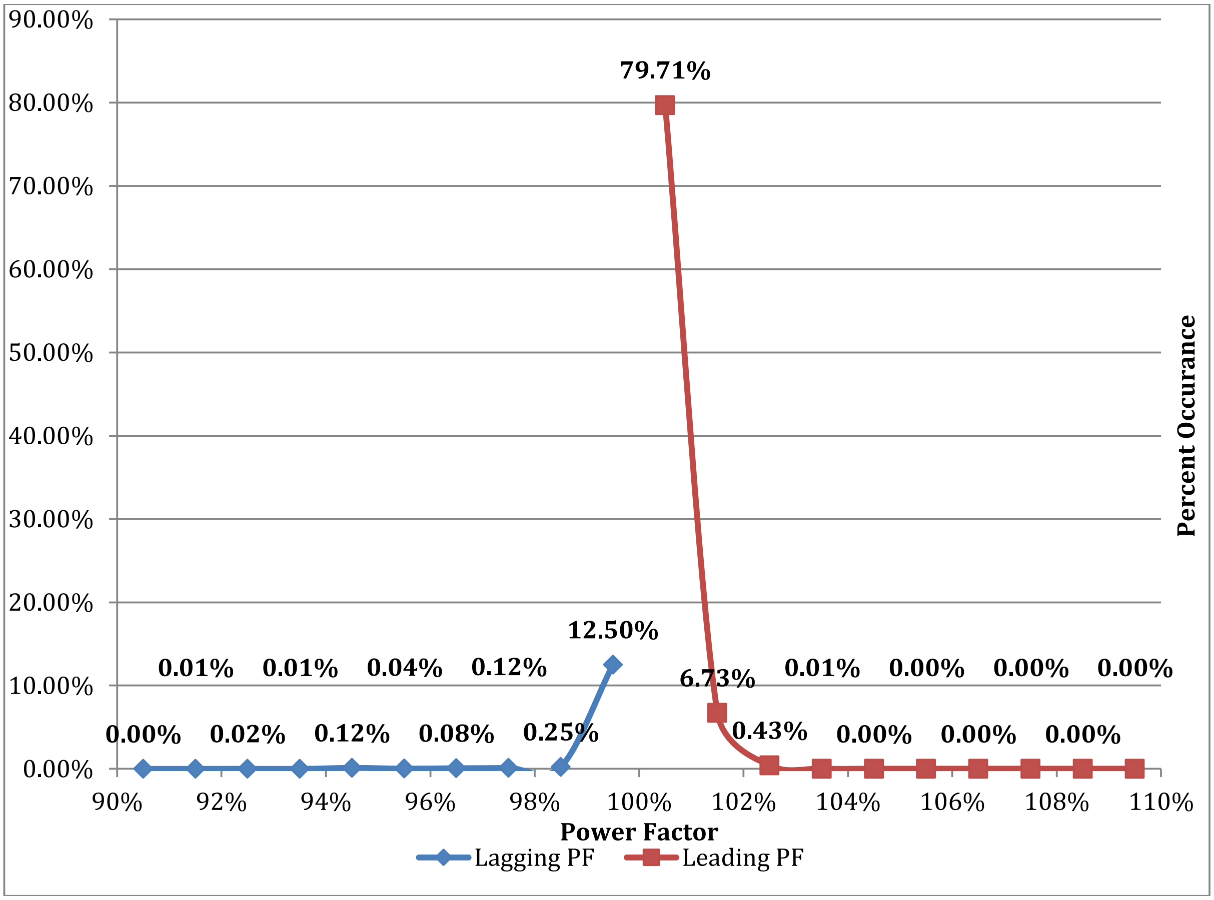


Figure 11. Percent Occurance of Power Factor

The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times.

The power factor on RAT 233 is generally in an acceptable range, although it is slightly leading during a majority of the time. There are two existing 600 kVAR fixed capacitor banks on RAT 233. After analyzing the variable VAR scenarios on the feeder, it is recommended to remove one of the existing 600 kVAR fixed capacitor banks, west of Idaho Highway 53 and Hidden Valley.

Automation

Distribution Automation will be deployed on RAT 233 as part of the Grid Modernization program. A customized solution for the feeder has been created in coordination with the Coeur d'Alene Operations Engineers to address the specific characteristics and issues associated with the load, customers, and geography on RAT 233.

RAT 233 currently contains overhead feeder ties to RAT 231 and IDR 253, including three separate ties between with RAT 231. The feeder tie to RAT 231 at C323R is scheduled to become an automated device in 2015 (CZ323R), which is when distribution automation will also be deployed on RAT 231. With this feeder tie connection, RAT 231 and RAT 233 will create a miniature smart grid.

The following intelligent devices will be deployed on the feeder to create a smart circuit:

Device Number	Location	Status	Device Type
ZC201R	N of Hwy 53 & Meyer	N.C.	Viper – Recloser
ZC202R	E of Hwy 53 & Meyer	N.C.	Viper – Recloser
ZC265R	E of Hwy 53 & Hidden Valley	N.C.	Viper – Recloser
ZC282R	Hwy 41 & Vernon	N.C.	Viper – Trunk Switch
ZC326R	S of Hwy 53 & Meyer	N.C.	Viper – Trunk Switch
ZC335R	W of Hwy 53 & Meyer	N.C.	Viper – Recloser
ZC879V	Hwy 53 & Idaho Road	N.C.	Smart Midline Voltage Regs
ZC880V	Hwy 41 & Diagonal	N.C.	Smart Midline Voltage Regs

Figure 12 illustrates the proposed automation device locations on RAT 233.

Distribution System Operations has recommended to install automation compatible voltage regulators and a breaker recloser in the substation to provide future FDIR and IVVC capabilities depending on the custom solution that is developed with the line device. Grid Mod will request the installation of the station voltage regulators by Substation Engineering, however Grid Mod is currently unable to secure the installation of the station breaker recloser due to scheduling and resource constraints.

The coordination of the automation devices will be managed by the Coeur d'Alene Operations Engineers. This will include, but is not limited to: confirming communication site surveys, working with Protection Engineering on the coordination study, procuring the automation devices through WMS/Maximo, working with the various Shops to route the documents as required, and scheduling the communication and device installations with Avista personnel.

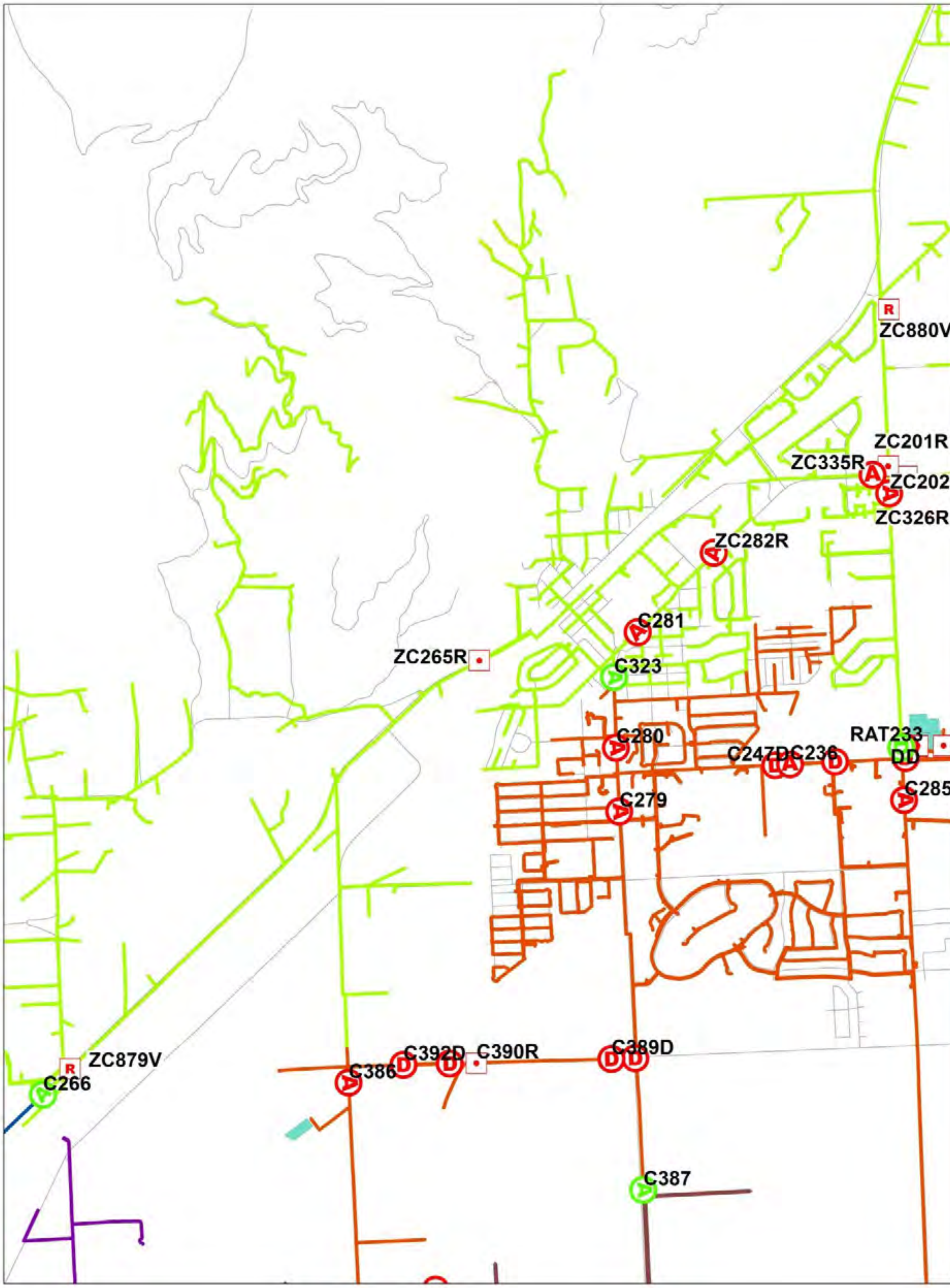


Figure 12. Proposed Automation Device Locations

<u>Open Wire Secondary</u>

RAT 233 was analyzed for open wire secondary districts in accordance to the Distribution Feeder Management Plan (DFMP). Only one district was identified to exist on RAT 233, however there may be others on the roughly 193 miles of circuit conductor on the feeder. Figure 13 identifies the open wire secondary district that was discovered that will require further field analysis to determine whether to leave or replace.

- **Polygon 16 –** further analyze 450’ of vertical open wire due to roadside accessibility to determine whether to replace or leave.

CPCs shall consult the DFMP if open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Program Engineer to provide direction on replacement.

Figure 13. Open Wire Secondary District in Polygon 16

Poles

All poles and structures on RAT 233 shall be examined by the assigned CPC for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Wood Pole Management (WPM) department based on the tested condition of the structure, however the final decision to replace a pole will reside with the CPC. An explicit list of poles will be provided and identified by WPM. The CPC shall consult the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

Transformers

All transformers on RAT 233 shall be identified by the assigned CPC for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by TCOP. However all transformers shall be analyzed and “right sized” by the CPC to most accurately reflect customer loads. The CPC shall consult the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned CPC for damage, removal, or replacement. The CPC shall consult the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program. This section of the DFMP requires more substance and explicit guidelines on the design requirements to assist the CPCs in correctly addressing these issues.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable.

Tree Trimming

Vegetation management shall be employed on RAT 233 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The CPC for each polygon is responsible for coordinating any tree trimming on their respective polygons with the Vegetation Management department. A methodical trimming scheduled developed by the CPCs that encompasses all assigned polygons is strongly recommended to reduce travel costs and maximize the allotted budget for the feeder.

Design Polygons

RAT 233 has been divided into 26 polygons for the Grid Modernization project work. These polygons were created with assistance from the Coeur d'Alene Operations Engineers. The polygons were created in an attempt to divide the work into near equivalent segments in regards to design and crew time. Additional considerations such as automation devices, reconductoring, geography, road access, and location of laterals further assisted in defining the boundaries of the polygons. Additional polygons can be created if necessary to better organize the work on the feeder, however they will be subsets of the existing numbered polygons.

All polygons will be formally assigned to the CPCs by the Grid Modernization Program Manager.

Although RAT 233 is scheduled for design in 2015 and construction in 2016, there is a possibility that some work may be constructed in 2015 based on the availability of designers and crews. The Coeur d'Alene Operations Engineers will play an integral role in prioritizing all polygons in 2015 and 2016. Polygons 1,13, 19 and 22 will likely be completed at the end of 2015, and therefore should be added into all other affected departments' work plans for 2015 (budget permitting). Expediting this work would affect Real Estate, Environmental, permitting, etc.

The CPC is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as notifying the Program Engineer by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

The following polygon summary lists the identified items that shall be incorporated into the final job designs:

- **Polygon 1**
  - Install Viper (ZC201R, N.C.) north of Hwy 53 & Meyer Road
  - Install Viper (ZC202R, N.C.) east of Hwy 53 & Meyer Road
  - Install Viper (ZC326R, N.C.) south of Hwy 53 & Meyer Road
  - Transfer URD riser lateral at Meyer and Silverado (≈7 A) from AΦ to BΦ.
- **Polygon 2**
  - Reconductor 3Φ trunk east of the C202R recloser on Hwy 53 to 2/0 ACSR with a 2/0 ACSR neutral (approximately 10,000')
  - Extend 1Φ lateral on CΦ at Hwy 53 and Trails End to 4 ACSR with a 4 ACSR neutral (approximately 500').
  - Transfer OH lateral south of Trails End and Krieg (≈17 A) from AΦ to CΦ.
- **Polygon 3**
  - Transfer OH lateral south of Trails End and Krieg (≈17 A) from AΦ to CΦ.
- **Polygon 4**
  - Reconductor 3Φ trunk east of the C202R recloser on Hwy 53 to 2/0 ACSR with a 2/0 ACSR neutral (approximately 10,000')

- **Polygon 6**
  - Reconductor 3Φ trunk north of the C201R recloser on Hwy 53 to 2/0 ACSR with a 2/0 ACSR neutral (approximately 12,000')
  - Install Smart Midline Regulators (ZC880V, N.C.) Hwy 41 & Diagonal
- **Polygon 9**
  - Reconductor 3Φ trunk north of the C201R recloser on Hwy 53 to 2/0 ACSR with a 2/0 ACSR neutral (approximately 12,000')
- **Polygon 11**
  - Transfer OH lateral north of Silver and Golden (≈11 A) from BΦ to CΦ.
- **Polygon 12**
  - Extend 1Φ lateral on AΦ at Hwy 41 and Rice Road to 4 ACSR with a 4 ACSR neutral (approximately 800').
  - Remove 2 spans of 6CR and 6A on the south side of lower Twin Lakes off of Gunning Road (approximately 1400').
- **Polygon 13**
  - Install Viper (ZC282R, N.C.) at Hwy 41 & Vernon
  - Install Viper (ZC335R, N.C.) west of Hwy 53 & Meyer Road
- **Polygon 15**
  - Transfer OH lateral north of Ohio and Crenshaw (≈18 A) from BΦ to AΦ.
- **Polygon 16**
  - Further analyze 450' of vertical open wire due to roadside accessibility to determine whether to replace or leave.
- **Polygon 18**
  - Transfer OH lateral northwest of Reservoir, Ada, and Oneida (≈25 A) from BΦ to CΦ.
- **Polygon 19**
  - Install Viper (ZC265R, N.C.) east of Hwy 53 & Hidden Valley
  - Remove 600 kVAR fixed capacitor bank west of Idaho Highway 53 and Hidden Valley.
- **Polygon 21**
  - Reconductor 3Φ primary trunk south of C327 cutouts to C309 cutouts to 2/0 ACSR with a 2/0 ACSR neutral (approximately 5000 circuit feet)
  - Add an additional phase to the 2Φ lateral east of Greensferry and Nagel, and reconductor to 2/0 ACSR with a 2/0 ACSR neutral (approximately 2,500').
  - Install new URD primary of 3Φ #1 AL (approximately 500'). The new 3Φ URD will be extended to a future JE3 that will be installed as part of the residential development work in the area.
- **Polygon 22**
  - Install Smart Midline Regulators (ZC879V, N.C.) Hwy 53 & Idaho Road

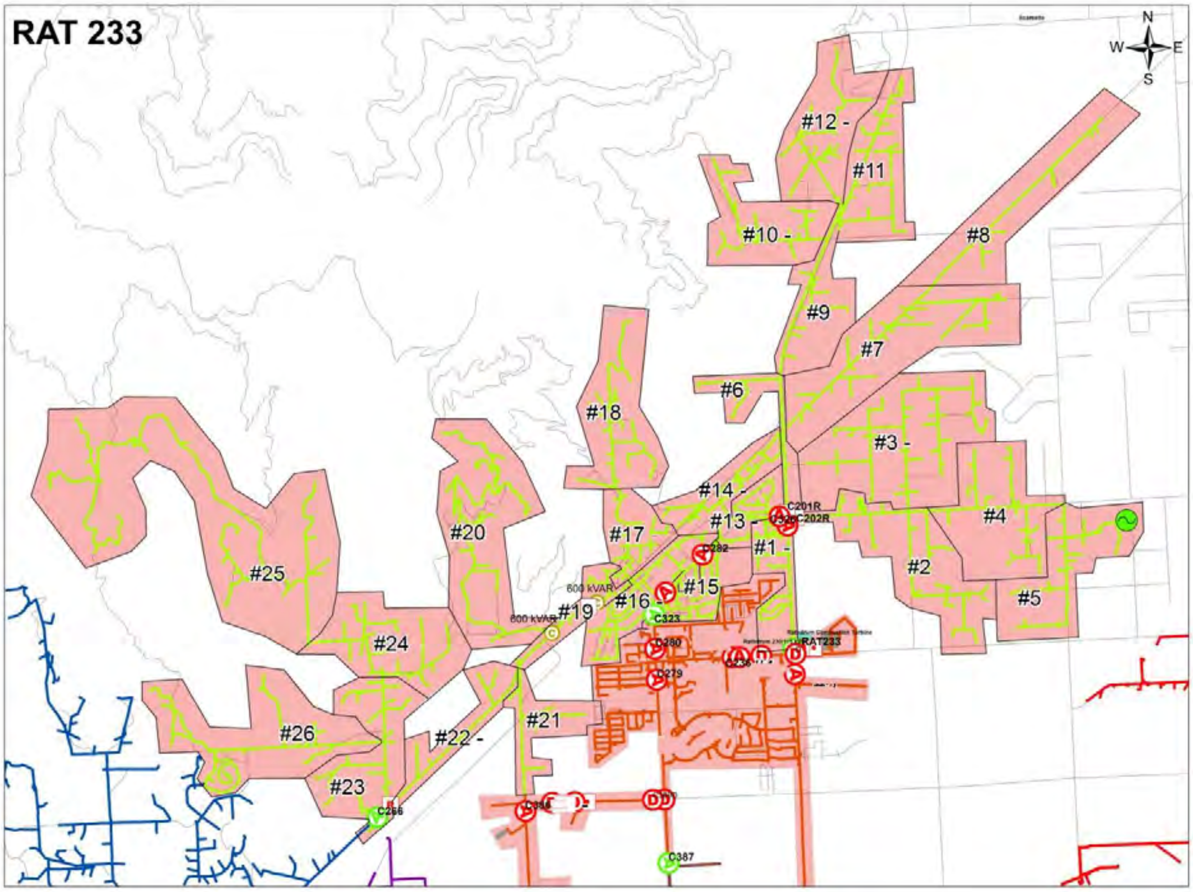


Figure 14. RAT 233 Polygon Numbers

Report Versions

Version 1	8/12/14 – Creation of the initial report
Version 2	9/9/14 – Incorporated suggestions from the Coeur d'Alene Operations Engineers
Version 3	9/17/14 – Incorporated suggestions from the report review meeting with the Coeur d'Alene Operations Engineers
Version 4	10/6/14 – Revised capacitor bank proposal
Version 5	3/17/15 – Updated the report to include the estimated energy savings through the identified transformer replacements.

Grid Modernization Program

ROS 12F5 Feeder Analysis Report

May 31, 2019

Version 1

Prepared by

Shane Pacini, P.E.
Senior Distribution Engineer

Index

Overview

The following report was established to analyze the ROS 12F5 circuit as part of the Grid Modernization program. ROS 12F5 is a 13.2/7.62 kV distribution feeder served from Transformer #2 at the Ross Park 115kV Substation in the Spokane service area. The feeder has 2.13 circuit miles of feeder trunk with 10.95 circuit miles of laterals that serves an urban mixture of residential and commercial loads in east-central Spokane, WA. ROS 12F5 serves 2004 customers during the current normal configuration, including the primary metered customer of the City of Spokane Water Department (~3312 kW peak demand). Additional feeder information is included throughout the sections of this report, as well as the 2017 Avista Feeder Status Report. ROS 12F5 is represented by the color *pink* on the system map shown in Figures 1 and 2.

Executive Summary

The Grid Modernization Program is a Capital initiative that was established in 2013 to holistically evaluate and systematically address the improvement of Avista's approximately 12,000 circuit miles of overhead and underground primary electric distribution lines. The objective of the Program is to provide a thorough examination of Avista's electric distribution circuits for programmatically addressing the modernization and upgrading of the facilities. The targeted improvement to the critical components on the system will result in significant upgrades to the broad areas of performance, health, reliability, efficiency, asset condition, operability, and distribution automation.

Grid Modernization performs a comprehensive inventory of each electric feeder in the system to appropriately prioritize and select the feeders that will benefit the most from the Program. The feeder criteria information is used to rank the potential benefits for each circuit compared against the other distribution feeders Avista's system. The Program focuses on selecting and improving the relatively poorer performing feeders that have been assessed in order to achieve the most opportunities for improvement.

While the efforts of the program will provide significant upgrades to all of these wide ranging categories, each circuit that is selected has its distinct characteristics, strengths and weaknesses. For example, a circuit may have exceptional reliability metrics, however the feeder may present the opportunities to capture significant line loss savings. This variability between circuits translates into a unique tailored solution for each feeder where the improvement opportunities may reside in various different areas.

The overall health and asset condition of the facilities and components on ROS 12F5 was a primary contributing factor to the selection of this circuit. For example, it is estimated that significant pole replacements will occur on the circuit. 409 poles (53.7%) will be replaced at a minimum due to the prescriptive replacement of the structures before their anticipated failure. In addition, 571 poles (73.2%) are Class 4 poles or smaller: suggesting that these structures may lack the physical strength required to support current construction standards and future grid initiatives. These numbers do not include pole height, which is a major contributing factor in ensuring Avista maintains safe working practices and clearance requirements of conductors.

The circuit also contains approximately 43,700' circuit feet of open wire secondary districts. It is anticipated that the removal of this less reliable construction practice will improve voltage quality for Avista's customers while improving line losses and overall circuit efficiency.

In addition, approximately 123 transformers (47.5%) on the feeder will be replaced due to being undersized or contain a higher than desired presence of Polychlorinated Biphenyls (PCBs). The replacement of these older units will result in improved efficiency through core loss savings, and improved health and performance.

The following summary is provided as a preview of the findings and recommendations of the Grid Modernization program for the ROS 12F5 circuit:

- Primary trunk is mostly comprised of 556 AAC, resulting in only one section of trunk reconductoring to upgrade from and 336 ACSR
- Primary laterals are currently sized appropriately for loading levels, voltage quality, and line losses. However the large amount of 6CU wire (9.58 miles) may result in reconductoring based on the physical condition of the wire.
- Phase changes will be performed to establish balanced loading across numerous strategic points on the circuit to enhance voltage quality and mitigate unnecessary over loading.
- Voltage regulator R/X settings and voltage output settings will not be provided, as the feeder has DMS enable IVVC/CVR that optimize the voltage levels.
- The power factor is within the optimal range, being observed between 0.99 lead and 0.99 lag approximately 98.94% of the time during two years being analyzed.
- No switchable capacitor banks will be installed or removed. The feeder has two automated capacitor banks that were installed as part of the SGIG Project.
- Opportunities exist to optimize the two fixed capacitor banks by energizing an offline bank and removing an antiquated bank which is not needed
- There is approximately 43,700' circuit feet of open wire secondary districts. It is expected that most of these districts will be removed to address voltage quality concerns and with the combined targeted pole and transformer replacements
- An estimated 123 of the 259 transformers (47.5%) on the feeder will be replaced
- SAIFI, SAIDI, and CEMI3 currently satisfy the 2019 Avista Target values
- CAIDI currently does not satisfy the 2019 Avista Target values
- No automated Viper midline reclosers will be installed. The feeder has one Viper midline recloser that was installed as part of the SGIG Project.
- No automated switches will be installed. The feeder has six automated line devices that were installed as part of the SGIG Project.
- 409 of the 762 poles (53.7%) on the circuit are will be replaced at a minimum due to the prescriptive replacement of the 60 year limit for mean-time to failure
- Comprehensive fuse sizing and coordination study was performed, with suggestions to optimize coordination and improve fault isolation to reduce the number of customers impacted by outages.

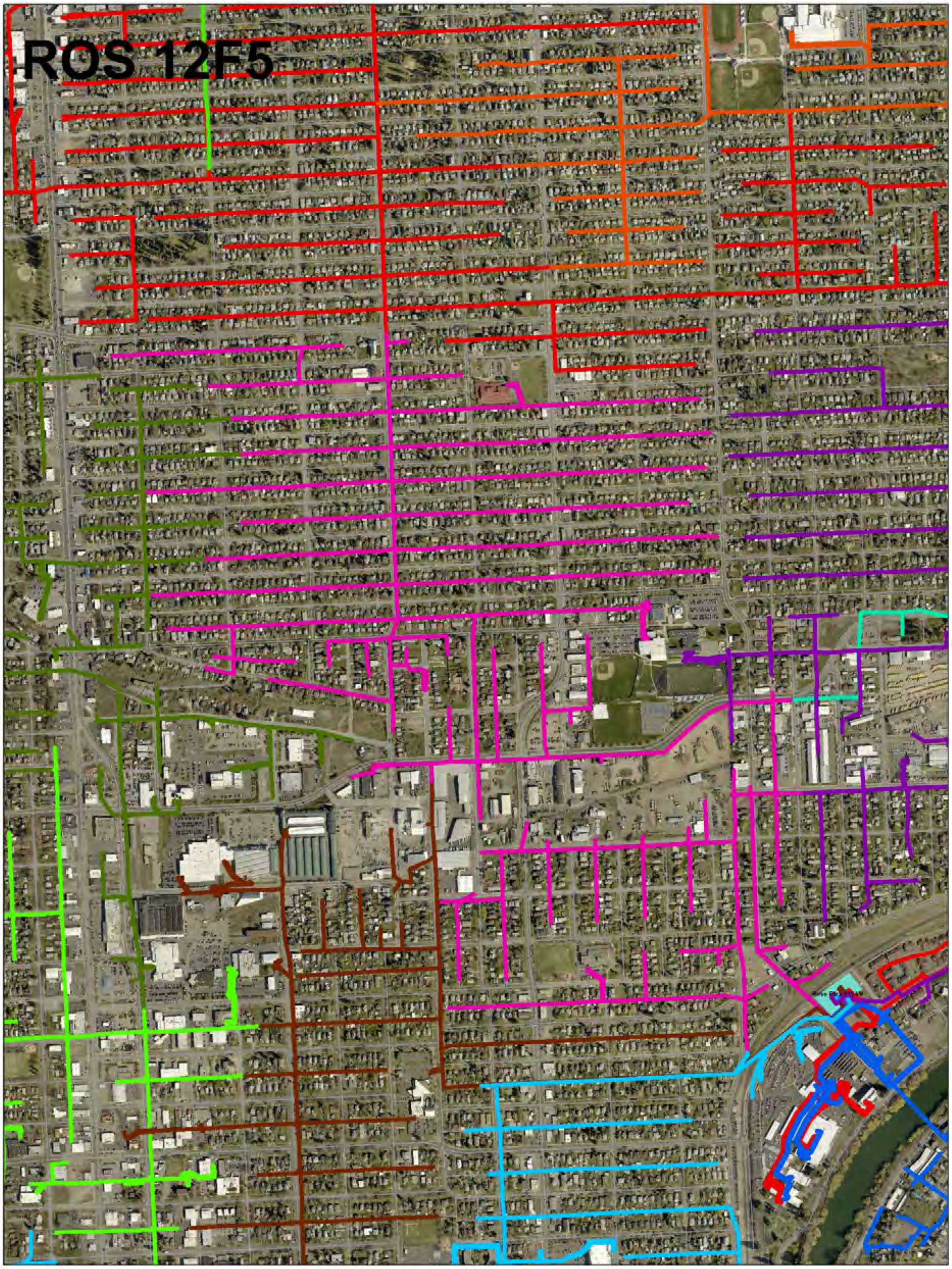


Figure 1. ROS 12F5 Circuit One-Line Diagram

Figure 2. ROS 12F5 Circuit One-Line Diagram

Program Ranking Criteria

The 2017 Avista Feeder Status Report contains detailed information on each distribution circuit and assesses each feeder in three key areas: health, performance, and criticality. The Health metric analyzes items such as the age of the wood pole population and projected reject rate, reliability indices, and OH-UG ration.
The Performance metric analyzes items such as the thermal utilization, efficiency, voltage, power factor, and reliability indices. The Criticality metric analyzes items such as customer density, commercial account density, load density, and the essential services on the circuit.

The Grid Modernization Program selects feeders by first individually analyzing the three categories of the Feeder Status Report. This research is performed on every distribution feeder in the system. Health and Performance are combined with Criticality to create a comprehensive score for each circuit. The comprehensive scores are not weighted or normalized. The summation of the values for each of the three categories creates the overall score for each feeder. The overall scores are then ranked from highest to lowest to create a prioritized selection list. The prioritized feeders then receive a qualitative analysis to incorporate additional considerations including: automation opportunities, primary metered customers, feeder length, feeder location, substation upgrades, etc.

The 2017 Avista Feeder Status Report illustrates that ROS 12F5 had a rating value of 60 in terms of Health, 62 on Performance, and 46 in terms of Criticality and the customers that are served. These ratings are based on a 100 point scale.

Metric	Rating Value
Health	60
Performance	62
Criticality	46

ROS 12F5 had a total ranking of 16th on the list of 350 feeders during the most recent selection and prioritization period analyzed in late 2018 using the Feeder Status Report.

In addition, the 2017 Avista Feeder Status Report provides the following ranks for ROS 12F5 in the Spokane service area: 3rd worst SAIFI performance (2.26%), 7th highest in Winter Peak Amps (499), and 10th worst in Feeder Status Report Performance (3.1).

Reliability Index Analysis

Reliability indices are significant components of a utility's ability to measure long-term electric service performance, and are one indicator of system health or condition. The common reliability indices of CAIDI, SAIDI, SAIFI, and CEMI3 are used by the Grid Modernization Program to analyze and illustrate the historical reliability performance of the feeders, as well as to assist in justifying any proposed circuit improvements or automation deployments. Each historically averaged reliability index for a feeder is compared to the Avista target value for that calendar year to determine the reliability performance of a feeder.

ROS 12F5 was found to have 61 sustained distribution outages from 2006 to 2017 through OMT analysis, for an average annual figure of 5.1 sustained distribution outages. In addition, ROS 12F5 was found to have 19 momentary distribution outages from 2006 to 2017 through OMT analysis, for an average annual figure of approximately 1.6 momentary distribution outages. The key reliability indicators for ROS 12F5 were analyzed from 2013 to 2017 to establish a five year average, to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed circuit improvements or automation deployments. The table below shows the annual value for each respective reliability index on ROS 12F5 in the corresponding year. The reliability indices that Grid Modernization uses for Measurement and Reporting do not include Major Event Days (MED). Major Event Days is an industry standard that is used to evaluate major events, such as severe weather or storms, which can lead to unusually long outages in comparison to the distribution system's typical outage. The reliability indices that are being used do not include MED, as this is standard per IEEE and reflects the same reliability information that Avista shares with the respective state Utility Commissions.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2013	0.0%	0.05	8	153
2014	0.0%	0.51	75	148
2015	0.0%	0.33	248	743
2016	0.5%	1.14	146	128
2017	0.0%	2.26	223	99
Average	0.1%	0.86	140.0	254.2

The previous table illustrates the annual value for each respective reliability index on ROS 12F5 in the corresponding year. This information is also provided in graphical form in Figures 3 through 6. The information in these graphs do not include MEDs.

CEMI3 is defined as the Total Number of Customers Experiencing 3 or More Sustained Interruptions /divided by the Total Number of Customers Served. The performance of this metric has been very good, with most years of zero customers experiencing 3 or more sustained outages. This index is showing a nearly flat linear trend during the 12 years of analyzed data. The CEMI3 index for ROS 12F5 has consistently been outperforming the annual Target value set internally by Avista.

SAIFI is defined as the Total Number of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has relatively varied over the years, however this index is showing an increasing linear trend during the 12 years of analyzed data. The SAIFI index for ROS 12F5 has mostly been outperforming the annual Target value set internally by Avista, however there are some years where the target was not satisfied.

SAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has largely been increasing since 2009, but it has relatively varied over the years. This index is showing an increasing linear trend during the 12 years of analyzed data. The SAIDI index for ROS 12F5 has mostly been outperforming the annual Target value set internally by Avista, however there are some years where the target was not satisfied.

CAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Interruptions. The performance of this metric has been inconsistent, and has relatively varied over the years. This index is showing a slightly increasing linear trend during the 12 years of analyzed data. The CAIDI index for ROS 12F5 has mostly been outperforming the annual Target value set internally by Avista, however there are some years where the target was not satisfied.

The average value of each index was calculated and then compared to the Avista 2019 Target values. CEMI3% is greatly outperforming the 2019 target, while SAIFI and SAIDI are slightly outperforming. CAIDI is failing to meet the 2019 target by a sizeable measure. This data suggests that customers experience relatively few sustained outages on the feeder, however the few outages tend to involve relatively large service restoration times that are outside of the desired range of Avista.

WA-ID Key Indicator	2019 Target	ROS 12F5	Variance
SAIFI Sustained Outages/Customer	1.12	0.86	0.26
SAIDI Outage Time/Customer (min)	166.0	140.00	26.0
CAIDI Ave Restoration Time (min)*	158.0	254.2	-96.2
CEMI3 % of Customers >3 Outages	6.6%	0.1%	6.5%

*CAIDI values were converted from hours to minutes for this report

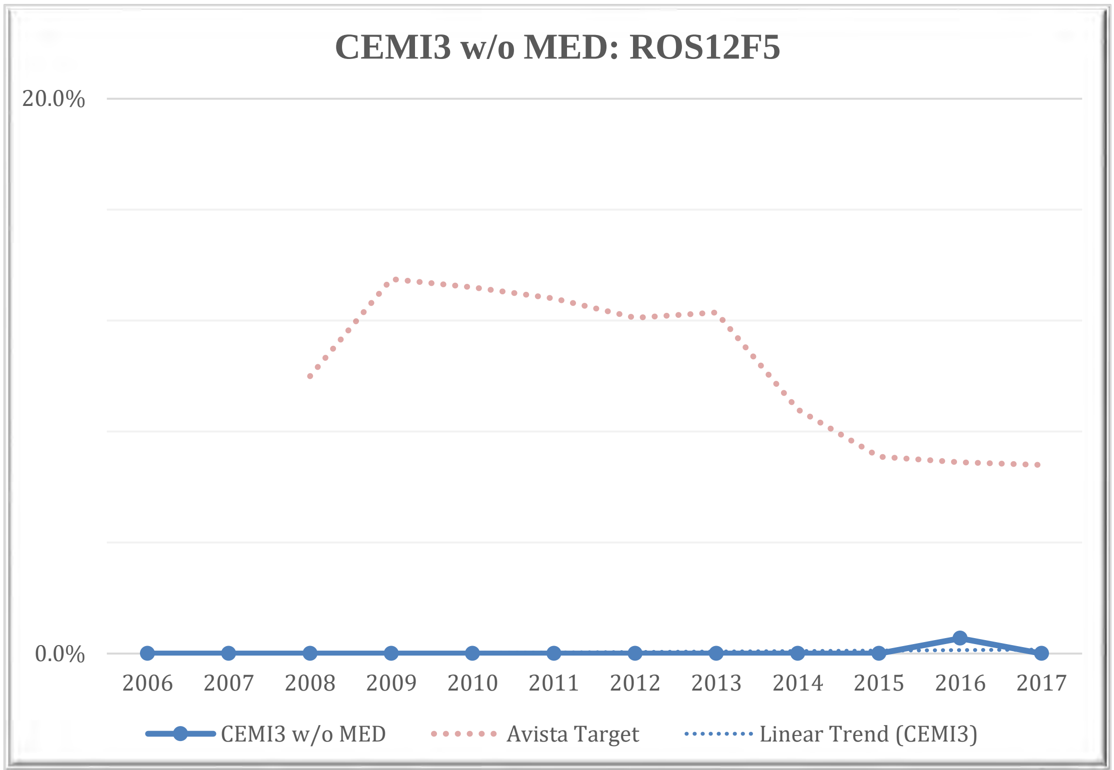


Figure 3. ROS 12F5 CEMI3 Performance

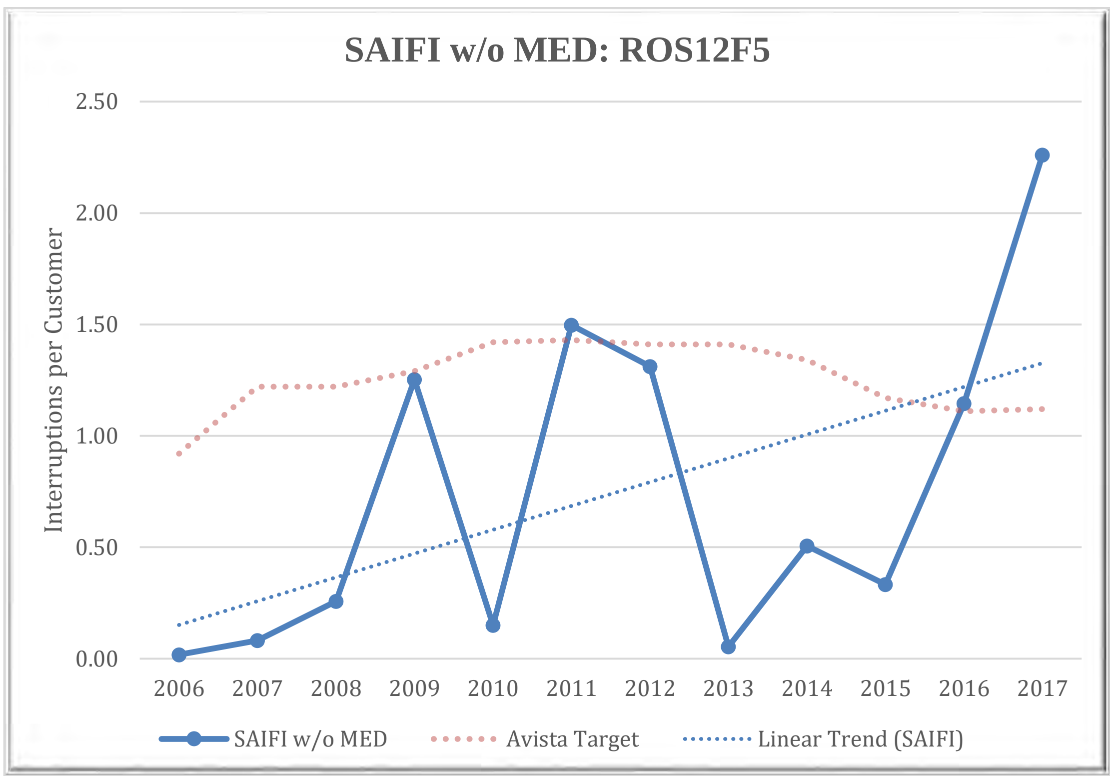


Figure 4. ROS 12F5 SAIFI Performance

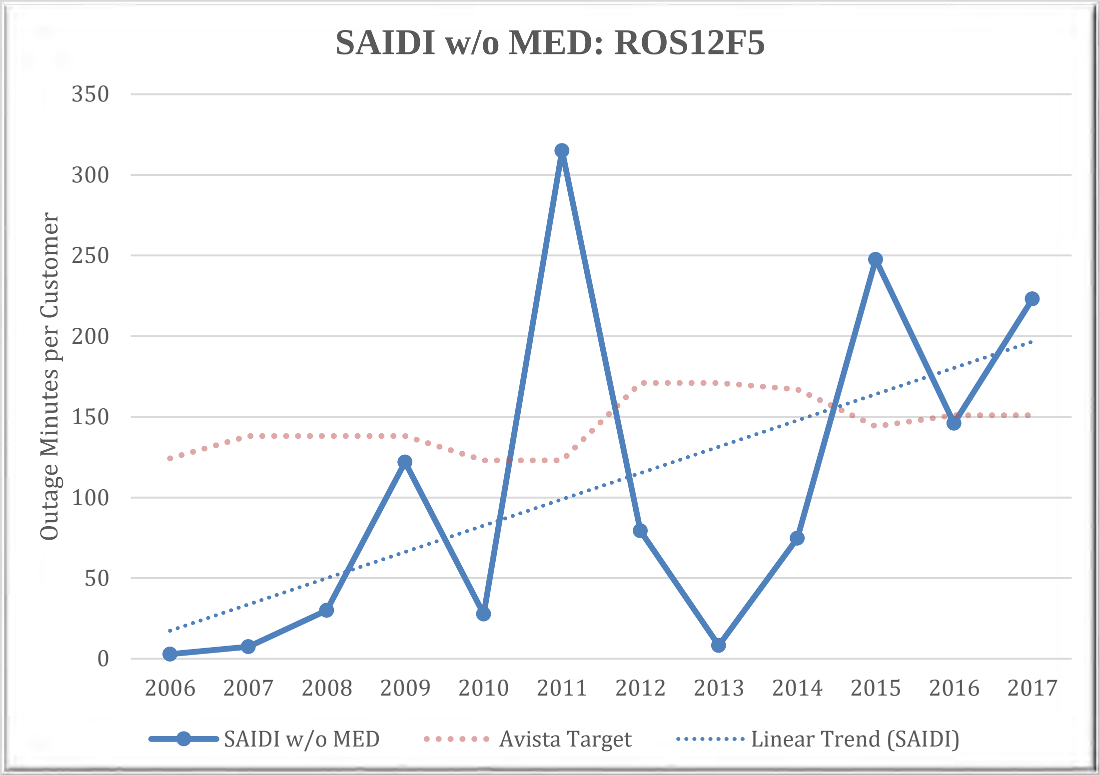


Figure 5. ROS 12F5 SAIDI Performance

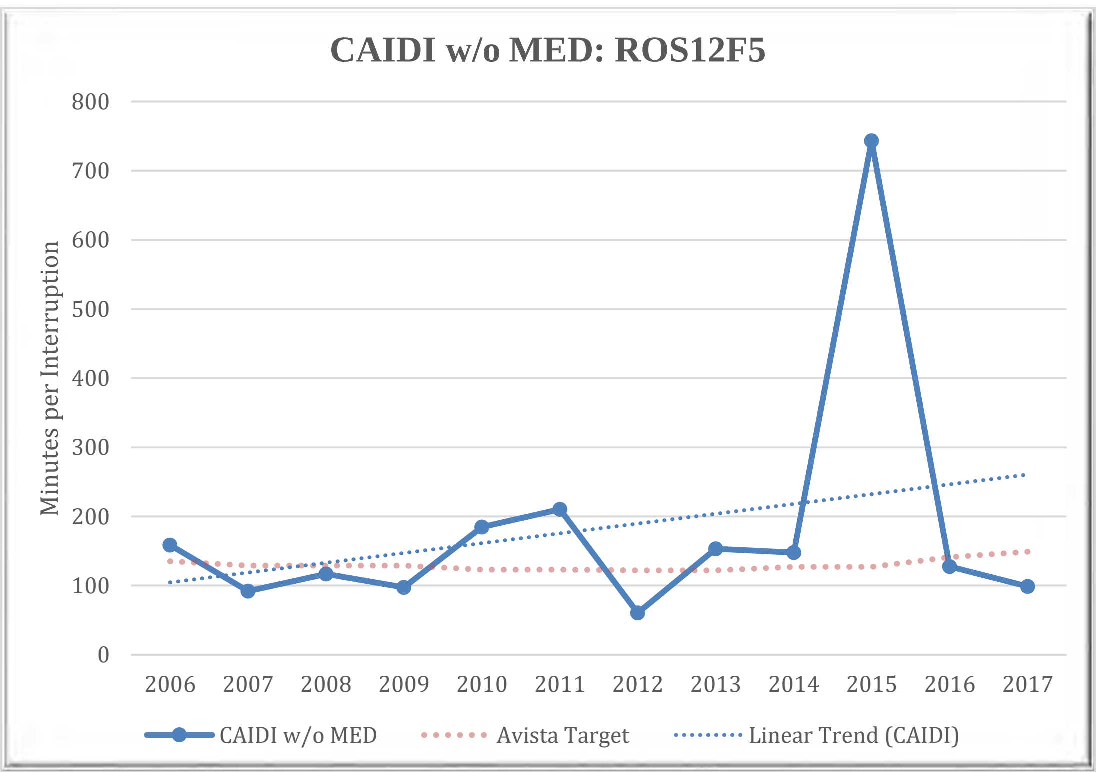


Figure 6. ROS 12F5 CAIDI Performance

Peak Loading

Three-phase ampacity loading from SCADA monitoring at the ROS 12F5 substation circuit breaker was analyzed from 3/19/17 to 3/19/19. The following ampacity loading values were established for ROS 12F5 during this timeframe. Loading information has been analyzed to determine if any data needed to be removed from selected timeframes due to temporary changes in loading from switching (verified through PI). It was identified that there were multiple durations that should be excluded from the loading due to ROS 12F5 being in an abnormal feeder configuration and serving additional load from an adjacent feeder.

Figure 7 illustrates the three durations that are excluded from loading analysis where additional load was serving during abnormal feeder configuration. The first duration of abnormal loading began at approximately 3/29/2017 9:00 AM and ended at approximately 3/31/2017 9:00 AM. The second duration of abnormal loading began at approximately 4/10/2017 11:00 AM and ended at approximately 4/20/2017 9:00 AM. The third duration of abnormal loading began at approximately 5/8/2017 10:00 AM and ended at approximately 5/12/2017 1:00 PM.

Figure 8 illustrates the two brief durations that are excluded from loading analysis where additional load was serving during abnormal feeder configuration. The first duration of abnormal loading began at approximately 6/6/2018 8:00 AM and ended at approximately 6/6/2018 2:00 PM. The second duration of abnormal loading began at approximately 6/7/2018 8:00 AM and ended at approximately 6/7/2018 12:00 PM.

Figure 9 illustrates one brief duration that is excluded from loading analysis where additional load was serving during abnormal feeder configuration. This duration of abnormal loading began at approximately 3/6/2019 12:00 PM and ended at approximately 3/6/2019 3:00 PM.

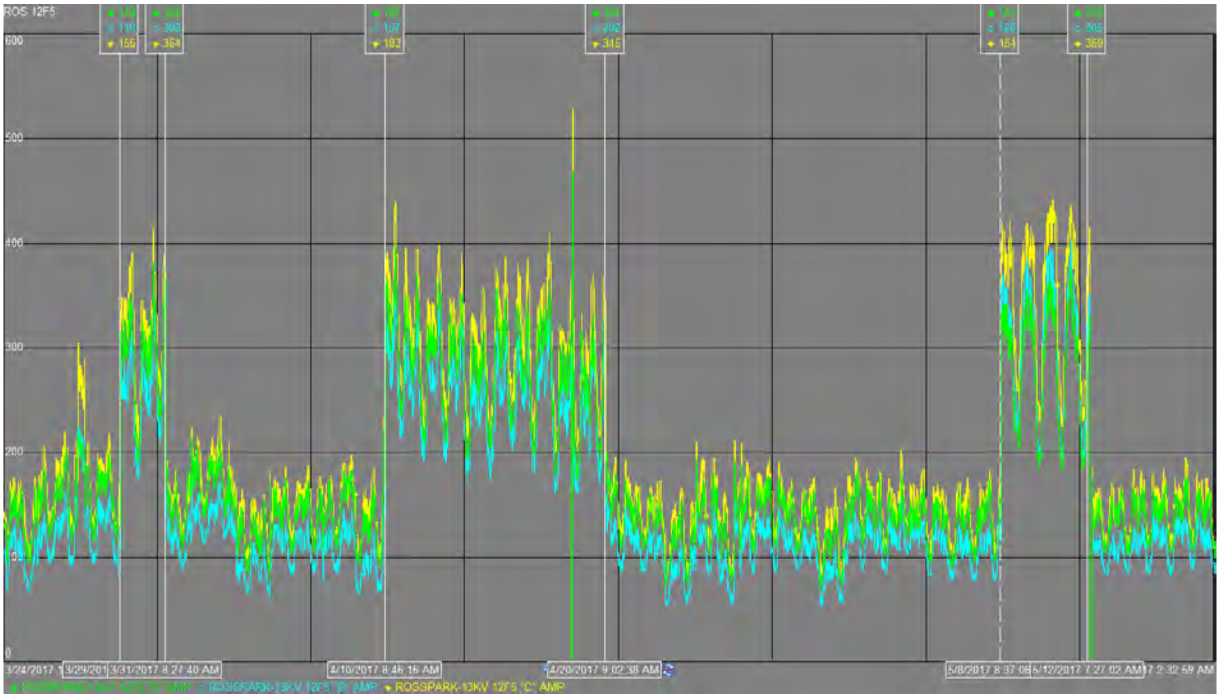


Figure 7. ROS 12F5 Abnormal Feeder Configurations from 3/29/2017 to 5/12/2017

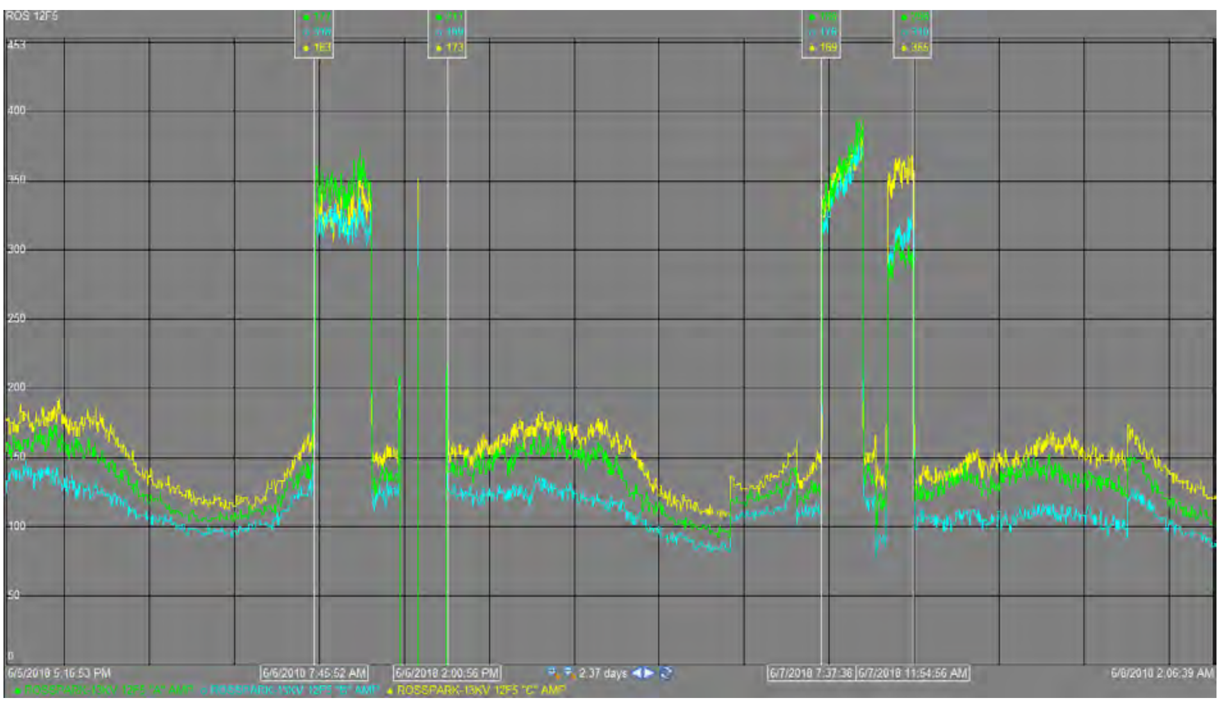


Figure 8. ROS 12F5 Abnormal Feeder Configurations from 6/6/2018 to 6/7/2018

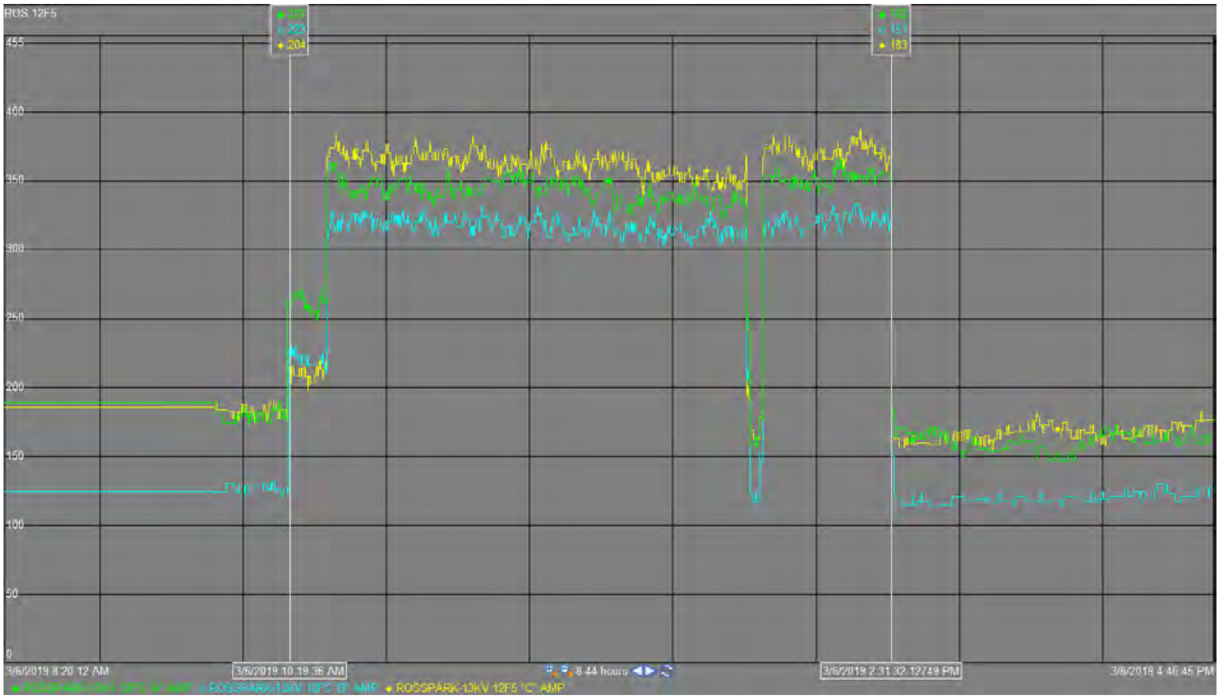


Figure 9. ROS 12F5 Abnormal Feeder Configuration on 3/6/2019

ROS 12F5 is a summer peaking feeder, with the highest loading occurring in early August, and comparable peak values observed from mid-July through mid-August. There are fairly distinct winter peaks as well on the feeder, however these were well below the summer peak values that were observed. The values below reflect the adjusted data set where loading values during abnormal feeder configurations has been removed. The peak loading values for each phase are used in the Synergi model analysis for the feeder, except where average load values are noted for establishing kW losses.

	Before Balancing	
	Peak Loading	**Average Loading**
A-Phase	352 A	156 A
B-Phase	314 A	125 A
C-Phase	381 A	169 A
Average	349 A	150 A

	After Balancing	
	Peak Loading	**Average Loading**
A-Phase	346 A	153 A
B-Phase	343 A	138 A
C-Phase	358 A	159 A
Average	349 A	150 A

Approximate percent loading figures were established through Demand Factor by analyzing the ratio of the maximum apparent power demand observed upon the circuit to the total kVA load that is actually connected. The lower the Demand Factor, the less system capacity is required to serve the connected load. This was performed on a Per Phase and Total basis from values extracted through Synergi at the model's initial configuration before balancing or performing improvements on the circuit.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**Demand Factor**
A-Phase	2806	3978	70.53%
B-Phase	2503	3226	77.59%
C-Phase	3019	4415	68.38%
Total	8328	11619	71.68%

*Values taken from Synergi Model created on 3/1/19

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**Demand Factor**
A-Phase	1243	3978	31.24%
B-Phase	996	3226	30.87%
C-Phase	1347	4415	30.51%
Total	3586	11619	30.86%

*Values taken from Synergi Model created on 3/1/19

Load Balancing

Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which will mitigate the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts will commence toward the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

Accurate load balancing can be analyzed and achieved on ROS 12F5 due to the three-phase ampacity loading from SCADA monitoring at the substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively before balancing:

	Connected KVA per Phase*
A-Phase	4015 kVA
B-Phase	3226 kVA
C-Phase	4415 kVA

* Connected kVA per Phase in AFM as of 3/19/19

The following list provides the phase changes to loads, laterals, or risers that can effectively balance the load on the phases between numerous strategic locations on the feeder, as illustrated in Figure 10. As a whole, the trunk sections and multi-phase laterals on ROS 12F5 were relatively well balanced, however opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate the following change into their appropriate polygon designs:

1. **Polygon 5** – transfer 1Φ OH lateral east of N Standard St & E Dalton-Liberty (≈23 A peak loading, ≈10 A average loading) from CΦ to BΦ.
2. **Polygon 8** – transfer 1Φ OH lateral east of N Standard St & E Providence-Kirenan (≈6 A peak loading, ≈3 A average loading) from AΦ to BΦ.

The result of this load transfer is listed in the following table. This change will approximately balance the feeder at the substation breaker to 346/343/358 during peak loading conditions, as well as between the numerous strategic points to approximately sectionalize the feeder to optimize switching and load transfers.

	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
ROS 12F5 Station Breaker	352	314	381	346	343	358
West of Z509	72	77	62	72	77	62
Switch Z101	287	243	302	281	272	279
Recloser Z789R	92	72	75	86	78	75

The decision to move forward with the proposed phase change will be confirmed and approved by the Regional Operations Engineer, and coordinated by the Designer in their respective polygon design(s). It is the Designer's responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any additional proposals for phase balancing prior to commencing the job designs.

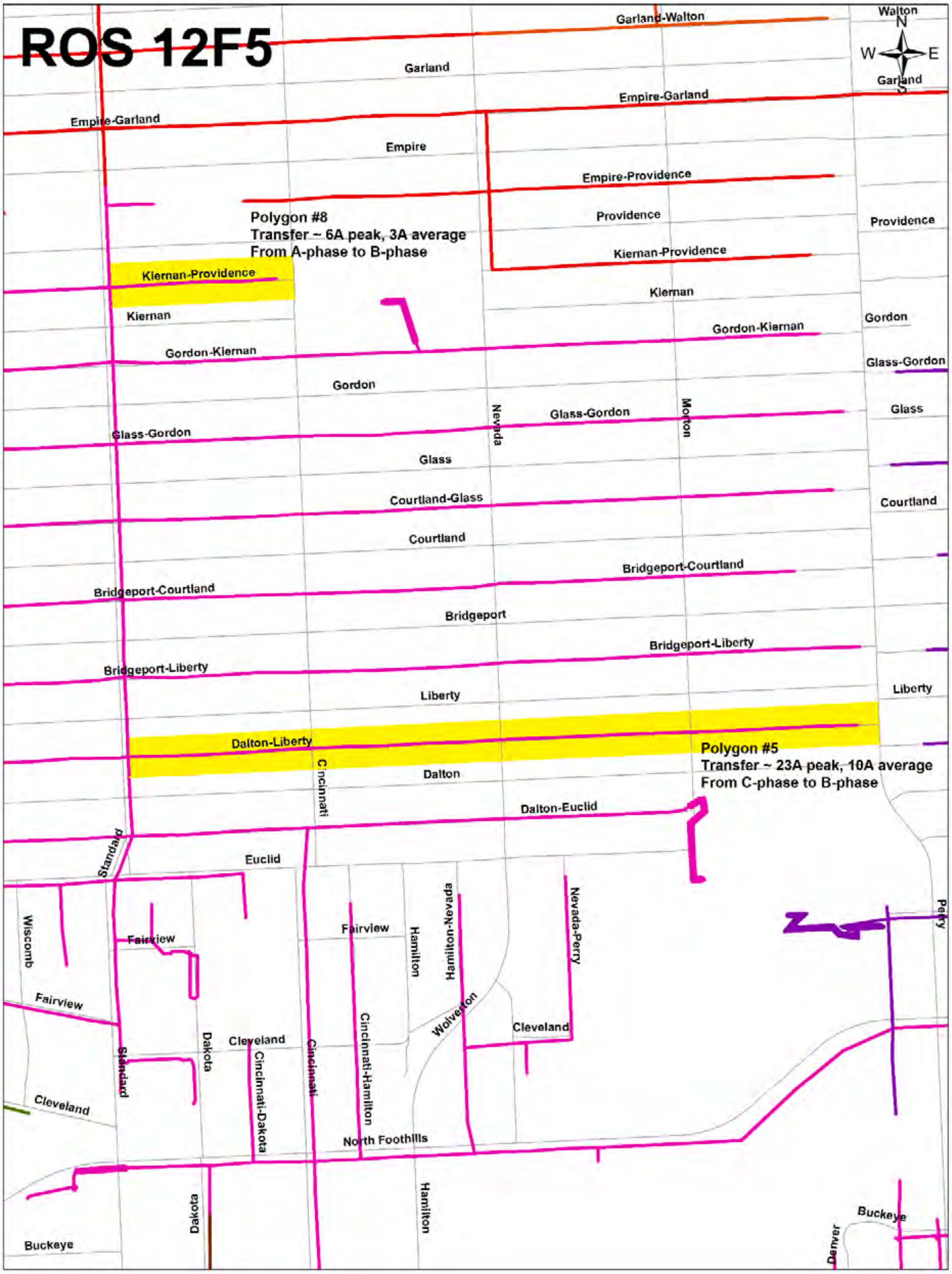


Figure 10. ROS 12F5 Recommended Phase Changes for Feeder Balancing

Conductor

All primary conductors on ROS 12F5 were analyzed in Synergi using the balanced peak ampacity values identified in the *Peak Loading* section of this report. Specific attention was given to conductors that have the potential for being overloaded, have relatively high line losses, serve areas with unacceptable voltage quality, and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on ROS 12F5, as well as the proposals for improving the efficiency, voltage quality, and performance of the feeder.

High loss conductors are inefficient conductors that result in increased line losses, especially where there is moderate to heavy loading. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on the suggested replacement of conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher loss conductors. An Engineering decision can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also decide to reconductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management (WPM) reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

The following table lists the various types of overhead conductors that are present on ROS 12F5, as well as the approximate circuit miles of each conductor type as analyzed through the Synergi modeling software on the creation date of the model. An initial analysis suggests that there are not any relative high loss conductors present on the ROS 12F5. If any higher loss conductors are found during field analysis, the Designer shall determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors. It is the Designer’s responsibility to consult the Grid Modernization Program Engineer on any additional reconductoring proposals prior to commencing the job designs.

Approximate Circuit Miles by Conductor Type		
Conductor	**Miles**	**Ohm/Mile (50°C)**
4ACSR	0.34	2.4590
6CU	9.58	2.4170
2CN15	0.15	1.6060
1CN15	0.61	1.2800
2STCU	0.73	0.9750
336AAC	0.10	0.3052
336ACSR	0.19	0.3027
750CUXLP	0.13	0.2060
556AAC	1.73	0.1855

The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the conductor analysis requirements for the Grid Modernization program. The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards.

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweigh the significant work required to rebuild the existing line to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors. Utility studies suggest that converting from Overhead to Underground has been shown to be cost effective when the conversion costs to Underground do not exceed 3x to 5x the Overhead equivalent. The ability to reconfigure and convert feeders for reliability and efficiency improvements is a characteristic that distinguishes Grid Modernization from other internal programmatic or capital work.

ROS 12F5 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, it is not likely that there are sections that would warrant reconfiguration due to the urban, established configuration of the circuit. The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole tests and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

Any designs to reconfigure overhead circuits or convert to underground shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements. All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer.

It is the Designer’s responsibility to consult the Grid Modernization Program Engineer on any proposals for reconfiguration or conversion to underground prior to initiating the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program’s scope, meets the system operations requirements, are economically justifiable, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Primary Conductor Analysis

Primary conductors can have the ability to negatively affect the reliability, voltage quality, and efficiency of a distribution circuit. Primary conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to serve peak loading demands and provide adequate voltage levels, and insure that they do not cause significant and unnecessary line losses. Primary conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

Primary Trunk Conductor Analysis

The primary trunk conductors on ROS 12F5 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. Almost the entire feeder trunk is currently conductored with 556 AAC in overhead applications, with only the small section listed below being less than 556 AAC.

Given the large amount of high capacity conductors already present the feeder trunk and ties, there is minimal evidence to support upgrading the primary trunk conductors on ROS 12F5 based on capacity concerns alone. Line losses on the trunk are currently optimized for both the peak and average loading scenarios, which has been aided by balancing the feeder. There are not concerns with voltage quality and under voltage scenarios that could be improved through feeder trunk reconductoring. The lone opportunity for reconductoring the primary trunk is the location listed below:

- Reconductor existing 3-phase overhead primary trunk west of the Z274 switch to pole #442305 with 556 AAC primary (approximately 720') in **Polygon 4**. This existing 3-phase overhead primary trunk is currently served by 335AAC primary and a 2/0 ACSR neutral. In addition, approximately 700' of primary trunk on BEA 12F2 will be reconductored as part of this work to established an ideal location for deadending the new wire. Figure 11 illustrates this proposed reconductor.

Any designs to reconductor primary trunk shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary trunk prior to initiating the job designs. It may be determined that additional primary or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary trunk conductors based on the conditions dictated through field analysis.

Figure 11. ROS 12F5 Primary Trunk Reconductor to 556AAC

Primary Lateral Conductor Analysis

The primary lateral conductors on ROS 12F5 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The laterals on ROS 12F5 were individually analyzed to determine if the wires were sized appropriately for load, line losses, and voltage quality. The analyzed models suggest reconductoring of selective laterals to meet peak loading conditions during normal system configuration, lower line losses, and promote improved voltage levels downstream. As part of the line loss analysis, attention was given to identify the presence of high loss conductors, even if relatively low loading levels did not provide high line losses.

It was determined that there is minimal evidence to support upgrading the primary lateral conductors on ROS 12F5 through model analysis based on capacity concerns alone. Line losses on the trunk are currently in the optimal range for both the peak and average loading scenarios, which has been aided by balancing the feeder and relatively lower loading conditions where high loss conductors exist. ROS 12F5 is not known to contain any of the traditional higher loss primary lateral conductors that are targeted for replacement. In addition, there are not concerns with voltage quality that could be improved through primary lateral reconductoring.

Any designs to reconductor primary laterals shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary lateral conductors based on the conditions dictated through field analysis.

Feeder Tie Locations and Opportunities

A reduction in the duration of outages can be achieved through rebuilding existing feeder ties and establishing new feeder ties. Existing feeder ties can be improved through increased capacity by reconductoring to higher ampacity conductors, as well as replacing existing manual switches with communications devices that can either be controlled remotely or through a distribution management system (DMS). New feeder ties can be established for circuits without connections to adjacent feeders or where additional ties could provide reliability improvements. Newly created feeder ties will generally be optimized by installing switches with communications that can either be controlled remotely or through a distribution management system (DMS).

ROS 12F5 currently contains four overhead feeder ties through: switch Z247 (BEA 12F2), switch Z278 (ROS 12F6), switch Z281 (ROS 12F4), and switch Z509 (ROS 12F1). All four of these feeder ties were upgraded and automated during the Smart Grid Investment Grant (SGIG) project in 2010 through the installation of S&C SCADA-Mate devices.

Device Number	Feeder Tie	Status	Device Type
Z274	BEA 12F2	N.O.	S&C Scada-Mate Switch
Z278	ROS 12F6	N.O.	S&C Scada-Mate Switch
Z281	ROS 12F4	N.O.	S&C Scada-Mate Switch
Z509	ROS 12F1	N.O.	S&C Scada-Mate Switch

Figure 12 illustrates the location of the distribution feeder ties on ROS 12F5.

ROS 12F5 already contains a feeder tie connection to every adjacent circuit except for FWT 12F2. There are eight single or two phase laterals on ROS 12F5 that have open jumper or de-energized spans within a span of FWT 12F2. While there are many options that could be enhanced to create a reliable tie, there is one reasonable lateral that could be rebuild to establish a three-phase connection between the two circuits. A solution exists to install a tie switch near pole #415030 between the two circuits. Figure 13 illustrates the location of the potential tie with FWT at pole #415030. Approximately 2000’ circuit feet of primary would need to be reconductored and upgraded to three-phase primary on ROS 12F5 to create a useful tie. In addition, FWT 12F2 is only conductored with 2/0ACSR at this location, so either additional work would have to be performed on FWT 12F2 to increase the ampacity of the tie, or it would be agreed that the tie would be accepted as a lower use manual option due to the limited capacity of the tie conductor. After discussing this option with the Spokane Area Engineers, it was decided for Grid Modernization not to pursue establishing a new tie in this area with FWT 12F2 due to the establishment of four other strong feeder tie options on ROS 12F5.

The decision to pursue additional feeder tie opportunities will be discussed and determined with the Regional Operations Engineer based on their anticipated frequency of using potential ties in the operation of the Spokane distribution system.

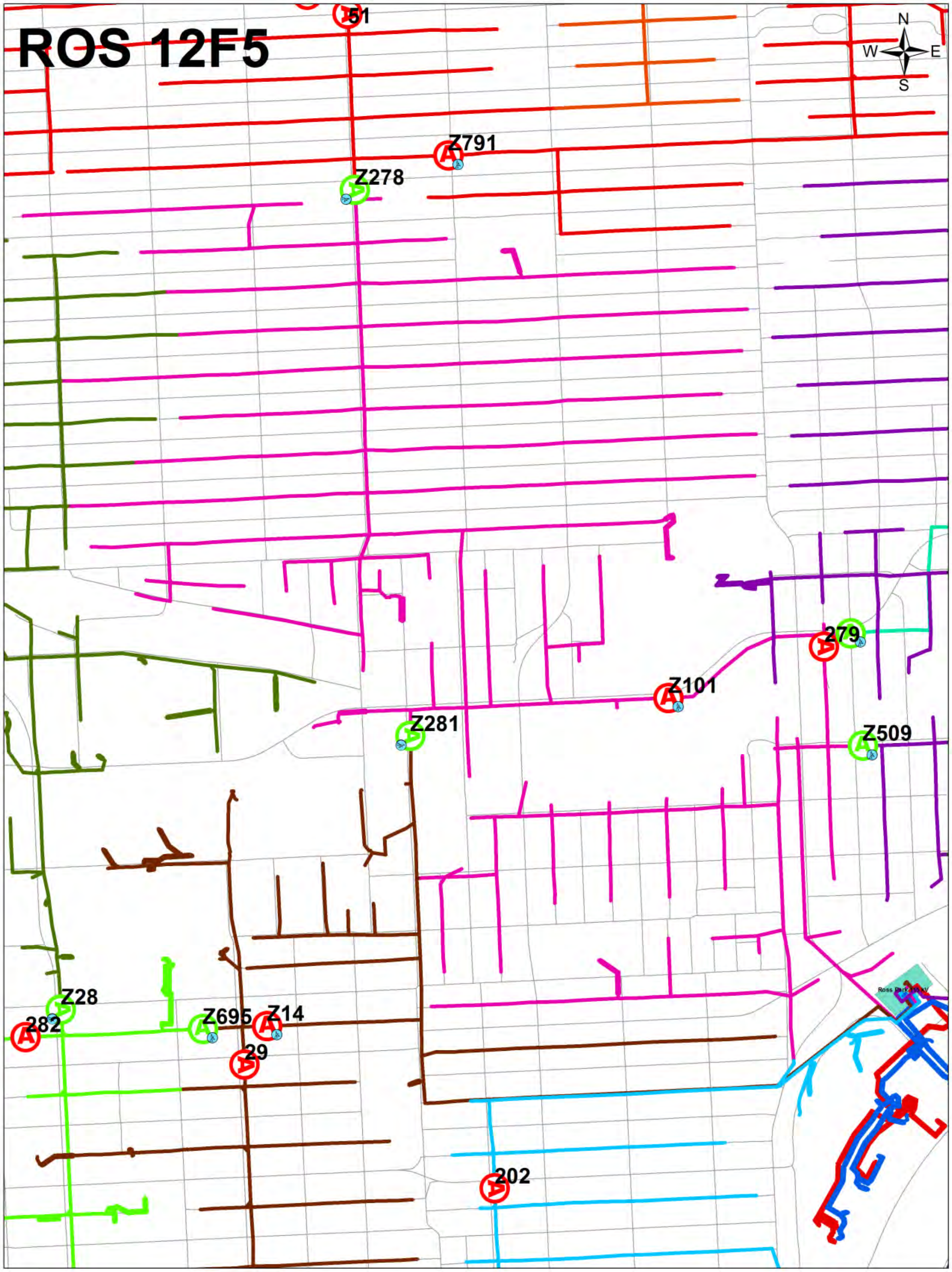


Figure 12. ROS 12F5 Distribution Feeder Tie Devices

Figure 13. Pontential New Feeder Tie with FWT 12F2 at Pole #415030

Transmission Underbuild

ROS 12F5 was identified to contain approximately 2,900' circuit feet of primary distribution underbuild on existing transmission lines. ROS 12F5 is collocated on the *Francis & Cedar- Ross Park* 115 kV transmission line in **Polygons 1 and 4** on 11 poles from structures 4/11 to 5/3. ROS 12F5 is also collocated on the *Ross Park-3rd & Hatch* 115 kV transmission line on 1 additional structure directly outside of the Ross Park Substation in Polygon 1.

The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is underbuilt distribution to ensure the pole class is adequate for the physical loading on the structure.

Figure 14 illustrates the locations where primary distribution is underbuilt on 115kV transmission.

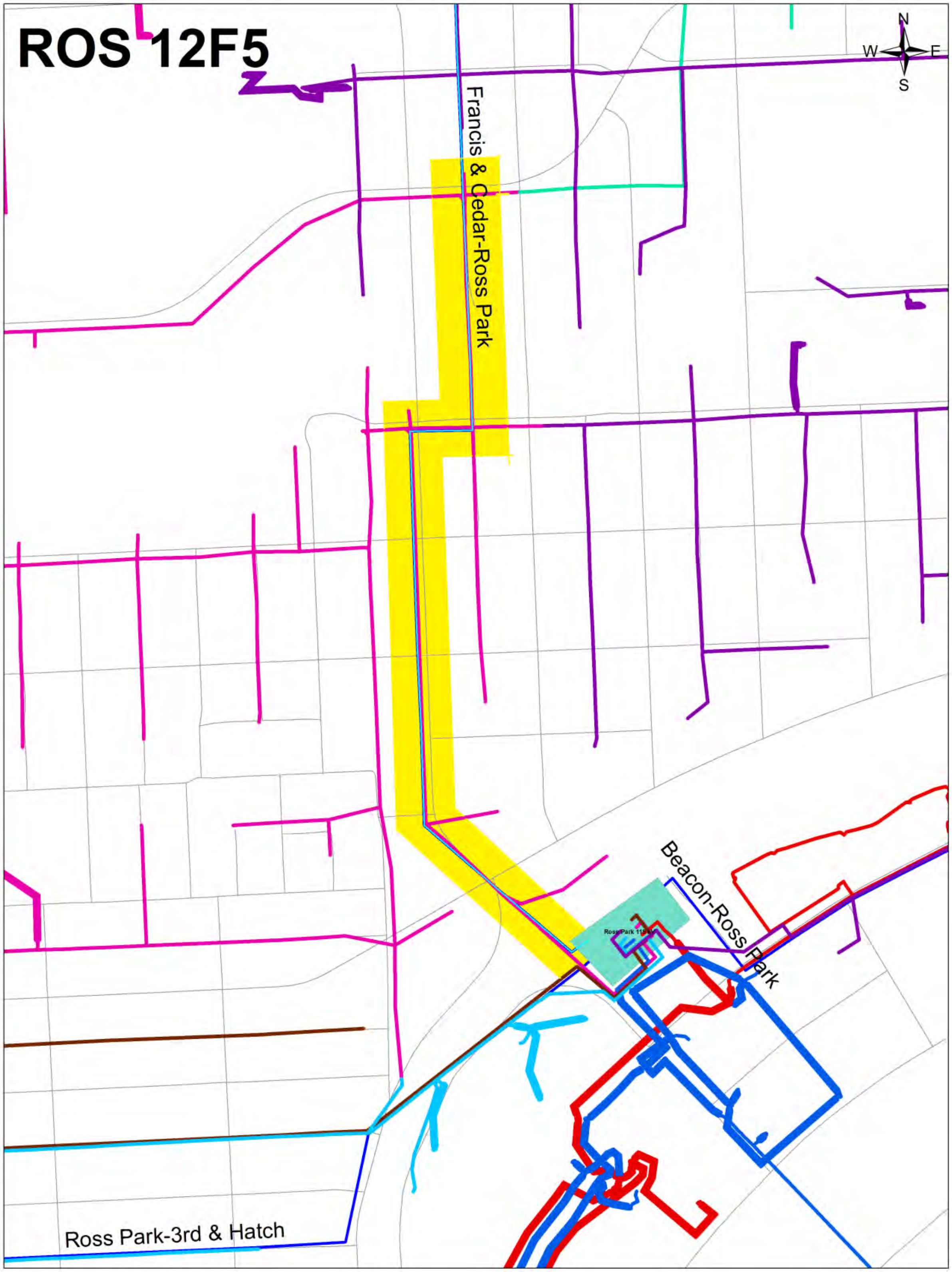


Figure 14. ROS 12F5 Distribution Primary Underbuild on Transmission Lines

Voltage Quality

Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. In addition, primary laterals and trunks are reconductored with more efficient conductors to increase sagging voltage levels. In some scenarios, an additional conductor phase(s) may be installed to offload a heavily loaded phase and assist in supporting the voltage.

The ROS 12F5 circuit was analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled in Synergi during both peak loading and average loading conditions under normal circuit configuration.

The following information on the substation voltage regulators for ROS 12F5 was taken from Maximo, which is the system of record for Avista T&D assets.

Serial Numbers	A	B	C
ROS 12F5 Station Regulators	1650001711	165000172	1650001713

Rated Power	333 kVA
Rated Current	438 A
C.T. Ratio	500/.02
Equipment P.T. Ratio	60.0:1
Corrected/Desired P.T. Ratio	63.5:1
Distribution Transformer Ratio	63.5:1

* Information in MAXIMO as of 3/27/19

Voltage Quality Analysis Before Incorporating Recommendations

Figures 15-16 illustrate the modeled voltage levels for the various scenarios on ROS 12F5 before any proposed recommendations were incorporated into the models. “Green” illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. “Yellow” illustrates voltage levels between 114–117 V and 123–126V. “Red” illustrates voltage levels lower than 114V and greater than 126V, which greater than +/- 6V of the ideal 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to ROS 12F5. During peak loading conditions, voltage levels nearest to the Ross Park Substation, were elevated however they were still acceptable and allowable. The maximum voltage modeled on the feeder occurred near the substation at approximately 124.5V. The minimum voltage modeled on the feeder was 121.6V.

Figure 15 illustrates the modeled voltage levels at peak loading on ROS 12F5.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	23	2.53	899	501
122.00 - 124.00 V	209	10.69	4048	1505
124.00 - 126.00 V	10	0.34	68	16
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading

The voltage levels on the feeder were again analyzed before balancing load or incorporating conductor upgrade proposals, however this time during average loading conditions. During average loading conditions, voltage levels nearest to the Ross Park Substation, were still slightly elevated. The maximum voltage modeled on the feeder occurred near the substation at approximately 123.9V. The minimum voltage modeled on the feeder was 122.6V.

Figure 16 illustrates the modeled voltage levels at average loading on ROS 12F5.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	241	13.53	428	2022
124.00 - 126.00 V	1	0.02	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 15. ROS 12F5 Modeled Voltage Levels at Peak Loading

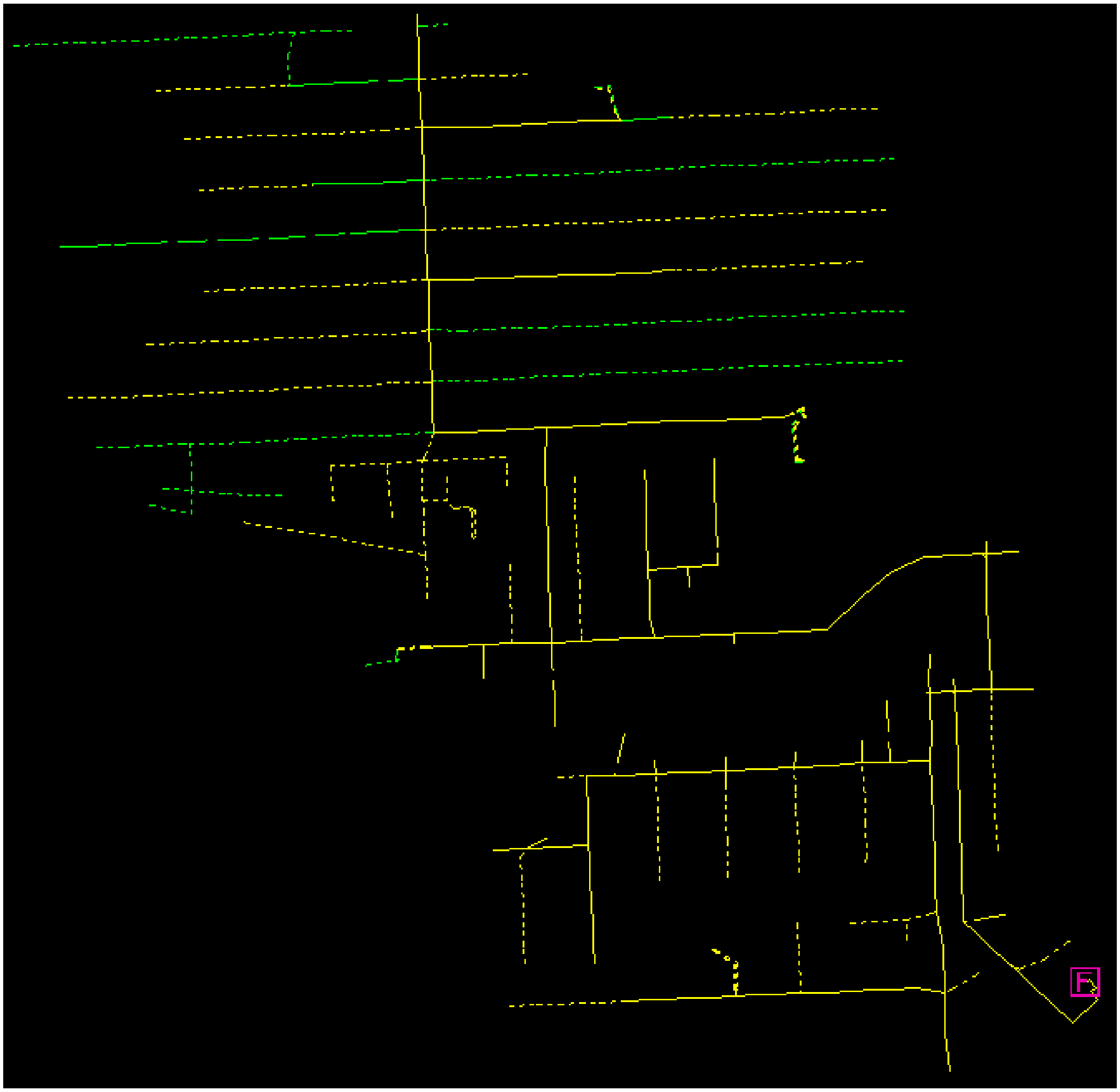


Figure 16. ROS 12F5 Modeled Voltage Levels at Average Loading

Voltage Quality Analysis After Incorporating Recommendations

The voltage levels on ROS 12F5 were re-analyzed after incorporating and modeling the upgrade proposals, and utilizing the proposed changes to the voltage regulator settings in the *Voltage Regulator Settings* section. The feeder was modeled with these proposals in Synergi during both Peak loading and Average loading conditions.

Figures 17-18 illustrate the modeled voltage levels for the various scenarios on ROS 12F5 after the proposed recommendations were incorporated into the models. “Green” illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. “Yellow” illustrates voltage levels between 114–117 V and 123–126V. “Red” illustrates voltage levels lower than 114V and greater than 126V, which greater than +/- 6V of the ideal 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading after Proposals

The voltage levels on the feeder were analyzed after performing the identified changes and improvements to ROS 12F5. During peak loading conditions, voltage levels nearest to the Ross Park Substation, were still elevated however they were still acceptable and allowable. The voltage levels were slightly higher than when modeled at peak loading before performing the identified changes and improvements. The maximum voltage modeled on the feeder occurred near the substation at approximately 124.5V. The minimum voltage modeled on the feeder was 122.4V.

Figure 17 illustrates the modeled voltage levels at peak loading on ROS 12F5.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	232	13.22	4969	2006
124.00 - 126.00 V	10	0.34	68	16
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Average Loading after Proposals

The voltage levels on the feeder were again analyzed after performing the identified changes and improvements to ROS 12F5, however this time during average loading conditions. During average loading conditions, voltage levels nearest to the Ross Park Substation, were still slightly elevated. The voltage levels were slightly higher than when modeled at average loading before performing the identified changes and improvements. The maximum voltage modeled on the feeder occurred near the substation at approximately 123.9V. The minimum voltage modeled on the feeder was 122.9V.

Figure 18 illustrates the modeled voltage levels at average loading on ROS 12F5.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	241	13.53	428	2022
124.00 - 126.00 V	1	0.02	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 17. ROS 12F5 Modeled Voltage Levels at Peak Loading after Proposals

Figure 18. ROS 12F5 Modeled Voltage Levels at Average Loading after Proposals

Voltage Regulator Settings

As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline voltage regulator settings. This is performed to reflect the changes to loading and to address the conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. The feeder is modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ranges for all customers during the modeled scenarios, and to eliminate over-voltage and under-voltage situations.

ROS 12F5 has one existing stage of voltage regulation at the Ross Park Substation. Due to the interconnected urban nature of the feeder, and the shorter feeder length, additional stages of midline voltage regulation are not recommended on the feeder to support voltage levels during normal configuration or times of switching.

The substation regulators at ROS 12F5 are enabled to be controlled through the Integrated Volt-VAR Compensation (IVVC) and Conservation Voltage Reduction (CVR) functions of Avista's Distribution Management System (DMS). The DMS algorithms will continuously provide equivalent R/X and voltage output settings that optimize the voltage levels on the distribution circuit based on the frequently changing loading conditions. The Grid Modernization Program will not be providing recommendations on the voltage regulators R/X settings or voltage output settings on feeders that have IVVC/CVR enabled.

The decision to move forward with implementing any changes to the voltage regulator settings will be pursued and provided by the Regional Operations Engineer.

Fuse Coordination and Sizing Analysis

Incorrect fuse sizes can compromise the reliability of the feeder through miscoordination of operation. Miscoordination can occur if the fuses in series are not correctly sized and managed to allow the furthest downstream device the opportunity to operate first. Fuses that are undersized and do not match the load being served can unnecessary operate and create unexpected outages. A customized fuse protection and coordination scheme has been determined to ensure that a consistent fusing philosophy is deployed and that all fuses are accurately sized.

Fuse sizing on ROS 12F5 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and underground risers. Fuse recommendations for ROS 12F5 were created by the Grid Modernization Program Engineer and approved by the Regional Operations Engineers. This file is located in the Electrical Engineering drive *c01m19* under the *ROS 12F5* folder within the *Feeder Upgrade – Dist Grid Mod* folder. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer with any questions regarding fuse sizing and coordination.

The fuse “blowing” philosophy was selected for ROS 12F5 where the smallest fuse was selected that would accurately coordinate to: satisfy peak loading conditions, protect the downstream conductor(s), and for fuse-to-fuse coordination based on preloading of source-side fuse link (maximum fault current). Distribution Construction Standard DU-2.500 was used as a reference to begin selecting the smallest allowable fuse for the downstream connected kVA/phase and the largest transformer on the phase. However, the *Distribution Feeder Protection General Guidelines* (Orange Book, S&C Table VII) was used in coordination with the fault duty found in the Synergi model to select the fuse size if there was an upstream fuse in series with a lateral fuse.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Figure 19 illustrates the proposed fuse sizes for improved coordination on ROS 12F5.

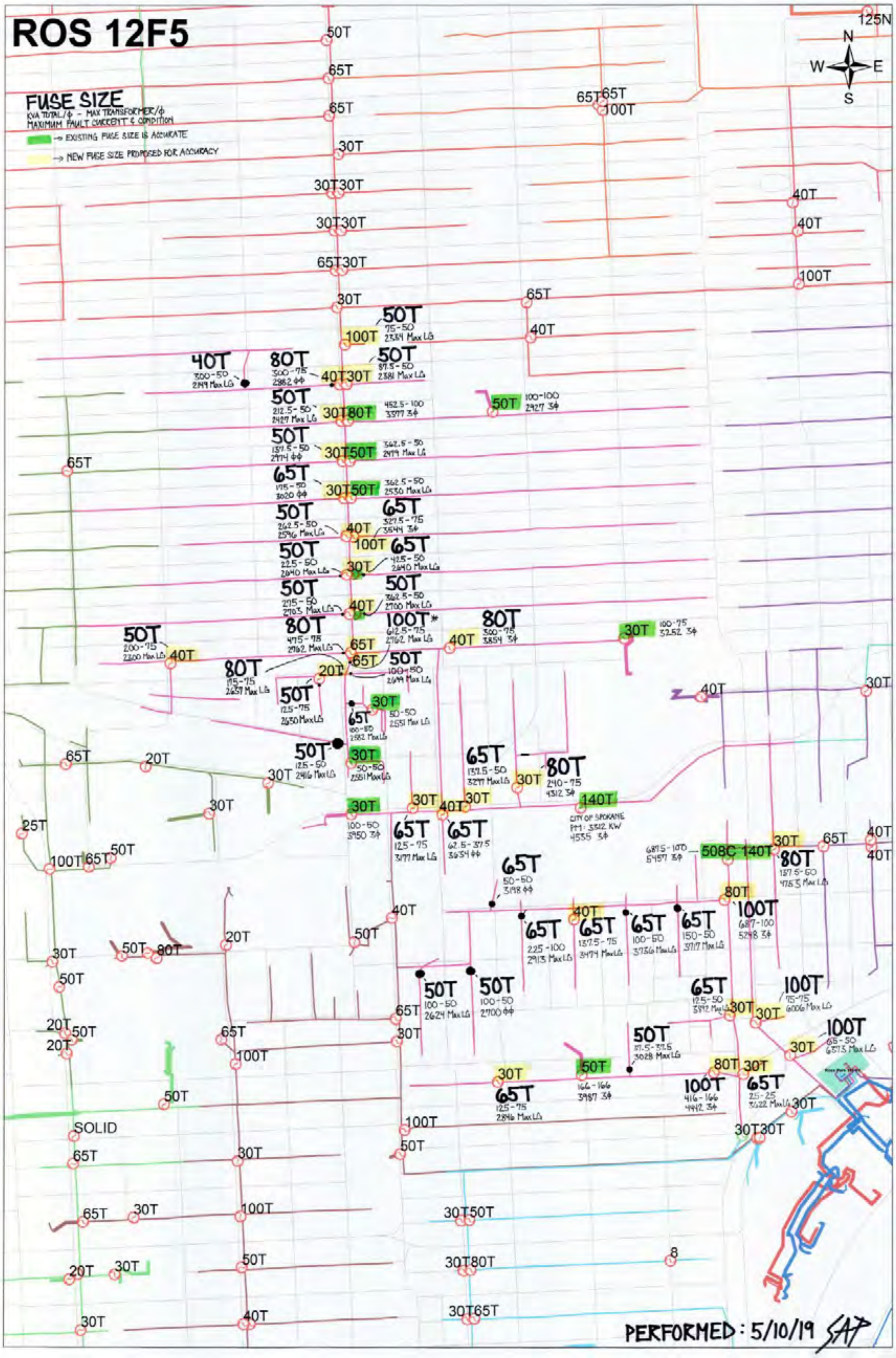


Figure 19. ROS 12F5 Fuse Size & Coordination Recommendations

Line Losses

The distribution of electricity results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors, among other improvements. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and to improve voltage levels on feeders. Line losses are generally addressed by balancing load on the phases between numerous strategic locations on the feeder, and then further minimized by replacing wire with more efficient conductors.

The primary trunk and lateral conductors on ROS 12F5 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the urban feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. It should be noted that the overwhelming majority of the feeder trunk and ties were already upgraded to 556 AAC during the Smart Grid Investment Project (SGIG).

	Polygon 5 556 AAC
Circuit Length (ft)	809.5
Existing Average kW Losses	1.8
Existing Peak kW Losses	6.9
Proposed Average kW Losses	1.1
Proposed Peak kW Losses	4.2
Average kW Loss Savings	0.7
Peak kW Loss Savings	2.7
Reconductor MWh Savings *	6.13

* Estimated average annual kW losses

An initial Synergi load study estimates that a total of 72 kW in peak line losses currently exist on ROS 12F5 (0.93%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved to approximately 69 kW (0.88%).

Peak Values	**Existing**	**After Balancing**	**After Reconductor**
kW Demand	8160	8180	8180
kW Load	8085	8103	8108
kW Line Losses	72	71	69
kW Loss %	0.93 %	0.91 %	0.88 %

Transformer Core Losses

Core losses are an inherent characteristic of distribution transformers. Core losses negatively affect efficiency and do not change with fluctuation in loading. The Grid Modernization program analyzes the approximate energy savings that are achieved through the reduction in transformer core losses. Savings are obtained when transformers are replaced with more efficient units, whether being replaced due to overloading or based on PCB levels. The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more efficient. Consequently, transformer core losses are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of a near equivalent size.

All distribution transformers on ROS 12F5 shall be analyzed and appropriately sized to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP), incorporating flicker and voltage drop analysis. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the assigned Designer.

The roughly 259 distribution transformers on ROS 12F5 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It is estimated that approximately 86 transformers will require replacement based on the TCOP replacement criteria, with an additional 37 requiring replacement for being incorrectly sized to serve the connected loads. The replacement of these 123 transformers would result in the prescriptive replacement of approximately 47.5% of the distribution transformers on ROS 12F5. The replacement of these transformers will result in an estimated 16.66 kW reduction in transformer core losses. This equates to an estimated annual savings of roughly 145.94 MWh. The estimated energy savings are achieved through the use of a unique algorithm that was created: to analyze each transformer on the feeder, determine the PCB/age replacement status, determine if the transformer is sized appropriately based on actual loading, make a recommendation on the appropriate size for the load, and then use historical core loss values to calculate the approximate energy savings that are achieved. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work, which is a form of line losses. Power factor is a value that can fluctuate with the variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of up to 17,000 hourly data pars covering a desired 24 month span to calculate the apparent power and power factor. This results in comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading, both in terms of time and quantity.

MVAR and MW data at the ROS 12F5 substation circuit breaker was analyzed from 3/19/17 to 3/19/19. It was determined that ROS 12F5 had a well balance lagging power factor 51.8% of the time during the time interval analyzed, and a leading power factor 48.2% of the time during the time interval analyzed. Additional detailed power factor information is available upon request. Some key power factor figures for ROS 12F5 are provided in the tables below.

Maximum Lagging Power Factor	99.99%
Minimum Lagging Power Factor	97.54%
Average Lagging Power Factor	99.86%
Median Lagging Power Factor	99.95%
Maximum Leading Power Factor	99.99%
Minimum Leading Power Factor	97.78%
Average Leading Power Factor	99.88%
Median Leading Power Factor	99.95%

The graph in Figure 20 shows the percent of time during the interval analyzed where the power factor on ROS 12F5 fell between the applicable ranges. There were no recorded instances where data fell outside this range. This information is also provided in a table format.

	Lagging	Leading
99%-100%	50.95%	47.99%
98%-99%	0.82%	0.20%
97%-98%	0.03%	0.01%
96%-97%	0.00%	0.00%
95%-96%	0.00%	0.00%
94%-95%	0.00%	0.00%
93%-94%	0.00%	0.00%
92%-93%	0.00%	0.00%
91%-92%	0.00%	0.00%
90%-91%	0.00%	0.00%
80%-90%	0.00%	0.00%
Below 80%	0.00%	0.00%

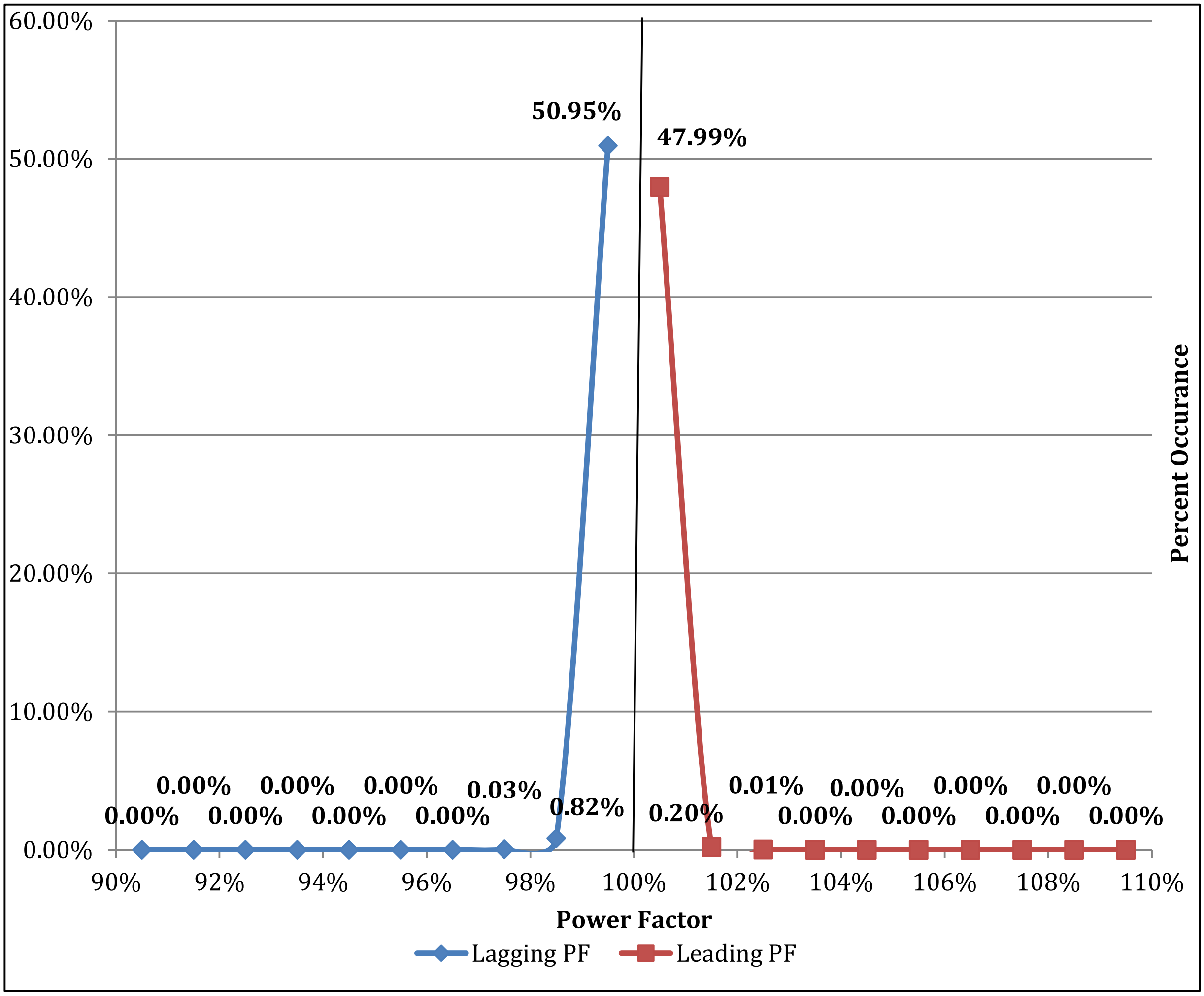


Figure 20. ROS 12F5 Existing Percent Occurance of Power Factor

Power Factor Correction

The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to unity. A power factor at or near unity is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and enacting a solution. The historical Watt and VAR data on the feeder was reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loads to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed in more severe situations to raise the power factor to a reasonable base value, and then switched capacitor banks are installed to supplement the power factor when required by loading. This approach optimizes the correction of the power factor and reduces line losses. The establishment of power factor also incorporates the field verification of existing deployed capacitor sizes, where it is not uncommon to discover capacitor banks that are incorrectly represented in Avista's GIS and modeling software.

There are four existing capacitor banks on ROS 12F5. Two of the banks are 600 kVAR fixed capacitor banks, and the other two are 600 kVAR switched capacitor banks (Z864F and Z999F). These four capacitor bank sizes were visually confirmed in the field by a local Serviceman to each be 600 kVAR units. Figure 21 illustrates the existing deployed capacitor banks on ROS 12F5.

The power factor on ROS 12F5 was consistently within the optimal range with the existing deployed capacitor banks. The power factor was observed between 0.99 lead and 0.99 lag approximately 98.94% of the time during the two year interval analyzed. This performance is nearly optimal and provides near ideal reactive power compensation for the circuit throughout the year. After analyzing the existing devices on the feeder, it is not recommended to add or remove any capacitor banks as part of the Grid Modernization program.

The decision to move forward with implementing any changes to the capacitors sizes and location will be confirmed, approved, and coordinated by the Regional Operations Engineer and Grid Modernization Program Engineer.

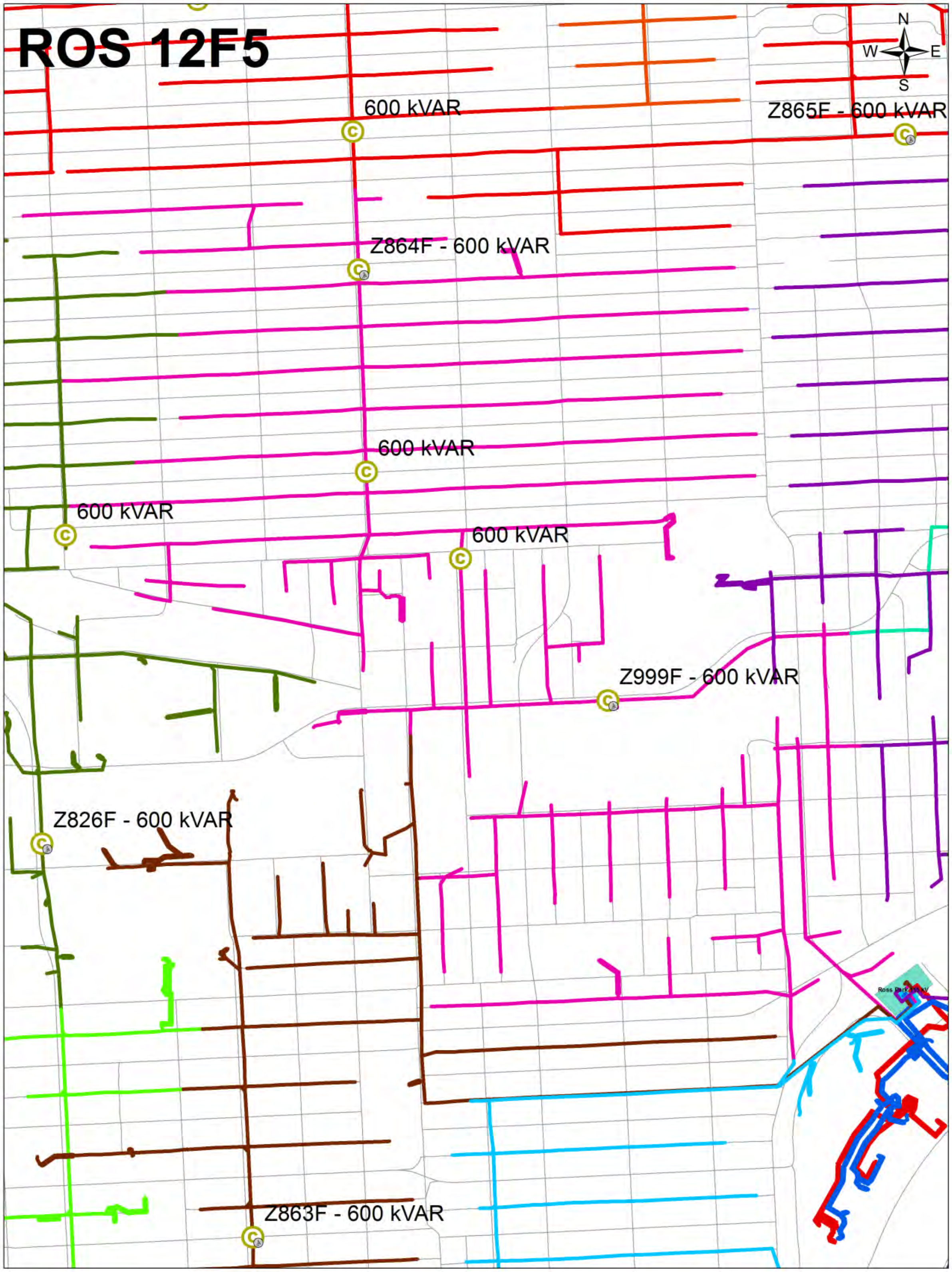


Figure 21. Existing Deployed Capacitor Banks on ROS 12F5

Distribution Automation

The Grid Modernization program currently represents Avista's largest centralized program to fully automate and improve the operating functionality and efficiency of the distribution system through the installation of automated distribution line devices. Grid Modernization has been programmatically addressing the distribution automation needs of Avista since the end of 2013, and the program focuses on installing air switches, reclosers, capacitor banks, and voltage regulators with communications and remote operability. The reduction in the duration of outages can be achieved through the installation of communications equipment that can either be controlled remotely or through a distribution management system (DMS). In addition, the number of customers impacted by an outage as well as a reduction in the frequency of outages can be achieved through the installation of devices with fault sensing and tripping capabilities. Time and cost savings can be achieved through the remote application of hot-line-holds. Fault detection, isolation, and restoration, conservation voltage reduction, and integrated volt/VAR control can also be achieved through Grid Modernization when the necessary substation equipment and components are in place.

Distribution Automation was analyzed for deployment on ROS 12F5 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on ROS 12F5.

ROS 12F5 currently contains numerous automated distribution line devices from the previous work performed during the Smart Grid Investment Project (SGIG). ROS 12F5 is distribution automation ready at the Ross Park Substation with the breakers, relaying, regulators, communications, and EMS/DMS ready. After analyzing the existing devices on the feeder, it is not recommended to add or remove any distribution line automation devices as part of the Grid Modernization program.

ROS currently has an existing midline recloser in device #Z789R to assist in fault detection and isolation. This device also assists in sectionalizing the feeder into two near equal sections based on the modeled amps allocated by connected kVA.

The following distribution line automation devices are currently deployed on the feeder:

Device Number	Location	Status	Device Type
Z101	E of Nevada & North Foothills	N.C.	S&C Scada-Mate Switch
Z274	N Hogan & North Foothills	N.O.	S&C Scada-Mate Switch
Z278	N Standard & E Empire	N.O.	S&C Scada-Mate Switch
Z281	S of Dakota & North Foothills	N.O.	S&C Scada-Mate Switch
Z509	N Hogan & E Buckeye	N.O.	S&C Scada-Mate Switch
Z789R	N Standard & E Bridgeport	N.C.	G&W Viper Recloser
Z864F	N Standard & E Kiernan	N.C.	600 kVAR Switched Cap Bank
Z999F	N Nevada & North Foothills	N.C.	600 kVAR Switched Cap Bank

Figure 22 illustrates the existing distribution line automation device locations on ROS 12F5.

There are two existing 600 kVAR fixed capacitor banks on the feeder. The first device is a 3-bushing style capacitor bank located at pole #084410. The Distribution Feeder Management Plan (DFMP) states that these style of capacitors can be left in service if they are accurately sized and are tested to be in good operating condition. The second device is a 2-bushing style capacitor bank located at pole #303125, which was taken off of service in 2013 by disconnecting the high side of the device and leaving the cutout doors open. The 2-bushing style capacitor was tested by as local Serviceman in May 2019 and found to be in good operating condition. Pole #303125 is Yellow Tagged. The Power Factor on the circuit only requires one of the fixed 600 kVAR capacitor banks to be energized. Therefore, the following steps should be executed to optimize the fixed capacitor banks on the circuit:

- Remove the 3-bushing style 600 kVAR capacitor bank located at pole #084410 in **Polygon 5**. Figure 23 illustrates the existing 3-bushing style 600 kVAR capacitor bank.
- Retest the 2-bushing style 600 kVAR capacitor bank located at pole #303125 **Polygon 4**. The device should be reused and put back in service if it is again tested and determined to be in good operating condition. If the testing of the device is not successful, a new 600 kVAR fixed capacitor bank shall be installed and energized. In either scenario, Pole #303125 is Yellow Tagged and it is recommended to be replaced with a critical distribution line device attached. Figure 24 illustrates the existing 2-bushing style 600 kVAR capacitor bank.

The proposed line device location(s) identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with either the Regional Operations Engineer, General Foreman, or District Manager to address any construction or Standards related concerns with the selected location.

The Grid Modernization program is not funded to perform work on adjacent feeders, including additional automation devices. Any requests to perform work on adjacent feeders are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on adjacent feeders.

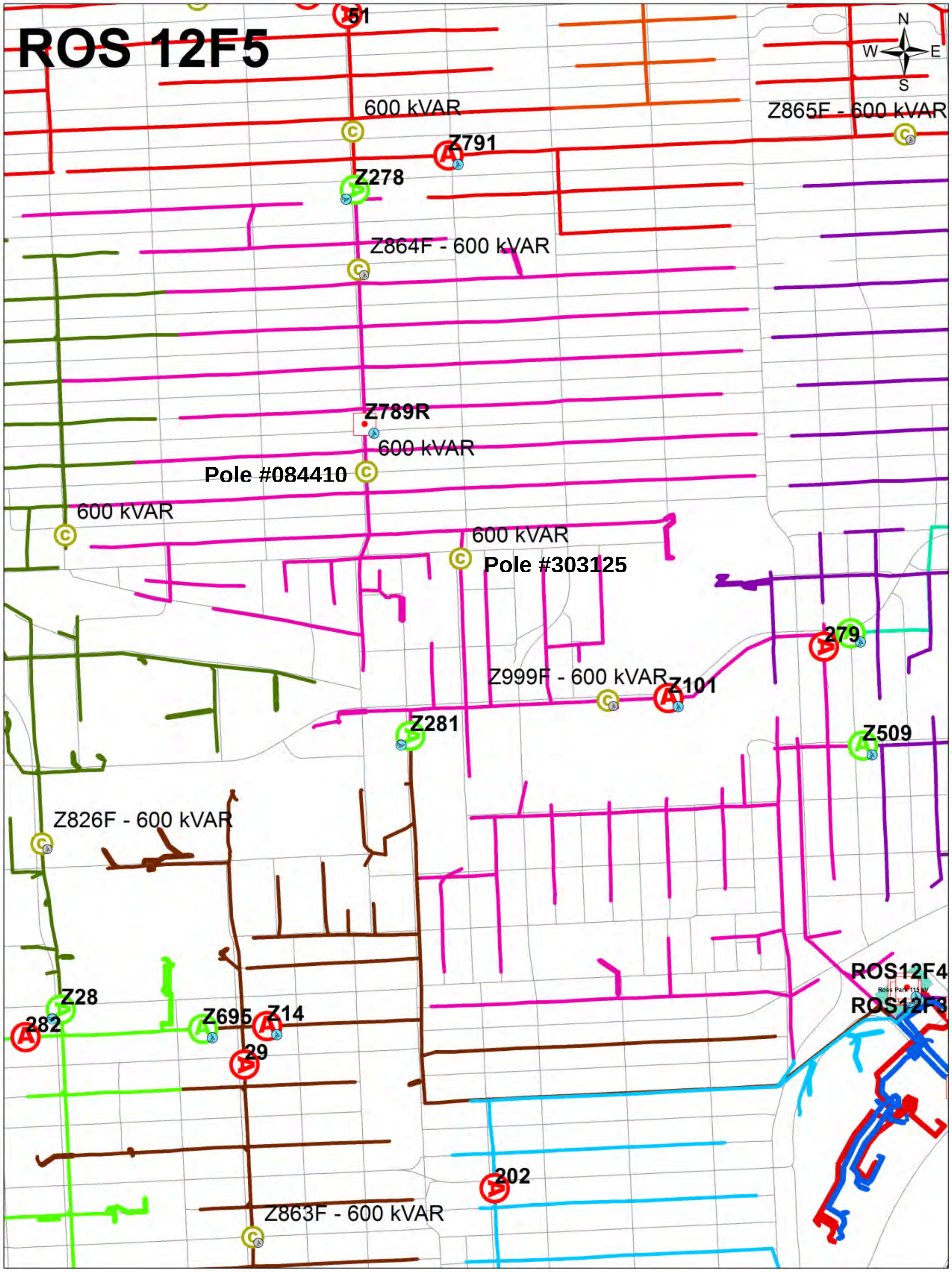


Figure 22. ROS 12F5 Automation Device Locations

Figure 23. 600 kVAR 3-Bushing Style Capacitor Bank at Pole #084410

Figure 24. 600 kVAR 2-Bushing Style Capacitor Bank at Pole #303125

Open Wire Secondary

Open wire secondary districts have the ability to negatively affect reliability due to the physical nature of construction and configuration. These districts are also predominantly located in areas with high vegetation growth and limited crew access. These factors have the ability to increase the number of outages and the duration of the outages. A distribution circuit's reliability can be improved by strategically splitting the districts with dedicated transformers and replacing these districts with an appropriately sized dedicated neutral. Grid Modernization is also initiating a study to analyze and quantify the estimated amount of open wire districts on feeders, as well as the amount requiring replacement based on the criteria of the Distribution Feeder Management Plan (DFMP). This will assist in planning and budgeting appropriately to address the needs of the feeders.

Open wire secondary districts have been analyzed for replacement on ROS 12F5 in accordance to the Distribution Feeder Management Plan (DFMP). Approximately 43,700' circuit feet of open wire secondary is currently estimated to be on ROS 12F5. This figure was established from physical observations obtained through field analysis by driving each circuit foot of the feeder. The existing open wire districts are almost entirely vertically constructed, however one horizontal district was discovered. In addition, most of the open wire districts are accessible via alley access, however numerous inaccessibly districts were identified.

Attempts were made to identify every open wire district on the feeder, however the Designer may identify districts that were not captured in this report. The Designer shall follow the same procedure and consult the DFMP if unidentified districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts.

Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Figures 25 and 26 identify the open wire secondary districts that were identified for analysis or removal in each polygon.

- **Polygon 1**
  - Analyze whether to replace approximately 770' of vertical open wire on Hogan-Perry due to the physical condition and alley accessibility.
- **Polygon 2**
  - Analyze whether to replace approximately 1370' of vertical open wire on Perry north of Carlisle due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 790' of vertical open wire on Denver-Morton & Carlisle-Jackson due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 510' of vertical open wire on Columbus-Morton due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 510' of vertical open wire on Columbus-Nevada due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 590' of vertical open wire on Hamilton-Nevada due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1030' of vertical open wire on Cincinnati-Hamilton due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 570' of vertical open wire on Cincinnati-Dakota due to the physical condition and alley accessibility.
- **Polygon 3**
  - Analyze whether to replace approximately 270' of vertical open wire on Perry south of Carlisle due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 240' of vertical open wire on Columbus-Morton due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 2200' of vertical open wire on Illinois-Montgomery due to the physical condition and alley accessibility.
- **Polygon 4**
  - Analyze whether to replace approximately 410' of vertical open wire on Nevada-Perry due to the physical condition and alley accessibility.
  - Replace approximately 900' of vertical open wire on Cincinnati-Hamilton due to inaccessibility.
  - Replace approximately 430' of vertical open wire on Cincinnati-Dakota due to inaccessibility.

- **Polygon 5**
  - Replace approximately 260’ of vertical open wire on Dalton-Euclid east of Nevada due to inaccessibility.
  - Replace approximately 680’ of vertical open wire on Dalton-Euclid west of Nevada due to inaccessibility.
  - Replace approximately 1860’ of vertical open wire on Dalton-Euclid west of Standard due to inaccessibility.
  - Replace approximately 190’ of vertical open wire on Addison-Wiscomb south of Euclid due to inaccessibility.
  - Replace approximately 280’ of vertical open wire on Standard-Wiscomb south of Euclid due to inaccessibility.
  - Replace approximately 650’ of vertical open wire on Euclid-Fairview west of Addison due to inaccessibility.
  - Replace approximately 1200’ of horizontal open wire on Fairview west of Wiscomb.
  - Analyze whether to replace approximately 4570’ of vertical open wire on Dalton-Liberty due to the physical condition and alley accessibility.
- **Polygon 6**
  - Analyze whether to replace approximately 4150’ of vertical open wire on Bridgeport-Liberty due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 3590’ of vertical open wire on Bridgeport-Courtland due to the physical condition and alley accessibility.
- **Polygon 7**
  - Analyze whether to replace approximately 4530’ of vertical open wire on Courtland-Glass due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 3800’ of vertical open wire on Glass-Gordon due to the physical condition and alley accessibility.
- **Polygon 8**
  - Analyze whether to replace approximately 3800’ of vertical open wire on Gordon-Kiernan due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 590’ of vertical open wire on Kiernan-Providence east of Standard due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1010’ of vertical open wire on Kiernan-Providence west of Standard due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1860’ of vertical open wire on Empire-Providence west of Standard due to the physical condition and alley accessibility.
  - Replace approximately 160’ of vertical open wire on Empire-Providence east of Standard due to inaccessibility.

Figure 25. Open Wire Secondary Districts on Polygons 1, 2, 3, and 4 of ROS 12F5

Figure 26. Open Wire Secondary Districts on Polygons 5, 6, 7, and 8 of ROS 12F5

Environmental

ROS 12F5 was identified to contain over 3,500’ circuit feet of distribution primary trunk and laterals that fall within the identified avian protection zone. The avian protection zones are located within **Polygons 1, 2, and 3**. Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space. Any designs to structures within the identified avian protection zone shall adhere to the Avista Electric Distribution Overhead Construction and Material Standards, Distribution Feeder Management Plan (DFMP), and the Avista Avian Protection Plan to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements and environmental regulations. Figure 27 illustrates the avian protection zone as it relates to ROS 12F5.

ROS 12F5 does not contain overhead primary distribution river crossings.

ROS 12F5 does not contain overhead or underground facilities that encroach upon the 200’ environmental shoreline buffer in Avista’s GIS mapping system.

The Environmental Compliance department shall be consulted by the assigned Designer to provide direction and assistance on any questions related with the avian protection zone, the Spokane River shoreline, or other environmentally sensitive areas.

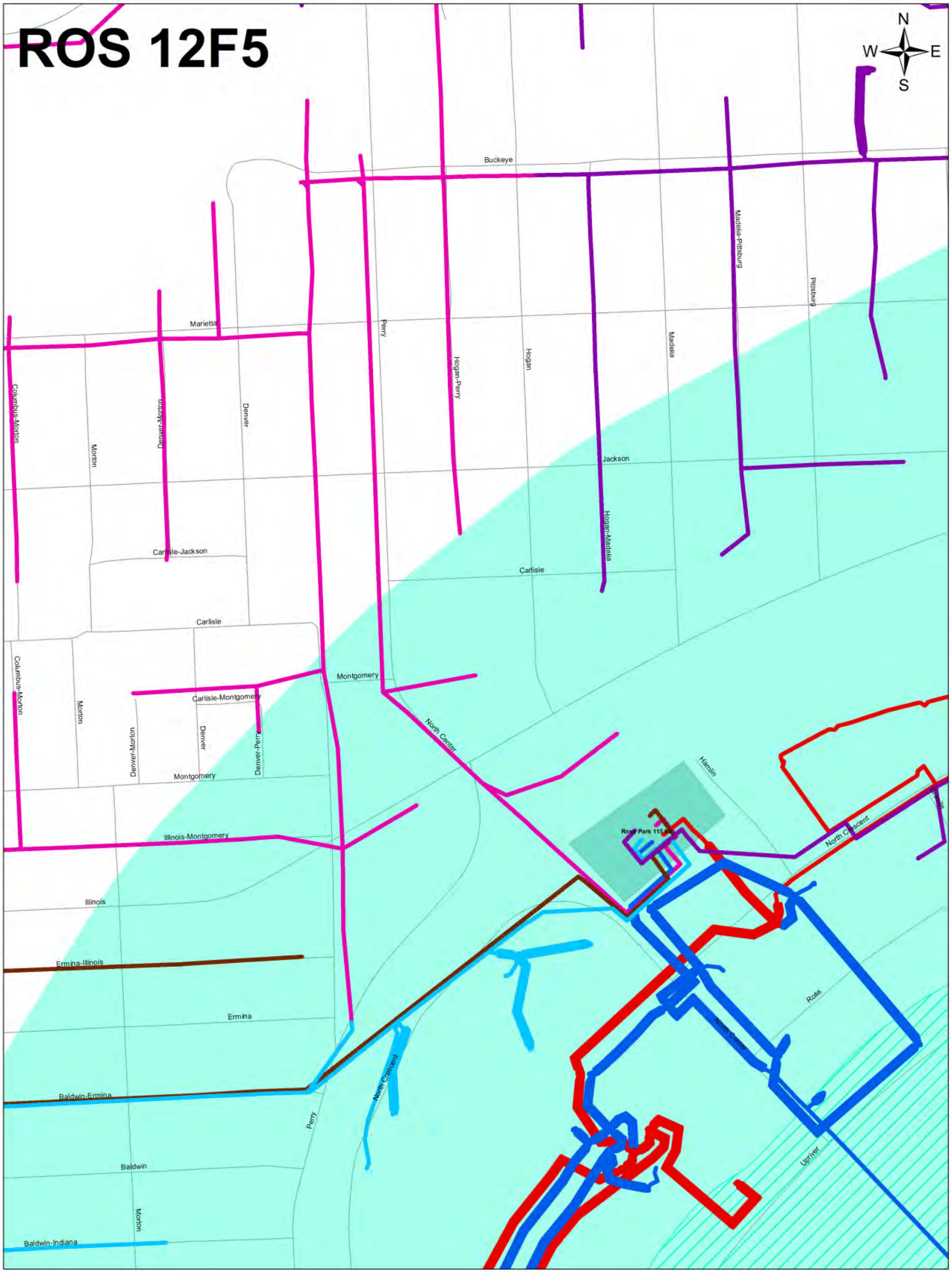


Figure 27. ROS 12F5 Avian Protection Zone and Shoreline Buffer

Poles

All components of an overhead distribution system rely on the integrity and health of poles to ensure the system remains safe, reliable, and operational. The Grid Modernization program performs engineering and field examination of all of the poles and structures on a feeder to determine the removal, installation, replacement, or reinforcement based on requirements of the Distribution Feeder Management Plan (DFMP). A pole inspection report is requested and conducted to obtain an explicit list of poles on the feeder. The pole information from the inspection report provides detailed information for Grid Modernization to leverage in the assessment and proposals.

All poles and structures on ROS 12F5 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Wood Pole section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the ROS 12F5 circuit was performed from 10/4/2018 to 11/7/2018. The ROS 12F5 feeder was determined to contain 762 distribution poles at the time of inspection. The average age of distribution pole on the circuit is approximate 49.5 years, which places the average year of installation around 1968. 409 poles on the circuit are older than the 60 year limit for mean-time to failure, which results in the prescriptive replacement of 53.7% of wood poles at a minimum based on age alone. This estimation does not include under height or under classed poles that will also require replacement to adhere to Avista’s Overhead Construction Standards.

The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	762
Average Pole Age in Years	49.5 (1968)
Year of Oldest Installed Pole	1927
Poles install between 1920-1929	16 (2.1%)
Poles install between 1930-1939	17 (2.2%)
Poles install between 1940-1949	222 (29.1%)
Poles install between 1950-1959	154 (20.2%)
Poles install between 1960-1969	41 (5.4%)
Yellow Tagged Poles (Re-enforceable)	59 (7.7%)
Red Tagged Poles (Replace)	0 (0%)
Average Pole Class	4.0
Class 4 Poles or Smaller	571 (74.9%)
Class 5 Poles or Smaller	189 (24.8%)

Transformers

All transformers on ROS 12F5 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

An improvement in the number of underground primary cable outages can be achieved by strategically replacing cable that has a known susceptibility to faulting. The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. This includes the targeted replacement of all pre-1982 non-jacketed primary cable, which Avista's historical data suggests has the highest failure rate of underground cable. Problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged, which allows water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable. In addition, the Program will replace any primary cable section that has multiple documented failures for either jacketed or non-jacketed primary cable.

The URD Cable Program has identified approximately 4,050' conductor feet of underground cable on the circuit. It has been previously observed in programmatic cable replacement efforts that approximately 20% of the unknown cable segments end up being identified as first generation unjacketed cable. The file containing this information is located in the Electrical Engineering drive *c01m19:\Feeder Upgrades - Dist Grid Mod\ROS 12F5\~Admin\Baseline Analysis/ROS 12F5 URD Segments*. Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for replacement, damage, or removal. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding the replacement of first generation non-jacketed primary cable or padmount transformers for the Grid Modernization program. Figure 28 illustrates the identified underground cable segments on ROS 12F5.

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding underground facilities and padmount transformers for the Grid Modernization program.

Figure 28. ROS 12F5 Identified Underground Cable Segments

Vegetation Management

Vegetation can pose serious reliability and safety problems for distribution feeders when not properly maintained. Trees can grow into overhead distribution lines as they mature, which creates access issues, public safety concerns, the possibility for trees or limbs to fall through the conductors, or the creation of electrical faults through physical contact. Proper vegetation maintenance along feeder corridors will remove many of these concerns while improving safety and system reliability. Vegetation Management will be included along easements where feeder reconductoring is being performed and/or poles are being replaced. Appropriate clearances need to be reestablished between vegetation and Avista's primary and secondary conductors so as not to compromise Avista's Vegetation Management Standards.

Grid Modernization's work is optimized when performed in coordination with Vegetation Management efforts. Vegetation management shall be employed on ROS 12F5 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

ROS 12F5 has been divided into 8 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Automation devices located within a polygon shall be sequentially renamed using alphabetic letters to reflect a sub-polygon (i.e. #1A, #1B, #1C, etc). Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Manager by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figures 29 illustrates the ROS 12F5 polygons and their boundaries. The CPC Design layer on AFM/Designer is available to provide more detailed boundaries of the polygons.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
  - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
  - Primary distribution underbuild is on the *Francis & Cedar- Ross Park* 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures to ensure the pole class is adequate for the physical loading on the structure.
  - Analyze whether to replace approximately 770’ of vertical open wire on Hogan-Perry due to the physical condition and alley accessibility.
- **Polygon 2**
  - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
  - Analyze whether to replace approximately 1370’ of vertical open wire on Perry north of Carlisle due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 790’ of vertical open wire on Denver-Morton & Carlisle-Jackson due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 510’ of vertical open wire on Columbus-Morton due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 510’ of vertical open wire on Columbus-Nevada due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 590’ of vertical open wire on Hamilton-Nevada due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 1030’ of vertical open wire on Cincinnati-Hamilton due to the physical condition and alley accessibility.
  - Analyze whether to replace approximately 570’ of vertical open wire on Cincinnati-Dakota due to the physical condition and alley accessibility.

- **Polygon 3**
    - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
    - Analyze whether to replace approximately 270' of vertical open wire on Perry south of Carlisle due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 240' of vertical open wire on Columbus-Morton due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 2200' of vertical open wire on Illinois-Montgomery due to the physical condition and alley accessibility.
- **Polygon 4**
    - Reconductor existing 3-phase overhead primary trunk west of the Z274 switch to pole #442305 with 556 AAC primary (approximately 720'). This existing 3-phase overhead primary trunk is currently served by 335AAC primary and a 2/0 ACSR neutral. In addition, approximately 700' of primary trunk on BEA 12F2 will be reconductored as part of this work to established an ideal location for deadending the new wire.
    - Retest the 2-bushing style 600 kVAR capacitor bank located at pole #303125. The device should be reused and put back in service if it is again tested and determined to be in good operating condition. If the testing of the device is not successful, a new 600 kVAR fixed capacitor bank shall be installed and energized. In either scenario, Pole #303125 is Yellow Tagged and it is recommended to be replaced with a critical distribution line device attached.
    - Primary distribution underbuild is on the *Francis & Cedar- Ross Park* 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures to ensure the pole class is adequate for the physical loading on the structure.
    - Analyze whether to replace approximately 410' of vertical open wire on Nevada-Perry due to the physical condition and alley accessibility.
    - Replace approximately 900' of vertical open wire on Cincinnati-Hamilton due to inaccessibility.
    - Replace approximately 430' of vertical open wire on Cincinnati-Dakota due to inaccessibility.

- **Polygon 5**
    - Remove the 3-bushing style 600 kVAR capacitor bank located at pole #084410
    - Transfer 1Φ OH lateral east of N Standard St & E Dalton-Liberty (≈23 A peak loading, ≈10 A average loading) from CΦ to BΦ.
    - Replace approximately 260' of vertical open wire on Dalton-Euclid east of Nevada due to inaccessibility.
    - Replace approximately 680' of vertical open wire on Dalton-Euclid west of Nevada due to inaccessibility.
    - Replace approximately 1860' of vertical open wire on Dalton-Euclid west of Standard due to inaccessibility.
    - Replace approximately 190' of vertical open wire on Addison-Wiscomb south of Euclid due to inaccessibility.
    - Replace approximately 280' of vertical open wire on Standard-Wiscomb south of Euclid due to inaccessibility.
    - Replace approximately 650' of vertical open wire on Euclid-Fairview west of Addison due to inaccessibility.
    - Replace approximately 1200' of horizontal open wire on Fairview west of Wiscomb.
    - Analyze whether to replace approximately 4570' of vertical open wire on Dalton-Liberty due to the physical condition and alley accessibility.
- **Polygon 6**
    - Analyze whether to replace approximately 4150' of vertical open wire on Bridgeport-Liberty due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 3590' of vertical open wire on Bridgeport-Courtland due to the physical condition and alley accessibility.
- **Polygon 7**
    - Analyze whether to replace approximately 4530' of vertical open wire on Courtland-Glass due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 3800' of vertical open wire on Glass-Gordon due to the physical condition and alley accessibility.
- **Polygon 8**
    - Transfer 1Φ OH lateral east of N Standard St & E Providence-Kirenan (≈6 A peak loading, ≈3 A average loading) from AΦ to BΦ.
    - Analyze whether to replace approximately 3800' of vertical open wire on Gordon-Kiernan due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 590' of vertical open wire on Kiernan-Providence east of Standard due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1010' of vertical open wire on Kiernan-Providence west of Standard due to the physical condition and alley accessibility.
    - Analyze whether to replace approximately 1860' of vertical open wire on Empire-Providence west of Standard due to the physical condition and alley accessibility.
    - Replace approximately 160' of vertical open wire on Empire-Providence east of Standard due to inaccessibility.

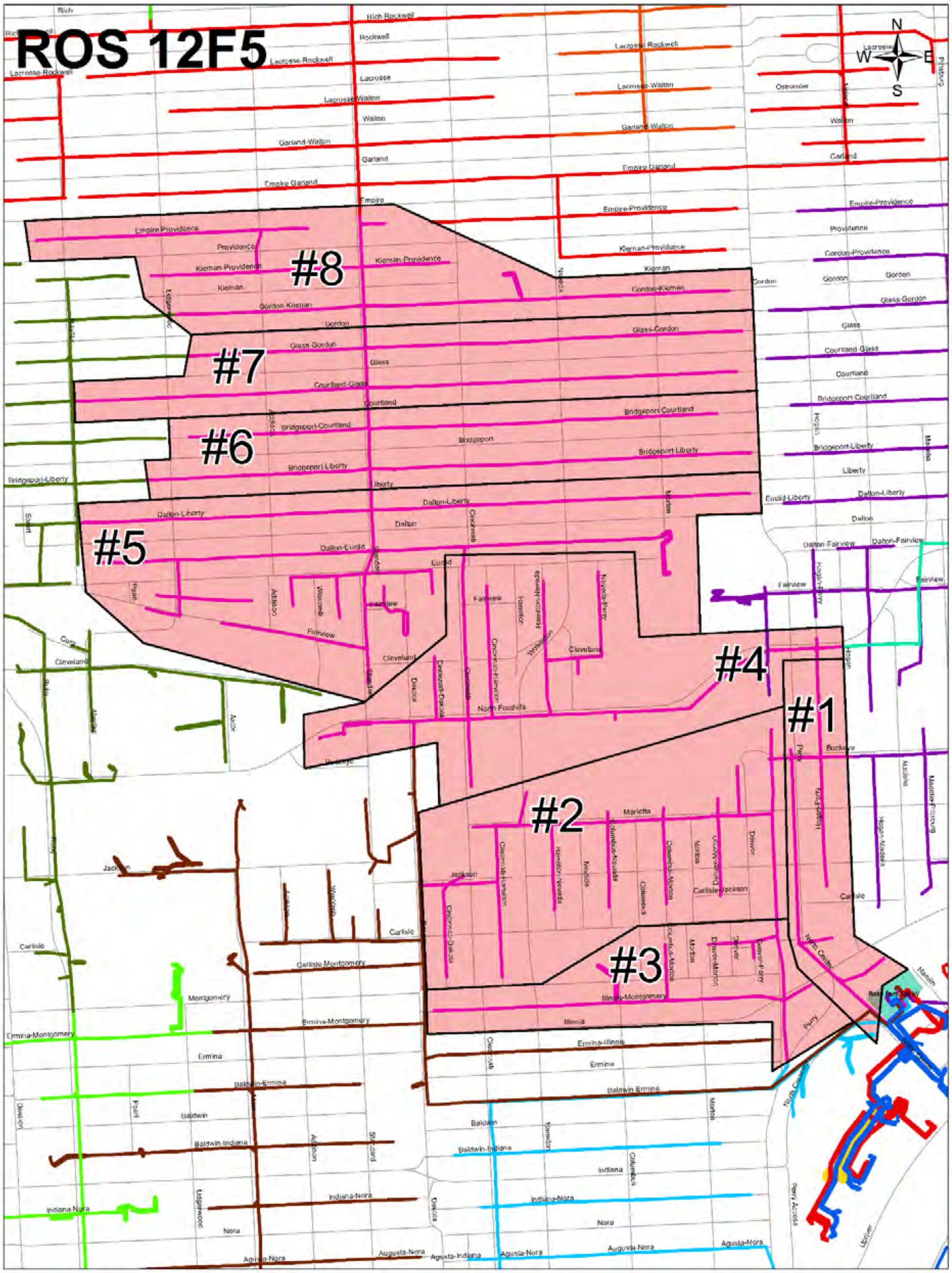


Figure 29. ROS 12F5 Assigned Polygon Numbers

Report Versions

Version 1 5/31/19 – Creation of the initial report

The figures, photos, and images found in this report can be located in c01m19:\Feeder Upgrades - Dist Grid Mod\ROS12F5\~Admin\Baseline Analysis

Grid Modernization Program

SIP 12F4 Feeder Analysis Report

October 29, 2018

Version 1

Prepared by

Shane Pacini, P.E.
Senior Distribution Engineer

Index

Overview

The following report was established to create a baseline analysis for SIP 12F4 as part of the Grid Modernization program.

SIP 12F4 is a 13.2/7.62 kV distribution feeder served from Transformer #2 at the Spokane Industrial Park Substation in the Spokane service area. The feeder has 3.78 circuit miles of feeder trunk with 24.79 circuit miles of laterals that serves an urban mixture of light residential and commercial loads in central Spokane Valley, WA. SIP 12F4 serves 2036 customers during the current normal configuration, including the primary metered customer Key Tronic Corporation. Additional feeder information is included throughout the sections of this report, as well as the 2016 Avista Feeder Status Report. SIP 12F4 is represented by the *dark yellow* color on the system map shown in Figure 1 and Figure 2.

Executive Summary

The following summary is provided as a preview of the findings and recommendations of the Grid Modernization program for the SIP 12F4 circuit.

Cost Avoidance and Energy Efficiency:

- Primary trunk is currently comprised of 556 AAC resulting in no recommendations for trunk reconductoring
- Opportunities exist to reconductor primary laterals due to a combination of physical condition, facility replacements, and high loss conductors
- Moderate phase changes will create balanced loading across numerous strategic points on the circuit
- Switchable capacitor banks will not be installed. The feeder has one existing 300 kVAR fixed capacitor bank that appropriately manages the VARs on the circuit
- There is approximately 9,750' circuit feet of open wire secondary districts.
- An estimated 277 of the 508 transformers (54.5%) on the feeder will be replaced
- Moderate peak loading (average 262A peak per phase) warrant a need to strategically address reconductoring certain primary laterals
- Voltage levels were elevated during normal and abnormal system configurations however this will be corrected through a revised output voltage setting

Reliability and Capital Offset from Reduced O&M:

- SAIFI, SAIDI, CAIDI, and CEMI3 currently satisfy the 2018 Avista Target values
- One Viper midline recloser will be installed to provide sectionalizing, fault sensing capabilities, and remote operability and HLH deployment
- Two Viper switches will be installed to provide remote operability and HLH deployment, future FDIR functionality, and automated tie switches to BKR 12F2 and MIL 12F4.
- 197 of the 833 poles (23.6%) on the circuit will be replaced at a minimum due to the prescriptive replacement of the 60 year limit for mean-time to failure
- Comprehensive fuse sizing and coordination study was performed

Figure 1. SIP 12F4 Circuit One-Line Diagram

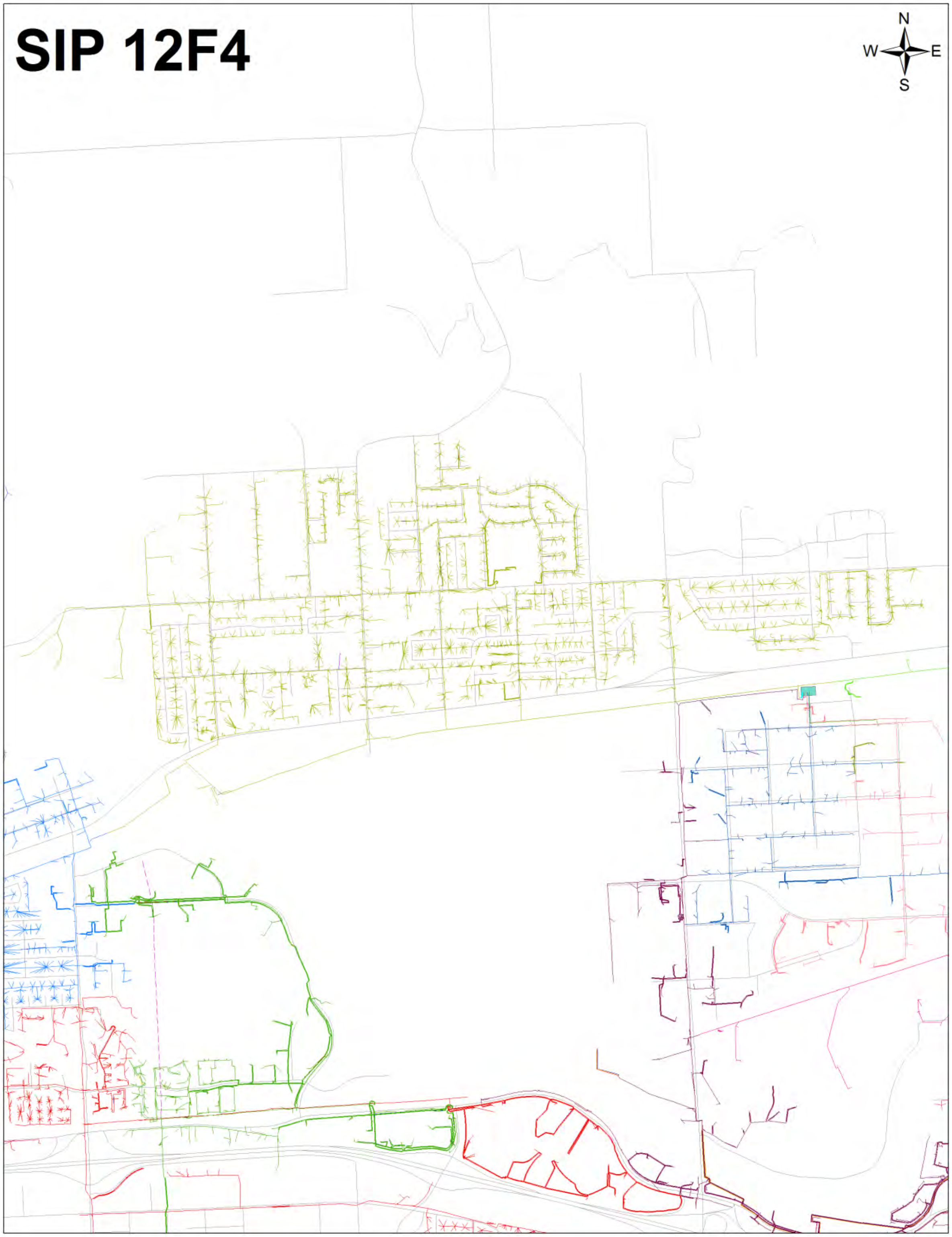


Figure 2. SIP 12F4 Circuit One-Line Diagram

Program Ranking Criteria

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (energy savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set could be measured on different scales, the normalization process offers the ability to convert each figure into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked for selection.

The 2016 Avista Feeder Status Report contains detailed information on each distribution circuit and assesses each feeder in three key areas: health, performance, and criticality. The Health metric analyzes items such as the age of the wood pole population and projected reject rate, reliability indices, and OH-UG ration.
The Performance metric analyzes items such as the thermal utilization, efficiency, voltage, power factor, and reliability indices. The Criticality metric analyzes items such as customer density, commercial account density, load density, and the essential services on the circuit. SIP 12F4 was determined to be performing relatively well in terms of Health and Performance, and is seen as being relatively non-critical based on the customers that are served.

Metric	Rating Value	Rating Scale
Health	3.70	Good to Very Good
Performance	4.00	Good to Very Good
Criticality	1.30	Very Low to Low

SIP 12F4 did not rank in the top 10 feeders in the Spokane service area for any of the measured categories in the 2016 Avista Feeder Status Report.

In terms of the Grid Modernization Program's independent assessment of the feeder, SIP 12F4 had a normalized total ranking of 0.422, ranking 73rd on the list of over 340 feeders during the 2018-2020 selection period analyzed in 2015.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.099	76.06	509770.25
Normalized Data	0.085	0.983	0.17
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.034	0.344	0.043

Reliability Index Analysis

Reliability indices are significant components of a utility's ability to measure long-term electric service performance, and are one indicator of system health or condition. The common reliability indices of CAIDI, SAIDI, SAIFI, and CEMI3 are used by the Grid Modernization Program to analyze and illustrate the historical reliability performance of the feeders, as well as to assist in justifying any proposed circuit improvements or automation deployments. Each historically averaged reliability index for a feeder is compared to the Avista target value for that calendar year to determine the reliability performance of a feeder.

SIP 12F4 was found to have 135 sustained distribution outages from 2006 through 2017 through and OMT analysis, for an average annual figure of 11.2 sustained distribution outages. In addition, SIP 12F4 was found to have 30 momentary distribution outages from 2006 through 2016 through and OMT analysis, for an average annual figure of approximately 5 momentary distribution outages. The key reliability indicators for SIP 12F4 were analyzed from 2006 to 2017 to illustrate the historical reliability performance of the feeder, as well as to assist in justifying any proposed circuit improvements or automation deployments. The table below shows the annual value for each respective reliability index on SIP 12F4 in the corresponding year. The reliability indices that Grid Modernization uses for Measurement and Reporting do not include Major Event Days (MED). Major Event Days is an industry standard that is used to evaluate major events, such as severe weather or storms, which can lead to unusually long outages in comparison to the distribution system's typical outage. The reliability indices that are being used do not include MED, as this is standard per IEEE and reflects the same reliability information that Avista shares with the respective state Utility Commissions.

Reliability Year	CEMI3	SAIFI	SAIDI	CAIDI
2006	0.0%	0.94	274	293
2007	0.0%	0.12	18	151
2008	0.2%	1.33	105	79
2009	0.3%	0.54	66	121
2010	0.3%	1.34	53	39
2011	0.0%	0.57	39	67
2012	0.0%	0.05	6	116
2013	0.2%	0.43	46	107
2014	0.0%	0.12	24	198
2015	0.0%	0.29	35	118
2016	0.1%	0.09	16	168
2017	4.0%	1.34	99	74
Average	0.51%	0.597	65.1	127.6

The previous table illustrates the annual value for each respective reliability index on SIP 12F4 in the corresponding year. This information is also provided in graphical form in Figures 3 through 6. The information in these graphs do not include MEDs.

CEMI3 is defined as the Total Number of Customers Experiencing 3 or More Sustained Interruptions /divided by the Total Number of Customers Served. The performance of this metric has been very good, with many years of zero customers experiencing 3 or more sustained outages. This index is showing a flat linear trend during the 12 years of analyzed data, with only a recent spike in 2017. The CEMI3 index for SIP 12F4 has consistently been outperforming the annual Target value set internally by Avista.

SAIFI is defined as the Total Number of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has generally performed well, however there is variation on the index between the years analyzed. This index is showing a declining linear trend during the 12 years of analyzed data. The SAIFI index for SIP 12F4 has mostly been outperforming the annual Target value set internally by Avista, however the 2017 figure did not meet the internal target.

SAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Served. The performance of this metric has been very good. This index is showing a generally decreasing linear trend during the 12 years of analyzed data. The SAIDI index for SIP 12F4 has consistently been outperforming the annual Target value set internally by Avista, which is showing a slightly increasing trend.

CAIDI is defined as the Sum of Durations of Customer Sustained Interruptions divided by the Total Number of Customers Interruptions. The performance of this metric has generally varied over the 12 years of analyzed data. This index is showing a slightly decreasing linear trend during the interval analyzed. The CAIDI index for SIP 12F4 has mostly been outperforming the annual Target value set internally by Avista, however there are some years where the annual target was not satisfied.

The average value of each index was calculated and then compared to the Avista 2018 Target values. All four of the historical averaged measured indices on SIP 12F4 are out performing the 2018 targets. This data suggests that customers experience relatively few outages on the feeder, and the average service restoration duration is within the desired range of Avista.

WA-ID Key Indicator	2018 Target	SIP 12F4	Variance
SAIFI Sustained Outages/Customer	1.14	0.597	0.543
SAIDI Outage Time/Customer (min)	167.00	65.1	101.9
CAIDI Ave Restoration Time (min)*	154.00	127.6	26.4
CEMI3 % of Customers >3 Outages	6.60%	0.51%	6.09%

*CAIDI values were converted from hours to minutes for this report

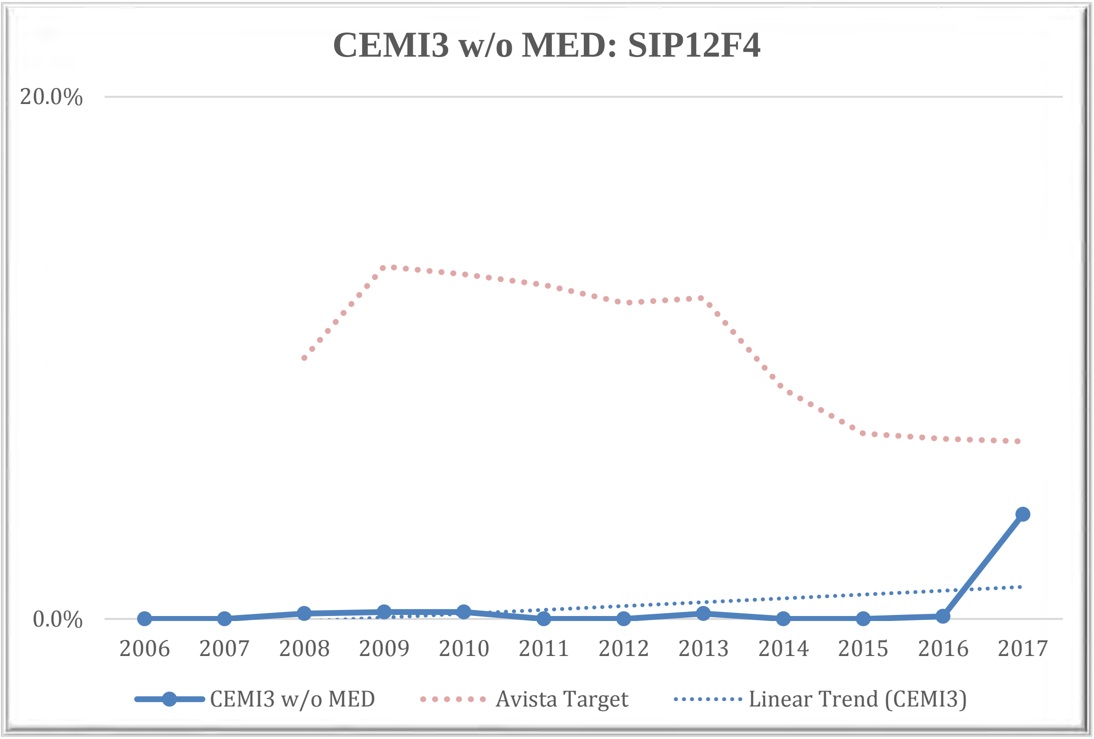


Figure 3. SIP 12F4 CEMI3 Performance

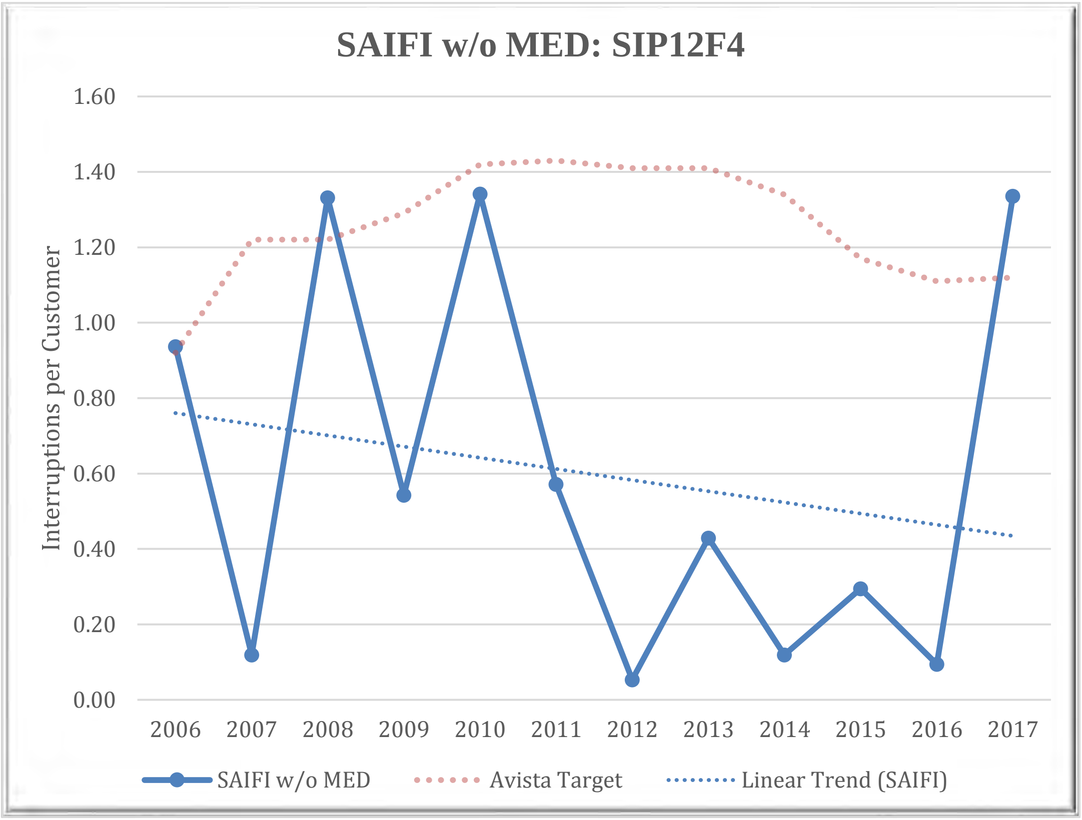


Figure 4. SIP 12F4 SAIFI Performance

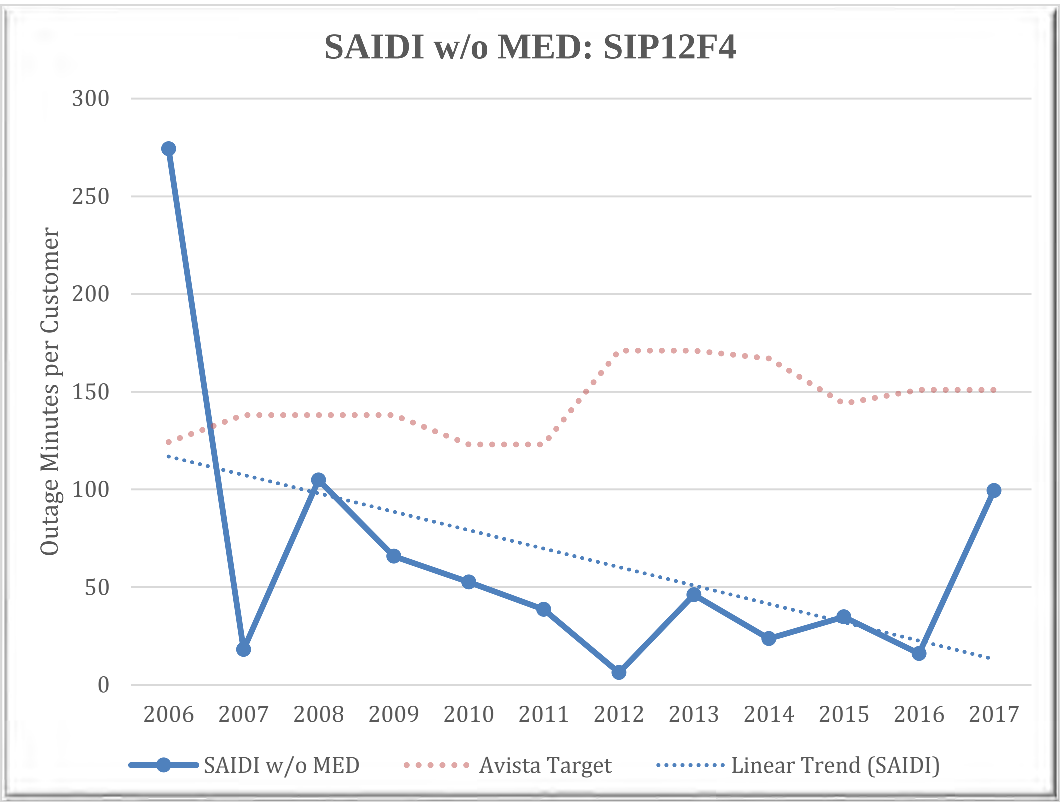


Figure 5. SIP 12F4 SAIDI Performance

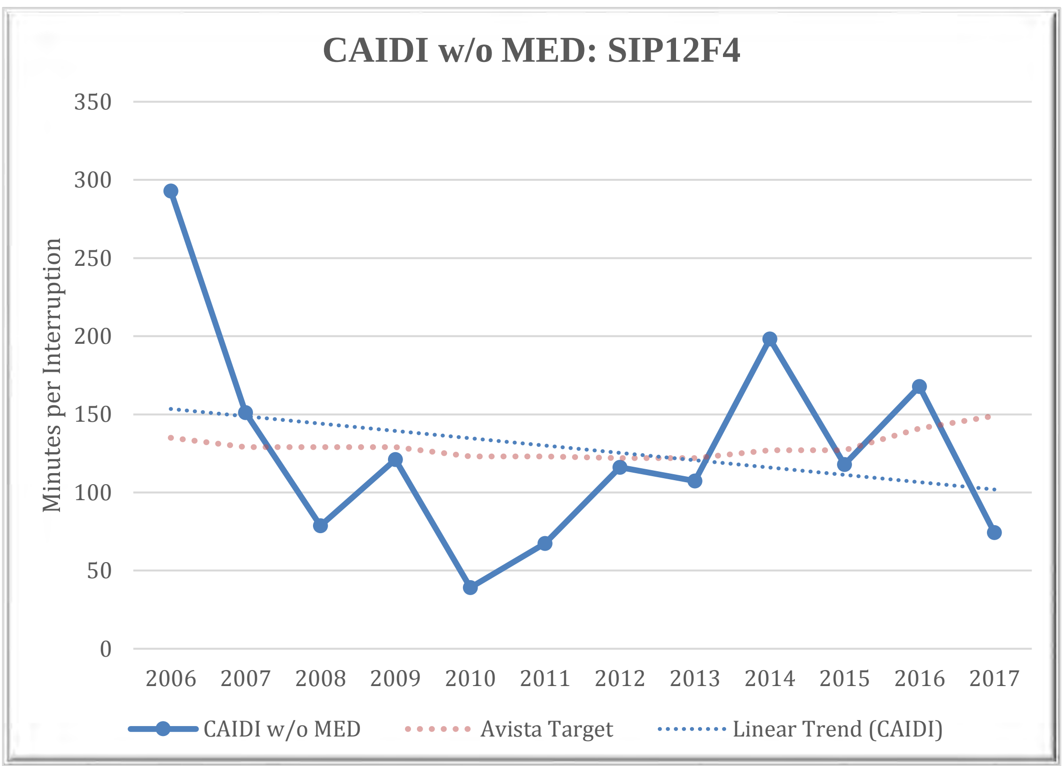


Figure 6. SIP 12F4 CAIDI Performance

Peak Loading

Three-phase ampacity loading from line sensor monitoring downstream of the SIP 12F4 substation circuit breaker was analyzed from 7/7/17 to 5/8/18. The following ampacity loading values were established for SIP 12F4 during this timeframe. Loading information has been analyzed to determine if any data needed to be removed from selected timeframes due to temporary changes in loading from switching (verified through PI). It was identified that there were two time durations that should be excluded from the loading due to SIP 12F4 being in an abnormal feeder configuration and serving additional load from an adjacent feeder. Figure 7 illustrates the two durations that are excluded from loading analysis where additional load was serving during abnormal feeder configuration. The first duration of abnormal loading began at approximately 10/4/2017 3:00 AM and ended at approximately 10/20/2017 5:00 AM. Figure 8 illustrates the beginning and ending of the first abnormal loading occurrence. The second duration of abnormal loading began at approximately 2/12/2018 10:00 AM and ended at approximately 2/13/2018 7:00 AM. Figure 9 illustrates the beginning and ending of the second abnormal loading occurrence.

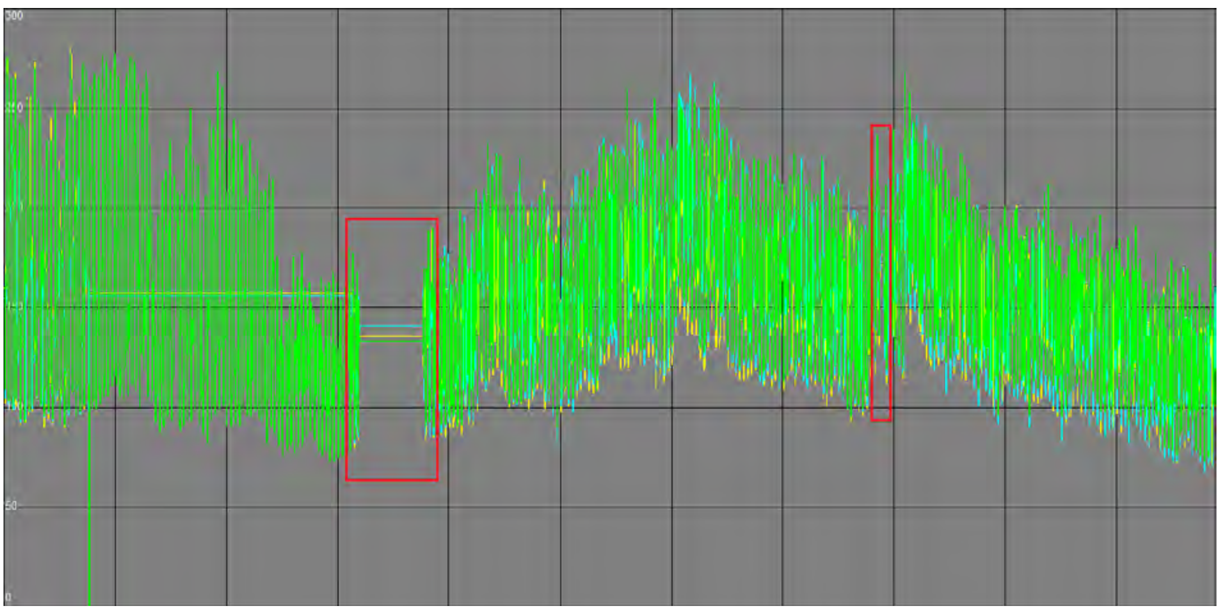


Figure 7. SIP 12F4 Abnormal Feeder Configuration Reflecting Additional Load Transfers

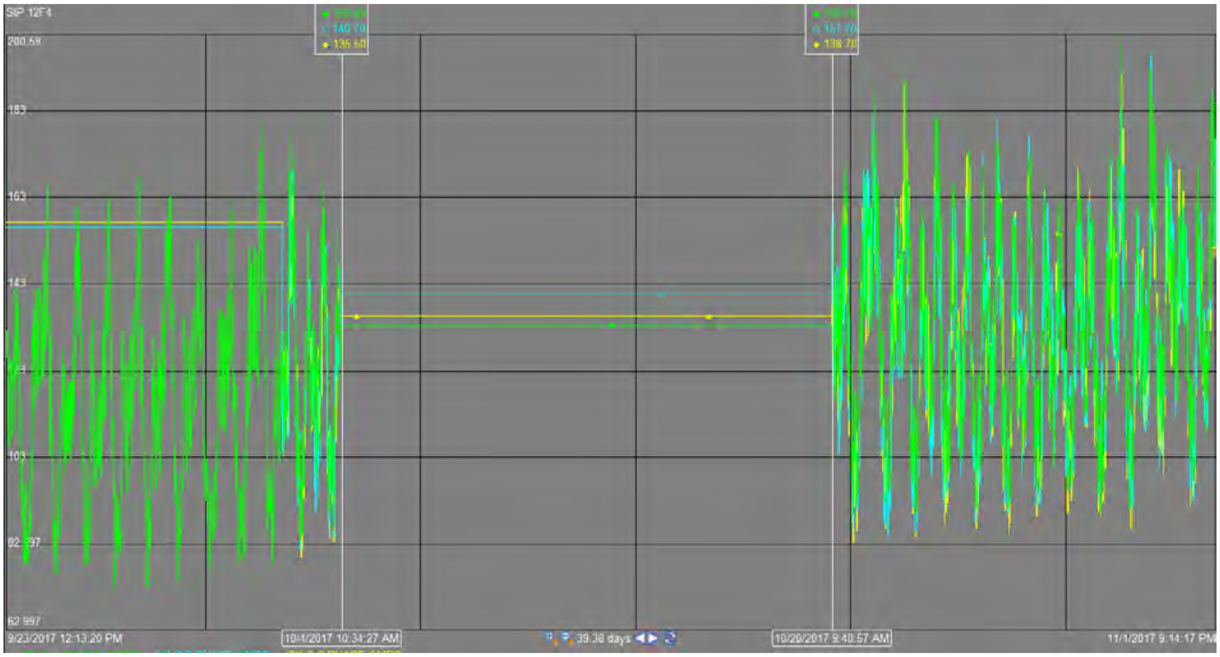


Figure 8. SIP 12F4 Abnormal Feeder Configuration from 10/4/17 to 10/20/17

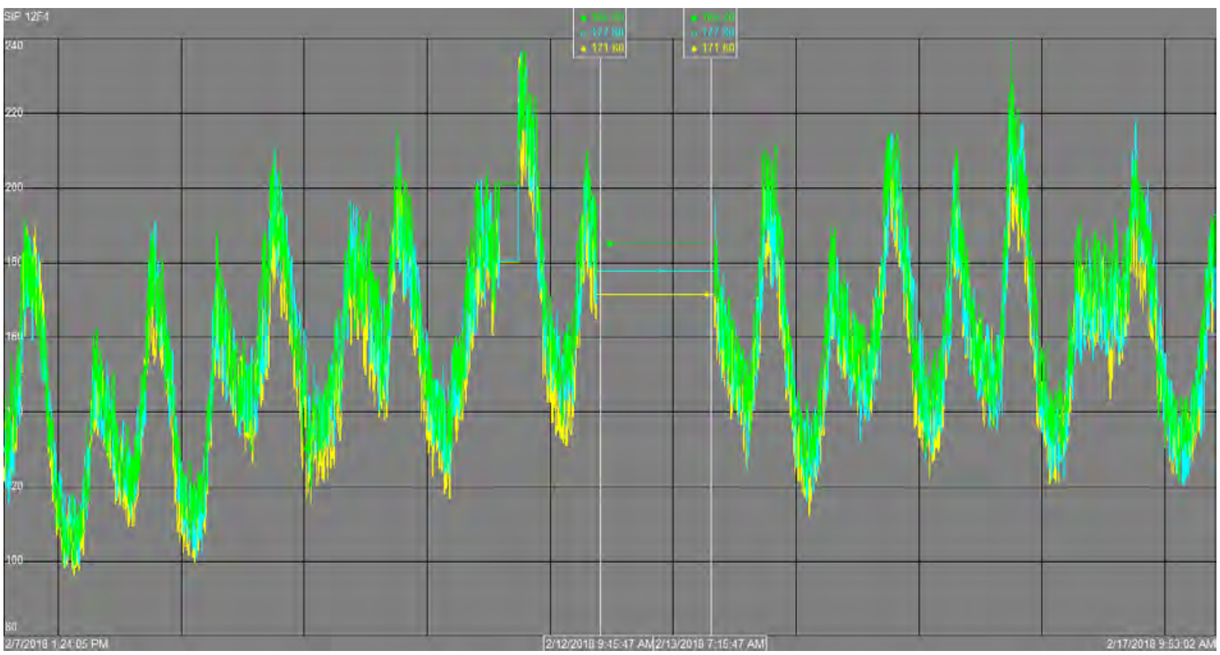


Figure 9. SIP 12F4 Abnormal Feeder Configuration from 2/12/2018 to 2/13/2018

SIP 12F4 is a summer peaking feeder, with comparable peak values observed from early July through late August. There are distinct winter peaks as well on the feeder, however these were slightly lower than the summer peaks and were observed from mid-December through mid-February. The values below reflect the adjusted data set where loading values during abnormal feeder configurations has been removed. The peak loading values for each phase are used in the Synergi model analysis for the feeder, except where average load values are noted for establishing kW losses.

	Before Balancing	
	Peak Loading	**Average Loading**
A-Phase	265 A	154 A
B-Phase	253 A	153 A
C-Phase	268 A	152 A
Average	262 A	153 A

	After Balancing	
	Peak Loading	**Average Loading**
A-Phase	262 A	155 A
B-Phase	254 A	152 A
C-Phase	269 A	152 A
Average	262 A	153 A

Approximate percent loading figures were established through Demand Factor by analyzing the ratio of the maximum apparent power demand observed upon the circuit to the total kVA load that is actually connected. This was performed on a per phase basis from values extracted through Synergi at the model's initial configuration before balancing or performing improvements on the circuit.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	2112	5804	36.39%
B-Phase	2017	6510	30.98%
C-Phase	2136	6040	35.36%

*kVA per Phase in Synergi as of 3/12/18

	Estimated Average Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	1228	5804	21.16%
B-Phase	1220	6510	18.74%
C-Phase	1212	6040	20.07%

*kVA per Phase in Synergi as of 3/12/18

Load Balancing

Imbalanced load on a feeder has the ability to create or worsen numerous problems which contribute to inefficiency. Unbalanced load can unnecessarily burden one conductor, potentially causing the highest loaded phase conductor to be overloaded or approach its ampacity limit. This can in turn create voltage quality concerns with low voltage scenarios, which are amplified when loads are higher. The exercise of load balancing also promotes the switching of balanced load between feeders during switching scenarios, which will mitigate the problem of overloading a particular phase on an adjacent feeder when load is transferred. Load will be approximately balanced on multi-phase laterals, between sectionalized switching devices or reclosers, and between strategic points on the feeder trunk. These balancing efforts will commence toward the end(s) of the feeder and roll up to nearly balanced load on each phase at the substation breakers.

Accurate load balancing can be analyzed and achieved on SIP 12F4 due to the three-phase ampacity loading from line sensor monitoring downstream the substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken AFM before balancing:

	Connected KVA per Phase*
A-Phase	5789 kVA
B-Phase	6510 kVA
C-Phase	6040 kVA

*Connected kVA per Phase in AFM as of 3/12/18

The following list provides the phase changes to loads, laterals, or dips that can effectively balance the load on the phases between numerous strategic locations on the feeder, as illustrated in Figures 10 and 11. As a whole, the trunk sections and multi-phase laterals on SIP 12F4 were relatively balanced, however opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate the following change into their appropriate polygon designs:

1. **Polygon 5** – transfer 1Φ OH lateral west of E Heroy Ave & N Progress Road (≈7 A peak loading, ≈4 A average loading) from CΦ to BΦ.
2. **Polygon 9** – transfer 1Φ URD laterals north of E Wabash Ave & N Bannen Road (≈10 A peak loading, ≈6 A average loading) from AΦ to BΦ.
3. **Polygon 10** – transfer 1Φ URD lateral south of E Rich Ave & N Blake Road (≈7 A peak loading, ≈4 A average loading) from BΦ to AΦ.
4. **Polygon 13** – transfer 1Φ OH lateral north of E Rich Ave between N Woodlawn Road & N Vercler Road (≈7 A peak loading, ≈4 A average loading) from BΦ to CΦ.

The result of this load transfer is listed in the following table. This change will approximately balance the feeder at the substation breaker to 262/254/269 during peak loading, as well as between the numerous strategic points to approximately sectionalize the feeder to optimize switching and load transfers.

	Existing			Proposed		
	A-Phase	**B-Phase**	**C-Phase**	**A-Phase**	**B-Phase**	**C-Phase**
SIP 12F4 Station Breaker	265	253	268	262	254	269
N on Sullivan	57	55	70	57	55	70
Switch #726	210	200	199	208	201	200
N on Adams	57	31	63	57	38	56
Switch #725	153	169	136	151	164	144
N on Best	79	43	50	69	53	50
Switch #371	74	126	86	81	111	93
N on Evergreen	30	71	54	37	63	54
Switch #1149	44	55	30	44	48	37

It is the Designer’s responsibility to consult the Grid Modernization Program Engineer and the Regional Operations Engineer on any proposals for phase balancing prior to commencing the job designs.

The decision to move forward with the proposed phase change will be confirmed and approved by the Regional Operations Engineer, and coordinated by the Designer in their respective polygon design(s).

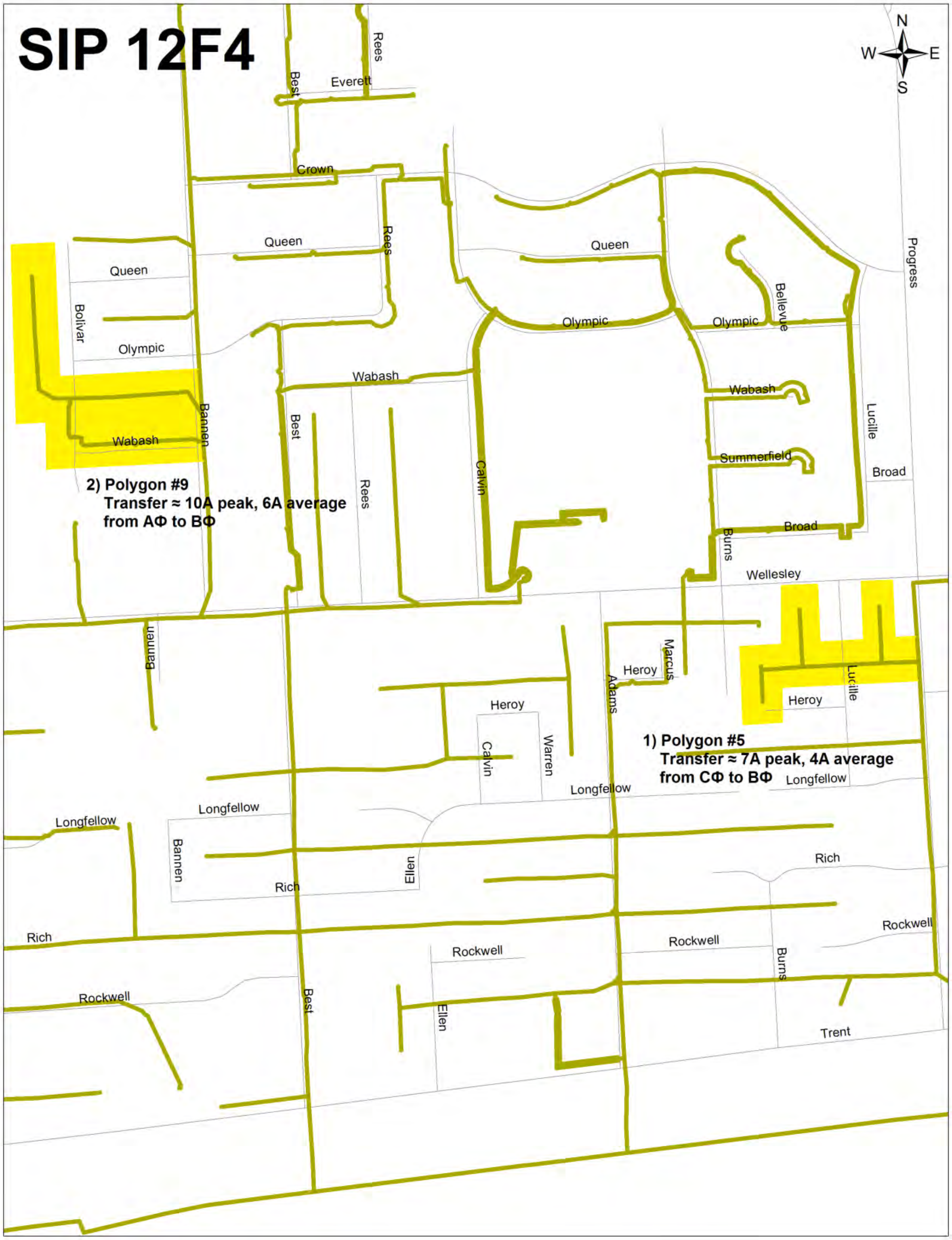


Figure 10. SIP 12F4 Load Balancing on Polygons 5 and 9

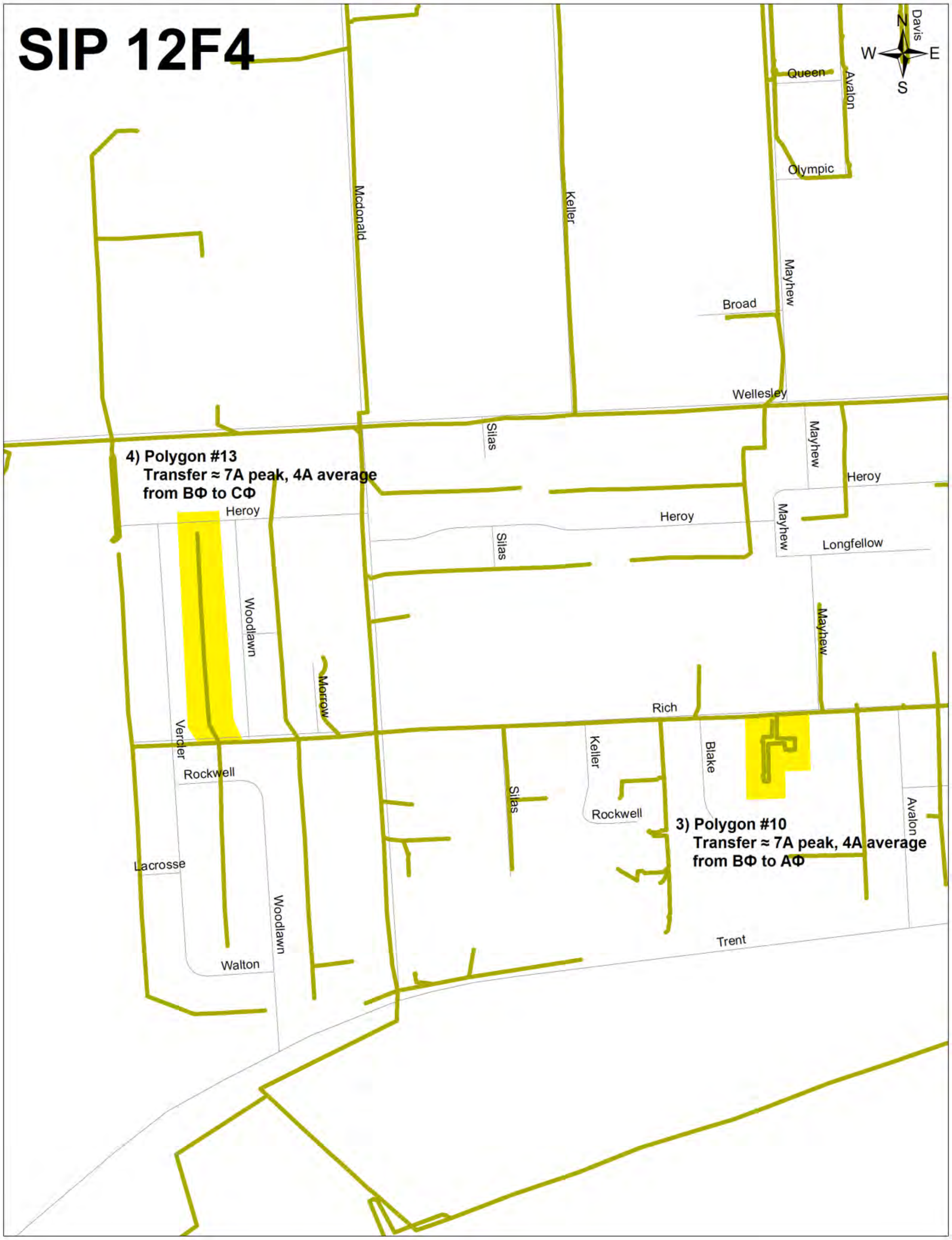


Figure 11. SIP 12F4 Load Balancing on Polygons 10 and 13

Conductor

All primary conductors on SIP 12F4 were analyzed in Synergi using the balanced peak ampacity values identified in the *Peak Loading* section of this report. Specific attention was given to conductors that have the potential for being overloaded, have relatively high line losses, serve areas with unacceptable voltage quality, and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on SIP 12F4, as well as the proposals for improving the efficiency, voltage quality, and performance of the feeder.

High loss conductors are inefficient conductors that result in increased line losses, especially where there is moderate to heavy loading. The Distribution Feeder Management Plan calls attention to higher loss conductors, with emphasis on replacing conductors that have a resistance greater than 5 ohms per mile. The Grid Modernization program analyzes all conductor sizes on a feeder to target and locate these higher loss conductors. An Engineering decision can immediately be made to replace the conductor based on loading, voltage drop, or line losses; however, a Designer may also decide to reconductor based on the effects of pole conditions and classifications, the results from the Wood Pole Management (WPM) reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

The following table lists the various types of overhead conductors that are present on SIP 12F4, as well as the approximate circuit miles of each conductor type as analyzed through the Synergi modeling software on the creation date of the model. An initial analysis suggests that the only higher loss conductors present on the feeder are approximately 1.1 circuit miles of 6CR conductor and 0.32 circuit miles of 6CW. If any of these additional conductors are found during field analysis, the Designer shall determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, and potential benefits from relocation as part of the targeted replacement of these conductors.

Approximate Circuit Miles by Conductor Type		
Conductor	**Miles**	**Ohm/Mile (50°C)**
6CR (Solid)	1.10	12.298
6CW	0.32	7.2044
4ACSR	6.33	2.4590
6A	0.97	2.4400
6CU	5.62	2.4170
2ACSR	1.95	1.5830
2CN15	2.03	1.5419
4CU	0.02	1.5196
1CN15	4.49	1.2229
1/0ACSR	0.18	1.0340
1/0CN15	0.58	0.9702
2/0ACSR	0.97	0.8430
556AAC	2.57	0.1855

The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the conductor analysis requirements for the Grid Modernization program. The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary conductor requiring attention.

SIP 12F4 was identified to contain over 13,500' circuit feet of primary distribution that is underbuilt on existing transmission lines. Approximately 8,300 circuit feet of distribution primary trunk is underbuilt on the Beacon-Boulder #1 115 kV transmission line in **Polygons 1, 4, and 7.** An additional 5,200 circuit feet of distribution primary trunk is underbuilt on the Beacon-Boulder #2 115 kV transmission line in **Polygons 12, 13, and 14**. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is underbuilt distribution to ensure the pole class is adequate for the physical loading on the structure. Figure 12 illustrates the locations where primary distribution is underbuilt on 115kV transmission.

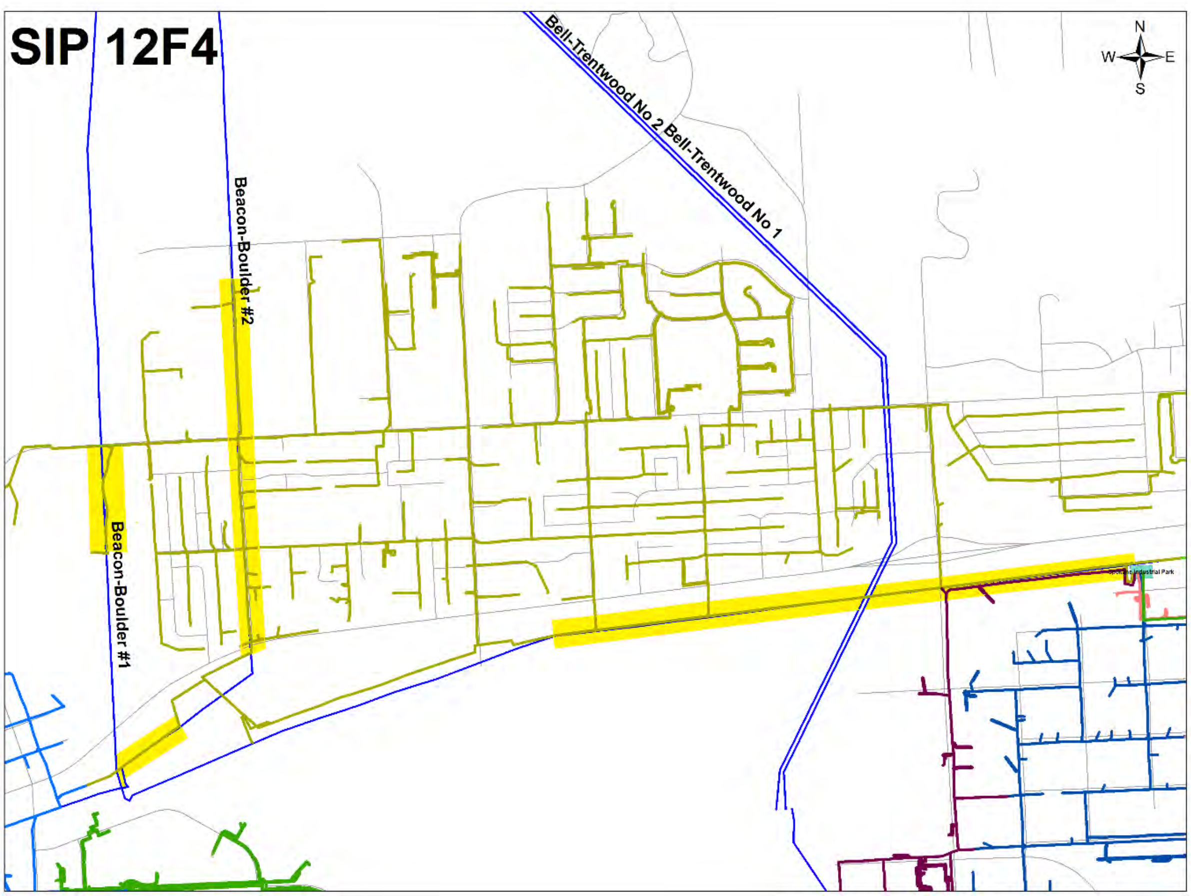


Figure 12. Underbuilt Distribution Primary on Transmission Lines

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweigh the significant work required to rebuild the existing line to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors. The ability to reconfigure and convert feeders for reliability and efficiency improvements is a characteristic that distinguishes Grid Modernization from other internal programmatic or capital work.

SIP 12F4 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, it is not likely that there are sections that would warrant reconfiguration due to proposed reconductoring, physical conditions, stubbing, and/or high resistant conductors. The assigned Designer is responsible for analyzing each polygon in conjunction with the WPM pole tests and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

Any designs to reconfigure overhead circuits or convert to underground shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements. All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconfiguration or conversion to underground prior to initiating the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, are economically justifiable, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Primary Conductor Analysis

Primary conductors have the ability to negatively affect the reliability and efficiency of a distribution circuit. Primary conductors will be analyzed to determine if they are in acceptable physical condition and modeled to assess if they are appropriately sized to serve peak loading demands and provide adequate voltage levels, and insure that they do not cause significant and unnecessary line losses. Primary conductors that do not meet these criteria will be replaced with the most appropriate standard conductor size to improve the feeder's operability, reliability, and energy efficiency.

Primary Trunk Conductor Analysis

The primary trunk conductors on SIP 12F4 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The entire feeder trunk is currently conductored with 556 AAC in overhead applications, however the large three-phase radial laterals range in conductor sizes between 6CU and 2/0ACSR. SIP 12F4 currently contains two overhead feeder ties through: switch 342 (BKR 12F2) and switch 260 (MIL 12F4). Both feeder ties on SIP 12F4 are constructed with 556 AAC conductor.

There are minimal findings to support upgrading the primary trunk conductors on SIP 12F4 based on capacity concerns given the use of the largest standardized conductor in the Distribution Construction Manual for the entire feeder trunk and feeder ties. In addition, line losses on the trunk are currently in the optimal range for both the peak and average loading scenarios, which has been aided by balancing the feeder and relatively moderate loading conditions. There are not concerns with voltage quality and under voltage scenarios that could be improved through feeder trunk reconductoring.

Any designs to reconductor primary trunk shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary trunk prior to initiating the job designs. It may be determined that additional primary or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary trunk conductors based on the conditions dictated through field analysis.

Primary Lateral Conductor Analysis

The primary lateral conductors on SIP 12F4 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The laterals on SIP 12F4 were individually analyzed to determine if the wires were sized appropriately for load, line losses, and voltage quality. The analyzed models suggest reconductoring of selective laterals to meet peak loading conditions during normal system configuration, lower line losses, and promote improved voltage levels downstream. As part of the line loss analysis, attention was given to identify the presence of high loss conductors, even if relatively low loading levels did not provide high line losses.

The following laterals should be reconductored by the assigned Designer in the field due to loading constraints and anticipated future load growth.

- **Polygon 8** – reconductor existing 6CR 1-phase overhead lateral east of N Best & E Longfellow with 4 ACSR primary and a 4 ACSR neutral (approximately 640'). The existing 6CR primary conductor is currently loaded at 14A peak, which is 80% of capacity. It is anticipated that the proposed 4ACSR primary will only be loaded to 12% of capacity. Figure 13 illustrates this proposed reconductor.
- **Polygon 10** – reconductor existing 6CU 3-phase overhead lateral south of N Evergreen & E Trent with 2/0 ACSR primary and a 2/0ACSR neutral (approximately 1230'). The existing 6CU primary conductor is currently loaded at 52A peak, which is 58% of capacity. It is anticipated that the proposed 2/0ACSR primary will only be loaded to 26% of capacity. Figure 14 illustrates this proposed reconductor.
- **Polygon 11** – reconductor existing 6CU 2-phase and 6CR 1-phase overhead lateral north of E Wellesley & N Evergreen with 4 ACSR primary and a 4 ACSR neutral (approximately 1000'). The existing 6CU primary conductor is currently loaded at 22A peak, which is 58% of capacity. In addition, the existing 6CR primary conductor is currently loaded at 19A peak, which is 103% of capacity. It is anticipated that the proposed 4ACSR primary will only be loaded to 18% of capacity. Figure 15 illustrates this proposed reconductor.

It should also be noted, that there a numerous platted residential developments that are tentatively proposed or under construction on SIP 12F4. Most of these platted developments are in **Polygons 6, 9, 11, and 12**, and north of E Wellesley Avenue. There are currently an estimated 136 new single family homes that will be served by SIP 12F4. This could equate to a 500kVA to 800kVA load increase on the circuit, under the assumption that an average new construction home ranges from 4kVA to 6kVA in load. This anticipated future load should be considered in all design work within these polygons. It may be determined that primary laterals could be reconductored as part of existing material conditions and replacement. The assigned Designer shall work with the Program Engineer to ensure that any proposed work remains within the program's scope, meets the system operations requirements, and to assist in identifying the appropriate material and equipment to install. Figure 16 illustrates the nine currently proposed platted residential developments on SIP 12F4.

In addition, the following lateral should be further examined by the assigned Designer in the field to support reconductoring to a minimum of 4ACSR. As part of the field analysis, the Designer should determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, potential benefits from relocation, etc. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program. Figure 15 identifies the primary lateral requiring additional field examination for possible replacement or reconfiguration on SIP 12F4

- **Polygon 2** – Approximately 1000' of 6CW, 26A peak (58% loaded). This three-phase, multi-span lateral serves 130 downstream customers. The physical condition of the wire, in combination with the condition of the poles, should be analyzed in the field to determine if the lateral should be reconductored. Although not necessary, it could be determined to convert this lateral to underground if it is determined that multiple pole replacements are required and the conductor is found in poor physical condition. Figure 17 illustrates this section requiring further analysis.

Any designs to reconductor primary laterals shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring primary laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address primary lateral conductors based on the conditions dictated through field analysis.

Figure 13. SIP 12F4 Primary Lateral Reconductor on Polygon 8

Figure 14. SIP 12F4 Primary Lateral Reconductor on Polygon 10

Figure 15. SIP 12F4 Primary Lateral Reconductor on Polygon 11

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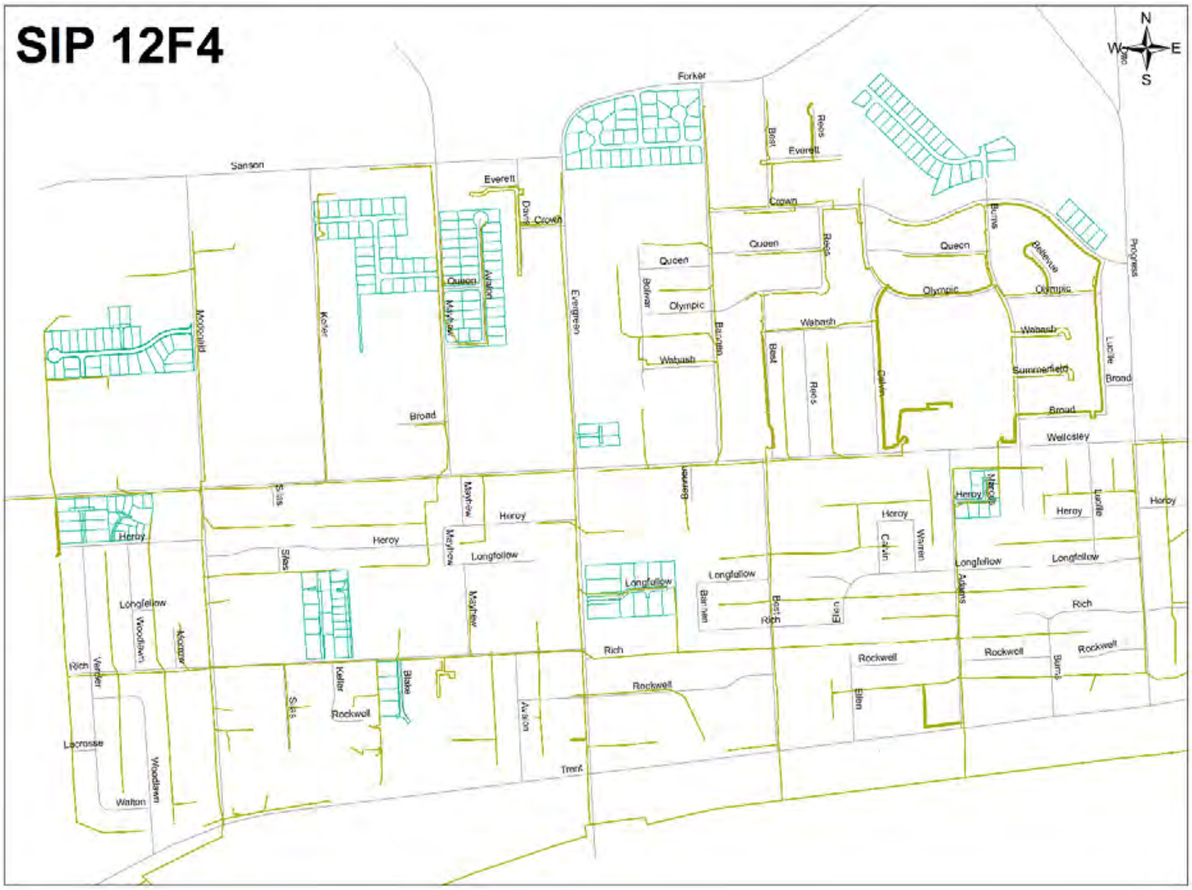

Figure 16. Platted Residential Developments on SIP 12F4

Figure 17. SIP 12F4 Primary Lateral Requiring Further Field Examination in Polygon 2

Feeder Tie Locations and Opportunities

A reduction in the duration of outages can be achieved through rebuilding existing feeder ties and establishing new feeder ties. Existing feeder ties can be improved through increased capacity by reconductoring to higher ampacity conductors, as well as replacing existing manual switches with communications devices that can either be controlled remotely or through a distribution management system (DMS). New feeder ties can be established for circuits without connections to adjacent feeders or where additional ties could provide reliability improvements. Newly created feeder ties will generally be optimized by installing switches with communications that can either be controlled remotely or through a distribution management system (DMS).

SIP 12F4 currently contains two overhead feeder ties through: switch #342 (BKR 12F2) and switch #260 (MIL 12F4). Both of these devices are currently in the form of three-phase, gang-operated manual air switches.

There was one additional feeder tie opportunity that was analyzed for SIP 12F4. A solution exists to install a new tie switch (#1114, N.O.) in **Polygon 1** close to the Spokane Industrial Park Substation with SIP 12F4 and SIP 12F3. The two feeders run parallel to each other for approximately 2000' west of the substation, but are not located on the same structures. It is desired to install a top/bottom manual air switch to establish a tie between the two circuits in this general location (see Figure 18). This can be achieved by slack spanning 556 AAC from SIP 12F4 to SIP 12F3. The manual air switch will be located on the SIP 12F3 line due to SIP 12F4 being underbuilt on transmission. The SIP 12F4 buck will land either above or below the switch depending on the selected pole's elevation. A specific location for the switch is not being provided at this time, as the structures on both SIP 12F4 and SIP 12F3 should be evaluated by the Designer in the field to determine the optimal accessible location. The Designer shall consult the Program Engineer for selecting and finalizing the location of the new manual air switch.

Even though both SIP 12F3 and SIP 12F4 are both served from Transformer #2 at the Spokane Industrial Park Substation, the creation of a new manual tie would provide improved reliability and flexibility for both circuits. Both circuits are already conductored with 556 AAC at this location, which would therefore not result in additional reconductoring to support load being transferred between the two feeders.

The decision to pursue additional feeder tie opportunities will be discussed and determined with the Regional Operations Engineer based on their anticipated frequency of using potential ties in the operation of the Spokane distribution system.

Figure 18 illustrates the location of the proposed new feeder tie between SIP 12F4 and SIP 12F3 at air switch #1114.

Figure 26 illustrates the location of the feeder ties on SIP 12F4, as well as the other distribution automation line devices.

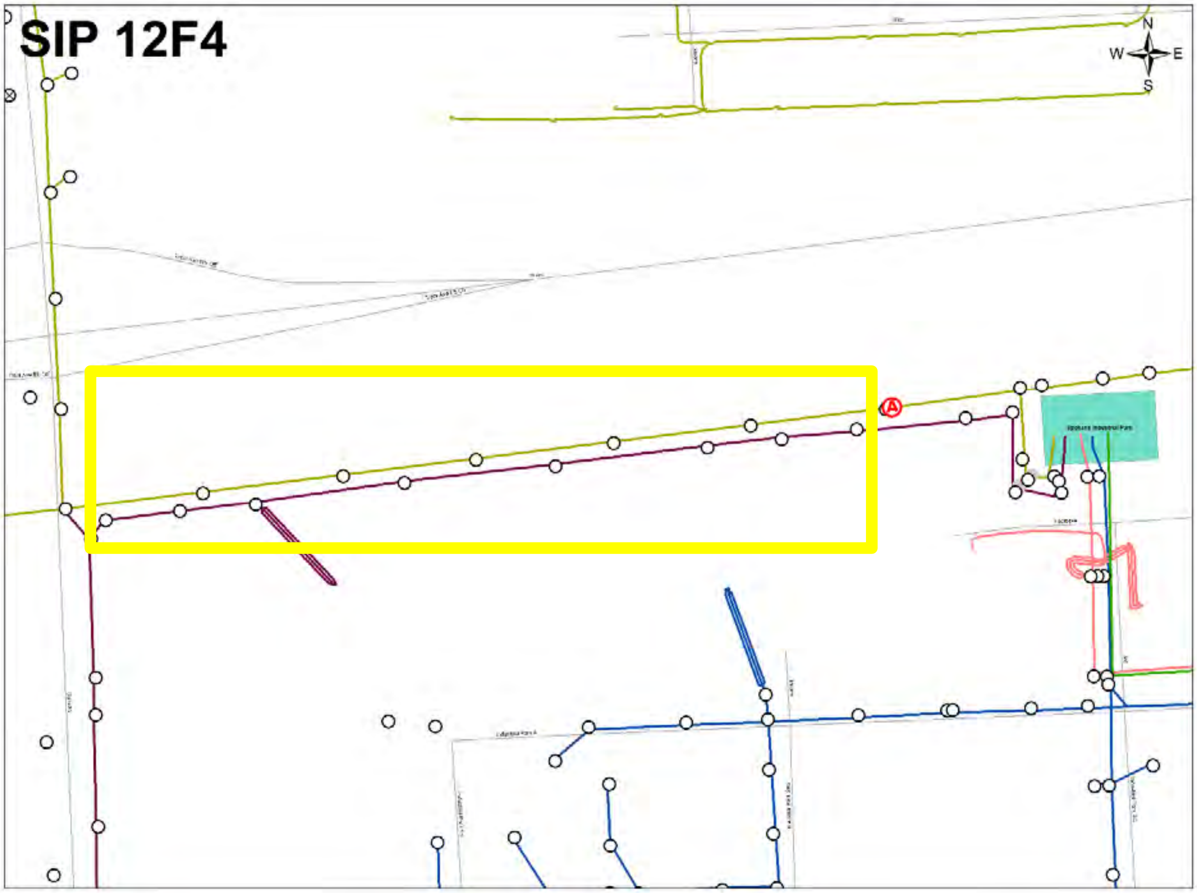

Figure 18. Feeder Tie Manual Air Switch #1114 between SIP 12F3-SIP 12F4

Voltage Quality

Service voltage at the point of delivery between the utility and the customer should be consistent to allow the safe and reliable operation of electrical equipment. Over-voltage and under-voltage situations negatively affect the service voltage that is provided, and can also be associated with inefficient operation of the distribution circuit. The Grid Modernization Program analyzes feeders to identify sections of the feeder where the service voltage level fell outside of the allowable ANSI 84.1 Range A or B operating limits. The feeder was modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. Improvements to voltage quality can first be addressed by balancing load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading. In addition, primary laterals and trunks are reconductored with more efficient conductors to increase sagging voltage levels. In some scenarios, an additional conductor phase(s) may be installed to offload a heavily loaded phase and assist in supporting the voltage.

SIP 12F4 was modeled in Synergi during both peak loading and average loading conditions, with both normal and abnormal circuit configurations.

The following information on the substation voltage regulators for SIP 12F4 was taken from Maximo, which is the system of record for Avista T&D assets. The Equipment P.T. Ratio of the voltage regulators (60.0:1) did not match the Desired P.T. Ratio (63.5:1) on the regulator controls.

Serial Numbers	A	B	C
SIP 12F4 Station Regulators	**1750001323**	**1750001324**	**1750001325**

Rated Power	**250 kVA**
Rated Current	**328 A**
C.T. Ratio	**400/.02**
Equipment P.T. Ratio	**60.0:1**
Corrected/Desired P.T. Ratio	**63.5:1**
Distribution Transformer Ratio	**63.5:1**

* Information in MAXIMO as of 6/20/18

The data in the following sections suggest that the existing voltage regulator settings at the Spokane Industrial Park Substation are providing output voltages that are higher than necessary to serve average and peak load on the circuit during normal feeder configuration. Recommendations will be provided for more optimum voltage levels for the modeled scenarios.

Voltage Quality Analysis Before Incorporating Recommendations

Figures 19 and 20 illustrate the modeled voltage levels for the various scenarios on SIP 12F4 before any proposed recommendations were incorporated into the models. Green illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V, which greater than +/- 6V of the ideal 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to SIP 12F4. During peak loading conditions, voltage levels nearest to the Spokane Industrial Park Substation, were elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.3V. The minimum voltage modeled on the feeder is 122.2V on a two-phase lateral south of E. Sanson Ave. & N. Keller Road.

Figure 19 illustrates the modeled voltage levels at peak loading on SIP 12F4 before incorporating the proposals.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	461	24.12	4453	1630
124.00 - 126.00 V	170	7.93	1301	436
126.00 - 140.00 V	0	0.00	0	0

Figure 19. SIP 12F4 Modeled Voltage Levels at Peak Loading

Modeled Voltage Levels at Average Loading

The voltage levels on the feeder were again analyzed before balancing load or incorporating conductor upgrade proposals, however this time during average loading conditions. This scenario saw slightly lower voltage levels across the feeder.

During average loading conditions, voltage levels nearest to the Spokane Industrial Park Substation, were still slightly elevated however they were still within the acceptable range. The maximum voltage modeled on the feeder occurred near the substation at approximately 124.6V. The minimum voltage modeled on the feeder is 122.7V on a two-phase lateral south of E. Sanson Ave. & N. Keller Road.

Figure 20 illustrates the modeled voltage levels at average loading on SIP 12F4 before incorporating the proposals.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	0	0.00	0	0
122.00 - 124.00 V	579	29.59	3068	1958
124.00 - 126.00 V	52	2.46	175	108
126.00 - 140.00 V	0	0.00	0	0

Figure 20. SIP 12F4 Modeled Voltage Levels at Average Loading

Voltage Quality Analysis After Incorporating Recommendations

The voltage levels on SIP 12F4 were re-analyzed after incorporating and modeling the upgrade proposals, and utilizing the proposed changes to the voltage regulator settings in the *Voltage Regulator Settings* section. The feeder was modeled with these proposals in Synergi during both Peak loading and Average loading conditions.

Figures 21-22 illustrate the modeled voltage levels for the various scenarios on SIP 12F4 after the proposed recommendations were incorporated into the models. Green illustrates voltages between 117–123 V, which are +/- 3V of the ideal 120V base. Yellow illustrates voltage levels between 114–117 V and 123–126V. Red illustrates voltage levels lower than 114V and greater than 126V, which greater than +/- 6V of the ideal 120V base and fall outside of the allowable ANSI 84.1 Range A operating limits.

Modeled Voltage Levels at Peak Loading after Proposals

The voltage levels on the feeder were analyzed after performing the identified changes and improvements to SIP 12F4. During peak loading conditions, voltage levels nearest to the Spokane Industrial Park Substation were noticeably lowered to 123.9V, which was the maximum voltage modeled on the feeder in this analysis. The minimum voltage modeled on the feeder is 120.3V on a two-phase lateral south of E. Sanson Ave. & N. Keller Road.

Figure 21 illustrates the modeled voltage levels at peak loading on SIP 12F4 after incorporating the proposals.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	380	20.38	3647	1251
122.00 - 124.00 V	250	11.67	2118	815
124.00 - 126.00 V	1	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 21. SIP 12F4 Modeled Voltage Levels at Peak Loading

Modeled Voltage Levels at Average Loading after Proposals

The voltage levels on the feeder were analyzed after performing the identified changes and improvements to SIP 12F4. During average loading conditions, voltage levels nearest to the Spokane Industrial Park Substation were noticeably lowered to 122.3V, which was the maximum voltage modeled on the feeder in this analysis. The minimum voltage modeled on the feeder is 120.6V on a two-phase lateral south of E. Sanson Ave. & N. Keller Road.

Figure 22 illustrates the modeled voltage levels at average loading on SIP 12F4 after incorporating the proposals.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	0	0.00	0	0
120.00 - 122.00 V	623	31.80	3251	2066
122.00 - 124.00 V	7	0.25	0	0
124.00 - 126.00 V	1	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 22. SIP 12F4 Modeled Voltage Levels at Average Loading

Voltage Regulator Settings

As a complement to the efforts of providing optimal voltage quality, the Grid Modernization Program analyzes and recalculates the substation and midline voltage regulator settings. This is performed to reflect the changes to loading and to address the conductor characteristics that the Program is proposing as part of the holistic upgrade and rebuild of the circuit. The feeder is modeled during both peak loading and average loading conditions, with both normal and abnormal circuit configurations. The result of the analysis is the establishment of regulator settings that bring the voltage quality back into the permissible ranges for all customers during the modeled scenarios, and to eliminate over-voltage and under-voltage situations.

SIP 12F4 has one existing stage of voltage regulation at the Spokane Industrial Park Substation. Due to the interconnected urban nature of the feeder, and the shorter feeder length, additional stages of midline voltage regulation are not recommended on the feeder to support voltage levels during normal configuration or times of switching.

The decision to move forward with implementing any changes to the voltage regulator settings will be confirmed, approved, and coordinated by the Regional Operations Engineer.

A group of alternative settings was analyzed to illustrate if there was the potential for improving voltage levels. The voltage levels on SIP 12F4 were re-analyzed and modeled with the voltage regulator settings change proposals in Synergi at peak and average loading conditions.

The existing and proposed voltage regulator settings are provided in the table below:

	Existing*		Proposed	
Forward Settings	**R**	**X**	**R**	**X**
SIP 12F4 Station Regulators	**2.0**	**6.0**	**4.2**	**2.8**

* Settings in Maximo, AFM, and SynerGEE as of 6/20/18

The recent work at the Spokane Industrial Park Substation upgraded SIP 12F4 with new CL-7 controllers to pair with the existing GE Type ML-32 station regulators. However, the existing ABB TYPE ESV1512 station breaker on the feeder was not upgraded, and would need to be replaced to the Myers Controlled Power (MCP) Type FVR low voltage vacuum circuit breaker. In addition, the Spokane Industrial Park Substation does not have SCADA. This work would need to be completed in order to make SIP 12F4 automation compatible from the substation perspective. Substation Engineering estimates that it will cost approximately $100k for the station breaker upgrade and integration, and an additional $300k for the SCADA upgrade. SIP 12F4 is not currently scheduled on any Substation Engineering list to receive a programmatic rebuild or upgrade. The necessary substation upgrades has been discussed with Substation Engineering to either address through their own capital project funding, or to pursue with the Engineering Round Table to determine support and prioritization.

Fuse Coordination and Sizing Analysis

Incorrect fuse sizes can compromise the reliability of the feeder through miscoordination of operation. Miscoordination can occur if the fuses in series are not correctly sized and managed to allow the furthest downstream device the opportunity to operate first. Fuses that are undersized and do not match the load being served can unnecessary operate and create unexpected outages. A customized fuse protection and coordination scheme has been determined to ensure that a consistent fusing philosophy is deployed and that all fuses are accurately sized.

Fuse sizing on SIP 12F4 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and underground risers. Fuse recommendations for SIP 12F4 were created by the Grid Modernization Program Engineer and approved by the Regional Operations Engineer. This file is located in the Electrical Engineering drive *c01m19* under the *SIP 12F4* folder within the *Feeder Upgrade – Dist Grid Mod* folder. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

The fuse “blowing” philosophy was selected for SIP 12F4 where the smallest fuse was selected that would accurately coordinate to: satisfy peak loading conditions, protect the downstream conductor(s), and for fuse-to-fuse coordination based on preloading of source-side fuse link (maximum fault current). A fuse “blowing” scheme is achieved by selecting the smallest allowable fuse for the first stage of protection by knowing the downstream connected kVA/phase and the largest transformer on the phase (using Distribution Construction Standard DU-2.500). If there was an upstream fuse in series with a lateral fuse, the *Distribution Feeder Protection General Guidelines* (Orange Book, S&C Table VII) was used in coordination with the fault duty found in the Synergi model to select the fuse size.

There may be situations where the transformer sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with upstream and downstream protection.

Line Losses

The distribution of electricity results in energy lost to resistance, which varies depending on the current magnitude, the resistive characteristic of the conductor(s), and the length of the conductor(s). The greater the line losses on a feeder, the higher the inefficiency. Line losses can be minimized by replacing higher loss conductors with more efficient conductors. Grid Modernization analyzes and sizes primary conductors appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and to improve voltage levels on feeders. Line losses are generally addressed by balancing load on the phases between numerous strategic locations on the feeder, and then further minimized by replacing wire with more efficient conductors.

The primary trunk conductors on SIP 12F4 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and average loading conditions during normal system configuration, and improve voltage levels on the urban feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading.

	Polygon 8	**Polygon 10**	**Polygon 11**
Circuit Length (ft)	640.7	1231.2	993.6
Existing Average kW Losses	0.1	1.4	0.1
Existing Peak kW Losses	0.2	4.3	0.3
Proposed Average kW Losses	0.0	0.4	0.0
Proposed Peak kW Losses	0.0	1.6	0.1
Average kW Loss Savings	0.1	1.0	0.1
Peak kW Loss Savings	0.2	2.7	0.2
Reconductor MWh Savings *	0.9	8.8	0.9

* Estimated average annual kW losses

An initial Synergi load study estimates that a total of 65 kW in peak line losses currently exist on SIP 12F4 (1.12%). After balancing the load on the feeder, performing the described reconductoring, and proposing adjusted station voltage regulators settings, it is estimated that peak line losses can be improved to approximately 64 kW (1.06%).

Peak Values	**Existing**	**After Balancing**	**After Reconductor**	**After Regulator Settings**
kW Demand	6140	6140	6132	6025
kW Load	6071	6073	6068	5961
kW Line Losses	65	64	61	64
kW Loss %	1.12 %	1.10 %	1.04 %	1.06 %

Transformer Core Losses

Core losses are an inherent characteristic of distribution transformers. Core losses negatively affect efficiency and do not change with fluctuation in loading. The Grid Modernization program analyzes the approximate energy savings that are achieved through the reduction in transformer core losses. Savings are obtained when transformers are replaced with more efficient units, whether being replaced due to overloading or based on PCB levels. The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more efficient. Consequently, transformer core losses are generally lower on newer units compared to a transformer of the same size from an older vintage. The transformer core losses can therefore be minimized through the replacement of older transformer to newer units of a near equivalent size.

All distribution transformers on SIP 12F4 shall be analyzed and appropriately sized to most accurately reflect the customer loads per the Distribution Feeder Management Plan (DFMP), incorporating flicker and voltage drop analysis. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the assigned Designer.

The roughly 508 distribution transformers on SIP 12F4 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It is estimated that approximately 170 transformers will require replacement based on the TCOP replacement criteria, with an additional 107 requiring replacement for being incorrectly sized to serve the connected loads. The replacement of these approximate 277 transformers will result in an estimated 31.14 kW reduction in transformer core losses. This equates to an estimated annual savings of roughly 272.79 MWh. The estimated energy savings are achieved through the use of a unique algorithm that was created: to analyze each transformer on the feeder, determine the PCB/age replacement status, determine if the transformer is sized appropriately based on actual loading, make a recommendation on the appropriate size for the load, and then use historical core loss values to calculate the approximate energy savings that are achieved. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer through verification with the Regional Operations Engineer or the local office.

Power Factor

Power factor is defined as the ratio of the real power in a circuit to the apparent power. The difference between the two values is caused by the presence of reactance in the circuit and represents reactive power that does not perform useful work, which is a form of line losses. Power factor is a value that can fluctuate with the variations in loading. The Grid Modernization Program analyzes the historical power factor scenario of up to 17,000 hourly data pars covering a desired 24 month span to calculate the apparent power and power factor. This results in comprehensive tabular and graphical representations that detail and explain the power factor performance of the feeder, the percent occurrence of lagging and leading power factors, and the severity to which a circuit could be lagging and leading, both in terms of time and quantity.

MVAR and MW data from line sensor monitoring downstream of the SIP 12F4 substation circuit breaker was analyzed from 7/7/17 to 5/8/18. It was determined that SIP 12F4 had a lagging power factor 100.0% of the time during the time interval analyzed, and a leading power factor 0.0% of the time during the time interval analyzed. Additional detailed power factor information is available upon request. Some key power factor figures for SIP 12F4 are provided in the tables below.

Maximum Lagging Power Factor	99.99%
Minimum Lagging Power Factor	95.81%
Maximum Leading Power Factor	0.00%
Minimum Leading Power Factor	0.00%
Average Lagging Power Factor	99.18%
Median Lagging Power Factor	99.72%

The graph in Figure 23 shows the percent of time during the interval analyzed where the power factor on SIP 12F4 fell between the applicable ranges. There were no recorded instances where data fell outside this range. This information is also provided in a table format.

	Lagging	Leading
99%-100%	75.53%	0.00%
98%-99%	6.42%	0.00%
97%-98%	13.91%	0.00%
96%-97%	4.02%	0.00%
95%-96%	0.12%	0.00%
94%-95%	0.00%	0.00%
93%-94%	0.00%	0.00%
92%-93%	0.00%	0.00%
91%-92%	0.00%	0.00%
90%-91%	0.00%	0.00%
80%-90%	0.00%	0.00%
70%-80%	0.00%	0.00%
60%-70%	0.00%	0.00%
Below 60%	0.00%	0.00%

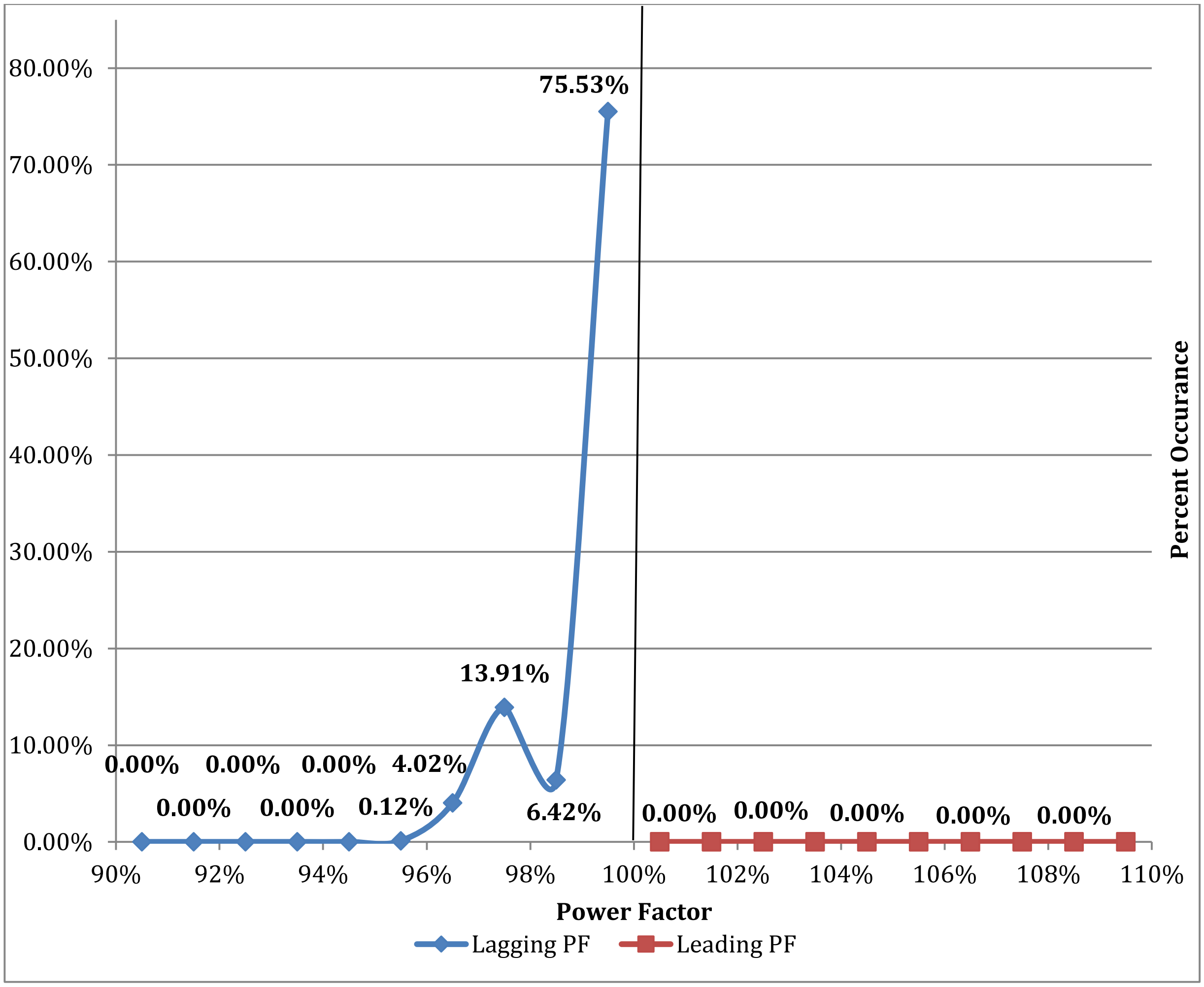

Figure 23. SIP 12F4 Existing Percent Occurance of Power Factor

Power Factor Correction

The power factor of a circuit can be corrected to offset the reactance in the system to a more optimal level and bring the circuit closer to unity. A power factor at or near unity is desirable in a power system to reduce losses and improve voltage regulation. The Grid Modernization Program corrects the circuit power factor and lowers line losses from reduced reactive power flow by analyzing the historical power factor scenarios and enacting a solution. The historical Watt and VAR data on the feeder was reanalyzed with a variable VAR to adjust the resulting power factor with the known capacitors values. This exercise allows the ideal amount of capacitance to be modeled on the circuit for the loads to optimize the power factor at variable times. In scenarios with significant or unnecessary leading power factors, existing fixed capacitor banks are removed or reduced in size. In scenarios with significant or unnecessary lagging power factors, fixed capacitor banks are installed in more severe situations to raise the power factor to a reasonable base value, and then switched capacitor banks are installed to supplement the power factor when required by loading. This approach optimizes the correction of the power factor and reduces line losses. The establishment of power factor also incorporates the field verification of existing deployed capacitor sizes, where it is not uncommon to discover capacitor banks that are incorrectly represented in Avista's GIS and modeling software.

There is one existing capacitor banks on SIP 12F4. This fixed bank is located on N. Sullivan Road south of E. Wellesley Ave. This bank was confirmed in the field by a local Serviceman to be a 300 KVAR unit (100 KVAR per phase).

The power factor on SIP 12F4 was consistently within the generally acceptable range with the existing deployed capacitor bank. The circuit consistently has a power factor between 0.96 lag and 0.99 lag approximately 99.9% of the time during the time interval analyzed. This performance is nearly optimal and provides near ideal reactive power compensation for the circuit throughout the year.

The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor with the known capacitors values. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times. After analyzing the existing devices on the feeder, it is not recommended to add or remove any capacitor banks as part of the Grid Modernization program.

To illustrate this conclusion, the feeder was first reanalyzed with the proposed removal of the 300 kVAR fixed capacitor bank and the installation of a 600 kVAR switched capacitor bank. The power factor was noticeably worsened, with the analysis suggesting that the SIP 12F4 circuit would now have a leading power factor roughly 86.3% of the time, as well as having lagging power factor at roughly 13.7% of the time. Some key power factor figures for SIP 12F4 are provided in the tables below.

Average Lagging Power Factor	98.77 %
Median Lagging Power Factor	98.78 %
Maximum Lagging Power Factor	99.95 %
Minimum Lagging Power Factor	97.09 %

Average Leading Power Factor	69.66 %
Median Leading Power Factor	76.65 %
Maximum Leading Power Factor	96.59 %
Minimum Leading Power Factor	20.75 %

The graph in Figure 24 shows the percentage of time during the re-analyzed interval where the power factor on SIP 12F4 fell between the applicable ranges with the proposed removal of the 300 kVAR fixed capacitor bank and the installation of a 600 kVAR switched capacitor bank. This information is also provided in a table format.

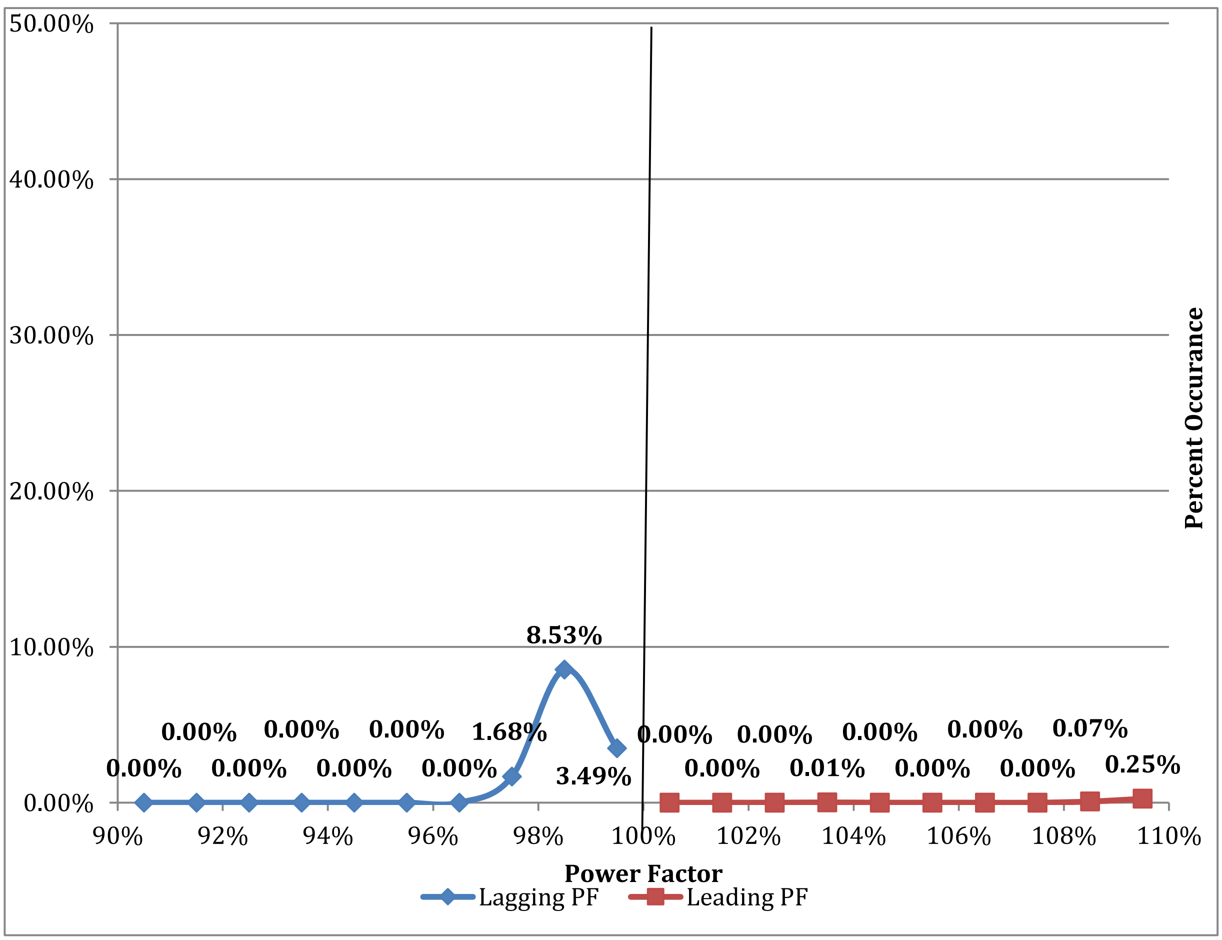

Figure 24. Proposed Percent Occurance of Power Factor with net 300 kVAR Installed

	Lagging	Leading
99%-100%	3.49%	0.00%
98%-99%	8.53%	0.00%
97%-98%	1.68%	0.00%
96%-97%	0.00%	0.01%
95%-96%	0.00%	0.00%
94%-95%	0.00%	0.00%
93%-94%	0.00%	0.00%
92%-93%	0.00%	0.00%
91%-92%	0.00%	0.07%
90%-91%	0.00%	0.25%
80%-90%	0.00%	25.54%
70%-80%	0.00%	31.22%
60%-70%	0.00%	7.72%
50%-60%	0.00%	2.14%

Next, the feeder was reanalyzed with the proposed installation of a 600 kVAR switched capacitor bank. The power factor was much worse in this scenario, with the analysis suggesting that the SIP 12F4 circuit would now have a leading power factor roughly 88.4% of the time, as well as having lagging power factor at roughly 11.6% of the time. Some key power factor figures for SIP 12F4 are provided in the tables below.

Average Lagging Power Factor	99.56 %
Median Lagging Power Factor	99.74 %
Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	98.16 %

Average Leading Power Factor	46.72 %
Median Leading Power Factor	50.03 %
Maximum Leading Power Factor	10.44 %
Minimum Leading Power Factor	99.99 %

The graph in Figure 25 shows the percentage of time during the re-analyzed interval where the power factor on SIP 12F4 fell between the applicable ranges with the 600 kVAR switched capacitor bank installed. This information is also provided in a table format.

This information of the two re-analyzed data sets illustrate what could be achieved with the power factor on the feeder. Both scenarios provided increased capacitance on the feeder that resulted in increased line losses from increased reactive power flow.

The decision to move forward with implementing any changes to the capacitors sizes and location will be confirmed, approved, and coordinated by the Regional Operations Engineer.

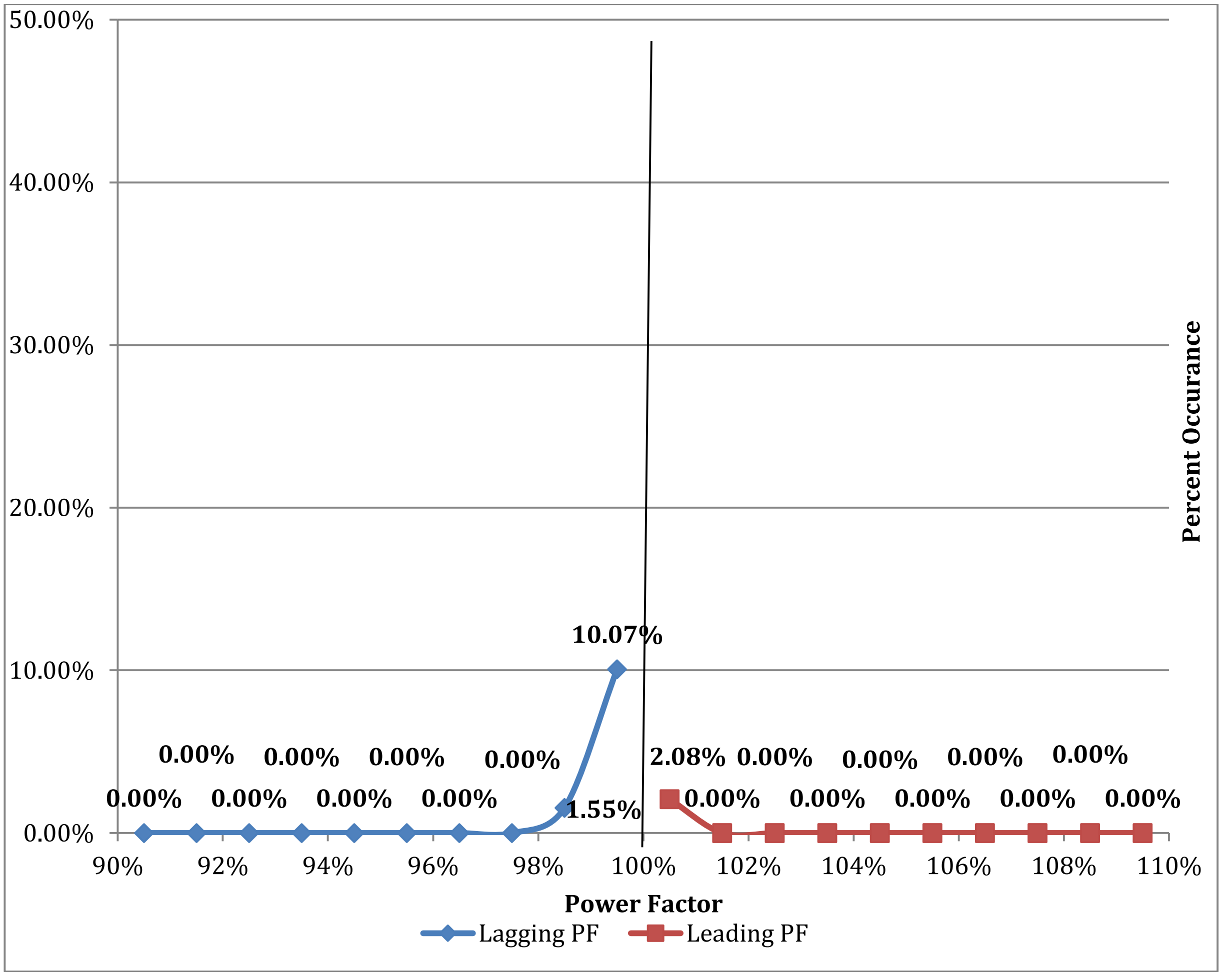

Figure 25. Proposed Percent Occurance of Power Factor with net 600 kVAR Installed

	Lagging	Leading
99%-100%	10.07%	2.08%
98%-99%	1.55%	0.00%
97%-98%	0.00%	0.00%
96%-97%	0.00%	0.01%
95%-96%	0.00%	0.00%
94%-95%	0.00%	0.00%
93%-94%	0.00%	0.00%
92%-93%	0.00%	0.00%
91%-92%	0.00%	0.00%
90%-91%	0.00%	0.00%
70%-90%	0.00%	0.19%
60%-70%	0.00%	10.60%
50%-60%	0.00%	31.41%
40%-50%	0.00%	23.28%

Distribution Automation

The Grid Modernization program currently represents Avista's largest centralized program to fully automate and improve the operating functionality and efficiency of the distribution system through the installation of automated distribution line devices. Grid Modernization has been programmatically addressing the distribution automation needs of Avista since the end of 2013, and the program focuses on installing air switches, reclosers, capacitor banks, and voltage regulators with communications and remote operability. The reduction in the duration of outages can be achieved through the installation of communications equipment that can either be controlled remotely or through a distribution management system (DMS). In addition, the number of customers impacted by an outage as well as a reduction in the frequency of outages can be achieved through the installation of devices with fault sensing and tripping capabilities. Time and cost savings can be achieved through the remote application of hot-line-holds. Fault detection, isolation, and restoration, conservation voltage reduction, and integrated volt/VAR control can also be achieved through Grid Modernization when the necessary substation equipment and components are in place.

Distribution Automation was analyzed for deployment on SIP 12F4 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on SIP 12F4.

SIP 12F4 does not currently have a midline recloser to assist in fault detection and isolation. Installing a new automated midline Viper recloser in **Polygon 4** will provide these benefits, as well as sectionalize the feeder into two near equal sections based on the modeled amps allocated by connected kVA.

- Install Viper tie switch (Z260R, N.O.) southeast of the E Trent Avenue & N Pines Road intersection in **Polygon 12** and remove the existing #260 air switch.
- Install Viper tie switch (Z342R, N.O.) south of E Trent Avenue & N Lillian Road in **Polygon 1** and remove the existing #342 air switch.
- Install Viper midline recloser (Z725R, N.C.) south of E Trent Avenue & N Ellen Road in **Polygon 4**.

The following automation devices are proposed for deployment on SIP 12F4:

Device Number	Location	Status	Device Type
Z260R	SE of E Trent Ave & N Pines Rd	N.O.	G&W Viper Switch
Z342R	S of E Trent Ave & N Lillian Rd	N.O.	G&W Viper Switch
Z725R	S of E Trent Ave & N Ellen Rd	N.C.	G&W Viper Recloser

Figure 26 illustrates the proposed automation device locations for SIP 12F4.

The existing 300 kVAR fixed capacitor bank on the feeder is a 3-bushing style capacitor bank. The DFMP states that these devices should be left in service if they are accurately sized and are in good operational condition. It was determined that the 300 kVAR device is accurately sized for the loading on the feeder. The 3-bushing style capacitor bank can be removed from service if the pole is being changed out of removed. The WPM pole inspection report does not suggest that the pole (#310131) be changed out. It is the Designer's responsibility to consult the Grid Modernization Program Engineer if is it determined that pole #310131 requires replacement. It may be determined this device would then be replaced with a similar size switched capacitor bank. Figure 27 illustrates the existing 300 kVAR fixed, 3-bushing style capacitor bank.

The recent work at the Spokane Industrial Park Substation upgraded SIP 12F4 with new CL-7 controllers to pair with the existing GE Type ML-32 station regulators. However, the existing ABB TYPE ESV1512 station breaker on the feeder was not upgraded, and would need to be replaced to the Myers Controlled Power (MCP) Type FVR low voltage vacuum circuit breaker. In addition, the Spokane Industrial Park Substation does not have SCADA. This work would need to be completed in order to make SIP 12F4 automation compatible from the substation perspective. Substation Engineering estimates that it will cost approximately $100k for the station breaker upgrade and integration, and an additional $300k for the SCADA upgrade. SIP 12F4 is not currently scheduled on any Substation Engineering list to receive a programmatic rebuild or upgrade. The necessary substation upgrades has been discussed with Substation Engineering to either address through their own capital project funding, or to pursue with the Engineering Round Table to determine support and prioritization. This information was previously discussed in the *Voltage Regulator Settings* section.

In order to promote complete automation on SIP 12F4, the Grid Modernization Program has notified Substation Engineering of the intended distribution line automation work on the circuit and the request to upgrade the necessary substation equipment. The decision on when the requested work will be performed will ultimately be made through discussions with Substation Engineering and the Engineering Roundtable.

The Grid Modernization program is not funded to perform work on adjacent feeders, including additional automation devices. Any requests to perform work on adjacent feeders are out of scope and will not be addressed by the Grid Modernization program. Separate funding would need to be pursued by the local construction office if any work is desired to be performed on adjacent feeders.

The proposed automation line device locations identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with either the Regional Operations Engineer, General Foreman, or District Manager to address any construction or Standards related concerns with the selected location.

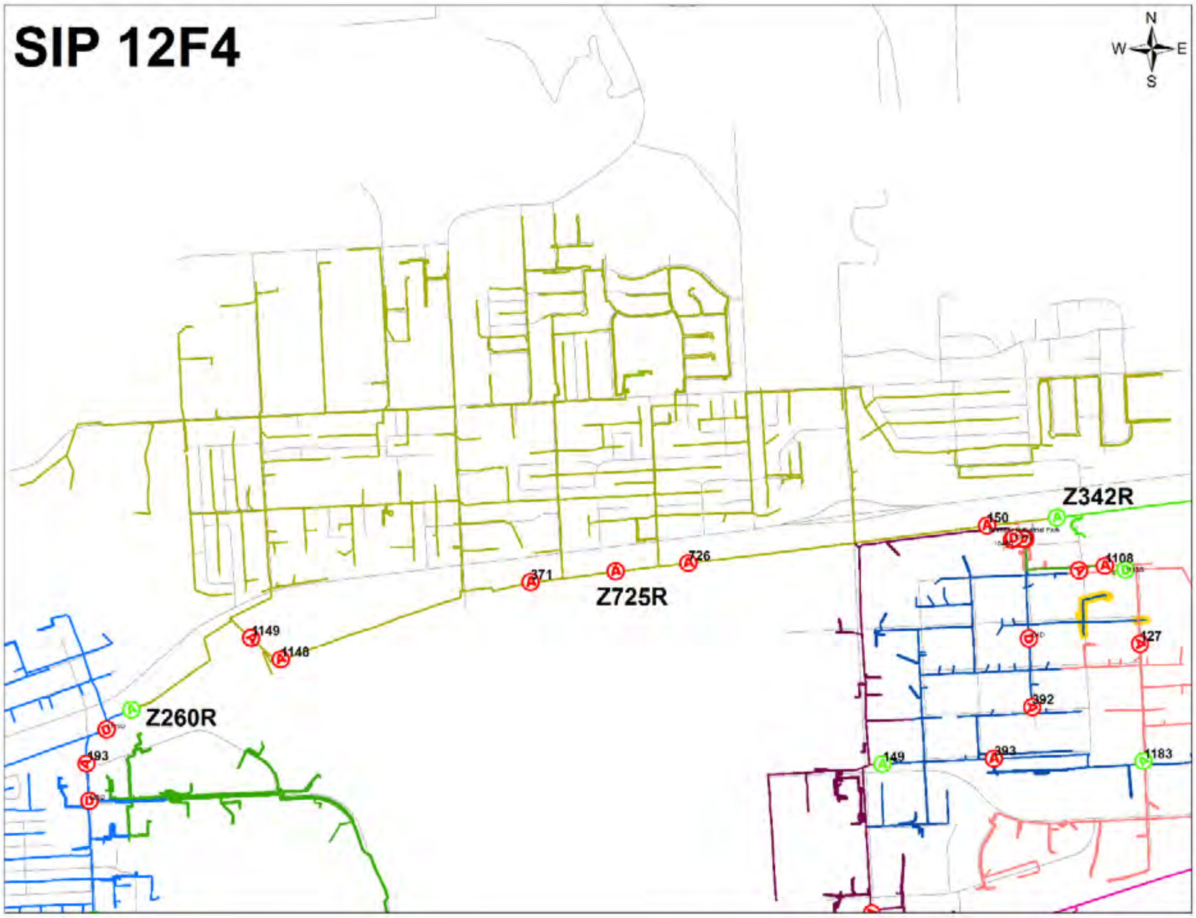

Figure 26. SIP 12F4 Automation Device Locations

Figure 27. Existing 300 kVAR fixed, 3-bushing Style Capacitor Bank on SIP 12F4

<u>Open Wire Secondary</u>

Open wire secondary districts have the ability to negatively affect reliability due to the physical nature of construction and configuration. These districts are also predominantly located in areas with high vegetation growth and limited crew access. These factors have the ability to increase the number of outages and the duration of the outages. A circuit's reliability can be improved by strategically splitting the districts with dedicated transformers and replacing these districts with an appropriately sized dedicated neutral. Grid Modernization is also initiating a study to analyze and quantify the estimated amount of open wire districts on feeders, as well as the amount requiring replacement based on the criteria of the Distribution Feeder Management Plan (DFMP). This will assist in planning and budgeting appropriately to address the needs of the feeders.

Open wire secondary districts have been analyzed for replacement on SIP 12F4 in accordance to the Distribution Feeder Management Plan (DFMP). Approximately 9,750' circuit feet of open wire secondary is currently estimated to be on SIP 12F4. This figure was established from physical observations obtained through field analysis. The existing open wire districts are almost entirely vertically constructed, and is largely located along inaccessible back lot lines. The Designers shall consult the DFMP if open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts.

Attempts were made to identify every open wire district on the feeder, however the Designer may identify districts that were not captured in this report. The Designer shall follow the same procedure and consult the DFMP if unidentified districts are present in their assigned polygons.

Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement.

Figures 28 and 29 identify the open wire secondary districts that were discovered for analysis or removal in each polygon.

- **Polygon 2**
    - Analyze whether to replace approximately 750' of vertical open wire east of Moore between Wellesley-Heroy due to the inaccessibility.
    - Analyze whether to replace approximately 400' of vertical open wire west of Moore between Wellesley-Heroy due to the inaccessibility.
    - Analyze whether to replace approximately 200' of vertical open wire west of Moore between Heroy-Longfellow due to the inaccessibility.

- **Polygon 5**
  - Analyze whether to replace approximately 300’ of vertical open wire east of Adams between Rich-Rockwell due to the inaccessibility.
  - Analyze whether to replace approximately 550’ of vertical open wire west of Adams and north of Rockwell due to the inaccessibility.
  - Analyze whether to replace approximately 400’ of vertical open wire west of Adams and south of Longfellow due to the inaccessibility.
  - of Moore between Heroy-Longfellow due to the inaccessibility.
- **Polygon 8**
  - Analyze whether to replace approximately 250’ of vertical open wire east of Calvin between Wellesley-Heroy due to the inaccessibility.
  - Analyze whether to replace approximately 200’ of vertical open wire west of Calvin and north of Longfellow due to the inaccessibility.
- **Polygon 9**
  - Analyze whether to replace approximately 1100’ of vertical open wire north of Wellesley and Bannen due to physical condition.
- **Polygon 10**
  - Analyze whether to replace approximately 600’ of vertical open wire south of Rich between Avalon-Evergreen due to the inaccessibility.
  - Analyze whether to replace approximately 500’ of vertical open wire west of Avalon and north of Trent due to the inaccessibility.
  - Analyze whether to replace approximately 450’ of vertical open wire north of Rich and Mayhew due to physical condition.
  - Analyze whether to replace approximately 550’ of vertical open wire south of Rich and Silas due to physical condition and inaccessibility.
- **Polygon 11**
  - Analyze whether to replace approximately 600’ of vertical open wire west of Wellesley and Evergreen due to physical condition.
- **Polygon 13**
  - Analyze whether to replace approximately 1200’ of vertical open wire south of Rich and west of Vercler due to the inaccessibility.
  - Analyze whether to replace approximately 700’ of vertical open wire south of Rich and between Vercler-Woodlawn due to the inaccessibility.
  - Analyze whether to replace approximately 1000’ of vertical open wire south of Rich and east of Woodlawn due to the inaccessibility.

Figure 28. Open Wire Secondary Districts on SIP 12F4

Figure 29. Open Wire Secondary Districts on SIP 12F4

Environmental

SIP 12F4 was identified to contain over 20,000’ circuit feet of distribution primary trunk and laterals that fall within the identified avian protection zone. The avian protection zones are located within **Polygons 7 through 14**. Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space. Any designs to structures within the identified avian protection zone shall adhere to the Avista Electric Distribution Overhead Construction and Material Standards, Distribution Feeder Management Plan (DFMP), and the Avista Avian Protection Plan to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements and environmental regulations. Figure 30 illustrates the avian protection zone as it relates to SIP 12F4.

SPI 12F4 contains a three-phase primary distribution river crossing that spans approximately 520’ between structures. The crossing is located south of E. Trent Avenue and east of N. Pines Road in **Polygon 12**. The structures on either side of the river (#000053 and #000056) appear to fall within the 200’ environmental shoreline buffer in Avista’s GIS mapping system. Any designs to replace or perform work on the structures within the identified shoreline boundary shall adhere to the Avista Electric Distribution Overhead Construction and Material Standards, Distribution Feeder Management Plan (DFMP), and the Avista Avian Protection Plan to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements and environmental regulations. In addition, this three-phase river crossing is underbuilt on the Beacon-Boulder #2 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work related to the river crossing structures. Figures 31, 32, and 33 illustrate the three-phase river crossing on SIP 12F4.

The Environmental Compliance department shall be consulted by the assigned Designer to provide direction and assistance on any questions related with the avian protection zone, the Spokane River shoreline, or the existing river crossing.

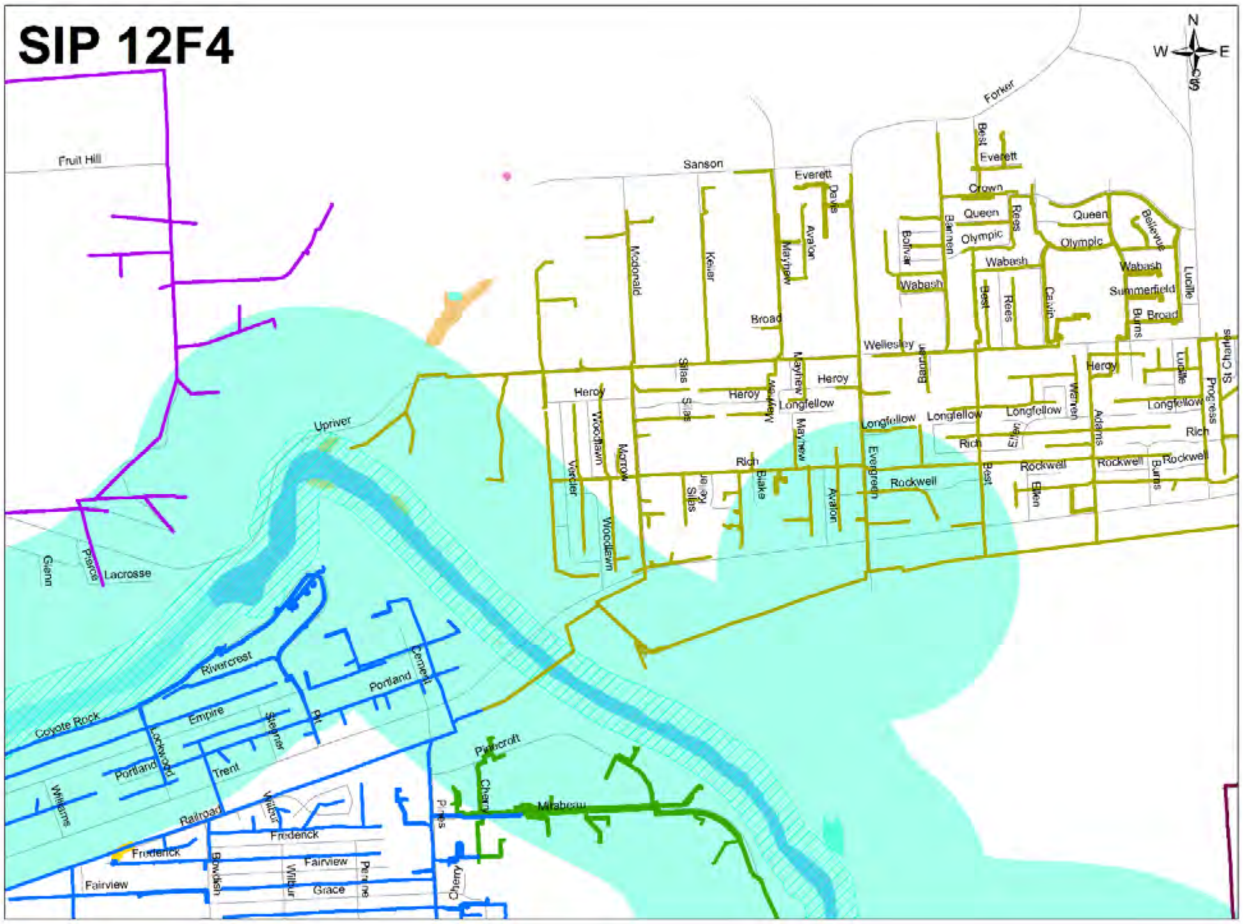

Figure 30. SIP 12F4 Avian Protection Zone and Shoreline

Figure 31. Three-Phase Primary River Cross in Polygon 12 (Looking East)

Figure 32. Three-Phase Primary River Cross in Polygon 12 (Looking Southeast)

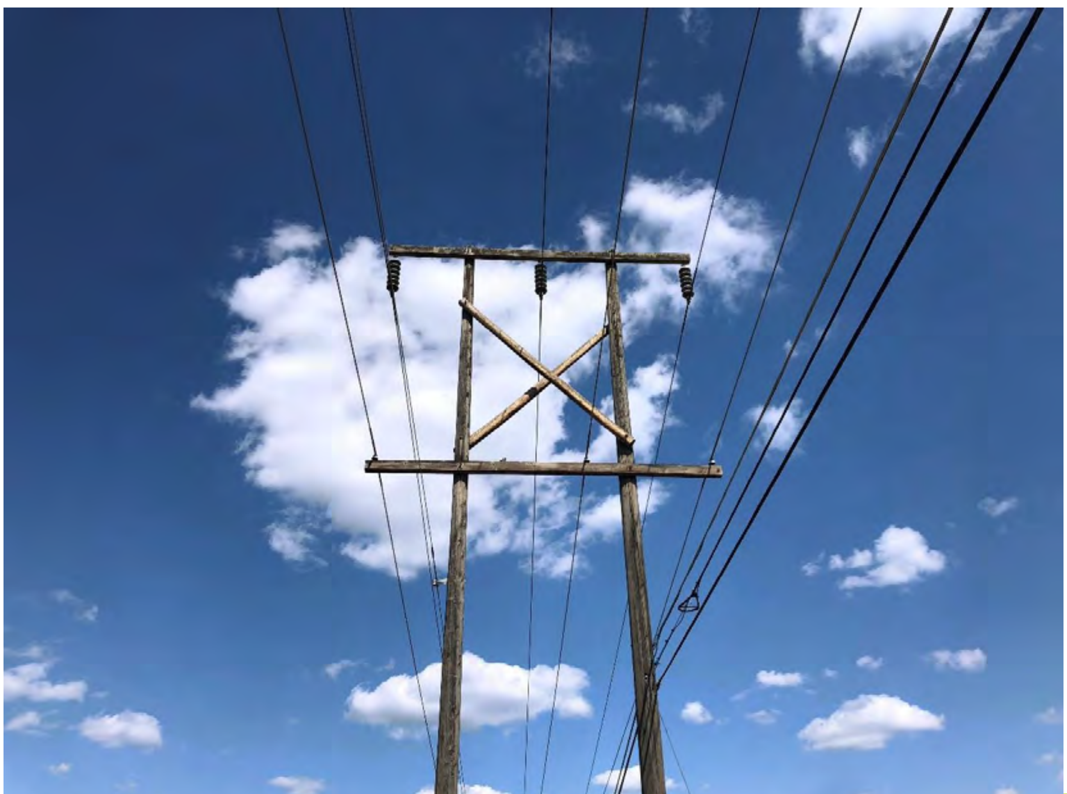

Figure 33. Three-Phase Primary River Cross at Pole #000053

Poles

All components of an overhead distribution system rely on the integrity and health of poles to ensure the system remains safe, reliable, and operational. The Grid Modernization program performs engineering and field examination of all of the poles and structures on a feeder to determine the removal, installation, replacement, or reinforcement based on requirements of the Distribution Feeder Management Plan (DFMP). A pole inspection report is requested and conducted to obtain an explicit list of poles on the feeder. The pole information from the inspection report provides detailed information for Grid Modernization to leverage in the assessment and proposals.

All poles and structures on SIP 12F4 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Wood Pole section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

A Wood Pole Management inspection of the SIP 12F4 circuit was performed from 5/14/2018 to 7/11/2018. The SIP 12F4 feeder was determined to contain 833 distribution poles at the time of analysis. The average age of distribution pole on the circuit is approximate 41 years, which places the average year of installation around 1977. 197 poles on the circuit are older than the 60 year limit for mean-time to failure, which results in the prescriptive replacement of 23.6% of wood poles at a minimum based on age alone.

The table below illustrates additional information on the inspected poles on the circuit in regards to age, condition, and pole classification.

Number of Poles on Feeder	833
Average Pole Age in Years	41 (1977)
Year of Oldest Installed Pole	1920
Poles install between 1920-1929	3 (1%)
Poles install between 1930-1939	7 (1%)
Poles install between 1940-1949	82 (10%)
Poles install between 1950-1959	160 (19%)
Poles install between 1960-1969	106 (13%)
Yellow Tagged Poles (Re-enforceable)	20 (2%)
Red Tagged Poles (Replace)	2 (1%)
Average Pole Class	4.2
Class 4 Poles or Smaller	610 (73%)
Class 5 Poles of Smaller	306 (37%)

Transformers

All transformers on SIP 12F4 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

An improvement in the number of underground primary cable outages can be achieved by strategically replacing cable that has a known susceptibility to faulting. The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. This includes the targeted replacement of all pre-1982 non-jacketed primary cable, which Avista's historical data suggests has the highest failure rate of underground cable. Problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged, which allows water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable. In addition, the Program will replace any primary cable section that has multiple documented failures for either jacketed or non-jacketed primary cable.

The URD Cable Program has identified 208 unknown segments that may be first generation non-jacketed cable. This translates into approximately 60,000' conductor feet of unknown cable on the circuit. It has been previously observed that approximately 20% of the unknown cable segments end up being identified as first generation unjacketed cable. The file containing this information is located in the Electrical Engineering drive *c01m19:\Feeder Upgrades - Dist Grid Mod\SIP12F4\~Admin\SIP 12F4 URD Segments*. Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for replacement, damage, or removal. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding the replacement of first generation non-jacketed primary cable or padmount transformers for the Grid Modernization program. Figure 34 illustrates the unknown URD cable segments on SIP 12F4. Identified unknown URD segments are located in each polygon on SIP 12F4.

Figure 34. SIP 12F4 Identified Unknown URD Cable Segments

Vegetation Management

Vegetation can pose serious reliability and safety problems for distribution feeders when not properly maintained. Trees can grow into overhead distribution lines as they mature, which creates access issues, public safety concerns, the possibility for trees or limbs to fall through the conductors, or the creation of electrical faults through physical contact. Proper vegetation maintenance along feeder corridors will remove many of these concerns while improving safety and system reliability. Vegetation Management will be included along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished between vegetation and Avista's primary and secondary conductors.

Grid Modernization's work is optimized when performed in coordination with Vegetation Management efforts. Vegetation management shall be employed on SIP 12F4 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

SIP 12F4 has been divided into 14 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Automation devices located within a polygon shall be sequentially renamed using alphabetic letters to reflect a sub-polygon (i.e. #9A, #9B, #9C, etc). Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Manager by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Figure 35 illustrates the SIP 12F4 polygons and their boundaries. The Grid Modernization Design layer on the Designer tool is available to provide more detailed boundaries of the polygons.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
    - Install Viper tie switch (Z342R, N.O.) south of E Trent Avenue & N Lillian Road and remove the existing #342 air switch.
    - Install manual tie air switch (#1114, N.O.) west of the Spokane Industrial Park Substation between SIP 12F4 and SIP 12F3. It is desired to install a top/bottom tie switch to establish a tie by slack spanning 556 AAC from SIP 12F4 to SIP 12F3. The manual air switch will be located on the SIP 12F3 line due to SIP 12F4 being underbuilt on transmission. The SIP 12F4 buck will land either above or below the switch depending on the selected elevation. A specific location for the switch is not being provided at this time, as the structures on both SIP 12F4 and SIP 12F3 should be evaluated to determine the optimal accessible location.
    - Determine if pole #310131 requires replacement. This pole contains an existing 300 kVAR, 3-bushing style fixed capacitor bank. It may be determined this device would be replaced with a similar size switched capacitor bank if the pole is identified for replacement.
    - Primary distribution is underbuilt on the Beacon-Boulder #1 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.

- **Polygon 2**
  - Approximately 1000' of 6CW, 26A peak (58% loaded) requires further field examination for possible reconductor, replacement, or reconfiguration.
  - Analyze whether to replace approximately 750' of vertical open wire east of Moore between Wellesley-Heroy due to the inaccessibility.
  - Analyze whether to replace approximately 400' of vertical open wire west of Moore between Wellesley-Heroy due to the inaccessibility.
  - Analyze whether to replace approximately 200' of vertical open wire west of Moore between Heroy-Longfellow due to the inaccessibility.
- **Polygon 4**
  - Install Viper midline recloser (Z725R, N.C.) south of E Trent Avenue & N Ellen Road.
  - Primary distribution is underbuilt on the Beacon-Boulder #1 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.
- **Polygon 5**
  - Transfer 1Φ OH lateral west of E Heroy Ave & N Progress Road (≈7 A peak loading, ≈4 A average loading) from CΦ to BΦ.
  - Analyze whether to replace approximately 300' of vertical open wire east of Adams between Rich-Rockwell due to the inaccessibility.
  - Analyze whether to replace approximately 550' of vertical open wire west of Adams and north of Rockwell due to the inaccessibility.
  - Analyze whether to replace approximately 400' of vertical open wire west of Adams and south of Longfellow due to the inaccessibility.
- **Polygon 6**
  - An estimated 136 new single family homes will be served on the circuit through numerous platted residential developments that are tentatively proposed or under construction. This anticipated future load should be considered in all design work within these polygons, to determine if primary laterals could be reconductored as part of existing material conditions and replacement.
- **Polygon 7**
  - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
  - Primary distribution is underbuilt on the Beacon-Boulder #1 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.

- **Polygon 8**
  - o Reconductor existing 6CR 1-phase overhead lateral east of N Best & E Longfellow with 4 ACSR primary and a 4 ACSR neutral (approximately 640'). The existing 6CR primary conductor is currently loaded at 14A peak, which is 80% of capacity. It is anticipated that the proposed 4ACSR primary will only be loaded to 12% of capacity.
  - o Analyze whether to replace approximately 250' of vertical open wire east of Calvin between Wellesley-Heroy due to the inaccessibility.
  - o Analyze whether to replace approximately 200' of vertical open wire west of Calvin and north of Longfellow due to the inaccessibility.
  - o Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
- **Polygon 9**
  - o Transfer 1Φ URD laterals north of E Wabash Ave & N Bannen Road (≈10 A peak loading, ≈6 A average loading) from AΦ to BΦ.
  - o Analyze whether to replace approximately 1100' of vertical open wire north of Wellesley and Bannen due to physical condition.
  - o An estimated 136 new single family homes will be served on the circuit through numerous platted residential developments that are tentatively proposed or under construction. This anticipated future load should be considered in all design work within these polygons, to determine if primary laterals could be reconductored as part of existing material conditions and replacement.
  - o Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
- **Polygon 10**
  - o Transfer 1Φ URD lateral south of E Rich Ave & N Blake Road (≈7 A peak loading, ≈4 A average loading) from BΦ to AΦ.
  - o Reconductor existing 6CU 3-phase overhead lateral south of N Evergreen & E Trent with 2/0 ACSR primary and a 2/0ACSR neutral (approximately 1230'). The existing 6CU primary conductor is currently loaded at 52A peak, which is 58% of capacity. It is anticipated that the proposed 2/0ACSR primary will only be loaded to 26% of capacity.
  - o Analyze whether to replace approximately 600' of vertical open wire south of Rich between Avalon-Evergreen due to the inaccessibility.
  - o Analyze whether to replace approximately 500' of vertical open wire west of Avalon and north of Trent due to the inaccessibility.
  - o Analyze whether to replace approximately 450' of vertical open wire north of Rich and Mayhew due to physical condition.
  - o Analyze whether to replace approximately 550' of vertical open wire south of Rich and Silas due to physical condition and inaccessibility.
  - o Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.

- **Polygon 11**
  - Reconductor existing 6CU 2-phase and 6CR 1-phase overhead lateral north of E Wellesley & N Evergreen with 4 ACSR primary and a 4 ACSR neutral (approximately 1000'). The existing 6CU primary conductor is currently loaded at 22A peak, which is 58% of capacity. In addition, the existing 6CR primary conductor is currently loaded at 19A peak, which is 103% of capacity. It is anticipated that the proposed 4ACSR primary will only be loaded to 18% of capacity.
  - An estimated 136 new single family homes will be served on the circuit through numerous platted residential developments that are tentatively proposed or under construction. This anticipated future load should be considered in all design work within these polygons, to determine if primary laterals could be reconductored as part of existing material conditions and replacement.
  - Analyze whether to replace approximately 600' of vertical open wire west of Wellesley and Evergreen due to physical condition.
  - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
- **Polygon 12**
  - Install Viper tie switch (Z260R, N.O.) southeast of the E Trent Avenue & N Pines Road intersection and remove the existing #260 air switch.
  - An estimated 136 new single family homes will be served on the circuit through numerous platted residential developments that are tentatively proposed or under construction. This anticipated future load should be considered in all design work within these polygons, to determine if primary laterals could be reconductored as part of existing material conditions and replacement.
  - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
  - Primary distribution is underbuilt on the Beacon-Boulder #2 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.
  - A three-phase primary distribution river crossing that spans approximately 520' between structures is located south of E. Trent Avenue and east of N. Pines Road. The structures on either side of the river (#000053 and #000056) appear to fall within the 200' environmental shoreline buffer in Avista's GIS mapping system.

- **Polygon 13**
  - Transfer 1Φ OH lateral north of E Rich Ave between N Woodlawn Road & N Vercler Road (≈7 A peak loading, ≈4 A average loading) from BΦ to CΦ.
  - Analyze whether to replace approximately 1200’ of vertical open wire south of Rich and west of Vercler due to the inaccessibility.
  - Analyze whether to replace approximately 700’ of vertical open wire south of Rich and between Vercler-Woodlawn due to the inaccessibility.
  - Analyze whether to replace approximately 1000’ of vertical open wire south of Rich and east of Woodlawn due to the inaccessibility.
  - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
  - Primary distribution is underbuilt on the Beacon-Boulder #2 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.
- **Polygon 14**
  - Avian protection shall be installed on all poles in the avian protection zone where work is required in the supply space.
  - Primary distribution is underbuilt on the Beacon-Boulder #2 115 kV transmission line. The Transmission Engineering department shall be consulted by the assigned Designer for any work where additional loading is being placed on the pole or reconductoring is being performed on transmission structures where there is distribution underbuilt to ensure the pole class is adequate for the physical loading on the structure.

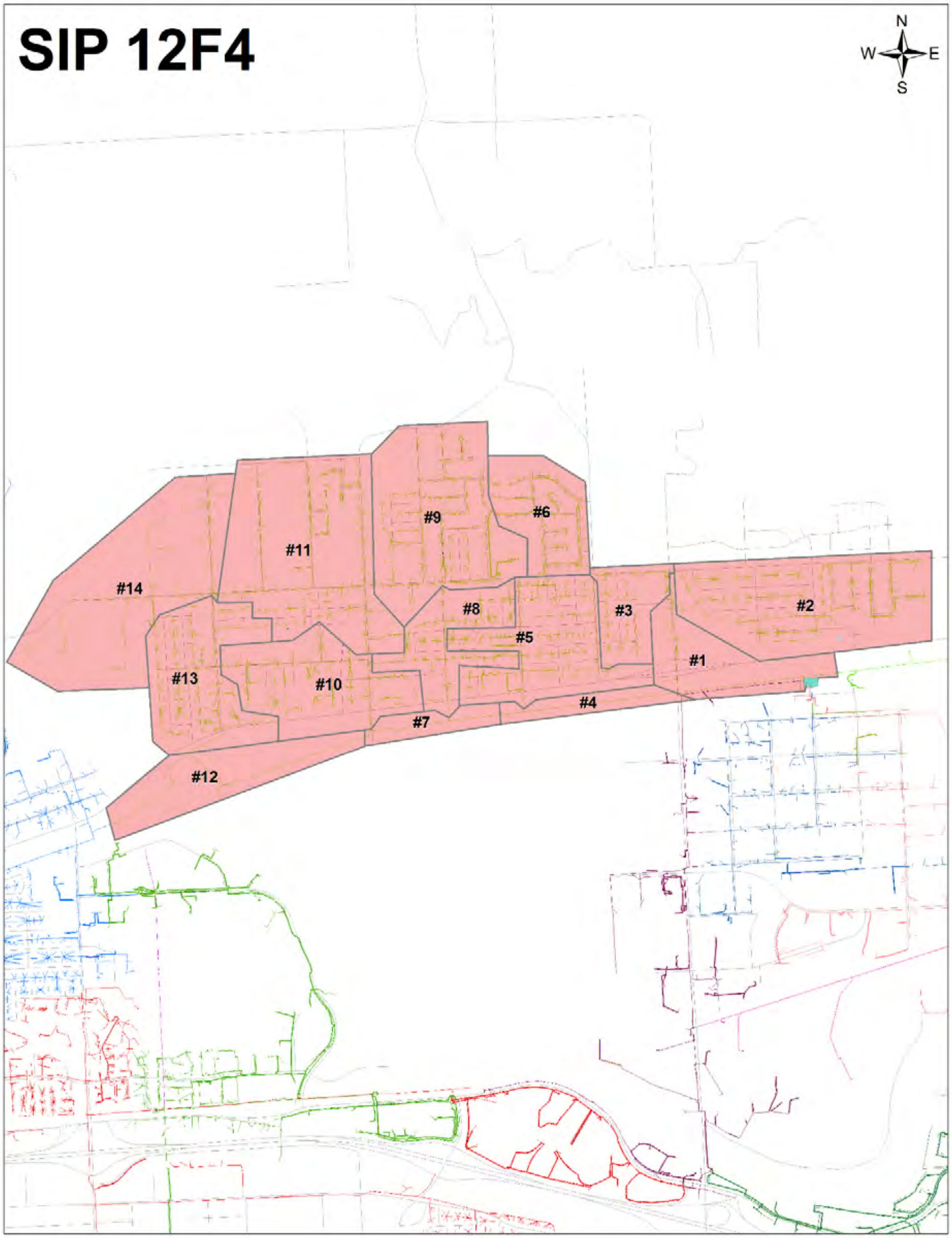

Figure 35. SIP 12F4 Assigned Polygon Numbers

Report Versions

Version 1 10/29/18 – Creation of the initial report

The figures, photos, and images found in this report can be located in c01m19:\Feeder Upgrades - Dist Grid Mod\SIP12F4\~Admin\Baseline Analysis

Grid Modernization Program

SPI 12F1 Baseline Report

4/1/2015

Version 2

Prepared by Shane Pacini

Index

SPI 12F1

The following report was established to create a baseline analysis for SPI 12F1 as part of the Grid Modernization program.

SPI 12F1 is a 12.5/7.2 kV distribution feeder served from Transformer #1 at the Spirit Substation in the Colville service area. The rural feeder has 80.53 miles of feeder trunk with 234.82 miles of laterals that serves predominately residential loads, including the town of Northport, WA. The lone feeder tie is to SPI 12F2 at the normally open E176 air switch. Additional feeder information is layered throughout the sections of this report. SPI 12F1 is represented as a bright blue color on the system map shown below.

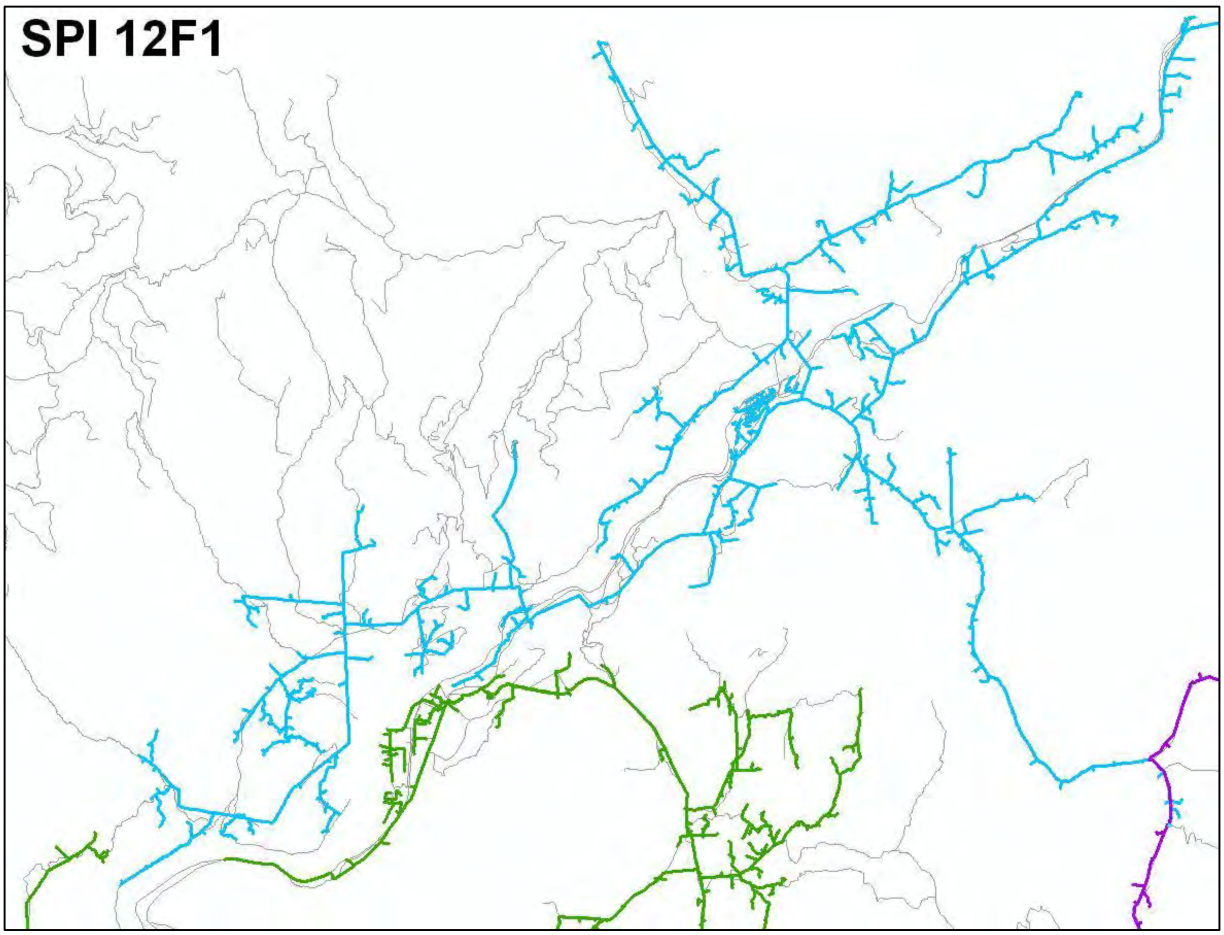

Figure 1. SPI 12F1 One-Line Diagram

Peak Loading

Three phase ampacity loading from SCADA monitoring at the SPI 12F1 substation circuit breaker was analyzed from 11/14/11 to 11/13/13, representing two continuous years of loading history in one hour intervals. The following values were established for SPI 12F1 during this timeframe. The peak loading values for each phase are used in the model analysis for the feeder, except where median load values are used for kW losses.

	Peak	Average	Median
A-Phase	125 A	40 A	41 A
B-Phase	122 A	39 A	40 A
C-Phase	146 A	51 A	51 A

Feeder Balancing

Accurate load balancing can be achieved on SPI 12F1 due to the three phase ampacity monitoring at the Spirit substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively:

	Peak Amps	Connected KVA per Phase*
A-Phase	125 A	4038 kVA
B-Phase	122 A	4968 kVA
C-Phase	146 A	4632 kVA

* Connected kVA per Phase as of 11/15/13

The following table provides laterals and dips that are candidates for effectively balancing the load on the phases between numerous strategic locations on the feeder. As a whole, the multi-phase laterals on SPI 12F1 are relatively balanced, however opportunities are available to improve feeder balancing. CPCs are recommended to design the following loads to be transferred within their assigned polygons:

- Transfer lateral on Mitchell Road (16 A) from A-Phase to B-Phase
- Transfer lateral at Sheep Creek & Hwy 25 (14 A) from B-Phase to A-Phase
- Transfer lateral at Fifteenmile Creek & Hill Loop (4 A) from C-Phase to B-Phase
- Transfer URD dip at Stoddard Mountain (3 A) from C-Phase to A-Phase

The result of these recommended load transfers will approximately balance the feeder at the substation breaker, as well as between the numerous strategic points listed in the table below:

	Current			**Proposed**		
	A-Phase	**B-Phase**	**C-Phase**	**A-Phase**	**B-Phase**	**C-Phase**
Substation Break	125	122	145	***127***	***130***	***135***
E177	117	121	134	120	128	125
Regs on Aladdin	111	114	130	114	122	120
E172	26	15	21	23	17	21
UNK Solid Doors*	24	0	17	8	16	17
UNK Air Switch*	42	38	50	42	43	45
E171	34	32	42	35	37	37
Regs on HWY 25	28	27	34	28	32	29

* Recommend assigning device numbers to UNK Air Switch south of Northport and the UNK Solid Doors south of Sheep Creek

<u>Conductor</u>

All primary conductors on SPI 12F1 were analyzed in SynerGEE using the balanced peak ampacity values identified above. Specific attention was given to overloaded conductors, conductors with relatively high line losses, and the conductors that serve areas with unacceptable voltage quality (primarily during peak conditions).

Overloaded Trunk Conductor

In general, the primary feeder conductors on SPI 12F1 are sized appropriately to meet peak loading conditions during normal system configuration. There is one section between Air Switch #E177 and the midline voltage regulators on Aladdin that is loaded slightly above 50% during peak loading; however the benefits of reconductoring this 7000' section of trunk are very minimal. Therefore, there are no sections of primary trunk that are being proposed for reconductoring due to ampacity overloading.

Feeder Reconfiguration

It is acknowledged that portions of the feeder trunk and laterals are currently located in heavily wooded areas that are also inaccessible. There is latitude within the Grid Modernization program to identify and either relocate or underground sections of the feeder when significant work is required to rebuild the line and bring the current facilities up to standard.

All proposals for reconfiguring sections of the feeder will be identified by the CPC assigned to each polygon. It is the CPC's responsibility to consult the Grid Modernization Lead Engineer on any proposals for reconfiguration prior to beginning their designs. The Engineer will work with the CPC to ensure the proposed work remains within the program's scope, and will assist in identifying the correct conductors and elements to install.

Feeder Tie

There is a reasonable possibility to construct a new feeder tie on SPI 12F1 to CLV34F1. The Colville Construction Office will be consulted on the opportunity and benefits of pursuing the feeder tie due to the associated construction challenges of selecting a route. It is possible that some sections of the primary feeder trunk on SPI 12F1 would need to be reconductored to create a reliable feeder tie. Any proposals will be amended to this document in the future.

Laterals

There are not overloaded laterals on SPI 12F1 during peak loads that would require a reconductor. In addition, there does not appear the need to install additional phases on laterals after balancing the feeder. If there are any questions on the actual sizes of conductors shown in AFM, CPCs are advised to consult a crew or serviceman for field verification to determine the actual wire sizes prior to design.

Most of the laterals on SPI 12F1 are served by high loss conductors such as 6A, 6CW, and 8CW. These specific conductors can result in significant reduction of service voltage when they are installed on long laterals. The NESC requires that service voltage levels remain within the allowable limit of 114V-126V. There are three long laterals that require reconductoring to appropriately elevate the low voltage levels that are seen at the end of the laterals during peak loads. Voltage levels at the ends of these three laterals can be significantly improved by installing a more efficient conductor with higher ampacity.

The following laterals shall be reconductored with the conductor that has been identified for each location. The CPC or designer for each polygon will be responsible for incorporating these reconductor designs on their assigned polygons, as well as incorporating an appropriately sized system neutral where required. Individual feeder one-line maps have been highlighted to illustrate the sections of the laterals requiring reconductoring. Additional information on voltage quality can be seen in the “Voltage Quality” section later in the report.

- Reconductor the entire 1-phase lateral along Northport Waneta from 8CW to 4 ACSR (approximately 47,000 feet)
- Reconductor the entire overhead section of the 1-phase lateral near Lael & Northport Flat Creek from 8CW to 4 ACSR (approximately 13,000 feet)
- Reconductor the entire 3-phase lateral north of Aladdin & Hwy 25 from 4CW to 2/0 ACSR (approximately 17,000 feet)

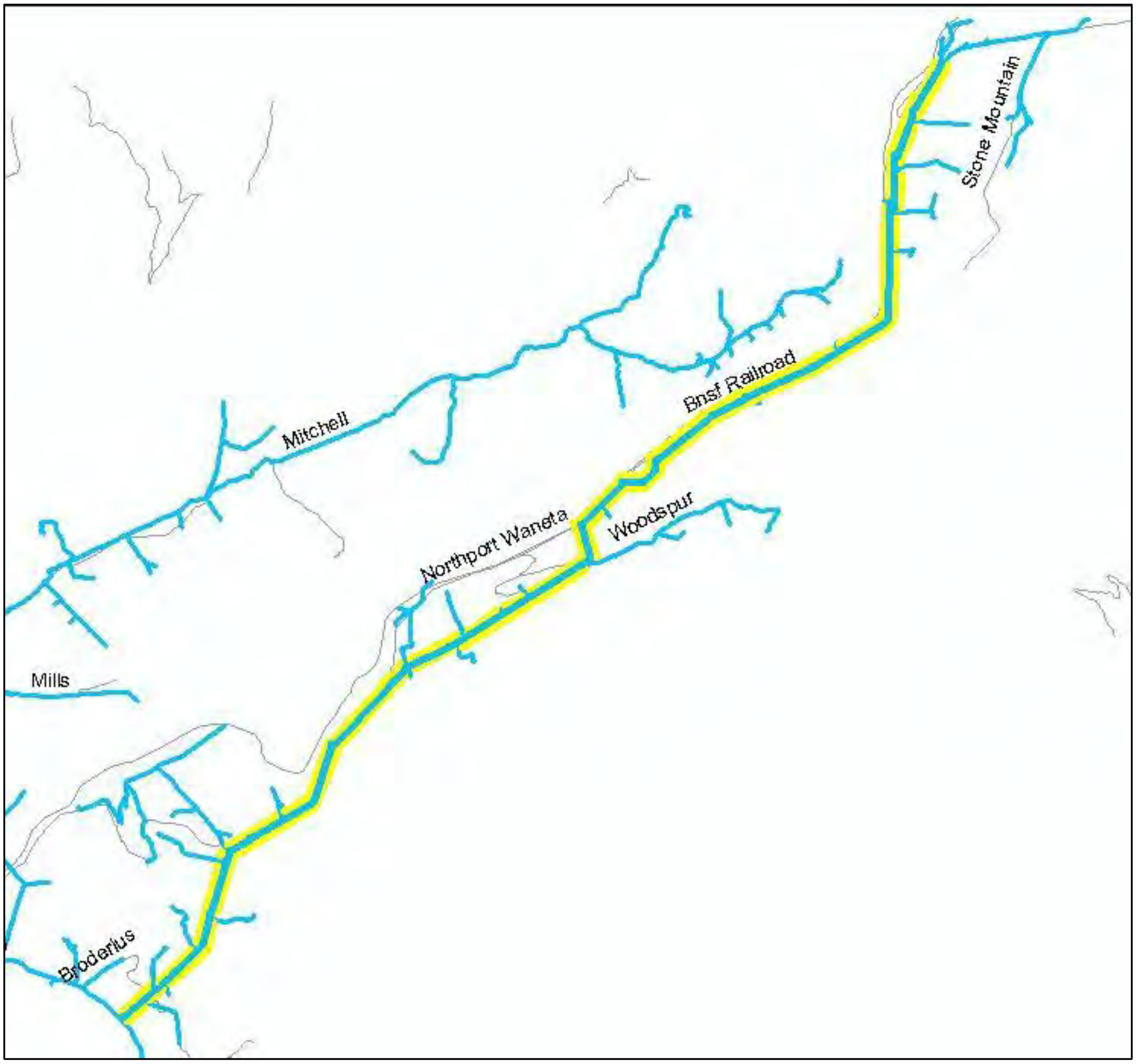

Figure 2. Section 1 Primary Reconductor to 4 ACSR

Figure 3. Section 2 Primary Reconductor to 4 ACSR

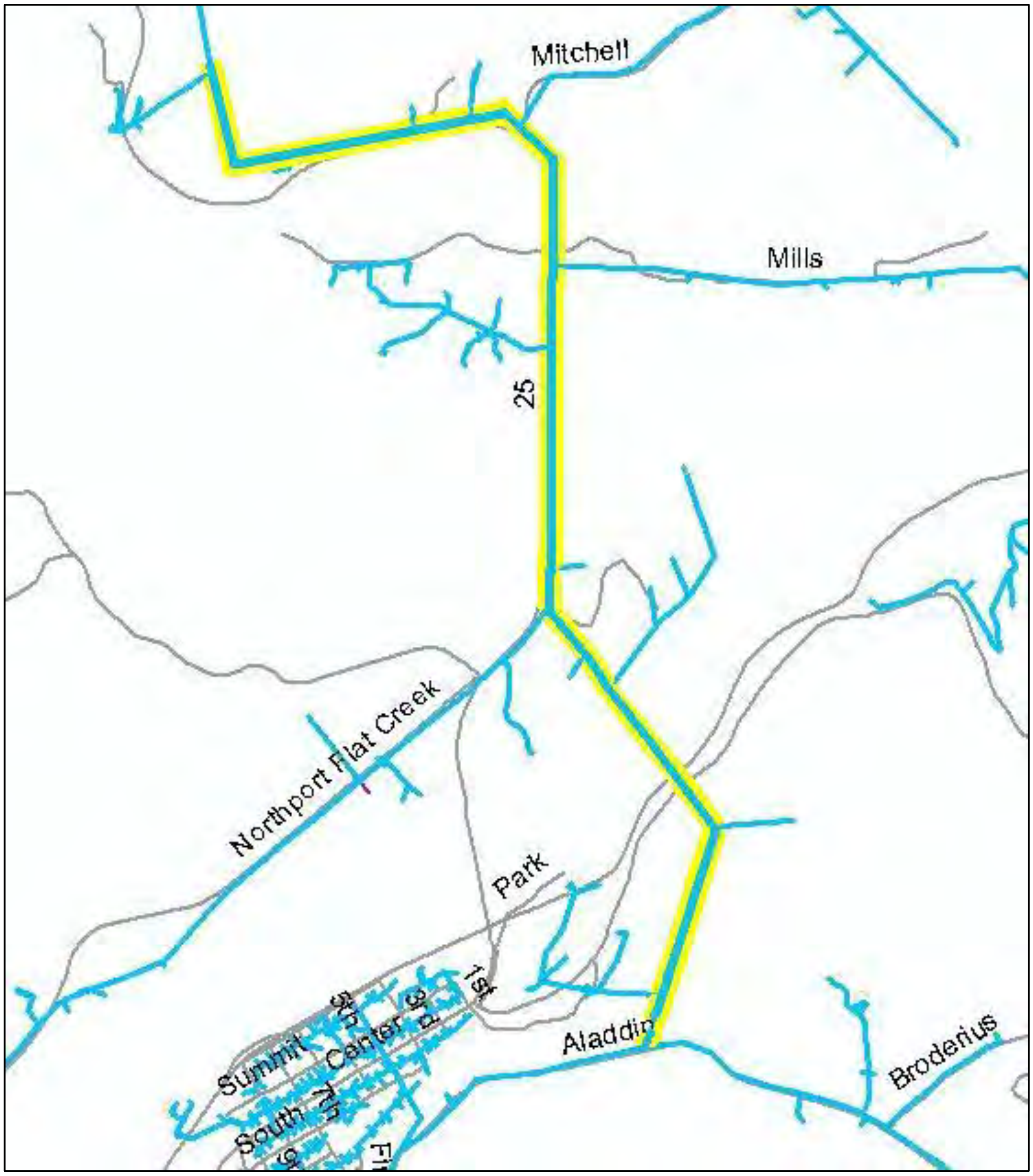

Figure 4. Section 3 Primary Reconductor to 2/0 ACSR

Voltage Quality

There are inherent voltage quality issues on SPI 12F1 due to the length of the trunk and laterals. Three stages of voltage regulation have been installed across SPI 12F1 in an attempt to accurately refine the voltage levels at all points on the feeder. However, the initial models show that numerous voltage quality issues are still present. Correcting the voltage levels and quality on SPI 12F1 required a multi-step approach to optimize the system while minimizing the costs associated with the improvements.

The feeder was first balanced to eliminate any unnecessary voltage problems. SPI 12F1 needed to be effectively balanced at numerous switching and regulation points on the feeder, especially on long laterals. These proposals were previously outlined in the "Feeder Balancing" section of this report.

Sections of the feeder were next identified where the service voltage level fell outside of the allowable limit required by the NESC (114V-126V). There were three laterals that had significantly low voltage levels. These three laterals were reconductored to replace the inefficient wire with conductors that will result in less voltage drop. These proposals were previously outlined in the "Conductor - Laterals" section of this report

Voltage Regulator Settings

The settings for the three stages of voltage regulation on SPI 12F1 have been recalculated to provide the most optimal voltage levels across the feeder. The following changes to the regulator settings are recommended to improve the voltage quality on SPI 12F1. The revised voltage regulator settings will supplement the changes made through reconductoring to bring the voltage levels on the feeder to within the allowable limit. The Grid Modernization Lead Engineer will work with the Regional Engineer and the Electric Shop to confirm and establish the new settings.

Forward Settings	Current		Proposed	
	R	X	R	X
Substation Regulators	8.4	6.5	4.6	9.4
Stage 1 Midline Regulators on Aladdin	3.0	3.0	3.6	1.8
Stage 2 Midline Regulators on Hwy 25	2.0	1.0	8.4	2.9

The SynerGEE models originally identified 590 voltage level exceptions on SPI 12F1 during peak loads. It is estimated that only 17 exceptions will remain on the feeder after the proposed balancing, lateral reconductors, and changes to the voltage regulator settings. It should be noted that a majority of the remaining exception warnings are low voltage readings that are at 114V, which is the lowest allowable service voltage level.

The following table summarizes the current voltage levels that are seen on the major laterals of SPI 12F1 during peak loading conditions. The values have been color coded to illustrate the severity of the voltage level. The voltage levels on these laterals will all be brought within the allowable limits during peak loads after the proposed lateral reconductors and changes to the regulator settings are made.

		Voltage	
	Phase	**Current**	**Proposed**
North Hwy 25	C	109.9 - 114.4	114.9 - 120.5
Mitchell	A	114.1 - 115.5	118.6 - 119.8
(NE) Flat Creek	A	116.0 - 119.1	116.9 - 120.8
Northport Waneta	B	103.5 - 121.1	117.0 - 122.2
Wright	A	117.2 - 118.4	117.9 - 119.1
Hubbard Mine	C	120.2 - 120.4	122.5 - 123.1
BNSF Railroad	A	122.8 - 123.0	124.1 - 124.3
Vineyard	C	118.5 - 118.7	121.2 - 121.4
Bull Hill	C	116.1 - 117.1	119.0 - 120.3
Lael	C	116.9 - 117.2	119.9 - 120.1
Butorac	B	113.2 - 115.0	114.7 - 115.5
Critter	B	117.3	115.7
China Bend	A	119.7	120.6
Fifteen Mile Creek	C	116.6	119.0 - 120.2
(SW) Flat Creek	A	119.5	120.4

Fuse Sizing

Fuse sizing on SPI 12F1 shall be verified and incorporated into all designs associated with Grid Modernization. This includes fusing for transformers, laterals, and on the feeder trunk (where applicable). The CPC for each polygon will be responsible for accurately sizing all fuses within their assigned polygons. The CPC shall consult the Grid Modernization Lead Engineer with any questions regarding fuse sizing and coordination on SPI 12F1. In addition, the CPC shall consult the Distribution Feeder Management Plan document for specific parameters regarding fuse application and replacement.

Losses

SPI 12F1 does not contain significant sections of the feeder with high line losses. The peak load seen on the feeder is relatively low (balanced peak average of 131A per phase), and the conductor sizes across the feeder reflect the lower loads. Thus, an initial SyngerGEE load study estimates that a total of 328 kW in peak line losses currently exists on SPI 12F1 (11.61%). This is the cumulative result of over 200 miles of laterals with high loss conductors. The losses on these laterals can be improved, however the high costs associated with reconductoring each lateral does not alone justify the small loss savings that would be captured with each small reconductor.

	Section 1	**Section 2**	**Section 3**
Length	46,800'	13,000'	39,400'
Reconductor Material Cost	$18,200	$5,100	$8,200
Current Ave kW Losses	2.1	0.6	1.8
Current Peak kW Losses	15.5	4.9	14.4
Proposed Ave kW Losses*	0.0	0.1	0.2
Proposed Peak kW Losses	3.5	1.1	4.6
Average kW Loss Savings	2.1	0.5	1.6
Peak kW Loss Savings	12.0	3.8	9.8
Peak $/kW**	$1,954	$415	$629
Conductor MWh Savings (Average) ***	26.3	8.8	28.0

* Losses are estimated as negligible and near zero
** Material cost only
*** From estimated average kW losses over two year span

If the proposed reconductoring of the system is performed on SPI 12F1, it is estimated that the peak line losses would be reduced by 25.6 kW, while the average loading line losses would be reduced by approximately 4 kW. In addition, 63.1 MWh savings could be captured over a two year span assuming average loading conditions from the feeder reconductor.

Peak Values	**Current**	**Section 1**	**Section 2**	**Section 3**
kW Demand	2899	2897	2896	2895
kW Total Losses	337	323	320	310
kW Loss %	11.61 %	11.17 %	11.03 %	10.69%
kW Line Losses	328	315	311	301

Transformer Core Losses

Core losses are an unavoidable characteristic of distribution transformers. Core losses are the dissipation of power that would ideally be transferred through the transformer, but that are however lost through the magnetizing current needed to energize the core of the transformer. These losses occur whenever the primary bushes of a transformer are energized, and occur regardless of having a connected load – thus being called “No Load Losses”. Core losses do not vary according to the loading on the transformer, and occur 24 hours a day.

The review of historically purchased transformers illustrate that Core Losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, No Load Losses are generally lower on newer units compared to a transformer of the same size from an older vintage. No Load Losses can therefore be minimized through the replacement of older transformer to newer units of the correct size.

All transformers on SPI 12F1 shall be analyzed and “right sized” by the assigned Designer to most accurately reflect the customer loads. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department.

The roughly 627 distribution transformers on SPI 12F1 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determine the correct transformer size. It was determined that 219 transformers will require replacement based on right sizing and the TCOP replacements. The replacement of these transformers will result in an estimated 9.49 kW reduction in No Load Losses. This equates to an annual savings of roughly 83.2 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer.

Power Factor

MVAR and MW data at the SPI 12F1 substation circuit breaker was analyzed from 11/14/11 to 11/13/13, representing two continuous years of loading history in one hour intervals. It was determined that SPI 12F1 had a lagging power factor at all times during the 2-year interval analyzed. Detailed power factor information is available upon request. Some key power factor figures for SPI 12F1 are provided in the tables below.

Average Lagging Power Factor	67.93 %
Median Lagging Power Factor	84.5 %
Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	00.87 %

The table below shows the percent of time over the two continuous years of loading history where the power factor on SPI 12F1 was greater than the corresponding lagging power factors, without ever becoming a leading power factor:

Greater than 99% Lagging	3.02 %
Greater than 98% Lagging	11.20 %
Greater than 97% Lagging	19.21 %
Greater than 96% Lagging	26.74 %
Greater than 95% Lagging	31.91 %
Greater than 90% Lagging	45.30 %

The graph in Figure 5 shows the existing percentage of power factor occurrence during the interval analyzed on SPI 12F1.

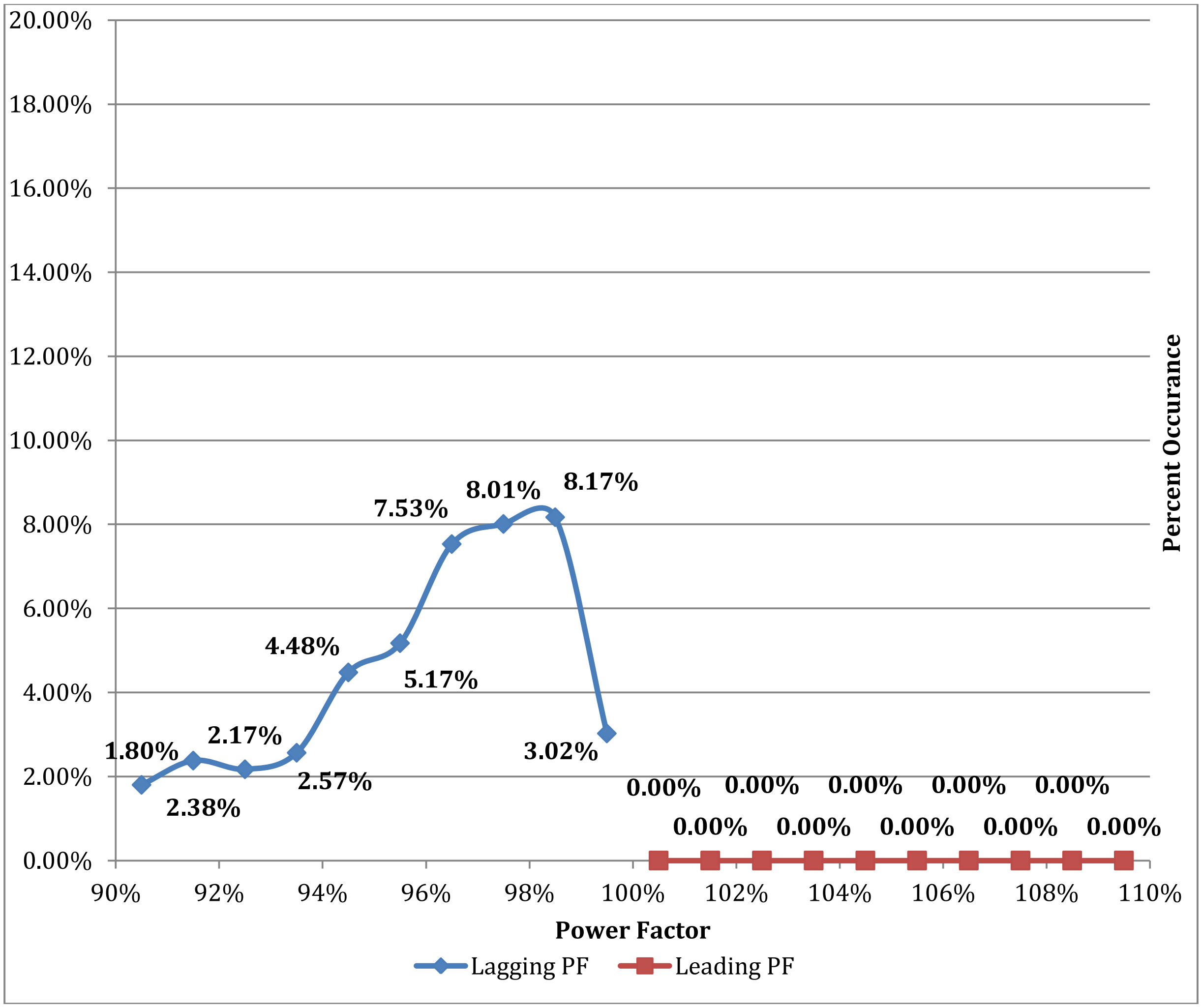

Figure 5. Existing Percent Occurance of Power Factor

Power Factor Correction

The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times.

The feeder was reanalyzed with numerous scenarios and combinations of switched capacitor banks. The installation of one 300 kVAR fixed capacitor bank, and one 600 kVAR switched capacitor banks would greatly improve the power factor on the feeder, and match the fluctuating reactive power flow due to the hydro co-generation on the feeder. The location of the switched capacitor banks was selected with the assistance of the placement model in SynerGEE, as well as the proximity to the larger inductive load centers on the feeder. A feeder one-line diagram with the location for the proposed capacitor banks is shown in the *Automation* section of this report.

The graph in Figure 6 shows the proposed percentage of power factor occurrence during the interval analyzed on M23 621 with the 600 kVAR switched capacitor bank installed.

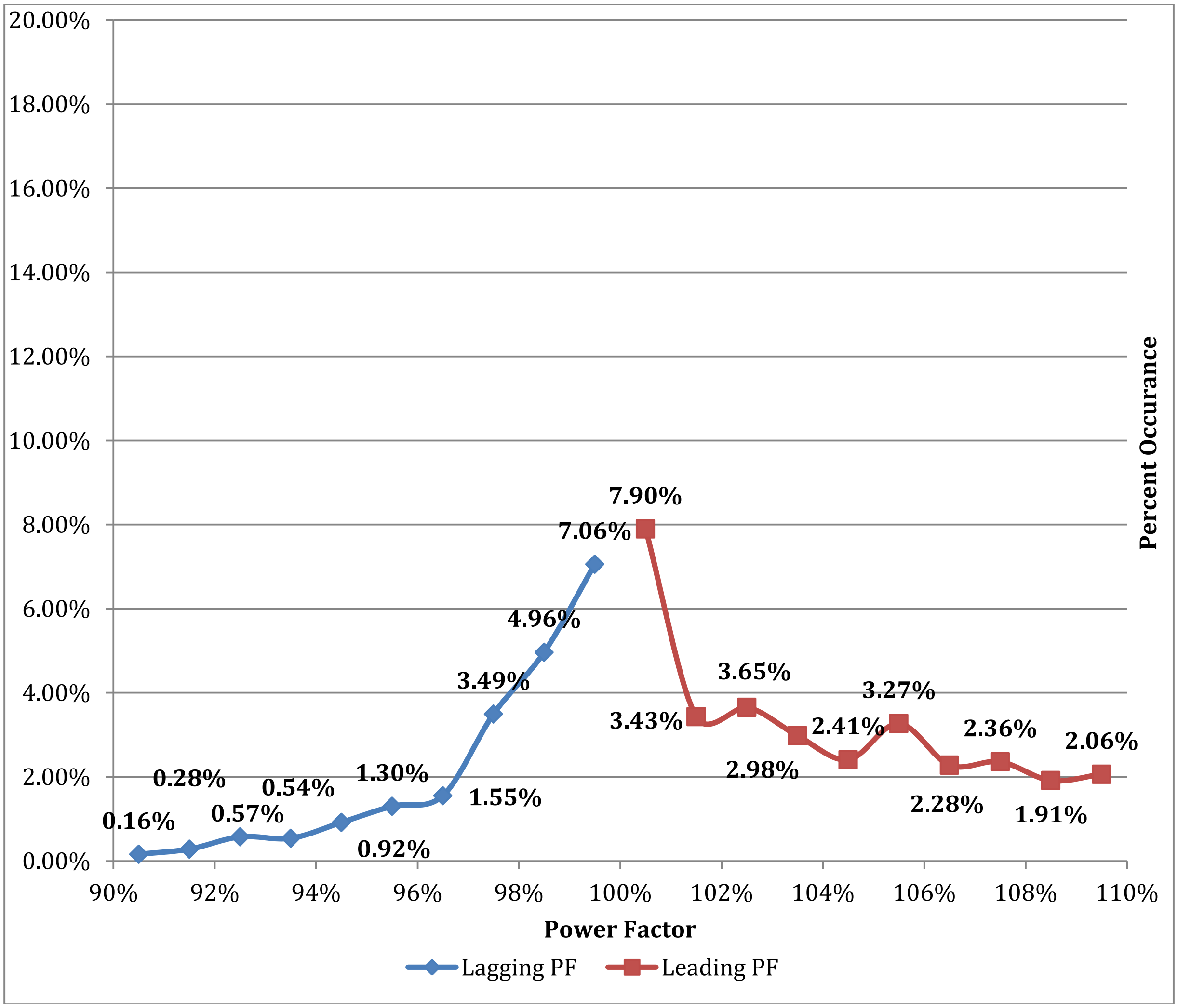

Figure 6. Proposed Percent Occurance of Power Factor

Automation

Distribution Automation will be pursued on SPI 12F1 as part of the Grid Modernization program. A customized solution for this feeder has been created to address the specific characteristics and issues associated with the load, customers, configuration, and geography on SPI 12F1. The final automation proposal on SPI 12F1 will ultimately be determined by the availability of wireless/remote communication throughout the feeder, as well standard automated devices that are approved for deployment.

SPI 12F1 does not currently contain ties to adjacent feeders.

The following automated devices will be deployed on the feeder:

Device Number	Location	Status	Device Type
ZE171R	Old Norhtport Hwy & Wright	N.C.	Viper – Recloser
ZE172R	W of Alladin & Broderius	N.C.	Viper – Recloser
ZE173R	SE of Northport Flat Creek & Hubbard Mine	N.C.	Viper – Recloser
ZE174F	W of WA Hwy 25 & Mitchell	N.C.	Switched 600 kVAR Cap

Figure 7 illustrates the proposed automation device locations on SPR 761.

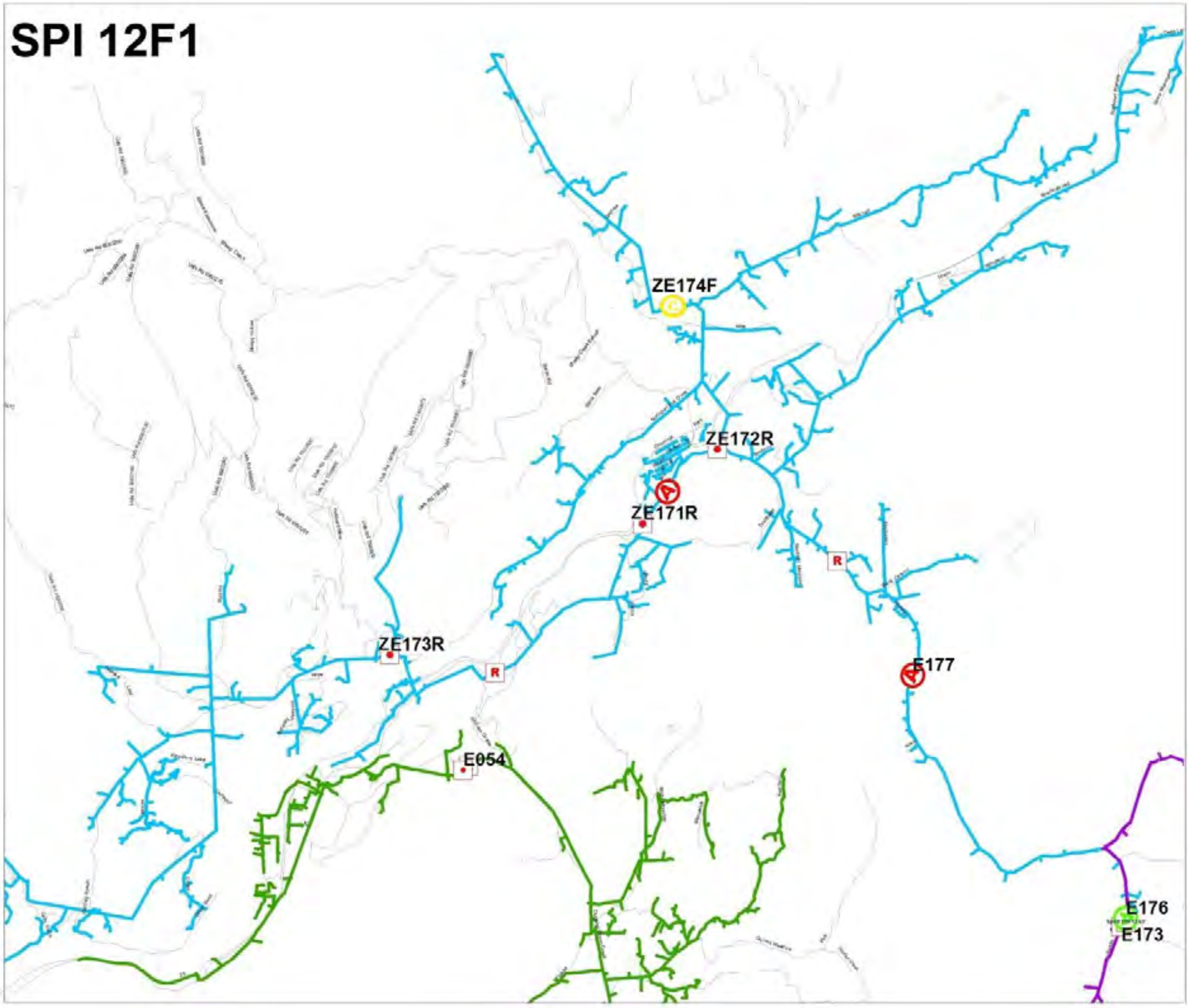

Figure 7. Proposed Automation Device Locations

Open Wire Secondary Districts

It is not believed that there are open wire secondary districts on SPI 12F1. This was established from physical observations obtained through field analysis. The Feeder Upgrade Scoping & Design Criteria Standard manual should be consulted if designer(s) discover open wire secondary districts on the feeder. This document will provide detailed information on when open wire secondary districts should be replaced. If there are any design questions associated with open wire secondary districts, they should be directed the Grid Modernization Program Engineer to provide guidance on replacement.

Transformers

All transformers on SPI 12F1 shall be identified by the assigned Design for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by TCOP. However all transformers shall be analyzed and “right sized” by the Designer to most accurately reflect customer loads. The Designer shall consult the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Poles

All poles and structures on SPI 12F1 shall be examined by the assigned Designer for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Wood Pole Management (WPM) department based on the tested condition of the structure, however the decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

Design Polygons

The SPI 12F1 feeder has been divided into 43 polygons for the Grid Modernization project work. These polygons were created with assistance from the Palouse Operations Engineer. The polygons were created in an attempt to divide the work into near equivalent segments in regards to design and crew time. Additional considerations such as automation devices, reconductoring, geography, road access, and location of laterals further assisted in defining the boundaries of the polygons. Additional polygons can be created if necessary to better organize the work on the feeder, however they will be subsets of the existing numbered polygons.

All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as notifying the Program Engineer by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

Tree Trimming

Vegetation management shall be employed on SPI 12F1 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The CPC for each polygon is responsible for coordinating any tree trimming on their respective polygons with the Vegetation Management department. A methodical trimming scheduled developed by the CPCs is strongly recommended to reduce travel costs and maximize the allotted budget for the feeder.

Report Versions

Version 1	11/25/13 – Initial report
Version 2	4/1/15 - Updated with transformer no-load loss information, and automation device information

Grid Modernization Program

SPR 761 Baseline Report

9/17/2015

Version 3

Prepared by Shane Pacini

Index

Overview

The following report was established to create a baseline analysis for SPR 761 as part of the Grid Modernization program.

SPR 761 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Sprague Substation in the Othello service area. The feeder has 24.69 miles of feeder trunk with 160.75 miles of laterals that serves predominately rural residential and agricultural loads, including the town of Sprague, WA. SPR 761 is a radial feeder that contains no feeder ties to other feeders. Additional feeder information is layered throughout the sections of this report. SPR 761 is represented as a purple color on the feeder map shown below.

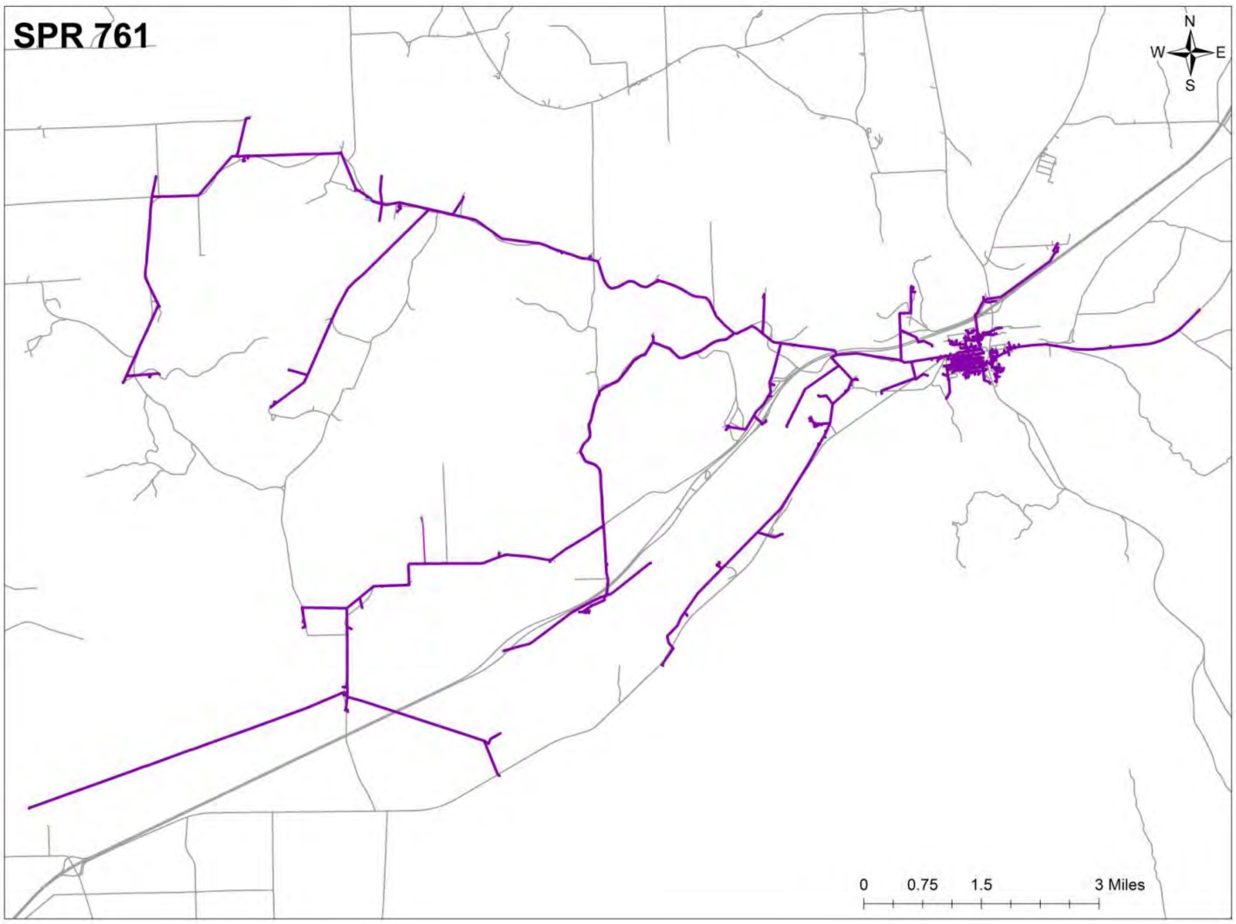

Figure 1. SPR 761 One-Line Diagram

Peak Loading

Three phase ampacity loading on SPR 761 is not monitored through SCADA. Therefore, load history was utilized from the monthly Substation Inspection Reports to establish accurate loading figures for the feeder. Three phase ampacity loading from the monthly Substation Inspection Reports at the SPR 761 substation circuit breaker was analyzed from 8/2/11 to 5/7/14. The following loading values were established for SPR 761 during this timeframe. Since SPR 761 does not have any feeder ties, loading information has not been adjusted due to switching. SPR 761 is a winter peaking feeder, with comparable peak values occurring between December and March. The peak loading values for each phase are used in the SynerGEE model analysis for the feeder, except where median load values are noted for establishing kW losses.

	Before Balancing	
	Peak	**Median**
A-Phase	87 A	50 A
B-Phase	62 A	45 A
C-Phase	68 A	49 A

	After Balancing	
	Peak	**Median**
A-Phase	80 A	46.0 A
B-Phase	69 A	50.1 A
C-Phase	68 A	49.0 A

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from SynerGEE at the model's initial.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	691	2582	26.76%
B-Phase	494	2463	20.06%
C-Phase	542	2028	26.73%

* Connected kVA per Phase in SynerGEE as of 9/15/14

	Estimated Median Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	398	2582	15.41%
B-Phase	359	2463	14.58%
C-Phase	391	2028	19.28%

* Connected kVA per Phase in SynerGEE as of 9/15/14

Feeder Balancing

Improved load balancing can be pursued on SPR 761 due to the three phase monthly Substation Inspection Reports at the Sprague 761 substation circuit breaker. The loading on SPR 761 is relatively balanced between the three phases both by connected kVA and amps (both peak and median). In addition, SPR 761 is a lightly loaded feeder, with only a handful of very lightly loaded laterals outside of the town of Sprague, WA. Therefore, significant improvements to the balancing will be difficult to achieve due to the small margin of improvement, and the limited opportunities to make these improvements.

The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively:

	Peak Amps	Connected KVA per Phase*
A-Phase	87 A	2584 kVA
B-Phase	62 A	2463 kVA
C-Phase	68 A	2028 kVA

* Connected kVA per Phase in AFM as of 9/15/14

The proposed phase change should be performed on the following lateral. This lateral is shown in Figure 2. The DESIGNERs should incorporate this lateral change into their designs for:

1. **Polygon 1** – transfer OH single-phase lateral to the northwest of Sprague Substation (≈7 A peak, 190 kVA) from AΦ to BΦ.

The result of this load transfer is listed in the table below. This change will assist in approximately balancing the feeder at the substation breaker to 80/69/68.

	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
SPR 761 Breaker	87	62	68	***80***	***69***	***68***

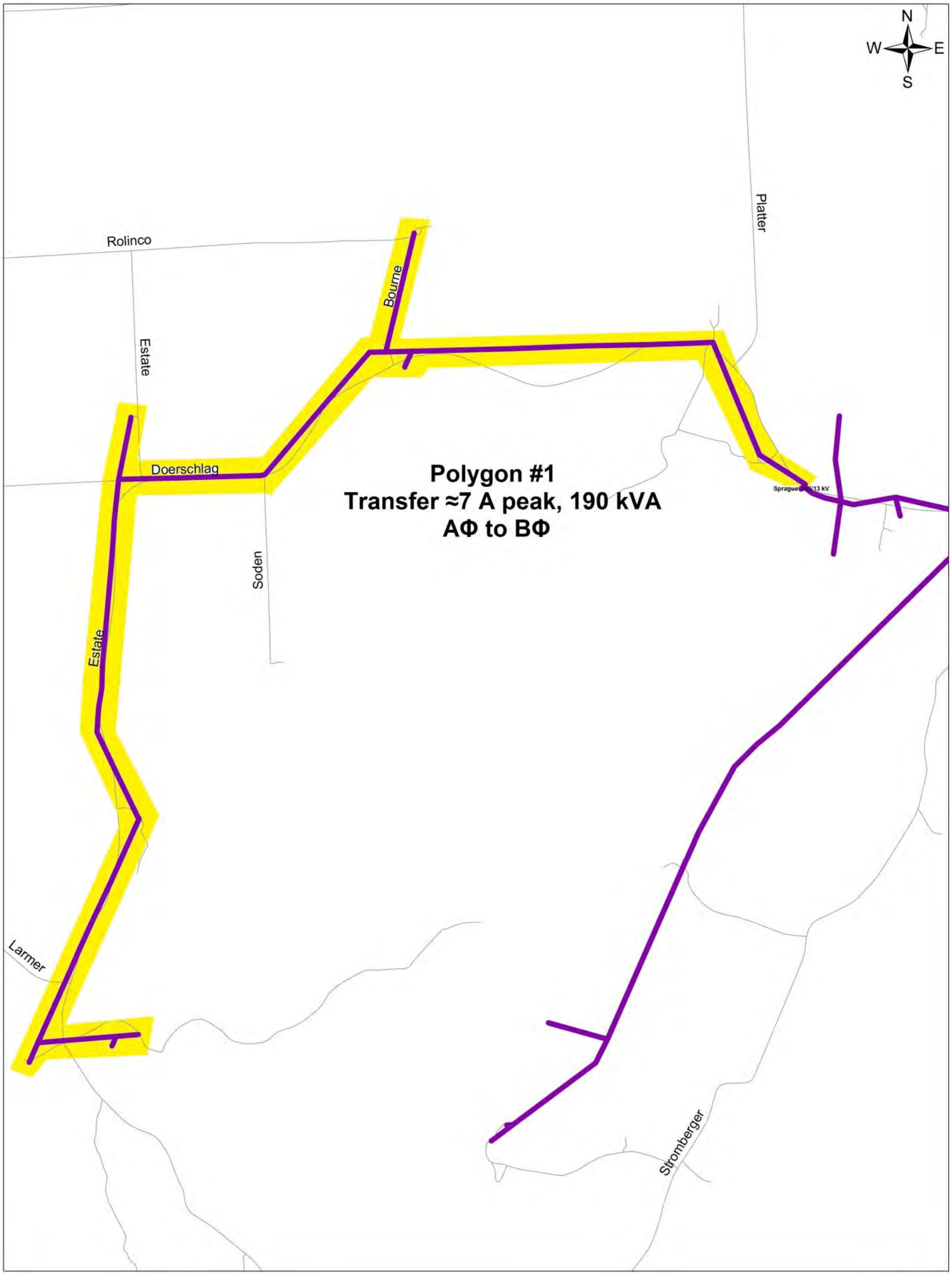

Figure 2. Feeder Balancing – Recommended Phase Changes

Conductor

All primary conductors on SPR 761 were analyzed in SynerGEE using the balanced peak ampacity values identified above (80/69/68). Specific attention was given to overloaded conductors, conductors with relatively high line losses, conductors that serve areas with unacceptable voltage quality (primarily during peak conditions), etc. The following sections provide detailed information on specific conductor issues that were identified on SPR 761, as well as the proposals for improving the efficiency and performance of the feeder.

The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary requiring reconductoring.

Transmission Engineering should be consulted for any reconductoring performed on Transmission structures where there is Distribution underbuild to ensure the pole class is adequate for the loading changes on the structure.

Feeder Reconfiguration

There is latitude within the Grid Modernization program to identify and relocate sections of the feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when the benefits of rebuilding in place are negligible, or if reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

SPR 761 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, there are numerous sections that could warrant reconfiguration due to physical conditions, stubbing, and high resistant conductors. These potential sections have been noted in Figure 3. These highlighted should not be interpreted as mandatory for reconfiguration, as well as the only sections that are candidates for reconfiguration. The assigned Designer is responsible to further analyze each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in indentifying locations where configuration or conversion is sensible. Designers should pay special attention to the number of stubbed poles on each section of line, as the cumulative effect of numerous stubbed poles could greatly support the proposal to configure.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory - unless specifically directed by the Grid Modernization Program Engineer. It is the Designer's responsibility to consult the Program Engineer on any proposals for reconfiguration prior to commencing the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and to assist in identifying the appropriate material and equipment to install.

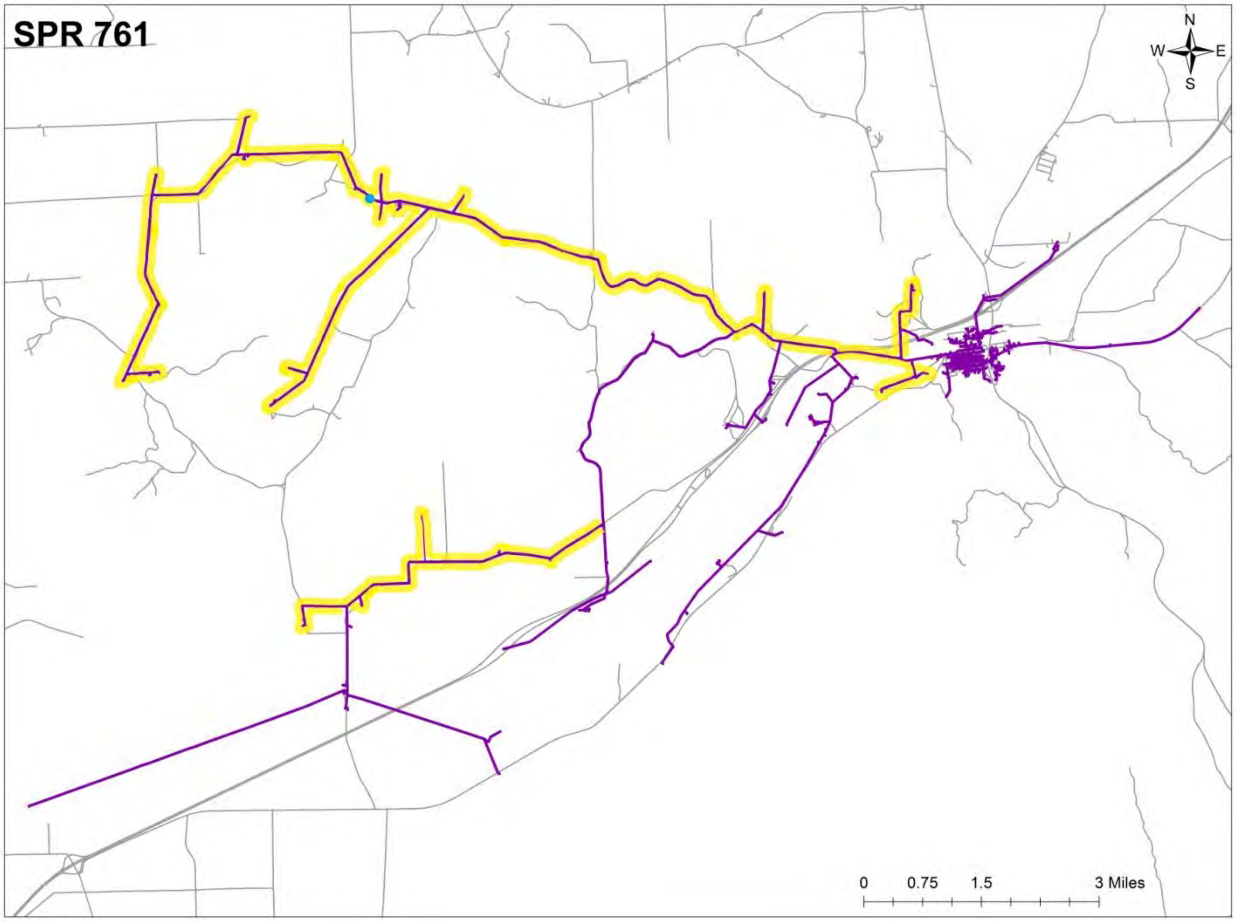

Figure 3. Potential Sections for Reconfiguration

Trunk

The primary trunk conductors on SPR 761 were analyzed for peak loading conditions during normal system configuration. The following section of feeder trunk was identified for reconductoring as part of Grid Modernization's work on the feeder.

- Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700') in **Polygons 1, 2, 3, 4, 5, 6 and 7**. This section of trunk is currently served with a mixture of 2STCU and 2/0 ACSR conductors. The conductor is not heavily loaded along this section, however the poles are in very poor condition, and there are noticeable line loss improvements can be captured with rebuilding this section with 2/0 ACSR. This reconductored section is a strong candidate to be reconfigured. Figure 4 illustrates the primary trunk reconductor on this section.

The assigner Designer may identify that additional laterals could be reconductored due to existing material conditions and improved performance with reconfiguration. It is the Designer's responsibility to consult the Program Engineer on any other proposals for reconductoring feeder trunk prior to initiating the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install.

The designs to reconductor shall adhere to the current Distribution Construction and Material Standards and Distribution Feeder Management Plan to ensure that all construction criteria are satisfied to bring these sections up to current standards.

Feeder Tie

SPR 761 currently does not contain ties to adjacent feeders. The creation of a tie feeder is not proposed through the Grid Modernization work.

Laterals

The primary lateral conductors on SPR 761 were analyzed at peak loading conditions during normal system configuration. The lateral conductors are generally sized appropriately for this loading scenario. However the condition of the existing poles and wire require further detailed field analysis by the assigned designer to determine if each lateral is better served in the future by relocating, reconductoring, or converting the primary from overhead to underground.

- The 17,400’ 1-phase (CΦ) lateral east of the Sprague Substation off of Stromberger Road is currently served with 6A conductor with a 6A neutral in **Polygon 27.** This lateral experiences roughly 3 amps loading (70 kVA connected) during peak conditions, and therefore is not at risk of overloading concerns with the existing conductor. The lateral is comprised of very long spans that are inaccessible by road. This lateral could be a prime candidate to be relocated directly along Stromberger Road to underground primary. The Designer shall analyze the physical condition of the existing poles and wire to ultimately determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion. Figure 5 illustrates the lateral conductor on this section.

- The 31,200’ 1-phase (BΦ) lateral west of the Sprague Substation along Doerschlag Road is currently served with 6A conductor with a 6A neutral in **Polygons 1, 28, 29, 30, and 31.** This lateral experiences roughly 6 amps loading (190 kVA connected) during peak conditions, and therefore is not at risk of overloading concerns with the existing conductor. The lateral is comprised of very long spans that are generally accessible by road. At a minimum, appropriately classed/height poles should be interest to shorten the long spans. The visible condition of the poles and wire suggest that a reconductor or reconfiguration could be justified. However, the Designer shall analyze the physical condition of the existing poles and wire to ultimately determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion. Figure 6 illustrates the lateral conductor on this section.

- The 20,200’ 3-phase section of lateral west Bob Lee Road along Lake Road is currently served with 6CR conductor with a 6CR neutral in **Polygons 22 and 23.** This balanced lateral experiences roughly 9A loading per phase during peak conditions, and therefore is not at risk of overloading concerns with the existing conductor. The lateral is comprised of very long spans that are generally accessible by road. At a minimum, appropriately classed/height poles should be interest to shorten the long spans. The visible condition of the poles and wire does not suggest that a reconductor or reconfiguration is necessary. However, the Designer shall analyze the physical condition of the existing poles and wire to ultimately determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion. Figure 7 illustrates the lateral conductor on this section.

It is the Designer’s responsibility to consult the Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs. It may be determined that additional laterals could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program’s scope, meets the system operations requirements, and will assist in identifying the appropriate location, material, and equipment to install.

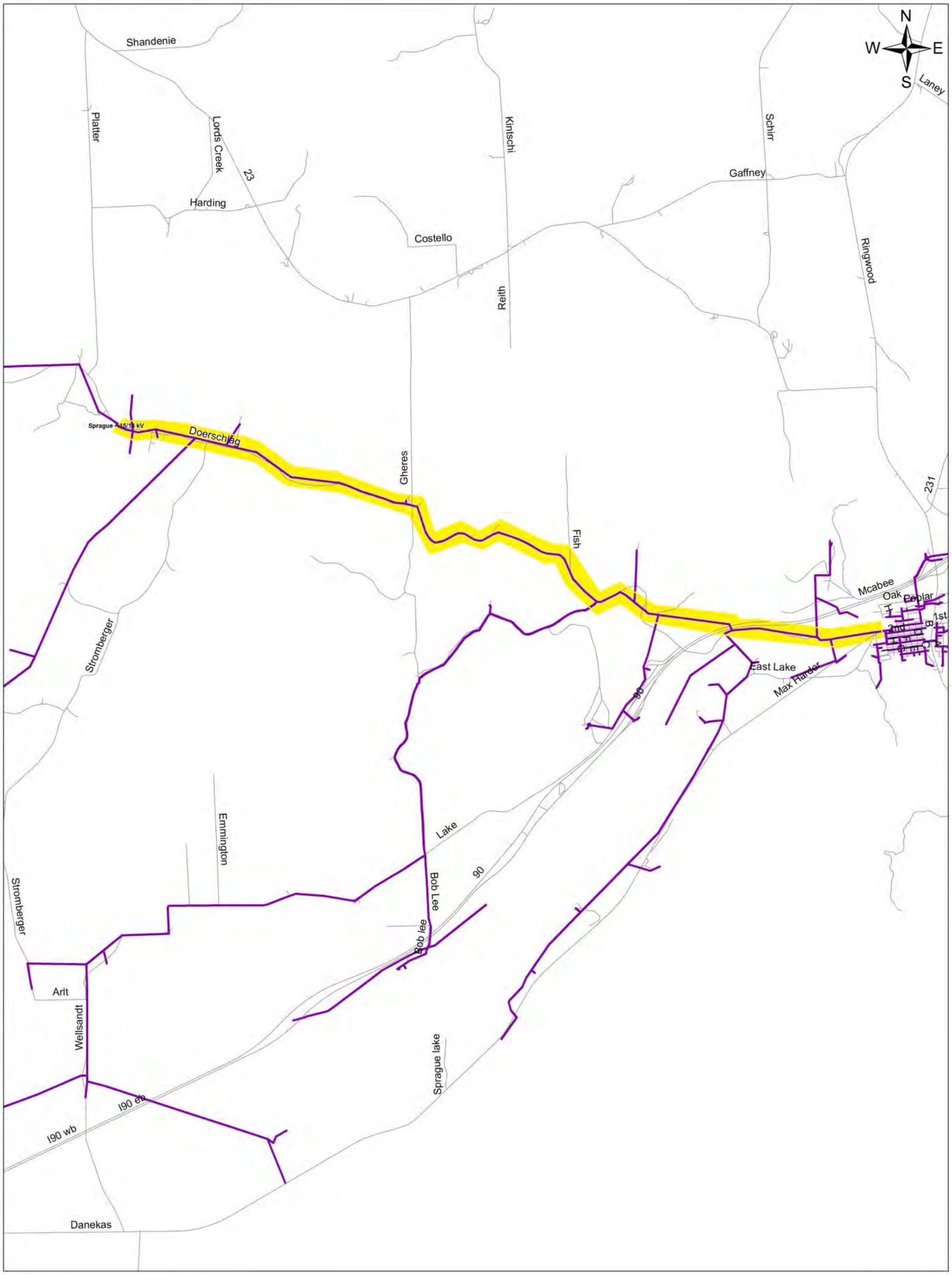

Figure 4. Polygons 1, 2, 3, 4, 5, 6 and 7 Reconductor to 2/0 ACSR

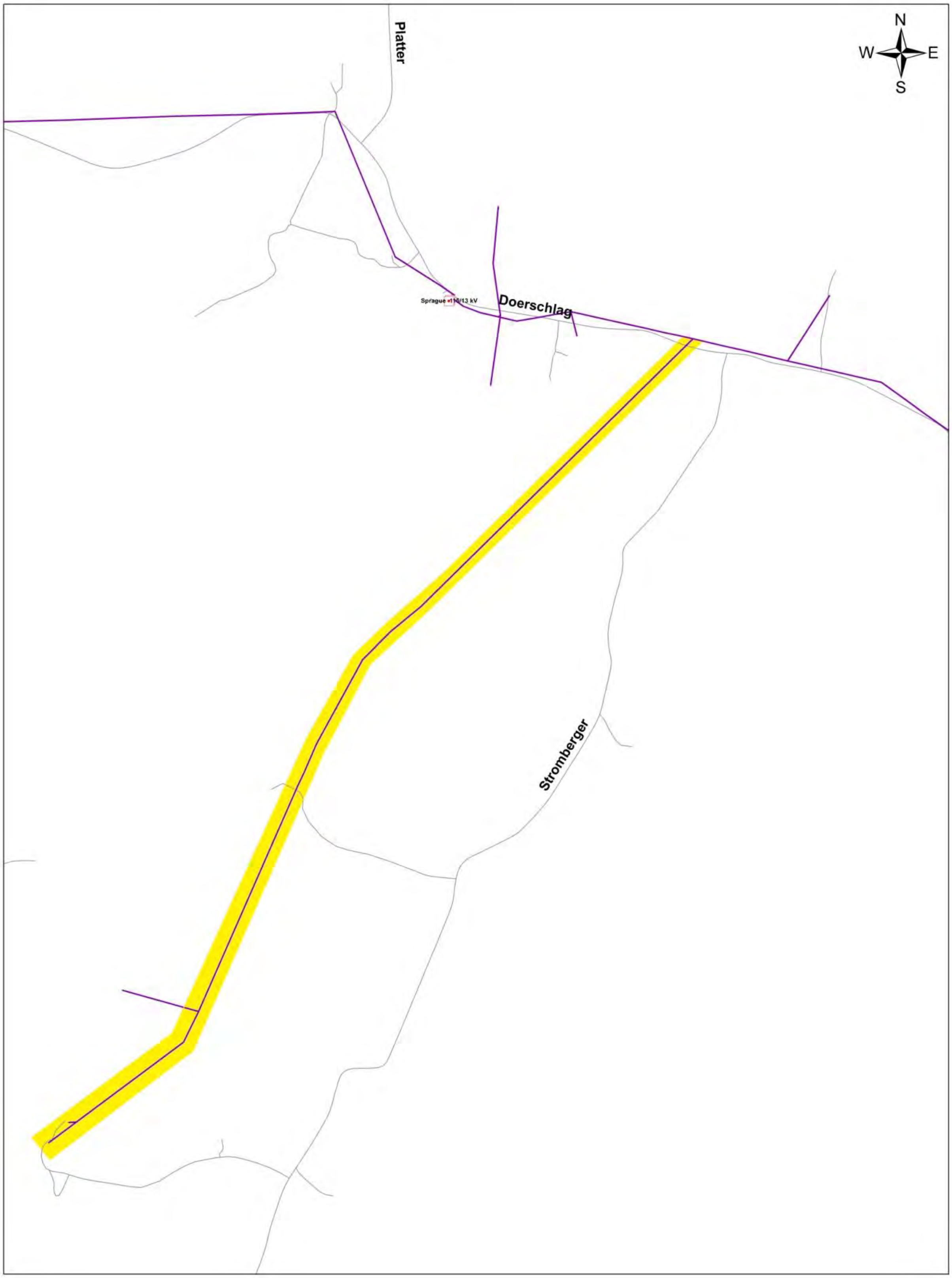

Figure 5. Polygon 27 Lateral Reconfiguration/URD Conversion along Stromberger

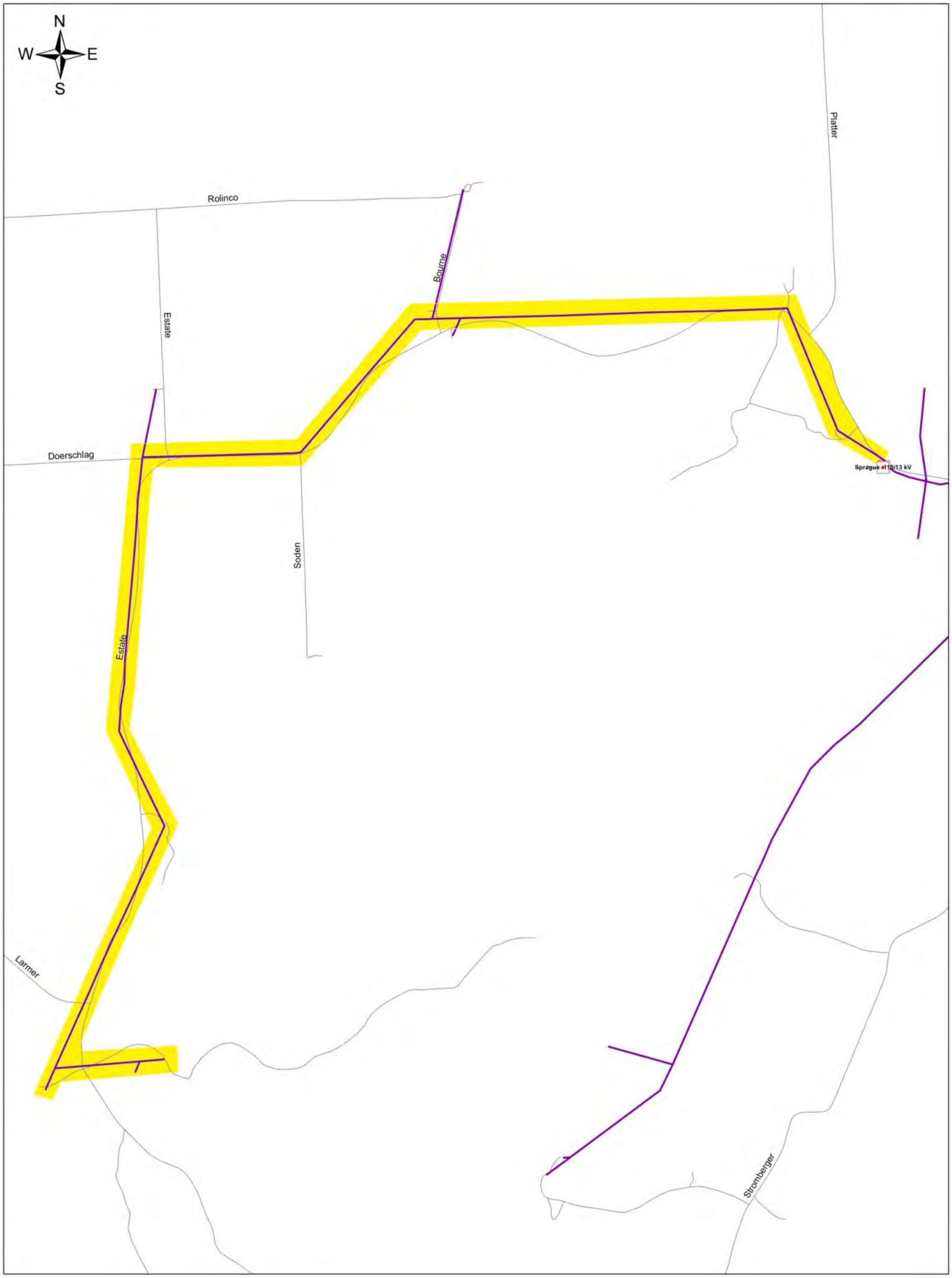

Figure 7. Polygon 1, 28, 29, 30 &31 Reconductor/URD Conversion on Doerschlag

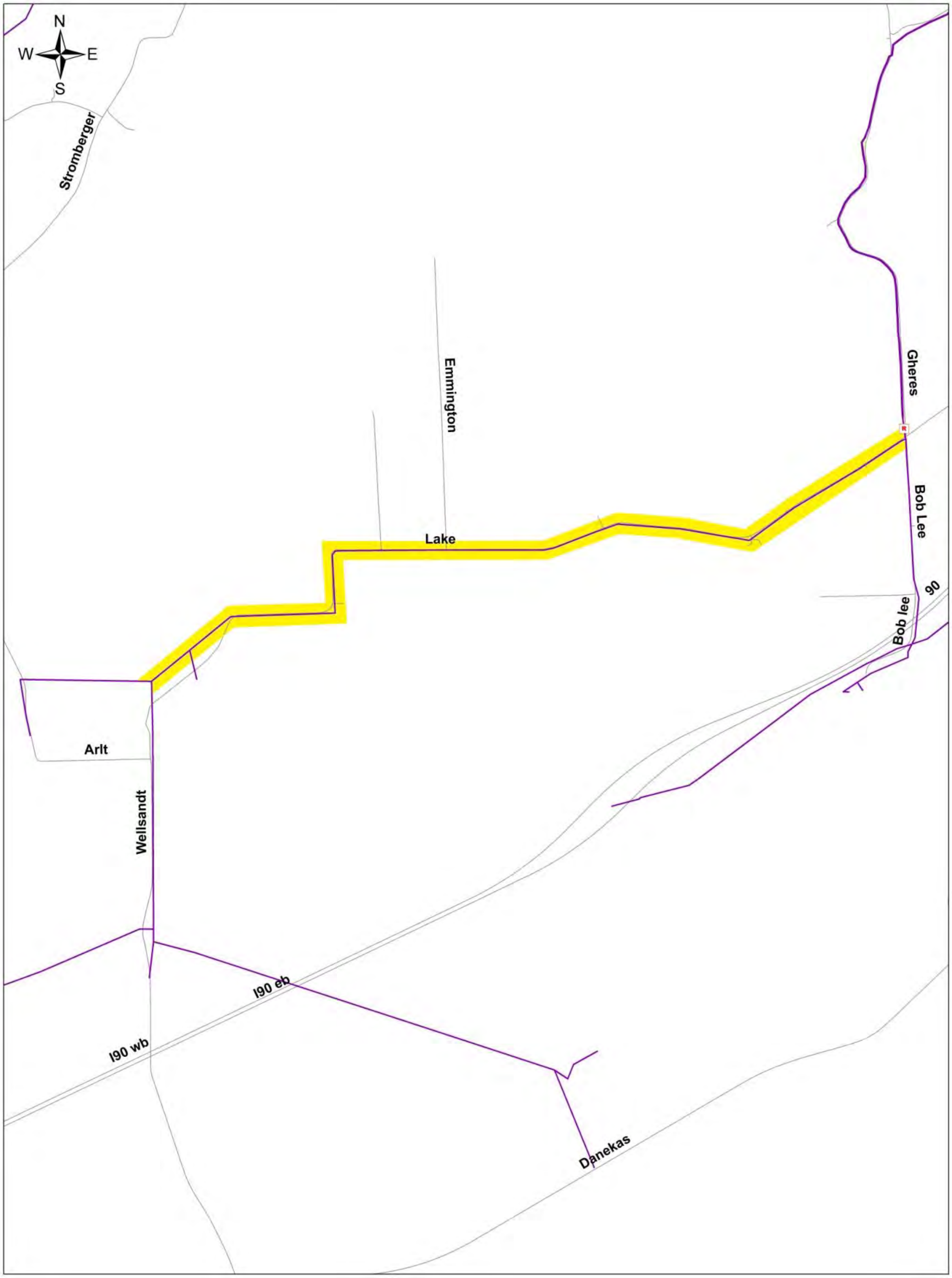

Figure 7. Polygon 22 and 23 Lateral Reconductor / URD Conversion along Lake

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Voltage Quality

The loading on SPR 761 was first balanced between phases to eliminate the unnecessary overloading of phases which may exacerbate voltage quality problems. Unfortunately, only monthly Substation Inspection Reports were available to balance the feeder – resulting in only modest recommendations. These proposals were previously outlined in the *Feeder Balancing* section of this report. SPR 761 was then analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable limit required by the NESC (114V-126V). The feeder was modeled in SynerGEE during both peak loading and median loading conditions.

- The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to SPR 761. During peak loading conditions, voltage levels remained within the allowable limits with the exception of high voltage near the Sprague Substation. With another stage of regulation roughly 3.5 miles downstream of the substation, this suggests that the regulator settings at the substation could be adjusted to lower the voltage. The maximum voltage modeled was approximately 126.3V, while the lowest voltage was 118.0V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	0	0.00	0	0
118.00 - 120.00 V	202	21.51	953	311
120.00 - 122.00 V	134	19.62	410	119
122.00 - 124.00 V	71	13.83	81	14
124.00 - 126.00 V	69	15.73	96	30
126.00 - 140.00 V	14	1.78	31	6

- Again, the voltage levels on the feeder were first analyzed prior to performing any changes or improvements to SPR 761, however this time during median loading conditions. This scenario saw slightly lower voltage levels across the feeder, however relatively high voltage levels are still present near the Sprague Substation. This support the suggestion that the regulator settings at the substation could be adjusted to lower the voltage. The maximum voltage modeled was approximately 125.4V, while the lowest voltage was 117.1V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	17	4.71	54	10
118.00 - 120.00 V	239	22.10	738	383
120.00 - 122.00 V	145	26.26	172	49
122.00 - 124.00 V	36	5.97	44	15
124.00 - 126.00 V	53	13.43	61	24
126.00 - 140.00 V	0	0.00	0	0

The voltage levels on SPR 761 were re-analyzed after trunk and lateral reconductoring were performed, as well as the proposed voltage regulator setting changes in the *Voltage Regulator Settings* section. The feeder was modeled with these proposals in SynerGEE during both peak loading and median loading conditions.

- During peak loading conditions, voltage levels remained within the allowable limits. The higher voltage levels occurred closer to the substation as to be expected, with lower voltage levels observed to the extreme east and south of the feeder. The maximum voltage modeled was approximately 125.4V, while the lowest voltage was 115.5V. Figure 8 represents service level voltages at peak load conditions.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	32	3.72	89	27
116.00 - 118.00 V	214	21.81	1090	351
118.00 - 120.00 V	126	21.03	207	54
120.00 - 122.00 V	36	7.57	51	11
122.00 - 124.00 V	30	5.32	60	14
124.00 - 126.00 V	52	13.02	89	24
126.00 - 140.00 V	0	0.00	0	0

- During median loading conditions, voltage levels remained within the allowable limits, but slightly higher overall when compared to levels during peak loading conditions. The higher voltage levels occurred closer to the substation as to be expected, with lower voltage levels observed to the extreme east and south of the feeder. The maximum voltage modeled was approximately 125.4V, while the lowest voltage was 117.6. Figure 9 represents service level voltages at medium load conditions.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	2	0.46	3	2
118.00 - 120.00 V	198	21.92	647	309
120.00 - 122.00 V	198	29.77	319	130
122.00 - 124.00 V	39	6.89	48	16
124.00 - 126.00 V	53	13.43	62	24
126.00 - 140.00 V	0	0.00	0	0

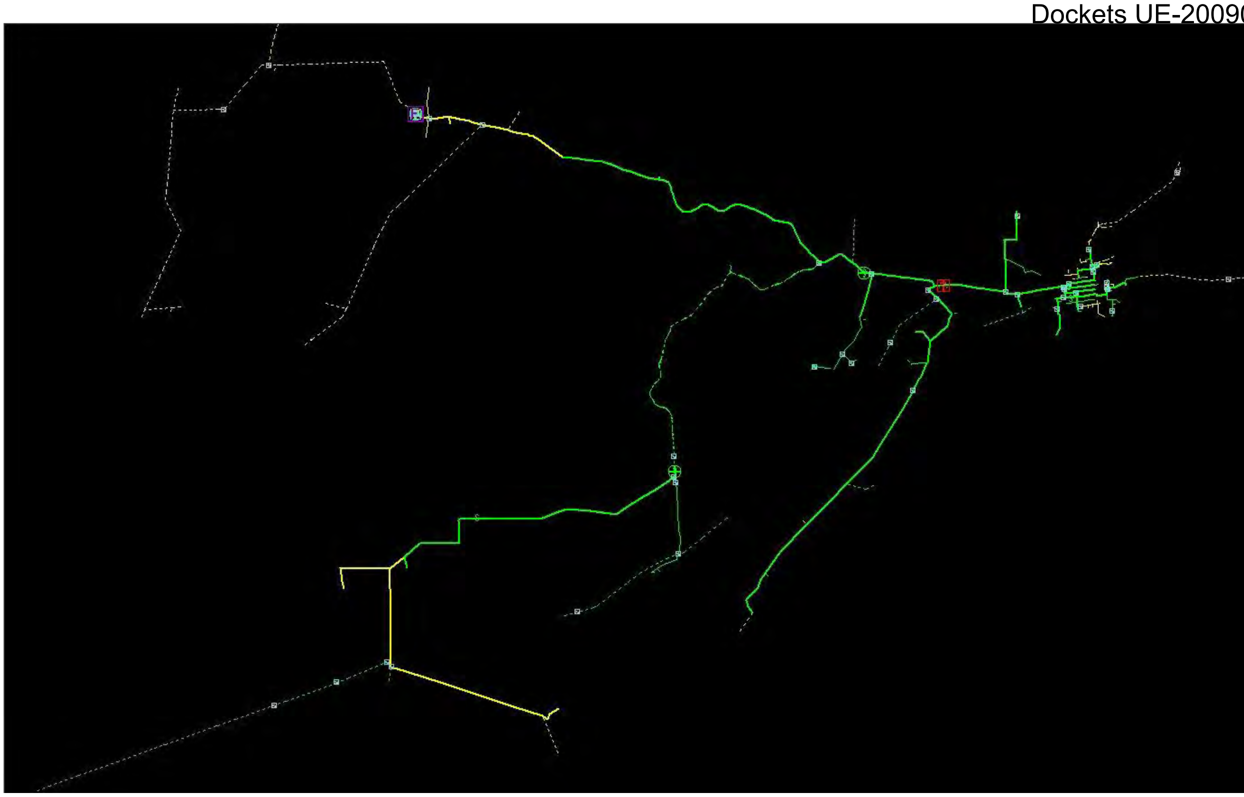

Figure 8. Service Voltage Levels at Peak Load Conditions

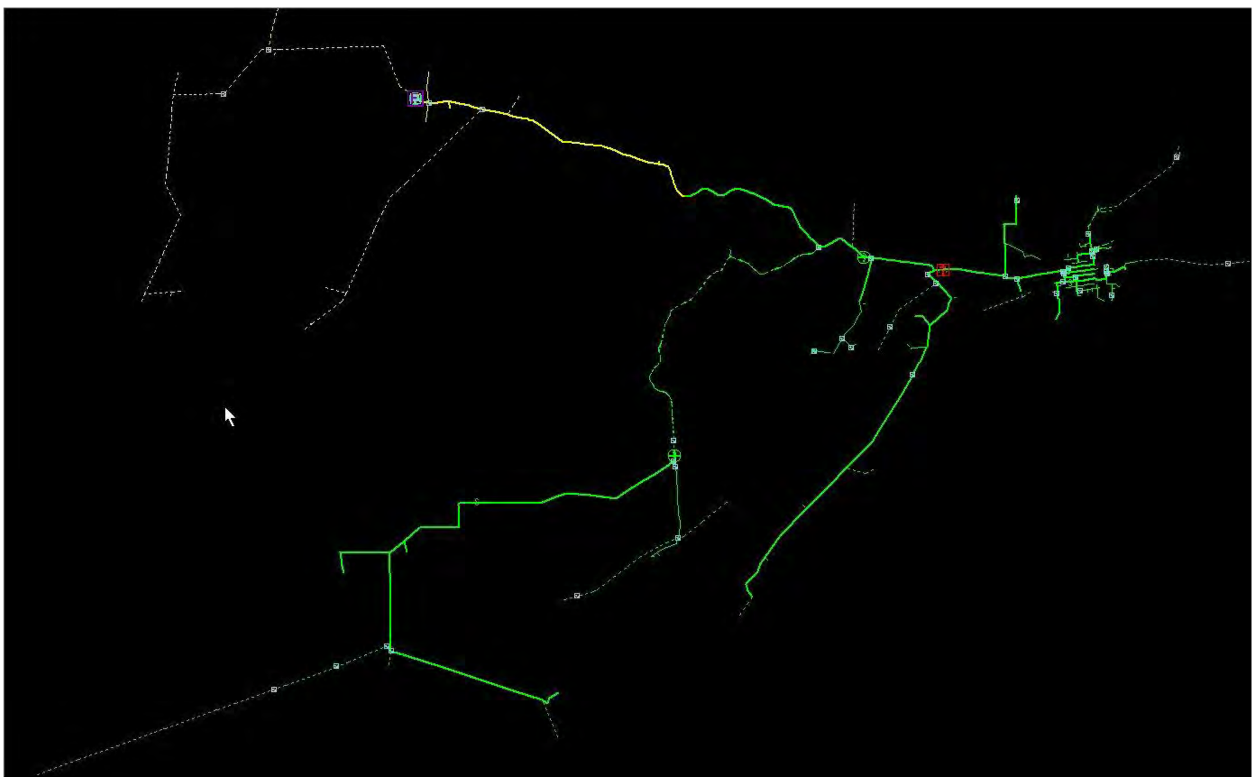

Figure 9. Service Voltage Levels at Median Load Conditions

Voltage Regulator Settings

SPR 761 has three existing stages of voltage regulation: one at the Sprague Substation, and two sets of midline regulators. The voltage levels on the feeder were modeled in SynerGEE during both peak loading and median loading conditions. The voltage levels across SPR 761 remained between 117.1V-126.3V in both modeled scenarios. Revised voltage regulator settings are recommended on SPR 761 due to the significant amount of primary reconductoring of the feeder trunk and laterals.

The voltage regulator settings were reanalyzed with the anticipated improvements to the feeder. These proposed regulator setting changes have been approved by the Othello area Engineering. The existing and proposed voltage regulator settings are provided in the following tables.

	Existing		Proposed	
Forward Settings	**R**	**X**	**R**	**X**
SPR 761 Station Regulators	**7**	**6**	**5.0**	**3.9**
W of Doerschlag & I-90	**2**	**4**	**3.7**	**1.9**
N of Bob Lee & Lake	**4.2**	**0.2**	**4.2**	**0.2**

	Existing		Proposed	
Reverse Settings	**R**	**X**	**R**	**X**
SPR 761 Station Regulators	**-**	**-**	**-**	**-**
W of Doerschlag & I-90	**1**	**2**	**-**	**-**
N of Bob Lee & Lake	**-**	**-**	**-**	**-**

Distribution System Operations has recommended to install automation compatible voltage regulators and a breaker recloser in the substation to provide future FDIR and IVVC capabilities depending on the custom solution that is developed with the line device. Grid Modernization will request the installation of the station voltage regulators by Substation Engineering; however Grid Mod is currently unable to secure the installation of the station breaker recloser due to scheduling and resource constraints.

Neither set of midline voltage regulators will be replaced with smart regulators as part of the Grid Modernization work.

Fuse Sizing

Fuse sizing on SPR 761 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and transformers (where applicable). Fuse recommendations for SPR 761 were created by the Grid Modernization Program Engineer and verified by the Area Engineer. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult the Grid Mod Program Engineer with any questions regarding fuse sizing and coordination.

There may be situations where the transformers sizes on a lateral are “right sized” (increased or decreased) to more accurately reflect customer loads. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Mod Program Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with the transformer fuse(s).

Line Losses

The primary trunk conductors on SPR 761 have been sized appropriately to minimize line losses at peak and median loading conditions during normal system configuration, and improve voltage levels on the long rural feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading.

After the proposed reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections are performed on SPR 761, it is estimated that the peak line losses could be reduced by as much as 12.3 kW, while the median loading line losses could be reduced by as much as 5.7 kW. In addition, up to 49.9 MWh savings could be annually assuming median loading conditions during normal system configuration.

	Substation E to Sprague
Circuit Length	44,000
Current Median kW Losses	41.7
Current Peak kW Losses	91.2
Proposed Median kW Losses*	36.0
Proposed Peak kW Losses	78.9
Median kW Loss Savings	5.7
Peak kW Loss Savings	12.3
Reconductor MWh Savings ***	49.9

* Losses are estimated as negligible and near zero
** Primary and neutral conductor material cost only
*** Estimated median kW losses over two year span

An initial SyngerGEE load study estimates that a total of 111 kW in peak line losses currently exists on SPR 761 (7.14%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved to approximately 98 (6.41%).

Peak Values	**Existing**	**After Balancing**	**After Trunk Reconductor**
kW Demand	1692	1689	1679
kW Load	1571	1568	1571
kW Line Losses	111	111	98
kW Loss %	7.14 %	7.13 %	6.41 %

Transformer No Load Losses

Core losses are an unavoidable characteristic of distribution transformers. Core losses are the dissipation of power that would ideally be transferred through the transformer, but that are however lost through the magnetizing current needed to energize the core of the transformer. These losses occur whenever the primary bushes of a transformer are energized, and occur regardless of having a connected load – thus being called "No Load Losses". Core losses do not vary according to the loading on the transformer, and occur 24 hours a day.

The review of historically purchased transformers illustrate that No Load Losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, No Load Losses are generally lower on newer units compared to a transformer of the same size from an older vintage. No Load Losses can therefore be minimized through the replacement of older transformer to newer units of the correct size.

All transformers on SPR 761 shall be analyzed and "right sized" by the assigned Designer to most accurately reflect the customer loads. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department.

The roughly 276 distribution transformers on SPR 761 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determine the correct transformer size. It was determined that 100 transformers will require replacement based on right sizing and the TCOP replacements. The replacement of these transformers will result in an estimated 6.36 kW reduction in No Load Losses. This equates to an annual savings of roughly 55.7 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer.

<u>Power Factor</u>

MVAR and MW data at the SPR 761 substation circuit breaker was not available through SCADA to analyze the power factor of the feeder. There is one existing 300 kVAR fixed capacitor bank on SPR 761. It is recommended to replace the fixed capacitor bank on SPR 761 to a 600 kVAR switched capacitor bank at the same location. While there is not overwhelming MW and MVAR data to support the specific size of the capacitor bank, the existing bank is in poor physical condition and is a unique style that is quite antiquated. Accurate power factor correction can be accomplished at a future date once a history of loading information is established through more detailed SCADA monitoring through automated devices on the line with communication capabilities.

Automation

Distribution Automation will be deployed on SPR 761 as part of the Grid Modernization program. A customized solution for the feeder has been created to address the specific characteristics and issues associated with the load, customers, and geography on SPR 761.

SPR 761 does not currently contain ties to adjacent feeders.

The following automated devices will be deployed on the feeder:

Device Number	Location	Status	Device Type
ZH645R	E of Doerschlag & I-90	N.C.	Viper – Recloser
ZH644F	W of Front Street & I Street	N.C.	Switched 600 kVAR Cap

Figure 10 illustrates the proposed automation device locations on SPR 761.

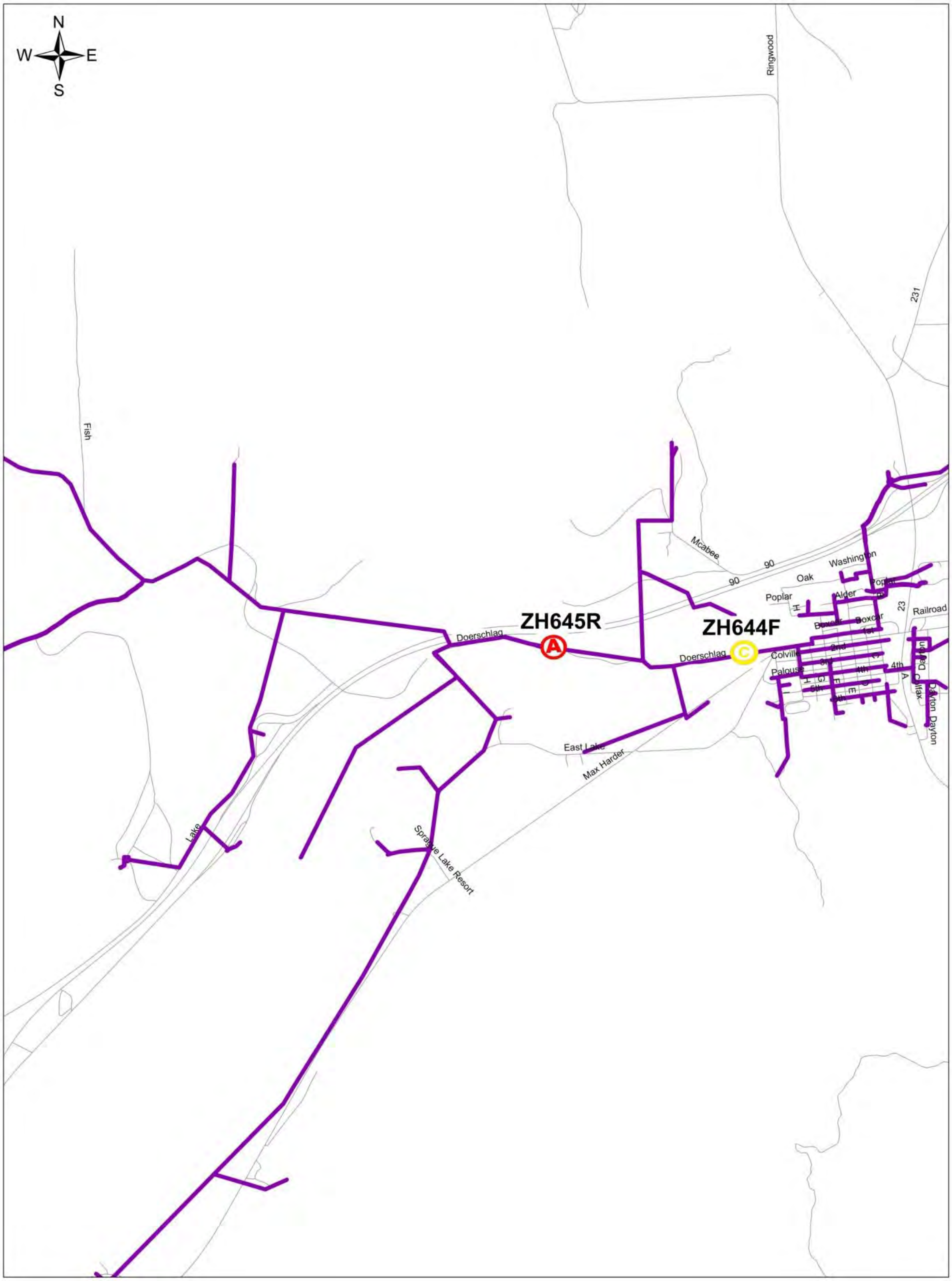

Figure 10. Proposed Automation Device Locations

Open Wire Secondary

SPR 761 was analyzed for open wire secondary districts in accordance to the Distribution Feeder Management Plan (DFMP). Two districts were identified to exist on SPR 761; however there may be others on the roughly 185 miles of trunk and lateral conductors the feeder. Figure 11 identifies the open wire secondary districts that were discovered for removal.

- **Polygon 9 –** remove 1300' of horizontal open wire secondary on two separate districts.

The designers shall consult the DFMP if additional open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Program Engineer to provide direction on removal and replacement.

Figure 11. Open Wire Secondary Districts in Polygon 9

Poles

All poles and structures on SPR 761 shall be examined by the assigned Designer for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. It is strongly recommended to replace all stubbed poles on the feeder. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

Transformers

All transformers on SPR 761 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance Department. However all transformers shall be analyzed and “right sized” by the Designer to most accurately reflect customer loads. The Designer shall consult the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer for damage, removal, or replacement. The Designer shall consult the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable. It is recommended for the Designer to consult the area Local Rep to obtain more information on known issues and recent outages.

Tree Trimming

Vegetation management shall be employed on SPR 761 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with the Vegetation Management department. A methodical trimming scheduled developed by the Designers that encompasses all assigned polygons is strongly recommended to reduce travel costs and maximize the allotted budget for the feeder.

Design Polygons

SPR 761 has been divided into 31 polygons for the Grid Modernization project work. The polygons were created in an attempt to divide the work into near equivalent segments in regards to design and crew time. Additional considerations such as automation devices, reconductoring, geography, road access, and location of laterals further assisted in defining the boundaries of the polygons. Additional polygons can be created if necessary to better organize the work on the feeder, however they will be subsets of the existing numbered polygons.

All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager. Designs will commence on SPR 761 in 2015, with construction beginning in 2016 and continuing through 2018.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as notifying the Program Engineer by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

The following polygon summary lists the identified items that shall be incorporated into the final job designs:

- **Polygon 1**
    - Transfer OH single-phase lateral to the northwest of Sprague Substation (≈7 A peak, 190 kVA) from AΦ to BΦ.
    - Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700' total).
    - Analyze the condition of the existing poles and wire on the 31,200' 1-phase (BΦ) lateral along Doerschlag Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 2**
    - Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700' total).
- **Polygon 3**
    - Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700' total).
- **Polygon 4**
    - Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700').
- **Polygon 5**
    - Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700').

- **Polygon 6**
  - Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700' total).
- **Polygon 7**
  - Reconductor 3Φ trunk east of the Sprague Substation along Doerschlag Road to 1st St to 2/0 ACSR with a 2/0 ACSR neutral (approximately 43,700' total).
  - Install 600 kVAR switched capacitor bank (ZH644F, N.C.) west of Front Street & I Street.
- **Polygon 9**
  - Remove 1300' of horizontal open wire secondary on two separate districts.
- **Polygon 10**
  - Install midline Viper recloser (ZH645R, N.C.) southeast of Doerschlag & I-90.
- **Polygon 22**
  - Analyze the condition of the existing poles and wire on the 20,200' 3-phase (CΦ) lateral along Lake Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 23**
  - Analyze the condition of the existing poles and wire on the 20,200' 3-phase (CΦ) lateral along Lake Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 27**
  - Analyze the condition of the existing poles and wire on the 17,400' 1-phase (CΦ) lateral along Stromberger Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 28**
  - Analyze the condition of the existing poles and wire on the 31,200' 1-phase (BΦ) lateral along Doerschlag Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 29**
  - Analyze the condition of the existing poles and wire on the 31,200' 1-phase (BΦ) lateral along Doerschlag Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 30**
  - Analyze the condition of the existing poles and wire on the 31,200' 1-phase (BΦ) lateral along Doerschlag Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 31**
  - Analyze the condition of the existing poles and wire on the 31,200' 1-phase (BΦ) lateral along Doerschlag Road to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.

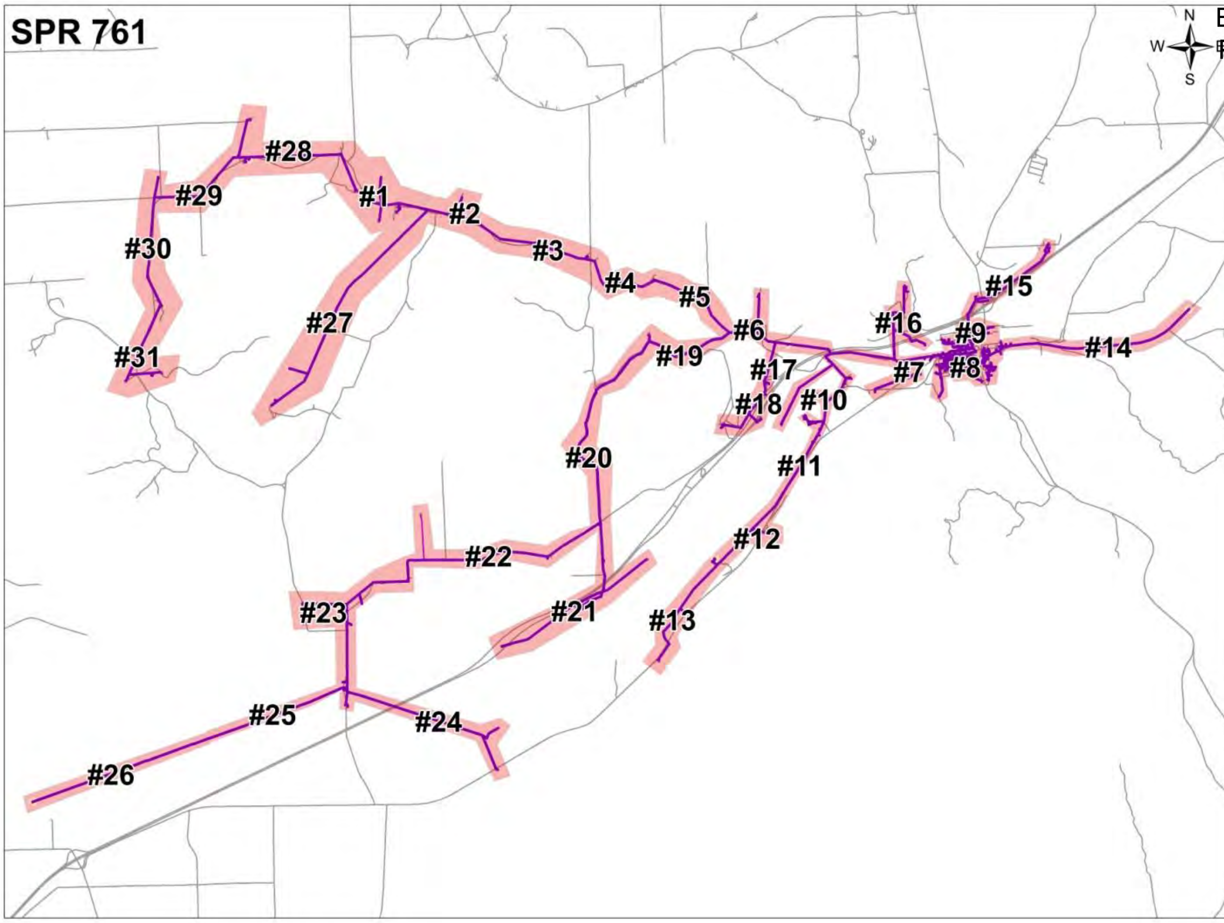

Figure 12. SPR 761 Polygon Numbers

Report Versions

Version 1 12/11/14 – Creation of the initial report

Version 2 3/31/15 – Minor updates from discussions with the Othello Office

Version 3 9/17/15 – Analyzed the results of three-phase load loggers that were installed on the feeder from 1/9/15 – 3/9/15 and 7/15/15 – 9/14/15. The load loggers were hung in an attempt to capture the winter and peak loads for 2015 and compare against the loading values that were originally used. The results from the load loggers were slightly lower than the manual monthly substation reads that were initially used, however the values were relatively close and appear consistent. It was determined that the feeder would not be reanalyzed with the new data.

Grid Modernization Program

TUR 112 Baseline Report

5/6/2016

Version 2

Prepared by Shane Pacini

Index

Overview

The following report was established to create a baseline analysis for TUR 112 as part of the Grid Modernization program.

TUR 112 is a 13.2/7.62 kV distribution feeder served from Transformer #1 at the Turner Substation in the Moscow/Pullman service area. The feeder has 19.72 miles of feeder trunk with 112.09 miles of laterals that serves a mixture of sparse rural residential loads and urban residential loads, including the west-central part of Pullman, WA. Additional feeder information is layered throughout the sections of this report, as well as the Avista Feeder Status Report. TUR 112 is represented as a blue color on the system map shown in Figure 1.

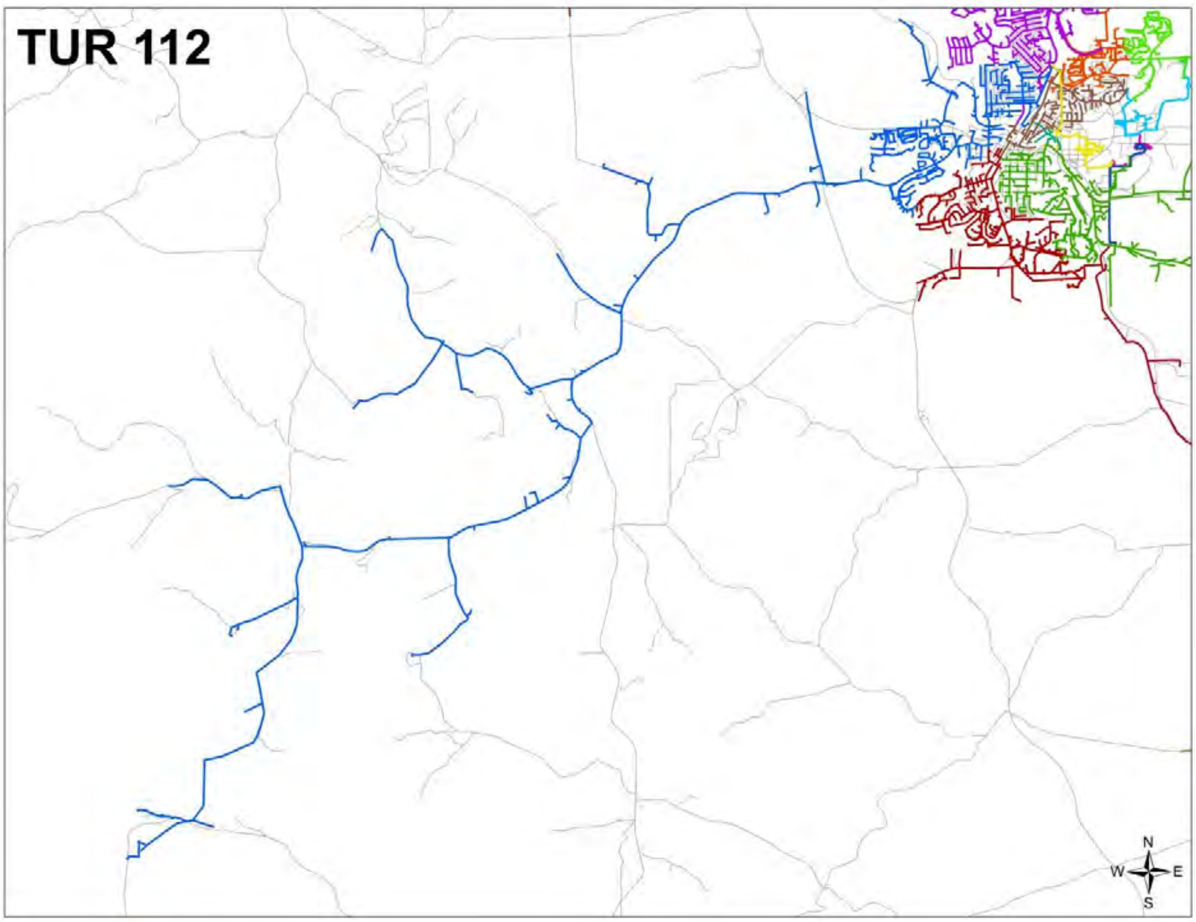

Figure 1. TUR 112 One-Line Diagram

The Grid Modernization Program selects feeders by first individually analyzing raw data in categories related to Reliability, Avoided Costs (Energy Savings), and Capital Offset of Future O&M. This research is performed on every distribution feeder in the system. Once all of the feeders are separately evaluated, the data can be normalized for each of the three categories. Since each categories' data set that could be measured on different scales, the normalization process offers the ability to convert each into a fractional value that is on the same scale and is relative to the feeders' data in that same category. Once this is performed for the three categories of each feeder, the normalized values can be weighted using the selection criteria weighting that was established at the creation of the program. The summation of the values for each of the three categories creates the overall score for each feeder. This score is how the feeder is initially ranked.

TUR 112 had a normalized total ranking of 0.518, ranking 16th on the list of over 340 feeders. Further analysis reveals that the primary reasons this feeder was selected was due to relatively higher potential to achieve avoided costs through energy savings and efficiency improvements (65.19%), as well as the opportunity to reduce future O&M expenses through capital improvements (33.75%). Designers should consider these factors when fielding and designing the work on TUR 112.

	Reliability	Avoided Costs	Capital Offset
Selection Data	0.01606652	163.7026731	2050693.207
Normalized Data	0.01371947	0.964991643	0.699382732
Program Weighting %	40.0%	35.0%	25.0%
Normalized Score	0.00548779	0.337747075	0.174845683
Weight of Category %	1.06%	65.19%	33.75%

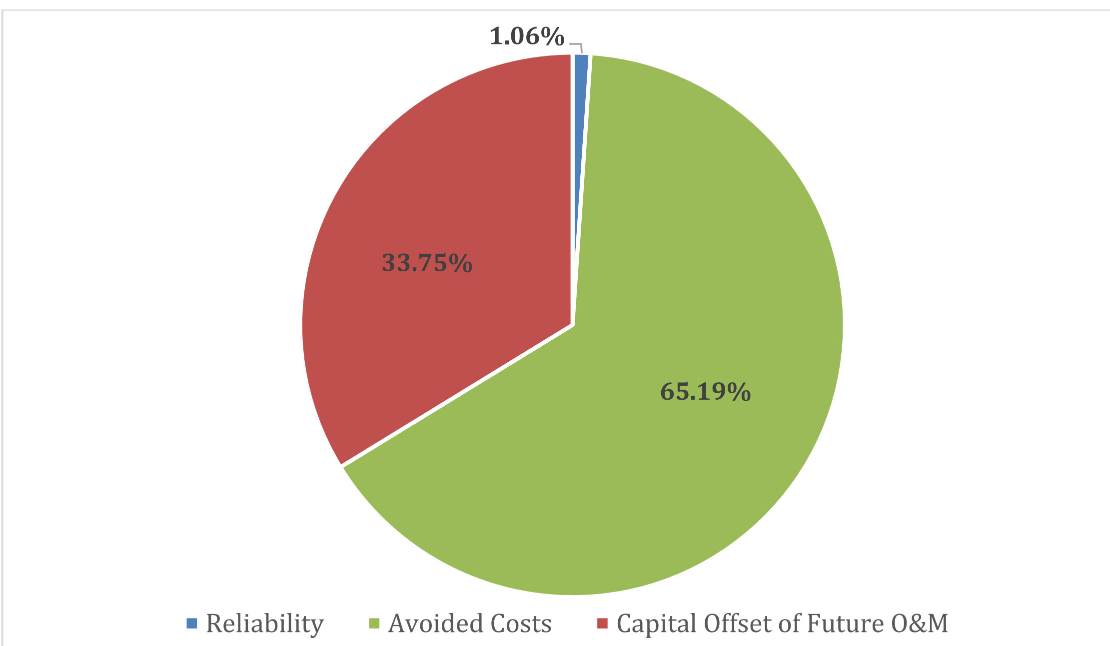

Figure 2. TUR 112 Selection Criteria

Peak Loading

Three phase ampacity loading from SCADA monitoring at the TUR 112 substation circuit breaker was analyzed from 9/15/13 to 9/14/15. The following loading values were established for TUR 112 during this timeframe. Loading information has been removed from selected timeframes due to temporary changes in loading from switching (verified through PI). TUR 112 is slightly a winter peaking feeder, with comparable peak values observed in November through February. The values below reflect the adjusted data set. The peak loading values for each phase are used in the SynerGEE model analysis for the feeder, except where median load values are noted for establishing kW losses.

	Before Balancing	
	Peak	**Median**
A-Phase	333.0 A	137.0 A
B-Phase	313.0 A	120.0 A
C-Phase	344.0 A	141.0 A

	After Balancing	
	Peak	**Median**
A-Phase	338 A	139.1 A
B-Phase	329 A	126.1 A
C-Phase	323 A	132.4 A

Approximate percent loading figures were established by analyzing the demand and connected kVA per phase values from SynerGEE at the model's initial configuration before balancing.

	Estimated Peak Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	2654	5929	44.76%
B-Phase	2495	6285	39.70%
C-Phase	2743	6946	39.49%

* Connected kVA per Phase in SynerGEE as of 9/15/15

	Estimated Median Loading Conditions		
	Demand kVA*	**Connected kVA***	**% Loading**
A-Phase	1092	5929	18.42%
B-Phase	948	6285	15.08%
C-Phase	1108	6946	15.95%

* Connected kVA per Phase in SynerGEE as of 9/15/15

Feeder Balancing

Accurate load balancing can be achieved on TUR 112 due to the three phase ampacity monitoring at the Turner 112 substation circuit breaker. The following loading values for peak ampacity and connected KVA totals per phase were taken from SCADA and AFM respectively before balancing:

	Connected KVA per Phase*
A-Phase	5961.67 kVA
B-Phase	6220.17 kVA
C-Phase	6985.67 kVA

* Connected kVA per Phase in AFM as of 9/15/15

The following list provides the loads, laterals, and dips that can effectively balance the load on the phases between numerous strategic locations on the feeder, shown in Figures 3 and 4. As a whole, the trunk sections and multi-phase laterals on TUR 112 were relatively balanced, however opportunities are available to improve feeder balancing by transferring loads. The Designers shall incorporate these changes into their appropriate polygon designs:

1. **Polygon 1** – transfer 1Φ OH lateral north of State & Timothy (≈18A) from CΦ to BΦ.
2. **Polygon 1** – transfer 1Φ OH lateral south of State & Webb (≈11 A) from AΦ to BΦ.
3. **Polygon 4** – transfer 1Φ URD lateral west of Golden Hills & Casey (≈15 A) from BΦ to CΦ.
4. **Polygon 6** – transfer 1Φ URD lateral north of Old Wawawai & Big Sky (≈15 A) from CΦ to BΦ.
5. **Polygon 13** – transfer 1Φ OH lateral northwest of Wawawai-Pullman & Klemgard (≈10 A) from BΦ to AΦ.
6. **Polygon 17** – transfer 1Φ OH lateral south of Klemgard & Ryan (≈6 A) from BΦ to AΦ.

The result of these load transfers are listed in the following table. These changes will approximately balance the feeder at the substation breaker to 338/329/323, as well as between the numerous strategic points to approximately sectionalize the feeder.

	Existing			Proposed		
	A-Phase	B-Phase	C-Phase	A-Phase	B-Phase	C-Phase
TUR 112 Station Breaker	333	313	344	**338**	**329**	**323**
S of Stadium & Grand	269	300	281	284	287	277
W of Stadium & Grand	69	17	67	58	46	49
E of Main & Old Wawawai	195	190	198	210	178	194
N or Main & Old Wawawai	87	95	74	87	80	89
NE of Old Wawawai & Marcia	85	97	120	99	101	101
ZP1803R (current location)	50	64	61	56	54	61
Wawawai-Pullman & Flat	8	44	29	24	28	29

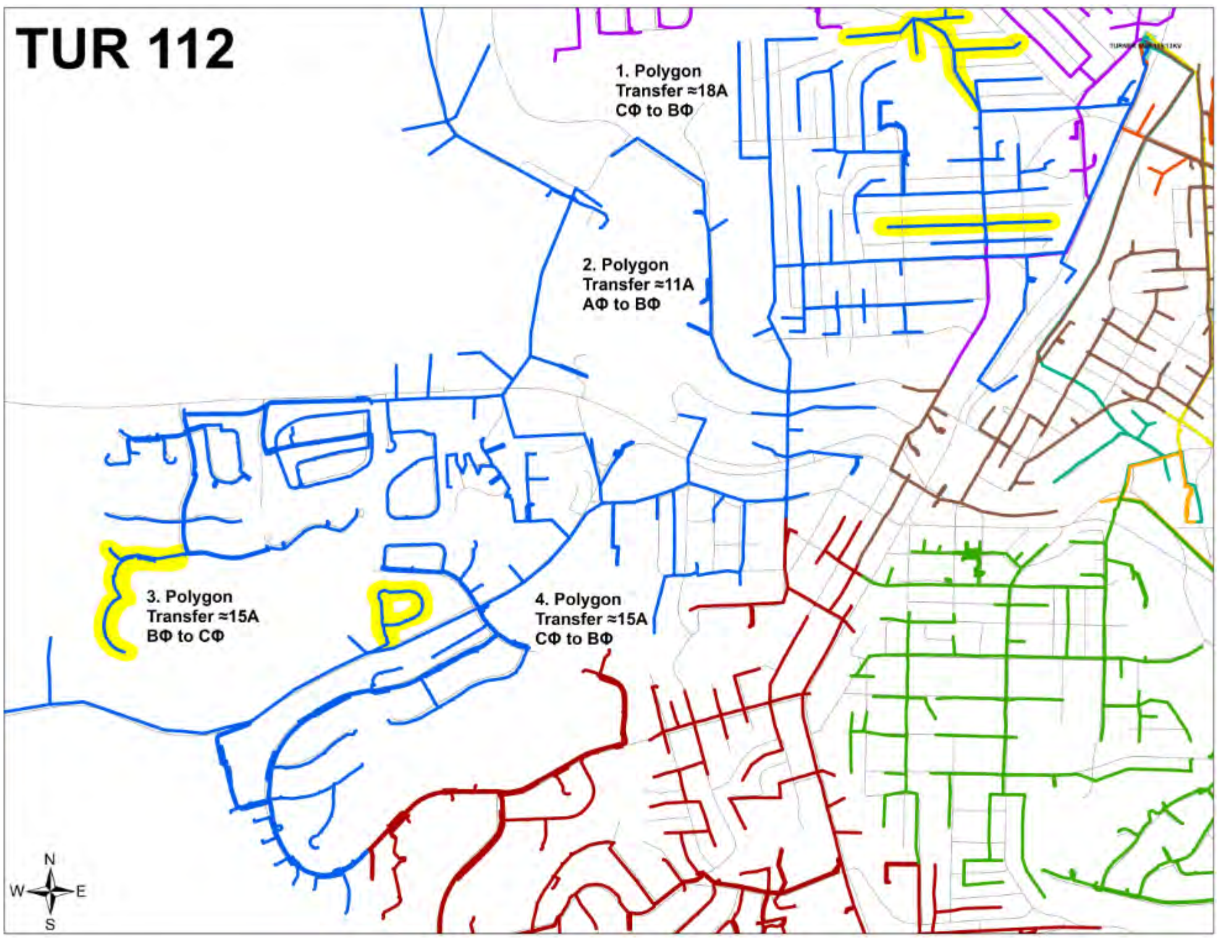

Figure 3. Feeder Balancing – Recommended Phase Changes

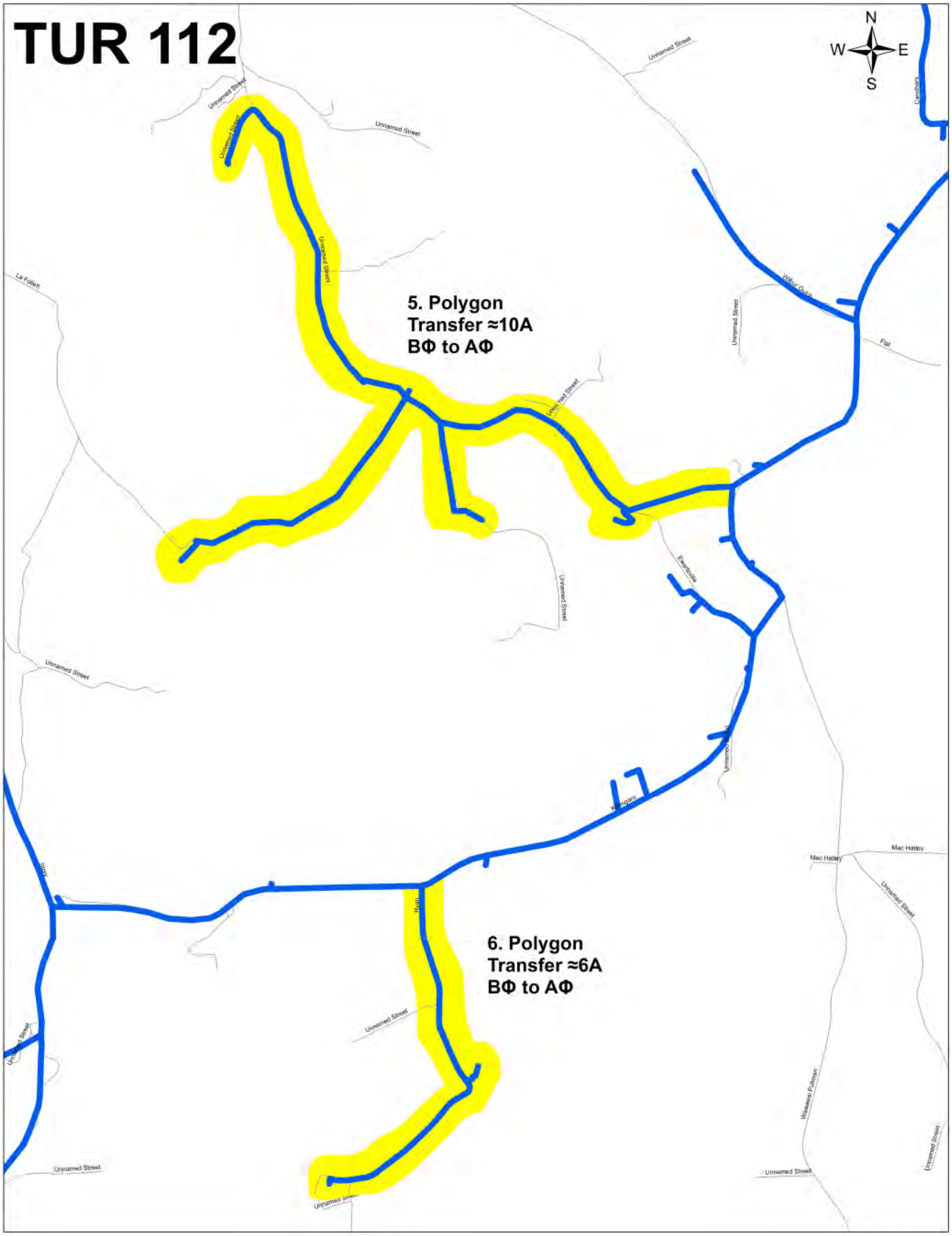

Figure 4. Feeder Balancing – Recommended Phase Changes

Conductor

All primary conductors on TUR 112 were analyzed in SynerGEE using the balanced peak ampacity values identified above (338/329/323). Specific attention was given to conductors that were potentially overloaded, have relatively high line losses, serve areas with unacceptable voltage quality (primarily during peak conditions), and feeder ties. The following sections provide detailed information on specific conductor issues that were identified on TUR 112, as well as the proposals for improving the efficiency and performance of the feeder.

The respective Designer for each polygon will be responsible for incorporating all proposed reconductor designs in their assigned polygons, as well as incorporating an appropriately sized system neutral where applicable in accordance with the Avista construction standards. Individual feeder one-line maps are provided in the following sections of the report for each proposal that illustrates the specific sections of primary requiring attention.

Transmission Engineering should be consulted for any reconductoring performed on Transmission structures where there is Distribution underbuilt to ensure the pole class is adequate for the loading on the structure.

Feeder Reconfiguration

The Grid Modernization program supports the efforts to identify and relocate sections of the distribution feeder where the cost and benefits of greenfield construction outweighs the significant work required to rebuild the existing line in place to current standards. In addition, overhead facilities can be converted to underground when: the benefits of rebuilding in place are not significant, the cost difference between overhead versus underground is comparable, or if notable reliability improvements can be achieved by removing sections of vulnerable overhead conductors.

TUR 112 was analyzed to identify sections that are candidates for reconfiguration. Upon physically observing the feeder, there are sections that could warrant reconfiguration due to proposed reconductoring, physical conditions, stubbing, and high resistant conductors. The assigned Designer is responsible to further analyze each polygon in conjunction with the WPM pole test and TCOP transformer reports. Incorporating this additional data will further assist in identifying locations where reconfiguration or conversion is sensible.

All proposals for reconfiguring sections of the feeder shall be identified by the assigned Designer during their field observations and material inventory – unless specifically directed by the Grid Modernization Program Engineer. It is the Designer's responsibility to consult the Program Engineer on any proposals for reconfiguration or conversion to underground prior to commencing the job designs. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and to assist in identifying the appropriate material and equipment to install.

Trunk

The primary trunk conductors on TUR 112 were analyzed to identify sections that require reconductoring to meet peak loading conditions during normal system configuration. The majority of the urban portion of the feeder trunk is currently conductored with 556 AAC, 2/0 ACSR, and 2STCU in overhead applications and 1CN15 in underground applications. The majority of the rural portion of the feeder trunk is currently conductored with 6A, 6CU, and 4 ACSR in overhead applications and 1CN15 in underground applications. All rural sections of primary are loaded under 35% of carrying capability during peak loading scenarios, and therefore there is minimal support to upgrade this conductor type based on capacity concerns alone. Line losses on the trunk are currently in the desired range for this scenario, which has been aided by balancing the feeder and relatively lower loading conditions where high loss conductors exist.

- Reconductor 3Φ trunk southwest of Main & Old Wawawai to 556 AAC with a 2/0 ACSR neutral (approximately 8430') in **Polygons 7 and 8**. This section of trunk is currently served by a combination of 2STCU, 2/0ACSR, and 4ACSR. In addition for being undersized for serving as primary feeder trunk, this section of the feeder is experiencing significant load growth and numerous new residential developments are planned. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. Figure 5 illustrates the primary trunk reconductor on this section.
- Reconductor 3Φ trunk along Wawawai-Pullman between US Hwy 195 and Carothers Road to 2/0 ACSR with a 2/0 ACSR neutral (approximately 8000') in **Polygon 9**. This section of trunk is currently served by a combination of 6A, 6CU, and 4ACSR. While this section is current appropriate sized for serving as primary feeder trunk, this section of the feeder is expected to experience load growth as residential developments extend west from Pullman. This reconductored section is not intended to be reconfigured, but rather rebuilt in place. Figure 6 illustrates the primary trunk reconductor on this section.
- Reconductor 3Φ trunk north of Main & Old Wawawai to 2/0ACSR with a 2/0 ACSR neutral (approximately 1700') in **Polygon 4**. This section of trunk is currently served by 6CU conductor that is heavily loaded, as well as being undersized for serving as primary feeder trunk. This reconductored section will also be reconfigured to be located along the road on both Wawawai Road and Davis Way. Figure 7 illustrates the primary trunk reconductor on this section.

The designs to reconductor shall adhere to the Avista Distribution Construction and Material Standards, Distribution Feeder Management Plan, and the Existing Facility Replacement/Modification Guidelines to ensure that all construction criteria are satisfied to bring these sections up to new installation requirements.

Laterals

The primary lateral conductors on TUR 112 are sized appropriately to meet peak loading conditions during normal system configuration. The analyzed models do not suggest reconductoring any of the laterals on the feeder based on peak loading conditions or downstream service voltage levels, however there are numerous lightly loaded laterals that contain high loss conductors. The Distribution Feeder Management Plan calls attention to these higher loss conductors, with emphasis on replacement conductors that have a resistance greater than 5 ohms per mile. Figures 8 and 9 identify the laterals on TUR 112 that are candidates for reconductoring based on containing high loss conductors.

The following list of laterals should be further examined by the assigned Designer in the field to support reconductoring these laterals to 4ACSR. As part of the field analysis, the Designer should determine the effects of pole conditions and classifications, the results from the WPM reports, condition of the primary and neutral overhead conductors, potential benefits from relocation, etc. The Designer shall specifically consult the *OH Conductor* and *Wood Poles* sections of the Distribution Feeder Management Plan for specific parameters on the requirements for the Grid Modernization program.

1. **Polygon 1** – Approximately 1200’ of 8CU, 17A peak (20% loaded)
2. **Polygon 3** – Approximately 850’ of 6CW, 2A peak (4% loaded)
3. **Polygon 3** – Approximately 950’ of 6A, 2A peak (2% loaded)
4. **Polygon 4** – Approximately 400’ of 6A, 1A peak (1% loaded)
5. **Polygon 5** – Approximately 450’ of 6A, 8A peak (8% loaded)
6. **Polygon 5** – Approximately 800’ of 6A, 1A peak (1% loaded)
7. **Polygon 5** – Approximately 2800’ of 6A, 2A peak (2% loaded)
8. **Polygon 11** – Approximately 250’ of 8CW, 1A peak (3% loaded)
9. **Polygon 14** – Approximately 6100’ of 6CR, 2A peak (14% loaded)
10. **Polygon 16** – Approximately 650’ of 6CR, 1A peak (8% loaded)
11. **Polygon 19** – Approximately 9700’ of 8CW, 4A peak (12% loaded)

The is also the potential to configure the feed to the lateral in Polygon 5 from Polygon 3 in order to eliminate a large section of inaccessible line. This would include the removal of approximately 1600’ of two-phase 6CU overhead primary in Polygon 5 and reserving the northern section of Polygon 5 from Polygon 3 by installing a two-phase 4ACSR primary extension. Figure 10 identifies the lateral reconfiguration proposal on TUR 112.

It is the Designer's responsibility to consult the Grid Modernization Program Engineer on any proposals for reconductoring laterals prior to initiating the job designs. It may be determined that additional laterals or spans could be reconductored due to existing material conditions and improved performance with reconfiguration. The Designer shall work with the Program Engineer to ensure the proposed work remains within the program's scope, meets the system operations requirements, and will assist in identifying the appropriate material and equipment to install. The Program Engineer will work with Regional Operations Engineer to validate any future proposals to address lateral conductors based on the conditions dictated through field analysis.

Feeder Tie

TUR 112 currently contains two overhead feeder ties through: tie switch ZP1705R (TUR 116) and tie switch ZP1800R (SPU 123). TUR 112 has one existing underground tie to SPU 123 through the J11007 junction enclosure. After analyzing the options and loading scenarios adjacent to TUR 112, there are two proposals for creating additional feeder ties as part of Grid Modernizations work on the feeder.

There is an opportunity to establish a new feeder tie with TUR 113. This location is just upstream from the ZP1711R (N.C.) sectionalizing switch and the ZP1800R (N.O.) tie with SPU 123. Due to the close proximate of the main 556 AAC feeder trunks for both TUR 112 and TUR 113, the creation of this tie would require relatively minimum work of rebuilding and reconductoring an existing 1000' three-phase lateral with 556AAC near the intersection of SW State Street & NW Olsen Street, near downtown Pullman. This proposal would create a tie with a new feeder (TUR 113), however the benefits may be limited for both feeders since it would be located near existing tie switches for both TUR 112 (with SPU 123) and TUR 113 (with TUR 116).

There is also opportunity to establish a new feeder tie with TUR 117, however the benefits of creating this tie is minimized due to the near proximity to the Turner Substation and the reduced ability to transfer manageable, sectionalized load. This tie would either rely on additional downstream ties to also pick up part of a fully loaded feeder, or to be used for switching during lower peak times. TUR 112 and TUR 117 are served from different station transformers at the Turner Substation (Transformer #1 and Transformer #2 respectively).

The decision to pursue either new feeder tie opportunity will be discussed and selected with the Regional Operations Engineer based on their anticipated frequency of using either tie in the operation of the Pullman distribution system. Figure 11 identifies the locations of the proposed options for creating new feeder ties on TUR 112.

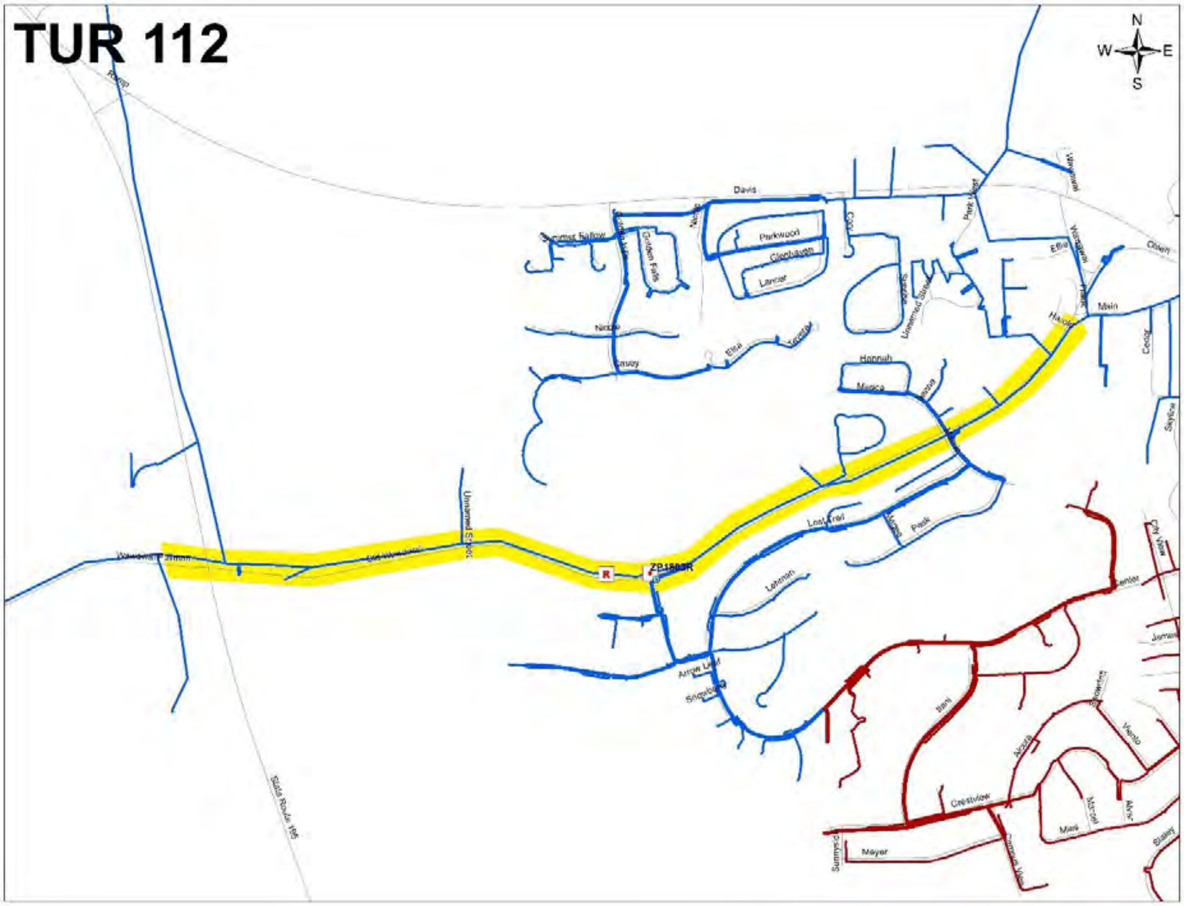

Figure 5. Polygons 7 & 8 Feeder Trunk Reconductor to 556 AAC

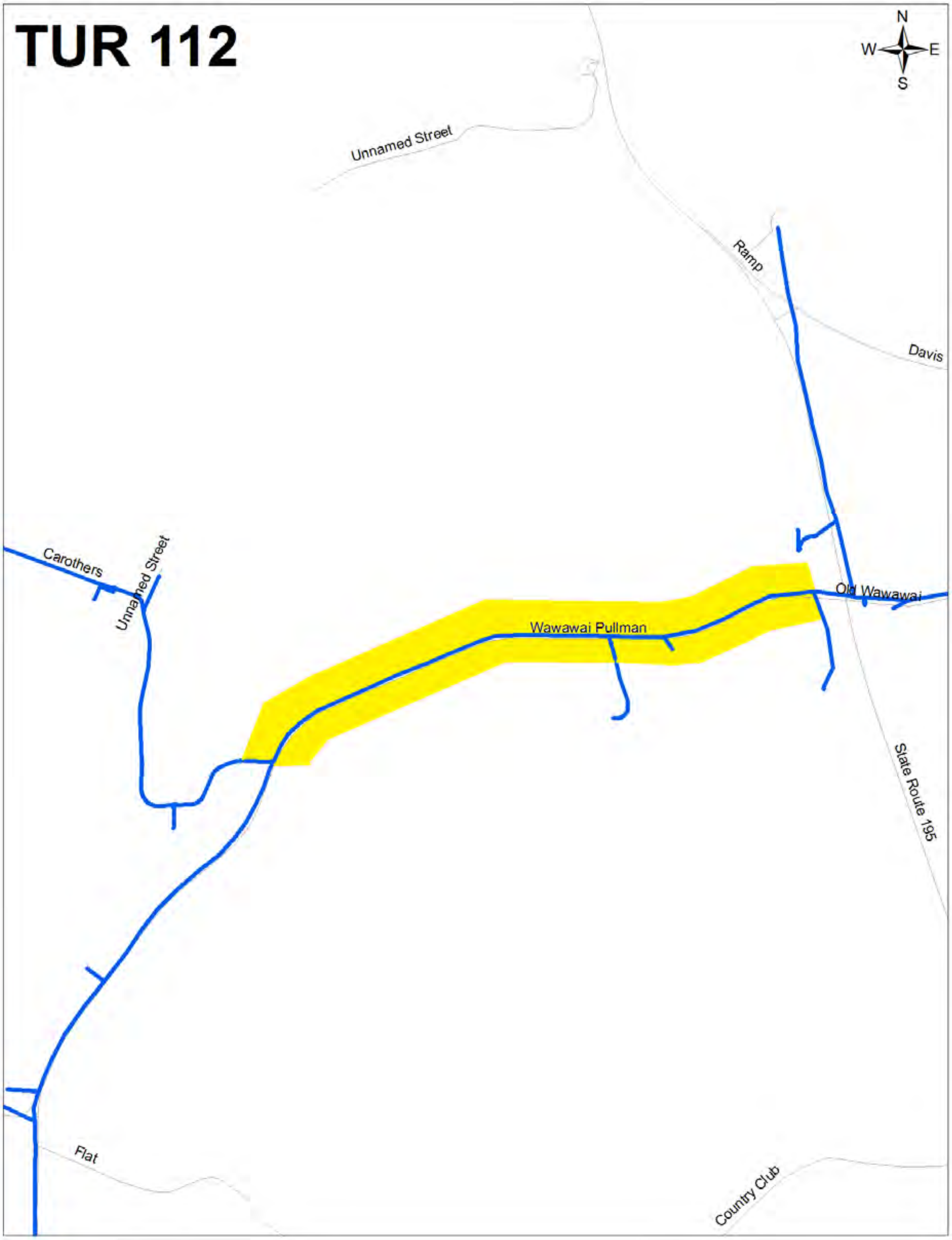

Figure 6. Polygon 9 Feeder Trunk Reconductor to 2/0ACSR

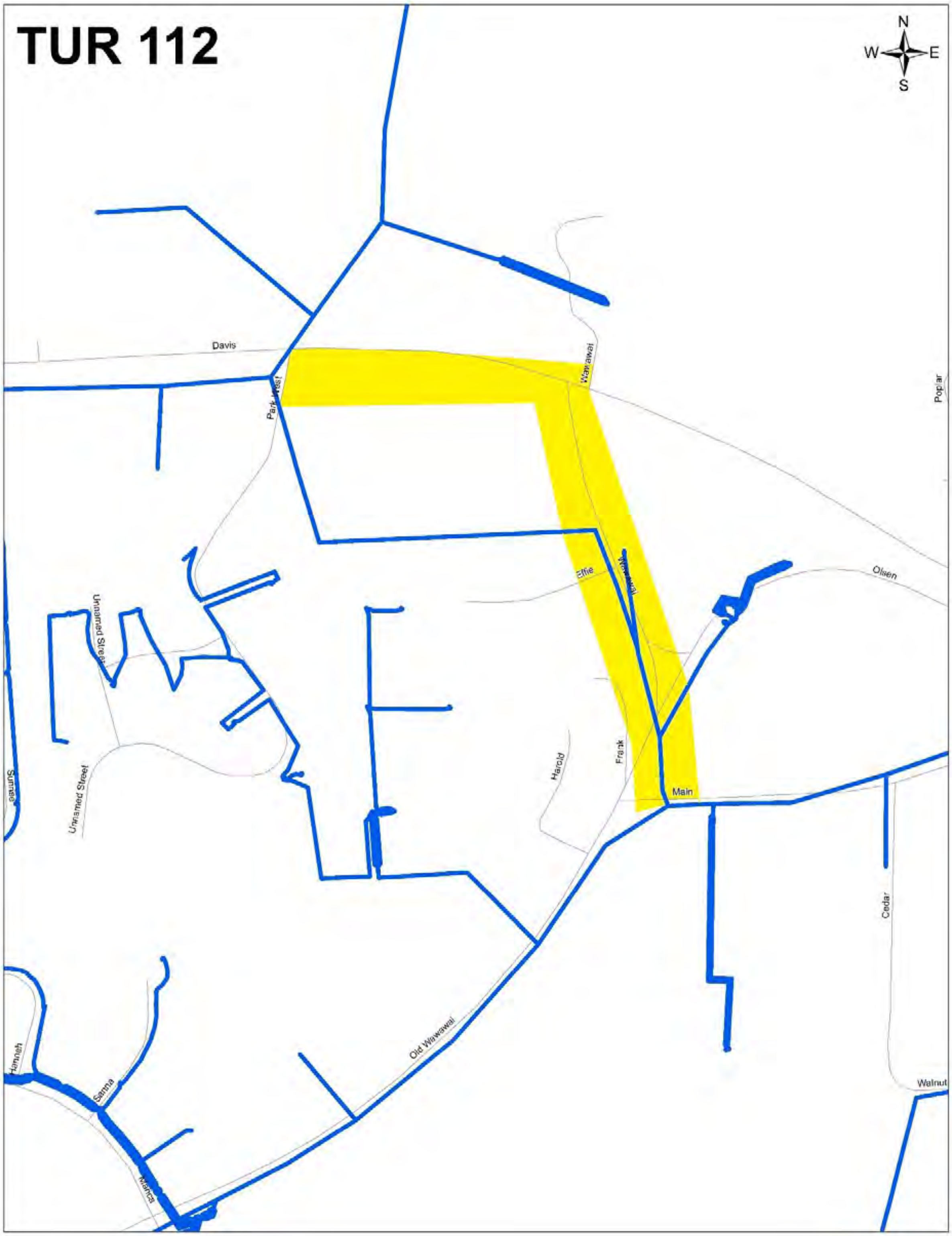

Figure 7. Polygon 4 Feeder Trunk Reconductor to 2/0 ACSR

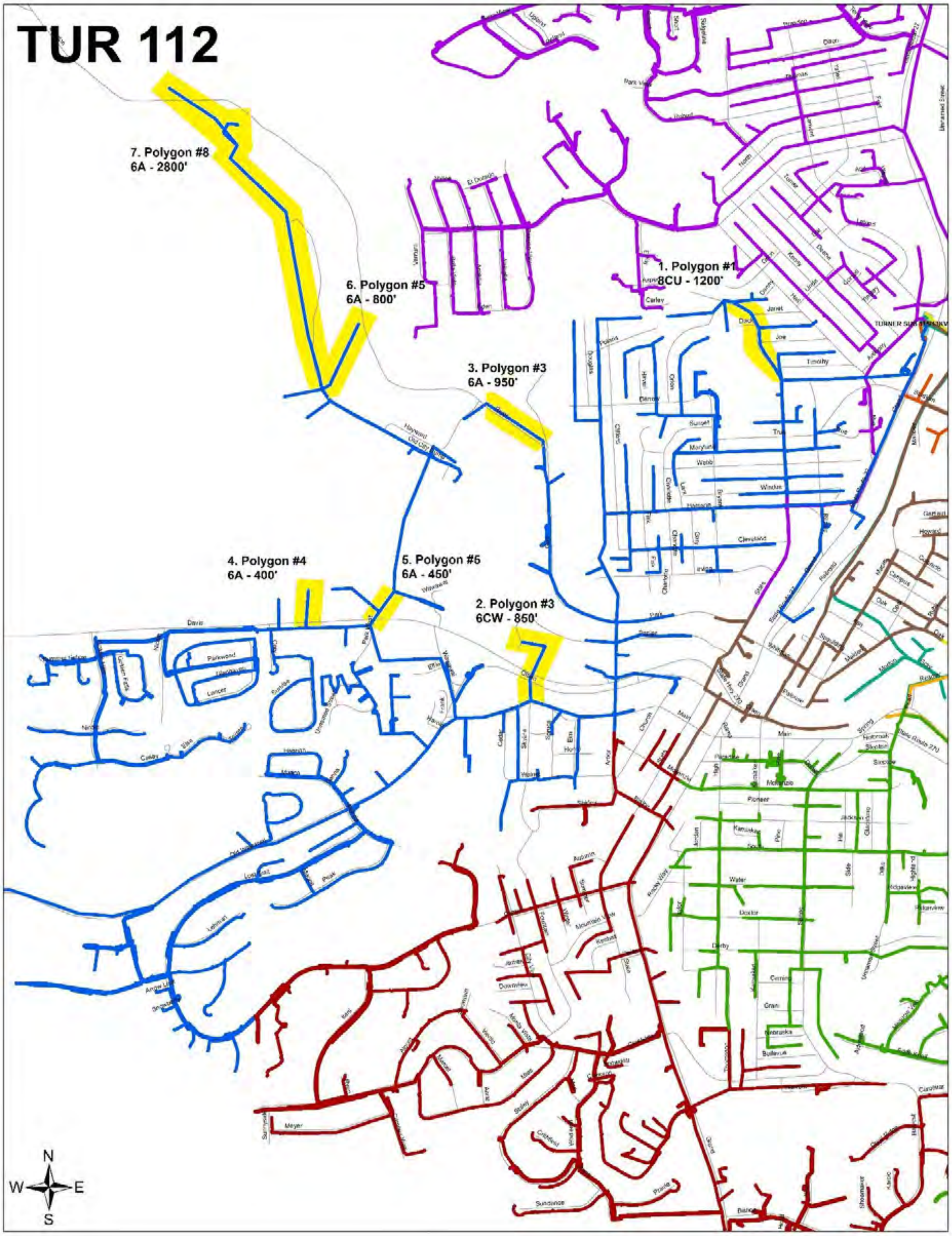

Figure 8. Laterals Requiring Field Analysis for Reconductoring to 4ACSR

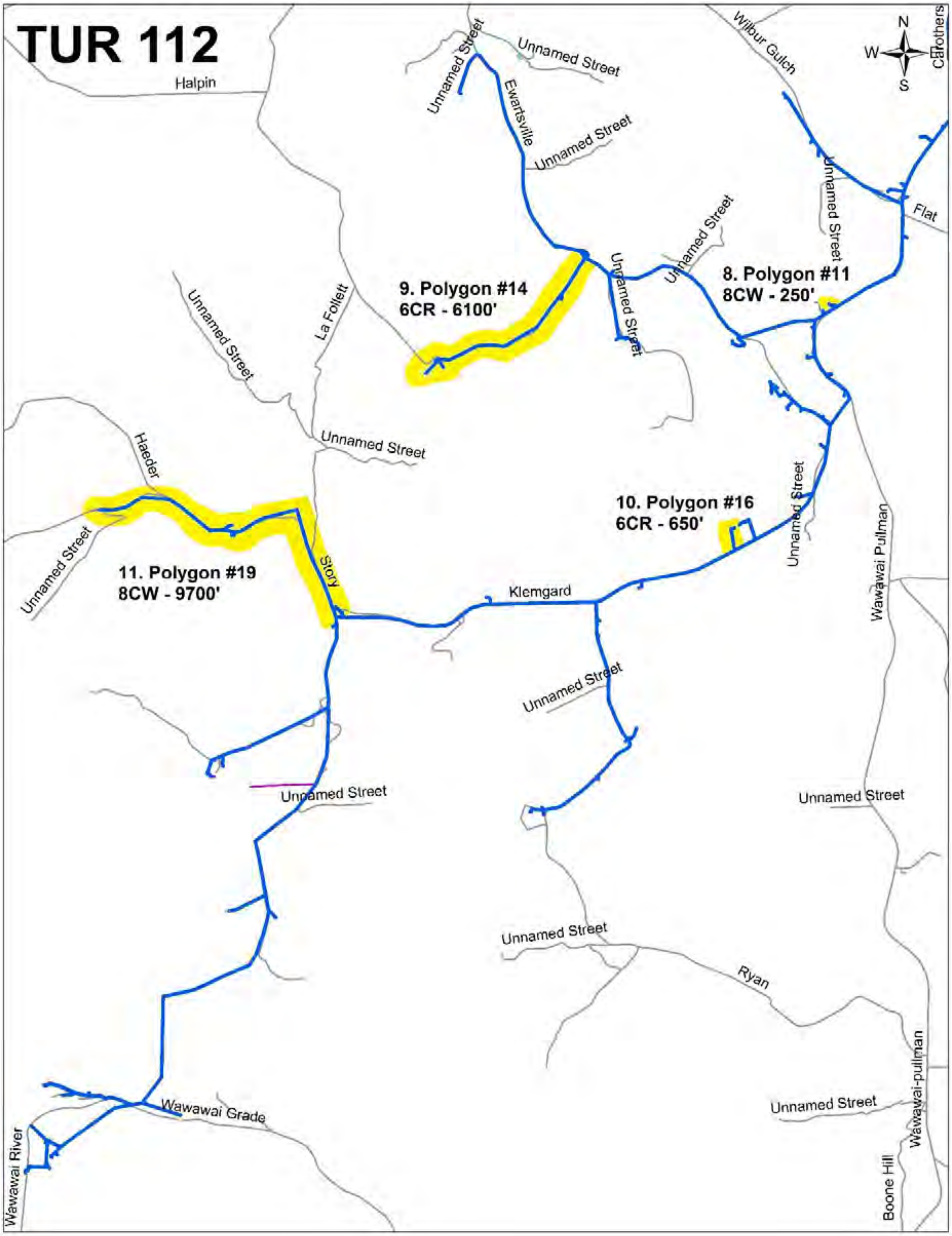

Figure 9. Laterals Requiring Field Analysis for Reconductoring to 4ACSR

Figure 10. Laterals Reconfiguration in Polygons 3 and 5

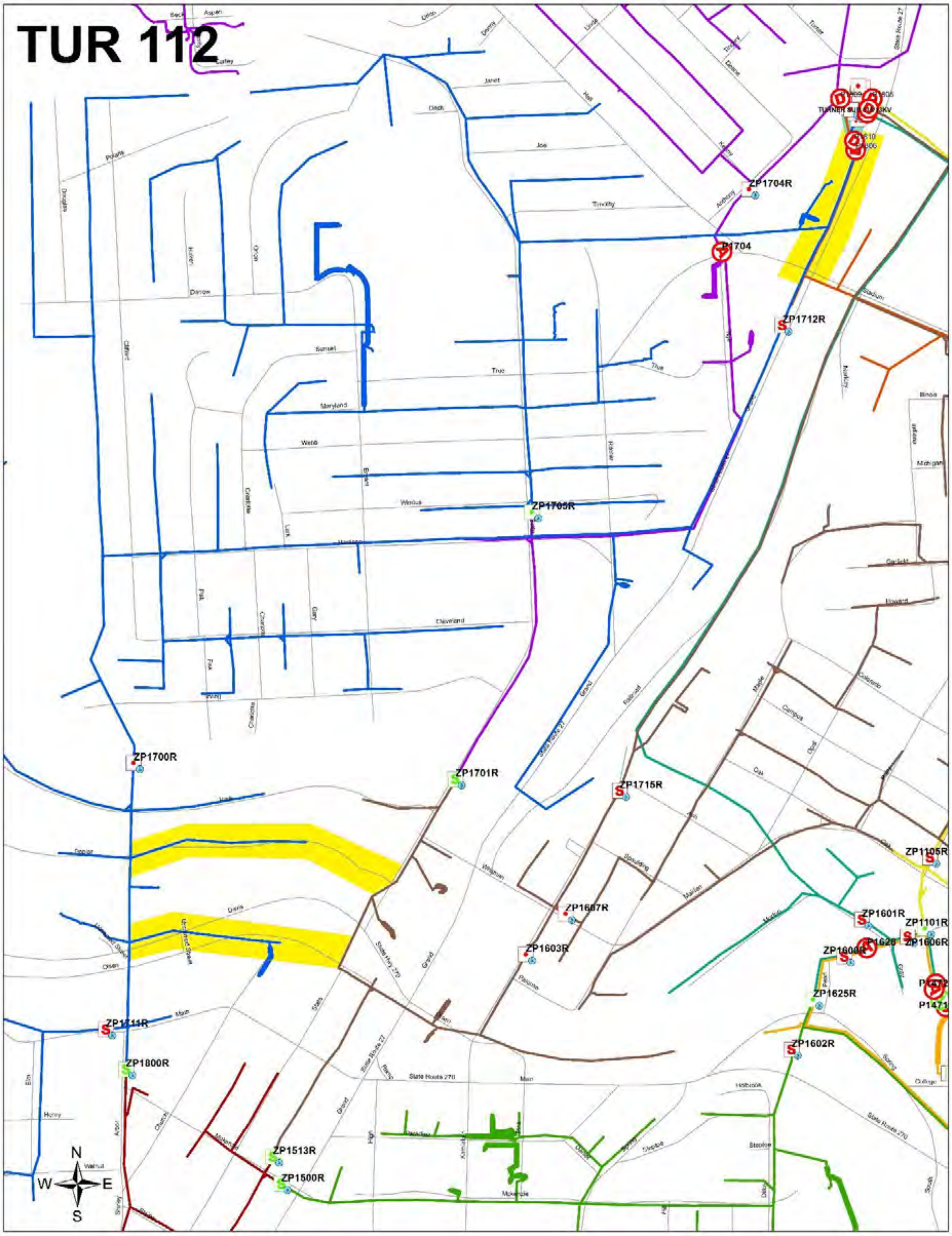

Figure 11. Proposed Opportunities for Creating New Feeder Ties

Voltage Quality

The loading on TUR 112 was first balanced between phases to eliminate the unnecessary overloading of phases which may exacerbate voltage quality problems. TUR 112 needed to be effectively balanced at numerous switching and sectionalzing points on the feeder. These proposals were previously outlined in the *Feeder Balancing* section of this report. TUR 112 was then analyzed to identify if there were any sections of the feeder where the service voltage level fell outside of the allowable operating limits. The feeder was modeled in SynerGEE during both peak loading and median loading conditions.

Modeled Voltage Levels at Peak Loading

The voltage levels on the feeder were first analyzed prior to performing any changes or improvements to TUR 112. During peak loading conditions, voltage levels nearest to the Turner Substation (east of the trunk on Charlotte St), were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 125.5V. Figure 12 identifies the sections on TUR 112 with relatively high voltage levels. Voltage levels west of that point through the predominately underground sections of the feeder and further west to the Chambers turnoff were within the optimal range. Voltage levels southwest of the Klemgard & Ewartsville intersection were very low, with sections towards the end of the feed modeled as low as 111.6V. Figure 13 identifies the sections on TUR 112 with low voltage levels that fall outside of the allowable limits.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	49	7.71	214	19
114.00 - 116.00 V	30	4.66	97	11
116.00 - 118.00 V	74	9.70	229	42
118.00 - 120.00 V	51	5.72	642	173
120.00 - 122.00 V	314	20.63	2912	785
122.00 - 124.00 V	330	11.61	3562	1203
124.00 - 126.00 V	2	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

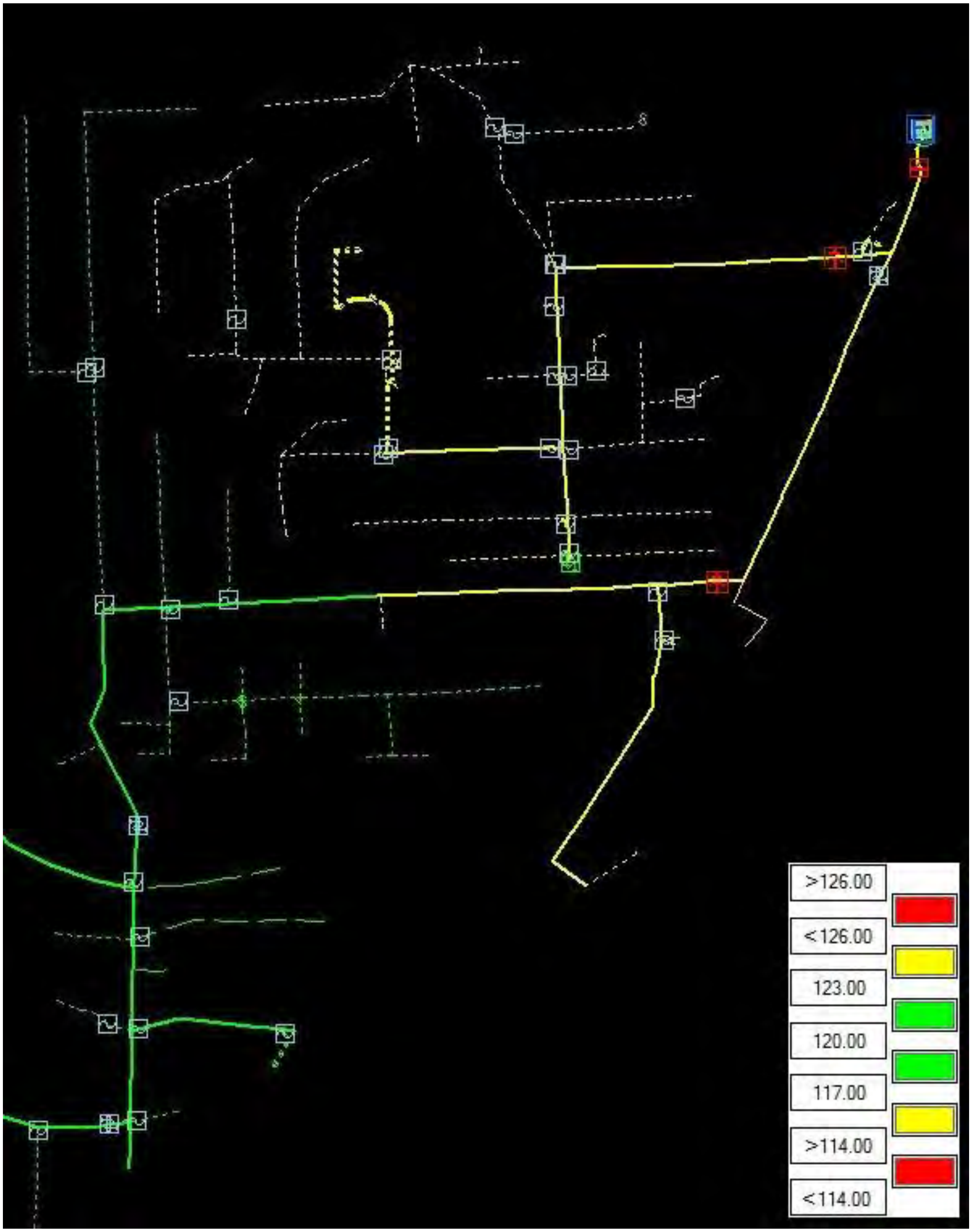

Figure 12. High Voltage Levels Modeled at Peak Loading

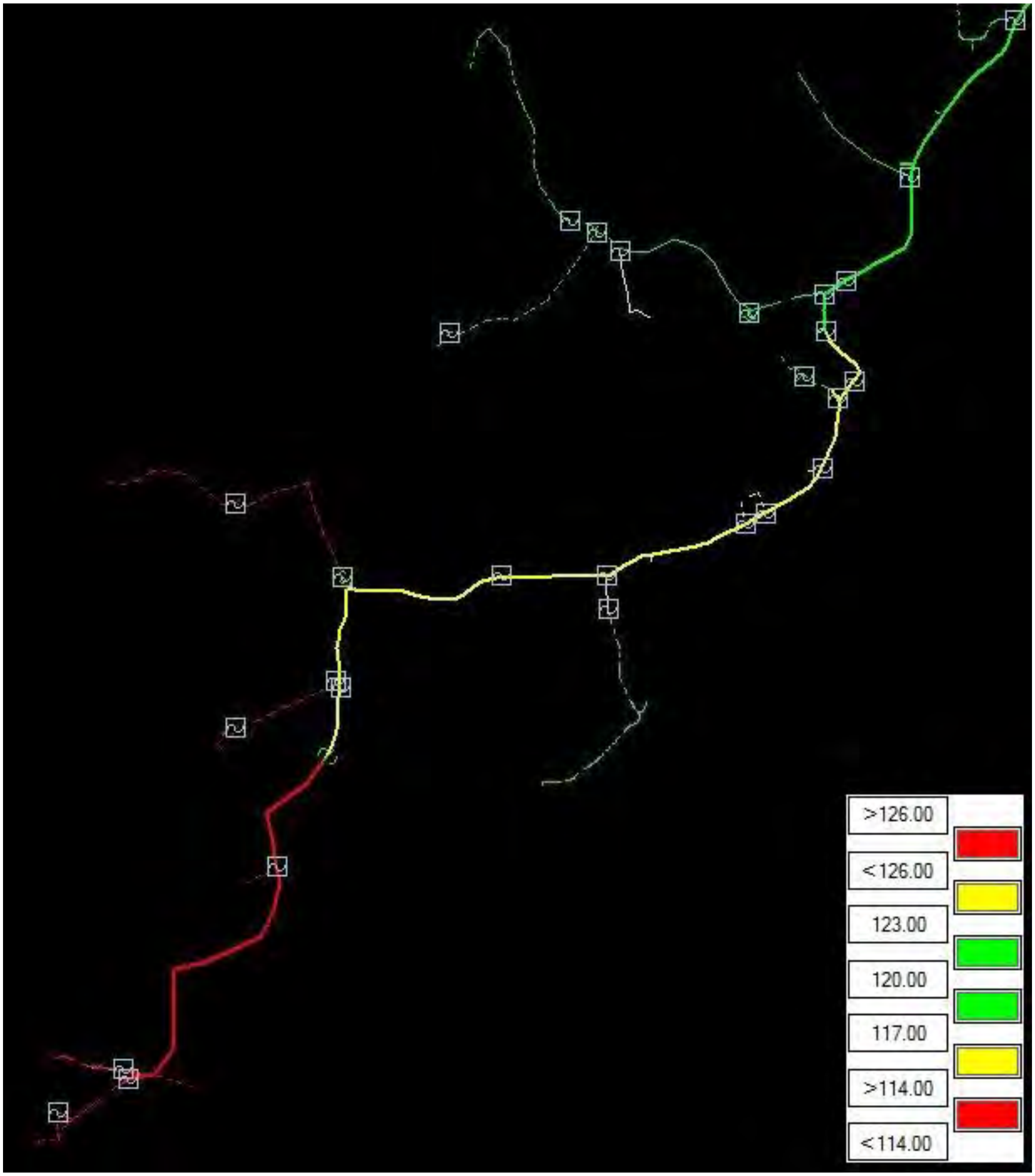

Figure 13. Low Voltage Levels Modeled at Peak Loading

Modeled Voltage Levels at Median Loading

The voltage levels on the feeder were again analyzed after balancing load, however this time during median loading conditions. This scenario saw more optimal voltage levels across the entire feeder. Voltage levels near the Turner Substation (east of the trunk on Charlotte St), generally range from 121.0 V to 121.5V. The maximum voltage modeled on the feeder occurred near the substation at approximately 121.5V. Voltage levels throughout the predominately underground sections of the feeder ranged consistently around 120V. Voltage levels downstream of the midline voltage regulators near the ZP1803R device again were consistently between 118.4V and 122.0V. The lowest voltages occurred at the farthest southwest laterals on the feeder, ranging from 116.5V to 116.8V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	48	6.83	89	19
118.00 - 120.00 V	123	14.99	348	195
120.00 - 122.00 V	672	38.07	2632	2015
122.00 - 124.00 V	5	0.13	25	4
124.00 - 126.00 V	2	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

The voltage levels on TUR 112 were re-analyzed after the trunk and lateral reconductoring and other improvements were performed. The feeder was modeled with these proposals in SynerGEE during both peak loading and median loading conditions.

Modeled Voltage Levels at Peak Loading after Proposals

During peak loading conditions, voltage levels nearest to the Turner Substation (east of the trunk on Charlotte St), were slightly elevated however they were still acceptable. The maximum voltage modeled on the feeder occurred near the substation at approximately 123.9V. Figure 14 identifies the sections on TUR 112 with relatively high voltage levels. Voltage levels west of Clifford and through the predominately underground sections of the feeder were within the optimal range. Voltage levels southwest of the Klemgard & Ryan intersection were very low, with sections towards the end of the feed modeled as low as 112.4V. Figure 15 identifies the sections on TUR 112 with low voltage levels that fall outside of the allowable limits.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	24	3.27	133	10
114.00 - 116.00 V	25	4.44	86	8
116.00 - 118.00 V	28	4.57	90	10
118.00 - 120.00 V	80	9.93	253	44
120.00 - 122.00 V	276	21.31	2996	815
122.00 - 124.00 V	416	16.49	4143	1345
124.00 - 126.00 V	2	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

Modeled Voltage Levels at Median Loading after Proposals

The voltage levels on the feeder were again analyzed after balancing load, however this time during median loading conditions. This scenario very optimal voltage levels across the entire feeder. Voltage levels near the Turner Substation (east of the trunk on Charlotte St), generally range from 120.8 V to 121.5V. The maximum voltage modeled on the feeder occurred near the substation at approximately 121.5V. Voltage levels throughout the predominately underground sections of the feeder ranged consistently around 120V. Voltage levels downstream of the midline voltage regulators near the ZP1803R device again were consistently between 121.0 and 122.1V. The lowest voltages occurred at the farthest southwest laterals on the feeder, ranging from 117.6V to 118.0V.

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	0	0.00	0	0
114.00 - 116.00 V	0	0.00	0	0
116.00 - 118.00 V	11	1.49	58	7
118.00 - 120.00 V	102	13.60	303	177
120.00 - 122.00 V	730	44.50	2738	2042
122.00 - 124.00 V	6	0.41	10	6
124.00 - 126.00 V	2	0.01	0	0
126.00 - 140.00 V	0	0.00	0	0

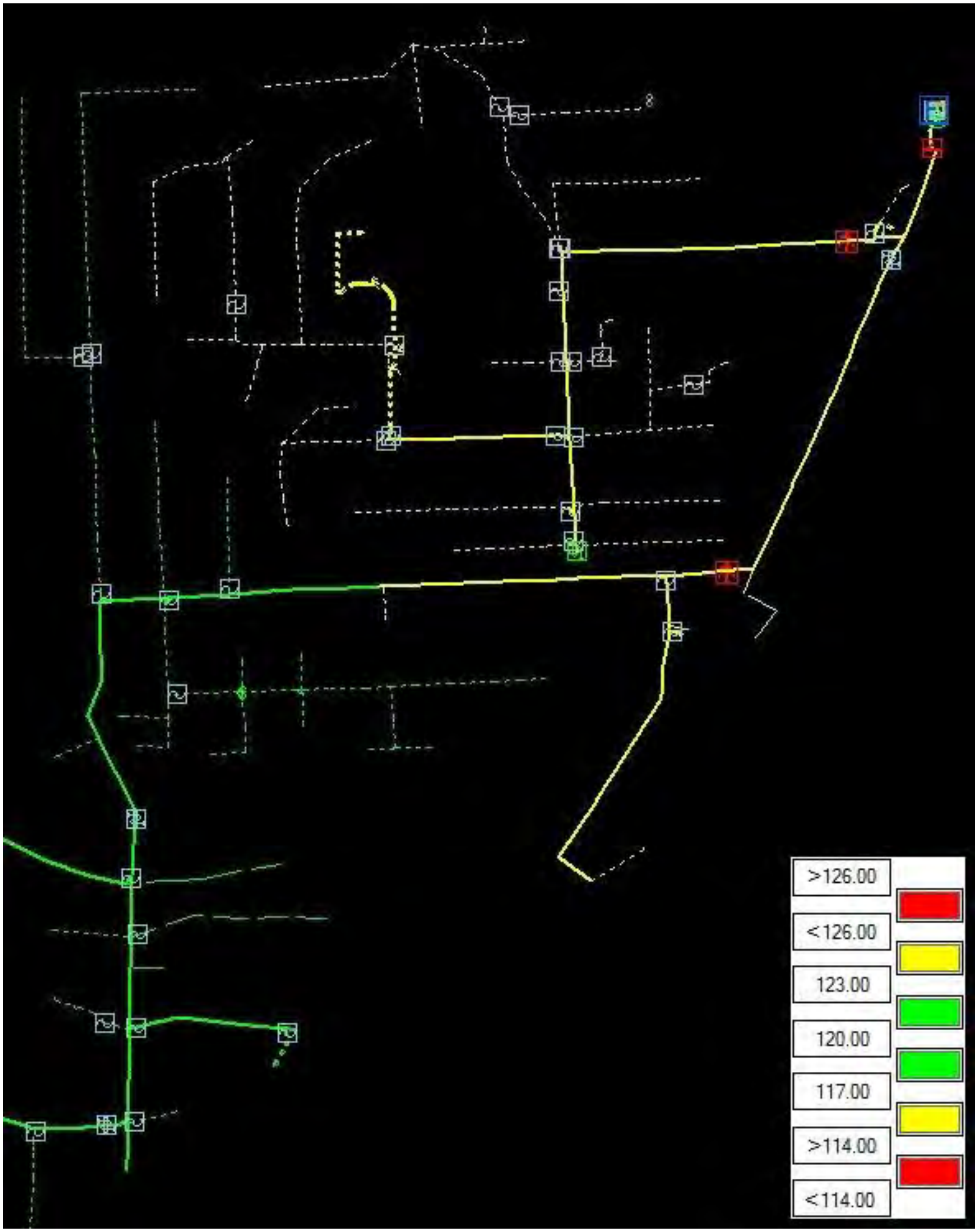

Figure 14. High Voltage Levels Modeled at Peak Loading

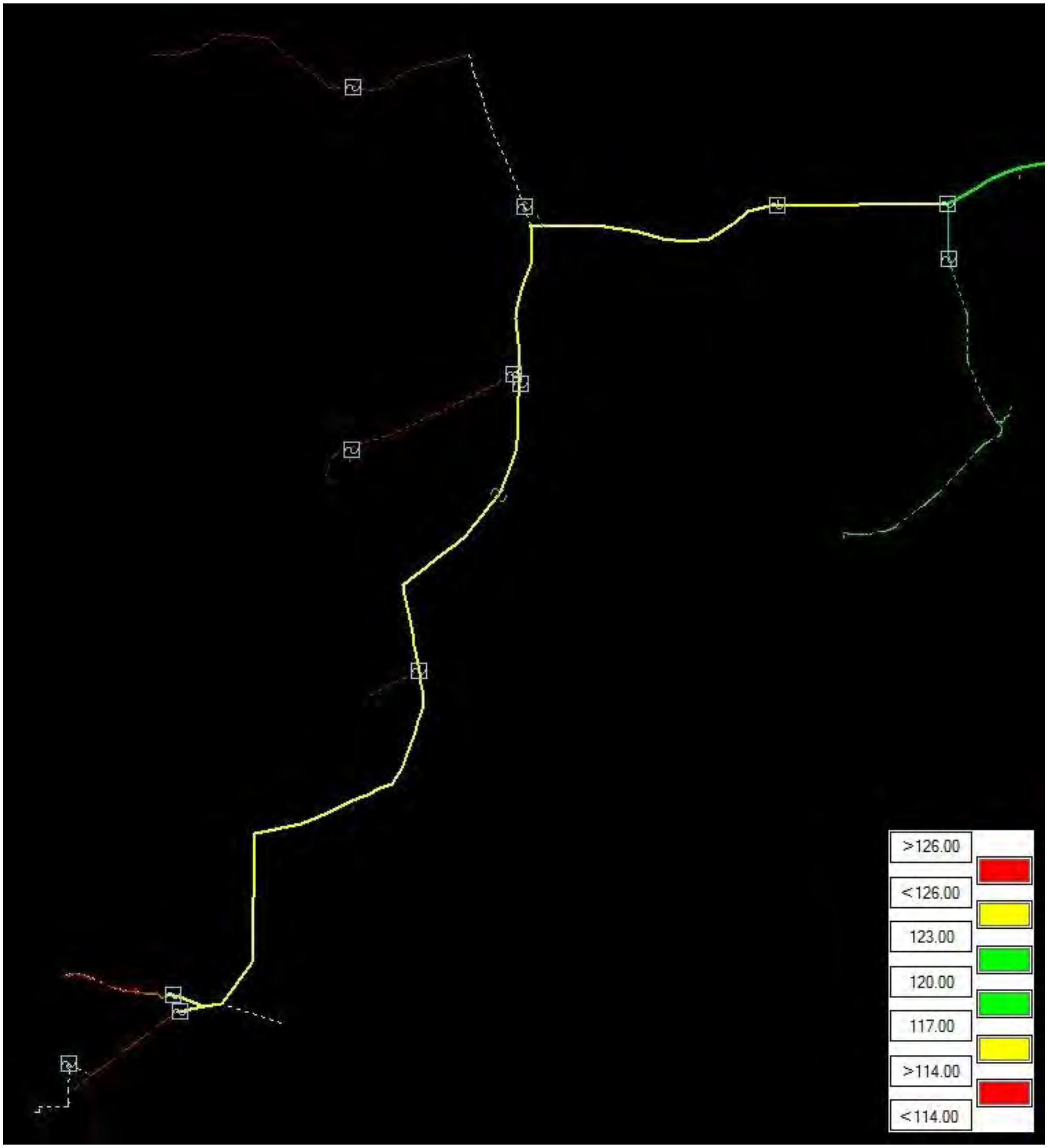

Figure 15. Low Voltage Levels Modeled at Peak Loading

Voltage Regulator Settings

TUR 112 has two existing stages of voltage regulation: one at the Turner Substation, and another set of midline regulators currently west of the ZP1803R. Due to the reconductoring being performed on the feeder, the ZP1803R device and midline regulators shall be moved just west of US Highway 195 on the primary feeder trunk along Old Wawawai Road in **Polygon 9**. In addition, the relocation of the midline voltage regulator and the substantial primary trunk reconductoring throughout the feeder warrant the analysis of the voltage regulator settings to determine the most appropriate settings for the future configuration and feeder characteristics. The existing and proposed voltage regulator settings are provided in the table below:

	Existing*		**Proposed**	
Forward Settings	**R**	**X**	**R**	**X**
TUR 112 Station Regulators	**4.0**	**2.0**	**2.8**	**9.8**
TUR 112 #ZP1508V Midline Regulators	**2.4**	**0.6**	**6.0**	**2.4**

* Settings in METS and SynerGEE as of 2/11/16

It has been confirmed through the Substation Engineering department that TUR 112 is currently equipped with automation compatible voltage regulators and breaker recloser in the substation to provide the ability for future FDIR and IVVC capabilities.

The decision to adopt and change the proposed voltage regulator settings will be determined and coordinated by the Regional Operations Engineer.

Fuse Sizing

Fuse sizing on TUR 112 shall be verified and incorporated by the Designer into all designs associated with Grid Modernization. This includes fusing for feeder trunk, laterals, and risers. Fuse recommendations for TUR 112 were created by the Grid Modernization Program Engineer and verified by the Regional Operations Engineer. The Designer shall incorporate the recommendations from the fuse size map into their polygon designs, as well as reference the current Distribution Construction and Material Standards and Distribution Feeder Management Plan for specific parameters regarding fuse and cutout application and replacement. The Designer shall consult either the Grid Modernization Program Engineer or Regional Operations Engineer with any questions regarding fuse sizing and coordination.

There may be situations where the transformers sizes on a lateral are resized to more accurately reflect customer loads, or the feeder is physically reconfigured. If there are significant changes to the overall connected kVA on a lateral, the Designer shall consult the Grid Modernization Program Engineer or Regional Operations Engineer to verify that the proposed lateral fuse is sized accurately for the load on the lateral and to coordinate with the transformer fuse(s).

Line Losses

The primary trunk conductors on TUR 112 have been sized appropriately to meet peak loading conditions, minimize line losses at peak and median loading conditions during normal system configuration, and improve voltage levels on the rural feeder. Line losses on the feeder were first addressed by balancing the load on the phases between numerous strategic locations on the feeder to eliminate the unnecessary overloading of phases that may worsen line losses caused by loading.

After the proposed reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections are performed on TUR 112, it is estimated that the peak line losses could approximately be reduced by up to 44.3 kW, while the median loading line losses could approximately be reduced by up to 16.0 kW. In addition, up to 140.1 MWh savings could be annually achieved assuming median loading conditions during normal system configuration.

	Polygon 4	**Polygons 7 & 8**	**Polygon 9**	**Total**
Circuit Length (ft)	1743.7	8430.6	7919.2	18093.5
Current Median kW Losses	4.1	11.6	4.0	19.7
Current Peak kW Losses	14.8	29.9	12.9	57.6
Proposed Median kW Losses	1.3	1.3	1.1	3.7
Proposed Peak kW Losses	4.9	4.0	4.4	13.3
Median kW Loss Savings	2.8	10.3	2.9	16.0
Peak kW Loss Savings	9.9	25.9	8.5	44.3
Reconductor MWh Savings *	24.5	90.2	25.4	140.1

* Estimated median kW losses over one year span

An initial SyngerGEE load study estimates that a total of 170 kW in peak line losses currently exists on TUR 112 (2.26%). After balancing the load on the feeder, and performing the reconductoring described in the *Trunk, Feeder Tie, and Lateral* sections, it is estimated that peak line losses can be improved from 170 kW (2.26%) to approximately 116 kW (1.57%).

Peak Values	**Existing**	**After Balancing**	**After Trunk Reconductor**
kW Demand	7821	7823	7819
kW Load	7644	7657	7697
kW Line Losses	170	161	116
kW Loss %	2.26 %	2.14 %	1.57 %

Transformer No Load Losses

The review of historically purchased transformers illustrate that transformer core losses generally increase as the kVA rating of the transformer increases. The losses also tend to improve over the years as technology and core materials become more advanced and efficient. Consequently, No Load Losses are generally lower on newer units compared to a transformer of the same size from an older vintage. No Load Losses can therefore be minimized through the replacement of older transformer to newer units of a more appropriate size.

All transformers on TUR 112 shall be analyzed and “right sized” by the assigned Designer to most accurately reflect the customer loads. In addition, some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department for incorporation by the Designer.

The roughly 444 distribution transformers on TUR 112 were individually analyzed to determine if the units are sized correctly to serve the connected loads. Flicker and voltage drop analysis shall be performed by the assigned Designer on each transformer in determining the most appropriate transformer size. It was determined that 260 transformers will require replacement based on right sizing and the TCOP criteria replacements. The replacement of these transformers will result in an estimated 10.58 kW reduction in No Load Losses. This equates to an annual savings of roughly 92.68 MWh. Additional loss savings can be captured by identifying and removing transformers that are found to be idle by the Designer.

Power Factor

MVAR and MW data at the TUR 112 substation circuit breaker was analyzed from 9/15/13 to 9/14/15. It was determined that a 600 kVAR switched capacitor bank (ZP2010F) was out of service from 5/1/2014 until 2/1/2016. It was determined that TUR 112 had a lagging power factor 59.2% of the time and a 40.8% leading power factor of the time during the time interval analyzed. Detailed power factor information is available upon request. Some key power factor figures for TUR 112 are provided in the tables below.

Maximum Lagging Power Factor	99.99 %
Minimum Lagging Power Factor	89.66 %
Maximum Leading Power Factor	99.99 %
Minimum Leading Power Factor	92.63 %

The graph in Figure 16 shows the percent of time during the interval analyzed where the power factor on TUR 112 fell between the applicable ranges. This information is also provided in a table format.

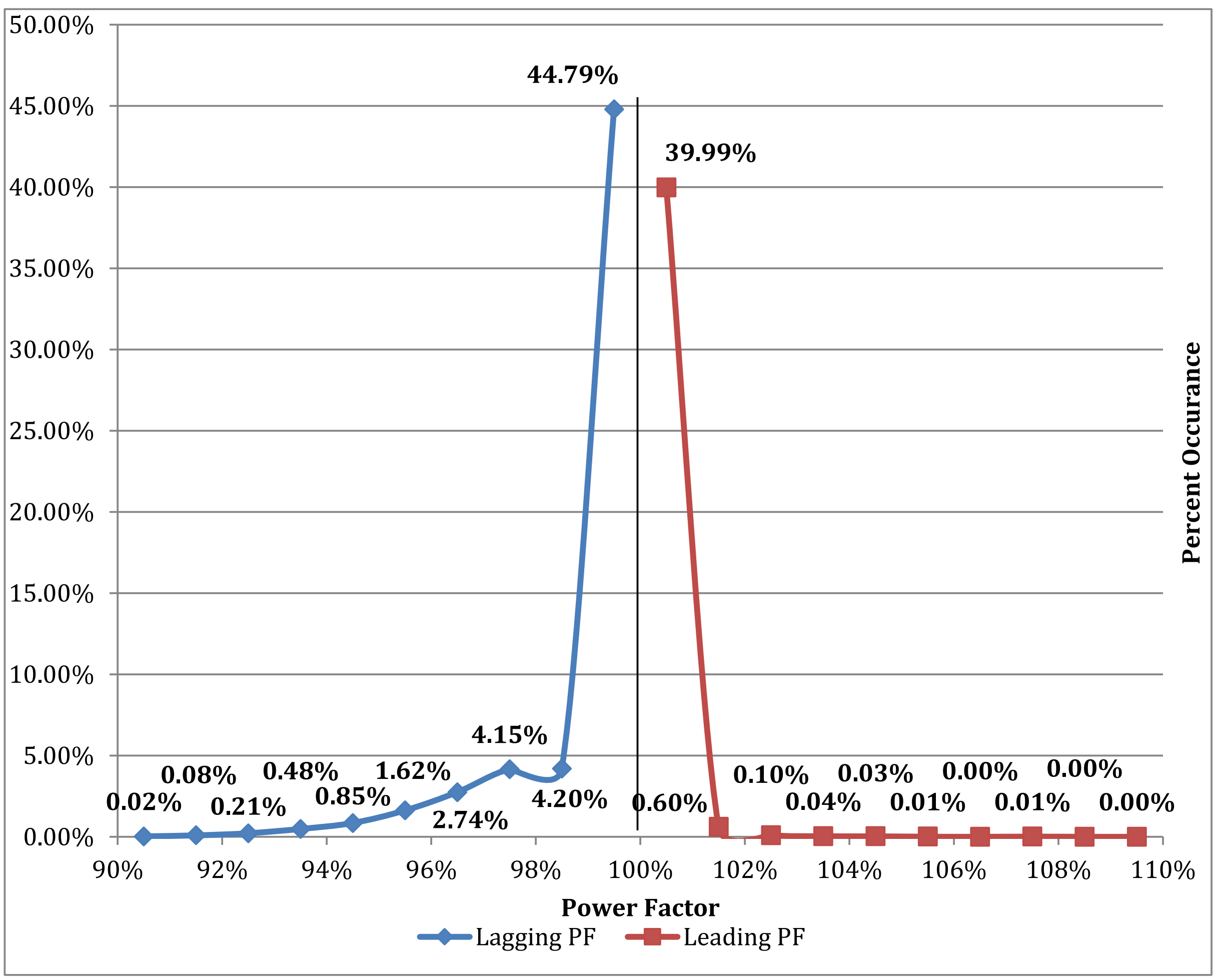

Figure 16. Existing Percent Occurance of Power Factor

	Lagging	Leading
Less than 90%	0.00%	0.00%
90%-91%	0.02%	0.00%
91%-92%	0.08%	0.00%
92%-93%	0.21%	0.01%
93%-94%	0.48%	0.00%
94%-95%	0.85%	0.01%
95%-96%	1.62%	0.03%
96%-97%	2.75%	0.04%
97%-98%	4.15%	0.10%
98%-99%	4.20%	0.60%
99%-100%	44.82%	40.02%

Power Factor Correction

There are four existing capacitor banks on TUR 112 ranging in size from 300 kVAR to 600 kVAR. The actual MW and MVAR data was reanalyzed with a variable MVAR to adjust the resulting power factor. This exercise allowed the ideal amount of capacitance to be modeled on the circuit for the inductive loads to optimize the power factor at variable times.

Numerous scenarios were modeled with the addition and subtraction of capacitance to determine if improvements could be made to the feeder's power factor. It was determined that the power factor on TUR 112 was currently inside the generally accepted optimal range during the period analyzed. This monitored range occurred during the time that a 600 kVAR switched capacitor bank (ZP2010F) was out of service from 5/1/2014 until 2/1/2016. Therefore, the data suggests that TUR 112 has a potential occurrence of 600 kVAR of excess capacitors currently installed on the feeder with the four fixed capacitor banks. In discussion with the Regional Operations Engineer, it was decided to leave the existing amount of switched capacitance on the circuit. In addition, there was agreement to remove a 3-bushing style 600 kVAR fixed capacitor bank east of Hwy 195 & Old Wawawai.and replace it with a 600 kVAR switched capacitor bank (ZP2031F, N.C.) in the same location.

Automation

Distribution Automation was analyzed for deployment on TUR 112 as part of the Grid Modernization program. A customized solution for the feeder has been created with assistance from the Regional Operations Engineer to address the specific characteristics and issues associated with the load, customers, and geography on TUR 112.

TUR 112 currently contains numerous automated distribution line devices from the work performed during the Smart Grid Demonstration Project (SGDP). Two of the previously installed distribution line automation devices will be relocated on TUR 112 due to the system improvements being implemented by Grid Modernization:

- Relocate Viper recloser (ZP1803R, N.C.) device from Polygon 8 at Old Wawawai Rd & Golden Hills Drive to just west of US Highway 195 on the primary feeder trunk along Old Wawawai Road in **Polygon 9**.
- Relocate midline voltage regulator (ZP1508V, N.C.) device from Polygon 8 at Old Wawawai Rd & Golden Hills Drive to just west of US Highway 195 on the primary feeder trunk along Old Wawawai Road in in **Polygon 9**.

The following automation devices will be deployed or relocated on the feeder:

Device Number	Location	Status	Device Type
ZP1803R *	W of US Hwy 195 & Old Wawawai	N.C.	Viper – Recloser
ZP1508V*	W of US Hwy 195 & Old Wawawai	N.C.	Midline Voltage Regulator
ZP2031F	E of US Hwy 195 & Old Wawawai	N.C.	Switched 600 kVAR Cap Bank

* Existing automation device that is being relocated

Figure 17 illustrates the proposed automation device locations on TUR 112.

TUR 112 is distribution automation ready at the Turner Substation with the breakers, relaying, regulators, communications, and EMS/DMS ready.

The proposed automation line device locations identified by the Grid Modernization Program Engineer are the preferred approximate location(s). The final location(s) may require minor adjustments based on the conditions discovered in the field by the Designer. The assigned Designer is responsible for verifying the proposed automation device location(s) in the field, as well as submitting their field assessment and design(s) to the Grid Modernization Program Engineer for approval. In addition the assigned Designer is responsible for then reviewing their proposed automation design(s) with either the Regional Operations Engineer, General Foreman, or District Manager to address any construction or Standards related concerns with the selected location.

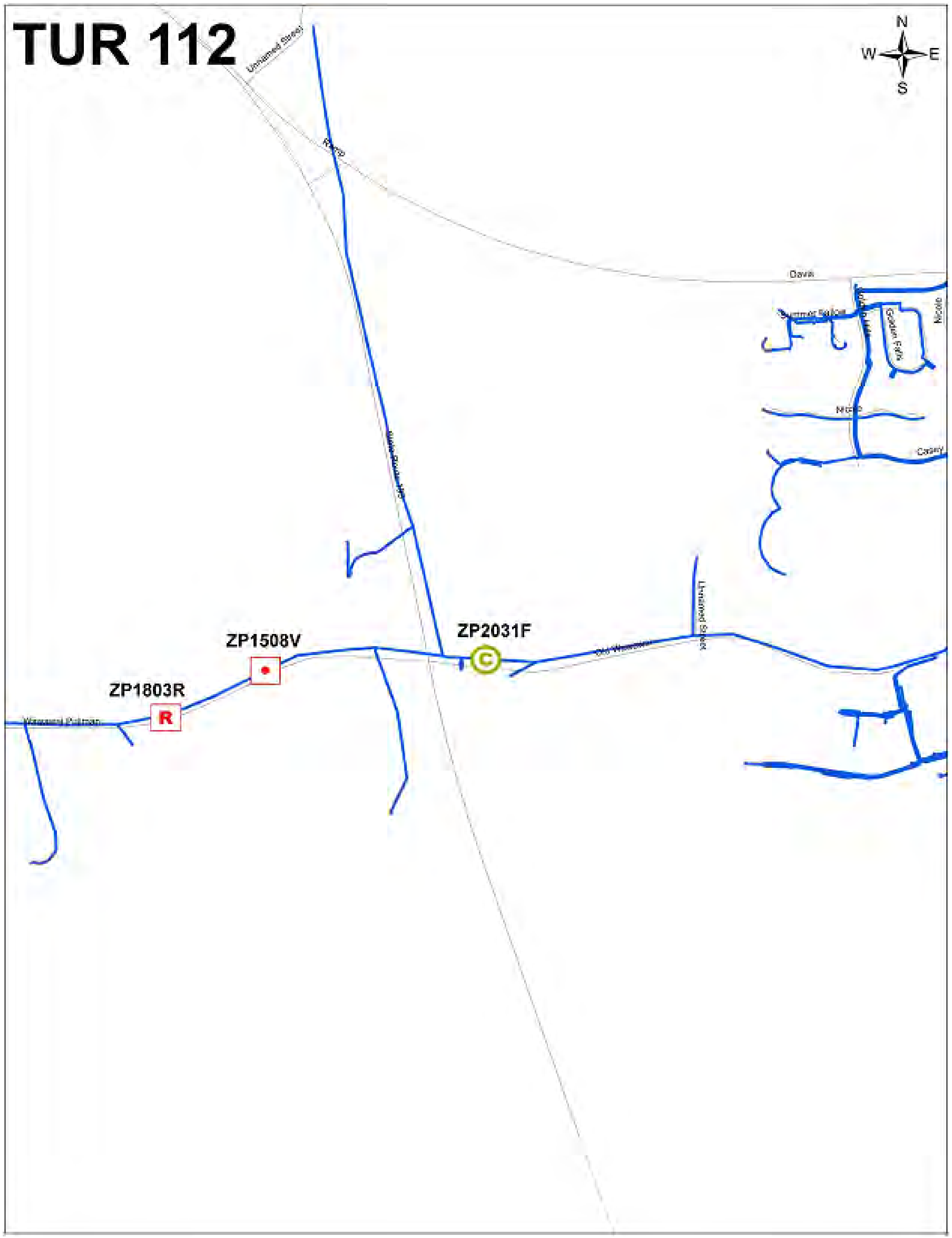

Figure 17. TUR 112 Proposed Automation Device Locations

Open Wire Secondary

Open wire secondary districts have been analyzed for replacement on TUR 112 in accordance to the Distribution Feeder Management Plan (DFMP). Multiple districts were identified to exist on TUR 112. The designers shall consult the DFMP if open wire secondary districts are present in their assigned polygons. This document will provide detailed information and guidance for replacing open wire secondary districts. Any design questions associated with open wire secondary districts should be directed to the Grid Modernization Program Engineer to provide direction on removal and replacement. Figure 18 identifies the open wire secondary districts that were discovered for analysis or removal.

- **Polygon 1 –** remove 625' of vertical open wire secondary that is inaccessible between Timothy & Joe.
- **Polygon 1 –** further analyze whether to replace 1500' of vertical open wire due to alley accessibility between Webb & Windus.
- **Polygon 1 –** further analyze whether to replace 1500' of vertical open wire due to the physical condition and roadside accessibility along Windus.
- **Polygon 1 –** remove 1500' of vertical open wire secondary that is inaccessible between Orion & Clifford, north of Darrow.
- **Polygon 2 –** remove 850' of vertical open wire secondary that is inaccessible north of Polaris & Clifford.
- **Polygon 2 –** remove 950' of vertical open wire secondary that is inaccessible west of Polaris & Douglas.
- **Polygon 2 –** remove 900' of vertical open wire secondary that is inaccessible west of Clifford.
- **Polygon 2 –** remove 400' of vertical open wire secondary that is inaccessible between Fisk & Clifford, north of Cleveland.
- **Polygon 3 –** remove 650' of vertical open wire secondary that is inaccessible along Park, west of State.
- **Polygon 3 –** remove 700' of vertical open wire secondary that is inaccessible south of Walnut & Elm.

Figure 18. Open Wire Secondary Districts on TUR 112

Transformers

All transformers on TUR 112 shall be identified by the assigned Designer for removal, installation, or replacement. Some transformers will be identified for replacement by the Transformer Change-Out Program (TCOP) based on the vintage and PCB level of the unit. An explicit list will be provided for the units identified by the Asset Maintenance department. However all transformers shall be analyzed and sized accordingly by the Designer to most accurately reflect customer loads. The Designer shall consult the *Transformer* section of the Distribution Feeder Management Plan for specific parameters regarding transformers for the Grid Modernization program.

Poles

All poles and structures on TUR 112 shall be examined by the assigned Designer(s) for removal, installation, replacement, or reinforcement. Some poles will be identified for replacement or stubbing by the Asset Maintenance department based on the tested condition of the structure, however the final decision to replace a pole will reside with the Designer. An explicit list of poles will be provided and identified by WPM. The Designer shall consult the *Wood Pole* section of the Distribution Feeder Management Plan document for specific parameters regarding poles and the attached components.

Underground Facilities

Underground cable, padmount equipment, and submersible equipment shall be assessed by the assigned Designer(s) for damage, removal, or replacement. The Designer(s) shall consult the *Underground* section in the Distribution Feeder Management Plan document for specific parameters regarding transformers for the Grid Modernization program.

The URD Cable Program was designed to programmatically replace aging underground primary distribution cable that is susceptible to faulting. Data suggests that outage problems typically exist on cable installed before 1982 due to the neutral conductor consisting of tinned bare copper wires that may corrode when damaged - allowing water migration into the insulation. Cable installed after 1982 has not shown the same high failure rate of the pre-1982 cable.

Tree Trimming

Vegetation management shall be employed on TUR 112 where applicable. This will include along easements where feeder reconductoring is being performed and where appropriate clearances need to be reestablished. The Designer for each polygon is responsible for coordinating any tree trimming on their respective polygons with Avista's Vegetation Management department. A methodical trimming scheduled developed by the Designer(s) that encompasses all assigned polygons is strongly recommended to maximize efficiency and reduce travel costs for the allotted budget for the feeder.

Design Polygons

TUR 112 has been divided into 23 polygons for the Grid Modernization project work. Feeders are divided into polygons for the Grid Modernization project work as a means to name and clearly identify a section of the feeder. The polygon concept provides additional benefits in scheduling, tracking, and budgeting the work on a feeder, as well as to divide the construction work into near equivalent segments in regards to design and crew time.

For rural feeders, fewer polygons will initially be created to allow the Designer greater flexibility for coordinating their work. Rural polygons boundaries will primarily be established by the location of existing laterals off of the primary trunk. The primary trunk will initially be divided into separate polygon numbers between the existing locations of two laterals that are longer than three spans. In addition, any rural lateral longer than three spans will be assigned its own polygon number. Any rural lateral that is three spans or shorter will be absorbed into the adjacent polygon number. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of a rural feeder.

The initial creation of polygon boundaries in urban environments will be subjective based on the greater presence of combined considerations such as: line devices, three-phase laterals, geography, road access, known proposals such as reconductoring, and the location of laterals, secondary districts, and underground risers. Additional considerations may also be included by the Grid Modernization Program Engineer based on the unique characteristics of an urban feeder.

Designers are not to change the boundaries of a defined polygon without prior approval from the Grid Modernization Program Engineer. If necessary, a polygon can be divided into subsets of the existing numbered polygon to better organize the work on the feeder. Designers should not create polygons with entirely new numbers.

All polygons will be initially created by the Grid Modernization Program Engineer. All polygons will be formally assigned to the Designers by the Grid Modernization Program Manager.

The Designer is responsible for routinely providing updated design estimate information for all their assigned polygons, as well as formally notifying the Program Engineer by email when each polygon design is completed for design review. Specific directions for accessing the polygons within AFM are located in the Distribution Feeder Management Plan.

The following polygon summary lists the identified items that shall be incorporated into the final job designs at a minimum:

- **Polygon 1**
  - Transfer 1Φ OH lateral north of State & Timothy (≈18A) from CΦ to BΦ.
  - Transfer 1Φ OH lateral south of State & Webb (≈11 A) from AΦ to BΦ.
  - Analyze the condition of the existing poles and wire on the 1200’ lateral of 8CU, 17A peak (20% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Remove 625’ of vertical open wire secondary that is inaccessible between Timothy & Joe.
  - Further analyze whether to replace 1500’ of vertical open wire due to alley accessibility between Webb & Windus.
  - Further analyze whether to replace 1500’ of vertical open wire due to the physical condition and roadside accessibility along Windus.
  - Remove 1500’ of vertical open wire secondary that is inaccessible between Orion & Clifford, north of Darrow.
- **Polygon 2**
  - Remove 850’ of vertical open wire secondary that is inaccessible north of Polaris & Clifford.
  - Remove 950’ of vertical open wire secondary that is inaccessible west of Polaris & Douglas.
  - Remove 900’ of vertical open wire secondary that is inaccessible west of Clifford.
  - Remove 400’ of vertical open wire secondary that is inaccessible between Fisk & Clifford, north of Cleveland.
- **Polygon 3**
  - Analyze the condition of the existing poles and wire on the 850’ lateral of 6CW, 2A peak (4% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 950’ lateral of 6A, 2A peak (2% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Remove 650’ of vertical open wire secondary that is inaccessible along Park, west of State.
  - Remove 700’ of vertical open wire secondary that is inaccessible south of Walnut & Elm.
  - Reconfigure the feed to the lateral in Polygon 5 by installing a two-phase 4ACSR primary extension in Polygon 3.
- **Polygon 4**
  - Transfer 1Φ URD lateral west of Golden Hills & Casey (≈15 A) from BΦ to CΦ.
  - Reconductor 3Φ trunk north of Main & Old Wawawai to 2/0ACSR with a 2/0 ACSR neutral (approximately 1700’)
  - Analyze the condition of the existing poles and wire on the 400’ lateral of 6A, 1A peak (1% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.

- **Polygon 5**
  - Analyze the condition of the existing poles and wire on the 450’ lateral of 6A, 8A peak (8% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 800’ lateral of 6A, 1A peak (1% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Analyze the condition of the existing poles and wire on the 2800’ lateral of 6A, 2A peak (2% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
  - Reconfigure the feed to the lateral in Polygon 5 from Polygon 3 in order to eliminate a large section of inaccessible line. This would include the removal of approximately 1600’ of two-phase 6CU overhead primary in Polygon 5.
- **Polygon 6**
  - Transfer 1Φ URD lateral north of Old Wawawai & Big Sky (≈15 A) from CΦ to BΦ.
- **Polygon 7**
  - Reconductor 3Φ trunk southwest of Main & Old Wawawai to 556 AAC with a 2/0 ACSR neutral (approximately 8430’).
- **Polygon 8**
  - Reconductor 3Φ trunk southwest of Main & Old Wawawai to 556 AAC with a 2/0 ACSR neutral (approximately 8430’).
  - Remove 600 kVAR fixed capacitor bank and install 600 kVAR switched capacitor bank (ZP2031F, N.C.) east of Hwy 195 & Old Wawawai.
- **Polygon 9**
  - Reconductor 3Φ trunk along Wawawai-Pullman between US Hwy 195 and Carothers Road to 2/0 ACSR with a 2/0 ACSR neutral (approximately 8000’)
  - Relocate Viper recloser (ZP1803R, N.C.) device from Polygon 8 at Old Wawawai Rd & Golden Hills Drive to just west of US Highway 195 on the primary feeder trunk along Old Wawawai Road.
  - Relocate midline voltage regulators (ZP1508V, N.C.) device from Polygon 8 at Old Wawawai Rd & Golden Hills Drive to just west of US Highway 195 on the primary feeder trunk along Old Wawawai Road.
- **Polygon 11**
  - Analyze the condition of the existing poles and wire on the 250’ lateral of 8CW, 1A peak (3% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 13**
  - Transfer 1Φ OH lateral northwest of Wawawai-Pullman & Klemgard (≈10 A) from BΦ to AΦ.
- **Polygon 14**
  - Analyze the condition of the existing poles and wire on the 6100’ lateral of 6CR, 2A peak (14% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.

- **Polygon 16**
  - Analyze the condition of the existing poles and wire on the 650' lateral of 6CR, 1A peak (8% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.
- **Polygon 17**
  - Transfer 1Φ OH lateral south of Klemgard & Ryan (≈6 A) from BΦ to AΦ.
- **Polygon 19**
  - Analyze the condition of the existing poles and wire on the 9700' lateral of 8CW, 4A peak (12% loaded) to determine if this lateral is a candidate for reconfiguration, OH reconductor, or URD conversion.

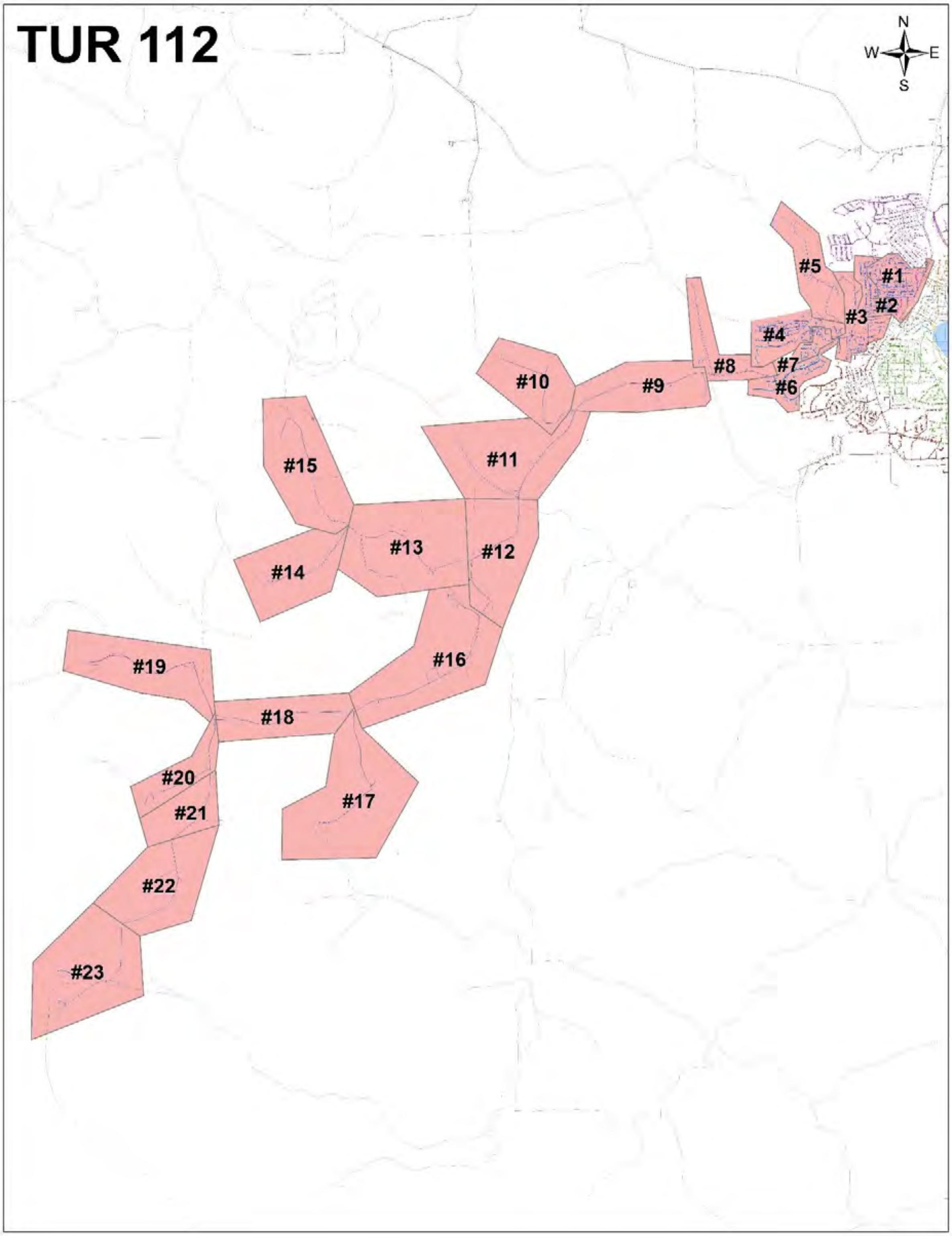

Figure 19. TUR 112 Polygon Numbers

Report Versions

Version 1 4/19/16 – Draft finalized for review by the South Regional Operations Engineers. This version of the report will require further verification of the voltage regulator settings, device numbers, and discussion of additional automation switches (either feeder tie or sectionalizing devices).

Version 2 5/8/16 – Received verification from the South Regional Operations Engineers on the proposed voltage regulator settings. Added a lateral reconfiguration recommendation for Polygons 3 and 5 shown in Figure 10. Information will be provided in the future by the South Regional Operations Engineers on the verification of the proposed fuse size recommendations, as well as the recommendation of the capacitors on the feeder based on new information on the ZP2010F device.